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Assessment of Different Development Scenarios for Sharara A-NC186 Field Using Simulation Models

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Abstract

The purpose of our study is to assess different development scenarios for Sharara A-NC186 pool using Eclipse models (E100 and E300). The studied scenarios are the natural depletion, water injection, water flooding and CO_2 WAG injection. Two models which are considered in this study using 5-spot pattern 3D model and sector 2D model. Eclipse PVTi package was used to model the phase behavior of A-NC186 using measured PVT analyses conducted on captured fluid samples from this field. The three-phase relative permeability for each model layer was established using Eclipse SCAL package. Area around the discovery well A1, with the proper characterization of field phase behavior and geological models as well as the dynamic flow parameters, was selected for this study. The main outcome of this study revealed that, the optimal and feasible development scenario is water flooding with the proper monitor and management of the injected water into the reservoir, as well as the proper distribution of the flooded water across the vertical section. Water flooding will prolong the well life and exploitation period and substantially improves the ultimate oil recovery. CO_2 Injection and CO_2 WAG injection has no added value to recovery enhancement, mainly due to reservoir heterogeneity and unfavorable mobility. Also, CO_2 is not fully miscible which will tend to segregate and override trapped oil and accordingly decreases its sweep efficiency. Natural depletion and water injection have both demonstrated low ultimate oil recovery. Water injection into the aquifer is hindered by the impermeable layers and will neither properly maintain the pressure nor improve oil recovery.

Keywords: 5-spot model; water flooding; CO_2 WAG injection

1. Introduction

"The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained. Primary oil recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water. Secondary oil recovery refers to the additional recovery that results from the conventional methods of water-injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Water flooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted. Tertiary (enhanced) oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits." [1].

The suitability of a candidate reservoir for water flooding is mainly governed by the reservoir uniformity and pay continuity as well as the fluid saturations and properties [2]. Reservoir simulations now days are extensively used to identify the most suitable water-flood patterns and the optimum number and locations of producers and injectors. The successful design and implementation of CO_2 gas injection project depends on the favorable fluid and rock properties. The use of CO_2 to increase the recovery of oil has received considerable attention since early fifties. Laboratory research has been conducted and field applications have been initiated and performed indicating a great interest in CO_2 flooding. [3]

The main objective of this study is to assess and compare different development scenarios for Sharara field (A-NC186 pool), including primary depletion, water injection into the aquifer, water flooding in the reservoir, and CO_2–WAG injection, with the aim of:

- Identifying the most suitable development scenario for maximizing the oil recovery.
- Investigate more deeply the optimized injection schemes (injection well completion and flood pattern) for maximizing the water-flood recovery.
- Finally, investigate the option of CO_2 injecting after water breakthrough and its contribution to the added oil recovery. Eclipse black oil model (E100) and compositional model (E300) using 3D and 2D grid models were utilized for this study with deep emphases on phase behavior modelling, formation evaluation as well as the SCAL analyses. Area around well A1 was selected for this study assuming it will represent the average field area dynamic flow behavior.

2. Phase Behavior Modelling

An important prerequisite for using an EoS-based compositional model is achieving satisfactory match between equation of state (EoS) results and laboratory fluid property measurements (PVT). Eclipse PVTi package was used to model the phase behavior of A-NC186 using measured PVT analyses conducted on fluid samples collected from this field. Three parameters Peng Robinson (3PR) EoS was tuned to match all the conventional PVT data (CCE, DL, flash separation, and viscosity data). [4] Extended compositional model, by breaking down C_{7+} into three pseudo components, as well as lumped compositional model were both used in phase behavior modelling and EoS tuning (Table 2.1). The match was achieved by adjusting heavy fractions, shift parameters, a and b for heavy pseudo fractions (FRC1, FRC2, and FRC3). A reasonable match was achieved to all measured data for both adopted compositional models (extended and lumped).

Eclipse PVTi was also used to calculate the Minimum Miscibility Pressure for CO_2. An injection study was established in Eclipse PVTi using multiple-contact miscibility with vaporizing gas drive option. The result of MMP for CO_2 is estimated at (2696 psia), which extremely above the initial pressure of A-NC186. Figure 2.1 shows the Ternary Diagram at initial pressure (1816 psia). As indicated in this plot, the A1 fluid will behave as immiscible with CO_2 injection at its initial pressure. Partial exchange in phase behavior and extraction of heavy component will happen but not to the extent of achieving miscibility. PVTi package was then utilized to export the PVT model for both black oil (E100) and compositional (E300) simulation models.

3. Formation Evaluation and Relative Permeability Modelling

Reservoir heterogeneity probably has more influence than any other factor on the performance of a fluid injection project. At the same time, it is the most difficult effect to quantify. Our purpose in this study is to characterize the vertical permeability variations and determine how these variations can influence the existing water flood injection scheme performance in terms of vertical and displacement sweep efficiencies. A

Table 2.1: A-NC186 reservoir fluid composition (extended vs lumped models)

PVT Data	Extended Model	Lumped Model

Fluid Sample		
Comp.	Zi (percent)	Mol. Weight
N2	1.29	28.013
Co2	0.95	44.01
C1	8.15	16.043
C2	5.93	30.07
C3	8.5	44.097
iC4	1.51	58.124
nC4	5.96	58.124
iC5	2.14	72.151
nC5	3.27	72.151
C6	3.25	84
C7+	59.05	195.73

Heptanes-plus (C7+) fractions		
Comp.	Zi (percent)	Mol. Weight
N2	1.29	28.013
Co2	0.95	44.01
C1	8.15	16.043
C2	5.93	30.07
C3	8.5	44.097
iC4	1.51	58.124
nC4	5.96	58.124
iC5	2.14	72.151
nC5	3.27	72.151
C6	3.25	84
C7+ (FRC1)	23.613	113.66
C7+ (FRC2)	26.452	202.5
C7+ (FRC3)	8.9856	391.46

Fluid Lumped		
Comp.	Zi (percent)	Mol. Weight
N2	1.29	28.013
Co2	0.95	44.01
C1	8.15	16.043
C2	5.93	30.07
C3+	15.97	50.658
C5+	8.66	76.598
C7+ (FRC1)	23.613	113.66
C7+ (FRC2)	26.452	202.5
C7+ (FRC3)	8.9856	391.46

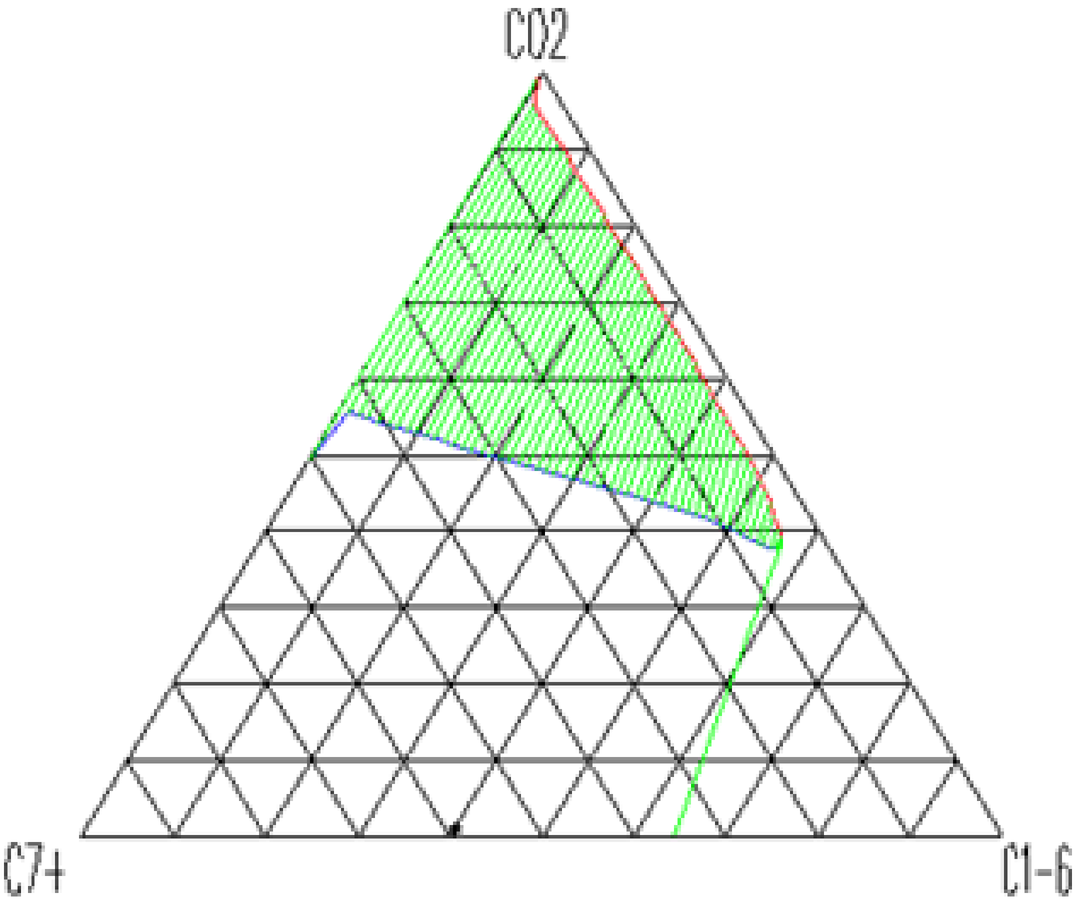

Figure 2.1: Ternary Diagram at initial pressure (1816 psia)

conventional core data was collected and used to characterize the A-NC186 geological layers. To perform the formation evaluation, we set up several calculations as described below: Lump all the measured RCA horizontal permeabilities with similar range of values in one geological layer and then calculate the arithmetic average of the horizontal permeability for this assigned geological layer. Calculate the arithmetic average for similar set of measured vertical permeabilities and measured porosities for the assigned chosen geological layer. The average connate water saturation of the assigned geological interval was then read from the log interpretation. Gross thickness and N/G ratio were determined from the log interpretation plots. The same above procedures were repeated for the remaining geological layers and based on our assessment we have identifies 23 layers with different geological characteristics (Kh, Kv,ϕ,Swi). Two impermeable layers have been identified based on log interpretation and RCA analyses. These two layers were treated as impermeable in the numerical models with very law horizontal and vertical permeability (0.00001 md) and low porosity (5%). Special core analyses (SCA) for 6 core samples were analyzed and used in our study. It is necessary to average the relative permeability data obtained on individual rock samples. Prior to usage for oil recovery prediction, the relative permeability curves were initially normalized to remove the effect of different initial water and critical oil saturations. The relative permeability can then be de-normalized and assigned to different regions/geological layers of the reservoir based on the existing critical fluid saturations for each reservoir region and/or geological layer. The most generally used method adjusts all data to reflect the assigned end values $(Kro)Swc$, $(Krw)Sor$, Sor), then determines an average adjusted curve, and finally constructs an average curve to reflect reservoir conditions. These procedures are commonly described as normalizing and de-normalizing of the relative permeability data,see Figure 3.1. [1]

The gas oil relative permeabilities for each geological model layer were estimated with Corey equation [5], as there are no available measured data. From experience Corey prediction is quite reasonable to model gas oil flow. Corey (1954) [5] proposed a simple mathematical expression, Equations 3.1 and 3.2, for generating the relative permeability data of the gas-oil system (Figure 3.2). The approximation is good for drainage processes (gas-displacing oil). The model of gas flow becomes important when the pressure drops below the bubble point, in case of depletion scenario, or for modelling the CO_2 injection. In Corey equation we assumed $ngo = 2, ng = 2.5, Sorg = 0.2, Sgc = 0.05$, and Swc and Kr end points are varying for each geological layer.

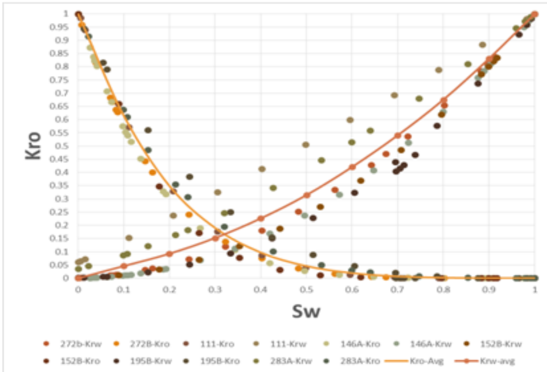

Figure 3.1: Shows the normalized and average curves for the set of measured SCA

$$K_{ro} = (k_{ro})_{s_gc}[\frac{1 - S_g - S_{lc}}{1 - S_{gc} - S_{lc}}]^{n_{go}} \tag{3.1}$$

$$K_{rg} = (k_{rg})_{s_wc}[\frac{S_g - S_{gc}}{1 - S_{lc} - S_{gc}}]^{n_g} \tag{3.2}$$

$$S_{lc} = S_{wc} - S_{org} \tag{3.3}$$

Where:
Slc= total critical liquid saturation (kro)
Sgc= oil relative permeability at critical gas saturation
$Sorg$= residual oil saturation in the gas-oil system
Sgc= critical gas saturation ng,
ngo= exponents on relative permeability curves
Having established the mechanisms and approaches of generating the water-oil and gas-oil relative permeabilities, then we exported all the relative permeabilities to Eclipse SCAL. The three-phase relative permeability for each model layer were then established using Eclipse SCAL package. Twenty three (23) data sets of relative permeabilities are generated to represent all different vertical layers used in the numerical models.

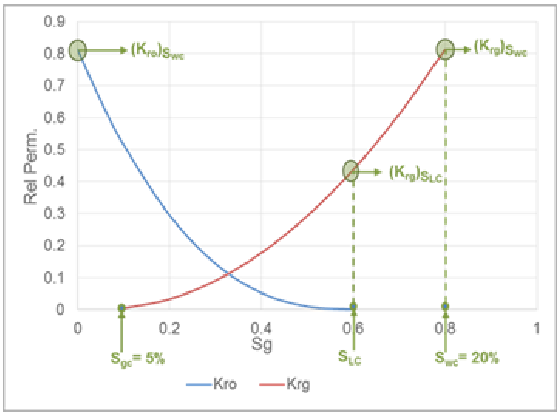

Figure 3.2: Relative permeability data of the gas-oil system

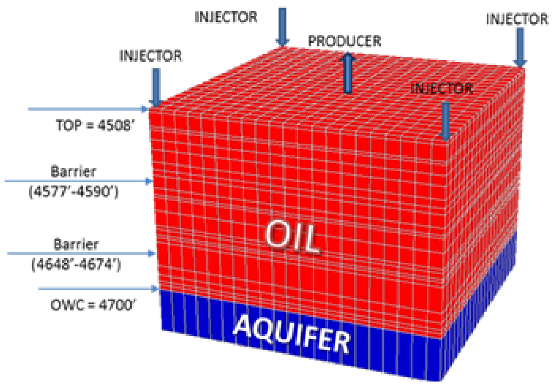

Figure 4.1: The 5 spot pattern 3D model

4. Numerical Models

Two models are considered in this study, 5-spot pattern 3D model and Sector (2D) model, using: 1. Eclipse100 (modified black-oil model) for cases that study the natural depletion, water injection and water flooding (2 Dimensions and 3 Dimensions). 2. Eclipse 300 (compositional model) for cases that study the CO2 injection (immiscible injection) and CO2 WAG model (Water Alternating Gas). The 5 spot pattern 3D model, Figure 4.1, was used to simulate water injection case, water flooding case, CO2 injection and WAG study cases with one producing well located in the middle and four injection wells located in the corners of the model. The natural depletion scenario was studied with one producing well located in the middle that vertically penetrates 22 cells. The sector 2D model, Figure 4.2, was used to focus on vertical sweep efficiency (EV) and evaluate the impact of injected water distribution across the well vertical intervals.

The models descriptions are summarized in Table 2.2.

A flux aquifer model was chosen to model the aquifer encroachment. Flux rate can be specified directly by:

$$Q_{ai} = F_a \text{ X } A_i \text{ X } m_i \tag{4.1}$$

Where;
Fa = the flux.
Ai = Area of the connecting cell block.
mi = an aquifer influx multiplier.

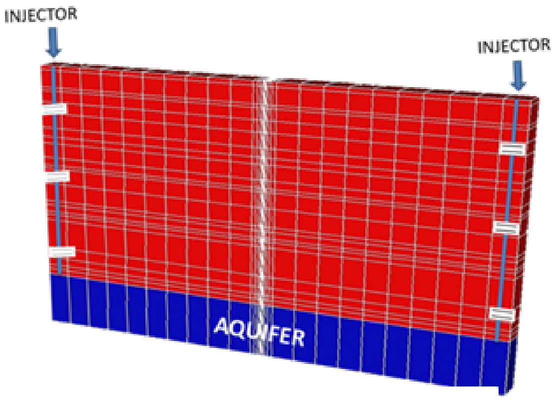

Figure 4.2: The sector 2D model

Table 4.1: Models descriptions

Variable	Quantity	Unit
Top of the reservoir	4508	ft
OWC	4700	ft
Aquifer Q flux	0.00006	Stb/day/ft^2
Water Compressibility	3.11 E-06	Psi-1
Water Viscosity	0.2894	Cp.
Rock Compressibility	4.5 E-06	Psi-1
Drainage radius	1640	ft
Oil Production Rate	3000	bbl/day
Oil Prod Rate Economic Limit	200	bbl/day
Wellbore Radius	0.3048	ft

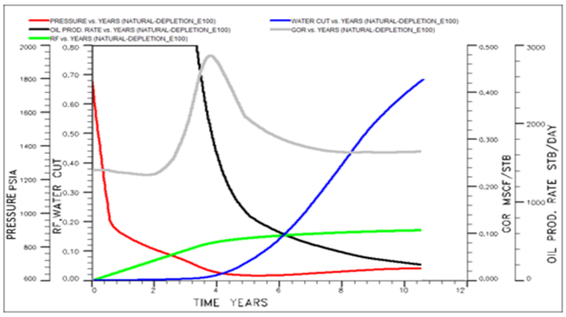

Figure 5.1: Main results for Natural depletion scenario

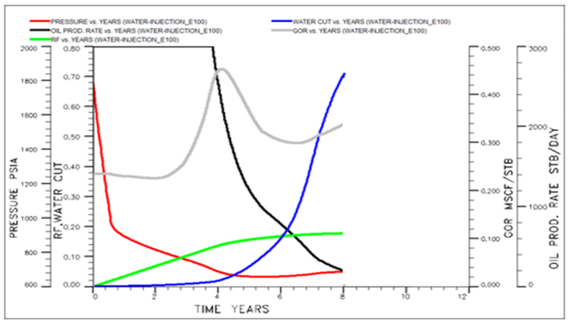

Figure 5.2: Main results for Water injection scenario

Aquifer Voidage replacement was set to 0.16 of PV produced to reflect the A-NC186 actual week aquifer support.

5. Simulation Models Results

5.1. Natural Depletion Scenario

Due to the insufficient natural energy of the reservoir and the week aquifer support, the reservoir pressure is steeply declining and will drop below the bubble point (785 psig) within two years (Figure 5.1). GOR will buildup with time, restricting the flow of oil and accelerating reservoir pressure drop. Expected plateau period for the well is 3.4 years with sharp harmonic decline after the end of buildup. Water cut is marginal and will buildup drastically after the plateau period to about 68% at the end of Well life. The life of the well is 10.6 years with ultimate recovery factor of 17.8 %.

5.2. Water Injection Scenario

Water injection to the aquifer has negligible improvement over natural depletion scenario, as shown in Figure 5.2 below, mainly due to the barriers that hindering the encroachment and sweep enhancement by water injection. GOR will build up with time, restricting the flow of oil and accelerating reservoir pressure drop. At the end of plateau period, GOR declines as oil rate declines. Water cut will build up after the plateau period to about 72% at the end of well life. Negligible change on plateau period and EUR (3.8 years and 18% RF) over natural depletion scenario.

5.3. Water Flooding Scenario

A sector 2D model was initially constructed to optimize the water injection distribution across the vertical direction with the aim of maximizing the vertical sweep efficiency (EV). Three perforation intervals are considered along the injector well. The amount of water entering each perforation interval was monitored to analyse its effect on the reservoir recovery efficiency. The optimum vertical sweep efficiency could reach to 64.6% with proper injection management and accordingly displacement efficiency [Movable Oil = $(Soi$ - $Sor/Soi)$] is estimated at 62%. Due to the close viscosity values of the injected water and displaced oil, the water flood mobility ratio is less than 1.0 (estimated at 0.4), indicating the favourability of water flooding for such reservoir (viscous forces impact are eliminated).
Accordingly, water flooding will prolong the well life and substantially improves the ultimate recovery (almost 20% over the natural depletion), as illustrated in Figure 5.3. The well will be produced at plateau rate of 3000 stb/d for 10.2 years followed by sharp decline and then another small oil bank carried by water, as shown by the hump, at the tail of production profile. Reservoir pressure will be maintained constant above the Pb until the end of plateau period, then will sharply decline due to the unbalanced voidage replacement ratio. GOR is maintained constant at the initial RS until the end of project life where it peaks. Water B.T. happens at Year 8, (after 0.3 PV of water injected) and builds up to a maximum W.C. of 80% at the end of plateau period and will continue at that level until the shut-in period (Year 16). The life of the well is 16 years with expected ultimate recovery factor of 43%.

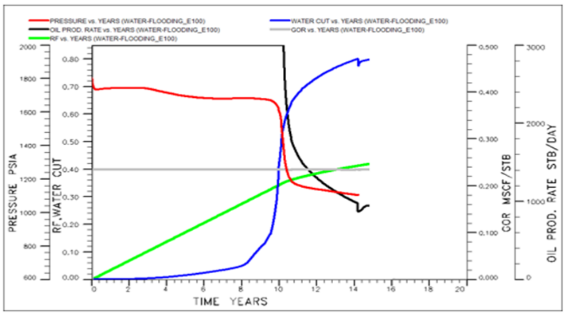

Figure 5.3: Main results for Water flooding scenario

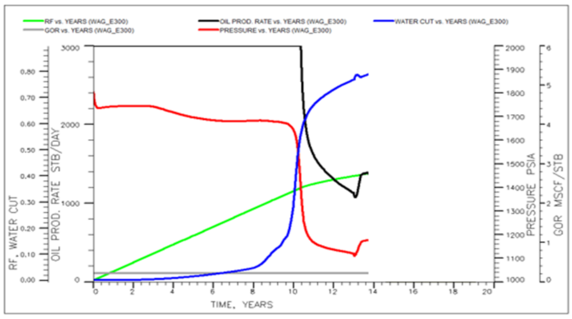

Figure 5.4: Main results for CO_2 WAG scenario

5.4. CO_2 – WAG injection Scenario

As outlined above, A-NC186 crude requires much higher pressure than Pi to achieve miscibility with CO_2, which practically cannot be attained. Therefore, the vaporizing mechanism of CO_2 with Sharara A-NC186 heavy components, under current operation conditions, is partial until it reaches an equilibrium stage with no more phase exchanges in which the enriched CO_2 acts as immiscible solvent. Along this mechanism, the interfacial tension (IFT), as we accounted, will reduce from 6 to 3.5 dyne/cm^2 with marginal reduction in Sharara crude viscosity due to CO_2 partial welling. The estimated CO_2 oil mobility ratio at immiscible condition is quite high 21 ($>>1.0$ – unfavorable), which provide big chance of CO_2 to override the displaced oil and decrease its sweep efficiency. The concept of interfacial tension (IFT) forces was activated in the dynamic flow modeling to allow for the base gas-oil relative permeability curves to approach straight line as IFT approaches to zero [6]. However, in this scenario, the IFT enhancement is marginal (i.e. 3.5 dyne.cm is still high) and will not contribute to any oil and gas flow improvement, resulting with CO_2 acts as fully immiscible with the displaced NC186 oil.

The WAG process was implemented by injection of CO_2 after water B.T. (i.e. after 0.3 PV of water injection). CO_2 slug size used is 0.2 PV followed by water injection. As shown in Figure 5.4, the contribution of CO_2 to overall recovery is marginal, mainly due to the unfavorable mobility ratios as well as the reservoir permeability variation and heterogeneity. The injected CO_2 after partial enrichment will tend to override and pass the un-swept oil resulting in bad sweep efficiency. Another hypothetical run, just for comparison, was carried out assuming full displacement of oil

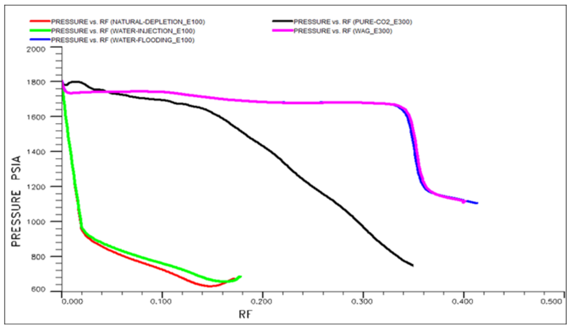

Figure 5.5: Pressure verses recovery factor for all studied cases

with CO_2 from the beginning of project life which resulted with law oil recovery (EUR = 34%) confirming the inefficiency of CO_2 injection (due to high mobility factor). CO_2 Injection will not add any value over water flooding, when we compare both predictions, as illustrated in Figure 5.5.

6. Conclusions

- Al Sharara A-NC186 field is producing from shallow Memouniat reservoir and is characterized by low GOR fluid (400 scf/stb) and light API gravity of 40º API. The field has weak energy by nature (Pi~1816 psia) which necessitates the introduction of external energy through water and/or gas injection to maintain the pressure and prolong its life.
- Natural depletion is not the optimal and feasible development option for the A-NC186 field. Reservoir pressure is steeply declining and will drop below the bubble point within two years. The production plateau period is short and the exploitation life of the field will not exceed 11 years with EUR of around 17.8% .

- Water injection into the aquifer is hindered by the impermeable layers and will not properly act to pressure maintenance neither to oil recovery improvement. Water injection into the aquifer almost behaves like natural depletion option .

- The optimal and feasible development scenario is the water flooding with the proper monitor and management of the injected water into the reservoir and also the proper distribution of the flooded water across the vertical section. Water flooding will prolong the well life and exploitation period (16 years) and also substantially improves the ultimate oil recovery.

- CO_2 WAG injection will not add any value to recovery enhancement for the A-NC186 field, mainly due to; heterogeneity of the reservoir, unfavorable mobility ratio between CO_2 and A-NC186 crude, and CO_2 is not fully miscible and because of high mobility ratio will tend to over pass oil and accordingly decreases its sweep efficiency.

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