CERTIFICATION OF APPROVAL

THE STUDY OF HYSTERESIS EFFECT ON WAG INJECTION

by
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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken by unspecified sources or persons.

Bior Atem Bior

ABSTRACT.

Evaluation of hydrocarbon recovery processes are always faced with more difficult complexities with regards to fluid displacement. These complexities are brought forth by a phenomenon called hysteresis, whereby certain dynamic rock properties and their flow are dictated upon by rock-fluid interaction. In these interactions, three-phase relative permeabilities and capillary pressure exhibit strong dependence on the saturation path and saturation history. Such dependence is characterized by a sequence of three-phase drainage and imbibitions processes which are especially relevant in immiscible water-alternating-gas (WAG) processes.

This paper investigate the impact of using history dependent saturation functions in reservoir simulation on water-alternating gas (WAG) injection, an Enhanced Oil Recovery (EOR) method, aimed at improving sweep and displacement efficiencies. In this work, the author identified the available hysteresis model in the literature that will be used in simulation by applying the experimental data obtained in the literature

A comparison of the simulation results using the hysteresis model and actual field performance data in the literatures is later evaluated as well as the methodology adopted.

Generally the results show that the impact of using three phase relative permeability and hysteresis is significant on the performance of the WAG injection, which must therefore, be considered in the evaluation of the WAG scenario in any field application. Also in this procedure, applying WAG injection with hysteresis effect and residual oil reduction due to gas trapping, the sweep efficiency can improve leading to a better recovery factor.

Keywords: Hysteresis; Drainage and imbibitions; Water-alternating-gas; Three phase flow; residual oil.

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NOMENCLATURE

WAG = Water-Alternating-Gas injection

WAGHYST = Water-Alternating-Gas with Hysteresis effect.

krog = oil relative permeability in an oil-gas system

krow = oil relative permeability in an oil-water system

Sorw = residual oil saturation to water

Sorg = residual oil saturation to gas

SWC = Connate Water Saturation (%)

FOPT = Field Oil Production Total

FOE = Field Oil Efficiency

FWGR = Field Water Gas Ratio.

M = Mobility Ratio

SG = Gas Saturation (%)

OOIP = Original Oil In Place (bbl)

CHAPTER 1

1.0 INTRODUCTION

An Introductory chapter herein this paper will describe brief information of the Project in terms of the background of this study, Problem statement, objectives and project scope.

1.1. Background of the study

Hysteresis effect is defined as a path-dependent relative permeability and capillary pressure curves during drainage and imbibitions cycles. In fact these flow paths are governed by fluid distribution in pores, the pore size distribution and interaction between fluid and the rock.

The imbibitions oil and gas relative permeability curves are generally lower than the drainage curves at the same saturation. However, the imbibitions water relative permeability curve is slightly greater than the drainage curves. This makes hysteresis greatest for gas phase and most important for WAG process. Many porous media, relative permeability values are a non-unique function of saturation, having different values when a given phase saturation is being increased than when it is being reduced. So, neglecting hysteresis effect can have significant effects as it may results into poor sweep efficiency hence less effective oil recovery as anticipated in WAG injection procedure.

WAG has also been used to improve oil recovery by increasing the sweep efficiency as residual oil to WAG is less than water and gas ($S_{sorWAG} < S_{orw}$ & $S_{org)}$. Therefore, WAG injection is aimed at avoiding gravity segregation and provide dispersed flow zone.

1.2. Problem Statement

Hydrocarbon recovery using Water-Alternating-Gas (WAG) injection is associated with high residual oil leading to less oil productivity. This problem comes with the process of injecting water and gas alternatively with periods of injection governed by the particularities of the reservoir, which has been historically used to reduce residual oil. This large amount of oil that remained underground unproduced is attributed by a situation known as gas fingering in which fingers of gas penetrates and leaving large amounts of oil behind due to the higher gas mobility, which becomes highly detrimental to oil recovery. The water injected alternatively with the gas stabilises the gas movement.

1.3. Objective and Scope of Study

Main objective: - To investigate and predict the oil recovery by studying hysteresis effect on WAG injection.

Sub-objectives:

To achieve the main objective these sub-objectives are to be highlighted:

1. Decrease severity of viscous fingering to increase sweep efficiency and gas overriding phenomena as a factor of mobility ratio of both oil and water
2. Accounting for the high residual oil saturation in the reservoir

Three- phase relative permeability values to oil, water and gas are very crucial for prediction of the reservoir performance and estimation of oil recovery under this process by putting into account capillary pressure. Generally, the aim of this study is to model and simulate the performance of WAG processes of oil recovery by comparing two case scenarios.

1. Creating a base case for WAG without hysteresis consideration; the base case is named as WAG BASE-CASE.

2. Simulating another case of WAG with hysteresis effect considered; the base case is called WAGHYST.

All these two cases will be run in ECLIPSE 300 (E300) since black oil model; ECLIPSE 100 is not compatible with compositional model. Both models will need reservoir properties, PVT data, and the WAGHYST need more additional data of components, drainage and imbibitions data. Some other appropriate and realistic engineering assumptions are considered in this study to achieve the objectives.

1.4. Significance and Relevancy of the Project

WAG injection is one of the most relevant EOR methods use in the tertiary recovery of hydrocarbons. Selection and optimization of WAG processes are very crucial in Reserves recovery in reservoir engineering section. The main concern in the industry is the cost factor where the cost of equipments, injection criteria, types of injections chemicals used are screened properly to maximize recovery and minimize cost. Thus, it would be of great advantage if the performances of the most of reservoirs recovery factors are optimized. Thus this project will assist in:

- The reduction of residual oil in the reservoirs/fields by optimizing sweep efficiency and increased recovery due to the hysteresis effect in WAG cycles
- Carters for trapping of fluids (oil and gas) as a result of irregular reservoir geometries,

- The WAG cycles decrease the viscosity of heavy oil hence easily flow to the producer wells and avoid gas fingering.

1.5. Feasibility of the Project within the scope and time frame

- Time allocated approximately 28 weeks
- Sufficient, for data acquisition and analysis on each procedures & compilation
- No equipment or lab experiment needed
- Simulations –Eclipse software (E300)
- Sufficient research paper/journal : One petro website
- Reference books & manual available : UTP IRC

Therefore, all the necessary equipment and the information are available for the study and the project is expected to be finished within the time frame.

CHAPTER 2

2.0. LITERATURE REVIEW

In the recent studies, the effect of relative permeability hysteresis on geological CO_2 storage in saline aquifer showed that only two phases (gas and saline) are needed to describe the injection of CO_2 (Kumar et al., 2004; Ozah et al., 2005; Spiteri et al., 2005) [1]. This didn’t so much put into account how using two-phase flow model best describes a multiphase reservoir consisting of oil, water and gas as the CO_2 injection as a recovery method cannot carter for a more complex three relative permeability flow.

Elizabeth J. Spiteri, Ruben Juanes (2005) [2], explained the impact of relative permeability hysteresis on numerical simulation of WAG injection that WAG injection cannot be modelled without accounting for hysteresis effect. They also reported a disparity they obtained when they used three-phase relative permeability data of Oak (1990) [3] for validation of relative permeability models with permeability interpolation models (Stone, 1970, 1973; Baker, 1988) [4] at the region of low oil saturation which according to them is the region of interest for WAG applications. Killough (1976), Carlson (1981) investigated trapping of the non-wetting phase using “two-phase” hysteretic models which failed to reproduce any good results on the irreversibility of relative permeability scanning curves. These models showed an overestimated result of gas relative permeability during gas injection following water flooding after implementing it in reservoir simulators [5].

Larsen and Skauge (1998) both proposed the currently available and being preferentially accepted in representing hysteresis which is considered convenient with the experimental data. All these explains how characteristic parameters that describe multiphase flow in porous media as process dependent [6].

In the recovery processes the immiscible WAG is much dependent on the saturation cycles that occur in core-flood for an experimental investigation. This needs numerical models with effective cycle-dependent hysteresis description of the three-phase oil, water and gas relative permeabilities.

A similar study, Relative Permeability hysteresis, for laboratory measurement and conceptual model by E.M. Baurun, SPE and R.F.Holland [7] , Exxon Production

Research Co. stressed that the relative permeability scanning curves that have measured for water- and mixed-wet rock show in both cases, that oil relative permeability was a weaker function of saturation on scanning curves than on either the imbibition or secondary-drainage curves, and as has been previously reported, little hysteresis occurred in water relative permeability; drainage, imbibition, and scanning curves were in close agreement. However, on the other hand when they compared the measurement of both water- and oil-wet samples, oil relative permeability scanning curves were shown to be reversible. Hence, this made them postulated that reversibility is associated with pinning of water/oil interfaces on pore walls which occur as a result of contact angle hysteresis in water-wet rock

2.1.0. Two-Phase and Three-Phase Hysteresis Models

The displacement process of each phase and also the hysteresis effect depend on the fluid distribution in the pore space. This therefore, implies that most hysteresis models are formulated with different behaviour for wetting and non-wetting phases. Other parameters like wettability and capillary pressure are seen to affect the multi-cycle flood but for this paper, hysteresis is the main focus.

Two types of hysteresis models which are presented in the literature are summarised below:

2.1.1. Two-Phase hysteresis models

These use empirical models which include trapping of non wetting phase and permeability reduction when processes are reversed. But subsequent saturation changes are seen to be reversible with no further permeability reduction. These models have been the mostly used.

2.1.2. Three- Phase hysteresis models

- **Treatment Of Three-Phase Relative Permeabilities**

To' predict three-phase relative permeabilities, the hysteresis simulator incorporates 'the revised model of Stone. Relative permeabilities in both two-phase systems (water-oil and gas-oil) are first treated as independent events. In the water-oil system, the relative permeabilities become functions only of water saturation and the maximum historical hydrocarbon saturation. Similarly, in the gas-oil system, relative permeabilities are calculated as a function of gas saturation and historical maximum gas saturation. Finally, given' the hysteretic, two-phase relative permeabilities, three phase oil relative permeability (for water-wet systems) is calculated using the predictive equation of Stone,

This one includes trapping of gas and reduction of wetting phase permeability in the presence of trapped gas. The intermediate wetting phase permeability is calculated using an interpolation formula which is modified to allow for the impact of trapped gas. These models are used in prediction of reduced gas permeability and increased trapping of gas on the second and subsequent gas injection cycles.

The author will focus on hysteresis models which best investigate and predict the future high increase of oil productivity during WAG processes. Hysteresis analysis will be carried out for a typical three phase flow during WAG process by using Killough's method, the nonwetting phase relative permeability along a scanning curve–computed as:

$$k_{ro} = k_{ro(cw)}\left[\left(\frac{k^{i}_{ro(w)}}{k_{ro(cw)}} + k^{d}_{rw(o)}\right)\left(\frac{k^{d}_{ro(g)}}{k_{ro(cw)}} + k^{d}_{rg(o)}\right)\right].$$

$$k^{i}_{rg}\left(S_g\right) = \frac{k^{i}_{rg(o)}\left(S_{g,norm}\right)k^{d}_{rg(o)}\left(S_{g,hy}\right)}{k^{d}_{rg(o)}\left(S_{g,max}\right)}$$

Land's parameter C, definition

This parameter governs the trapped gas saturation on imbibitions and the shape of the imbibitions curve. The trapped gas saturation is given by:

$$Sg_{trap} = Sg_{cr} + (Sg_{m} - Sg_{cr}) / (1+C\,.(Sg_{m} - Sg_{cr}))$$

Where Sg_{trap} is the trapped gas saturation
Sg_{m} is the maximum gas saturation
Sg_{cr} is the critical gas saturation

2.2 Effect of Trapped Gas on Residual Oil Saturations

In many literatures it has been shown that the presence of trapped gas should lower residual oil saturations and, hence, improves recoveries in waterflooding situations.

Based on those results, simulation studies have been made showing the effect of trapped gas saturation on simulation results; however, simplifying assumptions as to the residual oil saturations' were made in all these reports. By combining the hysteresis model with Stone's predictive equation for three-phase, oil relative permeabilities, and the hysteresis simulator can predict more realistic residual oil saturations. Results of one-dimensional, three-phase simulations demonstrate the effect of various data on oil recoveries.

The researchers who worked on these processes described these multiphase fluid relative permeabilities under different situation to account for their suitability. In that two phase relative permeability curves are measured in laboratories routinely unlike the measurements of three phase relative permeability curves which are very difficult. It is therefore common to use correlations for estimation of these curves. The most well known correlations for calculating three phase oil relative permeability are the Stone I and the Stone II methods [8]. However, a special case arises in the simulation of processes where the saturation is oscillating, such as the WAG process where injection normally is made in slugs. In this case trapping of the gas phase may occur, when injected water invades areas already swept by gas which resulted into hysteresis in the shape of the relative permeability curves, since the space available for liquid movement in the rock decreases (due to the presence of immobile gas). In such cases not only the three-phase relative permeability, but also the hysteresis must be modelled.

2.3. WAG Processes

Owing to the aim of the WAG injection process which is to squeeze more oil out of the reservoirs, most literature investigated and found out that the remaining (residual) oil in the flooded rock may be lowest when three phases – oil, water and gas – have been achieved in this volume. This is because water injection alone tends to sweep the lower parts of the reservoir, and the injected gas alone sweeps more of the upper parts of a reservoir to cancel the effect of gravitational forces.

2.3.1 Water/Gas injectivity

The sweep efficiency in many types of reservoirs such as stratified reservoirs, and also the profile control by WAG injection, is related to the injectivities of water and gas slugs in different layers of the reservoir. WAG injection is assumed to reduce the penetration of water in high permeability layers, compared to continuous injections. Injected gas, being the most mobile phase, enters preferentially the high

permeability layer and due to the three-phase and compressibility effects, water injectivity in the following up injection is reduced. Reduction of water injectivity can also be a result of the redistribution of pressure profiles when the injectant is changed from gas to water and vertical permeability is limited.
This results in a larger fraction of gas entering the highest permeable layer with WAG

It therefore, means that the three- phase, oil and water flow is better at displacing residual oil in the pore system than two-phase flow. WAG and SWAG thus improve the efficiency of both microscopic and macroscopic displacement. The challenge is to achieve sufficient sweep in the reservoirs.

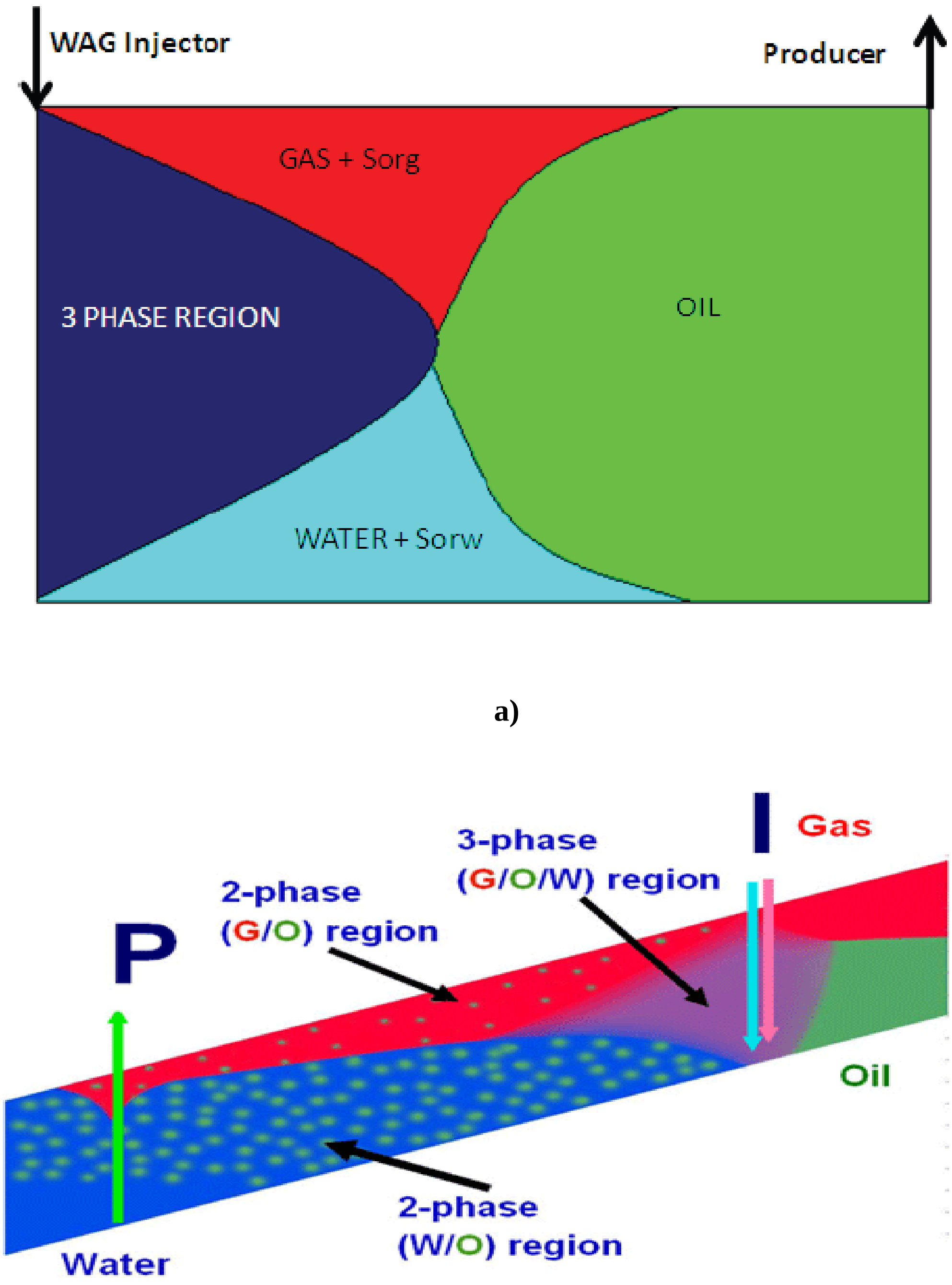
Some few consistent three-phase models for capillary pressure and relative permeability have been implemented in compositional eclipse in an effort to improve the ability to model hysteresis and miscibility effects. The model permits the use of primary drainage, imbibitions and secondary drainage data for both gas-oil and oil-water systems.

2.3.2. WAG Injection Rate

The dependence of oil recovery on viscous to gravity ratio is not uniform throughout reservoirs. The increase of injection rate does not always lead to the total recovery improvement from the whole reservoir. Different flow regimes can occur in different layers at the same time. In the section with restricted vertical permeability an increase of injection rate may even decrease the relative volume of gas entering the top low permeability zone. The higher injection rate improves oil recovery in the high permeability.

2.3.2 Gravity-stable displacement.

Gas injection alone has generally poor sweep efficiency because the low viscosity injected gas penetrates the oil bank with fingers leading to early breakthrough.
Low gas density leads to segregation and overriding. With low injection rates up-dip of the production well, gravitation hinders fingering. A particularly successful application of this recovery method has been the gas injection in stratigraphically low wells in the upper Statfjord formation of the Statfjord field (Haugen et al,, 1988) with stratigraphically high oil production wells in a down-dip line [9].



a)

b)

Figure 1.1: (a) Fluid Phases in WAG flooding (b) Segregated flow during up-dip WAG injection.

The WAG injection process aims to squeeze more oil out of the reservoirs. It is well known that remaining (residual) oil in the flooded rock may be lowest when three phases – oil, water and gas – have been achieved in this volume.

Water injection alone tends to sweep the lower parts of a reservoir, while gas injected alone sweeps more of the upper parts of a reservoir owing to gravitational forces.

Three-phase gas, oil and water flow is better at displacing residual oil in the pore system than two-phase flow. WAG and SWAG thus improve the efficiency of both microscopic and macroscopic displacement. The challenge is to achieve sufficient sweep in the reservoirs. A consistent three-phase model for capillary pressure and relative permeability has been implemented in compositional eclipse in an effort to improve the ability to model hysteresis and miscibility effects. The model permits the use of primary drainage, imbibition and secondary drainage data for both gas-oil and oil-water systems.

Carbon dioxide is usually injected in a WAG mode. Although carbon injection is treated as a separate technology in this strategy work, all the above-mentioned challenges are also relevant for the greenhouse gas.

These technologies are key to optimising WAG injection procedures and to improving forecasts, and thereby to creating value by improving oil recovery.

CHAPTER 3

3.0 RESEARCH METHODOLOGY

There were mainly two different approaches used in completing this project. These are analytical approach, and simulation approach.

3.1.0. Project Activities and Work Flow

Throughout this project, steps that are carried out were planned carefully as described herein the flow chart.

The study is carried out in two major phases. Phase one will involve the researching of the principles, application and industry best practices of WAG injection in multiphase relative permeability flow with and to compare the cases of WAG techniques that used hysteresis. So, this part which is primarily a research-based will be achieved through literature and industry papers. Phase two which involves modelling and simulation will be achieved by using available hysteresis models in ECLIPSE Simulator for WAG techniques and the obtained data from literature are inserted to generate results.

3.1.1. The project flow will be as presented below.

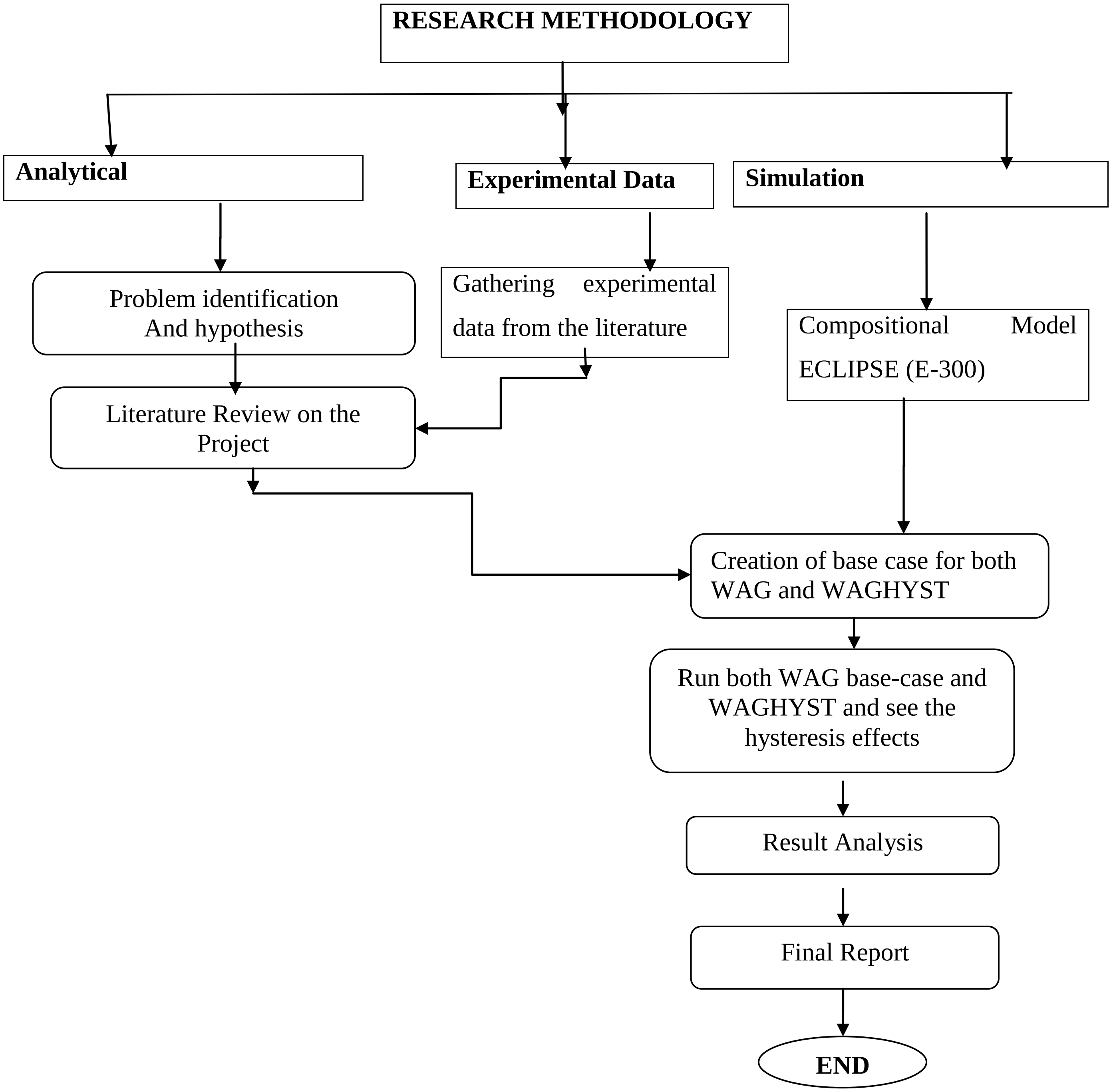
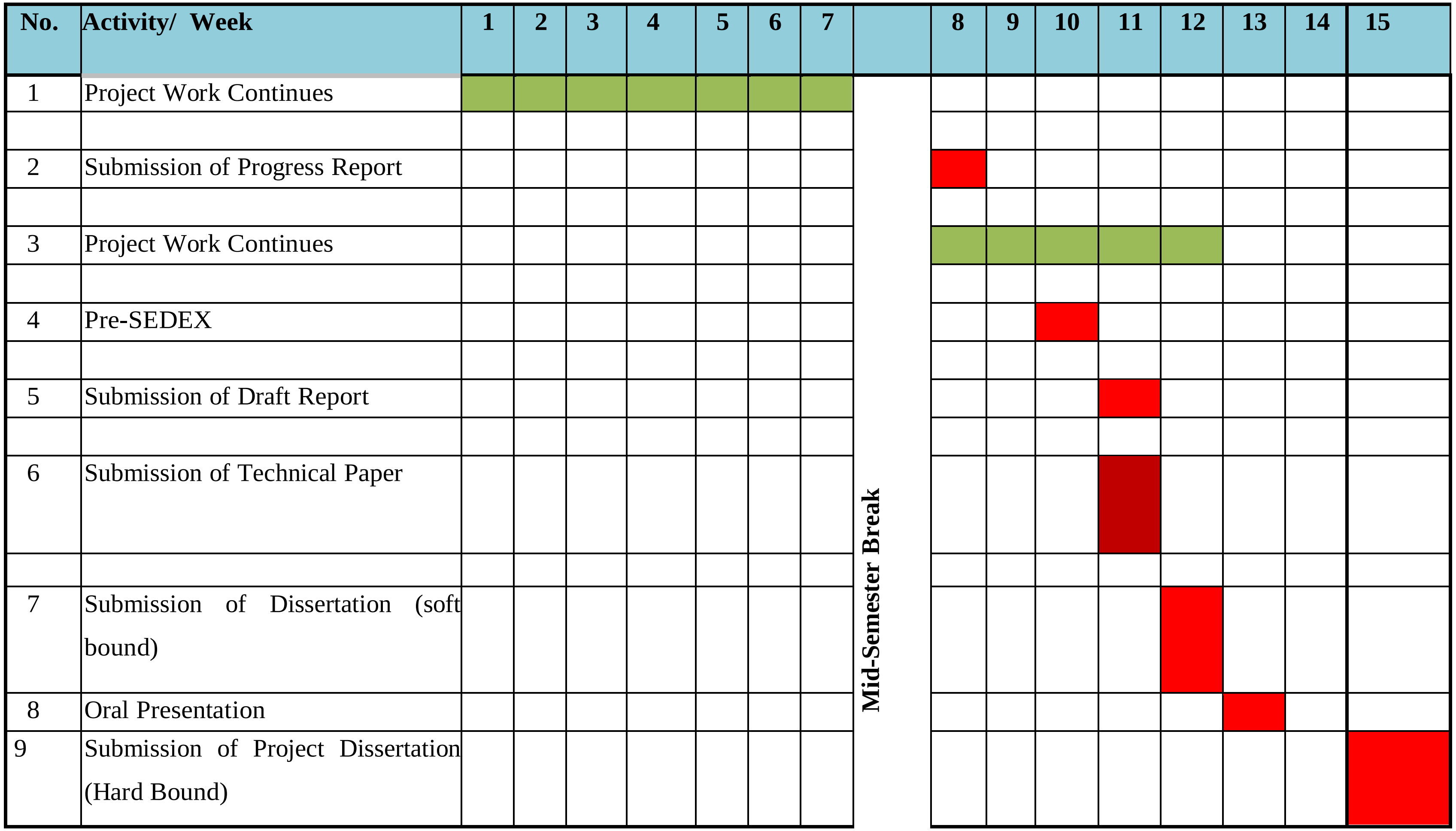


Figure 3.1.1: Project Flow Chart

3.1.2 Project Progress

No.	Activity/ Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15
1	Selection of Project Topic	🟩	🟩						**Mid-Semester Break**								
2	Extensive study on Hysteresis effect,			🟩	🟩	🟩											
3	Project Work Continues Study, Research and Write Literature					🟩	🟩										
4	Submission of Extended Proposal							🟥									
5	Proposal Defense									🟩	🟩						
6	Data collection and Modelling											🟩	🟩	🟩			
7	Interim Draft Report														🟥		
8	Submission of Interim Report															🟥	

Figure 3.1.2: Gantt chart for FYP 1



No.	Activity/ Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15
1	Project Work Continues	🟩	🟩	🟩	🟩	🟩	🟩	🟩	Mid-Semester Break								
2	Submission of Progress Report									🟥							
3	Project Work Continues									🟩	🟩	🟩	🟩	🟩			
4	Pre-SEDEX											🟥					
5	Submission of Draft Report												🟥				
6	Submission of Technical Paper												🟥				
7	Submission of Dissertation (soft bound)													🟥			
8	Oral Presentation														🟥		
9	Submission of Project Dissertation (Hard Bound)																🟥

Figure 3.1.3: Gantt chart for FYP 2

3.2.0. Project activities and Tools required.

Computer workstation Lab equipment

- Computer lab block 15
- ECLIPSE software(Compositional Model-E300)

ECLIPSE 300 is used when there are a number of components to be defined in the simulator simply because Black oil model (Eclipse-100) cannot handle the compositions. Therefore, E300 is the compatible software for WAG processes. Two cases of WAG injection processes are being run in this simulation work:

- WAG base case comprising of all the data in the file including the components and the equation of state (Pengu-Robinson) that defines the properties of these components in the simulator. This WAG injection case is run without considering hysteresis effect and it is here in this report referred to as WAG BASE-case.
- The second simulation is WAG injection run which considers hysteresis effect in displacing the oil in the three phases. The simulator also has the definition for the six components used clearly defined in the first model but this include more other properties for hysteresis runs which are drainage and imbibitions.

The two cases use Stone I and II in converting two-phase relative permeabilities to and three relative permeabilities. In the WAG hysteresis mode, the l aim is to provide a simple method of modeling these 3-phase effects. The model essentially consists of three components: a non-wetting phase model for the gas phase, a wetting phase model for water and a modification to the residual oil saturation in the STONE 1.

For the Water wet hysteresis models, Killough’s Hysteresis Model is selected in the simulator to be used for both wetting and non-wetting phases and Carlson’s Hysteresis Model to be used for the non-wetting phase(s)- defines both imbibition and drainage number and saturation functions used in the data file for the simulation in E300 to define the curve used for the wetting phase.

Table 1. Project Activities in details

Preliminary Research

- Conduct literature review on WAG techniques, Three phase relative permeabilities hysteresis, current technology of evaluating the effectiveness of sweep and displacement efficiencies

Data Setup

- Variable Identification: Factors that sweep efficiencies and displacing of oil during WAG injection(viscous fingering, early water breakthrough, and gas trapping)
- Processing Identification: The injection criteria; WAG cycle periods (slug lengths), and WAG ratio (slug ratio) are defined.

Analysis of Results

- The simulation is started and the WAG injection cycles are being changed alternatively
- Several graphs are generated for oil recovery, cumulative oil production, GOR, watercut and others.

Discussion of Results

- The findings are discussed and the best WAG injection based on the simulations, the correlation between simulation and experimental results is understood and then best technique which answers the problem of sweep efficiency is recommended.

Report Writing

- Compilation of all research findings, literature reviews, simulation works and outcomes into a final report

3.2.0 SIMULATION APPROACH

To execute this simulation, the parameters that are used in the simulator are defined. These parameters are ;the three fluid phase that are involved, water, gas and oil; Well dimensions (8*8*4); displacement gas components which are used(6 components) and their compositions; rock properties (porosity); fluid properties (saturation for water, gas and oil, relative permeabilities for the three fluids, capillary pressures, densities), which are defined in the simulation data file. The WAG injection cycles are grouped into three phases for the well WAG injection and oil production of for 20 years as follows:

3.2.1 First WAG Injection cycle

Oil production rate is at 12000 STB oil per day with a minimum bottomhole pressure of 1000 psia for the first two years with no injection. From year 2 WAG injections begins with one year cycle at a maximum injection Bottom-hole Pressure of 10,000 psia with the following:

- Gas Rate at 15,000 MCF/D and
- Water Rate: 15,000 STB/D.
- Slug lengths; 3 months, 6 months, 12 months and 36 months

The cycle goes as:

- 0.0 to less than 2.0 Years Production only
- 2 to less than 3.0 Years Water Inj. plus Production.
- 3 to less than 4.0 Years Gas Inj. plus Production.
- 4 to <5.0 Years Water Inj. plus Production.
- 5 to <6.0 Years Gas Inj. plus Production.
- 6 to <7.0 Years Water Inj. Plus Production.
- 7 to < 8 years Gas injection plus Production.

3.2.2 Second Injection cycle

Oil production at 12000 STB oil per day with a minimum bottomhole pressure of 3000 psia . The WAG injection begins at time 0.0 on a standard three month WAG cycles.

- Injection Bottomhole Pressure = 40000 psia maximum,
- Gas Rate = 15,000 MCF/D,

- Water Rate = 30,000 STB/D.
- 0.0 to less than 91.25 days water injection plus production
- 91.25 to less than 182.5 days Gas injection plus water production
- 182.5 to less than 273.75 days Water injection plus production
- 273.75 to less than 365.0 days Gas injection plus production
- 365.0 to less than 456.25 days Water injection plus production
- 456.25 to less than 547.6 days Gas injection plus production

3.2.3 Third Injection cycle

The Oil production rate is at 12000 STB oil per day with a minimum bottomhole pressure of 1000 psia. The Production is only for one year, then production plus water injection only for one year. Begin another WAG injection at time 2.0 years on a standard three month WAG cycle.

- Injection Bottomhole Pressure: 4,500 psia maximum.
- Gas Rate = 60,000 MCF/D,
- Water Rate = 30,000 STB/D.
- 0.0 to < 365.0 Days Production Only
- 365.0 to < 730.0 Days Water Inj. plus Production.
- 730.05 to < 821.25 Days Water Inj. plus Production.
- 821.25 to < 912.5 Days Gas Inj. plus Production.
- 912.5 to < 1003.75 Days Water Inj. plus Production.
- 1003.75 to <1095.0 Days Gas Inj. plus Production.

3.3.0 Properties Studied In This Work.

The multivariate responses are based on several simulations where the simulation model parameters are varied. Predicted observations from the simulation model are collected for each set of parameters. The parameter values must also be considered. The "true" values are found from the simulation model that matched the experimental observations, but in order to obtain a multivariate response, these parameters have to be varied in some way.

3.3.1 WAG injection cycle, gas/water ratios

The effect of water-gas ratio are studied for both WAG cycles without hysteresis (WAGBASE-case) and WAG cycle with three phase relative permeabilities hysteresis considered (WAGHYST). The ratios are the varied volumes of water and gas injections respectively for the duration of the well which 20 years and the behavior of the well is later described based on its oil recovery, water-cut, GOR and gas production; all collected and the producer well.

3.3.2 WAG Slug lengths (Months)

Duration of WAG cycles was varied from with respect to injection time and they were after every 3, 6, 12, and 36 months. Percentage oil recovery, Cumulative oil production, amount of water-cut, Gas Oil ratio (GOR), cumulative water produced were then studies. For each injection cycles for all the above different WAG slug injection periods, the same volumes of water and gas were used (a ratio of 1:1; 15,000 MCF/D for gas injection and 15,000 STB/D for water injection). This was done for the two cases of WAG processes with and without hysteresis.

A gas/water ratio of 1:1 and 3 months of slug injection is selected for the sensitivity study.

Table 2. Reservoir rock and Fluid properties

Reservoir rock		**Reservoir Fluid**	
Parameters	**Values-units**	**Parameters**	**Values-units**
Reservoir size	500 x 500 x 50 ft	Water density	62.4 lb/ft^3
Number of grids	8 x 8 x 4	Water viscosity	0.6 cP
K_x x K_y x K_z	200 x 200 20	Oil density	52.02 lb/ft^3
Kx/Kh	0.1	Oil viscosity range	3.2 cP
Porosity	0.2	Initial oil saturation	0.75
Reference Depth Initial pressure at Reference depth	84000 ft 4000 psi	Initial water saturation	0.25
Res. temperature	100 ^{0}f	Residual oil saturation	0.35
End point of water relative permeability K^{0}ro	0.45	Irreducible water saturation	0.45

End point of water Re.perm K^0rw	0.4	Residual gas saturation	0
Pore Volume, MM RB	78	Sgrmax	0.25
OIIP, MM STB	90	End point mobility	12-18
HCPV, MM RB	100		

Table 3: Three-phase hysteresis model (simulation data)

Reservoir pressure	900 psi
Average porosity	0.2
Sorw	0.75
Swi	0.25
Reservoir size	500 x 500 x 50 ft
Number of grids	8 x 8 x 4
K_x x K_y x K_z	200 x 200 20
Kx/Kh	0.1

CHAPTER 4

4.0 RESULTS AND DISCUSSSION

4.1.0 SIMULATION RESULTS

In this study we refer to WAG-case as conventional IWAG simulation without three-phase relative permeability hysteresis whereas the simulation with hysteresis is named as WAGHYST. Both cases WAG and WAGHYST models have been run with Eclipse 300 (E300), using field data and parameters extracted from literatures.

All results are based on a sector model of a representative reservoir that was previously considered for WAG injection.

The sector model contains two wells: an injector and a producer. The injector is a vertical well, which is perforated throughout the oil column and the producer is a horizontal well located updip compared to the injector. There are a limited amount of high permeable strikes from producer to injector, which can limit the sweep efficiency of gas and water and reduce the recovery potential for WAG. The reservoir model has a negligible transition zone and no initial gas cap. The total volume of oil is about 520 M RB and there is no solution gas in the simulations.

To do these analyses three different simulation strategies are presented:

a) Comparison of WAGHYST and WAG BASE-case WAG injection with gas water ratio 1:1 and slug lengths of 3.,6.,12., and 36 months
b) Comparison of WAGHYST and WAG BASE-case WAG injection with gas water ratio 1:2, 1:4, 2:1 and 4:1 at 3 months gas injection periods.

In the WAG processes, primary injections include gas injection and water injection which are used to define the relative permeabilities of water, oil and gas. In the WAG processes, the model does not incorporate gas trapping, three-phase relative permeability effects of gas and water and reduction of residual oil in presence of trapped gas. The WAGHYST model, however, addresses all these items.

The primary investigation can be done to compare the following parameters:

i. Total oil Production between WAGHYST and WAG injection scenarios
ii. GOR for both cases and Water cut and total amount of water produced.
iii. Field Oil Recovery for WAGHYST and WAGBASE-case

4.1.1. Comparison of Total Oil Production for WAGHYST and WAG BASE-case

The oil production from the WAG BASEcase and WAGHYST models are given in Figure 4a and Figure 4b. From this simulation results it's shown that the WAG BASE-case simulations predicts a total oil production during 20 years from 57 to 61 MMST depending on the WAG slug length, while the similar figures for the WAGHYST varies from about 59- 64 MMSTB. The WAG slug lengths vividly has shown how injection periods plays a significant role in WAG cycles in such a way that if we increase the injection lengths, the life of the reservoir is extended and the cumulative oil productions entirely depends on how our cycles last in the field's life. Therefore, the shorter the cyclic periods the lower the cumulative oil and the longer the cyclic period the higher the cumulative oil production. From this simulation several observations were noted:

4.1.2. Comparison of Total Oil Production for WAGHYST and WAG BASE-case:-

4.1.2.1. Total oil Production between WAGHYST and WAG injection scenarios

In this simulation, the WAG BASE-case tends to predict similar Field oil cumulative production for a certain period of injections until a point in time is reached where the cumulative oil production became independent of the slug lengths. The same trends were observed for water-cut and GOR. Figure 4(a) showed these trends in slug lengths, in that from first year of injection until Year 9, there is no observable change in the production profiles. A minor shift in production profiles manifested itself from year 9 to year 10 of the slug lengths and suddenly a major shift in production profiles is observed at a slug length of 10 to 20 years for WAG BASE-case. This latter sharp rise is explained with the consideration of gas tendency to segregate to the top of the reservoir or in high permeable regions when large amounts of gas are injected over a long period. Therefore, the slug lengths increases the amount of each fluid injected in the reservoir. With the increasing amount of gas in the reservoir and coupled with the low viscosity of gas, then comes in the gas tendency to collect at the top most part of the reservoir this happens when hysteresis effect of imbibitions is not accounted . However, the alternate water cycle is regarded to stabilize the gas front, this is especially important for a down-dip WAG injection where gravity effect is eminent. Thus the 36 months slug lengths clearly showed these phenomena as the recovery is above all because, as the alternate water injection reduces the viscosity of the injected gas, the mobility ratio of the displacing fluids is lowered and hence no more gas fingering as well as no water breakthrough thereby increasing the microscopic sweep efficiencies.

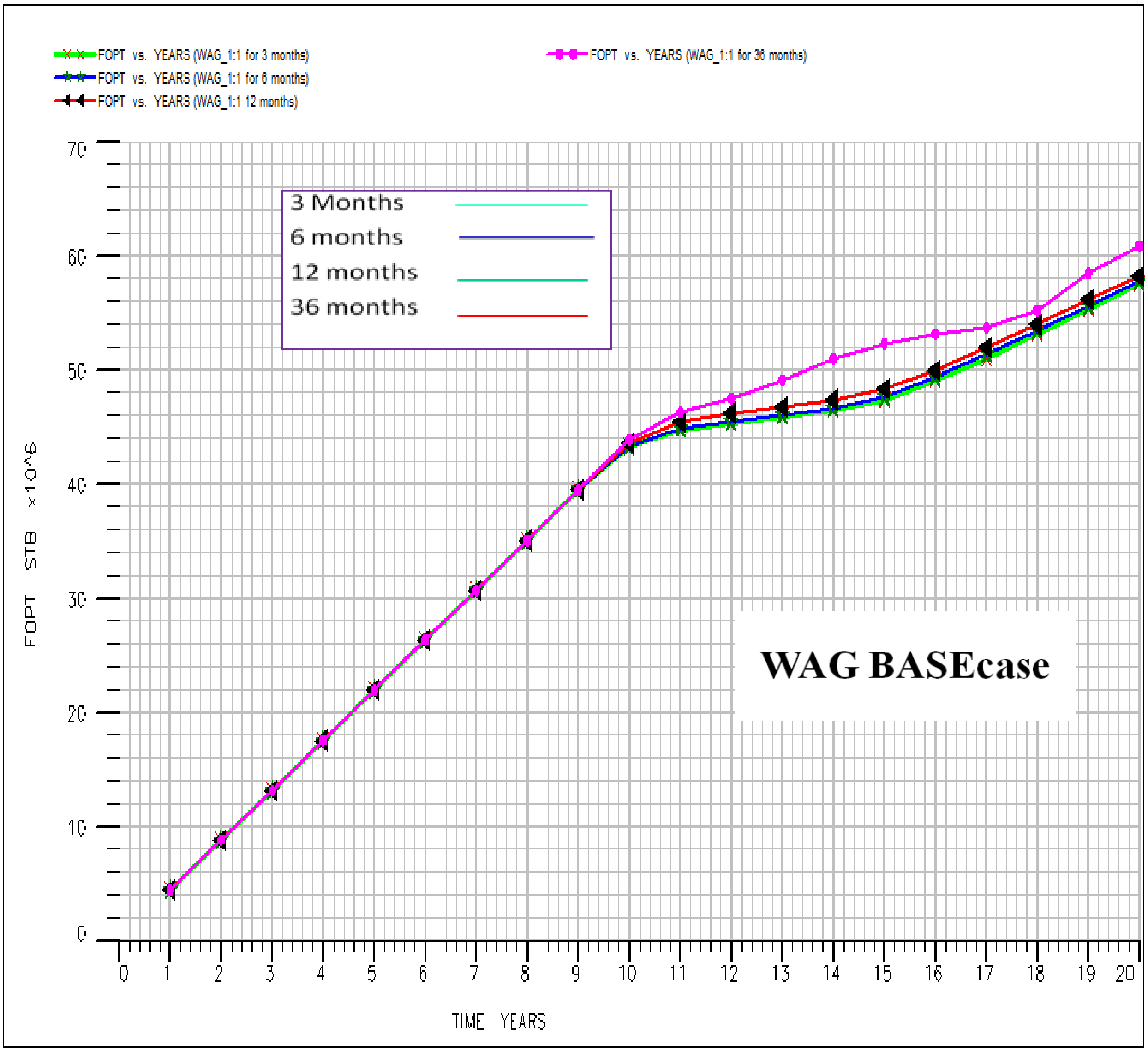


Figure 4a): Oil production at different WAG slug injection lengths for WAG BASE-case

i. Case two by considering hysteresis in WAG injection cycles

In Figure 4 (b) below the trend of Field cumulative oil production profiles depend most entirely on the same slug lengths and with additional imbibitions effect encountered as a consideration of hysteresis. In this case the displacing phase saturation is increased and this additional water has to occupy a space formerly occupied by oil thereby leading to production of an equal volume of oil at the producer well. This WAG processes when coupled with hysteresis carters for the gas trapping because as the mobility ratio of the displacing fluid(water and gas) in this case are lowered, the movement of these fluid behind oil becomes stable. The oil moves forward in the unswept zones in front while the gas and water flow from behind oil. In cases where the injected gas dissolved in the oil depending on their miscibility pressures, the viscosity and density of the oil is lowered, and consequently lowers the interfacial tension (IFT) to zero or nearly insignificant. At this stage the mixture of gas and oil expands and hence aids on the microscopic weep efficiency. Then, the tendency of trapped gas is reduced and more so the displacing fluids maximally contact the reservoir more efficiently

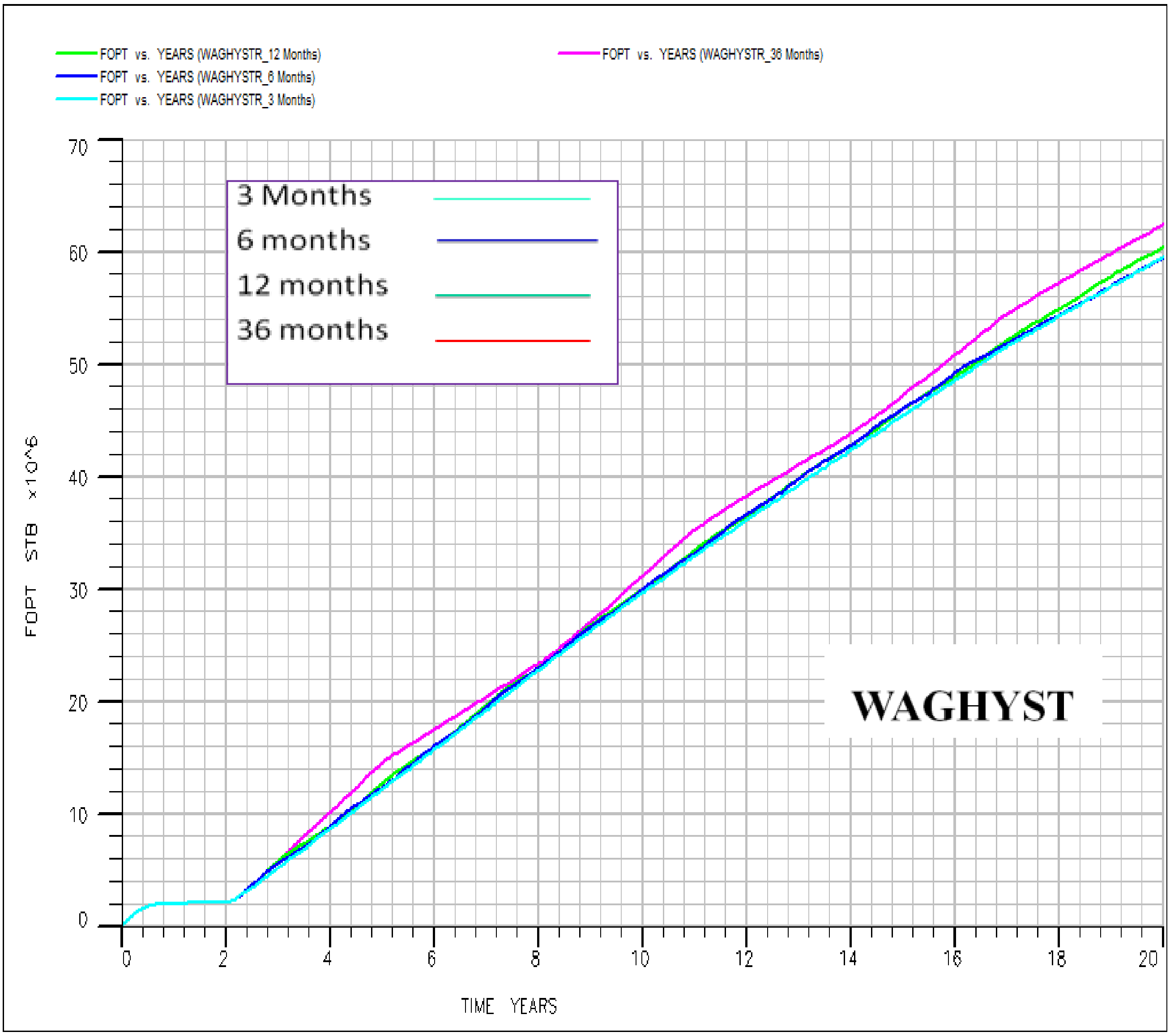


Figure 4b: Oil production at different WAG slug injection lengths for WAGHYST.

i. Comparing GOR

The production profiles from the WAGHYST simulations show a larger sensitivity on slug length than the WAG BASE-case simulations as seen from a shorter length of the sharp rise in GOR at 6 to 11 years and then reduce rapidly. This is observation is probably caused by local hysteresis effects which is dependent on the details in the injection scheme. From Figure 5b- the WAHYST case, it is also observed that at high injection volume of gas, there is much amount of GOR collected at the producer well (at the gas/water ratio of 4:1) compared to the ratio of 1:1. These results show the importance of including hysteresis in field-scale simulation in order to optimize the WAG process. The oil production, water-cut and GOR trends from the slug length sensitivity are also different for the WAG BASE-case model and the WAGHYST model.

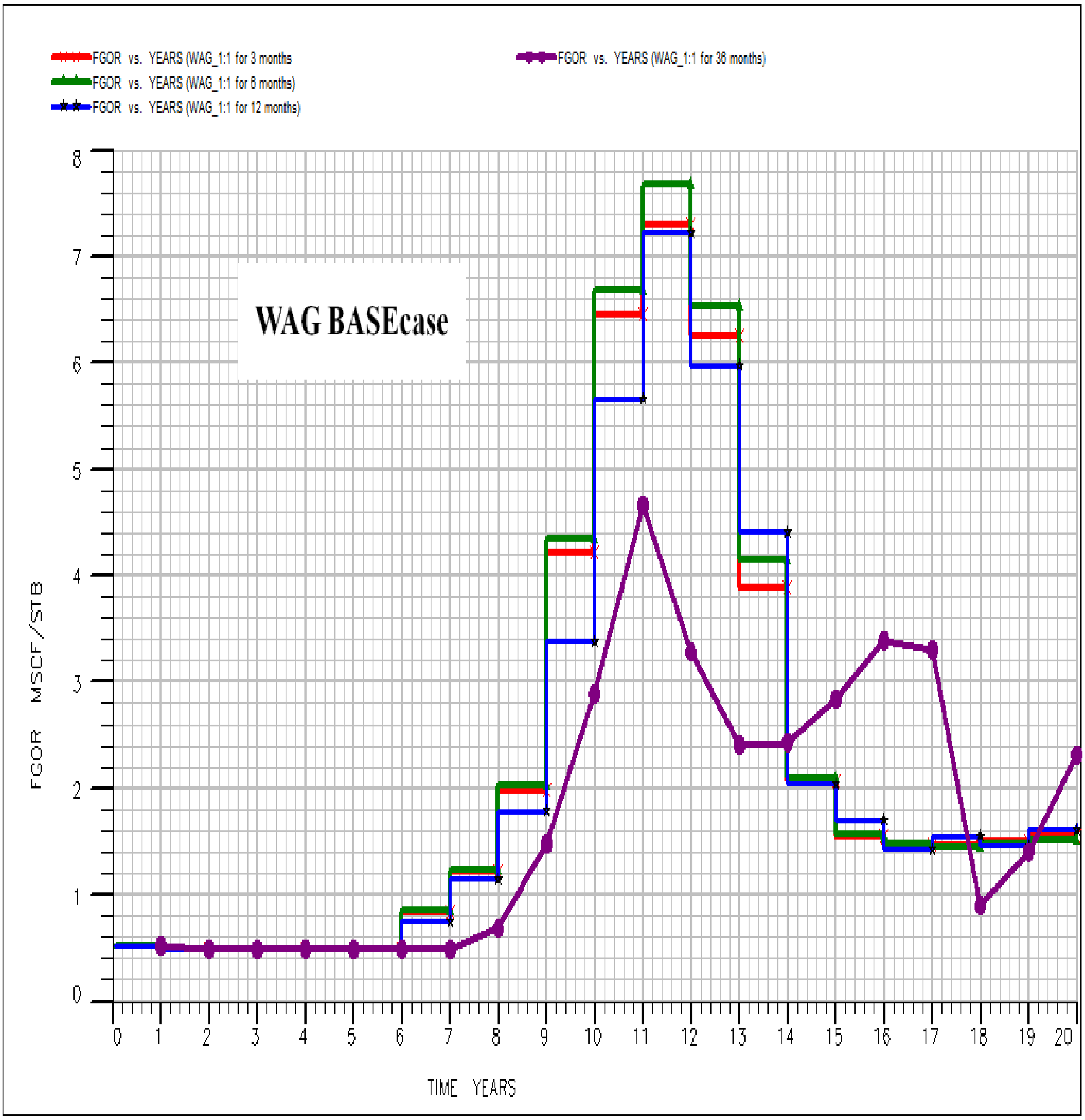


Figure 5a: GOR at different WAG slug injection lengths for WAG-BASE-case

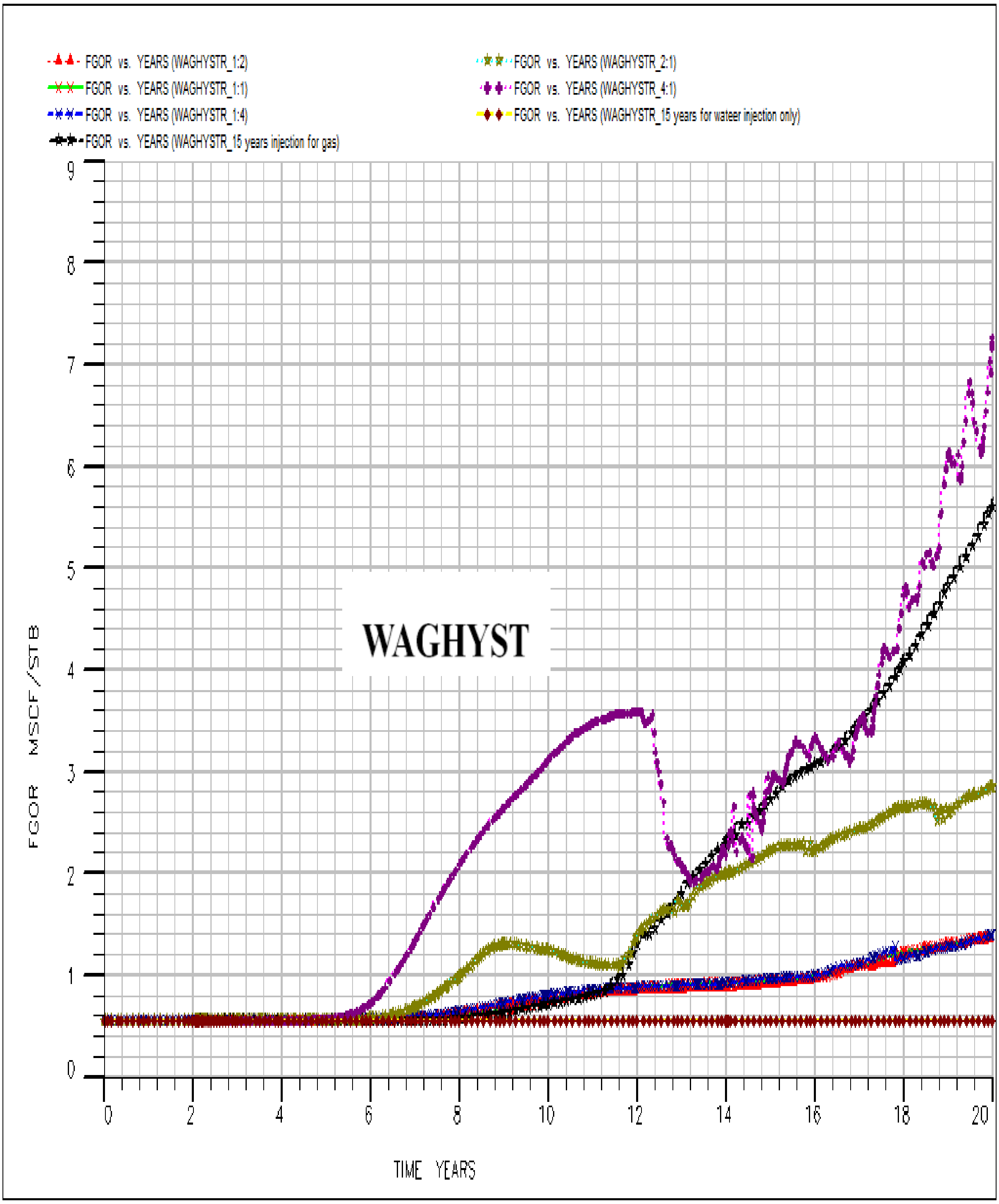


Figure 5b: GOR at different WAG slug injection lengths for WAGHYST.

ii. Field Water-cut

Based on the water/gas injectivity ratio, Figure 6a and 6b below show the variation of water cut for both WAG BASE-case and WAGHYST. In WAG BASE case, the injectivity ratio controls the amount of water that break through earlier. This is because of the stable mobility ratio which is controlled by alternatively injecting different slugs of each of the injecting fluids. At the ratio of 1:4 (gas/water ratio), the water cut suddenly raised at year 12 and drastically drops at year 14 until it becomes zero at year 15. This explains what happen when the injectivity ratio is increased so as water slug is 4 times more than the gas slugs. At this rate, there is much tendency for much more mobile water which otherwise increase the mobility of injected water and results into water channeling and hence water breakthrough. On the other hand, a little more gas slug cycles increased can't cause much change on the water cut. This is due to the fact that the availability of mobile water reduces the gas saturation and then the whole mobility ratio is adjusted to avoid viscous fingering.

For WAGHSYT Figure 6b, a condition caused by imbibitions however increase the water saturation in the pore spaces as it intends to displace the oil in the pores. This extra energy can however improve the sweep efficiency but with high water cut at the producer wells. Any oil left behind in the pores could be swept by the action of dissolves gas by expansion. This is why the recovery when hysteresis effect is considered is higher than WAG process alone. The water break through couldn't reduce oil sweeping here because much oil could be sweep so fast due to the higher sweeping force and the remaining oil in the pores still is later recovered as the injection cycles continue.

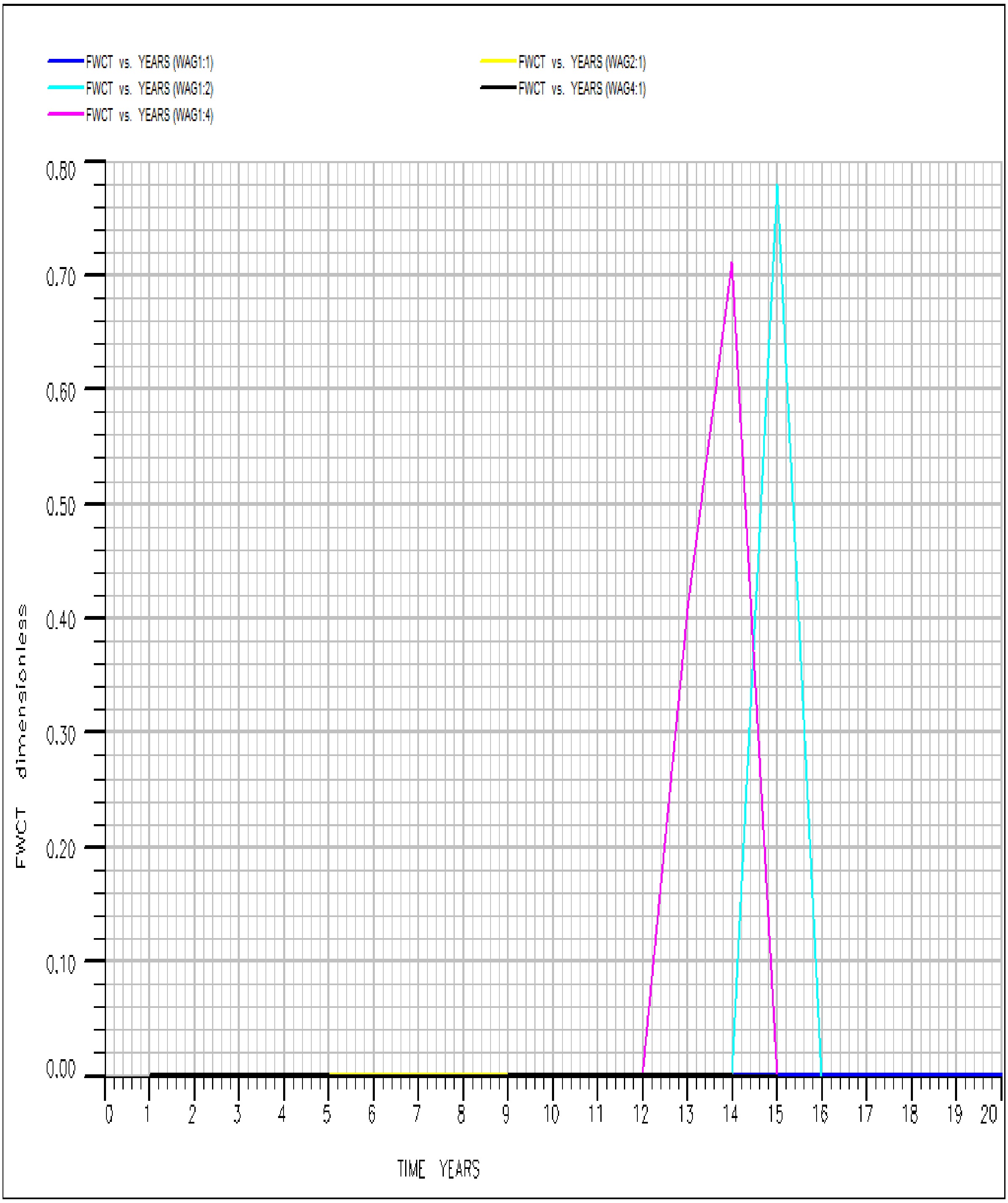


Figure 6a: Watercut at different WAG slug injection lengths for BASE-case

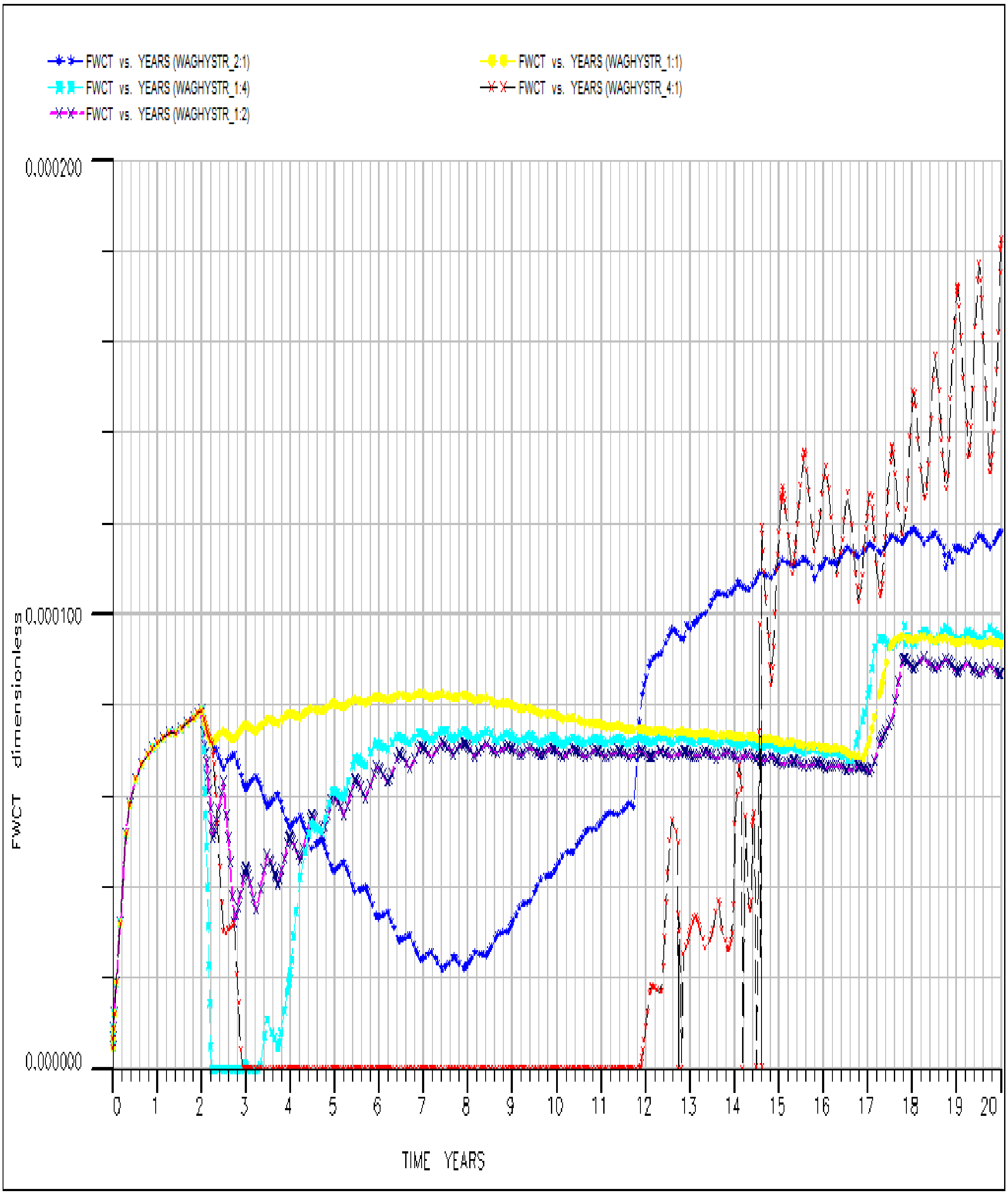


Figure 6b: Watercut at different WAG slug injection lengths for WAGHYST

4.1.3. Comparison of WAGHYST and WAG BASE-case WAG injection with gas water ratio 1:2, 1:4, 2:1 and 4:1 at 3 months gas injection periods

In figure 6, the Field Water/Gas ratio for both WAG Base case and WAGHYST shows a higher amount of water to that of Gas in WAGHYST model. This is because of the additional water from imbibitions cycles which is meant to increase the amount of wetting phase in the field in order to displace the mobile oil (the non wetting phase). In contrast with the WAG injection cycles, the oil displacement is just depending on the water injection in the WAG cycles. These differences in water-gas ratio results in optimum oil recovery which is caused by the hysteresis in the gas relative permeability. In the WAGHYST model water tends to stabilize the gas front in a much more efficient way, since the presence of mobile water will reduce the mobility of gas because of both trapping and due to the three-phase effect. In the WAG BASE-case, neither of these physical effects is included. The total oil production during 20 years is in the range of about 60 to 66 MM STB from the WAGHYST and 57 to 61 MMSTB from the WAG BASE-case simulation. The breakthrough time of gas is generally later in the WAGHYST model while the breakthrough time of water is about equal for both the simulation models.

WAG simulations with and without hysteresis has been compared in earlier studies found in several literatures. These new results confirms the importance of considering hysteresis in modelling the WAG process both for estimation of correct oil recovery by WAG and to optimize the WAG process. In all cases, the oil recovery is found to increase when considering hysteresis in relative permeabilities.

4.1.4. Field Oil Recovery for WAGHYST and WAGBASE-case

The optimum oil recovery from the WAG BASE-case simulations as shown on figure 7 may be found for cases where the injected volumes of water increase. This is because of the fact that the injected water, reduces the mobility of gas and thus leads to a stable mobility ratio of the displacing fluid however, increasing the volume of gas decrease the oil recovery and a gas injection would only give 42% (Table 4) recovery of oil whereas water injection during the same duration gives a recovery of 58%. All for WAG BASE-case which values otherwise is increased with the simulations in which hysteresis is considered. For the WAGHYST model Figure 8, more work is still needed to be done to optimize the WAG process due to the fact that local hysteresis and three-phase flow effects in relative permeability have a great influence on the results. Table 3 and 4 has shown that the simulations depend on the gas-water ratio and slug lengths. For a constant ratio (g/w) of 1:1 the maximum recovery (63.5%) was achieved for 12 months of slug injection length while for a constant 3 months of slug injection length, the maximum oil recovery (62%) was achieved for a g/w ratio of 1:2. These values are both much larger than the oil recovery from water injection (60.0%).

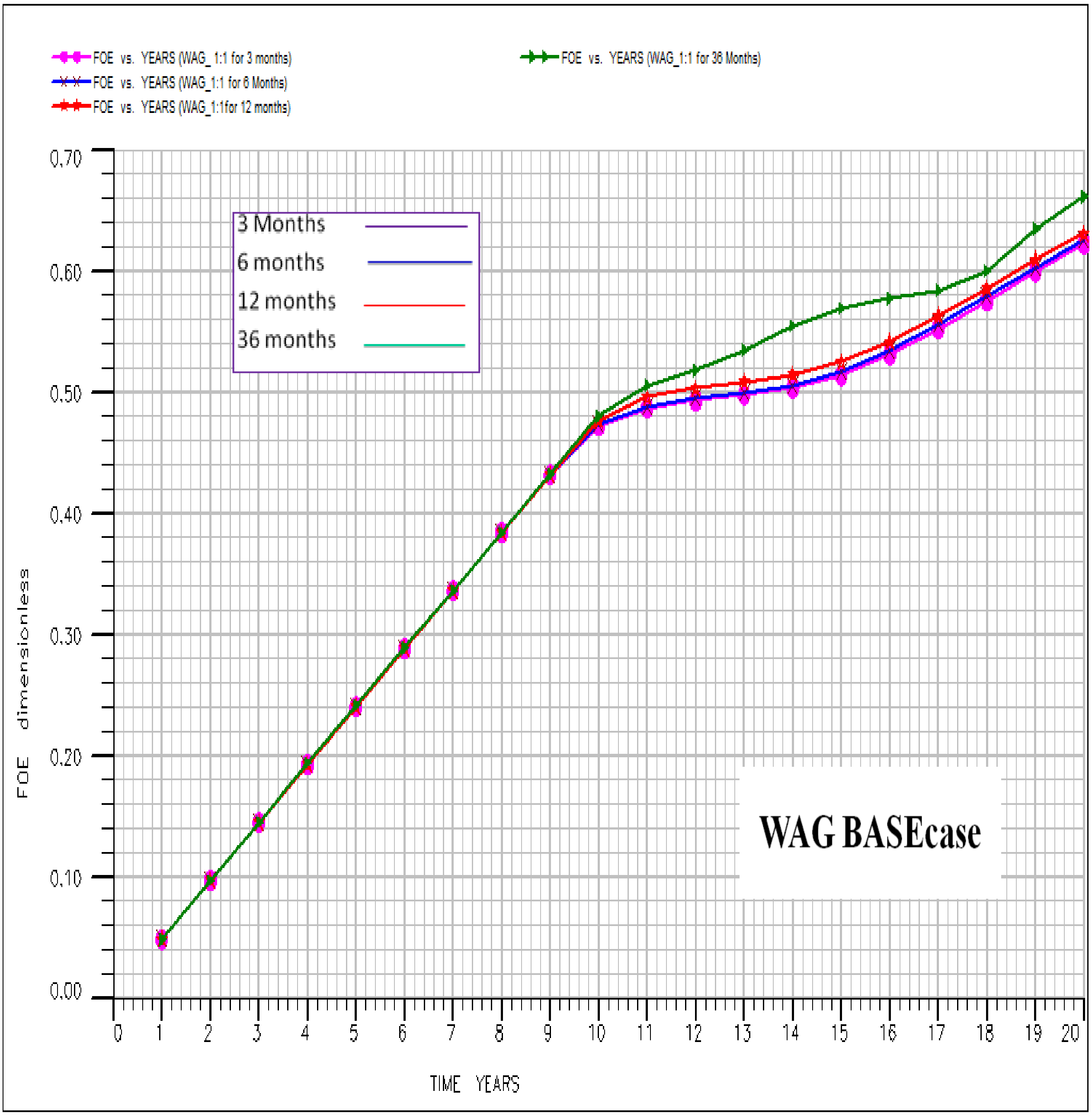


Figure 7: Oil recovery (%) for WAG BASE-case

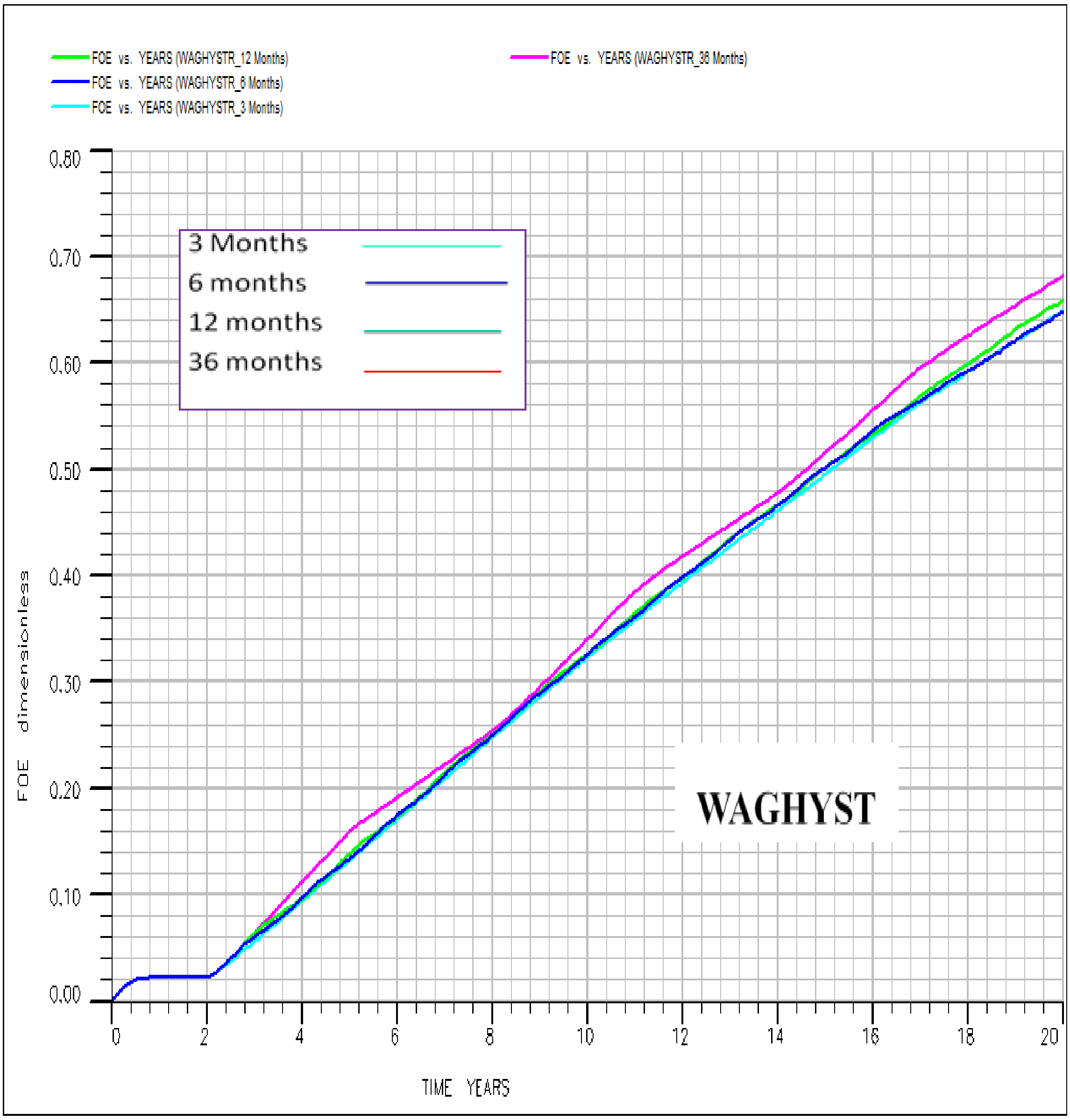


Figure 8: Oil recovery (%) for WAGHYST

Table 4: Oil recovery from WAG BASE-case and WAGHYST at different WAG slug injection periods

Gas-water ratio(g/w)	1:2	1:4	2:1	4:1	1:1	Water injection for 12 years	Gas injection for 12 years
Recovery (%) WAG BASE-case	56.8	58	55.2	56.2	49.5	58	42
Recovery (%) WAGHYST	62	60	59	57	50	60	39

Table 5: Oil recovery from WAGBASE-case and WAGHYST at different WAG injection slug injection period

WAG slug lengths (months)	3	6	12	36
Recovery (%) WAG BASE-case	62	62	63.5	62.5
Recovery (%) WAGHYST	64.25	64.5	65.8	65

CHAPTER 5

5. CONCLUSIONS AND RECOMMENDATION

5.1. CONCLUSIONS

The following conclusions were made based on the simulation results and analysis of the WAG processes in for sweep and displacement efficiencies.

5.1.1. Effects of WAG slug lengths in Total oil production

Both cases of WAG with and without hysteresis, showed a similar trend of oil cumulative productions with a WAG slug lengths dependence on the more the injection length was increased the higher the recovery. But the cumulative oil is at its maximum production for WAG case that considered hysteresis. This gives a highlight that in order to have higher production total, hysteresis effect should be included when designing tertiary oil recovery by WAG processes. These results showed the agreement between the already existing hysteresis done experimentally found in literature which has clearly shown that hysteresis influences WAG processes in sweeping oil across the entire reservoir and hence the total oil production is increased.

5.1.2. Effects of WAG injection ration, gas/water ratio in Total Oil Recovery

Increase in oil recovery and productivity is higher when the amount of water injection is increased compared to alternate gas slug. This is due to the drainage and imbibitions cycles. The hysteresis effect is considered during the WAG processes because the more water cycles during imbibitions tend to reduce the mobility of gas and thus reducing the gas fingering. The injection water during imbibitions will tend to increase the amount of water in the reservoir and create enough pressure to push the oil out the pore spaces in the reservoir, therefore increasing oil production thereby reducing residual oil as suggested in the objectives.

5.1.3. WAG process design

This Simulation studies have shown how three-phase flow description may influence the choice of drive mechanisms and also the design of a WAG process. The shape of reservoirs determines how the WAG injection techniques are going to contact the reservoir in a volumetric sense so as to increase the macroscopic efficiency as well as also contacting the pore scale for the residual oil and increase the microscopic efficiency. However the irregular shapes of most reservoirs always results into more problem such as high tendency of bypassing oil, hence leading to still high residual oil saturation inside the reservoir which goes against the prime objectives of this tertiary recovery. Therefore, designing WAG techniques to counter the effect of gas fingering as a result of gas property of being less viscous that makes it more mobile resulting in bypassing the oil coupled with early breakthrough of the injected water are the main reasons behind designing these drive mechanisms . If these effects are not addressed then millions of dollars will be waste on less recovery. Therefore, a well thought design criteria increase the company's recovery.

5.2. RECOMMENDATIONS

1. The reservoir parameters presented in this study are valid for the WAG and three phase relative permeability hysteresis.
2. The accuracy of the proposed models can be improved by accounting for many parameters such as relative permeability curves as a function saturations on which imbibitions and drainage depend
3. More simulation work is needed to include wettability and capillary pressures of the displacing and displaced fluid.

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11. Skauge A., Larsen J.A. :''Three-phase relative permeabilities and trapped gas measurements related to WAG processes'', SCA 9421, Stavanger, 12-14 Sept 1994.
12. Skauge A., Aarra M. :"Effect of wettability on the oil recovery by WAG", 7th IOR symp, Moscow, 26-28 Oct 1993.

APPENDICES

Table 6: Relative permeability and capillary pressure

Liquid saturation	Pcog	Kr Liquid	Krg
0.2	30	0.0	1.00
0.29	8.00	0.00	0.56
0.35	4.00	0.00	0.39
0.38	3.00	0.011	0.35
0.47	0.80	0.037	0.20
0.56	0.03	0.088	0.10
0.64	0.001	0.17	0.05
0.73	0.001	0.30	0.03
0.822	0.00	0.47	0.01
0.911	0.00	0.702	0.00
0.95	0.00	0.88	0.00
1.00	0.00	1.00	

Sw	Pcow	Krw	Krow
0.200	45.0	0.0	1.00
0.29	19.03	0.002	0.68
0.38	10.07	0.018	0.42
0.47	4.9	0.061	0.22
0.56	1.8	0.144	0.84
0.64	0.5	0.28	0.123
0.700	0.05	0.41	0.00
0.73	0.01	0.49	0.00
0.82	0.0	0.77	0.00
0.91	0.0	1.00	0.00
1.00	0.0	1.00	0.00

Table 7: Peng-Robbinson fluid description

Components	P_{CRIT}	T_{CRIT}	MW	ZCRIT	Accent Fraction
C1	667.8	343.0	16.04	0.290	0.013
C3	616.3	665.7	44.10	0.277	0.1524
C6	436.9	913.4	86.18	0.264	0.3007
C10	304.0	1111.8	149.29	0.257	0.4885
C15	200.0	1270.0	206.00	0.245	0.6500
C20	162.0	1380.0	282.00	0.235	0.8500

Table 8: Parameters used in the sensitivity study of the three phases Relative Permeabilities Model obtained from the literature

Parameter	Minimum	Most likely	Maximum
Secondary Drainage Reduction factor	0.01	2	5
Land's **parameter**	0.01	1	5
Three-Phase model Threshold saturation	0.0001	0.001	1
Residual oil modification fraction	0.001	0.9	1
Imbibition curve linear fraction	0.01	0.1	1

Table 9: Three-phase hysteresis model (simulation data)

Reservoir pressure	900 psi
Average porosity	0.2
Sorw	0.75
Swi	0.25
Reservoir size	8 x 8 x 4 ft
Number of grids	500x 500 x 50
K_x x K_y x K_z	200 x 200 20
Kx/Kh	0.1

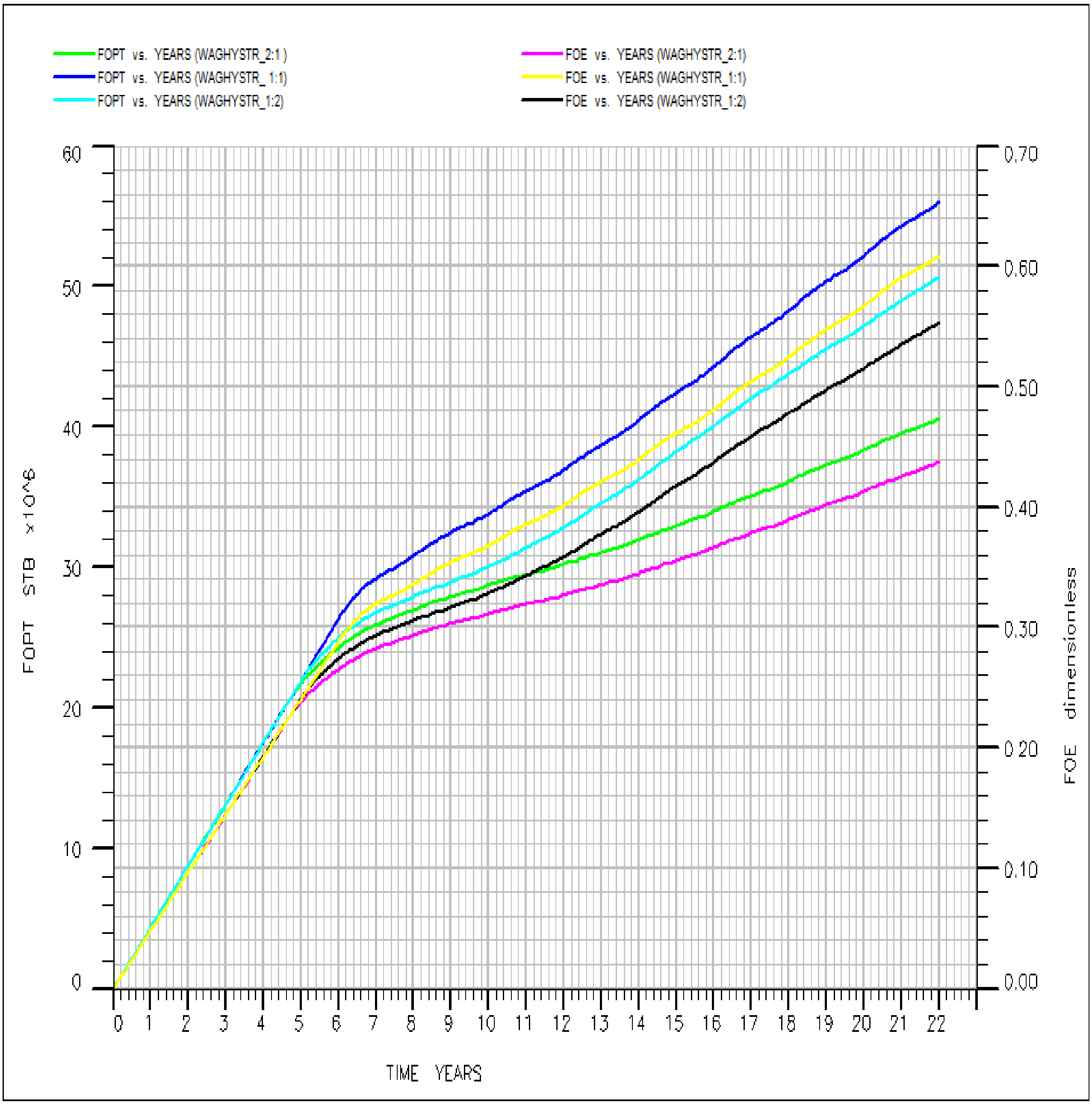

Figure 9: comparing Oil production Total and Field Oil Efficiency for WAGHYST at different WAG ratios

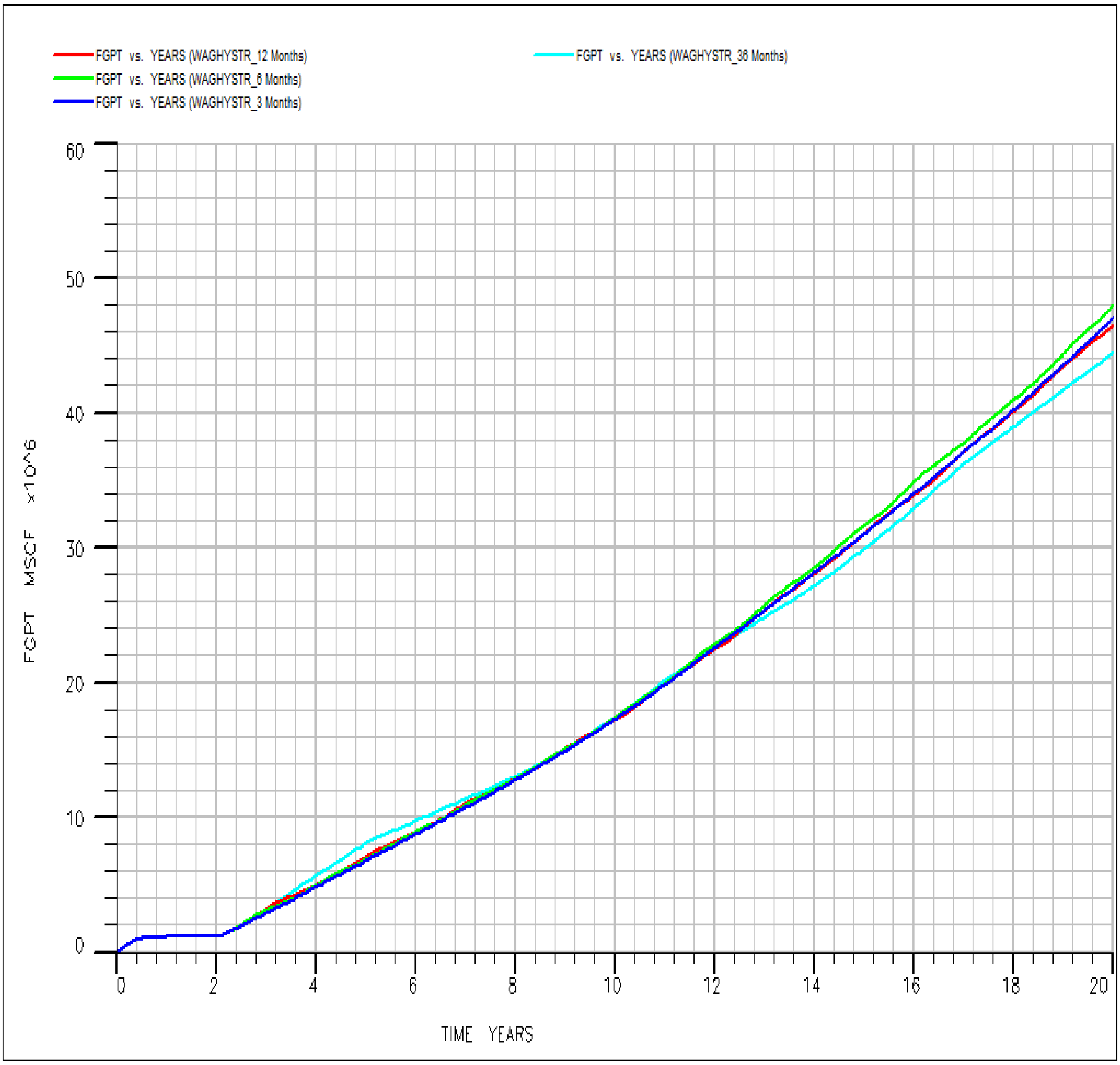

Figure 10: Field Gas production Total for different WAG slug lengths.

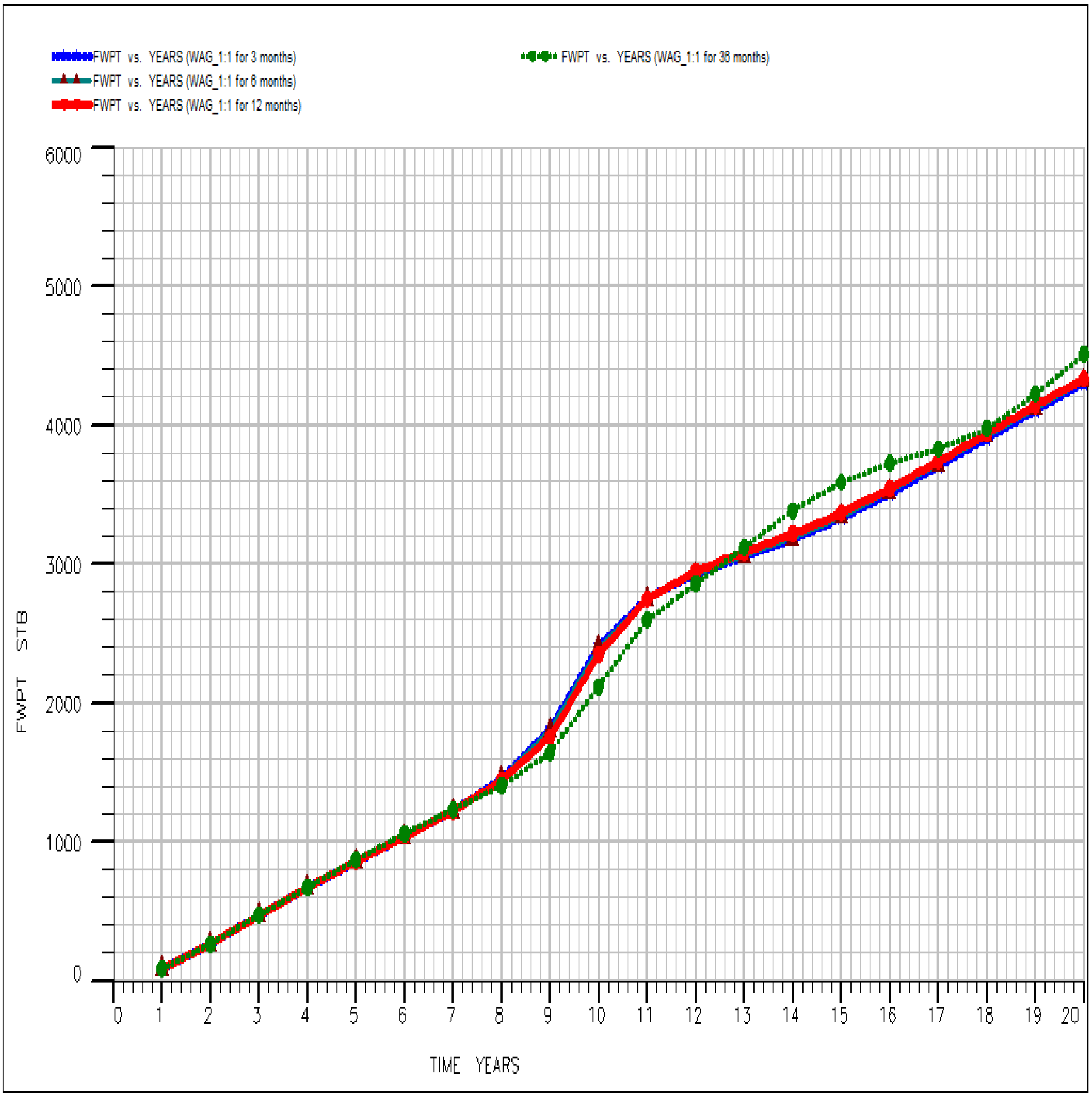

Figure 11: Field Water Production Total at different WAG ratio

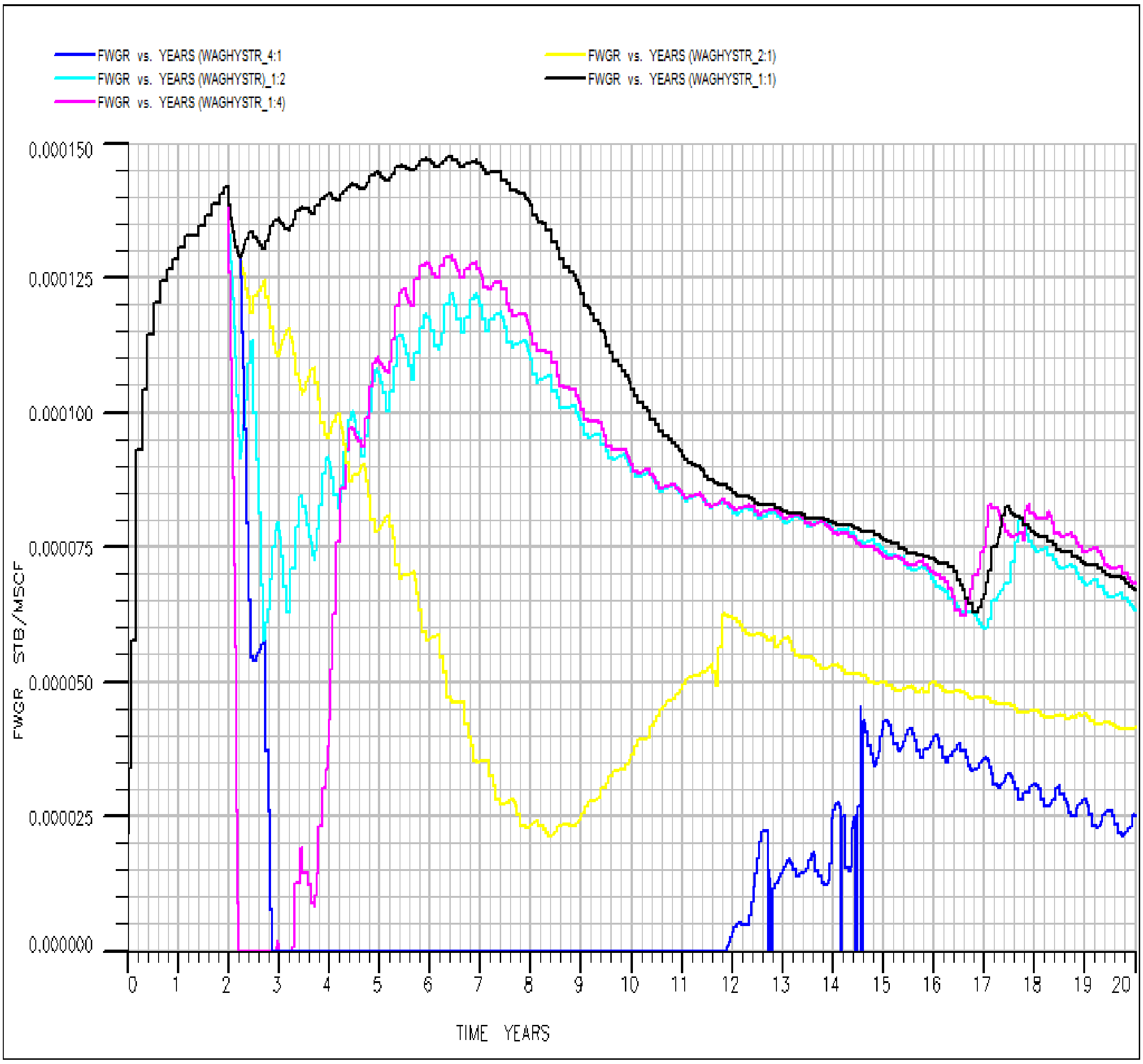

Figure 12: Field Water/Gas ratio at different WAG injection ratios.

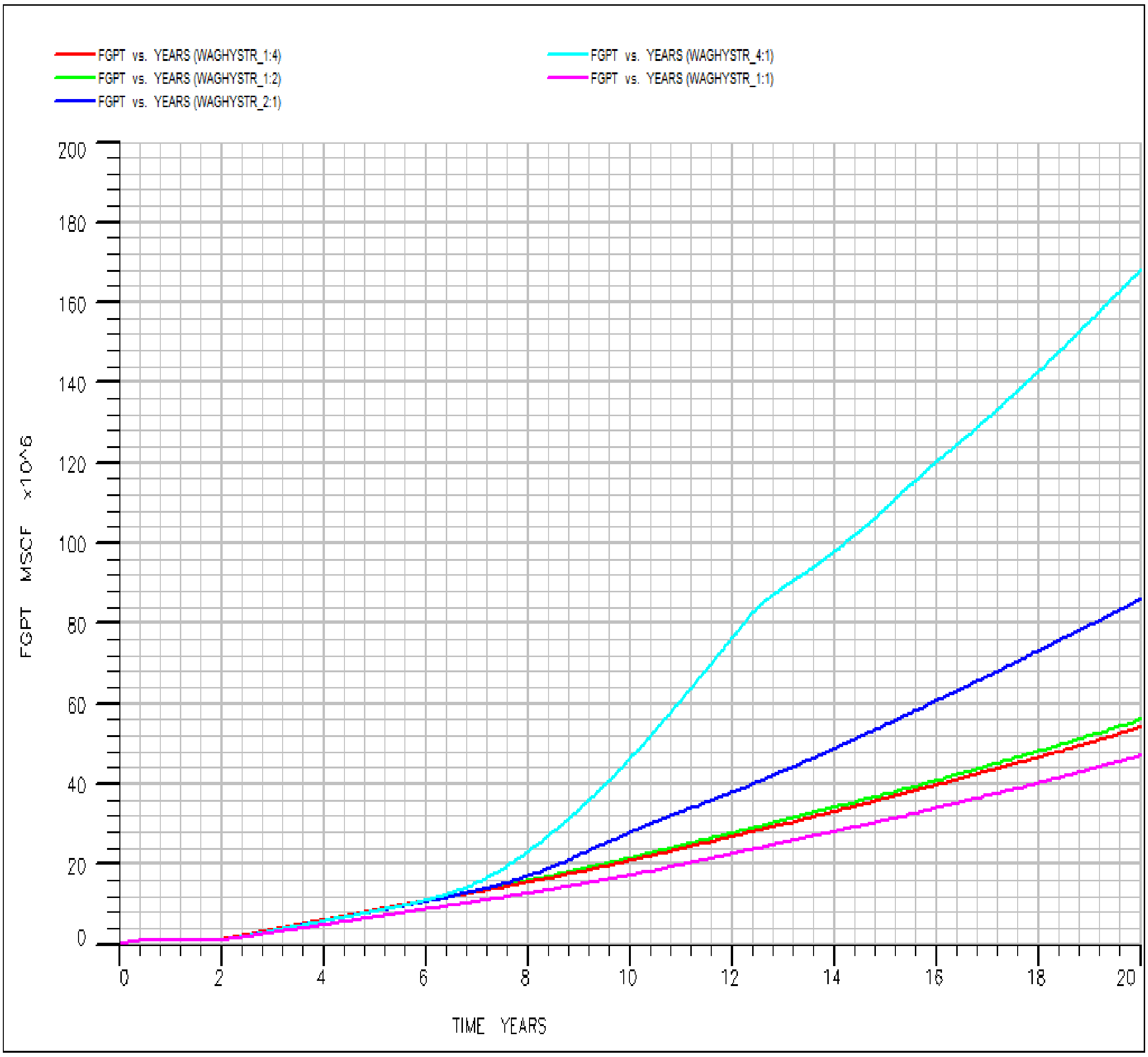

Figure 13: Field Gas Production Total based on WAG injection ratios for WAGHYST.

CASE ONE WAG MODEL ONLY

```
-- Dimension 8x8x4-
-- Run for a WAG cycle
----------------------------------------------------------------------
RUNSPEC   ==========
TITLE
3D 3 phase

-- Units
FIELD

OIL
WATER
GAS

TABDIMS
1 1 40 40 /

--        Number of cells
--       NX      NY      NZ
--       --      --      --
DIMENS    8       8       4/

EQLDIMS
1 20/
WELLDIMS
-- max    max max    max
-- wells conn groups wells/gr
    2    2 /


-- Simulation start date
1 Jan 1990 /

GRID  ==========

INIT
DXV        DYV
8*500 /
    8*500 /
DZV
20 30 40 50 /

--TVDSS of top layer only
-   X1 X2   Y1 Y2     Z1 Z2
    --      -- --   -- --
BOX  1   8   1   8   1   1 /

ENDBOX
TOPS
64*8325 64*8345 64*8375 /

-- Porosity of each cell
PORO
256*0.35  /

-- Permeability in X, Y and Z
directions for each cell
```

```
PERMX
64*200 64*1000 64*150 64*300 /

PERMY
64*200 64*1000 64*150 64*300  /

PERMZ
64*50 64*20 64*40 64*30 /

PROPS ===========================

BIC
  0.0
  0.0  0.0
  0.0  0.0   0.0
  0.05 0.005 0.0   0.0
  0.05 0.005 0.0   0.0   0.0 /

SWFN
    0.2    0      45.0
    0.2899 0.0022 19.03
    0.3778 0.0180 10.07
    0.4667 0.0607  4.90
    0.5556 0.1438  1.8
    0.6444 0.2809  0.5
    0.7000 0.4089  0.05
    0.7333 0.4855  0.01
    0.8222 0.7709  0.0
    0.9111 1.0000  0.0
    1.00   1.0000  0.0 /

SGFN
    0.00   0.000   0.0
    0.05   0.000   0.0
    0.0889 0.001   0.0
    0.1778 0.010   0.0
    0.2667 0.030   0.001
    0.3556 0.05    0.001
    0.4444 0.10    0.03
    0.5333 0.20    0.8
    0.6222 0.35    3.0
    0.65   0.39    4.0
    0.7111 0.56    8.0
    0.80   1.0    30.0
/
SOF3
    0.00   0.0     0.0
    0.0889 0.0     0.0
    0.1500 0.0     0.0
    0.1778 0.0     0.0110
    0.2667 0.0     0.0370
    0.3    0.0     0.0560
    0.3556 0.0123  0.0878
```

```
    0.4444 0.0835  0.1715
    0.5333 0.2178  0.2963
    0.6222 0.4153  0.4705
    0.7111 0.6769  0.7023
    0.80   1.0     1.0    /

ROCKTAB
 1000.0 1.0   1.0
 2000.0 1.005 1.0
 3000.0 1.010 1.0
 4000.0 1.015 1.0
 5000.0 1.020 1.0
 6000.0 1.025 1.0
 7000.0 1.030 1.0
 8000.0 1.035 1.0
 9000.0 1.040 1.0
10000.0 1.045 1.0 /

WATERTAB
 1000.0     1.0099 0.70
 4000.0     1.0000 0.70
 9000.0     0.9835 0.70 /

--Specify initial liquid
composition
ZMFVD
1000.0  0.5 0.03 0.07 0.2 0.15
0.05
10000.0 0.5 0.03 0.07 0.2 0.15
0.05 /

--Surface densities: only the
water value is used

DENSITY
1* 62.4 1* /

SOLUTION =============
RPTSOL
PRESSURE SOIL SWAT SGAS PSAT /

EQUIL
8400 4000 9000 0 7000 0 1 1 0 /
/
SUMMARY    =========

--Request field GOR, water cut
oil rate and total, gas rate

FGOR
FWCT
FOPR
FOPT
FWPR

RUNSUM
RPTONLY
SCHEDULE    =========

AIMCON
 6* -1 /

--Request FIP reports, group, sep
and well data, and solution maps.

SAVEEND

RPTPRINT
0 1 0 1 1 1 0 1 0 0 /

--Specify solution maps of
pressure and saturations

RPTSCHED
PRESSURE SOIL SWAT SGAS /

--One stage separator conditions

SEPCOND
Sep Field 1 60 14.7 /
/

--Define injection and production
wells

--WELLSPEC
--P Field 8 8 8400 Sep /
WELSPECS
P Field 8 8 8400 OIL /
/
WSEPCOND
P SEP /
/
--WELLCOMP
--P 8 8 4 4 1 0.5 /
COMPDAT
P 8 8 4 4 1* 1 1* 0.5 /
/
--Well P on oil rate of 12000
stb/day, with min bhp of 1000 psi

--WELLPROD
--P oil 12000 3* 1000 /
WCONPROD
P OPEN ORAT 12000 4* 1000 /
/

--Limits on water cut and GOR
--Note limit is on water cut,
rather than water-oil ratio

GRUPLIM
Field 2* 0.8333 10 1* A Y /
/
TSTEP
2*365 /
```

```
--Define injection well
WELLSTRE
Solvent 0.77 0.20 0.03 0.0 0.0 /
/
--WELLSPEC
--I Field 1 1 8335 /
WELSPECS
I Field 1 1 8335 GAS /
/
--WELLCOMP
--I 1 1 1 1 1 0.5 /
COMPDAT
I 1 1 1 1 OPEN 1 1* 0.5 /
/


--Start WAG cycles--------------

--WELLINJE
--I Stream Solvent Gas 1* 12000
12000 /
WCONINJE
I GAS OPEN RATE 12000/
/
WINJGAS
I Stream Solvent /
/
WELTARG
I WRATE 12000 /
/

WELLWAG
I T W 365.25 G 365.25 /
/

TSTEP
20*365.25 /

END
```

CASE TWO WAG WITH HYSTERESIS

```
-- Dimension 8x8x4-
-- Run for a WAG cycle with
Hysteresis
------------------------

RUNSPEC =============

TITLE
3D 3 phase

-- Units
FIELD

OIL
WATER
GAS

COMPS
6 /

TABDIMS
1 1 40 40 /

--    Number of cells
--    NX      NY      NZ
--    --      --      --
DIMENS
8 8 4/

EQLDIMS
1 20/

WELLDIMS
-- max    max max    max
-- wells conn groups wells/gr
    2    2 /

-- Simulation start date
1 Jan 1992 /
SATOPTS
HYSTER /

UNIFOUT
GRID =====================

--Size of each cell in X, Y
and Z directions
INIT
DXV
8*500 /
```

```
DYV
8*500 /
DZV
20 30 40 50 /


--TVDSS of top layer only
-- X1 X2     Y1 Y2     Z1 Z2
-- --  --    --  --    --  --
BOX
  1   8      1   8      1   1
/

ENDBOX
TOPS
64*8325 64*8345 64*8375 /

-- Porosity of each cell
PORO
256*0.35 /

-- Permeability in X, Y and Z
directions for each cell

PERMX
64*200 64*1000 64*150 64*300 /


PERMY
64*200 64*1000 64*150 64*300 /

PERMZ
64*50 64*20 64*40 64*30 /

==============================
===
PROPS
EOS
PR /

PRCORR

RTEMP
160 /

STCOND
60 14.7 /
CNAMES
C1
```

```
C3
C6
C10
C15
C20
/
TCRIT
 343.0
 665.7
 913.4
1111.8
1270.0
1380.0
/
PCRIT
667.8
616.3
436.9
304.0
200.0
162.0
/
ZCRIT
0.290
0.277
0.264
0.257
0.245
0.235
/
MW
 16.04
 44.10
 86.18
149.29
206.00
282.00
/
ACF
0.013
0.1524
0.3007
0.4885
0.6500
0.8500
/
BIC
0.0
0.0  0.0
0.0  0.0    0.0
0.05 0.005  0.0  0.0
0.05 0.005  0.0  0.0  0.0 /

STONE
```

```
SWFN
--drainage curve wetting
--table 1
--Sw   Krw   Pc
0.2    0      6
0.25   0.005 5
0.3    0.01  4
0.35   0.02  3
0.40   0.03  2.4
0.45   0.04  1.9
0.5    0.055 1.4
0.55   0.08  1.0
0.6    0.11  0.7
0.65   0.17  0.4
0.7    0.23  0.25
0.75   0.32  0.1
1.0    1.0   0.0
/

--imbibition curve wetting
--table 2
--Sw  Krw   Pc
0.2   0     6
0.25  0.04  3
0.3   0.1   2
0.35  0.17  1.15
0.4   0.25  0.6
0.45  0.32  0.3
0.5   0.39  0.12
0.55  0.46  0
1.0   1.0   0
/
SGFN
--Drainage curves
--Table 1 for SATNUM
--Sg  Krg   Pcog note must
have connate gas sat = 0

0.05   0      0.09
0.10   0.022 0.20
0.15   0.06  0.38
0.20   0.10  0.57
0.25   0.14  0.83
0.30   0.188 1.08
0.35   0.24  1.37
0.40   0.30  1.69
0.45   0.364 2
0.50   0.458 2.36
0.55   0.60  2.70
0.60   0.75  3
0.80   1.0   3/
--Imbibition curves
--Table 2 for IMBNUM
--Sg   Krg   Pcog
```

```
-- 0.0    0     0
-- 0.40   0     0
-- 0.45   0.066 0.80
-- 0.50   0.177 1.56
-- 0.55   0.40  2.24
-- 0.60   0.75  3
/
SOF3
--Drainage curves
--Table 1 for SATNUM
--So   Krow   Krog
0.0    0      0
0.1    0.02   0
0.2    0.05   0
0.25   0.08   0.01
0.30   0.11   0.02
0.35   0.15   0.03
0.40   0.2    0.04
0.45   0.25   0.08
0.50   0.32   0.14
0.55   0.4    0.225
0.60   0.5    0.33
0.65   0.6    0.434
0.70   0.7    0.575
0.75   0.8    0.72
0.80   1.0    1.0
/

--Imbibition curves
--Table 2 for IMBNUM
--So   Krow   Krog
-- 0.0    0      0
-- 0.1    0      0
-- 0.20   0      0
-- 0.25   0      0.048
-- 0.30   0      0.14
-- 0.35   0      0.40
-- 0.40   0      0.90
-- 0.50   0.03   1*
-- 0.55   0.1    1*
-- 0.60   0.18   1*
-- 0.65   0.3    1*
-- 0.70   0.45   1*
-- 0.75   0.64   1*
-- 0.80   0.90   1*/
--EHYSTR
--0.1  4    1*/
WAGHYSTR
 2.0  1.0  /
 2.0  1.0  /
ROCKTAB
 1000.0 1.0   1.0
 2000.0 1.005 1.0
 3000.0 1.010 1.0
 4000.0 1.015 1.0
 5000.0 1.020 1.0
 6000.0 1.025 1.0
 7000.0 1.030 1.0
 8000.0 1.035 1.0
 9000.0 1.040 1.0
10000.0 1.045 1.0 /

WATERTAB
 1000.0     1.0099 0.70
 4000.0     1.0000 0.70
 9000.0     0.9835 0.70 /

--Specify initial liquid
composition
ZMFVD
1000.0  0.5 0.03 0.07 0.2 0.15
0.05
10000.0 0.5 0.03 0.07 0.2 0.15
0.05 /
--Surface densities: only the
water value is used

DENSITY
1* 62.4 1* /

REGIONS ======================

SATNUM
256*1
/
IMBNUM
256*1
/
SOLUTION
=====================
--Request initial state
solution output

RPTSOL
PRESSURE SOIL SWAT SGAS PSAT /

EQUIL
8400 4000 9000 0 7000 0 1 1 0/
SUMMARY  ===========

--Request field GOR, water cut
oil rate and total, gas rate

FGOR
FWCT
FOPR
FOPT
FWPR
```

```
FOE
ALL
RUNSUM
FWSAT
FGSAT
FOSAT

BSWAT
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
8  8  1 /
4  4  1 /
BGSAT
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
8  8  1/
BOSAT
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
BPR
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
BKRO
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
8  8  1 /
4  4  1 /
BKRW
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /
8  8  1 /
4  4  1 /
BKRG
1  1  1 /
2  1  1 /
3  1  1 /
4  1  1 /
5  1  1 /
6  1  1 /
7  1  1 /
8  1  1 /

SEPARATE

SCHEDULE ===============

RPTRST
 'BASIC=2' SOIL SWAT SGAS
PRESSURE /

AIMCON
 6* -1 /

--Request FIP reports, group,
sep and well data, and
solution maps.

SAVEEND

RPTPRINT
0 1 0 1 1 1 0 1 0 0 /

--Specify solution maps of
pressure and saturations

RPTSCHED
PRESSURE SOIL SWAT SGAS /

--One stage separator
conditions

SEPCOND
```

```
Sep Field 1 60 14.7 /
/
--Define injection and
production wells

--WELLSPEC
--P Field 8 8 8400 Sep /
WELSPECS
P Field 8 8 8400 OIL /
/
WSEPCOND
P SEP /
/
--WELLCOMP
--P 8 8 4 4 1 0.5 /
COMPDAT
P 8 8 4 4 1* 1 1* 0.5 /
/

--Well P on oil rate of 12000
stb/day, with min bhp of 1000
psi

--WELLPROD
--P oil 12000 3* 3000 /
WCONPROD
P OPEN ORAT 12000 4* 3000 /
/
GRUPLIM
Field 2* 0.8333 10 1* A Y /
/

TSTEP
2*365 /

--Define injection well

WELLSTRE
Solvent 0.77 0.20 0.03 0.0 0.0
/
--WELLSPEC
--I Field 1 1 8335 /
WELSPECS
I Field 1 1 8335 GAS /
/
--WELLCOMP
--I 1 1 1 1 1 0.5 /
COMPDAT
I 1 1 1 1 OPEN 1 1* 0.5 /
/
--Start WAG cycles-----------
--WELLINJE
--I Stream Solvent Gas 1*
60000 60000 /
WCONINJE
I GAS OPEN RATE 30000/

/
WINJGAS
I Stream Solvent /
/
WELTARG
I WRATE 15000 /
/
WELLWAG
I T W 365.25 G 365.25 /
/
TSTEP
20*365.25 /

END.
```