

N° Série :/2021

Université Kasdi Merbah Ouargla



Faculté des Hydrocarbures, Energies Renouvelables et Science de la Terre et de l'Univers

Département de Production des Hydrocarbures

MEMOIRE

Pour obtenir le Diplôme de Master

Option : Production Académique

Présenté Par :

RAHMANI Abderrahmane, AOUACHERIA Ramzi, HAFNAOUI Abir

-THÈME-

Effect of the natural fracture reservoirs in the selection of the enhanced oil recovery
mechanism: Rhourde El Baguel reservoir – case

Soutenue le : / / 2021 devant la commission d'examen

Président :	GHALI AHMED		Univ. Ouargla
Rapporteur :	DJEBBAS FAYCAL	MCB	Univ. Ouargla
Examineur :	LEBTAHI HAMID		Univ. Ouargla

Acknowledgements

We first thank ALLAH, the almighty who enlightened
our way,
and gave us the courage, strength and patience to
complete this work.

We would also like to thank our promoter Mr DJABBES Faycel
for having accepted to lead this work with a lot of patience, we
thank you for your guidance and advice that you gave us during
this work. and we would also like to give a special thank you to Mr. NAOUI Ahmed,

Mr. BOUREDHA Abderraouf and all who helped us
during our trainee in REB

Our thanks also go to the president of the jury and to the
reviewers for doing us the honor of judging this work.

We thank all those who contributed directly or indirectly to the achievement of this brief.

Finally, our thanks go to all teachers
encountered in our course

DEDICATION

I dedicate this dissertation :

To my effort during these years

To my lovely parents may god keep them

To my brothers and wonderful sisters

*To my friends To my colleagues ramzi and Abderrahmane who have
supported me throughout the process*

HAFNAOU ABIR

DEDICATION

*I dedicate this modest work to my beloved parents for their love,
Patience, care, and continuous support during the five years of my*

Study

To my wonderful parents who have raised me to be the person, I am

Today.

Thank you for everything.

It is also dedicated to whom I love.

To my brother and sister for their encouragement and love.

To all my family

To My uncle Mr.Nasser for his biggest help throughout my career

To all the workers of ISOFROID Group

To all my teachers

To my best friend Akram

*To my colleagues Abderrahmane and Abir who completed this work
with me*

To all my friends and colleagues without exception.

I would like to say ‘ Thank you So much ‘

AOUACHERIA RAMZI

Dedication:

Every challenging work needs self efforts as well as guidance of elders especially those who were very close to our hearts.

My humble effort I dedicate to the memory of my Father who was always there for me, and to my mother who still supports me no matter what,

With my little sister who brightens my life

*Along with all hard working and respected
Teachers*

*As well as my colleagues Ramzi and Abir who
completed this work with me*

*RAHMANI
ABDELRAHMANE*

Abstract

Naturally fractured reservoirs are complex media and difficult to understand because of the peculiarity of the duality of matrix-crack media, cracks through which the fluid flows towards the well bottom have totally different characteristics to that of the matrix blocks in which the fluid is stored, the naturally fractured reservoirs are characterized by an enormous drop in production following a period of production with high flow rates.

The detection of the presence of fractures in the reservoirs is done by several techniques or well testing is one such technique. The need for improved recovery techniques (EOR) is very necessary following the huge drop in production in fractured reservoirs, but the choice of which EOR mode to apply is very difficult.

In Algeria the Rhourde El baguel reservoir (REB) is one of the naturally fractured reservoirs and its production has experienced a huge drop following the application of massive gas injection to achieve miscibility.

The aim of this work is to do an analytical study to derive conclusions to aid in the selection of enhanced or enhanced recovery mode to increase the rate of oil recovery (the ultimate oil recovery).

Key Words: Fractured reservoir, miscibility, dual permeability-porosity, EOR.

Résumé

Les réservoirs naturellement fractures sont des milieux complexes et difficiles à comprendre à cause de la particularité de la dualité des milieux matrice-fissure, les fissures à travers lesquelles le fluide s'écoule vers le fond de puits ont des caractéristiques totalement différents aux caractéristiques des blocs matriciels dans lequel le fluide se stocke, les réservoirs naturellement fracturés se caractérisés par une chute de production énorme suite à une période de production avec des grands débits.

La détection de la présence des fractures dans les réservoirs se fait par plusieurs techniques ou les tests des puits est l'une de ces techniques.

Le besoin des techniques de récupérations améliorées (EOR) est très nécessaire suite à la chute énorme de la production dans les réservoirs fracturés mais le choix du mode d'EOR à appliquer est très difficile.

En Algérie le réservoir de Rhoured Elbaguel (REB) est l'un des réservoirs naturellement fracturés et sa production a connu une chute énorme suite à l'application de l'injection massive de gaz pour but d'atteindre la miscibilité.

Le but de ce travail est faire une étude analytique pour dériver des conclusions pour aider à la sélection de mode de récupération assistée ou améliorée pour augmenter le taux de récupération d'huile (the ultimate oil recovery).

Mots clés : Réservoir fracturé, la miscibilité, dual permeability-porosity, EOR.

المخلص

الخرانات المكسورة بشكل طبيعي هي وسائط معقدة ويصعب فهمها بسبب خصوصية ازدواجية وسائط صدع المصفوفة ، والشقوق من خلال التي يتدفق فيها السائل نحو قاع البئر لها خصائص مختلفة تمامًا عن خصائص كتل المصفوفة التي يتم فيها تخزين السائل ، تتميز الخزانات المكسورة بشكل طبيعي بانخفاض هائل في الإنتاج بعد فترة إنتاج ذات معدلات تدفق عالية.

يتم الكشف عن وجود كسور في الخزانات بعدة تقنيات أو اختبار البئر هو أحد هذه التقنيات. تعد الحاجة إلى تقنيات الاسترداد المحسنة أمرًا ضروريًا للغاية في أعقاب الانخفاض الكبير في الإنتاج في الخزانات المكسورة ، ولكن اختيار وضع الاستخلاص المعزز للنفط الذي سيتم تطبيقه أمر صعب للغاية.

في الجزائر ، يعتبر مكن رور الباجويل (REB) أحد الخزانات المكسورة طبيعياً وقد شهد إنتاجه انخفاضاً هائلاً بعد تطبيق الحقن الضخم للغاز لتحقيق الامتزاج.

الهدف من هذا العمل هو إجراء دراسة تحليلية لاستخلاص استنتاجات للمساعدة في اختيار وضع الاسترداد المحسن أو المعزز لزيادة معدل استرداد النفط (الاسترداد النهائي للنفط).

الكلمات المفتاحية :

الخران المكسور ، الامتزاج ، النفاذية المزدوجة والمسامية ، الاستخلاص المعزز للنفط.

Table of Contents

Acknowledgements	
Dedications	
Abstract	
List of Figures	
List of Tables	
Symbols – abbreviations	
General Introduction	01

Chapter I: Naturally Fractured Reservoirs

1.1. Definition	02
1.2. Fracture properties	05
1.2.1. Fracture opening	05
1.2.2. Fracture size	05
1.2.3. Nature of fracture	05
1.2.4. Azimuth and dip	06
1.2.5. The length and shape	06
1.3. Characterization of naturally fractured reservoirs	06
1.3.1. Porosity	06
1.3.1.1. Definition of double porosity	07
1.3.2. Permeability	07
1.3.2.1. Intrinsic fracture permeability K_{if}	08
1.3.2.2. Permeability of fracture-matrix system	09
1.3.2.3. Relative permeabilities in fractured reservoir	09
1.3.3. Compressibility in fractured rock	10
1.3.4. Capillary pressure curve	10
1.3.5. Spontaneous imbibition	11
1.3.6. Fracture- matrix interaction	11

Chapter II: Indicators of NFRs

2.1. Indicators of natural fractures	12
2.1.1. Drilling	12
2.1.2. Coring	13
2.1.3. Well logs	14
2.1.4. Well test analysis	15
2.1.4.1. Homogeneous reservoir model	17
2.1.4.2. Multiple region or composite reservoir model	18
2.1.4.3. Single-fracture model	19
2.1.4.4. Anisotropic reservoir model	20
2.1.4.5. Double-porosity model	20
2.1.5. Very high productivity index	23

Chapter III: Enhanced oil recovery methods applied in NFRs

3.1. Introduction about the EOR methods applied in NFRs	24
3.2. EOR Methods On NFRs	24
3.2.1. Chemical flooding	24
3.2.1.1. Chemical flooding in naturally fractured reservoirs	25
3.2.2. Thermal recovery in fractured reservoir	27

3.2.2.1. Effect of temperature on reservoir rock and fluids	27
3.2.2.1.1. Rock porosity and permeability	27
3.2.2.1.2. Reservoir wettability	27
3.2.2.1.3. Capillary pressure curves	27
3.2.2.1.4. Relative permeability	28
3.2.2.1.5. Oil viscosity	28
3.2.2.1.6. Thermal conductivity	28
3.2.2.2. Mechanisms of thermal recovery from NFRs	28
3.2.2.2.1. Thermal expansion	28
3.2.2.2.2. Gas generation	29
3.2.2.2.3. Gravity drainage	29
3.2.2.2.4. In-Situ steam generation	29
3.2.2.2.5. Rock compaction	29
3.2.3. Miscibility	30
3.2.3.1. Carbon dioxide flooding	31
3.2.3.2. Water alternating gas	32
3.3. Selection of Proper EOR Method for Efficient Matrix recovery	32
3.3.1. Procedure	32
3.3.2. Selection Criteria for proper EOR fluid	34
3.3.2.1. Sandstones	34
3.3.2.2. Carbonates	35

Chapter IV: Rhourde El Baguel - Case study

4.1. Introduction	36
4.2. The fields of REB	36
4.2.1. Geographical situation	36
4.2.2. Field history	37
4.2.3. Production history	37
4.2.4. REB reservoir zones	37
4.2.5. Fracture network characterization in REB's reservoir	38
4.2.5.1. Aspect by coring	38
4.2.5.2. Logging aspect (Imagery)	41
4.2.5.3. Fracture index	41
4.3. Three major weaknesses	42
4.3.1. Understanding and modeling the fractures	42
4.3.2. Efficiently using the wealth of the acquired data	43
4.3.3. Lack of pilot tests	44
4.4. Results of the simulation	44
4.5. Impact of massive gas injection	46
4.6. Analysis of Tracers	48
4.7. Gas shutoff	49
4.8. Gas recycling	51
4.9. Seasonal Gas Injection	52
Conclusion	54
Bibliography	
Annexes	

List of Figures

Figure I.1: Naturally fractured rock cores taken from wells.	02
Figure I.2: Porosity distribution in fractured rocks.	03
Figure I.3: Nelso classification of NFRs.	03
Figure I.4: porosity and permeability distributin in fractured rocks.	04
Figure I.5: Reduction of fracture width as an effect of reservoir pressure depletion.	05
Figure I.6: Azimuth and dip of an inclined plane.	06
Figure I.7: Matrix blocks containing a single fracture.	08
Figure I.8: Anomalously shaped relative permeability curve.	09
Figure II.1: Mud loss indication and pit level behaviour in pores, natural fracture, and induced fractures.	12
Figure II.2: Typical distribution of porosity in the carbonate O-BOR-2E Reservoirs, Barbura Field, Venezuela.	13
Figure II.3: Dipmeter FIL.	14
Figure II.4: Images log FMS.	15
Figure II.5: Semilog pressure buildup curve is typical of fractured formation.	16
Figure II.6: Types of NFRs.	17
Figure II.7: Derivative and semilog graph for radial flow in homogeneous reservoir.	18
Figure II.8: Derivative and semilog graph for radial flow in a two-region reservoir.	19
Figure II.9: Derivative and specialized graphs for a well near a conductive fault.	19
Figure II.10: Log-log graph for observation pressures in interference tests in an anisotropic reservoir.	20
Figure II.11: Derivative and semilog graph for radial flow in a double porosity reservoir.	22

Figure III.1: Miscibility Method.	31
Figure III.2: Different boundary conditions used in the experiments.	33
Figure IV.1: The structure of REB.	36
Figure IV.2: Typical Upper Zone Shear Fractures.	38
Figure IV.3: Typical Lower Zone Shear Fractures.	38
Figure IV.4: Upper zone fractures.	39
Figure IV.5: Core analyses porosity and permeability REB 45.	40
Figure IV.6: UBI images and accompanying core section REB 45.	41
Figure IV.7: Fractures index in REB.	42
Figure IV.8: Evolution of production during the contract.	45
Figure IV.9: History of production of the Field REB since 1962 until 31/05/2021.	46
Figure IV.10: Analyze of tracers in REB Field.	49
Figure IV.11: Evolution of gas and oil rate before, during and after gas shutoff of RB43.	50
Figure IV.12: Evolution of gas and oil rate before, during and after gas shutoff of RB12.	50
Figure IV.13: Evolution of gas and oil rate before, during and after gas shutoff of RB57.	51
Figure IV.14: Gas potential in REB.	51
Figure IV.15: Evolution of GOR in REB before and after the reduction of injection.	52
Figure IV.16: Oil potential of REB.	53
Figure IV.17: Before and after the closure of the injection wells.	53

List of Tables

Table II.1: Parameters and applications of flow models for NFRs.	23
Table IV.1: Upper Zone vs Lower Zone Fracture Character.	38
Table IV.2: The fractures in the REB.	39
Table IV.3: Petrophysical Characterization of different zones.	40
Table IV.4: Tracer injected in INJ 01 from 16/18-Feb.	48
Table IV.5: Tracer injected in INJ 02 from 25-Mar to 1-Apr.	48
Table IV.6: Tracer injected in INJ 03 FROM 21-Juin-99 to 24 –Juin-99.	48

Symbols – abbreviations

EOR :	Enhanced oil recovery
NFRs :	Naturally Fractured reservoirs
IFT :	Interfacial tension
WAG :	Water Alternating Gas.
REB :	Rhourde el baguel
BP :	British petroleum
ARCO :	Atlantic Richfield Company
UBI:	Ultrasonic borehole image
BOPD :	Barrel oil production daily
OOIP :	Original Oil in place
PLT :	Production logging tool
GSO :	Gas shut off
Ri :	Isotropic reservoir
Ra :	Anisotropic reservoir
Swi :	Irreducible Water Saturation
UBI:	Ultrasonic borehole image
FIL :	Fracture Identification Log
FMI :	Fracture Micro Imager
MDI :	Modular Dynamics Tester
FMS :	Formation Micro Scanner
ATV :	Acoustic Tele-Viewer
Pi:	Initial reservoir pressure (P _{sia}).
b :	Fracture width (ft).
V _f :	Relative volume of fractures
V _m :	Relative volume of the matrix
φ _t :	Total porosity
φ _l :	Primary porosity

ϕ_2 :	Secondary porosity
K _{if} :	Intrinsic fracture permeability (md).
Q _f :	Flow in Fracture (bbl/d).
$\Delta p / \Delta L$:	Pressure gradient (Psia/ft)
A :	Cross-section (ft ²)
a :	Width of the simple(ft)
L :	Length of the simple (ft)
h :	Height of the simple (ft)
μ :	Viscosity (cp).
P :	Pressure (Psi).
K _t :	Permeability of fracture-matrix (md).
K _m :	Matrix Permeability (md).
K _o :	Oil Permeability (md).
K _w :	Water Permeability (md).
S _w :	Water Saturation
S _o :	Oil saturation
C _{pf} :	Compressibility of the pores in the matrix (Psi ⁻¹).
C _{pm} :	Compressibility of the pores in the fracture (Psi ⁻¹).
C _t :	Total compressibility (Psi ⁻¹).
C _o :	Oil compressibility (Psi ⁻¹).
C _w :	Water compressibility (Psi ⁻¹).
C _p :	Compressibility of pores (Psi ⁻¹).
C _{tf} :	Total compressibility of the fractures (Psi ⁻¹).
C _{tm} :	Total compressibility of the matrix (Psi ⁻¹).
kh :	Transmissibility (md.ft).
k _{max} :	Maximum permeability (md).
k _{min} :	Minimum permeability (md).

Ω :	Storativity ratio
λ :	Interporosity flow coefficient
η_{ma} :	Matrix hydraulic diffusivity
η_f :	Fracture hydraulic diffusivity
r_w :	Wellbore radius (ft)
h_{ma} :	Characteristics length of matrix block
V_b :	Rock bulk volume (ft ³).
V_{ma} :	Matrix volume (ft ³).
A_{fb} :	Matrix/fracture areas of interaction per unit of rock volume
x_d :	Average fracture-damage thickness (ft ⁻¹).
k_d :	Average fracture-damage permeability (md).
S_{maD} :	Skin factor of restriction in the matrix/fracture interaction
P_c :	Capillary pressure (Psi).
σ :	Shape factor
V_c :	Critical velocity
V :	Velocity
RF :	Recovery factor
MMP :	Minimum pressure of miscibility (Psi).

General Introduction

Naturally fractured reservoirs occupy the first places in the world's reserves and form a very special class of hydrocarbons reservoir, Their study is very specific and complex due to the secondary porosity and permeability of the fractures network, For the petroleum engineer, oil production finds itself in a paradox relative to the dual behavior observed in fractured reservoirs compared to unfractured reservoirs.

Fracture networks not only have positive effects on the dynamic behavior of the deposit, but they can act as a barrier or promote the circulation of hydrocarbons by creating anisotropy of the flow of fluids.

An enhanced oil recovery (EOR) application principally targets to minimize the residual oil in matrix depleting the matrix as effective as possible and/or to accelerate the recovery rate for rapid production of oil cost efficiently.

In Algeria, the Rhourd El-Baguel (REB) field located in the south-east of the country is considered according to its geological structure (Upper Cambrian fractured quartzites) in 1992 Sonatrach launched a call for tenders from foreign companies with the aim of increasing the recovery rate in this context an improved recovery project (EOR) consists of the massive injection of high pressure miscible gas was launched by Arco .

This work is made up of four chapters:

The first chapter: presents definitions and characteristics of fractures and fractured reservoirs.

The second chapter presents the indicators of naturally fractured reservoirs NFRs.

The third chapter introduction about EOR methods applied in NFRs..

The fourth chapter presents a discussion and analyzes the actual data in rhoudh el baguel, with the aim of knowing the effect of fractures on the production and recovery of hydrocarbons.

Chapter I

Chapter I : Naturally Fractured Reservoirs

1.1. Definition

Naturally fractured reservoirs (NFRs) are geological formations with two distinct types of porous media: a rock matrix and a fracture network, which give the reservoir a dual porosity and permeability characteristics. Formed in many depositional environments including carbonates, shales and sandstones, NFRs represent more than 50 % of hydrocarbons reservoirs and contribute in a large extent to the worldwide production of oil and gas .[1]

Although, the majority of the hydrocarbon reservoirs are fractured to some extent, their fractures have an ignored effect on the fluid flow and storage. In the case of naturally fractured reservoirs, the fracture network has a significant impact on fluid storage and its conductivity, the reservoir performance and oil recovery . The fractures may appear in a single or multiple rock formations, due to the mechanical failures of the rock under natural geological stresses such as tectonic movements, lithostatic (overburden) pressure changes, thermal stresses, high fluid pressures, drilling activities, and even fluid extraction.

These fractures can have dimensions of several micrometers (micro-fissures) to several thousand kilometres (continental fractures). Neglecting or failing to determine the distribution, the orientation, the interconnectivity and the degree of mineral cementation of these fractures, can have serious consequences on the development and production from the reservoir such as designing inappropriate wells patterns or drilling unnecessary in-fill wells. Performing a proper characterization of a naturally fractured reservoir was always a challenging task especially during the earliest stages of the reservoir history. While, the complex role of the fractures during the primary and secondary recovery phases makes the naturally fractured reservoirs a production paradox. [2]

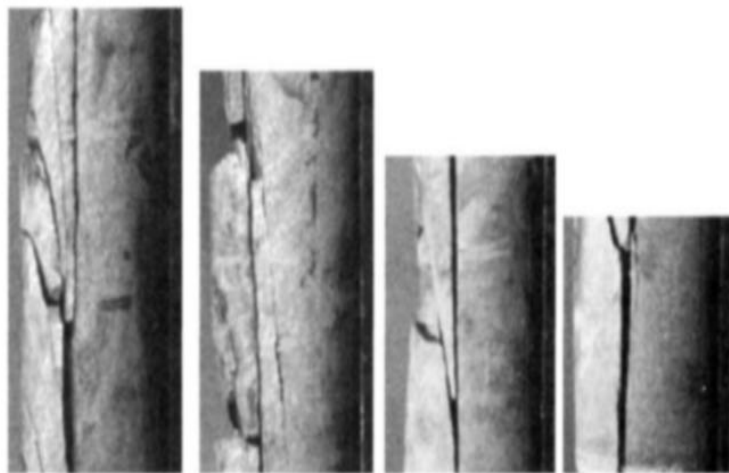


Figure I.1: Naturally fractured rock cores taken from wells. [3]

Chapter I : Naturally Fractured Reservoirs

Naturally fractured reservoirs can be classified in different types, depending on the storage capacities or porosity and permeability of the matrix and the fractures classified the naturally fractured reservoirs in types A, B and C (see Figure I.2).

In reservoirs of type A most fluid is stored in the matrix; the fractures provide only a very small storage capacity. Typically the matrix rock tends to have a low permeability, whereas the fractures exhibit a much larger permeability. In type B reservoirs approximately half of the hydrocarbon storage is in the matrix and half in the fractures. The fractures provide the storage capacity of type C reservoirs, without contribution of the matrix. [4]

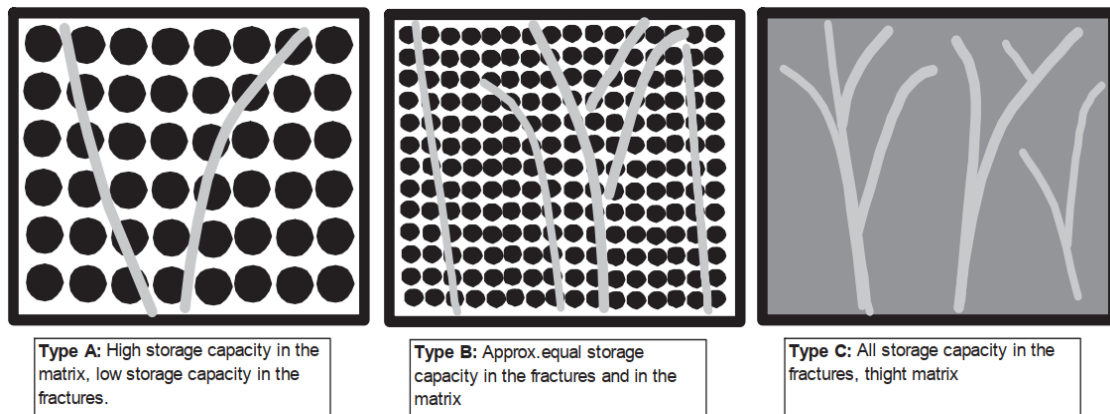


Figure I.2: Porosity distribution in fractured rocks. [3]

➤ Another classification of fractured reservoirs is given by Nelson : [3]

Nelson identified four types of naturally fractured reservoirs, based on the extent to which fractures have altered the porosity and permeability of the reservoir matrix.

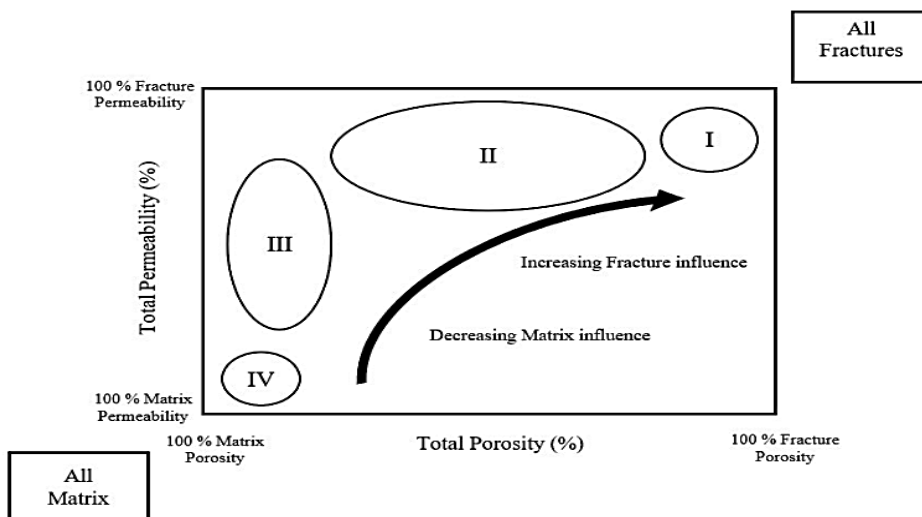


Figure I.3: Nelson Classification of NFRs. [3]

Chapter I : Naturally Fractured Reservoirs

Type 1: In type 1 reservoirs, fractures provide all the reservoir storage capacity and permeability. The matrix has a little porosity or permeability.

Type 2: In type 2 reservoirs, Rock matrix provides the essential storage capacity and fractures provide the essential permeability in a reservoir. The rock matrix has low permeability, but may have low or even high porosity.

Type 3: In type 3 naturally fractured reservoirs, the matrix has negligible permeability but contains most if not all the hydrocarbons. The fractures provide the essential reservoir permeability.

Type 4: In type 4 fractured do not provide significant additional storage capacity or permeability in an already producible reservoir, but instead create anisotropy.

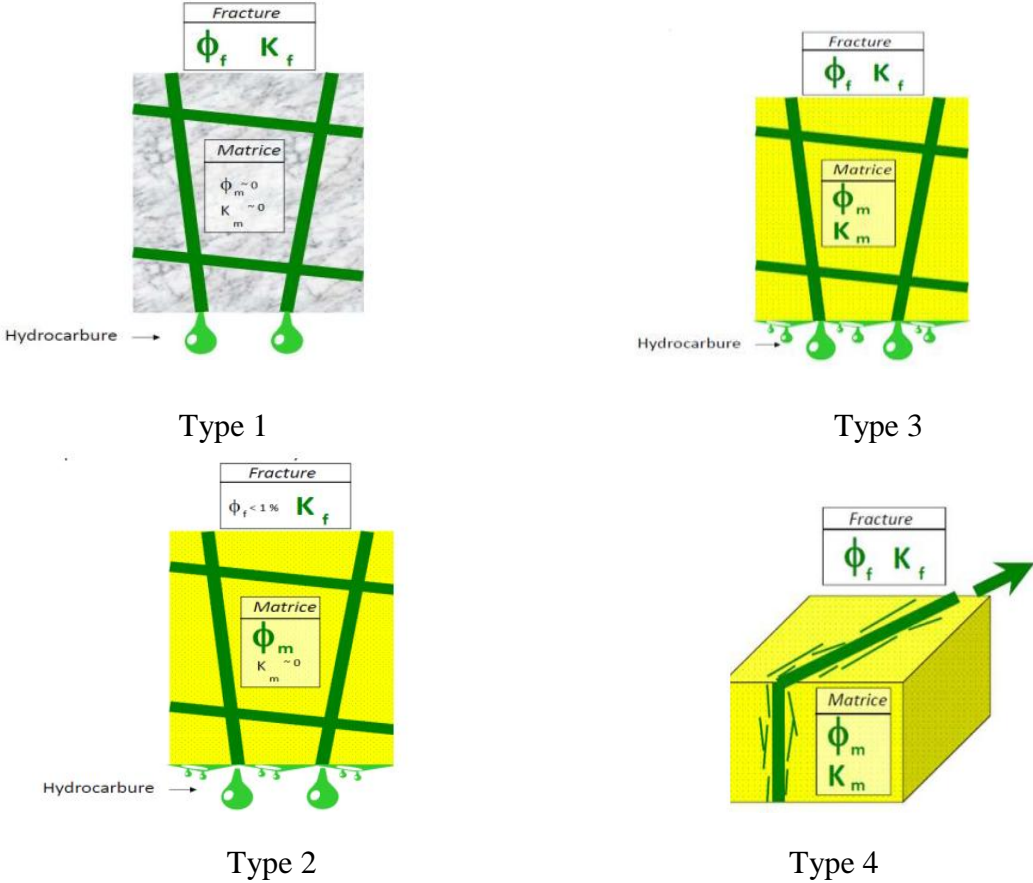


Figure I.4: Porosity and Permeability distribution in Fractured Rocks. [3]

Chapter I : Naturally Fractured Reservoirs

1.2. Fracture properties

1.2.1. Fracture opening

Fracture opening or fracture width is represented by the distance between the fracture walls. The width of the opening may depend (in reservoir conditions) on depth, pore pressure and type of rock. The fracture width varies between 10-200 microns, but statistics have shown that the most frequent range is between 10-40 microns. The fracture opening depends on the lithological petrography characteristics of the rock, nature of stresses and reservoir environment. [5]

1.2.2. Fracture size

Fracture size refers to the relationship between fracture length and layer thickness, especially if a qualitative evaluation is to be formulated. In this case fractures can be evaluated as minor, average and major 3:

- a. minor fractures have a length less than the single layer pay
- b. average fractures traverse more layers
- c. major fractures have a very large extension, often tens or even hundreds of meters.

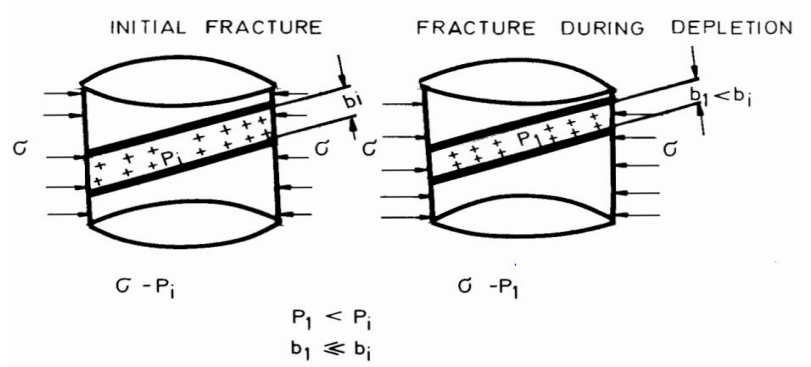


Figure I.5: Reduction of fracture width as an effect of reservoir pressure depletion. [5]

1.2.3. Nature of fracture

The nature of fractures mainly concerns the state of fractures under observation with reference to opening, filling and wall characteristics, and is generally discussed in the following terms:

- a. opening - open, joint, closed
- b. filling- mineral, various minerals
- c. closed by - homogeneous or diffused filling material
- d. fracture walls - rugose, smooth, polished, creeping . [5]

Chapter I : Naturally Fractured Reservoirs

1.2.4. Azimuth and dip

The azimuth is the average angle formed by the lineament of a fracture with respect to the north direction. The dip is the angle between the fault plane and the horizontal plane. [6]

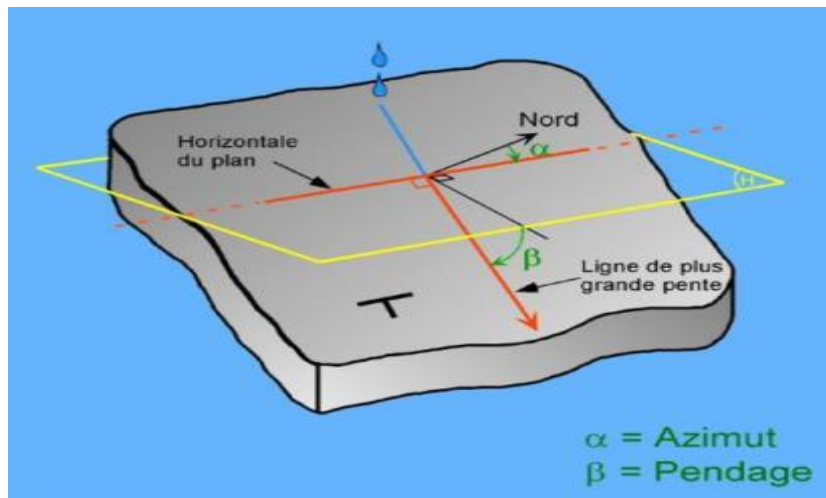


Figure I.6: Azimuth and dip of an inclined plane. [6]

1. 2.5. The length and shape:

The fracture is a plane discontinuity. It is modelled in 3D by a surface having a polygonal or elliptical shape and characterized by the length of the large radius of the ellipse.

In 2D space, the length of the fracture is the length of line segment corresponding to the intersection between the fracture and the observation plane

The dimensions can be millimetre (micro fractures), decimetric (minor fractures) or hectometre sees kilometric (major fractures). [6]

1.3. Characterization of naturally fractured reservoirs

1.3.1. Porosity

Porosity can be classified as primary or secondary:

- ✓ Primary porosity forms during deposition of sediments and includes interparticle and intraparticle porosities.
- ✓ Secondary porosity forms after deposition and develops during diagnosis by dissolution, dolomitization and through production of fractures in the rock.

The matrix porosity, also often called fabric porosity, can be both primary and secondary. The fracture porosity is always a secondary one and generally refers to porosity that occurs along breaks in sediment or rock body where there has been little mutual displacement along the fracture. [4]

Chapter I : Naturally Fractured Reservoirs

1.3.1.1. Definition of double porosity [5]

Fundamental it's obvious that the porosity of the matrix is different from that of fractures or the volume occupied by the networks of fractures and matrix blocks given by their relative volumes as a continuation.

$$V_f = \frac{\text{total volume of fractures}}{\text{total volume of the sample}} \quad (\text{I.1})$$

$$V_m = \frac{\text{total volume of matrix blocks}}{\text{total volume of the sample}} \quad (\text{I.2})$$

$$V_m + V_f = 1 \quad (\text{I.3})$$

In a fractured reservoir the total porosity (ϕ_t) is the result of the simple addition of the primary and secondary porosities.

$$\phi_t = \phi_1 + \phi_2 \quad (\text{I.4})$$

This total porosity is equivalent to the static definition of rock storage or total void space, the fracture porosity was considerably less than the matrix porosity. The two porosities are expressed by the conventional definitions:

$$\phi_1 = \frac{\text{matrix void volume}}{\text{total bulk volume}} \quad (\text{I.5})$$

$$\phi_2 = \frac{\text{fracture void volume}}{\text{total bulk volume}} \quad (\text{I.6})$$

Often secondary porosity is reduced with time by becoming partially filled with minerals younger than those of which the matrix is composed. These minerals are the result of dissolution and precipitation, occurring in large structures formed by limestones, dolomites, siltstones, etc., may be the result of tectonic or overburden stresses which reduce rock cohesion. [7]

1.3.2. Permeability

The permeability of a porous rock is a measure of the ability to transmit fluids. A reservoir can have primary and secondary permeability. The primary permeability is referred to as matrix permeability; the secondary permeability can be either called fracture permeability or solution vugs permeability. Matrix- and fracture permeability are other important parameters that have to be known for an estimate of the influence of the fractures on the overall reservoir performance. Solution vugs permeability refers to an increased permeability in matrix rocks (especially in carbonate reservoirs) where the natural permeability of the matrix is increased by percolation of acid waters that dissolve the matrix rock. [4]

Chapter I : Naturally Fractured Reservoirs

1.3.2.1. Intrinsic fracture permeability K_{if}

The intrinsic fracture permeability is associated to the conductivity measured during the **flow** of fluid through *a single fracture* or through a fracture network, independent of the matrix. It is, in fact, the conductivity of a single channel (fracture) or of a group of channels (Fracture network). [5]

In this case the **cross section** is represented **only by** the fracture void areas (excluding the surrounding matrix area). In a simplified case of a block, where the fracture is parallel to the flow direction (figure I.7, fracture 1 is parallel to the horizontal flow direction), the flow rate through the fracture is given by:

$$Q_f = a \cdot b \cdot \frac{b^2}{12\mu} \cdot \frac{\Delta P}{\Delta L} = a \cdot \frac{b^3}{12\mu} \cdot \frac{\Delta P}{L} \quad (I.7)$$

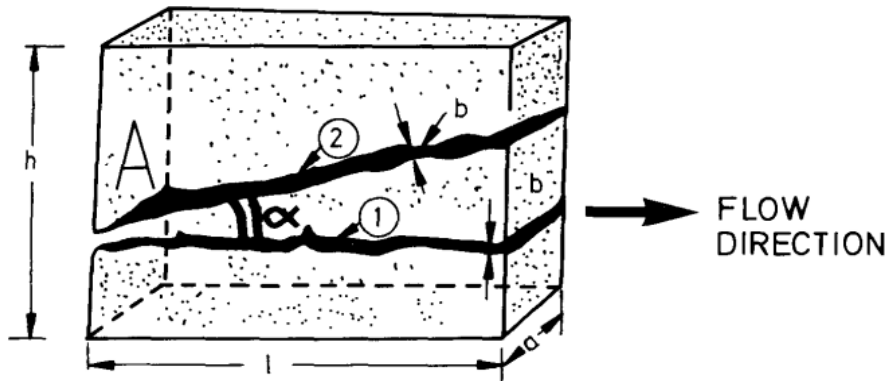


Figure I.7: Matrix blocks containing a single fracture. Fracture 1 ($\alpha=0$). Fracture 2 ($\alpha \neq 0$). [5]

If the single fracture forms an angle with the flow direction (figure 1.7, fracture 2), the cross-section (a.b) will remain unchanged, but the fracture will be projected on the flow direction:

$$Q_f = a \cdot b \cdot \frac{b^2 \cos^2 \alpha}{12 \mu} \cdot \frac{\Delta P}{L} \quad (I.8)$$

On the other hand, based on the Darcy concept:

$$Q_f = a \cdot b \cdot \frac{K_{ff}}{\mu} \cdot \frac{\Delta P}{L} \quad (I.9)$$

The further comparison between will lead to :

$$K_{if} = \frac{b^2 \cos^2 \alpha}{12} \quad (I.10)$$

For a fracture system having n fractures of similar orientation the intrinsic permeability is expressed by:

$$K_{if} = \frac{\cos^2 \alpha}{12} \left[\sum_1^n b_i^2 \right] \quad (I.11)$$

Chapter I : Naturally Fractured Reservoirs

For a fracture network formed by fracture systems α , each with its own orientation, the intrinsic permeability is :

$$K_{if} = \frac{1}{12} \left[\cos^2 \alpha \sum_1^{n_\alpha} b_{\alpha i}^2 + \cos^2 \beta \sum_1^{n_\beta} b_{\beta i}^2 + \dots \right] \quad (I.12)$$

1.3.2 .2. Permeability of fracture-matrix system

The permeability of a fracture-matrix system may be represented by the simple addition of the permeability of matrix K , and fractures K_f . [5]

$$K_t = K_m + K_f \quad (I.13)$$

1.3.2.3. Relative permeabilities in fractured reservoir

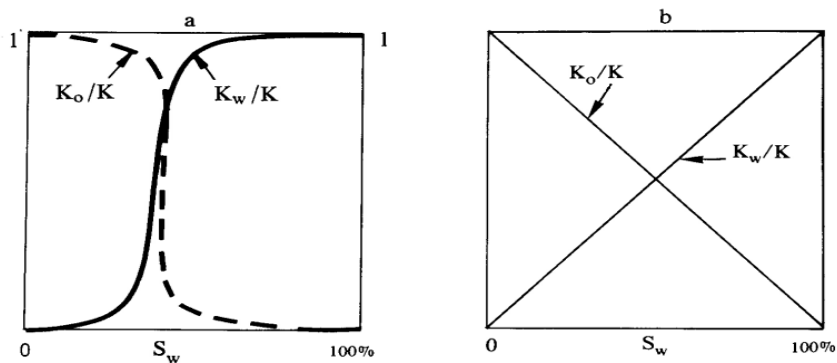
Relative permeabilities in a conventional reservoir are obtained from special core analysis. In a fractured reservoir, evaluation of relative permeability curves is complicated because of the nature of the double porosity system, where the fracturing plane between two matrix units develops a discontinuity in the multi-phase flowing process.[5]

In the literature the relative permeability of a specifically fractured reservoir is seldom examined, but the influence of heterogeneity within a porous media on relative permeability was studied in detail.

Since the behaviour of relative permeability vs. heterogeneity may be used as a basic approach of a fractured reservoir, it is interesting to examine the influence of flooding rate, core length, and wettability on the laboratory results in a heterogeneous reservoir .

Evaluation of relative permeability in heterogeneous rocks through water-flooding presents the risk of inaccuracy if an earlier water breakthrough has taken place. This means that the results become uninterpretable if the water breakthrough through fractures or vugs is ahead of the main advancing front in the matrix.

The fracture-matrix relative permeability curve in this case will resemble an anomalously shaped curve (Figure I.8) as a result of a piston-like displacement in some fractures (the largest), but not in the fracture-matrix system .



a) fractures not along core axis. b) fractures along core axis.

Figure I.8: Anomalously shaped relative permeability curve.

1.3.3. Compressibility in a fractured rock

In a fractured reservoir, compressibility of a rock system plays an important role, especially if there is a great contrast between the two porosities of matrix and fractures. The role of compressibility is essential in the interpretation of the transient pressure behaviour resulting from well testing. In this case, compressibility associated to the double porosity system is expressed by the **storage** capacity parameter which extensively controls pressure behaviour. [5]

For the fractured medium:

$$C_{tf} = C_0 + C_{pf} \quad (I.14)$$

C_{pm} and C_{pf} Are the compressibilities of the pores in the matrix and fractured medium respectively are defined according to the volume of the pores and not the total volume of the sample.

The capacity of each medium defined by:

- The matrix medium: $C_m = \Phi_m \cdot V_m \cdot C_{tm} \quad (I.15)$

- The fractured medium: $C_f = \Phi_f \cdot V_f \cdot C_{tf} \quad (I.16)$

- Total compressibility (rock and fluid) :

Total compressibility of the system, including the rocks and fluids which saturate the pores may be written as the sum of all terms contained in a porosity unit:

$$C_t = S_o C_o + S_w C_w + C_p \quad (I.17)$$

$$C_t = \Phi_m V_m C_{tm} + \Phi_f V_f C_{tf} \quad (I.18)$$

Generally the porosity of the fractures is negligible compared to that of the matrix; however, one can find capacities of the same order of magnitude this because of the large value of the total compressibility of the C_{pf} fractures.

Usually the compressibility of voids in C_{pf} fractures is 10 to 100 times greater than the compressibility of pores in the C_{pm} matrix block.

1.3.4. Capillary pressure curve

In a fractured reservoir the capillary pressure curve plays a much more important role than in a conventional reservoir. Capillary forces in fractured reservoirs are an extremely important component of the driving mechanism, while the dynamic role of the capillary forces in a conventional reservoir is more limited. In a fractured reservoir capillary forces may contribute to the displacement process inside the imbibition process, or may oppose it in the drainage displacement process. [5]

1.3.5. Spontaneous imbibition (SI)

Spontaneous imbibition, where water displaces oil from the matrix at the fracture by forces capillaries is an important recovery mechanism in fractured reservoirs. The large area open to imbibition in heavily fractured reservoirs can provide economical production rates, even in matrix reservoirs at low permeability. The spontaneous imbibition of water is a direct function of capillary forces and gravity, and depends on the pore system, wettability, sizes and shape of the matrix blocks, the interfacial tensions, the boundary conditions and the initial saturation in water . [6]

1.3.6. Fracture-matrix interaction

The hydrocarbon volume present in the high permeability fractures will be produced rapidly. After this “flush oil” production the rate will decrease rapidly before stabilizing at a lower decline rate. Fracture spacing and the amount of communication between the fracture and the matrix, as well as the drive mechanism will control the stabilized rate.

Depending, generally, on the contrast between matrix and fracture permeability and fracture spacing, the classical single continuum description may not be adequate for the simulation modeling of a fractured reservoir. For theoretical analysis and reservoir simulation, the irregular fracture distribution must be replaced by a regular matrix network (primary porosity) floating in the interconnected fractures (secondary porosity continuum). [8]

Chapter II

2.1. Indicators of natural fractures

Stearns and Friedman reviewed the multiple roles played by fractures in exploration and exploitation of naturally fractured reservoirs. They showed that fractures could alter the matrix porosity or the permeability, or both. If the fractures or connected vugs are filled with secondary minerals, they may restrict the flow. However, even in rocks of low matrix porosity, fractures and solution channels increase the pore volume by both increasing porosity and connecting isolated matrix porosity and therefore help the recovery of petroleum fluids economically. Hence, the ability to estimate a fractures' density and its distribution of porosity is essential for reservoir evaluation. One should keep in mind, however, that fractures alone constitute less than 1% of the porosity. [14]

2.1.1. Drilling

Loss of circulating fluids and an increase in penetration rate during drilling are positive indications that a fractured, cavernous formation has been penetrated (Figure2.1). [14]

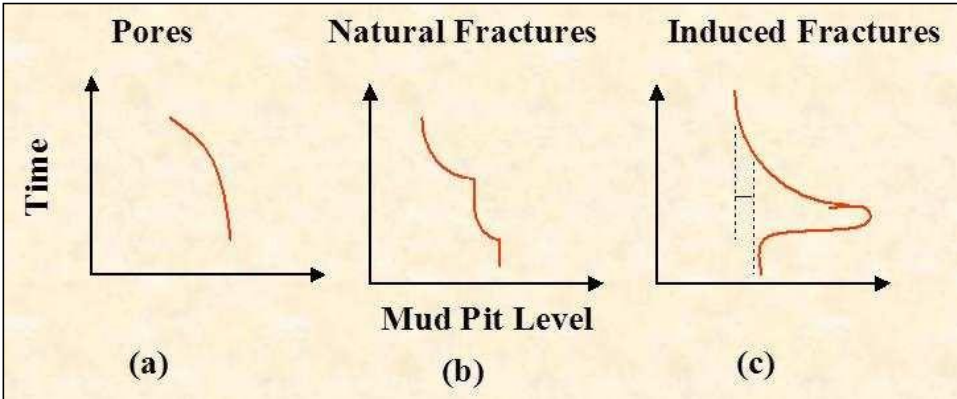


Figure II.1: Mud loss indication and pit level behavior in pores, natural fracture, and induced fractures. [14]

- (a) Gradual build-up in loss ratio with pressure ,
- (b) sudden start and exponential decline, and
- (c) Mud loss can occur as pumps are turned off/on

Chapter II: Indicators of NFRs

2.1.2. Coring

- Fractures and solution channels in cores provide direct information on the nature of a reservoir.
- A detailed systematic study of the cores must be made by geologist in order to distinguish natural fractures from those induced by core handling process.
- Careful examination of fracture faces and determination of density, length, width, and orientation, of fractures may lead to distinguishing fractures induced during coring from natural fractures.
- Preferably, naturally fractured formation should be analyzed with full diameter cores.
- Plug data, which do not reflect the permeability of fractures, often indicate a non-productive formation, whereas full diameter core data indicate hydrocarbon production.
- The actual production rates are several-fold higher than those calculated from permeability determined by core analysis, natural fractures not observed in the core are suspected.
- Low core recovery efficiency (less than 50%) suggests a highly fractured carbonate formation. [14]

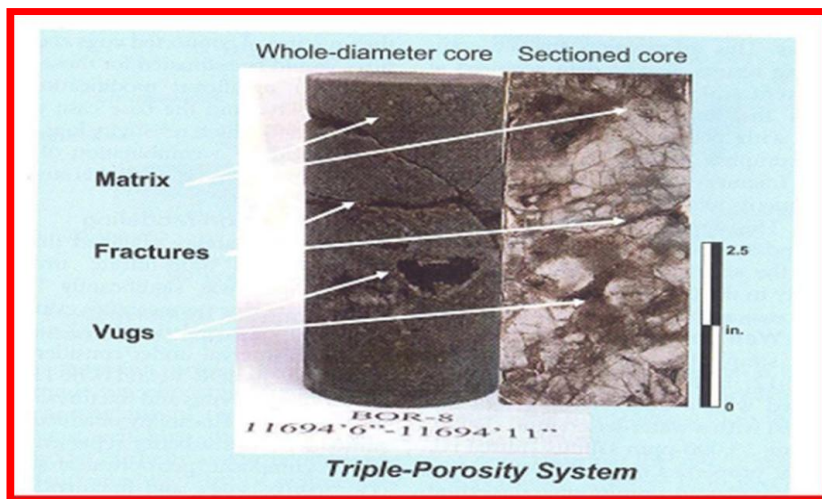


Figure II.2: Typical distribution of porosity in the carbonate O-BOR-2E Reservoirs, Barbura Field, Venezuela, The rock matrix is very tight; porosities range from 2 to 10%, and matrix permeability varies between 0.01 and 100 md [14]

Chapter II: Indicators of NFRs

2.1.3. Well logs

- Logging tools are designed to respond differently to various wellbore characteristics, such as lithology, porosity, and fluid saturation but not to natural fractures.
- The presence of large number of open fractures, however, will affect the response of some logging tools.
- Well loggings measurements based on sonic wave propagation, which are negligibly affected by the borehole conditions, are used as fracture indicators.
- Measurements by the calliper log, density log, or resistivity log, under proper conditions can be very effective in locating fractured zones.

Identification of fractured intervals is straightforward using resistivity images. The fractures fill with conductive. Drilling fluids and represent a Strong resistivity contrast to the Surrounding rock matrix.

Diameter data on FIL (Fracture Identification Log) and FMI (Fracture Micro Imager) provide most effective methods for fracture detection.

FMI images have allowed quantitative fracture evaluation and well comparison, providing data for completion design and reserve calculation.

Combination of FMI and dual packer MDI (Modular Dynamics Tester) adds a new dimension to fracture evaluation with the ability to straddle fracture intervals. [14]

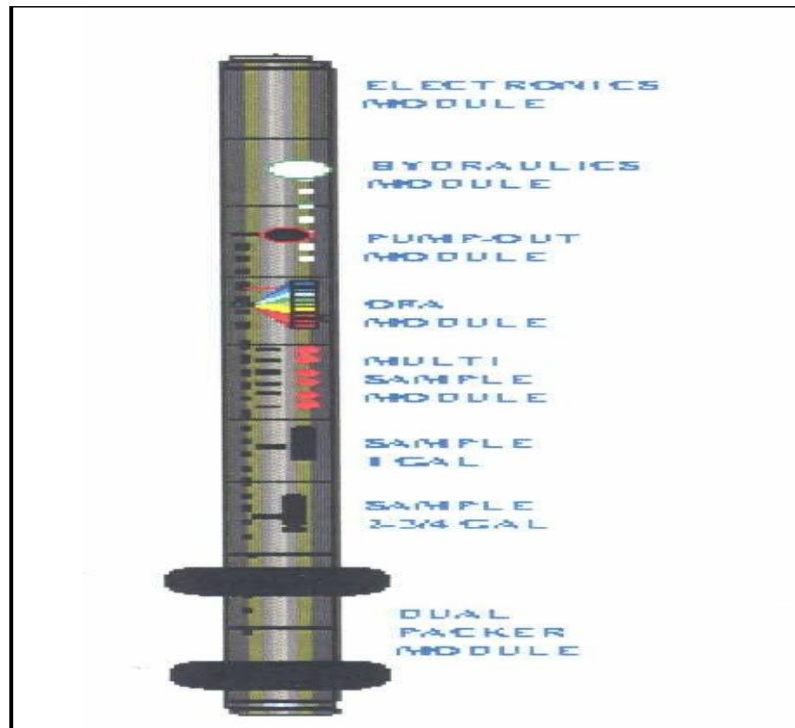


Figure.II.3: Dipmeter FIL [14]

Chapter II: Indicators of NFRs

- The openhole image logs such as Formation Micro Scanner (FMS), Formation Micro Imaging (FMI) and Acoustic Tele-Viewer (ATV) are widely used for detecting fractures in many oilfields.
- Borehole image logs in comparison to fullset openhole logs are costly, but they reveal important sub seismic images.
- Image logs have not been extensively used in the Iranian oilfields.
- The FMS was more commonly used in Iranian oilfield to determine orientation, dip and density of fractures.
- It was used to define fracture spacing and length for explaining of block size for reservoir modelling.
- This tool (FMS) can detect fractures that range from few millimeters to several centimeters long, distinguish two fractures as close as 1 cm apart and distinguish between open and close fractures.

Only fractures that are the least partially open contribute to production.

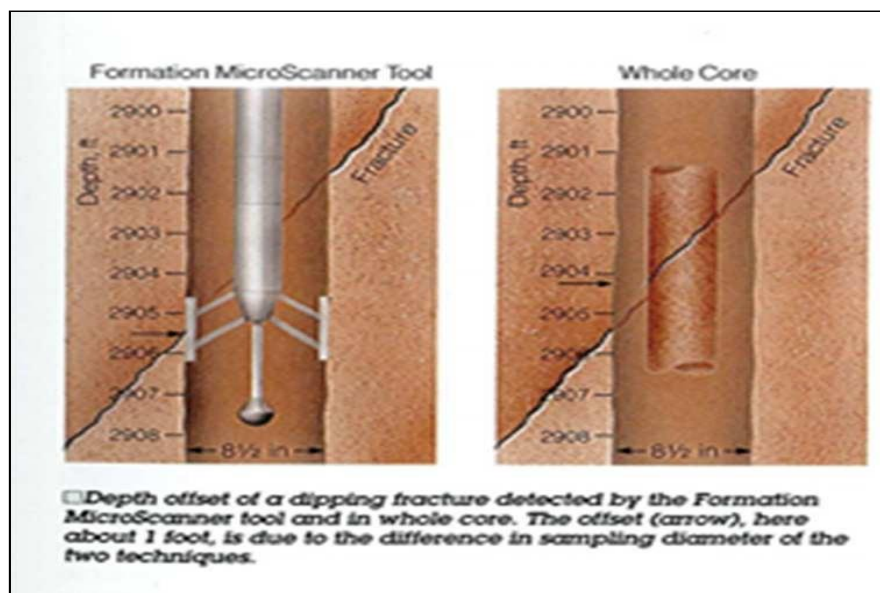


Figure II.4: Images logs FMS. [14]

2.1.4. Well test analysis

The subject of pressure buildup and flow tests in naturally fractured reservoirs has received considerable attention in the petroleum literature.

Chapter II: Indicators of NFRs

Warren and Root assumed that the formation fluid flows from the matrix to fractures under pseudosteady state and showed that a semilog pressure buildup curve similar to that shown in Figure II.5 is typical of fractured formation.

If the existing fractures dominantly trend in single direction, the reservoir may appear to have anisotropic permeability.

If enough observation wells are used, pressure interference and pulse tests provide the best results. [14]

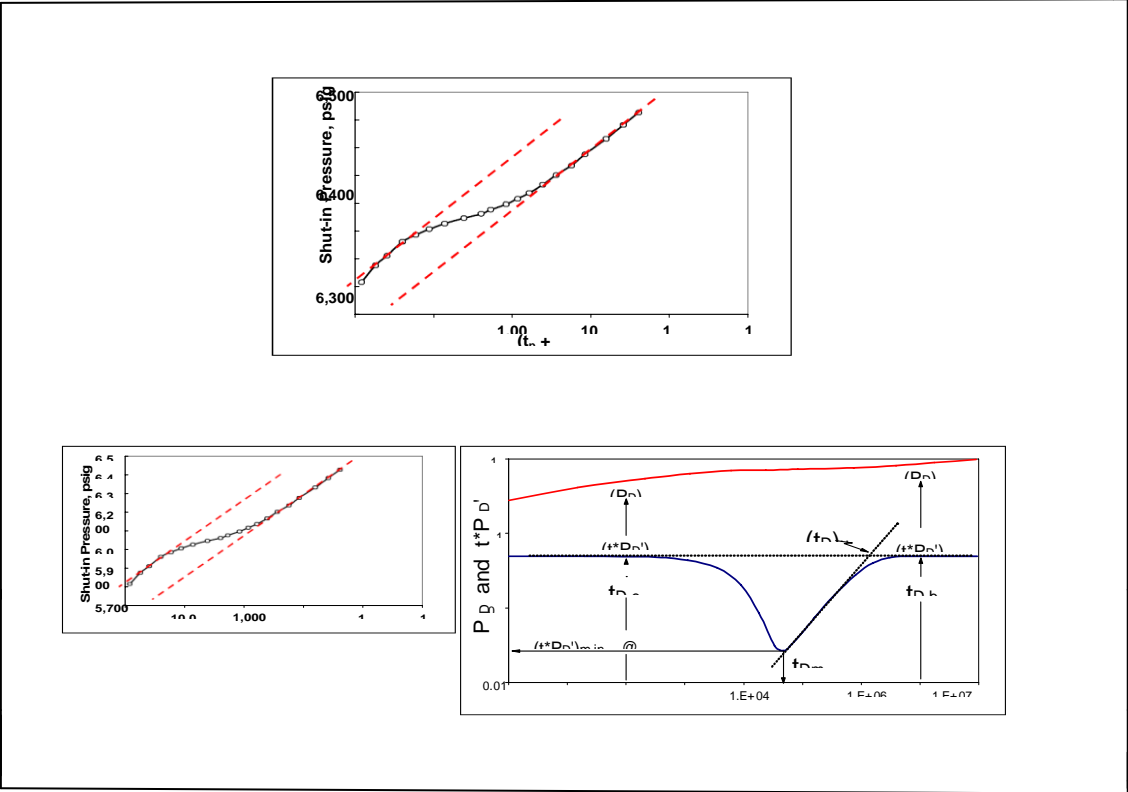


Figure II.5: Semilog pressure buildup curve is typical of fractured formation [14]

Well testing provides a powerful tool to detect and to evaluate heterogeneities in naturally fractured reservoirs (NFRs). Experience has shown that this type of reservoir may display behavior that consists applications and limitations of pressure transient tests in the evaluation of NFRs. [13]

Chapter II: Indicators of NFRs

2.1.4.1. Homogeneous reservoir model

This model considers that reservoir properties are constant and do not vary throughout the reservoir.

Fractures and rock matrix act as a single medium so that fluid production is caused by the simultaneous expansion of both elements, and fluid transfer between them, if any occurs instantaneously without resistance. This behavior is exhibited by either a heavily fractured reservoir with small matrix blocks (Figure II.6 a) or by an NFR where fluids are contained mainly in the fracture system (Figure II.6 b). The presence of fractures can be detected by the analysis of well logs and cores.

In general, well-test-analysis methods have been developed for homogeneous reservoirs. The pressure behavior in these systems is controlled by the formation flow capacity, kh ; porosity, Fluid viscosity, and total compressibility, c . An essential part of well-test-analysis methods is a flow-regime diagnosis achieved through the application of a log-log graph of both pressure and pressure derivative [9]. This process allows the detection of flow geometries and the presence of heterogeneities in the reservoir. The parameters of the system are estimated by use of the specialized graphs of pressure.

Figure II.7 illustrates the behavior of a single-well test (drawdown or buildup) for radial flow in homogeneous systems. The first part of the pressure-derivative graph (unit-slope straight line) shows the presence of well bore-storage effects followed (after a transition zone) by a horizontal portion representing a radial-flow behavior. The Kh of the formation and the skin factor can be determined from the straight line on the semilog graph. [11]

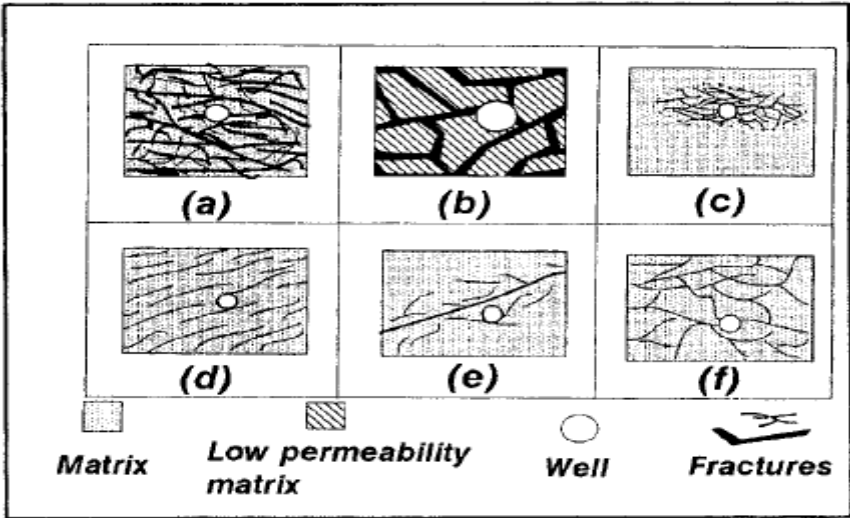


Figure II.6: Types of NFRs. [11]

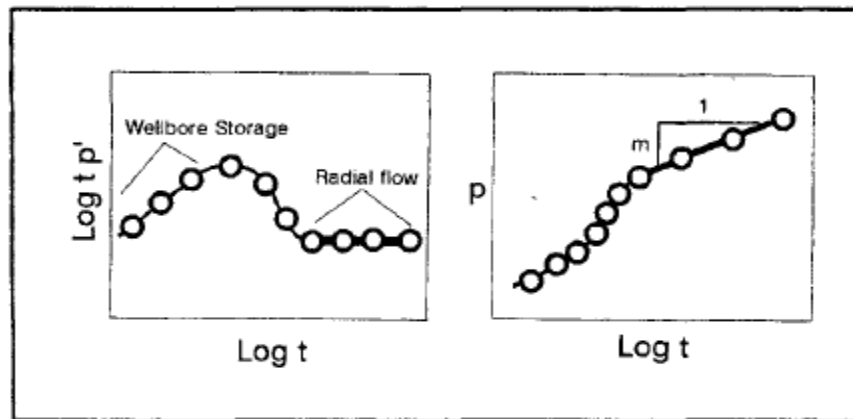


Figure II.7: Derivative and semilog graph for radial flow in homogeneous reservoir. [11]

2.1.4.2. Multiple region or composite reservoir model

Some NFR's are fractured regionally (Figure. II.6.c) and can therefore be considered to be composed of two regions: a high- and a low-transmissibility region. In this case, the reservoir behaves as a composite radial system [10]. Wells producing from the fractured region exhibit higher productivity than those in the unfractured region. The system is characterized by the flow capacity of both regions (kh) and (kh).

A single-well pressure test carried out in a well in the fractured region is first affected by the properties of this nearby region and then the pressure behavior is controlled by the unfractured region. (Figure.II.8) presents the graphs for the interpretation of this case. Here a log-log graph of the pressure derivative shows, at early time, the typical behavior for wellbore-storage effects, followed by a horizontal straight-line portion representing a radial flow controlled by the fractured region. Then, after a transition period, the derivative curve exhibits another straight-line portion above the first horizontal line. If a high contrast exists between the properties of the two regions, the transition period can reach a unit-slope straight line. Suggesting the presence of a pseudosteady-state flow; that is, the pressure varies linearly with time. This is similar to the pseudosteady-state flow that is exhibited by closed reservoirs at long times. [11]

The semilog graph shows two straight lines corresponding to the pressure data falling on the horizontal portions in the derivative graph. The flow capacity of both the fractured and unfractured regions can be estimated from the slope of these straight lines. The porous volume of the fractured region is calculated from the data falling in the pseudosteady -state-flow period.

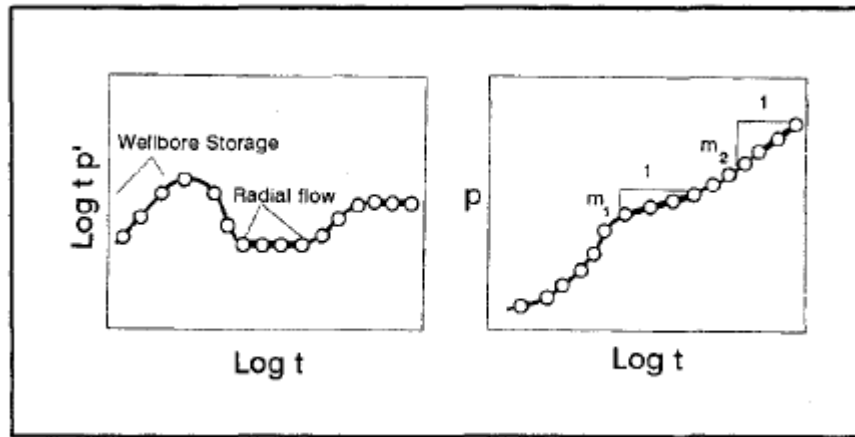


Figure II.8: Derivative and semilog graph for radial flow in a two-region reservoir. [11]

2.1.4.3. Single-fracture model

Sometimes a well is producing near a major fracture so that high flow rates are possible. The main fracture may represent a permeable fault that acts as a channel to drain reservoir regions located away from the wellbore (Figure II.6.e). The fracture can be detected and evaluated by well-test analysis [11]. According to the derivative log-log graph (Figure II.9), a single-well test is first affected by well bore-storage effects; then, if the fracture does not intersect the well bore, there is a radial-flow period (horizontal straight line); and, after a transition period, the well behaves as if it were located near a constant pressure boundary (1-slope straight line). Finally, the system reaches a bilinear-flow period represented by a one-quarter-slope straight line.

Figure II.9 presents the specialized graphs of interpretation. Here, the pressure data for the radial flow are analyzed by applying the semilog graph to estimate the formation flow capacity kh and the skin factors: is calculated from the slope of the straight-line portion in the constant pressure boundary graph (p vs. $1/t$). The conductivity of the fracture: is obtained from the Slope of the straight-line portion in the bilinear-flow graph.

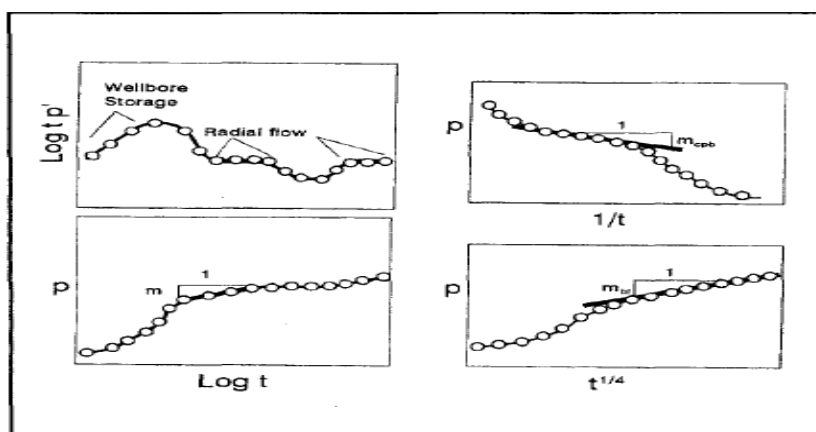


Figure II.9: Derivative and specialized graphs for a well near a conductive fault. [11]

Chapter II: Indicators of NFRs

2.1.4.4. Anisotropic reservoir model

Some NFR's exhibit parallel fracture planes (Figure II.6.d). The reservoir behaves as an anisotropic reservoir medium; that is, the equivalent permeability in the direction of fractures is much higher than the permeability in the direction normal to the fractures. This medium exhibits a maximum permeability, k_{max} and a minimum permeability k_{min} (Figure II.10).

The pressure-interference test is the ideal tool to evaluate the anisotropy parameters [12], including k_{max} , and k_{min} and the orientation of the principal axis of permeability. Simultaneous interference tests must be run with a minimum of three observation wells. As a recommendation, these wells must not be aligned in a straight line to ensure the correct evaluation of the parameters. The pressure responses of the observation wells look similar on a log-log graph (Figure.II.10), but they are displaced in time. The interpretation of the tests is carried out through the application of type-curve analysis for the radial-flow model by use of the line-source solution. Parameters of anisotropic reservoirs cannot be estimated from single-well tests because they only provide values for permeability that correspond to the geometric (average permeability: defined as: $(k_{min}k_{max})^{1/2}$). [11]

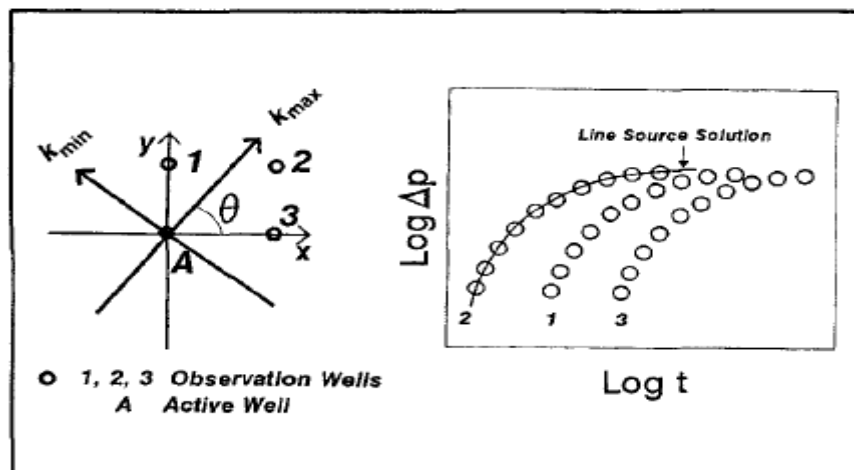


Figure II.10: Log-log graph for observation pressures in interference tests in an anisotropic reservoir [11]

2.1.4.5. Double-porosity model

This is the classic model for NFR's; it considers that the formation is composed of two media: fracture network and rock matrix. The fracture network essentially provides the reservoir-flow channels, and the hydrocarbons are contained in both parts of the system. The models is proposed to date in this category consider regularly shaped matrix blocks and assume that fluid transfer between matrix and fractures occurs through transient or pseudosteady-state

Chapter II: Indicators of NFRs

flow conditions. The matrix blocks are represented by cubes, parallelepipeds, cylinders, or spheres.

The behavior of the double-porosity model is characterized by several dimensions less parameters. A common variable for these models is the fracture storativity ratio, Ω , which represents the fracture expansion capacity defined as:

$$\Omega = (\phi c_t) / [(\phi c_t)_{ma} + (\phi c_t)_f] \quad (II.1)$$

In undersaturated reservoirs, (II.1) calculates how much oil is being produced from the fractures expressed as a fraction of the total oil produced; typical values of Ω are between 0.001 and 0.5.

Another parameter is the dimension less diffusivity of the matrix. [21]

$$\eta_{maD} = \eta_{ma} r_w^2 / \eta_f h_{ma}^2 \quad (II.2)$$

Where η_{ma} : matrix hydraulic diffusivity, η_f : Fracture hydraulic diffusivity, r_w : Wellbore radius, and h_{ma} : Characteristics length of matrix blocks. This parameter is related to how fast the matrix/fracture interaction occurs. Typical values of η_{maD} are between 10^{-9} and 10^{-4} . As the value of this parameter increases, the interaction between matrix and fractures occurs at shorter times.

A third parameter for double porosity reservoirs is the dimension less matrix/fracture interaction area defined as:

$$A_{fD} = A_{fb} V_b h_{ma} / V_{ma} \quad (II.3)$$

Where V_b = rock bulk volume, V_{ma} = matrix volume, and A_{fb} = matrix/fracture areas of interaction per unit of rock volume. A_{fb} is a key parameter in the imbibitions process present in water flooding or water encroachment. The value of A_{fD} is 2,4, and 6 for slabs, cylinders, and cubes, respectively.

In some NFR's, fractures are partially filled by minerals which reduce the flow interaction between matrix and fractures. This situation can be handled introducing a fracture skin factor expressed as:

$$S_{maD} = k_{ma} \bar{x}_d / \bar{k}_d h_{ma} \quad (II.4)$$

Where \bar{x}_d = average fracture-damage thickness and \bar{k}_d = average fracture-damage permeability. The effect of S_{maD} is to delay the interaction between matrix and fractures. For high S_{maD} values (severe restriction in the matrix/fracture interaction), the pressure behavior of the system can be described by two parameters only: Ω and λ . The λ results from a combination of A_{fD} , S_{maD} , and η_{maD} as:

$$\lambda = A_{fD} \eta_{maD} / S_{maD} \quad (II.5)$$

Chapter II: Indicators of NFRs

The values for λ are between 10^{-9} and 10^{-4} . A high value of this parameter indicates a fast interaction between matrix and fractures and vice versa. This case is referred to as the pseudosteady-state matrix flow model, or the Warren and Root model.

Figure II.11 presents typical behavior for a single-well test. Here, the log-log graph of the pressure derivative shows the wellbore storage effects at early time; and, after a transition period, there is a horizontal line showing a radial flow dominated by the expansion of the fractures. Following this, the rock matrix interacts with the fractures, producing a V-shaped curve; and finally, when the matrix-fracture fluid transfer reaches pseudosteady-state flow conditions, the derivative follows another horizontal line. The semilog graph shows two parallel straight lines, which represent the fracture dominated flow period and the total system (fracture/matrix) dominated flow period, respectively. The flow capacity kh of the total system is estimated from the slope of the semilog straight lines, and the skin factor is calculated from either the first or the second straight line.

The shape of the transition between the two partial semilog straight lines depends on the magnitude of the restriction of the matrix/fracture interaction; that is, if a free matrix/fracture interaction (no restriction) exists, the transition may approach a straight line with a slope equal to one-half the slope of the two parallel straight lines. The fracture area per unit of rock volume is estimated from the intersection of the transition straight line and the last straight line. If the matrix/fracture interaction is restricted, the transition zone approaches a stabilized value that can be used to calculate λ . [11]

The parameters of the double-porosity model may also be estimated through the application of type curves.

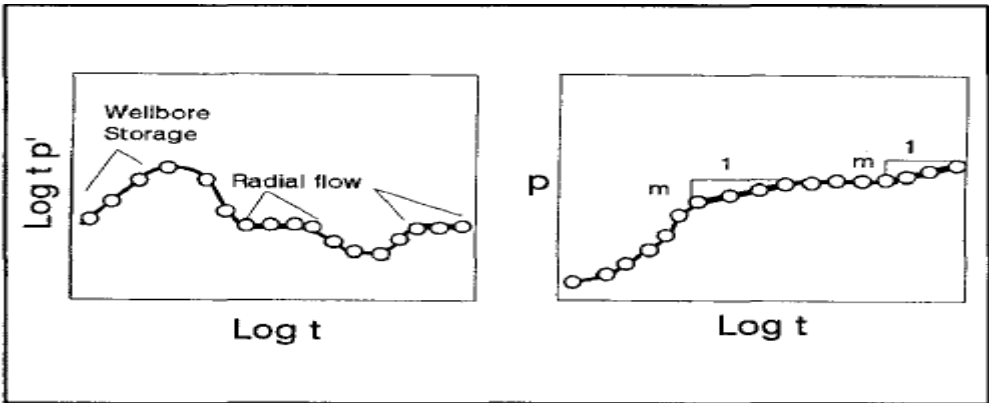


Figure II.11: Derivative and semilog graph for radial flow in a double porosity reservoir. [11]

Chapter II: Indicators of NFRs

Table II.1: Parameters and applications of flow models for NFRs. [11]

Model	Parameters	Applications
Homogeneous	kh and s	Highly fractured reservoir or low-permeability matrix
Multiple region or composite	$(kh)_1$ and $(kh)_2$, s	Regionally fractured reservoir
Anisotropic	k_{\max} and k_{\min}	Oriented fractures
Single fracture	F_{CD} , s_f , d_f , k_f , and s	Reservoir with dominant fracture or well near a permeable fault
Double porosity	$(kh)_f$, s , λ , and ω	Heavily fractured reservoir with intermediate matrix permeability

- The behavior of NFR's can be studied through the application of a variety of models that must be considered in simulation studies.
- Pressure transient testing provides a reliable tool to detect and to evaluate reservoir heterogeneities that affect the flow process and hydrocarbon recovery in NFR's.
- The application of the pressure-derivative curve is essential in the analysis of pressure tests to determine the proper flow model for the reservoir.
- Single and multiple-well tests are complementary for determining flow characteristics of reservoirs.
- Information obtained from a well test must be combined with data from other sources to understand their production mechanisms present in the reservoirs.

2.1.5. Very high productivity index

- Productivity index of 500 STB/D/psi or higher is typical of naturally fractured wells produced under laminar flow.
- Some wells in Iranian oilfields reported a productivity index of 100,000 STB/D/psi. In these wells 95% of flow is through fractures.
- A considerable increase in productivity of the well flowing after an artificial stimulation by acidizing is a strong indication of a naturally fractured formation.
- Acidizing is done essentially to increase the width of fractures and channels.
- Because of the high permeability of the fractures, the horizontal pressure gradient is typically small near the wellbore as well as throughout the reservoir.
- This is primarily true in Type-1 and to a lesser degree in Type-2 fractured reservoirs. [14]

Chapter III

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

3.1. Introduction about the EOR methods applied in NFRs

As most of the oil is stored in matrix due to its higher storage capacity than fracture network of naturally fractured reservoirs (NFR), reservoir development plans will aim at maximizing the matrix oil recovery. An enhanced oil recovery (EOR) application principally targets: [15]

- to minimize the residual oil in matrix depleting the matrix as effective as possible.
- to accelerate the recovery rate for rapid production of oil cost efficiently.

In fractured reservoirs there are four principal recovery processes,

- fluid expansion.
- capillary imbibition.
- diffusion and gravity-controlled displacement.

➤ There are three methods of enhanced oil recovery : [16]

- Miscible:
 - 1) Carbon Dioxides Flooding (CO_2)
 - 2) Nitrogen and Flue Gas Flooding,
 - 3) Enriched Hydrocarbon Gas Flooding.
- Chemical:
 - 1) Surfactant flooding,
 - 2) Polymer Flooding
 - 3) Alkaline Flooding.
- Thermal:
 - 1) Steam Flooding
 - 2) Fire Flooding.

3.2. EOR methods on NFRs

3.2.1. Chemical flooding

Chemical flooding includes a vast range of chemicals to help oil movement with different mechanisms. Three major mechanisms can be considered for chemical injection surface tension reduction, water shut-off, and wettability alteration. Although many chemicals are developed to EOR, the classifications can be limited to ASP and Polymer flooding.

The objective of ASP injection is interfacial tension reduction between oil and water to improve movement of trapped oil after water flooding.

Alkaline chemicals react with reservoir oil and create in situ surfactant. This surfactant is relatively cheaper than commercial surfactant. Also synthetic surfactant is injected with the alkaline. [18]

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

Another component of ASP is polymer, which is used to increase the viscosity of injected slug. This chemical controls the mobility of the ASP to increase efficiency. The polymer flooding process is used in high permeable reservoirs with high watercut. Polymers that are soluble in water are injected to the water sources in reservoirs to control the mobility of the water by viscosity thickening. Polymer injection is usually used in the first stages of the waterflooding to postpone the water breakthrough.

3.2.1.1. Chemical flooding in naturally fractured reservoirs

In chemical flooding, the fluid inside fractures may displace the oil out of matrix by viscous displacement, capillary displacement, and gradual mass transfer. If enough aqueous chemical solution is supplied in fractures in a water-wet NFR, capillary imbibition may significantly contribute to the oil recovery. Hence, the key to recovering oil is the wettability alteration to preferentially water-wet condition. Anionic surfactants can be used to shift the wettability of carbonates towards water-wet state. In absence of the capillary imbibition, then the gravity drainage may become the dominant mechanism. In gravity drainage, the surfactant molecules enter from fractures into the matrix via diffusion and convection. This changes the wettability and reduces the IFT. Consequently, gravitational forces overcome the entry capillary pressure and water invades the matrix and pushes the oil from the top. Furthermore, the injection of surfactant solution into oil-wet NFRs increases the oil relative permeability, enabling gravity to drain up the oil. Finally, since carbonate formations are normally positively charged; therefore nonionic and cationic surfactants are appropriate to reduce the surfactant adsorption. The alkali can also be used to reduce the surfactants adsorption.

Based upon chemical flooding pilot projects in NFRs, foremost factors have been identified in order to optimize the chemical flooding performance. The primary step to evaluate the efficiency in a large pilot or field is to run single well tests. Also, in order to reduce the water cut in the preferentially oil-wet NFRs, profile modification using cross linking gels is a possible candidate. The other suitable candidate might be treating wells with surfactant washes towards a large wettability alteration. Before performing any surfactant treatment, matrix stimulation might be necessary to further improve the near well-bore response. A wettability-shifting process like a surfactant-based chemical huff-n-puff process can also be carried out with different alkali/surfactant formulations. These two robust measures can reduce the water cut and improve the oil production. Finally, the main challenge of chemical flooding is the presence of fractures and vugs, which may prevent a uniform sweep and cause excessive chemical loss. Thus, to design the optimum slug size, chemical

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

loss to the fractures must be taken into account. Moreover, to obtain high oil recovery, the chemical slug composition should be optimized. [19]

The field projects of chemical flooding in NFRs have revealed several factors, which should be considered to design a successful flood. Several measures should be taken to assess the performance of chemical flooding. These include the tracer test, pressure fall-off test, temperature survey, monitoring water and oil production, and monitoring wellhead pressures and injection rates. In some NFRs, there exist problems associated with the clay swelling and migration and fractures. Clays swelling and migration limits injectivity and forces all the injected fluids into the fractures, causing premature breakthrough and poor sweep efficiency. The measures to overcome these obstacles are to stabilize the clays, to reduce the fracture flow, and to maximize the imbibition. To maximize the imbibition, pre-injecting alkali is an option. Also, another option is adding a wettability adjustment agent, such as a blend of an anionic polymer and an alkali. It is normally difficult to quantitatively measure the contribution of the wettability alteration in chemical flooding. However, it is believed that the wettability adjustment plays an important role in stabilizing a low water-oil ratio over a relatively long time.

Field-scale experiences of polymer flooding show that this process, if properly tailored to the reservoir condition, is an appropriate candidate for a NFR in which heterogeneities and high mobility ratios cause considerable oil bypassing. In addition, when the economics of surfactant flooding is unfavorable in the presence of extreme fracturing and heterogeneity, polymer flooding can be a candidate for a commercial project. In such cases, polymer flooding can significantly improve the oil recovery although there might be early polymer breakthrough. In particular, if a NFR is more matrix-dominated, then the performance of polymer flooding is more noticeable than that of a NFR influenced more by fractures with imbibition. The field projects have revealed several measures, which should be taken to design a successful flood. First, field test of polymer injectivity should be conducted to ensure injection without severe face plugging. A pressure fall-off test is also useful to assess any potential of near-well plugging problems. Second, care should be taken if polymer tends to cycle through channels or fractures. If polymer cycles through fractures and removes fines, then polymer breakthrough may cause tubular failure due to the entrained solids carried into the wellbore. In fact, oil recovery may decrease because of extensive polymer cycling. Finally, wellhead pressure should carefully be monitored during the flood. The reason is that an increase in wellhead pressure and an injectivity reduction may be an indicative factor that

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

the resistance to flow is being built in higher permeability zones and macrofracture network. This increases the sweep efficiency.

The field projects of chemical flooding in NFRs have revealed the most effective methods to improve the sweep efficiency of chemical flooding in NFRs. One of the methods is the in-depth conformance control using the surfactant/ alcohol-based technology, which modifies the permeability in highly permeable zones. The surfactant-alcohol blends reduce the permeability contrast and divert the primary drive fluid to the target. The other method is the polymer-aluminum citrate-polymer injection sequence. This method works in the fractured zones for eliminating a direct channeling of injectants to the producers. The field experiences show that the aluminum citrate cross-linker can minimize the direct channeling of polymer to the producers.

3.2.2. Thermal recovery in fractured reservoir

Most of the naturally fractured reservoirs which are produced by using thermal processes contain very low mobility oil and therefore heat conduction plays a very important role at the initial stages of production. With increasing oil mobility, convective gravity and capillary forces take over if the matrix, permeability is fairly high or the reservoir is fractured extensively. [23]

3.2.2.1. Effect of temperature on Reservoir rock and fluids

Heating heavy oil reservoirs during thermal recovery processes can affect the physical and chemical properties of their rock and fluids. Most important physical properties of the reservoir that are subject to change during thermal processes are:

3.2.2.1.1. Rock porosity and permeability

Rocks petrophysical properties of porosity and permeability are very weak function of temperature due to its low values of thermal expansion coefficient.

3.2.2.1.2. Reservoir wettability

Carbonate reservoirs are water wet before oil migration. However, their wettability may have changed to more mixed or oil-wet with time.

3.2.2.1.3. Capillary pressure curves

The effect of temperature on capillarity was investigated by Sinnokrot and al. Results of their experimental study indicated that capillary pressure curves for the limestone sample indicated negligible temperature level sensitivity.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

3.2.2.1.4. Relative permeability

Oil-water and gas-liquid relative permeabilities are very important rock- fluid data for reliably describing oil recovery mechanism from carbonate naturally fractured reservoir via thermal recovery processes.

The shape of oil relative permeability changed with increasing temperature which might have been caused by wettability alterations due to elevated temperature.

3.2.2.1.5. Oil viscosity

Viscosity of oil is a strong function of temperature. This function is even stronger with more viscous oils. Generally, bitumen does not flow at reservoir temperature due to its immensely high viscosity. Temperature increase during thermal recovery processes would help mobilize these resources.

3.2.2.1.6. Thermal conductivity

Average reservoir thermal conductivity of naturally fractured reservoirs is function of the thermal conductivities of rock matrix, fracture characteristics, mineralization in the fractures and its saturating fluids and their relative distribution. Thermal conductivity of liquids decreases with increasing temperature. Thermal conductivity of carbonate rocks and gases changes slightly with temperature. [23]

3.2.2.2. Mechanisms of thermal recovery from naturally fractured reservoirs

The recovery of oil from naturally fractured reservoirs must take into consideration the essence of drastic differences between the flow characteristics of the matrix and the fracture systems and interaction between them. For bitumen to be recovered from carbonate naturally fractured reservoirs, a pressure gradient need to be established at the pore level of the matrix blocks that displaces oil into the fracture network and eventually to the production well : [23]

3.2.2.2.1. Thermal expansion

During any steam injection process, both the matrix minerals and pore saturating fluids are heated and will expand. Matrix minerals expand into the pore volume upon heating and reduce the porosity. These effects combine to yield a differential thermal expansion coefficient to expel fluid from the matrix block.

The effect of thermal expansion is very important for fractured reservoirs. A significant amount of oil can be produced even in the absence of imbibition.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

At equivalent saturations matrix capillary pressure is much higher than fracture capillary pressure. This difference represents what is termed as imbibition driving force.

For water wet reservoirs, water in the fracture network will spontaneously imbibe into the matrix block through the smallest pores, increasing the internal pressure of the matrix block and expelling oil through of the larger pores.

3.2.2.2.2. Gas generation

Significant amounts of gas can be generated in a reservoir during steam injection from various water-oil or water-matrix chemical reactions, this gas will displace oil from the matrix as its volume increases. The volume of oil recovered from gas generation is uncertain but may be similar to recoveries in non-fractured reservoirs by solution gas drive; a recovery of 25% of the oil might be expected from this mechanism.

3.2.2.2.3. Gravity Drainage

Gravity drainage is not thought to be a significant recovery mechanism in naturally fractured reservoirs, except possibly in thick formations having high matrix permeability, a low matrix capillary pressure, and continuous, vertical, steam-filled fractures.

3.2.2.2.4. In-Situ steam generation

This mechanism is active during cyclic steam injection. During production, pressure may drop quicker than the drop in temperature by thermal conduction.

3.2.2.2.5. Rock compaction

Rock compaction is an important recovery mechanism for unconsolidated sand formations; this mechanism will not be effective in consolidated formations. Accordingly, compaction is not expected to be important in naturally fractured reservoirs.

Thermal recovery from conventional single porosity reservoirs is controlled mainly by viscous forces (pressures of the injection and production wells), and to certain and lesser extent by other mechanisms. It is also controlled by mobility ratio, relative permeability and reservoir heterogeneity. Viscous forces play minor role in oil recovery from natural fractured reservoirs. Thermal oil recovery from these reservoirs is controlled mainly by the forces that help steam and/or hot water to move into the matrix blocks driving oil into the fracture network. Modeling of fractured reservoirs is more delicate and very sensitive to the quality of the input data that describes the fracture network, and those that describes wettability of the matrix blocks.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

3.2.3. Miscibility

Through research over the past 25 years, miscible-phase displacement processes that use certain gases as injectants have been developed as successful means for increasing oil recovery from many reservoirs. To understand these processes it is first necessary to provide a definition of ‘miscibility’, particularly as distinguished from ‘solubility’. Solubility is defined as the ability of a limited amount of one substance to mix with another substance to form a single homogeneous phase. Miscibility is defined as the ability of two or more substances to form a single homogeneous phase when mixed in all proportions.

For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered immiscible. An interfacial tension (IFT) exists between the phases when they are immiscible. [17]

➤ **How is miscible gas used in EOR?**

Designing gas program is to optimize the properties of produced hydrocarbon gas by removing or adding other gases before injecting it back in the reservoir this can dramatically improve oil recovery, Miscible gas is usually made of carbon dioxide or hydrocarbon gas or a mixture of both, It is one of the most effective EOR methods for pore-scale displacement typically displacing 95% of the residual oil that it comes in contact with, when miscible gas comes in contact with the oil it exchanges components at the interface between the two so the gas gets heavier and looks more like oil and the oil gets lighter and looks more like the gas until finally the interface disappears the miscible performance of hydrocarbon gas can typically be improved by adding in more propane or butane, for example; in a water wet rock the residual oil is trapped in the middle of the pores because it has lost its flow continuity; miscible gas injection re-establishes that continuity by creating a new hydrocarbon flow path that enables the oil to flow out when the miscible gas flood is finally stopped water is injected to push the remaining gas out and gas takes the place of the residual oil in the pores while the oil is produced, miscible gas like normal gas is still very mobile in the reservoir so it is often injected alternately with water in a water alternating gas or WAG process, the water slows the gas down and also sweeps the rock lower down in the reservoir that the gas might not reach.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

3.2.3.1. Carbon dioxide flooding

When a reservoir's pressure is depleted through primary and secondary production, carbon dioxide flooding can be an ideal tertiary recovery method. It's particularly effective in reservoirs deeper than 2,000ft., where CO_2 will be in a supercritical state.

On injecting CO_2 into the reservoir, it dissolves in oil, the oil swells and the viscosity of any hydrocarbon will be reduced and hence, it will be easier to sweep to the production well. If the well is suitable for CO_2 flooding, then the pressure is restored by water injection. Then CO_2 is injected in these applications, between one-half and two-thirds of the injected CO_2 returns with the produced oil. This is then usually re-injected into the reservoir to minimize operating costs. Carbon dioxide as a solvent has the benefit of being more economical than other similarly miscible fluids such as propane and butane. Unless natural CO_2 exists in the near area, it's generally difficult to collect sufficient amounts of CO_2 for industry use. [16]

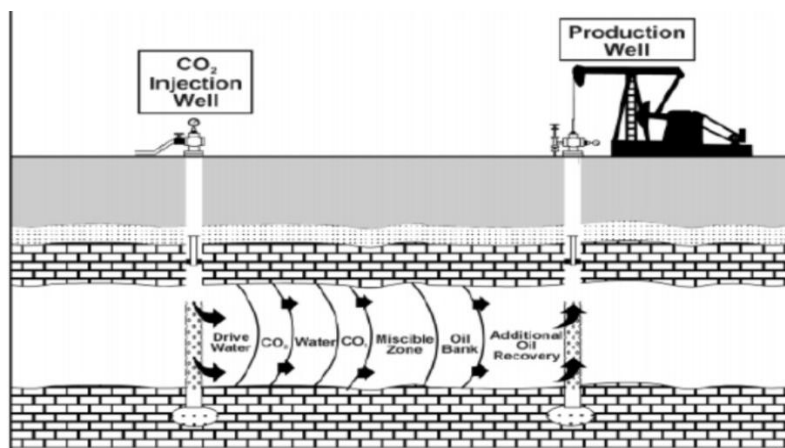


Figure III.1: Miscibility method. [16]

❖ Properties of CO_2 :

- Corrosive need special corrosion inhibitors / corrosion resistant infrastructure.
- Plugging due to asphaltene precipitation.
- CO_2 removal from production is costly.
- ✓ Only very slightly miscible with crude.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

❖ Source of CO₂:

- No natural source.
- Captured from flue gas of coal power plant.

3.2.3.2. Water alternating gas

Water-alternating-gas (WAG) injection has been found to be an effective enhanced recovery mechanism for carbonate reservoirs. WAG combines the benefits of gas injection to reduce the residual oil saturation and water injection to improve mobility control and frontal stability. Implementing dynamic miscibility during WAG could increase oil recovery even further by improving the microscopic sweep efficiency. [22]

The effect of wettability on the WAG simulations cannot be neglected. Water-wet reservoir conditions lead to reduced gas saturation in the matrix due to high capillary entry pressures that oppose gas oil gravity drainage. Increased imbibition in the water-wet medium also leads to higher oil recovery from water injection cycles. Conversely, the imbibition potential is very poor in the oil-wet medium leading to much lower recovery from water injection cycles. Trapping of the non-wetting phase is also more significant in the water-wet media. This is because snap-off occurs and gas becomes increasingly disconnected in the pore throats from the continuous gas phase. Because trapping entails a reduction of the gas mobility, it ultimately leads to higher recoveries. Reducing the gas mobility delays gas breakthrough, increases the stability of gas-water mobility front and improves contact of gas with residual oil, thereby ensuring better macroscopic and microscopic sweep of the reservoir.

3.3. Selection of Proper EOR Method for Efficient Matrix recovery

3.3.1. Procedure

Two types of experiments were conducted under static conditions: (a) co-current and (b) counter-current capillary imbibition. The type of transfer is determined by the boundary conditions created by the coating procedure. Different boundary conditions obtained by coating the sample are shown in Figure III.2-a and b. After coating and saturating the samples with 100 % oil (no initial water in the system), they were immersed into an imbibition cell filled with the aqueous phase (brine, polymer solution, surfactant solution or preheated hot water) and exposed to capillary imbibition. The recovery was monitored against time.

For counter-current experiments, the cylindrical core sample, 3.80 cm in diameter and 10 cm. in length, was cut vertically and the halves of the samples were used. In all cases, the outer side (curved part), top and bottom parts were coated (Figure III.2-a). Thus, the counter-

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

current imbibition takes place through the flat surface of the semi-cylindrical sample (COU-C1). The other different boundary conditions were created by coating the 50 % (COU-C2) and 90 % (COU-C3) of the flat surface with the epoxy.

Co-current experiments were conducted using cylindrical samples. CO-C1 in Figure III.2-b represents non-coated case. CO-C2 and CO-C3 are 50 % and 90 % coated cases, respectively. In all the experiments, the samples were positioned as seen in Fig. 1 and the coated part was kept upward in the imbibition cell. Thus, the aqueous phase imbibes from the bottom of the coated sample and rises up through the sample displacing the oil by oil by capillary forces against the gravity. The extreme boundary conditions were applied to be able to fully distinguish the effect boundary conditions on the recovery. In fact, the boundary condition is one of the main causes of high residual oil saturation in the matrix that entails additional E applications. In some of the co-current experiments 2.54 cm diameter samples were used. [15]

For carbonate core sample experiments, only CO-C1 type boundary condition was applied. It should be emphasized that all the samples were saturated with 100% oil phase (without S_{wi}) also in this group of experiments.

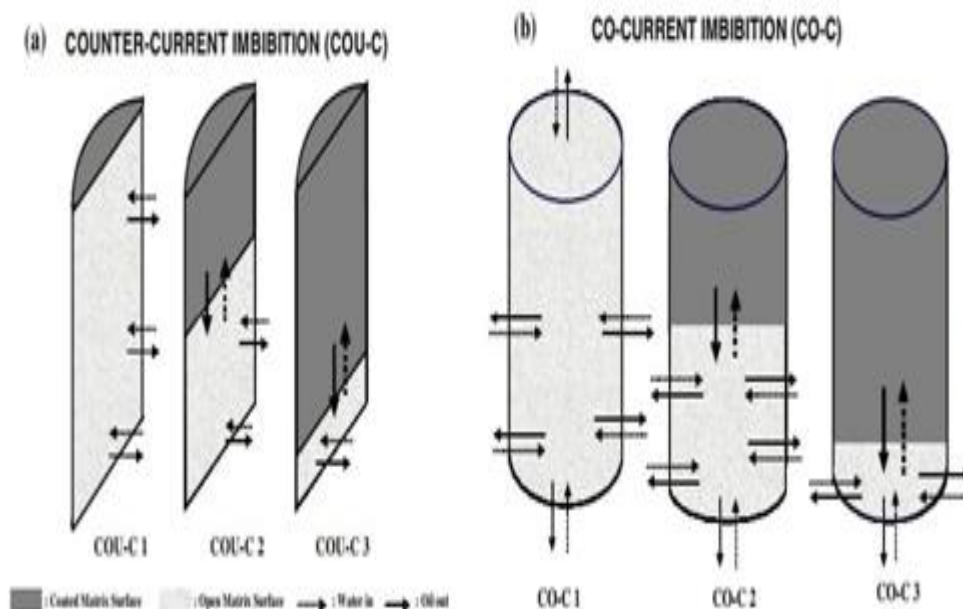


Figure III.2: Different boundary conditions used in the experiments. [15]

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

3.3.2. Selection criteria for proper EOR fluid

The selection criteria of the proper method (or EOR fluid) will be summarized and discussed in terms of (a) recovery rate and (b) ultimate recovery for different oil types and matrix properties, namely wettability and boundary conditions. [15]

3.3.2.1. Sandstones

For the recovery of light oils (kerosene and crude oil) by capillary imbibition under favorable boundary conditions (CO-C1 and CO-C2), addition of surfactant did not contribute to the rate of recovery. Ultimate recovery increased slightly by surfactant addition. However, in case of unfavorable boundary condition (CO-C3), the negative effect of low IFT on the recovery rate was obvious. The recovery rate was reduced significantly but the ultimate recovery did not change. Therefore, low IFT is not suggested for any boundary condition and slight increase in the ultimate recovery would not support the idea of injecting expensive chemicals continuously. This obviously would not turn out to be an economic application. The same conclusions are applicable for the counter-current matrix-fracture transfer as well.

For heavy-oil case, surfactant addition yielded a significant increase in the recovery rate and ultimate recovery for unfavorable boundary condition (CO-C2). For favorable boundary condition (CO-C1) brine recovery rate was slightly higher but ultimate recovery was slightly lower. The slight changes in these performance indicators suggest that surfactant addition would not be desirable if the economics of the process is a concern for the favorable boundary condition.

For heavy-oil recovery under favorable (CO-C1) and unfavorable (CO-C2) boundary conditions, polymer addition to brine yielded much faster recovery and higher ultimate recovery than surfactant case. For unfavorable boundary condition, the ultimate recovery obtained by the polymer solution is higher than hot water injection but high temperature water injection (80°C) resulted in much faster recovery. Thus, the selection of proper method depends on the cost of the project as well as the managerial concerns. In heavy oil case, the major concern, from the long-term reservoir management point of view, is expected to be increasing the production rate rather than increasing the ultimate recovery. In summary, hot water is more advisable if it reflects an economic application for long term plans in particular.

Also, for unfavorable boundary conditions, starting with brine and continuing with hot water is not an effective project implementation due to very slow recovery rate even though the same ultimate recovery is achieved at the end. For this type of boundary conditions, polymer solution is preferable to the surfactant solution.

Chapter III: Enhanced Oil Recovery Methods Applied in NFRs

In light crude oil recovery, polymer is not recommendable for unfavorable boundary conditions (COU- C2) of counter-current flow due to much slower recovery rate and lower ultimate recovery. Hot water injection yields much faster recovery. If the concern is to increase the ultimate recovery, no additional method is recommended. If the faster production rate is desired, hot water is recommendable.

3.3.2.2. Carbonates

For oil-wet carbonate matrix, the improvement of capillary imbibition is more crucial issue. Even for the most favorable boundary condition (CO-C1), the recovery was as low as 5 % and an additional “accelerator” was required. Technically, the most recommendable methods are hot water, surfactant and polymer, from the best to the worst, if the recovery rate is concerned. The methods yielded a doubled recovery (from 5 to 10 %) and this can be considered as an achievement for a challenging naturally fractured reservoir. Even though the polymer rate is somewhat lower, it yields the highest recovery due to combined effect of lowered IFT and increased displacing phase viscosity. Considering the fact that some part of the recovery is due to thermal expansion of oil in case of hot water injection, combination of hot water and chemical injection is technically recommendable for a successful management of the reservoir. But the economics of the process should be evaluated.

Two issues were not addressed in this paper. They are adsorption of chemicals and wettability change. For recovery performance analysis, the effect of wettability change is critical. Although the temperature range applied through the experiments is not expected to be influential on the wettability, surfactants are expected to affect the wettability. The clarification of the wettability change effect on the recovery and chemical adsorption are considered to be the subject of a further study.

The selection of proper EOR method was discussed above from a technical point of view. For an effective field management, these observations can be helpful for decision making. If the purpose is to deplete the matrix oil effectively (or thoroughly), the target should be the ultimate recovery. Big size fields with high recovery rate are an example for this situation. If, on the other hand, the purpose is to increase the production rate, one should focus on the increase in recovery rate instead of ultimate recovery. Fields with low recovery factor (heavy-oil, carbonates) can be good candidates for this effort. These managerial concerns will determine the type of the proper EOR fluid. Obviously, the next issue will be the inclusion of the project cost to the analysis.

Chapter IV

Chapter IV: Rhourde El Baguel - Case Study

4.1. Introduction

The development problems of REB are not unique and similar cases could be found on every continent. In all these cases, we find that the main reason behind the failure is the complete lack of understanding of the fractures and the inability to model them in 3D. As these fractures entirely control the reservoir response, especially during secondary and tertiary recovery processes, it is no surprise to see outcomes such as REB.

The entire E&P industry is still struggling to adopt a standard procedure on how to deal with the complexity of modeling the fractures. Different teams has proposed different solutions - some very successful, others not - and that creates more confusion in the E&P industry regarding which approach to use. Some large companies have decided to develop their own approach, while others are relying on service companies. It is in this confusion that REB development was considered.

To make matters worse, the development of REB happened during a period of consolidation, where the original partner ARCO was acquired by BP. This change of companies may have some minor effects on the continuity of the work initiated by ARCO, but this cannot be considered a major issue. [24]

4.2. The fields of Rhoude El Baguel

4.1.1. Geographical situation

The Rhourde El Baguel field is located in the North East part of the Algerian Sahara at about 90 km south-east of Hassi-Messaoud on the western edge of the Ghadamès basin, on the road to El Borma , The structure of REB is asymmetric anticlinal extending north south delineated in the east and west by the bigger fissures extended in north and south. [24]

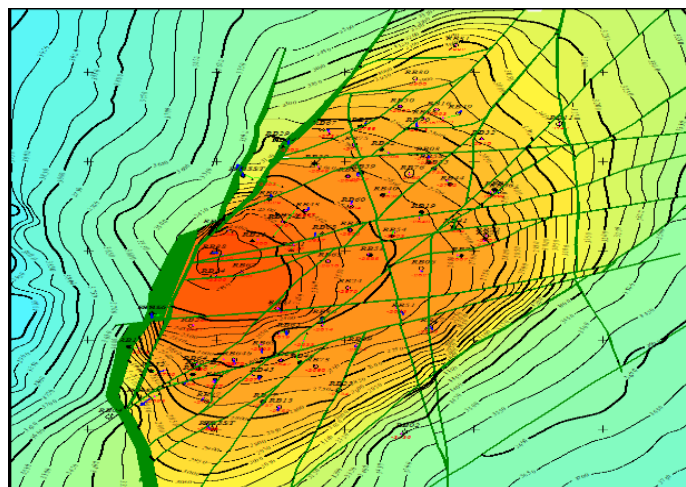


Figure IV.1: The structure of REB. [24]

Chapter IV: Rhourde El Baguel - Case Study

4.1.2. Field history

In 1962: was discovered and put into production by the company Sinclair-Oil.

In 1962 until 1996: 35 wells were drilled.

From 1996: and after the call for tenders launched by SONATRACH to international oil companies targeting the provision of advanced technology in assisted recovery techniques for 11 producing oil fields. [24]

4.1.3. Production history

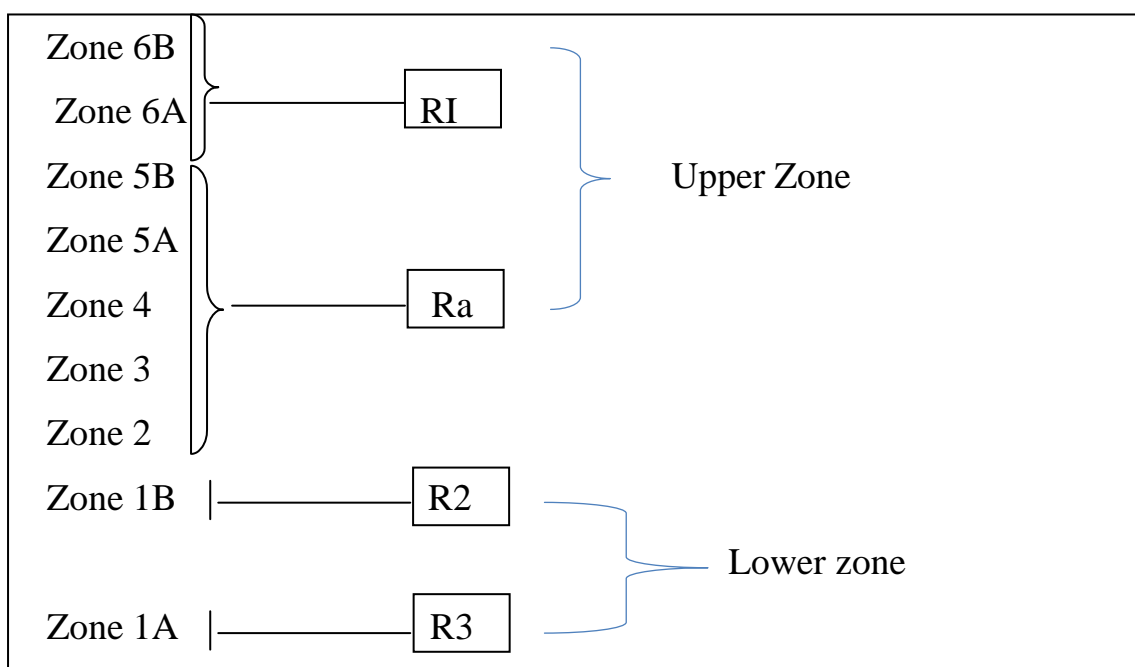
Production fell to 25,000 barrels / day **in 1996**, Following the drop in pressure which dropped dramatically from 5840 psig to 1700 psig, following this drop in production an application of an enhanced EOR recovery mode was essential.

In 1976, a pressure maintenance system by water injection was implemented unfortunately this mode posed a problem of water entry (the water breakthrough) at the level of the producing wells which made these wells little eruptive. And demand the closure of certain wells.

In July 1997 a project to maintain reservoir pressure by gas injection (gas flood) was started and was implemented with a capacity of 3MM m³ / day and a delivery pressure of 275 barg.

4.1.4. REB reservoir zones :

The producer tank of REB is a Cambrian age in a average depth 2845 from the levels of the sea . It's subdivided into 6 zones (R_{1-1} et R_{1-2} (R_1), R_a and R_a (R_A)), R_2 and R_3 :



Chapter IV: Rhourde El Baguel - Case Study

4.1.5. Fracture network characterization in REB’s reservoir

4.1.5.1. Aspect by coring

- Upper Zone vs Lower Zone Fracture Character:



Figure IV.2: Typical Upper Zone Shear Fractures.[24]



Figure IV.3: Typical Lower Zone Shear Fractures.[24]

Table IV.1: Upper Zone vs Lower Zone Fracture Character. [24]

Upper Zone	Lower Zone
<ul style="list-style-type: none"> •Strong, brittle quartz-rich sandstone •Brittle deformation processes dominate •Open fractures, occasionally vuggy •Often lined with euhedral quartz crystals •High permeability (average Kf = 190 mD) •No halo effect documented •Could reduce fracture/matrix interaction 	<ul style="list-style-type: none"> •Weaker, less stiff clay-rich sandstone •Ductile deformation dominates •Cataclastic smear prevalent, reduced aperture •Reduced permeability (average Kf = 5mD) •Cemented ‘halo’ effect evident •May reduce fracture/matrix interaction

Chapter IV: Rhourde El Baguel - Case Study

Upper Zone Fractures – Brittle Breccias:


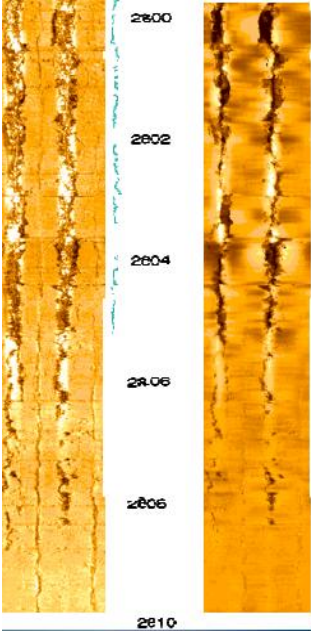

- Intimately associated with sheared fractures.
- Positioned in ‘relay zones’ between shear fractures.
- Strike-slip with low vertical offsets (1-2 cm).
- Estimate lateral offsets of decimetres.
- Highly porous.



Figure IV.4: Upper zone fractures.[24]

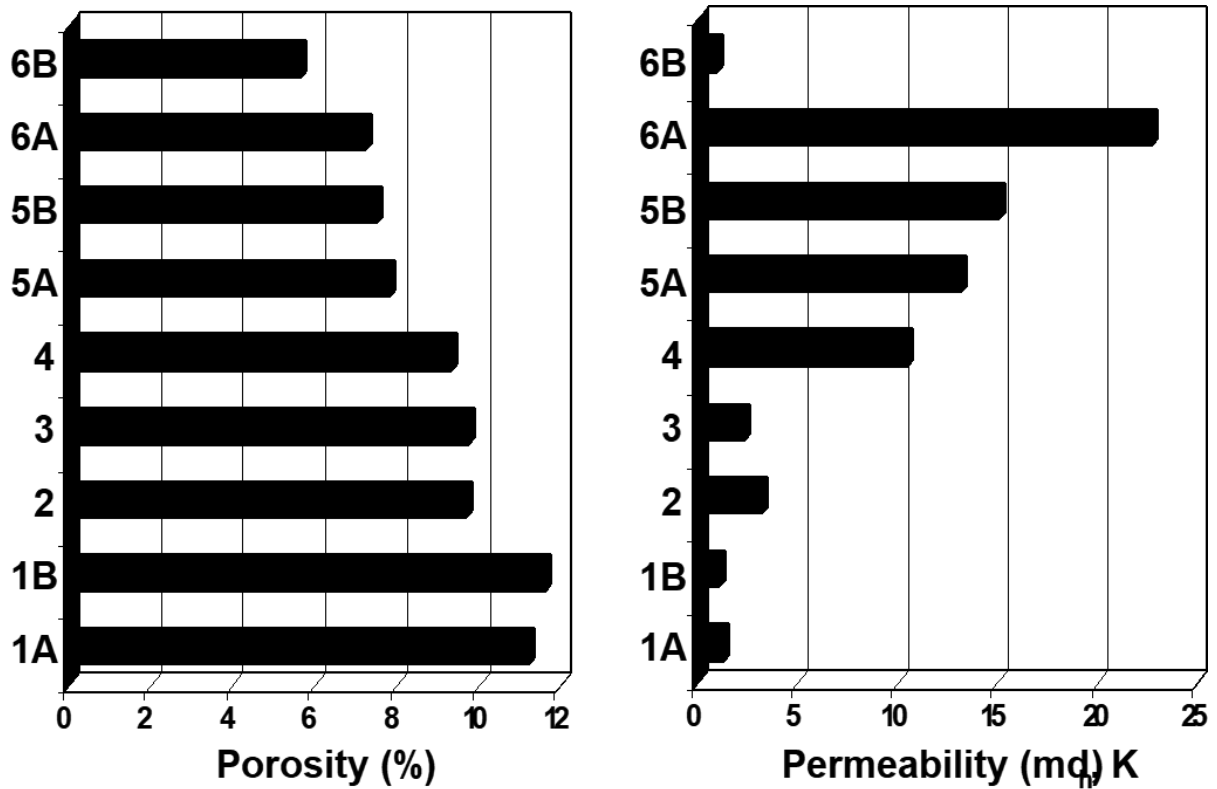
The fractures encountered in the REB:

Table IV.2: The fractures in the REB.

Horizontal Fractures are practically non-existent	Vertical Fractures (dip from 70 ° to 60 °) represent almost 80% of fractures .	Oblique fractures of 50 ° to 60 ° are also common but mainly in areas where the intensity is sufficient .
		

Chapter IV: Rhourde El Baguel - Case Study

- Petrophysical Characterizations by analysis of coring



Core Analyses RB 1 - 45

Figure IV.5: Core analyses porosity and permeability RB 1 – 45. [24]

Table IV.3: Petrophysical Characterization of different zones

Zones	Epaisseur utile(m)	Porosité (%)	Perméabilité (md)
$R_I(R_{I-1} + R_{I-2})$	50	6.3	17.0
Ra	53	8.4	36.2
Raa	61	9.8	6.3
R_2	36	11.9	1.0
R_3	24	10.2	1.0

Chapter IV: Rhourde El Baguel - Case Study

4.1.5.2. Logging aspect (Imagery)

Fractures were interpreted from an ultrasonic borehole image log ,the image log complements the cores , providing a continuous record of fracture distribution , and allowing measurement of fracture orientations ;the data are generally of good quality Figure IV.6 show representative UBI images along with individual section of core.

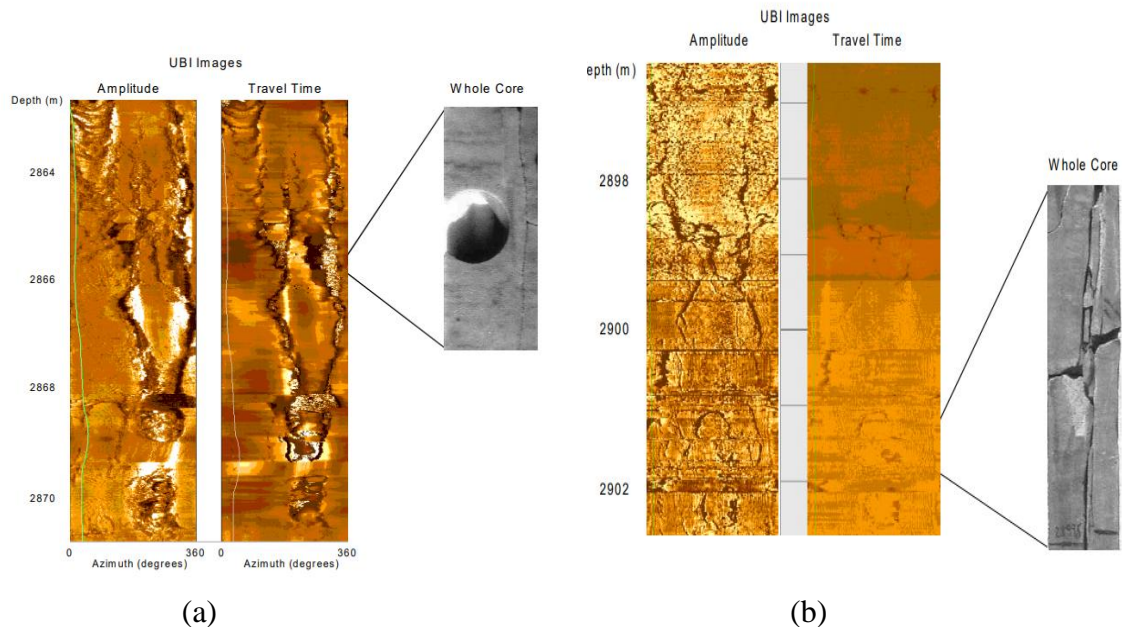


Figure IV.6: UBI images and accompanying core section RB 45. [24]

In Figure IV.6-a the core reveals an open incipient fracture. adjacent to a fracture healed with quartz cement . on the borehole image a large , near vertical fracture is seen intersecting the borehole over approximately 8m failure are apparent both on travel time and amplitude images.

In Figure IV.6-b large open fractures are seen on the core consistent with features observable on the UBI amplitude image, suggesting that there is a little local enhancement of the fracture opening.

4.1.5.3. Fracture index

Is the ratio of total kh (permeability-thickness) measured in flow tests to matrix kh estimated from core analyses and logs. The large enhancements of kh are attributed to fractures, which are well documented by cores, image and sonic logs. Zone 1 fracture indices are estimated, because hydraulic competition with much higher permeability zones above generally prevents accurate measurement of total kh lower reservoir areas

Chapter IV: Rhourde El Baguel - Case Study

(Lower Zones) and especially the 1B have appreciable fracturing indexes the curve below shows the fracturing index for each zone of the reservoir:

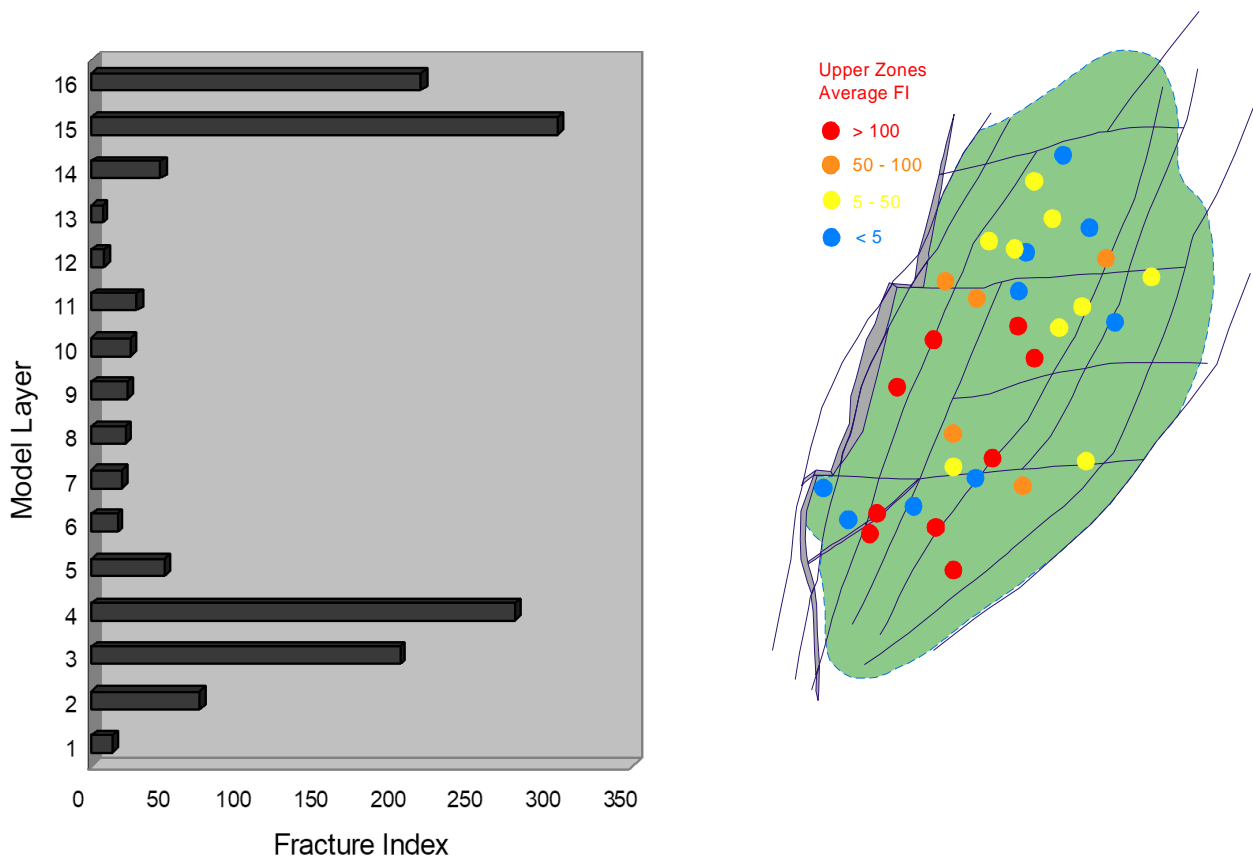


Figure IV.7: fractures index in REB. [24]

4.3. Three major weaknesses

4.3.1. Understanding and modeling the fractures

The biggest problem throughout the development of REB was the inadequate modeling tools used to tackle the complexity of the fracture system and the geology. The partner has developed some models that are able to match the production history of the entire field. Similar results could be derived with a simple material balance model that uses only field average properties. Plotting any single well performance in REB will show the inability of these simplistic models to reproduce the complexity of the fractures and the geology. It is not expected that the partner have a perfect model that matches all single well performances, but at least an attempt has to be made to derive meaningful reservoir models that utilize and integrate the large amount of data collected throughout the years. The examination of these

Chapter IV: Rhourde El Baguel - Case Study

models reveals their overly simplistic representation of the reservoir. The shortcomings of the modeling effort will be described in details in the next section. [24]

4.3.2. Efficiently using the wealth of the acquired data

Another apparent problem with REB development plans is the lack of a clear objective for the data collection. It seems that large budgets were spent to collect all types of static and dynamic data, but very little was done to use them efficiently to improve the overall understanding of the reservoir. A good example of this lack of objective is the 3D seismic acquired in 1996. During the acquisition and processing of this 3D seismic some basic precautions were not taken and the survey shows a very noisy character in the area delimited by the existing wells. The seismic survey quality is good on the edge of the field, which makes us believe that some machinery was not turned off during the seismic acquisition, and the ensuing man-made noise significantly degraded the recorded signal. It is uncertain if this noise could have been removed or severely attenuated during processing. Although the resulting 3D seismic data is of bad quality in the area populated by the wells, it is still valuable and critical information that could have been used for modeling the reservoir. The partner limited his efforts primarily to a structural interpretation of the horizons, aided by generation of a coherency volume. As with all the other data acquired, the efforts were limited to describe the observed data without trying to use the information in some kind of modeling tools – the data were primarily used in a qualitative, rather than quantitative, fashion. The use of this extensive data in modern reservoir modeling tools would have allowed the partner to build reservoirs models that could improve the history match on a well by well basis and forecast the failure of many undertaken development plans.

A major effort that was underutilized is the facies modeling done by petrophysicists. The partner did a very detailed division of the facies that lead to the recognition of eight facies in REB. Unfortunately, a facies model that takes into account and uses this detailed description was not found. The only attempts made to generate a facies model were limited to a shale-sand facies distribution. As facies plays a major role in fracturing, a facies model could have been very helpful in understanding in a quantitative manner the different fracture zones. The extensive use of REB 3D seismic and facies data, and the valuable information that could be extracted from them, is demonstrated in the completed integrated reservoir study.

Chapter IV: Rhourde El Baguel - Case Study

4.3.3. Lack of pilot tests

Assuming that the modeling tools were not available and the entire industry lacks the means to model such complex reservoirs, there are still many development issues that remain questionable. The most important one is the lack of pilot tests to try the proposed ideas and development plans. It is an industry standard to try new and risky plans on small pilots to better understand the phenomena involved. Since its first gas injection experience in the late 1940's in West Texas Block 31, ARCO and all other major US and international companies have always tested the gas injection on small pilots before moving to a large scale injection. For some unfortunate reason, this common procedure was not used in REB and large-scale injection was undertaken without a pilot. A small pilot in REB would have rapidly indicated the problem of the fractures and the impossibility to reach miscible conditions.

The combination of these three major problems lead to the poor results observed in REB. The purpose of this audit and the ongoing reservoir study is to try to draw the appropriate lessons from this experience and learn from them. From these lessons one can find the best approach to redevelop REB, and most importantly, avoid similar problems with other Sonatrach fields that could have similar problems. To better understand the problems related to REB fractures, the approach used by the partner is presented and analyzed.

4.4. Results of the simulation

From its start up until the signing of the contract between Sonatrach and Arco in 1996, the Rhourd El-Baguel's field experienced many of the problems that affected his production which was then explained by the low production rate through comparing by input has its reserve in place and its operating life, which is why a recovery project improved EOR was necessary to increase it, this project which was proposed by Arco consists of the massive injection of miscible gas at high pressure (420 barg) in order to reach the miscibility after the 8th year of injection and according to a drilling program that has been established thus in parallel with the injection for the purpose of increasing field production, project forecasts showed that production will increase as and when the injection of gas into the tank to achieve maximum production of the order of 134000 BOPD, and cumulative production during the term of the contract was estimated at 563 Million barrels.

The graph below shows the evolution of production according to forecasts during the period of contract. [24]

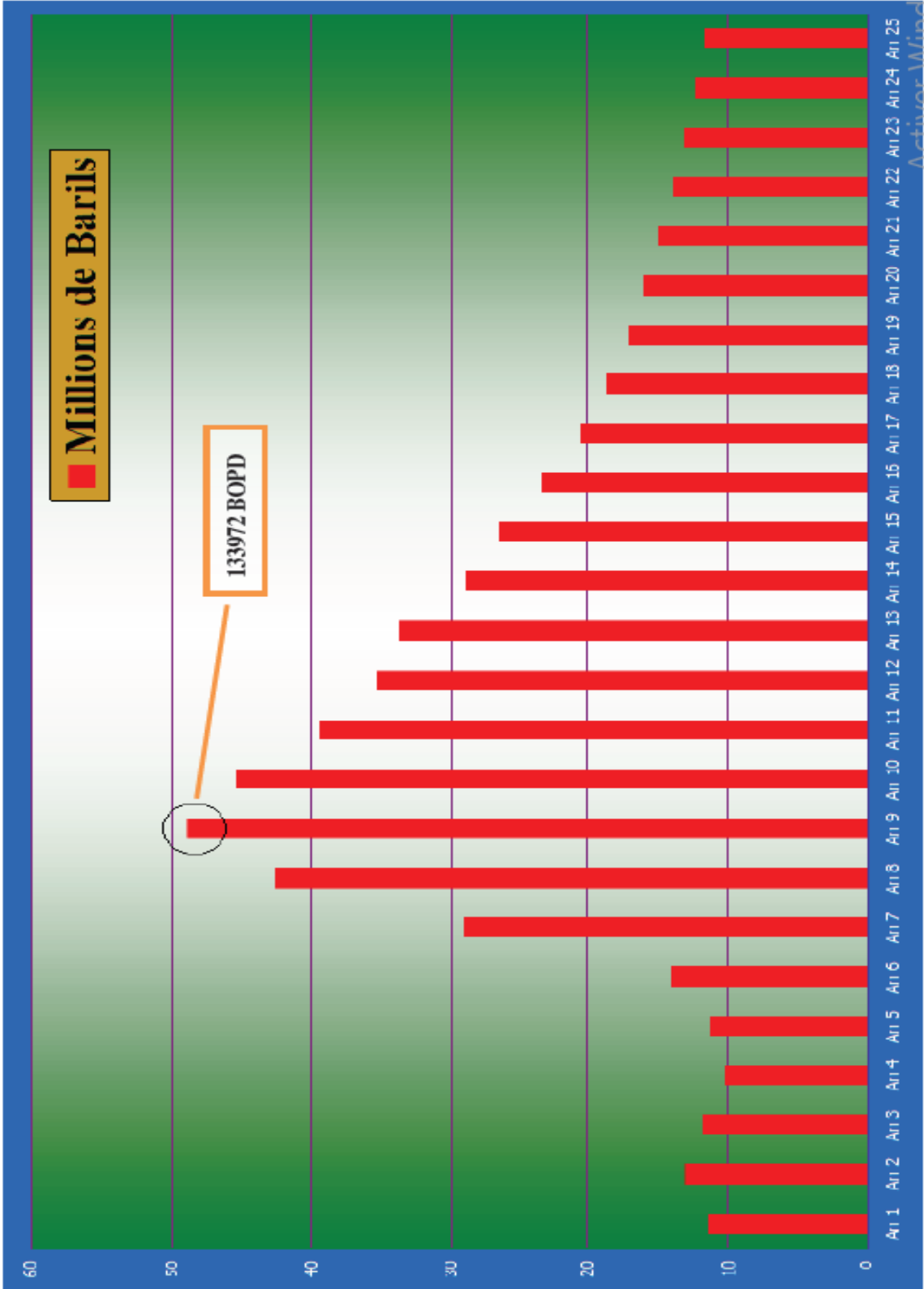


Figure IV.8: Evolution of production during the contract. [24]

4.5. Impact of massive gas injection [24]

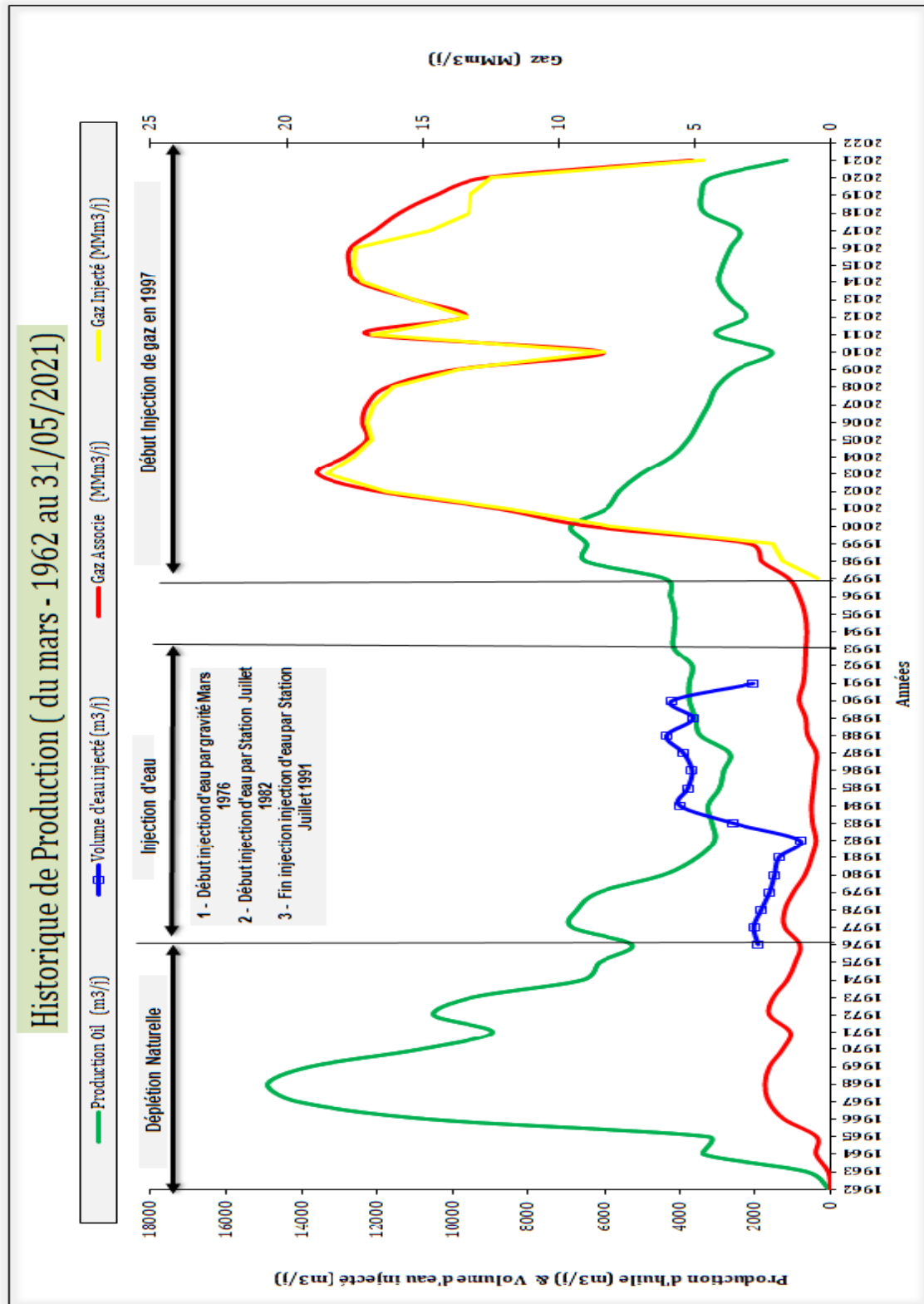


Figure IV.9: History of production of the Field REB since 1962 until 31/05/2021.

[24]

Chapter IV: Rhourde El Baguel - Case Study

Rhourde El Baguel (REB) is a fractured Cambrian reservoir with OOIP of 2+ billion barrels, initially discovered in 1962 : 450 million had been produced under primary depletion and partial waterflood prior to 1996 redevelopment project initiated between SONATRACH and ARCO (BP).the redevelopment project was a high pressure (420 barg) miscible dry gas injection scheme to significantly increase the remaining reserves potential of the field, they expect 133972 BOPD in 9 years, but unfortunately it failed, the figure above represent the history of production of the field REB since 1962 until 31/05/2021, we remarked a slight increase in production following the start of gas injection due to producing the sweep of the oil that has already been present in the fractures either due to Draw Down: the phenomenon of capillarity at the moment when the pressure in the fracture lower than in matrix, or spontaneous imbibitions where the water of the secondary recovery: water flooding displaces oil from the matrix at the fracture by gravity; REB has a water wet rock, this is what led to expel a large amount of oil from matrix blocks to fracture network and the high pressure of the injected gas had swept away this oil towards the bottom of producing wells, after producing this amount of oil by the injected gas, and due to high pressure of this gas the oil has been trapped in the matrix block and the breakthrough happened: the gas has created a favorite flow path from injector wells to the producing wells while crossing the drains of fractures and this information has been confirmed by the analysis of tracers. And so we observe a decrease in production.

Chapter IV: Rhourde El Baguel - Case Study

4.6. Analysis of tracers [24]

The gas tracer tests carried out at the level of injectors in the lower zone have shown that the gas displacement time between the injector wells in the lower zone and the producer wells in the upper zone was less than a week which indicates the presence of vertical fractures at the latter. The injection of the tracers into an injector well in the upper zone gave the same observation.

Table IV.4: Tracer injected in INJ 01 from 16/18-Feb

Observation	Sampling Date of first Sample	Time for tracer on Day
Wells	With Dimethyl content above BL	to Breakthrough
Prod 1	03- mars-01	15
Prod 2	31-mars-01	43

Table IV.5: Tracer injected in INJ 02 from 25-Mar to 1-Ap

Observation	Sampling Date of first Sample	Time for tracer on Day
Wells	With Dimethyl content above BL	to Breakthrough
Prod 3	08-avr-01	14
Prod 4	22-avr-01	28

Table IV.6: Tracer injected in INJ 03 FROM 21-Juin-99 to 24 –Juin-99

Observation	Sampling Date of first Sample	Time for tracer on Day
Wells	With Dimethyl content above BL	to Breakthrough
Prod 5	28-juin-99	4
Prod 6	15-nov-99	144

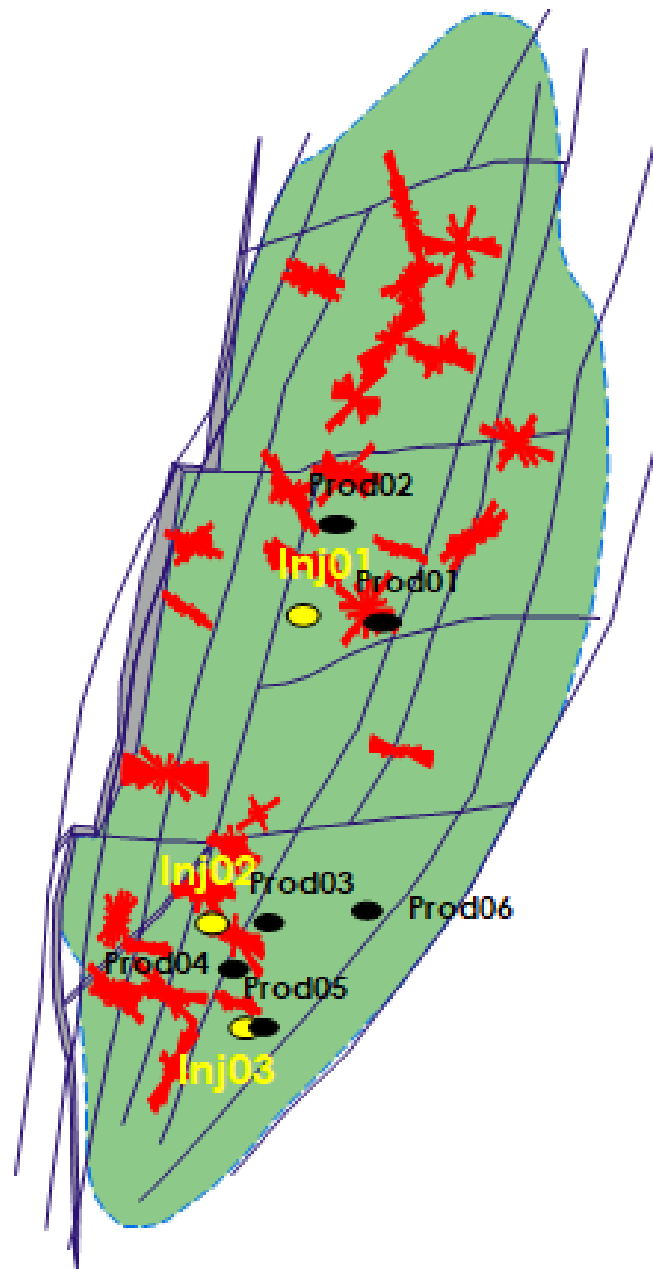


Figure IV.10: Analyze of tracers in REB Field. [24]

4.7. Gas shutoff [24]

During production generally there are cases when the gas breakthrough the zones of production which leads to the fall of oil production rate and the increase in the gas oil ratio, so when the engineer notices this problem his first response is to determine the zone in which the breakthrough happened, and to do that we use the PLT logging to determine the productivity rate and which fluid is produced in each zone. Once the zone of the breakthrough is found we use cement squeeze in order to plug the zone of the breakthrough but not completely (to

Chapter IV: Rhourde El Baguel - Case Study

alleviate the hydrostatic pressure), once the zone is plugged the gas rate diminish while the oil rate increase.

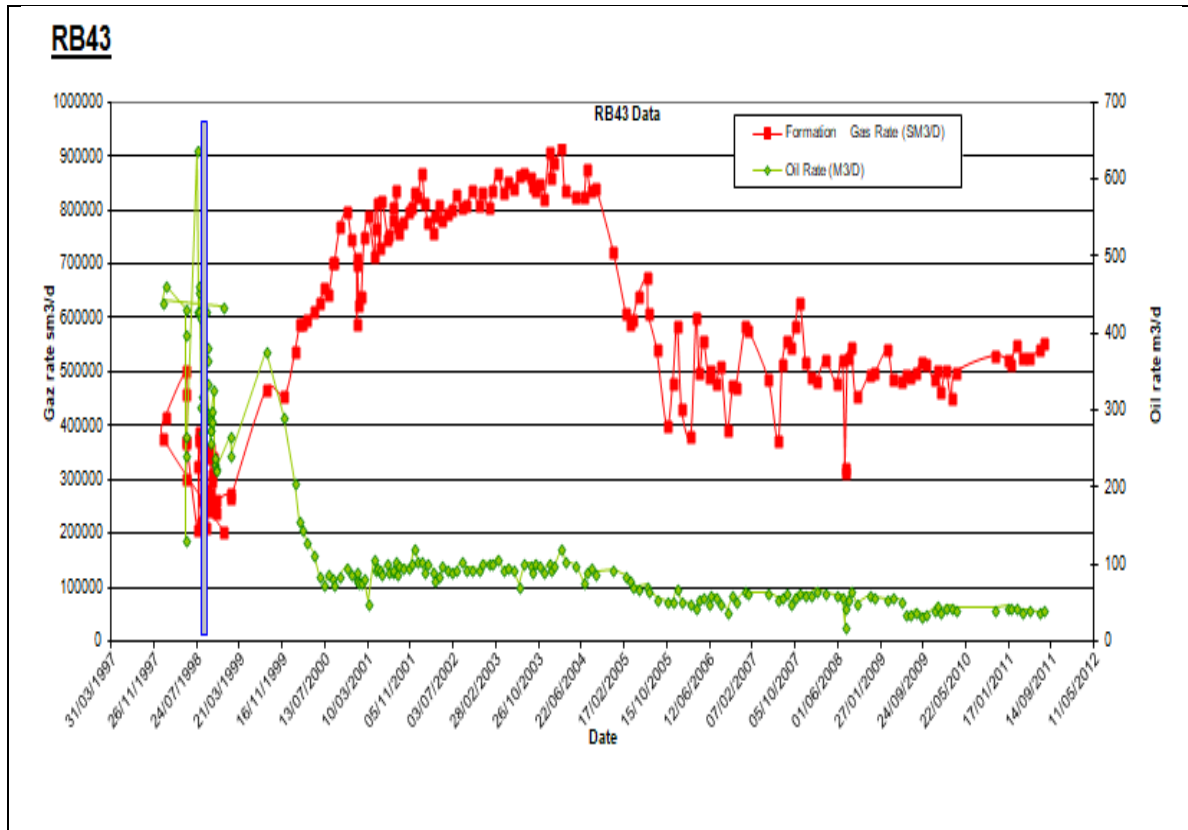


Figure IV.11: Evolution of gas and oil rate before, during and after gas shutoff of RB43

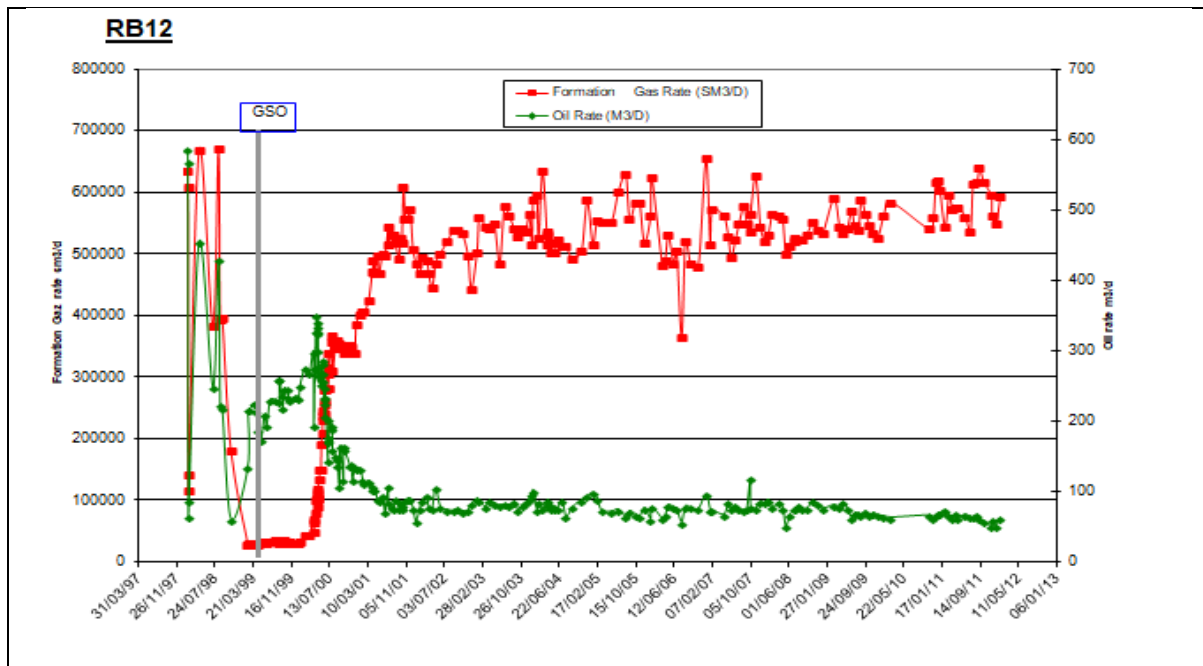


Figure IV.12: Evolution of gas and oil rate before, during and after gas shutoff of RB12.

Chapter IV: Rhourde El Baguel - Case Study

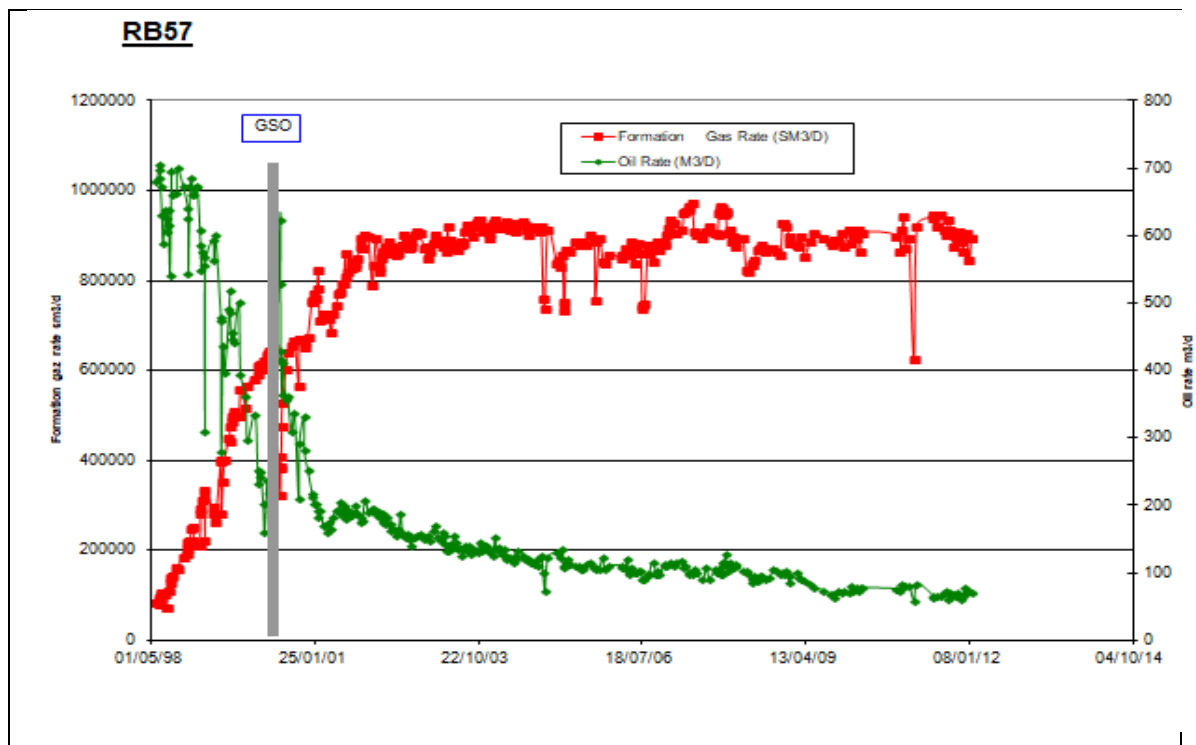


Figure IV.13: Evolution of gas and oil rate before, during and after gas shutoff of RB57.

4.8. Gas recycling

After the fail of the miscibility operation in REB the process of gas recycling started which consisted on reinjecting the produced associated gas in its entirety which made the associated gas and the injected gas and the potential gas the same, however soon after a new process came to be which is seasonal gas injection as it shows in the Figure IV.14.

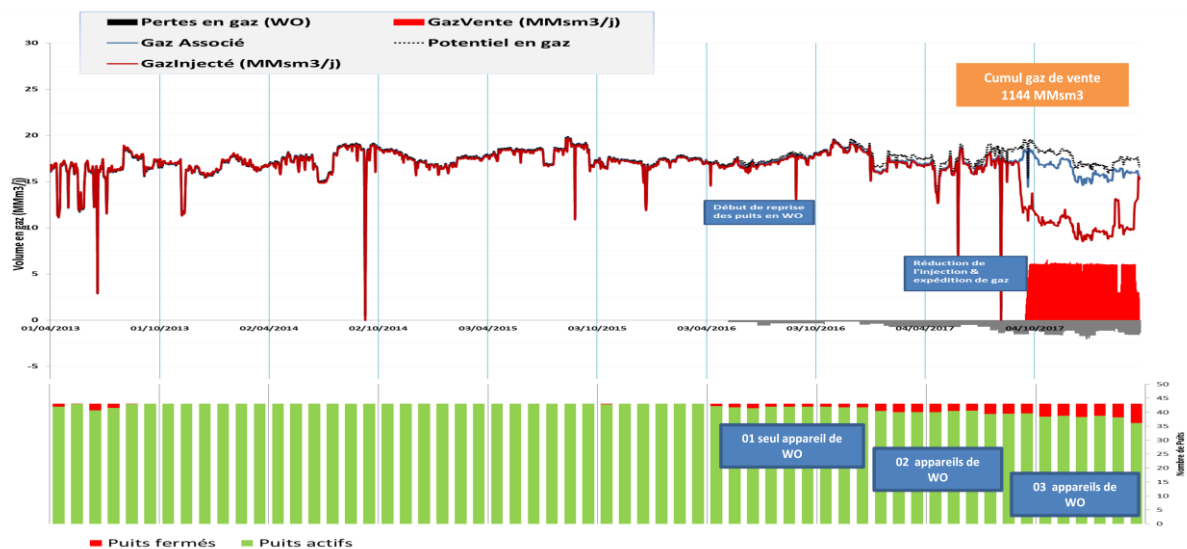


Figure IV.14: Gas potential in REB.

Chapter IV: Rhourde El Baguel - Case Study

4.9. Seasonal gas injection

Looking at the high demand of gas during winter, a modification on the process of gas recycling was made which consisted on injecting a fixed amount of the produced associated gas to maintain the pressure and sell the rest.

From the Figure IV.15 it is shown that by closing a certain number of injection wells that leads to the reduction of the gas injected an amount of **1144 MMsm³** was accumulated to be sold.

The reduction of the injected gas can be seen to have impacted the majority of the wells in REB as the GOR has diminished (**1000 sm³/sm³**) and the oil flow rate has increased Figure IV.16.

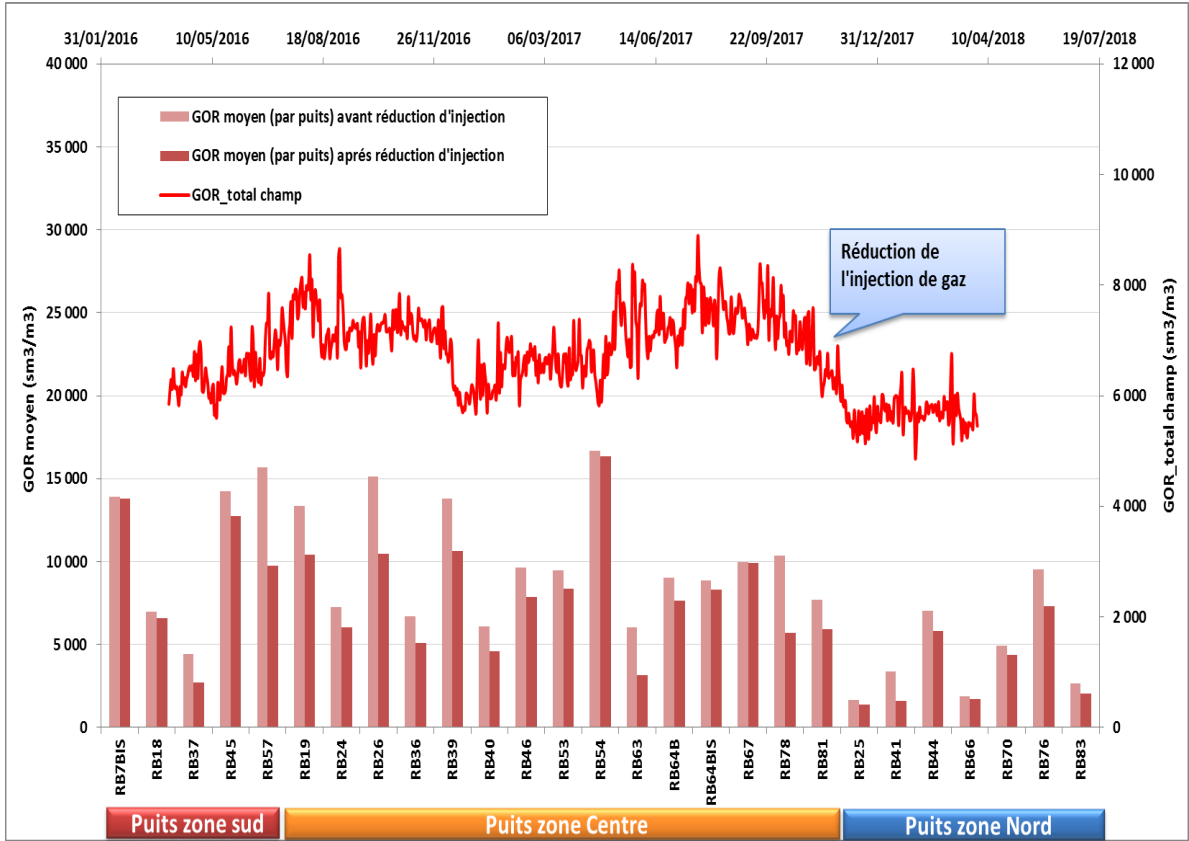


Figure IV.15: Evolution of GOR in REB before and after the reduction of injection.

Chapter IV: Rhourde El Baguel - Case Study

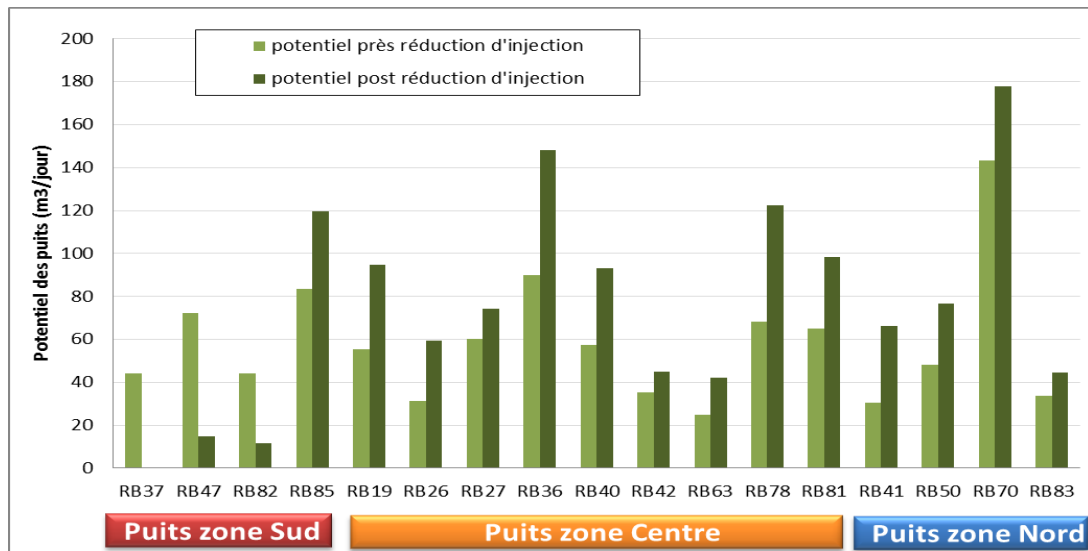


Figure IV.16: Oil potential of REB.

It can be observed from Figure IV.16 that the reduction of the injected gas had a positive influence on the oil production with the accumulation of **396 000 bbl** produced.

However the reduction of the injected gas wasn't without a cost as the closing of a certain number of injection wells has led to the loss of two injection well in the south zone due to the manifestation of an aquifer as it shows in the Figure IV.17 below.

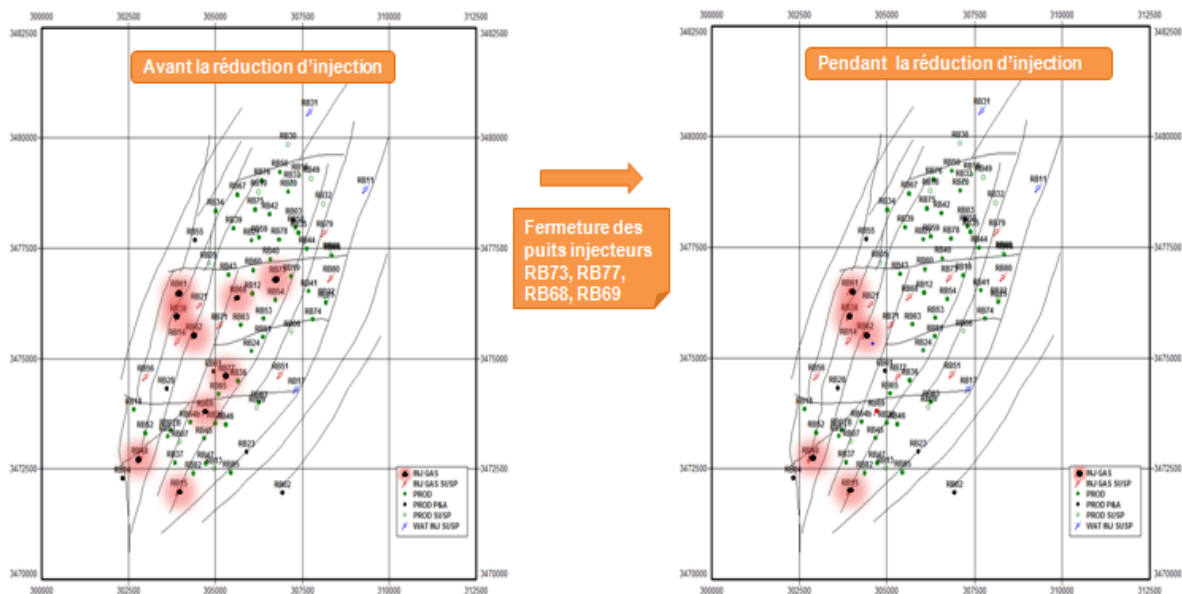


Figure IV.17: Before and after the closure of the injection wells.

While the reduction of the injected gas and the closing of certain number of injection wells has many perks it needs to be done with a detailed study on which wells are closed otherwise the consequences can be catastrophic.

Conclusion

Conclusion

Naturally fractured reservoirs play a very important role in oil exploitation. They sometimes consist of two media through which fluids flow. But the presence of fracture networks does not always make it possible to estimate the production or recovery of hydrocarbons, since natural fractures not only have positive effects but also negative effects.

We use chemical flooding in NFRs basically for the purpose of altering the wettability from oil or mixed wet to water wet and to reduce the IFT between oil and water. As for thermal flooding we use it when we have heavy oil. The miscibility is basically used in light oil.

In this study and after data analysis of the production we find that:

- The density of fractures is the main reason for the gas breakthrough.
- The main reason behind the failure is the complete lack of understanding of the fractures and the inability to model them in 3D.
- The main causes of breakthrough are the high density of the natural fractures and the high MMP of the miscible gas injected (METHANE: 420 barg).
- After the breakthrough the injected gas traces its paths in the medium porous in addition to the higher mobility of gases refers to liquids, the oil gets trapped inside the matrix blocks.
- In one time the only solution after the failure of miscible injection project gas recycling was the only economical existing solution due to availability of the gas.
- Due to the increase of gas demand in winter, an economical recovery was adapted in similar high GOR NFRs to overcome this worldwide gas demand called by seasonal gas injection:
 - ✓ This kind of recovery is based off injecting the minimum optimum rates in winter and recycling all the produced associated gas in the rest of the year.
 - ✓ A gain of oil production was registered after the winter in refers of what was predicted. This phenomenon is due to the draw down from the matrix to the fracture after decrease of fracture pressures
- Nowadays REB reservoirs it's a case study of chemical Enhanced oil recovery with polymers and surfactants (this project is at laboratory level), the pandemic, the low oil prices and the uncertainty of the results are the main reasons for the delay of this project.

Bibliography

- [1] Ahmed, T., Reservoir engineering handbook. 2018: Gulf Professional Publishing (2006).
- [2] Mohammed Abdelfetah GHRIGA , Optimisation des formulations EOR (Enhanced Oil Recovery) chimique pour les réservoirs pétroliers fissurés THÈSE En cotutelle Pour obtenir le grade de Docteur de l'Université de Pau et des Pays de l'Adour, Submitted on 12 nov 2020 .
- [3] Djebbar Tiab and Erle C. Donaldson, Petrophysics, second edition, Gulf Professional, publishing (2004)
- [4]. ‘ ‘ Zoltán E. HEINEMANN and Dr. Georg Mittermeir’’ Natural Fractured Reservoir Engineering Tehran, February 2014.
- [5] T.D. VAN GOLF-RACHT , fundamentals of fractured reservoir engineering NEW YORK 1982. Published, 1st April 1982
- [6] JERBI C, Simulation des transferts diphasiques en réservoir fracturé par une approche hiérarchique, Université Pierre et Marie Curie, paris 2016
- [7] Asmund Haugen, Fluid Flow in Fractured Carbonates: Wettability Effects and Enhanced Oil Recovery, the Department of Physics and Technology at the University of Bergen, Norway, April 2011.
- [8] Narr Wayne, David S. Schechter, and Laird B, Thompson; Naturally fractured reservoir characterization; Richardson, TX: Society of Petroleum Engineers; 2006
- [9] Bourdet. D. et al.: "A New Set of Type Curves Simplifies Well Test Analysis," World Oil, (May 1983).
- [10]van Poolden, H.K. and Bixel, H.C.: "Pressure Drawdown and Buildup in the Presence of Radial Discontinuities," SPEJ (Sept 1967) 30 I; Trails .AIME,240.
- [11]Abbaszadeh. M.D. and Cinco-Ley, H.: "Pressure Transient Behavior in a Reservoir With a Finite-Conductivity Fault." SPEFE (March 1995) 26.
- [12] Ramey. H.1. Jr.: "Interference Analysis for Anisotropic Frnrrnations-A Case History." JPT (Oct. 1975) 1290; Trans .. AIME. 259.
- [13] Well-Test Analysis for Naturally Fractured Reservoirs;Heber Cinco-Ley. CSIPSA and UNAM, January 1996.
- [14] Djebbar TIAB, Ph.D.General Manager, United Petroleum Technology (UPTEC):ADVANCED WELL TEST ANALYSIS, Copyright 2018
- [15] : T. Babadagli, SPE, Sultan Qaboos University SPE 69564, Published March 25 2001.
- [16] : Bakhtyar Abdulstar , Huner Mahdi , Muhammad Faisal Improving Oil Recovery In

Fractured Reservoirs (Eor), Academic year (2016-2017).

[17] : L.W. Holm, SPE, UNOCAL Corp. August 1986.

[18] : An Introduction to Enhanced Oil Recovery Amirhossein Mohammadi Alamooti and Farzan Karimi Malekabadi Department of Chemical and Petroleum Engineering, Sharif University of Technology, Tehran, Iran, January 2018.

[19] : Chemical Flooding in Naturally Fractured Reservoirs: Fundamental Aspects and Field-Scale Practice B. Yadali Jamaloei Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, 2500 University Drive NW, Calgary, Alberta, T2N 1N4 - Canada e-mail: byadali@ucalgary.ca, Oil & Gas Science and Technology – Rev. IFP Energies nouvelles, Vol. 66 (2011), No. 6, pp. 991-1004 Copyright © 2011, IFP Energies nouvelles DOI: 10.2516/ogst/2010040, November 2011.

[20]: Miscible Gas Injection Study in a Naturally Fractured Reservoir: A Case Study B. Moradi, SPE, Iranian Central Oil Fields Company, and H. Tousinia, Petroleum University of Technology Copyright 2010, Society of Petroleum Engineers. This paper was prepared for presentation at the Trinidad and Tobago Energy Resources Conference held in Port of Spain, Trinidad, 27–30 June 2010.

[21] De Swaan-O., A.: "Analytical Solutions for Determining Naturally Fractured Reservoir Properties by Well Testing," *SPEJ* (June 1976) 117;*Trans.*, AIME, **261**.

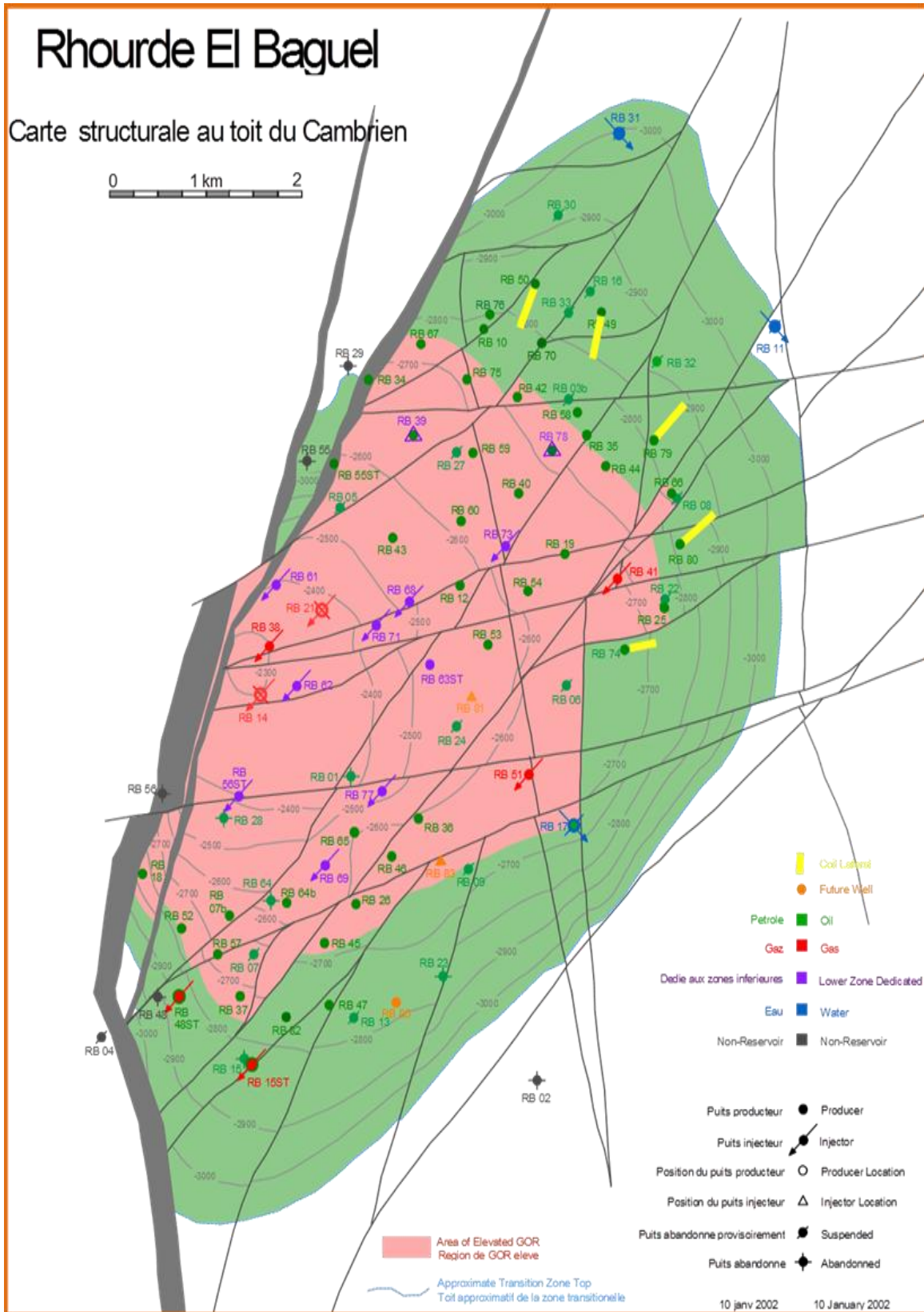
[22] Wettability, Trapping and Fracture-Matrix Interaction during WAG Injection in Fractured Carbonate Reservoirs. Simeon Agada, SPE, and Sebastian Geiger, SPE, Heriot-Watt University, Published: April 12 2014.

[23] Shawket G. Ghedan and Anjani Kumar, Computer Modeling Group, Ltd. "Impact of Fractures Characterization, Wettability and Hysteresis on Thermal Recovery Processes in Carbonate Naturally Fractured Reservoirs", June 10 2014.


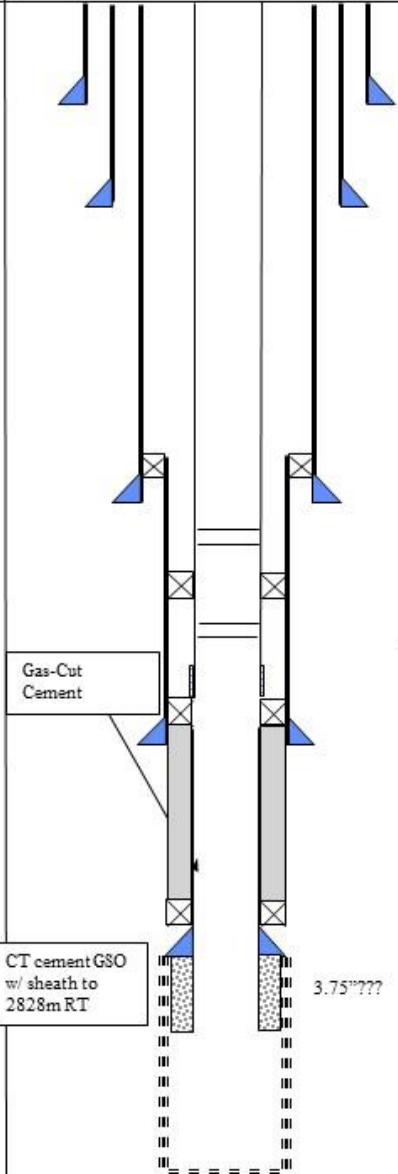
[24] Document REB SH: Rhourde El Baguel, Juin 2021

Annexes


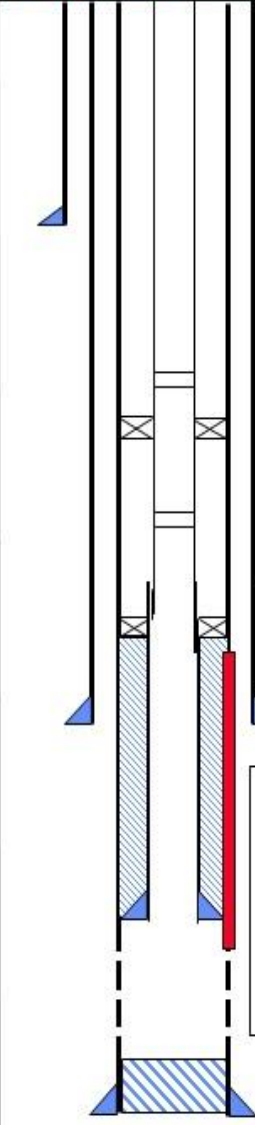
Annex 1



Annex 2 : RB 43 Well

 SONARCO <i>Rhourde El Baguel</i>		WELL: RB43 Producer well		Completion après WO Du 11-11-2017 au 07-12-2017	
DESCRIPTION	Depth (m)/ VC	Tree: FMC, 6500 psi, 4"1/16 nominal Top Cap: ACME OTIS 6.5 x 4.125", 4 pitch		ID	DRIFT
20", 106.5 #, K-55 Casing Shoe	268 m				
13-3/8", 72 #, HC-80 Casing Shoe 4-1/2", 13,5#, NV Tbg.	1207 m			3.920"	3.795"
7" Liner Top	2291 m				
9-5/8", 53.5 #, HC95 Casing Shoe	2393 m				
4-1/2" "X" 1-nipple	2548 m			3.813"	
7" MHR Pkr with R/L and mill-out Extension	2553 m				
4-1/2" "XN" 1-nipple	2568 m			3.813"	
Smith Tie-Back Seal Assy. w/25' seals	2579 m	Gas-Cut Cement			
7", 32 #, P110 Liner shoe	2696 m				ZONES (RT) : Ri Z - 6B = 2727 m Z - 6A = 2749.2 m Ra Z - 5B = 2779.1 m Z - 5A = 2798 m Z - 4 = 2839 m Z - 3 = 2854 m Z - 2 = 2874 m R2 Z - 1b = 2897 m
ECP	2785 m				
4-1/2", 13.5 #, P110 Scab Liner shoe	2789 m	CT cement GSO w/ sheath to 2828m RT	3.75"???		
6" Open hole TD	2915 m				Notes: Zs (GL)=162.01 m Zt (RT)=169,64m Zc (VC)=165,01m RT-VC= 4.63 m
				N.Ahmed 30/12/2017	

Annex 3 : RB 12 Well

 SONARCO <i>Rhourde El Baguel</i>		WELL: RB12 Producer Well		Complétion après Workover du 02/10/2017 au 04/10/2017	
DESCRIPTION	Depth (m)/ RT	Tree : FMC , 6500 psi , 4 "1/16 nominal Top Cap : ACME OTIS 6.5 " x 4.125 " , 4 pitch		ID (drift)	
Tubing 4-1/2" , 13,5# , P110,NVAM				3.958 "	
13-3/8" casing shoe	889 m			3.813 "	
4-1/2" « X » nipple	1710,5m			3.75 "	
packer Weather ford ULTRA PACK 7"x4"1/2, 32#	1714 m				
4-1/2" « XN » nipple	1765 m				
Tie Back Seal Nipple W/MULESHOE 3"1/2 N.V ID=3,883 OD= 5,750	1767 m				
4-1/2" Liner Top	1776 m				
9-5/8" casing shoe	2425 m				
Squeeze perforations from. 2739m - 2868m before running & cementing liner in place.					
4-1/2" Liner Shoe	2845 m				
Bottom of ciment squeezer	2868 m				
Ancien Perforations 2868 m à 3010m					
Top Sediment WL côte	3131 m cc				
7" casing shoe	3173 m				
Note RAN 94mm GAUGE RING TO LOCATE TOP OF SEDIMENT FILL, TAGGED SAME AT 3131m		Section between 1800 – 2720 m shows significant to severe corrosion		ZONES (RT) : Ri 6B = 2739 m 6A = 2760 m Ra 5B = 2790 m 5A = 2808 m 4 = 2845 m 3 = 2858 m 2 = 2878 m R2 1b = 2899 m R3 1a = 2984 m	
		Additional perfor 28/29 Aug 99 2880 - 2892 m 2908 - 2956 m			
		Additional perfor 26/27 May 00 2965 - 2992m 3000 - 3018m			
		Notes: Zs (GL) = 153,44m Zt (RT) = 158,44m Z (VC) = RT-GL = 7.65 m RT-VC = 5,06 m RT-Tbg hd flange = 6.83 m Tbg hd flange-Swab.V = 1.77 m Perforations 2739 - 3010m 2965 - 3018m (non-continuous)			
		S.M - 13 Octobre 2017			

Annex 4 : RB 57 Well

