COMBINATION OF UNDERGROUND CO2 STORAGE AND INCREASED OIL RECOVERY IN SU TU DEN-SW FRACTURED BASEMENT RESERVOIR

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ABSTRACT: The Su Tu Den-South West (STD-SW) field is located in the Cuu Long basin. The basement reservoir contained 450 MMstb oil initial in place. The current oil recovery after 7 years of production is about 87 MMstb. The area was produced by water injection with support of bottom aquifer. The producers, located at the crest of the high relief structure are exhibiting a high water cut. Since 2007, some producers with high water cut have been side tract to optimize the oil production of the reservoir that consists of granite. A kaolinezed weathered zone ranging in thickness from 4 to 55m covers the fresh granite. A Black Oil model was used to simulate the flow in the both weathered and granite zones. The main recovery mechanisms for this reservoir are imbibition and water/oil gravity drainage. The study results show that an economical attractive option for the field development is establishing an underground CO_2 storage after using EOR-CO_2 technique. The CO_2 injection lead to CO_2/oil gravity drainage of the oil and water present in the micro fractures of reservoir. The oil collected by the horizontal producers, resutling in incremental oil recovery of up to 15% of oil in place. To increase the amount of CO_2, that can be used for underground, water (and more oil) have to be withdrawn from the reservoir.

INTRODUCTION

Human activity since the industrial revolution has had the effect of increasing atmospheric concentrations of gases with a greenhouse effect, such as carbon dioxite (CO_2) and methane (CH_4), leading to climate warning and wather changes. Because of its relative abundance compared with the other greenhouse gases, CO_2 is by far the most important, being responsible for about 70% of the enhanced "greenhouse effect". The fossil fuels, which today provide about 75% of the World's energy, are likely to continue to remain the major component of World's energy supply for at least next 30 years. Thus, the World, especialy development contries, needs to reduce CO_2 emissions into the atmosphere while at the same time ensuring sustainnable economic development.

One of the possible approaches in mitigating anthropogenic climate change is carbon sequestration through the capture and diversion to secure storage of anthropogenic carbon emissions. Storage of CO_2 in geological media is likely to provide the first large-scale opportunity for concentrated sequestration of CO_2, being immediately applicable as a result of the experience already gained in oil and gas production, storage of natural gas, and groundwater resource mangement. Currently, CO_2 is used in enhanced oil recovery (EOR) operations at more than 70 sites in the world, of which more than 40 are in west Texas (USA), and in enhanced coalbed methane recovery. Acid-gas, a mixture of CO_2 and H_2S produced by gas plants, is already being injected into depleted hydrocarbon reservoirs and deep saline aquifers.

The STD-SW oil field, which located approximately 50km northeast of VungTau, in the Cuu Long basin, was identified as a suitable canditate field for high performace CO_2-EOR. The field consists of granit cut by several to many dykes/veins of basalt/andesite, and shows dual-permeability behavior. It exhibiets high permeabilities, has a large engough size, and is at the and of the oil-production lifetime.

In 2007-2010, an integrated study has performed to evaluate the suitability of using CO_2 injection for EOR. In the case the STD-SW basement reservoir suitable for CO_2 flooding, CO_2-storage is already achieved during the EOR operation. The incremental oil recovery form CO_2 flooding, estimated to increase the ultimate oil recovery by 8 - 15% of the Oil Initial in Place (OIIP), is achieved by oil swelling, reduction of oil viscosity, contribution to internal solution gas drive, and vaporization of crude. The CO_2 utiliztion of about 10 mscf per incremental barrel of oil includes the reinjected CO_2 production.

To address these results, a detailed geological study and laboratory experiments have been performed. The static and dynamic numerical models were created, history matched, and used for prediction of the EOR-CO_2 behavior. These simulations were complemented by model using g optimized grid to investigate reservoir processes in more detail.

Most anthropogenic CO_2 emissions in the South of Vietnam come from large point sources associated with power generation from fossil fuels and large industrial processes such as refineries and steel, cement and petro-chemical plants or high CO_2 content of oil producing fields. Carbon dioxide separated from flue gases, effluents, and during fuel-decarbonization processes could be captured and concentrated in to a liquid or gas stream that could be transported an injected in to basement reservoirs.

The geological study included various data sources such as outcrop analysis, geomechanic analysis, log data, formation microimage (FMI) analysis, production data (PLT/DST), seismic attributes and DFN modeling. The overview of the geological setting and parameters derived from this study is gieven in the following section. Also, production data of 7 years were used for constraining the geological model. The overall production history of the field is given in the production history section, followed by showing the results of history match. After a satisfactory history match including uncertainties was achieved, injection of CO_2 for EOR was simulated with the optimization of the field development plan for incremental oil recovery is described.

Geological reservoir characteristics

The Cuu Long basin is an Early Tertiary rift basin located off the southeast coast of Vietnam, covering an area of approximately 150,000 km^2. Block 15-1 is located in the northern part of the northern sub-basin, with its southwest corner is approximately 50km northeast of Vungtau city, in water depths ranging from 20m -55m.

The Su Tu Den structure is located at the northeastern part of Block 15-1 and represents the largest structural feature within the Block. The structures are a series of en-echelon paleo-basement highs, or “buried hills”, that were formed during the basin-rifting period before Early Oligocene, with drape-over closures within the overlying clastic intervals of the Upper Oligocene and Lower and Middle Miocene, particularly evident over the Su Tu Den structure.

There are 3 primary reservoirs associated with the Su Tu Den: the fractured Pre-Tertiary Basement; Lower Miocene B10 sandstone unit, drape-closed over the basement high of the Su Tu Den structure; Upper Oligocene C30 reservoir unit, also over in the Su Tu Den structure.

The STD-SW basement has a maximum structural relief of approximately 1500m, down to the mapped spill point of 4000m TVDss, providing a gross rock volume of 82MM acre-ft and covering an area of 60km^2. The basement rock of STD-SW is mainly composed of granite, with minor amounts of quartz monzonite, quartz monzodiorite, monzodiorite, diorite and dikes/veins, and is the main producing basement lithology in STD-SW and the neighbouring analogue fields of Bach Ho, Rang Dong and Ruby.

The basement lithology has, to a greater or lesser degree, been fractured and altered in response to stress and strain, with the maximum accommodation to the stress and strain occurring at the crest of the structures. Fractured intervals of granite rock are proven to be good reservoir and are associated with good oil production. It is generally recognized that the matrix porosity for the basement reservoir is nearly zero and that the open fracture system comprises 100% of the porosity and permeability of the reservoir. The porosity and permeability of the fractured basement decreases with depth from the crest of the structures.

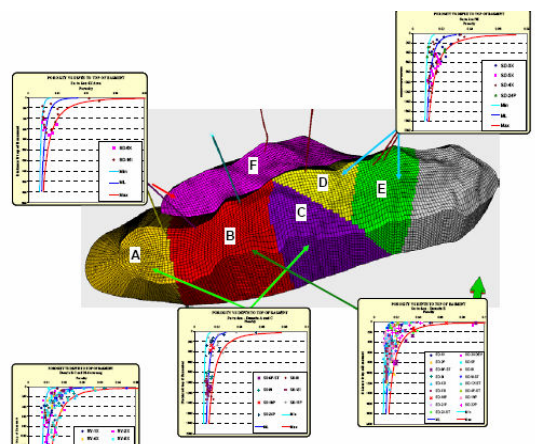

Figure 1 Structured block with parameters of STD-SW basement reservoir

The fractured basement reservoir contains porosity and permeability systems that are dependent on tectonic systems and thus can be segregated into smaller structural blocks (Fig. 1). Multiple structural domains exist within these basement structures. The domain boundaries are typically large tectonic features that exhibit evidence for strike-slip movement, often having structural relief, and may provide anything from a partial to complete cata-clastic barrier to communication and fluid flow. The basement reservoir is sealed by the thick sequence “D” shale, both vertically and laterally, with 340-600m of shale lying directly on top of the altered and fractured basement, at the structures crest.

The PVT properties ranges for all reservoirs are summarized in table 1 below. PVT data has been collected through an extensive fluids sampling and analysis program during the DST operations for all the Exploration and Appraisal wells. The reservoir fluid properties in the basement reservoirs in Su Tu Den Southwest are consistent across the field. In the Su Tu Den Northeast basement reservoir much more variation in fluid properties has been observed, with higher GOR's and Bubble Point pressures than observed in STD- SW.

Table 1 Summary of reservoir fluid properties

Properties	
Oil API gravity	35 - 36
Bubble point pressure (psia)	1150-1460
Flashed GOR (scf/stb)	200 - 250
FVF Boi (rb/stb)	1.10 – 1.20
Oil viscosity (cp)	0.8 – 1.2
Porevolume compressibility (psi-1)	9.0 E-6
Initial Pressure	4450
Temperature (deg F)	250
Residual oil sat. (%)	30 - 50
Initial water sat.(%)	15

For reservoir engineering purposes. The basement compressibility estimates are from detailed analysis of the tidal response data measured in the STD-SW basement prior to placing the field on production. Reservoir Temperature and Pressure are also summarized in the table 1. This data was acquired during the Exploration and Appraisal DST program and from the initial development wells in the Su Tu Den Phase 1 Area.

The basement reservoirs have relatively low natural reservoir energy provided by fluid and rock expansion. In order to supplement this energy water will be injected to provide pressure maintenance as is currently being done in the Su Tu Den Phase 1 Area. In order to maintain optimum field production rates, gas lift has been used to assist individual well production on an as needed basis.

G&G model

Fractured Basement Reservoirs provide a unique challenge with respect to reservoir modeling. Two types of modeling approaches are used to describe the reservoir. These are the Net Pore Volume Model and the Fracture Halo Model. The Net Pore Volume Model is used to generate HIIP volumes in a block/domain based model using porosity and net to gross with bulk rock volume to describe the net pore volume in a scenario and probabilistic methods. Fracture Enhanced Halo Model is used to characterize the reservoir with a fracture enhanced halo around lineaments described by seismic in the reservoir. This is used to further simulate fluid flow modeling. Both models are matched against historical data and or dynamic data to ensure quality.

The structural blocks had been described in the Fig. 1. Each structural block supposed to have similar fluid properties (GOR, finger printing, pressure, etc). However, the properties of fluid (from DST of the drilled wells) could be different from area to area within a block, such as SD-C. This could be understood as there are seal faults, dykes or massive (without fractures) basement "wall" themselves play role as the seals and they divided the structural block into structural reservoir domains.

The geologic model for fractured basement reservoir simulation in the STD- SW is based on the 'Fracture Halo' model. The Fracture Halo model assumes that the regions around major fracture systems as identified on seismic data contain fracture systems that comprise the bulk of the porosity and permeability in the fractured basement reservoir system.

An illustration of this concept is shown in Fig. 2. The porosity associated with each seismically identified fault feature is quantitatively modeled using a lateral and vertical porosity decay function as shown in Fig. 3 below. The halo model porosities are tuned to match the total OIP as calculated using the Net Pore Volume model

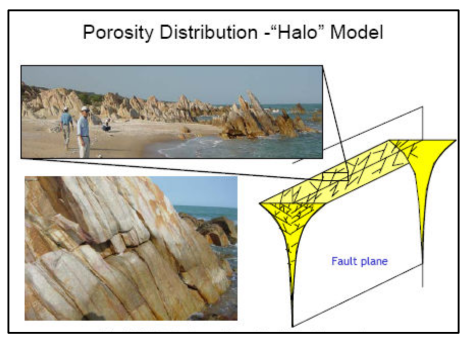

Figure 2 Fracture porosity Halo concept

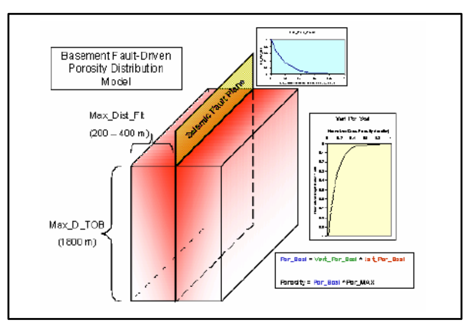

Figure 3 Fault halo porosity model

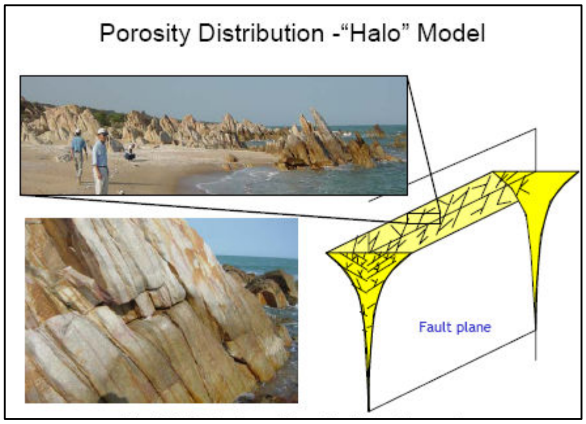

Figure 4 Permeability distribution function

The model permeability is then populated as a function of the porosity. There is some minor permeability modification in the top 50 meters of the basement to account for any permeability reduction as a result of meteoric alteration. Fig. 4 illustrates the permeability function. Permeability values were matched against productivity indexes from DST data and producing wells The STD-SW models were constructed by using major bounding fault features to define the outer boundaries and major internal boundaries. The grid was constructed based on these major features.

All other seismically identified fault features were used to populate the porosity and, in turn, the permeability, in the detailed geologic model. The grid cell sizes in the geologic model are approximately 50m x 50m with 50-meter thickness. For flow simulation the fine-scale geologic model was upscaled into a coarse grid model with 100m x 100m grid cells with 50 meter thickness. The example of Su Tu Den SW model construction process is outlined in Fig. 5 below.

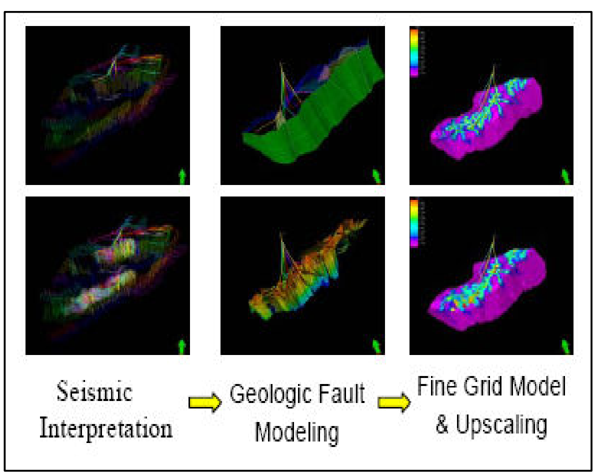

Figure 5 STD Model construction process

Production History

Phase 1 prodution from the STD-SW basement reservoir commenced on 29 October 2003 from seven producers (1P to 7P). Initial production was under natural depletion. Water injection commenced a year after intial production from the converted 2P well. Since the initial production period, additional producers and injector have been drilled to maximize oil recovery. The current oil rate is about 10,000 bbl of oil per day (Figure 6).

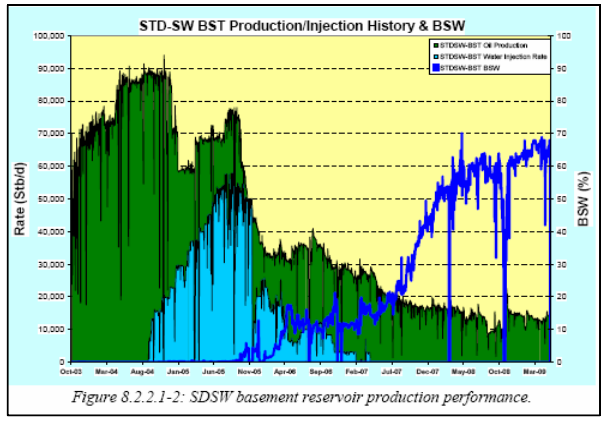

Figure 6 STD-SW basement reservoir production performance

Crude oils produced from wells in the STD-SW structure show that bubble point pressures and gas oil ratios are lower than 1,300 psia and 250 scf/bbl, respectively. Therefore solution gas and secondary gas cap drive mechanisms are minor and not considered to be major energy sources for supporting oil production. The area of STD-NE part shows that bubble point pressures and gas oil ratios are higher than 4050 psia and 930 scf/bbls, respectively. Therefore solution gas and secondary gas cap drive mechanisms are considered to be of major energy sources for supporting oil production.

Secondary gas cap would bring the benefit of oil incremental recovery if gas cap expansion could be well managed by maintaining reservoir pressure.

Compaction of the fracture system is usually considered as the primary energy support for oil production in basement reservoirs. However, based on the pressure evolution in STD-SW, the average reservoir pressure behavior indicates that the presence of aquifer feeding in the reservoirs– see Fig 7. In the Su Tu Den reservoir has been confirmed that there is pressure support from a bottom aquifer as mentioned above.

The behavior of all parts of STD field as a whole is similar to that of STD-SW basement reservoir, which had clearly experienced aquifer influx. The additional energy can be from the following separate aquifer source or any combination of sources:

- Natural aquifer.

- On lapping clastic reservoirs.

- Secondary porosity system, this case assumes the wells produce oil initially from high permeability fractures then later have significant volume feed in from lower permeability systems.

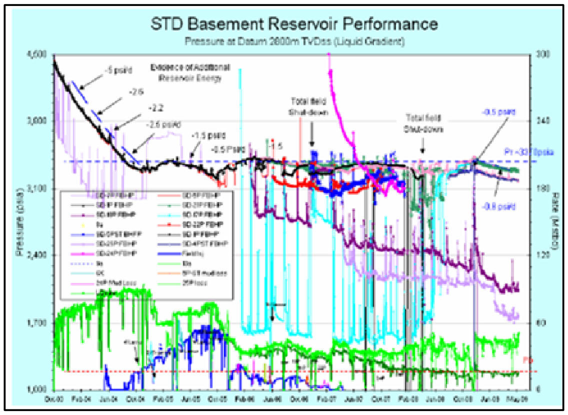

Figure 7 Pressure evolution in SDSW basement reservoir

The behavior of all parts of STD field as a whole is similar to that of STD-SW basement reservoir, which had clearly experienced aquifer influx. The additional energy can be from the following separate aquifer source or any combination of sources:

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History matching

To achieve a history match, first, the pressure of the producers was matched. Next, the simulated movement of the oil-water contact was compared with observed field data. Then, the water cut of individual wells were matched. After a satisfacory history match was achieved, the main uncertain parameters were modified and the dynamic model was again history matched using the modified parameters.

Several reservoir simulation models have been built to cover the range of potential drive mechanisms. As discussed in the section above of Drive Mechanism, the closed system model does not adequately account for all the reservoir energy currently seen in the STD- SW area. To capture the most natural reservoir energy another model was constructed with an infinite acting aquifer. Currently additional models are under construction to further investigate the potential drive mechanisms. For field development planning, various scenarios are evaluated using the infinite acting models.

Current reservoir simulation studies indicate that there are numerous reservoir models that could match the production and injection history data for a given initial oil in place volume and rock compressibility. These models still depend on a volume of outside additional energy and influx rate from this energy source for supporting the pressure in the current production area.

Connected Initial Oil In Place is about 462MMstb excluding the SD-3X/6X area, and three aquifers provide energy support for the current production area. It is assumed that the influx index of the aquifer is 240 stb/day/psi. With this assumption current influx rate of the aquifers is about 40,000stb/day.

This model runs with production data up to end Jun 2010 and actual pressure from down hole gauge of the six production wells (SD-1P, SD-3P, SD-4P, SD-5P, SD-6P and SD-7P) are very well matched with calculated pressure from reservoir simulation model (See some illustrations history match results in Fig 8. And Fig 9).

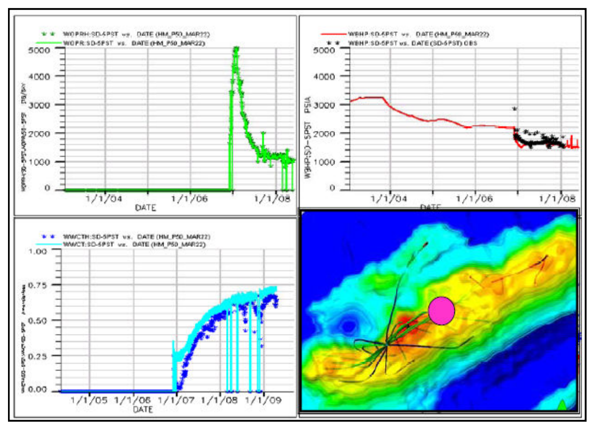

Figure 8 History match for the Central are wells (5P)

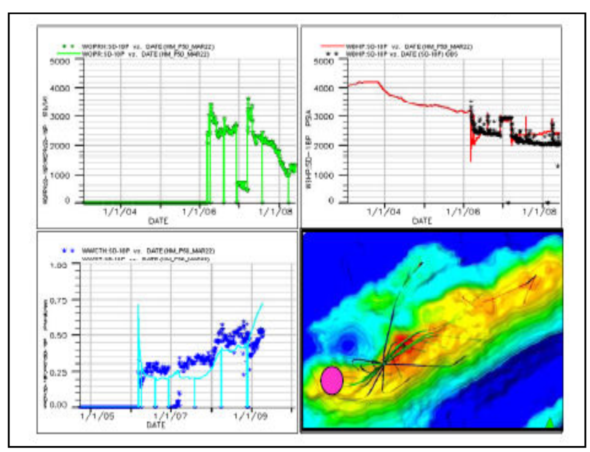

Figure 9 History match for Western area wells (18P)

The field was produced by water injection and by bottom aquifer supporting. When changing the reservoir management strategy from bottom water influx to crestal gas injection, uncertainties concerning the gas injection and liquid-withdrawal rate have to be considered.

To capture the major uncertainties, some parameters such as residual-oil saturation, local permeability, relative permeability curves were modified and a history match was perform using the changed parameters.

The STD-SW basement reservoir was produced very fast in the period 2003 - 2005. But since 2006 the reservoir has been produced slowly, then the imbibition of the water from the macro fractures into microfactures could keep pace with the upward movement of the water-oil contact. Increasing or deacreasing the local permeability by a factor of two results in very similar history matches. The difference between micro and macro fractures is large in all cases. Because of the low production rates, only limited coning in the local modification system was observed.

The relative permeability has some influence on the history match; for some wells the history match is improved, and for others it is worse. The volumes of movable oil that are present in the various depths of the reservoir have the largest impact on history matching. To achieve a history match for a change in residual-oil saturation of 5% of the pore volume, the porosity has to be increase or decreased accoridngly. Hence, the volume of movable oil remain the same, resuting in a good history match.

CO2-EOR performed because of CO2 storage in basement reservoir

Oil recovery from fractured reservoir suffers from large volumes of oil in the matrix (or micro fractures in granitic basement reservoir) that is bypassed if a viscous-force drive mechanism is used. In USA, CO_2 injection has been the primary method to increas oil recovery in carbonate reservoirs, which are fractured. The popularity of CO_2 project in the USA seems to be closely related to the abundant availability of natural sources of CO_2 and various other technologies have been considered to recover more oil from fractured reservoir. Laboratory experiments showed that in-situ conbustion could be aviable process in this kind of reservoirs. Steam injection into heavy oil fractured reservoirs has been successfully field tested and simulated and extended to the recovery of light oil. Miscible gas injection for fractured reseroviors has been investigated experimentally. Beside on that, surfactant injection to alter the wettability has been suggested, and the limitations and the difficulties of these methods have been determined.

For the case of STD-SW basement reservoir, a detailed fluid analysis, including swelling and slimtube tests with various gases, has been simulated. These tests and calculations showed that for the CO_2, the minimum miscibility pressure is lower than the initial reservoir pressure, but for other gases, the MMP is greater than initial reservoir pressure. For the methane, even at 5000psia, only 60% recovery at 1.2 porevolumes injected could be recovered in a slimtube simulation. The reason for this high MMP, as seen also for other oil fields in the Cuu Long basin (BachHo and Rong), is the low fraction of middle components present in the oil.

Owing to the high temperature and granitic fractured basement of the oil field, the reservoir rock is mixed-wet. Imbibition of the water from the fracture system into the micro system resulted in effective recovery of oil. The production analysis and simulation were performed in 2009 showed that residual oil saturation toward water is very high in areas deep below the oil-water contact moved up very fast while 7 years of production.

The good oil production rate in the water injection period and high temperatures along oil column leave limited scope for improving imbibition by using chemicals. The high reservoir pressure and large reservoir depth make steam injection an unattractive method. Gravity-stable miscible CO2 injection was identified as the most attractive method to improve the recovery for this reservoir.

During the development of combination under ground CO_2 storage an EOR of the STD-SW oil field, the reservoir dynamics can be captured by simulating continuous CO2 injection. Three phases could be distinguished during CO2 injection:

- Increasing the pressure to the designed MMP of the Top part of reservoir.
- Withdrawal of fluids (oil and water), enabling injeciton of the equivalent CO2 volumes.
- Shutting in of liquid producing wells because of CO2 backthrough, hence slower increase in the injected CO2 volume. Drilling some more liquid producing wells in the bottom aquifer to keep reservoir pressure not excced the initial reservoir pressure.

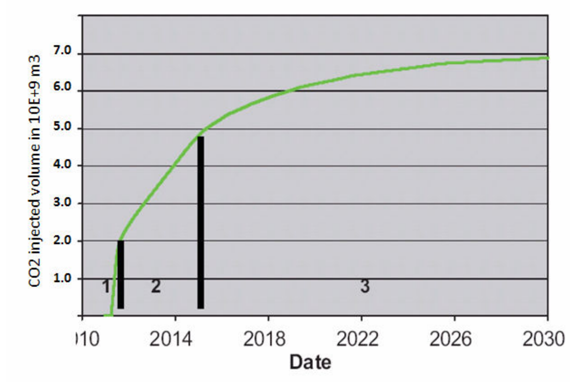

Figure 10 Cummulated CO2 gas injection with 03 phases

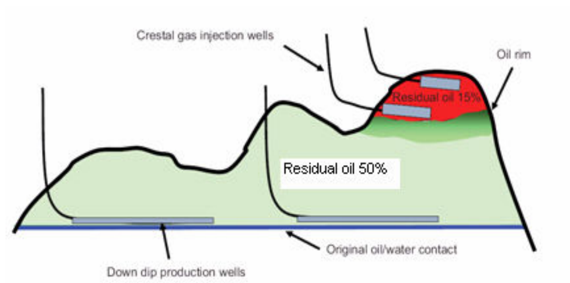

Figure 11 Schematic cross section through STD-SW reservoir with the injecters and producers.

The planned CO_2 injection wells are situated on the screst of the reservoir. Injection in the top of reservoir with higher initial injectivities are observed in the model compared with injecting deeper in the reservoir. The CO2-oil contact in the fractures is descending with the increas in pressure. As indicated in Fig 10 approximately 2 billion scm of CO_2 canbe injected until the initial pressure of the reservoir is reached.

To be able to inject larger amount of CO_2, liquids have to be withdrawn from the reservoir. To avoid CO_2 backthrough into the wells producing the liquids, these are planned as horizontal wells group close to the original oil water contact (4000mTVD). This position ensures that no CO_2 can move below the spill point of the reservoir and that these wells can be produced for along period of time before the CO_2-oil contact in the fractures reaches this depth in the reservoir.

The slope of the injected CO_2 volume in phase 2 is dependent on the withdrawal rate of liquids (oil and water). The equivalent volume of reservoir liquids withdrawn can be injected into reservoir. Initially, oil located close to the oil-wate contact is not mobile. Therefore, the wells are producing oil with high water cut. The CO_2 injected will mobilize oil because of the lower residual oil saturation vs. gas compared with the residual oil saturation vs. water, and oil bank is formed. When this oil bank has reached the wells in the fractures, these wells start producing oil with low water cut, ultil the CO_2 contact in fractures reaches the wells, and they are closed in. As soon as the first horizontal liquid producing well group experiences CO_2 production by backthrough, its production rate is decreased with CO_2 production rates. The lower production rates lead to smaler drawdowns and less CO_2 producing, accordingly. Because of the decreasing production rates and wating for the stable of CO_2-oil contact, the CO_2 injection rate is reduced.

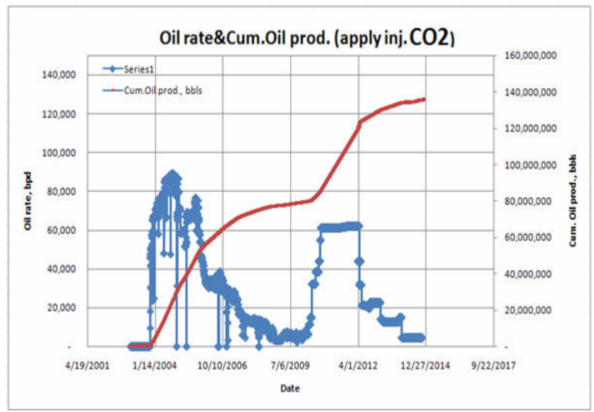

Figure 12 Oil rate and cummulative of STD-SW production with CO_2-EOR

Simulation of continuous CO_2 injection gives an idea about volumes that can be injected. Cyclic CO_2 injection was simulated to investigate some of the detail, such as the minimum pressure in the system and working-volume/CO_2-cushion ratio. During the development of he field into CO_2 storage the injection volume will be increased steadily. The study case of cyclic CO2 injection, shows the net injection volume for the CO_2 continuous injection and cyclic injection with the small deviation exits between the maximum annual injected volumes for cyclic vs. continuous injection. These can be explained by small differences in the amount of liquid that has been withdrawn. Fig 12 shows the oil production performance with the good results of CO2-EOR combined undergroud storage.

The uncertain paramers, such as residual-oil saturation and the permeability of micro fractures, were changed to simulate ranges of production forecasts. Before predictions were performed, the simulation model was history matched for the changed parameters. The macro fracture permeability have much small inpact on CO_2 injection and oil production. The reason for the small sensitivity of the macro fracture permeability is that, in all cases, the macro fracture permeability is very large compared with the micro fracture permeability.

CONCLUSIONS

Geological storage of CO2 is an immidiately-available means of reducing CO2 emission in to the atmosphere from major point sources in area of southern of Vietnam. In the case of oil basement reservoirs, application of the CO2 injection, together with high relief of attractive miscible characters, provides a powerful tool for optimizing oil production.

Among the issues that need addressing is the evaluation of potential sites, means of sequestration and capacity estimation based on insitu characteristics and CO_2 properties and behavior ate these specific conditions.

From the series of simulation results, we believe that CO_2 gravity drainage could significanlty enhanced oil recovery after water flooding in the naturally fractured basement reservoir of STD-SW field. The study results indicate that the fracture systems could improve the mobility of residual oil by smearing out from micro fractures, which contain the oil bypassed after water flooding. During CO_2 gravity drainage after water production, water in rock is moveable because of high water saturation indicating that much water would be produced with oil.

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