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ESP PRODUCTION OPTIMIZATION BY USING PIPESIM

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A B S T R A C T

Artificial lift systems are among the most extensively employed production methods. Lift methods are required to facilitate production in wells that cannot produce liquids to the surface under their pressure. One of the important types of artificial lift methods, which is lowers the producing bottom hole pressure on the formation to obtain a higher production rate from the well. It is an efficient and reliable method for lifting moderate to high volumes of fluids from wellbores.

This study aims to design & Simulate an Electrical submersible pump by using PIPESIM software also to change WC, GOR and Tubing size to observe the effects of each one of them on the ESP design and on production system.

The input data from the Nafoora oil field that is operated by the Arabian Gulf Oil Company (AGOCO) a subsidiary of the state owned national oil corporations (NOC).

1 Introduction

Artificial lift methods, especially Electrical Submersible Pumps (ESPs), are widely used to enhance oil production from wells that cannot flow naturally due to insufficient reservoir pressure. ESPs are reliable and efficient systems capable of lifting moderate to high volumes of fluids, making them essential in modern petroleum engineering (Ahmed, 2019). To ensure optimal performance, simulation tools such as PIPESIM are employed to model and optimize production systems by analyzing parameters like Water Cut (WC), Gas-Oil Ratio (GOR), Productivity Index (PI), and tubing size (Ahmed, 2019). This study focuses on optimizing the performance of an ESP installed in Well X1 at the Nafoora oil field, operated by AGOCO in the Sirte Basin, Libya (ALDBIA, 2021). Using nodal analysis through PIPESIM, the well's deliverability is evaluated, and various design changes are simulated to maximize output and solve initial productivity issues (Beggs, 1991; Davies, 2004). The research demonstrates how digital modeling can support effective decision-making in artificial lift design and production optimization (Brown, 1977; Forero & McFadyen, 1993).

2 Electrical Submersible Pump (ESP)

The electrical submersible pump (ESP) is a reliable and practical artificial-lift device for lifting moderate to large volumes of fluids from wellbores. These capacities range from 150 B/D to 150,000 B/D (24 to 24,600 m3/d). Variable-speed controllers can considerably increase this range, both on the high and low end. The following are the essential components of the ESP: a multistage centrifugal pump, a three-phase induction motor, a seal-chamber section, a power cable, and surface controls.

2.1 PIPESIM

It is a computational fluid dynamics (CFD) software package that allows you to correctly recreate the behavior of various fluids (defined here as both liquids and gases). It gives businesses that deal with oil, water, and other fluids flow assurance by modeling how they will function during transit and storage.

2.2 Study Area

The field was discovered in the early 1960s and started production at 1964. The operational company of The Nafoora field was OXY until Nationalization in 1972. Nafoora field is located in the Sirte Basin in the east of Libya between Aojala and Ahskara oasis with The field has an estimated 7.5 billion barrels of oil in place, making it one of Libya's major oil fields.

3 Optimization Approach

It is a kind of intelligence-based approach it allows some values of parameters to be determined by the computer program in one run the parameter values are optimized to ensure the objective function is either maximized (production rate as the objective function) or minimized (cost as the objective function) under given technical or economical constraints apparently, the optimization approach is more efficient than the simulation approach.

4 Problem Statement

One of the challenges faced in lifting the oil and gas from the reservoir via the production tubing to the surface facilities is artificial lift installed in wells to increase the production rate, there are some problems encountered after the installation of these lifting methods to help recover the column of fluid to the production facilities at the surface.
The main problem in this study;

- No productivity in X1 well.
- Production optimization at a selected well.
- Improve and solve ESP problems at wells that use this artificial lift method.

5 Methodology

The following steps should be taken to accomplish the objectives:

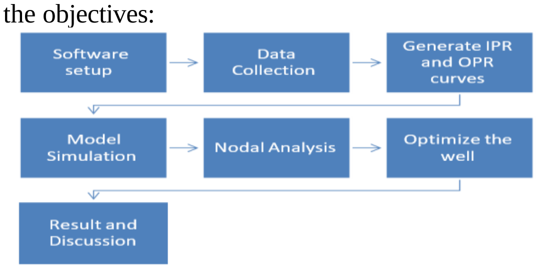

Figure 1: Research Procedure

6 ESP Installation

6.1 Well Data

Well X1 – Location: Nafoora Oil Field

Table 1: Physical well data

Casing size (in)	7
Tubing size (in)	3.5
Datum depth (ft)	8800
Deviation survey	vertical

Table 2: Production and reservoir data

Productivity Index (bpd/Psi)	2
Static BHP (psig)	2800
Flowing BHP (psig)	2000
Well-head Pressure (psig)	200
Desired fluid rate (bpd)	1600
Bottom hole temperature (deg F)	200

Table 3: Produced fluid data

Water specific gravity	1.04
API Gravity	35
Bubble point (psig)	600
Water Cut (%)	44
GOR	150
Oil formation volume factor(Bo)	1.14

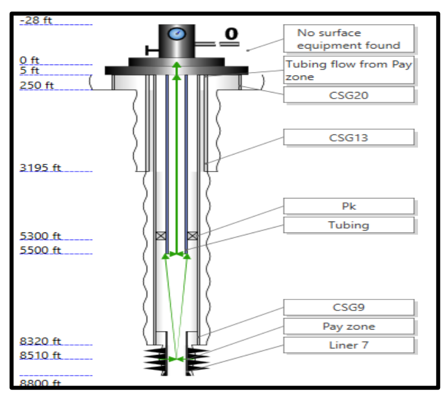

Figure 2: Well sketch by using PIPESIM

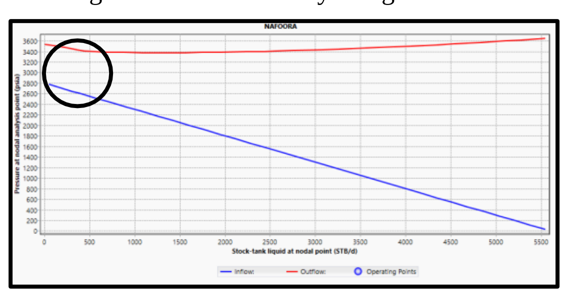

Figure 3: IPR VS OPR

It can be clearly observed in Figure 3 that there is no intersection between the IPR curve and the OPR curve, which explains why the well is not producing.

When all the well data were entered into the software The software suggested the type of pump REDA DN1800 as shown in Figure 4.

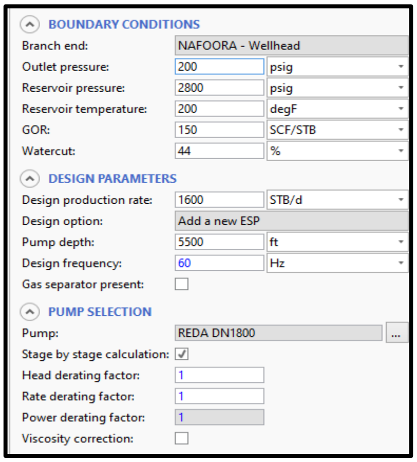

Figure 4: ESP Design Data

From the next Figure, we can find the pump efficiency 74% HP 53 and head 3570ft This curve represents the actual data for the DN1800 pump with 197 stage.

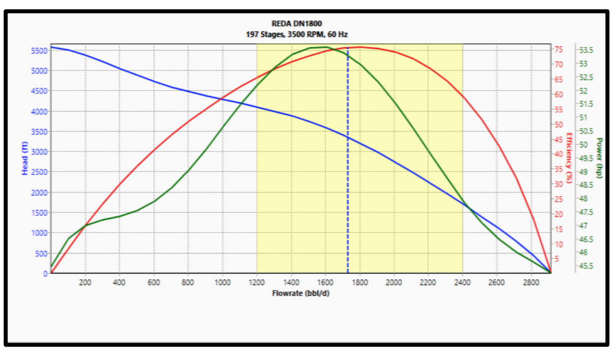

Figure 5: Actual pump performance curve

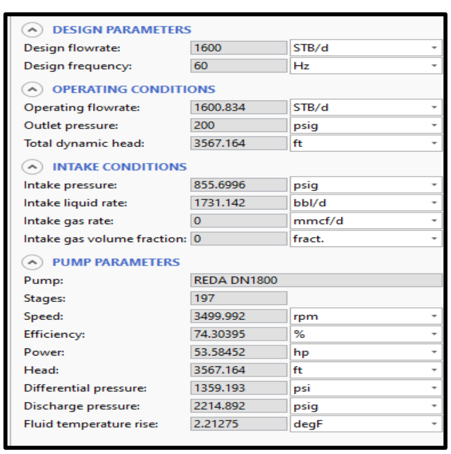

Figure 6: Design and pump parameters

After the pump is installed the nodal analysis shows the operating point, and the intersection between IPR curve and OPR curve is clear, and at this point the production is about 1600 bbl/day

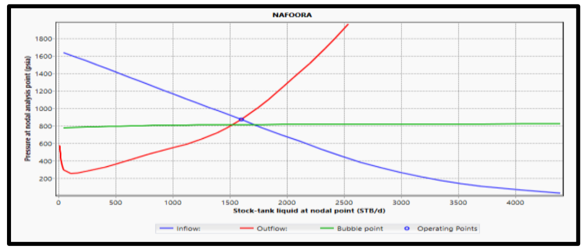

Figure 7: Well nodal analysis

7 Nodal Analysis

Now, after we finish the ESP design, we want to change some variables and analyze the data to achieve the optimum production rate and to know their effect on the ESP

7.1 Effect Of Water Cut

Table 4: Effect of Water Cut VS Flowrate

Water cut %	Flowrate stb/day
20	1699.94
30	1662.695
40	1623.558
50	1581.978
60	1537.874
70	1496.913
80	1447.037

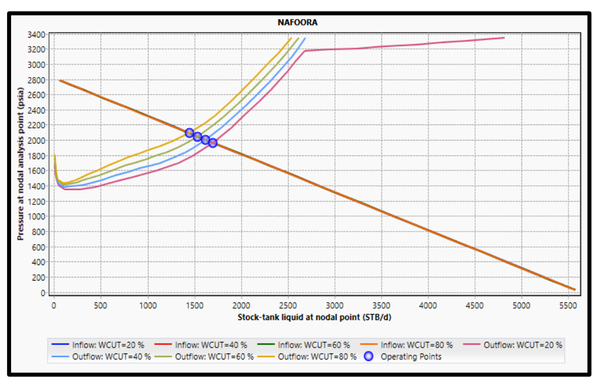

Figure 8: Effect of water-cut vs flowrate

As shown in the table 4 the relationship between WC and flowrate is inverse relationship when the WC increases the flowrate decreases this due to heavy column of fluid and the water density also on current WC 44% we can note that the production is about 1600 as we designed the pump as shown in figure 8.

7.2 Effect of GOR

Table 5: Effect Of GOR VS Flowrate

GOR scf/stb	Flowrate stb/day
150	1607.838
250	1691.685
350	1681.973
450	1643.723
550	1600.713
650	1554.666

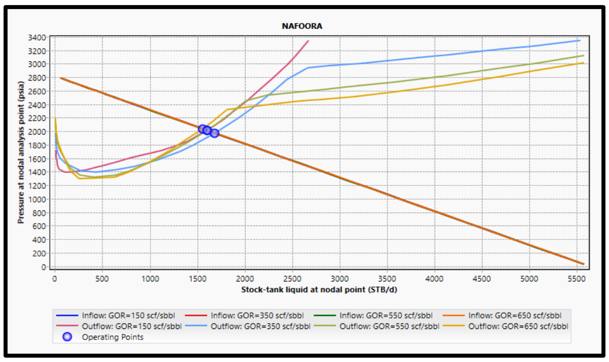

Figure 9: Effect of GOR vs Flowrate

As shown in the table at the beginning when the GOR reaches 250, the flow rate increases due to a decreased density of the column, but then starts to decrease due to gas restrictions and gas slugging. In general, the relationship between GOR and flowrate in ESP is an inverse relationship; when the GOR increases, the flowrate decreases. On the other hand, for the current GOR 150 scf/stb, we can note that the production is about 1600 stb/day as we designed the pump and there is no need to install the gas separator due to the low volume of gas.

7.3 Effect of Productivity Index (PI)

Table 6: Effect of Productivity Index VS Flowrate

PI stb/day/psi	Flowrate stb/day
2	1607.838
3	1812.54
4	1925.94
5	1996.589
6	2045.926
7	2082.303
8	2111.425

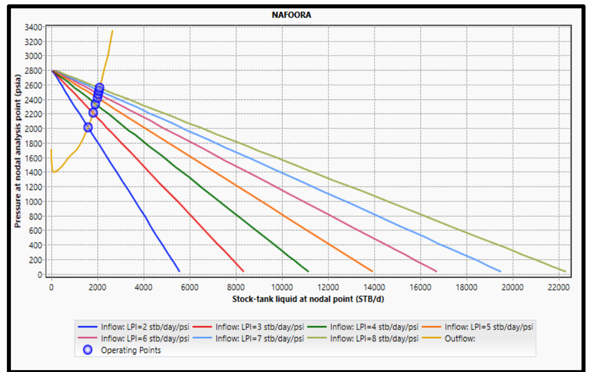

Figure 10: Effect of PI vs Flowrate

As shown in the table the relationship between PI and flowrate is proportional relationship when the PI increases, this is clear because the PI is the ability of a reservoir to deliver fluids to the wellbore. On the current PI 2 stb/day/psi we can note that the production rate is about 1600 stb/day as we designed the pump .

7.4 Effect of Tubing ID Dimeter

Table 7: Effect of Tubing ID diameter vs flowrate

Tubing ID dimeter in	Flowrate stb/day
1	762.4373
1.5	1378.367
2	1613.126
2.5	1673.646
3	1690.243
3.5	1694.793
4	1694.793
4.5	1692.348

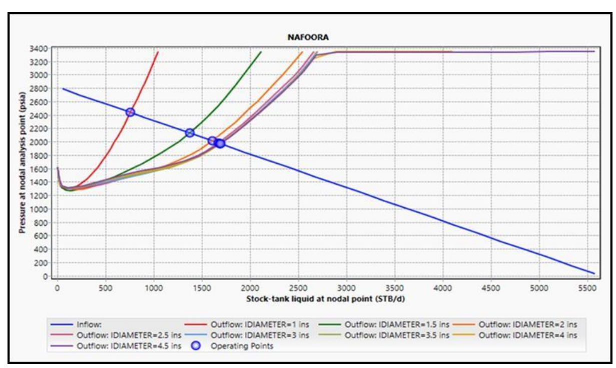

Figure 11: Effect of Tubing diameter vs flowrate

As shown in the table the relationship between Tubing diameter and flowrate is proportional relationship when the diameter increase the flowrate increase but when we reach the 3.5 in we reach the limit after that any increase will not increase the flow rate but on the contrary will decrease it and on this dimeter the production rate is about 1600 stb/day as we designed the pump.

7.5 Effect of Number of Stages

Table 8: Effect of number of stages vs flowrate and hp

Number Of Stages	Flowrate stb/day	HP
50	No flow	12.13222
100	726.6557	25.01354
150	1289.148	40.71765
200	1616.731	54.20811
250	1812.711	65.9963
300	1944.462	77.06777

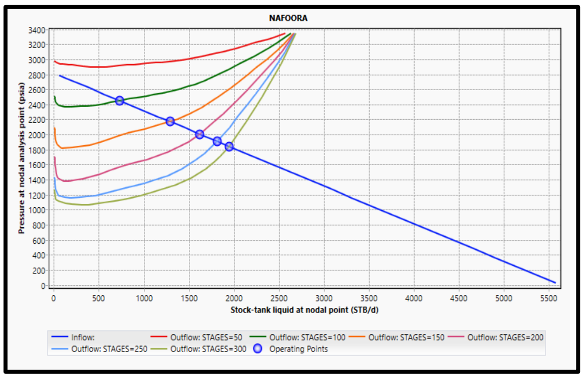

Figure 12: Effect of Number of Stages vs Flowrate

As shown in the table the relationship between number of stages and flowrate is proportional relationship when number of stages increase the flowrate increase but on the other hand also the power needed to operate the pump will increase. Also on 197 stages the production rate is about 1600 stb/day as we designed the pump.

8 Conclusion & Recommendation

8.1 Conclusion

1. Well deliverability is determined by analyzing the performance of the system" well" by the combination of IPR and the OPR. This technique of analysis is called "Nodal Analysis".
2. The IPR model is affected by the pressure drawdown, whereas the VLP model is affected by various parameters including tubing size, GOR, tubing head pressure and temperature, and water cut.
3. ESP can operate over a wide range of parameters e. g. depths and volumes of production rates.
4. There are many software available in companies and petroleum fields for using them in Nodal analysis technique and drawing the required graphs such as SNAP, Petroleum expert (prosper).
5. The most effective variables that we should really take in our consideration are WC and GOR the other variables don't have much effect.
6. The best pump efficiency was obtained at a water cut of 44%. Is 74%

8.2 Recommendations

1. The pressure drawdown must be increased to maintain a high inflow rate of formation fluids into the wellbore.
2. Using the worldwide developed software program, like Pipesim software, to help you in optimizing your production.
3. For collecting more accurate data, the model should be made with bigger scale design so the process is more clear and higher amounts of fluid used for circulating and separation.

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Conflict of interest: The authors declare that there are no conflicts of interest

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