Mixed scaling control technology of produced water in different layers of the Dingbian oil production plant

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Abstract. Water injection is a common method for enhancing oil recovery in oilfield production processes. However, in the process of water injection development, the incompatibility between injected and formation water can easily cause formation pores and wellbore scaling problems, which compromise the oilfield production process. Considering a scaling well area in northern Shaanxi as example, scaling mechanism analysis and scale inhibition technology research were performed. The scale samples were subjected to water quality testing by total ion analysis and static compatibility experiment, in addition to scaling trend prediction and X-ray diffraction analysis. The calcium carbonate scale was found to be the main scale in this region and the main reasons for scale formation were: high content of CO3²⁻ and HCO3⁻ in reinjection wastewater, high content of Ca²⁺ and Mg²⁺ in the produced water of the oil well, and poor compatibility between the formation water and reinjection wastewater. The formation of calcium carbonate scale was prevented by chemical scale inhibitor compounding and good chelation. Hence, the screened inhibitor showed good scale inhibitory effect and can provided technical support for the water injection process.

Key words: Compatibility; Structural prediction Scale inhibition; Compound.

1. Introduction

For low-permeability reservoir development, water injection has become an important method to maintain the formation pressure [1,2]. In the process of oilfield development, the produced sewage in some blocks cannot meet the injection amount required for water injection and oil production; therefore, the process of mixed injection of source water and sewage, and mixed combination of produced water in different zones in some blocks has emerged [3-5]. However, in the water injection development process, owing to the incompatibility between injection and formation water, formation pores and wellbore scaling frequently occur [6-8]. Formation of scale blocks the pore throats and reduces the reservoir permeability, which increases the seepage resistance and operating pressure of the pump. If the scaling problem in the process of water injection is not addressed, it may hamper the oilfield
production. Therefore, the mixed scaling problem of produced water from different layers has gradually attracted more attention. In this study, the compatibility of mixed produced water of different layers in the Dingbian oil production plant of Yanchang Petroleum Company was evaluated to understand the cause and mechanism of incompatibility of water injection in this oil field. Moreover, an improved scale inhibitor, suitable for managing the water compatibility in the Dingbian oil field, was screened to resolve water injection incompatibility.

Herein, 6334 and 5423 water injection stations of the Xin'anbian and Jiyuan oil production teams, respectively, two typical scaling blocks in the Dingbian oil production plant of Yanchang Petroleum, were selected to conduct a comprehensive investigation. The composition and indexes of the blocks with prominent compatibility contradictions were systematically analyzed according to the SY/T5392-2012 Recommended Indexes and Analysis Methods for Clastic Reservoir Water Quality \[9\], and the compatibility was explored based on water type analysis. Subsequently, static test evaluation was performed to record the appearance and structure of the water samples that were mixed in different proportions with the produced water, source water, and water samples for the mixing compatibility of the produced water in different formations after being placed under the condition of simulated formation temperature for 20 days to obtain the static compatibility evaluation results. In combination with different approaches, such as the saturation index prediction method, stability index prediction method, and other methods, as well as the collection of scaling sample composition analysis, the scaling trend can be accurately predicted \[10-12\].

2. Materials and Methods

2.1. Materials
The 6334 water injection station of the Xin'anbian oil production team of Yanchang Petroleum Dingbian oil production plant, comprising 6334: sewage, 6334:6107-3 (Chang layer 10), 6160: sewage, 6160:6385-10 (Yan 9), along with the 5423 water injection station of the Jiyuan oil production team, comprising 5423: water source wells, 5423: sewage, 5423:5433-1(Chang layer 2), were evaluated.

2.2. Instruments
The main instruments used in this study were an electric blast drying oven, a circulating water multipurpose vacuum pump, an ultraviolet spectrophotometer, an ion chromatograph, and an X-ray diffractometer.

The reagents used in this experiment were BaCl$_2$, HCl, phenolphthalein, methyl orange, o-phenanthroline, hydroxylamine hydrochloride, calcium standard solution, and magnesium standard solution.

2.3. Methods
2.3.1. Titration experiment. A certain amount of evenly mixed water sample was tested, added an appropriate amount of indicator, and titrated until the solution changed color. Each group was assayed in triplicate and the error was controlled within 0.04 mL.

2.3.2. $\text{Fe}^{2+}$ and $\text{Fe}^{3+}$ determination. A certain amount of evenly mixed water sample was tested. HCl (1+1), hydroxylamine hydrochloride solution, and Congo red test paper and saturated sodium acetate were added until the test paper turned red. Then, buffer and o-phenanthroline were added, and the mixture was allowed to stand for 15 min followed by the measurement of absorbance at 510 nm.

2.3.3. $\text{SO}_4^{2-}$ determination. A certain amount of evenly mixed water sample was tested, and 1+1 HCl was added. The pH was adjusted to 2–3, and the solution was heated and boiled. BaCl$_2$ was added and the mixture was boiled again for 3–5 min, allowed to cool at 25 °C, filtered, dried at 45 °C, and weighed.
2.3.4. Ion chromatography experiment. Mixed water (1 mL) was diluted with ultrapure water for a certain number of times. The sample was loaded with the sample, and the ion content was determined by ion chromatography.

2.3.5. Compatibility experiment. The two water samples were evenly mixed according to a certain proportion, sealed with a sterile sealing film, and dried in an oven for 3 days. The temperature of the drying oven was consistent with the corresponding stratum of the water sample. Afterwards, the water sample was removed, the scaling amount was measured by the gravimetric method, and other water sample indexes were measured by the methods mentioned above. The scale was determined by X-ray diffractometry.

2.3.6. Scale inhibition experiment. The two water samples were evenly mixed according to a certain proportion and the corresponding scale inhibitor was added. The mixture was sealed with a sterile sealing film, and dried in an oven for 3 days. The temperature of the drying oven was consistent with the corresponding stratum of the water sample. Afterwards, the water sample was removed, the scaling amount was measured by the gravimetric method, and other water sample indexes were detected by the abovementioned methods.

3. Results and discussion

3.1. Analysis of water sample ions and sewage water quality indexes
According to SY/T5392-2012 "Recommended Indexes and Analysis Methods for Clastic Reservoir Water Quality," the qualitative and quantitative analysis of the water samples from typical blocks from the Dingbian Oil Production Plant of Yanchang Petroleum was conducted. Water ions, including Ca$^{2+}$, Mg$^{2+}$, Ba$^{2+}$, Sr$^{2+}$, Cl$^{-}$, SO$_4^{2-}$, CO$_3^{2-}$, HCO$_3^{-}$, Fe$^{3+}$, Fe$^{2+}$, S$^{2-}$, along with some necessary indicators of water injection, were analyzed. Owing to the serious emulsification of oil and water in some formation water, simple demulsification treatments, such as heating, should be performed to separate oil and water. Table 1 shows the total ion analysis of the produced water and injected sewage in different layers of the Xinanbian and Jiyuan oil production teams.

| Name                  | Ion content (mg/L) |
|-----------------------|--------------------|
|                       | SO$_4^{2-}$ | CO$_3^{2-}$ | HCO$_3^{-}$ | Ca$^{2+}$ | Mg$^{2+}$ | S$^{2-}$ | Fe$^{3+}$ | Fe$^{2+}$ | Cl$^{-}$ | Ba$^{2+}$ | Sr$^{2+}$ |
| 6334: sewage          | 1435.56    | 444.07     | 2010.61    | 42.48     | 11.99     | 6.44     | 0.53      | 0.38      | 134.82   | 0.00      | 0.00      |
| 6334: 6107-3 (Chang layer 10) | 173.68    | 81.01      | 192.21     | 300.80    | 10.45     | 0.00     | 0.07      | 0.06      | 189.54   | 0.00      | 0.00      |
| 6160: sewage          | 1638.05    | 402.07     | 2279.1     | 64.13     | 26.38     | 0.64     | 0.54      | 0.69      | 251.53   | 0.00      | 0.00      |
| 6160:6385-10 (Yan 9)  | 2825.84    | 453.08     | 3395.76    | 31.66     | 17.75     | 3.87     | 0.11      | 0.45      | 165.23   | 0.00      | 0.00      |
| 5423: water source well | 1349.95  | 144.02     | 2550.64    | 681.36    | 188.4     | 4.51     | 0.36      | 0.12      | 101.14   | 0.00      | 0.00      |
| 5423: sewage          | 2773.16    | 0.00       | 204.42     | 439.54    | 147.48    | 1.93     | 0.18      | 0.63      | 104.12   | 0.00      | 0.00      |
| 5423:5433-1 (Chang layer 2) | 435.60    | 0.00       | 125.09     | 9298.56   | 1409.9    | 6.44     | 0.53      | 0.38      | 134.82   | 0.00      | 0.00      |
As shown in Table 1, CO$_3^{2-}$ and HCO$_3^{-}$ were elevated in the reinjected sewage of the Xinanbian oil production team, and Ca$^{2+}$ was elevated in the produced water of the oil well, suggesting that calcium carbonate scale precipitates are generated in the formation after the mixing of the two types of water. The contents of CO$_3^{2-}$ and HCO$_3^{-}$ in the reinjection wastewater of the Jiyuan oil production team was high, and the content of Ca$^{2+}$ and Mg$^{2+}$ in the produced water of the oil well was also high, suggesting that calcium carbonate or magnesium carbonate scale precipitate are generated in the formation after mixing the two types of water.

3.2. Compatibility experimental analysis

Based on the comparative analysis of the water quality of the two water samples, the compatibility of the produced and injected waters in different proportions was studied according to the actual field setting. After 20 days of simulated formation temperature, the changes in the water ion content before and after compatibility were evaluated, and the magnesium and calcium loss rates were calculated. The results of the water quality analysis after compatibility are shown in Table 2. The calculation of calcium and magnesium loss rates and scaling amount are shown in Table 3.

### Table 2. Compatible water quality analysis

| Name | Ratio | Ion content (mg/L) |
|------|-------|--------------------|
|      |       | SO$_4^{2-}$ | CO$_3^{2-}$ | HCO$_3^{-}$ | Ca$^{2+}$ | Mg$^{2+}$ |
| 6334: sewage + 6107-3 (Chang layer 10) | 2:8 | 434.62 | 78.01 | 122.04 | 82.77 | 7.17 |
|      | 4:6 | 651.10 | 138.02 | 381.38 | 9.22 | 8.27 |
|      | 6:4 | 954.02 | 294.05 | 707.83 | 1.20 | 8.51 |
|      | 8:2 | 1243.76 | 465.08 | 1183.79 | 2.00 | 10.45 |
| 5423: water source well + 5423:5433-1 (Chang layer 2) | 2:8 | 726.83 | 1980.33 | 3325.59 | 6.01 | 35.25 |
|      | 4:6 | 1718.72 | 1224.20 | 2828.28 | 7.21 | 65.80 |
|      | 6:4 | 1092.31 | 918.15 | 1897.72 | 10.15 | 94.65 |
|      | 8:2 | 1284.1 | 516.09 | 1159.38 | 9.08 | 145.54 |

### Table 3. Analysis of loss of calcium and magnesium

| Name | Ratio | Theoretical value (mg/L) | Actual value (mg/L) | Loss rate of Ca$^{2+}$ (%) | Loss rate of Mg$^{2+}$ (%) | Scale and quantity (mg/L) |
|------|-------|--------------------------|---------------------|---------------------------|---------------------------|--------------------------|
| 6334: sewage + 6334:6107-3 (Chang layer 10) | 2:8 | 249.14 | 10.76 | 82.77 | 7.17 | 366.00 |
|      | 4:6 | 197.47 | 11.07 | 9.22 | 8.27 | 25.27 | 473.00 |
|      | 6:4 | 145.81 | 11.37 | 1.20 | 8.51 | 9.28 | 95.00 |
|      | 8:2 | 94.14 | 11.68 | 2.00 | 10.45 | 9.78 | 10.55 | 247.50 |
| 5423: water source well + 5423:5433-1 (Chang layer 2) | 2:8 | 142.47 | 45.20 | 6.01 | 35.25 | 95.78 | 22.01 | 733.50 |
|      | 4:6 | 277.19 | 81.00 | 7.21 | 65.8 | 97.40 | 18.77 | 1162.00 |
|      | 6:4 | 411.92 | 116.80 | 10.15 | 94.65 | 97.54 | 18.96 | 1392.50 |
|      | 8:2 | 546.64 | 152.60 | 9.08 | 145.54 | 98.34 | 4.63 | 1764.50 |

In summary, the collected data demonstrated that the selected blocks had prominent compatibility contradictions and obvious scaling phenomena, which may lead to frequent replacement of flowmeters and maintenance of external delivery pumps in the long term, potentially seriously affecting the normal production of the oil field, with hidden dangers for production safety.

3.3. Scaling prediction and analysis

Combined with the scaling situation in these typical areas, the ion concentration product method was used to predict the scaling. Moreover, the scale sample components were collected for X-ray diffraction analysis to predict the structure trend. Table 4 shows the static compatibility and compatibility scaling prediction analysis data. Figures 1 and 2 show the X-ray diffraction spectra.
Table 4. Scale prediction analysis of the compatibility experiment

| Water injection station | Name | $K_{CaCO_3}$ | $K_{CaSO_4}$ | $\frac{K_{CaCO_3}}{K_{spCaCO_3}}$ | $\frac{K_{CaSO_4}}{K_{spCaSO_4}}$ | Scaling trend |
|-------------------------|------|---------------|--------------|-----------------------------------|----------------------------------|---------------|
| Xinanbian 6334 | sewage + 6107-3 (Chang layer 10) | $2.40 \times 10^{-6}$ | $2.58 \times 10^{-4}$ | 858.42 | 5.23 | CaCO$_3$ |
| Jiyuan 5423 | water source well + 5433-1 (Chang layer 2) | $8.84 \times 10^{-6}$ | $4.35 \times 10^{-4}$ | 3156.14 | 8.83 | CaCO$_3$ |

Figure 1. X-ray diffraction pattern of scale produced from 6334: sewage + 6334:6107-3 (Chang layer 10).

Figure 2. X-ray diffraction pattern of scale produced from 5423: water source well +5423:5433-1 (Chang layer 2).

Table 5. Specimen phase analysis

| Name | Identifying code | Compound | Displacement [$^\circ 2\theta$] | Scale factor | Chemical formula |
|------|------------------|----------|-------------------------------|-------------|-----------------|
| 6334: sewage + 6334:6107-3 (Chang layer 10) | 01-085-1108 | Calcium Carbonate | 0.000 | 0.935 | CaCO$_3$ |
| 5423: water source well +5423:5433-1 (Chang layer 2) | 01-083-1762 | Calcium Carbonate | 0.000 | 0.832 | CaCO$_3$ |
Overall, the water samples analyzed by the ion-solubility product method showed a trend of calcium carbonate scaling, but no calcium sulfate scaling, which is consistent with the X-ray diffraction analysis results of the scaling product composition. Therefore, it can be concluded that the formation and injection waters are not compatible, and the precipitation after mixing is the main reason for the scaling in the oil collecting system.

3.4. Investigation of scale inhibition technology

As concluded from Table 5, the scale-type component of the block with a prominent scaling contradiction in this oil field is mainly calcium carbonate. Currently, there is no scale inhibitor with particularly good performance for this type of scale, resulting in an inability to meet the on-site demand for water treatment at the water injection station in this oil field platform. Based on scale sample analysis, scale cause, and scale trend prediction, along with previous investigation on calcium carbonate scale prevention methods at home and abroad, and the typical field process of this oilfield, it was found that adding a scale inhibitor is the most economical and effective method among all types of scale removal methods. However, many scale inhibitors only have good inhibitory effects on one or two types of scale salts [13-15]. A combination of scale inhibitors was used to compensate for the limitations of single scale inhibition to improve its scale inhibition performance and solve the scaling problem of the water injection system and oil collection system from the source.

3.4.1. Scale inhibitor optimization

Organic phosphonic acid (Numbers A, B, C, D, E, F), which is commonly used as a scale inhibitor were tested. First, a single dose of A compound used to treat serious scaling blocks was screened. Subsequently, three agents with better effect were identified, and their mixtures (with different proportions) was evaluated to determine the most appropriate strategy for inhibiting calcium carbonate scale blocks.

The indoor static compatibility experiment showed that the scale inhibitory effect of agents A, B, C, and F was better than that of the other agents, with the scale inhibition rates reaching 37.14%, 35.22%, 38.86%, and 33.72%, respectively. Moreover, the scale inhibitory effect of a single agent was poor. Next, the compound agent B+F+C (2:2:6) was evaluated through a static compatibility experiment at dosages of 60, 80, 100, 120, and 140 mg/L. Overall, with an increase in the dosage of the scale inhibitor, the scale inhibition first increased and then decreased (Figure 2). When the dosage was 100 mg/L, the scale inhibitory effect was the best compared with the other dosages, and the scale inhibitory rate reached 90.51%. This shows that the scale inhibitor compound method can meet the requirements of calcium carbonate scale prevention treatment in this oilfield.

![Figure 3. Dosage screening of the organic phosphonic acid scale inhibitor.](image)

3.4.2. Evaluation of scale inhibitors

Currently, the chemical scale removal method mainly refers to the oil and gas industry standard SY/T5673-93 "Performance evaluation method of scale inhibitors used in oil fields" that refers to several commonly used scale inhibitors and organic phosphoric acid scale inhibitors. Among them, B+F+C had the best effect on preventing the calcium carbonate scale (Table 6).
Table 6. Anti-scaling effect comparison of scale inhibitor and other anti-scaling agents

| Anticrustator                                | Dosage (mg·L⁻¹) | Scale inhibition rate (%) |
|----------------------------------------------|------------------|---------------------------|
| B+F+C                                        | 60               | 90.51                     |
| Amino trimethylephosphoric acid (ATMPA)      | 60               | 37.14                     |
| Sodium ethylenediamine tetramethylphosphate (EDTMPS) | 60               | 35.22                     |
| polymaleic acid (PMA)                        | 60               | 38.86                     |
| Hydroxyethyl phosphate (HEDP)                | 60               | 23.07                     |
| Acrylate-maleic acid copolymerization (AA-MA) | 60               | 25.18                     |
| polyepoxysuccinic acid (PESA)                | 60               | 27.69                     |

4. Conclusion
In summary, through the analysis of water quality full ion and necessary indexes of water injection, combined with scaling prediction and X-ray diffraction analysis, it was determined that there is a scaling tendency of water injection in the Dingbian Oil Production Plant of Yanchang Petroleum, which was identified to be a calcium carbonate scale that forms the sulfate scale.

Furthermore, through complex screening of scale inhibitors, the scale compound inhibitor B+F+C (2:2:6) showed was most efficient in preventing this type of calcium carbonate scale in the oil field studied, reaching a scale inhibition rate of 90.51%, which has certain advantages compared with other scale inhibitors available in the market.

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