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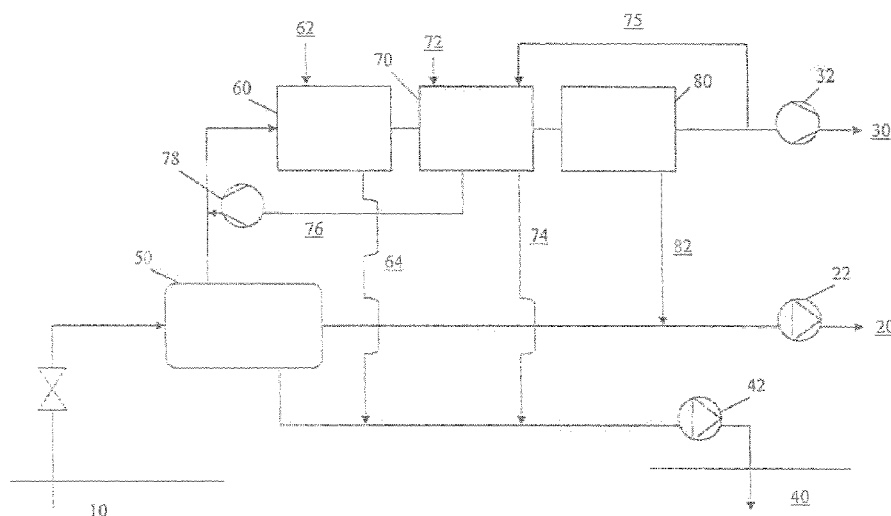


FIG. 1

(57) Abstract: In order to improve the treatment of at least one stream from at least one subsea well (10), a system and a corresponding method produce the following streams by means of at least one three-phase inlet separator (50): - at least one oil stream being sent to at least one export, in particular to at least one oil export (20) or to at least one combined oil-gas export (550); - at least one gas stream being treated further prior to being sent to at least one export, in particular to at least one gas export (30) or to the at least one combined oil-gas export (550); and - at least one water stream being returned to at least one injection well (40; 140; 145).

SUBSEA WELL STREAM TREATMENT

Technical field of the present invention

The present invention relates to a system and to a method or process for the treatment of subsea well streams.

Background of the present invention

Oil and gas streams from subsea wells are often treated in the subsea environment by a number of processes. For example, subsea well stream processes include pumping, phase fraction separation, cooling or heating operations and gas compression.

A number of patent applications and patents relate to at least one of these processes; in particular, WO 92/00438 A1, WO 2007/067059 A1, or US 8 382 457 B2 relate to subsea well stream pumping processes. WO 2013/004275 A1, WO 2011/079321 A2, WO 2011/059919 A1, or EP 1 518 595 A1 relate to subsea well stream processes for phase fraction separation. Cooling and heating operations for subsea well stream processes are represented by WO 2013/004276 A1, by WO 2013/004277 A1, by WO 2008/147219 A2, by WO 2010/002272 A1, or by WO 2010/135772 A1. Gas compression processes for subsea well streams are described in US 7 819 950 B2, in WO 2009/131462 A2, in WO 2010/110674 A2, or in EP 2 530 326 A2. In addition US 6 502 635 B1, or US 6 620 091 B1 relate to subsea carbon capture solutions.

However, none of the above patent documents provide processes that treat the subsea well stream in a manner that provides a well stream flow meeting pipeline specifications. In particular, the specifications for water content, hydrocarbon dew point and CO₂ content are not met.

Natural gas pipeline specifications usually limit the water content of the natural gas delivered to the pipeline to ensure there is no formation of gas hydrates or accumulation of liquid water which could lead to corrosion of the pipeline, particularly in the presence of sour gases containing CO₂ and H₂S. If the water content cannot be reduced to the set limitation, then a method for controlling or inhibiting the formation of gas hydrates has to be installed.

In addition, the natural gas pipeline specifications set limits on the hydrocarbon dew point to ensure there is no accumulation of hydrocarbon liquids in the pipeline. Without control of hydrocarbon dew point there is a risk of formation of liquid slugs that may cause severe damage to controlling devices and rotating equipment such as downstream natural gas compressors and expanders.

Further, the natural gas pipeline specifications limit the CO₂ and H₂S content in order to reduce corrosion issues and to meet heating value specifications of the sales gas. High levels of sour gases

especially in the presence of liquid water require expensive, corrosion resistant pipe materials and require increased pipeline diameters for transporting the gas.

In general, the sour gas content (mainly CO₂ and H₂S) of natural gases from subsea sources lies below five percent but values as high as of eighty percent or more occur in some areas (see for example Burgers et al.: Worldwide development potential for sour gas. Energy Procedia 4 (2011), 2178 to 2184).

There remains a need in the art for improvements to treatment of subsea well streams.

Disclosure of the present invention: object, solution, advantages

Starting from the disadvantages and shortcomings as described above and taking the prior art as discussed into account, an object of the present invention is to improve the treatment of subsea well streams.

This object is accomplished by a system comprising the features of claim 1 as well as by a method comprising the features of claim 15. Advantageous embodiments and expedient improvements of the present invention are disclosed in the respective dependent claims.

The present invention provides for a system and for a method for the treatment of subsea well streams wherein the disadvantages of the prior art are overcome and the well stream is treated in such a manner that the pipeline specifications set at sales gas limitations can be met and the cost of downstream treatment, and especially the need for offshore topside treatment of the gas stream from a subsea well can be significantly reduced.

More particularly, the system and the method for the treatment of the at least one stream from the at least one subsea well comprises at least one three-phase inlet separator for treating the at least one stream and for producing

- at least one oil stream being sent to at least one export, in particular to at least one oil export or to at least one combined oil-gas export;
- at least one gas stream being treated further prior to being sent to at least one export, in particular to at least one gas export or to the at least one combined oil-gas export; and
- at least one water stream being returned to at least one injection well.

According to an advantageous embodiment of the present invention, C3+ fractions may be separated from the gas stream by means of at least one dew point controller, wherein said C3+ fractions may be combined with the oil stream from the three-phase inlet separator and may be sent to the oil export.

According to an expedient embodiment of the present invention, water may be removed from the gas

stream by means of at least one dehydration unit, in particular by means of at least one glycol scrubber, wherein said removed water may be combined with the water stream from the three-phase inlet separator.

5 The corresponding dehydration agent, in particular the corresponding active scrubbing agent, may favourably be chosen from monoethyleneglycol (MEG), diethyleneglycol (DEG), triethyleneglycol (TEG), or glycerol.

10 In case the dehydration unit is embodied as glycol scrubber, said dehydration unit may preferably be arranged before the dew point controller; otherwise, the dehydration unit may preferably be arranged after the dew point controller.

15 According to an advantageous embodiment of the present invention, particulate and gas impurities may be removed from the gas stream by means of at least one pressurized water scrubber being supplied with sea water and producing a water and sour gas stream, which may be used for injection into the injection well and/or which may be combined with the water removed from the gas stream in the dehydration unit.

20 According to an expedient embodiment of the present invention, wet gas, in particular wet stripping gas, from the dehydration unit may be combined with the gas stream from the three-phase inlet separator and may be fed back to the pressurized water scrubber or to the dehydration unit or to the dew point controller, in particular through at least one compressor.

25 According to a favoured embodiment of the present invention, sour gas, in particular including carbon dioxide, may be separated by means of at least one separation unit, in particular by means of at least one membrane unit or by means of at least one Rectisol scrubbing unit, said sour gas being in particular supplied to the injection well, for example through at least one compressor.

30 According to a preferred embodiment of the present invention, the separated sour gas may be dissolved in the water by means of at least one contacting unit, in particular by means of at least one jet pump (ejector) with the water on the motive and the separated sour gas on the suction inlet.

35 Advantageously, at least one pump may be arranged upstream of the contacting unit, said pump in particular providing additional sea water to the water on the motive. Alternatively or additionally, the water stream from the three-phase inlet separator may be fed to the contacting unit to provide more water for dissolving the separated sour gas.

40 - A portion of the gas stream exiting the dew point controller and/or the separation unit and/or the dehydration unit may expediently be used as dry stripping gas for the dehydration unit, in particular for the regeneration of the dehydration agent, and

- the remainder of said gas stream may expediently be delivered to the gas export, in particular through at least one gas export compressor.

According to a favoured embodiment of the present invention, the oil stream from the three-phase separator may be dehydrated by means of at least one heat exchanger by way of cooling, in particular supplied actively by at least one refrigerator or passively by at least one cold refrigerant and/or by the local ambient temperature.

According to a preferred embodiment of the present invention, water may be removed by means of at least one oil-water separator arranged behind the heat exchanger, said water being sent to the injection well, in particular through at least one pump.

The present invention provides for a versatile system as well as for a versatile method allowing for many different configurations of components to meet different combinations of well related factors and also allowing for the addition, subtraction or reconfiguration of components as well conditions change.

Components used can be built modularly to accommodate the versatility of changing configurations. The system according to the present invention and the method according to the present invention take advantage of the subsea environment for process operation.

Brief description of the drawings

For a more complete understanding of the present inventive embodiment disclosures and as already discussed above, there are several options to embody as well as to improve the teaching of the present invention in an advantageous manner. To this aim, the present invention is described in more detail below; in particular, reference may be made to the claims dependent on claim 1; further improvements, features and advantages of the present invention are explained below in more detail with reference to a preferred embodiment by way of non-limiting example and to the accompanying drawings taken at least partly in connection with the following description of the embodiments, of which:

FIG. 1 is a schematic diagram of a first embodiment for a subsea well stream treatment system according to the present invention, said system working according to the method of the present invention;

FIG. 2 is a schematic diagram of a second embodiment for a subsea well stream treatment system according to the present invention, said system working according to the method of the present invention;

FIG. 3 is a schematic diagram of a third embodiment for a subsea well stream treatment system according to the present invention, said system working according to the method of the present invention;

5 FIG. 4 is a schematic diagram of a fourth embodiment for a subsea well stream treatment system according to the present invention, said system working according to the method of the present invention; and

10 FIG. 5 is a schematic diagram of a fifth embodiment for a subsea well stream treatment system according to the present invention, said system working according to the method of the present invention.

In the appended drawing figures, like equipment is labelled with the same reference numerals throughout the description of FIG. 1 to FIG. 5.

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Detailed description of the drawings; best way of embodying the present invention

Before describing the present inventive embodiments in detail, it is to be understood that the inventive embodiments are not limited in their application to the details of construction and arrangement of parts illustrated in the accompanying drawing figure, since the present invention is capable of other embodiments and of being practiced or carried out in various ways. Also, it is to be understood that the phraseology or terminology employed herein is for the purpose of description and not of limitation.

25 The present invention will be described with reference to the drawing figures.

In particular, FIG. 1 is a schematic diagram of a first embodiment of the present invention. As shown in FIG. 1, a subsea production well 10 produces oil exports 20 and gas exports 30 from a subsea reservoir. An injection well 40 for injection of water and sour gas, that may include CO₂, H₂S and other gas components using a pump 42 is also shown.

30

The injection well 40 can be connected to the subsea reservoir and aid in Enhanced Oil Recovery (EOR) from the production well 10. Alternatively, the injection well 40 can deliver water and sour gas to a geological formation such as an aquifer for safe storage.

35

The product leaving the well 10 is initially treated in a three-phase inlet separator 50 which produces three streams: a water stream that is returned to the injection well 40; an oil stream that is sent to oil exports 20; and a gas stream that is treated further prior to being sent to gas exports 30.

40 In particular, the gas stream is first treated in a pressurized water scrubber 60 to remove particulate

and gas impurities, which are primarily made up of CO₂, H₂S and other sour gas components. The pressurized water scrubber 60 is supplied with sea water 62 and produces a combined water and sour gas stream 64 that may be used for injection into the injection well 40. According to the present invention, CO₂ and other sour gases are dissolved in the sea water advantageously using the high ambient pressure of the subsea location of the open water scrubber 60.

Once treated by the pressurized water scrubber 60, the gas stream is then treated in a glycol scrubber 70 to remove water 74; i. e. gas dehydration. The water 74 removed in the glycol scrubber 70 is combined with the water and sour gas stream 64 from the pressurized water scrubber 60 and is re-injected to the injection well 40.

Make-up scrubbing agent 72 can be provided to the glycol scrubber 70 by umbilical. The active scrubbing agent is preferably chosen from monoethyleneglycol (MEG), diethyleneglycol (DEG), triethyleneglycol (TEG), or glycerol.

Dry stripping gas 75 for the glycol scrubber is provided from a down stream operation. Wet stripping gas 76 from the glycol scrubber 70 is combined with the gas stream from the three-phase inlet separator 50 and fed back to the pressurized water scrubber 60 through a compressor 78.

Following the treatment in the glycol scrubber 70 the gas stream is treated in dew point controller 80 to separate C3+ fractions 82 from the gas stream. The C3+ fractions 82 may be combined with the oil stream from the three-phase inlet separator 50 and sent to oil exports 20.

A boosting pump 22 can be used to improve delivery of the oil exports 20. A portion of the cooled dry gas stream exiting the dew point controller 80 is used as the dry stripping gas 75 for the glycol scrubber 70.

The remainder of the cooled dry gas stream from the dew point controller 80 is delivered to the gas exports 30 through a gas export compressor 32 that is used to achieve the desirable pipeline send out pressure.

The embodiment of the present invention described with reference to FIG. 1 provides a number of advantages:

As noted above, the CO₂ and other sour gases can be dissolved into sea water in the water scrubber taking advantage of the high ambient pressure and low temperature of the subsea location. Because the water and sour gases are then combined in a single stream for injection, the need for a separate gas compressor is eliminated.

Further, this embodiment uses one of the simplest sour gas removal processes. The ability to use

high water injection flow rates according to the present invention provides for the ability to carry out EOR from the production well.

5 The combination of treatments for the gas stream from the three-phase separator enables the provision of the clean, dry gas stream to the pipeline at sales gas specifications that allow for reduced pipeline diameter and material requirements.

Another embodiment of the present invention is shown in FIG. 2 wherein like reference numerals will be used to describe like elements.

10 In this embodiment water and sour gases, including CO₂, are injected separately as shown by water injection well 140 and gas injection well 145.

15 The product leaving the production well 10 is again treated in the three-phase inlet separator 50 to produce three streams: a water stream that is returned to the water injection well 140; an oil stream that is sent to oil exports 20; and a gas stream that is treated further prior to being sent to gas exports 30.

20 In this embodiment, the gas stream is first treated using the glycol scrubber 270; i. e. dehydration unit, to remove water 274; i. e. gas dehydration, with the water 274 being combined with the water stream from the three-phase inlet separator 50 and re-injected at water injection well 140 using pump 142.

25 Make-up scrubbing agent 272 can again be provided to the glycol scrubber 270 by umbilical. Wet stripping gas 276 from the glycol scrubber 270 is combined with the gas stream from the three-phase inlet separator 50 and fed back to the glycol scrubber 270 through a compressor 278.

30 Dry stripping gas 275 for the glycol scrubber 270 is provided from a down stream operation. Following treatment in the glycol scrubber 270 the gas stream is treated in dew point controller 280 to separate C3+ fractions 282 from the gas stream. The C3+ fractions 282 may be combined with the oil stream from the three-phase inlet separator 50 and sent to oil exports 20. A boosting pump 22 can be used to improve delivery of the oil exports 20.

35 The dry gas stream exiting the dew point controller 280 is then treated by separation unit 290 to separate sour gas 292 (including CO₂) which is supplied to gas injection well 145 through compressor 147. A portion of the product gas exiting the separation unit 290 is used as dry stripping gas 275 for the glycol scrubber 270.

40 The remainder of the gas stream from the separation unit 290 is delivered to the gas exports 30 through a gas export compressor 32 that is used to achieve the desirable send out pressure.

A similar embodiment of the present invention to that shown in FIG. 2 is described with reference to FIG. 3.

5 This embodiment is the same as that described with respect to FIG. 2, except that the water and sour gas are injected in a combined water and sour gas injection well 40 using pump 42. This embodiment can be utilized when the sour gas 292 from the separation unit 290 separation is of relatively low volume.

10 When the volume of separated sour gas 292 is sufficiently low enough, the separated sour gas 292 may be completely dissolved in the water stream 274 in a contacting unit 395 thereby eliminating the need for a separate sour gas injection well and compressor. The contacting unit 395 is preferably a jet pump (ejector) with the water stream 274 on the motive and the separated sour gas 292 on the suction inlet.

15 If the amount of separated sour gas 292 is too large to enable complete dissolution by the water stream 274 in the contacting unit 395, than a pump may be installed upstream of the contacting unit 395 that provides additional sea water to the water (motive) stream 274.

20 Advantageously, the water stream from the three-phase inlet separator 50 can also be fed to the contacting unit 395 to provide more water for dissolution of the sour gas 292. As an alternative the water stream 274 may be pressurized using the pump 42 prior to entering the contacting unit 395 and then the combined water and dissolved sour gas can be subsequently re-injected without the need of an additional injection pump.

25 For the embodiments shown in FIG. 2 and FIG. 3, the separation unit 290 can be either a membrane unit or a Rectisol scrubbing unit, both of which are useful technology for separation of CO₂ and other sour gases.

30 The use of a Rectisol scrubbing unit would be more applicable for larger concentrations of CO₂ and other sour gases coming into the separation unit 290 or in the event that the specification of sour gas (CO₂) content for the pipeline is very low, for example required for further treatment in a downstream (onshore) gas liquefaction unit (LNG production).

35 The embodiments of the present invention described with reference to FIG. 2 and FIG. 3 also provide a number of advantages:

The separation unit is able to provide separated sour gas at elevated pressure as compared to top site treatment, and therefore reduces the amount of compression needed for injection. By combining
40 the water and sour gas injection as shown in FIG. 3, the mechanical compressor can be eliminated.

A further advantage of these embodiments is that less water is injected which can be important when the injection well has limited storage volume for re-injected material.

Further, by using an ejector as the contacting unit, the need for additional and expensive subsea compressors is eliminated. Moreover, the combination of treatments for the gas stream from the three-phase separator enables the provision of the clean, dry gas stream to the pipeline at sales gas specification and therefore allows for reduced pipeline diameter and material requirements.

Another embodiment of the present invention is described with reference to FIG. 4 wherein like reference numerals will be used to describe like elements.

In this embodiment, water and sour gas including CO₂ are injected separately as shown by water injection well 140 and sour gas injection well 145.

The product leaving the production well 10 is treated in the three-phase inlet separator 50 to produce three streams: a water stream that is returned to the water injection well 140; an oil stream that is sent to oil exports 20; and a gas stream that is treated further prior to being sent to gas exports 30.

In this embodiment, the gas stream is first treated by a dew point controller 480 to remove water and C3+ fractions 485. The C3+ fractions 485 are combined with the oil stream from the three-phase inlet separator 50 and sent to oil exports 20.

A boosting pump 22 can be used to improve delivery of the oil exports 20. A hydrate inhibitor, such as aqueous glycol or an aqueous amine solution is used in the dew point controller 480 with inhibitor make up 482 being provided by umbilical.

Following treatment by the dew point controller 480, the gas stream may be treated to remove excess hydrate inhibitor that could damage a downstream amine wash 400, with the excess hydrate inhibitor being recycled to the dew point controller 480 or being fed to the oil export 20.

After such treatment, the amine wash 400 is used to remove sour gases 404 (including CO₂) which is then supplied to sour gas injection well 145 through compressor 147. Amine make-up 402 for the amine wash 400 is provided by umbilical.

Because the amine wash 400 process is a wet process, if required, an optional dehydration process 470 is provided downstream from the amine wash 400. The dehydration unit 470 removes water 474 which is combined with the water stream from the three-phase inlet separator 50 and is injected at water injection well 140 using pump 142.

Wet gas 476 from the dehydration unit 470 is combined with the gas stream from the three-phase inlet separator 50 and fed back to the dew point controller 480 through compressor 478. Dehydration agent make-up 472 for the dehydration unit 470 is supplied by umbilical. A portion of the dry gas stream exiting the dehydration unit 470 is used as dry stripping gas 475 for the regeneration of the dehydration agent.

The remainder of the gas stream from the dehydration unit 470 is delivered to the gas exports 30 through a gas export compressor 32 that is used to achieve the desirable pipeline pressure.

The embodiment shown in FIG. 4 exhibits many of the advantages of the other embodiments as described above, including delivering a clean, dry gas stream to the pipeline at the pipeline specifications for dew point, pressure and temperature as well as at the desired water and sour gas content.

This embodiment is similar to those shown in FIG. 2 and FIG. 3, the main difference being the different sequence of sour gas removal and dehydration.

The advantages of the FIG. 4 embodiment are that the water content of the gas stream exiting the amine scrubber may already be at sufficiently low levels to meet the pipeline specifications and thereby obviating the need for the optional dehydration unit.

Also the embodiment of FIG. 4 would be more efficient at removing low concentrations of sour gas, including CO₂ than the embodiments described with respect to FIG. 2 and FIG. 3.

As note in the description of FIG. 1, the injection well can be connected with the production reservoir in order to aid in EOR. Alternatively the injection well can provide the material to a geological storage formation. This is also the case for the injection wells shown in the embodiments shown in FIG. 2, FIG. 3 and FIG. 4 as well as the embodiment shown in FIG. 5 as described below.

In a further embodiment shown in FIG. 5 the stream from the production well 10 is fed into the three-phase separator 50 where oil and water are separated from the gas. The water is sent to water injection well 140.

The gas stream is dehydrated in dehydration unit 510 and then recombined with the treated oil stream after compression with compressor 520. Water 515 removed from the gas stream is combined with the water from the three-phase separator 50 and sent to water injection well 140.

The oil stream from the three-phase separator 50 is dehydrated by means of cooling in a heat exchanger 530 where required cooling is supplied actively by a refrigerator or passively by a cold refrigerant or the local ambient temperature. Following cooling the oil stream is treated in an oil-water

separator 540 to remove water 545 that is also sent to water injection well 140 through pump 142.

As noted the treated oil stream is then combined with the treated gas stream for oil-gas export 550 that can then be transported in a single pipeline. To aid transport, the treated oil stream can be delivered through a pump 552 prior to combination with the treated gas stream.

The present invention as described in the embodiments shown in FIG. 1 through FIG. 4 above enable the delivery of dry, sweet and rich gas directly to existing transport pipelines. This provides a number of advantages:

For example, by treating the well stream according to the present invention, hydrate inhibition and recycling systems do not need to be associated with the pipeline or can be significantly reduced in size. Further corrosion issues and liquid accumulation pigging along the pipeline are greatly reduced.

The present invention can transport the processed gas for an unlimited length and the exported gas can be adjusted to any desired transport temperature and pressure conditions. The present invention enables the delivery of gas having an increased sales value.

Further, the present invention reduces sour gas, including CO₂ emissions while locally providing for sour gas assisted EOR which eliminates the need for an extra CO₂ injection pipeline.

With respect to the embodiment shown in FIG. 5 the present invention enables the delivery of a dry hydrocarbon stream to existing transport pipelines. This provides a number of advantages:

For example, by treating the well stream according to the present invention, hydrate inhibition and recycling systems do not need to be associated with the pipeline or can be significantly reduced in size.

Further, water accumulation along the pipeline and the risk of gas hydrate formation are reduced.

While several embodiments and options have been described above, the present invention is even more versatile. The various configurations for dehydration, hydrocarbon dew point control and gas sweetening (sour gas such as CO₂ removal) can be combined in many different combinations and sequences depending on factors, such as, composition of the well stream, the local pipeline specification, the availability or necessity of raw water injection, etc.

Further, the various components used in the present invention systems can be built modularly so that different combinations and arrangements are easy to put in place. This also allows for additional processes to be added to the system, such as heaters, coolers, and separators, etc. In addition, the configuration of the system can be easily changed to meet changing well conditions.

With respect to heating, electric heating or heat exchange with available hot process streams can be utilized. For cooling, refrigeration or heat exchange with the cold ambient sea water or with available cold process streams can be advantageously used.

5

It is anticipated that other embodiments and variations of the present invention will become readily apparent to the skilled artisan in the light of the foregoing description, and it is intended that such embodiments and variations likewise be included within the scope of the present invention as set out in the appended claims.

10

List of reference numerals

- 10 well, in particular production well, for example subsea production well
- 20 oil export
- 22 pump, in particular boosting pump
- 30 gas export
- 32 compressor, in particular gas export compressor
- 40 water / sour gas injection well
- 42 pump
- 50 three-phase inlet separator
- 60 open water scrubber or pressurized water scrubber
- 62 sea water
- 64 water / sour gas stream
- 70 dehydration unit, in particular glycol scrubber
- 72 make-up scrubbing agent, in particular glycol make-up scrubbing agent
- 74 water stream
- 75 stripping gas, in particular dry stripping gas
- 76 wet gas, in particular wet stripping gas
- 78 compressor
- 80 dew point controller
- 82 C3+ fraction
- 140 water injection well
- 142 pump
- 145 sour gas injection well
- 147 compressor
- 270 dehydration unit, in particular glycol scrubber
- 272 make-up scrubbing agent, in particular glycol make-up scrubbing agent
- 274 water stream
- 275 stripping gas, in particular dry stripping gas
- 276 wet gas, in particular wet stripping gas

- 278 compressor
- 280 dew point controller
- 282 C3+ fraction
- 290 separation unit, in particular membrane unit or Rectisol scrubbing unit
- 292 sour gas
- 395 contacting unit, in particular jet pump (ejector)
- 400 amine wash
- 402 amine make-up
- 404 sour gas
- 470 dehydration unit
- 472 dehydration agent make-up
- 474 water stream
- 475 stripping gas, in particular dry stripping gas
- 476 wet gas, in particular wet stripping gas
- 478 compressor
- 480 dew point controller, in particular with hydrate inhibitor, for example with aqueous glycol or aqueous amine solution
- 482 inhibitor make-up
- 485 C3+ fraction
- 510 dehydration unit
- 515 water stream
- 520 compressor
- 530 heat exchanger
- 540 oil-water separator
- 545 water stream
- 550 oil-gas export
- 552 pump, in particular boosting pump

Claims

1. A system for the treatment of at least one stream from at least one subsea well (10), comprising at least one three-phase inlet separator (50) for treating the at least one stream and for producing
 - at least one oil stream being sent to at least one export, in particular to at least one oil export (20) or to at least one combined oil-gas export (550);
 - 5 - at least one gas stream being treated further prior to being sent to at least one export, in particular to at least one gas export (30) or to the at least one combined oil-gas export (550); and
 - at least one water stream being returned to at least one injection well (40; 140; 145).
2. The system according to claim 1, further comprising at least one dew point controller (80; 280; 480) for separating C3+ fractions (82; 282; 485) from the gas stream, said C3+ fractions (82; 10 282; 485) in particular being combined with the oil stream from the three-phase inlet separator (50) and in particular being sent to the oil export (20).
3. The system according to claim 1 or 2, further comprising at least one dehydration unit (70; 270; 470; 510), in particular at least one glycol scrubber, for removing water (74; 274; 474; 515) from 15 the gas stream, said removed water (74; 274; 474; 515) in particular being combined with the water stream from the three-phase inlet separator (50).
4. The system according to claim 3, wherein a dehydration agent, in particular an active scrubbing agent, is chosen from monoethyleneglycol (MEG), diethyleneglycol (DEG), 20 triethyleneglycol (TEG), or glycerol.
5. The system according to claim 2 and to claim 3 or 4,
 - wherein the dehydration unit (70; 270), in the form of the glycol scrubber, is arranged before the 25 dew point controller (80; 280) or
 - wherein the dehydration unit (470) is arranged after the dew point controller (480).
6. The system according to at least one of claims 1 to 5, further comprising, for removing particulate and gas impurities from the gas stream, at least one pressurized water scrubber (60) 30 being supplied with sea water (62) and producing a water and sour gas stream (64), which may be used for injection into the injection well (40) and/or which may be combined with the water (74) removed from the gas stream in the dehydration unit (70).
7. The system according to at least one claims 3 to 6, wherein wet gas (76, 276, 476), in particular 35 wet stripping gas, from the dehydration unit (70, 270, 470) is combined with the gas stream from the three-phase inlet separator (50) and is fed back to the pressurized water scrubber (60) or to the dehydration unit (70; 270; 470) or to the dew point controller (80; 280; 480), in particular through at least one compressor (78; 278; 478).

8. The system according to at least one of claims 1 to 7, further comprising at least one separation unit (290), in particular at least one membrane unit or at least one Rectisol scrubbing unit, for separating sour gas (292), in particular including carbon dioxide (CO₂), said sour gas (292) being in particular supplied to the injection well (145), for example through at least one compressor (147).
9. The system according to claim 8, further comprising, for dissolving the separated sour gas (292) in the water (274), at least one contacting unit (395), in particular at least one jet pump (ejector) with the water (274) on the motive and the separated sour gas (292) on the suction inlet.
10. The system according to claim 9, further comprising at least one pump upstream of the contacting unit (395), said pump providing additional sea water to the water (274) on the motive.
11. The system according to claim 9 or 10, wherein the water stream from the three-phase inlet separator (50) is fed to the contacting unit (395) to provide more water for dissolving the separated sour gas (292).
12. The system according to at least one of claims 1 to 11,
- wherein a portion of the gas stream exiting the dew point controller (80) and/or the separation unit (290) and/or the dehydration unit (70; 270; 470) is used as dry stripping gas (75; 275; 475) for the dehydration unit (70; 270; 470), in particular for the regeneration of the dehydration agent, and
 - wherein the remainder of said gas stream is delivered to the gas export (30), in particular through at least one gas export compressor (32).
13. The system according to at least one of claims 1 to 12, further comprising at least one heat exchanger (530) for dehydrating the oil stream from the three-phase separator (50) by means of cooling, in particular supplied actively by at least one refrigerator or passively by at least one cold refrigerant and/or by the local ambient temperature.
14. The system according to at least one of claims 1 to 13, further comprising at least one oil-water separator (540) for removing water (545) being sent to the injection well (140), in particular through at least one pump (142).
15. A method of treating at least one stream from at least one subsea well (10), wherein the following streams are produced with at least one system according to at least one of claims 1 to 14:
- at least one oil stream being sent to at least one export, in particular to at least one oil export (20) or to at least one combined oil-gas export (550);
 - at least one gas stream being treated further prior to being sent to at least one export, in particular to at least one gas export (30) or to the at least one combined oil-gas export (550); and
 - at least one water stream being returned to at least one injection well (40; 140; 145).

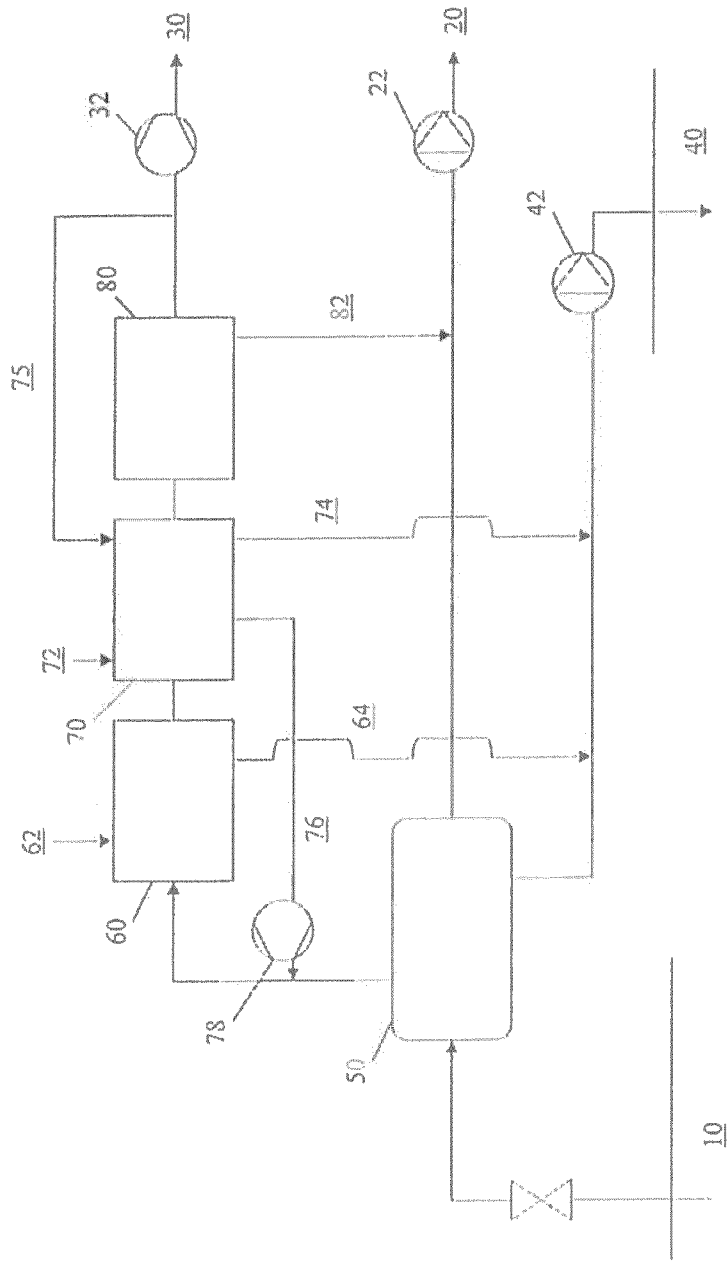
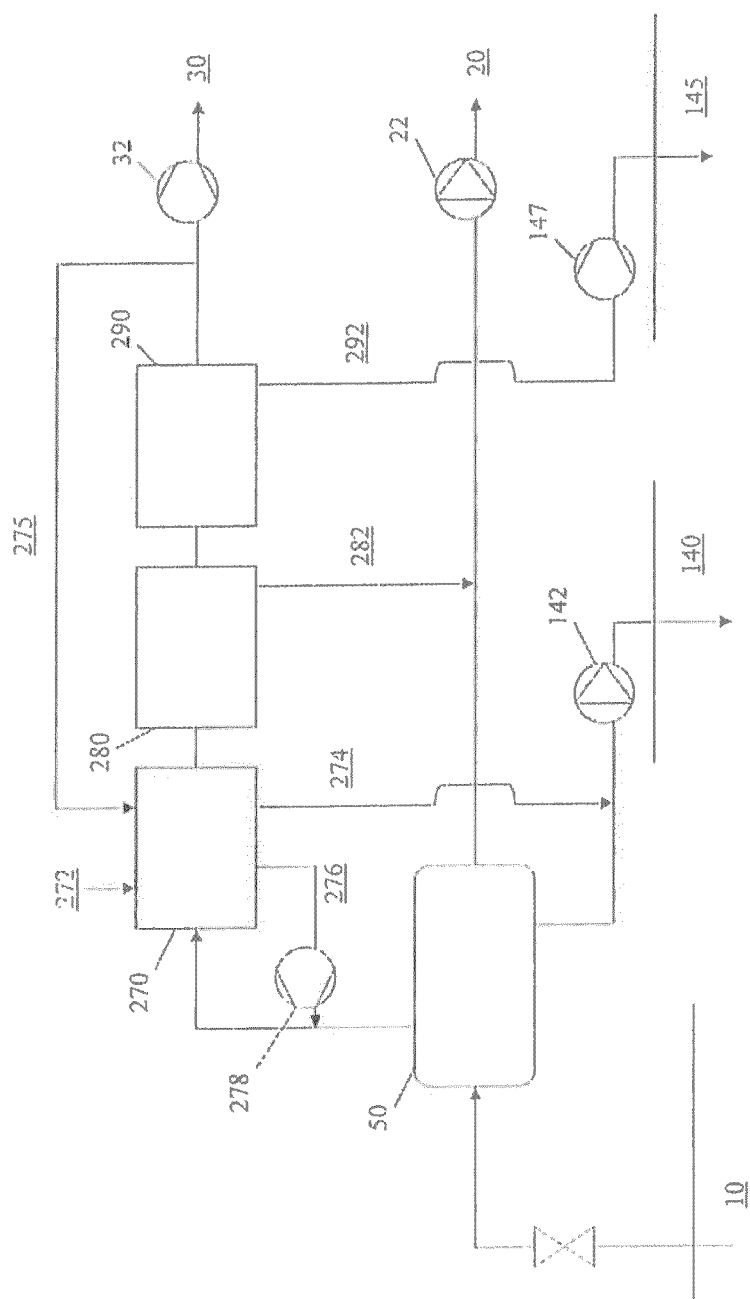


FIG. 1



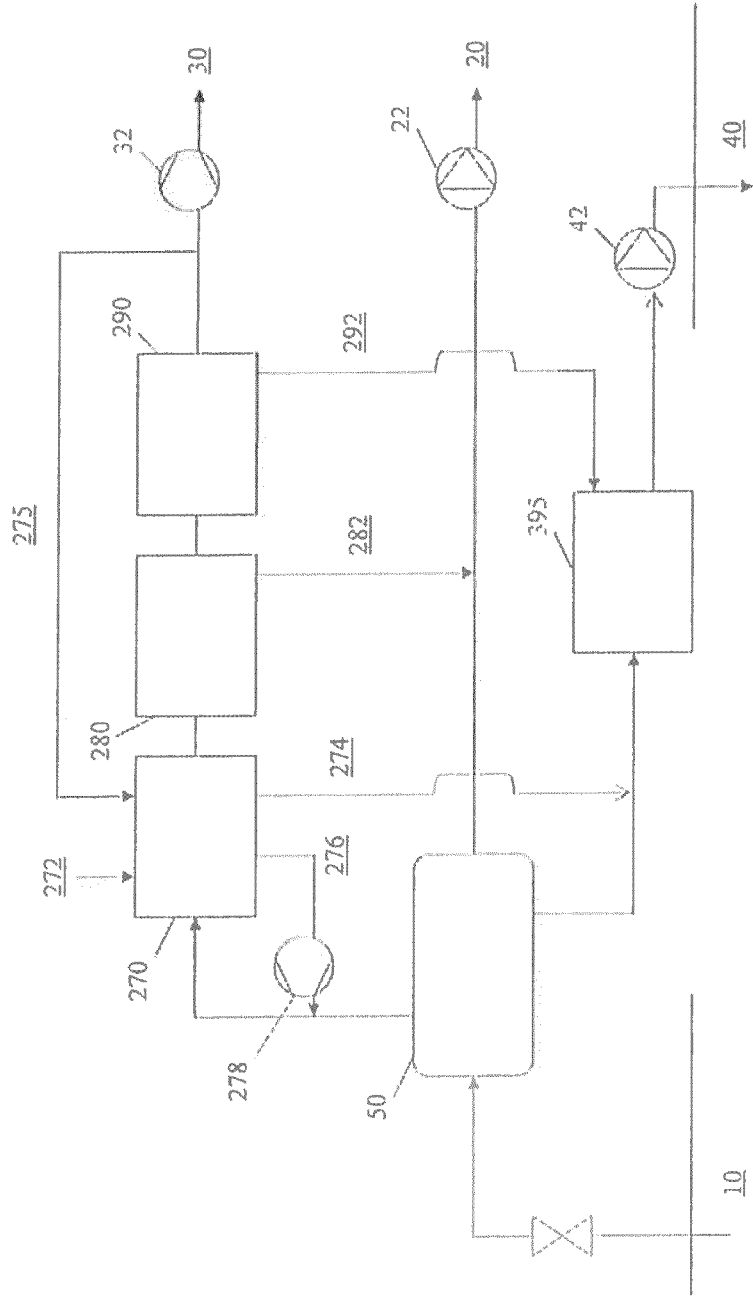


FIG. 3

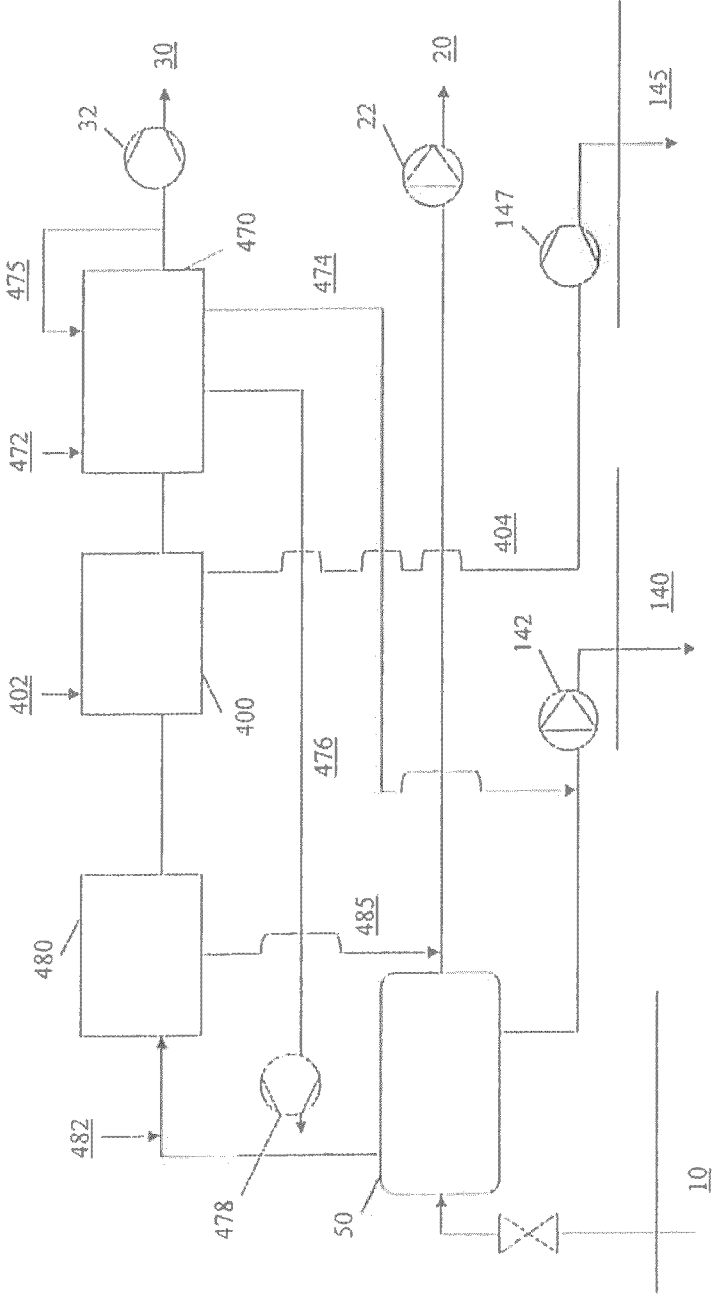


FIG. 4

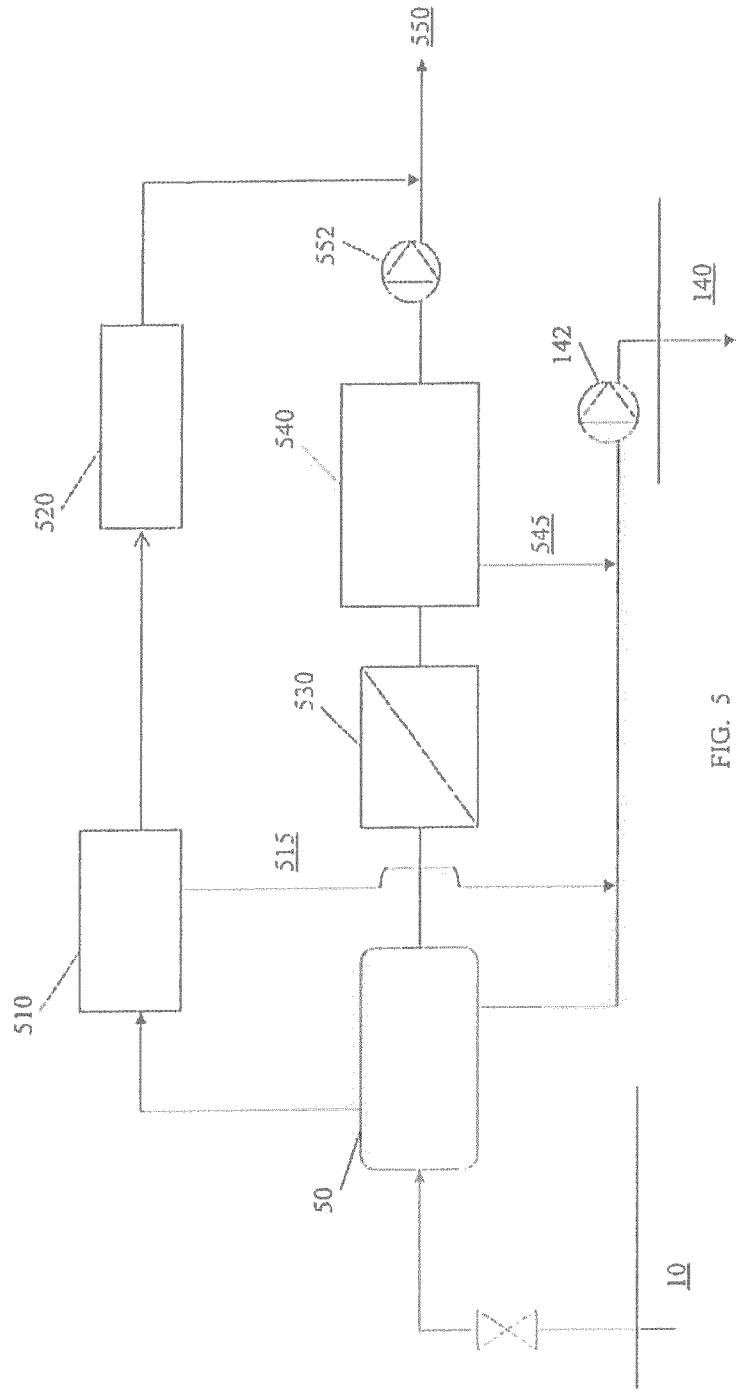


FIG. 5