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Reservoir Redevelopment by CO2 Injection Using Compositional Model Simulation in Carbonate Oilfield

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Reservoir Redevelopment by CO_2 Injection Using Compositional Model Simulation in Carbonate Oilfield

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I. Abstract

1.1 Objectives/Scope

The SK field is a carbonate oil reservoir with current oil production decreased from +/- 28,000 BOEPD to around 10,000 BOPD due to highly decline rate. The objective of this study is to identify and propose CO_2 Injection in order to sustain and increase the matured oilfield production & oil recovery by using the economic feasible CO_2 EOR Technology. From this model and simulation study we found that this CO_2 EOR Injection can be increase the recovery factor of this field by $\pm$ 7-9% of inplace.

1.2 Methods, Procedures, Process

The challenges of this study is to get the representative model with limited reservoir data by using some correlations. The reservoir is also quite complicated since the production data indicated that there are some fractures and permeability streak. Moreover, the well was completed with the poor quality of cementing bond and it was a challenge in the history matching process as well. EOS modelling is an essential part to build a compositional model. Being able to improve EOS model accuracy would make reservoir model more representatives. The number of component in EOS model also gives significant effect to running time of simulation and we have examined some EOS model to get the fastest running process. In development scenario, CO_2 would be injected through top structure considering it's a thick reservoir and the injection pressure was set to near minimum miscible pressure to get near miscible condition.

1.3 Results, Observations, Conclusions

The result of this study by using CO_2 EOR compositional simulation showing the increasing of Oil Recovery by 4.03 % over the baseline (means another 11.96 MMBBL additional oil will be recovered by applying this technology to this oilfield) which is required 4 additional infill production well with 2 injection well).This paper will discuss the process of the simulation model from static modelling up to dynamic modelling through data gathering, EOS modelling, History matching up to the oil and gas forecasting by using Compositional Model. Using compositional model means the numerical computation would be more complicated than the conventional black oil simulation model and needed more running time, which will be more than triple or fourth time slower that the conventional one. Therefore, in order to boosting the running time of the simulation of this model, we are using 8 Core of the hardware of the computer to run our model. There are many interesting we found during our study by using this kind of model (Compositional Model) and by applying CO2 EOR injection with this model.

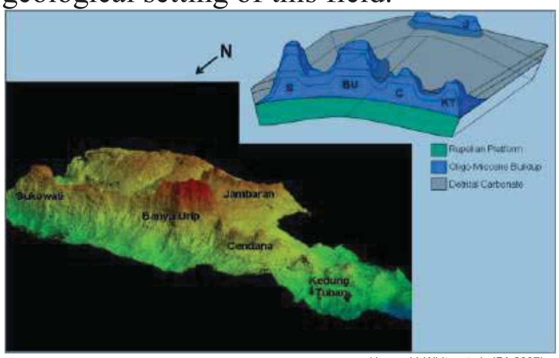
Keywords: CO2 Injection. Compositional Model, EOS modelling, History matching

II. Introduction

The "SK Field" was discovered in 2001 and came on stream in 2004 from the first two wells which initially produced 5,000 BOEPD. The peak of production from this field was $\pm$ 28,000 BOEPD five-fold increase) in 2008 from 32 infill wells which is drilled between 2001 to 2008 from 5 POFD that has approved by BPMIGAS/SKKMigas. Currently, the oil production has been decreased to around 10,000 BOPD after reaching its peak production in 2008.and the field has very highly decline rate due to its characteristic of heterogenous platform carbonate reservoir.

The initiation of this study by Pertamina UTC in order to optimize its recovery and to counteract its decline production by using EOR. From the previous study, which is approved as a Plan Of Development (POD) phase 5 by SKKMigas in 2015, is proposed to implement water injection by using black oil simulation model. Its scenario is to drill several infill wells and 3 injection wells and it will increase its recovery less than 5%. In 2017, the model from this POFD/study was evaluated and found that the actual rate of production which decline continually is not matched with prediction result from the model. It implies many changes to the next study consider the water injection realization and try to implement the other EOR method to this field, i.e. : CO_2EOR .

SK Field is a strong water drive Carbonate reservoir which has been producing for more than 13 years with its current Recovery Factor is 36% (primary recovery) and oil saturation is still high above 55% with good pressure about 2600 psia (still above bubble point pressure 2454 psia) and is expected to reach its ultimate recovery by 55-60% as well. Fig.1 shown the characteristic of the geological setting of this field.



(James V. White, et al., IPA 2007)

Fig.1 the Carbonate reservoir characteristic of the SK field

The characteristic of this reservoir is classified as : light oil (API approximately 39) with medium viscosity (at reservoir pressure condition), average permeability $\pm$ 150 md, temperature 275 deg F and the main composition of the fluid is between C5-C12. Its criteria as input to EOR screening program reveals that miscible CO_2 injection is suitable to implement in SK Field and this is supported by prior empirical studies. Most cases in the worldwide shown that miscible CO_2EOR injection can increase recovery factor by 10-15%.

In reservoir, the process of miscible CO_2 involves interaction between oil and the injector fluid (CO_2). The miscible agents will mix in all proportions with the oil to be placed and it form a single-fluid phase that will generate X-shaped relative permeability curve. However, to be mentioned, there are some areas in reservoir that are not reached with full-miscible process. Although this immiscible process is not considered, it has many adventegous effect to increasing recovery by reducing viscosity and change the mobility of the oil. In order to depict all these processes, compositional simulation and EOS modelling is needed as fundamental requirement. In this paper, the key explanation will be emphasized in EOS characterization and CO_2 injection scenario while the other step are frequently used in a normal development field study

III. Equation of State Characterization

Miscible CO_2EOR simulation requires prediction of the complex phase equilibrium during EOR processes. Therefore, fluid characterization in CO_2 flood reservoir simulation was an essential part. Its objective is to compare and to match between regressed EOS and PVT laboratory data. There are two types of fluid analysis in laboratory to match EOS model, i.e. :

- routine fluid analysis including Differential Liberation (DL), compositional analysis (CA), Constant Composition Expansion (CCE) and Multi-stage separator test) and
- special fluid analysis, including Slim Tubes and Solubility-Swelling Tests.

Routine fluid analysis is used as an inputs to the reservoir and surface facilities simulation while special fluid analysis is performed to determine the influence of CO_2 to the original reservoir fluid.

In this study, EOS Modelling was developed by CMG Winprop PVT software. Laboratory data was matched for AA-06 and AA-29. In summary, EOS characterization was purposed to develop EOS for simulation, to predict oil swelling due to CO_2 injection, to estimate the MMP using empirical correlations, and to examine the effect of adding intermediates oil into the injected CO2 on the MMP and oil recoveries.

The fluid was taken from different wells; AA-06, AA-14, AA-18 and AA-29. The first three PVT (AA-06, AA-14 and AA-18) was sampled from the separator and evaluated by recombination method while AA-29 was taken by bottomhole sampling method. The tests are tabulated in **Table 1**..

It was believed that AA-06 was more representative PVT test because the PVT was taken at earlier production time which is near the initial conditions. Nevertheless, the significant difference in reservoir temperature, Rsb and the molecular weight of heptanes plus **(Table 2)** may cause significant difference calculation result in MMP value between AA-06 and AA-29.

Both PVT data of AA-06 and AA-29 were utilized in tuning of the EOS by using modified Peng-Robinson method. The preliminary results did not have a good match between basic EOS and laboratory data. Adjustment in some parameters was required to obtain appropriate EOS model. One of parameter that should be tuned is single heptane plus (C7+) fraction properties. Since this fraction was lumped from thousands of compounds with carbon number higher than seven, the properties of the heavy component of C7+ are usually not known precisely. Thus, it represents the main cause of inappropriate EOS model and reducing its accuracy. The regressions were performed to improve EOS accuracy by adjusting some parameters including V shift coefficient, viscosity parameter, binary interaction coefficient and weight factor.

Acceptable number of components was one of the factor to determine running time. Computational process is more complicated and complex in line with the number of component and it consumes more time to simulate the dynamic model. Therefore, after regression was completed and the result was satisfactory match, the components was lumped into several components. AA-06 was lumped into 6 components while AA-29 was lumped into 7 components. Lumped component was tabulated in **Table 3.** In EOS AA-29, component of C7+ was grouped into three dummy components (HYP01, HYP02, HYP03) and it was fair enough as a representative model. The next step was to match the points of Rs, Bo, etc. from lumped EOS Model data with the points from PVT laboratory data. Overall, the quality of matches was acceptable except for the swelling test. The result of the test shown an unusual value of swelling factor which yield more than 200% value after injection of CO_2. Thus, swelling factor was not included in EOS matching process of PVT AA-6.

In the last PVT test (AA-29), slim tube test was conducted to measure minimum miscible pressure. In this paper, there are no further explanation about MMP but experiment results only. MMP result of slim tube experiment for the AA-29 fluid sample is about 2800 psi as shown in **Figure 2**

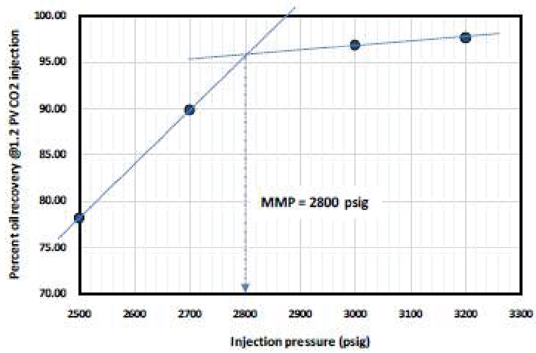


Figure 2. MMP Slim Tube Experiment AA-29

In order to validate the EOS characterization and compare the MMP measured slim tube experiments, the slim tube simulation using EOS model was performed. The slim tube model was developed using a simple 1-D, fully compositional and single porosity. Oil recovery factor at 1.2 PV CO_2 injection was recorded and plotted as a function of injection pressure **(Figure 3).** The MMP calculation from some correlations was also conducted to compare it with the result from experiment and simulation and select the one with the least error. Once the correlation has been selected, then the correlation from the other PVT can be made.

The summary of estimation MMP with different correlations can be seen in **Table 4**. Based on slim tube test and numerical model, the most representative empirical correlation is Cronquist correlation. The correlation estimates the MMP for AA-29 relatively close to slim tube and numerical model results.

IV. Reservoir Description

Accurate permeability determination is critical to improve reservoir description. Distribution of rock properties in the model was estimated by limited data and the accuracy had to be considered due to the lack of SCAL data. The source of SCAL was only from two wells which represented 36 wells total in the field. The magnitude of porosity and permeability was quite large and it indicates that the reservoir is very heterogeneous.

In this study, a permeability log using a non-parametric multivariable correlation utilizing combination of five existing logs (DTCO, GR, NPHI, PEF, and RHOB) was generated independently from the porosity. The predicted permeability values were compared to the actual values in a cross-plot to establish the validity of a regression and to measure how widely the predicted values were dispersed from the actual values **(Figures 4)**. The results show that a good correlation exists between calculated and measured permeability values. The figure 5 showing the consistent behavior between porosity and permeability although, as stated earlier, the permeability was determined independently from porosity

Similar to distributing porosity to unsampled locations, permeability was distributed through Sequential Gaussian Simulation (SGS) approach. By using rock typing division through Flow Zone Indicator (FZI) approach, the distribution of rock typing in the geomodel can be done. All samples with similar FZI values belongs to the same petrophysical properties, reservoir quality and flow zone indicators will lie on the same straight line with a unit slope. The intercept of the unit slope line, designated as the Flow Zone Indicator(“FZI”), is a unique parameter for each hydraulic unit **(Figure 6).**

Furthermore, the appropriated sets of reservoir properties (relative permeability, capillary pressure, and irreducible water saturation) are defined for each rock type. SCAL core data (Kr and Pc) from SS 2 and 15 were selected and normalized through J-function accordingly following rock typing that was defined through FZI **(Figure 7)**.

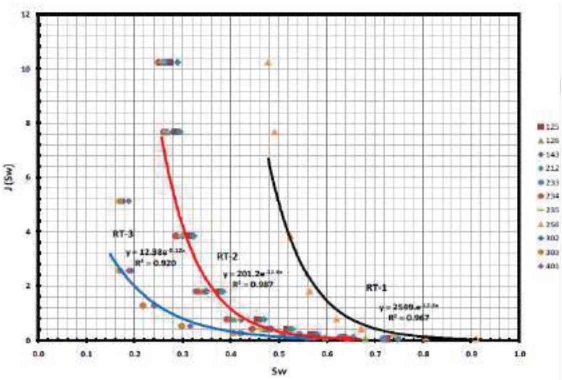


Figure 7. Capillary Pressure curve after denormalized

V. Initialization and History Matching

The static model was built in Petrel and the dynamic model was generated in CMG GEM model with up scaling the fine grid to 26 layers. The grid blocks in X and Y directions remain the same without being upscaled to coarse grid blocks. The grid number is 271 x 177 x 26 single porosity grid system with a total number of grid blocks of 1,247,142. Grid cell dimensions are 100-ft in X and Y directions and grid thickness varies following the grouping of the layers. The relative permeability, PVT and other pertinent data used in this study has been discussed earlier in the previous chapters. The simulation model uses a compositional model from AA-29 EOS PVT model. The dynamic model was successfully conducted a stabilization test by closing all producer and injector wells. Initial oil in place was also checked and its error is below five percent.

The next step is history matching process to validate the model which using the production data as its constraint. In this simulation model, the liquid production was used as the constraints. During history matching process, there are no transmissibility multiplier and/or proe volume modifier adjusted. The parameter that were altered to match the constraint were Krw and completion data of the wells. These parameters were altered because water production increased suddenly at a certain point after the choke size was open due to poor cement condition causing water channeling behind casing. The oil and water production shows a good match after adjsutment in vertical transmissibility. The pressure matching confirm that pore volume and aquifer supply of the model is quite accurate **(Figure 8)**. However, the gas productions at the middle time interval shows large separation between actual and simulated results because of measurement discrepancy in history data. It was proven with the pressure data that shows the reservoir is still in undersaturated conditions and gas production should follow the trend of oil production.

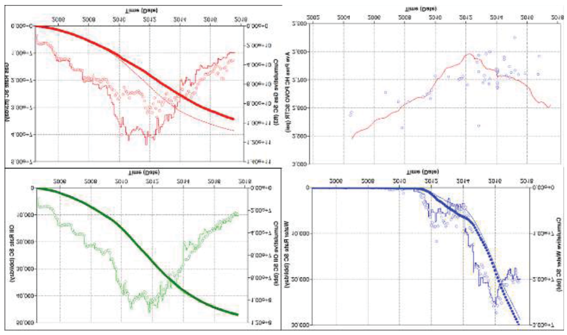


Figure 8. History Matching result of SK Field

VI. CO_2 Flood Scenario

Once the simulation model had been reasonably matched to the production and pressure data, the model was used to forecast the future production scenarios and the effects of major operational shifts and strategies to maximize the opportunity of a positive economic outcome. Since the reservoir has tall carbonates build up, it requires a significant amount of CO_2 to reach 1.0 PV CO_2 injection volume. After running several scenario, it was found that the best strategy of CO2 flood in this field is to inject CO2 from the top most of the structure using a gravity stable flood mechanism.

In this study, two scenarios were run; CO_2 pilot and CO_2 fullfield scenarios. CO_2 pilot simulation was objected to investigate the CO_2 flood to increase oil recovery and to reduce investment risk when applying the full field CO_2 flood. Therefore, the CO_2 pilot should mimic the condition of the full field CO_2 flood.

The pilot criteria were selected based on injection well location, properties of the reservoir and location of observation wells. To minimize the cost of drilling new wells, the injection well and observation wells must be selected from the existing wells. The well converted to be an injection well should be located at high structure since the flooding will be from the top of the structure and the location of the pilot should have good reservoir properties. The injection well should be near the observation wells so the CO2 response can be seen quickly.

These criteria met the AA-27 as an injector (convert form producer) and its surrounding wells, AA-02, AA-07, AA-08 and AA-21 as observation wells **(Figure 9).** This makes a pattern size of CO_2 pilot about 30 acres. Observation wells was produced with near miscible pressure and its perforation was opened approximatley 100 ft below the top surface.

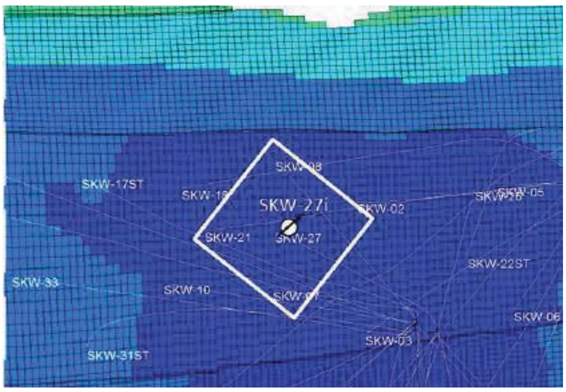


Figure 9. Pattern of CO_2 Injection Pilot

With these criteria, the CO_2 saturation distribution laterally and vertically after 1.5 years CO_2 injection can be seen in **Figure 10**. At this year, the CO_2 has been reached the observation wells and CO_2 has created a gas cap as expected and pushed slowly (drained) the oil downward into the production wells (gravity drainage mechanism).

The reservoir properties will affect the CO2 flow. It will flow faster in high permeability area, slow down in lower permeability and may not flow in poor permeability area. The difference in reservoir properties and in distance to injection wells affect well responses **(Figure 11)**. Some wells respond it immediately (AA-06 and AA-07), some are delayed (AA-12A) and the other wells have not responded at all (AA-29).

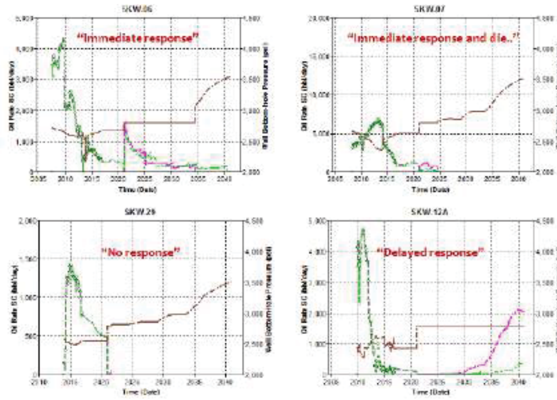


Figure 11. Different types of CO2 response in production wells

Sensitivity of injection rate was performed in pilot model to observe how fast the response of varied injection rate. The maximum rate was set to 5 MMSCFD due to the limit in supply from this field. The results indicate that varied rate of CO_2 injection affects the breakthrough time from observed wells and oil recovery. Case scenario with 5 MMCFD has the fastest breakthrough time (less than 4 month) and has good oil recovery gain (**Figure 12**).

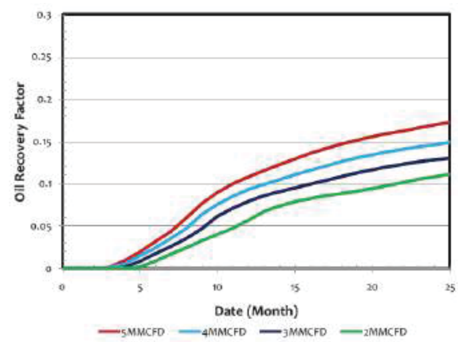


Figure 12. Effect of varied injection rates to oil recovery and breakthrough time

The good response in CO_2 pilot encourages full scale implementation of CO_2 injection. The injection concept similar to the pilot. The CO_2 will be injected at the top of the structure to form a gas cap. Oil will be drained from the top part of the reservoir and push downward into production wells or accumulated in oil column. The production wells will produce the oil from the top structure down to oil column. The completion data will be open from top to bottom above the WOC. The completion of these injection wells was open only ~100 ft below the top structure with total injection rates 50 to 100 MMCFD.The completion will be closed and recompleted down if it exceeds a certain GOR limit (10 Mcuft/Bo). Injection BHP constraints was set to 4500 psi a little bit below the fracture pressure while production wells BHP were set 2800 psi at MMP.

The scenario of miscible CO_2 injection was run for 20 years with nine new injection wells and addition AA-27 injection well. The new wells were distributed at the top structure while production wells were using existing 36 wells (**Figure 13**).

After 20 years injection, CO_2 saturation is not evenly distributed in the reservoir depending on the structure high and properties of reservoir. The CO2 will fill the top most part of the reservoir first then it will fill downward as CO_2 volume increases. Only a small protion of this high thickness reservoir filled by CO2 volume but the production response remarkably good.

Three different injection rates were run in these scenarios. They are 53 MMCFD, 77 MMCFD and 100 MMCFD. The results are graphed in **Figure 14**. It is noticeable that after CO2 was injected for one month, the pressure increases immediately above MMP and remains at the same pressure until several wells well were closed due to exceeding the GOR limit. The 100 MMCFD injection rate yields the highest incremental oil production rate. The peak gain is almost 13000 bbl/day. Meanwhile, the scenarios with 77 MMCFD and 53 MMCFD yields about 12,000 bbl/day and 7,000 bbl/d, respectively. The oil production response from 100 MMSCFD injection rate yields highest peak rate compared to the responses from other injection rates but later on the oil rates at 100 MMSCFD case tend to decline and cease faster because of the GOR limit.

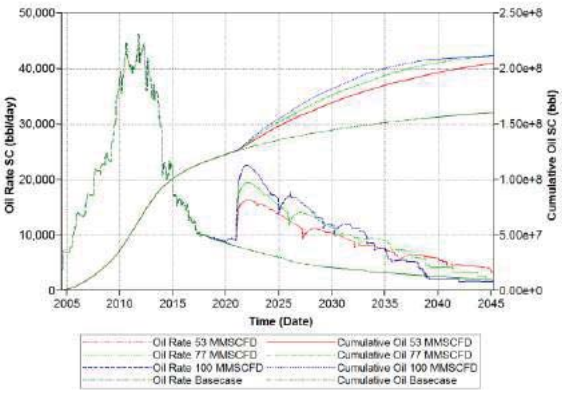


Figure 14. Full-field CO_2 flood forecast with varied injection rates

In order to choose which the best scenario to be implemented in the field, CO_2 Utilization was used as an indicator to evaluate its efficiency. Base on net CO_2 Utilization, the best injection rate from three cases is 77 MMCFD as encapsulated in **Table 5.** This case will increase at least 18.11 % recovery factor from current prodution and 14.38% from basecase. It shows that CO_2 injection in SK Field was successfully optimize the production.

Table 5. Comparison results for different CO_2 injection rates

CO2 Performance Parameters	CO2 Injection Rate, MMCFPD		
	53	77	100
Recovery Factor, % OOIP	14.16	18.11	18.41
Incremental CO2 RF, % OOIP	5.41	9.36	9.66
Cum CO2 Inj, BCF	390	565	692
Cum CO2 Prod, BCF	210	292	316
Gross CO2 Utilization, MCF/STB	23.4	19.6	23.3
Net CO2 Utilization, MCF/STB	10.8	9.5	12.6

VII. Conclusion

1. EOS PVT for SK field has been completed and ensure that injecting more CO2 still swells the oil despite significant CO2 content is apparent.
2. Slim tube modelling has also been completed. The MMP result from this model appeared to be closed to the Cronquist correlation.
3. Permeability estimation has been improved using a non-parametric multivariable correlation. The estimation using Flow Zone Indicator (FZI) approach with sets of reservoir properties (relative permeability, capillary pressure, and irreducible water saturation).
4. There was no transmissibility multiplier and/or pore volume modifier adjusted during history matching process which provides greater confident in prediction of the reservoir and field development forecasting.
5. CO_2EOR pilot injection with rate 5 MMSCFD at about 100 ft below the top structure is selected. The simulation results show a total increase of 66,000 stb of oil gained duringthe pilot period (6 months).
6. Three different injection scenarios is running (from 53 to 100 MMSCFD) for 20 years of prediction with the best result is by using injection rate of 77 MMSCFD will give RF is about 9.4% above the baseline

VIII. Reference

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2. Pertamina : “Laporan Akhir Pre-feasibility Study EOR CO2 Lapangan SS“, 2018 (unpublished)
3. James V. White,”Temporal Controls and resulting Variation in Oligo-Miocene Carbonates from the East Java Basin, Indonesia : Example from the Cepu area “ IPA, 2007

IX. Table, figures, and appendix

a. Table

Table 1. PVT Properties of Different Well

Well	Date	Interval (ft)	Pb (psig)	Pres (psig)	T (F)	BoSb	BoDb	RsSb	RsDb
AA-6	28-Jul-07	6620-6660	2405	2814	275	1.631	1.885	810	1112
AA-14	30-Dec-09	7180-7202	2667	2721	269	1.761	1.955	1084	1297
AA-18	8-Feb-12	8260-8310	2835	2840	284	1.637	1.869	930	1192
AA-29	26-Dec-13	6300-	2440	2697	260	1.605	1.986	1019	1535

Table 2. Composition difference between AA-06 and AA-29

SKW-06	
Component	**Mol%**
CO_2	20.99
Nitrogen	1.19
Methane	21.36
Ethane	2.69
Propane	2.88
i-Butane	1.21
n-Butane	2.44
i-Pentane	1.52
n-Pentane	1.88
Hexanes	2.97
Heptanes+	40.13
Properties of Heptanes plus	
API Gravity @60°F	39.4
Specific Gravity @60/60°F	0.8274
Molecular Weight	189.4
Temperature, °F	275

SKW-29	
Component	**Mol%**
CO_2	23.5836
Nitrogen	0.1121
Methane	22.2354
Ethane	3.0437
Propane	3.5124
i-Butane	1.6136
n-Butane	3.0874
i-Pentane	2.3715
n-Pentane	2.6808
Hexanes	4.5181
Heptanes+	33.0095
Properties of Heptanes plus	
API Gravity @60° F	39
Specific Gravity @60/60° F	0.8386
Molecular Weight	151.7
Temperature, ° F	260

Table 3. Components of AA-06 and EOS tuning flow process

SKW-06	
Component	**Mol%**
CO2	20.99
Nitrogen	1.19
Methane	21.36
Ethane	2.69
Propane	2.88
i-Butane	1.21
n-Butane	2.44
i-Pentane	1.52
n-Pentane	1.88
Hexanes	2.97
Heptanes+	40.13
Properties of Heptanes plus	
API Gravity @60°F	39.4
Specific Gravity @60/60°F	0.8274
Molecular Weight	189.4
Temperature, °F	275

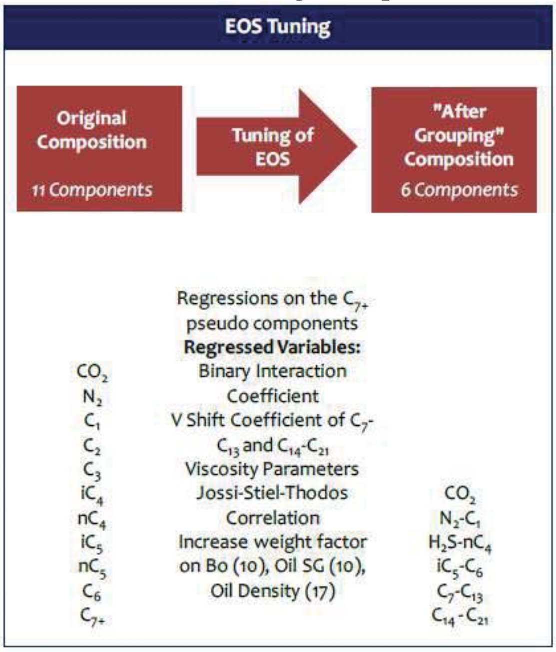

Table 4. MMP estimation with different correlations

Correlation	SKW-6	SKW-14	SKW-18	SKW-29
Cronquist (1978)	3,735	3,901	4,643	2,781
Holm-Josendal (1980) and Mungan (1981)	3,957	4,150	4,242	3,596
Yellig-Metcalfe (1980)	3,436	3,356	3,559	3,236
Shokir (2006)	3,639	3,606	4,120	3,572

b. Figures

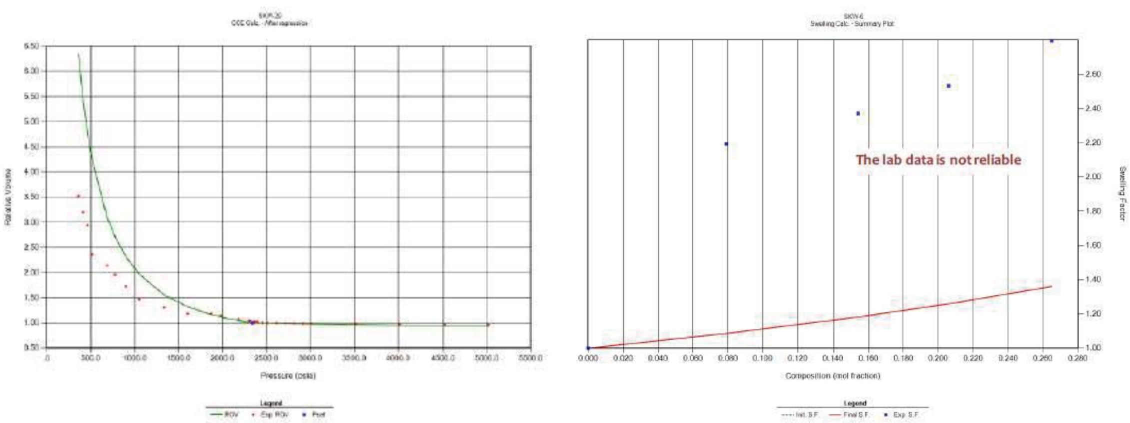

Figure 1. EOS Matching

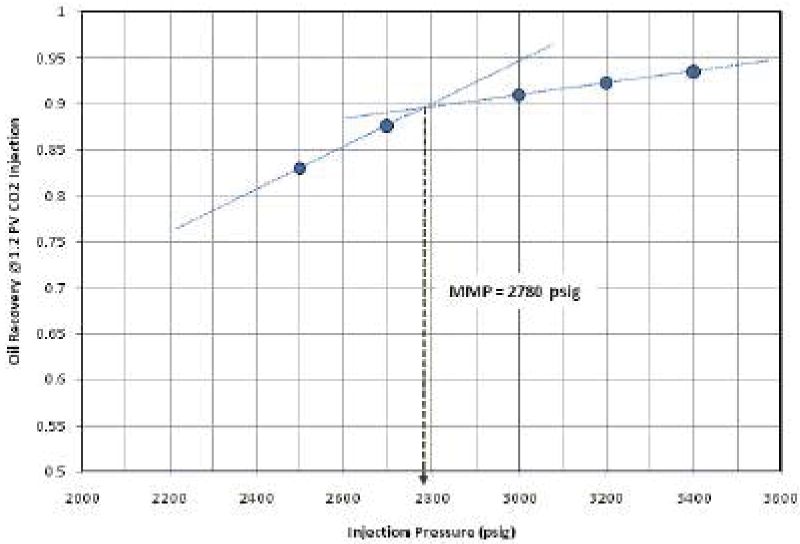

Figure 3. MMP Slim Tube Simulation Result SS -29

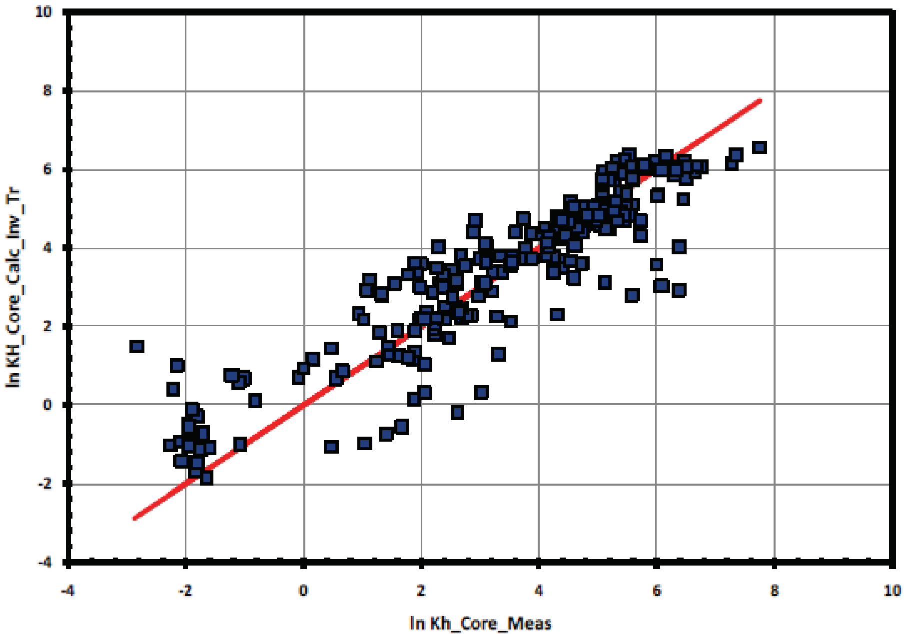

Figure 4. Comparison between measured and calculated core permeabilities

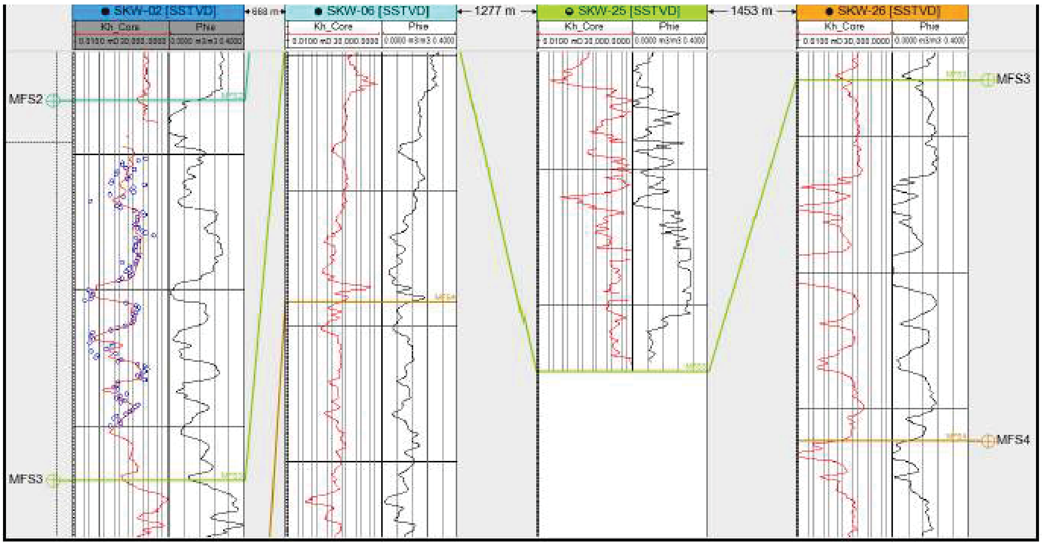

Figure 5. Consistent behavior between permeability and porosity logs

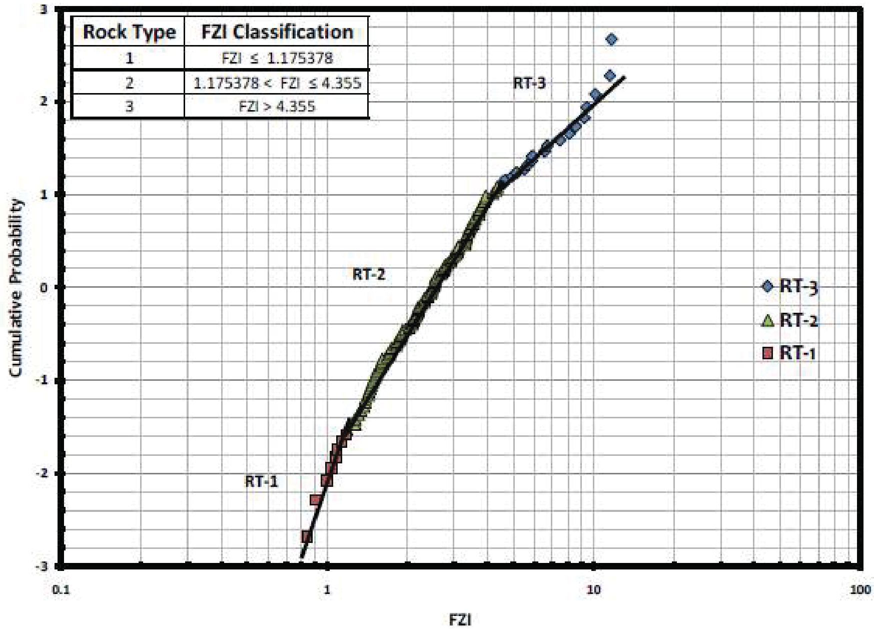

Figure 6. Rock Type Classification based on FZI Method

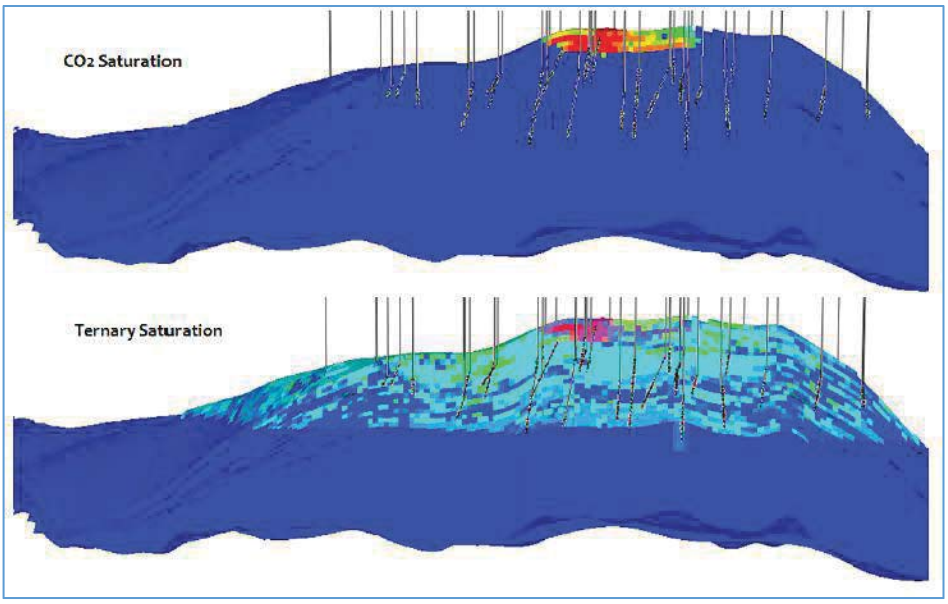

Figure 10. Vertical distribution of CO2 and Ternary Saturation

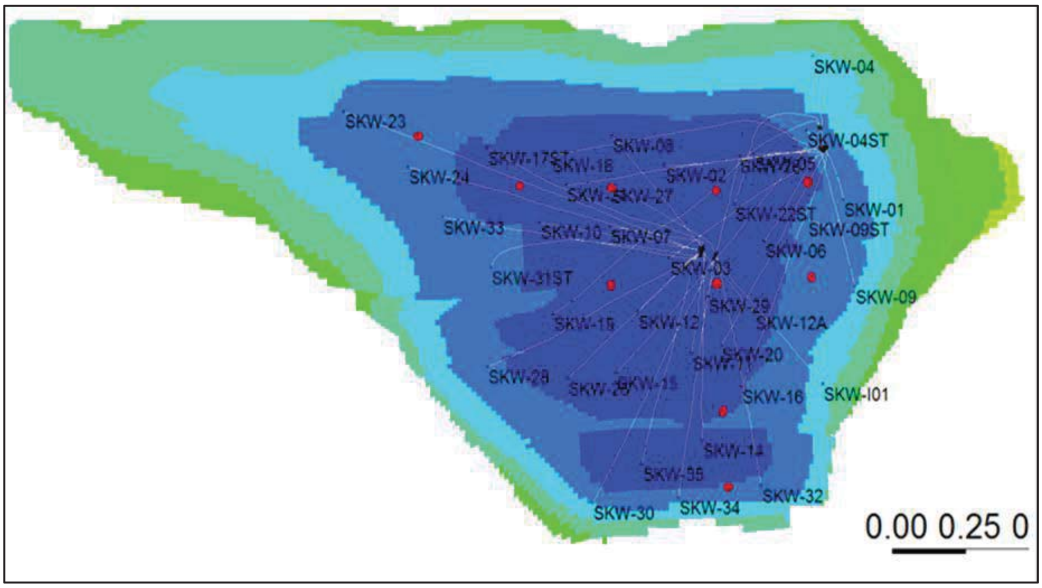

Figure 13. Location of new injection wells and gravity stable injection strategy