

Article

Phase Behavior and Rational Development Mode of a Fractured Gas Condensate Reservoir with High Pressure and Temperature: A Case Study of the Bozi 3 Block

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Abstract: The Bozi 3 reservoir is an ultra-deep condensate reservoir (−7800 m) with a high temperature (138.24 °C) and high pressure (104.78 MPa), leading to complex phase behaviors. Few PVT studies could be referred in the literature to meet such high temperature and pressure conditions. Furthermore, it is questionable regarding the applicability of existing condensate production techniques to such a high temperature and pressure reservoir. This study first characterized the phase behavior via PVT experiments and EOS tuning. The operating conditions were then optimized through reservoir numerical simulation. Results showed that: (1) the critical condensate temperature and pressure of Bozi 3 condensate gas were 326.24 °C and 43.83 MPa, respectively; (2) four gases (methane, recycled dry gas, carbon dioxide, and nitrogen) were analyzed, and methane was identified as the optimal injection gas; (3) gas injection started when the production began to fall and achieved higher recovery than gas injection started when the pressure fell below the dew-point pressure; (4) simultaneous injection of methane at both the upper and lower parts of the reservoir can effectively produce condensate oil over the entire block. This scheme achieved 8690.43 m³ more oil production and 2.75% higher recovery factor in comparison with depletion production.

Keywords: PVT experiment; phase behavior; reservoir simulation; gas injection



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1. Introduction

Different to conventional oil and gas reservoirs, a condensate gas reservoir has their dual properties, as well as complex phase behavior [1]. During the production process, as pressure drops below the dew-point pressure, the heavier components fall out in the reservoir as liquid accumulates in large quantities near the wellbore, blocking the pore space and reducing the gas phase permeability [2]. Therefore, in order to optimize the development of a condensate gas reservoir, it is necessary to understand the phase behaviors, for which the pressure/volume/temperature (PVT) laboratory experiments can provide data to tune the equation of state (EOS) and predict phase behaviors [3]. Based on the phase behaviors, operating conditions need to be optimized to reduce the condensate damage, and improve the recovery of gas fields [4].

At present, there are generally two methods to extract condensate gas: pressure depletion [5] and gas injection [6]. Li [7] believes that depletion production is suitable for gas reservoirs with high initial pressure, large differences between initial dew-point pressures, small reserves, low condensate saturation, strong reservoir heterogeneity, and considerable edge/bottom aquifers. Zhu et al. [8] state that gas cycling is good for low-permeability gas reservoirs in the middle and later stages of depletion production, or with

poor connectivity and serious condensate banking. In addition, the selection of gas type and optimization of injecting conditions (including volume, timing, etc.) are critical for successful development of a condensate gas reservoir [9–12].

The major recovery mechanisms of gas injection for condensate reservoirs include extraction, displacement, and evaporation of liquid condensate, which eventually mitigate the condensate banking near the borehole [13,14]. Generally, common gases employed in field practice consist of recycled dry gas [15–20], carbon dioxide [21–29], methane [30–35], and nitrogen [33,36–42].

The recycled gas is applicable to displace condensate in reservoirs with good connectivity and minor condensate blockage, and in the early production periods. Yet it is economically unviable for tight condensate gas reservoirs with poor connectivity.

The application of carbon dioxide is because of its large relative density (1.977), stable chemical properties, and good solubility and mobility. Injecting carbon dioxide into a low-permeability condensate reservoir can not only maintain reservoir pressure and prevent retrograde condensation, but also increase the condensate oil production and ultimate hydrocarbon recovery. Carbon dioxide is separated from produced fluid at surface facilities, and re-injected into the reservoir, which saves the operation cost and protects the environment. However, the use of carbon dioxide is limited by both the source and its corrosion.

Methane injection can effectively reduce condensate oil saturation, which is due to the unique thermodynamic characteristics; methane can effectively evaporate condensate oil and improve gas relative permeability. Nevertheless, methane is hardly soluble in water and thus difficult to eliminate the water lock effect near the borehole.

Nitrogen is able to enter into low permeability areas that cannot be accessed by water, to move the oil there by ‘extraction’ or ‘displacement’. Furthermore, nitrogen also has favorable compressibility and expansibility, which functions well in plug removal, water drainage, oil displacement, and gas lift, while releasing its energy. This helps overcome capillary pressure and brings out reverse imbibition water absorption, thus weakening the water lock effect. However, the injection of nitrogen increases the dew-point pressure of condensate gas, resulting in the loss of condensate oil.

Bozi 3 Block is a condensate gas reservoir located in the west of Tarim Basin, China. The reservoir is characterized by super deep burial (depth > −7800 m), high temperature (reservoir temperature = 138.24 °C), high pressure (initial reservoir pressure = 104.78 MPa), large difference between reservoir and dew-point pressure (pressure difference = 60.67 MPa), and developed natural fissures. This leads to complex fluid phase behavior and low condensate oil recovery due to condensate blockage, which is different from conventional condensate gas reservoirs.

PVT laboratory experiments are commonly employed to address the above-mentioned challenges. However, few references in the literature meet the following requirements of Bozi 3 reservoirs: pressure above 100 MPa and a temperature higher than 100 °C. On the other hand, it is questionable regarding the applicability of existing condensate production techniques to such a high temperature high pressure (HTHP) reservoir. Therefore, it is unclear whether the existing solutions to mitigate condensate banking in conventional condensate reservoirs are suitable or not for such gas reservoirs.

This study first performed PVT experiments using fluid samples from Bozi 3 Block, and then tuned the EOS equation to characterize the phase behaviors. On this basis, a compositional reservoir model was developed for sensitivity analysis and operating condition optimization, as shown in Figure 1.

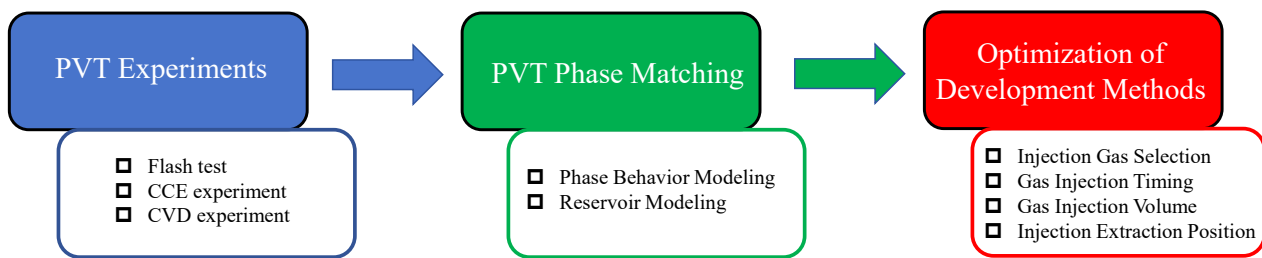


Figure 1. Technology roadmap.

2. Experimental Section

2.1. PVT Experiment

The fluid samples used in this paper were collected from the BZ3 well at a depth of 7200 m, a pressure of 104.78 MPa, and a temperature of 138.24 °C. Following the Methods for Physical Property Analysis of Fluid in Standard Oil and Gas Reservoirs (GB/T 26981-2020) [43], we conducted a series of laboratory experiments including sample check, flash, constant composition expansion (CCE), and constant volume depletion (CVD). Specifically, the sample storage bottle goes through an opening pressure test and quantity measurement under separator pressure and temperature. Both flash and CCE experiments were conducted at the initial reservoir temperature $T = 138.24$ °C. For CVD, the test pressure was dropped seven times from $p = 109$ MPa to $p = 12$ MPa, at $T = 138.24$ °C and 108.24 °C, 118.24 °C, 128.24 °C, 148.24 °C, and 158.24 °C, respectively.

2.2. Experimental Results

a. Flash test

The fluid sample bottles were opened for pressure testing and quantity checking under separator conditions. Table 1 indicates that the quality of fluid sample met the requirement for the following experiment.

Table 1. Fluid sampling check.

Sampling Depth/m	Vial Volume/mL	Sampler Numbering	Temperature/20 °C		Sample Type
			External Pressure/MPa	Turn on the Pressure/MPa	
7200	700	818,796	96	81.9	Condensate

Table 2 shows the flash experiment results and Figure 2 displays the phase diagram based on the experiment results. The composition of the fluid samples were C_1+N_2 : 89.16 mol.%, $CO_2+C_2-C_6$: 9.04 mol.%, and C_{7+} : 1.8 mol.%, which is shown as the red pentagram in Figure 2. According to the fluid composition and triangular phase diagram, the target fluid sample was identified as dry gas, wet gas, or condensate gas.

Table 2. Composition of the Bozi 3 reservoir fluid sample.

Component	Flash Oil	Flash	Well Flow	g/m ³
	% (Molar Score)	% (Molar Score)	% (Molar Score)	
H ₂ S	0.00	0.00	0.00	
N ₂	0.00	0.80	0.78	
CO ₂	0.00	0.38	0.38	
C ₁	0.00	90.16	88.38	
C ₂	0.00	6.99	6.85	85.62
C ₃	0.00	0.81	0.79	14.48

Table 2. Cont.

Component	Flash Oil	Flash	Well Flow	
	% (Molar Score)	% (Molar Score)	% (Molar Score)	g/m ³
iC ₄	0.34	0.31	0.31	7.49
nC ₄	0.72	0.32	0.33	7.97
iC ₅	1.22	0.13	0.16	4.80
nC ₅	1.29	0.09	0.11	3.30
C ₆	5.43	0.00	0.11	3.84
C ₇	16.51	0.00	0.33	13.17
C ₈	23.38	0.00	0.46	20.46
C ₉	12.45	0.00	0.25	12.57
C ₁₀	8.96	0.00	0.18	10.03
C ₁₁₊	29.71	0.00	0.58	49.91
total	100.00	100.00	100.00	233.64
C ₁₁₊ Relative molecular weight			203.5	
C ₁₁₊ Relative density			0.8279	

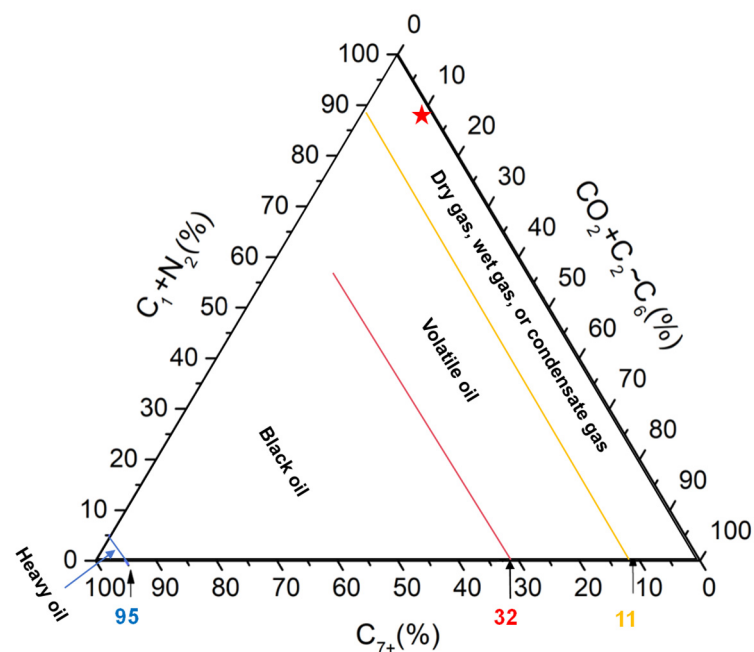


Figure 2. Triangular phase diagram of sample composition.

b. Constant composition expansion

Figure 3 shows the relative volume (which is the ratio of the sample volume at each pressure to that at the dew-point pressure), the condensate volume percentage, and compressibility factor. It was found that over the expansion with decreasing pressure at the reservoir initial temperature, the relative volume changed from 0.6202 to 3.0492, the condensate volume percentage changed from 0 to 1.53%, and the compressibility factor varied from 1.7276 to 1.0704. With the decrease in pressure, the relative volume increased monotonically and the compressibility factor decreased monotonically. The condensate volume percentage rose rapidly below the dew-point pressure with the decrease in pressure. While with the increase in temperature, the condensate volume percentage declined due to evaporation, and the dew-point pressure dropped as well.

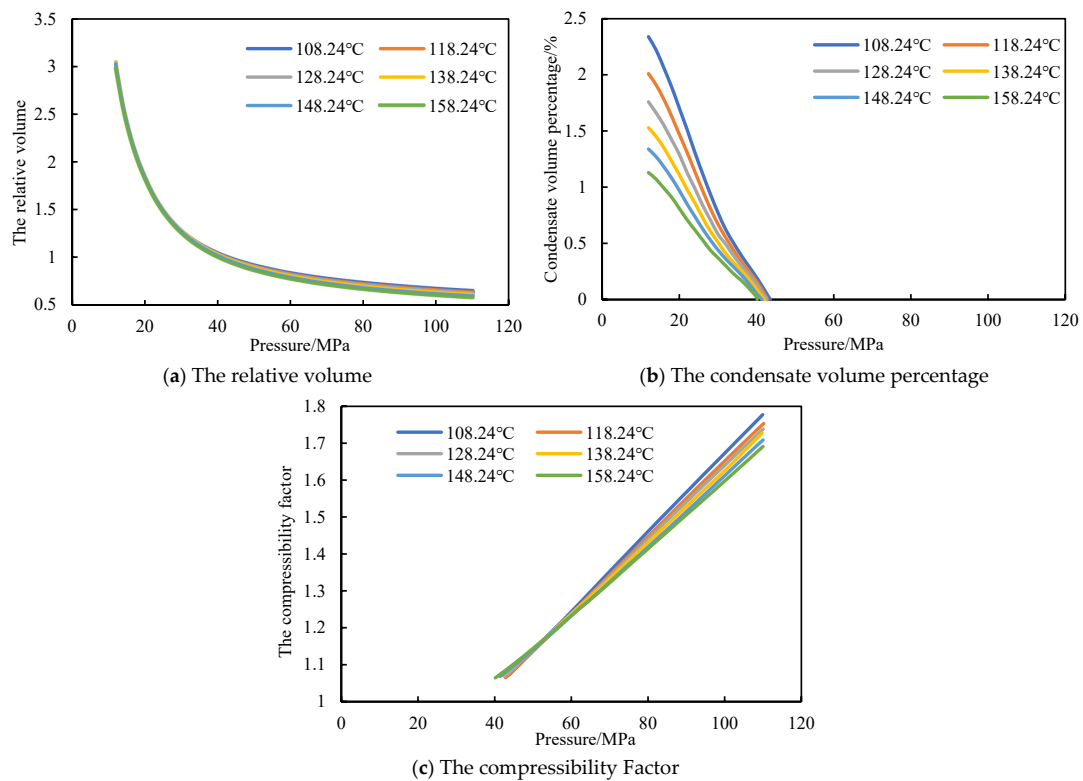


Figure 3. Plot of CCE experimental results.

c. Constant volume depletion

Table 3 shows the measured fluid composition, compressibility factor, recovery factor, and the amount of retrograde condensate over the pressure depletion process. As the pressure dropped from 42.11 MPa to 6 MPa, the content of C_1 – C_5 increased slightly, the content of C_1 rose from the initial 88.38% to the final 89.06%, and the content of C_{11+} decreased from 0.58% to 0.28%. It clearly shows that the fluid tended to be lighter and lighter during constant volume depletion. Figure 4 shows that when the pressure dropped below the dew-point pressure, $p = 42.11$ MPa, which is marked as * in Table 3, the amount of retrograde condensate increased. When the pressure dropped to $p = 12$ MPa, the content of the retrograde condensate reached the peak at 0.95%. A further decrease in pressure made the retrograde condensate smaller and smaller, which was caused by the evaporation of condensate under high temperature.

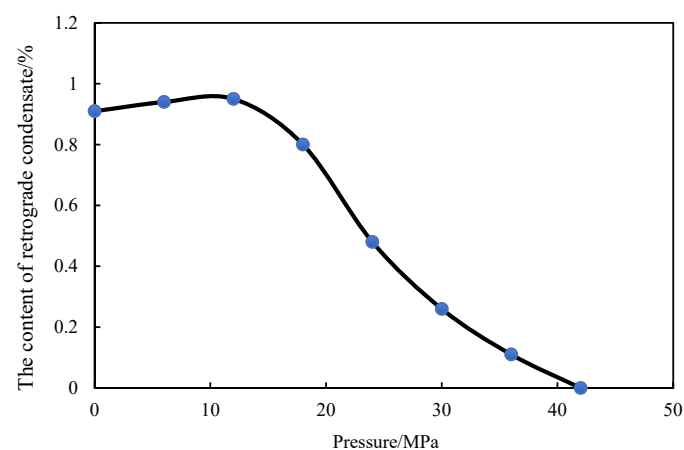


Figure 4. The content of retrograde condensate.

Table 3. Test data of constant volume depletion (138.24 °C).

Pressure, MPa		42.11 *	36.00	30.00	24.00	18.00	12.00	6.00
The compressibility factor Z		1.0704	1.0066	0.9566	0.9119	0.8966	0.9030	0.9435
Two-phase compressibility factor		1.0704	0.9295	0.9060	0.8747	0.8572	0.8514	0.8583
Cumulative percentage of extraction			10.76	21.24	34.89	49.50	66.46	83.33
Viscosity/mPa·s		0.0278	0.0254	0.0231	0.0208	0.0188	0.0171	0.0158
Composition/mol %								
N ₂	Nitrogen	0.78	0.86	0.75	0.71	0.72	0.74	0.73
CO ₂	Carbon dioxide	0.38	0.36	0.38	0.39	0.38	0.38	0.39
C ₁	Methane	88.38	88.67	88.83	88.79	89.03	89.20	89.06
C ₂	Ethane	6.85	6.62	6.88	6.99	6.88	6.87	7.00
C ₃	Propane	0.79	0.82	0.82	0.84	0.83	0.82	0.85
iC ₄	Isobutane	0.31	0.33	0.33	0.35	0.34	0.33	0.35
nC ₄	n-butane	0.33	0.34	0.36	0.38	0.38	0.36	0.38
iC ₅	Isopentane	0.16	0.20	0.18	0.20	0.19	0.18	0.19
nC ₅	n-pentane	0.11	0.15	0.13	0.14	0.14	0.13	0.14
C ₆	Hexane	0.11	0.09	0.08	0.07	0.06	0.06	0.05
C ₇	Heptane	0.33	0.28	0.23	0.21	0.19	0.17	0.16
C ₈	Octane	0.46	0.40	0.33	0.29	0.26	0.24	0.22
C ₉	Nonane	0.25	0.21	0.17	0.16	0.14	0.13	0.12
C ₁₀	Decane	0.18	0.15	0.13	0.11	0.10	0.09	0.08
C ₁₁₊	Undecane or more	0.58	0.52	0.40	0.37	0.36	0.30	0.28
Total		100.00	100.00	100.00	100.00	100.00	100.00	100.00
C ₁₁₊ molecular weight		203.5	199.7	195.9	192.2	188.4	184.6	184.9
C ₁₁₊ relative density		0.8279	0.8241	0.8203	0.8166	0.8128	0.8090	0.8098

* means the dew point pressure.

3. EOS Tuning

3.1. Phase Behavior Modeling

The experimental data were used to tune a Peng-Robinson EOS in a fluid property characterization tool, Winprop (CMG Ltd., Canada). The tuning was regarded as satisfactory as the error between the theoretical value and the experimental data was below 20%. Figures 5 and 6 show the respective errors for CCE and CVD experiments. Figure 7 shows all the differences between experimental data and the corresponding theoretical prediction. All of the errors in the data (137) were smaller than 16%, among which 129 data were below 5% and those with larger errors (>10%) took place in the tuning of the compressibility factor. This was caused by the small experimental data itself.

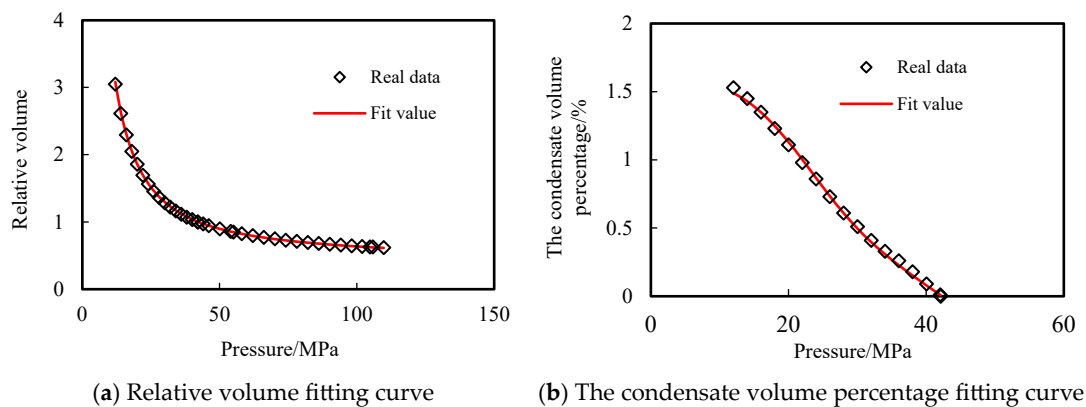


Figure 5. Cont.

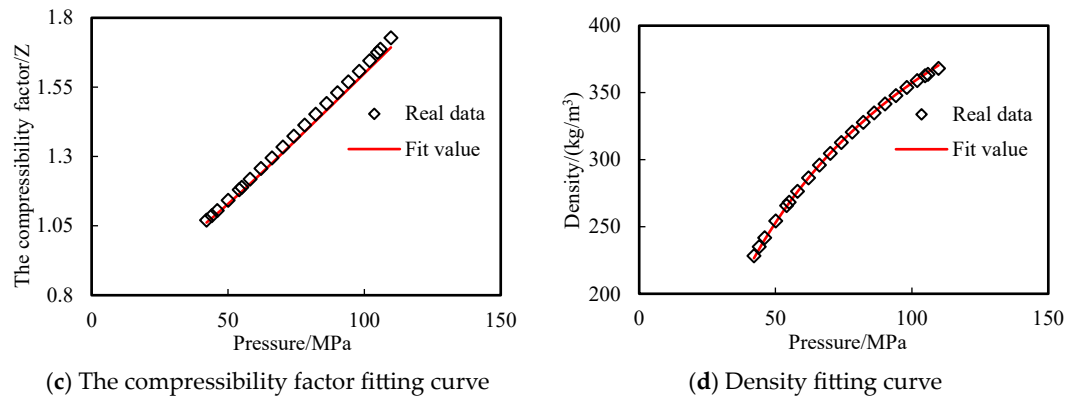


Figure 5. CCE fitting results.

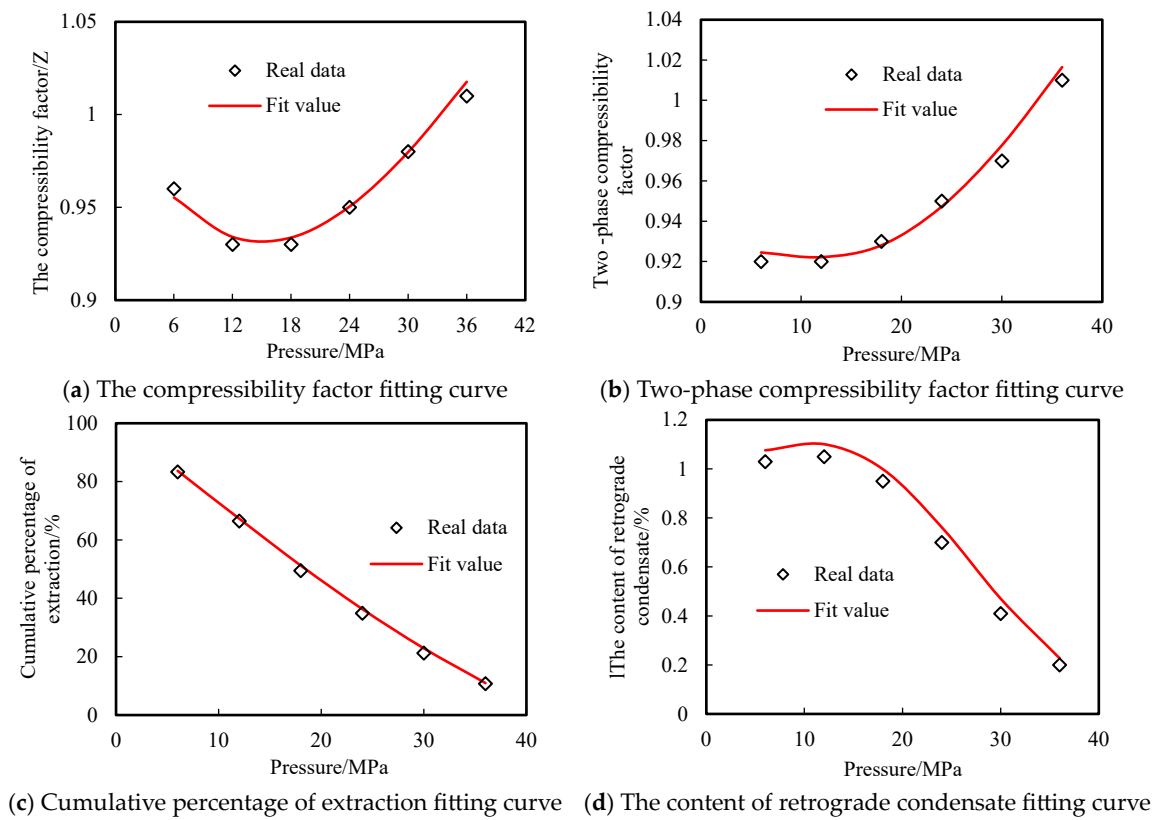


Figure 6. CVD fitting results.

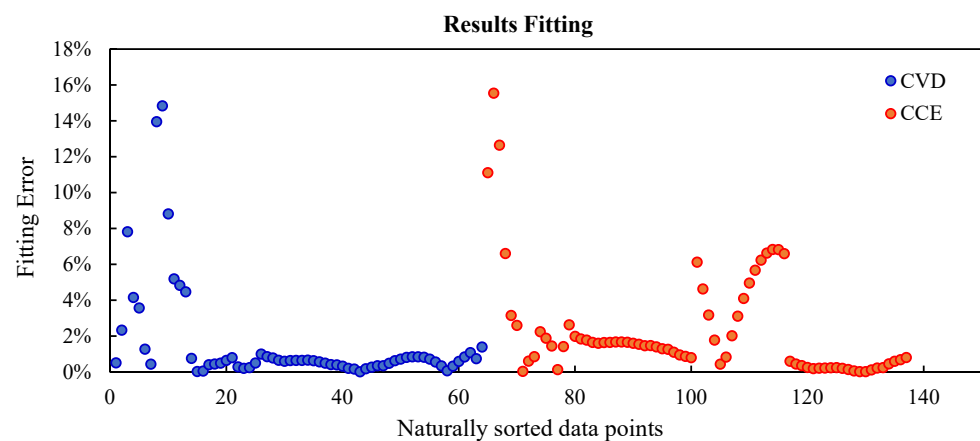


Figure 7. The differences between experimental data and the corresponding theoretical prediction.

Figure 8 shows the phase diagram of the condensate, which indicated the target reservoir was a typical undersaturated condensate gas reservoir whose initial pressure was much higher than the dew-point pressure. The CVD data show that the maximum amount of retrograde condensate was 0.95%, implying the retrograde condensation would not be problematic. However, if the flowing bottom-hole pressure (BHP) and reservoir pressure drop below 42.11 MPa, there would be serious condensate banking near the wellbore.

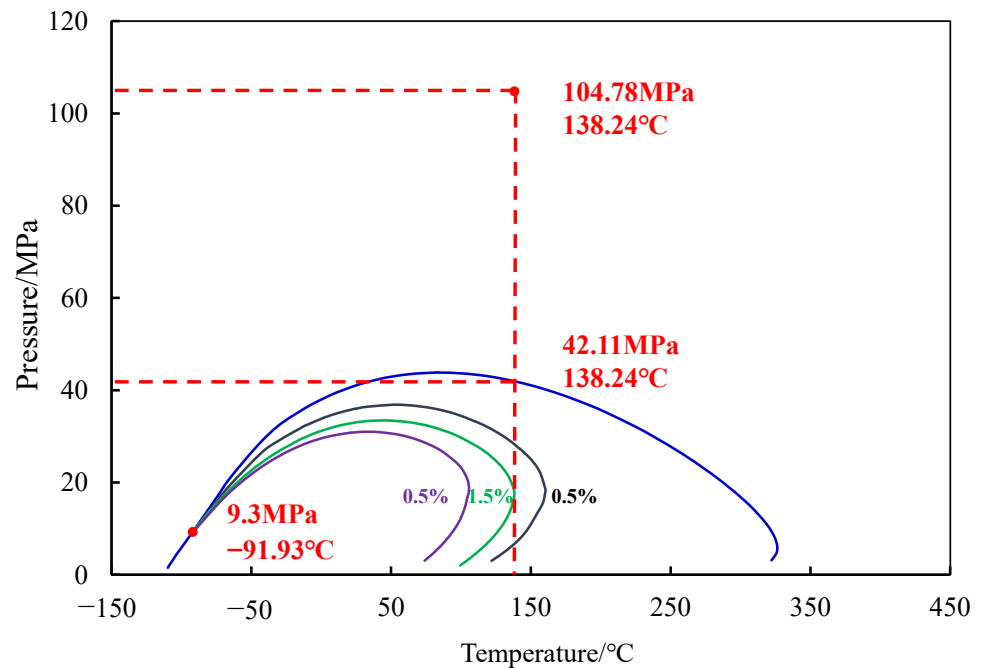


Figure 8. The P-T phase diagram.

3.2. Reservoir Modeling

A dual-perm compositional reservoir model of the Bozi 3 Block was developed by using a commercial simulator GEM (CMG Ltd., Canada) (Figure 9). Table 4 shows the basic physical properties and operation conditions regarding the numerical model. With the model, history match was first conducted for the BZ3 well production data, as shown in Figure 10. Then, the gas injection process was optimized via sensitivity analysis.

Table 4. Basic parameters of the model.

Parameter	Values	Unit	Source
Reservoir pressure	104.78	MPa	Geological data
Reservoir temperature	138.24	°C	PVT data
Matrix permeability	0.024	mD	Geological data + historical fitting adjustment
Matrix porosity	6	%	Geological data + historical fitting adjustment
Water saturation	36	%	Geological data
Net gross ratio	0.32	/	Geological data + historical fitting adjustment
Crack permeability	10	mD	Geological data + historical fitting adjustment
Crack porosity	0.1	%	Geological data + historical fitting adjustment
Crack density	5	strip/m	Geological data + historical fitting adjustment

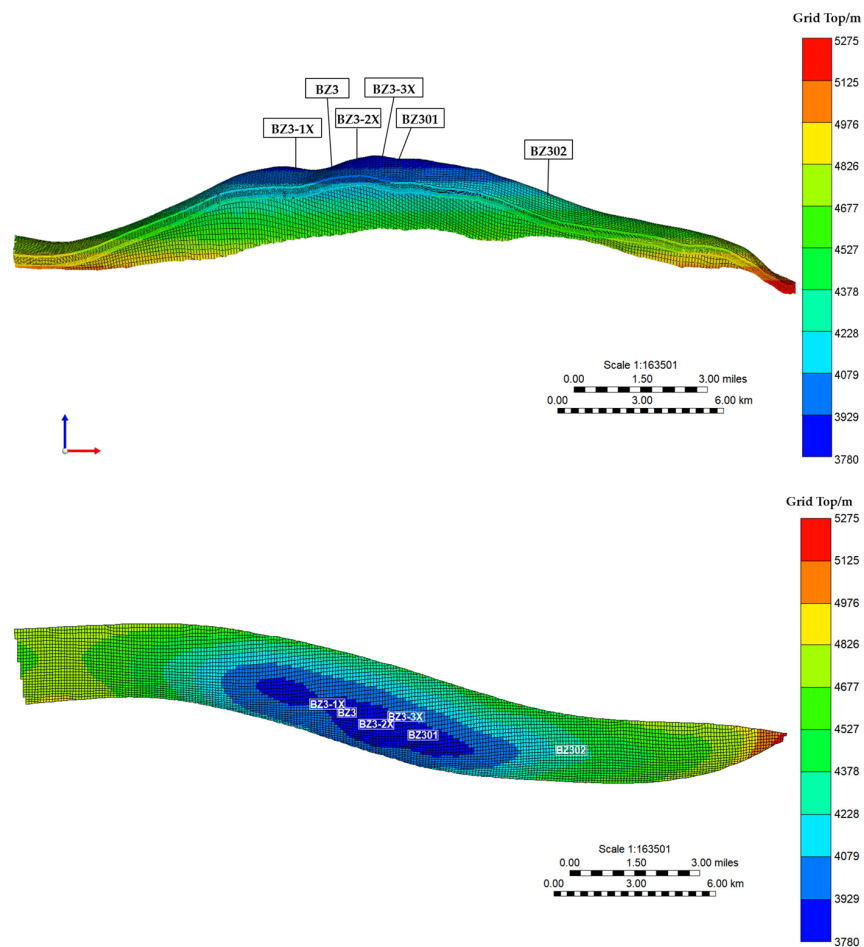


Figure 9. Model diagram of Bozi 3.

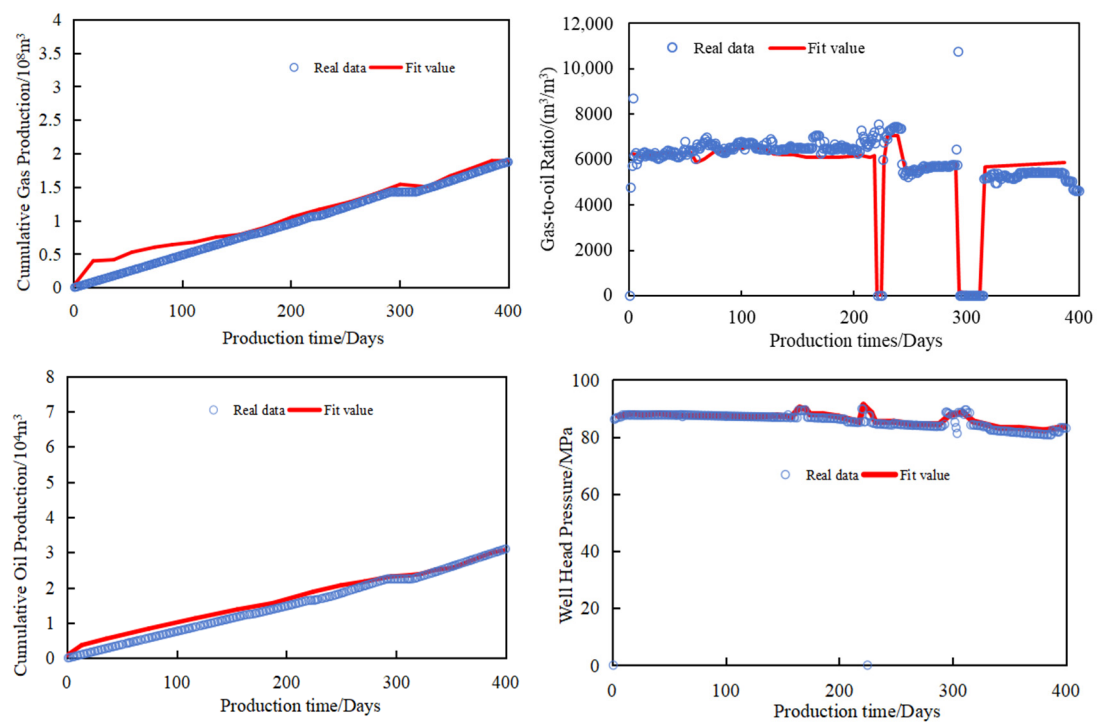


Figure 10. Production dynamic history fitting.

4. Injection Gas Selection

In order to eliminate the influence of heterogeneity in actual geological models, a conceptual model was established to select the rational injection gas type with the maximum condensate oil recovery. The reservoir was discretized in space as $118 \times 59 \times 5$ (total grids = 34,810), with each grid having a dimension of $30 \text{ m} \times 30 \text{ m} \times 23 \text{ m}$. The other basic physical properties and operation conditions regarding the conceptual model were the same as the Bozi 3 reservoir model, as shown in Table 4. Two wells were set to simulate the retrograde condensation during the pressure decline process.

According to its production history of Bozi 3 Block, the retrograde condensation took place after 2600 days of production at a constant rate of $q = 50 \times 10^4 \text{ m}^3/\text{d}$. Afterwards, methane, recycled dry gas (90.3% of C_1 and 9.7% of C_{2+} , CO_2 and N_2), nitrogen, and carbon dioxide were injected respectively into Well 2 at an injection rate of $50 \times 10^4 \text{ m}^3/\text{d}$ for 1000 days, following a pressure depletion at the same rate of $50 \times 10^4 \text{ m}^3/\text{d}$. Figures 11–15 compare their retrograde condensate saturations. It was found that: (1) the recovery mechanisms of methane and recycled gas were similar, maintaining the formation pressure and reducing the condensate oil saturation, which effectively alleviated the condensate blocking around the injection well. There was nearly no retrograde condensate between wells during gas injection. (2) Injecting nitrogen aggravated the retrograde condensation, because nitrogen increased the dew-point pressure and caused retrograde condensation to occur earlier. (3) Carbon dioxide injection created an extraction zone near the borehole, which inhibited retrograde condensation between wells. Overall, methane was identified as the optimal injection gas.

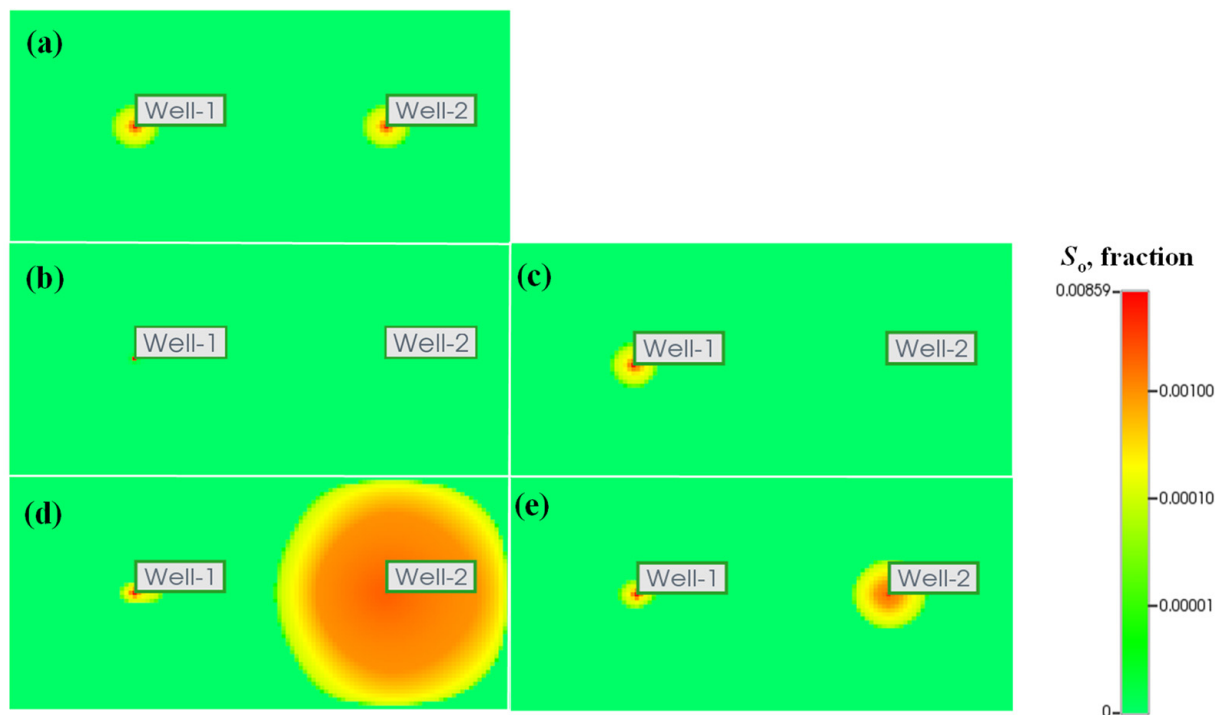


Figure 11. Retrograde condensate saturations for 3000 days. (a) 3000 day's depletion; (b) 2600 day's depletion+400 days' CH_4 injection; (c) 2600 day's depletion+400 days' recycle gas injection; (d) 2600 day's depletion+400 days' N_2 injection; (e) 2600 day's depletion+400 days' CO_2 injection.

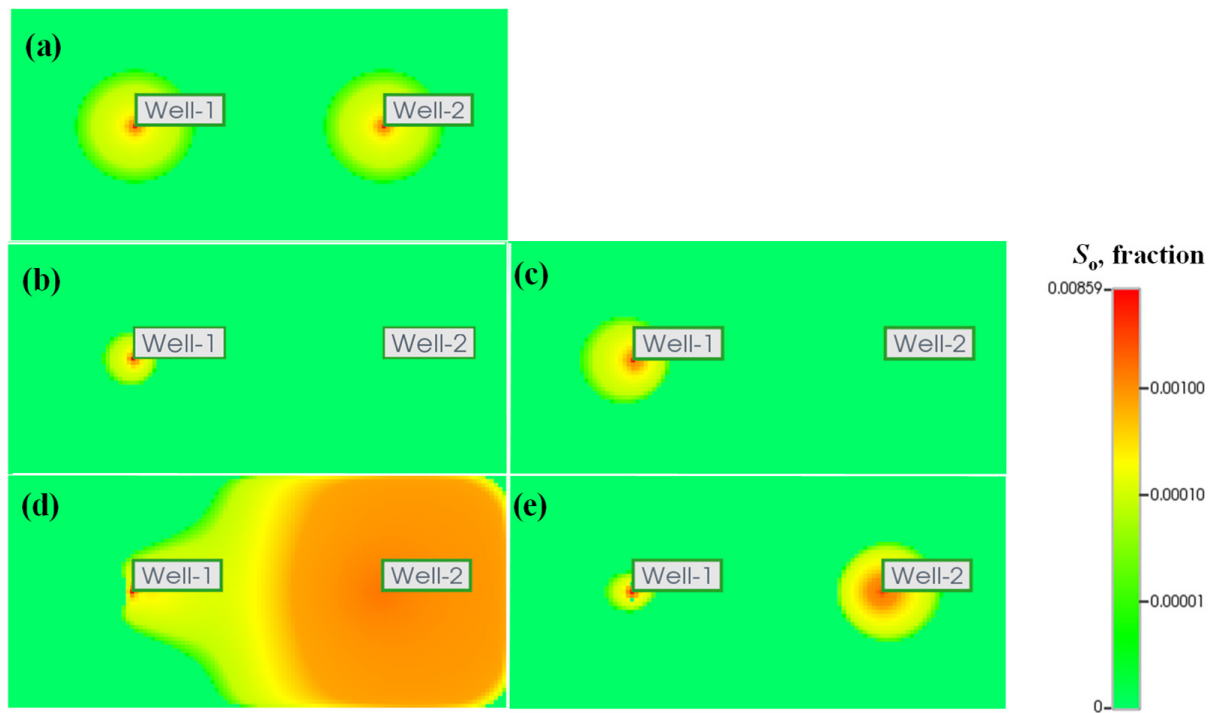


Figure 12. Retrograde condensate saturations for 3100 days. (a) 3100 day's depletion; (b) 2600 day's depletion+500 days' CH₄ injection; (c) 2600 day's depletion+500 days' recycle gas injection; (d) 2600 day's depletion+500 days' N₂ injection; (e) 2600 day's depletion+500 days' CO₂ injection.

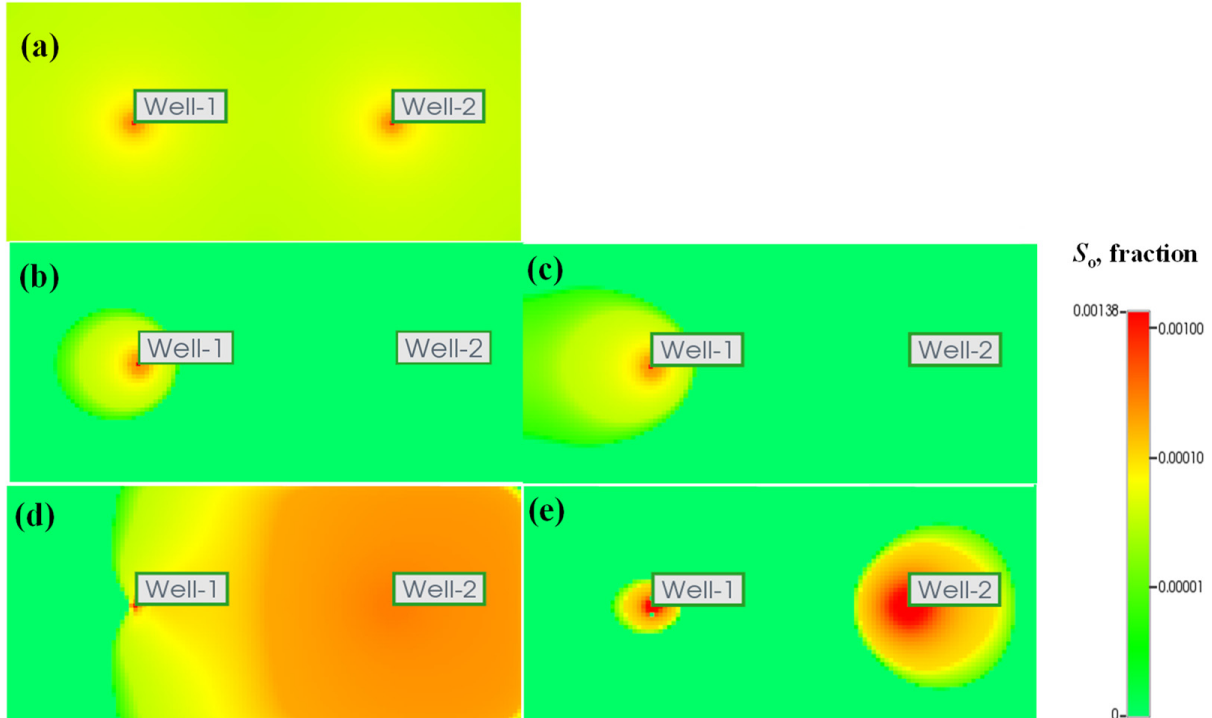


Figure 13. Retrograde condensate saturations for 3200 days. (a) 3200 day's depletion; (b) 2600 day's depletion+600 days' CH₄ injection; (c) 2600 day's depletion+600 days' recycle gas injection; (d) 2600 day's depletion+600 days' N₂ injection; (e) 2600 day's depletion+600 days' CO₂ injection.

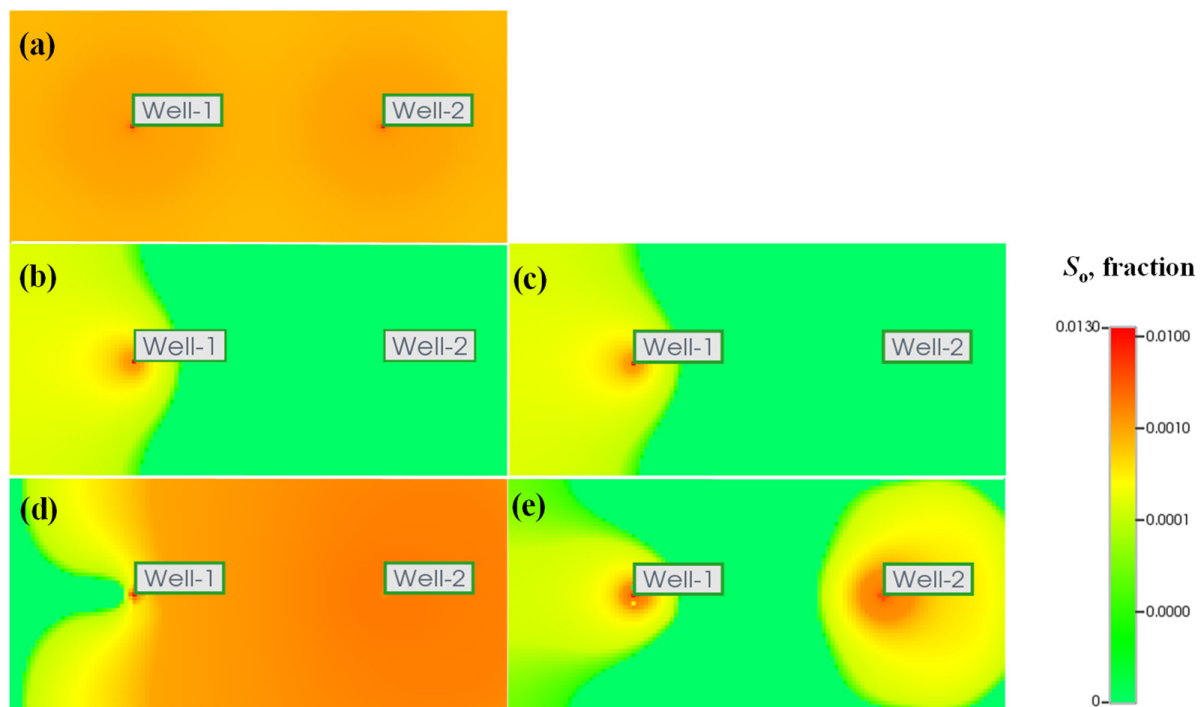


Figure 14. Retrograde condensate saturations for 3500 days. (a) 3500 day's depletion; (b) 2600 day's depletion+900 days' CH₄ injection; (c) 2600 day's depletion+900 days' recycle gas injection; (d) 2600 day's depletion+900 days' N₂ injection; (e) 2600 day's depletion+900 days' CO₂ injection.

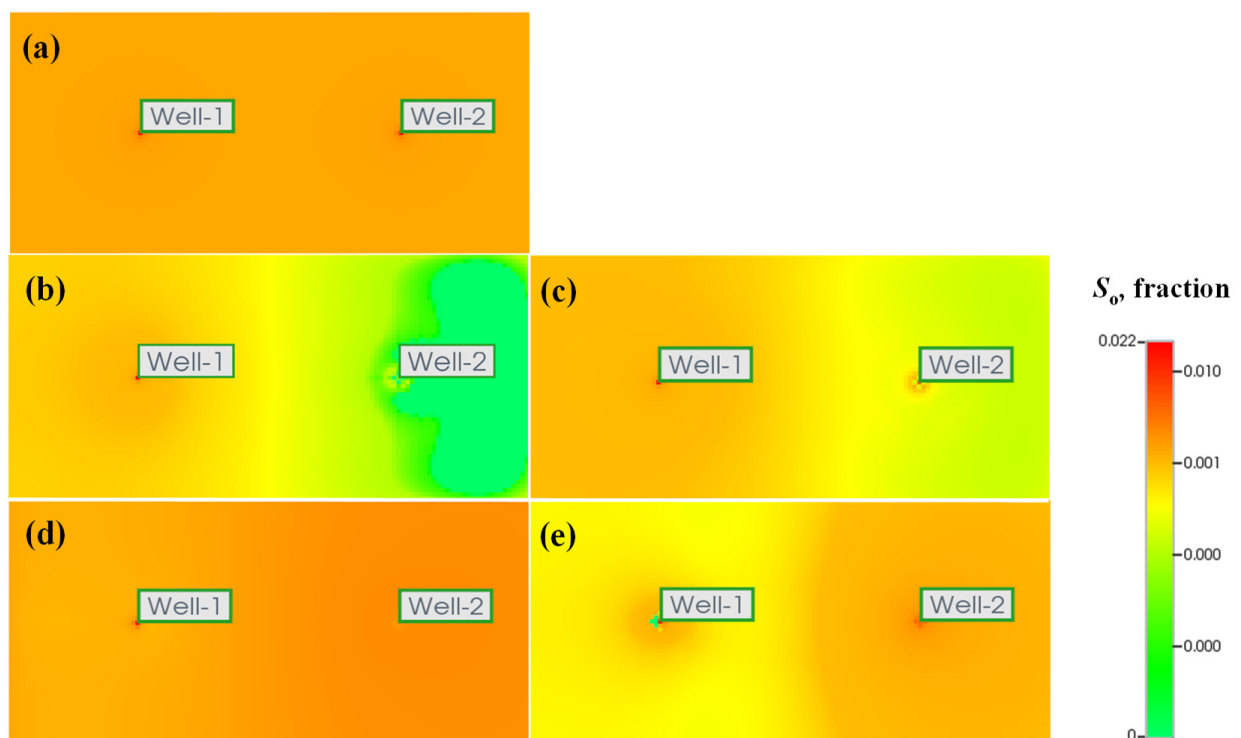


Figure 15. Retrograde condensate saturations for 4550 days. (a) 4550 day's depletion; (b) 2600 day's depletion+1000 days' CH₄ injection+ 950 day's depletion; (c) 2600 day's depletion+1000 days' recycle gas injection+ 950 day's depletion; (d) 2600 day's depletion+1000 days' N₂ injection+ 950 day's depletion; (e) 2600 day's depletion+1000 days' CO₂ injection+ 950 day's depletion.

5. Sensitivity Analysis

5.1. Gas Injection Timing

Bozi 3 Block is a long and narrow anticline trap with a large east/west length and a small south/north width. The high point has an elevation of -3800 m, a burial depth of -5827 m, and a structural amplitude of 900 m. The east/west length is about 22.7 km and the south/north width 3 km, with a long axis/short axis ratio of about $7.6:1$ and a coverage area of 55.42 km².

After 2400 days of depletion production, the Bozi 3 reservoir pressure dropped to the dew-point pressure and the pre-set production rate ($q = 50 \times 10^4$ m³/d) did not stay stable at $t = 2600$ th day. To determine the optimal timing for gas injection, three cases were run and compared. Case 1: depletion production for 10,000 days (base case); Case 2: injection of gas for 1000 days at $t = 2400$ th day when BHP declined below dew-point pressure; and Case 3: injection of gas for 1000 days at $t = 2600$ th day when the production rate started to drop. Table 5 shows the respective oil production of gas injection results.

Table 5. Sensitivity analysis for injection timing.

Option	Case 1	Case 2	Case 3
Development Approach	Depletion development	Inject at the Dew-point pressure	Inject when production is reduced
Timing of injection/Day	/	2400	2600
Injection duration/Days	/	1000	1000
Final oil production/m ³	571,901	573,871	574,755
Oil production before injection/m ³	/	403,089	434,261
Increase oil production/m ³	/	1970	2854
Proportion of condensate production increase	/	1.17%	2.07%
Cumulative gas production/m ³	3.56×10^9	4.03×10^9	4.03×10^9
Injection volume/m ³	/	5.00×10^8	5.00×10^8
Gas boost/m ³	/	4.63×10^8	4.65×10^8
Total loss of gas volume/m ³	/	3.67×10^7	3.54×10^7

It was found that Case 3 better improved the condensate oil recovery, which was 2.07% higher than that of Case 1. In addition, the average reservoir pressure increased by 2.4 MPa to 15 MPa after 1000 days of gas injection (Figure 16). When the BHP dropped below the dew-point pressure, a small amount of the condensate was separated near the borehole, as reflected by the CVD test data. Injecting methane at this moment (Case 2) raised the reservoir pressure, yet its oil production was not higher than that of Case 3.

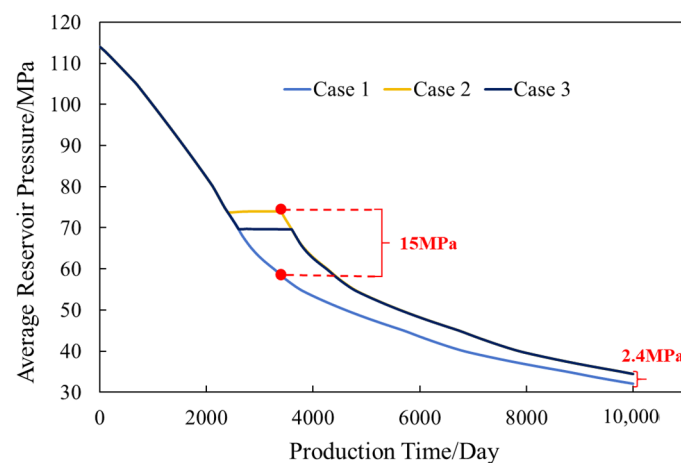


Figure 16. Variation in the average pressure of the reservoir.

5.2. Gas Injection Volume

To analyze the effects of gas injection volume in Bozi 3 Block, two more cases were run. Case 4: methane was injected for 2000 days when the reservoir pressure dropped to the dew-point pressure (at $t = 2400$ th day); Case 5: methane was injected for 2000 days when the pre-set production rate became unstable (at $t = 2600$ th day). Table 6 shows the respective oil production of gas injection results. With all the cases (Cases 1–5) compared, it was found that Case 3 had a higher oil production improvement, whereas the condensate oil production decreased by 1.15% and 0.58% in Case 4 and Case 5, respectively. The average reservoir pressure increased by 4.7 MPa–23 MPa (Figure 17). Moreover, it was clear that 2000 days of gas injection can over lift the reservoir pressure, resulting in a drop in condensate production. Therefore, the gas injection volume needed to be set in a reasonable range.

Table 6. Sensitivity analysis for injection volume.

Option	Case 1	Case 4	Case 5
Development approach	Depletion development	Inject at the Dew-point pressure	Inject when production is reduced
Timing of injection/Days	/	2400	2600
Injection duration/Days	/	2000	2000
Final oil production/m ³	571,901	569,967.25	571,098
Oil production before injection/m ³	/	403,089	434,261
Increase oil production/m ³	/	−1933.98	−802.281
Proportion of condensate production increase	/	−1.15%	−0.58%
Cumulative gas production/m ³	3.56×10^9	3.48×10^9	3.48×10^9
Injection volume/m ³	/	1.00×10^9	1.00×10^9
Gas boost/m ³	/	9.17×10^8	9.17×10^8
Total loss of gas volume/m ³	/	8.29×10^7	8.28×10^7

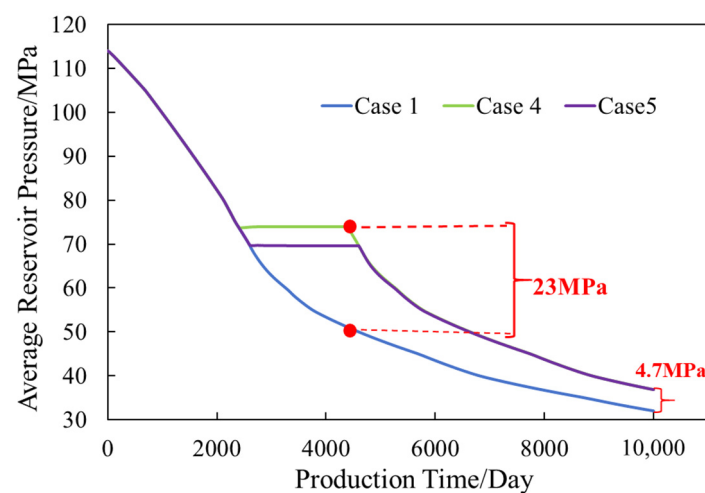


Figure 17. Variation in the average pressure of the reservoir.

5.3. Injection and Extraction Position

There are six wells in the Bozi 3 Block, namely BZ3, BZ301, BZ3-1X, BZ3-2X, BZ3-3X, and BZ3-K2. The burial depth difference of the block is up to 40 m, and the perforations can be set at the upper or lower part of the reservoir. To optimize injection/production positions, three cases were analyzed. Case 6: injection at the upper part and production at the lower part (BZ3 well), Case 7: injection at the lower part and production at the upper part (BZ3-3X well), Case 8: simultaneous injection at both the upper and lower parts (BZ3 and BZ3-3X wells). Table 7 compares the corresponding simulation results. It was found

that Case 8 had higher condensate oil production than the other two cases; its oil production was 8690.43 m³ more and recovery 2.75% higher than those of the base case. Case 8 reached a more effective production of condensate oil and obtained the largest recovery. Case 7 had better performance than Case 6 because the condensate oil was distributed more on the upper half of the reservoir.

Table 7. Sensitivity analysis for injection and production positions.

Option	Injection Method	Gas Injection Concept	Increase Oil Production	Percentage of Increase in Production
Case 6	BZ3 inject (K1bs)	Injection at the upper part and production at the lower part	6193.91	1.96%
Case 7	BZ3-3X inject (K1bx)	Injection at the lower part and production at the upper part	6731.13	2.13%
Case 8	BZ3 and BZ3-3X inject	Simultaneous injection at both the upper and lower parts	8690.43	2.75%
Case 1	No Injection (Depletion development)	/	/	/

6. Conclusions and Recommendation

- (1) Bozi 3 Block is a super deep condensate reservoir with a high temperature (138.24 °C) and high pressure (104.78 MPa). PVT experiments showed the composition of the fluid sample were: C₁+N₂: 89.16 mol.%, CO₂+C₂-C₆: 9.04 mol.%, and C₇₊: 1.8 mol.%.
- (2) The phase diagram indicated that the critical temperature and pressure of the fluid were −91.93 °C and 9.30 MPa, respectively; the critical condensate temperature and pressure were 326.24 °C and 43.83 MPa, respectively.
- (3) Compositional reservoir simulation showed that the recovery mechanisms of methane and recycled gas injection were similar, maintaining the formation pressure and reducing the condensate oil saturation, which effectively mitigated the condensate blocking around the injection well. There was nearly no retrograde condensate between wells during gas injection. Injecting nitrogen aggravated the retrograde condensation. Carbon dioxide injection created an extraction zone near the borehole, which inhibited retrograde condensation between wells. Overall, methane was identified as the optimal injection gas.
- (4) Gas injection started when the production began to fall, achieving higher recovery than gas injection starting when the pressure fell below the dew-point pressure. When the production rate starts to fall, simultaneous injection of methane at both the upper and lower parts of the reservoir, at a rate of 50 × 10⁴ m³/d for 1000 days, can effectively produce condensate oil over the entire block. This scheme achieved 8690.43 m³ more oil production and 2.75% higher recovery factor in comparison with depletion production.

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