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Solubility Variation and Prediction Model of CO_2 in Water-Bearing Crude Oil

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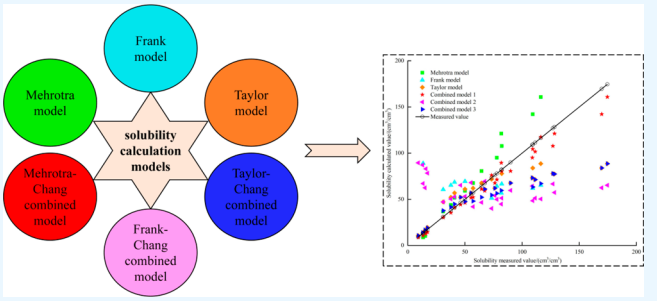
ABSTRACT: The solubility of CO_2 in water-bearing crude oil is of great significance for the calculation of crude oil reserves, the development of CO_2-EOR (CO_2-enhanced oil recovery), CO_2-CCUS (carbon capture, utilization, and storage), and CO_2 assisted steam huff-and-puff technology, and the optimization of the design of CO_2 for heavy oil pipeline transportation. In order to determine the variation of the solubility of water-bearing crude oil by injecting CO_2 into the formation, taking the Upper Wuerhe Formation reservoir in the 5_3 East Block as an example, the study of the dissolution characteristics of CO_2 in water-bearing crude oil at different temperature and pressure conditions was carried out by using a high-temperature and high-pressure reaction kettle. At the same time, a new solubility prediction model of CO_2 in water-bearing crude oil was proposed based on the existing solubility prediction models. The results show that, under the same water cut, the solubility of CO_2 in water-bearing crude oil decreases with the increase of temperature and decreases with the decrease of pressure. At the same time, the solubility of CO_2 in water-bearing crude oil is more sensitive to pressure. At the same temperature, the solubility of CO_2 in water-bearing crude oil decreases with the increase of water cut, and the higher the pressure, the greater the effect of water cut on the solubility of CO_2 in water-bearing crude oil. The newly established combined prediction model of CO_2 solubility in water-bearing crude oil is convenient for calculation and has a wide range of applications. The average relative error is only 9.5%, which can meet the requirements of engineering calculation accuracy.



1. INTRODUCTION

Conventional water injection development has the problems of high water injection pressure, rapid production decline, low water flooding recovery, and strong reservoir damage for low permeability reservoirs and unconventional reservoirs. Gas injection can effectively solve the shortcomings of water injection development and has become an important means to enhance oil recovery in the world. At present, the gas injection media mainly include CO_2, N_2, air, hydrocarbon gas, and flue gas.[1−5] Compared with other injection gases, CO_2 has the advantages of being easily miscible with crude oil, having a low miscible pressure, promoting volume expansion of crude oil, reducing crude oil viscosity, reducing oil−water interfacial tension, improving crude oil flow characteristics, and forming dissolved gas flooding.[6,7] In addition, the weak acidity of CO_2 dissolved in water can play a role in acidizing plugging to a certain extent. CO_2 flooding can enhance oil recovery by 7−18%.[8] It has been widely used in the Lick Creek, Yates, and Kelly-Synder Oil Fields in the United States,[8−10] Jilin, Xinjiang, and Shengli Oil Fields in China,[11−13] and Weyburn, Ruofur, and Pabina Oil Fields in Canada.[14,15] Injecting CO_2 into the formation can achieve a win-win goal of enhancing oil recovery and reducing emission, with significant economic and social benefits. However, a large amount of CO_2 dissolved in crude oil and the precipitation of CO_2 in the production wells at the later stage of production will lead to changes in the physical properties of crude oil, making it more difficult to predict the PVT parameters of wellbore fluid. The solubility of CO_2 in water-bearing crude oil is one of the PVT parameters of crude oil, which determines the changes of other PVT parameters of crude oil and CO_2 flooding efficiency. Therefore, it is necessary to systematically study the solubility of CO_2 in water-bearing crude oil. In addition, the PVT parameters of crude oil such as solubility are usually obtained by PVT sampling analysis. Due to the lack of sampling data in the new exploration area and the old oil area not meeting the sampling analysis conditions, prediction models such as the Briggs viscosity model,[16] Quail density model,[17] Vazquez volume coefficient model,[18] and McCain solubility model[19] are formed to calculate the PVT parameters

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Table 1. Molar Composition of Flash Gas Components in Well W[a]

	component												
	C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_6	C_7	C_8	CO_2	N_2	sum
mole fraction (%)	82.92	7.37	4.81	1.42	1.02	0.02	0.21	0.04	0.03	0.03	0.17	1.96	100

[a]"i" is isomeric hydrocarbon, and "n" is normal hydrocarbon.

of crude oil,[20−23] but these empirical formulas have low accuracy and are only suitable for reservoirs of specific properties.

The comprehensive water cut of the Upper Wuerhe Formation reservoir in the 5_3 East Block of the Xinjiang Oil Field in China is 81.3%,[24] and the potential of water flooding development is small. Carrying out the development test of CO_2 injection to supplement energy is urgent. In this paper, the solubility characteristics of CO_2 in water-bearing crude oil were obtained by an indoor miscible experiment of CO_2-water-bearing crude oil, and the idea of a combined model was proposed based on the existing solubility models, which can lay a theoretical foundation for this reservoir to enhance oil recovery by CO_2 flooding and provide a reference for solubility prediction of other reservoirs.

2. BASIC OVERVIEW OF THE RESERVOIR

The Upper Wuerhe Formation reservoir in the 5_3 East Block of the Xinjiang Oil Field in China is located in the monoclinic zone of the footwall of the Ke-Wu fault in the Junggar Basin, which is a monoclinic structural lithologic reservoir with a southeast-sloping shape. The oil-bearing area of the upper Wuerhe Formation reservoir is 18 km^2. The SW_3^2 sand layer is the most developed, and the thickness is the largest, making it the main oil layer of the reservoir. The porosity of the oil layer is 9%, and the permeability is 23.89 mD, which makes it an extra-low porosity and low permeability reservoir.[25] The original formation pressure of the reservoir is 28.20 MPa, and the saturation pressure is 24.00 MPa. It is an unsaturated reservoir with normal formation pressure. The formation temperature is 64 °C, the viscosity of the crude oil is 1.29 mPa·s, and the original gas−oil ratio is 121 m^3/t. The reservoir has been dominated by water injection development for a long time. At present, the comprehensive water cut is 81.3%, and the potential of water flooding development is small. It is urgent to carry out the development test of gas injection to supplement energy. At the same time, the CO_2 source is close to the oil area, and the CO_2 emissions of major chemical enterprises near the Junggar Basin are large, which provides convenience for the reservoir to carry out CO_2-EOR (CO_2-enhanced oil recovery) and CCUS (carbon capture, utilization, and storage).

3. EXPERIMENT ON THE DISSOLUTION CHARACTERISTICS OF CO_2 IN WATER-BEARING CRUDE OIL

3.1. Experimental Instrument. The main experimental instrument used for testing the solubility of CO_2 in water-bearing crude oil includes a PY-2 high-temperature and high-pressure sampler (reaction kettle), with an effective volume of 1000 mL, a maximum pressure resistance of 100 MPa, a maximum temperature resistance of 200 °C, a temperature control accuracy of 0.1 °C, a stirring speed of 10 r/min, and a stirring angle of 180°; a BY100-II high-pressure displacement pump, with an effective volume of a single pump body of 500 mL, a maximum pump pressure of 100 MPa, a pressure control accuracy of 0.1 level, and a flow range of 0.001−30 mL/min; an Agilent 6890 gas chromatograph for the determination of CO_2, N_2, O_2, and C_1−C_8 components; an Agilent 7890 gas chromatograph for the determination of C_1−C_{50} components; a QL-I gas meter, with an effective volume of 1000 + 1000 mL and volume accuracy of 1 mL; a BSA423 electronic balance, with an indexing value of 0.001 g; a ZR-III intermediate container; a constant temperature air bath; a gas booster pump, etc. The whole experimental device has good temperature and pressure control and can be tested under set temperature and pressure conditions, which provides a guarantee for the accuracy of experimental data.

3.2. Experimental Samples. The CO_2 sample industrial analytical purity was 99.999%.

3.2.1. Crude Oil and Formation Water Samples. Oil and water samples were taken from Well W of the Upper Wuerhe Formation reservoir in the 5_3 East Block of the Xinjiang Oil Field in China. In order to obtain individual oil and water samples, oil and water were separated before the experiment. The oil released after separation was the experimental oil, and the released water was the experimental formation water after filtration.

3.2.2. Natural Gas Samples. Compounding natural gas samples was based on the known composition data of separated gas. The molar composition of the flash gas in Well W is shown in Table 1. The flash gas of Well W is mainly composed of C_1−C_8, CO_2, and N_2, so the natural gas compounding is divided into two parts: the compounding of CO_2, N_2, C_1, C_2, C_3, and C_4 gas and the compounding of C_5, C_6, C_7, and C_8 liquid. The gas compounding needs to use the deviation factor parameter (which can be simulated by PVTsim software according to the cylinder pressure and indoor temperature) to calculate the injection volume of each gas component, and the liquid compounding needs to use the mass and density parameters to calculate the injection volume of each liquid component.

3.3. Experimental Scheme. Temperature and pressure are two important parameters affecting the solubility of CO_2 in water-bearing crude oil. According to the temperature and pressure conditions of Well W of the Upper Wuerhe Formation reservoir in the 5_3 East Block, the solubility of CO_2 in different water cut crude oils is tested under the conditions of temperature change of 20−65 °C and pressure change of 2−20 MPa. The specific experimental scheme is as shown in Table 2.

Table 2. Solubility Experiment Scheme

water cut (%)	0, 30, 60, 80
pressure (MPa)	20, 14, 8, 2
temperature (°C)	20, 35, 50, 65

3.4. Experimental Steps. The solubility of CO_2 in water-bearing crude oil refers to the volume of CO_2 dissolved in a unit volume of degassed water-bearing crude oil under certain temperature and pressure conditions. The dissolution characteristics of the experiment mainly include four parts: natural gas compounding, formation crude oil compounding, CO_2

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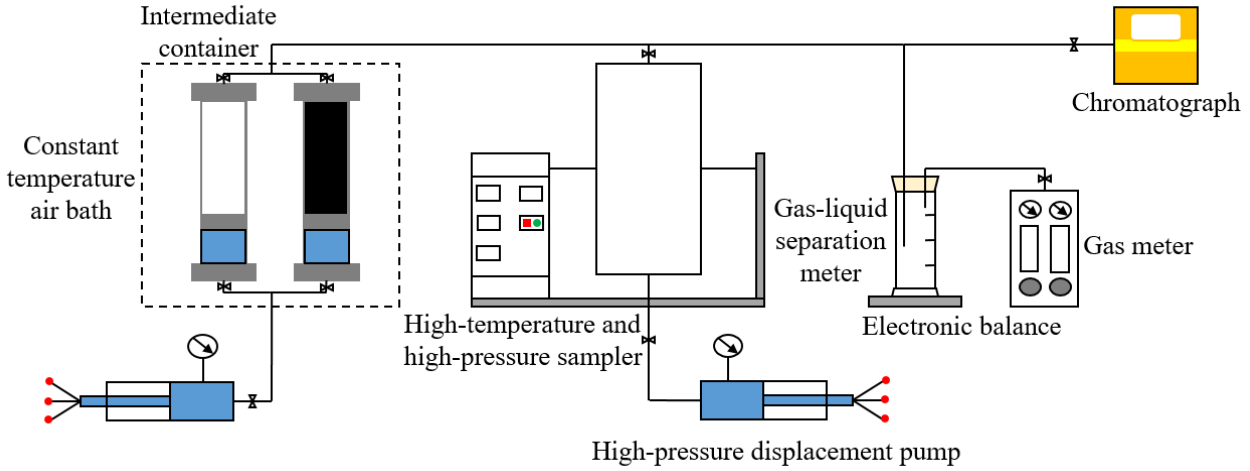

Figure 1. Determination process of CO_2 solubility in water-bearing crude oil.

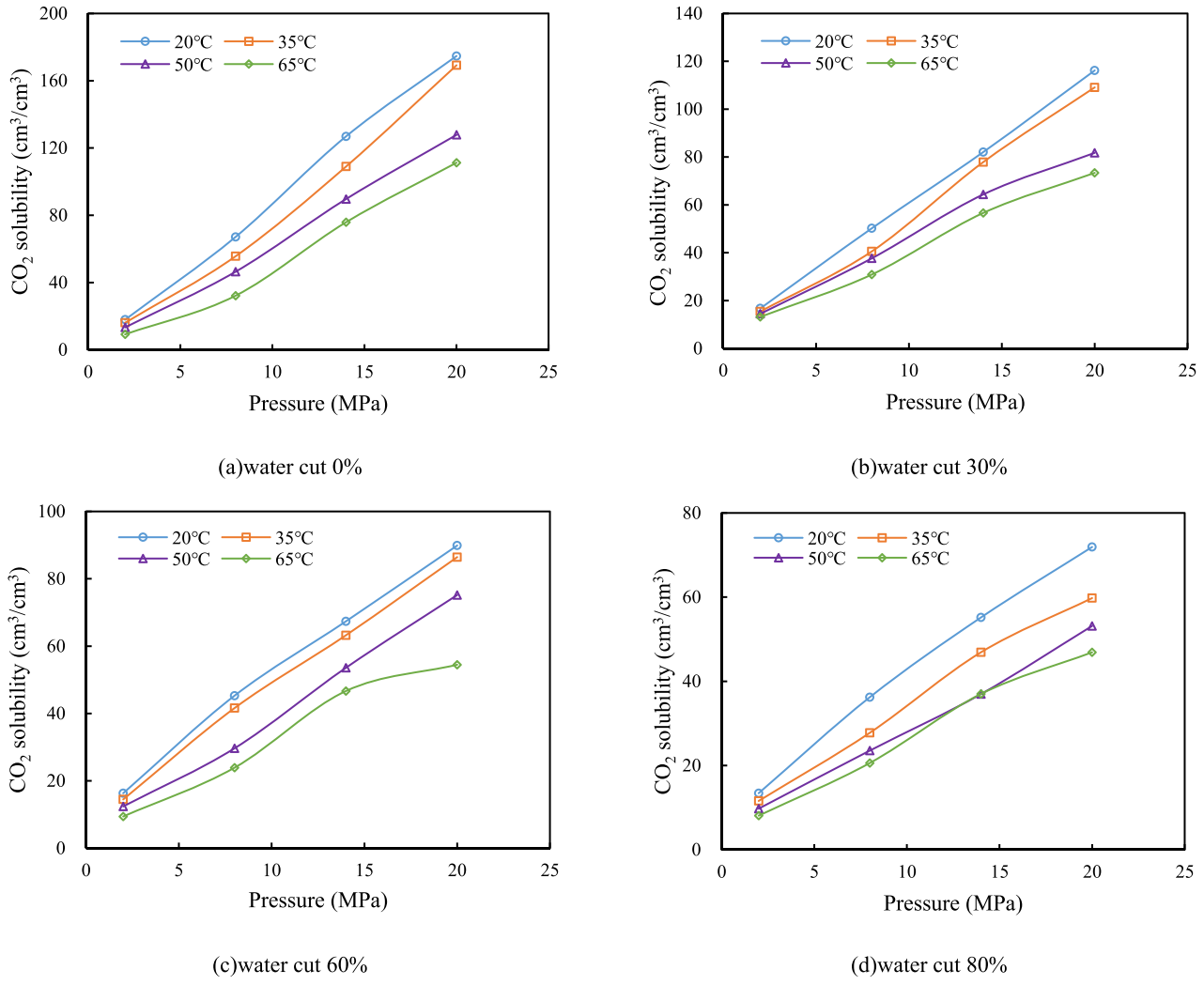

Figure 2. Solubility of CO_2 in water-bearing crude oil at different temperatures.

injection, and solubility test. The experimental process is shown in Figure 1.

3.4.1. Natural Gas Compounding. The actual injection volumes of CO_2, N_2, and C_1−C_4 gas are calculated according to the molar compositions of each component of the flash gas in Well W and the original gas−oil ratio. Each gas is transferred to the intermediate container in order 2−3 times according to the

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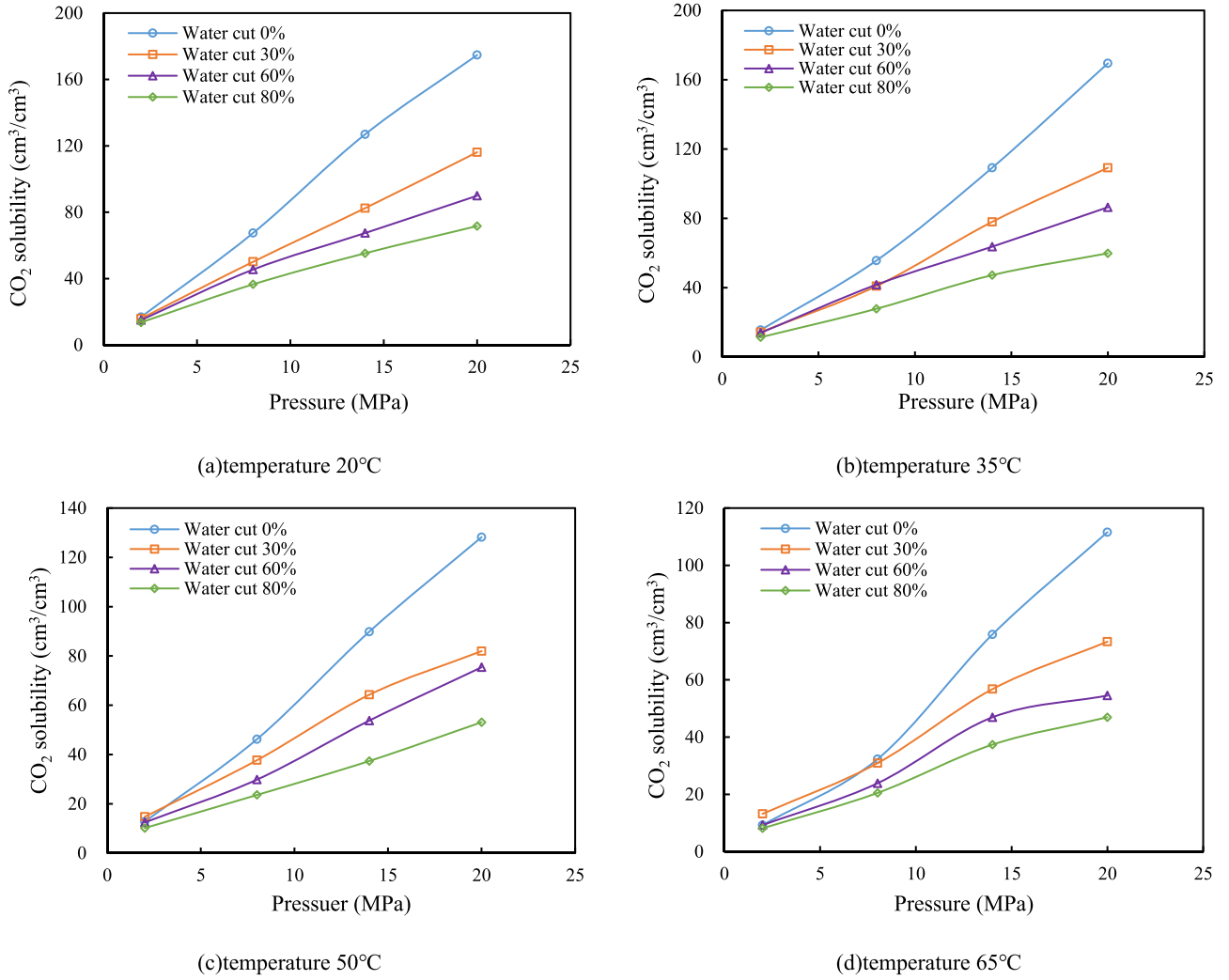

Figure 3. Solubility of CO_2 in water-bearing crude oil at different water cuts.

order of cylinder pressure from small to large and pressurized to 20 MPa for subsequent formation crude oil compounding.

3.4.2. Formation Crude Oil Compounding. The actual injection volume of C_5−C_8 liquid injected into the high-temperature and high-pressure sampler equipped with dead oil in turn is calculated, and the sampler is closed. The formation water sample is injected into the sampler in a certain proportion according to the water cut requirement, and then the compounded natural gas samples is injected into the sampler. The sampler is shaken for 2−3 h, making the gas and liquid in the sampler mix evenly, then left still to complete the formation crude oil compounding.

3.4.3. CO_2 Injection. First, excess CO_2 is injected into the sampler at 30 MPa, shaken for 2 h, and left to stand still, and undissolved CO_2 gas is released. The pressure is lowered to 20 MPa, and the shaking and standing steps are repeated. The valve is opened to release the gas, and then the valve is closed after the oil is discharged; at this time the solubility test can begin.

3.4.4. Solubility Test. The valve is opened under the test pressure, and the gas is released; a certain amount of gas is collected for chromatographic testing, until crude oil appears, when the the valve is closed. In order to prevent the slight decrease of pressure from causing the change of solubility, the solubility under this experimental condition can be calculated by increasing the pressure by 1 MPa and collecting crude oil and gas respectively after opening the valve. Then, the pressure is reduced in turn, and the above steps are repeated to obtain the solubility under the corresponding pressure until the experimental scheme is completed.

After a set of pressure measurements is completed, the experimental temperature and moisture content are changed to test the other experimental schemes.

4. EXPERIMENTAL RESULTS AND DISCUSSION

The solubility of CO_2 in water-bearing crude oil was tested under different pressures (2 MPa, 8 MPa, 14 MPa, 20 MPa) and different temperatures (20 °C, 35 °C, 50 °C, 65 °C). Figure 2 and Figure 3 show the solubility variation of CO_2 in water-bearing crude oil at different temperatures and different water cuts, respectively.

4.1. Dissolution Characteristics of CO_2 in Water-Bearing Crude Oil at Different Temperatures. It can be seen from Figure 2 that under the same water cut conditions, the solubility of CO_2 in water-bearing crude oil decreases with the increase of temperature and decreases with the decrease of pressure. On the whole, when the pressure decreases from 20 to 2 MPa, the CO_2 solubility decreases by 38.80−156.78 cm^3/cm^3, and when the temperature increases from 20 to 65 °C, the

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solubility of CO_2 decreases by 3.54−63.45 cm^3/cm^3, indicating that the solubility of CO_2 in water-bearing crude oil is more sensitive to pressure. Therefore, in the process of fluid flow, the solubility of CO_2 will gradually decrease, and a large amount of CO_2 will precipitate from the fluid.

4.2. Dissolution Characteristics of CO_2 in Water-Bearing Crude Oil at Different Water Cuts. It can be seen from Figure 3 that, under the same temperature conditions, the solubility of CO_2 in water-bearing crude oil decreases with the increase of the water cut, and the higher the pressure, the greater the effect of water cut on the solubility of CO_2. In addition, Figure 3a,b follows almost the same pattern at different water cuts, and the same tendency is also observed in Figure 3c,d, but slightly different. The main reason is that the solubility of CO_2 in water-bearing crude oil is less affected by the change of temperature, which further confirms the above conclusion about the solubility of CO_2 in water-bearing crude oil at different temperatures. On the whole, the water cut increases from 0% to 80%. When the pressure is not higher than 8 MPa, the water cut has little effect on the solubility of CO_2 in water-bearing crude oil, and the maximum decrease of CO_2 solubility is only 30.91 cm^3/cm^3. When the pressure is higher than 8 MPa, the water cut has a great influence on the solubility of CO_2 in water-bearing crude oil, and the maximum decrease of CO_2 solubility can reach 109.60 cm^3/cm^3. Therefore, the lower the oil well pressure and the higher the water cut, the smaller the CO_2 solubility and the worse the CO_2 flooding efficiency.

5. ANALYSIS AND CORRECTION OF SOLUBILITY PREDICTION MODEL OF CO_2 IN WATER-BEARING CRUDE OIL

5.1. Comparison of Existing CO_2 Solubility Prediction Models in Water-Bearing Crude Oil. At present, the solubility prediction models of CO_2 in crude oil mainly include the Mehrotra model, Frank model, and Taylor model. The following introduces the above three commonly used prediction models, which provide a theoretical basis for the selection of the solubility prediction model of the Upper Wuerhe Formation reservoir in the 53 East Block.

In 1982, Mehrotra et al.[26] studied the solubilities of synthetic gas and N_2, CO_2, and CH_4 components in asphalt through experiments and proposed a solubility prediction model for each component. The average deviation of CO_2 solubility prediction in asphaltene crude oil was 6.3%. The model is suitable for a temperature range of 23.89−99.22 °C and pressure range of 0.4−6.8 MPa.

$$R_s = b_1 + b_2P + b_3\frac{P}{T} + b_4\left(\frac{P}{T}\right)^2 \quad (1)$$

where R_s is the solubility of CO_2 in asphaltene crude oil (cm^3/cm^3), T is the system temperature (K), P is the system pressure (MPa), and b_1, b_2, b_3, and b_4 are model coefficients; the specific values are shown in Table 3.

In 1988, Frank Chung et al.[27] tested the solubility of CO_2 in five kinds of heavy oil under different temperature and pressure conditions. It was found that the solubility of CO_2 in crude oil was mainly related to the temperature, pressure, and relative density of crude oil. It decreased with the increase of temperature and increased with the increase of pressure. However, when the pressure was higher than 6.9 MPa, the solubility is not very sensitive to pressure. Through the analysis of experimental data, the calculation formula of CO_2 solubility in heavy oil is proposed. The model is suitable for the temperature range of 24−94 °C and the pressure below 6.9 MPa.

$$R_s = 1/[a_1\gamma^{a_2}T^{a_7} + a_3T^{a_4}\exp(-a_5P + a_6/P)] \quad (2)$$

where R_s is CO_2 solubility (m^3/m^3), γ is the relative density of heavy oil (API), T is the temperature (°F), P is the pressure (psia), and a_1, a_2, a_3, a_4, a_5, a_6, and a_7 are model coefficients; the specific values are shown in Table 4.

In 2016, Taylor Barclay et al.[28] established a calculation model for the solubility of CO_2 in light crude oil based on the experimental data integrated by Emera. The model is suitable for the temperature range of 32.2−73.9 °C, pressure range of 1.81−27.4 MPa, crude oil weight range of 0.85−0.90, and CO_2 solubility (mole fraction) range of 0.12−0.85.

$$R_s = (a + bT)\cdot\ln(P) + (c + dT) \quad (3)$$

where R_s is the solubility of CO_2 in crude oil (mole fraction), T is the temperature (°C), P is the pressure (MPa), and a, b, c, and d are model coefficients; the specific values are shown in Table 5.

In 2011, Xing et al.[29] conducted a physical property test experiment of CO_2 flooding produced fluid and studied the effect of water on the solubility of CO_2 in crude oil and the effect of oil on the solubility of CO_2 in water. It is found that the effect of water (oil) on the solubility of CO_2 in crude oil (water) can be ignored. The solubility of CO_2 in water-bearing crude oil can be expressed by the weighted average of its solubility in pure oil and pure water:

$$R_s = X_wR_w + X_oR_o \quad (4)$$

where R_s is the solubility of CO_2 in the oil−water mixture, R_w and R_o are the solubilities of CO_2 in water and oil, respectively, and X_w and X_o are the volume fractions of water and oil in the oil−water mixture, respectively.

In 2012, Wang et al.[30] studied the solubility of CO_2 in formation fluid at 45 °C and 3.0−8.5 MPa for Daqing Oil Field fluid and obtained similar conclusions. Under the same temperature and pressure conditions, the relationship between the solubility of CO_2 in the oil−water mixture and its solubility in crude oil and formation water is

$$R_{1:1} = \frac{1}{2}R_o + \frac{1}{2}R_w \quad (5)$$

$$R_{2:1} = \frac{2}{3}R_o + \frac{1}{3}R_w \quad (6)$$

$$R_{4:1} = \frac{4}{5}R_o + \frac{1}{5}R_w \quad (7)$$

where $R_{1:1}$, $R_{2:1}$, and $R_{4:1}$ are the solubility of CO_2 in the mixtures with oil−water volume ratios of 1:1, 2:1, and 4:1, respectively.

Therefore, based on the research of Xing et al. and Wang et al., it can be concluded that the solubility of CO_2 in the oil−water mixture at constant temperature is only related to pressure and liquid composition, which can be expressed by the weighted average of its solubility in pure oil and pure water, which is called the combined model. When applying the combined model, it is

Table 3. Mehrotra Model Correlation Coefficients

	coefficient			
	b_1	b_2	b_3	b_4
value	−0.0073508	−14.794	6428.5	4971.39

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Table 4. Frank Model Correlation Coefficients

	coefficient						
	a_1	a_2	a_3	a_4	a_5	a_6	a_7
value	0.4934×10^{-2}	4.0928	0.571×10^{-6}	1.6428	0.6763×10^{-3}	781.334	−0.2499

Table 5. Taylor Model Correlation Coefficients

	coefficient			
	a	b	c	d
value	0.36913	−0.00106	0.01280	−0.00160

necessary to know not only the solubility of CO_2 in crude oil but also the solubility of CO_2 in water. The solubility of CO_2 in crude oil can be calculated by the Mehrotra model, Frank model, and Taylor model. The solubility of CO_2 in water can be calculated by the model proposed by Chang et al.[31] in 1996. The model is suitable for the temperature range of 12−100 °C, pressure range of 0.1−69 MPa and NaCl solution with salinity of 0−6 mol/L. The specific expressions are as follows:

If $P < P^o$:

$$R_{sw} = aP\left[1 - b\cdot\sin\left(\frac{\pi}{2}\cdot\frac{cP}{cP+1}\right)\right] \tag{8}$$

If $P \geq P^o$:

$$R_{sw} = R_{sw}^{o} + m(P - P^o) \tag{9}$$

where

$$a = \sum_{i=0}^{4} a_i\cdot 10^{-3i}\cdot T^i \tag{10}$$

$$b = \sum_{i=0}^{4} b_i\cdot 10^{-3i}\cdot T^i (0 < b < 1) \tag{11}$$

$$c = 10^{-3}\cdot\sum_{i=0}^{4} c_i\cdot 10^{-3i}\cdot T^i \tag{12}$$

$$P^o = \frac{2}{\pi}\cdot\frac{\sin^{-1}(b^2)}{c\left[1 - \frac{2}{\pi}\sin^{-1}(b^2)\right]} \tag{13}$$

$$R_{sw}^{o} = aP^o\cdot(1 - b^3) \tag{14}$$

$$m = a\left\{1 - b\left[\sin\left(\frac{\pi}{2}\cdot\frac{cP^o}{cP^o+1}\right) + \frac{\pi}{2}\cdot\frac{cP^o}{cP^o+1}\cdot\cos\left(\frac{\pi}{2}\cdot\frac{cP^o}{cP^o+1}\right)\right]\right\} \tag{15}$$

R_{sw} is the solubility of CO_2 in water (scf/STB), T is temperature (°F), P is pressure (psia), and a, b, and c are model coefficients; the specific values are shown in Table 6.

Table 6. Chang Model Correlation Coefficients

coefficient	$i = 0$	$i = 1$	$i = 2$	$i = 3$	$i = 4$
a_i	1.163	−16.630	111.073	−376.859	524.889
b_i	0.965	−0.272	0.0923	−0.1008	0.0998
c_i	1.280	−10.757	52.696	−222.395	462.672

In summary, domestic and foreign scholars have conducted a lot of research on the solubility of the CO_2−crude oil mixed fluid and put forward many prediction models. Table 7 lists the commonly used prediction models of CO_2 solubility and their applicable ranges.

Table 7. Application Scope of Common CO_2 Solubility Prediction Models in Water-Bearing Crude Oil

prediction model	temperature (°C)	pressure (MPa)	others	medium
Mehrotra model	23.89−99.22	0.4−6.8	—	oil
Frank model	24−94	<6.9	—	oil
Taylor model	32.2−73.9	1.81−27.4	crude oil weight range of 0.85−0.90, CO_2 solubility (mole fraction) range of 0.12−0.85	oil
Chang model	12−100	0.1−69	NaCl solution with salinity of 0−6mol/L	water

By comparing the reservoir conditions of the test block and the applicable scope of various commonly used solubility prediction models, it is found that it is impossible to find a complete set of physical parameter calculation methods suitable for the target block from Table 7. Therefore, it is necessary to carry out the solubility prediction model correction of CO_2 in water-bearing crude oil.

5.2. Correction of Solubility Prediction Model of CO_2 in Water-Bearing Crude Oil. Based on the research results of Xing et al. and Wang et al., it is considered that the solubility of CO_2 in the oil−water mixture at constant temperature is only related to pressure and liquid composition. The solubility combination model is established by the weighted average method:

$$R_s = (1 - X_w)R_o + X_wR_w \tag{16}$$

where R_s is the solubility of CO_2 in the oil−water mixture, R_o and R_w are the solubilities of CO_2 in crude oil and water, respectively, and X_w is the volume fraction of water in the oil−water mixture.

The solubility prediction models of CO_2 in crude oil include the Mehrotra model, Frank model, and Taylor model, and the solubility prediction model of CO_2 in water includes the Chang model. The solubility of CO_2 in crude oil and water is calculated by different methods, and different combination models will be formed. Therefore, the solubility prediction model of CO_2 in water-bearing crude oil can be divided into six solubility models as shown in Table 8.

The above six models were used to calculate the solubility of CO_2 in water-bearing crude oil under different experimental conditions, and the calculated values were compared with the measured values, as shown in Figure 4. The average error of each model is shown in Figure 5. The solubility relative error of each group of data points = (solubility calculated value − solubility measured value)/solubility measured value. The average solubility error of each model is the average value of the

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Table 8. Different Solubility Prediction Models

type	model
single models	Mehrotra model
	Frank model
	Taylor model
combined models	Mehrotra−Chang combined model (combined model 1)
	Frank−Chang combined model (combined model 2)
	Taylor−Chang combined model (combined model 3)

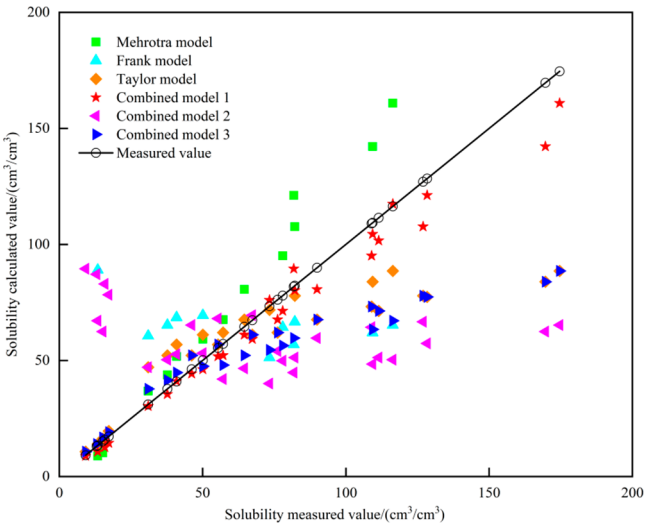

Figure 4. Comparison of different solubility calculation models of CO_2 in water-bearing crude oil.

solubility relative error of each group of data points of each model.

It can be seen from Figure 4 and Figure 5 that the CO_2 solubility calculated by the combined model 1 (Mehrotra−Chang combined model) is in good agreement with the measured value, and the average error is 9.5%. Therefore, for the upper Wuerhe Formation reservoir in the 5_3 East Block, the solubility of CO_2 in crude oil can be calculated by the Mehrotra model, and the solubility of CO_2 in water can be calculated by the Chang model; then, the solubility of CO_2 in water-bearing crude oil can be calculated by the weighted average method according to the water cut.

6. CONCLUSIONS

The study of the solubility characteristics of CO_2 in water-bearing crude oil under different pressure and temperature conditions was carried out. The existing solubility prediction models of CO_2 in water-bearing crude oil were compared, and a new prediction model was proposed. The main conclusions are as follows:

(1) The solubility of CO_2 in water-bearing crude oil shows that, under the same water cut, the solubility of CO_2 in water-bearing crude oil decreases with the increase of temperature and decrease with the decrease of pressure. At the same temperature, the solubility of CO_2 in water-bearing crude oil decreases with the increase of water cut, and the higher the pressure, the greater the effect of water cut on the solubility of CO_2 in water-bearing crude oil.

(2) A combined model was established by combining the Mehrotra model, Frank model, Taylor model, and Chang model. The average error of the optimal combined model for the solubility prediction of the Upper Wuerhe Formation reservoir in the 5_3 East Block of the Xinjiang Oil Field was only 9.5%, which was much lower than that of other solubility prediction single models.

(3) The existing solubility prediction models of CO_2 in water-bearing crude oil have low accuracy and poor adaptability. The combination of different CO_2 solubility prediction models in crude oil and water provides a new idea for predicting the solubility of CO_2 in water-bearing crude oil in other reservoirs. The combined model has strong adaptability and is easy to calculate. The best solubility prediction model of CO_2 in water-bearing crude oil can be selected by combining different models.

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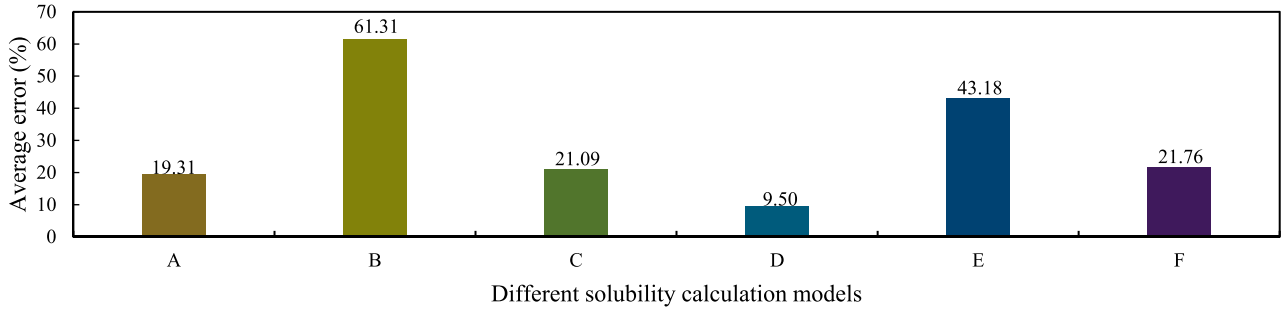

Figure 5. Error comparison of different solubility calculation models of CO_2 in water-bearing crude oil where "A" is the Mehrotra model, "B" is the Frank model, "C" is the Taylor model, "D" is combined model 1, "E" is combined model 2, and "F" is combined model 3.

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Notes

The authors declare no competing financial interest.

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