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(54) **METHOD OF PRODUCING A LOW PRESSURE WELL**

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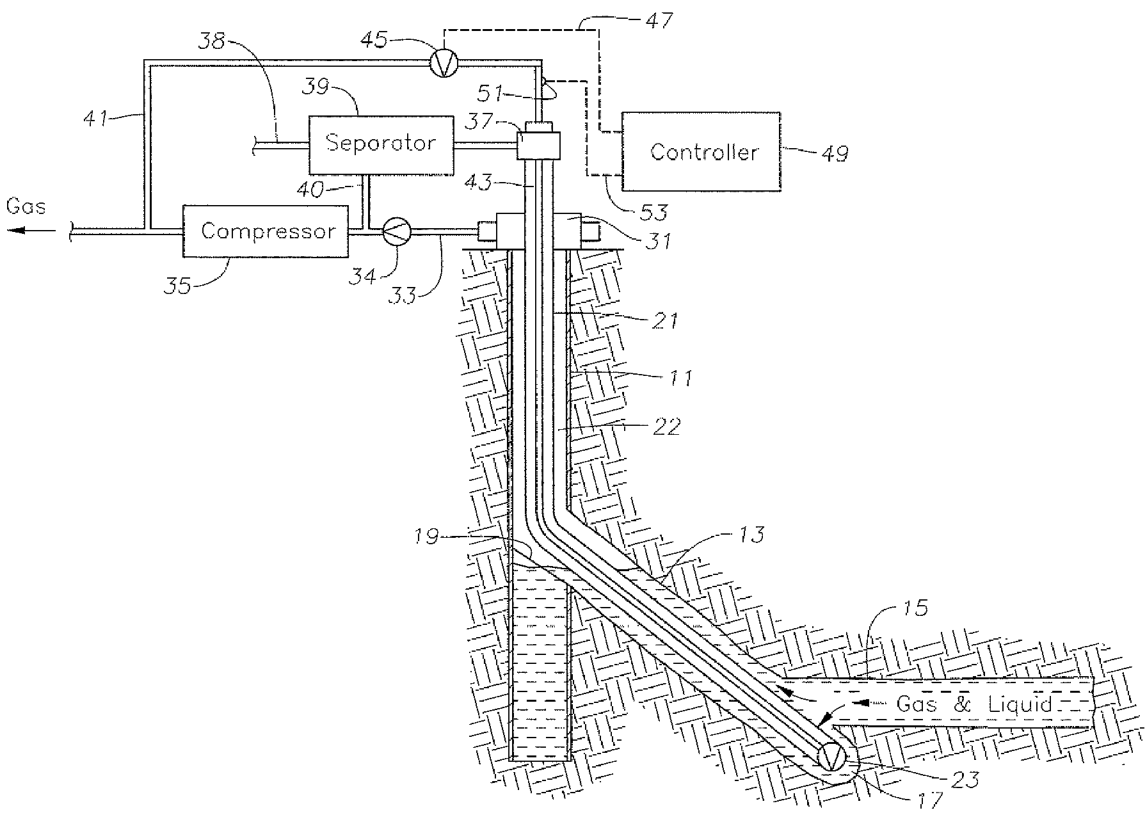
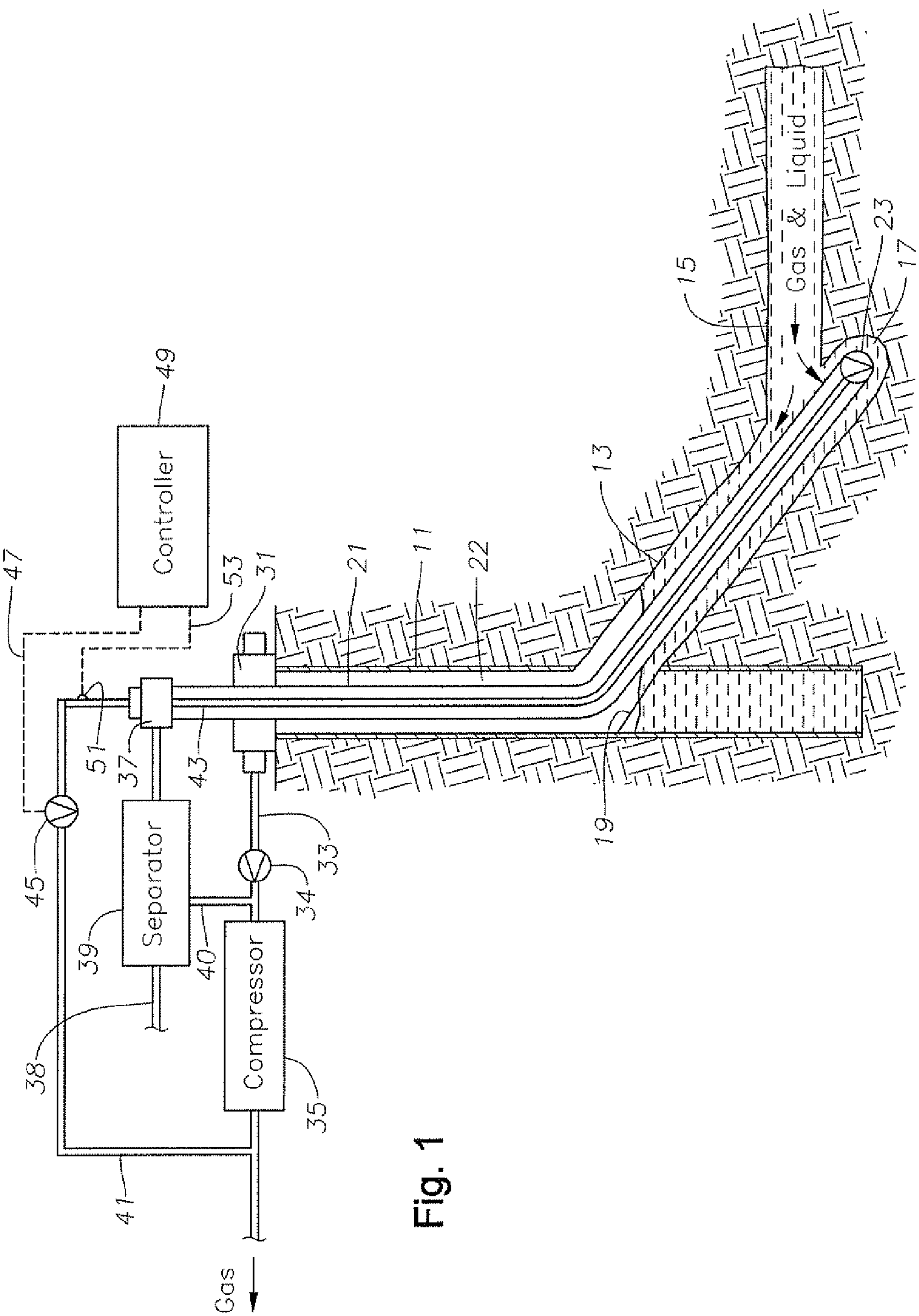
(57) **ABSTRACT**

A method of producing natural gas from a well has a mode that removes liquid collected in the well by injecting gas. The well has a string of tubing with a valve at its lower end that is submerged in the liquid produced by the well. An injection tube extends into the tubing. With the valve open, natural gas from the well flows up the tubing annulus and out the well to a gas pipeline and liquid flows into the tubing as well as into the injection tube. Periodically, an injection gas is injected down the injection tube with the valve closed to prevent the injection gas from flowing into the tubing annulus. This causes liquid collected in the tubing to be pushed to the surface and out of the well.





Controller
Separator
Compressor
Gas & Liquid
Gas
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47
53
51
31
21
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37
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33
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Fig. 1

Fig. 2

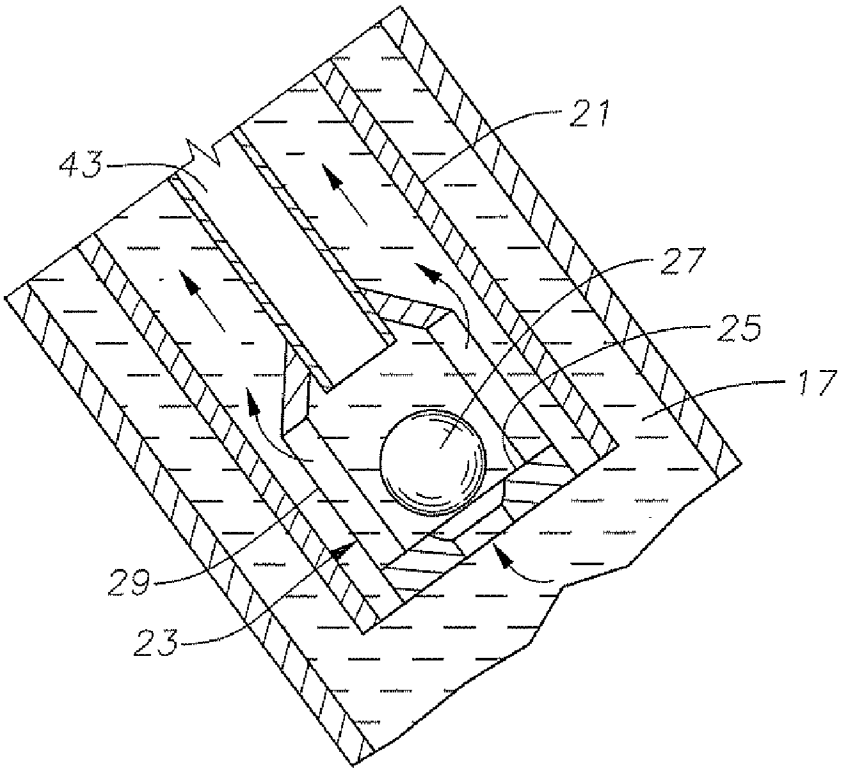
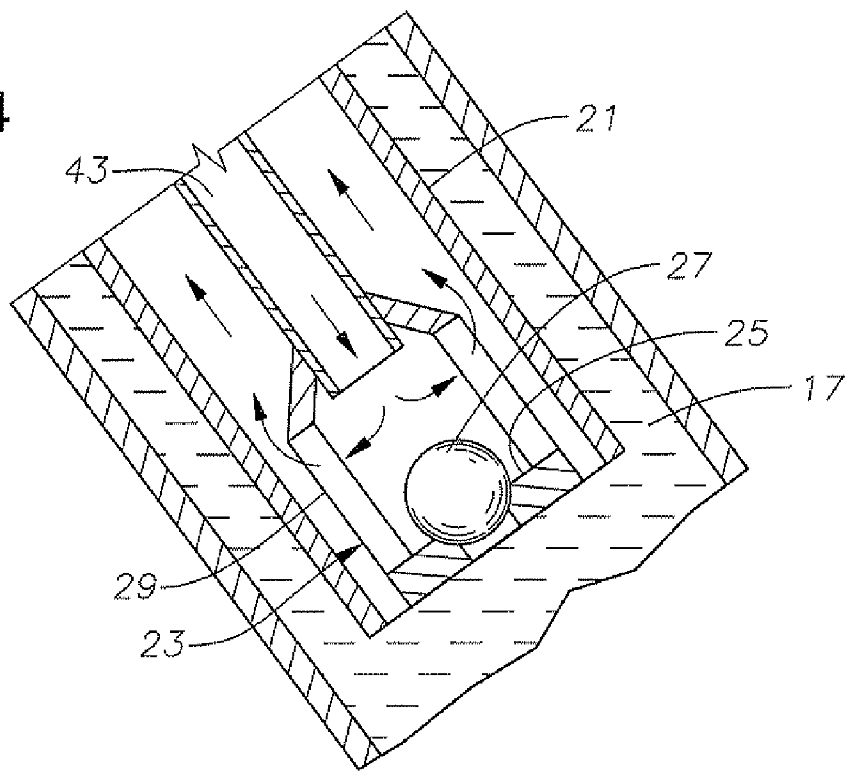
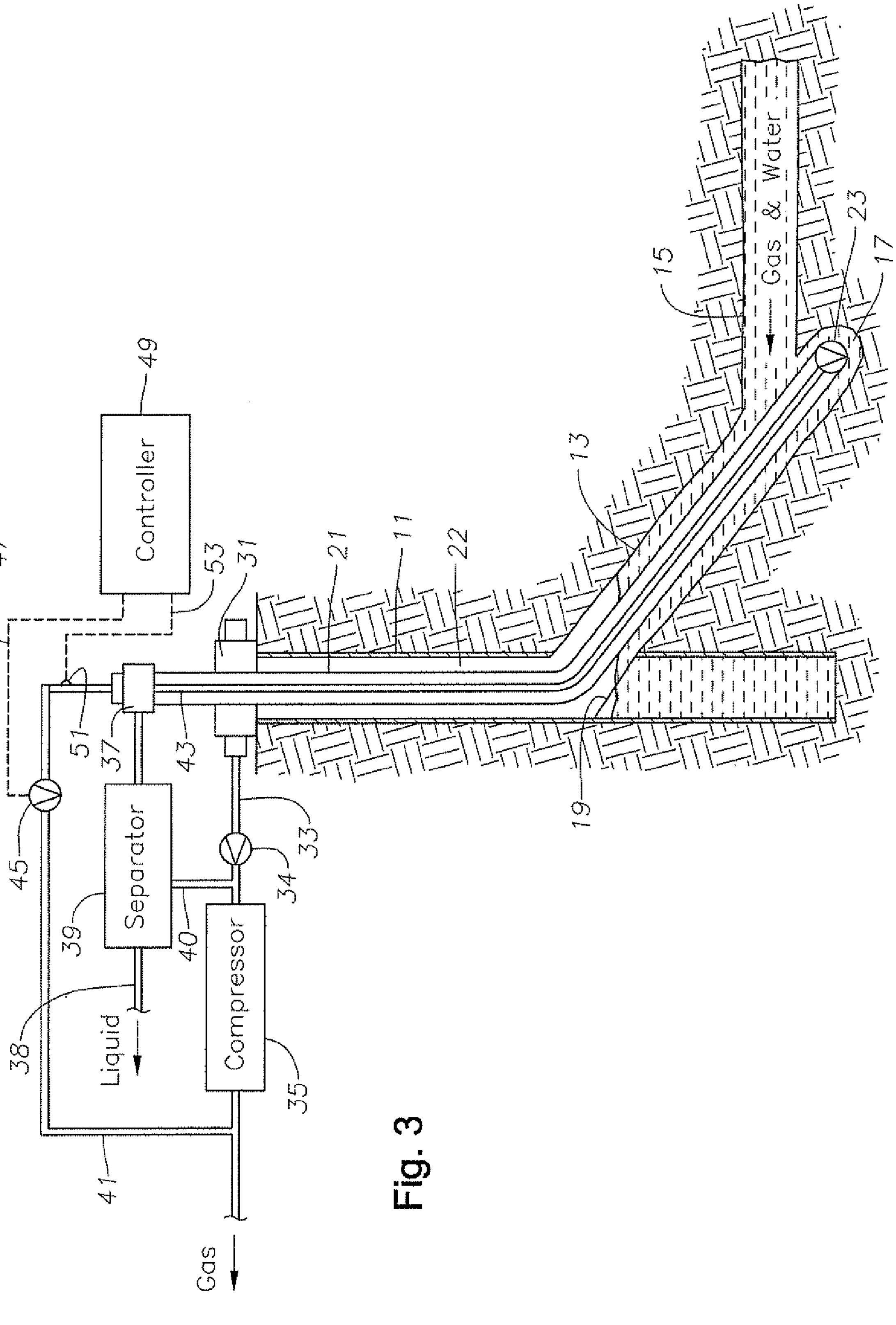


Fig. 4




Controller
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Gas & Water
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Separator
39
40
34
33
Compressor
35
38
Liquid
41
Gas

Fig. 3

METHOD OF PRODUCING A LOW PRESSURE WELL

FIELD OF THE INVENTION

[0001] This invention relates in general to producing wells that have formations containing gas and liquid under low pressure, and in particular to a method of injecting gas to produce the liquid without affecting the gas producing formation,

BACKGROUND OF THE INVENTION

[0002] Many wells have formations that contain commercial quantities of gas but at low pressure. Most of these wells also produce liquid, which may be a gas condensate or it may be water or both. A variety of methods are employed in the prior art to produce the gas depending upon the particular conditions of the well.

[0003] For example, an operator might utilize a plunger lift system. With the plunger lift system, a string of tubing extends into the well. The gas is produced up the annulus surrounding the tubing. The tubing has a plunger and a down hole gas lift valve that allow liquid being produced to flow into the tubing above the plunger. Periodically, the operator pressurizes the tubing annulus with gas pressure to cause the plunger to move upward and lift the column of liquid in the tubing to the surface. The plunger then slides back to the lower end of the tubing for another cycle.

[0004] While plunger-lift is a successful method, injecting gas into the casing annulus of a low pressure gas well causes the injection gas to enter the gas producing formation. With very low pressure formations, the operator may not be able to recover most of the injected gas.

SUMMARY OF THE INVENTION

[0005] In this invention, the operator runs an injection tube into the tubing and positions a valve at the lower end of the tubing. With the valve in the tubing open, natural gas being produced by the well flows up the annulus surrounding the tubing and out of the wellhead to a gas pipeline. At the same time, liquid migrates into the annulus and into the tubing. The level of liquid in the annulus and in the tubing rises and periodically the operator will inject gas down the injection tube with the valve closed. The gas being injected down the injection tube lifts the liquid collected in the tubing to the surface. The operator then shuts off the injected gas, which causes liquid in the annulus to flow into the lower end of the tubing, dropping the level of liquid in the annulus.

[0006] Preferably, the valve is a normally open check valve that closes in response to injection pressure. The operator may determine the point at which to inject gas either by a timer or by detecting the approximate level of liquid in the tubing and in the annulus. Detecting the liquid level may be done by using a pressure sensor in the tubing or injection tube above the column of liquid. The injection tube is closed prior to injecting gas, thus the rising level of liquid will increase the pressure in the chamber located above the level of liquid in the injection tube.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] FIG. **1** is a schematic view illustrating a well having a system in accordance with this invention and shown in a normal production mode.

[0008] FIG. **2** is an enlarged schematic view of the lower portion of the tubing, the injection tube and the check valve used with the system of FIG. **1**.

[0009] FIG. **3** is a view similar to FIG. **1** but shown in a mode with liquid previously collected in the tubing being pushed up by injecting gas into the injection tube.

[0010] FIG. **4** is a sectional view similar to FIG. **2**, but showing the injection gas pushing the liquid from the tubing.

DETAILED DESCRIPTION OF THE INVENTION

[0011] Referring to FIG. **1**, the well in this example has a vertical casing section **11**. A branch has been drilled from the original vertical casing section **11**, using a deflecting device **19** to form an inclined branch or section **13**. A substantially horizontal section **15** extends laterally outward from inclined section **13** from a junction above the lower end of inclined section **13**. The portion of inclined section **13** located below the junction with horizontal section **15** may be considered a sump section **17**. Inclined section **13** and horizontal section **15** are illustrated to be open hole, containing no casing. Alternately, one or both could contain casing, a liner with perforations or a slotted liner.

[0012] A string of tubing **21** extends through vertical section **11**, inclined section **13** and into sump **17**. Deflecting device **19** serves to deflect tubing **21** over so that it will enter inclined section **13** while being run. Tubing **21** may comprise joints of conventional production tubing secured together by threads. Alternately, tubing **21** could comprise a single continuous length of coiled tubing. The lower end of tubing **21** is preferably located within sump **17** below the junction of horizontal section with inclined section **13**. A tubing annulus **22** surrounds tubing **21**.

[0013] Tubing **21** has an inlet at its lower end that contain a valve **23**. As shown in FIG. **2**, preferably valve **23** is a normally open check valve that admits liquid into tubing **21** but blocks outward flow when closed. As an example, valve **23** may have a valve seat **25** and a ball **27** located on the interior side of seat **25**. Ball **27** is located within a cage **29** that allows limited upward and downward movement of ball **27** within cage **29**. Unless ball **27** is forced against valve seat **25** under pressure, liquid is free to enter and exit through seat **25**. If the internal pressure within tubing **21** at seat **25** is greater than the external pressure, ball **27** will seal against seat **25** to prevent any outward flow of fluid from tubing **21**.

[0014] Referring again to FIG. **1**, a casing head **31** is located at the upper end of vertical section **11**, forming part of a wellhead. Casing head **31** has an outlet **33** that discharges natural gas flowing up tubing annulus **22**. Outlet **33** may have a check valve **34** to prevent any reverse flow down tubing annulus **22**. Normally, a compressor **35** will be required to compress the gas to a sufficient pressure level before it can be received into a commercial gas pipeline. Compressor **35** is connected to outlet **33** and may be a type that is equipped only to compress gas and not receive any significant quantities of liquid. Alternately, it could be a type, such as a liquid ring type, that can accommodate a significant percentage of liquid.

[0015] The wellhead assembly also has a tubing head **37** that supports tubing **21** and seals the upper end of tubing **21**. Tubing head **37** has an outlet that leads to a liquid/gas separator **39** in this example. Separator **39** has a liquid outlet **38** for discharging principally a liquid, which may comprise water, a light hydrocarbon liquid, or a mixture of both. Separator **39** has a gas outlet **40** that joins gas outlet **33** at the inlet of compressor **35**, downstream from check valve **34**.

[0016] A gas injection line **41** extends from the outlet side of compressor **35** over to tubing head **37**. Gas injection line **41** is coupled to an injection tube **43** that extends into tubing **21**. A valve **45** selectively opens and closes gas injection line **41**. Valve **45** is controlled by control line **47** leading from a controller **49**. Controller **49** may have an adjustable timer for opening and closing valve **45** at desired intervals.

[0017] Alternately, controller **49** has means for detecting a level of liquid within tubing **21**. The detection may be handled by a pressure sensor **51** that senses the internal pressure within injection tube **43** at the wellhead. Pressure sensor **51** is connected by a signal line **53** to controller **49**. When injection valve **45** is closed, liquid from horizontal section **15** migrates into the lower end of tubing **21** and also migrates up the open lower end of injection tube **43**. The space in injection tube **43** above the level of liquid is closed by injection valve **45**, thus as the liquid rises in injection tube **43**, the pressure in this closed column increases. This pressure increase is sensed by pressure sensor **51**. Alternately, pressure sensor **51** could monitor pressure in the upper end of tubing **21**.

[0018] Injection tube **43** comprises a tubing of smaller diameter than tubing **21**. Injection tube **43** preferably comprises continuous metal coiled tubing, but it could be made up of sections of tubing secured together by threads. Gas injection tube **43** extends to a point near the lower end of tubing **21** above valve **23**, shown in FIG. **2**. Preferably the lower end of gas injection tube **43** is no more than a few inches from valve **23**.

[0019] In the preferred embodiment, check valve cage **29** is secured to the lower end of injection tube **43**, such that check valve **23** is run into tubing **21** when injection tube **43** is being installed. The outer diameter of seat **25** preferably forms a seal with the inner diameter of tubing **21** at the lower end. The sealing arrangement could be done many ways, such as by an elastomeric or metal ring sealing against a lip or band located in the inner diameter of tubing **21** at the lower end. Alternately, check valve **23** could be mounted to tubing **21** and ran with tubing **21**.

[0020] During the first mode of operation, gas injection valve **45** is closed and valve **23** will be open because of the lack of any pressure differential at seat **25**, as shown in FIG. **2** Gas flows from horizontal section **15** into inclined section **13**. The gas flows up annulus **22** surrounding tubing **21**, and through casing head **31** to compressor **35**. Compressor **35** compresses the gas for delivery to a gas pipeline. The gas being produced will normally not flow into tubing **21** or injection tube **43** even though check valve **23** is open because of several factors: check valve **23** is at a lower elevation than horizontal section **15**; check valve **23** is normally submersed in liquid in sump **17**; and the gas in horizontal section **15** is at a very low pressure, such as about 100 psi.

[0021] The liquid produced along with the gas migrates or flows into sump **17** and into tubing **21** through the open valve **23**. The liquid will flow into injection tube **43**, which is always open at is lower end, as well as up tubing **21** surrounding injection tube **43**. The level of liquid in tubing annulus **22**, tubing **21** and injection tube **43** will be the same and will rise as the liquid continues to be produced. As the level of liquid rises in injection tube **43**, the closed chamber in injection tube **43** above the level will become smaller. This reduction causes an increase in pressure in injection tube **43** that is sensed by pressure sensor **51**, if one is utilized, which provides a signal to controller **49**. At a point previously selected by the operator, the liquid level will be high enough to cause controller **49** to open gas injection valve **45**. Preferably, the opening of gas injection valve **45** occurs before horizontal section **15** is completely filled with liquid, which would impede the flow of gas. Rather than detecting the liquid level, the operator could determine appropriate times to open and close gas injection valve **45** by trial and error, then use a timer.

[0022] When valve **45** is open, compressed natural gas flows through injection line **41** and injection tube **43** to the lower end of tubing **21**. As shown in FIG. **4**, this increased pressure causes ball **27** to seal against seat **25**. The sealing of ball **27** against seat **25** and the sealing arrangement of seat **25** against the inner diameter of tubing **21** block the outward flow of injection gas from tubing **21**. The injection gas thus does not flow into horizontal section **15**. Rather, the injection gas turns at valve **23** and begins flowing upward in tubing **21**, pushing the column of liquid above it. Liquid along with injection gas will flow into separator **39**, which separates the liquid from the injection gas. The liquid flows out liquid outlet **38** for disposal, re-injection, or if the liquid contains hydrocarbons, for sale. The injection gas flows through line **40** back into compressor **35** for re-compressing and delivery to a gas pipeline.

[0023] When a significant quantity of the liquid has been produced out liquid outlet **38**, controller **49** will close valve **45**. Normally, the amount of time that gas is injected is determined by trial and error and set by a timer. When injection gas valve **45** closes initially, the upper end of injection tube **43** will again be closed. The closure of injection gas valve **45** removes the pressure on ball **27** that caused it to seal against seat **25**. The liquid contained within sump **17** above the lower end of tubing **21** will then flow through seat **25** into tubing **21** until the level within tubing **21**, injection tube **43**, and tubing annulus **22** in sump **17** equal each other.

[0024] When the pressure level in the chamber above the liquid in injection tube **43** again reaches the maximum allowable sensed by sensor **51**, controller **49** repeats the cycle. During the injection period, since valve **23** is closed, the production of gas will continue unimpeded by the injection through injection tube **43**.

[0025] The invention has significant advantages. The system allows an operator to produce low pressure gas economically. The injection gas pressure is not applied to the producing formation, thus the injection gas does not flow into the producing formation. An electrical or mechanical pump is not required. If tubing is already in place, the operator does not have to pull the tubing, rather can run the check valve and injection tube into previously installed tubing.

[0026] While the invention has been shown in only one of its forms, it should be apparent to those skilled in the art that it is not so limited but is susceptible to various changes without departing from the scope of the invention. For example, although shown with a well having a branch with an inclined and a horizontal section, the system could also be employed with a vertical well. The injection gas could be a hydrocarbon gas from another well or source. The injection gas could also be a non-hydrocarbon gas, such as carbon dioxide or nitrogen.

1. A method of producing natural gas from a well that also produces liquid, the well having a string of tubing comprising:

(a) installing an injection tube in the tubing and positioning a valve in a lower portion of a string of tubing with the valve submersed in the liquid produced by the well;

(b) with the valve in the tubing open, flowing natural gas up the well in an annulus surrounding the tubing and out of the well to a gas pipeline and migrating liquid through the valve into the tubing; and
(c) periodically injecting an injection gas down the injection tube and closing the valve to prevent the injection gas from entering the annulus, causing the injection gas to flow back up the tubing along with the liquid collected in the tubing.

2. The method according to claim **1**, further comprising:
after flowing liquid from the tubing for a selected interval, stopping the injection of injection gas, and opening the valve to allow liquid in the annulus around the tubing to migrate into the tubing, then repeating step (c) to remove more liquid from the well.

3. The method according to claim **1**, wherein the injection gas of step (c) comprises the natural gas produced by the well.

4. The method according to claim **1**, wherein;
step (b) further comprises compressing the natural gas before flowing the natural gas into the gas pipeline; and
step (c) comprises delivering some of the natural gas after being compressed to the injection tube to serve as the injection gas.

5. The method according to claim **1**, wherein during step (b), the method further comprises:
detecting the level of liquid as it migrates into the tubing; and
when the level of liquid reaches a selected maximum level, beginning step (c).

6. The method according to claim **1**, wherein during step (b), the method further comprises:
monitoring a pressure in the tubing or the injection tube to provide an indication of the level of liquid in the tubing to determine when to begin step (c).

7. The method according to claim **1**, wherein;
the valve of step (a) is a normally open check valve; and
in step (c), the valve is closed in response to the injection gas pressure.

8. The method according to claim **1**, wherein step (b) comprises positioning a lower end of the injection tube above and in close proximity to the valve.

9. The method according to claim **1**, wherein natural gas continues to flow up the annulus in step (b) while step (c) is occurring.

10. The method according to claim **1**, wherein step (a) comprises securing the valve to the injection tube, then inserting the injection tube into the tubing.

11. A method of producing a low pressure gas and liquid producing well having a string of tubing, comprising:
(a) positioning a check valve within a string of tubing adjacent a lower end of the tubing, and extending an injection tube from a wellhead into the tubing a short distance above the check valve; then
(b) flowing gas produced in the well up an annulus surrounding the tubing and out the wellhead, then compressing the gas produced and delivering the gas to a gas pipeline;
(c) while step (b) is occurring, allowing liquid produced in the well to flow through the check valve into the tubing, causing a level of the liquid in the tubing to rise; and
(d) at a selected point, injecting some of the gas compressed in step (b) down the injection tube, which closes the check valve and causes the injected gas to flow up the tubing along with liquid collected in the tubing in step (c).

11. The method according to claim **10**, further comprising:
after injecting the gas in step (d) for a selected interval, ceasing step (d), which causes the check valve to again open and allows liquid in the annulus to flow into the tubing.

12. The method according to claim **10**, further comprising:
monitoring a pressure in an upper end of the tubing or an upper end of the injection tube during step (c) to determine when to begin step (d).

13. The method according to claim **10**, wherein step (b) occurs without interruption while step (d) is occurring.

14. The method according to claim **19**, wherein step (a) comprises securing the check valve to the injection tube, then inserting the injection tube and the check valve into the tubing.

15. A well, comprising:
a casing having a downhole casing inlet for the entry of natural gas and liquid produced by the well;
a string of tubing in the casing and having a tubing inlet positioned below the casing inlet;
a valve in the tubing inlet;
an injection tube inserted into the tubing;
a source of gas pressure connected to an upper end of the injection tube for selectively injecting an injection gas into the tubing; and
a controller having a first mode wherein the valve is open, natural gas flows up an annulus surrounding the tubing and out the well, and liquid rises in the annulus and in the tubing, and a second mode wherein the valve is closed, injection gas is injected into the injection tube, the injection gas entering a lower portion of the tubing and pushing the liquid collected within the tubing up and out the tubing.

16. The well according to claim **15**, wherein the valve comprises a normally open check valve, the valve closing in response to the injection gas being injected into the injection tubing.

17. The well according to claim **15**, further comprising:
a pressure sensor linked to the controller for determining a pressure within the tubing or the injection tube above the level of liquid while the controller is in the first mode to determine when the controller switches to the second mode.

18. The well according to claim **15**, further comprising:
a gas compressor at the surface for compressing the natural gas produced by the well and delivering the compressed natural gas to a gas pipeline; wherein
the compressed natural gas serves as the injection gas; and wherein the pressure source comprises:
an injection line leading from the gas compressor to the upper end of the injection tube; and
an injection line valve for blocking flow of compressed natural gas during the first mode and flowing compressed natural gas down the injection tube during the second mode.

19. The well according to claim **15**, wherein the controller allows the natural gas to flow up the annulus surrounding the tubing and out the well while the second mode is occurring.

20. The well according to claim **15**, wherein a lower end of the injection tube is located above and in close proximity to the valve.

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