JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, E-ISSN: 2723-1496
Vol. 6 No. 2 2025

# Re-Design of ESP Pump in EHS-155 Well in Tanjung Field Based on Problematic Scale and Economic Analysis

**Ekwal Hesmatiar *), Herianto, Harry Budiharjo**
Petroleum Engineering, Universitas Pembangunan Nasional Veteran Yogyakarta
* corresponding email:

**ABSTRACT**

The repair of Electric Submersible Pump (ESP) in well X-155 at the Tanjung Field has become a major issue impacting production rates and increasing operational costs. In 2024, well X-155 experienced 7 well service interventions due to pump failures, which caused damage to the pump impeller and resulted in a loss of oil production. This failure was identified as being caused by the deposition of carbonate minerals (scale), which became the primary cause of damage to the ESP pump. To confirm the presence of scale, solid scale deposition was analyzed using X-ray Diffraction (XRD) methods in an independent laboratory, along with fluid property testing. This method was used to determine the composition and crystalline phases of the scale formed in the well. This study aims to analyze the causes of scale formation in the ESP system. It is expected that the findings from this research will provide solutions to pump failures, reduce the frequency of such failures, and improve operational efficiency at the Tanjung Field, particularly through the implementation of scale inhibitor treatments. The scale treatment for well X-155 is unique due to the need to formulate a scale inhibitor that can function effectively under the high-temperature and high-pressure conditions present in the well.

**Keywords:** Electric Submersible Pump, Failure, Fluid Property, Scale, X-Ray Diffraction

## I. INTRODUCTION

The main factors that influence the formation, growth of crystals and deposition of scale include changes in reservoir conditions (decreased reservoir pressure and temperature changes), mixing of two types of fluids that have incompatible mineral compositions, the presence of supersaturation, evaporation (due to changes in concentration), stirring (agitation, the influence of turbulence), contact time between p In the production process, changes in solubility occur along with decreases in pressure and changes in temperature during production. Changes in the solubility of each solute in formation water will cause disruption of the balance in the formation water, so that a chemical reaction will occur between positive ions (cations) and negative ions (anions) by forming precipitated compounds in the form of crystals. From the explanation above, the conditions that support the formation and deposition of scale include the following: Water contains ions that have a tendency to form compounds that have low solubility numbers. Changes in the physical conditions or composition of water will reduce solubility lower than the existing concentration. An increase in temperature will cause an evaporation process, so that changes in solubility will occur. Formation water that has a high degree of acidity (pH) will accelerate the formation of scale deposits. Scale deposition will increase with the length of contact time and this will lead to the formation of denser and harder scales.adherence to the surface of the settling medium and changes in pH.

PT Pertamina EP Tanjung Field currently operates a waterflood production system. There are 137 production wells using artificial lift pumps (20 wells using Electrical Submersible Pumps (ESPs) and 117 wells using Sucke Rod Pumps (SRPs). Most of the wells in Tanjung Field are commingled wells, with an average of 4-5 productive zones. The advantage of commingled production is that it produces higher gross and net yields compared to single-layer production. However, this system also has disadvantages, including the inability to determine the production volume of each zone. Minerals in the produced fluid flow from one zone can mix with incompatible ones in other zones, causing scale buildup in the wellbore. Scale is a common problem in wells in Tanjung Field. The presence of scale in the wellbore can cause the well pump to decrease in efficiency and even become stuck in both the SRP and ESP wells. This can result in production losses and costs for well maintenance. The current problem is that the Electric Submersible Pump (ESP) in well EHS-155 is damaged due to mineral deposits. Therefore, a rig service is required to repair the ESP equipment and reduce production at the Tanjung Field. The resulting mineral deposits need to be tested to determine whether they are calcium carbonate or other deposits by dripping acid onto them. If the minerals react with the acid, the resulting mineral is considered calcium carbonate scale.

JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, E-ISSN: 2723-1496
Vol. 6 No. 2 2025

According to Low & Off data (Figure 1), the 9.90% loss, with a total potential loss of 123,345 Bbl of oil, is due to the following factors: 4.26% increase in KA, 0.23% increase in GOR, 1.61% scale-up, 0.33% sand content, and 0.49% artificial lift.

| | PROBLEM | TOTAL | | | |
|---|---|---|---|---|---|
| | | LOW | OFF | L & O | % |
| | SUBSURFACE | | | | |
| A | Tekanan Turun | 8,382 | 530 | 8,912 | 0.72% |
| B | KA Naik | 53,033 | - | 53,033 | 4.26% |
| C | GOR Naik | 2,826 | 17 | 2,844 | 0.23% |
| D | Scale-up | 17,711 | 2,365 | 20,076 | 1.61% |
| E | Kepasiran | 2,163 | 1,892 | 4,055 | 0.33% |
| F | Problem Rangkaian Pipa Produksi | 2,143 | 13,736 | 15,879 | 1.27% |
| G | Bean down | 103 | 34 | 138 | 0.01% |
| H | Artificial Lift (GasLift/ESP/SRP/HPU/HJP/PCP) | 5,016 | 1,111 | 6,127 | 0.49% |
| | TOTAL SUB SURFACE | 91,377 | 19,685 | 111,063 | 8.91% |
| | SURFACE | | | | |
| I | Wellhead/Flowline/Trunkline/Transfer Pump | - | 516 | 516 | 0.04% |
| J | Peralatan Atas Tanah Artificial Lift (Gas Lift/ESP/SRP/HPU/HJP/PCP) | 416 | 1,668 | 2,084 | 0.17% |
| K | Fasilitas Produksi | - | - | - | 0.00% |
| L | Gas Lift Compressor/Gas Lift Injector Well | - | - | - | 0.00% |
| M | Power Supply (Listrik/Gas Engine/Diesel Engine) | 437 | 4,813 | 5,250 | 0.42% |
| N | Water Injection System | - | - | - | 0.00% |
| O | Well Program (BHP survey/Stimulasi/PES/Reparasi/KUPL/Drilling) | - | 4,226 | 4,226 | 0.34% |
| P | Non teknis (pencurian,demo,banjir,sabotase,akses jalan lokasi,dll) | - | 206 | 206 | 0.02% |
| | TOTAL SURFACE | 853 | 11,429 | 12,282 | 0.99% |
| | T O T A L | 92,230 | 31,115 | 123,345 | 9.90% |
| | TOTAL LOW AND OFF | | | 123,345 | 9.90% |
| | GAIN PRODUKSI | | | 108,617 | 8.72% |
| | POTENSI (P) | | | 1,246,268 | |
| | Low & Off / Potensi, % | 7.40 | 2.50 | 9.90 | |

**Figure 1. Low & Off Tanjung Field**

The EHS-155 well, which will be studied, is subject to artificial lift problems using an Electric Submersible Pump (ESP) at a depth of 1,272 mm (m)d. It consists of a 13-3/8" casing at a depth of 30 mm (m), a 9-5/8" casing at a depth of 206 mm (m), and a 7" casing at a depth of 1,288 mm (m). This well penetrates productive layers ranging from zones A, B, C, and D. The average production of the EHS-155 well is 37 barrels per day (BOPD), with an average gross yield of 314 barrels per day (BFPD) and a water cut of 88.1%. In 2024, the EHS-155 well underwent seven well services due to ESP pump outages. Following the well service, damage to the impeller occurred due to the formation of mineral scale deposits.

This resulted in the well being out of production during ESP pump repairs, reducing production in the Tanjung field and increasing operational costs for removing the ESP assembly using a service rig and replacing ESP pump spare parts. Thus, this problem needs to be addressed by analyzing the causes of scale formation under the surface and treating the scale using chemical scale inhibitors.

This study aims to analyze the thermodynamic triggers for the formation of abrasive carbonate (aragonite) scale in the environment of the EHS-155 Well, and to formulate a stable scale inhibitor injection strategy that is compatible with the program to restore the operational reliability of the ESP. Particularly, this study has the following sub-objective:

1. Identify the type of problem scale
2. Determine the appropriate scale inhibitor composition and concentration
3. Apply it on a field scale
4. Calculate its economic feasibility

## II. METHODS

Data Collection Methods Field Observation, Interviews with Stakeholders, Laboratory Measurements, and Comparative Study. Figure 2 depicts the flowchart of methodology used in this study. The methodology of this study is as follows:

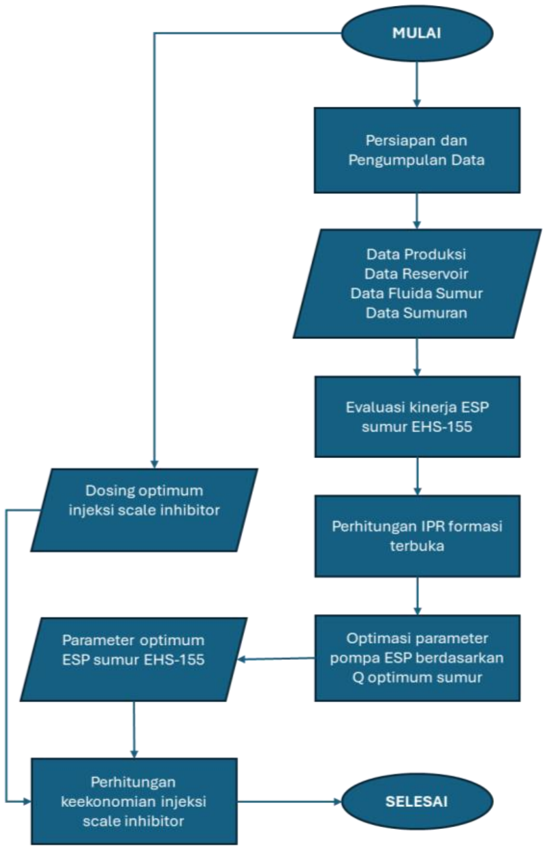


**Figure 2. Flowchart**

The data analysis method begins with the preparation and collection of geological data, reservoir data, and fluid properties data. From this data, this study can identify and draw conclusions about the mineral scale formation. After determining the mineral scale content, laboratory-scale scale inhibitor testing is necessary. Lab-scale scale inhibitor testing is expected to represent field-scale conditions; therefore, data such as temperature, pressure, and fluid properties are adjusted to those in the field. After obtaining a scale inhibitor formulation that can work to inhibit scale formation, dosage optimization is necessary to save costs. The smaller the dose used, the lower the cost. Finally, a field-scale trial is carried out to assess the performance of the chemical scale inhibitor and recalculate the optimal ESP pump design to optimize the production rate of the EHS-155 well. Finally, a thorough analysis is conducted to see the final result. The thesis then can be concluded and several recommendations might be made to further support the result of this study.

## III. RESULTS AND DISCUSSION

The Tanjung Raya Field is located in the Northeastern Barito Basin as can be seen at **Figure 3**. Structurally, this field is characterized by an asymmetrical faulted anticline-oriented NE-SW, with an area of approximately 27 $km^2$. This field is divided into several productive zones at depths varying from 645 to 2161 meters. The main P Zone is volcanic sandstone deposited in a delta environment, with a combination of thrust mechanisms (solution gas and water drive). The reservoir characteristics of this field include: Porosity ranging from 8% to 27%. Wide permeability, from 4 to 1649 mD. Initial water saturation $S_w$ ranging from 28% to 50%. Oil type is paraffinic, with a specific gravity of 40.3 API. Production operations in the Tanjung Field rely heavily on artificial lift systems, including the use of Sucker Rod Pumps (SRP) and Electric Submersible Pumps (ESP).

The EHS-155 well that will be researched is included in the artificial lift problem using an ESP (Electric Submersible Pump) pump with a depth of 1272 mMD consisting of 13-3/8” casing at a depth of 30 mMD, 9-5/8” casing at a depth of 206 mMD and 7” casing at a depth of 1288 mMD. This well penetrates productive layers starting from zones A, B, C and D. The average production of the EHS-155 well is 37 BOPD with an average gross of 314 BFPD and a watercut of 88.1%.

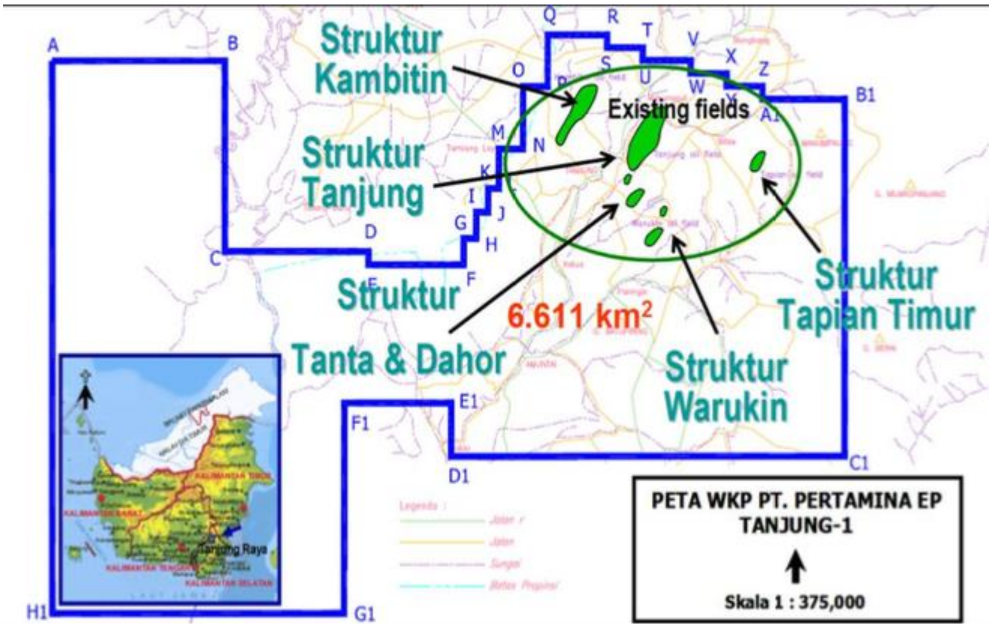


**Figure 3. PT Pertamina Tanjung Working Area Map**

Reservoir characteristics in the Tanjung Field consist of rock and fluid characteristics based on log interpretation results and other existing measurements with an average production depth of around 1100 meters. The reservoir structure is asymmetric anticline, with productive layers are: A, B, and C sandstone and Conglomerate Fluvial-alluvial fan zone; D, E, F sandstone lacustrine delta zone; also, P zone volcanic stone with natural fracture. Drive mechanism is solution gas and water drive combination. Oil type is paraffinic with 40-degree API, specific gravity 0,822; wax content 30% WT and pour point at 98-degree F. Average porosity are 21,3%; rock permeability 30 mD and water permeability 136 mD; last the water saturation 35,33%. Essentially, the Tanjung field produces hydrocarbons from six isolated reservoir units in the lower Tanjung formation, plus the underlying volcanic reservoir. A brief explanation of the description and quality of the formation is as follows.

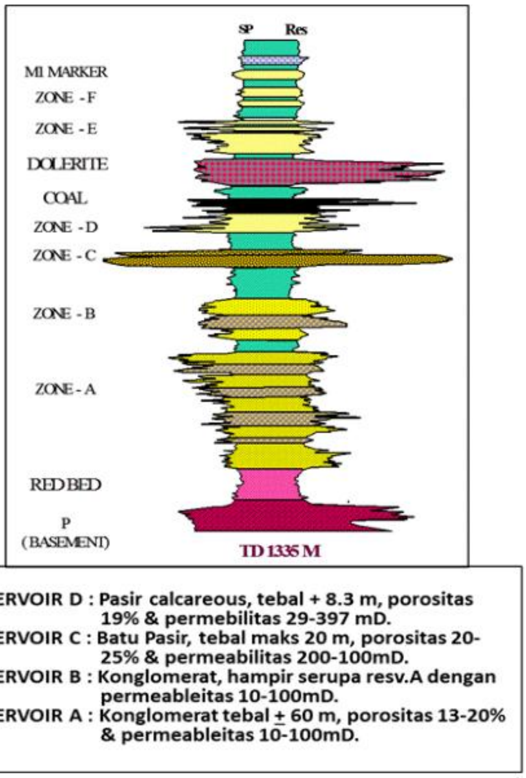


**Figure 4. Division of Layers and Characteristics of Reservoir Layers A, B, C, D**

Figure 5 shows the production history of the EHS-155 well. In 2024, the EHS-155 well underwent seven well services due to the failure of the ESP pump. Following the well service, the impeller was damaged due to the formation of mineral scale deposits. Under these conditions, the EHS-155 well only has a lifetime of 1.7 months, resulting in an LPO of approximately 7 weeks per year and a high frequency of well service work, potentially resulting in significant additional operating costs.

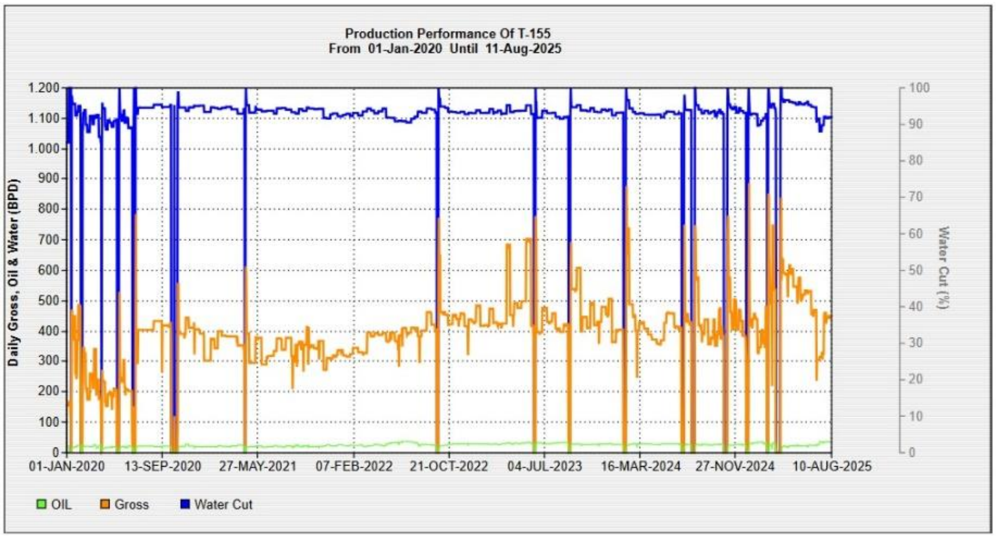


**Figure 5. EHS-155 Well Production History**

### 3.1. Inflow Performance Relationship Analysis

The IPR calculation was performed to determine the production capacity of the open reservoir interval in the EHS-155 well. Based on the latest data, the EHS-155 well produces from Layers A, B, C, and Lower D concurrently. The IPR

JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, E-ISSN: 2723-1496
Vol. 6 No. 2 2025

calculation method used is a single-phase IPR because the GOR in this well is insignificant based on production data and also considering the availability of existing well test data. Figure 6 shows a well diagram of the EHS-155 well.

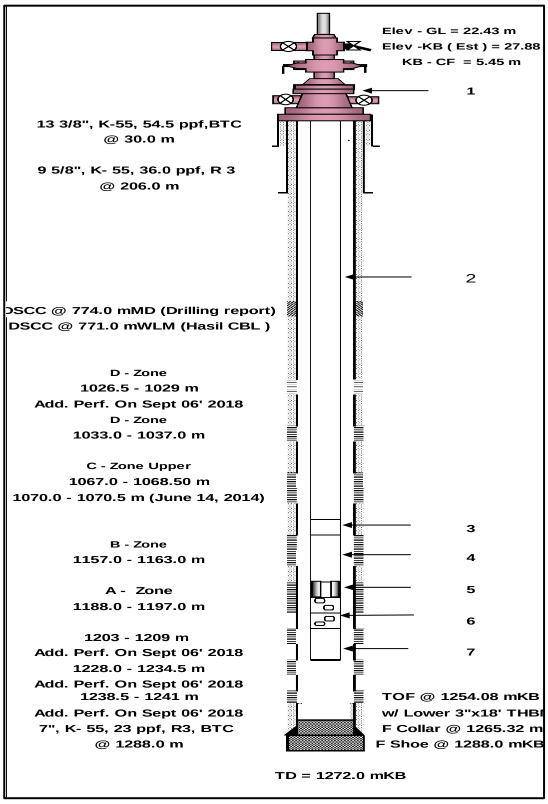


**Figure 6. EHS-155 Well Diagram**

The data available for the IPR calculation are well test data (Q, WC) and fluid depth data obtained from the sonological survey conducted on the EHS-155 well as shown in Figure 7. The bottomhole flow pressure used in the calculation utilizes sonological data converted into well data flow pressure. The well static pressure data uses well static pressure data obtained from the EMR survey activity as shown in Figure 8.

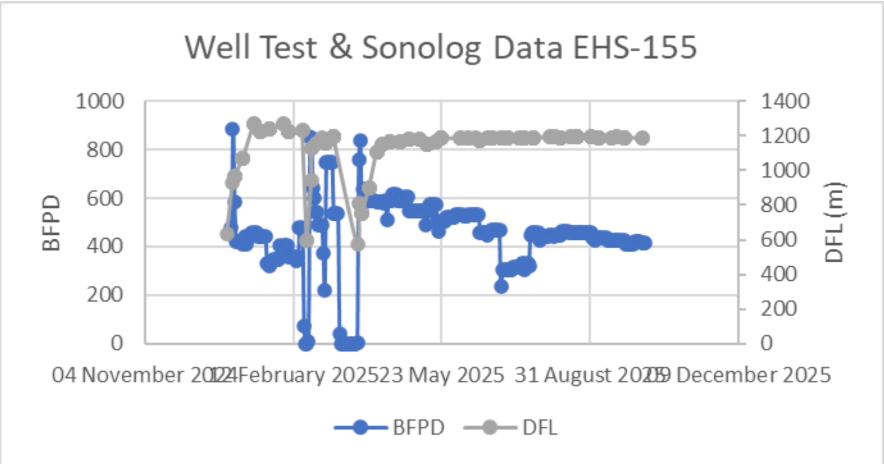


**Figure 7. Well and Sonolog Test History**

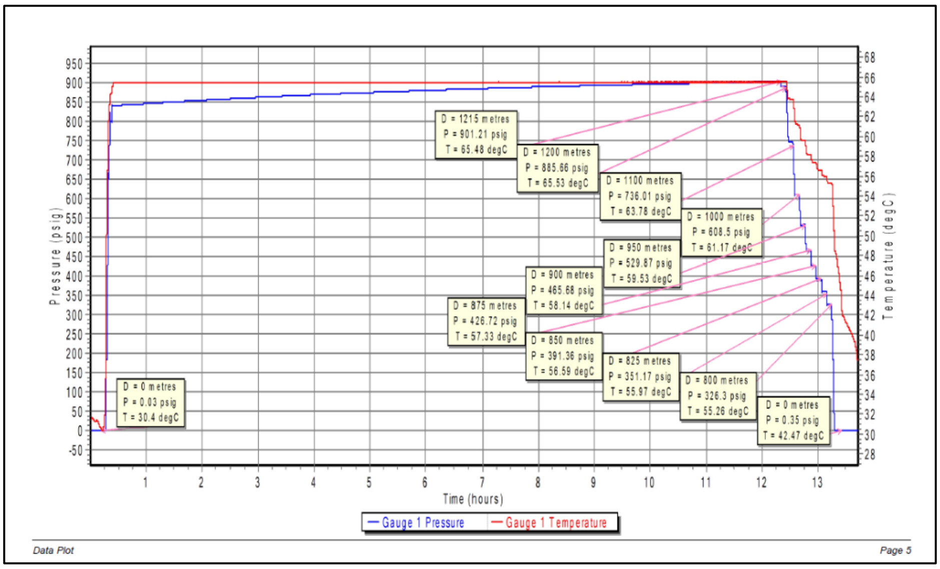


**Figure 8. EHS-155 Well SBHP**

The IPR calculation was performed using the Prosper IPM software to facilitate the research. The input data for the IPR calculation is shown in Table 1. The input data for Q and Pwf were taken from the most recent test data and have shown stable values.

**Table 1. IPR Calculation Data Input**

| Q | DFL, m | Perf, m | Pwf, psi | Ps, psi | WC (%) |
|---|---|---|---|---|---|
| 502 | 1188 | 1241 | 75 | 900 | 96,57 |
| 575 | 1151 | 1241 | 128 | 900 | 96,11 |
| 592 | 1167 | 1241 | 105 | 900 | 96,63 |
| 415 | 1187 | 1241 | 77 | 900 | 93,70 |

Based on the IPR calculation produced in Figure 9 below, it is known that the Qmax of the EHS-155 well is 658.4 BFPD, so the ESP design target can be set based on the Qoptimum of 80% of Qmax, which is 526.72 BFPD with an estimated Pwf of 193 psi. This 80% figure is taken as a margin to ensure that the pump intake is still below the liquid level.

JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, E-ISSN: 2723-1496
Vol. 6 No. 2 2025

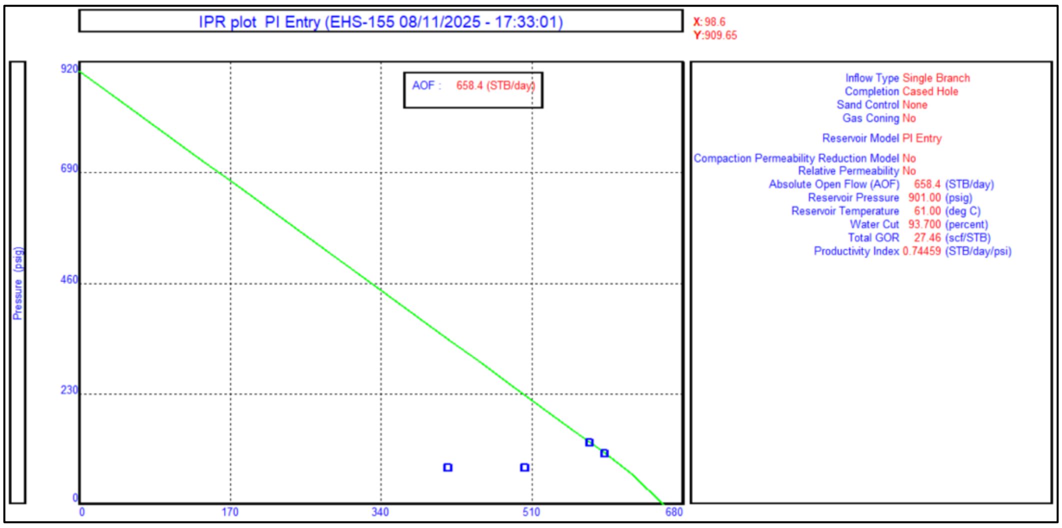


**Figure 9. EHS-155 Well Inflow Performance Relationship**

### 3.2. ESP Pump Redesign Based from Q Optimum

PSD calculations are performed to determine the ESP pump intake depth setting. In determining the PSD in this study, the PSD is determined as deep as possible to maximize gross fluid without making it unsubmerged considering the formation production capacity is quite small for the ESP pump. In the case of the EHS-155 well, the PSD depth limit is the top of fish (TOF) at a depth of 1254 m, so by reducing the maximum depth by 20 m as a rathole, the PSD depth is set at 1234 m.

#### 3.2.1. SG Mixture

Before this, we must calculate the SG mixture with:

$$SG\ mixture = (\text{SG oil } \times (1 - \text{Wc}) + (\text{SG water } \times \text{Wc}) \qquad (1)$$

$$= (0{,}835 \times (1 - 0{,}9663) + (1{,}03 \times 0{,}9663)$$

$$= 1{,}023$$

Where:

SG mixture = liquid mixture production specific gravity

SG oil = oil specific gravity

SG water = production water specific gravity

WC = production water amount

#### 3.2.2. Dynamic Fluid Level

Then, we must calculate the DFL when the ESP are operated at Q target:

$$DFL = Perforation\ depth - (\frac{Pwf}{0{,}433 \times SG\ mixture}) \qquad (2)$$

$$= 1241 - (\frac{193}{0{,}433} \times 1{,}023))/3{,}281$$

$$= 1108 \text{ m}$$

Where:

DFL = dynamic fluid level, m

SG mixture = liquid mixture production specifi gravity

Pwf = bottom well pressure, psi

#### 3.2.3. Pump Intake Pressure

After that, we must calculate the Pump Intake Pressure (PIP)

$$PIP = (PSD - DFL) \times (0{,}433 \times SG\ mix) \quad (3)$$

$$= (1234 - 1108) \times 3{,}281 \times (0{,}433 \times SG\ mix)$$

= 183 psi

Where:

PIP = pump intake pressure, psi

SG mixture = liquid mixture production specific gravity

PSD = pump setting depth, m

DFL = dynamic fluid level, m

### 3.2.4. Total Dynamic Head

After that, we must calculate total dynamic head (TDH). TDH is the head (in units of length) which indicates the height of the fluid pumped by the pump. TDH is calculated from the sum of: (1) Net well lift Hl, (2) friction loss in the tubing Ft, and (3) wellhead pressure Hwh. In the case of the EHS-155 well, the minimum well pressure to enter the manifold system was set at 50 psi.

$$TDH = HI + Ft + Hwh \quad (4)$$

$$= \left[PSD - \left(\frac{PIP}{0{,}433} \times SGmix\right)\right] + \left[\frac{15{,}11 \times \left(\frac{Q}{C}\right)^{1{,}85}}{ID^{4{,}8655}} \times PSD\right] + [50/(0{,}433 \times 1{,}023]$$

= 1139,0011344 m

Where:

F = friction loss factor (ft/1000 ft)

C = Correction factor (100 for old pipe, 140 for new pipe, 120 for a typical valve)

Q = volumetric flow rate (bbl/day)

ID = pipe inner diameter (in)

### 3.2.5. Pump Selection

The main factors that influence pump selection include (1) the previously determined target flow rate, (2) casing clearance, (3) pump availability in the field. The previously determined production target is 526.72 bbl, with a 7" K-55 casing clearance of 23 ppf with an ID of 6.366" and based on the target Q and the availability of own pumps in the field, the selected pump is the ESP Novomet type NFV 450, as can be seen at figure 10 below.

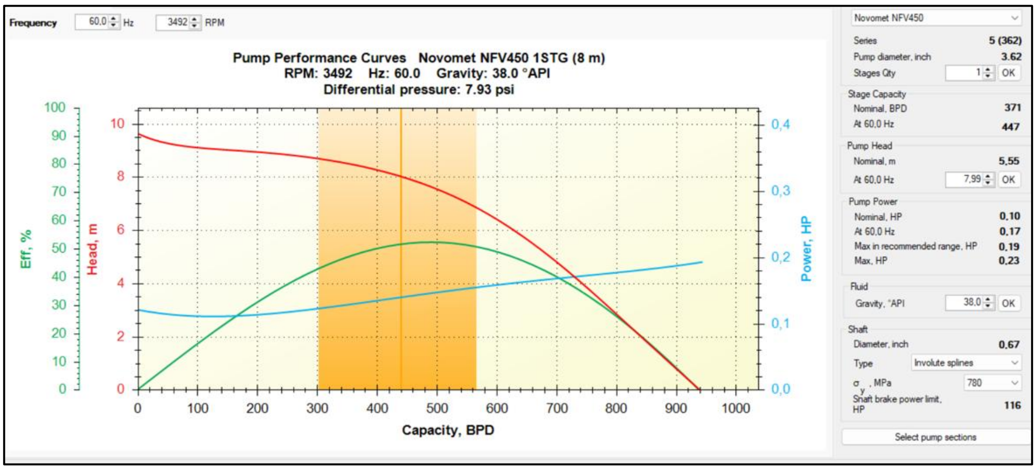


**Figure 10. Pump Curve NFV 450**

3.2.6. Pump Stage and Pump Power Determination

Pump stages and pump power can be determinate from below equation:

$$Pump\ stage = TDH/(head\ stage) \quad (4)$$
$$= 1139/7{,}3$$
$$= 157 \text{ stages}$$

$$Power\ Amount = stages \times hp\ per\ stages \times SG\ mixture \quad (5)$$
$$= 157 \times 0{,}19 \times 1{,}023$$
$$= 30{,}5 \text{ hp}$$
$$= 22{,}74 \text{ kW}$$

**3.2.6. Scale Inhibitor Injection Planning**

Scale inhibitor injection was planned for well EHS-155 to prevent scale mineral deposition, which reduces pump lifetime. Laboratory tests were conducted to determine the optimum dose to prevent scale deposition using formation water samples from EHS-155. Based on the laboratory tests, 75 ppm was found to be the optimum dose for this well. The results of the scale inhibitor dose laboratory tests are shown in Table 2.

**Table 2. Scale Inhibitor Laboratory Analysist**

| Dosage (ppm) | treatment | Sample volume (ml) | Titration Volume (ml) | | | $Ca^{2+}$ (ppm) | $CaCO_3$ sediment (dosage/treated) | %protection | Temp (degC) |
|---|---|---|---|---|---|---|---|---|---|
| | | | simplo | Duplo | Average | | | | |
| 75 | Heated | 10 | 4,62 | 4,55 | 4,58 | 220 | 4 | 96,47 | 80 |
| 50 | Heated | 10 | 4,37 | 4,38 | 4,38 | 210 | 14 | 87,65 | 80 |
| 25 | Heated | 10 | 3,60 | 3,70 | 3,65 | 175 | 49 | 56,95 | 80 |
| 25 | Heated | 10 | 4 | 4,10 | 4,03 | 194 | 30 | 73,18 | 80 |
| 25 | Heated | 10 | 4,25 | 4,15 | 4,22 | 203 | 21 | 81,23 | 80 |
| 25 | Heated | 10 | 4,25 | 4,25 | 4,25 | 204 | 20 | 82,36 | 80 |

The injection volume requirement can be calculated based on the optimum dose generated by comparing it with the estimated daily formation water production at the target Q of 96.57% of 526.72 BFPD, or 508 BWPD. With a concentration of 75 ppm, the daily volume requirement of chemical scale inhibitor is 0.0381 bbl/day (6.03 liters/day).

**3.3. Economical Analysist**

The economic evaluation was conducted to determine the economics of the EHS-155 well production target against the additional operating costs of scale inhibitor injection, investment costs for installing chemical injection facilities in the tubing and reducing the frequency of well maintenance work from increasing the lifetime of the ESP pump on the EHS-155 well.

Table 3 below shows the costs required for the implementation of scale inhibitor injection in the EHS-155 well, while Table 4 shows the economic assumptions used in the economic calculation of the EHS-155 well scale inhibitor project. Details of the ESP costs are not included in the cost details because the ESP unit used is a proprietary unit whose usage costs are included in the existing OPEX. Rig and fuel costs come from rig maintenance costs for the ESP installation with a work duration of 3 days.

**Table 3. ESP Installation Price and Chemical Scale Inhibitor**

| Item | Amount | Price (USD) | Unit | Subtotal (USD) |
|---|---|---|---|---|
| Scale inhibitor per day | 0,394 | 60,61 | Each bbl | 23,88 |
| Injection line | 1250 | 10,91 | each m | 13.636,36 |
| Injection pump | 1 | 2.909,09 | EA | 2.909,09 |
| ESP downhole + Surface unit | 0 | - | EA | - |

| | | | | |
|---|---|---|---|---|
| Rig and fuel | 1 | 15.850,00 | each job | 15.850,00 |

**Table 4. Economical Assumption**

| Parameter | Amount | Unit |
|---|---|---|
| Qoi | 18 | BFPD |
| Qgi | 0 | MMSCFD |
| Decline | 35% | Each year |
| Oil Price | 75 | USD |
| OPEX | 75 | USD/bbl |
| OPEX additional from SI | 1,3 | USD/bbl |

The economic calculations were carried out based on the PSC economic scheme, which is the scheme applicable to the Tanjung Field. Based on the economic calculations carried out, it was found that the cost of implementing Scale Inhibitor in the EHS-155 well resulted in positive economic parameters as shown in Figure 11 below.

**OUTPUT DATA FOR SIMPLE CALCULATION**
**EHS-155**

| | | | |
|---|---|---|---|
| | Total Gross Revenue | US $ (000) | 718,73 |
| 1 | Opex & Depresiasi | US $ (000) | 286,94 |
| 2 | Contractor Take | US $ (000) | 172,72 |
| 3 | Government Take | US $ (000) | *259,08* |
| | **NPV (DF 9.22%)** | US $ (000) | **136,72** |
| | **IRR** | % | **307,8** |
| | **POT** | Years | **0,29** |
| | **PI** | US$ / US$ | **4,92** |

**Figure 11. Economical Implementation Calculation for Scale Inhibitor**

To compare the economic parameters of well production with and without scale inhibitors, economic calculations were performed for the base case. The well was produced without the use of scale inhibitors and the well maintenance frequency was seven times per year. Another difference is the absence of costs resulting from the implementation of scale inhibitors.

**OUTPUT DATA FOR SIMPLE CALCULATION**
**EHS-155 (Tanpa SI)**

| | | | |
|---|---|---|---|
| | Total Gross Revenue | US $ (000) | 718,73 |
| 1 | Opex & Depresiasi | US $ (000) | 358,56 |
| 2 | Contractor Take | US $ (000) | 144,07 |
| 3 | Government Take | US $ (000) | *216,10* |
| | **NPV (DF 9.22%)** | US $ (000) | **104,54** |
| | **IRR** | % | **79,7** |
| | **POT** | Years | **0,78** |
| | **PI** | US$ / US$ | **1,88** |

**Figure 12. Results of Economic Calculations Without Implementing Scale Inhibitors**

Based on the calculation results shown figure 12, it is known that without scale inhibitor injection, well EHS-155 is still economical to produce, even with a well maintenance frequency of seven times per year. However, the implementation of scale inhibitor injection proved to produce better well economics with a 23% higher NPV and a 74% better IRR compared to without scale inhibitor injection.

The EHS-155 production well in the Tanjung Field, which uses an Electric Submersible Pump (ESP) system, faced a serious operational crisis with seven pump failures throughout 2024. These failures were caused by calcium carbonate deposits ($CaCO_3$), confirmed through X-ray diffraction (XRD) analysis, which clogged and damaged the pump impeller. As a result, the average ESP lifetime was only 1.7 months, resulting in a significant Loss of Production Opportunity (LPO) and soaring well service costs.

Technical Analysis and Design: Based on Inflow Performance Relationship (IPR) modeling, the well's maximum production rate (Q max) was set at 658.4 BFPD, with a target optimum production rate (Q opt) of 526.72 BFPD. The selected ESP pump was a Novomet NFV 450, installed at a Pump Setting Depth (PSD) of 1,234 meters to ensure operational reliability.

Preventive Solution: To address the root cause of the problem, a continuous scale inhibitor injection program was planned. Laboratory tests determined that the optimum dose effective in preventing $CaCO_3$ precipitation was 75 ppm.

Economic Conclusion: The economic evaluation clearly demonstrated that the scale inhibitor implementation scenario was significantly superior to the Base Case scenario (without inhibitor). Although requiring initial investment (CAPEX) and ongoing chemical costs (OPEX), this preventive program is estimated to drastically reduce the well service frequency (from 7 to 1 per year) and extend the ESP lifetime to >12 months. Consequently, the scale inhibitor scenario yielded significantly better Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period, confirming that the preventive chemical approach is the most economical long-term strategy for well EHS-155.

## IV. CONCLUSION

Several conclusions are made to summarize this study:

1. The Primary Cause of ESP Failure Identified as Calcium Carbonate (CaCO3) Scale. Mineralogical analysis using X-ray Diffraction (XRD) confirmed that the scale deposits clogging and damaging the ESP pump impeller were predominantly composed of Calcium Carbonate (CaCO3). Its formation was triggered by changes in pressure and temperature conditions within the well, which disrupted the chemical balance of the formation water.
2. Based on the Inflow Performance Relationship (IPR) analysis and Total Dynamic Head (TDH) calculation, the Novomet NFV 450 ESP pump was selected as the most optimal. The recommended configuration is with 157 stages and requires a power of 30.5 hp (22.74 kW) to achieve the target production rate of 526.72 BFPD.
3. Laboratory tests showed that scale inhibitor injection at an optimum dose of 75 ppm was effective in preventing the formation of CaCO3 scale. The chemical volume requirement was 4.7 liters per day, which is feasible for continuous implementation at the bottom of the well.
4. Economic evaluations demonstrated that the prevention scenario with a scale inhibitor yielded better economic performance than the scenario without the inhibitor. This strategy significantly reduced operational costs by reducing the well service frequency from seven times to once per year and minimizing production losses.
5. This study emphasizes that addressing scale issues requires more than just redesigning robust mechanical equipment (ESPs) and addressing the root cause chemically. The combination of ESP redesign tailored to well capacity and an effective scale prevention program can extend equipment lifetime, maintain production continuity, and optimize well economics.

## ACKNOWLEDGEMENTS

This work was supported by the Universitas Pembangunan Nasional “Veteran” Yogyakarta and PT Pertamina EP Tanjung Field. The author acknowledges the support that has been given during research, publication and presented this paper. Writer too receives input and recommendations.

## REFERENCES

Amer Badr Bin Merdhah and Abu Azam Mohd Yassin. (2007). *Scale Formation in Oil Reservoir During Water Injection at High-Salinity FormationWater*, Universiti Teknologi Malaysia

Amijaya W, Ghozali F, Kusuma H, Aryanto A, Hidayat A, Mardani P. (2018). *Integrated Application of ESP & Sand Control in Sandy & Gassy Wells*, Medco E&P Indonesia

Badr, A., & Yassin, A. A. M. (2007). *Barium Sulfate Scale Formation in Oil Reservoir During Water Injection at High-Barium Formation Water. Journal of Applied Sciences*

Edgie Yuda Kaesti, Mia Ferian Helmy, and Muhammad Zakiy Yusrizal. (2020). *Production optimization with ESP methods on high GOR wells, AIP Conference Proceedings*

Guihong Pei, Chuyang Wang, and Lili Liu. (2014). *Experimental Study on the Cause of Inorganic Scale Formation in the Water Injection Pipeline of Tarim Oilfield*

L.S.Boak and K.S Sorbie. (2010). *New Development in the Analysis of Scale Inhibitor, Heriot Watt University*

Mohammad Mohsen Vazirian, Thibaut V.J. Charpentier1, Mônica de Oliveira Penna and Anne Neville. (2015). *Surface Inorganic Scale Formation in Oil and Gas Industry: as Adhesion and Deposition Processes, Institute of Functional Surfaces*

M.S.H. Bader. (2005). *Sulfate scale problems in oil fields water injection operations*, Bader Engineering, Inc

Musa Mpelwa and Shan-Fa Tang. (2019). *State of the art of synthetic threshold scale inhibitors for mineral scaling in the petroleum industry: a review, Petroleum Science*

Reinhard Fredik Batubara, Suranto and Dyah Rini Ratnaningsih. (2021). *TECHNICAL AND ECONOMICAL EVALUATION FOR ELECTRICAL SUBMERCIBLE PUMP OPTIMAZATION USING VARIETY OF STAGES AND FREQUENCIES AT THE "INTB-12" WELL IN THE WIDURI FIELD*, Universitas Pembangunan Nasional Veteran Yogyakarta

R. Sharma and B. Glemmestad. (2013). *Optimal control strategies with nonlinear optimization for an Electric Submersible Pump lifted oil field*, Telemark University Collage

Wang, Y., Moo, Y. X., Chen, C., Gunawan, P., & Xu, R. (2010). *Fast Precipitation of Uniform CaCO3 Nanospheres and Their Transformation to Hollow Hydroxyapatite Nanospheres. Journal of Colloid and Interface Science*

William L Salgado, Roos Sophia de F Dam, Tamara P Teixeira, C Conti and M Salgado. (2019). *Aplication of Artificial Intelligence in Scale Thickness Prediction on Offshore Petroleum Using a Gamma-Ray Densitometer*, Universidade Federal do Rio De Janeiro

Zahra Besharati, *Farshid Torabi and Nuno Pimentel.* (2024). *Thermodynamic Prediction of Scale Formation in Oil Fields During Water Injection*