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A Model for Screening Oil Reservoirs for Carbon Dioxide Flooding

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ABSTRACT

The use of Carbon Dioxide (CO_2) flooding as an Enhance Oil recovery (EOR) method is well established in the petroleum industry. An important component of this process is the screening criteria used in assessing the prospective reservoirs. Most of the common screening models passively qualify reservoirs as good or poor candidates for CO_2 EOR. However, the huge upfront capital investment involved in CO_2 EOR projects makes it important for the development of more robust screening criteria. This study used detailed reservoir simulation and Design of Experiment (DOE) techniques to evaluate the key parameters that affect the performance of oil reservoirs undergoing CO_2 flooding and develop a proxy model for the performance prediction. The key parameters affecting performance were established as reservoir heterogeneity, dip, mobility ratio of the CO_2 to oil, injection rate, volume of CO_2 available and the nature of the reservoir fluids. The proxy model was validated with detailed reservoir simulation and comparison with existing correlations.

Keywords: R*eservoir performance, CO_2 Flooding, Enhance Oil Recovery, Design of Experiment, Reservoir simulation.*

I. INTRODUCTION

The displacement and recovery of oil by CO_2 injection has been extensively applied and studied in the industry since early 1950s. Injection of CO_2 into oil reservoirs can enhance oil recovery and at the same time mitigate the problem of increased CO_2 concentration in the atmosphere. One major advantage of CO_2 as a choice fluid in EOR projects is that at most reservoir conditions, it is a supercritical fluid with high solvency power to extract hydrocarbon components and displace oil miscibly.

Carbon dioxide flooding is a capital intensive project and highly technical in execution. There is therefore the need for robust screening criteria for investigating a reservoir's suitability for the process. Good screening could reduce risk and uncertainty. However, it could be difficult to develop screening criteria that captures all the variables that inclusively contribute to the overall effect of a successful CO_2 flood. This could be responsible for the low performance in some fields that seem to meet the major screening criteria.

The interaction between CO_2, rocks and reservoir fluids varies with type of rock and fluids as well as pressure and temperature. In addition, CO_2 shows more complex phase behavior with reservoir oil than many other solvents. The relatively high solubility in water and the associated reduction in pH will affect the reservoir chemistry depending on the PVT conditions, reservoir fluid and rock composition, Griggs and Siagian (1998).

II. DESCRIPTION AND MODEL DEVELOPMENT

Compositional simulation and pseudo-miscible black oil models have been widely used to reproduce CO_2 displacement processes. ECLIPSE compositional simulator was used in this study.

A total of 104 reservoir-to-fluid designs to bolster the effect of the contributing factors to the overall performance of CO_2 were investigated. The design entailed building a 30 by 30 by 20 grid cells in the X, Y and Z axis respectively of 100 by 100 by 25ft resulting to 18000 cells. The model has a constant porosity of 25% and a water saturation end point of 10% across all the regions. All the cells are active with no faults. However, the models are hypothetical models built to the Niger delta geologic representation possessing rock and petro physical properties obtainable in the region. A total of 24 different crudes from shell Nigeria fields in the Niger Delta were obtained and characterized using ECLIPSE PVT*i* to reproduce fluid performance in the simulator. Other designed parameters are as follows:

Reservoir Depth: To generate a robust scenario, the analysis was carried out at three different depths: 5000ft, 10,000ft and 15,000ft. This serves as a guide in obtaining the formation pressure, equation 1, at various reservoir depths which control injection pressure.

$$p_f = 0.052\rho h$$
(1)

This has a direct translation on the choice of injection rates of the CO_2 since operation must be within safety limits to ensure that the formation parting pressure is not exceeded.

For the three depths investigated, the temperature gradients were estimated using equation 2.

Tg=1.67 °F/100ft
(2)

Reservoir Dip: Five different dip angles: 0°, 5°, 15°, 30° and 40° were used.

(C) Modeling Reservoir Permeability: The reservoir permeability was divided into two: (a) Homogeneous permeability distribution; where all the permeabilities of cells in the in the X and Y directions are similar; and the Z axis permeability is constant all through the reservoir (b) Heterogeneous permeability distribution where the permeability distribution differs across the reservoir in both the horizontal and vertical directions.

PETREL pre-processor was used for designing seven different reservoir heterogeneity profiles. A normal distribution profile was used to populate the permeability in the X, Y and Z axis of the 18000 cells as shown in Table A.1.

A permutational selection of each of these cases is done and imported into ECLIPSE compositional simulator with the corresponding angle of dip included prior to importing the fluid. PVT simulation model for EOS tuning process was performed using the Peng-Robinson EOS.

The performance model developed here is a fractional-flow based screening model. It is based on the Koval method, Koval (1963), for predicting recovery in a secondary CO_2 – flood, to model secondary miscible flooding process modified by Claridge (1972) for aerial sweep in an inverted five –spot pattern.

Minimum Miscibility Pressure: In this study, MMP for the twenty four fluids investigated were estimated using Equation 3.

$$MMP = 15.988 * T^{(0.774206 + 0.0011039) + MWC_{5+}}$$
(3)

Where:

T = Temperature in °F

MWC_{5+} = The molecular weight of pentane and heavier hydrocarbons in the reservoir's oil.

From material balance, the voidage rate is computed as follows:

$$dv/dt = q_o\left(B_t + \left(R_p - R_{si}\right)B_g\right)$$
(4)

Where:

dv/dt = Reservoir voidage rate, RM^3/Day

q_o = Oil production rate at start of CO_2 injection, (SM^3/Day)

B_t = Two phase formation volume factor, (RM^3 / SM^3)

R_s = Solution gas ratio (SM^3/ SM^3)

R_p = Produced gas oil ratio (SM^3 / SM^3)

B_g = Gas formation volume factor (RM^3 / SM^3)

An injection rate that corresponds to the calculated voidage rate was adopted. The surface equivalence of the voidage rate was obtained as follows:

$$Q_{inj.rate} = \frac{Void\ Rate}{B_{g.CO_2} @ P_{fi}}$$
(5)

Where:

$Q_{Inj.Rate}$ = Injection rate, SM^3/Day

$Void\ Rate$ = Reservoir Voidage Rate, RM^3/Day

$B_{g.CO_2} @ P_{fi}$ = CO_2 formation volume factor at formation pressures (P_{fi}), RM^3/SM^3

The Hydrocarbon Pore Volume Injected (HCPV) and Fractional Pore Volume (FPV):

The hydrocarbon pore volume injected was estimated by equation 6:

$$HCPV = Q_{Inj.Rate} + t_{eff}$$
(6)

Where,

$$t_{eff} = 25 * 365 - t_{initial}$$
(7)

Where:

$Q_{Inj.Rate}$ = CO_2 injection rate, SM^3/Day

t_{eff} = Time of effective CO_2 injection, Day

$t_{initial}$ = Time before inception of CO_2 injection, Day

$$FPV = \frac{HCPV}{RSPV}$$
(8)

Where:

FPV = Fractional Pore Volume, ratio

$HCPV$ = Hydrocarbon Pore Volume, RM^3

$RSPV$ = Reservoir Pore Volume, RM^3

CO_2 Mobility Ratio:

Since the viscosity of CO_2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and therefore, oil recovery Campbell (1985).

$$M = \frac{K_{r\cos_2} / u_{co_2}}{K_{rowg} / u_o}$$

(9)

Where:

M = Mobility ratio of CO_2 to oil
$K_{r\cos_2}$ = Relative permeability of rock to CO_2
K_{rowg} = Relative permeability of rock to oil in the presence of water and gas
μ_{CO_2} = Viscosity of CO_2, cp
μ_o = Viscosity of oil, cp

Proxy Model Development

A 'fold over' Plackett-Burman design, which has been observed to be very efficient in screening models was used (Yeten *et. al.*, (2005). The implicit assumption is that all interactions are negligible (Myers, *et al.*, 2008). The main contribution effects out of the 28 parameters examined on the response were obtained from the contrast of the average of the highs and the lows, or mathematically expressed as follows:

$$Effect = \frac{\sum Y+}{n_+} - \frac{\sum Y-}{n_-}$$

(10)

Where:

N= Number of data points collected at each level
Y= Associated responses

The half-normal probability curve was used to identify the sensitivities of the factors along with their interactions. Half probability plot was used to take the absolute values of the effects as shown in Fig. B.2.

The inverse transformation principle was adopted and applied over the sample spaces available to generate a final equation for the additional recovery obtainable from the Carbon dioxide flooding as:

$$A = C + B1 + B2 + B3 + B4 + B5 + B6$$

(11)

Where:
A = Additional Recovery inverse
C = Constant
B1 = Porosity
B2 = Permeability and Heterogeneity
B3 = Fluid property
B4 = Pressures
B5 = Reservoir orientation and Mobility
B6 = Gas conditions at start of CO_2 injection

Simplifying Equation 11 will yield:

$$A = \frac{1}{ADD\,RECOV + 1000002} \quad (11a)$$

$$C = 100003E-06 \quad (11b)$$

$$B1 = -1.32294E-11*\phi - 5.38567E-11*NTG \quad (11c)$$

$$B2 = -1.29548E-14*Kx + 7.03298E-15*Ky + 6.24671E-14*Kz + 1.76294E-11*\frac{K_V}{K_h} -1.77156E-14*HH + 2.15642E-14*VH \quad (11d)$$

$$B3 = -1.33092E-13*API - 1.66683E-12*\mu_O \quad (11e)$$

$$B4 = -5.30945E-15*MMP - 2.07089E-12*Pc + 1.62500E-14*Pi + 5.2738E-15*P_b + 9.6858E-15*P_{ref} \quad (11f)$$

$$B5 = 1.12521E-17*V_r - 1.50031E-13*Dip + 7.50462E-17*D - 5.33625E-16*K_{ro} + 2.85318E-16*M \quad (11g)$$

$$B6 = -1.52557E-14*R_S - 6.73741E-16*R_P + 7.74225E+13*S_O + 1.23132E-12*HPVi - 1.6768E-17*Q_i + 2.57234E-14*T \quad (11h)$$

Where:

* ADD RECOV = Additional recovery
*Ø = Porosity of the formation
* NTG = Net to gross ratio
* Kx = Horizontal permeability in the x axis
* Ky = Horizontal permeability in the y axis
* Kz = Vertical permeability
* Kv/Kh = Vertical to horizontal permeability ratio
* HH = Heterogeneity index in the horizontal direction
* VH = Heterogeneity index in the vertical direction
* API = Fluid gravity
* μo = Fluid viscosity
* MMP = Minimum miscibility pressure
* Pc = Capillary pressure
* Pi = Reservoir initial pressure
* Pb = Reservoir bubble pressure
* Pref = Reference presure for CO_2 injection
* Vr = Reservoir voidage rate at inception of CO_2 injection
* Dip = Reservoir angle of dip
* D = Formation depth
* Kro = Oil relative permeability at inception of CO_2 injection
* M = CO_2 to oil mobility ratio at inception of CO_2 injection
* Rs = Solution gas at inception of CO_2 injection
* Rp = Produced gas at inception of CO_2 injection
* So = Oil saturation at inception of CO_2 injection
* HPVi = HCPV of CO_2 introduced to the formation
* Qi = CO_2 injection rate
* T = Reservoir temperature

Model Validation

Validation of the model developed was done by comparing the prediction of the model to the predictive performance of Claridge Correlation. The predictions were then compared with results of ECLIPSE® CO_2 compositional simulation runs. A program dedicated to the prediction of CO_2 EOR performance, based on the principles of the generated model, was presented and its attendant results obtained from imputation of reservoir and fluid parameters was juxtaposed with simulated values from ECLIPSE compositional simulator.

The results are shown in Tables (1-3) and figures (1-3)

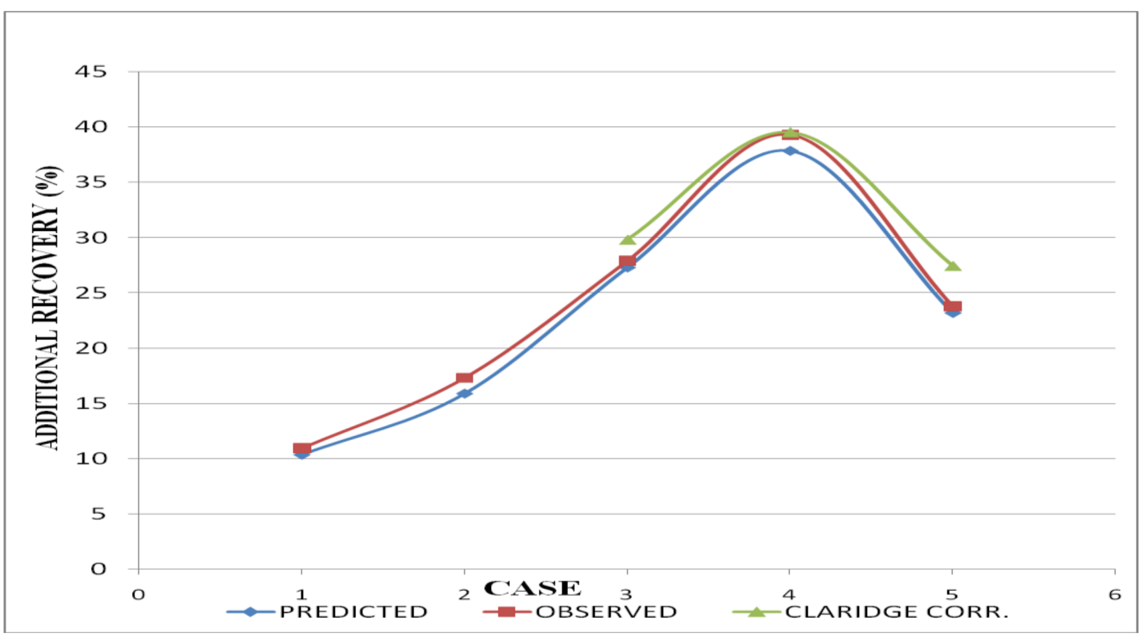

Figure 1: Models Predictions Vs ECLIPSE Observed performance @ 5000ft & 110°F

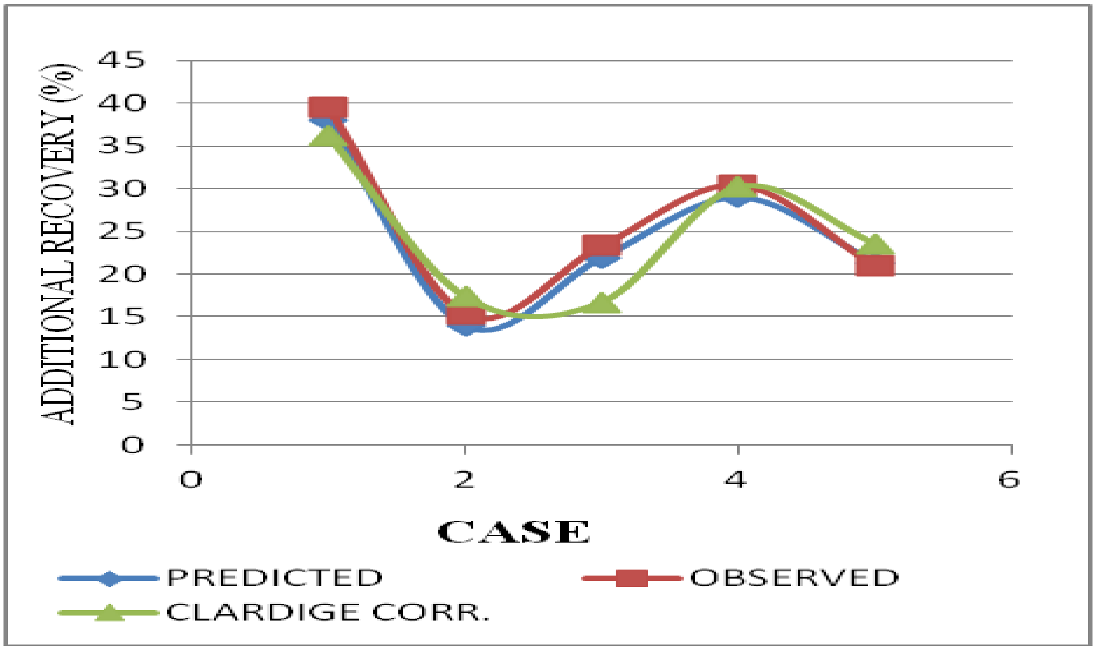

Figure 2: Models Predictions Vs ECLIPSE Observed performance @ 10000ft & 187°F

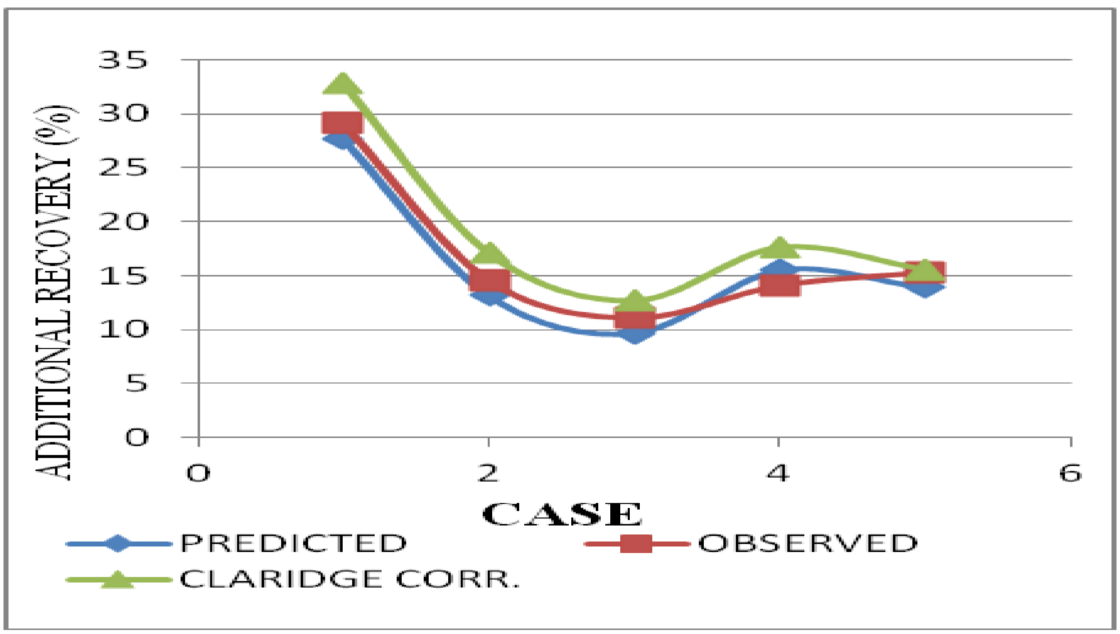

Figure 3: Models Predictions Vs ECLIPSE Observed performance @ 15000ft & 280°F

Analysis of Model Predictions

Tables 1, 2 and 3 presents the observed data from ECLIPSE® and the predicted data from this study and Claridge correlation.

From the tables, the average deviation is calculated using:

$$Average\ Deviation = \frac{1}{n}\sum_{i=1}^{5} x\,|-\bar{x}\,| \qquad (21)$$

Where:
n = no of runs
x = calculated difference
$\bar{x}$= mean of calculated difference

The deviations in the 5000ft, 10000ft and 15000ft are 0.399%, 0.906% and 0.586% respectively for the generated model in this study. The Claridge Correlation exhibits deviations of 1.145%, 1.11% and 1.59% respectively.

Table 1: Analysis of Models Precisions @ 5000ft

RUNS	PREDIC-TED	CLARIDGE CORR.	OBSER-VED	DIFF. BTW MODEL & OBSERVED	DIFF. BTW CLARIDGE CORR. & OBSERVED
1	10.3791	46.724	10.9632	0.584095792	-
2	15.9116	35.48	17.3275	1.415867637	-
3	27.3159	29.802	27.9	0.584073637	1.902
4	37.8675	39.5119	39.2834	1.415926817	0.2285
5	23.2059	27.432	23.79	0.584085276	3.642

Table 2: Analysis of Models Precisions @ 10000ft

RUNS	PREDIC-TED	CLARIDGE CORR.	OBSER-VED	DIFF. BTW MODEL & OBSERVED	DIFF. BTW CLARIDGE CORR. & OBSERVED
1	27.7371	32.81	29.153	1.415925876	3.657
2	13.2033	17.126	14.6192	1.415913736	2.50682
3	9.7033	12.6904	11.1192	1.415903825	1.5712
4	15.5259	17.6324	14.11	- 1.415887313	3.5224
5	13.9141	15.59	15.33	1.415886733	0.26

Table 3: Analysis of Models Precisions @ 15000ft

RUNS	PREDICTED	CLARIDGE CORR.	OBSERVED	DIFF OF MODEL & OBSERVED	DIFF. OF CLARIDGE CORR. & OBSERVED
1	38.024	36.166	39.44	1.415955007	3.274
2	13.9141	17.35	15.33	1.415886733	2.02
3	21.8841	16.71	23.3	1.415909302	6.59
4	28.9841	30.1874	30.4	1.415929408	0.213

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5	21.3359	23.546	20.92	-0.415906597	2.626

III. CONCLUSION

This work presented a model that can be used to screen Carbon dioxide flood projects. The results have shown that degree of heterogeneity of the reservoir, reservoir dip, mobility ratio of the CO_2 to oil, injection rate, volume of CO_2 introduced to the formation and injection well configurations are important parameters that could affect the performance of CO_2 EOR projects. A *priori-knowledge* of extra recovery expected to be obtained if CO_2 EOR is embarked on is no doubt a prudent approach and promotes best engineering practices.

Nomenclature

BOPD = Barrel of Oil Produced per day
CO_2 = Carbon Dioxide
DOE = Design of Experiment
EOR = Enhanced Oil Recovery
EOS = Equation of State
HC = Hydrocarbon
IPM = Integrated Petroleum Management
MMP = Minimum Miscibility Pressure
MW = Molecular Weight
P_{fi} = Formation Pressure
RM^3 = Reservoir Cubic Meter
RSM = Response Surface Methodology
SM^3 = Standard Cubic Meter
WAG = Water Alternating Gas

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APPENDIX

Table A.1 Design Cases of Populated Heterogeneity

Property	1	2	3	4	5	6	7
Kx (md)	100-400	250-310	80-600	200-800	150-750	90-200	300-1000
Ky(md)	100-400	250-310	80-600	200-800	150-750	90-200	300-1000

Kz(md)	10-20	5-9	12-33	2-7	1-15	3-30	2-18

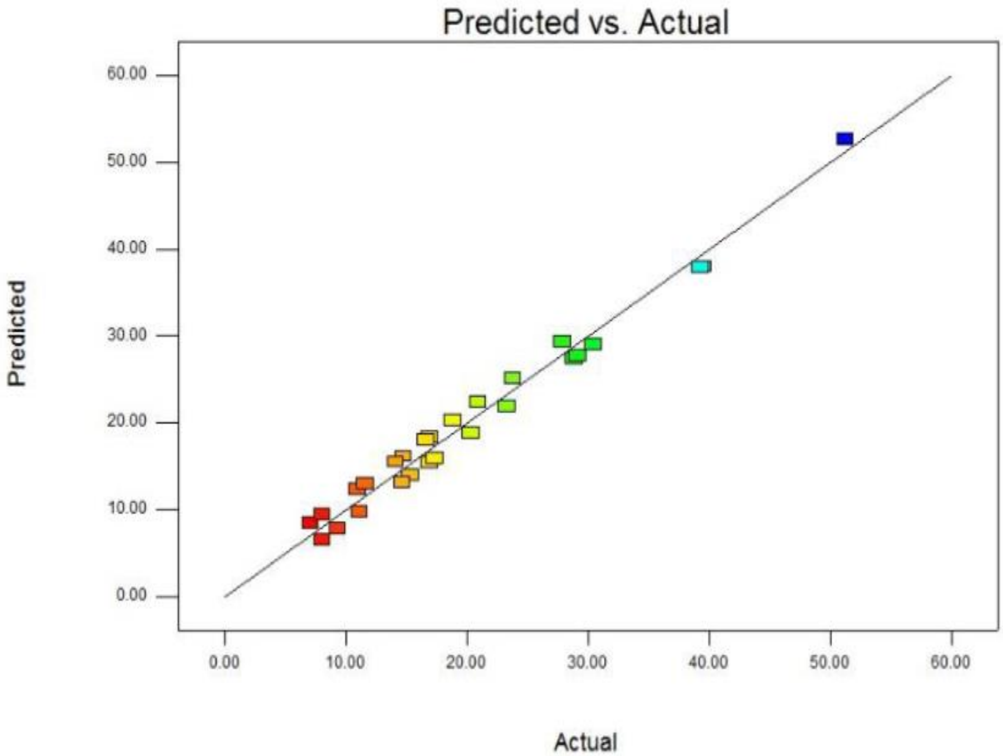

Figure A1: Predicted Vs Actual Profile for Factors

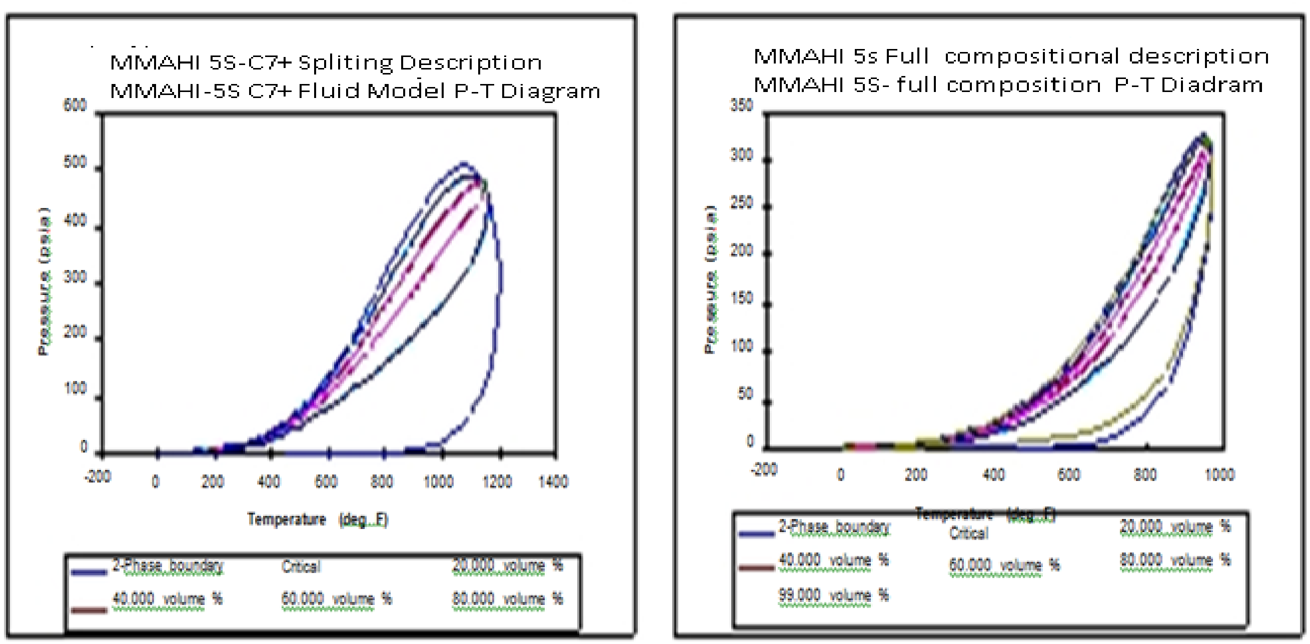

Figure B.1 Descriptions of a C_{7+} and Full Fluid Compositional Model

Figure B.2 Predicted Vs Actual Profile for Factors

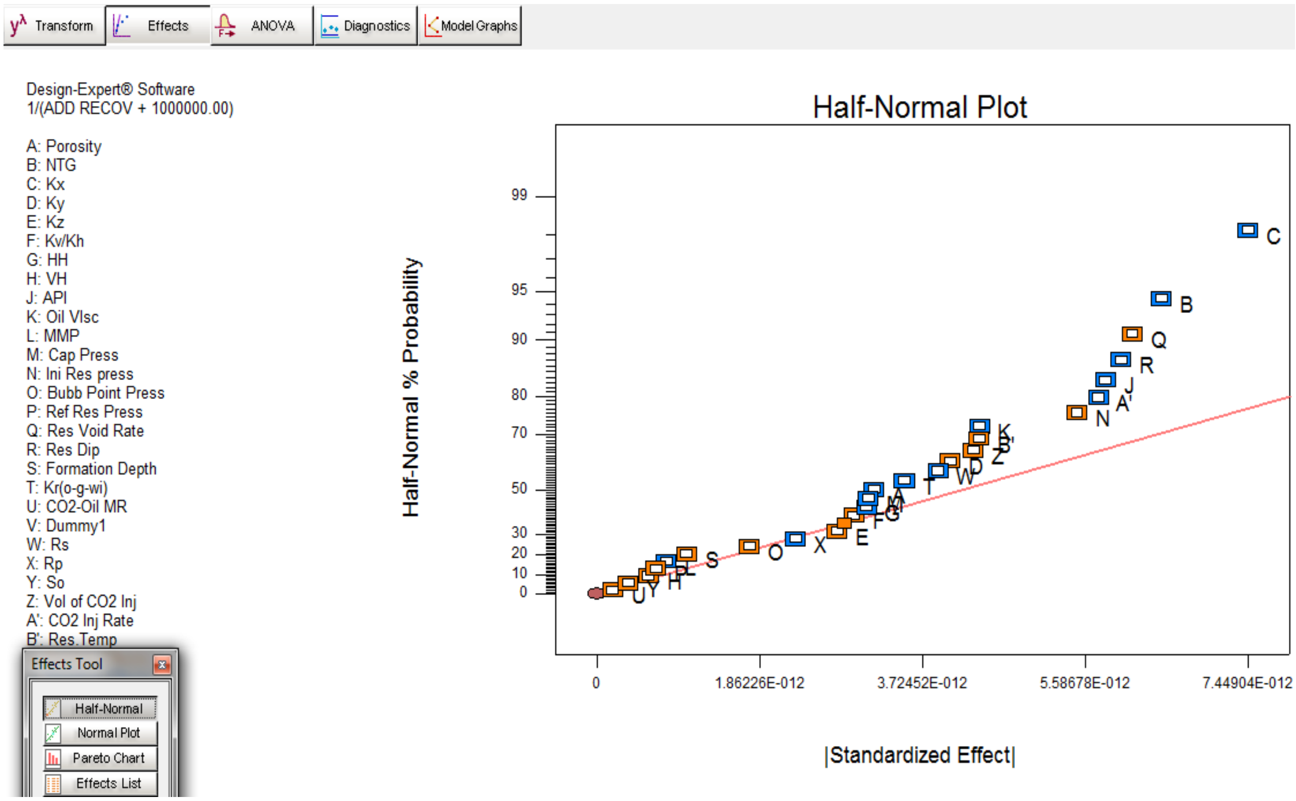

Figure B.3 Half Normal Plot for Effect of Factors in CO_2 Injection

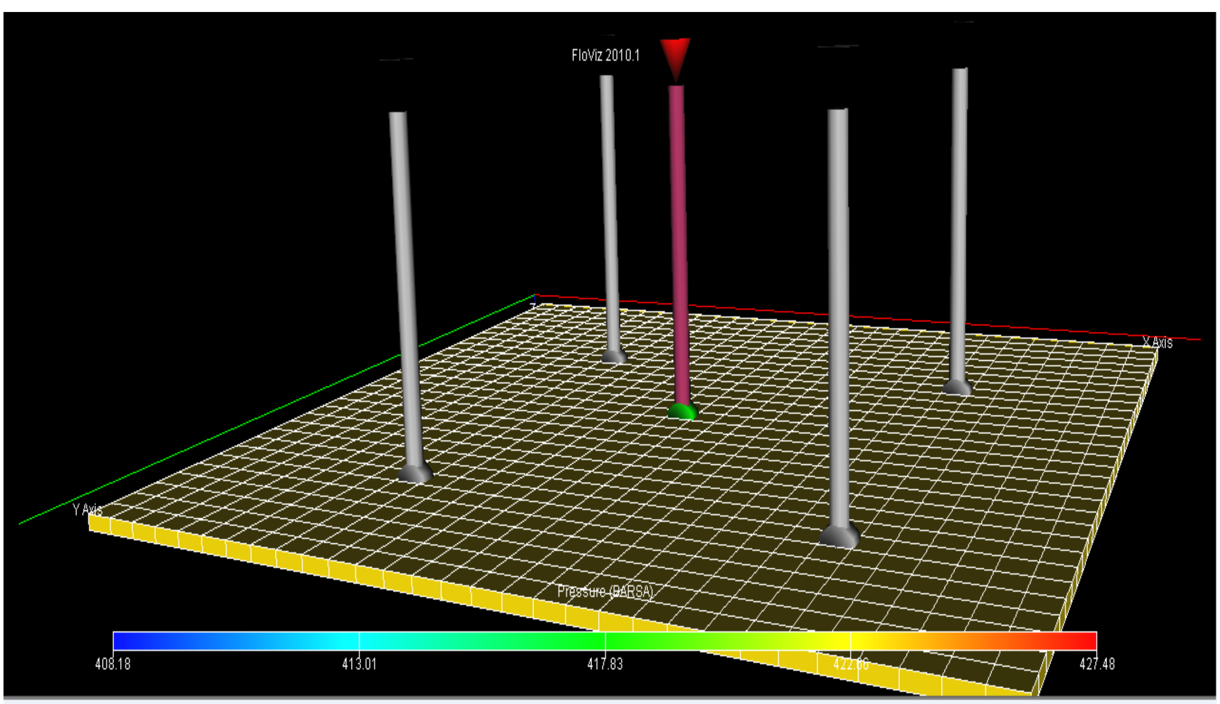

Figure B.4 Well Configurations for a Horizontal Reservoir (0° Dip)