CCS: A China Perspective

Yanchang Petroleum Report 2: CO2 storage and EOR in ultra-low permeability reservoir in the Yanchang Formation, Ordos Basin.

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1 Contents

1 Project introduction

The Yanchang Petroleum Group's Carbon Capture and Utilisation Project is located in the northern Shaanxi Province, China and focuses on the Triassic Yanchang Formation on the eastern slope of Ordos Basin. Ordos Basin in north western China is the most important energy-chemical base with abundant oil, gas and coal resources. The Yanchang Formation hosts a series of oil fields that are low and ultra-low permeability oil-bearing reservoirs. These reservoirs are typical of the basin, where the reservoir permeability is less than 1 x 10^{-3} μm^2 (1 millidarcy, mD); these accumulations account for 60% of Yanchang total proven reserves. The tight reservoirs contain huge oil reserves and are the key to maintain steady and increasing yields from the Yanchang Formation. However, the arid and semi-arid northern Shaanxi Province, has a lack of water to conduct water flooding development, which is needed to increase oil production. Improving the efficiency of the development of low and ultra-low permeability oil-bearing reservoirs in the northern Shaanxi Province with a lack of water becomes a technical problem for Ordos Basin's oil and gas development projects.

The Northern Shaanxi Province has abundant coal and oil resources, which promote the development of a coal to chemical industry. At the same time, this industry will increase the emissions of greenhouse gases including CO_2. In recent years, Yanchang Petroleum Group has committed to research and experimental work in the coal chemical industry focusing on CO_2 capture and CO_2-enhanced oil recovery (CO_2-EOR) in the Yanchang tight reservoir. In 2012 the Yanchang Petroleum Group built a 50,000 tonnes per year (tpa) CO_2 capture plant at its Yulin Coal Chemical Coal Company coal to chemical plant. This is providing the CO_2 for a CO_2-EOR test injection at the Qiaojiawa oil zone of the Jingbian Oil Field. The test injection was started on September, 2012 and as of May 2015, the accumulative total amount of CO_2 injected had reached 41,000 tonnes, and the average oil production increased by 50%. An additional 360,000 tpa CO_2 capture project at the Yulin Energy Coal to Chemical Plant is under construction to increase CO_2-EOR flooding operations in a pilot injection project.

Application of CO_2 flooding technology, under miscible conditions of CO_2 and crude oil, can decrease crude oil viscosity, reduce oil-water interfacial tension, and expand crude oil volume (See Global CCS Institute, 2013 for more information). Compared with water, CO_2 flooding has better impact and displacement efficiency on oil production. At the same time, CO_2 flooding can save a lot of water. Also, water flooding is often used to improve oil production at the well through maintaining or increasing the reservoir pressure, which previously was difficult. CO_2 will be used instead of water due to the abundance of CO_2 produced by the chemical industry and therefore will be used as the displacement agent to maintain reservoir pressures and oil production. Prior to CO_2-EOR flooding operations, a series of key topics that needed to be addressed included:

- Characterisation of low and ultra-low permeability oil-bearing reservoirs, which have been fractured to enhance permeability for oil production;
- Dynamic production of low and ultra-low permeability oil-bearing reservoirs after water flooding and then confirm distribution of remaining oil;
- Selection of one field for quantitative CO_2 flooding to study the effects of a low and ultra-low permeability oil-bearing reservoirs on oil production;
- Key factors influencing CO_2 plume movement;
- Confirm the operational requirements for CO_2 injection; and
- Establish pilot experiment demonstration for 20 well groups. A well group is a platform that contains multiple injection and production wells.

Through successful implementation of laboratory-based research and the current test site, the project will now complete a quantitative site evaluation for CO_2 flooding in low permeability sandstone reservoirs through dynamic reservoir simulation and surface monitoring technologies. A goal of this project is to create a methodology for CO_2-EOR operations in low and ultra-low permeability oil-bearing reservoirs and develop advanced CO_2-EOR technology to improve sweep volume in fractured reservoirs in the Ordos Basin.

1.1 CO_2 capture

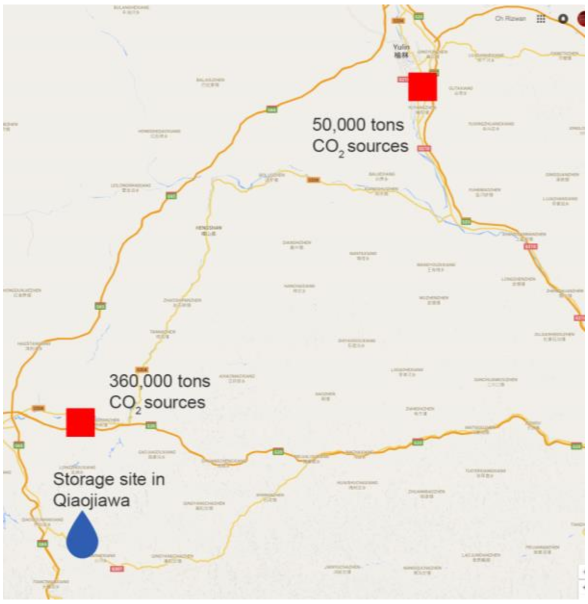


Figure 1: CO_2 capture (red squares) and storage (blue area) sites of the Yanchang project.

Yanchang Petroleum Group takes full advantage of the co-development of coal to chemical industry and oil field production to carry out integrative work of CO_2 capture, utilisation and storage. Currently, there are two main coal to chemical CO_2 capture projects located in Yulin city not far from the CO_2-EOR injection site, and these capture sites are the CO_2 sources for this project; as shown in figure 1.

The construction of the first project, a 50,000 tpa CO_2 capture project by Yulin Coal Chemical Company was completed on November 2012 producing 0.2 Mtpa of acetic acid. The capture method is the absorption physical solvent-based process. In 2014, Yanchang Petroleum Group started construction of the second CO_2 capture plant, a 360,000 tpa at Yulin Energy-Chemical Plants was scheduled to be completed in 2015. The plant will produce 0.45 Mtpa of polypropylene, 0.25 Mtpa of polyethylene and 0.2 Mtpa of 2-ethyl hexanol, and will use same process for CO_2 capture as the Yulin Coal Chemical Company capture project. See *CCS: A China Perspective Yanchang Petroleum Report 1: Capturing CO_2 from Coal to Chemicals*, 2015 report for more information on capture.

1.2 CO_2 transportation

The CO_2 will be transported by twenty tonne tanker trucks over a distance of around 140 km. Using tanker trucks to transport CO_2 conforms to the environmental requirements and reduces costs given the relatively short distance and difficult terrain in the area. The larger scale 360,000 tpa capture facility is only around 10 km from the CO_2-EOR site and will also utilise tanker trucks. See *CCS: A China Perspective Yanchang Petroleum Report 1: Capturing CO_2 from Coal to Chemicals*, 2015 report for more information on the transport process including the liquefaction and compression process.

1.3 CO_2-EOR

Figure 2: Location of 203 well block and nomenclature

The CO_2-EOR operations are located in 203 well block, called the Qiaojiawa oil zone of the Jingbian Oil Field in the greater Yanchang Formation, near Yulin city (Figure 2). After a comprehensive comparison and analysis, Chang6 layer of the Yanchang Formation was found to have suitable geological conditions for CO_2 flooding and storage (Table 1). The planned CO_2-EOR evaluation period in the Jingbian Oil Field will be for 15 years. After this time a monitoring program will be ongoing and a CO_2 geological storage technology research program will continue after the CO_2-EOR operation is completed. There are currently no plans to undertake a dedicated geological storage program at the pilot site.

Table 1: Generalised stratigraphic column of the Triassic in the Ordos Basin.

Age		Formation	Oil Members	Layers	
Triassic	Upper	Yanchang	Chang1		
			Chang2		
			Chang3		
			Chang4+5 (caprock)		
			Chang6 (reservoir)	Chang6_1	
				Chang6_2	Chang6_2^{1-3}
				Chang6_3	
			Chang7		
	Middle		Chang8		
			Chang9		
			Chang10		

1.3.1 Site Selection for CO_2-EOR

Reservoir selection criteria for CO_2 flooding included the development of coal chemical industry; the location of CO_2 emissions and capture engineering construction; a pilot injection site close to the CO_2 gas source; and reservoir conditions suitable for CO_2 flooding.

At present, Yulin Coal Chemical Company's first-stage project has been put into production (50,000 tpa CO_2) and its location is relatively close to Qiaojiawa 203 well block, in the Jingbian Oil Field. The Yanchang Oil Group created selection criteria according to the characteristics of the geological and fluid properties of the reservoir, to determine CO_2 flooding potential, which could be used locally and in other fields abroad to identify a successful site. The criteria are based on a set of principles that include:

1. Reservoir with simple structure, lower fracture development, and no faulting.
2. A well understood petroleum system, with previously completed static and dynamic modelling data.
3. Reservoir fluid properties and the geological conditions favorable to CO_2 flooding either miscible or immiscible flooding operations (Table 2).
4. Reservoir with no edge water, bottom water and gas cap.
5. The ground condition is suitable for on-site construction.
6. Reservoir production poorly developed and in need of alternative development.

Table 2: Reservoir parameters for CO_2 flooding under miscible or immiscible flooding conditions (Lewin and Associates, 1976; Klins and Farouk, 1982)

Special filter parameters	CO_2 miscible flooding	CO_2 immiscible flooding
Oil Viscosity（MPa.s）	<12	100-1000
Oil density（kg/m3）	<876.2	904-1000
Reservoir depth（m）	>900	>700
Layer thickness（m）	No requirement	<10
Layer pressure（MPa）	>10	>7
Reservoir temperature（℃）	Non-critical parameter	Non-critical parameter
Average permeability（mD）	Non-critical parameter	Non-critical parameter
Oil saturation（%）	>25	>50
Porosity × Oil saturation（f）	>0.04	>0.08
Favorable conditions	Thick layer, high dip angle, no significant secondary water flooding before CO2 injection, low Kv (vertical permeability) and natural CO_2.	
Adverse conditions	Severe heterogeneity and serious cracks, atmospheric top, and active bottom water.	

CO_2 flooding is influenced by many factors which can stop an operation including fracture, edge or bottom water drive etc. To gain a better understanding of the Yanchang Formation, a sensitivity analysis against a set of geological and fluid properties of the target reservoirs was completed; the details are shown in Table 3.

Table 3: Reservoir Properties and sensitivity to CO_2-EOR production. Analysis was based on three factors: laboratory results, field tests and results from other CO_2-EOR studies.

Properties	Sensitivity	Effect on oil recovery
Reservoir dip	Relatively insensitive	Increased angle is conducive to recovery
Layer depth	Very sensitive	Increased depth is conducive to recovery
Pressure	Very sensitive	Increased pressure is conducive to recovery
Temperature	Not sensitive	Little influence on CO_2 flooding
Total reservoir thickness	Very sensitive	Increased thickness is not conducive to recovery
Average permeability	Sensitive	Increased average permeability is conducive to recovery initially
Permeability anisotropy (KV/KH ratio)	Sensitive	Sensitive to recovery; not sensitive to accumulative oil-gas ratio; between layers is not conducive to recovery
Initial oil saturation	Very sensitive	A higher initial oil saturation is conducive to recovery
Permeability direction KY/KX	Relatively insensitive	Sensitive to recovery, insensitive to accumulative oil-gas ratio
Well distance	Sensitive	Increased well distance is not conducive to recovery
Well pattern	Sensitive	Relatively high recovery with five point, when compared to seven and nine point pattern
Fluid density and viscosity	Sensitive	Increased density and viscosity is not conducive to recovery

Properties	Sensitivity	Effect on oil recovery
Variation Coefficient	Relatively insensitive	Sensitive to recovery, insensitive to accumulative oil-gas ratio
Sedimentary heterogeneity	Very sensitive	Low heterogeneity is more advantageous

We evaluated 176 different oil reservoirs in the Yanchang Formation, based on suitability for CO_2 flooding (including miscible flooding and immiscible flooding). The results shows that 153 reservoirs are suitable for CO_2 flooding. This represents 84% of all blocks operated by Yanchang Petroleum that are suitable for CO_2 flooding; comprising of 80% of oil reserves. Through comprehensive comparison and analysis, 203 well block in Qiaojiawa area best matched the screening standard for CO_2 flooding reservoir, determining it as CO_2 flooding pilot test area.

2 Qiaojiawa 203 Well Block CO_2 EOR Project

2.1 Site implementation

2.1.1 Pre-CO_2 injection and water flooding

The Qiaojiawa test area was put into operation in September 2007, and in September 2009, all oil wells were put into production. Water injection was started in March 2008. In early development, fluid production was relatively large. With the increase of oil field development, production fell sharply. Because of the low reservoir permeability, water injection is difficult, and the water flooding effect is not obvious. Water injection pressure was near to fracture pressure in some areas. Till the end of 2008, water injection pressure was 21 MPa. Since January 2012, there were 92 wells, including 79 production wells, six water injection wells and seven closed wells. A production rate of 0.26%, with recovery factor of 1.14% was achieved, including a water cut of 65.39%, and cumulative water injection 7.431 x 10^4 m^3.

2.1.2 Test CO_2 injection Project

A CO_2-EOR test injection project was started on September 5, 2012 and since then, the test experiment at the Qiaojiawa area has injected 41,000 tonnes through five injection wells and the average single well production rate has increased by 50%. In the early stages of CO_2 gas injection, injecting pressure of each injection well was 2.0 ~ 3.0 MPa, and the current pressure is 4.5 ~ 8.8 MPa. There are 15 front line oil production wells, and 16 second-line oil production wells, which are distributed amongst 11 well groups. According to production data from the wells, the previously discussed decrease in production at the wells during water flooding has been controlled, and a gradual rising trend has started. There is ongoing continuous monitoring of the wells since initial injection.

2.1.3 Pilot CO_2 injection Project

In 2015 Yanchang Petroleum plans to increase CO_2 injection at the Qiaojiawa 203 well block for a pilot injection project. The well group will consist of 20 injection wells and 68 first line oil wells make up to the total 88 wells. Water injection wells around the CO_2 injection test well groups will be closed, forming relatively isolated injection and production areas around the well groups. Now the public bidding work of the CO_2 injection stations is finished, the successful bidder will complete the safety evaluation, environment evaluation, and planning.

Meanwhile, Yanchang Petroleum will continue to do the field testing for CO_2 flooding including injection-production dynamic simulation analysis, and research and development of the plugging technology that can applied at the test site. Furthermore, more research and development will be undertaken on CO_2 flooding storage prediction and monitoring, as well as research on gas CO_2 separation and recycle technology.

2.1.4 Well bore integrity study

First line oil wells of Qiaojiawa Project were drilled in 2012, and were completed in the Chang6 horizon. Cementing work used G class cement. Average density of high density cement slurry is 1.85 g/cm^3, and average density of low density cement is 1.40 g/cm^3. After cementing work, we used an acoustic variable density logging method to evaluate the cementing quality, and the cementing quality qualified.

Yanchang Petroleum undertook laboratory experiments to simulate CO_2 flooding performance under different environments, including corrosion of the typical material, as well as the effect of screen coating, corrosion inhibitor and scale inhibitor under conditions suitable for corrosion in a CO_2 flooding environment. This provides support for the corrosion control management and economic development.

2.2 Geology of Qiaojiawa CO_2-EOR Project

2.2.1 Structural characteristics

Qiaojiawa area is located in the middle of the northern Shaanxi slope of Ordos Basin. Tectonism associated with the Yanshan Orogen (Late Jurassic) formed the tectonic framework of the Ordos Basin with a general structural high in the east and low in the west. There are a series of small anticlines in Yanchang and Yanan horizons with obvious inheritance from the tectonism.

The combination of the overall regional high in combination with small anticlines results in the small oil accumulations of the Yanchang Formation. At the pilot site specifically, the structure is the same with a monoclonal high in the north with a stratigraphic tilt to a low in the west.

2.2.2 Stratigraphic sequence

Ordos Basin comprises two sequences of strata from the Mesozoic and Cenozoic. The Upper Triassic Yanchang Formation is the main formation in the basin and is composed of detrital lake-river-delta sediments. It is divided into 10 sub-formations from bottom up, Chang1 to Chang10 (Table 1).

Typically, 10 marker beds (K0—K9) are found in the Yanchang Formation, but in the test site area only eight marker beds, namely K1-K9 are identified. According to the eight marker beds, the Yanchang Formation at the site is divided into Chang1, Chang2, Chang3, Chang4+5, Chang6, and Chang7 from bottom-up. The main oil layer is Chang6. Chang6 is further divided into depositional cycles, Chang6_1, Chang6_2, and Chang6_3. Chang6_2 is the focus CO_2 injection layer of the injection project.

Above the Yanchang Formation, the Jurassic limonitic facies is a set of continental clastic deposits, deposited in a fluvial environment. The facies are divided into the Fuxian, Yanan, Zhiluo and Anding formations (bottom to top respectively). The Luohe Formation (Lower Cretaceous) is a fluvial continental clastic deposit. The uppermost Cenozoic formations are aeolian soils.

2.2.3 Reservoir and caprock

The Chang6 is the reservoir layer for CO_2-EOR operations. It ranges in thickness from 105-150m with an average thickness of 127m. The average thickness of the main Chang6_2 reservoir is about 40m. The reservoir temperature is 40°C, and pressure is 8.2 MPa. The porosity of Chang6 reservoir ranges from 8-13.0%, and average porosity is 10.5%. The permeability ranges from 0.05-2 mD, and average permeability is 1.02 mD. Chang6 member consists of alternating dark grey mudstones, fine sandstones and siltstones.

The cap rock (Chang4+5) is an extensive, regional sealing unit with an average thickness of 85 m (Figure 3). According to core observation and analysis it is a fine-grained argillaceous sandstone and mudstone. Core physical property studies, displacement pressure, and mercury injection analysis shows it has good sealing capacity.

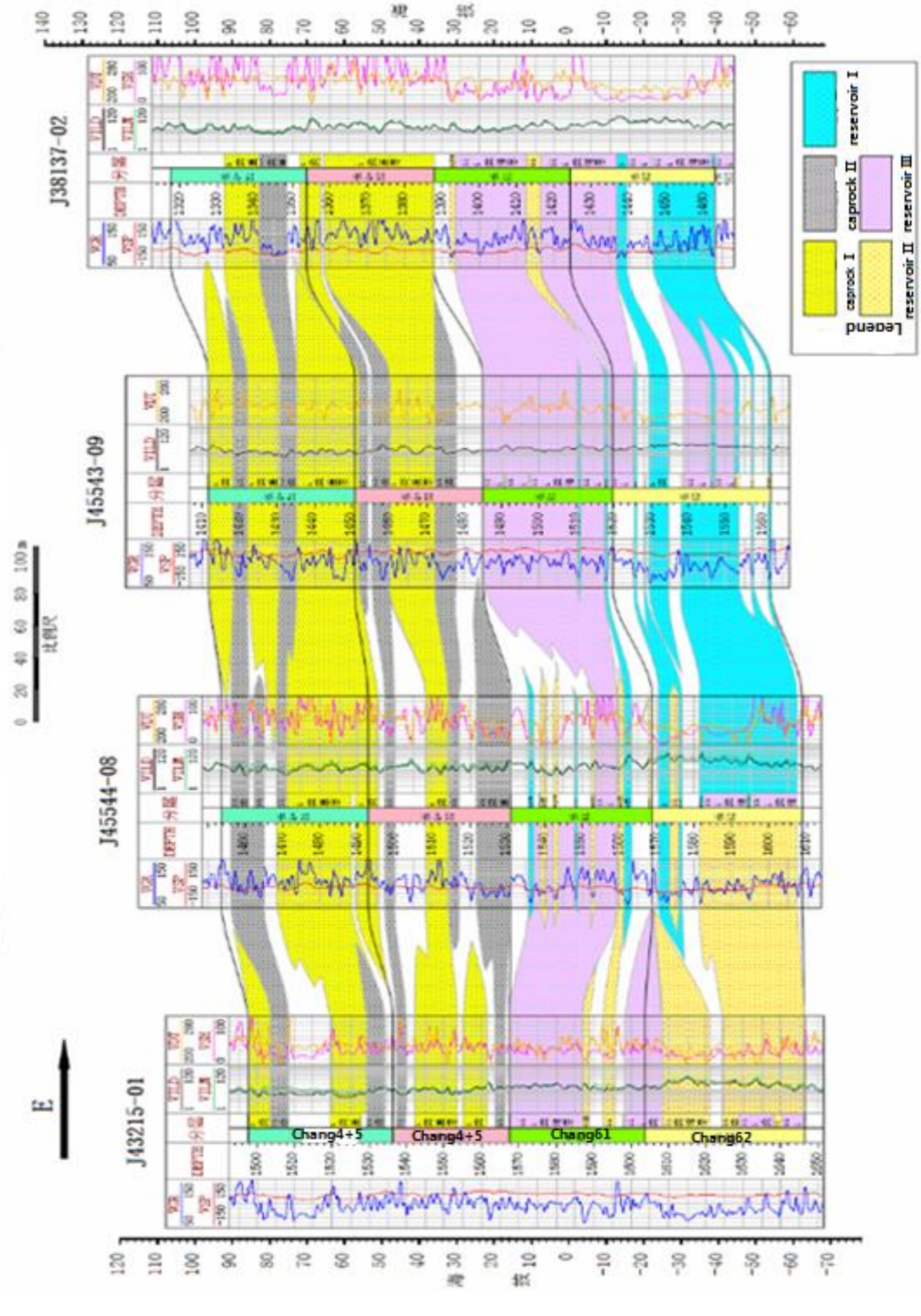


Figure 3: Cap-reservoir well section profile

2.2.4 Reservoir fluid characteristics

Crude oil analysis shows that the oil is low hypobaric, low viscosity, low layer viscosity, low freezing point, and low initial boiling point. Total salinity of formation water is 50.52g/L~95.11g/L, pH 5.5, $CaCl_2$ water type, and original gas-oil ratio is 54-76m^3/t. Chang6 reservoir saturation pressure is 5.7 MPa. Natural gas belongs to associated moisture gas without sulfur, relative density is 0.9-1.2, methane content is 42.8%, and amount of C3 + C4 is 27.5%. There is no sulfur.

2.3 Oil reserves

Reserves were calculated by volumetric method, calculation formula is:

$$N = 100Ahf\, S_{oi} r_o / B_{oi}$$

N ——Geological reserves，10^4t；

A ——Oil-bearing area, km^2；

h ——Average effective thickness, m；

f ——Average effective porosity, decimal；

S_{oi} ——Average initial oil saturation, decimal；

r_o ——Average ground crude oil density/m^3；

B_{oi} ——Average Original oil volume factor

Parameter for calculation of reserves is as follows:

According to the log interpretation data and core test results, the calculated total oil reserves of 203 well block is 4,354,100 tonne. The reserves within the 20 pilot test well groups is 2,160,000 tonne.

2.4 CO_2 storage resource potential

During the CO_2 injection period the CO_2 will dissolve in the residual oil and formation water and the remaining will remain in free phase state (Figure 4). During the storage period in the oil reservoir there are four types of storage mechanisms, physical (structural and residually bound gas), chemical (dissolved gas) and mineralisation, as shown in Figure 4. The volumetric calculation for the CO_2 storage resources in the Chang6 reservoir of the Yanchang Formation was calculated using the DOE (2012) method and the results are in Table 4. The theoretical capacity represents the total pore volume of the Chang6 reservoir whereas the effective storage is the amount of CO_2 which can be stored in that pore space under the conditions of the reservoir. Finally, practical capacity is the amount that is physically accessible according to the engineering and economic analysis from the Yanchang Petroleum Group.

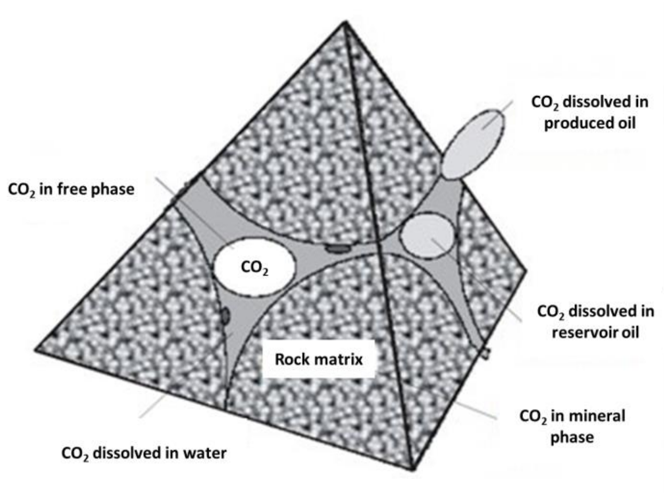


Figure 4: CO_2 storage mechanism in oil reservoir

Table 4: CO_2 Volume of the Chang6 reservoir in Qiaojiawa Area.

Reservoir	Geological reserves （Kt）	Theoretical storage （Kt）	Effective storage （Kt）	Practical storage （Kt）	Oil Recovery （%）	CO_2 usage factor （f）	CO_2 storage factor （f）
Chang6	9310	4370.23	2620.34	2090.87	4.03	0.18	0.23

3 Laboratory experiments

Laboratory experiments using slim tube displacement experiments will assist with the CO_2-EOR flooding operations by understanding the interaction between formations fluid (oil, gas, water) under different reservoir conditions. The experiments are used to determine the minimum miscible pressure (MMP) and minimum miscible composition (MMC) in conditions similar to the reservoir. Other experiments completed include the calculation of PVT (pressure-volume-temperature) properties. This test is to ensure that optimal pressures and fluid compositions are met to enhance production of oil.

3.1 CO_2-Oil analysis

CO_2 flooding to improve oil recovery can not only increase reservoir pressure and fluid flow, but can also reduce viscosity and reduce density of crude oil. Through sampling of crude oil from Jingbian Oil Field, laboratory test assays have been undertaken to quantify the CO_2 effects on crude oil properties.

3.1.1 Crude oil PVT test after CO_2 injection

(1) Bubble point pressure under different injection concentration

Figure 5 shows change of bubble point pressure along with the injected CO_2 concentration. Bubble point pressure of crude oil in the formation is 7.45 MPa. Bubble point of the crude oil increases slowly when injected CO_2 concentration is low, but with the increase of CO_2 concentration, bubble point pressure rises faster, especially when CO_2 rises more than 41%. When CO_2 injection concentration is 67.13%, bubble point pressure reaches 25.25 MPa.

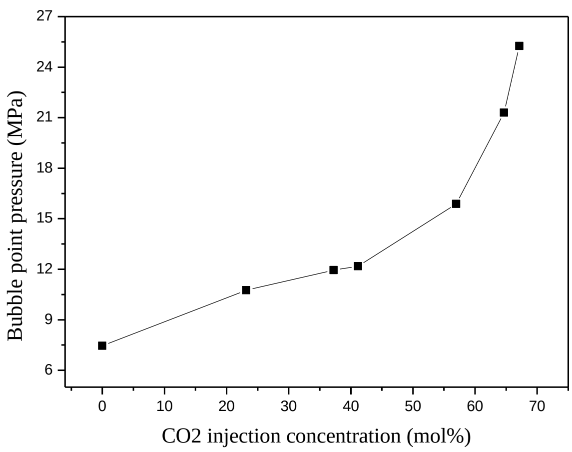


Figure 5: Bubble point pressure changes along with CO_2 concentration

(2) Fluid density data after CO_2 injection

Figure 6 represents the fluid density under different CO_2 concentrations in percentage. When CO_2 concentration remains constant, fluid density decreases when the pressure decreases. When the pressure decreases below bubble point pressure, fluid density drops significantly. Along with the increase of CO_2 concentration, fluid density changes also level off. Under a constant pressure, fluid density is lower with higher CO_2 concentrations.

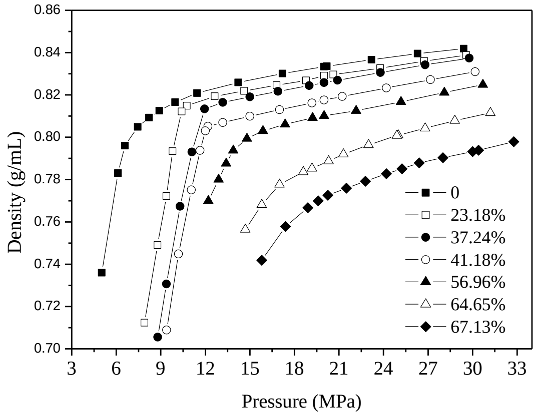


Figure 6: Fluid density changes along with pressure under different CO_2 concentration

(3) Fluid volume expansion data after CO_2 injection

Figure 7 shows the curve of reservoir fluid volume changes relative to pressure under different CO_2 concentrations. It can be seen that when the concentration of CO_2 is over 60 mol %, the relative volume change is not obvious between vapor and liquid phase around bubble point pressure.

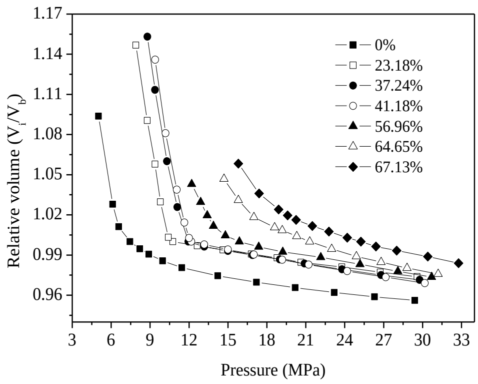


Figure 7: Reservoir fluid relative volume change under different CO_2 injecting condition

Figure 8 shows the curve of reservoir fluid volume factor changes along with pressure under different CO_2 concentration. It can be seen that volume factor increases gradually along with the increase of CO_2 concentration. Before CO_2 injection, reservoir fluid volume factor is about 1.12 under the pressure of 30 MPa. When CO_2 injection concentration reaches 67.13%, reservoir fluid volume factor can be 1.81 under the pressure of 30 MPa. From the point of purely volume factor, it can be seen that CO_2 injection will increase oil production.

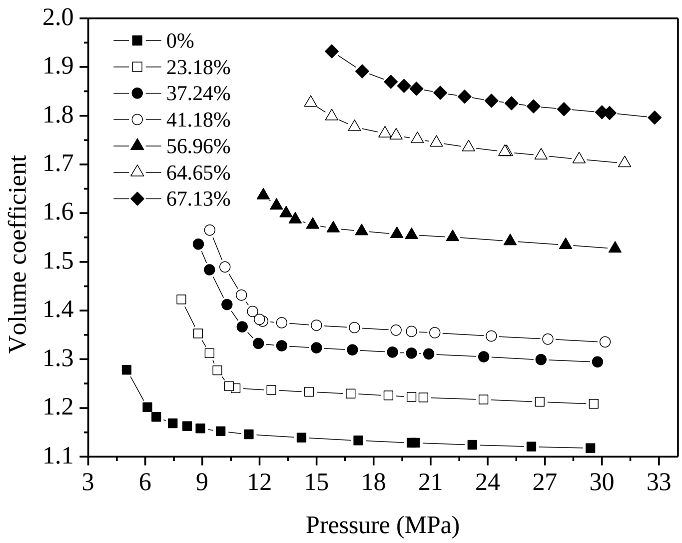


Figure 8: Fluid volume factor changes along with pressure under different CO_2 concentration

3.1.2 CO_2 solubility in crude oil

According to the laboratory results, analysis shows that with an increase of the CO_2 concentration and an increase of pressure, CO_2 solubility of degassed oil production will rise rapidly. At pressures of 25.25 MPa, 1 tonne of total well flow may contain 266.69 cubic meters of CO_2. Figure 9 depicts the relationship between the CO_2 solubility and pressure, of which the black zone refers to CO_2 that can be completely dissolved, white zone refers to fraction of CO_2 that cannot be completely dissolved.

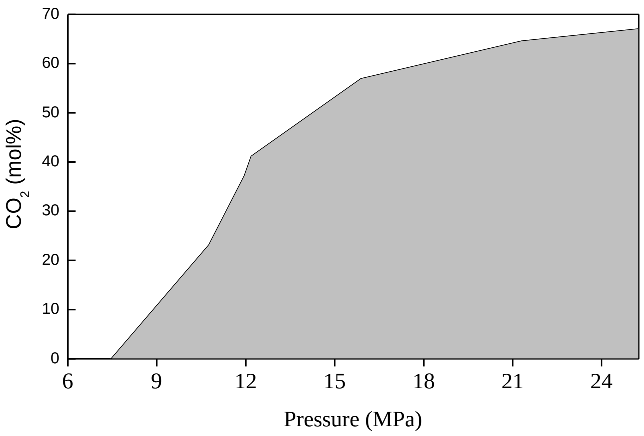


Figure 9: Relationship between the CO_2 solubility and pressure. Black zone refers to CO_2 that can be completely dissolved, white zone refers to fraction of CO_2 that cannot be completely dissolved.

3.1.3 Crude oil viscosity after CO_2 injection

Figure 10 shows the effect of CO_2 molar concentration to crude oil viscosity. It can be seen that under the same pressure, reservoir fluid viscosity decreased with the increase of CO_2 concentration. When the pressure is about 29.5 MPa, crude oil viscosity is about 3.7 MPa before CO_2 injection. When the concentration of injected CO_2 was 23.18%, the crude oil viscosity was about 1.5 MPa, and when the concentration of injected CO_2 was 67.13%, the crude oil viscosity was about 0.5 MPa, the viscosity dropped nearly 7 times. From the viscosity decrease after CO_2 injection, CO_2 injection can improve crude oil viscosity. Under the same CO_2 concentrations however, the crude oil viscosity changes little under different pressures. This indicates that under the same CO_2 concentration, the gas and liquid phases are near to miscible state.

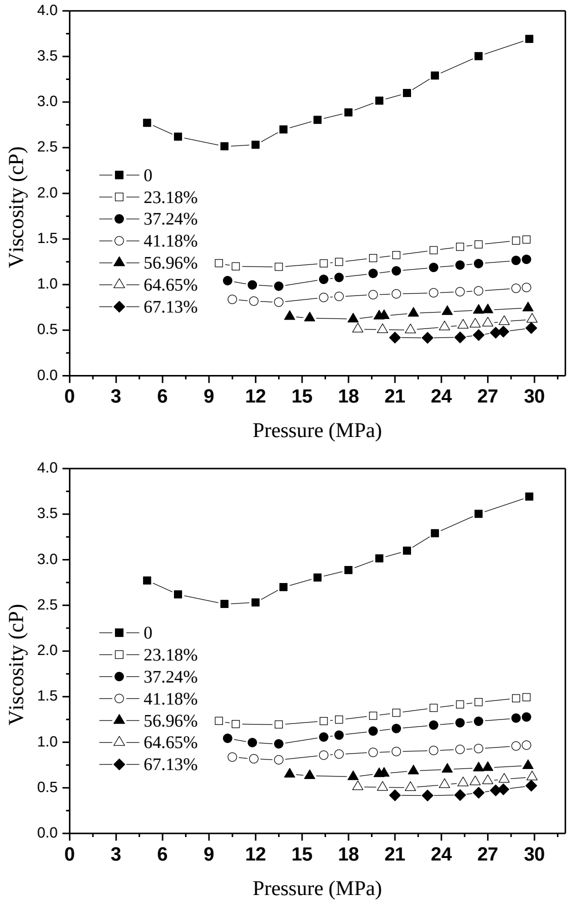


Figure 10: Effect of CO_2 concentration on viscosity of crude oil

3.1.4 The minimum miscible pressure test

(1) Interfacial tension method

This experiment adopts the JEFRI high interfacial tension measuring device, using the hanging drop method.

This experiment was completed under different pressures to measure interfacial tension between CO_2 and crude oil, in order to measure the miscible pressure of first contact.

Figure 11 shows CO_2-reservoir fluid interfacial tension. From test results we can see that with the increase of pressure, the CO_2 solubility in the oil droplets increases, gas-oil density difference reduces, and the interfacial tension decreases constantly. Figure 12 shows oil drip shape before and near to miscible state, it can be seen that due to the decrease between the two phases, that it is hard to keep oil droplets. It can be identified from interfacial tension data that first contact miscible pressure is 24.8 MPa.

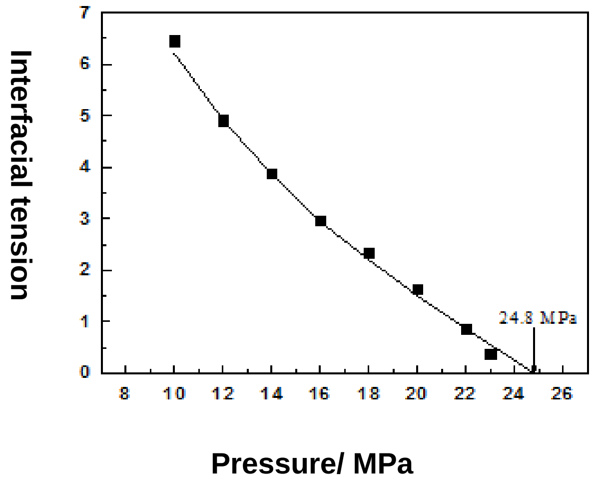
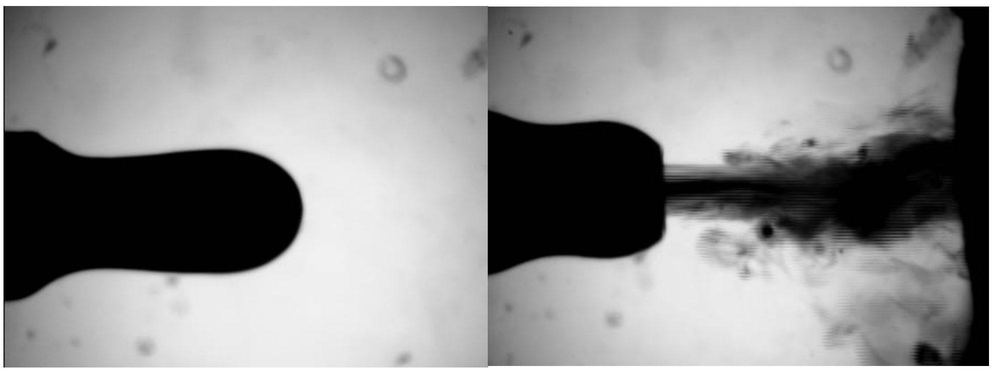


Figure 11: CO_2/reservoir fluid interfacial tension change along pressure



(a) Before miscible (b) After miscible

Figure 12: Oil droplets before and after miscible

As we can see from the figure 12, this is an interfacial tension experiment. The black part is an oil droplet, while the surrounding fluid is CO_2. Along with increase of pressure, the oil droplet is unable to keep its shape, reaching miscible state.

(2) Slim tube experiment method

Figure13 shows crude oil recovery changes along with pressure after CO_2 break through. It can be seen that when pressure is 21.3 MPa and 22.0 Mpa, oil recovery is 70.48% and 86.78% respectively, both below 90%, and the system is in an immiscible state. When the pressure is 22.4 MPa, 23.5 MPa and 25.3 MPa, oil recovery is 90.14%, 90.86%, and 91.52% respectively, all above 90%, and the system is in a miscible state. The minimum miscible pressure determined by the figure is about 22.15MPa.

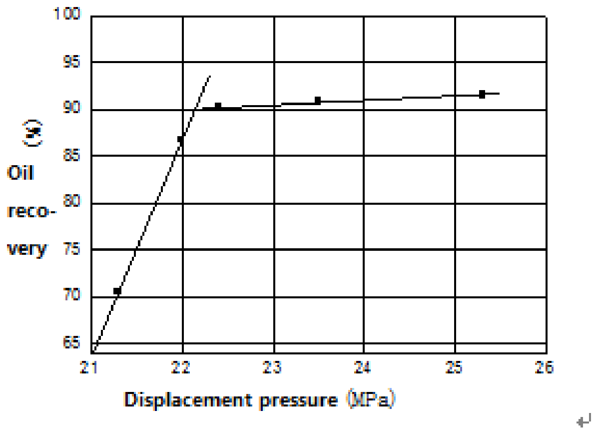


Figure 13: Oil recovery change along with pressure when CO_2 break through

4 Reservoir simulation modelling

4.1 Reservoir geological model

The main task of geological modeling is to build the structural model and populate it with facies and reservoir properties for the CO_2 test area in 203 well block in Jingbian Oil Field. The purpose is to provide 3D data representing various reservoir parameters. Considering geological characteristics, we chose the following modeling method:

- Combining deterministic model and stochastic model;
- Two-step modeling strategy; and
- Collaborative simulation of reservoir data.

The modeling methodology was:

- Build the geological model using convergence interpolation method to establish the structure model;
- Using indicator kriging method to apply the facies model to the structural model; and
- Moving average (inverse square of the distance weighted (Inverse short squared) algorithm was used to populate the model with porosity and permeability data).

4.1.1 Data for geological model

According to the requirement of the Petrel modeling software, the 92 wells district (41 well intersect the target zone) that are in the 3D geological models need:

- Drilling location coordinates and ground elevation ;
- Well paths;
- Logging interpretation data such as porosity and permeability; and
- Stratigraphic data including formation tops according to well logs.

4.1.2 Grid construction

The plane grid spacing is 20 meters x 20 meters, which is divided into a 211 x 148 grid as shown in figure 14, with total number of grid about 1.25 million. The modeling area range is about 9.88 km^2, with total 92 wells, including 41 wells in the target zone.

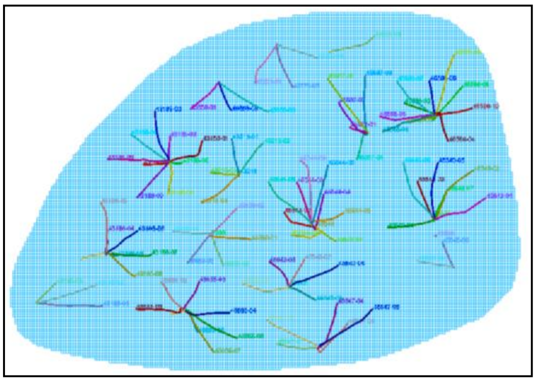


Figure 14: Meshing diagram of 3D geological modeling plane

4.1.3 Structural model

3D structural model is a composite model based on the well's coordinate data and hierarchical data, and the used deterministic modeling methods to build the Chang6 stratigraphic surfaces. The surfaces were built from the well data and the convergence interpolation method was used to extrapolate out away from the wells (Figure 15)

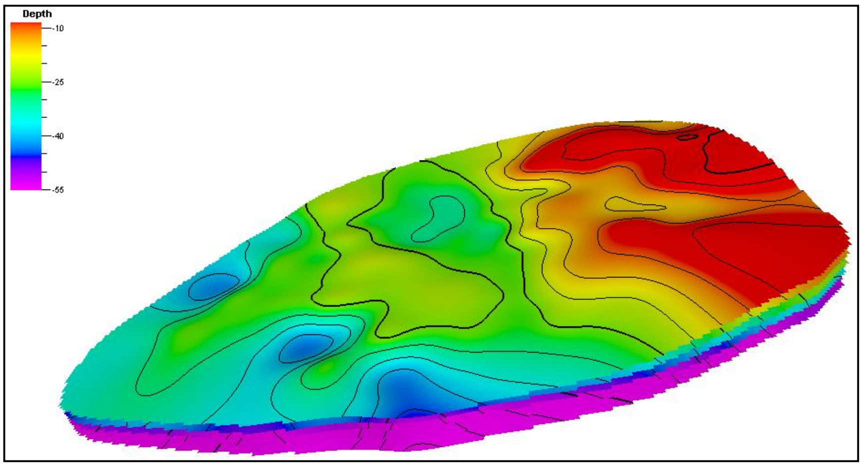


Figure 15: Geological model showing Chang6$_{21}$, 6$_{22}$, 6$_{23}$, 6$_{24}$ stratigraphic surfaces

4.1.4 Lithofacies model

The lithofacies are divided using comprehensive logging interpretation results. The lithofacies included in the model are sandstone (includes the reservoir sands, oil layer, water layer, and oil-water); dry fine sand, and mudstone, indexed with numbers 0, 1, 2, respectively. Using kriging the structural model was populated with lithofacies data (Figure 16 to Figure 18)

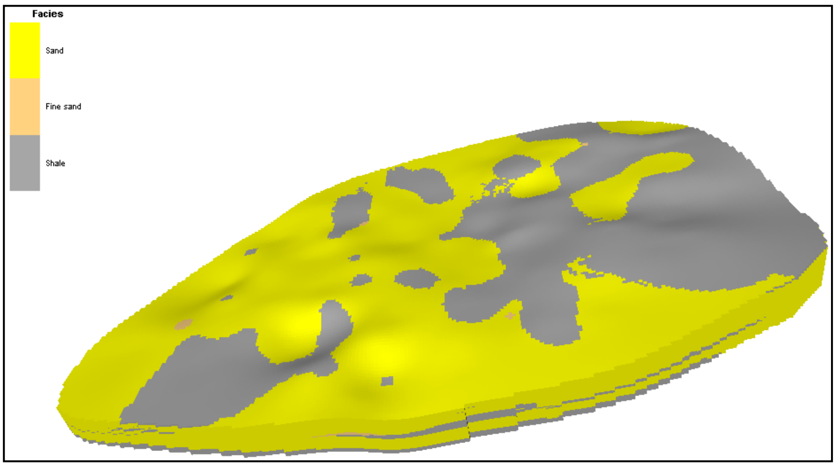


Figure 16: 3D lithofacies model

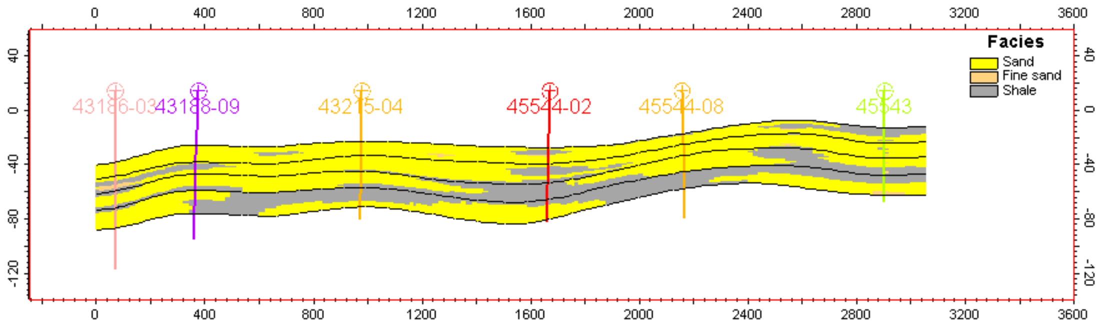


Figure 17: Lithofacies well section（East-west）

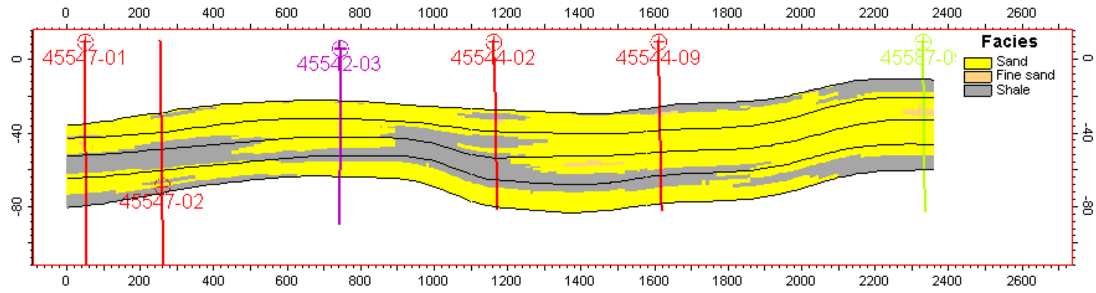


Figure 18: Lithofacies well section（North-south）

4.1.5 Reservoir model

The reservoir properties (porosity, permeability, net-to-gross (NTG)) are controlled by the lithofacies model. In the CO_2 injection area in 203 well block the range of porosity and permeability distribution is small, and the well row spaces are between 250m and 300m. The data for the porosity model (Figure 19-21), permeability model (Figure 22-24), and NTG model (Figure 25 -27) are derived from the well logs. In order to avoid the shortcomings of kriging interpolation method, the project adopts square weighted algorithm to populate the model with porosity and permeability data.

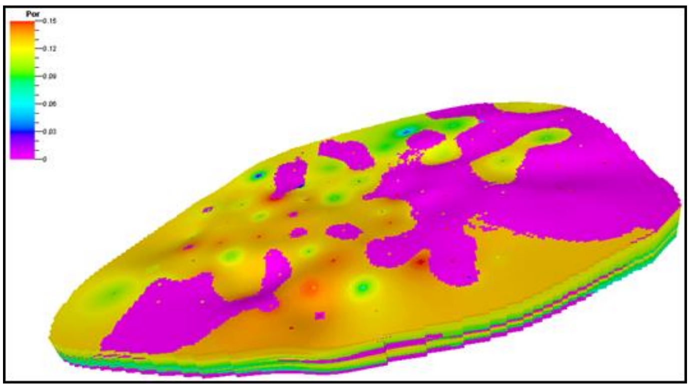


Figure 19: Reservoir porosity model

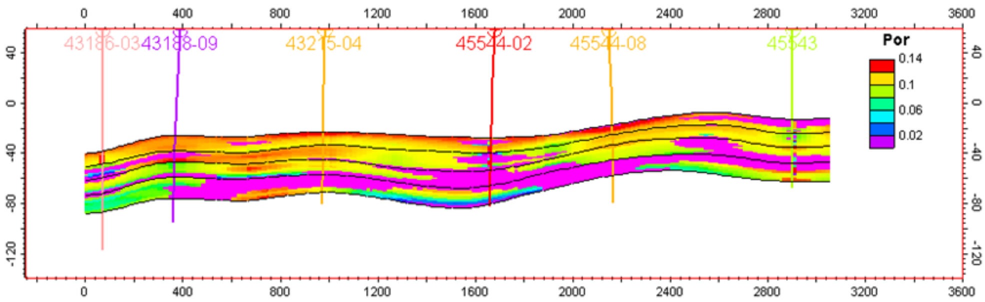


Figure 20: Well section of the reservoir porosity model（East-west）

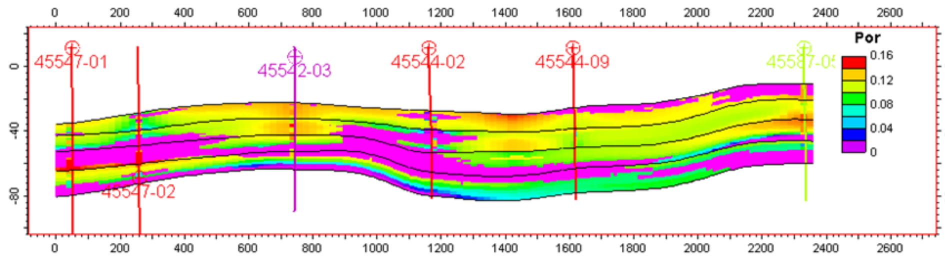


Figure 21: Well section of the reservoir porosity model （North-south）

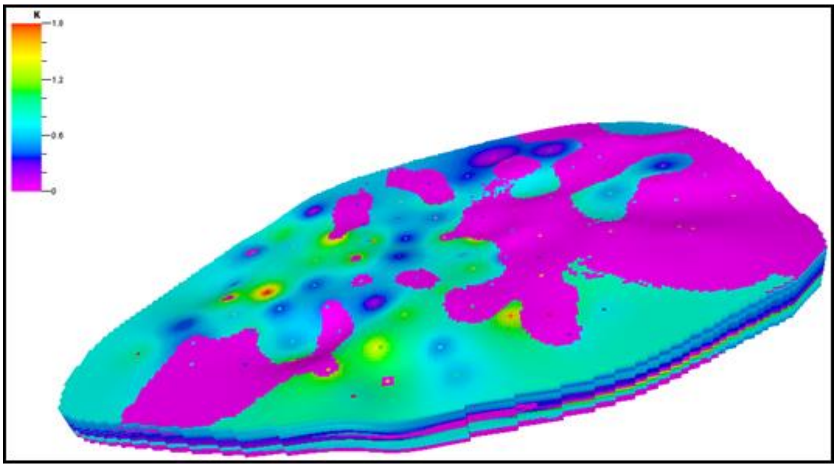


Figure 22: Reservoir permeability model

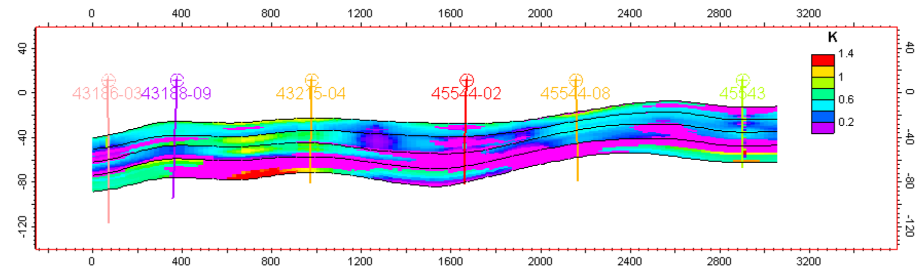


Figure 23: Well section of the reservoir permeability model（East-west）

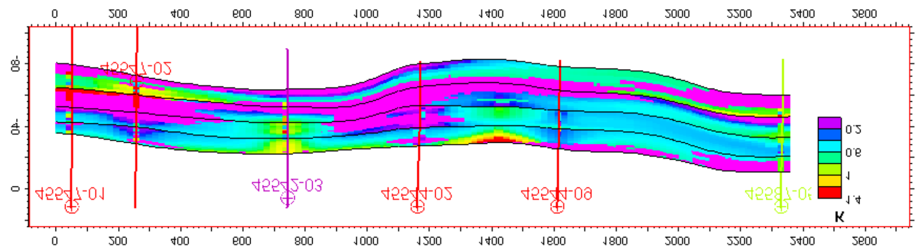


Figure 24: Well section of the reservoir permeability model（North-south）

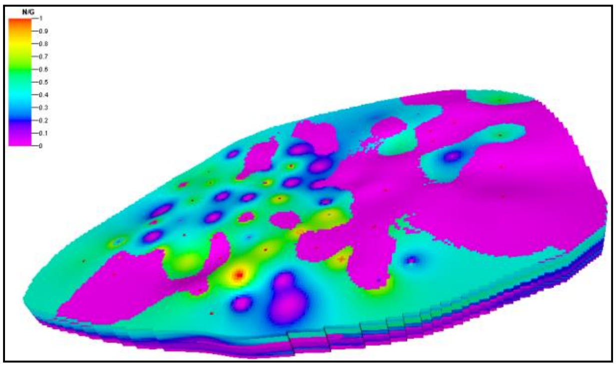


Figure 25: Reservoir NTG model

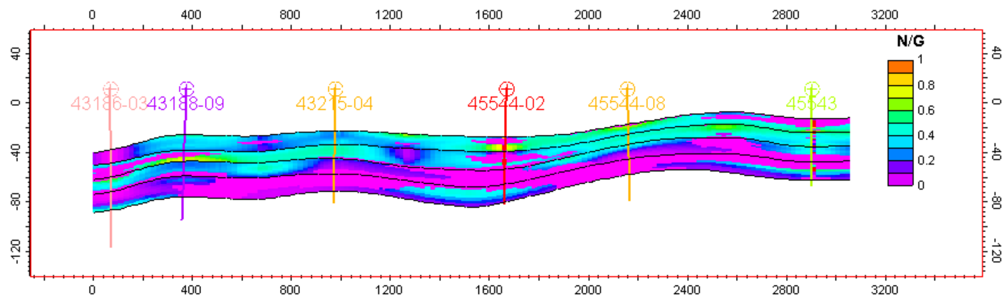


Figure 26: Well section of the reservoir Net to Gross model（East-west）

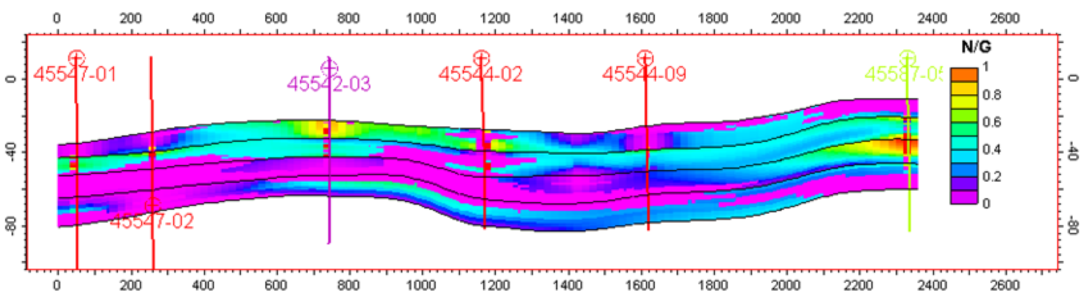


Figure 27: Well section of the reservoir Net to Gross model（North-south）

4.2 Dynamic simulation results from oil production development

4.2.1 History matching of oil production

History matching was undertaken from September 2007 to January 2012; the simulation results are shown in figure 28, 29 and 30. Considering measurement error under low liquid production situation, the matching results are acceptable.

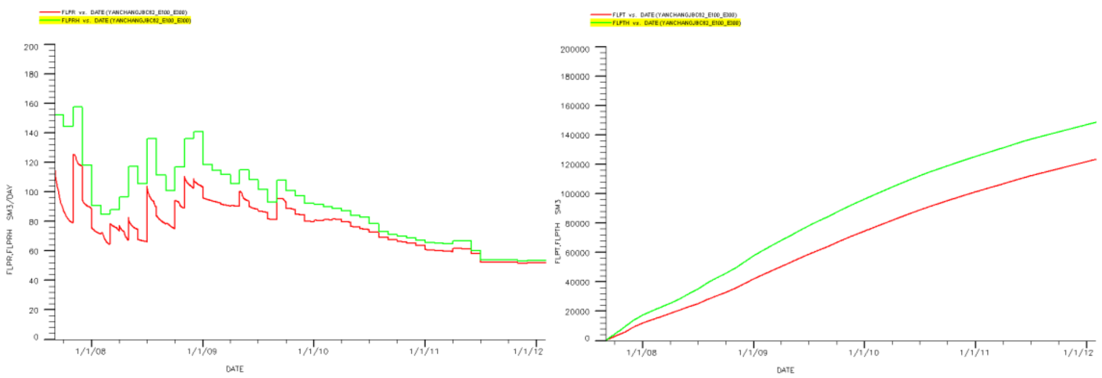


Figure 28: Liquid production rate log and cumulative liquid production log

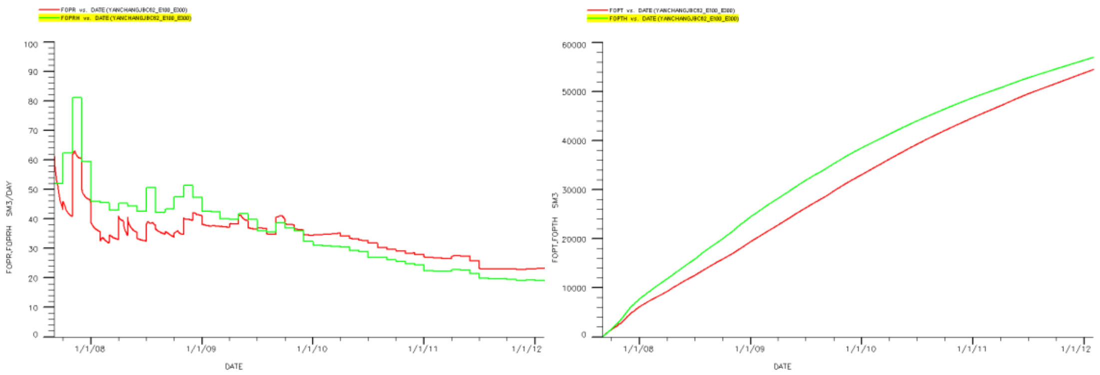


Figure 29: Matching log of oil production rate and cumulative oil production

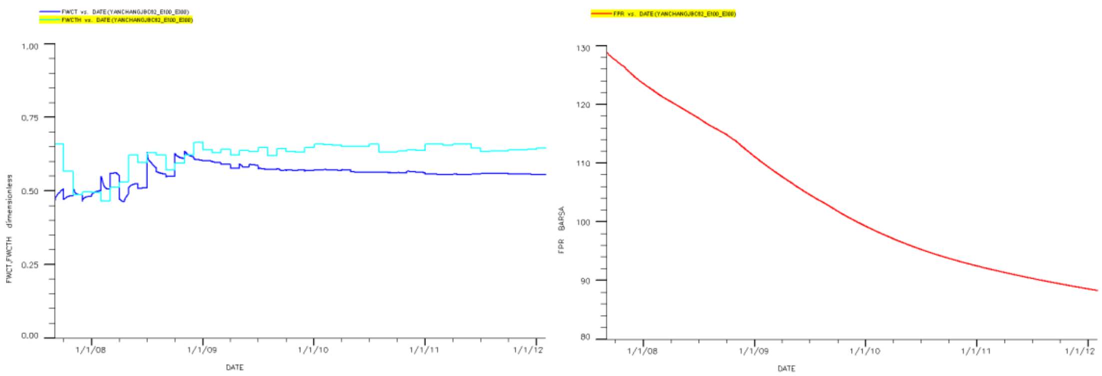


Figure 30: Pressure and water content matching log

4.2.2 Remaining oil distribution

Numerical simulations indicate that since water injection from March 2008 to January 2012 in the test area, the sweep displacement by the injected water is around the wellbore zone and the sweep area is limited. Most of the remaining oil is around the production wells (Figure 31), as shown in figures 32 and 33 .The well group with relatively larger sweep area is centered on injection well 45544-1 and production well 45586-03 near the location of the water flooding front in the main production layer, Chang6_2^2; about 90 m from the two wells. The well groups with small sweep area are about 70 m away from the water-flooding front.

From the remaining oil profiles in Chang6_2^2, 6_2^3, 6_2^4 (horizons of Chang6_2) of production wells 45544-04 and 45586-03 and injection wells 4554-01 and 4554-09, oil saturation is low with distance of 70 m from oil wells, mass remaining oil gathering between wells, as shown in Figure 31 and Figure 32.

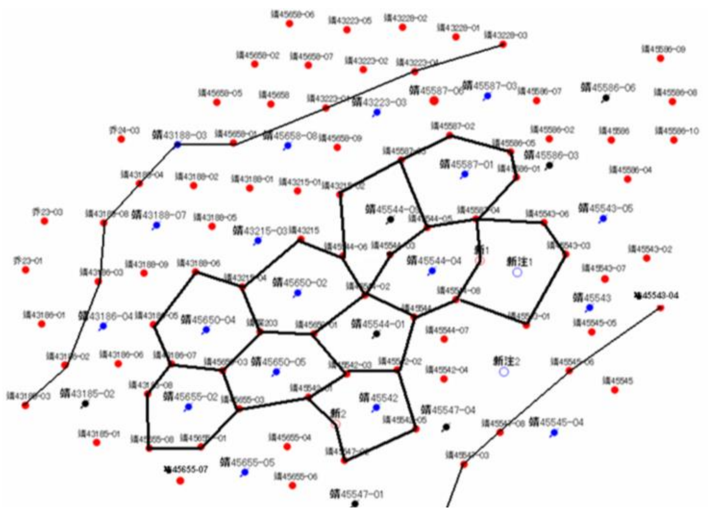


Figure 31: Distribution of INJECTION (blue) and PRODUCTION (red) wells

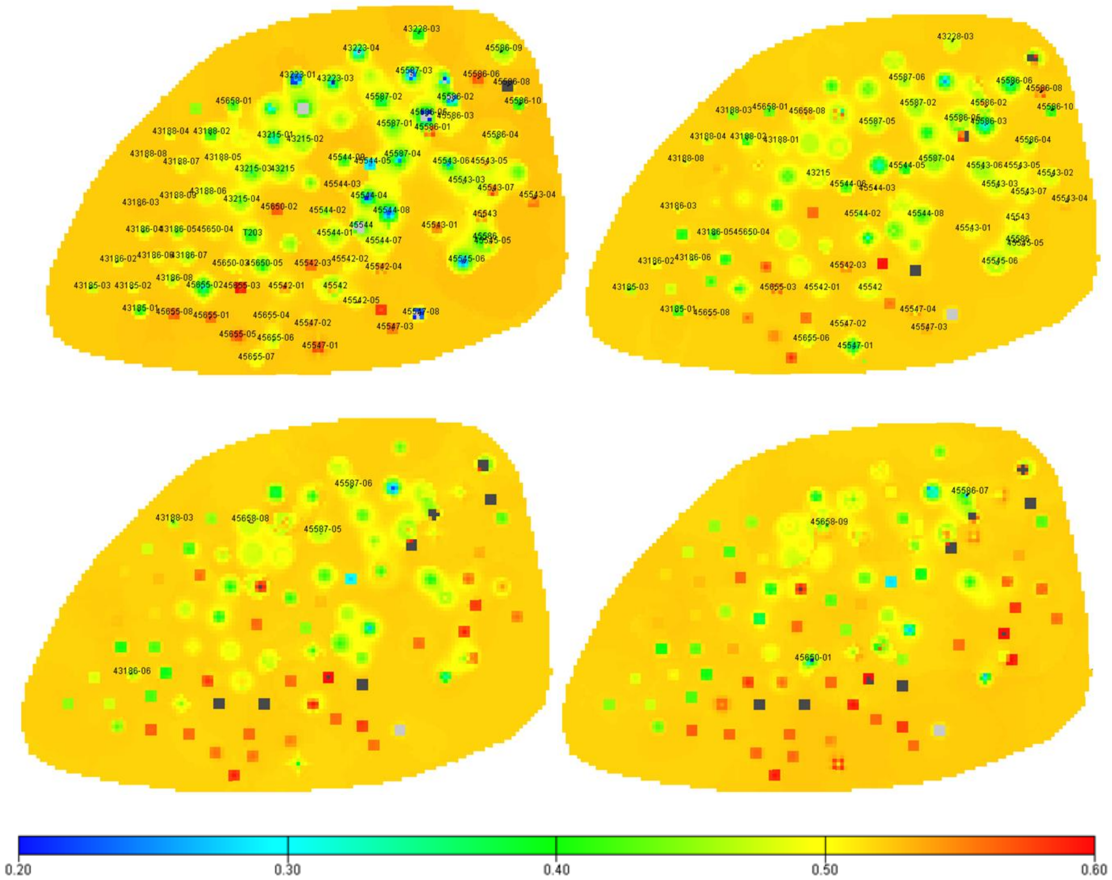


Figure 32: Simulated results of remaining oil distribution of Chang6$_2^1$ (top left), Chang6$_2^2$ (top right), Chang6$_2^3$ (bottom left), Chang6$_2^4$ (bottom right). Colour bar indicates oil saturation from blue to red (0.2-0.6 fraction respectively). See Figure 31 for wells types.

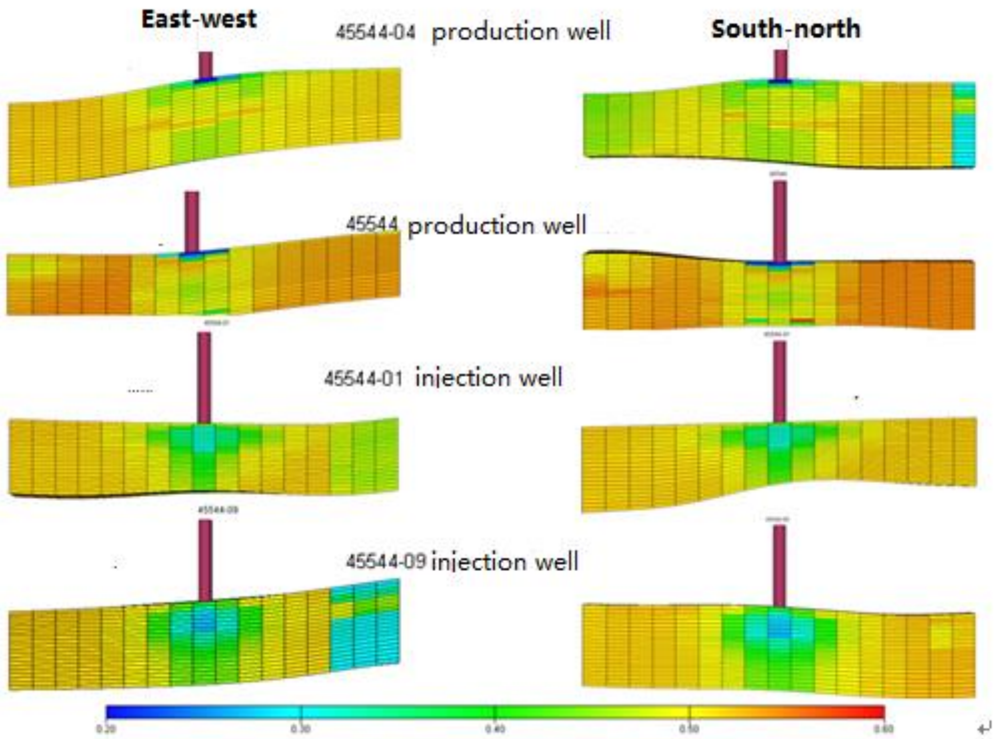


Figure 33: Chang6 Reservoir: Remaining oil profile around oil or injection wells (East-west, South-north). Colour bar indicates oil saturation from blue to red (0.2-0.6 fraction respectively)

5 Test CO_2-EOR operation results

On the basis of the early reservoir research and the conclusions from laboratory research, 20 well groups in 203 well block were selected as the CO_2 injection test well group. The test well group consists of 88 wells with 20 injection wells and 68 front line oil wells.

5.1.1 Initial design of test CO_2-EOR operation

The low permeability reservoirs have low formation pressures and poor stratigraphic connectivity between reservoirs. During the appraisal program, the reservoir pressure dropped quickly, the formation pressure declined, and flow velocity of oil in reservoirs dropped rapidly, which led to a fast decline in production rates. Water injection operations have shown that even with re-pressurising the formation the permeability does not return to pre-operational conditions and therefore injection rates are low.

However, laboratory long core displacement tests found that under the same static conditions of permeability, CO_2 injection capability is five times higher than water flooding. The numerical simulation shows that using the existing well pattern, water injection is 5 tpd while CO_2 injection can be increased to as much as 10 tpd, resulting in increased oil recovery rate and increased production development.

So we can conclude that CO_2 injection is more advantageous to maintain formation pressure and improve reservoir development. In 203 well block, CO_2 injection will begin in the early stages and then switch to water injection (known as water alternating gas, WAG). Simulation research shows that the continuous water injection for 5 years then returning to gas injection can effectively control oil/gas ratio, getting a better development effect.

5.1.2 CO_2 injection style simulation

The water flooding operations at the site have been difficult in the low permeability reservoir due to low reservoir pressure. Therefore, the main purpose of CO_2 flooding is to solve this problem. In order to study the influence of different injection modes and injection parameters to oil recovery, using modeling and simulation data, a modeling test was completed. From the point of enhancing oil recovery and avoiding gas break through, we recommend continuous gas injection or early continuous gas injection, and then switching to WAG injection.

In the Jingbian test area, simulation modeling estimated that reserve recovery is 19.27% at the end of 2015 using a continuous CO_2 injection method, 13.04% larger than water flooding, and average oil production rate is 1.17%. According to the simulation models, the producing gas-oil ratio is 196.78m^3/ m^3, and CO_2 storage rate is 80%, as shown in figure 34.

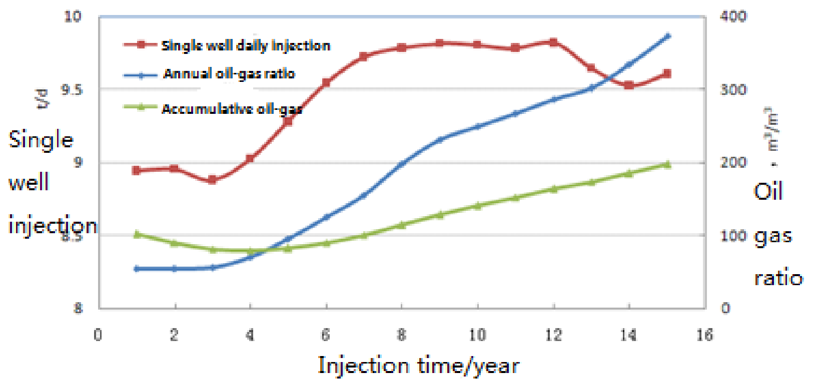


Figure 34: Simulation modelling of the daily gas injection and gas-oil ratio prospect

5.1.3 Ten years of WAG solution after continuous gas injection for five years

Predicting the production development using the WAG method for a 10 year period following five years of continuous gas injection found that the recovery will be 18.44% after 15 years, which is 12.98% more than natural depletion, 12.11% more than water flooding, and the average oil production rate is 1.11%. The ultimate calculated oil recovery is 46.2%, which is 22.12% more than water flooding.

The cumulative gas injection is 0.32 hydrocarbon-pore-volume (HCPV), producing a gas-oil ratio 170.84 m^3/m^3, and CO_2 storage rate is 75%, as shown in figure 35

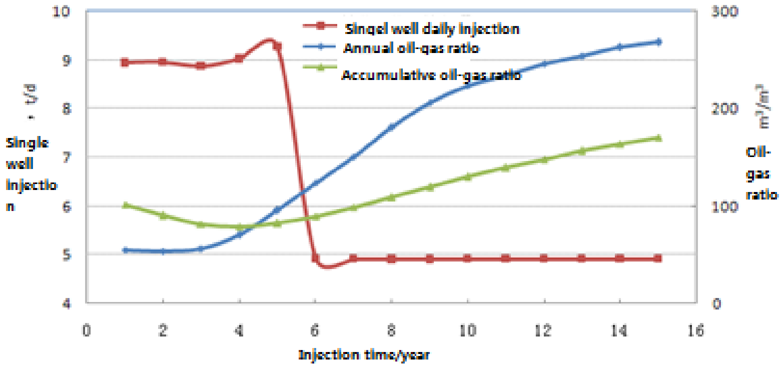


Figure 35: Daily single well gas injection and gas-oil ratio prospect for 10 years of WAG after 5 years of continuous gas injection

5.1.4 Production estimation

According to the forecast from the modelling, the production effect from CO_2 flooding will be seen in the second year, and production will rise. In the 4th to 6th years, production will reach peak. After this time CO_2 break through will begin, and production rates will decline. A comparison of the simulation results from different development styles are listed in table 5. Presently at the CO_2 injection test site the CO_2 break through rates are small and CO_2 is not currently being recycled. However, as CO_2 rates increase in the oil production wells, different well injection and/or WAG scenarios will be tested and further studies on CO_2 recycling will be conducted.

Table 5: comparison of different development styles according simulations.

Evaluation period	15 years			Maximum potential
Flooding Technique	Oil Recovery	CO_2 oil exchange ratio	CO_2 storage retention*	Oil Recovery
	（%）	（tonne oil/tonne CO_2）	（%）	（%）
WAG	18.44	0.58	75	46.2
Continuous gas injection	19.27	0.40	80	37.91
Water flooding	6.23	--	--	24.1

*Note: Closed loop systems would result in all CO_2 being stored.

6 Economic evaluation of pilot project

The economic viability of the pilot CO_2-EOR operation depends largely on the geology of the reservoir, increases in production rates through optimisation of the wells for production and surface engineering, and reducing building costs and project risks. These factors are guided according to the:

1. Reservoir engineering plan
2. Production engineering and production-injection well project budget
3. Surface engineering and its project budgetary estimate.

6.1 Investment cost estimate and financing

The investment cost estimates are as follows:

Total investment = Construction investment + Fixed assets investment orientation regulation tax + Interest incurred during construction + Working capital

The estimated value and proportion of total investment for each of these items is shown in Table 6.

Table 6: Total investment estimation table of the test site in 203 well area

Engineering or name		Estimated value (Yuan million)	Proportion of total investment （%）
1	Construction investment	166.60	98.36
2	Fixed Assets Investment Regulation Tax	0.00	0.00
3	Working capital	2.19	1.29
4	Interest	0.58	0.34
5	Total investment	169.3668	100
Approved investment		**169.3668**	**100**

6.2 Operating costs estimation

The main operating costs includes production costs, management costs, sale costs and financing costs.

- ‘Production costs’ include electricity, CO_2 injection fees, oil and gas handling fees, salaries, welfare funds, factories and mines management fees, maintenance fees, repair fees and so on.
- ‘Management costs’ include amortisation fees, mineral resources compensation fees, oil windfall tax and other management fees.
- ‘Sales costs’ are calculated as 1% of sales revenues.
- ‘Financing costs’ include interest and debt repayments.

6.3 Estimate for sales revenue, sale tax and associate fee, income tax

The crude oil price is assumed to be $70 a barrel (3225.92 Yuan/tonnes). Sales tax and associate fees mainly include value added tax, urban maintenance and construction tax, education tax and resource tax. Value added tax is 17% of the sales income. Urban maintenance and construction tax and education tax are calculated at 10% of the value-added tax. Resource tax is 4.09%.

6.4 Analysing profitability

The financial internal rate of return for the entire project is 24.99% after income tax with a payback period of 5.16 years after income tax. Based on industry standards for low permeability reservoirs, a minimum rate of return requirement is 12% (Investment Project Feasibility Study Guide), which indicates that the Jingbian project is financially acceptable.

Considering the potential variance in CO_2 injection costs to the project, when assuming a higher injection cost of 650 Yuan/tonne the project has an internal rate of return of 12.58%, which is still above the industry standard of 12% (Investment Project Feasibility Study Guide) (Table 7).

Table 7: Benefit analysis contrast table of CO_2-flooding project

Injection cost (Yuan/tonne CO_2)	200	650	1000
Internal rate of return（%）	24.99	12.58	4.27
Net present value（million Yuan）	123.48	6.23	92.04
Payoff period（year）	5.16	7.77	11.51

6.5 Economic sensitivity analysis

In order to calculate the degree of risk the project may bear and find out sensitive factors that influence the economic benefit, we did the sensitivity analysis by oil price, production rates, investment, and operation cost as well as other factors.

The sensitivity analysis found that the greatest influence to the financial benefits of the CO_2-EOR Jingbian operation came from oil price and production rates, next is investment costs and then operational costs. As shown above when the price of oil is $70 / barrel, financial internal rate of return for the project is 24.99%. However, the sensitivity analysis shows that if the price of oil decreases by 20%, the rate of return reduces to 18.30%.

7 Measurement, Monitoring and Verification strategy

In order to guarantee that the CO_2-EOR project is running smoothly and to evaluate the results correctly, the project will undertake a measurement, monitoring and verification (MMV) strategy.

7.1 The basic principle of MMV

1. The project must be based on environmental protection laws, environmental quality standards, industry specifications of Yanchang Oil Group and related organisation, as well as well as the national, industry and local regulations.
2. The project must follow the principles of scientific assurance, accuracy and practical applicability. The purpose of monitoring after CO_2 injection is to understand the impact on the surface, near surface, ecology and reservoir environments.
3. Focus on the first-line oil production wells, and pay close attention to second-line wells during the initial CO_2 injection.
4. Strengthen the inspection of wellbore leakage indicators. According to statistics of the world scope of CO_2 storage projects (Mingxing and Reinicke, 2013), wellbore leakage is a primary channel for CO_2 leakage from the reservoir.
5. Comprehensive planning, rational layout. The complexity of the CO_2 leakage determines the diversity of monitoring methods. It needs reasonable arrangements to the monitoring points, sampling, analysis, testing and data processing. According to different situations different technical options are required that play to their respective strengths.

7.2 Baseline surveys

Baseline surveys that will be completed are listed in Table 8.

Table 8: Baseline surveys

Technology	Reason
Groundwater well monitoring	Understand the groundwater system in the area
Surface and near-surface monitoring	Catalogue surface water sources
	Catalogue vegetation growth/change
	Catalogue soil type and distribution
	Soil gas composition
	Atmospheric CO_2 concentration and isotopic composition
Dynamic monitoring of injection and production wells	Produced fluid analysis including oil component
	Production rate

	Pressure and temperature
	Interwell tracer injection
	Corrosion monitoring

7.3 The main monitoring items

1. Dynamic monitoring of CO_2 injection

Mainly focusing on injection wells, monitoring includes: single well injection rate, injection pressure, pump pressure, injection temperature, and single well injection flow parameters, these are the most direct parameters during CO_2 injection process.

2. Dynamic monitoring of oil wells

Focus on the first-line oil wells in the pilot area and pay close attention to the second-line oil wells. The main monitoring contents are:

- Well production performance monitoring: daily liquid production, daily oil production, moisture content, working fluid level, as well as CO_2 concentration monitoring.
- Reservoir pressure monitoring: pressure monitoring through downhole pressure meter in monitoring wells.
- Component of oil monitoring including oil, water and gas: refers to analysis of crude oil composition, analysis of associated gas composition, and analysis of formation water quality.
- Corrosion monitoring: two kinds of monitoring methods that is the total iron tests in field and laboratory simulation environment test to measure corrosion rate during CO_2 flooding.

3. Surface and near-surface monitoring

To monitor the surface and near surface environments including atmosphere, water quality, soil and plant, etc. the main monitoring content includes:

- Near-surface monitoring: groundwater quality in water wells and production wells；
- Surface monitoring: includes monitoring of surface water quality, investigation of plant growth condition, survey of soil types, ion distribution of soil, etc.;
- Atmospheric monitoring: CO_2 concentration and isotopic variation.

4. Interwell tracer monitoring

Before the start of the CO_2 injection pilot operation, injection of tracers into the reservoirs will assess the reservoir flow rate and direction preference of the CO_2 by testing fluid samples in the injection and monitoring wells. Tracers can identify change in the trend of reservoir's permeability and water injection flow channels, as well as determine water flood sweep area. By analysing traces, the direction of the CO_2 flow when gas breakthrough is achieved in the oil wells, can help adjust the injection profile

5. Monitoring of CO_2 migration and distribution in reservoir

The acquisition of 3D seismic data will enable monitoring to understand the distribution of reservoirs and caprocks, as well as monitor CO_2 migration, and confirm the CO_2 volume.

7.4 MMV schedule

According to the basic principle of MMV, the specific monitoring items and monitoring frequency are as shown in Table 9.

Table 9: MMV content and schedule

<table>
<tr><th>Stage</th><th>NO.</th><th>Testing item</th><th>Target</th><th>Time</th></tr>
<tr><td rowspan="11">Before CO_2 injection</td><td>1</td><td>Groundwater survey</td><td>Catalogue water sources</td><td>Once a quarter</td></tr>
<tr><td rowspan="4">2</td><td rowspan="4">Surface surveys</td><td>Quality of ground water</td><td>Once a quarter</td></tr>
<tr><td>Plant growth and type</td><td>Once a quarter</td></tr>
<tr><td>Soil type and distribution</td><td>Once a quarter</td></tr>
<tr><td>Atmospheric survey</td><td>Once a quarter</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">Oil well monitoring</td><td>Produced fluid analysis</td><td>Once a month</td></tr>
<tr><td>Production rate</td><td>Once a day</td></tr>
<tr><td>Reservoir Pressure</td><td>Once half a year</td></tr>
<tr><td rowspan="2">4</td><td rowspan="2">Injection well monitoring</td><td>Injection rate</td><td>Once a day</td></tr>
<tr><td>Injection profile testing</td><td>Before CO_2 injection</td></tr>
<tr><td rowspan="2"></td><td>1</td><td>Near ground survey</td><td>Catalogue water sources</td><td>Once a quarter</td></tr>
<tr><td>2</td><td>Surface</td><td>Quality of ground water</td><td>Once a quarter</td></tr>
</table>

First year CO_2 injection		survey	Plant growth and type	Once a quarter
			Soil type and distribution	Once a quarter
			Atmospheric survey	Once a quarter
	3	Oil well monitoring	Produced fluid analysis	Once a month
			Production rate	Once a day
			Reservoir Pressure	Once half a year
	4	Injection well monitoring	Injection rate	Once a day
			Injection profile testing	CO_2 injection half a year
Second year CO_2 injection	1	Near ground survey	Catalogue water sources	Once a quarter
	2	Ground environment survey	Quality of ground water	Once a quarter
			Plant growth and type	Once a quarter
			Soil type and distribution	Once a quarter
			Atmospheric survey	Once a quarter
	3	Oil well monitoring	Produced fluid analysis	Once a month
			Production rate	Once a day
			Reservoir Pressure	Once half a year
	4	Injection well monitoring	Injection rate	Once a day
			Injection profile testing	CO_2 injection for a year

7.5 Risk and countermeasure analysis

The project faces technology, energy resources, environment, society and market risks as well as the risks surrounding policies and regulations.

1. Technical risks and countermeasures

There are no mature CO_2-EOR operations in China, so the project needs field research on CO_2-EOR projects both in China and abroad. With the Yanchang CO_2-EOR operation there exists technical uncertainty, including uncertainty of technological prospects and risk, and insufficient understanding of the suitability of the CO_2-EOR technology. These uncertainties are mainly in two areas. Firstly, long distance pipeline transportation has not yet been undertaken in China, which brings challenges to pipeline technology design. It may result in reduced supply efficiency, CO_2 leakage, pipe burst or other accidents if the design is not suitable. The second uncertainty is data gaps in the subsurface, because for historical reasons, Yanchang Formation has a lack of data, which brings uncertainty to the implementation of the project

To counter these two main uncertainties, firstly we need to strengthen technology research and develop new technologies to improve technical efficiency and level of knowledge in pipeline transport and CO_2-EOR technology and operation. Second, promote more CCUS technology practice through cooperation among enterprises and research institutes, absorb technical staff with rich technical experience to improve scientific research ability of the research group. Third, establish a rigid CCUS process data management information system, especially the data related to the geological characteristics of CO_2 geological storage, monitoring data, etc., and to reduce the uncertainty in the process. Fourth, carry out CCUS skills training.

2. Environmental risk and countermeasures

After CO_2 injection and in the event of leakage, it may impact the groundwater system and the ecological system in the immediate zone. Countermeasures to this risk include design and drilling of reliable oil, CO_2 injection and monitoring wells; develop monitoring techniques and detailed monitoring regulations; and generate strict monitoring and supervision mechanism. Also prevention, early warning and error correction schemes incidents will also reduce the risk.

3. The investment risk: CO_2-EOR field test project investment cost is high.

Although CO_2 used for the EOR operation is produced from coal to chemical production, which makes CO_2 costs low, the long distance for truck tank transportation is 200-300km which increases the cost. At the same time, engineering and infrastructure for CO_2 injection is demanding, as investment for gas injection may be several times bigger than water injection.

To counter the risk of increasing costs, Yanchang Oil Group will strengthen technology research and product research, develop and optimise project design, undertake research and evaluation work before production, to reduce investment risk. Also, strengthening international cooperation to attract foreign capital and expanding the financing channels can decrease costs. Strengthening the communication with relevant government departments and strive for more policy support, financial subsidies, and tax cuts can also reduce the enterprise investment.

4. Policy risk and countermeasures

The development of CCUS projects needs strong policy, backed by a robust legal and regulatory framework. While China has a clear policy commitment including international agreements that recognise the role of CCUS in meeting climate goals, it would benefit from more targeted incentives and regulations for CCUS development. Greater certainty in international climate policy, where China plays a major role, can also create an environment where the risk of investing in CCUS projects is reduced. The development of stable, long term policy and regulations in turn is dependent on policy-makers and key stakeholders in the community receiving consistent and up-to-date information on the progress of CCUS technology around the world. Similarly, participating in international activities related to CCUS technology is also critical.

8 Conclusion

In the northern Shaanxi Province a CO_2-EOR project is underway, targeting the ultra and low permeability Chang6 reservoir of the Yanchang Formation. The CO_2 is sourced from the coal chemical process at 50,000 tpa of the Yulin Coal Chemical Company and will be expanded to include a 360,000 tpa CO_2 capture project by Yulin Energy Chemical Company. The 203 well block in Jingbian Oil Field has been selected as the CO_2 flooding pilot area. This site began oil production in 2007 and has been the subject to water flooding since 2008. In 2012 test CO_2 flooding operations began and a total of 41,000 tonnes CO_2 have been stored to date. The Chang6 oil-bearing reservoir was deemed feasible for EOR based on geological modeling and numerical simulations, as well as the analysis of the data from previous water and CO_2 flooding results. Also, laboratory results of samples from the site have increased the understanding of the interaction of the oil, CO_2 and reservoir.

The successful laboratory and field testing has laid the foundation for technical support for realising the development of a tight reservoir for enhanced oil recovery using CO_2 into a larger pilot and future demonstration project.

9 Future Program

Based on previous CO_2-EOR test site results and according to the arrangement of the project, a 20 injection well pilot CO_2-EOR project will operate in the 203 well block in Jingbian Oil Field. On the basis of experience, ongoing technology maturity and equipment improvement, more injection wells will gradually be added and increase the CO_2 storage volume, leading to a demonstration project in 2016. The ongoing project will also include:

- According to the MMV strategy, monitoring of CO_2 injection wells and oil wells regularly and according to the field dynamic monitoring results, adjust CO_2 injection scheme and scale timely. This is achieved by monitoring the CO_2 injection wellbores and production wellbores regularly; study CO_2 corrosion on wellbores; develop more efficient corrosion inhibitor and do a good anti-corrosive job for injection and production system in test area.

- In view of the limitations of field sampling and laboratory experiment, carry out additional CO_2 flooding tests, get more detailed data and provide theoretical support for CO_2 flooding and storage.
- Along with the development of the project and data acquisition, processing and analysis, adjust CO_2 flooding scheme in 203 well block as required.
- Summarise the theory and field case of CO_2 flooding and geological storage, and write a CO_2 flooding and storage monograph to provide valuable experience and practice of CO_2 flooding and storage in China and globally.

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