VATICINATING MULTIPHASE FLOW CHATTELS OF ELECTRICAL SUBMERSIBLE PUMPS OPERATING POINTS

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ABSTRACT

Pressure Volume and Temperature (PVT) data, reservoir and production data and Electrical Submersible Pumps (ESP) Equipment data were used with PROSPER software in a sensitivity analysis for a severely depleted Gas to Oil Ratio (GOR) well in an offshore XM-Oil Field of the Niger Delta, Nigeria. The objectives were to run comprehensive and detailed sensitivity analysis of ESP model using IPM-PROSPER suite for different flow conditions from the ESP operating point locations in casing slugs, tubing slugs, tie-back intermittent and riser intermittent model predictions within the vicinity of the superficial liquid and gas velocity domains in order to predict pump discharge pressures and rates, the actual head, pump frequency, pump intake pressures, fluid rates and temperatures. The result shows that the centrilift pump discharge rate was 12,755.3 RB/day. The actual head required is 6712.02ft and the best pump operating frequency is 60Hz. The predicted slip liquid velocity is from a minimum of 1.181ft/sec for casing slugs, 1.874ft/sec for riser-intermittent, 3.158ft/sec for tubing slugs and a maximum of 3.349ft/sec for tie-back intermittent flow. Furthermore, a mathematical model was generated as $V_{SL} = -0.863x^2 + 4.542x – 2.492$ for the slip liquid velocity with $R^2 = 0.999$. The model predicted the slip gas velocities from a minimum of 4.470ft/sec for riser intermittent, 17.964ft/sec for casing slugs, 23.640ft/sec for tie back intermittent to a maximum of 42.343ft/sec for tubing slug flows and the physico-mathematical model generated $V_{SG} = 7.102x^3 -64.15x^2 + 167.1x – 92.11$ with $R^2 = 1$. Upon installation of the ESP, oil production was improved while critical parameters such as pump speed or electric – power frequency (Hz) are set to optimize pump performance while monitoring multiphase problems which reduces the operating efficiency or damages the pumps technically designed for liquids and not gases or solids.

INTRODUCTION

The XM-Field was discovered in 1982 and put on stream in 1988 with six production wells with initial low Gas Oil Ratio (GOR) and a production rate of over 40,000 bbl/day per well, which depleted because of the inherent aquifer energy though water influx replacement was introduced as a candidate for its fast depleting energy Obi *et al* (2017). This field is characterized with multiphase flow issues thereby, making Electrical Submersible Pump (ESP) the first choice to combat the inherent multiphase flow issues particularly with two general topologies which was identified beyond the depth of 6,500ft namely the dispersed flows consisting of finite particles, drops or bubbles distributed within a continuous phase and the separated flows consisting of two or more continuous streams of fluids separated by interfaces. The prominent three phase flow identified was the gas-liquid-liquid flows which abound within the proximity of the predicted ESP operating points. Production enhancement of oil from this severely depleted reservoir could be very problematic when devoid of adequate technical ideas of managing multiphase flow challenges aimed at not just solving the problem but offering managerial/monitoring solutions (Aronofsky, 1983, Gill *et al* 1981, Obi *et al*. 2015 and Ilozobhie and Egu, 2018,).

Choice of decision of ESP artificial lift technique is most times very difficult when technical, experience and economics are not considered. Electrical submersible pumps on the other hand may pose a major challenge when its performance are not well modeled with fluid phase issues as this could affect the operational efficiency before, during and after installation [Aronofsky and

Lee 1988, Barnes *et al*. 1990, Dutta-Roy and Kattapuram, 1997 and Wang, 2003) thus the thrust of this research is to run sensitivity analysis of ESP model for different flow conditions from the ESP operating points in casing slugs, tubing slugs, tie-back intermittent and riser intermittent model predictions within the vicinity of the superficial liquid and gas velocity domains to predict pump discharge pressures and rates and to predict the actual head, pump frequency, pump intake pressures, rates and temperatures (Bertsimas and Tsitsiklis, 1997).

MATERIALS AND METHOD

Materials used are PVT data, reservoir and production data and ESP Equipment data. A well model was built for a natural flowing oil with PVT calibration and then matched against actual well test data. The well has been in production since 1988, reservoir pressure had declined, water cut has increased and well deliverability has reduced. To improve well productivity the well has to be converted to an Electrical Submersible Pump – lifted well. The choice of selection of the electrical submersible pump is purely based on strict technical and economic specification. The pump type used is the centrilift K140: 538 inches with a liquid operating rate ranging from 11,500 RB/day to a maximum of 18,400 RB/day. The in-built motor capacity is the centrilift 562: 450 HP: 2460: at 105 amps. The cable capacity is the number 1 copper 0.26 (volts/1,000ft); at 115 amps maximum capacity (Fig. 1).

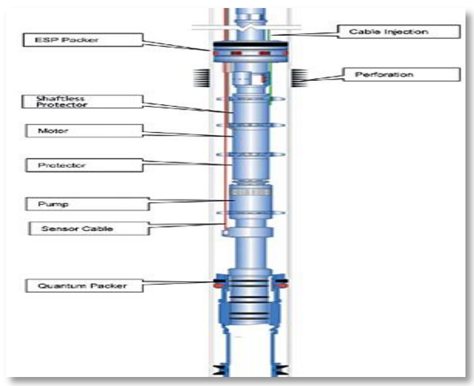


Fig. 1: Schematic for an Electrical Submersible Pump

RESULTS

Results obtained were for the IPR Plot (Darcy), Gas Separation Plot, Pump Performance Curve, Pump Discharge Pressure against Vertical Lift Performance (PDP vs. VLP), Sensitivity Plot and ESP solution Pump Plot for the multiphase modeling.

Results of IPR (Darcy) and Gas Separation

The Inflow Performance Relationship curve of the existing production data shows that between a pressure of 4000psig and 1300psig at corresponding flow rates of 0STB/day and 19863.5STB/day, this corresponds to the straight line region indicating the single phase oil zone and also between a pressure of 1300psig and 1.108psig at corresponding flow rates of 19863.5STB/day and 26044.6STB/day and this corresponds to the curved region indicating a multi – phase oil and gas zone. Results also show that the Absolute Open Flow (AOF) was predicted as 26044.6STB/day while the Formation Productivity Index and the Skin Factor obtained are 10.06STB/day/psi and 2.0 respectively (Fig. 2).

Results of the Gas separation sensitivity plot predicts the test point at an intake pressure of 2000psig and a gas liquid ratio of approximately 0v/v and the Dunbar factor (red curve) at an intake pressure of 1500psig and a gas liquid ratio of 2.4 v/v. Due to the test point pressure being above the red curve (Dunbar factor) this thereby indicates that down-hole separation is not needed (Fig. 3).

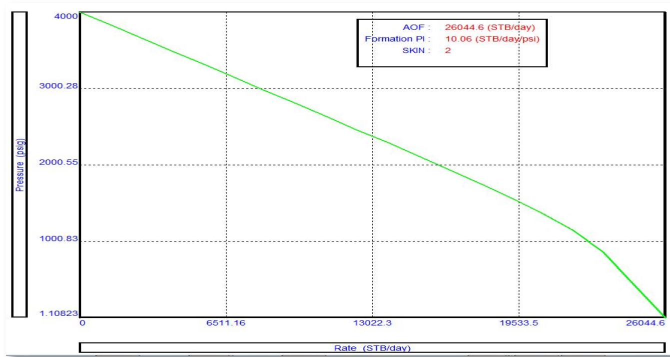


Fig. 2: The IPR Plot Darcy

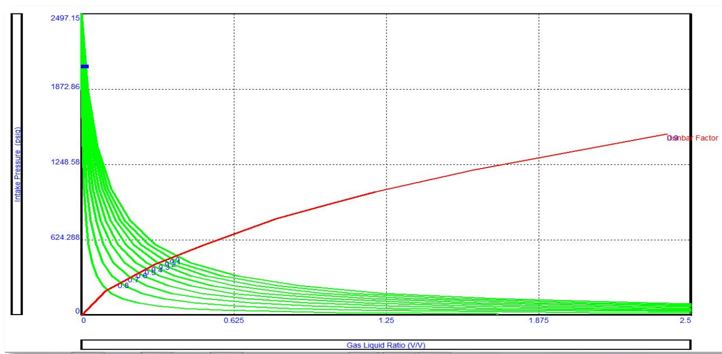


Fig. 3: Result of Gas Separation Sensitivity Plot

The pump performance curve

The pump performance curve calculates the minimum operating range of the pump which shows that at a maximum frequency of 70Hz the pump will have an operating rate of 8000RB/day at a depth of 6800feet and at a minimum frequency of 40Hz the pump will have an operating rate of 4550RB/day at a depth of 2200feet and also calculates the maximum operating range of the pump which shows that a maximum frequency of 70Hz the pump will have an operating rate of 17800RB/day at a depth of 3300feet and at a minimum frequency of 40Hz the pump will have an operating rate of 10000RB/day at a depth of 1000feet. It then calculates the best efficiency line of the pump which shows that at a maximum frequency of 70Hz the pump will have an operating rate of 13500RB/day at a depth of 5470feet and at a minimum frequency of 40hertz the pump will have an operating rate of 8000RB/day at a depth of 1800feet (Fig. 4).

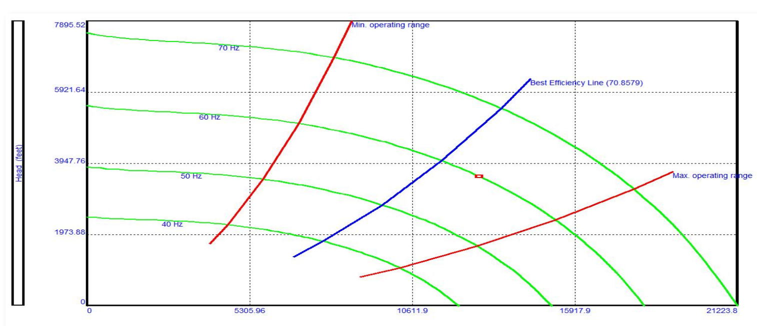


Fig. 4: Result of Pump Performance Curve

Results of PDP and VLP pressure plot

The plot of the Pump Discharge Pressure against Vertical Lift Performance shows that the Pressure plot combines Inflow performance relation curve, vertical lift performance curve, pump intake pressure curve and the pump discharge pressure curve. The intersection between the VLP curve and the PDP curve is the solution rate which shows that at a minimum frequency of 40Hz the pump will be operating at a pressure of 3335psig and have a liquid rate of 7500stb/day and at a frequency of 45Hz the pump will be operating at a pressure of 3378psig and have a liquid rate of 8500stb/day and at a frequency of 50Hz the pump will be operating at a pressure of 3400psig and have a liquid rate of 9700stb/day and at a frequency of 55Hz the pump will be operating at a pressure of 3500psig and have a liquid rate of 10800stb/day and at a frequency of 60Hz the pump will be operating at a pressure of 3550psig and have a liquid rate of 12000stb/day and at a frequency of 65Hz the pump will be operating at a pressure of 3660psig and have a liquid rate of 13200stb/day and also at a maximum frequency of 70Hz the pump will be operating at a pressure of 3720psig and have a liquid rate of 14400stb/day (Fig. 5).

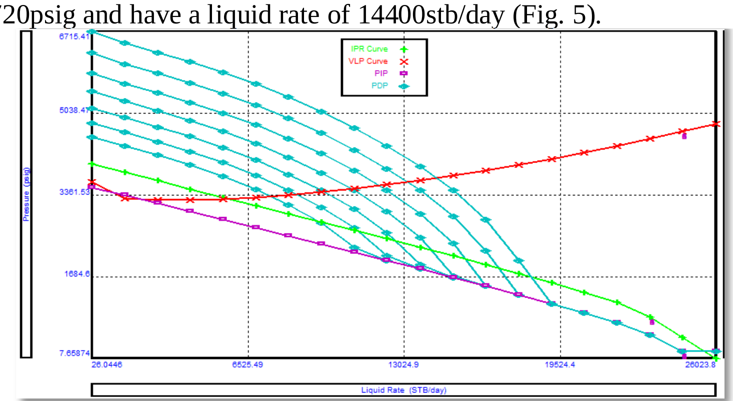


Fig. 5: The PDP vs. VLP Pressure Plot

The sensitivity analysis and ESP solution pump

Results of gas separation sensitivity showed that of the 10 models used, the predicted operating pump intake pressure is 2087.32psig; the pump intake temperature is 199.168^{o}F and pump intake rate of 12,936.5RB/day. Free Gas Oil Ratio (GOR) entering the pump is 67.7666scf/STB and pump discharge pressure is 3225.07psig. The pump discharge rate is given as 12,755.3 RB/day. The actual head required is 2712.02ft and pump frequency is 60Hz (Fig. 6).

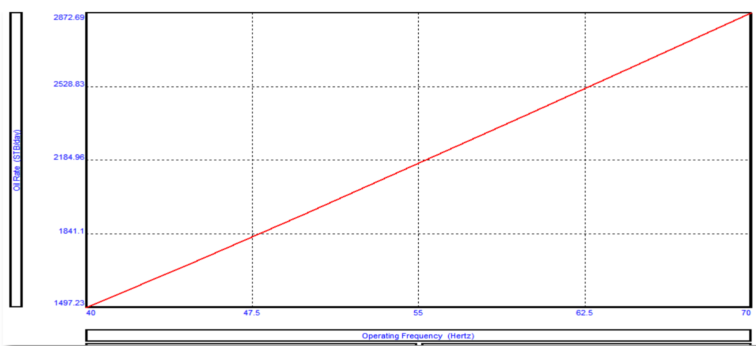


Fig. 6: Sensitivity Plot of Oil rate vs. Pump operating frequency

However the results of the ESP solution pump plot predicts that at a minimum frequency of 40Hz the pump will have a depth of 1700ft and an operating rate of 7950RB/day and at a frequency of 45hertz the pump will have a depth of 2150ft and an operating rate of 9100RB/day and at a frequency of 50hertz the pump will have a depth of 2600ft and an operating rate of 10300RB/day and at a frequency of 55Hz the pump will have a depth of 3050ft and an operating rate of

11600RB/day and at a frequency of 60hertz the pump will have a depth of 3550ft and an operating rate of 12650RB/day and also at a frequency of 65Hz the pump will have a depth of 4100ft and an operating rate of 14100RB/day and lastly at a maximum frequency of 70Hz the pump will have a depth of 4680ft and an operating rate of 15400RB/day. This shows that the ESP will be operating within a safe operating range i.e. between its minimum and maximum operating range (Fig. 7).

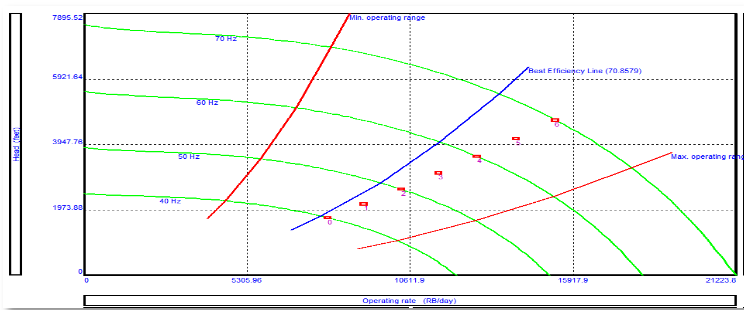


Fig. 7: Result of ESP Solution Plot

Result of multiphase flow regime modeling for casing slug and Tubing slug

The casing slug modeling shows that the ESP operating point was located at approximately a superficial liquid velocity of 0.2ft/sec and superficial gas velocity of 1.3ft/sec. This is far away from the annular flow (green), dispersed bubble (blue) and the bubble flow (red) as shown in Fig. 8, while the results for the Tubing slug was slightly better than the

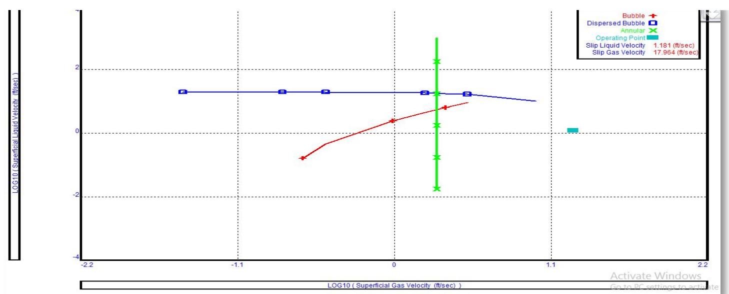


Fig. 8: Casing slug indicating the operating point against the superficial gas and liquid velocity.

casing slug modeling because the predicted operating point was further away from the bubble, dispersed bubble and annular flow regimes. Operating point was actually located at a superficial liquid velocity of 0.35ft/sec at a corresponding gas velocity of 1.16ft/sec as shown in Fig. 9.

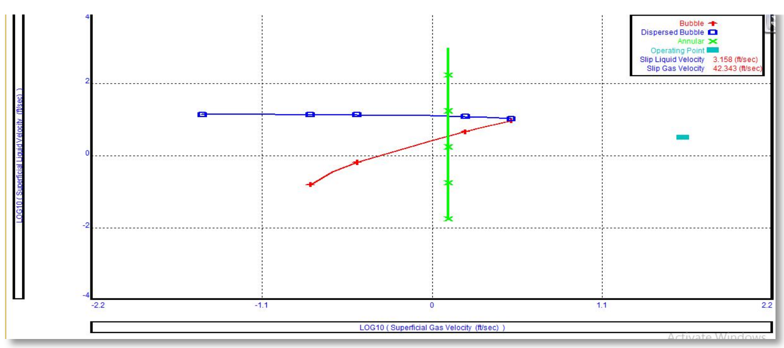


Fig. 9: Tubing slug indicating the operating point against the superficial gas and liquid velocity.

The multiphase flow regime modeling for Tie-back intermittent and Riser Intermittent
The tie back liner is run from a liner hanger back to the well head after the initial liner and hanger system have been installed and cemented and provides pressure support during flow test periods and not cemented in place. Results of the tie-back intermittent shows that the operating point located at a superficial liquid velocity of 0.4ft/sec and at a superficial gas velocity of 1.5ft/sec is too close to the slug annular flow (yellow) while the stratified-slug/annular flow regime, severe slugging line and slug dispersed bubble are close to the operating point. This is not a good candidate for the ESP design installation (Fig. 10).

The riser is the pipe that connects an offshore floating production structure or a drilling rig to a sub-sea system either for production (for storage, transportation and export), drilling, injection, completion and work-over operations.

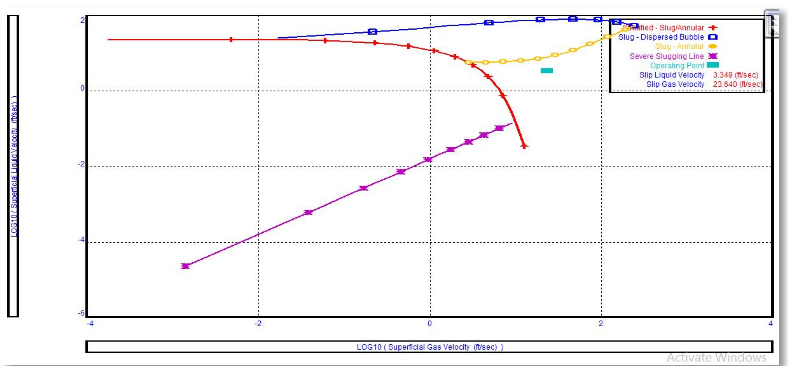


Fig. 10: Tie back – intermittent indicating the operating point against the superficial gas and liquid velocity.

Result of exact location of the operating point was located at superficial liquid velocity of 0.3ft/sec and superficial gas velocity of 0.7ft/sec. The nearest flow regime is bubble followed by dispersed bubble and annular flow regime (Fig. 11).

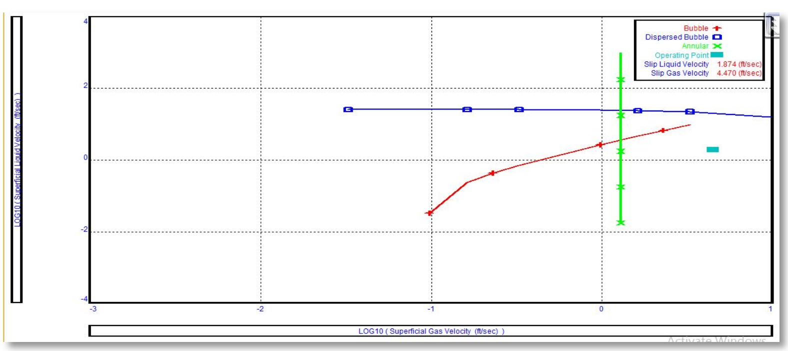


Fig. 11: Riser intermittent indicating the operating point against the superficial gas and liquid velocity.

DISCUSSIONS

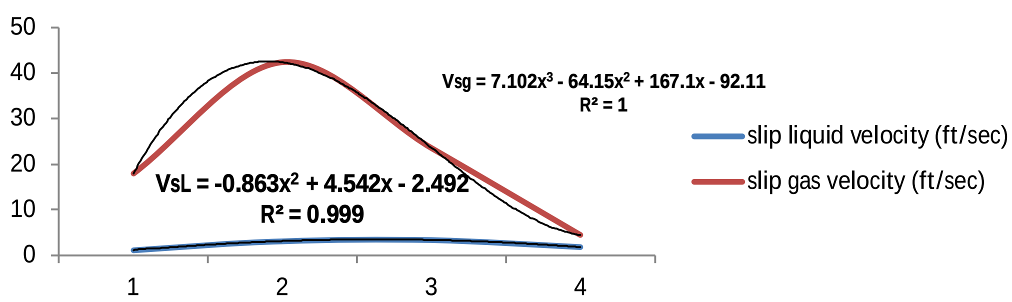
The predicted slip liquid velocities is from a minimum of 1.181ft/sec for casing slugs, 1.874ft/sec for riser-intermittent, 3.158ft/sec for tubing slugs and a maximum of 3.349ft/sec for tie-back intermittent flow while its physic-mathematical model gave $V_{SL} = -0.863x^2 + 4.542x - 2.492$ with $R^2 = 0.999$. The predicted slip gas velocities is from a minimum of 4.470ft/sec for riser intermittent, 17.964ft/sec for casing slugs, 23.640ft/sec for tie back intermittent to a maximum of 42.343ft/sec for tubing slug flows and its physic-mathematical model gave $V_{SG} = 7.102x^3 - 64.15x^2 + 167.1x - 92.11$ with $R^2 = 1$ (Table 1 and figure 12). The ESP solution plot portrayed all the operating points lying close to the middle placed best efficiency curve line indicating the higher the ESP operating efficiency, the higher the liquid rates. Results of casing slugs effects on the ESP operating points indicates that by increasing the superficial gas velocity and reducing the superficial liquid velocities of the dispersed bubble phase model, this would have adverse operating effects on the ESP while the bubble and annular flows have literally no effects on pump.

However, results of tubing slug model effects indicates that the ESP operating point was located farther away than its location in the casing slug model showing an improvement in the modeling but if on the other hand there was a simultaneous slight increase in the superficial liquid and gas velocities, the pump would definitely be affected.

Results of the tie-back intermittent models showed the presence of 4 multiphase flows which includes stratified slug annular, slug-dispersed bubble, severe slug line and slug annular. The predicted slip liquid velocity is 3.349 ft/sec and the slip gas velocity is 23.640ft/sec. Interestingly, it was identified that a reduction in the superficial liquid velocity of the slug annular flow will affect the pump. Caution should however be applied in managing the scenario as any disruption in the phases may affect the ESP operating performance efficiency capacity. Results of the riser intermittent flow indicates a three phase scenario with serious issues if reductions in dispersed bubble and bubbles exist for the superficial liquid velocities with increase superficial gas velocities.

Table 1: Predicted Multiphase Fluids and Superficial Velocities

Multiphase parameters	Casing slugs	Tubing slugs	Tie-back intermittent	Riser intermittent
Slip liquid velocity (ft/sec)	1.181	3.158	3.349	1.874
Slip gas velocity (ft/sec)	17.964	42.343	23.640	4.470
Multiphase fluids	Bubble, Dispersed bubble and annular	Bubble, Dispersed bubble and annular	Stratified-slug annular, slug-dispersed bubble, slug-annular and severe slugging line	Bubble, Dispersed bubble and annular



CONCLUSION

A careful technical juxta-positioning of all the sensitized models of casing slugs, tubing slugs, tie-back intermittent and Riser intermittent results showed the advantage and preferred option of the tubing slug model over others because the predicted operating ESP points is located away from the complex multiphase fluids. This is followed by the casing slug, riser intermittent and the tie-back intermittent as the most sensitive.

This research can greatly improve the way we model ESP in the vicinity of complex fluids that can trigger multiphase flows. The technical thinking should be concise pre-modeling, history matching and post-modeling (or ESP production monitoring to curtail flow challenges). The optimization methods investigated here are effective for problems of varying complexities and sizes. The methods can be used for both short-term production optimizations and long-term reservoir development studies. Upon installation of the ESP, oil production was improved while critical parameters such as pump speed or electric – power frequency (Hz) are set to optimize pump performance while monitoring multiphase problems which reduces the operating efficiency or damages the pumps technically designed for liquids and not gases or solids.

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