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Production Optimization of an Oil Well by Restraining Water Breakthrough

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Abstract

This study investigates the well named X (for confidential reasons) of the field called Y which initially was productive with the natural energy of the reservoir of the oil in the absence of water. After a few years of production, water began to overflow excessively in the well. The goal of this paper is to maximize the oil production in an oil well X by reducing water ingress. The Pressure Volume Temperature (PVT) data, completion data, and reservoir data are analyzed via PIPESIM and Excel software by using the nodal analysis method to get the well performance and decline curve for predictions. Two scenarios are considered: firstly, to install an electric submersible pump (ESP) to activate the X well and secondly to make a new perforation. The ESP is installed at 11300 ft where the water production flow rate is 5586.264 STB/d and the oil production flow rate is 1396.566 STB/d. The new perforation is installed at 12038 ft where the water production flow rate is 277.1693 STB/d and the oil production flow rate is 5543.387 STB/d. To have the optimal parameters, the sensitivity analysis is applied to the flowline diameter and the wellhead pressure. The optimal parameter values obtained are 308.6128 STB/d for the water production flow rate and 5863.643 STB/d for the oil production flow rate. The new perforation is appropriate because this scenario allows water reduction, oil production maximization, profitability of 98086854 $, and a return on investment in 5 months during 16 years of production.

Keywords: Water breakthrough; electric submersible pump; nodal analysis; perforation; oil production; return on investment.

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1- Introduction

According to the International Energy Agency, world energy demand is expected to grow by 0.7 to 1.4 %/year between 2008 and 2035 according to different scenarios (such as total world energy resources (coal, gas, oil, Uranium and so on), percentage of world energy consumption, world population growth structure, and the GNP per capita) and will remain dominated by fossil fuels and in particular hydrocarbons, even if their share is expected to decline [1]. Following this continuous increase in global demand for hydrocarbons and the decrease in the number of discoveries per year, there is a need to increase oil production more efficiently and economically [2-5]. Water inflows represent a competitor associated with the production of oil, currently and on a global scale, the daily production of water is approximately 210 million barrels accompanying 75 million barrels of oil, an average of three barrels of water for each barrel of oil [6-8]. During the life of most wells, the percentage of water or water ingress in the oil wells increases. The water produced represents a technical, economic, and environmental problem during the exploitation of oil fields [9-13]. It is usually responsible for both a rapid decrease in productivity or even the closure of wells and an increase in operational costs associated with the need to transport, separate, and store large quantities of water. Every year more than 40 billion dollars are spent worldwide on the treatment of produced water [14-16]. It can also create irreversible impacts on the environment if, during storage and discharge, it is not properly taken care of. Problems such as corrosion of tubular equipment or deposits are often encountered [17-20]. This results in the premature closure of these wells due to production that has become uneconomically profitable. Different techniques have been employed to control the problem of water ingress in oil wells, each type of problem has solution options that extend to mechanical, chemical, and completion solutions [21-25]. Multiple water control problems are common and a combination of these solutions is required. Nonaqueous cement slurries have been used for many years to prevent unwanted water or gas production and to repair

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holes/cracks or other pathways that could have formed in the casing, cement column, or interface [21]. The authors of [22] have described the successful best practices and mistakes of the implementation of the ultra-fine cement slurry system in Offshore Mexico to seal off unwanted water flowing through natural fractures and/or behind the casing. The results of successful applications of polymer gels to control undesirable water production in mature fissured reservoirs in northern Italy have been presented in [23]. In several fields in South Mexico, waterless cement slurry squeezes have been proven to be an effective solution to unwanted water production as shown in [24]. In [25], the solution selected to control the water breakthrough in the studied well was a combination of two conformance technologies for water control that permit sealing high permeability channels and fractures and, more importantly, help provide selective water control. One is a swelling polymer designed to shut off water channels, fractures, or highly vugular zones, and the other is hydrocarbon-based slurry cement that reacts in contact with water.

This article document is about maximizing the oil production rate by alleviating water inflow from X well of the Y field of the basin named Z (for confidential reasons). The field Y was developed in 2003. Since then, oil production has rapidly declined over time due to an increase in water content. Introducing the concept of integrated production modeling, the model of a well was built using PIPESIM software, and the production prediction curve was produced by Microsoft Excel software. The well modeling is the bridge between the reservoir and the surface equipment. After building the well model, liquid flow rates and oil flow rates are analyzed as a function of water percentage through the production data. This article consists of evaluating the performance of the wells, identifying the cause of water inflow and justifying these solutions, developing a design of the ESP, developing a design of perforations, and carrying out economic analysis. The point of this paper is to expose via justification how to manage water ingress in an oil well economically and to add to the existing literature on oil well production by using a practical example of a selected field well named X in the basin called Y (for confidential reasons). This article is organized into three sections, the first of which is the introduction. The second section presents the data, the tools, the methodology used to carry out this work, and the results obtained. The third section presents the conclusion.

2- Data, Tools, and Results

The X Well is located in the Y field. It is a vertical well whose design begins with a conductor pipe at 500 ft having an outside diameter (OD) of 24 inch and an internal diameter (ID) of 23 inch of grade X56, a surface casing at 3500ft having an OD of 16 inch and an ID of 15.124 inch of grade M65, an intermediate casing at 8500ft having an OD of 13.625 inch and an ID of 13.375 inch grade L80, a production casing at 10000 ft having an OD of 9.625 inch and an ID of 8.535 inch of grade X56. The zone 10000 to 12500 ft is the zone where the perforation is done with a grade L80 tubing with an OD of 4 inch and an ID of 3.17 inch is at a depth of 11,300 ft. The wellhead is connected to the choke (ID: 3 inch) which in turn is connected to the skin by the flow line (ID: 2.5 inch).

2.1. Data and Tools

The PVT data, reservoir data, and completion data are presented in Table 1 to Table 3. The data in Table 1 to Table 3 are processed by using PIPESIM and Microsoft Excel software.

2.2. Results

In Fig. 1, the intersection between the curves confirms that X well is indeed producing, associated with an oil rate of 5788.994 STB/d and a water production rate of 0 STB/d at a flow pressure of 2415.733 Psi. This point corresponds to the operating point that satisfies the needed requirements. After a few years of production, water begins to be produced excessively in X well. Fig. 2 presents the nodal analysis of X well carried out after the water inflows.

Table 1. PVT Data

Parameters	Values
Reservoir Pressure	5500 psi
Reservoir Temperature	220°F
Productivity Index	2.5 stb/d .psi
Absolute Open-Flow Profile	7639 stb/d
Vogel Coefficient	0.8
Dietz Factor	31.6
Permeability	333 md
Reservoir Area	340 acres
Diameter	0.3 ft
Drainage Radius	1500 ft
Skin	2
Bubble Point Pressure	2631 psi
Water Cut	80%
Gas Specific Gravity	0.7
Gas-Oil Ratio	650 scf/stb
Oil Formation Volume Factor	1.2
Oil Density	40° API
Water Salinity	15000 ppm
IPR Model	Vogel
Heat Transfer Coefficient	3 Btu/ (h.degF.ft)
Wellhead Pressure	350 psi
Surface Temperature	60°F
Oil Viscosity	1.1 Cp
Water Density	1.25

Table 2. Reservoir Data

Parameters	Values
Reservoir Thickness	600 ft
Oil Net Pay	350 ft
Net Water Height in the Reservoir	200 ft
Net Gas Height in Reservoir	50 ft
Perforation Height	37,5ft
Well Profile	Vertical

Table 3. Completion Data

Parameters	Measure depth	OD	ID	Grade
Conductor Pipe	500 ft	24 inch	23 inch	X56
Surface Casing	3500 ft	16 inch	15.124 inch	M65
Intermediate Casing	8500 ft	13,625 inch	12.375 inch	L80
Production Casing	10000 ft	9,625 inch	8.535 inch	C95
Liner	10000 to 12500 ft	7 inch	6.094 in	C95
Tubing	11300 ft	4 inch	3.17 inch	L80
Choke	In surface	3.75 inch	3 inch	M65
Flowline	2500 ft	3 inch	2.5 inch	L80

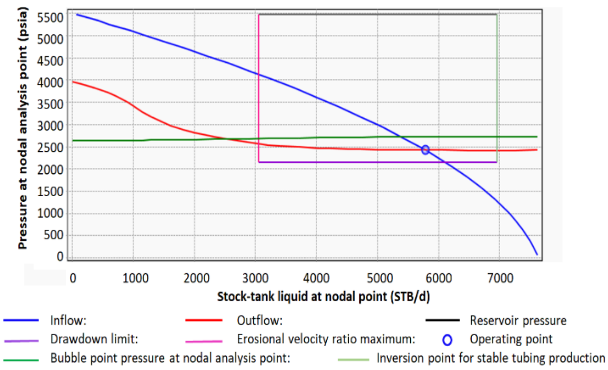

Fig. 1. Nodal Analysis of Well X at Initial State. It is Observed that the Operation Point Pressure is below the Bubble Pressure Which Means that the Operating Point of the Well under Study is Unstable

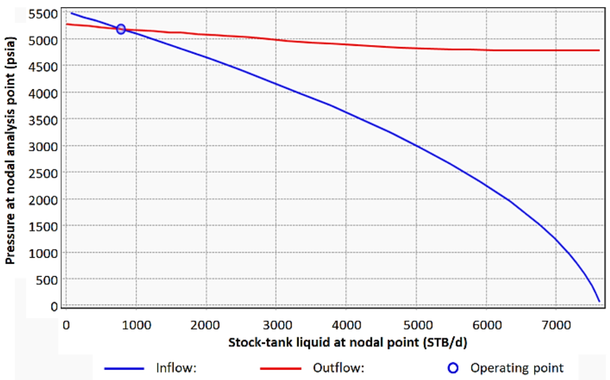

Fig. 2. Nodal Analysis of X Well after Water Breakthrough

In Fig. 2, the IPR and VLP curves show a point of intersection which indicates a liquid production rate of 793.0512 STB/d with an oil production rate of 158.6102 STB/d and a water production rate of 634.4409 STB/d at a flow pressure of 5174.207 psi. Two scenarios are proposed to increase oil production and reduce water inflow into the X well:

- By using an ESP to activate X well but by doing this not only does oil production increase but water production does too;

- However, to remedy the problem of excessive water production, a new zone is perforated, which will reduce water inflows by 90%.

2.2.1. ESP Activated the X Well Design

After entering elements such as the desired flow rate, the inside diameter of the casing, the pressure at the wellhead, certain reservoir data, and installation of the separator at the bottom, the PIPESIM software makes a certain number of calculations automatically to determine the results summarized in Table 4.

As shown in Fig. 3, which provides information on the flow rate range that the pump can produce (minimum flow rate or maximum flow rate), the efficiency of the pump, and its power. Following the design steps, the configuration representing the completion of X well after installation of the ESP is shown in Fig. 4.

Table 4. Results Obtained after Installation of the ESP

Parameters	Values
Pump Depth	11300 ft
Discharge Pressure	8193.197 psi
Pump Suction Pressure	1930.781 psi
Number of Stages	917
Pressure Difference	8193.197 psi
Pump Efficiency	64
Pump Power	1093.637 hp
Pump Height in the Turbine	16086.4 ft

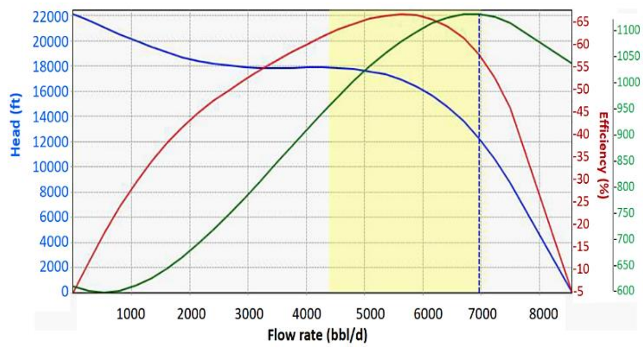

Fig. 3. ESP Performance Curves

In Fig. 4, the ESP is placed at 11,300 ft just above the perforations. Fig. 5 shows a graph of pressure against flow rate in X well after installation of the ESP.

Fig. 5 shows a point of intersection between the VLP and IPR curves which translates to a liquid production rate of 6982.83 STB/d with a high water production rate of 5586.264 STB/d and a low oil production rate of 1396.566 STB/d. From Fig. 5 the flow rate of the liquid can be determined which is equal to the flow rate of oil plus the flow rate of water. The flow rates of oil and water are given in the PIPESIM software. This is a very minimal production process and does not cover the expenses that the company incurred for its realization. The scenario is based on the installation of EPS to control the problem of water inflow into the technical oil wells produced more water than oil. Here the objective is to reduce the production of water, but the ESP produces as much water as oil. This is the reason why the scenario based on perforation is used. In the following subsection, it is shown that perforating the new oil zone increases the productivity index and reduces water inflow by 90%. In addition, the logistics of the perforation are very space-saving. The problem of water inflow in oil production wells has been reported in the literature as reported by Khashayar [17]. Highlighting from the findings of Ouyang [26], the development of inflow control devices for the improvement of Well performance and building chambers to control unwanted water in oil Wells as a consequence of heel-toe effects, heterogeneity and reservoir permeability, and the effects of pressure from other reservoirs in other region penetrated by a well were some highlighted factors. Furthermore, the employment of autonomous inflow control devices completion was a success with its first installation in March 2016, as part of the standard lower completion solution at East Belumut. From then, additional Wells have been completed with autonomous inflow control devices completions in East and West Belumut fields, demonstrating a significant increase in cumulative oil production, reduction in GOR of the autonomous inflow control devices wells by 50%, and achieving 50% more oil production compared to offset inflow control devices Wells. In this view, Mohd Ismail *et al*. [27] established a full field implementation for the application of autonomous inflow control devices in a super thin layer, oil reservoir offshore in Malaysia.

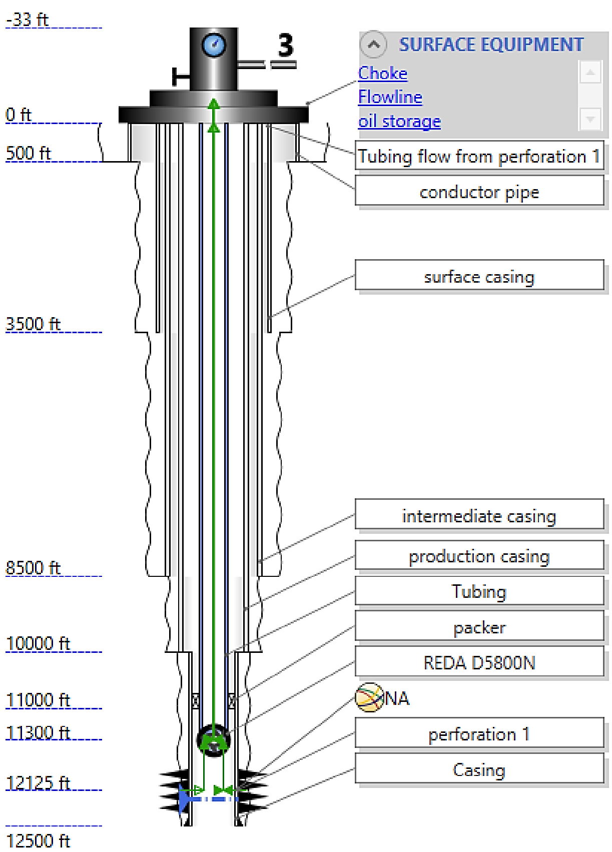

Fig. 4. Design of X Well after Pump Installation

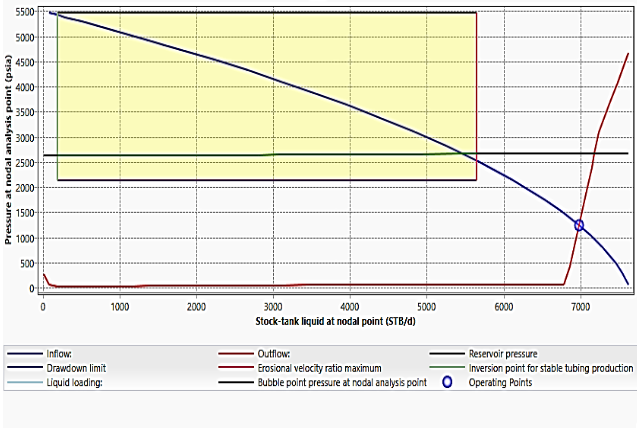

Fig. 5. Nodal Analysis of X Well after Pump Installation

2.2.2. Design of X Well with the New Perforation

Following the design steps, the first perforated area must be sealed with cement. After plugging, isolate with a plug as shown in Fig. 6.

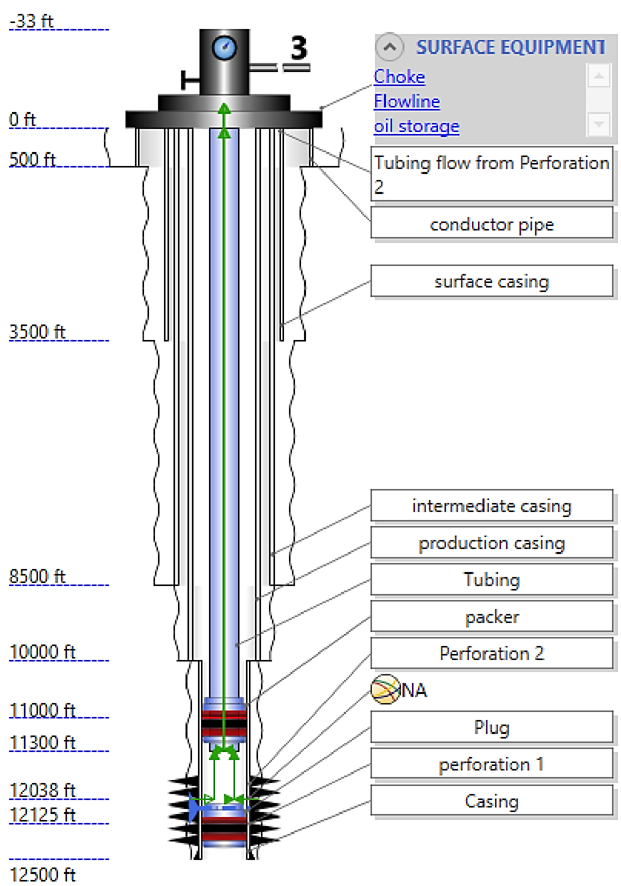

Fig. 6. X Well Design with New Perforation

Fig. 6 reveals that the well is perforated at 12038 ft. Fig. 7 shows a point of intersection between the VLP and IPR curves which indicates a production possibility from the X well.

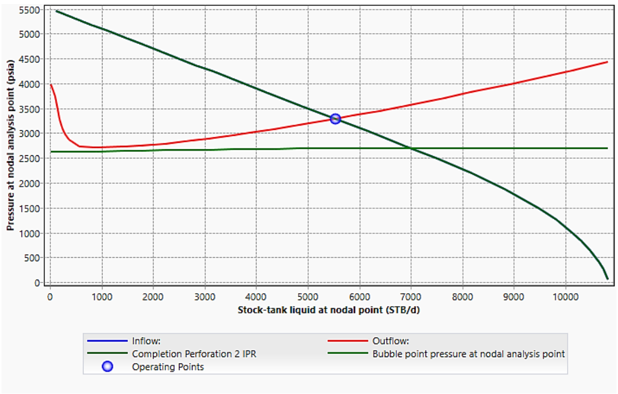

Fig. 7. Nodal Analysis of X Well with the New Perforation

In Fig. 7, the liquid production rate is 5543,387 STB/D with a low water production rate of 277,1693 STB/D and a high oil production rate of 5266.217 STB/D. The sensitivity tests carried out in this study are based on the diameter of the tubing, the diameter of the flow line, and the pressure at the wellhead to see the influence of each on the production flow rate of the global system. The sensitivity analysis of X well done after the new perforation according to the diameter of the tubing is presented in Fig. 8.

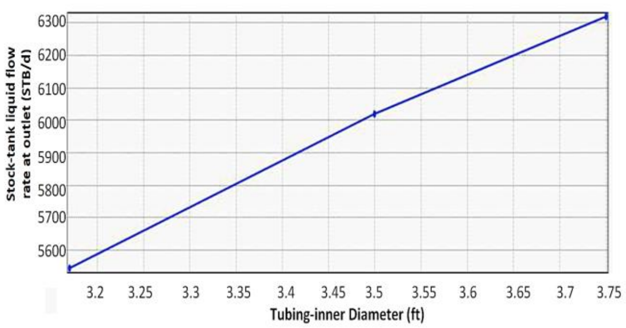

Fig. 8. Production of Well X with the New Perforation according to the Diameter of the Tubing

According to Fig. 8 a, the increase in oil flow rate is obtained by varying different tubing sizes namely 3.17 inch, 3.5 inch, and 3.75 inch. This variation in the diameter of the tubing does not make a very big change in the production of well X. However, changing the size of the tubing is not recommended, as this leads to very expensive operations and it will be necessary to remove the equipment from start to completion (operations taking too long). The analysis of the sensitivity of well X with the new perforation according to the diameter of the flow line and the pressure at the wellhead is presented in Table 5.

Table 5. Production of the Well X with the New Perforation according to the Diameter of the Flow line and the Pressure at the Wellhead

Flowline ID in inch	Liquid Flowrate in bbl/d	Flowline ID in inch	Liquid Flowrate in bbl/d	Flowline ID in inch	Liquid Flowrate in bbl/d
2.5	6745.259	3.5	6776.321	4.5	6781.101
2.5	6553.505	3.5	6565.851	4.5	6567.69
2.5	6004.342	3.5	6009.035	4.5	6009.728

According to Table 5, the sensitivity was made by varying the pressure at the wellhead from 50 to 350 psi and the diameter of the flow line from 2.5 to 4.5 inch. The increase in wellhead pressure and the diameter of the flow line leads to a considerable increase in production. When combining these 2 parameters, that is decreasing the pressure at the wellhead and increasing the diameter of the flowline, there is always an increase in production. From the 3.5 to 4.5 inch interval and a pressure of 50 to 200 psi, a constant production is observed, hence the optimal parameters are found in this interval. The selection of optimal parameters as illustrated in Table 6 is based on the results and interpretations of Fig. 8 and Table 5. In essence, the sensitivity curves make it possible to see the parameters that the producer can use to make the pump even more efficient without modifying the downhole equipment and without however trying to destroy the pump life span. Also, increasing the number of stages may cause a load on the pump, so producing using the same number of stages and changing the inner diameter of the flow line and the frequency of the pump are other considerations for selecting the optimal parameters.

Table 6. Optimal Parameters

Optimal parameters	Values			Optimal Values
Tubing Diameter	3,17 inch	to	3,75 inch	3,17 inch
Flowline Diameter	2,5 inch	to	4,5 inch	3,5 inch
Wellhead Pressure	50 psi	to	350 psi	150 psi

After sensitivity analysis is done, the optimal parameters are obtained and these parameters are replaced, simulated, and computed again to have the results of Fig. 9.

Fig. 9 shows that the optimal liquid production rate is 6172.256 STB/D with low water production of 308.6128 STB/D and high oil production of 5863.643 STB/D at a pressure of 5174.207 PSI. It is important to note that the production of oil and water from well X with the new perforation is better than those obtained with the activation of well X by the ESP. Thus, it is wise to make an economic assessment to have the profitability of the scenario based on the new perforation.

Comparatively, the installation of the ESP design at 11300 ft observed a water production flow rate of 5586.264 STB/d and oil production flow rate of 1396.566 STB/d while the installation of the new perforation at 12038 ft observed a water production flow rate of 277.1693 STB/d and oil production flow rate of 5543.387 STB/d. The new perforation is appropriate because this scenario allows water reduction and oil production maximization via the sensitivity analysis for obtaining the optimal parameters values with 308.6128 STB/d for the water production flow rate and 5863.643 STB/d for the oil production flow rate.

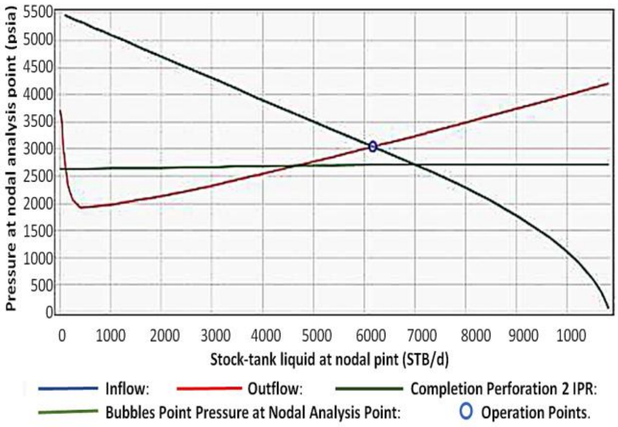

Fig. 9. Nodal Analysis of Well X with the New Perforation after Optimization

2.2.3. Economical results

The prediction of oil production is made with the decline curve based on the harmonic model as shown in Fig. 10. It should be highlighted that this exposes the detailed economic profitability of the chosen method for reducing water ingress in well X. Also, this gives the producers an idea about the outcome of the entire exploration process economically.

The producer's objective is to produce on average more than or equal to 1000 stb/d. Below 1000 stb/d, well X is not economically profitable. Fig. 10 reveals that well X remains economically viable for 16 years. Table 7 and Table 8 show the cost of capital, i.e. the cost until the end of the exploitation of the well X. It is the cost of the supply, the construction, the administration, and the operational cost during installation. These data are field data from the field explorations.

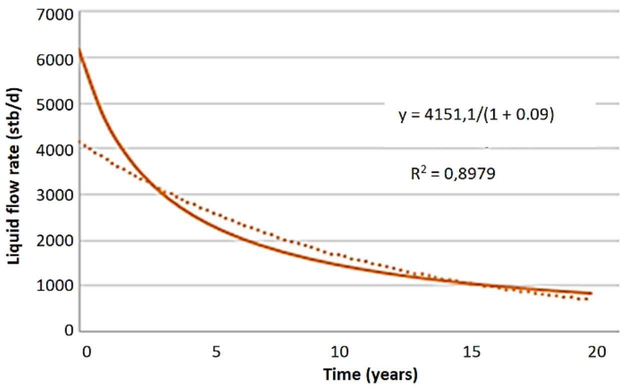

Fig. 10. Well X Production Prediction Curve with the New Perforation. The Full Line Denotes the Actual Line While the Dotted Line is the Best-Fit Line

Table 7. Capex

Activities	Cost
Surface Equipements	100000 $
Cold Tubing Equipment Renting	72000 $
Taxes	362277915 $

Table 8. Opex

Activities	Cost
Water Treatment	10000 $
Operation Cost	18000 $
Maintenance Cost	80000 $
Cost to Produce 1 Barrel of Oil	3 $

Table 9 shows the maintenance rate and total expenditure.

Table 9. Maintenance and Expenses

Total Revenue	Total Taxes	Total Expenses	Cash-Flow	Net Cash-Flow	NPV	ROI
1207593051$	362277915$	67368502,83$	1140224548$	798157184$	98086854$	0,499578339/an

The results in Table 7 to Table 9 indicate a water production rate of 308.6128 STB/d and profitability of 98,086,854$ and a return on investment over 5 months during 16 years of production. While this exploration remains economically viable, economic evaluation of productive Wells is reported also in the following works. Recently, the research paper concerning the heightening of the petroleum productivity of an eruptive well by an electric submersible pump with a free gas separator done by Biloa *et al*. [28] reported a higher economic profit of 9,152,939,013.84$ with a return on investment within one year from the year of production. Also, Kamga-Ngankam *et al*. [12] exploring the production mechanisms of an oil Well via the nodal analysis predicted an increased production of the Well between 800 to 1000 barrels per day. Lastly, Matateyou *et al*. [29] put on view in the existing literature that an optimal flow rate of 262.9 STB/d of oil can be produced and the payback period is one year and two months from their investigations concerning the activation of a non-eruptive well by employing gas lift techniques and mechanisms of its productivity, sensitivity, and economical analysis.

3- Conclusion

This study aimed to maximize oil production from the X well of field Y by reducing water inflow into Well X. Well data was analyzed by using PIPESIM and Microsoft Excel software based on the nodal and decline curve analysis. In order to optimize the production of X well by reducing water inflows, two scenarios were proposed. Scenario 1 was based on the activation of well X by the ESP gave an oil production rate of 1396.566 STB/day with a water production rate of 5586.264 STB/day. While scenario 2 based on the new perforation of X well gave an oil production of 5543.387 STB/day while producing 2771.693 STB/day of water. A sensitivity analysis was carried out from scenario 2 by modifying the diameter of the flow line and the pressure at the wellhead, which generated an optimal oil flow rate of 5886.643 STB/day with a water production rate of 308.6128 STB/day, the profitability of $98,086,854 and a return on investment of 5 months over a production period of 16 years. The results clearly indicate that Scenario 2 (based on the new perforation in X well) is better than scenario 1 (based on the activation of X well by an electric submersible pump) in terms of production and economy.

Data Availability

Data will be made available upon reasonable request.

Conflict of Interest

The authors declare that they have no conflicts of interest.

Funding Statement

Not Applicable.

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تحسين انتاج بئر النفط عن طريق تقييد اختراق الماء

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الخلاصة

تتناول هذه الدراسة البئر المسمى X (لاسباب سرية) للحقل المسمى Y والذي كان في البداية منتجا بالطاقة الطبيعية لمكمن النفط في غياب الماء. وبعد بضع سنوات من الانتاج بدأت المياه تتدفق بشكل مفرط في البئر. ان الهدف من هذا البحث هو زيادة الانتاج في بئر النفط X عن طريق تقليل دخول الماء. تم تحليل بيانات درجة الحرارة، الحجم والضغط (PVT)، وبيانات الانجاز، وبيانات المكمن عبر برنامج PIPESIM و Excel باستخدام طريقة التحليل العقدي للحصول على اداء البئر ومنحني الانخفاض للتنبؤات. تم اخذ سيناريوهين في الاعتبار: اولا تركيب مضخة غاطسة كهربائية (ESP) لتنشيط البئر X وثانيا اجراء ثقب جديد. تم تركيب نظام ESP على ارتفاع ١١٣٠٠ قدم حيث يبلغ معدل تدفق انتاج المياه ٥٥٨٦,٢٦٤ برميل/يوم ومعدل تدفق انتاج النفط ١٣٩٦,٥٦٦ برميل/يوم. تم تركيب الثقب الجديد على ارتفاع ١٢٠٣٨ قدم حيث يبلغ معدل تدفق انتاج المياه ٢٧٧,١٦٩٣ برميل/يوم ومعدل تدفق انتاج النفط ٥٥٤٣,٣٨٧ برميل/يوم. للحصول على الظروف المثلى، يتم تطبيق تحليل الحساسية على قطر خط التدفق وضغط راس البئر. حيث كانت الظروف المثالية التي تم الحصول عليها هي ٣٠٨,٦١٢٨ برميل/يوم لمعدل تدفق انتاج المياه و ٥٨٦٣,٦٤٣ برميل/يوم لمعدل تدفق انتاج النفط. يعد التثقيب الجديد مناسبا لان هذا السيناريو يسمح بتقليل المياه وزيادة انتاج النفط وربح قدره ٩٠٨٦٨٥٤ دولارا وعائدا على الاستثمار في ٥ اشهر خلال ١٦ عاما من الانتاج.

الكلمات المفتاحية: اختراق الماء، المضخة الغاطسة الكهربائية، التحليل العقدي، التثقيب، انتاج النفط، العائد على الاستثمار.