

APPARATUS, SYSTEM AND METHOD FOR REMOVING GAS FROM FLUID PRODUCED FROM A WELLBORE

CROSS-REFERENCE TO RELATED APPLICATIONS

- 5 [0001] This application claims the benefit of U.S. Provisional Application No. 61/674,996, filed July 24, 2012, which is incorporated herein by reference.

BACKGROUND

[0002] The present disclosure relates generally to the production of fluid from a wellbore. More specifically, the present disclosure relates to techniques for removing gas from
10 produced wellbore fluid.

[0003] Wellbores are drilled into the earth to locate and produce valuable hydrocarbons. Land or water based rigs are positioned about the wellbores to retrieve downhole fluid from subsurface reservoirs. Various devices, such as tubing, pumps, manifolds, valves and other fluid control devices, may be positioned about a wellsite and/or deployed into the
15 wellbore to facilitate production of downhole fluid. During production, various fluids, such as water, oil, gases and other downhole fluid, may be produced from the wellbores.
[0004] In some cases, it may be desirable to separate the downhole fluid produced from the wellbore. For example, separators may be coupled to production tubing to separate hydrocarbons from the produced fluid. Examples of fluid separation techniques are shown
20 in US Patent No. 4,778,443. It may also be desirable to remove gas from produced fluid. Techniques for degassing are described in US Patent Nos. 4,755,372, 8,105,422, and 8,002,878.

[0005] Separation techniques have also been used in desalination processes involving the removal of salt or other minerals from water. Desalination may involve the use of pressure
25 exchangers, for example, in reverse osmosis applications. Examples of desalination are provided in US Patent/Application Nos. 3,522,152, 2008/0290032, and 2011/0006005. Despite the advances in fluid separation techniques, there remains a need to provide advanced techniques for separating fluid.

SUMMARY

30 [0006] In at least one aspect, the disclosure relates to a degasser for removing gas from fluid produced from a wellbore penetrating a subterranean formation, the produced fluid

separated by a fluid separator connectable to the wellbore and receiving the produced fluid therefrom. The fluid separator separates the produced fluid into a plurality of separated fluids including hydrocarbons and high pressure fluid. The degasser is provided with a pressure exchanger and a gas separator. The pressure exchanger is fluidly connectable to the fluid separator and receives the high pressure fluid therefrom. The pressure exchanger is also fluidly connectable to a low pressure source. The pressure exchanger exchanges high pressure from the high pressure fluid and low pressure from the low pressure source whereby the high pressure fluid is converted into a reduced pressure fluid. The gas separator is fluidly connectable to the pressure exchanger and receives the reduced pressure fluid therefrom. The gas separator separates gas from the reduced pressure fluid.

[0007] The degasser may be provided with a filter (e.g., coalescing filter), at least one pump and fluid connections to the wellbore, the sea, the surface and/or a container. The gas separator may be used to separate a separated low pressure fluid from the reduced pressure fluid. The gas separator may be fluidly connectable to the pressure exchanger for passing at least a portion of the separated low pressure fluid thereto such that the separated low pressure fluid is usable as the low pressure source.

[0008] The degasser may be part of a system including a fluid separator fluidly connectable to the wellbore and receiving the produced fluid therefrom such that the fluid separator separates the produced fluid into a plurality of separated fluids including hydrocarbons and high pressure fluid. The system may also have at least one filter, at least one pump, a container, and a fluid treatment source for applying treatment fluid to the reduced pressure fluid. The treatment fluid may include, for example, acid, base, biocide, corrosion inhibitor, antiscalant, and/or calcium nitrate.

[0009] In another aspect, the disclosure relates to a method for removing gas from a fluid produced from a wellbore penetrating a subterranean formation. The method involves providing a system for degassing the produced fluid including a fluid separator fluidly connected to the wellbore and receiving the produced fluid therefrom, a pressure exchanger fluidly connected to the fluid separator, and a gas separator fluidly connected to the pressure exchanger. The method also involves separating the produced fluid into a plurality of separated fluids including hydrocarbons and high pressure fluid using the fluid separator, converting the high pressure fluid into a reduced pressure fluid by exchanging pressure from the high pressure fluid with a low pressure source using the pressure exchanger and separating gas from the reduced pressure fluid with the gas separator.

[00010] The method may also involve discharging at least a portion of the gas to the wellbore and performing artificial lift using the discharged gas, discharging at least a portion of the separated low pressure fluid to the sea, a storage container, and/or the wellbore, using the separated low pressure fluid as the low pressure source and converting the separated low pressure fluid into a separated high pressure fluid by exchanging pressure with the high pressure fluid, discharging at least a portion of the separated high pressure fluid to one of the sea, a storage container and the wellbore, applying a treatment fluid to the reduced pressure fluid, filtering one of the high pressure fluid and the separated low pressure fluid.

10 [00011] The separating gas may involve separating a separated low pressure fluid from the reduced pressure fluid. The separated high and/or low pressure fluid may have less than 5 ppm of suspended solids and the separated high pressure fluid may have a pressure of at least 60 Bar.

BRIEF DESCRIPTION OF THE DRAWINGS

15 [00012] So that the above recited features and advantages of the disclosure may be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to the embodiments thereof that are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are, therefore, not to be considered limiting of its scope. The figures are not necessarily to scale, and certain features and certain views of the figures may be shown exaggerated in scale or in schematic in the interest of clarity and conciseness.

[00013] Figure 1 is a schematic diagram, partially in cross-section depicting a wellsite with a system for removing gas from fluid produced from a wellbore.

25 [00014] Figure 2 is a graph depicting hydrocarbons dissolved in water under pressure.

[00015] Figures 3A and 3B are a flow chart depicting a method of removing gas from fluid produced from a wellbore.

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DETAILED DESCRIPTION

[00016] The description that follows includes exemplary apparatuses, methods, techniques, and instruction sequences that embody techniques of the inventive subject matter. However, it is understood that the described embodiments may be practiced
5 without these specific details.

[00017] The disclosure relates to techniques for processing high pressure fluid produced from a wellbore to separate dissolved gas from the produced fluid. The techniques provide for such separation without losing mechanical energy contained in the fluid. The high pressure fluid provides an energy source that may be used to power a
10 degasser to remove gas from the water being discharged. The high pressure fluid may also be used, for example, to operate a gas separator and a pressure exchanger (as well as other fluid components) to separate and divert fluid, such as gas, for further use. Additionally, the removal of hydrocarbons will make the discharged fluid cleaner. By separating produced brine from oil and dissolved hydrocarbons, sufficient hydrocarbons may be
15 removed to allow discharge into the ocean or for reinjection into subsurface reservoirs.

[00018] Figure 1 illustrates a subsea wellsite system 100 for degasification of fluid produced from a wellbore. While the wellsite system 100 shown is in a subsea environment involving subsea production operations, the systems, apparatus and methods of the present disclosure are equally applicable to land operations. A rig 102 is configured
20 for production operations in the vicinity of the wellbore 104 disposed in a formation 106. Fluid from a reservoir 105 in the formation 106 is produced into the wellbore 104, for example, via formation pressure and/or enhanced oil recovery (EOR) techniques.

[00019] The produced fluid 108 passes from the wellbore 104 to a fluid separator 110 as indicated by the arrows. The fluid separator 110 may be a conventional fluid
25 separator usable, for example, for separating hydrocarbons 112 from the produced fluid 108. The separator 110 may be, for example, a cylindrical or spherical vessel positionable in a horizontal or vertical position along flowlines of the wellsite system 100 used to transport the produced fluid. The fluid separator 110 may include a single separator unit, or a series of separator units coupled together to achieve the ultimate result of separating the
30 hydrocarbons 112 from the remainder of high pressure fluid 114 of the produced fluid 108. The separated hydrocarbons 112 may be pumped via a pump 115 (e.g., a boost pump) to the rig 102 for collection at the surface as indicated by the arrows. Other fluids, such as

gas 117 may also optionally be separated and sent to the surface as indicated by the arrows.

[00020] The remaining high pressure fluid 114 left after removal of the hydrocarbons 112 and gas 117 from the produced fluid 108 may include, for example, water, dissolved salts, dispersed oil and/or dissolved gas (e.g., methane, other soluble
5 hydrocarbons, carbon dioxide, hydrogen sulfide, nitrogen and the like). The high pressure fluid 114 may be at a pressure of, for example, at least about 600 psi (41 Bar). The high pressure fluid 114 emerging from the fluid separator 110 may optionally be discharged to sea.

[00021] In some cases, as shown in Figure 2, certain amounts of hydrocarbons may
10 remain in water even after passing through a separator, such as the separator 110 of Figure 1. Figure 2 is a plot 200 depicting hydrocarbons remaining dissolved in water after passing through a separator device. The hydrocarbons in water in parts per million (ppm) (y-axis) are plotted versus pressures in Bara (x-axis). Lines 217, 219, 221, 223, 225 and 227 plot the amount of hydrocarbons in water versus pressure at 25, 40, 70, 100, 60 and 90 degrees
15 C, respectively. This plot indicates that the amount of hydrocarbons that remain in water after separation increases at lower temperatures and higher pressures.

[00022] Referring back to Figure 1, in cases where a certain amount of hydrocarbons remain, such as those at higher temperatures and pressures as shown in Figure 2, the high pressure fluid 114 may be passed to a degasser 116 for further separation. Optionally, the
20 high pressure fluid 114 may be passed through a filter 120 before entering degasser 116. The filter 120 may be a conventional filter for removing selected components, debris, and the like from the high pressure fluid 114. One or more filters and/or other fluid devices may be used to alter the high pressure fluid 114.

[00023] The high pressure fluid 114 may then pass into the degasser 116 for further
25 separation. The degasser includes a pressure exchanger 122 and a gas separator 124. In the pressure exchanger 122, the high pressure fluid 114 exchanges pressure with a low pressure fluid source 126 and reduces to a low pressure fluid 128. The pressure exchanger 122 enables the high pressure fluid source (e.g., high pressure fluid 114) and the low pressure source (e.g., low pressure source 126) to come into direct contact without
30 substantial mixing.

[00024] The pressure exchanger 122 may be a conventional pressure exchanger that transfers pressure from high to low on one side, and low to high on another side. The rotary pressure exchanger may be provided with a plurality of longitudinal fluid channels

in a rotor that selectively establishes fluid communication between a high pressure source and a low pressure source. The rotor may be turned by the momentum of the water at a speed that adjusts to flow variations. An example of a pressure exchanger usable with the degasser 116 is a rotary pressure exchanger, such as a PXTM pressure exchanger,

5 commercially available from Energy Recovery Inc. (see: www.energyrecovery.com).

[00025] The low pressure fluid 128 may be treated with a treatment fluid 118 and/or then passed into the gas separator 124 as indicated by the arrows. The treatment fluid 118 may be located in a subsea container or provided from the surface as indicated by the arrows. The treatment fluid may be, for example acid, base, biocide, corrosion inhibitor, antiscalant, calcium nitrate, and the like, and combinations thereof. The selected treatment
10 fluid may be used, for example, to prevent souring.

[00026] Optionally, a pump 129 may be used to pump the low pressure fluid 128 to the gas separator 124. The gas separator 124 may be a conventional gas separator, such as a vertical, centrifugal separator capable of removing gas from liquid. The gas separator
15 124 may be used to separate gas 130 from the low pressure fluid 128. The gas 130 may be passed to the surface as indicated by the arrow. Portions of the degassed and separated low pressure fluid 132 may be passed through a filter 131.

[00027] The filter 131 may be, for example, a conventional coalescing media filter provided to filter and remove the dispersed or remaining dissolved oil of the degassed low
20 pressure fluid 132 for use as the low pressure source 126. This filtered and separated low pressure fluid 132 may then be used as the low pressure source 126 and redirected back to the pressure exchanger 122 for pressure exchange with the high pressure fluid 114 as indicated by the arrows. Portions of the separated low pressure fluid 134 may be discharged from the liquid gas separator 124. This discharged separated low pressure fluid
25 134 may be discharged into the sea and/or redirected back to the wellbore, for example, for use reinjection into the wellbore as indicated by the arrows.

[00028] At least a portion of the filtered separated low pressure fluid 132 may be used as the low pressure source 126. A portion of the filtered, separated low pressure fluid 132 may optionally be discharged back to the wellbore 104 as indicated by the arrow. The
30 portion of the filtered, separated low pressure fluid 132 used as the low pressure source 126 may be passed into the pressure exchanger 122 for exchanging pressure with the high pressure fluid 114.

[00029] Once the low pressure source 126 exchanges pressure with the high pressure

source 114, the low pressure source 126 will be converted to a separated high pressure source 136. This separated high pressure source 136 may be diverted to the surface, discharged to the sea, and/or re-injected to the well 104 as indicated by the arrows.

Moreover, partial or full desalination of the high pressure fluid 136 may be possible before
5 reinjection into the reservoir for low salinity waterflood (EOR). Part or all of the separated high pressure fluid 136 may form a reject stream that may be disposed in an aquifer back at the wellbore 104 or discharged into the sea as indicated by the arrows.

[00030] Various fluids may be discharged from the degasser 116, for example, the various separated fluids 126, 132, 134, 136 may be discharged to the sea, the wellbore or
10 containers at the surface. The gas separator 124 (and/or filter 131) may be used to condition the fluids such that they are fit for such discharge. In some cases, portions of the separated fluids may be diverted for discharge depending on various factors, such as a level of solids in the separated fluid that may indicate whether discharge into the sea is an option. For example, the gas separator 124 and/or filter 131 may remove sufficient
15 hydrocarbons and other particles from the low pressure fluid 128 to provide separated fluids having less than 5 ppm of suspended solids and a pressure of at least 60 Bar. The separated fluid may also have dissolved hydrocarbons of less than 100 parts per million (ppm), less than 20 ppm, less than 5 ppm, or less than 1 ppm, or some other amount. In some cases, the pressure may be between 40 to 2000 bar, between 80 to 1000 bar, 200 to
20 600 bar or other pressure ranges.

[00031] The high pressure source 136 discharged from the pressure exchanger 122 may be a high pressure 'cleaned' water fluid at a pressure close to the pressure of the produced fluid 108, leading to minimal loss of mechanical energy. The pressure exchanger 122 may be used to achieve energy efficiency of from about 90 to about 98%. The
25 pressure exchanger 122 may be used to provide the low pressure fluid 132 with a sufficiently high pressure fit for discharge or re-injection. In cases where an adjustment to the separated high pressure fluid 136 discharged from the pressure exchanger 122 may be desired, additional energy, power lines and pump equipment may be used to convert the separated fluid (e.g., high pressure fluid 136) to a desired pressure. In such cases, a pump
30 137 may be provided to supplement a loss of energy, if present.

[00032] While various fluid components and fluid flow arrangements have been depicted, various arrangements of the fluid separator, pressure exchanger and gas separator (as well as other depicted components) may be provided to achieve gas separation using

fluid pressure.

[00033] Figures 3A and 3B show a flowchart of a method 300 for removing gas from fluid produced from a wellbore. The method 300 involves 340 - providing a system for degassing the produced fluid, comprising a fluid separator fluidly connected to the wellbore and receiving the produced fluid therefrom, a pressure exchanger fluidly connected to the fluid separator, and a gas separator fluidly connected to the pressure exchanger (see, e.g., Fig. 1). The method also involves 342 - separating the produced fluid into a plurality of separated fluids comprising hydrocarbons and high pressure fluid using the fluid separator, 344 - converting the high pressure fluid into a reduced pressure fluid by exchanging pressure from the high pressure fluid with a low pressure source using the pressure exchanger, and 345 - applying a treatment fluid to the reduced pressure fluid.

[00034] The method may also involve 346 - separating gas from the reduced pressure fluid with the gas separator, 348 - discharging at least a portion of the gas to the wellbore and performing artificial lift using the discharged gas, 350 - using the separated low pressure fluid as the low pressure source and converting the separated low pressure fluid into a separated high pressure fluid by exchanging pressure with the high pressure fluid, 352 - discharging at least a portion of the separated high and/or low pressure fluid to one of the sea, a storage container and the wellbore, and/or 356 - filtering the high pressure fluid and/or the separated low pressure fluid.

[00035] The method may also involve discharging 346 at least a portion of the low pressure fluid to the sea, discharging 348 at least a portion of the low pressure fluid to a storage container, 350 discharging at least a portion of the low pressure fluid back to the wellbore, 352 applying a treatment fluid to the high pressure fluid, 354 filtering one of the high pressure fluid and the low pressure fluid, and/or 356 discharging at least a portion of the gas to the wellbore. The method may also involve 358 performing artificial lift using the discharged gas, 360 discharging at least a portion of the high pressure fluid to the sea, 362 discharging at least a portion of the high pressure fluid to a storage container, and 364 discharging at least a portion of the high pressure fluid back to the wellbore.

[00036] The method may be repeated as desired and performed in any order.

[00037] While the embodiments are described with reference to various implementations and exploitations, it will be understood that these embodiments are illustrative and that the scope of the inventive subject matter is not limited to them. Many variations, modifications, additions and improvements are possible. For example, one or

more degassers, separators, pressure exchangers, filters and/or other fluid components may be provided to remove gas from the fluid produced from the wellbore.

[00038] Plural instances may be provided for components, operations or structures described herein as a single instance. In general, structures and functionality presented as
5 separate components in the exemplary configurations may be implemented as a combined structure or component. Similarly, structures and functionality presented as a single component may be implemented as separate components. These and other variations, modifications, additions, and improvements may fall within the scope of the inventive
subject matter.

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CLAIMS

1. A degasser for removing gas from fluid produced from a wellbore penetrating a subterranean formation, the produced fluid separated by a fluid separator connectable to the wellbore and receiving the produced fluid therefrom, the fluid separator separating the produced fluid into a plurality of separated fluids comprising hydrocarbons and high pressure fluid, the degasser comprising:

a pressure exchanger fluidly connectable to the fluid separator and receiving the high pressure fluid therefrom, the pressure exchanger fluidly connectable to a low pressure source, the pressure exchanger exchanging high pressure from the high pressure fluid and low pressure from the low pressure source whereby the high pressure fluid is converted into a reduced pressure fluid; and

a gas separator fluidly connectable to the pressure exchanger and receiving the reduced pressure fluid therefrom, the gas separator separating gas from the reduced pressure fluid.

2. The degasser of Claim 1, wherein the gas separator separates a separated low pressure fluid from the reduced pressure fluid.

3. The degasser of Claim 2, wherein the gas separator is fluidly connectable to the pressure exchanger for passing at least a portion of the separated low pressure fluid thereto, the separated low pressure fluid usable as the low pressure source.

4. The degasser of Claim 2, wherein the gas separator has an outlet for discharge of a portion of the separated low pressure fluid to one of the sea, the wellbore, a surface container and combinations thereof.

5. A system for degassing fluid produced from a wellbore penetrating a subterranean formation, the system comprising:

a fluid separator fluidly connectable to the wellbore and receiving the produced fluid therefrom, the fluid separator separating the produced fluid into a plurality of separated fluids comprising hydrocarbons and high pressure fluid;

a pressure exchanger fluidly connectable to the fluid separator and receiving the high pressure fluid therefrom, the pressure exchanger fluidly connectable to a low pressure source, the pressure exchanger exchanging high pressure from the high pressure fluid and low pressure from the low pressure source whereby the high pressure fluid is converted into a reduced pressure fluid; and

a gas separator fluidly connectable to the pressure exchanger and receiving the reduced pressure fluid therefrom, the gas separator separating gas from the reduced pressure fluid.

6. The system of Claim 5, further comprising at least one filter.

7. The system of Claim 5, further comprising at least one pump.

8. The system of Claim 5, further comprising a fluid treatment source for applying treatment fluid to the reduced pressure fluid.

9. A method for removing gas from a fluid produced from a wellbore penetrating a subterranean formation, the method comprising:

providing a system for degassing the produced fluid, comprising a fluid separator fluidly connected to the wellbore and receiving the produced fluid therefrom, a pressure exchanger fluidly connected to the fluid separator, and a gas separator fluidly connected to the pressure exchanger;

separating the produced fluid into a plurality of separated fluids comprising hydrocarbons and high pressure fluid using the fluid separator;

converting the high pressure fluid into a reduced pressure fluid by exchanging pressure from the high pressure fluid with a low pressure source using the pressure exchanger; and

separating gas from the reduced pressure fluid with the gas separator.

10. The method of Claim 9, further comprising discharging at least a portion of the gas to the wellbore and performing artificial lift using the discharged gas.
- 5 11. The method of Claim 9, wherein the separating gas comprises separating a separated low pressure fluid from the reduced pressure fluid.
12. The method of Claim 11, further comprising discharging at least a portion of the separated low pressure fluid to one of the sea, a storage container, and the wellbore.
13. The method of Claim 12, wherein the separated low pressure fluid comprises less
10 than 5 ppm of suspended solids and has a pressure of at least 60 Bar.
14. The method of Claim 11, further comprising using the separated low pressure fluid as the low pressure source and converting the separated low pressure fluid into a separated high pressure fluid by exchanging pressure with the high pressure fluid.
15. The method of Claim 14, further comprising discharging at least a portion of the
15 separated high pressure fluid to one of the sea, a storage container and the wellbore.
16. The method of Claim 14, wherein the separated high pressure fluid comprises less than 5 ppm of suspended solids and has a pressure of at least 60 Bar.
17. The method of Claim 9, further comprising applying a treatment fluid to the reduced pressure fluid.
- 20 18. The method of Claim 9, further comprising filtering one of the high pressure fluid and the separated low pressure fluid.

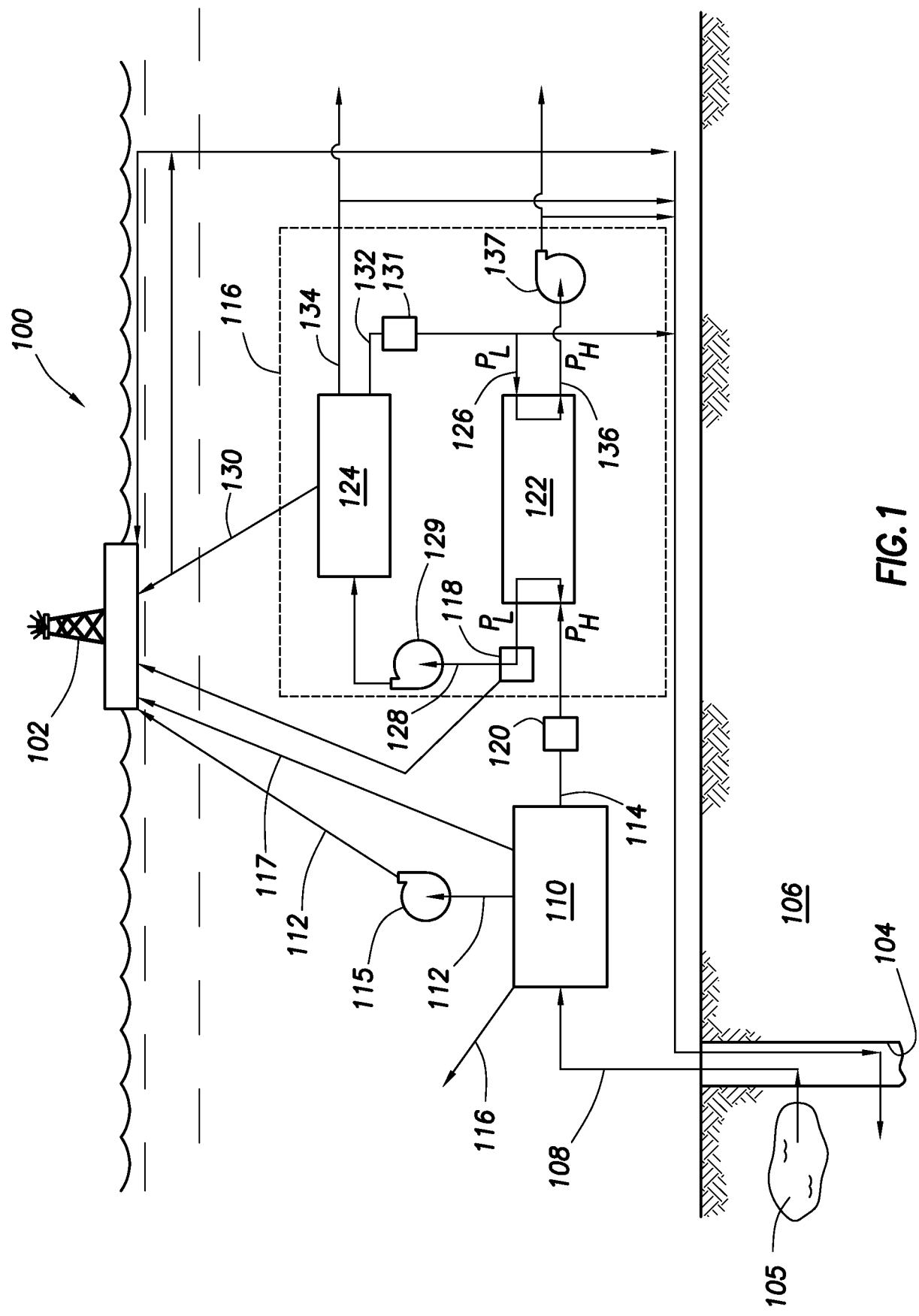


FIG. 1

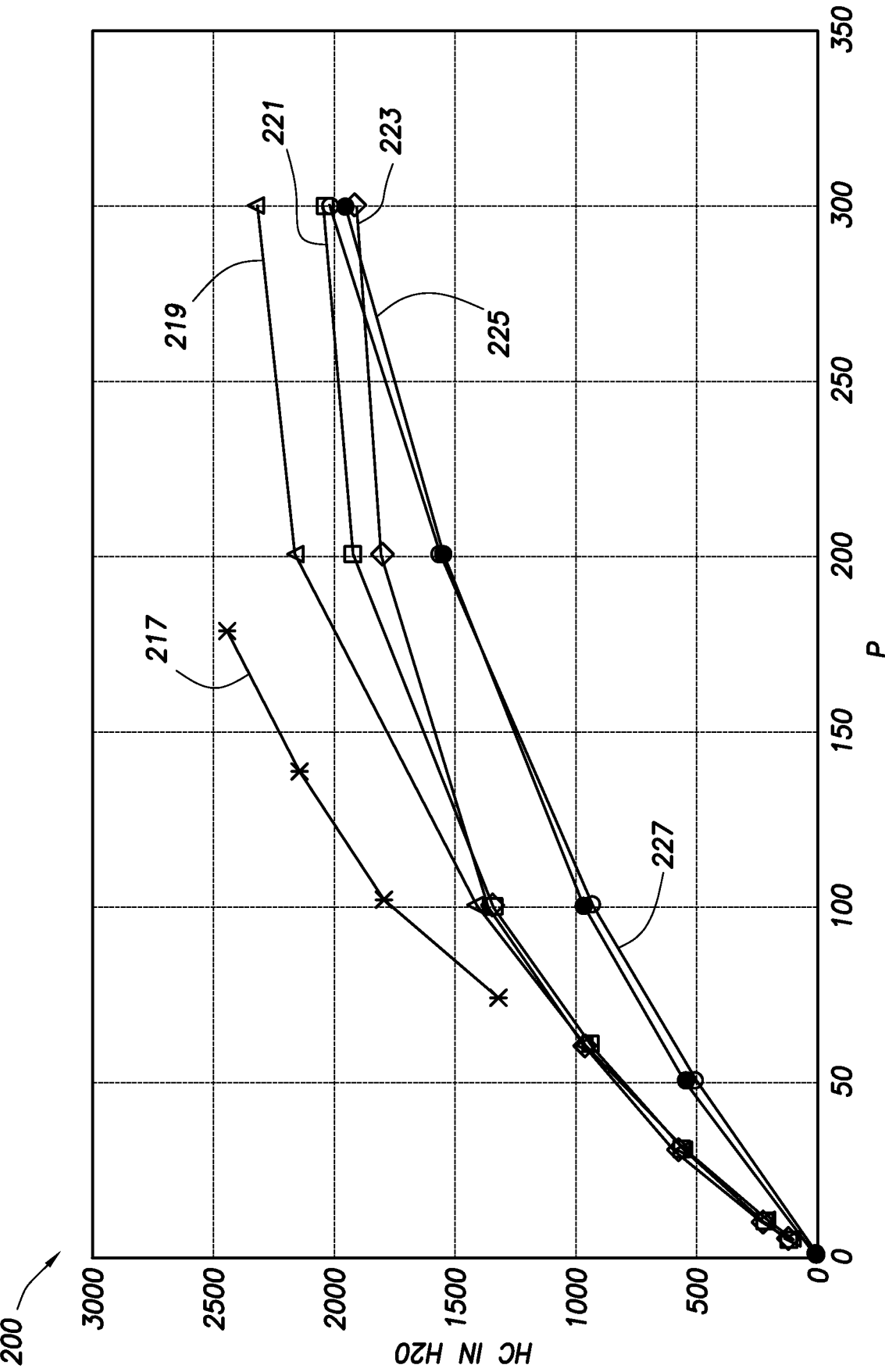
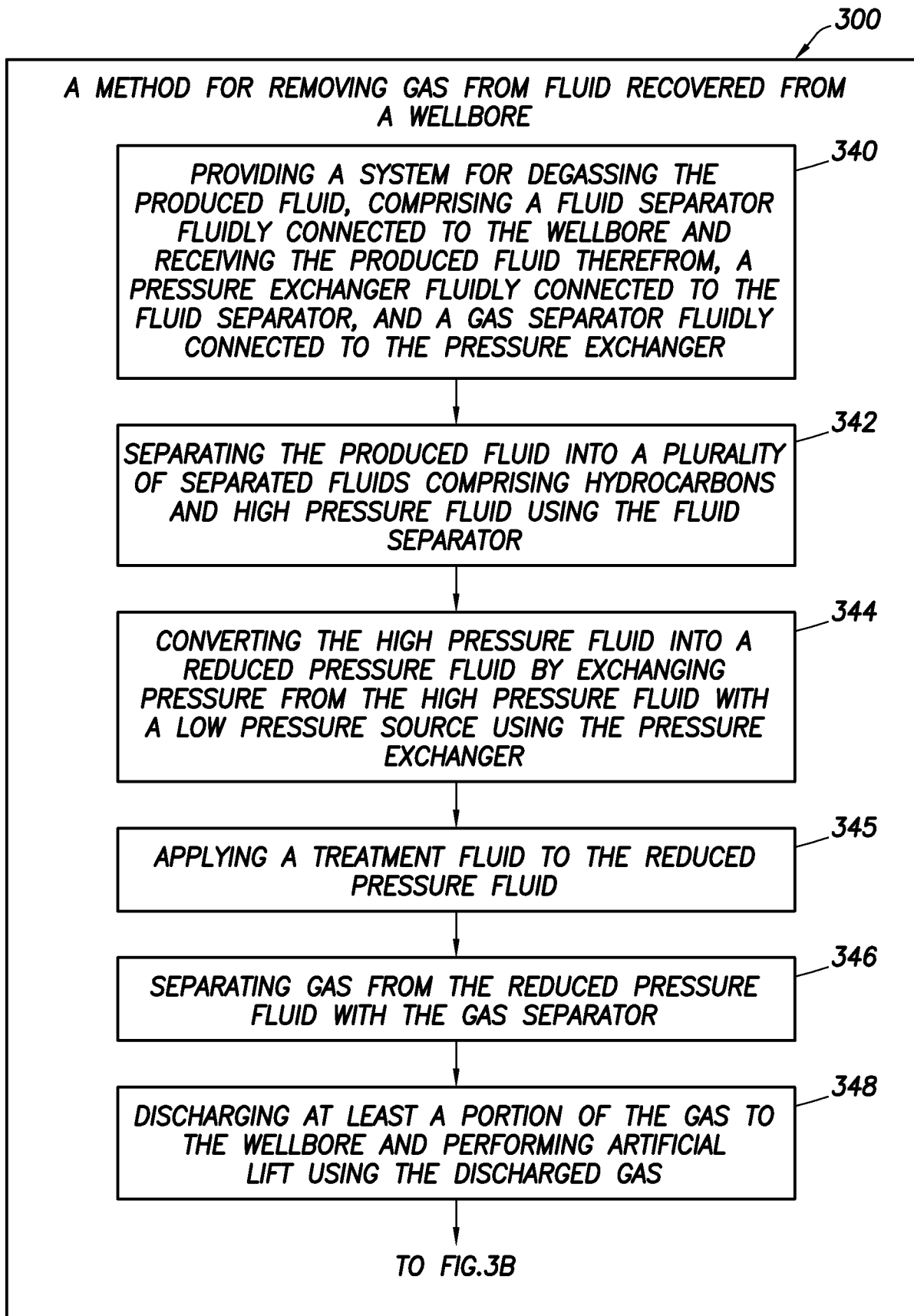


FIG.2

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**FIG.3A**

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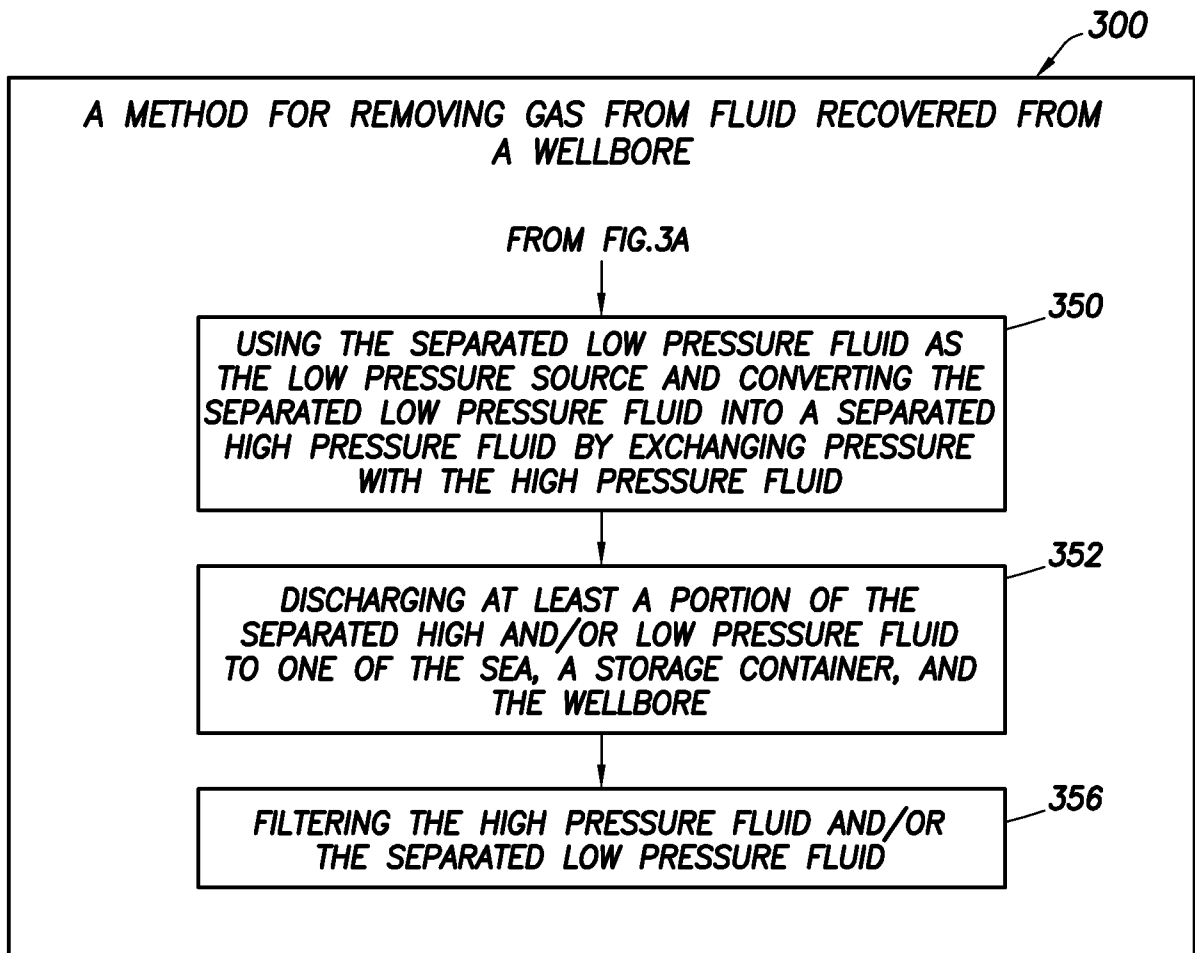


FIG.3B

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2013/051763**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/34(2006.01)i, E21B 43/36(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 43/34; E21B 43/12; E21B 7/12; E21B 43/36; E21B 43/22; E21B 43/38

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: separator, degasser, pressure exchanger, high pressure, and reduced pressure

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2003-0188873 A1 (ANDERSON et al.) 09 October 2003 See paragraphs [0005]-[0032] and figures 2-3.	1-18
A	US 6907933 B2 (CHOI et al.) 21 June 2005 See column 1, line 50 - column 2, line 67 and figures 1-7.	1-18
A	US 2009-0321366 A1 (POORTE, EDWIN) 31 December 2009 See paragraphs [0011]-[0028] and figures 1-2.	1-18
A	US 2011-0155385 A1 (HAHEIM, SVEIN AUDUN) 30 June 2011 See paragraphs [0007]-[0040] and figure 1.	1-18
A	US 2011-0088896 A1 (PRESTON, WILLIAM E.) 21 April 2011 See paragraphs [0015]-[0035] and figures 1-2.	1-18



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

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"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

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Date of the actual completion of the international search

13 November 2013 (13.11.2013)

Date of mailing of the international search report

13 November 2013 (13.11.2013)

Name and mailing address of the ISA/KR

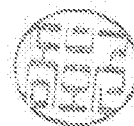
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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2013/051763

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