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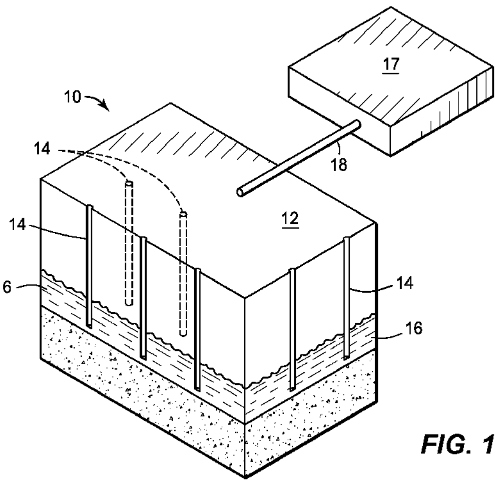

FIG. 1

(57) Abstract: A method for containing and capturing liquids and gases generated during in situ pyrolysis that migrate through pyrolysis generated or natural fractures includes placing a row of horizontal hydraulic fractures above and below the heated zone and completing production wells within the horizontal hydraulic fractures. The method serves at least two purposes: 1) provides a local zone of weak mechanical strength to blunt the propagation of vertical pyrolysis generated fractures and 2) provides a drainage point for fluids to relieve pressure in the formation and improve recovery. Preferably, the organic-rich rock formation is an oil shale formation.

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METHODS FOR CONTAINMENT AND IMPROVED RECOVERY IN HEATED HYDROCARBON CONTAINING FORMATIONS BY OPTIMAL PLACEMENT OF FRACTURES AND PRODUCTION WELLS

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims the priority benefit of U.S. Provisional Patent Application 61/642,807 filed 4 May 2012 entitled Methods For Containment and Improved Recovery in Heated Hydrocarbon Containing Formations By Optimal Placement of Fractures and Production Wells, the entirety of which is incorporated by reference herein.

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] The present invention relates to the field of hydrocarbon recovery from subsurface formations. More specifically, the present invention relates to the *in situ* recovery of hydrocarbon fluids from organic-rich rock formations, including, for example, oil shale formations, coal formations and tar sands formations.

Background of the Invention

[0003] Certain geological formations are known to contain an organic matter known as "kerogen." Kerogen is a solid, carbonaceous material. When kerogen is imbedded in rock formations, the mixture is referred to as oil shale. This is true whether or not the mineral is, in fact, technically shale, that is, a rock formed from compacted clay.

[0004] Kerogen is subject to decomposing upon exposure to heat over a period of time. Upon heating, kerogen molecularly decomposes to produce oil, gas, and carbonaceous coke. Small amounts of water may also be generated. The oil, gas and water fluids become mobile within the rock matrix, while the carbonaceous coke remains essentially immobile.

[0005] Oil shale formations are found in various areas world-wide, including the United States. Oil shale formations tend to reside at relatively shallow depths. In the United States, oil shale is most notably found in Wyoming, Colorado, and Utah. These U.S. formations are often characterized by limited permeability. A significant oil shale formation is also located in Jordan;

this formation is characterized by a higher permeability than the U.S. formations. Some consider oil shale formations to be hydrocarbon deposits which have not yet experienced the years of heat and pressure thought to be required to create conventional oil and gas reserves.

[0006] The decomposition rate of kerogen to produce mobile hydrocarbons is temperature dependent. Temperatures generally in excess of 270° C (518° F) over the course of many months may be required for substantial conversion. At higher temperatures substantial conversion may occur within shorter times. When kerogen is heated, chemical reactions break the larger molecules forming the solid kerogen into smaller molecules of oil and gas. The thermal conversion process is referred to as pyrolysis or retorting.

[0007] Attempts have been made for many years to extract oil from oil shale formations. Near-surface oil shales have been mined and retorted at the surface for over a century. In 1862, James Young began processing Scottish oil shales. The industry lasted for about 100 years. Commercial oil shale retorting through surface mining has been conducted in other countries as well such as Australia, Brazil, China, Estonia, France, Russia, South Africa, Spain, and Sweden. However, the practice has been mostly discontinued in recent years because it proved to be uneconomical or because of environmental constraints on spent shale disposal. (See T.F. Yen, and G.V. Chilingarian, "Oil Shale," Amsterdam, Elsevier, p. 292, the entire disclosure of which is incorporated herein by reference.) Further, surface retorting requires mining of the oil shale, which limits application to very shallow formations.

[0008] In the United States, the existence of oil shale deposits in northwestern Colorado has been known since the early 1900's. While research projects have been conducted in this area from time to time, no serious commercial development has been undertaken. Most research on oil shale production has been carried out in the latter half of the 1900's. The majority of this research was on shale oil geology, geochemistry, and retorting in surface facilities.

[0009] In 1947, U.S. Pat. No. 2,732,195 issued to Ljungstrom. That patent, entitled "Method of Treating Oil Shale and Recovery of Oil and Other Mineral Products Therefrom," proposed the application of heat at high temperatures to the oil shale formation *in situ* to distill and produce hydrocarbons. The '195 Ljungstrom patent is incorporated herein by reference.

[0010] Ljungstrom coined the phrase "heat supply channels" to describe bore holes drilled into the formation. The bore holes received an electrical heat conductor which transferred heat to the surrounding oil shale. Thus, the heat supply channels served as heat injection wells. The electrical heating elements in the heat injection wells were placed within sand or cement or other heat-conductive material to permit the heat injection wells to transmit heat into the surrounding oil shale while preventing the inflow of fluid. According to Ljungstrom, the "aggregate" was heated to between 500° and 1,000° C in some applications.

[0011] Along with the heat injection wells, fluid producing wells were also completed in near proximity to the heat injection wells. As kerogen was pyrolyzed upon heat conduction into the rock matrix, the resulting oil and gas would be recovered through the adjacent production wells.

[0012] Ljungstrom applied his approach of thermal conduction from heated wellbores through the Swedish Shale Oil Company. A full scale plant was developed that operated from 1944 into the 1950's. (See G. Salamonsson, "*The Ljungstrom In Situ Method for Shale-Oil Recovery*," 2nd Oil Shale and Cannel Coal Conference, v. 2, Glasgow, Scotland, Institute of Petroleum, London, p. 260-280 (1951), the entire disclosure of which is incorporated herein by reference.

[0013] Additional *in situ* methods have been proposed. These methods generally involve the injection of heat and/or solvent into a subsurface oil shale. Heat may be in the form of heated methane (see U.S. Pat. No. 3,241,611 to J.L. Dougan), flue gas, or superheated steam (see U.S. Pat. No. 3,400,762 to D.W. Peacock). Heat may also be in the form of electric resistive heating, dielectric heating, radio frequency (RF) heating (U.S. Pat. No. 4,140,180, assigned to the ITT Research Institute in Chicago, Illinois) or oxidant injection to support *in situ* combustion. In some instances, artificial permeability has been created in the matrix to aid the movement of pyrolyzed fluids. Permeability generation methods include mining, rubblization, hydraulic fracturing (see U.S. Pat. No. 3,468,376 to M.L. Slusser and U.S. Pat. No. 3,513,914 to J. V. Vogel), explosive fracturing (see U.S. Pat. No. 1,422,204 to W. W. Hoover, *et al.*), heat fracturing (see U.S. Pat. No. 3,284,281 to R.W. Thomas), and steam fracturing (see U.S. Pat. No. 2,952,450 to H. Purre)

[0014] In 1989, U.S. Pat. No. 4,886,118 issued to Shell Oil Company, the entire disclosure of which is incorporated herein by reference. That patent, entitled "Conductively Heating a

Subterranean Oil Shale to Create Permeability and Subsequently Produce Oil," declared that "[c]ontrary to the implications of . . . prior teachings and beliefs ... the presently described conductive heating process is economically feasible for use even in a substantially impermeable subterranean oil shale." (col. 6, ln. 50-54). Despite this declaration, it is noted that few, if any, commercial *in situ* shale oil operations have occurred other than Ljungstrom's application. The '118 patent proposed controlling the rate of heat conduction within the rock surrounding each heat injection well to provide a uniform heat front.

[0015] Additional history behind oil shale retorting and shale oil recovery can be found in co-owned patent publication WO 2005/010320 entitled "Methods of Treating a Subterranean Formation to Convert Organic Matter into Producible Hydrocarbons," and in patent publication WO 2005/045192 entitled "Hydrocarbon Recovery from Impermeable Oil Shales." The Background and technical disclosures of these two patent publications are incorporated herein by reference.

[0016] *In situ* oil shale processes involve heating a rock formation to pyrolysis temperatures to convert kerogen in the oil shale to oil and gas products. Containment of generated fluids in *in situ* oil shale conversion processes is critical for preventing contamination of sensitive areas and improving oil recovery. Fluids can migrate from the heated zone through generated and natural fractures. Fractures can be generated from thermal gradients that develop in the rock formation from the heating process that create tensile stress zones, thereby facilitating the initiation of fractures. Fractures can also be generated or propagated by increases in pore pressure in the system from the generated fluids. Porous and permeable overburden and underburden rocks can also facilitate the migration of generated fluids from the heated zone and into sensitive areas, such as aquifers. Thus, it becomes critical to develop methods to contain the fractures to prevent contamination of sensitive areas and to improve product recovery.

[0017] A need exists for improved processes for the production of shale oil. In addition, a need exists for an improved method of increasing shale oil recovery and to prevent contamination of sensitive areas.

SUMMARY OF THE INVENTION

[0018] In one embodiment, the invention provides a method for producing hydrocarbon fluids from an organic-rich rock formation. Preferably, the organic rich rock formation comprises solid hydrocarbons. More preferably, the organic rich rock formation is an oil shale formation.

[0019] An embodiment of this invention is a method for containing and capturing liquids and gases generated during *in situ* pyrolysis that migrate through pyrolysis generated or natural fractures. The pyrolysis generated fractures can be horizontal or vertical depending on the heater configuration, *in situ* stress state, reservoir properties, and other factors. In shallow reservoirs, vertical fractures can be created and propagate to the surface and/or to the underburden / overburden, potentially creating a pathway for the contamination of the surface and aquifers. This method involves placing a row of horizontal hydraulic fractures above and below the heated zone and completing production wells within the horizontal hydraulic fractures. The method serves at least two purposes: 1) provides a local zone of weak mechanical strength to blunt the propagation of vertical pyrolysis generated fractures and 2) provides a drainage point for fluids to relieve pressure in the formation and improve recovery.

[0020] As an additional step, a proppant material may be introduced into one or more of the hydraulic fractures. As yet an additional step, hydrocarbons fluids may be produced from the production well.

BRIEF DESCRIPTION OF THE DRAWINGS

[0021] So that the manner in which the features of the present invention can be better understood, certain drawings, graphs and flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[0022] Figure 1 is a cross-sectional view of an illustrative subsurface area. The subsurface area includes an organic-rich rock matrix that defines a subsurface formation.

[0023] Figure 2 is a cross-sectional view of an illustrative subsurface area. The subsurface area includes a heated zone in an organic-rich rock matrix and illustrates vertical fractures originating from the heated zone.

[0024] Figure 3 is a cross-sectional view of the illustrative subsurface area of Figure 2 in which horizontal hydraulic fractures have been created above and below the heated zone.

[0025] Figure 4 is a flow chart demonstrating a general method of *in situ* thermal recovery of oil and gas from an organic-rich rock formation, in one embodiment.

[0026] Figure 5 is a graph illustrating vertical normal stress as a function of distance from a heater in a thermal-mechanical simulation.

[0027] Figure 6 is thermal-mechanical simulation indicating tensile stress zones of a core sample with a planar heater.

[0028] Figure 7 is a cross-section showing induced thermal fractures in a core sample with a planar heater.

DETAILED DESCRIPTION OF CERTAIN EMBODIMENTS

Definitions

[0029] As used herein, the term "hydrocarbon(s)" refers to organic material with molecular structures containing carbon bonded to hydrogen. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur.

[0030] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions or at ambient conditions (15° C and 1 atm pressure). Hydrocarbon fluids may include, for example, oil, natural gas, coalbed methane, shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

[0031] As used herein, the terms "produced fluids" and "production fluids" refer to liquids and/or gases removed from a subsurface formation, including, for example, an organic-rich rock formation. Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids. Production fluids may include, but are not limited to, pyrolyzed shale oil, synthesis gas, a pyrolysis product of coal, carbon dioxide, hydrogen sulfide and water (including steam). Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids.

[0032] As used herein, the term "condensable hydrocarbons" means those hydrocarbons that condense at 25° C and one atmosphere absolute pressure. Condensable hydrocarbons may include a mixture of hydrocarbons having carbon numbers greater than 4.

[0033] As used herein, the term "non-condensable hydrocarbons" means those hydrocarbons that do not condense at 25° C and one atmosphere absolute pressure. Non-condensable hydrocarbons may include hydrocarbons having carbon numbers less than 5.

[0034] As used herein, the term "heavy hydrocarbons" refers to hydrocarbon fluids that are highly viscous at ambient conditions (15° C and 1 atm pressure). Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20 degrees. Heavy oil, for example, generally has an API gravity of about 10-20 degrees, whereas tar generally has an API gravity below about 10 degrees. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15° C.

[0035] As used herein, the term "solid hydrocarbons" refers to any hydrocarbon material that is found naturally in substantially solid form at formation conditions. Non-limiting examples include kerogen, coal, shungites, asphaltites, and natural mineral waxes.

[0036] As used herein, the term "formation hydrocarbons" refers to both heavy hydrocarbons and solid hydrocarbons that are contained in an organic-rich rock formation. Formation hydrocarbons may be, but are not limited to, kerogen, oil shale, coal, bitumen, tar, natural mineral waxes, and asphaltites.

[0037] As used herein, the term "tar" refers to a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15° C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10 degrees. “Tar sands” refers to a formation that has tar in it.

[0038] As used herein, the term "kerogen" refers to a solid, insoluble hydrocarbon that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Oil shale contains kerogen.

[0039] As used herein, the term "bitumen" refers to a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide.

[0040] As used herein, the term "oil" refers to a hydrocarbon fluid containing a mixture of condensable hydrocarbons.

[0041] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[0042] As used herein, the term “hydrocarbon-rich formation” refers to any formation that contains more than trace amounts of hydrocarbons. For example, a hydrocarbon-rich formation may include portions that contain hydrocarbons at a level of greater than 5 volume percent. The hydrocarbons located in a hydrocarbon-rich formation may include, for example, oil, natural gas, heavy hydrocarbons, and solid hydrocarbons.

[0043] As used herein, the term “organic-rich rock” refers to any rock matrix holding solid hydrocarbons and/or heavy hydrocarbons. Rock matrices may include, but are not limited to, sedimentary rocks, shales, siltstones, sands, silicilytes, carbonates, and diatomites.

[0044] As used herein, the term "formation" refers to any finite subsurface region. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any subsurface geologic formation. An "overburden" and/or an "underburden" is geological material above or below the formation of interest. An overburden or underburden may include one or more different types of substantially impermeable materials. For example, overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate (i.e., an impermeable carbonate without hydrocarbons). An overburden and/or an underburden may include a hydrocarbon-containing layer that is relatively impermeable. In some cases, the overburden and/or underburden may be permeable.

[0045] As used herein, the term “organic-rich rock formation” refers to any formation containing organic-rich rock. Organic-rich rock formations include, for example, oil shale formations, coal formations, and tar sands formations.

[0046] As used herein, the term "pyrolysis" refers to the breaking of chemical bonds through the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone or by heat in combination with an oxidant. Pyrolysis may include modifying the nature of the compound by addition of hydrogen atoms which may be obtained from molecular hydrogen, water, carbon dioxide, or carbon monoxide. Heat may be transferred to a section of the formation to cause pyrolysis.

[0047] As used herein, the term "water-soluble minerals" refers to minerals that are soluble in water. Water-soluble minerals include, for example, nahcolite (sodium bicarbonate), soda ash (sodium carbonate), dawsonite ($NaAl(CO_3)(OH)_2$), or combinations thereof. Substantial solubility may require heated water and/or a non-neutral pH solution.

[0048] As used herein, the term "formation water-soluble minerals" refers to water-soluble minerals that are found naturally in a formation.

[0049] As used herein, the term "migratory contaminant species" refers to species that are both soluble and moveable in water or an aqueous fluid, and are considered to be potentially harmful or of concern to human health or the environment. Migratory contaminant species may include inorganic and organic contaminants. Organic contaminants may include saturated hydrocarbons, aromatic hydrocarbons, and oxygenated hydrocarbons. Inorganic contaminants may include metal contaminants, and ionic contaminants of various types that may significantly alter pH or the formation fluid chemistry. Aromatic hydrocarbons may include, for example, benzene, toluene, xylene, ethylbenzene, and tri-methylbenzene, and various types of polyaromatic hydrocarbons such as anthracenes, naphthalenes, chrysenes and pyrenes. Oxygenated hydrocarbons may include, for example, alcohols, ketones, phenols, and organic acids such as carboxylic acid. Metal contaminants may include, for example, arsenic, boron, chromium, cobalt, molybdenum, mercury, selenium, lead, vanadium, nickel or zinc. Ionic contaminants include, for example, sulfides, sulfates, chlorides, fluorides, ammonia, nitrates, calcium, iron, magnesium, potassium, lithium, boron, and strontium.

[0050] As used herein, the term "cracking" refers to a process involving decomposition and molecular recombination of organic compounds to produce a greater number of molecules than were initially present. In cracking, a series of reactions take place accompanied by a transfer of hydrogen atoms between molecules. For example, naphtha may undergo a thermal cracking reaction to form ethene and H_2 among other molecules.

[0051] As used herein, the term "sequestration" refers to the storing of a fluid that is a by-product of a process rather than discharging the fluid to the atmosphere or open environment.

[0052] As used herein, the term "subsidence" refers to a downward movement of a surface relative to an initial elevation of the surface.

[0053] As used herein, the term "thickness" of a layer refers to the distance between the upper and lower boundaries of a cross section of a layer, wherein the distance is measured normal to the average tilt of the cross section.

[0054] As used herein, the term "thermal fracture" refers to fractures created in a formation caused directly or indirectly by expansion or contraction of a portion of the formation and/or fluids within the formation, which in turn is caused by increasing/decreasing the temperature of the formation and/or fluids within the formation, and/or by increasing/decreasing a pressure of fluids within the formation due to heating. Thermal fractures may propagate into or form in neighboring regions significantly cooler than the heated zone.

[0055] As used herein, the term "hydraulic fracture" refers to a fracture at least partially propagated into a formation, wherein the fracture is created through injection of pressurized fluids into the formation. The fracture may be artificially held open by injection of a proppant material. Hydraulic fractures may be substantially horizontal in orientation, substantially vertical in orientation, or oriented along any other plane.

[0056] As used herein, the term, “underburden” refers to the sediments or earth materials underlying the formation containing one or more hydrocarbon-bearing zones.

[0057] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shapes (e.g., circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes). As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

Description of Specific Embodiments

[0058] The inventions are described herein in connection with certain specific embodiments. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use, such is intended to be illustrative only and is not to be construed as limiting the scope of the invention.

[0059] As discussed herein, some embodiments of the invention include or have application related to an *in situ* method of recovering natural resources. The natural resources may be recovered from an organic-rich rock formation, including, for example, an oil shale formation. The organic-rich rock formation may include formation hydrocarbons, including, for example, kerogen, coal, and heavy hydrocarbons. In some embodiments of the invention the natural resources may include hydrocarbon fluids, including, for example, products of the pyrolysis of formation hydrocarbons such as oil shale. In some embodiments of the invention the natural resources may also include water-soluble minerals, including, for example, nahcolite (sodium bicarbonate, or $2NaHCO_3$), soda ash (sodium carbonate, or Na_2CO_3) and dawsonite ($NaAl(CO_3)(OH)_2$).

[0060] An embodiment of this invention is a method for containing and capturing liquids and gases generated during *in situ* pyrolysis that migrate through pyrolysis generated or natural fractures. The pyrolysis generated fractures can be horizontal or vertical depending on the heater configuration, *in situ* stress state, reservoir properties, and other factors. In shallow reservoirs, vertical fractures can be created and propagate to the surface and/or to the underburden / overburden, potentially creating a pathway for the contamination of the surface and aquifers. This method involves placing a row of horizontal hydraulic fractures above and below the heated zone and completing production wells within the horizontal hydraulic fractures. The method serves at least two purposes: 1) provides a local zone of weak mechanical strength to blunt the propagation of vertical pyrolysis generated fractures and 2) provides a drainage point for fluids to relieve pressure in the formation and improve recovery. A proppant material may be introduced into the one or more hydraulic fractures.

[0061] The depth of the hydrocarbon containing formation plays a role in the containment strategy. In shallow reservoirs, such as oil shale reservoirs in Jordan and Rundle, Australia, the in situ stress state will favor the creation of horizontal fractures for containment. In deep reservoirs, such as the Piceance Basin, Colorado, the stress state will favor the creation of vertical fractures. Vertical fractures would not be ideal for containment as the areal coverage would be limited. Instead, containment should involve conventional methods to produce horizontal fractures in stress states favoring vertical fractures, discussed in patent U.S. Patent No. 3,613,785 and incorporated by reference herein. An alternative method would be to drill a horizontal production well and notch and/or perforate from the horizontal well, as is known to one of ordinary skill in the art, and thereby create a number of cavities that may intersect the pyrolysis generated or natural fractures and serve to blunt their propagation and/or provide a drainage point for production of produced hydrocarbons.

[0062] The geology of the over- and underburden to the *in situ* pyrolysis can also be taken into account by choosing a stratigraphic interval that aids in the containment. For example, the presence of relatively impermeable layers, such as, for example shales, chert and basalt, that are just above the fractured horizon will help to confine the fluid in the pyrolysis generated and/or natural fracture(s). This confinement will act in concert with production wells by limiting the ability of the liquids and gases to migrate out of the production zone as they move toward the producing well.

[0063] Sections of the stratigraphy might also be selected to optimize the process of horizontal fracturing. This could be done by selecting a horizon for fracturing that has a lithologic contact between a relatively strong and weak rock types such as chert and clay-rich mudstone. Alternatively, the hydraulic fractures might be placed along a horizon that represents a substantial hiatus in deposition and therefore limited mechanical bonding between the rock packages above and below the hiatus.

[0064] Choosing an optimal lithologic setting can also be helpful when a horizontal hydraulic fracture is to be generated in a stress state were vertical fractures are favored. It is possible to define settings that would respond favorably to either notching or perforating efforts to create the horizontal barrier. For example, notching geometry could be improved by initiating the notch in a layer of rock that is readily notched (e.g., a weakly cemented sandstone) but is bounded by layers that resist notching (e.g., a carbonate mudstone).

[0065] Figure 1 presents a perspective view of an illustrative oil shale development area 10. A surface 12 of the development area 10 is indicated. Below the surface is an organic-rich rock formation 16. The illustrative subsurface formation 16 contains formation hydrocarbons (such as, for example, kerogen) and possibly valuable water-soluble minerals (such as, for example, nahcolite). It is understood that the representative formation 16 may be any organic-rich rock formation, including a rock matrix containing coal or tar sands, for example. In addition, the rock matrix making up the formation 16 may be permeable, semi-permeable or non-permeable. The present inventions are particularly advantageous in oil shale development areas initially having very limited or effectively no fluid permeability.

[0066] In order to access formation 16 and recover natural resources therefrom, a plurality of wellbores is formed. Wellbores are shown at 14 in Figure 1. The representative wellbores 14 are essentially vertical in orientation relative to the surface 12. However, it is understood that some or all of the wellbores 14 could deviate into an obtuse or even horizontal orientation. In the arrangement of Figure 1, each of the wellbores 14 is completed in the oil shale formation 16. The completions may be either open or cased hole. The well completions may also include propped or unpropped hydraulic fractures emanating therefrom.

[0067] In the view of Figure 1, only seven wellbores 14 are shown. However, it is understood that in an oil shale development project, numerous additional wellbores 14 will most likely be drilled. The wellbores 14 may be located in relatively close proximity, being from 10 feet to up to 300 feet in separation. In some embodiments, a well spacing of 15 to 25 feet is provided. Typically, the wellbores 14 are also completed at shallow depths, being from 200 to 5,000 feet at total depth. In some embodiments the oil shale formation targeted for *in situ* retorting is at a depth greater than 200 feet below the surface or alternatively 400 feet below the surface. Alternatively, conversion and production of an oil shale formation may occur at depths between 500 and 2,500 feet.

[0068] The wellbores 14 will be selected for certain functions and may be designated as heat injection wells, water injection wells, oil production wells and/or water-soluble mineral solution production wells. In one aspect, the wellbores 14 are dimensioned to serve two, three, or all four of these purposes. Suitable tools and equipment may be sequentially run into and removed from the wellbores 14 to serve the various purposes.

[0069] A fluid processing facility 17 is also shown schematically. The fluid processing facility 17 is equipped to receive fluids produced from the organic-rich rock formation 16 through one or more pipelines or flow lines 18. The fluid processing facility 17 may include equipment suitable for receiving and separating oil, gas, and water produced from the heated formation. The fluid processing facility 17 may further include equipment for separating out dissolved water-soluble minerals and/or migratory contaminant species, including, for example, dissolved organic contaminants, metal contaminants, or ionic contaminants in the produced water recovered from the organic-rich rock formation 16. The contaminants may include, for example, aromatic hydrocarbons such as benzene, toluene, xylene, and tri-methylbenzene. The contaminants may also include polyaromatic hydrocarbons such as anthracene, naphthalene, chrysene and pyrene. Metal contaminants may include species containing arsenic, boron, chromium, mercury, selenium, lead, vanadium, nickel, cobalt, molybdenum, or zinc. Ionic contaminant species may include, for example, sulfates, chlorides, fluorides, lithium, potassium, aluminum, ammonia, and nitrates.

[0070] Referring to Figures 2 and 3, illustrated is an exemplary embodiment of hydrocarbon development area 200 containing formation 202 comprising an *in situ* heated zone 204. The heated zone 204 may be heated by any type of *in situ* heating method, such as planar electric resistive heaters, wellbore heaters, in situ combustion, electric resistive heaters, etc., which may collectively be referred to as heat injection wells. The *in situ* heating of the hydrocarbon containing formation 202 has generated vertical fractures 206 that extend through the hydrocarbon containing formation and into the underburden 208 and overburden 210. The generated vertical fractures 206 nearly extend into an aquifer 212 that is located below the underburden 208.

[0071] Referring to Figure 3, illustrated is an exemplary embodiment of the invention in which horizontal hydraulic fractures 214 and 216 have been created in the overburden 210 and underburden 208, respectively. Horizontal hydraulic fractures 214 in the overburden 210 are shown in this embodiment to be created with vertical wellbores 218. The hydraulic fractures 214 may be created with other wellbore arrangements, including a single vertical wellbore, or with the use of a deviated or horizontal wellbore. Horizontal hydraulic fractures 216 in the underburden 208 are shown in this embodiment to be created with horizontal wellbore 220, which in this embodiment allows the vertical portion 222 of the horizontal wellbore 220 to be placed outside of the heated zone 204. After wellbores 218 and 220 create the horizontal hydraulic fractures, the wellbores may later be used as production wells to produce hydrocarbon fluids that have traveled through the generated vertical fractures 206 to reach the horizontal hydraulic fractures. This method of creating horizontal hydraulic fractures in the overburden and/or underburden to intersect the generated vertical fractures serves at least two purposes: 1) provides a local zone of weak mechanical strength to blunt the propagation of vertical pyrolysis generated fractures so that the vertical fractures do not reach an aquifer, the surface, or other environmentally sensitive area; and 2) provides a drainage point for fluids to relieve pressure in the formation and improve recovery. A proppant material may be introduced into the one or more hydraulic fractures.

[0072] In other embodiments, the hydraulic fractures 216 may be created with other wellbore arrangements, including a single vertical wellbore, or with the use of a deviated or horizontal wellbore. For example, the hydraulic fractures in the underburden could be created with vertical wellbores before the creation of a heated zone, and then one or more of the vertical wellbores that were used to create the hydraulic fractures could be converted to either a producing well or a heater well. Furthermore, although the horizontal fractures are indicated to be in the overburden and/or the underburden, horizontal fractures could be placed either alternatively or in addition to, in the hydrocarbon containing formation, such as in an oil shale formation. In addition, in some embodiments of the invention, it may be desirable to place hydraulic vertical fractures to intersect possible horizontal or vertical heat or pyrolysis generated fractures.

[0073] In order to recover oil, gas, and sodium (or other) water-soluble minerals, a series of steps may be undertaken. Figure 4 presents a flow chart demonstrating a method of *in situ* thermal recovery of oil and gas from an organic-rich rock formation 400, in one embodiment. It is understood that the order of some of the steps from Figure 4 may be changed, and that the sequence of steps is merely for illustration. For convenience, use of some of the terminology and reference numerals from Figure 1 is provided in the following discussion.

[0074] First, the oil shale (or other organic-rich rock) formation 16 is identified within the development area 10. This step is shown in box 410. Optionally, the oil shale formation may contain nahcolite or other sodium minerals. The targeted development area within the oil shale formation may be identified by measuring or modeling the depth, thickness and organic richness of the oil shale as well as evaluating the position of the organic-rich rock formation relative to other rock types, structural features (e.g. faults, anticlines or synclines), or hydrogeological units (i.e. aquifers). This is accomplished by creating and interpreting maps and/or models of depth, thickness, organic richness and other data from available tests and sources. This may involve performing geological surface surveys, studying outcrops, performing seismic surveys, and/or drilling boreholes to obtain core samples from subsurface rock. Rock samples may be analyzed to assess kerogen content and fluid hydrocarbon-generating capability.

[0075] Based on the above study of the geology of the oil shale formation and the overlying and underlying formations, the optimal placement of the hydraulic fractures may be determined. For example, determining the optimal placement of the hydraulic fractures may be based on the anticipated extent of the heat or pyrolysis generated fractures. This step is shown in box 412.

[0076] The kerogen content of the organic-rich rock formation may be ascertained from outcrop or core samples using a variety of data. Such data may include organic carbon content, hydrogen index, and modified Fischer assay analyses. Subsurface permeability may also be assessed via rock samples, outcrops, or studies of ground water flow. Furthermore, the connectivity of the development area to ground water sources may be assessed.

[0077] Next, a plurality of wellbores 14 is formed across the targeted development area 10. This step is shown schematically in box 415. The purposes of the wellbores 14 are set forth above and need not be repeated. However, it is noted that for purposes of the wellbore formation step of box 415, only a portion of the wells need be completed initially. For instance, at the beginning of the project heat injection wells are needed, while a majority of the hydrocarbon production wells are not yet needed. It may be desirable to also establish the hydraulic fractures prior to heating the formation. Production wells may be brought in once conversion begins, such as after 4 to 12 months of heating.

[0078] It is understood that petroleum engineers will develop a strategy for the best depth and arrangement for the wellbores 14, depending upon anticipated reservoir characteristics, economic constraints, and work scheduling constraints. In addition, engineering staff will determine what wellbores 14 shall be used for initial formation 16 heating. This selection step is represented by box 420.

[0079] Concerning heat injection wells, there are various methods for applying heat to the organic-rich rock formation 16. The present methods are not limited to the heating technique employed unless specifically so stated in the claims. The heating step is represented generally by box 430. Preferably, for *in situ* processes the heating of a production zone takes place over a period of months, or even four or more years.

[0080] The formation 16 is heated to a temperature sufficient to pyrolyze at least a portion of the oil shale in order to convert the kerogen to hydrocarbon fluids. The bulk of the target zone of the formation may be heated to between 270° C to 800° C. Alternatively, the targeted volume of the organic-rich formation is heated to at least 350° C to create production fluids. The conversion step is represented in Figure 4 by box 435. The resulting liquids and hydrocarbon gases may be refined into products which resemble common commercial petroleum products. Such liquid products include transportation fuels such as diesel, jet fuel and naptha. Generated gases include light alkanes, light alkenes, H_2, CO_2, CO, and NH_3.

[0081] Conversion of the oil shale will create permeability in the oil shale section in rocks that were originally impermeable. Preferably, the heating and conversion processes of boxes 430 and 435, occur over a lengthy period of time. In one aspect, the heating period is from three months to four or more years. Also, as an optional part of box 435 the formation 16 may be heated to a temperature sufficient to convert at least a portion of nahcolite, if present, to soda ash. Heat applied to mature the oil shale and recover oil and gas will also convert nahcolite to sodium carbonate (soda ash), a related sodium mineral.

[0082] In connection with the heating step 430, the rock formation 16 may create vertical and/or horizontal fractures that may aid heat transfer or later hydrocarbon fluid production. As mentioned above, these heat or pyrolysis generated fractures may also aid in the transportation of contaminants to the surface or to aquifers in the underburden and/or overburden. In order to prevent the heat or pyrolysis generated vertical fractures from providing a pathway to the surface or to aquifers in the underburden and/or overburden, a hydraulic fracturing step provides horizontal fractures that will intersect the heat or pyrolysis generated vertical fractures before the vertical fractures reach an aquifer or the surface. This hydraulic fracturing step is shown in box 425. Hydraulic fracturing is a process known in the art of oil and gas recovery where a fracture fluid is pressurized within the wellbore above the fracture pressure of the formation, thus developing fracture planes within the formation to relieve the pressure generated within the wellbore. This method of creating horizontal hydraulic fractures in the hydrocarbon containing formation, the overburden and/or the underburden, to intersect the generated vertical fractures serves at least two purposes: 1) the horizontal hydraulic fractures provide a local zone of weak mechanical strength to blunt the propagation of vertical pyrolysis generated fractures so that the vertical fractures do not reach an aquifer, the surface, or other environmentally sensitive area; and 2) the horizontal hydraulic fractures provide a drainage point for fluids to relieve pressure in the formation and improve recovery.

[0083] Pyrolysis or heat generated fracturing may be accomplished by creating thermal fractures within the formation through application of heat. By heating the organic-rich rock and transforming the kerogen to oil and gas, the permeability is increased via thermal fracture formation and subsequent production of a portion of the hydrocarbon fluids generated from the kerogen.

[0084] As part of the hydrocarbon fluid production process 400, certain wells 14 may be designated as oil and gas production wells. This step is depicted by box 440. Oil and gas production might not be initiated until it is determined that the kerogen has been sufficiently retorted to allow maximum recovery of oil and gas from the formation 16. In some instances, dedicated production wells are not drilled until after heat injection wells (box 430) have been in operation for a period of several weeks or months. Thus, box 440 may include the formation of additional wellbores 14. In other instances, selected heater wells or hydraulic fracturing wells are converted to production wells.

[0085] After certain wellbores 14 have been designated as oil and gas production wells, oil and/or gas is produced from the wellbores 14. The oil and/or gas production process is shown at box 445. At this stage (box 445), any water-soluble minerals, such as nahcolite and converted soda ash may remain substantially trapped in the rock formation 16 as finely disseminated crystals or nodules within the oil shale beds, and are not produced. However, some nahcolite and/or soda ash may be dissolved in the water created during heat conversion (box 435) within the formation.

[0086] Box 450 presents an optional next step in the oil and gas recovery method 400. Here, certain wellbores 14 are designated as water or aqueous fluid injection wells. Aqueous fluids are solutions of water with other species. The water may constitute "brine," and may include dissolved inorganic salts of chloride, sulfates and carbonates of Group I and II elements of The Periodic Table of Elements. Organic salts can also be present in the aqueous fluid. The water may alternatively be fresh water containing other species. The other species may be present to alter the pH. Alternatively, the other species may reflect the availability of brackish water not saturated in the species wished to be leached from the subsurface. Preferably, the water injection wells are selected from some or all of the wellbores used for heat injection or for oil and/or gas production. However, the scope of the step of box 450 may include the drilling of yet additional wellbores 14 for use as dedicated water injection wells. In this respect, it may be desirable to complete water injection wells along a periphery of the development area 10 in order to create a boundary of high pressure.

[0087] Next, optionally water or an aqueous fluid is injected through the water injection wells and into the oil shale formation 16. This step is shown at box 455. The water may be in the form of steam or pressurized hot water. Alternatively the injected water may be cool and becomes heated as it contacts the previously heated formation. The injection process may further induce fracturing. This process may create fingered caverns and brecciated zones in the nahcolite-bearing intervals some distance, for example up to 200 feet out, from the water injection wellbores. In one aspect, a gas cap, such as nitrogen, may be maintained at the top of each "cavern" to prevent vertical growth.

[0088] Along with the designation of certain wellbores 14 as water injection wells, the design engineers may also designate certain wellbores 14 as water or water-soluble mineral solution production wells. This step is shown in box 460. These wells may be the same as wells used to previously produce hydrocarbons or inject heat. These recovery wells may be used to produce an aqueous solution of dissolved water-soluble minerals and other species, including, for example, migratory contaminant species. For example, the solution may be one primarily of dissolved soda ash. This step is shown in box 465. Alternatively, single wellbores may be used to both inject water and then to recover a sodium mineral solution. Thus, box 465 includes the option of using the same wellbores 14 for both water injection and solution production (box 465).

[0089] In connection with heating the organic-rich rock formation, the organic-rich rock formation may fracture naturally by creating thermal fractures within the formation through application of heat. Thermal fracture formation is caused by thermal expansion of the rock and fluids and by chemical expansion of kerogen transforming into oil and gas. Thermal fracturing can occur both in the immediate region undergoing heating, and in cooler neighboring regions. The thermal fracturing in the neighboring regions is due to propagation of fractures and tension stresses developed due to the expansion in the hotter zones. Thus, by both heating the organic-rich rock and transforming the kerogen to oil and gas, the permeability is increased not only from fluid formation and vaporization, but also via thermal fracture formation. The increased permeability aids fluid flow within the formation and production of the hydrocarbon fluids generated from the kerogen.

[0090] In addition, pressure generated by expansion of pyrolysis fluids or other fluids generated in the formation may increase to or above a lithostatic stress. In this instance, fractures in the hydrocarbon containing formation may form when the fluid pressure equals or exceeds the lithostatic stress. For example, fractures may form from a heater well to a production well. The generation of fractures within the heated portion may reduce pressure within the portion due to the production of produced fluids through a production well.

[0091] The generated fractures can be horizontal or vertical depending on the heater configuration, *in situ* stress state, rock properties (flow and mechanical), and other factors. Figure 5 illustrates the results of a thermal-mechanical simulation of a planar heater conducted in CMG STARS in the graph 500. The graph 500 has on the x-axis 502 the distance in feet from the planar heater. On the y-axis 504 is the vertical normal stress in pounds per square inch (psi). In this simulation, the baseline vertical normal stress 506, on day zero without any heating is approximately 300 psi at the location of the heater and is constant as the distance extends away from the heater. After heating for 15 days, line 508 indicates that the vertical normal stress near the heater has increased, but as the distance from the heater approaches ten feet and up to fifteen feet from the heater there is a tensile stress zone, or zone of negative normal stress. Tensile stress zones, the negative vertical normal stresses indicated in zone 510, develop as a result of the thermal gradient between the heated area and the cold, unconverted rock. Because the thermal front will continue to move with time, the tensile stress zone also moves, thereby providing a means to initiate and propagate fractures. Line 512 represents the stress state after 30 days of heating, after which the tensile stress zone has extended to over 20 feet from the heater. Line 514 represents the stress state after 45 days of heating, after which the tensile stress zone has extended to approximately 30 feet from the heater.

[0092] Figures 6 and 7 illustrate a validation of the CMG STARS models through core experiments. Figure 6 illustrates a simulation 600 in CMG STARS of a core sample 602 with a planar heater 604 located in the center of the core sample 602. The simulation 600 predicted tensile stress zones 606 located to the right and left of the planar heater 604 as indicated in the Figure. The simulation 600 predicted tensile stress zones 606 that are large enough to develop fractures within these tensile stress zones 606 and in which the fractures would be oriented approximately perpendicular to the planar heater 604.

[0093] Figure 7 shows a core sample 700 in which a planar heater 702 was placed within the core sample 700. After heating to a sufficient temperature, fractures 704 were observed in the core sample 700 that were in accordance with the location of the fractures predicted in the simulation 600.

[0094] Temporary control of the migration of the migratory contaminant species, especially during the pyrolysis process, can be obtained via placement of the injection and production wells 14 such that fluid flow out of the heated zone is minimized. Typically, this involves placing injection wells at the periphery of the heated zone so as to cause pressure gradients which prevent flow inside the heated zone from leaving the zone.

[0095] As noted above, several different types of wells may be used in the development of an organic-rich rock formation, including, for example, an oil shale field. For example, the heating of the organic-rich rock formation may be accomplished through the use of heater wells. The heater wells may include, for example, electrical resistance heating elements. The production of hydrocarbon fluids from the formation may be accomplished through the use of wells completed for the production of fluids. The injection of an aqueous fluid may be accomplished through the use of injection wells. Finally, the production of an aqueous solution may be accomplished through use of solution production wells.

[0096] The different wells listed above may be used for more than one purpose. Stated another way, wells initially completed for one purpose may later be used for another purpose, thereby lowering project costs and/or decreasing the time required to perform certain tasks. For example, one or more of the production wells may also be used as injection wells for later injecting water into the organic-rich rock formation. Alternatively, one or more of the production wells may also be used as solution production wells for later producing an aqueous solution from the organic-rich rock formation.

[0097] In other aspects, production wells (and in some circumstances heater wells) may initially be used as dewatering wells (e.g., before heating is begun and/or when heating is initially started). In addition, in some circumstances dewatering wells can later be used as production wells (and in some circumstances heater wells). As such, the dewatering wells may be placed and/or designed so that such wells can be later used as production wells and/or heater wells. The heater wells may be placed and/or designed so that such wells can be later used as production wells and/or dewatering wells. The production wells may be placed and/or designed so that such wells can be later used as dewatering wells and/or heater wells. Similarly, injection wells may be wells that initially were used for other purposes (e.g., hydraulic fracturing, heating, production, dewatering, monitoring, etc.), and injection wells may later be used for other purposes. Similarly, monitoring wells may be wells that initially were used for other purposes (e.g., hydraulic fracturing, heating, production, dewatering, injection, etc.). Finally, monitoring wells may later be used for other purposes such as water production.

[0098] The wellbores for the various wells may be located in relatively close proximity, being from 10 feet to up to 300 feet in separation. Alternatively, the wellbores may be spaced from 30 to 200 feet or 50 to 100 feet. Typically, the wellbores are also completed at shallow depths, being from 200 to 5,000 feet at total depth. Alternatively, the wellbores may be completed at depths from 1,000 to 4,000 feet, or 1,500 to 3,500 feet. In some embodiments, the oil shale formation targeted for *in situ* retorting is at a depth greater than 200 feet below the surface. In alternative embodiments, the oil shale formation targeted for *in situ* retorting is at a depth greater than 500, 1,000, or 1,500 feet below the surface. In alternative embodiments, the oil shale formation targeted for *in situ* retorting is at a depth between 200 and 5,000 feet, alternatively between 1,000 and 4,000 feet, 1,200 and 3,700 feet, or 1,500 and 3,500 feet below the surface.

[0099] In connection with the development of an oil shale field, it may be desirable that the progression of heat through the subsurface in accordance with steps 430 and 435 be uniform. However, for various reasons the heating and maturation of formation hydrocarbons in a subsurface formation may not proceed uniformly despite a regular arrangement of heater and production wells. Heterogeneities in the oil shale properties and formation structure may cause certain local areas to be more or less productive. Moreover, formation fracturing which occurs due to the heating and maturation of the oil shale can lead to an uneven distribution of preferred pathways and, thus, increase flow to certain production wells and reduce flow to others. Uneven fluid maturation may be an undesirable condition since certain subsurface regions may receive more heat energy than necessary where other regions receive less than desired. This, in turn, leads to the uneven flow and recovery of production fluids. Produced oil quality, overall production rate, and/or ultimate recoveries may be reduced.

[0100] To detect uneven flow conditions, production and heater wells may be instrumented with sensors. Sensors may include equipment to measure temperature, pressure, flow rates, and/or compositional information. Data from these sensors can be processed via simple rules or input to detailed simulations to reach decisions on how to adjust heater and production wells to improve subsurface performance. Production well performance may be adjusted by controlling backpressure or throttling on the well. Heater well performance may also be adjusted by controlling energy input. Sensor readings may also sometimes imply mechanical problems with a well or downhole equipment which requires repair, replacement, or abandonment.

[0101] In one embodiment, flow rate, compositional, temperature and/or pressure data are utilized from two or more wells as inputs to a computer algorithm to control heating rate and/or production rates. Unmeasured conditions at or in the neighborhood of the well are then estimated and used to control the well. For example, *in situ* fracturing behavior and kerogen maturation are estimated based on thermal, flow, and compositional data from a set of wells. In another example, well integrity is evaluated based on pressure data, well temperature data, and estimated *in situ* stresses. In a related embodiment the number of sensors is reduced by equipping only a subset of the wells with instruments, and using the results to interpolate, calculate, or estimate conditions at uninstrumented wells. Certain wells may have only a limited set of sensors (e.g., wellhead temperature and pressure only) where others have a much larger set of sensors (e.g., wellhead temperature and pressure, bottomhole temperature and pressure, production composition, flow rate, electrical signature, casing strain, etc.).

[0102] Certain features of the present invention are described in terms of a set of numerical upper limits and a set of numerical lower limits. It should be appreciated that ranges formed by any combination of these limits are within the scope of the invention unless otherwise indicated. Although some of the dependent claims have single dependencies in accordance with U.S. practice, each of the features in any of such dependent claims can be combined with each of the features of one or more of the other dependent claims dependent upon the same independent claim or claims.

[0103] While it will be apparent that the invention herein described is well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the invention is susceptible to modification, variation and change without departing from the spirit thereof.

CLAIMS

What is claimed is:

1. A method for producing hydrocarbon fluids from an organic-rich rock formation, comprising:

completing at least one heater well in a heated zone in the organic-rich rock formation;

completing a production well;

heating the heated zone of the organic-rich rock formation from the at least one heater well, thereby pyrolyzing at least a portion of the organic-rich rock into hydrocarbon fluids and thereby creating thermal fractures in the organic-rich rock formation due to thermal stresses created by heating;

placing a barrier to decrease the propagation of the thermal fractures wherein placing the barrier comprises placing hydraulic horizontal fractures above and/or below the heated zone from the production well; and

producing hydrocarbon fluids from the production well.

2. The method of claim 1, wherein the organic-rich rock formation is an oil shale formation.

3. The method of claim 2, wherein the thermal fractures are substantially vertical.

4. The method of claim 2, further comprising:

performing geomechanical modeling to determine the direction and extent of thermal fractures.

5. The method of claim 2, wherein the step of hydraulically fracturing is performed before the step of heating the oil shale formation.

6. The method of claim 2, wherein the step of hydraulically fracturing is performed after the step of heating the oil shale formation has begun, but before the substantial formation of thermal fractures.

7. The method of claim 2, further comprising:

determining a distance from the production well in which to form the one or more hydraulic fractures in order to provide fluid communication with anticipated thermal fractures.

8. The method of claim 2, wherein the thermal fractures intersect at least one of the hydraulically fractures within one year of initiating heating.

9. The method of claim 2 wherein the step of heating results in at least a portion of the oil shale formation reaching a temperature of 270° C or greater.

10. The method of claim 2, further comprising introducing a proppant material into one or more of the hydraulic fractures.

11. The method of claim 2, wherein the hydraulic fractures are placed in the organic-rich rock formation.

12. The method of claim 2, wherein the hydraulic fractures are placed in a formation above or below the organic-rich rock formation.

13. The method of claim 2, wherein the production well is horizontal.

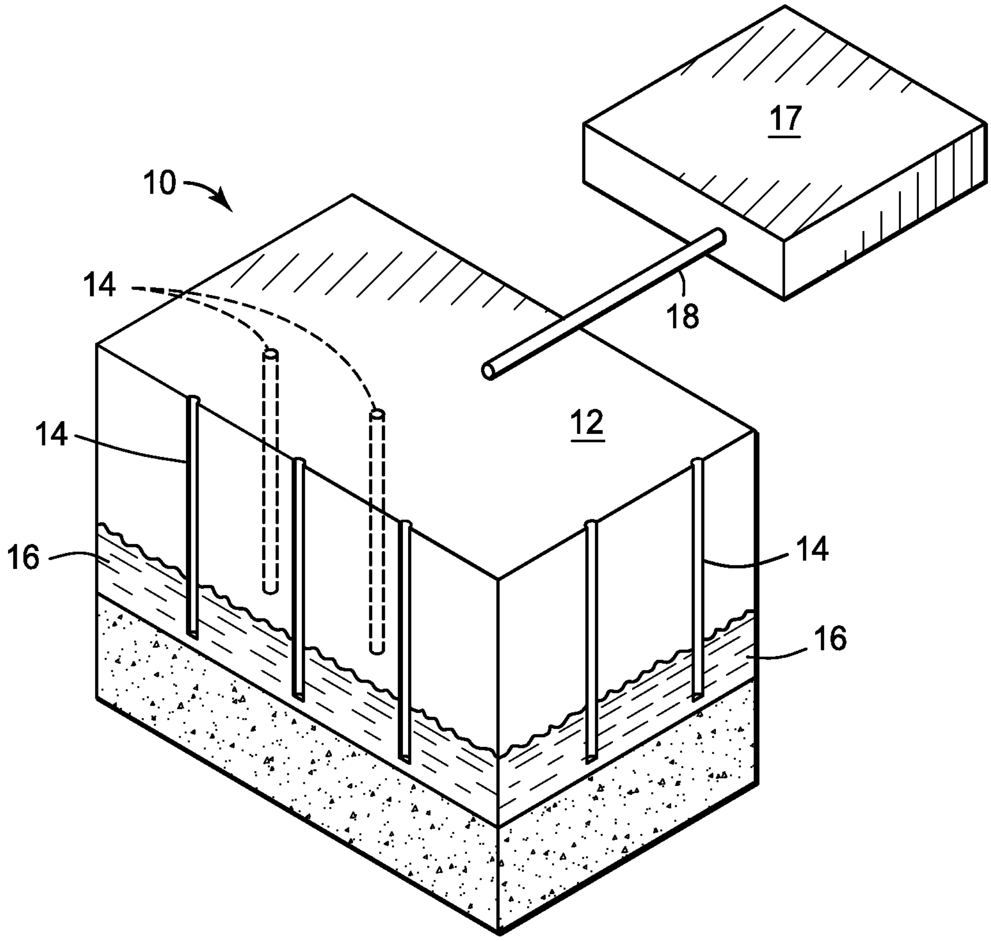

FIG. 1

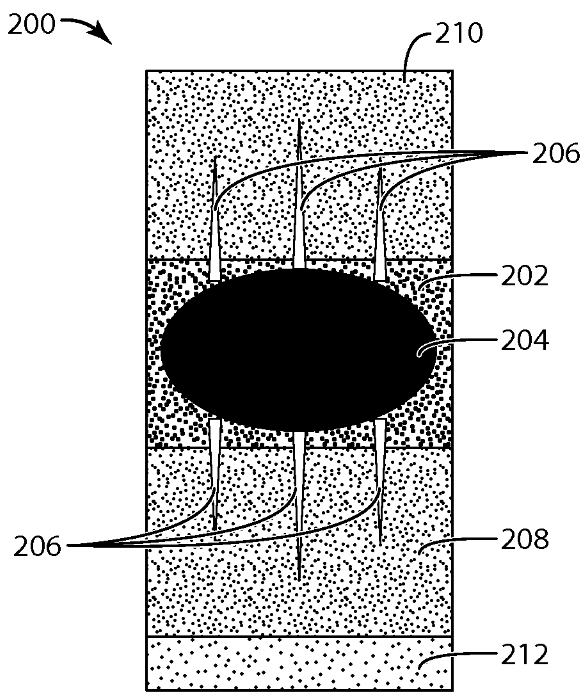
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FIG. 2

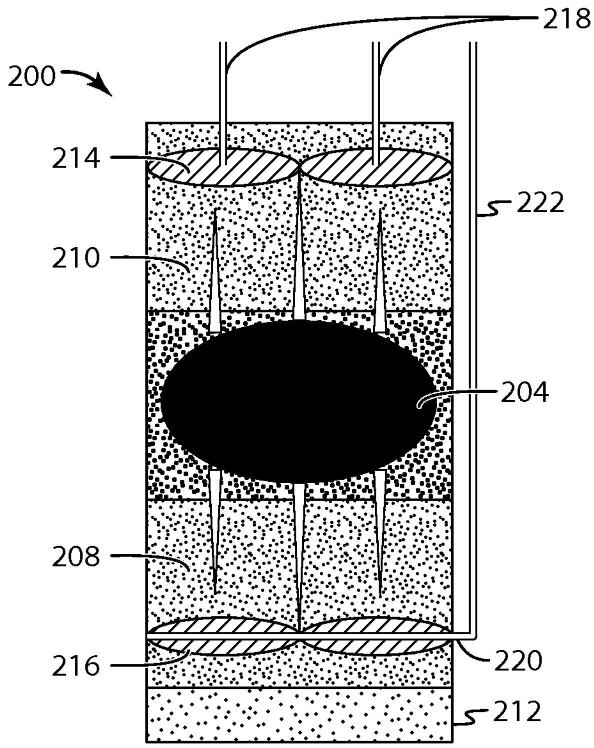
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FIG. 3

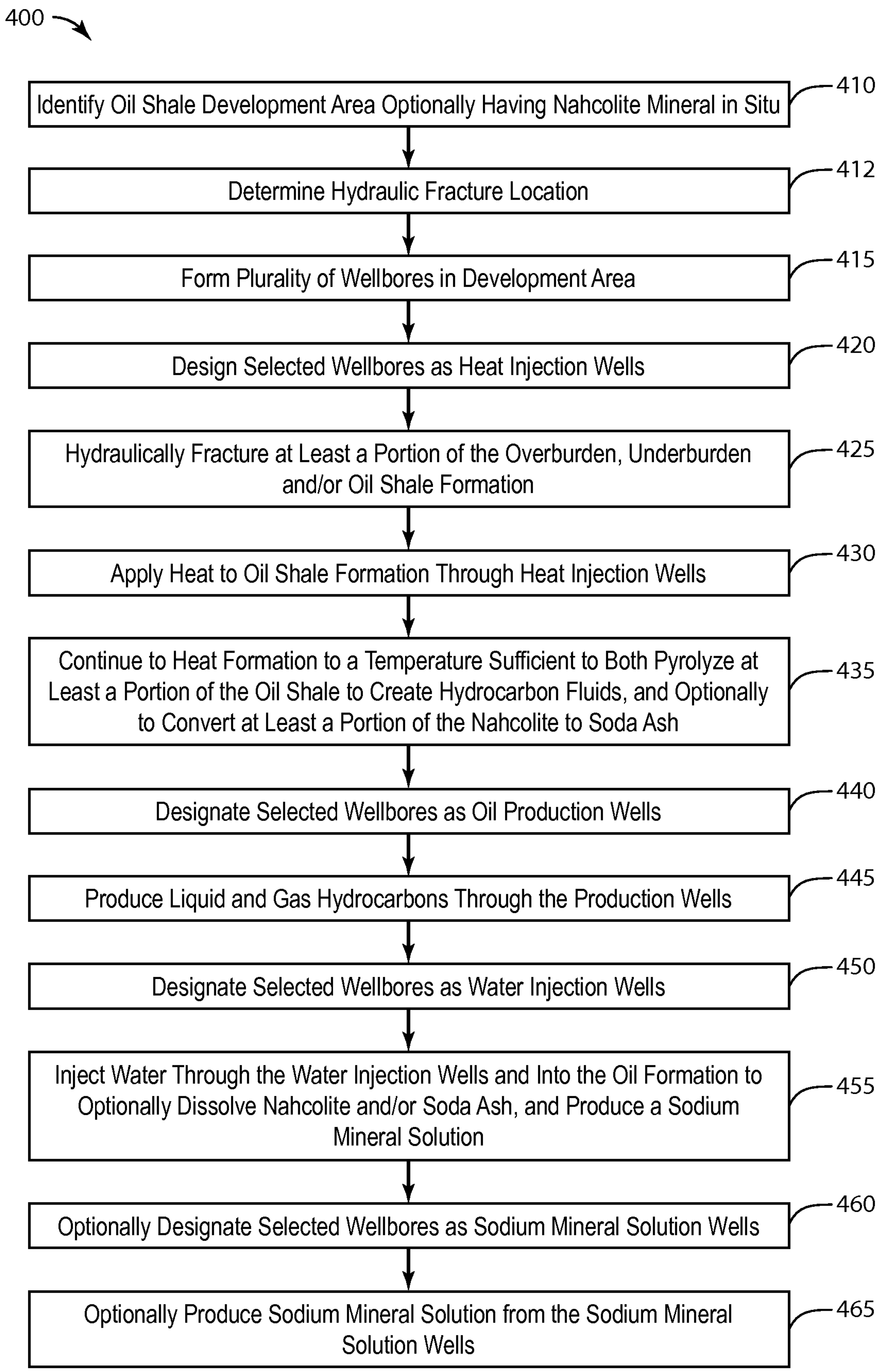
400
Identify Oil Shale Development Area Optionally Having Nahcolite Mineral in Situ
410
Determine Hydraulic Fracture Location
412
Form Plurality of Wellbores in Development Area
415
Design Selected Wellbores as Heat Injection Wells
420
Hydraulically Fracture at Least a Portion of the Overburden, Underburden and/or Oil Shale Formation
425
Apply Heat to Oil Shale Formation Through Heat Injection Wells
430
Continue to Heat Formation to a Temperature Sufficient to Both Pyrolyze at Least a Portion of the Oil Shale to Create Hydrocarbon Fluids, and Optionally to Convert at Least a Portion of the Nahcolite to Soda Ash
435
Designate Selected Wellbores as Oil Production Wells
440
Produce Liquid and Gas Hydrocarbons Through the Production Wells
445
Designate Selected Wellbores as Water Injection Wells
450
Inject Water Through the Water Injection Wells and Into the Oil Formation to Optionally Dissolve Nahcolite and/or Soda Ash, and Produce a Sodium Mineral Solution
455
Optionally Designate Selected Wellbores as Sodium Mineral Solution Wells
460
Optionally Produce Sodium Mineral Solution from the Sodium Mineral Solution Wells
465

FIG. 4

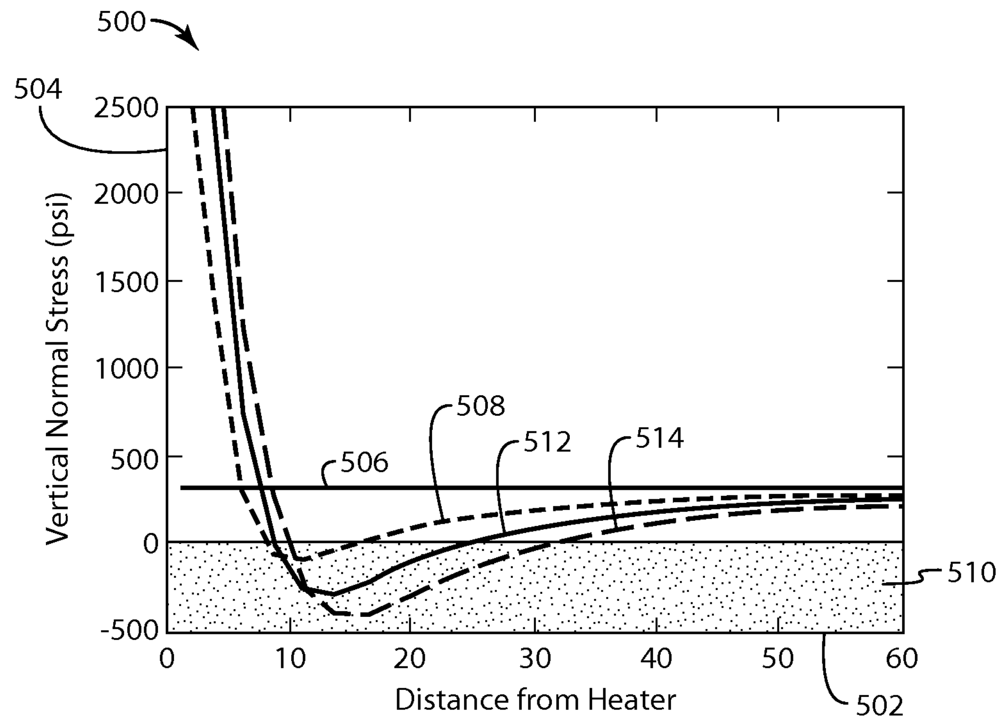

FIG. 5

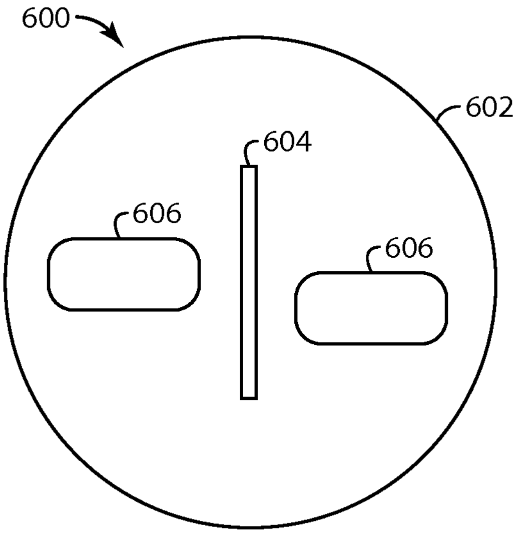

FIG. 6

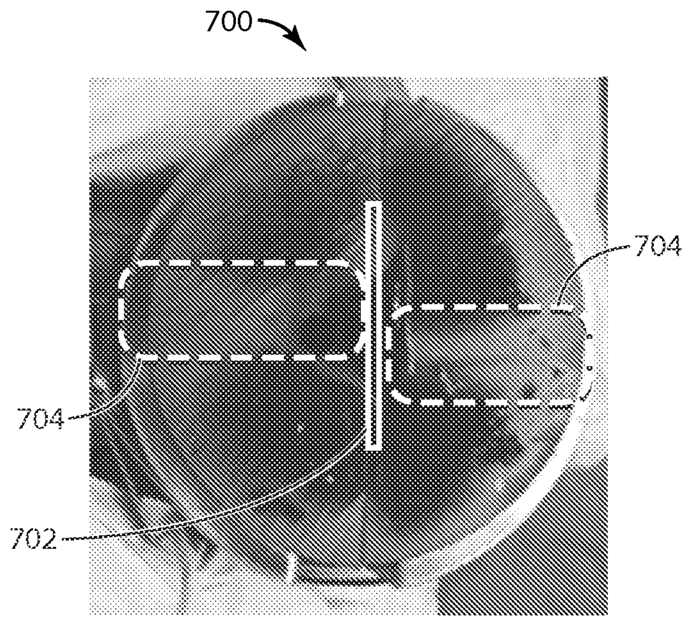

FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2013/037448

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - E21B 43/16 (2013.01)
USPC - 166/272.1
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC(8) - E21B 36/04, 43/16, 43/24, 43/34 (2013.01)
USPC - 62/260; 166/50, 60, 245, 248, 272.1, 272.3, 303; 175/17, 61; 208/390; 299/2, 3, 14; 392/301; 405/130

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
CPC - E21B 43/2401, 43/2405, 43/2406, 43/243, 43/305 (2013.01)

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
PatBase, Google Patents

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X -- Y	US 2010/0319909 A1 (SYMINGTON et al) 23 December 2010 (23.12.2010) entire document	1-12 ------- 13
Y	US 2005/0211434 A1 (GATES et al) 29 September 2005 (29.09.2005) entire document	13
A	US 2007/0000662 A1 (SYMINGTON et al) 04 January 2007 (04.01.2007) entire document	1-13

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

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

Date of the actual completion of the international search	Date of mailing of the international search report
17 July 2013	02 AUG 2013

Name and mailing address of the ISA/US	Authorized officer:
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