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Analyses of the Field Development Plan and EOR Screening based on Reservoir Properties of the "A" Field in Mongolia

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Abstract

The "A" oilfield in Mongolia has been explored since 1991 and entered the appraisal stage in 2009. The proven reserves are estimated to reach up to 1.3 billion barrels (175.5 million tons). The oil is expected to be displaced mainly by solution gas and water drive based on various tests during exploration and appraisal. The estimated recovery factor based on primary and secondary recovery is in the range of 10% to 14%. Therefore, the field development plan considers the application of enhanced oil recovery (EOR) to the field. However, a detailed screening process of EOR technologies is not adapted. In this study, screening and scoring of EOR methods for the three main formations of the "A" oilfield are conducted using field information. The CO_2 and immiscible gases (hydrocarbon; N_2) injections have the highest scores without any violation of criteria. Therefore, it can be concluded that these two methods have a better chance of success in field applications. Each formation seems to have a different promising EOR method. However, if the cost of EOR is considered, it may not be a good option. Based on averaging the scores of the screening results, 2–3 candidates can be selected for more detailed studies, including reservoir modeling and simulation to make decisions about large investments in EOR.

Keywords: EOR screening; immiscible gas injection; EOR scoring; CO_2 injection; EOR technologies

INTRODUCTION

Oil Industry Profile of Mongolia

In 1892, the Russian geologist V. A. Obruchev conducted the Central Asian Geological Survey, which is recorded in history as the beginning of Mongolian geological study. A few decades later, oil exploration in Mongolia started with the classification of Mesozoic and Tertiary sediments. The first discovery of oil shale outcrops in the Gobi region was made by American geologists H. Berkley and C. Morris. The development of the oil industry since then can be broadly divided into two stages:

– Stage one started in 1931 with help from the former Soviet Union. The Zuunbayan (translation: east–rich) and Tsagaan-els (translation: white sand) oilfields were discovered in the Dornogobi Province, Mongolia. The construction of the country's first refinery was completed in 1950 and production started by refining oil produced in the Zuunbayan field. The two small-sized reserves produced 3.95 million barrels (538.7 thousand tons) of oil during 1950–1969 [1]. In 1969, the refinery and production ceased activities due to declining rates, a fire at the refinery, and economic factors.

– Stage two started in 1991 when a parliamentary democracy was put in place after collapse of the Soviet Union, development of petroleum upstream operation recommenced, and the Petroleum Law of Mongolia was adopted by the Mineral Resources and Petroleum Authority of Mongolia (MRPAM) [2]. In the same year, the national petroleum company, Mongol Gazariin Tos (MGT), was founded. The MGT cooperated with the Texas Joint Exploration Company, accomplished research related to hydrocarbons in Mongolia, and successfully organized two rounds of exploration biddings.

As of now, Mongolia's sedimentary oil basins are divided into 32 petroleum exploration blocks, illustrated in Figure 1 (source: MRPAM). Those blocks have been compared to major production fields in China [3] because the two countries are neighbors. In addition, the "A" oilfield adjacent to the Hailaer oilfield of China is considered. These oilfields are within the same Mesozoic and Cenozoic sedimentation. Chinese and Mongolian resources, in contrast, are of the order of 100 billion barrels [4]. Currently the Government of Mongolia has signed a production sharing contract (PSC) for 25 of these blocks with 21 companies [5].

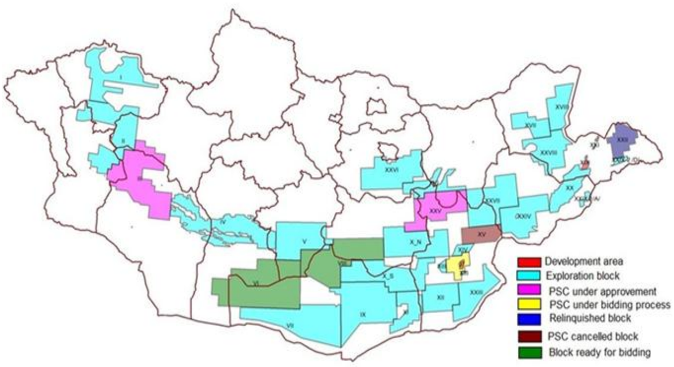

Figure 1: Petroleum blocks of Mongolia

Since 2010, Mongolia has become an "oil-producing country" by registering reserves of blocks XIX, XXI, and PSC-97 in Mongolian minerals fund. These reserves account for a total of 2.45 billion barrels (332.64 million tons) of "proven" reserves of which 318.6 million barrels (43.258 million tons) are "proven recoverable" reserves [5]. The current oil potential can put Mongolia at 33rd place on the "Top countries list with proven oil reserves," on par with larger producers such as Argentina, Colombia, and Gabon [7]. The proven reserves are estimated by PetroChina Daqing Tamsag Mongolia LLC, a subsidiary of the largest integrated petroleum company in China, Chinese National Petroleum Corporation (CNPC), and Dongsheng Petroleum (Mongol) LLC, a subsidiary of the second largest Chinese petroleum company, Sinopec.

Approximately 43.8 million barrels (5.9 million tons) of oil were produced between 1996–2016 and 41.6 million barrels (5.6 million tons) were exported to China based on which 1.1 trillion MNT of revenue was accrued by the Government of Mongolia. In 2016, Mongolia produced 8.25 million barrels (1.12 million tons) and exported 8.06 million barrels (1.09 million tons) to China, which generated 134.2 billion MNT in state revenue. The average of total daily oil production was 22,710 barrels (3,083 tons) by 2016, associated with the three oilfields in production [5].

Project Profile

Production Sharing Contract (PSC) of the project

The main oil exploration and production activities are performed under a Production Sharing Contract (PSC) in Mongolia. The Government of Mongolia adopted the simple version of the PSC in 1993 and aggressively attempted to attract foreign investments in its prospective petroleum blocks. Although Mongolia's petroleum prospective was murky, the Government of Mongolia managed to sign its first PSC with contractor "S" from the USA in 1993 [1]. As agreed in the PSC, the Government of Mongolia share the profit from oil or gas with the contractor. The amount of profit from oil allocated to the government shall be determined and specified in the contract in relation to the daily extraction volume [6].

In addition, the Petroleum Law of Mongolia was revised on July 1, 2014, and now includes product sharing. The law allows the exploration for up to 8 years and exploitation for up to 25 years, plus extensions. Depending on the agreed terms of the PSC and the nature of hydrocarbon (conventional and unconventional oil or natural gas), royalties vary from 5% to 15%. Cost recovery of exploration and exploitation is allowed up to 40% of the oil. If applicants for exploration or exploitation licenses fail to reach an agreement with the Government of Mongolia on production sharing, unsealed bids (open bidding) are required. Also, the customs duty and Value Added Tax (VAT) are excluded for contractors because of the recent tax reform.

In the revised law, the PSC procedure takes approximately six months to complete. First, applicants apply for negotiation and the MRPAM evaluates the applicant`s experience with the petroleum business, financial capability, and basic conditions of the PSC such as the production sharing percentage. After the evaluation of the applicants, the contractor is selected, MRPAM agrees on the PSC draft with the contractor within 60 days, and submits the draft to the Ministry of Mining of Mongolia. The Ministry of Mining examines the draft within 30 days and sends it to the Parliament of Mongolia. The Parliament of Mongolia makes a decision within 60 days. If the Parliament of Mongolia grants the right to MRPAM, then MRPAM concludes the PSC with the selected contractor within 30 days and notifies related local government organizations [5,6], shown in Figure 2 (source: MRPAM).

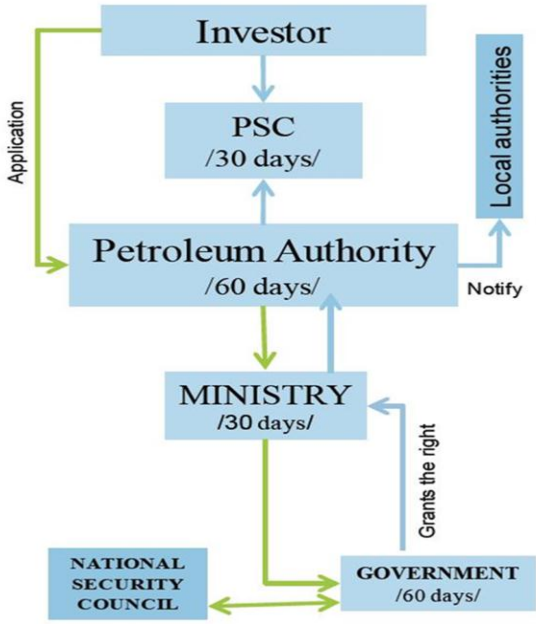

Figure 2: PSC procedure in Mongolia

With respect to the project of the "A" oilfield, the "P" company acquired the PSC for the "A" oilfield from the "S" company in 2005. The MRPAM and "P" company signed an agreement about the purchase of the exploration and development entitlement of the "A" oilfield in the same year. As mentioned before, the Government of Mongolia signed its first PSC with the "S" company in 1993 and the "P" company acquired the PSC for the "A" oilfield from the "S" company. Therefore, the PSC of "A" oilfield is still in the form of 1993 and the basic terms are very simple compared with PSCs that have been written since 1993. The Petroleum Law of Mongolia was revised in 2014, but the PSC for the "A" oilfield is still in its original form, which is not very profitable for Mongolia. To better understand the PSC of the project, a table comparing the PSC for the "A" oilfield with that of the "B" oilfield, signed in 2011, is shown in Table 1 (barrels per day: bbl/day) [1,5].

Table 1: Comparison of the “A” oilfield PSC with that of the “B” oilfield

Conditions of PSC			**"B" oilfield (signed in 2011)**	**"A" oilfield (signed in 1993)**
Production sharing terms	0–5,000 bbl/day	Government	43%	40%
		Company	57%	60%
	5,001–10,000 bbl/day	Government	45%	40%
		Company	55%	60%
	10,001–15,000 bbl/day	Government	50%	40%
		Company	50%	60%
	15,001–20,000 bbl/day	Government	55%	40%
		Company	45%	60%
	20,001 and above bbl/day	Government	60%	40%
		Company	40%	60%
	50,001 and above bbl/day	Government	60%	40%
		Company	40%	60%
	75,001 and above bbl/day	Government	60%	50%
		Company	40%	50%
	100,001 and above bbl/day	Government	60%	55%
		Company	40%	45%
Royalty%			10.75%	-
Cost Recovery%			40%	40%
Environmental recovery fee for each contract year			$60,000	-
Minimum required investment		1st year	$3,066,050	$438,000
		2nd year	$5,010,000	$1,000,000
		3rd year	$6,900,000	$2,750,000
		4th year	$8,720,000	$1,150,000
		5th year	$15,080,000	$3,500,000
Training bonus (USD)/ fee at exploration stage			$350,000	-
Signing bonus (USD)/ one-time fee			$120,000	$10,000
Extraction bonus			$500,000	-
Extraction bonus fee (USD)	0–5,000 bbl/day		-	-
	5,001–10,000 bbl/day		$500,000	-
	10,001–15,000 bbl/day		$800,000	-
	15,001–20,000 bbl/day		$1,200,000	-
	20,001 and above bbl/day		$2,000,000	-
	100,000 and above bbl/day		$2,000,000	$500,000

The initial contract exploration period of the “A” oilfield expired in 2010 and the oilfield entered the fine exploration and appraisal stage in 2009. The reserves of the “A” oilfield have been submitted to the Mongolian government in 2010 and 2011. The extraction period is 20 years, with a permission to extend the period twice per five years. The Government of Mongolia has supportive terms for the PSC investor that allow the investor to cover expenses for petroleum-related activities. The investor bears all expenses related to developing the petroleum block. The investor takes up to 40% of the oil to cover some expenses indicated by the MRPAM and the rest of the oil will be shared (government: 40% including royalty, investor: 60%).

The Government of Mongolia required the inclusion of several fees in the PSC: when the PSC is ratified by the government, the investor pays a signing fee of $10,000. Because the environment is damaged by exploration and extraction of the mineral resources sector, the Government of Mongolia implied environmental recovery expenses. The oil is shared between the two parties in accordance with the percentage stated in the contract depending on the daily production volume per calendar year. If the production increases, a one-time extraction bonus will be paid to the government. The daily production is determined by dividing the produced oil per calendar year by 365 days.

The "B" oilfield has been five years in the exploration stage and twenty years in the extraction stage. The investor can extend the exploration period twice per two-year extension in the case of force majeure (fire, epidemics, unavoidable accidents, declared and undeclared war, strikes, lockouts, and other disturbances, floods, storms, earthquake and other natural disturbances, and insurrections or riots). If oil is discovered, the extraction period is 20 years, with a permission to extend twice per five years. In the extraction stage, the government will take 10.75% as royalty. After the deduction of royalty, the investor takes up to 40% of the oil to cover some expenses indicated by the MRPAM and the rest of the oil will be shared (government: 43%, investor: 57%) [1].

Because the investor decided to operate on the "B" oilfield, the Government of Mongolia required the inclusion of several fees in the PSC. Historically, the petroleum upstream sector has been abandoned for over two decades in Mongolia. Because of the associated shortage of knowledgeable workforce for this project, the investor therefore pays a training fee of $70,000 for five years. When the PSC is ratified by the government, the investors pays a signing fee of $120,000. Because the environment is damaged by exploration and extraction of the mineral resources sector, the Government of Mongolia implied an environmental recovery expense limit of not less than $60,000 per calendar year of the PSC. Representative office and local assistance fees are paid by the investor each year because Mongolia has vast land and most of the government offices are in the capital. The ministry and agency are limited to the expansion of local offices; therefore, the expenses are paid by the investor. If the production increases, the government's production sharing percentage will increase and the one-time extraction bonus will be paid to the government.

It is known that PSCs often used in Middle East and Central Asia have a rate of ~80% for the government and 20% for the company based on the "profit oil" money. However, the PSC for the "A" oilfield was one of the first PSCs in Mongolia. Therefore, the split rate is only 40% for the government including royalty and 60% for the investor. Because it was the first PSC, the Mongolian government had no experience and the investing company took a considerable risk, which turned into profit. Also, the Government of Mongolia aggressively attempted to attract foreign investments in its prospective petroleum blocks in the 1990s. However, the situation and PSC basic terms have significantly changed since then.

Research area and project status

The "A" oilfield is in eastern Mongolia. With an average elevation of 640 m, the area is dominated by flat grassland. It belongs to arid climate of the medium extratropical zone and has significant diurnal amplitudes.

In the 1950s, the former Soviet Union carried out general survey work in the "A" basin in which the "A" oilfield is located. Several western companies have conducted additional seismic exploration in the "A" basin since 1991. The "A" oilfield entered the fine exploration and appraisal stage in 2009. The reserves of the "A" oilfield have been submitted to the Mongolian government in 2010 and 2011. At present, the Mongolian government approved proven oil reserves of 1.3 billion barrels and 147.8 million barrels of proven recoverable oil reserves for the "A" oilfield [8,9].

The daily oil production of 848 wells, including 456 oil producers and 392 injectors, was estimated to range between 13000–14000 bbl/day by the end of 2016 [5]. The predicted annual oil production of 1638 wells, including 1171 oil producers and 467 injectors, varies from 5.2–5.7 million barrels between 2025–2039; a slow decline is predicted thereafter [11].

To improve the recovery of oil in the "A" oilfield, numerical simulations with respect to natural depletion and water flooding are carried out by the "P" company. The simulation results show that the cumulative oil production and recovery factor by water flooding is much higher than that of natural depletion. Therefore, water injection is recommended for development. Natural driving forces were expected such as solution gas drive and edge-bottom water drive. The solution gas drive force and edge-water drive are estimated to improve the recovery factor by 5.5%–7% and 1%–2.5%, respectively [11]. Unfortunately, the development performance of the "A" oilfield shows that the oil output based on natural energy decreases fast and the economic benefit is poor. Therefore, hydraulic fracturing is recommended to improve the well performances without considering the natural energy, except for a few fault blocks with high productivity. Also, waterflooding development is characterized by its strength in mature technology, simple equipment, few investments, and fast effectiveness and has been the most frequently used technology worldwide that can maintain the high and stable yield of oilfields and improve the ultimate recovery. The oilfield will be developed by waterflooding in the first stage and a recovery ratio of 10%–14% is expected. However, due to its large strata dip, water injection may not be as good as expected. Hence, it has been suggested to carry out air injection, if applicable. Also, if technical and economic conditions are feasible in later periods, gas drive or polymer flooding will be applied. Because the oilfield is still in the primary stage of development, it is too early to prepare models for air drive and polymer flooding; they should be prepared in the middle development stage.

RESERVOIR CHARACTERISTICS OF THE "A" OILFIELD

Reservoir static and fluid properties

From a geological perspective, the "A" oilfield is in a Mesozoic and Cenozoic sedimentation basin, with good correspondence of formation, sedimentation, and structural characteristics. The formation of the "A" basin is divided into the basement (general terms of the formation before the Cretaceous system with unclear era division), Tsagaantsav Formation of the Lower Cretaceous system, Lower Zuunbayan Formation (LLZ), Upper Zuunbayan Formation (ULZ), Sainshand Formation, Bayanshiree Formation, Tertiary system, and Quaternary system, from bottom to top. The ULZ, LLZ, and Tsagaantsav Formation are the main pay zone of the oil reservoir.

Table 2 summarizes the static and fluid reservoir properties of the Lower Zuunbayan and Tsagaantsav formations. The distribution of average values for the net pay thickness is based on the coring thickness and electric log interpretation [2,10,11,15]. The pressure, volume, and temperature (PVT) test results and other static and fluid reservoir properties of the "A" oilfield are shown. The PVT test was performed in 13 wells of the LLZ and 14 wells of the Tsagaantsav Formation [11].

Table 2: Average values of static and fluid reservoir properties

Reservoir properties	Formation		
	ULZ	LLZ	Tsagaantsav
Fluid properties			
Static pressure (MPa)	19.26	25.21	23.4
Reservoir temperature (℃)	72.95	91.22	87.47
Saturated pressure (MPa)	5.16	9.14	6.6
Gas/Oil ratio (m^3/m^3)	27.34	54.18	39.8
Oil formation volume factor	1.1199	1.2047	1.1675
Compressibility coefficient (10^{-3}/MPa)	1.3284	1.6782	1.6366
Crude oil density (t/m^3)	0.7591	0.7241	0.7447
Viscosity (cP)	2.37	1.17	1.91
Oil API gravity	37.4	37.4	37.4
Static Properties			
Top depth (m)	-1380.5	-1755.2	-1644.9
Net pay thickness (m)	11.875	15.4	22.18
Porosity (%)	18.9	9.4	14.3
Permeability XY (mD)	22.77	3.44	109.27
Oil saturation (fraction)	0.50875	0.496	0.5118
Initial gas oil ratio (m^3/m^3)	30	66.6	29.6
Water cut (%)	18.5833	26.8	24.6952381

Table 3: Analysis and statistics of the formation water

Formation	Chloride ion content (mg/L)	Total salinity (mg/L)	pH value	Water type
Tsagaantsav	248.20–1613.4 595.5	1797.2–7498.4 3523.2	6.2–11.0 7.7	$NaHCO_3$
LLZ	159.6–1081.5 573.0	2908.9–7347.6 4477.5	6.5–8.3 7.3	$NaHCO_3$
ULZ	224.2–993.0 503.8	3958.7–7345.05 5189.1	7.0–9.0 7.8	$NaHCO_3$

Table 3 shows that the average total salinity of the formation water in the Tsagaantsav Formation is 3523.2 mg/L, chloride ion content is 595.50 mg/L, pH is 7.7, and water type is $NaHCO_3$. The average total salinity of the formation water in the LLZ Formation is 4477.5 mg/L, chloride ion content is 573.0 mg/L, pH is 7.3, and water type is $NaHCO_3$. The average total salinity of the formation water in the ULZ Formation is 5189.1 mg/L, chloride ion content is 503.8 mg/L, pH is 7.3, and water type is $NaHCO_3$ [2,11,15].

The crude oil is classified into four types based on the surface crude oil density: light crude oil with a surface crude oil density below 0.87 t/m^3, medium crude oil with 0.87–0.92 t/m^3, and heavy crude oil with 0.92 t/m^3-1.0 t/m^3. If the crude oil density is larger than 1.0 t/m^3, it is classified as ultra heavy crude oil. Also, crude oil can be classified into two categories and six subcategories based on its viscosity. Crude oil with a crude oil viscosity below or equal to 50 cP is classified as conventional oil, which includes low-viscous oil (0.1 ≤ 5 cP), medium viscous oil (5–20 cP) and highly viscous oil (20–50 cP). Crude oil with a crude oil viscosity larger than 50 cP is heavy oil including conventional heavy oil (50–10000 cP), extra heavy oil (10000–50000 cP), and ultra-heavy oil (natural bitumen, larger than 50000 cP).

The average values of the density and viscosity of surface crude oil for the Tsagaantsav Formation of the "A" oilfield in Table 4 are 0.8361 t/m^3 and 5.64 cP, respectively. The average values of the density and viscosity of surface crude oil for the LLZ are 0.8356 t/m^3 and 5.96 cP and that for the ULZ are 0.8337 t/m^3 and 5.67 cP, respectively, which belong to conventional light crude oil [2,10,11].

Dynamic reservoir properties

Deliverability evaluation:

Table 5 shows the statistics of commercial layers based on the deliverability test [11]. A natural deliverability test was implemented in a total of 64 wells; among them, 24 wells have commercial oil flow. The LLZ has a daily average oil production of 11.1 t and an average oil production intensity of 2.1 t/d·m. The Tsagaantsav Formation has a daily average oil production of 25.4 t and an average oil production intensity of 3.8 t/d·m. It has been proven that the reservoirs have a relatively high heterogeneity in terms of productivity and stimulation because non-flowing wells were considered.

Table 4: Properties of surface crude oil of the "A" oilfield

Formation	Density (t/m^3)	Viscosity (cP)	Wax (%)	Colloid (%)	Solidifying point (℃)
ULZ	0.8557–0.8144 0.8337	10.4–2.5 5.67	19.29–2.51 11.56	16.5–2.32 8	30–8 21
LLZ	0.8711–0.8042 0.8356	47.9–1.5 5.96	28.78–0.08 13.09	31.9–2.59 10.6	39–7 22
Tsagaantsav	0.8615–0.7956 0.8361	19–1.6 5.64	50.74–2.71 12.79	31.8–2.02 10.4	38–6 22

Stimulation effect evaluation:

Table 6 shows that the stimulation effect of fracturing is notable in the "A" oilfield [11,15]. With respect to wells that did not naturally flow, hydraulic fracturing helped to make the oil flow with an economical rate. Therefore, fracturing stimulation is considered to be the main method to increase production.

Table 5: Statistics of commercial oil layers based on the natural deliverability test

Formation	Average perforated net pay thickness (m)	Daily production (average)			Average oil production intensity (t/d·m)
		oil tons (t)	water (m^3)	gas (m^3)	
Lower Zuunbayan	5.3	11.1	0.3		2.1
Tsagaantsav	6.7	25.4			3.8

Table 6: Comparison of production before and after fracturing in test wells

Well No.	Formation	Well interval (m)	Perforated net pay thickness (m)	Type of well test	Daily production		Oil production intensity (t/d·m)
					oil (t)	water (m^3)	
A19-115	Lower Zuunbayan	2375.6–2377.6	1.5	MFE II + swab	0.03		0
				Postfrac swab	29.88		19.9
A19-17	Lower Zuunbayan	1886.0–1890.0	3	swab	4.7		1.6
				Postfrac swab	25.24	1.9	8.4
A19-28	Tsagaantsav	2340.7–2347.8	4	MFE II + swab	0.001		0
				Postfrac flow	23.68		5.9

Performance analysis of the water injection test area:

A water injection pilot test was started in Block A-1 (fault block) in June 2008 and Block A-2 was chosen as the extended water injection test area in October 2009. The response to water injection can be determined based on the comparison of the production situation in Blocks A-1 and A-2 before and after water injection development. Table 7 shows that both test areas respond to water injection and the production rate notably rises after water injection [11]. Considering the statistical analysis of formation pressure testing data from water injection test areas, the formation pressure of all water injection areas resumed, indicating the response to water injection.

Table 7: Comparison of the production rate in Blocks A-1 and A-2 before and after water injection development

Fault block	Water injection time	Stage	Number of well startup (well)		Daily liquid production rate (t)	Daily oil production rate (t)	Daily liquid production rate per well (t)	Daily oil production rate per well (t)
			Water well	Oil well				
A-1	June 2008	Three months before water injection		6	25.6	23.8	4.3	4.0
		One month before water injection		6	24.0	23.0	4.0	3.8
		Three months after water injection	2	6	28.1	26.4	4.7	4.4
		Six months after water injection	2	6	31.5	30.7	5.3	5.1
		October 2010	1	4	27.8	24.8	7.0	6.2
A-2	October 2009	–Three months before water injection		21	273.6	246.7	13.0	11.7
		–One month before water injection		27	272.9	266.3	10.1	9.9
		–Three months after water injection	7	26	316.4	306.3	12.2	11.8
		–Six months after water injection	5	26	276.6	258.2	10.6	9.9
		–October 2010	6	25	310.5	337.2	12.4	13.5

DEVELOPMENT WELL PATTERN DESIGN

Fracturing is not needed for the production in a few fault blocks of the "A" oilfield to reach higher productivity, which has been proven based on production test results. However, other fault blocks have poor physical properties and a lower natural productivity; therefore, fracturing stimulation is needed to raise the seepage capacity and flow conductivity of the reservoir. The production test showed that the fracturing effectiveness of the rest of the blocks is better. Hence, mechanically pumping is adopted for the oil wells after fracturing and fracturing is not conducted in water wells.

Well spacing

The reasonable well spacing of the oil layers in the Tsagaantsav Formation is demonstrated mainly using methods such as reservoir engineering, economical evaluation, and reservoir simulation [11]. Based on the combination of physical reservoir properties, the geometry of the oil-bearing area, and economical limit method, the average well spacing of the blocks ranges between 220–300 m.

Well pattern

The overlapping zones of the Tsagaantsav and Lower Zuunbayan oil reservoirs adopt the same set of well pattern for combined production. However, their non-overlapping zones adopt a set of well patterns. The oil-bearing area of most fault blocks is narrow, faults are complex, and structures are broken. Therefore, triangular well patterns are used as the main well patterns. In some fault blocks with an extremely narrow oil-bearing area, the triangular well patterns cannot be formed. Instead, flexible well patterns with a W-shape are used for extremely narrow oil-bearing areas with a well spacing of 220–300 m, shown in Figure 3a. In some other fault blocks, the maximum width of the oil-bearing area is > 1000 m, which meets the conditions needed for the deployment of normal well patterns. Square well patterns are used for a well spacing of 240–260 m, which is illustrated in Figure 3b [11].

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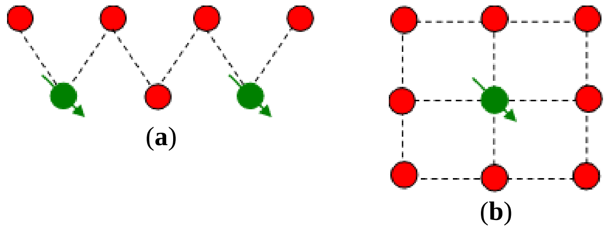

Figure 3: (a) Flexible "W"-shaped well pattern; (b) Square-shaped well pattern

Direction

Many theoretical studies and production tests indicated that the reasonable allocation relationship between injection–production well patterns and artificial fracture systems is that the fracturing action is displayed sufficiently, the well spacing can be enlarged, and the distance of well array needs to be reduced. Therefore, it is designed such that the direction of the well array is parallel to the artificial fractures formed after fracturing and the well locations between the well arrays are deployed crisscross. The well array direction of various faults is the same as the artificial fracture direction of the faults [2,11].

SCREENING OF EOR TECHNOLOGIES

The EOR screening technology is widely applied in oil reservoirs to identify, evaluate, and rank the EOR methods. The effective evaluation and recognition of the potential for enhanced oil recovery can substantially increase the reservoir value and mitigate development risks. Multiple EOR methods can be applied to screen EOR technology: chemical, thermal, and miscible/immiscible injection. The goal of this study is to assist in reservoir analysis and interpret the qualitative evaluation of the "A" oilfield in Mongolia. The ULZ, LLZ, and Tsagaantsav Formation are the main oil layers accounting for development and production.

EOR screening criteria

The field development plan included the application of enhanced oil recovery to the field. However, a detailed screening process of EOR technologies was not adapted. In this paper, we suggested detailed EOR screening based on criteria proposed in prior research [13,14,16,18]. Table 8 shows the criteria from Taber et al. (1997). They presented ranges of reservoir and fluid properties as criteria for good projects. Underlined values indicate the average or mean of the parameter for that EOR method. For example, the gravity criterion >35↗48↗ means that the process should work for oils with > 35° API, higher-gravity oils (↗) are better, and the approximate mean or average of current miscible nitrogen projects is 48° API [14].

Table 9 shows the average values of the reservoir properties in three formations of the "A" field [11,15]. Because these formations have many thin layers, averaging of the reservoir properties was adopted as practical way to screen and evaluate the EOR methods.

EOR scoring

Each formation must be evaluated individually because of different reservoir properties. Trujillo et al. (2010) proposed a scoring technique to quantify the fit of more detailed screening of EOR methods. It considers how the EOR method fits the real field and therefore it should use the reservoir and fluid properties and criteria for screening. The difference to conventional screening is the concurrent use of limits and averages of criteria, which are collected from the real EOR project [17-21].

Stairwise scores are determined depending on the data for these formations and average number of actual projects. A deeper green color represents the best case and strongly suggested EOR method to apply, which equals 1. A lighter green color reflects good cases and yellow represents normal cases, equivalent to 0.7 and 0.5, respectively. Orange is used for barely applicable cases and red represents the worst case, equivalent to 0.3 and 0, respectively.

Table 10 shows the scoring results for three formations. Although the overall score of certain EOR methods is high, it must be removed from the potential list of EORs if any criteria are red because red reflects the violation of lower or upper limits. Table 11 shows the rank of the EOR methods using the scores in Table 10. In this table, CO_2 and immiscible gas injections have the highest scores. No red color is present in Table 10; therefore, it can be concluded that these two methods have a better chance of success when they are applied in the field. Polymer flooding has been ranked number four; however, it shouldn't be considered because the viscosities of the three formations are not consistent with the criteria.

Each formation seems to correlate with a different EOR method based on Table 11. However, if the cost of EOR is considered, these may not be good options and therefore the use of an average score is suggested. Based on the screening results, 2–3 candidates are selected to conduct more detailed studies including reservoir modeling and simulation.

Table 8: Summary of the screening criteria for EOR methods

		Oil properties			Reservoir characteristics					
Detail: Ref. 16	EOR method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (%)	Formation type	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
1	Nitrogen and flue gas	>35↗48↗	<0.4↘ 0.2↘	High percent of C_1 to C_7	>40↗ 75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23↗41↗	<3↘ 0.5↘	High percent of C_2 to C_7	>30↗ 80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗[a]	<10↘1.5↘	High percent of C_5 to C_{12}	>20↗ 55↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
4	Immiscible gases	>12	<600	NC	>35↗ 70↗	NC	NC	NC	>1,800	NC
5	Micellar/ Polymer, ASP, and Alkaline Flooding	>20↗ 35↗	<35↘ 13↘	Light, intermediate, organic acids for alkaline floods	>35↗ 53↗	Sandstone preferred	NC	>10↗450↗	<9,000↘3,250	<200↘ 80
6	Polymer Flooding	>15	<150, >10	NC	>50↗ 80↗	Sandstone preferred	NC	>10↗800↗[b]	<9,000	<200↘ 140
7	Combustion	>10↗ 16→?	<5,000→ 1,200	Some asphaltic components	>50↗ 72↗	High-porosity sand/ sandstone	>10	>50[c]	<11,500↘ 3,500	>100↘ 135
8	Steam	>8↗ 13.5→ ?	<200,000 → 4,700	NC	>40↗ 66↗	High-porosity sand/ sandstone	>20	>200↗ 2,540↗[d]	<4,500↘1,500	NC

NC = not critical.

Underlined values represent the approximate mean or average for current field projects.

Table 9: Average values of screening criteria for EOR methods in the "A" oilfield

ULZ Formation, LLZ Formation & Tsagaantsav Formation: Summary of the screening criteria for EOR methods

	EOR method	Oil properties									Reservoir characteristics														
		Gravity (°API)			Viscosity (cp)			Oil saturation (% PV)			Formation type			Net thickness (ft)			Average permeability (md)			Depth (ft)			Temperature (°F)		
		ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav
1	Nitrogen and flue gas	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.8	3.4	109.3	4529.2	5758.5	5396.7	163.3	196.2	189.5
2	Hydrocarbon	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.8	3.4	109.3	4529.2	5758.5	5396.7	163.3	196.2	189.5
3	CO_2	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.8	3.4	109.3	4529.2	5758.5	5396.7	163.3	196.2	189.5
4	Immiscible gases	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.8	3.4	109.3	4529.2	5758.5	5396.7	163.3	196.2	189.5
5	Micellar/ Polymer, ASP, and Alkaline Flooding	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.77	3.44	109.27	4529.20	5758.53	5396.65	163.32	196.19	189.45
6	Polymer Flooding	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.77	3.44	109.27	4529.20	5758.53	5396.65	163.32	196.19	189.45
7	Combustion	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.77	3.44	109.27	4529.20	5758.53	5396.65	163.32	196.19	189.45
8	Steam	37.4	37.4	37.4	2.37	1.17	1.91	50.88	49.60	51.18	Sandstone	Sandstone	Sandstone	39.0	50.5	72.8	22.77	3.44	109.27	4529.20	5758.53	5396.65	163.32	196.19	189.45

Table 10: ULZ, LLZ & Tsagaantsav Formation: Result of the scoring criteria for EOR methods

ULZ Formation, LLZ Formation & Tsagaantsav Formation: Summary of Screening Criteria for EOR Methods

		Oil Properties												Reservoir Characteristics											
	EOR Method	Gravity (°API)			Viscosity (cp)			Oil Saturation (% PV)			Formation type			Net Thickness (ft)			Average Permeability (md)			Depth (ft)			Temperature (°F)		
		ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav
	Gas Injection Methods (Miscible)																								
1	Nitrogen and flue gas	0.3	0.3	0.3	0	0	0	0.3	0.3	0.3	1	1	1	1	1	1	1	1	1	0	0	0	1	1	1
2	Hydrocarbon	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	CO_2	1	1	1	0.3	1	0.5	0.7	0.7	0.7	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	Immiscible gases	1	1	1	1	1	1	0.3	0.3	0.3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	(Enhanced) Waterflooding																								
5	Micellar/ Polymer, ASP, and Alkaline Flooding	1	1	1	0.3	0.3	0.3	0.7	0.7	0.7	1	1	1	1	1	1	0.3	0	0.5	0.3	0.3	0.3	0.3	0.3	0.3
6	Polymer Flooding	1	1	1	0	0	0	0.3	0.3	0.3	1	1	1	1	1	1	0.3	0	0.5	1	1	1	0.7	0.3	0.5
	Thermal/ Mechanical																								
7	Combustion	0.3	0.3	0.3	0	0	0	0.3	0	0.3	1	1	1	1	1	1	0	0	1	0.3	0.3	0.3	0.7	0.3	0.5
8	Steam	0	0	0	0	0	0	0.3	0.3	0.3	1	1	1	1	1	1	0	0	0	0	0	0	1	1	1

0 = Not Applicable (N/A)

0.3 = Barely applicable

0.5 = Normal

0.7 = Recommended

1 = Strongly Recommended

Table 11: Scoring results for EOR methods

ULZ Formation, LLZ Formation & Tsagaantsav Formation: Result of the screening criteria for EOR methods										
	EOR Method	Compatibility			Averaged result			EOR ranking result		
		ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav	ULZ	LLZ	Tsagaantsav
Gas injection methods (Miscible)										
1	Nitrogen and flue gas	0.58	0.58	0.58	0.575			6		
2	Hydrocarbon	0.76	0.76	0.76	0.763			3		
3	CO_2	0.88	0.96	0.90	0.913			1		
4	Immiscible gases	0.91	0.91	0.91	0.913			1		
(Enhanced) Waterflooding										
5	Micellar/ Polymer, ASP, and Alkaline Flooding	0.61	0.58	0.64	0.608			5		
6	Polymer Flooding	0.66	0.58	0.66	0.633			4		
Thermal/Mechanical										
7	Combustion	0.45	0.36	0.55	0.454			7		
8	Steam	0.41	0.41	0.41	0.413			8		
0 = Not Applicable (N/A)										
0.3 = Barely applicable										
0.5 = Normal										
0.7 = Recommended										
1 = Strongly Recommended										

CONCLUSIONS

Oil exploration and production in Mongolia is in an early stage in terms of the daily production compared with resources reported in several reports. Therefore, contractors favor fiscal terms of the PSC. The “A” oilfield is in the production stage and large amounts of information can be acquired for field development and operation. Based on the field information, the “A” oilfield reserves belong to conventional light crude oil and the reservoir properties are good, but the recovery factor is low due to the low energy of the reservoir. Oil is expected to be displaced through solution gas and water drive, with respective recovery ratios of 5.5%–7% and 10%–14% based on various tests during exploration and appraisal in the field. In terms of improving the recovery ratio, fracturing is suggested to improve the well performances without considering its natural productivity. Water injection is suggested for the first stage of recovery. Although water injection is applied, the recovery factor remains low due to large strata dip. Thus, EOR technologies are considered for the “A” oilfield.

In this study, detailed processes for EOR screening and scoring were carried out on the three main formations using field information. Based on the results, CO_2 and immiscible gases (hydrocarbon; N_2) injections are the most promising EOR methods for the “A” oilfield. Each formation indicates different promising EOR methods; however, if the cost of EOR is considered, these may not be good options. The results can be used as fundamental information for decision-making about large investments in EOR together with more detailed studies, such as reservoir simulation. In addition, the rationality of the value selection of the recovery ratio in the “A” oilfield needs to be further studied and corrected along with the development of the oilfield.

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