CORROSION UNDER INSULATION IN OIL AND GAS PLANTS: CASE STUDIES IN A JAPANESE FIELD

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ABSTRACT

This paper presents several case studies of Corrosion Under Insulation (CUI) in oil and gas plants in Japan. Our plants commonly use calcium silicate or mineral wool as thermal insulation. However, CUI poses a significant challenge, particularly under mineral wool insulation. Carbon steel equipment is susceptible to metal loss, while stainless steel equipment faces the risk of External Chloride Stress Corrosion Cracking (ECSCC). Water-repellent insulation materials were installed to address these issues, and organic protective coatings were applied to prevent corrosion. Despite our efforts, we have recently observed instances of CUI in piping with on-site applied coatings. To address this issue, the application of corrosion inhibitors for insulation materials was investigated as a temporary method to mitigate CUI. Based on laboratory experiments simulating our plant conditions, it was observed that while sodium nitrite inhibits general corrosion, it may also contribute to localized corrosion.

Keywords: Corrosion Under Insulation, Corrosion Inhibitor

INTRODUCTION

Corrosion Under Insulation (CUI) is a costly problem in the oil and gas industries. CUI occurs when moisture infiltrates the interface between insulation and piping or equipment, forming corrosion cells. Detecting CUI is challenging as it remains hidden under the insulation, affecting all parts of the plant and requiring comprehensive monitoring.

Removing insulation and inspecting piping and equipment is time-consuming and expensive, with maintenance costs primarily allocated to external piping inspections, insulation replacement, painting, and repairs. The presence of moisture and corrosive substances under the insulation is the root cause of CUI. Oxygen from the atmosphere dissolves into humidity, leading to corrosion. The insulation traps moisture within, initiating electrochemical cells that corrode pipes and equipment. Severe corrosion can occur in highly moist and prolonged wetting conditions.

API RP583 states that CUI can occur between -4 °C and 177 °C, with temperatures between 77 °C and 110 °C being particularly severe [1]. CUI is more likely in cyclic service with alternating wet and dry conditions. Chlorides, commonly derived from sources like sea breeze, can increase corrosion rates. Trapped water under insulation combines with chlorides, sulphates, and other corroding substances. They become concentrated during the formation of corrosion cells as the water evaporates.

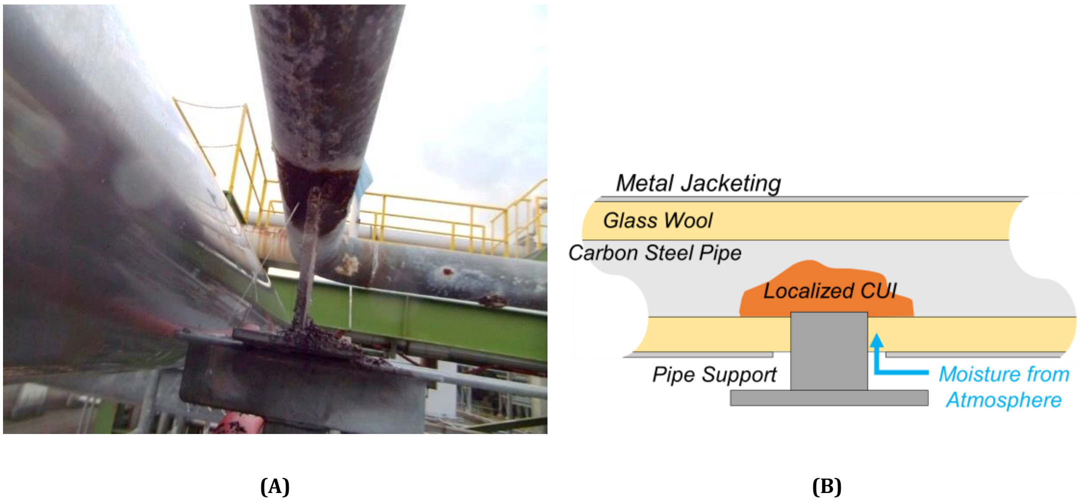
Applying an organic protective coating on the outer metal surface effectively prevents water contact, mitigating CUI. However, coating pinholes and blisters can occur, leading to severe localized CUI. Repairing anti-corrosion coatings during plant operation poses challenges in preparing metal surfaces with power tools. Alternative technologies are required to extend equipment service life without power tool removal of damaged coatings in our plant. In the industries, for example, measures such as vapor phase corrosion inhibitors and corrosion inhibitor-infused insulation materials are being considered and proposed [2,3].

This study aims to assess the feasibility of applying a corrosion inhibitor to the inner surface of insulation materials, evaluating its effectiveness in extending the service life of piping and equipment. In a previous study, a commercial corrosion inhibitor product designed for inner insulation surfaces revealed localized corrosion occurrences [4]. The corrosion inhibition performance of the product was like sodium nitrite ($NaNO_2$). Based on these findings, the immersion tests were conducted under various conditions to determine the chemical concentration requirements for preventing localized corrosion under insulation when using $NaNO_2$ as a corrosion inhibitor.

CASE STUDIES

CUI ON CARBON STEEL PIPES

Figure 1 shows an example of CUI failure on a boiler feedwater line. The original thickness of the pipe was 5.5 mm, and after 11 years of usage, it developed leakage, indicating a corrosion rate of 0.50 mm/y. The operating temperature of the line was 105 °C, which falls within the temperature range of concern for high corrosion rates according to API RP583. What was notable about this pipe was the occurrence of localized CUI around the pipe support. It was hypothesized that moisture may have infiltrated the interior through gaps where the pipe support penetrated the metal jacket. Furthermore, moisture-absorbent glass wool insulation was commonly utilized, and external coatings designed explicitly for CUI prevention were not considered then. Due to numerous CUI cases, adopting water-repellent insulation materials and exploring external coatings gained momentum in our plant.



(A)

(B)

FIGURE 1: (A) SHOWS THE PHOTOGRAPH OF CUI AROUND A PIPE SUPPORT, (B) SHOWS THE SCHEMATIC DIAGRAM ILLUSTRATING CUI AROUND A PIPE SUPPORT

CUI on Stainless-Steel Pipes

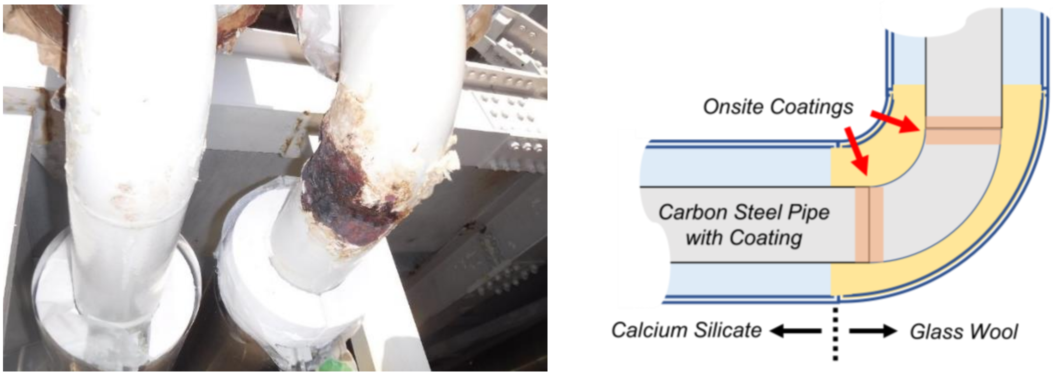
Figure 2 illustrates an example of CUI failure on an amine line. This pipe, made of type 304L, exhibited external stress corrosion cracking during an inspection after 20 years of use. The design temperature of this pipe was 130 °C, falling within the temperature range of concern for stress corrosion cracking according to API RP583. What was distinctive about this case was the cracks at the welds between the pipe and flanges and in their vicinity. It is hypothesized that the heat affected during pipe fabrication sensitized the material and introduced residual welding stresses, potentially promoting SCC. At that time, moisture-absorbent glass wool insulation was widely used, and external coatings specifically for CUI prevention were not considered. As a result of numerous similar cases, the use of water-repellent insulation materials and external coatings started to be actively explored, even for stainless steel equipment.

(A) **(B)**

FIGURE 2: (A) SHOWS THE PHOTOGRAPH OF ECSCC AT TYPE 304L PIPE WELDS, (B) SHOWS ITS ENLARGEMENT

CUI on Carbon Steel Pipes with Coating Applied

Figure 3 illustrates an example of CUI failure on a hot water line with an external coating. The original thickness of the pipe was 7.1 mm, and after 91 months of usage, it developed leakage, indicating a corrosion rate of 0.93 mm/year. The operating temperature of the line was 80 °C, which falls within the temperature range of concern for high corrosion rates according to API RP583. What was notable about this pipe was the occurrence of localized CUI around the area where the coating was damaged. This example demonstrates that CUI can occur even in piping where coatings have been applied.



(A) **(B)**

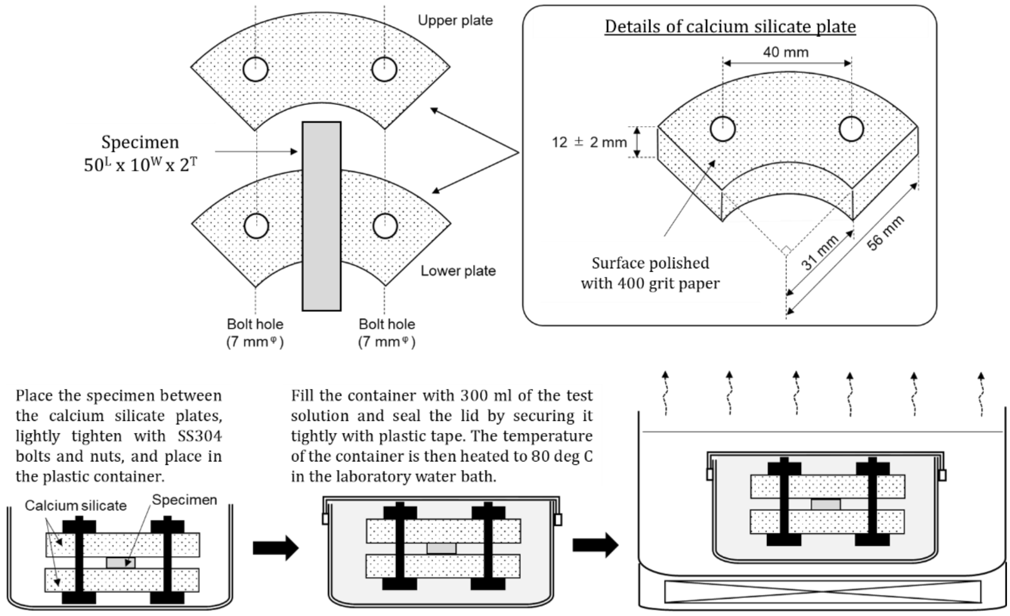
FIGURE 3: (A) SHOWS THE PHOTOGRAPH OF CUI WITH COATING DAMAGE, (B) SHOWS THE SCHEMATIC DIAGRAM ILLUSTRATING CUI WITH COATING DAMAGE

METHODS AND MATERIALS

The immersion test was performed with only a part of the specimen covered with calcium silicate plates as a simulated CUI condition to confirm the susceptibility to crevice corrosion. Each carbon steel specimen was sandwiched between two pieces of calcium silicate plate and immersed in 300 mL of the test solution pre-added sodium nitrite in a polypropylene container. Each closed container was engaged in a laboratory water bath warmed to 80 °C. After the 7-day test period, the mass loss of each specimen was measured, and the surfaces of post-test specimens were observed. The test conditions are shown in Table 1, and the schematic diagram of the test procedure is shown in Figure 4. Sodium nitrite was pre-added to the test solution before starting the immersion test. After the immersion test, the pH of each solution was measured with a pH meter to examine the corrosiveness to exposed areas under the test environment, and the pitting depth was measured with a laser scanning microscope to estimate the pitting corrosion rate per year.

TABLE 1: TEST CONDITIONS FOR THE IMMERSION TEST

Specimen Material	Carbon steel (ASTM A135 Gr. A) 50 mm x 10 mm x 2 mm, wet polished with silicon carbide paper to P400
Test Solution	0.030, 0.30, or 3.0 wt.% NaCl solution 300 mL (Solution/Specimen ratio: 24 cm^3/cm^2)
Corrosion Inhibitor	Sodium nitrite ($NaNO_2$)
Addition Amount	0,10, 100, or 1000 ppm
Test Container	Polypropylene container, 100 mm x 70 mm x 50 mm in size
Insulation Material	Commercially available calcium silicate for piping (shown in Figure 4)
Test Temperature	80 °C
Test Duration	Seven days (168 hrs.)



Place the specimen between the calcium silicate plates, lightly tighten with SS304 bolts and nuts, and place in the plastic container.

Fill the container with 300 ml of the test solution and seal the lid by securing it tightly with plastic tape. The temperature of the container is then heated to 80 deg C in the laboratory water bath.

FIGURE 4: SCHEMATIC DIAGRAMS OF THE IMMERSION TEST PROCEDURE

RESULTS

The results converted to corrosion rate based on mass loss after 7-day immersion tests are shown in Table 2. In the case of a 3.0 wt.% NaCl solution with 1,000 ppm $NaNO_2$ added, the corrosion rate was 0.47 mm/y, which was the highest value among the test conditions. Without the addition of $NaNO_2$, the corrosion rate ranged from 0.14 mm/y to 0.21 mm/y, while with $NaNO_2$, the corrosion rate ranged from 0.07 mm/y to 0.47 mm/y. $NaNO_2$ was found to inhibit the corrosion rate in some cases, but in others, it increased the corrosion rate.

The depth of metal loss on the post-test surface was measured using a laser microscope and converted to the pitting rate, as shown in Table 3. In the case of a 3.0 wt.% NaCl solution with 1,000 ppm $NaNO_2$ added, the pitting rate was 11.3 mm/y, which was the highest value among the test conditions. Without the addition of $NaNO_2$, the pitting rate ranged from 1.9 mm/y to 3.9 mm/y, while with $NaNO_2$, the pitting rate ranged from 3.4 mm/y to 11.3 mm/y. $NaNO_2$ generally tended to increase the pitting rate.

Photographs of the post-test metal surface are shown in Figure 5. For the test specimens without $NaNO_2$ added, the primary corrosion was general corrosion in the exposed area. On the other hand, the surfaces of the test specimens with $NaNO_2$ added at concentrations ranging from 10 ppm to 1,000 ppm exhibited localized corrosion. $NaNO_2$ played a role in suppressing general corrosion and maintaining metallic lustre when added above 100 ppm or chloride ion concentration was below 0.03 wt. %. However, it was observed that $NaNO_2$ induced localized corrosion in the under-deposit area and the under-insulation area.

In the case of a 0.030 wt.% NaCl solution with 1,000 ppm $NaNO_2$ added, the corrosion rate was 0.07 mm/y, the smallest corrosion rate among all test conditions. However, the pitting rate was high at 5.7 mm/y. The metal surface of the post-test specimen exhibited both the inhibition of general corrosion and the induction of localized corrosion.

TABLE 2: THE IMMERSION TEST RESULTS (CORROSION RATE AT 80 °C)

Corrosion inhibitor	0.030 wt.% NaCl Solution	0.30 wt.% NaCl Solution	3.0 wt.% NaCl Solution
$NaNO_2$ 0 ppm	0.18 mm/y	0.14 mm/y	0.21 mm/y
$NaNO_2$ 10 ppm	0.31 mm/y	0.30 mm/y	0.17 mm/y
$NaNO_2$ 100 ppm	0.21 mm/y	0.34 mm/y	0.29 mm/y
$NaNO_2$ 1,000 ppm	0.07 mm/y	0.28 mm/y	0.47 mm/y

TABLE 3: THE IMMERSION TEST RESULTS (PITTING RATE AT 80 °C)

Corrosion inhibitor	0.030 wt.% NaCl Solution	0.30 wt.% NaCl Solution	3.0 wt.% NaCl Solution
$NaNO_2$ 0 ppm	3.9 mm/y	3.1 mm/y	1.9 mm/y
$NaNO_2$ 10 ppm	8.3 mm/y	5.2 mm/y	4.7 mm/y
$NaNO_2$ 100 ppm	3.4 mm/y	7.3 mm/y	5.2 mm/y
$NaNO_2$ 1,000 ppm	5.7 mm/y	9.4 mm/y	11.3 mm/y

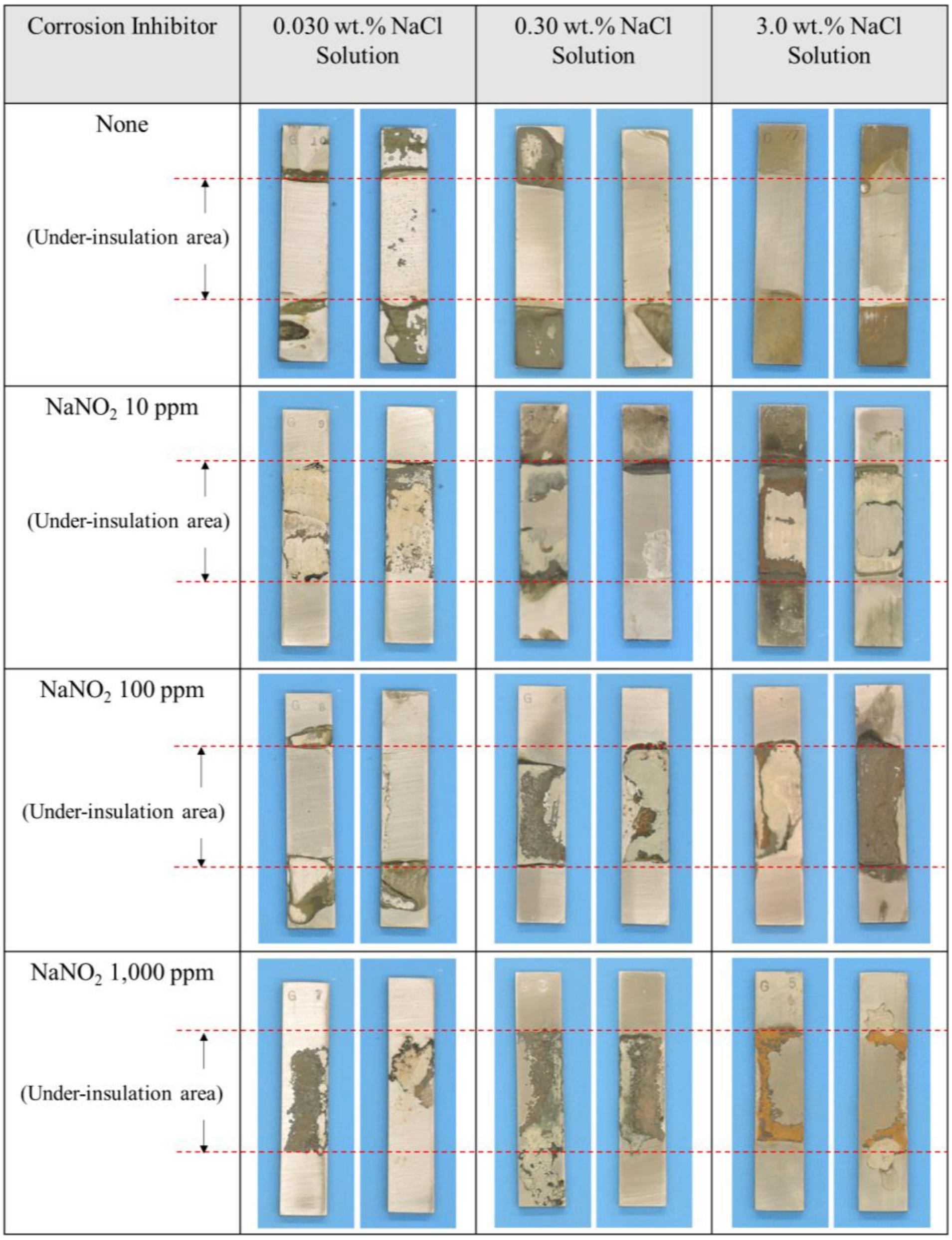


FIGURE 5: THE PHOTOGRAPHS OF THE SPECIMEN SURFACE AFTER THE IMMERSION TEST

DISCUSSION

The possible mechanism for the induction of localized corrosion under the test conditions with the addition of the corrosion inhibitor, $NaNO_2$, is shown in Figure 6. A protective film formed by dense corrosion products is established in areas where the corrosion inhibitor functions effectively, acting as a cathode. However, the protective film is not maintained in areas where the corrosion inhibitor's function is insufficient, resulting in anodic behaviour. In other words, forming a corrosion cell with a fixed anode leads to concentrated metal loss due to localized corrosion. Areas prone to insufficient supply of the corrosion inhibitor include the crevice portion under the insulation or the deposit. Localized corrosion was observed in the under-deposit regions in specimens with deposits on the exposed area. While adding $NaNO_2$ can slow down corrosion progression in areas where their effects are practical, there is a concern that they may promote corrosion in areas where their effects are not working effectively (e.g., under insulation materials).

Previous studies showed localized corrosion could occur when corrosion inhibitors were applied to insulation materials. To investigate this further, we conducted tests using various concentrations of NaCl and $NaNO_2$ to determine if they could avoid such corrosion. However, localized corrosion was observed under all tested conditions except without $NaNO_2$ addition. This suggests that the concentration threshold required to inhibit localized corrosion may be even lower than the concentrations used in the present study. Alternatively, it is possible that the temperature of 80 °C falls within a range where localized corrosion is more likely to occur. Therefore, it will be necessary to conduct further tests in different temperature ranges to confirm the results.

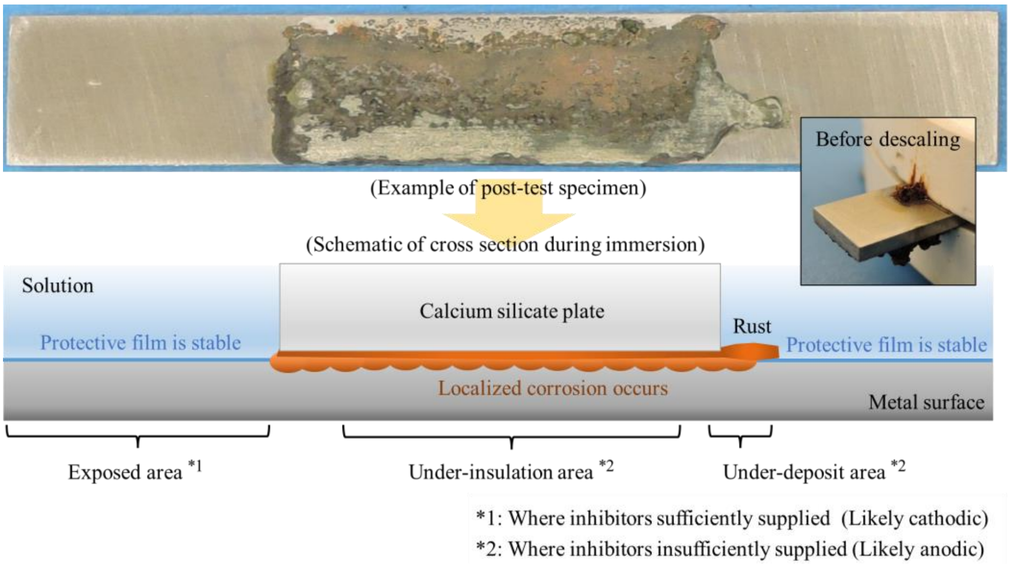


FIGURE 6: THE SCHEMATIC DIAGRAM OF THE ESTIMATED MECHANISM OF LOCALIZED CORROSION

CONCLUSIONS

After experiencing cases of CUI and ECSCC, we have implemented external coating on the pipes. However, in recent years, we have encountered CUI in the areas where the coating was applied. Therefore, we are investigating the application of corrosion inhibitors to insulation materials to temporarily extend the service life of piping and other equipment damaged by CUI. Immersion tests were conducted using a test solution of $NaNO_2$ added to a NaCl solution at 80 °C. The tests yielded the following results and considerations. The immersion test was conducted with a 3.0 wt.% NaCl solution containing 1,000 ppm $NaNO_2$ showed a corrosion rate of 0.47 mm/y and a pitting rate of 11.3 mm/y. These values were higher compared to the test results obtained without adding $NaNO_2$. The observed high pitting rate in the case of $NaNO_2$ addition was attributed to localized corrosion based on the surface condition after the immersion test. Areas where the corrosion inhibition effect of NaNO2 is effective, may actually promote corrosion in areas where it is insufficient. To prevent localized corrosion, the concentration of the chemicals may need to be further reduced, or the temperature conditions relaxed.

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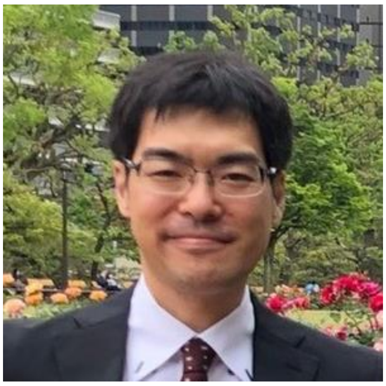
AUTHOR DETAILS

	T. Toyoda is the corresponding author of this paper. He is a research engineer at INPEX, a position he has held since 2019. He is responsible for selecting metal materials for OCTG (Oil Country Tubular Goods), evaluating corrosion inhibitors for pipelines, and conducting RCA (Root Cause Analysis) on corrosion failures that occur in their plants. email: takehiro.toyoda@inpex.co.jp
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