The Effect of Pressure and Temperature of Residual Life on Separator as Types of Pressure Vessel in “Z” Oil and Gas Field
(Pengaruh Tekanan Dan Temperatur Terhadap Sisa Umur Layan Pada Bejana Tekan Jenis Separator Di Lapangan Minyak Dan Gas “Z”)

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Abstract
Field Z is a mature oil and gas field with several production facilities that have passed their service life design, re-assessment of service life for the critical equipment is needed to carry out. This study focuses on identifying the damage mechanism, determining the residual life assessment, and assessing the effect of pressure and temperature on the residual service life of four separators in field Z. The approach is to recalculate the maximum allowable pressure and the minimum thickness of the separator, estimates the corrosion rate using API 510 and API 581, and estimates the residual life assessment of the separator. The result shows that estimation of corrosion rate with API 581 provide lower value than API 510 due to different methodology. However, the result prove that the operating pressure and temperature of separator will affect to the residual life through minimum thickness and corrosion rate, respectively. The higher operating temperature, the higher corrosion rate. Both of these will reduce the residual life. The calculation estimates that at current operation condition, three of four separators in field Z still can be utilize at least until next five years. While one separator needs to replace immediately considering to the negative remaining service life.

Keywords: Separator; Corrosion Rate; Residual Life Assessment; Carbon Steel; Oil and Gas Field

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Lapangan Z merupakan lapangan migas dengan beberapa fasilitas produksi yang telah melewati masa sisa umur layan peralatan, maka perlu dilakukan penilaian sisa umur layan kembali untuk peralatan kritis. Penelitian ini berfokus pada mengidentifikasi mekanisme kerusakan, menentukan penilaian sisa umur layan, dan menilai pengaruh tekanan dan suhu terhadap sisa umur layan empat separator di lapangan Z. Pendekatannya adalah menghitung ulang tekanan maksimum yang dilanjutkan pada operasi separator dan minimum ketebalan separator, memperkirakan laju korosi menggunakan API 510 serta API 581, dan memperkirakan penilaian sisa umur layan. Hasil penelitian menunjukkan bahwa estimasi laju korosi dengan API 581 menghasilkan nilai yang lebih rendah dari API 510 dikarenakan perbedaan metodologi. Namun, hasil penelitian membuktikan bahwa tekanan operasi dan suhu separator mempengaruhi sisa umur layan melalui ketebalan minimum dan laju korosi. Semakin tinggi suhu operasi, semakin tinggi laju korosi. Kedua factor ini akan mengurangi sisa umur separator. Perhitungan tersebut memperkirakan bahwa pada kondisi operasi saat ini, tiga dari empat separator di lapangan Z masih dapat digunakan setidaknya sampai lima tahun ke depan. Sedangkan satu separator perlu segera diganti mengingat sisa umur layan yang negatif.

Kata-kata kunci: Separator; Laju Korosi; Penilaian Sisa Umur Layan; Baja Karbon; Lapangan Minyak dan Gas

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I. INTRODUCTION
Pressure vessels are one of the critical equipment in the oil and gas field that need to be designed, manufactured, installed, and maintained or inspected according to the requirements. Pressure vessels have a dangerous impact on the environment in the event of a failure due to loss of primary containment (LOPC), namely fire, poisoning, and pollution. LOPC is an unplanned or uncontrolled release of material from primary containment, including non-toxic and non-flammable materials.

In 2021, there were three cases of refinery tank fires, (1) Pertamina Balongan refinery fire on 29 March 2021, (2) Pertamina Cilacap refinery fire on 11 June 2021, and (3) Cilacap refinery tank fire on 13 November 2021. Therefore, one way to prevent this from happening is to analyze the residual service life of the equipment. It is aligned with Minister of Energy and Mineral Resources regulation No. 18 / 2018 related to the inspection of the safety installations and equipment in oil and gas business activities in chapter 23 regarding the extension of the residual service life.

Field Z is an offshore oil and gas field located in the Java Sea that has been produced since 1971. There are 125 active platforms to process the oil and gas from hundreds of wells in field Z, including production separators for 2-phase and 3-phase separation. The contract to develop field Z is valid
until next 20 years, therefore it is necessary to evaluate the remaining service life of pressure vessel equipment, in this case is separator and the factors that affect the assessment of remaining service life. This research will only focus on four production separators that have reached the design life of pressure vessel for more than 30 years.

II. LITERATURE REVIEW
Pressure vessel is one of the equipments used to explore and exploit oil and gas in Indonesia [1]. Pressure vessel is a container designed to withstand internal and external pressure and accommodate gases or liquids at different temperatures [2]. Based on their function, pressure vessels used in the oil and gas industry are classified into several types: heat exchangers, reactors, strippers, separators, storage, deaerators, absorbers, and desilters. There are two types of pressure vessels. The types of pressure vessels are distinguished based on their position and process. Vertical type pressure vessels used for separators that use the principle of gravity usually are applied to gas fluids. The horizontal type pressure vessel is applied to liquid fluids such as oil [3].

The pressure vessel design using the shell and head material is SA 516 Grade 70 [3]. Residual service life assessment in pressure vessels with actual thickness data at the time of inspection 59.7 mm, design thickness 53.7 mm, and corrosion rate 0.54 mm/year. The results obtained that the remaining service life of the pressure vessel is 11.1 years [4]. SA-516 Grade 70 is made of carbon steel, which can operate in a temperature of minus 50°F until 775°F [5].

The effect of temperature on the corrosion rate is directly proportional [6]. However, the trend changes at higher temperatures where the corrosion rate tends to decrease. The effect of pressure on the corrosion rate is directly proportional. Pressure is a force that burdens a separator. The greater the pressure causes the degradation process of the separator to be greater the force to degrade the separator will be the greater the corrosion rate is directly proportional to the greater the increase in carbon dioxide content [6].

2.1 Damage Mechanisms
Based on API 571 [7], equipment in the petrochemical, refinery, oil and gas industry, and industry, in general, is susceptible to damage by various damage mechanisms. The main factor affecting the assessment of the residual service life is the corrosion rate. Identification of the damage mechanism can be a factor that affects the composition of the fluid type of a pressure vessel. Based on API 510 [8] for pressure vessels and API 571 for the following damage mechanisms, the following types of damage mechanisms can affect the rate of internal corrosion in the separator material type SA 516 Gr.70:

- H2S Corrosion (API 571, Section 4.4.2)
- CO2 Corrosion (API 571, Section 4.3.6)
- Microbiologically Induced Corrosion (MIC) (API 571, Section 4.3.8)

2.2 Residual Service Life Assessment
The residual service life assessment is used to predict the residual life of the equipment and to estimate the time for replacement or repairment the equipment [9]. Referring to API 510 in Table 1, there are several variables needed to assess the residual service life, such as temperature, pressure, maximum allowable stress, connection efficiency, required thickness, corrosion allowance, and corrosion rate.

Table 1. Key Parameters of Residual Life Assessment [8]

| Parameter                             | Description                                      |
|---------------------------------------|--------------------------------------------------|
| Operating Temperature (T)             | Operating temperature is the temperature required for the production process that works on pressure vessels |
| Operating Pressure (P)                | Operating pressure is the pressure used for the production process that works during the operation of the pressure vessel. |
| Maximum Allowable Stress (s)          | The maximum allowable stress in pressure vessels has been determined according to the ASME II Part D standard. The maximum allowable stress to determine the minimum wall thickness of pressure vessels based on the tensile and yield properties of the material at the design temperature of the pressure vessel. |
| Joint Efficiency (E)                  | Connection form and percentage of radiographic tests performed on pressure vessels. The determination of the efficiency value can refer to the ASME VIII standard. Div.1 (UW-12) |
| Required Thickness (Treq)             | The minimum thickness required for the separator to operate |
| MAWP                                  | Maximum allowable pressure on pressure vessel operation |
| Corrosion Allowance (CA)              | the thickness of a material that must be added to a material for a planned period at the time of the initial planning of material manufacture so that corrosion only erodes the additional part of the thickness |
| Corrosion Rate (CR)                   | the rate of degradation or reduction in the thickness of the material of equipment due to corrosion both internally and externally |

III. METHODOLOGY
The research was conducted in five steps, on the below explanation.

a. Collecting construction and operational data of four separators from the library archives belonging to the company, with detailed data in Table 3.
b. Identify the damage mechanism referring to the
API 571 standard as shown in Table 2. It includes damage mechanism, material, fluid containment, and temperature. The identification refers to the unpublished internal inspection result.

Table 2. Screening of Damage Mechanism [7]

| Damage Mechanism Type | Material | Fluid Containment | Temperature (°F) |
|-----------------------|----------|-------------------|-----------------|
| CO₂ Corrosion         | Carbon steel and low | CO₂ | 32<T<800 |
| Microbiologic Induced Corrosion (MIC) | Commonly All material | Water, sulfur, ammonia, carbon, | T < 250 |
| Sulfidation           | Carbon steel, low alloy, 400series | Sulfur | T>400 |

c. Perform a re-calculation to determine the maximum pressure and minimum thickness of the separator so that it can operate following current conditions using the calculations in Table 4.

d. Perform corrosion rate calculations. The value of the corrosion rate used in the calculation to determine the value of the residual service life is the largest value from the comparison between the short-term corrosion rate, the long-term corrosion rate, and the CO₂ corrosion rate. In this study the calculation of the corrosion rate using API 510 and API 581. Calculation of the corrosion rate based on API 510 in Table 5 and the calculation of the corrosion rate based on API 581 in Table 6.

e. Calculation of residual service life refers to API 510

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\text{Residual life assessment} = \frac{t_{actual}}{t_{required}} \cdot \text{corrosion rate} \quad (11)
\]

Table 3. Input Parameters and Key Assumptions of Offshore Field Z

|          | Separator 1 | Separator 2 | Separator 3 | Separator 4 |
|----------|-------------|-------------|-------------|-------------|
| Design Pressure | 230 Psig | 230 Psig | 197 Psig | 240 Psig |
| Operating Pressure (P) | 180 Psig | 50 Psig | 120 Psig | 90 Psig |
| Design Temperature | 200 °F | 200 °F | 200 °F | 200 °F |
| Operating Temperature (T) | 140 °F | 100 °F | 112 °F | 100 °F |
| Dimension | 2133.6 mm x 6096 mm | 3657.6 mm x 18288 mm | 1676.4 mm x 5435.6 mm | 2286 mm x 2286 mm |
| Diameter (D) | 2133.6 mm | 3657.6 mm | 1674.4 mm | 2286 mm |
| Radius (R) | 1066.8 mm | 1828.8 mm | 838.2 mm | 1143 |
| Production year | 1984 | 1984 | 1986 | 1981 |
| Joint Efficiency (E) | 1.0 (Full) | 1.0 (Full) | 1.0 (Full) | 1.0 (Full) |
| Material | SA 516 Gr. 70 | SA 516 Gr. 70 | SA 516 Gr. 70 | SA 516 Gr. 70 |
| Fluid Content | Oil & Gas | Oil & Gas | Oil & Gas | Oil & Gas |
| Corrosion Allowance (CA) | 1.575 mm | 3.175 mm | 1.57 mm | 1.57 mm |
| Allowable Stress (σ) | 17500 psi | 17500 psi | 17500 psi | 17500 psi |
| Fluid Flow Rate | 1008 BFPD | 45000 BFPD | 2068 BFPD | 4900 BFPD |
| Gas Flow Rate | 4.29 MMCFD | 0.8 MMCFD | 2.7 MMCFD | 5.1 MMCFD |
| Watercut | 68% | 96% | 62% | 80% |
| Partial Pressure CO₂ (PCO₂) | 12.6 psi | 1 psi | 1.2 psi | 4.5 psi |
| Fraction Factor (f) | 0.0065 | 0.0127 | 0.0075 | 0.0077 |
| Mixture Mass Density (ρₘ) | 12.48 kg/m³ | 156.12 kg/m³ | 12.8 kg/m³ | 5.19 kg/m³ |
| Mixture Flow Velocity (μₘ) | 0.009 m/s | 0.00049 m/s | 0.007 m/s | 0.007 m/s |
| Initial Thickness (tₘₐₜₐ) | Shell: 15.88 mm | Shell: 25.58 mm | Shell: 12.7 mm | Shell: 19.05 mm |
|          | Head: 15.88 mm | Head: 25.58 mm | Head: 12.5 mm | Head: 19.05 mm |
| Actual Thickness (tₐₛₜₐ) | Shell: 7.16 mm | Shell: 21.65 mm | Shell: 8.66 mm | Shell: 14.6 mm |
|          | Head: 8.55 mm | Head: 28.43 mm | Head: 11.69 mm | Head: 18.68 mm |
| Previous Thickness (tₚₑᵱₑ) | Shell: 15.01 mm | Shell: 23.2 mm | Shell: 9.23 mm | Shell: 17.83 mm |
|          | Head: 14.57 mm | Head: 28.58 mm | Head: 13.22 mm | Head: 18.7 mm |
Table 4. Recalculation to Determine the Maximum Pressure and Minimum Thickness [10, 11]

| Parameter                              | Description                                      | Eq.   |
|----------------------------------------|--------------------------------------------------|-------|
| Thickness Required Shell (Tshell)      | trshell = \( \frac{P x R}{S \times E - 0.6 \times P} + CA \) | (1)   |
| Thickness Required                      | trhead = \( \frac{2 \times s \times E - 0.2 \times P}{P \times D} + CA \) | (2)   |
| Maximum Allowable Working               | MAWPshell = \( \frac{s \times E \times t}{(Ri + (0.6 \times t))} \) | (3)   |
| Pressure Shell (MAWPshel)              | MAWPhead = \( \frac{2 \times s \times E \times t}{((D) + (0.2 \times t))} \) | (4)   |

Table 5. Corrosion Rate Calculation [8]

| Parameter          | Description                                                                 | Eq.   |
|--------------------|-----------------------------------------------------------------------------|-------|
| Short Term CR (ST) | \( \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time between } t_{\text{prev}} \text{act} (\text{years})} \) | (5)   |
| Long Term CR (LT)  | \( \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time between } t_{\text{init}} \text{act} (\text{years})} \) | (6)   |

Table 6. Corrosion Rate Base Calculation [12]

| Parameter     | Description                                                                 | Eq.   |
|---------------|-----------------------------------------------------------------------------|-------|
| pH            | \( f(T, pH) = 2.8686 + 0.7931 \times \log_{10}[T] - 0.57 \times \log_{10}[\rho_{CO2}] \) | (7)   |
| Constant Kf   | The constant value is associated with the temperature as stated in Table 7 which has been calculated from the results of extrapolation between temperature and corrosion rate |       |
| f(T, pH)      | \( f(T, pH) \) is a function of temperature-pH                               |       |
| Fugacity CO2  | \( f_{CO2} = \rho_{CO2} \times \alpha \)                                    | (8)   |
| Shear Stress  | \( S = \frac{f x p m \times \mu^2}{m} \)                                       | (9)   |
| Corrosion Rate| \( CR_{\text{base}} = K f(T, pH) f^{0.62}_{CO2} \left( \frac{S}{19} \right)^Z \) | (10)  |

Table 7. The constant Kf at a certain temperature for the calculation of the corrosion rate [13, 14]

| Temperature (°C) | Constant (Kf) |
|------------------|---------------|
| 5                | 0.42          |
| 15               | 1.59          |
| 20               | 4.762         |
| 40               | 8.927         |
| 60               | 10.675        |
| 80               | 9.949         |
| 90               | 6.25          |
| 120              | 7.77          |
| 150              | 5.203         |

IV. RESULT AND DISCUSSION

4.1 Damage Mechanism

The results of the 2020 inspection report suggest that those four separators have internal corrosion anomalies considering the separator material is SA 516 Gr.70. Internal corrosion can occur due to the content of CO2 and H2S. However, in this study, the corrosion rate due to H2S does not occur in this material because H2S in carbon steel only reacts when the operating temperature is more than 400°F. The 3-phase fluid comes from the production header before oil and gas are separated in the production separator. Carbon dioxide content below 3 psi is not corrosive [15]. Internal corrosion may also occur in microbiologically induced corrosion due to water flowing in four production separators.

4.2 Recalculation of MAWP and Minimum Required Thickness

The calculation of Maximum Allowable Working Pressure Shell (MAWP) and minimum required thickness are presented in Tables 8 and 9. It is shown that separator 1 is no longer feasible to operate due to higher minimum thickness required than the actual, and higher operating pressure value than the MAWP value. Thus, it is suggested to lower the operating pressure if the company will continue to use the separator.

Table 8. Recalculation of MAWP

| Name       | Part | Pressure (psig) | Operating MAWP | Remarks       |
|------------|------|----------------|----------------|---------------|
| Separator 1| Shell| 180            | 116.98         | Non-Acceptable|
| Separator 1| Head| 180            | 141.97         | Non-Acceptable|
| Separator 2| Shell| 50             | 205.71         | Acceptable    |
| Separator 2| Head| 50             | 277.74         | Acceptable    |
| Separator 3| Shell| 120            | 179.69         | Acceptable    |
| Separator 3| Head| 120            | 246.4          | Acceptable    |
| Separator 4| Shell| 90             | 221.83         | Acceptable    |
| Separator 4| Head| 90             | 289.74         | Acceptable    |
API 510 and 581 is seen in Figure 1. It shows that the corrosion rate with API 581 has a lower value than API 510, due to differences in assessment parameters. In the API 581 standard, the predicted corrosion rate is based on the value of CO₂ content, operating temperature, and operating pressure. While the calculation of corrosion rate on API 510 is based on the difference between actual and previous inspection thickness results, thus allowing other factors to influence on the thinning of the material.

Identification relative corrosion resistance refers to Fontana [16] and Ginanjar [17]. Assessment of relative level of corrosion rate based on API 510 presents that Separators 1 and 4 fall into the "poor" category with a value of corrosion rate range of 1 - 5 mm/years. Separators 2 and 3 falls into the “fair” category with a corrosion rate range of 0.5 - 1 mm/year. Meanwhile, the API 581 calculations present that separator 1 is included in the “fair” category with a range of corrosion rate values between 0.5 - 1 mm/year. Separators 2, 3, and 4 are included in the "good" category due to a lower corrosion rate in a range of 0.1 - 0.5 mm/year.

4.4 Residual Service Life Assessment

The result of the residual service life calculation are presents in Table 9. It is seen that Separator 1 is critical equipment with the remaining service life of 4.87 years, as the effect of operating pressure loads that have exceeded the maximum allowable pressure, as seen in Table 8. Meanwhile, the calculation estimates other separators can be utilized until 2026 for Separator 3, until 2027 for Separator 4, and until 2042 for Separator 2.

Table 9. Recalculation of the Minimum Required Thickness

| Name       | Part   | Pressure (psig) | Thickness (mm) | Remarks       |
|------------|--------|----------------|----------------|---------------|
|            |        | Act     | Req          |               |
| Separator 1| Shell  | 210     | 7.16         | 14.4          | Non-Acceptable|
| Separator 1| Head   | 210     | 8.55         | 14.4          | Non-Acceptable|
| Separator 1| Shell  | 180     | 7.16         | 12.6          | Non-Acceptable|
| Separator 1| Head   | 180     | 8.55         | 12.5          | Non-Acceptable|
| Separator 1| Shell  | 150     | 7.16         | 10.7          | Acceptable    |
| Separator 1| Head   | 150     | 8.55         | 10.7          | Acceptable    |
| Separator 2| Shell  | 80      | 21.6         | 11.5          | Acceptable    |
| Separator 2| Head   | 80      | 28.4         | 11.5          | Acceptable    |
| Separator 2| Shell  | 50      | 21.6         | 8.41          | Acceptable    |
| Separator 2| Head   | 50      | 28.4         | 8.4           | Acceptable    |
| Separator 2| Shell  | 20      | 21.6         | 5.27          | Acceptable    |
| Separator 2| Head   | 20      | 28.4         | 5.27          | Acceptable    |
| Separator 3| Shell  | 150     | 8.66         | 8.79          | Acceptable    |
| Separator 3| Head   | 150     | 11.6         | 8.76          | Acceptable    |
| Separator 3| Shell  | 120     | 8.66         | 7.34          | Acceptable    |
| Separator 3| Head   | 120     | 11.6         | 7.32          | Acceptable    |
| Separator 3| Shell  | 90      | 8.66         | 5.89          | Acceptable    |
| Separator 3| Head   | 90      | 11.6         | 5.88          | Acceptable    |
| Separator 4| Shell  | 120     | 14.6         | 9.44          | Acceptable    |
| Separator 4| Head   | 120     | 18.6         | 9.41          | Acceptable    |
| Separator 4| Shell  | 90      | 14.6         | 7.47          | Acceptable    |
| Separator 4| Head   | 90      | 18.6         | 7.45          | Acceptable    |
| Separator 4| Shell  | 60      | 14.6         | 5.50          | Acceptable    |
| Separator 4| Head   | 60      | 18.6         | 5.49          | Acceptable    |

4.3 Corrosion Rate

Correlation of the corrosion rate calculation using
Figure 2. Analysis of the Effect of Pressure on the Remaining Service Life of Four Separators

Figure 3. Analysis of the Effect of Temperature on the Remaining Service Life of Four Separators
Table 10. Corrosion Rate and Residual Service Life Assessment

| Name      | Corrosion Rate (mm/years) | Residual Service Life (years) | Years |
|-----------|--------------------------|-------------------------------|-------|
| Separator 1 | 1.12                     | -4.87                         | -     |
| Separator 2 | 0.52                     | 25.46                         | 2042  |
| Separator 3 | 0.77                     | 5.68                          | 2026  |
| Separator 4 | 1.08                     | 6.6                           | 2027  |

Considering that separator 1 has been used for more than 36 years, it was suggested to reduce the operating pressure to below the maximum allowable pressure, or replace with the new one. Consequences on reducing operating pressure is a decrease in production rate, however, prolong the remaining residual life, as shown in Table 11. Meanwhile, for the new separator replacement in these field cases, there will 7-10 day production shutdown for the installation with potential loss of 3,250 bbls oil and 429 MMscf gas.

Table 11. Recalculation Residual Life Assessment on Separator 1

| Pressure (psig) | Thickness (mm) | Corrosion Rate (mm/years) | Residual Service Life (year) | Years |
|-----------------|----------------|---------------------------|-----------------------------|-------|
| 180             | 12.62          | 1.12                      | -4.87                       | -     |
| 70              | 5.86           | 1.12                      | 1.16                        | 2020  |
| 60              | 5.25           | 1.12                      | 1.71                        | 2020  |
| 50              | 4.63           | 1.12                      | 2.25                        | 2021  |
| 40              | 4.02           | 1.12                      | 2.8                         | 2021  |
| 30              | 3.41           | 1.12                      | 3.34                        | 2022  |
| 20              | 2.8            | 1.12                      | 3.89                        | 2022  |
| 10              | 2.19           | 1.12                      | 4.43                        | 2023  |

Refer to Table 4 on minimum thickness required calculation, where the operating pressure is a variable that affect to the residual service life results. Correlation between pressures to the remaining service life on four separators shown in Figure 2 has proven the result. In a closed pressure value system, the higher operating pressure, the lower minimum thickness required, which in turn will reduce the residual life.

Refer to API 581 on corrosion rate calculation in Table 6, where the operating temperature is a variable that affects the corrosion rate results. Correlation between temperatures to the remaining service life on four separators shown in Figure 3 has proven the result. In a closed pressure value system, the higher operating temperature, the higher corrosion rate, which in turn will reduce the residual life.

V. CONCLUSIONS

Calculation of the remaining service life for field Z is recommended using the highest corrosion rate value between API 581 and API 510. It was found that the corrosion rate with API 581 provides a lower value than API 510. API 510 calculation is based on differences between actual and previous inspection thickness results, thus allowing other factors to influence on the thinning of the material, while API 581 is based on the value of CO₂ content, operating temperature, and operating pressure. The higher operating pressure, the lower minimum thickness required, which in turn will reduce the residual life. The higher operating temperature, the higher corrosion rate, which will also reduce the residual life. From calculation estimates that at current operation condition, three of four separators in field Z still can be utilize at least until next five years. While one separator is needs to replace immediately considering to the negative remaining service life.

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