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Identification and optimization of production bottleneck in a deviated oil well: a case study using nodal analysis

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Abstract

Hydrocarbons play a substantial role in the energy industry; however, maintaining a steady and optimal production rate in deviated wells remains a significant challenge, especially due to flow bottlenecks that reduce output efficiency. This study focuses on identifying and resolving production constraints in a deviated well located in the TK oil field in North Iraq with a total measured depth of 9639.5 ft. The true vertical depth is at 8137 ft. at an inclination angle of 39.90º. The well failed to meet the pre-evaluated rate of 1044 STB/D based on the current conditions. To accomplish the optimum rate, the deviated well S17 is subjected to nodal analysis and various possible alterations in the well geometry and production system. The nodal analysis through the Inflow Performance Relationship and Vertical Lift Performance characteristics is addressed utilizing IPM suites Prosper to replicate the flow in the tubing through integrated correlations, the fluid behavior, and the phase envelope. The saturation pressure is tuned with the correlations in the PVTp program. Different scenarios were set, such as the change in wellhead pressure, tubing internal diameter, reservoir pressure, skin factor, and the introduction of artificial lift. Following the simulation, as referred to previously, the detailed analysis of the variables provides an exhaustive insight for the field operators. The key finding of this well is that reducing skin factor and alongside the use of Electrical submersible pump (ESP) installation, significantly enhance production feasibility and the well will be able to produce when the reservoir pressure drops to 1500 psi These results provide actionable insides for field operators to improve production performance in similar well conditions.

Keywords: *Optimization; Nodal analysis; IPR; VLP; phase envelope; ESP; Prosper.*

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1- Introduction

Extracting the crude oil requires a link between the surface and the subsurface, and is connected through the well's geometry. Thus, the need to analyze and predict the performance of the well's anticipated productive capacity, pressure drop, and flow rate is emphasized [1-3]. The pressure drop in oil wells is a crucial criterion of production engineering as it guides a cost-effective well design, well completions, and production optimization [4]. Overall, well performance analysis identifies early problems, which can lead to premature abandonment of the well [5] By implementing improved practices, the operator can achieve the maximum natural life cycle of the well and ensure compliance with production quotas, prolonging well life, and maximizing reservoir management efficiency [6, 7] To thoroughly comprehend the production system's complex interactions with specific scenarios, various studies have been conducted on the flow patterns and variables of the working point through a detailed description of the inflow performance relationship and vertical lift performance, each addressing a specific issue. Nodal analysis delivers a distinct operational efficiency approach and a predictive role in the optimization [8]. Investigation of a low efficiency well in Southwest Iran and an attempt to optimize the field concluded that tubing production provided a higher production rate compared to the annulus [9]. Four vertical wells are studied in the Faihaa oil Field and concluded via the application of the Pipesim program that decreasing the wellhead pressure would have outstanding outcomes [10]. Other findings suggest that increasing choke size positively affects flow rate, and the production rate rose by 50 % at lower wellhead pressure with a smaller tubing size [11]. A well struggles to produce as reservoir pressure decreases, even when parameters like wellhead and gas-oil ratio remain constant [12]. Nodal analyses were conducted on the tubing inside diameter, water cuts, and the application of artificial lift [13]. Running simulations and re-examining a slightly deviated well with low-scale production indicates that the well and reservoir delivery led to a finding that the cause of low productivity was inadequate equipment application [14]. Insights were yielded by investigating the impact of various well parameters, such as well length, skin, and perforation distribution, on the inflow performance of

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horizontal wells [15]. The production rate of both hydrocarbons and water, as well as the water cut, are susceptible to both the degree and direction of horizontal anisotropy when producing from vertical wells [16]. And the introduction of new wells into a mature oil field and their bottleneck effect on the production system, concluded that decreasing the separator pressure would increase the production four times [17].

The main objective of this study is to analyze the performance of the S17 well to improve and maximize the oil flow rate. The evaluation is conducted in two stages. First: Re-evaluation of the PVT analysis, as it is a major influencer in the fluid flow through the production. The nodal analysis has been covered extensively in the past studies in the PVT section in Prosper, but not addressed extensively. The second stage is the sensitivity of well performance to various parameters individually and combined to offer a more robust insight into optimizing flow rates.

2- Methodology

To fully grasp the reservoir fluid behavior, it is analyzed through PVTp for modeling phase behavior, which is particularly suited for pressure and temperature ranges above the critical region. EOS parameters are fine-tuned to match laboratory data closely, achieving a minimal deviation within acceptable limits. Estimating the pressure losses from the reservoir to the wellhead segments the production system into nodes. Obtaining the inflow performance relationship (IPR) and the losses from the bottom well to the wellhead represented in vertical lift performance (VLP) utilizing a properly selected correlation depending on the proper. Sensitivity analysis was performed for parameters such as the production flow capacity, represented in the tubing size, the damage around the wellbore, represented in the skin factor, the pressure losses in the pay zone due to straining the reservoir, wellhead pressure variation, and the overpassing the pressure losses through the utilization of ESP.

3- Data collection

The S17 well was drilled into a carbonate reservoir. The formation consists of three hydrocarbon-bearing units with a total thickness of 150 meters (492.126 ft). The well was put on stream and produced at an average rate of 1044 BPD with a 0% water cut. However, the production rate decreased significantly. To comprehend the reservoir fluid behavior, specifics are required. Firstly, PVT Laboratory analysis was organized. The reservoir fluid characteristics, the wellbore geometry, and PVT data are summarized in Table 1, Table 2, and Table 3**,** respectively.

Table 1. Reservoir fluid characteristics

Data	Value	Unit
API Gravity @ (60° F)	24.9	
Residual oil viscosity @ Tr	6.091	(Cp)
Reservoir temperature	175.6	(°f)
Water content	0.01	(%)
Hydrogen Sulphide	0.0	(%)
Crude oil viscosity at reservoir conditions	1.1214	(Cp)
Saturation pressure	2175	(Psia)
Oil formation volume factor at reservoir conditions	1.1486	STB/SCF

Table 2. Well equipment data

Parameter	Data	Unit
Reservoir Temperature	175	Degree F
Surface Temperature	90	Degree F
Tubing depth	7732.64	Feet
Casing depth	9637.79	Feet
Tubing inside diameter	3.46457	Inch
Casing inside diameter	9.625	Inch
Overall thermal heat coefficient	8.171	Btu/h/ft2/f

Table 3. PVT

Parameter	Data	Unit
GOR	519	SCF/STB
Oil Gravity	25.08	API
Gas Gravity	0.67	Sp.gr
Water Salinity	10000	Ppm
H_2S %	0.59	%
Co_2%	1.15	%
N_2%	0.47	%

- PVT validation

The main purpose of the utilization of the PVTp program from the IPM suite is to evaluate the fluid analysis from the laboratory report and, specifically, the saturation pressure. Input parameters were driven from laboratory reports, including pressure, temperature, and fluid composition. The Peng-Robinson equation of state (EOS) [18]. If selected to model phase behavior, the reservoir conditions are not compatible with those generated by the equation of state, where the saturation pressure is underestimated. Further investigation is required through the BI coefficient and separating the pseudo component into two instead of one to secure detailed observation of the fluid behavior. As is noticed in Fig. 1, an utter match is achieved in a modified phase envelope. Fig. 2 is executed, and the saturation pressure from the EOS is compatible with the reported one.

4-Model setup

Well definition is set as a producer through the tubing, and no artificial lift is carried out. Secondly, Equipment data includes (a) the well geometry stats from tubing, going through the final node at the production casing and (b) deviation survey: once the measured depth and the true vertical depth are, the program automatically calculates the angel of the well (c) geothermal gradient the version of temperature with depth, considering the overall thermal coefficient(d) average heat capacity remains as default, and the surface equipment is not considered in this study. The equipment data is tabulated in Table 2.

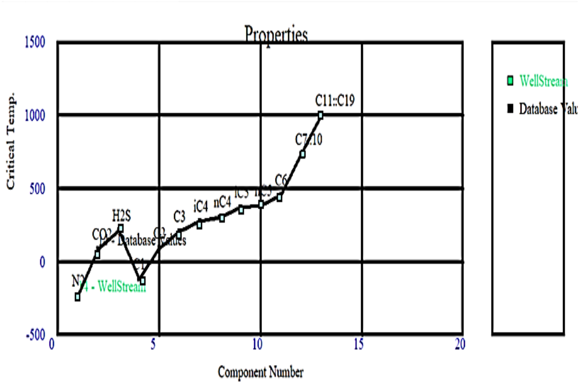


Fig. 1. Composition matching results between the database and well-stream

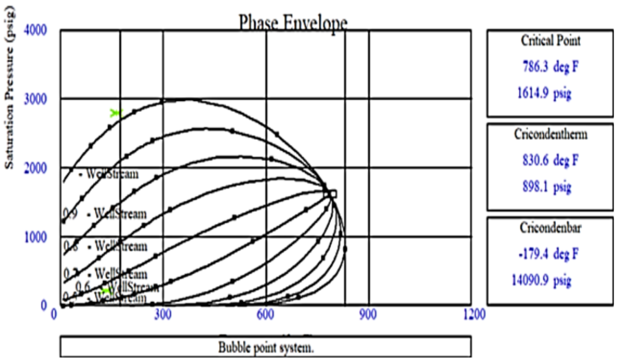


Fig. 2. The phase envelope after tuning the well stream data to EOS

4.1. Inflow performance relationship

The generation of Well Inflow Performance Relationship (IPR) PROSPER 11.5 is utilized. Selecting the model to generate the IPR of the well, several correlations are available, including Darcy's law, which is the base for most of the flow in porous media correlation, and it is usually adjusted to best fit the model. Primarily, it was assumed that the reservoir is homogenous, and this is not the case for most reservoirs [19], generated a correlation to evaluate IPR based on the inclination angle and accounted for horizontal permeability as well [20] Productivity index where the reservoir is above the bubble point pressure [21] and horizontal wells [22]. No general correlation is at pace to be applied for all conditions. Each one can be run with a specific parameter domain. Since the well is deviated with a relatively high productivity index, the Darcy model is selected, the reservoir properties are tabulated in Table 4, and the absolute open flow potential is 17007.9 STB/D as shown in Fig. 3 a.

Table 4. Reservoir data

Parameter	Value	unit
Reservoir pressure	3192	Psig
Gor	519	Scf/STB
Reservoir thickness	459.856	ft
Wellbore radius	4.812	ft
Skin	+ 5	

4.2. Vertical flow performance

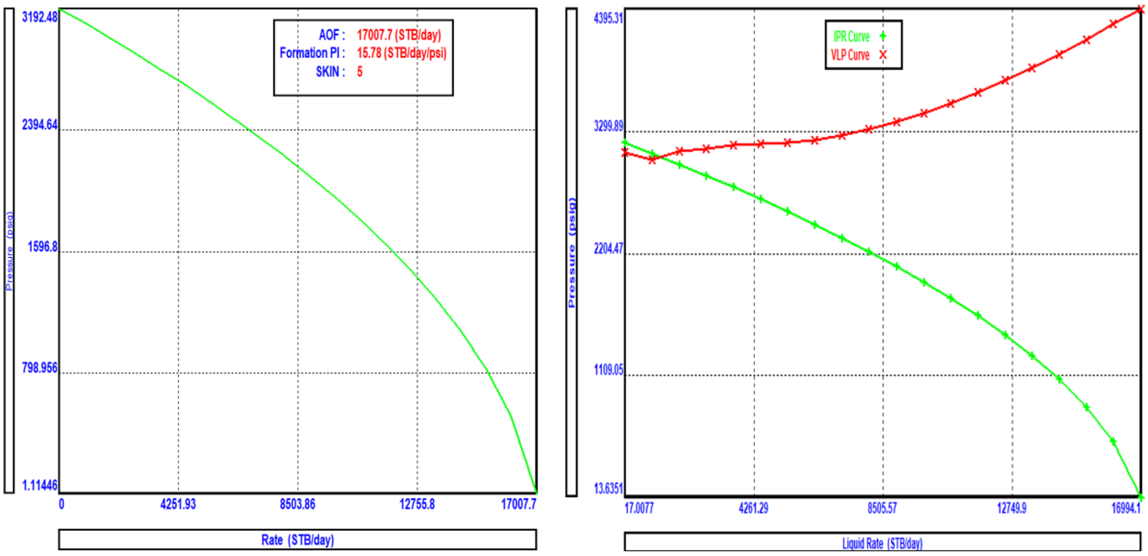
To estimate the pressure losses through the tubing represented in the Vertical Lift Performance (VLP), the top node pressure is set to 660 Psig with a GOR of 519 SCF/STB. Several vertical lift Correlations are available to be chosen. In the presence of two immiscible fluids in the tubing, a variety of patterns are presented. We have attempted to predict the patterns. The estimation of fluid behavior is affected by various flow conditions, and the liquid holdup is found to be dependent on the flow pattern, and the latter is dependent on the angle of inclination of the pipe and the direction of flow. [23]. Other options are provided to predict the flow behavior in the tubing, such as Gray. [24 - 27] Duns and Ros applied for deviated wells. [28, 29] is applied with a significant gas-liquid interaction. At a wellhead pressure of 660 Psig, no intersection was attained, so the pressure was decreased to 575 Psig. Carrying on with tuning the correlation's results to real-time data represented in the actual test to adjust the IPR and VLP intersection to the Field test data. The solution node in the well is bottom well pressure at 3139.59 Psig and an intersection of 500 STB/D as shown in Fig. 3 b, after the tubing's correlation comparison. Duns and Ros are selected, which have a specific set of multiphases and are verified with the actual production data. The well is unable to lift the hydrocarbon to the surface with overall losses in the tubing, a majority due to gravity and a minority due to friction. The tubing roughness is examined and presented minimum contribution to the well losses.

5-Optimization

The fluid composition varies along the production path as the pressure and temperature drop. This approach is applied to correctly predict the flow conditions in the tubing since pressure and temperature changes are unavoidable in vertical upward fluid flow [30]. Analyze all available correlations to determine the best match to the field data, reducing errors while forecasting the flow rate during various scenarios.

5.1. The wellhead and tubing diameter

The wellhead pressure (WHP) significantly affects the flow performance. Five options are to be evaluated according to their intersection with the VLP curve, the values lie below the current WHP (200,400,600,575,660) Psi as shown in Fig. 4.



(a) (b)

Fig. 3. (a) IPR curve for the deviated well (S17); (b) the well (S17) working point, the red line is the VLP and the green one is the IPR

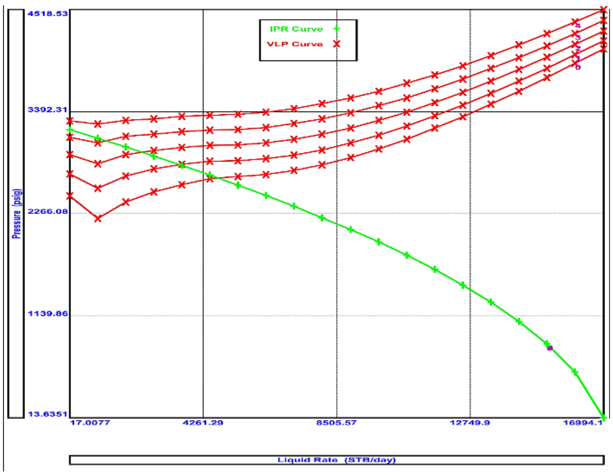


Fig. 4. Wellhead variations (curves (0,1,2,3,4) represent (200,400,600,575,660) Psi

Through sensitivity analysis, the optimal pressure is to be selected to ensure higher fluid velocity, taking into consideration the integrity of the flowing path through the tubing and wellhead assembly. The effect of the tubing's internal diameter is examined separately, and reducing it has a limited impact on optimum flow as seen in Fig. 5.

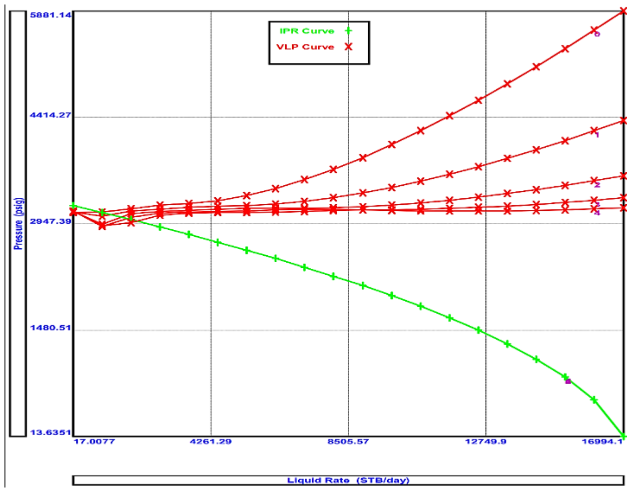


Fig. 5. Tubing altering effects on the VLP and production rate (curves (0,1,2,3,4) represent (2.99,3.467,4.02,4.5,5) inch)

Both variables are addressed to evaluate their combined contribution, and the details are illustrated in Table 5.

Table 5. Wellhead and the tubing variation to the flow

Case	Wellhead pressure (Psig)	Tubing Diameter	Flowrate (STB/D)	Pwf (Psig)	DP losses to gravity (Psig)	Dp losses to friction (Psig)	DP losses to skin (Psig)
1	575	2.47	287.60	3162.10	2574.30	12.78	11.60
2	400	2.47	1630.90	3017.97	2495.52	121.93	68.06
3	250	2.47	2578.80	2912.59	2381.19	278.76	110.28
4	575	3.46	495.10	3140.17	2560.50	4.65	20.90
5	400	3.46	2446.30	2927.59	2477.10	49.89	104.27
6	250	3.46	3931.50	2759.31	2388.62	118.95	176.46

The gravity losses appear to be at an expectedly high rate given the high depth and the deviated angle. Gravity losses tend to correlate with higher flow rates. The second and third cases deliver an outstanding outcome concerning the flow rate. However, due to the smaller cross-sectional area, the velocity exceeds the erosional limit, thus the integrity of the tubing is jeopardized.

Case (4) by reducing the wellhead pressure to 575 Psig and keeping the tubing as it is. It will offer a conservative potential without exceeding the tubing erosion to ensure the well's infrastructure remains intact. However, this option provides limited revenue that may not be economical. As for the rest, a larger drawdown pressure offers a substantial increase in the flow rate. Case 5 delivers a balanced approach at a manageable Pwf with slightly formation damage than case 6, which offers the highest flow rate that maximizes the recovery but could also put the well at risk of formation damage.

5.2. The reservoir contribution

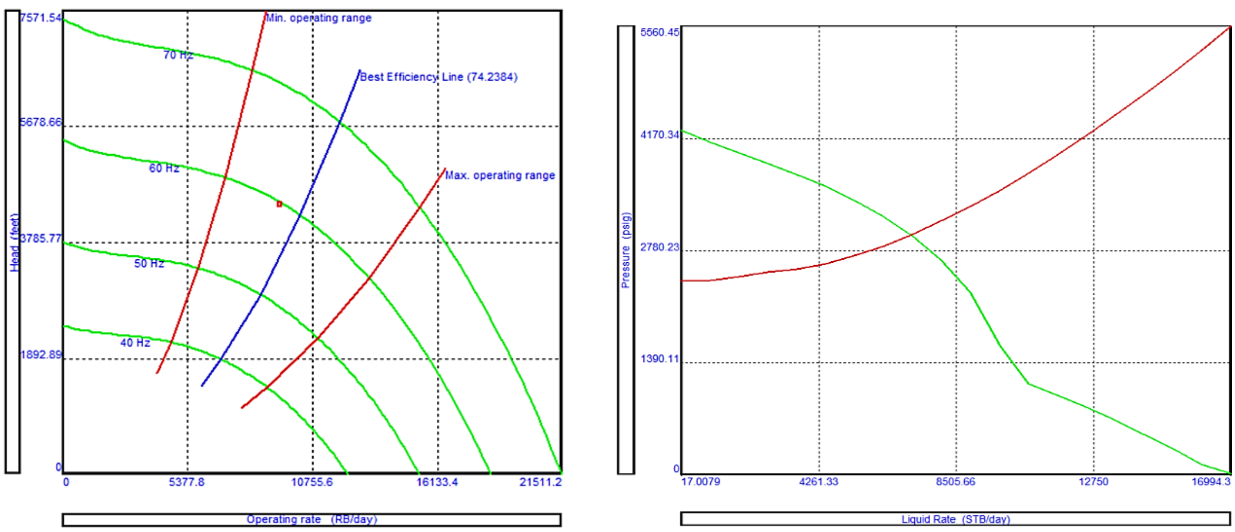
The reservoir pressure immensely affects the IPR as it is the leading parameter to construct the relationship. The curve shape recedes to a lower position as the reservoir pressure declines with time. Specifically, dropping below the bubble point pressure releases dissolved gases from the reservoir fluids. Supposedly, the reservoir pressure drops from 3192 psi to (2700,2400,2000), leaving the system in the bubble point phase. The current well’s conditions that are provided state impairment of formation occurred at a value of the skin factor at (+5). Stimulation of the formation around the well bore can crucially exert influence on the flow rate by altering the permeability and bypassing the skin permeability. Two scenarios are proposed to eliminate the damage or enhance the permeability around the wellbore. The first refers to a damage pass where the skin permeability is equal to zero, the second one reverses the effect and enhances the formation, so the dimensionless value of the skin is equal to (-5). A slight improvement is provided by the stimulation effect on the flow rate at the current reservoir pressure. However, it becomes invaluable when the pressure drops to 2800 Psig.

5.3. Artificial lift

Lifting the fluid from the bottom of the well naturally presents an obstacle, considering the future pressure drop. To tackle the pressure losses in this well, considering the reservoir pressure declines with no natural driving force for maintaining a stable production. Sensitivity analysis was performed in an attempt to alter the main influencing parameters in the production system to achieve optimal nature production in the long term, and no feasible outcome was attained. The next option is to convert the well into an artificial lift using the electrical submersible pump (ESP). The input requirements for the ESP model are tabulated in Table 6. In Fig. 6a, the best efficiency curve is observed, and the rate design is observed in Fig. 6 b.

Table 6. Pump input

Parameter	Value	Unit
Tubing outside diameter	3.83	Inch
Pump depth	7000	Ft
Maximum Pump OD	6	Inch
Caple length	8200	Ft
Design rate	2000	STB/D
Water cut	0	%
Gor	519	SCF/STB



(a) (b)

Fig. 6. (a) Pump efficiency curve; (b) Pump discharge pressure curve VS VLP

Throughout the nodal analysis, the main issue presented in optimization is the inevitable reservoir pressure decline. Sensitivity analysis is performed to examine the pump delivery at various frequencies and declining pressure, as illustrated in Table 7.

Table 7. Pump's sensitivity analysis outcome

Case	PR (Psig)	Frequency (Hertz)	Pump setting depth (Ft)	GLR (SCF/STB)	Skin (-)	Flow rate (STB/D)	Skin (-)	Flow rate (STB/D)
1	3000	40	7000	500	+5	3377.6	0	4214.5
2	2500	50	7500	550	+5	2642.1	0	3630.4
3	2000	50	8000	600	+5	2062.3	0	2875
4	1500	60	8200	650	+5	1388	0	1964.6
5	1000	70	8400	700	+5	0	0	0

Based on the sensitivity analysis:

a. Flow rate decline is expected as the reservoir pressure decreases. To maintain a stable production rate, a frequency adjustment is applied conversely to the reservoir pressure decline.

b. The pump setting increases with each case. The adjustment helps to ensure the pump's effectiveness as the reservoir pressure decreases. A deeper setting allows for more effective fluid lifting.

c. Higher GLR values at lower pressures may also contribute to reduced pump efficiency as gas volume in the fluid increases, impacting the pump's ability to handle the fluid.

d. Stimulating would enhance the flow rate in most cases.

6- Economic feasibility

Using Table 7 production rates (in STB/D), we can calculate the daily revenue for each case and then determine the annual revenue based on assumed conservative pricing to be on the safe side. Subtracting the operational costs will provide the net profit for each case. The feasibility evaluation is shown in Table 8 and is calculated based on the following:

Oil Price: $50 per barrel (USD).

Cost of Stimulation: 100,000$ (one time for each case)

ESP operational cost and maintenance: 150,000 $/year.

Well, labor and maintenance cost: 100000 $/Year

Table 8. Feasibility evaluation

Case	Post simulation Flow rate (STB/D)	Revenue ($)	Annual Net profit ($)	Pre-simulation flow rate (STB/D)	Revenue ($)	Annual Net profit ($)
1	4214.5	76914625	76464625	3377.6	61641200	61391200
2	3630.4	66254800	65804800	2642.1	48218325	47968325
3	2875.0	52468750	52018750	2062.3	37636975	37386975
4	1964.6	35853950	35403950	1388.0	25331000	25081000

a. Highest Annual Profit: Case 1 yields the highest annual net profit after considering both the stimulation and ESP installation costs.

b. Feasibility of ESP: Using ESP is feasible in cases where post-stimulation flow rates are significantly high, as ESP can handle increased volumes and is cost-effective.

Recommendation: Proceed with stimulation and ESP installation, especially in Case 2, which provides the highest profit.

7- Conclusions

Optimization of oil production in deviated wells is essential for maintaining production and ensuring profitability. Through nodal analysis, bottlenecks could be systematically assessed and solutions for productivity enhancement implemented. In this context, the simulation process through Prosper software has been used for analyzing the performance of a deviated oil well. The outcomes of this study present that:

a. The production path experiences excessive loss due to the length of the well and the deviation angle; recovering the losses through lowering the wellhead pressure is possible for the current reservoir pressure.

b. Sensitivity analysis for the reservoir pressure drop shows that the well is not able to deliver hydrocarbon when it plummets below 2900 psi naturally.

c. The skin sensitivity test shows that overcoming the skin and diminishing the damage through stimulation can increase the productivity index. Despite the positive outcome, it has a slight impact on the flow rate due to pressure losses under natural flow. In the case of the installation of ESP, it causes a rise in the flow rate

d. The ESP pump is economically feasible at reservoir pressures of 1,500 psi and above, as each case yields substantial profit after accounting for operational costs.

e. At 1,000 psi, production ceases, making it uneconomical to continue using the ESP pump at this pressure level without other forms of lift assistance or rese

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تحديد وتحسين ضعف الإنتاج في بئر نفطي ذو ميلان: دراسة حالة باستخدام التحليل العقدي

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الخلاصة

يعد الهيدروكربون أحد المؤثرين المهمين في صناعة الطاقة، ومع ذلك يظل الحفاظ على معدل إنتاج ثابت ومثالي في الآبار المنحرفة تحديًا كبيرًا حيث تعمل اختناقات التدفق على تقليل كفاءة الإنتاج. تركز هذه الدراسة على تحديد وحل قيود الإنتاج في بئر منحرف في حقل النفط TK بعمق إجمالي مقاس ٩٦٣٩,٥ قدمًا، ويبلغ العمق الرأسي الحقيقي ٨١٣٧ قدمًا بزاوية ميل ٣٩,٩٠ درجة. البئر لا يفي معدل إنتاج النفط بالمعدل المقدر مسبقًا وهو ١٠٤٤ STB / D بناءً على الظروف الحالية. يتم إخضاع البئر المنحرف S17 لتحليل عقدي وتغييرات مختلفة محتملة في هندسة البئر ونظام الإنتاج. يتم التعامل مع التحليل العقدي من خلال خصائص علاقة أداء التدفق الداخلي وأداء الرفع الرأسي باستخدام مجموعات IPM Prosper لتكرار التدفق في الأنابيب من خلال الارتباطات المتكاملة وسلوك السوائل وغلاف الطور. يتم ضبط ضغط التشبع مع الارتباطات في برنامج PVTp. تم وضع سيناريوهات مختلفة، مثل التغيير في ضغط رأس البئر، والقطر الداخلي للأنابيب، وضغط الخزان، وعامل السطح، وإدخال الرفع الاصطناعي. يوفر التحليل التفصيلي للمتغيرات نظرة شاملة لمشغلي الحقل. النتيجة الرئيسية لهذه البئر هي أن تقليل التضرر في النفاذية حول البئر وتحسين هندسة البئر، إلى جانب استخدام تركيب المضخة الغاطسة الكهربائية (ESP)، يعزز بشكل كبير من جدوى الإنتاج حتى عند نزول الضغط المكمني الى (١٥٠٠ psi.) توفر هذه النتائج تفاصيل قابلة للتنفيذ لمشغلي الحقل لتحسين أداء الإنتاج في ظروف بئر مماثلة.

الكلمات الدالة: IPR، VLP، تحسين الآبار، تحليل الحساسية، المحاكاة، التحليل العقدي.