HOW ARE ESP-LIFTED WELLS AFFECTED BY SHUT-INS FOR OFFSET HYDRAULIC FRACTURING TREATMENTS?

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ABSTRACT

The discovery of shale formations laden with hydrocarbons marked a significant turning point in the energy industry, especially because these formations exhibited minimal to no permeability. This inherent characteristic posed a substantial challenge for traditional extraction methods, leading to the advent of what is known as the unconventional play. The core of this approach is hydraulic fracturing, a revolutionary technique that not only generates high-conductivity fractures within the shale but also fosters the interconnection of these fracture networks, dramatically enhancing the extraction process.

The advent of hydraulic fracturing has revolutionized the extraction of hydrocarbons from shale formations, characterized by minimal to no permeability. This paper discusses the mechanics of hydraulic fracturing, focusing on its role in creating high-conductivity fractures and interconnecting fracture networks to facilitate hydrocarbon flow. The study further explores technological advancements aimed at optimizing production plans, despite the inherent unpredictability of fracture outcomes. Emphasis is made on the impact of well spacing on fracture interaction. The overall extraction process is examined, highlighting the complex dynamics between well proximity and hydrocarbon recovery efficiency.

Electrical Submersible Pumps (ESPs) are designed to apply a constant force to lift fluids in a well, with their flow rate being influenced by the pressure difference they generate. Optimal ESP design considers the formation's fluid yield, the fluid's density, and the required lift height, which together determine the pump's energy transfer needs. For high-productivity wells, the ESP's ability to increase pressure and consequently enhance flow capacity is crucial.

This research explores the impact of frac-hits, triggered by hydraulic fracturing in proximity to active wells, focusing on well performance metrics such as reservoir pressure changes, oil recovery, and the efficiency of Electrical Submersible Pumps (ESPs) in recovery. Through a comparative analysis of ESPs and Gas Lift systems in mitigating frac-hit repercussions, this paper aims to enhance strategic planning and risk mitigation in hydraulic fracturing operations.

INTRODUCTION

Hydraulic fracturing has revolutionized oil extraction from shale formations, presenting unique challenges, including frac-hits, where fracturing fluids and pressures adversely affect adjacent wells. This research delves into the operational consequences of frac-hits, emphasizing the comparative effectiveness of ESPs against traditional Gas Lift systems in facilitating rapid recovery and optimizing well performance. By focusing on single wells in parallel configurations, the study navigates through the complexities introduced by such operational disturbances.

The phenomenon of frac-hits, an inadvertent consequence of hydraulic fracturing where fracturing fluids and pressures impact adjacent wells, serves as the focal point of this investigation. This research aims to dissect the repercussions of a frac-hit on a well's operational parameters, specifically examining alterations in reservoir pressure, fluctuations in projected oil recovery, and the efficacy of employing optimized artificial lift techniques post-frac-hit incident. The study acknowledges that artificial lift systems are not universally applicable across all wells due to the diversity in well characteristics and reservoir conditions. Therefore, the scope of this analysis is narrowed to wells utilizing Electrical Submersible Pumps (ESPs), which facilitate a high rate of fluid extraction. These are juxtaposed with wells employing Gas Lift, another high-rate artificial lift method, to establish a comparative framework for evaluating lift efficiencies in the context of frac-hits.

To ensure a robust and precise examination, the research methodology focuses on individual wells situated in parallel configurations. This excludes the complexities introduced by multi-well pads, except in cases where such scenarios are explicitly included for analysis. By isolating the study to single wells, the research intends to provide a clearer understanding of the direct impacts of frac-hits and the subsequent recovery strategies involving artificial lift systems. The findings aim to contribute to the strategic planning and risk mitigation processes associated with the deployment of hydraulic fracturing operations in oil and gas extraction, enhancing industry knowledge in managing and optimizing well performance in the face of inter-well interference.

RESEARCH

Shut In for Frac Hits

When completing a new well with another producing well in close proximity, there are critical considerations to ensure safety, protect equipment, and maintain wellbore integrity. Safety is paramount because the operations at one well can inadvertently affect the neighboring wells, particularly if there is a blowout or uncontrolled release of hydrocarbons. The positioning and robustness of equipment must be carefully planned to prevent any cross-well incidents that could lead to operational failure or accidents.

Wellbore integrity refers to maintaining the well structure without any leaks or damage. When wells are closely spaced, the completion activities, such as hydraulic fracturing in one well, could potentially compromise the structural integrity of nearby wellbores (King, George E., and Randy L. Valencia, 2016).

The common practice of shutting in a well during nearby completion activities is a precautionary measure. However, when the shut-in well is brought back into production, it might not perform as anticipated. This discrepancy in performance could be due to several factors:

1. Pressure Variations: The completion process in one well could alter the reservoir pressure which, in turn, affects the production characteristics of adjacent wells. The pressure changes could either be beneficial, by enhancing oil recovery, or detrimental, by reducing the flow rates or creating unexpected pressure conditions that need to be managed. Hydraulic fracturing can create connections between wellbores that are meters apart, indicating extensive network connectivity. The strongest pressure interactions often predict the greatest production interference between wells (Lehmann, Budge, Palghat, Petr, and Pyecroft., 2016)

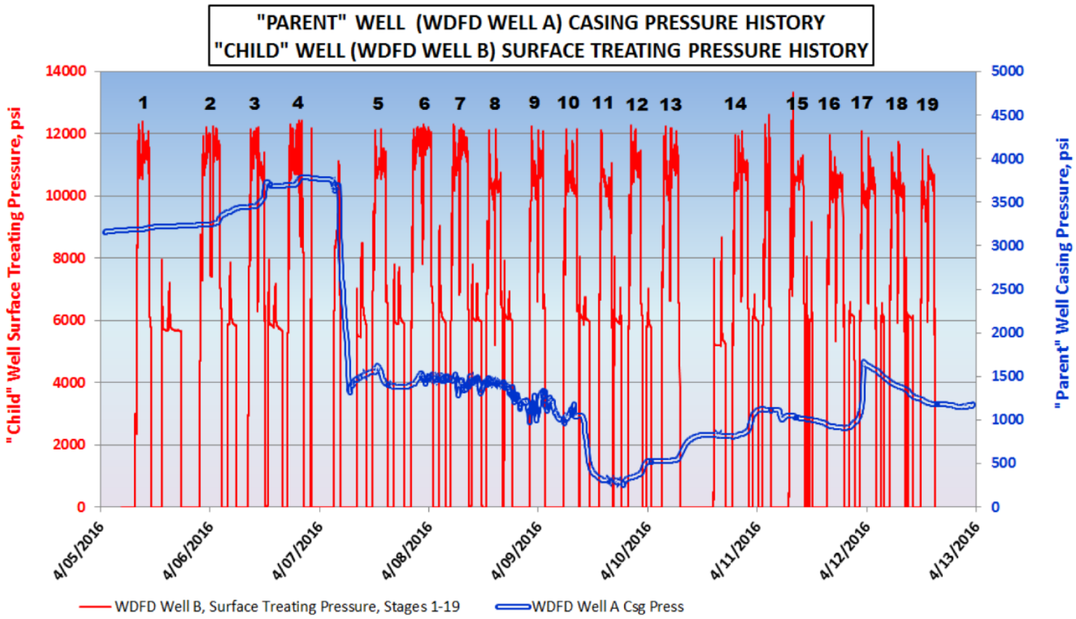

Figure 1, Pressure Hit During Offset Frac Job

Figure 1 (King, George E., Rainbolt, Michael F., and Cory Swanson, 2017) demonstrates increase in pressure in 'Well A' which is shut-in while adjacent 'Well B' is being hydraulically fractured. The well is opened after stage 4 of 'Well B' completion.

2. Communication Through Fractures: There is a possibility of creating fractures that extend to adjacent wellbores during completion. If these fractures allow for fluid communication between the wells, it could lead to cross-contamination or production changes due to the fluids' intermingling. (King, Rainbolt, and Swanson, 2017)
3. Frac Fluid Migration: The fluids used in the fracturing process of the new well might migrate to adjacent wellbores, which can alter the fluid composition and properties within the reservoir. This could affect the flow characteristics and production rates when the nearby shut-in well resumes operation. Evidence from microseismic data, inter-well fluid migration, and the analysis of fracturing fluid in produced water suggest that natural fractures often guide complex fracture paths. To prevent the risk of frac hits, reducing fracture volume can be beneficial, especially when managed alongside the rate and specific injection sites. Although larger volumes can increase the initial contact area, the effectiveness often depends on the area of propped fractures or shear fractures. These fractures, even when shifted by minimal amounts, can create rough surfaces that enhance flow rates (King, Rainbolt, and Swanson, 2017).

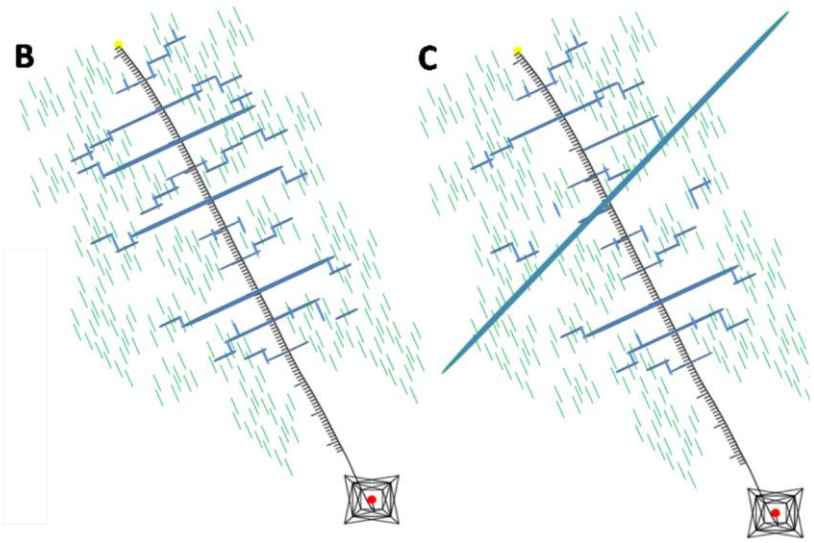

Figure 2, Fracture Connectivity Example

Figure 2 shows enforced fractures as well as natural fractures. These can vary depending on the completion plan, stresses applied as well as many other factors regarding rock characterization (Stephenson, Ben, Fannin, Randall, Dick, Chris, Williams, Marty, and Deniz Cakici, 2013)

Managing these risks involves a detailed understanding of the geological conditions, careful monitoring of pressure and fluid movement, and a strategic plan for the placement and operation of wells. Monitoring technology and predictive modeling are often employed to forecast possible outcomes and prepare contingency plans for any unforeseen changes in well performance.

Production Curve Forecast

Diagnostics involved analyzing water samples from two wells (referred to as the child and parent wells) to check for the presence of water tracers, which had been added to each fracturing stage to track fluid movement. Unique tracers were used for all stages in both wells. The findings showed the detection of tracers from the child well in the parent well's produced water. This indicates clear evidence of fluid communication between the wells. The sampling timeline indicates that the frac water from the child well reached the parent well quickly (King, George E., Rainbolt, Michael F., and Cory Swanson, 2017).

After a well has been shut-in due to a frac hit, wells often experience a rapid drop in oil and gas production with a gradual recovery period. Water output can spike immediately after the hit and then decrease over time as the well stabilizes. However, this pattern can vary by region. In areas with an underlying brine formation, a frac hit could also increase brine production in the affected well and any others it connects with. The financial consequences of such bottom-water hits hinge on several factors, including the ability of the fractures to seal over time and the presence of a driving force from the underlying water. Overall, frac hits tend to negatively affect the performance of wells in liquid-rich reservoirs, particularly as the well's reservoir pressure decreases (King, George E., Rainbolt, Michael F., and Cory Swanson, 2017).

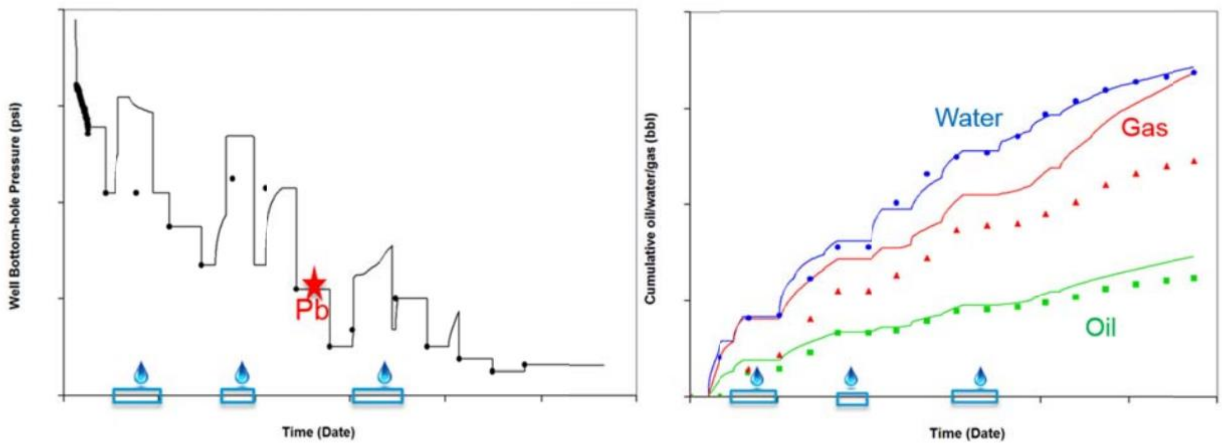

Figure 3, Induced Frac Hits to Show Water Hit

In Figure 3, three frac hits were added to baseline without any additional mechanism to influence the history match. Dots represent pressure and curves represent results (Dengen et al., 2017). Water increase in the cumulative production of said well can be differentiated as well as the subsequent increase in pressure.

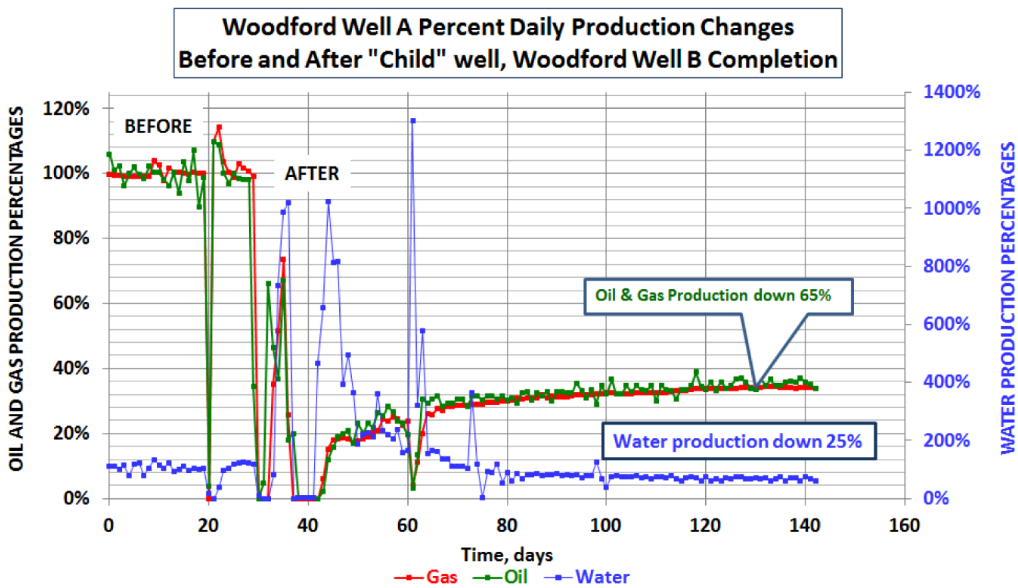

Figure 4, Before and After Shut-In Production Curve

Figure 4 (King, George E., Rainbolt, Michael F., and Cory Swanson, 2017) delineates the production trajectory of a parent well prior to and subsequent to the completion of an adjacent "child" well. The depicted production curve incorporates a phase during which the parent well was temporarily shut in, followed by its reintegration into the production regime. In this case study, the parent well, which was operated using Gas Lift artificial lift technology, required 28 days to restore its production levels to the pre-shut-in trajectory. On day 60, a coiled tubing cleanout run was made to ensure that no bridges had been formed in the lateral during offset completion operations. This is not always the case, since fracture development is still unpredictable, there can be instances where the well never achieves going back to the decline curve or can even produce more oil than expected due to the communication between wells.

One of the primary concerns is the effect on Estimated Ultimate Recovery (EUR). Shutting in a well may alter the reservoir dynamics and fluid distribution, potentially reducing the total volume of hydrocarbons that can be economically extracted over the well's lifespan. The disruption caused by the fracturing treatments in nearby wells can affect the pressure equilibrium and fluid flow paths within the reservoir, which, in turn, may impact the EUR.

Furthermore, the time required for a well to return to its pre-shut-in production levels—referred to as the recovery time—can be extended. This delay is not just a matter of lost production time but also reflects the well's resilience to operational disturbances and its ability to regain momentum after being impacted by external activities. The longer recovery time translates directly into deferred revenues, complicating the financial planning and profitability forecasts for the operation.

Additionally, the process of shutting in a well and subsequently bringing it back online entails extra costs. These may include the expenses associated with monitoring and evaluating well status, implementing additional interventions to restore production rates, and the potential need for equipment adjustments or repairs caused by the shut-in and restart processes.

ESP Lifted Wells and Water Cut Increase

The implementation of Electrical Submersible Pumps (ESPs) in oil wells is a nuanced process that demands a comprehensive understanding of several interrelated factors. Unlike traditional pumping mechanisms that might aim to lift a predetermined volume of fluid, ESPs are engineered to exert a consistent amount of force across the fluid column present in the well. This approach allows ESPs to adapt to varying conditions within the well, altering the flow rate based on the differential pressure they can generate. Consequently, the performance of an ESP is inherently linked to the characteristics of the fluid it is tasked with lifting and the physical parameters of the well itself.

Key to optimizing an ESP's design is the evaluation of the inflow performance relationship (IPR), which predicts the volume of fluid the reservoir can deliver under certain conditions. This aspect of design involves analyzing the reservoir's behavior in response to different pressures to estimate how much fluid can be feasibly extracted. Alongside the IPR, the outflow performance of the wellbore must be considered, encompassing factors such as the fluid's density (or specific gravity) and the vertical distance the fluid must be lifted. These considerations help define the energy requirements of the ESP, as the pump must be capable of imparting sufficient energy to the fluid to overcome these physical challenges and ensure efficient transportation to the surface.

The design of Electrical Submersible Pumps (ESPs) plays a vital role in optimizing oil well production, particularly through the manipulation of pressure conditions within the wellbore. According to Darcy's Law, which governs the flow of fluids through porous media, the differential pressure across the formation face is directly proportional to the flow rate of the fluid. In the context of ESP design, this principle implies that an increase in the pressure differential created by the pump will result in a greater drawdown of pressure at the reservoir level, thereby enhancing the well's flow capacity (Qahtani, 2013).

However, the performance of an ESP and, by extension, the productivity of the well, can be affected by the water cut or the ratio of water to the total volume of fluids produced. As the water cut increases, it leads to a corresponding decrease in pressure, which can be attributed to the specific gravity or density of the produced water. Specific gravity, a dimensionless quantity, measures the density of a substance relative to the density of water. Thus, in scenarios where the produced water has a high specific gravity, the resulting increase in the density of the fluid mixture necessitates more energy (or a higher pressure gradient) to lift the fluids to the surface.

This relationship between water cut and well productivity becomes particularly pronounced in wells that encounter high specific gravity of water. Despite these wells potentially possessing high intrinsic productivity—owing to favorable reservoir characteristics such as high permeability or porosity—their output is considerably diminished by the challenges associated with managing high water production. The presence of water with high specific gravity increases the load on the ESP, requiring it to work harder to achieve the same level of fluid lifting, thus directly impacting the efficiency of hydrocarbon production.

In the context of mitigating the effects of frac hits, a scenario wherein hydraulic fracturing fluid invades an adjacent well, the primary objective is to expediently extract the influx of water from the formation to resume hydrocarbon production. To this end, the deployment of Electrical Submersible Pumps (ESPs) is a strategic choice, favored for their ability to enhance recovery rates due to the higher fluid lifting capacities associated with this method of artificial lift. As elucidated in Figure 5 (Bagci, A. et al., 2010), empirical data delineates the superior performance of ESPs relative to Gas Lift systems across varying degrees of water saturation within the reservoir. The efficiency of ESPs becomes particularly pronounced as the water cut escalates, thereby substantiating their effectiveness in minimizing the duration required for a well to regain its productive capacity in the aftermath of frac-hit incidents. This advantage is attributable to the ESP's robust mechanism, which is inherently suited to handle substantial volumes of water, thus expediting the recovery process and promptly restoring oil production.

Therefore, the design and selection of ESPs for oil wells with high water cuts necessitate careful consideration of the specific gravity of the water to ensure that the system is capable of handling the anticipated fluid densities. This entails not only choosing a pump with adequate pressure-generating capacity but also implementing strategies to manage or minimize water production, thereby optimizing the overall production performance of the well.

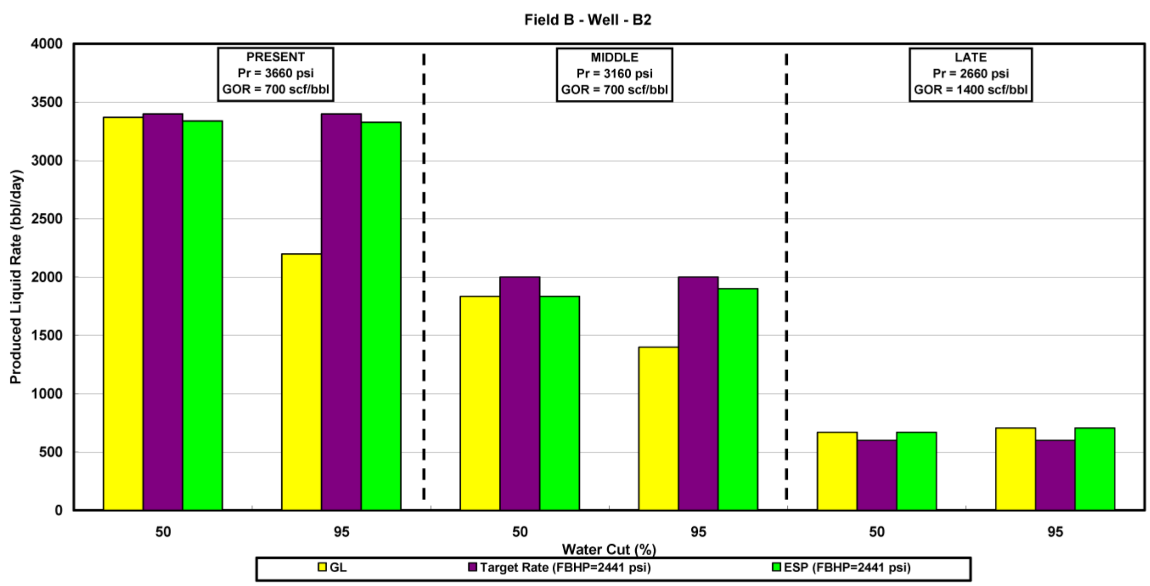

Figure 5, ESP, and Gas Lift performance comparison on increased water-cut reservoir

<u>CONCLUSIONS</u>

- Temporarily shutting in wells during the completion activities of neighboring wells presents both benefits and drawbacks. Designed primarily as a precautionary measure, this strategy aims to protect operational integrity and prevent cross-well contamination or interference.
- Resumption of production often uncovers a spectrum of performance disparities, attributed to a complex interplay of factors that fundamentally reshape the production landscape. Key among these factors are alterations in reservoir pressure, the unintended migration of fluids through newly created fractures, and the dispersal of fracturing fluids, all of which underscore the interconnected nature of well networks and the potential for widespread operational impacts.

- The phenomenon of increased water production post-frac-hit and the challenges it presents in terms of fluid management spotlight the critical role of artificial lift technologies, particularly Electrical Submersible Pumps (ESPs), in navigating these challenges.
- ESPs, with their robust design for handling substantial fluid volumes, emerge as invaluable assets in mitigating the adverse effects of frac-hits. Their capability to efficiently manage the influx of water post-fracturing significantly abbreviates the recovery period, thereby minimizing downtime and facilitating a swifter resumption of production activities.
- The strategic deployment of ESPs in this context not only highlights their utility in ensuring operational resilience but also showcases their superiority over alternative artificial lift methods. By enabling a more efficient fluid handling and recovery process, ESPs help maintain production efficiency and economic viability such as enhancing or stimulating the Estimated Ultimate Recovery (EUR) when possible in the face of the disruptions associated with neighboring completion activities.

In conclusion, the practice of well shut-ins, while beneficial as a protective measure, introduces a range of operational challenges that demand sophisticated management strategies. The adoption of ESPs represents a proactive approach to addressing these challenges, underscoring the importance of technological innovation and strategic planning in the oil and gas industry. As the sector continues to navigate the complexities of reservoir management and production optimization, the insights garnered from the application of ESPs in managing post-frac-hit recovery illuminate a path forward. By leveraging advanced technologies and adopting an integrated approach to well management, operators can enhance production resilience and safeguard the long-term productivity of their assets.

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