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**Emtiazian et al.**(10) **Pub. No.: US 2009/0211753 A1**(43) **Pub. Date: Aug. 27, 2009**(54) **SYSTEM AND METHOD FOR REMOVING  
LIQUID FROM A GAS WELL**(21) Appl. No.: **12/038,264**(22) Filed: **Feb. 27, 2008**(75) Inventors: **Bahman Emtiazian**, Aberdeen  
(GB); **Thomas Cairney**, Aberdeen  
(GB)**Publication Classification**(51) **Int. Cl.**  
**E21B 43/00** (2006.01)(52) **U.S. Cl.** ..... **166/250.03; 166/66**(57) **ABSTRACT**

A technique is employed to remove liquid from a gas well to improve gas production from the well. An electric submersible pumping system is deployed into the wellbore and positioned to remove accumulated liquid. The electric submersible pumping system is constructed and controlled to maintain a flow of liquid during operation of the pumping system.

Correspondence Address:  
**SCHLUMBERGER RESERVOIR COMPLE-  
TIONS**  
**14910 AIRLINE ROAD**  
**ROSHARON, TX 77583 (US)**

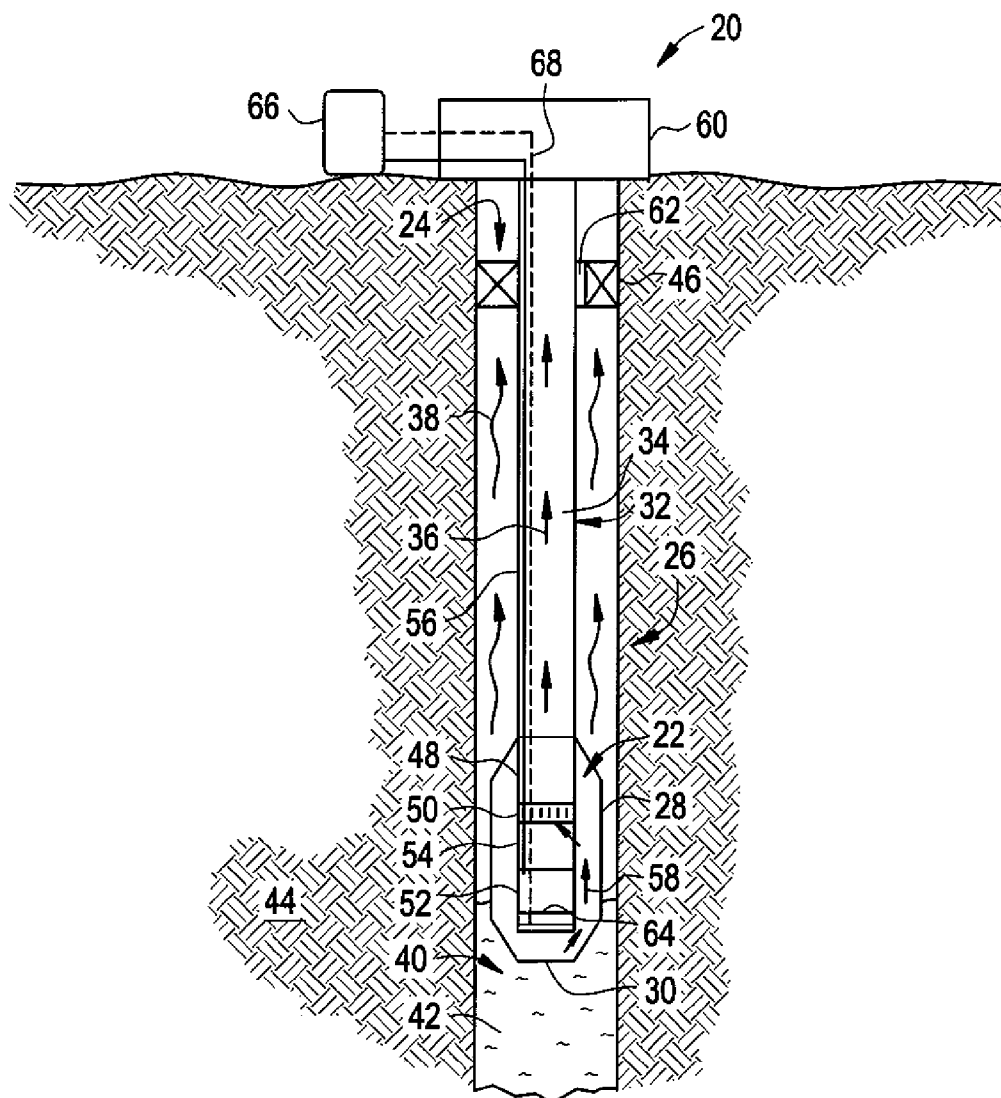
(73) Assignee: **SCHLUMBERGER**  
**TECHNOLOGY**  
**CORPORATION**, Sugar Land, TX  
(US)

FIG. 1

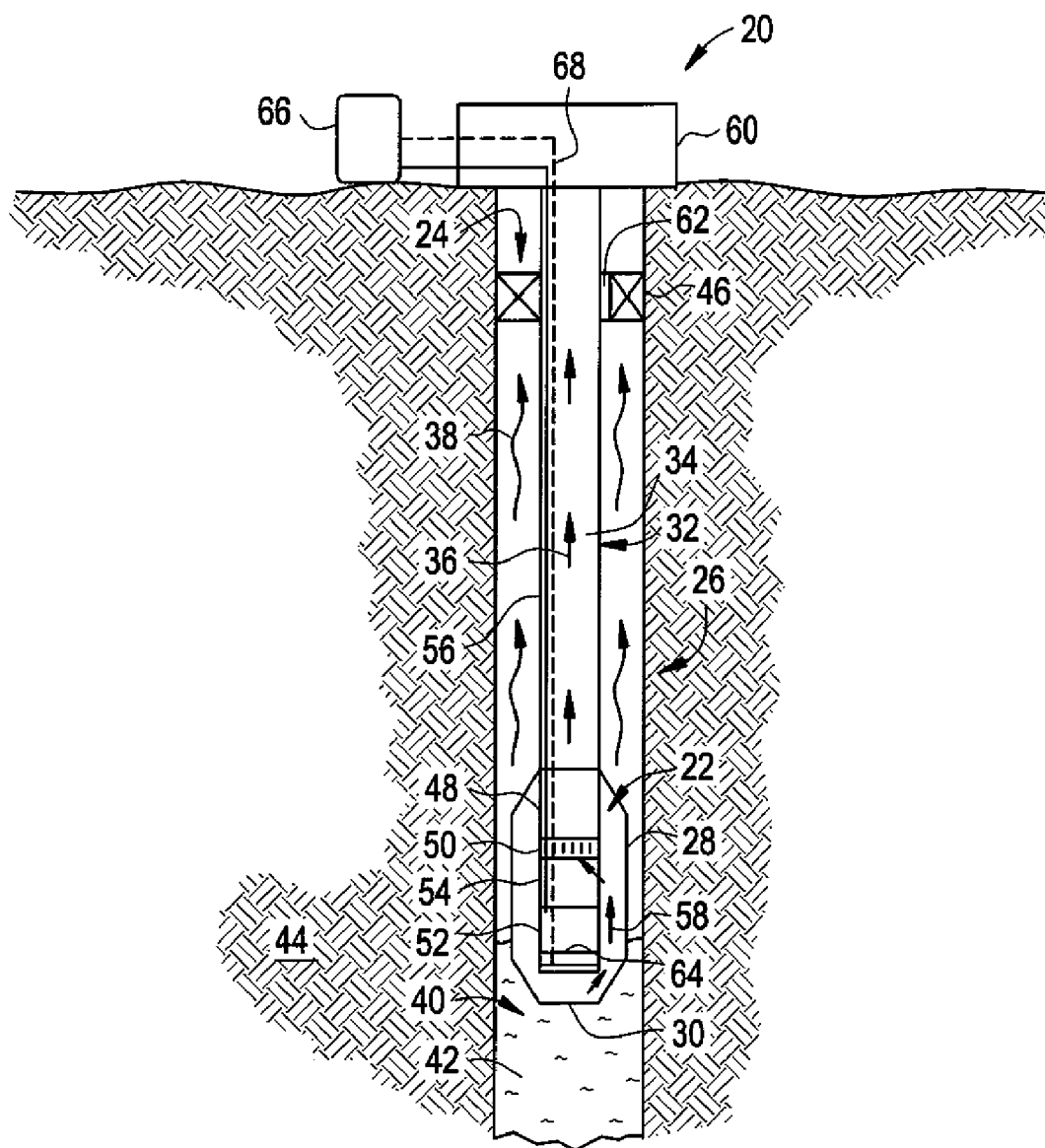


FIG. 2

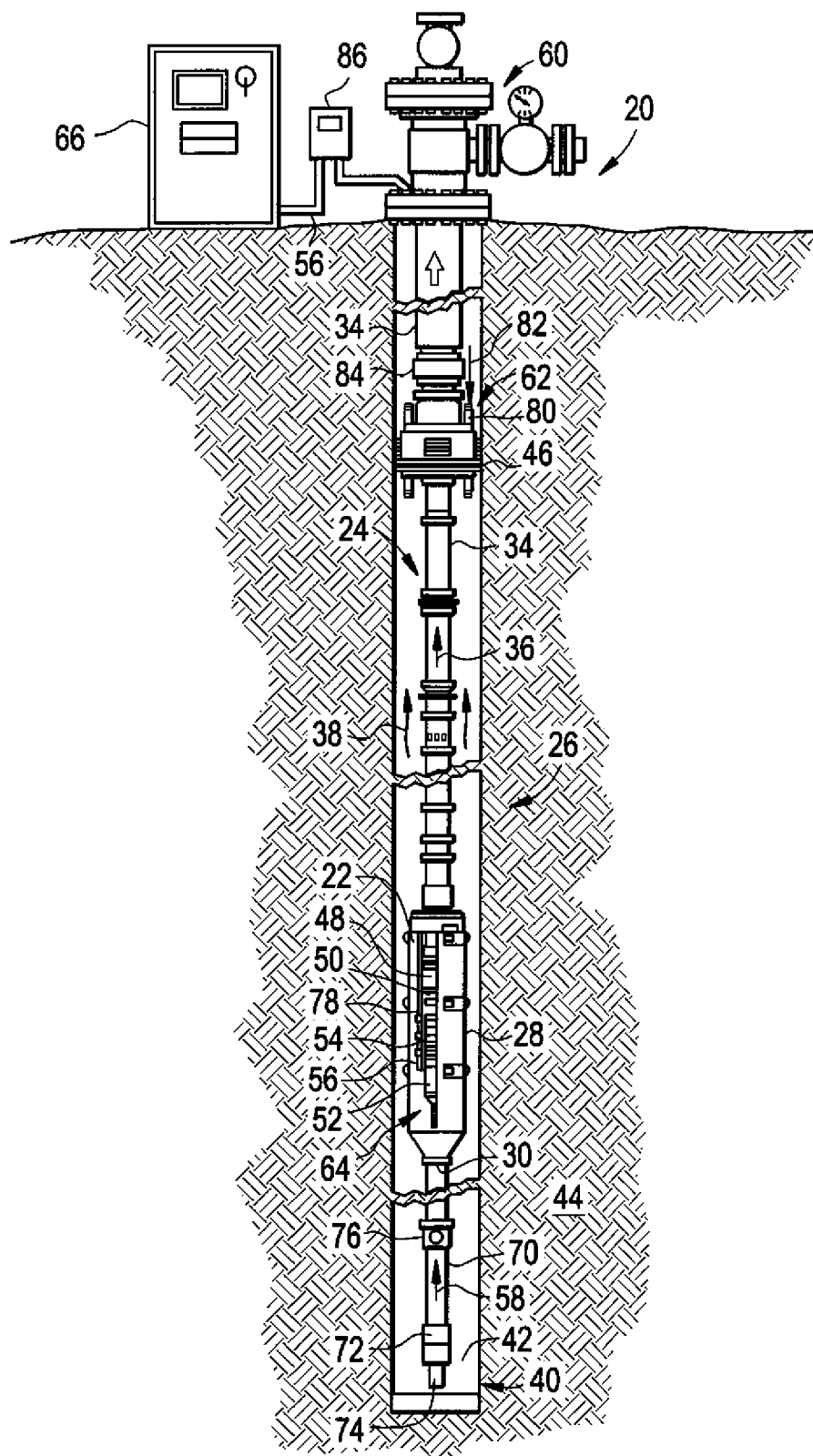


FIG. 3

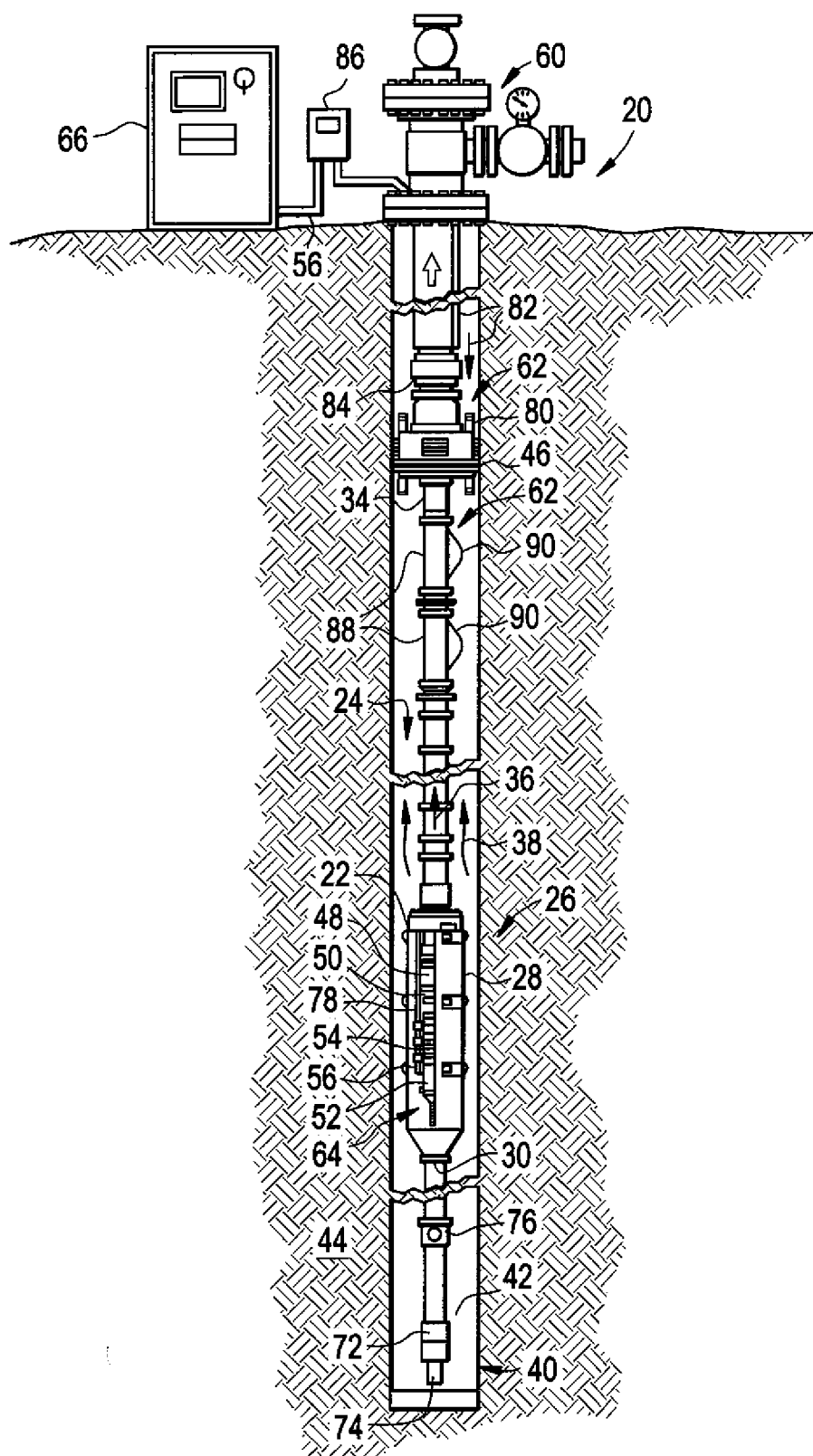
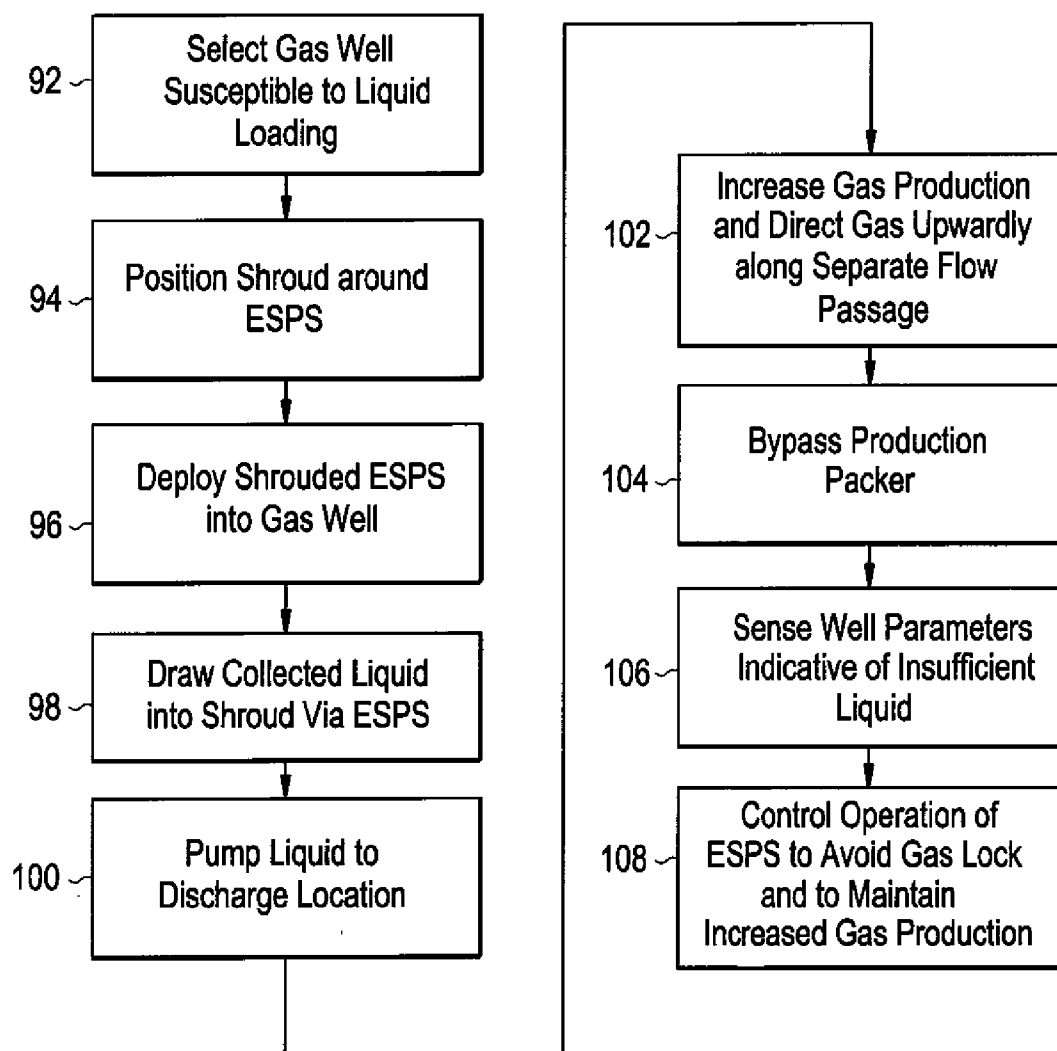


FIG. 4



## SYSTEM AND METHOD FOR REMOVING LIQUID FROM A GAS WELL

### BACKGROUND

[0001] Gas wells exist in a variety of environments throughout many regions of the world. Generally, a wellbore is drilled and gas is produced up through the wellbore. Over time, a significant percentage of the gas wells lose lift capability due to liquid accumulation in the wellbore. The liquid loading of gas wells results from formation water influx and/or condensation in the wellbore at regions of reduced wellbore temperature. Temperature, well depth, and water-gas ratio are three common factors that affect the liquid loading of gas wells.

[0002] Often, liquid loading in gas wells occurs late in the field life of the well when gas flow rates decrease and gas velocities in the wellbore are not sufficient to lift the condensed liquids to the surface. The well may flow at a stable rate for many days but a small reduction in flow rate, or an increase in hydrostatic back pressure, can trigger instability and load the well with liquid in days or even hours. Sufficient condensation of water or influx of water from the formation ultimately can lead to cessation of gas production. The liquid loading of a gas well creates a particularly challenging environment for application of any assisted lift solutions.

### SUMMARY

[0003] In general, the present invention provides a system and method for removing liquid from a gas well, i.e. gas well deliquification. The system and method involve determining whether liquid has accumulated, or is likely to accumulate, in a gas well. An electric submersible pumping system is deployed into the wellbore and positioned to remove accumulated liquid. Operation of the electric submersible pumping system is then controlled to remove sufficient liquid for improvement of gas production from the gas well.

### BRIEF DESCRIPTION OF THE DRAWINGS

[0004] Certain embodiments of the invention will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements, and:

[0005] FIG. 1 is a front elevation view of an electric submersible pumping system deployed in a wellbore of a gas well, according to an embodiment of the present invention;

[0006] FIG. 2 is a front elevation view of another example of an electric submersible pumping system deployed in a wellbore of a gas well, according to an embodiment of the present invention;

[0007] FIG. 3 is a front elevation view of another example of an electric submersible pumping system deployed in a wellbore of a gas well, according to an embodiment of the present invention; and

[0008] FIG. 4 is a flow chart illustrating one example of a procedure for conducting a liquid removal operation to improve gas well production, according to an embodiment of the present invention.

### DETAILED DESCRIPTION

[0009] In the following description, numerous details are set forth to provide an understanding of the present invention. However, it will be understood by those of ordinary skill in the art that the present invention may be practiced without

these details and that numerous variations or modifications from the described embodiments may be possible.

[0010] The present invention generally relates to a system and method to remove liquid loading in gas wells. The methodology is amenable to use in deep, low pressure, high water-gas ratio gas wells, however the methodology can be used in a wide variety of gas wells to remove liquid that is limiting or potentially limiting gas production from the well. An artificial lift mechanism, such as an electric submersible pumping system, is deployed into the well to a position at which the liquid can be drawn into the mechanism and moved to a discharge location, such as a surface location. Use of the electric submersible pumping system enables deliquification of the gas well in an economical manner, resulting in continued operation and/or improved operation of the gas well. The electric submersible pumping system can be operated intermittently or continuously, as necessary, to remove sufficient liquid for improved operation of the gas well.

[0011] Initially, candidate gas wells are selected based on existing liquid loading or on the potential for liquid loading. Background information on the environment, reservoir, and specific gas well can be used to target candidate wells. A variety of gas well related data also can be collected and analyzed to identify the reasons for underperformance of the gas well and to evaluate the potential for improvement. The data may include historical production trends that are evaluated and analyzed for a given gas well or for groups of gas wells. Once a candidate gas well is selected, the artificial lift mechanism can be deployed into the wellbore to effectively unload liquid from the gas well or to at least be positioned for future liquid removal.

[0012] Referring generally to FIG. 1, one embodiment of a system 20 for unloading liquid from a gas well is illustrated. In this example, the artificial lift mechanism is in the form of an electric submersible pumping system 22 deployed in a wellbore 24 of a gas well 26. A shroud 28 is deployed around electric submersible pumping system 22 and encloses the submersible pumping system 22 except for a shroud inlet 30. The shroud 28 can be made of a liquid impermeable material, e.g., metal or polymer, and can connect to an outer radial portion of the electrical submersible pumping system 22 and extend downward from the connection thereby providing a space between the shroud 28 and the electrical submersible pumping system 22. The shroud inlet 30 is located proximate to the end of the shroud 28 that is distal from the connection of the shroud 28 to the electrical submersible pumping system 22. Essentially, the shroud 28 can act as a barrier to fluid in a radial direction around the electric submersible pumping system 22, while allowing fluid to enter into the shroud through the shroud inlet 30. Preferably, the shroud 28 is both fluid impermeable and liquid impermeable.

[0013] Electric submersible pumping system 22 and shroud 28 are conveyed downhole into wellbore 24 via a suitable conveyance 32. Conveyance 32 may comprise a tubing 34, such as production tubing or coiled tubing, able to convey fluid upwardly along wellbore 24. For example, conveyance 32 may be used to define a first fluid flow path 36 along the interior of the conveyance 32 and a second fluid flow path 38 along the exterior of the conveyance 32 in the annulus formed between conveyance 32 and the wall defining wellbore 24. In the embodiment illustrated, liquid is directed through tubing 34 along flow path 36, and gas is produced through the annulus along second flow path 38.

[0014] Conveyance 32 is used to deliver the shrouded electric submersible pumping system 22 to a region 40 in which a liquid 42 has collected or is likely to collect. Liquid 42 can result from condensation or the influx of liquid from a surrounding formation 44. The liquid 42 collects in region 40, generally at a lower portion of wellbore 24. Once pumping system 22 is positioned at the desired region 40, a packer 46, e.g. a production packer, is set and liquid 42 can be removed from region 40 by controlled operation of the electric submersible pumping system 22.

[0015] Electric submersible pumping system 22 may have a variety of components depending on the depth of region 40, the characteristics of liquid 42, the general design of system 20, and other system and environmental factors. In the example illustrated, electric submersible pumping system 22 comprises a submersible pump 48 coupled to a pump intake 50. The submersible pump 48 is driven by a submersible motor 52 coupled to a motor protector 54. Power is provided to submersible motor 52 via a suitable power cable 56.

[0016] When electric submersible pumping system 22 is operated, liquid 42 is drawn through shroud inlet 30 and routed upwardly between pumping system 22 and shroud 28 until the liquid reaches pump intake 50, as represented by arrows 58. Submersible pump 48 pumps the liquid 42, discharges the liquid 42 into tubing 34, and delivers the liquid 42 upwardly along flow path 36. In this example, the liquid 42 is delivered upwardly through a surface wellhead 60 for delivery to a surface discharge location. In other embodiments, the discharged liquid 42 could be delivered to a subterranean storage location. As the liquid loading is reduced, greater gas production occurs along second flow path 38. The produced gas is moved past production packer 46 via an appropriate bypass mechanism 62, as discussed in greater detail below.

[0017] The shroud 28 ensures that a flow of liquid is maintained along submersible motor 52 to cool the motor. Additionally, shroud 28 can be designed in a variety of configurations to enable removal of liquid 42 without necessarily submerging pump intake 50 within the liquid. However, operation of electric submersible pumping system 22 is controlled to ensure operation only when sufficient liquid is available at pump intake 50 to avoid gas lock or other detrimental conditions due to excess gas in submersible pump 48. If the liquid 42 is about to be pumped off to an extent that it cannot be drawn through shroud inlet 30, the operational speed of pumping system 22 is reduced or stopped.

[0018] A sensor system 64 having at least one sensor, but preferable a variety of sensors, can be used to monitor one or more well related parameters that are indicative of insufficient liquid entering the electric submersible pumping system 22. For example, sensors 64 may comprise pressure sensors positioned to measure a pump intake pressure and/or an annulus pressure. Data from sensors 64 can be relayed uphole to a surface control system 66 via an appropriate communication line 68. Communication line 68 may be an electric line, optical line, wireless communication line, or other suitable communication line or communication lines. Based on data from sensors 64, surface control system 66 is used to control, for example, the operational speed of electric submersible pumping system 22. By way of example, surface control system 66 may comprise a variable speed drive that can be used to selectively control the power supply to submersible motor 52 which, in turn, controls the operational speed of pumping system 22. Surface control system 66 may be constructed in a variety of configurations depending on the moni-

toring and control functionality required. In a variety of applications, surface control system 66 further comprises a computer-based system that can be programmed to collect and analyze data and to automatically control operation of electric submersible pumping system 22.

[0019] A more detailed example of one type of deliquification system 20 is illustrated in FIG. 2. In this embodiment, a tail pipe 70 is connected to shroud 28 and extends downwardly into region 40. The tailpipe 70 is preferable a hollow tubular member. During operation of electric submersible pumping system 22, liquid 42 is drawn upwardly through tail pipe 70 into shroud 28 and then into electric submersible pumping system 22, which pumps the liquid 42 upwardly along flow path 36. The use of tail pipe 70 and shroud 28 enables removal of liquid 42 from a desired region 40 even when the electric submersible pumping system 22 is separated from the liquid 42 within region 40.

[0020] Other components can be used in combination with tail pipe 70. For example, a tail pipe screen 72 may be mounted at an inlet to the tail pipe to screen or filter liquid drawn into tail pipe 70. Additionally, a half mule shoe 74 can be mounted at a lower end of the tail pipe 70. A check valve 76 also can be mounted in the flow of fluid through tail pipe 70 to prevent backflow of the fluid that is drawn into shroud 28. Furthermore, a gas handler 78 can be combined with electric submersible pumping system 22 to remove entrained gas from liquid 42, thus further optimizing the performance of electric submersible pumping system 22. By way of example, gas handler 78 may comprise an Advanced Gas Handler available from Schlumberger Corporation.

[0021] In the example illustrated in FIG. 2, the removed liquid 42 and the produced gas are maintained along separate flow paths to wellhead 60. This configuration of system 20 can be referred to as a parallel concentric flow system in which liquid is pumped upwardly along the interior of tubular 34 and gas is produced through the surrounding annulus to the wellhead 60. One or more gas vent valves 80 are deployed in production packer 46 and serve as bypass mechanism 62 to enable the bypass flow of gas past the production packer 46. The gas vent valves 80 can be constructed in a variety of configurations that are controllable to selectively open or close the flow path through packer 46. By way of example, the gas vent valve 80 may be a hydraulically actuated valve controlled by hydraulic input supplied through a control line 82. In the parallel concentric flow embodiment, liquid 42 is lifted from region 40 through tubing 34, e.g. production tubing or coiled tubing, to the surface at a wellhead pressure independent of the produced gas wellhead pressure.

[0022] The ability to control gas vent valves 80 enables selective placement of a barrier to gas flow and pressure beneath packer 46. A further barrier can be provided by a tubing installed subsurface safety valve 84 positioned to provide control over flow of liquid along flow path 36. The valve 84 may be selectively opened to enable flow or closed to isolate the region below packer 46. By way of example, valve 84 may be a hydraulically actuated valve also controlled via hydraulic input through control line 82 or through another suitable control line.

[0023] In this embodiment, surface control system 66 comprises a motor controller incorporated into a variable speed drive so electric submersible pumping system 22 can be shut off or operated at a desirable speed to enable sufficient removal of liquid 42 from region 40 without incurring gas lock. The surface control system 66 is connected to electric

submersible pumping system 22 via power cable 56 routed through an appropriate junction box 86. Application of the variable speed drive and a motor controller increases the flexibility of system 20 and directly influences the volume of liquid 42 that can be lifted to the surface via pumping system 22. In this way, the liquid removal rate can be fine tuned in an effective manner to maintain a desired liquid level in wellbore 24.

[0024] Additionally, surface control system 66 receives data from sensors 64 to facilitate analysis and action based on liquid removal from region 40. By way of example, sensor system 64 may comprise a Phoenix Multisensor available from Schlumberger Corporation. The downhole measurements can be combined with surface measurements to enable detailed analysis of the lifting performance and to ensure the liquid pumping operation stays within the limits of the pump curve associated with the electric submersible pumping system 22. The downhole sensor data, e.g. wellbore pressure data, can be provided in real-time to control system 66. Furthermore, the downhole data and surface data can be analyzed according to a variety of available wellbore models related to a specific artificial lift system, e.g. electric submersible pumping system 22. The ongoing evaluation of data provides an efficient and cost-effective way of maintaining desired operation of electric submersible pumping system 22 and the consequent removal of liquid 42 from region 40. In many applications, pump intake pressure and annulus pressure fluctuations provide helpful information related to the detection and control of liquid loading as well as providing an indication of the potential for gas lock.

[0025] Referring generally to FIG. 3, another embodiment of system 20 is illustrated. In this embodiment, many features and components are the same as those described and illustrated with respect to FIG. 2. However, the gas is produced upwardly along flow path 38 and along a portion of the annulus surrounding tubing 34 before being diverted into the tubing 34. Within tubing 34, the gas and liquid 42 are commingled and delivered to the surface.

[0026] In the example illustrated, one or more gas mandrels 88 are installed below the production packer 46 to serve as bypass mechanism 62. Each gas mandrel 88 comprises a valve 90, e.g. a gas vent valve, that enables flow of gas from the annulus into the interior of tubing 34. The liquid 42 removed from region 40 by electric submersible pumping system 22 is commingled with the gas at gas mandrels 88 and delivered upwardly to wellhead 60 through tubing 34. This technique can be referred to as a shallow diverted flow technique for the removal of liquid loading in a gas well. The approach provides independent production of gas and liquid until the point of convergence via gas mandrels 88 which are positioned at a shallower depth of the well profile. Diversion of the gas flow back into tubing 34 below packer 46 can create a strong gas lift effect which reduces the required horsepower for electric submersible pumping system 22, thus enhancing the overall efficiency of the pumping system. Because the gas and liquid are commingled in the tubing 34, the risk of gas leakage due to lack of casing integrity at the top section of the wellbore is reduced and preferably eliminated.

[0027] The number of gas mandrels 88, the orifice sizes, and the depth of production packer 46 can be varied according to specific gas well and environmental factors. Additionally, a variety of other features can be selected or changed in any of the embodiments described herein. For example, the depth of the electric submersible pumping system 22 and the length of

tail pipe 70 can vary from one application to another for optimization of the deliquification procedure. The number of submersible pumps, submersible electric motors, and other components of electric submersible pumping system 22 also can vary from one application to another. Selection of the various components can be affected by a variety of well related factors, including well depth, bottom hole temperature, source of water production, bottom hole pressure, gas composition, and artificial lift technique implemented. In the shallow diverted flow technique, the addition of gas vent valve 80 is optional to provide a secondary, controllable gas flow path through production packer 46.

[0028] In operation, a variety of system configurations can be used to perform many types of deliquification procedures in various gas wells. One example of such a procedure is provided by the flowchart illustrated in FIG. 4. In this example, a gas well having liquid loading or being susceptible to liquid loading is selected, as indicated by block 92. An artificial lift mechanism is then prepared by, for example, constructing electric submersible pumping system 22 with a surrounding shroud 28, as illustrated by block 94. Selection of the specific type of artificial lift mechanism, e.g. electric submersible pumping system, depends on a variety of factors, including well/reservoir analysis, equipment features, completion configuration, performance envelope, component constraints and limitations, risk control factors, completion installation procedures and other factors.

[0029] Once the artificial lift mechanism is selected, the artificial lift mechanism can be deployed into the gas well 26. In this example, a shrouded electric submersible pumping system is deployed into the gas well 26, as illustrated by block 96. The electric submersible pumping system is then operated to draw collected liquid from region 40 into the shroud 28, as illustrated by block 98. The liquid is then pumped to a discharge location, such as a surface discharge location, as illustrated by block 100. Reduction of the liquid loading in the gas well increases production of gas which is directed upwardly along a separate flow passage, as indicated by block 102. The produced gas is moved past a production packer by an appropriate bypass mechanism, as illustrated by block 104. Examples of bypass mechanisms comprise gas vent valves, installed at the production packer, or gas mandrels, installed below the production packer, to commingle the gas with the flowing stream of liquid discharged by the electric submersible pumping system.

[0030] The liquid at region 40 of the gas well and/or the liquid flow to electric submersible pumping system 22 is monitored. One or more sensors can be used to detect and monitor well parameters, e.g. pump intake pressure and annulus pressure, indicative of insufficient liquid, as illustrated by block 106. The sensors also can be used to monitor a variety of other parameters related to maintaining and/or optimizing production of gas. Based on sensor data, the electric submersible pumping system is controlled via control system 66 to maintain the increased gas production while avoiding gas lock or other detrimental problems associated with excess gas reaching submersible pump 48, as illustrated by block 108.

[0031] Use of the electric submersible pumping system facilitates maintenance of flow rates in many types of gas wells that would otherwise suffer from decreased production or a production stoppage. Additionally, the electric submersible pumping system provides excellent dynamic response to the liquid accumulation in a given gas well or to changes in operating conditions. The electric submersible pumping sys-



tem requires little or no stabilization time to bring liquid to a surface location in the case of intermittent gas well operation.

**[0032]** Many configurations of completions and artificial lift mechanisms can be used to provide an easily controlled system for removing accumulated liquid from gas wells. The arrangement and selection of components depends on the size, depth and characteristics of the gas well and on the design of the electric submersible pumping system and related components. Various components can be added or substituted depending on the requirements of the specific operation that is designed to improve gas production for a given well.

**[0033]** Accordingly, although only a few embodiments of the present invention have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this invention. Such modifications are intended to be included within the scope of this invention as defined in the claims.

What is claimed is:

1. A method of gas well deliquification, comprising:  
enclosing an electric submersible pumping system with a shroud;  
connecting a tail pipe to a lower end of the shroud;  
conveying the electric submersible pumping system into a gas well via a tubing until the tail pipe enters a region susceptible to liquid accumulation;  
operating the electric submersible pumping system to pump liquid from the region and up through the tubing;  
and  
producing gas along an annulus formed around the shroud and the tubing.
2. The method as recited in claim 1, further comprising directing the gas into the tubing via at least one gas mandrel installed below a production packer.
3. The method as recited in claim 1, comprising setting a production packer in the annulus; and directing the gas through the production packer via a gas vent valve installed at the production packer.
4. The method as recited in claim 3, comprising controlling the gas vent valve via a hydraulic control line.
5. The method as recited in claim 1, comprising using a downhole sensor to monitor a well characteristic at the electric submersible pumping system.
6. The method as recited in claim 1, comprising utilizing a gas handler in cooperation with the electric submersible pumping system.
7. The method as recited in claim 1, comprising controlling operation of the electric submersible pumping system to ensure liquid is not entirely pumped off.
8. The method as recited in claim 5, wherein using the downhole sensor comprises monitoring a pump intake pressure.
9. The method as recited in claim 8, wherein using the downhole sensor further comprises monitoring an annulus pressure.

10. A method, comprising:

determining accumulation of a liquid in a gas well; and  
utilizing an electric submersible pumping system to pump a sufficient amount of the liquid from the gas well to improve gas production from the gas well.

11. The method as recited in claim 10, comprising drawing liquid along the electric submersible pumping system within a shroud.

12. The method as recited in claim 10, comprising controlling operation of the electric submersible pumping system to avoid gas lock.

13. The method as recited in claim 10, comprising operating a gas handler in cooperation with the electric submersible pumping system to remove gas from the liquid to be pumped by the electric submersible pumping system.

14. The method as recited in claim 10, wherein utilizing comprises pumping liquid upwardly through a tubing.

15. The method as recited in claim 14, comprising producing gas upwardly along an annulus surrounding the tubing.

16. The method as recited in claim 15, comprising directing the gas into the tubing below a production packer.

17. The method as recited in claim 15, comprising directing the gas through a production packer via a gas vent valve.

18. A system for use in gas well deliquification, comprising:

an electric submersible pumping system deployed in a gas well;

a shroud positioned around the electric submersible pumping system, the shroud having an inlet located to receive liquid from a liquid accumulation region of the gas well;  
a tubing by which the electric submersible pumping system is deployed in the gas well, the tubing defining a liquid flow path and a gas flow path;

a production packer located above the electric submersible pumping system; and

a mechanism to enable gas flow past the production packer.

19. The system as recited in claim 18, wherein the mechanism comprises a gas mandrel oriented to direct gas into the tubing from an annulus surrounding the tubing.

20. The system as recited in claim 18, wherein the mechanism comprises a gas vent valve positioned in the production packer.

21. The system as recited in claim 18, comprising a tail pipe extending downwardly from the inlet of the shroud.

22. The system as recited in claim 18, comprising a sensor system positioned downhole to detect parameters indicative of insufficient liquid entering the electric submersible pumping system.

23. The system as recited in claim 18, comprising a surface control system, wherein the surface control system selectively reduces the speed of the electric submersible pumping system to avoid gas lock.

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