Prediction of corrosion life of nitrogen blanket casing in salt cavern gas storage

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Abstract
In this paper, to analyze the oxygen corrosion of the casing string under the nitrogen blanket condition of the salt cavern underground gas storage and to predict the casing’s service life, an indoor corrosion weight-loss experiment was used to study the effects of oxygen concentration, temperature, and pressure on the gas and liquid phase of N80 steel pipe corrosion laws. The corrosion products were examined using scanning electron microscopy, X-ray fluorescence spectroscopy, and X-ray diffraction analyses. Finally, the corrosion life of the casing was predicted based on the uniform corrosion rate and casing strength check. The results indicated the following: (1) under the experimental conditions, the gas-liquid two-phase corrosion rate gradually decreased with the increase in nitrogen concentration, while when the concentration was 78%–95%, the liquid-phase corrosion was serious, and in the liquid nitrogen environment (nitrogen concentration is 99.9%), the liquid-phase corrosion rate was lower than the oilfield corrosion control index (0.076 mm/a); (2) the temperature and pressure had no significant effect on the casing corrosion; (3) with the increase in nitrogen concentration, the service life of the inner and outer pipes under different working conditions gradually increased, with the minimum service life equaling 28 years when the concentration was 99.99%; (4) nitrogen concentrations of 99.99%, 95%, 90%, and 78% can meet the column strength of the 3-year cavity-building cycle, while under the 5-year cavity-building cycle, it is recommended that the lower limit of the purity is 90%. Overall, the research results will provide a strong information basis for the construction of salt cavern gas storage cavities.

KEYWORDS
blanket, life prediction, nitrogen, oxygen corrosion, residual strength, salt cavern gas storage

1 INTRODUCTION
Natural gas is a highly efficient and clean energy source, and its consumption proportion is increasing on a daily basis as the demand increases year on year.1,2 Due to the distance between the natural gas production areas and the consumption areas, as well as the uneven seasonal utilization, underground gas storage has emerged as an important means of natural gas peak shaving and strategic storage. Salt cavern gas storage involves an
underground facility that stores oil (gas) in a cavity formed following artificial salt melting and presents an energy infrastructure that integrates seasonal peak shaving, emergency gas supply in the case of accidents, and national energy strategic reservation due to its good sealing, low permeability and plastic deformation, and strong automatic healing capabilities.\textsuperscript{3-7} The world's first salt cavern gas storage was built in Michigan, the United States, in 1961, and the United States, Canada, Armenia, and various other countries have subsequently built salt cavern underground gas storage sites. In fact, from the 1970s onwards, the rapid development of natural gas utilization has resulted in the rapid development of salt cavern underground gas storage construction.\textsuperscript{8}

In terms of the construction of salt cavern gas storage facilities in China, diesel has been used as a blanket to control the shape of the cavity; however, its cost is high and it creates pollution issues for the environment. To resolve this issue, in the 1990s, the United States, Canada, Germany, and other countries began to investigate a cavity-making process using gas as a blanket. Here, Canada carried out related research on the use of nitrogen as a protective layer material, with the use of this gas subsequently promoted,\textsuperscript{9} while Germany successfully used nitrogen as a blanket to build a cavity in the Neuheuntorf NKIII salt cavern gas storage, with an average consumption of 0.4 m\textsuperscript{3}/m\textsuperscript{3} of the cavity.\textsuperscript{10} Germany used air as the blanket to carry out experiments in the Stabfurt salt cavern gas storage and conducted research on casing corrosion.\textsuperscript{11} Elsewhere, the United States carried out research on the cavity-making process of natural gas blanket and redissolving, with the MOSS Bluff salt cavern storage facility using this technology experiencing a blowout in the cavity-creation process, which led to a large fire.\textsuperscript{12} Meanwhile, China's research on cavity building in nitrogen environments began relatively late. On August 15, 2018, China's first salt cavern nitrogen barrier cavity-building test returned successful results. During the test, the on-site monitoring of all the key cavity-building parameters returned normal results, with the nitrogen–brine interface control, cavity shape development, and so forth all meeting the design requirements.\textsuperscript{13} Dong et al.\textsuperscript{14} established a preliminary calculation model of the gas–liquid interface depth with nitrogen as a protective layer material and devised a wellhead calculation model when the gas–water interface in the cavity is stable. The calculation results show that nitrogen can greatly reduce the cost of building gas storage. Elsewhere, Kang\textsuperscript{15} compared the advantages and disadvantages of using nitrogen as an inhibitor in foreign countries and domestic use of diesel as an inhibitor in terms of technology and economy, while Kang et al.\textsuperscript{16} established a nitrogen injection rate calculation formula for the gas–liquid interface in the open hole and the cavity roof in the process of cavity making.

Downhole, various factors can cause pipe string corrosion, the first of which relates to the wellbore temperature changes. Here, Li et al.\textsuperscript{17} used high-temperature autoclaves to simulate the production environment of high CO\textsubscript{2} partial pressure and high salinity in oilfields for corrosion tests and analyzed the corrosion rates of N80, P110, and 32CrMo sheets of steel under different temperature conditions. Elsewhere, Fan and Zhou\textsuperscript{18} used simulated formation water as the experimental medium and a high-temperature and high-pressure dynamic kettle to conduct H\textsubscript{2}S/CO\textsubscript{2} corrosion experiments on T95 casing steel to explore the effect of H\textsubscript{2}S/CO\textsubscript{2} corrosion product film on the T95 corrosion behavior at different temperatures.

The second factor relates to the wellbore pressure changes. Here, Xu et al.\textsuperscript{19} simulated actual produced water, temperature, and pressure to investigate the corrosion laws of N80 and P110 casings using experiments, such as CO\textsubscript{2} partial pressure experiments. Meanwhile, the third factor relates to the difference in the material of the pipe string,\textsuperscript{12,14} while the fourth relates to the oxygen content. Here, the wall thickness of the corroded pipe string will be thinner, and its bearing capacity will be reduced; there may even be the risk of pipe string breakage and tubing and casing string collapse.\textsuperscript{20-22}

At present, domestic research on oxygen corrosion has made some progress. Li et al.\textsuperscript{22} studied the corrosion of high-temperature and high-pressure steam on a string of thermal recovery wells under different working conditions and found that the most effective way to control high-temperature corrosion is to control the water content and oxygen content. Elsewhere, Li\textsuperscript{23} studied the oxygen corrosion law and protection of downhole tubing strings during air injection, with the results indicating that the higher the oxygen partial pressure, the more obvious the corrosion rate increase of N80 tubing and casing strings. Clearly, the oxygen content is an important factor in the corrosion of downhole tubing strings.

However, the above studies did not consider the corrosion and wear of the pipe column under the condition of salt cavern gas storage as a barrier solvent, and the current research on this aspect is lacking. In view of this, we selected the N80 steel test piece as the experimental sample to conduct simulation-based research on the corrosion of the pipe string under different nitrogen purity conditions to clarify the corrosion law of the N80 steel test sheet and evaluate the service life of the downhole pipe string based on the experimental results to provide data support for the later
development of nitrogen-gas-resistant safe and stable salt cavern gas storage operations.

2 | EXPERIMENTAL SECTION

2.1 | Experiment preparation and equipment

The experimental material was selected from the N80 casing pipe of the nitrogenblanket used in Jiangsu Oilfield. A number of samples were taken from the pipe material, and the chemical composition and relative content of the sample were determined using a direct-reading spectrometer and an infrared carbon–sulfur analyzer, with the results shown in Table 1. The metal test piece was processed into a rectangular parallelepiped measuring 40 × 10 × 3 mm, with a small circular hole with a diameter of 3 mm drilled above the test piece for its installation. The test piece was connected by bolts and fixed on the upper and lower parts of the rotating rod of the kettle body, with the upper part used for gas-phase corrosion and the lower part used for liquid-phase corrosion. A schematic of the corrosion test piece is shown in Figure 1.

The corrosive medium was simulated formation water and nitrogen gas with different purities, while the simulated formation water formula was 29.7% NaCl + 0.905% Na2SO4 + 0.069% CaCl2 + 0.002% MgCl2, and the cleaning solution formula was 10 g of hexamethylenetetramine + 100 ml of hydrochloric acid + deionized water (up to 1 L).

Meanwhile, the main experimental equipment included the following: a GSH-1/10-type strong magnetic stirring high-temperature and high-pressure reactor, a JD210-4P-type electronic balance (precision 0.1 mg), a YBS002B-type electronic Vernier-caliper, an oxygen cylinder, a nitrogen cylinder, and an 866A-type digital display electric heating constant temperature blast drying box.

2.2 | Experimental method

The main experimental steps were as follows:

1. The test piece was ground to a mirror-like surface step by step using 180#, 320#, 600#, and 1000# metallographic sandpaper before the size of the test piece was measured with a Vernier-caliper, conducting the measurement three times, taking the average value, and recording the data.
2. The test piece was wiped with a cotton ball soaked in absolute ethanol before being dried and placed in a desiccator and subsequently weighed to a constant weight using an electronic balance, with the relevant data recorded.
3. Under the experimental conditions, the test piece was hung in the gas-phase and liquid-phase corrosion media before being taken out following a 5-day (120-h) corrosion reaction.
4. After rinsing with tap water, the piece was placed in the cleaning solution and soaked for 3–5 min before being rinsed with tap water again until the surface of the test piece was as smooth as before and then dried with a cloth strip.
5. The test piece was again wiped with a cotton ball soaked in absolute ethanol before being dried and placed in a desiccator and subsequently weighed to a constant weight using an electronic balance, with the relevant data recorded.
6. The annual corrosion rate was calculated according to the quality difference before and after the corrosion of the test piece using the following formula:

\[ V_a = C \times \frac{\Delta m}{\rho \times A \times \Delta t}, \]

where \( V_a \) is the annual corrosion rate (mm/a), \( C \) is the conversion factor (365 days/year), its value is 8.76 × 10^4, \( \Delta m \) is the quality difference before and after corrosion of the test piece (g), \( \rho \) is the metal test density of the piece (g/cm^3; here: 7.85 g/cm^3) (accounted for), \( A \) is the surface area of the metal test piece (cm^2), and \( \Delta t \) is the corrosion time (h).
7. Simultaneous testing of gas-phase and liquid-phase corrosion rates in each set of experiments. The gas-phase and liquid-phase corrosion test pieces are both

| Chemical composition | C   | Si  | Mn  | P   | S   | Cr  | Mo  | Ni  | V   | Ti  | Cu  |
|----------------------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| (wt%)                | 0.41| 0.31| 1.44| 0.012| 0.004| 0.05| 0.18| 0.028| 0.017| 0.011| 0.010|

FIGURE 1 Schematic of the corrosion sample
three pieces, and the average value of the three corrosion rates is taken as the respective experimental results.

3 | RESULTS AND DISCUSSION

3.1 | Corrosion rate

3.1.1 | Influence of nitrogen concentration on corrosion rate

To simulate the corrosion rate of the test piece under the harshest temperature and pressure conditions, the total pressure was determined to be 14 MPa and the temperature 40°C. When the formation water salinity was 306,760 mg/L, the rotation speed was 120 r/min, the corrosion time 120 h, and the nitrogen concentration was 99.9%, 95%, 90%, and 78% to observe the N80 steel test piece in the liquid- and gas-phase environments in relation to the corrosion morphology and the change in corrosion rate. The macroscopic corrosion morphology of the test piece is shown in Figures 2 and 3, while the trend of the corrosion rate change is shown in Figure 4.

As Figure 2 shows, in the liquid environment, the surface of the test piece was covered by a dense brown-red corrosion product after the 120 h corrosion reaction, while the nitrogen concentration was 78% (simulating air injection) and the surface of the test piece was uneven. Furthermore, there was an exposed matrix and the test piece was corroded the most severely, while when the nitrogen concentration was 99.9%, the surface of the test piece was not seriously corroded, the surface relatively was flat, and no red corrosion products appeared.

From the corrosion morphology of the N80 steel test piece under different working conditions in the gas-phase environment (Figure 3), it was clear that, under all working conditions, the N80 steel test piece was slightly corroded in the gas-phase environment. When the nitrogen concentration was 95%, very few red corrosion products were formed on the surface of the test piece, while at concentrations of 78% and 90%, slight pitting marks appeared on the surface of the test piece, resulting in spot-like red-brown corrosion products. Finally, when the nitrogen concentration was 99.9%, there was almost no sign of corrosion on the film.

As shown in Figure 4, under the experimental conditions, the uniform corrosion rate of the test piece in the gas-phase environment was lower than the uniform corrosion rate in the liquid-phase environment, while both were lower than the oilfield corrosion control index of 0.076 mm/a. When the nitrogen concentration was 78%, the vapor-phase corrosion rate of the test piece reached the maximum value of 0.0176 mm/a, while as the nitrogen concentration was increased, the oxygen content in the nitrogen gradually decreased, as did the vapor-phase corrosion rate. Meanwhile, when the nitrogen concentration reached 95%, the corrosion rate was only 0.0165 mm/a, far lower than the oilfield corrosion control standard value of 0.076 mm/a, meaning the nitrogen concentration had little effect on the gas-phase
corrosion rate. When the nitrogen concentration was 78% and 90%, the liquid-phase corrosion was severe, reaching 1.3629 mm/a at 78%, while with the increase in nitrogen concentration, the liquid-phase corrosion rate gradually decreased. Finally, when the nitrogen concentration was 95% and 99.9%, the corrosion rate was 0.6059 and 0.6059 mm/a.

3.1.2 Influence of temperature on corrosion rate

When the total pressure was 10 MPa, the nitrogen concentration was 78% (the oxygen partial pressure is 3.08 MPa), the formation water salinity was 306,760 mg/L, and the rotation speed was 120 r/min, while the temperature was set to 40°C, 30°C, and 20°C. In this condition, corrosion reaction 120 h, test the corrosion rate of the N80 steel test piece in the formation, and observe the corrosion of the N80 steel test piece in the liquid and gas phase environment, and the trend of the corrosion rate. The macroscopic corrosion morphology of the test piece is shown in Figures 5 and 6, while the relationship between temperature and corrosion rate is shown in Figure 7.

As Figure 5 shows, in the liquid-phase environment under different temperature conditions, the surface of the test piece had an uneven appearance following the corrosion reaction and was covered by a layer of a dense granular brown-red corrosion product. Here, the corrosion was more serious, and the higher the temperature, the larger the area covered by the corrosion product on the surface of the piece. In fact, when the temperature reached 40°C, the surface of the test piece was almost completely covered.

In the gas-phase environment, the macroscopic corrosion morphology of the N80 steel test piece under different working conditions (Figure 6) revealed that when the temperature was 30°C and 20°C, the surface of the test piece exhibited almost no corrosion marks, with its quality and surface gloss similar to before the reaction. However, when the temperature was increased to 40°C, mesa-like corrosion appeared on the surface of the test piece, while the corrosion marks were slight.

As shown in Figure 7, overall, the corrosion rates of the liquid phase and the gas phase both exhibited an upward trend with the increase in temperature. In the gas-phase environment, the corrosion rate of the N80 steel test piece was lower than that in the liquid-phase environment. When the maximum temperature of the experiment condition reached 40°C, the corrosion rate was only 0.0089 mm/a, much lower than the standard value of oilfield corrosion prevention and control (0.076 mm/a). Meanwhile, the corrosion of the test piece in the liquid-phase environment was more serious, where when the temperature was increased to 20°C, 30°C, and 40°C successively, the corrosion rate was 0.4393, 0.4736, and 0.4829 mm/a, respectively. Overall,
the fluctuation in corrosion rate was small, indicating that the temperature had a weak influence on the corrosion rate.

3.1.3 Influence of pressure on corrosion rate

The high-temperature and high-pressure reactors were used to evaluate the influence of pressure on the corrosion rate at a temperature of 40°C, a nitrogen concentration of 78% (oxygen partial pressure of 3.08 MPa), and pressures of 10, 12, 13, and 14 MPa, with the N80 steel specimens tested within a simulated nitrogen-dissolution-resistant working environment. The macroscopic corrosion morphology of the test piece is shown in Figure 8, while the relationship between pressure and corrosion rate is shown in Figure 9. From the results, it could be inferred that the gas-phase corrosion rate of the N80 steel test piece was extremely low; in fact, even when the simulated air was injected, the gas-phase corrosion rate of the test piece was still lower than 0.076 mm/a. Therefore, in the evaluation of the influence of pressure on the corrosion rate, only the corrosion rate of the test piece in the liquid phase was considered.

As Figure 8 shows, the test piece was corroded in the liquid-phase environment, with a layer of brown-red corrosion products formed on the surface, while as the pressure was increased, the corrosion products proliferated and the product density increased. When the pressure was 10 MPa, the surface of the test piece contained local corrosion products (i.e., local corrosion), while when the pressure was increased to 14 MPa, the surface of the test piece was completely wrapped by the corrosion products and the surface was uneven.

As shown in Figure 9, with the increase in pressure, the corrosion rate of the test piece increased from 0.5442 to 0.6059 mm/a, an increase of 0.0617 mm/a, while the corrosion rate fluctuated only slightly, indicating that the temperature had little effect on the corrosion rate.

3.2 Corrosion products and morphology analysis

3.2.1 Physical analysis of corrosion products

After the experiment, the water in the high-temperature and high-pressure reaction kettle was poured out (see Figure 10B). Compared with the simulated formation water just prepared (see Figure 10A), the color of the water body after the corrosion experiment was dark yellow. Granular substances were suspended in the water; after standing for 4 h, the suspended substances settled at the bottom of the beaker and turned yellowish-brown. It was confirmed that a large amount of iron-containing substances existed in the corrosion products, which was consistent with the X-ray characterization results.

3.2.2 Scanning electron microscopy (SEM), X-ray fluorescence (XRF) spectroscopy, and X-ray diffraction (XRD) analyses

The results of the SEM morphology analysis and the XRF spectroscopy and XRD characterization analysis of the liquid-phase corrosion products are shown in Figure 11. Here, as shown in Figure 11A,B, a large number of dense
flake corrosion products appeared on the surface of the test piece, while, as Figure 11C,D shows, the content of oxygen in the corrosion product was relatively high, which was mainly iron oxide and a small amount of calcium salt. At the same time, the partial pressure of the oxygen was 3.08 MPa (the nitrogen concentration is 78% and the total pressure is 14 MPa), and it is believed that the corrosion products of this system were mainly Fe₂O₃ and FeO(OH).

4 | EVALUATION OF THE SAFE SERVICE LIFE OF DOWNHOLE PIPE STRINGS

Corrosion will thin the wall thickness of the pipe string and reduce its strength, and when the strength drops below a safe value, the risk of failure and collapse of the pipe string will increase and its safe service life will be reduced. On the basis of the corrosion test results under the simulation conditions described in the previous sections, combined with the downhole casing data of the gas storage in Jiangsu Oilfield (see Table 2 for casing data) while referring to API 5C3-2018, Calculating Performance Properties of Pipe Used as Casing or Tubing, we conducted a uniform corrosion strength test for safe service life assessment.

Depending on the water injection method and the direction of water flow in the salt cavern, the cavity-creation process can be divided into positive circulation cavity creation and reverse circulation cavity creation (see Figure 12). Here, positive circulation cavity creation involves the injection of freshwater from the central casing, with the water flowing upward from the bottom of the cavity and the brine discharged from the cavity through the middle casing, while the cavity is discharged through the central casing.

FIGURE 10 Comparison of water color before and after liquid-phase corrosion of N80 steel. (A) Simulated formation water, (B) after corrosion, and (C) stand for 4 h.

(A) (B) (C)

FIGURE 11 Microscopic morphology of the corrosion products on the N80 steel under a 95% nitrogen concentration liquid environment. (A) SEM analysis (100x), (B) SEM analysis (1000x), (C) XRF analysis of corrosion products, and (D) XRD analysis of corrosion products. SEM, scanning electron microscopy; XRD, X-ray diffraction; XRF, X-ray fluorescence.
When the cavity-making system performs the forward and reverse circulation processes, the force of the inner and outer casings will be different, that is, during the entire cavity-making cycle of the gas storage, the inner casing exerts a certain axial tension on itself due to the action of gravity. Since the outer pipe and the production casing are cemented, the tensile condition does not apply for the outer pipe, while when the cavity is being circulated, the inner and outer pipes are affected by internal pressure. At this point, both require some consideration of the safety factor related to the internal pressure. In terms of life evaluation, when the cavity is reverse-circulated, the inner casing is squeezed by brine, and the life evaluation of the residual antiextrusion safety factor must be considered. Meanwhile, the outer casing is subjected to internal pressure, and the life evaluation of the residual internal pressure safety factor must be considered.

4.1 | Life assessment when considering the residual tensile safety factor

The residual tensile safety factor reflects the ratio of the residual tensile load to the tensile load during the service life of the casing. The residual tensile strength and safety factor under different working conditions were calculated based on the experimental data and the parameters of the pipe string, with the relationship between the residual tensile safety factor and the service life determined (Figure 13).

As Figure 13 shows, the tensile safety factor decreased as the service life increased. The higher the injected nitrogen concentration, the slower the downward trend of the pipe string tensile safety factor with the service life increase and the longer the safe service life of the casing. According to the aforementioned standards, the residual tensile safety factor threshold of the casing during service is 1.6. Taking the current world salt cavern gas storage cavity construction cycle of 3 and 5 years as the life evaluation standard, it can be stated that nitrogen concentrations of 90%, 95%, and 99.99% can meet the 5-year cavity-building cycle, while the service life with a nitrogen concentration of 78% is 3.98 years, which does not meet the 5-year cavity-building cycle standard.

4.2 | Life assessment when considering the residual internal pressure safety factor

4.2.1 | Positive circulation

When creating a cavity in a positive cycle, the inner casing is subjected to internal pressure. Here, the

| Table 2: String parameters | Outer pipe (intermediate pipe) | Inner pipe (central pipe) |
|---------------------------|-------------------------------|--------------------------|
| Outer diameter (mm)       | 177.8                         | 144.3                    |
| Nominal wall thickness (mm) | 9.19                          | 6.88                     |
| Steel grade               | N80                           |                           |
| Density of brine outside the inner pipe (g/cm³) | 1                               |
| Density of clean water inside the inner pipe (g/cm³) | 1.3                             |
| Maximum working pressure of wellhead (MPa) | 1100                           | 7                         |
residual internal pressure and the attendant safety factor under different working conditions were calculated using the basic data processing of the inner casing, and the internal pressure safety factor and the service life were determined. The residual internal pressure safety factor reflects the ratio of the residual internal pressure to the effective internal pressure of the wellhead section during the service life of the casing. The relationship between the internal pressure safety factor of the positive circulation inner casing and the service time is shown in Figure 14.

As Figure 14 shows, the overall internal pressure safety factor of the inner casing decreased with the increase in service time, while the higher the concentration of injected nitrogen, the slower the downward trend. During the service period of the casing, the residual anti-internal pressure safety factor threshold was 1.2. Meanwhile, under the different nitrogen concentration conditions, only the concentrations of 90%, 95%, and 99.99% met the 5-year cavity-building cycle standard. In terms of the nitrogen concentration of 78%, when the residual internal pressure safety factor reached 1.2, the service life was only 4.27 years, which does not meet the 5-year cavity-building cycle standard.

As shown in Figure 15, the initial value of the safety factor of the outer pipe in relation to the internal pressure was 4.2, which was lower than that of the inner pipe, while the changing trend of the safety factor was also slower. The internal pressure safety factor of the
inner casing decreased with the increase in service time, while the higher the concentration of injected nitrogen, the slower the downward trend. During the service period of the casing, the residual anti-internal pressure safety factor threshold was 1.2. Meanwhile, when the nitrogen concentration was 90%, 95%, and 99.99%, the 5-year cavity-building cycle standard was met, while when the nitrogen concentration was 78% and the pressure safety factor reached 1.2, the service life was only 4.78 years, which does not meet the 5-year cavity-building cycle standard.

4.2.2 | Reverse cycle

When creating a cavity via reverse circulation, the internal pressure must be considered in terms of the outer casing. Here, the remaining internal pressure resistance and the attendant safety factor under different working conditions were calculated using the basic data processing of the outer casing, with the relationship between the internal pressure safety factor and the service life determined. The results are shown in Figure 16.

On the basis of the internal pressure safety coefficient curve of the outer casing, the safety coefficient of the internal pressure resistance strength of the outer casing decreased with the increase in service life during the reverse cycle. Under all experimental conditions, the outer casing could meet the requirements of the 5-year standard. Here, when the nitrogen concentration was 78%, the internal pressure safety factor of the outer casing was 1.31, which is close to 1.2, indicating that the impact of the internal pressure on the outer casing under reverse circulation was smaller than that when under positive circulation.

4.3 | Life assessment considering the residual extrusion safety factor

When the cavity is built via reverse circulation, only the squeezing strength has to be considered in terms of the
inner casing. Here, we calculated the residual collapse strength and safety factor of the inner pipe under different working conditions and determined the relationship between the extrusion safety factor and the service life, with the results shown in Figure 17. The residual antiextrusion safety factor reflects the ratio of the residual collapse strength to the effective external pressure during the service life of the casing.

On the basis of the antiextrusion safety factor curve of the inner casing, it was clear that during reverse circulation, the inner casing’s extrusion safety factor decreased with the increase in service life. Here, when the nitrogen concentration was lower than 99.99%, the curve was steep, while when the nitrogen concentration was 78% and the outer casing met the antiextrusion safety factor of 1.2, the service life was 4.24 years, which does not meet the 5-year cavity-building cycle standard.

4.4 Comparison of corrosion life of inner and outer casing under different working conditions

We compared the service life of the inner casing under different working conditions while considering the tensile strength, the internal pressure, and the antiextrusion safety factors, as shown in Figure 18.

By the picture above known, comprehensive consideration of the life prediction results in the antiextrusion safety factor, internal pressure safety factor, and antiextrusion safety factor. When the nitrogen concentration was 78%, the service life of the inner casing under the three working conditions was less than 5 years (4.8, 4.8, and 4.7 years, respectively), while with the increase in nitrogen concentration, the service life gradually increased. Here, the life of the inner casing with the tensile safety factor exhibited the fastest increasing trend, while the life of the inner casing with the antiextrusion safety factor increased the slowest. In fact, the predicted life of the inner casing when considering the antiextrusion safety factor was the shortest at 28 years, which was slightly shorter than the predicted life when considering the tensile safety factor and the internal pressure safety factor (30 years). At this point, cracks will likely appear on the inner casing. When the nitrogen concentration was increased to 99.99%, the safe service life of the inner pipe under the three working conditions was more than 28 years, while, here, only uniform corrosion was considered.

When considering the safety factor of anti-internal pressure under different working conditions, the service life of the outer pipe presented a positive and reverse cycle, as shown in Figure 19.

By the picture above known, comprehensive consideration of the life prediction results in the anti-internal pressure safety factor of the outer casing forward circulation and reverse circulation. When the nitrogen concentration was 78%, the service life of the outer casing in the forward circulation and reverse circulation operations was 6.8 and 6.6 years, respectively, with both clearly fewer than 7 years. With the increase in injected nitrogen concentration, the service life of the outer casing gradually increased, and when the nitrogen concentration was within the range of 78%–95%, the life expectancy of the positive cycle increased more steeply.
During the reverse cycle, the predicted life of the outer casing was slightly shorter than the predicted life in the positive cycle, with the outer casing potentially rupturing first during the former. When the nitrogen concentration was increased to 99.99%, the safe service life of the outer casing under the forward and reverse cycle operations was over 30 years in both cases (only uniform corrosion was considered).

5 | CONCLUSIONS AND RECOMMENDATIONS

On the basis of the experimental results, the following conclusions could be drawn:

1. When the total pressure was 14 MPa and the temperature was 40°C, the liquid-phase corrosion rate gradually decreased with the increase in nitrogen concentration. When the nitrogen concentration was within the range of 78%–95%, the liquid-phase corrosion of the steel test piece was serious, indicating that attention must be paid to the anticorrosion of the pipe under such conditions. Meanwhile, in the liquid nitrogen environment (nitrogen concentration = 99.9%), the liquid-phase corrosion rate of the N80 steel test piece was lower than 0.076 mm/a, and the corrosion effect of the pipe was negligible. Under the experimental conditions, the uniform corrosion rate of the N80 steel specimens in the gas-phase environment was less than that in the liquid environment, while both were less than the oilfield corrosion control index of 0.076 mm/a. Here, the main corrosion products were Fe₂O₃ and FeO(OH).

2. The influence of temperature and pressure on the casing corrosion is not significant. In the liquid-phase environment, when the temperature was increased to 20°C, the corrosion rate only increased to 0.0436 mm/a, while when the pressure was increased to 14 MPa, the corrosion rate increased to 0.0617 mm/a. Meanwhile, in the gas-phase environment, the corrosion rate was only 0.0089 mm/a, far lower than the oilfield corrosion prevention and control standard value of 0.076 mm/a, meaning the influence of temperature and pressure on the gas-phase corrosion rate can be ignored.

3. The safe service life of the outer pipe is longer than that of the inner pipe. Here, under a nitrogen concentration of 78%, the service life of the inner pipe, when considering the tensile strength, internal pressure, and antixtrusion safety factors, was fewer than 5 years, while the outer pipe was deemed to resist the internal pressure. The service life of the safety factor was more than 6.5 years, while with the increase in nitrogen concentration, the service life of the inner and the outer casings under different working conditions gradually increased.

4. In the process of on-site nitrogen-gas-barrier-cavity building, nitrogen concentrations of 99.99%, 95%, 90%, and 78% allow for meeting the 3-year cavity-building cycle standard for the string strength. Meanwhile, in terms of the 5-year cavity-building cycle standards, when the nitrogen concentration was 78%, the safety factors of tensile resistance, internal pressure resistance, and collapse resistance were all less than the threshold values of 1.6, 1.2, and 1.2, respectively, meaning the pipe string will be prone to safety hazards. Therefore, it is recommended that a nitrogen concentration of 90% is selected as the lower limit of the nitrogen concentration to meet the 5-year cavity-building cycle requirements.

AUTHOR CONTRIBUTIONS
Liping Wan: Formal analysis and writing—original draft. Bohui Wang: Writing—review and editing, and data curation. Meng Xie: Supervision and project administration. Cheng Hu: Software. Yunfei Wen: Investigation resources.

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