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(54) **METHOD FOR ENHANCED OIL RECOVERY**

(57) A method of treating a hydrocarbon containing formation, comprising the following steps:
(i) drilling a first well (5), in the hydrocarbon containing formation,
(ii) introducing heating means (13) into the first well,
(iii) drilling a second and a third well in the hydrocarbon containing formation, said second and third wells being parallel to the first well,

(iv) applying heat to the hydrocarbon containing formation, and simultaneously,
(v) injecting a flooding fluid into the hydrocarbon containing formation through the second and the third well, wherein the flooding fluid is a water composition with a viscosity superior or equal to 10 mPa.s, and
(vi) extracting hydrocarbon from the hydrocarbon containing formation.

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Description

[0001] The invention is directed to an improved method for enhanced oil recovery in high viscosity oils, said method combining heating the oil reservoir and injecting polymer or surfactant thickened water. Said method is particularly efficient for recovering high viscosity oils.

State of the art

[0002] Enhanced oil recovery (EOR) is based on various methods, including steam or hot water injection, CO₂ injection, polymer/surfactant injection.

[0003] Drilling and producing wells efficiently are major production difficulties for the petroleum industry, in reservoirs containing high-viscosity oil, difficult to fluidize.

[0004] In horizontal well field development, hot water injection generally consists in injecting water into two lateral wells, parallel to the production well, to increase pressure around the central well and sweep the oil, while fluidizing the oil by the heat transmitted by the injected water. The inconvenient of hot water injection is water production in association with crude oil, and the method requests a separation step to recover oil without water. Problems due to water production often decrease the economic performance of a well. Another problem encountered in the oil or gas industry relates to water channelling problems between injection wells and production wells. When injected into the injection well, water may follow a preferential pathway through high-permeability streaks of the reservoir. Some oil- or gas-rich zones, of lower permeability, remain unswept by the water flow.

[0005] In order to reduce excessive water production, it is known to inject, through wells parallel to the production wells, a water solution thickened by a polymer. Polymer flooding consists in mixing high-molecular-weight viscosity-enhancing polymers with the injected water in order to increase the water viscosity. This method improves the vertical and areal sweep efficiency as a consequence of improving the water/oil mobility ratio. This injection increases the pressure applied to the reservoir, as compared to water injection. It also solves at least in part the problem of preferential pathway followed by water since polymer thickened solutions are less subject to channelling problems. Polymer flooding provides a mixture of oil and polymer thickened water that have to be separated, but the ratio of oil to water is higher as compared to water flooding. Polymer flooding is well suited to areas of the hydrocarbon comprising reservoirs wherein the viscosity of the oil is not too high (for example less than 5000 centipoise). For higher-viscosity oil reservoirs, alternative technologies have to be developed.

[0006] Another EOR method consists in heating the oil reservoir, generally by hot water edge injection, wherein hot water circulates in an insulated tubing inside the production well, the tubing continuously delivers hot water to the toe of the producer. Circulating hot water heats the wellbore and heats the reservoir by conduction. Heating the reservoir reduces the oil viscosity, reducing the pressure losses in the formation. Increased productivity can be achieved with the same pressure drop if a sufficient temperature is maintained at the wellbore. This continuous stimulation results in improved oil production. Hot water circulation has been developed satisfactorily in high-viscosity oil reservoirs (K. Duval et al., SPE-174491-MS, SPE Canada heavy Oil Conference, 9-11 June 2015).

[0007] However, even hot water circulation combined with water injection finds limits once the lower viscosity part of the reservoir has been extracted. Therefore, there remains a need for a method providing higher efficiency in oil extraction, especially in reservoirs areas wherein the viscosity of the oil is high.

[0008] The inventors have surprisingly discovered that combining heating the oil reservoir and polymer flooding provides a synergistic effect that is significantly superior to the sum of single effects of these methods. Enhanced oil recovery, with a yield significantly higher than that expected from the single methods, and access to oils of high viscosity are the main benefits of the method according to the invention.

Summary of the invention

[0009] The invention is directed to a method of treating a hydrocarbon containing formation, comprising the following steps:

- (i) drilling a first well, into the hydrocarbon containing formation,
- (ii) introducing heating means into the first well,
- (iii) drilling a second and a third well into the hydrocarbon containing formation, said second and third well being parallel to the first well,
- (iv) applying heat to the hydrocarbon containing formation, and simultaneously,
- (v) injecting a flooding fluid into the hydrocarbon containing formation through the second and the third well, wherein the flooding fluid is a polymer-thickened water composition, and
- (vi) extracting hydrocarbon from the hydrocarbon containing formation.

[0010] According to a favourite embodiment, heat is applied to the hydrocarbon containing formation by activating the heating means of the first well.

[0011] According to a favourite embodiment, heating means are selected from: hot water circulation, steam heating, electromagnetic heating, electrical resistive heating.

[0012] According to a favourite embodiment, heating means consist of injection of hot water in an insulated tubing.

[0013] According to a favourite embodiment, the polymer is selected from the group consisting of polyacrylamide homopolymers, polyacrylamide copolymers, polyacrylonitrile homopolymers, polyacrylonitrile copolymers, xanthan gum, carboxymethylcellulose, hydroxyethylcellulose, carboxymethylhydroxyethylcellulose, and combinations thereof.

[0014] According to one particular embodiment, the flooding fluid further comprises at least one surfactant.

[0015] According to a favourite embodiment, the second and the third well are located at a distance of from 25 to 1000 m from the first well.

[0016] According to a favourite embodiment, product recovery is achieved through the first well.

[0017] According to a favourite embodiment, hydrocarbon is an oil of viscosity superior or equal to 40 mPa.s, preferably superior or equal to 100 mPa.s, advantageously superior or equal to 500 mPa.s.

[0018] According to a favourite embodiment, the wells are horizontal.

[0019] The hydrocarbon containing formation is heated by conduction and associated hydrocarbon fluids are lowered in viscosity and drain by gravity back to the well and are extracted to the surface. The polymer comprising composition flooding from the lateral wells exerts pressure on the hydrocarbon containing formation. By controlling the reservoir temperature and pressure, a fraction of the in-situ hydrocarbon reserve that was not accessible is extracted and water inflow into the heated zone is minimized. Polymer composition mixes with the extracted hydrocarbon, but is at least partially degraded by heat, resulting in low-molecular-weight fragments, so that polymer separation is not necessary.

[0020] The method according to the invention provides enhanced reservoir sweep efficiency to the thickened water, notably to the polymer flood. Said method is particularly applicable to produce heavy hydrocarbons such as bitumen or heavy oil from a heterogeneous reservoir.

Detailed description

[0021] The hot fluid recirculation technology heats an oil reservoir by conduction using a circulation of hot fluid in the well. This technology requires very high performance insulation material which avoids most thermal losses between the surface heat source and the production zone. Heating the oil drastically reduces the viscosity of heavy oil in the reservoir around the well.

[0022] Advantageously, hot water is used as the circulating fluid, this technology is known as Hot Water Recirculation (HWR). Alternately, the circulating fluid can be steam. As an example of an insulated tubing that can be used in the method according to the invention for controlling hot water recirculation, mention may be made of the devices disclosed in US-8,327,530.

[0023] Alternate methods to heat an oil reservoir include, non limitatively: applying electromagnetic heat to the reservoir, wherein the electromagnetic heat can be from a source selected from the group consisting of resistive AC/low frequency, induction heat, radiofrequency radiation heat and microwave radiation heat. Electric resistive heating can also be used as a heating means. Such means are well known to the skilled professional.

[0024] Injection of hydrogel polymer to the reservoir is to increase the viscosity of the fluid containing water so that the fluid is more difficult to flow than the oil, and as a result, the oil production increases, the preferential pathway difficulties are lessened.

[0025] Among the polymers that are known for application in polymer flooding, one can mention: polyacrylamide polymers, polyacrylamide copolymers and polyacrylamide derivatives, notably: synthetic (PAM) and partially hydrolyzed polyacrylamide (HPAM). One can also mention the natural polymers and their derivatives, like polysaccharides, notably xanthan gum, and some modified natural polymers, including HEC (hydroxyl ethyl cellulose), guar gum and sodium carboxymethyl cellulose, carboxyethoxyhydroxyethylcellulose

[0026] The most common polymers used for this application belong to the polyacrylamide group. The polymers most generally used for preparing polymer flooding compositions are high-molecular-weight linear acrylamide/acrylate copolymers. Such copolymers are not stable beyond 70°C, they do not resist shear stress, and they are sensitive to the presence of salts that tend to reduce their thickening efficiency.

[0027] Other polymer compositions that can be used for enhanced oil recovery include a self-invertible inverse latex or of a self-invertible inverse microlatex of a crosslinked polyelectrolyte, obtained by copolymerization, in the presence of a crosslinking agent of partially- or totally-salified free 2-methyl-2-[(1-oxo-2-propenyl)amino]-1-propanesulfonic acid, with at least one cationic monomer chosen from: 2,N,N,N-tetramethyl-2-[(1-oxo-2-propenyl)amino]propanammonium chloride; N,N,N-trimethyl-3-[(1-oxo-2-propenyl)amino]propanammonium chloride; diallyldimethylammonium chloride; N,N,N-trimethyl-2-[(1-oxo-2-propenyl)ethanammonium chloride; N,N,N-trimethyl-2-[(1-oxo-2-methyl-2-propenyl)ethanammonium chloride; or N,N,N-trimethyl-3-[(1-oxo-2-methyl-2-propenyl)amino]propanammonium chloride; and

with at least one neutral monomer chosen from: acrylamide; N,N-dimethylacrylamide; N-[2-hydroxy-1,1-bis(hydroxymethyl)-ethyl]propenamide; or 2-hydroxyethyl acrylate. Such polymers are disclosed for example in WO2010/001002.

[0028] The water-thickened polymer composition is selected by the skilled professional according to the nature of the oil reservoir that is to be extracted and to his general knowledge.

[0029] The water-thickened polymer composition can, in a known manner, comprise surfactants that improve compatibility between the water-thickened polymer composition and the oil, thus reducing the water-thickened polymer composition/oil mobility ratio.

[0030] Alternate compounds that can be used to increase the viscosity of the water containing fluid include surfactants, notably betaines, for example: cetyl betaine, cocamidopropyl betaine, coco-betaine, that can be partially sulfonated.

[0031] It is also possible to increase the viscosity of the flooding fluid by incorporating glycerol into water.

[0032] A mixture of water-thickening agents, ie, polymers, surfactants, glycerol, can also be used in the flooding fluid.

[0033] The amount of thickening agent is advantageously calculated to provide a water composition with a viscosity superior or equal to 10 mPa.s, more preferably superior or equal to 20 mPa.s.

[0034] Advantageously, the viscosity of the water composition is adapted as a function of the oil to be extracted from the hydrocarbon reservoir. Preferably, the viscosity of the water composition is superior or equal to 1.10^{-2} x the viscosity of the oil to be extracted from the hydrocarbon reservoir.

[0035] The method according to the invention finds application in hydrocarbon containing formations wherein the oil is of a high viscosity and those wherein the matrix rock permeability is sufficient.

[0036] The invention is especially useful for the extraction of oils of viscosity superior or equal to 40mPa.s, more preferably superior or equal to 100 mPa.s.

[0037] Especially of concern are matrix-rock of permeability $> 10 \text{ md} = 10^{-14} \text{ m}^2$.

[0038] In the sentence: "applying heat to the hydrocarbon containing formation, and simultaneously, injecting a flooding fluid into the hydrocarbon containing formation", "simultaneously" means that the two events: "heating" and "polymer flooding", simultaneously occur during a lapse of time sufficient to produce a synergistic effect on well production. However, when achieving the process, heating can start some time before polymer flooding, and polymer flooding can start some time before heating.

[0039] Polymer flooding is achieved through the second and third well, located on both sides of the first well. The second and third well create a polymer flooding environment on both sides of the hydrocarbon containing formation, that acts synergistically with the heat to favour hydrocarbon extraction from the hydrocarbon containing formation.

Figures:

[0040]

Figure 1: Typical stratigraphy in the area surrounding the pilot site

Figure 2: Graphical representation of oil production history in the well 02/11-33-081-20W4/0. Abscissa: dates in month/year. Ordinates: oil rate at surface conditions (sm³/day). Reference A corresponds to primary production, reference B corresponds to water flooding, reference C corresponds to hot water recirculation (HWR process)

Figure 3: Graphical representation of oil and water production history in the well 02/11-33-081-20W4/0. Abscissa: dates in month/year. Ordinates: oil rate or water rate at surface conditions (sm³/day). Reference A corresponds to primary production, reference B corresponds to water flooding, reference C corresponds to hot water recirculation (HWR process. Curve (2): oil; curve (1) water.

Figure 4: Schematic representation of the first well completion

Figure 5: Schematic representation of the HWR process

Figure 6: Schematic representation of the option selected for the reservoir configuration for simulation of HWR technology

Figure 7: Cells distribution and location of the wells in the model (areal view)

Figure 8: Relative permeability in bar complex zone. Abscissa: Water Saturation (SW). Ordinates: water relative permeability (K_{rw}: ■) and oil relative permeability (K_{ro}: ♦). SWI represents the Irreducible Water Saturation, ie the minimum amount of water that can be found in an oil field. The point named SOR represents the Residual Oil Saturation, ie the minimum amount of oil that is found in an oil reservoir after water sweeping

Figure 9: Relative permeability in bar margin zone. Abscissa: Water Saturation (SW). Ordinates: water relative permeability (K_{rw}: ■) and oil relative permeability (K_{ro}: ♦). The point named SWI represents the Irreducible Water Saturation. The point named SOR represents the Residual Oil Saturation.

Figure 10a: Relative permeability in drain zone. Abscissa: Water Saturation (SW). Ordinates: water relative permeability (K_{rw}: A). SWI represents the Irreducible Water Saturation.

Figure 10b: Relative permeability in drain zone. Abscissa: Water Saturation (SW). Ordinates: oil relative permeability (K_{ro}: ♦). SOR represents the Residual Oil Saturation.

Figure 11: Oil viscosity plots under different pressures. Abscissa: Temperature ($^{\circ}\text{C}$), ordinates: viscosity (cp)

Figure 12: Oil production rate with four different scenarios. Abscissa: time (years), ordinates: oil rate at surface conditions (sm³/day). 1: Primary Recovery + Secondary Recovery + Hot Water Recirculation; 2: Primary Recovery + Hot Water Recirculation; 3: Primary Recovery + Secondary Recovery; 4: Primary Recovery.

Figure 13: Water production rate with four different scenarios. Abscissa: time (years), ordinates: water rate at surface conditions (sm³/day). 1: Primary Recovery + Secondary Recovery + Hot Water Recirculation; 2: Primary Recovery + Hot Water Recirculation; 3: Primary Recovery + Secondary Recovery; 4: Primary Recovery.

Figure 14: Graphical representation of simulated water production rate (plain lines) compared to historical water production rate (black dots). Abscissa: time (months/years), ordinates: water rate at surface conditions (sm³/day).

Figure 15: Graphical representation of simulated oil production rate (plain lines) compared to historical oil production rate (black dots). Abscissa: time (months/years), ordinates: oil rate at surface conditions (sm³/day).

Figure 16: Graphical representation of cumulative oil production without lateral polymer injection. Abscissa: time (days/months/years), ordinates: cumulative oil rate at surface conditions (hm³). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery; 3: Primary Recovery + Secondary Recovery + HWR.

Figure 17: Graphical representation of oil rate without lateral polymer injection. Abscissa: time (days/months/years), ordinates: oil rate at surface conditions (sm³/day). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery; 3: Primary Recovery + Secondary Recovery + HWR.

Figure 18: Graphical representation of cumulative oil production with lateral polymer injection. Abscissa: time (days/months/years), ordinates: cumulative oil rate at surface conditions (hm³). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery; 3: Primary Recovery + polymer flooding; 4: Primary Recovery + Secondary Recovery + polymer flooding + HWR.

Figure 19: Graphical representation of oil rate with lateral polymer injection. Abscissa: time (days/months/years), ordinates: oil rate at surface conditions (sm³/day). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery; 3: Primary Recovery + polymer flooding; 4: Primary Recovery + Secondary Recovery + polymer flooding + HWR.

Figure 20: Graphical representation of cumulative oil production with combined polymer flooding and HWR technology. Abscissa: time (days/months/years), ordinates: cumulative oil rate at surface conditions (hm³). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery + HWR; 3: Primary Recovery + Secondary Recovery + polymer flooding + HWR.

Figure 21: Graphical representation of oil rate with combined polymer flooding and HWR technology. Abscissa: time (days/months/years), ordinates: oil rate at surface conditions (sm³/day). 1: Primary Recovery; 2: Primary Recovery + Secondary Recovery + HWR; 3: Primary Recovery + Secondary Recovery + polymer flooding + HWR.

Simulation Study:

Introduction:

[0041] The first step consisted in building a representative reservoir model and then simulating HWR technology in a reservoir.

[0042] HWR technology consists in injecting hot water (or another hot fluid) via an insulated tubing at the toe of a horizontal heavy-oil production well, while pumping with a pump placed at the heel. The increase in temperature induced by hot water injection induces a decrease in viscosity of the fluids surrounding the wellbore, thus stimulating oil production.

[0043] The present study aims at simulating the HWR process, which gives good tool for HWR optimization and production predictions. The simulations used PumaFlow® reservoir software. Since the reservoir model does not simulate flow in the pipe, adaptations of the settings have been achieved to reproduce as much as possible the HWR process. When applied to the HWR technology, the settings selected provided results close to the historical data.

Reservoir:

[0044] This study is based on a treatment in Britnell field (also known as Pelican Lake field) located in Canada. The Pelican Lake field is located approximately 250 km north of Edmonton, Alberta, Canada. It contains approximately 6.5 billion barrels of heavy oil and has been producing since the early 1980s. Main characteristics are as follows:

- High permeability sand reservoir
- Thin continuous pay layer (5m)
- Shallow, with fresh water
- Horizontal well primary and secondary production, and polymer flooding

[0045] Dead Oil viscosity, in the pattern of the candidate well, is around 4800 cP (4.8 Pa.s) and oil density is 960

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kg/m³. This heavy oil is 14°API. Reservoir pressure was initially at 30 bar (at 400m deep). Reservoir temperature in the pattern is 15°C. No initial water-oil contact was found. The total height of the reservoir is 5m and the producing interval in the field corresponds to the Wabiskaw A zone as shown in Figure 1. This zone is divided in three sand intervals as shown in Table 1.

Table 1

	Reservoir zone	Total thickness of the unit (m)
Top Bar Complex	Top	1
Good pay Bar Complex	Middle	3
Bar Margin	Bottom	1

[0046] Primary production of the candidate well in the pattern started on November 2010. Then, water flooding with lateral wells started on August 2011, and HWR technology was started on March 2012.

[0047] Permeabilities in the candidate well range from 100 mD to 3000 mD, the highest permeability is in good pay Bar Complex. The average porosity is from 28% to 33%. Details are shown in Table 2. The lower zone (called "Bar Margin"), having lower permeability and higher water saturation, does not contribute significantly to oil production.

Table 2: Petrophysical properties of the model

	Total thickness of the unit (m)	Kx/Ky (mD)	Kz (mD)	Porosity Φ (%)
Top Bar Complex	1	500	30	28
Good pay Bar Complex	3	3000	150	33
Bar Margin	1	100	10	31

Wells

[0048] Three wells are considered in the pattern, i.e. one central producer and two lateral injectors. The horizontal wells are 2000 m long with a spacing of 50 m between injector and producer. All the wells are located in the middle layer of the "Good pay Bar Complex" unit.

[0049] Oil production started on November 2010 at relatively low rate (around 5 m³/day) and remained stable until HWR process. When hot water (HWR process) was injected, oil rate started to increase and reached a maximum of 49 m³/day. Oil and water production history are plotted in Figure 2 and Figure 3.

[0050] A typical well completion diagram in Pelican lake field is shown in Figure 4. The well is equipped with:

- a conductor 1 (406mm, 96.7kg/m, ST&C, landed at approximately 25mKB,
- an intermediate casing 2 (311.2mm hole)
- a tubing string 3
- a rod string 4
- a slotted liner 5, and
- a progressing cavity pump 6

[0051] Measure Depth (MD) is 800 to 2800m KB and True Vertical Depth TVD is 370 to 410 m.

Hot Water Recirculation process

[0052] Hot Water Recirculation (HWR) technology heats an oil reservoir by conduction using a circulation of hot water (it may be another fluid) in the production well, which reduces the viscosity of heavy oil in the reservoir surrounding the well. Heating by conduction requires a significant temperature gradient between the hot source and the cold one. Therefore, this technology requires very high performance insulation material that avoids thermal loss between the surface heat source and the production zone.

[0053] The fluid produced is directed to a buffer tank where water and oil separate by gravity. Part of the water is pumped to a heater and then into the insulated HWR tubing run till the toe of the horizontal well. The water is mixed with the produced fluids on the horizontal section of the system.

[0054] During their flow in the horizontal section, the heated fluids heat the formation by conduction thereby reducing

oil viscosity in the vicinity of the well and increasing flow rate.

[0055] Figure 5 shows a simplified scheme of the HWR process: A heater 16 and a pump 17 provide hot water (arrow 15) into the dual completion well head 10, through an insulated coiled tubing 11. The hot water is liberated at the toe of the well 12 between the liner and the insulated tubing and provides conduction heating (cone 14) to the reservoir. Oil and water are pumped through pump 13 and transferred (arrow 18) to the oil tank 19 and to the production facilities 20. It has to be noted that the heat created in such a process takes the form of a cone with large section at the toe and thin section at the heel.

Model

[0056] Puma Flow ® is designed to perform reservoir simulations. It has been adapted to simulate HWR technology.

[0057] The following options have been selected for the simulations: The reservoir model is built as a simple cuboid structure. Lengths are defined to obtain sufficient volume to generate enough energy in the reservoir. Permeabilities of each sand interval is supposed homogeneous in X and Y directions. Generic data were used to account for thermal effects. Model construction includes gridding refinement set on reservoir zone close to the horizontal production well.

[0058] Main modifications in the model were well configuration and cells properties. The length of the production well is 2020m. An injection well (120m long) is created under the production well at the toe. A 1900 m drain is created from injector up to the heel. The drain is not connected to the reservoir over a length of 1740m and open at the heel over a distance of 160m. Details of the option are given in Figure 6. This figure shows a simplified view of the reservoir (in XZ section) at the level of the producing well and explains the necessary changes in the model to simulate the HWR process with a reservoir software (PumaFlow ®).

[0059] For the model construction, we proceeded as follows:

Grid: The reservoir pattern dimensions are 2500m on X, 1000m on Y and 5m on Z axis. Gridding is refined close to the production well. Around the production well dimensions of the cells are 40.4 x 0.40 x 0.45 (in m). The total number of grid cells in the model is 26 568 . Figure 7 shows an areal view (in XY) of the gridding of the wells and the surrounding reservoir. Layering on Z axis is described in Table 3.

Table 3: Layering description on Z axis

Sand Interval	Layer (1 at the bottom)	Thickness of each layer (m)	Total thickness of the unit (m)
Top Bar Complex	11 to 12	0.45	0.90
Good pay Bar Complex	8 to 10	0.45	1.35
	6 to 7	0.225	0.45
	3 to 5	0.45	1.335
Bar Margin	1 to 2	0.45	0.90

[0060] The petrophysical properties of the three sand intervals are given in Table 4.

Table 4: Petrophysical properties of the sand intervals

	Total thickness of the unit (m)	Kx/Ky (mD)	Kz (mD)	Porosity Φ (%)
Top Bar Complex	1	500	30	28
Good Pay Bar Complex	3	3000	150	33
Bar Margin	1	100	10	31

[0061] A modification is applied only for the drain. To mimic a pipe, we assigned very high permeability in the cells along the length of the drain (up to 1.10^{12} mD) and we adjusted the porosity in order to match the pipe volume to the pore volume of the drain.

Relative Permeability and Capillary Pressure (Kr-PC)

[0062] Figure 8 to Figure 10a and 10b show saturation and relative permeability curve used for Bar Complex, Bar Margin and drain. The capillary pressure was neglected.

Thermodynamics (PVT)

[0063] Table 5 gives general PVT input data and Table 6 gives the evolution of oil viscosity versus temperature.

Table 5: General PVT input data

Reservoir pressure		3000kPa
Reservoir Temperature		15°C
Bubble pressure		21 bar
Oil density		960 kg/m ³
Specific heat	Heavy oil	1.675 J/(g°C)
	Volatile oil	2.512 J/(g°C)
Heat of vaporization		232.6 (J/g)

Table 6: Evolution of oil viscosity versus temperature at pressure = 30 bar

Temperature (°C)	Viscosity (cp)
15	1600
45	52
95	8.5

[0064] The viscosity/temperature plots at different pressures are reported in Figure 11 The maximum viscosity is 1600 cp at 15°C and the minimum is 5 cp at 95 °C. The drop in viscosity is sharp from 15 to 45°C then becomes lower from 45 to 95°C. The three curves (for pressures: 1,013 bar, 21 bar and 30 bar) are close. They were established from correlations. Maximum viscosity used in the study is 1600 cp.

Wells:

[0065]

The Productivity Index of each well was taken as:

Lateral waterflood injectors, PI=2840 cP.m³/(day.bar).

Hot water injector, PI=150 cP.m³/(day.bar).

Producer, PI=745 cP.m³/(day.bar).

Production mode

[0066] It is possible to simulate all production processes in the reservoir (primary, secondary recovery, polymer flooding and HWR process) with Puma Flow®. Four simulations were performed:

- Primary recovery (1).
- Primary recovery plus secondary recovery (lateral water injection) (2).
- Primary recovery plus HWR process (3).
- Primary recovery plus secondary recovery plus HWR process (4).

[0067] The temperature of hot water injected was 65°C and the recirculation rate was maintained at 100 m³/day. In the case of secondary recovery, water rate was 30 m³/day in each lateral well. At the producer, the minimum BHP constraint was 5 bar.

- Production results:

[0068] Figure 12 shows the evolution of oil production rate for each simulation performed. Best oil recovery scenario

is obtained with HWR technology + lateral water injection after producing the reservoir with two periods of primary and secondary recovery (the oil production rate during the HWR secondary scenario peaks at 18 m³/day versus 4 m³/day on primary). Secondary recovery and Primary + HWR show close performances although oil rate production decline is steeper with primary HWR (because of no pressure support). The results in terms of water production rate are reported in Figure 13. Water production rate is roughly equal to total water injected (lateral injectors + hot water injection at producer).

HWR Field case: History marching

[0069] To validate the simulation of HWR process, a history matching with real production data was undertaken. The period of this simulation starts in December 2010 and ends in September 2013. The two lateral wells have the same water injection rate. PVT is changed by increasing the oil viscosity from 1600 to 2500 cP at 15°C. For this field case, contrary to the previous simulation study on synthetic case, the water injection temperature for HWR is 80°C. The production well is constrained on total liquid rate (water rate + oil rate) with a BHP at 5 bar.

[0070] Results of water and oil production are shown in Figure 14 and Figure 15. On these graphs the black dots are actual data and curves in plain lines are simulation results. We can see that, with the HWR model used, water and oil production rates obtained by simulation match very well actual field data.

Polymer injection

[0071] Polymer injection has been tested with the first synthetic case model. Injection rate in the lateral wells was set at 30 m³/day per well. The viscosity of the oil is 1600cp @ 15°C. The temperature for HWR is 65°C and the production wells are constrained in pressure at a BHP of 5 bar.

[0072] The simulations performed are:

- Primary recovery
- Primary recovery + Secondary recovery
- Primary recovery + Polymer flooding
- Primary recovery + Secondary Recovery + HWR 65°C
- Primary recovery + Secondary Recovery + Polymer flooding and HWR 65°C The pattern is produced for 20 years.

[0073] Recovery Factor obtained with these simulations is shown in Table 7.

Table 7: Recovery Factor with different simulation scenarios

	Cumulated oil (m3)	Recovery Factor
Primary recovery	42455	16%
Primary recovery + Secondary recovery	53699	21%
Primary recovery + Polymer flooding	71631	28%
Primary recovery + Secondary Recovery + HWR 65°C	83701	32%
Primary recovery + Secondary Recovery + Polymer flooding and HWR 65°C	123673	48%

[0074] Figure 16 to Figure 21 compare the efficiency of HWR process in terms of cumulative oil and oil rate. The scenarios represented are as follows:

- Figure 16 and Figure 17: Without lateral polymer injection.
- Figure 18 and Figure 19: With lateral polymer injection.
- Figure 20 and Figure 21: Only HWR with or without polymer injection.

[0075] The most efficient scenario is the last one (Primary recovery + Secondary Recovery + Polymer flooding and HWR 65°C) with a recovery of 48% of oil in place (OOIP= 260000 m³).

Conclusion

[0076] Polymer flooding coupled with HWR improves significantly and in a synergistic manner the oil recovery.

Claims

1. A method of treating a hydrocarbon containing formation, comprising the following steps:

- (i) drilling a first well, in the hydrocarbon containing formation,
- (ii) introducing heating means into the first well,
- (iii) drilling a second and a third well in the hydrocarbon containing formation, said second and third wells being parallel to the first well,
- (iv) applying heat to the hydrocarbon containing formation, and simultaneously,
- (v) injecting a flooding fluid into the hydrocarbon containing formation through the second and the third well, wherein the flooding fluid is a water composition with a viscosity superior or equal to 10 mPa.s, and
- (vi) extracting hydrocarbon from the hydrocarbon containing formation.

2. The method according to claim 1, wherein heat is applied to the hydrocarbon containing formation by activating the heating means of the first well.

3. The method according to claim 1 or claim 2, wherein heating means are selected from: hot water circulation, steam heating, electromagnetic heating, electrical resistive heating.

4. The method according to claim 3, wherein heating means consist of injection of hot water in an insulated tubing.

5. The method according to any of the preceding claims, wherein the flooding fluid is a water composition comprising at least one water soluble thickening agent selected from: polymers, surfactants, glycerol, and their mixtures.

6. The method according to claim 5, wherein the polymer is selected from the group consisting of polyacrylamide homopolymers, polyacrylamide copolymers, polyacrylonitrile homopolymers, polyacrylonitrile copolymers, xanthan gum, carboxymethylcellulose, hydroxyethylcellulose, carboxymethylhydroxyethylcellulose, and combinations thereof.

7. The method according to claim 5, wherein the surfactant is selected from betains.

8. The method according to any of the preceding claims, wherein the second and the third well are located at a distance from 25 to 1000 m from the first well.

9. The method according to any of the preceding claims, wherein product recovery is achieved through the first well.

10. The method according to any of the preceding claims, wherein the hydrocarbon is an oil with a viscosity superior or equal to 40 mPa.s, preferably superior or equal to 100 mPa.s, advantageously superior or equal to 500 mPa.s.

11. The method according to any of the preceding claims, wherein the viscosity of the flooding fluid is superior or equal to 1.10^{-2} x the viscosity of the hydrocarbon.

12. The method according to any of the preceding claims, wherein the wells are horizontal.

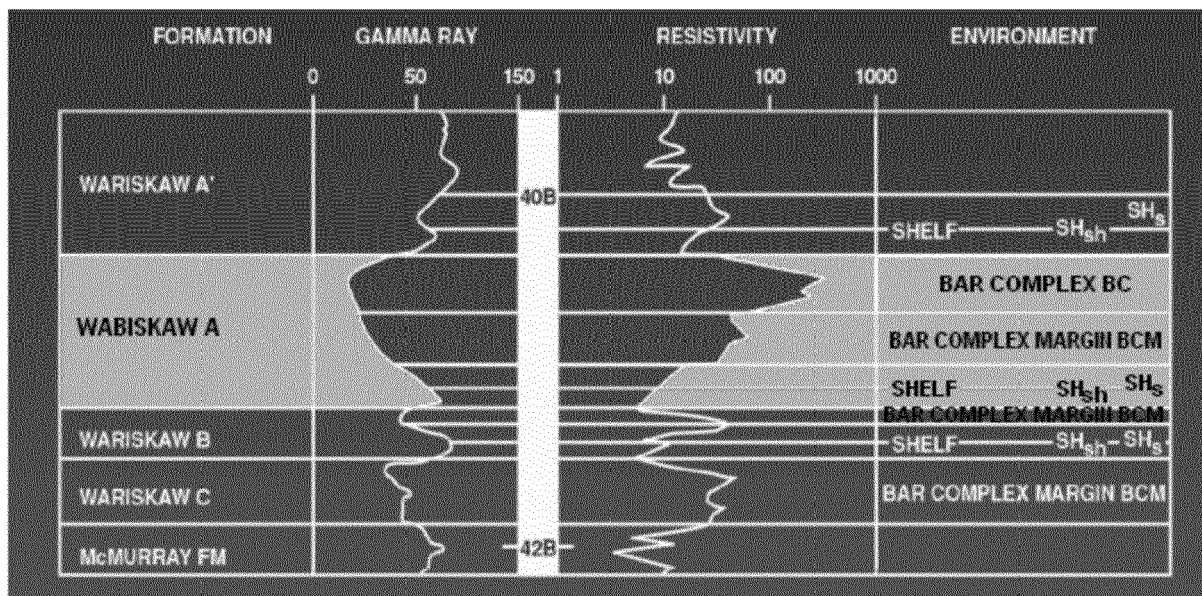


Figure 1

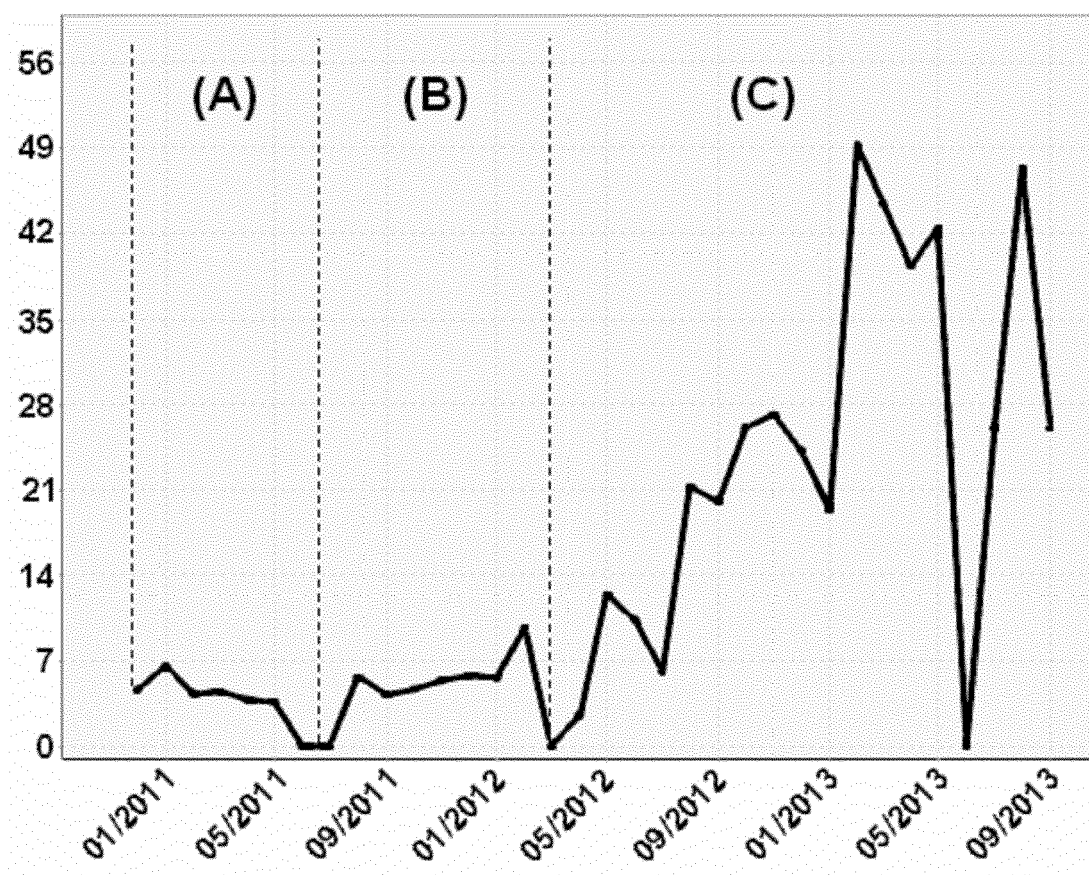


Figure 2

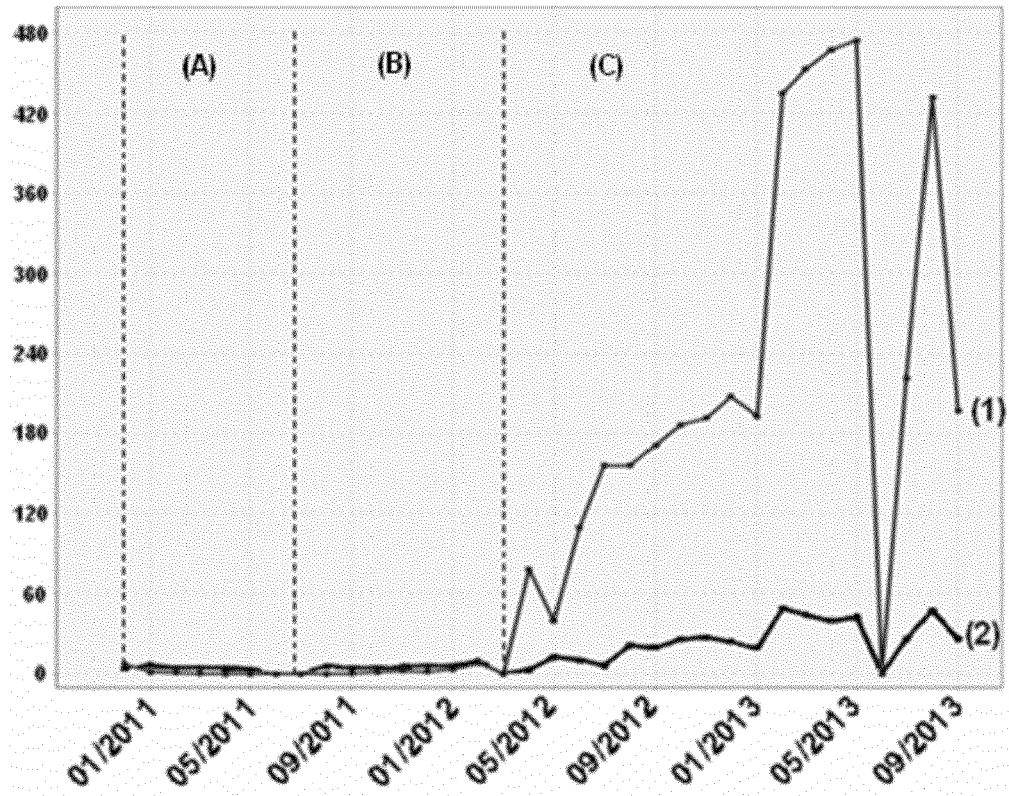


Figure 3

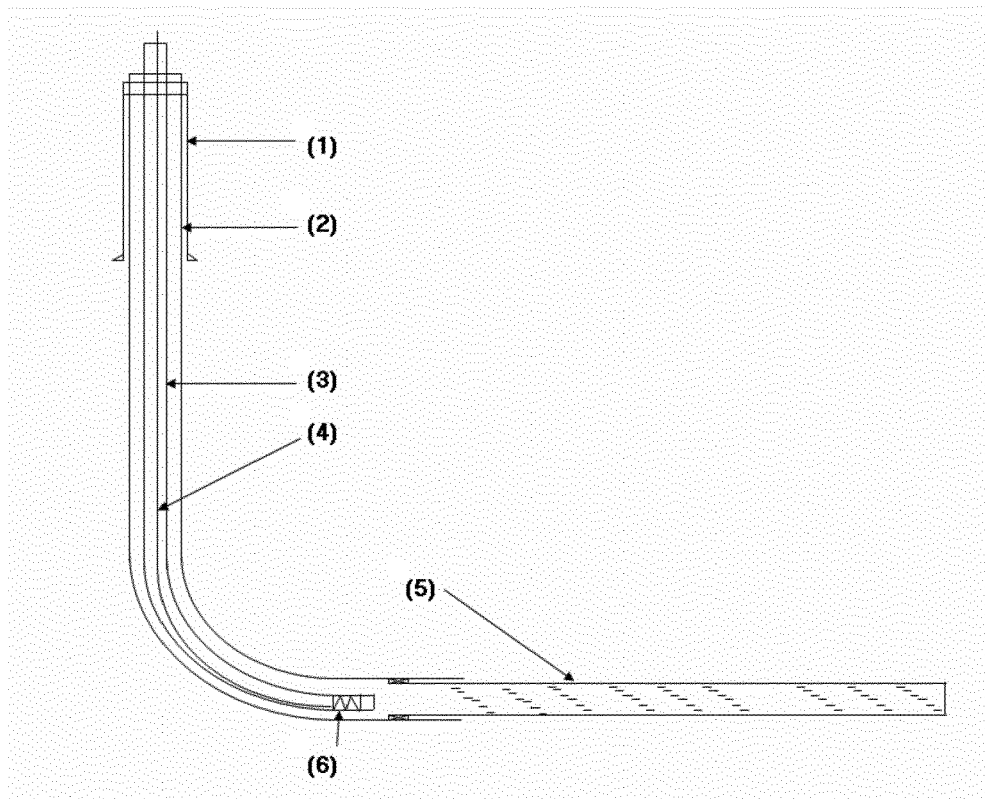


Figure 4

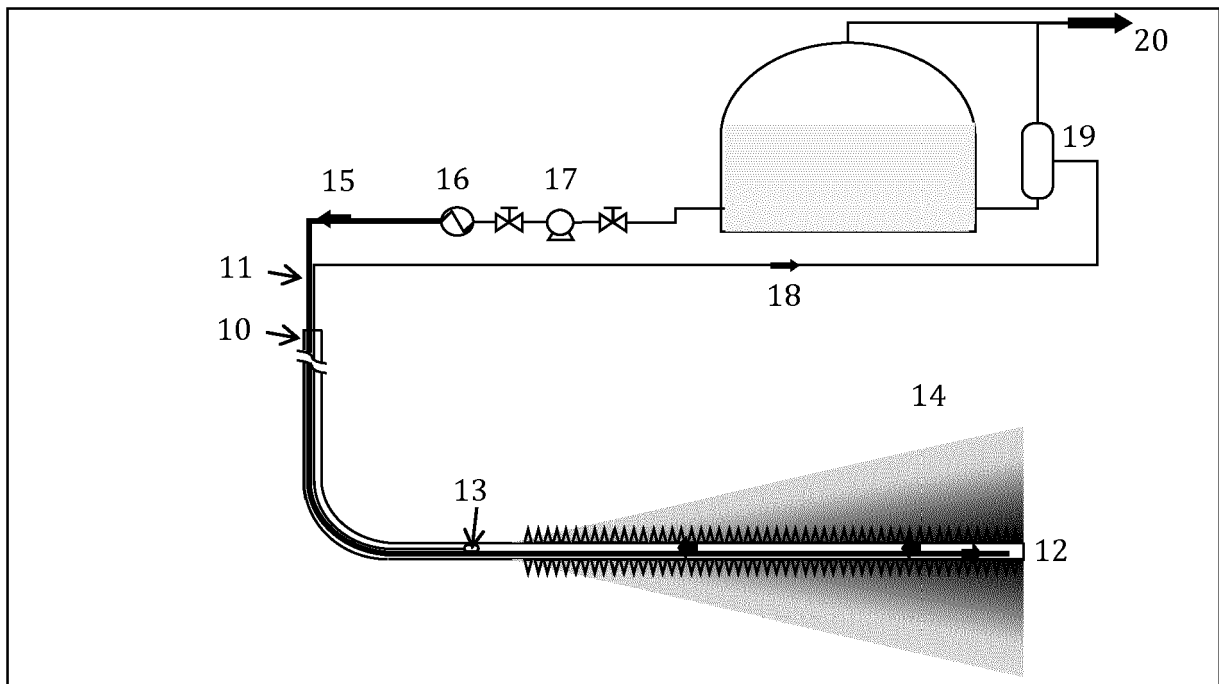


Figure 5

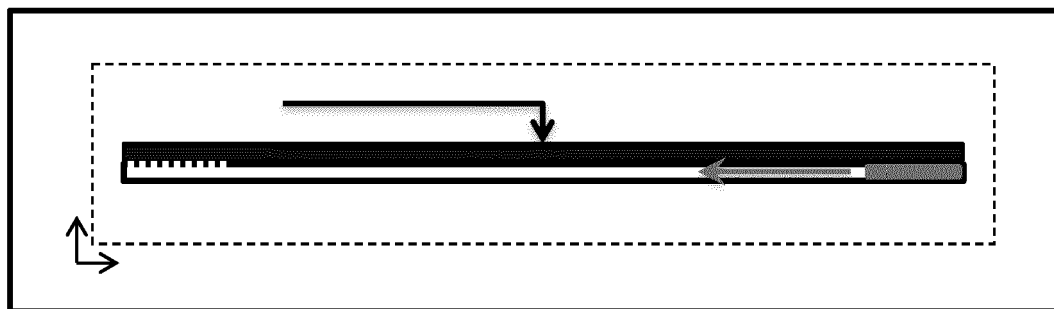


Figure 6

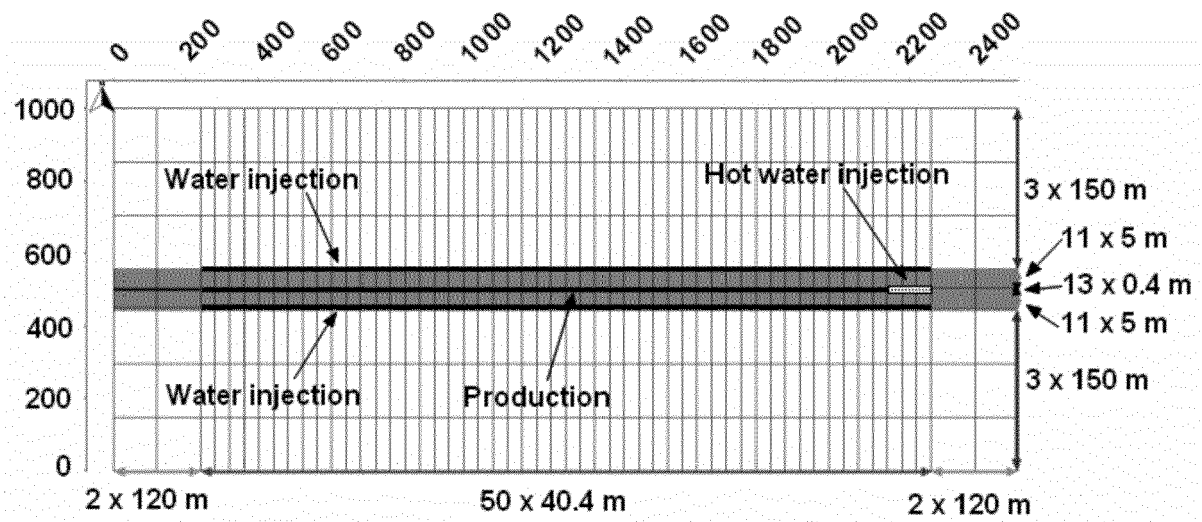


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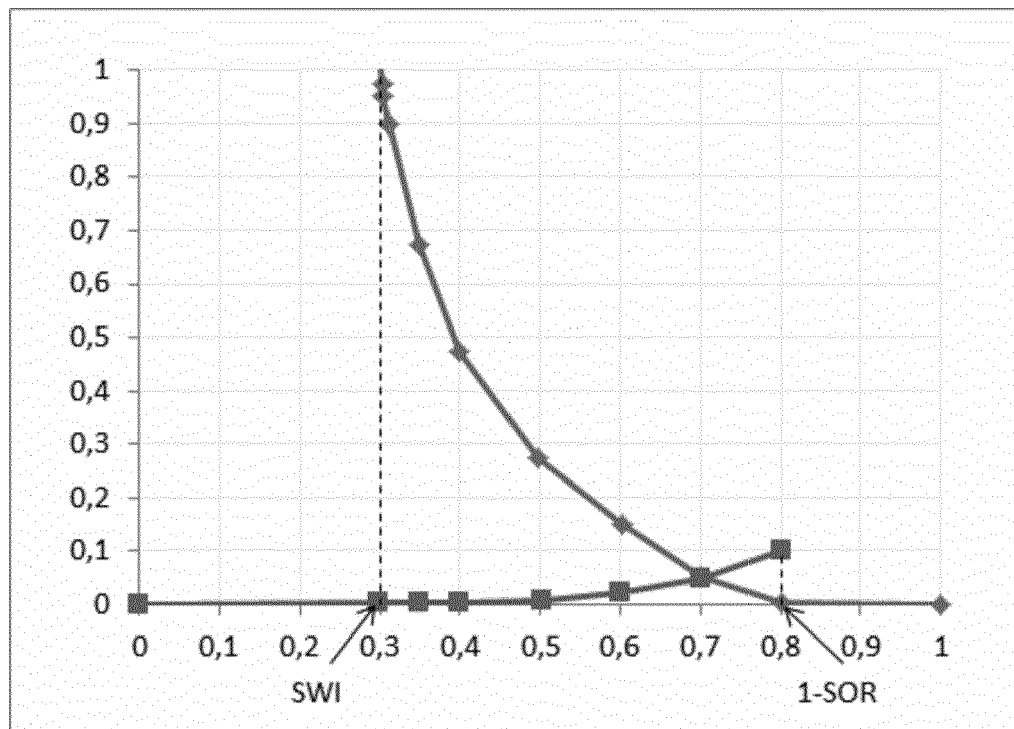


Figure 8

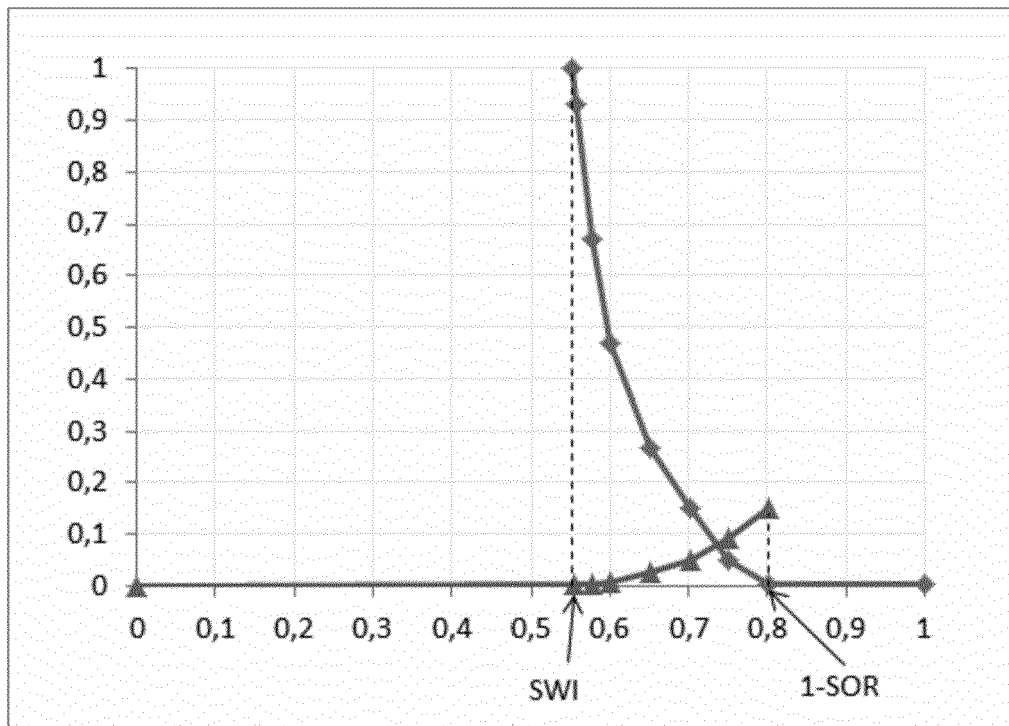


Figure 9

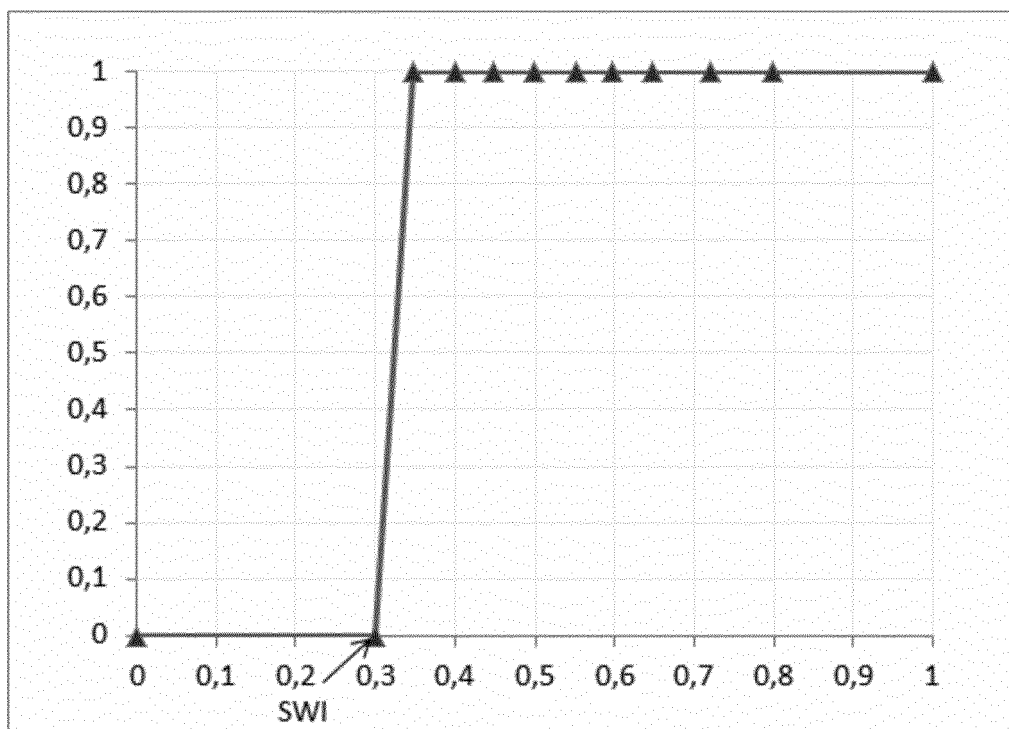


Figure 10a

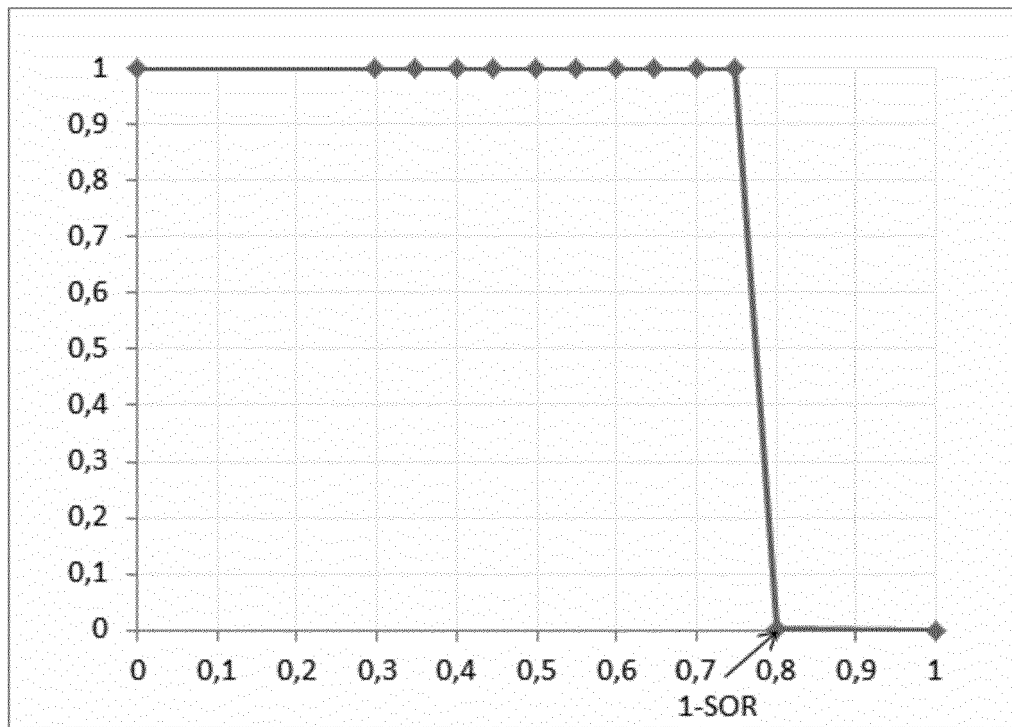


Figure 10b

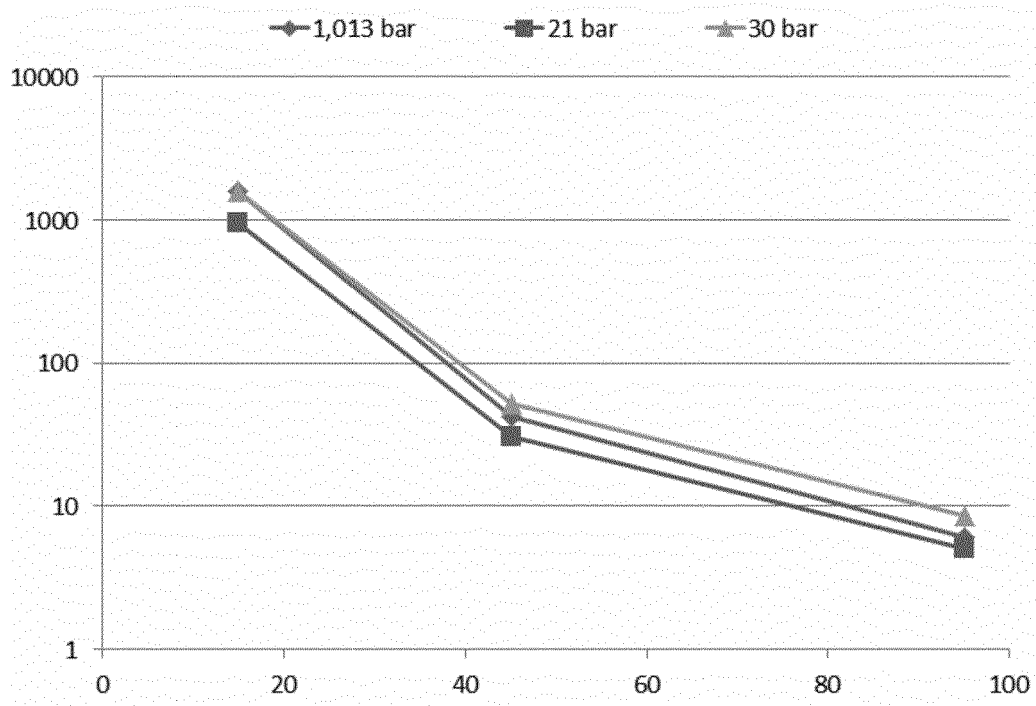


Figure 11

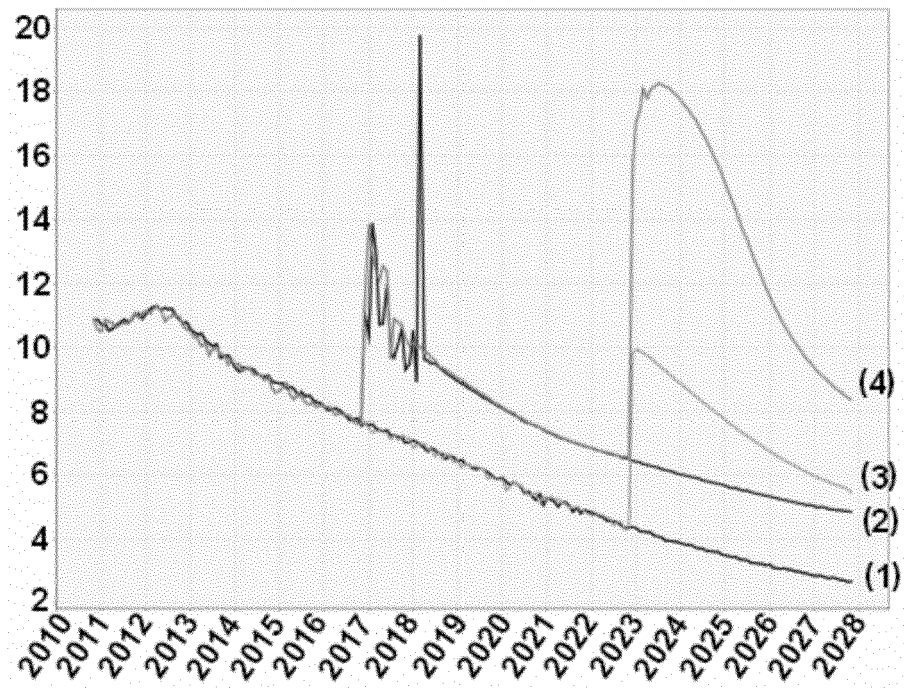


Figure 12

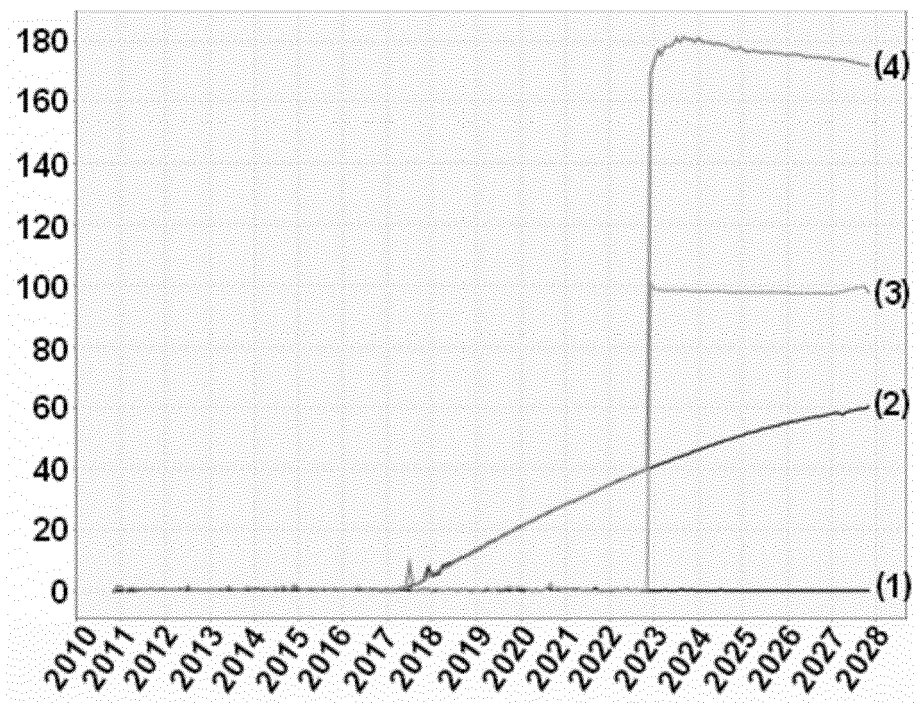


Figure 13

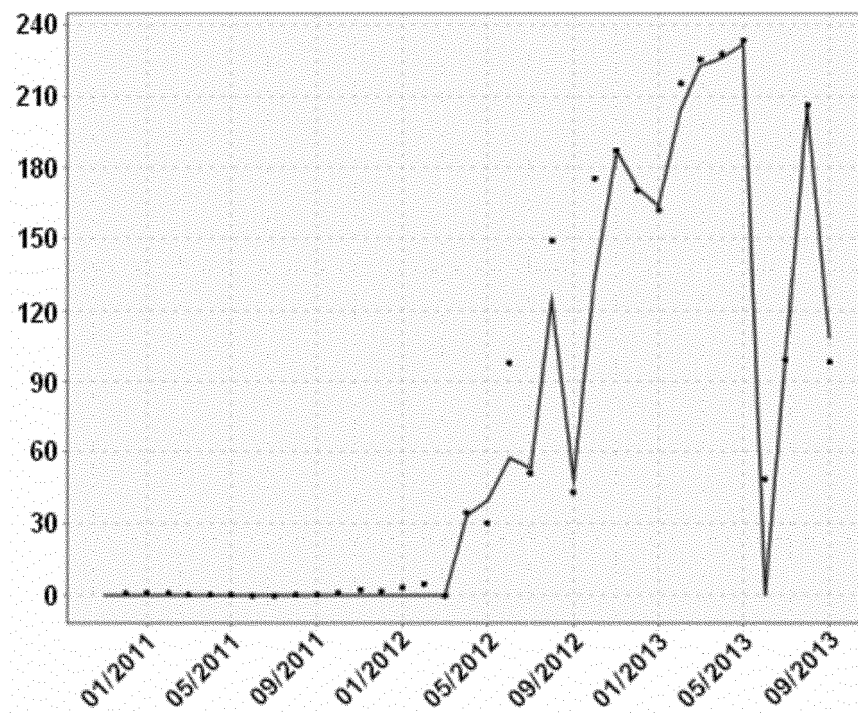


Figure 14

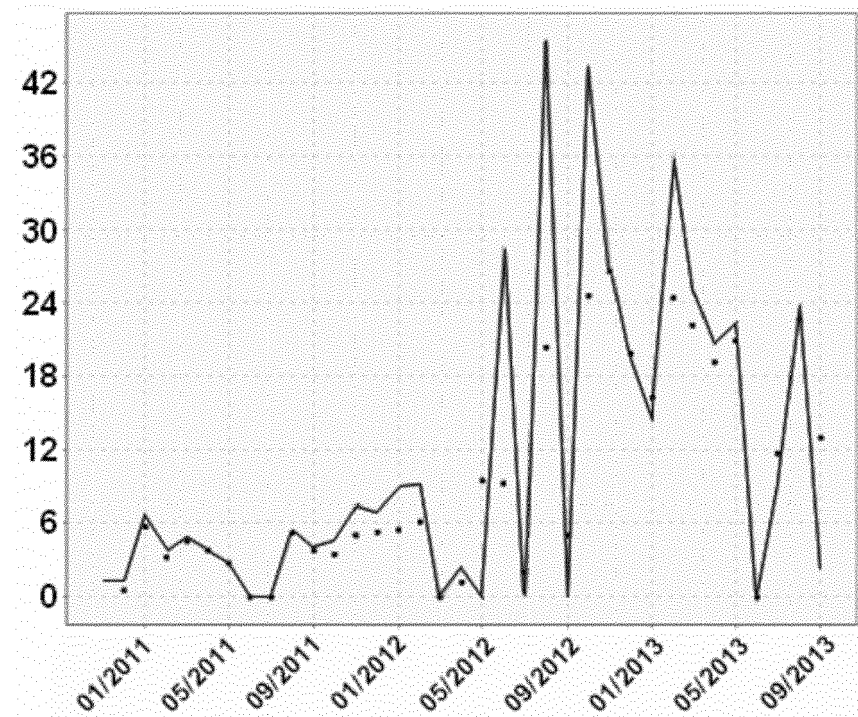


Figure 15

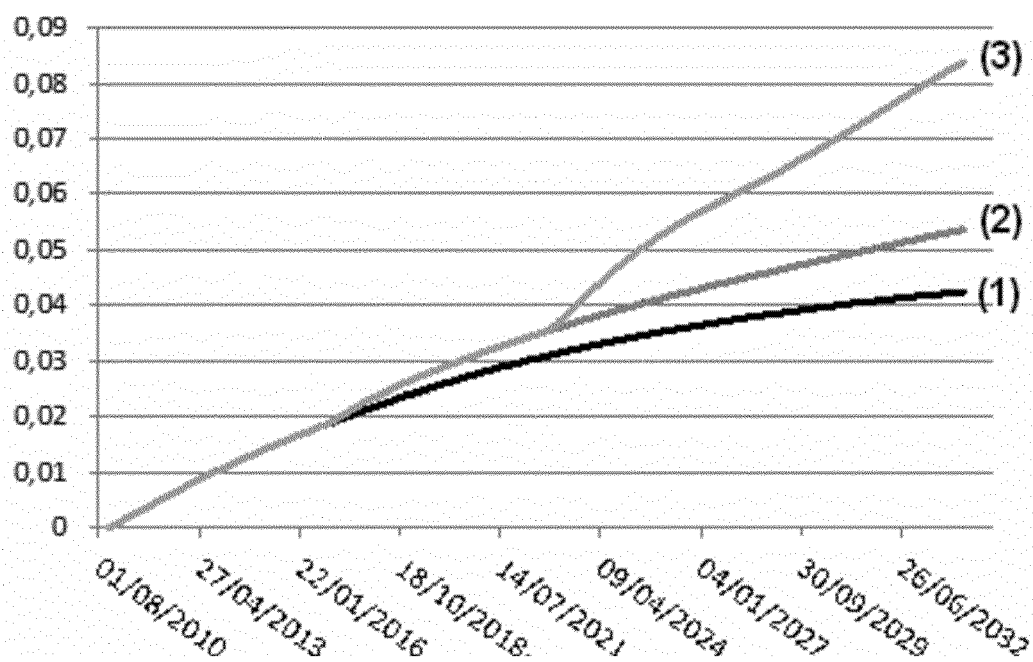


Figure 16

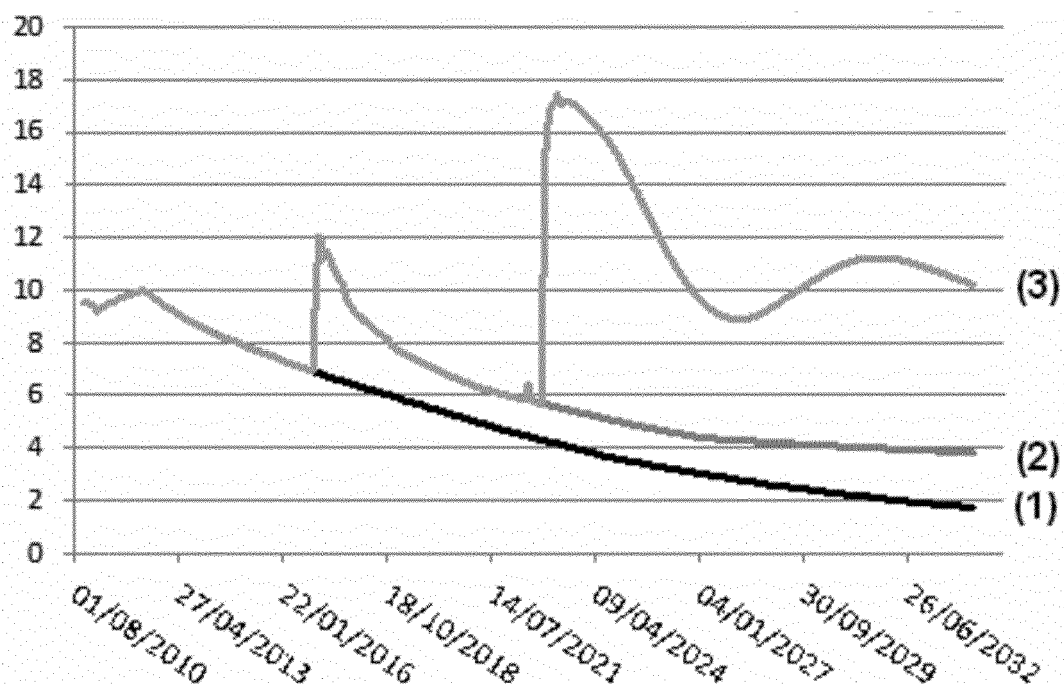


Figure 17

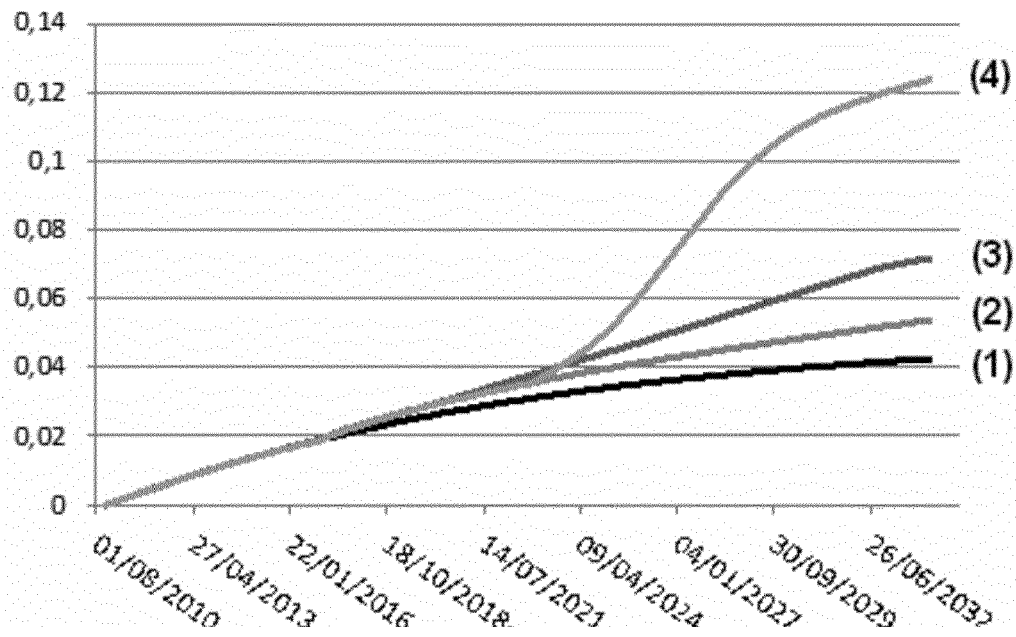


Figure 18

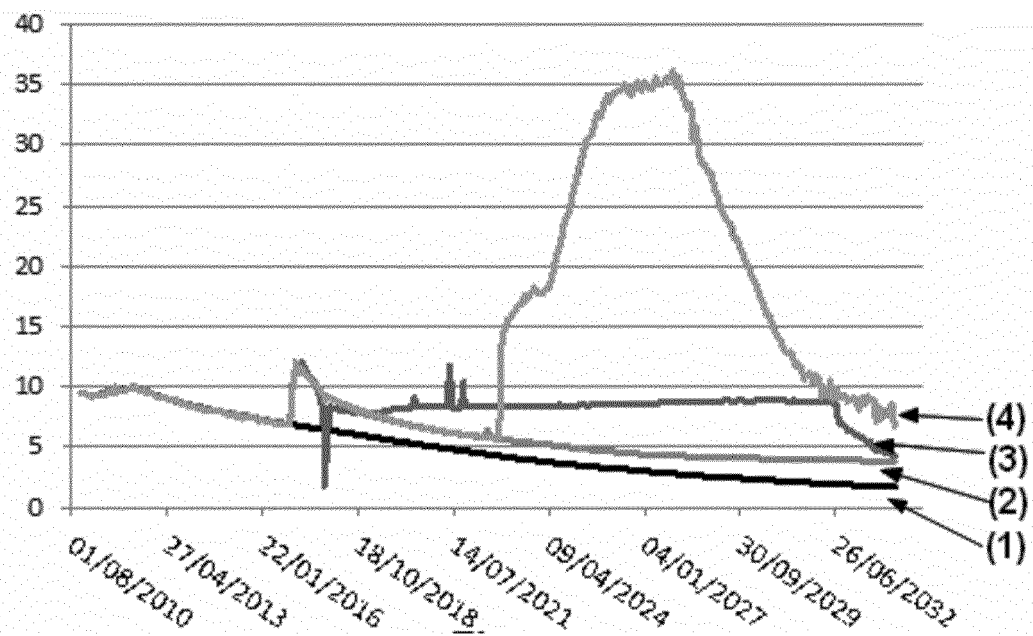


Figure 19

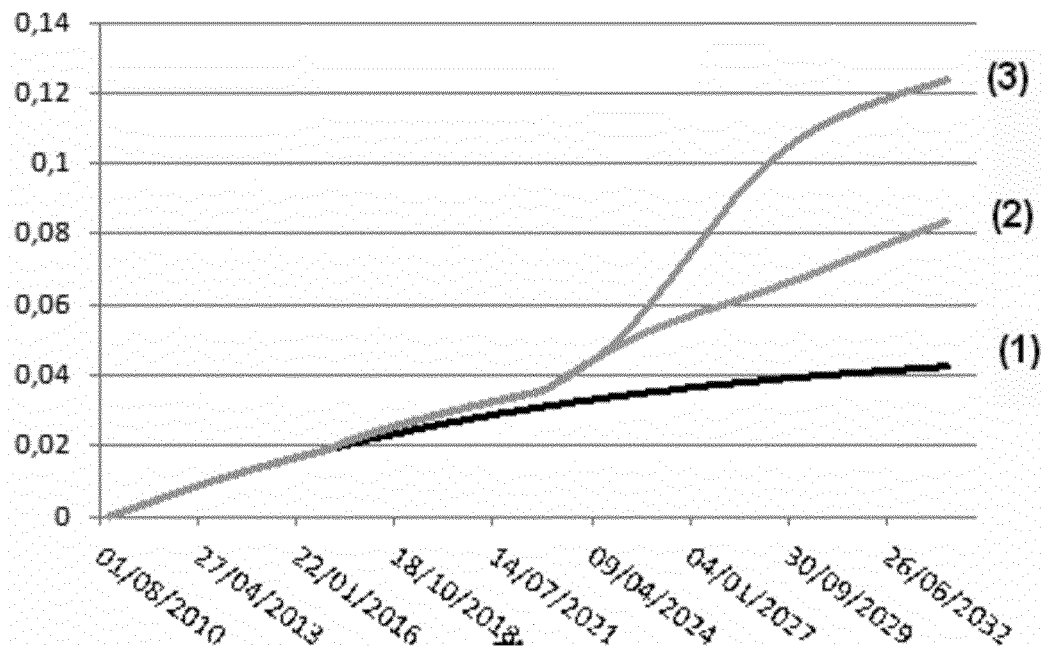


Figure 20

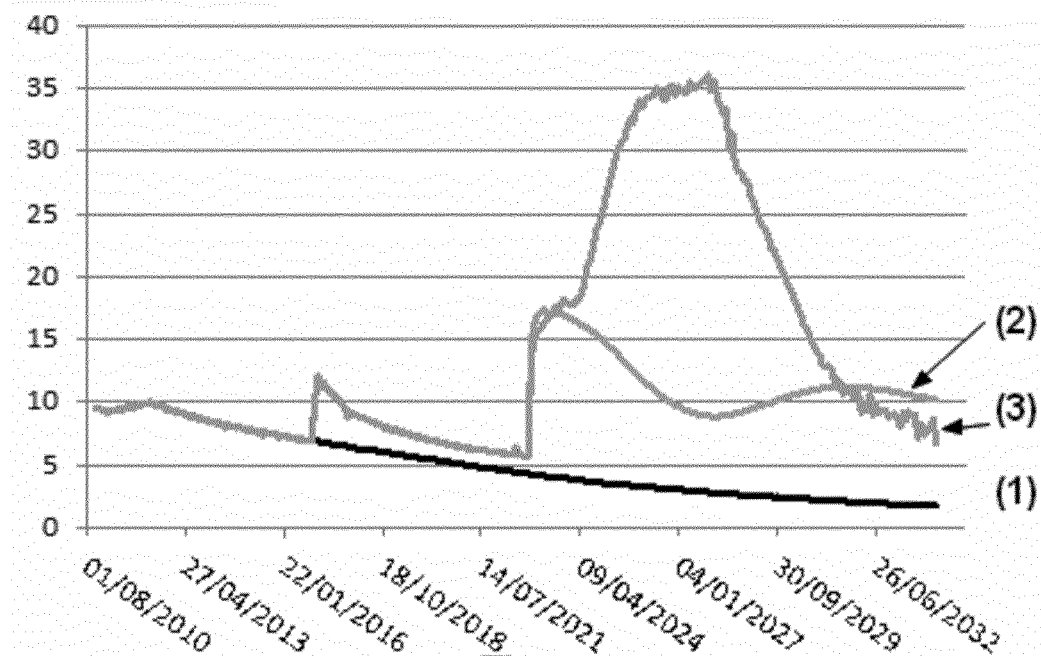


Figure 21



EUROPEAN SEARCH REPORT

Application Number
EP 16 30 6393

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Y	----- RANDALL SERIGHT: "Potential for Polymer Flooding Reservoirs With Viscous Oils", SPE RESERVOIR EVALUATION AND ENGINEERING, vol. 13, no. 04, 1 August 2010 (2010-08-01), pages 730-740, XP055334263, US ISSN: 1094-6470, DOI: 10.2118/129899-PA * the whole document *	1-3,5-12	
Y	----- WO 2013/142242 A1 (FUTURE ENERGY LLC [US]) 26 September 2013 (2013-09-26) * paragraphs [0047], [0048], [0049], [0050], [0051], [0052], [0053] - paragraphs [0054], [0055], [0056], [0057]; figure 1 *	4	TECHNICAL FIELDS SEARCHED (IPC) E21B
The present search report has been drawn up for all claims			
Place of search Munich		Date of completion of the search 12 January 2017	Examiner Patrascu, Bogdan
CATEGORY OF CITED DOCUMENTS X : particularly relevant if taken alone Y : particularly relevant if combined with another document of the same category A : technological background O : non-written disclosure P : intermediate document		T : theory or principle underlying the invention E : earlier patent document, but published on, or after the filing date D : document cited in the application L : document cited for other reasons & : member of the same patent family, corresponding document	

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**ANNEX TO THE EUROPEAN SEARCH REPORT
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EP 16 30 6393

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The members are as contained in the European Patent Office EDP file on
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