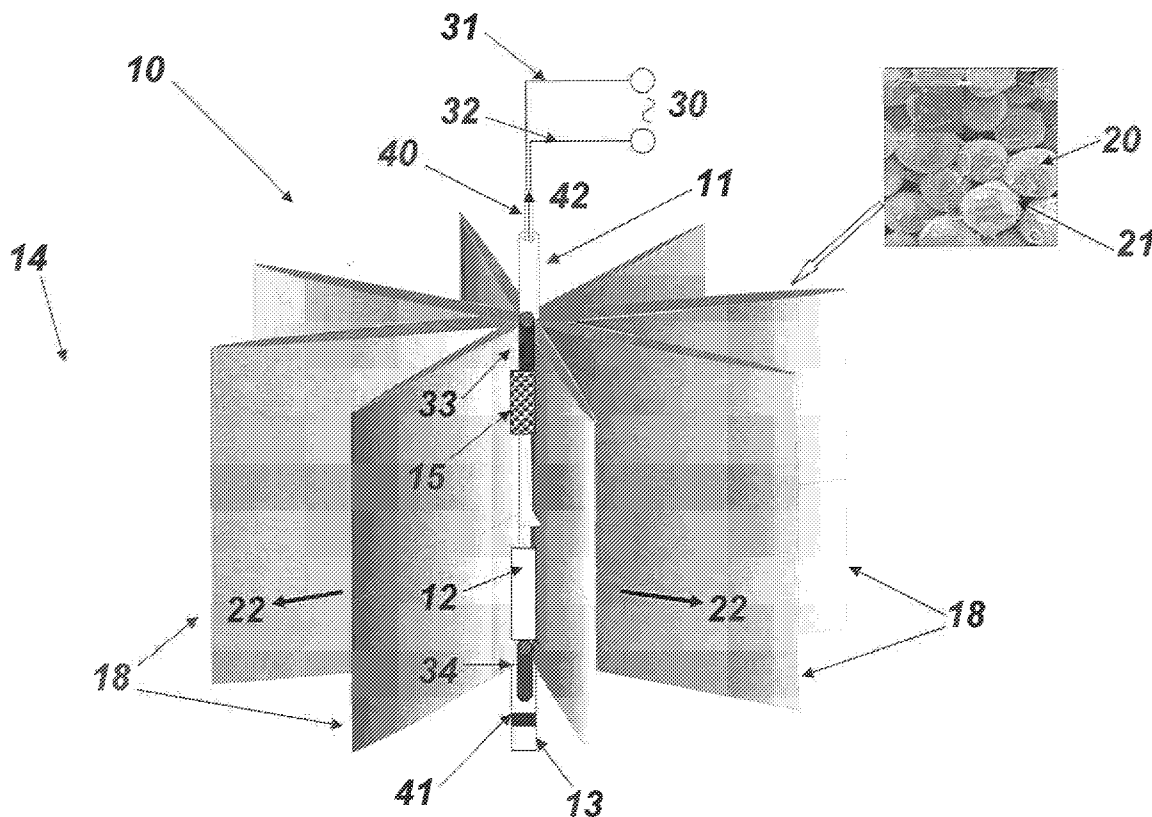


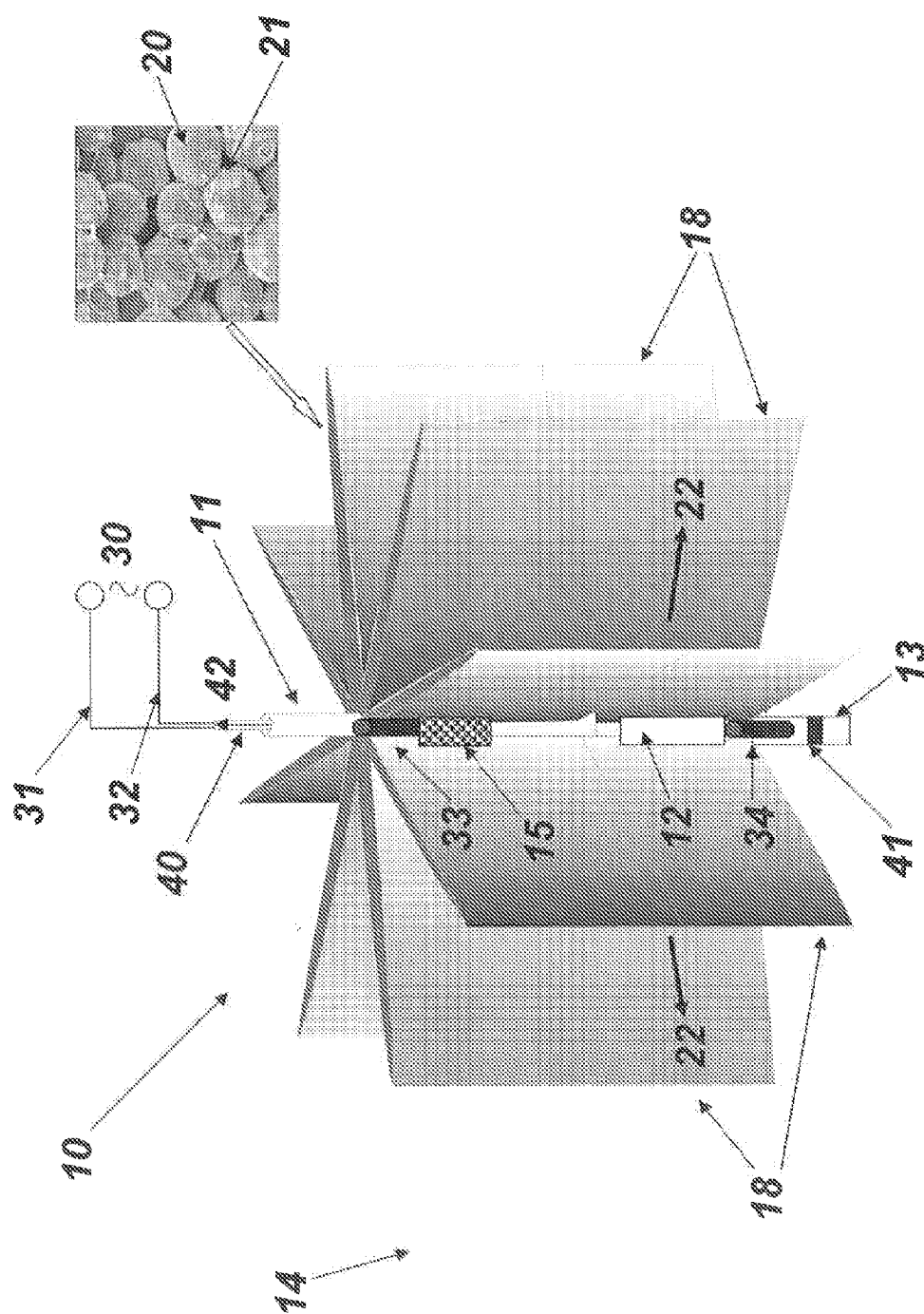


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(19) **United States**(12) **Patent Application Publication**
Hocking(10) **Pub. No.: US 2014/0096952 A1**(43) **Pub. Date: Apr. 10, 2014**(54) **ENHANCED HYDROCARBON RECOVERY
FROM A SINGLE WELL BY ELECTRICAL
RESISTIVE HEATING OF A SINGLE
INCLUSION IN AN OIL SAND FORMATION**(57) **ABSTRACT**(71) Applicant: **GeoSierra LLC**, (US)(72) Inventor: **Grant Hocking**, Alpharetta, GA (US)(73) Assignee: **GeoSierra LLC**, Alpharetta, GA (US)(21) Appl. No.: **13/644,584**(22) Filed: **Oct. 4, 2012****Publication Classification**(51) **Int. Cl.**
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The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by electrical resistive heating of the oil sand formation and the heavy oil and bitumen in situ, by electrically energizing vertical inclusion planes containing electrically conductive proppant. The inclusion is propagated into a portion of the formation having a Skempton's B parameter of greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the inclusion. Multiple propped vertical inclusions at various azimuths are constructed from the well. Electrodes are placed in the well in electrical contact with the inclusions and an alternating direction current is passed through the proppant. By electrically resistive heating of the inclusion, the formation is heated by conduction and associated hydrocarbon fluids are lowered in viscosity and drain by gravity back to the well and produced to the surface. By controlling the reservoir temperature and pressure, a particular fraction of the in situ hydrocarbon reserve is extracted and water inflow into the heated zone is minimized.





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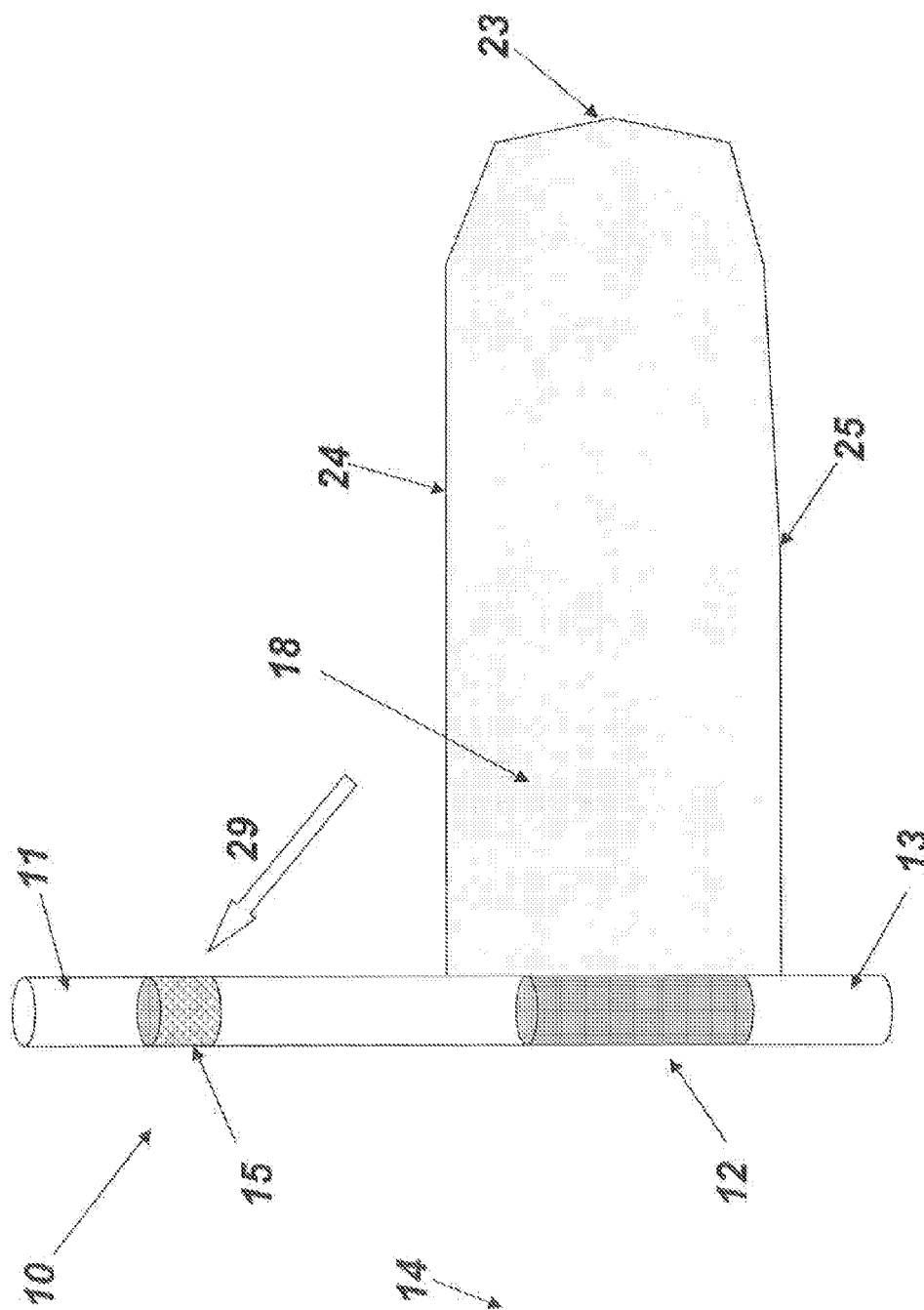


FIG. 2

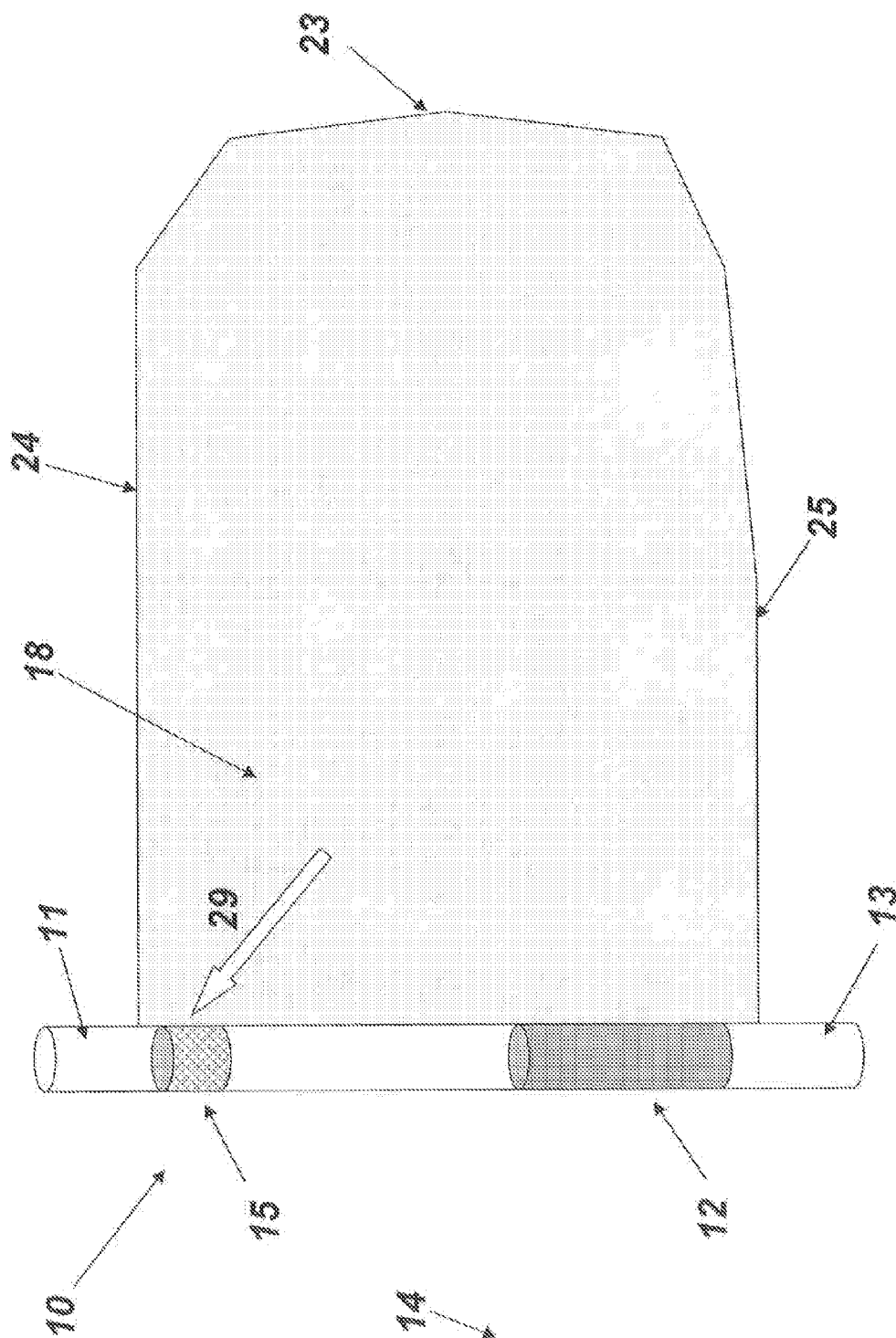


FIG. 3

**ENHANCED HYDROCARBON RECOVERY
FROM A SINGLE WELL BY ELECTRICAL
RESISTIVE HEATING OF A SINGLE
INCLUSION IN AN OIL SAND FORMATION**

TECHNICAL FIELD

[0001] The present invention generally relates to enhanced recovery of petroleum fluids from the subsurface by electrical resistive heating of electrically conductive proppant in vertical inclusions, thereupon heating the oil sand formation and the viscous heavy oil and bitumen in situ, more particularly to a method and apparatus to extract a particular fraction of the in situ hydrocarbon reserve by controlling the reservoir temperature and pressure, while also minimizing water inflow into the heated zone and well bore, resulting in increased production of petroleum fluids from the subsurface formation.

BACKGROUND OF THE INVENTION

[0002] Heavy oil and bitumen oil sands are abundant in reservoirs in many parts of the world such as those in Alberta, Canada, Utah and California in the United States, the Orinoco Belt of Venezuela, Indonesia, China and Russia. The hydrocarbon reserves of the oil sand deposit is extremely large in the trillions of barrels, with recoverable reserves estimated by current technology in the 300 billion barrels for Alberta, Canada and a similar recoverable reserve for Venezuela. These vast heavy oil (defined as the liquid petroleum resource of less than 20° API gravity) deposits are found largely in unconsolidated sandstones, being high porosity permeable cohesionless sands with minimal grain to grain cementation. The hydrocarbons are extracted from the oil sands either by mining or in situ methods.

[0003] The heavy oil and bitumen in the oil sand deposits have high viscosity at reservoir temperatures and pressures. While some distinctions have arisen between tar or oil sands, bitumen and heavy oil, these terms will be used interchangeably herein. The oil sand deposits in Alberta, Canada extend over many square miles and vary in thickness up to hundreds of feet thick. Although some of these deposits lie close to the surface and are suitable for surface mining, the majority of the deposits are at depth ranging from a shallow depth of 150 feet down to several thousands of feet below ground surface. The oil sands located at these depths constitute some of the world's largest presently known petroleum deposits. The oil sands contain a viscous hydrocarbon material, commonly referred to as bitumen, in an amount that ranges up to 15% by weight. Bitumen is effectively immobile at typical reservoir temperatures. For example at 15° C., bitumen has a viscosity of ~1,000,000 centipoise. However at elevated temperatures the bitumen viscosity changes considerably to be ~350 centipoise at 100° C. down to ~10 centipoise at 180° C. The oil sand deposits have an inherently high permeability ranging from ~1 to 10 Darcy, thus upon heating, the heavy oil becomes mobile and can easily drain from the deposit.

[0004] Solvents applied to the bitumen soften the bitumen and reduce its viscosity and provide a non-thermal mechanism to improve the bitumen mobility. Hydrocarbon solvents consist of vaporized light hydrocarbons such as ethane, propane or butane or liquid solvents such as pipeline diluents, natural condensate streams or fractions of synthetic crudes. The diluent can be added to steam and flashed to a vapor state or be maintained as a liquid at elevated temperature and

pressure, depending on the particular diluent composition. While in contact with the bitumen, the saturated solvent vapor dissolves into the bitumen. This diffusion process is due to the partial pressure difference between the saturated solvent vapor and the bitumen. As a result of the diffusion of the solvent into the bitumen, the oil in the bitumen becomes diluted and mobile and will flow under gravity. The resultant mobile oil may be deasphalted by the condensed solvent, leaving the heavy asphaltene behind within the oil sand pore space with little loss of inherent fluid mobility in the oil sands due to the small weight percent (5-15%) of the asphaltene fraction to the original oil in place. Deasphalting the oil from the oil sands produces a high grade quality product by 3°-5° API gravity. If the reservoir temperature is elevated the diffusion rate of the solvent into the bitumen is raised considerably being two orders of magnitude greater at 100° C. compared to ambient reservoir temperatures of ~15° C.

[0005] In situ methods of hydrocarbon extraction from the oil sands consist of cold production, in which the less viscous petroleum fluids are extracted from vertical and horizontal wells with sand exclusion screens, CHOPS (cold heavy oil production system) cold production with sand extraction from vertical and horizontal wells with large diameter perforations thus encouraging sand to flow into the well bore, CSS (cyclic steam stimulation) a huff and puff cyclic steam injection system with gravity drainage of heated petroleum fluids using vertical and horizontal wells, steamflood using injector wells for steam injection and producer wells on 5 and 9 point layout for vertical wells and combinations of vertical and horizontal wells, SAGD (steam assisted gravity drainage) steam injection and gravity production of heated hydrocarbons using two horizontal wells, VAPEX (vapor assisted petroleum extraction) solvent vapor injection and gravity production of diluted hydrocarbons using horizontal wells, and combinations of these methods.

[0006] Cyclic steam stimulation and steamflood hydrocarbon enhanced recovery methods have been utilized worldwide, beginning in 1956 with the discovery of CSS, huff and puff or steam-soak in Mene Grande field in Venezuela and for steamflood in the early 1960s in the Kern River field in California. These steam assisted hydrocarbon recovery methods including a combination of steam and solvent are described in U.S. Pat. No. 3,739,852 to Woods et al, U.S. Pat. No. 4,280,559 to Best, U.S. Pat. No. 4,519,454 to McMillen, U.S. Pat. No. 4,697,642 to Vogel, and U.S. Pat. No. 6,708,759 to Leaute et al. The CSS process raises the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance the surface area access of the steam to the bitumen. Successive steam injection cycles reenter earlier created fractures and thus the process becomes less efficient over time. CSS is generally practiced in vertical wells, but systems are operational in horizontal wells, but have complications due to localized fracturing and steam entry and the lack of steam flow control along the long length of the horizontal well bore.

[0007] Descriptions of the SAGD process and modifications are described in U.S. Pat. No. 4,344,485 to Butler, and U.S. Pat. No. 5,215,146 to Sanchez and thermal extraction methods in U.S. Pat. No. 4,085,803 to Butler, U.S. Pat. No. 4,099,570 to Vandergrift, and U.S. Pat. No. 4,116,275 to Butler et al. The SAGD process consists of two horizontal wells at the bottom of the hydrocarbon formation, with the injector well located approximately 10-15 feet vertically above the producer well. The steam injection pressures

exceed the formation fracturing pressure in order to establish connection between the two wells and develop a steam chamber in the oil sand formation. Similar to CSS, the SAGD method has complications, albeit less severe than CSS, due to the lack of steam flow control along the long section of the horizontal well and the difficulty of controlling the growth of the steam chamber.

[0008] A thermal steam extraction process referred to a HASDrive (heated annulus steam drive) and modifications thereof heat and hydrogenate the heavy oils in situ in the presence of a metal catalyst. See U.S. Pat. No. 3,994,340 to Anderson et al., U.S. Pat. No. 4,696,345 to Hsueh, U.S. Pat. No. 4,706,751 to Gondouin, U.S. Pat. No. 5,054,551 to Duerksen, and U.S. Pat. No. 5,145,003 to Duerksen. It is disclosed that at elevated temperature and pressure the injection of hydrogen or a combination of hydrogen and carbon monoxide to the heavy oil in situ in the presence of a metal catalyst will hydrogenate and thermal crack at least a portion of the petroleum in the formation.

[0009] Thermal recovery processes using steam require large amounts of energy to produce the steam, using either natural gas or heavy fractions of produced synthetic crude. Burning these fuels generates significant quantities of greenhouse gases, such as carbon dioxide. Also, the steam process uses considerable quantities of water, which even though may be reprocessed, involves recycling costs and energy use. Therefore a less energy intensive oil recovery process is desirable.

[0010] Solvents applied to the bitumen soften the bitumen and reduce its viscosity and provide a non-thermal mechanism to improve the bitumen mobility. Hydrocarbon solvents consist of vaporized light hydrocarbons such as ethane, propane or butane or liquid solvents such as pipeline diluents, natural condensate streams or fractions of synthetic crudes. The diluent can be added to steam and flashed to a vapor state or be maintained as a liquid at elevated temperature and pressure, depending on the particular diluent composition. While in contact with the bitumen, the saturated solvent vapor dissolves into the bitumen. This diffusion process is due to the partial pressure difference in the saturated solvent vapor and the bitumen. As a result of the diffusion of the solvent into the bitumen, the oil in the bitumen becomes diluted and mobile and will flow under gravity. The resultant mobile oil may be deasphalted by the condensed solvent, leaving the heavy asphaltenes behind within the oil sand pore space with little loss of inherent fluid mobility in the oil sands due to the small weight percent (5-15%) of the asphaltene fraction to the original oil in place. Deasphalting the oil from the oil sands produces a high grade quality product by 3°-5° API gravity. If the reservoir temperature is elevated the diffusion rate of the solvent into the bitumen is raised considerably being two orders of magnitude greater at 100° C. compared to ambient reservoir temperatures of ~15° C.

[0011] Solvent assisted recovery of hydrocarbons in continuous and cyclic modes are described including the VAPEX process and combinations of steam and solvent plus heat. See U.S. Pat. No. 4,450,913 to Allen et al, U.S. Pat. No. 4,513,819 to Islip et al, U.S. Pat. No. 5,407,009 to Butler et al, U.S. Pat. No. 5,607,016 to Butler, U.S. Pat. No. 5,899,274 to Frauenfeld et al, U.S. Pat. No. 6,318,464 to Mokrys, U.S. Pat. No. 6,769,486 to Lim et al, and U.S. Pat. No. 6,883,607 to Neniger et al. The VAPEX process generally consists of two horizontal wells in a similar configuration to SAGD; however, there are variations to this including spaced horizontal

wells and a combination of horizontal and vertical wells. The startup phase for the VAPEX process can be lengthy and take many months to develop a controlled connection between the two wells and avoid premature short circuiting between the injector and producer. The VAPEX process with horizontal wells has similar issues to CSS and SAGD in horizontal wells, due to the lack of solvent flow control along the long horizontal well bore, which can lead to non-uniformity of the vapor chamber development and growth along the horizontal well bore.

[0012] Direct heating and electrical heating methods for enhanced recovery of hydrocarbons from oil sands and oil shales have been disclosed in combination with steam, hydrogen, catalysts and/or solvent injection at temperatures to ensure the petroleum fluids gravity drain from the formation and at significantly higher temperatures (300° to 400° range and above) to pyrolysis the oil shales. See U.S. Pat. No. 2,780,450 to Ljungström, U.S. Pat. No. 4,597,441 to Ware et al, U.S. Pat. No. 4,926,941 to Glandt et al, U.S. Pat. No. 5,046,559 to Glandt, U.S. Pat. No. 5,060,726 to Glandt et al, U.S. Pat. No. 5,297,626 to Vinegar et al, U.S. Pat. No. 5,392,854 to Vinegar et al, U.S. Pat. No. 6,722,431 to Karanikas et al. In situ combustion processes have also been disclosed see U.S. Pat. No. 5,211,230 to Ostapovich et al, U.S. Pat. No. 5,339,897 to Leaute, U.S. Pat. No. 5,413,224 to Laali, and U.S. Pat. No. 5,954,946 to Klazinga et al.

[0013] In situ processes involving downhole heaters are described in U.S. Pat. No. 2,634,961 to Ljungström, U.S. Pat. No. 2,732,195 to Ljungström, U.S. Pat. No. 2,780,450 to Ljungström. Electrical heaters are described for heating viscous oils in the forms of downhole heaters and electrical heating of tubing and/or casing, see U.S. Pat. No. 2,548,360 to Germain, U.S. Pat. No. 4,716,960 to Eastlund et al, U.S. Pat. No. 5,060,287 to Van Egmond, U.S. Pat. No. 5,065,818 to Van Egmond, U.S. Pat. No. 6,023,554 to Vinegar and U.S. Pat. No. 6,360,819 to Vinegar. Flameless downhole combustor heaters are described, see U.S. Pat. No. 5,255,742 to Mikus, U.S. Pat. No. 5,404,952 to Vinegar et al, U.S. Pat. No. 5,862,858 to Wellington et al, and U.S. Pat. No. 5,899,269 to Wellington et al. Surface fired heaters or surface burners may be used to heat a heat transferring fluid pumped downhole to heat the formation as described in U.S. Pat. No. 6,056,057 to Vinegar et al and U.S. Pat. No. 6,079,499 to Mikus et al.

[0014] The thermal and solvent methods of enhanced oil recovery from oil sands, all suffer from a lack of surface area access to the in place bitumen. Thus the reasons for raising steam pressures above the fracturing pressure in CSS and during steam chamber development in SAGD, are to increase surface area of the steam with the in place bitumen. Similarly the VAPEX process is limited by the available surface area to the in place bitumen, because the diffusion process at this contact controls the rate of softening of the bitumen. Likewise during steam chamber growth in the SAGD process the contact surface area with the in place bitumen is virtually a constant, thus limiting the rate of heating of the bitumen. Therefore both methods (heat and solvent) or a combination thereof would greatly benefit from a substantial increase in contact surface area with the in place bitumen. Hydraulic fracturing of low permeable reservoirs has been used to increase the efficiency of such processes and CSS methods involving fracturing are described in U.S. Pat. No. 3,739,852 to Woods et al, U.S. Pat. No. 5,297,626 to Vinegar et al, and U.S. Pat. No. 5,392,854 to Vinegar et al. Also during initiation of the SAGD process overpressurized conditions are usually

imposed to accelerate the steam chamber development, followed by a prolonged period of underpressurized condition to reduce the steam to oil ratio. Maintaining reservoir pressure during heating of the oil sands has the significant benefit of minimizing water inflow to the heated zone and to the well bore.

[0015] Electrical resistive heating of oil shale and oil sand formations utilizing a hydraulic fracture filled with an electrically conductive material are described in U.S. Pat. No. 3,137,347 to Parker, involving a horizontal hydraulic fracture filled with conductive proppant and with the use of two (2) wells to electrically energizing the fracture and raise the temperature of the oil shale to pyrolyze the organic matter and produce hydrocarbon from a third well, in U.S. Pat. No. 5,620,049 to Gipson et al. with a single well configuration in a hydrocarbon formation predominantly a vertical fracture filled with conductive temperature setting resin coated proppant and the electric current passes through the conductive proppant to a surface ground and the single well is completed to raise the temperature of the oil in-situ to reduce its viscosity and produce hydrocarbons from the same well, in U.S. Pat. No. 6,148,911 to Gipson et al. with a single well configuration in a gas hydrate formation with predominantly a horizontal fracture filled with conductive proppant and the electric current passes through the conductive proppant to a surface ground, raising the temperature of the formation to release the methane from the gas hydrates and the single well is completed for methane production, in U.S. Pat. No. 7,331,385 to Symington et al. in U.S. Pat. No. 7,631,691 to Symington et al. and in Canadian Patent No. 2,738,873 to Symington et al. all with a predominantly vertical fracture filled with conductive proppant and the conductive fracture is electrically energized by contact with at least two (2) wells or in the case of a single well presumably through the well and surface ground with the oil shale raised to a temperature to pyrolyze the organic matter into producible hydrocarbons, with the electrically conductive fracture composed of electrically conductive proppant and non-electrically conductive non-permeable cement. The single well systems described above all suffer from low efficiency and high energy loss due to the current passes through a significant distance of the formation from the conductive fracture to the surface ground. Also the systems with two or more wellbores do not disclosed how the electrode to conductive fracture contact will be other than a point contact resulting in significant energy loss and overheating at such a contact.

[0016] It is well known that extensive heavy oil reservoirs are found in formations comprising unconsolidated, weakly cemented sediments. Unfortunately, the methods currently used for extracting the heavy oil from these formations have not produced entirely satisfactory results. Heavy oil is not very mobile in these formations, and so it would be desirable to be able to form increased permeability planes in the formations and by placing electrically conductive proppant in these planes, and by passing an electric current through the propped planes, heating the formation and thus increase the mobility of the heavy oil in the formation and by drainage through the permeable planes to the wellbore for production up the well.

[0017] However, techniques used in hard, brittle rock to form fractures therein are typically not applicable to ductile formations comprising unconsolidated, weakly cemented sediments. The method of controlling the azimuth of a vertical hydraulic planar inclusion in formations of unconsoli-

dated or weakly cemented soils and sediments by slotting the well bore or installing a pre-slotted or weakened casing at a predetermined azimuth has been disclosed. The method disclosed that a vertical hydraulic planar inclusion can be propagated at a pre-determined azimuth in unconsolidated or weakly cemented sediments and that multiple orientated vertical hydraulic planar inclusions at differing azimuths from a single well bore can be initiated and propagated for the enhancement of petroleum fluid production from the formation. See U.S. Pat. No. 6,216,783 to flocking et al, U.S. Pat. No. 6,443,227 to flocking et al, U.S. Pat. No. 6,991,037 to Hocking, U.S. Pat. No. 7,404,441 to Hocking, U.S. Pat. No. 7,640,975 to Cavender et al. U.S. Pat. No. 7,640,982 to Schultz et al., U.S. Pat. No. 7,748,458 to Hocking, U.S. Pat. No. 7,814,978 to Steele et al., U.S. Pat. No. 7,832,477 to Cavender et al., U.S. Pat. No. 7,866,395 to Hocking, U.S. Pat. No. 7,950,456 to Cavender et al., U.S. Pat. No. 8,151,874 to Schultz et al. The method disclosed that a vertical hydraulic planar inclusion can be propagated at a pre-determined azimuth in unconsolidated or weakly cemented sediments and that multiple orientated vertical hydraulic planar inclusions at differing azimuths from a single well bore can be initiated and propagated for the enhancement of petroleum fluid production from the formation. It is now known that unconsolidated or weakly cemented sediments behave substantially different from brittle rocks from which most of the hydraulic fracturing experience is founded.

[0018] The methods disclosed above find especially beneficial application in ductile rock formations made up of unconsolidated or weakly cemented sediments, in which it is typically very difficult to obtain directional or geometric control over inclusions as they are being formed. Weakly cemented sediments are primarily frictional materials since they have minimal cohesive strength. An uncemented sand having no inherent cohesive strength (i.e., no cement bonding holding the sand grains together) cannot contain a stable crack within its structure and cannot undergo brittle fracture. Such materials are categorized as frictional materials which fail under shear stress, whereas brittle cohesive materials, such as strong rocks, fail under normal stress.

[0019] The term "cohesion" is used in the art to describe the strength of a material at zero effective mean stress. Weakly cemented materials may appear to have some apparent cohesion due to suction or negative pore pressures created by capillary attraction in fine grained sediment, with the sediment being only partially saturated. These suction pressures hold the grains together at low effective stresses and, thus, are often called apparent cohesion.

[0020] The suction pressures are not true bonding of the sediment's grains, since the suction pressures would dissipate due to complete saturation of the sediment. Apparent cohesion is generally such a small component of strength that it cannot be effectively measured for strong rocks, and only becomes apparent when testing very weakly cemented sediments.

[0021] Geological strong materials, such as relatively strong rock, behave as brittle materials at normal petroleum reservoir depths, but at great depth (i.e. at very high confining stress) or at highly elevated temperatures, these rocks can behave like ductile frictional materials. Unconsolidated sands and weakly cemented formations behave as ductile frictional materials from shallow to deep depths, and the behavior of such materials are fundamentally different from rocks that exhibit brittle fracture behavior. Ductile frictional materials

fail under shear stress and consume energy due to frictional sliding, rotation and displacement.

[0022] Conventional hydraulic dilation of weakly cemented sediments is conducted extensively on petroleum reservoirs as a means of sand control. The procedure is commonly referred to as "Frac-and-Pack." in a typical operation, the casing is perforated over the formation interval intended to be fractured and the formation is injected with a treatment fluid of low gel loading without proppant, in order to form the desired two winged structure of a fracture. Then, the proppant loading in the treatment fluid is increased substantially to yield tip screen-out of the fracture. In this manner, the fracture tip does not extend further, and the fracture and perforations are backfilled with proppant.

[0023] The process assumes a two winged fracture is formed as in conventional brittle hydraulic fracturing. However, such a process has not been duplicated in the laboratory or in shallow field trials. In laboratory experiments and shallow field trials what has been observed is chaotic geometries of the injected fluid, with many cases evidencing cavity expansion growth of the treatment fluid around the well and with deformation or compaction of the host formation.

[0024] Weakly cemented sediments behave like a ductile frictional material in yield due to the predominantly frictional behavior and the low cohesion between the grains of the sediment. Such materials do not "fracture" and, therefore, there is no inherent fracturing process in these materials as compared to conventional hydraulic fracturing of strong brittle rocks.

[0025] Linear elastic fracture mechanics is not generally applicable to the behavior of weakly cemented sediments. The knowledge base of propagating viscous planar inclusions in weakly cemented sediments is primarily from recent experience over the past ten years and much is still not known regarding the process of viscous fluid propagation in these sediments.

[0026] Accordingly, there is a need for a method and apparatus for enhancing the extraction of hydrocarbons from oil sands in a single well and in multiple wells by direct electrical resistive heating of electrically conductive permeable vertical inclusions combined with steam, gas and/or solvent injection or a mixture thereof and controlling the subsurface environment, both temperature and pressure to optimize the hydrocarbon extraction in terms of produced rate, efficiency and produced product quality, as well as limit water inflow into the process zone.

SUMMARY OF THE INVENTION

[0027] The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by electrical resistive heating of the oil sand formation and the heavy oil and bitumen in situ, by electrically energizing vertical inclusion planes containing electrically conductive proppant. In one embodiment of this invention, multiple propped vertical inclusions at various azimuths are constructed from a single well and propagate into the oil sand formation and filled with a highly electrically conductive proppant. An upper portion of the well is hydraulically connected to the formation and provides for a sink for mobile formation and injected fluids. This pore pressure sink attracts the lower propagating inclusion and ensures the inclusion propagates upward in the formation and connects with the well at the upper hydraulically open section. Electrodes are placed in the well in electrical contact with the lowermost and

uppermost portions of the inclusions and an alternating direction current is passed through the proppant contained in the inclusions. By electrically resistive heating of the inclusions, the formation is heated by conduction and associated hydrocarbon fluids are lowered in viscosity and drain by gravity back to the well to be produced to the surface.

[0028] The heating of the formation and in place heavy oil and bitumen is via heat conduction from the electrically resistive heated inclusions and is predominantly circumferential, i.e. orthogonal to the propped vertical inclusions. To limit upward growth of the process and/or to limit loss of heat by conduction to overlying formations, a non condensing gas can be injected to remain in the uppermost portions of the heated process zone.

[0029] Although the present invention contemplates the formation of vertical propped inclusions which generally extend laterally away from a vertical or near vertical well penetrating an earth formation and in a generally vertical plane, those skilled in the art will recognize that the invention may be carried out in earth formations wherein the fractures and the well bores can extend in directions other than vertical.

[0030] Therefore, the present invention provides a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by electrically resistive heating propped electrical conductive permeable inclusions, thereupon heating the oil sand formation and the viscous heavy oil and bitumen in situ, more particularly to a method and apparatus to extract a particular fraction of the in situ hydrocarbon reserve by controlling the reservoir temperature and pressure, while also minimizing water inflow into the heated zone and well bore resulting in increased production of petroleum fluids from the subsurface formation.

[0031] Other objects, features and advantages of the present invention will become apparent upon reviewing the following description of the preferred embodiments of the invention, when taken in conjunction with the drawings and the claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0032] FIG. 1 is a schematic isometric view of a well system and associated method embodying principles of the present invention;

[0033] FIG. 2 is a schematic isometric view of the well system with a single lower propagating inclusion with an upper section of the well hydraulically connected to the formation;

[0034] FIG. 3 is a schematic isometric view of the well system completed with a single inclusion that extends upward to the upper open section of the well.

DETAILED DESCRIPTION OF THE DISCLOSED EMBODIMENT

[0035] Several embodiments of the present invention are described below and illustrated in the accompanying drawings. The present invention involves a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by electrical resistive heating of propped vertical inclusions in the oil sand formation, and thus heating the oil sand formation and the heavy oil and bitumen in situ by conduction. Multiple propped vertical inclusions at various azimuths are constructed from the well into the oil sand formation and filled with a electrically conductive proppant. Electrodes are placed in the well, and an alternating current passes through

the electrically conductive proppant contained in the inclusions, thus heating the inclusion by electrical resistive heating and in turn heating the formation and fluids by thermal conduction. The low viscosity heated hydrocarbon liquids drain by gravity and are produced to the surface up the well.

[0036] It is well known that extensive heavy oil reservoirs are found in formations comprising unconsolidated, weakly cemented sediments. Unfortunately, the methods currently used for extracting the heavy oil from these formations have not produced entirely satisfactory results. Heavy oil is not very mobile in these formations, and so it would be desirable to be able to form increased permeability planes in the formations and by placing electrically conductive proppant in these planes, and by passing an alternating electric current through the propped planes, giving rise to electrically resistive heating of the proppant, and heating the formation by thermal conduction and thus increase the mobility of the heavy oil in the formation and by gravity drainage through the permeable planes to the wellbore for production up the well.

[0037] Representatively illustrated in FIG. 1 is a well system 10 and associated method which embody principles of the present invention. The system 10 is particularly useful for producing heavy oil 42 from a formation 14. The formation 14 may comprise unconsolidated and/or weakly cemented sediments for which conventional fracturing operations are not well suited. The term "heavy oil" is used herein to indicate relatively high viscosity and high density hydrocarbons, such as bitumen. Heavy oil is typically not recoverable in its natural state (e.g., without heating or diluting) via wells, and may be either mined or recovered via wells through use of steam and solvent injection, in situ combustion, etc. Gas-free heavy oil generally has a viscosity of greater than 100 centipoise and a density of less than 20 degrees API gravity (greater than about 900 kilograms/cubic meter).

[0038] As depicted in FIG. 1, a single vertical well has been drilled into the formation 14 and the well casing 11 has been cemented in the formation 14. The term "casing" is used herein to indicate a protective lining for a wellbore. Any type of protective lining may be used, including those known to persons skilled in the art as liner, casing, tubing, etc. Casing may be segmented or continuous, jointed or unjointed, conductive or non-conductive made of any material (such as steel, aluminum, polymers, composite materials, etc.), and may be expanded or unexpanded, etc.

[0039] The casing string 11 has an expansion device 12, an open section 15 and a sump section 13 interconnected therein. The open section 15 of the well could be a perforated section of the casing, a screen, slotted liner, etc providing hydraulic connection between the upper portion of the well 15 and the formation 14. The open section 15 of the well is maintained at a lower pressure and independently of the injected fluid 22 pressure. The expansion device 12 operates to expand the casing string 11 radially outward and thereby dilate the formation 14 proximate the devices, in order to initiate forming of generally vertical and planar inclusions 18, extending outwardly from the wellbore at various azimuths. Suitable expansion devices for use in the well system 10 are described in U.S. Pat. Nos. 6,216,783, 6,330,914, 6,443,227, 6,991,037, 7,404,441, 7,640,975, 7,640,982, 7,748,458, 7,814,978, 7,832,477, 7,866,395, 7,950,456 and 8,151,874. The entire disclosures of these prior patents are incorporated herein by this reference. Other expansion devices may be used in the well system 10 in keeping with the principles of the invention.

[0040] Once the device 12 is operated to expand the casing string 11 radially outward, fluid 22 is forced into the dilated formation 14 to propagate the inclusions 18 into the formation. It is not necessary for the inclusions 18 to be formed simultaneously. Shown in FIG. 1 is an eight (8) wing inclusion well system 10, with eight (8) inclusions 18 formed. The well system 10 does not necessarily need to consist of eight (8) inclusions at the same depth orientated at various azimuths, but could consist of one, two, three, four, five, six or even seven vertical planar inclusions at various azimuths at the same depth, with such choice of the number of inclusions constructed depending on the application, formation type and/or economic benefit.

[0041] Typically, the inclusions 18 are constructed with each wing of the eight (8) inclusions 18 injected independently of the others. As the inclusions 18 are propagated into the formation 14, the upper open section 15 of the well acts as a pore pressure sink and thus attracts and accelerates the upward propagation of the inclusions 18, so as to extend up to this open section 15. The formation 14 pore space may contain a significant portion of immobile heavy oil or bitumen generally up to a maximum oil saturation of 90%; however, even at these very high oil saturations of 90%, i.e. very low water saturation of 10%, the mobility of the formation pore water is quite high, due to its viscosity and the formation permeability. The open section 15 allows mobile formation pore fluids and the injected fluid 22 to enter the well at 15 at a reduced pressure, with 15 being at a lower pressure and independent of the injected fluid 22 pressure. Upon the inclusions 18 reaching the upper open section 15, its upward tip propagation rate will be reduced significantly. The well system 10 is shown with inclusions 18 constructed at only a single depth, this well system 10 is cited as only one example of the invention, since there could be alternate forms of the invention containing numerous of upper inclusions constructed at progressively shallower depths, depending on the formation thickness, the distribution of hydrocarbons within the formation 14, and/or economic benefit.

[0042] The injected fluid 22 carries the proppant to the extremes of the inclusions 18. Upon propagation of the inclusions 18 to their required lateral and vertical extent, the thickness of the inclusions 18 may need to be increased by utilizing the process of tip screen out. The tip screen out process involves modifying the proppant loading and/or inject fluid 22 properties to achieve a proppant bridge at the inclusion tips. The injected fluid 22 is further injected after tip screen out, but rather than extending the inclusion laterally or vertically, the injected fluid 22 widens, i.e. thickens, and fills the inclusion from the inclusion tips back to the well bore.

[0043] The behavioral characteristics of the injected viscous fluid 22 are preferably controlled to ensure the propagating viscous inclusions maintain their azimuth directionality, such that the viscosity of the injected fluid 22 and its volumetric rate are controlled within certain limits depending on the formation 14 and the specific gravity and size distribution of the proppant 20. For example, the viscosity of the injected fluid 22 is preferably greater than approximately 100 centipoise. However, if foamed fluid is used, a greater range of viscosity and injection rate may be permitted while still maintaining directional and geometric control over the inclusions. The viscosity and volumetric rate of the injected fluid 22 needs to be sufficient to transport the electrically conductive proppant 20 to the extremities of the inclusions. The size distribution of the proppant 20 needs to be matched with that

of the formation **14**, to ensure formation fines do not migrate into the propped pack inclusion during hydrocarbon production. Typical size distribution of the proppant would range from #12 to #20 U.S. Mesh for oil sand formations, with an ideal proppant being ceramic beads coated with a electrically conductive resin, of which one particularly suitable conductive resin comprises phenol formaldehyde containing fine graphite particles. Such a resin is heat hardenable at temperatures of around 60° C. or higher, thus capable of mechanically binding the proppant together **21** without loss of permeability of the propped inclusion.

[0044] The well system **10**, has electrodes **33, 34** placed inside of the casing and in electrical contact with the conductive proppant **20**. These electrodes **33, 34** are connected via insulated cables **31, 32** to an alternating direction current power source **30**. Upon energizing the electrical power source **30**, current passes through the proppant **20** from the top to the bottom of the inclusions **18** and by electrical resistive heating raises the temperature of the proppant **20** in the inclusions **18**. At elevated temperature the conductive resin heat hardens to bind the proppant particles together at their contacts **21**, without impacting the proppant pack permeability of the inclusions **18**. The resistive heat propagates circumferentially from the inclusions **18** and conductively heats the formation **14** and its associated fluids. Heated heavy oil and bitumen will thus be mobilized and flow under gravity towards the well and enter the sump **13** and pumped to surface via a PCP (progressive cavity pump), ESP (electrical submersible pump), gas lift or natural lift **41**, depending on operating temperatures, pressures and depth, via a production tubing **40**.

[0045] The selected range of temperatures and pressures to operate the process will depend on reservoir depth, ambient conditions, quality of the in place heavy oil and bitumen, and the presence of nearby water bodies. The process can be operated at a low temperature range of ~100° C. for a heavy oil rich oil sand deposit and at a moderate temperature range of ~150°-180° C. for a bitumen rich oil sand deposit, basically to reduce the heavy oil and bitumen viscosity and thus mobilized the in place oil. However, the process can be operated at much higher temperatures >270° C. to pyrolysis the in place hydrocarbon in the presence of H₂, CO and/or catalysts. Thus the proppant could contain such catalysts, or these catalysts could be incorporated into a canister in line with the production tubing in the well. Such catalysts are really available as HDS (hydrodesulfurization) metal containing catalysts, and FCC (fluid catalytic cracking) rare earth aluminum silica catalysts.

[0046] The operating pressure of the process may be selected to closely match the ambient reservoir conditions to minimize water inflow into the process zone and the well bore by the injection of steam, gas or vaporized solvent. The process zone can be injected with a vaporized hydrocarbon solvent, such as ethane, propane or butane and mixed with a diluent gas, such as methane, nitrogen and carbon dioxide. The solvent will contact the in situ bitumen at the edge of the process zone, diffusive into and soften the bitumen, so that it flows by gravity to the well bore. Dissolved solvent and product hydrocarbon are produced and further solvent and diluent gas injected into the process zone. The elevated temperature of the process zone will significantly accelerate the diffusion process of the solvent diffusing into the bitumen compared to ambient reservoir conditions. The solvent and diluent gas will be injected at near reservoir pressures to minimize water inflow into the process zone. The solvent

vapor in the injection gas is maintained saturated at or near its dew point at the process operating temperatures and pressures.

[0047] The formation **14** could be comprised of relatively hard and brittle rock, but the system **10** and method find especially beneficial application in ductile rock formations made up of unconsolidated or weakly cemented sediments, in which it is typically very difficult to obtain directional or geometric control over inclusions as they are being formed.

[0048] However, the present disclosure provides information to enable those skilled in the art of hydraulic fracturing, soil and rock mechanics to practice a method and system **10** to initiate and control the propagation of a viscous fluid in weakly cemented sediments, and importantly for the propagating inclusion to intersect and coalesce with earlier placed permeable inclusions and thus form a continuous planar inclusion on a particular azimuth from within a single well or between multiple wells.

[0049] The system and associated method are applicable to formations of weakly cemented sediments with low cohesive strength compared to the vertical overburden stress prevailing at the depth of interest. Low cohesive strength is defined herein as no greater than 3 MegaPascas (MPa) plus 0.4 times the mean effective stress (p') in MPa at the depth of propagation.

$$c < 3 \text{ MPa} + 0.4p' \quad (1)$$

where c is cohesive strength in MPa and p' is mean effective stress in the formation.

[0050] Examples of such weakly cemented sediments are sand and sandstone formations, mudstones, shales, and siltstones, all of which have inherent low cohesive strength. Critical state soil mechanics assists in defining when a material is behaving as a cohesive material capable of brittle fracture or when it behaves predominantly as a ductile frictional material.

[0051] Weakly cemented sediments are also characterized as having a soft skeleton structure at low effective mean stress due to the lack of cohesive bonding between the grains. On the other hand, hard strong stiff rocks will not substantially decrease in volume under an increment of load due to an increase in mean stress.

[0052] In the art of poroelasticity, the Skempton B parameter is a measure of a sediment's characteristic stiffness compared to the fluid contained within the sediment's pores. The Skempton B parameter is a measure of the rise in pore pressure in the material for an incremental rise in mean stress under undrained conditions.

[0053] In stiff rocks, the rock skeleton takes on the increment of mean stress and thus the pore pressure does not rise, i.e., corresponding to a Skempton B parameter value of at or about 0. But in a soft soil, the soil skeleton deforms easily under the increment of mean stress and, thus, the increment of mean stress is supported by the pore fluid under undrained conditions (corresponding to a Skempton B parameter of at or about 1).

[0054] The following equations illustrate the relationships between these parameters in equations denoted as (2) as follows:

$$\begin{aligned} \Delta u &= B \Delta p \\ B &= (K_u - K) / (\alpha K_u) \\ \alpha &= 1 - (K / K_s) \end{aligned} \quad (2)$$

where Δu is the increment of pore pressure, B the Skempton B parameter, Δp the increment of mean stress, K_u is the undrained formation bulk modulus, K the drained formation bulk modulus, α is the Biot-Willis poroelastic parameter, and K_s is the bulk modulus of the formation grains. In the system and associated method, the bulk modulus K of the formation for inclusion propagation is preferably less than approximately 5 GPa.

[0055] For use of the system **10** and method in weakly cemented sediments, preferably the Skempton B parameter is as follows with p' in MPa:

$$B > 0.95 \exp(-0.04p') + 0.008p' \quad (3)$$

The system and associated method are applicable to formations of weakly cemented sediments (such as tight gas sands, mudstones and shales) where large extensive propped vertical permeable drainage planes are desired to intersect thin sand lenses and provide drainage paths for greater gas production from the formations^o in weakly cemented formations containing heavy oil (viscosity > 1.00 centipoise) or bitumen (extremely high viscosity > 100,000 centipoise), generally known as oil sands, propped vertical permeable drainage planes provide drainage paths for cold production from these formations, and access for steam, solvents, oils, and heat to increase the mobility of the petroleum hydrocarbons and thus aid in the extraction of the hydrocarbons from the formation. In highly permeable weak sand formations, permeable drainage planes of large lateral length result in lower drawdown of the pressure in the reservoir, which reduces the fluid gradients acting towards the wellbore, resulting in less drag on fines in the formation, resulting in reduced flow of formation fines into the wellbore.

[0056] Proppant is carried by the injected fluid, resulting in a highly permeable planar inclusion. Such proppants are typically clean sand or specialized manufactured particles (generally ceramic in composition), and depending on the size composition, closure stress and proppant type, the permeability of the fracture can be controlled. Electrically conductive proppant can consist of metal coated ceramics, metal proppant, calcined petroleum coke, graphite beads, green or black silicon carbide, boron carbide, metal fiber, shaving or platelets, or non-conductive sands, glass or ceramics with electrically conductive resin or metal coating, or a mixture thereof to achieve the desired electrical conductivity, permeability and also to limit flow back of the proppant from the propped inclusion into the well bore during production of the hydrocarbons from the formation. The permeability of the propped inclusions **18** will typically be orders of magnitude greater than the formation **14** permeability, generally at least by two orders of magnitude. As regards the electrical conductivity of the propped inclusions **18**, the electrical conductivity needs to be greater than the formation **14** electrical conductivity, but not too great whereas electric energy is lost by excessive short-circuiting between the electrodes, but an optimum value to achieve optimum, efficient and economical resistive heating of the inclusions **18**.

[0057] The injected fluid **22** varies depending on the application and can be water, oil or multi-phased based gels. Aqueous based fracturing fluids consist of a polymeric gelling agent such as solvatable (or hydratable) polysaccharide, e.g. galactomannan gums, glycomannan gums and cellulose derivatives. The purpose of the hydratable polysaccharides is to thicken the aqueous solution and thus act as viscosifiers, i.e. increase the viscosity by 100 times or more over the base

aqueous solution. A cross-linking agent can be added which further increases the viscosity of the solution. The borate ion has been used extensively as a cross-linking agent for hydrated guar gums and other galactomannans, see U.S. Pat. No. 3,059,909 to Wise. Other suitable cross-linking agents are chromium, iron, aluminum, and zirconium (see U.S. Pat. No. 3,301,723 to Chrisp) and titanium (see U.S. Pat. No. 3,888,312 to Tiner et al). A breaker is added to the solution to controllably degrade the viscous fracturing fluid. Common breakers are enzymes and catalyzed oxidizer breaker systems, with weak organic acids sometimes used.

[0058] An enlarged scale isometric view of the system **10** is representatively illustrated in FIG. **2**. This view depicts the system **10** during the propagation of only one of the inclusions **18**, to provide a clearer description of the process used to construct the system **10**. The viscous fluid propagation process in these sediments involves the unloading of the formation **14** in the vicinity of the tips **23**, **24**, **25** of the propagating viscous fluid **22**, causing dilation of the formation **14**, which generates pore pressure gradients towards this dilating zone. As the formation **14** dilates at the tips **23**, **24**, **25** of the advancing viscous fluid **22**, the pore pressure decreases dramatically at the tips, resulting in increased pore pressure gradients surrounding the tips.

[0059] The pore pressure gradients at the tips **23**, **24**, **25** of the inclusion **18** result in the liquefaction, cavitation (degassing) or fluidization of the formation **14** immediately surrounding the tips. That is, the formation **14** in the dilating zone about the tips **23**, **24**, **25** acts like a fluid since its strength, fabric and in situ stresses have been destroyed by the fluidizing process, and this fluidized zone in the formation immediately ahead of the viscous fluid **22** propagating tips **23**, **24**, **25** is a planar path of least resistance for the viscous fluid to propagate further. In at least this manner, the system **10** and associated method provide for directional and geometric control over the advancing inclusions **18**.

[0060] The behavioral characteristics of the injected viscous fluid **22** are preferably controlled to ensure the propagating viscous fluid does not overrun the fluidized zone and lead to a loss of control of the propagating process. Thus, the viscosity of the fluid **22** and the volumetric rate of injection of the fluid should be controlled to ensure that the conditions described above persist while the inclusions **18** are being propagated through the formation **14**. The propagation rate of the inclusion **18** due to the injected fluid **22**, varies depending on direction, in general due to gravitation effects, the lateral tip **23** propagation rate is generally much greater than the upward tip **24** propagation rate and the downward tip **25** propagation rate. However, these tips **23**, **24**, **25** propagation rates can change due to heterogeneities in the formation **14**, pore pressure gradients especially associated with pore pressure sinks, and stress, stiffness and strength contrasts in the formation **14**.

[0061] During propagation of the inclusion **18**, the pore pressure in the overall formation will rise due to the injection of the fluid **22**. As the inclusion **18** propagates, the upper open section **15** of the well acts as a pore pressure sink and mobile formation pore fluids and injected fluid **22** flows towards **15** as shown by **29**. The open section **15** thus attracts and accelerates the upward tip **24** propagation rate of the inclusion **18**. The inclusion **18** grows upward towards the depth of the open section **15**, and upon reaching that depth its upward tip **24** propagation rate drops significantly.

[0062] Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 3. This view depicts the system 10 during the completion of only one of the inclusion 18, to provide a clearer description of the process used to construct the system 10. The inclusion 18 has been constructed to its final dimension, and upon reaching the depth of the open section 15, slows in its upward tip 24 propagation rate due to fluid loss 29, and thus extends further laterally, since its lateral tip 23 is not restricted by fluid loss 29 as is its upward tip 24. The inclusion 18 is now completed to its full lateral extent as shown and is increased in thickness if necessary by utilizing tip-screen out.

[0063] Finally, it will be understood that the preferred embodiment has been disclosed by way of example, and that other modifications may occur to those skilled in the art without departing from the scope and spirit of the appended claims.

1. A method of improving production of hydrocarbons from a subterranean formation of weakly cemented sediments, the method comprising the steps of:

- a) propagating a first substantially vertical inclusion into the formation at a first depth and in a first preferential direction from a substantially vertical wellbore intersecting the formation, wherein the first vertical inclusion is filled with an injected fluid including electrically conductive proppant particles;
 - b) locating an open section of the wellbore at a second depth displaced from the first depth;
 - c) maintaining the open section at a reduced pressure;
 - d) propagating the first inclusion vertically to the second depth of the open section;
 - e) passing an electric current through the inclusion by electrodes placed in the wellbore and heating the formation in a process zone in the vicinity of the first inclusion; and
 - f) producing the heated hydrocarbons up the wellbore.
2. The method of claim 1, wherein the second depth of the open section of the wellbore is below the first depth.
3. The method of claim 1, wherein the method includes propagating a plurality of inclusions at varying azimuths.
4. The method of claim 1, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are ceramic beads substantially coated with an electrically conductive resin.

5. The method of claim 4, wherein the resin is phenol formaldehyde containing fine graphite particles and is heat hardenable, with resin present in an amount sufficient to consolidate the proppant, but insufficient to fill the openings between the proppant.

6. The method of claim 1, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are selected from a group of conductive materials such as metals, melt alloys, metal oxides, metal salts, metal-containing catalysts, calcined petroleum coke or graphite beads, green or black silicon carbide, boron carbide or a mixture thereof.

7. The method of claim 1, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are selected from a group of non-conductive materials such as ceramics, glass and sands coated with a conductive layer either being metal, metal oxide, metal salts, conductive resins or mixtures thereof.

8. The method of claim 1, wherein pressure in the majority of the heated process zone is held at ambient reservoir pres-

sure by injecting into the process zone steam, non-condensing gas, or a hydrocarbon solvent in a vaporized state or a mixture thereof.

9. The method of claim 8, wherein the solvent is one of a group of ethane, propane, butane or a mixture thereof.

10. The method of claim 8, wherein the solvent is mixed with a diluent gas.

11. The method of claim 10, wherein the diluent gas is non-condensable under the process conditions.

12. The method of claim 11, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbons than the saturated hydrocarbon solvent.

13. The method of claim 12, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas or a mixture thereof.

14. The method of claim 1, wherein the method further includes injecting a hydrogenizing gas into the wellbore and thus into the fluids in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the hydrocarbons in the process zone.

15. The method of claim 14, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.

16. (canceled)

17. The method of claim 14, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.

18. The method of claim 17, wherein the catalyst is contained in a canister in tubing inside of the wellbore.

19. The method of claim 1, wherein the proppant particles in the inclusions include the catalyst for the hydrogenation and thermal cracking reactions.

20. The method of claim 1, wherein the second depth of the open section of the wellbore is above the first depth.

21. The method of claim 1, wherein a portion of the formation in which the first inclusion is formed has a Skempton B parameter greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the first inclusion and the water saturation in the formation pores is greater or equal to 10%.

22. A hydrocarbon production well in a subterranean formation of weakly cemented sediments having an ambient reservoir pressure and temperature comprising:

- a) a substantially vertical bore hole in the formation to a first depth;
- b) an injection casing grouted in the bore hole to create a substantially vertical wellbore, the injection casing being radially expandable by the introduction of a fluid;
- c) a vertical first inclusion in the formation created by the fluid delivered into the injection casing with sufficient pressure to dilate the injection casing and to create the first inclusion in the formation, wherein the first inclusion is filled with the fluid including electrically conductive proppant particles and wherein the first inclusion is oriented in the formation in a first preferential direction extending from and in communication with the substantially vertical wellbore
- d) an open section of the wellbore located at a second depth displaced from the first depth;
- e) means for maintaining a reduced pressure at the open section;
- f) the first inclusion extending from the first depth to the second depth; and

g) electrodes placed in the wellbore for passing an electric current through the inclusion for heating the formation in a process zone in the vicinity of the first inclusion and thereby producing the heated hydrocarbons up the wellbore from the formation.

23. The hydrocarbon production well of claim **22**, wherein the second depth of the open section of the wellbore is below the first depth.

24. The hydrocarbon production well of claim **22**, wherein the production well includes a plurality of inclusions propagated at varying azimuths.

25. The hydrocarbon production well of claim **22**, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are ceramic beads substantially coated with an electrically conductive resin.

26. The hydrocarbon production well of claim **25**, wherein the resin is phenol formaldehyde containing fine graphite particles and is heat hardenable, with resin present in an amount sufficient to consolidate the proppant, but insufficient to fill the openings between the proppant.

27. The hydrocarbon production well of claim **22**, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are selected from a group of conductive materials such as metals, melt alloys, metal oxides, metal salts, metal-containing catalysts, calcined petroleum coke or graphite beads, green or black silicon carbide, boron carbide or a mixture thereof.

28. The hydrocarbon production well of claim **22**, wherein the proppant particles range in size from #4 to #100 U.S. mesh and are selected from a group of non-conductive materials such as ceramics, glass and sands coated with a conductive layer either being metal, metal oxide, metal salts, conductive resins or mixtures thereof.

29. The hydrocarbon production well of claim **22**, wherein pressure in the majority of the heated process zone is held at ambient reservoir pressure by injecting into the process zone steam, non-condensing gas, or a hydrocarbon solvent in a vaporized state or a mixture thereof.

30. The hydrocarbon production well of claim **29**, wherein the solvent is one of a group of ethane, propane, butane or a mixture thereof.

31. The hydrocarbon production well of claim **29**, wherein the solvent is mixed with a diluent gas.

32. The hydrocarbon production well of claim **31**, wherein the diluent gas is non-condensable under the process conditions.

33. The hydrocarbon production well of claim **32**, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbons than the saturated hydrocarbon solvent.

34. The hydrocarbon production well of claim **33**, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas or a mixture thereof.

35. The hydrocarbon production well of claim **22**, wherein the production well further includes means for injecting a hydrogenizing gas into the wellbore and thus into the fluid in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the hydrocarbons in the process zone.

36. The hydrocarbon production well of claim **35**, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.

37. The hydrocarbon production well of claim **35**, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.

38. The hydrocarbon production well of claim **37**, wherein the catalyst is contained in a canister in tubing inside of the wellbore.

39. The hydrocarbon production well of claim **22**, wherein the proppant particles in the inclusion include the catalyst for the hydrogenation and thermal cracking reactions.

40. The hydrocarbon production well of claim **22**, wherein the second depth of the open section of the wellbore is above the first depth.

41. The hydrocarbon production well of claim **22**, wherein a portion of the formation in which the first inclusion is formed has a Skempton B parameter greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the first inclusion and the water saturation in the formation pores is greater or equal to 10%.

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