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Sudan University of science and Technology

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Simulation Study on Nitrogen Injection Performance

For Jake Oil Field Reservoirs-Sudan as pressure support

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الإستهلال

قال تعالى:

بسم الله الرحمن الرحيم

﴿ قَالَ يَا قَوْمِ أَرَأَيْتُمْ إِن كُنتُ عَلَىٰ بَيِّنَةٍ مِّن رَّبِّي وَرَزَقَنِي مِنْهُ رِزْقًا حَسَنًا ۚ وَمَا أُرِيدُ أَنْ أُخَالِفَكُمْ إِلَىٰ مَا أَنْهَاكُمْ عَنْهُ ۚ إِنْ أُرِيدُ إِلَّا الْإِصْلَاحَ مَا اسْتَطَعْتُ ۚ وَمَا تَوْفِيقِي إِلَّا بِاللَّهِ ۚ عَلَيْهِ تَوَكَّلْتُ وَإِلَيْهِ أُنِيبُ ﴾

سورة هود الآية (88)

Dedication

We would like to donate this unpretentious effort to

Our Parents; who have endless presence and for the never ending love and encouragement

Our brothers and sisters; who sustained us in our life and still

Our teachers; ho lighted candle in our ways and provided us with light of knowledge

Finally; our best friends……..

Acknowledgement

Everything that has a beginning must equally have an end. Thanks, of Allah for the gift of life in good health and abundant grace throughout our stay in this great citadel. It’s indeed a privilege and honor to pass through this college. We acknowledge the effort of every lecturer that has impacted knowledge into us, without your contributions we would not be who we are today

Abstract

Nitrogen injection is one of enhance oil recover method that has been used widely over the world for decades and recently in Sudanese oilfields for gas lifting, reservoir pressure maintenance, huff & puff, and flooding.

Nitrogen injection becomes economical effective, alternative than natural gas and carbon dioxide due to the law cost, increased extraction factor, and availability of nitrogen in addition to the many problems associated with other gas injection methods such as equipment corrosion as in carbon dioxide injection the price of natural gas that used to injection become more expensive.

The Jake oilfield in block 6 located in west Kordofan State, the field reach the tertiary recovery stage thus reservoir pressure decrease with production life time, this work focus on the best simulation scenarios for pressure support by the injection nitrogen using five wells;(js-1) (js-4) (js-18) (js-22) (js-35), as well as using the current available data to simulate the best model.

The wells were simulated using the GEM's model and set the base case before to compare by nitrogen injection scenarios after, the result of the research work done indicated decrease after nitrogen injection in water cut by 42% and increase in both oil production rate and oil cumulative production rate by 43.4%and 9.33 % respectively.

Well18 in Jake south is high water cut well that reduce the entire field productivity therefore is converted to a nitrogen injection well to decrease the water cut ratio.

التجريد

يعد حقن النيتروجين أحد الأساليب المحسنة لاستخراج النفط التي تم استخدامها على نطاق واسع في جميع أنحاء العالم لعقود من الزمن ومؤخراً تم في حقول النفط السودانية تدعيم ضغط المكمن والغمر ولتقنيات الرفع بالغاز.

أصبح حقن النيتروجين فعالاً اقتصادياً ، كبديل عن الغاز الطبيعي وثاني أكسيد الكربون بسبب تكلفته القليلة ، وزيادة معامل الاستخراج ، وتوافر النيتروجين بالإضافة إلى العديد من المشاكل المرتبطة بطرق حقن الغاز الأخرى مثل تآكل المعدات كما هو الحال في حقن ثاني أكسيد الكربون وسعر التكلفة العالي للغاز الطبيعي.

حقل جيك النفطي مربع 6 الواقع في ولاية غرب كردفان ، وصل الحقل إلى مرحلة الاستخلاص المحسن وبالتالي انخفض ضغط المكمن مع عمر الإنتاجية للمكمن ، ويركز هذا العمل على أفضل سيناريوهات المحاكاة

لدعم الضغط بواسطة حقن النيتروجين باستخدام خمسة آبار ، وكذلك استخدام البيانات الحالية المتاحة لمحاكاة أفضل نموذج.

تمت محاكاة الآبار بإستخدام نموذج وضبط الحالة الأساسية من قبل للمقارنة بسيناريوهات حقن النيتروجين بعد ذلك ، أظهرت نتيجة التمثيل المكمني بعد الحقن انخفاضًا في المياه الزائدة المنتجة مع النفط بنسبة 42 ٪ في وزيادة في كل من معدل إنتاج النفط والإنتاج التراكمي بنسبة 8.277 و26٪ على التوالي.

البئر 18 في جنوب جيك عبارة عن بئر تنتج مياه بشكل كبير مما يقلل من إنتاجية الحقل بالكامل لذلك تم تحويله إلى بئر حقن النيتروجين لتقليل نسبة إنتاج المياه.

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N	Original oil in place
h_o	Net thickness of oil zone
S_{oi}	Initial reservoir oil saturation
B_{oi}	Initial oil formation volume factor
G	Original free gas in place
h_g	Net thickness of gas zone
S_{gi}	Initial reservoir gas saturation
B_{gi}	Initial gas formation volume factor
S_{wi}	Initial water saturation
Q	Flow rate
K	Permeability
A	Area
μ	Viscosity
L	Length
ΔP	Pressure Gradient
V	Volume
P	Density
G	Acceleration
Φ	Porosity
C_t	Total Compressible
U	Variable convenient
Pc	Capillary Pressure
K_r	Relative Permeability
M	Mobility Ratio
γ_g	Specific gravity of gas
γ_o	Specific gravity of oil
K_{rg}	Relative permeability of gas
K_{rw}	Relative permeability of water
μ_o	Oil viscosity
μ_g	Gas viscosity
F_g	Gas friction Factor

Chapter (1)

Introduction

1.1 Introduction:

The process of oil production goes through several stages of its life and at each stages uses specific techniques and method

1.1.1 Primary recovery stage:

In this stage the natural reservoir pressure pushes oil into the wellbore

Approximately less than 30% of the reservoir's original oil in place, also pumps and Gas lifting are involved in this stage.

1.1.2 Secondary Recovery Stage:

In this stage the pressure of oil reservoir is decrease and the oil does not arrive to the wellbore therefore use some techniques such as water or gas injection to maintain the pressure and displaced the oil to the production well; which recovery an additional (30-50) %of the original oil in place.

1.1.3 Tertiary Recovery Stage (EOR):

The rise in world oil prices has encouraged the petroleum engineers to use the new technical developments. Enhanced oil recovery (EOR) is a collection of sophisticated methods, to extract the most oil from a reservoir, and this method could have divided into two major types: thermal and non-thermal recovery methods, each type has specific use in a certain type of reservoir; thermal EOR techniques such as steam or hot water injection are generally utilized for heavy and extra heavy oils and bitumen ,non-thermal methods such as water flooding and gas and chemical injection are typically applied in light and intermediate-oil reservoirs

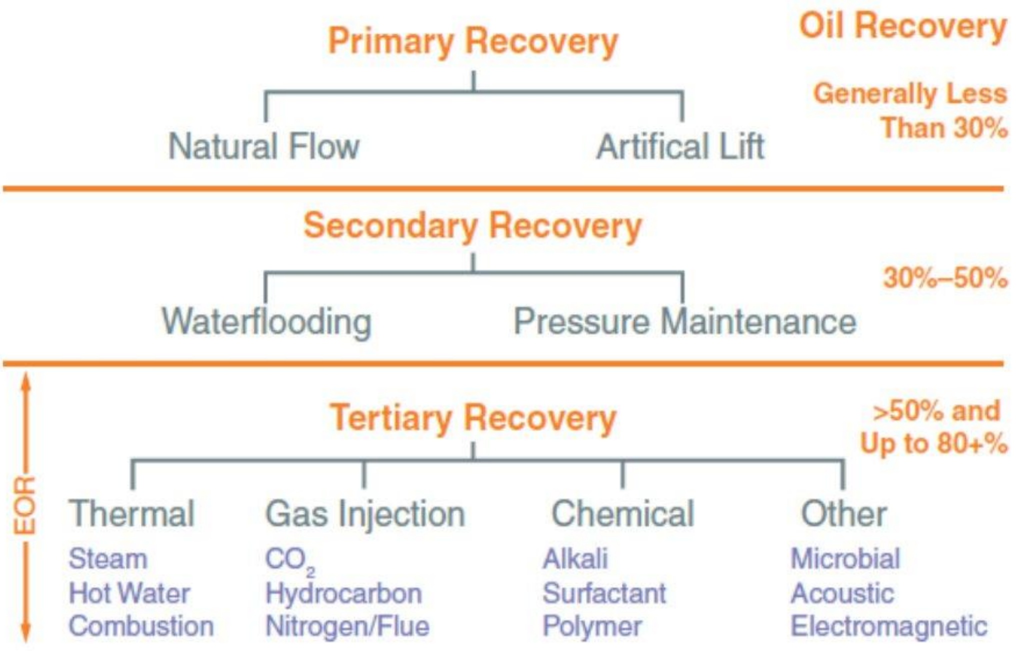

Fig. (1. 1) Oil recovery stages

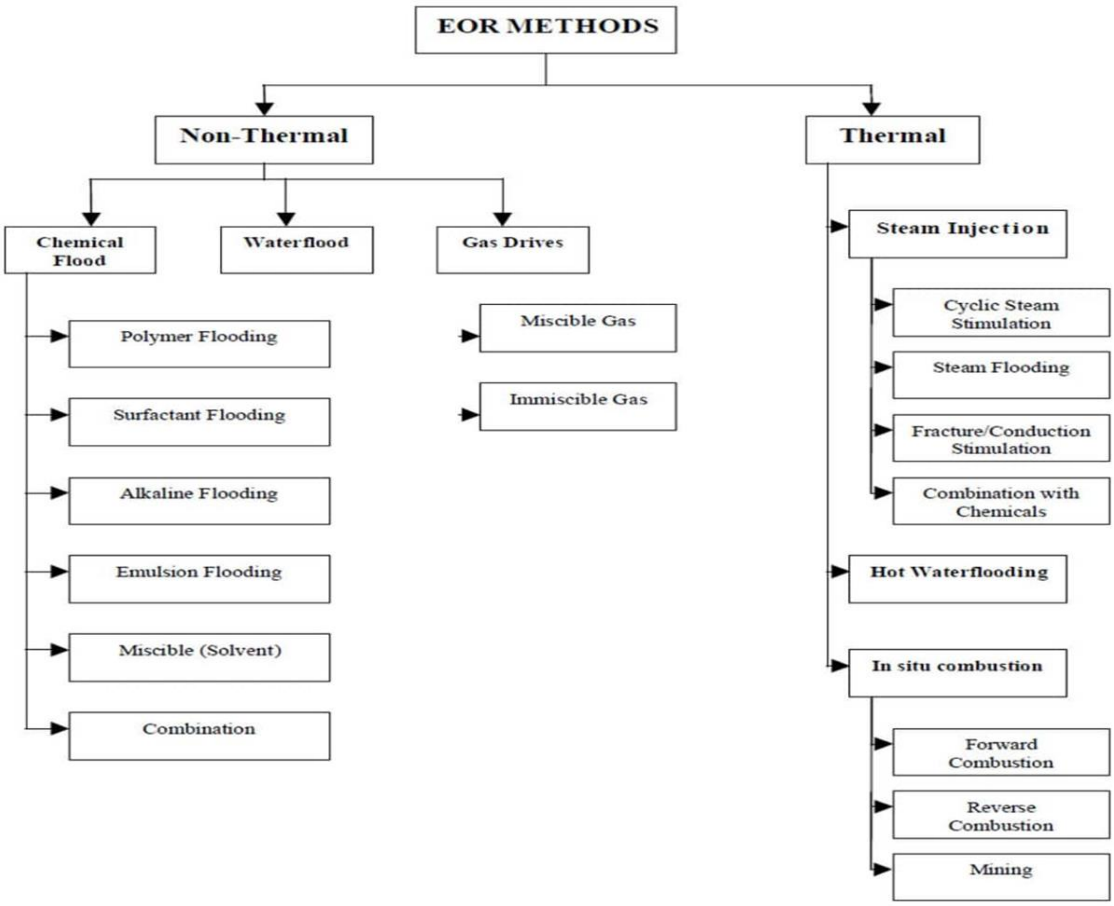

Fig. (1. 2) EOR methods

During the tertiary stage, Gas injection can be Used with this techniques nitrogen (immiscible) Or carbon dioxide (miscible) gas injection into the oil reservoir.

These techniques also called Gas Flooding, which can be either miscible or immiscible.

In miscible gas, flooding the gas (Co_2) mixes with the oil to reduce it is viscosity and improves flow.

In immiscible gas, flooding the gas (Nitrogen) does not mix with the oil but rather creates energy, which increases pressure to drive oil into the well bore.

1.2 Gas injection:

Gas injection process uses gases including hydrocarbon gas injection (natural gas and liquefied petroleum gas), carbon dioxide (CO_2), and nitrogen (N_2), and lead to the enhancement of oil recovery via four main mechanisms:

a) Viscosity reduction of hydrocarbon phase,
b) Interfacial tension (IFT) reduction via mass transfer between displacing and displaced phases during condensing/vaporizing gas drive,
c) Oil swelling
d) Reservoir pressure maintenance

In lower permeability reservoir gas injection also has the potential to improve the gravity drainage recovery rate and ultimate oil recovery.

In this process we can use many different types of gas to inject to the reservoir depend on different factors, the most popular types are:

- CO_2
- N_2
- Natural gas

1.3 Nitrogen Injection:

1.3.1 Definition:

A process whereby nitrogen gas is injected into an oil reservoir to increase the oil recovery factor, it can be used for gas cap pressure maintenance, immiscible or miscible drive of oil fields.

1.3.2 Nitrogen injection screening:

Table (1. 1) nitrogen screening

Oil gravity (API$^{\circ}$)	>35°
Oil viscosity (cp)	<10
Composition	High % of C_1-C_7
Oil saturation	>30% PV
Formation type	Sand stone or carbonate
Net thickness (ft)	Thin unless dipping
Average permeability (md)	N.C
Reservoir depth (ft)	>4500 ft
Reservoir temperature ($^{\circ}$F)	N.C

1.3.3 Injection pattern of nitrogen:

Below the minimum miscibility pressure (MMP), this is an immiscible process in which recovery is increased by oil swelling, viscosity reduction and limited crude-oil vaporization. Above the MMP, nitrogen injection is a miscible vaporizing drive. Miscibility of nitrogen can be achieved only with light oils that are at high pressures; therefore, the miscible method is suitable only in deep reservoirs.

As previously discussed one of the enhanced oil recovery methods is gas injection. In miscible gas injection, the gas is injected at or above the minimum miscibility pressure (MMP) which causes the gas to be miscible in oil. When flooding by the gas is conducted below MMP, it is known as immiscible gas injection. Primary conditions affecting miscibility are composition, fluid characteristics, pressure, and temperature.

One gas employed for these gas injection techniques is nitrogen. Nitrogen has long been successfully used as the injection fluid for EOR and widely used in oil field operations for gas cycling, reservoir pressure maintenance, and gas lift. The costs and limitations on the availability of natural gas and CO2 have made nitrogen an economic alternative for oil recovery by miscible gas displacement. Nitrogen is usually cheaper than CO2 or a hydrocarbon derived gas for displacement in EOR applications and has the added benefit of being non-corrosive

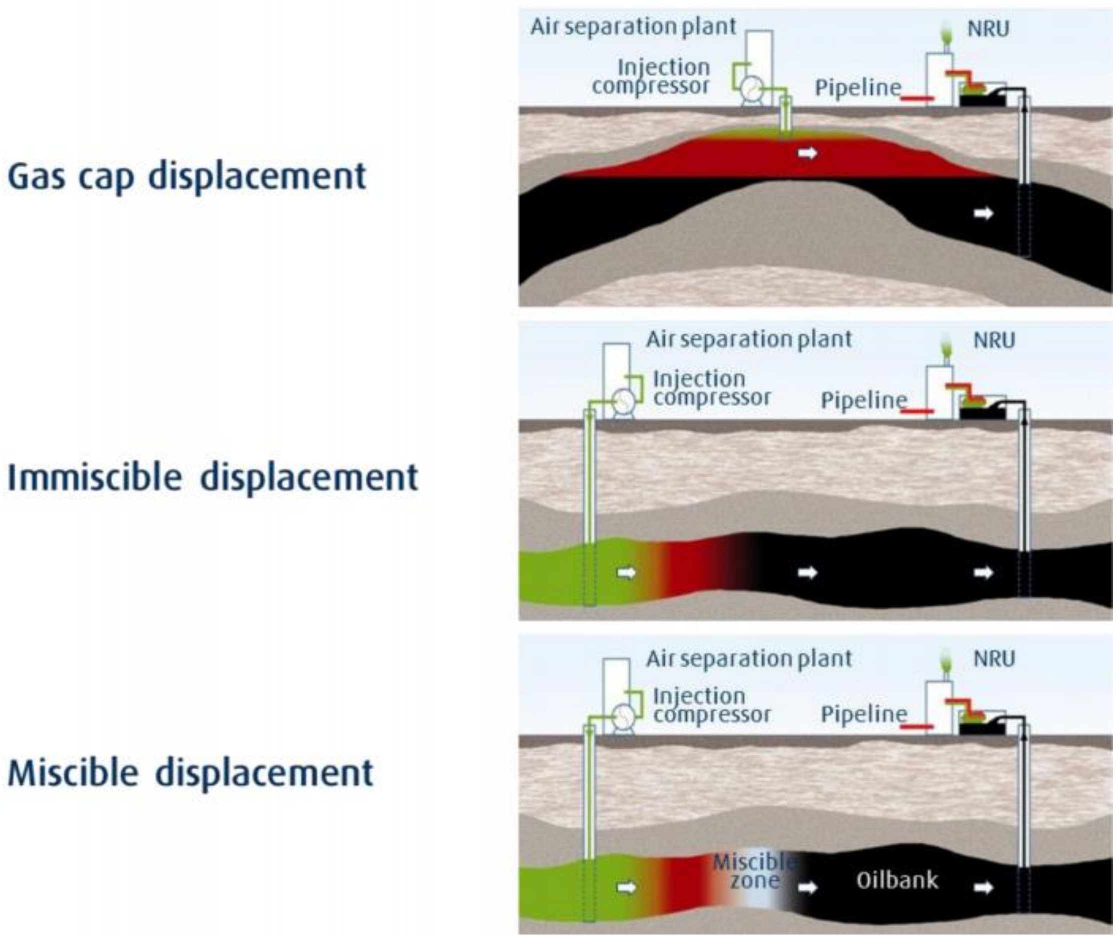

Fig. (1. 3) Injection Pattern of Nitrogen

1.3.4 Major applications:

The injection of high-pressure pure nitrogen gas has been selected for the following applications to increase oil production:

1.3.4.1 Miscible displacement of oil:

In many deep reservoirs containing light crude, nitrogen achieves multiple contact miscibility with oil, dramatically increasing recovery in the swept zone. Nitrogen has been selected over carbon dioxide for many of these applications.

1.3.4.2 Gas cap displacement:

Nitrogen injection is being used to replace the gas cap over an oil column, allowing immediate production and sale of gas while maintaining the reservoir pressure needed to maximize production from the oil column.

1.3.4.3 Cycling rich gas reservoirs:

The injection of nitrogen maintains the reservoir pressure needed to maximize natural gas liquid sand condensate recovery, eliminates the need to buy makeup gas, and allows immediate sale of produced gas.

1.3.5 Immiscible displacement of oil:

Nitrogen is being used to augment gravity drainage in dipping reservoirs, to maintain pressure in solution gas drive reservoirs, and to form secondary gas caps in attic oil formations.

1.3.5.1 Pushing carbon dioxide miscible fronts:

In reservoirs where carbon dioxide must be used to achieve miscibility, lower-cost nitrogen can be used to push a slug of more expensive carbon dioxide.

1.3.6 Why Nitrogen injection?

At today's prices natural gas becomes more and more expensive for use in pressure maintenance of oil reservoirs, and the problem caused by using the CO2 injection from corrosion in the surface facilities and the production well’s, difficulties in separated from the produced hydrocarbons or any other environmental or industrial sources and asphaltene precipitation that would cause formation damage and wettability alteration. In light of all these reasons it founded that the nitrogen is the suitable alternative gas for injection and further EOR for the reservoir especially in deep, high-pressure reservoirs that bear hydrocarbon fluids rich in light and intermediate components (C_1–C_7), and the high cost of boosting declining reservoir pressure and production can be reduced through the substitution of nitrogen for natural gas.

Nitrogen gas, produced on-site by cryogenic air separation, has replaced hydrocarbon gas injection in many enhanced oil and gas recovery applications.

Air Products pioneered the on-site supply of pure cryogenic nitrogen gas for enhanced oil and gas recovery in 1977 and is a leading supplier of nitrogen to the global oil industry for such applications.

1.4 Nitrogen generation:

Nitrogen is available in unlimited quantities from the air and can be produced in an Air Separation Unit (ASU) which is differ from type to another in purity, quantity and physical condition of the desired products and also in a relation in varying condition of energy and capital cost which include cost of energy, maintenance and personnel staff.

ASU are produced nitrogen by cryogenic distillation of air, to a purity of 99.995% mol. The nitrogen is produced by the Low Temperature air separation process which is still considered the most economical method.

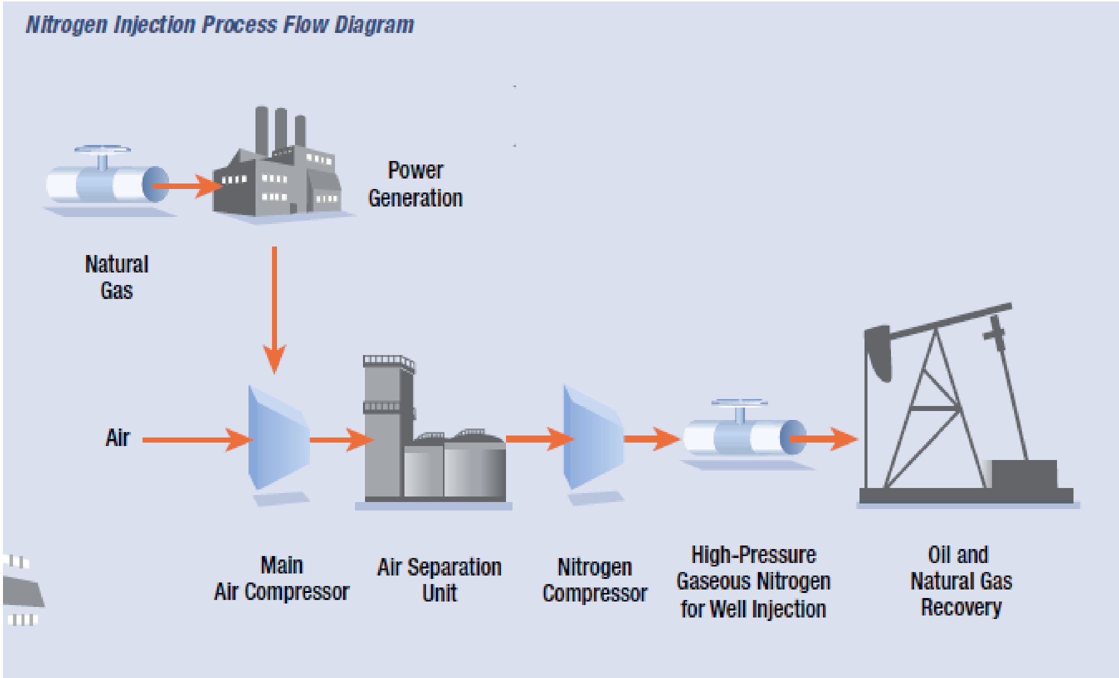

Fig. (1. 4) General flow diagram of the nitrogen recovery unit (NRU)

1.4.1 APSA Nitrogen generation unit:

The APSA nitrogen generation unit uses the latest technology, combining air compression, adsorption, purification, and cryogenic distillation of the main components.

The APSA unit is fully packaged, enabling easy plug-and-play installation. Depending on customer requirements, it can be configured to optimize capital expenditures (CAPEX) and/or operational expenditures (OPEX). The unit can also be customized, with options that include:

•Back-up vaporizers and storage for increased availability and reliability

•Liquid co-production to refill back-up liquid storage

Fig. (1. 5) Air Separation Unit (ASP)

1.4.2 The Low Temperature Air Separation process:

In this process the air is first compressed, then purified by removing water vapor and carbon dioxide, and then cooled down to liquefaction temperature Since the industrial air is also contaminated with some dangerous components (especially hydrocarbons) in an ASU have to be removed before the rectification takes place to obtain the required components.

The removal of the water vapor and the carbon dioxide from the air is accomplished by one of the following processes:

- •Molecular sieve plants.
- •Reversing heat exchanger plant (Revex plants).

- Regenerator plant

1.4.2.1 Typical applications:

Installed in liquefied natural gas (LNG) terminals, electronics plants, and oil refineries (special version meets the most stringent oil industry standards).

1.5 Advantages of Nitrogen Injection:

Although the reservoir engineering and the design of each nitrogen injection project are unique, nitrogen is being chosen for five primary reasons:

- Nitrogen is economical.
- Nitrogen is readily available and can be generated and injected wherever, whenever and in whatever quantities are needed.
- Nitrogen is environmentally friendly, completely inert, and remains inert in the presence of water.
- Nitrogen can be removed economically from a sales gas stream if necessary to increase Btu content.
- Nitrogen gas is less compressible than either carbon dioxide or natural gas, so less is required.

1.6 The project objectives:

The main objective is toenhance the natural energy of the reservoir to produce more oil from the well and increase the reverse inventory that able to be produce and:

1. To test the feasibility of improvingthe recovery factor of the Jake South reservoirs- block 6by Nitrogen injection as pressure maintenance.
2. To study the production performance of the selected wells after injection of the nitrogeninjection in the selected area.
3. To compare between the current base case situations with proposed scenarios of the nitrogen injection in selected area
4. To designed the optimum simulation modelusing available actual data to accomplish the best well condition and pattern for the feasible injection process.

1.7 The problem Statement:

The main problem that facing Jake oil field is the sever decline of the field pressure and water cut increment, and thus resulting in decrease in the productivity of the wells. In Addition, **Low VRR (**optimal voidage replacement ratio: is the ratio between the volume of the injected and the volume of the produced fluid, usually for the primary recovery VRR=0, and for it vary from 0 to 1 to hybrid recovery process**)**There are Other Problems Such as High liquid rates

Chapter 2

Literature Review and Theoretical Background

2.1 History of Nitrogen Injection:

The use of nitrogen injection to enhance oil recovery has been used successfully worldwide since the mid of 1960's and its use is becoming increasingly popular due to its lower production costs and availability when compared to conventional hydrocarbon gases, making it a popular choice among small local field operators.

Interestingly, the very first reported use of nitrogen injection in reservoir also coincided with the advent of EORin the U.S. The origins of nitrogen injection and thus EOR in the U.S. can be traced back to the profile Permian basin in the west Texas. In 1945 Atlantic Rich field discovered an unusual field, which they called Block 31 contained an estimated amount of 300 million barrels of light oil, gas and OOIP had an initial reservoir pressure approximately of 4000 psi. The development of Block 31 proved to be a challenge because of its low permeability 1 md.

This resulted in very poor well production rates. In efforts to overcome this problem, studies of fluid movements within the reservoir were conducted. These results of these studies showed that injecting natural gas at pressures sufficiently high that it became miscible with oil created an oil/gas phase that was much more mobile than the oil phase alone.

Thus, the oil/gas phase could permeate through the reservoir toward wellbore more easily. In 1949, Atlantic-Richfield began compressing and injecting natural gas from a nearby source into Block31. The field began to produce slowly at first, but production grew steadily. By 1965 cumulative production from Block 31 approached 90 million barrels. The industry hailed the success at Block 31, recognized that miscible gas injection could extract oil that would remain in the ground under conventional methods, with such poor permeability, no oil was extracted under primary or secondary methods, all production was tertiary or enhanced oil recovery.

In 1966, to avoid using marketable natural gas Atlantic Rich field developed a system to inject flue gas (deficient in oxygen but rich in nitrogen and carbon-dioxide) from a nearby processing plant. Production gradually increased to a peak of 20000 BOPD in 1978. However, production slid steadily there for to 2500 BOPD in 1998, with an average production of 15 BOPD per well (standing, 2007).

The success of Block 31 led to the emergence of number of other enhanced oil recovery projects utilizing nitrogen in Texas, Louisiana, Wyoming, Utah, Oklahoma, and California.

2.2 Real Case studies of Nitrogen injection:

2.2.1 Case (1) Nitrogen injection Application in Trinidad and Tobago:

Trinidad and Tobago has Implemented Many EOR Projects in The Past This include:

(Immiscible Carbon Dioxide, Steam floods, cyclic Steam Stimulation, microbial Enhance Oil Recovery), Despite the increases in oil production, the projects faced such as many challenges:

- (Unreliable CO_2 supply. (Most significant
- Unreliable equipment
- CO_2 breakthrough
- (High GOR (pattern issues
- (Poor Sweep Efficiency (pattern issues
- Limited Pressure and Gas Measurements
- .Corrosion

ThePrevious problems Lead to ection technology in Trinidad and use of nitrogen inj Tobago to recover the large quantities of hydrocarbons that are still trapped. Studies of the reservoir were carried out in terms of reservoir description, characteristics and .ere as shown belowpetrophysical evaluation, and the properties w

The injection was performed in four scenarios:

1. Crestal or gas cap
2. Oil zone injection
3. Water zone injection
4. .Simultaneous crestal or gas cap and water zone injection

Results:

1. Injection nitrogen up-dip into the secondary gas cap would result in maximum oil recovery.
2. Increase the numbers of injection wells did not result in an increase in oil recovery and hence cumulative oil production because of a faster nitrogen breakthrough time.
3. Lower injection rates resulted in a higher recovery due to a longer breakthrough time.
4. Higher injection rates resulted in a shorter project life, compared to lower injection rates, because of a faster nitrogen breakthrough time. (Sinanan, 2012)

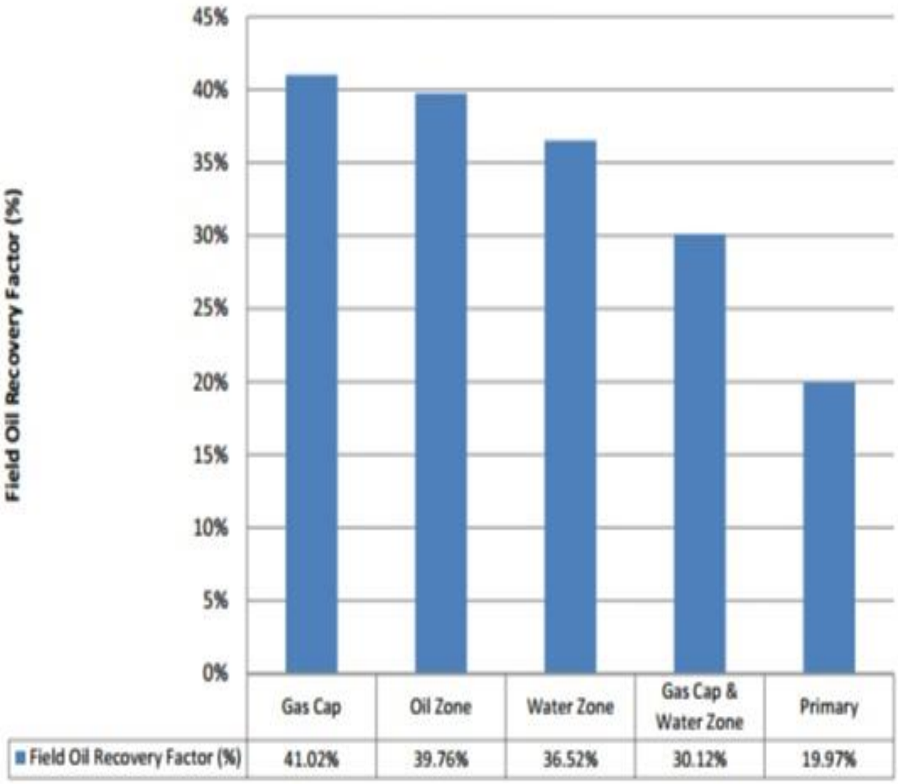

Fig. (2. 1) Result for Real Model – Trinidad & Tobago

2.2.2 Case (2) Cantrell Field Nitrogen Injection:

The project includes five trains of each 10,000 tons' nitrogen production per day (300 MMSCFD or 335,000 Nm3/h), totaling in a supply of 50,000 tons per day at 110 bar via a 95 Km of pipeline to the offshore platforms Akal and Nohoch-A for pressure maintenance. The plants were built from 1998 to 2000 with four trains and expanded in 2004 to 2006 with a five train, with a total investment sum of 1.3 billion US-dollars.

Fig. (2. 2) Cantrell production history before and after nitrogen injection start

The production of the Cantrell field increased from 1 million barrels per day in 1996 to 2.2 million barrels per day peak production in 2004. About 30% of the can be attributed to the effect of nitrogen injection.

2.2.2.1 Field assessment for nitrogen EOR/IOR potential:

To assess the potential of oil field for nitrogen injection numerous screening criteria have been developed, and refined by analysis data from many commercial EOR projects. Three critical parameters for nitrogen injection have been defined, being the API gravity of the oil, depth of reservoir, which related to the pressure in the oil field, and the viscosity of oil, other parameters as permeability or temperature are not seen as not critical.

The effectiveness of nitrogen was observed and compared in various nitrogen injection projects with different recovery mechanisms, showing incremental recovery factors of 12% to 36% of the OOIP. For this assessment, we have used a conservative approach of 10% incremental recovery factor for miscible gas injection, and 5% for immiscible gas injection including pressure maintenance, in order to estimate the potential incremental recovery of a specific field.

The efficiency of nitrogen injection is defined as sweep efficiency in barrels of incremental oil produced per ton of injected gas, and estimate on a conservative level for this assessment.

Table (2. 1) Screening Criteria For Field assessment

EOR Method	Gravity range [°API]	Depth range [m]	Viscosity range [cP]	Incremental recovery [% OOIP]	Sweep efficiency [bbl/ton]
CO2 miscible	22-50	750 - 9,000	< 10	12%	2.4
N2 miscible	35-50	1,800 - 9,000	< 10	10%	2.4
N2 immiscible	12-50	550 - 1,800	< 600	5%	1.7

2.2.3 Case (3) The North Africa oil field assessment:

The field assessment lists the producing oil field that fulfills the screening above. Based on the given OOIP, an incremental oil recovery potential is calculated in million barrels:

1-Egypt:

Table (2. 2) Nitrogen EOR Field Screening Example Egypt

Field	Area	Operator	Recovery potential [MMbbl]	OOIP [MMbbl]	API Gravity [°API]	Viscosity [cP]	Depth [m]
Miscible N2 EOR:							
Zeit East	Zeit Bay	Dana/KNOC	**59.1**	591	40	0.45	11,480
Meleiha W	Qarun	Agiba	**58.9**	589	39	0.62	8,003
Badr El Din 01	Badr El Din 03	Bapetco/Shell	**52.8**	528	39	0.45	11,132
Ashrafi	Zeit Bay	Eni	**50.1**	501	39	0.81	6,399
Qarun	Qarun	Khalda/Apache	**45.4**	454	40	0.48	9,932
... and 44 more							
Immiscible N2 EOR:		SUCO/RWE					
Zeit Bay	Zeit Bay	BP	**49.1**	983	44	0.47	1,200
Badri	Morgan	BP	**44.9**	898	32	2.64	1,750
Shoab Ali	Zeit Bay	SUCO/RWE	**41.2**	824	33	2.48	1,600
Ras Fanar	Belayim Marine	Eni	**31.8**	636	31	7.75	623
Razzak West	North Alamein	EGPC	**14.1**	281	36	1.19	1,745
... and 34 more							

Taking in account a 10 years scheme for nitrogen injection, and a sweep efficiency as given above, the average demand is calculated I tons per day, as well as the average incremental oil recovery potential in barrel per day.

Table (2. 3) Nitrogen EOR Potential for Egypt

Field	Area	Operator	Recovery potential [bbl/d]	Nitrogen demand [t/d]
Miscible N2 EOR:				
Zeit East	Zeit Bay	Dana/KNOC	16,182	6,797
Meleiha W	Qarun	Agiba	16,132	6,776
Badr El Din 01	Badr El Din 03	Bapetco/Shell	14,458	6,072
Ashrafi	Zeit Bay	Eni	13,719	5,762
Qarun	Qarun	Khalda/Apache	12,440	5,225
... and 44 more				
Immiscible N2 EOR:				
Zeit Bay	Zeit Bay	SUCO/RWE	13,463	8,078
Badri	Morgan	BP	12,297	7,378
Shoab Ali	Zeit Bay	BP	11,282	6,769
Ras Fanar	Belayim Marine	SUCO/RWE	8,706	5,224
Razzak West	North Alamein	Eni	3,850	2,310
... and 34 more				

2-Algeria:

Algeria has many oil fields which may be suitable for nitrogen injection. The potential capacity is in the range of the Cantrell reference, with a possibility to use nitrogen in a staged injection approach in the HassiMessaoud field.

Table (2. 4) Nitrogen EOR Potential for Algeria

Field	Area	Operator	Recovery potential [bbl/d]	Nitrogen demand [t/d]
Miscible N2 EOR:				
Hassi Messaoud	Hassi Messaoud	Sonatrach	**1,638,362**	688,112
Ourhoud	Ourhoud	Sonatrach	**161,677**	67,904
Rhourde El Baquel	Rhourde El Baquel	BP	**90,253**	37,906
Hassi Berkine Sud (South)	Ourhoud Area	Anadarko	**79,240**	33,281
Haoud Berkaoui	Guellala Area	Sonatrach	**75,723**	31,804
... and 43 more				
Immiscible N2 EOR:				
Ordovician+Devonian	Tin Fouye-Tabankort	Sonatrach	**58,878**	35,327
Gassi Touil	Gassi Touil	Sonatrach	**51,264**	30,758
Edjeleh	Zarzaitine	Sonatrach	**40,652**	24,391
Alrar	Alrar	Sonatrach	**12,955**	7,773
Amassak	Tin Fouye-Tabankort	Sonatrach	**5,123**	3,074
... and 15 more				

3-Libya:

Also in Libya many fields with potential for large nitrogen injection units be feasible. Significant incremental oil recovery could be achieved in a sustainable environment.

Table (2. 5) Nitrogen EOR for Libya

Field	Area	Operator	Recovery potential [bbl/d]	Nitrogen demand [t/d]
Miscible N2 EOR:				
Sarir	Sarir Area	NOC (Libya)	760,322	319,335
Amal	Amal (012-B/E/N/R)	Suncor Energy	452,940	190,235
Bu Attifel	Bu Attifel (100-A)	Eni	343,316	144,193
Nasser	Attahadi Area	NOC (Libya)	297,268	124,852
Augila-Nafoora	Nafoora Non-Unit	NOC (Libya)	191,610	80,476
... and 45 more				
Immiscible N2 EOR:				
Defa	Waha Libya Area	Waha	145,535	87,321
Dahra	Dahra Area	Waha	127,327	76,396
El Sharara A	El Sharara A Area	Repsol	115,068	69,041
Beda	Beda Area	NOC (Libya)	80,766	48,459
Raguba	Raguba Area	NOC (Libya)	51,527	30,916
... and 36 more				

4-Tunisia:

Tunisia has one major field with potential for nitrogen injection, which is EL Borma. Some more, smaller fields may be suitable for a nitrogen injection scheme with a reduced budget, also with some cluster potential in the El-Borma area.

Table (2. 6) Nitrogen EOR Potential For Tunisia

Field	Area	Operator	Recovery potential [bbl/d]	Nitrogen demand [t/d]
Miscible N2 EOR:				
El Borma	El Borma Area	Eni	105,410	44,272
Cherouq (x-Farrah)	El Borma Area	OMV	9,324	3,916
Didon	Miskar Area	PA Resources	5,721	2,403
Sidi El Itayem	Sidi El Kilani Area	Spyker Energy	5,501	2,311
El Badr	El Borma Area	OMV	3,717	1,561
Ezzaouia	Ezzaouia Area	ETAP (Tunisia)	3,689	1,550
Sabria	El Borma Area	Winstar Resources	2,913	1,223
... and 12 more				
Immiscible N2 EOR:				
Sidi El Kilani	Sidi El Kilani Area	Kuwait Petroleum Corp	3,005	1,803
Cercina	Ashtart Area	OMV	1,212	727
Oudna	Zelfa Area	Lundin Petroleum	1,009	605

(Huecke, 2015)

Evaluation of characteristics of Jake-S reservoir

2.2.4 Geological characteristics of reservoir

2.2.4.1 Formation characteristics

For Jake-S Oilfield, from bottom to top, the formations are:Sharaf, Abu Gabra, Bentiu, Aradeiba, Zarqa, Ghazal, Baraka, Amal, Tendi/Senna, Adok and Zeraf.

Aradeib: Lithology is thick mudstone and sandstone interbed; **Bentiu:** lithology is massive sandstone with mudstone;

The target of this study is Bentiu and it can be classified as 6 sands and 12 sublayers (see table 2-1)

Table (2. 7) Numbers of sands and sublayers

Horizon	Sand formations	Number of sublayer
Bentiu	B1a	B1a-1,B1a-2,B1a-3
	B1b	B1b-1,B1b-2,B1b-3,B1b-4
	B1c	B1c-1,B1c-2
	B1d	B1d
	B2	B2
	B3	B3

2.2.4.2Characteristics of structure:

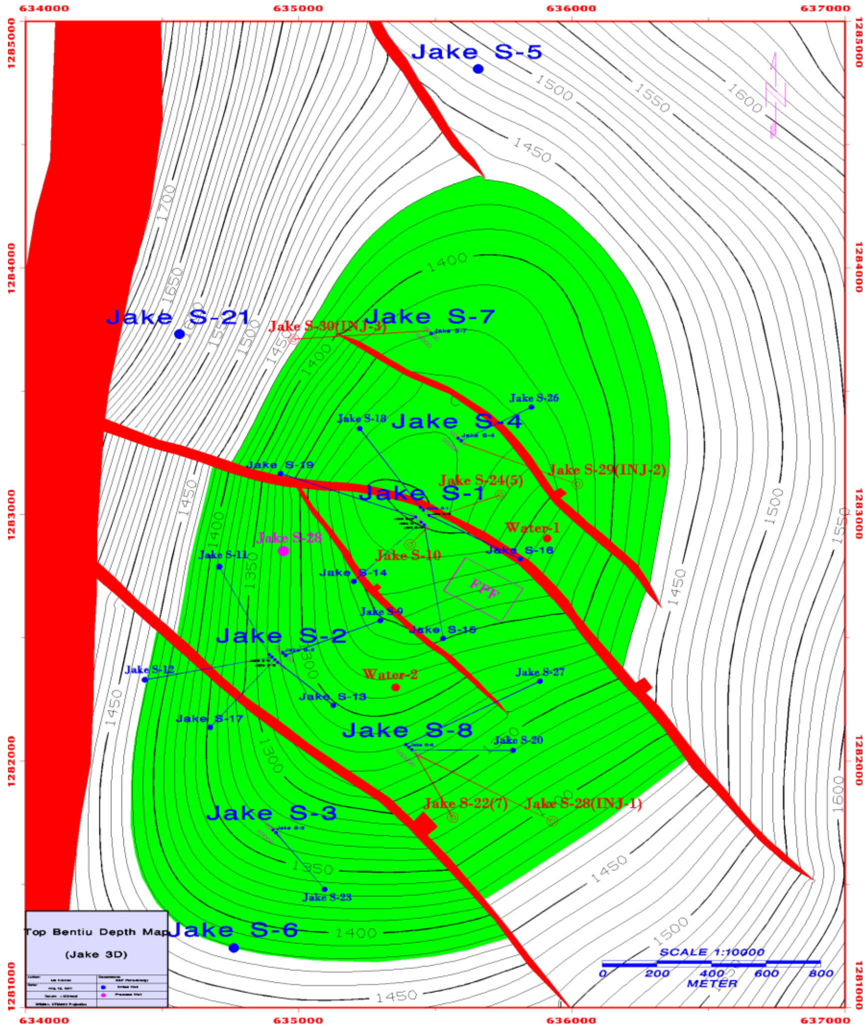

Fig. (2. 3) Structure map of Jake South Oilfield

Jake South Oilfield is located in the southeast of the Fula **depression**. Fula depression represents strike of SN with Fula East fault being east boundary and controlled by Fula West fault in the west. 5 secondary structure zones of “3-positive 2-negative” of south fault terrace zone, south secondary depression, middle structural zone, north secondarydepression and north fault terrace zone are developed from WS to NE, distributed in diagonal manner. Jake South structure is located in the south of the Jake 3D survey and is fault anticline structure cut by cluster of small faults with strike of WN. The early Jurassic strata are complete and discovered and overall, it is cut with cluster of small faults from WN to ES and the pattern of structure is not damaged (Fig. 1-1). The reservoir of Bentiu formation of Fula North fault block is a massive reservoir of fault anticline on horst block with strong bottom water and shallow burial depth （1245m－1420m）. The oil and water system of Bentiu formation is relatively clear. The OWCs of the wells are comprehensively ascertained with the bore logs, well test data, regular core analysis and evaluation of wireline logging etc., while the OWCs of reservoirs are obtained with analysis of the OWCs of different wells. The altitude of the OWC for Jake S-4 is -1430m ; the altitude of the OWC for Jake S-1 is -1425m ; the altitude of the OWC for Jake S-3 is -1423.0m, and analysis result of oil and water system is shown in table below:

Table (2. 8) OWCs of Bentiu

<table>
<tr><th>Block</th><th>Well</th><th>OWC</th></tr>
<tr><td rowspan="6">Jake S-4</td><td>JS-04</td><td rowspan="6">-1430</td></tr>
<tr><td>JS-16</td></tr>
<tr><td>JS-18</td></tr>
<tr><td>JS-19</td></tr>
<tr><td>JS-21</td></tr>
<tr><td>JS-26</td></tr>
<tr><td rowspan="11">Jake S-1</td><td>JS-01</td><td rowspan="11">-1425</td></tr>
<tr><td>JS-02</td></tr>
<tr><td>JS-05</td></tr>
<tr><td>JS-08</td></tr>
<tr><td>JS-09</td></tr>
<tr><td>JS-11</td></tr>
<tr><td>JS-13</td></tr>
<tr><td>JS-14</td></tr>
<tr><td>JS-20</td></tr>
<tr><td>JS-27</td></tr>
<tr><td>JS-28</td></tr>
<tr><td rowspan="5">Jacke S-3</td><td>JS-03</td><td rowspan="5">-1423</td></tr>
<tr><td>JS-06</td></tr>
<tr><td>JS-12</td></tr>
<tr><td>JS-17</td></tr>
<tr><td>JS-23</td></tr>
</table>

2.2.4.3 Sedimentary characteristics:

Bentiu formation is a set of sediment of braided river to meandering river and the channel is filled with fine to coarse crystalline particles of medium grading. The formation is composed of sandstone tending to be finer upward with local stratum of glutinite, representing cross bedding in shapes of trough and plane and parallel bedding, massive appearance and local structure of deformation. The sedimentary setting is flood plain. Based on the analysis of the subsurface faces, the Bentiu formation can be further divided into 3 sections of lower, middle and upper and each section features different characteristics of facies assemblage and different sedimentary modes. The lower part indicates deposition in moderately deep mixed-load high sinuosity stream showing transition to lacustrine delta. The middle part suggests deposition in low sinuosity braided sand-bed dominated stream. The upper part dominated by gravel sandstone and sandstone facies indicates deposition in outwash plain of low sinuosity braided shallow channels.

The sandstone facies crisscrosses large scale horizontal bedded sandstone from trough and plane. The fine crystalline phase comprises large amount of sandstone and mudstone facies of ripple fine sandstone layer, which indicates that the association of the sedimentary facies is the setting of channel, sand bar, river shoal and constructional plain.

2.2.4.5 Physical property of reservoir:

2.2.4.5.1 Lithology:

Bentiu formation is composed of massive medium and coarse quartz sandstone with multiple thin mudstones in thick layers. The thickness of formation is **380～487** m and can be divided into three sections of upper, middle and lower with fairly thick massive gray mudstone interbeds in between. Based on the comprehensive geological analysis of the work area and the neighboring oilfield, the oil layers are mainly distributed in the upper section (B1) of the Bentiu formation. Mainly lithology analysis is conducted for Bentiu 1, which is composed of sandstone of small scaleinterbeds of mudstone and shale. The data of the rock samples of wells of JS-2，JS-3 and JS-6 indicate that the sandstone is mainly secondary arcose of light gray color in unconsolidated and weak cementation pattern with distribution from aleurolite to conglomerate, but mainly is fairly coarse cross bedding sandstone with gravels. The median size is 0.128mm and the grading of sandstone is from bad to good, but in general, worse than Aradeiba formation. The psephicity is from sub-angular to sub-round and minority is in shape of edge angle. Kaolinite is main cementing material and is dominated by point contact between particles. The type of pore is dominated by primary pore and the selection of pore throat is not very good, being **0～400μm**. The content and distribution characteristics of the authigenic mineral are the same as that of the sandstone of Aradeiba formation.

2.2.6 Reservoir characteristics

Via core analysis, the porosity is 14%～37%, average is 24%, permeability is 500×10^{-3}～$7000\times10^{-3}\mu m^2$, and average is $2100\times10^{-3}\mu m^2$. The reservoir is of middle and high porosity and high permeability. The diagenesis of the rock is weak, featuring unconsolidated cementing of sandstone and good physical property.

It can be seen from the result of logging interpretation that the top (shale) of Bentiu is shown as high density, relatively high acoustic travel time, high neutron, low resistivity and high gamma ray; in contrast with shale, the reservoir represents low density, relatively small acoustic travel time, low neutron, high resistivity, low gamma ray and obvious abnormal spontaneous potential in oil zone. There is good shale barrier from top to bottom for the reservoir. The quality of sand on top section of Bentiu is good. The average porosity of reservoir is 25％, permeability is 2000 MD, shale volume is 18％－20％, the reservoir water saturation is close to 34％, and the aquifer water saturation even exceeds 60％.

2.3 Evaluation of reservoir characteristics:

2.3.1 Basic physical and chemical parameters:

Table (2. 9) Basic data of 4 oil wells

Well	Horizon	Interval (mKB)	Formation pressure MPa(psi)
Jake South-1	Bentiu	1380.99~1388.00	12.69(1841.80)
	Bentiu	1476.48~1483.00	13.6(1973.88)
	AG	2452.98~2457.50	23.317(3384.18)
	AG	2566.96~2573.00	24.385(3539.19)
Jake South-2	AG	2571.00~2573.00	24.175(3508.71)
Jake S-3	Bentiu	1500.00-1502.00 1503.35-1507.01 1508.01-1511.99	6.45(936.14)
Jake South-4	Bentiu	1544.02~1550.00	13.62(1976.78)
	AG	2275.00~2278.00	20.736(3009.58)
	AG	2413.00~2416.00	22.572(3276.05)

Chapter 3

Methodology

3.1 Reservoir simulation:

Reservoir simulation has become a standard predictive tool in the oil industry. It can be used to obtain accurate performance predictions for a hydrocarbon reservoir under different operating conditions, it defines as:

A numerical tool, which is used to dynamically model fluid flow through porous underground reservoirs.

The major goal of reservoir simulation is to predict future performance of the reservoir and find ways and means of optimizing the recovery of some of the hydrocarbons under various operating conditions and it could be very useful in minimize the risk in the oil project when it usually involves a capital investment of hundreds millions of dollars, and the risk associated with its selected development and production strategies must be assessed and minimized, this risks can be taken into account in reservoir simulation through data input into the simulation model and find the best solution for it.

3.1.1 The simulation process involves four major interrelated modeling stages:

• **Establishment of physical models:**

Is developed incorporating as much physics as is deemed necessary to describe the essential features of the underlying physical phenomena.

• Design a mathematical model:

A set of coupled systems of time-dependent nonlinear partial differential equations is developed and analyzed for existence, uniqueness, stability, and regularity.

• **Design of the numerical model:**

Numerical model with the basic properties of both the physical and mathematical models is derived and analyzed.

• **Design computer algorithms or codes:**

The computer model is developed to solve efficiently the systems of linear and nonlinear algebraic equations arising from the numerical discretization. In addition, the simulation requires a combination of skills of physicists, mathematicians, reservoir engineers, and computer scientists.

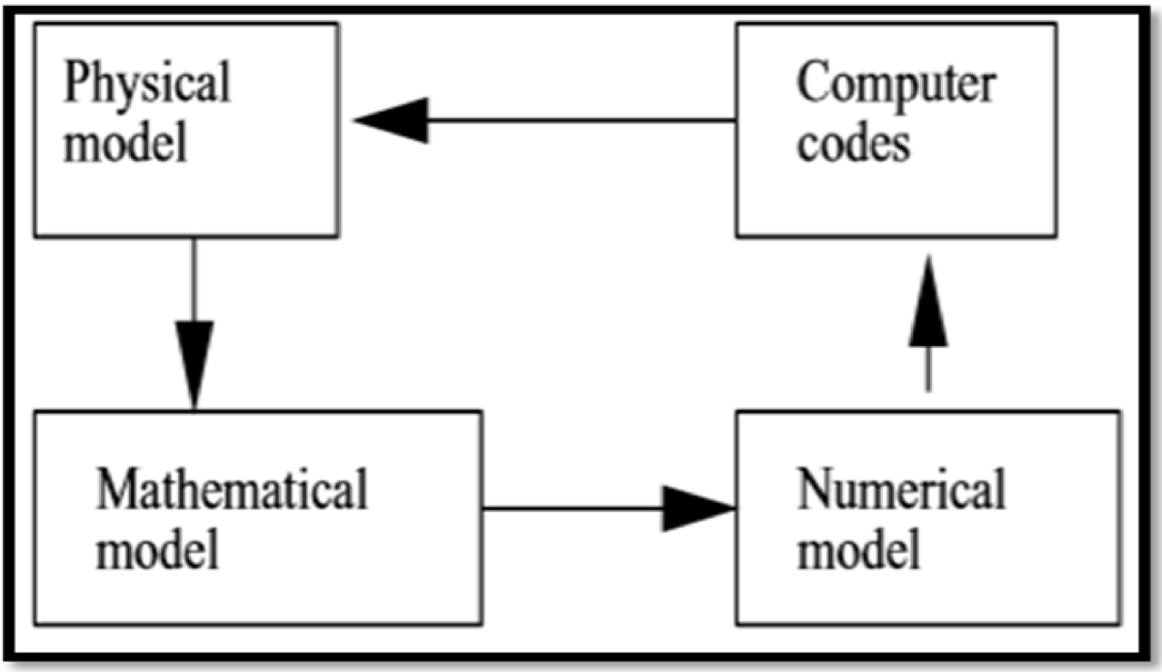

Fig. (3. 1) Reservoir simulation stages

Each of these stages is essential to reservoir simulation, and a number of iterations among these stages are sometimes necessary to adjust the physical, mathematical, and numerical models and computer algorithms so that accurate reservoir performance forecast can be obtained.

The widespread acceptance of reservoir simulation can be assign to the advance in computing facilities, mathematical modeling, numerical methods, solver techniques, and visualization tools.

3.1.2 Reservoir Simulator Classifications:

The reservoir simulator can be classified into different approaches; the most common are based on:

• The type of reservoir fluid being studied

• The recovery process being modeled

The other types of approaches include:

• The number of dimensions (1D, 2D, and3D),

• The number of phases (single-phase, two-phase, and three-phase)

• The coordinate system used in the model (rectangular, cylindrical, and spherical)

The simulators can also be divided by the rock structure or response to:

- Ordinary
- Dual porosity/permeability
- Coupled hydraulic/thermal fracturing and flow.

Reservoir simulator classification based on type of reservoir fluid:

• Black oil simulator: are conventional recovery simulator used when the process is not sensitive to the compositional changes in reservoir fluids.

• Compositional simulators: are used when recovery processes are sensitive to compositional changes, it includes primary depletion of volatile oil and gas condensate reservoirs and pressure maintenance operations in these reservoirs, and multiple contact miscible processes.

• Gas simulator**.**

Reservoir classification based on type of recovery process:

- Conventional process (black oil) simulator
- Miscible displacement simulator
- Thermal recovery includes: steam injection, suit combustion simulator.
- Chemical flood simulator.

3.1.3 Reservoir Simulation Applications:

Reservoir simulation is usually applied in the following steps (Ertekin, Abou-Kassem, and King, 2001):

Set simulation study objectives. The first step in any reservoir simulation study is to set clear objectives. These objectives must be achievable and compatible with available reservoir and production data.

Gather and validate reservoir data. After the simulation objectives have been set, reservoir and production data are gathered. The data meeting the objectives are incorporated into the simulator.

Design the reservoir simulator. Once the data are gathered and validated, the simulator is designed. This step involves the four major interrelated stages outlined above: construction of a conceptual physical model, development of mathematical and numerical models, and design of computer codes.

History matches of the reservoir simulator**.** After the reservoir simulator is constructed, it must be tuned, or history matched, with available reservoir and production data since much of the data in a typical simulator needs to be verified.

Make predictions. In the final application step, various development and production plans are evaluated, and a sensitivity analysis of various reservoir and production parameters is carried.

Why to simulate the reservoir?

Simulation had become one of the important reservoir technique and it very useful in:

1. **Economics**: the main incentive for simulation is to minimize the cost of project and increase the profitability through better planning and management of the reservoir, and cash Flow Prediction which needs Economic Forecast of Hydrocarbon Price (corporate impact), and the realistic model with best economic studies can be an effective tool for evaluating plans for new fields for estimating the facility needs such as platform, compassion, etc.
   Even for evaluating plans to increase and or accelerate the production, reduce the operating cost, and to improve the recovery factor.
2. Reservoir management the simulation is used to:

- Coordinate Reservoir Management Activities
- Evaluate Project Performance
- Interpret/Understand Reservoir Behavior
- Model Sensitivity to Estimated Data
- Determine Need for Additional Data
- Estimate Project Life
- Predict Recovery versus Time
- Compare Different Recovery Processes
- Plan Development or Operational Changes

- Select and Optimize Project Design
- Maximize Economic Recovery

3. Credibility and Reliability of the simulation are related and sometimes are indistinguishable are often the key for using the reservoir simulator. When a program is known to be mathematically reliable and calculation can be represented as unbiased and discussing results generated by such program focusing in the quality of input data, also can be more reliable if a relationship with a third party (government agency, partner) is important.
4. Decssion making**:** reservoir simulation can be an excellent tool for predicting the possible outcome of reservoir management, while no single prediction may be accurate the difference in predicted the performance generated by simulation of alternative operating strategies can be correct.

3.2 Numerical reservoir simulator:

As mentioned earlier the reservoir simulators are the best tools for solving problems that cannot be solved in any other way, but the numerical models extend beyond solving difficult problems, even in a single problem its faster, cheaper, and more reliable than any other methods. So the numerical simulation is “An analysis method that supplements and sometimes competes with reservoir simulator includes:

- Well test
- Field observation
- Laboratory tests
- Field pilot tests
- Simple mathematical analysis
- Exploration of other performance of other reservoir

Before the numerical simulators/model appears there were two kinds of simulator predating the numerical model:

1. Electrical analog model
2. Scale physical (fluid flow) model

The electrical analogs are outmoded now because any problem they will solve can be handled more efficient by the numerical models and the physical model are more expensive, more time consume, and less flexible than the numerical model.

When the reservoir modeling is the application of a computer simulation system to the description of fluid flow in a reservoir or the input data set in the computer program the numerical model is the best one because it's very simple compear to others.

The final selection of an analysis method must not base only on the proper level of simplification but also on time, cost, and acceptability.

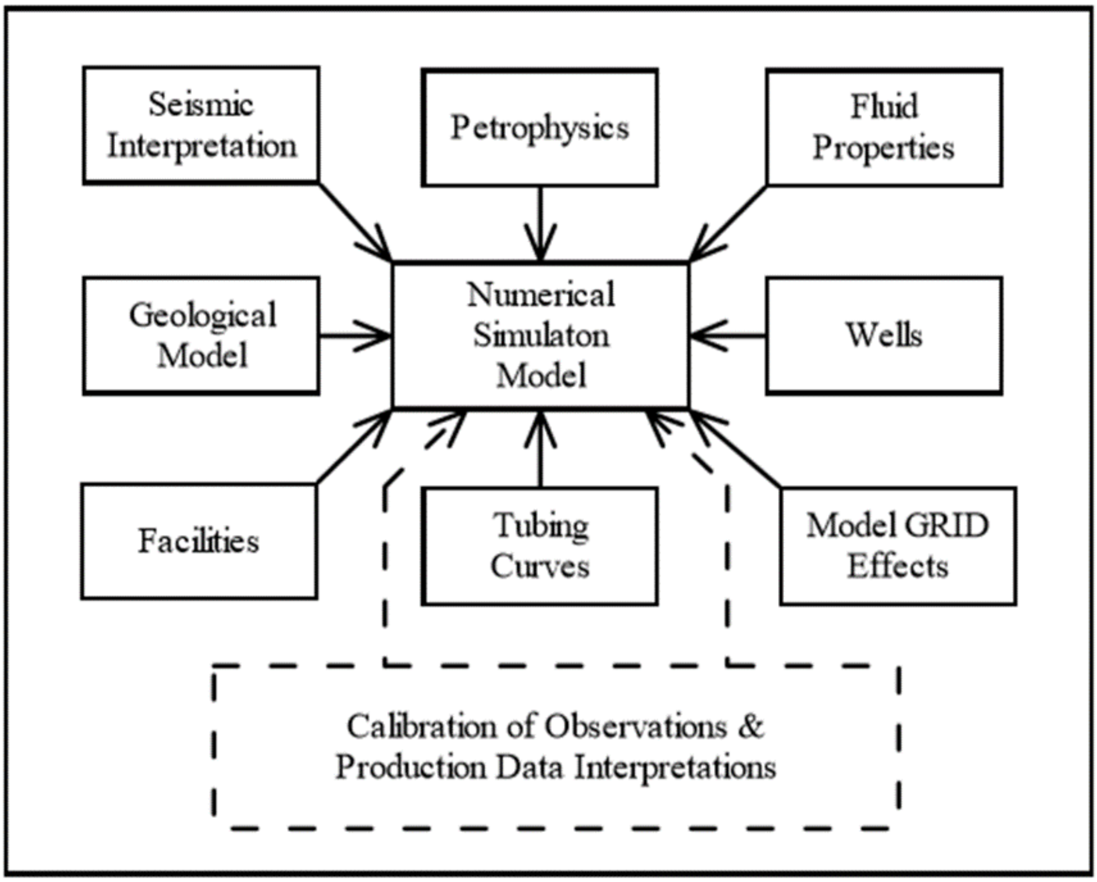

Fig. (3. 2) Disciplinary contributions to reservoir modeling (after H.H. Haldorsen and E. Damsleth, ©1993; reprinted by permission of the American Association of Petroleum Geologists).

3.2.1 Planning a simulation study:

A comprehensive study may take a year or more to complete and time, maybe place an intake demand on computer hardware and skilled personnel, less-comprehensive studies requires fewer resource and staff and usually conducted under sever time constraints, both types need to follow clear plane steps to ensure that they supply an accurate information in details to the management team and used time effectively. Most studies involve the essential the same planning steps, although they vary in distribussion effort.

The planning steps are:

problem definition: the first step in conducting study is to define the associated problem in the reservoir performance and the operating problem thus induce to gather enough information about reservoir and its operation environment to identify what performance projection are needed, when they needed, and how they can contribute to the reservoir. Although this part is relatively short, it can have a major impact on the efficiency with which the project is conducted and the decision making process.

Data review: the gathered data must usually be reviewed and reorganized; because they will have been obtained for number of loosely related reason and normally will not have been organized enough to immediate use. Detailed data review is time consuming and tedious so effort should be carefully focused. If additional data must be collected, data requirements should be prioritized and collection must be timed to meet the schedules of each project phase.

Selecting the study approach: having defined the fluid mechanism one must be decided what suitable simulators are to solve them. Most often one should use a combination of models that may include fine-grid, detailed models to analyze the flow near the well or in selected part of the reservoir, and the full field model to analyze & study the overall performance of the reservoir. There are some factors influence the approach of the study includes:

1. availability of the simulator that can solve the reservoir problem
2. programming changes that must be made to the simulator to model the well & facilities
3. Type and number of simulator runs needed to meet study objective
4. Calinder time, labor, computing, and financial resources available for the study.
5. The need for special editing capabilities
6. Availability of peripheral resources needs to complete study on time.

Model design: the design of the simulator model will be influenced by many factors such as the type of process be modeled, the difficulty of the fluid mechanism problem, the objective of the study, the quality of the reservoir description data, time and budget constraints, and the level of credibility needed to ensure acceptance the study result. Time and cost constraints frequently impose compromises on the type of the reservoir to use and the design of the reservoir models, the number of grid blocks and detailed included the type of treatment of individual wells are perhaps the most two common areas of compromises.

Programming support: after the appropriate has been chosen and the model designed, it’s usually necessary to tailor parts of the model especially to the problem which concern about.

History matching.

Prediction performance and analyzing result: once an acceptable history matching has been obtained, the model can be used to predict the future performance of the field and to a chive the objective established for the study. There are different types of performance prediction by the model include:

1. Oil production rates
2. WOR & GOR performance
3. Well and well work over requirements
4. Reservoir pressure performance
5. Position of fluids fronts
6. Recovery efficiency by area
7. General concerning of facility requirements
8. Estimates of ultimate recovery

Once the most difficult aspects are making prediction to evaluating the results of the computer runs, because the simulator can generate thousands of lines as output so care must be taken to consecrate on the result that needed to meet the goals of the studies. The accuracy of the performance prediction usually depends on the characteristic of the model and the accuracy and completeness of the reservoir description,

•**Reporting:** the final step in the simulation study is to assemble result and conclusion in a clear and conscious report.

3.3 Basic Reservoir Analysis:

There are several methods of Reservoir Analysis These Methods include volumetric analysis, material balance 0ppe analysis, and decline curve analysis

3.3.1 Volumetric Method:

Original oil in place of Reservoir can be given by:

$$N = \frac{7758\Phi \ hoSoi}{Boi}$$

Where:

N ≡ original oil in place (STB)

Original free gas in place for a gas reservoir is given by:

$$G = \frac{7758\Phi AhgSgi}{Bgi}$$

Where:

G ≡ original free gas in place (SCF)

H_g ≡ net thickness of gas zone (feet)

S_{gi}≡ initial reservoir gas saturation (fraction)

B_{gi}≡ initial gas formation volume factor (RB/SCF)

Equation (2.2) is often expressed in terms of initial water saturation $S_{wi,}$ by writing $S_{gi} = 1 - S_{wi}$

*Initial water saturation is usually determined by well log or core analysis

3.3.2 Material Balance Equation Method:

Material balance calculations may be used for several purposes. They provide an independent method of estimating the volume of oil, water and gas in a reservoir for comparison with volumetric estimates.

Material balance can be used to predict future reservoir performance and aid in estimating cumulative recovery efficiency

The General Form of material balance equation:

$N\ (D_o+D_{go}+D_w+D_{gw}+D_r) = N_pB_o - N_PR_{so}B_g + (G_{ps}B_g+G_{pc}B_{gc} - G_iB_{gi}') - (W_e+W_i-W_p)$ Bw

3.3.3 Single-phase flow:

The basic differential equations that govern the flow of a single phase through a reservoirare described. They include a mass conservation equation, Darcy's law, and an equation ofstate relating the fluid pressure to its density. The cases of incompressible, slightly compressible,and compressible fluids are considered. Then an analytic solution for a 1D radial flow is obtained, a numerical solution of single-phase flow equations using finite difference methods ispresented.

Mass Conservation

$$\frac{\partial}{\partial t}\left(\frac{\emptyset}{B}\right) = -\nabla.\left(\frac{1}{B}u\right) + \frac{q}{\rho_S}$$

Darcy low:

Darcy's law for single-phase flow states that in a horizontal system the volumetric flow rate, Q, through a sample of porous material of length L and a cross-sectional area $\boldsymbol{A}$**,** is given by

$$Q = \frac{KA}{\mu}\frac{\Delta P}{L}$$

Where Δp is known as the applied pressure drop across the sample, for the flow in only one direction we can write Darcy law in the following differential equation:

$$V = \frac{Q}{A} = -\frac{K}{\mu}\frac{\partial p}{\partial x}$$

Where $\partial p/\partial\, x$ is the pressure gradient in the direction of the flow, and the negative sign indicates that the pressure decline in the direction of the flow.

General equation for single phase flow:

By defining the geometric factor "α" as follows:

One dimension: α (x, y, z) = A(x)

Twodimension: α (x, y, and z) = H (x, y)

Threedimension: α (x, y, and z) = 1

We can write the equation of the general form as

$$\nabla \cdot \left[\frac{\alpha\, \rho\, k}{\mu}\ (\nabla p - \rho g \nabla D)\right] + \alpha g = \frac{\partial(\rho\phi)}{\partial t}$$

In addition to specifying boundary condition, it's necessary to define the relationship between the porosity, density and the pressure as:

$$\phi = \phi(p)\rho = \rho(p)$$

Boundary condition:

In reservoir simulation, a frequent boundary condition is that the reservoir lies within some closed curve **C** across which there is no flow, and fluid injection and production take place at wells which can be represented by point sources and sinks.

$$u = -\frac{1}{\mu} k\ (\nabla p - \rho \wp \nabla z)$$

Slightly compressible flow:

$$\varphi \rho c_t \frac{\partial p}{\partial t} = \nabla \cdot \left(\frac{\rho}{\mu} k\ (\nabla\, p - \rho \wp \nabla z)\right) + q$$

3.3.4 Immiscible gas injection flowing:

For describing the immiscible gas displacement, we assuming equilibrium between injected gas and displaced oil phases while accounting for differing physical characteristics of the fluids, the effects of reservoir heterogeneities, and injection/production well configurations. Included modifications to typical displacement equations, evaluating sweep efficiency, and calculating performance.

In simple calculation the reservoir is treated for in term of average reservoir rock properties, and the production performance is described for average well. It is important to comprehend the physics of displacement to understand the simulation results and to identify incorrect results, the fundamental of different kinds of displacement are:

Microscopic and Macroscopic Displacement Efficiency of Immiscible Gas Displacement:

There are three aspects to this displacement:

Gas and oil viscosities: usually the gases viscosity at reservoir condition is 0.2 where the ranges between 0.5 to 1. The density of the gas is on third or less than the oil.
Gas/Oil capillary pressure (P_c) and relative permeability (Kr) data: the relative data is typically measured by commercial laboratories using routine special core analysis procedures. Gas-oil capillary pressure data can be measured with either porous-plate or centrifuge equipment. One approach for obtaining gas/oil relative permeability data is the viscous displacement method in which gas displaces oil. A second method is the centrifuge method, which is generally used to obtain capillary pressure and relative permeability information simultaneously.
The compositional interaction, or component mass transfer, between the oil and gas phases.

In all of these cases the gas is the wetting phase, hence it passes through the largest pours first.

Mobility ratio:

The mobility of a fluid is defined as it's the fluid permeability divided by its viscosity, its consider as combination of a rock property and a fluid property (permeability/viscosity).

$$\gamma i = Krwi/\mu i$$

Mobility ratio is defined as the ratio between the displacing fluid to the displaced fluid, in case of gas/oil case the gas is the displacing phase and oil is the displaced phase.

$$M = \frac{\gamma gas}{\gamma oil} = \frac{Krg\ \mu o}{Krw\ \mu g}$$

Mainly the fluid mobility relates to its flow resistance in a reservoir at a given saturation of the fluid, because viscosity is in the denominator of this definition, gases, which are very-low-viscosity fluids, have very high mobility.

For a simple calculation the equation of the mobility ratio can be calculated at the endpoint relative permeability, and the practical equation that the engineering use for mobility ratio is:

$$M = \frac{Kg\ @\ Sorg}{Ko\ @\ Swi}\frac{\mu o}{\mu g}$$

Gas/Oil liner displacement efficiency:

This equation developed by Buckley and Leveret to describe the mechanism of the immiscible fluid displacement by using the relative permeability concept and Darcy’s law describing the steady state flow through porous media, the resulting friction flow equation describes quantitatively the fraction of displacing fluid flowing in terms of the physical characteristics of a unit element of porous media.

The assumption of the equation is:

1. steady state flow
2. constant pressure
3. no compositional effects
4. no production fluid behind the gas front
5. no capillary effects
6. movement of advancing gas parallel to the bedding plane
7. immobile water saturation
8. uniform cross sectional flow

Welge model made the Buckley and leveret to more easily calculate, and the friction factor calculated as follows:

$$fg = \frac{1 + (0.044\ k\ \text{kro}\ \Delta\rho\ sin\alpha/qt\ \mu o)}{1 + 1/M}$$

When neglecting the effect of the gravity, the equation becomes:

$$fg = \frac{1}{1 + 1/M}$$

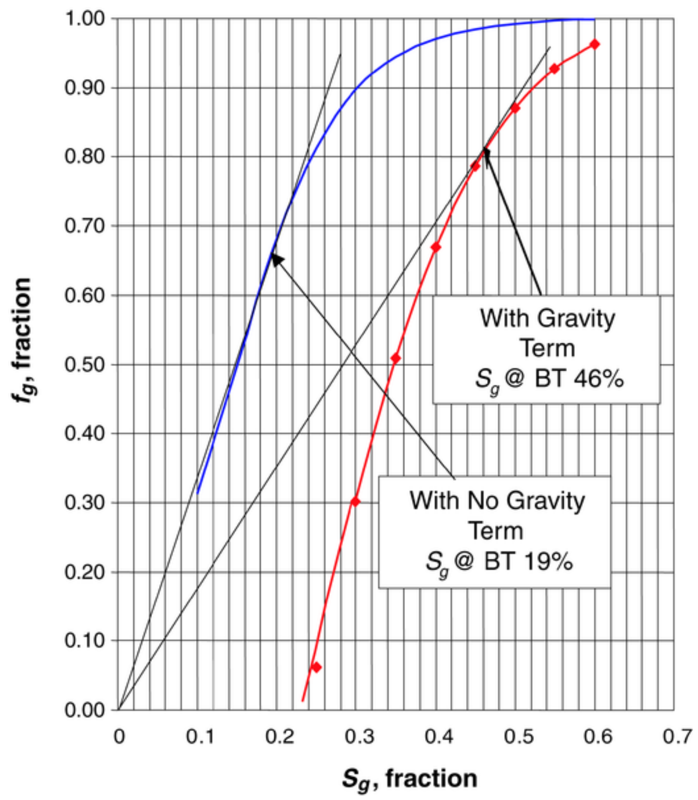

Fig. (3. 3) Buckley-Leverett fractional gas flow plot (based on data from the Hawkins field).

To relate the fraction of gas following to time, Buckley and Leverett developed the following material-balance equation:

$$L = \frac{qt\ t}{\phi\ A}\left(\frac{dfg}{dSg}\right)$$

Vertical sweep efficiency:

Several methods for determine the vertical efficiency based on statistical treatment of the routine core data analysis, one of the most familiar method used is stiles method for evaluating the relative permeability on water flood performance, the same assumptions and calculation procedures may be used for immiscible gas/oil displacements. The relative permeability ratio used in such calculations is considered to be a constant equal to the relative permeability to gas at residual oil saturation ($K_{rg@Sor}$) divided by the relative permeability to oil at initial gas saturation ($k_{ro@Sgi}$).

Areal sweep efficiency:

Several investigators have shown that areal sweep efficiency is primarily a function of injection/production well pattern arrangement, mobility ratio, and volume of displacing phase injected. Various studies have confirmed what would be expected intuitively, that areal sweep efficiency increases with the volume injected and with a lower mobility ratio

Calculating immiscible gas injection performance:

Reservoir simulation represent the best way to perform the immiscible gas injection if there are sufficient data to simulate/characterize the reservoir rock and fluids adequately. When adequate data are unavailable or when screening work is being done, simple models may suffice.

Viscous, gravitational, and capillary forces and diffusion are involved in the displacement of oil by gas, complicating technical analysis of a particular reservoir if each of these forces and flow in all three dimensions are important. Fortunately, there are instances in which one force is dominant and only one dimension is involved in the rate-limiting step. In these circumstances, engineering solutions can be direct and simple. One such circumstance is that of thick reservoirs with high permeability’s. In steeply dipping oil reservoir which contains sand with high permeability, the gravity drainage of the oil can be more sufficient than the calculated one, even at lower oil saturations, oil behind the gas front can continue to flow vertically downward through the reservoir and in reservoir with stabilize gravity drainage its controls the gas/oil displacement process and increases the ultimate oil recovery.

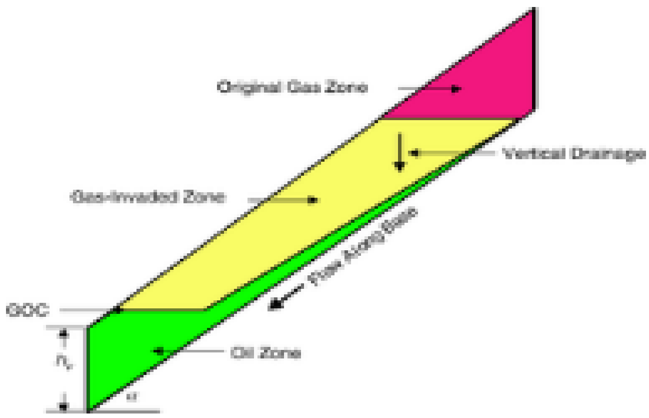

Fig. (3. 4) Mechanisms of gravity drainage

Explicit Method:

$\alpha(Ui-1^{n+1}$-Ui^{n+1}+$Ui+1^{n}$-Ui^{n})=Ui^{n+1}-Ui^{n}

Implicit:

$2\Delta^{2}Ui^{n+1}$=3/2(Ui^{n+1}-Ui^{n})-1/2(Ui^{n}-Ui^{n-1})

U≡ variable convenient

α≡ mesh ratio

Chapter 4

Result and Discussion

Result and Discussion

This result of case study is based on five wells of Jake south oil field, that are studied at bentiu formation, by using CMG program to simulate the injection process in the selection grid.

4.1 Simulation Model result:

- Graphs shown hereinafter are results of plotting the field collecting data using CMG
- Jake south (1, 4, 18, 22, 35) production data and wells parameters are been used as a case study of the research.
- Jake south (18) is been selected as an injector well so accordingly for the well a sector has been extracted from the main Jake Model Fig (4-1) which done by CMG software.
- The sub models/grid tops which are shown in Figs (4-2) respectively; have been ran to simulate the current field situation and prepared for prediction.
- Once the system has been tuned to real data, CMG is confidently used to model the different injection wells and to make forward predictions of reservoir pressure based on surface production data.

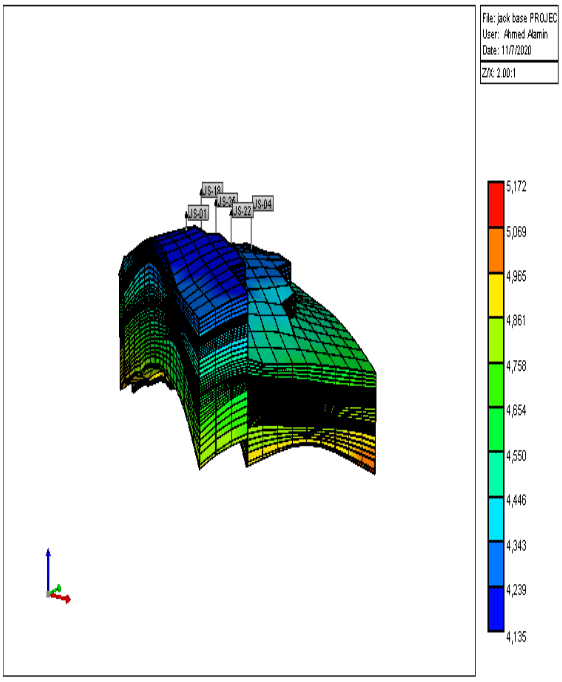

Fig. (4. 1) show Jake south sub model

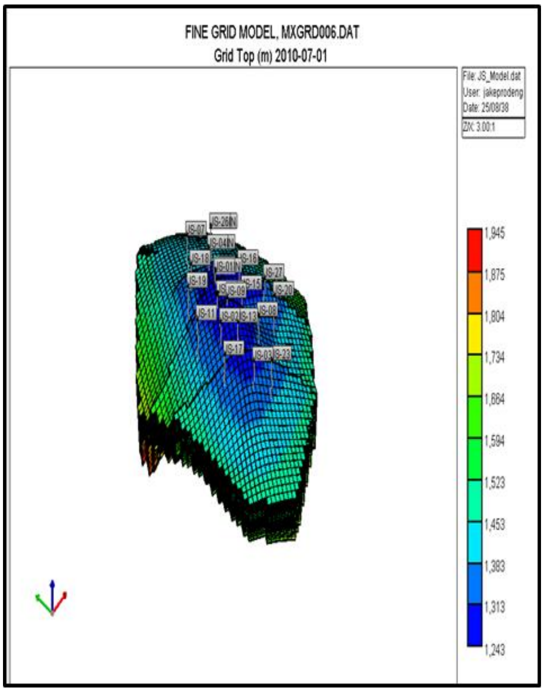

Fig. (4. 2) shows Jake field main model

Wells before injection:

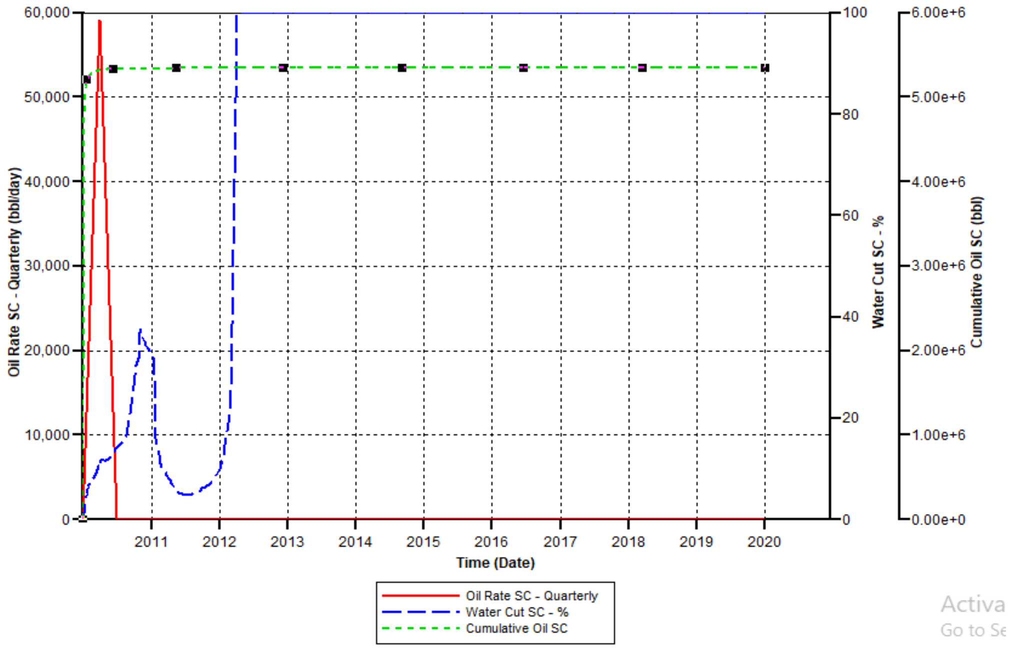

Fig. (4. 3) shows that a high water cut in 2012 and decline the production of oil which is the main problem that facing the Jake south (base case)

2-JS-18 water cut:

The is high water cut ratio that affect the productivity of the selected grid, JS-18 water cut is shown in Fig(4-3)

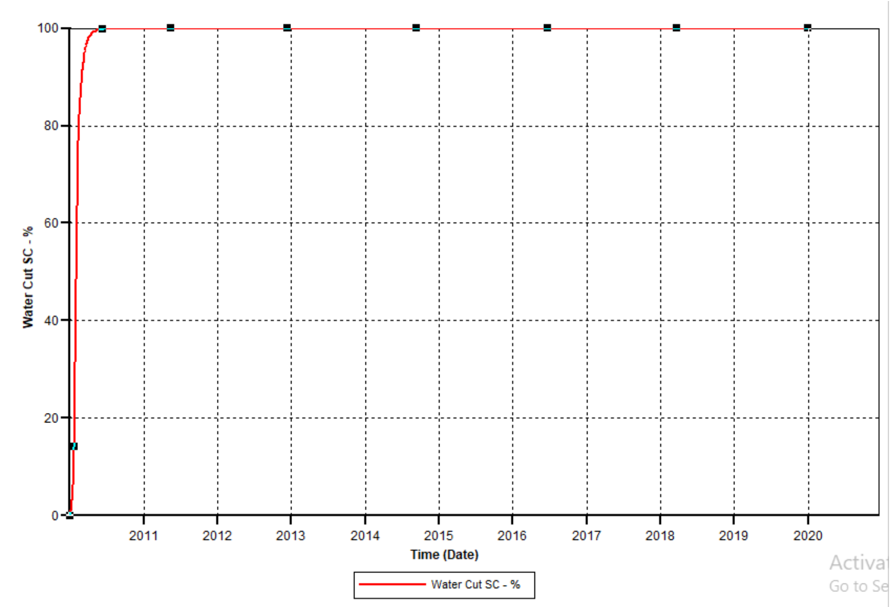

Fig. (4. 4) JS-18 water cut

4.2 Nitrogen injection performance in selected grid:

As regarded to the grid of the case study performance which should affected by the injection of the nitrogen in Jake south 18, the calculating of the daily oil rate after the injection are 8.277 % (barrel/day) as the maximum value and 0.508%(barrel/day) as the minimum value respectively, where the cumulative oil production rate shown an increment of 0.2646% Ft^3(9.3360%m^3).

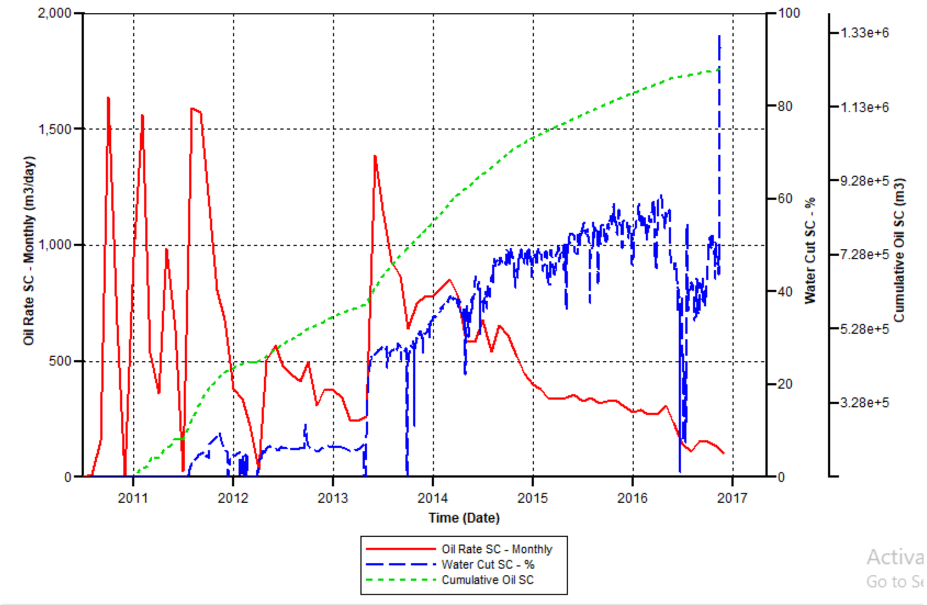

Fig. (4. 5) nitrogen injection performance

4.3 JS-01&JS-04 Oil rate prediction after injection:

Fig (4-5) & (4-6) shown the prediction of JS-04 & JS-01 production respectively, JS-01 oil rate increment by 54.14%. For JS-04 oil rate the increment by 39.96%

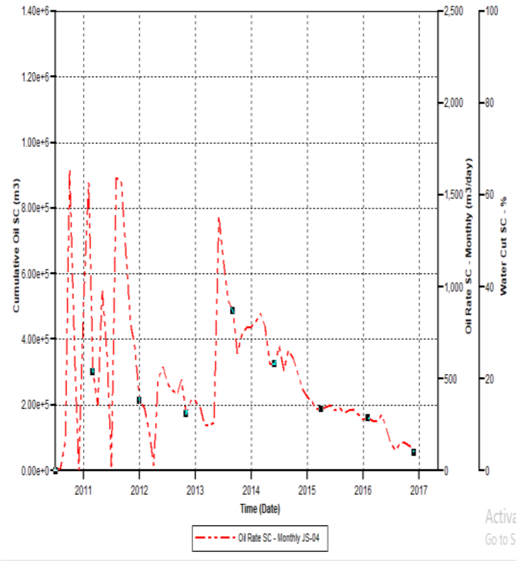

Fig. (4. 6) JS-04 oil rate

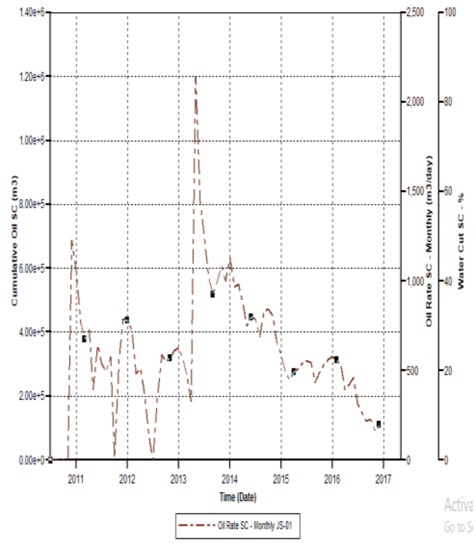

Fig. (4. 7) JS-01 oil rate

4.4 JS-35& JS-22 results:

Fig (4-7) shown that JS-35 has late oil production that is not affected the selected grid recovery performance.

Fig (4-8) shown that JS-22 has not been effective by nitrogen injection to the selected grid

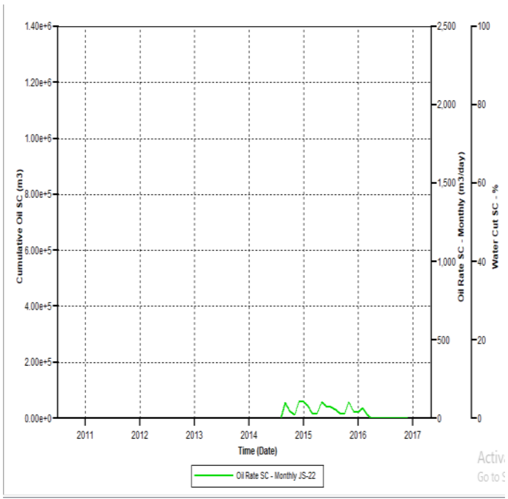

Fig. (4. 8) JS-22 oil rate

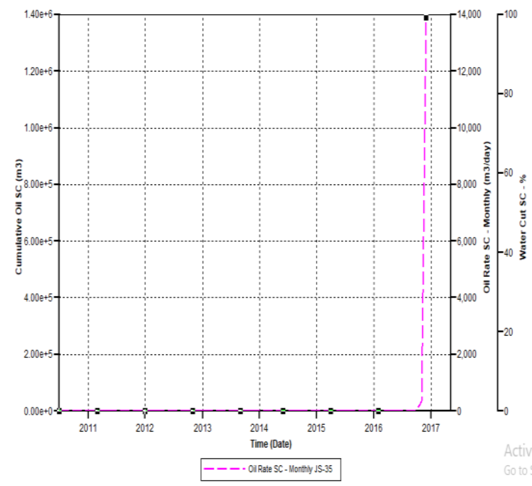

Fig. (4. 9) JS-35 oil rate

Chapter 5

Conclusion & Recommendations

5.1 Conclusion:

- Simulation model program was developed to test the current nitrogen injection and production performance in Jake south field.
- Nitrogen continuously injected for 1 year in the selected grid of the field which shows a different response in the targeted wells.
- Jake south 18 was a high water well in the early field history that cause the decline in both pressure and productivity of the field.
- In the simulation model J.S 18 convert to injection well that shows a great response in the field productivity.
- Successful implementation results appeared in JS-01 and JS-04 while JS-22 well give a good result after the injection with a medium water cut production and JS-35 show a poor productivity of oil that indicate a high water cut.

5.2 Recommendation:

- Conduct technical study for maintain pressure support as the immiscible nitrogen displacement for the Jake South Field and also alternative process as WAG should also be studied.
- The simulation study recommends shutting down JS-35 because of early water breakthrough and law productivity.
- The simulation study recommends converting JS-18 well to injector well for minimizing the higher water cut values.
- Proactive approach of complete data and geological information must be prepared and then stage of quality control of all these data must be done before the simulation studies.
- For more accurate results in simulation model, the uncertainty and ambiguity in the Jake South field geological model should be updated and re-evaluated.

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