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(54) **METHOD OF HYDROCARBON RECOVERY**

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(57) **ABSTRACT**

A method is given for treating a wellbore to increase the production of hydrocarbons from a subterranean formation penetrated by a wellbore, involving a period of injecting into the formation an aqueous injection fluid having a different chemical potential than the aqueous fluid in the formation. If there is water blocking, an osmotic gradient is deliberately created to cause flow of water into the injected fluid; hydrocarbon is then produced by imbibition. If the pore pressure in the water-containing pores in the formation is too low, an osmotic gradient is deliberately created so that water flows from the injected fluid into the water-containing pores, increasing the pore pressure and facilitating hydrocarbon production by imbibition. The method may be repeated cyclically. A semipermeable membrane may be created to enhance the osmosis. Wetting agents may be used to influence imbibition.

METHOD OF HYDROCARBON RECOVERY

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application is related to commonly-assigned and simultaneously-filed U.S. patent application Ser. No. 12/253,406, entitled "Enhancing Hydrocarbon Recovery", incorporated herein by reference in its entirety.

BACKGROUND OF THE INVENTION

[0002] The invention relates to the recovery of hydrocarbons from subterranean formations. More particularly, it relates to methods of using osmotic pressure effects to increase the rate and/or amount of hydrocarbon that flows to producing wells.

[0003] Hydrocarbons (gas, supercritical fluid, condensate, and oil) are typically found in the pores of subterranean rock formations. Although occasionally hydrocarbons flow naturally to a producing well at a commercially acceptable rate and extent due to inherent hydraulic forces, normally some means must be employed to increase the rate and/or extent of this flow. Methods include pumping, which will not be discussed further, stimulation, and enhanced recovery. Stimulation methods increase or improve the flow path from the reservoir to the producing well. They include acidizing (and treating with other chemically reactive treating fluids designed to remove various types of damage and pumped at bottomhole pressures less than that required to hydraulically fracture the formation), and hydraulic fracturing (including acid fracturing). Enhanced recovery may involve drilling both injection and production wells. Another method of enhanced recovery may involve systematically converting existing production wells into injection wells. Additionally, it is common to utilize the same wellbore as both injector and producer in cycles to obtain the desired effect in the reservoir. We can call these cases A, B, and C. In cases A and B, fluid is forced into the injection wells and causes formation fluids to flow to the production wells. The injected fluid may act solely hydraulically or, more commonly, it has an additional function. As examples, the fluid may be hot and cause a reduction in oil viscosity; the fluid may be a solvent for the hydrocarbon; and the fluid may contain chemicals, for example surfactants, that change the formation rock wettability and/or change the interfacial tensions between the hydrocarbon and water phases and the rock. In case C, fluid is injected into the wellbore in order to create/modify fluid-rock properties in the reservoir such that when the wellbore is cycled back to production mode it will recover hydrocarbons at a higher rate with better ultimate recovery. Other stimulation methods include the use of explosives (i.e. nitroglycerine) and propellants, hydrodynamic and acoustic pulsing, special perforating techniques, and jetting (such as hydrojetting).

[0004] There are three main driving forces of interest in this discussion that govern fluid flow in reservoir rocks: hydraulic pressure, capillary pressure, and osmotic pressure. Because of these different driving forces, a fluid, for example water, does not necessarily flow from a region of high pressure to a region of low pressure, rather it flows from a region of high potential to a region of low potential.

[0005] There is a need for methods of manipulating osmotic flow to improve hydrocarbon recovery.

SUMMARY OF THE INVENTION

[0006] One embodiment of the Invention is a method of producing hydrocarbon from a subterranean formation penetrated by a wellbore. The method includes a period of injecting into the formation an aqueous injection fluid having a higher chemical potential than the aqueous fluid in the formation. Water in the injection fluid flows into the formation fluid by osmosis, there is an increase in pressure in the formation, and a portion of the hydrocarbon flows to the wellbore. This flow may be by co-current and/or counter-current imbibition (hereinafter referred to collectively simply as "imbibition"). The injection fluid may contact, for example, at least one quarter of the practical wellbore drainage volume. The period of injection may be followed by a period of production without injection. The period of production without injection may be followed by a second period of injection. The method may additionally include injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane. The injection fluid may, for example, include a formate. The injection fluid may also include an agent that increases the contact angle of the formation with water. The injection fluid may alternatively include an agent that decreases the contact angle of the formation with water. In the method, the osmotic pressure may generate fractures in the formation.

[0007] Another embodiment of the Invention is a method of producing hydrocarbon from a subterranean formation penetrated by a wellbore involving injecting into the formation an aqueous injection fluid having a lower chemical potential than the aqueous fluid in the formation. A portion of the water in the formation fluid flows into the injection fluid by osmosis, phase trapping is reduced, and a portion of the hydrocarbon flows to the wellbore. This flow may be due to imbibition. The injection fluid may contact, for example, at least one quarter of the practical wellbore drainage volume. The period of injection may be followed by a period of production without injection. The period of production without injection may be followed by a second period of injection. The method may additionally include injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane. The injection fluid may, for example, include a formate. The injection fluid may also include an agent that increases the contact angle of the formation with water. The injection fluid may alternatively include an agent that decreases the contact angle of the formation with water. In the method, the osmotic pressure may generate fractures in the formation.

[0008] Yet another embodiment of the Invention is a method of producing hydrocarbon from a subterranean formation penetrated by a wellbore that involves injecting into the formation an aqueous injection fluid having the same chemical potential as the aqueous fluid in the formation. No osmotic pressure gradient is created, but a portion of the hydrocarbon flows to the wellbore. This flow may be due to imbibition. The injection fluid may contact, for example, at least one quarter of the practical wellbore drainage volume. The period of injection may be followed by a period of production without injection. The period of production without injection may be followed by a second period of injection. The method may additionally include injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane. The injection fluid may, for example, include a formate. The injection fluid may also include an agent that increases the contact angle of the formation with water. The injection fluid may alternatively include an agent that decreases the contact angle of the formation with water. Osmotic pressure may be used in a separate step to generate fractures in the formation.

DETAILED DESCRIPTION OF THE INVENTION

[0009] Although some portions of the following discussion may emphasize hydraulic fracturing, and other portions may emphasize enhanced recovery, it is to be understood that, with suitable modification, the methods of the Invention may be used with any type of fluid recovery technique. The Invention will be described for hydrocarbon recovery, but it is to be understood that the Invention may be used for wells for the recovery of other fluids, such as water or carbon dioxide, or, for example, for injection or storage wells. It should also be understood that throughout this specification, when a concentration or amount range is described as being useful, or suitable, or the like, it is intended that any and every concentration or amount within the range, including the end points, is to be considered as having been stated. Furthermore, each numerical value should be read once as modified by the term "about" (unless already expressly so modified) and then read again as not to be so modified unless otherwise stated in context. For example, "a range of from 1 to 10" is to be read as indicating each and every possible number along the continuum between about 1 and about 10. In other words, when a certain range is expressed, even if only a few specific data points are explicitly identified or referred to within the range, or even when no data points are referred to within the range, it is to be understood that the inventors appreciate and understand that any and all data points within the range are to be considered to have been specified, and that the inventors have possession of the entire range and all points within the range.

[0010] It is widely believed that water imbibition into a reservoir from a well that will be used for production is deleterious in several ways. (See, for example, Bennion, D. B., et al., "Low Permeability Gas Reservoirs: Problems, Opportunities and Solutions for Drilling, Completion, Stimulation and Production," SPE 35577, Gas Technology Conference, Calgary, Alberta, Canada, Apr. 28-May 1, 1996, and Bennion, D. B., et al., "Formation Damage Processes Reducing Productivity of Low Permeability Gas Reservoirs," SPE 60325, 2000 SPE Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition, Denver, Colo., Mar. 12-15, 2000.) Imbibed water increases the water saturation and is thought to become trapped and to block hydrocarbon flow. If imbibed water is fresher than formation water, it may affect fresh water sensitive expanding clays present in the reservoir. Furthermore, imbibition of water into formations such as shales during drilling may be responsible for spalling and wall (borehole) collapse. For these reasons, operators often would like to complete wells with non-aqueous fluids but do not do so in the vast majority of the cases because of such reasons as significantly higher costs and environmental risks. Water invasion of reservoirs, except in water-flooding with distinct injectors and producers, is considered a damage mechanism and is to be avoided.

[0011] Bennion, et al. (2000) illustrate both the present understanding of one example of how capillary pressures lead to phase trapping of water and to blocking of hydrocarbon production, and give proposed solutions that are opposite the principles and method of the present Invention. Bennion, et al. (2000) teach that very low permeability gas reservoirs are typically in a state of capillary undersaturation, where the initial water (and sometimes oil) saturation is less than would be expected from conventional capillary mechanics for the pore system under consideration. Retention of fluids (phase trapping) is considered to be one of the major mechanisms of reduced productivity, even in successfully hydraulically fracture-stimulated completions in these types of formations. In a low permeability gas reservoir, due to the very small size of the pore throats and pore bodies, the tortuous nature of the pore system and the high degree of micro-porosity, the observed radii of curvature of the gas-liquid interfaces are very small, particularly at low water saturations, which gives rise to the higher capillary pressure values and higher irreducible water saturation values which are commonly associated with poor quality porous media. In general, as permeability and porosity decrease and the relative fraction of micro-porosity increases, both the capillary pressure and the irreducible water saturation tend to increase substantially.

[0012] Bennion, et al. (2000) further teach that often associated with this increase in trapped initial liquid saturation is a significant reduction in the net effective permeability to gas, caused by the occlusion of a large portion of the pore space by the irreducible and immobile trapped initial liquid saturation present. On a relative permeability basis, in general, the greater the value of the initial trapped fluid saturation, the less original reserves of gas in place are available for production, and also the lower the initial potential productivity of the matrix. In reservoir situations where exceptionally low matrix permeability is present, one finds that, if the reservoir is in a normally saturated condition (that is, if the reservoir is in free contact and capillary equilibrium with mobile water and is at a normal level of capillary saturation for the specific geometry of the porous media under consideration), Bennion, et al. (2000) teach that very high trapped initial liquid saturations tend to be present, and that it can be observed that in reservoir rocks of permeability to gas on an absolute basis of less than 0.1 mD, effective initial water saturations are often in the 60% plus region. (It should be appreciated that such high saturations may be erroneous, due to contamination during handling.) This often results in significant reductions of the original reserves of gas in place in the porous media, and may also result in a very low or zero effective permeability to gas, as the gas saturation may be at or near the critical mobile value, and hence it will exhibit limited or no mobility when a differential pressure gradient is applied to the formation during production operations.

[0013] Therefore, Bennion, et al. (2000) teach that in most cases where very low permeability gas reservoirs are potentially productive, the reservoir exists in a situation where the reservoir sediments have been isolated from effective continual contact with a free water source which is capable of establishing an equilibrium and uniform capillary transition zone. They believe that a combination of long-term regional migration of gas through the isolated sediments (resulting in an extractive desiccating effect as temperature and pore pressure are increased over geologic time), or an osmotically-motivated suction of connate water into highly hydrophilic clays or overlying/interbedded sentiments, may be responsible for the establishment of what is commonly referred to as a "sub-irreducible" initial water saturation condition.

[0014] A reservoir having a sub-irreducible initial water saturation is defined by Bennion, et al. (2000) as a reservoir which exhibits an average initial water saturation less than the irreducible water saturation expected to be obtained for that porous medium at the given column height present in the reservoir above a free water contact (based on a conventional water-gas capillary pressure drainage test). In situations where exceptionally low matrix permeability is present in a gas-producing reservoir, unless a sub-irreducibly saturated original condition is present, the reservoir will exhibit insufficient initial reserves/permeability to be a viable gas-producing candidate. Therefore, Bennion, et al. (2000) believe that, with few exceptions, the vast majority of ultra-low permeability gas reservoirs that would be classified as exhibiting economic gas-producing pay, would fall into this classification of subnormally saturated systems. This phenomenon, they teach, gives rise to one of the most severe potential damage mechanisms in low permeability gas reservoirs: fluid retention or phase trapping.

[0015] Bennion, et al. (2000) then teach that "considerable invasion, due to capillary suction effects, can occur when water based fluids are in contact with the formation, even in the absence of a significant overbalance pressure. A phenomena [sic] known as countercurrent capillary imbibition has been well documented in the literature in previous papers and studies by the authors . . . and illustrates how a significant increase in water saturation in the near wellbore or fracture face region can occur in such a situation, even if underbalanced operations are being used when water based fluids (including foams), are circulated in contact with the formation face." They then propose that this problem can be mitigated by not using water based fluids in drilling, completion, and stimulation. If water based fluids must be used, then they recommend minimizing the exposure time so as to minimize the depth of water invasion. They then advise that "Capillary pressure, which is the dominant variable controlling fluid retention, is a direct linear function of interfacial tension between the water and gas phase. If this interfacial tension can be reduced between the invading water-based filtrate and the in-situ reservoir gas, the magnitude of the capillary pressure and the degree of observed fluid retention may also be lessened." and they teach that "natural capillary imbibition will want to 'wick' or imbibe water from the high water saturation zone (encompassing the original invaded area) deeper into the formation, resulting in a 'smearing' of the water saturation profile . . . . As long as a recharge source of unbound water is removed from the wellbore or fracture, this will obviously result in a gradual reduction in the value of the trapped water saturation in the near wellbore or fracture face region, which may result in a slow long term improvement in the permeability to gas in the region which previously exhibited near zero gas permeability." In other words, Bennion, et al. (2000) advise that availability, let alone injection, of water should be minimized, especially if the interfacial tension has been lowered. This is the exact opposite of the method of the present Invention.

[0016] Formulating drilling and completion fluids with high ionic strength in order to use osmotic forces to dehydrate shales to promote wellbore stability during drilling and completion operations is well known. Recently, Mese et al., in US Patent Application Publication No. 2008/0156484, taught injecting a high ionic strength fluid into a wellbore drilled, for example, through a shale or clayey sandstone containing a target fluid, and allowing osmotic forces to extract pore fluid from the formation and lower the pore pressure in the formation, where the target fluid is released. They further taught injecting a high ionic strength fluid, allowing osmotic forces to extract fluid from the formation, applying a hydraulic pressure to fracture the formation, and producing from the formation. They explained that using osmotic pressure to dehydrate shales in combination with hydraulic fracturing of a formation lowers the hydraulic fracturing threshold pressure and/or creates microfractures. They further taught rehydrating shales (using a second fluid having lower ionic strength than the fluid used in the fracturing but higher ionic strength than the formation fluid) to strengthen or "harden" them, for example to allow microfractures to stay open, and to release the fluid from the formation. In none of this was there a suggestion of using osmotic (or hydraulic) pressure to move large volumes of fluid deep into a formation.

[0017] Hinkel and England (U.S. Pat. No. 6,069,118) teach adjusting the ionic strength of fracturing fluids to use osmotic pressure gradients to cause flow of leaked-off fracture fluids from the formation through fracture faces into the fracture, for the purpose of removing stagnant fracture fluid from the reservoir, or flow of fracture fluids from the fracture into the formation, for the purpose of cleaning up fractures. (The latter is accomplished, for example, by injecting a high salt brine before the fracturing treatment or using a high salinity fracture fluid early in the fracturing treatment and then in the later stages of the fracture fluid using a lower salinity fracturing fluid.) The amount of fluid moved from the formation to the fracture is no more than the amount of fluid leaked off into the formation during the fracturing step; the amount of fluid moved from the fracture to the formation is no more than the fluid volume of the fracture. In fact, the amount of fluid moved is determined by the equilibrium between the two fluids. Again, there was no suggestion of using osmotic (or hydraulic) pressure to move large volumes of fluid deep into a formation.

[0018] We have found that osmotic pressure effects combined with imbibition may be used to increase hydrocarbon production from hydrocarbon reservoirs. This may be accomplished when any type of wettability is present (oil-wet, water-wet, intermediate-wet, and mixed wettability) We define a water-wet solid as having a contact angle, measured through the water, of from 0 to about 70 degrees when a drop of water is placed on the surface. A surface is intermediate-wet when that angle is from about 70 to about 110 degrees; a surface is oil-wet when the angle is from about 110 to 180 degrees. A mixed wettability surface is defined as a surface having regions of differing wettability. With suitable adjustments, the method of the Invention may be applied to a formation of any type of wettability. "Water" is defined as including fresh water and water containing any dissolved materials, for example salt or surfactant. In this application, the terms "Hydrocarbons" and "Oil" are intended to be defined broadly as any type of hydrocarbon material that is able to flow to the surface under achievable subsurface conditions, including for example petroleum, gas, kerogen, paraffins, asphaltenes, supercritical fluid, and condensate. Osmotic pressure is the fluid pressure produced by a solution that is separated from a solvent by a semipermeable membrane, due to a differential in the concentrations of solute. A semipermeable membrane, also termed a selectively-permeable membrane (selectively permeable to the solvent (water) in preference to the solute), a partially-permeable membrane or a differentially-permeable membrane, is a membrane that will allow certain molecules or ions to pass through it by diffusion. Thus, water will spontaneously flow from a region of lower ionic strength (salinity; solute concentration) to a region of higher ionic strength. Lower ionic strength is also called higher potential (or higher chemical potential) or higher activity, because the solvent (water) flows from higher potential to lower potential. Osmosis is an equilibrium process. The rate of passage depends on the pressure, concentration, and temperature of the molecules or solutes on either side, as well as on the permeability of the membrane to each solute. Depending on the membrane and the solute, permeability may depend on solute size, solubility, properties, or chemistry. We will generally discuss aqueous systems. The pressure that must be applied to the solution on the low activity side to make the activity of water equal to the activity of water on the high activity side is the osmotic pressure; if the pressure on the low activity side is less than this pressure, then water will flow from the high activity side, through the membrane, into the low activity fluid by osmosis.

[0019] The "membrane" is the interface separating the higher and lower activity fluids. Low-permeability shales, for instance, can act as membranes (or at least imperfect membranes). Consider a wellbore or fracture in a shale formation; water in the wellbore or fracture diffuses through the shale interface and into the more solute-rich shale pore fluid. The extent (equilibrium) of fluid transfer is dependent upon the solute differential between the two regions separated by the membrane. Fluid transfer in response to the chemical potential gradient occurs until it is eventually countered by the osmotic pressure—i.e., the pressure exerted against the membrane by the fluid being diluted by solvent transfer. Thus fluid transfer occurs until equilibrium is reached. Moreover, the osmotic pressure is a function of the membrane's efficiency. Thus, an imperfect membrane will sustain a lower osmotic pressure since solvent and solute can readily migrate back and forth across the membrane until equilibrium is reached. Obviously, what is desired is to maximize fluid transfer, for example from the fracture or wellbore across the membrane and into the formation. As evidenced by this discussion, the skilled artisan can now see that the greater the efficiency of the membrane (i.e., the more selectively permeable it is to solvent) the greater the osmotic pressure it can sustain, and therefore the greater the solvent transfer at equilibrium. Thus, it is highly desirable to increase the efficiency of the membrane that exists in the subterranean formation and that separates the wellbore or fracture from the formation. Occasionally the formation comprises a naturally good membrane, for instance, a low-permeability shale is an effective membrane, which may not require any artificially established membrane in order to execute the method of the present Invention; optionally an artificial membrane may be superimposed on the natural membrane to enhance its effectiveness. Typically, a sandstone is not a suitable intrinsic membrane. In those instances where the formation does not provide a sufficient membrane, one must be artificially created to maximize fluid removal according to the present Invention.

[0020] Methods of creating subterranean semipermeable membranes are discussed in U.S. Pat. No. 6,069,118, hereby incorporated by reference in its entirety. The list of possible materials that can form a semipermeable membrane suitable for the present Invention is long. The person skilled in the art of semipermeable membrane chemistry, working in concert with one skilled in the art of reservoir engineering can select suitable candidates for the semipermeable membrane material by following the general guidance provided in the present Specification, by following the teachings in the art, and by following certain specific guidelines. The following references are helpful in this regard and are hereby incorporated by reference: H. P. Gregor and C. D. Gregor, "Synthetic-Membrane Technology," 239, *Scientific American,* 112 (1978); R. Durbin, "Osmotic Flow and Water Across Permeable Cellulose Membranes," 44 *J. General Physiol.,* 315 (1960). U.S. Pat. No. 7,398,829, hereby incorporated by reference in its entirety, discloses the use of water inert polymers, for example emulsion polymers and latex polymers, to form a film on fracture surfaces; such films may be useful as semipermeable membranes. Preferred semipermeable membranes of the present Invention should possess the following attributes. First, the semipermeable membrane must be water-wettable. Second, the semipermeable membrane material, once in place, should comprise pore spaces of sufficient size to yield acceptable osmotic pressures. Naturally, the semipermeable membrane should be easy and cost-effective to establish. Numerous more specific considerations, known to the one skilled in the arts to which this Invention is directed, will direct the engineer or well operator to the optimal semipermeable membrane candidate. For instance, in the brine stages of a treatment, conventional polymers may not be suitable due to their tendency to destabilize at high temperatures in the presence of brine.

[0021] Again, the formation itself may, in some instances, provide an intrinsic membrane—without the need to establish one artificially. In other instances, a suitable membrane may exist, having been established during another step in the fracturing process—e.g., lining the fracture faces with filter cake to prevent leak-off of the fracture-inducing fluid.

[0022] If one desires to establish a selectively permeable membrane suitable to practice the present Invention, then it can be done, for instance, by injecting into a wellbore or into a fracture, a membrane-forming material (for example, a conventional fluid-loss additive). This membrane-forming material forms a membrane layer at the appropriate interface, thus ideally sealing in the solute-rich solution-containing formation. The ideal membrane is one that is freely permeable to water, but impermeable to all solutes. Again, creating this membrane may comprise a separate step—i.e., it may not be an intrinsic part of the drilling, completion, or stimulation process—or a coating placed on the formation from a prior injecting step may be further utilized as the membrane of the present Invention. For instance, a "filter cake," comprised of, for instance, a dewatered guar gum, is often deliberately established on the formation face of a wellbore or fracture. The purpose of this filter cake is to prevent leak-off, or loss of drilling or fracturing fluid into the formation. A filter cake may also be created (generally unintentionally) when a guar gum solution carrying proppant is delivered into a fracture and the gum sticks to the formation and dewaters, forming a filter cake. The filter cake diverts the fluid's flow path so that instead of leaking off from the hydraulic fracture laterally into the formation, it continues to move down the hydraulic fracture and thus extending deeper into the formation. The process would be exactly the same for any additional fractures created by branching off from the main hydraulic or additionally in the case where multiple hydraulic fractures are propagated simultaneously. The point is that this filter cake can then be used as the selectively permeable membrane of the present Invention. Thus, it may be desirable to manipulate the composition of the material used to create the filter cake so that it forms a membrane suitable for the present Invention.

[0023] Numerous materials may be used to establish the membrane of the present Invention. Several membrane compositions suitable upon modification for use in accordance with the present Invention include those disclosed in U.S. Pat. Nos. 5,041,225, and 4,851,394. In particular, the '394 patent discloses membranes comprised of polyhydroxy compounds. Both of these patents are hereby incorporated by reference in their entirety. Galactomannans crosslinked with boric acid, and cellulose acetate (commonly used in dialysis) can also form membranes suitable for use in the present Invention. Many suitable semipermeable membrane materials are associated with the medical industry. For reverse osmosis and other applications, the use of Thin Film Composite Membranes (TFC or TFM) is common. Essentially, a TFC material is a molecular sieve constructed in the form of a film from two or more layered materials. Membranes used in reverse osmosis are typically made out of polyamide, chosen primarily for its permeability to water and relative impermeability to various dissolved impurities including salt ions and other small, unfilterable molecules. One example of a reverse osmosis membrane is made from cellulose acetate as an integrally skinned asymmetric semipermeable membrane. This membrane was made by Loeb and Sourirajan at UCLA in 1959 and is described in U.S. Pat. Nos. 3,133,132 and 3,133,137, both of which are hereby incorporated by reference in their entirety. Another example of reverse osmosis (RO) membrane materials is based on a composite material described in U.S. Pat. No. 3,551,331, hereby incorporated by reference in its entirety. FilmTec's FT30™ membrane is known as a polyamide thin film composite membrane. As is suggested by the name, such TFC membranes are composed of multiple layers, for example a polyamide layered with a polysulfone as an interlayer and a polyester as a porous support layer. It is the aromatic or mixed aromatic, aliphatic polyamide that may be used to form the semipermeable membrane of the present Invention. Other materials, usually zeolites, are also used in the manufacture of TFC membranes.

[0024] In one preferred embodiment of the present Invention, the membrane is comprised of polyhydroxy compounds; in one particularly preferred embodiment, it is comprised of polyethylene glycol (PEG). Other hydroxylated polymers, for example polypropylene glycol (PPG), and PEG-PPG block copolymers, may be used. Other types of materials are also particularly suitable: e.g., colloids, polymers, aluminosilicates and mixtures of aluminosilicates and fatty acid, starch, and silica flower. Methyl glucoside (methyl-glucopyranose) which can be formed by reacting methanol with the anomeric hydroxyl on glucose, and other similar classes of materials may also be used. A copper hexacyanoferrate membrane may be formed either by sequential injection of solutions, or by the injection of one solution followed by the diffusion of the solute from a second solution. Copper sulfate and potassium ferrocyanide are known to react on contact to form a copper hexacyanoferrate membrane. In addition, silicates may form membranes suitable for the present Invention. More particularly, clays, such as bentonite, are preferred embodiments of the present Invention.

[0025] The following non-limiting list of additives, if applied correctly, may increase the efficiency of a semipermeable membrane formed on the face of a formation, for example a shale formation: electrolytes, phenols, tetra methylammonium laurate, tetra methylammonium oleate, silicic acid, potassium methyl siliconate, sodium methyl siliconate, biopolymers, hydroxyethyl cellulose, sodium carboxylmethyl-hydroxethyl cellulose, synthetics such as polyethylene amines, copolymers of 2-acrylamide-2-methyl propane sulfonic acid and N-vinyl-N-methyl acetamide, HALAD-344 (a random copolymer of 2-acrylamide-2-propane sulfonic acid and N,N-dimethyl acrylamide), HALAD-413 (a caustized lignite grafted with 2-acryamide-2-methylsulfonic acid, N,N-dimethylacrylamide, and acrylamide), latexes such as polyvinylalochol and styrene butadiene, and silicate compounds such as sodium silicate and potassium silicate.

[0026] Whenever two or more fluids co-exist in a system of pores (capillaries), the combination of surface tension and curvature due to the capillaries causes the two phases to experience different pressures. As the relative saturations of the phases change, it has been found that these pressure differences also change. The difference between the pressures of any two phases is referred to as the capillary pressure. We define the capillary pressure, for example in the pores of a formation, as the difference in pressure across the interface between two immiscible fluids:

$$p_c = p_{non\text{-}wetting\ phase} - p_{wetting\ phase}.$$

[0027] In oil-water systems or oil-gas systems, either the water or the hydrocarbon may be the wetting phase; for gas-oil systems, oil is the wetting phase. The Young-Laplace equation states that the pressure difference is proportional to the surface tension, y, and to the cosine of the wetting angle, θ, of the liquid on the surface, and inversely proportional to the effective radius, r, of the interface (for example a formation pore throat):

$$p_c = \frac{2\gamma\cos\theta}{r}$$

[0028] This equation for capillary pressure is actually valid only under capillary equilibrium, in the absence of flowing phases. The capillary pressure as defined here is the maximum driving force for fluid flow. During flow, both the contact angle—advancing—and the effective radius may change. The radius of curvature of the interface is greatest when the length of the 'suspended' column reaches its maximum. Clearly, in a subterranean formation, the capillary pressures may be altered by changing the interfacial tension between the fluid phases and the wettability of the surface. Typically in the practice of the Invention, these parameters are used to maximize the imbibition of the injected water; this is done, for example, by increasing the water-wetting properties of the formation and/or by lowering the hydrocarbon/water interfacial tension. It may be found in some cases that lowering the interfacial tension may maximize the ultimate hydrocarbon recovery but lower the imbibition rate. Enhancing water imbibition by adding water-wetting agents and/or by adding water/oil interfacial tension lowering agents has been proposed (see U.S. Pat. No. 5,411,086) for use in driving water from injection wells to production wells for enhanced oil recovery in diatomaceous reservoirs. That patent taught that "Some oil or hydrocarbonaceous fluids will be displaced by counter current imbibition into fractures communicating with the injection well or wells. For this reason it is preferred that the injector well or wells occasionally be placed on production to produce additional oil or hydrocarbonaceous fluids from the diatomaceous formation or reservoirs."

[0029] Capillary pressure affects imbibition and drainage. It is the hysteresis effect during the cycles of drainage and imbibition that impacts the capillary pressure. Primarily this phenomenon is a result of the changing wettability in the system. The higher the saturation of the wetting fluid, the lower the capillary pressure. In real porous media the changes mean that some fluid advancing via imbibition cannot then be displaced by drainage, which results in phase trapping. In other words, the capillary pressure can vary during drainage and imbibition; this variation accounts for the observed hysteresis. The hysteresis results from differences between the advancing (imbibition) and receding (drainage) contact angles. The relative values of the contact angles are:

Advancing>Receding>Static.

[0030] The saturation changes capillary pressure, with increasing wetting fluid saturation always leading to lower capillary pressure. An easy way to envision this is to consider the common capillary rise experiment. At the beginning of the experiment the capillary is empty (zero wetting fluid saturation) and the capillary pressure is at its highest. At equilibrium, i.e. maximum rise, the capillary pressure has fallen to zero and the capillary has reached its maximum wetting fluid saturation. The concept is best illustrated by the following expression for capillary pressure:

$$P_c = \rho g(h - z)$$

in which z represents the height of the column at any instant during filling, and h represents the maximum height (equilibrium). (This assumes that the contact angle is 0 degrees and that the capillary is vertical.) Fractional saturation can be stated as z/h. Phase trapping can best be explained by referring to the Jamin effect. (See, for example, R. Cossé, "Basics of Reservoir Engineering", Gulf Publishing Company, Houston, Tex. (1993), p. 180.) Displacement of the non-wetting phase can be stopped when a blob reaches a small pore. Surfactants will reduce phase trapping. In the present Invention, the fluid movement is controlled by selecting the proper surfactants to take advantage of these processes, or to mitigate the negative effects, in order to maximize hydrocarbon production and/or ultimate recovery.

[0031] Non-limiting examples of agents that lower hydrocarbon/water interfacial tension are those surfactants used in enhanced oil recovery by surfactant flooding; they are well known and include sulfonates, ammonium salts of linear alcohols, ethoxy sulfates, calcium phenol ethoxylated alkyl sulfonates, and mixtures of these materials. Particularly suitable agents are carboxylates, ethoxylates, ethoxylated alcohols, alkyl ethoxylated alcohols, nonyl phenol ethoxylated alcohols, sulfonates, alpha olefin sulfonates, alkyl benzyl sulfonates, sulfonic acids, sulfates, ethoxylated sulfates, phosphates and phosphate esters of vegetable oils containing polyunsaturated fatty acid ester groups in the triglyceride molecules, such as soybean, cottonseed, corn, safflower, and sunflower oils. The effects of these materials may be enhanced by the use of co-surfactants and suitable electrolyte concentrations. Caustic, such as sodium or potassium hydroxide, may be used to form natural surfactants by reaction with organic acids if oil is present.

[0032] Non-limiting examples of agents that increase water-wetting of formations include mono-, di-, and tri-basic forms of sodium or potassium phosphate, sodium silicate, oxyalkylated alkyl phenols and sulfates, fluorocarbons, alkyl di-methyl amine oxides, and other amine oxides. It should be noted that surfactants may be generated in situ, for example by the action of acids on petroleum components.

[0033] Non-limiting examples of agents that increase hydrocarbon-wetting of formations include lecithin; organic surfactant compounds having the formula R1-(EOx-PrOy-BuOz)H wherein R1 is an alcohol, phenol or phenol derivative or a fatty acid having 1 to 16 carbon atoms, EO is an ethylene oxide group and x is 1 to 20, PrO is a propylene oxide group and y is 0 to 15, and BuO is a butylene oxide group and z is 1 to 15; an organic polyethylene carbonate having the formula R2-(—CH2-CH2-O—C(O)—O—)qH wherein R2 is an alcohol having 7 to 16 carbon atoms and q is 7 to 16; butoxylated glycols having 1 to 15 butylene oxide groups; ethoxylated-butoxylated glycols having 1 to 5 ethylene oxide groups and 5 to 10 butylene oxide groups; and alkyl-aminocarboxylic acids or carboxylates. In general, a strong cationic surfactant is appropriate to oil-wet sandstone and a strong anionic surfactant is appropriate to oil-wet carbonate.

[0034] The use of osmotic forces to transport large volumes of fluid from a wellbore to the producing formation may be done with or without hydraulic fracturing (fracture-stimulated, stimulated, etc.), depending primarily upon the overall permeability of the formation. If satisfactory volumes and rates of injection and production cannot otherwise be achieved, the well is fracture-stimulated. Fracturing may be accomplished by hydraulic fracturing with any kind of fluid (water-based, acid-based, oil-based, gaseous, energized, foamed, crosslinked polymer, non-crosslinked polymer, viscoelastic surfactant, other non-polymeric viscosifier, friction reducer, straight water, etc.). Fracturing may also be accomplished by the use of osmotic forces themselves (in which the osmotic pressure is higher than the formation fracturing pressure; this is particularly desirable when it occurs along the face of a very long hydraulic fracture already extended or dynamically extending into the reservoir. Especially in low permeability, high salinity, shaley formations (in which capillary pressures can be high because of low pore radii of curvature, formation chemical potentials are low, and the formation is an effective semipermeable membrane) osmotic pressures can be created that are greater than the pressure required to fracture the reservoir. This generally results in many microfractures being created where the higher chemical potential fluid contacts the formation. This is achieved by injecting into the wellbore, and/or into a hydraulic fracture, a fluid having a higher chemical potential (lower ionic strength) than the fluid that it will contact across a semipermeable membrane. The microfractures increase the surface available for imbibition. Osmotic forces may also be used in conjunction with well treatments involving explosives, propellants, perforating, hydrojetting, thermal fracturing, and other techniques. Osmotic forces may also be utilized whenever fracturing or any other methods are used to create a connection between existing disconnected or partially disconnected natural fractures in the formation and a wellbore.

[0035] Once it has been determined that adequate flow rates to and from the wellbore and the reservoir are possible, large volumes of fluid are injected so that they penetrate deep into the formation. By deep into the formation we mean that the fluid contacts a significant portion of the producing wellbore drainage volume, also known as the "practical" wellbore drainage volume of the well, for example at least one quarter of the practical wellbore drainage volume, or in another example at least one half of the practical wellbore drainage volume. By "practical" wellbore drainage volume, we mean the wellbore drainage volume the operator intends to drain over the lifetime of the well via the well, any hydraulic fractures and any natural fractures in fluid communication with the well. This drainage area is estimated with current geophysical, petrophysical, etc. information and well production performance data available at the time based on standard reservoir engineering practice. It should be understood that with additional information over time, the expected drainage area of a wellbore may be changed accordingly. The drainage area of a well is not to be confused or associated with the current well spacing as this spacing is regulated by various regional (for example county, parish, state, or federal authorities) and is also subject to change over time as better information on the reservoir and well production behavior becomes available. The minimal volume injected into a hydraulically fractured system is preferably the volume of the hydraulic fracture plus the volume of any natural fractures contacted plus the volume leaked off during the hydraulic fracturing treatment.) This contact does not necessarily occur in the first injection cycle, or even the first few injection cycles of a treatment, but preferably occurs by the end of the treatment. The most desirable result is to impact all of the practical wellbore drainage volume of every hydraulic fracture that extends from a wellbore into the reservoir. In sufficiently permeable reservoirs, no hydraulic fractures are likely needed but on occasion may be utilized as individual situations warrant. In very low permeability reservoirs, it may be necessary to fracture-stimulate, treat the practical wellbore drainage volume by the method of the Invention, refracture on a different azimuth, treat, refracture, etc. Often, only a single hydraulic fracture is created during an individual treatment. The length of the hydraulic fractures created is dependent on all of the geomechanical factors of the reservoir itself along with the limitations imposed by the wellbore configuration and construction, the surface pumping equipment and other logistical aspects. In the optimal case, the operator determines what the potential practical wellbore drainage area could be for a given well. The operator then creates fractures and injects fluid so that all of the practical wellbore drainage area is reached by the injected fluid. This is in contrast to other methods in which fluids that have higher potential than formation fluids may be injected for other reasons; such fluids do not contact a substantial portion of the practical wellbore drainage area of the well. Optionally, diverting materials are used in the fracturing process in order to create hydraulic fracture branches off of the main fracture in order to expose more reservoir surface area. The goals may also be achieved on existing wells by going back in and performing a refracturing treatment or treatments. The ultimate aim is to increase the hydrocarbon production rate and/or ultimate recovery from each wellbore and to optimize overall reservoir development.

[0036] The fluid to be injected is designed (after suitable analysis of the formation rock and fluid properties, if possible, or by analogy to similar wells or reservoirs) to alter the pore pressures in the formation by osmosis in order to aid in hydrocarbon production by imbibition. Production of hydrocarbon in low permeability formations by imbibition is described, for instance, in commonly-assigned and simultaneously-filed U.S. patent application Ser. No. 12/253,406, entitled “Enhancing Hydrocarbon Recovery” incorporated by reference above. However, imbibition alone may not be capable of producing economical rates and/or volumes of hydrocarbon in some reservoirs. The proper fluid selection, for osmosis to aid imbibition in the present Invention, depends upon the formation wettability and the wetting and non-wetting phase saturations and activities. In one embodiment, if the rock is water-wet, osmosis may be used to aid recovery by increasing the pore pressure in the pores containing water such that this pressure may be transmitted to adjacent pores containing the non-wetting fluid (the hydrocarbons). On the other hand, if the reservoir is hydrocarbon-wet (by non-limiting example kerogenic and heavy oil reservoirs) then osmotic forces may be used to cause an increase in non-wetting fluid saturation, resulting in an increase in the pressure in the water-containing pores. Finally, if the rock is above its irreducible oil saturation, then even injection of a fluid having the same chemical potential as the formation fluid will cause an increase in capillary pressure and so will allow hydrocarbon to flow to the well by imbibition. Furthermore, if the fluid also contains a wetting agent, such as a surfactant, the wetting agent will be moved into capillaries containing non-wetting fluid both by hydraulic and saturation gradients, and aid any of the above processes by reducing phase trapping.

[0037] The method of the Invention takes advantage of the forces which dominate fluid movement within the reservoir. Under some conditions there may be limitations as to how much advantage is possible, but knowing the details of the reservoir and the initial conditions, the treatment fluid may be formulated, designed and pumped as necessary. In a mixed-wettability reservoir, the same approach as has already been described may be taken. Since the method of the Invention uses aqueous fluids, both osmosis and imbibition forces may be taken advantage of when the reservoir is primarily water-wet. In oil-wet reservoirs, osmosis will likely be the greatest contributor to success. For mixed-wet reservoirs, the operator may use both osmosis and imbibition. In other words, osmotic processes may be used to manipulate events in the reservoir to aid hydrocarbon recovery. Reservoir characterization determines how the method of the Invention is best carried out. In the case of a oil-wet reservoir, imbibition using an aqueous fluid may be less effective, but the pore pressure in the hydrocarbon-filled pores may be increased by osmotic action in adjacent water-wet pores, and this facilitates hydrocarbon recovery. In other words, proper manipulation of the osmotic pressure may be an aid to imbibition in either water-wet or oil-wet reservoirs, or it may be used alone in cases where imbibition might not be effective or feasible.

[0038] Particularly suitable agents for controlling the ionic strength (raising or lowering the chemical potential or the activity) of water include formates, such as cesium formate, potassium formate, sodium formate, ethyl formate, methyl formate, methyl chloro formate, triethyl ortho formate, trimethyl ortho formate, and the like. Other particularly suitable agents for use in the inventive method include salts that are commonly used to add salinity and/or density to drilling, completion, and stimulation fluids, for example, but not limited to ammonium chloride, calcium bromide, calcium chloride, potassium chloride, potassium bromide, sodium bromide, sodium chloride, zinc bromide, zinc chloride, calcium nitrate, and blends of these salts. Other suitable materials include magnesium chloride and sugars. Any soluble substance may be used that alters the ionic potential of the solution. Incompatibility with formation rock or formation fluid should not be a problem, because invasion of the agents into the formation is not intended. The fluid injected may contain any of the typical oilfield fluid additives, as appropriate, for example biocides, and friction reducing agents such as polyacrylamides. Compatibility with formation rocks, formation fluids, and any other fluids to be used should be checked in the laboratory as usual.

[0039] The method of the Invention is particularly applicable in reservoirs in which fluids are likely to be trapped in the pores. If either the wetting phase or the non-wetting phase, either water or hydrocarbon, is trapped, this may inhibit the desired flow of hydrocarbon to the well during production. For example, particularly in a water-wet reservoir, trapped water may block the flow of hydrocarbon. Obviously, under any conditions, trapped hydrocarbon is undesirable.

[0040] The steps normally followed in the use of osmotic pressure to assist imbibition in hydrocarbon production include the following. Not every step may be needed in every treatment, and additional steps may be included in some treatments as necessary as would be understood by one skilled in the art. This description does not include hydraulic fracturing, which may be done before, during (at any point), or after the following:

[0041] 1. Characterize the Reservoir

[0042] 2. Select the Injection Fluid Major Component(s)

[0043] 3. Formulate the Injection Fluid

[0044] 4. Test Formation Fluid and Rock Compatibility (and other tests as necessary)

[0045] 5. Design the Job

[0046] 6. Determine the Need to Create or Improve an Existing Semipermeable Membrane in the Reservoir and Optionally Create or Improve the membrane

[0047] 7. Inject Fluid

[0048] 8. Optional Shut-In

[0049] 9. Produce Fluid

[0050] 10. Repeat Steps 7 through 9

[0051] 11. Optionally Repeat Any of Steps 1-6 and then 7-9 (or then 9 and then 7-9)

[0052] The individual steps may include the following procedures:

[0053] 1. Characterize the Reservoir: This is typically done from information already available, or obtained for the purpose, from adjacent wells in the reservoir, for example from analysis and interpretation of data from well logs and histories, formation cores, and fluid samples. If no such data are available, inferences from reservoirs believed to be similar may be used, but this may not be as satisfactory. It is recommended that data from the wells to be treated, or from adjacent wells, be obtained and used if possible.

[0054] 2. Select the Injection Fluid Major Component (s): The major components of the fluid, as defined here, are those that would most effectively affect the osmotic and capillary pressures. These include potentially major contributors to ionic strength (such as buffers; pH adjusters; and clay stabilizers), and surfactants (such as emulsifiers; demulsifiers; foaming agents; and anti-foaming agents; and agents specifically chosen for their ability to affect formation wettability and/or interfacial tension). Other materials that may be incorporated in the fluid but are less likely to have a major affect on osmotic and capillary pressures include biocides; oxygen scavengers; antioxidants; iron control agents; and corrosion inhibitors. The major components may be selected through the use of laboratory tests, such as wettability, sorption, and imbibition, on cores, preferably using cores and formation fluids from wells to be treated. Suitability of a fluid for providing the benefits of osmosis for increasing hydrocarbon recovery may be tested and confirmed in the laboratory with an imbibition test using a core having one end open and all other surfaces sealed. Any other fluid components should be tested to ensure that they are compatible with the major fluid components. If laboratory tests are not feasible, or if the reservoir is well characterized and candidate injection fluids are well known, correlations may be used. Compatibilities must always be taken into account; for example, some components, such as some surfactants, may sorb onto formation surfaces.

[0055] 3. Formulate the Injection Fluid: In conjunction with selection of major components, the base fluid is identified. This may be fresh water, formation water, creek water, municipal water, or another water, and may be dictated by availability or cost. (It is unlikely that the base fluid is sea water or a brine, because the injection water normally must have lower activity than the formation water.) Typically, the amounts of major components to be added are then determined, followed by the amounts of other components. In formulating the fluid, care must taken to avoid harmful interactions of the injection fluid with the formation or formation fluids. For example, if core analyses or information on the formation in adjacent or similar wells or reservoirs indicates that the formation to be treated may contain fresh-water-sensitive clays or zeolites or clays that could be destabilized, then the injection fluid should be formulated accordingly. Similarly, if formation fluid analysis, or information on the fluids from adjacent or similar wells or reservoirs, indicates the possibility of precipitation of scales, asphaltenes, paraffins, or other materials, then the injection fluid should be formulated to minimize these possibilities. Those skilled in the art will know how to minimize such fluid-formation and fluid-fluid interactions.

[0056] 4. Test Formation Fluid and Rock Compatibility (and other tests as necessary) and make any adjustments in the injection fluid formulation if required.

[0057] 5. Design the Job: This involves primarily the determination of the optimal rate and volume of fluid to be injected in each cycle before the well is put on production. The rate and volume are generally economic considerations, provided that the volume does not exceed that sufficient to fill the expected drainage area of the well. Models may be used to calculate, predict and optimize the job design and results. The rate and volume may be affected by the pumping horsepower available, fluid formulation equipment limitations, chemical availabilities, hydrocarbon gathering, storage, and shipment capabilities, and other factors. Fluid injection rate and volume are not believed to be major factors in hydrocarbon recovery. Hydrocarbon production may be stopped, and another injection stage begun, when hydrocarbon recovery rates becomes unacceptably low; on the other hand, it is believed that the switch from production to injection may be made before it is economically necessary without deleteriously affecting the ultimate recovery. At this time, also, ensure that the zone to be treated is properly isolated, using packers, diverting agents, etc., as is well known to those of skill in the art.

[0058] 6. Determine the Need to Create or Improve an Existing Semipermeable Membrane in the Reservoir and Optionally Create or Improve the membrane: If the characterization, testing, and/or correlations done above indicate that it is necessary or economically warranted, a semipermeable membrane may be created or enhanced by the injection of a fluid containing suitable chemicals, as described elsewhere in this specification. Of course, care must be taken to avoid a deleterious reduction in permeability.

[0059] 7. Inject Fluid: The initial job design may be altered, either during the first injection cycle, or more especially in subsequent cycles. Note that if fluid is being pumped to improve or create a semipermeable membrane, this may be done in a number of ways. 1) An initial (separate from the main imbibition/osmosis treating fluid) treatment may be pumped to improve or create the semipermeable membrane. There may be a shut-in period required in order for the membrane to reach its best condition. 2) The semipermeable membrane forming fluid may be pumped and immediately followed by the imbibition/osmosis fluid (optionally separated by a spacer fluid). 3) It is possible, although less preferred, that the semipermeable membrane fluid and the imbibition/osmosis fluid be pumped together as a single stage. Also, the fluids may be pumped as single stage sequences, alternating sequences, etc. in order to contact as much of the reservoir as possible.

[0060] 8. Optional Shut-In: Whether or not a shut-in period is needed, or beneficial if not needed, depends on the reservoir characterization and an estimation of the rate at which the processes reach an equilibrium or optimum. Shutting in the well, or wells, to allow the processes to progress, will almost always be beneficial, since all the processes of the method take time. The method may be carried out in stages, for example inject, shut-in, sweep, inject, shut-in, sweep, etc.

[0061] 9. Produce Fluid: Production in each cycle is generally continued as long as economically warranted. Optimal producing conditions may be estimated by numerical modeling (reservoir simulation). Cycle times are generally long enough to allow installation of a pump for artificial lift. A lot of the artificial lift equipment may optionally remain in place during the injection cycles.

[0062] 10. Optionally Repeat Steps 7 through 9: Normally a number of injection/production cycles will be repeated as long as the economics warrants.

[0063] 11. Optionally Repeat Any of Steps 1-6 and then 7-9 (or then 9 and then 7-9): Typically, the job is closely monitored, especially pressure during the injection cycles(s) and pressure and fluid composition during the production cycle(s). The use of evaluation technology would be very beneficial in these cases. For example, microseismic monitoring may be used to determine hydraulic fracture behavior in real-time. It may also be warranted to use permanent downhole monitoring (this may be in specific wells used only for monitoring or in the production wells themselves) to gauge the overall reservoir behavior. Other techniques may also be used, such as tagging fluids with chemical tracers to monitor during flowback to estimate efficiency (first in, first out) and overall zonal coverage. If performance is unsatisfactory or unexpected, or if additional information becomes available (for example core, fluid, and/or performance data from one or more adjacent wells) any or all of the first 5 steps may be repeated.

[0064] The method of the Invention may be applied in formations of any permeability, but if production is economically unsatisfactory, or expected to be, then a well or wells may optionally be hydraulically fractured or otherwise stimulated before, during or after the above procedure. An operator may utilize an existing hydraulic fracture proppant-pack as the conduit to deliver the treatment of the Invention to the reservoir. Most commonly, an operator uses the method of the Invention during, or as a part of, a hydraulic fracture stimulation process. The method may also be applied to wells that have already been fracture-stimulated, in which case the treatment is a re-frac. A decision to hydraulically fracture may be made during any step. If a well is then hydraulically fractured, as many of the original steps as possible should then be repeated. The fracture treatment and subsequent injection/production cycles of the Invention must be carefully designed to ensure that effects of the fracture fluid (and pad) components have been accounted for. For example, the viscosifier (polymer or viscoelastic surfactant or other non-polymeric viscosifier such as a vesicle former) may significantly alter capillary pressures and osmotic effects; fluid loss control agents could affect the semipermeable membrane; and clay stabilizers could affect osmotic forces. On the other hand, flowback after hydraulic fracturing may not be appropriate, and water that flows into the formation during the fracturing may be beneficial.

[0065] The methods of the Invention may be used in cased or open-hole wells.

[0066] The methods of the Invention have been described thus far primarily for a single well. Typically, however, the methods of the Invention may be performed using more than one well in a field and/or to more than one formation location accessible using a particular wellbore. In this way, the inventive method may be performed in different places in the formation. These different places can include two or more locations in different dual-laterals, multiple-laterals, multiple wellbore branches (such as sidetracks, multiple-laterals located in different vertical layers of the same geologic reservoir, multiple-laterals located in different vertical layers covering one or more different geologic reservoirs, etc.) from the main wellbore, injecting fluids into two or more separate wellbores (wells) for the purpose of improving injection coverage, etc. Many formations consist of multiple layers. Performing the inventive method in different places in the formation may include performing the inventive method in the same and/or in different layers of the formation and, as noted immediately above, these places may accessed from the same wellbore or from different wellbores. Any well pattern may be used. Having some wells on injection and some on production at any one time normally optimizes use of people and equipment. Normally, although hydrocarbons flow toward the production well during the injection stage, they might or might not reach the well. If they reach the production well, injection may be stopped and production begun. The operator may monitor produced fluid for trace components of the treatment fluid or other materials (tagging agents) that may have been added to the treatment fluid for identification purposes. It is also possible to infer injector influence on producers by monitoring the reservoir pressure changes. It is common to model the reservoir numerically and match the pressure behavior by adjusting the influence of the injectors on the producers.

[0067] Another option is suitable and falls within the scope of the Invention. Hydrocarbon released from the formation pores may be produced from another well under certain circumstances. For example, if an injection/production well is a first horizontal well in a formation, at least some of the released hydrocarbon may flow due to buoyancy to a second producing horizontal well in the same formation, i.e. dual-lateral wells with one of the horizontal wellbores above the other. Optionally, the second well may also be an injection/production well with the cycles of the two wells coordinated by monitoring tracers or hydrocarbons, as the fluid sweeps the reservoir. In another embodiment, the first injection/production well penetrates a non-horizontal formation layer at a lower point and the second production (or injection/production) well penetrates the formation at a higher point. In this case one of the wells is higher on the geological structure. In these cases gravity effects play a larger role in the overall process. As mentioned before, this is taken into account with the numerical models to determine which injection and production conditions are optimal for increasing the rate and/or ultimate cumulative hydrocarbon production from the reservoir. All of this may be modeled by one of skill in the art using fluid compositions (viscosities and densities), flow rates, water and gas/oil saturations, etc., optionally using any oilfield diagnostic evaluation techniques (such as chemical tracers, radioactive tracers, microseismic monitoring, permanent downhole monitoring systems, etc.).

[0068] While the Invention is described through the above exemplary embodiments, it will be understood by those of ordinary skill in the art that modification to and variation of the illustrated embodiments may be made without departing from the inventive concepts herein disclosed. Moreover, while the preferred embodiments are described in connection with various illustrative structures, one skilled in the art will recognize that the system may be embodied using a variety of specific structures. Accordingly, the Invention should not be viewed as limited except by the scope and spirit of the appended claims.

1. A method of producing hydrocarbon from a subterranean formation penetrated by a wellbore comprising a period of injecting into the formation an aqueous injection fluid, other than a fracturing fluid or a pad, having a higher chemical potential than the aqueous formation fluid, wherein water in the injection fluid flows into the formation fluid by osmosis, whereby there is an increase in pressure in the formation, and whereby a portion of the hydrocarbon flows to the wellbore, and further wherein, if the formation is hydraulically fractured, the volume of aqueous injection fluid having a higher chemical potential than the aqueous fluid in the formation is greater than the volume of the hydraulic fracture plus the volume of any natural fractures contacted plus the volume leaked off during the hydraulic fracturing treatment.

2. The method of claim **1** wherein the injection fluid contacts at least one quarter of the practical wellbore drainage volume.

3. The method of claim **1** wherein injection is performed in different places in the formation.

4. The method of claim **1** wherein the period of injection is followed by a period of production without injection.

5. The method of claim **4** wherein the period of production without injection is followed by a second period of injection.

6. The method of claim **1** further comprising injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane.

7. The method of claim **1** wherein the injection fluid comprises formate.

8. The method of claim **1** wherein the injection fluid further comprises an agent that increases the contact angle of the formation with water.

9. The method of claim **1** wherein the injection fluid further comprises an agent that decreases the contact angle of the formation with water.

10. The method of claim **1** wherein the osmotic pressure generates fractures in the formation.

11. The method of claim **1** wherein the formation is hydraulically fractured.

12. (canceled)

13. A method of producing hydrocarbon from a subterranean formation penetrated by a wellbore comprising injecting into the formation an aqueous injection fluid, other than a fracturing fluid or a pad, having a lower chemical potential than the aqueous formation fluid, wherein a portion of the water in the formation fluid flows into the injection fluid by osmosis, whereby a portion of the hydrocarbon flows to the wellbore, and further wherein, if the formation is hydraulically fractured, the volume of aqueous injection fluid having a lower chemical potential than the aqueous fluid in the formation is greater than the volume of the hydraulic fracture plus the volume of any natural fractures contacted plus the volume leaked off during the hydraulic fracturing treatment.

14. The method of claim **13** wherein the injection fluid contacts at least one quarter of the practical wellbore drainage volume.

15. The method of claim **13** wherein injection is performed in different places in the formation.

16. The method of claim **13** wherein the period of injection is followed by a period of production without injection.

17. The method of claim **16** wherein the period of production without injection is followed by a second period of injection.

18. The method of claim **13** further comprising injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane.

19. The method of claim **13** wherein the injection fluid comprises formate.

20. The method of claim **13** wherein the injection fluid further comprises an agent that increases the contact angle of the formation with water.

21. The method of claim **13** wherein the injection fluid further comprises an agent that decreases the contact angle of the formation with water.

22. The method of claim **13** wherein the osmotic pressure generates fractures in the formation.

23. The method of claim **13** wherein the formation is hydraulically fractured.

24. (canceled)

25. A method of producing hydrocarbon from a subterranean formation penetrated by a wellbore comprising injecting into the formation an aqueous injection fluid having the same chemical potential as the aqueous fluid in the formation, whereby no osmotic pressure gradient is created, and whereby a portion of the hydrocarbon flows to the wellbore.

26. The method of claim **25** wherein the injection fluid contacts at least one quarter of the practical wellbore drainage volume.

27. The method of claim **25** wherein injection is performed in different places in the formation.

28. The method of claim **25** wherein the period of injection is followed by a period of production without injection.

29. The method of claim **28** wherein the period of production without injection is followed by a second period of injection.

30. The method of claim **25** further comprising injecting a semipermeable-membrane forming material in an amount sufficient to form a semipermeable membrane.

31. The method of claim **25** wherein the injection fluid comprises formate.

32. The method of claim **25** wherein the injection fluid further comprises an agent that increases the contact angle of the formation with water.

33. The method of claim **25** wherein the injection fluid further comprises an agent that decreases the contact angle of the formation with water.

34. The method of claim **25** wherein osmotic pressure is used in a separate step to generate fractures in the formation.

35. The method of claim **25**, wherein the formation is hydraulically fractured.

36. The method of claim **35**, wherein the volume of injected fluid is at least the volume of the hydraulic fracture.

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