ESTIMATION OF WATER ALTERNATING GAS (WAG) INJECTION PERFORMANCE OF AN OFFSHORE FIELD (AZERI FIELD,AZERBAIJAN) USING A SECTOR SIMULATION MODEL

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

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IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

SEPTEMBER 2008

Approval of thesis:

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ABSTRACT

ESTIMATION OF WATER ALTERNATING GAS (WAG) INJECTION PERFORMANCE OF AN OFFSHORE FIELD (AZERI FIELD,AZERBAIJAN) USING A SECTOR SIMULATION MODEL

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September 2008, 129 pages

The WAG injection project feasibility of South Flank of Central Azeri field on the basis of simulation model was studied in this thesis work. The 58 sensitivity scenarios were considered to evaluate and analyze the behavior of WAG in this field. Scenarios are based on the important WAG parameters, such as half slug size volume, cycles, WAG ratio, start time, bottomhole injection pressure etc. The Base Case is set with static and dynamic characteristic close to real field. From the scenarios calculated, the Best (Scenario 53, 9.3% incremental oil) and the Worst (Scenario 52, 3.4% incremental oil) cases were analyzed to get general view of WAG in terms of profitability in comparison to the Base Case. For more profound conviction of feasibility of the WAG project, additional cases with Simultaneous WAG injection and cases with changed permeabilities have been considered. The Best case was re-evaluated under application of Carlson's relative permeability hysteresis model. All results eventually were analyzed in terms of economical profitability – net present value (NPV). Economical analysis of scenarios is provided at the end of the work.

Keywords: Central Azeri, WAG, sector model simulation

ÖZ

DENİZ SAHASINDA (AZERİ SAHASI,AZERBEYCAN) BİRBİRİNİ İZLEYEN SU VE GAZ ENJEKSİYON PERFORMANSININ BİR SEKTOR SİMÜLASYON MODELİ İLE TAHMİNİ

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Eylül 2008, 129 sayfa

Bu çalışmada, Central Azeri sahasının Güney Kanadının birbirini izleyen su ve gaz (WAG) enjeksiyon projesinin uygulanabilirliği simulasyon modeline dayanarak çalışıldı. Bu sahada WAG enjeksiyonunu analiz etmek ve değerlendirmek için 58 hassasiyet senaryosu gözönünde bulundurulmuşdur. Senaryolar kuyudibi enjeksiyon basıncı, başlama zamanı, WAG oranı, enjeksiyon döngüsü, basım hacmı gibi önemli WAG parametrelerine dayanmaktadır. Baz senaryo gerçek sahanın statik ve dinamik özellikleri ile ayarlanmıştır. Karlılık açısından genel görüş elde etmek için baz senaryo sonucuyla tasarlanmış WAG senaryolarının karşılaştırılarak en iyi (Senaryo 53, 9.3% artışlı petrol) ve en kötü (Senaryo 52, 3.4%) durumlar analiz edilmiştir. Ayrıca WAG projesinin uygulanabilirliğinin daha inandırıcı olması için eşzamanlı WAG enjeksiyon durumları ve değişken geçirgenlik durumları göz önüne alınmıştır. En iyi durum Karlsonun göreli geçirgenlik histerezis modelinin uygulanması esasında yeniden değerlendirilmiştir. Sonunda, tüm sonuçlar ekonomik karlılık açısından Net Bugünkü Değeri analizi edilmişdir. Çalışmanın sonunda senaryoların ekonomik analizi sunulmuştur.

Anahtar Kelimeler: Central Azeri, WAG, sektor model simulasyon

To my Family

ACKNOWLEDGEMENTS

I would like to express my deepest gratitude to my supervisor, Prof. Dr. Serhat Akin, whose expertise, understanding, encouragement and patience, added considerably to my graduate experience. I appreciate his vast knowledge and skills in many areas, and his assistance in writing this thesis. I would like to thank my co-supervisor Prof. Dr. Mahmut Parlaktuna for his attention and for valuable recommendations.

A very special thanks goes out to all my friends for their friendships, motivations and endless encouragements.

I am grateful to Turan Ibrahimov, Samir Sadigov and Orkhan Pashayev for their ideas and invaluable suggestions that greatly helped to improve this thesis research. Also, I want to thank Elshan Rzayev for his enormous contribution and help during my thesis research.

I would like to express my grateful appreciation to my family and fiancee for their support and encouragements all the way through my study at METU.

I would like to express my gratitude to BP Caspian Sea Exploration for providing me with scholarship and financial support. Thanks to Azerbaijan State Oil Company and BP Caspian Sea Exploration for giving me permission to work on data from Caspian Sea.

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CHAPTER 1

1. INTRODUCTION

In recent years interest in water-alternating-gas (WAG) processes, both miscible and immiscible, has substantially increased. Managing WAG injection projects requires making decisions regarding to the WAG ratio, half-cycle-slug size, and ultimate solvent slug size for each WAG injector in the field. The impact of these decisions affects the capital cost of solvent purchase, water and gas plant loads, fluid handling and lifting operation costs, and ultimate incremental oil recovery. Simulation models provide a tool for examining strategies for these decisions.

Simulation model for evaluation of WAG project feasibility in South Flank of Azeri field is developed. Azeri is the part of the 50km long Azeri-Chirag-Gunashli (ACG) field located offshore Azerbaijan in the South Caspian Sea, and comprises three culminations – Azeri, Chirag, and Gunashli. The field is subject to a 30-year production sharing agreement (PSA) started from 1994 and operated on behalf of the Azerbaijan International Oil Company (AIOC) by BP. Sanctioned development plan is considering crestal gas injection for North Central Azeri and peripheral water injection for rest of the field.

The Base Case is set with static and dynamic characteristic close to real field. In this study 58 cases with different WAG parameter scenarios (e.g. half slug size, total slug, WAG volume ratio, slug period ratio, and cycle numbers) have been designated to evaluate the effect of the EOR project. Results and behaviour tendency of all cases are given in tables and briefly described. From all cases performed, the best and the worst are chosen for more detailed analysis. Three phase relative permeability hysteresis model then have been applied for the best case in order to consider the hysteresis effect in WAG behaviour. For more profound conviction of feasibility of the WAG project, additional cases with Simultaneous WAG injection and cases with changed permeabilities have been considered. Economical analysis of scenarios is provided at the end of the work.

CHAPTER 2

2. LITERATURE REVIEW

2.1 WAG injection:

2.1.1 Introduction:

Enhanced Oil Recovery (EOR) is oil recovery by the injection of materials not normally present in reservoir [1]. Traditionally, EOR has been divided into three broad methods: thermal methods, gas injection methods, and chemical methods. Thermal methods include in-situ combustion (or fireflooding) and steamflooding. Gas methods include hydrocarbon miscible flooding, nitrogen and flue gas flooding, and carbon dioxide flooding. Chemical methods consist of polymer injection, alkaline flooding, and surfactant flooding (or some combination of several or all types of chemicals) [2]. One of the most important methods of EOR is Water-Alternating-Gas (WAG) injection.

WAG injection is an oil recovery method primarily intended to improve sweep efficiency during gas injection. In order to increase oil recovery and improve pressure maintenance, produced hydrocarbon gas in some applications has been re-injected in water injection wells.

Oil recovery by WAG injection has been applied to reach unswept areas, mainly recovery of attic or cellar oil by utilizing the segregation of gas to the top or the accumulation of water toward the bottom. WAG injection has the potential for increased microscopic displacement efficiency, because the residual oil after gasflooding is usually lower than the residual oil after waterflooding and three-phase zones may obtain lower remaining oil saturation. Thus, by combining better mobility control and contacting unswept zones and by leading to improved microscopic displacement, WAG injection can lead to improved oil recovery [3].

Even though mobility control is a significant issue, there are other advantages of the WAG injection as well. Compositional exchanges may result in some extra recovery and affect the fluid densities and viscosities. Gas reinjection is auspicious due to environmental concerns, enforced restrictions on flaring, and (in some areas) CO_2 taxes. The main factors affecting the WAG process are the fluid properties, miscibility conditions, reservoir heterogeneity (stratification and anisotropy), gas trapped, injection technique and WAG parameters as cycling frequency, slug size, WAG ratio, and injection rate [4].

In practice the WAG process consist of the injection of water and gas as alternate slugs by cycles or simultaneously. The cyclic nature of the WAG process may have negative unreliability on the profile injection control in layered reservoirs. Also, simultaneous injection of water and gas can improve the profile control relative to alternate WAG injection and continuous water/gas injection [4]. A schematic view of the WAG process is shown on the Figure 2.1.

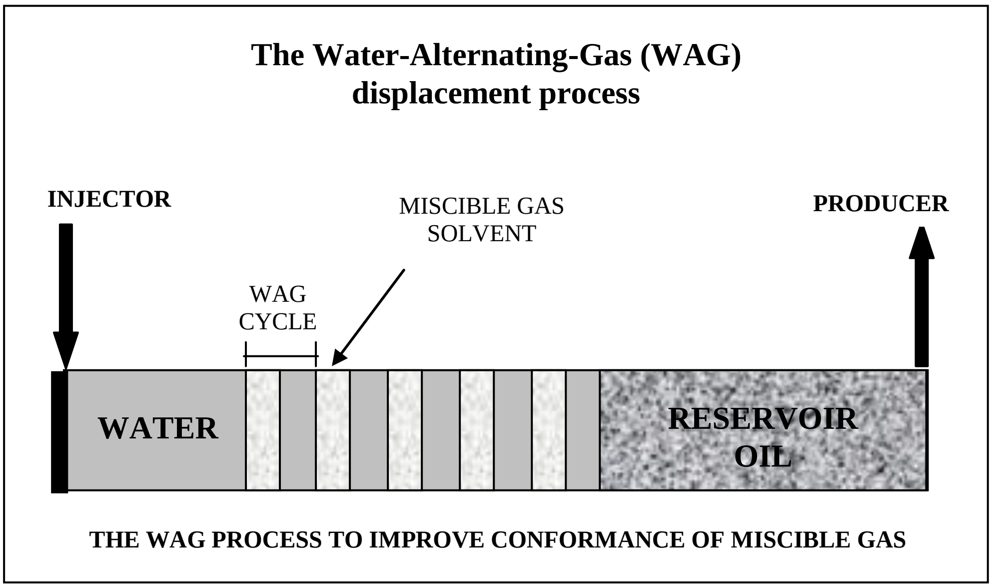

Figure 2.1 Schematic view of the process [4]

The gas and water slug injection is fulfilled in cycles injecting both fluids into the same well and displacing with water after injection of the total estimated solvent volume (approximately 40% of the hydrocarbon pore volume) injecting between 1 to5% by year of the calculated original hydrocarbon flow unit in the pattern [5]. Minimum slug size is usually in order of 1 to 5% of the original HCPV, whereas field experiences suggest projects require slug sizes much larger than this [5].

WAG ratio, the volume of fluid injected in each cycle and changing from cycle to cycle are the injectivity dependence criteria into each layer. The strategies for injectivity are different. For example a WAG ratio 2:1 injecting gas for 30 days follow by a 60 days water injection period, injecting several cycles until reach the estimated hydrocarbon pore volume. Thus, the total number of WAG cycles depends on the amount of solvent injected by cycle [4].

2.2 Classification of the WAG

WAG processes can be classified in many ways. However the most common way is to characterize between miscible and immiscible displacements as a first classification.

2.2.1 Miscible WAG injection

Normally it is hard to distinguish between miscible and immiscible WAG injections. Even if multicontact gas/oil miscibility may have been obtained in many cases, much uncertainty remains about the actual displacement process. It has not been possible to isolate the degree of compositional effect on oil recovery by WAG. Miscible projects are mostly found onshore and the early cases used expensive solvents like propane, which seem to be a less economically appropriate process nowadays. Most of the miscible projects are repressurized in order to bring the reservoir pressure above the Minimum Miscibility Pressure (MMP) of the fluids. In the real field cases the process may vary between miscible and immiscible gas during the life of the oil production as a result of failure to maintain sufficient pressure [3]. Miscible WAG injections have been mostly performed on a close well spacing, but they have also been attempted at offshore type well spacing (where wells can be placed several km apart) [6].

2.2.2 Immiscible WAG injection

Immiscible WAG process has been applied with the purpose of improving frontal stability or contacting unswept zones, in reservoirs where gravity-stable gas injection cannot be applied due to limited gas resources or low dip or strong heterogeneity reservoir properties. In addition to sweep, the microscopic displacement efficiency may be improved. Because of the effect of three-phase and cycle-dependent relative permeability, residual oil saturations are usually lower for WAG injection than for a waterflood and sometimes even lower than a gasflood [7]. Sometimes the first gas slug dissolves to some degree into the oil, what causes mass exchange (swelling and stripping) and a suitable change in the fluid viscosity/density relations at the displacement front. The displacement can then become near miscible [3].

2.2.3 Simultaneous WAG injection

A process where gas and water are injected simultaneously is called Simultaneous Water-Alternating-Gas injection (SWAG) and it has been suggested as a method to reduce capillarity entrapment of oil in small scale reservoir heterogeneity, providing better mobility control of the gas than alternating water and gas injection process. The process consists in mixing the gas with water at a sufficient pressure in order to maintain bubble flow of dispersed gas in a flowstream. Improvement of the displacement efficiency by SWAG is proven by experimental results which show obtaining recoveries twice as high as the obtained by waterflooding [4].

2.3 General description of WAG injection process

The WAG displacement will be optimized if the mobility ratio is favorable (<1). As a result, increasing the gas viscosity or reducing the relative permeability of the injecting fluids can lead to obtaining the reduction of the mobility ratio.

Injecting water and gas alternately result in reduced mobility of gas phase. Furthermore, the mobility is expected to be reduced when compared to gas injection. It is also important to obtain correctly adjusted amount of water and gas in order to have the best possible displacement efficiency. Too much gas will result in poor vertical and possibly horizontal sweep, and too much water will result in poor microscopic displacement.

The oil recovery, R_f, can be described by three contributions:

$$R_f = E_v * E_h * E_m \ldots\ldots\ldots\ldots.. (2.1)$$

,where E_v – vertical sweep, E_h – horizontal sweep and E_m – microscopic sweep efficiency. By maximizing any or all of the three factors in this formula we can optimize the oil recovery. Vertical sweep efficiency E_v and horizontal sweep efficiency E_h contributions are considered as the macroscopic displacement efficiency.

The residual oil saturation will go toward zero in the flooded areas while performing a miscible displacement. However, the remaining oil saturation after gas flooding is usually lower than after waterflooding, even with an immiscible displacement. According to recent simulation studies, inclusion of gas trapping, reduced phase mobility, and lower residual oil saturation in three-phase zones may influence the extent of the WAG zone (three-phase zone) in the reservoir and lead to higher oil recovery [3].

2.3.1 Horizontal displacement efficiency

The stability of the front that is defined by the mobility of the fluids will strongly influence the horizontal displacement efficiency (E_h). The mobility ratio (M) can be described as:

$$M = \frac{k_{rg} / \mu_g}{k_{ro} / \mu_o} \ldots\ldots\ldots\ldots(2.2)$$

,where k_{rg} and k_{ro} are the relative permeabilities and μ_g and μ_o are the viscosities for gas and oil respectively. In case of obtaining unfavorable mobility ratio, the gas fingering (or channeling) will occur, causing early gas breakthrough and decreasing sweep efficiency. Normally, gas tends to breakthrough earlier. The reason for that is not only mobility ratio but also the reservoir heterogeneity and particularly high permeable layers as well as premature breakthrough of the water phase [3].

2.3.2 Vertical displacement efficiency

The relation between viscous and gravitational forces has influence on the vertical sweep efficiency (E_v). The viscous/gravity ratio can be expressed as:

$$R_{v/g} = \left(\frac{\upsilon \mu_o}{kg\Delta\rho} \right) * \left(\frac{L}{h} \right) \qquad \text{.............(2.3)}$$

,where υ – Darcy velocity, μ_o – oil viscosity, L – distance between the wells, k – permeability to oil, g – gravity force, $\Delta\rho$ – density difference between fluids and h – height of the displacement zone. The reservoir dip angle, and variation in permeability and porosity is the reservoir properties affecting the vertical sweep. Usually, permeability and porosity increasing downward is advantageous for the WAG injection, because this combination increases the stability of the front [3].

2.3.3 Design of the WAG

The WAG injection is an enhanced oil recovery method, considering that the oil field has been in production for some time period and has undergone under both waterflooding and primary depletion mechanisms. The main point is to obtain incremental oil recovery in comparison to other injection operations. One of the first issues to determine in WAG injection is whether the process will continue under miscible or immiscible drive. In fact this decision is based not only on availability, but also on economic consideration.

2.3.4 Injection Gas

CO_2, hydrocarbons, and nonhydrocarbons (CO_2 excluded) are the main gases used in WAG projects today. CO_2 is an expensive gas and is usually utilized when special options for deliverance exist or when miscible drive should be obtained. However, during CO_2 injection application occurrence of corrosion problem is very high. Hydrocarbon gas is available directly from the production. As a result of it all offshore WAG projects today use hydrocarbon gases. It is believed that there is an optimal amount of gas to be injected during WAG flood. When this value is exceeded the gas recycling occurs and the gain of additional oil recovery from further WAG injection without major changes is very little [3].

2.3.5 Injection pattern

The most popular onshore injection pattern is the five-spot injection pattern with a fairly close well spacing. Although this pattern is normally applied onshore, it is seldom used offshore. The reason for that is increased price of drilling and data collection [3].

2.4 Operational Problems

In the production life of an oil field, some operational problems are inevitable. Because of frequent change of injection fluid, the WAG injection is more challenging than pure gas or water injection. Some of the problems believed to have been most severe and common in many WAG applications are the followings:

2.4.1 Early gas breakthrough

Early gas breakthrough problem is a result of poor understanding of the reservoir or an inadequate reservoir description. Mainly, early gas breakthrough is caused by channeling or override. These problems are difficult to solve, and the wells are usually shut in long before scheduled. In case of offshore fields, override can be very crucial because of the limited number of wells in the projects [3].

2.4.2 Reduced injectivity

The meaning of reduced injectivity is less gas or water injection in the reservoir. This will lead to a more rapid pressure drop in the reservoir, which will affect displacement and production. There are many factors affecting reduced injectivity: change in relative permeability owing to three-phase flow, wellbore heating, and thereby reduced effects of thermal fractures during gas injection or precipitates (hydrates and asphaltenes) formed in the near-wellbore zone. Even though the reduced injectivity of water is observed after a gas slug, the injectivity of the gas after a water slug usually is not a problem. In some cases injectivity even is increased, for example owing to dissolved reservoir rock [3].

2.4.3 Corrosion

Corrosion is a problem which needs to be necessarily solved in almost all WAG injection projects. This is mostly due to the fact that the WAG normally is applied as a secondary or tertiary recovery method and the project takes over old injection and production facilities originally not designed for WAG injection. Also, projects using CO_2 as injection gas reported severe corrosion problems. There are different solutions for this problem, which are usage of high quality steel, coating of pipes, and treatment equipment [3].

2.4.4 Scale formation

When CO_2 is the injected gas source in WAG projects, usually the occurrence of scales in formations is very high. The scale formation may stress the pipelines and can lead to failure. In CO_2 floods, casings often have been coated with an extra layer for corrosion protection: this layer can be damaged by scale, which will lead to occurrence of corrosion. In worst cases, production stop is needed either for chemical squeeze treatments or while repairing the damage [3].

2.4.5 Hydrate and Asphaltene formations

Hydrates and asphaltenes may lead to problems and disturbances in production. Despite the fact that problems connected with the precipitations are the common, the factors influencing the formation are better known for hydrates than for asphaltenes. Thus, hydrate formation normally can be controlled with methanol solvent treatment [3].

2.4.6 Temperature differences of injected phases

Sometimes temperature difference between water and gas phases under injection may result in stress-related tubing failure. In some cases, further adjustment of the possibility for tubing expansion eliminated this problem in other WAG injectors [3].

2.5 Field studies

The first field application of WAG injection is a pilot in the North Pembina field in Alberta, Canada. It is reported to have started in 1957 and was operated by Mobil. The displacement type was miscible and injectant was hydrocarbon gas. A total of 59 WAG field applications is shown in Table 2.1, which summarizes these field cases in chronological order, includes comments on rock type and gas injection. A miscible displacement WAG project was begun in the Midland Farms (Wolfcamp) field [8], Texas in 1960. The steps planned in the recovery process were: (1) injection of a propane-enriched gas phase to form the miscible zone; (2) injection of a dry gas buffer zone to serve as a flexible barrier between the miscible zone and driving medium; and (3) injection of alternate slugs of dry gas and water as a driving medium. The average water injection rate over the life of the project has averaged approximately 750 BWPD/well at about 1,000 psi wellhead injection pressure. Gas injection rates during the initial stages of the project averaged about 523 Mcf/D/well at an average injection pressure of 2,500 psi.

Table 2.1 Summary of the field WAG experience [3]

WAG	Startup	Name	Location	Injectant	Drive/Displ.	Formation
1	1957	North Pembina	Alberta, Canada	HC	Misc.	Sandstone
2	1959	Romashkinskoye	Minnebaevsky Unit, Russia			
3	1960	University Block 9	Texas	LPG	Misc.	Limestone
4	1960	Midlands Farm	Texas	propane	Misc.	Limestone
5	1960	Juravlevsko-Stepanovskoye	Orenburg, Russia		Immisc.	Carbonate
6	1961	South Ward	Texas	propane	Misc.	Sandstone
7	1962	Adena	Colorado	propane	Misc.	Sand
8	1964	Hassi-Messaoud	Algeria	HC	Misc.	
9	1964	Mead Strawn	Texas	CO_2		Sand
10	1966	Fairway	Texas	HC	Misc.	Limestone
11	1968	Ozek-Suat	Chichen-Inguish, Russia	HC	Misc.	Sandstone
12	1970	Goyt-kort	Chichen-Inguish, Russia	HC	Misc.	Sandstone
13	1972	Kelly Snyder	Texas	CO_2	Misc.	Carbonate
14	1972	Levelland	Texas	ENG/CO_2	Misc.	Limestone
15	1972	Willard (Wasson)	Texas	CO_2	Misc.	Dolomite
16	1973	South Swan	Alberta, Canada	NGL	Misc.	Carbonate, calcarenite
17	1976	Rock Cr eek	West Virginia	CO_2	Misc.	Sandstone
18	1976	Lick Creek	Arkansas	CO_2	Immisc.	Sandstone
19	1976	Granny's Creek	West Virginia	CO_2	Misc.	Sandstone
20	1976	Slaughter Estate (SEU)	Texas	CO_2	Misc.	Dolomite
21	1977	Willesden Green	Alberta, Canada	HC/N_2	Misc.	Sandstone
22	1980	Garber	Oklahoma	CO^2	Misc.	Sandstone
23	1980	Purdy Springer NE	Oklahoma	CO_2	Misc.	Sandstone
24	1981	Maljamar	New Mexico	CO_2	Misc.	Dolomite
25	1981	Jay Little Escambia		N_2	Misc.	Dolomite,carbonate
26	1981	Little Knife	North Dakota	CO_2	Misc.	Carbonate
27	1981	Quarantine Bay	Louisiana	CO_2	Misc.	Sandstone
28	1981	Twofreds (Delaware)	Texas	Exhaust gas		Sandstone
29	1982	Wilmington	California	CO_2N_2	Immisc.	Sands
30	1983	Joffre Viking	Alberta	CO_2	Misc.	Sandstone
31	1983	San Andres	SESSAU,Texas	CO_2	Misc.	Dolomite
32	1983	Wasson Denver	Texas	CO_2	Misc.	Dolomite
33	1983	Fenn Big Valley	Alberta	HC	Misc.	Dolomite
34	1982–83	Prudhoe Bay	Alaska	Enriched	Misc.	Sandstone
35	1984	Samotlor	Siberia, Russia		Immisc.	Sandstone
36	1984	Caroline	Alberta, Canada		Misc.	Sandstone
37	1985	Kuparuk River	Alaska	HC	Immisc.	Sandstone
38	1985	Kuparuk River	Alaska	HC	Misc.	Sandstone
39	1985	Judy Creek	Alberta	HC	Misc.	Limestone
40	1985	Mitsue	Alberta	HC	Misc.	Sandstone
41	1985	East Vacuum	New Mexico	CO_2	Misc.	Dolomite
42	1985	Dollarhide	Texas	CO_2	Misc.	
43	1986	Rangely Weber	Colorado	CO_2	Misc.	Sandstone
44	1986	Hanford	Texas	CO_2	Misc.	Dolomite
45	1986	S. Wasson Clearfork	Texas	CO_2	Misc.	Dolomite
46	1986	Wertz Tensleep		CO_2	Misc.	Sandstone
47	1988	Kaybob North	Alberta	HC	Misc.	Carbonate
48	1989	N. Ward Estes	Texas	CO_2	Misc.	Dolomite, sandstone
49	1989	Lost Soldier Field	Wyoming	CO_2	Misc.	Sandstone
50	1989	Gullfaks	North Sea	HC	Immisc.	Sandstone
51	1989	Daqing	China	HC	Immisc.	Sandstone
52	1993	Neches	Texas	CO_2	Misc.	Sandstone
53	1994	Snorre	North Sea	HC	Misc.	Sandstone
54	1994	Brage	North Sea	HC	Immisc.	Sandstone
55	1994	Slaughter Sundown (SSU)	Texas	CO_2	Misc.	Dolomite
56	1994	Brae South	U.K.	HC	Misc.	Sandstone
57	1994	Statfjord	North Sea	HC	Misc.	Sandstone
58	1995	Mattoon	Illinois	CO_2	Immisc.	Sandstone
59	1996	Ekofisk	North Sea	HC	Immisc.	Carbonate

A common gas-water injection system was first considered for the Midland Farm project. Some minor freezing was encountered during enriched gas injection from small amounts of water left in the lines when they were hydrostatically tested prior to project start up. This and other operational problems indicated that separate water and gas injection systems would be more feasible. Favorable response, such as increased reservoir pressure, increased producing capacity and apparent miscible–bank movement indicates predicted recoveries may be achieved. Additional performance may prove many field applications now considered impractical can be economically justified [8].

The Fairway (Texas) [9] miscible WAG project started in 1966 and ultimate recovery was expected to be about 50 percent, compared with an estimated recovery of 37 percent for waterflooding. Controlled water injection has retarded viscous fingering of the injected gas. Scheduling of alternating cycles of gas and water injection have been able to control producing GOR'S and water cuts at reasonable levels after breakthrough. High-pressure gas injection in previously water swept areas has recovered additional oil.

Many problems associated with the poor permeability distribution in a stratified reservoir have been solved by the use of packers and other down-hole equipment to selectively isolate producing zones. Radioactive isotopes have been very useful in tracing gas breakthrough. Alternating gas-water injection has prolonged the flowing life by furnishing the necessary energy to maintain substantial oil rates even at high water cuts. Numeric model studies indicated that the average gas-water injection ratio should be reduced to 0.7 RB/RB from the initial value of 1.0. Field performance has verified that numeric model calculations were reasonably accurate [9].

The Lick Creek (Arkansas) immiscible CO_2 waterflood project [10] was initiated in 1976 to increase oil recovery from heavy oil sand. The immiscible CO_2 waterflood project was scheduled to be developed in four stages: 1) cycle all producing wells with CO_2, 2) continuous CO_2 injection into unit injection wells, 3) alternate CO_2 and water (WAG process) injection in the injection wells, and 4) water injection only into the injection wells. The purpose of the immiscible CO_2/WAG process was to reduce oil viscosity and also to increase reservoir oil volume due to oil swelling.

Channeling of CO_2 in the Lick Creek reservoir has been a problem as well as in other reservoirs and it continued to be as such after WAG injection initiated. A foam treatment and two different types of gelled polymer treatments were performed in the unit in an attempt to minimize CO_2 channeling. The application of an immiscible CO_2 waterflood project to the Lick Creek field has increased oil recovery by 1.75 MMSTB, (11.1% OOIP) of oil compared to an initial prediction of 16% OOIP incremental oil recovery. The WAG injection process was also effective in increasing the sweep efficiency of the injected CO_2 in the reservoir. The lower than projected oil recovery was due to channeling of the injected CO_2 and water in the reservoir and also due to the premature termination of the project because of low oil prices at that times (1970's) [10].

An enriched, miscible WAG flood was brought on stream in 1982 in the Prudhoe Bay field on Alaska's North Slope [11]. The project consisted of WAG injecting a slug of more than 10% total pore volume miscible gas at injection rate of approximately 1% total pore volume per year, followed by water injection to displace miscible gas through the reservoir and tertiary oil to producing wells. The estimated incremental-to-waterflood recovery was 5.5% of the OOIP.

WAG ratios and cycle lengths were studied with reservoir simulation. Even though studies mainly projected increased recovery with increasing WAG ratios up to a point, the limited water availability dictated a WAG ratio of 2:1 prior to start-up of the waterflood. The injection schedule was planned as a three month gas and six month water cycle. The reason for that was that longer cycles were less burdensome, less expensive to implement and more recovery benefit than from shorter cycles [11].

The Kuparuk River, Alaska, immiscible and miscible WAG injection of hydrocarbon gas projects were started in 1985 and 1988 respectively [12;13]. The objective of both projects was to reduce the rapid movement of injected gas by using the WAG process for mobility control. Incremental recovery was also expected from WAG injection areas as a result of increased water flood sweep efficiency. In addition to the direct recovery benefits of immiscible WAG injection, some indirect benefits were also realized: the gas relative mobility in the reservoir is reduced compared with gas injection due to alternating the gas injection with water injection, less gas breakthrough occurs to producing wells, thus reducing gas handling requirements which lead to increase of the field oil production rate. Even though both projects suggested 1:1 WAG ratio for mobility control, sometime this ratio was changed to 1:0.5.

Immiscible CO_2 WAG injection project was successively implemented and increased the oil recovery in the thick, heterogeneous reservoir in 1991 in the Daqing oil field, China [14;15]. The CO_2 was transported through low pressure pipeline. In this project two gas and two water injection wells were used, exchanging each others once whenever gas injection reaching amount of 0.05 hydrocarbon pore volume, and totally exchanging for four times. Cumulative amount of CO_2 injected was 0.2 hydrocarbon pore volume and water gas ratio was 1:1. There were two reasons for that: one is to keep continuation of gas injection and supply, another is to meet a demand for injection rate.

Good response was observed soon after the start of WAG injection. The WAG injection test proved that immiscible WAG can greatly improve the ultimate recovery and the rate of oil production. However, the incremental value of recovery factor derived from the pilot was lower than that from numerical simulation, 4.67% OOIP and 5.1% OOIP respectively. The reasons were that the heterogeneity of the reservoir in pilot was much greater than expected, which resulted early gas breakthrough in some producing wells and that in the recommended project four wells injected gas simultaneously, so the distribution of CO_2 in the reservoir was better than that of the actual project in which CO_2 was injected in two and water in two wells.

The immiscible pilot WAG injection project [16] was used as a supplement to water injection at Statfjord field in 1997 in North Sea (Norway) in order to displace remaining oil in the roof and attic areas and to improve sweep efficiency in waterflood areas. Because of the structure of the area, a large amount of roof and attic oil was assumed bypassed by water flooding.

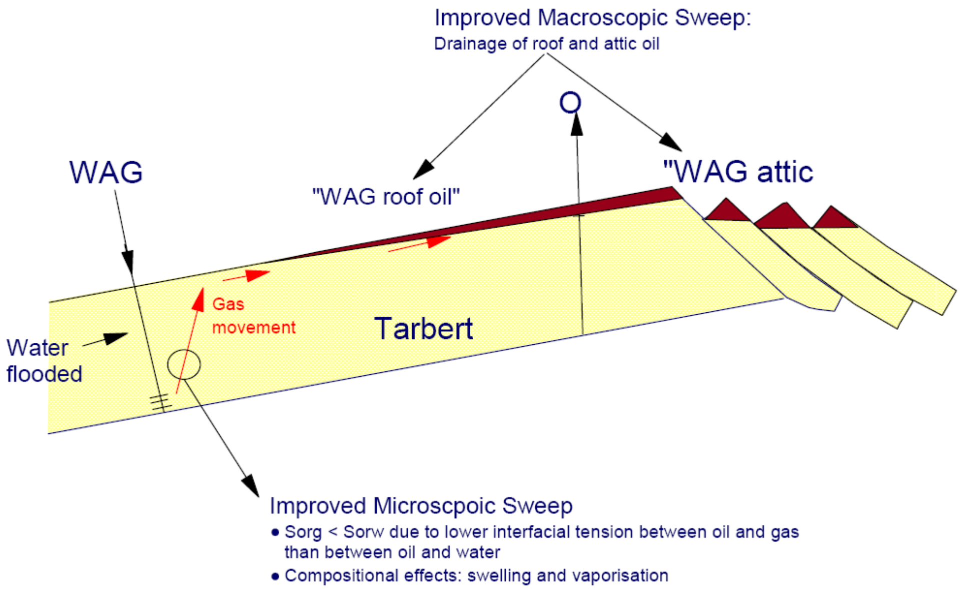

Figure 2.2 Illustration of the displacement of attic and roof oil by WAG injection at Statfjord field [16]

The attic and roof oil were mainly drained by gas, displacing the oil to areas that were drained by subsequent water slug. This mechanism was observed in the production wells, as oil production increased after the injection wells were switched from gas to water injection. Both water and gas slugs contributed to incremental oil in the WAG process. The typical effects of the WAG process observed in oil producers were decreasing water cut, doubled or even in some wells tripled oil rates and increasing GOR with a subsequent lifting effect.

In order to increase the oil recovery, a re-evaluation and reservoir management study was started in 2000 in Bati Kozluca field, Turkey [17]. Since there was CO_2 reservoir at Camurlu field (10 km from Bati Kozluca) and since Bati Kozluca is a heavy oil field with high viscosity and low aquifer constraints, CO_2 EOR study was firstly initialized. However later WAG scenarios studied showed that WAG will be better than only CO_2 injection.

By using various simulation scenarios optimum injection pattern, number of injection wells, injection periods and injection rates were determined. At the end 60 day CO_2 injection with 1MMSCFD/well plus 30 day water injection with 800 STB/day/well were chosen as the best case. Also the effect of additional perforations was proved by these studies. Studies also showed that, even though new injection wells increase cumulative oil production, new production wells are just accelerating the oil production and has a limited effect in cumulative oil production. Therefore it was decided that, additional injection wells could be drilled in the future and new production wells may be drilled depending on the performance of the project. It was predicted in this study that with WAG process cumulative oil production would be 14.2 MMSTB (10.3% of OOIP) in comparison with 7.5 MMSTB (5.5% of OOIP) without WAG application.

WAG injection simulation study was performed in the large offshore producing field Sirri-A, Iran, in 2006 [18]. Because of low porosity and permeability range of this field, strategy of horizontal producers and injectors was used. Common rapid decline in production rates of all wells from 20,000 BOPD to 9,000 BOPD was reason for consideration of EOR WAG injection project for this field. For more accurate investigation of various processes and parameters on Sirri-A field a 6km*6km sector model was prepared. The sensitivity analysis on various WAG parameters in this simulation study showed that some of these parameters like WAG ratio and WAG cycle have no considerable effect on behavior of WAG process, as a result of the field's low porosity and low permeability. However, increasing permeability anisotropy led to increasing oil recovery.

Thus, from the field studied, in order WAG injection to be successful it should be considered that it is important to have a good understanding of the phase behavior of reservoir oil, injected gas mixtures, and reservoir heterogeneities to avoid early breakthrough of injection gas. Even though most field studies have been successful, the main problems connected with the operation of a WAG injection process seem to be corrosion, mainly of injection facilities but also of production equipment after gas breakthrough when using CO_2 as a gas phase; and loss of water injectivity. Negative effects of WAG injection are rarely seen, and most operational problems are handled successfully. Application of the WAG process has also shown that the option of disposing produced gas may lead to considerable improved oil recovery. This is of special interest in offshore environments with limited gas-handling, storage, and export capacities.

CHAPTER 3

3. FIELD OVERVIEW

3.1 Azeri-Chirag-Gunashli (ACG)

3.1.1 Field introduction

The ACG Oil Field is situated to the SE of Baku, offshore Azerbaijan in water depths of between 60m and 280m. The ACG structure is comprised of three linked culminations, which are, from west to east Shallow Water Gunashli (not in PSA), Deep Water Gunashli, Chirag and Azeri. The AIOC (Azerbaijan International Oil Company) consortium, made of 10 different oil companies, from 6 different countries agreed the Production Sharing Agreement (PSA) terms with Azerbaijan in December, 1994 (Figure 3.1). The PSA term is for 30 years at which time the field will revert back to Azerbaijan. BP operates the field on behalf of the shareholders which include the following companies: BP 34.14%, UNOCAL 10.28%, SOCAR 10%, LUKOIL 10%, Statoil 8.56%, ExxonMobil 8%, TPAO 6.75%, Devon 5.63%, Itochu 3.92% and Delta Hess 2.72% [19].

1994: AIOC signs PSA Agreement

BP	34.14%
Unocal	10.28%
SOCAR	10.00%
LUKoil	10.00%
ExxonMobil	8.00%
Statoil	8.56%
TPAO	6.75%
Devon	5.63%
Itochu	3.92%
Delta Hess	2.72%

1997: Chirag First Oil
2005: Azeri First Oil
2024: PSA expires

Figure 3. 1 Location map and PSA agreement of the field [19]

3.1.2 Reservoir Description

The trap, which forms the giant ACG Oil Field, is a NW-SE trending, steeply dipping thrusted anticline (Figure 3.2). Within structural closure there are a number of crestal faults oriented along strike as well as mud volcanoes of varying size which complicate the otherwise straight forward structural geometry. Hydrocarbons are found within several different stratigraphic intervals within the Pliocene, the most important reservoirs occur in the Pereriv and overlying Balakhany Formations.

The extensive oil column that characterizes the field is the result of high structural relief combined with excellent top and lateral seals, for example, 900m on the north flank of Azeri and 580m on the south of Chirag. Differing pressure regimes combined with effective seals may be responsible for the greater than 300 m north-south changes in oil contacts. At the main Pereriv reservoir level, the ACG Field is 50km in length and 5km in width.

Hydrocarbons are thought to have been sourced and migrated from Late Miocene to Early Pliocene aged Maykop lacustrine shales buried in the deep and rapidly subsiding South Caspian basin to the south of ACG. The ACG structure formed in the Late Pliocene in response to compression associated with the formation of the Alpine/Himalayan mountain belts to the south. Release of overpressure from deeply buried shales exploited lines of weakness associated with the inversion and faulting forming the numerous mud volcanoes some of which are still active today.

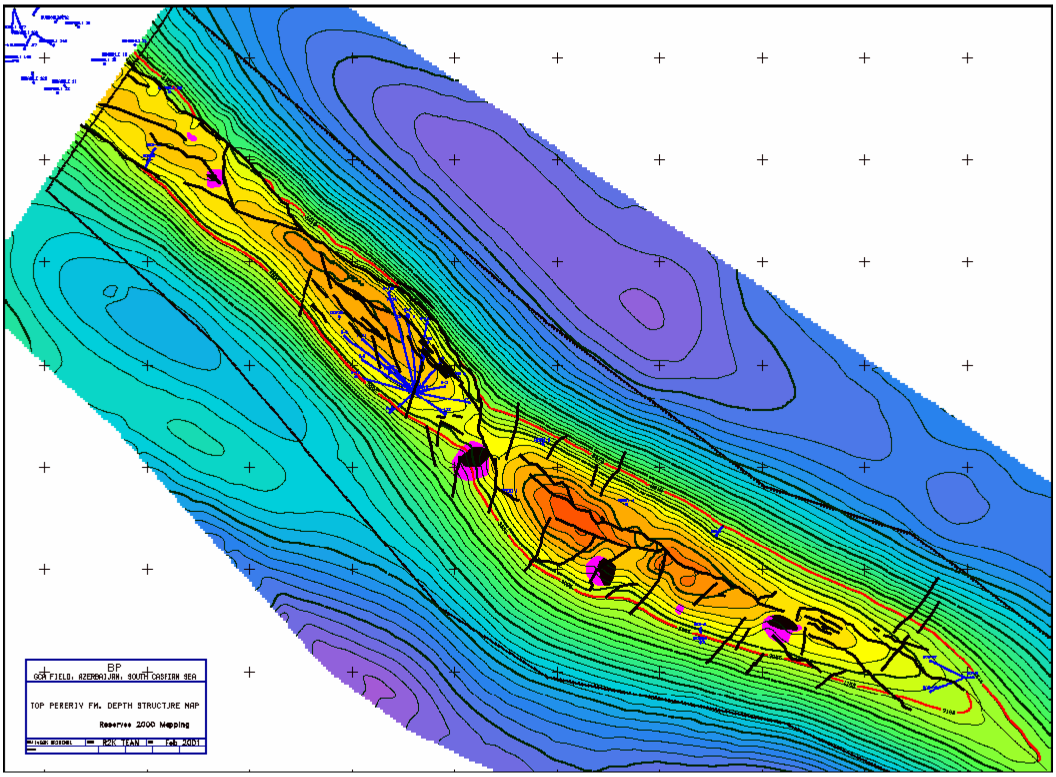

Figure 3. 2. Structural map of ACG [20]

3.1.3 Stratigraphy and reservoir development

The Pereriv Formation forms the main ACG reservoir and is subdivided into 5 units, A to E. The Pereriv B and D sands are the most significant producing intervals. Secondary reservoirs are found both beneath (NKP, PK, Kalinsk) and above (Balakhany, Sabunchi, Surakhany) the Pereriv (Figure 3.3). The Balakhany is subdivided from V through X with the Balakhany VIII and X the most significant. The main ACG reservoirs were deposited in a range of environments associated with a large river-dominated lacustrine delta.

Pereriv reservoirs are laterally extensive and vary little in thickness reflecting sand-rich depositional systems and low relief palaeo-topography. Laterally persistent lacustrine shales separate the Pereriv into five separate reservoirs and records the interplay between lacustrine expansion across a low-relief floodplain and fluvial deposition. The Pereriv and Balakhany sediments record sand-prone and shale-prone stacking patterns associated with alternation between more proximal and distal environments of deposition. Delta plain facies are more sand-rich and have better connectivity than delta front facies. The cyclicity records delta advance and retreat related to climate changes in the palaeo-Volga system producing variations in lake level.

Reservoir quality is controlled by facies (ductile content and grain size) and maximum depth of burial. Although grain sizes are dominantly fine-grained, the overall reservoir quality is good to excellent due to excellent sorting (absence of interpartical shale) and the absence of pervasive antigenic cements in the main reservoirs. Average net to gross ranges for the Pereriv B and D are 0.80 to 0.95 while other reservoirs in the Pereriv and Balakhany are more variable averaging 0.12 to 0.50. Average porosity ranges for the Pereriv B and D and the Balakhany VII and VIII are 0.19 to 0.22 while other reservoirs in the Pereriv and Balakhany range from 0.16 to 0.18. Average permeabilities for the Pereriv B range from 50mD - 500mD in the Chirag and Azeri Fields. There is a decrease in permeability from West Chirag to East Chirag towards the large field-bounding mud volcano. The Pereriv D reservoir has slightly lower average permeabilities than the overlying Pereriv B.

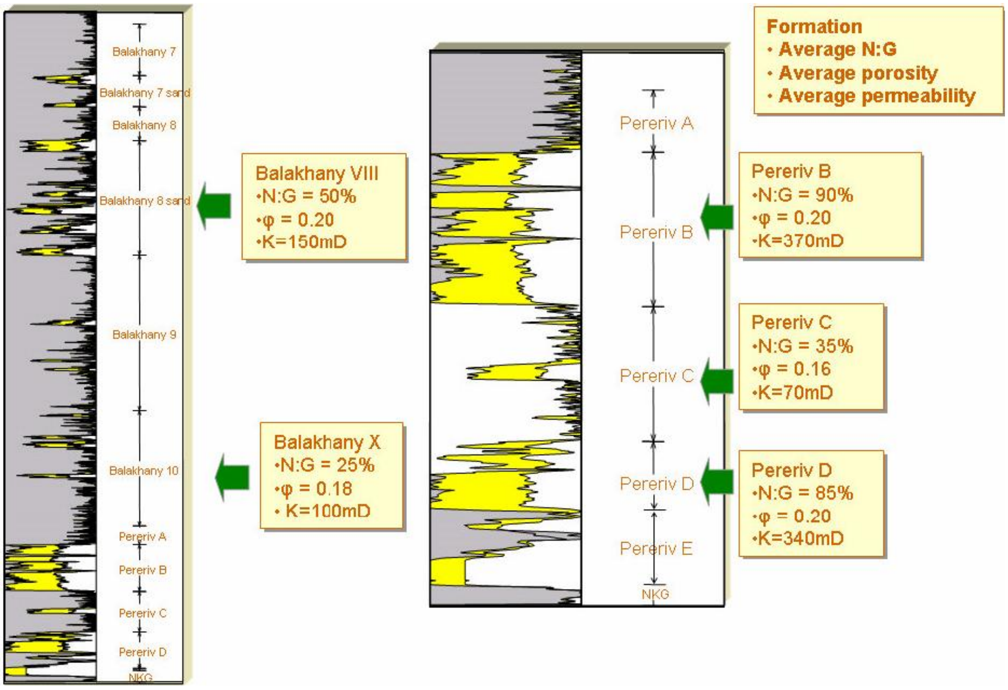

Figure 3. 3 Stratigraphy of ACG (logs showing different sand packages) [19]

3.1.4 Fluid Properties

Ten appraisal wells have been tested in ACG but only three have reasonable pressure build-up data. These three tests cover the Balakhany X, Pereriv B and Pereriv D reservoirs. The Chirag platform wells have been production or injection tested. Fluid samples are available from Chirag platform wells, but elsewhere on the ACG structure representative fluid properties have only been taken in a few wells from the Balakhany X, Pereriv B and Pereriv D intervals.

ACG appraisal wells GCA-1 and GCA-2 have DST data that were used to derive GOR.s of between 700 scf/bbl and 900 for the Balakhany X and Pereriv reservoirs. Crude oils from these reservoirs have moderate API.s, varying from 32° to 36° that generally increase from west to east, low sulphur, and low to moderate wax content (up to 8.5%wt in Chirag, 16%wt in Azeri) (Figure 3.4). Shallower reservoirs in Chirag, for example the Balakhany VIII and VII, have suffered biodegradation leading to a reduction in API to 25° to 26° and have higher viscosities, higher sulphur and lower wax than the underlying reservoir intervals. Significant concentrations of H_2S have been found in the Pereriv D and E in the Azeri Field in association with sulphate reduction close to oil-water contacts.

Fluid contacts are defined partially by well data and partially on 3D seismic. Contacts vary between stratigraphic intervals and between fault-bounded segments. Mud volcanoes that puncture the crest of the structure also provide vertical and lateral barriers. Upper Balakhany reservoirs are generally gasfilled. From the Balakhany VI through the Pereriv, reservoirs are oil-filled and some of the Balakhany reservoirs have extensive gas caps. Aquifers extending down-flank the Chirag Pereriv hydrocarbon column have provided excellent pressure support.

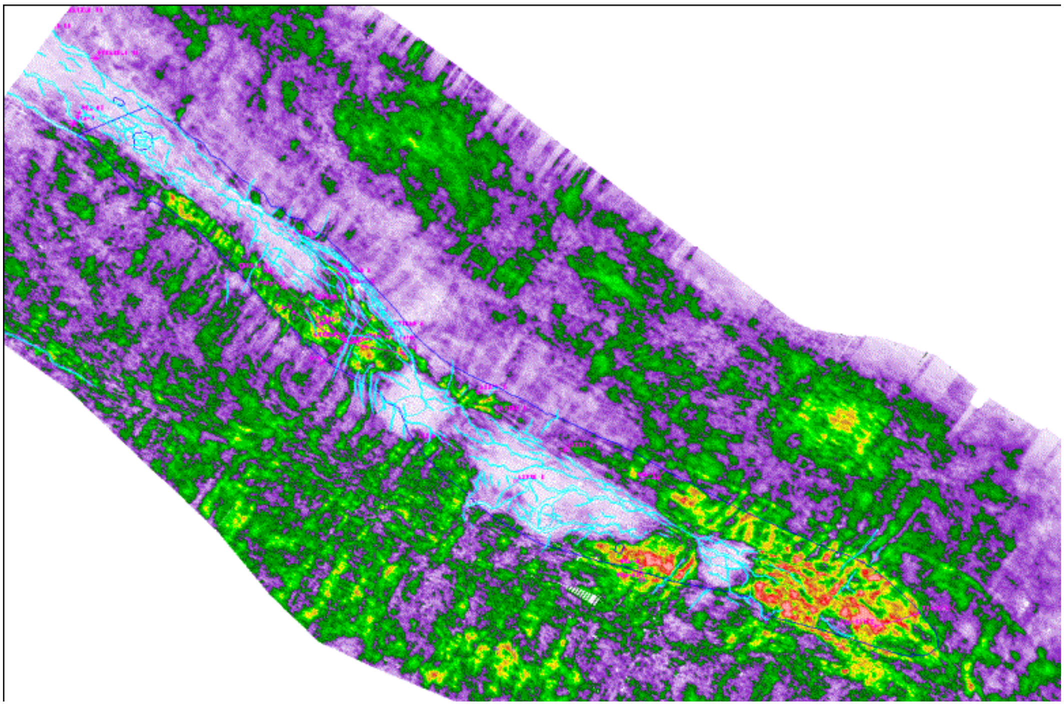

Figure 3. 4. Hydrocarbon indicator of Pereriv B [20]

3.2 Azeri Field

3.2.1 Field Geometry

The Azeri field, contained within the overall ACG mega structure, is an elongated, thrusted, anticline stretching some 25km within the PSA area. It has originally a gas cap. The structure has steep dips and has an oil column height of 900m. The reservoir dips significantly more on the northern side than the southern side.

The Northern flank of Azeri has a dip of 30 to 35 degrees while the South flank has a shallower dip of 20 to 30 degrees. As seen previously, there are two major formations: the shallower Balakhany and deeper Pereriv. The Pereriv is much more prolific that the Balakhany which has both lower permeability and net to gross. Of all the sands, the Pereriv B and D have the largest net to gross, permeability and porosity and will be the most prolific.

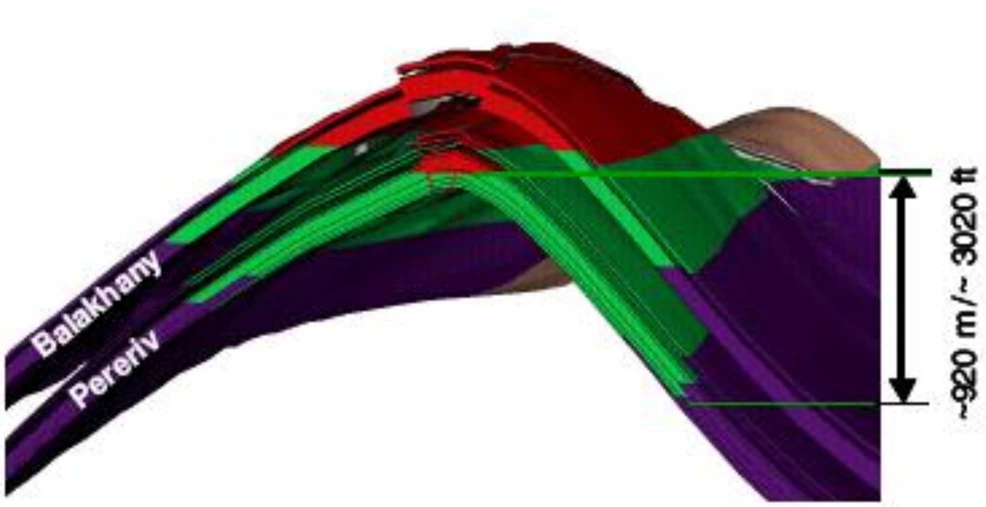

Figure 3. 5 Geometry of Azeri field [20]

3.2.2 Development plan of the field

The full field development for ACG is based on three Phases of development covering the undeveloped segments of the structure – Azeri and Deepwater Gunashli. Approximate development timings and profiles are indicated in the Table 3.1.

Table 3. 1 Schedule of the different injection processes and expected start of oil production [20]

		2005	2006	2007	2008
PHASE 1	CA	🟢	🔴	🔵	
PHASE 2	WA		🟢	🔵	
PHASE 2	EA			🟢	🔵

🟢 first oil 🔴 gas injection 🔵 water injection

In the sequencing of the development, priority is given to the Azeri segment, which contains a higher reserve density and a lower level of pressure depletion than the Deepwater Gunashli segment. Phases 1 and 2 are focused on the development of the Azeri portion of the field [20].

Phase 2 development plan optimizes full Azeri development and therefore supersedes Phase 1. Phase 1 was a standalone development of the Central Azeri platform. Phase 2 continues the Azeri development by adding platforms in west and east Azeri plus increased water and gas injection capacity. In order to optimize reserve recovery the development strategy from the Central Azeri platform changes significantly in the context of the full field, Phase 2 development.

3.2.3 Segment development of the field

The Full Azeri Development uses 291 penetrations from 132 production slots (40 in West & 46 in Central and East), including 25 pre-drills (9 in West, 11 in Central and 5 in East), to generate more than 3Bstb of reserves within the PSA. The Full Azeri development is based on a depletion plan. In the Pereriv, the North flank is developed by a gas flood in its steepest part at the centre of the field in order to exploit the benefit of gas displacement. All gas injection wells were drilled off the central platform. The western and eastern edges of the North flank and the whole of the South flank is developed by a peripheral water flood. The open hole gravel pack (OHGP) well completion design, with fibre optics temperature and pressure sensors, has been selected to minimize sand production and interventions while maximizing rate [20].

CHAPTER 4

4. STATEMENT OF THE PROBLEM

In this thesis, WAG injection feasibility of the South Flank of the Central Azeri field will be studied. The sector simulation model of the Pereriv B reservoir of South Flank of the Central Azeri field (Base Case) will be set on the basis of the reservoirs static and dynamic properties. Then, sensitivity scenarios for WAG injection with different parameters (half slug size volume, cycles, WAG ratio, start time, bottomhole injection pressure etc.) will be designated in accordance with injecting fluids availability and platform constraints. Effect of rock properties like vertical to horizontal permeability ratio and operational parameters such as injection rate, slug size, SWAG process will be compared with the Base Case performance. The best parameters for WAG effectiveness for this sector model will be determined. Relative permeability hysteresis effect will also be considered. The simulation performance forecasts for the various operating scenarios will be converted to cash flow projections for economic evaluation purposes.

CHAPTER 5

5. METHOD OF SOLUTION

5.1 Use of commercial software

5.1.1 Introduction

The Landmark VIP product line is a group of software products designed to simulate the flow of fluids in underground hydrocarbon reservoirs. In particular, VIP let:

- Define the structure and topography of the reservoir.
- Divide the reservoir into modelling units called *gridblocks*.
- Specify the properties of each gridblock in the reservoir.
- Model a variety of recovery processes including:
    - Primary depletion
    - Water floods
    - Miscible and immiscible gas injection
    - Gas cycling
    - Hot water and steam floods
    - Oil recovery in naturally fractured reservoirs
    - Polymer floods
    - Tracer tests
    - Water or gas coning
    - Infill drilling

Landmark VIP has a black oil capability, compositional capability, dual porosity, local grid refinement, polymer capabilities, and thermal capabilities. The VIP simulator includes two separate modules: one (VIP-CORE) used to set up an initial state for reservoir models and another (VIP-EXEC) to perform time dependent studies [21].

5.1.2 The Initialization Module (VIP-CORE)

The initialization module called VIP-CORE or just CORE calculates initial reservoir conditions which are used by the simulation module. The initial state is based on a complete description of:

- Reservoir structure and topography.
- Reservoir rock properties and initial saturations.
- Fluid properties and equilibrium data.

The reservoir being studied may be initialized to capillary-gravity equilibrium or to a non-equilibrium state. Once the initial state is calculated, the resulting data values serve as a starting point for a more detailed, time-dependent study.

The first step in using VIP is to prepare the initial data, run an initialization (VIP-CORE), and analyze the results. The initial data includes all data needed to accurately describe the physical characteristics of the reservoir. VIP-CORE uses this data to build an initial state which prepares the reservoir model for simulation. The following types of data may be needed to describe the initial state:

- Rock and fluid properties such as saturation tables, oil fluid properties, etc.
- Gridblock structure of the reservoir for use in entering, calculating, and reporting data.
- Data arrays listing the porosity, permeability, and other values at each reservoir gridblock.
- Additional “Scalar” data including physical property constants and equilibrium data.

All these data must be prepared in a structured keyword format that VIP recognizes. The first step is to give VIP sufficient information to describe the initial state of the reservoir (initialization). This information is presented to VIP in the form of a data file. These data files are ASCII files that may be created directly using a text editor or automatically using the preprocessing tools in DESKTOPVIP.

5.1.3 Scalar Data

Scalar data is a broad category that may include any of the following elements:

- Type of simulator to run (black-oil, compositional, etc.)
- Run titles
- User preferences with regard to:
  - Metric units
  - Cross-sectional studies
  - Relative permeability output
  - Vertical equilibrium tracking
  - Dual porosity/permeability modeling
  - Fault modeling
  - Nonequilibrium initialization
  - Metric pressure units
  - Lines of output per page
  - Three phase relative permeability model
  - Initialization Map output
  - Printing of data arrays
- Gridblock dimensions for Cartesian or radial grids
  - Physical property constants including:
  - Stock tank water density
  - Water formation volume factor (VIP-COMP, VIP-ENCORE)
  - Water viscosity (VIP-COMP, VIP-ENCORE)
  - Water compressibility (VIP-COMP, VIP-ENCORE)
  - Rock compressibility
  - Reservoir temperature
  - Standard temperature and pressure
- Equilibrium table data including:
    - Initial reservoir pressure/depth

- Water-oil or gas-oil capillary pressure/depth
- Initial saturation pressure

5.1.4 Fluid and Rock Properties

Hydrocarbon fluid properties can be specified in four ways.

- They can be defined as simple pressure-dependent functions (Black-Oil), with tabulated values of saturation pressure, formation volume factor, solubility and viscosity for the oil and gas phases (VIP-ENCORE).
- They can be defined as pressure dependent K-values and z factors (K-value), in a table similar to that which is calculated internally from black-oil data (VIP-ENCORE).
- In VIP-THERM, hydrocarbon may be defined as a single non-volatile dead oil component with density, enthalpy and viscosity represented analytically or by tables.
- Alternatively, equation of state (EOS) parameters can be specified for use in characterizing the fluids - this is the fully compositional mode (VIP-COMP or VIP-THERM).

Since all runs except thermal dead oil are compositional (a black-oil fluid is treated as a two component K-value fluid) it is possible to specify separator conditions which materially affect the relationship between reservoir and surface phase volumes. In fact, volume in place calculations will not match field data unless correct separator data is provided, or the data entered is modified appropriately.

Tables of saturation dependent properties of the rock such as relative permeability and capillary pressure are required for each phase. These quantities are usually entered from core analysis reports after averaging and smoothing, if necessary. For an oil-water gas system, relative permeability and capillary pressure data are entered as pairs of two-phase oil-water and gas-oil tables. Different rock properties may be applied to different areas of the reservoir by assigning different rock types, or generic tables may be used and the table and points varied spatially.

5.1.5 Arrays

Some reservoir properties - such as permeability and porosity – may vary continuously across the reservoir. To describe these variations accurately, the reservoir is divided into a series of gridblocks and then specified a value for each gridblock. For example, the illustration below shows a three-dimensional gridblock structure, with each producing zone represented by a single layer of gridblocks.

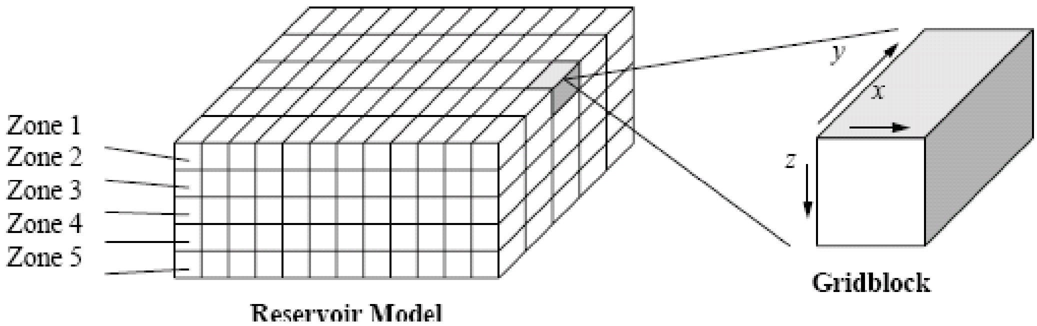

Figure 5. 1 Example of division of Reservoir into the gridblocks

5.1.6 The Simulation Module (VIP-EXEC)

Once a gridblock structure is defined, it is possible to specify a value for each gridblock that will be used in model calculations. For example, the following illustration shows porosity values for all the gridblocks in a single layer of the reservoir. The row-column format shown below is called a *data array* and corresponds exactly to the rows and columns in the grid structure. These data need to be entered in a specific order. VIP-CORE requires you to enter variable reservoir data in arrays like the one shown below in Table 5.2.

```
Porosity for plane Z 1
 0.160 0.163 0.174 0.190 0.200 0.217 0.231 0.245 0.240 0.231
 0.214 0.200 0.192 0.182 0.180 0.180 0.184 0.193 0.199 0.200
 0.160 0.168 0.180 0.192 0.205 0.219 0.234 0.249 0.255 0.235
 0.214 0.201 0.192 0.190 0.187 0.188 0.192 0.196 0.201 0.204
 0.160 0.172 0.183 0.195 0.208 0.220 0.236 0.257 0.260 0.238
 0.215 0.201 0.191 0.187 0.194 0.196 0.201 0.207 0.212 0.214
 (etc.)
```

Figure 5. 2 Example of Porosity Data Array

5.1.7 Keywords for Model Input

All data prepared for the VIP-CORE module must be in a structured keyword format like the one shown below on the Figure 5.3. More detailed representation of keywords as long as initialization file of the representative model are given in Appendices A and B.

```
INIT
TITLE1
 SPE COMPARISON PROBLEM #1
TITLE2
 EXAMPLE DATASET
DATE 1 1 80
C ------------------------------------------------------------------
C OUTPUT CONTROLS
C ------------------------------------------------------------------
MAP P SO SW SG
C PRINT NONE
C ------------------------------------------------------------------
C MODEL DIMENSIONS
C ------------------------------------------------------------------
NX NY NZ NCOMP
10 10 3 2
C ------------------------------------------------------------------
C CONSTANT PROPERTIES
C ------------------------------------------------------------------
 DWB BWI VW CW CR TRES TS PS
.997 1.0265 .31 3E-6 3E-6 200 60 14.7
C ------------------------------------------------------------------
C INITIALIZATION DATA
C ------------------------------------------------------------------
IEQUIL PINIT DEPTH PCWOC WOC PCGOC GOC BP
 1 4800 8400 0. 8450 0. 8320 4014.7
C ------------------------------------------------------------------
C PVT DATA -- ALLOW GAS TO GO INTO SOLUTION.
C ------------------------------------------------------------------
BOTAB
DOR WTRO
.7868 210
PSAT RS BO BG GR VO VG
9014.7 2984 2.357 .386 .792 .203 .0470
5014.7 1618 1.827 .649 .792 .449 .0309
```

Figure 5. 3 Example of keywords for model input

5.1.8 The Simulation Module (VIP-EXEC)

The simulation module called VIP-EXEC or just EXEC is used to perform the time-dependent calculations required to simulate ongoing operation of the reservoir. VIP-EXEC simulates changes in reservoir pressures and saturations over time, subject to the operating constraints of the wells. For added flexibility, VIP-EXEC is structured as a number of separately licensed modules that allows the user to perform specialized studies:

- VIP-ENCORE is a black oil simulator which can be used for conventional black oil simulation and for multi-component systems with PVT properties.
- VIP-COMP is an n-component, equation-of-state; compositional simulator that takes into account the fact that fluid properties and phase behavior can vary strongly with fluid composition.
- PARALLEL-VIP provides the capability to simulate over multiple processors simultaneously.
- VIP-THERM models hot water and steam injection processes.
- VIP-LGR improves the resolution and detail of a reservoir study without a large amount of extra computer CPU time or memory.
- VIP-DUAL simulates the performance of reservoirs that are naturally fractured, heterogeneous, or highly stratified.
- VIP-POLYMER supports polymer studies performed using VIPENCORE, VIP-COMP or VIP-DUAL.

After completing a successful initialization run, reservoir model is ready to begin the simulation. A reservoir simulation is a time-dependent study of reservoir operation that simulates well production and injection, as well as the movement of fluids through the reservoir itself. To simulate reservoir performance, you need to specify:

- Where and when wells are drilled.
- When they come on stream.
- The flow rates at which they produce or inject.

- When they are shut in.

The simulation itself is performed by the VIP-EXEC module based on type of time-dependent data. This chapter explains how to prepare data for the simulation run, how to execute the simulation run, and how to analyze the results.

The types of data that can be entered into VIP-EXEC are:

- Dates for new data, changed data, and output
- Numerical control parameters
- Well definitions and constraints
- Well model parameters and hydraulics parameters
- Well management system hierarchy
- Production/injection targets

To be usable for simulation purposes, the data must be in a keyword format such as the one shown in the Figure 5.4. The more detailed version of simulation input data for model is given in Appendix C.

```
RUN
DIM NWMAX NPRFMX NPRFTOT
     35       7     100
RESTART    0
START
C
C SIMULATOR CONTROL
DT   -1.0 1.0 90.0  500.00  0.0800  0.0500  0.1000
ITNLIM  1  5  500.00  0.0800  0.0500  0.1000
TOLD   0.5  0.0001  0.0001  0.0001
TOLR   .001    .001   REL TOL
IMPSTAB ON
C
BLITZ
C
C OUTPUT CONTROL
C PRINT ITER 1
C PRINT WELLS WLLYR REGION FIELD TIME
OUTPUT P SW SG SHFTOG TSSUM HCPVTS
WPLOT TIME
WMAP TIME
C
C WELL DATA
WELL  N  NAME   I     J  IGC
      1 J1       5     5  1
      2 J2       5     6  1
      3 J3       6     7  1
(etc.)
```

Figure 5. 4 Keywords for simulation data

5.2 Sector Model simulation

5.2.1 Sector model description

Location on the map of the dynamic simulation model of reservoir performance of Central Azeri field is represented in Figure 5.5. The model of Pereriv B reservoir of Central Azeri sector model has 8 producer wells (4 (SP1;SP2;SP3;SP4) in South Flank and 4 (NP1;NP2;NP3;NP4) in North Flank) , 2 water injector wells (WI1;WI2) (South Flank) and 1 crestal gas injection well (GI1). However, it is assumed in the model that the crestal gas injection affects mostly the North Flank rather than to South Flank. The reservoir dips steeply on the North Flank (ranging from 30 to 40 degrees) and less steeply on the South Flank (ranging from 15 to 25 degrees). Net to gross ratio is averaging to 0.8.

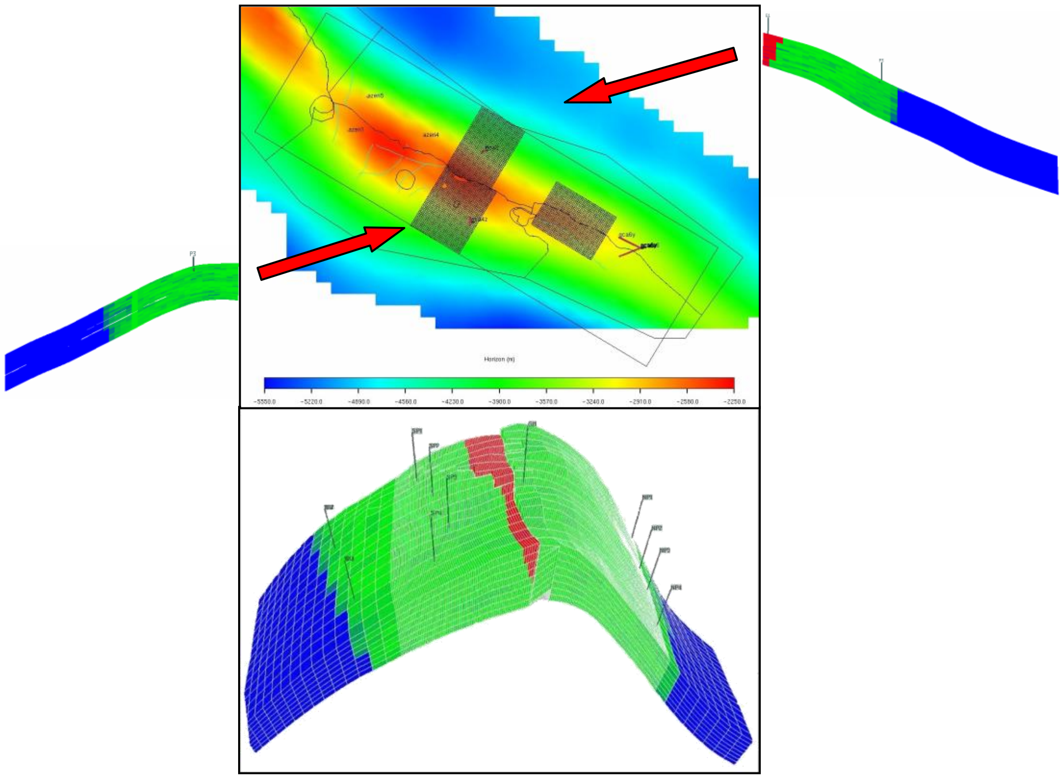

Figure 5. 5 Central Azeri representation

The model has 15 coarse gridblocks in X direction, 42 gridblocks in Y direction and 8 gridblocks in Z direction. For more realistic and detailed geological and attributable input data representation of the model, some gridblocks, from 12 to 28 in Y direction, are refined and divided into 170 fine grids. Thus, there are two types of gridblocks with dimensions 656 ft x 65.6 ft x 26.2 ft for fine grid and 656 ft x 820 ft x 26.2 ft for coarse grid, as represented in Figure 5.6:

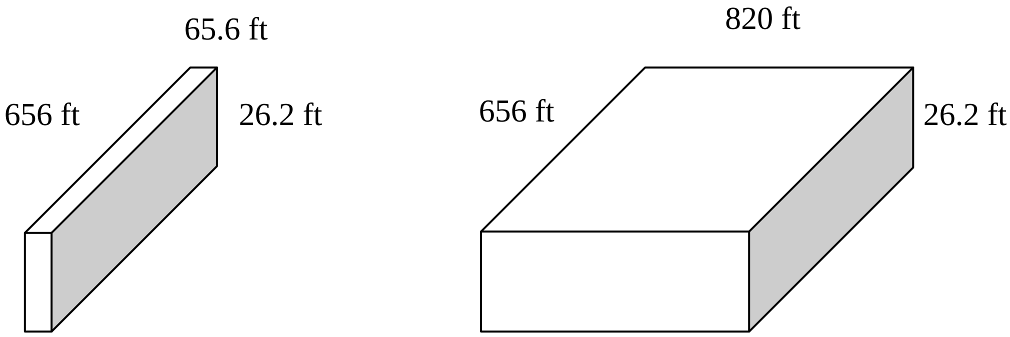

Figure 5. 6 Schematic views of gridblocks

In this model, initial pressure and saturation distribution set is provided from real core sample analysis, RFT and well test data obtained from the reservoir. This data are concluded in an equilibrium table which is used to relate each gridblock to the appropriate value. The simulator initializes to equilibrium conditions on the basis of data found in the equilibrium table. Thus initial pressure distribution is in range from 4060 psi to 6961 psi (280 – 480 Bar) in Figure 5.7 and permeability, porosity and saturation distribution in X, Y and Z direction is shown in the Figures (5.8 -5.10):

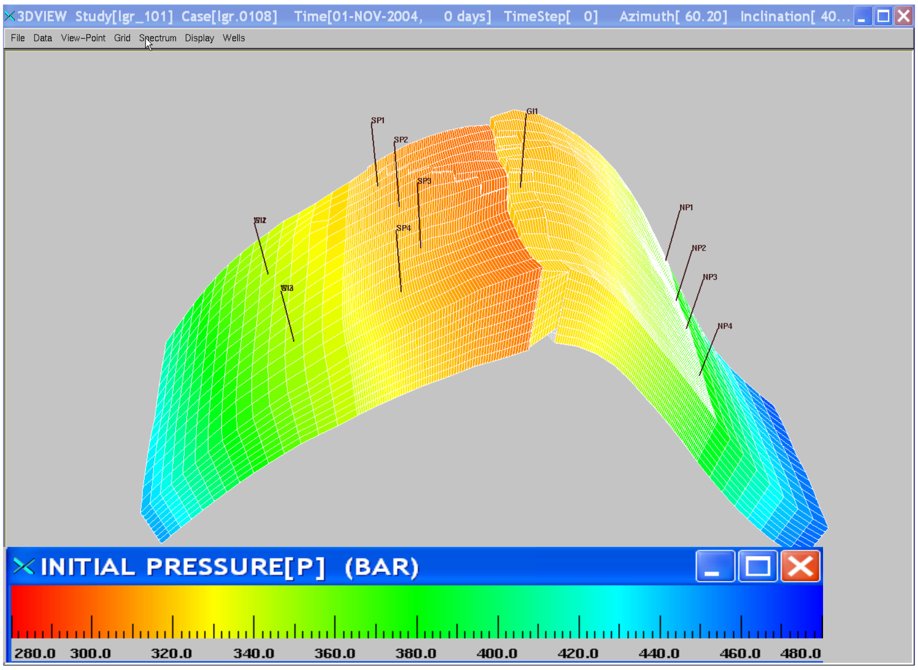

Figure 5. 7 Initial pressure distributions

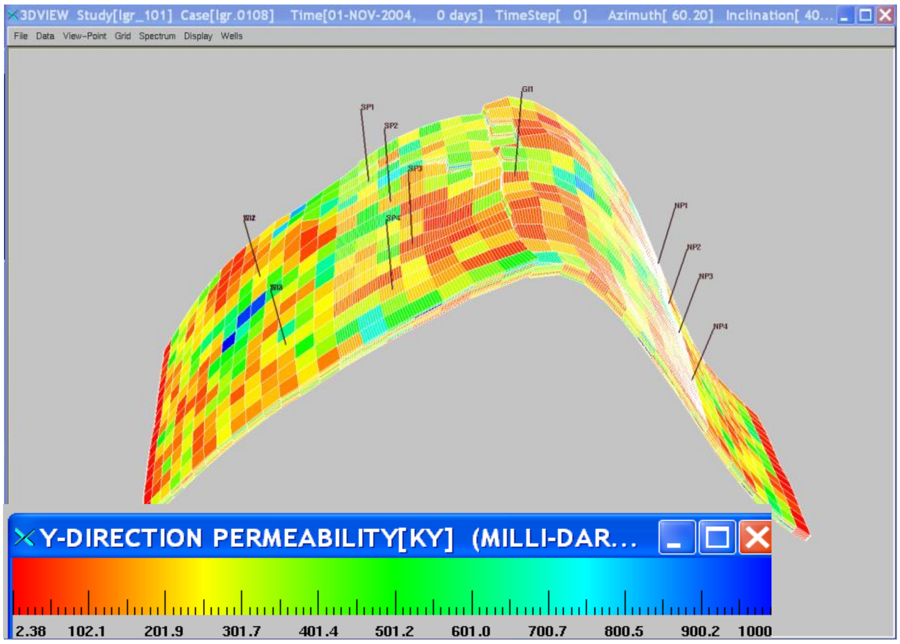

Figure 5. 8 Permeability distribution in X and Y direction

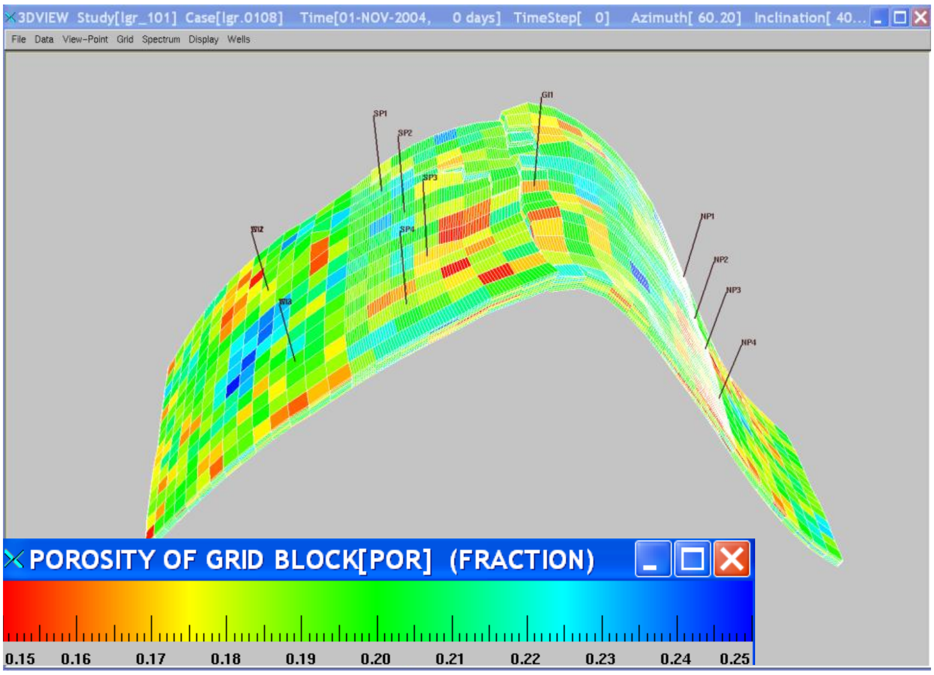

Figure 5. 9 Porosity distribution

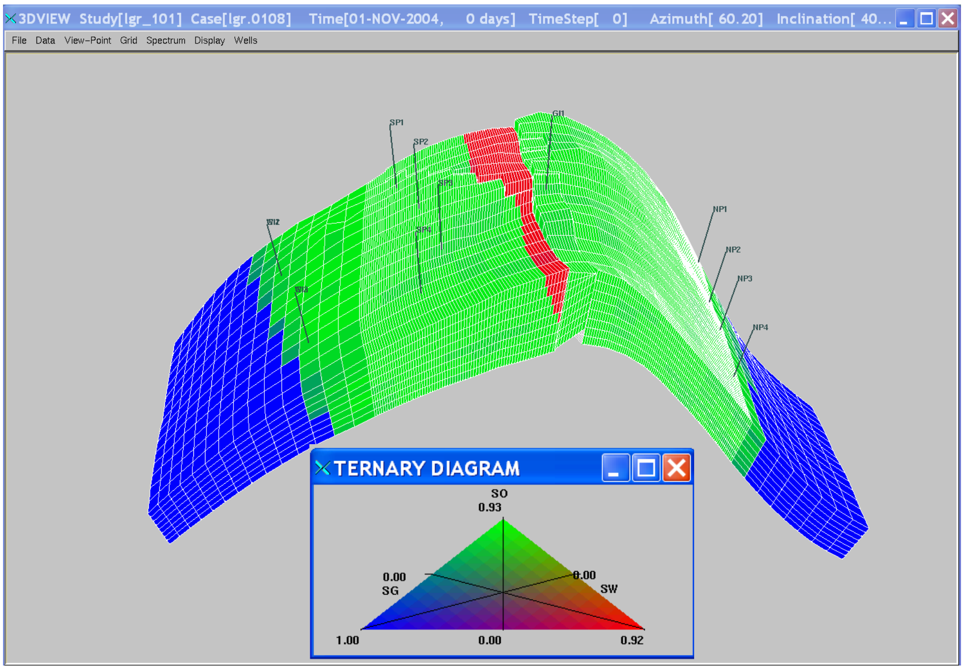

Figure 5. 10 Ternary Diagram (So, Sw, Sg saturations)

Water and gas saturation data of this model versus relative permeability to water, gas and oil is given in the Figures 5.11 – 5.12:

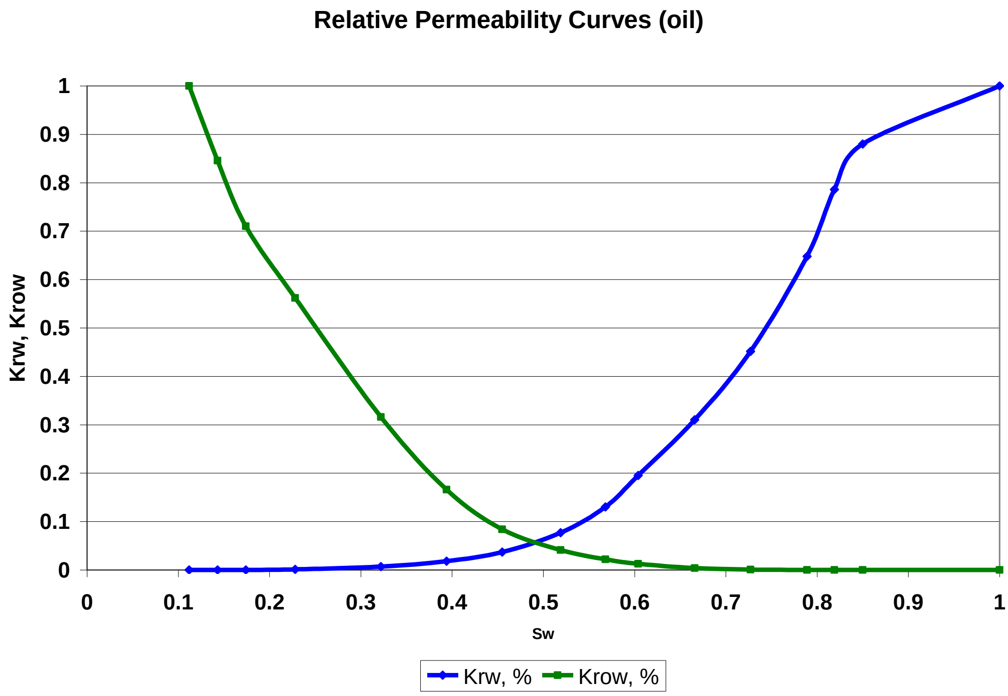

Figure 5. 11 Water saturation versus relative permeability to water and oil

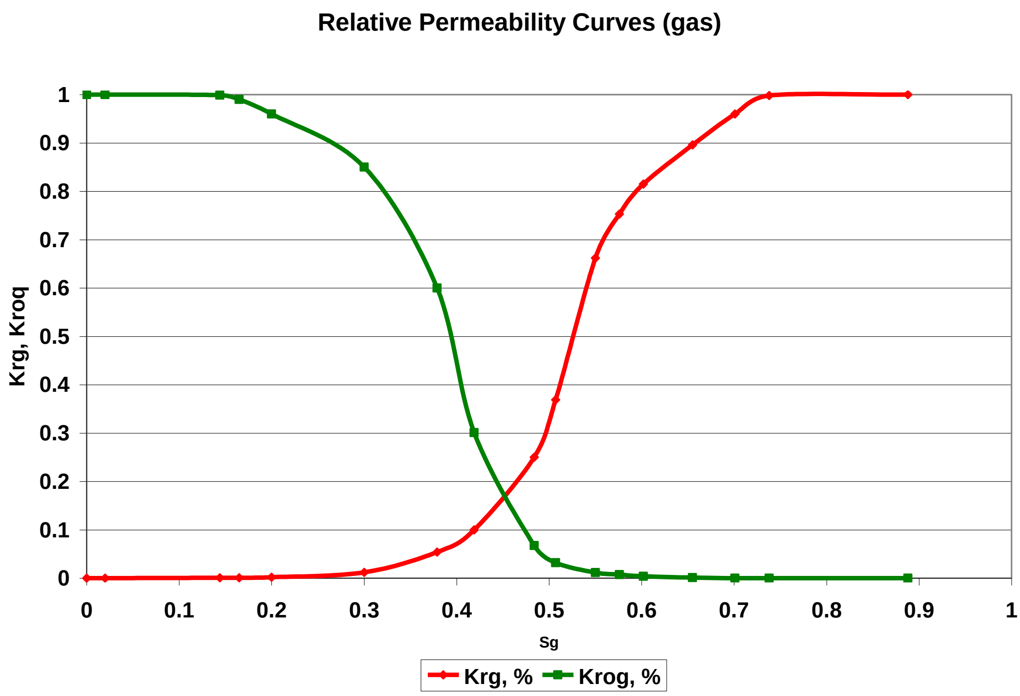

Figure 5. 12 Gas saturation versus relative permeability to gas and oil

5.2.2 Base case performance description

Central part of the Azeri field can be divided into two parts, North flank and South Flank. South Flank of the Central Azeri was chosen as the main interest zone for this research work (Figure 5.13). The reason for this was the injecting ability from the currently installed topsides on this part of Azeri field. There are two water injectors and four producers simulated in this region of the sector model. This is inline with the current reservoir depletion strategy of the Azeri field. The two water injection wells initially started preproduction in 2005 with initial oil rate of 11733 STB/day. This pre-production lasted two years. In the beginning of 2007 these wells were converted to water injectors. The maximum water injection rate of these wells was 46,350 STB/day.

South Flank producers SP1, SP2, SP3, and SP4 started to produce in 2007 with assigned maximal production rate of 55 MSTB/day. Production profiles for the base case are illustrated in Figures 5.14 – 5.16 for overall South Flank region and separately for individual wells in Figures 5.17 – 5. 31. Thus, the Central Azeri South Flank region produced 134 MMSTB, with 40 MMSTB, 36 MMSTB, 27 MMSTB, 18 MMSTB for SP1, SP2, SP3, SP4 wells and 6.9 MMSTB and 6.7 MMSTB per injection wells in preproduction periods respectively. Initial production rates for wells were 29761.1 STB/day, 24331.6 STB/day, 23168.7 STB/day, and 20489.4 STB/day for SP1, SP2, SP3, and SP4 respectively, whereas abandonment rates of each well were 803.8 STB/day, 1087.4 STB/day, 4275.1 STB/day and 3812.9 STB/day. Even though all wells started to produce in 2007, shut in for wells was different: SP1 in 2016, SP2 in 2015, SP3 in 2012 and SP4 in 2010. The reason for that was exceeding of water cut limit of 95 %. Cumulative water injection is 229326.9 MSTB for WI1 and 229555.6 MSTB for WI2. Instantaneous GOR limit of 10000 SCF/STB is reached very slowly in two wells, SP 2 and SP3. Sector’s initial reservoir pressure is 4330 Psi with the end pressure 8700 Psi. The reason for such increase of pressure is that the producing wells are closed and injectors are still injecting due to model’s characteristic. Ultimate recovery factor for the region is 52.3 %. This case is the base case for comparing all the following scenarios for WAG applications.

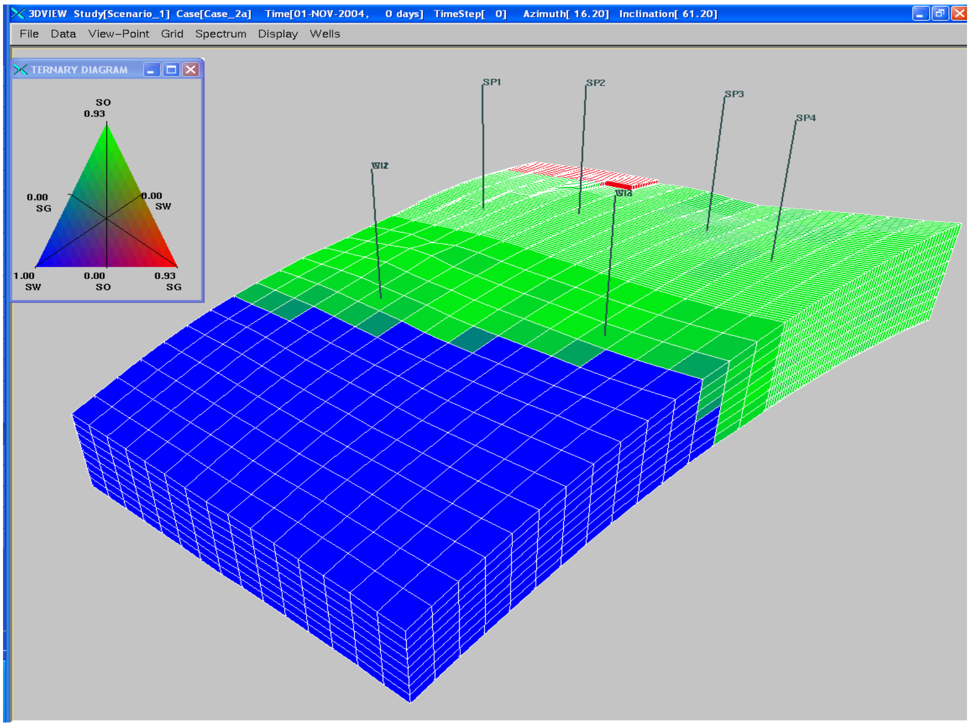

Figure 5. 13 South Flank of Central Azeri sector model with injector and production wells.

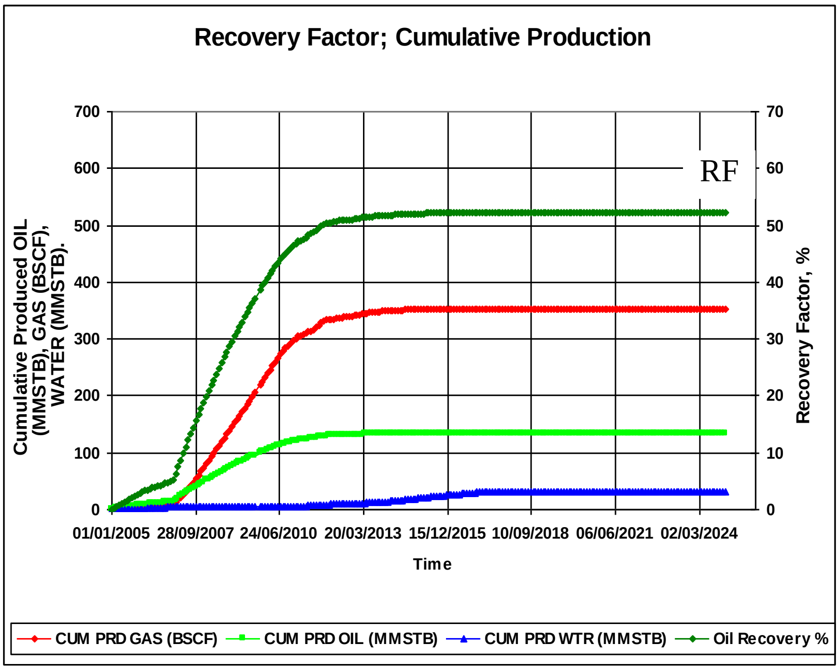

Figure 5. 14 Recovery factor and Cumulative Production history for the Base Case of the South Flank region

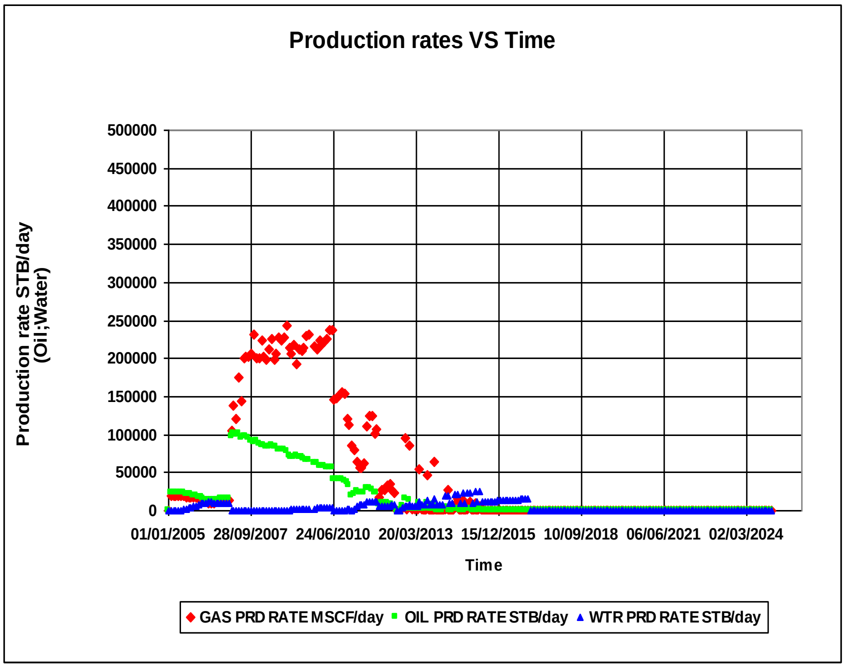

Figure 5. 15 Gas, oil, and water production rates for the Base Case of the South Flank region

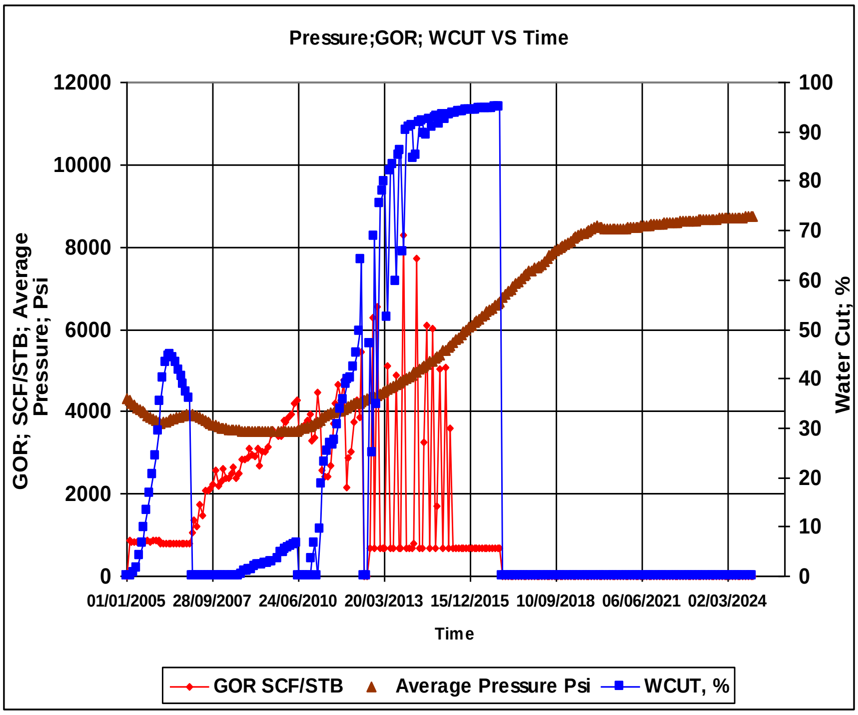

Figure 5. 16 Average Pressure, Water cut and GOR for the Base Case of the South Flank region

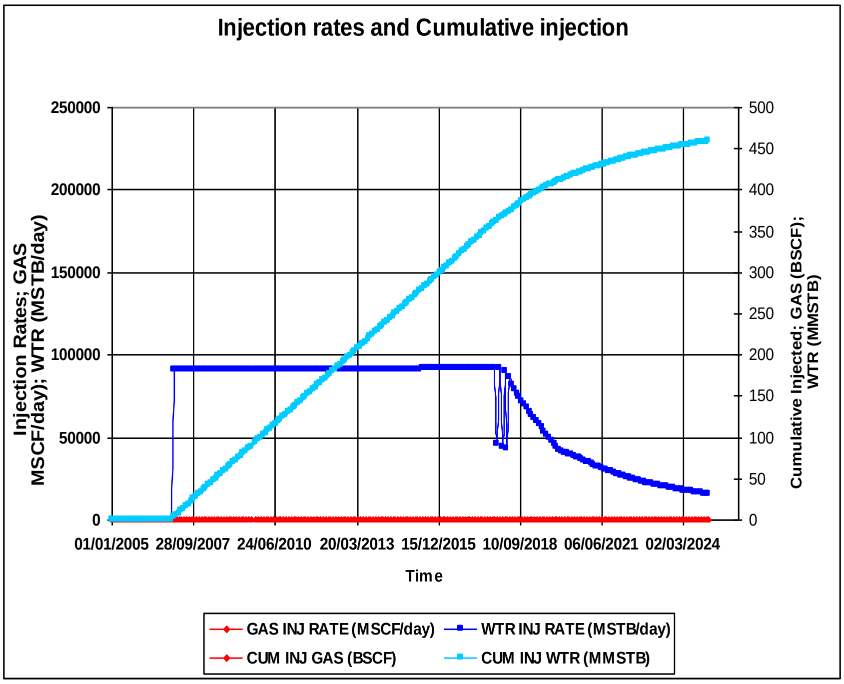

Figure 5. 17 Injection Rates and Cumulative Injection for Base Case of the South Flank region

SP1

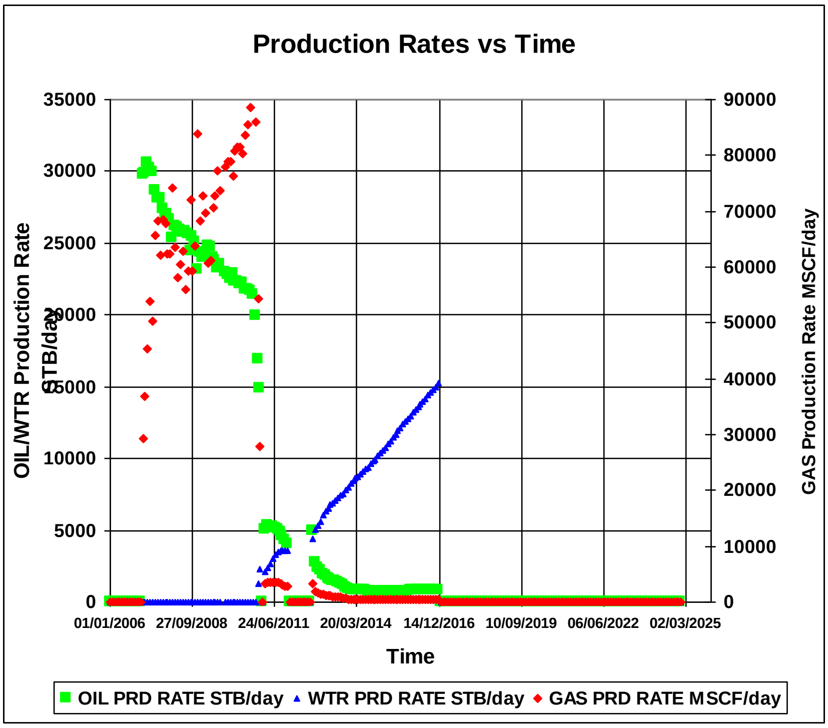

Figure 5. 18 Gas, Oil, Water Production rates for SP1 well of the Base Case

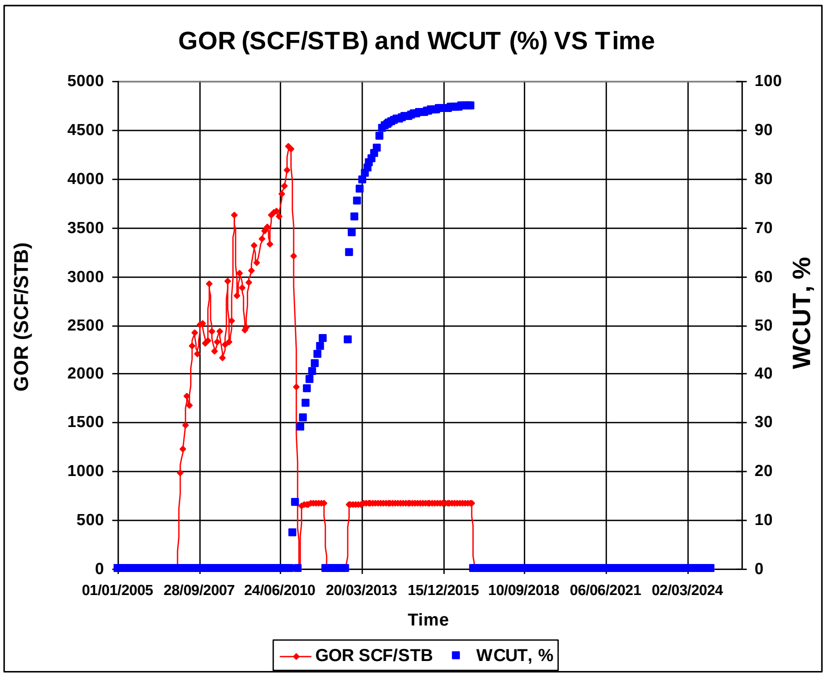

Figure 5. 19 GOR and Water cut for SP1 well of the Base Case

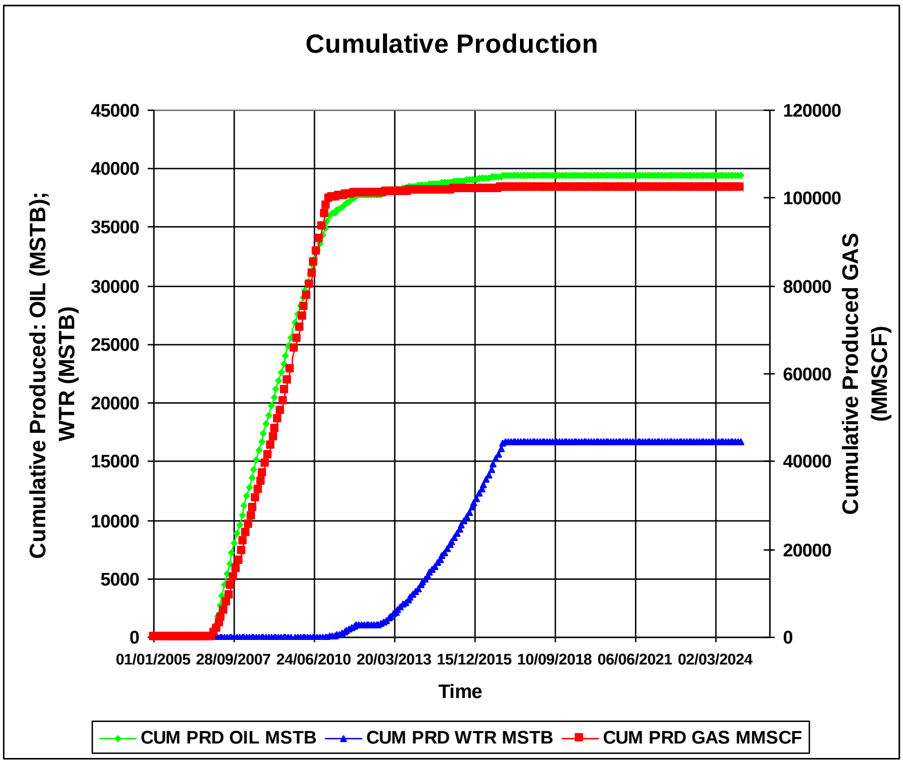

Figure 5. 20 Cumulative Produced Gas, Oil, and Water from SP1 well of the Base Case

SP2

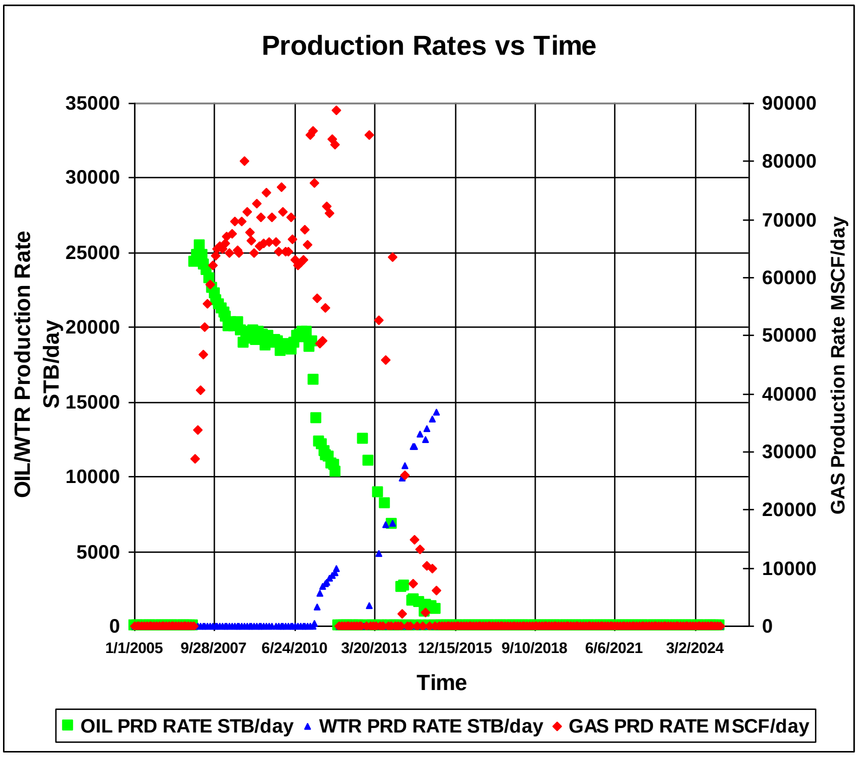

Figure 5. 21 Gas, Oil, Water Production rates for SP2 well of the Base Case

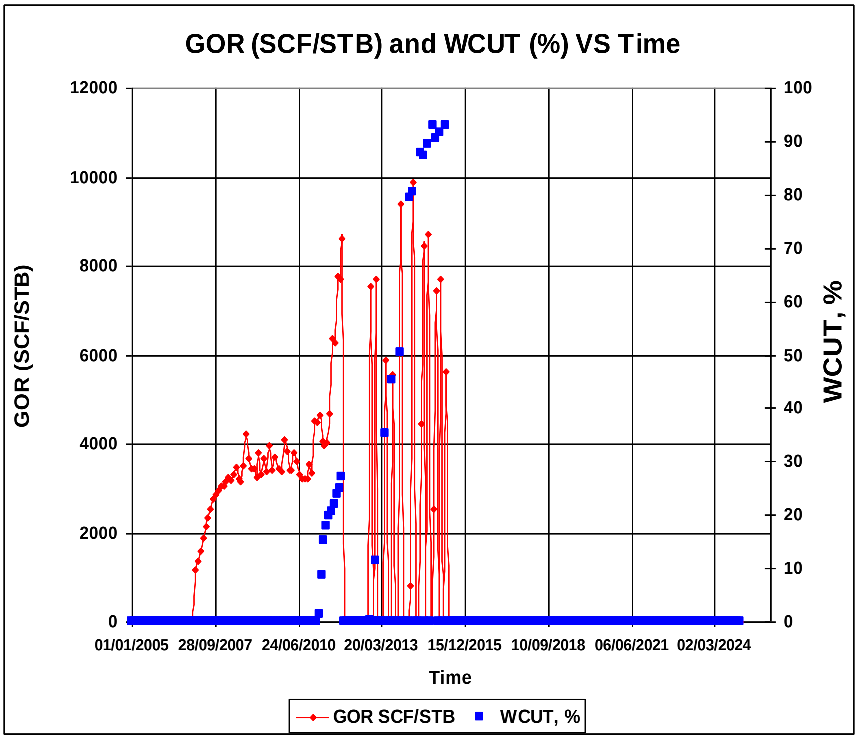

Figure 5. 22 GOR and Water cut for SP2 well of the Base Case

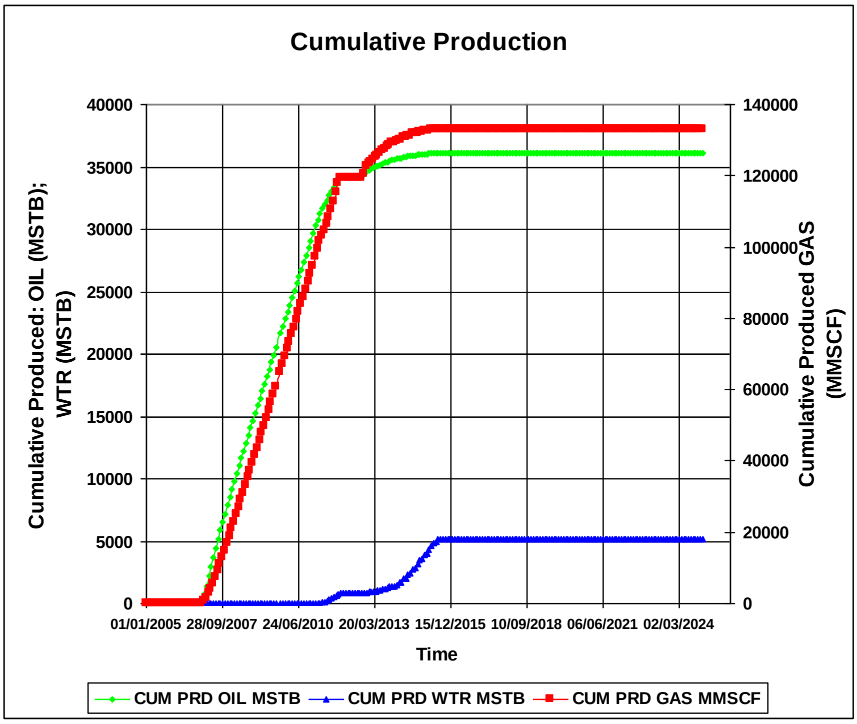

Figure 5. 23 Cumulative Produced Gas, Oil, and Water from SP2 well of the Base Case

SP3

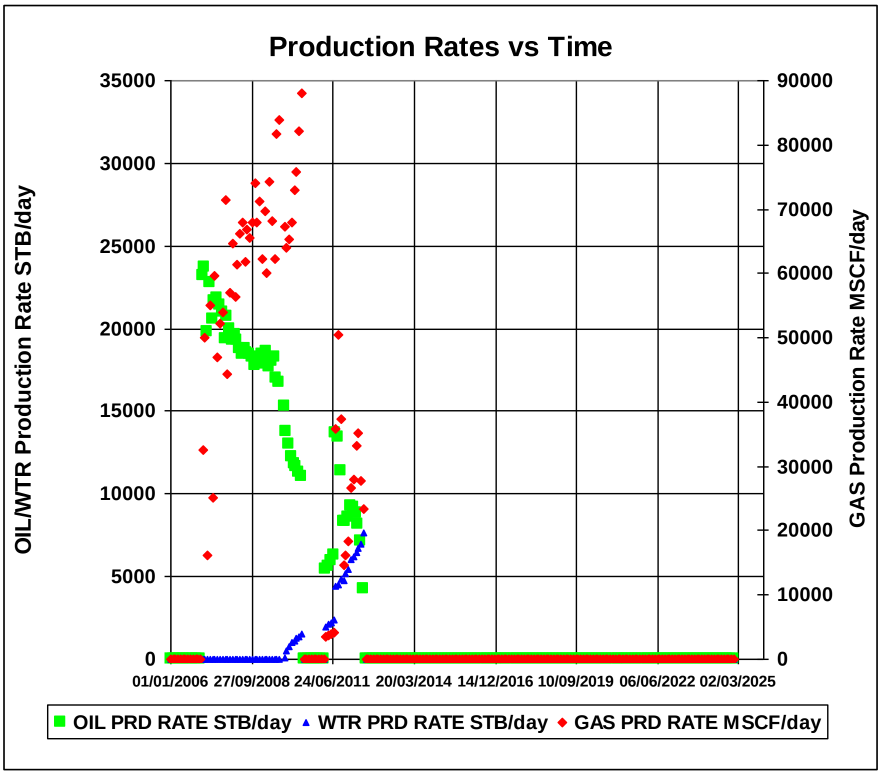

Figure 5. 24 Gas, Oil, Water Production rates for SP3 well of the Base Case

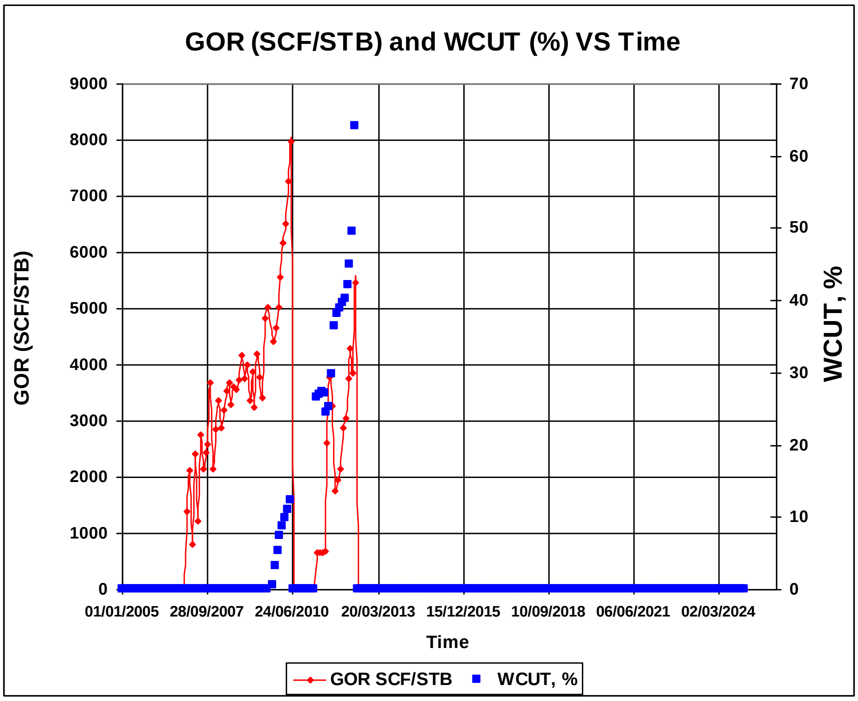

Figure 5. 25. GOR and Water cut for SP3 well of the Base Case

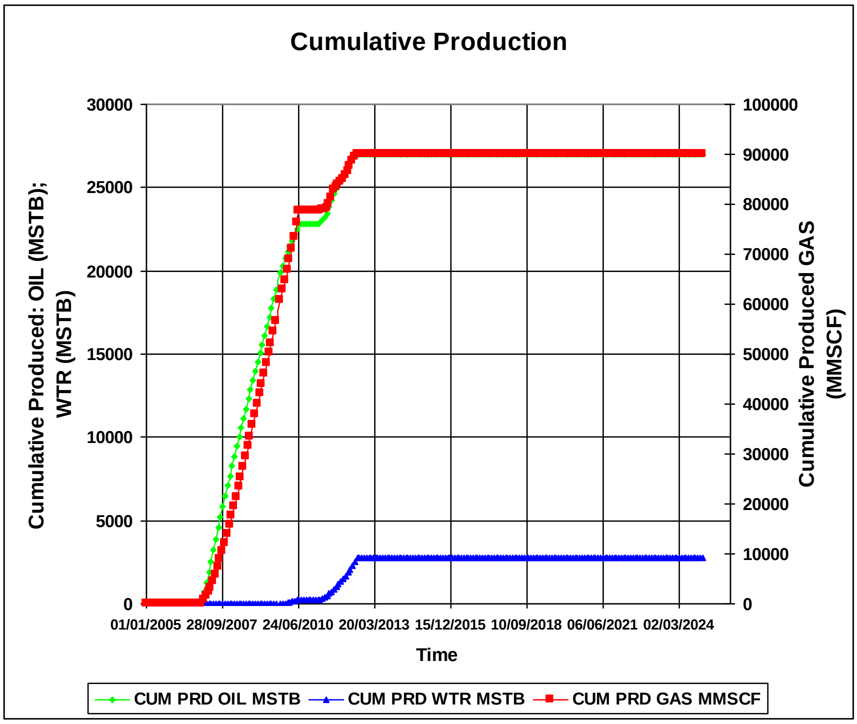

Figure 5. 26 Cumulative Produced Gas, Oil, and Water from SP3 well of the Base Case

SP4

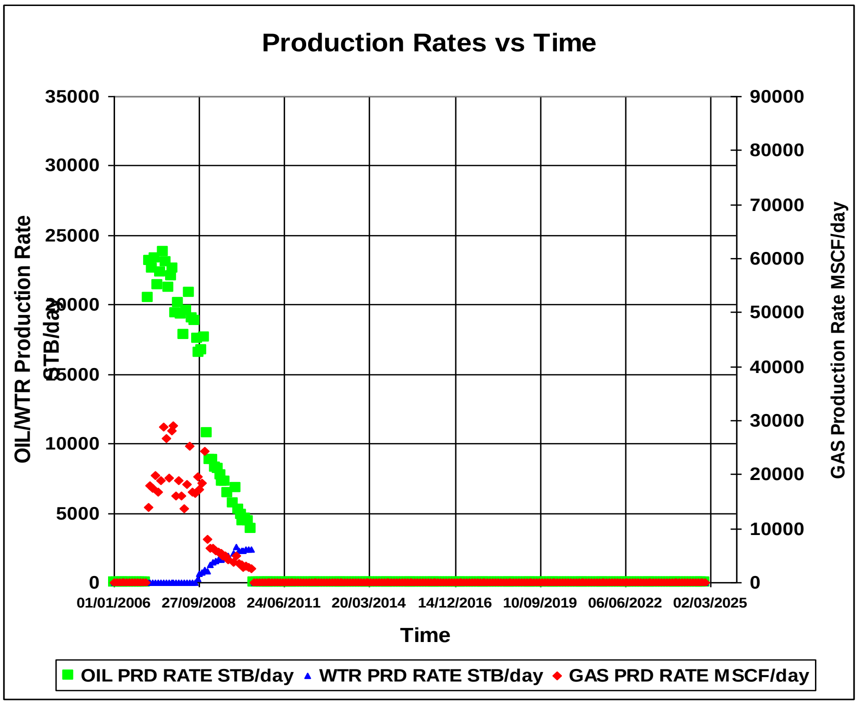

Figure 5. 27 Gas, Oil, Water Production rates for SP4 well of the Base Case

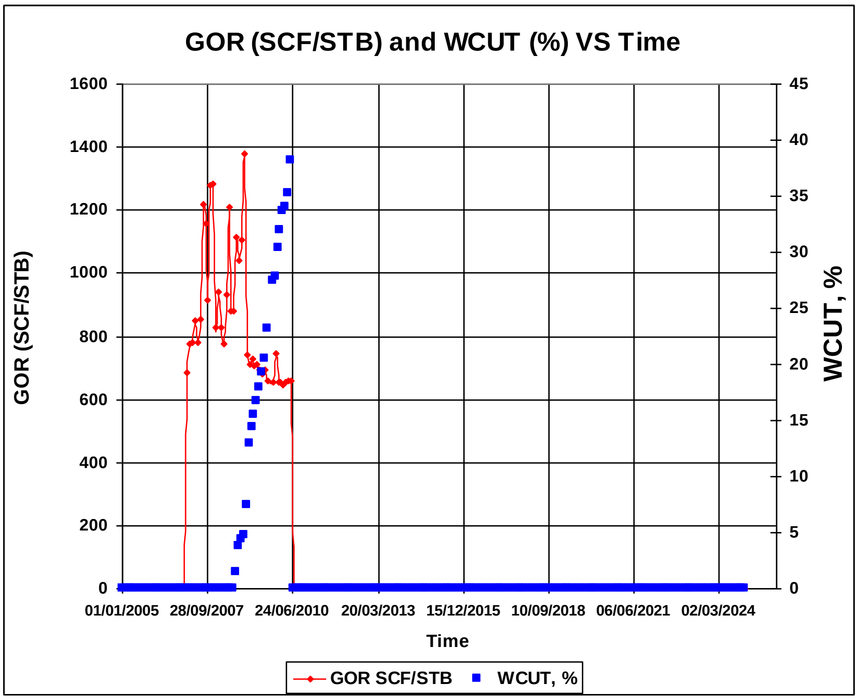

Figure 5. 28 GOR and Water cut for SP4 well of the Base Case

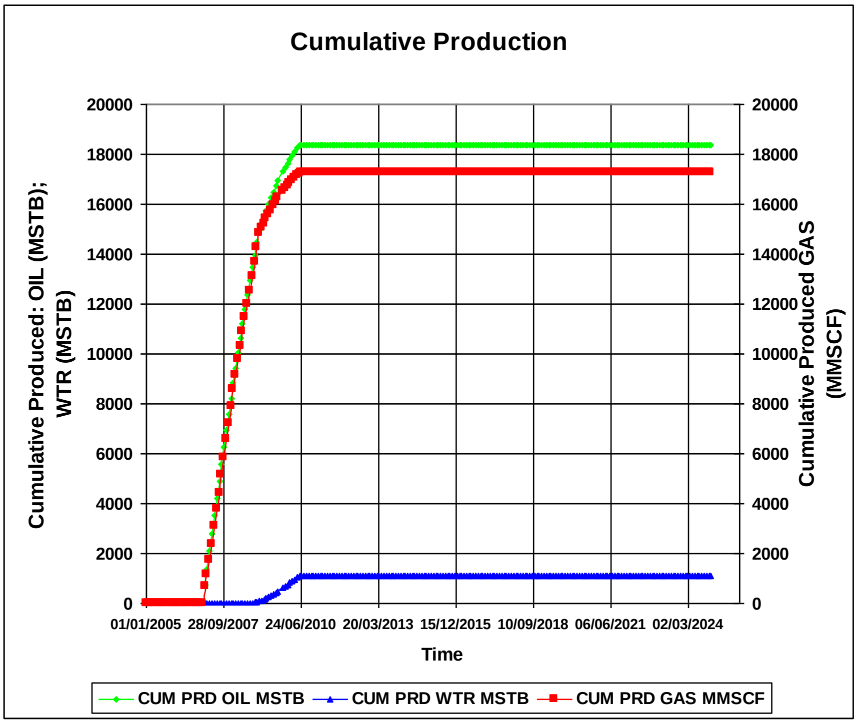

Figure 5. 29 Cumulative Produced Gas, Oil, and Water from SP4 well of the Base Case

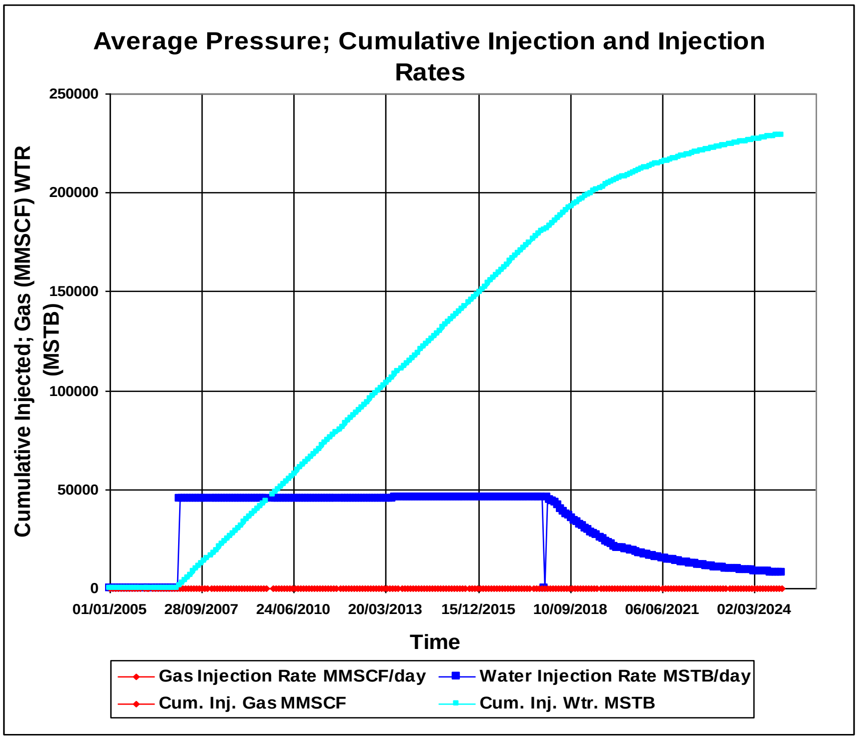

Figure 5. 30 Injection Rates and Cumulative Injection of WI1 well of Base Case

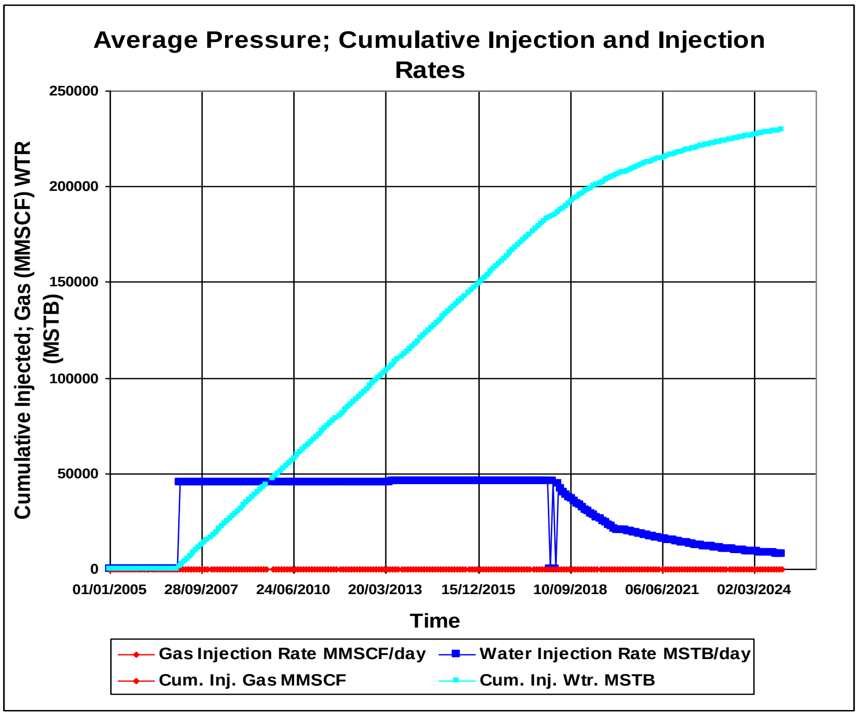

Figure 5. 31 Injection Rates and Cumulative Injection of WI2 well of Base Case

5.2.3 Sensitivity scenarios for WAG injection

In order to investigate the performance of WAG injection mechanisms in the South Flank part of Central Azeri, the Base Case has been changed from previous conventional water injection to WAG profile, injecting water and produced gas by determined slug sizes. As long as crestal gas re-injection was initially intended for production optimization of North Flank, the effect of it will be neglected in this work. For determination of optimal WAG profile for our reservoir, various sensitivity scenarios for WAG project implementation have been assigned. The differences between these scenarios are in WAG ratio, water and gas injected slug size, time periods between water and gas injection swap, initial start date of WAG project (29 scenarios started in 2009 and 29 scenarios in 2011), bottomhole pressures and number of cycles. The initial injection rates are chosen in accordance with availability and injection constraints of injected fluid. Hence, the initial injection rate for water and gas was 46 MSTB/day and 100 MMSCF/day respectively. Thus, slug size volume of 1, 2, 3, 4, 6% HCPV per cycle is intended to inject with different ratios, cycles, bottomhole pressures and volumes. Slug volumes and cycle numbers are chosen so that WAG injection period doesn't exceed beyond 2020 due to the wells life. The set of scenarios with these parameters are included in the Table 5.1.

Table 5. 1 Sensitivity scenarios with different WAG parameters

Case	WAG start	WAG end	WI rate; MSTB/d	GI rate; MMSCF/d	WI period, month	GI period, month	Cycles	WI BHP, Psi	WAG Slug Size Ratio	WAG Period Ratio	Cum. Gas Inj. Per cycle; BSCF	Fraction of HCPV of Gas per cycle; %	Cum. Wtr. Inj. Per cycle; MMSTB
Scenario1	2011	2019	46	50	12	4	6	9425	1:1	3:1	6	2	18
Scenario2	2011	2019	46	50	12	12	4	9425	1:1	1:1	18	6	18
Scenario3	2009	2020	46	50	12	4	8	9425	1:1	3:1	6	2	18
Scenario4	2009	2019	46	50	12	12	5	9425	1:1	1:1	18	6	18
Scenario5	2011	2020	46	50	24	4	4	9425	1:1	6:1	6	2	36
Scenario6	2009	2018	46	50	24	4	4	9425	1:1	6:1	6	2	36
Scenario7	2011	2019	46	100	12	4	6	9425	1:2	3:1	12	4	18
Scenario8	2009	2020	46	100	12	4	8	9425	1:2	3:1	12	4	18
Scenario9	2011	2020	46	100	24	4	4	9425	1:2	6:1	12	4	36
Scenario10	2009	2018	46	100	24	4	4	9425	1:2	6:1	12	4	36
Scenario11	2011	2019	15	25	12	4	6	9425	0.6:1	3:1	3	1	5
Scenario12	2011	2019	23	50	12	4	6	9425	0.5:1	3:1	6	2	9
Scenario13	2009	2017	15	25	12	4	6	9425	0.6:1	3:1	3	1	5
Scenario14	2009	2020	23	50	12	4	8	9425	0.5:1	3:1	6	2	9
Scenario15	2011	2019	15	25	12	12	4	9425	0.6:1	1:1	9	3	5
Scenario16	2011	2019	23	50	12	12	4	9425	0.5:1	1:1	18	6	9
Scenario17	2009	2019	15	25	12	12	5	9425	0.6:1	1:1	9	3	5
Scenario18	2009	2019	23	50	12	12	5	9425	0.5:1	1:1	18	6	9
Scenario19	2011	2020	23	50	24	4	4	9425	0.5:1	6:1	6	2	18
Scenario20	2009	2018	23	50	24	4	4	9425	0.5:1	6:1	6	2	18
Scenario21	2011	2019	23	50	6	6	8	6525	0.5:1	1:1	9	3	5
Scenario22	2011	2019	23	50	6	6	8	9425	0.5:1	1:1	9	3	5

Table 5.1 (Continued)

Case	WAG start	WAG end	WI rate; MSTB/d	GI rate; MMSCF/d	WI period, month	GI period, month	Cycles	BHP, Psi	WAG Slug Size Ratio	WAG Period Ratio	Cum. Gas Inj. Per cycle; BSCF	Fraction of HCPV of Gas per cycle; %	Cum. Wtr. Inj. Per cycle; MMSTB
Scenario23	2009	2019	23	50	6	6	10	6525	0.5:1	1:1	9	3	5
Scenario24	2009	2019	23	50	6	6	10	9425	0.5:1	1:1	9	3	5
Scenario25	2011	2019	23	50	6	3	10	6525	0.5:1	2:1	5	1	5
Scenario26	2011	2019	23	50	6	3	10	9512	0.5:1	2:1	5	1	5
Scenario27	2009	2017	23	50	6	3	10	6525	0.5:1	2:1	5	1	5
Scenario28	2009	2017	23	50	6	3	10	9541	0.5:1	2:1	5	1	5
Scenario29	2011	2019	23	50	12	6	5	6525	0.5:1	2:1	9	3	9
Scenario30	2011	2019	23	50	12	6	5	9570	0.5:1	2:1	9	3	9
Scenario31	2009	2018	23	50	12	6	6	9599	0.5:1	2:1	9	3	9
Scenario32	2009	2018	23	50	12	6	6	6525	0.5:1	2:1	9	3	9
Scenario33	2011	2019	23	25	12	4	6	9614	0.5:1	3:1	3	1	9
Scenario34	2011	2019	23	25	12	12	4	9440	1:1	1:1	9	3	9
Scenario35	2009	2020	23	25	12	4	8	9628	1:1	2:1	3	1	9
Scenario36	2009	2019	23	25	12	12	5	9454	1:1	1:1	9	3	9
Scenario37	2011	2020	23	25	24	4	4	9454	1:1	6:1	3	1	18
Scenario38	2009	2018	23	25	24	4	4	9454	1:1	6:1	3	1	18
Scenario39	2011	2019	23	100	12	4	6	9454	0.5:2	3:1	6	2	9
Scenario40	2009	2020	23	50	12	4	8	9454	0.5:1	3:1	6	2	9
Scenario41	2011	2019	23	50	12	12	4	9454	0.5:1	1:1	18	6	9
Scenario42	2009	2019	23	50	12	12	5	9454	0.5:1	1:1	18	6	9
Scenario43	2011	2020	23	50	24	4	4	9454	0.5:1	6:1	6	2	18
Scenario44	2009	2018	23	50	24	4	4	9454	0.5:1	6:1	6	2	18
Scenario45	2011	2019	11.5	25	12	4	6	9454	0.5:1	3:1	3	1	5

Table 5.1 (Continued)

Case	WAG start	WAG end	WI rate; MSTB/d	GI rate; MMSCF/d	WI period, month	GI period, month	Cycles	BHP, Psi	WAG Slug Size Ratio	WAG Period Ratio	Cum. Gas Inj. Per cycle; BSCF	Fraction of HCPV of Gas per cycle; %	Cum. Wtr. Inj. Per cycle; MMSTB
Scenario46	2009	2020	11.5	25	12	4	8	9454	0.5:1	3:1	3	1	5
Scenario47	2011	2019	11.5	25	12	12	4	9454	0.5:1	1:1	9	3	5
Scenario48	2009	2019	11.5	25	12	12	5	9454	0.5:1	1:1	9	3	5
Scenario49	2011	2020	11.5	25	24	4	4	9454	0.5:1	6:1	3	1	9
Scenario50	2009	2018	11.5	25	24	4	4	9454	0.5:1	6:1	3	1	9
Scenario51	2011	2020	11.5	25	24	4	3	9454	0.5:1	6:1	18	6	5
Scenario52	2009	2021	11.5	25	24	24	3	9454	0.5:1	1:1	18	6	9
Scenario53	2009	2019	46	100	6	6	10	9454	1:2	1:1	18	6	9
Scenario54	2011	2019	46	100	6	6	8	9454	1:2	1:1	18	6	9
Scenario55	2011	2019	15	25	6	6	8	9454	0.6:1	1:1	4.5	1	3
Scenario56	2009	2017	15	25	6	6	8	9454	0.6:1	1:1	4.5	1	3
Scenario57	2011	2019	15	25	24	24	2	9454	0.6:1	1:1	18	6	11
Scenario58	2009	2017	15	25	24	24	2	9454	0.6:1	1:1	18	6	11

CHAPTER 6

6. RESULTS AND DISCUSSIONS

In this section the results and analysis obtained from sector model simulations are compared with each other and the base case. Description of reservoir region's performance for some scenarios was given well by well. Tendencies of choosing inherent WAG injection strategies for this particular region and the best and the worst case examples are analyzed in detail. Special cases after general analysis are performed. Economical aspects of projects are also provided.

6.1 General view of simulation results

Table 6.1 presents recovery factors of different scenarios. According to the table below all WAG injection scenarios look beneficial in terms of incremental oil recovery in comparison to the Base Case. Figures 6.1 and 6.2 are the overview of scenarios started in 2009 and 2011 respectively. The results obtained from simulations are very close to those received from real operated with WAG fields – Prudhoe Bay – 5.2%, Daqing - 8.6%, Gulfaks, - 5%, Statfjord 13% etc. incremental oil recovery [3].

Table 6. 1 Recovery Factor and Incremental Oil Recovery values for each scenario

Case	**Recovery Factor, %**	**Incremental Oil Recovery, %**	**Fraction of HCPV of Gas per cycle; %**	**Total Fraction of HCPV injected, %**	**WAG Slug Size Ratio**	**WAG Period Ratio**
BaseCase	52.3	-	-	-	-	-
Scenario1	59.7	7.4	2	12	1:1	3:1
Scenario2	60.9	8.6	6	24	1:1	1:1
Scenario3	59.1	6.7	2	16	1:1	3:1
Scenario4	61.1	8.8	6	30	1:1	1:1
Scenario5	58.6	6.3	2	8	1:1	6:1
Scenario6	59.0	6.7	2	8	1:1	6:1
Scenario7	60.2	7.9	4	24	1:2	3:1

Table 6.1 (Continued)

Case	Recovery Factor, %	Incremental Oil Recovery, %	Fraction of HCPV of Gas per cycle; %	Total Fraction of HCPV injected, %	WAG Slug Size Ratio	WAG Period Ratio
Scenario8	60.5	8.2	4	32	1:2	3:1
Scenario9	59.5	7.2	4	16	1:2	6:1
Scenario10	60.3	8.0	4	16	1:2	6:1
Scenario11	58.6	6.2	1	6	0.6:1	3:1
Scenario12	60.0	7.6	2	12	0.5:1	3:1
Scenario13	58.6	6.3	1	6	0.6:1	3:1
Scenario14	60.5	8.2	2	16	0.5:1	3:1
Scenario15	58.1	5.8	3	12	0.6:1	1:1
Scenario16	59.3	6.9	6	24	0.5:1	1:1
Scenario17	59.9	7.6	3	15	0.6:1	1:1
Scenario18	60.0	7.7	6	30	0.5:1	1:1
Scenario19	60.3	7.9	2	8	0.5:1	6:1
Scenario20	59.2	6.9	2	8	0.5:1	6:1
Scenario21	58.3	6.0	3	24	0.5:1	1:1
Scenario22	58.3	6.0	3	24	0.5:1	1:1
Scenario23	59.7	7.4	3	30	0.5:1	1:1
Scenario24	59.7	7.4	3	30	0.5:1	1:1
Scenario25	58.1	5.8	1	15	0.5:1	2:1
Scenario26	58.2	5.9	1	15	0.5:1	2:1
Scenario27	59.3	7.0	1	15	0.5:1	2:1
Scenario28	59.3	7.0	1	15	0.5:1	2:1
Scenario29	58.1	5.8	3	15	0.5:1	2:1
Scenario30	58.1	5.8	3	15	0.5:1	2:1
Scenario31	59.6	7.3	3	18	0.5:1	2:1
Scenario32	59.6	7.3	3	18	0.5:1	2:1
Scenario33	58.8	6.5	1	6	0.5:1	3:1
Scenario34	59.1	6.7	3	12	1:1	1:1
Scenario35	59.4	7.0	1	8	1:1	2:1
Scenario36	59.0	6.7	3	15	1:1	1:1
Scenario37	58.5	6.1	1	4	1:1	6:1
Scenario38	59.3	7.0	1	4	1:1	6:1
Scenario39	60.1	7.8	2	12	0.5:1	3:1
Scenario40	60.1	7.8	2	16	0.5:1	3:1
Scenario41	57.9	5.6	6	24	0.5:1	1:1
Scenario42	60.8	8.5	6	30	0.5:1	1:1
Scenario43	56.9	4.6	2	8	0.5:1	6:1
Scenario44	59.6	7.3	2	8	0.5:1	6:1
Scenario45	59.3	7.0	1	6	0.5:1	3:1
Scenario46	59.6	7.3	1	8	0.5:1	3:1
Scenario47	58.8	6.5	3	12	0.5:1	1:1
Scenario48	57.6	5.3	3	15	0.5:1	1:1
Scenario49	58.5	6.2	1	4	0.5:1	6:1
Scenario50	58.7	6.4	1	4	0.5:1	6:1
Scenario51	59.5	7.2	6	3	0.5:1	6:1
Scenario52	55.7	3.4	6	18	0.5:1	1:1

Table 6.1 (Continued)

Case	Recovery Factor, %	Incremental Oil Recovery, %	Fraction of HCPV of Gas per cycle; %	Total Fraction of HCPV injected, %	WAG Slug Size Ratio	WAG Period Ratio
Scenario53	61.6	9.3	6	60	1:2	1:1
Scenario54	59.2	6.9	6	48	1:2	1:1
Scenario55	59.6	7.3	1	8	0.6:1	1:1
Scenario56	59.0	6.7	1	8	0.6:1	1:1
Scenario57	59.3	7.0	6	12	0.6:1	1:1
Scenario58	59.1	6.8	6	12	0.6:1	1:1

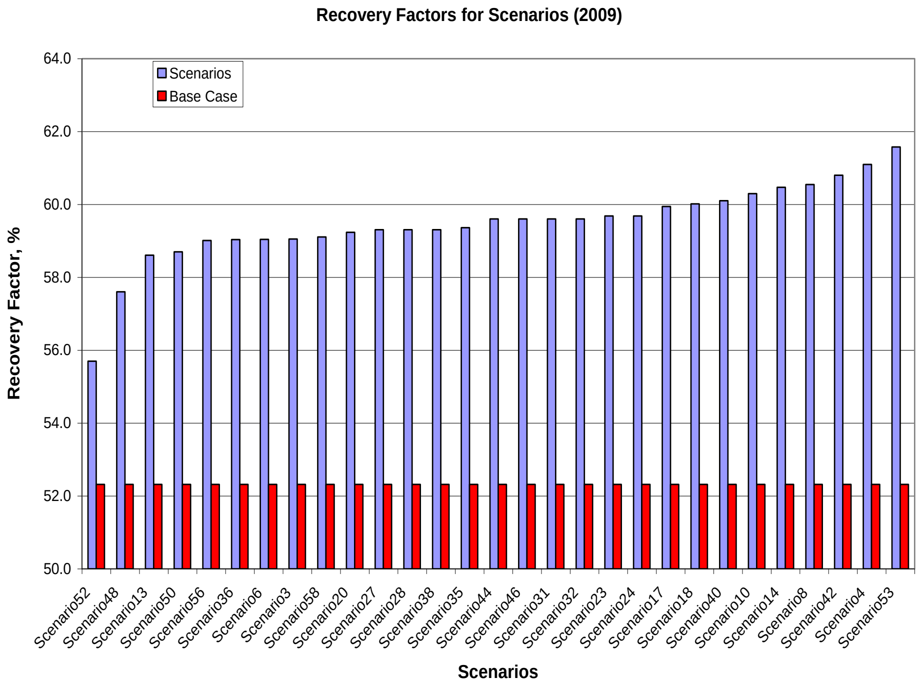

Figure 6. 1 Diagram of scenarios started in 2009

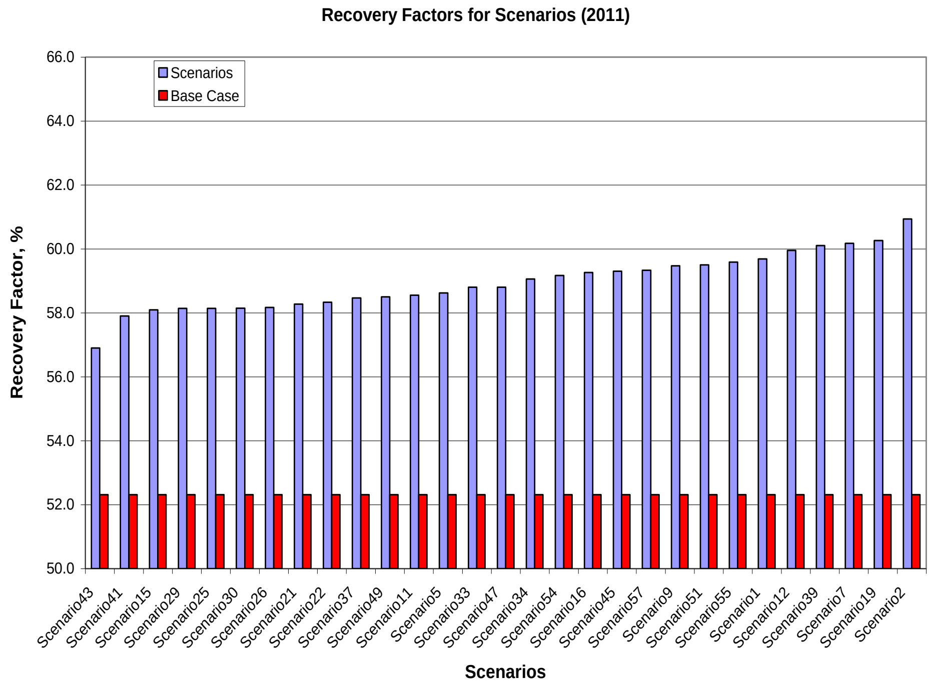

Figure 6. 2 Diagram of scenarios started in 2011

From Figures 6.1 and 6.2 and the tables 5.1 and 6.1 general picture of injection strategy is quite noticeable: WAG slug size ratios of 1:1 and 1:2 injecting higher fraction of HCPV per cycle with WAG injection period ratio of 1:1 no longer than 12 months both for water and gas per injection cycle is more favourable and economically advantageous from all other scenarios applied for our simulation model (e.g. Scenario2; Scenario4; Scenario53). Conditions for cycles are chosen in compliance with depletion plan, so that production from the field is completed by 2024. Studies show that starting WAG project earlier will give additional incremental recoveries, but by increasing gas injection volumes it is possible to achieve same recoveries (Scenario39 and Scenario40, Figures 6.3 – 6.10).

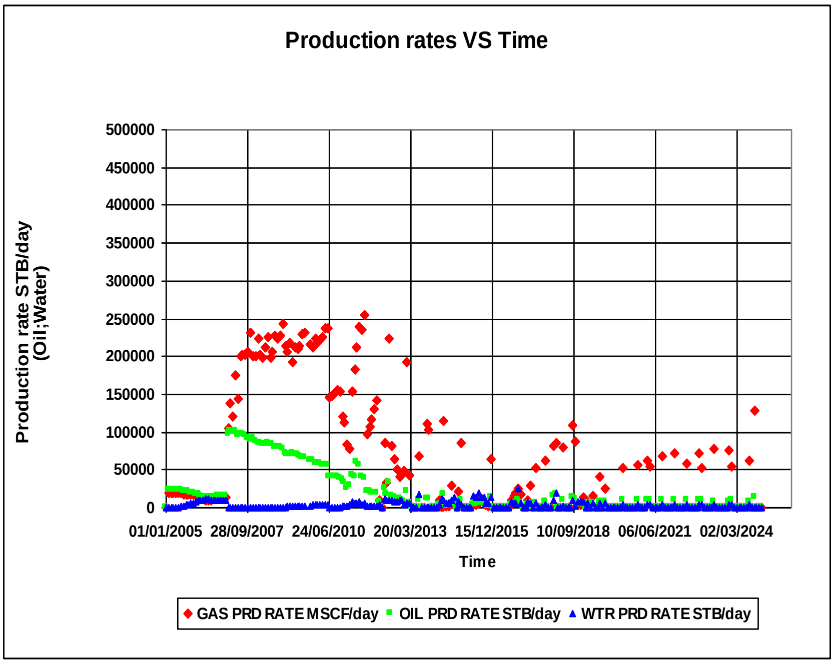

Figure 6. 3 Production Rates of Scenario 39 of South Flank Region

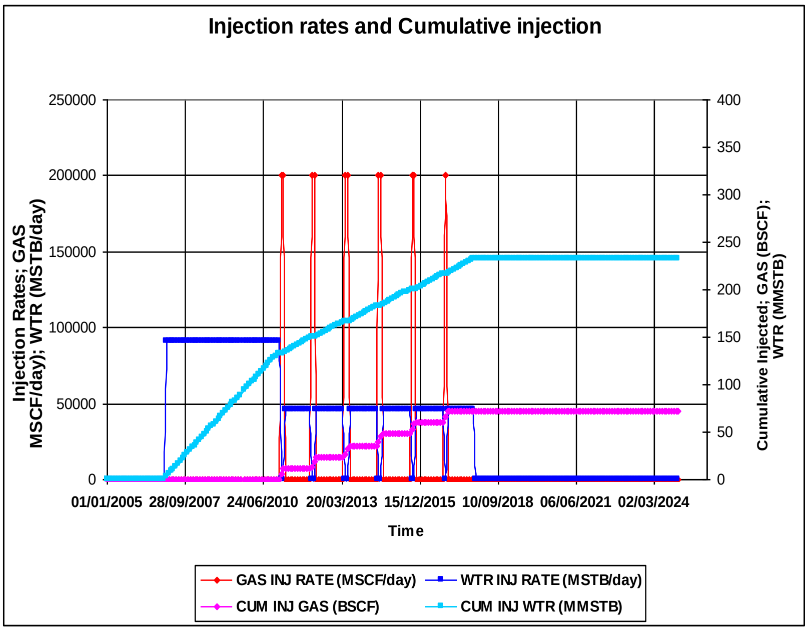

Figure 6. 4 Injection Rates and Cumulative Injection of Scenario 39 of South Flank Region

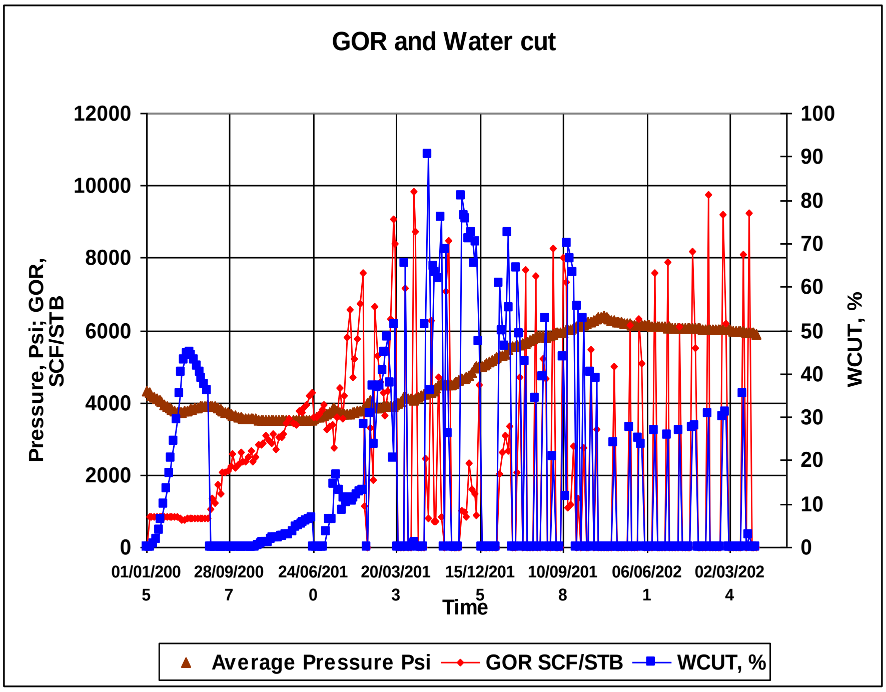

Figure 6. 5 Pressure GOR and Water Cut of Scenarios 39 of South Flank Region

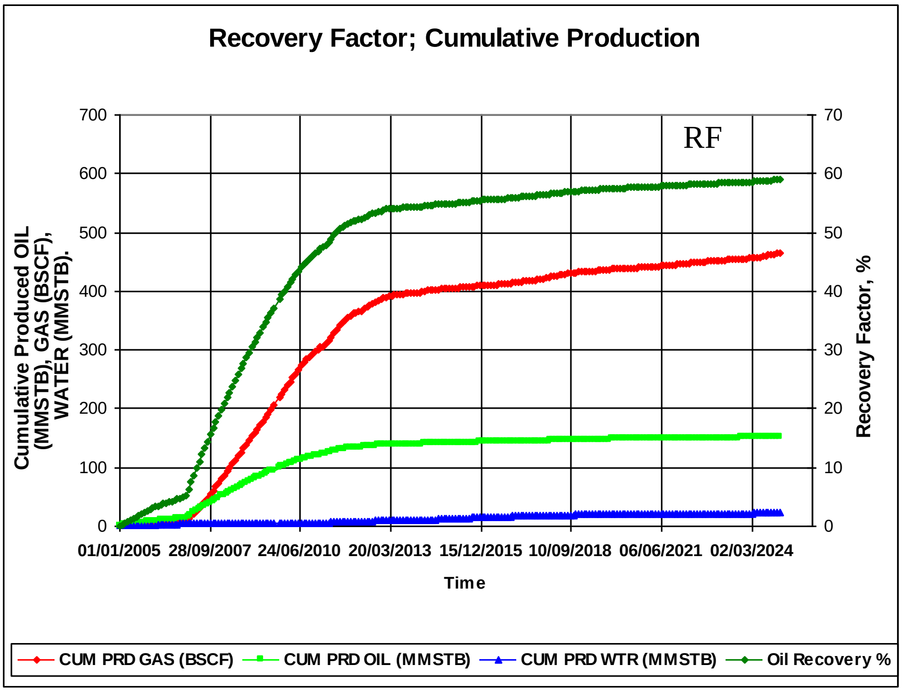

Figure 6. 6 Recovery Factor and Cumulative Production of Scenario 39 of South Flank Region

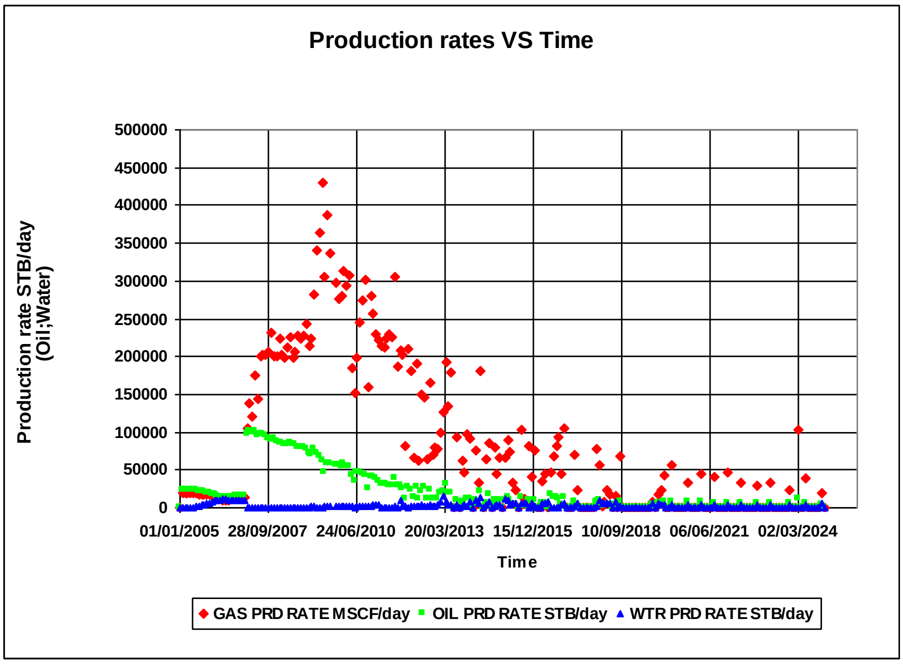

Figure 6. 7 Production Rates of Scenario 40 of South Flank Region

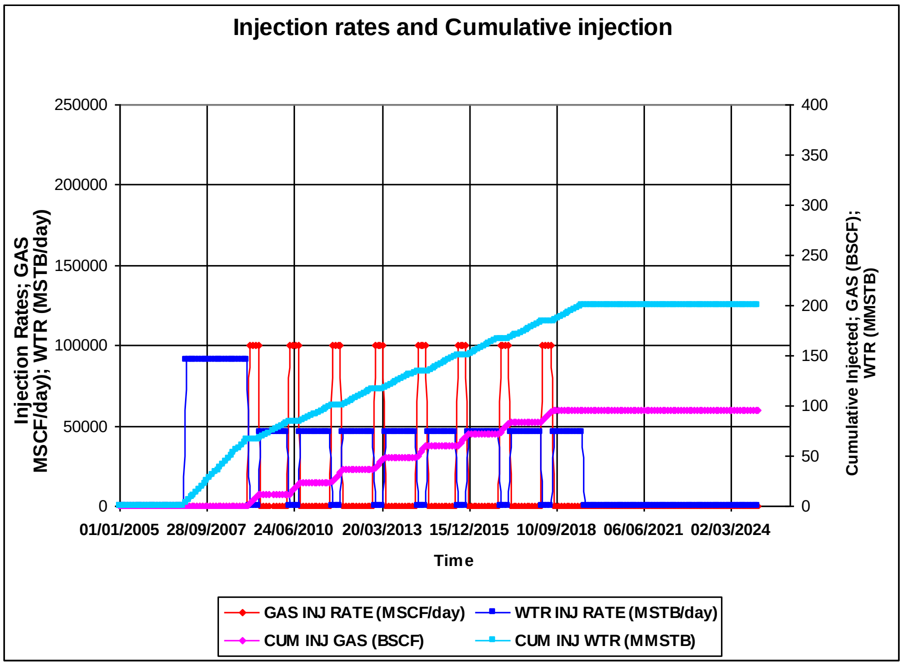

Figure 6. 8 Injection Rates and Cumulative Injection of Scenario 40 of South Flank Region

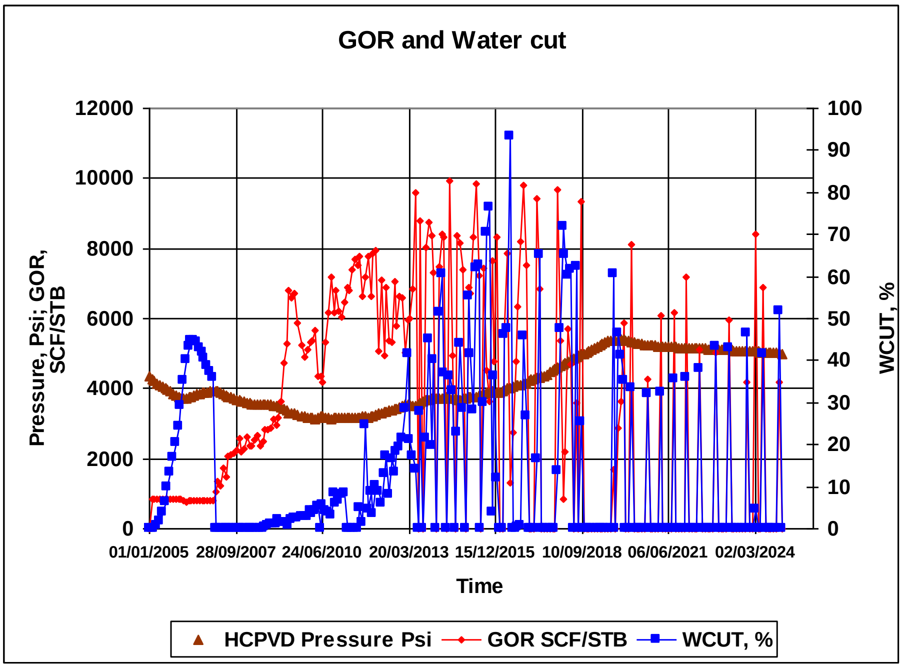

Figure 6. 9 Pressure GOR and Water Cut of Scenarios 40 of South Flank Region

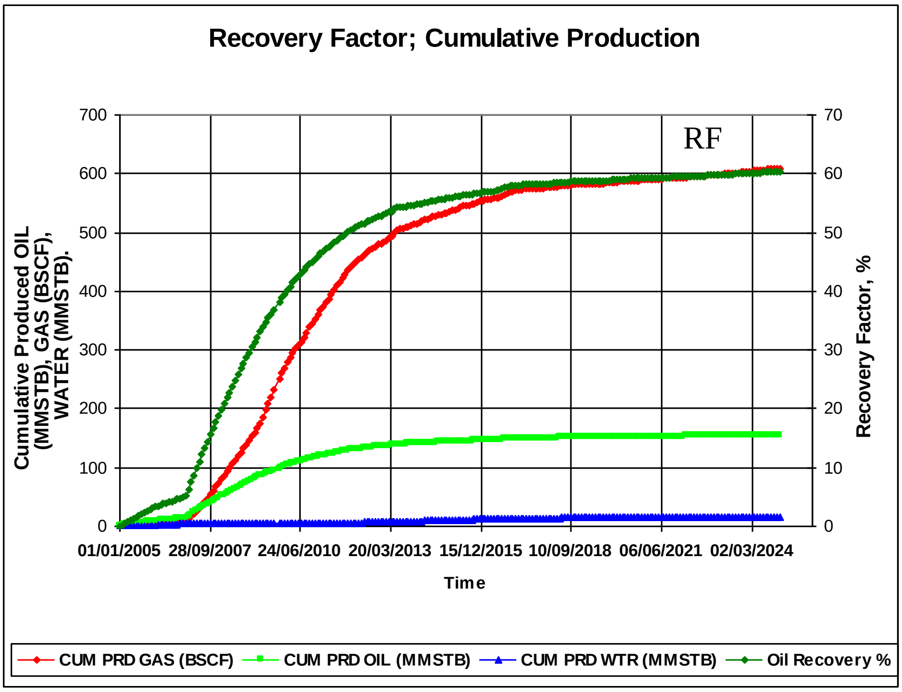

Figure 6. 10 Recovery Factor and Cumulative Production of Scenario 40 of South Flank Region

6.1.1 The Best and The Worst Case Scenarios

The case with the best result (61.6% recovery factor) of all runs performed is Scenario 53. In this case water and gas was injected with 46 MSTB/day of water injection rate and 100 MMSCF/day of gas injection rate. Injecting both water and gas for 12 months period per slug with 6% of total HCPV, generate 60% of total HCPV of gas injected after 10 cycles. Alternately cycling water and gas with these parameters, increase the lifetime of the produced region from 2015 to the end of production 2024 in comparison to the Base Case. Namely, cycling nature of WAG helps to deal with early water breakthrough better than in the Base Case and give favourable pressure support at the end of production.

Figures 6.11 and 6.12 show that gravity segregation has played expected role: gas rising to the top of a field displaces trapped oil and dense water settling into low structure areas can displace oil up to a producer. Instantaneous GOR reaches specified limit more often than in the Base Case, this GOR limit is assumed to be handled by platform facilities. Cumulative oil produced from South Flank region in the Scenario 53 is 158.1 MMSTB which is 24.1 MMSTB (9.3 %) more than in the Base Case (Figures 6.13-6.16). Cumulative gas injected is equal to 360 BSCF while water injected is 246.5 MMSTB.

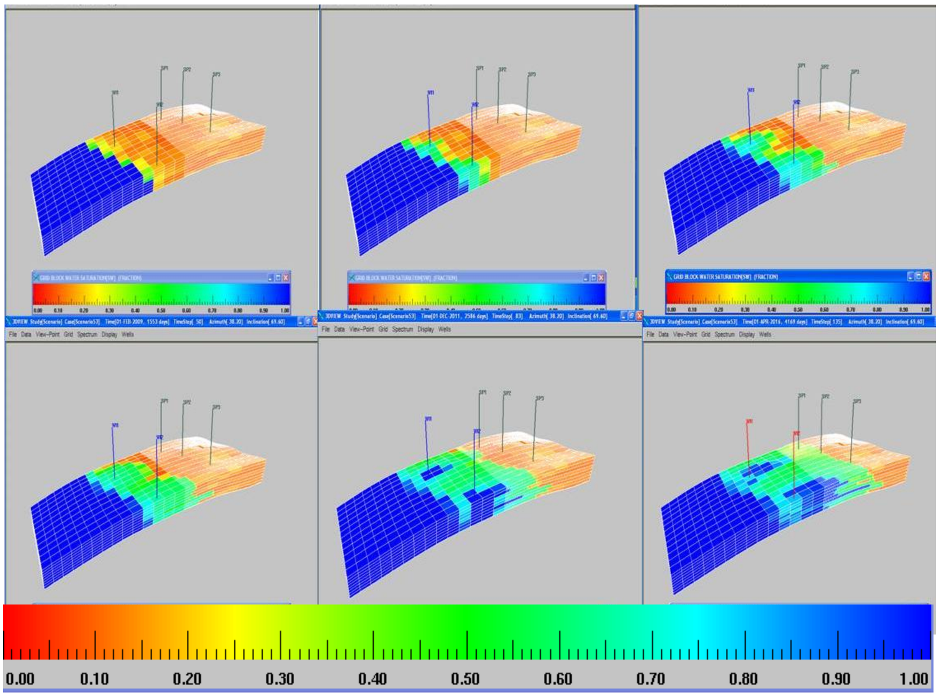

Figure 6. 11 Water saturation map showing down flow of water during injection for Scenario 53

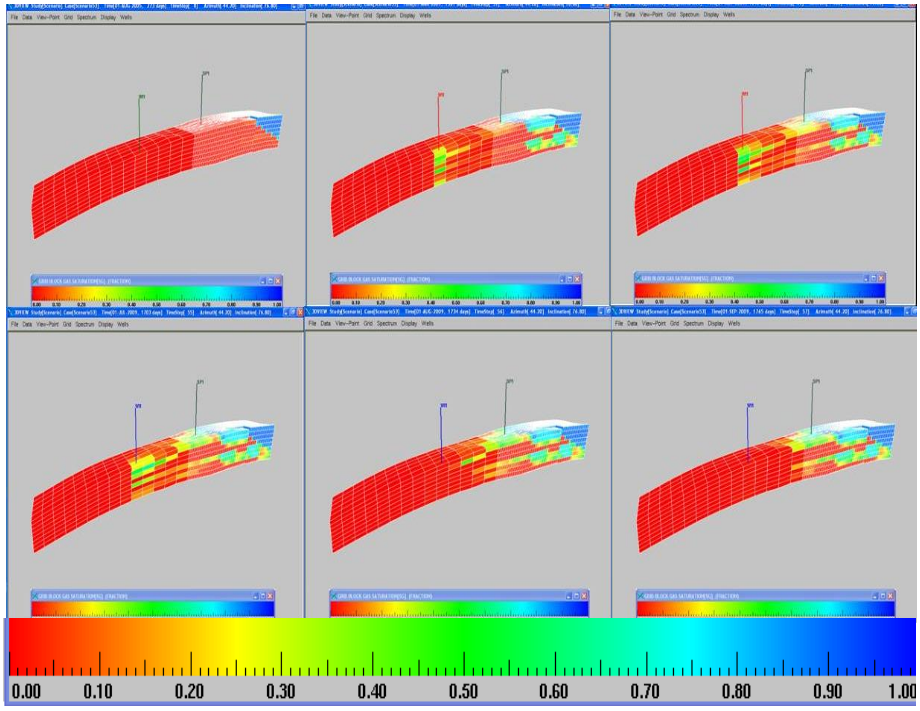

Figure 6. 12 Gas saturation map showing upper segregation of gas during injection for Scenario 53

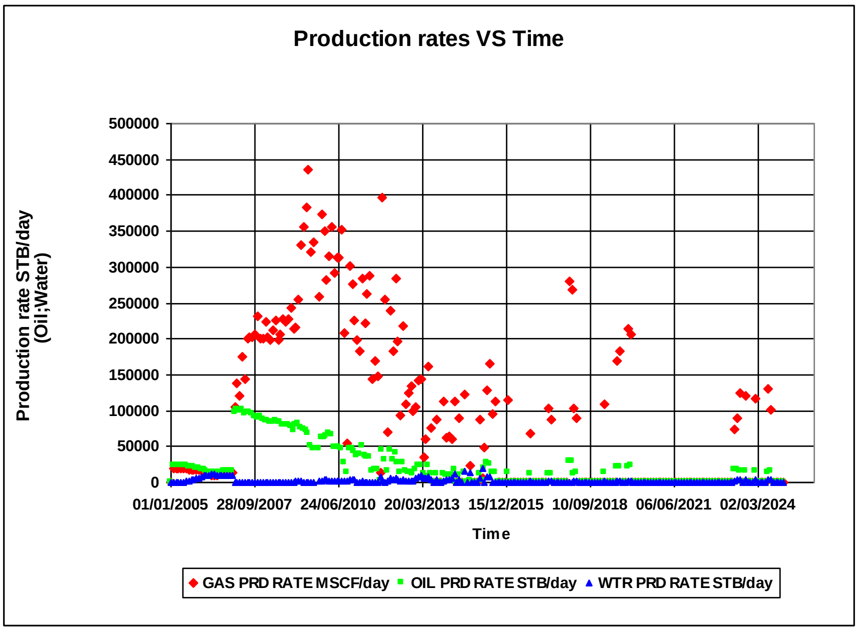

Figure 6. 13 Production Rates of Scenario 53 of South Flank Region

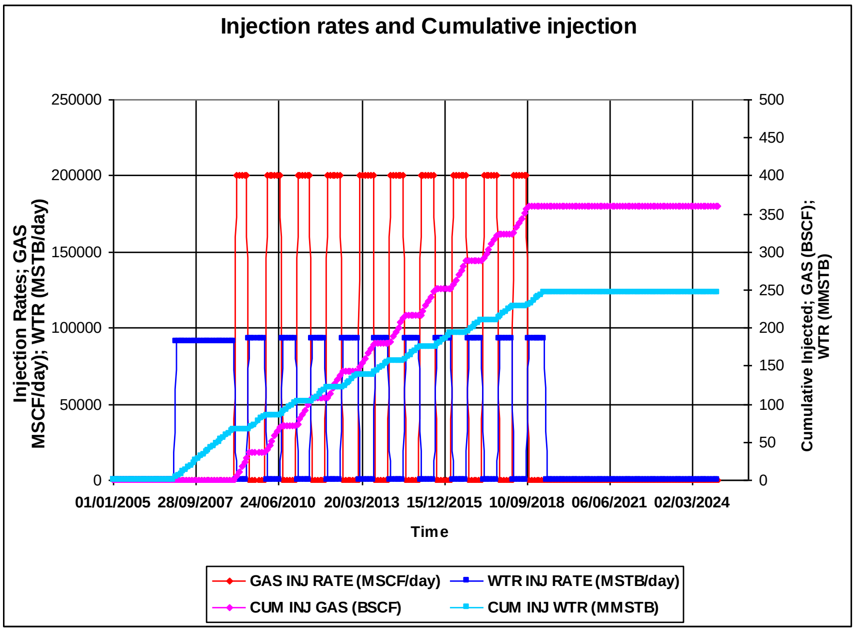

Figure 6. 14 Injection Rates and Cumulative Injection of Scenario 53 of South Flank Region

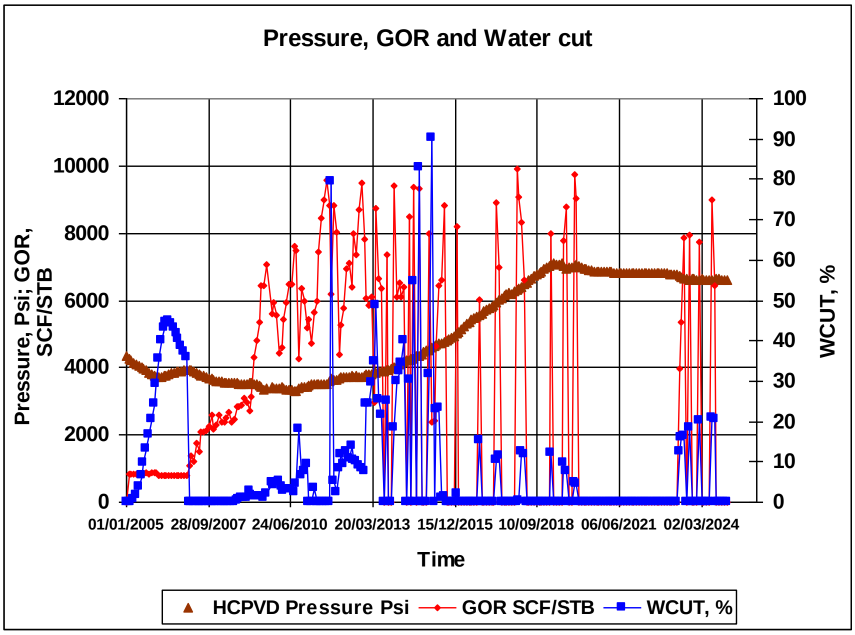

Figure 6. 15 Pressure GOR and Water Cut of Scenarios 53 of South Flank Region

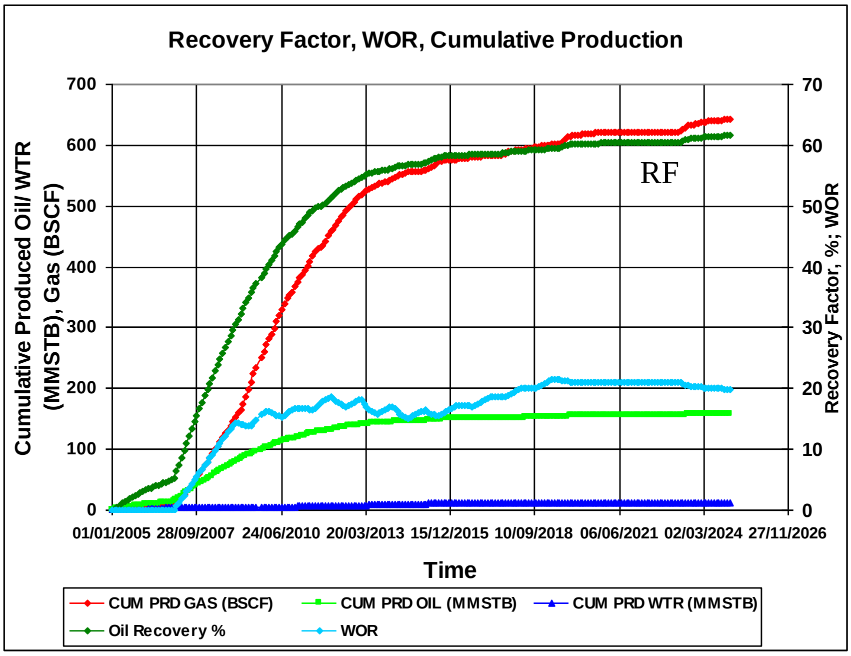

Figure 6. 16 WOR, Recovery Factor and Cumulative Production of Scenario 53 of South Flank Region

Production increase in terms of wells is considerable fact in comparison to Base Case. Thus, cumulative oil produced by SP1, SP2, SP3 and SP4 of Best Case (Scenario 53) is 46455 MSTB, 39406 MSTB, 29189 MSTB, and 29661 MSTB respectively. In comparison to the Base Case, wells decline less rapidly keeping up steadily higher rates and continuation of production life increase especially in wells SP3 and SP4. For example SP3 closed in 2024 in the Best Case, while SP4 closed in 2019, where as they were closed in 2012 and 2010 respectively in the Base Case. Reversal but still beneficial process was observed in wells SP1 and SP2. Namely, in these wells production stopped earlier than in Base Case (in the middle of 2013 in comparison to the end of 2016) but cumulative oil produced by that time was 4891 MSTB higher than that of the Base Case. Besides, production started again in the middle of 2019 until the middle of 2020 giving 2172.7 MSTB additional recovery from SP1 well. The similar process was observed in well SP2: production stopped in the beginning 2015 with 38102.6 MSTB and then restarted in the beginning 2018 and went on for 1.5 year. The reason for shut in of wells was decreasing oil production rate and increasing water production rate. Description of well behaviour is in the following pictures (Figure 6.17-6.30).

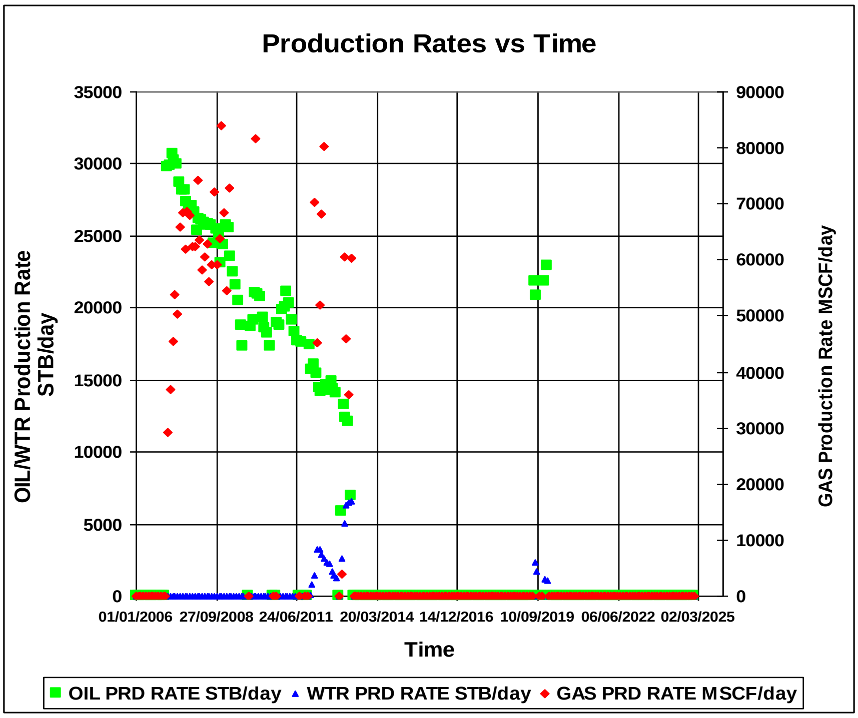

Figure 6. 17 Gas, Oil, Water Production rates for SP1 well of the Scenario 53

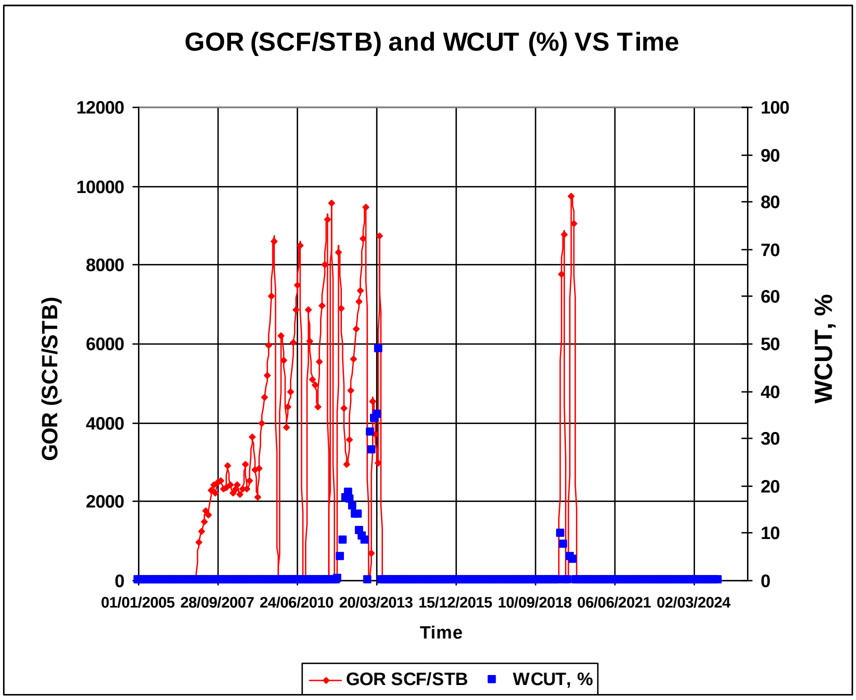

Figure 6. 18 GOR and Water cut for SP1 well of the Scenario 53

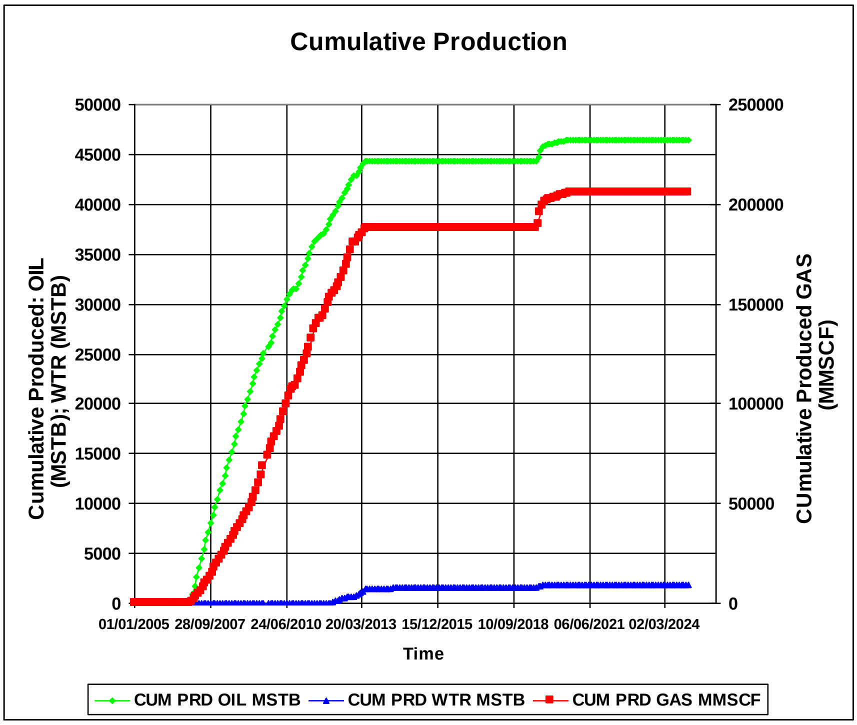

Figure 6. 19 Cumulative Produced Gas, Oil, and Water from SP1 well of the Scenario 53

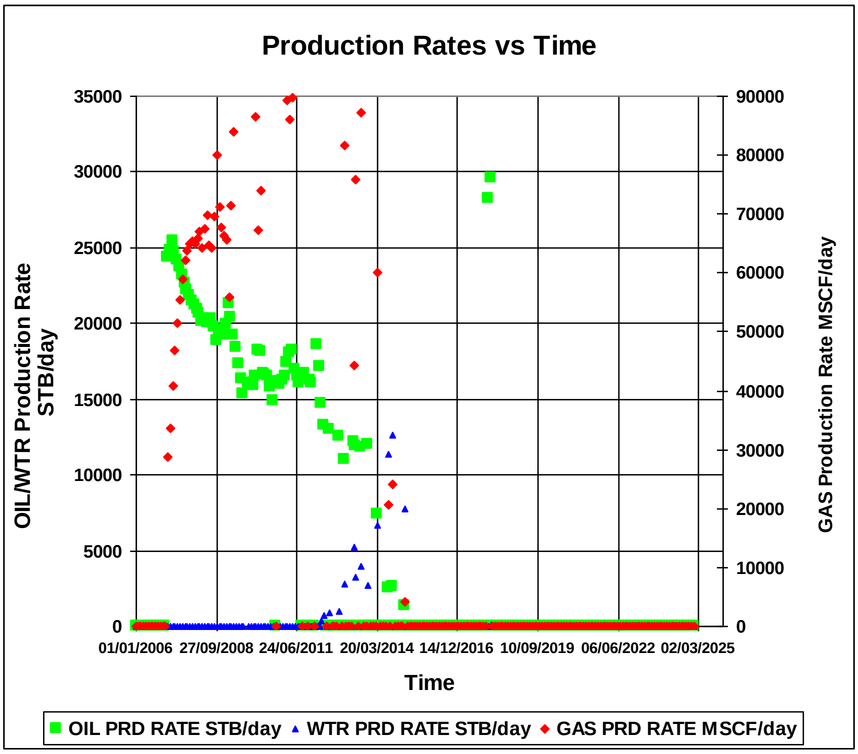

Figure 6. 20 Gas, Oil, Water Production rates for SP2 well of the Scenario 53

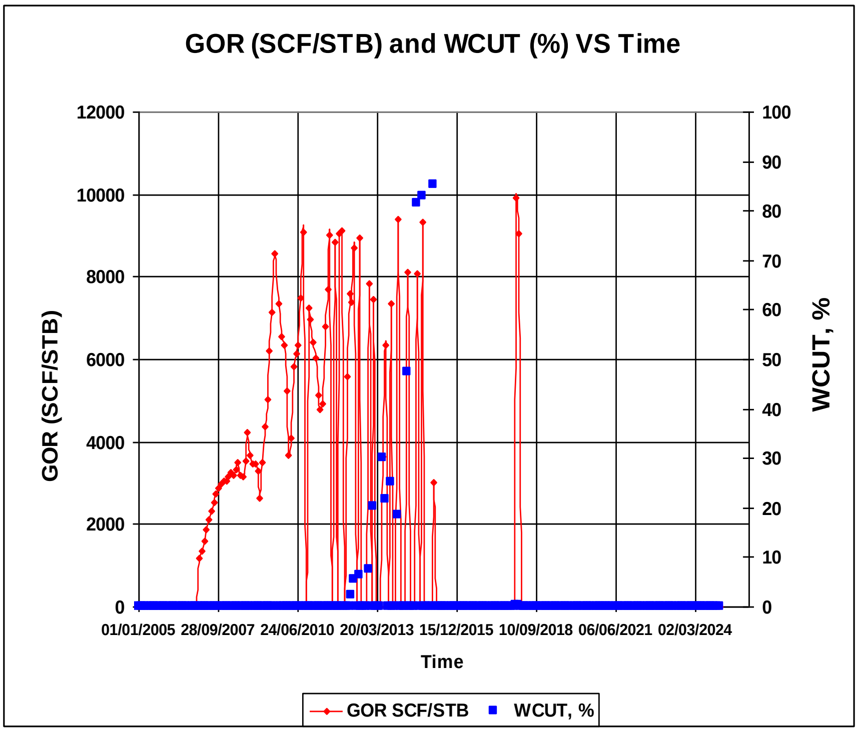

Figure 6. 21 GOR and Water cut for SP2 well of the Scenario 53

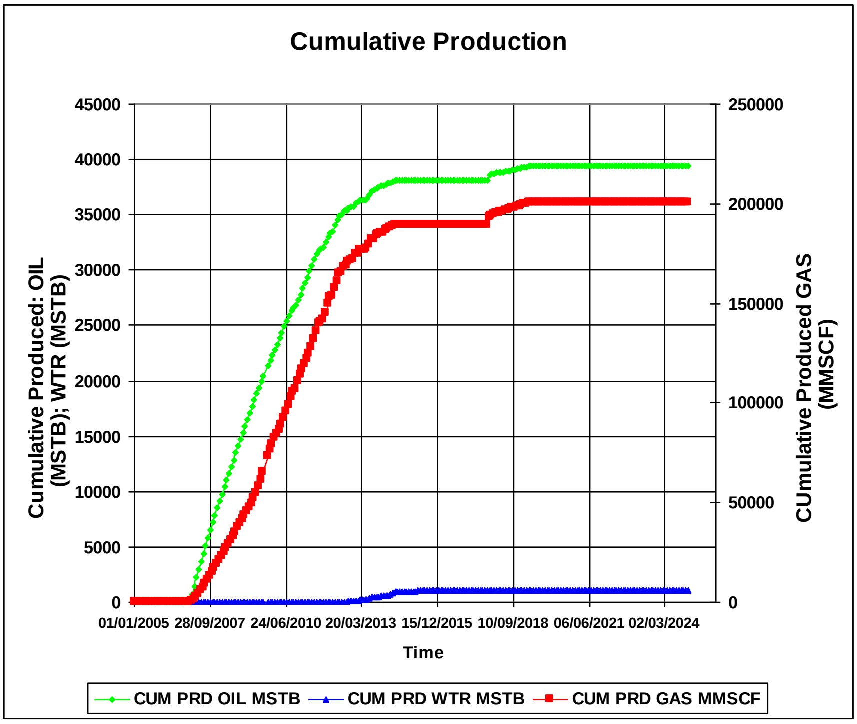

Figure 6. 22 Cumulative Produced Gas, Oil, and Water from SP2 well of the Scenario 53

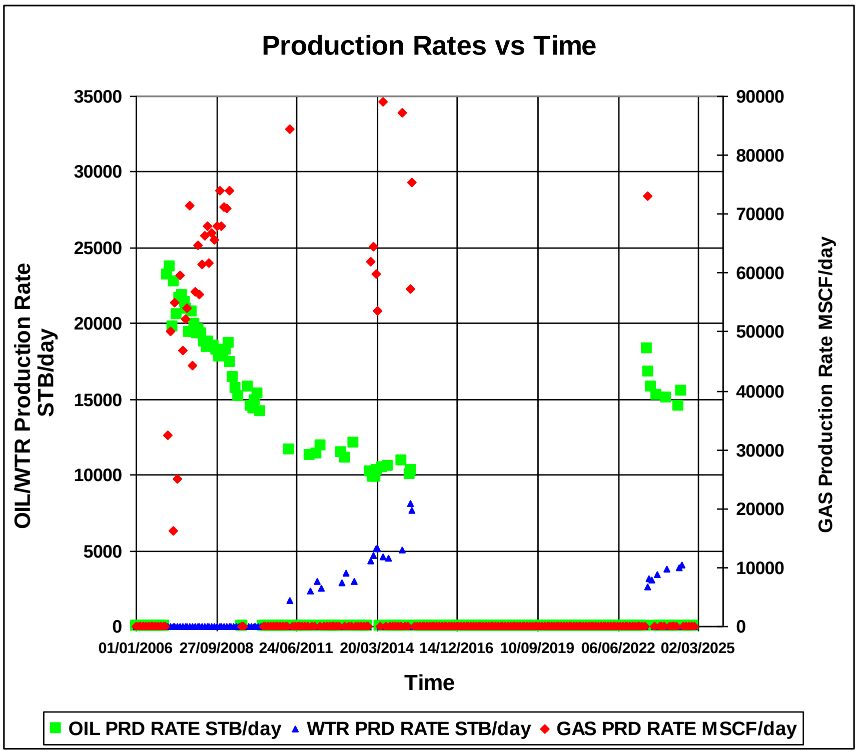

Figure 6. 23 Gas, Oil, Water Production rates for SP3 well of the Scenario 53

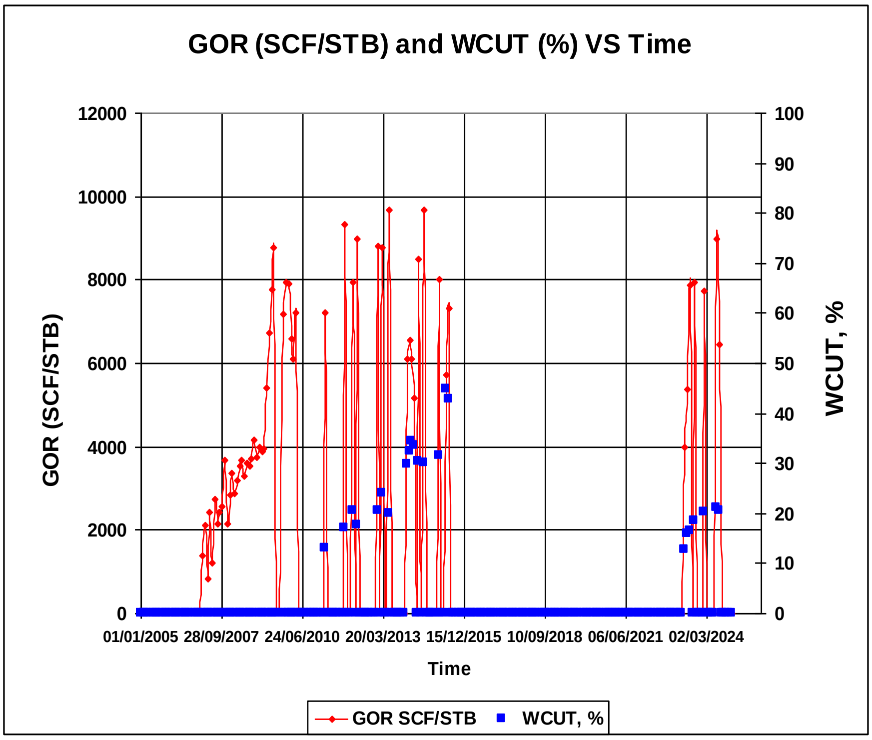

Figure 6. 24 GOR and Water cut for SP3 well of the Scenario 53

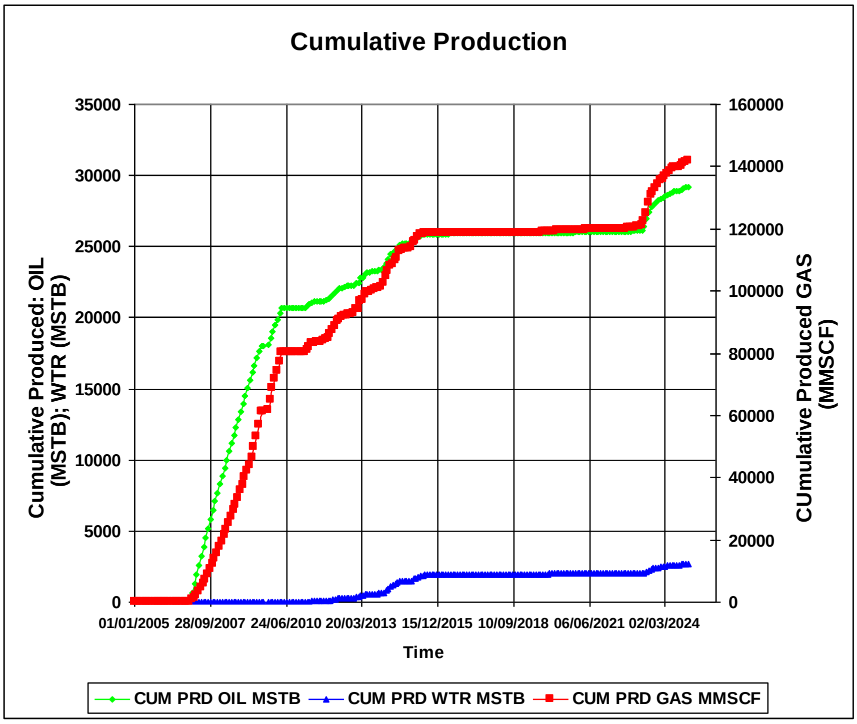

Figure 6. 25 Cumulative Produced Gas, Oil, and Water from SP3 well of the Scenario 53

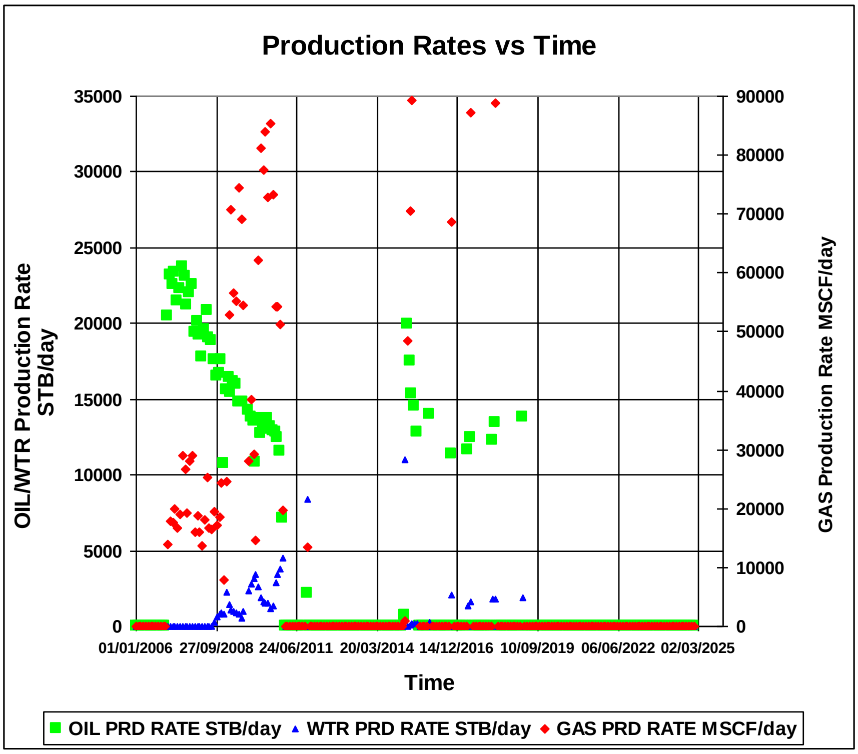

Figure 6. 26 Gas, Oil, Water Production rates for SP4 well of the Scenario 53

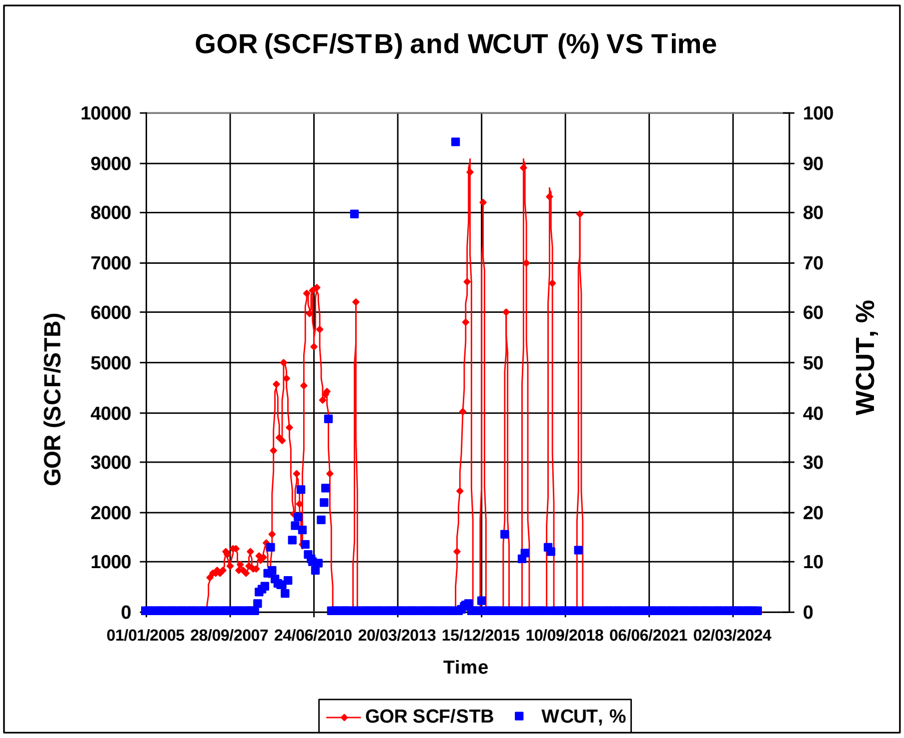

Figure 6. 27 GOR and Water cut for SP4 well of the Scenario 53

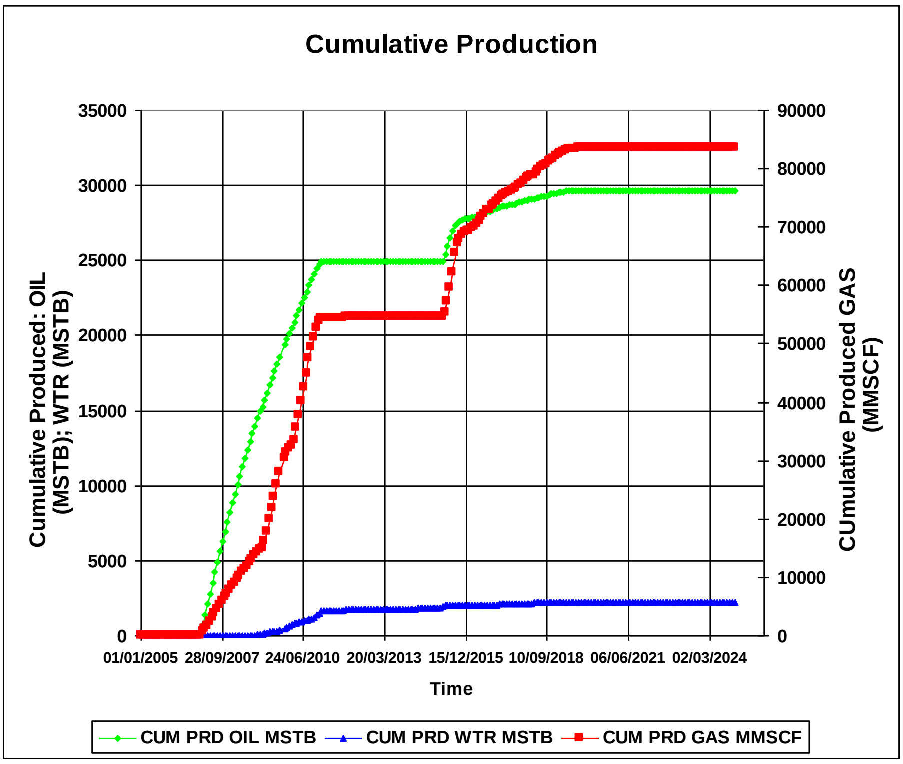

Figure 6. 28 Cumulative Produced Gas, Oil, and Water from SP4 well of the Scenario 53

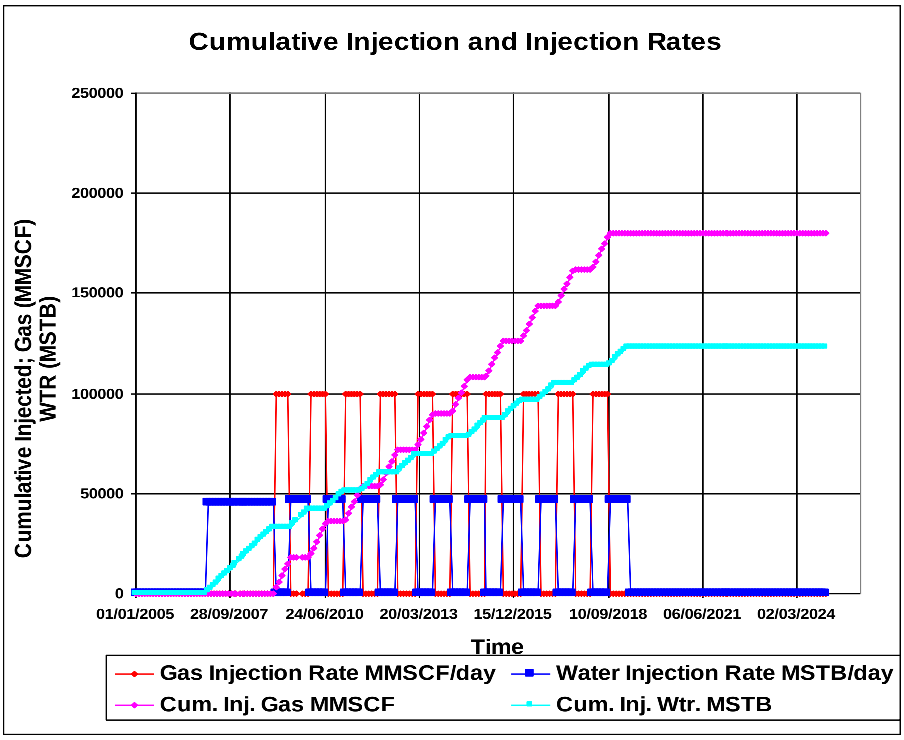

Figure 6. 29 Injection Rates and Cumulative Injection of WI1 well of Scenario 53

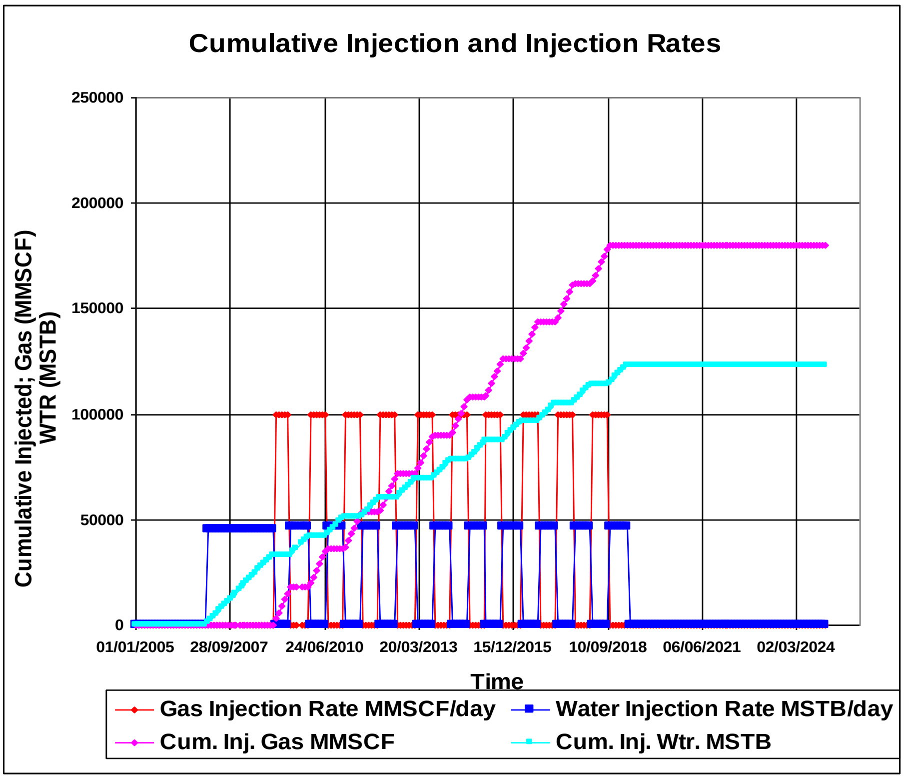

Figure 6. 30 Figure 27 Injection Rates and Cumulative Injection of WI2 well of Scenario 53

The worst result obtained from simulations (recovery factor 55.7%), but still looking advantageous (3.4% incremental recovery) in comparison to the Base Case is the Scenario 52. In this case water is injected with rate 11.5 MSTB/day while gas is injected with rate 25 MMSCF/day. Swapping from water injection to gas injection and vice versa takes 24 months. Injection of 6% fraction of HCPV gas per cycle, results in 18% of total gas injected. Gas segregation to above and movement of water to down part is in the Figures 6.31 – 6.32 Cumulative oil production from the region is 143 MMSTB reached in the end of 2019, with cumulative gas injected 108 BSCF and water injected 117 MMSTB. In comparison to the Base and Best cases water production is reduced due to less injected water.

This injection strategy helps to increase rates of wells but not to prolongate life of them in Scenario 52. For instance if in Scenario 53 SP1 shuts in the beginning of 2020, SP2 in the beginning 2018, SP3 in the end of 2024, SP4 in the beginning of

2019, but in Scenario 52 SP1 shuts in the middle of 2018, SP2 in the middle of 2017, SP3 in the end of 2016, and SP4 in the end of 2012. But still they work longer and with higher rates in comparison with the Base Case. Cumulative produced oil from wells is in the following order: SP1 45582.5 MSTB; SP2 34321.8 MSTB; SP3 21078.4MSTB; SP4 28620.1 MSTB. Production history of the Scenario 52 for the South Flank region and its wells is represented in Figures 6.33 – 6.48.

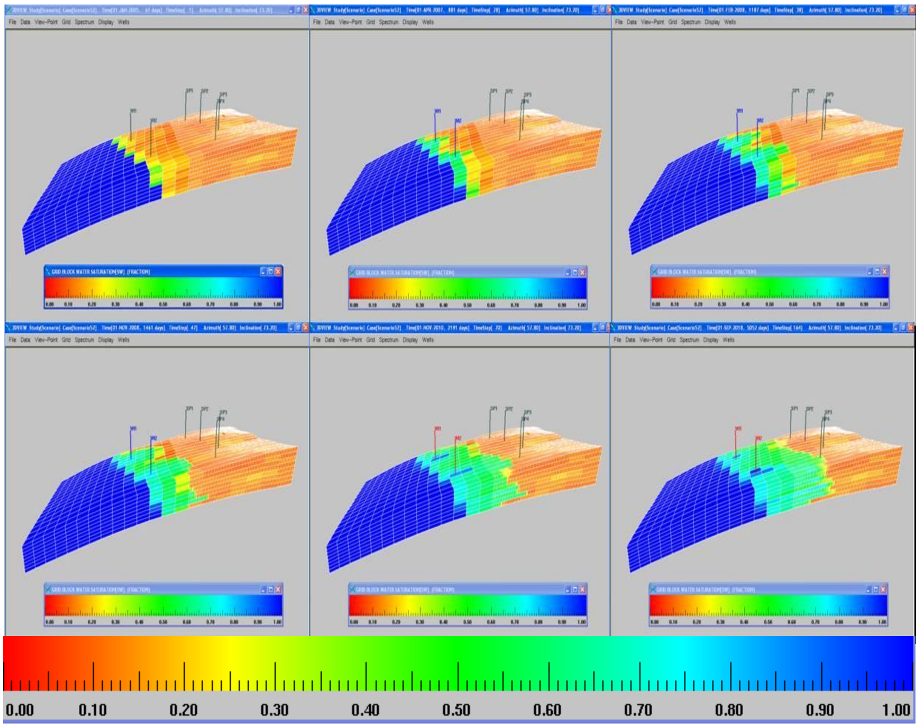

Figure 6. 31 Water saturation map showing down flow of water during injection for Scenario 52

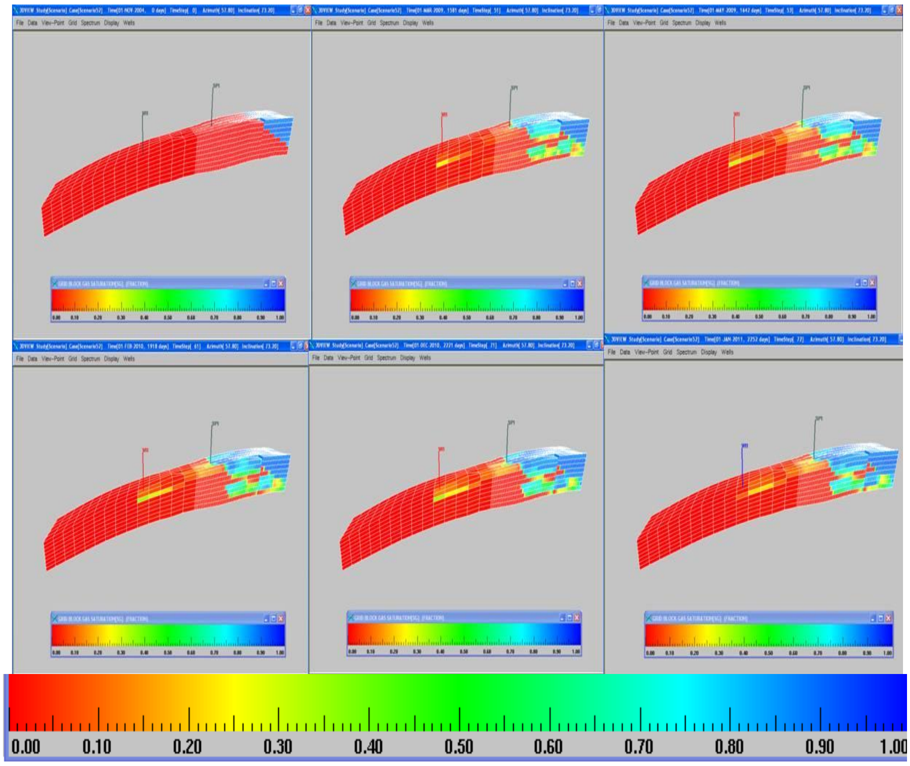

Figure 6. 32 Gas saturation map showing upper segregation of gas during injection for Scenario 52

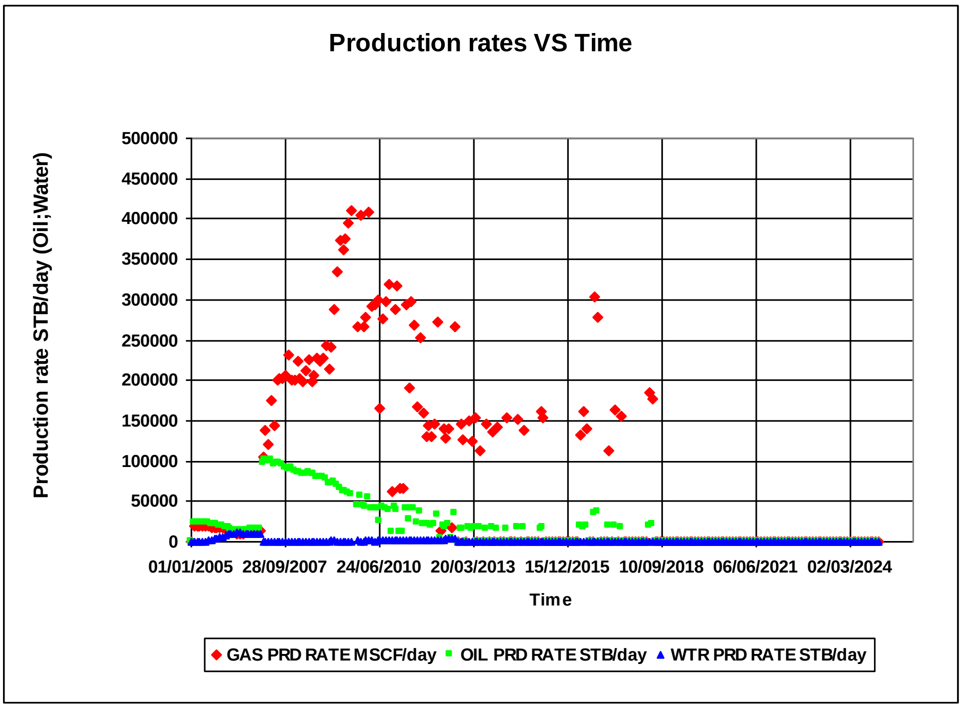

Figure 6. 33 Production Rates of Scenario 52 of South Flank Region

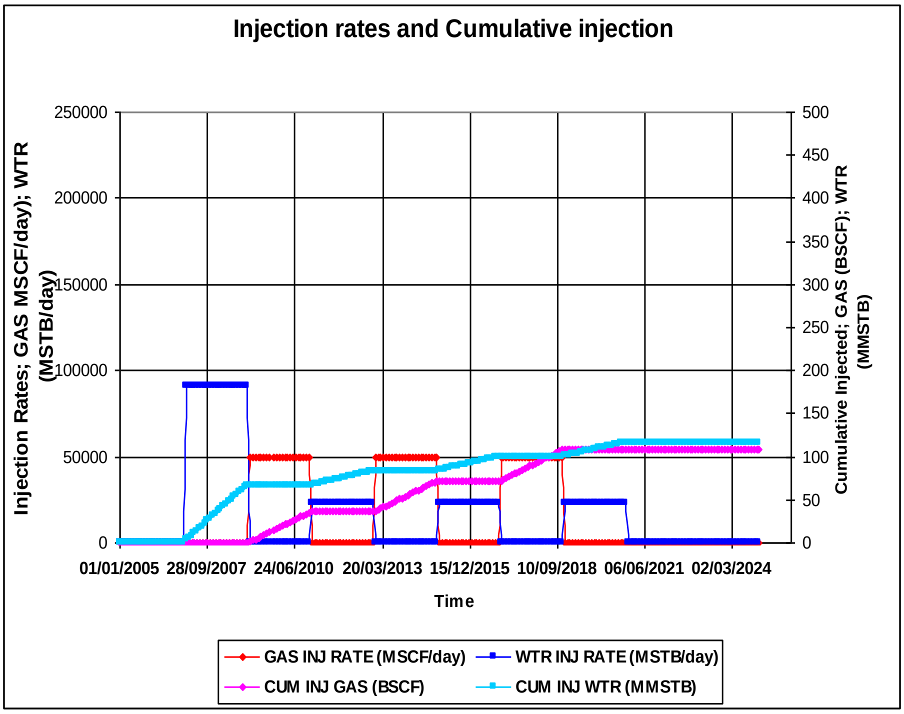

Figure 6. 34 Injection Rates and Cumulative Injection of Scenario 52 of South Flank Region

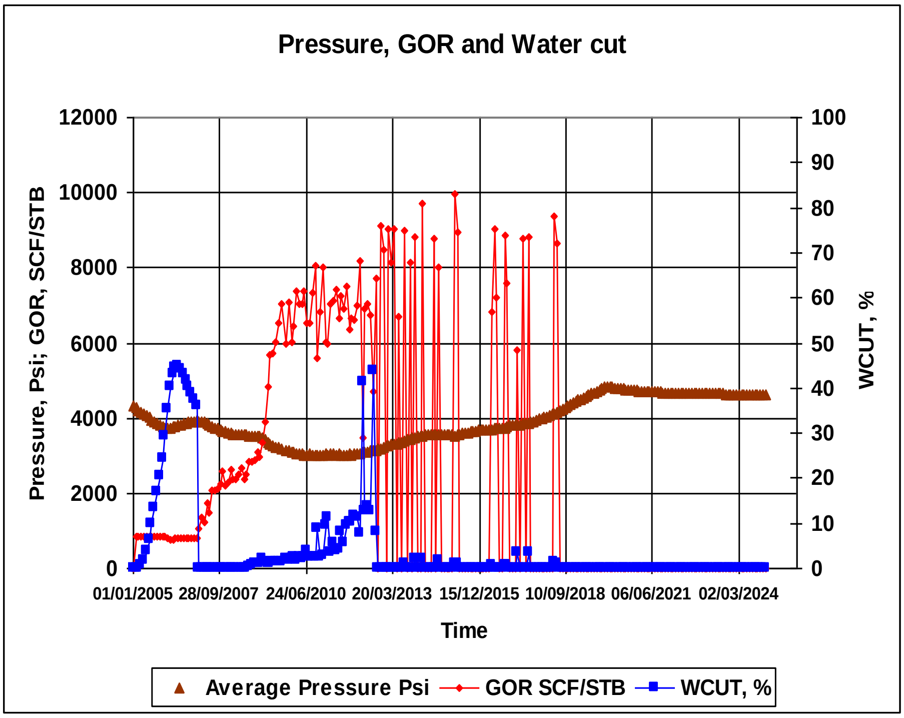

Figure 6. 35 Pressure GOR and Water Cut of Scenarios 52 of South Flank Region

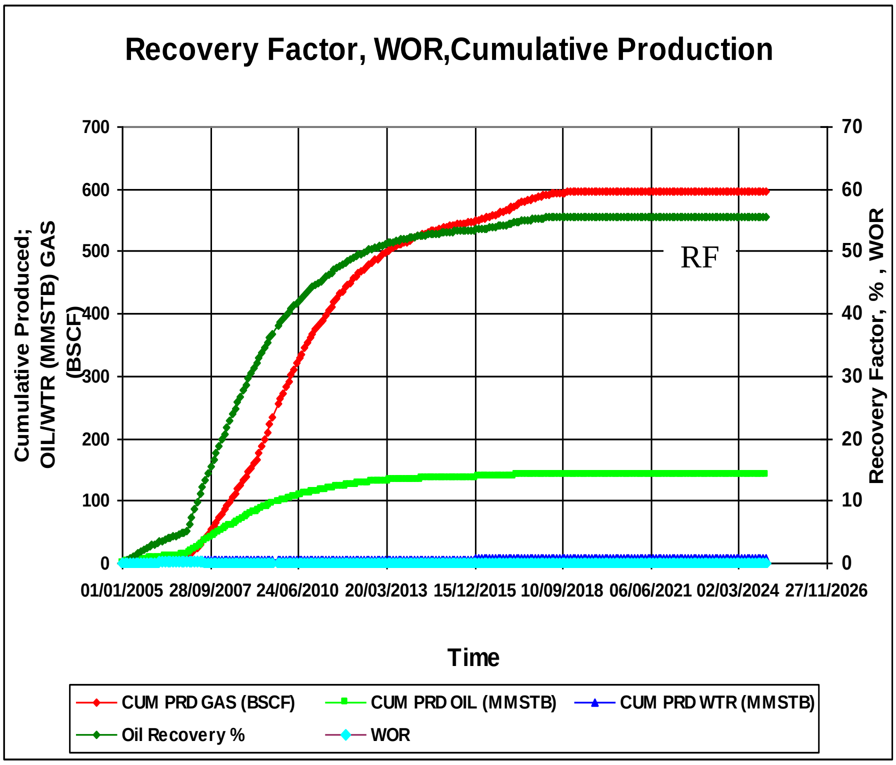

Figure 6. 36 Recovery Factor and Cumulative Production of Scenario 52 of South Flank Region

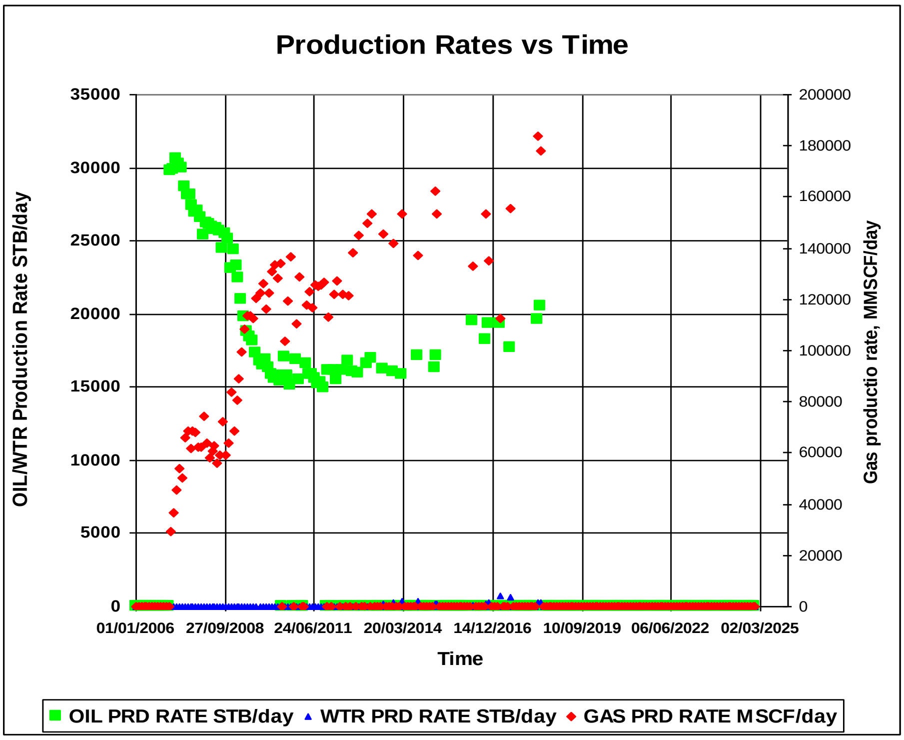

Figure 6. 37 Gas, Oil, Water Production rates for SP1 well of the Scenario 52

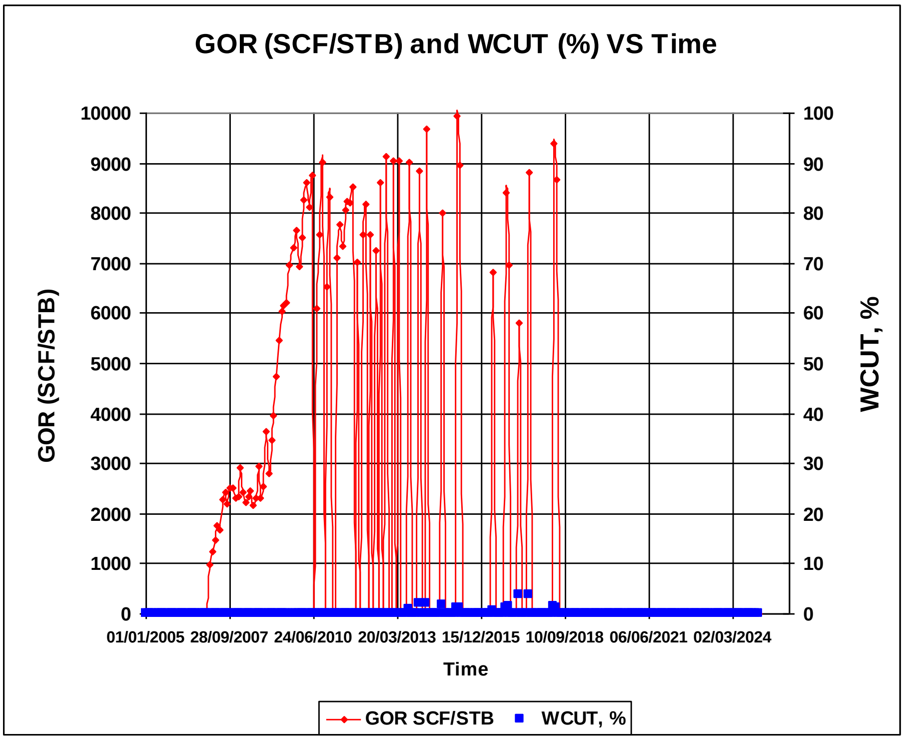

Figure 6. 38 GOR and Water cut for SP1 well of the Scenario 52

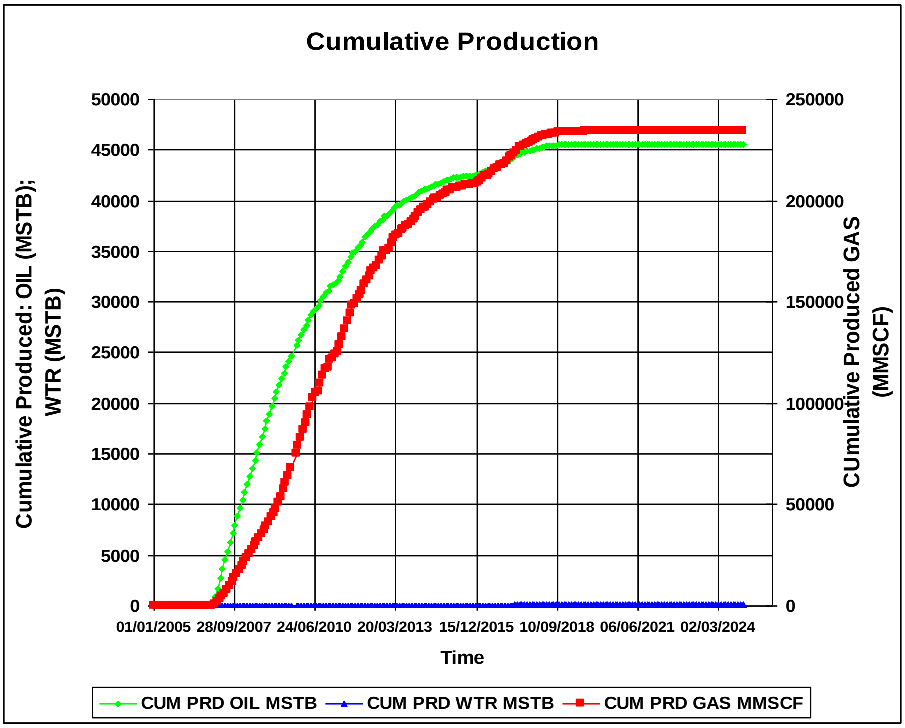

Figure 6. 39 Cumulative Produced Gas, Oil, and Water from SP1 well of the Scenario 52

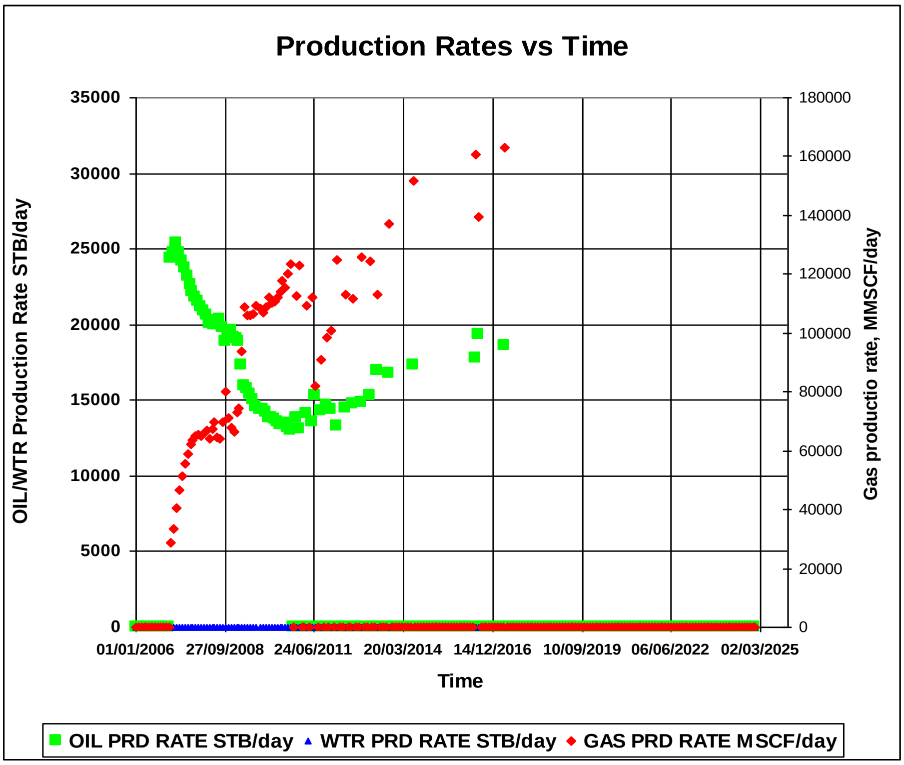

Figure 6. 40 Gas, Oil, Water Production rates for SP2 well of the Scenario 52

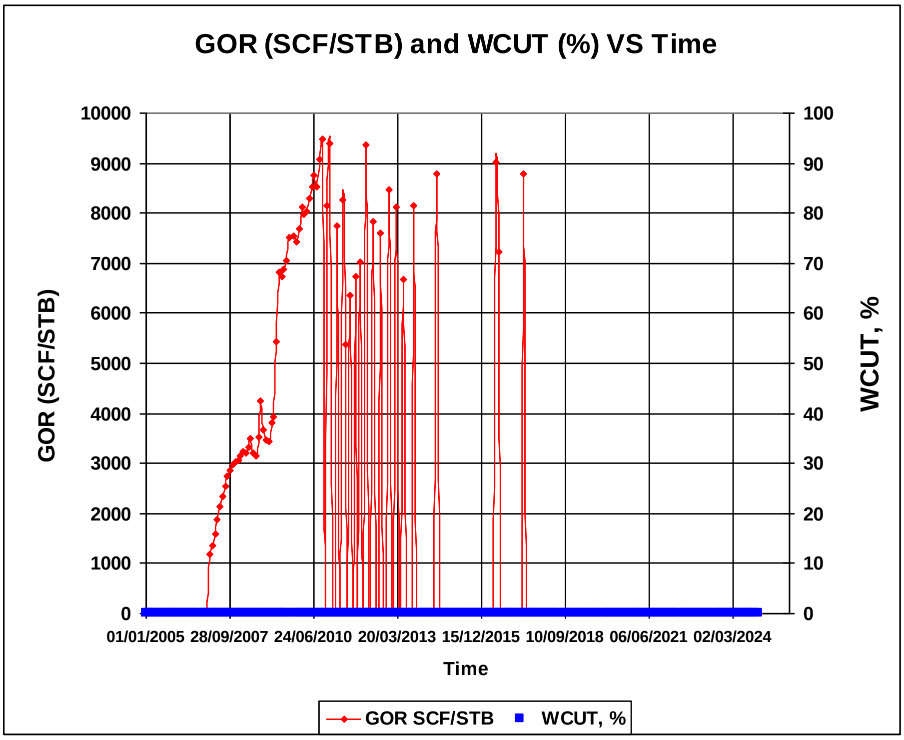

Figure 6. 41 GOR and Water cut for SP2 well of the Scenario 52

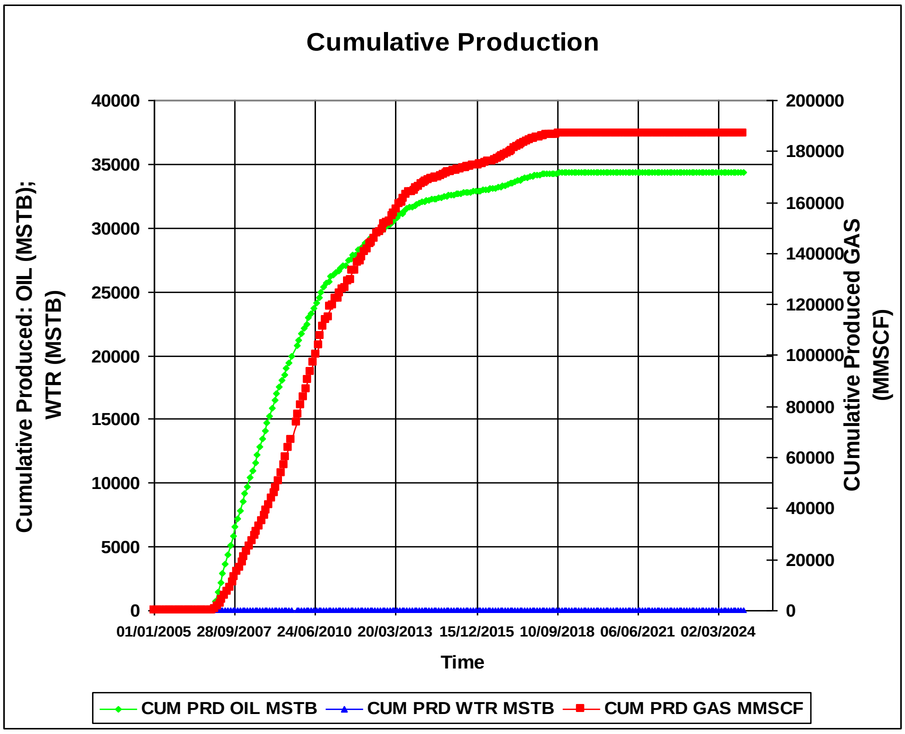

Figure 6. 42 Cumulative Produced Gas, Oil, and Water from SP2 well of the Scenario 52

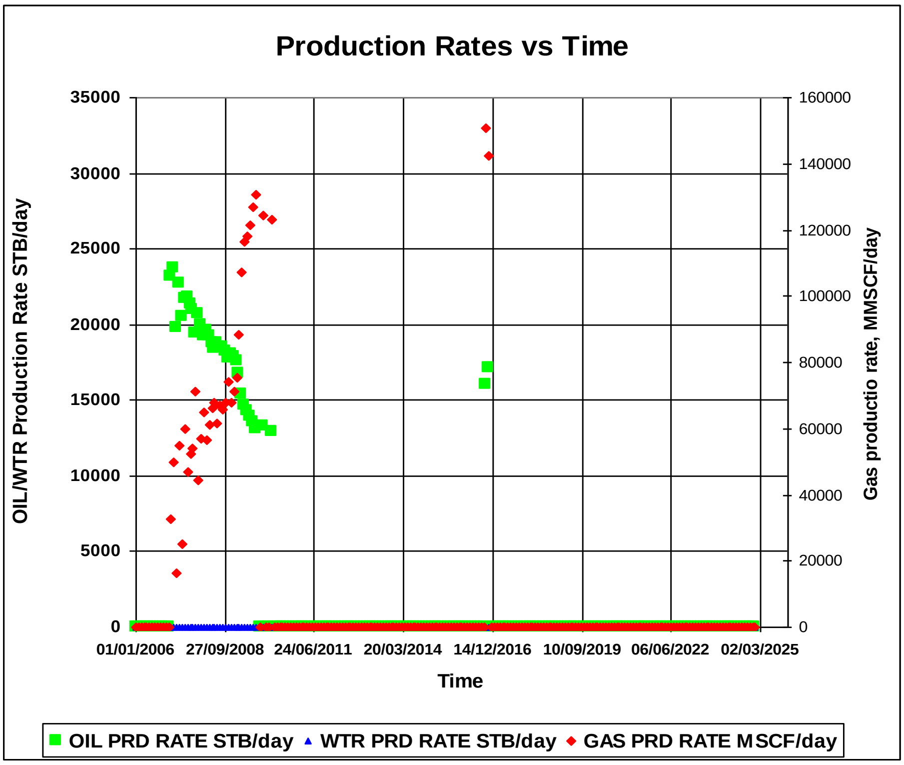

Figure 6. 43 Gas, Oil, Water Production rates for SP3 well of the Scenario 52

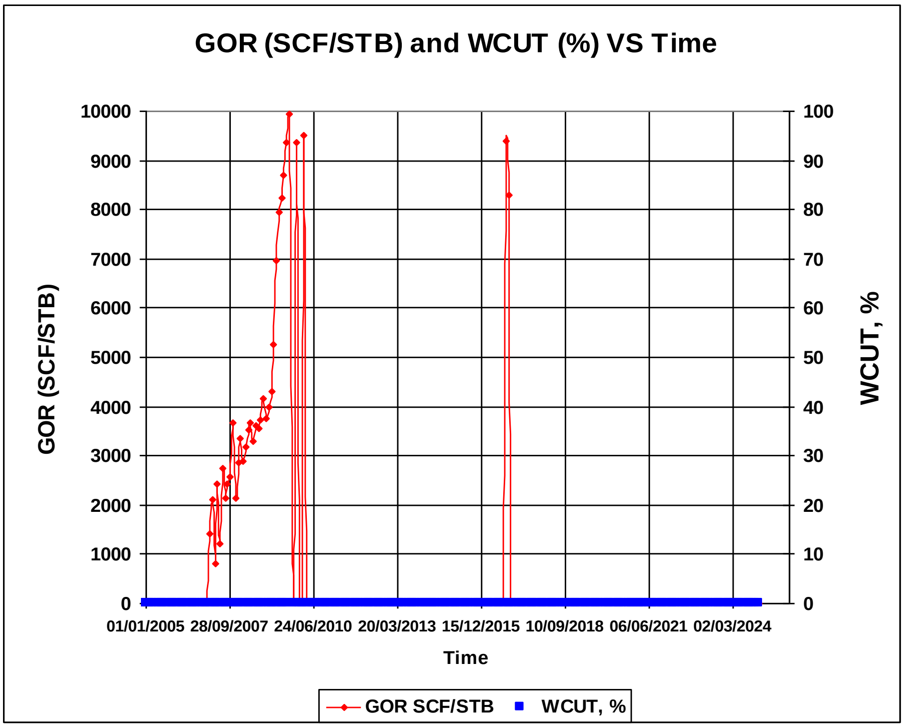

Figure 6. 44 GOR and Water cut for SP3 well of the Scenario 52

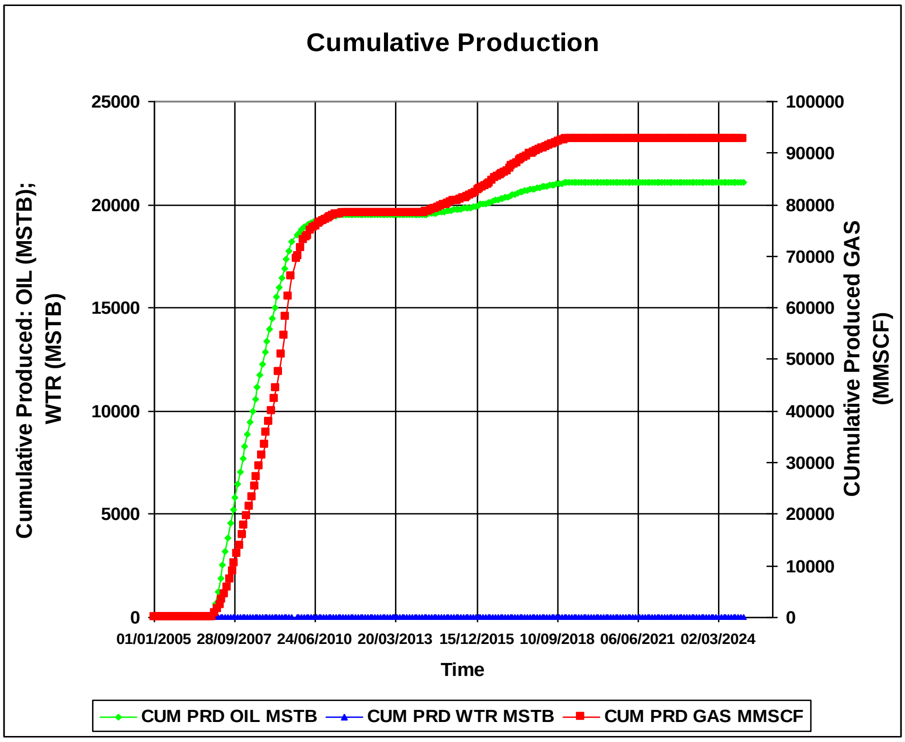

Figure 6. 45 Cumulative Produced Gas, Oil, and Water from SP3 well of the Scenario 52

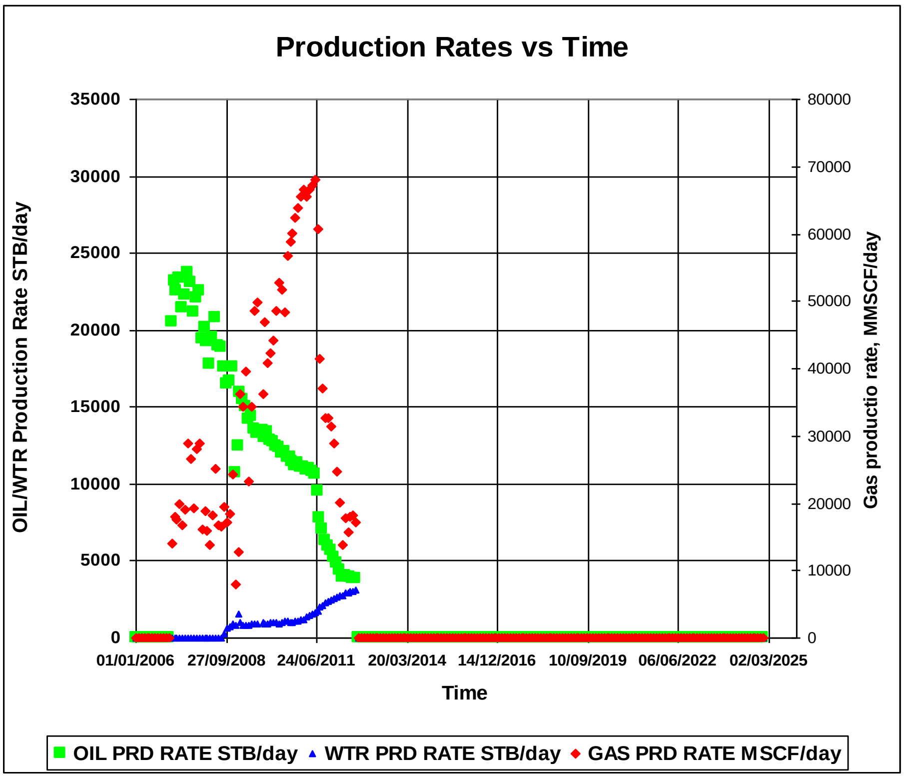

Figure 6. 46 Gas, Oil, Water Production rates for SP4 well of the Scenario 52

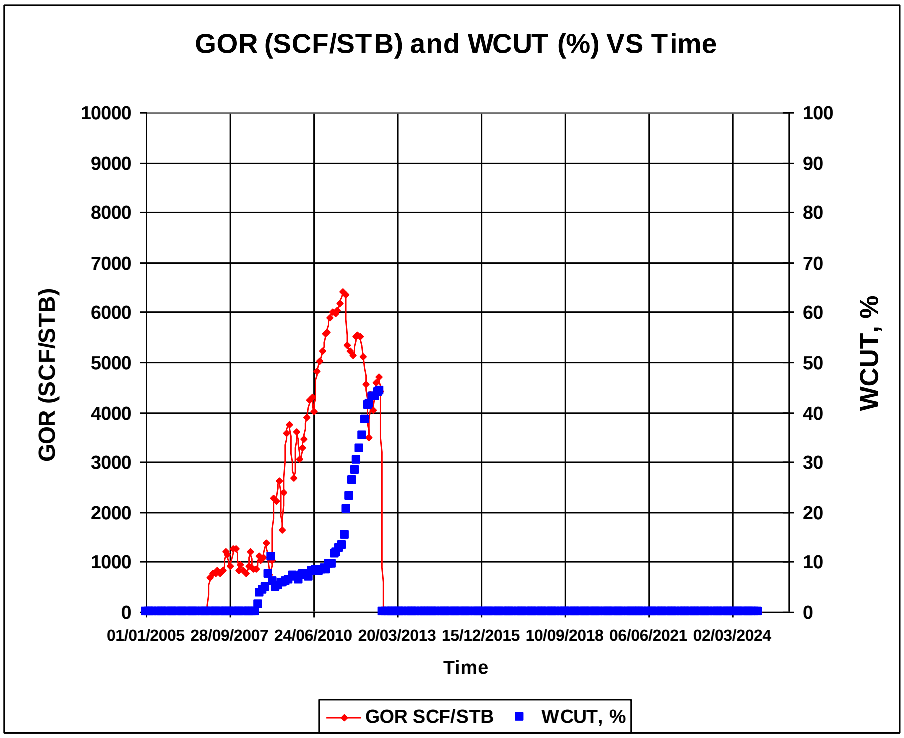

Figure 6. 47 Figure 37 GOR and Water cut for SP4 well of the Scenario 52

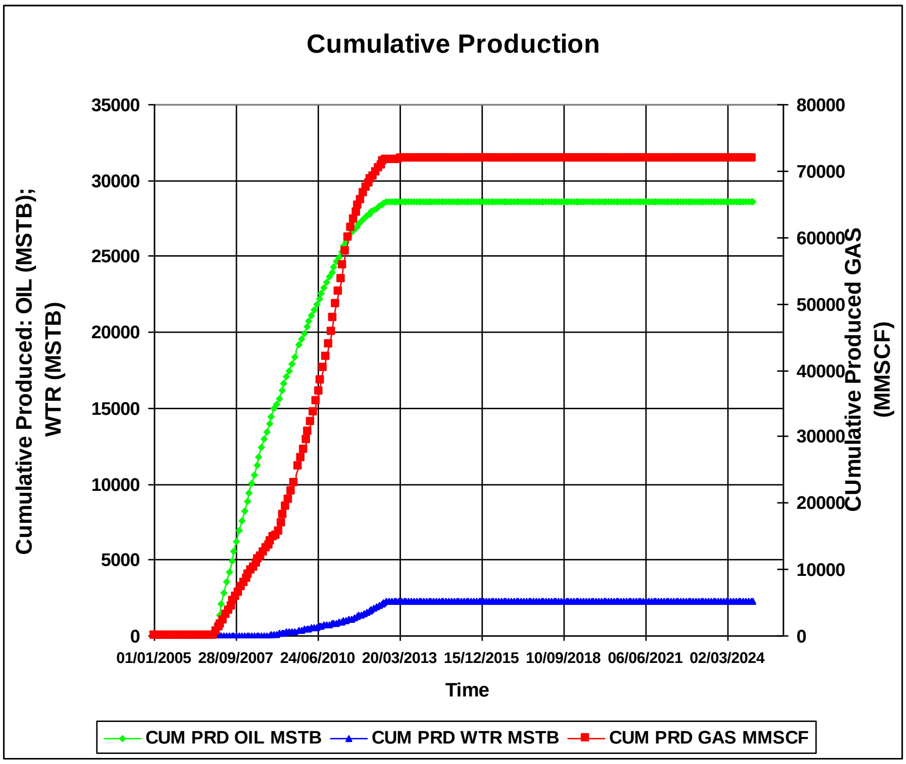

Figure 6. 48 Cumulative Produced Gas, Oil, and Water from SP4 well of the Scenario 52

6.1.2 Special Cases

Alongside with Scenarios stated in Table 5.1 some special additional cases have been done in order to be assured in accuracy of results represented in Table 6.1. Thus, three additional Simultaneous WAG injection projects with different gas injection rates (25 MMSCF/day; 7.5 MMSCF/day; 2.5 MMSCF/day) and the same water injection rate (15 MSTB/day), two cases with twice reduced and twice increased permeability sets, and one case with three phase relative permeability hysteresis was considered. Fundamental understanding of three phase relative permeability hysteresis and the Carlson model used in this simulation run is described in Appendix C. The description of cases is shown in Tables 6.2 -6.3. Scenarios 62, 63, 64 are derivatives of the Best Case Scenario 53.

Table 6. 2 Description of SWAG

Case	WAG start	GI end	WI end	WI rate; MSTB/d	GI rate; MMSCF/d	BHP, Psi
Scenario59	2009	2017	2020	15	25	9454
Scenario60	2009	2017	2020	15	7.5	9454
Scenario61	2009	2017	2020	15	2.5	9454

Table 6. 3 Description of different cases

Case	WAG start	WAG end	WI rate; MSTB/d	GI rate; MMSCF/d	WI period, month	GI period, month	Cycles	BHP, Psi	WAG Slug Size Ratio	WAG Period Ratio	Cum. Gas Inj. Per cycle; BSCF	Fraction of HCPV of Gas per cycle; %	Cum. Wtr. Inj. Per cycle; MMSTB
Three Phase Relative Permeability Hysteresis													
Scenario62	2009	2019	46	100	6	6	10	9454	1:2	1:1	18	6	9
Permeability increased by 2													
Scenario63	2009	2019	46	100	6	6	10	9454	1:2	1:1	18	6	9
Permeability reduced by 2													
Scenario64	2009	2019	46	100	6	6	10	9454	1:2	1:1	18	6	9

Table 6. 4 Results for special cases

Case	Recovery Factor, %	Incremental Oil Recovery, %	Fraction of HCPV of Gas per cycle; %	Total Fraction of HCPV injected, %	WAG Slug Size Ratio	WAG Period Ratio
Simultaneous WAG						
Scenario59	61	8.4	-	-	-	-
Scenario60	59.3	7.0	-	-	-	-
Scenario61	58.8	6.5	-	-	-	-
Three Phase Relative Permeability Hysteresis						
Scenario62	61.0	-	6	60	1:2	1:1
Permeability increased by 2						
Scenario63	62.5	-	6	60	1:2	1:1
Permeability reduced by 2						
Scenario64	60.2	-	6	60	1:2	1:1

Results of special cases are represented in the Table 6.4. Summing up with results obtained from simulations shows that SWAG and increasing or decreasing permeability cases as long as application of three phase relative permeability hysteresis in this model still beneficial from incremental recovery point of view. In SWAG cases decreasing gas injection rate brings to increased water cut and early stop of productions of wells. Figures 6.49 and 6.50 are confirmation of gas segregation and water down flow owing to gravity forces. Increase of permeabilities twice of the representative model causes in increase of rates of wells and production life gaining some additional recoveries, while decreasing permeabilities twice affects decreases recovery factor.

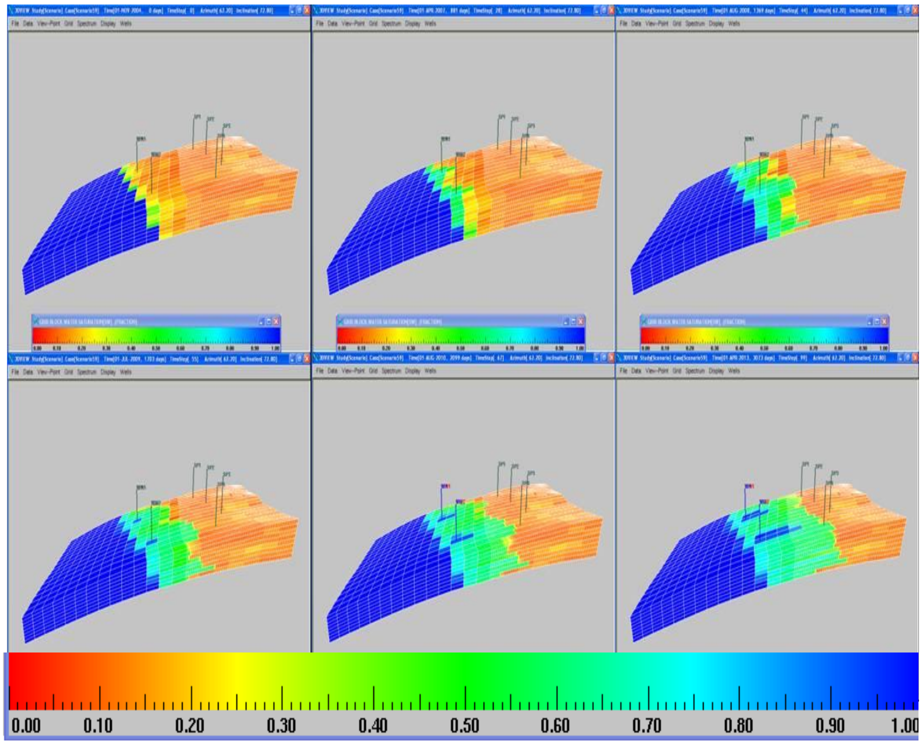

Figure 6. 49 Water saturation map showing down flow of water during injection for Scenario 59

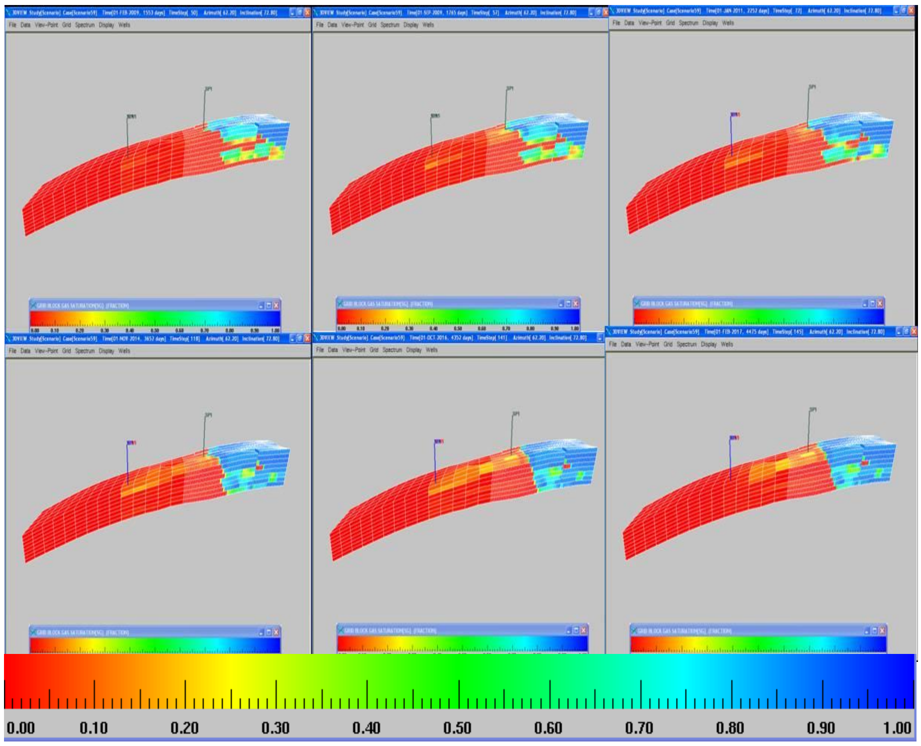

Figure 6. 50 Gas saturation map showing upper segregation of gas during injection for Scenario 59

6.2 Economical Aspect

In order to optimize the oil production, it is necessary to maximize the profit - net present value (NPV). In this section brief economical analysis for all cases will be provided. For economical analysis of this work simple NPV calculations have been performed, on the basis of excel spreadsheet prepared for this purpose (Appendix D). NPV for set of oil prices (60$; 80$; 100$) is calculated. Capital expenditure is only considered for gas flow line to the water injectors construction, and the value is 1.5$ million. The swap expenses from gas to water and vice versa is 0.3$ million per each. Operational expenses are changing depending on scenarios, as long as there are different numbers of WAG cycles. The other parameters for analysis are discount rate 10% and tax 25% in average for all periods, profit share changing from 50 to 22% with time. NPV values for all cases besides its total incremental costs (CAPEX+OPEX) are given in the Table 6.5. Thus, NPV analysis has proven WAG feasibility in South Flank of Azeri field, as we can see that the Best Case (Scenario 53) has 110$ mln., 149.7$ mln., 189.5$ mln, at oil prices 60$, 80$ and 100$ NPV in respect to 15$ mln. total incremental cost, while the Worst Case (Scenario 52) has 21.8$ mln., 29.4$ mln., 37.1$mln in respect to 6$ mln. total incremental cost. The another case (Scenario2) looks beneficial as well: 107.6$ mln., 146.4$ mln., and 185.1$ mln., to 7$ total incremental cost.

Table 6. 5 NPV analysis for scenarios

Case	Recovery Factor, %	Incremental Oil Recovery, %	Total Increm. Costs; (mln. $)	NPV (mln. $)		
				at 60$	at 80$	at 100$
Scenario1	59.7	7.4	10	89.9	122.3	154.8
Scenario2	60.9	8.6	7	107.6	146.4	185.1
Scenario3	59.1	6.7	12	67.2	91.5	115.8
Scenario4	61.1	8.8	9	101.3	137.7	174.0
Scenario5	58.6	6.3	7	80.4	109.5	138.6
Scenario6	59.0	6.7	8	53.8	73.0	92.1
Scenario7	60.2	7.9	10	84.6	115.0	145.4
Scenario8	60.5	8.2	12	94.9	129.1	163.4
Scenario9	59.5	7.2	7	80.0	108.7	137.5
Scenario10	60.3	8.0	8	69.9	94.8	119.8
Scenario11	58.6	6.2	10	82.4	112.2	142.0
Scenario12	60.0	7.6	10	94.2	128.2	162.2
Scenario13	58.6	6.3	10	67.5	91.8	116.1
Scenario14	60.5	8.2	12	86.2	117.2	148.2
Scenario15	58.1	5.8	7	82.7	112.7	142.6
Scenario16	59.3	6.9	7	97.4	132.6	167.8
Scenario17	59.9	7.6	9	65.5	88.7	111.9
Scenario18	60.0	7.7	9	81.3	110.3	139.3
Scenario19	60.3	7.9	7	90.5	123.1	155.6
Scenario20	59.2	6.9	8	77.4	105.2	132.9
Scenario21	58.3	6.0	12	84.7	115.6	146.4
Scenario22	58.3	6.0	12	85.1	116.0	147.0
Scenario23	59.7	7.4	15	78.7	107.1	135.4
Scenario24	59.7	7.4	15	81.9	111.4	140.9
Scenario25	58.1	5.8	15	85.2	116.3	147.4
Scenario26	58.2	5.9	15	85.5	116.6	147.8
Scenario27	59.3	7.0	15	82.3	112.2	142.0
Scenario28	59.3	7.0	15	82.3	112.2	142.0
Scenario29	58.1	5.8	9	85.6	116.7	147.8
Scenario30	58.1	5.8	9	85.7	116.8	147.9
Scenario31	59.6	7.3	9	89.8	122.1	154.4
Scenario32	59.6	7.3	10	89.7	122.0	154.3
Scenario33	58.8	6.5	10	85.8	116.8	147.8
Scenario34	59.1	6.7	7	98.6	134.2	169.8
Scenario35	59.4	7.0	12	83.3	113.3	143.3
Scenario36	59.0	6.7	9	66.9	90.9	114.8
Scenario37	58.5	6.1	7	74.4	101.1	127.8
Scenario38	59.3	7.0	8	75.2	102.2	129.2
Scenario39	60.1	7.8	10	78.6	106.9	135.3
Scenario40	60.1	7.8	12	87.6	119.2	150.7
Scenario41	57.9	5.6	7	97.3	132.5	167.7
Scenario42	60.8	8.5	9	97.7	132.6	167.5
Scenario43	56.9	4.6	7	71.3	97.1	123.0

Table 6.5 (Continued)

Case	Recovery Factor, %	Incremental Oil Recovery, %	Total Increm. Costs; (mln. $)	NPV (mln. $)		
				at 60$	at 80$	at 100$
Scenario44	59.6	7.3	8	69.5	94.4	119.2
Scenario45	59.3	7.0	10	97.4	132.6	167.8
Scenario46	59.6	7.3	12	76.1	103.4	130.6
Scenario47	58.8	6.5	7	92.2	125.5	158.9
Scenario48	57.6	5.3	9	45.7	62.0	78.2
Scenario49	58.5	6.2	7	90.4	123.0	155.7
Scenario50	58.7	6.4	8	60.5	82.1	103.7
Scenario51	59.5	7.2	6	104.8	142.5	180.3
Scenario52	55.7	3.4	6	21.8	29.4	37.1
Scenario53	61.6	9.3	15	110.0	149.7	189.5
Scenario54	59.2	6.9	12	88.0	119.9	151.7
Scenario55	59.6	7.3	12	102.8	140.0	177.3
Scenario56	59.0	6.7	12	63.0	85.6	108.3
Scenario57	59.3	7.0	5	96.8	131.7	166.6
Scenario58	59.1	6.8	5	60.4	81.7	103.0
Scenario59	61	8.4	3	98.2	133.3	168.3
Scenario60	59.3	7.0	3	78.0	105.9	133.7
Scenario61	58.8	6.5	3	69.8	94.6	119.5

CHAPTER 7

7. CONCLUSION

Simulation model for evaluation of WAG project feasibility in South Flank of Azeri field is developed and wide range of simulation runs were carried out. The results from simulations, by evaluating and comparing them with the Base Case the following conclusions were drawn:

- Range of incremental recoveries (3.4%-10.2%) were obtained from simulations for different WAG parameter scenarios (e.g. half slug size, total slug, WAG volume ratio, slug period ratio, and cycle numbers). Obtained results are in similar range to those described in the literature about different fields operated around the world (Prudhoe Bay – 5.2%, Daqing - 8.6%, Gulfaks, - 5%, Statfjord 13%).

- Simulation of the Base Case shows that under continious water flooding, water invasion to wells occurs earlier, therefore resulting in a shorter well life. From simulation results of WAG scenarios improvement in production as well as longer life of wells in comparison to the Base Case is noticeable.

- Early start of WAG project in South Flank of Central Azeri will result in additional incremental oil recovery. However, by increasing half slug size (e.g. Scenario 39 and Scenario 40) it is possible to obtain similar to earlier started cases.

- Expected effect of gas rising to the top of the field displacing trapped oil and dense water settling into low structure areas displacing oil up to producers is observed from 3D saturation maps. Besides of this, improvement of sweep efficiency can also be seen from graphics of water oil ratio and recovery factor.

- Relative permeability hysteresis effect considering representing more realistic behaviour of cycle dependent injection proves accuracy of constructed model, as Scenario62 is close to Scenario53 in recovery factor.

- Simultaneous WAG (SWAG) cases are also considered in simulations. Results show that alongside with WAG, SWAG also has potential to be implemented in South Flank of Central Azeri field. From SWAG scenarios concluded that the more volume of gas injected the more effect in terms of recovery, sweep and pressure support will be achieved.

- Economical analysis and net-present-value (NPV) calculation under certain PSA considerations proved beneficial efficiency of all WAG scenarios in comparison to the Base Case. Scenario53 and Scenario 2 are chosen as better from other Scenarios results with 110$ mln., 149.7$ mln., 189.5$ mln, at oil prices of 60$, 80$ and 100$ NPV in respect to 15$ mln. total incremental cost and 107.6$ mln., 146.4$ mln., and 185.1$ mln., to 7$ total incremental cost respectively. Scenario52 is tend to be worst in terms of both incremental recovery (3.4%) and NPV (21.8$ mln., 29.4$ mln., 37.1$mln in respect to 6$ mln. total incremental cost). Results show that WAG injection project is favourable and has potential to be applied in South Flank of Central Azeri field.

RECOMMENDATIONS:

The simulation model used in this study is reflecting sector about 25% of Central Azeri South of the full scale project estimated to be 4 times higher. However, detailed Azeri full field model and laboratory research including core floods and slim-tube displacement would be advisable in order to evaluate and better understand the process. The number of injectors and producers could be increased as well.

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APPENDIX A

KEYWORDS FOR INPUT DATA OF INITIALIZATION MODULE

Table A1: Keywords for input data of initialization module [21]

Card Name	Function
DIM	Change default dimensions.
TITLE	Descriptive information.
DATE	Specify initial date.
END	End of file marker.
MAP	Specify creation of MAP file, its format, and data selection.
METRIC	Cause all data to be read and printed in metric units.
CROSS	Cause arrays to be printed by cross-section.
GASWATER	Invoke 2-phase gas-water option.
WATEROIL	Invoke 2-phase oil-water option.
TWOPT	Invoke 2-point upstream weighting.
NINEPT	Invoke 9-point finite difference.
END2P	Invoke 2-point scaling of relative permeabilities.
STONEn	Stone's 3-phase oil relative permeability.
PCHYSW	Invoke/ define parameters for water-oil capillary pressure hysteresis.
PCHYSG	Invoke/define parameters for gas-oil capillary pressure hysteresis.
RPHYSO	Invoke oil relative permeability hysteresis.
RPHYSG	Invoke gas relative permeability hysteresis.
JFUNC	Use Leverett J-Function scaling to compute capillary pressures.
COMPACT	Invoke compaction option.
FRZPCW	Freeze water-oil capillary pressure at its initial value.

Table A1: (continued)

Card Name	Function
FRZPCG	Freeze gas-oil capillary pressure at its initial value.
NONEQ	Invoke non-equilibrium initialization.
GBC	Invoke gridblock center initialization algorithm.
INTSAT	Invoke integrated saturation initialization algorithm.
VAITS	Invoke volume averaged integrated saturation initialization algorithm.
PINCHOUT	Causes program to automatically generate nonstandard gridblock connections across pinchouts.
FAULTS	Invoke fault modeling options.
FLOW360	Complete the circle for 360 degree radial grids.
VEWO	Invoke water-oil vertical equilibrium.
VEGO	Invoke gas-oil vertical equilibrium.
GIBBS	Invoke Gibbs energy minimization algorithm.
IFT	Invoke and specify parameters for near critical fluid property adjustments.
FLASH	Specify flash calculation method.
CRINIT	Invoke super critical initialization.
CORTOL	Specify tolerance associated with corner point grid and fault connections.
CORCHK	Specify amount of error checking for corner point grid

APPENDIX B

INITIALIZATION MODULE FOR REPRESENTATIVE MODEL

```
**********************************************************************
---------------------------------------------------------------------
! This model is a Pereriv B sector from the Azeri  model.
---------------------------------------------------------------------
! Run: Base case data set, open faults
**********************************************************************
!
=======================================================================
! Initialisation
!
=======================================================================
INIT

TITLE1
Azeri Model

TITLE2
Base Case

TITLE3


METRIC BAR

! Don't add capillary pressures in transition zone.
NONEQ

! 2 component model without BLACKOIL option.
NX  NY  NZ  NCOMP
15  42  8   2

! LGR over middle of the model, refined in Y direction only

LGR ROOT
  CARTREF MIDDLE
    01 15  12 28  1 8
    15*1
    17*10
    8*1
  ENDREF
ENDLGR

! Set up corner point grid calculation.
CORNER
CORTOL 1.0E-3 1.0E-8 200.0
PINCHOUT
```

```
FAULTS

!Three phase oil rel perm calculation
STONE1

! Various dimensioning parameters
DIM NCDPMX NCBLKS
   20     2000
DIM NSATNT NPINCM
   40     40
DIM NPSATM NNTMAX NREGMX NEQLMX
   40     17000  150    40

! Physical constants
 DWB    BWI   VW     CW       CR    TRES
1.001 1.0249 0.45 0.000046 0.000145 65.0

! ----------------------------------------------------------------------
! Output
! ----------------------------------------------------------------------
! Use text versions of old map output formats.
NOVDB
MAP FORM ALL
PRINT NONE

!
=============================================================================
! Tables
!
=============================================================================
TABLES

! Equilibrium tables.
NOLIST
INCLUDE directory
LIST

! PVT properties.
NOLIST
INCLUDE directory
LIST

! Relative permeability tables.
NOLIST
INCLUDE directory
LIST

!
=============================================================================
! Arrays
!
=============================================================================
ARRAYS
NOLIST

! Include corner point grid:
!  Layer  01       -> Balakhany 8 Upper
!  Layer  02       -> Balakhany 8 Lower
```

```
!  Layer  03       -> Balakhany 10c
!  Layer  04       -> Balakhany 10e
!  Layer  05       -> Pereiv A
!  Layers 06 to 13 -> Pereiv B
!  Layer  14       -> Pereiv C
!  Layers 15 to 18 -> Pereiv D
!  Layer  19       -> Pereiv E
CORP
INCLUDE directory

corp

! ---------------------------------------------------------------------
! Rock Properties.
! ---------------------------------------------------------------------
! The contoured values are always read in, with the stochastic values
! read in as modifiers where they are available.
!
! The aquifer properties are from the old (pre-2000) Azeri Eclipse
! model.

POR VALUE
 INCLUDE directory

KX VALUE
 INCLUDE directory
 MOD
  01 15  04 04  1 8  *0.1 ! North Pereriv B
  01 15  42 42  1 8  *0.1 ! South Pereriv B

KY VALUE
 INCLUDE directory
 MOD
  01 15  04 04  1 8  *0.1 ! North Pereriv B
  01 15  42 42  1 8  *0.1 ! South Pereriv B

KZ VALUE
 INCLUDE directory

! NTG in Pereriv B is the long shale NTG from the Azeri 2000
NETGRS VALUE
 INCLUDE directory
 MOD
  01 15  01 42  1 8  *0.97

! ---------------------------------------------------------------------
! Transmissibility Multipliers.
! ------------------------------------------------------------------
TMX CON
 1.0

TMY CON
 1.0

TMZ VALUE
 INCLUDE directory

! ------------------------------------------------------------------
```

```
! Initial water saturation
------------------------------------------------------------------
SW VALUE
 INCLUDE iclude
------------------------------------------------------------------
! Relative Permeability End Points
------------------------------------------------------------------

SWL CON
 0.112

SWR MULT
 1.0 SWL

! The water relative permeability is altered to give 10% Sorw in
! Pereriv B.
SWRO CON
 0.900

SWU CON
 1.0

SGL CON
 0.0

SGR CON
  0.02

! The gas relative permeability curve is altered to give a 8% Sorg in
! Pereriv B.
SGRO CON
 0.808

SGU CON
 0.888

------------------------------------------------------------------
! Regions
------------------------------------------------------------------

! Define reporting regions.
IREGION VALUE
 INCLUDE directory
 MOD
  01 15  04 04  1 8  =79
  01 15  42 42  1 8  =80

! Define saturation regions.
ISAT VALUE
 INCLUDE directory

! Define equilibration regions.
IEQUIL VALUE
 INCLUDE directory

! Define transmissibility regions.
ITRAN VALUE
 INCLUDE directory
```

```
LIST

--------------------------------------------------------------------
! LGR Array Properties
--------------------------------------------------------------------
ARRAYS MIDDLE
SGR CON
 0.02

--------------------------------------------------------------------
! Functions
--------------------------------------------------------------------
! Cap kx and ky at 1D and kz at 100 mD everywhere.
FUNCTION
ANALYT LE 1000.0 1000.0
KX OUTPUT KX

FUNCTION
ANALYT LE 1000.0 1000.0
KY OUTPUT KY

FUNCTION
ANALYT LE 100.0 100.0
KZ OUTPUT KZ

! Do some end point re-scaling of the oil-water rel-perms.
! Note that if Sw>55%, then we're in the water leg and we shouldn't
! rescale the rel-perms.
FUNCTION
ANALYT LE 0.55 0.112
SW OUTPUT SWL

FUNCTION
ANALYT POLYN 1.0 0.0
SWL OUTPUT SWR

! Now do the same for the gas-oil rel-perms while still honouring the
! trapped oil saturation (held in WORKA1).
FUNCTION
ANALYT SUBT
SGU SGRO OUTPUT WORKA1

FUNCTION
ANALYT POLYN -1.0 1.0
SWL OUTPUT SGU

FUNCTION
ANALYT SUBT
SGU WORKA1 OUTPUT SGRO

!
======================================================================
! Pore Volume and Transmissibility Overrides
!
======================================================================

! Normalise STOIIP and GIIP to probabilistic mean.
```

```
NOLIST
INCLUDE /datavol03/vip/azeri/Azeri_2007/Farid_WAG/Sector/inc/Rock/pvmult.inc
LIST

! Cut out North edge
OVER PV
 01 15  01 03  1 8  =0.0

! Now add in the aquifers
OVER PV
 01 15  04 04  1 8  =4.29E6 ! Pereriv B North
 01 15  41 41  1 8  =3.05E6 ! Pereriv B South

!
==========================================================================
! Inter-Transmissibility Region Connections
!
==========================================================================

! Stop equilibration zones talking to each other.
! (Note that the crest talks to the North.)
MULTIR
 01 02  0.1
 01 03  0.0
 01 04  0.0
 01 05  0.1
 01 06  0.0
 02 03  0.0
 02 04  0.0
 02 05  0.1
 02 06  0.0
 03 04  0.0
 03 05  0.0
 03 06  0.0
 04 05  0.0
 04 06  0.0
 05 06  0.0

!
==========================================================================
! Regions
!
==========================================================================

NOLIST
INCLUDE directory
LIST

! Associate all regions with separator 1 (as per GCA2 PVT definition).
REGSEP 80*1

! *******************************************************************
STOP
END
```

APPENDIX C

SIMULATION MODULE FOR REPRESENTATIVE MODULE

```
=====================================================================
! Utility Data
!
=====================================================================
RUN

DIM NWMAX NPRFMX NPRFTOT NRCMUN NIRMX NBHPMX NBHPV NBHPQ
   20   70     500     6      5     20     30000 20

OPTMBL

IMPES

RESTART 0

TITLE1
Pereriv B Sector Model

TITLE2
Baffled Fault Case

TITLE3
Base Depletion Plan

! ---------------------------------------------------------------------
! Output
! ---------------------------------------------------------------------

NOVDB
PLOT FIELD WELL WLLYR REGION
FLOWVEC
PRINT NONE

START

!
=====================================================================
! Well Management
!
=====================================================================

! ---------------------------------------------------------------------
! Injection Regions
! ---------------------------------------------------------------------
INJRNM 1  NPER
INJRNM 2  SPER

! Area definitions exclude crumply bit at crest
```

```
! JRC - they don't! otherwise GI is not under any voidage control
INJREGN 1
01 15  01 21  1 8

INJREGN 2
01 15  22 42  1 8

! Define method of pressure maintenance
RINJOP INJREG NODIST UNIFORM

! Source water at 1,000 Mstb/day, make up gas at 920 MMscf/day
IRSRCW 158987.0
GASMKP FIELD 1 QMAKE 26051501.0
YINJMK FIELD 1
1 0

IRDIST INJREG TYPVDG PRMEXP TRGPRS RFRPRS TYPPRS   VDGFCT INFLUX
      1      ALL    1.0    330.0  350.0  HCWEIGHT 1.0    YES
      2      ALL    1.0    330.0  350.0  HCWEIGHT 1.0    YES

! ---------------------------------------------------------------------
! Well Definition
! ---------------------------------------------------------------------

NOLIST

WELL N  NAME IW JW GRID
    01 GI1  04 96 MIDDLE
    02 WI1  05 33 ROOT              ! WI 1 cell from OWC
    03 WI2  12 31 ROOT
    04 NP1  X  X  MIDDLE
    05 NP2  X  X  MIDDLE
    06 NP3  X  X  MIDDLE
    07 NP4  X  X  MIDDLE
    08 SP1  X  X  MIDDLE
    09 SP2  X  X  MIDDLE
    10 SP3  X  X  MIDDLE
    11 SP4  X  X  MIDDLE

FPERF
WELL L    SKIN  RADW  GRID   IW   JW
GI1  1 -8 5.0   0.108 MIDDLE 08   96
WI1  1 -8 5.0   0.108 ROOT   05   33
WI2  1 -8 5.0   0.108 ROOT   12   31

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA GRID
NP1   1 02 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     2 02 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     3 02 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     4 02 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     5 03 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     6 03 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     7 03 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     8 03 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA GRID
```

```
NP2   1 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     2 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     3 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     4 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     5 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     6 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     7 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     8 06 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA GRID
NP3   1 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     2 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     3 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     4 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     5 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     6 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     7 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     8 09 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA GRID
NP4   1 13 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     2 13 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     3 13 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     4 13 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     5 14 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     6 14 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     7 14 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE
X     8 14 06  0.108 1.0    1.0E-6 0.0   0.0   MIDDLE

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA RCMPUNT GRID
SP1   1 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     2 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     3 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     4 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     5 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     6 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     7 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     8 03 155 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
SP1   1 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE    ! move sidetrack 03 -> 02
X     2 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     3 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     4 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     5 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     6 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     7 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     8 02 145 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE

FPERF
WELL  L IW JW   RADW  LENGTH ROUGH  ANGLV ANGLA RCMPUNT GRID
SP2   1 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     2 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     3 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     4 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     5 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     6 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
```

```
X     7 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     8 06 145  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
SP2   1 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE   ! move sidetrack 06 25 -> 07 24
X     2 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     3 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     4 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     5 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     6 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     7 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     8 07 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE

FPERF
WELL  L IW JW   RADW  LENGTH ROUGH  ANGLV ANGLA RCMPUNT GRID
SP3   1 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     2 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     3 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     4 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     5 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     6 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     7 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     8 10 135  0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
SP3   1 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     2 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     3 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     4 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     5 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     6 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     7 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     8 10 125  0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE

FPERF
WELL  L IW JW  RADW  LENGTH ROUGH  ANGLV ANGLA RCMPUNT GRID
SP4   1 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     2 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     3 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     4 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     5 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     6 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     7 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
X     8 13 145 0.108 1.0    1.0E-6 0.0   0.0   1       MIDDLE
SP4   1 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE !change 13 -> 14
X     2 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     3 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     4 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     5 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     6 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     7 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE
X     8 14 125 0.108 1.0    1.0E-6 0.0   0.0   2       MIDDLE

NOFRICTION

! Increase PI in line with expected range 20-35-47
WKHMULT WI* NP* SP*
3*2.0

INJ G FRES GI*

! Note the pre-produced water injectors.
```

```
PROD LIQUID STD WI* NP* SP*

C YINJ GI*
C 1.0 0.0

RCMPPERF
WELL RCMPUNT STATUS WCTMAX
SP1  1      OPEN   0.75    ! run initial penetrations to 95% wcut
SP2  1      OPEN   0.75
SP3  1      OPEN   0.95
SP4  1      OPEN   0.75
SP1  2      AUTO   0.95    ! sidetracks used for SP1,2,4 in this run
SP2  2      AUTO   0.95
SP3  2      SHUT   0.95
SP4  2      AUTO   0.95

RCMPOR SP*
1 2

! Lift curves
! Use 7" Pereriv CA near for producers
! No lift curves for injectors
INCLUDE directory
ITUBE NP* SP* WI*
3*8
3*2800
3*2800

NEWBHPTAB NP* SP*
2*7    ! change to 5.5" gas lift completion
2*795  ! change at liquid rate = 5000 stbd

! Gas lift supply
QLIFT NP* SP*
2*-1   ! automatic allocation of gas lift

QLIFTA FIELD 1 679604 PFMCRV ! 24 mmscf gas lift gas available

GLGMAX FIELD 1 169901        ! Maximum well gas lift rate = 6 MMscf/day

! Add produced gas to gas lift gas when calculating efficiency
PFMCRV
TOTGAS ON

----------------------------------------------------------------------
! Initial Well Constraints
----------------------------------------------------------------------
QMAX GI*
    0.0

QMAX WI*
    0.0

QMAX NP* SP*
    0.0 0.0

! Flow wells to "split the difference" HP pressure (40 bar)
THP NP* SP* WI*
```

```
3*40.0

LIST

! ---------------------------------------------------------------------
! Shut Off Controls
! ---------------------------------------------------------------------
! Well Shut-In If GOR Exceeds 5,000 scf/stb (890 m3/m3) in South flank
! and 3,000 scf/atb (534 m3/m3) in North flank
GLIMIT SHUTIN NP*   SP*
          534.0 890.0

! Well Shut-in If Watercut Exceeds 95%
WLIMIT SHUTIN WI* NP* SP*
          3*0.95

! Test wells for limit criteria 1 month after well shut-in
! (-ve value means applied by well from SI time, rather than all wells)
  TEST PRESSURE MOBILITY RATE
     -30.0    -30.0    -30.0

!
=============================================================================
! Output
!
=============================================================================

OUTPUT WELRPT TSSMFG RCMRPT
MAPOUT P PDAT SO SW SG
                           ! PV TX TY TZ VISO VISG DENO DENG KRO KRW KRG FLOWO
SSSUM REGION TAB HEADER DATE  HCPVPD OIP OREC
SSSUM FIELD TAB HEADER DATE COP CWP CGP CWI CGI
PRINT WELLS SSSUM TIME
                           ! REGIONS FIELD
WMAP TIME
WPLOT 3

!
=============================================================================
! Timestep Control
!
=============================================================================

!   dt  dtmin dtmax dPmax dSmax dVmax dZmax
DT -1.0 0.01  30.0  30.0  0.05  0.05  0.05

ITNLIM 1 10 200 0.1 0.1 0.1

TOLR 0.001 0.001 RELTOL SUM

CBLITZ JCPR
    0

IMPSTAB OFF

ITNSTP 3
ITNSTQ 3
PRDWC
```

```
TOLD 0.1 0.0005 0.0005 0.0005

MAXOVR 2.5

!
==============================================================================
! Time and Dates.
!
==============================================================================

DATE 01 01 2005

QMAX NP*    WI*
     1676.0 2650.0

TSTPRF 30.0

DATE 01 01 2006

! Start up gas injection (7% STOIIP/annum in rm3)
QMAX GI*
     9316.9

DATE 01 01 2007

! Turn the water injectors round (9% STOIIP/annum in rb)
INJ W FRES WI*
QMAX WI*
     7368.5

BHP WI*
450.0
2900

QMAX SP*
     2650.0

DATE 01 01 2008

DATE 01 01 2009

DATE 01 01 2010

DATE 01 01 2011

DATE 01 01 2012

DATE 01 01 2013

DATE 01 01 2014

DATE 01 01 2015

DATE 01 01 2016

DATE 01 01 2017

DATE 01 01 2018
```

```
DATE 01 01 2019

DATE 01 01 2020

DATE 01 01 2021

DATE 01 01 2022

DATE 01 01 2023

DATE 01 01 2024

! WREST TNEXT

DATE 01 01 2025

STOP
END
```

APPENDIX D

RELATIVE PERMEABILITY HYSTERESIS. CARLSON'S MODEL

Relative permeability hysteresis is the effect caused by a situation in which the nonwetting phase fluid saturation increases, followed by an increase in the wetting phase fluid saturation. In such a situation in modelling reservoir fluid flow, the imbibition-drainage relative permeability is a function of the historical maximum nonwetting phase saturation. Figure 1D is a set of drainage and imbibition-drainage curves, where k_{rn}^{D} is the user-specified drainage curve, k_{rn}^{ID} is the bounding imbibition drainage curve, and $k_{rn}^{ID`}$ is a generated intermediate imbibition-drainage curve. The end points of the bounding imbibition-drainage curve are S_{nu} and S_{ntr}.

As nonwetting phase saturation increases initially, the drainage relative permeability curve, k_{rn}^{D} , is used. If nonwetting phase saturation monotonically increases, the drainage curve is followed to the end point at S_{nu}. If nonwetting phase saturation then decreases, the bounding imbibition-drainage curve, k_{rn}^{ID}, is used for gas relative permeability. However, if while following the drainage curve, gas saturation decreases before S_{nu} is reached, then an intermediate imbibition-drainage curve, $k_{rn}^{ID`}$, is followed.

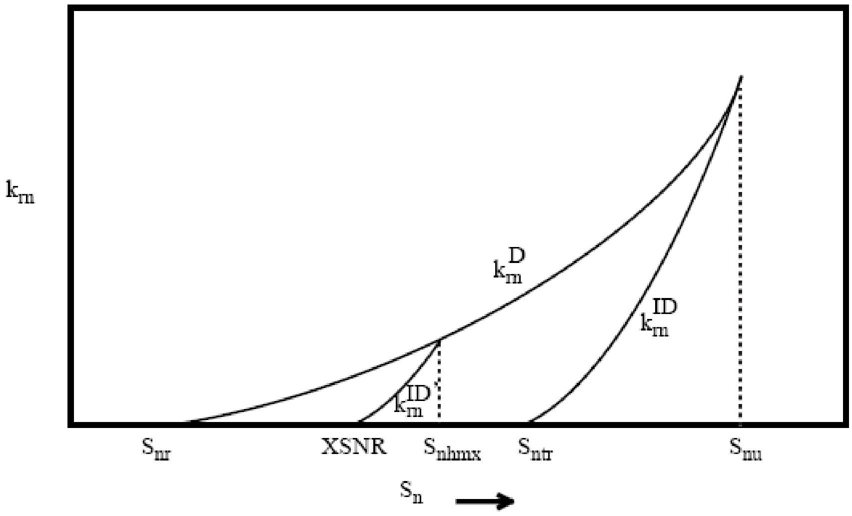

Figure 1D. 1 Nonwetting Phase Relative Permeability Curves for Hysteresis

The end points of a typical intermediate imbibition-drainage curve are the historical maximum nonwetting phase saturation, S_{nhmx}, and the corresponding trapped nonwetting phase saturation, XSNR.

1D. Carlson's Method

Carlson's method allows all intermediate imbibition-drainage curves to be parallel to the bounding imbibition-drainage curve. The historical maximum nonwetting saturation, S_{nhmx}, is tracked for each gridblock. If the nonwetting phase saturation equals or exceeds S_{nhmx}, the drainage curve applies and no special hysteresis calculation is needed. On the other hand, intermediate drainage-imbibition curves are employed if the nonwetting saturation in a gridblock falls below S_{nhmx}. The trapped nonwetting phase saturation for each gridblock is calculated from S_{nhmx} by using Land's formula. There are two options; one using the original Land formula and one using a modified formula. Using the original Land's formula:

$$XSNR = \frac{S_{nhmx}}{1 + CS_{nhmx}} \quad \text{……..1D}$$

Where Land's constant, C, is given by

$$C = \frac{S_{nu} - S_{ntr}}{S_{nu} S_{ntr}} \ldots\ldots 2D$$

Using the modified Land's formula:

$$XSNR = S_{nr} + \frac{S_{nhmx} - S_{nr}}{1 + C(S_{nhmx} - S_{nr})} \ldots\ldots.. 3D$$

Where Land's constant, C, is given by:

$$C = \frac{S_{nu} - S_{ntr}}{(S_{nu} - S_{ntr})(S_{ntr} - S_{nu})} \ldots\ldots\ldots 4D$$

S_{nu} is the maximum possible nonwetting saturation for the gridblock. For oil relative permeability hysteresis, S_{nu} = 1 - connate water saturation. S_{nr} is the critical nonwetting phase saturation for the drainage curve. Carlson's approach assumes that the imbibition-drainage relative permeability is equal to the primary drainage non-wetting phase relative permeability evaluated at the free nonwetting phase saturation:

$$k_{rn}^{ID`}(S_n) = k_{rn}^{D}(S_{npd}) \ldots\ldots 5D$$

Where the free non-wetting phase saturation is defined as:

$$S_{npd} = S_{nr} + 0.5\left[X_{sn} + \sqrt{X_{sn}^2 + \frac{4X_{sn}}{C}}\right] \ldots\ldots 6D$$

And

$$X_{sn} = S_n - XSNR \ldots\ldots.. 7D$$

Carlson's method may result in large derivatives of relative permeability with respect to saturation change near end-point $k_{rn}(XSNR) = 0$. These derivatives may cause convergence problems when using the implicit formulation [9].