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A Successful Experience in Optimization of a Production Well in a Southern Iranian Oil Field

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Abstract
Production optimization ensures that wells and facilities are operating at their peak performance at all times to maximize production. This paper describes a procedure, to develop Inflow Performance Curves, Tubing Performance Curves and Choke Performance Curves, for one of the Iranian southern oil wells, from the results of a multiphase flow simulator (PIPESIM). The goal of this project is to optimize the production from one of the southern Iranian oil fields. Increasing the choke size leads to maximizing production, and causes an optimum reduction in wellhead pressure and bottomhole flowing pressure. Controlling flow patterns in all sensitivity analysis play a major role in selecting the proper variables. Using 7in. OD tubing size rather than 9 5/8 in. casing size and selecting 9/16 in. choke size rather than 7/16 in., the wellhead pressure between 700 to 1180 psia will be the result and optimum range in selected well No. 305b. The results show a successful experience in optimization of well No.305b and the production can be increased from 2000 BOPD to 3150 BOPD.

Keywords: *Nodal Analysis, Choke, Tubing, Flow Patterns, IPR, TPC*

Introduction
A valuable history description and a complete review of optimization methods used in reservoir development are presented in reference [1]. Operation such as drilling scheduling, well placement, and production rate scheduling, have been an active area for optimization. Early optimization studies featured simple reservoir models and linear programming techniques. Aronofsky and Lee built a linear programming model to maximize profit by scheduling production from multiple homogeneous reservoirs [2]. Bohanon presented a linear programming model to find the optimum 15-years development plan for a multi-reservoir pipeline system [3]. McFarland et al applied a generalized reduced gradient nonlinear programming method to maximize the present value of profits from a reservoir by deciding how many wells to drill in each time period, the production rates, abandonment time, and platform size [4]. Palke and Horne used a generic algorithm to

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estimate the cost of uncertainty in reservoir data [1], [5], [6]. A method called Process Optimization Review is used in production operation to identify opportunities to increase profitability while reducing green house gases such as methane [7]. Muskat and Wyckoff show that the proper selection of the producing interval within the water zone is done either by selective perforating or by the depth to which the well should penetrate the oil zone. They show that elevation of oil-water interface (cone) is due to producing gradient [8 and 9]. The results of the Thomas study show the effect of various well parameters such as well length, anisotropy ratio, and skin and perforation distribution on the inflow performance of the horizontal well [10]. The path of success in the Issaran field with a heavy oil and low flow rate began with the definition of the reservoir flow mechanism, optimized perforating schemes, enhanced carbonate stimulation and improved completion designs [11]. Clark presents a significantly improved simple method to predict future oil well deliverability and inflow performance relationship. He reduced the error by the new approach from 117% to 9% [11]. Lee and Brown [12] used Nodal analysis to find the best production value in each well.

Nodal analysis is defined as a system approach to the optimization of oil and gas wells, used to evaluate thoroughly a complete producing system. The procedure consists of selecting a division point or node in the well and dividing the system at this point [13]. Its application to well producing systems was first proposed by Gilbert [14] and discussed by Nind [15] and Brown [16]. All components beginning with the static reservoir pressure, and ending with the separator were analyzed. Important completion parameters can be entered, and varied, to enable the assessment of their contribution to the overall performance of the completion system. Selection of correct tubing size is important for maintaining an economical flow rate for the desired production period. Several correlations for tubing performance are in use in the petroleum industry [17 and 18]. Brown [19], in a widely used work, outlined the procedure for pressure drop calculations in production strings. The choke was designed to control the production rate from a well. Sachdeva [20] modelled the wellhead choke as a pipe restriction. This model is capable of modeling critical and subcritical flow. In critical flow, the flow rate through the choke reaches a maximum value with respect to the upstream conditions and the fluids equal or exceed the speed of sound. For subcritical flow, the flow velocity is less than the speed of sound and the flow rate depends upon the pressure drop through the device, and changes in the upstream pressure affect the downstream pressure. Wellhead choke is usually selected so that the fluctuations in the line pressure downstream of the choke have no effect on the well flow rate. To ensure this condition, flow through the choke must be at critical flow conditions; that is, flow through the choke is at the acoustic velocity. For this condition to exist, downstream line pressure must be approximately 0.55 or less of the tubing or upstream pressure. Under this condition, the low flow rate is a function of the upstream or tubing pressure only [22].

Whenever two fluids with different physical properties flow simultaneously in a pipe, there is a wide range of possible flow patterns. Many investigators such as Mukherjee and Brill [21] have attempted to predict the flow pattern that will exist for various flow conditions. This is particularly important as the liquid holdup is found to be dependent on the flow pattern. In recent studies, it was confirmed that the flow pattern is also dependent on the angle of inclination of the pipe and direction of flow (e.g., production or injection). The flow capacity of the tubing and perforations always should be greater than the inflow performance behavior of the reservoir.

An increase in the wellhead pressure ordinarily results in a disproportionate increase in the bottom hole pressure because the higher pressure in the tubing causes a more liquid-like fluid and a larger hydrostatic pressure component (density is higher) [23].

This paper describes a procedure to develop Inflow Performance Curves, Tubing Performance Curves and Choke Performance Curves, for one of the Iranian southern oil wells from the results of a multiphase flow simulator (PIPESIM). Pressure drop, fluid properties and related changes in the well column, Inflow Performance Curve, and Tubing Performance Curve, are evaluated. Studying the flow regime changes in the well column is also considered. Liquid regime (single phase) has priority in selecting each variable and it is presented in each sensitivity analysis. Finally, optimizing the surface choke size, tubing size, and choosing the proper well head pressure are conducted by doing sensitivity analysis in this paper.

Material and method

Productivity index and inflow performance relationship

A commonly used measure of the ability of the well to produce is the productivity index. The inflow performance relationship or IPR is defined as the functional relationship between the production rate and the bottom hole flowing pressure. Equation (1) shows the productivity index for a water-free oil production [22].

$$J = \frac{Q_o}{P_r - P_{wf}} \tag{1}$$

Gilbert 1974 [2] first proposed well analysis using this relationship. IPR is defined in the pressure range as being between the average reservoir pressure and atmospheric pressure.

The productivity index is numerically calculated by recognizing that J must be defined in terms of semi steady-state flow conditions (Equation (2)).

$$J = \frac{0.00708 K_o h}{\mu_o B_o \left[\ln\left(\frac{r_e}{r_w} \right) - 0.75 + s \right]} \tag{2}$$

A straight-line productivity index method is considered adequate in this work because the fluid flows into the completion at the pressure considerably above the bubble point and no gas comes out of the solution at this stage. This applies throughout field life and the productivity index is not expected to change. The PI will not be affected by changes to the reservoir pressure because the reservoir pressure is to be maintained by the water drive mechanism. The PI will not be affected by changes to the water cut through the field life because the oil and water have similar mobilities. The pressure drop across the reservoir is identical for all of the sensitivity cases due to the PI and flow rate being constant.

Well system analysis

The process of optimizing the production of well No. 305b involves first understanding the actual condition. Gathering necessary information to simulate this well include: average reservoir pressure in well drainage data, skin, permeability, bottom hole flowing pressure, well head pressure and other specifications that are needed for the calculation of well performance. Among four correlations; (1) Hagedorn & Brown, (2) Duns & Ros, (3) Govier, Aziz & Forgarasi, and (4) Begs & Brill; the Hagedorn & Brown correlation was the best choice. As shown in Fig. 1, among the mentioned correlations, the Hagedorn & Brown correlation shows the proper estimation of actual flow rate of the selected well. Actual data were used in this simulation so that the bottomhole traverse of the flowing pressure (measured data) is a good match with the Hagedorn & Brown correlation. As shown in Fig. 2, performing wellhead Nodal Analysis is basically a correction of the well design, so that the intersect indicate the actual flow rate and pressure of well No. 305b.

The characteristic 'J' shape of the tubing performance curve (TPC) or outflow curve is due to differences in phase velocities, known as slippage. At low rates, the liquid phase accumulates allowing only gas to flow from the well. As the flow rate increases, the hydrostatic component decreases due to the entrained gas. The minimum (TPC point) occurs as the increased frictional pressure drop exactly offsets the hydrostatic pressure drop.

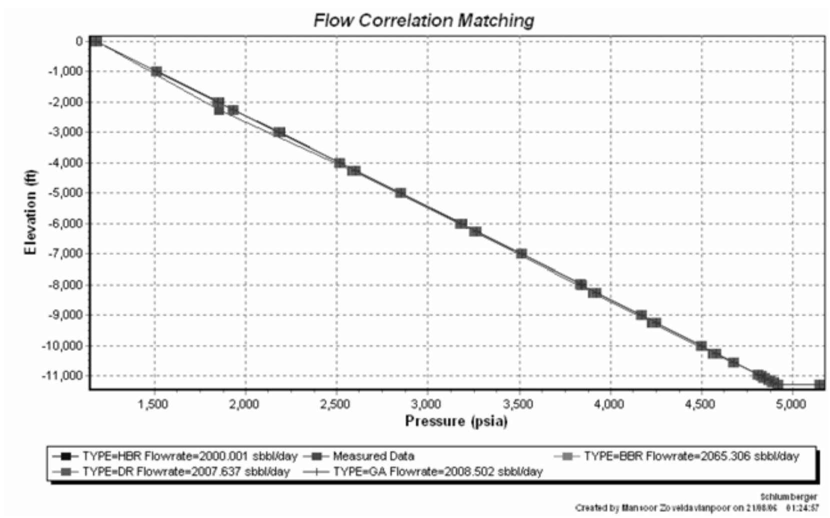

Figure 1. Flow correlation matching for well No.305b.

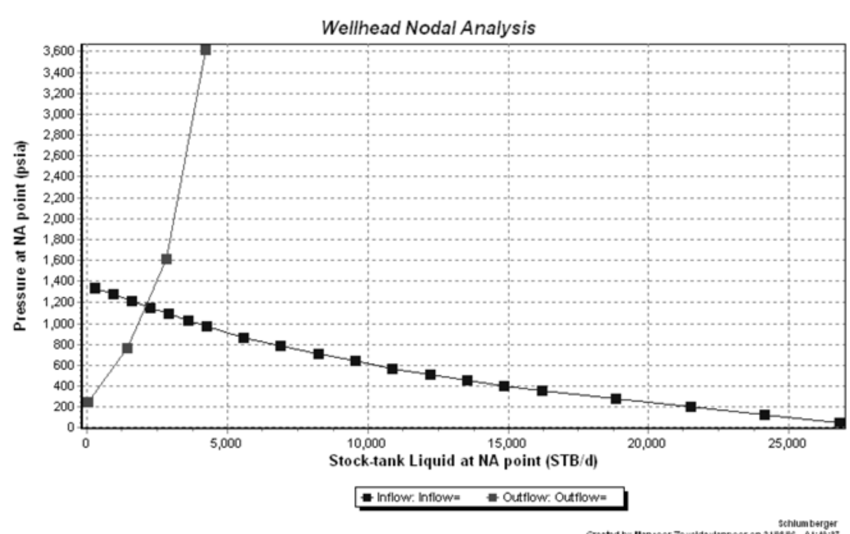

Figure 2. Wellhead Nodal Analysis of well No. 305b.

Nodal analysis

As shown in Fig. 2, as the flow rate increases (on the right side of the outflow curve) the required bottomhole flowing pressure increases, reflecting higher friction pressures at the higher rates. On the left side of the TPC curve, the peculiar shape is due to liquid holdup; lower rates do not have sufficient momentum to purge liquid accumulation in the well, resulting in an unavoidable increase in the hydrostatic pressure. The point at which the TPC and IPR curves intersect indicate the flow rate and pressure that satisfies both inflow and outflow components and it is known as the operating point or natural flow point. Fig. 2 and Fig. 3 present bottomhole and Wellhead Nodal Analysis in well No. 305b.

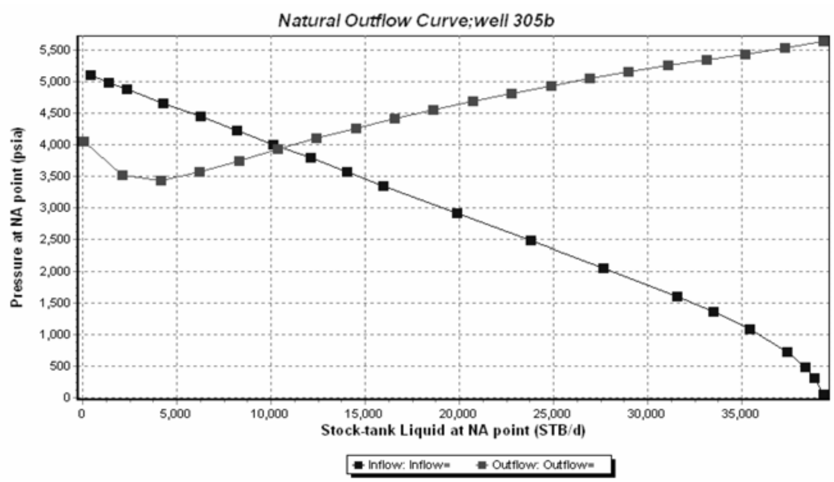

Figure 3. Bottomhole Nodal Analysis in well No. 305b.

Results and discussion

Pressure losses

Hydrostatic or elevation pressure gradient dominated among other pressure gradients. Hydrostatic pressure gradient in well No. 305b is equal to 3740 psia, that means 94% of total pressure gradient. Friction gradient is always more dominant in horizontal flow. Also in vertical or inclined gas, gas condensate or high GLR (Gas Liquid Ratio) multiphase flow, the friction loss can be very dominant. In this well, friction is no more that 0.02% of total pressure losses. The acceleration component, which sometimes is referred to as the kinetic energy term, constitutes a velocity-squared term and is based on changing velocity that must occur between various positions in the pipe. This component in well No. 305b is zero.

Liquid and gas phase changes

Liquid holdup from 100 ft to the wellhead is equal to unity, but as the pressure decrease and gas appeares in the well column, this number changes to 0.968 (Fig. 4). As the pressure decreases from the bottomhole to the wellhead, the liquid holdup decreases. Therefore, the liquid flow rate decreases to maintain the mass flow rate constant. As the pressure decreases the gas density decreases, therefore, the gas holdup increases and the gas velocity has to increase to maintain a constant mass flow rate. The gas volumetric flow rate increases with decreasing pressure due to gas expansion (Fig. 5). The single-phase moody correlation is used in the first part of the pipe and the Hagedorn & Brown correlation is used in the second part of the pipe. The viscosity of the liquid increases as the pressure decreases due to gas coming out of the solution. The gas viscosity decreases as the pressure decreases. The temperature in this well varies from 209 F from the bottom hole to 80 F to the wellhead. The highest inlet temperature generates the lowest pressure drop. This is because as the temperature increases, the viscosity decreases, therefore the Reynolds Number increases, the corresponding friction factor and the frictional pressure gradient is lower. Many two-phase flow correlations are based on a variable called superficial velocity. As shown in Fig. 6, superficial velocity changes that have harmony with the tubing inside the diameter changes. Liquid holdup is a fraction which varies from zero, for single-phase gas flow, to one for single-phase liquid flow. Liquid holdup in well No. 305b from bottom hole to a depth of 1000 ft is equal to one and the liquid phase occupies the total cross section of the pipe. But, liquid holdup decrease from the depth of 1000 ft to the wellhead with gas coming out from the liquid (Fig. 7).

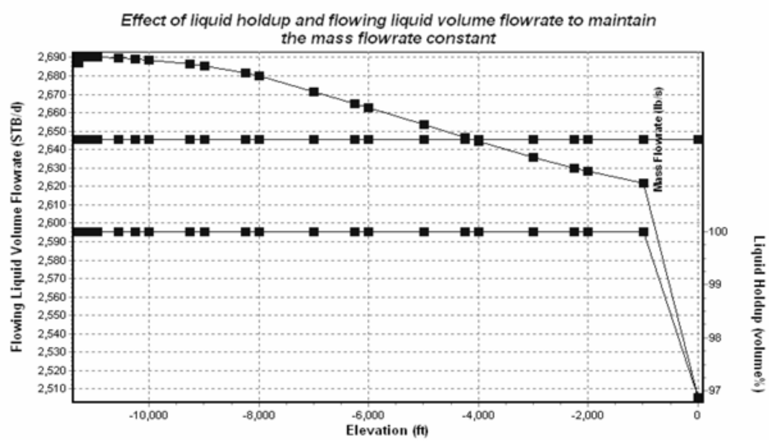

Figure 4. Effect of liquid holdup and flowing liquid volume flowrate to maintain the mass flowrate.

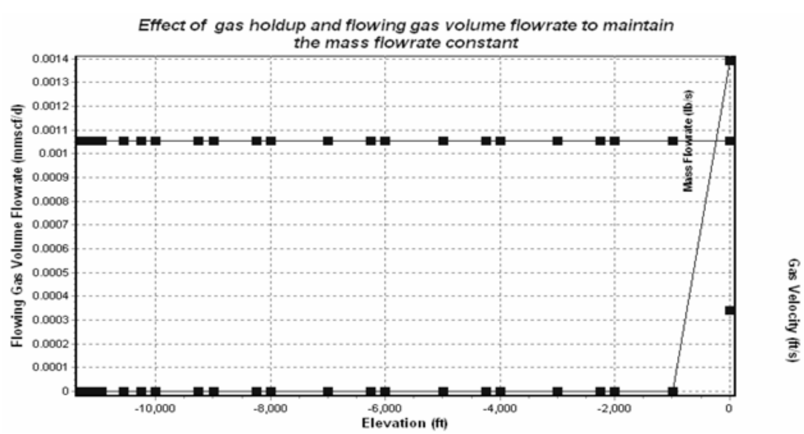

Figure 5. Effect of gas holdup and flowing gas volume flowrate to maintain the mass flowrate constant.

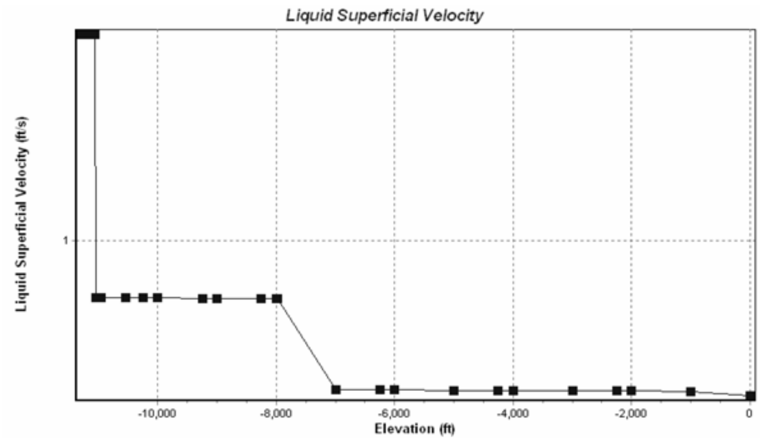

Figure 6. Liquid superficial velocity.

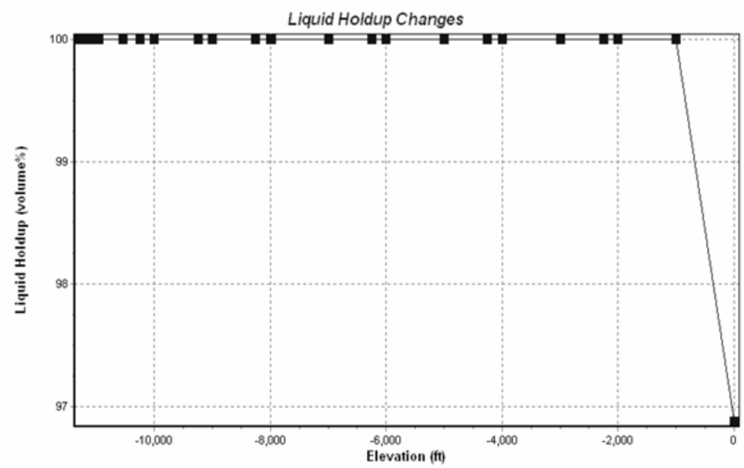

Figure 7. Liquid holdup changes in well No.305b.

Flow pattern changes

The main flow pattern in well No. 305b is liquid flow. Bubble flow produced from a depth of 1000 ft to the wellhead. Bubble flow in gas/liquid two phases flow are defined as the flow regime where both the phases are almost homogeneously mixed or the gas phase travels as small bubbles in a continuous liquid medium. In this work we have attempted to show flow patterns with each sensitivity analysis (Tables 2-6). The slug flow, on the other hand, is defined as the flow condition where gas bubbles are longer than one pipe diameter and flow through the pipe as discrete slugs of liquids followed by slugs of gas. Due to continuous segregation of phases in the direction of the flow, slug flow results in substantial pressure fluctuations in the pipe. This creates production problems, e.g., separator flooding, improper functioning of gas lift valves, etc. The basis of selection tubing sizes, choke sizes and wellhead pressures is the flow pattern in a way that the selected variables should not cause any produced slug regime.

Surface choke performance

Tables 1 and 2 summarize the sensitivity analysis of different wellhead choke sizes. Variables such as hydrostatic loss, friction loss, free gas, bottom hole and wellhead liquid velocity, flow patterns and liquid flow rate was introduced to each of the choke sizes. Fig. 8 is a graphical presentation with varied choke sizes. Fig. 9 is a graphical presentation of a well performance operation with a five choke size variable.

Table 1. Effect of changing choke size on the different system variables.

Choke size(inch)	Hydrostatic pressure gradient (psia)	Friction pressure gradient (psia)	Free gas (MMscf/d)	Liquid holdup (fraction)	Liquid holdup (bbl)
5/16	3755	0	0.0564	0.991	746
7/16	3738	1	0.1978	0.963	745
9/16	3719	2	0.4357	0.913	747
11/16	3695	3	0.7518	0.846	737
12/16	3681	3	0.9313	0.809	734
13/16	3664	4	1.1716	0.771	730
14/16	3638	5	1.3118	0.639	724

Table 2. Effect of changing choke size on the different system variables

Choke size (inch)	Flow regime	Bottom hole liquid velocity (ft/s)	Wellhead liquid velocity (ft/s)	Flow rate (bbl/d)
5/16	Bubble	1.1	0.2	1216
7/16	Bubble	2	0.4	2136
9/16	Bubble	2.9	0.7	3153
11/16	Bubble	3.9	1	4202
12/16	Bubble	4.3	1.2	4725
13/16	Bubble	4.8	1.4	5245
14/16	Slug	5.3	1.6	5791

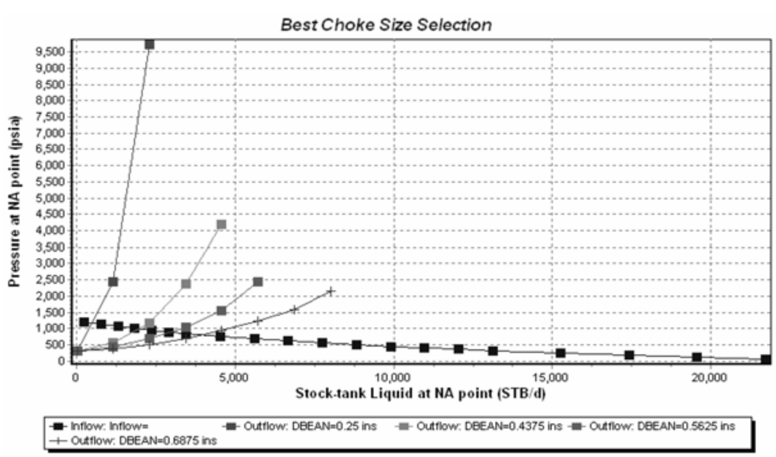

Figure 8. Choke size sensitivity analysis in well No. 305b.

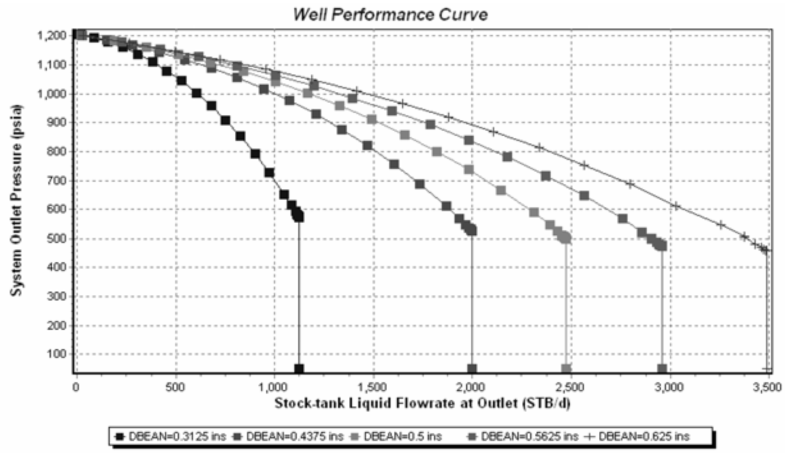

Figure 9. Well performance operation in well No. 305b.

Tubing performance

Large tubing is good for the higher flow rates, low-pressure loss and lower fluid velocity desirable during the early life of the well. However, as the reservoir pressure and flow rate decline, large tubing may become less advantageous as liquid holdup problems are encountered at lower fluid velocities. Thus, smaller tubing sizes may be necessary. The lower flow rates and incurred higher pressure losses will be compensated by the higher fluid velocity which they alleviate problems associated with liquid holdup (Fig. 10). As shown in Fig. 10, input data for a system analysis with the node at the bottom of the well bore is required. Relevant fluids, wellbore, completion, and the reservoir data were entered in the software with outflow sensitized at various tubing IDs. The resulting outflow sensitivity graph shows the tubing size vs. flow rate. The optimum tubing size was obtained from this graph by judging a tubing size where increasing tubing size has a minimum effect in increasing production. A hump in the middle of Fig. 10 is due the larger tubing sizes that cause reducing the flow rate and resulting in a liquid holdup problem. The systems analysis graph should be reviewed to identify liquid holdup regions of the outflow curves. These are unstable flow regions of the outflow curve where the pressure is decreasing while the flow rate is increasing. When an inflection is reached, the curve begins a trend of increasing pressure with increased flow rate. This appears as a characteristic 'J' curve profile. Table 3 shows the sensitivity analysis for four different tubing IDs varies from existing 8.921 to 3.25 in. sizes.

Optimum wellhead pressure selection

Control of wellhead pressure may be necessary to maintain flow velocities below the erosional limit. The surface choke plays a major role in selecting an optimum wellhead pressure. As shown in Fig. 11 different pressures are located in X axis and relative flow rate in Y axis; so the wellhead pressure 1180 psia presented an actual flow rate. As shown in Tables 4 and 5, reducing the wellhead pressure from 1180 to 1000 psia cause lower flow rate, lower density, higher liquid velocity. In contrast, the reduction of the wellhead pressure from 1180 to 1000 psia causes an appearance of free gas in the wellhead and reduction of the liquid holdup in that segment.

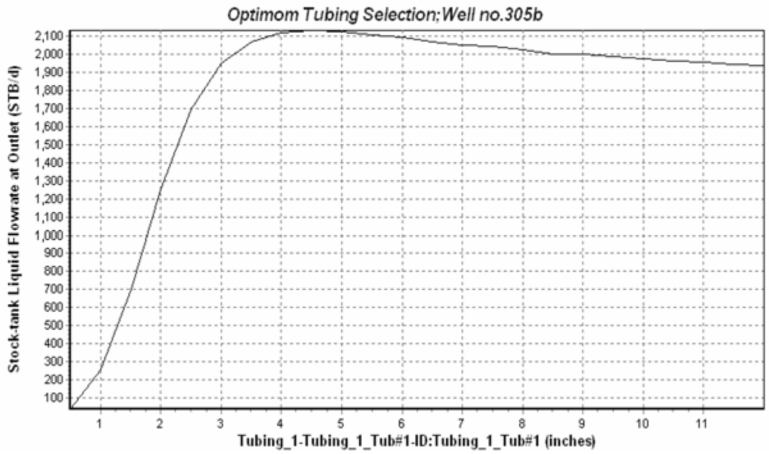

Figure 10. Tubing size sensitivity analysis in well No. 305b.

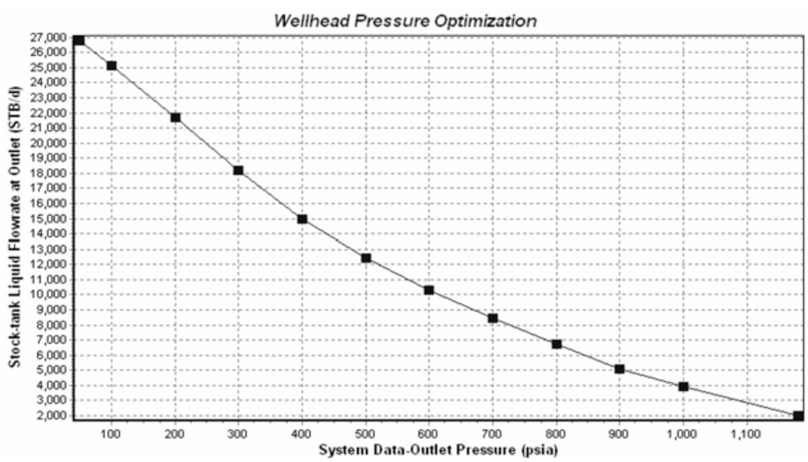

Figure 11. Wellhead pressure sensitivity analysis.

Table 3. Tubing size sensitivity analysis.

Tubing ID (inch)	Elev. pres. gradient (psia)	Fric. pres. gradient (psia)	Liq. holdup (fraction)	Flowing regime	Flowrate (bbl/d)
8.921	3740	1	0.9688	Bubble	2000
6.451	3731	1	0.9463	Bubble	2066
4.184	3718	8	0.9098	Bubble	2167
3.52	3715	18	0.8987	Bubble	2070

Table 4. Sensitivity analysis on wellhead pressures.

Wellhead pressure (psia)	Flowing regime		Free gas (mmscfd)	Liquid holdup (fraction)	Hydrostatic pressure gradient (psia)
	Flowing regime	Produced depth (ft)			
1180	Bubble	0	0.1717	0.9688	3740
1000	Bubble	1000	0.6654	0.8647	3702
900	Bubble	1000	1.0702	0.7816	3669
800	Bubble	2000	1.667	0.5940	3586
700	Bubble	2000	2.3926	0.5091	3489
	Slug	0			
600	Bubble	3000	3.2588	0.4267	3378
	Slug	2000			
400	Bubble	5000	5.713	0.2689	3033
	Slug	4000			
300	Bubble	6000	7.490	0.2021	2758
	Slug	5000			
200	Bubble	7000	9.599	0.1862	2441
	Slug	6000			

Table 5. Wellhead pressures sensitivity analysis.

Wellhead pressure (psia)	Flowing regime		Drawdown (psia)	Total Pressure gradient (psia)	Flow rate (bbl/d)
	Flowing regime	Produced depth (ft)			
1180	Bubble	0	224	3965	2000
1000	Bubble	1000	441	4145	3935
900	Bubble	1000	572	4245	5108
800	Bubble	2000	752	4344	6713
700	Bubble	2000	946	4445	8445
	Slug	0			
600	Bubble	3000	1152	4545	10283
	Slug	2000			
400	Bubble	5000	1681	4745	14999
	Slug	4000			
300	Bubble	6000	2038	4845	18187
	Slug	5000			
200	Bubble	7000	2428	4945	21671

Conclusions

The results of this study are shown in Table 6. In particular, the following may be concluded:

1- Controlling flow patterns in this study play a major basis to select the proper variables such as tubing size, wellhead pressure, and choke size.
2- Optimized wellhead pressure in the optimum condition "A" is 1080 psia which causes a proportional reduction of bottom hole pressure.
3- Installation of 9/16 in. choke size increases the flow rate from 2000 to 3180 bbl/d with critical flow condition settlement.
4- The smallest tubing size in the production optimization of the selected well is 6.456 in. ID.
5- Choke installation in optimum condition "B" without changing tubing size results in the flow rate of 3125 bbl/d.

Table 6. Comparison of existing condition of well No.305b with two kinds of performed optimization.

Well parameters	Existing condition of well No. 305b	Optimum condition "A"	Optimum condition "B"
Wellhead pressure (psia)	1180	1080	1071
Choke size (Inch)	7 / 16	9 / 16	9 / 16
Tubing ID (Inch)	8.921	6.456	8.921
Bottom hole pressure (psia)	4920	4788	4791
Drawdown (psia)	224	356	353
Flow rate (STB/d)	2000	3180	3156
PI (STB/d/Psi)	8.92	8.92	8.92

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