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Evaluation of tubing diameter and bean size for optimization of well production rate

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Abstract

Gas field development is a costly affair, thus it is essential that each component of the production system operates properly. The objective of field optimization is to discover the parameter range that maximizes productivity. In addition, the development of natural gas reserves for both fuel and petrochemical purposes is accelerating. Well X is an approximately 4-year-old natural-flow gas well with a gas flowrate of 7.7 MMSCF/D, condensate flowrate of 55 BCPD, and water flowrate of 2 BWPD. As fluid is generated from the reservoir to the surface, the production rate of the well decreases. This well's productivity was evaluated using nodal analysis in conjunction with a comparison of tubing size and bean size aiming to satisfy gas demand without exceeding the critical limit. The nodal analysis approach is utilized to determine the well's optimal and efficient performance. Moreover, utilizing system analysis, which is a graphical plot between the tubing size and the resulting flow rate, as depicted in Fig. 6, we can determine which tubing size delivers the highest or most efficient rate at a particular moment under constant wellhead pressure (node at the wellhead). If the demand grows by 14.4 MMSCF/D, the installed tube size can be changed to 40/64" for optimization purposes. This procedure is more cost-effective because it does not squander money and does not halt gas production at the well. To satisfy the increased gas demand of 14.4 MMSCF/D, the production operator can rotate the bean or choke from its initial 24/64" size to 40/64" size.

Keywords:

Optimum tubing size, choke, production rate, gas field.

1 Introduction

Gas well fields are absolutely vital in the industrialized world, because the output of these wells may be converted into numerous high-value goods. As oil reserves diminish, natural gas becomes a more lucrative option. Typically, fluid production from a well can flow to the surface due to reservoir pressure and natural push (Pr). As a result of continual production, the reservoir pressure will progressively decline to the point where it can no longer force the fluid to the surface. It is vital to optimize production in order to prevent the reservoir pressure from falling significantly. This can be accomplished using a well productivity study that tries to establish the well's potential to produce and aids in determining the flow rate for natural flow and artificial lift wells [1]. Optimization of oil and gas well production using well optimization has contributed to better efficiency and higher production [2]. The method used is a modeling technique to assess all elements of the production system. This procedure often identifies possible modifications to the well that if performed would result in higher flow rates [3].

Actual inflow performance shows a linear relationship between wellhead pressure and production rate [4]. However, utilizing systematic numerical modeling, nodal system analysis was created to optimize production and reservoir sustainability. Nodal system analysis evolved into a system approach for optimizing oil and gas well production operations by evaluating the entire well production system holistically [5]. It involves correlations to estimate multiphase flow behavior through pipelines, well completions components, restrictions due to skin and reservoir factors to analyze production inflow and outflow performance [6]. A non-linear relationship curve between inflow and outflow performance in multi-phase flow behavior was obtained.

Planning the production system is an integral aspect of the oil and gas field development process. Its purpose is to carry the fluid from the reservoir to the surface facilities and export point. A production system may be a basic system with minimal pressure loss, or it may be a rather complicated system with numerous pressure-loss-causing components [7]–[9]. As a result of the compressibility of the fluids generated by oil and gas activities, the pressure drop is influenced by the interaction between the system's numerous components. This is due to the fact that the pressure drop in a specific component is dependent on the flow rate and average pressure through that component [10]. Pressure drops in liquid lifting from the bottom of the well to the surface can reach 80% of the total pressure drop in oil and gas well systems. Many oil well systems have performed tubing size optimization.

The selection of production tube diameters that can handle the ideal flow rate, both when the well is able to flow naturally and utilizing artificial lift methods, is one of the crucial phases in the production system. During the well's flowing production stage, sensitivity analysis on various tubing diameters is typically conducted utilizing nodal analysis to perform optimal tubing selection (OTS) [11].

Because too-small tubing increases friction resistance and results in excessive flow velocity, it will slow down production. On the other hand, excessively large tubing sizes will result in excessive liquid phase loss as a result of the surface slippage effect brought on by excessive downhole liquid loading during lifting. As a result, it is necessary to do a sensitivity analysis of the tubing size. Use of nodal analysis is one of them.

IPR and TPR are two things that are closely related in determining the production rate in a well. Kosmidis et al. [12] focused on the fact that nodal analysis is limited to oil fields with a few wells due to its trial-and-error nature during forecasting. Otherwise, similar to gas lift optimization systems, injection systems and tubing size optimization using nodal analysis have been developed on gas wells as well. Mustafa Al Lawati [13] has investigated a gas lift nodal analysis model, which describes a mature well producing an additional 153 BOPD after the optimization process. Nodal analysis is a combination of Inflow Performance Relationship (IPR) and Tubing Performance Relationship (TPR) curves to obtain the operating flow rate and pressure at a node [14]. Nodal analysis is a commonly used method in production system design, given its proven usefulness and worldwide trustworthiness [15].

In order to maintain the intended production rate from the established nodal analysis curve, the factors that can affect the production rate of gas wells are tubing size and changing to the bean size (choke). When performing a nodal analysis, the bottom hole or wellhead is typically employed as the solution node [1]. It can provide a comprehensive overview of the entire integrated system. Gas well flow rate optimization is required to obtain the desired production rate.

The purpose of this research is to predict the outcome of optimizing the gas production rate by examining the tubing size and bean size in order to meet the spike in consumer gas demand under specific circumstances, which reaches 14.4 MMSCF/D. Additionally, the best rate of gas production is sought after by taking into account the well's capacity from an assessment of the tubing size and bean size variable.

2 Materials and methods

2.1 Production data

Gas well "X" at the time of well testing obtained data as shown in Table 1. The reservoir fluid in this gas field is a wet gas dominated by methane gas.

Table 1. Production test data.

Parameters	Value	Unit
Gas flowrate	7.7	MMSCF/D
Condensate	55	BCPD
Water cut	21	%
Reservoir pressure	5023	Psi
Reservoir temperature	338	°F
Wellhead pressure	3000	Psi
Bean size	24/64	Inch
Separator pressure	435	Psi
Separator temperature	145	°F
Flowline length	6	KM
Flowline diameter	6	Inch

In addition, there are impurities in the gas with Hydrogen Sulfide and Carbon Sulfide content in the gas production also quite high as presented in Table 2. With a high H2S content of 5249 ppm.

Table 2. Composition of the production gas content.

Composition	Mol (%)
C1	71.51
C2	2.719
C3	0.986
C4	0.198
C4	0.267
C5	0.097
C5	0.09
C6	0.111
C7	0.191
C8	0.119
C9	0.073
C10	0.043
N2	0.837
C02	22.419
H2S	0.313
H20	0.026

2.2 Model initialization

Well completion design refers to the fluid flow from the reservoir to the wellhead and includes information about the tubing size, hole size, and depth of the gas wellbore. Fig. 1 describes the flowchart diagram for this investigation. So that it can recognize the presence of a large pressure decrease in the well, all data on Fig. 2. By employing compositional fluid type correlation to enter data on the composition of the produced gas, reservoir fluid modeling can be produced so that Fig. 3 shows the phase pattern of the reservoir fluid.

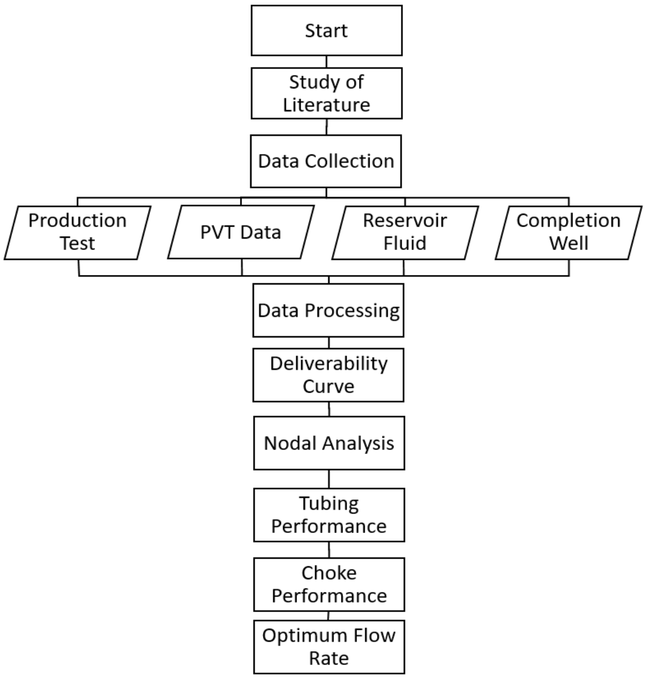

Fig. 1. Research flowchart.

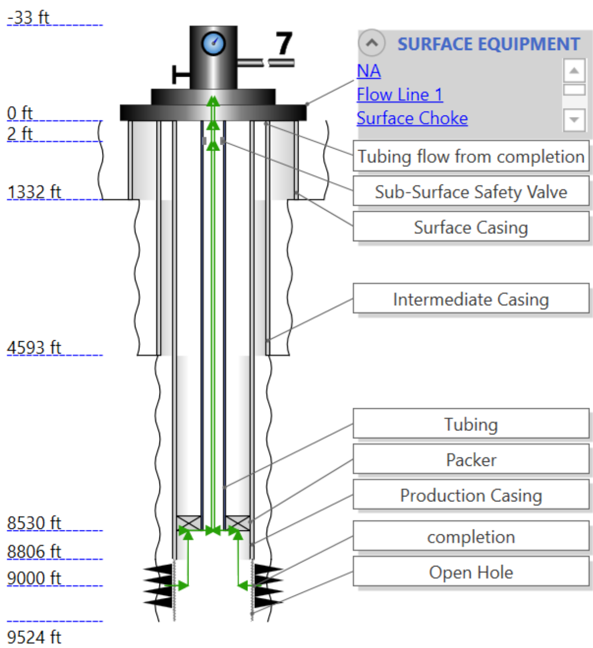

Fig. 2. Modeling of well X completion.

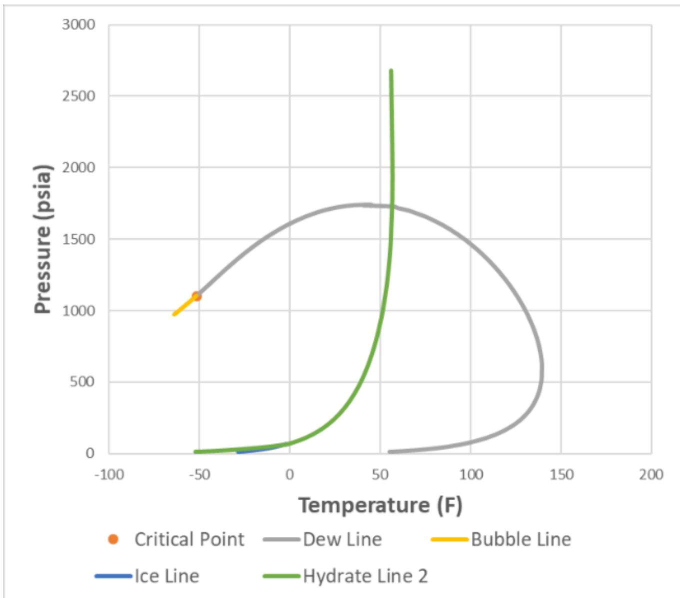

Fig. 3. Phase diagram of the reservoir fluid.

2.3 Data analysis process

The data is used to determine the well's production capability (productivity index) in gas wells using back pressure correlation eq.(1) [16].

$$Q_G = C \cdot (P_{ws}2 - P_{wf}2)^{n} \quad (1)$$

Determine the Inflow Performance Relationship (IPR) and Tubing Performance Relationship (TPR) curves at Fig. 4 for vertical gas wells by using gray correlation in calculating pressure drop eq.(2).

$$144\frac{\Delta p}{\Delta h} = \bar{\rho}_m + \rho_m \frac{f v_m^2}{2 g_c D} + \rho_m \frac{\Delta\left(\frac{v_m^2}{2g_c}\right)}{\Delta h} \quad (2)$$

Based on the results of the IPR and TPR curves, it can be used to estimate the operational points of gas production at the well. This research also uses variations in the size of the tubing inner diameter and bean size to determine the gas production produced in the separator. Bean size or choke size is an important indicator of the productivity of an oil and gas well so sensitivity test studies and choke performance analysis are commonly used to address issues related to increasing production eq.(1), eq.(2) [1], [17].

$$Q_{sc} = 879 C_D A P_{up} \sqrt{\left(\frac{k}{\gamma_g T_{up}}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad (3)$$

$$\Delta P_G = \frac{\rho_n}{2c}\left(\frac{v}{c_v G Z_G}\right)^2 \quad (4)$$

The size of the inner diameter and bean size causes a pressure drop that will pass through the reservoir fluid from the wellbore to the separator. However, the pressure drop in the flowline is not too significant when recalculating. Data processing is carried out using a nodal analysis system located at the wellhead as the node point.

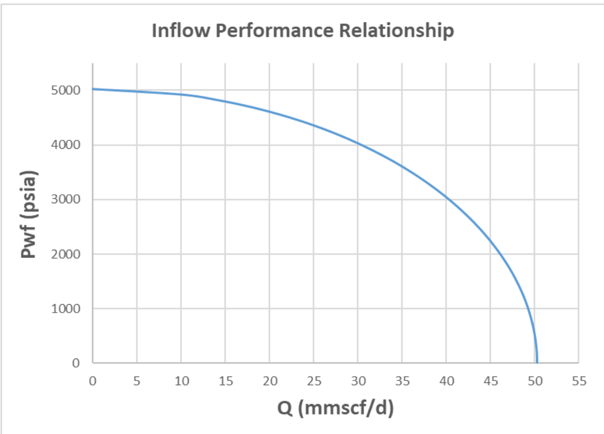

Fig. 4. Inflow performance relationship.

3 Results and discussion

3.1 Simulation result of tubing size

The beginning circumstances are depicted in Fig. 5 at a reservoir static pressure of 5023 psi. Tubing having a diameter of 2.441" and a tubing grade of API Standard L-80 are used to create the gas fluid. The same tube grade, L-80 standard, which meets the specifications for the tubing strength itself, is used in the simulation process along with variations in tubing diameter size. The ID diameters of the tube that are utilized include 1.95 (2-3/8"), 2.441 (2-7/8"), 2.992 (3-1/2"), and 3.34" (4"). The analysis of the well's operational points for gas production rate is accomplished by using bean size. In order to analyze data, bean size employs the same sizes: 20/64, 24/64, 28/64, 32/64, 36/64, 40/64, 44/64, 48/64, 52/64, 56/64, and 64/64. The tubing's surface area leads to pressure drops, which reduce the well's capacity to produce. The pressure drop effect results in resistance to the production fluid due to bean size opening size.

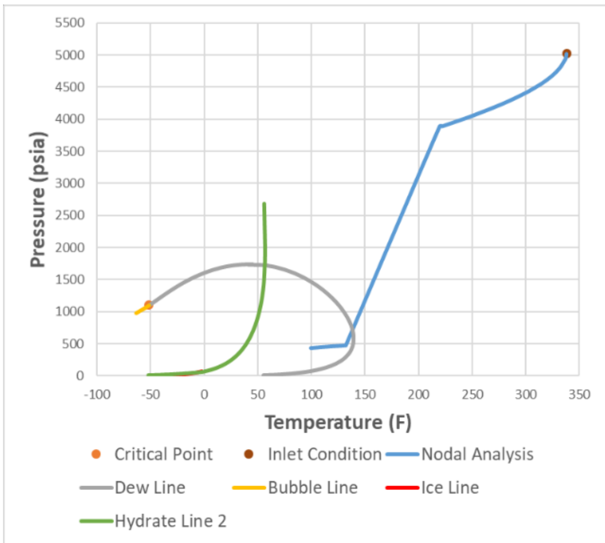

Fig. 5. Phase diagram and pressure path of the reservoir fluid.

Based on IPR data, the gas well has a maximum production capacity of 50.23 mmsc/d. The maximum production represents the absolute open flow potential that the gas can produce. Currently, general guidelines which is used for an optimum production rate or Absolute Open Flow (AOF) is 30% of the Absolute Open Flow Potential (AOFP) [18] so that the AOF of the gas well is 15 MMSCF/D.

The simulation results were produced with 1.995-inch ID tubing, as shown in Table 3 and Fig. 6. According to Table 3, bean size 20/64 had the greatest wellhead pressure "with 3635 psia and a 5 MMSCF/D gas production rate. Bean size 64/64 had the lowest wellhead pressure at the same time "with a production rate of 14.7 MMSCF/D at 1060 psia. However, for a bean size of 64/64, it displays 14.7 MMSCF/D, which is nearly the AOF number but has a negative factor at the wellhead itself, where the safety factor will drop.

Table 3. The simulation result of tubing 2-3/8 inch.

Bean size	Operational point	
(inch)	P at NA(psia)	ST gas at NA(MMSCF/D)
20/64	3635	5.0
24/64	3414	6.6
28/64	3140	8.2
32/64	2836	9.7
36/64	2528	10.9
40/64	2233	12.0
44/64	1965	12.8
48/64	1728	13.4
52/64	1522	13.9
56/64	1344	14.2
60/64	1191	14.5
64/64	1060	14.7

The simulation outcomes were obtained using a 2.441-inch tube ID size, as shown in Table 4 and Fig. 7. The wellhead pressure at bean size 20/64", which was 3847 psia, produced gas at a rate of 5.3 MMSCF/D. Bean size 64/64" had the lowest wellhead pressure at 1598 psia and a production rate of 21.9 MMSCF/D. For the 2,441 ID tubing size. It is already in place and capable of meeting the AOF standard; specifically, it generates a value of 15.3 MMSCF/D when the bean size is opened by 40/64 at a pressure of 2912 psia. Due to the gas flow rate exceeding 15 MMSCF/D from the AOF value, formation water output will rise.

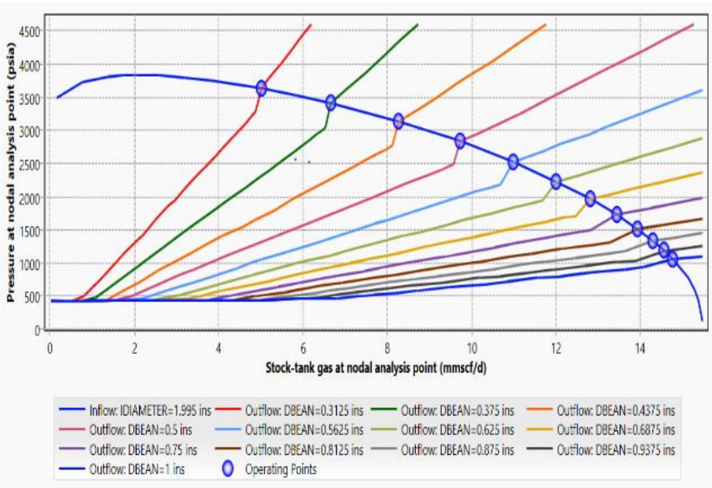

Fig. 6. Graph of operational points at tubing ID 1.995” (2-3/8”).

Table 4. The simulation result of tubing 2-7/8 inch.

Bean size	Operational point	
(inch)	P at NA(psia)	ST gas at NA(MMSCF/D)
20/64	3847	5.3
24/64	3742	7.2
28/64	3586	9.3
32/64	3388	11.4
36/64	3159	13.4
40/64	2912	15.3
44/64	2659	16.9
48/64	2412	18.3
52/64	2179	19.5
56/64	1965	20.5
60/64	1772	21.3
64/64	1598	21.9

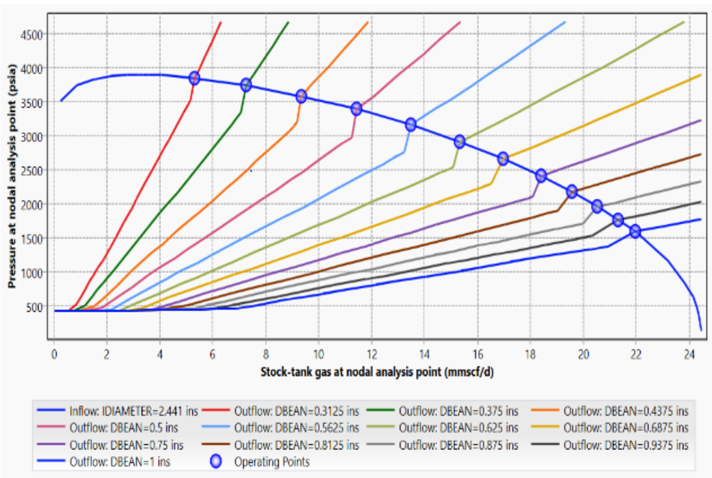

Fig. 7. Graph of operational points at tubing size 2.441” (2-7/8”).

The simulation results were generated with 2.992-inch ID tubing, as shown in Table 5 and Fig. 8. The wellhead pressure at bean size 20/64", which was 3932 psia, produced gas at a rate of 5.4 MMSCF/D. The wellhead pressure with the lowest production rate, 2108 psia at bean size 64/64", was also the lowest. For tube sizes, it is said that the AOF value that is the closest is 14.9 MMSCF/D at a pressure of 3543 psia and a bean size of 36/34. Tubing and bean size can function at their best with that.

The simulation results were obtained using 3.34-inch ID tubing, as shown in Table 6 and Fig. 9. The wellhead pressure at bean size 20/64", which was 3946 psia, produced gas at a rate of 5.5 MMSCF/D. Bean size 64/64" had the lowest wellhead pressure at 2314 psia and a production rate of 31.2 MMSCF/D. Due to the gas flow rate exceeding 15 MMSCF/D from the AOF value, formation water output will rise.

Table 5. The simulation result of tubing 3-1/2 inch.

Bean size	Operational point	
(inch)	P at NA(psia)	ST gas at NA(MMSCF/D)
20/64	3932	5.4
24/64	3893	7.6
28/64	3813	9.9
32/64	3696	12.4
36/64	3543	14.9
40/64	3362	17.5
44/64	3160	19.9
48/64	2945	22.1
52/64	2725	24.1
56/64	2509	25.8
60/64	2302	27.3
64/64	2108	28.5

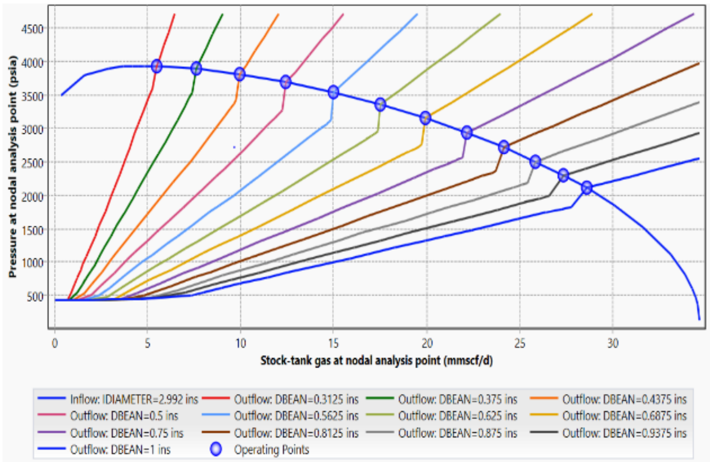

Fig. 8. Graph of operational points at tubing size 2.992” (3-1/2”).

Table 6. The simulation result of tubing 4 inch.

Bean size	Operational point	
(inch)	P at NA(psia)	ST gas at NA(MMSCF/D)
20/64	3946	5.5
24/64	3930	7.7
28/64	3875	10.1
32/64	3785	12.7
36/64	3662	15.4
40/64	3508	18.2
44/64	3330	20.9
48/64	3134	23.4
52/64	2928	25.7
56/64	2718	27.8
60/64	2512	29.6
64/64	2314	31.2

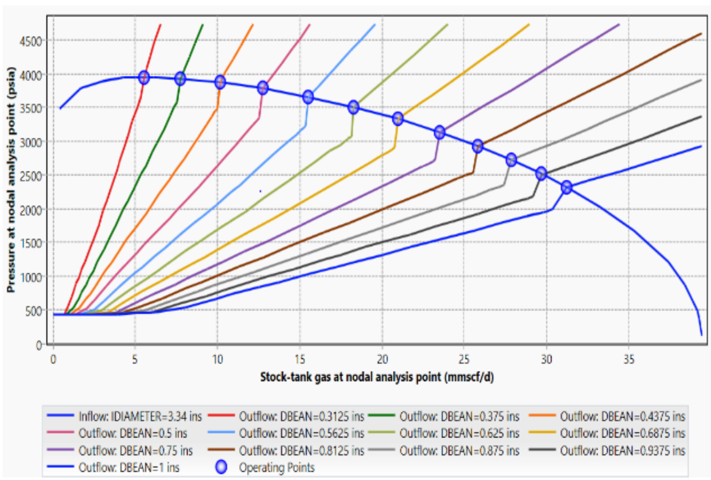

Fig. 9. Graph of operational points at tubing size 3.34” (4”).

3.2 Bean size and tubing size correlation

In this scenario, multiple tubing diameters were tested for sensitivity to determine the flow rate for each tubing size. The next step is to identify the tube size that offers the best flow rate. If the TPR and IPR still cross, then the fluid can still flow through that size of tubing; but, if they no longer do so, then there is no flow possible with that size of tubing. It becomes important to utilize an artificial lift method when flow can no longer be achieved at a given time with a specific reservoir pressure and specific tubing size.

Tubes are utilized for the assessment. The maximum production from the inner diameter of the tubing, which is 1.995 inches based on the AOF value, is insufficient to produce wells at their greatest potential. This is because the tube has the smallest surface area and experiences the most pressure drop when the choke is fully opened. Based on the principle of nodal analysis, the biggest pressure drop will result in a reduction in the gas flow rate from the reservoir.

When the bean size and the diameter inside the various tubing are the same, the rate of gas generation will vary, as shown in Table 7 and Fig. 10, which is caused by the area of the tubing diameter. Where the inner diameter of the tubing is increased, the rate of gas flow increases. At bean diameters 20/64" and 24/64", the gas flow rate did not significantly deviate from the flow rate of each tube. However, the 64/64 bit size "Bean revealed a notable difference. The inner diameter tubing of 1.991" and the size of the inner diameter of the tubing 2.991" and 3.34" explain a low increase in addition to the increase in flow rate followed by an increase in bean size" showed a minimal increase. It is advised that the inner diameter of the tubing be increased from the current inner diameter tubing size of 2.441 inches to 2.991 inches if we want to change it to boost the flow rate of gas production.

Table 7. Comparison of bean size and tubing size to production rate.

Bean size (inch)	Production rate (MMSCF/D)			
	2-3/8"	2-7/8"	3-1/2"	4"
20/64	5.0	5.3	5.4	5.5
24/64	6.6	7.2	7.6	7.7
28/64	8.2	9.3	9.9	10.1
32/64	9.7	11.4	12.4	12.7
36/64	10.9	13.4	14.9	15.4
40/64	12.0	15.3	17.5	18.2
44/64	12.8	16.9	19.9	20.9
48/64	13.4	18.3	22.1	23.4
52/64	13.9	19.5	24.1	25.7
56/64	14.2	20.5	25.8	27.8
60/64	14.5	21.3	27.3	29.6
64/64	14.7	21.9	28.5	31.2

A lesser pressure drop due to the tubing's somewhat greater inner diameter will result in less resistance or burden being placed on the reservoir's ability to create gas for the surface. Using an inner diameter of 3.34 inches, the tubing has a production rate interval and wellhead pressure that are relatively higher because the pressure drop at each bean size is relatively smaller, resulting in a high productivity index for the gas well. Until the size of the tube reaches the maximum flow rate, which is represented by a flat trend when the flow rate includes critical flow, the rate of gas production can still increase.

The maximum tubing flow rate for a tubing inner diameter of 1.995 inches will be demonstrated by a production rate graph that is approaching a flat trend. In order to achieve the optimum production rate in accordance with the productivity index of the gas well, the tubing's inner diameter should be 2.991 inches with a bean size of 36/64 inches of 14.9 MMSCF/D, which is approaching the AOF value of 15 MMSCF/D. This evaluation's findings will help determine the ideal tubing size for reservoir conditions.

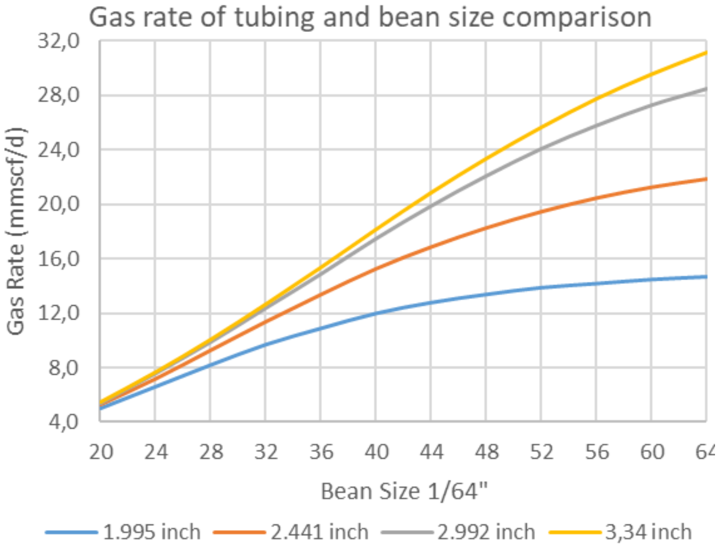

Fig. 10. Comparison of bean size and tubing size to production rate.

According to the research mentioned above, the pressure drop that happens down the tubing to the wellhead causes the ID diameter of the tubing to have an impact on the production rate. In comparison to lower tubing ID, there is less pressure drop along the tube with greater tubing ID.

Table 8. Comparison of bean size and tubing size to wellhead pressure.

Bean size (inch)	Wellhead pressure (psi)			
	2-3/8"	2-7/8"	3-1/2"	4"
20/64	3635	3847	3932	3946
24/64	3414	3742	3893	3930
28/64	3140	3586	3813	3875
32/64	2836	3388	3696	3785
36/64	2528	3159	3543	3662
40/64	2233	2912	3362	3508
44/64	1965	2659	3160	3330
48/64	1728	2412	2945	3134
52/64	1522	2179	2725	2928
56/64	1344	1965	2509	2718
60/64	1191	1772	2302	2512
64/64	1060	1598	2108	2314

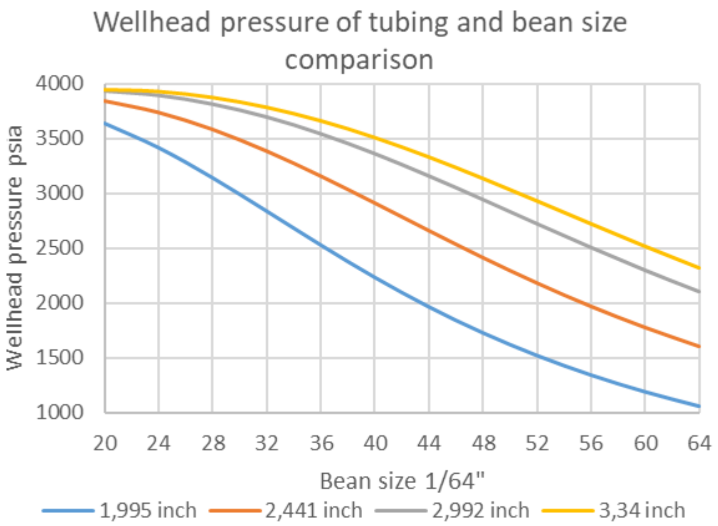

Fig. 11. Comparison of bean size and tubing size to wellhead pressure.

Under normal conditions, gas well "X" produces 7.2 MMSCF/D of gas at 2.441" tubing size and 24/64" bean. However, under certain conditions, gas demand surged to 14.4 MMSCF/D.

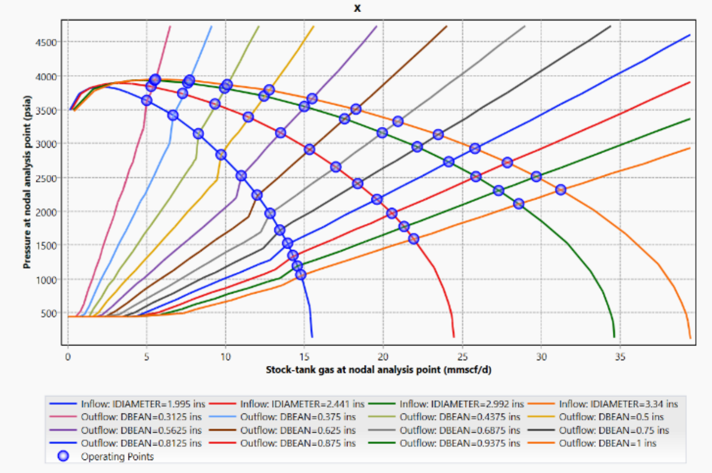

Fig. 12. Operational graph of gas production rate points with variation of tubing size and bean size of well X.

4 Conclusion

The pressure drop parameter has the greatest impact on the output rate. Since pressure drop and production rate are negatively correlated, a higher pressure drop results in a lower production yield. Conversely, the manufacturing yield increases as the pressure drop decreases. The anticipated output rate may be obtained utilizing a tubing size of 2.441" and a bean size of 40/64 if consumer consumption increases by more than 14.4 MMSCF/D. This process is more cost-effective since it avoids expenses like rig rental, tubing replacement, deadly mud, and others. Additionally, gas well "X" production is not stopped.

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