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(54) Title: METHOD OF CONTROLLING SOLVENT INJECTION TO AID RECOVERY OF HYDROCARBONS FROM AN UNDERGROUND RESERVOIR

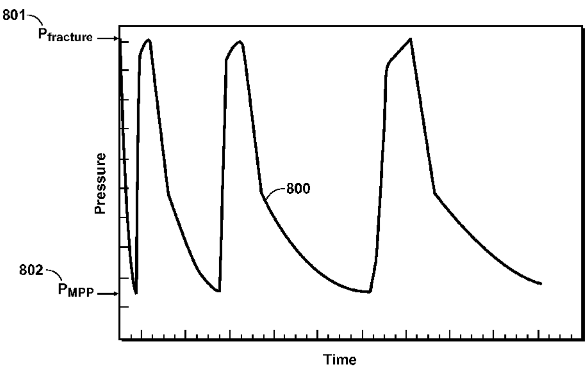

FIG. 8

(57) Abstract: A method of operating a cyclic solvent-dominated recovery process (CSDRP) for recovering viscous oil from a subterranean reservoir of the viscous oil. The cyclic solvent process involves using an injection well to inject a viscosity-reducing solvent into a subterranean viscous oil reservoir. Reduced viscosity oil is produced to the surface using the same well used to inject solvent. The process of alternately injecting solvent and producing a solvent/viscous oil blend through the same wellbore continues in a series of cycles until additional cycles are no longer economical. Aspects of the invention relate to the particular volume of solvent injected in each cycle, when to switch from production to injection, the injection pressure to be used, the production pressure to be used, and to middle and late life operation.

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METHOD OF CONTROLLING SOLVENT INJECTION TO AID RECOVERY OF HYDROCARBONS FROM AN UNDERGROUND RESERVOIR

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority from Canadian Patent Application 2,688,392 filed 9 December 2009 entitled METHOD OF CONTROLLING SOLVENT INJECTION TO AID RECOVERY OF HYDROCARBONS FROM AN UNDERGROUND RESERVOIR, the entirety of which is incorporated by reference herein.

FIELD OF THE INVENTION

[0002] The present invention relates generally to in-situ viscous recovery of hydrocarbons. More particularly, the present invention relates to the use of a cyclic solvent-dominated recovery process (CSDRP) to recover in-situ hydrocarbons including bitumen.

BACKGROUND OF THE INVENTION

[0003] At the present time, solvent-dominated recovery processes (SDRPs) are rarely used to produce highly viscous oil. Highly viscous oils are produced primarily using thermal methods in which heat, typically in the form of steam, is added to the reservoir. Cyclic solvent-dominated recovery processes (CSDRPs) are a subset of SDRPs. A CSDRP is typically, but not necessarily, a non-thermal recovery method that uses a solvent to mobilize viscous oil by cycles of injection and production. Solvent-dominated means that the injectant comprises greater than 50% by mass of solvent or that greater than 50% of the produced oil's viscosity reduction is obtained by chemical solvation rather than by thermal means. One possible laboratory method for roughly comparing the relative contribution of heat and dilution to the viscosity reduction obtained in a proposed oil recovery process is to compare the viscosity obtained by diluting an oil sample with a solvent to the viscosity reduction obtained by heating the sample.

[0004] In a CSDRP, a viscosity-reducing solvent is injected through a well into a subterranean viscous-oil reservoir, causing the pressure to increase. Next, the pressure is lowered and reduced-viscosity oil is produced to the surface through the same well through which the solvent was injected. Multiple cycles of injection and production are used. In some instances, a well may not undergo cycles of injection and production, but only cycles of injection or only cycles of production.

[0005] CSDRPs may be particularly attractive for thinner or lower-oil-saturation reservoirs. In such reservoirs, thermal methods utilizing heat to reduce viscous oil viscosity may be inefficient due to excessive heat loss to the overburden and/or underburden and/or reservoir with low oil content.

[0006] References describing specific CSDRPs include: Canadian Patent No. 2,349,234 (Lim et al.); G. B. Lim et al., "Three-dimensional Scaled Physical Modeling of Solvent Vapour Extraction of Cold Lake Bitumen", The Journal of Canadian Petroleum Technology, 35(4), pp. 32-40, April 1996; G. B. Lim et al., "Cyclic Stimulation of Cold Lake Oil Sand with Supercritical Ethane", SPE Paper 30298, 1995; US Patent No. 3,954,141 (Allen et al.); and M. Feali et al., "Feasibility Study of the Cyclic VAPEX Process for Low Permeable Carbonate Systems", International Petroleum Technology Conference Paper 12833, 2008.

[0007] The family of processes within the *Lim et al.* references describe embodiments of a particular SDRP that is also a cyclic solvent-dominated recovery process (CSDRP). These processes relate to the recovery of heavy oil and bitumen from subterranean reservoirs using cyclic injection of a solvent in the liquid state which vaporizes upon production. The family of processes within the *Lim et al.* references may be referred to as *CSP*^{TM} processes.

[0008] With reference to Figure 1, which is a simplified diagram based on Canadian Patent No. 2,349,234 (Lim et al.), one *CSP*^{TM} process embodiment is described as a single well method for cyclic solvent stimulation, the single well preferably having a horizontal wellbore portion and a perforated liner section. A vertical wellbore (1) driven through overburden (2) into reservoir (3) is connected to a horizontal wellbore portion (4). The horizontal wellbore portion (4) comprises a perforated liner section (5) and an inner bore (6). The horizontal wellbore portion comprises a downhole pump (7). In operation, solvent or viscosified solvent is driven down and diverted through the perforated liner section (5) where it percolates into reservoir (3) and penetrates reservoir material to yield a reservoir penetration zone (8). Oil dissolved in the solvent or viscosified solvent flows into the well and is pumped by downhole pump through an inner bore (6) through a motor at the wellhead (9) to a production tank (10) where oil and solvent are separated and the solvent is recycled.

SUMMARY OF THE INVENTION

[0009] Generally, embodiments of the instant invention relate to: the particular volume of solvent and non-solvent fluid injected in each cycle, the timing of the switch from production to injection, the injection pressure to be used, the production pressure to be used, and to middle and late life operation, all in a CSDRP.

[0010] In a first aspect, the present invention provides a method of controlling a cyclic solvent injection and production process to aid recovery of hydrocarbons from an underground reservoir, the method comprising: (a) injecting a volume of fluid comprising greater than 50 mass % of a viscosity-reducing solvent into an injection well completed in the underground reservoir; (b) halting injection into the injection well and subsequently producing at least a fraction of the solvent and the hydrocarbon from the reservoir through a production well; (c) halting production through the production well; and (d) subsequently repeating the cycle of steps (a) to (c); wherein, in at least one subsequent cycle, the *in situ* volume of fluid injected in step (a) is equal to a net *in situ* volume of fluids produced from the production well in an immediately preceding cycle plus an additional *in situ* volume of fluid.

[0011] Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

Fig. 1 is a schematic of a *CSP*™ process in accordance Canadian Patent No. 2,349,234 (Lim et al.);

Fig. 2 is a flow chart depicting a strategy for the operation of a CSDRP in accordance with a disclosed embodiment;

Figs. 3a, 3b, and 3c show flow charts depicting sub-schemes of the strategy shown in Fig. 2 in accordance with a disclosed embodiment;

Fig. 4 is a graph of pore volume versus pressure, illustrating dilation;

Fig. 5 is a flow chart depicting fracturing of the reservoir on injection in accordance with a disclosed embodiment;

Fig. 6 is a flow chart depicting certain CSDRP production steps in accordance with a disclosed embodiment;

Fig. 7 is a flow chart depicting recovery subsequent to a CSDRP in accordance with a disclosed embodiment; and

Fig. 8 is a chart showing bottom-hole pressure as a function of time based on reservoir simulation results.

DETAILED DESCRIPTION

[0013] The term "viscous oil" as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute (API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and bitumen are used interchangeably herein since they may be extracted using similar processes.

[0014] *In situ* is a Latin phrase for "in the place" and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. For example, *in situ* temperature means the temperature within the reservoir. In another usage, an *in situ* oil recovery technique is one that recovers oil from a reservoir within the earth.

[0015] The term "formation" as used herein refers to a subterranean body of rock that is distinct and continuous. The terms "reservoir" and "formation" may be used interchangeably.

[0016] During a CSDRP, a reservoir accommodates the injected solvent and non-solvent fluid by compressing the pore fluids and, more importantly in some embodiments, by dilating the reservoir pore space when sufficient injection pressure is applied. Pore dilation is a particularly effective mechanism for permitting solvent to enter into reservoirs filled with viscous oils when the reservoir comprises largely unconsolidated sand grains. Injected solvent fingers into the oil sands and mixes with the viscous oil to yield a reduced viscosity mixture with significantly higher mobility than the native viscous oil. Without intending to be bound by theory, the primary mixing mechanism is thought to be dispersive mixing, not diffusion. Preferably, injected fluid in each cycle replaces the volume of previously recovered fluid and then adds sufficient additional fluid to contact previously uncontacted viscous oil. Preferably, the injected fluid comprises greater than 50% by mass of solvent.

[0017] On production, the pressure is reduced and the solvent(s), non-solvent injectant, and viscous oil flow back to the same well and are produced to the surface. As the pressure in the reservoir falls, the produced fluid rate declines with time. Production of the solvent/viscous oil mixture and other injectants may be governed by any of the following mechanisms: gas drive via solvent vaporization and native gas exsolution, compaction drive as the reservoir dilation relaxes, fluid expansion, and gravity-driven flow. The relative importance of the mechanisms depends on static properties such as solvent properties, native GOR (Gas to Oil Ratio), fluid and rock compressibility characteristics, and reservoir depth, but also depends on operational practices such as solvent injection volume, producing pressure, and viscous oil recovery to-date, among other factors.

[0018] During an injection/production cycle, the volume of produced oil should be above a minimum threshold to economically justify continuing operations. In addition to an acceptably high production rate, the oil should also be recovered in an efficient manner. One measure of the efficiency of a CSDRP is the ratio of produced oil volume to injected solvent volume over a time interval, called the OISR (produced Oil to Injected Solvent Ratio). Typically, the time interval is one complete injection/production cycle. Alternatively, the time interval may be from the beginning of first injection to the present or some other time interval. When the ratio falls below a certain threshold, further solvent injection may become uneconomic, indicating the solvent should be injected into a different well operating at a higher OISR. The exact OISR threshold depends on the relative price of viscous oil and solvent, among other factors. If either the oil production rate or the OISR becomes too low, the CSDRP may be discontinued. Even if oil rates are high and the solvent use is efficient, it is also important to recover as much of the injected solvent as possible if it has economic value. The remaining solvent may be recovered by producing to a low pressure to vaporize the solvent in the reservoir to aid its recovery. One measure of solvent recovery is the percentage of solvent recovered divided by the total injected. In addition, rather than abandoning the well, another recovery process may be initiated. To maximize the economic return of a producing oil well, it is desirable to maintain an economic oil production rate and OISR as long as possible and then recover as much of the solvent as possible.

[0019] The OISR is one measure of solvent efficiency. Those skilled in the art will recognize that there are a multitude of other measures of solvent efficiency, such as the inverse of the OISR, or measures of solvent efficiency on a temporal basis that is different from the temporal basis discussed in this disclosure. Solvent recovery percentage is just one measure of solvent recovery. Those skilled in the art will recognize that there are many other measures of solvent recovery, such as the percentage loss, volume of unrecovered solvent per volume of recovered oil, or its inverse, the volume of produced oil to volume of lost solvent ratio (OLSR).

Solvent composition

[0020] The solvent may be a light, but condensable, hydrocarbon or mixture of hydrocarbons comprising ethane, propane, or butane. Additional injectants may include CO_2 , natural gas, C_{3+} hydrocarbons, ketones, and alcohols. Non-solvent co-injectants may include steam, hot water, or hydrate inhibitors. Viscosifiers may be useful in adjusting solvent viscosity to reach desired injection pressures at available pump rates and may include diesel, viscous oil, bitumen, or diluent. Viscosifiers may also act as solvents and therefore may provide flow assurance near the wellbore and in the surface facilities in the event of asphaltene precipitation or solvent vaporization during shut-in periods. Carbon dioxide or hydrocarbon mixtures comprising carbon dioxide may also be desirable to use as a solvent.

[0021] In one embodiment, the solvent comprises greater than 50% C_2-C_5 hydrocarbons on a mass basis. In one embodiment, the solvent is primarily propane, optionally with diluent when it is desirable to adjust the properties of the injectant to improve performance. Alternatively, wells may be subjected to compositions other than these main solvents to improve well pattern performance, for example CO_2 flooding of a mature operation.

Phase of injected solvent

[0022] In one embodiment, the solvent is injected into the well at a pressure in the underground reservoir above a liquid/vapor phase change pressure such that at least 25 mass % of the solvent enters the reservoir in the liquid phase. Alternatively, at least 50, 70, or even 90 mass % of the solvent may enter the reservoir in the liquid phase. Injection as a liquid may be preferred for achieving high pressures because pore dilation at high pressures is thought to be a particularly effective mechanism for permitting solvent to enter into reservoirs filled with viscous oils when the reservoir comprises largely unconsolidated sand grains. Injection as a liquid also may allow higher overall injection rates than injection as a gas.

[0023] In an alternative embodiment, the solvent volume is injected into the well at rates and pressures such that immediately after halting injection into the injection well at least 25 mass % of the injected solvent is in a liquid state in the underground reservoir. Injection as a vapor may be preferred in order to enable more uniform solvent distribution along a horizontal well. Depending on the pressure of the reservoir, it may be desirable to significantly heat the solvent in order to inject it as a vapor. Heating of injected vapor or liquid solvent may enhance production through mechanisms described by "Boberg, T.C. and Lantz, R.B., "Calculation of the production of a thermally stimulated well", JPT, 1613-1623, Dec. 1966. Towards the end of the injection cycle, a portion of the injected solvent, perhaps 25% or more, may become a liquid as pressure rises. Because no special effort is made to maintain the injection pressure at the saturation conditions of the solvent, liquefaction would occur through pressurization, not condensation. Downhole pressure gauges and/or reservoir simulation may be used to estimate the phase of the solvent and other co-injectants at downhole conditions and in the reservoir. A reservoir simulation is carried out using a reservoir simulator, a software program for mathematically modeling the phase and flow behavior of fluids in an underground reservoir. Those skilled in the art understand how to use a reservoir simulator to determine if 25% of the injectant would be in the liquid phase immediately after halting injection. Those skilled in the art may rely on measurements recorded using a downhole pressure gauge in order to increase the accuracy of a reservoir simulator. Alternatively, the downhole pressure gauge measurements may be used to directly make the determination without the use of reservoir simulation.

[0024] Although preferably a CSDRP is predominantly a non-thermal process in that heat is not used principally to reduce the viscosity of the viscous oil, the use of heat is not excluded. Heating may be beneficial to improve performance, improve process start-up or provide flow assurance during production. For start-up, low-level heating (for example, less than 100°C) may be appropriate. Low-level heating of the solvent prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may benefit recovery.

First Aspect (A): Determining the Volume of Solvent to Inject

[0025] Prior descriptions of CSDRP embodiments have not specified criteria such as the volume of solvent to inject per cycle and the point at which injection should be converted to production and vice versa. These aspects of the cyclic process are considerations for improving oil recovery while achieving efficient use of solvent. To obtain a high OISR during a cycle, a significant portion of the solvent must contact viscous oil which has not been exposed to solvent in previous cycles and the mobilized mixture of solvent and oil must flow back to the well. The spatial distribution of the injected solvent may be difficult to ascertain without the use of expensive surveillance techniques such as seismic surveys, real time passive seismic monitoring and/or subsurface electrical resistivity imaging; and therefore methods for judging when solvent has mixed with viscous oil sufficiently to obtain an economic OISR and oil production rate are not readily available. Disclosed below are methods for estimating the optimal solvent injection volume and methods for estimating when to switch to production.

[0026] Theoretically, from an overall production rate optimization perspective, production should cease (and injection be restarted) shortly after the current oil production rate falls below the average oil production rate expected over the next injection and production cycle. Of course, the average production rate of the next cycle is not known and is dependant on previous production history and therefore must be directly or indirectly estimated. In most cases, it is acceptable to use the average oil rate from the current cycle as a first order estimate of the average oil rate for the next cycle. Disclosed below are methods for estimating when to switch from production to injection such that the performance (e.g. solvent efficiency, oil production) is enhanced to achieve economic benefit. In a commercial operation, it may not be possible to optimize each cycle for each well due to field constraints; as such, CSDRP cycle strategies may be flexible at the discretion of the operator to optimize overall field performance.

[0027] Injection of a solvent-containing fluid into a well is the first step of a CSDRP and the rates and volumes of injected fluid are an integral part of any CSDRP. Note that, unlike thermal recovery methods where minimum injection rates are often specified to minimize wellbore heat loss, CSDRP injection rates may have considerable flexibility to either reduce and/or increase injection rate depending on specific reservoir conditions, in particular the level of reservoir depletion. Rate flexibility allows the operator to optimize the distribution of solvent among wells in order to balance field injection/production volumes and surface gathering system constraints. Three non-limiting options for determining the volume of solvent-containing injectant to inject are: a purely volume-based approach, a hybrid volume and pressure approach, and a purely pressure-based approach. Each of these three approaches are described below and referred to as A1, A2, and A3.

<u>A1: Volume-Based Determination of Injection Volume</u>

[0028] One method of managing fluid injection in a CSDRP is for the volume injected during a cycle to equal the net reservoir voidage resulting from previous injection and production cycles plus an additional volume, for example approximately 2-15%, or approximately 3-8% of the pore volume (PV) of the reservoir volume associated with the well pattern. In mathematical terms, the volume may be represented by:

[0029] $$V_{INJECTANT} = V_{VOIDAGE} + V_{ADDITIONAL}.$$

[0030] One way to approximate the net *in situ* volume of fluids produced is to determine the total volume of non-solvent liquid hydrocarbon fractions and aqueous fractions produced minus the net injectant fractions produced. For example, in the case where 100% of the injectant is solvent and the reservoir contains only oil and water, an equation that represents the net *in situ* volume of fluids produced is,

$$V_{VOIDAGE} = V_{OIL}^{PRODUCED} + V_{WATER}^{PRODUCED} - (V_{SOLVENT}^{INJECTED} - V_{SOLVENT}^{PRODUCED}).$$

[0031] Estimates of the PV are the reservoir volume inside a unit cell of a repeating well pattern or the reservoir volume inside a minimum convex perimeter defined around a set of wells. Fluid volume may be calculated at *in situ* conditions, which take into account reservoir temperatures and pressures. If the application is for a single well, the "pore volume of the reservoir" is defined by an inferred drainage radius region around the well which is approximately equal to the distance that solvent fingers are expected to travel during the injection cycle (for example, about 30-200m). Such a distance may be estimated by reservoir surveillance activities, reservoir simulation or reference to prior field trials. In this approach, the pore volume may be estimated by direct calculation using the estimated distance, and injection ceased when the associated injection volume (2-15% PV) has been reached.

[0032] Sometimes, it is challenging to define the "pore volume accessible to the well" because of geological heterogeneity or uncertainties in the distance the solvent fingers are expected to travel. The relative ease of pressure measurement and generally higher accuracy versus volumetric measurement may lead to a preference for pressure or hybrid pressure-volume methods.

<u>A2: Volume-Pressure Hybrid Determination of Injection Volume</u>

[0033] Rather than estimating the net reservoir voidage resulting from previous injection and production cycles, it may be more practical to establish a threshold pressure which must be obtained before injecting a predetermined volume, for example also equal to approximately 2-15%, or approximately 3-8%, of the pore volume.

<u>A3: Pressure-Based Determination of Injection Volume</u>

[0034] An alternative to a volume-based scheme is one based on pressure measurements. In this approach, the solvent injection continues until an approximately predetermined time after the injection pressure during a cycle first passes from less than to greater than a designated threshold injection pressure. In some cases, it may be desirable to continue injection past the threshold pressure for only a minimal amount of time. In other cases, it may be desirable to stop injection once the threshold pressure is met.

[0035] In one embodiment, in both the volume-pressure hybrid and pressure-only approaches, the designated threshold injection pressure is a pressure close to but below fracture pressure, for example above 90% of fracture pressure, or above 80% of fracture pressure, or above 95% of fracture pressure. In one embodiment, the threshold injection pressure is a pressure within 1 MPa of, and below, the fracture pressure. As used herein, "fracture pressure" is the pressure at which injection fluids will cause the formation to fracture.

[0036] In unconsolidated formations, it is also desirable that the threshold injection pressure be above the dilation pressure of the formation. As used herein, "dilation pressure" refers to the onset of in-elastic dilation, the yielding of the geo-materials, or the onset of non-linear elastic deformation. As used herein, "geomechanical formation dilation" means the tendency of a geomechanical formation to dilate as the pore pressure is raised towards the formation minimum in-situ stress, typically by injecting a liquid or a gas. Fig. 4 illustrates reservoir dilation in the elastic compressibility (400) and the dilation compressibility (401) regimes. As illustrated in Fig. 4, as is sometimes the case for unconsolidated sands, there is a particular pressure at which dilation, the change of pore volume (porosity) with change in pressure, markedly increases. This pressure may be referred to as the dilation pressure, although strictly speaking dilation occurs above and below the dilation pressure, albeit at a lower level when below the dilation pressure. If the pressure is subsequently reduced after dilation, the pore volume may decrease along a path (402) that is different from the path followed when pressure was rising.

[0037] The formation *in situ* stress can be determined in a well test in which water is injected into the formation at high rates while bottom-hole pressure response is recorded. Alternatively, the stress may be measured during the first cycle injection of solvent. Analysis of the pressure response would reveal the conditions at which formation failure occurs (the pressure at which the *in situ* stress is exceeded). As used herein, "Pore fluid compression" means compression of a pore fluid by pressure. In the field, the operator can obtain pore fluid compression by multiplying pressure increase by fluid compressibility, which is a fluid property measurable in laboratory tests by procedures well known to those skilled in the art. Pore dilation refers to dilation of pores in rock or soil. However, as shown in Figure 5 (described below), it may also be desirable for the threshold pressure to be close to or at the fracture pressure or be below the dilation pressure, depending on the specific reservoir characteristics and overall depletion plan. The benefits of reaching facture pressure or being below dilation pressure are discussed below.

[0038] Fig. 2 provides an outline of a process according to one aspect of the instant invention and Figs. 3a, 3b, and 3c provide additional details of three sub-schemes thereof. In Fig. 2 solid lines represent the process steps of one embodiment and dashed lines represent the process steps of alternative embodiments. Beginning with Fig. 2, in the first step of a cycle, fluid injection into a well is initiated (202). Injection continues and the bottomhole pressure gradually rises. Then, one of the three options (A1, A2, or A3) are used to determine the volume of fluid to inject. In a CSDRP, the injected volume of fluid contains greater than 50% by mass solvent.

[0039] Either a volume of solvent is injected (204) or injection continues until the designated threshold pressure is achieved (206). The fluid volume (204) is the approximate net *in situ* volume of fluids produced in a previous cycle or cycles. Where the pressure is raised to the designated threshold pressure (206), either an additional volume of solvent is injected (208) (e.g. about 2-15% or about 3-8% of PV as described above) or injection continues for an additional amount of time (210), after which injection is ceased (212). Where the fluid volume (204) is injected, it is preferred that an additional volume of solvent is injected (208), but injection may also continue for an additional amount of time (210), after which injection is ceased (212). Optionally, there is a soak period (214) of a flexible duration depending on overall depletion plan before production (216) begins. If the oil rate is not too low (218) and if the gas rate is not too high (220), production continues. If the oil rate is too low (218) or if the gas rate is too high (220), production is stopped (222) and an assessment is made as to whether the next cycle will be economic (224). If the next cycle will be economic, another cycle begins with fluid injection (202). If the next cycle will not be economic, additional oil may be recovered by other means (226), described below. Alternatively, the well may be produced at the lowest achievable (blowdown) pressure (228), and an assessment is made as to whether continued production will be economic (230). If it will not be economic, the well may be suspended or abandoned (232). If it will be economic, production at blowdown pressure is continued or reused as per the specific depletion plan (i.e. recompleted to different hydrocarbon interval or converted to an alternative service such as dedicated injection or disposal). Production at blowdown pressure is continued if deemed to be economic (228).

[0040] As discussed above, it may also be desirable in some situations for the threshold pressure to be about equal to the fracture pressure or be below the dilation pressure. According to the process depicted in Figure 5, fluid injection is initiated (502) until the injection pressure reaches the threshold pressure, which is the fracture pressure (504). Then, an additional predetermined volume of fluid (for example, 2-15% or 3-8% of the pore volume (PV) is injected (506). Alternatively, fluid is injected for a predetermined time period (508), for example, 0-21 days, or 5-10 days, or about 7 days.

How fast to inject the solvent-containing fluid

[0041] Regardless of the particular volume injected, the injection rate need not be constant during the injection of the volume. In certain reservoir conditions affecting the fluid injectivity, tailoring the injection rate throughout the cycle volume may enhance solvent conformance.

[0042] In embodiments where the injected fluid is 100% by mass solvent, reservoir simulation suggests high solvent injection rates may favor solvent injection in a relatively thin but areally extensive conformance region whereas low injection rates may promote the formation of a vertical (or thicker) conformance region. Therefore, the solvent injection rate may be tailored to the specific reservoir where a CSDRP is being implemented, depending on reservoir thickness, spacing of wells, geomechanical properties, level of reservoir depletion, etc. In addition, the deliberate oscillation of injection rate above and below some predetermined value may enable some degree of solvent conformance control.

[0043] For example, a CSDRP operation with a high solvent injection rate in a thick reservoir may result in poor solvent conformance vertically throughout the pay zone. The injected solvent would be largely confined to a thin, areally extensive conformance region. If so confined, the injected solvent may be under-running a significant amount of the oil column and thereby promoting early well-to-well communication, which is deleterious to production. If a thin conformance layer or well-to-well communication is observed, reducing the solvent injection rate during the current or future injection cycles may promote vertical conformance of injected solvent. The vertical conformance pathways established during low injection periods are subsequently further extended during periods of high injection. Rate control thus provides the practitioner with a means of optimizing oil production by designed solvent conformance for the given target reservoir.

[0044] This technique of oscillating injection rate may be particularly beneficial for reservoirs with poor vertical permeability, where the natural tendency for predominantly horizontal conformance may be further exacerbated by aggressive solvent injection. Decreasing the solvent injection rate increases the likelihood of oil confined in low permeability rock to become mobilized by injected solvent. In addition to recovering the oil, this may also increase the overall transmissibility of fluids within the low permeability rock. Conversely, continued aggressive injection may force injected solvent to mobilize oil in predominantly high permeability rock which has already been swept.

[0045] Another example of accomplishing conformance control is controlling injection rate in relation to the onset of fracturing. High injection rates after fracturing promote the distribution of solvent in a relatively thin, extensive layer. Lower rates favor a more spherical injection.

When to stop the production phase of a cycle

[0046] Regardless of the producing pressure of a well, if the production phase of a cycle is too short, a disproportionate amount of solvent-rich fluid near the wellbore is produced during the cycle, resulting in a low oil production rate and perhaps an uneconomic process. If the production phase continues for too long, the oil rate declines to a low level resulting in delay of the next cycle of oil production due to delay in the next cycle of solvent injection. Two criteria are used to judge the end of the production phase of a cycle: a low oil rate criterion and a high gas rate criterion. Note that unlike thermal recovery methods where production performance has a time dependency due to cooling, CSDRP performance is expected to be relatively unaffected by short production cycle and/or large delays in solvent injection; this offers the operator significant depletion plan flexibility. For example, CSDRP operation cycle length can be adapted to unusual market conditions such as commodity price fluctuations in order to maximize economic performance.

[0047] If a low oil rate criterion is used, production is halted when the oil production rate falls to a specified percentage of the average rate obtained during a cycle, for example a value between 60% and 90%. Such a cutoff generally allows production of the majority of mobilized heavy oil from cyclic solvent injection and halts the production when the rate is about equal to or somewhat below the expected average rate over the next cycle, resulting in minimum oil production deferral. This is shown in scheme 3b of Fig. 3, where the current oil rate is measured (307), and the average daily rate obtained during the cycle is recorded (308) and using these values, the ratio of current oil rate to average rate is calculated (310). If the ratio is below a cutoff ratio (312 and 313), the oil rate is too low (314), and production may be stopped.

[0048] Alternatively, production may be halted if the current oil rate falls to less than a predetermined percentage (e.g. 30%, or 20 to 40%) of the maximum oil rate for the cycle. Those skilled in the art will recognize that there are many equivalent criteria for stopping oil production. For example, fractions or percentages of the calendar day oil rate (CDOR), or fractions or percentages of a running average. CDOR is the total oil produced during an injection/production cycle divided by the number of days since injection began.

[0049] Also, if the oil rate is too low (314) based on the oil measurement (307), production may be stopped. In viscous oil recovery processes, gravity is often a significant mechanism for moving oil towards the well. Processes with significant contribution from gravity are often slow and production for a lengthy period of time at a low rate may be necessary, especially in later cycles. Correspondingly, an absolute rate cutoff (314) could be low, especially in later cycles.

[0050] Production at low pressure (i.e. pressure less than the bubble-point of the native fluid or injected fluid) may cause excessive gas-phase production and cause difficulties in artificial lift performance and/or production gathering facilities operation. High gas rates may significantly degrade oil recovery performance and efficient use of injected solvent. To mitigate these effects, in addition to the rate-based production stop criterion discussed above, the production may also be halted due to the produced gas rate or an estimated downhole gas rate exceeding a specified value.

[0051] In Fig. 3c, the current gas rate (316) and the current oil rate (318) are measured and using these values, a gas to oil ratio (GOR) is computed (320). An artificial lift and/or surface facility gas handling capacity is determined (322) and is compared with the computed GOR (320) on the same basis, such as downhole or surface conditions. If the GOR is higher than the handling capacity (324), the gas rate is too high (326) and the production phase of the cycle is stopped.

[0052] After production halts due to at least one criterion being met, a determination is made whether or not another cycle would be economic (224, see Figure 2). Cyclic injection-production may be halted due to a criterion of the oil rate falling below a specified absolute level indicative of an insufficient rate to be economic. Or, cyclic injection-production may cease if the produced oil to injected solvent ratio (OISR) for the cycle is too low. Fig. 3a illustrates the steps for determining if another cycle should be started using the OISR-based criterion. The volume of oil produced over a cycle (302) and the volume of solvent injected over a cycle (303) are measured, and using these measurements, the OISR is calculated (304). The calculated OISR is compared with an economic OISR value (305) and an assessment is made as to whether the next cycle will be economic (306). If it is determined that another cycle would not be economic, all further injection of solvent ceases and any remaining solvent in the reservoir is partially recovered by allowing the production pressure to decrease to much lower levels (e.g., 100-300 kPa), typically termed the abandonment pressure (228, see Figure 2). Even at abandonment pressure, eventually the oil rate is uneconomic and the well may be permanently shut in or suspended (232, see Figure 2).

[0053] All criteria for ceasing production and switching to injection discussed thus far have applied to all cycles and use data measured in the oilfield. Reservoir surveillance activities and numerical simulation programs provide another tool for developing optimal production rate cutoff criteria on a cycle-by-cycle basis. One method of optimization is to simulate a CSDRP and then choose switch points where the production rate meets the criteria discussed above. This simulation may be updated based on actual field performance data. The anticipated production rate for the next cycle can be estimated using reservoir simulation using the existing production data. Alternatively, collection of historical production data through reservoir surveillance can lead to development of empirical performance curves whereby historical performance of mature wells is used to predict performance of similar wells yet to be drilled and/or in early state of depletion. Reservoir surveillance, numerical simulation studies, and evolving geologic understanding may improve field depletion strategies.

Second Aspect (B): Producing Pressures

[0054] In a CSDRP embodiment (particularly a *CSP*™ process) as described in Canadian Patent No. 2,349,234 (Lim et al.), a well typically produces at a bottomhole pressure low enough to result in solvent vaporization and the formation of a secondary gas cap. However, such low pressures may not be preferred, especially in early cycles. There are several potential advantages to operating above such low pressures. First, solvent vaporization may necessitate increased facilities costs to handle the produced gas as well as necessitate complex solvent management strategies to efficiently satisfy the highly dynamic solvent requirements. Moreover, some solvent blends may introduce additional facilities and operational complexities due to their tendency to enter the reservoir at low pressures and as a multi-phase fluid. Finally, solvent vaporization may result in hydrate formation in some reservoirs, requiring the injected solvent to be heated prior to injection.

[0055] A second aspect of the invention is a method of injecting solvent into an underground reservoir in a liquid state and producing at a bottomhole pressure above the bubble point of the injected solvent. Producing at bottomhole pressures above the bubble point of the solvent results primarily in the production of the viscous oil and the solvent in the liquid phase, potentially eliminating, or reducing, the need for additional costs associated with gas handling facilities. Since operating at production pressures above the solvent bubble point does not create as large of a pressure drop as operating below the bubble point, it is may be preferred to operate at a higher cycle frequency to maintain acceptable recovery rates of the viscous oil. The potential advantage of more rapid cycling is that most portions of the reservoir in which the *in situ* fluids have been displaced remain filled with liquid solvent, reducing the volume of solvent injected during a cycle compared to previous CSDRP strategies at a given volume of viscous oil produced. This technique potentially reduces the complexities of solvent management as well as storage and facilities costs. In addition, operation above the bubble point pressure of the solvent eliminates, or reduces, the challenges associated with multi-phase injection. One challenge for multiphase injection is that it may require more complex or costly pumping equipment than single-phase injection.

[0056] A well's production rate may be constrained by facility design and artificial lift capacity. If the well is producing at lower than its maximum production rate, the producing pressure may be progressively lowered until it reaches some minimum threshold pressure or the maximum design production capacity is achieved. The bottomhole pressure of the well may be controlled by means of choking flow to keep the bottomhole pressure above a specified producing pressure, for example, 300-1000 kPa. The minimum producing pressure controls whether or not the produced fluid is produced primarily as a liquid or primarily as a gas. In one embodiment, the minimum pressure is less than the vapor pressure of the produced fluid, causing the production of a principally gaseous fluid. In an alternative embodiment, the minimum pressure is above the vapor pressure of the produced fluid, causing the produced fluid to be produced primarily as a liquid.

[0057] Figure 6 illustrates an example of a production process. First, the production rate is measured (602). As per decision points (604) and (606), if the measured production rate is less than the maximum production rate, and the producing pressure is greater than a minimum pressure, the producing pressure is decreased (608). If the measured production rate is less than the maximum production rate, but the producing pressure is already at the minimum pressure, production is continued (610). Also, if the measured production rate is at the maximum production rate, production is also continued (610).

<u>Third Aspect (C): Early Time Fracturing and Injection Pressures</u>

[0058] The first few cycles of a producing oil well may strongly impact the profitability of a well. Key to good performance during the first few cycles is achieving high injection rates while maintaining good distribution of solvent. One approach to increasing injectivity is to inject solvent at extremely high pressure, even close to or at fracture pressure, in order to achieve high rates.

[0059] Whereas Canadian Patent No. 2,349,234 to *Lim et al.* implies that injecting at the fracture pressure may be beneficial in any cycle, it has now been discovered that being close to or at the fracture pressure in early cycles only, especially the first cycle, may be optimal whereas being close to or at fracture pressure in later cycles may be unachievable due to well to well communication and/or may be detrimental to production by causing injected fluids to poorly distribute in the reservoir. Therefore, the range of the total volume injected at less than the minimum in-situ stress pressure can be outside the range of 15-50%; in fact, it may be desirable to inject substantially more than 50% of the fluid at below the minimum in-situ stress or even below the dilation pressure. Reducing the amount of injection after fracture provides operational flexibility which has advantages in terms of solvent supply, storage management, and process robustness. The expression close to or at fracture pressure means between 95 and 100% of fracture pressure.

Fourth Aspect (D): Operation Strategy during Middle and Late Life

[0060] Rather than abandoning a CSDRP well once a cyclic strategy becomes uneconomic, continued economic recovery may be possible by utilizing non-cyclic injection strategies or coordinated multiwell strategies. Two situations envisioned where a CSDRP well may be converted to a different production process are: 1) that producing a well using a CSDRP is no longer profitable and 2) even while continued production using a CSDRP is economic, conversion to a new recovery process in the mid or late life of a CSDRP well may recover more oil in the long term. This situation may occur when, for example, adjacent CSDRP wells begin to interact via fluid and/or pressure communication. Depending on the spacing between adjacent CSDRP wells, well performance will eventually be influenced by adjacent well operation. Any multiwell cyclic solvent-dominated process, not only the specific CSDRP embodiments discussed herein, may suffer from well-to-well communication due to increased difficulty in optimizing conformance due to increasing network of interconnected pathways comprised of high mobility fluids at low reservoir pressure. Well-to-well communication can be detected via reservoir surveillance, for example a sudden loss of pressure at an injection well or an unexplained rise in pressure at a producing well or unusual cycle production volumes indicating fluid migration between wells and/or patterns of wells. After detection, one well can be converted to a permanent injection well and the communicating well can be converted to a permanent production well. The solvent is supplied at a near-constant rate and injected at pressures above (liquid) or below the bubble point pressure of the hydrocarbon solvent. Solvent flooding in the liquid phase suffers from higher total solvent cost because of higher total injection rates, but can potentially achieve higher oil production rates as well. However, because the reservoir is already partially depleted from CSDRP it is more preferable that the follow-up solvent flood use vapor-phase injection in order to obtain better solvent efficiency whilst minimizing solvent cost.

[0061] Figure 7 illustrates the conversion of a cyclic process to a non-cyclic process using a solvent-flood example. A solvent flood is one kind of SDRP. The pressure and production performance of the wells is monitored (702). If extensive communication is detected among wells (704), the recovery process is converted (706) to a continuous solvent injection, known as a solvent flood.

[0062] In one variant, in order to build pressure above dilation pressure, the solvent flood producer is periodically shut-in (710). In another variant, the role of injector and producer is periodically reversed (708) in order to improve sweep.

[0063] Unlike thermal recovery methods where minimum injection rates are often specified to minimize wellbore heat loss, injection rates in a solvent flood are flexible and may either be reduced or increased without much detriment. A low injection rate may improve flood performance of a highly connected well by minimizing solvent breakthrough volumes at adjacent wells. High injection rates may be used to stimulate injectors with poor communication. High injection rates may also be used to overwhelm established communication pathways by rapidly filling the near well drainage region, enabling solvent to contact bypassed oil prior to excessive leak off to adjacent depleted reservoir. Also, a high injection rate could accelerate reservoir pressure build up after solvent injection system downtime.

[0064] Even before communication is achieved, it may be more economic to switch to a solvent flood process because of onerous solvent injection requirements. The specific timing of the conversion to solvent flooding may instead be based upon a specific oil-to-solvent ratio (OISR), average oil rate, or oil recovery percentage.

[0065] To optimally recover hydrocarbons after fluid communication is achieved, and to make efficient use of a preferably constant solvent supply, conversion of an oilfield being produced using a CSDRP to a solvent flood, SDRP, or other late-life recovery process is proposed. Conversion to a solvent flood allows unswept viscous oil trapped in pockets between wells to be accessed by solvent and thereby produced.

<u>Modeled Example</u>

[0066] A two-dimensional reservoir simulation model was built with geological and geomechanical properties representative of shallow in-situ bitumen deposits (11° API). The solvent was modeled as propane. A CSDRP was simulated using a model according to the cycle strategy outlined in Fig. 2, with the option for a pore volume-based strategy (option A1). The cycles were terminated when the oil rate reached an absolute minimum production rate. The injection continued until the injected volume equaled the voidage plus 5% of the pattern volume. Computer simulation showed that excellent conformance was obtained using this strategy. The propane was well distributed, and contacted enough bitumen to produce oil-rich fluid whilst being contained in the effective drainage radius of the well to facilitate sufficient solvent recovery. A non-optimized comparison case in which production was allowed to continue to a rate that is too low recovered only half as much oil as the optimized case before reaching the OISR cutoff for permanent well shut-in.

[0067] A three-dimensional reservoir simulation model was built with similar properties to the 2D model. A CSDRP was simulated using the model according to the cycle strategy outlined in Fig. 2 and the pressure-based option (option A3) that is not reliant upon knowledge of the pore volume. The cycles were terminated when the oil rate reached an absolute minimum rate, and was not terminated based on gas production or rate decline as a percent of maximum rate criterion. The absolute cutoff rate corresponded to 30-35% of the maximum oil rate obtained during a cycle. Other simulations showed that a cutoff of 30-40% was optimal, and a percent-of-maximum criterion was also acceptable as a cycle strategy. Using a percentage of the average rate obtained to-date during the cycle may be a more practical cycle cutoff for field operations. The injection continued for a predetermined time of 7 days past the time when the bottomhole pressure reached pressure just below the minimum in-situ stress pressure. Excellent finger formation was obtained using the strategy.

[0068] In addition to a low oil production rate, it may be important to set an absolute minimum to the producing bottomhole pressure, especially if gas production presents operational difficulties. A low pressure may lead to too much gas production and a high pressure may leave behind producible oil. In some embodiments the bottomhole-producing pressure of the well is between 500 and 1500 kPa. These values are specific to a reservoir in Cold Lake, Alberta, and are based on depth, reservoir temperature, and injectant composition. The particular choice of bottomhole pressure is depth, reservoir temperature, and injectant composition dependant. Fig. 8 shows a simulated example of a pressure profile (800) for a well produced using a CSDRP. The pressure was held just under the fracture pressure (801) for 7 days and was produced until the pressure fell to the minimum production pressure (802) of 1500 kPa and the oil rate fell to a low absolute level.

[0069] Table 1 outlines the operating ranges for CSDRPs of some embodiments. The present invention is not intended to be limited by such operating ranges.

[0070] Table 1. Operating Ranges for a CSDRP.

Parameter	Broader Embodiment	Narrower Embodiment
Injectant volume	Fill-up estimated pattern pore	Inject, beyond a pressure

	volume plus 2-15% of estimated pattern pore volume; or inject, beyond a pressure threshold, for a period of time (e.g. weeks to months); or inject, beyond a pressure threshold, 2-15% of estimated pore volume.	threshold, 2-15% (or 3-8%) of estimated pore volume.
Injectant composition, main	Main solvent (>50 mass%) C_2-C_5. Alternatively, wells may be subjected to compositions other than main solvents to improve well pattern performance (i.e. CO_2 flooding of a mature operation or altering in-situ stress of reservoir).	Main solvent (>50 mass%) is propane (C_3).
Injectant composition, additive	Additional injectants may include CO_2 (up to about 30%), C_{3+}, viscosifiers (e.g. diesel, viscous oil, bitumen, diluent), ketones, alcohols, sulphur dioxide, hydrate inhibitors, and steam.	Only diluent, and only when needed to achieve adequate injection pressure.
Injectant phase & Injection pressure	Solvent injected such that at the end of injection, greater than 25% by mass of the solvent exists as a liquid in the reservoir, with no constraint as to whether most solvent is injected above or below dilation pressure or fracture pressure.	Solvent injected as a liquid, and most solvent injected just under fracture pressure and above dilation pressure, $P_{fracture} > P_{injection} > P_{dilation} > P_{vaporP}$.

Injectant temperature	Enough heat to prevent hydrates and locally enhance wellbore inflow consistent with Boberg-Lantz mode	Enough heat to prevent hydrates with a safety margin, Thydrate + 5°C to Thydrate +50°C.
Injection rate	0.1 to 10 m^3/day per meter of completed well length (rate expressed as volumes of liquid solvent at reservoir conditions).	0.2 to 2 m^3/day per meter of completed well length (rate expressed as volumes of liquid solvent at reservoir conditions). Rates may also be designed to allow for limited or controlled fracture extent, at fracture pressure or desired solvent conformance depending on reservoir properties.
Threshold pressure (pressure at which solvent continues to be injected for either a period of time or in a volume amount)	Any pressure above initial reservoir pressure.	A pressure between 90% and 100% of fracture pressure.
Well length	As long of a horizontal well as can practically be drilled; or the entire pay thickness for vertical wells.	500m – 1500m (commercial well).
Well configuration	Horizontal wells parallel to each other, separated by some regular spacing of 60 – 600m; Also vertical wells, high angle slant wells & multi-lateral wells. Also infill injection	Horizontal wells parallel to each other, separated by some regular spacing of 60 – 320m.

	and/or production wells (of any type above) targeting bypassed hydrocarbon from surveillance of pattern performance.	
Well orientation	Orientated in any direction.	Horizontal wells orientated perpendicular to (or with less than 30 degrees of variation) the direction of maximum horizontal in-situ stress.
Minimum producing pressure (MPP)	Generally, the range of the MPP should be, on the low end, a pressure significantly below the vapor pressure, ensuring vaporization; and, on the high-end, a high pressure near the native reservoir pressure. For example, perhaps 0.1 MPa – 5 MPa, depending on depth and mode of operation (all-liquid or limited vaporization).	A low pressure below the vapor pressure of the main solvent, ensuring vaporization, or, in the limited vaporization scheme, a high pressure above the vapor pressure. At 500m depth with pure propane, 0.5 MPa (low) – 1.5 MPa (high), values that bound the 800 kPa vapor pressure of propane.
Oil rate	Switch to injection when rate equals 2 to 50% of the max rate obtained during the cycle; Alternatively, switch when absolute rate equals a pre-set value. Alternatively, well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against	Switch when the instantaneous oil rate declines below the calendar day oil rate (CDOR) (e.g. total oil/total cycle length). Likely most economically optimal when the oil rate is at about 0.8 x CDOR. Alternatively, switch to injection when rate equals 20-40% of the max rate obtained during the cycle.

	backpressure of gathering system or well is "pumped off" unable to sustain flow from artificial lift. Alternatively, well is out of sync with adjacent well cycles.	
Gas rate	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. Well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against backpressure of gathering system with/or without compression facilities.	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. During production, an optimal strategy is one that limits gas production and maximizes liquid from a horizontal well.
Oil to Solvent Ratio	Begin another cycle if the OISR of the just completed cycle is above 0.15 or economic threshold.	Begin another cycle if the OISR of the just completed cycle is above 0.3.
Abandonment pressure (pressure at which well is produced after CSDRP cycles are completed)	Atmospheric or a value at which all of the solvent is vaporized.	For propane and a depth of 500m, about 340 kPa, the likely lowest obtainable bottomhole pressure at the operating depth and well below the value at which all of the propane is vaporized.

[0071] In Table 1, embodiments may be formed by combining two or more parameters and, for brevity and clarity, each of these combinations will not be individually listed.

[0072] In the context of this specification, diluent means a liquid compound that can be used to dilute the solvent and can be used to manipulate the viscosity of any resulting solvent-bitumen mixture. By such manipulation of the viscosity of the solvent-bitumen (and diluent) mixture, the invasion, mobility, and distribution of solvent in the reservoir can be controlled so as to increase viscous oil production.

[0073] The diluent is typically a viscous hydrocarbon liquid, especially a C_4 to C_{20} hydrocarbon, or mixture thereof, is commonly locally produced and is typically used to thin bitumen to pipeline specifications. Pentane, hexane, and heptane are commonly components of such diluents. Bitumen itself can be used to modify the viscosity of the injected fluid, often in conjunction with ethane solvent.

[0074] In certain embodiments, the diluent may have an average initial boiling point close to the boiling point of pentane (36°C) or hexane (69°C) though the average boiling point (defined further below) may change with reuse as the mix changes (some of the solvent originating among the recovered viscous oil fractions). Preferably, more than 50% by weight of the diluent has an average boiling point lower than the boiling point of decane (174°C). More preferably, more than 75% by weight, especially more than 80% by weight, and particularly more than 90% by weight of the diluent, has an average boiling point between the boiling point of pentane and the boiling point of decane. In further preferred embodiments, the diluent has an average boiling point close to the boiling point of hexane (69°C) or heptane (98°C), or even water (100°C).

[0075] In additional embodiments, more than 50% by weight of the diluent (particularly more than 75% or 80% by weight and especially more than 90% by weight) has a boiling point between the boiling points of pentane and decane. In other embodiments, more than 50% by weight of the diluent has a boiling point between the boiling points of hexane (69°C) and nonane (151°C), particularly between the boiling points of heptane (98°C) and octane (126°C).

[0076] By average boiling point of the diluent, we mean the boiling point of the diluent remaining after half (by weight) of a starting amount of diluent has been boiled off as defined by ASTM D 2887 (1997), for example. The average boiling point can be determined by gas chromatographic methods or more tediously by distillation. Boiling points are defined as the boiling points at atmospheric pressure.

[0077] In the preceding description, for purposes of explanation, numerous details are set forth in order to provide a thorough understanding of the embodiments of the invention. However, it will be apparent to one skilled in the art that these specific details are not required in order to practice the invention.

[0078] The above-described embodiments of the invention are intended to be examples only. Alterations, modifications and variations can be effected to the particular embodiments by those of skill in the art without departing from the scope of the invention, which is defined solely by the claims appended hereto.

WHAT IS CLAIMED IS:

1. A method of controlling a cyclic solvent injection and production process to aid recovery of hydrocarbons from an underground reservoir, the method comprising:

(a) injecting a volume of fluid comprising greater than 50 mass % of a viscosity-reducing solvent into an injection well completed in the reservoir;

(b) halting injection into the injection well and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the reservoir through a production well;

(c) halting production through the production well; and

(d) subsequently repeating the cycle of steps (a) to (c);

wherein, in at least one subsequent cycle, an *in situ* volume of fluid injected in step (a) is equal to a net *in situ* volume of fluids produced from the production well in an immediately preceding cycle plus an additional *in situ* volume of the fluid.

2. The method of claim 1 wherein immediately after halting injection into the injection well, at least 25 mass % of the injected solvent is in a liquid state in the reservoir.

3. The method of claim 1 wherein at least 25 mass % of the solvent in step (a) enters the reservoir as a liquid.

4. The method of claim 1 wherein at least 50 mass % of the solvent in step (a) enters the reservoir as a liquid.

5. The method of claim 1 wherein the fluid of step (a) comprises greater than 75 mass % of the viscosity-reducing solvent.

6. The method of claim 1 wherein the additional *in situ* volume of fluid in any one of the at least one subsequent cycle varies by no more than 25 vol.% from an *in situ* volume of any other of the at least one subsequent cycle.

7. The method of claim 1 wherein, in the at least one subsequent cycle, the *in situ* volume of fluid injected in step (a) is equal to a net *in situ* volume of fluids produced from the production well summed over all preceding cycles plus an additional *in situ* volume of the fluid.

8. The method of claim 1 wherein the method is operated using a plurality wells, each undergoing the cycles of injection and production according to substantially the same schedule.

9. The method of claim 1 wherein the injection well and the production well utilize a common wellbore.

10. The method of claim 1 wherein an idle period exists subsequent to halting injection and prior to initiating production.

11. The method of claim 1 wherein the hydrocarbons are a viscous oil having a viscosity of at least 10 cP at initial reservoir conditions.

12. The method of claim 1 wherein the net *in situ* volume of fluids produced from the production well in the immediately preceding cycle is determined by:

(i) separating produced fluids into one or more aqueous fractions, non-solvent liquid hydrocarbon fractions, injected solvent fractions, injected non-solvent fractions; and then,

(ii) approximating the net *in situ* volume of fluids produced as the total volume of aqueous and non-solvent liquid hydrocarbon fractions produced minus the net injected solvent and injected non-solvent fractions produced.

13. The method of claim 12 wherein the approximated non-solvent liquid hydrocarbon fractions produced includes an adjustment for *in situ* pressure and temperature conditions, and an account of the produced gas fractions.

14. The method of claim 1 wherein the net *in situ* volume of fluids produced from the production well in the immediately preceding cycle is determined by:

(i) injecting the volume of fluid into the injection well until an estimated bottomhole pressure reaches a threshold pressure.

15. The method of claim 1 wherein the additional *in situ* volume of fluid is injected by continuing injection for a predetermined period of time after an estimated bottomhole pressure reaches a threshold pressure.

16. The method of claims 1 wherein the additional *in situ* volume of fluid is injected by continuing injection of a predetermined volume of fluid after an estimated bottomhole pressure reaches a threshold pressure.

17. The method of claim 1 wherein the additional *in situ* volume of fluid is, at reservoir conditions, equal to 2% to 15% of a pore volume within the reservoir within a zone around the injection well within which solvent fingers are expected to travel during the cycle, wherein the reservoir conditions comprise a maximum *in situ* pressure expected during injection.

18. The method of claim 1 wherein the additional volume of solvent is, at reservoir conditions, equal to 3% to 8% of a pore volume within the reservoir within a zone around the injection well within which solvent fingers are expected to travel during the cycle, wherein the reservoir conditions comprise a maximum *in situ* pressure expected during injection.

19. The method of claim 17 wherein the zone around the injection well within which solvent fingers are expected to travel is defined by a repeating well pattern area.

20. The method of claim 14 wherein the threshold pressure is between 90 and 100% of a reservoir minimum *in situ* stress.

21. The method of claim 1 wherein the solvent comprises, ethane, propane, butane, pentane, carbon dioxide, or a combination thereof.

22. The method of claim 1 wherein the solvent comprises greater than 50 mass % propane.

23. The method of claim 17 wherein the zone around the injection well within which solvent fingers are expected to travel is defined by midpoints between the injection well and adjacent injection wells.

24. The method of claim 1 wherein production of the injected fluid and the hydrocarbons from the reservoir is halted and injection of the fluid into the reservoir is initiated, to begin a new cycle, when gas production exceeds a specified value.

25. The method of 24 wherein the specified value is a flowing volume fraction of a vapor phase at bottomhole conditions of at least 0.1 or a Gas-to-Oil Ratio of at least 1000 scf/stb.

26. The method of claim 1 wherein production of the injected fluid and the hydrocarbons from the reservoir in a cycle is halted and injection of the fluid into the reservoir is initiated, to begin a new cycle, when a rate of oil production from the reservoir drops below a threshold percentage of an average rate of oil production during the cycle.

27. The method of claim 26 wherein the percentage of the rate of oil production from the reservoir to the average rate of oil production during the cycle is estimated using reservoir simulation and production data obtained in previous cycles.

28. The method of claim 26 wherein the threshold percentage is between 60% and 90%.

29. The method of claim 1 wherein the injected fluid further comprises diesel, viscous oil, bitumen, or diluent, to provide flow assurance.

30. The method claims 1 wherein the injected fluid further comprises CO_2, natural gas, C_{3+} hydrocarbons, ketones, or alcohols.

31. The method of claim 1 further comprising:

measuring a rate of production of step (c); and

decreasing a producing pressure if the measured production rate is less than a maximum production rate, and a producing pressure is greater than a minimum threshold pressure.

32. The method of claim 1 wherein the pressure in the reservoir in step (c) is maintained above a liquid/vapor phase change pressure of the solvent in at least one cycle.

33. The method of claim 1 wherein the pressure in the reservoir in step (c) is maintained above a liquid/vapor phase change pressure of the solvent.

34. The method of claim 1 wherein the fluid is injected at an injection pressure in the underground reservoir, in the first cycle, at 95-100% of the fracture pressure of the reservoir, and in subsequent cycles, the fluid is injected at an injection pressure in the underground reservoir below the fracture pressure of the reservoir and below the injection pressure of the first cycle.

35. The method of claim 1 wherein the fluid is injected at an injection pressure in the underground reservoir, in initial cycles, at 95-100% of the fracture pressure of the reservoir, and in subsequent cycles, the fluid is injected at an injection pressure in the underground reservoir below the fracture pressure of the reservoir and below the injection pressure of the initial cycles.

36. The method of claim 1 further comprising:

(e) operating a well as an injection well, and operating at least one additional well as a production well, to operate a solvent flood between or among the wells, when:

the well establishes pressure communication with the at least one additional well, or when
an oil-to-injected-solvent ratio drops below a specified threshold; or when
an amount of oil being produced drops below a specified threshold.

37. The method of claim 36 wherein, in step (e), solvent is injected at a pressure above a liquid/vapor phase change pressure.

38. The method of claim 36 wherein, during the solvent flood, the roles of the injection well and the production well are reversed to improve sweep of the oil.

39. The method of claim 36 further comprising periodically shutting-in the production well of step (e) to increase pressure in the reservoir above a reservoir dilation pressure.

40. The method of claim 36 wherein the specified threshold oil-to-injected-solvent ratio is at least 0.15.

41. The method of claim 36 wherein the specified threshold amount of oil being produced is 10 bbl/day.

42. The method of claim 1 wherein the fluid injection comprises a period of deliberate oscillation between a relatively higher injection rate and a relatively lower injection rate in order to assist solvent conformance.

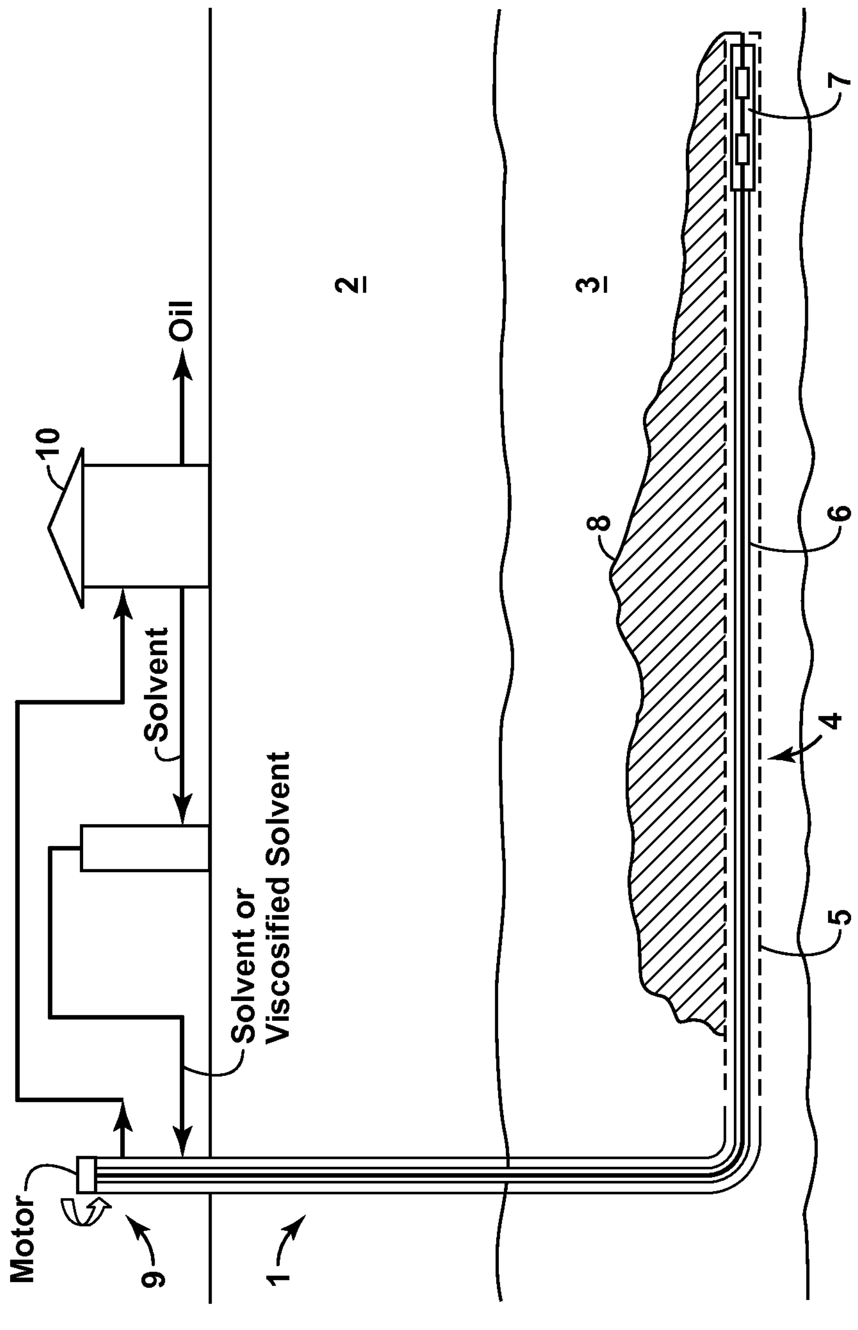
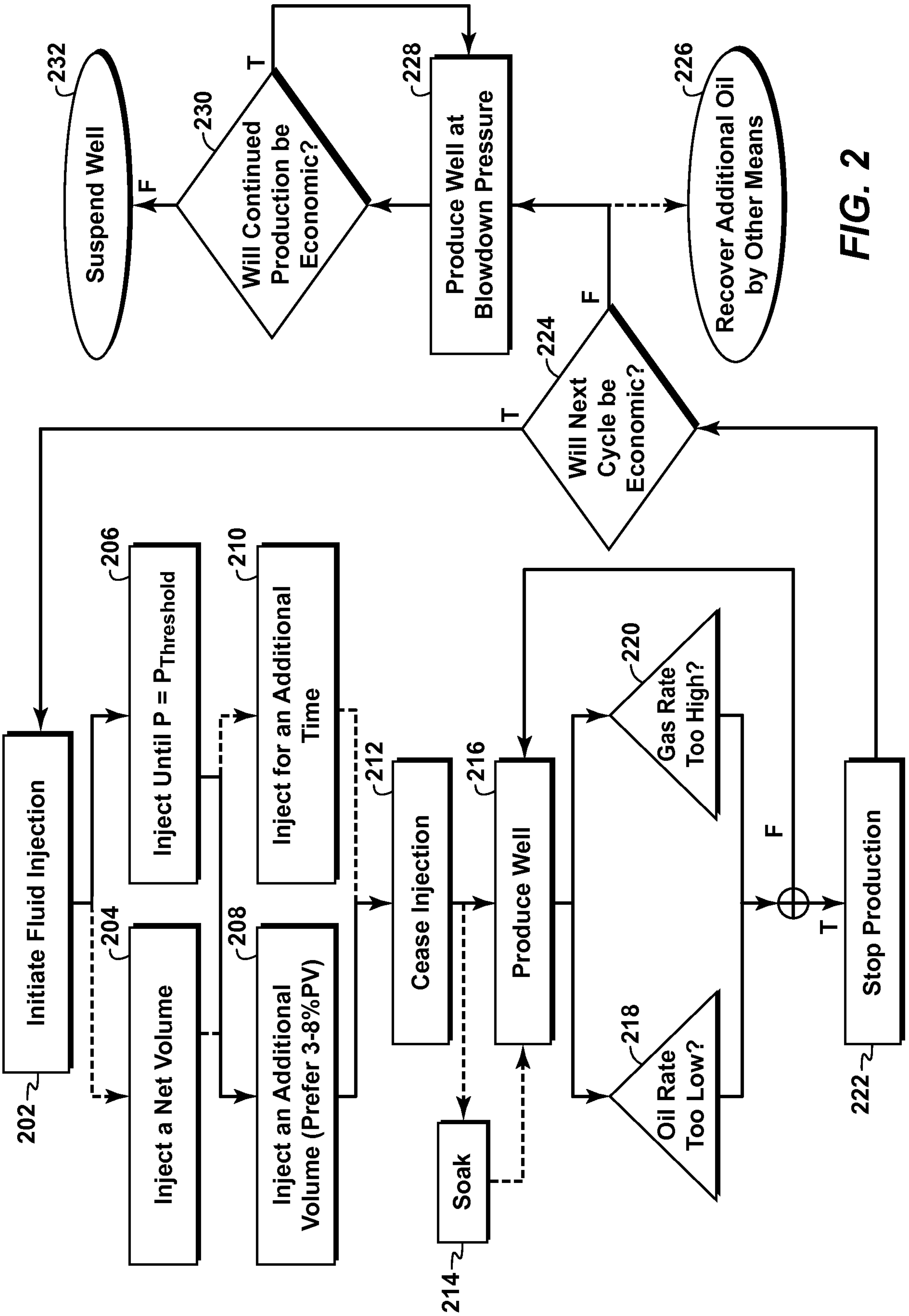


FIG. 1
(Prior Art)



Suspend Well
232
F
Will Continued Production be Economic?
230
T
Produce Well at Blowdown Pressure
228
Recover Additional Oil by Other Means
226
Will Next Cycle be Economic?
224
T
F
Initiate Fluid Injection
202
Inject a Net Volume
204
Inject Until P = P Threshold
206
Inject an Additional Volume (Prefer 3-8%PV)
208
Inject for an Additional Time
210
Cease Injection
212
Soak
214
Produce Well
216
Oil Rate Too Low?
218
Gas Rate Too High?
220
F
T
Stop Production
222

FIG. 2

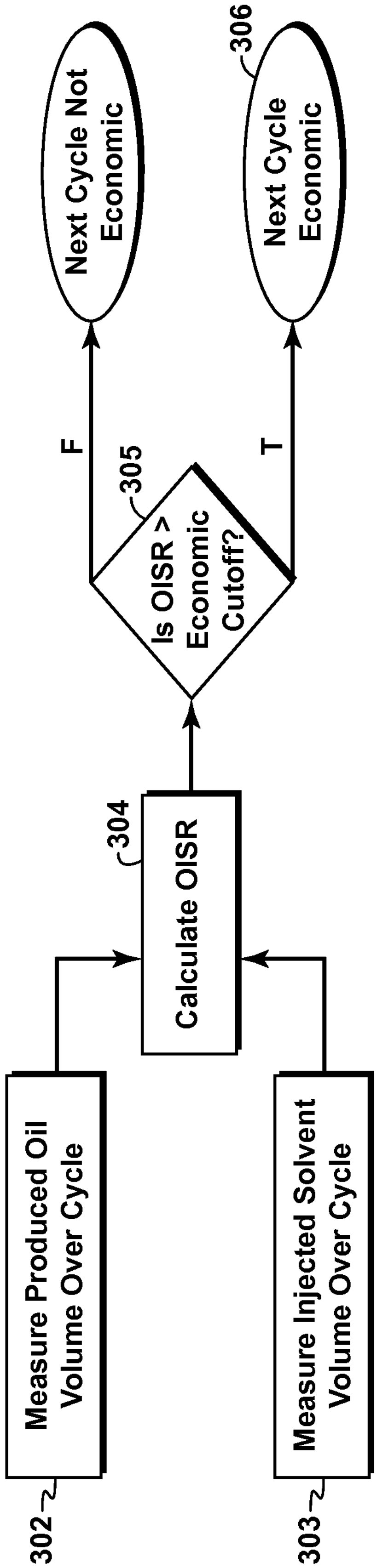
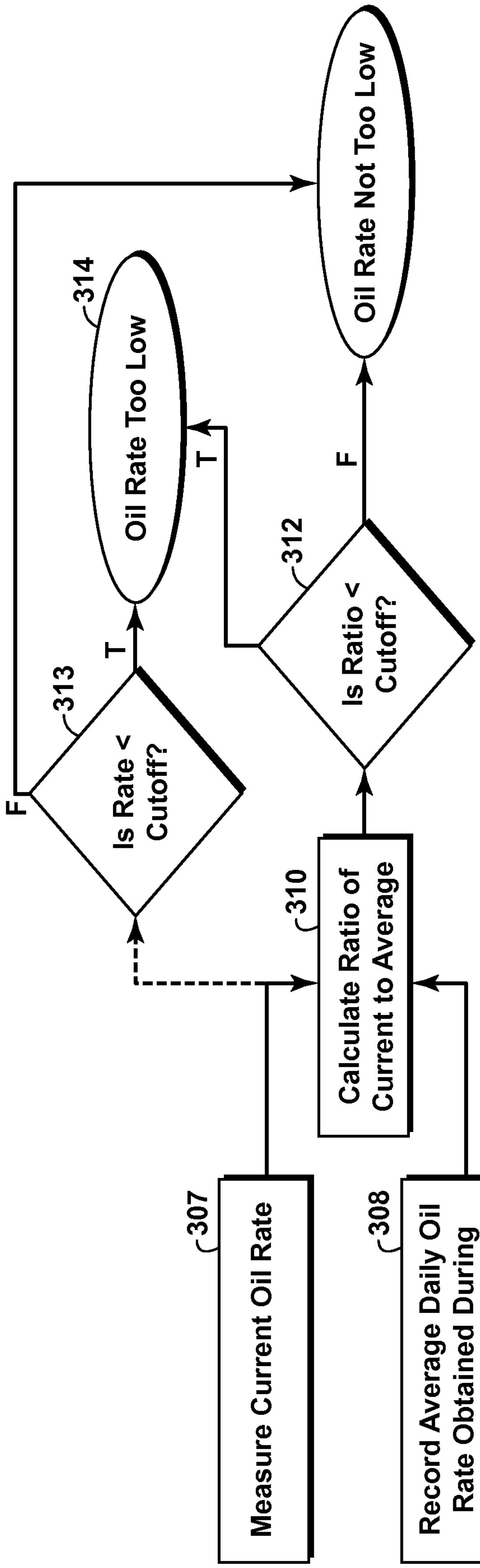
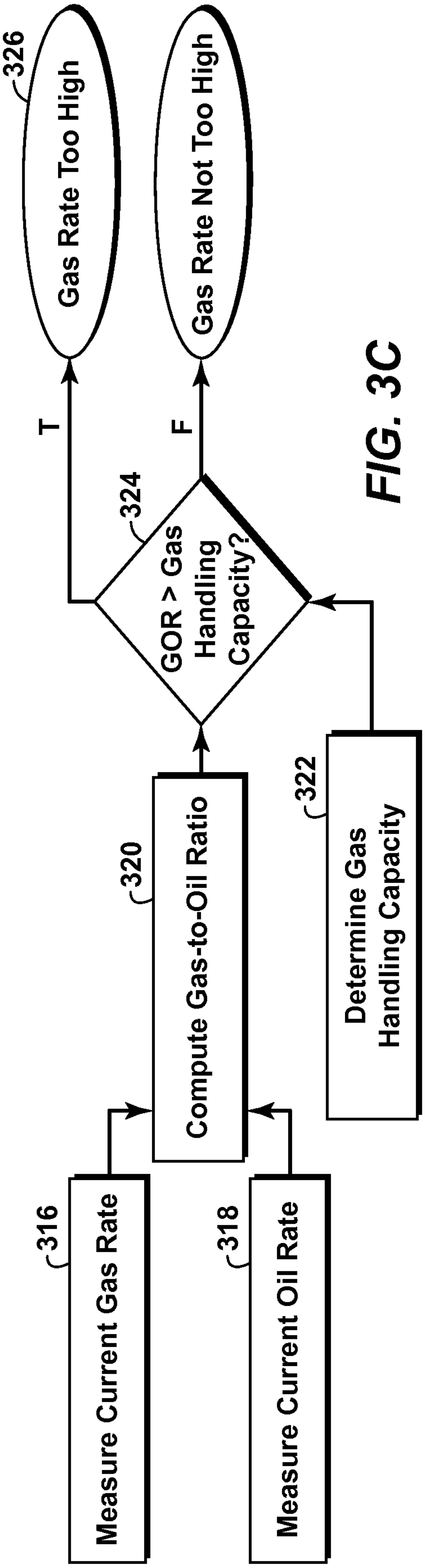

Measure Produced Oil Volume Over Cycle
302
Measure Injected Solvent Volume Over Cycle
303
Calculate OISR
304
Is OISR > Economic Cutoff?
305
F
T
Next Cycle Not Economic
Next Cycle Economic
306

FIG. 3A



307
Measure Current Oil Rate
308
Record Average Daily Oil Rate Obtained During the Cycle
310
Calculate Ratio of Current to Average
313
Is Rate < Cutoff?
T
F
314
Oil Rate Too Low
312
Is Ratio < Cutoff?
T
F
Oil Rate Not Too Low

FIG. 3B



316
Measure Current Gas Rate
318
Measure Current Oil Rate
320
Compute Gas-to-Oil Ratio
322
Determine Gas Handling Capacity
324
GOR > Gas Handling Capacity?
T
F
326
Gas Rate Too High
Gas Rate Not Too High

FIG. 3C

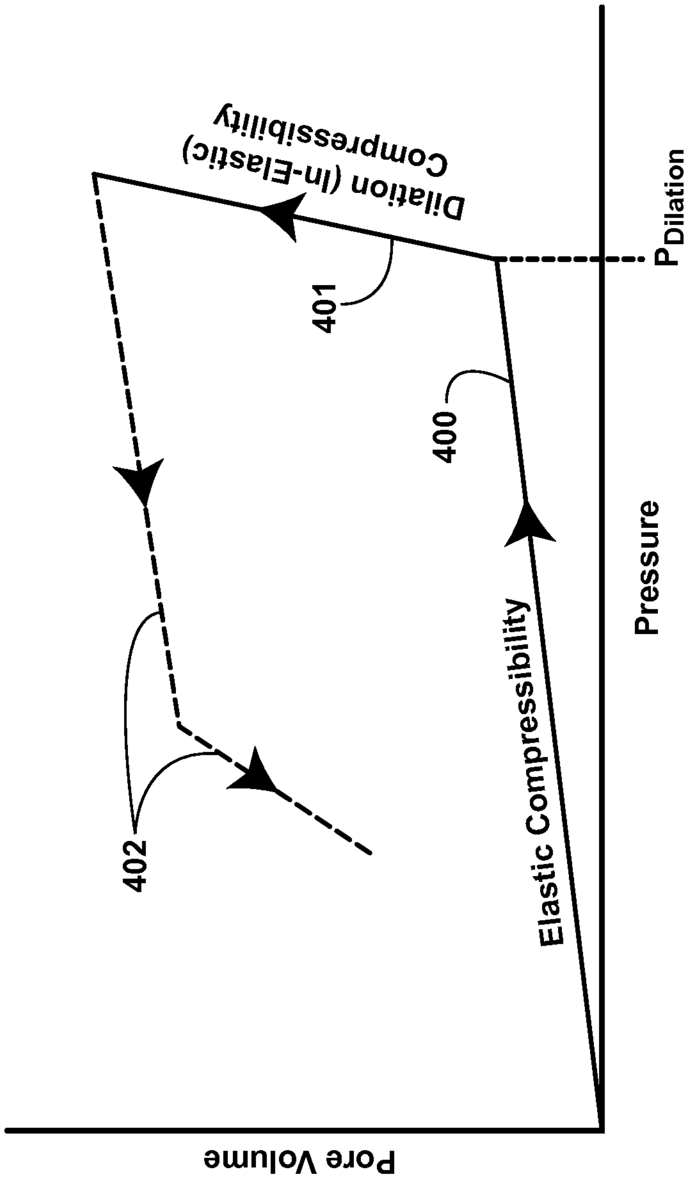

Dilation (In-Elastic) Compressibility
401
400
402
Elastic Compressibility
$P_{Dilation}$
Pressure
Pore Volume

FIG. 4

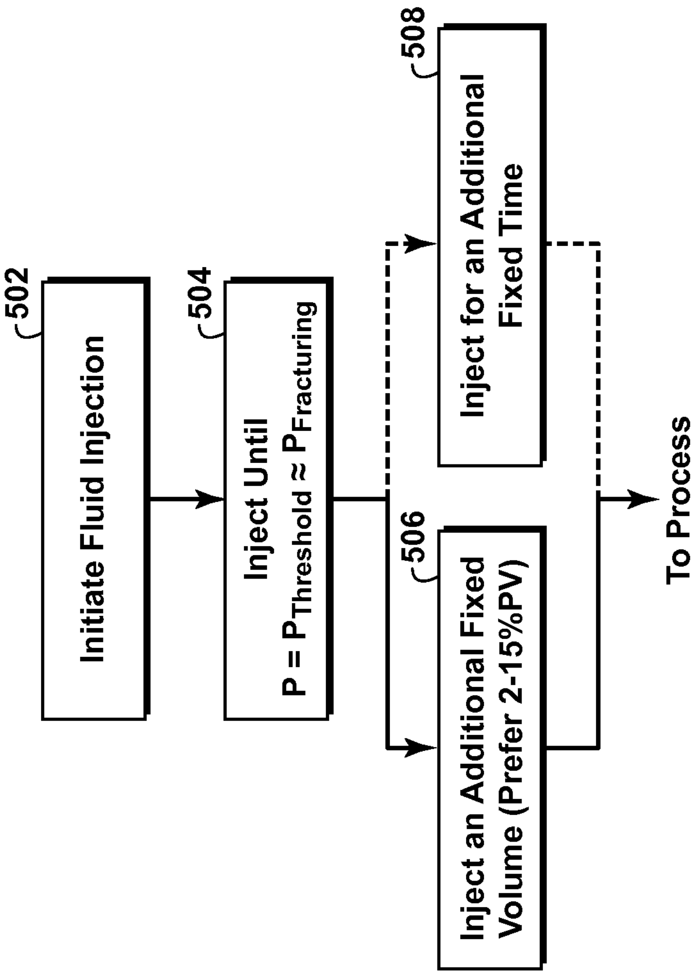
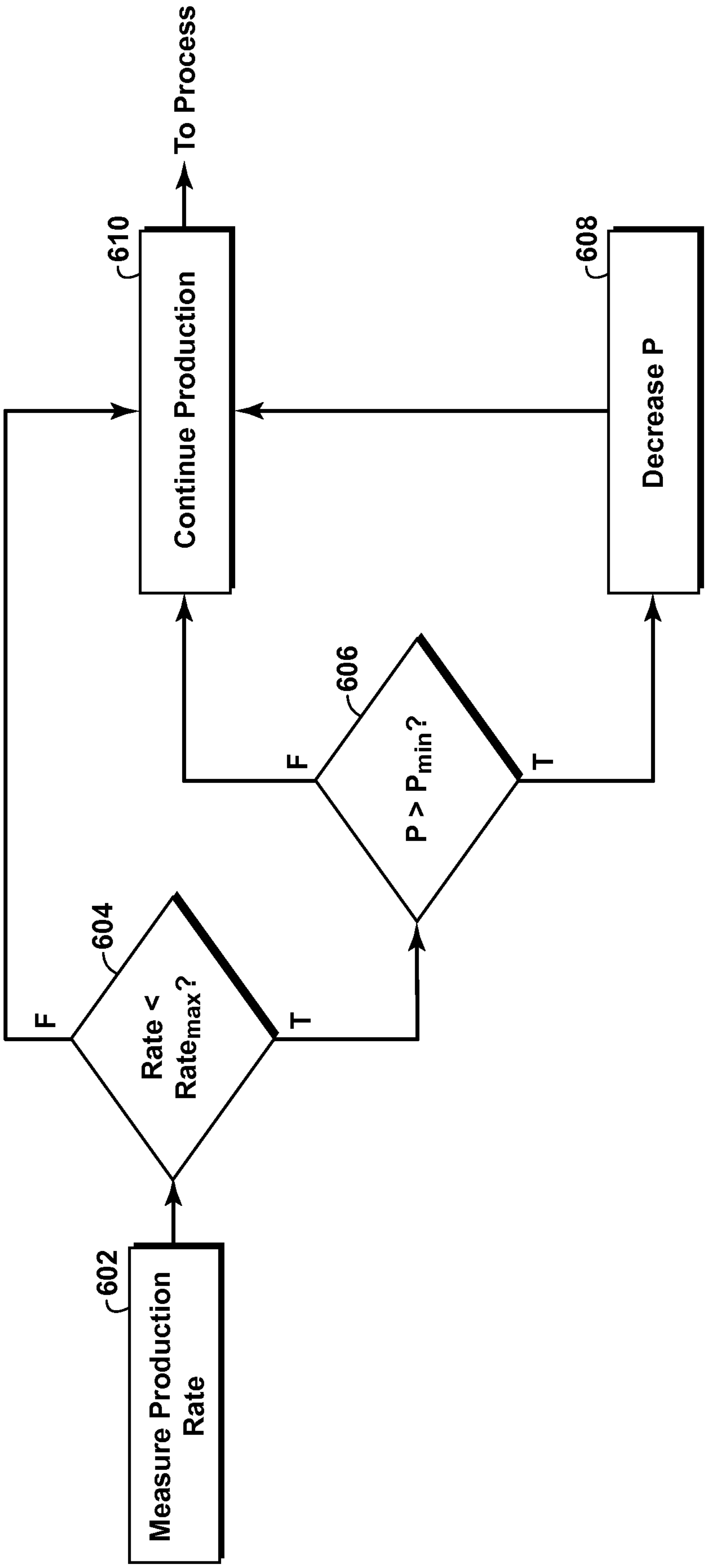

502
Initiate Fluid Injection
504
Inject Until
P = P_Threshold ≈ P_Fracturing
506
Inject an Additional Fixed Volume (Prefer 2-15%PV)
508
Inject for an Additional Fixed Time
To Process

FIG. 5



To Process
610
Continue Production
608
Decrease P
606
F
$P > P_{min}$?
T
604
F
Rate < $Rate_{max}$?
T
602
Measure Production Rate

FIG. 6

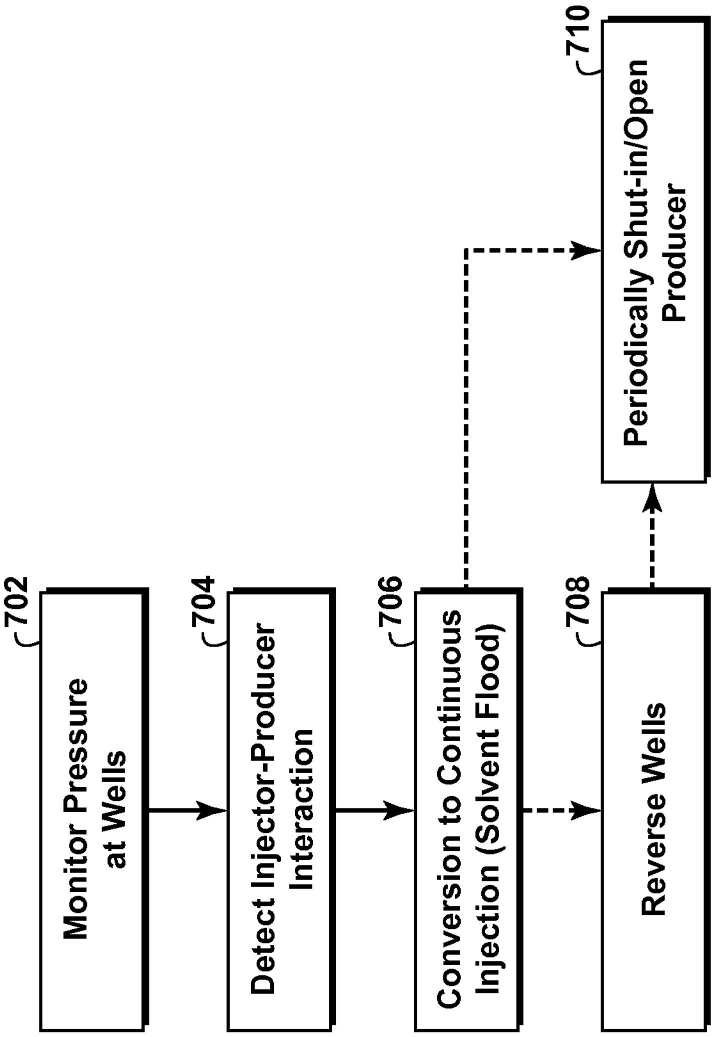

702
Monitor Pressure at Wells
704
Detect Injector-Producer Interaction
706
Conversion to Continuous Injection (Solvent Flood)
708
Reverse Wells
710
Periodically Shut-in/Open Producer

FIG. 7

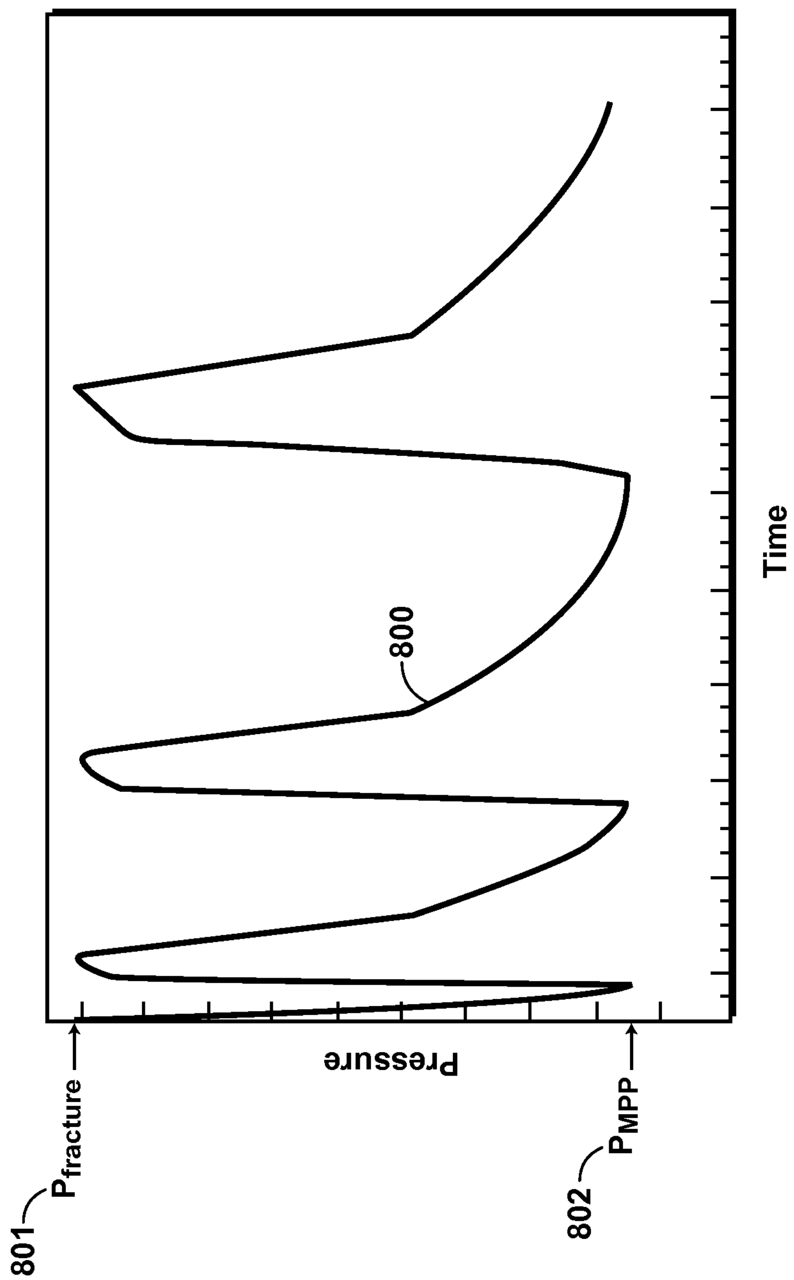


FIG. 8

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 10/51644

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - E21B 43/00 (2010.01)
USPC - 166/263
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
USPC: 166/263

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
USPC: 166/305.1, 306, 244.1, 252.5, 250.01, 266, 269, 268, 263 (text search - see terms below)

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
PubWEST(USPT,PGPB,EPAB,JPAB); Google
Search Terms: solvent, in situ, viscosity, hydrocarbon, injection, cyclic, pore dilation, threshold, mass, percent, reservoir, model, simulation, well, pressure, producing

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 4,007,785 A (ALLEN et al.) 15 February 1977 (15.02.1977), entire document especially the Abstract; col 2, lns 64-66; col 4, lns 32-36; col 4, ln 53-col 5, ln 4; col 6, lns 5-22; col 7, lns 8-11	1-42
Y	KOVSCEK et al., Geologic storage of carbon dioxide and enhanced oil recovery. I. Uncertainty quantification employing a streamline based proxy for reservoir flow simulation, 05 November 2004 (05.11.2004) [retrieved on 01 December 2010 (01.12.2010)]. Retrieved from the Internet:<URL: http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_Presentations%20on%20sequestration%20and%20CH4/CO2%20science%20and%20Uncertainty%20for%20EOR%20sequestration.pdf>, Abstract; pgs 7-8	1-42
Y	US 2,365,591 A (RANNEY) 19 December 1944 (19.12.1944), entire document especially col 3, ln 73-col 4, ln 14	8-9
Y	US 4,617,993 A (BROWN) 21 October 1986 (21.10.1986), entire document especially the Abstract	10
Y	BRAUTASET, In situ fluid dynamics and CO2 injection in porous rocks, October 2009 (10.2009) [retrieved on 01 December 2010 (01.12.2010)]. Retrieved from the Internet:<URL: https://bora.uib.no/bitstream/1956/3752/1/Dr.thesis_Amund%20Brautaset.pdf>, pgs 2-3	14-18, 20, 23
Y	US 5,725,054 A (SHAYEGI et al.) 10 March 1998 (10.03.1998), entire document especially col 1, lns 33-42	19
Y	US 2003/0015321 A1 (Lim et al.) 23 January 2003 (23.01.2003), entire document especially the Abstract; Fig 11; paras [0044], [0049]-[0050], [0071]	26-29, 39, 42

☒ Further documents are listed in the continuation of Box C. ☐

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
02 December 2010 (02.12.2010)	16 DEC 2010

Name and mailing address of the ISA/US	Authorized officer:
Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-3201	Lee W. Young PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 10/51644

C (Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2009/0194282 A1 (BEER et al.) 06 August 2009 (06.08.2009), entire document especially para [0825]	31
Y	US 5,386,875 A (VENDITTO et al.) 07 February 1995 (07.02.1995), entire document especially col 5, lns 22-25	20, 34-35
Y	US 4,228,853 A (HARVEY et al.) 21 October 1980 (21.10.1980), entire document especially col 14, lns 19-26 --	23
Y	US 2007/0187090 A1 (NGUYEN et al.) 16 August 2007 (16.08.2007), entire document especially the Abstract	39
A	US 4,280,559 A (BEST) 28 July 1981 (28.07.1981), entire document	1-42
A	US 4,617,993 A (BROWN) 21 October 1986 (21.10.1986), entire document	1-42
A	Heavy Oil And Oil Sands Operations Industry Recommended Practice (IRP), Volume 3 - 2002, ENFORM, January 2001 (01.2001) [retrieved on 01 December 2010 (01.12.2010)]. Retrieved from the Internet:<URL: http://www.enform.ca/media/3669/irp3_final_2005.pdf>	1-42