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Application of EOR Using Water Injection in Carbonate Condensate Reservoirs in the Tarim Basin

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Abstract: The largest carbonate condensate field has been found in the Tarim Basin, NW China. Different from sandstone condensate gas reservoirs, however, the conventional gas injection for pressure maintenance development is not favorable for Ordovician fracture-cave reservoirs. Based on this, in this paper, 21 sets of displacement experiments in full-diameter cores and a pilot test in 11 boreholes were carried out to study enhanced oil recovery (EOR) in complicated carbonate reservoirs. The experimental results show that the seepage channels of the gas condensate reservoirs are fractures, which are quite different from sandstone pore-throat structures. Condensate oil recovery using water injection was up to 57–88% in unfilled fractured caves and at ca. 52–80% in sand-filled fractured caves. These values are much higher than the 14–46% and 17–58% values obtained from the depletion and gas injection experiments, respectively. The water injection in 11 wells showed that the condensate oil recovery increased by 0–17.7% (avg. 3.1%). The effective EOR for residual oil replacement using water injection may be attributed to fractures, as the gas channel leads to an ineffective gas circulation and pipe flow in fracture-cave reservoirs, which is favorable for waterflood development. The complicated fracture network in the deep subsurface may be the key element in the varied and lower oil recovery rates obtained from the wells than from the experiments. This case study provides new insights for the exploitation of similar condensate gas reservoirs.

Keywords: Tarim Basin; fracture-cave reservoir; oil recovery from condensate gas reservoir; water injection; enhanced oil recovery

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1. Introduction

In order to increase oil recovery in condensate gas fields, the methods and technologies that are usually used include depletion recovery, circulating gas injection and nitrogen injection, as well as horizontal well development [1]. These mainly involve sandstone condensate gas reservoirs. In the production process of condensate gas reservoirs, when the reservoir pressure drops below the dew-point pressure, the retrograde condensation phenomenon will occur and lead to low oil recovery due to a capillary force with low relative permeability [1–3]. The retrogression of condensates in sandstone reservoirs can affect the recovery of both oil and gas in condensate gas fields [2–4]. In order to increase the recovery of oil in condensate gas fields, many enhanced oil recovery (EOR) technologies, such as gas injection, water injection, water–gas alternation and nitrogen injection, have been studied in laboratories and in condensate fields [5–7]. In China, the Kekeya condensate gas field, Yaha condensate gas field and Dazhangtuo condensate gas reservoir were developed using circulating gas injection, which increased the recovery of oil [8–11]. The oil recovery rate of the Yaha condensate field increased by 25% compared with depletion development, and the oil recovery rate of the Dazhangtuo condensate gas field after gas injection increased by 26% compared with depletion in a pilot test of circulating gas injection in the Kekeyasi gas formation. In fractured condensate gas reservoirs, cyclic gas injection research shows an abnormal phenomenon during the gas injection phase where the oil recovery degree is lower than the depletion recovery. However, the oil recovery degree increases with an increase in the gas reinjection ratio. With the recycle ratio being used for a long time, the greater and earlier the gas injection, the longer the production time of the gas injection and the higher the oil recovery, which is better than the depletion recovery effect [9]. At present, gas injection and pressure-preserving development technology are widely used, and the main purpose of their enhanced oil recovery is to prevent the occurrence of retrograde condensation. These can effectively avoid or slow down the oil loss in formations that are difficult to extract from subsurfaces.

Fishlock et al. (1996) experimentally studied the development effect of condensate gas reservoir depletion after water flooding [10,11], and they noted that maximum recovery was achieved when 25%HCPV water was injected before gas reservoir depletion. Furthermore, the optimal injection amount was different from the amount required to achieve the highest oil recovery and the highest natural gas recovery in condensate gas fields. Cheng et al. (2003) studied the recovery of condensate gas reservoirs by water injection in a laboratory experiment and a field test [12]. The Banqiao abandoned condensate gas reservoir achieved a significant increase in oil through sewage injection, which basically confirms the feasibility of water injection for condensate gas reservoirs. Wang et al. (2006) studied the water flooding mechanism of a condensate gas reservoir based on the lab core water flooding experiment of the Banqiao abandoned condensate gas reservoir in the Dagang Oilfield in China [13]. The results showed that the depletion rate had little influence on oil and gas recovery in the Banqiao condensate gas reservoir. It is feasible to develop condensate gas reservoirs with water flooding after depletion, and the natural gas captured during water flooding can be recovered in the process of depleted production after water flooding. Under the same conditions, increasing the water injection speed is beneficial to improve oil recovery, and the effect of increasing the pressure of the water injection at the end of the failure period is worse than that of low-pressure water injection. Xiao et al. (2012) conducted an experiment comparing the effect of different development modes for fracture-vuggy condensate gas reservoirs by using artificial fracture-vuggy cores [14]. The study showed that early water injection to maintain pressure should be given priority for horizontally connected fracture-vuggy units, and water injection to replace oil is the best for vertically connected fracture-vuggy units. Guo et al. (2013) studied the exhaustion development effect of a fracture-vuggy condensate gas reservoir [15], and they showed that bottom exhaustion was the best depletion development mode and that the existence of a water body was conducive to oil recovery. Peng et al. (2014) showed that the effect of water injection is better in experiments on the water injection development for fracture-vuggy condensate gas reservoirs [16], and the higher the formation pressure, the better the water injection effect. In short, the research on water injection for both conventional sandstone and fracture-vuggy carbonate condensate gas reservoirs is mainly in the stage of experimental mechanism research [14–19]. Although a mechanism study has shown that water injection is feasible to some extent, the traditional view is that gas reservoirs are repellent to water. Once water cuts into gas reservoirs, the gas well will stop spraying prematurely, and water sealing occurs after water flooding. Moreover, the recovery factor of a water-cut gas reservoir is usually not as high as that of a gas drive reservoir. Therefore, condensate gas reservoirs lack applications of water injection in fracture-cave reservoirs in deep subsurfaces.

The Tazhong I Gasfield is the largest carbonate condensate gas field in China, and it was discovered in the central section of the Tarim Basin [20]. In this condensate gas field, there are complicated fractured carbonate reservoirs and fluid phases. Due to the oil economic value being much higher than the gas in this field, development is mainly focused on the middle/high-oil-content reservoirs. Since the development of condensate gas reservoirs, depletion development has been the main development method of their middle/high oil content. However, the recovery of oil from complicated fracture-cave reservoirs is limited with the depletion recovery method.

To contribute to this field, this paper presents 21 sets of displacement experiments in full-diameter cores and a pilot test in 11 boreholes, and it discusses the method to enhance oil recovery in this kind of special condensate gas reservoir.

2. Geological Background

The Tarim Basin is the largest petroliferous basin in northwest China. It covers more than 560,000 km^2 and is surrounded by the Tianshan Mountains to the north and the Tibetan Plateau to the south (Figure 1). It has an Archean–Early Neoproterozoic crystalline basement, which is covered by thick Late Neoproterozoic–Quaternary sediments with multi-stage sedimentary–tectonic evolution, recording the supercontinent assembly and breakup in the Late Neoproterozoic, the opening and closure of the Tethys in the Palaeo–Mesozoic and the Indo–Asian collision in the Cenozoic [20–23].

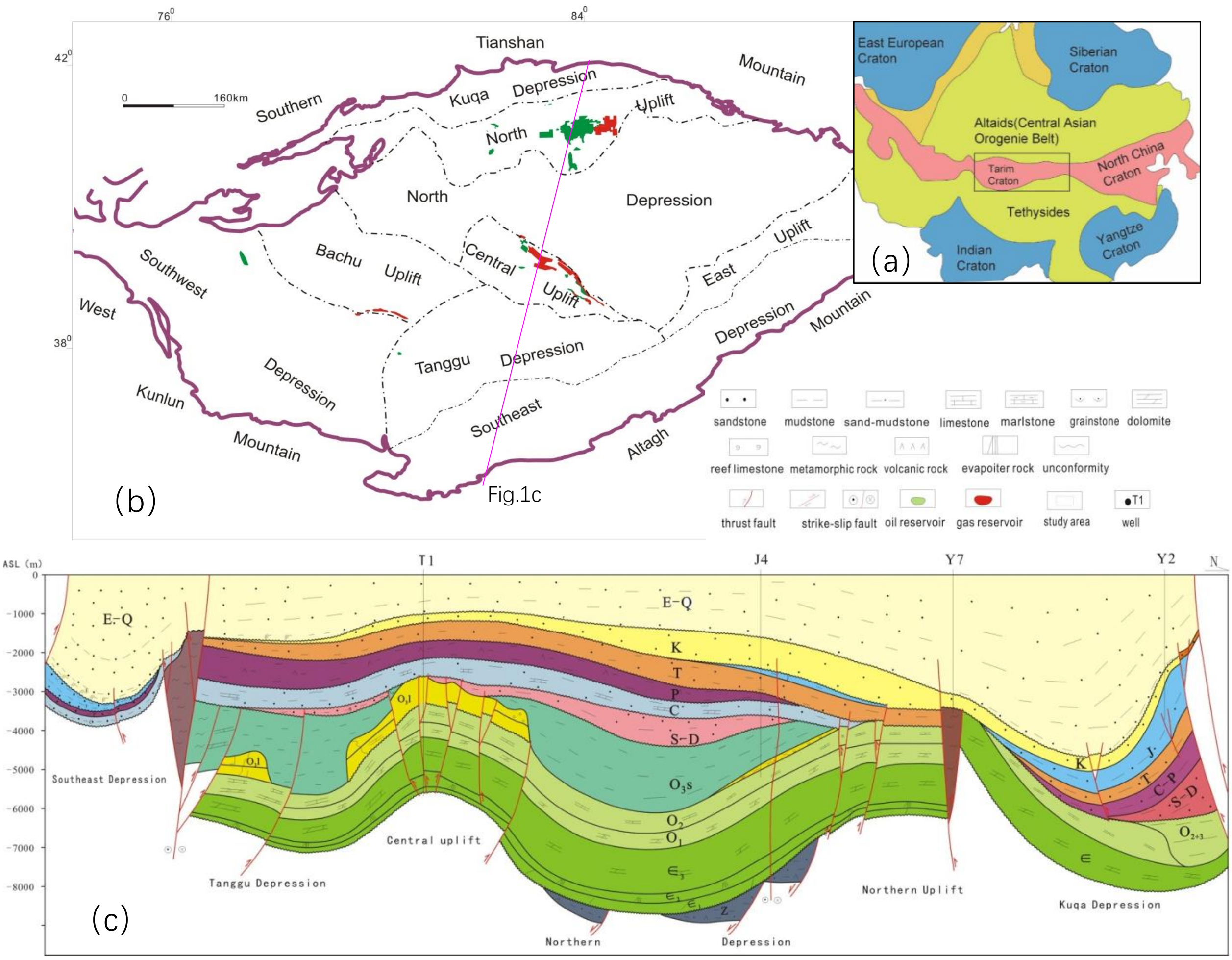

Figure 1. (**a**) The tectonic location of the Tarim Craton, (**b**) the tectonic unit division and the oil/gas accumulation in the Cambrian–Ordovician carbonates, and (**c**) geological section across the Tarim Basin (revised after reference [22]).

The Central Uplift is in the central part of the Tarim Basin, and it has an area that covers about 22,000 km^2 (Figure 1). It is part of the platform of the western Tarim area in the Cambrian–Late Ordovician and has a carbonate thickness of more than 2000 m. The Central Uplift, striking NW–SE, formed before the Late Ordovician, had a tectonic uplift before the Silurian and had regional unconformities in the Late Devonian (Figure 1c). There has been little deformation since the Carboniferous [21,22]; a multi-layered and uniform succession of sediments was laid on the Lower Paleozoic anticline without large fault activities. The Ordovician carbonates in the Central Uplift are about 1000–1200 m thick, with 300–500 m of the Upper Ordovician and 600–700 m of the Lower–Middle Ordovician and an unconformity between the two intervals (Figure 1c). In addition to the large platform margin reef–shoal complex of the Upper Ordovician that developed along the north margin, a detailed lithology and microfacies description of the Ordovician carbonates show that there is a stable platform in the northern slope [22]. The main body of the platform consists of different kinds of packstones and wackstones, as well as grainstones and mudstones with a polycyclic depositional combination. The Lianglitage Formation carbonates, which are mainly reef–shoal reservoirs, occur widely in the area, especially in the platform margin [24,25]. The Yingshan Formation carbonate of the Early–Middle Ordovician, part of the stable inner platform of the Tarim platform, has undergone karstification to form weathering crust reservoirs across the paleo-uplift [26].

These carbonate reservoirs significantly differ from the high-matrix-porosity carbonates described in other parts of the world. Except for a few scattered caves with high porosity and permeability, the tight carbonate reservoirs distributed with a large area in the broad slope have a very low matrix porosity (<5%) and low permeability (<0.5 mD) with intensive heterogeneity [25–27]. Regardless of their lithology, the host rocks lost almost all of their matrix porosity during the long process of diagenesis. Oil/gas is produced mainly from the fracture-cave reservoir by the large karst fractures and caves. The fracture-cave reservoir generally shows drilling blowout and a large amount of mud loss during drilling. The average throat radius of the Ordovician matrix reservoirs is about 0.02–1.82 μm, with a mean of 0.12 μm; however, the fracture opening width ranges from 2 to 100 μm [28]. The permeability in the fractured reservoirs can be more than 5 mD, which is 1–3 orders of magnitude higher than the matrix reservoirs. As such, the Ordovician carbonate reservoirs can be divided into tight matrix reservoirs and localized large "sweet spot" fracture-cave reservoirs [22]. The large fracture-cave reservoirs are the main targets for oil/gas production in gas field development.

3. Methods and Data

Experiments were carried out to optimize the development process in condensate gas fields. According to the geological background of typical reservoirs, the displacement experimental temperature was set at 140.6 °C, the dew-point pressure was set at 55.4 MPa, and the content of the condensate was 533 g/cm^3. Condensate gas was prepared from in situ oil/gas samples. The injected water and gas were from the field, and the mineralization degree of injected water was mg/L with a water type of calcium chloride. Full-diameter core equipment with a high temperature and high pressure was adopted to cut the core without fractures obtained from outcrops, and 3 holes were made on the fracture surface (Figure 2) to simulate the cave reservoir. The length of the core is about 11.117 cm, and the diameter is 9.965 cm. The unfilled fractures were used as seepage channels with a fracture permeability of 48.26 mD, and the host rock permeability was neglected. The porosity of the fracture cave is up to 15%, and the fracture cave has longitudinal connectivity.

Figure 2. Photograph of artificial fractured-vuggy full-diameter core.

Twenty-one sets of full-diameter core displacement experimental studies were designed for vertical depletion, horizontal depletion, the injection of dry gas to maintain pressure, the injection of water to maintain pressure, the injection of dry gas to refine the structure and the phased injection of water to maintain pressure (see detailed procedure in references [14,15]). The water injection and pressure preservation in different stages refer to the step-like decline in the gas reservoir pressure. First, the dew-point pressure dropped by 10% to 50 MPa, then the water injection was maintained until the pressure was restored to the dew-point pressure, and finally the water injection was stopped after the collapse to 50 MPa, completing one-time water injection and pressure preservation. For the second time, the water injection was carried out until the formation pressure recovered to the dew-point pressure and then collapsed to 50 MPa. After several rounds of water injection under a pressure of 50 MPa, the pressure of the gas reservoir reduced by 5 MPa, which became the pressure-preserving value (45 MPa) to carry out the water injections and preserve pressure preserving in the second-stage. The last stage of the water injection maintained a pressure of 30 MPa, and then it decreased to atmospheric pressure. In order to simulate the filling of the fracture cavity, we set up sand filling of the fracture and cave as the control experiment. The experimental process was divided into core vacuuming, dry gas injection and saturated condensate gas in the original formation conditions, and then the 21 sets of displacement experiments designed above were carried out successively.

Water injection for oil replacement in a well of a fracture-cave reservoir mainly uses the difference in oil–water density to replace the injected water with formation oil via gravity differentiation. This aims to recover formation energy and drive crude oil to wellbore production. We took the procedure of "water injection–soaking–oil recovery" in oil wells as an injection cycle for production. This can gradually improve oil recovery through multiple rounds of water injection for oil replacement [18,19]. In gas fields, simple equipment such as water injection pumps can be directed into the fracture-cave reservoirs. This technology has been applied in the northern oil fields. Considering the characteristics of the fracture-cave condensate gas reservoir with oil accumulating at the bottom of the fracture-cave reservoirs, the water injection production field test was carried out based on experiments assessing means of developing the water injection mechanism as references [14–17]. The injection modes of the water were cyclic water injection in a single well and water flooding in a reservoir unit. Injected water was water produced from adjacent wells.

4. Results

4.1. Experiments to Enhance Oil Recovery in Fracture-Cave Reservoir

In the unfilled cores (Table 1), the experimental results show an oil recovery of 15.95% with horizontal depletion and 14.64% with vertical upward depletion to 10 MPa. It should be noted that oil recovery is 46.90% with vertical downward depletion. These results suggest that vertical downward depletion can obtain a much higher oil recovery from condensate reservoirs. For the gas injection, dry gas above the dew point obtains a higher oil recovery of 56.52% after a 1.7 HCPV (injected water volume ratio) dry gas injection to avoid retrograde condensation. However, the oil recovery ratio is 29.34% after a 2.2 HCPV gas injection at maximum condensate saturation. Furthermore, the oil recovery ratios with depletion to 10 MPa are much lower, 19.43% and 17.51% with the horizontal and vertical maximum condensate saturations at dry gas huff, respectively. In the experiments of water injection, the oil recovery after depletion to 10 Ma is up to 88.22% for the staged injection for pressure retention in the vertical model, and it is 79.95% for water flooding above the dew point in the horizontal model. In the water injection with the horizontal maximum condensate oil saturation and vertical downward injection, the oil recovery ratios decrease to 57.45% and 65.54%, respectively.

Table 1. The results from simulation experiments in cave-type reservoir.

Displacement Mode			Oil Recovery (%)
unfilled cores	depletion	horizontal depletion (to 10 MPa)	15.95
		vertical upward depletion (to 10 MPa)	14.64
		vertical downward depletion (to 10 MPa)	46.90
	gas injection	dry gas above dew point (horizontal)	56.52 (1.7 HCPV), 58.24 (to 10 MPa)
		maximum condensate saturation (horizontal)	29.34 (2.2 HCPV), 30.91 (to 10 MPa)
		maximum condensate saturation at dry gas huff (horizontal)	16.64 (3 times throughput), 19.43 (to 10 MPa)
		maximum condensate saturation at dry gas huff (vertical)	14.7 (3 times throughput), 17.51 (to 10 MPa)
	water injection	staged injection for pressure retention (vertical)	86.58 (3.07 HCPV), 88.22 (to 10 MPa)
		water flooding above dew point (horizontal)	72.6 (0.8 HCPV), 79.95 (to 10 MPa)
		maximum oil saturation (horizontal)	55.33 (0.8 HCPV), 57.45 (to 10 MPa)
		vertical downward injection	10.83 (to 31 MPa), 65.54 (injection to 0.9 HCPV and then to 10 MPa)
sand-filled cores	depletion	horizontal depletion (to 10 MPa)	16.44
		vertical upward depletion (to 10 MPa)	15.55
	gas injection	dry gas above dew point (horizontal)	45.35 (1.8 HCPV), 47.10 (to 10 MPa)
	water injection	water injection above dew point (horizontal)	55.27 (0.9 HCPV), 61.39 (to 10 MPa)
		vertical lower water injection and upper gas recovery	50.04 (to 10 MPa and then water injection 0.7 HCPV), 52.99 (to 10 MPa)
		gas replacement by water injection (vertical)	78.07 (32 times), 80.24 (to 10 MPa)

Compared with the sand-filled cores (Table 1), the oil recovery ratios are similar to those of the unfilled cores with horizontal and vertical depletion. The oil recovery for the gas injection decreases to 47.10% with the dry gas above the dew point. In the experiments of water injection, the oil recovery ratios after depletion to 10 Ma also decrease to 61.39% for the water injection above the dew point, but they are much higher at 80.24% for gas replacement using water injection.

4.2. Applications of Water Injection in the Gas Field

In the field test, 11 condensate wells in the Tazhong I Gasfield had cyclic water injection production (Table 2). The wells present reef–shoal reservoirs and unconformity reservoirs. The well dynamic oil reserves are from 0.5×10^4 t to 42.9×10^4 t. The pre-injection oil production is in the range of 0.04–12.01×10^4 t. In the test, the cumulative injected water of a well is up to $(0.15–71.12) \times 10^4$ m^3 with a total 1.36×10^8 m^3 of water injection. The subsequent cumulative oil enhancement of a well is in a large range of 17–t, with a total oil enhancement of 29,185 t. The enhanced oil recovery ratio is from 0 to 17.7%.

According to the analysis of the water injection effect, the oil increase from the fracture-cave reservoirs is generally less than that from oil reservoirs in previous experiments and in references [18,19]. The comparative analysis shows that the enhanced recovery by water injection from condensate gas reservoirs is lower than that from oil reservoirs. In terms of reservoir types, the unconformity reservoirs of the Lower Ordovician had a better water injection effect than the Upper Ordovician reef–shoal reservoirs. These results suggest that the type of the reservoir has an influence on the effect of the water injection. However, even in the same type of reservoirs in adjacent wells, there are varied oil recovery rates when using a similar water injection process.

Table 2. Water injection effect in Tazhong I Gasfield.

Well	Reservoir	Dynamic Oil Reserve /10^4 t	Pre-Injection Production/10^4 t/10^8 m^3			Cumulative Injected Water/10^4 m^3	Cumulative Enhanced Oil/t	Enhanced Oil Recovery/%
			Oil	Gas	Water			
TZ83-HX	unconformity	6.35	1.25	0.25	0.02	11.03	11,245	17.7
TZ24X	reef–shoal	42.9	12.01	1.92	6.99	7.45	8496	2.0
TZ62-A	unconformity	21.1	5.06	2.21	0.25	71.12	3132	1.5
ZG15X	unconformity	6.10	0.67	0.28	0.00	3.20	2961	4.9
ZG4X	reef–shoal	5.53	1.27	0.12	0.96	1.08	2621	4.7
TZ821-B	unconformity	12.2	3.00	1.09	0.09	25.55	479	0.4
TZ721-C	unconformity	0.50	0.04	0.03	0.00	0.15	124	2.5
TZ26-HX	reef–shoal	2.60	0.59	0.17	0.14	4.81	57	0.2
ZG10X	unconformity	6.93	1.59	0.32	0.93	5.65	32	0.0
TZ62-HX	unconformity	1.60	0.33	0.15	0.00	2.07	21	0.1
TZ26-HY	reef–shoal	1.11	0.28	0.33	0.90	4.16	17	0.2

5. Discussion

5.1. Difficulties in Enhancing Oil Recovery from Fracture-Cave Reservoirs by Gas Injection

Condensate gas reservoir development can be divided into three types: depletion development, pressure maintenance development and partial pressure maintenance development. Pressure maintenance development mainly involves the use of a gas injection to maintain pressure. Considering its special characteristics, depletion development was used for most wells in the Tazhong I Gasfield.

Considering the retrograde condensation effect in condensate reservoirs, there are generally low oil recovery rates in the experiment and production data (Table 2) [6,7,14–19]. The main reason for this is gravity differentiation in the fracture-cave reservoir. The relatively high oil recovery with vertical downward depletion is possibly related to water injection, which can avoid retrograde condensation, and gravity differentiation is feasible in large fracture-cave reservoirs.

The experimental results show that water injection and pressure preservation can achieve a high recovery of 50–86% with a low injection volume. However, the oil recovery rate of gas injection is no more than 58%. Furthermore, the effect of water injection is better than that of gas injection under the maximum retrograde condensation pressure. In addition, a comparison between filled sand and unfilled sand shows that water injection is still better than gas injection. The experiments show that the effect and economy of gas injection are inferior to those of water injection, so water injection development should be given priority to enhance oil recovery in condensate reservoirs (Table 1).

The effect of water injection is better than that of gas injection, which may be attributed to the heterogeneity of the reservoir and the distinct flow mode in fracture-cave reservoirs. On the one hand, fractures are well developed in the carbonate condensate gas reservoir [20,22], and gas injection is prone to gas channeling, which leads to ineffective gas circulation. Therefore, ideal results can be achieved with large-scale gas injections. On the other hand, the pipe flow is given priority in reservoirs where the waterflood development of such a special condensate gas reservoir is similar to that of the fracture-cave reservoir [18,19]. Compared with gas injection, water injection has a good effect with small compressibility and a low cost, and it can faster achieve the purpose of pressure preservation or oil replacement.

In large fracture-cave reservoirs, the fluid flow pattern is dominated by the pipe flow. As such, the injected gas easily forms gas channeling along the high-conductivity fractures at the top of the reservoirs, and it is difficult to inject gas to maintain pressure. The trajectory of horizontal wells is close to the top surface of the reservoirs, and injected gas can migrate along the top surface of the reservoir to form gas channeling due to gravity differentiation. It is difficult to drive gas injection, and an improper circulation of injected gas may even occur in serious cases. Consequently, more than 50% of wells are horizontal wells where gas injection is difficult to apply.

In addition, there are mostly isolated fracture-cave reservoir units in the long diagenetic history. Most wells are not connected reservoirs, which restricts the development of circulating gas injection between wells. Moreover, there is a relatively small, well-controlled oil reserve weighing tens of thousands of tons in the isolated fracture-cave reservoir. For example, the dynamic geological reserves of the well-controlled reserve in the high-production well ZG8 is about 6×10^4 t. Furthermore, there is a large well spacing, and the average well spacing is more than 1 km. Therefore, the production well has the characteristics of a scattered well location and wide spacing. It is difficult to carry out the overall deployment of a gas injection pipe network, and the huff and puff development of gas injection is even more difficult to economically carry out in a single well. There is large formation deficit volume in the late stage of depletion development. Some condensate gas wells remain at low pressure with an accumulative gas production of more than 100×10^6 m^3. The high H_2S content and acidic gas are highly corrosive to equipment for gas injection in this gas field. These also increase the investment and maintenance cost of gas injection pipelines. As such, it is difficult to achieve economic benefits using gas njection.

Therefore, Tazhong I Gasfield is a typical deep, carbonate fracture-cave condensate gas reservoir. Gas injection is constrained by the reservoir characteristics, horizontal well trajectory and reservoir configuration, the well pattern and well spacing, connected well group, formation voidage and pressure maintenance. These can hamper the application of cyclic gas injection and throughput pressure maintenance of single-well gas injection.

5.2. Effects of Enhancing Oil Recovery by Water Injection in the Deep Subsurface

The pilot tests in 11 wells confirm that the fluid channel mainly consists of a fracture network and that gravitational differentiation led to retrograded oil accumulation at the base of the fracture-cave reservoirs. As such, water injection is favorable for the displacement of retrograded oil from fracture-cave reservoirs. However, the application effects varied in different wells and are inferior to the experiments and prediction.

Recent studies suggest that the tight Ordovician matrix reservoirs (porosity < 5% and permeability <0.5 mD) cannot support economical production in the gas field [22,25,26]. The reservoir space is dominated by dissolution pores, vugs, caves and fractures, forming a large fracture-cave reservoir with a "bead shape" seismic reflection (Figure 3) [22]. The localized fracture-cave reservoirs have become the major drilling targets for oil/gas production rather than the large areas of tight reef–shoal reservoirs and unconformity reservoirs.

After retro-condensation occurs in this kind of condensate gas reservoir, the oil in sandstone porosity reservoirs is usually adsorbed on the pore surface under the leading effect of the capillary force [2–4,29,30]. It does not flow in the early stage, but with a further decrease in the formation pressure in the middle and late stages, the retro-condensation intensifies. In addition, it does participate in seepage when the oil in condensate reservoirs reaches the critical flow saturation. Different from sandstone condensate gas reservoirs, the Tazhong fracture-cave reservoir is mainly composed of caves, dissolution pores and fractures. Fractures are the main circulation channels with a weak capillary force. The formation fluid flow pattern is dominated by the pipe flow of the fracture-cave system. During the whole process of retrograde condensation, the condensate is dominated by gravity. Therefore, the retrograde condensation in condensate gas reservoirs mainly exists in the form of accumulation at the bottom of fracture-cave reservoirs. In addition, the oil in condensate reservoirs almost does not flow until the condensate oil/gas interface reaches the bottom of the well, resulting in a lower oil recovery rate in depletion production.

The capillary force can be ignored in the carbonate fracture-cave reservoir space, and the main flow channel comprises the big cave and fracture. The main distribution of oil, gas and water is affected by gravity. The retrograde condensation phenomenon in depletion development shows aggregation at the bottom similarly to retrograde condensate fluid PVT. In depletion development, oil is enriched at the bottom of the fracture-cave reservoir. Therefore, the existence state of retrograde condensation in the cave is the same as that of crude oil after the depletion of the fracture-cave reservoir. In this context, the retrograde condensation effect in the cave can be recovered using water injection to replace the oil in the fracture-cave reservoir.

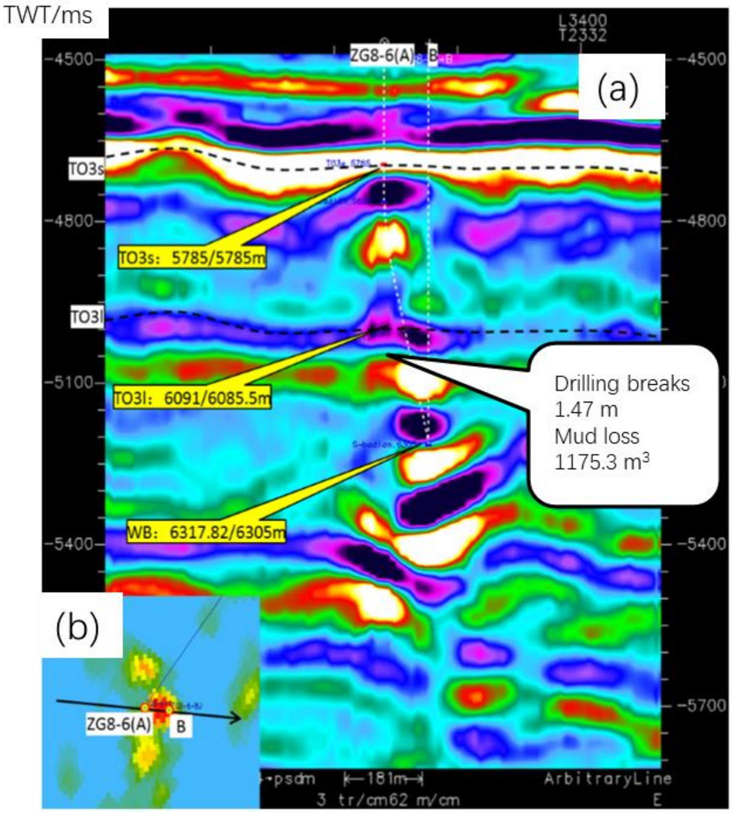

Figure 3. "Bead shape" seismic reflection in the seismic profile (**a**) and the strong amplitude in root mean square amplitude attribute (**b**) of the fracture-cave reservoir in Tazhong I Gasfield (large fracture-cave reservoir with caving and large mud loss during drilling; O_3s: Sangtamu Formation of the Upper Ordovician; O_3l: Lianglitage Formation of the Upper Ordovician).

In the study area, carbonate reservoirs can be divided into reef–shoal reservoirs and unconformity karst reservoirs [20,22]. These are mainly fracture-cave reservoirs with a fracture-controlled seepage channel. Condensates accumulate in a specific manner in the cave-dominated reservoir at the bottom of the caverns after depletion development. The feasibility study of gas injection for this kind of condensate gas reservoir shows that it is difficult to achieve economic benefits using cyclic gas injection and single-well huff and puff gas injection. In addition, the results of the mechanism experiments further confirmed that water injection development is the better method for enhancing oil recovery from cave reservoirs. In the analysis, the special reservoir structure and weak capillary force had distinct effects on water injection development. Water injection in the condensate field has numerous advantages: in addition to easily being put into production, it has a relatively simple process, low cost, good time efficiency, quick energy replenishment and high displacement efficiency. The pilot test of water injection confirms the feasibility of using water injection in fracture-cave reservoirs and provides a feasible method for the development of this kind of condensate gas reservoir.

It was noted that fracture networks are the major permeable structures that influence oil/gas production. Although the reservoir permeability varied by 1–3 orders magnitude, the daily oil/gas production in one well varied by 1–2 orders magnitude. These results suggest a bad connectivity of the fracture networks and reservoirs in the deep subsurface. In addition, there is intense heterogeneity of the fractured reservoirs in the secondary carbonate porosity. In many cases, each well is an isolated reservoir unit and constrained the development with water injection. As such, the carbonate fracture-cave reservoirs are mainly composed of secondary pores and fractures that show weak capillary action that is not suitable for gas injection to improve oil recovery as is the case with sandstone condensate gas reservoirs. Furthermore, gas condensate reservoirs are restricted by a strong reservoir heterogeneity, large well spacing, unconnected well groups and serious formation shortfalls, resulting in the difficult application of cyclic water injection and thereby demonstrating the relatively low oil recovery from complicated reservoirs. The fracture network is a key factor in enhancing oil recovery from deep subsurface carbonate reservoirs, which need further study.

6. Conclusions

(1) In the displacement experiments in the fracture-cave reservoirs, the oil recovery ratios from the condensate gas reservoirs achieved with water injection were up to 57–88% in unfilled fractured caves and at ca. 52–80% in sand-filled fractured caves, but they were much lower at 14–46% and 17–58% in the depletion and gas injection experiments, respectively. These results suggest that the effect of water injection is better and more feasible than that of gas injection and depletion development in this kind of condensate gas reservoir.

(2) The water injection displacement tests in 11 wells showed that the condensate oil recovery increased by a large range of 0–17.7% (avg. 3.1%). These results suggest that water injection can be used to enhance oil recovery after depletion development in this kind of reservoir. Except for three wells, the oil recovery ratio increased by less than 2.5% in the other eight wells when using cyclic water injection. These oil recovery rates that were much lower than those of the experiments suggest a more complicated seepage network in the heterogeneous fractured reservoirs.

(3) The effective oil replacement achieved with water injection may be attributed to fractures acting as seepage channels leading to ineffective gas circulation and pipe flow in fracture-cave reservoirs, which is favorable for waterflood development. However, there are more complicated fracture networks in the deep subsurface than in the experiment, which may play a key role in the various oil recovery rates in boreholes and may have led to a better effect in the karst reservoirs that developed fractures than in the reef–shoal reservoirs.

(4) This case study suggests that the seepage channels of the heterogeneous fracture network need to be studied to enhance this kind of oil recovery.

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