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OPTIMAL ARTIFICIAL LIFT METHODS FOR SMALL OIL FIELD PRODUCTION

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Abstract: Artificial lift methods are essential for maintaining productivity of oil wells that are depleted or lack sufficient natural energy for self-sustaining production. Properly selected artificial lift methods enable fluid production continuity, ensure stability and maintain long-term economic viability, especially when the reservoir can no longer support natural fluid lift to the surface. On the small oil field X, the initial production phase utilized natural flow methods, whereas declining reservoir energy prompted the implementation of sucker rod pumps (SRP), which were later replaced by electrical submersible pumps (ESP). Performance analysis revealed that ESP systems encountered challenges, including motor overheating due to reduced fluid inflow and insufficient cooling. In contrast, SRP systems exhibited more stable and reliable performance under the specific operating conditions of oil well at field X. This study investigates artificial lift methods, and through analyzing SRP and ESP system performance, concludes that SRP systems are more suitable for sustained and efficient production on small oil field X.

Keywords: artificial lift methods, electrical submersible pump, sucker rod pump, small oil fields, system performance analysis

1 INTRODUCTION

With increasing global energy demand and limited new hydrocarbon reserves, maintaining current production levels is essential to meet market needs. Artificial lift methods play a crucial role in achieving this goal (Flatern, 2015). These processes enable reservoirs to produce oil at the desired rate (Ugochukwu Ilozurike Duru, 2021). Although there are various artificial lift methods, they can generally be divided into two main categories: pump systems and gas lift (Ladopoulos, 2020). Pump systems include sucker

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rod pumps (SRP), electrical submersible pumps (ESP), progressing cavity pumps (PCP), hydraulic jet pumps (HJP), and plunger lift systems (PP) (Ugochukwu Ilozurike Duru, 2021) (Crnogorac, 2020).

Figure 1. shows the global application of artificial lift methods, where sucker rod pumps account for 82%, gas lift for 10%, and electric submersible pumps account for 4%. Hydraulic and progressing cavity pumps have a combined share of 2% (Crnogorac, 2020).

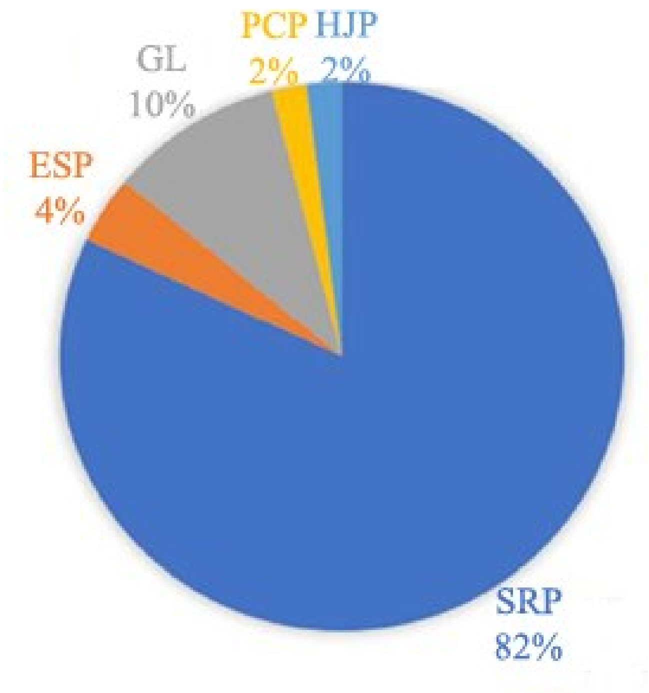

Figure 1 Global Prevalence of Artificial Lift Methods (Crnogorac, 2020)

Figure 2. highlights the most important artificial lift methods. For example, electrical submersible pumps (ESP) and gas-lift systems are often suitable for offshore wells because they can support high production rates and operate at great depths. These systems are efficient under stable operating conditions and provide consistent productivity.

On the other hand, sucker rod pump (SRP) systems are typically the best choice for onshore wells. Although they require more surface space, these pumps are reliable, easy to maintain, and often represent a more economical solution in cases where total installation and maintenance costs are significant factors (Flatern, 2015) (Ugochukwu Ilozurike Duru, 2021) (Akchay L. Pandit, 2015).

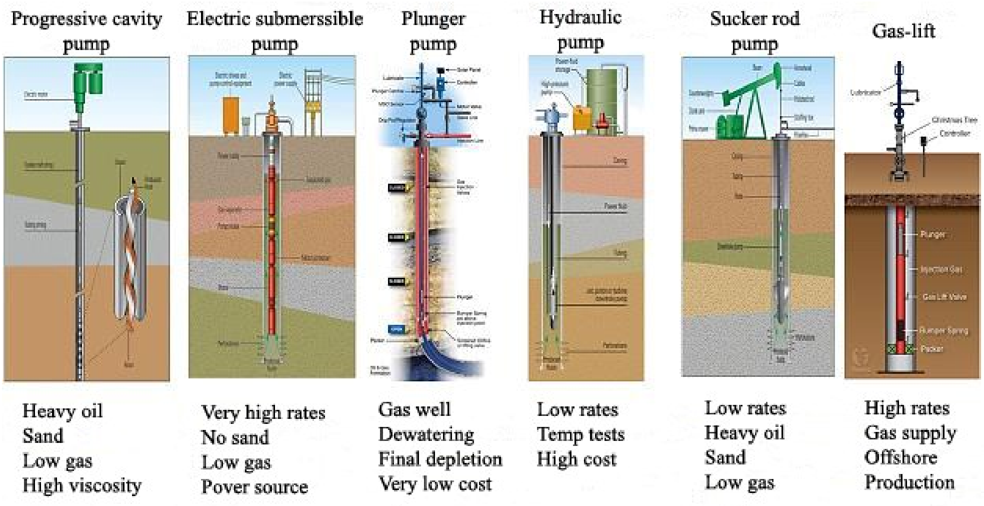

Figure 2 Most Common Artificial Lift Methods and Their Application Conditions and Areas (Ugochukwu Ilozurike Duru, 2021)

A primary characteristic of small oil and gas fields is that exploration investments and development costs are relatively high, with limited space for production management expenses. This makes production highly sensitive to fluctuations in oil prices and production costs. It is well-known that oil prices on the global market are variable, influenced by specific factors tied to the immediate and strategic objectives of economically leading countries, where political factors are dominant. While there are periods of relatively stable prices, there are also times of rapid price changes, adding complexity to managing production on small oil fields.

In managing oil and gas production in small fields, it is not possible to influence capital production costs or the market price of crude oil and natural gas. Consequently, variable costs, i.e., production management costs (operational expenses) are the element through which production profitability must be regulated to ensure economic viability.

2 CHARACTERISTICS OF ELECTRICAL SUBMERSIBLE PUMPS (ESP) AND SUCKER ROD PUMPS (SRP)

Electrical submersible pumps (ESP) and sucker rod pumps (SRP) represent two of the most common artificial lift methods. These two technologies play a key role in oil production but differ significantly in their operating principles, productivity, well condition resilience, and maintenance costs, as detailed below.

2.1 Operating principle of ESPs and SRPs

Electric Submersible Pumping (ESP) systems operate based on the centrifugal principle, utilizing centrifugal force to lift fluids. The ESP uses impellers that rotate at high speeds to generate centrifugal force, lifting fluid from the wellbore to the surface. The pump motor is submerged in the fluid along with the pump, allowing efficient energy conversion and enabling the lift of large fluid volumes. ESP systems are known for their ability to handle high flow rates and are suited for stable well conditions where free gas content is low, and the fluid is relatively clean (Suelem Sa Dela Fonte, 2022).

In contrast to the ESP, the sucker rod pump (SRP) utilizes a mechanical piston and rod system. A surface motor drives the sucker rods, transferring energy deep into the well, where a piston moves up and down, lifting fluid to the surface. SRP systems are better suited for wells with lower flow rates and higher gas content or solid particles in the fluid. This mechanism is more resilient to changing well conditions and can operate effectively in more complex environments (Okodi, 2017).

2.2 Productivity and resistance to downhole conditions

ESP pumps are designed for high-production wells, with fluid lifting capacities exceeding 400 m^3/day, making them ideal for wells with substantial production potential. However, high concentrations of free gas or sand in the fluid can negatively impact ESP efficiency, as gas creates bubbles that reduce pressure, and sand can damage the impellers. Additionally, high-viscosity oil can present operational challenges for ESP systems (Takacs, 2017).

On the other hand, SRP systems have lower productivity but are significantly more resilient to conditions that may impair ESPs. They perform better in environments with higher free gas content, sand, or viscous fluids, and are suitable for wells where significant water production is expected. This resilience makes SRP systems more appropriate for wells with variable or challenging conditions. SRP systems are also well-suited for wells with low to medium flow rates, where ESP systems may not be economically viable (Sherif Fakher, 2021).

2.3 Installation and maintenance costs of ESPs and SRPs

One of the significant differences between ESPs and SRPs lies in installation and maintenance costs. ESPs require a more complex installation and higher initial costs. In the event of a failure, the pump must be pulled to the surface, that greatly increases repair costs and production downtime. Furthermore, ESP systems require special equipment for monitoring and adjustments, adding to their operational complexity.

SRP systems have a simpler design and lower maintenance costs. Most of the SRP equipment is located on the surface, making it more accessible for maintenance and repairs. In case of a malfunction, it is often possible to service the system without the need for high costly operations to pull the pump from the well (Akchay L. Pandit, 2015).

2.4 Reasons for replacing one artificial lift method with another one

In modern oil well management, the selection of the appropriate artificial lift method plays a critical role in optimizing production and maintaining operational efficiency. Switching from one lifting system to another may be necessary to optimize productivity and reduce operating costs. Based on the unique conditions of the well, properties of the produced fluid, the presence of gas and water, and economic factors, the choice of an artificial lift method or replacement of an existing one is made.

One of the most common reasons for a switch is a change in well conditions. For instance, if a oil well begins to produce higher quantities of gas, sand, or water, sucker rod pumps may be a better choice due to their resilience to such conditions. For example, when water production increases, ESP systems may lose efficiency due to increased pressure and hydraulic complications. In these cases, switching to SRP becomes logical, as SRP systems are better equipped to handle high water cuts and impurities (Clegg, Bucaram, & N.W. Hein, 1993).

Conversely, if the well produces larger volumes of fluid with a low gas content, ESPs become preferable due to their ability to handle high fluid volumes. Their higher productivity can significantly boost the overall production of the well.

Economic factors may also drive a change in lift systems. If the maintenance of an ESP system becomes too costly or complex, the operator may choose to switch to an SRP system to reduce costs and simplify operations. (Clegg, Bucaram, & N.W. Hein, 1993)

2.5 Selection of artificial lift methods for small oil fields

In the context of oil wells in Serbia utilizing artificial lift methods, given that fluid production is relatively low, and most fields are in the mature stage of depletion, sucker rod pumps (SRP) are a significantly more suitable solution. Within the Petroleum Industry of Serbia (NIS a.d., Novi Sad), oil wells employing electrical submersible pumps (ESP) often require transitioning to an intermittent operation mode. However, this approach is not optimal, as ESPs are not designed for intermittent use and are consequently more susceptible to failures and reduced efficiency.

Sucker rod pumps are much better adapted to intermittent operation, as their mechanical system tolerates operational interruptions more effectively and adjusts to the specific conditions of low-productive wells. In such scenarios, SRPs not only offer greater reliability but are also more economically viable for sustained production.

From an economic standpoint, SRPs represent another considerable advantage. NIS a.d. Novi sad- company already possesses sucker rod pumps and has trained personnel for their operation and maintenance, indicating that leveraging existing assets constitutes a more financially prudent option. In contrast, ESPs entail rental and additional costs, rendering their application less cost-effective in the long run.

3 CASE STUDY: CHANGE OF ARTIFICIAL LIFT METHOD AT OIL WELL X-001

At oil field X, few exploitation methods have been employed to date. Initially, natural flow production was present. However, with the decline of reservoir energy, sucker rod pumps were used. These have been partially replaced by electrical submersible pumps (ESP). This paper aims to provide an analysis of which artificial lift method should be considered appropriate for this oil field.

Well X-001, located in the northeastern part of oil field X, reservoir X-1, has been in production since January 1, 2016, with a perforation interval between 2070-2085 meters. The well is equipped with a "Borets ESP DP190" model of electrical submersible pump, installed at a depth of 2030 meters. Following the initial adjustment phase, the well entered stable operation, producing between 18 and 19 m^3 daily, with a dynamic fluid level ranging from 1400 to 1600 meters. The pump temperature fluctuated between 130 and 140 °C.

Over time, a gradual decline in the dynamic fluid level and an increase in pump temperature were observed, culminating on February 11 and April 4, 2017, when two automatic shutdowns of the ESP occurred due to high-temperature protection activation. These situations necessitated production interruptions and further analysis.

In Figure 3, the production profile of well X-001 is presented from the start of production until the well was shut in. It involves total fluid production (Qf) as a green line, which remains stable, water cut (Wc) as a blue line indicating consistently high-water content, and oil production (Qn) as a black line, significantly lower than the total fluid but steady. The dynamic fluid level (Hdin), shown in yellow, fluctuates with noticeable drops, while the temperature (Temp), represented by the red line, increases sharply from 170°C to 185°C at one point. Key operational changes or anomalies are highlighted with blue rectangles, emphasizing shifts in fluid level and temperature.

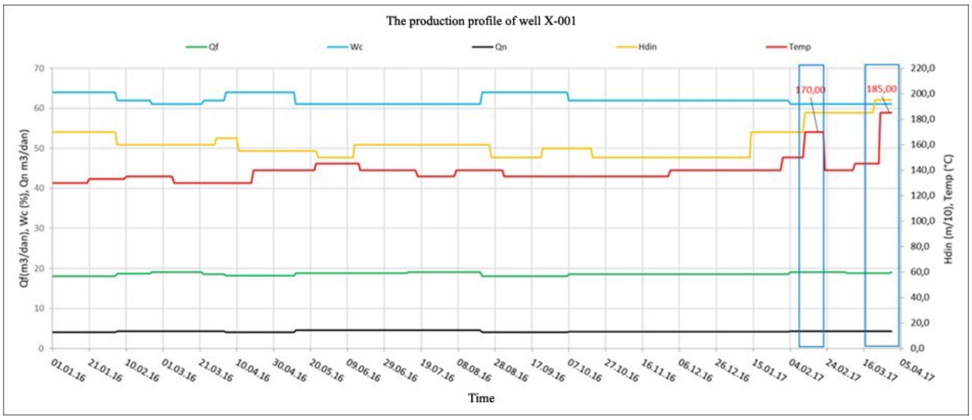

Figure 3 The production profile of well X-001

A detailed analysis of the equipment performance in well X-001 is required, addressing two key questions that will aid in optimizing operations and resolving pump issues. It refers to overheating of the ESP pump and determining the exploitation method for continuous operation.

The performance analysis of the electrical submersible pump (ESP) was done using “Pengtools.com” software, online petroleum engineering software.

Table 1 presents the input data, i.e. characteristics of the electrical submersible pump (ESP), including parameters such as flow rate, fluid properties, and operational conditions essential for the performance analysis.

Table 1 Input data for an ESP

Pump intake depth	2030	m
Tubing outside diameter	73	mm
Tubing inside diameter	62	mm
Coupling outside diameter	86.7	mm
Caseing inside diameter	150	mm
Top of perforation depth MD	2070	m
Liguid flowrate at surface conditions	18	m^3/d
Producing watercut	73	%
Reservoir pressure	80	bar
Reservoir temerature	130	ºC
Specific gravity of oil relative to water	0.85	
Specific gravity of gas relative to air	0.65	
Specific gravity of water	1	
Soluton gas-oil ratio	50	m^3/m^3
Oil density	737.1	kg/m^3
Oil formation volume factor	1.19	m^3/m^3
Oil viscosity	0.63	mPa·s
Z factor	0.94	
Gas densiy	48.3	kg/m^3
Gas formation volume factor	0.016	m^3/m^3
Gas viscosity	0.016	mPa·s
Water densiy	940.8	kg/m^3
Water formation volume factor	1.06	m^3/m^3
Water viscosity	0.22	mPa·s
Productivity index	6.57	m^3/day/bar
Producing gas-oil ratio	100	m^3/m^3
Producing gas-liquid ratio	27	m^3/m^3
Frequency	60	Hz

Table 2 displays the overall results of the calculations performed for the electrical submersible pump (ESP) analysis in Pengtools.

Table 2 The results for the electrical submersible pump (ESP)

Well folowing pressure	P_{wf}	78.2	bar
Pump intake pressure	PIP	74.68	bar
Pump discharge pressure	PDP	143.48	bar
Liguid flowrate at surface conditions	q_{liq}	18	m^3/d
Mixture flowrate at intake	$q_{mixture}$	24.7	m^3/d
Mixture flowrate at intake after separation	$q_{mixture\_sep}$	20.4	m^3/d
Gas into pump before separation	GIP_{before_sep}	23.3	%
Gas into pump after separation	GIP_{after_sep}	7.05	%
Total dynamic head	TDH	742.9	m
Breaking horsepower	BHP	5.14	kW
Breaking horsepower	BHP	6.89	hp

Figure 4 illustrates the characteristic performance curve of the electrical submersible pump (ESP), highlighting its operational efficiency for various flow rates and total dynamic head (TDH) conditions. This curve provides valuable insights into the pump's performance characteristics, including its optimal operating range, efficiency values, and the impact of varying fluid properties on its output.

The horizontal axis represents the flow rate in cubic meters per day, indicating the volume of fluid moved by the pump. The blue line shows the head capacity, reflecting the pump's ability to lift fluid at different flow rates, while the green line represents the pump efficiency, demonstrating how effectively the pump operates across the flow range. The red line indicates the brake horsepower, or the power required by the pump to operate under varying conditions. The yellow shaded area marks the optimal operating range, ensuring reliable and efficient performance, while the blue circle highlights a specific operational point, likely the current or design condition. This diagram helps analyze the pump's suitability for handling oil, water, or fluid mixtures, providing a basis for optimizing production.

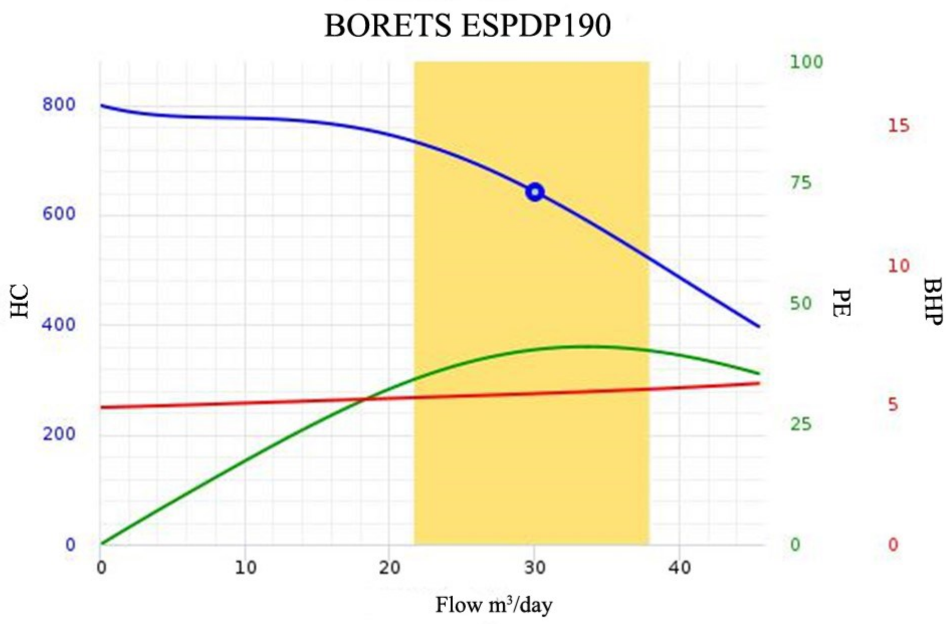

Figure 4 The ESP pump performance curve ("Pengtools.com")

The optimal operating range for this pump is between 20 and 40 m^3/day, with the highest efficiency observed around 25 m^3/day. Operating within this range will be the most energy-efficient and will provide a good balance between fluid lifting and motor power. However, at the current liquid flow rate of 18 m^3/day, the pump's efficiency will be lower than within the optimal range. According to the graph, efficiency falls below 50% at this flow rate. This indicates that the pump will not operate at its energy-optimal level, which could lead to higher operational costs and potential system overloads, ultimately resulting in increased expenses for the same scope of work.

In Figure 5 the relationship between frequency and torque versus flow rate is presented.

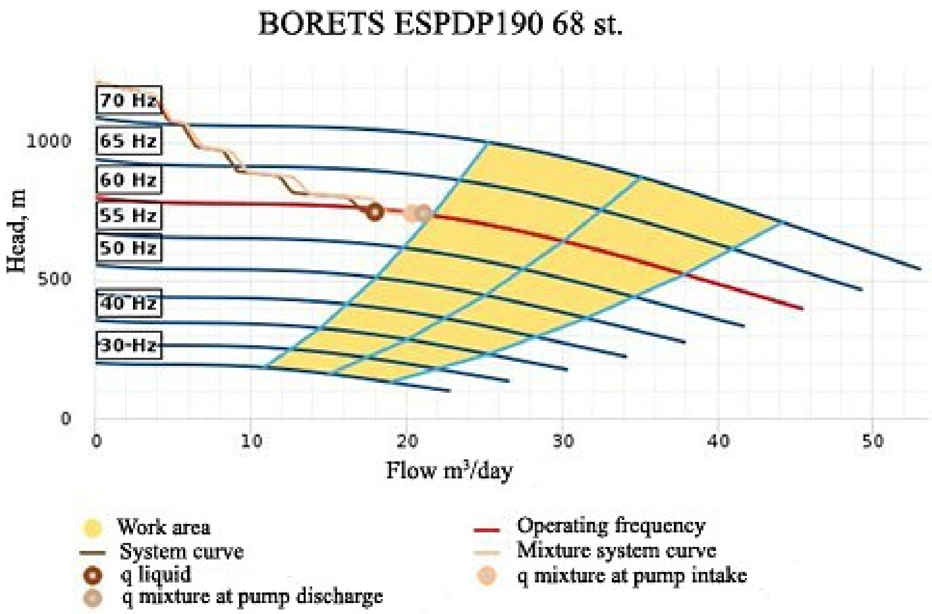

Figure 5 The frequency and torque versus flow rate diagram ("Pengtools.com")

The diagram in Figure 5 shows that the system curve indicates potential stability issues in the pump's operation. This is primarily due to the pump's production of a small volume of fluid, despite its capability to handle significantly large quantities. These instabilities can lead to:

- Inefficient pump operation, which may result in increased energy costs and reduced fluid flow.
- Damage to the pump due to improper functioning, particularly if the fluctuations become excessively large.

4 SELECTION OF A NEW ARTIFICIAL LIFT METHOD

It is important to note that, for the workover and restart of the well, the Company has the following equipment:

- Beam pumping weight of 9 t and 12 t,
- Sucker rods with a diameter of 19 mm, 22 mm, and 25 mm,
- Tubing with a diameter of 73 mm.

This equipment can facilitate the transition to a **subsurface pumping system (SRP)**, which could potentially stabilize production and reduce issues with pump temperature.

Further analysis for the sucker rod pump is done by using the **Qrod 3.1** software package, Echometer company. Table 3 presents the pumping parameters that are used as input data for the **QRod 3.1** software.

Table 3 Input data for a sucker rod pump (SRP)

Pump depth	2090	m
Surface stroke length	2508	mm
Pump diameter	38,1	mm
Tubing outside diameter	73	mm
Tubing inside diameter	62	mm
Tubing pressure	4	bar
Casing pressure	13	bar
Reservoir pressure	80	bar
Productivity index	6.57	m^3/day/bar
Pump volumetric efficiency	80	%
Surface unit efficiency	80	%
Stroke rate	6.55	

The calculation results are presented in Table 4. These results provide valuable insights into the performance and efficiency of the selected pumping method, highlighting key parameters such as production rates, operational efficiency, and potential issues identified during the analysis.

Table 4 Calculation results for the sucker rod pump (SRP)

Rate (100% pump volumetric eff.)	21.9	m^3/d
Rate (80% pump volumetric eff.)	17.5	m^3/d
Rod taper	34.0, 66.0	%
Top steel rod loading	72.8	%
Min API unit rating	320-173-99	
Min NEMA D motor size	8.66	kW
Polished rod power	4.16	kW
TVLoad	6 573	kg
SVLoad	5 038	kg

Figure 4 shows three dynamically updated graphs generated by Qrod 3.1, analyzing the performance of a sucker rod pump system. The "Dynamometer Cards" graph illustrates rod load versus position, providing insights into pump mechanics and efficiency. The "Pump Velocity vs. Position" graph shows plunger velocity changes during the stroke, revealing fluid movement dynamics. The "Torque" graph displays gearbox torque variations with crank angle, highlighting peak loads and counterbalancing effects. This analysis supports the optimization of oil production operations.

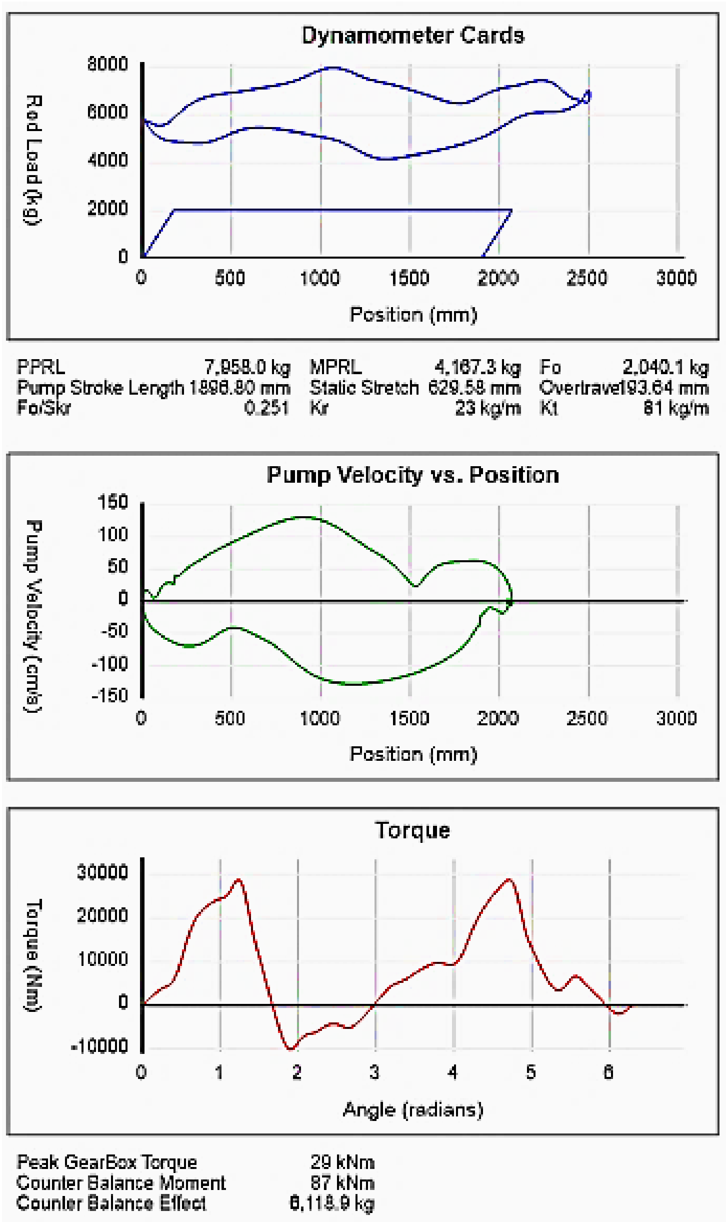

Figure 6 Diagrams of the operational characteristics of a sucker rod pump ("Qrod 3.1.")

To calculate the stability of SRP systems, the methodology involves analyzing key operational parameters such as rod load dynamics, pump velocity profiles, and torque variations, as shown in the provided dynamometer card data. This data is used to assess the pump's ability to handle variations in flow rates and well conditions, ensuring consistent performance under the given operational constraints.

The SRP has been evaluated for flows between:

- **21.9 m^3/day at 100% volumetric efficiency**
- **17.5 m^3/day at 80% volumetric efficiency**

Given that the fluid flow from the well is 18 m^3/day, the pump appears to be suitable for this flow for the following reasons:

- **Efficiency and Flow Adaptability**: The pump is designed to operate close to 18 m^3/day (at an efficiency of around 80%). The current flow rate of 18 m^3/day is very close to these values, indicating that the pump will function within its design parameters without significant overload issues.
- **Proximity to Maximum Capacity**: The pump is rated for a slightly higher flow (21.9 m^3/day), but given that the difference is minimal, it will continue to operate efficiently. Therefore, issues such as insufficient delivery or loss of volumetric efficiency are not expected.

5 CONCLUSION

The choice between sucker rod pumps (SRP) and electric submersible pumps (ESP) application depends on the specific demands of the oil well. SRP systems provide flexibility and resilience in challenging operating conditions, such as high pressures and exposure to corrosive chemicals, making them suitable for complex environments. Conversely, ESP systems offer high efficiency and stability in more consistent operating conditions, ensuring steady production and simpler maintenance.

In wells with low fluid inflow, where ESP systems are applied, intermittent operation is often used to reduce energy costs and extend equipment life. However, ESPs are not designed for intermittent operation, which increases susceptibility to failures, decreases efficiency, and raises maintenance costs. By contrast to that, SRP equipment is available, and trained personnel are on hand for maintenance and management, making the SRP method a more reliable and long-term stable solution for low-inflow wells. It offers higher productivity and lower maintenance costs compared to the intermittent operation mode of ESP systems.

Through an analysis of the ESP and oil well parameters, a significant reduction in fluid inflow into the well was observed.

The primary cause of ESP overheating was insufficient reservoir fluid inflow, leading to reduced fluid circulation around the pump and, therefore, limited motor cooling. In these conditions, the sucker rod pump exhibited significantly better performance compared to the ESP.

Calculation results for the sucker rod pump show operational stability under specific well and fluid conditions.

These results confirm that the SRP provides reliable and efficient operation, which is crucial for optimizing production in complex and demanding conditions. The observed operational stability, confirmed by the calculations, indicates its ability to handle variations in operating conditions and fluid properties effectively, ensuring continuous productivity and minimizing the risk of production interruptions.

In this case, potential limitations of SRP include the ongoing maintenance and the need for periodic upgrades to adapt to changing well conditions or improve efficiency. These requirements can increase operational costs over time and may affect the overall cost-effectiveness of SRP systems. However, in addition to this, in this case, the SRP pump remains a better option both technically and economically.

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