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(71) Applicant (for all designated States except US):
**EXXONMOBIL USPSTREAM RESEARCH
COMAPNY** [US/US]; CORP-URC-SW359, P.O.Box
2189, Houston, TX 77252-2189 (US).

(72) Inventors; and

(75) Inventors/Applicants (for US only): **DALE, Bruce, A.**
[US/US]; 7122 Hidden Tralls Court, Sugar Land, TX
77479 (US). **LIANG, Yueming** [CN/US]; 542 Newing-
ton Lane, Sugar Land, TX 77479 (US). **SEARLES,
Kevin, H.** [US/US]; 4206 Rock Springs Dr., Kingwood,
TX 77345 (US). **BARRETT, Elizabeth, L. Templeton**
[US/US]; 2324 Bartlet St., Houston, TX 77098 (US).

(74) Agents: **JAMES, Rick F.** et al.; Exxonmobil Usptream
Research Comapny, CORP-URC-SW359, P.O.Box 2189,
Houston, TX 77252-2189 (US).

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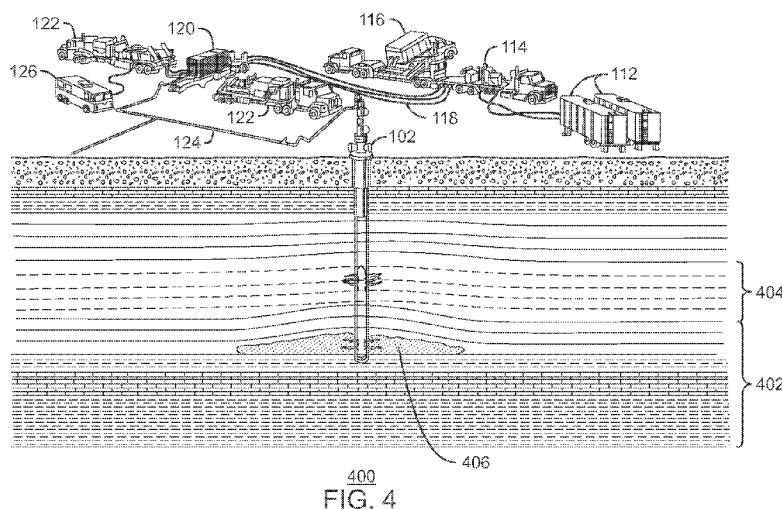
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[Continued on next page]

(54) Title: METHOD AND SYSTEM FOR FRACTURE STIMULATION



(57) Abstract: The present techniques provide systems and methods for fracturing a production formation. A method includes creating a notch in a formation and causing a volumetric change in a treatment interval proximate to a production interval so as to apply a mechanical stress on the production interval, wherein the treatment interval, the production interval, or both are located within the formation. A horizontal fracture is created in the formation originating from the notch.



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METHOD AND SYSTEM FOR FRACTURE STIMULATION

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims the benefit of U.S. Provisional Patent Application No. 5 61/407,249 filed October 27, 2010 entitled METHOD AND SYSTEM FOR FRACTURE STIMULATION, and also claims benefit to U.S. Provisional Application No. 61/544,757, filed October 7, 2011, entitled METHOD AND SYSTEM FOR FRACTURE STIMULATION BY CYCLIC FORMATION SETTLING AND DISPLACEMENT and U.S. Provisional Application No. 61/544,766, filed October 7, 2011 entitled METHOD AND 10 SYSTEM FOR FRACTURE STIMULATION BY FORMATION DISPLACEMENT.

FIELD OF THE INVENTION

[0002] Exemplary embodiments of the present techniques relate to a method and system for fracture stimulation of subterranean formations to enhance the recovery of hydrocarbons. 15 Specifically, an exemplary embodiment provides for creating fractures and other flow paths by delamination and rubblization of formations.

BACKGROUND

[0003] This section is intended to introduce various aspects of the art that may be topically associated with exemplary embodiments of the present techniques. This discussion 20 is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present techniques. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0004] As hydrocarbon bearing subterranean formations that are easily harvested, such as reservoirs on land or reservoirs located in shallow ocean water, are used up, other 25 hydrocarbon sources must be used to keep up with energy demands. Such reservoirs may include any number of unconventional hydrocarbon sources, such as biomass, deep-water oil reservoirs, and natural gas from other sources.

[0005] One such unconventional hydrocarbon source is natural gas produced from formations that form unconventional gas reservoirs, including, for example, shale and coal 30 seams. Because unconventional gas reservoirs may have insufficient permeability to allow significant fluid flow to a wellbore, many of such unconventional gas reservoirs are currently not considered as practical sources of natural gas. However, natural gas has been produced

for years from low permeability reservoirs having natural fractures. Furthermore, a significant increase in shale gas production has resulted from hydraulic fracturing, which can be used to create extensive artificial fractures around wellbores. When combined with horizontal drilling, which is often used with wells in tight gas reservoirs, the hydraulic
5 fracturing may allow formerly unpractical reservoirs to be commercially viable.

[0006] The fracturing process is complicated and often requires numerous hydraulic fractures in a single well and numerous wells for an economic field development. More efficient fracturing processes may provide a more productive reservoir. In other words, a greater amount of the gas, or other hydrocarbon, trapped in a relatively non-porous reservoir,
10 such as a tight gas, tight sand, shale layer or even a coal seam may be harvested. Accordingly, numerous researchers have explored ways to improve fracturing.

[0007] For example, U.S. Patent No. 3,455,391, to Matthews, et al., discloses a process for horizontally fracturing subterranean earth formations. The process is performed by injecting a hot fluid at high pressure, until vertical fractures are formed and then closed due to
15 thermal expansion of the earth formation. A fluid is then injected at a pressure sufficient to form horizontal fractures.

[0008] A similar process is disclosed in U.S. Patent No. 3,613,785, to Closman and Phocas. In this process a wellbore is extended into the formation and a vertical fracture is generated by pressurizing the borehole. A hot fluid is injected into the formation to heat the
20 formation, until thermal stressing of the formation matrix material causes the horizontal compressive stress in the formation to exceed the vertical compressive stress at a location selected for a second well. Hydraulically fracturing the formation through this second well can form a horizontal fracture extending into the formation.

[0009] Other approaches have focused on relieving stress in the formation, for example,
25 by cavitation of the formation. For example, U.S. Patent No. 5,147,111, to Montgomery, discloses a method for cavity induced stimulation of coal degasification wells. The method can be used for improving the initial production of fluids, such as methane, from a coal seam. To perform the method, a well is drilled and completed into the seam. A tubing string is run into the hole and liquid carbon dioxide is pumped down the tubing while a backpressure is
30 maintained on the well annulus. The pumping is stopped, and the pressure is allowed to build until it reached a desired elevated pressure, for example, 1500 to 2000 psia. The pressure is quickly released, causing the coal to fail and fragment into particles. The particles are

removed to form a cavity in the seam. The cavity can allow expansion of the coal, potentially leading to opening of cleats within the coal seam.

[0010] A similar concept has been described in Ukraine Patent No. 35282, which discloses another method for coal degasification, but through subsurface gasification of an underburden coal seam (a coal seam that underlies the gas-containing formation). In this process, wellbores are drilled through an underburden coal bed so that a gasification catalyst can be applied. Once gasification occurs and lowers the underburden pressure due to depletion, subsidence of the overburden (e.g., the layer containing the gas) occurs due to gravitational loading. The subsidence can potentially create microfractures within the overburden reservoir, thereby allowing improved gas migration to the degassing wells.

[0011] It has also been noted that vertical wells and mining processes can lower stress points on coal seams, leading to increases in the production of coal bed methane. For example, S. Sang, et al., "Stress relief coalbed methane drainage by surface vertical wells in China," *International Journal of Coal Geology*, Volume 82, 196–203 (2010), presents a summary of studies on improved coalbed methane production by stress relief. The paper summarizes the status of engineering practice, technology, and research related to stress relief coalbed methane (CBM) drainage using surface wells in China during the past 10 years. Comments are provided on the theory and technical progress of this method. In high gas mining areas, such as the Huainan, Huaibei and Tiefu mining areas, characterized by heavily sheared coals with relatively low permeability, stress relief CBM surface well drainage has been successfully implemented and has broad acceptance as a CBM exploitation technology. The fundamental theories underpinning stress relief CBM surface well drainage include elements relating to: (1) formation layer deformation theory, vertical zoning and horizontal partitioning, and the change in the stress condition in mining stopes; (2) a theory regarding an Abscission Circle in the development of mining horizontal abscission fracture and vertical broken fracture in overlaying formations; and (3) the theory of stress relief inducing permeability increase in protected coal seams during mining; and the gas migration–accumulation theory of stress relief CBM surface well drainage.

[0012] Other techniques for increasing production from coal beds, and other reservoirs, have focused on in-situ pyrolysis of hydrocarbons in a reservoir, followed by production of hydrocarbons from the reservoir. All of these techniques above have focused on the treatment of the hydrocarbon bearing subterranean formation itself. Further, some techniques

have taught that relieving a stress on a reservoir may enhance the production of hydrocarbons, for example, by allowing cleats to open up in coal seams.

[0013] The other technique is to use wellbore notching or other methods to induce stress concentrations near the wellbore so that a hydraulic fracture may be initiated and propagated in a desired direction. For example, during 1959 and 1960, the British American Oil Company conducted an experimental program on fracturing with the single-plane entry technique (Strain, H.J., "Well-Bore Notching and Hydraulic Fracturing", 12th SPE Annual Technical Meeting, Edmonton, 1961). With this technique, the wellbore is prepared at a selected point using a hydraulic or a mechanical notching tool, then the well is fractured with a treatment designed to generate a single, extensive horizontal fracture. A partial monolayer of large-sized propping agent is distributed in the fracture to give high-flow capacity after the treatment. Field tests indicated that wells fractured with this technique have higher and more sustained productivity than those fractured by conventional methods.

[0014] U.S. Patent 5,482,116, to El-Rabaa and Olson, discloses a method to guide hydraulic fracturing through a wellbore that is drilled in a direction parallel to a desired fracture direction. The wellbore is prepared with notches or perforations that lie in the desired fracture plane. A longitudinal fracture is then created in the desired direction by pumping fracturing fluid at high rate. It was found that the higher the net pressure in the fracture, the longer the fracture will extend in the plane.

[0015] Related information may be found in S.E. Laubach, et al., "Characteristics and origins of coal cleat: A review," International Journal of Coal Geology 35 (1998), 175-207; Ian Palmer, "Coalbed methane completions: A world view," International Journal of Coal Geology 82 (2010), 184-195; Jack A. Pashin, "Stratigraphy and structure of coalbed methane reservoirs in the United States: An overview," International Journal of Coal Geology 35 (1998), 209-240; Pablo F. Sanz, et al., "Mechanical models of fracture reactivation and slip on bedding surfaces during folding of the asymmetric anticline at Sheep Mountain, Wyoming," Journal of Structural Geology 30 (2008), 1177-1191; V. Palchik, "Localization of mining-induced horizontal fractures along formation layer interfaces in overburden: field measurements and prediction," Environ. Geol. 48 (2005), 68-80; and Stephen P. Laubach, et al., "Differential compaction of interbedded sandstone and coal," from: Cosgrove, J.W. and Ameen, M.S. (eds.), Forced Folds and Fractures, Geological Society of London, Special Publications, 169, 51-60 (The Geological Society of London 2000).

SUMMARY

[0016] An embodiment of the present techniques provides a method for fracturing a production formation. The method includes creating a notch in a formation and causing a volumetric change in a treatment interval proximate to a production interval so as to apply a mechanical stress on the production interval. The treatment interval, the production interval, or both are located within the formation. A horizontal fracture in the formation is created originating from the notch.

[0017] Another embodiment of the present techniques provides a method for production of a hydrocarbon from a reservoir. The method includes expanding a treatment interval below a production interval to mechanically stress the production interval. A fracture field is created to enhance conductivity within the production interval. A notch is created a notch in the production interval. The production interval is fractured at the notch to form a horizontal fracture coupling the fracture field to a production well. Hydrocarbons are produced from the production interval.

[0018] Another embodiment provides a hydrocarbon production system that includes a production interval in a hydrocarbon bearing subterranean formation and a treatment interval that is proximate to the production interval. The system also includes a stimulation well that is drilled to the treatment interval and a production well that is drilled to the production interval. A notching system is configured to create notches in a formation comprising the production interval, the treatment interval, or both. A stimulation system is configured to create a volumetric change in the treatment interval, and a fracturing system is configured to fracture the formation at the notches to create horizontal fractures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0019] The advantages of the present techniques are better understood by referring to the following detailed description and the attached drawings, in which:

[0020] **Fig. 1** is a diagram of a hydraulic fracturing process;

[0021] **Fig. 2** is a drawing of a local stress state for an element in a hydrocarbon bearing subterranean formation;

[0022] **Fig. 3** is a drawing of an opening mode (mode I) of fracture formation, commonly resulting from a standard hydraulic fracturing process;

[0023] **Fig. 4** is an exemplified drawing of a well treatment system such as a hydraulic fracturing system, wherein a zone below a hydrocarbon bearing subterranean formation is subjected to a volumetric expansion, which can place stress on the hydrocarbon bearing subterranean formation leading to fracturing;

5 [0024] **Fig. 5** is a block diagram of a method for stimulation of a hydrocarbon bearing subterranean formation by treating a formation outside of the reservoir;

[0025] **Fig. 6** is a more detailed schematic view of a delamination fracture stimulation performed by inflating a zone proximate to a production zone;

10 [0026] **Fig. 7** is a drawing of two modes of sliding fracture formation that may participate in delamination fracture stimulation as discussed herein;

[0027] **Fig. 8** is a drawing of rubblization during shearing at a fracture interface or boundary;

[0028] **Figs. 9(A) and 9(B)** are plots of surface deformation induced by a vertical fracture and a horizontal fracture in a underlying formation;

15 [0029] **Fig. 10** is a drawing of an azimuthal rotation of fracture planes within a formation that may occur as a result of cyclic treatment of the formation;

[0030] **Fig. 11** is a drawing of a vertical well passing through a reservoir interval and a treatment interval, in which a notch has been formed in the treatment interval;

20 [0031] **Fig. 12** is a drawing of the stress distribution in the formation around the tip of a notch;

[0032] **Figs. 13(A) and 13(B)** are plots of horizontal stress states in a formation around a vertical well and in the formation when vertical fractures are present in the formation;

[0033] **Fig. 14** is a drawing of a fracturing process;

25 [0034] **Fig. 15** is a drawing of a technique that may be useful for increasing the effects of the treatment of a zone on the hydrocarbon bearing subterranean formation by fracturing and injecting pressurized fluid or steam into a treatment formation at multiple points along a well;

[0035] **Fig. 16** is a drawing of a multi-stage injection method that may be useful for increasing the effects of the treatment of a zone on the hydrocarbon bearing subterranean formation if particulate solids are used to dilate the zone;

[0036] Fig. 17 is a plot of formation uplift resulting from sequentially fracturing at ten points along a well, using the procedure discussed with respect to Fig. 16;

[0037] Fig. 18 is process flow diagram of a method for completing a formation using a notching procedure for the direct stimulation of the hydrocarbon bearing subterranean formation;

[0038] Fig. 19 is process flow diagram of a method for fracturing a formation using a notching procedure in conjunction with a treatment of a zone other than the production interval;

[0039] Fig. 20 is process flow diagram of a method for an inverse pumping sequence to fracture a hydrocarbon bearing subterranean formation through notches.

[0040] Fig. 21 is process flow diagram of another method for an inverse pumping sequence to fracture a hydrocarbon bearing subterranean formation through notches;

[0041] Figs. 22(A) – (D) are well configurations that may be used to directly stimulate a subterranean hydrocarbon bearing formation; and

[0042] Figs. 23(A) – (D) are drawings of a number of well configurations that can be used in embodiments of the techniques described herein.

DETAILED DESCRIPTION

[0043] In the following detailed description section, the specific embodiments of the present techniques are described in connection with exemplary embodiments. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present techniques, this is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the present techniques are not limited to the specific embodiments described below, but rather, such techniques include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

[0044] At the outset, and for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents,

synonyms, new developments, and terms or techniques that serve the same or a similar purpose are considered to be within the scope of the present claims.

[0045] The “Bulk modulus” of a rock sample from a formation relates the pressure to the volume change given by the dilation ϵ_{kk} . It is an elastic property of the material and is usually denoted by the English alphabet K having units the same as that of stress, and is given by:

$$K = \frac{3\lambda + 2\mu}{3}.$$

[0046] “Cavitation completion” or “cavitation” is a process by which an opening may be made in a formation. Generally, cavitation is performed by drilling a well into a formation. The formation is then pressurized in the vicinity of the well. The pressure is suddenly released, causing the material in the vicinity of the well to fragment. The fragments and debris may then be swept to the surface through the well by circulating a fluid through the well.

[0047] “Cleat system” is the system of naturally occurring joints that are created as a coal seam forms over geologic time. A cleat system allows for the production of natural gas if the provided permeability to the coal seam is sufficient.

[0048] “Coal” is a solid hydrocarbon, including, but not limited to, lignite, sub-bituminous, bituminous, anthracite, peat, and the like. The coal may be of any grade or rank. This can include, but is not limited to, low grade, high sulfur coal that is not suitable for use in coal-fired power generators due to the production of emissions having high sulfur content.

[0049] “Coalbed methane” (CBM) is a natural gas that is adsorbed onto the surface of coal. CBM may be substantially comprised of methane, but may also include ethane, propane, and other hydrocarbons. Further, CBM may include some amount of other gases, such as carbon dioxide (CO₂) and nitrogen (N₂).

[0050] A “compressor” is a machine that increases the pressure of a gas by the application of work (compression). Accordingly, a low pressure gas (for example, 5 psig) may be compressed into a high-pressure gas (for example, 1000 psig) for transmission through a pipeline, injection into a well, or other processes.

[0051] “Directional drilling” is the intentional deviation of the wellbore from the path it would naturally take. In other words, directional drilling is the steering of the drill string so that it travels in a desired direction. Directional drilling can be used for increasing the

drainage of a particular well, for example, by forming deviated branch bores from a primary borehole. Directional drilling is also useful in the marine environment where a single offshore production platform can reach several hydrocarbon bearing subterranean formations or reservoirs by utilizing a plurality of deviated wells that can extend in any direction from the drilling platform. Directional drilling also enables horizontal drilling through a reservoir to form a horizontal wellbore. As used herein, "horizontal wellbore" represents the portion of a wellbore in a subterranean zone to be completed which is substantially horizontal or at an angle from vertical in the range of from about 15° to about 75°. A horizontal wellbore may have a longer section of the wellbore traversing the payzone of a reservoir, thereby permitting increases in the production rate from the well.

[0052] "Exemplary" is used exclusively herein to mean "serving as an example, instance, or illustration." Any embodiment described herein as exemplary is not to be construed as preferred or advantageous over other embodiments.

[0053] A "facility" is tangible piece of physical equipment, or group of equipment units, through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets, which are the locations at which hydrocarbon fluids either leave the model (produced fluids) or enter the model (injected fluids). Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, and delivery outlets. In some instances, the term "surface facility" is used to distinguish those facilities other than wells.

[0054] As used herein, the force "f" could be compressional, leading to longitudinally compressing the strength member, or tensional, leading to longitudinally extending the strength member. In the case of a strength member in a seismic section, the force will typically be tension.

[0055] "Formation" refers to a body or section of geologic strata, structure, formation, or other subsurface solids or collected material that is sufficiently distinctive and continuous with respect to other geologic strata or other characteristics that it can be mapped, for example, by seismic techniques. A formation can be a body of geologic strata of predominantly one type of rock or a combination of types of rock, or a fraction of strata having substantially common set of characteristics. A formation can contain one or more hydrocarbon-bearing subterranean formations. Note that the terms formation, hydrocarbon

bearing subterranean formation, reservoir, and interval may be used interchangeably, but may generally be used to denote progressively smaller subsurface regions, zones, or volumes. More specifically, a geologic formation may generally be the largest subsurface region, a hydrocarbon reservoir or subterranean formation may generally be a region within the geologic formation and may generally be a hydrocarbon-bearing zone, a formation, reservoir, or interval having oil, gas, heavy oil, and any combination thereof. An interval or production interval may generally refer to a sub-region or portion of a reservoir. A hydrocarbon-bearing zone, or production formation, may be separated from other hydrocarbon-bearing zones by zones of lower permeability such as mudstones, shales, or shale-like (highly compacted) sands. In one or more embodiments, a hydrocarbon-bearing zone may include heavy oil in addition to sand, clay, or other porous solids.

[0056] A “fracture” is a crack, delamination, surface breakage, separation, crushing, rubblization, or other destruction within a geologic formation or fraction of formation that is not related to foliation or cleavage in metamorphic formation, along which there has been displacement or movement relative to an adjacent portion of the formation. A fracture along which there has been lateral displacement may be termed a fault. When walls of a fracture have moved only normal to each other, the fracture may be termed a joint. Fractures may enhance permeability of rocks greatly by connecting pores together, and for that reason, joints and faults may be induced mechanically in some reservoirs in order to increase fluid flow.

[0057] “Fracturing” refers to the structural degradation of a treatment interval, such as a subsurface shale formation, from applied thermal or mechanical stress. Such structural degradation generally enhances the permeability of the treatment interval to fluids and increases the accessibility of the hydrocarbon component to such fluids. Fracturing may also be performed by degrading rocks in treatment intervals by chemical means. “Fracture network” refers to a field or network of interconnecting fractures, usually formed during hydraulic fracturing. A “fracture field” is a group of fractures, which may or may not be interconnected, and are created by a single fracturing event, such as by a volumetric change in a zone proximate to a target formation, which fractures the target formation.

[0058] “Fracture gradient” refers to an equivalent fluid pressure sufficient to create or enhance one or more fractures in the subterranean formation. As used herein, the “fracture gradient” of a layered formation also encompasses a parting fluid pressure sufficient to separate one or more adjacent bedding planes in a layered formation. It should be understood

that a person of ordinary skill in the art could perform a simple leak-off test on a core sample of a formation to determine the fracture gradient of a particular formation.

[0059] “Geomechanical stress” or “stress” including a change related thereto, or similar phrase, refers generally to the forces external to or interior to a formation acting upon or
5 within such formation. The forces may define a stress state, condition, or property of a formation, zone, or other geologic strata, and/or any fluid contained therein. In embodiments, the stress state may be manipulated to control the creation of fractures in particular directions.

[0060] “Heat source” is any system for providing heat to at least a portion of a formation substantially by conductive or radiative heat transfer. For example, a heat source may
10 include electric heaters such as an insulated conductor, an elongated member, or a conductor disposed in a conduit. Other heating systems may include electric resistive heaters placed in wells, electrical induction heaters placed in wells, circulation of hot fluids through wells, resistively heated conductive propped fractures emanating from wells, downhole burners, exothermic chemical reactions, and in situ combustion. A heat source may also include
15 systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural gas distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or
20 indirectly heats the formation. For example, an “electrofrac heater” may use electrical conductive propped fractures to apply heat to the formation. In an electrofrac heater, a formation is hydraulically fractured and a graphite proppant is used to prop the fractures open. An electric current may then be passed through the graphite proppant causing it to generate heat, which heats the surrounding formation.

25 [0061] “Hydraulic fracturing” is used to create single or branching fractures that extend from the wellbore into reservoir formations so as to stimulate the potential for production. A fracturing fluid, typically a viscous fluid, is injected into the formation with sufficient pressure to create and extend a fracture, and a proppant is used to “prop” or hold open the created fracture after the hydraulic pressure used to generate the fracture has been released.
30 When pumping of the treatment fluid is finished, the fracture “closes.” Loss of fluid to a permeable formation results in a reduction in fracture width until the proppant supports the fracture faces. 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. Generally, the fractures tend to be vertical at greater depths, due to the increased magnitude of the vertical stress relative to the horizontal stresses. As used herein, fracturing may take place in portions of a formation outside of a hydrocarbon bearing subterranean formation in order to enhance hydrocarbon production
5 from the hydrocarbon bearing subterranean formation.

[0062] “Hydrocarbon production” refers to any activity associated with extracting hydrocarbons from a well or other opening. Hydrocarbon production normally refers to any activity conducted in or on the well after the well is completed. Accordingly, hydrocarbon production or extraction includes not only primary hydrocarbon extraction but also secondary
10 and tertiary production techniques, such as injection of gas or liquid for increasing drive pressure, mobilizing the hydrocarbon or treating by, for example chemicals or hydraulic fracturing the wellbore to promote increased flow, well servicing, well logging, and other well and wellbore treatments.

[0063] “Hydrocarbons” are generally defined as molecules formed primarily of carbon
15 and hydrogen atoms such as oil and natural gas. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be produced from hydrocarbon bearing subterranean formations through wells penetrating a hydrocarbon containing formation. Hydrocarbons derived from a hydrocarbon bearing subterranean formation may include, but are not limited to, kerogen,
20 bitumen, pyrobitumen, asphaltenes, oils, natural gas, or combinations thereof. Hydrocarbons may be located within or adjacent to mineral matrices within the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media.

[0064] A “hydraulic fracture” is a fracture at least partially propagated into a formation,
25 wherein the fracture is created through injection of pressurized fluids into the formation. While the term “hydraulic fracture” is used, the techniques described herein are not limited to use in hydraulic fractures. The techniques may be suitable for use in any fractures created in any manner considered suitable by one skilled in the art. Hydraulic fractures may be substantially horizontal in orientation, substantially vertical in orientation, or oriented along
30 any other plane. Generally, the fractures tend to be vertical at greater depths, due to the increased magnitude of the vertical stress relative to the horizontal stresses.

[0065] “Ideally elastic” refers to a material in which a body formed of the material recovers its original form completely upon removal of the forces causing the deformation,

and a material that has a one-to-one, i.e., unique relationship between the state of stress and the state of strain at a given temperature. For many materials, strain is directly proportional to the stress, at least at stresses below the yield strength of a material. This linear relationship between strain ϵ_{ij} and stress σ_{ij} occurring at stresses below the yield strength is known as the generalized Hooke's law, and is represented by the formula:

$$\sigma_{ij} = C_{ijkl} \epsilon_{kl}$$

where summation convention is employed, meaning that in Cartesian coordinates whenever the same letter subscript occurs twice in a term, that subscript is to be given all possible values and the results added together, and here i,j,k,l each take the values 1,2,3. The 9 equations represented above contain 81 elastic constants, C_{ijkl} , but symmetry of the stress tensor, σ_{ij} , and existence of a strain energy function reduce the number of distinct constants to 21. A “plane of elastic symmetry” is a plane in which the elastic constants at a point have the same values for every pair of coordinate systems which are mirror images of each other in a certain plane.

[0066] “Imbibition” refers to the incorporation of a fracturing fluid into a fracture face by capillary action. Imbibition may result in decreases in permeation of a formation fluid across the fracture face, and is known to be a form of formation damage. For example, if the fracturing fluid is an aqueous fluid, imbibition may result in lower transport of organic materials, such as hydrocarbons, across the fracture face, resulting in decreased recovery. The decrease in hydrocarbon transport may outweigh any increases in fracture surface area resulting in no net increase in recovery, or even a decrease in recovery, after fracturing.

[0067] “In-Situ” or “insitu” refers to a state, condition, or property of a geologic formation, strata, zone, and/or fluids therein, prior to changing or altering such state, condition, or property by an action affecting the formation and/or fluids therein. Changes to the insitu properties may be effected by substantially any action upon the formation, such as producing or removing fluids from a formation, injecting or introducing fluids or other materials into a formation, stimulating a formation, causing a collapse such as permitting a wellbore collapse or dissolving supporting strata, removing adjacent formation or fluid, heating or cooling the formation, or other action that effects change in the state, condition or property of the formation. The insitu state may or may not be the virgin or original state of the formation, but is a relative term that may in fact merely reference a state that exists prior to undertaking some action upon the formation.

[0068] An “isotropic” material is one in which the body’s elastic constants, C_{ijkl} , are the same in every set of reference axes at any point for a given situation. For a such a material, the number of distinct elastic constants is two, and the strains can be related to the stresses by Hooke’s Law:

$$5 \quad \sigma_{ij} = \lambda \delta_{ij} \epsilon_{kk} + 2\mu \epsilon_{ij},$$

where the distinct elastic constants are λ and μ , the Lamé constants. μ is also known as the “modulus of rigidity” or “shear modulus” and is sometimes expressed as G . Three additional constants, E , K , and ν can be defined as combinations of the Lamé constants.

[0069] As used herein, “material properties” represents any number of physical constants that reflect the behavior of a rock. Such material properties may include, for example, Young’s modulus (E), Poisson’s Ratio (ν), tensile strength, compressive strength, shear strength, creep behavior, and other properties. The material properties may be measured by any combinations of tests, including, among others, a “Standard Test Method for Unconfined Compressive Strength of Intact Rock Core Specimens,” ASTM D 2938-95; a “Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens [Brazilian Method],” ASTM D 3967-95a Reapproved 1992; a “Standard Test Method for Determination of the Point Load Strength Index of Rock,” ASTM D 5731-95; “Standard Practices for Preparing Rock Core Specimens and Determining Dimensional and Shape Tolerances,” ASTM D 4435-01; “Standard Test Method for Elastic Moduli of Intact Rock Core Specimens in Uniaxial Compression,” ASTM D 3148-02; “Standard Test Method for Triaxial Compressive Strength of Undrained Rock Core Specimens Without Pore Pressure Measurements,” ASTM D 2664-04; “Standard Test Method for Creep of Cylindrical Soft Rock Specimens in Uniaxial Compressions,” ASTM D 4405-84, Reapproved 1989; “Standard Test Method for Performing Laboratory Direct Shear Strength Tests of Rock Specimens Under Constant Normal Stress,” ASTM D 5607-95; “Method of Test for Direct Shear Strength of Rock Core Specimen,” U.S. Military Rock Testing Handbook, RTH-203-80, available at “<http://www.wes.army.mil/SL/MTC/handbook/RT/RTH/203-80.pdf>” (last accessed on October 1, 2010); and “Standard Method of Test for Multistage Triaxial Strength of Undrained Rock Core Specimens Without Pore Pressure Measurements,” U.S. Military Rock Testing Handbook, available at <http://www.wes.army.mil/SL/MTC/handbook/RT/RTH/204-80.pdf> (last accessed on June 25, 2010). One of ordinary skill will recognize that other methods of testing rock specimens from formations may be used to determine the physical constants used herein.

[0070] “Natural gas” refers to various compositions of raw or treated hydrocarbon gases. Raw natural gas is primarily comprised of light hydrocarbons such as methane, ethane, propane, butanes, pentanes, hexanes and impurities like benzene, but may also contain small amounts of non-hydrocarbon impurities, such as nitrogen, hydrogen sulfide, carbon dioxide, and traces of helium, carbonyl sulfide, various mercaptans, or water. Treated natural gas is primarily comprised of methane and ethane, but may also contain small percentages of heavier hydrocarbons, such as propane, butanes, and pentanes, as well as small percentages of nitrogen and carbon dioxide.

[0071] An “orthotropic” material is one that has three symmetry planes and nine independent elastic constants if a strain-energy function exists. If the principal axes of strain coincide with the symmetry axes, then so do the principal axes of stress.

[0072] “Overburden” refers to the subsurface formation overlying the formation containing one or more hydrocarbon-bearing zones (the reservoirs). For example, overburden may include rock, shale, mudstone, or wet/tight carbonate (such as an impermeable carbonate without hydrocarbons). An overburden may include a hydrocarbon-containing layer that is relatively impermeable. In some cases, the overburden may be permeable.

[0073] “Overburden stress” refers to the load per unit area or stress overlying an area or point of interest in the subsurface from the weight of the overlying sediments and fluids. In one or more embodiments, the “overburden stress” is the load per unit area or stress overlying the hydrocarbon-bearing zone that is being conditioned or produced according to the embodiments described. In general, the magnitude of the overburden stress may primarily depend on two factors: 1) the composition of the overlying sediments and fluids, and 2) the depth of the subsurface area or formation. Similarly, underburden refers to the subsurface formation underneath the formation containing one or more hydrocarbon-bearing zones (reservoirs).

[0074] “Permeability” is the capacity of a formation to transmit fluids through the interconnected pore spaces of the rock. Permeability may be measured using Darcy's Law: $Q = (k \Delta P A) / (\mu L)$, where Q = flow rate (cm^3/s), ΔP = pressure drop (atm) across a cylinder having a length L (cm) and a cross-sectional area A (cm^2), μ = fluid viscosity (cp), and k = permeability (Darcy). The customary unit of measurement for permeability is the millidarcy. The term “relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). The

term “relatively low permeability” is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. An impermeable layer generally has a permeability of less than about 0.1 millidarcy. By these definitions, shale may be considered impermeable, for example, ranging from about 0.1 millidarcy (100 microdarcy) to
5 as low as 0.00001 millidarcy (10 nanodarcy).

[0075] “Porosity” is defined as the ratio of the volume of pore space to the total bulk volume of the material expressed in percent. Although there often is an apparent close relationship between porosity and permeability, because a highly porous formation may be highly permeable, there is no real relationship between the two; a formation with a high
10 percentage of porosity may be very impermeable because of a lack of communication between the individual pores, capillary size of the pore space or the morphology of structures constituting the pore space. For example, the diatomite in one exemplary rock type found in formations, Belridge, has very high porosity, at about 60%, but the permeability is very low, for example, less than about 0.1 millidarcy.

15 [0076] The “Poisson’s ratio” of a rock sample from a formation is the ratio of a unit of lateral contraction to a unit of longitudinal extension for tension. It is a dimensionless elastic property of the material and is usually denoted by the Greek alphabet ν , and is given by:

$$\nu = \frac{\lambda}{2(\lambda + \mu)}.$$

[0077] “Pressure” refers to a force acting on a unit area. Pressure is usually shown as
20 pounds per square inch (psi). “Atmospheric pressure” refers to the local pressure of the air. Local atmospheric pressure is assumed to be 14.7 psia, the standard atmospheric pressure at sea level. “Absolute pressure” (psia) refers to the sum of the atmospheric pressure plus the gauge pressure (psig). “Gauge pressure” (psig) refers to the pressure measured by a gauge, which indicates only the pressure exceeding the local atmospheric pressure (a gauge pressure
25 of 0 psig corresponds to an absolute pressure of 14.7 psia).

[0078] As previously mentioned, a “reservoir” or “hydrocarbon reservoir” is defined as a pay zone or production interval (for example, a hydrocarbon bearing subterranean formation) that includes sandstone, limestone, chalk, coal, and some types of shale. Pay zones can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m). The
30 permeability of the reservoir formation provides the potential for production.

[0079] “Reservoir properties” and “Reservoir property values” are defined as quantities representing physical attributes of rocks containing reservoir fluids. The term “reservoir properties” as used in this application includes both measurable and descriptive attributes. Examples of measurable reservoir property values include impedance to P-waves, impedance to S-waves, porosity, permeability, water saturation, and fracture density. Examples of descriptive reservoir property values include facies, lithology (for example, sandstone or carbonate), and environment-of-deposition (EOD). Reservoir properties may be populated into a reservoir framework of computational cells to generate a reservoir model.

[0080] A “rock physics model” relates petrophysical and production-related properties of a formation (or its constituents) to the bulk elastic properties of the formation. Examples of petrophysical and production-related properties may include, but are not limited to, porosity, pore geometry, pore connectivity volume of shale or clay, estimated overburden stress or related data, pore pressure, fluid type and content, clay content, mineralogy, temperature, and anisotropy and examples of bulk elastic properties may include, but are not limited to, P-impedance and S-impedance. A rock physics model may provide values that may be used as a velocity model for a seismic survey.

[0081] “Shale” is a fine-grained clastic sedimentary rock that may be found in formations, and may often have a mean grain size of less than 0.0625 mm. Shale typically includes laminated and fissile siltstones and claystones. These materials may be formed from clays, quartz, and other minerals that are found in fine-grained rocks. Non-limiting examples of shales include Barnett, Fayetteville, and Woodford in North America. Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. Shale gas reservoirs may be hydraulically fractured to create extensive artificial fracture networks around wellbores. Horizontal drilling is often used with shale gas wells.

[0082] “Stimulated Rock Volume” (SRV) describes a relatively large formation volume that has experienced increased permeability and associated hydrocarbon production potential through the use of changed in-situ stress (either applied or reduced stress) and strain techniques, such as but not limited to hydraulic fracturing or other related reservoir stimulation or stressing techniques. In one potential SRV scenario, a network of hydraulic fractures could be in communication with fractures that naturally occur in the formation so that the formation volume outside of one specific hydraulic fracture experiences improved reservoir properties.

[0083] “Strain” is the fractional change in dimension or volume of the deformation induced in the material by applying stress. Strain is usually denoted by the Greek alphabet ϵ . The nine components which fully define the strain at a given point are expressed as ϵ_{ij} , where i, j , each take the values 1, 2, 3.

5 [0084] “Stress” is the application of force to a material, such as a through a hydraulic fluid used to fracture a formation. Stress can be measured as force per unit area. Thus, applying a longitudinal force f to a cross-sectional area S of a strength member yields a stress which is given by f/S . The force f could be compressional, leading to longitudinally compressing the strength member, or tensional, leading to longitudinally extending the
10 strength member. Stress is usually denoted by the Greek alphabet σ . The nine components which fully define the stress state at a given point are expressed as σ_{ij} , where i, j , each take the values 1, 2, 3.

[0085] “Substantial” when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that
15 the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

[0086] “Thermal fractures” are fractures created in a formation caused by expansion or contraction of a portion of the formation or fluids within the formation. The expansion or contraction may be caused by changing the temperature of the formation or fluids within the
20 formation. The change in temperature may change the pressure of fluids within the formation, resulting in the fracturing. Thermal fractures may propagate into or form in neighboring regions significantly cooler than the heated zone.

[0087] “Tight oil” is used to reference formations with relatively low matrix permeability, porosity, or both, where liquid hydrocarbon production potential exists. In
25 these formations, liquid hydrocarbon production may also include natural gas condensate.

[0088] “Underburden” refers to the subsurface formation below or farther downhole than a formation containing one or more hydrocarbon-bearing zones, e.g., a hydrocarbon reservoir. For example, underburden may include rock, shale, mudstone, or a wet/tight carbonate, such as an impermeable carbonate without hydrocarbons. An underburden may include a
30 hydrocarbon-containing layer that is relatively impermeable. In some cases, the underburden may be permeable. The underburden may be a formation that is distinct from the hydrocarbon bearing formation or may be a selected fraction within a common formation

shared between the underburden portion and the hydrocarbon bearing portion. Intermediate layers may also reside between the underburden layer and the hydrocarbon bearing zone.

[0089] The “Young's modulus” of a rock sample from a formation is the stiffness of the rock sample, defined as the amount of axial load (or stress) sufficient to make the rock sample undergo a unit amount of deformation (or strain) in the direction of load application, when deformed within its elastic limit. The higher the Young's modulus, the more stress is required to deform it. It is an elastic property of the material and is usually denoted by the English alphabet E having units the same as that of stress, and is given by:

$$E = \frac{\mu(3\lambda + 2\mu)}{\lambda + \mu}.$$

10 Overview

[0090] Embodiments of the present techniques provide well completions and methods for stimulation of hydrocarbon bearing subterranean formations, or portions thereof, on a large scale, up to stimulating an entire formation at once. The methods include fracturing a subterranean formation by applying stress in a zone proximate to the subterranean formation to indirectly translate a mechanical stress to the subterranean formation and affect a permeability increase within the subterranean formation. The desired permeability increase is effected by creation of a fracture field in the subterranean formation, such as by delamination fracturing during uplifting, down-folding or other affected movement of the subterranean formation. The desired permeability may also be the result of other types of fracturing, but it is noted that for simplification purposes, all such fracturing and displacements may be referred to herein generally as fracturing.

[0091] In embodiments, a notch may be formed from a well into a formation, creating a stress concentration at the tip of the notch. When a notch parallel to the horizontal plane is pressurized with a fracturing fluid, the stress concentration can change the orientations of principal stresses at notch tip and promote the growth of a horizontal fracture. As the fracture grows out away from the notch, stresses in the formation can cause the fracture to change direction, for example, shifting to vertical. The distance over which the fracture will remain horizontal may depend on the notch size and geometry, differential between in-situ vertical and horizontal stresses, the pumping rate, and the viscosity of the fracturing fluid, among others. Notches may be formed in the zone proximate, the hydrocarbon bearing subterranean formation, or both.

[0092] A notch formed in the hydrocarbon bearing subterranean formation may be used to create a horizontal fracture to couple the production well to a fracture field created by imposing a stress on the zone proximate to the hydrocarbon bearing subterranean formation. The horizontal fracture may follow a bedding plane in the hydrocarbon bearing subterranean formation. The notching may be performed before treating the zone proximate to lubricate the delamination planes, increasing the amount of delamination resulting from stressing the zone proximate.

[0093] A notch formed in the zone proximate to the hydrocarbon bearing subterranean formation may increase the effectiveness of a treatment of that zone, for example, by increasing the lateral extent of the stress that can be placed on the field. Further, the notching may be used to control the formation of multiple horizontal fractures that are vertically stacked in either the zone or the hydrocarbon bearing subterranean formation. The formation of multiple fractures may increase the effects without requiring higher net pressure or flow rates for each fracture and may also allow achieving a desired treatment displacement profile.

[0094] The fracturing may follow a normal sequence for the injected fluids or may use an inverted injection sequence. In a normal injection sequence, the fluids increase in viscosity as the injection occurs, for example, from a thin fluid to a crosslinked polymer solution. In an inverted sequence, a thin fluid is injected first, then thicker fluids, followed by thinner fluids to finish.

[0095] The techniques may be used with any type of hydrocarbon bearing subterranean formation, such as oil, gas, or mixed reservoirs and may also be used to fracture other types of formations, such as formations used for the production of geothermal energy. In exemplary embodiments, the techniques can be used to enhance production of natural gas from unconventional, e.g., low permeability, gas reservoirs.

[0096] In embodiments described herein a single wellbore may be used to reach both the zone proximate and the hydrocarbon bearing subterranean formation, or separate wellbores may be used for access to each of the zone proximate and the subterranean formation. Similarly, a set of wells may be used for application of the principles and methods disclosed and provided herein, such as in a field-wide plan that utilizes numerous wellbores to effect the techniques provided herein. The inventive methods and systems provided herein may also be applied using any of a variety of wellbore configurations, such as substantially vertical wells, horizontal wells, multi-branch wells, deviated wellbores, and combinations

thereof. Well completions that may be used in embodiments are discussed further with respect to **Figs. 22 and 23**.

[0097] In embodiments, the stress on the zone proximate to the target formation may be applied by increasing a volume of the zone proximate. For example, a volumetric increase
5 may be created in the zone proximate by introducing a stress-inducing force into the zone proximate, such as via hydraulic fluid, explosively generated gases or pressure, thermal expansion, proppant or cuttings introduction, or other means of affecting such forces. The introduced force may be residual and long lasting or maintained such as via hydraulic fluid introduction, or short in duration such as via explosives. Either such action may introduce
10 residual volume increases, even though at least a portion of the volume increase may be lost when the force is removed. The action in the zone proximate is then translated or transferred into the objective formation, the subterranean formation, whereby a fracture field is created within the subterranean formation.

[0098] In embodiments, the stresses within the zone proximate to the target formation
15 may be altered by decreasing a volume of the zone proximate. The decrease in the volume of the zone proximate may effect a reduction in stress and structural support within the zone proximate. This reduction in structural support translates into a corresponding reduction in stability of the hydrocarbon bearing subterranean formation, resulting in creation of a fracture field within the subterranean formation. Examples of effecting a stress reduction in the zone
20 proximate may include freshwater dissolution of salt from a zone proximate, production of water or other fluids from a zone proximate to reduce structural support in the subterranean formation, chemical dissolution of the formation material within the zone proximate, physical removal of portion of the zone proximate, such as via a network of relatively large or under-reamed wellbores within the zone proximate, and similar actions or treatments to reduce
25 structural strength of the zone proximate with respect to the in-situ, pre-treatment, or pre-action strength.

[0099] Further, the changes in the stress of the zone proximate do not have to involve a volumetric change. The methods described herein may include any number of other techniques that alter the geomechanical stresses of a formation, including external or internal
30 stresses, by dislocation, displacement, strain changes, or fracturing of a zone proximate or subterranean formation, without substantial volumetric change therein. Although a volumetric change is not necessarily involved, the stress can still be communicated from the zone proximate to the targeted subterranean formation. The techniques described herein

generally include treating a zone proximate to a target formation to effect a stress change in the zone proximate, which will effect a permeability increase in the target formation.

[0100] Further, the application of the stress, e.g., through volumetric changes, does not have to be performed as a single event. In some embodiments, application and removal of the stress and strain on the zone proximate may be cycled to cause subsequent rubblization and fracturing within the subterranean formation. The increased rubblization at fracture surfaces can lead to further improvements in permeability within the targeted formation.

[0101] The stress applied to the targeted formation can cause delamination of layers and other forms of non-hydraulic fracturing, leading to the formation of cracks over a broad area. The cracks or fractures may result from a residual or “hysteresis” displacement of the formation components due to the strain displacement that remains, both while the stress is applied and after the stress is relaxed. The hysteresis effect results from the failure of the crack or fracture to heal completely, in the event further fracturing happens and/or the applied stress is reduced. Thereby, the permeability may be at least somewhat permanently improved. Ideally, the stress applied to the target formation creates some residual permeability in at least a portion of the targeted subterranean formation. The treatment duration may range from seconds, such as if explosives are used, to a period of months, such as if waste tailings are used to fracture and prop open the fractures in the zone proximate formation.

[0102] At the delaminated fractures, the formation surfaces or rock strata within the formation can be destroyed, forming a rubble layer or interface between the surfaces. Further, the formation surfaces can be offset from their original position, forming open apertures between the surfaces. If the volume changes in the proximate formation are repeated, the rubblization may be increased, forming channels through which natural gas, other hydrocarbons, or heated water, may be harvested. The use of an applied mechanical stress may be considered counterintuitive, since such stresses would normally tend to close fractures or cleats, leading to lower production. However, in exemplary embodiments, the application of stress may provide increased permeability and production rates, due to delamination along weak layers and rubblization within the target reservoir, as mentioned above and discussed in further detail below.

[0103] Although shown as being substantially parallel or coplanar with respect to each other in the figures to follow, the zone proximate and the hydrocarbon bearing subterranean formation may be situated in non-parallel planes. The zone proximate and hydrocarbon bearing subterranean formation may also be oriented substantially horizontal, vertical,

deviated, folded, originally arched, faulted, or irregularly positioned with respect to the wellbore and each other. Each may comprise a single geologic formation, zone, lens, or structure, or multiple formations, zones, lenses, or structures.

[0104] As discussed herein, embodiments of the present techniques can increase well productivity, lessen environmental impact, enhance well integrity and reliability, and improve well utilization and hydrocarbon recovery. Further, production rates and the recovery factor may be enhanced by cyclic “rubblization” over the full formation thickness. In contrast to hydraulic fracturing, which is generally halted by geological drainage boundaries, such as faults and pinchouts, delamination fractures may extend beyond geologic drainage boundaries, thereby reducing the number of wells and associated environmental footprint required for economic development. For example, the delamination may cover an area of about nine times the area of the volumetric expansion when the strength of the activated bedding plane interfaces is sufficiently low.

[0105] **Fig. 1** is a diagram of a hydraulic fracturing process **100**. The traditional method of fracture stimulation utilizes “hydraulic” pressure pumping and is a proven technology that has been used since the 1940s in more than 1 million wells in the United States to help produce oil and natural gas. In typical oilfield operations, the technology involves pumping a water-sand mixture into subterranean formation layers where the oil or gas is trapped. The pressure of the water creates tiny fissures or fractures in the formation. After pumping is finished the sand props open the fractures, allowing the oil or gas to escape from the formation and flow up a well.

[0106] For example, a well **102** may be drilled through an overburden **104** to a hydrocarbon bearing subterranean formation **106**. Although the well **102** may penetrate through the hydrocarbon bearing subterranean formation **106** and into the underburden **108**, perforations **110** in the well **102** can direct fluids to and from the hydrocarbon bearing subterranean formation **106**. The hydraulic fracturing process **100** may utilize an extensive amount of equipment at the well site. This equipment may include fluid storage tanks **112** to hold the fracturing fluid, and blenders **114** to blend the fracturing fluid with other materials, such as proppant **116** and other chemical additives, forming a low pressure slurry. The low pressure slurry **118** may be run through a treater manifold **120**, which may use pumps **122** to adjust flow rates, pressures, and the like, creating a high pressure slurry **124**, which can be pumped down the well **102** to fracture the formations in the hydrocarbon bearing subterranean formation **106**. A mobile command center **126** may be used to control the fracturing process.

[0107] The goal of hydraulic fracture stimulation is to create a highly-conductive fracture zone **128** by engineering subsurface stress conditions to induce pressure parting of the formation in the hydrocarbon bearing subterranean formation **106**. This is generally performed by injecting fluids with a high permeability proppant **116**, such as sand, into the hydrocarbon bearing subterranean formation **106** to overcome “in-situ” stresses and hydraulically-fracture the formation. The fracture zone **128** may be considered a network or “cloud” of fractures generally radiating out from the well **102**. Depending on the depth of the hydrocarbon bearing subterranean formation **106**, the fractures may often be predominately perpendicular to the bedding planes, e.g., vertical within the subsurface.

10 [0108] After the fracturing process **100** is completed, the treating fluids are flowed back to minimize formation damage. For example, contact with the fracturing fluids may result in imbibement of the fluids by pores in the hydrocarbon bearing subterranean formation **106**, which may actually lower the productivity of the reservoir. Further, a carefully controlled flowback may ensure proper fracture closure, trapping the proppant **116** in the fractures and holding them open. Stimulation is generally effective at near-well scale, for example, in which the fracture dimensions are in the 100s of feet. Treating and production are often conducted in the same interval, e.g., the portion of the hydrocarbon bearing subterranean formation **106** reached by the well **102**. The fracturing process **100** may use significant amounts of freshwater and proppant materials. The orientation of the fractures is controlled by the local stresses in the hydrocarbon bearing subterranean formation **106** as discussed further with respect to **Fig. 2**.

25 [0109] **Fig. 2** is a drawing of a local stress state **200** for an element **202** in a hydrocarbon bearing subterranean formation. The state of stress in the earth is defined by the mass of the overburden, the pressure in the pores of the rock, the tectonic stresses governing boundary conditions, and the basic mechanical properties of the rock, such as elastic moduli or stiffness. The in-situ earth stresses determine the predominant orientation of hydraulic fractures. The presence of natural fractures, the configuration of the completion itself, and the characteristics of the treating fluids may alter the earth stresses near the well and thereby influence growth of hydraulic fractures for a relatively short distance away from the well.

30 [0110] The earth stresses can be divided into three principal stresses where σ_v is the vertical stress in this drawing, $\sigma_{\max}^H$ is the maximum horizontal stress, while $\sigma_{\min}^h$ is the minimum horizontal stress, where $\sigma_v > \sigma_{\max}^H > \sigma_{\min}^h$. These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction and from layer to layer. The magnitude and direction of the principal stresses are

important because they control the pressure required to create and propagate a fracture in the reservoir, the shape of the fracture, the vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush or embed the propping agent during production.

5 [0111] Fractures in a horizontal direction, e.g., perpendicular to a vertically drilled well or parallel to a horizontally drilled well, may be more effective at conducting hydrocarbons back to the well for production. In deeper wells, the higher vertical stress from the overburden may often force fractures to be predominately vertical, e.g., perpendicular to a horizontally drilled wellbore.

10 [0112] However, other stress conditions may exist in formations. These stress conditions may contribute to the tendency for horizontal or vertical fractures to form. For example, depending on geologic conditions, the vertical stress could be substantially equivalent to the orthogonal lateral stresses. In this condition, termed lithostatic, the direction of a fracture may be controlled by any stress perturbations that take place in the formation. One such perturbation is the wellbore itself, which may favor the formation of vertical fractures.

15 Another perturbation would be the creation of a notch in the formation, as discussed with respect to **Fig. 11**. The notch may favor the creation of horizontal fractures in the formation.

[0113] In another condition, the formation may be formed from a rock that is transversely isotropic. In this case, the rock itself is formed along planar layers that favor the formation of fractures along the planes. If the planes are parallel to the surface, the formation may have an

20 increased tendency to form horizontal fractures, even under high vertical stress. As another example, a formation may be overpressured, in which the formation has a high pore pressure. Under this condition, the high pore pressure may have a tendency to offset a high vertical stress, allowing the fracturing to be controlled by the addition of stress perturbations in the formation. Generally, as the pressure in the hydrocarbon bearing subterranean formation

25 drops, for example, during production, further fracturing may be horizontal due to reorientation of the stresses. This is discussed in further detail with respect to **Fig. 9**. The stresses may also be adjusted to favor the growth of horizontal fractures, as discussed with respect to **Figs. 10-12**.

[0114] **Fig. 3** is a drawing of an opening mode (mode I) **300** of fracture formation, commonly resulting from a standard hydraulic fracturing process. Fractures generally propagate in one or more of three primary modes as discussed with respect to **Figs. 3 and 7**. While each mode is capable of propagating a fracture, standard hydraulic fracture stimulation

5 predominantly utilizes mode I **300**, resulting from “direct” fluid pressure parting of the formation. In mode I **300**, the pressure of the hydraulic fracturing fluid either creates fractures or advances pre-existing fractures. The fractures are propagated by tensile breaking of the formation at the crack tip.

[0115] As noted herein, the fractures may often be nearly vertical and approximately

10 perpendicular to bedding planes. At shallow depths, the fractures produced may be horizontal, in which case they likely will be parallel to bedding planes. In standard hydraulic fracturing, the hydraulic pressure and fluids directly contact the formation being fractured or treated. Application of the traditional hydraulic fracturing method to unconventional hydrocarbon resources, such as tight gas or shale gas reservoirs, requires both large numbers

15 of wells and large numbers of fracture treatments in each well. These requirements are largely driven by the relatively small “effective” area that is created during the hydraulic fracturing process due to inherent limitations in the treating fluids, proppants, reservoir stratigraphy, and in-situ stresses. In exemplary embodiments of the present techniques, a new fracturing concept can be used to achieve massive fracture stimulation of wells, particularly

20 for unconventional hydrocarbon resources. In these embodiments, a volumetric increase or decrease in a layer adjacent to the hydrocarbon bearing subterranean formation can be used to place or relieve a stress on the reservoir, leading to fracturing in the reservoir.

[0116] **Fig. 4** is an exemplified drawing of a hydraulic fracturing system **400**, wherein a zone **402** below a hydrocarbon bearing subterranean formation **404** is subjected to a

25 volumetric expansion **406**, which can place stress on the hydrocarbon bearing subterranean formation **404** leading to fracturing. The techniques are not limited to a hydrocarbon bearing subterranean formation **404**, but may be used in any number of situations where fracturing a formation layer would be useful, such as in the production of geothermal energy. In the hydraulic fracturing system **400**, all like units are as discussed with respect to **Fig. 1**. In this

30 embodiment, the drilling and production wastes from the field may be used for the hydraulic fracturing of the zone **402**, lowering the requirements for freshwater over standard hydraulic fracturing. Further, the drilling cuttings may be used to provide a proppant to maintain the fractures open in the zone **402**. The present techniques are not limited to hydraulic fracturing of the zone **402**. In embodiments, thermal expansion may be used to create the volumetric

expansion **406**. Further, a pressurized liquid may be used to cause the volumetric expansion **406** of the zone **402** without fracturing. The volumetric expansion **406** may be cycled by successive heating and cooling cycles, or successive fluid injections and removal cycles.

[0117] In other embodiments, a chemical treatment may be applied in the zone **402** to create an area of cavitation. The present techniques are not limited to a chemical treatment of the zone **402**. In embodiments, the volumetric contraction **406** may be provided through production of fluids from non-hydrocarbon productive zone **402** to create subsidence in both the non-hydrocarbon-bearing zone and in the adjacent hydrocarbon bearing subterranean formation **404**, thereby creating a network of conductive fractures in both zones, including any intermediate zones, such that hydrocarbon can flow from the HC-bearing reservoir to the non-hydrocarbon bearing zone and finally to the wellbore. In some embodiments, the network of conductive fractures may facilitate production of the hydrocarbons directly from the HC-bearing zone directly to the wellbore or another wellbore that is separate from the wellbore used for the treatment process. Further, a borehole could be drilled in the zone **402** to induce the volumetric contraction **406**. The effects of volumetric contraction **406** may be enhanced by alternately injecting (for example, hours, days, weeks, months, and even years) and then producing fluid in successive cycles.

[0118] A number of liquids may be sequentially injected to perform the horizontal hydraulic fracturing in the hydrocarbon bearing subterranean formation. A first liquid pumped into the fracture zone is termed a pad, and may be a low viscosity brine solution. After the pad, a higher viscosity linear or cross-linked gel may be pumped into the fracture zone to create the primary planar fractures. Once the planar fractures are created, a slick water fluid can be pumped, along with the high permeability proppant **116**, to fill the primary fracture and to create secondary fractures or open natural fracture systems. Other pumping orders and system may be used in embodiments, for example, when fracturing zones proximate to the hydrocarbon bearing subterranean formation.

[0119] In some embodiments, the formation layers of interest are mechanically damaged or “delaminated,” for example, by arching, or bending flexure, of the hydrocarbon bearing subterranean formation **404**. This may occur from dilating, enlarging, or uplifting formations in the zone **402** from below. The method used to treat the hydrocarbon bearing subterranean formation **404** would need to create the stress state sufficient to impose delamination fracturing along preferred layers of interest. The delamination fractures may be created without pressurizing the fracture surfaces of the hydrocarbon bearing subterranean formation **404** with treating fluids. As stimulation fluids do not need to contact the surfaces of the

formation, the hydrocarbon bearing subterranean formation **404** may not be damaged by imbibement of the treating fluids. The stimulation may be effective at reservoir scale, i.e., the fracture dimensions may be on the order of 1000s of feet. Further, the treating and the production may be conducted in different intervals, using the same or separate wells.

5 **[0120]** **Fig. 5** is a block diagram of a method **500** for stimulation of a reservoir by treating an interval outside of the reservoir. As used herein, a reservoir is a portion of hydrocarbon bearing subterranean formation that is being used for the production of hydrocarbons. A treatment interval is a zone proximate to the reservoir that is being treated to enhance the production from the reservoir. The treatment interval or zone may lie within the reservoir, or
10 may be separate from the reservoir. The method **500** begins at block **502**, with the drilling and completing of a well to the treatment interval. The treatment interval may be a formation under the hydrocarbon bearing subterranean formation, as generally discussed with respect to **Fig. 4**. In other embodiments, the treatment interval may be beside or above the hydrocarbon bearing subterranean formation, for example, if the hydrocarbon bearing subterranean
15 formation is in a deviated formation. At block **504**, the treatment interval may be treated. For example, fracturing fluids may be injected into the treatment interval. The fracturing fluids may or may not include solids for proppants, such as crushed drilling cuttings from wells. In embodiments, the treatment may be performed by successively inflating and deflating the treatment interval to cause rubblization of the hydrocarbon bearing subterranean
20 formation. The treatment may be performed by inserting a heat source into the treatment interval to cause inflation of the treatment interval by thermal expansion.

[0121] At block **506**, a production well is completed to the reservoir to produce hydrocarbons. The production well may be drilled after stimulation from the treating well, thereby reducing the potential for subsequent well integrity or reliability issues. In
25 embodiments, the production well may be the same as the treatment well, for example, by creating perforations in the well at the interval of the hydrocarbon bearing subterranean formation, or by drilling production wells from the treatment well. At block **508**, hydrocarbons may be produced from the production well. The method **500** is not limited to the order shown. In embodiments, the well may be completed at block **506** before the
30 treatment at block **504** to allow direct treating of the reservoir prior to production.

[0122] It will be clear that the techniques described herein are not limited to the production of hydrocarbons, but may be used in other circumstances where a subterranean formation is fractured to aid in the production of fluid. For example, in embodiments, the techniques may be used to fracture a hot dry rock layer for use in geothermal energy

production. Water or other fluids may then be circulated through the fractures, collected in a production well, and returned to the surface for harvesting heat energy. The wells are not limited to the conformations discussed above. In embodiments, various treating, and producing well patterns and operational schemes may be considered to concurrently optimize reservoir stimulation, gas production, waste disposal, and well operability.

[0123] Fig. 6 is a more detailed schematic view of a delamination fracture stimulation 600 showing the physics that may lead to delamination fracturing. A well 602 may be drilled through a hydrocarbon bearing subterranean formation 604, and into a treatment interval or zone 606 below the hydrocarbon bearing subterranean formation 604. The treatment interval or zone 606 does not have to be adjacent to the hydrocarbon bearing subterranean formation 604, but may have one or more intervening layers 608. These layers 608 may lower the chance that a treatment fluid, if used, will leak into the hydrocarbon bearing subterranean formation 604. Further, if waste tailings are used as proppants, the layers 608 may assist in fixing the tailings in place, lowering the probability that material may migrate into the hydrocarbon bearing subterranean formation 604 or other locations, such as aquifers.

[0124] As the treatment progresses, a volumetric expansion 610 occurs in the treatment interval or zone 606, which presses upwards on the layers 608, forming an arch or dome 612 in the hydrocarbon bearing subterranean formation 604. In the embodiment shown, fluids and/or particulate solids are injected into the treatment interval or zone 606 to dilate, uplift, “arch,” and shear fracture the hydrocarbon bearing subterranean formation 604. The distance, or vertical distance, between the zone 606 and the hydrocarbon bearing subterranean formation 604 may control the size of the area over which the treatment affects the hydrocarbon bearing subterranean formation 604. A layer that is further from the hydrocarbon bearing subterranean formation 604 may affect a wider area, but with a lower total movement or rubblization. For example, if a treatment of a zone 606 located around 50 m under the hydrocarbon bearing subterranean formation 604 caused a vertical motion of about 2 cm over a distance of about 500 m, treatment of a zone 606 located about 100 m under the hydrocarbon bearing subterranean formation 606, using the same expansion conditions, may cause a vertical motion of about 1 cm over a horizontal distance of about 1000 m.

[0125] Further, the arch or dome 612 may have a highest stress region, e.g., the area in which the fractures form within the hydrocarbon bearing subterranean formation 604, that is not centered on the injection well 602. As the distance between the volumetric expansion 610 and the hydrocarbon bearing subterranean formation 604 increases, so does the distance

between the well **602** and the highest stress point in the hydrocarbon bearing subterranean formation **604**. Accordingly, if the highest stress point in the hydrocarbon bearing subterranean formation **604** is sufficiently separated from the well **602**, fracturing of the hydrocarbon bearing subterranean formation **604** may be used to couple the fracture field
5 around the highest stress point with the well **602**.

[0126] In addition to separation distance, the choice of the treatment zone **606** may be made on the basis of formation properties, both in the zone **606** and in the hydrocarbon bearing subterranean formation **604**. A relatively impermeable formation may be useful for treatment using hydraulic fracturing techniques, as the zone **606** may have lower leak-off,
10 making the treatment more efficient. If waste tailings are going to be used, this may be less of an issue, as the zone **606** may be propped open and expanded, even after pressure has leaked off. If thermal expansion is going to be used, the zone **606** may be selected to have a higher coefficient of thermal expansion than other surrounding zones.

[0127] In addition to the properties of the formation within the zone **606**, the properties of
15 the material in the hydrocarbon bearing subterranean formation **604** may also influence the choice of expansion techniques and location. For example, if the hydrocarbon bearing subterranean formation **604** is shale, a slow expansion may not open sufficient cracks, as a ductile shale may have enough plastic deformation to reseal the cracks. Thus, an explosive deformation may cause a fast enough deformation, such as on the order of seconds, to shatter
20 the shale without plastic flow resealing the cracks. In this case, the zone **606** may be selected to have a hard rock, such as granite, that can transfer the energy of expansion to the hydrocarbon bearing subterranean formation **604**.

[0128] A hydrocarbon bearing subterranean formation **604** may often have weaker layers
25 **614**, or even inherent fracture planes **616**. The arching can cause shear stress in the hydrocarbon bearing subterranean formation **604**, leading to sliding or breaking of the hydrocarbon bearing subterranean formation **604** along these layers **614** and fracture planes **616**, as indicated by the arrows **618**, creating delamination fractures **620**. Thus, the delamination fracture stimulation **600** can create a highly-conductive multi-fracture / dual-porosity reservoir system by delaminating formation layers, parting the formation within
30 layers, and rubblelizing the formation "in-situ." The injection operations may also create relative movement or displacement between the fracture surfaces along the layers **614** and fracture planes **616** to achieve fracture conductivity, for example, by creating delamination fractures **620** that contain enhanced permeability debris. Vertical fractures **622** may also be created during the delamination process. The control of stresses in the formation may be

used to control the direction of the fractures, as discussed with respect to **Figs. 10-13**.

[0129] In addition to the injection of fluids, embodiments may induce delamination fractures in the hydrocarbon bearing subterranean formation **604** using in-situ techniques, such as thermal heating, explosive detonations, and the like to enlarge the volume of the treatment interval or zone **606** and thereby increase the stresses at the target formation intervals such that shear-dominated fractures delaminate along, and possibly normal to, the bedding planes. In some embodiments, the zone **606** may be decreased in volume, for example, by erosion, chemical attack, removal of fluids and the like. The reduction of volume in the zone **606** can cause delamination fractures to occur from subsidence of the hydrocarbon bearing subterranean formation **604**.

[0130] The flow conductivity of the delamination fractures may be enhanced by cyclically inflating and deflating the treatment interval or zone **606** such that the delaminated formations “rubblize” due to frictional contact and relative sliding motion between formation surfaces, creating an in-situ propped bed of failed formation material. This is discussed further with respect to **Fig. 8**.

[0131] In contrast with the direct hydraulic fracture stimulation of a hydrocarbon bearing subterranean formation **604**, the delamination fracture stimulation **600** can decrease direct fluid contact with the formation fracture face, thereby reducing the potential for formation damage and the need for flowback clean-up. Further, fracture “conductivity” is created *in-situ* over the full fracture dimensions, thereby enhancing productivity and eliminating the need for transporting proppants. The fractures **620** may also extend beyond geologic drainage boundaries, such as faults, pinchouts and the like, reducing the number of wells required for economic development. The fracture delamination may be created using “waste disposal” products, such as drill cuttings, produced brines, and the like, to enhance volumetric strain, reducing the need for customized fracturing formulations and large volumes of freshwater.

[0132] In some embodiments described herein, a notching technique may be used to promote the growth of horizontal fractures in the zone **606**. This can increase the efficiency of the indirect process by increasing the area over which the forces act on the hydrocarbon bearing subterranean formation **604**. Notching may also be used in the hydrocarbon bearing subterranean formation **604** to promote horizontal fractures used to couple the fracture field to the well **612** for production. This may be performed before the treatment of the zone **606**, in order to initiate and lubricate the fracture planes in the hydrocarbon bearing subterranean formation **604**, increasing the effects resulting from the treatment of the zone **606**.

[0133] In summary, the delamination fracture stimulation **600** is based on three physical components, including delamination, rubblization, and stress control. The relative importance of each of these components is dependent on the parameters of the particular application, for example, the depths of treatment interval or zone **606** and hydrocarbon bearing subterranean formation **604**, the thicknesses of each interval **604** and **606**, the formation properties, the pore pressures, the in-situ stress environments, and the like. These parameters are discussed in more detail with respect to **Figs. 7-10**.

[0134] **Fig. 7** is a drawing **700** of two modes of fracture formation that may participate in delamination fracture stimulation as discussed herein. Both of these modes are based on shearing the formation, rather than tensile parting of the formation. An in--plane shear mode **702** develops a fracture **704** that is aligned (i.e., in the same two-dimensional plane) with the applied shear stress **706**. The in-plane shear mode **702**, also termed mode II, may develop as an arch or bend that distorts a reservoir. Further, the in-plane shear mode **702** may develop horizontal fractures, for example, as some layers **708** are placed under compressive stress, while other layers **710** are released from compressive stress. Additional mode I **300** "non-hydraulic" tensile fractures also may be incurred from stress arching of the reservoir. Another mode of fracture formation is an anti-plane shear mode **712**, also termed mode III. Similarly, the anti-plane shear mode **712** develops a fracture **714** that also is aligned in the same two-dimensional plane with the applied shear stress **716**. This mode may also participate in both vertical and horizontal fractures as adjacent layers are moved in opposite directions. In embodiments, both mode II **702**, and mode III **712**, or any combinations thereof, may propagate damage and fractures perpendicular or parallel to bedding planes through the use of a volumetric increase in layers outside of a reservoir interval. The shearing modes may cause material to disaggregate.

[0135] **Fig. 8** is a drawing of rubblization **800** during shearing **802** at a fracture boundary **804**. Direct hydraulic fracturing of a reservoir generally causes tensile fracturing of reservoir rocks as discussed with respect mode I shown in **Fig. 3**. In contrast, the shearing **802** that takes place in embodiments, as discussed with respect to **Fig. 7**, can force formation surfaces to slide against each other at a bedding plane interface or fracture boundary **804**. Frictional engagement of features on the surfaces may cause the formation to break, leading to the formation of a rubblized layer within or adjacent to the fracture boundary **804**.

[0136] As mentioned previously, the flow conductivity of delamination fractures may be enhanced by cycling the induced flexures such that the delaminated formations "rubblize" within or adjacent to the fracture boundaries **804** due to frictional contact and relative

movement between formation surfaces. This process may create a propped bed of failed formation material *in-situ*. Based on measurements of formation debris fields created during movements of faults, the thickness of the rubblized zone adjacent to the delamination fractures may up to about 20 % of the cumulative linear or transverse movement of the fracture surfaces. Although the amount of formation debris created may be lower with each subsequent cycle, significant porosity may be created in fracture debris zones through the cyclic movement. The failed formation is referred to herein as Cyclic Rubblized Material (“CRM”). CRM results in secondary permeability, i.e., dual permeability and porosity.

Stress Distribution and Rearrangement

[0137] Figs. 9(A) and 9(B) are plots 900 of surface deformation induced by fractures in a lower lying formation. In Fig. 9(A), a vertical fracture field 902 induces a surface deformation 904 that has a minimum in the vicinity of a well 906 that is used for the treatment. In Fig. 9(B), a horizontal fracture field 908 causes a larger surface deformation 910. A local maximum may exist in the vicinity of the well 912, but this depends on the separation 914 between the surface and the horizontal fracture field 908. Accordingly, the measured deformation pattern may reveal the shape and dimension of the treatment. The deformations also show an advantage of creating a horizontal fracture field 908 over a vertical fracture field 902 can create a larger deformation, and, thus, a greater stress, in an overlying formation. Horizontal fracture fields 908 may be promoted in a number of different ways, as discussed with respect to Figs. 10-13.

[0138] Fig. 10 is a drawing of an azimuthal rotation 1000 of fracture planes 1002 within a formation that may occur as a result of cyclic treatment of the formation. The in-situ earth stresses determine the predominant orientation of hydraulic fractures. At shallow depths, hydraulic fractures generally are horizontal and easily create arching, uplift and delamination fractures in formation layers above. However, at deeper depths, hydraulic fractures generally are vertical and the horizontal stresses must be increased to locally re-orient hydraulic fractures.

[0139] As discussed above with respect to Fig. 2, the earth stresses can be expressed as three principal stresses. In this case, σ_v is the vertical overburden stress and is initially the highest stress in the system. Further, $\sigma_{\max}^H$ is the maximum horizontal stress, while $\sigma_{\min}^H$ is the minimum horizontal stress, where $\sigma_v > \sigma_{\max}^H > \sigma_{\min}^H$. Although, at all depths, injection of fluids creates volumetric increases due to pore dilation or thermal expansion, the initial fracture plane 1004 that forms within the treatment zone may be vertical, which may not place an effective amount of stress on the hydrocarbon bearing subterranean formation.

Specially engineered stress conditions may shift the position of the overburden stress to the intermediate ($\sigma_{\max}^H$) or minimum stress ($\sigma_{\min}^H$), especially in regions near the well. For example, the engineering of the stress conditions may be performed by sequentially fracturing and propping the formation, leading to an increase in horizontal stresses. As the horizontal stresses dominate the vertical stresses, the fracture planes will rotate into the horizontal.

[0140] As a result, the axis of each successive fracture plane **1002** in a cyclic fracturing process may be slightly shifted or rotated from the last fracture plane **1002**, as indicated by an arrow **1006**. This may continue until a final fracture plane **1008** may be horizontal. Fracture re-orientation is dependent on the characteristics of the pumping treatment (i.e., fluid rheology, temperature, pressure, rate, solids content, treatment duration, shut-down schedule), and generally occurs initially about the “azimuth” axis and subsequently about the “inclination” axis until turning horizontal.

[0141] Although the technique discussed with respect to **Fig. 10** will increase stress in the formation and rotate the fracture plane to generate horizontal fractures, it will take a number of cycles to perform the rotation. Other techniques may be used to initiate horizontal fracture in a faster time frame, as discussed with respect to **Figs. 11-13**.

[0142] **Fig. 11** is a drawing **1100** of a vertical well **1102** passing through a reservoir interval **1104** and a treatment interval **1106**, in which a notch **1108** has been formed in the treatment interval. The notch **1108** is a carved indentation in the treatment interval **1106** that creates a stress increase at the tip, promoting a horizontal fracture. The notch **1106** can be created using any number of down hole tools, such as a jet drilling tool. The notch **1106** can also be created using any number of other techniques, such as an under-reaming tool to mechanically remove material around the wellbore in the desired plane for fracture growth. Alternative, other means may include an acid wash to create a plane of wormholes in the treatment interval **1106**. The notching is not limited to the treatment interval **1106**, but may also be performed in the reservoir interval **1104** to promote the growth of a horizontal fracture, for example, to couple a fracture field to the vertical well **1102**, to lubricate fracture planes, or both.

[0143] **Fig. 12** is a drawing **1200** of the stress distribution in the formation around the tip of a notch **1202**. As can be seen in **Fig. 12**, the notch **1202** creates a high stress region **1204** at the tip, facilitating an origination of a crack which propagates out in a perpendicular direction **1206** from a well **1208**. This technique may also be used in the hydrocarbon bearing subterranean formation to enhance the growth of horizontal fractures that may be

used to couple the well to a fracture field.

[0144] Although the induced stress will preferentially start a horizontal fracture in the perpendicular direction **1206** from the well **1208**, as the fracture moves out into a formation, the stress distribution in the formation may steer the fracture in a different direction. For example, the fracture may turn from the horizontal direction to the vertical direction in formations having a higher vertical stress component.

[0145] **Figs. 13(A) and (B)** are plots of horizontal stress states **1300** in a formation around a vertical well **1302** and in the formation when vertical fractures are present in the formation. Stress states **1300** in the formation may be altered using thermal heating, poroelastic dilation, or fracture opening approaches. Each approach will induce dilation in the formation volume so that horizontal stresses in the formation are increased. **Fig. 13(A)** shows the changes in stress states after dilating a formation using a thermal or poroelastic approach, in which the dilation occurs over a formation volume near the wellbore.

[0146] **Fig. 13(B)** shows an example of increased horizontal stresses around a well **1302** due to the opening of a vertical fracture. In this case, high stress states extend farther out from the well **1302** than for the poroelastic dilation. A combination of the various approaches may be used to perform an efficient stress control treatment. For example, steam may be injected through a vertical fracture at high pressure so that all three components of the dilation, e.g., thermal heating, poroelastic dilation, and fracture opening, may be combined to alter earth stress. This stress control treatment may include an initial injection of steam or cold fluid through the well **1302**, and / or a vertical fracture, into the treatment interval to increase horizontal stresses. Once the horizontal stresses become greater than the vertical stress, the formation can be fractured to create horizontal treatment fractures.

[0147] **Fig. 14** is a schematic **1400** of fracturing by an inverse pumping sequence. In an inverse pumping sequence, the fluids are not injected in order of increasing viscosity, but are injected in an order that is, at least in part, from higher viscosity fluids to lower viscosity fluids. The fracturing is performed from the well **1402** by forming notches in the formation at openings **1404** in the well **1402**. Packers **1406** can be placed in the well **1402** to isolate sections that have already been treated from sections that are currently being treated. After notching, the fracture **1408** can be created by the injection of various fluids under pressure.

[0148] A first injection fluid can be a thin brine solution, called the pad **1410**. The pad **1410** is normally present in wells, as the brine solution can be a component of many of the drilling fluids. In the inverse fracturing process shown, a thick solution **1412** can be used to create the initial horizontal fractures **1408**, generally of significant fracture aperture width than

lower viscosity fluids. The thick solution **1412** can be a cross linked polymer solution, a linear polymer solution, or any number of other high viscosity fluids. For example, the thick solution **1412** can include guar, cellulose acetates, polyacrylamides, and the like.

[0149] After the thick solution **1412** is injected, a slick water solution **1414** can be injected. Slick water is an aqueous solution that contains low molecular weight additives that lubricate the flow of the solution, such as low molecular weight surfactants, polyethylene oxides, and the like. The wider fractures created with the more viscous fluids allow the slick water solution to be pumped at a higher rates than other materials, resulting in higher down hole pressures. The higher down hole pressures result in the opening of secondary fractures **1416** along the horizontal fractures **1416**.

[0150] The slick water **1414** can also be mixed with proppants to hold open the fractures **1408** and **1416**, allowing materials to flow from the formation. The proppants can include any number of known materials, such as sieved sand, crushed not shells, ceramic spheres, polymer spheres, and the like. In some embodiments, the proppant may be selected to match the density of the slickwater solution, lowering the amount of proppant that may settle or float out.

[0151] The delamination fracture (D-frac) stimulation process described herein may use a large volume of fluid to dilate and /or heat the treatment interval. As a result, long treatment times and increased treatment cost, may be required if the permeability or the thermal conductivity of the treatment interval are low. Further, when particulate solids, such as drill cuttings, cements, or waste products, are used as the primary treating agent, dilation of the treatment interval is mainly achieved through the opening of the treatment fractures. If a single treatment fracture is used, extremely large net pressure may be required to create a large volumetric dilation. Due to the brittle nature of most rock types in unconventional resources, achieving large net pressure in a single fracture may be impossible as the fracture will propagate.

[0152] The control of the fracturing direction allows techniques to be used to increase the efficacy of the treatments. For example, a sequence of horizontal fractures may be generated in a zone or formation and expanded as described herein. The use of multiple fractures may decrease the net pressure required to expand the formation, as well as the amount of time needed for the treatment.

[0153] **Fig. 15** is a drawing **1500** of a technique that may be useful for increasing the effects of the treatment of a zone on the hydrocarbon bearing subterranean formation by fracturing and treating a treatment formation at multiple points along a well. In this example,

the well **102** is vertically drilled to a zone **402** below a hydrocarbon bearing subterranean formation **404**. Like numbered items are as described with respect to **Fig. 4**. As shown in the drawing **1500**, multiple horizontal fractures **1502** may first be created and propped open in the zone **402**, then fluid or steam may be injected into the treatment interval at a pressure slightly higher than the vertical stress so that fluid or steam may enter the fractures **1502** and diffuse into the formation. Due to the smaller spacing between fractures allowed by the controlled formation of the horizontal fractures **1502**, pressure or temperature within the zone **402** will increase and equilibrate over a shorter time frame. Thus, if thermal or poroelastic treatment methods are used, simultaneous injection through multiple treatment fractures may greatly reduce the treatment time required for generating sufficient delamination. Further, if particulate solids, such as cement, drill cuttings or waste products, are used as treating materials, multi-stage injection may be performed through a number of stacked horizontal fractures with manageable net pressure for each stage. In either case, the Multi-Zone Stimulation Technology (MZST) may be used to expedite the process of creating multiple treatment fractures, thereby reducing time, and cost of the treatment.

[0154] **Fig. 16** is a drawing **1600** of a multi-stage injection method that may be useful for increasing the effects of the treatment of a zone **402** on the hydrocarbon bearing subterranean formation **404**. Like numbered items are as described with respect to **Fig. 4**. In the technique, multiple horizontal fractures **1602**, **1604**, and **1606** are created in the zone **402**. Each of the horizontal fractures **1602**, **1604**, and **1606** may be successively inflated by the pumping of high pressure fluid containing particulate solids into the horizontal fractures **1602**, **1604**, and **1606** in a sequential fashion, for example, inflating horizontal fracture **1602**, then horizontal fracture **1604**, and finally horizontal fracture **1606**. The techniques are not limited to this order, as any sequence may be used. The procedure generally includes determining a total required net pressure (P_{total}) for a single fracture with the designed treatment volume (V) and the radius (R) of the treatment fracture using an equation:

$$P_{total} = P_{total}(V, R, M),$$

wherein C_{ijkl} are the elastic constants of the rock in the treatment interval. In a particular embodiment in which the treatment interval has very low permeability and the fracture is stable or stationary, the total required pressure is given as

$$P_{total} = \frac{3}{16} \frac{V}{R^3} \frac{E}{1-\nu^2}.$$

wherein E is the Young's modulus of the rock in the treatment interval and ν is Poisson's ratio for the rock in the treatment interval. A number of stages (N_{stage}) may be determined using the maximum allowable net pressure per stage (P_c): $N_{\text{stage}} = P_{\text{total}} / P_c$. The location of the fractures in each stage can be determined, for example, based on the thickness of the treatment interval, with Stage 1 being farthest from the reservoir interval. The treatment can then be sequentially performed through each stage while maintaining manageable and relatively constant net pressure for each stage

[0155] Fig. 17 is a plot of formation uplift resulting from sequentially fracturing at ten points along a well 102, using the procedure discussed with respect to Fig. 16. The treatment is started towards the bottom of the formation and is sequentially progressed up the formation, as shown by an arrow 1702.

Methods for fracturing a well

[0156] Fig. 18 is process flow diagram of a method 1800 for completing a formation using a notching procedure for the direct stimulation of the hydrocarbon bearing subterranean formation. At block 1802, geologic data about the hydrocarbon bearing subterranean formation is collected, including core, logs, stresses, stratigraphy, etc. The data is used to select initial treatment locations based on in-situ stresses, stratigraphy and reservoir properties. The optimal treatment location and volumes are selected based on economic constraints and recovery models

[0157] At block 1804, a plug is set below the reservoir interval or above last treatment location. At block 1806, a notching tool is lowered to the treatment location, the notch is created, and the tool is tripped out of the well. At block 1808, the fracturing treatment is performed. At block 1810, a determination is made as to whether all stages have been treated. If not, process flow returns to block 1804 to treat the next stage. If, at block 1810, it is determined that all stages have been treated, at block 1812, the plugs are milled out.

[0158] Fig. 19 is process flow diagram of a method 1900 for fracturing a formation using a notching procedure in conjunction with a treatment of a zone other than the production interval. At block 1902, treatment locations and processes may be determined, as discussed with respect to block 1802 of Fig. 18. At block 1904, the well is completed and the hydrocarbon bearing subterranean formation is fractured, generally following the method 1800 described with respect to Fig. 18.

[0159] At block 1906, a plug is placed above toe depth (TD) or the last treatment location. At block 1908, a notching tool is lowered to the treatment location, the notch is created, and

the tool is tripped out of the well. At block **1910**, the treatment of the zone is performed to create delamination fractures (D-Frac) in the reservoir interval by dilation or contraction of the treating interval. At block **1910**, a determination is made as to whether all stages of the treatment have been completed.

5 [0160] If at block **1910**, it is determined that more stages remain, process flow returns to block **1906** to perform the next treatment. If not, process flow ends at block **1914**.

[0161] Fig. **20** is process flow diagram of a method **2000** for an inverse pumping sequence to fracture a hydrocarbon bearing subterranean formation through notches. The method begins at block **2002** with the pumping of a pad. At block **2004**, a linear or cross-
10 linked gel is pumped to create a primary planar fracture. At block **2006**, slick water and proppants are pumped to fill the primary fracture and to create secondary fractures or open natural fracture systems. At block **2008**, the fluids are flushed, leaving the proppants in place. When used in conjunction with the treatment of the zone to cause D-Frac in the reservoir interval, the fracture design is similar to that for the reservoir except that it may not be
15 necessary to create secondary fractures.

[0162] Fig. **21** is process flow diagram of another method **2100** for an inverse pumping sequence to fracture a hydrocarbon bearing subterranean formation through notches. The method begins at block **2102** with the pumping of a pad. At block **2104**, linear or cross-linked gel is pumped to create a primary fracture. At block **2106**, fluids, for example, mixed
20 with waste tailings, chemicals, steam, or other materials, are pumped to induce a volumetric increase or decrease in the zone. At block **2108**, the fracturing fluids are flushed out. This may not be used if the fracturing is used as a waste disposal process.

Well configurations

[0163] The techniques described herein may be used in any number of well
25 configurations, both in the zone and in the hydrocarbon bearing subterranean formation. Figs. **22** and **23** are drawings of a number of well configurations that can be used in various embodiments of the techniques described herein. The well design options include, but are not limited to: vertical wells, deviated wells, multi-arm vertical wells, and multi-arm deviated well.

30 [0164] Figs. **22(A) – (D)** are well configurations that may be used to directly stimulate a subterranean hydrocarbon bearing formation. Fig. **22(A)** is a drawing of a vertical well **2202** having a series of notches **2204**, at which a fracturing treatment can be used to create horizontal fractures **2206**. The fracturing may be performed at all notches in a substantially simultaneous procedure. In other embodiments, the fracture treatment may be performed at

each notch **2204** from the base of the reservoir interval, for example, in a number of stages as described in **Figs. 16 and 17**.

[0165] **Fig. 22(B)** is a drawing of a deviated well **2208** having a series of notches **2204** through which horizontal treatment fractures have been created and propagated into the reservoir formation. As used herein, a deviated well has an angle that is substantially offset from vertical, for example, being at an angle of 5°, 10°, or more. The fracture treatment may be performed substantially simultaneously, or sequentially from the base of the reservoir interval in a number of stages as described in **Figs. 16 and 17**. A deviated configuration may allow coupling of a production well to a fracture field without further fracturing, since the well may directly pass through an offset fracture field.

[0166] **Fig. 22(C)** is a drawing of a multi-arm vertical well **2210** having a series of notches **2204** through which horizontal treatment fractures have been created and propagated into the reservoir formation. The fracture treatment may be performed substantially simultaneously, or sequentially from the base of the reservoir interval in a number of stages as described in **Figs. 16 and 17**.

[0167] **Fig. 22(D)** is a drawing of a multi-arm deviated well **2210** having a series of notches **2204** through which horizontal treatment fractures have been created and propagated into the reservoir formation. The fracture treatment may be performed substantially simultaneously, or sequentially from the base of the reservoir interval in a number of stages as described in **Figs. 16 and 17**.

[0168] **Figs. 23(A) - (D)** are drawings of a number of well configurations that can be used in embodiments of the techniques described herein. In each of the well configurations shown in **Fig. 23**, the wells penetrate both a treatment zone **402** and a hydrocarbon bearing subterranean formation **404**. In some embodiments, the D-Frac method may first be used in the hydrocarbon bearing subterranean formation **404** to create lubricating fractures and then in the zone **402** to create treatment fractures. This may be performed substantially simultaneously or sequentially from the bottom to the top of each interval.

[0169] **Fig. 23(A)** is a drawing of a vertical well **2302** drilled through both the zone **402** and the hydrocarbon bearing subterranean formation **404**. **Fig. 23(B)** is a deviated well **2304** drilled through both the zone and the hydrocarbon bearing subterranean formation.

[0170] **Fig. 23(C)** is a drawing of a multi arm vertical well **2306** drilled through both the zone **402** and the hydrocarbon bearing subterranean formation **404**. **Fig. 23(D)** is a drawing of a multi arm deviated well **2308** drilled through both the zone **402** and the hydrocarbon bearing subterranean formation **404**. The multi-arm deviated wells may be drilled to

penetrate both the zone **402** and the hydrocarbon bearing subterranean formation **404** at multiple locations. For each arm, the hydrocarbon bearing subterranean formation **404** may be treated first to create lubricating fractures and then the zone **402** may be treated to create delamination fractures. Optimal stimulation results may be achieved through manipulation of treatment between treating arms.

[0171] Embodiments of the claimed subject matter may include the methods and systems disclosed in the following lettered paragraphs:

- A. A method for fracturing a production formation, including:
 - creating a notch in a formation;
 - causing a volumetric change in a treatment interval proximate to a production interval so as to apply a mechanical stress on the production interval, wherein the treatment interval, the production interval, or both are located within the formation; and
 - creating a horizontal fracture in the formation originating from the notch.
- B. The method of paragraph A, including creating a fracture field in the production interval from the mechanical stress.
- C. The method of paragraph A, including creating the notch in the treatment interval.
- D. The method of paragraph A, including creating the notch in the production interval.
- E. The method of paragraph D, including creating the horizontal fracture in the production interval to couple a fracture field to a production well.
- F. The method of paragraph A, wherein both the treatment interval and the production interval are located in a reservoir.
- G. The method of paragraph A, including:
 - pumping a higher viscosity fluid to sustain an initial fracture; and
 - pumping a lower viscosity fluid to create or open secondary fractures.
- H. The method of paragraph A, including:
 - creating a plurality of notches in the treatment interval; and

fracturing the treatment interval sequentially at each of the plurality of notches to create a volumetric increase in the treatment interval.

I. The method of paragraph H, including fracturing the plurality of notches in a sequence from a lowest notch to a highest notch.

5 J. The method of paragraph A, including
drilling a deviated well through the treatment interval and the production interval;
stimulating the treatment interval through the deviated well; and
producing hydrocarbons from the production interval through the deviated well.

K. A hydrocarbon production system, including:
10 a production interval in a hydrocarbon bearing subterranean formation;
a treatment interval proximate to the production interval;
a stimulation well drilled to the treatment interval;
a production well drilled to the production interval;
a notching system configured to create notches in a formation including the
15 production interval, the treatment interval, or both;
a stimulation system configured to create a volumetric change in the treatment interval; and
a fracturing system configured to fracture the formation at the notches to create horizontal fractures.

20 L. The hydrocarbon production system of paragraph K, wherein the production interval includes a tight gas layer.

M. The hydrocarbon production system of paragraph K, wherein the treatment interval includes a layer in an underburden.

N. The hydrocarbon production system of paragraph K, including a fracture field
25 created by mechanical stress induced by the volumetric change in the treatment interval.

O. The hydrocarbon production system of paragraph K, wherein the production well and stimulation well are portions of a single deviated or vertical wellbore.

[0172] Still other embodiments of the claimed subject matter may include the methods and systems disclosed in the following numbered paragraphs:

1. A method for fracturing a production formation, including:
creating a notch in a formation;
5 causing a volumetric change in a treatment interval proximate to a production interval so as to apply a mechanical stress on the production interval, wherein the treatment interval, the production interval, or both are located within the formation; and
creating a horizontal fracture in the formation originating from the notch.
- 10 2. The method of paragraph 1, including creating a fracture field in the production interval from the mechanical stress.
3. The method of paragraph 1, including creating the notch in the treatment interval.
4. The method of paragraph 1, including creating the notch in the production
15 interval.
5. The method of paragraph 4, including creating the horizontal fracture in the production interval to couple a fracture field to a production well.
6. The method of paragraph 1, wherein both the treatment interval and the production interval are located in a reservoir.
- 20 7. The method of paragraph 1, wherein only the production interval is located in a reservoir.
8. The method of paragraph 1, including repeating the volumetric change for one or more cycles to cause rubblization along a delamination fracture.
9. The method of paragraph 1, including:
25 pumping a higher viscosity fluid to sustain an initial fracture; and
pumping a lower viscosity fluid to create or open secondary fractures.
10. The method of paragraph 1, including:
creating a plurality of notches in the treatment interval; and

fracturing the treatment interval sequentially at each of the plurality of notches to create a volumetric increase in the treatment interval.

11. The method of paragraph 10, including fracturing the plurality of notches in a sequence from a lowest notch to a highest notch.

5 12. The method of paragraph 1, including
drilling a deviated well through the treatment interval and the production interval;
stimulating the treatment interval through the deviated well; and
producing hydrocarbons from the production interval through the deviated well.

10 13. The method of paragraph 12, including:
drilling a well including a plurality of deviated branches through the treatment
interval and the production interval;
stimulating the treatment interval through the plurality of deviated branches; and
producing hydrocarbons from the production interval through the plurality of deviated
branches.

15 14. The method of paragraph 1, including:
creating a plurality of notches in the treatment interval; and
fracturing the treatment interval substantially simultaneously at each of the plurality
of notches to create a volumetric increase in the treatment interval.

20 15. The method of paragraph 1, including pumping a fracturing fluid into the
treatment interval to cause the volumetric change.

16. The method of paragraph 1, including thermally expanding the treatment
interval to cause the volumetric change.

17. The method of paragraph 1, including expanding the treatment interval with
explosives to cause the volumetric change.

25 18. The method of paragraph 1, including producing hydrocarbon from the
production interval.

19. A method for production of a hydrocarbon from a reservoir, including:
expanding a treatment interval below a production interval to mechanically stress the
production interval;

creating a fracture field to enhance conductivity within the production interval;

creating a notch in the production interval;

fracturing the production interval at the notch to form a horizontal fracture coupling the fracture field to a production well; and

5 producing hydrocarbon from the production interval.

20. The method of paragraph 19, including:

creating a notch in the treatment interval; and

fracturing the treatment interval at the notch to create a horizontal fracture.

21. The method of paragraph 19, including:

10 creating a plurality of notches in the treatment interval; and

fracturing the treatment interval at the plurality of notches to create an uplifted fractured field.

22. A hydrocarbon production system, including:

a production interval in a hydrocarbon bearing subterranean formation;

15 a treatment interval proximate to the production interval;

a stimulation well drilled to the treatment interval;

a production well drilled to the production interval;

a notching system configured to create notches in a formation including the production interval, the treatment interval, or both;

20 a stimulation system configured to create a volumetric change in the treatment interval; and

a fracturing system configured to fracture the formation at the notches to create horizontal fractures.

23. The hydrocarbon production system of paragraph 22, wherein the production
25 interval includes a tight gas layer.

24. The hydrocarbon production system of paragraph 22, wherein the treatment interval includes a layer in an underburden.

25. The hydrocarbon production system of paragraph 22, including a fracture field created by mechanical stress induced by the volumetric change in the treatment interval.

26. The hydrocarbon production system of paragraph 22, wherein the production well and stimulation well are portions of a single deviated or vertical wellbore.

5 [0173] While the present techniques may be susceptible to various modifications and alternative forms, the exemplary embodiments discussed above have been shown only by way of example. However, it should again be understood that the present techniques are not intended to be limited to the particular embodiments disclosed herein. Indeed, the present techniques include all alternatives, modifications, and equivalents falling within the true spirit
10 and scope of the appended claims.

CLAIMS

What is claimed is:

1. A method for fracturing a production formation, comprising:
5 creating a notch in a formation;
causing a volumetric change in a treatment interval proximate to a production interval
so as to apply a mechanical stress on the production interval, wherein the
treatment interval, the production interval, or both are located within the
formation; and
10 creating a horizontal fracture in the formation originating from the notch.
2. The method of claim 1, comprising creating a fracture field in the production
interval from the mechanical stress.
- 15 3. The method of claim 1, comprising creating the notch in the treatment interval.
4. The method of claim 1, comprising creating the notch in the production
interval.
- 20 5. The method of claim 4, comprising creating the horizontal fracture in the
production interval to couple a fracture field to a production well.
6. The method of claim 1, wherein both the treatment interval and the production
interval are located in a reservoir.
- 25 7. The method of claim 1, wherein only the production interval is located in a
reservoir.

8. The method of claim 1, comprising repeating the volumetric change for one or more cycles to cause rubblization along a delamination fracture.

5 9. The method of claim 1, comprising:
pumping a higher viscosity fluid to sustain an initial fracture; and
pumping a lower viscosity fluid to create or open secondary fractures.

10 10. The method of claim 1, comprising:
creating a plurality of notches in the treatment interval; and
fracturing the treatment interval sequentially at each of the plurality of notches to
create a volumetric increase in the treatment interval.

15 11. The method of claim 10, comprising fracturing the plurality of notches in a
sequence from a lowest notch to a highest notch.

12. The method of claim 1, comprising
drilling a deviated well through the treatment interval and the production interval;
stimulating the treatment interval through the deviated well; and
producing hydrocarbons from the production interval through the deviated well.

20 13. The method of claim 12, comprising:
drilling a well comprising a plurality of deviated branches through the treatment
interval and the production interval;
stimulating the treatment interval through the plurality of deviated branches; and
25 producing hydrocarbons from the production interval through the plurality of deviated
branches.

14. The method of claim 1, comprising:

creating a plurality of notches in the treatment interval; and

fracturing the treatment interval substantially simultaneously at each of the plurality of notches to create a volumetric increase in the treatment interval.

5

15. The method of claim 1, comprising pumping a fracturing fluid into the treatment interval to cause the volumetric change.

16. The method of claim 1, comprising thermally expanding the treatment interval
10 to cause the volumetric change.

17. The method of claim 1, comprising expanding the treatment interval with explosives to cause the volumetric change.

15 18. The method of claim 1, comprising producing hydrocarbon from the production interval.

19. A method for production of a hydrocarbon from a reservoir, comprising:
expanding a treatment interval below a production interval to mechanically stress the
20 production interval;
creating a fracture field to enhance conductivity within the production interval;
creating a notch in the production interval;
fracturing the production interval at the notch to form a horizontal fracture coupling
the fracture field to a production well; and
25 producing hydrocarbon from the production interval.

20. The method of claim 19, comprising:
creating a notch in the treatment interval; and
fracturing the treatment interval at the notch to create a horizontal fracture.

5 21. The method of claim 19, comprising:
creating a plurality of notches in the treatment interval; and
fracturing the treatment interval at the plurality of notches to create an uplifted
fractured field.

10 22. A hydrocarbon production system, comprising:
a production interval in a hydrocarbon bearing subterranean formation;
a treatment interval proximate to the production interval;
a stimulation well drilled to the treatment interval;
a production well drilled to the production interval;
15 a notching system configured to create notches in a formation comprising the
production interval, the treatment interval, or both;
a stimulation system configured to create a volumetric change in the treatment
interval; and
a fracturing system configured to fracture the formation at the notches to create
20 horizontal fractures.

23. The hydrocarbon production system of claim 22, wherein the production
interval comprises a tight gas layer.

25 24. The hydrocarbon production system of claim 22, wherein the treatment
interval comprises a layer in an underburden.

25. The hydrocarbon production system of claim 22, comprising a fracture field created by mechanical stress induced by the volumetric change in the treatment interval.

26. The hydrocarbon production system of claim 22, wherein the production well
5 and stimulation well are portions of a single deviated or vertical wellbore.

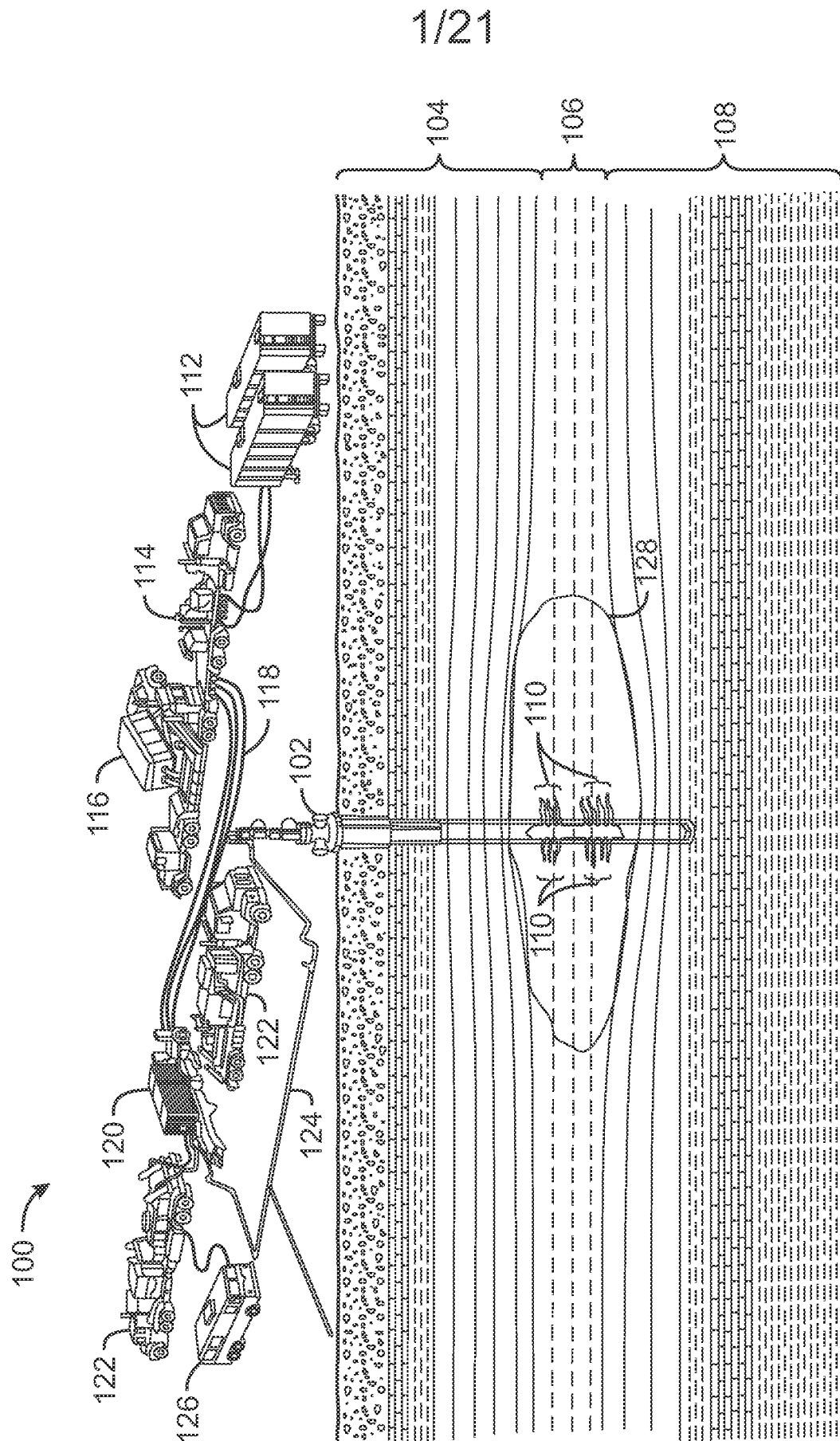
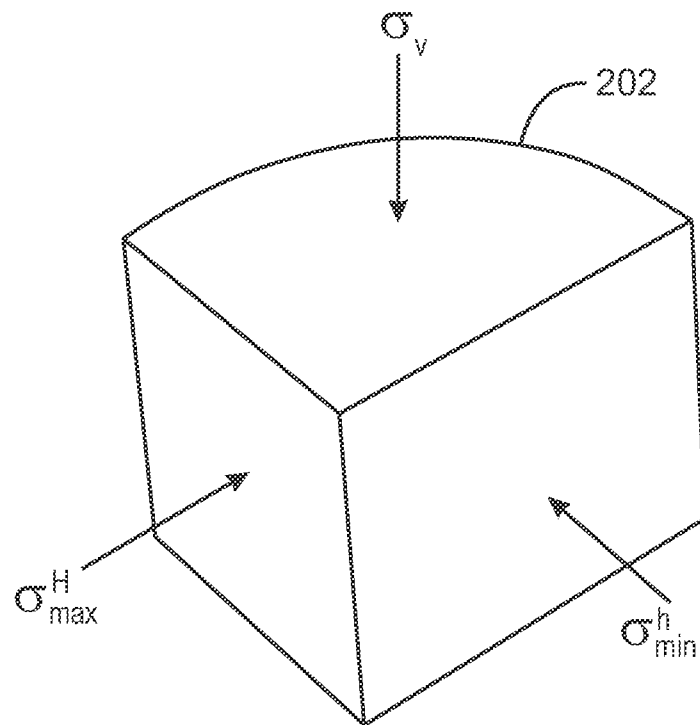


FIG. 1 (PRIOR ART)

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200
FIG. 2

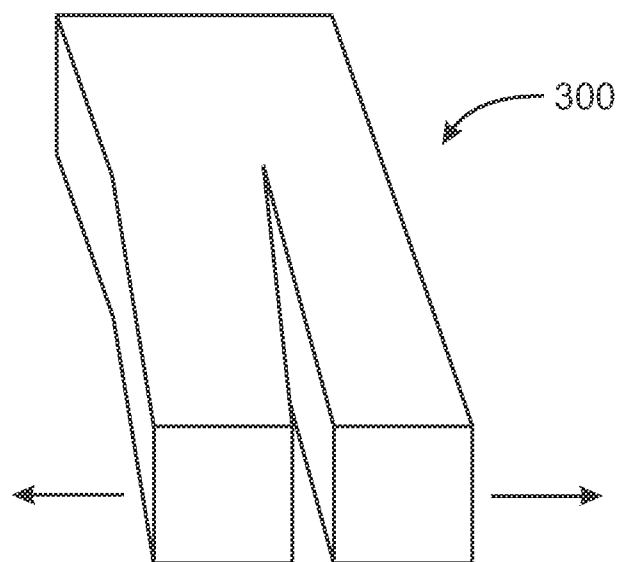
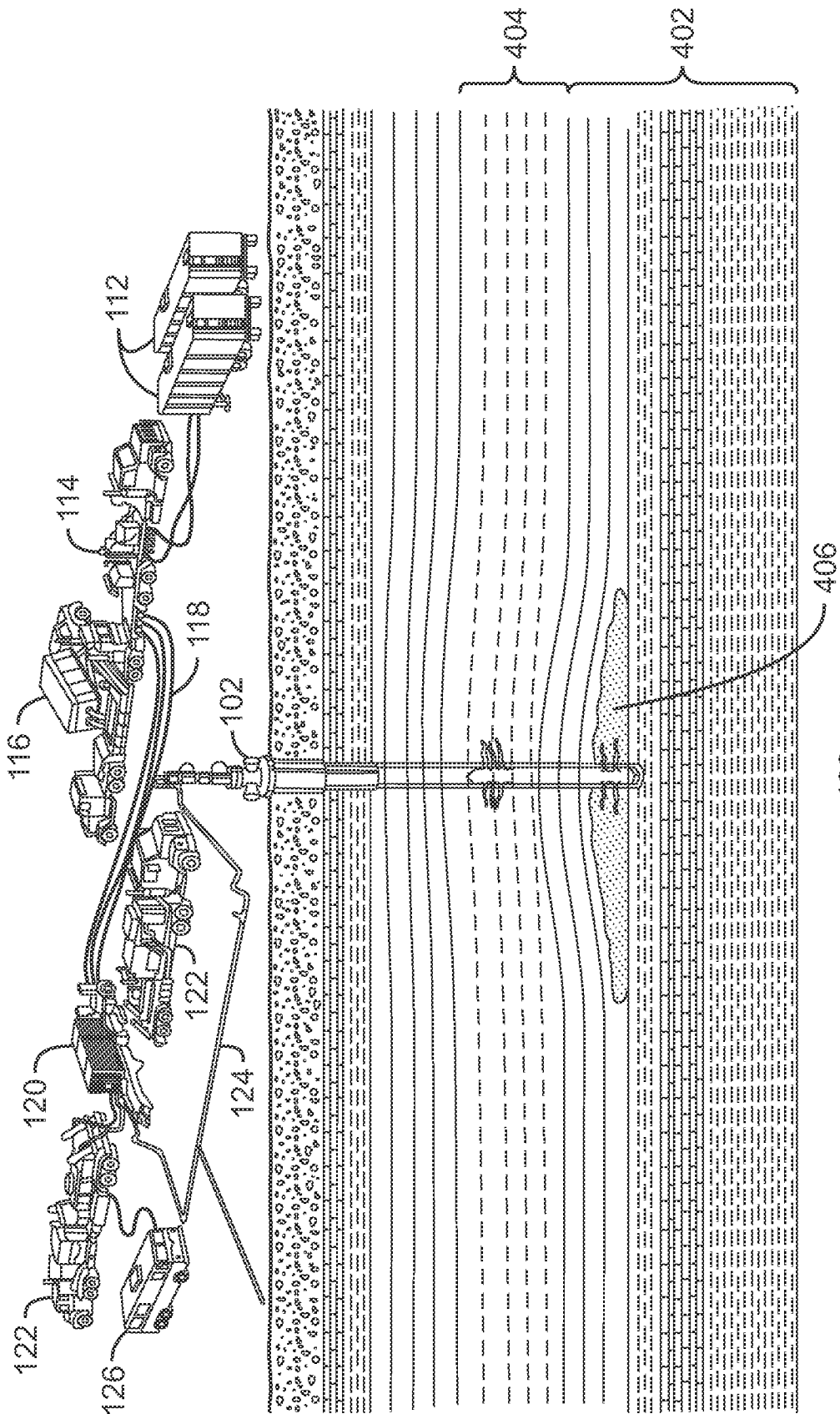
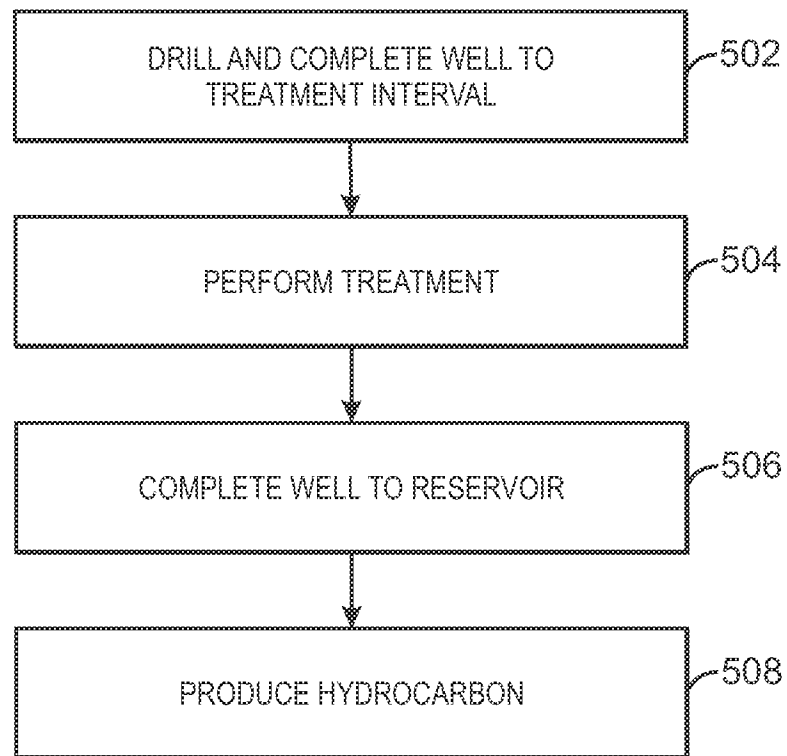


FIG. 3



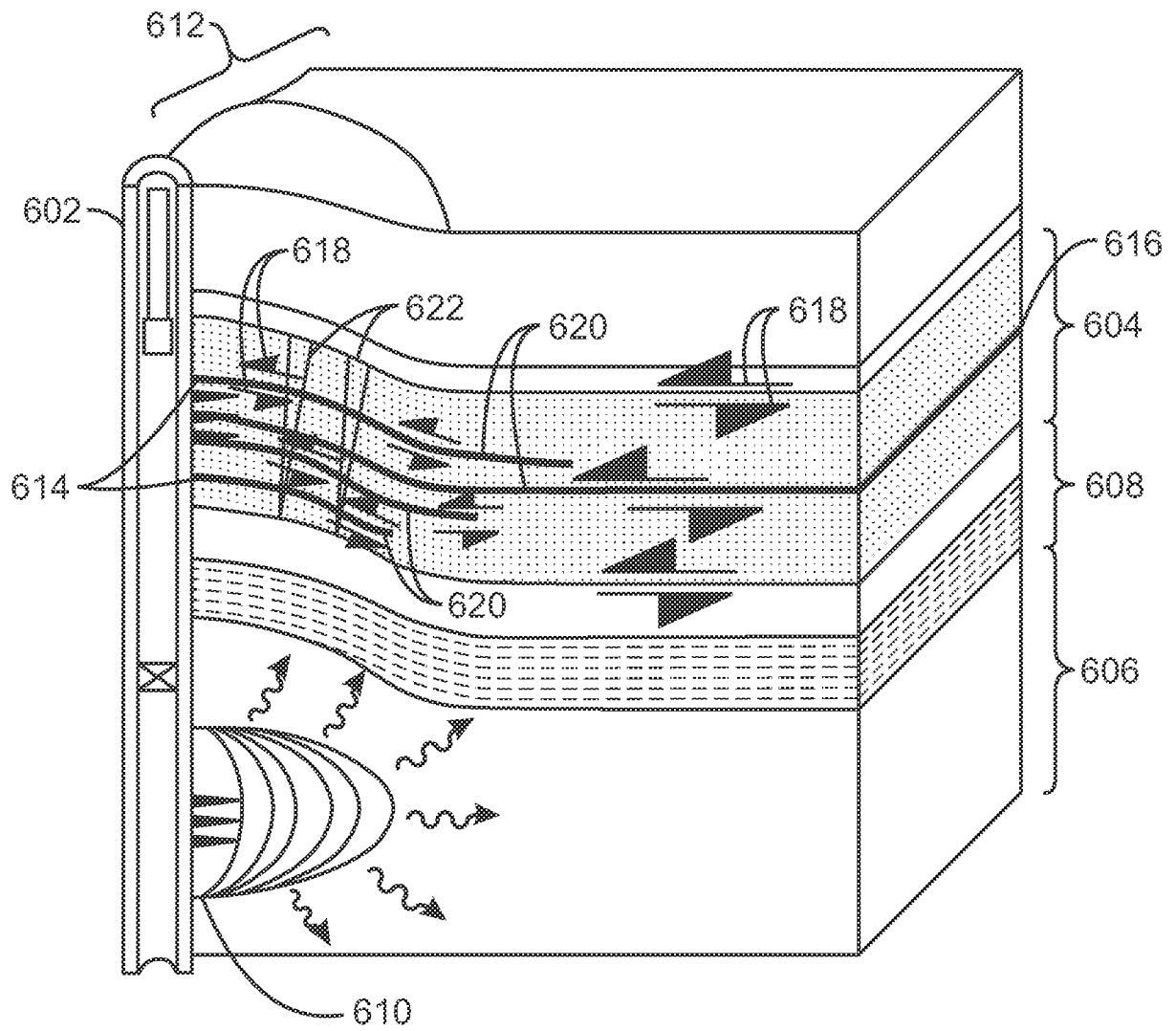
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FIG. 4

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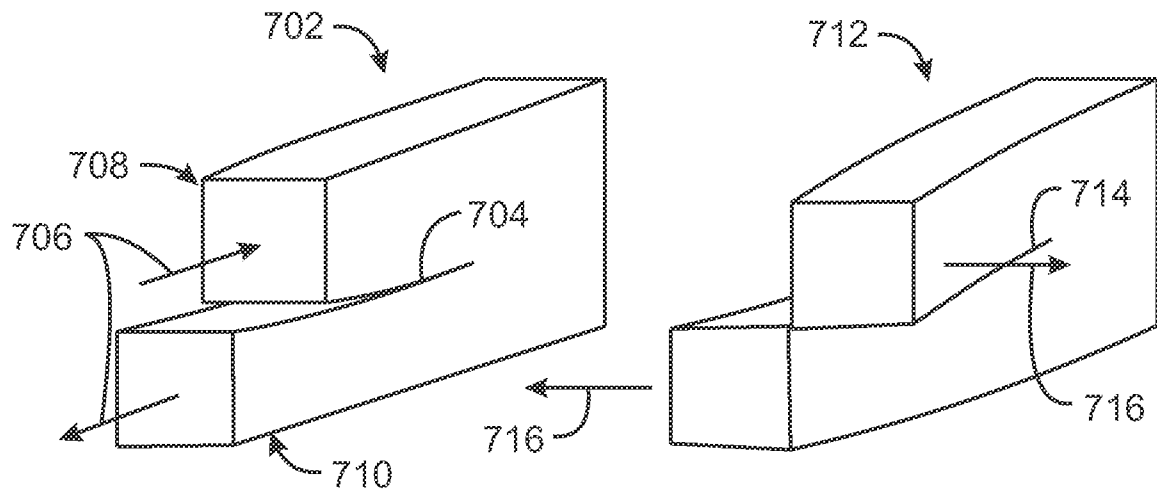
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FIG. 5

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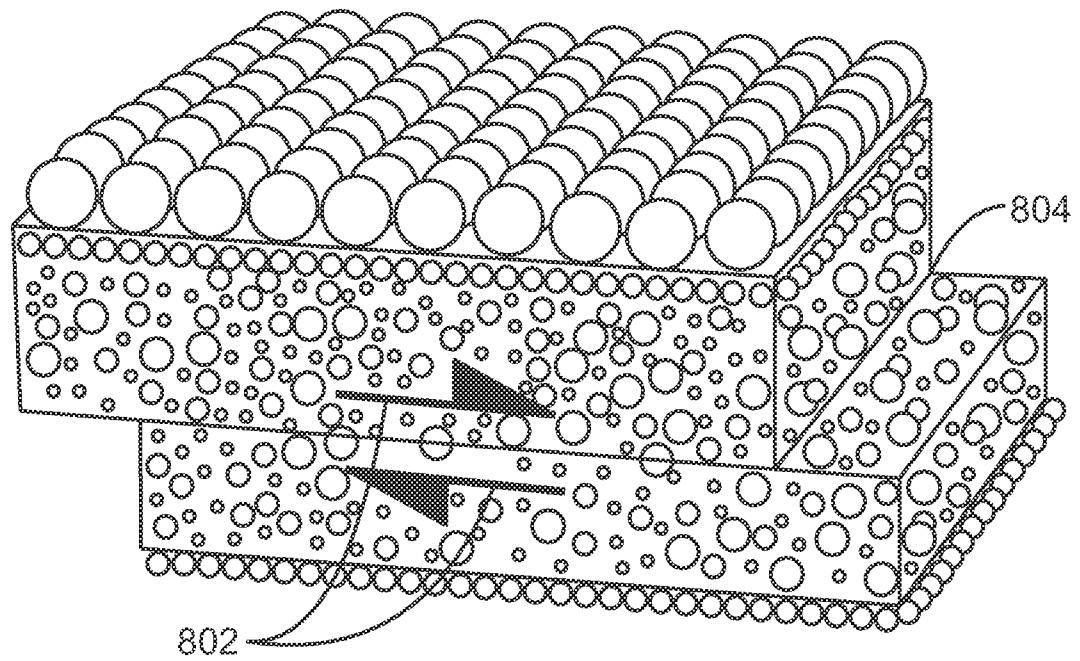


600
FIG. 6

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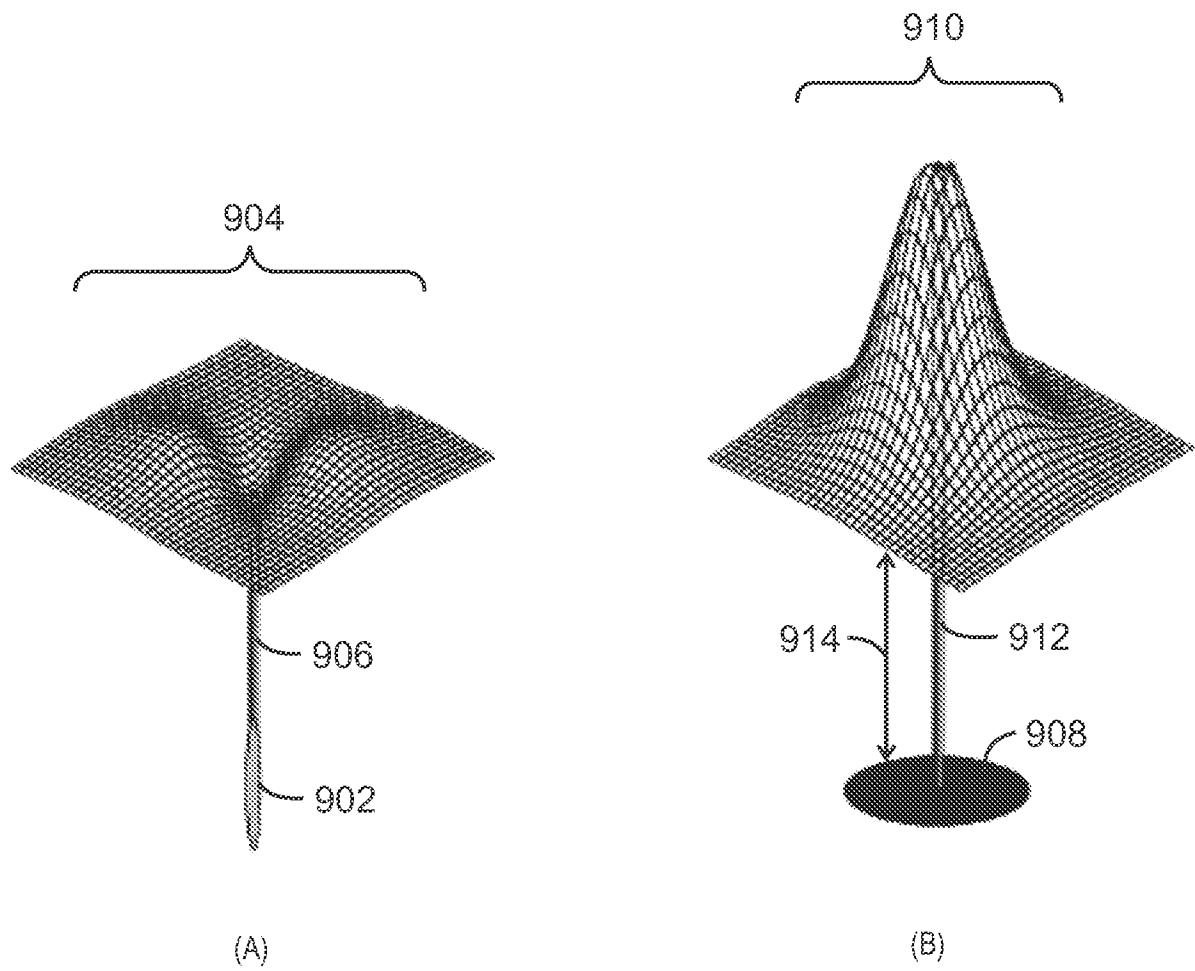


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FIG. 7



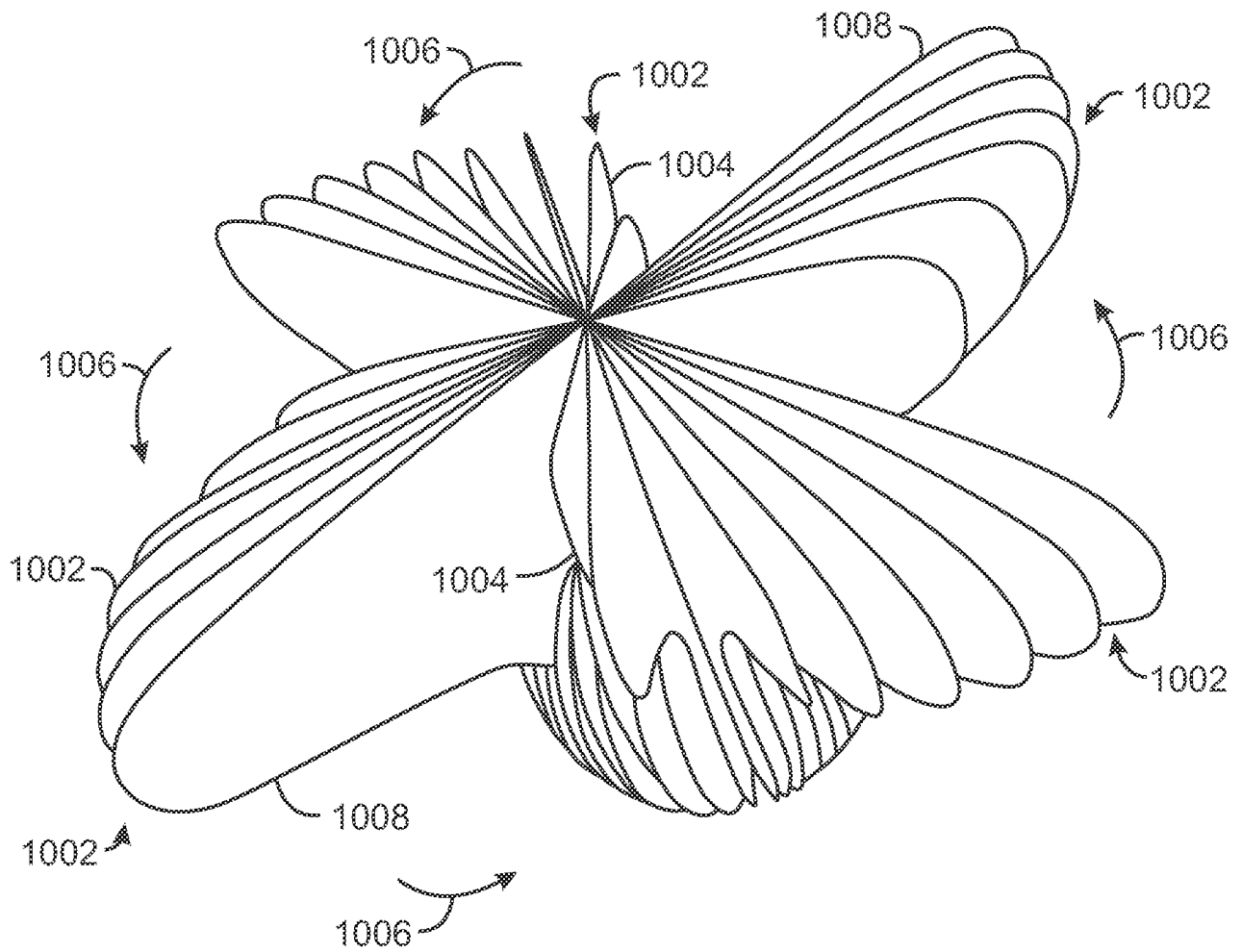
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FIG. 8

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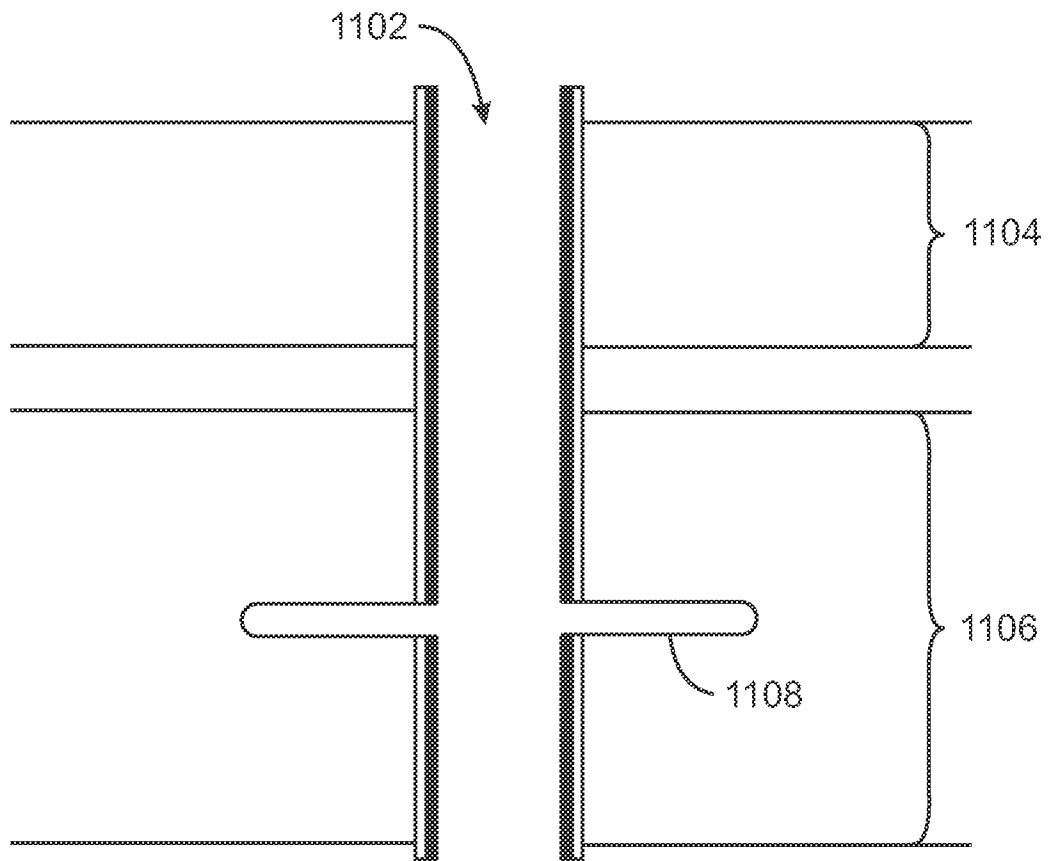
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FIG. 9

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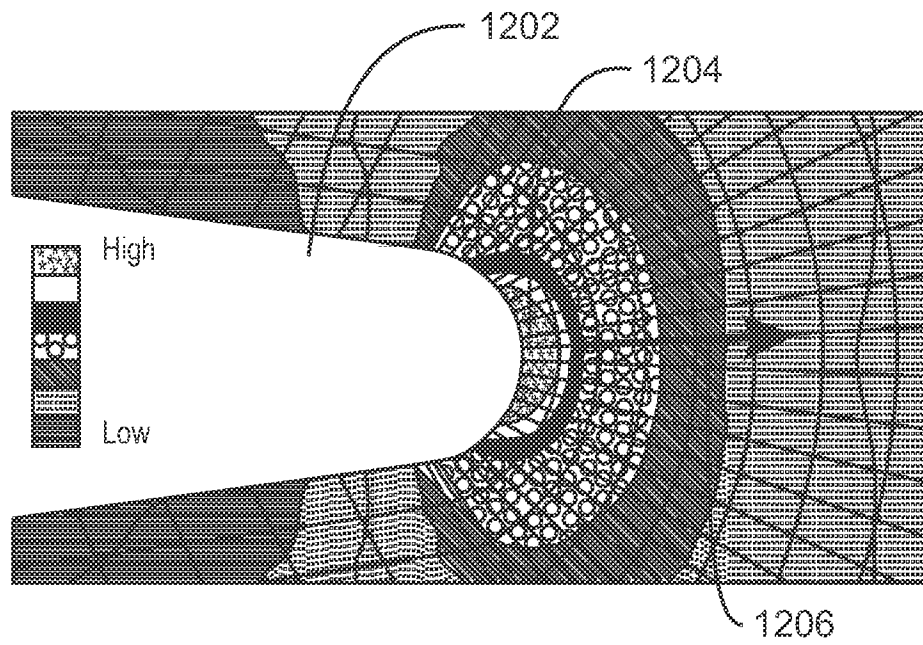
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FIG. 10

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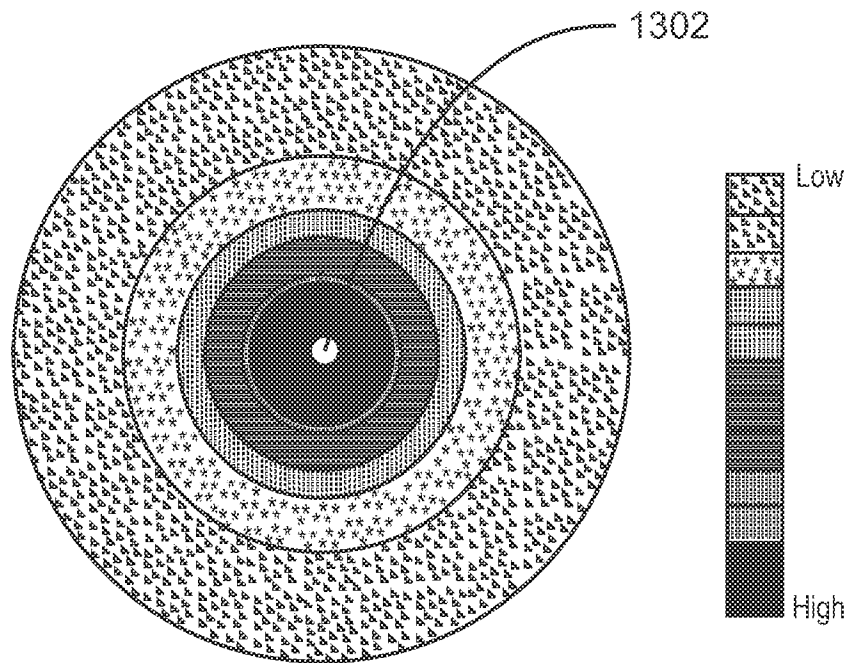
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FIG. 11

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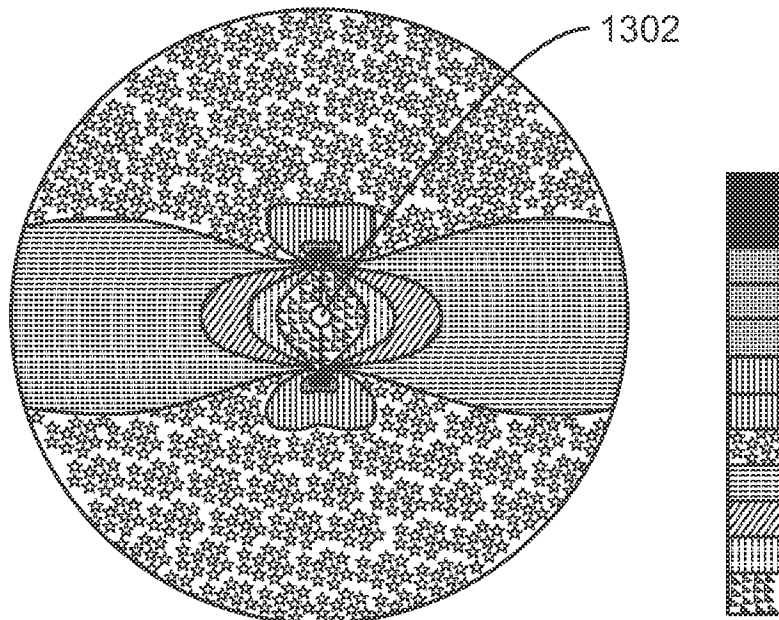


1200
FIG. 12

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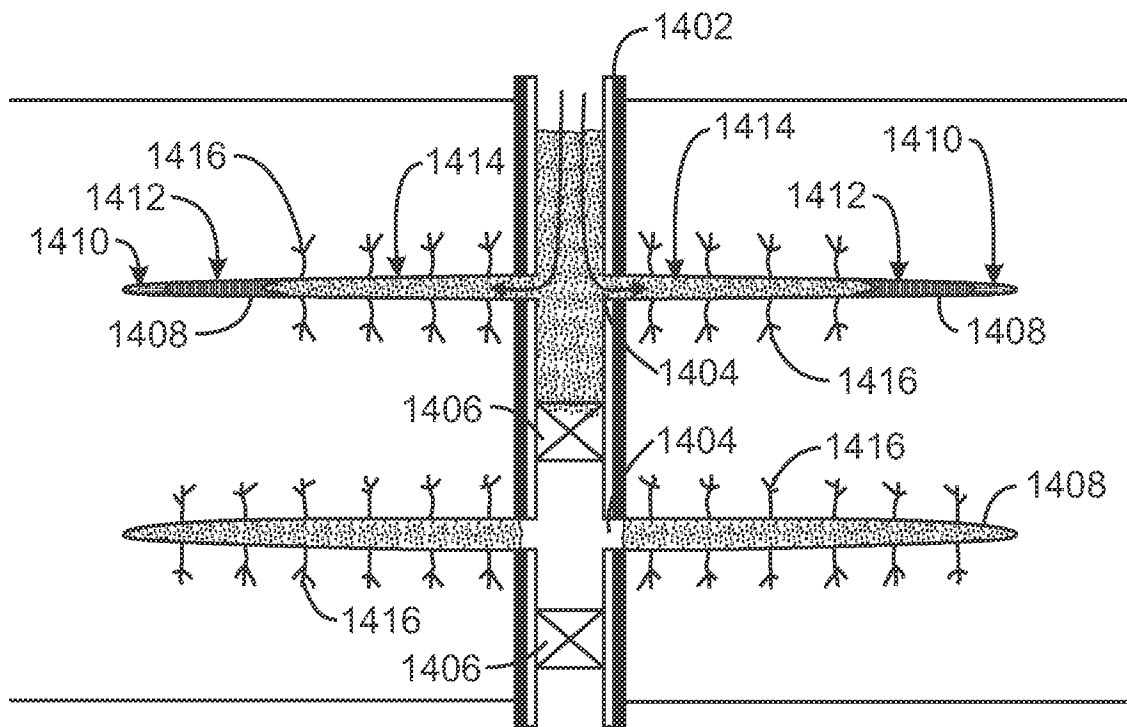
(A)



(B)

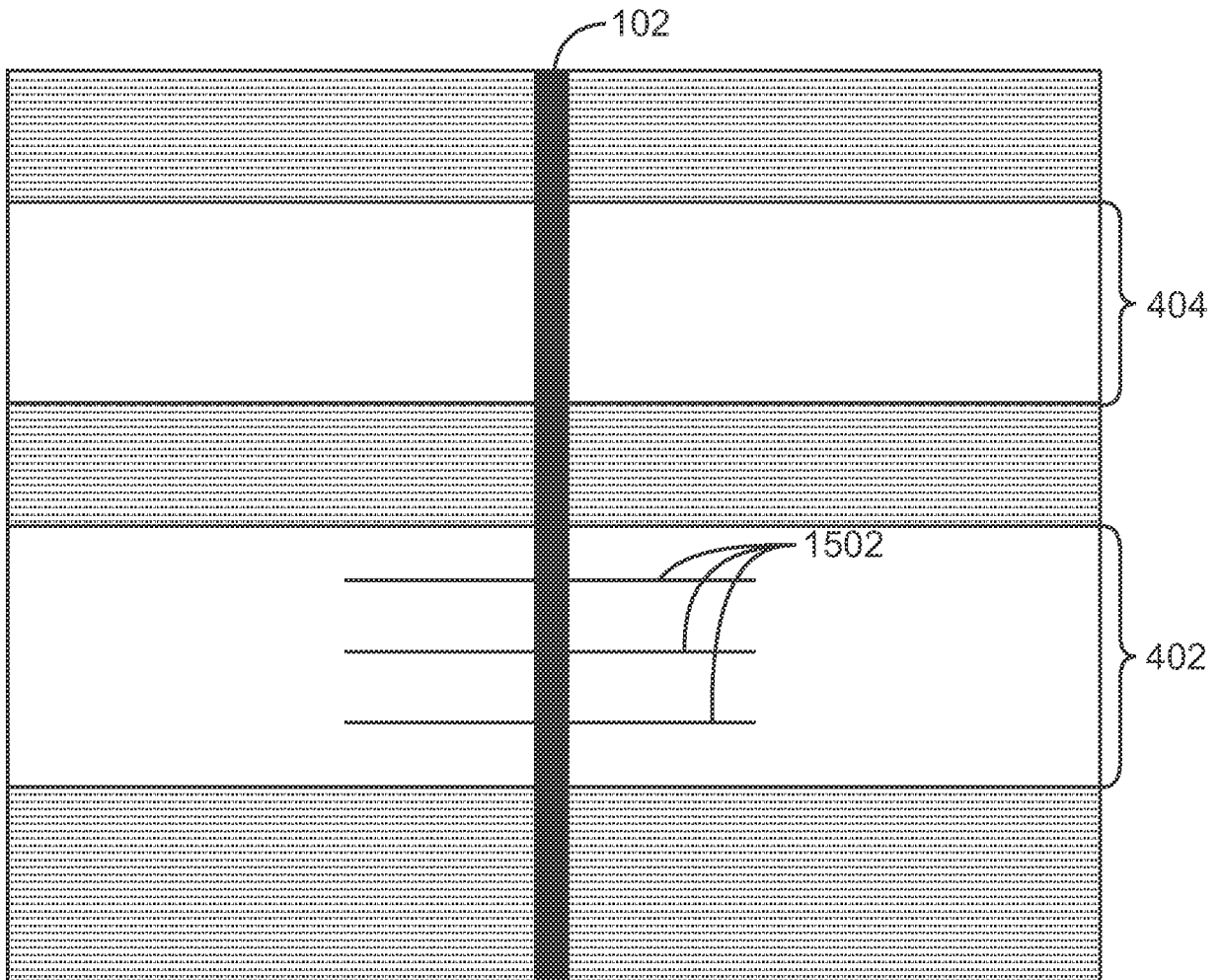
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FIG. 13

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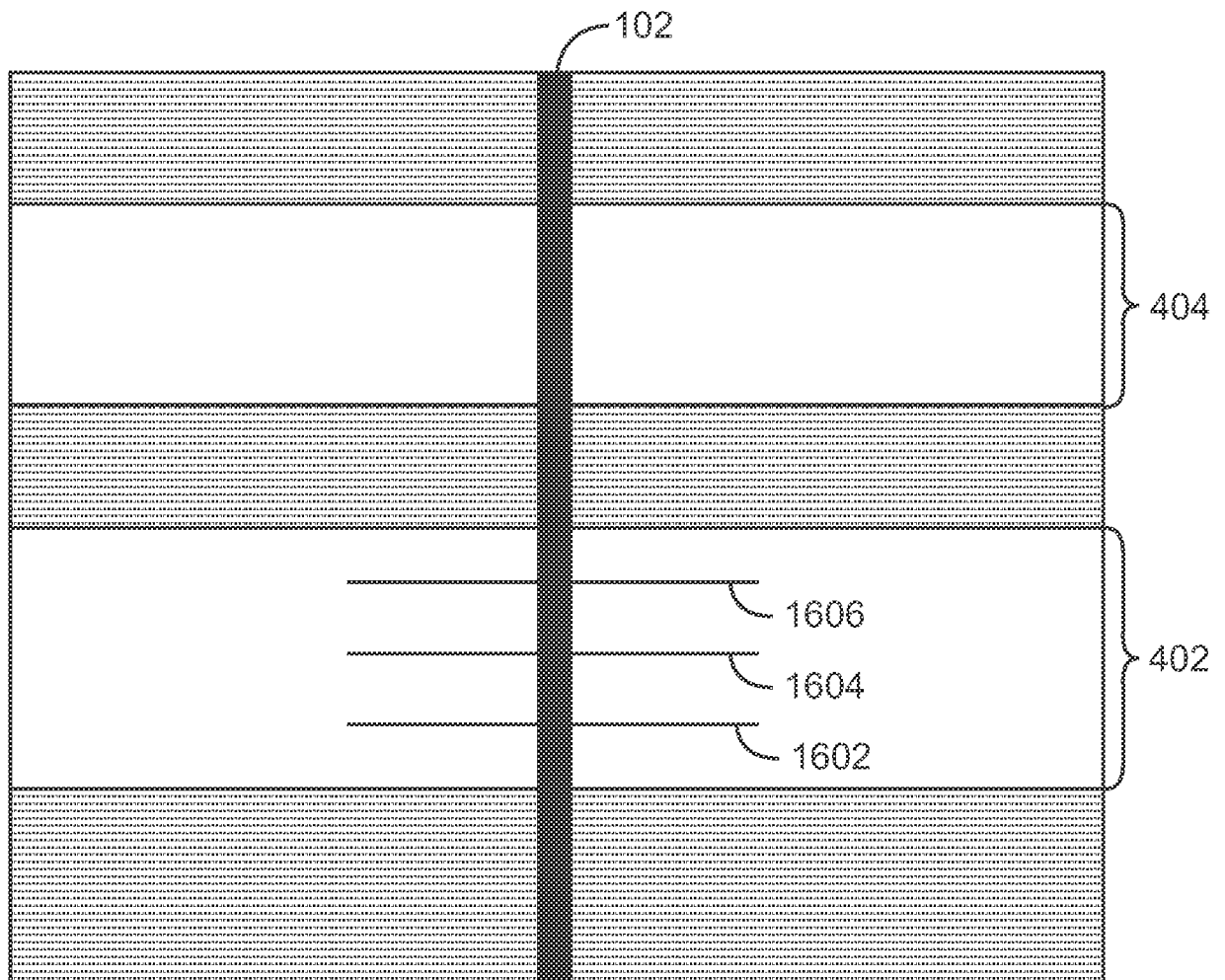
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FIG. 14

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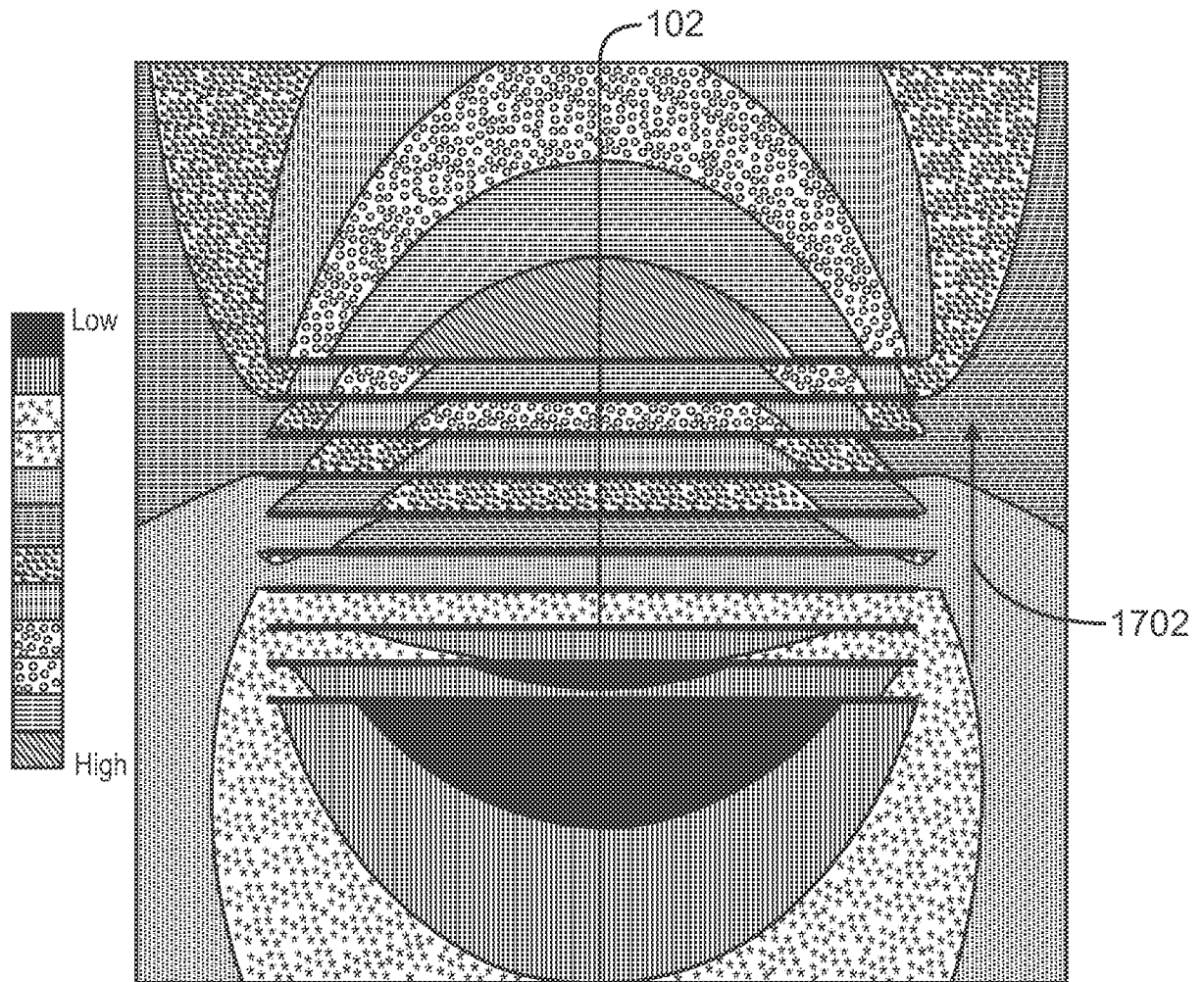
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FIG. 15

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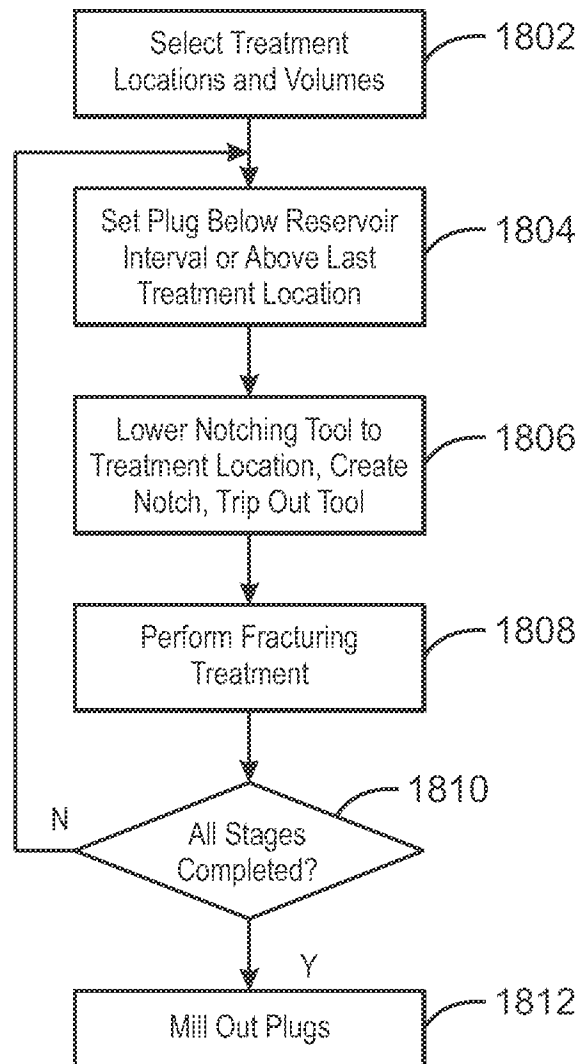
1600
FIG. 16

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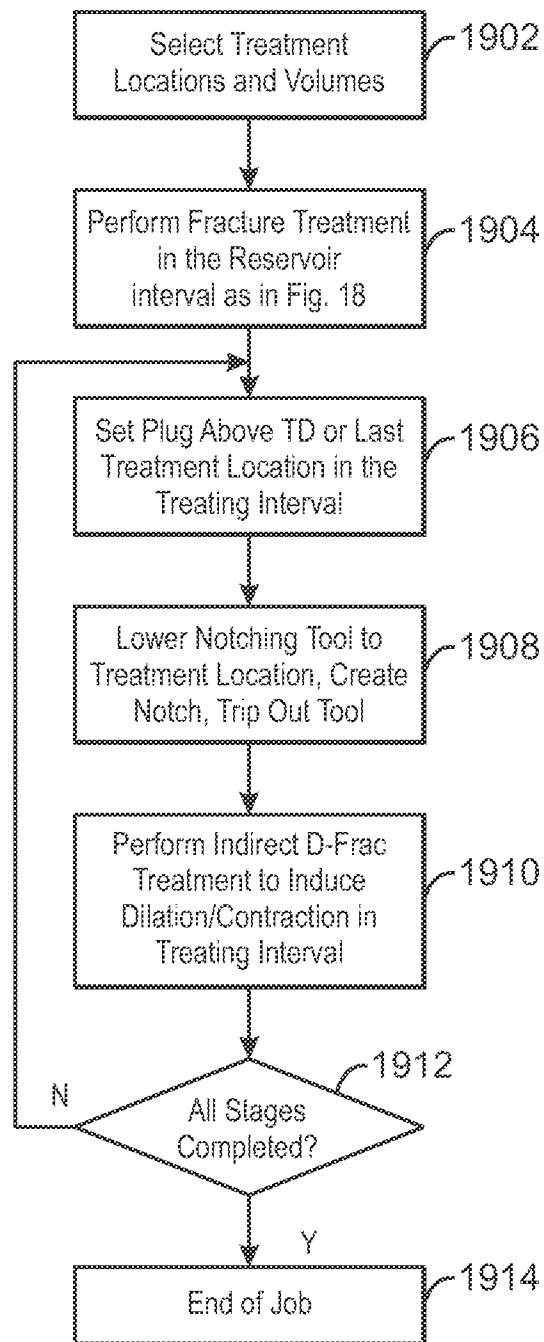
1700
FIG. 17

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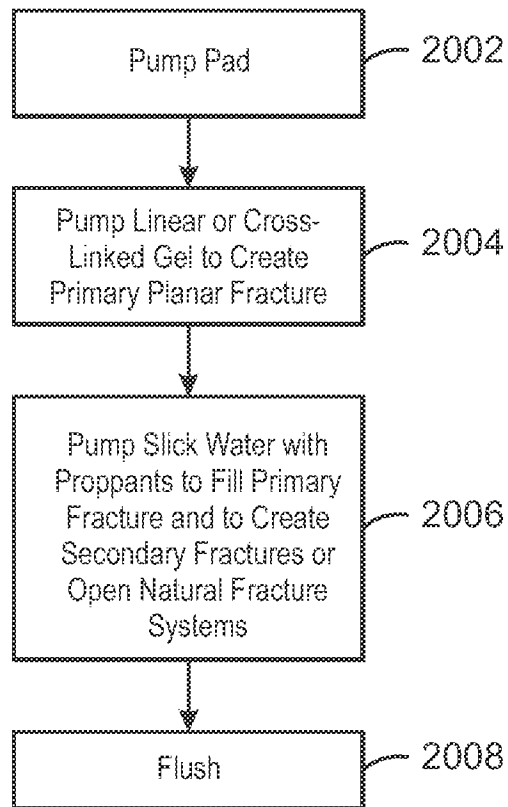
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FIG. 18

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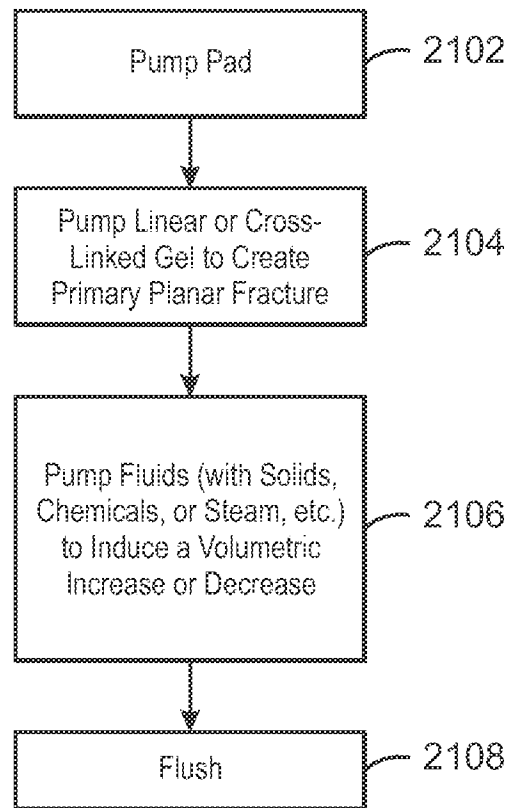
1900
FIG. 19

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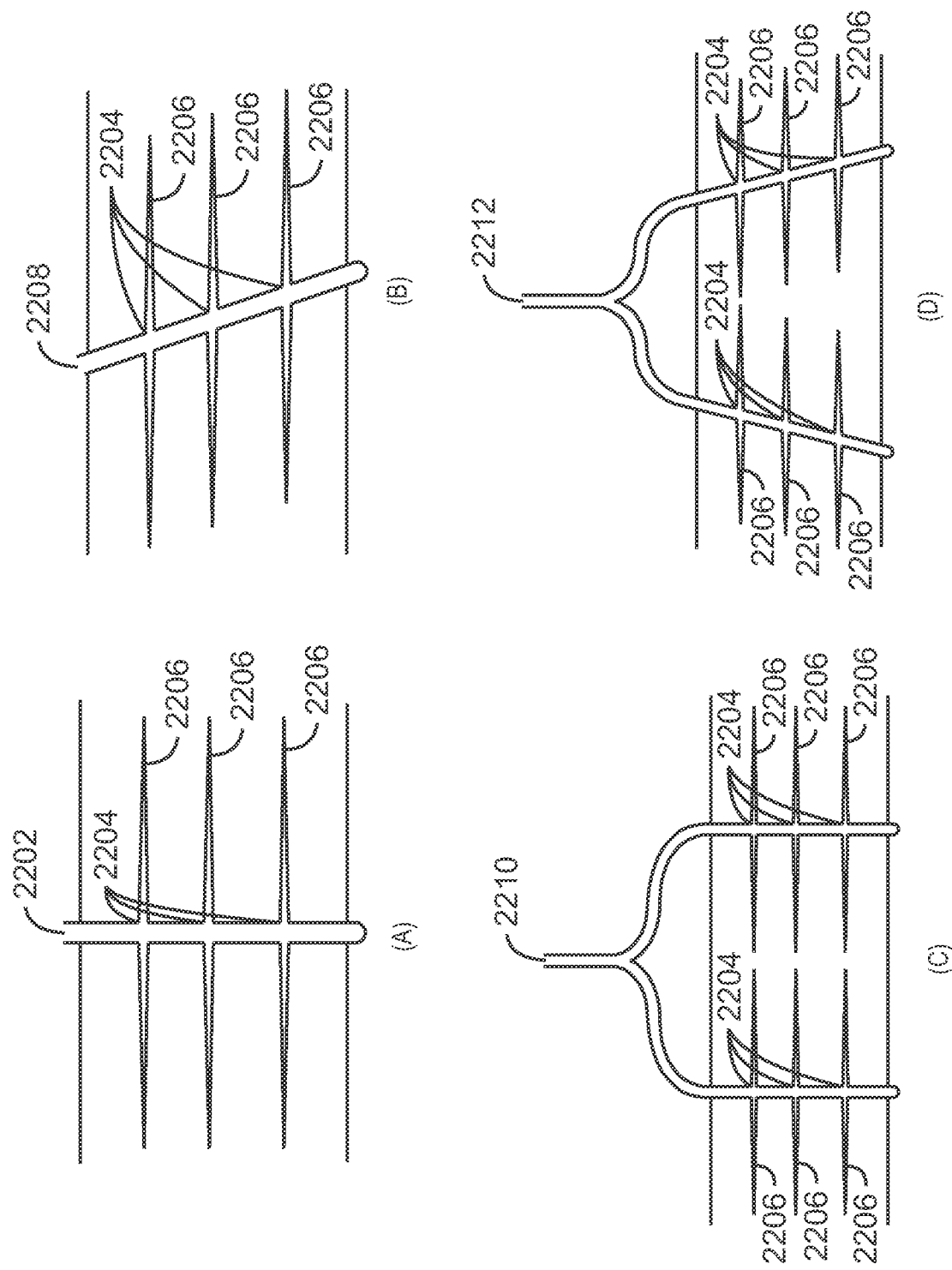


2000
FIG. 20

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2100
FIG. 21



2200
FIG. 22

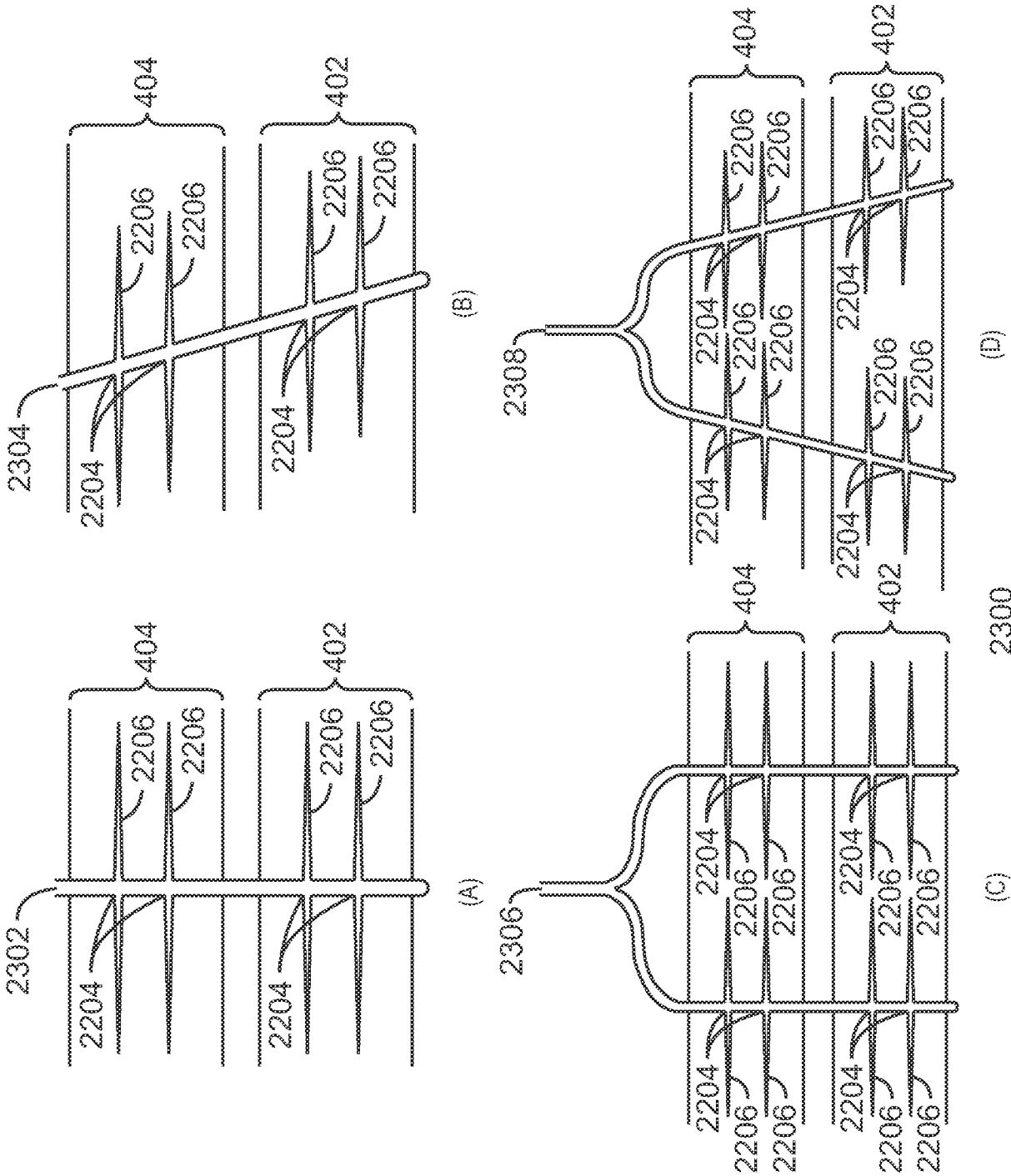


FIG. 23

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2011/056361

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - E21B 43/26 (2012.01)

USPC - 166/308.1

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 43/16, 43/25, 43/26 (2012.01)

USPC - 166/263, 271, 308.1

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

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

PatBase

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2,547,778 A (REISTLE, JR) 03 April 1951 (03.04.1951) entire document	1-6, 9, 15, 18
Y		8, 10, 11, 14, 19-26
X	US 3,066,733 A (BRANDON) 04 December 1962 (04.12.1962) entire document	1, 7, 12, 13, 16, 17
Y	US 3,220,475 A (BRANDON) 30 November 1965 (30.11.1965) entire document	8
Y	US 3,353,602 A (GEERTSMA) 21 November 1967 (21.11.1967) entire document	10, 11, 14, 19-26

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"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

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Date of the actual completion of the international search

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Date of mailing of the international search report

29 FEB 2012

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