

ACTIVATION OF A NON-ERUPTIVE WELL BY USING AN ELECTRICAL PUMP TO OPTIMISE PRODUCTION

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Summary

The purpose of the study is to activate a well named X (for confidential reasons) in order to improve its production by proposing an electrical submersible pump. The nodal analysis is performed to understand the well's condition and an economic evaluation is done to determine the applicability of the project. The initial completion data, the pump placement data and the economic data are considered and used as input in PIPESIM 2017 software for operations and simulations. The results obtained from nodal analysis show that the well is in a total depletion situation. Upon analysis, the electrical submersible pump type REDA S6000N with operational diameter of 5.38 inches is appropriately chosen and installed, resulting in a flowrate of 4,891.36 stock-tank barrels per day (stb/d) with a bottom pressure of 2,735 pounds per square inch (psi). A flowrate of 5,000 stock-tank barrels per day at a pressure of 2,707 psi is obtained after optimisation of the pump through sensitivity curves. The economic balance sheet presents a net present value of USD 110,718,250, showing the profitability of the project over a period of one year.

Key words: Non-eruptive well, electrical submersible pump, nodal analysis, optimisation, sensitivity curves, economic balance sheet.

1. Introduction

The world's demand for energy keeps growing especially for hydrocarbons as they are of high and of primary importance in the industry domain, not to mention the society's needs [1 - 3]. This increasing demand is not favoured by the reducing number of discoveries done as years go on, it is then necessary to increase production in an efficient and profitable manner. Nowadays, many wells cannot rely solely on its natural energy to pull up the hydrocarbons to the surface; this is simply due to the pressure drop in the reservoirs and increase in the volume of basic sediments and water [4 - 7]. Thus, using activation methods, whose objective is to decrease the downhole pressure and enable production of hydrocarbons, is necessary. Artificial lift refers to the use of artificial means to increase the flow of liquid, such as crude oil

or water, from a production well through downhole pressure reduction. There are several different types, which are electrical submersible pumps (ESP), gas lift, progressive cavity pump, rod lift systems and hydraulic pump [8 - 11]. It is, therefore, always important to optimise oil production from existing wells by using the appropriate artificial lift [12 - 14]. Activation using an electrical submersible pump is one of the most effective and efficient methods to increase production of a depleted well [15 - 17]. For confidential reasons, the well and the field used in this paper are called well X and field X, respectively. The question which arises is in what way the differential pressure can be increased to maximise the production. This work aims at activating well X to improve production by proposing an electrical submersible pump case of an abundant water production.

The paper focuses on the configuration design of the electrical submersible pump (ESP), a nodal analysis to confirm the actual rate of the well to optimise the activated well X, and an economic evaluation. The content is, there-



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Table 1. Initial completion data

Reservoir pressure	4,000 psi
Reservoir temperature	200 °F
Productivity index	2.5 stb/d.psi
Water cut	60%
Gas - Oil ratio (GOR)	250 SCF/stb (>)
Production specific gravity	0.865
Oil formation volume factor	1.25
Maximum flow rate (MFR)	10,000 stb/d
Model	Vogel
Production tubing	9,000 ft; ID = 3.5"; OD = 5"
Packer	8,850 ft
Perforation depth	9,500 ft
Wellhead pressure	250 psi

Table 2. Data for the pump design

Operational oil rate	5,000 stb/d
Wellhead pressure	250 psi
Water cut	60%
Activation objectives by the submersible pump	Choose the appropriate pump Place the pump at the required depth Produce with the pump at an optimal rate

Table 3. CAPEX, OPEX and profits

CAPEX	OPEX	Profits
Surface and downhole equipment USD 500,000	/	Oil price: USD 75
Maintenance done on a well three times a year USD 50,000	Cost of producing one barrel of oil USD 10	Daily oil price
Running equipment cost USD 350,000	/	/
A tax of 5% on revenues	/	/

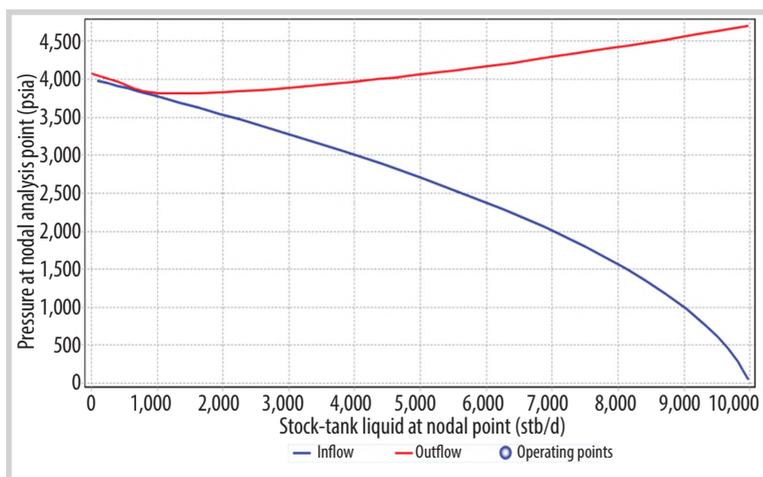


Figure 1. Nodal curve of well X: IPR/VLP.

fore, sliced into three sections: the first one presents the introduction; the second devotes to the data and highlights these obtained results followed by a discussion and the last is for conclusion.

2. Material and methods

Well X is a vertical one whose profile starts with a conductor pipe at 1,000 ft having an outer diameter (OD) = 26 inches and inner diameter (ID) = 20 inches of grade H40; a surface casing of OD = 17.5 inches and ID = 13.25 inches of grade J55; an intermediate casing of OD = 12.25 inches and ID = 9.625 inches of grade K55; and a production casing of OD = 8.5 inches and ID = 7 inches of grade C75. The well head is connected to a choke (ID = 2 inches) by a connector and the choke itself is connected to the sink by the flowline (ID = 3 inches) having a horizontal distance of 2,000 ft. The initial completion data, the pump placement and the economic data supporting the results of this paper are presented in Tables 1 to 3.

The data of Tables 1 to 3 help to achieve the initial completion of well X, develop a good design of the pump, install the pump at a required depth and conduct the nodal analysis in order to obtain an optimised flow rate of the activated well X. The PIPESIM 2017 software, nodal analysis and economic evaluation are used.

3. Results and discussions

According to the nodal analysis results shown in Figure 1, the non-eruptivity of the well is confirmed as no operating point is present on the graph: the inflow and the outflow curves do not meet, which means the well is not producing.

To make well X become productive again, it is necessary to use activation methods. An electrical submersible pump is applied in this case because of the high-water level, the desire to produce at a flow rate of 5,000 stock-tank barrels per day (initially at 4891.36 stock-tank barrels per day), the absence of gas, and an average reservoir temperature. The pump is installed after the introduction of certain elements such as the desirable flow rate, the inside tubing, the wellhead pressure and certain reservoir data.

Table 4. Pump results presentation

Results of the pump after simulations	Parameters values
Pump depth	9,000 ft
Tubing total depth	3,294.4 ft
Suction pressure of the pump	2,506.905 psi
Discharge pressure	3,795.141 psi
Differential pressure	1,288.235 psi
Number of stages	63
Frequency of the pump	60 Hz
Power of the pump	163.93 hp
Diameter of the pump	5.38"
Pump model	REDA S6000N
Downhole pressure	2,735.315 psi

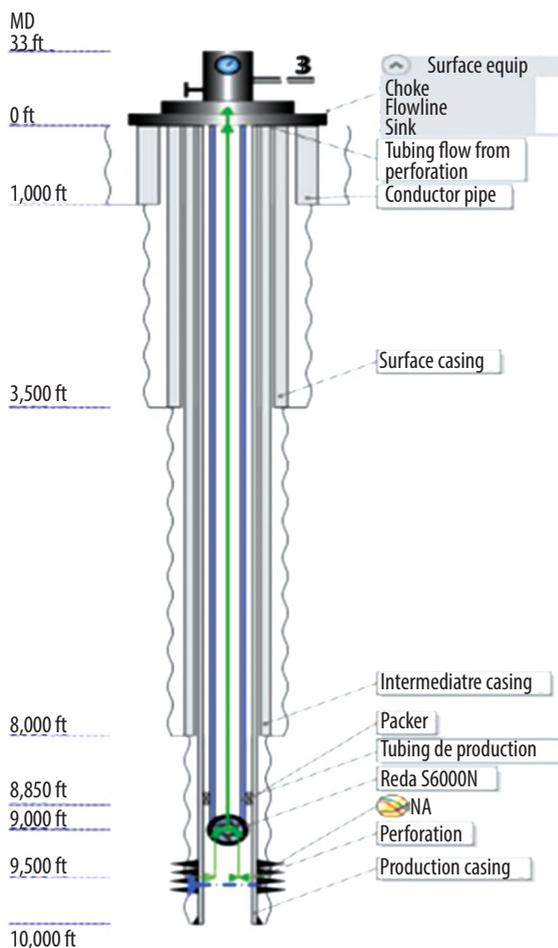


Figure 2. Installation of the pump.

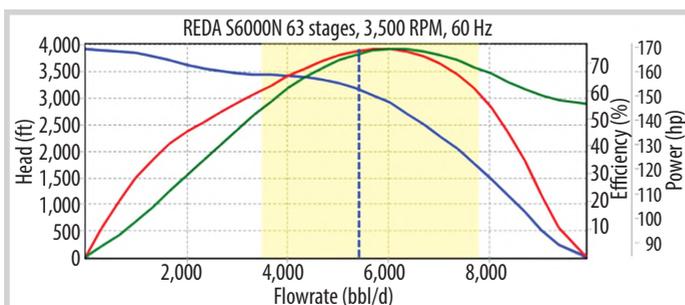


Figure 3. Appropriate performance of the pump.

Electrical submersible pump characteristics

- The standard 60 Hz producing range is from 100 barrel per day up to 90,000 barrel per day;
- Electrical submersible pump characteristics are based on a constant rotation speed, which depends on the frequency of the AC supply: 3,500 RPM with 60 Hz and 2,915 RPM with 50 Hz;
- Currently operating in wells with BHT up to 350°F;
- Efficiently lifting fluids in wells deeper than 12,000 ft;
- System efficiency ranging from 18% to 68%;
- Having a narrow production rate range;
- Not handling free gas.

The simulations performed on PIPESIM to determine the placement depth of the pump, the number of required stages, the suction pressure and discharge, the pump frequency, the pump height in the tubing, the model of the pump, and the efficiency installed are presented in Table 4 and Figure 2.

One can notice from Figure 2 that the installation of the pump at a depth of 9,000 ft is correct as it is close to the perforations. This is to reduce the bottom pressure as much as possible but also for the good cooling of the pump motor. Figure 3 shows the performance curve of the pump.

In Figure 3, the pump curves are customised for each pump in order to plot the ability to move fluids; the delivery capacity (blue curve), the pump efficiency (red curve), and power (green curve) are plotted against flow. The most important part of this performance graph is the load capacity curve, which plots the relationship between the total wellhead dynamics and the flow capacity of a specific pump. A pump can only develop a certain drop height for a given flow, and vice versa. The yellow area on the pump curve indicates the most efficient operating range of that specific pump. In this case, the dotted blue line shows that at 60 Hz, this 63-stage pump is operating in the optimum range. The flow produced by the well after installation of the pump is shown in Figure 4.

The point at which the inflow performance relationship - IPR (blue curve) and vertical lift performance - VLP (red curve) meet is marked as the op-

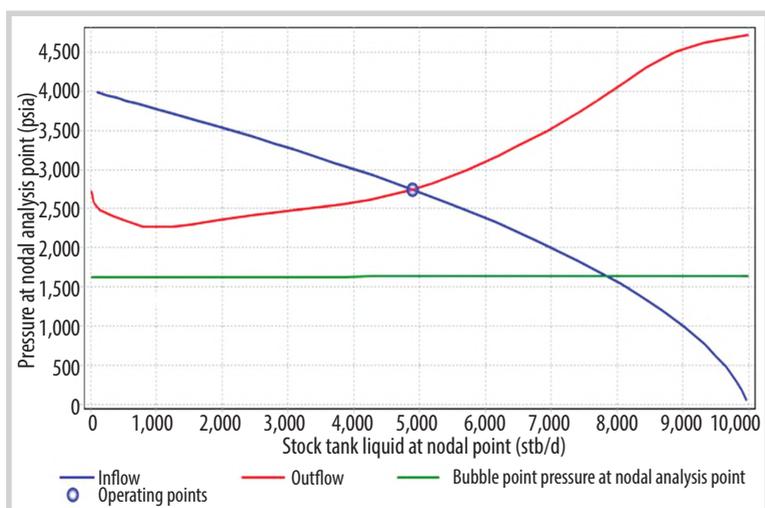


Figure 4. IPR/VLP after the installation of the pump.

Table 5. Results of the activation of the well using ESP

Operating rate	4,891,368 stb/d
Operating pressure	2,735.31 psi
Water cut	60 %
Bubble pressure	1,600 psi
GOR = 250 SCF/stb (>)	Presence of a separator at the bottom (100%)
Effectiveness of the pump	72%

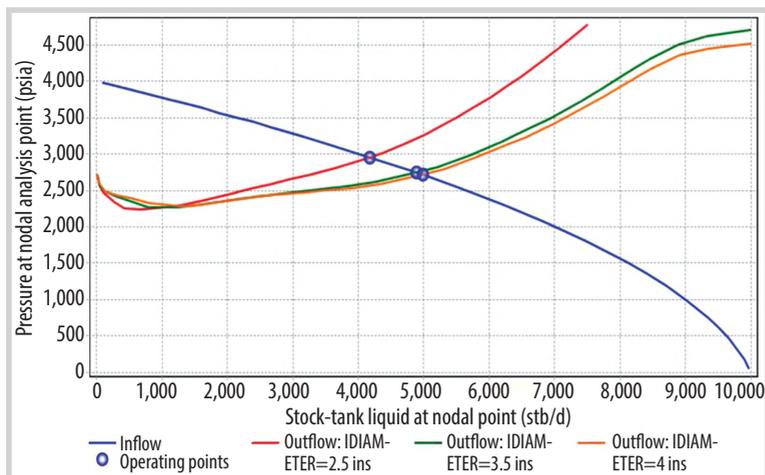


Figure 5. Tubing diameter influence on the well.

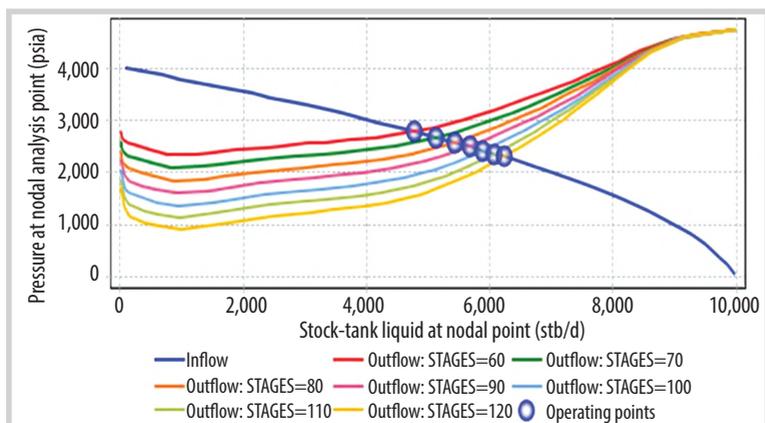


Figure 6. Influence of the number of stages on the flowrate.

erating point, which specifies the flow rate of well X and the pressure at the bottom of well X to Figure 4 and Table 5.

Even though well X becomes eruptive, it does not produce at an optimal rate. Thus, it is necessary to optimise the well by using nodal analysis from the PIPESIM software considering the sensitivity curve. In order to know the influence of the tubing diameter on production using the electrical submersible pump system and justify the casing choice, a sensitivity test is done as shown in Figure 5.

Figure 6 shows the variation of the vertical lift performance (outflow performance relationship) at different stages and their influence on the flow rate. This decreases the pressure at the bottom but increases the load on the pump which can lead to early weariness of the engine. The nodal analysis was then used to verify the impact of the variation at the wellhead and its performance on the well, the pump and the nodal point as presented in Figure 7.

From Figure 5, the variation of the tubing diameter does not significantly influence the operating point of the well. Moreover, by keeping the pump system unchanged, the same results are obtained. The sensitivity of the number of pump stages is depicted in Figure 6.

Figure 7 is a graph of pressure at nodal point against flow rate. It is easily seen that increasing the wellhead pressure decreases the flow rate and simultaneously increases the bottom hole pressure. So, it is wise to reduce the pressure at the wellhead because it renders the pump more efficient. For the safety of the well and the pump, the pressure will be reduced to 50 psi because a high production can lead to the production of sand from the formation, which can corrode the pump and the tubing. Figure 8 shows the nodal analysis curves for well X showing the optimal flow rate.

After optimisation of the well, the desired flow rate of 5,000 stock-tank barrels per day is

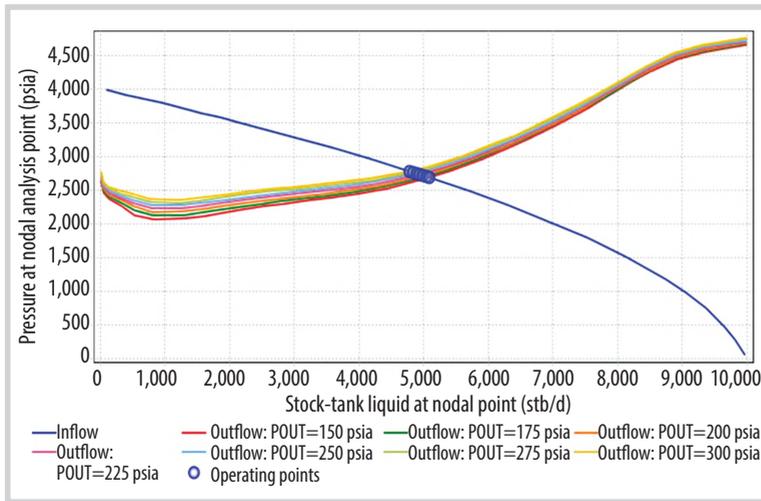


Figure 7. Pressure influence at the wellhead.

Table 6. Wellhead pressure sensitivity results

	Operating point	Stock-tank liquid at nodal analysis stb/d	Pressure at nodal analysis psi
1	$P_{out}=150$ psi	5,091.4	2,672.885
2	$P_{out}=175$ psi	5,045.852	2,687.208
3	$P_{out}=200$ psi	4,988.474	2,702.039
4	$P_{out}=225$ psi	4,945.792	2,718.449
5	$P_{out}=250$ psi	4,893.312	2,734.714
6	$P_{out}=275$ psi	4,835.977	2,752.391
7	$P_{out}=300$ psi	4,778.374	2,770.054

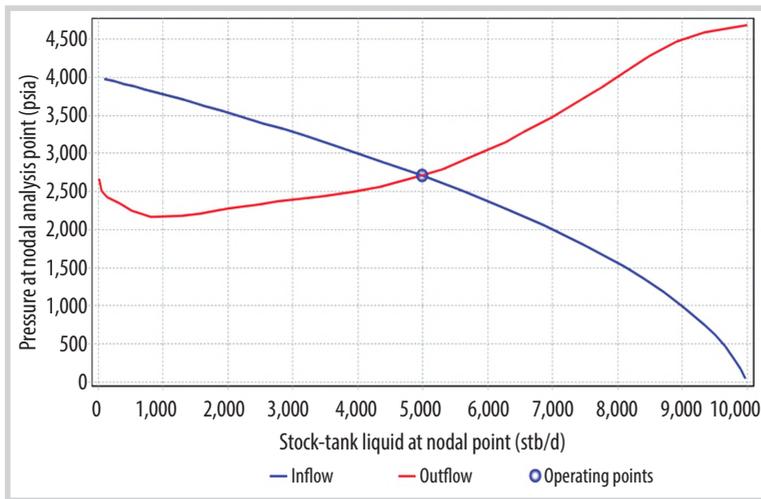


Figure 8. IPR/VLP of the well after optimisation.

Table 7. Production profit

Activation method	Stb/d	Stb/y	Per year (USD)
Electric submersible pump	5,000	1,825,000	1,365,000

Table 8. NPV of the company over a year

CAPEX + OPEX (USD)	Oil benefits for a year	NPV
26,093,750	136,875,000	110,781,250

attained at a pressure of 2,702.5 psi and the effectiveness of the chosen pump is found to be 69%. The pump has a life span of three years, so the well will produce at a constant flow rate of 5,000 stock-tank barrels per day based on the sensitivity curves analysis done for the well.

3.1. Economic evaluation

The production profile of the well activated by electrical submersible pump was obtained by carrying out simulations on the PIPESIM 2017 software, which is the first part, and the second part consists of carrying out an economic evaluation to know the profits the company will get. Capital expenditure (CAPEX) and operation expenditure (OPEX) must be taken into consideration; the income is based only on the oil production; the company pays a 5% income tax per year, and the oil price is USD 75 per barrel. Table 7 shows the profit of production without withdrawal of taxes.

After pulling out the expense and income tables, the business gain during this operation must be known. The net present value (NPV) represents the net money recovered by the company, it is estimated using the formula: $NPV = REVENUES - EXPENDITURES$. The results are shown in Table 8.

In view of the economic analysis which shows a good NPV value, activating the well is a good choice as it makes it possible to recover a higher rate of hydrocarbons at an average or low cost. In an alternative where oil price increases, the method will still be applicable and remain the best.

3.2. Discussion

When simulating the production of well X, it was noticed that the well no longer produced with a water level of 60%. This led to the installation of a pump at 9,000 ft above the perforations, which allowed the well to produce at a flow rate of 4,891.36 stock-tank barrels per day with a bottom hole pressure of 2,735 psi. The production did not reach

the required flow rate of 5,000 stock-tank barrels per day, this led to the optimisation of the pump using sensitivity curves. After simulating these different sensitivity parameters, the first option was to change the diameter of the tubing, but it is not recommended as it has no great impact on the production rate and also because of the high cost related to the tubing changes. The second option was to increase the number of stages but it put more loads on the engine. Then the next possible option was to reduce the pressure at the wellhead to 200 psi to increase the flow rate to 5,000 stock-tank barrels per day and decrease the pressure drop in the tubing. The economic evaluation carried out after optimisation showed that it was a profitable project. Palen and Goodwin indicated that the optimisation of daily production will increase the production rate by 1 to 4% [18]. Alias had studied optimisation of the production of a well named B in field X in southern Malaysia [19]. This well had a production of 600 stock-tank barrels per day; by reducing the pressure at the wellhead and injecting 2 million standard ft³ per day, it had a production flow rate of 1,040 stock-tank barrels per day, which is a production gain of 73%. The authors of [17] worked on a well which was optimised by using the nodal analysis. They obtained a flow rate of 1,800 barrels per day (previously 800 barrels per day) by decreasing the wellhead pressure from 350 psi to 100 psi and increasing the tubing diameter from 2.5 inches to 2.99 inches. The wellhead pressure is, therefore, an important parameter to consider when optimising a well.

4. Conclusion

This work aims to activate well X in order to improve production by using an electric submersible pump. For this, two approaches were implemented: (i) a technical study allowing the nodal analysis of the well to be carried out using the PIPESIM 2017 software, and (ii) an economic approach to assessing the profitability of the project. The nodal analysis carried out shows that the natural energy of the reservoir is not enough to push up the hydrocarbons from the reservoir to the surface. Thus, the REDA S6000N model pump with a power of 163.93 hp was installed at a depth of 9,000 ft with the aim of reducing the bottom-hole pressure as much as possible but also cooling the latter's engine. The nodal analysis was done again to evaluate the production flow rate after the pump installation (4,891.36 stock-tank barrels per day). Though it is eruptive, the bottom-hole pressure remains high which could end up creating a problem with the operation of the engine in

the long run. So, it will be advantageous to optimise the pump and the well to reduce the pressure at the bottom and produce at an optimal flow rate. This part was done using the nodal analysis based on the sensitivity curves. The study of the sensitivity on the tubing diameter, number of stages of the pump and the pressure at the wellhead reveals that varying the tubing diameter influences less on production, whereas increasing the number of stages increases the production but creates an overload on the engine. Reducing the pressure at the wellhead can help to overcome this problem and make the pump's operation more efficient. These sensitivity tests improved the activated well and gave an optimal production flow rate of 5,000 stock-tank barrels per day and a net present value of USD 110,781,250.

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