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# ESP Wells Performance Analysis and Prediction on their Future Performance by Using the Nodal Analysis

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## Abstract

*This paper presented the research and the result obtained by the author regarding the actual and future performance of ESP wells. The ESP is capable of delivering high pressure increments for large oil rates so predicting their performance in the future became very important for economic reasons or issues related to reservoir parameters or to the system itself such as declining flow rate, water-cut variations, pump power etc. By using software specialized in simulating the whole process, we can determine a sensitivity analysis of the operating parameters and predict future performance that could help to manage future issues and deal with upcoming problems.*

**Key words:** *Electric submersible pump, Nodal analysis, productivity index, pump's parameters, simulation.*

## Introduction

Centrifugal submersible pumps were implemented for the first time in petroleum production in 1928. The most widely used are REDA centrifugal pumps. These submersible pumps are available for production rates ranging from about 30 - 40 m$^3$/day to 6 000 – 8 000 m$^3$/day, depending on tubing size where they are introduced. They are used for producing high rates of liquids and are ideal for high water-cut, low gas-liquid ratio wells.

We can add that ESPs are excellent choice for highly deviated wells. We must refer to the fact that many high-volume wells are equipped with electric submersible pumps (ESP) to lift the liquid and to decrease the flowing bottom hole pressure.

A submersible pump is a multistage centrifugal pump that is driven by an electric motor located in the well below the pump. This system works by electrical power, where this power it supplied by means of a cable from the surface. By combining the nodal analysis with the Pipesim software (owned by Schlumberger co.) allows us to create inflow-outflow plots at any points in the system, and perform sensitivity analyses on any system variables, providing an understanding of where our production enhancement opportunities exist.

In ESP case all present components beginning with the static pressure, ending with the wellhead pressure, and including inflow/outflow performance can be analyzed.

## Nodal Analysis

Nodal analysis supposes to choose a nodal point and to determine the inflow performance relationship (IPR) curve and the outflow performance curve. After that we can determine the operating point at the intersection of two curves mentioned above.

In order to carry out the nodal analysis in the submersible centrifugal pumps, the pump can be treated as an independent component, and the position of the node can be chosen at the pump level. In the case of pressure, the node can either be at pump intake pressure *($p_{up}$)* or discharger pressure *($p_{dn}$)* [1]. The difference in terms of pressure the pump must generate in order to produce the fluid rate from the pump can be determined according to the following relation:

$$\Delta p = p_{dn} - p_{up} \tag{1}$$

The pump's intake pressure will be calculated based on the gas-liquid ratio (GLR) of the formation and the pump's submergence, whereas the discharger pressure will be calculated based on the gas-liquid ratio entered within the pump and the tubing size (head required). If there is no valid information on the amount of gas separated, a percentage of 50% is considered [1].

The IPR shows us how the changes of bottom hole pressure at well perforations affect the production of the well. As for the ESP operations, the inflow of fluid from the layer into the bottom hole is set by the following relation [3]:

$$p_{up} = p_{wf} - \left|\Delta p_H + \Delta p_f\right|_{reservoir}^{ESP} - \Delta p_c \tag{2}$$

where $p_{wf}$ stands for bottom hole flowing pressure, $\Delta p_H$ - hydrostatic pressure drop, $\Delta p_f$ - frictional pressure drop and $\Delta p_c$ - pressure drop across the down hole choke.

The productivity index *(J)* is being introduced:

$$J = \frac{q}{p_r - p_{wf}} \tag{3}$$

where $q$ represents the flow rate and $p_r$ is the reservoir pressure. From relation (3) we have:

$$p_{wf} = p_r - \frac{q}{J} \tag{4}$$

The relation (4) is being replaced in relation (2), thus resulting the relation which can be used to build the IPR curve:

$$p_{up} = \left(p_r - \frac{q}{J}\right) - \left|\Delta p_H + \Delta p_f\right|_{reservoir}^{ESP} - \Delta p_c \tag{5}$$

So that the flow rate may reach the separator, a discharge pressure is necessary, $p_{dn}$ is calculated through the relation:

$$p_{dn} = p_{wf} + \left|\Delta p_H - \Delta p_f\right|_{ESP}^{wellhead.} + p_{wh} \tag{6}$$

where $p_{wh}$ is the well head pressure.

The discharge pressure is a factor which refers to the total pressure loss within the production system (Pump - Christmas tree) for any given flow rate. The relation (6) expresses the tubing intake or (The outflow performance relationship, OPR), it depends on several factors and allows to build the outflow performance curve. All these factors are all related to the geometry of the production system or the well's flow rate, as well as to the properties and temperature of the well flow.

If the IPR curves and the OPR curves are drawn in a common diagram, the intersection of the two curves represents the predicted well flow rate. Figure 1 presents the nodal analysis of a natural flowing well, for which the two types of curves intersect, and the well produces a certain flow rate. If the two curves do not intersect, then the well requires an artificial lift system (see fig. 2).

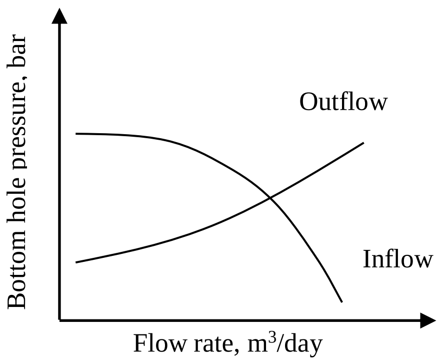



**Fig. 1.** Natural flowing well

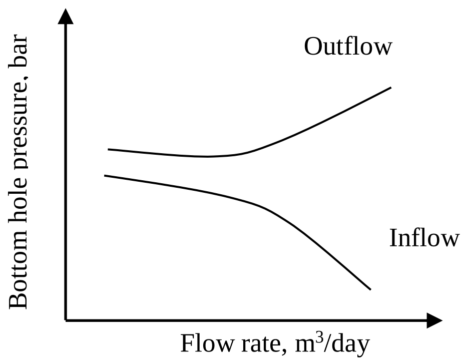



**Fig. 2.** The well needs an artificial lift system to flow

## Sensitivity Analysis of Operating Parameters for ESP Wells

The data used to determine this analysis come from onshore vertically drilled well, the well 01 (drilled in 1981*)*, produce in centrifugal pumping with ESP (electrical submersible pumps) ); it is part of field of wells drilled in the Al-Zaggut reservoir in North-Eastern Libya, and has following initial data: Casing size $d$ = 7 in; the well's depth is about 2316 m; perforation interval is at 1973 m; reservoir pressure $p_r$ = 146 bars; bottom hole flowing pressure $p_{wf}$ = 117 bars; wellhead pressure $p_{wh}$ = 7 bars; production rate $q$ = 208 m$^3$/day; oil density $\rho_o$ = 82 kg/m$^3$; oil viscosity $\mu_o$ = 7.78 cP; bottom hole temperature $T$ = 91.75 °C; water-cut is 33 %; the internal tubing diameter $ID$ = 3.5 in; estimated production rate to be produced $q_{ESP}$ = 278 m$^3$/day; productivity index $J$ = 9.5 m$^3$/day·bar.

By using the Pipesim software, in order to determine the nodal analysis for the well, we proceed as follows:

- pump selecting will be made by considering the pump's efficiency to the estimated production rate (%),
- the pumps' parameters corresponding to the above-mentioned data will be calculated,
- the motor will be chosen depending on the pump's power (kW),
- the power cable will be chosen depending on the motor's electric power intensity (A).

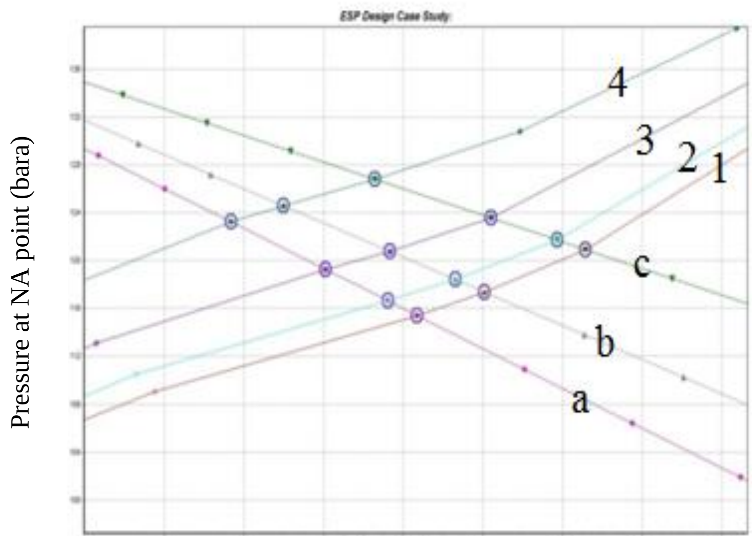
After having done all the above-mentioned calculations, we proceed to carry out an analysis of the well's performance and its predictions for the future, taking into account certain working scenarios. The results of the calculations as per the Pipesim software are presented in table 1.

The working scenarios for the well 01 are to consider variation of productivity index and pump, and reservoir parameters. We considered three constant values for productivity index in the all figures below, (curve "*a*" is 6 m$^3$/day·bar, curve "*b*" is 7 m$^3$/day·bar and curve "*c*" is 9 m$^3$/day·bar). The scenarios we considered are listed below:

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 m$^3$/day·bar and various water-cut percentages, ranging from 23 - 83 % (fig. 3). We notice that the well produces certain liquid rates with high value of water-cuts.

**Table 1.** ESP parameters determined by Pipesim for well 01.

| **Parameters** | | **Calculations Results** |
|---|---|---|
| Selected Pump | Model | REDA DN1800 |
| | Diameter | 4 in |
| | $q_{max}$ | 381.57 $m^3$/day |
| | $q_{min}$ | 190.78 $m^3$/day |
| Number of stages | | 135 |
| Pump's Efficiency to the estimated production rate | | 70.56 % |
| Power required | | 30 kW |
| Intake pressure | | 104 bar |
| Discharge pressure | | 164 bar |
| Head required | | 706 m |
| Liquid density | | 858.55 kg/$m^3$ |
| Free gas fraction | | 0 |
| Chosen Motor | Model | Reda 375 Series S, Single |
| | Power | 33.55 kW |
| | Voltage | 1200 V |
| | Intensity | 28 A |
| Power cable | Length | 1855.48 m |
| | Voltage | 1200 V - Motor and 1631.92 -surface |

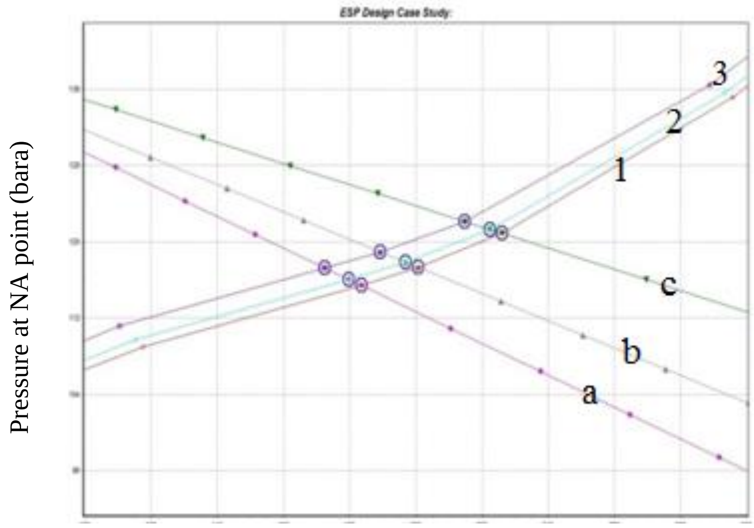



Stock-tank Liquid at NA point ($sm^3$/d)

water cut percentage: Curve 1: 23%, Curve 2: 33%, Curve 3: 53%, Curve 4: 83%.

**Fig. 3.** Nodal analysis of the pump and taking account the productivity index variation from 6 - 9 $m^3$/day·bar and various water cut percentages, ranging from 23 - 83 %

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 $m^3$/day·bar and wellhead pressure variation ranging from 6 - 9 bars (fig. 4). In Figure 4, we notice that the well may produce without problems but a decrease of production rate may occurs at higher wellhead pressures.

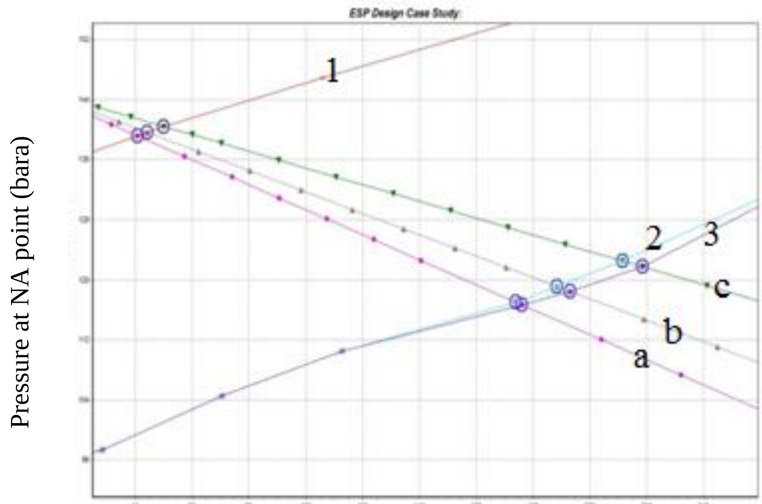



Stock-tank Liquid at NA point ($sm^3/d$)

wellhead pressures: Curve 1: 6 bara, Curve 2: 7 bara, Curve 3: 9 bara.

**Fig. 4.** Nodal analysis of the pump and taking account the productivity index variation from 6 - 9 $m^3$/day·bar and of the wellhead pressure variation ranging from 6 - 9 bars

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 $m^3$/day·bar and power variation ranging from 7 - 33 kW (fig. 5). We can notice that the well may produce without any problems at higher electrical power.

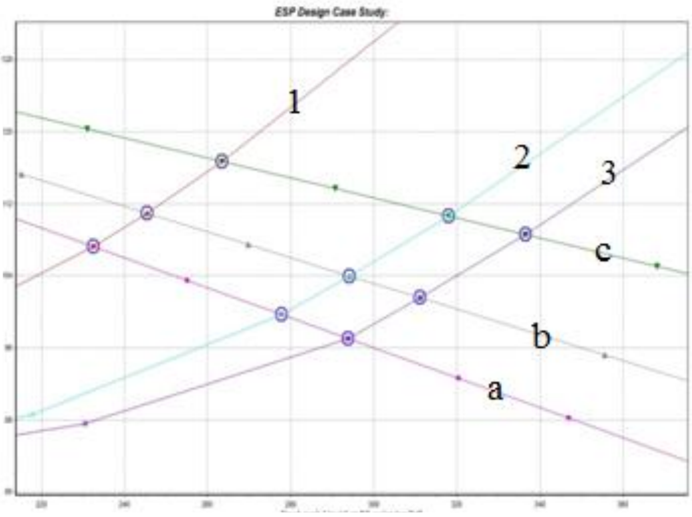



Stock-tank Liquid at NA point ($sm^3/d$)

power variation: Curve 1: 7 kw, Curve 2: 22 kw, Curve 3: 33 kw.

**Fig. 5.** Nodal analysis of the pump and taking account the productivity index variation from 6 - 9 $m^3$/day·bar and power variation ranging from 7 - 33 kW

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 $m^3$/day·bar and various sizes of the internal tubing diameter of 2 in, 3 1/2 in and 4 in (fig. 6). We notice from Figure 6 that the production of the well drops at low tubing diameters.



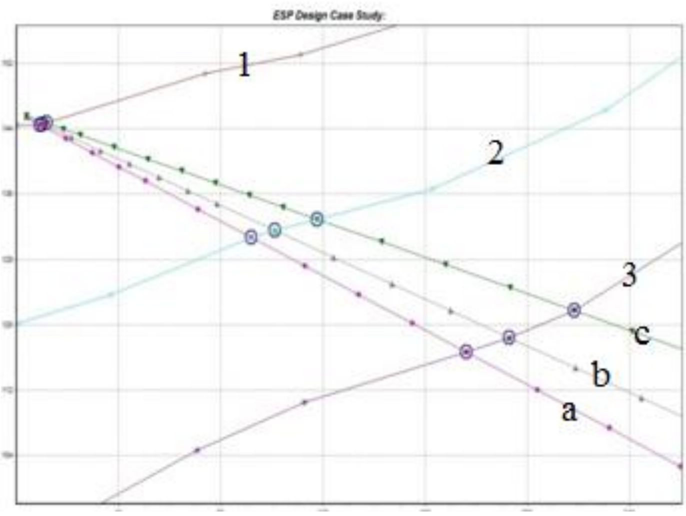

Pressure at NA point (bara)

Stock-tank Liquid at NA point ($sm^3/d$)

Sizes of tubing diameter: Curve 1: 2 in, Curve 2: 3 1/2 in, Curve 3: 4 in.

**Fig. 6.** Nodal analysis of the pump and taking account the productivity index variation from 6 - 9 $m^3$/day·bar and various sizes of tubing diameter of 2, 3 1/2 and 4 in

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 $m^3$/day·bar and a speed variation ranging from 2216 - 3500 rot/min (fig. 7). We notice from Figure 7 that has good results at high pumping speeds, but once with the drop in the pumping speed, the production also drops.



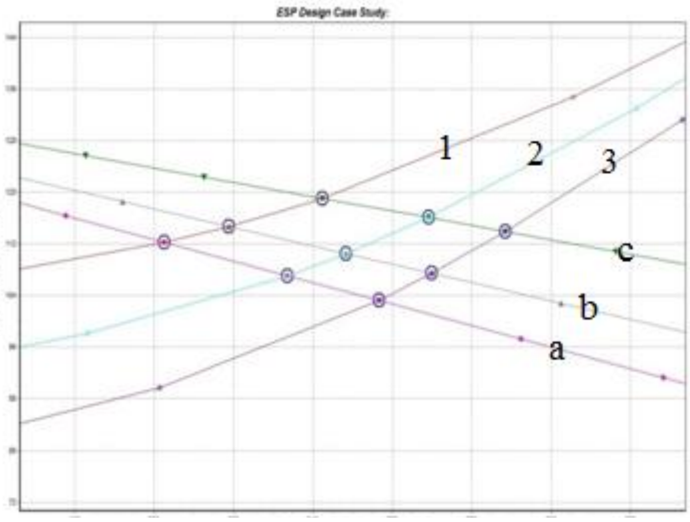

Pressure at NA point (bara)

Stock-tank Liquid at NA point ($sm^3/d$)

Speed variation: Curve 1: 2216 rot/min, Curve 2: 2916 rot/min, Curve 3: 3500 rot/min.

**Fig. 7** Nodal analysis of the pump and taking account the productivity index variation from 6 - 9 $m^3$/day·bar and a speed variation ranging from 2216 - 3500 rot/min

- Nodal analysis of the pump and taking into consideration the variation of the productivity index from 6 - 9 $m^3$/day·bar and the number of stages variation ranging from 115 - 155 stages (fig. 8). Once the number of stages gets higher we have higher production rate as a result of decrease of wellbore bottom hole pressure.




Pressure at NA point (bara)

Stock-tank Liquid at NA point ($sm^3$/d)

Number of stages variation: Curve 1: 115 stages, Curve 2: 135 stages, Curve 3: 155 stages.

**Fig. 8.** Nodal analysis of the pump and taking into account the productivity index variation from 6 - 9 $m^3$/day·bar and the number of stages variation ranging from 115 - 155 stages

## Conclusions

The following conclusions are drawn, as a result of the simulations:

- The operating regime of the centrifugal pumping well is limited, since it depends on several parameters such as: reservoir pressure, wellhead pressure, tubing diameter, rotation speed, power and the number of pump stages. By means of the nodal analysis we can determine the conditions in which a well may work in centrifugal pumping and how long.
- As the tubing's diameter increases, we can notice an increase in the production rate of the wells as a result of the drop in the pressure within the tubing, which is triggered by the decrease of the frictions' gradient.
- Lowering the pressure in the wellhead leads to decreasing of the reservoir backpressure, thus triggering an increase in the well's flow rate
- As the water-cut level becomes higher, the flow rate of the well decreases, as a result of the increasing of the produced fluids density.
- The drop in the power of the pump affects the efficiency of the pump for pumping the fluid to the surface.
- The decrease in the rotation speed will cut down the flow rate of the well.
- As the number of stage is higher, the operating point go down at lower pressures thus generating an increase in the fluid flow rate.

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# Analiza performanţelor sondelor echipate cu ESP şi prevederea performanţelor acestora în viitor cu ajutorul analizei nodale

## Rezumat

*Sistemul ESP este cunoscut ca un sistem cu capacitate foarte mare de extragere a fluidelor din sonde. Astfel estimarea performantei acestui sistem in viitor a devenit foarte importanta din motive economice, din cauza problemelor legate de parametrii din zãcãmânt sau problemelor legate de sistemul în sine, precum scăderea debitului actual, variaţia impurităţilor, a puterii de acţionare a pompei, a vitezei de rotaţie a pompei... etc. În cadrul lucrării se face analiza parametrilor de funcţionare* ai sondelor echipate *cu pompe centrifugale(ESP) şi se studiază performanţele actuale* ale sondelor *şi* anticiparea *performanţelor acestora în viitor combinând teoriilor practice cu softuri specializate în simularea acest gen de operaţii.*