SPE Brazil Flow Assurance Technology Congress
Rio de Janeiro, Brazil, November 15 – 18 2022

Evaluation of flow improver injection in ESP performance

Rennan M. S. Damasceno[1*], Rafael M. Charin[1]
[1]Department of Industrial Engineering, UFRJ, Brazil
rennan.msd@poli.ufrj.br

Abstract
A usual application of electrical submersible pumps (ESPs) is the scenario of high flow rates, high water cuts, heavy oil and low GLR. The emulsion formation is a problem because of high viscosities and instabilities, which reduce the production and damage the equipment. The injection of chemical demulsifies, called in this paper as flow improver, influence the multiphase flow behavior in such a way that the pump works better and more safely in terms of device integrity. This study shows a case of chemical injection upstream the ESP for improving the lifting performance. The production system is modeled using a commercial software to reproduce the results before and after the chemical injection. Alter that, the flow behavior is discussed and finally an economic analysis is presented. The chemical injection was very positive in economic and technical terms.

Keywords
ESP; Flow Stability; Flow improver

Introduction
Some offshore petroleum production fields in Brazil are more than 40 years old. In Campos Basin, where petroleum production has started long time ago, many post-salt fields are mature. However, in 2017, Campos Basin production was still responsible for approximately 50% of Brazilian oil production. This fact shows the high relevance of post-salt production. On the other hand, paradoxically, the Campos Basin reservoirs have a low recovery factor. Therefore, it suggests the need for improvements of the oil production efficiency in Campos Basin.
When the field matures, an increased water production is expected. In heavy oil production, the use of electrical submersible pumps (ESPs) become feasible. ESP is an excellent solution for high BSW (basic sediments and water) in which gas lift is not a good option. Specifically, ESP is the artificial lift method for high flow rates.
With increasing water content volumes over time, a problem with viscous water-in-oil emulsions can lead to substantial production losses. Moreover, in high-water cuts, hydrodynamic instabilities can lead to substantial operational fluctuations which can damage the equipment.
To overcome such problems, chemicals known as flow improvers (FI) can be used. The present paper discusses the changes in ESP operation parameters after FI injection upstream the intake. In this context, the analyzed well is called POLI-22-RD.
Regarding to fluid flow modeling, commercial software was used to represent the observed production gain. In addition, a discussion was carried out about the phenomena involved in the pump operation and, finally, an economical study shows the impact generated on the company's profit by using the chemical product.

Methodology
In this paper, a real case consisting of a well with ESP producing heavy oil is presented. The production system operates with problems related to emulsion influence in pump parameters such as inlet pressure, outlet pressure, wellhead pressure, inlet temperature, ESP current and ESP frequency. A test was carried out by injecting a chemical and observing the changes of the ESP parameters.
The multiphase flow simulation used the software ALFAsim in order to represent the condition before and after the demulsifier injection.
Table 1 and Table 2 show data used in the flow modeling and the PVT correlation package.

Table1: Data and PVT correlations.

PVT correlations	**Standing**
Dead oil density **[kg/m³]**	978,6
Gas specific gravity	0,724
GOR **[sm³/sm³]**	24
API°	14

Table 2: Reservoir and inflow performance information.

Absolute pressure in the reservoir [psi]	**2029**
Reservoir temperature [°C]	55
Productivity index (PI) of liquid [bbl/psi.d]	6,3

The well trajectory is shown in Fig. (1) (see appendix).
The linear geothermal gradient is obtained using data of the Tab. (3).

Table 3: Geothermal data.

Posição [m]	T amb [ºC]
0	4
1400	55

The well dimensions are indicated in Fig. (2) (see appendix).
The ESP position was 2700 m below the position of the Christmas tree (0 m seabed reference). The differential pressure of the pump used in the simulation was 1038 psi.

Results and Discussion

The ESP was operating with many instabilities in many operating parameters before the FI injection, as shown in Fig. (3) (see appendix). A similar behavior was reported by Hartenbach et al. 2015 [1]. According to the authors, the instability is a cyclic behavior governed by the high viscosity of the emulsion and the heat caused by the pump running with a viscous fluid. The heat dissipated by the pump warms up the fluid, and then it becomes a water-oil mixture with lower dispersion stability and consequently lower equivalent viscosity, which diminishes the pressure drop and, consequently, increases the drawdown. Therefore, the pump starts to work with a better performance in a higher temperature and the flow rate increases, causing the fluid to exchange less heat and therefore a cooling of the fluid is observed, which sets up a new cycle of instabilities, as the emulsion become stable again. After the flow improver injection in the pump inlet, the instabilities attenuate significantly as shown in Fig. (4) (see appendix). The product dosage optimization took 8 days.
The indication of production gain observed in the ESP parameters was confirmed by the difference in the total production of the field before and after the FI injection. The production data of the field before and after the FI injection in the POLI-22-RD well is the following.
Average of total production before FI injection:
- Oil: 10,148 bbl/d
- Water: 55,371 bbl/d
- WC: 0,21

Average of total production after FI injection:
- Oil: 10,889 bbl/d
- Water: 56,284 bbl/d
- WC: 0,62

Another influence of the FI injection was the water cut increase from 21 to 62% in the POLI-22-RD, as there is an increase in the drawdown of about 300 psi.
It is possible to observe in Fig. (4) (see appendix) a reduction in the "intake pressure" after the FI injection, which means a greater drawdown. Without the FI, the well was producing with a drawdown of approximately 430 psi. After the FI injection, the well started to produce with a drawdown of approximately 730 psi. This increase was reflected both in an oil production gain (740 bbl/d on average) and in water cut increase.
The ALFAsim simulation software was used to represent the real scenario before and after the flow improver injection (Figs. (6 and 7) (see appendix)).
As shown in Fig. (6) (see appendix), according to the simulation the well was producing with an "intake pressure" of approximately 1600 psi before the FI injection, which results in the same drawdown value presented in the real scenario (430 psi). After the FI injection, the simulation captured the "intake pressure" of approximately 1300 psi, which results 730 psi of drawdown.
According to the simulation, the well POLI-22-RD produced about 740 bbl/d more oil after the FI injection. Although the PI value increased from 6,3 to 6.6 bbl/psi.d, this magnitude was close one another, as a drawdown increase of 300 psi was observed.
According to these results, the FI injection in the POLI-22-RD proved to be beneficial because the well's production increased and the instabilities almost vanished. From the point of view of pump durability, this is fundamental.
When injecting the FI, which is a surfactant, the HLD of the mixture tends to become more hydrophilic. Furthermore, because the water cut increase, the mixture should enter a catastrophic phase inversion region. As shown in the WOR map of Fig. (8), the FI injection should make the mixture more hydrophilic according to HLD approach and the water cut increase drove the agitated mixture inside the pump to a catastrophic inversion region.

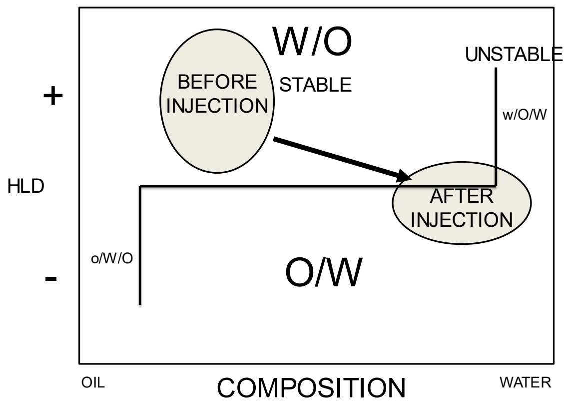

Figure 8: FI influence on the physical chemistry of the emulsion mixture.

Finally, an economic analysis was made in order to evaluate the gain using the FI. Table 3 informs the premises for the calculus. According to Table 4, the production gain in 30 days was about R$ 12 million.

Table 3: Inputs for the economical evaluation.

Assumptions	
Taxes FX (R$)	5,65
Oil price (USD/bbl)	100
Production period (days)	30
Production gain (bbl/d)	740

Table 4: Economical evaluation.

FI			
Cost	**Quantity**	**Total (USD)**	**Total (R$)**
6,1(USD/L)	6000**(L)**	$36.600,00	R$ 206.790,00
Balance (R$)			
Costs	R$ 206.790,00		
Incomes	R$ 12.543.000,00		
Total	R$ 12.336.210,00		

Thus, the FI injection was considered a very efficient operation from economic point of view.

Conclusions

This paper studied a demulsifier injection upstream the ESP. The POLI-22-RD well was modeled using a commercial multiphase flow software. In addition, in order to represent the oil production gain, it was made an economic analysis which proved the advantage in using the chemical.

It was suggested that the changes observed in the ESP parameters that made the flow more stable occur due to the hydrophilic characteristic of the chemical, generating unstable emulsions which cause less pressure drop. The chemical acts to stabilize the flow within the ESP.

The flow improver use was validated in the economic analysis.

Responsibility Notice

The authors are the only responsible for the paper content.

REFERENCES

[1] Hartenbach, G., Magalhães, J., Belsvik, Y., Pessoa, R., Lemos, D. *SPE Artificial Lift Conference — Latin America and Caribbean 2015,* SPE-173972-MS.

Appendix

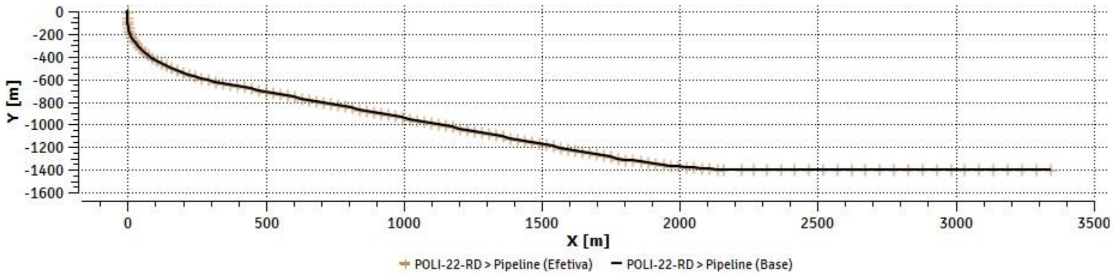

Figure 1: Well trajectory.

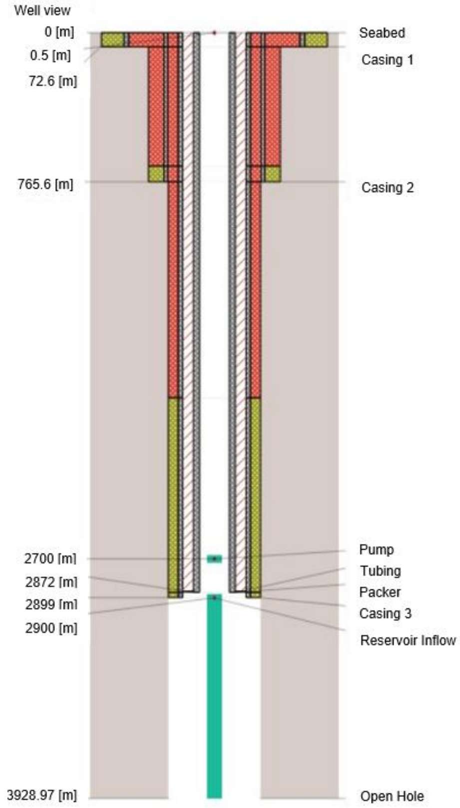

Figure 2: The dimensions of the well using ALFAsim well editor.

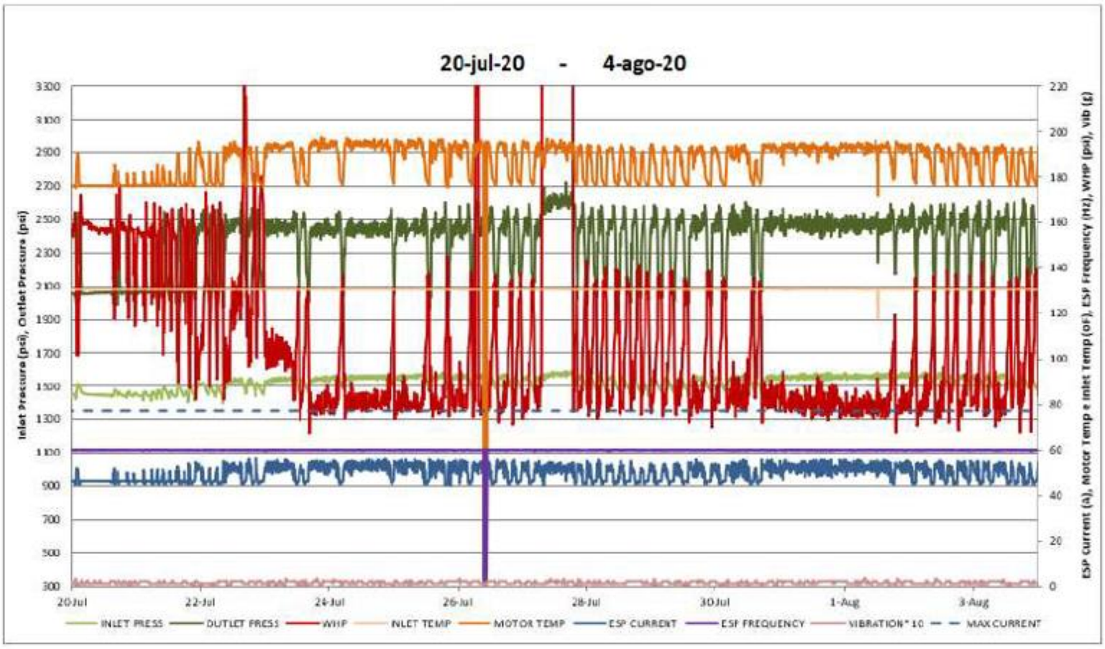

Figure 3: Before product injection.

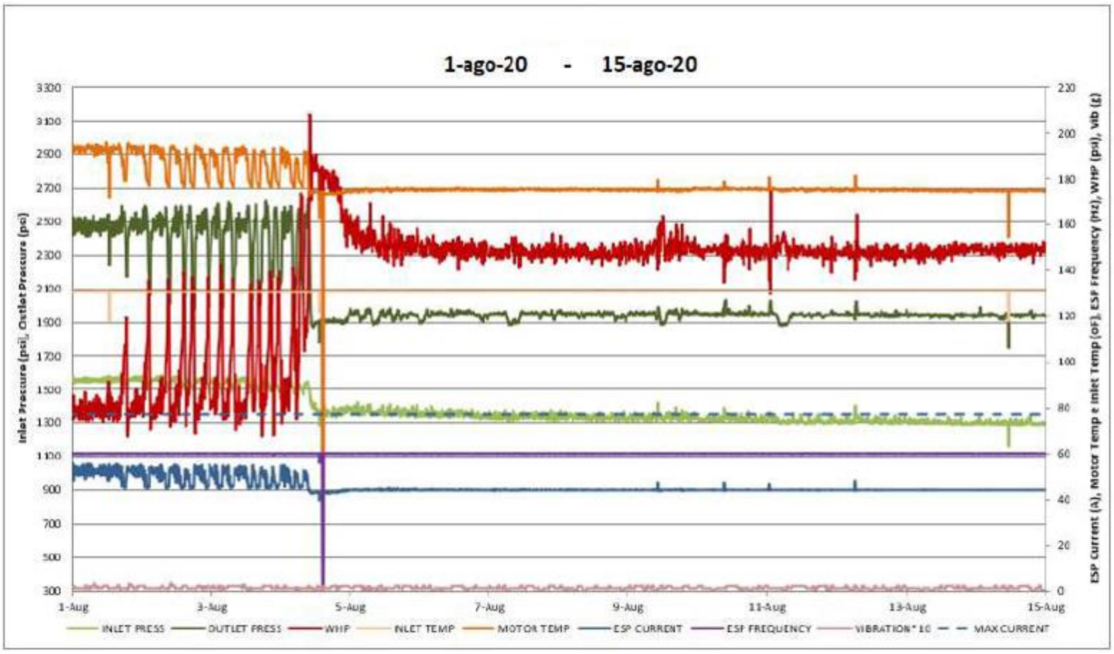

Figure 4: After product injection.

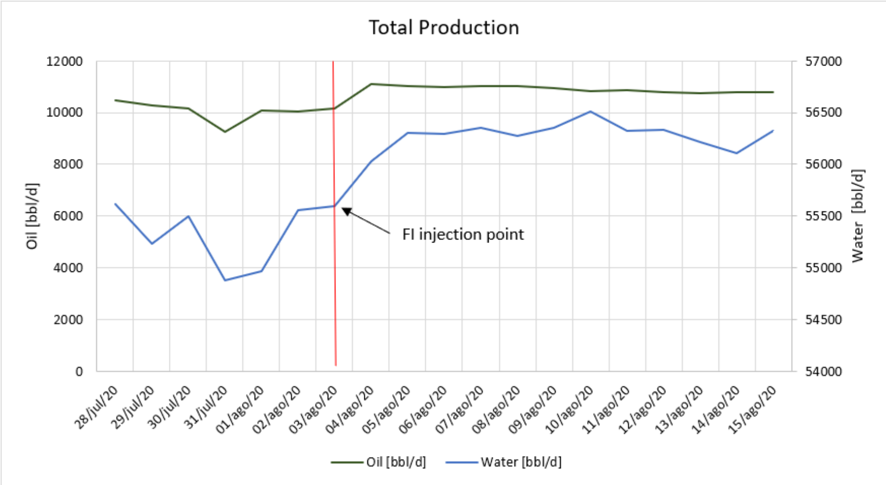

Figure 5: Production increase after FI injection.

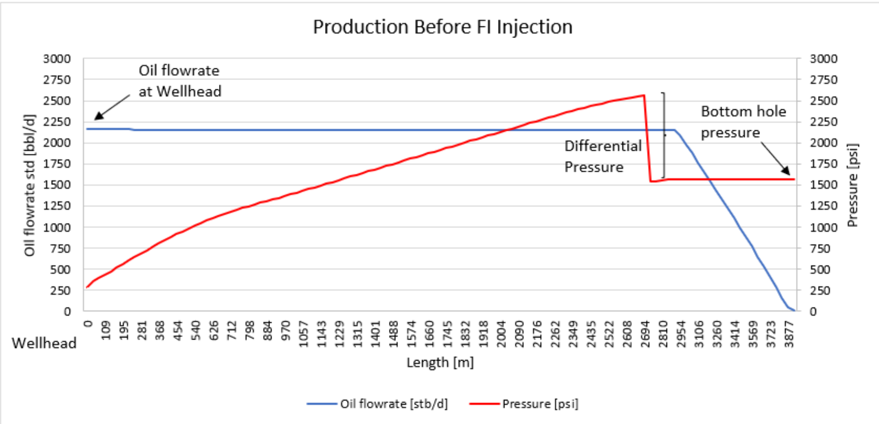

Figure 6: Before product injection.

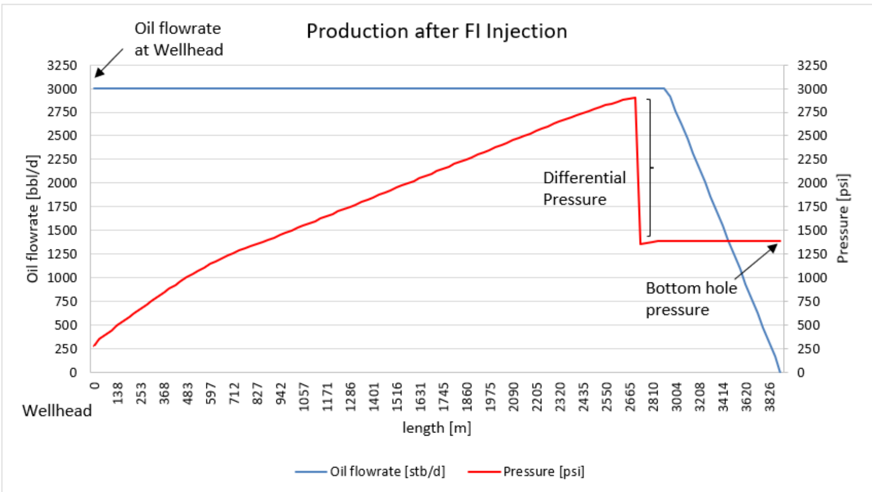

Figure 7: After product injection.