Application of internal corrosion direct assessment in CO₂ slug flow submarine pipelines

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ABSTRACT
This paper aims to establish a direct method for evaluating the internal corrosion in submarine pipelines, including four steps: pre-assessment, indirect inspection, detailed inspection, and post-assessment. The evaluation of corrosion severity and the determination of key monitoring points are particularly important in indirect detection. Taking CO₂ gathering and transmission pipeline of an offshore oil field as an example, the overall internal corrosion rate of the pipeline is calculated to be 0.253 mm/a. The 12–45 m long pipeline is selected as the focus of corrosion monitoring. Through the comparative analysis of internal detection data and loss wall thickness calculation method, it is found that the results of indirect evaluation and direct evaluation are consistent, indicating the correctness of corrosion rate prediction model and loss wall thickness calculation method. The pipeline reevaluation time is five years. The evaluation method can accurately predict the corrosion status of multiphase flow pipeline and locate the corrosion.

1. Introduction
Carbon steel pipelines and piping used in transportation of hydrocarbon products are prone to internal corrosion when exposed to an aqueous CO₂ environment [1,2], especially at the riser [3]. The CO₂ corrosion majors affective factors are pressure and temperature, acid gas content, in-situ pH, flow regime and so on [4]. The general mechanisms of CO₂ corrosion have been extensively studied and are well understood [5–10]. López et al. [11] showed that pearlite/ferritic steel (P/F steel) and quenched martensitic steel (TM steel) exhibit a better corrosion resistance. The total pressure has no direct impact on corrosion. However, it should be noted that the total pressure is proportional to the partial pressure of CO₂, which has a major effect on corrosion [12]. Zhao et al. [13] researched that the 35MoCr steel corrosion rate increases with the increase of CO₂ partial pressure (0.8MPa ~ 1.6 MPa). With the increase of temperature (60°C ~ 120°C), the corrosion rate of the sample first increases and then decreases [14]. The corrosion resistance of X70 decreases in the pH range of 5.5 ~ 6.5 at 65°C [15].

However, there is gas–liquid two-phase flow in submarine mixed transportation pipeline. The hydrodynamic characteristic of multiphase flow is correlated to the fluid properties (such as the density, viscosity, and crude chemistry), the interfacial behaviour, the reactions at steel surfaces, and so on. Multiphase flow affects internal corrosion through three aspects: (1) distribution of phases in fluid, (2) mass transport of species, and (3) flow-induced corrosion [16]. Especially the effect of slug flow on corrosion. Elision and Wen (1981) proposed three types of flow corrosion: convective mass transfer corrosion, phase transition corrosion and erosion corrosion [17]. The above three corrosion effects are fully reflected in slug flow corrosion. Sun and Jepson and Zhou and Jepson (1993) have proved that in slug flow, there are often areas with high wall shear stress and high turbulence [18]. The combination of slug flow and CO₂ forms CO₂ slug flow corrosion, which is the result of slug flow scouring wear (dynamic action) and corrosion (electrochemical action). Yuhua S. [19] and Mamdouh M. [20] respectively studied the effects of temperature, pressure, CO₂ partial pressure, corrosion product film, pH value, corrosion inhibitor and other influencing factors on the corrosion rate in the pipeline conveying moisture and multiphase flow through loop experiments. Jiabin H [21] studied the effect of corrosion product film on CO₂ corrosion rate and corrosion morphology by autoclave experiment, and obtained experimental results different from previous understanding, which provided a new idea for the study of CO₂ corrosion product film. The influencing factors of CO₂ corrosion in slug flow are mainly electrochemical factors and kinetic factors. Electrochemical factors include temperature, pressure, pH value, medium composition, etc. The dynamic factors include gas–liquid velocity and slug flow pattern. Overall, the
effects of kinetic factors on corrosion are mainly manifested in mass transfer, diffusion and scouring shear. A lot of research has been done on the mechanism of CO₂ slug flow corrosion, but there are still some problems in the research on the prediction model of CO₂ slug flow corrosion. What’s more, the question on whether these corrosion models are suitable for submarine pipelines still requires further verification [22,23].

To clearly grasp the internal corrosion of CO₂-containing submarine pipelines, an OLGA model based on the Multiphase Low Internal Corrosion Direct Assessment (MP-ICDA) Methodology for pipelines, released in 2016 by the International Association of Corrosion Engineers (NACE), is proposed in the current work. This approach consists of collecting extensive design and operation data, corrosion monitoring data and any other related information. In particular, the performance of relevant tests and calculations allows one to establish whether the corrosion of the target pipeline is severe enough to affect the integrity of the latter, as well as put forward the corresponding repair and protective measures against corrosion defects. According to the MP-ICDA requirements, the direct method for multiphase flow internal corrosion evaluation of CO₂-containing submarine pipelines takes the following steps. First, the data are collected to determine whether the target pipeline fulfils the demands for choosing this approach. Then, the operating conditions are selected. After that, the relevant specifications are formulated using the established pipeline corrosion and node division coordinates, and the area under investigation is divided into sub-regions for further assessment. The pipeline flow is afterwards simulated to obtain the flow parameters along the pipeline. Finally, the CO₂ corrosion rate is predicted at each node of the pipeline and the key monitoring area is determined according to the judging criteria. The proposed model is therefore shown to be reliable for providing support and suggestions for the detection and monitoring of corrosion on the large pipeline networks during operation.

2. Pipeline information parameters

The submarine mixed transmission pipeline is a tee pipeline connecting platform A and the mixed transmission submarine pipeline from pipeline B to platform C. Figure 1 shows the geographical location of the pipeline. The pipeline information is shown in Table 1.

The geographical location of the pipeline is shown in Figure 2. The submarine pipeline has extremely severe corrosion at 32 m, there is extremely severe corrosion on the inner surface of the pipe. According to the qualitative classification of corrosion rate in NACE standard rp0775-2005, the CO₂ partial pressure range of the pipeline is 0.03 MPa ∼ 0.06 MPa. Hence, the pipeline is at risk of CO₂ corrosion.

3. Internal corrosion direct assessment for CO₂ multiphase flow submarine pipelines

Corrosion evaluation methods for CO₂-containing multiphase flow submarine pipelines include assessment of feasibility and severity of corrosion and determination of key monitoring points. In particular, the flow simulated along with the elevation map of the pipelines is used to predict the internal corrosion possibility and corresponding corrosion risks at each internal corrosion evaluation area and provide data support for internal inspection and pipeline maintenance.

3.1. Evaluation of feasibility judgment

3.1.1. Collection of information related to the evaluation of the pipeline

For each evaluated pipe segment, the data to be collected includes the information about the entire design, construction, and operation stages of the pipeline, as shown in Table 2 [24].

3.1.2. Evaluation of internal corrosion of a multiphase flow containing CO₂

The information for “Importance Level 1” is required. Based on the collected data, the corrosion area in the pipeline is pre-determined for evaluation. An internal corrosion area is a part of any long pipe section, which includes one or more internal corrosion pipe sections. Its total length is equal to a sum of the lengths of all the sections carrying out the internal corrosion assessment.

Figure 1. The geographical location of pipeline.
Table 1. The basic information of pipeline.

| Medium/Gas/Water | Material | External diameter/mm | Wall thickness/mm | Minimum yield strength/MPa | Production Time | Pipeline Length | Corrosive Medium |
|------------------|----------|-----------------------|-------------------|----------------------------|-----------------|-----------------|------------------|
| X65              | 219.1    | 14.3                  | 450               | 75m                        | 2014            | 75 m           | CO₂              |

Figure 2. Elevation map along submarine pipeline.

3.1.3. Select typical working conditions
During the operation of the pipeline, there may be a shutdown situation, which will cause changes in the flow rate of the pipeline and thereby alter the corrosion behaviour. Furthermore, the operating pressure and temperature of the pipeline will also affect the corrosion rate of the latter.

Therefore, taking the less fluctuation periods in the operating conditions of the pipeline for assessment is conducive to improving the prediction accuracy of the corrosion rate and the accuracy of the evaluation.

3.1.4. Division of the assessment pipeline
Since the corrosion mechanisms and the severity of corrosion impacting a pipeline vary under different operating conditions, such as apparent gas/liquid velocity, flow pattern, terrain, liquid holding rate, and solid deposition, the internal corrosion evaluation requires the knowledge of the hydrodynamic processes in the pipeline. In this respect, the pipe section with a maximum corrosion rate was chosen as a priority assessment site. The risk-based method was used for the evaluation. For this, at least two pipe sections were selected and at least four sections were less than 10 km (see Table 3).

3.2. Corrosion severity assessment
The aim of corrosion severity assessment is to identify sub-segments in each evaluation area, which are prone to corrosion or being under the internal corrosion, and determine their relationship with a length and the elevation of the pipeline. For this, multiphase flow simulation is required to establish the flow parameters of each sub-segment and the use of a CO₂ corrosion rate prediction model to assess the corrosion rate and calculate the wall thickness loss distribution.

3.2.1. Multiphase flow pipeline simulation
OLGA software is the worldwide recognized industrial standard multi-phase flow analysis software developed by a ScandPower (SPT) group (Norway) [25]. The basic module of the software allows analysis of the multi-phase and single-phase flows such as oil and gas, oil–water, and oil and water [26]. In this model, the multiphase flow simulation is based on a two-fluid physical model composed of three continuity equations, two momentum equations, and a mixed energy equation [27], as was shown in Figure 3.
Table 3. Minimum number of evaluation sections.

| Length of continuous pipe sections in all evaluation areas and sub-areas (km) | Low wall thickness loss < 20% | 21-40% loss in medium wall thickness | 41-60% high wall thickness loss > 60% | Minimum number of evaluation sections |
|---|---|---|---|---|
| 0.1–10.0 | 1 | 1 | 1 | 4 |
| 10.1–50.0 | 1 | 1 | 2 | 6 |
| 50.1–100.0 | 1 | 2 | 2 | 8 |
| 100.1–500.0 | 1 | 2 | 3 | 10 |
| > 500.1 | 2 | 3 | 4 | 5 |

The continuity equation of gas–liquid two-phase flow is as follows:

\[ \frac{\partial}{\partial t} (V_g \rho_g V_g + V_D \rho_L V_D) = - \frac{1}{A} \frac{\partial}{\partial z} \left( AV_g \rho_g V_g^2 + AV_D \rho_L V_D^2 \right) - (V_g + V_D) \frac{dP}{dz} \]

\[ - \frac{1}{2} \lambda_g \rho_g |V_g| V_g S_g \left( \frac{1}{4A} \right) + (V_g \rho_g + V_D \rho_L) g \cos \alpha \]

\[ + \psi_g \left( \frac{V_L}{V_L + V_D} \right) V_a + \psi_e v_i - \psi_d V_D \]

where, \( \alpha \) is the inclination angle between the pipe and the vertical direction; \( P \) is pressure; \( v_i \) is the relative velocity; \( S \) is the wetted perimeter of each phase interface; \( g \) is the acceleration of gravity; The subscripts \( g \), \( L \) and \( i \) represent the interfaces among the gas phase, liquid phase and gas–liquid phase respectively.

Energy equation:

\[ \frac{\partial}{\partial t} \left[ m_g \left( E_g + \frac{1}{2} V_g^2 + gh \right) \right] + m_l \left( E_L + \frac{1}{2} V_L^2 + gh \right) + m_D \left( E_D + \frac{1}{2} V_D^2 + gh \right) - \frac{\partial}{\partial z} \left[ \begin{array}{c} m_g V_g \\ \frac{1}{2} m_l V_L \\ \frac{1}{2} m_D V_D \end{array} \right] \]

\[ + \left. \begin{array}{c} m_g H_g \\ \frac{1}{2} m_l H_L \\ \frac{1}{2} m_D H_D \end{array} \right\} + H_S + U \]

where, \( E \) is the internal energy of fluid per unit mass; \( h \) is the elevation; \( H_S \) is the enthalpy of mass source; \( U \) is the heat transfer of pipe wall.

The above physical models generate a series of coupled first-order nonlinear one-dimensional partial differential equations with rather complex coefficients.
Most of the two fluid models are solved by the finite difference staggered grid contribution element method.

OLGA judges two flow patterns according to the “minimum slip criterion”. The “minimum slip criterion” refers to selecting the flow pattern with the minimum linear velocity difference between gas and liquid or the highest gas velocity (so as to minimize the liquid holdup) for a given pressure drop [29].

### 3.2.2. Determination of other factors that affect the location of corrosion in the pipeline

During the startup process, it will run in a non-steady state for a while. While executing temporary shutdowns and regular switching, the liquid stagnates in a lower position. After restarting, the gas either cannot take away all the stagnant liquid or pour out the liquid to a slug formed. A sudden increase or decrease in the production also affects the fluid.

Besides the frequency and effectiveness of pigging, as well as the information on the location, frequency, and time of pigging; there are the data on sludge and liquid removed from liquid separators or pigging processes, hydration, etc., excluding the chemical properties and corrosion severity reports.

### 3.2.3. Identification and division of each evaluation area into the sub-segments

Since the distribution of a three-phase flow, whether it is oil, gas, or water, in the pipe is more complex, it can be divided into several flow patterns according to a two-phase flow pattern classification method. The distribution and structural characteristics of each phase composing the three-phase flow may vary. Since the flow patterns possess different energy losses, the corresponding formulas are applied to calculate the pressure drop [30].

### 3.2.4. Prediction of corrosion rate at each sub-segment

Based on the CO₂ corrosion prediction model established for the target pipeline, the flow parameters along the pipeline calculated through the multiphase flow simulation are afterwards used to predict the corrosion rate at each sub-segment of the pipeline. For this, a corrosion module with three models, namely Norsok M506, De Waard 95, and Top of Line [31] has been embedded in OLGA software. Among these, the corrosion rate predicted by De Waard 95 approach has the smallest error [32], allowing this corrosion model to be chosen for the further assessment of pipelines. After that, the average corrosion rate of the pipeline is evaluated to see whether it exceeds the corrosion rate at each sub-segment.

In the De Waard 95 model, the effects of mass transfer and electrochemical kinetic reaction rate on the corrosion are described by the following expressions:

\[
\frac{1}{V_{\text{corr}}} = \frac{1}{V_r} + \frac{1}{V_m}
\]

\[
V_m = 0.245 \left( \frac{U}{D} \right)^0.8 PCO_2
\]

\[
\log V_r = 4.93 - \frac{1119}{t + 273} - 0.58 \log PCO_2
\]

\[
- 0.34(\text{pH}_{\text{act}} - \text{pH}_{\text{CO}_2})
\]

\[
\text{pH}_{\text{CO}_2} = 3.71 + 0.00417 t + 0.5 \log PCO_2
\]

where \(V_{\text{corr}}\) is the corrosion rate (mm/a); \(V_m\) is the mass transfer rate (mm/a); \(V_r\) is the reaction rate (mm/a); \(U\) is the liquid flow velocity (m/s); \(D\) is the pipeline diameter (mm); \(PCO_2\) is the CO₂ partial pressure (MPa); \(t\) is the temperature (°C); \(\text{pH}_{\text{act}}\) is the actual pH value; \(\text{pH}_{\text{CO}_2}\) is the pH value of CO₂ saturated solvent.

### 3.2.5. Corrosion severity evaluation in the pipe section

To assess the corrosion-induced damages of the wall thickness at each sub-segment, the cumulative and average wall thickness losses are calculated based on the corrosion rates for the relevant time segments.

### 3.3. Identification of key monitoring points

The internal corrosion assessment of pipeline sections ensures subsequent supervision and maintenance of the pipeline by determining the key monitoring locations, thereby providing a choice point for detailed inspection.

According to the requirements of the code, the key monitoring points can be selected in obedience with the criteria below:

1. Criterion 1: The corrosion rate of the node is greater than the average corrosion rate.
2. Criterion 2: The obstacles causing unstable flow of the pipeline or exacerbating pipeline corrosion should be considered taking into account such conditions as excessive bending, isolation valve, oil injection point, stagnation flow, and so on.

The complete algorithm of corrosion evaluation in a submarine mixed pipeline is illustrated in Figure 4.

### 4. Application of internal corrosion direct assessment method

In this paper, a CO₂ multiphase pipeline is taken as the research object, and the internal corrosion of the pipeline is analyzed by using the direct evaluation method.
4.1. Pre-assessment

The main task of pre evaluation stage is to collect data and determine ICDA evaluation area. The submarine pipeline chosen for the analysis has a total length of 75 m and undergoes the influence of a three-phase environment, including oil, gas, and water. The pipe steel grade is API X65, and the specification size is φ219.1×14.3 mm. The gas phase composition is shown in Table 4.

Since the operating temperature and pressure, as well as oil and water flow, exhibit the same change trend, the conditions to be evaluated are divided into 10 time periods (the pipeline is shut down in three cases). The working conditions of a multiphase flow were thus simulated according to the basic data. In this respect, Table 5 shows the specific time division and typical working conditions of the mixed pipeline.
be accurately presented. In this respect, the pipeline is
ing trend of flow parameters along the pipeline cannot
3(a)). However, due to the large grid division, the chang-
7 sections whose average length is 10.7 m (see Figure
portation submarine pipeline, the latter is divided into
large.

is too long; otherwise the iterative calculation error is
the calculation accuracy is high but the iteration time
establishment. The pipeline length must be set accord-
sion of the grid length is the key to the process of model

discretization component, and the ratio of the lengths of
the adjacent two sections is between 0.5 and 2. The divi-
sion of the grid length is the key to the process of model

OLGA software meshing mainly uses its internal dis-
cretization component, and the ratio of the lengths of
the adjacent two sections is between 0.5 and 2. The divi-
sion of the grid length is the key to the process of model

Using the data of the nodes along the mixed trans-
portation submarine pipeline, the latter is divided into
7 sections whose average length is 10.7 m (see Figure
3(a)). However, due to the large grid division, the chang-
ning trend of flow parameters along the pipeline cannot
be accurately presented. In this respect, the pipeline is
divided into 62 sections with average length of 1.2 m
(Figure 5(b)), thereby allowing more accurate visual-
ization of the changes in flow parameters along the
pipeline. A further division of the pipeline into 124 sec-
tions causes no visual difference between the plots in
Figure 5(b) and 5(c), exhibiting only a few small fluctuations
in Figure 5(c).

Therefore, considering the calculation accuracy and
the later application of multiphase flow simulation
results, the pipeline is divided into 62 sections to estab-
lish the proper OLGA simulation model and calculate
the flow patterns and node parameters under 7 working
conditions. Therefore, the requirement that the mini-
imum number of 10 km pipe sections be 4 is fulfilled.

4.2.2. Results and analysis of multiphase flow
parameters
The multi-phase flow simulation results are afterwards
analyzed using the black oil model by choosing case 4.
For this, the water content is 38%, and the gas-oil ratio is
186.32. The inlet boundary condition is MASSFLOW, and
the oil phase is selected as the standard phase state, at
which the oil delivery volume is 207.14 m³/d, and the
inlet temperature is 67.5°C. The outlet boundary con-
dition is PRESSUREDRIV, and the pressure is constant
at 1.43 MPa. Figure 4 displays the graphs of the multi-
phase flow simulation parameters along the pipeline,
obtained at the given conditions [34].

The liquid holding rate along the pipeline cannot be
measured directly. Therefore, the OLGA simulated tem-
perature values of the two pipelines are compared with
the actual test values on site. As shown in Figure 6 and
Table 7, the temperature error was controlled within 5%.

Due to the short pipeline length, the tempera-
ture and pressure fluctuations along the pipeline are
small, covering the ranges of 63.86°C–56.62°C and

### Table 4. Gas phase composition.

| Sampling date | CO₂ vol% | CH₄ vol% | C₂H₆ vol% | C₃H₈ vol% |
|---------------|----------|----------|------------|------------|
| 2017.06.20    | 2.03     | 97.51    | 0.43       | 0.03       |
| 2017.12.22    | 2.17     | 97.43    | 0.36       | 0.04       |
| 2018.06.18    | 2.13     | 97.41    | 0.42       | 0.04       |
| 2018.12.15    | 2.11     | 97.47    | 0.36       | 0.06       |
| 2019.06.19    | 2.21     | 97.26    | 0.46       | 0.07       |
| 2019.12.13    | 2.10     | 97.41    | 0.43       | 0.06       |
| 2020.06.17    | 2.01     | 97.49    | 0.47       | 0.03       |
| 2020.12.16    | 2.05     | 97.46    | 0.45       | 0.04       |

### Table 5. Time segmentation of mixed pipelines.*

| Case   | The period          | Inlet temperature (°C) | Inlet pressure (MPa) | Daily gas production (m³) | Daily oil production (m³) | Water content (%) | CO₂ volume fraction (%) |
|--------|---------------------|------------------------|----------------------|---------------------------|---------------------------|-------------------|------------------------|
| 1      | 2017.05.08 – 2017.12.29 | 70.0                   | 1.42                 | 54764                     | 143.92                    | 6.4               | 2.530                  |
| 2      | 2017.12.30 – 2018.02.13 | 67.8                   | 1.60                 | 75290                     | 110.53                    | 24.5              | 3.475                  |
| 3      | 2018.02.14 – 2018.03.20 | 63.8                   | 1.33                 | 38574                     | 207.14                    | 38.1              | 3.475                  |
| 4      | 2018.03.21 – 2018.07.08 | 63.8                   | 1.33                 | Shut down                 | 207.14                    | 38.1              | 3.475                  |
| 5      | 2018.07.09 – 2018.07.22 | 63.8                   | 1.33                 | Shut down                 | 132.87                    | 35.1              | 2.130                  |
| 6      | 2018.07.23 – 2019.03.01 | 64.2                   | 1.32                 | 6154.7                    | 73.02                     | 28.4              | 2.130                  |
| 7      | 2019.03.02 – 2019.07.07 | 64.3                   | 1.33                 | 20596                     | 111.56                    | 39.8              | 4.270                  |
| 8      | 2019.07.08 – 2019.09.13 | 56.5                   | 1.38                 | 29583                     | 100.51                    | 48.0              | 4.270                  |
| 9      | 2019.09.14 – 2019.09.23 | 55.9                   | 1.37                 | Shut down                 | Shut down                 | Shut down         | Shut down             |
| 10     | 2019.09.24 – 2020.05.16 | 55.9                   | 1.37                 | Shut down                 | Shut down                 | Shut down         | Shut down             |

*Data source: actual production data of submarine pipeline.
Figure 5. Gas flow velocity changes along the pipeline depending on the number of grids.

Figure 6. Temperature from OLGA results vs field condition data.

1.331–1.330 MPa (Figure 7), respectively. The pressure and temperature simulation results of the model are consistent with the actual situation, and can be used for the calculation and analysis of node parameters along the pipeline.

As follows from Figure 8, the fluid is characterized by the stratified flow (ID:1) and slug flow (ID:3) [35], occurring at 30 m of the pipeline. There are a certain amount of bubbles in the liquid phase of slug flow, which is easy to lead to the emergence and aggregation of bubbles in

Table 7. Calculation error of multiphase flow in OLGA software.

| Pipelinelength (m) | Temperature-OLGA (°C) | Temperature-Operating conditions (°C) | Error |
|--------------------|------------------------|--------------------------------------|-------|
| 0                  | 63.86                  | 65.16                                | 2.00% |
| 20                 | 61.87                  | 63.46                                | 2.50% |
| 41                 | 59.75                  | 61.25                                | 2.44% |
| 60                 | 57.91                  | 59.65                                | 2.92% |
| 75                 | 56.62                  | 58.15                                | 2.62% |

Figure 7. Temperature(TM) and pressure (PT) distribution along the pipeline.
Figure 8. Flow pattern (ID) and HOL (liquid holding rate) distribution along the pipeline.

Figure 9. Profile of different regions of a slug [37].

Figure 10. Liquid velocity (UL) and Gas velocity (UG) distribution along the pipeline.
the change of pipe flow direction and turbulence area [36]. With the emergence of slug flow, the gas flow rate increases significantly, leading to an increase in the liquid holding rate. At this time, more energy is required to push the liquid forward, which increases the static pressure loss in the pipeline. Accordingly, the pressure distribution diagram (Figure 8) reveals the large pressure drop gradient in the uphill section. However, due to the lower pipeline pressure and the smaller fluid flow, the pipeline pressure changes less. Figure 9 shows the profile of different regions of a slug. The slug is composed of liquid film, gas pocket, mixing zone, plug body and front. Firstly, waves are generated on the surface of the liquid film, which constantly fill the pipeline to accelerate the liquid. When the liquid plug flows forward, the liquid plug will exceed the liquid film at the front end and its propagation speed will increase. In this process, a gas–liquid mixing zone will be formed in front of the liquid plug, which will strongly scour the pipe wall, resulting in great shear force. At the same time, when the liquid inside the slug produces “cavitation”, the front of the slug will move above the pipe and absorb a large amount of gas, which makes the front of the slug form a highly turbulent area. In the turbulent region, liquid and gas will be continuously drawn into the slug and accelerated to the propagation speed of the slug. The rapid change of pressure and velocity in the mixing zone causes bubbles to generate from it and move to the bottom of the pipe, which has a strong impact on the bottom of the pipe wall and burst, and instantly produces high temperature and high pressure. At the same time, the liquid film adjacent to the bubble produces a great instantaneous shear force on the pipe wall. This comprehensive effect causes the corrosion inhibitor film of the pipeline to be torn, and the metal protective film may peel off and fail in a short time, resulting in sharp corrosion of the internal metal. Therefore, according to the results of flow pattern, corrosion is more likely to occur where slug flow exists.

The liquid velocity and gas velocity are found to be within the ranges of 0.05–1.15 m/s and 0.16–1.01 m/s (Figure 10), respectively. There is a steep slope at 8 m of the pipeline, and the liquid velocity of the pipeline increases from 1.1 to 1.9 m/s. At 15 m of the pipeline, the liquid flow rate dramatically fell, and the gas flow rate rapidly increased, which is testimony to the emergence of multiple bubbles caused by a slug flow. At 30 m of the pipeline, the liquid flow rate slightly rebounded, stabilizing at a low value, and the gas flow rate gently decreased after the slug flow ended [38].

4.2.3. Determination of corrosion sensitive area
Based on the multiphase flow simulation results and given the target pipeline CO₂ corrosion rate, the average corrosion rate of the pipeline was calculated, to predict the corrosion rate of each node. The results are shown in Figure 11. For this, the key monitoring points were determined according to criteria 1 and 2 of the internal corrosion evaluation method (see Table 8). According to the multiphase flow simulation results under various working conditions, the recommended focus area is 12–45 m, and the predicted corrosion rate is 0.080–0.253 mm/a.

4.2.4. Cumulative uniform wall thickness reduction
According to the division of time nodes of the evaluation pipeline and combined with the results of OLGA multiphase flow simulation, calculated the average corrosion thinning accumulation along the evaluation pipeline, as shown in equation (11).

$$t_{\text{loss total}} = \sum_{i=0}^{n} \frac{v_{\text{corr}_i} \times (t_{i+1} - t_i)}{365}$$

where $t_{\text{loss total}}$ is Cumulative wall thickness reduction, mm; $t_i$ is the $i$-th time node; $t_{i+1}$ is the $i+1$-th time node; $v_{\text{corr}_i}$ is the corrosion rate of the $i$-th time node.

Hence, the estimated loss uniform wall thickness of the pipeline from 2017 to 2020 is 5.0 mm ~ 7.0 mm, as shown in Figure 12.

4.3. Detailed examination
4.3.1. Basic situation of the detector
The pipeline was inspected with the In-line High Resolution Metal Loss Detection and Sizing (RoCorr MFL-
A). One (1) RoCor MFL-A run was performed during the inspection. The detection time is May 2020, the average running speed is about 0.53 m/s, and the maximum operating temperature during the running period is 28.2°C. Figure 13 is the operating speed, and Figure 14 is the magnetization level.

4.3.2. Basic situation of test data
A total of 14605 metal loss anomalies that exceeded the reporting threshold by 10% depth were detected in the pipeline. Most of these metal loss abnormalities are classified as internal corrosion, which is mainly detected at the bottom of the pipeline (between 5:00 and 7:00). Figure 15 shows the clock position of all metal corrosion defects. Figure 16 shows the depth distribution of metal corrosion defects. The depth percentage of corrosion defects is 30%–49%, distributed in 0–5 m, 15–20 m and 30–40 m of the pipeline. The maximum loss wall thickness is 7.007 mm. The internal detection results are consistent with the multiphase flow simulation results.

4.4. Post-assessment
Based on the collection and analysis of basic data of submarine pipeline, it is inferred that the internal corrosion type of pipeline is CO₂ slug flow corrosion, and the internal corrosion degree is extremely serious. Through multiphase flow simulation analysis, it is determined that the corrosion sensitive section in the submarine pipeline is 12–45 m and extremely severe corrosion. Based on the evaluation results of the detector, it is determined that the pipeline is extremely severe corrosion, and the corrosion areas are 0–5 m, 15–20 m and 30–40 m. Through this MP-ICDA inspection and evaluation, it is determined that the results of indirect evaluation and direct evaluation of seabed evaluation are consistent, indicating the effectiveness of this direct evaluation of internal corrosion.

4.4.1. Evaluation of residual strength prediction of pipeline
In this paper, the modified B31G evaluation method is used to evaluate the residual strength and predict the residual life of metal loss. In the evaluation, only the influence of internal pressure on the pipeline is considered, and the influence of other loads is not considered. The pressure determination diagram shows the relative severity of each internal corrosion defect. [39]. The estimated repair factor (ERF) is the ratio of the maximum allowable operating pressure (MAOP) of the pipeline to the safe operating pressure ($P_{SW}$) at the defect [40], as shown in equation (12)-(15).

\[
M = (1 + 0.8\frac{l}{n_{wt}})^{0.5}
\]

\[
SF = \frac{2n_{wt} SMYS}{P_i D}
\]

\[
P_{SW} = \left[ \frac{1 - 2l/3n_{wt}}{1 - (2l/3n_{wt})/M} \right] \cdot \frac{2n_{wt} \cdot (SMYS + 68.94)}{SF \cdot D}
\]

\[
ERF = \frac{MAOP}{P_{SW}}
\]

where $l$ is the axial length of internal corrosion defects, mm; $D$ is the outer diameter of the pipeline, mm, $D = 219.1$ mm; $n_{wt}$ the nominal wall thickness of the...
Figure 13. The operating speed.

Figure 14. The magnetization level.

pipeline, mm, \( n_{wt} = 14.3 \) mm; \( M \) is the Folias coefficient; MAOP is the maximum allowable operating pressure, MPa, MAOP = 2.0 MPa; SMYS is the rated minimum yield strength, MPa, SMYS = 450 MPa, \( P_{SW} \) is the residual strength of pipeline, MPa.

The higher the ERF value is, the higher the severity of the feature is, and the farther the feature point is from the curves [41]. The ERF distribution of the evaluation pipeline is shown in Figure 17. The number of pipelines evaluated is the largest at 5–15 m, which is why there is \( \text{CO}_2 \) slug flow in this area, resulting in serious pipeline corrosion.

4.4.2. Evaluate the prediction of pipeline remaining life and re-inspection period

According to MP-ICDA, the re-inspection period should be half of the remaining life. Combining with API 570 “Piping Inspection Code Inspection, Repair, Alteration and Rerating of In-Service Piping Systems [42]”, under the condition of no large fluctuation of pipeline transportation conditions (corrosive medium content, pressure and temperature), the remaining life of pipeline system is calculated as follows:

\[
R_L = \frac{t_{mm} - R_t \cdot t_{min}}{C_{cate}} \tag{16}
\]

where \( R_L \) is remaining life, a; \( C_{cate} \) is predict corrosion rate, mm/a; \( t_{mm} \) is measured average wall thickness of pipeline, mm; \( t_{min} \) is minimum required wall thickness of pipeline, mm; \( R_t \) is the residual wall thickness ratio can be obtained from the residual strength evaluation. When the straight pipe section is uniformly corroded, \( R_t \) is replaced by \( R_{SFa} \). When the straight pipe section is locally corroded, the calculation formula of \( R_t \) is as follows (17):

\[
R_t = \begin{cases} 
0.2 & 0.354 \leq \lambda \\
\left( R_{SFa} - \frac{R_{SFa}}{R_t} \right) \left( 1 - \frac{R_{SFa}}{R_t} \right)^{-1} & 0.354 \leq \lambda \leq 20 \\
0.9 & \lambda \geq 20 
\end{cases} \tag{17}
\]
Figure 15. The clock position of all metal corrosion defects.

Figure 16. The depth distribution of metal corrosion defects.

Figure 17. ERF distribution of all metal loss anomalies.
where $M_t$ is Fourier factor, $M_t = (1 + 0.48\lambda^2)^{0.5}$; $\lambda$ is shell parameters, $\lambda = 1.285s(D_i \times t_{\min})^{-0.5}$, if circumferential defects are evaluated, $c$ replaces $s$; $RSFa$ is the allowable residual strength factor; $D_i$ is the pipe inner diameter, mm; $s$ is the measured axial length of local metal loss, mm; $c$ is the measured circumferential length of local metal loss, mm.

Figure 18. The remaining life curve of the pipeline.

Based on the future service conditions, measured wall thickness and corrosion rate, the remaining life is calculated by wall thickness method, followed in Figure 18.

The effectiveness of internal corrosion direct assessment method depends on the correlation between the results of detailed detection and the results of corrosion prediction. The comparison of the data in Figure 17 show that the results of the internal corrosion prediction model are basically consistent with the results of the inspection in the riser, which is within the allowable error range specified in internal corrosion direct assessment standard. Therefore, the model is effective and the reliability of internal corrosion direct assessment is verified again. The corrosion degree of the submarine pipeline is extremely serious, so it is recommended to strengthen the evaluation frequency, and the reevaluation interval is five year.

5. Conclusion

In this paper, the internal corrosion assessment method for the mixed submarine pipeline is studied, and the following conclusions are drawn:

1. A set of methods for direct evaluation of corrosion in submarine pipelines containing CO₂ included such steps as feasibility assessment, corrosion severity evaluation, and determination of key monitoring points.
2. The flow model analysis results and elevation routing map are used to evaluate the potential risk points of each internal corrosion evaluation area.
3. Combined with the two criteria of key monitoring, it can play a reference role for the internal corrosion evaluation of similar pipelines.

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Data availability statement

All datasets underlying the conclusions of the paper should be available to readers. We deposit their datasets in publicly available repositories in the manuscript.

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