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(54) **Titre : Process for recovery of oil from an oil-bearing formation.**

(57) **Abrégé :**

The present invention is directed to a process for producing oil. The mass action ratio (MAR) of divalent cations to monovalent cations of water from an oil-bearing formation is determined, and an aqueous displacement fluid having a total dissolved solids content of from 200 ppm to 5,000 ppm and a MAR of divalent cations to monovalent cations of from 70% to 130% of the MAR of divalent cations to monovalent cations of the formation water is introduced into the formation. Oil is produced from the formation after introducing the aqueous displacement fluid into the formation.

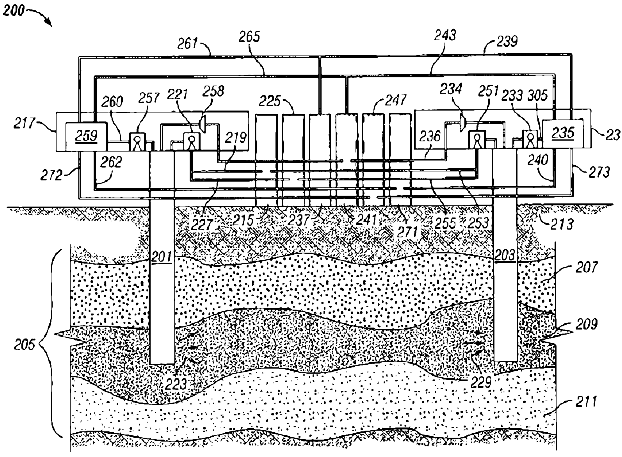

Fig 4

PROCESS FOR RECOVERY OF OIL FROM AN OIL-BEARING FORMATION

Field of the Invention:

The present invention is directed to a process for recovery of oil from an oil-bearing formation. In particular, the present invention is directed to a process for recovering oil from an oil-bearing formation with a polymer-containing fluid.

Background of the Invention

Only a portion of oil present in an oil-bearing formation is recoverable as a result of the natural pressure of the formation. The oil recovered from this "primary" recovery typically ranges from 5% to 35% of the oil in the formation. Enhanced oil recovery methods have been developed to increase the amount of oil that may be recovered from an oil-bearing formation above and beyond that recovered in primary recovery.

Water-flooding, in which water is injected through an injection well into an oil-bearing formation to mobilize and drive oil through the formation for production from a production well, is a widely used method of secondary recovery used to increase the amount of oil recovered from a formation beyond primary recovery. The amount of oil produced by water-flooding may be reduced by water fingering through the oil in the formation due in part to viscosity differences between the injected water and oil in the formation rendering water more mobile than oil in the formation. Oil by-passed by water fingering is left in place in the formation and is typically not recovered by further water-flooding since additional water injected into the formation follows the path of the initial water through the formation.

Water-soluble polymer has been added to water injected into an oil-bearing formation to increase the viscosity of the water and decrease the viscosity difference between the injected water and oil in the formation, improving the water-to-oil mobility ratio and thereby reducing water fingering through the oil. This improves the sweep efficiency of the water in the formation and increases oil recovery. The aqueous polymer mixture may drive through the formation in a plug-like flow to mobilize the oil in the formation for production with reduced fingering of the aqueous drive solution through the oil relative to water without polymer.

Ionically charged water-soluble polymers have been utilized with low salinity water, where "low salinity" water has a total dissolved solids ("TDS") content of 15,000 ppm or less, to produce an aqueous polymer mixture for use in recovering oil from an oil-bearing formation. Use of an ionically charged water-soluble polymer with low salinity water provides a substantial viscosity increase to the water with a minimum quantity of polymer so that a given polymer concentration will provide a higher aqueous phase viscosity as the salinity of the aqeous phase is reduced.

The viscosity of an aqueous polymer mixture, however, may be changed upon introduction of the mixture into an oil-bearing formation as a result of ion exchange, particularly divalent ion exchange, between the aqueous polymer mixture, the rock (minerals and clays) of the formation, and formation water due to differences in ion concentration, particularly divalent cation concentration, between the aqueous polymer mixture, the rock of the formation, and the formation water. Ion exchange between the formation water and the aqueous polymer mixture occurs upon mixing as the ionic concentration of the mixture of formation water and aqueous polymer mixture equilibrates—and may result in an increase in total cation and divalent cation concentration in the aqueous environment of the polymer as the aqueous polymer mixture is mixed with formation water having a higher TDS content than the low salinity water of the aqueous polymer mixture. Ion exchange between the aqueous polymer mixture and the rock of the formation may result in divalent cations being stripped from the aqueous polymer mixture when the water of the aqueous polymer mixture has a lower TDS content than the formation water.

The viscosity of the aqueous polymer mixture may be reduced upon mixing with the formation water if the formation water has a divalent cation concentration that is greater than the divalent cation concentration of the aqueous polymer mixture, thereby altering the mobility ratio of the aqueous polymer mixture to oil in the formation and potentially reducing the effectiveness of the aqueous polymer mixture to inhibit fingering of the mixture through oil in the formation. Furthermore, formation water having a greater divalent cation content relative to the aqueous polymer mixture may precipitate polymer from the mixture due to the affinity of the polymer for divalent cations, potentially reducing permeability of the formation. The viscosity of the aqueous polymer mixture may be increased if the formation water has a divalent cation content less than that of the aqueous polymer mixture and/or if a significant amount of divalent cations are stripped from the aqueous polymer mixture by ion exchange with the formation rock, potentially inhibiting flow of the mixture through the formation. Furthermore, formation damage and clay swelling may be induced by contact of the aqueous polymer mixture with formation water having a higher divalent cation content relative to the aqueous polymer mixture since the aqueous polymer mixture may strip divalent cations from the formation and formation water due to the affinity of the polymer for divalent cations, inducing clay deflocculation.

Improved processes are desirable for maintaining the viscosity of aqueous polymer mixtures introduced into an oil-bearing formation to produce oil from the formation.

Summary of the Invention

The present invention is directed to a process for producing oil from an oil-bearing formation comprising:

determining the mass action ratio of divalent cations relative to monovalent cations of water from the oil-bearing formation, where the mass action ratio of divalent cations relative to monovalent cations of the water from the oil-bearing formation is defined by formula (I)

$$\text{(I)} \qquad MAR_{fw} = [C^{+}_{(fw)}]^2/C^{2+}_{(fw)}$$

where MAR_{fw} is the mass action ratio of divalent cation to monovalent cations of the formation water, $C^{+}_{(fw)}$ is the concentration of monovalent ions in the formation water, and $C^{2+}_{(fw)}$ is the concentration of divalent cations in the formation water;

providing an aqueous displacement fluid comprising water and an ionically charged polymer, wherein the water of the aqueous displacement fluid has a total dissolved solids content of from 200 parts per million by weight (ppmw) to 5,000 ppmw and a mass action ratio of divalent cations relative to monovalent cations from 70% to 130% of the MAR_{fw}, where the mass action ratio of the divalent cations to monovalent cations of the water of the aqueous displacement fluid is defined by formula (II)

$$\text{(II)} \qquad MAR_{adf} = [C^{+}_{(adf)}]^2/C^{2+}_{(adf)}$$

where MAR_{adf} is the mass action ratio of divalent cation to monovalent cations of the aqueous displacement fluid, $C^{+}_{(adf)}$ is the concentration of monovalent ions in the aqueous displacement fluid, and $C^{2+}_{(adf)}$ is the concentration of divalent cations in the aqueous displacement fluid;

introducing the aqueous displacement fluid into the oil-bearing formation to displace oil within the formation;

producing oil from the oil-bearing formation subsequent to introducing the aqueous displacement fluid into the formation.

Brief Description of the Drawings

Fig. 1 is a diagram of an ionic filter that may be used in the process of the present invention.

Fig. 2 is a diagram of an ionic filter that may be used in the process of of the present invention.

Fig. 3 is a diagram of an ionic filter that may be used in the process of of the present invention.

Fig. 4 is a diagram of an oil-production and separation system that may be used in the process of the present invention.

Fig. 5 is a diagram of a well pattern for production of oil than may be used in the process of the present invention.

Fig. 6 is a graph showing the sodium and calcium concentrations in effluents of a synthetic formation brine, a designed low salinity water solution, a high salinity polymer solution, and a designed low salinity water solution injected into an oil-bearing core.

Fig. 7 is a graph showing the magnesium and potassium concentrations in effluents of a synthetic formation brine, a designed low salinity water solution, a high salinity polymer solution, and a designed low salinity water solution injected into an oil-bearing core.

Fig. 8 is a graph showing the viscosity of effluents of a high salinity polymer solution and a designed low salinity polymer solution injected into an oil-bearing core.

Detailed Description of the Invention

The present invention is directed to a process in which an aqueous displacement fluid comprising water having a total dissolved solids ("TDS") content of from 200 ppm to 5,000 ppm and an ionically charged water-dispersable polymer is introduced into an oil-bearing formation comprising oil and water, and the viscosity of the aqueous displacement fluid is maintained upon contact with the formation and the water in the formation. The viscosity of the aqueous displacement fluid may be selected or designed to be compatible in terms of mobility with the oil in the formation at formation temperature conditions so that the aqueous displacement fluid may drive mobilized oil through the formation in substantially plug-like flow without substantial fingering of the aqueous displacement fluid through the oil or oil through the aqueous displacement fluid. The viscosity of the aqueous displacement fluid may be a function of the type and concentration of polymer in the aqueous displacement fluid and the divalent cation concentration of the aqueous displacement fluid—where the divalent cation concentration may affect the viscosity of the aqueous displacement fluid by its effect on the ionically charged polymer. Prior to introducing the aqueous displacement fluid into the formation, the ionic polymer species and the divalent cationic content of the aqueous displacement fluid may be selected or designed to provide the aqueous displacement fluid with a viscosity effective to provide the aqueous displacement fluid with a mobility effective to enable the aqueous displacement fluid to drive mobilized oil in the formation in a substantially plug-like flow at formation temperature conditions.

In the process of the present invention, the viscosity and relative mobility of the aqueous displacement fluid may be maintained upon introduction of the aqueous displacement fluid into the oil-bearing formation and contact with formation water and formation clays, rocks, and/or minerals by selecting or designing the ionic content of the aqueous displacement fluid such that the mass action ratio ("MAR") of divalent cations to monovalent cations of the aqueous displacement fluid is comparable to, or insubstantially different from, the MAR of divalent cations to monovalent cations of the formation water and the formation rock. As used herein, the MAR of divalent cations to monovalent cations of the aqueous displacement fluid or the water in the formation or the formation rock is defined as the ratio of the sum of the concentrations of monovalent cations squared to the sum of the concentrations of divalent cations in the aqueous displacement fluid or the formation water or the formation rock, or MAR = $(C^{+})^{2}/(C^{2+})$, where C^{+} is the sum of the concentration of all monovalent cation species in milliequivalents per liter, and C^{2+} is the sum of the concentration of all divalent cation species in milliequivalents per liter—the definition utilizes a sum of concentrations rather than a conventional product of concentrations to simplify the calculation on the assumption that monovalent cations will react similarly (e.g as a species, compared to divalent cations) and divalent cations will react similarly (e.g. as a species, compared to monovalent cations). When used herein "MAR" refers to the MAR of divalent cations to monovalent cations. When the aqueous displacement fluid has a MAR that is comparable to the formation water MAR and the formation rock MAR (which are similar since the cation exchange between the formation water and formation rock is in a state of equilibrium), little change in the divalent cation to monovalent cation ratio occurs within the aqueous displacement fluid, the formation water, and the formation rock when the aqueous displacement fluid is contacted with the formation water and the formation rock. As a result, the viscosity of the aqueous displacement fluid is not increased or reduced as a result of a change in the divalent cation to monovalent cation ratio as the aqueous displacement fluid is contacted with the formation and the formation water, and the viscosity of the aqueous displacement fluid may be maintained at or near an optimal viscosity for inhibiting fingering of the aqueous displacement fluid through oil in the formation or vice versa as the aqueous displacement fluid is utilized to mobilize and force oil through the formation for production from the formation.

The process of the present invention involves determining the MAR of water from an oil-bearing formation, providing an aqueous displacement fluid comprising water and an ionically charged polymer, where the water of the aqueous displacement fluid has a total dissolved solids ("TDS") content of from 200 parts per million by weight (ppmw) to 5,000 ppmw and a MAR from 70% to 130% of the MAR of the water from the formation; introducing the aqueous displacement fluid into the oil-bearing formation to displace oil within the formation; and producing oil from the formation subsequent to introducing the aqueous displacement fluid into the formation. The MAR of the formation water is defined herein by formula (I):

$$\text{(I)} \qquad \text{MAR}_{\text{fw}} = (C^{+}_{(\text{fw})})^2/(C^{2+}_{(\text{fw})})$$

where MAR_{fw} is the mass action ratio of divalent cation to monovalent cations of the formation water, $C^{+}_{(\text{fw})}$ is the sum of the concentrations of monovalent cations in milliequivalents per liter in the formation water and $C^{2+}_{(\text{fw})}$ is the sum of the concentrations of divalent cations in milliequivalents per liter in the formation water. The MAR of the aqueous displacement fluid is defined herein by formula (II):

$$\text{(II)} \qquad \text{MAR}_{\text{adf}} = (C^{+}_{(\text{adf})})^2/(C^{2+}_{(\text{adf})})$$

where MAR_{adf} is the mass action ratio of divalent cations to monovalent cations of the water of the aqueous displacement fluid, $C^{+}_{(\text{adf})}$ is the sum of the concentrations of monovalent cations in milliequivalents per liter in the aqueous displacement fluid, and $C^{2+}_{(\text{adf})}$ is the sum of the concentrations of divalent cations in milliequivalent per liter in the aqueous displacement fluid. The process of the present invention may further involve determining the viscosity of oil in the formation and providing an aqueous displacement fluid having a viscosity of from 10% to 500% of the viscosity of the oil in the formation, where the viscosity of the aqueous displacement fluid and the oil may be determined at a temperature within a range of temperatures in the formation.

The MAR of divalent cations to monovalent cations of water from the oil-bearing formation may be determined by obtaining a sample of water from the oil bearing formation, measuring the concentrations of each divalent cation species and each monovalent cation species in the formation water, and calculating the formation water $MAR_{(fw)}$ according to formula (I) above. Samples of water from the oil-bearing formation may be obtained in accordance with conventional methods known to those skilled in the art of producing oil. For example, formation water may be obtained by drawing fluids from a formation through a well and separating the formation water from other produced fluids such as oil. The divalent cation concentration of divalent cation species and the monovalent ion concentration of monovalent cation species in the formation water sample may be determined in accordance with conventional methods known to those in the art of analytical chemistry.

After determining the MAR of the formation water, an aqueous displacement fluid comprised of water and a water dispersable ionic polymer is provided having a TDS content of 200 ppm to 5,000 ppm and a MAR from 70% to 130% of the MAR of the formation water. The water of the aqueous displacement fluid may be provided from natural source water having a TDS content of from 200 ppm to 5,000 ppm and a MAR of from 70% to 130% of the MAR of the formation water. Alternatively, the water of the aqueous displacement fluid may be provided from a source water having a TDS content outside of the range of from 200 ppm to 5,000 ppm and/or having a MAR of less than 70% or greater than 130% of the MAR of the formation water, wherein the source water is treated to adjust the TDS content to within a range of from 200 ppm to 5,000 ppm, or is treated to adjust the MAR to a MAR of from 70% to 130% of the MAR of the formation water, or is treated to adjust the TDS content to within a range of 200 ppm to 5,000 ppm and to adjust the MAR to a MAR of from 70% to 130% of the MAR of the formation water.

The water of the aqueous displacement fluid may be provided from a source water having a TDS content of from 200 ppm to 5,000 ppm, or may be provided from a source water having a TDS content of less than 200 ppm or greater than 5,000 ppm that is treated to condition the water to have a TDS content of from 200 ppm to 5,000 ppm. The water of the aqueous displacement fluid may be provided from a low salinity natural source water such as an aquifer, a lake, water produced from the oil-bearing formation, or a river comprising water containing from 200 ppm to 5,000 ppm total dissolved solids, where the source water may be utilized as the water of the aqueous displacement fluid without processing to adjust the TDS content of the source water.

In another embodiment, the water of the aqueous displacement fluid may be provided by processing water from a low salinity natural source water such as an aquifer, a lake, or a river or from water produced from an oil-bearing formation wherein the water from the natural source or the oil-bearing formation has a TDS content of from 0 ppm to less than 200 ppm. The TDS content of the water having a TDS content of from 0 ppm to less than 200 ppm may be adjusted to 200 ppm to 5,000 ppm by adding one or more water soluble salts, for example NaCl and/or $CaCl_2$, to the water. The one or more water soluble salts may be added to the source water as an aqueous solution of the salt(s), or may be added to the source water in solid form.

In another embodiment, the water of the aqueous displacement fluid, or at least a portion thereof, may be provided by processing a saline source water. The saline source water to be processed may have a TDS content of greater than 10,000 ppm, or at least 20,000 ppm, or at least 25,000 ppm, or at least 30,000 ppm, or at least 35,000 ppm, or at least 40,000 ppm, or at least 50,000 ppm, or from 15,000 ppm to 250,000 ppm, or from 20,000 ppm to 200,000 ppm, or from 25,000 ppm to 150,000 ppm, or from 30,000 ppm to 100,000 ppm, or from 35,000 ppm to 50,000 ppm. The saline source water to be processed to provide the water of the aqueous displacement fluid may be selected from the group consisting of aquifer water, seawater, brackish water, estuarine water, water produced from the oil-bearing formation, and mixtures thereof.

Referring now to Fig. 1, a saline source water having a TDS content of greater than 10,000 ppm as described above may be processed to produce at least a portion of the water of the aqueous displacement fluid by contacting the saline source water 111 with an ionic filter 113, where the mechanism for processing the saline source water may comprise the ionic filter. A portion of the source water 111 may be passed through the ionic filter 113 to form treated water 115 having reduced salinity relative to the source water 111, wherein the treated water may have a TDS content of up to 5,000 ppm, and more preferably of from 200 ppm to 5,000 ppm, and most preferably from 500 ppm to 4,000 ppm. At least a portion of the treated water 115 may be utilized as at least a portion of the water of the aqueous displacement fluid.

A portion of the source water 111 may be excluded from passing through the ionic filter 113 to form a brine retentate 117 having increased salinity relative to the source water. The brine retentate may have a TDS content of at least 20,000 ppm, or from 25,000 ppm to 300,000 ppm. At least a portion of the brine retentate may be utilized as described in further detail below.

If the treated water has a MAR that is greater than 130% or less than 70% of the MAR of the formation water, the treated water may be adjusted so the treated water has a MAR that is from 70% to 130% of the MAR of the formation water. Monovalent cation-containing salts, or aqueous solutions thereof, or divalent cation-containing salts, or aqueous solutions thereof, may be utilized to adjust the MAR of the treated water upwards or downwards to adjust the MAR of the treated water to within 70% to 130% of the MAR of the formation water. If necessary, at least a portion of the brine retentate 117 may be added to the treated water 115 to adjust the MAR of the treated water to within 70% to 130% of the MAR of the formation water. At least a portion of the MAR adjusted treated water may be utilized as the water of the aqueous displacement fluid.

The ionic filter 113 may be a membrane based system utilizing ionic separation membrane units selected from the group consisting of a nanofiltration membrane unit, a reverse osmosis membrane unit, and combinations thereof. A nanofiltration membrane unit may be comprised of one or more nanofiltration membranes effective for preferentially or selectively removing multivalent ions, including divalent cations, from the source water so the treated water may contain less than 80%, or less the 90%, or less than 95% multivalent ions and/or divalent cations than the source water fed to the nanofiltration membrane(s), and the retentate may contain a corresponding increase of multivalent ions and/or divalent cations relative to the source water. The one or more nanofiltration membranes of a nanofiltration membrane unit may also moderately reduce the monovalent ion content of source water fed to the nanofiltration membrane(s), where the treated water may contain less than 20%, or less than 30%, or less than 50%, or less than 70% of monovalent ions than the source water fed to the nanofiltration membrane(s), and the brine retentate may contain a corresponding increase of monovalent ions relative to the source water. Nanofiltration membranes may be formed of charged polymeric materials (e.g. having carboxylic acid, sulfonic acid, amine, or amide functional groups) including polyamides, cellulose acetate, piperazine, or substituted piperazine membranes in which a thin ion discriminating layer of membrane is supported on a thicker porous material, which is sandwiched between the discriminating layer and a backing material. Suitable commercially available nanofiltration membranes in sheet form or in spirally wound form that may be utilized in a nanofiltration membrane unit in the ionic filter 13 include, but are not limited to, SEASOFT 8040DK, 8040DL, and SEASAL DS-5 available from GE Osmonics, Inc., 5951 Clearwater Drive, Minnetonka, MN 55343, United States; NF200 Series, and NF-55, NF-70, and NF-90 available from Dow FilmTec Corp., 5239 W. 73rd St., Minneapolis, MN, 55345, United States; DS-5 and DS-51 available from Desalination Systems, Inc., 760 Shadowridge Dr., Vista, CA, 92083, United States; ESNA-400 available from Hydranautics, 401 Jones Road, Oceanside, CA 92508, United States; and TFCS available from Fluid Systems, Inc., 16619 Aldine Westfield Road, Houston, TX 77032, United States.

A reverse osmosis membrane unit useful in the ionic filter 113 may be comprised of one or more reverse osmosis membranes effective for removing substantially all ions, including monovalent ions, from the source water so the treated water may contain less than 85%, or less than 90%, or less than 95%, or less than 98% ions than the source water fed to the reverse osmosis membrane(s), and the brine retentate may contain a corresponding increase of ions relative to the source water. Reverse osmosis membranes may be spirally wound or hollow fiber modules, and may be asymmetric membranes prepared from a single polymeric material, such as asymmetric cellulose acetate membranes, or thin-film composite membranes prepared from a first and a second polymeric material, such as cross-linked aromatic polyamides in combination with a polysulfone. Suitable commercially available reverse osmosis membranes that may be utilized in a reverse osmosis membrane unit in the ionic filter 113 include, but are not limited to, AG8040F and AG8040-400 available from GE Osmonics; SW30 Series and LF available from Dow FilmTec Corp.; DESAL-11 available from Desalination Systems, Inc.; ESPA available from Hydranautics; ULP available from Fluid Systems, Inc.; and ACM available from TriSep Corp., 93 S. La Patera Lane, Goleta, CA 93117, United States.

Typically, pressure must be applied across the ionic filter 113 to overcome osmotic pressure across the membrane when saline source water 111 is filtered to reduce the TDS content of the source water and produce the treated water 115. The pressure applied across the ionic filter 113 may be at least 2.0 MPa, or at least 3.0 MPa, or at least 4.0 MPa, and may be at most 10.0 MPa, or at most 9.0 MPa, or at most 8.0 MPa, and may range from 2.0 MPa to

10.0 MPa, or from 3.0 MPa to 9.0 MPa. The pressure applied across a nanofiltration membrane in the ionic filter 113 may be in the lower portion of the pressure range relative to the pressure applied across a reverse osmosis membrane. The pressure applied across a nanofiltration membrane unit of the ionic filter 113 may range from 2.0 MPa to 6.0 MPa, and the pressure applied across a reverse osmosis membrane unit of the ionic filter 113 may range from 4.0 MPa to 10.0 MPa. If the ionic filter 113 is comprised of membrane units—either nanofiltration, reverse osmosis, or both—combined in a series, the pressure applied across each membrane of the membrane unit may be less than the previous membrane unit by at least 0.5 MPa as less pressure is required to overcome the osmotic pressure of the permeate of a preceding membrane unit.

Referring now to Fig. 2, the ionic filter 113 may be comprised of a first ionic membrane unit 119 and one or more second ionic membrane units 121 arranged in series, wherein each ionic membrane unit may be a nanofiltration membrane unit or a reverse osmosis membrane unit. The saline source water 111 having a TDS content of greater than greater than 10,000 ppm as described above may be contacted with the first ionic membrane unit 119 to pass at least a portion of the saline source water through the first ionic membrane unit to form a permeate 123 having a reduced TDS content relative to the saline source water, wherein the permeate may have a TDS content of at least 1,000 ppm, or at least 2,500 ppm, or at least 5,000 ppm, or at least 7,000 ppm, or at least 10,000 ppm, or at least 15,000 ppm. A portion of the saline source water may be excluded from passing through the first ionic membrane unit 119 to form a primary brine retentate 125 having increased salinity relative to the source water. The permeate 123 may be contacted with each of the second ionic membrane units 121 in sequence to pass at least a portion of the permeate through each of the second ionic membrane units to form treated water 115 having reduced salinity relative to the permeate 123 and the saline source water 111, wherein the treated water may have a TDS content of from 200 ppm to 5,000 ppm. At least a portion of the treated water 115 may be utilized as at least a portion of the water of the aqueous displacement fluid.

A portion of the permeate 123 may be excluded from passing through each of the one or more second ionic membrane units 121 to form one or more secondary brine retentates 127. The primary brine retentate 125, one or more of the secondary brine retentates 127, or a combination of the primary brine retentate 125 and one or more of the secondary brine retentates 127 may form the brine retentate 117 from the ionic filter 113, where the brine retentate 117 has an increased salinity relative to the source water 111 and may have a TDS content of at least 20,000 ppm, or from 25,000 ppm to 300,000 ppm. At least a portion of the brine retentate 117 formed of the primary brine retentate 125, one or more of the secondary brine retentates 127, or a combination thereof may be utilized as described in further detail below.

Referring now to Fig. 3, the ionic filter 113 may be comprised of a first ionic membrane unit 129 and a second ionic membrane unit 131 arranged in parallel, wherein the first ionic membrane unit may be comprised of one or more nanofiltration membranes or one or more reverse osmosis membranes, or a combination thereof, and the second ionic membrane unit may be comprised of one or more nanofiltration membranes, one or more reverse osmosis membranes, or a combination thereof. A first portion 133 of the saline source water 111 as described above may be contacted with the first ionic membrane unit 129 and a portion of the first portion of the saline source water 133 may be passed through the first ionic membrane unit 129 to form a first permeate 135 having reduced TDS content relative to the saline source water 111. The first permeate 135 may have a TDS content of less than 10,000 ppm, or less than 7,500 ppm, or less than 6,000 ppm , or less than 5,000 ppm, or from 200 ppm to 5,000 ppm. A portion of the first portion of the saline source water 133 may be excluded from passing through the first ionic membrane unit 129 to form a first brine retentate 137 having a TDS content greater than the saline source water 111. The first brine retentate 137 may have a TDS content of at least 20,000 ppm, or at least 25,000 ppm, or at least 30,000 ppm, or at least 35,000 ppm, or at least 40,000 ppm, or at least 50,000 ppm. A second portion 139 of the saline source water 111 may be contacted with the second ionic membrane unit 131, and a portion of the second portion of the saline source water 139 may be passed through the second ionic membrane unit 131 to form a second permeate 141 having reduced TDS content relative to the saline source water 111. The second permeate may have a TDS content of less than 10,000 ppm, or less than 7,500 ppm, or less than 5,000 ppm, or from 200 ppm to 5,000 ppm. A portion of the second portion of the saline source water 139 may be excluded from passing through the second ionic membrane unit 131 to form a second brine retentate 143 having a TDS content of at least 20,000 ppm , or at least 25,000 ppm, or at least 30,000 ppm, or at least 25,000 ppm, or at least 40,000 ppm, or at least 50,000 ppm. At least a portion of the first and second permeates 135 and 141 may be combined to form the treated water 115 having a TDS content of up to 5,000 ppm, or less than 40,000 ppm, or from 200 ppm to 5,000 ppm, where at least a portion of the treated water 115 may be used as the water of the aqueous displacement fluid. The first brine retentate 137, a portion thereof, the second brine retentate 143, a portion thereof, a combination of the first brine retentate 137 and the second brine retentate 143, or a combination of portions thereof, may form the brine retentate 117 which may be utilized as described in further detail below.

In an embodiment, the first ionic membrane unit 129 may consist of one or more nanofiltration membranes and the second ionic membrane unit 131 may consist of one or more reverse osmosis membranes. The second permeate 141 passed through the second ionic membrane unit 131 may have a TDS content of less than 200 ppm provided the one or more reverse osmosis membranes of the second ionic membrane unit 131 remove substantially all of the total dissolved solids from the saline source water 111. The first permeate 135 passed through nanofiltration membranes may have sufficient monovalent ions therein to have a TDS content of at least 200 ppm, or at least 1,000 ppm, or at least 2,000 ppm, so that the combined first and second permeates form the treated water 115 having a TDS content of from 200 ppm to 5,000 ppm.

Referring now to Figs. 1, 2, and 3, if the treated water 115 has a TDS content of less than 200 ppm, the TDS content of the treated water may be adjusted so the treated water has a TDS content to a range of from 200 ppm to 5,000 ppm. A portion of the brine retentate 117 may be added to the treated water 115 to adjust the TDS content from below 200 ppm to a range of from 200 ppm to 5,000 ppm. Alternatively, one or more salts or aqueous salt solutions, for example NaCl and/or $CaCl_2$ salts or aqueous salt solutions, may be added to the treated water 115 to adjust the TDS content of the treated water to a range of from 200 ppm to 5,000 ppm. At least a portion of the resulting TDS adjusted treated water may be utilized as the water of the aqueous displacement fluid.

The water of the aqueous displacement fluid also has a MAR of from 70% to 130% of MAR of the formation water. The water of the aqueous displacement fluid may be selected from a water source having a MAR of from 70% to 130% of the MAR of the formation water or water from a water source may be treated so the water has a MAR of from 70% to 130% of the MAR of the formation water. The water source may be treated water from a source water that has been treated to adjust the TDS content of the water to a range from 200 ppm to 5,000 ppm as described above. In one embodiment of the process of the present invention, water from a low salinity natural source water or from a saline source water as described above is treated to adjust the TDS content of the water to a range of from 200 ppm to 5,000 ppm, then the TDS adjusted treated water is treated to adjust the MAR of the TDS adjusted treated water to within 70% to 130% of the MAR of the formation water while maintaining the TDS content of the MAR adjusted water in a range of from 200 ppm to 5,000 ppm. In another embodiment, the MAR of water from a low salinity natural source water or a saline source water as described above is treated to adjust the MAR of the water to a range of from 70% to 130% of the formation water, then the MAR adjusted water is treated to adjust the TDS content of the MAR adjusted water to a range of from 200 ppm to 5,000 ppm as described above while maintaining the MAR of the water within 70% to 130% of the MAR of the formation water. In another embodiment, the MAR of water from a low salinity natural source water having a TDS content of from 200 ppm to 5,000 ppm as described above is treated to adjust the MAR of the water to within 70% to 130% of the MAR of the formation water while maintaining the TDS content of the water in a range of from 200 ppm to 5,000 ppm. In another embodiment, the TDS content of water from a low salinity natural source water or a saline source water having a MAR of from 70% to 130% of the MAR of the formation water is treated to adjust the TDS content to a range of from 200 ppm to 5,000 ppm while maintaining the MAR ratio of the water in a range of from 70% to 130% of the formation water. In another embodiment, the water of the aqueous displacement fluid may be selected from a source water having a TDS content of from 200 ppm to 5,000 ppm and a MAR in a range of from 70% to 130% of the MAR of the formation water.

The MAR of divalent cations to monovalent cations of water from a source water for use in the aqueous displacement fluid may be determined by measuring the concentrations of each divalent cation species and each monovalent cation species in the water, and calculating the water $\mathrm{MAR}_{(\mathrm{adf})}$ according to formula (II) above. The divalent cation concentration of divalent cation species and the monovalent ion concentration of monovalent cation species in the water may be determined in accordance with conventional methods known to those in the art of analytical chemistry.

The MAR of the water for use in the aqueous displacement fluid may be adjusted, if necessary, by 1) calculating the amount of monovalent cations and/or divalent cations required to adjust the MAR of the water to be used in the aqueous displacement fluid to an MAR in a range of from 70% to 130% of the measured MAR of the formation water; and 2) adding or removing the calculated amount of monovalent cations and/or divalent cations to the water to adjust the MAR of the water to a range of from 70% to 130% of the MAR of the formation water.

Monovalent cations and/or divalent cations may be added to the water to be used in the aqueous displacement fluid to adjust the MAR of divalent cations to monovalent cations of the water to a range of from 70% to 130% of the MAR of the formation water. Monovalent cations and/or divalent cations may be added to the water by adding a selected amount of one or more selected monovalent cation salts and/or one or more selected divalent cation salts, or adding an aqueous solution of a selected amount of one or more monovalent cation salts and/or one or more selected divalent cation salts. In one embodiment of the process of the present invention, one or more brine retentates 117, 125, 127, 137, or 143 produced in the treatment of water to reduce the TDS content of the water as described above may be added to water to adjust the MAR of the water to a range of from 70% to 130% of the formation water.

Monovalent cations and/or divalent cations may be removed from the water to be used in the aqueous displacement fluid to adjust the MAR of divalent cations to monovalent cations of the water to a range of from 70% to 130% of the formation water. Divalent cations may be removed from the water preferentially relative to monovalent cations by passing the water through a nanofiltration membrane as described above. Monovalent cations may be removed from the water preferentially relative to divalent cations by passing the water through an ion exchange column packed with an ion exchange material selective for adsorbing monovalent cations.

The aqueous displacement fluid also comprises a water-dispersible, preferably water-soluble, ionic polymer that is dispersed in the water described above. After selection or production of water having a TDS content of from 200 ppm to 5,000 ppm and a MAR of divalent cations to monovalent cations that is from 70% to 130% of the MAR of divalent cations to monovalent cations of the formation water, the ionically charged polymer is mixed with the water to increase the viscosity thereof and to produce the aqueous displacement fluid. The ionically charged polymer may be added in an amount effective to increase the viscosity of the treated water to within 10% to 500% of the viscosity of oil within the oil-bearing formation as measured at a temperature within the temperature range in the oil-bearing formation. The ionically charged polymer may be added in an amount effective to reduce the mobility of the treated water relative to the mobility of oil in place in the formation, preferably so that the mobility ratio of the resulting aqueous displacement fluid relative to oil in the oil-bearing formation is from 0.2 to 5.

The polymer that is mixed with the water to form the aqueous displacement fluid may be any ionically charged polymer usable in an enhanced oil recovery application, where the polymer is soluble or uniformly dispersable in the water. The polymer may be a homopolymer or a heteropolymer comprised of two or more monomeric units. The ratio of monomeric units of a heteropolymer to be mixed with the treated water may be selected to provide the aqueous displacement fluid with a selected viscosity in accordance with conventional knowledge in the art of mixing water-soluble or water-dispersable polymers in water. The polymer may be a water-soluble polyacrylamide or polyacrylate. The polymer may be a partially hydrolyzed polymer. A partially hydrolyzed polymer for mixing in the treated water may have a degree of hydrolysis of from 0.1 to 0.4, or from 0.2 to 0.3. A preferred polymer for use in the aqueous displacement fluid is a partially hydrolyzed polyacrylamide having a degree of hydrolysis of from 0.15 to 0.4, preferably from 0.2 to 0.35. Preferred polymers for use in the aqueous displacement fluid are commercially available partially hydrolyzed polyacrylamides sold under the trade name of FLOPAAM™ by SNF SAS, particularly FLOPAAM™ 3330 and FLOPAAM™ 3630.

The polymer and the water of the aqueous displacement fluid may be mixed by adding the polymer to the water, or adding the water to the polymer, and mixing utilizing any conventional mechanism for mixing water and a water-soluble or water-dispersable polymer. The polymer and the water may be mixed to form the aqueous displacement fluid by agitating the polymer and the water in a stirred tank. Excessive shear should be avoided when mixing the polymer and the water to inhibit mechanical reduction of the size of the polymer molecules.

The polymer may be provided for mixing with the water in a solid powder form or in a concentrated aqueous solution containing from 5 wt. % to 25 wt. % of the polymer. If the polymer is provided for mixing in a solid powder form, the water and polymer should be mixed for a sufficient time to allow for hydration of the polymer.

The amount of polymer mixed with the water to form the aqueous displacement fluid may be selected to provide the aqueous displacement fluid formed with a selected viscosity relative to oil in place in the oil-bearing formation in which the aqueous displacement fluid is to be introduced. The viscosity of a polymer solution is a function of the polymer, its molecular weight, the degree of hydrolysis of the polymer, the salinity of the polymer solution, the pH of the solution, the temperature of the solution, the shear rate, and the concentration of the polymer in the solution. The amount of polymer mixed with the water may be selected to provide the aqueous displacement fluid with a selected viscosity since the polymer, its molecular weight, its degree of hydrolysis, the salinity and pH of the water of the aqueous displacement fluid, and the temperature of the aqueous displacement fluid (relative to the formation temperature) are fixed and the shear rate may be held constant by controlling the pressure at which the aqueous displacement fluid is injected into the formation. The selected viscosity may be from 10% to 500%, or from 40% to 400% of the viscosity of the oil in place in the oil-bearing formation as determined at formation temperature conditions. The viscosity of the oil in place in the formation at formation temperature conditions may be determined in accordance with conventional methods within the art. The selected viscosity of the aqueous displacement fluid may range from 0.5 mPa s (cP) to 250 mPa s (cP) as measured at a temperature within the range of formation temperature conditions.

The amount of polymer provided in the aqueous displacement fluid may also be selected to provide a selected mobility ratio of the aqueous displacement fluid relative to oil within the formation. The selected mobility ratio of the aqueous displacement fluid to oil in the formation may range from 0.2 to 5, or from 0.5 to 3.

The amount of polymer in the aqueous displacement fluid may be from at least 350 ppm up to 10,000 ppm by weight of the aqueous displacement fluid. The amount of polymer in the aqueous displacement fluid may range from 500 ppmw to 5,000 ppmw, or from 1,000 ppmw to 2,500 ppmw of the aqueous displacement fluid.

The aqueous displacement fluid is introduced into the oil-bearing formation to enhance recovery of oil from the formation by displacing and mobilizing oil in the formation for production from the formation. The oil-bearing formation may be comprised of a porous matrix material, oil, and connate water. The oil-bearing formation comprises oil that may be separated and produced from the formation after introduction of the aqueous displacement fluid into the formation.

The porous matrix material of the formation may be comprised of one or more porous matrix materials selected from the group consisting of a porous mineral matrix, a porous rock matrix, and a combination of a porous mineral matrix and a porous rock matrix. Formation temperatures may range from 5°C to 275°C, or from 50°C to 250°C; formation pressures may range from 1 MPa to 100 MPa; pH of the connate water in the formation may range from 4 to 9, or from 5 to 8; and salinity of the connate water may range from a TDS content of 2000 ppm to 300,000 ppm.

The rock and/or mineral porous matrix material of the formation may be comprised of sandstone and/or a carbonate selected from dolomite, limestone, and mixtures thereof—where the limestone may be microcrystalline or crystalline limestone. Minerals that may form the mineral porous matrix material may be clays or transition metal compounds. Clays that may form at least a portion of the mineral porous matrix material include smectite clays, smectite/illite clays, montmorillonite clays, illite clays, illite/mica clays, pyrophyllite clays, glauconite clays, and kaolinite clays. Transition metal compound minerals that may form at least a portion of the mineral porous matrix material include carbonates and oxides, for example, iron oxide, siderite, and plagioclase feldspars.

The porous matrix material may be a consolidated matrix material in which at least a majority, and preferably substantially all, of the rock and/or mineral that forms the matrix material is consolidated such that the rock and/or mineral forms a mass in which substantially all of the rock and/or mineral is immobile when oil, the aqueous displacement fluid, or other fluid is passed therethrough. Preferably at least 95 wt.% or at least 97 wt.%, or at least 99 wt.% of the rock and/or mineral is immobile when oil, the aqueous displacement fluid, or other fluid is passed therethrough so that any amount of rock or mineral material dislodged by the passage of the oil, the aqueous displacement fluid, or other fluid is insufficient to render the formation impermeable to the flow of the oil, the aqueous displacement fluid, or other fluid through the formation. Alternatively, the porous matrix material may be an unconsolidated matrix material in which at least a majority, or substantially all, of the rock and/or mineral that forms the matrix material is unconsolidated. The formation, whether formed of a consolidated mineral matrix, an unconsolidated mineral matrix, or combination thereof may have a permeability of from 0.00001 to 15 Darcys, or from 0.001 to 1 Darcy.

The oil-bearing formation may be a subterranean formation. The subterranean formation may be comprised of one or more porous matrix materials described above, where the porous matrix material may be located beneath an overburden at a depth ranging from 50 meters to 6,000 meters, or from 100 meters to 4,000 meters, or from 200 meters to 2,000 meters under the earth's surface. The subterranean formation may be a subsea formation.

The oil contained in the oil-bearing formation may have a viscosity under formation conditions (in particular, at temperatures within the temperature range of the formation) of at least 0.2 mPa·s (0.2 cP), or at least 1 mPa·s (1 cP), or at least 5 mPa·s (10 cP), or at least 10 mPa·s (100 cP). The oil contained in the oil-bearing formation may have a viscosity under formation temperature conditions of from 0.2 to 10,000 mPa·s (0.2 to 10,000 cP), or from 1 to 1,000 mPa·s (1 to 1,000 cP) or from 1 to 500 mPa·s (1 to 500 cP), or from 1 to 250 mPa·s(1 to 250 cP). Preferably the oil in the oil-bearing formation has a viscosity under formation temperature conditions of from 0.2 to 500 mPa·s so that the aqueous displacement fluid may be provided having a mobility ratio relative to the oil of at most 2 without inclusion of inordinate amounts of polymer in the aqueous displacement fluid.

Oil in the oil-bearing formation may be located in pores within the porous matrix material of the formation. The oil in the oil-bearing formation may be immobilized in the pores within the porous matrix material of the formation, for example, by capillary forces, by interaction of the oil with the pore surfaces, by the viscosity of the oil, or by interfacial tension between the oil and water in the formation.

The oil-bearing formation may also be comprised of water, which may be located in pores within the porous matrix material. The water in the formation may be connate water, water from a secondary or tertiary oil recovery process water-flood, or a mixture thereof. Connate water in the oil-bearing formation may have a TDS content of at least 500 ppm, or at least 1,000 ppm, or at least 2,500 ppm, or at least 5,000 ppm, or at least 10,000 ppm, or at least 25,000 ppm, or from 500 ppm to 250,000 ppm, or from 1,000 ppm to 200,000 ppm, or from 2,000 ppm to 100,000 ppm, or from 2,500 ppm to 50,000 ppm, or from 5,000 ppm to 45,000 ppm. Connate water in the oil-bearing formation may have a multivalent ion content of at least 50 ppm, or at least 100 ppm, or at least 150 ppm, and may have a multivalent ion content of from 50 ppm to 40,000 ppm, or from 100 ppm to 20,000 ppm, or from 150 ppm to 15,000 ppm. Connate water in the oil-bearing formation may have a divalent ion content of at least 20 ppm, or at least 40 ppm, or at least 50 ppm, or at least 100 ppm, or from 20 ppm to 35,000 ppm, or from 40 ppm to 20,000 ppm, or from 50 ppm to 15,000 ppm. Preferably the connate water in the formation has at most a moderate amount of total dissolved solids and a relatively low concentration of multivalent cations therein, preferably having a TDS content of at most 30,000 ppm and a total multivalent cation content of at most 250 ppm.

The water in the oil-bearing formation may be positioned to immobilize oil within the pores. Introduction of the aqueous displacement fluid into the formation may mobilize at least a portion of the oil in the formation for production and recovery from the formation by freeing at least a portion of the oil from pores within the formation. Introduction of the aqueous displacement fluid into the formation may mobilize oil for production therefrom by driving the oil through the formation in a plug-like flow.

The viscosity of the aqueous displacement fluid may be maintained upon introduction to the formation and contact of the aqueous displacement fluid with the formation water and with the clays, minerals, and rock of the formation due to the relative equivalence of the MAR of divalent cations to monovalent cations of the aqueous displacement fluid and the formation water. Prior to introduction of the aqueous displacement fluid to the formation, the divalent cation and monovalent cation content of the formation water, the oil, and the clays, minerals, and rock of the formation is in relative equilibrium so the divalent cation and monovalent cation concentration of the formation water, of the oil, and of the formation are relatively constant. Introduction of the aqueous displacement fluid into the formation to mobilize the oil therein does not disturb this equilibrium since the MAR of divalent cations to monovalent cations of the aqueous displacement fluid and the formation water are similar even though the TDS content of the aqueous displacement fluid may be significantly different than the formation water TDS content. As a result, viscosity of the aqueous displacement fluid is not significantly changed upon contact with the formation water and the formation rock by ion exchange with the formation water and formation rock, and the polymer of the aqueous displacement fluid is not precipitated.

Referring now to Fig. 4, a system 200 for practicing a process of the present invention is shown. The system includes a first well 201 and a second well 203 extending into an oil-bearing formation 205 such as described above. The oil-bearing formation 205 may be comprised of one or more formation portions 207, 209, and 211 formed of porous material matrices, such as described above, located beneath an overburden 213. An aqueous displacement fluid as described above is provided. The aqueous displacement fluid may be provided from an aqueous displacement fluid storage facility 215 fluidly operatively coupled to a first injection/production facility 217 via conduit 219. First injection/production facility 217 may be fluidly operatively coupled to the first well 201, which may be located extending from the first injection/production facility 217 into the oil-bearing formation 205. The aqueous displacement fluid may flow from the first injection/production facility 217 through the first well to be introduced into the formation 205, for example in formation portion 209, where the first injection/production facility 217 and the first well, or the first well itself, include(s) a mechanism for introducing the aqueous displacement fluid into the formation. Alternatively, the aqueous displacement fluid may flow from the aqueous displacement fluid storage facility 215 directly to the first well 201 for injection into the formation 205, where the first well comprises a mechanism for introducing the aqueous displacement fluid into the formation. The mechanism for introducing the aqueous displacement fluid into the formation 205 via the first well 201—located in the first injection/production facility 217, the first well 201, or both—may be comprised of a pump 221 for delivering the aqueous displacement fluid to perforations or openings in the first well through which the aqueous displacement fluid may be introduced into the formation.

The aqueous displacement fluid may be introduced into the formation 205, for example by injecting the aqueous displacement fluid into the formation through the first well 201 by pumping the aqueous displacement fluid through the first well and into the formation. The pressure at which the aqueous displacement fluid is introduced into the formation may range from the instantaneous pressure in the formation up to the fracture pressure of the formation or exceeding the fracture pressure of the formation. The pressure at which the aqueous displacement fluid may be injected into the formation may range from 10% to 95%, or from 20% to 90%, of the fracture pressure of the formation. The pressure at which the aqueous displacement fluid is injected into the formation may be selected to limit degradation of polymer in the aqueous displacement fluid by shear, where lower injection pressures limit degradation of the polymer by shear. Preferably the aqueous displacement fluid is injected into the formation at pressures of from 10% to 50% of the fracture pressure of the formation.

The volume of the aqueous displacement fluid introduced into the formation 205 via the first well 201 may range from 0.001 to 5 pore volumes, or from 0.01 to 2 pore volumes, or from 0.1 to 1 pore volumes, or from 0.2 to 0.9 pore volumes, where the term "pore volume" refers to the volume of the formation that may be swept by the aqueous displacement fluid between the first well 201 and the second well 203. The pore volume may be readily be determined by methods known to a person skilled in the art, for example by modeling studies or by injecting water having a tracer contained therein through the formation 205 from the first well 201 to the second well 203.

Introduction of the aqueous displacement fluid to the formation may mobilize oil in the formation for production from the formation. As the aqueous displacement fluid is introduced into the formation 205 through the first well 201, the aqueous displacement fluid spreads into the formation as shown by arrows 223. The aqueous displacement fluid contacts the oil in the porous matrix material of the formation and pushes the oil through the formation to the second well 203 for production from the formation. Fingering of the aqueous displacement fluid through the oil or the oil through the aqueous displacement fluid may be inhibited by the viscosity of the aqueous displacement fluid relative to the viscosity of the oil, and in a preferred embodiment the aqueous displacement fluid mobilizes and drives the oil through the formation in a substantially plug-like flow.

The mobilized oil and the aqueous displacement fluid may be pushed across the formation 205 from the first well 201 to the second well 203 by further introduction of more aqueous displacement fluid or by introducing water into the formation subsequent to introduction of the aqueous displacement fluid into the formation. The water may be introduced into the formation 205 through the first well 201 after completion of introduction of the aqueous displacement fluid into the formation to force or otherwise displace the oil and the aqueous displacement fluid toward the second well 203 for production.

The water to be introduced into the formation after introduction of the aqueous displacement fluid into the formation may be stored in, and provided for introduction into the formation 205 from, a water storage facility 225 that may be fluidly operatively coupled to the first injection/production facility 217 via conduit 227. The water to be introduced into the formation after introduction of the aqueous displacement fluid into the formation preferably has an MAR of divalent cations to monovalent cations that is from 70% to 130% of the MAR of divalent cations to monovalent cations of the aqueous displacement fluid, and preferably the water is provided from a source utilized to provide the water for the aqueous displacement fluid. The first injection/production facility 217 may be fluidly operatively coupled to the first well 201 to provide the water to the first well for introduction into the formation 205. Alternatively, the water storage facility 225 may be fluidly operatively coupled to the first well 201 directly to provide water to the first well for introduction into the formation 205. The first injection/production facility 217 and the first well 201, or the first well itself, may comprise a mechanism for introducing the water into the formation 205 via the first well 201. The mechanism for introducing the water into the formation 205 via the first well 201 may be comprised of a pump or a compressor for delivering the water to perforations or openings in the first well through which the water may be injected into the formation. The mechanism for introducing the water into the formation 205 via the first well 201 may be the pump 221 utilized to inject the aqueous displacement fluid into the formation via the first well 201.

The water may be introduced into the formation 205, for example, by injecting the water into the formation through the first well 201 by pumping the water through the first well and into the formation. The pressure at which the water may be injected into the formation 205 through the first well 201 may be up to or exceeding the fracture pressure of the formation, or from 20% to 99%, or from 30% to 95%, or from 40% to 90% of the fracture pressure of the formation, or greater than the fracture pressure of the formation, and preferably is substantially the same pressure utilized to inject the aqueous displacement fluid into the formation.

The amount of water introduced into the formation 205 via the first well 201 following introduction of the aqueous displacement fluid into the formation through the first well may range from 0.001 to 5 pore volumes, or from 0.01 to 2 pore volumes, or from 0.1 to 1 pore volumes, or from 0.2 to 0.6 pore volumes, where the term “pore volume” refers to the volume of the formation that may be swept by the water between the first well and the second well. The amount of water introduced into the formation 205 should be sufficient to drive the mobilized oil and the aqueous displacement fluid across at least a portion of the formation.

Oil may be mobilized for production from the formation 205 via the second well 203 by introduction of the aqueous displacement fluid and, optionally, water into the formation through the first well 201, where the mobilized oil is driven through the formation from the first well 201 for production from the second well 203 as indicated by arrows 229. At least a portion of the aqueous displacement fluid may pass through the formation 205 from the first well 201 to the second well 203 for production from the formation along with the mobilized oil.

After introduction of the aqueous displacement fluid and, optionally, water into the formation 205 via the first well 201, oil may be recovered and produced from the formation via the second well 203. A mechanism may be located at the second well for recovering and producing oil from the formation 205 subsequent to introduction of the aqueous displacement fluid into the formation. The mechanism for recovering and producing oil from the formation may also recover and produce at least a portion of the aqueous displacement fluid, other water, and/or gas from the formation subsequent to introduction of the aqueous displacement fluid into the formation. The mechanism located at the second well 203 for recovering and producing the oil, the aqueous displacement fluid, other water, and/or gas may be comprised of a pump 233, which may be located in a second injection/production facility 231 and/or within the second well 203. The pump 233 may draw the oil, at least a portion of the aqueous displacement fluid, other water, and/or gas from the formation 205 through perforations in the second well 203 to deliver the oil, at least a portion of the aqueous displacement fluid, other water, and/or gas, to the second injection/production facility 231.

Alternatively, the mechanism for recovering and producing the oil, at least a portion of the aqueous displacement fluid, other water, and/or gas from the formation 205 may be comprised of a compressor 234 that may be located in the second injection/production facility 231. The compressor 234 may be fluidly operatively coupled to a gas storage tank 241 via conduit 236, and may compress gas from the gas storage tank for injection into the formation 205 through the second well 203. The compressor may compress the gas to a pressure sufficient to drive production of oil, the aqueous displacement fluid, other water, and/or gas from the formation via the second well 203, where the appropriate pressure may be determined by conventional methods known to those skilled in the art. The compressed gas may be injected into the formation from a different position on the second well 203 than the well position at which the oil, aqueous displacement fluid, other water, and/or gas are produced from the formation, for example, the compressed gas may be injected into the formation at formation portion 211 while oil, aqueous displacement fluid, other water, and/or gas are produced from the formation at formation portion 209.

Oil, at least a portion of the aqueous displacement fluid, other water, and/or gas may be drawn from the formation 205 as shown by arrows 229 and produced up the second well 203 to the second injection/production facility 231. The oil may be separated from gas and an aqueous mixture comprised of the produced portion of aqueous displacement fluid and other formation water produced from the formation, for example connate water, mobile water, or water from a oil recovery waterflood. The produced oil may be separated from the produced aqueous mixture and produced gas in a separation unit 235 located in the second injection/production facility 231 and, in an embodiment, operatively fluidly coupled to the mechanism 233 for recovering and producing oil, the components of the aqueous mixture, and/or gas from the formation.

A brine solution having a TDS content of greater than 20,000 ppm, or from 25,000 ppm to 250,000 ppm may be provided from a brine solution storage facility 247 to the separation unit 235 via conduit 273 for mixing with the produced oil and the produced aqueous mixture, and optionally with produced gas. The brine solution may have a TDS content of at least 20,000 ppm, or at least 25,000 ppm, or at least 30,000 ppm, or at least 40,000 ppm, or at least 50,000 ppm, or from 20,000 ppm to 250,000 ppm, or from 25,000 ppm to 200,000 ppm, or from 30,000 ppm to 150,000 ppm, or from 40,000 ppm to 100,000 ppm. The brine solution may be selected from seawater, brackish water, estuarine water, or production water produced from the formation and separated from oil and/or gas produced from the formation. Alternatively, the brine solution may be comprised of at least a portion of a brine retentate 117, a primary brine retentate 125 and/or a secondary brine retentate 127, or a first brine retentate 137 and/or a second brine retentate 143 (as shown in Figs. 1-3) produced by contact of a saline source water with an ionic filter as described above.

A demulsifier may also be provided to the separation facility 235 from a demulsifier storage facility 271 which may be fluidly operatively connected to the separation unit via conduit 240. The demulsifier may be provided to the separation facility 235 for mixing with the produced oil, the produced water, and the brine solution, and optionally with produced gas, to facilitate separation of the produced oil and the produced water.

The demulsifier may be selected from the group consisting of amylresins; butylresins; nonylresins; acid- or base-catalyzed phenol-formaldehyde resins; phenol-acrylate anhydride polyglycol resins; urethanes; polyamines; polyesteramines; sulfonates; di-epoxides; polyols; esters and polyol esters including triol fatty acid esters, triol adipate esters, and triol fumarate esters; ethoxylated and/or propoxylated compounds of amyl resins, butylresins, nonylresins, acid- or base-catalyzed phenol-formaldehyde resins, fatty acids, polyamines, di-epoxides, and polyols; and combinations thereof which may be dispersed in a carrier solvent selected from the group consisting of xylene, toluene, heavy aromatic naphtha, isopropanol, methanol, 2-ethoxyhexanol, diesel, and combinations thereof. A suitable demulsifier for separating the oil and water produced from the formation 205 may be selected by conducting a bottle test, a conventional test known to those skilled in the art for selecting a demulsifier effective to separate crude oil and water. Commercially available demulsifiers include the EB-Series from National Chemical Supply, 4151 SW 47th Ave., Davie, FL, 33314, United States, and

Tretolite demulsifiers from Baker Petrolite Corporation, 12645 W. Airport Blvd., Sugar Land, TX 77478, United States.

In an embodiment of a method of the present invention the first well 201 may be used for injecting the aqueous displacement fluid and, optionally, water into the formation 205 and the second well 203 may be used to produce and separate oil, water, and optionally gas from the formation as described above for a first time period, and the second well 203 may be used for injecting the aqueous displacement fluid and, optionally, water into the formation 205 to mobilize the oil in the formation and drive the mobilized oil across the formation to the first well and the first well 201 may be used to produce and separate oil, water, and gas from the formation for a second time period, where the second time period is subsequent to the first time period. The second injection/production facility 231 may comprise a mechanism such as pump 251 that is fluidly operatively coupled the aqueous displacement fluid storage facility 215 by conduit 253 and that is fluidly operatively coupled to the second well 203 to introduce the aqueous displacement fluid into the formation 205 via the second well. The pump 251 may also be fluidly operatively coupled to the water storage facility 225 by conduit 255 to introduce water into the formation 205 via the second well 203 subsequent to introduction of the aqueous displacement fluid into the formation via the second well. The first injection/production facility 217 may comprise a mechanism such as pump 257 or compressor 258 for production of oil, water, and gas from the formation 205 via the first well 201. The first injection/production facility 217 may also include a separation unit 259 for separating produced oil, produced water, and produced gas fluidly operatively connected to the mechanism 257 by conduit 260, where the separation unit 259 may be similar to separation unit 235 as described above. The brine solution storage facility 247 may be fluidly operatively connected to the separation unit 259 by conduit 272 to provide brine solution to the separation unit 259, and the demulsifier storage facility 271 may be fluidly operatively connected to the separation unit 259 by conduit 262 to provide demulsifier to the separation unit 259. The separation unit 259 may be fluidly operatively coupled to the liquid storage tank 237 by conduit 261 for storage of produced and separated oil in the liquid storage tank and to the gas storage tank 241 by conduit 265 for storage of produced gas in the gas storage tank.

The first well 201 may be used for introducing the aqueous displacement fluid and, optionally, subsequently water into the formation 205 and the second well 203 may be used for producing and separating oil, water, and gas from the formation for a first time period; then the second well 203 may be used for introducing the aqueous displacement fluid and, optionally, subsequently water into the formation 205 and the first well 201 may be used for producing and separating oil, water, and gas from the formation for a second time period; where the first and second time periods comprise a cycle. Multiple cycles may be conducted which include alternating the first well 201 and the second well 203 between introducing the aqueous displacement fluid and, optionally, subsequently water into the formation 205, and producing and separating oil, water, and gas from the formation, where one well is introducing and the other is producing and separating for the first time period, and then they are switched for a second time period. A cycle may be from about 12 hours to about 1 year, or from about 3 days to about 6 months, or from about 5 days to about 3 months. The aqueous displacement fluid may be introduced into the formation at the beginning of a cycle and water may be introduced at the end of the cycle. In some embodiments, the beginning of a cycle may be the first 10% to about 80% of a cycle, or the first 20% to about 60% of a cycle, the first 25% to about 40% of a cycle, and the end may be the remainder of the cycle.

Referring now to Figure 5 an array of wells 500 is illustrated. Array 500 includes a first well group 502 (denoted by horizontal lines) and a second well group 504 (denoted by diagonal lines). In some embodiments of the method of the present invention, the first well of the method described above may include multiple first wells depicted as the first well group 502 in the array 500, and the second well of the method described above may include multiple second wells depicted as the second well group 504 in the array 500.

Each well in the first well group 502 may be a horizontal distance 530 from an adjacent well in the first well group 502. The horizontal distance 530 may be from about 5 to about 5,000 meters, or from about 7 to about 1,000 meters, or from about 10 to about 500 meters, or from about 20 to about 250 meters, or from about 30 to about 200 meters, or from about 50 to about 150 meters, or from about 90 to about 120 meters, or about 100 meters. Each well in the first well group 502 may be a vertical distance 532 from an adjacent well in the first well group 502. The vertical distance 532 may be from about 5 to about 5,000 meters, or from about 7 to about 1,000 meters, or from about 10 to about 500 meters, or from about 20 to about 250 meters, or from about 30 to about 200 meters, or from about 50 to about 150 meters, or from about 90 to about 120 meters, or about 100 meters.

Each well in the second well group 504 may be a horizontal distance 536 from an adjacent well in the second well group 504. The horizontal distance 536 may be from about 5 to about 5,000 meters, or from about 7 to about 1,000 meters, or from about 10 to about 500 meters, or from about 20 to about 250 meters, or from about 30 to about 200 meters, or from about 50 to about 150 meters, or from about 90 to about 120 meters, or about 100 meters. Each well in the second well group 504 may be a vertical distance 538 from an adjacent well in the second well group 504. The vertical distance 538 may be from about 5 to about 5,000 meters, or from about 7 to about 1,000 meters, or from about 10 to about 500 meters, or from about 20 to about 250 meters, or from about 30 to about 200 meters, or from about 50 to about 150 meters, or from about 90 to about 120 meters, or about 100 meters.

Each well in the first well group 502 may be a distance 534 from the adjacent wells in the second well group 504. Each well in the second well group 504 may be a distance 534 from the adjacent wells in first well group 502. The distance 534 may be from about 5 to about 5,000 meters, or from about 7 to about 1000 meters, or from about 10 to about 500 meters, or from about 20 to about 250 meters, or from about 30 to about 200 meters, or from about 50 to about 150 meters, or from about 90 to about 120 meters, or about 100 meters.

Each well in the first well group 502 may be surrounded by four wells in the second well group 504. Each well in the second well group 504 may be surrounded by four wells in the first well group 502.

In some embodiments, the array of wells 500 may have from about 10 to about 1,000 wells, for example from about 5 to about 500 wells in the first well group 502, and from about 5 to about 500 wells in the second well group 504.

In some embodiments, the array of wells 500 may be seen as a top view with first well group 502 and the second well group 504 being vertical wells spaced on a piece of land. In some embodiments, the array of wells 500 may be seen as a cross-sectional side view of the formation with the first well group 502 and the second well group 504 being horizontal wells spaced within the formation.

To facilitate a better understanding of the present invention, the following example of certain aspects of some embodiments is given. In no way should the following example be read to limit, or define, the scope of the invention.

EXAMPLE

An experiment was conducted to determine the effect of using a low salinity aqueous displacement fluid containing a polymer and having a TDS content of less than 5,000 ppm and less than half the TDS content of a formation water and having a MAR within 70% to 130% of the MAR of the formation water on viscosity and divalent cation exchange in an oil-bearing formation relative to an aqueous displacement fluid formed by combining a polymer with formation water. The amount of polymer required to provide the same viscosity was measured for the low salinity aqueous displacement fluid and the aqueous displacement fluid formed by combining a polymer with formation water.

A sandstone core was aged with crude oil for 4 weeks at a temperature of 50°C (corresponding to the formation temperature of the formation from which the crude oil was obtained). Diffraction analysis showed that the core material was composed of 95% quartz with the remaining 5% containing illite-smectite, kaolinite, and illite-mica clays, K-feldspar, and traces of chlorite, anhydrite, calcite, and pyrite. The core was then saturated with synthetic formation water having the composition shown in Table 1.

A designed low salinity water solution was prepared having a TDS content of 2170 ppm (2.5x dilution relative to the TDS of the formation water) and a MAR of divalent cations to monovalent cations equal to the MAR of divalent cations to monovalent cations of the synthetic formation water (MAR of the designed low salinity water solution = 99% of the MAR of the synthetic formation water). The composition of the low salinity water solution is shown in Table 1.

A high salinity polymer solution (HSP) and a low salinity polymer solution (LSP) were formed from the synthetic formation water and the designed low salinity water solution, respectively. Sufficient hydrolyzed polyacrylamide polymer FLOPAAM 3630S was added to the synthetic formation water and to the designed low salinity water solution to produce an HSP solution and an LSP solution each having a viscosity of 125 cP at 50°C. The HSP solution contained 2483 ppm of the polymer and the LSP solution contained 1761 ppm of the polymer.

Table 1

Synthetic formation water		
NaCl	4.517	g/L
KCl	0.000	g/L
$CaCl_2 \cdot 2H_2O$	0.359	g/L
Na2SO4	0.497	g/L
NaHCO3	0.293	g/L
$MgCl_2 \cdot 6H_2O$	0.059	g/L
Na^+	**2.018**	g/L
K^+	0.000	g/L
Ca^{2+}	0.098	g/L
Mg^{2+}	0.007	g/L
SO4	0.336	g/L
HCO3	0.213	g/L
Cl^-	2.9339	g/L
MAR 38.8 meq/l		
TDS	**5605.745**	ppm

Designed LS water		
NaCl	1.807	g/L
KCl	0.000	g/L
$CaCl_2 \cdot 2H_2O$	0.058	g/L
Na2SO4	0.199	g/L
NaHCO3	0.117	g/L
$MgCl_2 \cdot 6H_2O$	0.009	g/L
Na^+	**0.807**	g/L
K^+	0.000	g/L
Ca^{2+}	0.016	g/L
Mg^{2+}	0.001	g/L
SO4	0.134	
HCO3	0.085	
Cl^-	1.127	g/L
MAR 38.3 meq/l		
TDS	**2170.604**	ppm TDS

The core saturated with synthetic formation water was then treated sequentially with 30 PV of the synthetic formation water, then 30 PV of the designed low salinity water, then 80 PV of the HSP solution, then 30 PV of the designed LSP solution. The effluent from each of these steps was collected in 3 ml fractions. The concentration of sodium, potassium, calcium, and magnesium cations of the effluent fractions from each step was measured by inductive coupled plasma elemental analysis to determine the stripping effect of the injected water and polymer solutions. Figs. 10 and 11 show the measured concentrations of Na^+, Ca^{2+}, Mg^{2+}, and K^+ in the effluents of the injected synthetic formation brine, the designed low salinity water, the HSP solution, and the LSP solution. The concentration of $Ca^{2+}$and Mg^{2+} in the HSP solution effluent and the LSP solution effluent is slightly higher than the concentration of these cations in the HSP and LSP solutions at the beginning of the injection of each of these solutions, which may be an effect of the affinity of the polymer for calcium and magnesium. Over the course of the injections of the HSP and LSP solutions, however, the calcium and magnesium concentrations in the effluent quickly revert to the baseline of the concentrations of these cations in the injected solutions. Importantly, the LSP solution does not show a significant stripping of Ca^{2+} and Mg^{2+} relative to the HSP solution, indicating that the low salinity of the LSP solution does not induce any significant amount of stripping of the calcium and magnesium cations from the core.

The viscosity of the effluent from the HSP solution injection and the LSP solution injection effluents was measured by a rheometer. Fig. 12 shows the viscosity of the HSP solution effluent and the LSP solution effluent. Each effluent shows a viscosity drop of about 10% occurring at the beginning of the injection, then the viscosity levels out. Significantly, the viscosity drop of the LSP solution is substantially similar to the viscosity drop of the HSP solution, indicating that the viscosity of the LSP solution is not significantly affected by the low salinity of the LSP solution. This may correlate to the LSP solution not stripping substantial quantities of Ca^{2+} and Mg^{2+} from the core, which may be attributable to the MAR of the LSP solution being equivalent to the MAR of the HSP solution.

The present invention is well adapted to attain the ends and advantages mentioned above as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. While systems and methods are described in terms of "comprising," "containing," or "including" various components or steps, the compositions and methods can also "consist essentially of" or "consist of" the various components and steps. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, "from a to b," or, equivalently, "from a-b") disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Whenever a numerical range having a specific lower limit only, a specific upper limit only, or a specific upper limit and a specific lower limit is disclosed, the range also may include any numerical value "about" the specified lower limit and/or the specified upper limit. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles “a” or “an”, as used in the claims, are defined herein to mean one or more than one of the element that it introduces.

CLAIMS

1. A process for producing oil from an oil-bearing formation, comprising:
   determining the mass action ratio of divalent cations to monovalent cations of water from the oil-bearing formation;
   providing an aqueous displacement fluid comprising water and an ionically charged polymer, wherein the water of the aqueous displacement fluid has a total dissolved solids content of from 200 parts per million by weight (ppmw) to 5,000 ppmw and a mass action ratio of divalent cations to monovalent cations from 70% to 130% of the mass action ratio of divalent cations to monovalent cations of the water from the oil-bearing formation;
   introducing the aqueous displacement fluid into the oil-bearing formation to displace oil within the formation;
   producing oil from the oil-bearing formation subsequent to introducing the aqueous displacement fluid into the formation.

2. The process of claim 1 further comprising the steps of:
   determining the viscosity of oil of the oil-bearing formation at a temperature within the range of temperatures in the formation;
   providing the aqueous displacement fluid having a viscosity of from 10% to 500% of the viscosity of the oil of the oil-bearing formation, where the viscosity of the aqueous displacement fluid is determined at the temperature at which the viscosity of the oil of the oil-bearing formation is determined.

3. The process of claim 1 or 2 wherein the ionically-charged polymer is a selected from the group consisting of a water-soluble polyacrylamide, a water-soluble polyacrylate, a partially hydrolyzed water-soluble polyacrylamide, and mixtures thereof.

4. The process of claim 1 or 2, wherein the MAR of divalent cations to monovalent cations of water of the oil-bearing formation is determined by obtaining a sample of water from the oil-bearing formation, measuring the concentrations of each divalent cation species and each monovalent cation species in the water obtained from the oil-

bearing formation, and calculating the MAR of the water obtained from the oil-bearing formation according to formula (I)

(I) $MAR_{fw} = (C^{+}_{(fw)})^2/(C^{2+}_{(fw)})$

where MAR_{fw} is the mass action ratio of divalent cations to monovalent cations of the water from the formation, $C^{+}_{(fw)}$ is the sum of the concentrations of the monovalent cation species in the water from the formation, and $C^{2+}_{(fw)}$ is the sum of the concentrations of the divalent cation species in the water from the formation.

5. The process of claim 1 or 2 wherein the water of the aqueous displacement fluid is provided from a natural source water having a TDS content of from 200 ppm to 5,000 ppm.

6. The process of claim 1 or 2 wherein the water of the aqueous displacement fluid is provided from a saline source water having a TDS content greater than 10,000 ppm wherein the saline source water is treated to adjust the TDS content of the saline source water to within a range of from 200 ppm to 5,000 ppm.

7. The process of claim 1 or 2 wherein the water of the aqueous displacement fluid is provided from a source water having a TDS content less than 500 ppm wherein the source water is treated to adjust the TDS content of the source water to within a range of from 500 ppm to 5,000 ppm.

8. The process of claim 1 or 2 wherein the water of the aqueous displacement fluid is provided from a source water having a MAR of divalent cations to monovalent cations that is from 70% to 130% of the MAR of divalent cations to monovalent cations of the water of the formation, where the MAR of the water of the aqueous displacement fluid is calculated according to formula (II)

(II) $MAR_{adf} = (C^{+}_{(adf)})^2/(C^{2+}_{(adf)})$

where MAR_{adf} is the mass action ratio of divalent cations to monovalent cations of the water of the aqueous displacement fluid, $C^{+}_{(adf)}$ is the sum of concentrations of monovalent cation species in the water of the aqueous displacement fluid, and $C^{2+}_{(adf)}$

is the sum of concentrations of divalent cation species in the water of the aqueous displacement fluid.

9. The process of claim 1 or 2 wherein the water of the aqueous displacement fluid is provided from a source water having a MAR of divalent cations to monovalent cations that is less than 70% or greater than 130% of the MAR of divalent cations to monovalent cations of the water of the formation and the MAR of divalent cations to monovalent cations of the source water is adjusted to a range of from 70% to 130% of the MAR of divalent cations to monovalent cations of the water of the formation, where the MAR of the water of the aqueous displacement fluid is calculated according to formula (II)

$$\text{(II)}\quad MAR_{adf} = (C^{+}_{(adf)})^2/(C^{2+}_{(adf)})$$

where MAR_{adf} is the mass action ratio of divalent cations to monovalent cations of the water of the aqueous displacement fluid, $C^{+}_{(adf)}$ is the sum of concentrations of monovalent cation species in the water of the aqueous displacement fluid, and $C^{2+}_{(adf)}$ is the sum of concentrations of divalent cation species in the water of the aqueous displacement fluid.

10. The process according to claim 1 or 2 further comprising producing water from the oil-bearing formation along with oil from the oil-bearing formation and separating the produced oil from the produced water.

ABSTRACT

The present invention is directed to a process for producing oil. The mass action ratio (MAR) of divalent cations to monovalent cations of water from an oil-bearing formation is determined, and an aqueous displacement fluid having a total dissolved solids content of from 200 ppm to 5,000 ppm and a MAR of divalent cations to monovalent cations of from 70% to 130% of the MAR of divalent cations to monovalent cations of the formation water is introduced into the formation. Oil is produced from the formation after introducing the aqueous displacement fluid into the formation.

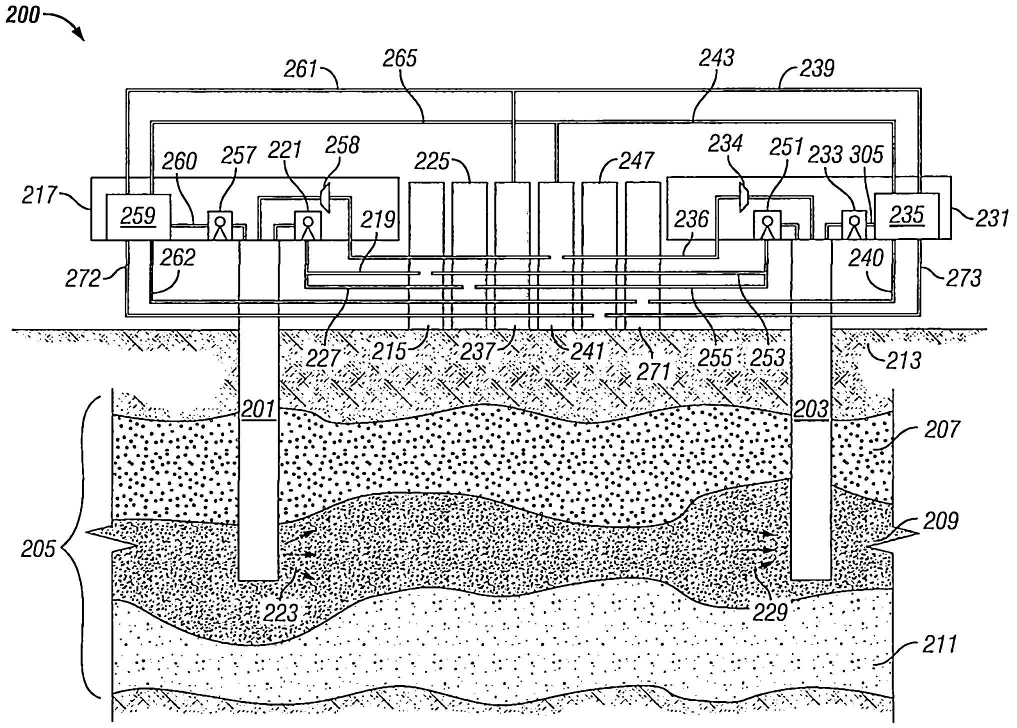

FIG. 4

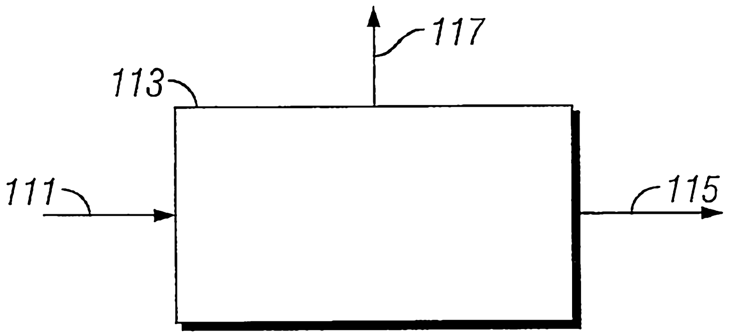

FIG. 1

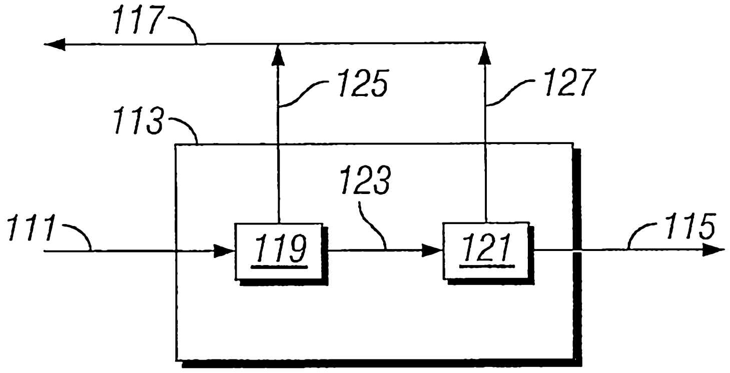

FIG. 2

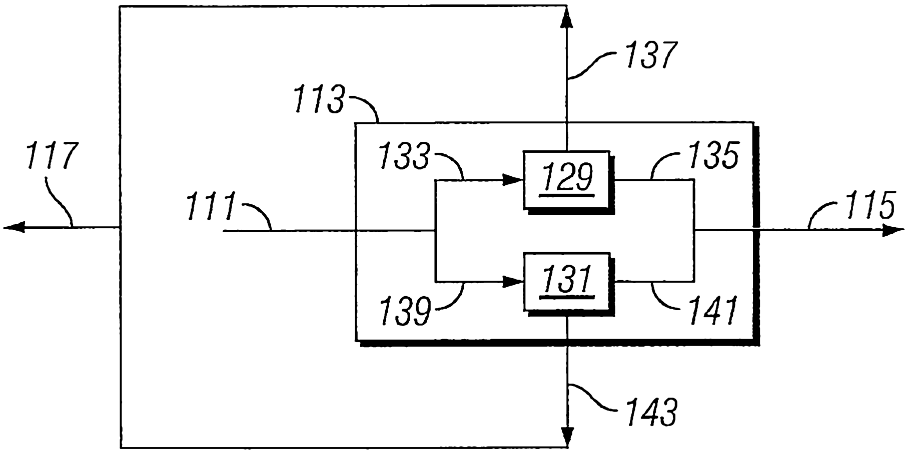

FIG. 3

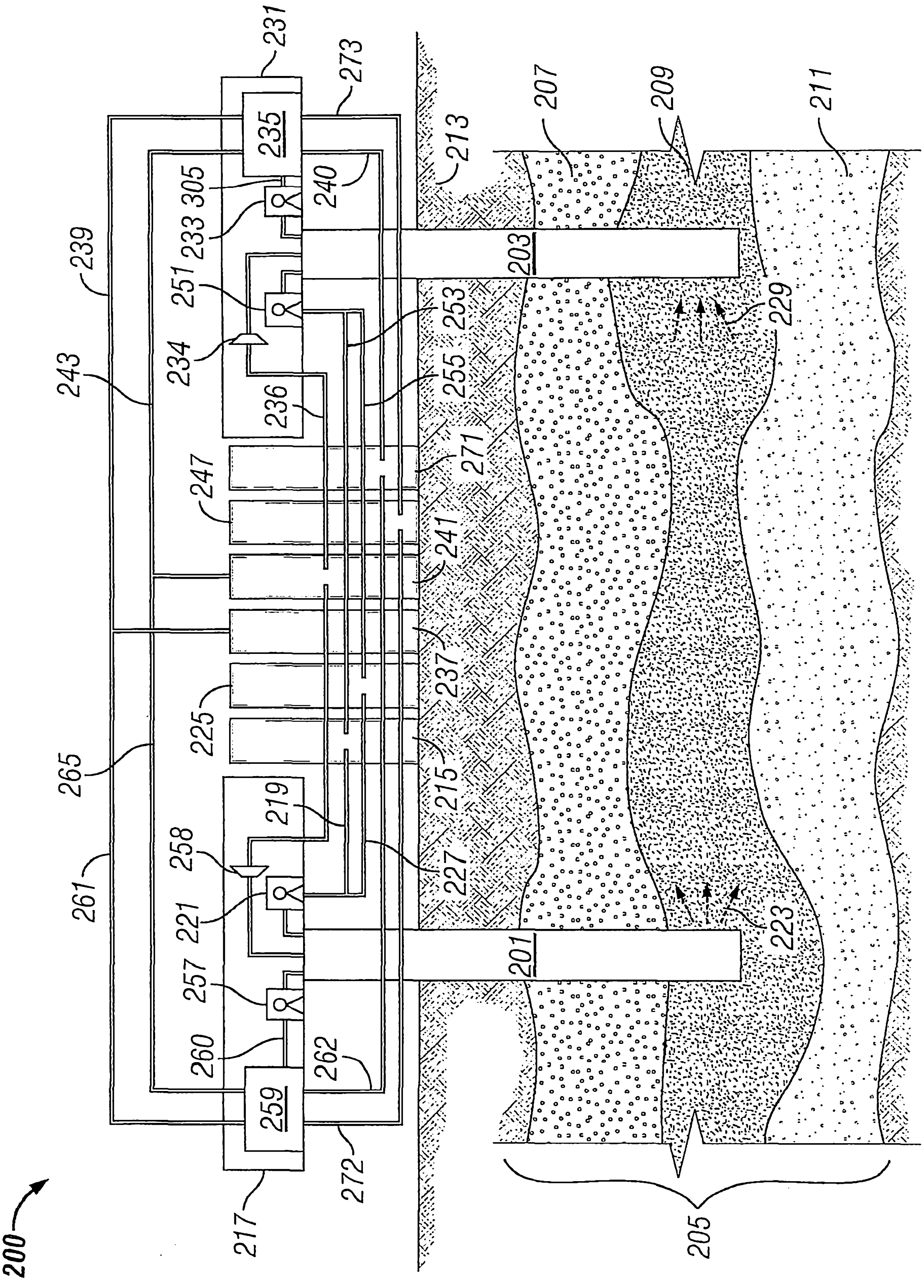
200
217
272
259
260
262
257
201
221
258
261
265
219
227
225
215
237
241
247
243
271
236
234
255
251
253
239
233
305
240
235
231
273
203
229
223
213
207
209
211
205

FIG. 4

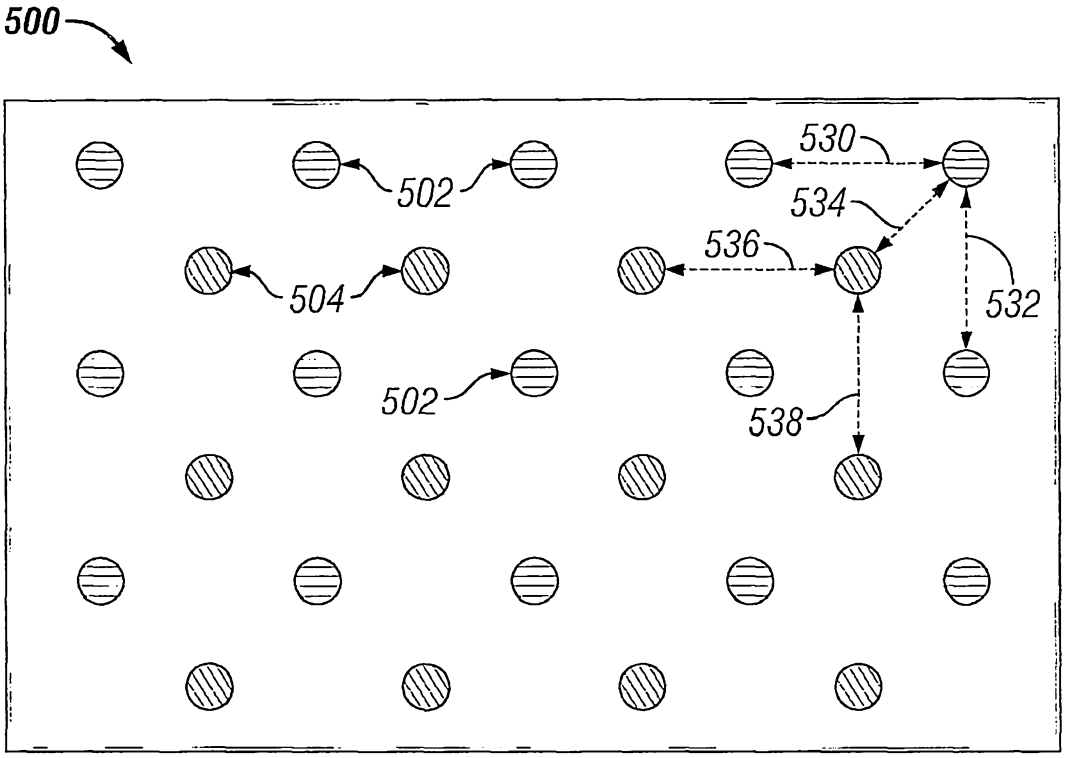

FIG. 5

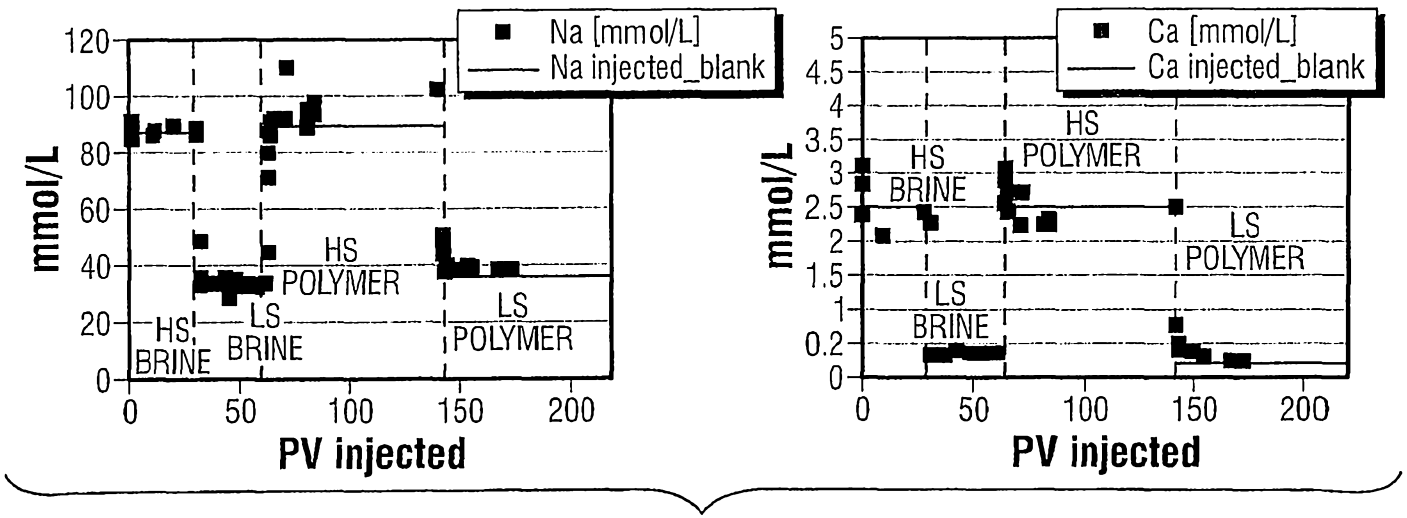
120
100
80
60
40
20
0
mmol/L
0
50
100
150
200
PV injected
■ Na [mmol/L]
—— Na injected_blank
HS BRINE
LS BRINE
HS POLYMER
LS POLYMER
5
4.5
4
3.5
3
2.5
2
1.5
1
0.2
0
mmol/L
0
50
100
150
200
PV injected
■ Ca [mmol/L]
—— Ca injected_blank
HS BRINE
LS BRINE
HS POLYMER
LS POLYMER

FIG. 6

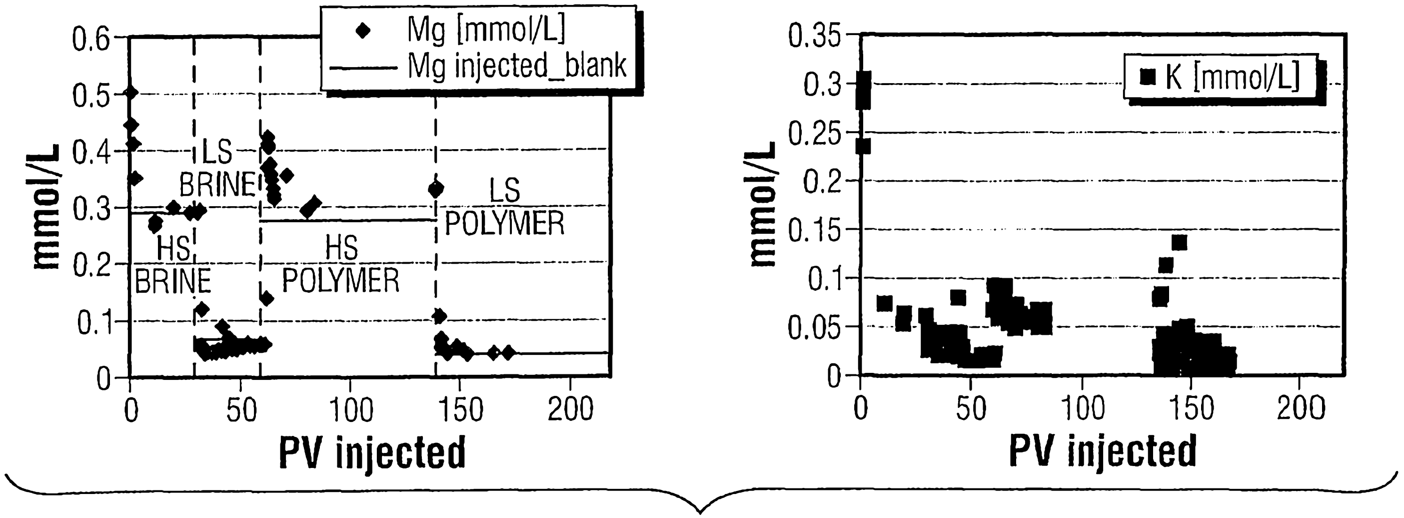
0.6
0.5
0.4
0.3
0.2
0.1
0
mmol/L
0
50
100
150
200
PV injected
◆ Mg [mmol/L]
—— Mg injected_blank
HS BRINE
LS BRINE
HS POLYMER
LS POLYMER
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
mmol/L
0
50
100
150
200
PV injected
■ K [mmol/L]

FIG. 7

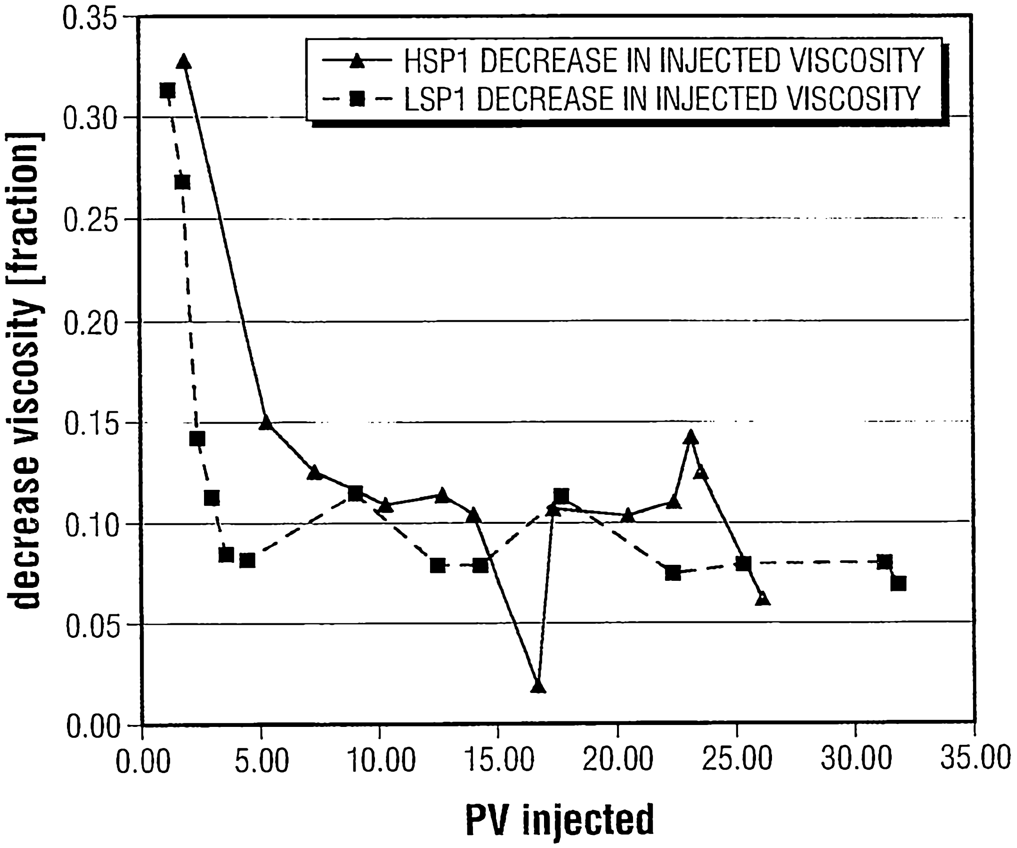
HSP1 DECREASE IN INJECTED VISCOSITY
LSP1 DECREASE IN INJECTED VISCOSITY
decrease viscosity [fraction]
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
0.00
5.00
10.00
15.00
20.00
25.00
30.00
35.00
PV injected

FIG. 8