



- | | |
|---|--|
| <p>(51) International Patent Classification:
<i>E21B 43/25</i> (2006.01) <i>C09K 8/62</i> (2006.01)
<i>E21B 43/26</i> (2006.01)</p> | <p>(74) Agent: THOMAS, Kimberly M. et al.; Chamberlain Hrdlicka, 1200 Smith Street, 14th Floor, Houston, Texas 77002 (US).</p> |
| <p>(21) International Application Number:
PCT/US2016/061686</p> | <p>(81) Designated States (<i>unless otherwise indicated, for every kind of national protection available</i>): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.</p> |
| <p>(22) International Filing Date:
11 November 2016 (11.11.2016)</p> | |
| <p>(25) Filing Language: English</p> | |
| <p>(26) Publication Language: English</p> | |
| <p>(71) Applicant: HALLIBURTON ENERGY SERVICES, INC. [US/US]; 3000 North Sam Houston Parkway East, Houston, Texas 77032-3219 (US).</p> | |
| <p>(72) Inventors: DUSTERHOFT, Ronald G.; 1902 Crescent Common Drive, Katy, Texas 77494 (US). STEGENT, Neil A.; 15907 Linwood Manor Ct., Cypress, Texas 77429 (US). REYES, Enrique A.; 18715 Cascade Timbers Ln., Tomball, Texas 77377 (US). WALSER, Doug W.; 12702 Reedwood Ridge Rd., Houston, Texas 77065 (US).</p> | <p>(84) Designated States (<i>unless otherwise indicated, for every kind of regional protection available</i>): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM,</p> |

(54) Title: STORING AND DE-LIQUEFYING LIQUEFIED NATURAL GAS (LNG) AT A WELLSITE

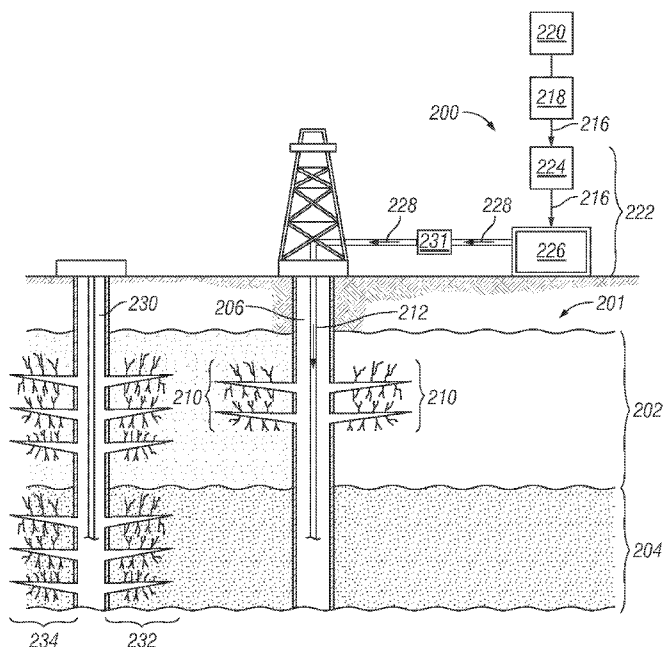


FIG. 28

(57) Abstract: A method and a system for pressurizing a reservoir volume including fluid in a formation with a parent well extending through the formation includes storing liquefied natural gas (LNG) at an on-site location of the parent well, de-liquefying the LNG to form natural gas at the on-site location, and injecting the natural gas into the parent well to pressurize the reservoir volume through the parent well.

TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW,
KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

Storing and De-liquefying Liquefied Natural Gas (LNG) at a Wellsite

Background

[0001] This section is intended to provide relevant background information to facilitate a better understanding of the various aspects of the described embodiments. Accordingly, it should be understood that these statements are to be read in this light and not as admissions of prior art.

[0002] A reservoir volume through a parent well (“original well”) may be under sufficient pressure to flow fluids, such as oil, gas, and hydrocarbons, to a surface. As the fluids are produced, the pressure in the reservoir volume will often decline, and production from the parent well is reduced or halted. If an infill well, such as a child well, is completed before the reduced-pressure reservoir volume through the parent well is re-pressured, asymmetrical fractures from the child well may propagate in the direction of the parent well. In such cases, natural gas may be used to partially or fully re-pressurize the reduced-pressure reservoir volume.

[0003] A natural gas pipeline system begins at a natural gas producing wellhead or field. Transporting the natural gas used for re-pressuring from the wellhead to a point of use involves several physical transfers of custody and multiple processing steps. Depending upon the initial quality of the wellhead product, a pipeline gathering system directs the flow of the natural gas to a processing plant. During processing, the natural gas is subjected to various extraction processes to remove water and other impurities and contaminants. After cleaning, the natural gas is directed to a mainline transmission grid to be distributed to the point of use.

[0004] However, due to its volume, natural gas is not easily stored or moved by various modes of transportation, such as railways or tankers, and is usually transported through an extensive, yet complex, network of pipelines. The natural gas pipeline system in the United States alone includes 305,000 miles of interstate and intrastate transmission pipe, more than 1,400 compressor stations to maintain pressure of the network, and more than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points to provide transfer of the natural gas.

Brief Description of the Drawings

[0005] For a detailed description of the embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0006] FIG. 1 is a schematic view of an example liquefied natural gas (“LNG”) pressuring system for pressuring a formation, according to one or more embodiments;

[0007] FIG. 2A is a schematic view of a subterranean formation before pressuring a reservoir volume, according to one or more embodiments;

[0008] FIG. 2B is a schematic view of a subterranean formation after pressuring the reservoir volume of FIG. 2A using an example LNG pressuring system, according to one or more embodiments;

[0009] FIG. 3A a schematic view of an example LNG pressuring system and an example fracturing pump system, according to one or more embodiments;

[0010] FIG. 3B is schematic view of an example recovery and separation system in the example fracturing pump system of FIG. 3A, according to one or more embodiments;

[0011] FIG. 4 is a schematic view of an example LNG pressuring system and an example tracer injection system, according to one or more embodiments; and

[0012] FIG. 5 is a schematic view of an example LNG pressuring system and an example treatment system, according to one or more embodiments.

Detailed Description

[0013] FIG. 1 is a schematic view of an example liquefied natural gas (“LNG”) pressuring system 100 for pressuring a formation 101, according to one or more embodiments. The formation 101 includes reservoir volumes 102, 104 composed of porous and permeable rocks (*i.e.*, reservoir rocks) that contain reservoir fluids (*e.g.*, oil, gas, water, hydrocarbons) located in an onshore environment or in an offshore environment. A well system includes at least one well 106 drilled to penetrate the formation 101 to carry out exploration and extraction of fluids from the reservoir volumes 102, 104. The well 106 of FIG. 1 is shown as near-vertical, but can be formed at any suitable angle to reach a hydrocarbon-rich portion of the formation 101. In other examples, the well 106 can follow a partially-vertical, angled, or even a partially-horizontal path through the formation 101. The well 106 is shown as being lined with a protective lining 108 extending through the formation 101. The protective lining 108 may include a casing, liner, or tubing made of any material, including steel, alloys, or polymers, among others. The well 106 may also be partially or fully openhole, *i.e.*, no protective lining. The protective lining 108 is perforated so that the reservoir fluids flow through fractures 110 formed in the formation 101 and into the well 106.

[0014] During primary recovery techniques (*e.g.*, natural depletion), reservoir pressure is sufficient so that reservoir fluids can flow from the fractures 110 and into the well 106. As

described herein, the reservoir pressure includes the pressure of the fluids present in pore spaces of the reservoir rocks. As the reservoir fluids are produced from the reservoir rocks, the pressure, flow capacity, and recovery factor from the reservoir volume 102 is reduced until production from the well 106 is minimal or no longer feasible. Since the reservoir volume 102 may contain oil that has been relieved of pressure such that the oil is near, at, or below its bubble point, natural gas can be injected into the well 106 to increase pressures to a level equal to or greater than the original reservoir pressures, for example, pressures exhibited at original production conditions. The terms pressured, re-pressured, pressurized, and re-pressurized are used interchangeable herein to imply that reservoir volume pressures are increased or restored to pressure levels occurring during initial recovery from the well 106.

[0015] In operation, the natural gas is injected into the well 106 to flow into a tubing string 112 or an annular area 114 located between an inner surface of the well 106 and the string 112. Specifically, the natural gas introduced into the formation 101 is miscible and/or displaced in the fluids of the reservoir volume 102 to help mobilize and flow the fluids from the volume 102 and into the well 106. Natural gas, as opposed to water, includes a miscibility that is greater in reservoir fluids than the miscibility of water in such fluids. In particular, the molecules of the injected natural gas are capable of mixing or dissolving within the reservoir fluids to lower fluid viscosity and, thus, subsequently assist in the production of higher volumes of reservoir fluids from the volume 102. Further, the natural gas mixed or dissolved within the reservoir fluids can be released, for instance, using liberation techniques. Thus, unlike water, a portion of the natural gas used to pressurize the reservoir volume 102 can be recovered and later sold and/or further used in other operations.

[0016] However, before the natural gas is transported for use via remote pipelines or other remote transportation methods, heavier hydrocarbons and contaminants are often extracted to produce a processed natural gas. In a gaseous form, the low density and flammable nature of the processed natural gas presents various challenges during transportation to the point of use, *i.e.*, the well 106. However, natural gas can be compressed in volume and cooled to or below cryogenic temperatures, *e.g.*, -260 Fahrenheit (°F) (-162 Celsius (°C)), to produce liquefied natural gas (“LNG”) 116. The reduction in volume enables natural gas to be transported in liquid form across extended distances and to remote locations where pipelines are not available.

[0017] The LNG pressuring system 100 includes a LNG source vessel 118 to store LNG 116 on-site at the well 106. The storage of LNG at the well 106 reduces the distance between

the source of the natural gas, *e.g.*, remote pipelines, supply and the point of injection into the well 106 and thus, overcomes any challenges associated with using and transporting natural gas. The LNG source vessel 118 includes a cooling system or a separate cooling system 120 located at the well 106 to maintain the LNG 116 at cryogenic temperatures. The LNG source vessel 118 is further in fluid communication with a cryogenic system 122 capable of de-liquefying the LNG 116 to a gaseous state. The cryogenic system 122 includes a cryogenic pump 124 capable of processing fluids at cryogenic temperatures. The cryogenic pump 124 supplies a feed pressure to flow the LNG 116 into a heating unit 126 to be heated and vaporized into natural gas, *e.g.*, de-liquefied LNG 128. Once in a gaseous state, the de-liquefied LNG 128 may flow into the well 106 to increase the reservoir pressure of the reservoir volume 102. In some cases, an injection pump 131 pressurizes the de-liquefied LNG 128 to maintain an injection flow rate sufficient to inject and deliver the LNG 128 into the well 106 and further into the fractures 110.

[0018] The LNG 116 transported to the well 106 may already be processed and thus, free of contaminants including water, hydrogen sulfide, and carbon dioxide, among others. In other examples, the LNG 116 stored in the LNG source vessel 118 may be processed at the well 106 or requires additional processing so that additional equipment may be located at the well 106. However, equipment in contact with the LNG 116 must be suitable for cryogenic service, *i.e.*, suitable to handle cryogenic temperatures, *e.g.*, at or below -260 °F (-162 °C).

[0019] It should be clearly understood that the LNG pressuring system 100 of FIG. 1 is merely one embodiment of an application of the principles of this disclosure in practice, and a wide variety of other embodiments are possible. Therefore, the scope of this disclosure is not limited at all to the details of FIG. 1 described herein and/or depicted in the additional drawings.

[0020] FIG. 2A is a schematic view of a subterranean formation 201 before pressuring a reservoir volume 202, according to one or more embodiments. An initial well drilled to discover and produce fluids from one or more reservoir volumes 202, 204 is often referred to as a parent well 206. As fluids are recovered from the reservoir volume 202 through the parent well 206, the reservoir pressure decreases so that the reservoir volume 202 is referred to as a “depleted” reservoir volume. As described herein, a depleted reservoir volume includes reservoir pressures that have been reduced due to production, production from other producing wells, or due to low permeability of the formation 201. The reduction in pressure limits the recovery of reservoir fluids that may remain in the reservoir volume 202 after

implementing primary recovery techniques, such as natural pressure recovery. Other recovery techniques, such as artificial lift recovery, water injection recovery, or steam injection recovery, among others, may be implemented to further produce and recover the fluids from the reservoir volume 202 or fluids from an adjacent reservoir volume 204. In some cases, a child well 230 is drilled and completed in a producing area or between a producing well(s), such as the parent well 206, to sustain rates or contact portions of one or more reservoir volumes 202, 204 that are inadequately drained or untouched using existing production methods. To promote production, the child well 230 is stimulated to produce fluids unrecovered from the reservoir volume 202, not easily accessible through the parent well 206, and/or fluids from the adjacent reservoir volume 204.

[0021] However, during stimulation of the child well 230, asymmetrically induced fractures 232 may generate to propagate in the direction of the reservoir volume 202, *i.e.*, the depleted reservoir volume. Specifically, the asymmetrically induced fractures 232 generated in the child well 230 migrate to lower pressure, *i.e.*, lower stress, zones of the formation 201, such as the reservoir volume 202, or any other previously depleted well(s) with a low reservoir pressure. The fractures 232 of the child well 230 follow the path of least resistance or the path that requires less fracture energy, thus, resulting in the asymmetric fracture pattern. As shown in FIG. 2A, the asymmetrically induced fractures 232, as described herein, can include fractures that grow preferentially on one side of the child well 230 in the direction of the reservoir volume 202. Such asymmetric fracture growth restricts the fractures 232 from generating on another side of the child well 230 or fracturing in the direction of other producing reservoirs, such as the reservoir volume 204 that is pressured and capable of producing reservoir fluids. As a result, the reservoir volume 204 may be bypassed or untouched due to the asymmetric induced fractures 232 propagating in the direction of the reservoir volume 202.

[0022] FIG. 2B is a schematic view of a subterranean formation 201 after pressuring the reservoir volume 202 of FIG. 2A using a LNG pressuring system 200, according to one or more embodiments. As described with respect to FIG. 1, the reservoir volume 202 can be pressurized using the LNG pressuring system 200, for example, to pre-recovery reservoir pressures using LNG 216 before completion and/or stimulation of a child well 230. The system 200 includes a LNG source vessel 218 to store the LNG 216 and a cooling system or a separate cooling system 220 located at the well 206 to maintain the LNG 216 at or below cryogenic temperatures, *e.g.*, -260 °F (-162 °C). The LNG source vessel 218 supplies the

LNG 216 to a cryogenic system 222 capable of de-liquefying and returning the LNG 216 to a gaseous state. The cryogenic system 222 includes a cryogenic pump 224 to supply a feed pressure to flow the LNG 216 into a heating unit 226. The unit 226 heats and vaporizes the LNG 216 into natural gas, *i.e.*, de-liquefied LNG 228. Once in a gaseous state, the de-liquefied LNG 228 flows into the well 206 via a tubing string 212 to increase the reservoir pressure of the reservoir volume 202. In some cases, an injection pump 231 pressurizes the de-liquefied LNG 228 to maintain an injection flow rate sufficient to deliver and inject the de-liquefied LNG 228 into the well 206. In the embodiments, the storage of LNG 216 at the well 206 reduces the distance between the natural gas supply source (*e.g.*, remote natural gas pipelines) and the point of injection into the well 206 for various operations, such as the pressuring of the reservoir volume 202. In this way, storage of LNG 216 at the well 206 overcomes any challenges associated with using natural gas, remote pipelines, and other remote transportation methods.

[0023] After injecting the de-liquefied LNG 228 to increase the pressures of the reservoir volume 202, the child well 230 may be drilled or if already drilled, it may be completed. Upon stimulation of the child well 230, asymmetric fracturing from the child well 230 towards the parent well 206, as previously shown in FIG. 2A, is mitigated. Instead, stimulation of the child well 230 generates more symmetric fractures 234 that do not grow in an unbalanced pattern towards the re-pressurized reservoir volume 202. Instead, the symmetric fractures 234 may propagate in a balanced direction towards the reservoir volume 204 that is capable of producing reservoir fluids and also in the direction of the re-pressurized reservoir volume 202, if capable of producing fluids into the well 206. Thus, re-pressuring the reservoir volume 202 before stimulating the child well 230 promotes symmetric fracturing upon stimulating the child well 230 that is balanced and does not grow into lower pressure/lower stressed areas of the formation 201, *i.e.*, a depleted reservoir volume such as the reservoir volume of FIG. 2A. As described herein, symmetrically induced fracturing includes fractures 234 growing simultaneously upward and downward, or along one or more sides of the child well.

[0024] It should be clearly understood that the embodiments described with respect to FIGS. 2A and 2B include merely one example of an application of the principles of this disclosure in practice, and a wide variety of other embodiments are possible. Therefore, the scope of this disclosure is not limited at all to the details of FIG. 2A and 2B described herein and/or depicted in the additional drawings.

[0025] FIG. 3A a schematic view of a LNG pressuring system 300 and a fracturing pump system 336, according to one or more embodiments. Pressuring a previously depleted reservoir volume 302 before stimulating a child well 330, re-establishes a pathway for any remaining reservoir fluids to flow from the reservoir volume 302. Thereafter, the pressured reservoir volume 302 may be re-stimulated to subsequently produce and flow the remaining reservoir fluids into an original well, *i.e.*, a parent well 306.

[0026] A reduction in the pressure in the reservoir volume 302 through the parent well 306 can lead to asymmetrically-induced fracturing in the direction of the well 306 during stimulation of an adjacent reservoir volume(s), *e.g.*, 304. As described with respect to FIG. 1, the reservoir volume 302 is re-pressurized to restore reservoir volume pressures to pre-production levels using LNG 316 returned to a gaseous state. The LNG 316 is stored in a LNG source vessel 318 located at the well 306 that includes a cooling system 320 to maintain the LNG 316 at or below cryogenic temperatures, *e.g.*, -260 °F (-162 °C). The LNG source vessel 318 is in fluid communication with a cryogenic pump 324 capable of supplying a feed pressure to flow a first stream of LNG 316 into a heating unit 326. The heating unit 326 heats and vaporizes the LNG 316 into natural gas, *i.e.*, de-liquefied LNG 328. The de-liquefied LNG 328, thereafter, flows into the well 306 to increase the reservoir pressure or re-pressurize the reservoir volume 302 and thus, mitigates asymmetrically-induced fracturing in the direction of the parent well 306.

[0027] After the reservoir volume 302 is pressurized, fractures 334 propagate away from the child well 330 to grow symmetrically into previously bypassed reservoirs, for example, the adjacent reservoir volume 304. However, the fracturing fluid injected into the child well 330 during stimulation may flow into and infiltrate the pressured reservoir volume 302, now capable of being re-stimulated. The infiltrating fracturing fluid from the child well 330 reduces and/or destroys any remaining producible fluids and reserve fluids of the reservoir volume 302.

[0028] Various stimulation techniques, such as fracturing techniques, are implemented to re-stimulate the reservoir volume 302 and recover any remaining fluids in the parent well 306 after stimulating the child well 330. Fracturing, a type of stimulation technique, includes creating a fracture system in the reservoir volume 302 by injecting fluid(s) under pressure into the well 306 to overcome stress and cause material failure of the volume 302. Certain fluids injected into the well 306 to re-stimulate production, such as water, nitrogen and carbon dioxide, may damage reservoir rocks and/or cause formation contamination during

recovery of such fluids from the formation 301 and/or the well 306. For example, water retention due to higher capillary forces within the reservoir volume 302 can affect the reservoir volume permeability, reservoir volume wettability, and the geophysical integrity of the well 306 and/or formation 301 in the form of fines migration, deconsolidation, and rock weakening and softening. Such factors affect the ability of the fluids to be released and recovered from the reservoir volume 302. However, the de-liquefied LNG 328 is non-damaging to reservoir rocks, inert and miscible in various reservoir volume fluids, and recoverable without contamination. As described in one or more embodiments, the de-liquefied LNG 328 used for pressuring the reservoir volume 302 is also used as a fracturing fluid to stimulate and increase the rate of fluid recovered from the pressured reservoir volume 302.

[0029] The fracturing pump system 336 receives a second stream of LNG 338 from the cryogenic pump 324. The fracturing pump system 336 includes a fracturing pump 340, such as a high-pressure LNG pump, and a heating unit 342. The fracturing pump 340 receives and pressures the second stream of LNG 338 at a fracturing pressure sufficient to fracture the reservoir volume 302. A pressurized LNG 346 flows into the heating unit 342 to be heated and vaporized into natural gas, *e.g.*, de-liquefied LNG 348. The de-liquefied LNG 348, acting as a fracturing fluid, is injected in the well 306 to flow into perforations 350 at a fracturing pressure sufficient to re-stimulate and generate fractures 352 in the reservoir volume 302. Before injection into the well 306, the de-liquefied LNG 348 may flow into a mixer 354 to be admixed with a stimulation material 356, such as viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents, and the like. The combination of the de-liquefied LNG 348 and the stimulation material 356 provides a fracturing fluid 358 capable of re-stimulating and re-fracturing the reservoir volume 302. The mixer 354 may include static or dynamic mixing devices, diverters, and turbulizers, among others.

[0030] The stimulation material 356, as described, may include acidic agents, such as a regular acid or a salt of hydrochloric acid (HCl) where the salt is thioamide, urea, glycine, or an amino acid such as tryptophan, proline, valine, among others. The acidity of some of the acidic agents increases in the presence of water at certain concentrations. For example, HCl is

soluble in the presence of water and other aqueous solutions but insoluble and thus, non-acidic in the presence of other well fluids, *e.g.*, oil, gas, hydrocarbons, corrosion inhibitors, surfactants, foaming agents, and nanoparticles. Removing water from the well 306 or from the formation 301 is not feasible since water naturally forms in the reservoir volume 302 and is often injected into the formation 301 during fracturing operations. Therefore, using de-liquefied LNG 348 in the presence of the acidic agents mitigates the acidic impact caused by acidic agents in the presence of the water and other aqueous based solutions.

[0031] The injection location, pressure, flow rate, fluid composition, and/or other parameters of the de-liquefied LNG 348 may be modified to improve sweep efficiency and rates of recovery. In some examples, the de-liquefied LNG 348, as a fracturing fluid, is water-based and can be commingled with an aqueous solution to aid in load recovery, *i.e.*, the amount of fracturing fluid produced back, after stimulating and fracturing the reservoir volume 302. The de-liquefied LNG 348 can also be foam-based to transport additional agents commingled in the fracturing fluid, such as proppants, diverter materials, solid acids, and scale inhibitors, among others surface active agents. In some cases, before de-liquefying, a stream of the LNG 316 is injected into the well 302 as a fracturing fluid, with or without the stimulation material 356, to re-fracture the formation 302.

[0032] FIG. 3B is schematic view of an example recovery and separation system 362 in a fracturing pump system 336 of FIG. 3A, according to one or more embodiments. The de-liquefied LNG 328, 348 of FIG. 3A that flows into the well 306 is miscible in fluids 329 recovered from the reservoir 302. The de-liquefied LNG 328, 348 that is in solution with the recovered fluids 329 is releasable using various techniques, such as flash liberation and differential liberation, among others. As shown in FIG. 3B, the recovered fluids 329 released from the reservoir 302 may flow into the well 306 and into a processing facility 362. The processing facility 362 includes one or more separators 364 to separate out the various components within the recovered fluids 329, such as the de-liquefied LNG 328, 348 previously injected into the well 306 for pressuring and fracturing the reservoir 302. The recovered de-liquefied LNG 366 flows from the processing facility 362 to be further processed and/or later sold or further used other operations.

[0033] It should be clearly understood that FIGS. 3A and 3B merely depict one embodiment of an application of the principles of this disclosure in practice, and a wide variety of other embodiments are possible. Therefore, the scope of this disclosure is not limited at all to the details of FIGS. 3A and 3B described herein and/or depicted in the

additional drawings. For example, instead of using the fracturing pump system 336 to generate and flow de-liquefied LNG 348 into the well 306, the cryogenic pump 324 can be rated to pressurize the LNG 316 at a fracturing pressure sufficient to fracture the formation 301 after re-pressuring. Further, the heater 326 can be used to heat and vaporize the LNG 316 to generate the de-liquefied LNG 348 before being injected into the well 306 as a fracturing fluid.

[0034] FIG. 4 is a schematic view of an example LNG pressuring system 400 and an example tracer injection system 444, according to one or more embodiments. As described with respect to FIG. 3A, a heating unit 426 heats and vaporizes LNG 416 to generate de-liquefied LNG 428, *e.g.*, natural gas. To increase the pressure of a reservoir volume 402, a first stream of de-liquefied LNG 428 is injected into a well 406 to flow into a reservoir volume 402, as described with respect to FIG. 1.

[0035] Well and reservoir monitoring of the first stream of de-liquefied LNG 428, among other components within the well 406 and formation 401, can be traced and monitored using tracers 414. In general, tracers 414 are chemical compounds that are injected into the well 406 to trace and analyze the flow of fluids in the well 406 and/or a formation 401 during various operations, such as reservoir pressurization and fluid recovery. The tracers 414 can observe and track well and reservoir conditions, such as, the injection profile of injected fluids, the extent of injected fluid recovery, the influx of water, the amount of fluids produced from the well 406, the location of fractures, and the like. In the embodiments, the tracers 414 can be injected during the re-pressuring of the reservoir volume 402 or during fracturing of the re-pressurized volume as described with respect to FIG. 3A.

[0036] The tracers 414 can include various tracer compounds including tritiated methane (CH_3T), CH_2TCH_3 ; 2-*t* propane ($\text{CH}_3\text{CHTCH}_3$) Krypton 85 (^{85}Kr), radio-carbon dioxide ($^{14}\text{CO}_2$), xenon-133 (^{133}Xe), xenon-127 (^{127}Xe), perfluorodimethylmethylcyclohexane (PDMCH), perfluoromethylcyclopentane (PMCP), Perfluoromethylcyclohexane (PMCH), 1,2-perfluorodimethylcyclohexane (1,2-PDMCH), 1,3-perfluorodimethylcyclohexane (1,3-PDMCH), perfluoroethyl-cyclohexane (PECH), freon-11, freon-12, freon-113, perdeuterated methane (CD_4), d_6 -ethane (C_2D_6), d_6 -ethane (C_3D_8), nitrogen (N_2), carbon dioxide, helium, and volatile surfactants, among other tracers, that maintain a gaseous state under downhole conditions and that include low detection limits and resistant to downhole conditions. The tracers 414 can include various types of tracers including, but not limited to, radioactive tracers, non-radioactive tracers, noble gas tracers, chemical tracers, and the like.

[0037] To monitor various characteristics and fluids in the well 406, including the injected de-liquefied LNG 428, the tracer 414 is mixed with a second stream of de-liquefied LNG 438. For example, a mixer 454 admixes the second stream of the de-liquefied LNG 438 with the tracer 414 to form an injectable tracer material 458. The tracer material 458 is continuously injected into the well or in a spiked or single injection process using injection equipment 460. The injection equipment 460 can include tubing, pipes, pumps, compressors, or other equipment to flow the tracer material 458 through the well 406 and/or into the formation 401. The tracer material 458 flows through the formation 401 to be produced back into the well 406, for example, at a location where the tracer material 458 originally entered or leaked from a fracture formed in the formation 401. In some cases, the first stream of de-liquefied LNG 428 can be considered as a tracer material and solely injected into the well 406 without the tracer 414 after pressuring the reservoir volume 402.

[0038] The de-liquefied LNG 438 is suitable for use as a tracer due to a pure methane (CH_4) content and a non-detectable presence at a measurable level in the reservoir fluids recovered from the well 406. Further, the de-liquefied LNG 438 does not interfere or interact undesirably with reservoir fluids, *e.g.*, oil, gas, water, hydrocarbons, etc., and is injected into the well 406 at concentrations above detection limits. The detection limits may include, for example, at about five (5) parts per trillion to about 1,000 parts per million and more, preferably at a range of about 100 parts per trillion to about 100 parts per million.

[0039] In operation, the de-liquefied LNG 438 that is produced back into the well 406 is detected by one or more tracer detectors 462 installed in the well 406 and/or at a ground surface 415. The tracer detectors 462 can include electrochemical detectors and gamma ray detectors, among other types of detectors and/or sensors. The tracer detectors 462 can detect and analyze characteristics of the de-liquefied LNG 438, such as the concentration of the de-liquefied LNG 438 in the fluids recovered from the formation 401 and/or well 406. In addition to data related to concentrations, the parameter data can include data related to the time of de-liquefied LNG 438 detection, the location of the de-liquefied LNG 438 when detected, the amount of de-liquefied LNG 438 detected, and the like. A computing system 464 may receive and analyze the parameter data from the trace detectors 462. For instance, the computing system 464 analyzes the parameter data to provide information related to various characteristics of the formation 401 and/or the well 406, for example, information related to the pressure of the first stream of de-liquefied LNG 428 injected into the well to pressurize the reservoir volume 402.

[0040] It should be clearly understood that the fracturing system of FIG. 4 is merely one embodiment of an application of the principles of this disclosure in practice, and a wide variety of other embodiments are possible. Therefore, the scope of this disclosure is not limited at all to the details of FIG. 4 described herein and/or depicted in the additional drawings.

[0041] FIG. 5 is a schematic view of an example LNG pressuring system 500 and an example treatment system 544, according to one or more embodiments. A formation 501 includes a reservoir volume 502 composed of porous and permeable rocks that contain fluids, *e.g.*, oil, gas, hydrocarbons, water. A well 506 is drilled to penetrate the formation 501 to carry out exploration and production of fluids from the reservoir volume 502. However, after production, the reservoir volume 502 may be depleted of pressure and incapable of further production. In some cases, natural gas is injected into the well 506 using the LNG pressuring system 500 to re-pressurize the reservoir volume 502 for subsequent re-stimulation and production of additional fluids from the well 502.

[0042] LNG is transported to and stored in a LNG source vessel 518 at an on-site location of the well 506. The LNG source vessel 518 can include a cooling system or a separate cooling system 520 can be located at the on-site location to maintain the LNG at or below cryogenic temperatures, *e.g.*, -260 °F (-162 °C). As described with respect to FIG. 1, a cryogenic pump 524 supplies a feed pressure to flow a first stream of LNG 516 the into a heating unit 526. The heating unit 526 heats and vaporizes the first stream of LNG 516 into the natural gas, *e.g.*, de-liquefied LNG 528. Once in a gaseous state, the de-liquefied LNG 528 flows into the well 506 to increase the reservoir pressure of the reservoir volume 502. Pressuring the reservoir volume 502 mitigates or reduces asymmetrically-induced fracturing in the direction of the well 506. Further, after pressuring, production operations from the well 506 may be re-established to recovery any remaining fluids in the reservoir volume 502 or bypassed in the adjacent reservoir volume 504.

[0043] However, various physical and chemical factors reduce the permeability of the reservoir volume 502 to flow the fluids, thus, leading to a reduction in fluid recovery. For example, various fluids injected into the well 506 during operations, such as drilling, completion, and production operations, can cause damage to the formation 501 and/or well 506. Additionally, reactions among drilling fluids, production fluids, and formation fluids, such as emulsification due to oil/water incompatibilities, the precipitation of solids, the creation of an immiscible fluid, and water saturation, among others, can limit gas and oil

permeabilities. Other damaging factors include organic and inorganic scale formation and depositions, fines production and accumulation, mechanical damage, microorganism growth, and the like.

[0044] Chemical agents 517 are injected into the well 506 to combat such physical and chemical factors. The chemical agents 517 may improve the natural formation permeability around the well 506 by removing formation damage, dissolving material plugging pore spaces of the reservoir volume 502, or by enlarging the pore spaces, for example. The chemical agents 517 include, but are not limited to, acids (*e.g.*, hydrochloric acid (HCl)), organic acids (*e.g.*, formic, acetic, methanesulfonic), salts (*e.g.*, hydrochloride salts “HCL-adducts”) where the salt includes thioamide, urea, glycine, or an amino acid, among others, chelating agents (*e.g.*, N-phosphonomethyliminodiacetic acid (PMIDA), methylglycindiacytic acid (MGDA), glutamic acid N,N-diacytic acid (GLDA), hydroxyethyl ethylenediamine triacytic acid (HEDTA), citric acid, malic acid, tartaric acid, succinic acid, gluconic acid, lactic acid), surfactants, emulsions, and microemulsions, diverting agents, corrosion inhibitors, scale inhibitors, foaming agents, and chemically-active nanoparticles and particulates, among others.

[0045] In one or more embodiments, a second stream of LNG 538 and the chemical agents 517 flow into a mixer 554 to form a treatment fluid 558 that is thereafter injected into the well 506. In examples, the second stream of LNG 538 may be in a gaseous state (*i.e.*, de-liquefied LNG) or a gas/liquid mixture of natural gas upon entering the well 506. The second stream of LNG 538 combined with the chemical agent 517 provides an enhanced treatment solution to remove formation and well damage. The treatment fluid 558 lands at a near wellbore region 519 of the formation 501 or in an area of reduced permeability around the well 506. As described herein, the near-wellbore region 519 is the subterranean material and rock surrounding the well 506 and is considered the region within about 100 feet (ft) of the well 506. The treatment fluid 558 flows into the well 506 and into the fractures 510 propagating through the reservoir volume 502 that have been damaged during the course of the drilling and the production operations. The treatment fluid 558 is used to carry out pre-fracturing treatments, fracture clean-out treatments, scale and deposit removal treatments, emulsion removal treatments, and corrosion inhibition, among others. The treatment fluid 558 can be injected during or after re-pressuring of the reservoir volume 502.

[0046] Using the LNG 538 as a component of the treatment fluid 558 changes the physiochemical characteristics of one or more chemical agents 517, for instance, the LNG

538 modulates or adjusts the reactive force of the agents 517 when in the presence of water. For example, one or more chemical agents injected into the well 506 can react with a metal surface, such as a metal surface of a packer 521, to induce corrosion. Further, one or more of the chemical agents 517 may react with water injected or naturally found in the well 506 to produce an acidic solution. However, injecting the second stream of LNG 538 with the chemical agents 517 reduces or mitigates the acidic nature of the chemical agents 517 to reduce corrosion or other damaging effects in the well 506 and or formation 501. In some cases, an injection rate of the second stream of LNG 538 is adjusted to control the corrosion rate of the surfaces susceptible to corrosion, such as the packer 521.

[0047] It should be clearly understood that the fracturing system of FIG. 5 is merely one embodiment of an application of the principles of this disclosure in practice, and a wide variety of other embodiments are possible. Therefore, the scope of this disclosure is not limited at all to the details of FIG. 5 described herein and/or depicted in the additional drawings.

[0048] In addition, to the embodiments described above, many examples of specific combinations are within the scope of the disclosure, some of which are detailed below:

Example 1. A method for pressurizing a reservoir volume including fluid in a formation with a parent well extending through the formation, the method comprising: storing liquefied natural gas (LNG) at an on-site location of the parent well; de-liquefying the LNG to form natural gas at the on-site location; and injecting the natural gas into the parent well to pressurize the reservoir volume through the parent well.

Example 2. The method of Example 1, further comprising transporting the LNG to the on-site location, wherein the LNG is a processed cryogenic fluid at or below a temperature of about -260 Fahrenheit (°F) (-162 Celsius (°C)).

Example 3. The method of Example 1, further comprising pumping the LNG at the on-site location to increase a pressure of the LNG before heating the LNG.

Example 4. The method of Example 3, further comprising vaporizing the pressurized LNG at the on-site location to form the natural gas.

Example 5. The method of Example 1, further comprising drilling a child well after pressurizing the reservoir volume through the parent well.

Example 6. The method of Example 1, wherein injecting the natural gas into the parent well to pressurize the reservoir volume decreases asymmetric fracturing towards the parent well during stimulation of a reservoir volume through a child well.

Example 7. The method of Example 6, further comprising: pumping a portion of the LNG at a fracturing pressure; and injecting the portion of pressurized LNG into the parent well as a fracturing fluid to fracture the parent well.

Example 8. The method of Example 7, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.

Example 9. The method of Example 1, further comprising: drilling a child well; stimulating a reservoir volume through the child well; injecting a portion of pressurized LNG into the reservoir volume through the parent well to stimulate fluid flow from the reservoir volume through the parent well; and wherein the reservoir volume through the child well is stimulated before injecting the portion of pressurized LNG into the reservoir volume through the parent well.

Example 10. The method of Example 1, wherein fluids of the reservoir volume through the parent well are near, at, or below a bubble point of the reservoir volume.

Example 11. The method of Example 1, further comprising recovering a portion of the natural gas after pressurizing the reservoir volume through the parent well.

Example 12. The method of Example 1, further comprising: injecting a portion of the LNG as a tracer material into the parent well; and detecting the portion of the injected LNG to infer information related to at least one of the parent well or the formation.

Example 13. A method for pressurizing a reservoir volume including a fluid in a formation with a parent well extending through the formation, the method comprising: storing liquefied natural gas (LNG) at an on-site location of the parent well; de-liquefying the LNG into natural gas at the on-site location; injecting the natural gas into the parent well to pressurize

the reservoir volume through the parent well; and drilling a child well after pressurizing the reservoir volume through the parent well.

Example 14. The method of Example 13, wherein the injecting of the natural gas into the parent well decreases asymmetric fracturing towards the parent well during stimulation of a reservoir volume through the child well.

Example 15. The method of Example 14, further comprising pumping a portion of the LNG at a fracturing pressure; injecting the portion of pressurized LNG into the parent well as a fracturing fluid to fracture the parent well.

Example 16. The method of Example 15, further comprising, after stimulating the reservoir volume through the child well, injecting the portion of pressurized LNG as a fracturing fluid into the pressurized reservoir volume through the parent well to fracture the parent well.

Example 17. The method of Example 15, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of a viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.

Example 18. The method of Example 13, further comprising recovering a portion of the natural gas after pressurizing the reservoir volume through the parent well.

Example 19. The method of claim 13, further comprising: injecting a portion of the LNG as a tracer material into the parent well; and detecting the portion of injected LNG to infer information related to at least one of the parent well or the formation.

Example 20. A system for pressurizing a reservoir volume including a fluid in a formation with a parent well extending through the formation, the system comprising: a source of liquefied natural gas (LNG) locatable at an on-site location of the well; a cryogenic system locatable at the on-site location and comprising a pumping unit and a heating unit configured to de-liquefy the LNG to form natural gas; and injection equipment connectable and in communication with the parent well and configured to inject the natural gas into the parent well to pressurize the reservoir volume through the parent well.

Example 21. The system of Example 20, wherein the pumping unit and the heating unit are operable to pressurize and vaporize the LNG into natural gas.

Example 22. The system of Example 20, wherein the LNG comprises a processed cryogenic fluid and the cryogenic system further comprises a cooling system to maintain the LNG at or below a temperature of about -260 Fahrenheit (°F) (-162 Celsius (°C)).

Example 23. The system of Example 20, wherein fluids of the reservoir volume through the parent well are near, at, or below a bubble point of the reservoir volume fluids.

Example 24. The system of Example 20, wherein a portion of the LNG is useable and injectable into the parent well as a fracturing fluid to fracture the parent well.

Example 25. The system of Example 24, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, alcohols, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.

Example 26. The system of Example 20, wherein another portion of the LNG is a tracer material used to monitor and provide information related to at least one of the parent well or the formation.

Example 27. The system of Example 20, wherein the reservoir volume is a depleted reservoir volume.

[0049] One or more specific embodiments of the present disclosure have been described. In an effort to provide a concise description of these embodiments, all features of an actual implementation may not be described in the specification. It should be appreciated that in the development of any such actual implementation, as in any engineering or design project, numerous implementation-specific decisions must be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which may vary from one implementation to another. Moreover, it should be appreciated that such a development effort might be complex and time-consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.

[0050] In the previous discussion and in the claims, the articles “a,” “an,” and “the” are intended to mean that there are one or more of the elements. The terms “including,” “comprising,” and “having” and variations thereof are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . .” Also, any use of any form of the terms “connect,” “engage,” “couple,” “attach,” “mate,” “mount,” or any other term describing an interaction between elements is intended to mean either an indirect or a direct interaction between the elements described. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the central axis. The use of “top,” “bottom,” “above,” “below,” “upper,” “lower,” “up,” “down,” “vertical,” “horizontal,” and variations of these terms is made for convenience, but does not require any particular orientation of the components.

[0051] Certain terms are used throughout the description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or features that differ in name but not function.

[0052] Reference throughout this specification to “one embodiment,” “an embodiment,” “an embodiment,” “embodiments,” “some embodiments,” “certain embodiments,” or similar language means that a particular feature, structure, or characteristic described in connection with the embodiment may be included in at least one embodiment of the present disclosure. Thus, these phrases or similar language throughout this specification may, but do not necessarily, all refer to the same embodiment.

[0053] The embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. It is to be fully recognized that the different teachings of the embodiments discussed may be employed separately or in any suitable combination to produce desired results. In addition, one skilled in the art will understand that the description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment.

Claims

What is claimed is:

1. A method for pressurizing a reservoir volume including fluid in a formation with a parent well extending through the formation, the method comprising:
 - storing liquefied natural gas (LNG) at an on-site location of the parent well;
 - de-liquefying the LNG to form natural gas at the on-site location; and
 - injecting the natural gas into the parent well to pressurize the reservoir volume through the parent well.
2. The method of claim 1, further comprising transporting the LNG to the on-site location, wherein the LNG is a processed cryogenic fluid at or below a temperature of about -260 Fahrenheit (°F) (-162 Celsius (°C)).
3. The method of claim 1, further comprising pumping the LNG at the on-site location to increase a pressure of the LNG before heating the LNG.
4. The method of claim 3, further comprising vaporizing the pressurized LNG at the on-site location to form the natural gas.
5. The method of claim 1, further comprising drilling a child well after pressurizing the reservoir volume through the parent well.
6. The method of claim 1, wherein injecting the natural gas into the parent well to pressurize the reservoir volume decreases asymmetric fracturing towards the parent well during stimulation of a reservoir volume through a child well.
7. The method of claim 6, further comprising:
 - pumping a portion of the LNG at a fracturing pressure; and
 - injecting the portion of pressurized LNG into the parent well as a fracturing fluid to fracture the parent well.
8. The method of claim 7, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.

9. The method of claim 1, further comprising:
- drilling a child well;
 - stimulating a reservoir volume through the child well;
 - injecting a portion of pressurized LNG into the reservoir volume through the parent well to stimulate fluid flow from the reservoir volume through the parent well;
 - and
- wherein the reservoir volume through the child well is stimulated before injecting the portion of pressurized LNG into the reservoir volume through the parent well.
10. The method of claim 1, wherein fluids of the reservoir volume through the parent well are near, at, or below a bubble point of the reservoir volume.
11. The method of claim 1, further comprising recovering a portion of the natural gas after pressurizing the reservoir volume through the parent well.
12. The method of claim 1, further comprising:
- injecting a portion of the LNG as a tracer material into the parent well; and
 - detecting the portion of the injected LNG to infer information related to at least one of the parent well or the formation.
13. A method for pressurizing a reservoir volume including a fluid in a formation with a parent well extending through the formation, the method comprising:
- storing liquefied natural gas (LNG) at an on-site location of the parent well;
 - de-liquefying the LNG into natural gas at the on-site location;
 - injecting the natural gas into the parent well to pressurize the reservoir volume through the parent well; and
 - drilling a child well after pressurizing the reservoir volume through the parent well.
14. The method of claim 13, wherein the injecting of the natural gas into the parent well decreases asymmetric fracturing towards the parent well during stimulation of a reservoir volume through the child well.
15. The method of claim 14, further comprising:
- pumping a portion of the LNG at a fracturing pressure;
 - injecting the portion of pressurized LNG into the parent well as a fracturing fluid to fracture the parent well.

16. The method of claim 15, further comprising, after stimulating the reservoir volume through the child well, injecting the portion of pressurized LNG as a fracturing fluid into the pressurized reservoir volume through the parent well to fracture the parent well.

17. The method of claim 15, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of a viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.

18. The method of claim 13, further comprising recovering a portion of the natural gas after pressurizing the reservoir volume through the parent well.

19. The method of claim 13, further comprising:

injecting a portion of the LNG as a tracer material into the parent well; and
detecting the portion of injected LNG to infer information related to at least one of the parent well or the formation.

20. A system for pressurizing a reservoir volume including a fluid in a formation with a parent well extending through the formation, the system comprising:

a source of liquefied natural gas (LNG) locatable at an on-site location of the well;
a cryogenic system locatable at the on-site location and comprising a pumping unit
and a heating unit configured to de-liquefy the LNG to form natural gas; and
injection equipment connectable and in communication with the parent well and
configured to inject the natural gas into the parent well to pressurize the
reservoir volume through the parent well.

21. The system of claim 20, wherein the pumping unit and the heating unit are operable to pressurize and vaporize the LNG into natural gas.

22. The system of claim 20, wherein the LNG comprises a processed cryogenic fluid and the cryogenic system further comprises a cooling system to maintain the LNG at or below a temperature of about -260 Fahrenheit (°F) (-162 Celsius (°C)).

23. The system of claim 20, wherein fluids of the reservoir volume through the parent well are near, at, or below a bubble point of the reservoir volume fluids.

24. The system of claim 20, wherein a portion of the LNG is useable and injectable into the parent well as a fracturing fluid to fracture the parent well.
25. The system of claim 24, wherein the fracturing fluid further comprises a base fluid selected from the group consisting of viscosifier agents, carrier aqueous fluids, proppants, demulsifiers, corrosion inhibitors, friction reducers, clay stabilizers, scale inhibitors, biocides, breaker aids, mutual solvents, alcohols, surfactants, anti-foam agents, defoamers, viscosity stabilizers, iron control agents, diverters, emulsifiers, non-emulsifiers, foamers, foaming agents, nanoparticles-stabilized foams, oxygen scavengers, pH control agents, and buffering agents.
26. The system of claim 20, wherein another portion of the LNG is a tracer material used to monitor and provide information related to at least one of the parent well or the formation.
27. The system of claim 20, wherein the reservoir volume is a depleted reservoir volume.

1/7

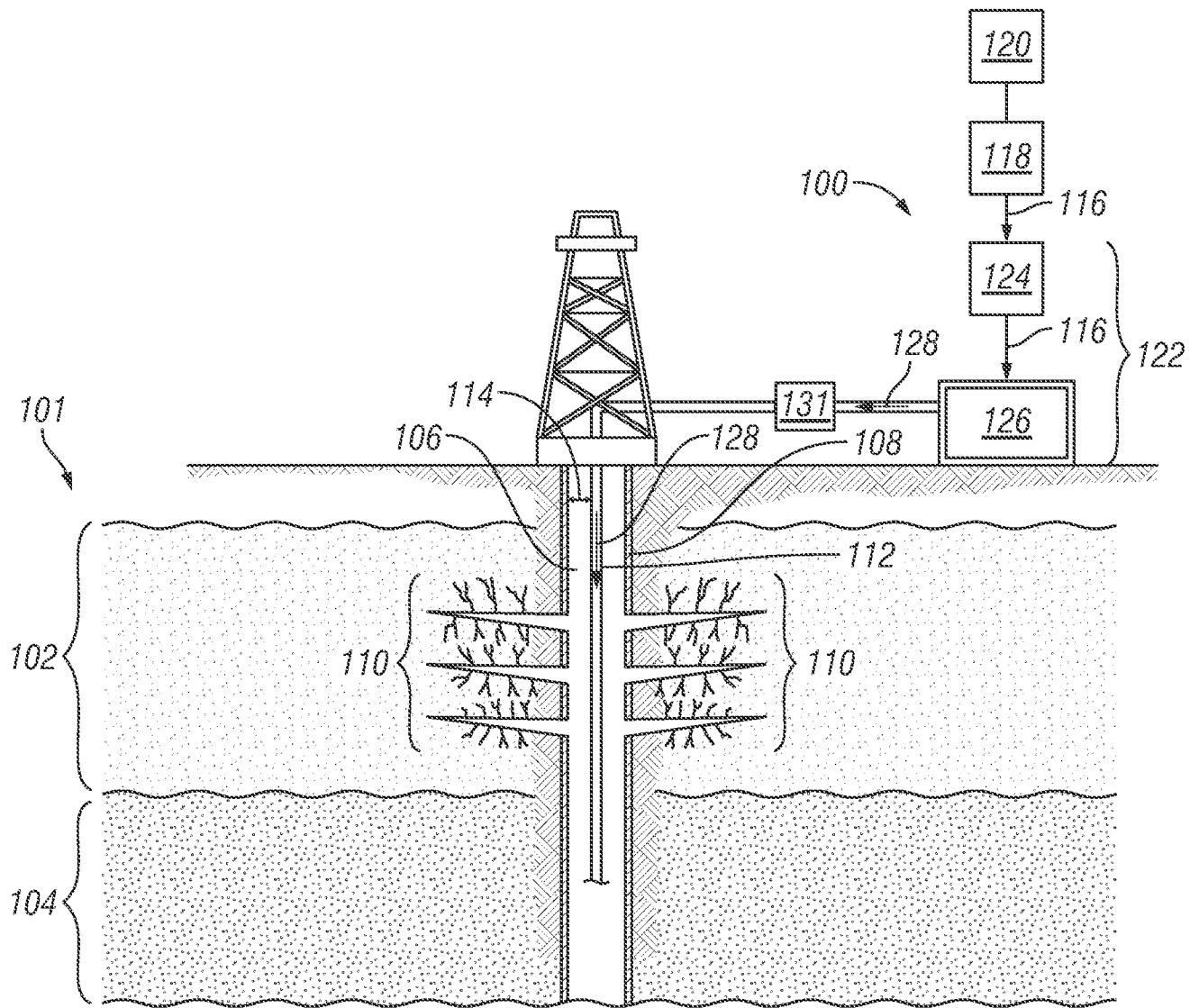


FIG. 1

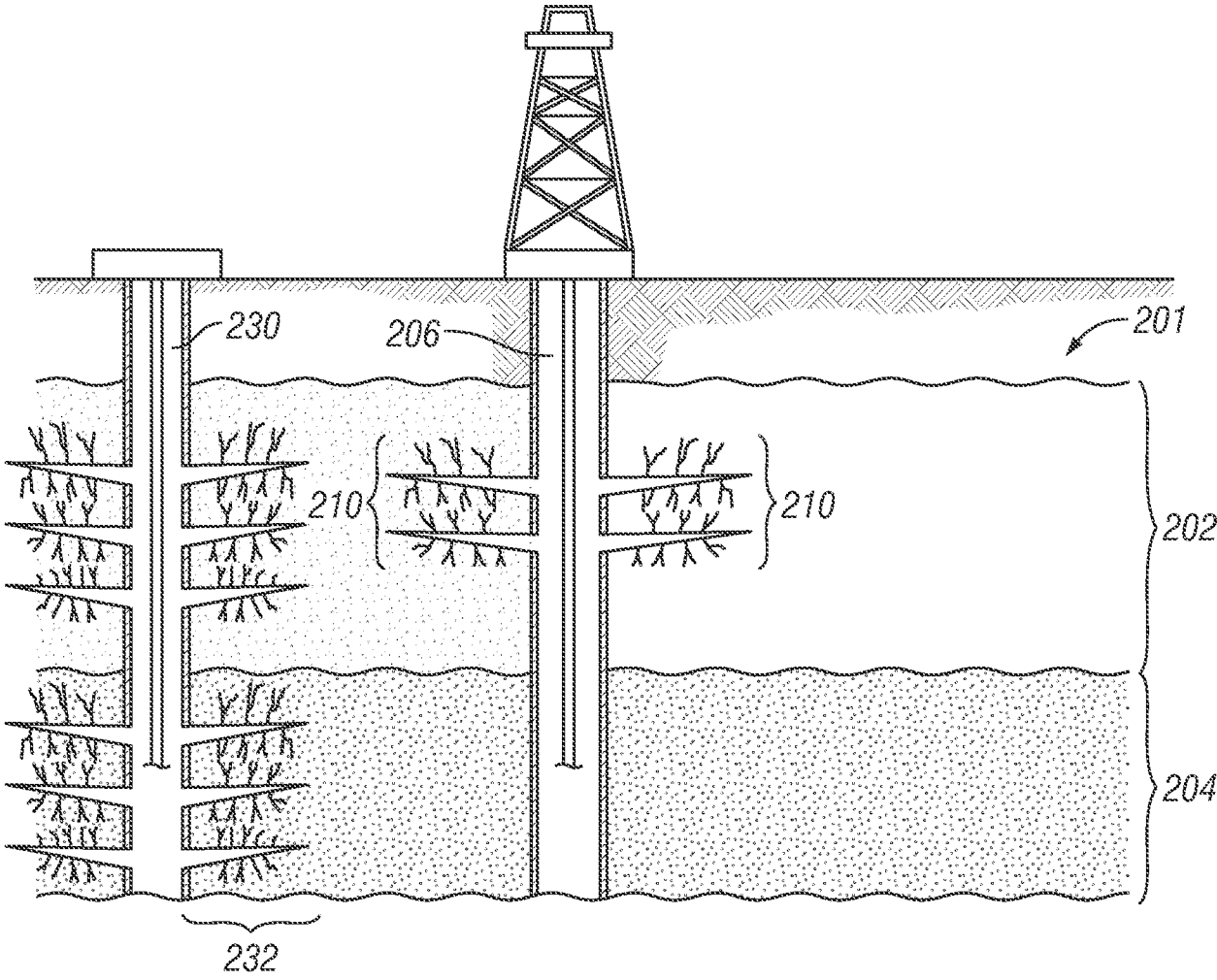


FIG. 2A

3/7

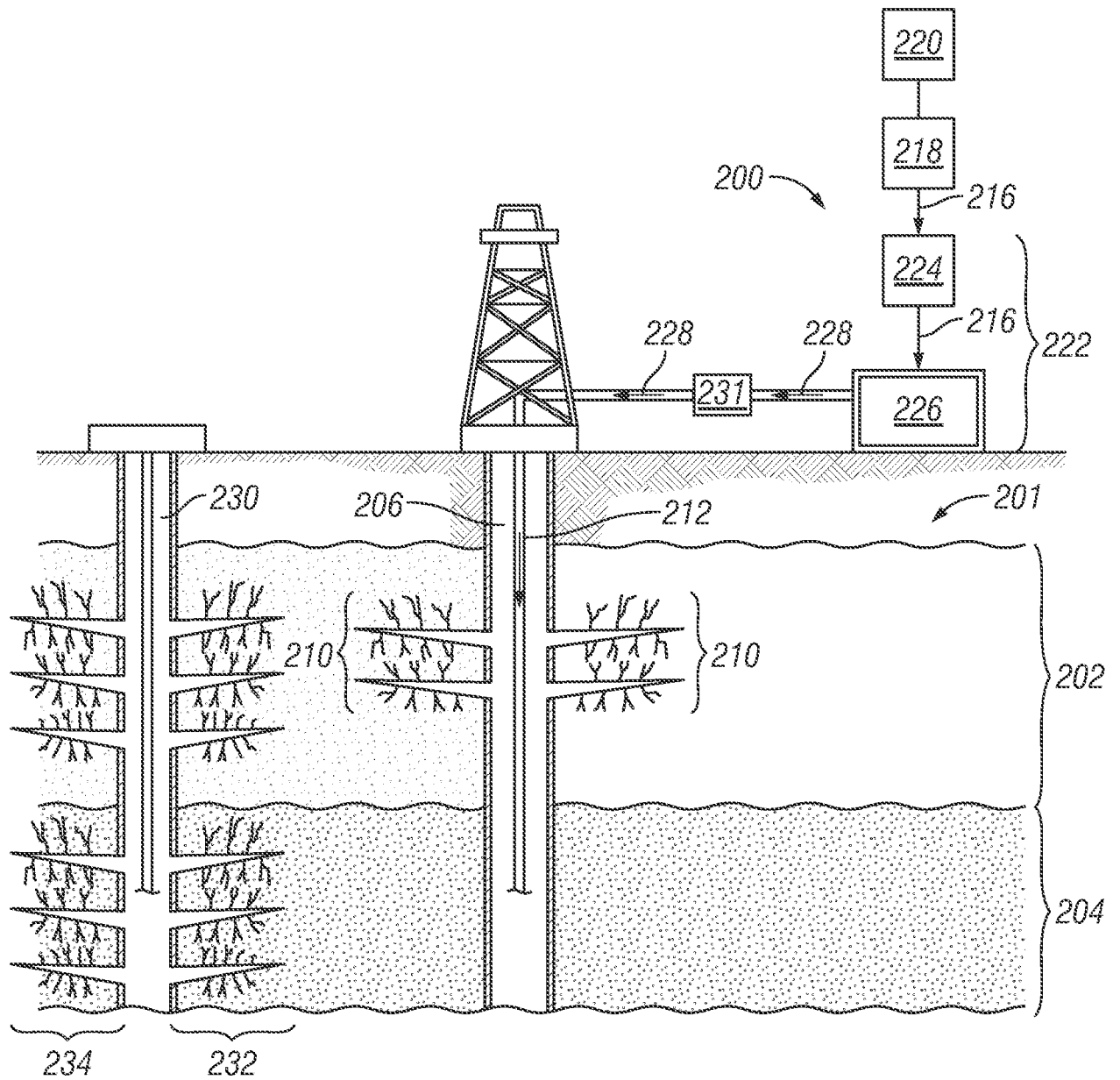


FIG. 2B

4/7

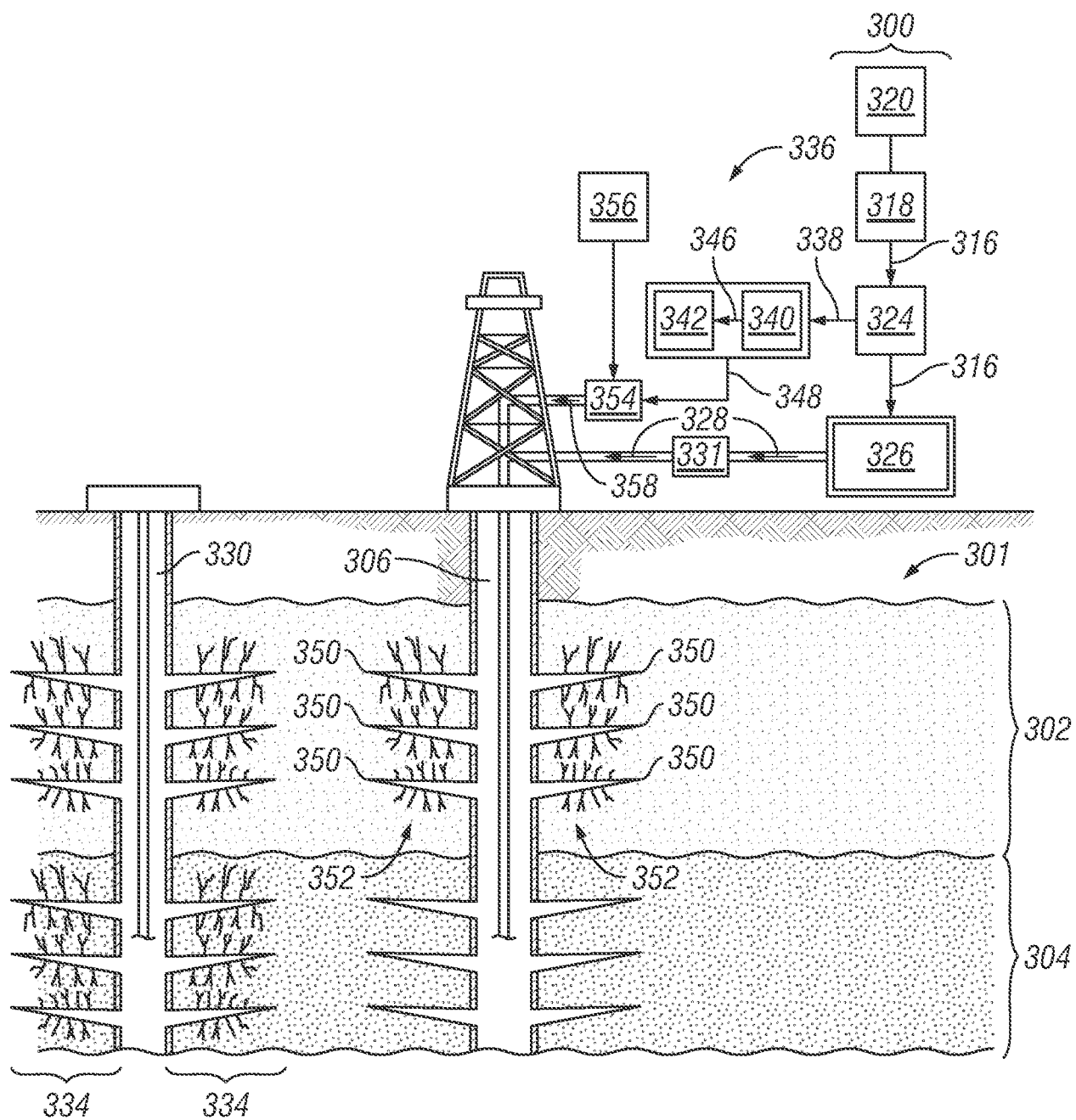


FIG. 3A

5/7

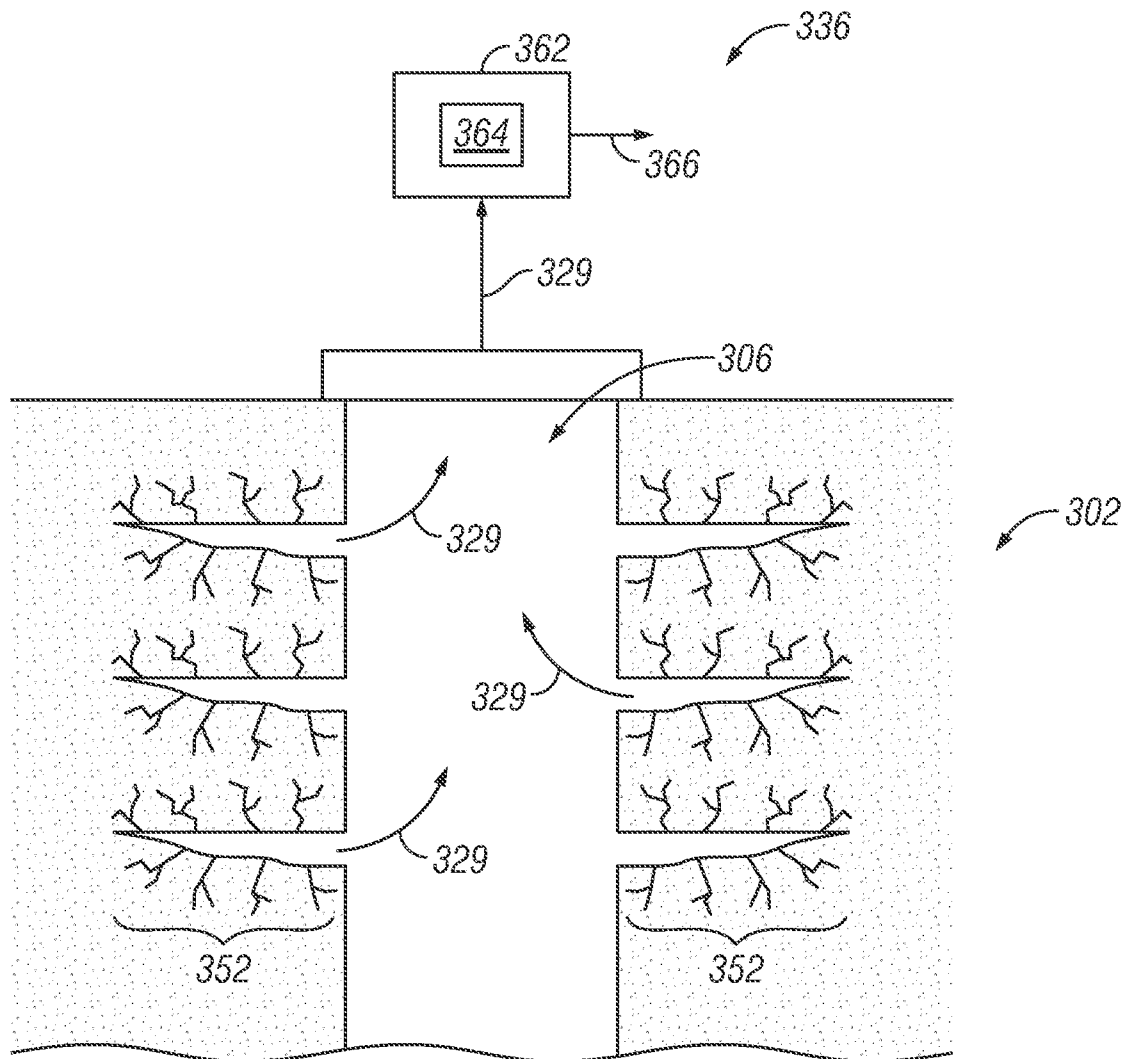


FIG. 3B

6/7

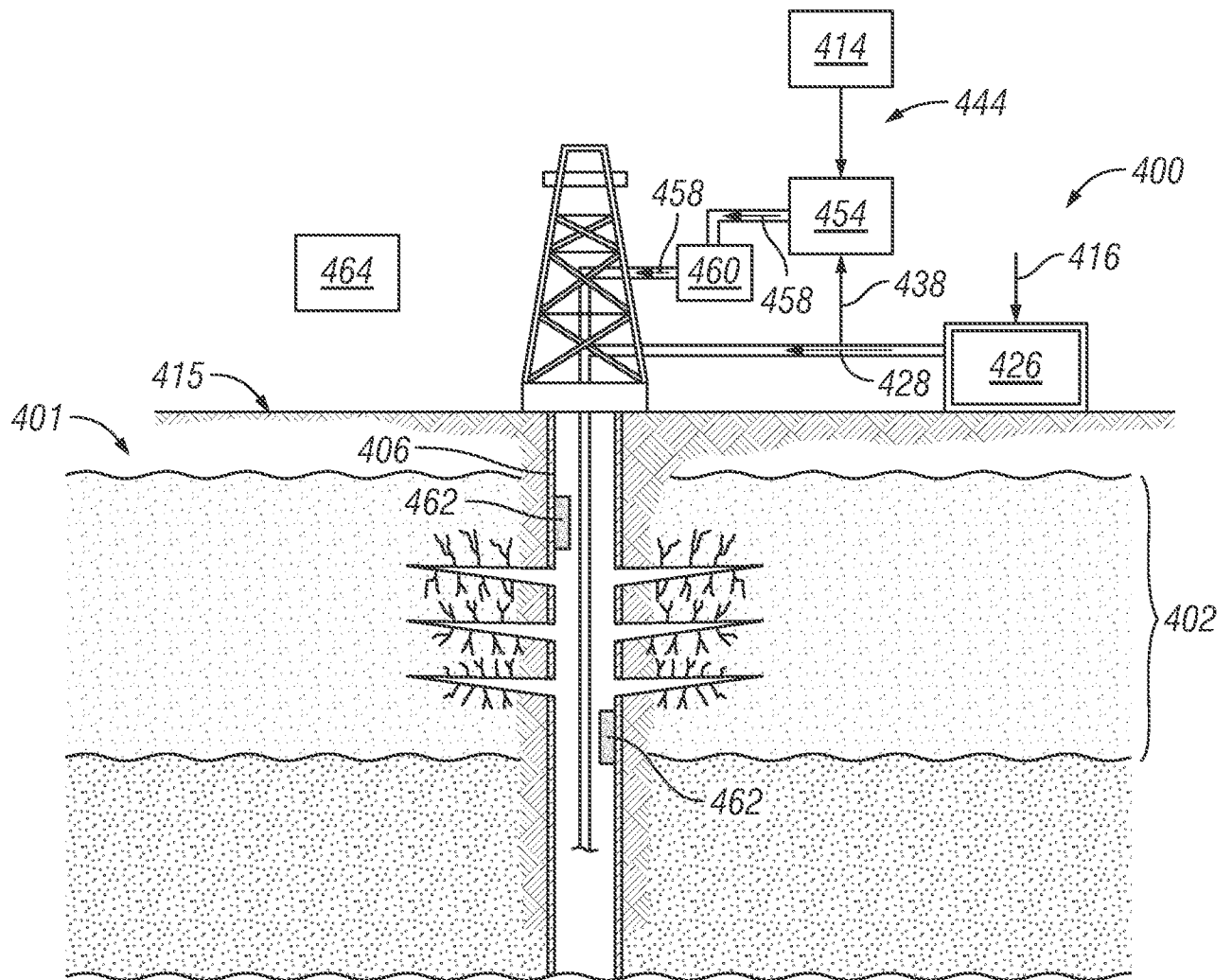


FIG. 4

7/7

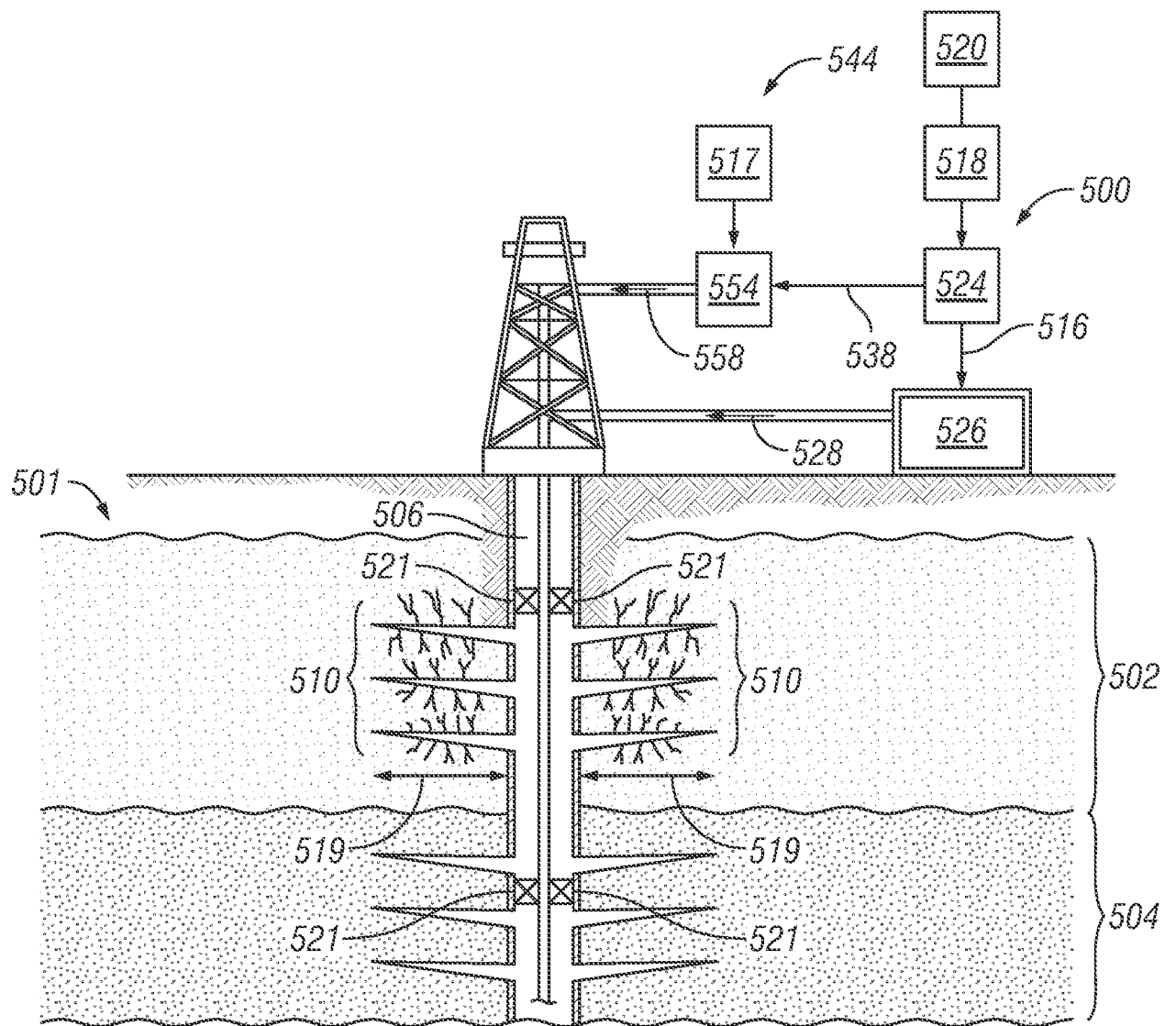


FIG. 5

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/061686**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/25(2006.01)i, E21B 43/26(2006.01)i, C09K 8/62(2006.01)i**

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)

E21B 43/25; E21B 43/34; E21B 43/267; E21B 19/22; E21B 43/26; E21B 19/00; F17C 9/02; C09K 8/80; C09K 8/62

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

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

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

eKOMPASS(KIPO internal) & Keywords: reservoir, parent, child, well, on-site, re-pressure, de-liquefy, LNG

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2014-0008074 A1 (NEVISON, GRANT W.) 09 January 2014 See paragraphs [0003], [0012], [0034]-[0053], [0088]; and figures 3, 10, 13.	1-27
A	US 2016-0273327 A1 (HALLIBURTON ENERGY SERVICES, INC.) 22 September 2016 See paragraphs [0022]-[0030]; and figures 1-2.	1-27
A	US 2013-0228330 A1 (LOREE et al.) 05 September 2013 See paragraphs [0031]-[0054]; and figures 1-6, 10-11.	1-27
A	WO 2015-131284 A1 (TRICAN WELL SERVICE LTD.) 11 September 2015 See page 9, line 10 - page 14, line 15; page 17, line 5 - page 20, line 3; and figures 3-4, 7-9.	1-27
A	US 6298671 B1 (KENNELLEY et al.) 09 October 2001 See column 2, line 60 - column 5, line 10; and DRAWING.	1-27



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

28 July 2017 (28.07.2017)

Date of mailing of the international search report

28 July 2017 (28.07.2017)

Name and mailing address of the ISA/KR

International Application Division

Korean Intellectual Property Office

189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea



Facsimile No. +82-42-481-8578

Authorized officer

LEE, Se Gyoung

Telephone No. +82-42-481-8740



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/061686

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2014-0008074 A1	09/01/2014	AU 2011-356580 A1	26/07/2012
		AU 2011-356580 B2	28/04/2016
		AU 2011-356581 A1	26/07/2012
		AU 2011-356581 B2	28/04/2016
		AU 2011-356582 A1	26/07/2012
		AU 2011-356582 B2	28/04/2016
		CA 2824169 A1	26/07/2012
		CA 2824169 C	10/02/2015
		CA 2824181 A1	26/07/2012
		CA 2824181 C	17/02/2015
		CA 2824206 A1	26/07/2012
		CA 2824206 C	17/02/2015
		CN 103429845 A	04/12/2013
		CN 103429845 B	28/12/2016
		CN 103429846 A	04/12/2013
		CN 103429846 B	10/02/2016
		CN 103443397 A	11/12/2013
		CN 103443397 B	17/08/2016
		EA 024378 B1	30/09/2016
		EA 024675 B1	31/10/2016
		EA 201370157 A1	30/12/2013
		EA 201370158 A1	28/02/2014
		EA 201370160 A1	30/05/2014
		EP 2665890 A1	27/11/2013
		EP 2665891 A1	27/11/2013
		EP 2665892 A1	27/11/2013
		MX 2013008324 A	21/11/2014
		MX 2013008325 A	06/02/2014
		MX 2013008326 A	27/02/2014
		MX 339167 B	09/05/2016
		US 2013-0341010 A1	26/12/2013
		US 2014-0000899 A1	02/01/2014
		US 2016-0084058 A1	24/03/2016
		US 8991499 B2	31/03/2015
		US 9033035 B2	19/05/2015
		US 9181789 B2	10/11/2015
		WO 2012-097424 A1	26/07/2012
		WO 2012-097425 A1	26/07/2012
		WO 2012-097426 A1	26/07/2012
US 2016-0273327 A1	22/09/2016	None	
US 2013-0228330 A1	05/09/2013	CA 2801144 A1	08/12/2011
		EP 2627865 A1	21/08/2013
		WO 2011-150486 A1	08/12/2011
WO 2015-131284 A1	11/09/2015	CA 2941454 A1	11/09/2015
US 6298671 B1	09/10/2001	AU 2001-43629 A1	24/12/2001

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/061686

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		AU 2001-43629 B2	06/05/2004
		AU 4362901 A	24/12/2001
		AU 772688 B2	06/05/2004
		BR 0106738 A	14/05/2002
		BR 0106738 B1	26/01/2010
		CN 1380966 A	20/11/2002
		EP 1290388 A1	12/03/2003
		EP 1290388 B1	05/03/2014
		ES 2453487 T3	07/04/2014
		ID 30525 A	20/12/2001
		IL 147551 A	19/06/2005
		JP 2004-503698 A	05/02/2004
		JP 4623928 B2	02/02/2011
		KR 10-0767232 B1	17/10/2007
		TW 489198 A	01/06/2002
		WO 01-096797 A1	20/12/2001