

PROCESSES FOR INCREASING HYDROCARBON PRODUCTION**CROSS-REFERENCE TO RELATED APPLICATIONS**

[0001] This application claims priority to U.S. Continuation-in-Part Application no. 17/220,470 filed on April 1, 2021. This application also related to continuation-in-part of pending U.S. Application Number 17/034,849 filed September 28, 2020 which application is a continuation of 16/780,089 filed February 3, 2020 which issued as U.S. Patent No. 10,822,933 which application was a continuation of 16/282,831 filed February 22, 2019 which issued as U.S. Patent No. 10,584,566 which application claimed priority from provisional application number 62/634,423 filed February 23, 2018. All of the aforementioned applications are incorporated herein by reference.

FIELD OF THE DISCLOSURE

[0002] The present disclosure relates to systems and methods for increasing hydrocarbon production by, for example, inducing gas lift.

BACKGROUND AND SUMMARY

[0003] Hydrocarbon production from, for example, an oil and gas well, may often consume a large amount of energy and be limited in efficiency due to equipment limitations and/or other constraints. The present application is directed to processes and systems to improve the amount of energy, e.g., reduce the power required, and/or increase the production of a given well.

[0004] In one embodiment the application is directed a process for increasing hydrocarbon production using an electrical submersible pump. The process comprises configuring an electrical submersible pump comprising a gas separator to induce a gas lift effect in a well. The well comprises a central tubing within a casing such that an annulus is formed between the central tubing and the casing. Hydrocarbons may be produced from the well with the electrical

submersible pump such that reservoir fluid is produced up the central tubing and a mixture comprising reservoir gas and reservoir fluid is produced up the annulus.

[0005] In another embodiment the application is directed to a system for increasing hydrocarbon production using an electrical submersible pump. The system comprises a well with at least a central tubing within a casing. The central tubing comprises a fluid exit opening near a surface of the well and a fluid entrance opening downhole. An electrical submersible pump may be suspended from the fluid entrance opening of the central tubing. The electrical submersible pump comprises a pump operably connected to the fluid entrance opening of the central tubing, a gas separator operably connected to the pump, and a motor operably connected to the gas separator. The system is configured to produce reservoir fluid up the central tubing and to produce a mixture comprising reservoir fluid and reservoir gas up an annulus between the central tubing and the casing. The system is also configured to induce a gas lift effect in the absence of injecting gas into the well from the surface.

[0006] These and other objects, features and advantages of the exemplary embodiments of the present disclosure will become apparent upon reading the following detailed description of the exemplary embodiments of the present disclosure, when taken in conjunction with the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] Various embodiments of the present disclosure, together with further objects and advantages, may best be understood by reference to the following description taken in conjunction with the accompanying drawings.

[0008] FIG. 1A depicts an ESP installation using an annulus between the central tubing and casing as a second fluid production flow path.

[0009] FIG. 1B depicts an ESP installation using a second tubing string as an additional fluid production flow path.

[0010] FIG. 1C depicts an ESP installation using three tubing strings as additional fluid production flow paths.

[0011] FIG. 2 depicts a nodal analysis comparing conventional production methods vs. the methods described herein.

[0012] FIG. 3 depicts a second nodal analysis comparing conventional production methods vs. the methods described herein

[0013] FIG. 4 depicts a third nodal analysis comparing conventional production methods vs. the methods described herein.

[0014] FIG. 5 depicts a fourth nodal analysis comparing conventional production methods vs. the methods described herein.

[0015] FIG. 6 shows critical velocities as related to wellhead pressure and flow rate.

DETAILED DESCRIPTION

[0016] The following description of embodiments provides a non-limiting representative examples referencing numerals to particularly describe features and teachings of different aspects of the invention. The embodiments described should be recognized as capable of implementation separately, or in combination, with other embodiments from the description of the embodiments. A person of ordinary skill in the art reviewing the description of embodiments should be able to learn and understand the different described aspects of the invention. The description of embodiments should facilitate understanding of the invention to such an extent that other implementations, not specifically covered but within the knowledge of a person of skill in the art having read the description of embodiments, would be understood to be consistent with an application of the invention.

[0017] The systems and methods disclosed herein generally relate to systems and methods for increasing hydrocarbon production from a well by, for example, inducing gas lift and then producing hydrocarbons from the well with an electrical submersible. That is, a process for increasing hydrocarbon production may be employed that uses an electrical submersible pump. The specific electrical submersible pump is not particularly critical and may be any conventional electrical submersible pump known in the art. Particularly suitable electrical submersible pumps are those employing a gas separator such as those described in, for example, U.S. Patent No. 10,822,933 which is incorporated by reference. The electrical submersible pumps used herein may comprise a pump module, a motor such as a permanent magnet motor, and a gas separator between the pump module and motor.

[0018] As is known in the art, typical wells comprise a central tubing within a casing. Advantageously, the processes and systems used herein may induce gas lift in the absence of injecting gas into the well from the surface simply by configuring the electrical submersible pump within the well as described herein. Of course, injecting gas into the well from the surface may further induce gas lift.

[0019] Configuring the electrical submersible pump within the well may be accomplished in any convenient manner so long as the desired gas lift effect is achieved. In some cases the configuring step may comprise suspending the electrical submersible pump from the central tubing such that reservoir fluid is produced up the central tubing and a mixture comprising reservoir gas and reservoir fluid is produced up the annulus. As used herein reservoir gas may comprise a hydrocarbon, carbon dioxide, other gases, and mixtures thereof. The present methods and systems are typically employed to induce gas lift without injecting gas into the well from the surface. However, if gas has been previously injected, then it may also form a portion of reservoir gas.

[0020] The configuring step may comprise suspending the electrical submersible pump from the central tubing such that velocity of a gas separated by the gas separator is preferably above a critical velocity for the well. Critical velocity may vary depending upon such factors as cross-sectional flow area, wellhead pressure, and the like as shown in Figure 6. Thus, to achieve a condition where the velocity of gas separated by the gas separator is above a critical velocity the critical velocity may somehow be reduced and/or a velocity of the gas separated by the gas separator may be increased. Generally, it has been discovered that this may be accomplished by configuring the respective geometries (such as shown in Figures 1A-1C) within the pump to overcome and/or ensure the gas velocity is at equal to or above the critical velocity of reservoir fluid. In this manner the velocity of gas up the annulus (with or without added tubing strings) is sufficient to lift reservoir fluid up the annulus with the gas (which annulus may have one or more additional tubing strings within it). It has been discovered that critical velocity is related to, for example, a cross-sectional area of clearance between a central tubing (and the sum of any additional tubing strings), if employed, as well as perhaps wellhead pressure and to a lesser extent perhaps density of any reservoir fluid.

[0021] In some embodiments the gas lift effect herein is advantageously induced in the absence of injecting gas into the well from the surface. That is, a clearance between the central tubing (including any additional tubing strings) and the casing is sufficient to achieve and/or induce a desired gas lift effect. This may be accomplished in many different manners depending upon the specific electrical submersible pump, casing, tubing, and other parameters. In some embodiments it has been found that the pump, casing, central tubing and, if present, any additional tubing strings, should be configured such that the casing clearance wherein the pump is suspended is less than about 30%, or less than about 25%, or less than about 20%, or less than about 18%, or less than about 15%, or less than about 10%, or less than about 8% of

the casing diameter. In the cases wherein one or more additional tubing strings are employed into the annulus that extend at least from a surface into the well and terminate uphole from the electrical submersible pump, then the sum of diameters of the central tubing and the one or more additional tubing strings is usually less than about 30% less, or than about 25%, or less than about 20%, or less than about 18%, or less than about 15%, or less than about 10%, or less than about 8% of the casing diameter uphole from the electrical submersible pump. In this manner, at least a portion of the mixture comprising reservoir gas and reservoir fluid produced up the annulus may pass through, if present, the one or more, e.g., two, three, or four or more additional tubing strings. It is not particularly critical where any additional tubing strings that extend into the annulus terminate so long as they terminate uphole of the electrical submersible pump as shown in Figure 1B and 1C. In some embodiments, it may be desirable to have the additional tubing terminate uphole and close to the electrical submersible pump, e.g., within 500 feet, or within 400 feet, or within 300 feet, or within 200 feet, or within 100 feet, or within 50 feet, or even closer depending upon the well configuration and parameters.

[0022] While not wishing to be bound to any particular theory it is believed that the “tighter” configuration, for example, less than about 30% clearance described above, facilitates gas lift up the annulus which may include one or more 2nd flow paths which flow paths may be the annulus between the central tubing and casing and, of course, may also include any one or more tubing strings within the annulus. That is, in some cases the annulus between the central tubing and the casing may include a second, and/or third and/or fourth or more tubing strings.

[0023] Advantageously, a desired tighter clearance may be accomplished in a number of ways. For example, as shown in Figure 1A, the desired casing clearance may be configured by selecting the pump diameter at an appropriate location, e.g., at or above the ESP gas separator in this instance, such that flow path 2 in Figure 1A (the annulus between the tubing

and casing) adjacent the pump is within the desired casing clearances described above. Alternatively or additionally, desired casing clearances may be accomplished by employing additional tubing strings, e.g., one, or two, or three or more additional tubing strings. Figure 1B shows the casing clearance configured for the desired tighter fit in the region of a second tubing which creates at least one flow path 2 for enhancing gas lift.

[0024] Figure 1C shows a casing clearance configured for the desired tighter fit in the region of a second, third, and/or fourth or more tubing which creates additional flow paths 2 or more for enhancing gas lift. In the case of adding a second, third, and/or a fourth or more tubing string each tubing string may be of the same diameter in cross-section and length and/or of different diameters and lengths so long as the desired gas lift effect is achieved due to the casing clearance and/or annulus describe above. In some specific embodiments the second, third, and/or a fourth tubing string are uphole from the pump and up to all of the tubing strings may be smaller in cross-section than the central tubing from which the pump is suspended. In most circumstances hydrocarbon fluids are produced up the tubing on which the pump is suspended while reservoir fluid, reservoir gas, and mixtures thereof are produced up the annulus between the tubing and the casing which annulus may include the one or more added tubing strings such as those shown in Figures 1B and 1C.

[0025] Advantageously, using the configurations described herein hydrocarbons produced from the well may be at least about 3%, or at least 5%, or at least 10%, or at least 20%, or more than a comparable process without the configuring step as shown in the data below. Similarly, horsepower or energy consumed for the production process may be diminished by at least 5%, or at least 10%, or at least 20% or more than a comparable process without the configuring step or other methods and systems described herein. In some embodiments, hydrocarbons produced from a well configured as described herein may be about the same or more than a comparable

process without the configuring step wherein the comparable process uses more horsepower over the time of a given ESP run.

[0026] The table below shows representative casing and tubing sizes that may be employed in combination to induce gas lift. The casing clearance as a percent of the casing diameter is shown in the “clearance” column.

[0027]

Casing		Tubing		Clearance	
Size	ID (in)	Size	OD (in)	(in)	(% of Dc)
7.000" 26.00 ppf	6.276	3.500" 9.30 ppf	3.500	1.3880	22.1%
7.000" 26.00 ppf	6.276	2.875" 6.50 ppf	2.875	1.7005	27.1%
5.500" 17.00 ppf	4.892	2.875" 6.50 ppf	2.875	1.0085	20.6%
5.500" 17.00 ppf	4.892	2.375" 4.70 ppf	2.375	1.2585	25.7%
5.000" 15.00 ppf	4.408	2.375" 4.70 ppf	2.375	1.0165	23.1%

[0028] **Example 1:** The methods described above are employed on a well with the parameters shown in the table below.

[0029] Well Parameters

Perf Datum:	11,300' TVD
Kick Off Point:	10,850' TVD
Casing:	7.000" 20 ppff
ESP Tubing:	2.875" 6.5 ppf
Dual Lift Tubing:	2.375" 4.7 ppf
Est. Reservoir Pressure:	5400 PSI
ESP Description:	528 stages of 3000 Barrels Per Day pump stage

[0030] Well Productivity Test

WH Pressure:	800 PSI
Oil Rate:	875 BPD
Water Rate:	1105 BPD
Gas Rate:	1000 MCF
Test BH Flowing Pressure:	3900 PSI

[0031] Potential horsepower savings using the methods described herein on the well described above is shown below.

Dual Lift Example - HP Savings Projection										
Est. Reservoir Pressure (PSI)	Total Fluid Prod (BPD)	Total Gas Prod (MCFD)	PIP (PSI)	Gas Takeaway - Dual Lift String (MCFD)	Fluid Takeaway - Dual Lift String (%)	Power Requirements - ESP Only (Freq) (HP)		Power Requirements - Dual Lift (Freq) (HP)		HP Reduction %
5400	3000	1650	2650	165	0	57	225	57	225	0
4600	3000	1800	1800	774	20	63	311	56	221	29
4000	2500	1750	1350	1050	12	62	300	58	244	19
3000	2000	1400	1000	840	5	60	269	59	254	6
2200	1500	1050	680	840	4	59	249	59	249	0
1700	1000	700	640	560	3	56	211	56	206	2

[0032] Potential production increase using the methods described herein on the well described above is shown below.

Dual Lift Example – Production Uplift								
Est. Reservoir Pressure	Total Fluid Prod - ESP Only	Total Fluid Prod - Dual Lift	Total Gas Prod	PIP	Gas Takeaway - Dual Lift String	ESP Power Requirements		Production Uplift
(PSI)	(BPD)	(BPD)	(MCFD)	(PSI)	(MCFD)	(Freq)	(HP)	%
5400	3000	3000	1650	2650	165	57	225	0
5200	3000	3600	2160	1800	929	63	311	20
4100	2500	2800	1960	1350	1176	62	300	12
3100	2000	2100	1470	1000	882	60	269	5
2400	1500	1560	1092	680	874	59	249	4
1700	1000	1030	721	640	577	56	211	3

[0033] Figures 2 and 3 show a nodal analysis comparing conventional production methods vs. the methods described herein. As shown in Figure 2 employing the methods and systems described herein may result in reduced energy requirements while Figure 3 shows employing the methods and systems described herein may additionally or alternative result in increased production.

[0034] **Example 2:** The methods described above are employed on a well with the parameters shown in the table below.

[0035] Well Parameters

Perf Datum:	9,950' TVD
Kick Off Point:	9,250' TVD
Casing:	5.500" 23 ppff
ESP Tubing:	2.875" 6.5 ppf
Dual Lift Takeaway:	5.5"x 2.875" Annulus
Est. Reservoir Pressure:	4000 PSI
ESP Description:	268 stages of 4000 Barrels Per Day

[0036] Well Productivity Test

WH Pressure:	400 PSI
Oil Rate:	600 BPD
Water Rate:	3400 BPD
Gas Rate:	1500 MCF
Test BH Flowing Pressure:	2800 PSI

[0037] Potential horsepower savings using the methods described herein on the well described above is shown below.

[0038]

PIP (PSI)	Gas Takeaway - Dual Lift String (MCFD)	Fluid Takeaway - Dual Lift String (%)	Power Requirements - ESP Only		Power Requirements - Dual Lift		HP Reduction %
			(Freq)	(HP)	(Freq)	(HP)	
2170	1350	53	60	258	40	68	74
1700	1440	44	63	296	50	125	58
1540	1440	41	60	249	53	143	43
1400	1440	39	60	246	54	143	43
1100	1260	23	62	249	61	201	18
850	1080	13	65	249	65	241	3

[0039] Potential production increase using the methods described herein on the well described above is shown below.

Est. Reservoir Pressure (PSI)	Total Fluid Prod - ESP Only (BPD)	Total Fluid Prod - Dual Lift (BPD)	Total Gas Prod (MCFD)	PIP (PSI)	Gas Takeaway - Dual Lift String (MCFD)	ESP Power Requirements		Production Uplift %
						(Freq)	(HP)	
4000	4000	5200	2300	1700	2070	63	296	58
3800	3800	4500	2250	1540	2025	61	250	58
3400	3400	3900	2200	1400	1980	60	250	58
2600	2600	2950	1700	1100	1530	61	250	58
2000	2050	2250	1700	850	1530	63	250	58

[0040] Figures 4 and 5 show a nodal analysis comparing conventional production methods vs. the methods described herein. As shown in Figure 4 employing the methods and systems described herein may result in reduced energy requirements while Figure 5 shows employing the methods and systems described herein may additionally or alternatively result in increased production.

[0041] In the preceding specification, various embodiments have been described with references to the accompanying drawings. It will, however, be evident that various modifications and changes may be made thereto, and additional embodiments may be

implemented, without departing from the broader scope of the invention as set forth in the claims that follow. The specification and drawings are accordingly to be regarded as an illustrative rather than restrictive sense.

WE CLAIM:

1. A process for increasing hydrocarbon production using an electrical submersible pump comprising:

configuring an electrical submersible pump comprising a gas separator to induce a gas lift effect in a well wherein the well comprises a central tubing within a casing such that an annulus is formed between the central tubing and the casing; and

producing hydrocarbons from the well with the electrical submersible pump such that reservoir fluid is produced up the central tubing and a mixture comprising reservoir gas and reservoir fluid is produced up the annulus.

2. The process of claim 1 wherein the configuring step comprises suspending the electrical submersible pump from the central tubing such that velocity of a gas separated by the gas separator is above a critical velocity of reservoir fluid.

3. The process of claim 1 wherein the gas lift effect is induced in the absence of injecting gas into the well from the surface.

4. The process of claim 1 wherein the configuring step comprises suspending the electrical submersible pump from the central tubing such that the central tubing within the casing comprises a clearance which is less than about 30% of the casing diameter uphole from the electrical submersible pump.

5. The process of claim 1 wherein the configuring step comprises suspending the electrical submersible pump from the central tubing such that the central tubing within the casing comprises a clearance which is less than about 20% of the casing diameter uphole from the electrical submersible pump.

6. The process of claim 1 wherein the configuring step comprises suspending the electrical submersible pump from the central tubing and employing one or more additional tubing strings into the annulus that extend at least from a surface into the well and terminate uphole from the electrical submersible pump wherein the sum of diameters of the central tubing and the one or

more additional tubing strings is less than about 30% of the casing diameter uphole from the electrical submersible pump.

7. The process of claim 1 wherein the configuring step comprises suspending the electrical submersible pump from the central tubing and employing one or more additional tubing strings into the annulus that extend at least from a surface into the well and terminate uphole from the electrical submersible pump wherein the sum of diameters of the central tubing and the one or more additional tubing strings is less than about 30% of the casing diameter uphole from the electrical submersible pump.

8. The process of claim 6 wherein the mixture comprising reservoir gas and reservoir fluid is produced up the annulus wherein at least a portion of the mixture comprising reservoir gas and reservoir fluid produced up the annulus passes through the one or more additional tubing strings.

9. The process of claim 6 wherein the one or more additional tubing strings comprise a smaller diameter than the central tubing.

10. The process of claim 1 wherein the separation efficiency of the gas separator is from about 60 to about 100%.

11. The process of claim 1 wherein the electrical submersible pump has an intake pressure below the bubble point of the reservoir.

12. The process of claim 1 wherein the hydrocarbons produced from the well are at least 5% or more than a comparable process without the configuring step.

13. The process of claim 1 wherein the hydrocarbons produced from the well are about the same or more than a comparable process without the configuring step wherein the comparable process uses at least 6% or more horsepower over the ESP run.

14. The process of claim 1 wherein the hydrocarbons produced from the well are at least 5% or more than a comparable process without the configuring step and wherein the hydrocarbons produced from the well are about the same or more than a comparable process

without the configuring step wherein the comparable process uses at least 6% or more horsepower over the ESP run.

15. A system for increasing hydrocarbon production using an electrical submersible pump comprising:

a well comprising a central tubing within a casing wherein the central tubing comprises a fluid exit opening near a surface of the well and a fluid entrance opening downhole;

an electrical submersible pump suspended from the fluid entrance opening of the central tubing;

wherein the electrical submersible pump comprises a pump operably connected to the fluid entrance opening of the central tubing, a gas separator operably connected to the pump, and a motor operably connected to the gas separator;

wherein the system is configured to produce reservoir fluid up the central tubing and to produce a mixture comprising reservoir fluid and reservoir gas up an annulus between the central tubing and the casing; and

wherein the system is configured to induce a gas lift effect in the absence of injecting gas into the well from the surface.

16. The system of claim 15 which further comprises: one or more tubing strings uphole from the electrical submersible pump wherein the one or more tubing strings are in the annulus between the casing and the central tubing wherein the one or more tubing strings are configured to produce a mixture comprising reservoir fluid and reservoir gas up the annulus through the one or more tubing strings.

17. The system of claim 16 wherein the one or more tubing strings are smaller in cross-section than the central tubing.

18. The system of claim 15 wherein the system is configured such that velocity of a gas separated by the gas separator is above a critical velocity of reservoir fluid.

19. The system of claim 15 wherein the central tubing within the casing comprises a clearance which is less than about 30% of the casing diameter uphole from the electrical submersible pump.

20. The system of claim 15 wherein the central tubing within the casing comprises a clearance which is less than about 30% of the casing diameter uphole from the electrical submersible pump.