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PLANNING OF THE COILED TUBING GAS LIFT METHOD TO OVERCOME ESP START-UP FAILURE IN WELL PPA-003

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Abstract
The PPA-003 well in the Puspa Structure, Jambi Field, faces technical challenges due to the start-up failure of the Electric Submersible Pump (ESP) caused by the presence of heavy complex fluids. This condition hampers the initial production process and reduces the operational efficiency of the well. This study aims to design a nitrogen (N_2) injection method through coiled tubing applied alongside the ESP start-up as a solution to lift the heavy complex fluids and enable the well to flow stably. The proposed approach involves using coiled tubing to inject N_2 into the well during the start-up process, thereby reducing the pressure gradient inside the tubing and lowering the total dynamic head (TDH) that must be supported by the ESP pump. Once the well flows and stable flow is achieved, the coiled tubing will be removed, and the operation will continue solely with ESP support. This study includes a technical analysis of the causes of start-up failure, N_2 injection design, ESP performance evaluation, and well flow simulation. The research results indicate that this method is effective in overcoming start-up obstacles by reducing the density of the heavy mud (kill fluid), allowing the ESP to operate within the equipment's operational limits. The recommendations from this study are expected to serve as a reference for addressing similar challenges in other wells, particularly in the Jambi Field area

Keywords: coiled-tubing-gas-lift; gas-lift-assisted-esp; start-up; HPHT

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INTRODUCTION

Well PPA-003 is a former exploration well located in the Puspa Structure, Jambi Field. This vertical well has a total depth (TD) of 3,123 meters (Weimer et al., 2016). The production target for PPA-003 is the GUF layer, situated at a depth interval of 2,003–2,009 meters. Based on Drill Stem Test (DST) data analysis, this well has an oil production potential of up to 1,000 BFPD with 0% water content (Wikipedia, 2025). The reservoir pressure is 5,095 psi, and the reservoir temperature reaches 200°F, classifying it as a High Pressure High Temperature (HPHT) well. According to the American Petroleum Institute (2012), HPHT wells are defined as wells with pressures ≥ 10,000 psi and temperatures ≥ 300°F. Although the temperature is slightly below that threshold, the pressure characteristics of PPA-003 bring it close to HPHT operations. HPHT wells often account for less than 2% of global drilling but present significant technical and economic value (Hashem, 2020). Such conditions require specialized equipment that can withstand pressures up to 15,000–20,000 psi and temperatures exceeding 400°F (Schlumberger, 2016). DST tools used in these conditions must be tested under full-scale scenarios to ensure operational reliability (Oil & Gas Journal, 2021). Technical challenges in HPHT operations include casing integrity, pressure and thermal control, and custom DST tool design (Drilling Contractor, 2020.).

In the completion program designed to transition the well into production using natural wellhead pressure, early indications of formation damage severely constrained influx, resulting in low and intermittent flow rates (SLB, 2016; Core Lab, 2023) . Reports have shown that such intermittent production often stems from sand and fines plugging near-wellbore formations, exacerbated by reservoir compaction and fluid interactions (Rahman et al., 2022; SLB, 2016) . To mitigate these production shortfalls, an Electrical Submersible Pump (ESP) is proposed, which is widely recognized as an effective artificial lift solution in low-pressure/high-temperature (HPHT) wells and is capable of handling moderate to high-volume fluid inflows (Wikipedia, 2025; Wood Group ESP, 2008). Nonetheless, ESP systems are susceptible to operational pitfalls such as gas locking, erosion, and mechanical failure—especially in formations with high solid production—and proper selection and maintenance protocols are essential for ensuring system reliability (Springer review, 2021; OGJ, 2010). Field evidence demonstrates that utilizing an ESP in wells experiencing intermittent influx can significantly improve and stabilize production, provided the pump is appropriately sized and protected from formation solids (SPEEURO, 2020; Core Lab, 2023).

The ESP available for well PPA-003 is an extreme specification pump capable of withstanding high-temperature operations, often exceeding 200°F, which is typical in HPHT (High Pressure High Temperature) wells (Banjar et al., 2013). However, challenges emerge as the largest motor capacities become inefficient once completion fluids are fully unloaded, reducing cooling effectiveness and risking motor burnout (Chu et al., 2022). Installing the ESP in this well requires pulling the tubing and using high-specific-gravity (SG) completion fluids—up to 1.7 SG—to "kill" the well, which dramatically increases the total dynamic head (TDH) beyond the pump's capacity (Duran & Prado, 2004). When TDH is too high, the pump operates under stress, and cooling is inadequate, leading to overheating and accelerated degradation of internal components (Ellexson, 2020). Studies confirm that in high-SG environments, motor current spikes due to excessive resistance, which can surpass the thermal limits of the system (Hollund, 2010). Therefore, balancing fluid density, pump performance, and motor protection is essential to avoid catastrophic ESP failure in HPHT well scenarios like PPA-003 (SLB, 2014).

There are several options for production start-up with high-SG completion fluids in this well: 1. Performing direct circulation. 2. Installing a Sliding Sleeve Door (SSD). 3. Unloading the tubing using coiled tubing.

Direct circulation using formation water is a technique to clean completion fluids through the tubing to the annulus. However, this cannot be done because the ESP pump assembly in the tubing poses a risk of pump damage. Installing an SSD is another feasible option, but SSD units are not available. Given these considerations, using coiled tubing can provide a solution for start-up by reducing the well's TDH during production in well PPA-003, which utilizes an ESP.

RESEARCH METHOD

This research employs a combined theoretical and field-data approach to problem-solving, utilizing both primary and secondary data. The methodology involves several key stages: (1) data collection, including well diagrams, fluid and pressure data, and coiled tubing (CT) equipment specifications; (2) determining operational limits based on CT nitrogen pump capacity and ESP maximum capacity; (3) identifying the optimal nitrogen injection depth; (4) calculating the ideal nitrogen injection flow rate; (5) analyzing well pressure gradients during ESP start-up; and (6) developing a detailed execution plan for the operation. This structured approach ensures a comprehensive and practical solution.

RESULT AND DISCUSSIONS

Analysis of Well Data

The first step in this research is evaluating data related to Well PPA-003, which is the object of study and forms the basis for calculations in this research. The collected data can be categorized into well mechanical data, reservoir data, and equipment data used during the start-up of the Electrical Submersible Pump (ESP) in Well PPA-003. Figures 1 shows the diagrams of Well PPA-003 before and after the ESP installation work. It is known that before the ESP installation, the well was in a shut-in status with a natural flow completion configuration (tubing and packer).

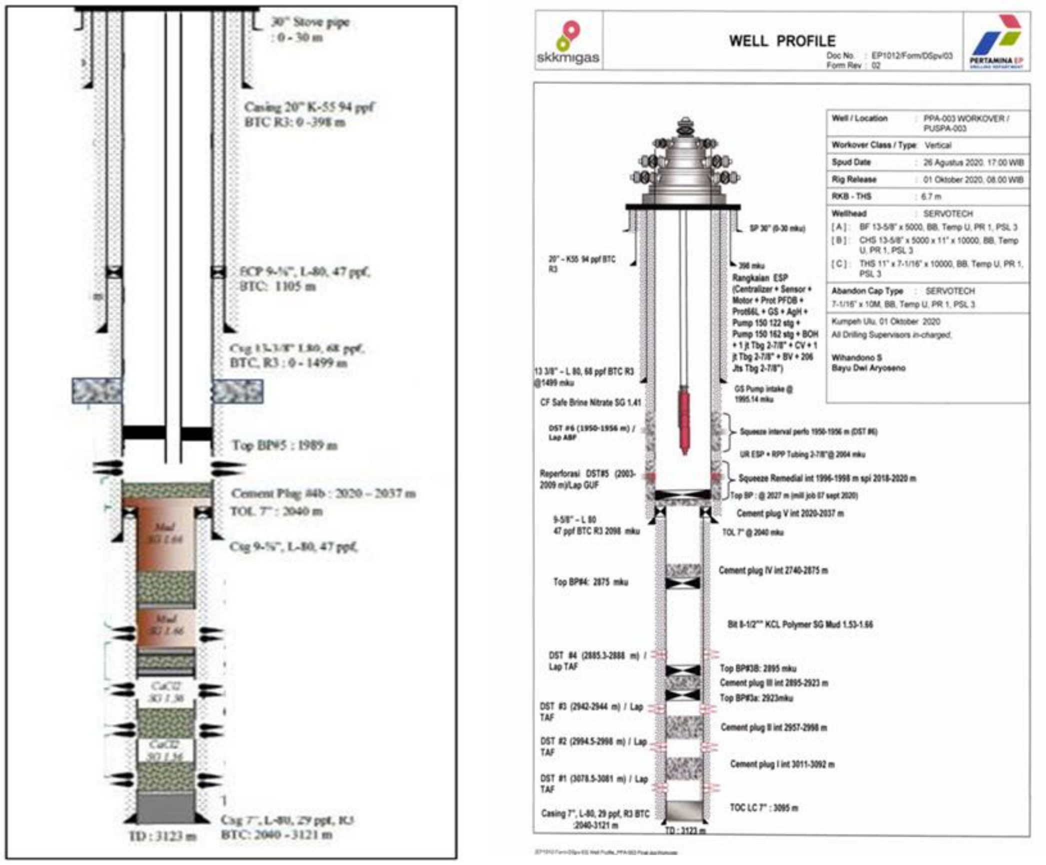


Figure 1 : Well Diagram PPA-003, Before (Left), After (Right)

Based on the stimulation potential analysis of the GUF layer (DST#5), the well was proposed as a candidate for a workover job involving hydraulic fracturing stimulation. This was intended to unlock the oil reserve potential in this layer, which has low permeability (xx mD) and reservoir characteristics of High Pressure High Temperature (HPHT) with a reservoir pressure of 4,800 psi and a reservoir temperature of 113°C (235°F), as measured by SBHP, as shown in Figure 2.

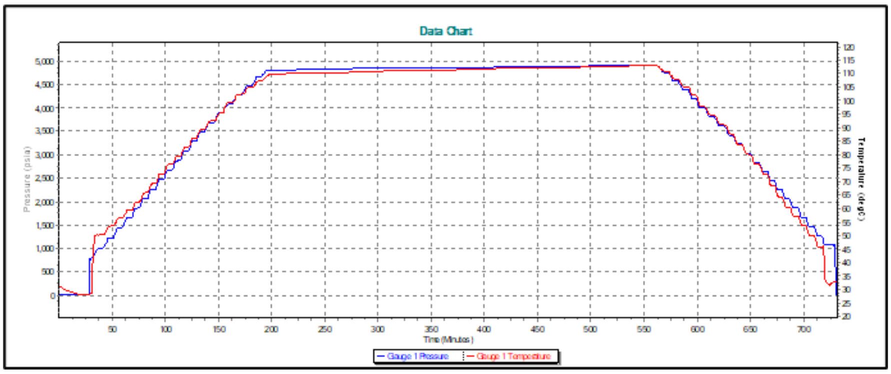


Figure 2 : Static Bottom Hole Pressure Data (SBHP)

PRODUCTION DATA		
GROSS PRODUCTION	80.0	BFPD
WATER PRODUCTION		BWPD
OIL PRODUCTION	72.0	BOPD
WATER CUT	10.0	%
OIL VISCOSITY	0.5	Cp
OIL API GRAVITY	45.0	DEG API
FLUID LEVEL	1200	mt
BHFP	971	Psi

Table 1 : Fluid Data

The installation of the ESP during the workover job was a contingency plan in case the well could not produce optimally through natural flow after the hydraulic fracturing work. Figure 4 shows the flow performance of Well PPA-003 in the GUF layer during the well test.

Based on the initial data provided by Pertamina, the ESP equipment provider conducted the design calculations for the ESP pump to be installed under normal operating conditions, assuming the ESP start-up would occur with the wellbore filled with oil. This calculation did not account for the well conditions requiring a kill operation using heavy mud to counteract the high reservoir pressure, which significantly increases the mud density. Figure 3 illustrates the results of the ESP design for Well PPA-003.

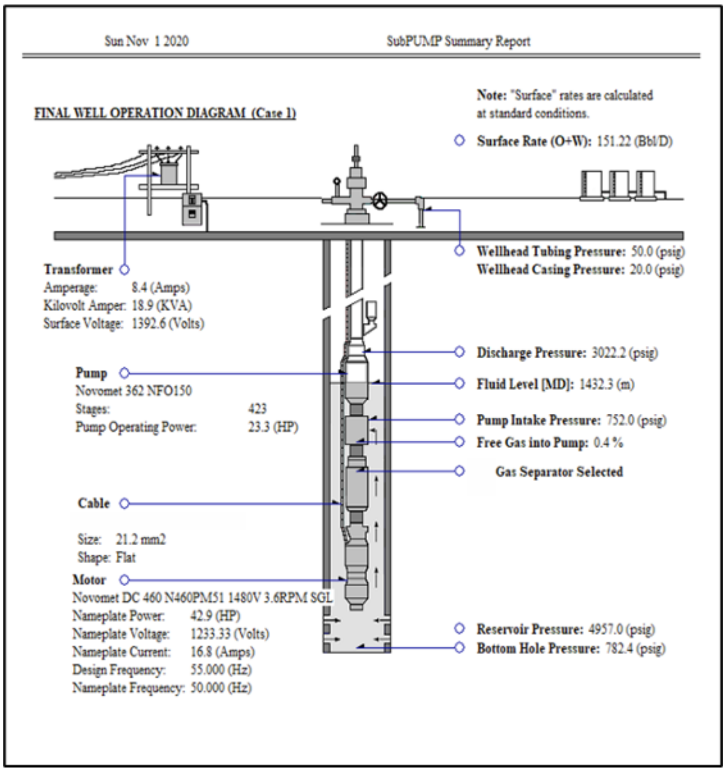
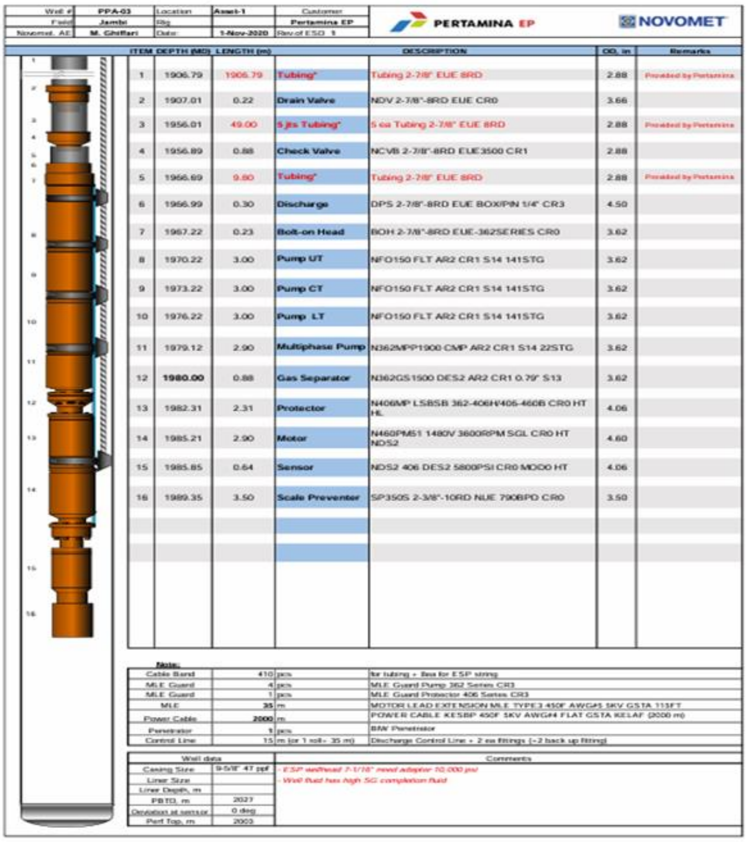


Figure 3 : ESP Design of Well PPA-003

From the perspective of the well completion design, the well control conditions were not considered. As a result, a Sliding Sleeve Door (SSD) was not installed, which would have allowed reverse circulation to replace the heavy mud in the wellbore with a lighter fluid (freshwater) after the ESP assembly installation. This omission leads to the requirement for significantly higher horsepower (HP) for the ESP during start-up compared to a scenario where the well contains lighter fluid. Figure 4 presents the ESP assembly design for Well PPA-003.



Well #	PPA-03	Location	Asset-1	Customer
Field	Jambi	Rig		Pertamina EP
Novomet, AE	M. Ghiffari	Date:	1-Nov-2020	Rev.of ESD 1

ITEM	DEPTH (MD)	LENGTH (m)		DESCRIPTION	OD, in	Remarks
1	1906.79	1906.79	Tubing*	Tubing 2-7/8" EUE 8RD	2.88	Provided by Pertamina
2	1907.01	0.22	Drain Valve	NDV 2-7/8"-8RD EUE CR0	3.66	
3	1956.01	49.00	5 jts Tubing*	5 ea Tubing 2-7/8" EUE 8RD	2.88	Provided by Pertamina
4	1956.89	0.88	Check Valve	NCVB 2-7/8"-8RD EUE3500 CR1	2.88	
5	1966.69	9.80	Tubing*	Tubing 2-7/8" EUE 8RD	2.88	Provided by Pertamina
6	1966.99	0.30	Discharge	DPS 2-7/8"-8RD EUE BOX/PIN 1/4" CR3	4.50	
7	1967.22	0.23	Bolt-on Head	BOH 2-7/8"-8RD EUE-362SERIES CR0	3.62	
8	1970.22	3.00	Pump UT	NFO150 FLT AR2 CR1 S14 141STG	3.62	
9	1973.22	3.00	Pump CT	NFO150 FLT AR2 CR1 S14 141STG	3.62	
10	1976.22	3.00	Pump LT	NFO150 FLT AR2 CR1 S14 141STG	3.62	
11	1979.12	2.90	Multiphase Pump	N362MPP1900 CMP AR2 CR1 S14 22STG	3.62	
12	1980.00	0.88	Gas Separator	N362GS1500 DES2 AR2 CR1 0.79" S13	3.62	
13	1982.31	2.31	Protector	N406MP LSBSB 362-406H/406-460B CR0 HT HL	4.06	
14	1985.21	2.90	Motor	N460PM51 1480V 3600RPM SGL CR0 HT NDS2	4.60	
15	1985.85	0.64	Sensor	NDS2 406 DES2 5800PSI CR0 MODO HT	4.06	
16	1989.35	3.50	Scale Preventer	SP350S 2-3/8"-10RD NUE 790BPD CR0	3.50	

Note:

Cable Band	410	pcs	for tubing + 8ea for ESP string
MLE Guard	4	pcs	MLE Guard Pump 362 Series CR3
MLE Guard	1	pcs	MLE Guard Protector 406 Series CR3
MLE	35	m	MOTOR LEAD EXTENSION MLE TYPE3 450F AWG#5 5KV GSTA 115FT
Power Cable	2000	m	POWER CABLE KESBP 450F 5KV AWG#4 FLAT GSTA KELAF (2000 m)
Penetrator	1	pcs	BAW Penetrator
Control Line	15	m (or 1 roll= 35 m)	Discharge Control Line + 2 ea fittings (+2 back up fitting)

Well data		Comments
Casing Size	9-5/8" 47 ppf	- ESP wellhead 7-1/16" need adapter 10,000 psi
Liner Size		- Well fluid has high SG completion fluid
Liner Depth, m		
PBTD, m	2027	
Deviation at sensor	0 deg	
Perf Top, m	2003	

Figure 4 : Detailed ESP Assembly Design for Well PPA-003

A workover operation was conducted on Well PPA-003 with the primary objective of performing hydraulic fracturing on the GUF formation (DST#5) using a drill pipe and packer assembly. It was planned to replace the drill pipe with tubing after the fracturing operation, assuming the well could produce naturally. The installation of an ESP was prepared as a contingency measure in case the well could not achieve optimal production through natural flow.

Upon completion of the hydraulic fracturing operation, the job resulted in a screen-out due to damage to the hydraulic fracturing pump during the main operation. Consequently, the plan shifted to replacing the drill pipe assembly with an ESP (as swab testing showed fluid flow was not continuous). During this process, Well PPA-003 experienced a kick. This condition necessitated killing the well before the drill pipe assembly could be retrieved. The well was killed using water-based mud with a density of 15 ppg (SG 1.75).

Evaluation of Designed ESP Operating Conditions

This subsection of the study calculates the limitations of the available ESP motor capacity in the field. The calculations compare the designed ESP capacity with changes in wellbore conditions, specifically when the well contains mud with a density of 15 ppg. The analysis is conducted using software provided by the ESP supplier by adjusting the specific gravity (SG) of the well fluid to match the SG of the heavy mud present in the well.

Figure 5 illustrates the pump curve results after adjusting the fluid SG. It is evident that, with the well filled with mud weighing 1.75 SG, the pump operates in the red zone, indicating a risk of shaft failure. Furthermore, the calculations show that with the current pump configuration, the required horsepower (HP) is 39 HP, approximately 93% of the available motor capacity. This poses a risk of overheating the pump components due to the already high well temperature exceeding 100°C.

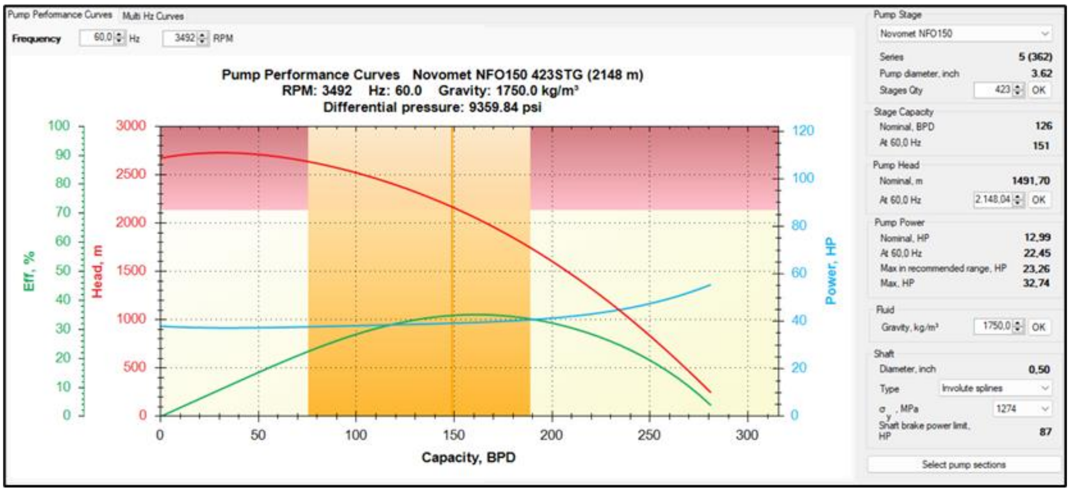


Figure 5 : ESP Pump Curve for Well PPA-003 with Heavy Mud Fluid

Calculating Depth of N_2 Injection

This calculation is performed to determine the coiled tubing (CTU) injection depth for nitrogen (N_2) with the objective of reducing the well's hydrostatic pressure and the load on the ESP during start-up. The determination of the N_2 injection depth is carried out by comparing the gradient of the injected N_2 gas within the coiled tubing to the gradient of the heavy mud within the tubing. The calculation is performed using Microsoft Excel.

Based on the calculation, it was found that the bottom-hole pressure is balanced at a depth of 1,450 meters, and the planned injection depth is set at 1,370 meters to achieve a pressure differential of 100 psi.

	Coiled Tubing	**Tubing**
ID (inch)	1.075	2.442
Initial Fluid	N2	Water Based Mud
Fluid Gradient (psi/ft)	0.0204	0.75775
Initial Psurf	3500	0

Table 2 : Calculation Input Parameters

Depth (m)	P CTU (psi)	P Tub (psi)
0	3500	0
200	3513	497
400	3527	994
600	3540	1492
800	3554	1989
1000	3567	2486
1200	3580	2983
1370	3592	3406

1400	3594	3481
1450	3597	3605
1600	3607	3978
1800	3620	4475
2000	3634	4972
2005	3634	4985

Table 3 : Calculation Result of Well Static Pressure Gradient

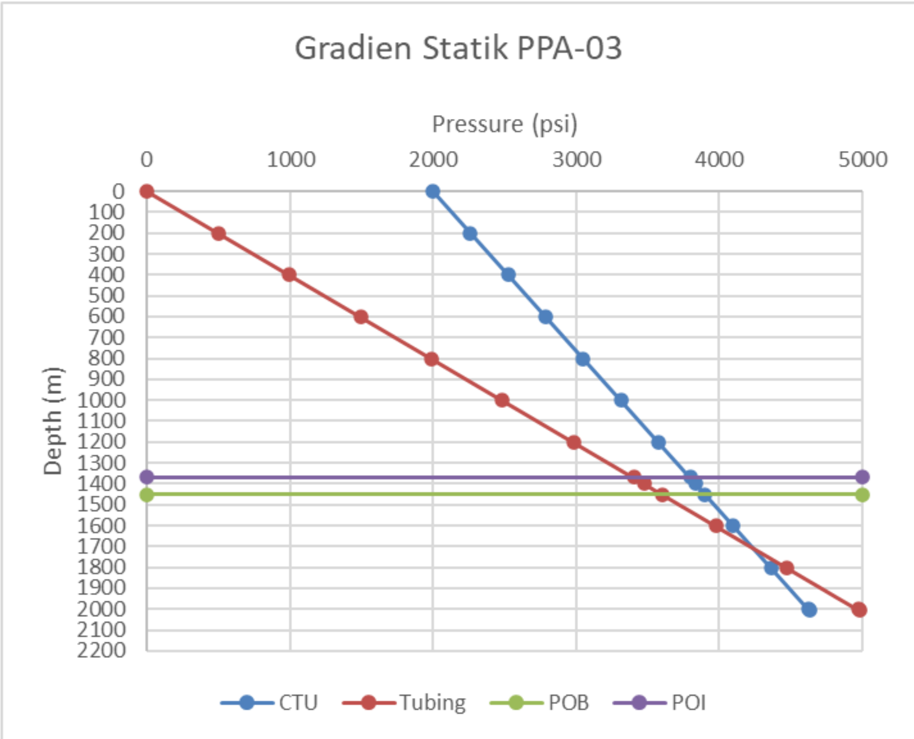


Figure 6 : Well Pressure Gradient Plot

Well Modeling

The next step after determining the estimated nitrogen (N_2) injection depth is to model the gas lift for Well PPA-003. This modeling is performed to understand the well's gradient during the unloading/start-up operation. The modeling is conducted using the PIPESIM 2016 simulator. The objectives of this modeling are to determine: (1) the estimated unloading flow rate to identify the duration of the injection period required, (2) the optimal nitrogen injection flow rate, and (3) the volume of nitrogen needed.

The use of PIPESIM 2016 has limitations in modeling the coiled tubing injection flow scenario into the tubing, so several approaches were applied in this study to ensure that the model closely resembles real conditions.

Based on the initial model created, the estimated production rate and pressure gradient within the well can be calculated. The well configuration was developed based on the ESP design data and the planned injection depth of 1,370 meters. Additionally, the model accounts for the reduction in flow diameter due to the presence of coiled tubing inside the tubing. Figure 7 shows an illustration of the well configuration approach for the PPA-003 well model in the ESP start-up scenario with nitrogen injection via coiled tubing.

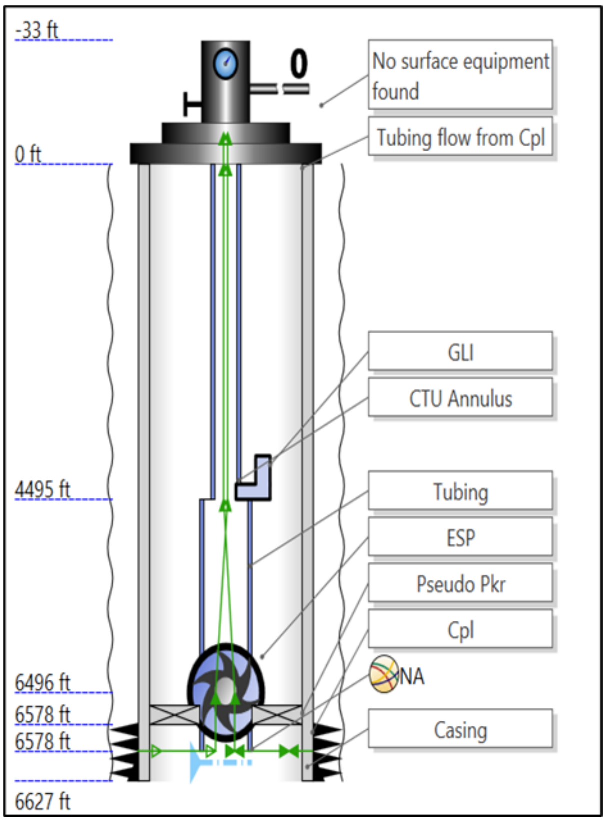


Figure 7 : Model Schematic of PPA-003

The initial calculation was performed using the well model that had been successfully created earlier. This calculation includes a nodal analysis and the calculation of the well gradient, assuming a wellhead pressure of 30 psi and a nitrogen injection flow rate of 300 SCFM (0.42 MMSCFD). Based on the nodal analysis, the estimated operating point is obtained at 128 BFPD, as shown in Figure 8.

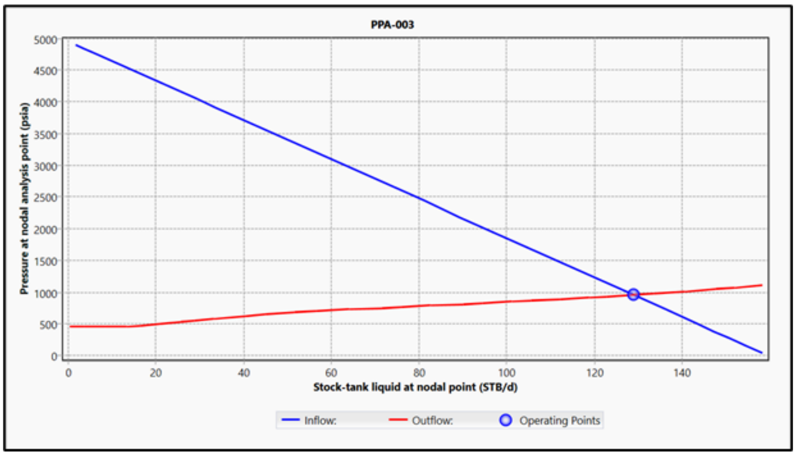


Figure 8 : Nodal Analysis for ESP Start Up with N_2 Injection

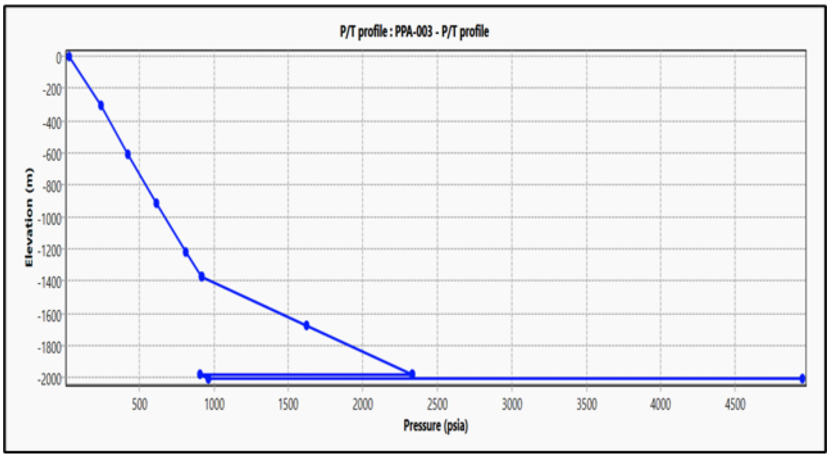


Figure 8 : Well Pressure Gradient During ESP Start Up

Calculating Optimum N_2 Injection Rate

The calculation of nitrogen injection flow rate is conducted to determine the injection rate that provides the most optimal unloading/production rate. This calculation is performed using the previously developed model by testing the sensitivity of the unloading rate to the amount of nitrogen gas injected. Based on the results of the nitrogen injection sensitivity analysis shown in Figure 9, the optimal nitrogen flow rate for the ESP start-up operation is determined to be 0.648 MMSCFD or 450 SCFM.

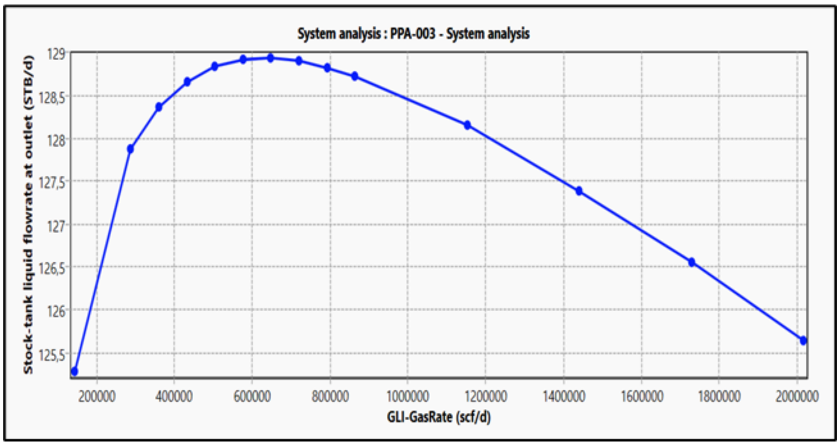


Figure 9 : Sensitivity Analysis of N2 Injection Rate

From the nitrogen injection flow rate previously calculated, the required amount of nitrogen and the duration needed to unload a single volume of heavy mud in well PPA-003, from the surface to the pump intake depth, can be determined.

Wellbore Volume:

Vtotal = V (PI-GLI) + V (GLI-Surface)

= 117.68 + 353.00

= 470.68 BFPD

Injection Duration:

t injeksi = Vtotal: Q

= 470.68 : 129

= 3.6 hari / 87 jam

Required Liquid N2:

V_{N2liq} = $(VN_{2ga}s : 93) \times 1.1$
= $(450 \times 60 \times 87) : 93 \times 1.1$
= 27,783 gal

where:

V (PI-GLI)	= Mud volume from pump intake to CTU nozzle, bbls
V (GLI-Surface)	= Mud volume from CTU nozzle to surface, bbls
t injeksi	= N2 injection duration, days
Q	= Return / production flow rate, BFPD
V_{N2liq}	= Liquid N2 volume, gal
V_{N2gas}	= Gas N2 volume, scf

Tubing Pressure Gradient Comparison

The purpose of nitrogen injection during the ESP start-up in well PPA-003 is to reduce the gradient in the tubing. At this stage, a comparison of the pressure gradient in the tubing with and without nitrogen injection will be conducted. Figure 10 illustrates the tubing gradient without nitrogen injection, while Figure 11 depicts the tubing gradient with nitrogen injection.

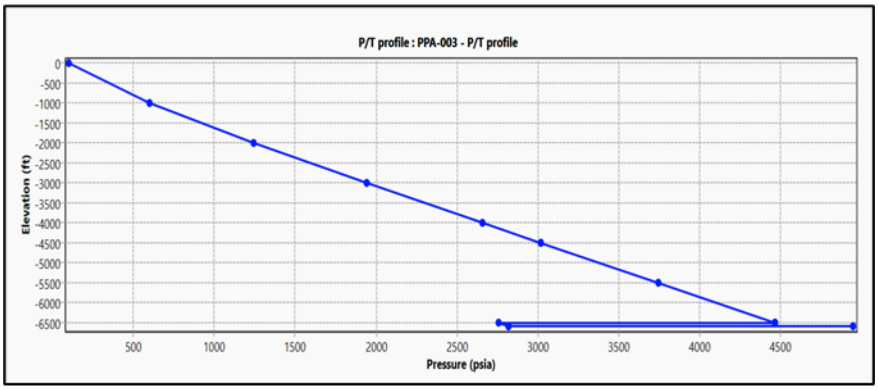


Figure 10 : Pressure Gradient Without N2 Injection

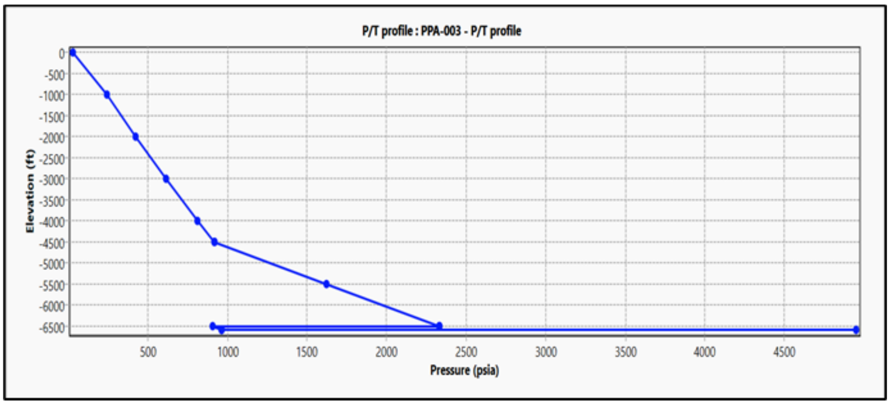


Figure 11 : Pressure Gradient With N2 Injection

Based on the gradient analysis conducted, if nitrogen injection is not applied to well PPA-003, the average tubing gradient is 0.694 psi/ft, with a discharge pressure of 4,252 psi at the pump. In contrast, with nitrogen injection, the average tubing pressure gradient is reduced to 0.380 psi/ft, with a discharge pressure of 2,331 psi at the pump. This analysis indicates a 45% reduction in the average tubing pressure gradient with nitrogen injection during the ESP start-up in well PPA-003.

ESP Start Up Program of PPA-003

Based on the previous calculations, the start-up program for the well can be planned as follows:

1. Run In Hole (RIH) with production tubing and ESP assembly.
2. Nipple Down (N/D) BOP, Nipple Up (N/U) Christmas Tree (XT).
3. Rig Up (R/U) Coiled Tubing Unit (CTU), perform pressure testing of the Pressure Control Equipment (PCE), and conduct a CTU function test.
4. RIH coiled tubing to a depth of 1,370 m while pumping nitrogen at a minimum flow rate.
5. Upon reaching 1,370 m, build up nitrogen pressure to 3,500 psi or until flow is observed.
6. Start the ESP and reduce the nitrogen pumping rate to 450 SCFM.
7. Monitor return volume and continue pumping nitrogen until a return volume of 470 bbls is achieved or until the pump current reading normalizes.
8. Pull Out of Hole (POOH) the CTU and Rig Down (R/D) the CTU.
9. Monitor production.
10. Release the rig.

KESIMPULAN

Based on the research shown above, starting up the ESP with a mud density of SG 1.75 poses a risk of shaft failure in the pump and causes the ESP motor to operate at 93% of its horsepower capacity. The point of balance for the nitrogen injection plan at a pressure of 3,500 psi is at a depth of 1,450 m, with the operating point planned at a depth of 1,370 m to achieve a pressure difference of 100 psi. The estimated well unloading rate with nitrogen injection and ESP, based on the nodal analysis conducted, is 128 BFPD. The optimal nitrogen injection flow rate for the ESP start-up operation is 0.648 MMSCFD or 450 SCFM, with a liquid nitrogen volume requirement of 27,783 gallons, including a 10% excess to account for evaporation during the operation, and a total operation duration of 87 hours. Nitrogen injection during the ESP start-up in well PPA-003 results in a 45% reduction in the average pressure gradient in the tubing, which contributes to a decrease in the power and temperature demands on the pump motor during the ESP start-up.

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