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Executive summary

The Subei Basin is located in the east of China, across Jiangsu and Anhui provinces and extends into the Yellow Sea. The region is the most developed in China, with many large cities, such as Nanjing, XuZhou and Shanghai, with a population of more than 100 million. The Jiangsu Oilfield complex, together with a few smaller oilfields, lies in the centre of the basin and is currently operated by Sinopec. There are also many natural carbon dioxide (CO_2) reservoirs, which in the last ten years have been used to support CO_2 flooding pilot projects. The natural CO_2 reservoirs can be considered as analogues for CO_2 storage.

The Jiangsu Oilfield complex is relatively small with complex geological features and many small faulted reservoirs. Most reservoirs are 2,000-3,000 metres deep, with light to medium oil, which are good candidates for near-miscible CO_2 flooding. The region has significant CO_2 emissions, and there is potential for using depleted hydrocarbon reservoirs and deep saline aquifers as CO_2 storage sites. In this study, enhanced oil recovery (EOR) and CO_2 storage potential have been assessed along with the main geological features of the basin, which will have an impact on the safe storage of CO_2.

Most of the oil and gas reservoirs discovered in the region are located within faulted depressions. Many unproven aquifers may pose some leakage risks for CO_2 due to these complicated faulted depressions. Currently, thirty four small to medium sized oilfields have been developed in the basin, with cumulative proven original oil in place (OOIP) of 196.24 million tonnes (Mt), and original gas in place (OGIP) over 8 billion m^3. Of this 186 million tonnes of reserves have been assessed.

In order to calculate the CO_2 storage potential in the Jiangsu Oilfield complex, an assessment method and software, including oil reservoir CO_2-EOR (CO_2 – enhanced oil recovery) screening and storage potential calculation (at reservoir scale), have been developed. In total, 108 oil reservoirs have been assessed, containing a total of 132.37 million tonnes OOIP. The calculated CO_2 storage potential is expected to be in the order of 20 Mt, and the incremental oil production via CO_2 injection is expected to be up to 4.67 Mt.

The Subei Basin also has abundant natural CO_2 resources as well as oil and gas in place. It has been suggested that the natural CO_2 in the region was generated inorganically, being related to volcanic activities which started in the early Jurassic, lasting until the Miocene Epoch. In terms of geological evolution, the oil bearing formations were formed first, then CO_2 was generated from carbonate rocks of the Palaeozoic Era due to volcanic activities. This in turn caused the formation of the main faults in the basin, which allowed CO_2 to migrate and invade the Tertiary oil bearing formations. All CO_2 reservoirs discovered in Tertiary rocks have traces of oil residue though some CO_2 remained in the original Palaeozoic formations. Most CO_2 reservoirs are located in the Xuzhang and Fumin-Xiaoji regions close to ShangHai. The total CO_2 reserve proven is up to 7.9 Mt. These natural CO_2 reservoirs can be used as analogues for CO_2 storage studies.

This study has shown that the CO_2 storage potential in oil reservoirs in the Subei Basin is limited because the faulted oil fields are relatively small. There are also

many aquifers that formed in similar structures (faulted) associated to the oil reservoirs, which may be considered as sites for CO_2 storage, but it may be difficult to prove the integrity of the seals of these heavily faulted structures. On the other hand, many oil reservoirs are associated (or connected) with large lateral or underlying aquifers. To some extent, these aquifers can be expected to be good sites for CO_2 storage. The K_2T_1 oil reservoir in Wa-6 block of the Wangzhuang Oilfield was studied as an example. The oil reservoir K_2T_1 is connected to a large lateral aquifer, ten times the volume of the oil reserve. Based on the CO_2 solubility calculation method, the aquifer has CO_2 storage capacity of 2.24 Mt, while the upper oil reservoir can only store 0.5 Mt CO_2. Therefore, in terms of CO_2 storage in oil reservoirs, the extra storage capacity provided by their associated aquifers should be considered. This however is negligible when compared to lifetime CO_2 emissions from a large power plant.

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1 Introduction

CO_2 injection into heavy and tertiary light oil reservoirs is accepted as an effective technique for EOR (enhanced oil recovery), and has been used by the oil industry for over 40 years. In recent years, concerns over greenhouse gas emissions are leading to the investigation and deployment of CO_2-EOR and geological storage by injection into depleted oil and gas reservoirs. Naturally, oil and gas reservoirs are attractive as CO_2 storage sites since they are known to have effective seals that have retained liquid and gas hydrocarbons for millions of years. CO_2-EOR has been extensively investigated and is commercially pursued. There have been many projects where CO_2 is injected for EOR; however the implementation of CO_2-EOR with the potential of geological CO_2 storage poses new challenges and opportunities to the oil and energy industries.

In this report, a general assessment of CO_2-EOR and storage potential is given in the Subei Basin, especially for the Jiangsu Oilfield complex, in terms of reservoir selection.

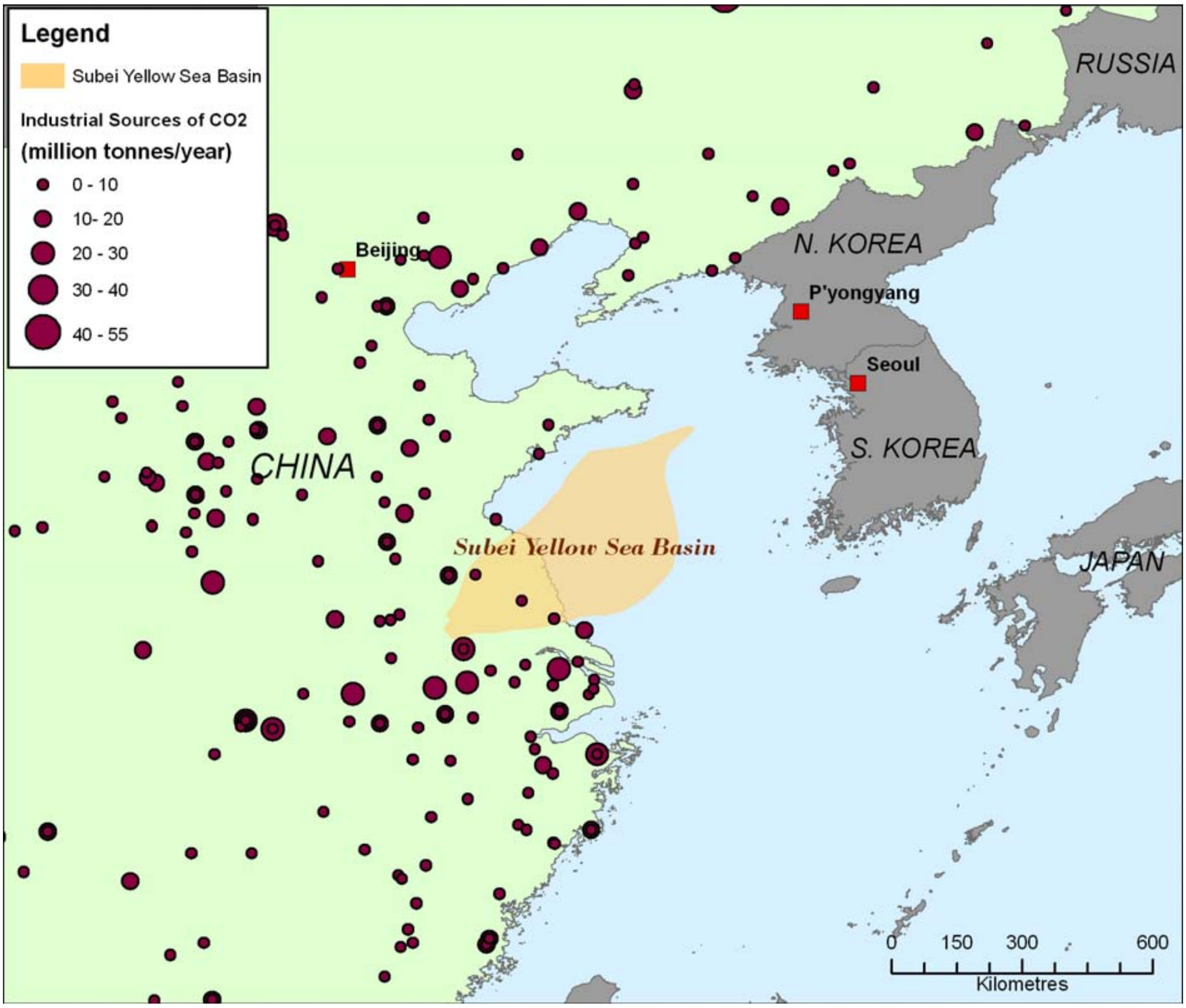


Figure 1: The location of Subei and Yellow Sea Basin and industrial sources of CO_2 in East China

The Subei Basin is located in the east of China, across the Jiangsu and Anhui Provinces, and extends into the Yellow Sea (see Figure 1). The region is the most developed area in China, with many medium to large cities, such as Yangzhou, Zhenjiang, Suzhou, Wuxi, Nanjing and Shanghai, where the population is greater than 100 million and there are many significant CO_2 emission sources (Figure 1). The aim of this assessment is to identify sites suitable for CO_2-EOR and evaluate potential for CO_2 storage in depleted reservoirs. This study has focussed on the Jiangsu Oilfield complex, which is operated by Sinopec and is located in the centre of the basin. The oilfield started oil production in 1975, and has now entered the middle-late stage of development after primary production via natural depletion and water flooding has been employed for the past 20 years. Currently, many mature reservoirs can be proposed for EOR, including through CO_2 injection.

Many natural CO_2 reservoirs have also been discovered in the Subei Basin, which in the last ten years have been used to provide CO_2 for pilot CO_2 flood projects. The natural CO_2 reservoirs can also be used as analogues for CO_2 storage, and are also described in this report. Like other regions worldwide, deep saline aquifers in the Subei Basin are not well investigated during conventional geological surveying and oil exploration due to their low priority as an economic resource. Some limited and useful information about underlying aquifers or those adjacent to the oil or gas reservoirs may be used for assessing CO_2 storage potential. In general, these aquifers (with connections to oil and gas traps) can be considered as better candidates for CO_2 storage.

2 Geological Evolution of the Subei Basin

2.1 Tectonic Evolution

The Subei Basin formed during the Mesozoic-Cenozoic Era. Fluvial sediments of the Yellow and Huaihe rivers were deposited after depressions and troughs formed during the XiangShan and Yanshan orogenies in the early Jurassic to late Cretaceous periods. It is a continental sedimentary basin influenced by the dual effects of faulting and depression on the basal limestone formation generated in the Xiangshan orogeny. The main migration of oil and gas took place during the Sanduo deformation. The main tectonic evolution of the Subei Basin is shown in .There were four stages in the tectonic evolution of the Subei basin, described in more detail below. The main oil and gas generation system is the structural-I formation of the Lower Tertiary, oil was also formed during the end of the structural-II period of the Lower Tertiary.

(1) Initial Fault and Depression stage

After the Xiangshan Orogeny, between the early Jurassic and Late Cretaceous, the Subei region was subjected to faulting and strong volcanic activities, during which time 4,000-5,000 metres of red clastic and volcaniclastic rocks were deposited. The basin was rapidly filled by sediment during the rift-faulting phase. The Yizheng movement at the end of Yanshan Orogeny caused uneven regional uplift, with the uplifted regions suffering from further strong erosional effects. The residual thickness of the Jurassic–Cretaceous sediment in the uplifted region is up to 1,000 metres. The residual thickness of the deep depression region is 2,000-4,000 metres. This period is marked primarily by two major uplifts and two depressions in the Subei Basin.

(2) Strong depression stage

After the Yizheng Orogeny, the basin was affected by strong extension and rapid subsidence movement. From Palaeocene-Eocene Epochs, since the rate of subsidence was greater than the sedimentary depositional rate, the water depth increased greatly and the area of the depression zone expanded continuously. As a result, the top part of the Taizhou Formation and the second and fourth members of the Funing Formation were deposited as deep lacustrine (lake) sediments containing oil source rocks up to 1,000 metres thick. Due to periodic changes of the extensional movement, the Taizhou-I, Funing-I and Funing-III^{d} members were deposited, which had good combinations of oil source (generation), reservoir and trapping (seals) formations. Meanwhile, the effect of the sub-level faults on sediment deposition was insignificant, and the deposition thickness in the region was quite stable. The area of the lacustrine basin extended from Shuyang County in Jiangsu Province in the north, to Zhixiqiao Town, Changzhou City in Jiangsu Province, and Nanling County in Anhui Province in the south, and provided the most important period of oil generation and trapping in the Subei Basin.

In the late Eocene Epoch, the Wubao movement during the early Xishan movement uplifted the basin again. This caused the major faulted blocks to sink deeper, while the basal igneous rocks were forced up and eroded repeatedly. Sub-level faulting occurred mainly along the North-East edge. The formations at the top of faulted blocks were subjected to strong erosion. The top formations of the uplifted Taizhou and Funing Formations were nearly all eroded away, and members II to IV, located on the lower uplifts of the Funing Formation, were also eroded away. However, the IV member of the Funing Formation in the depression areas was only slightly eroded and as a result, the Taizhou and Funing formations in the centre of the depression are up to 3,000 metres thick. At this time, two major uplifts, two major depressions, 12 small troughs, and 14 small horseback uplifts in the Subei basin were initiated.

(3) Strong fault and depression stage

After the Wubao movement, the Subei Basin entered a new phase of inversion, from the previous rapid sinking into overall uplift. During the whole Oligocene Epoch, faulting and volcanic activity increased. The basin split into a series of small-scale faulted depressions creating half graben-like depressions. Faulting occurred frequently, which caused the uplifted regions to continue rising and erode away, in contrast, the areas of depression became deeper, resulting in a variation in thickness of formations; for example the Dainan and Sanduo Formations reached up to 2,000-3,000 metres within the depression while in the uplifted regions, they became very thin and even totally eroded away. The late Sanduo movement caused whole-basin uplift again, causing further erosion e.g. in the 2nd member of the Sanduo Formation. At the end of this period, the basic pattern and structure of the basin had been formed, characterised by large uplifts and depressions, small ridges and troughs, with faulting/depression activities continuing to the end.

(4) Depression ending stage

During the Miocene Epoch, fault movement decreased and the sediment of the Yancheng Formation with mainly glutenite rock extended across the whole basin. The entire basin tilted towards the east, with its sediment-filled depression centre formed at the Haian region. The thickness is up to 1400 meters. Table 1 shows the tectonic evolution of the Subei Basin and Figure 2 is a map of the thickness distribution of the Yancheng Formation.

Table 1: The tectonic evolution of the Subei basin

Geologic Formation	Sedimentary Characteristics	Tectonic Characteristics	Evolution Stage	
Neocene—Quaternary (N—Q)	fluvial facies	depression	IV	Late Himalayan Period—present period
Eocene Dainan—Sanduo (Ed—Es)	fluvial facies of residual lacustrine delta	fault and depression	III	Middle Himalayan Period
Cretaceous: Taizhou Palaeocene: Funing (Ct—Pf)	lacustrine facies (major) mingled with fluvial facies	depression	II	Early Himalayan Period
Jurassic—Cretaceous (J—K)	continental facies with volcaniclastic facies	Fracture and depression (sinking)	I	Yanshan Period
Lower Yangtze Para-platform				

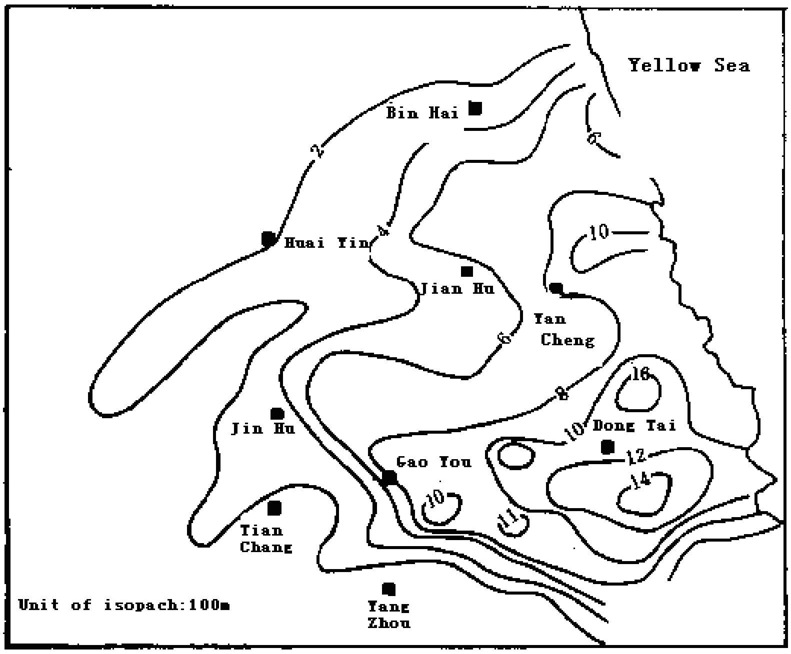


Figure 2: Thickness distribution of the Yancheng Formation in the Subei Basin.

2.2 Sediment evolution

The Yizheng movement in the end of Yanshan period created differences in ground elevation. During early deposition of the Taizhou Formation, alluvial-facies were deposited by talus accumulation. Afterwards, the crust declined and the surface drained, leaving a set of fluvial facies layers which mainly consisted of sandstone. |During late deposition of the Taizhou Formation, crustal movement reduced, and a set of lake facies were deposited with characteristic black shale. The Taizhou-Funing period was the development stage of the big lake basin depression. The lake basin underwent three crustal uplifts all followed by crustal equilibrium, causing three transgressive-regressive events and therefore three major sedimentary cycles. At the bottom of each cycle lies a sediment of mainly coarse fragmented rocks, which is a reservoir layer; the top of each cycle is dominated by a dark mudstone, which was the main oil generating layer and also acts as a good cap rock. Therefore, the Palaeocene Epoch consists of several vertical sequences of generation/source, reservoir, and cap rocks.

After the Wubao movement, the basin was again uplifted, accompanied by north-east trending fault development, splitting the large lake basin into a series of small north-east half-graben fault basins. The sedimentary rocks were mainly clastic and mud rocks, carbonate deposition ceased due to movement as the water changed from brackish to fresh as it was cut off from the sea. In the early stages of half-graben faulted lake formation, Dai-I member of the Dainan Formation appeared to onlap older deposits and the lake basin grew. A warm and humid climate resulted in abundant rainfall, and therefore large amounts of fresh water were introduced continuously into the lake. The water gradually became less saline and eventually changed to fresh-water. The lake was far-flung and the water became deeper, the depression centre was in a deep lake region. An underwater flood-type fan formed by gravity flow deposition on the steep sloped southern Gaoyou Sag. A deltaic system formed on the gentle slope of the northern Gaoyou Sag, along with a syngenetic downthrown block due to a landslide along the front edge.

After the deposition of the Dai-I member, the fault lake basin was in its final stage of development. The lake basin became smaller. In the deep depression region, a good combination of hydrocarbon generation, reservoir, and cap rocks were still being formed. In the middle and late period of the Dai-II member, the climate turned dry and hot with a little rainfall, the lake became smaller in size and depth, which influenced deposition. The steep slope of the southern Gaoyou Sag changed from a deep-water fan into a shallow-water lake alluvial fan. The northern delta of Gaoyou Sag extended gradually southwards. The slope of the downthrown block became shallower and gravity flows of landslide deposits reduced. In the area of southern Gaoyou Sag where water was blocked in a semi-closed environment, evaporation became greater than water supply and the water body became a salty semi-closed lake. It formed by a combination of delta, shore-lake alluvial fan and semi-closed lakeshore facies.

During early deposition of the Duo-I member of the Sanduo Formation, due to variations in ground elevation caused by uplift and a warm and humid climate with abundant rainfall, the water system was well developed. In the south of Gaoyou Sag deposition was via alluvial fans and braided river systems. In the north and centre of the basin, a vast region was dominated by river-flood plain and deltaic deposits. In the middle and late period of deposition of the Duo-I member, geographical relief reduced and the braided rivers became low-sinuosity rivers.

After deposition of the Duo-II member' deposition, the fault basin went through a stage of mainly fluvial outwash, the lake body dispersed and sedimentation ceased.

After the Sanduo movement, the fault basin gradually became flat, and moved into a stage of deposition in depressions, which resulted in the backfilling and draping of upper Tertiary.

The distribution of Tertiary deposits in the Subei Basin indicates a sub-plain forming process. The lake basin split into smaller faulted basins, which gradually became smaller and eventually disappeared. The sediment colour changed from black to red and then to multi-coloured. In addition, periodic change of palaeoclimate is another factor which influenced sedimentation. For example, during deposition of the Dai-I member to Duo-I member, under the same tectonic environment, the size of the lake increased and decreased, rivers also increased and decreased in size and flow; this is highlighted by the changes in colour of the mudstones and sandstones. These all prove the influence of climate on deposited material.

As well as tectonic movement and climatic influence, faulting also has an apparent controlling role in deposition. In particular, after Dai-I member, the lake basin split into several small lake basins aligned in an north-east direction. The generation and distribution of different facies in these smaller basins were controlled by faulting.

3 Geological Structures

The Subei Basin covers an area of 35,000 km^2, which stretches from Jiangdu-Rugao in the south, to Binhai in the north , from Sihong and Xuyi in the west, to the coast of the Yellow Sea in the east (Figure 2).

The Subei Basin consists of four parts: Binhai Uplift, Yanfu Depression (trough), Jianhu Uplift and Dongtai Depression. Each depression contains several small troughs (sags). There are ten sub-troughs in this basin: Jinhu, Gaoyou, Qintong, Hai’an, Yancheng, Funing, Liannan, Lianbei, Hongze. There are many small-scale fault-bounded uplifts and sag structures in the basin.

The oil reservoirs of the Jiangsu Oilfield are mainly located in the JinHu, Gaoyou, QinTong and Haian troughs in Dongtai Depression of the Subei Basin (as shown in Red dots in Figure 3).

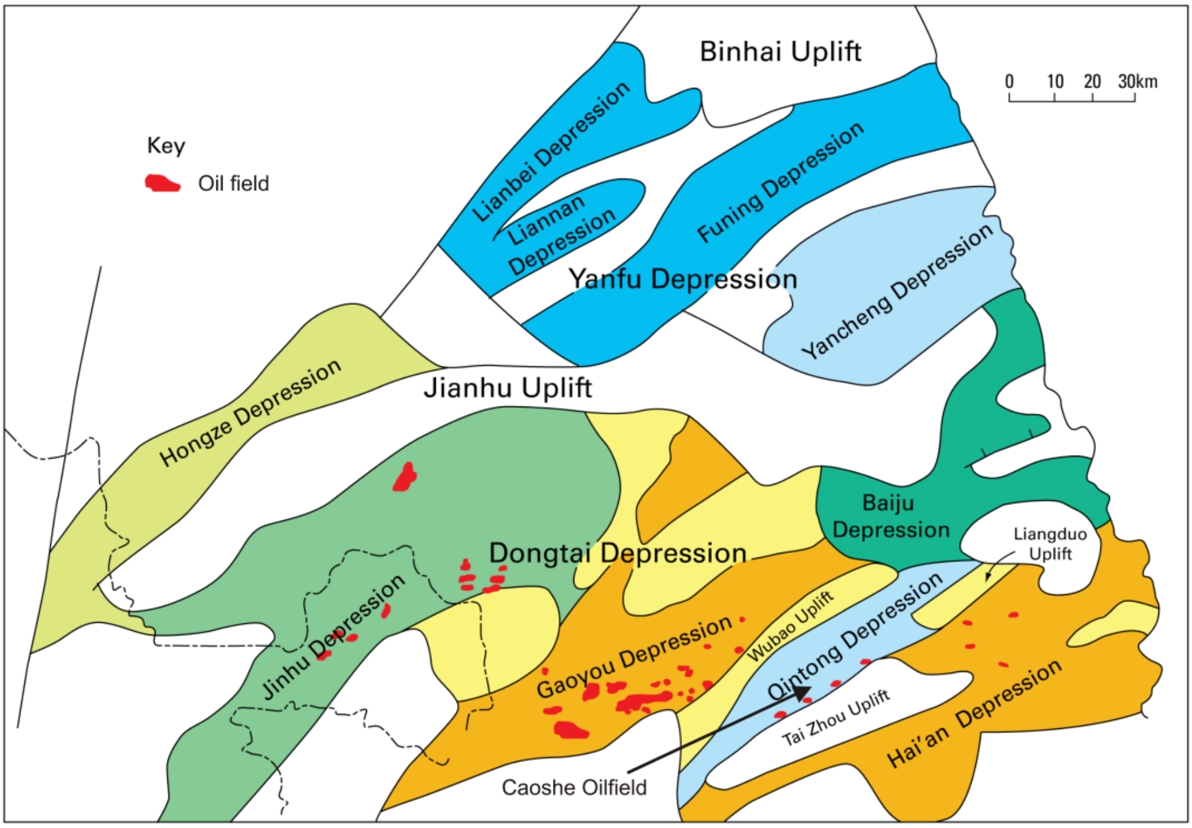
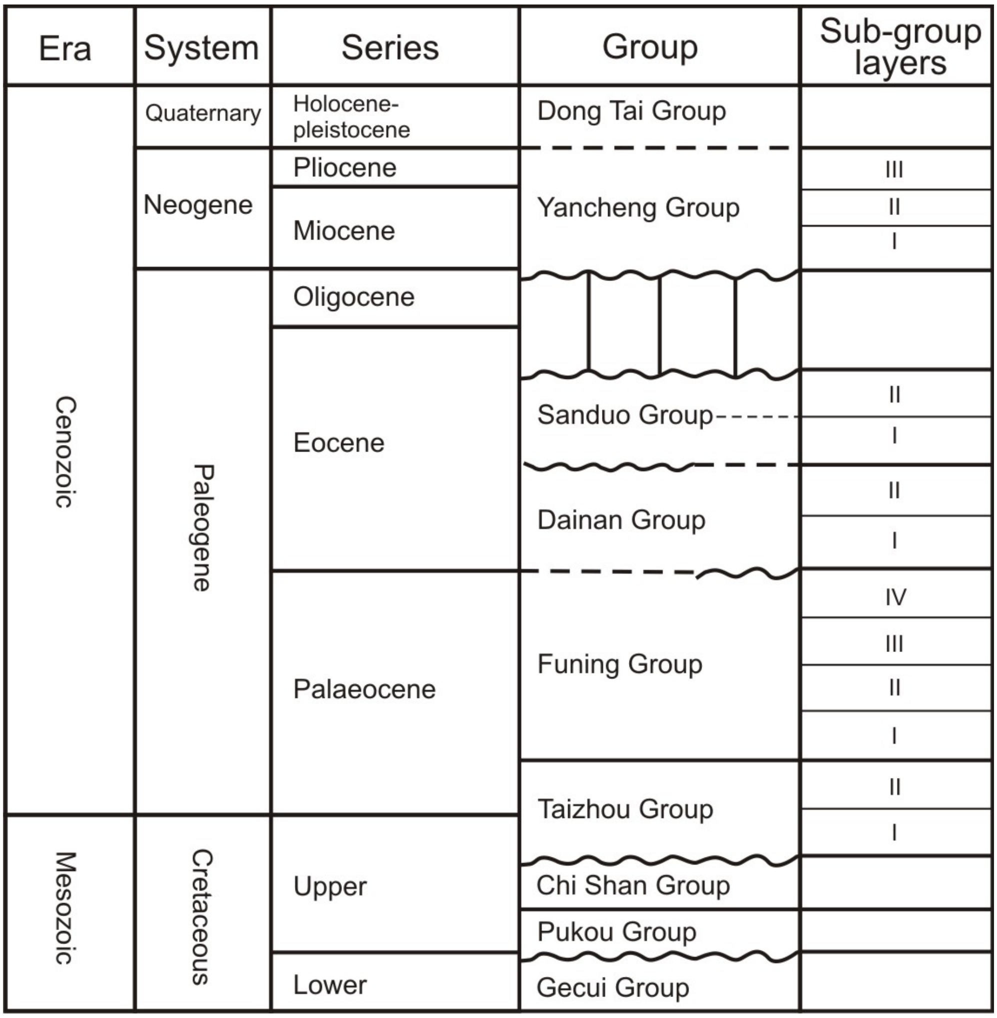


Figure 3: Geotectonic map of the Subei Basin

4 Stratigraphy

The stratigraphy features of the main sedimentation in the Subei Basin is shown in Figure 4. The Lower Tertiary strata of the Subei Basin are well developed, and consist of six series of source beds, including the Upper Part of the Taizhou Formation, Member II to IV of the Funing Formation, and Member I of the Dainan Formation. The main source beds are Members II and IV of the Funing Formation, the lithology is predominately lacustrine mudstones with a small amount of oil shales, carbonates, oolitic limestones, and biolithites.

Among the series of source beds, the mature (oil) source rocks are distributed over a total area of 5,951 square kilometres, and the bulk volume of the source rock is 2,520 m^3. Around 94% of the total hydrocarbon resources in the Subei Basin are distributed in the many small troughs of the Dongtai Depression in the southern part of the basin: in the Dongtai depression, about 50% of the oil resource is located in the Gaoyou Trough; in addition, the Jinhu, Hai'an, and Qintong troughs each contain about 13% of oil source rocks. The remaining oil resource exists in the Yancheng and Hongze troughs of the Yanfu Depression in the northern Subei Basin, which are the only troughs in this depression that have oil source rocks.



Era	System	Series	Group	Sub-group layers
Cenozoic	Quaternary	Holocene-pleistocene	Dong Tai Group	
	Neogene	Pliocene	Yancheng Group	III
		Miocene		II
				I
	Paleogene	Oligocene		
		Eocene	Sanduo Group	II
				I
			Dainan Group	II
				I
		Palaeocene	Funing Group	IV
				III
				II
				I
			Taizhou Group	II
				I
Mesozoic	Cretaceous	Upper	Chi Shan Group	
			Pukou Group	
		Lower	Gecui Group	

Figure 4: Stratigraphy of the Subei Basin

5 CO_2 storage potentials in Jiangsu Oilfield complex: reservoir scale assessment

5.1 Introduction of Jiangsu Oilfield complex

The Jiangsu Oilfield complex is relatively small with complex geological features. Most reservoirs are 2,000-3,000 metres deep, with light to medium oils. According to the evaluation criterion of CO_2 miscible displacement recommended by API, the current reservoir pressure of most oil reservoirs in Jiangsu Oilfield complex is below the MMP (minimum miscible pressure), which may be suitable for near-miscible CO_2 flooding.

The oil fields in the Jiangsu complex are mainly located in Zhenwu, Fumin, Caozhuang, Xujiazhuang, and Lianmengzhuang regions. In this study, 108 oil reservoirs have been assessed based on reservoir data available in the public domain and company reports.

Key facts for the Jiangsu Oilfield complex are:

- Cumulative proven OOIP is 196.24 Million tonnes
- Proven OGIP is over 8 billion m^3
- Developed and producing reserves are 186 Million tonnes.
- Exploration started during 1956-1975.
- Commercial production since 1975.
- The current oil production is over 2 million tonnes per year, with an 8% annual increase rate (Figure 5).
- Up to 2007, the cumulative oil production was close to 30 million tonnes (Figure 6).
- Primary oil recovery was 10%; Secondary water flooding can achieve 24-30%. Currently, water cut-off is around 70%, and the average recovery factor is 24.6%.
- Several CO_2 miscible displacements have been tried in the field with good EOR response.

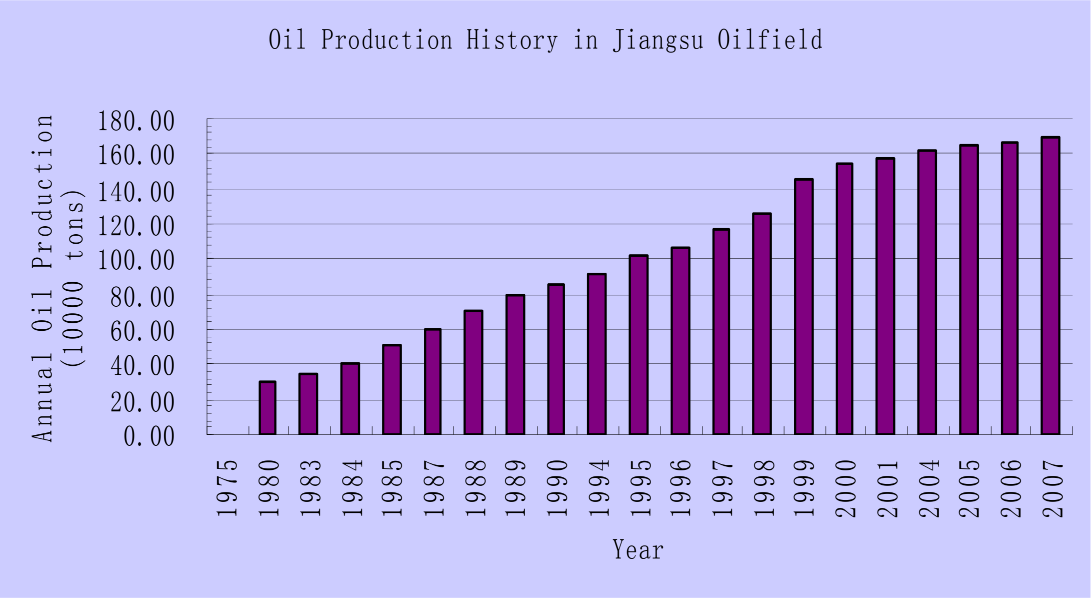


Figure 5: Oil production history of Jiangsu Oilfield

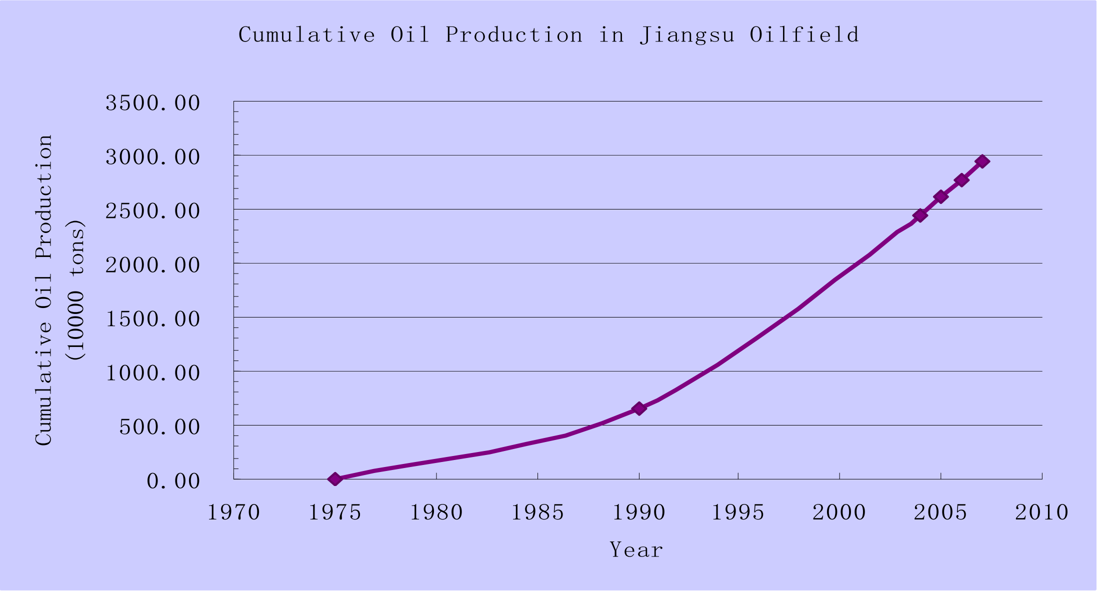


Figure 6: Cumulative oil production of Jiangsu Oilfield

5.2 Mechanisms of CO_2-EOR and Storage

The process of CO_2-EOR can be classified into two major types: CO_2 miscible displacement and CO_2 immiscible displacement, which depend on the properties of the gas injected and the reservoir fluids under reservoir conditions.

Minimum Miscibility Pressure (MMP) is one of the critical parameters of CO_2 displacement processes, which is influenced by oil properties, reservoir temperature and composition of the injected gas.

Miscible displacement occurs at pressures above the MMP of oil, in which the injected gas and the hydrocarbons are completely miscible and form a stable singlephase fluid. The light hydrocarbons can be extracted by using CO_2 in its gas phase; consequently, oil viscosity declines and displacement efficiency increases. With the restrictions of formation fracture pressure, miscible displacement can only be applied in light oil reservoirs. One of the main advantages of miscible displacement is the reduction of capillary effect retaining oil in place. Miscibility also promotes oil swelling, reduces oil viscosity and increases its mobility. Both vertical and horizontal flooding can be applied through a miscible process.

Immiscible displacement occurs at pressures below the MMP of the oil, in which there is less interchange of components between the gas injected and the reservoir fluids. The injected gas can be used for pressure maintenance and gravity stabilised drainage. The application of immiscible displacement can improve the oil mobility and displacement efficiency, and can be used for the development of high viscosity crude oil and reservoirs with high vertical permeability.

5.2.1 Mechanisms of CO_2-EOR

The mechanisms of CO_2-EOR are complicated, and involve a multi-phase flow in the reservoir, accompanied with the phase transformation of the oil components, reduction of viscosity, and an increase in sweep efficiency and other complex behaviours. The main mechanisms of CO_2-EOR are described below:

Reduction of Oil Viscosity

Reducing oil viscosity will promote the flow of crude oil. CO_2 can be readily dissolved in crude oil and leads to a significant reduction on oil density and viscosity. Viscosity reduction due to mixing with CO_2 is more profound in heavy (viscous) crude oils.

Improvement of the mobility ratio between oil and water

CO_2 dissolved in oil can decrease oil viscosity; therefore, increasing oil's mobility. Consequently, the mobility ratio between oil and water can be improved to favour oil production.

Solution Gas Drive Effect

The dissolved CO_2 comes out of solution in the reservoir to form a free gas as the reservoir temperature rises and the reservoir pressure decreases; this drives the crude oil into the wellbore. Dissolved CO_2 can drive more oil out of the reservoir, which is one of the important outcomes of enhanced oil recovery by CO_2 injection.

Improvement of Formation Permeability

Dissolved CO_2 can react with carbonate rocks, thereby improving the reservoir permeability. Carbonated water is slightly acidic, and reacts with the rock matrix, dissolving some minerals. CO_2 gas also can have strong erosion effects on the formation; it can effectively clear blockages caused by drilling fluids or other contaminants.

Hydrocarbon Extraction and Gasification

CO_2 can promote light hydrocarbon extraction from crude oil, thus residual oil saturation can be reduced. Light hydrocarbons are readily miscible with CO_2. When the pressure exceeds a certain value (critical pressure-extraction mainly happens when CO_2 is in super-critical state at reservoir conditions), CO_2 can have beneficial effects on extraction and gasification on light hydrocarbons and in particular light crude oils.

Reduction of Interfacial Tension

After the extraction and gasification of light hydrocarbons by CO_2, abundant light hydrocarbons are mixed with CO_2, which decreases the interfacial tension between CO_2/oil and oil/water. As a result, residual oil saturation is reduced and so the oil recovery factor can be increased.

Miscibility Effect

Under reservoir conditions, CO_2 may not be fully miscible with crude oil directly, but CO_2 multi-contact miscible displacement can be achieved, which can lead to a higher recovery factor. In laboratory slim tube tests recovery factors of more than 90% can potentially be achieved. In real reservoirs, recovery factors might be much less due to gravity, viscous fingering, and heterogeneity. The CO_2-oil interfacial tension can be reduced; therefore, the capillary force of porous media will be reduced. This means the residual oil saturation can be reduced, and the efficiency of oil displacement enhanced.

CO_2 has a lower minimum miscible pressure than other gases, so most field projects make use of the CO_2 miscible flooding mechanism. The pressure of miscible or multiple contacts depend on the reservoir pressure, temperature and composition of crude oil. For screening and selection of a reservoir for CO_2 miscible EOR, CO_2 MMP is a very important parameter. Compared to the water flooding upward, CO_2 miscible flooding EOR (gravity stabilized gas injection; GSGI) can improve recovery by 15-40% of OOIP. During miscible displacement using WAG (water alternating gas) injection, because of the existence of gravity and viscous fingering the injection profile is more difficult to manage. For example, the estimated recovery ratio can increase by 5-15%.

Expansion of Oil

The dissolution of CO_2 in oil can increase the oil volume, thus increasing the pore volume occupied by the oil. This can provide favourable conditions for oil flow in porous media. Subsequent injection of water would decrease the residual oil volume. The CO_2 expansion of crude oil has two results:

1. After water flooding in the reservoir, the relationship between the expansion coefficient and residual oil is such that the greater the expansion, the less residual oil there is in the reservoir.
2. The swelling oil can displace water.

Many laboratory and field tests have shown that CO_2 dissolved in crude oil can expand the oil volume by 10%-40%. Therefore, CO_2 injection can not only increase the internal energy of crude oil, but can also greatly reduce the oil viscosity and capillary flow resistance, increasing the mobility of the crude oil.

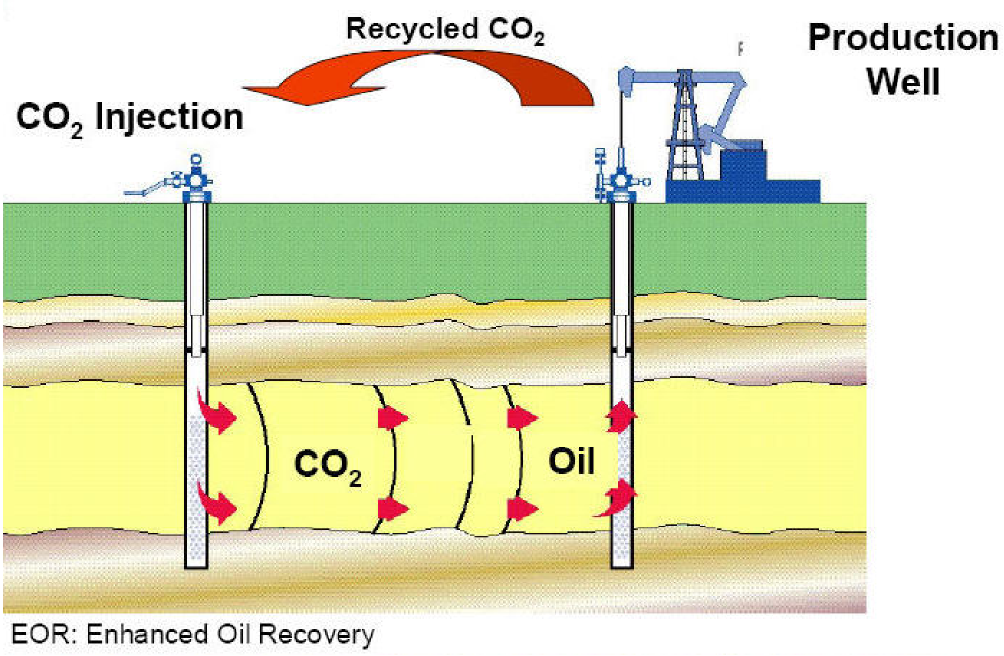


Figure 7: Schematic diagram of CO_2 EOR (adapted from IEAGHG Information sheet).

5.2.2 Mechanisms of CO_2 geo-storage in oil reservoirs

There are two types of CO_2 storage in oil fields:

- CO_2 storage in depleted oil reservoirs.
- CO_2 EOR in producing oil reservoirs.

For depleted oil reservoirs without the simultaneous production of oil, CO_2 can be injected directly into reservoirs for long term storage. The reservoir volume that was occupied by oil can be used to store injected CO_2. However, some of the pore space will be occupied by water because of water invasion or water flooding, so the volume used for storage is reduced. A certain amount of CO_2 can dissolve into the water and oil potentially increasing the amount of CO_2 stored. Note however, that this solution process is relatively slow without significant mixing, which will reduce the potential for solution trapping during injection.

CO_2-EOR may be an economic-return option for storage. Injection of CO_2 into reservoirs under high pressure can drive crude oil into producing wells and the oil recovery factor can be increased. At the same time, most CO_2 will be stored in the pore space of reservoirs which were previously occupied by oil and water. A certain amount of CO_2 can dissolve into the water and the residual oil potentially increasing the amount of CO_2 stored. All of these methods can realise permanent sequestration. At the end of production, breakthrough CO_2 can be re-injected into reservoirs as depleted fields. This technology is relatively mature at present.

5.3 Screening and Assessment Methods

The main goal of this study is to assess CO_2 storage potential in oil reservoirs. CO_2 storage in oil reservoirs requires effective storage space and safe trapping conditions. It is thought that not all oil reservoirs are suitable for storage, so it is necessary to screen oil reservoirs based on a set of criteria to select suitable sites for storage. Based on literature research, we know there are no standard screening methods for CO_2 storage in oil reservoirs at present. However, some assessment/selection methods for gas injection or natural gas storage in geological reservoirs are, to a certain extent, fit for oil reservoirs. We can modify these methods or criteria, and use them to screen oil reservoirs for CO_2 storage suitability.

Among the oil reservoirs suitable for CO_2 storage, not all are suitable for CO_2-EOR. General CO_2-EOR screening criteria can be applied to divide these oil reservoirs into two groups, those fit for CO_2 EOR and those only suitable for storage. The last step is to calculate the CO_2 EOR and storage potentials. Figure 8 is the basic technical assessment flow chart.

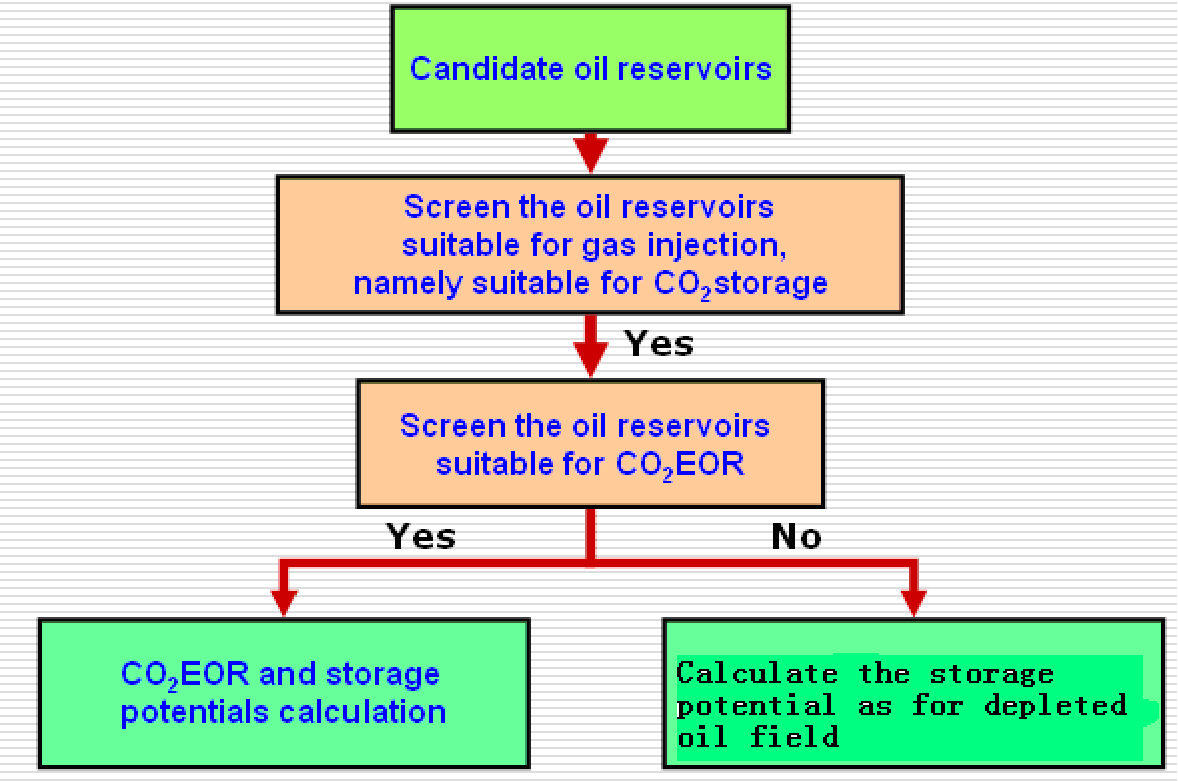


Figure 8: The screening process for CO_2 injection and EOR

5.3.1 Screening Criteria of CO_2 Storage and EOR Reservoirs

When considering a reservoir, appropriate sedimentary basins are highlighted initially, and their characteristics and resources are investigated. When screening reservoirs for CO_2 storage potential, we analyse the geological conditions and make the initial selection based on the geology. Appropriate storage locations within the basins are then chosen, and the characteristics of sealing medium, field conditions and any results of CO_2 injection experience are examined.

There are many methods can be used to select reservoirs suitable for CO_2-EOR and storage. In this study, a screening criteria proposed by Zeng *et al.* (2005) is used. The screening criteria are shown in Table 2.

Table 2: Screening criteria for gas injection reservoirs

(Suitable for storage in depleted reservoirs)

	Appraisal characteristic parameter	**Standard value**
Forced-choice condition	Recovery percent of reserves	Percent of recoverable reserves already recovered >85% Percent of OOIP already recovered >30%
	Effective Porosity	>15%
	Effective Permeability	$>50\times10^{-3}\mu$ (50.7 mD)
	OOIP	>0.02 Mt
Optional Condition	Injection Production Capability / Planning Requirements	>35%
	Annual Oil Recovery Capacity	<0.01 Mt
	Distance to Emissions Sources	<150km

Before determining the applicability of CO_2-EOR in reservoirs, the reservoirs were screened for suitability for enhanced oil recovery, and candidate reservoirs ranked based on technical data.

In 2001, Zhao Fulin of CUP (China University of Petroleum) proposed method for the evaluation of CO_2-EOR, which summarised various CO_2-EOR techniques and considered the complex conditions in different oil fields in China. The screening criteria for the CO_2-EOR reservoir selection used in this study are shown in Table 3.

Table 3: The screening criteria for CO_2 EOR reservoirs

Reservoir Parameter	Appraisal Index Criteria
Depth / m	>762
Crude Oil Gravity /°API	>22
Viscosity / MPa·s	<10
Crude Oil Saturation / %	>20

5.3.2 Calculation Methods of CO_2-EOR and Storage Potential in Reservoirs

There are several different methods used for the calculations of CO_2 storage in depleted oil fields and EOR, these are essentially derived from the Material Balance Equation. The differences between these methods are the different assumptions, and the fundamental assumption that the storage potential for CO_2 is equal to the volume of oil and water which was previously stored in the reservoir. As there are many factors that can influence the results, the most important factors should be taken into consideration first.

The most important and popular methods for the assessment of CO_2 storage potential include the Shaw and Bachu (2002), Bachu et al., (2007), ECL (2001) and Ecofys and TNO (Hendriks et al., 2004) methods.

In this assessment, the calculation equation chosen for CO_2 storage and EOR potential assessment was the method provided by Ecofys energy source consulting firm and TNO-NITG (Hendriks et al., 2004). In this method, it is not necessary to consider complicated development modes and reservoir conditions, nor is there a need to distinguish miscible and immiscible displacement.

CO_2 Storage Capacity during EOR Process

In terms of the statistical law and correlation diagrams, equations are provided for assessment of CO_2 geo-storage potential and CO_2-EOR in different types of geological formation. After all the influencing factors were considered we have adopted the Ecofys and TNO method as it is widely used and its assessment conditions are well suited to the situation of Jiangsu Oilfield complex. As calculation of storage capacity includes CO_2 remaining in the reservoir at the end of an EOR operation plus CO_2 injected to maintain initial formation pressure, we have included an equation to estimate the amount of CO_2 required reaching that pressure. Some adjustments have been made to the equations and parameters to adapt to the conditions in the Jiangsu Oilfield complex. The equations are provided below (Hendriks et al., 2004):

(i) Maximum Value:

$$EOR_{\max} = ER_{\max} \times OOIP \times C = ER_{\max} \times \left[\frac{URR}{(API_{gravity} + 5)/100} \right]_{OOIP} \times C \tag{1}$$

$$(M_{CO2})_{\max} = EOR_{\max} \times (R_{CO2})_{\max} / \rho_o \tag{2}$$

(ii) Optimized Value:

$$EOR_{\text{opti}} = ER_{\text{opti}} \times OOIP \times C = ER_{\text{opti}} \times \left[\frac{URR}{(API_{gravity} + 5)/100} \right]_{OOIP} \times C \tag{3}$$

$$(M_{CO2})_{\text{opti}} = EOR_{\text{opti}} \times (R_{CO2})_{\text{opti}} / \rho_o \tag{4}$$

(iii) Minimum Value:

$$EOR_{\min} = ER_{\min} \times OOIP \times C = ER_{\min} \times \left[\frac{URR}{(API_{gravity} + 5)/100} \right]_{OOIP} \times C \tag{5}$$

$$(M_{CO2})_{\min} = EOR_{\min} \times (R_{CO2})_{\min} / \rho_o \tag{6}$$

Where:

URR - ultimate recoverable reserves, 10^4t;

OOIP - original oil in place, 10^4t;

$API_{gravity}$ - API gravity;

C - contact coefficient, a conservative value is 0.75;

EOR - extra oil due to enhanced oil recovery by CO_2 injection, 10^4t;

M_{CO2} - the mass of CO_2 that can potentially be sequestered, 10^4t;

ρ_o - density of oil at ground condition, t/m^3;

R_{CO2} - the ratio for net CO_2 injection versus oil production, ton/m^3, and the maximum, minimum and optimized value equal to 5.0, 0.94 and 2.83 respectively;

ER - enhanced oil recovery factor by CO_2 injection, which is derived from Stevens (1999) empirical curve of the relationship between API and enhanced oil recovery factor, and the maximum, minimum and optimized values shown in Figure 9.

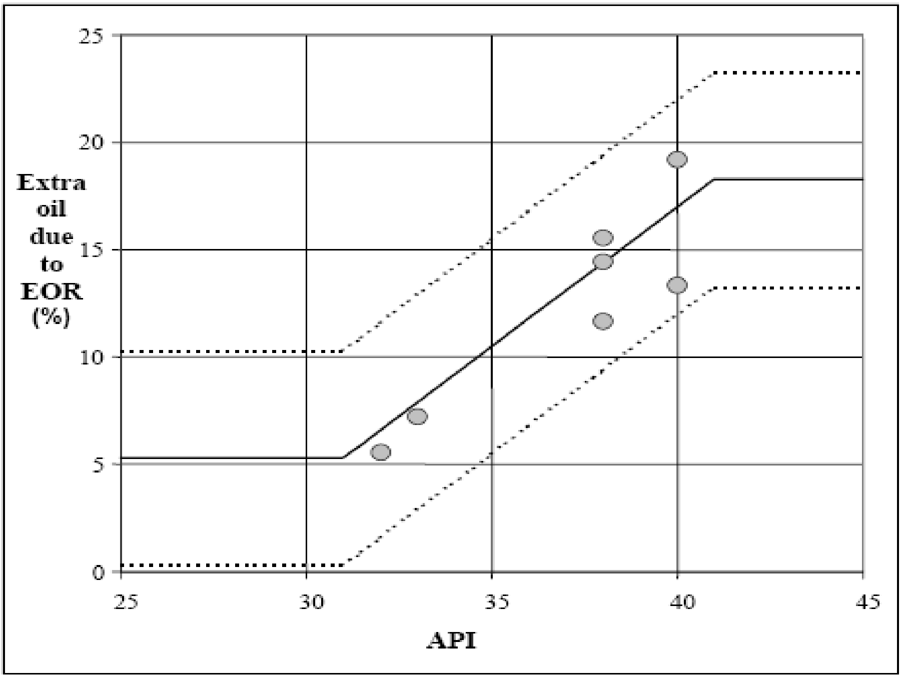


Figure 9: Relation Curve of API Gravity and Extra Oil due to EOR (after Stevens 1999)

CO_2 Storage in Depleted Reservoirs

$$M_{CO2} = V_{total} \times B_o \times \rho_{CO2} / \rho_o \times S \tag{7}$$

Where:

M_{CO2} - mass of stored CO_2 potentially, 10^4t;

V_{total} - total oil produced in the past, 10^4t;

B_o - oil formation volume factor;

ρ_{CO2} - density of CO_2 at reservoir condition, ton/m^3;

ρ_o - density of oil at ground condition, ton/m^3;

S - "space factor", % of the original space that can be used for CO_2 storage, 80, 40, and 60% respectively for maximum, minimum, optimized value.

Other calculation methods that need more data

After the CO_2 EOR process, CO_2 is continuously injected into reservoirs until the initial formation pressure is reached. The equations are shown below:

(a) During EOR process,

$$M_{CO2} = \rho_{CO2} \times \left(ER \times OOIP \times B_o / \rho_o + V_{pw} - V_{iw} \right) + S_{CO2,w} \times V_{rw} + S_{CO2,o} \times V_{ro} + M_{reaciton}$$

(8)

(b) After EOR, continue injection of CO_2, until the pressure of reservoirs returns to the original pressure or the maximum safe pressure,

$$M_{CO2} = \Delta P \times \rho_{CO2} \times \left(V_{ro} \times C_o + V_{rw} \times C_w + V_{CO2} \times C_{CO2} + V_p \times C_p \right) \tag{9}$$

(c) For depleted reservoirs by water flooding,

$$M_{CO2} = \rho_{CO2} \times \left[\left(RF \times OOIP \times B_o / \rho_o + V_{pw} - V_{iw} \right) + \Delta P \times \left(V_{ro} \times C_o + V_{rw} \times C_w + V_p \times C_p \right) \right]$$

(10)

Where, ***M_{CO2}*** — mass of stored CO_2 potentially, 10^4t.

ρ_{CO2} — density of CO_2 at reservoir condition, ton/m^3;

ρ_o — density of oil at ground condition, ton/m^3;

OOIP — original oil in place, 10^4t;

V_{pw}, V_{iw} — the volumes of produced water and invaded water at reservoir conditions respectively, 10^4m^3

$S_{CO2,w}$, $S_{CO2,o}$ — CO_2 solubility in formation water and crude oil respectively, ton/m^3

V_{rw}, V_{ro}, V_{CO2}, V_p — the volumes of the residual water, residual oil, injected CO_2, and formation pore at reservoir condition respectively, 10^4m^3

C_w, C_o, C_{CO2}, C_p — the compressibility factor of formation water, crude oil, injected CO_2, and formation pore respectively, 1/MPa

$M_{reaction}$ — the amount of CO_2 which reacts with minerals of formation rocks, 10^4t

Δ**P** — the difference between initial formation pressure and current formation pressure, MPa.

RF —t he ultimate recovery after water flooding.

Further data is required to compare the above methods which lack manoeuvrability. Based on the data availability and character, we have decided to use the simpler method.

Influencing Factors of CO_2 Storage Potentials

The methods mentioned above are approximate estimations where many factors have been either simplified or ignored, such as water influx, gravity segregation, reservoir heterogeneity, and dissolution of CO_2 into formation water, etc.

Technological and economic influences are possible barriers for selection e.g. CO_2 stored in shallow reservoirs is in its gas phase, whereas storage in deep reservoirs may be expensive due to the cost of compression. The economic depths for storage range from 900 to 3,500 m. The capital expenditure on CO_2 capture, transportation, injection and operation should also be taken into consideration. The result of this is that reservoirs with greater storage capacities can be considered in the short or middle term.

5.3.3 Assessment Process and Software

Assessment process

The approach used in this assessment is to evaluate all the candidate reservoirs for CO_2 storage capacity. Reservoirs can be divided into those suitable for gas injection and those unsuitable for gas injection via the screening process as well as identifying those suitable for the application of EOR techniques. Recoverable reserves greater than 85% of the OOIP from selected reservoirs is a standard screening criteria for selecting fields suitable for gas injection. Reservoirs that are unsuitable for EOR can be considered as depleted reservoirs for CO_2 storage only.

The classification process can be described as below and shown in Figure 10:

Stage 1: data collection for candidate reservoirs.

Stage 2: the candidate reservoirs can be divided into two groups: reservoirs that are suitable for CO_2 storage and reservoirs that unsuitable for CO_2 storage.

Stage 3: the reservoirs that are suitable for CO_2 storage are subdivided into: reservoirs suitable for EOR and reservoirs unsuitable for EOR. The reservoirs unsuitable for CO_2 storage can be further divided into: reservoirs with recovery rate >85% and reservoirs with recovery rate < 85%.

Stage 4: Reservoirs with recovery rate > 85% can be considered as depleted reservoirs that can be further divided into reservoirs that are suitable for EOR and reservoirs that are unsuitable for EOR. Similarly, the reservoirs with recovery rate < 85% can also be divided into reservoirs suitable for EOR and reservoirs unsuitable for EOR.

Stage 5: The reservoirs suitable for EOR and reservoirs unsuitable for EOR are summed together.

Stage 6: EOR and storage potential calculations.

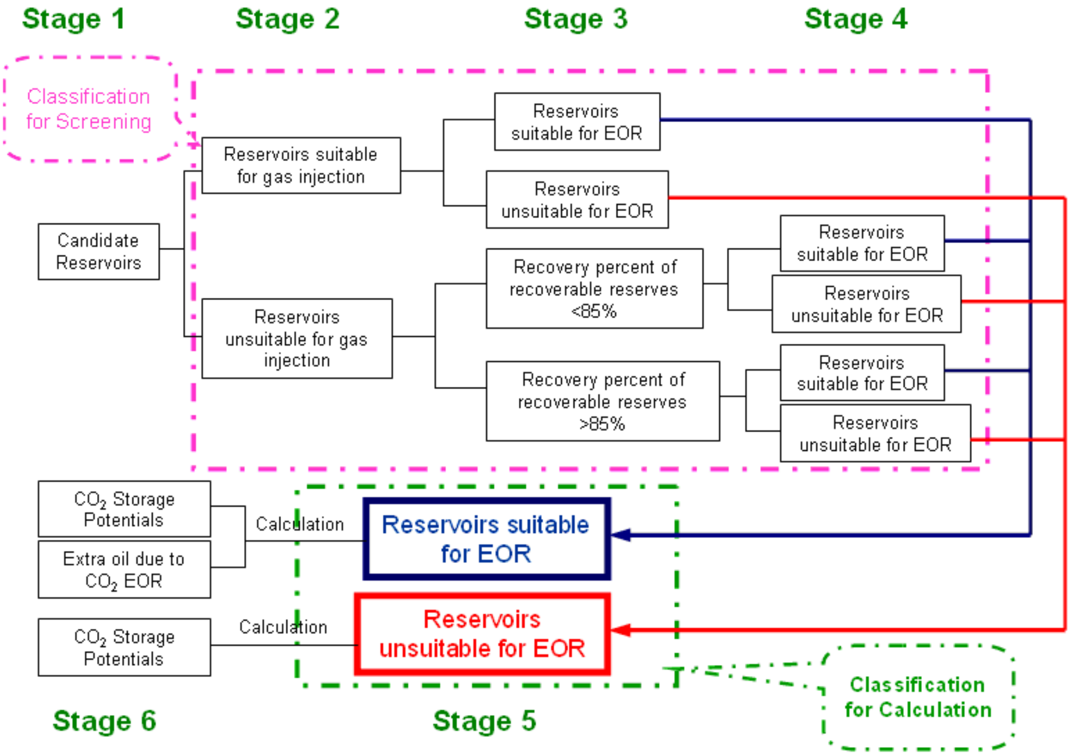


Figure 10: The process of reservoir screening and EOR and Storage potential calculation

Software for the assessment process described was coded with Visual Basic. The input data file and data requirement are listed in Table 4.

Table 4: Standard Reservoir data requirement (data sheet example)

Reservoir name	unit	reservoir 1	reservoir2
Crude Oil Saturation	%	-	-
Storage Potentials / Planning Requirements	%	-	-
Injection Production Capability / Planning Requirements	%	-	-
Distance to City	m	-	-
Recovery percent of OOIP	%	21.91752	8.197337
Recovery percent of URR	%	87.67009	27.32446
Oil production past	Mt	0.219175	0.130338
Depth	m	3175	2930
Effective porosity	%	12	21.8
Effective permeability	mD	15.37	33
API	API°	35.758	26.955
Oil density (under- ground)	-	0.774936	0.817988
Oil density (ground)	-	0.846	0.893
Viscosity (ground)	mPa.s	1.3	6.3
Viscosity (under- ground)	mPa.s	6.5	45.7
Ultimate recovery	%	25	30
URR	Mt	0.25	0.48
OOIP	Mt	1	1.59

This standard data structure contains 19 parameters, some of which are conditional, some of which are optional. It was developed based on the screening criteria of CO_2 storage and EOR Reservoirs, and calculation methods of CO_2-EOR and storage potential in oil reservoirs. The oil reservoir data collected was input into Microsoft Office Excel following the format of the above standard data structure (Table 5). The excel file is saved using the format “filename.txt” which can be recognized and input into the Assessment Software for selection and calculation.

5.4 Data Collection

- The reservoir and oil field data are being collected through published papers, internal reports and the Sinopec and Jiangsu Oilfield Ltd EOR Assessment Reports.
- A uniform reservoir database has been established for the input of the Assessment Software developed by CUP (Huadong).

- Unavailable (important) data or parameters for a reservoir are either estimated using accepted correlations or by analogising with near-by reservoirs.
- There are 108 reservoirs in the region which have been assessed.

Table 5: Data standard structure of some oil reservoirs of the Jiangsu Complex

Reservoir name	OOIP	URR	Ultimate Recovery	Viscosity (underground)	Viscosity (ground)	Oil Density (ground)	Oil Density (underground)	API	Effective Permeability	Effective Porosity	Depth	Past Oil Production	Recovery Percent of URR	Recovery Percent of OOIP	Distance To City	Injection Production Capability/ Planning Requirements	Storage Potentials /Planning Requirements	Crude Oil Saturation
unit	Mt	Mt	%	mpa.s	mpa.s	g/cm^3	g/cm^3	API°	mD	%	m	10^4t	%	%	km	%	%	%
zhen11E2s1	1.76	0.81136	46.1	21	5.55	0.841	0.77	36.75	1300	23.25	2022	0.7722	95.17354	43.875	-	-	-	71
zhen11E2d2	1.92	0.85824	44.7	10	2.1	0.834	0.758	38.16	238.3	20.3	2500	0.7801	90.89532	40.63020833	-	-	-	69.5
zhen12E2s1	6.37	3.83474	60.2	11	5.55	0.841	0.791	36.75	1300	23.25	1959	3.0332	79.09793	47.61695447	-	-	-	71
zhen12E2d2	1.48	0.665408	44.96	18	2.1	0.834	0.761	38.16	238.3	20.3	2358	0.5048	75.86323	34.10810811	-	-	-	71

5.5 Selection and calculation Results

5.5.1 Screening results

Screening of 108 oil reservoirs reveals that, at current field production conditions, 75 reservoirs are potentially suitable for CO_2-EOR and storage, 33 reservoirs are suitable for CO_2 storage only as depleted oil reservoirs. The detailed screening flow diagram and selection results are shown in Figure 11 and Figure 12.

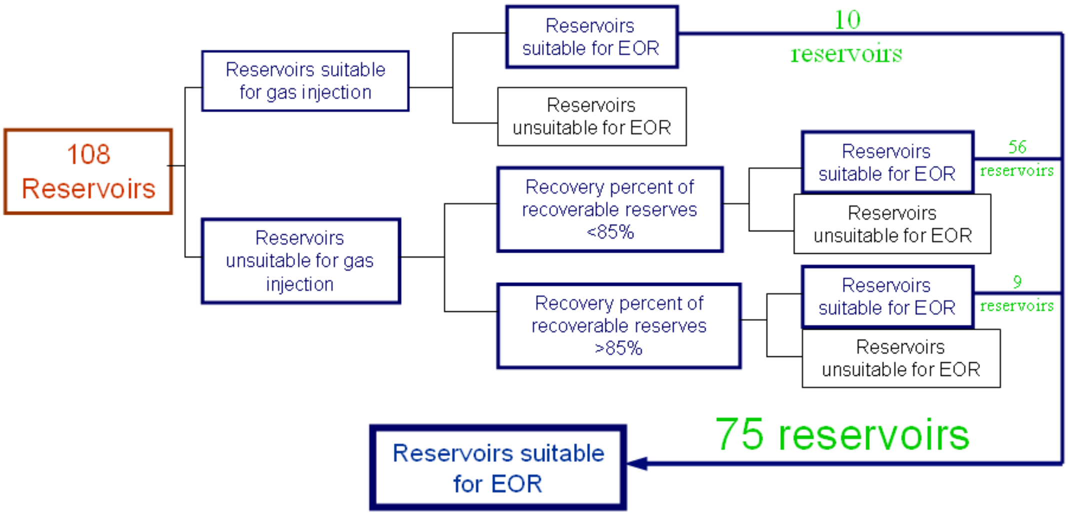


Figure 11: Screening results of oil reservoirs suitable for EOR and storage

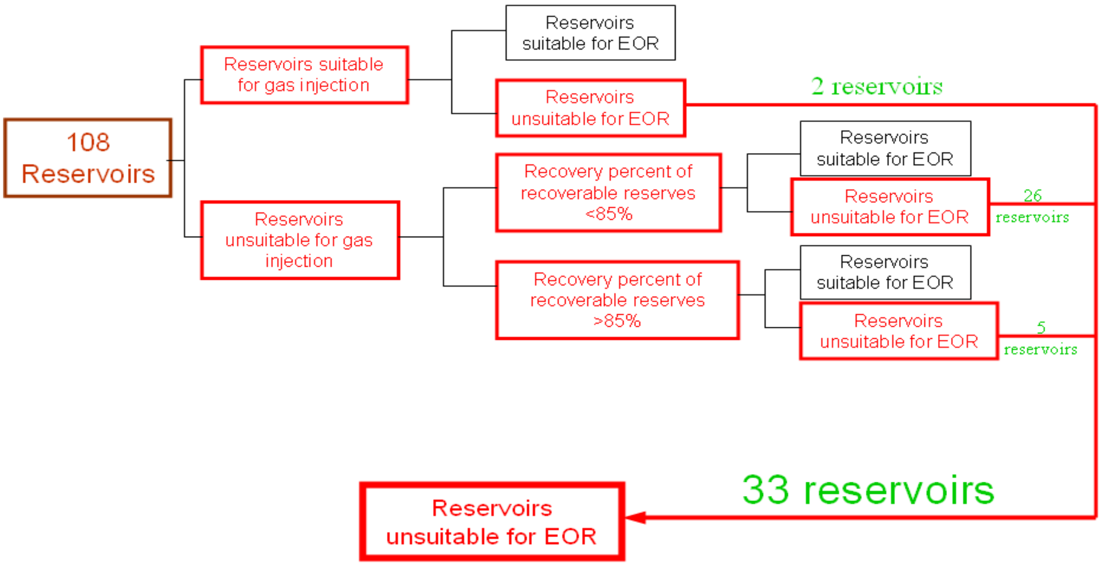


Figure 12: Screening results of oil reservoirs unsuitable for EOR

5.5.2 Potential assessment results

Ecofys-TNO Method

The results of applying the Ecofys-TNO assessment method described above are presented below. It should be noted that the Ecofys-TNO method gives an estimation of CO_2 storage capacity via oil displacement only, that is that CO_2 will fill the space that was previously occupied by oil, thus the EOR potential and storage potential of the field may be underestimated.

1. **For the 75 reservoirs suitable for CO_2-EOR and storage, the total OOIP is 84.32 Mt,**

The CO_2 storage capacities calculated based the Ecofys-TNO method are:

   a. minimum value: 3.4902 Mt (with expected less oil production by CO_2 injection)
   b. maximum value: 40.715 Mt (reservoirs most favourable for CO_2-EOR)
   c. optimized value: 15.7608 Mt (the expected value)

The corresponding (to CO_2 storage capacity) incremental oil production by CO_2-EOR is:

   d. minimum value: 2.5676 Mt
   e. maximum value: 6.8116 Mt
   f. optimized value: 4.6725 Mt

Incremental recovery factors are, respectively:

   g. minimum value : 3.41%
   h. maximum value : 8.01%
   i. optimized value: 5.71%

2. **For the 33 reservoirs unsuitable for CO_2-EOR (suitable for CO_2 storage in depleted reservoirs only), the total OOIP is 48.05 Mt**

CO_2 storage capacity:

minimum value: 3.13 Mt

maximum value: 6.2677 Mt

optimized value: 4.7006 Mt (the expected value)

3. **Thus for all the 108 reservoirs given above, the total OOIP is 132.37 Mt**

CO_2 storage capacity:

minimum value is 6.6232 Mt

maximum value is 46.9827 Mt

optimized value is 20.4614 Mt

The detailed calculation results of CO_2 reservoir storage potential are shown in Tables 6-11. Some of the results are also shown in Figures 13-16 to give examples of CO_2 storage capacity corresponding OOIP.

As stated above, this is a conservative estimation due to low EOR factor which was assumed for near-miscible CO_2 flooding which was expected to prevail at the current field conditions, and the water displacement and reservoir repressurisation (by CO_2 injection) was not considered in this assessment.

CSLF-based calculation method:

A CSLF-based CO_2 storage capacity calculation method was also applied (Bachu et al., 2007). This is based on the assumption that CO_2 will occupy the space of the maximum recoverable oil reserves, and water displacement will occur during the tertiary CO_2 injection. The CO_2 storage capacity can be simply calculated as:

Recoverable reserves × Formation volume factor × CO_2 density in reservoir × Storage coefficient

The maximum recoverable oil reserve is equivalent to:

OOIP X (recovery factor via water flood + recovery factor via CO_2 flood)

If we take the storage coefficient as 0.4-0.8 and the average oil and reservoir properties of the whole Jiangsu Oilfield complex as:

Oil density is 0.86 g/cm^3,

Density of CO_2 is 0.7 g/cm^3 at reservoir conditions,

Formation volume factor is 1.1,

Total OOIP is 132.37 million tonnes,

Overall average EOR by CO_2 is 12%,

Average recovery factor via water flood is 30%.

Therefore the CO_2 storage capacity can be estimated as:

CO_2 capacity = 132.37/0.86 x (0.30+0.12) x 1.1 x 0.7 x $\text{Storage}_{\text{coeff}}$

= 49.78 x (0.4 to 0.8)

=19.91 to 39.82 Mt CO_2

Table 6: 10 Reservoirs suitable for CO_2 injection and CO_2 EOR

Basic Units Included	EOR, Mt			CO_2, Mt			OOIP	EOR/OOIP, %		
\	Minimum Value	Maximum Value	Optimized Value	Minimum Value	Maximum Value	Optimized Value	Mt	Minimum Value	Maximum Value	Optimized Value
Zhen 11E$_2$s$_1$	0.1143	0.261	0.1874	0.1539	1.5619	0.6309	1.76	6.49	14.82	10.64
Zhen 11E$_2$d$_2$	0.1442	0.2946	0.2195	0.1958	1.7774	0.7451	1.92	7.51	15.34	11.43
Caozhuang E$_2$s$_1$	0.0873	0.1574	0.1227	0.1201	0.9624	0.422	0.88	9.92	17.88	13.94
Fu 18E$_2$s$_1$	0.0192	0.0339	0.0266	0.0412	0.3234	0.1429	0.70	2.74	4.84	3.80
Fu 18E2s1	0.0835	0.1535	0.1188	0.1146	0.9361	0.4076	1.06	7.87	14.48	11.20
Xu 7E$_2$d$_2$	0.0102	0.0198	0.015	0.0139	0.1203	0.0513	0.12	8.50	16.50	12.50
Zhou 36E$_2$d$_1$	0.0423	0.0794	0.0609	0.0579	0.4831	0.2087	0.74	5.71	10.72	8.22
Zhou 44K$_2$t$_1$	0.0008	0.0242	0.0122	0.001	0.1394	0.0396	0.33	0.24	7.33	3.69
Ma 8E$_2$d$_{2+1}$	0.0396	0.0769	0.0583	0.054	0.4663	0.199	0.69	5.73	11.14	8.44
Yong 21E$_2$d$_1$	0.0159	0.0303	0.0231	0.0218	0.1842	0.0792	0.42	3.78	7.21	5.50
sum	**0.5573**	**1.131**	**0.8445**	**0.7742**	**6.9545**	**2.9263**	**8.62**	**58.5**	**12.03**	**8.94**

Table 7: 2 reservoirs suitable for CO_2 injection and unsuitable for CO_2 EOR

Basic Units Included	CO_2			OOIP
	Mt			
\	Minimum Value	Maximum Value	Optimized Value	Mt
Zhou 31K$_2$t$_1$	0.0747	0.1495	0.1121	0.50
Zhou 41K$_2$t$_1$	0.0359	0.0719	0.0539	0.19
sum	**0.1106**	**0.2214**	**0.166**	**0.69**

Table 8: 9 reservoirs unsuitable for CO_2 injection and suitable for CO_2-EOR, recoverable reserves of >85%

Basic Units Included	EOR, Mt			CO_2, Mt			OOIP	EOR/OOIP, %		
\	Minimum Value	Maximum Value	Optimized Value	Minimum Value	Maximum Value	Optimized Value	Mt	Minimum Value	Maximum Value	Optimized Value
Caozhuang E_2d_2	0.048	0.101	0.0745	0.065	0.6079	0.2523	2.56	1.88	3.95	2.91
Caozhuang E_2d_1	0.024	0.0485	0.0363	0.0327	0.2929	0.1234	1.36	1.76	3.57	2.67
Fu $30E_2d_1$	0.0063	0.0122	0.0093	0.0086	0.0744	0.0317	0.19	3.32	6.42	4.89
Fu $11E_2d_1$	0.0212	0.0412	0.0313	0.029	0.2501	0.1067	0.83	2.55	4.96	3.77
Sha 20 west $E_1f_1^1$	0.0012	0.0362	0.0183	0.0016	0.2082	0.0592	0.68	0.18	5.32	2.69
Wei $2Ef_2Ef_1^1$	0.0491	0.1579	0.1028	0.0651	0.9305	0.3409	2.92	1.68	5.41	3.52
Cui $6Ef_{2+1}$	0.007	0.0609	0.0334	0.0092	0.3534	0.1091	1.88	0.37	3.24	1.78
Cui $10Ef_{2+1}$	0.0013	0.0113	0.0062	0.0017	0.0658	0.0203	0.35	0.37	3.23	1.77
Yang $1Ef_1$	0.004	0.116	0.0586	0.0051	0.6701	0.1906	3.58	0.11	3.24	1.64
sum	**0.1621**	**0.5852**	**0.3707**	**0.218**	**3.4533**	**1.2342**	**14.35**	**1.36**	**4.37**	**2.84**

Table 9: 5 reservoirs unsuitable for CO_2 injection and CO_2-EOR, recoverable reserves of >85%

Basic Units Included	CO_2			OOIP
	Mt			
\	Minimum Value	Maximum Value	Optimized Value	Mt
Min $7Ef_2$	0.0292	0.0584	0.0438	0.66
Min $20Ef_{2+1}$	0.0311	0.0623	0.0467	0.91
Min $28Ef_3$	0.0152	0.0305	0.0229	0.30
Fan $1Ef_2$	0.1359	0.2718	0.2039	1.95
Bian $13Ef_2$	0.0484	0.0968	0.0726	0.86
sum	**0.2598**	**0.5198**	**0.3899**	**4.68**

Table 10: Selected reservoirs unsuitable for CO_2 injection and suitable for CO_2 EOR, recoverable reserves of <85%

Basic Units Included	EOR			CO_2			OOIP	EOR/OOIP		
	Mt			Mt				%		
\	Minimum Value	Maximum Value	Optimized Value	Minimum Value	Maximum Value	Optimized Value	Mt	Minimum Value	Maximum Value	Optimized Value
Zhen 12E_2s_1	0.5405	1.2339	0.8861	0.7276	7.3824	2.9820	6.3700	8.49	19.37	13.91
Zhen 16E_2d_2	0.0016	0.0034	0.0025	0.0022	0.0207	0.0086	0.1000	1.60	3.40	2.50
Zhen 35E_2s_1	0.0025	0.0057	0.0041	0.0034	0.0346	0.0139	0.1800	1.39	3.17	2.28
Zhen 35E_2d_2	0.0649	0.1327	0.0989	0.0882	0.8007	0.3356	1.1600	5.59	11.44	8.53
Zhen 35E_2d_1	0.0064	0.0126	0.0095	0.0087	0.0767	0.0326	0.3600	1.78	3.50	2.64
Fu 14E_2d_1	0.0036	0.0071	0.0053	0.0049	0.0430	0.0183	0.1100	3.27	6.45	4.82
Fu 18E_2d_2	0.1811	0.3361	0.2592	0.2482	2.0475	0.8881	1.7300	10.47	19.43	14.98
Fu 18E_2d_1	0.0236	0.0458	0.0348	0.0322	0.2781	0.1187	0.7100	3.32	6.45	4.90
Fu 30E_2s_1	0.0047	0.0086	0.0067	0.0064	0.0529	0.0230	0.0600	7.83	14.33	11.17
Fu 30E_2d_2	0.0188	0.0349	0.0269	0.0258	0.2130	0.0924	0.1800	10.44	19.39	14.94

Table 11: Selected reservoirs unsuitable for CO_2 injection and CO_2 EOR, recoverable reserves of <85%

Basic Units Included	CO_2			OOIP
	Mt			
\	Minimum Value	Maximum Value	Optimized Value	Mt
Zhou 43K_2t_1	0.1139	0.2279	0.1709	1.27
Huang 8E_2s_1	0.0439	0.0879	0.0659	0.77
Huang 8E_2d_2	0.125	0.2501	0.1876	2.59
Zhuang 2$Ef_2^{2、3}$	0.0714	0.1428	0.1071	1.12
Zhuang 2Ef_1	0.239	0.4781	0.3586	3.78
Wei 5$Ef_2^{2、3}$	0.0332	0.0665	0.0498	1
Wei 5Ef_1^1	0.1574	0.3148	0.2361	3.73
Wei 8$Ef_2Ef_1^1$	0.029	0.058	0.0435	0.94
Nanhu Ef_3	0.0739	0.1478	0.1109	1.28
Nanhu Ef_2	0.0348	0.0696	0.0522	0.68
Anfeng K_2t_1	0.0321	0.0643	0.0482	0.63
Bian 1Ef_2	0.1722	0.3444	0.2583	1.81
Yong 7-15E_2s_2	0.1154	0.2309	0.1732	2.54
Chen 3$E_1f_1^{1+2}$	0.0881	0.1763	0.1322	1.61
Chen 3$E_1f_1^{3+4}$	0.0914	0.1828	0.1371	1.16
Chen 3K_2t_1	0.1937	0.3875	0.2906	2.46
Chen 3K_2c	0.6018	1.2036	0.9027	5.81
Dun 2$E_2d_1^2$	0.284	0.568	0.426	2.72

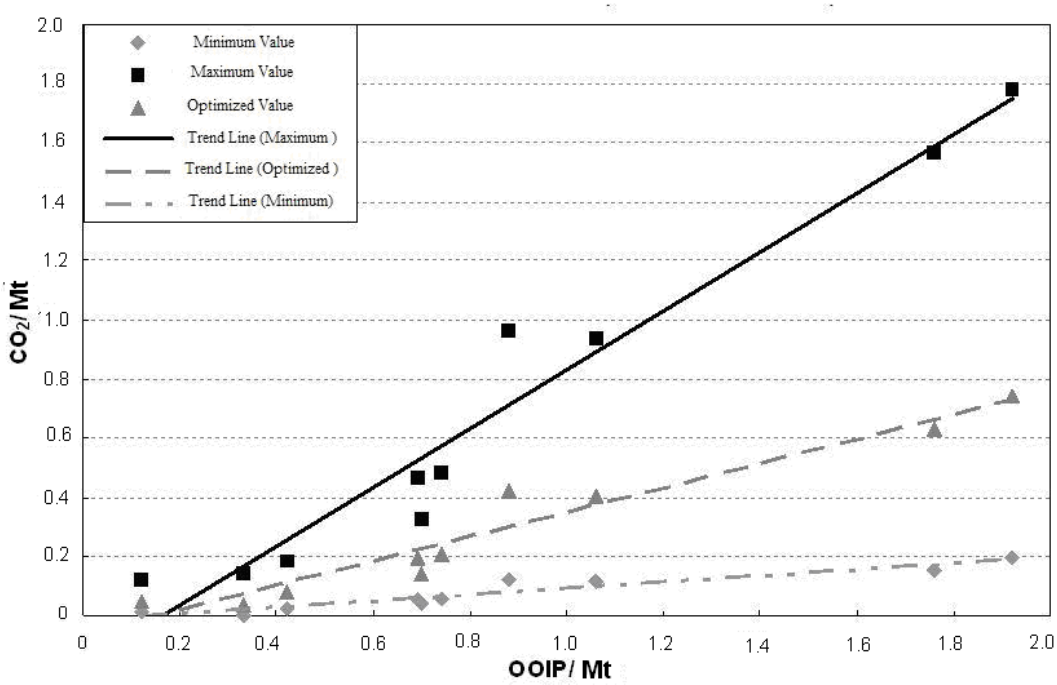


Figure 13: CO_2 storage capacity calculated corresponding the OOIP for the oil reservoirs suitable for gas injection and CO_2 EOR selected in Jiangsu Oilfield complex

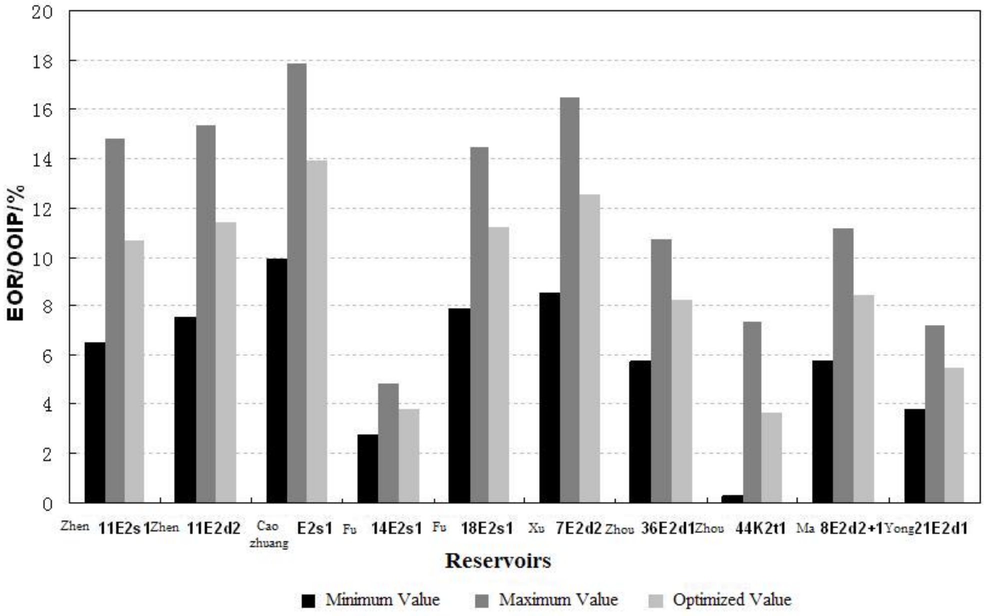


Figure 14: Distribution of enhanced recovery factors (EOR/OOIP) in the Jiangsu oilfields for reservoirs suitable for gas injection (storage) and CO_2 EOR

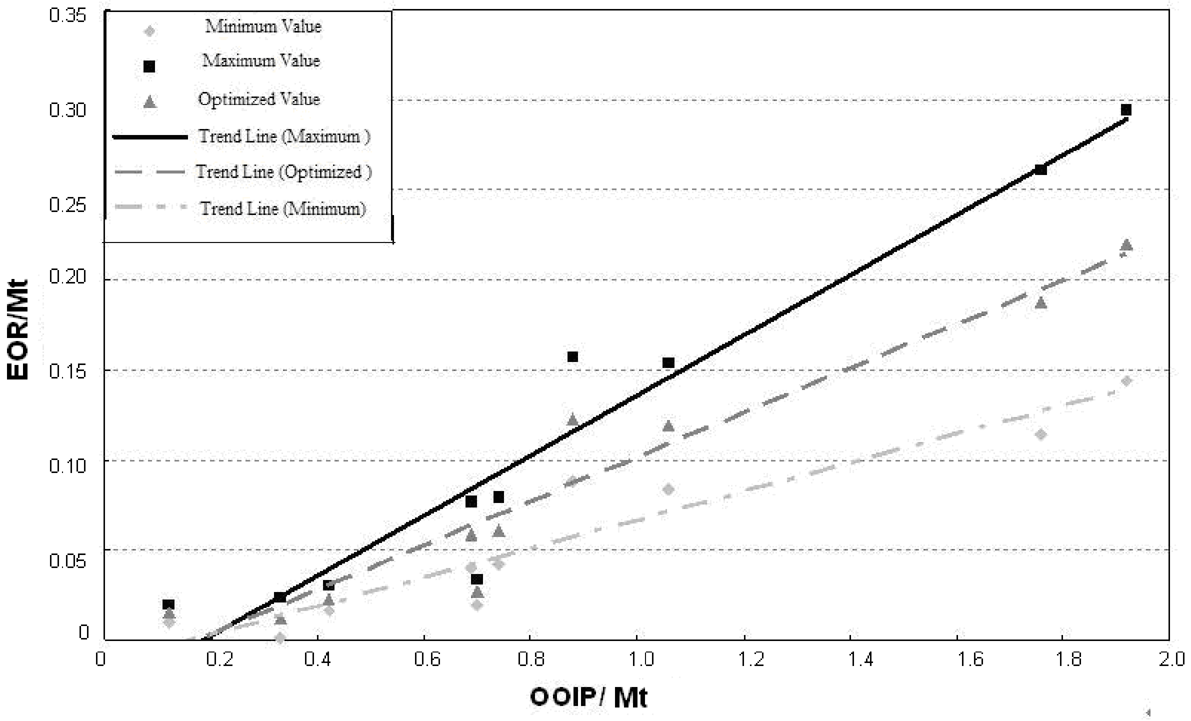


Figure 15: The calculated oil recovery by CO_2-EOR corresponding to the OOIP for oil reservoirs suitable for CO_2 storage and CO_2-EOR in Jiangsu Oilfield complex

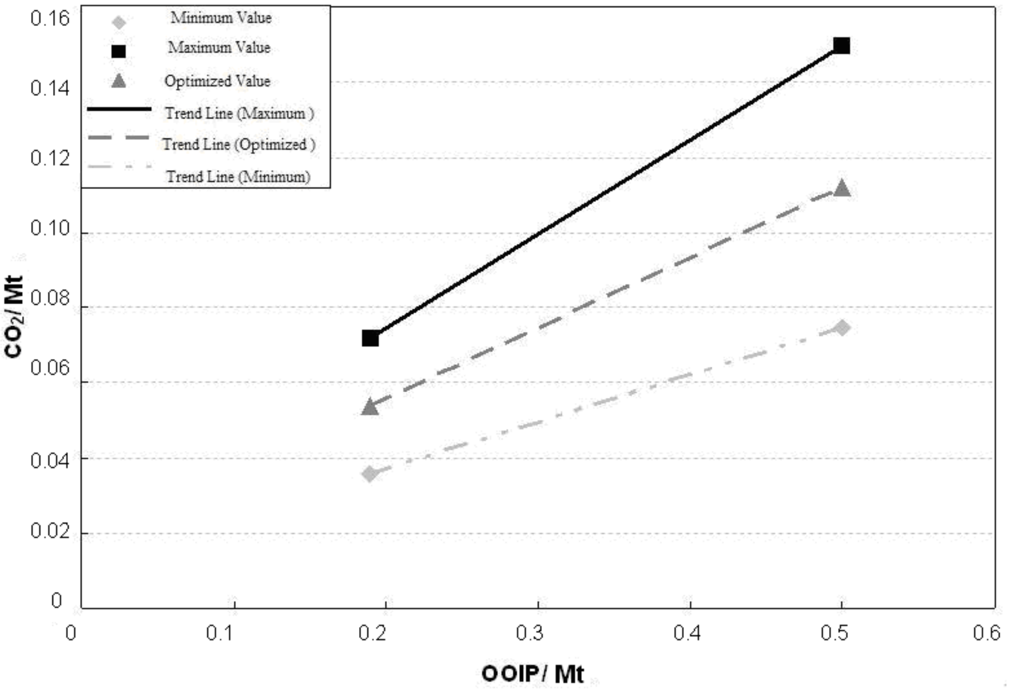


Figure 16: CO_2 storage capacity calculated corresponding to the OOIP for oil reservoirs in the Jiangsu Oilfield complex

6 Natural CO_2 gas reservoirs

6.1 Genesis of Natural CO_2 and CO_2 Reservoirs

The Subei Basin has an abundant natural CO_2 resource alongside the oil hydrocarbon reserves. Huangqiao CO_2 gasfield is the largest natural CO_2 gas field, which is located in the northeast part of the Nanjing depression of Xiayangzi Basin at the south edge of the Subei Basin close to the Yangtze River.

The genesis of natural CO_2 gas formation is complicated. It can be broadly grouped into two types:

1. Inorganic: CO_2 gas was formed from inorganic material due to physical and chemical actions at high pressure and temperature.
2. Organic: Anaerobic methane bacteria bred largely at underground temperatures of 10 – 60 ^oC. Organic matter degraded into methane (CH_4), carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulphide (H_2S), water (H_2O), and other gaseous volatiles. As long as there is organic matter, it will form CO_2 gas. As organic matter was widespread, generation of CO_2 gas was common creating large-scale CO_2 accumulations.

CO_2 accumulation conditions are very like hydrocarbon gas reservoirs, consisting of a gas source rock, reservoir, cap, and trapping mechanisms. They lie at depths of between 1870 and 2274m. There is not enough data to prove whether the seal or caprock for the natural CO_2 reservoirs is representative of the whole basin.

It is thought that the Subei CO_2 accumulations formed inorganically in relation to volcanic activity. CO_2 reservoirs found in the Jiangsu complex have the following geological backgrounds:

CO_2 generation may be related to the deep Paleozoic carbonate rocks. All the CO_2 reservoirs found are close to big deep faults – the Zhen 1 and Zhen 2 faults. In both the Sanduo and Yancheng periods, there were anogenic activities which could promote CO_2 formation. It is speculated that the natural CO_2 gas in the Subei Basin was formed due to the effect of heated decomposition or contact metamorphism of deep carbonate rocks during the Sanduo and Yancheng periods.

In addition, all the CO_2 reservoirs were originally associated with natural gas and are stained with residual oil, they are thought to be oil reservoirs which were invaded and flooded by CO_2. It is assumed that oil generation and oil reservoirs might form firstly, and then due to volcanic activity, CO_2 could be generated and major faults (and faulted traps) were formed later in the basin. CO_2 gas then migrated along the faults and seepages into the reservoirs currently occupied by CO_2.

6.2 Natural CO_2 resource

Based on generation of CO_2 and the geological trapping conditions, the region around the main faults in the south of the Gaoyou Trough was considered as an inactive site for the formation of natural CO_2 reservoirs.

In this region, there are currently a total of 11 wells with CO_2 gas flows, of which seven wells can produce an industrial gas flow with 97% CO_2. These wells are located in two regions, Xuzhang (four wells) and Fumin-Xiaoji (seven wells).

6.2.1 Natural CO_2 resource in the Xuzhuang region

In the Xuzhuang natural CO_2 resource region, there are three apparent features that are understood from limited exploration data:

1. CO_2 is a dissolved gas. The G/W ratio is 12.68:1. CO_2 solubility is 26.3 g/l under reservoir temperature and pressure.
2. The aquifers with dissolved CO_2 are not linked to the Tertiary aquifers, and the aquifers with dissolved CO_2 are considered not to be very large.
3. It is believed that above the aquifers with dissolved CO_2 could be associated with large natural gas reservoirs. This is assumed because high reservoir pressure and unexpected large solution gas drive have been observed in the complex. The gas reserve is expected to be 20×10^8 sm^3 (at standard condition).

6.2.2 Natural CO_2 resource in the Fumin-Xiaoji region

Seven wells have been drilled that can produce industrial CO_2 gas flow to support CO_2-EOR activities in the oil fields. All these wells are located in the Fumin-Xiaoji region. Five faulted-block CO_2 gas reservoirs have been discovered with small gas-bearing areas. The total CO_2 reserve is expected as 20.3×10^8 sm^3.

Table 12: CO_2 gas reserve in Fumin-Xiaoji region

Block	Layer	Gas bearing area (km^2)	Effective thickness (m)	Porosity (%)	Saturation (%)	P (MPa)	T(°C)	Z-factor	Unit reserve factor ($10^8m^3/km^2.m$)	Reserve (10^8sm^3)	Reserve (Mt)
Fu44	E1s12	0.5	4.2	23	63	18.09	72	0.487	0.457	0.96	0.192
	E1s13	0.3	3.6	23	64	18.09	72	0.487	0.464	0.50	0.1
Wang1	E1s	0.2	55.0	20	68	19.77	74	0.553	0.411	4.52	0.904
Ji1	E1f1	0.9	18.3	16	65	19.06	75	0.573	0.288	4.74	0.948
	k2t1	0.8	19.0	18	71	23.17	90	0.573	0.417	6.41	1.282
Ji2	E1f1	0.4	17.0	13	51	21.60	87	0.601	0.194	1.30	0.260
Fu12-1	E1f1	0.4	19.0	13	60	21.60	87	0.547	0.251	1.87	0.374
Sum		-	-	-	-	-	-	-	-	20.3	4.06

7 Saline aquifers

The study has shown that the storage potential of CO_2 in oil reservoirs in the Subei Basin is limited because the faulted oil fields are relatively small. Saline aquifers in the basin can also be considered as important CO_2 storage sites, but as there is little detailed information due to a lack of geological exploration on these sites, and they are more difficult to assess at present. However data for aquifers associated (connected) with oil reservoirs are available. During the process of the development of oil and gas fields, oil companies have collected a lot of information about the bottom or edge of aquifers connected to the oil and gas reservoirs. Pressure support from active bottom or edge water around the reservoirs generally indicates the presence of a large body of water. Injecting CO_2 into the bottom or edge water-body of oil and gas reservoirs would be a good option for CO_2 geological storage, because this would allow operators to take advantage of the large storage volume of the aquifers and the proven structure and effective seal of the oil reservoir.

Based on the data availability, the K_2T_1 reservoir of the Wa-6 block in the Wangzhuang Oilfield was studied as an example. The oil reservoir has a large edge aquifer body, and its potential for CO_2 storage has been calculated. The geological structure diagrams of the K_2T_1 are shown in Figure 17 and Figure 18.

The K_2T_1 reservoir is located at depths between 2790-2910 m; the oil/water contact lies at 2910 m. The dip angle of the reservoir is about 13°-14°, the oil-bearing area is 0.93 km^2. The net thickness of oil bearing layers in the reservoir is about 10-15 m; the total thickness is up to 30 m. The average porosity of reservoir is 15.9%, and the average absolute permeability is 55.1mD.

The oil density at reservoir conditions is 0.8254 g/cm^3 (surface: 0.8571 g/cm^3), oil viscosity is 6.89 mPa.s (surface: 15.15 mPa·s), gas/oil ratio is 5.5:1, saturation pressure is 1.05 MPa, the oil formation volume factor is 1.0389, the total salinity is 54,519 mg/l, chloride ion content is 32012 mg/l, and the formation water is calcium chloride ($CaCl_2$) rich.

At a depth of 2873.9 m, the static pressure of the reservoir is 28.78 MPa, the pressure coefficient is 1.018, and the reservoir temperature is 107^oC. The reservoir belongs to a typical temperature-pressure system.

As the reservoir inclines at an angle, the edge water-body (or aquifer) is a downwards extension of the oil reservoir. The geological properties of the oil reservoir and the aquifer are similar and the aquifer also has a good potential regional caprock to prevent migration of CO_2 upwards. Thus CO_2 could be injected at the base of this aquifer away from the oil reservoir. Eventually, the injected CO_2 will migrate up to the bottom of the oil reservoir. If CO_2 migrates into the oil reservoir, it may improve the pressure and expand the oil, which is good for improving oil production. However, it could also corrode the tubulars and break through to production wells and need to be separated.

This aquifer is about 10 times the volume of the oil reservoir, it is at a depth between 2910-3520 m (average depth is 3215 m), the other geological parameters are below:

- area: 9.5 km^2
- formation thickness: 30 m
- porosity: 15.9 %

- salinity: 54,519 mg/l
- temperature: 119 °C (temperature gradient is 3.5 °C/100m)
- pressure: 32.07 MPa (pressure coefficient is 1.018)

According to the solubility method for calculating CO_2 storage capacity, this aquifer can provide a storage potential of 2.24 Mt (equal to 11.21×10^8 sm^3) which is quite considerable when compared with 0.5 Mt in the upper oil zones.

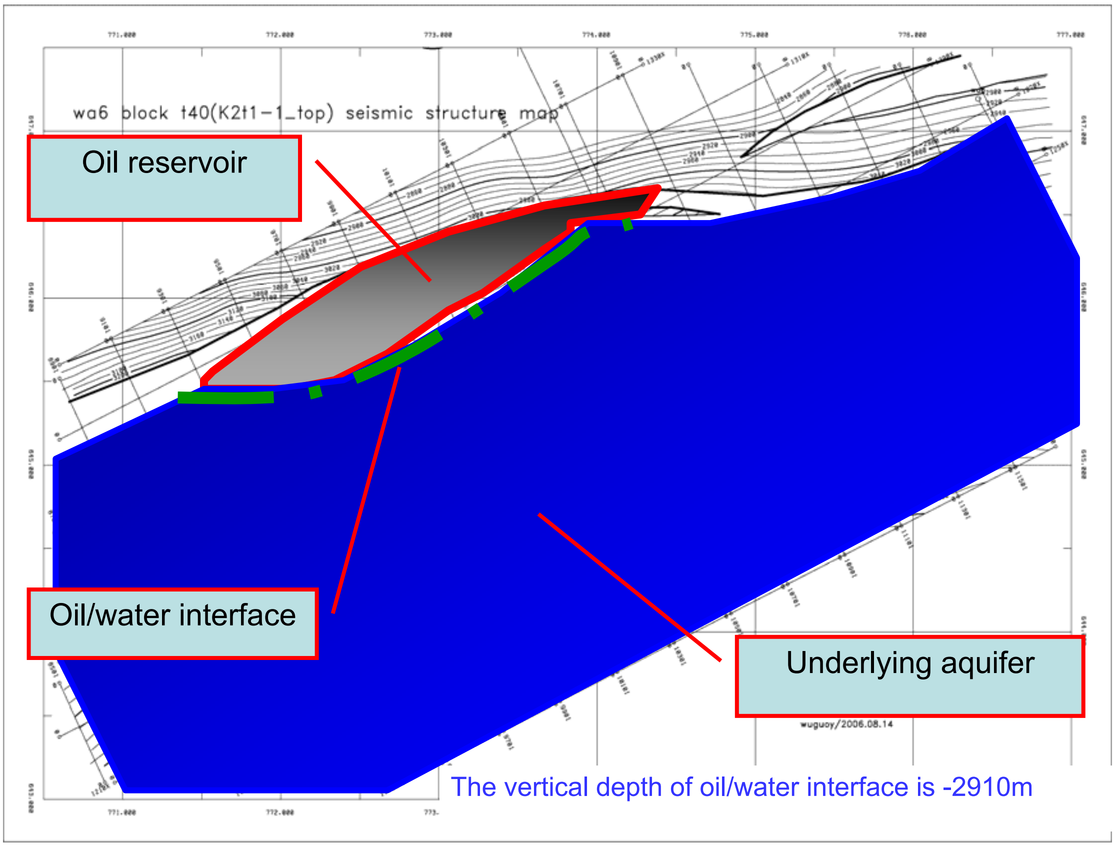


Figure 17: Structure map of the K_2t_1 oil reservoir and its associated aquifer in the Wa6 block of the Wazhuang Oilfield, JiangSu complex

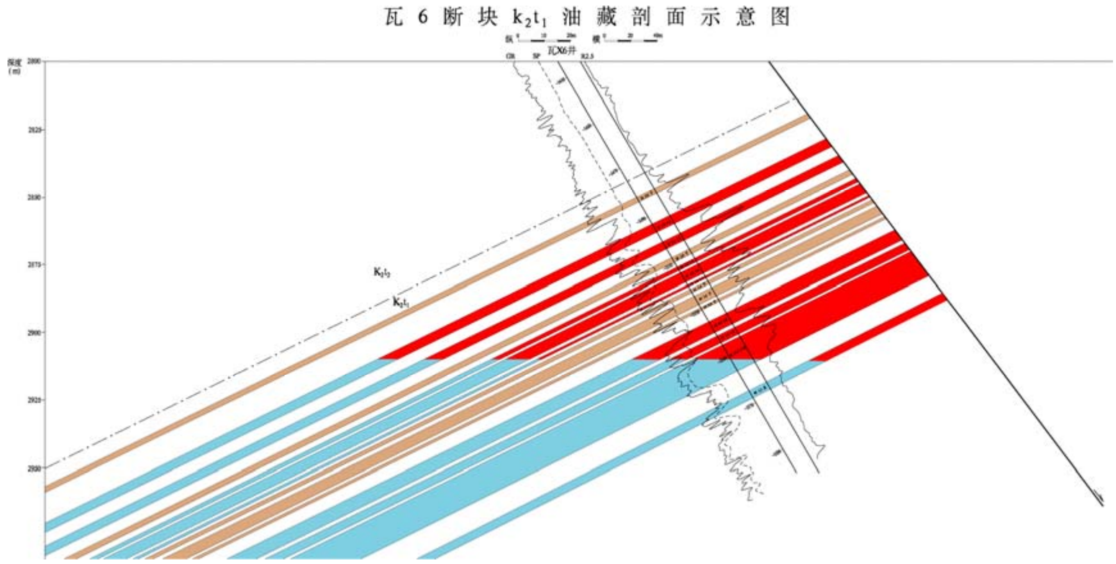


Figure 18: Cross section of the K_2t_1 reservoir in the Wa6 block of the Wazhuang Oilfield (red – gas; blue – porous aquifer formations)

8 Conclusions

The Subei Basin is located in the east of China, stretching across the Jiangsu and Anhui provinces, and extends to the Yellow Sea. The oil E&P have been focused on the onshore region in the past 30 years.

The Basin was formed from fluvial sediments of the Yellow and Huaihe rivers in the depressions and troughs formed after the XiangShan and Yanshan orogenies during the early Jurassic to late Cretaceous periods. The basin consists of two major uplifts (Binhai and Jianhu), and two big depressions (Yanfu and Dongtai). There are ten small sub-troughs (sags) in total. The boundaries between horsebacks and sags of the basin are all divided by faults. Structures formed in faulted complexes are a typical feature of the Subei Basin.

The Jiangsu Oilfield complex is mainly located in the JinHu, Gaoyou, QinTong and Haian troughs in the Dongtai Depression. This oil field is relatively small with complicated geological features. In total, 108 oil reservoirs have been assessed in this study, which account for over 70% of the OOIP estimated in the region. There are 75 reservoirs which were considered to be suitable for CO_2-EOR and storage and 33 reservoirs which are suitable for CO_2 storage as depleted oil reservoirs only. The total OOIP in the 75 reservoirs suitable for CO_2-EOR and storage is 84.32 Mt, the expected CO_2 storage capacity is 15.76 Mt, and the expected incremental oil production is 4.67 Mt (via an incremental oil recovery factor of 5.71%). The total OOIP for the 33 reservoirs suitable for CO_2 storage (not via EOR) is 48.05 Mt. The expected CO_2 storage capacity is 4.7 Mt. The total CO_2 storage capacity in the Jiangsu Oilfield complex was estimated to be 20 Mt. This is a conservative estimation due to a low EOR factor which was assumed for near-miscible CO_2 flooding, and because water displacement was not considered in the assessment. This figure can be doubled based on a CSLF method if water displacement by CO_2 and reservoir repressurisation is considered. Thus the CO_2 storage capacity in the Jiangsu Oilfield complex was estimated to lie within the range of 20-40 Mt. The assessment method applied is important and quite complicated as different CO_2 injection schemes can be applied in the field for EOR and storage.

The Subei Basin also has abundant natural CO_2 resources associated with hydrocarbon reservoirs. It has been speculated that the natural CO_2 in the Subei basin was formed inorganically, and was related to volcanic activity during Paleozoic to Tertiary times. In terms of geological evolution, the oil bearing formations were firstly formed in the region and CO_2 was generated later through volcanic activity and introduced into the reservoirs by migration along faults. Nearly all the Tertiary CO_2 reservoirs in the Basin show traces of residual oil. The CO_2 reservoirs are mainly located in Xuzhang Region and Fumin-Xiaoji Region close to the Yangtze River in the south of Jiangsu Province. The total CO_2 reserve in these two regions is estimated at $40.3\times10^8 m^3$ at standard condition (equal to 7.9 Mt).

This study has shown that the CO_2 storage potential in the Subei Basin oil reservoirs is limited since the faulted oil fields are relatively small. Saline aquifers in the basin can also be considered as important CO_2 storage sites, but there is a lack of detailed information due to previous geological exploration being mainly focused on oil and gas reserves. Data are available for aquifers associated (connected) with oil reservoirs. To some extent, these aquifers are safe and can be considered as good sites for CO_2 storage. The K_2T_1 reservoir in the Wa-6 block of the Wangzhuang

Oilfield was studied as an example: the oil reservoir is connected to a large aquifer, ten times of the volume of the oil bearing body. Based on the CO_2 solubility calculation method, the aquifer has a CO_2 storage potential of 2.24 Mt, while the upper oil reservoir can only store 0.5 Mt CO_2.

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