WELL CONFIGURATION DESIGN IN WATER ALTERNATING GAS SIMULATION

By

Mohd Ashraf Bin Nor Azrol

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Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Mohd Ashraf Bin Nor Azrol

A project dissertation submitted to the
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Approved by,

____

(PROF. DR. MUSTAFA ONUR)
UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK

SEPTEMBER 2012

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 or done by unspecified sources or persons.

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MOHD ASHRAF BIN NOR AZROL

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ABSTRACT

Water Alternating Gas (WAG) is one of the popular EOR techniques to displace oil after natural depletion. Essentially, WAG is a sequential injection of water and gas in specific ratio to sweep oil from the pores. It is a popular technique because of availability of water and gas as well as cheaper cost than chemical injection technique. More importantly, this project discovered that there is a relationship between well configuration design and efficiency of WAG in a 5 spot injection pattern. For example, the ideal WAG ratio of 1:1 that supposedly allows piston-like displacement is not always efficient for all well configurations. Only a horizontal injector and a vertical producer configuration gave the highest oil recovery while the other configurations did not. Ultimately, this project proposed approaches for both new field and mature field. For a new field, one might want to consider well configuration that gives the highest oil recovery to be drilled. On the other hand, for a mature field, the well configuration is already present. Therefore, it is proposed that a WAG scheme that yield the highest oil recovery for that well configuration design should be used.

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NOMENCLATURE

VI-VP : Vertical Injector-Vertical Producer
VI-HP : Vertical Injector- Horizontal Producer
HI-VP : Horizontal Injector-Vertical Producer
HI-HP : Horizontal Injector-Horizontal Producer
REC : Oil Recovery
E_v : Vertical sweep efficiency
E_h : Horizontal sweep efficiency
E_m : Microscopic sweep efficiency
k_{rg} : Gas relative permeability
k_{ro} : Oil relative permeability
k_{rog} : Oil-gas relative permeability
k_{row} : Oil-water relative permeability
μ_g : Gas viscosity (cp)
μ_o : Oil viscosity (cp)
P : Present worth ($M)
F : Future amount of money ($M)
i : Discount rate (%)
n : Number of years present (yr)
NPV : Net present value ($M)
N_p : Oil initially in place (RB)
N_s : Cumulative oil produced (RB/day)
S_{wi} : Initial water saturation
T : Temperature (°F)
p_i : Initial pressure (psi)
PV : Pore volume (RB)
MW : Molecular Weight (mol)
T_C : Critical temperature (°F)
P_C : Critical pressure (psi)
ACF : Accentric factor
Z_c : Compressibility factor
k_{rw} : Relative permeability of water
S_w : Water saturation
S_g : Gas saturation
MMP : Minimum miscibility pressure (psi)
BV : Bulk Volume (RB)
Q_{ig} : Gas injection rate (Mscf/day)
Q_{iw} : Water injection rate (Mstb/day)

CHAPTER 1

INTRODUCTION

1.1 Background

1.1.1 Enhanced Oil Recovery (EOR)

Generally, there are three recovery phases for oil reservoir which are primary, secondary, and tertiary recovery. Primary recovery of the reservoir depends on natural energy that ensures pressure maintenance of the reservoir such as solution gas drive, aquifer, fluid and rock expansion, and gravity drainage. Secondary recovery includes water-flooding, pressure maintenance, and solvent injection but more synonymous to water-flooding. Meanwhile, the tertiary recovery uses miscible gases, chemical and/or thermal energy to displace leftover oil after secondary recovery. However, such chronological order seldom works. There are heavy crude oil reservoirs that began production with thermal injection, skipping the primary and secondary phases. Hence the term Enhanced Oil Recovery (EOR) is widely used to indicate injection of fluid to interact with the reservoir creating a favourable condition for oil recovery [1].

1.1.2 Water Alternating Gas (WAG)

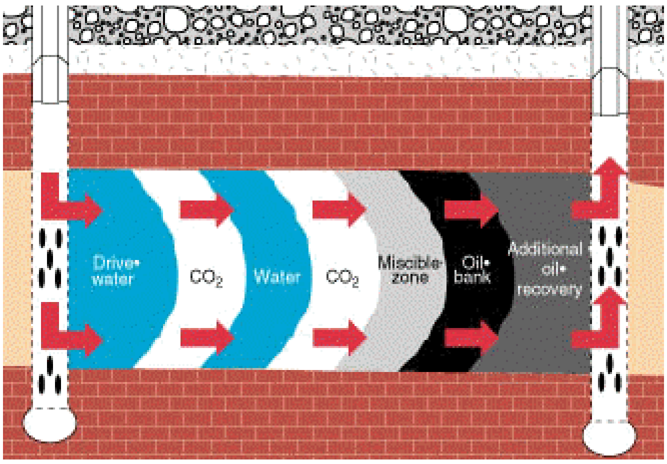


Figure 1.1 Schematic of Water Alternating Gas Process.[2]

Initially, the aim of WAG is to improve sweep efficiency in gas injection, but in 1958, Caudle and Dyes [1] proposed it as a method to improve oil recovery. Since then, it has commercially been used. Often single-phase gas injection has unfavourable mobility ratio resulting in viscous fingering due to unstable interface of two fluids. Being less viscous, gas will ‘bypass’ some of the oil, reducing volumetric sweep efficiency [3].

To solve this problem, two fluids are flowed simultaneously in succession resulting in improved mobility ratio. Therefore, with the improved displacement efficiency by the gas and improved microscopic sweep by the water, oil recovery increased. WAG has been associated with recovery of attic oil by exploiting the segregation of gas to the top and water accumulation at the bottom [4].

The first reported WAG used was in 1957 at North Pembina field in Alberta, Canada. Since then, it has been popular in USA and widely used in Russia, Canada and Norway. About 50% of the reported applications in actual fields were initiated in 1980. The average increase in recovery is about 9.7% for miscible WAG and 6.4% of immiscible WAG. Only a few WAG application were unsuccessful while others increased recovery of about 5-10% of OIIP [4]. Other simulation indicated that with better pressure support improved oil recovery can be achieved through WAG (36 – 43 % of OIIP for 20-30 years of prediction) [5].

1.1.3 Well Configuration Design

Vertical well configuration is the standard configuration ever since the discovery of oil. Not until the development of Seminole, Oklahoma reservoir in United States of America that the oil and gas industry realized the need to have directional drilling since the wells in this field are closely packed. Some wells were accidently drilled into another producing well. From then onwards, wells have been drilled with some inclination for sidetracking, fault drilling and to avoid surface obstruction above producible reservoir, etc. As the inclination increases, horizontal well that reduces the effect of gas or water coning is discovered [6]. It is popular because the contact area with the reservoir is bigger; increasing effective recovery or injection spread. This project intends to study the effectiveness of either vertical or horizontal well in WAG process.

1.2 Problem Statement

Poor understanding of well configuration design for WAG may cause higher cost and inefficient oil sweep. Cost increases due to additional injection wells required to be drilled while oil sweep is inefficient due to high mobility ratio and viscous fingering.

1.3 Objectives and Scope of Study

This project has two objectives which are:

i) To study the effect of well configuration design towards overall oil recovery for both isotropic and anisotropy conditions.

ii) To assess economic viability of each well configuration.

This project revolves around the simulation knowledge, WAG, EOR, permeability model and reservoir engineering in general. These topics are relevant to Petroleum Engineering discipline in accordance with Final Year Project guideline.

Two commercial software; Tempest™ and Enable™ will be used for the simulation and sensitivity analysis.[1]

[1] Tempest and Enable are registered trademarks of simulation software from ROXAR Software Solution: http://www2.emersonprocess.com/en-us/brands/roxar/Pages/Roxar.aspx

1.4 Project Significance

This project can:

i) contribute to WAG implementation program in Malaysia.

ii) encourage further studies on impact of well configuration design on EOR techniques.

iii) inspire new development on making WAG more effective, efficient and economically viable.

iv) improve understanding on horizontal well's impact on EOR.

CHAPTER 2

LITERATURE REVIEW AND THEORY

2.1 Water Alternating Gas

2.1.1 WAG Theory

Oil recovery is described by:

$$REC = E_v \cdot E_h \cdot E_m \tag{2.1}$$

where *REC* is oil recovery, E_v is vertical sweep, E_h is horizontal sweep, and E_m is the microscopic displacement efficiency. Therefore, recovery is increased if one of these factors is increased. Note that E_h and E_v are related to macroscopic displacement. It is also note that gas has a better sweeping efficiency than water.

2.1.2 Horizontal Displacement Efficiency

E_h is strongly influenced by the stability of the front defined by the mobility of the fluids given by this equation:

$$M = \frac{k_{rg}/\mu_g}{k_{ro}/\mu_o} \tag{2.2}$$

where k_{rg} and k_{ro} are the relative permeability of gas and oil respectively while μ_g and μ_o are the gas and oil viscosity respectively. Unfavourable mobility ratio will cause early gas breakthrough and decreased sweep efficiency. This is called viscous fingering. There are other reasons for fingering as well such as reservoir heterogeneity and high permeable layers.

2.1.3 Vertical Displacement Efficiency

On the other hand, E_v is influenced by relationship between viscosity and gravitational forces.

$$R_{v/g} = \left(\frac{v\mu_o}{kg\Delta\rho}\right)\left(\frac{L}{h}\right) \tag{2.3}$$

where μ_o is oil viscosity, v is the Darcy velocity, L the distance between wells, k, absolute permeability of oil, g the gravity force, $\Delta\rho$ is the density difference between the fluids and h is the height of the displacement zone [3]. After computing $R_{v/g}$, the graph below is used to find the vertical displacement efficiency.

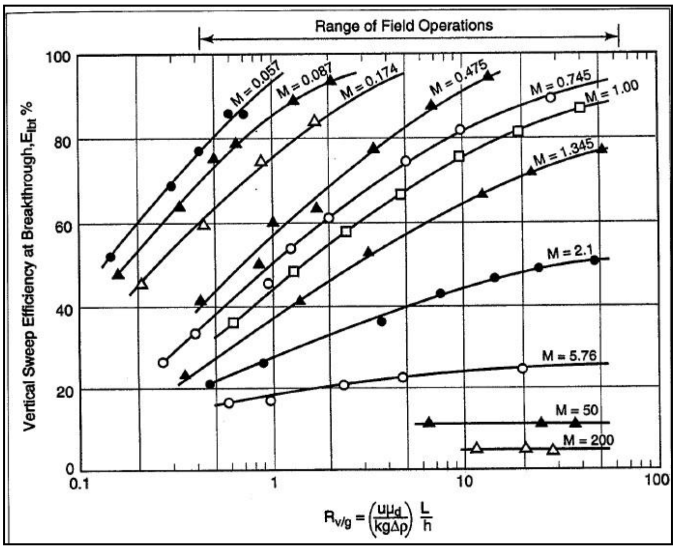


Figure 2.1 Vertical Displacement Efficiency as a Function of Viscosity Ratio / Gravity Forces (Craig et al) [1]

2.2 WAG Classification

2.2.1 Immiscible WAG (I-WAG)

Immiscible refers to a mixture of two fluids but with interfacial tension or interface between them. The displacement of oil then depends on the injected phase using the interface to 'push' oil to the production well. It has been proven that microscopic displacement efficiency is greatly improved by this technique. This type of WAG has been used to improve frontal stability and contacting unswept zone [3].

Oil is recovered by raising the capillary number due to the relatively low interfacial tension values between the oil and injected gas [7]. Usage of CO_2 gas in I-WAG has been proven to yield higher oil recovery for example in Dulang Field, Malaysia [8]. CO_2 injected below MMP was found to improve oil recovery by 18% [9]. CO_2 gas is said to be favourable because of availability, higher viscosity, lower formation volume factor (FVF) and lower mobility ratio make volumetric efficiency for CO_2 higher than other solvents or solvent mixtures. It also has closer density to typical light oil density making CO_2 less prone to gravity segregation [10].

In IWAG, the recovery could be because of one or more reasons [11]:

- Relative permeability of water flowing after gas experience reduction, causing water to flow in unswept area.
- Three-phase flow and hysteresis effect reduce residual oil saturation.
- Gas is able to displace water at the pore throat.

2.2.2 Miscible WAG (M-WAG)

Miscible from Petroleum Engineering point of view is a physical condition where two or more fluids (in this case gas and oil) will mix in any proportion without the existence of interface between them (Interfacial Tension = 0). Introduction of miscible gas maintains pressure in the reservoir. The reservoir is pressurized to above the Minimum Miscibility Pressure (MMP) so that the gas remains dissolved in the oil which effect would resemble solution gas drive mechanism. This will reduce oil viscosity easing its flow to the production well.

Historically, hydrocarbon gases such as propane, butane, and mixtures of Liquified Petroleum Gases (LPG) were used as injection gas [12]. However, the industry now is moving to carbon dioxide for better miscibility and lower cost. Nevertheless, it is actually difficult to distinguish between miscible and immiscible WAG. Due to availability, M-WAG are mostly onshore while I-WAG offshore. Since maintaining pressure is difficult, real field cases may oscillate between I-WAG and M-WAG [4]. One of the reported mass transfer mechanisms in this technique is condensing gas drive mechanism where gas injection that is rich of intermediate components condenses to liquid [3].

2.2.3 Hybrid WAG (H-WAG)

When a large slug of gas is injected followed by a number of small slugs of water and gas, this process is referred to as hybrid WAG [5].

2.2.4 Simultaneous WAG (S-WAG)

S-WAG was first introduced in 1962 in Seelington Field, USA. This method involves simultaneous injection of water at the top of the reservoir formation and injecting gas at the bottom of the formation [3].

2.3 Well Configuration Design

Finding well configuration design that gives higher oil production is a complex challenge because it is a function of geological rock and fluid properties as well as economic constraints. Traditionally, well configuration design is determined by analyzing a few scenarios using a numerical simulator [13].

2.3.1 Analysis of Main Literature

There are few literatures focusing on this topic. However, one in particular will be the subject of reference for this project. This study by Bagci and Tuzunoglu [14] performed an investigation on WAG process through horizontal wells. There are three well configurations which are:

a) Vertical injection and vertical production wells
b) Vertical injection and horizontal production wells
c) Horizontal injection and horizontal production wells.

These will be applied on four CO_2/Water displacement processes used to recover oil:

a) Continuous CO_2 injection
b) Water-flooding
c) Simultaneous injection of CO_2 and water (S-WAG)
d) Water Alternating Gas

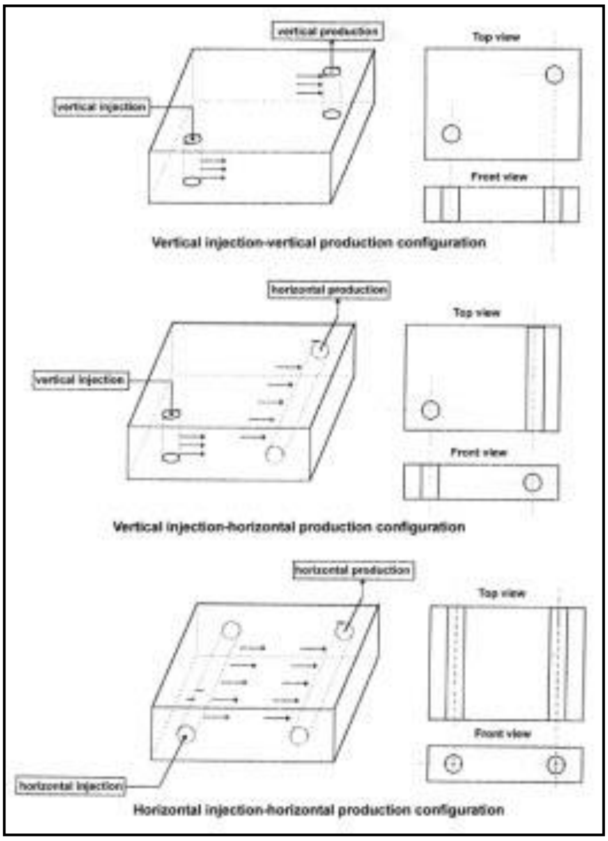


Figure 2.2 Well Configurations [14]

However, as we are only interested in WAG, its result is the main focus. Reference [14] found that the combination of vertical injector and horizontal producer yielded the highest oil recovery.

Several improvements could be made to this experiment.

a) Increase the experiment's scale

The sand pack model used by this experiment is 6x30x30cm which is too small to safely extrapolate its properties for a larger region. Therefore, this project used a simulation model of 3500x3500x100ft size to study the impact of well configuration design on a larger scale.

b) Include well length in sensitivity study

Studies have shown that the length of horizontal well affects well performance. Lab experiment [14] does not conduct sensitivity analysis on well length factor. Thus, this project would improve this experiment by running simulation for full and half the length of the injector well.

c) Include economic analysis

Often practicality of a method depends on the cost it incurred vs. the expected revenue that method can generate after its completion. By adding the economic dimension into the analysis of well configuration, the actual real world application can be better understood.

CHAPTER 3

METHODOLOGY AND PROJECT WORK

3.1 Research Methodology

3.1.1 General Approach on Model Characterization

The main consideration is to characterize the simulation model to be amiable to WAG process as experienced in actual fields globally. This project will maintain a simulation model that fits the screening criteria for WAG application. Below is the summary of miscible WAG screening criteria [15].

Table 3.1 Miscible WAG Screening Criteria

Criteria	Parameters	Range
Oil Properties	API Gravity	33-39
	Viscosity (cp)	0.3-0.9
Reservoir Properties	Porosity	11-24%
	Permeability (md)	130-2000
	Depth (ft)	7545-8887

It is also noted that reservoir temperature, depth and formation type are not critical factors in WAG screening [16]. The grid dimension is 7x7x3 with grid size of 3500ft x 3500ft x 100 ft. The simulation runs for 20 years.

3.1.2 General Approach on PVT Data and MMP

Pressure, volume, and temperature (PVT) data are one of the inputs for simulator as well as to determine minimum miscible pressure (MMP), the minimum pressure for gas and oil to be miscible. The injection pressure for this project must be above MMP to best maintain miscible condition. There are three possible sources of PVT data for this project which are core and fluid sample, research paper, and Tempest More software generated PVT table. All sources were considered throughout this project based on time constraint, availability of data, and simulation result.

If the data are generated by Tempest More software, then correlation will be used to determine MMP. Data from research paper on the other hand would be characterized first using Tempest PVTx, a PVT characterization suite in the software before undergoing correlation to get MMP. If core and fluid sample are available, the slim tube test will be conducted first before performing the mentioned steps. The picture below depicts the process.

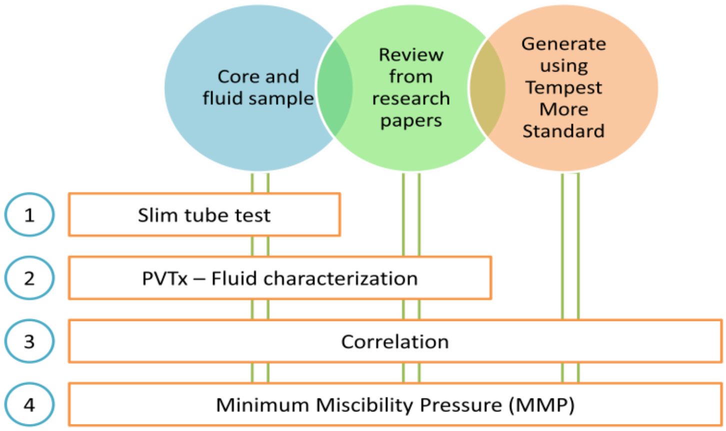


Figure 3.1 PVT Process for simulation and MMP determination

3.1.3 General Approach on Economic Studies

This project uses Net Present Value (NPV) as the main indicator of economic viability. NPV is essentially the summation of annual net cash flow at a given discount rate. It is a method to evaluate positive or negative cash flow of an investment alternative using present worth calculation:

$$P = \frac{F}{(1+i)^n} \tag{3.1}$$

where P is the present worth, F future amount of money, i the discount rate, and n, number of years from present. NPV will be computed at three sets of discount rates purpose of this study which are 5% (low case), 15% (middle case) and 40% (high case). Economic inputs include:

1) CAPEX and OPEX
2) Inflation rate
3) Fluid price

3.2 Work Procedures

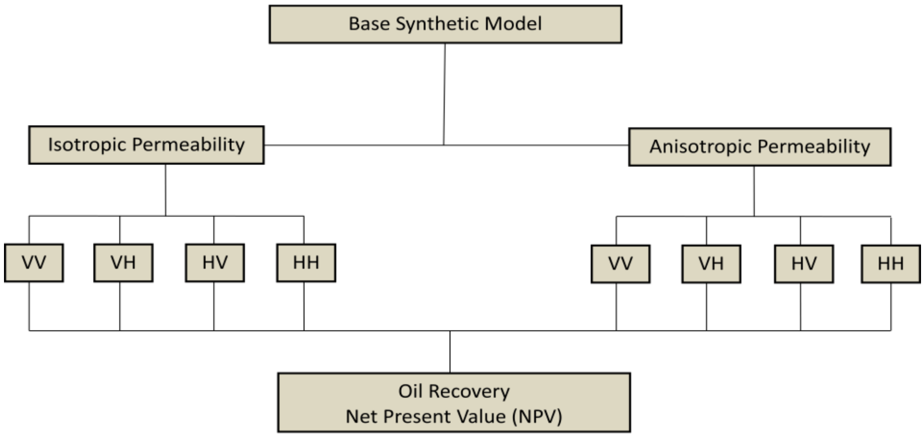


Figure 3.2 Planned cases in simulation study

A synthetic model was created as a basic model for this project. The initial condition includes a homogenous, water-wet and isothermal reservoir. Next, three synthetic models with 0.1, 1, and 2 permeability anisotropy ratios, (k_v/k_h) were created respectively. There are four well configuration designs:

a) Vertical injector – Vertical producer (VI-VP)
b) Vertical injector – Horizontal producer (VI-HP)
c) Horizontal injector – Vertical producer (HI-VP)
d) Horizontal injector – Horizontal producer (HI-HP)

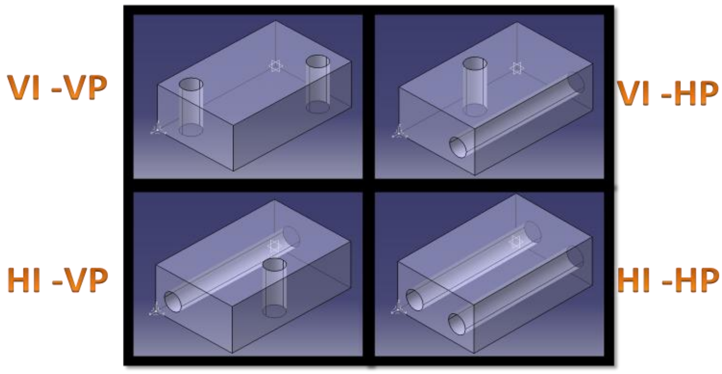


Figure 3.3 Well configuration designs for this project

All three synthetic models were duplicated for each well configuration design. The simulation deck creation process is further visualized in Figure 3.4 for VI-VP. The same figure applies for the other well configurations. In total, there are seventy two simulation decks.

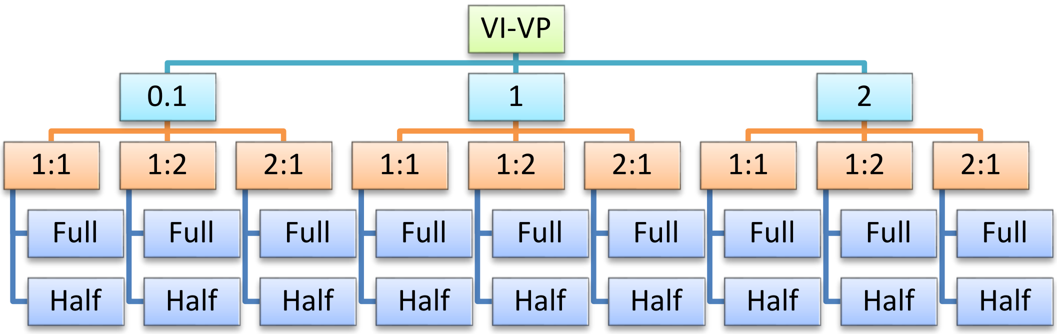


Figure 3.4 Simulation Deck Creation Process

Figure 3.4 illustrates that for each anisotropy ratio case, three decks were created for 3 WAG Ratio cases. Under each WAG ratio cases, two simulation decks were created; one with full injector well length and half injector well length for the other.

Next, simulation was conducted to obtain EOR ultimate recovery for all the simulation decks. Oil recovery factor is computed based on this equation [17].

$$REC = \frac{N_p}{N_s} \tag{3.2}$$

where N_p is cumulative oil produced while N_s is estimated oil initially in place. Modified Example from Tarek Ahmad, Reservoir Engineering Handbook [18]:

Table 3.2 Data for example oil recovery calculation [18]

A = 3000 acres	h = 30 ft	$ø$ = 0.15	S_{wi} = 20%
T = 150 °F	p_i = 2600 psi		

Here A is area, h, thickness, $ø$, porosity,S_{wi}, initial water saturation, T, temperature and p_i, initial pressure.

Step 1: Calculate reservoir pore volume (PV)

$$PV = 43560Ah\emptyset = 43560(3000)(30)(0.15) = 588.06MMft^3$$

Step 2: Calculate oil initially in place (N_s)

$$N_s = (1 - S_{wi})PV = \frac{(1-0.2)(588.06MMft^3)}{5.615ft^3/RB} = 83MMRB$$

Step 3: Calculate oil recovery factor given measured cumulative oil production after 10 years is 56*MMRB*.

$$REC = \frac{N_p}{N_s} = \frac{56MMRB}{83MMRB} = 0.675$$

Parameters for sensitivity analysis are:

- Anisotropy Ratio, $\frac{k_v}{k_h}$ – 3 cases (0.1, 1, and 2)
- WAG Ratio – 3 cases (1:1, 1:2, and 2:1)
- Injection well length – 2 cases (Full length of the grid and ½ grid length)

After sensitivity analysis, economic analysis was investigated. Net Present Value (NPV), potential revenue loss and net cash flow of each well configuration design are studied and interpreted. The chart below describes the complete simulation flow chart.

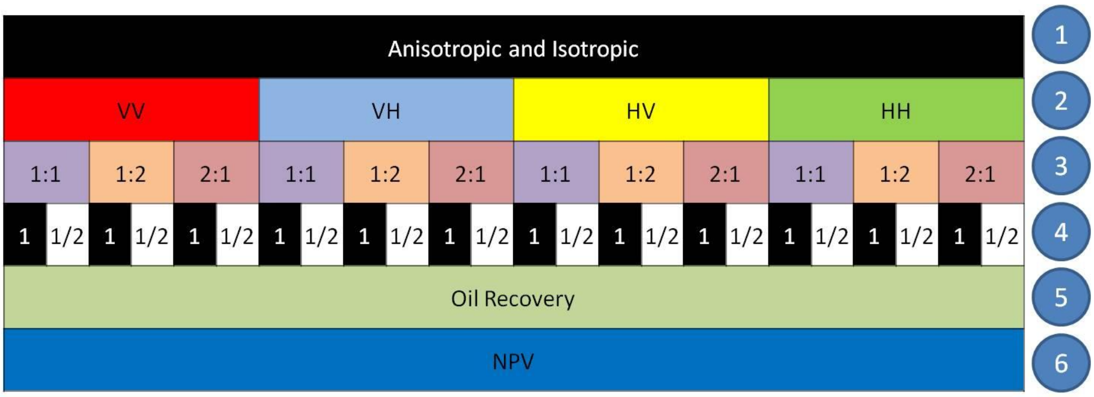
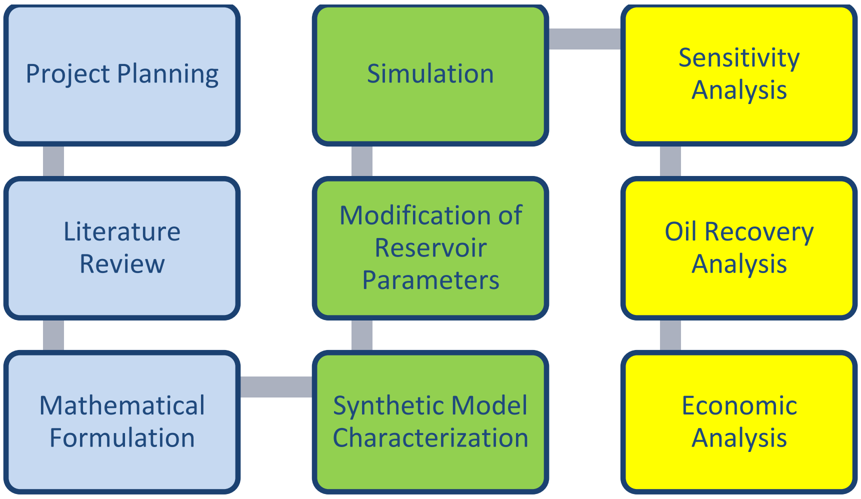


Figure 3.5 Simulation cases flow chart

1 – Permeability case ; 2 – well configuration case ; 3 – WAG ratio sensitivity ; 4 – Injection well length sensitivity ; 5 – Result ; 6 – Economic analysis

3.3 Project Activities and Tools

The project activities and the tools used are pictorially illustrated in the chart given below:



3.6 Project activities flow chart

3.3.1 First Phase: Preliminary Study

This phase includes Project Planning, Literature Review and Mathematical Formulation. Project planning ensures clear objective, flow of research and project work. It improves efficiency of project execution as well as effectiveness of simulation work. Literature review provides background knowledge on simulation, WAG and conventional problems of WAG related optimization and simulation works. Mathematical formulation is the stage to understand mathematical equations that describe simulation and WAG sweep efficiency process.

3.3.2 Second Phase: Synthetic Simulation

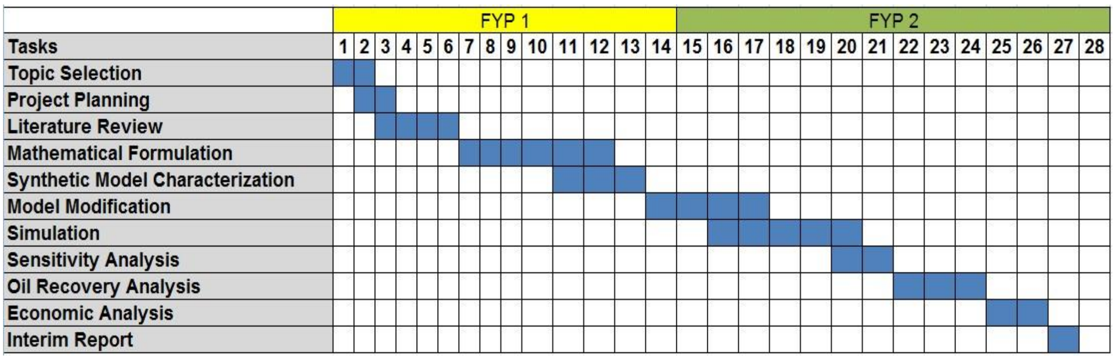
This phase includes synthetic model characterization, modification of reservoir parameters, and simulation works. A synthetic model was created with all the necessary reservoir properties such as PVT and relative permeability data. Modification procedure is to include the isotropic and anisotropy models preparation, defining well orientation for each case, as well as testing for WAG ratio and water-CO_2 injection. Then, all the simulation decks were run.

3.3.3 Third Phase: Result Analysis and Application

This phase includes sensitivity analysis. Sensitivity analysis is to understand the weightage each factors affecting the oil recovery. Oil recovery analysis assesses parameter combination in each scenario in terms of oil recovery increment. Lastly, economic studies provide cost-revenue insight on each scenario; indicating whether such modification in well configuration design is worth the cost.

3.4 Gantt Chart

Table 3.3 Project Gantt Chart



This Gantt chart spans from May 2012 semester to September 2012. It includes the general tasks explained in methodology section earlier which are performed in the designated weeks.

CHAPTER 4

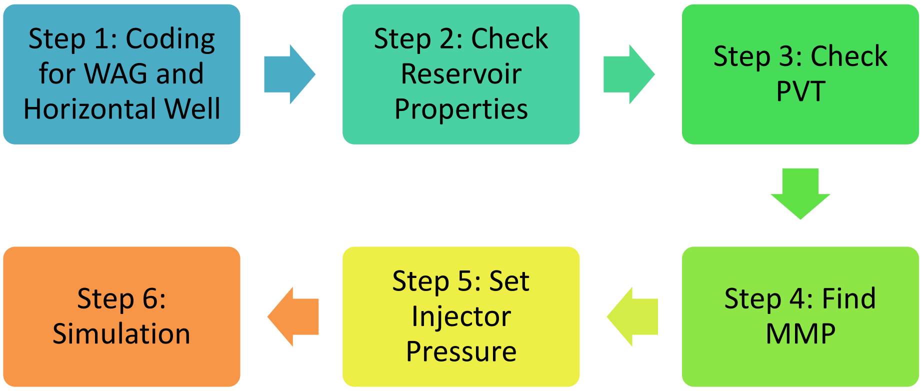
RESULTS AND DISCUSSIONS

4.1 Data Gathering and Preparation

This section explains the process of obtaining and preparing the necessary data needed for the simulation studies.

4.1.1 Progress Flow

The flow chart below portrays step by step procedure to require data needed for simulation and preparing the simulation deck.



4.1 Flow chart of simulation deck preparation

Step 1 in the chart has been achieved by studying Tempest Manual. CIJK command was used for defining horizontal well trajectory and perforation interval meanwhile READ and DELT keywords were used to create WAG-like injection sequence. All cases created were simulated with no error. The simulation deck is in appendix A.

Steps 2, 3 and 4 are required because initially a new synthetic model was needed. However, MSPE 5 model which is available from the paper entitled '**Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulators**' by **J.E. Killough et al** was used [18].

However, the model is a compositional one. The original plan for the project is to use black oil instead of compositional due to simplicity. However, it turns out that availability of the model is practically much simpler and reduces time for creating and testing a new synthetic model. Therefore, effectively Steps 2, 3, 4 and 5 have been greatly reduced when using MSPE 5 model with some modifications.

4.1.2 Data Properties and Configuration

Below are the properties used in the simulation:

Table 4.1: Injection Water Properties

Properties	Density (lb/ft^3)	Compressibility (1/psi)	Reference Pressure	Viscosity (cp)	Density Ref (lb/ft^3)
Water	62.4	3.30E-06	4000	0.7	62.4

Table 4.2: Injection Gas Composition

Comp	Mol Fraction
C1	0.77
C3	0.20
C6	0.03

Table 4.3: Oil Composition

Comp	*MW*	T_C	P_C	*ACF*	Z_C	*SGR*
C1	16.04	343	667.8	0.013	0.29	0.29832
C3	44.1	665.7	616.3	0.1524	0.277	0.54914
C6	86.18	913.4	436.9	0.3007	0.264	0.65778
C10	142.29	1111.8	304	0.4885	0.257	0.67168
C15	206	1270	200	0.65	0.245	0.57818
C20	282	1380	162	0.85	0.235	0.59965

Table 4.4: Oil-water relative permeability table, k_{row}

S_w	k_{rw}	k_{row}
0.2	0	1
0.2899	0.0022	0.6769
0.3778	0.018	0.4153
0.4667	0.0607	0.2178
0.5556	0.1438	0.0835
0.6444	0.2809	0.0123
0.7	0.4089	0
0.7333	0.4855	0
0.8222	0.7709	0

0.9111	1	0
1	1	0

Table 4.5: Oil-gas relative permeability table, k_{rog}

S_g	k_{rg}	k_{rog}
0	0	1
0.05	0	0.88
0.0889	0.001	0.7023
0.1778	0.01	0.4705
0.2667	0.03	0.2963
0.3556	0.05	0.1715
0.4444	0.1	0.0878
0.5333	0.2	0.037
0.6222	0.35	0.011
0.65	0.39	0
0.7111	0.56	0
0.8	1	0

Temperature: 160 °F

This model injects at 4500psi above the MMP of 3000psi.

Wettability : Water

Configuration (top view)

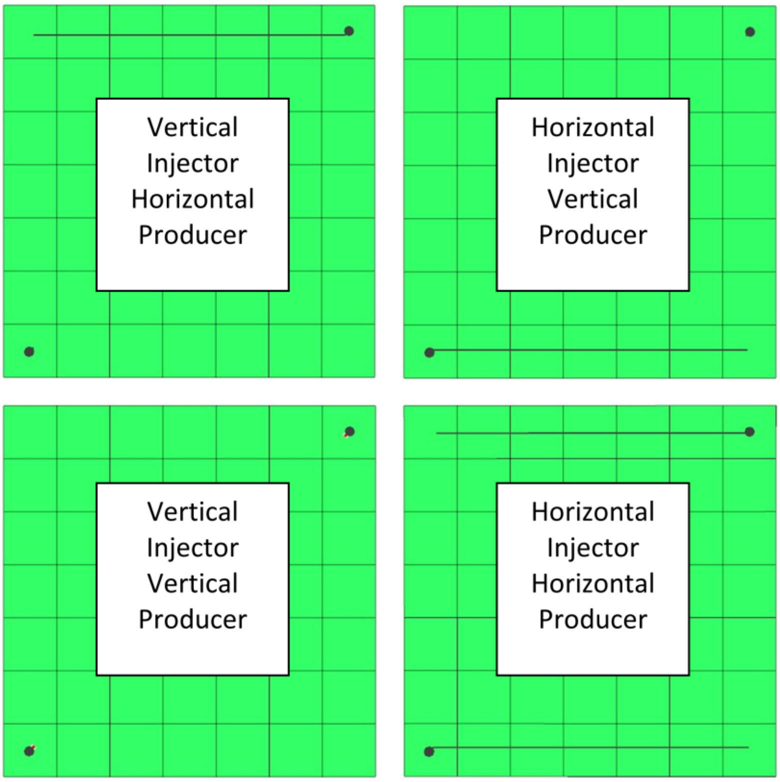


Figure 4.2 Five spot pattern for the well configuration design

4.1.3 Simulation Preparation

Before the simulation begins, the injection rates for water and gas were determined first. This is to ensure the desired WAG ratio is achieved.

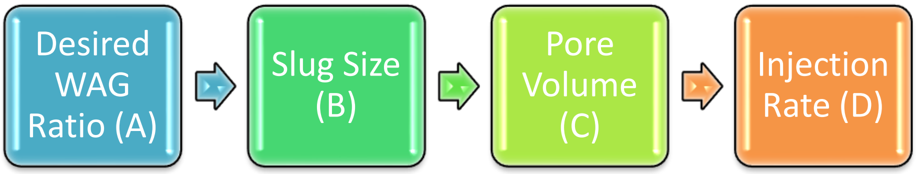


Figure 4.3 Calculation process to determine injection rate

For the sensitivity analysis, there will be 3 WAG ratios; 1:1, 1:2 and 2:1. The total slug is determined to be 0.4PV, from observation of other research papers. The process is to first decide on the desired WAG ratio for analysis which is followed by the computation of slug size based on the WAG ratio. A slug size equation is:

$$SLUG\ SIZE = \frac{Q_i\,(t)}{\emptyset(BV)} \tag{4.1}$$

0.2PV means that injected volume $Q_i(t)$ is one fifth of the pore volume, *PV* where *BV* is bulk volume. The desired WAG ratio is obtained through the steps below:

Figure 4.6 WAG Ratio calculation

	Water Gas		Water Gas Gas		Water Water Gas	
A	1:1		1:2		2:1	
B	0.2PV	0.2PV	0.133PV	0.267PV	0.267PV	0.133PV
C	$\frac{Q_{iw}\,(t)}{\emptyset(BV)}$	$\frac{Q_{ig}(t)}{\emptyset(BV)}$	$\frac{Q_{iw}(t)}{\emptyset(BV)} \times \frac{1}{3}$	$\frac{Q_{ig}\,(t)}{\emptyset(BV)} \times \frac{2}{3}$	$\frac{Q_{iw}\ w(t)}{\emptyset(BV)} \times \frac{2}{3}$	$\frac{Q_{ig}(t)}{\emptyset(BV)} \times \frac{1}{3}$
D	$Q_{iw}(M)$	$Q_{ig}(M)$	$0.333Q_{iw}(M)$	$0.667Q_{ig}(M)$	$0.667Q_{iw}(M)$	$0.333Q_{ig}(M)$
	Half of the total injected volume	Half of the total injected volume	A third of the total injected volume	Two third of the total injected volume	Two third of the total injected volume	A third of the total injected volume

*By fixing the time interval as constant for all cases that means the injection rate is ought to be change to get the desired ratio. Noted that the total injected volume is constant; 0.4PV.

* Taking the entire constant variable as constant the equation can be simplified to $Q_{iw}(M)$ or $Q_{ig}(M)$ where:

$$M = \frac{(t)}{\emptyset(BV)} \tag{4.2}$$

Sample calculation to obtain the flow rate injection for 0.2PV and 1:2 WAG ratio:

$$Q_i = \frac{0.2 \times PV}{t} == \frac{0.2 \times 64.8291 \times 10^6 \ RB}{365 \ days} = 35\,865.47945 \ RB/d$$

where RB, is reservoir barrel.

Therefore, total volume is,

$Vt = 35\,865.47945 \ RB/d \ \times 2 = 71730.9589 \ \ RB/d$

For water injection rate, divide with the formation volume factor:

$$Q_{iw} = \frac{71730.9589 \ \ RB/d}{1 \ Rb/STB} \times \frac{1}{3} = \ 23\,910.3296 \ \ STB/day$$

For gas injection rate

$$Q_{ig} = \frac{71730.9589 \ \ RB/day}{0.69940 \ RB/Mcf} \times \frac{2}{3} = \ 68373.8051 \ Mcf/day$$

4.14 Economic Analysis Preparation

A simple economic analysis was done to understand the possible lost in revenue in case a less efficient and effective WAG Scheme that do not consider the well configuration design. Note that the economic analysis was done in with indicator values that are constant for each simulation case for simplicity to compare the results later. Some of the values are estimated because usually budgeting and costing information is not made available to public.

Many of these values are negotiated in case by case basis and revealing the negotiated deal would jeopardize a company's either reputation, marketing strategy and competitiveness in the market.

Some of the input parameters include:

1) Capital Expenditure (CAPEX)

   Only well cost being considered for the economic analysis because other costs such as upstream and downstream facilities are too big to be assumed. For the cost of an injection well, it is estimated that for a shallow well in Malaysia the cost is around $15 million. A typical deep well in Malaysia might cost up to $50 million. On the other hand, a well in China only costs around $100, 000. Therefore, it is important also to note that the cost of well is defined by country and by region. For consistency sake, the well cost is constant for all the simulation cases.

2) Operational Expenditure (OPEX)

   There are fixed cost and variable cost per well. These are the costs to maintain a well. It is estimated that to operate a well in Malaysia the total cost is $4000 per day. This value is also kept constant for all simulation cases.

3) Inflation rate

   By looking at average inflation rate of the US dollar, it is estimated 4% is the average inflation rate.

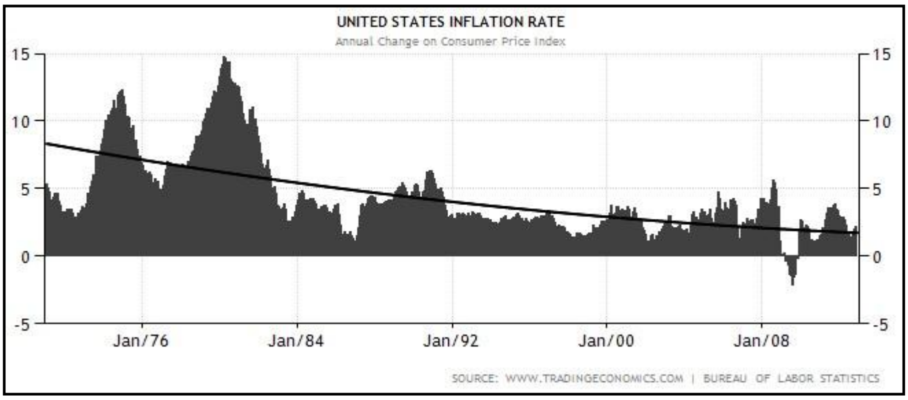


Figure 4.4 Inflation rate of US Dollar since 1970's[20]

4) <u>Fluid price</u>

There are 3 fluid prices used. $60/bbl is for the low case, $100/bbl is the medium case and $160/bbl as the high case. These values are to account for fluctuating oil price. By observing Figure 4.5 below, both WTI and Brent experienced great fluctuation in 2008 where oil price reached up to $140/ bbl and dropped as low as $60/bbl especially for Brent Crude Oil. That is the reason this project conducted three oil price values for economic analysis from low to high case. The entire oil price set for all simulation is based on the Brent Crude Oil Price since it is the global standard oil price. All three values are kept constant for all economic analysis.

Figure 4.5 Oil Price History for WTI and Brent Crude Oils [21]

4.2 Results

There are several considerations before analyzing the data. First of all, the simulation conducted for 20 years for 9 WAG cycles with 0.4PV injected fluids in total. The model created may or may not be of any actual field application. The recovery is indeed higher than industry average due to several reasons. This tank model is an ideal case where heterogeneity is neglected. There are no structural and stratigraphic anomalies that might have in real application hamper such a high recovery.

Furthermore, the simulation was run for 20 years anyways for the sake of continuity and standardization despite high water cut and gas-oil ratio.

4.2.1 Physical Representation of Sensitivity Parameters

a) Anisotropy Ratio, $\frac{k_v}{k_h}$

0.1 Ratio is commonly used in simulation. Vertical permeability is expected to be lower compared to the horizontal permeability due to layering of different facies on top of one another. Flowing fluids from the bottom layer to the top layer is hampered by the change of rock type at each layer-to-layer interface. Rock property factors such as grain size, porosity, and permeability difference and geological factors such as unconformity are most probably the cause of this phenomenon.

Meanwhile, a high anisotropy ratio (1 and 2) is most probably because of vertical hydraulic fracturing or the reservoir is a fractured reservoir. Since the simulation did not apply fractured reservoir model for example dual porosity model or dual permeability model, discussion on fractured reservoir will be dropped. Acidizing treatment also will not be included, although it too can improve vertical permeability, but the simulation did not account for damaged rock properties and fluid properties alteration caused by the acid. Instead, only vertical hydraulic fracturing is considered in the discussion.

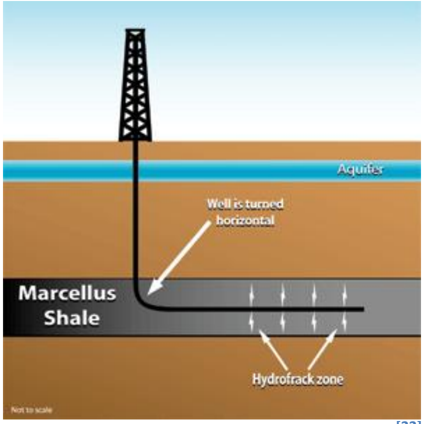


Figure 4.6 Vertical Hydraulic Fracturing [22]

b) WAG Ratio

1:1 Ratio indicates that the pore volume of water injected is equivalent to the pore volume of gas injected with respect to different volume conversion. Hence the ratios of 1:2 and 2:1 mean half pore volume of water injected as to gas injected and twice the pore volume of water injected as to gas injected respectively.

c) Well length

Full length well indicates the perforation was done completely along the well while half length means perforation was completed only at the top half of the well (for vertical well) or the first half of a horizontal well.

This condition is called, limited entry well or partial penetration well.

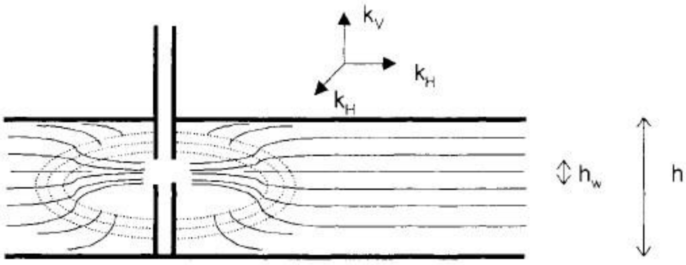


Figure 4.7 Limited Entry Well [23]

4.2.2 Sensitivity Analysis: Anisotropy Ratio

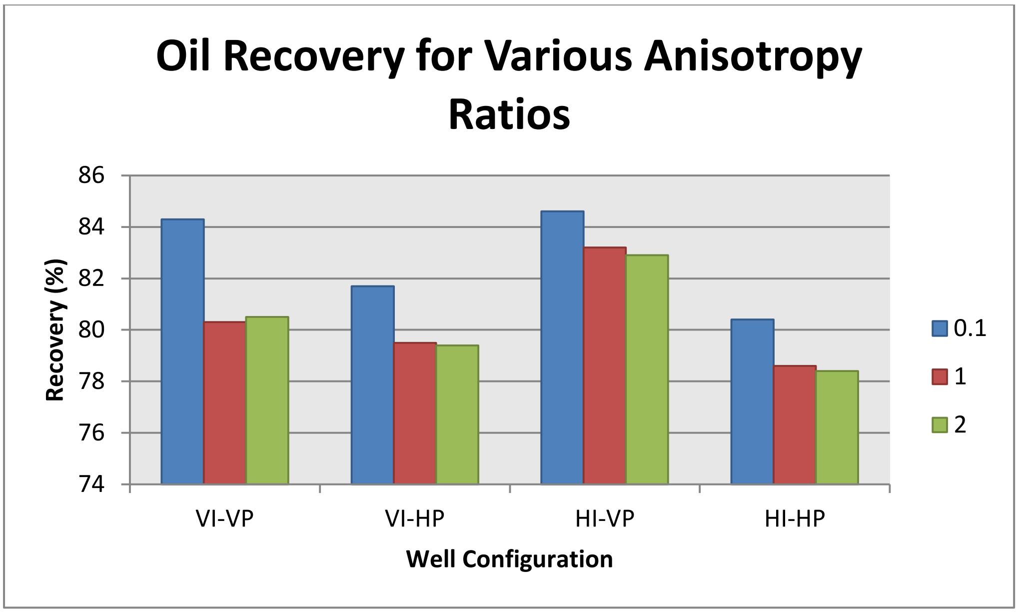


Figure 4.8 Oil recovery for different anisotropy ratio

On average HI-VP with all the three anisotropy ratio of 0.1, 1, and 2 gave the highest oil recovery with one exception for VI-VP of 0.1 ratio showed high oil recovery as well. HI-HP configuration with all three ratios gave lower recovery compared to the others. On the other hand, 0.1 ratio gave higher recovery on average while 1 and 2 ratios gave mix result.

4.2.3 Discussion on Anisotropy Ratio Results

a) 0.1 anisotropy ratio yielded highest average recovery

This might be due to slower segregation between gas and water injected due to the smaller vertical permeability.

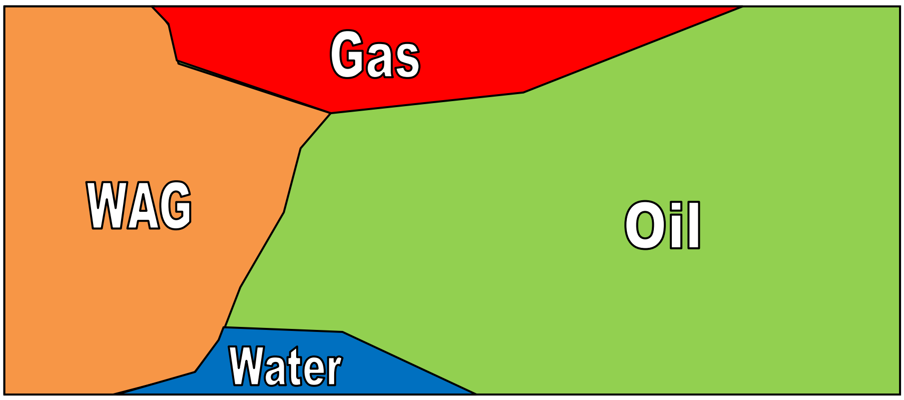


Figure 4.9 Ideal displacements for WAG injection

According to Figure 4.9, the WAG region is a mixture between gas and water where compared to only gas or only water has better sweeping mechanism. It is the region where water and gas reduced each other mobility allowing better areal and microscopic displacement.

Higher vertical permeability allows density segregation between gas and water to set in faster. Water with higher density will sink to the bottom of the oil zone while gas rises up due to its light density. When separated, each has lesser sweeping efficiency then when combined, thus oil recovery will drop.

Gas has good micro-sweep efficiency but moves faster than oil which leads to viscous fingering. Water has good areal displacement but often moves faster than oil due to water-wet rock and channelling.

The opposite is postulated for permeability ratio of 0.1 where the vertical permeability is smaller in comparison with horizontal permeability. The segregation will become slower allowing the WAG region to travel deeper in the reservoir sweeping more oil.

4.2.4 Sensitivity Analysis: WAG Ratio

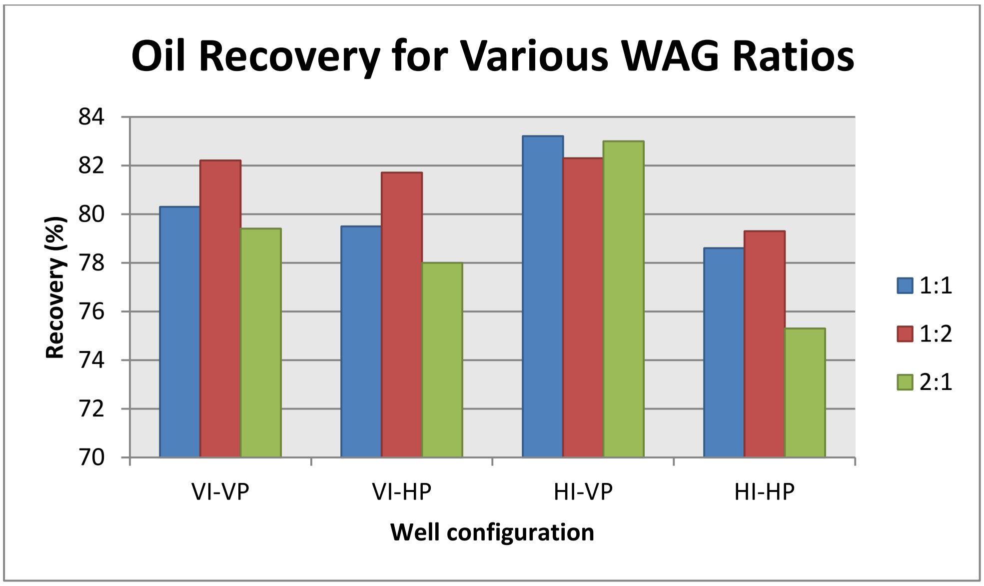


Figure 4.10 Oil recovery for different WAG ratio

On average ratio of 1:2 gave the highest oil recovery while ratio of 1:1 and 2:1 gave mix result. HI-VP gave better performance than the rest.

4.2.5 Discussion on WAG Ratio Results

Since this simulation is injected at higher MMP, meaning gas is miscible with oil. Except for HI-VP, the other well configuration designs indicated that 1:2 WAG ratio gave the highest recovery. The more volume of gas injected, the more volume of gas dissolved in oil, making the oil less viscous. As recalled from the mobility ratio equation, reduction of viscosity increases oil mobility and in short, more mobile oil means more oil can flow to the producing well.

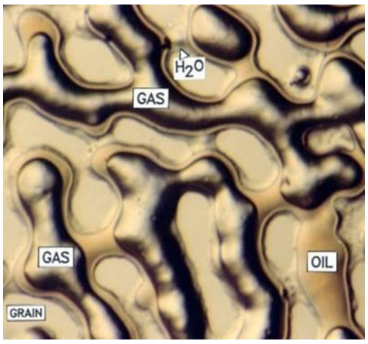


Figure 4.11 Sample of Miscible Gas in Oil [24]

4.2.6 Sensitivity Analysis: Well Length

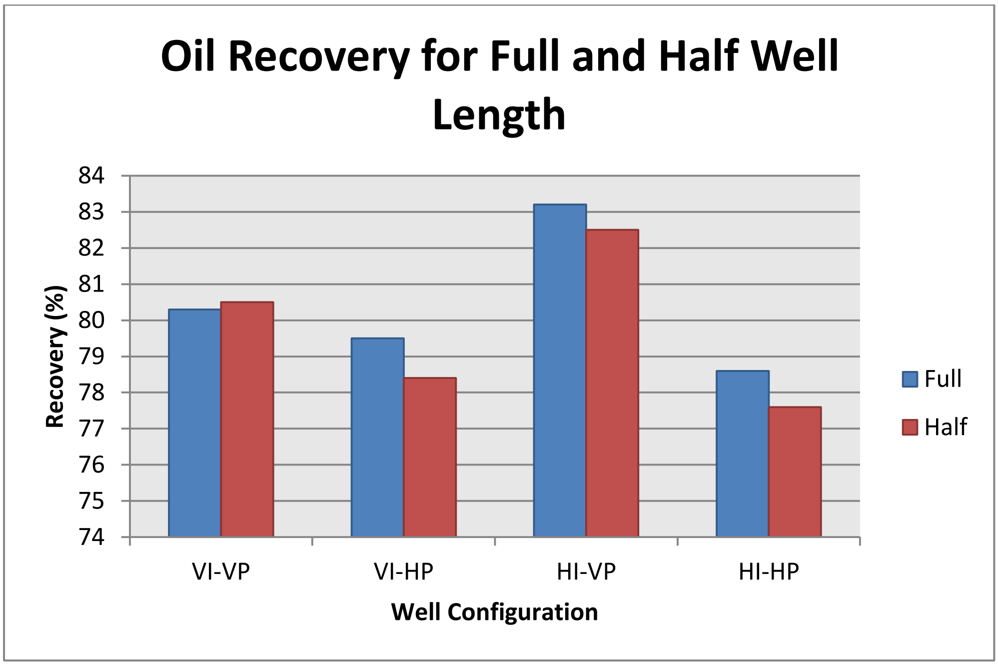


Figure 4.12 Oil recovery for different well length

On average full length perforation gave higher recovery compared to half length perforation except for VI-VP configuration.

4.2.7 Discussion on Well Length Results

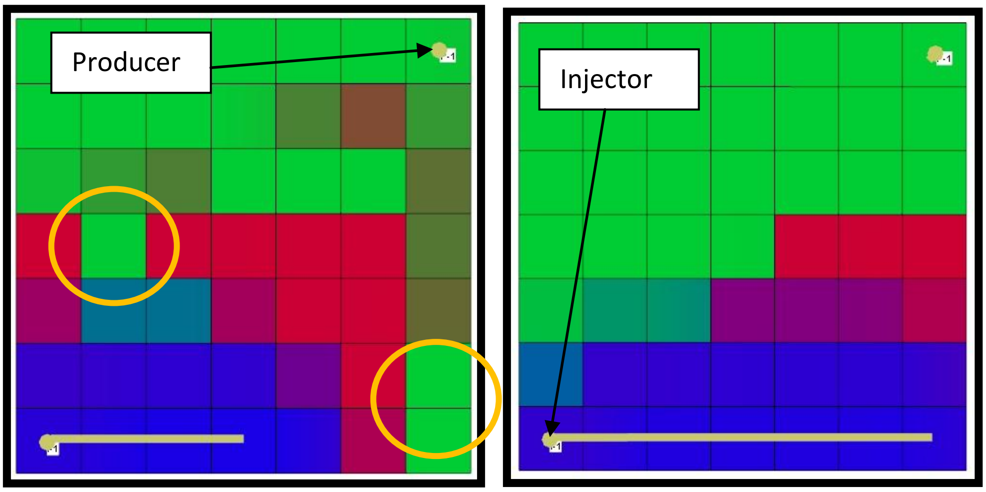


Figure 4.13 Injectants areal spread comparison between half length and full length well perforation for horizontal injector-vertical producer configuration

For horizontal injector, the full length well gives a better spread of the injecting fluids along the length of the model. From quick look, Figure 4.13 showed that full length perforation has better areal sweep while for half length perforation there are oil trappings in the model. This explains why horizontal well injector has better oil recovery. However if coupled with horizontal producer, the recovery becomes worst because water and gas reaches the producer faster as compared to a vertical producer.

This is call gas and water breakthrough where injected water and gas are started to be produced. Cumulative gas and water produce will increase over time due to viscous fingering and channelling. Ultimately, there is more residual oil left inside the reservoir as compared to using a vertical producer.

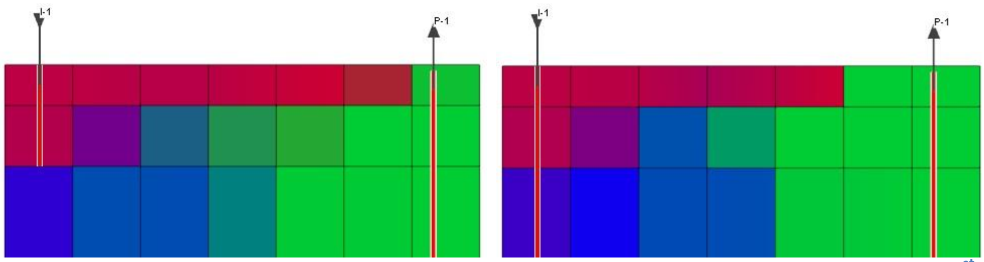


Figure 4.14 Vertical Sweep Efficiency comparisons between full and half length perforation for 1st May 1893 simulation date

On the other hand, partially penetrating well gave higher oil recover compared to full well perforation. Looking the simulation in Figure 4.14, at the same date, more region of oil has been swept by WAG in half length well case as compared to the full well length. It is noticed too that intensity of blue colour, indicating water is darker in full well length case. This indicates more water presence which means that in half well length case has lesser water; more oil zone can be swept to improve recovery.

In essence, half well length injects water farther from the water zone delaying gravity segregation of water for some time. As such, more water and gas at the WAG zone as described in Figure 4.9 exists thus improving vertical sweep and subsequently oil recovery.

4.2.8 Analysis Based on Well Configuration

Another way of looking at the results is to compare the better-performance and the poor-performance WAG scheme for each well configuration design. This shows that there is different WAG scheme for each well configuration design to obtain the best oil recovery.

Table 4.7: Better and Poor WAG Scheme Analysis for Each Well Configuration Design.

Well Configuration	Performance	Oil Recovery (%)	Anisotropy Ratio	WAG Ratio	Well Length (ft)
VI-VP	Better	85.7	0.1	1:2	Full
	Poor	77.9	1	2:1	Half
VI-HP	Better	81.7	0.1	1:1	Full
	Poor	76.5	2	2:1	Half
HI-VP	Better	84.6	0.1	1:1	Full
	Poor	81.8	1	2:1	Half
HI-HP	Better	80.4	0.1	1:1	Full
	Poor	75	2	2:1	Full

From this table, it can be said that there is WAG scheme (different combination of anisotropy ratio, WAG ratio and well length) to give a better recovery. This means that, if the well configuration is already present, usually in mature fields, to apply efficient WAG, an optimization of all the three factors must be considered to obtain high oil recovery.

4.3 Economic Analysis

4.3.1 Net Present Value at Different Discount Rate

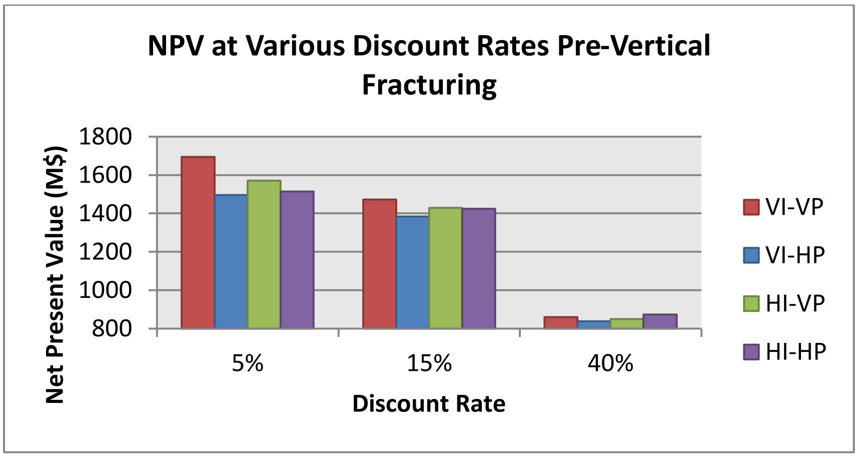


Figure 4.15 NPV at Various Discount Rates Pre-Fracturing

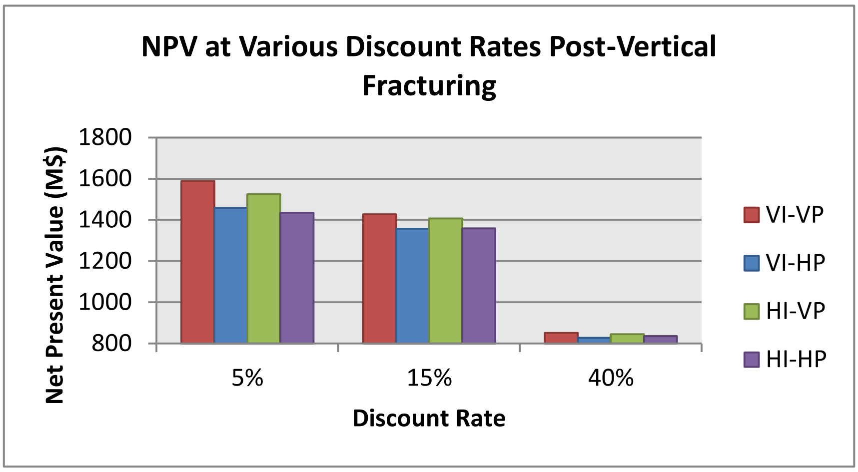


Figure 4.16 NPV at Various Discount Rates Post-Fracturing

From the results obtained from Figures 4.15 and 4.16, it can be said that all well configuration designs gave above $1.3 billion NPV at 5% and 15% for both pre-vertical fracturing and post-vertical fracturing. At 40% discount rate, the average NPV dropped below $1 billion NPV.

Not to miss, the highest NPV is given by VI-VP for both pre and post vertical fracturing. This is expected since the cost to drill a vertical well is much cheaper compared to a horizontal well. Therefore the total cost is much lower.

4.3.2 Oil Price Sensitivity

The first analysis is to compare the potential revenue lost if a poor WAG scheme is chosen instead of a better WAG scheme pre-vertical fracturing and post-vertical fracturing.

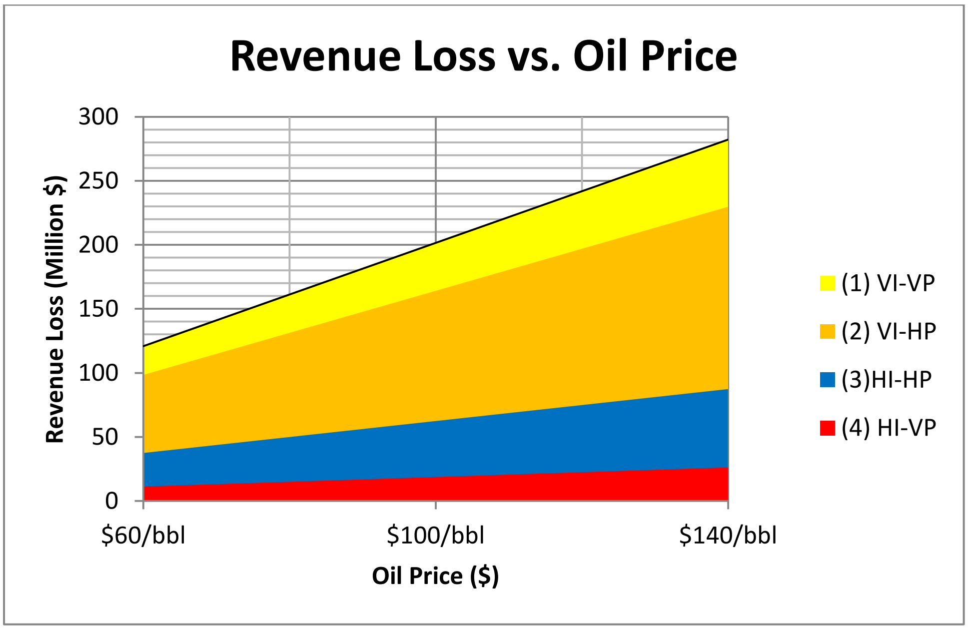


Figure 4.17 Revenue Loss Pre-Vertical Fracturing

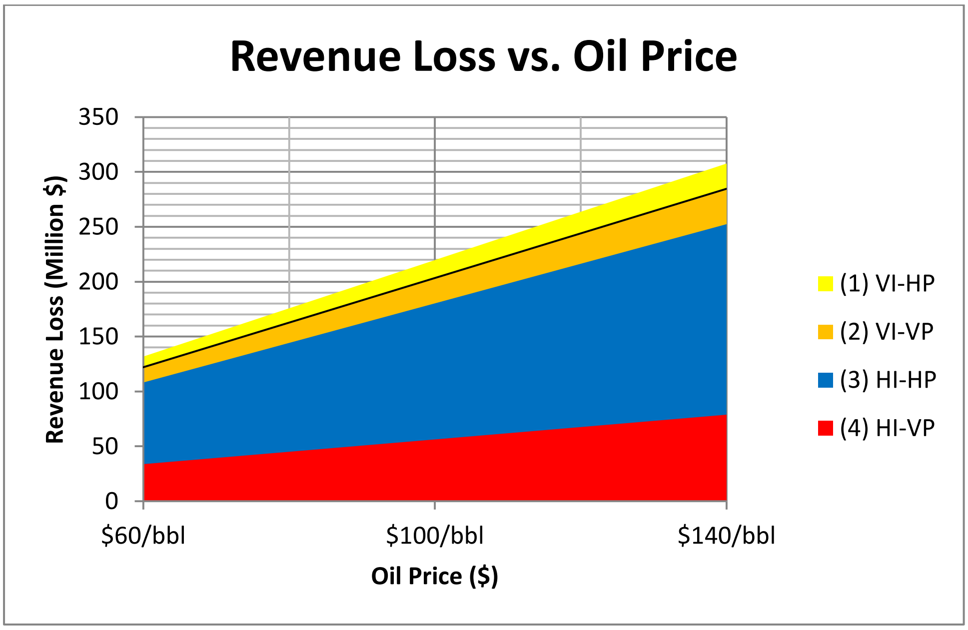


Figure 4.18 Revenue Loss Post-Vertical Fracturing

Figures 4.17 and 4.18 demonstrate the potential revenue loss at corresponding oil price between choosing the better WAG scheme and the poor WAG scheme. The table below summarizes the amount of loss calculated.

Table 4.8: Summary of Revenue Loss

Well Configuration Design		Total Revenue Loss (M$)		
	Oil Price	$60/bbl	$100/bbl	$140/bbl
Pre-Fracturing	VI-VP	121	202	282
Pre-Fracturing	VI-HP	98	164	230
Pre-Fracturing	HI-VP	11	19	26
Pre-Fracturing	HI-HP	37	62	87
Post-Fracturing	VI-VP	122	203	285
Post-Fracturing	VI-HP	132	220	308
Post-Fracturing	HI-VP	34	56	79
Post-Fracturing	HI-HP	108	180	252

For example, if the poor scheme of WAG is chosen for VI-VP, the potential loss is about $121 million, $202 million and $282 million for $60/bbl, $100/bbl and $140/bbl respectively. Note that this is just for only a pair of a producer and an injector scenario. The numbers will multiply for a reservoir that has multiple injector wells and producer wells.

The second analysis is to compare the cost and revenue of the better-performed WAG schemes for each well configuration. This is to show that although the recovery is very attractive, but the cost might be a limiting factor in choosing a certain well configuration design.

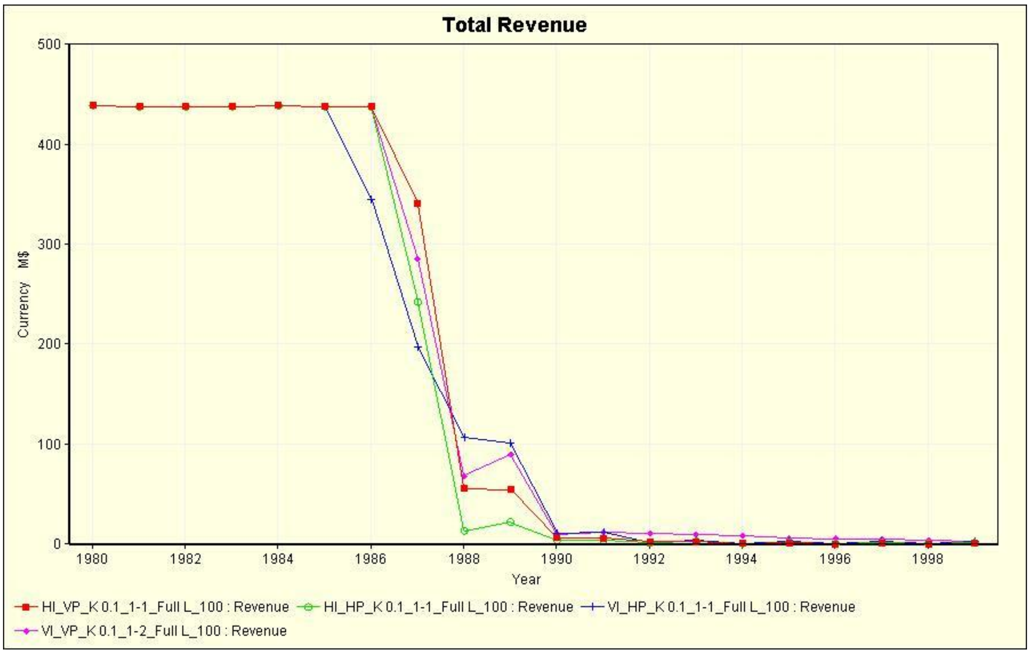


Figure 4.19 Total Revenue Comparison for the Better-performing WAG Scheme for Each Well Configuration

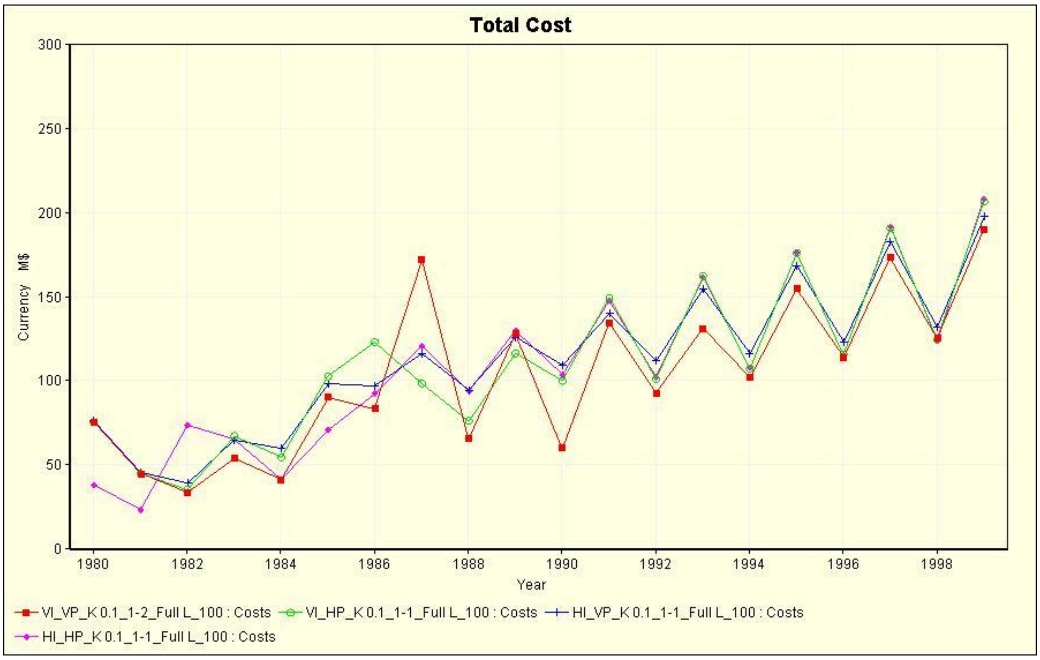


Figure 4.20 Total Cost Comparison for The Better-performing WAG Scheme for Each Well Configuration

Using both plots, a net cash flow plot was generated by subtracting the cost from the revenue to estimate the gross profit.

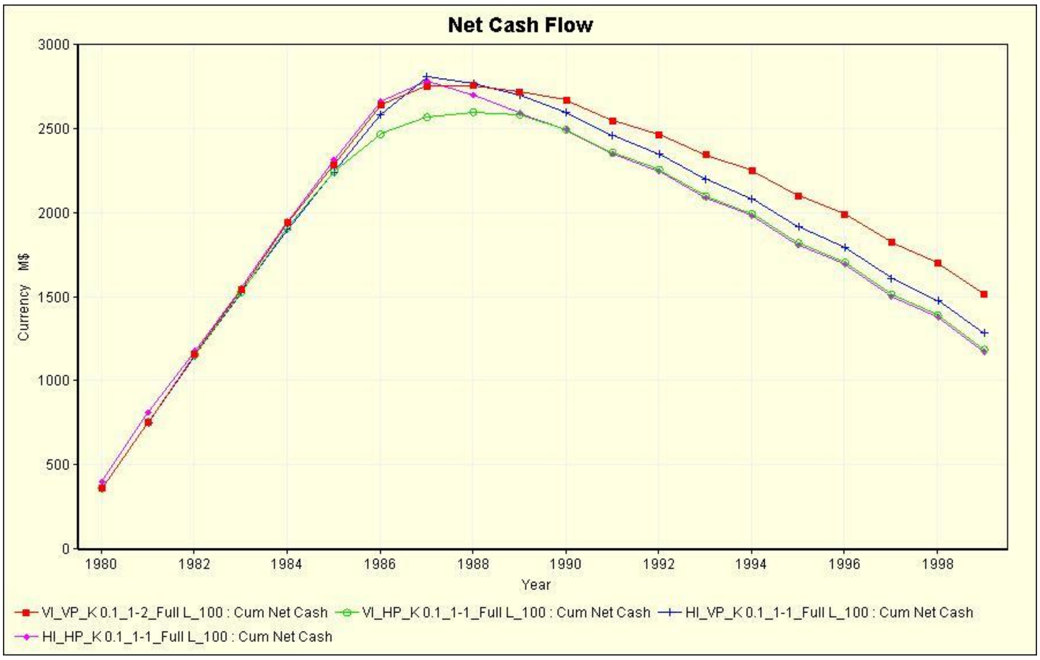


Figure 4.21 Net Cash Flow Comparison for The Better-performing WAG Scheme for Each Well Configuration

Looking at the best performing WAG scheme for VI-VP (anisotropy ratio of 0.1, WAG ratio of 1:2 and full perforation) for example, the red line in all the three plots shows revenue is higher than the other configuration and with a lower average costs as well. This gives a higher net cash flow to the project.

This is expected because the cost to drill a vertical well is much less compared to the cost of drilling horizontal well. For a tank model in this simulation, clearly from the oil recovery and economical aspects, the VI-VP well configuration is the most optimum design. However, in actual filed application, reservoir geometry and structure will yield a different oil recovery for each configuration.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

There are several conclusions that can be made from results obtained in this project.

1. Permeability anisotropy ratio (k_v/k_h) of 0.1 has been found to give the highest oil recovery while permeability ratio of 1 gives the lowest oil recovery for all well configurations.
2. 1:2 WAG ratio give relatively the highest oil recovery while 1:1 ratio has the lowest recovery for all four well configurations.
3. HI-HP, VI-HP and HI-VP gave highest oil recovery for full length injector well length while only VI-VP gives the highest oil recovery for half length injector well.
4. In economic analysis of NPV, oil price sensitivity, and cost-revenue analysis, VI-VP is more favourable compared to other well configuration.
5. In general, it is observed that the performance of VI-VP and HI-VP is much better compared to VI-HP and HI-HP for WAG EOR scheme in a horizontal reservoir for 5 spot pattern.
6. On average, HI-VP configuration gave better oil recovery which is consistent with the results obtained from literature review by Bagci and Tuzunoglu [13].
7. Finally, although from sensitivity analysis, HI-VP gave better oil recovery, but economic analysis indicated that VI-VP yielded higher cash flow. This means that economic consideration is a key determinant of the best option for a WAG scheme for different well configuration design.

5.2 Recommendations

There are two recommendations that can be made:

1. New Field

   New field is a reservoir that has not been developed and is still at the appraisal stage. At this stage, well configuration that gives the best oil recovery should be chosen to maximize the reserve and reduce costs.

2. Mature Field

   For a mature field that has been producing for quite some time the well configuration is already present. The next step is to find the best WAG scheme that has optimum WAG ratio, well length and anisotropy ratio for that specific well configuration. This will give the best oil recovery option in producing the reservoir.

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APPENDIX A

This appendix provides detail production data for all sensitivity analysis cases, reservoir pressure and a sample simulation deck.

A-1) Numerical Results for the Effect of Anisotropy Ratio on Oil Recovery for each Well Configuration Design

Well Configuration	Permeability Ratio (md)	WAG Ratio	Well Length (ft)	Oil Recovery (%)	Cumulative Oil Production (MSTB)	Cumulative Gas Production (mmscf)	Cumulative Water Production (MSTB)
V-V	0.1	1:1	Full	84.3	35292.26	173797.2	45914.98
	1	1:1	Full	80.3	33627.68	169537	53091.75
	2	1:1	Full	80.5	33717.94	171919.3	171919.3
V-H	0.1	1:1	Full	81.7	34226.77	188604.5	73190.45
	1	1:1	Full	79.5	33305.55	192241	73611.72
	2	1:1	Full	79.4	33259.21	192958.3	192958.3
H-V	0.1	1:1	Full	84.6	35429.88	187397.2	75200.47
	1	1:1	Full	83.2	34826.02	190191.9	75380.18
	2	1:1	Full	82.9	34704.54	190438.7	75381.74
H-H	0.1	1:1	Full	80.4	33662.13	167623.5	80843.52
	1	1:1	Full	78.6	32919.63	171492.2	81892.02
	2	1:1	Full	78.4	32818.33	172459.3	82103.51

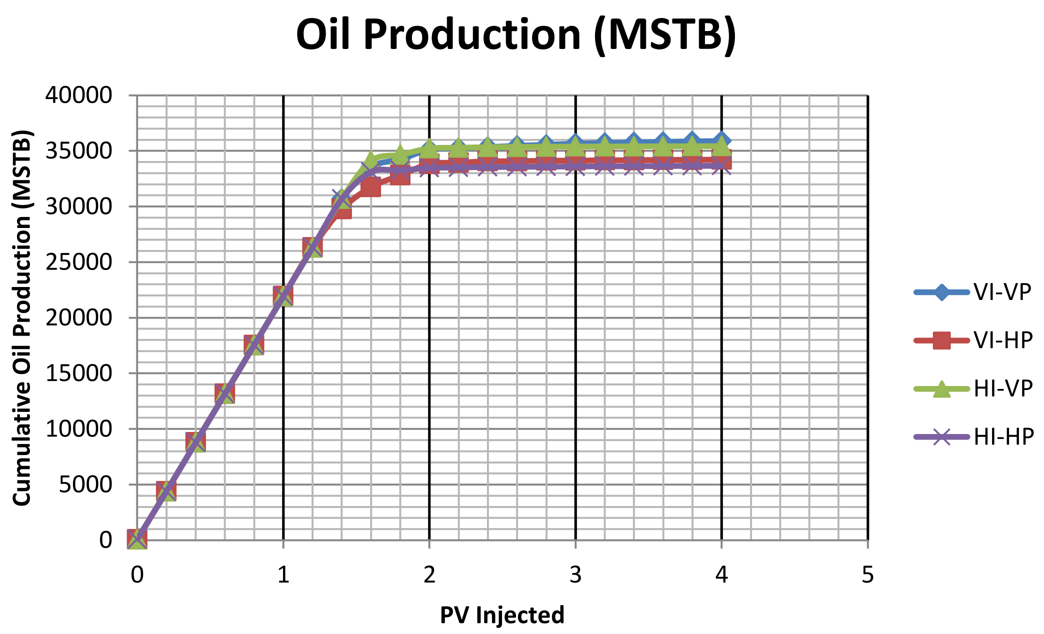
A-2) Numerical Results for the Effect of WAG Ratio on Oil Recovery for all Well Configuration Design

Well Configuration	Permeability Ratio (md)	WAG Ratio	Well Length (ft)	Oil Recovery (%)	Cumulative Oil Production (MSTB)	Cumulative Gas Production (mmscf)	Cumulative Water Production (MSTB)
V-V	1	1:1	Full	80.3	33627.68	169537	53091.75
		1:2	Full	82.2	34412.67	223551.7	41149.52
		2:1	Full	79.4	33253.43	131508.3	52582.25
V-H	1	1:1	Full	79.5	33305.55	192241	73611.72
		1:2	Full	81.7	34216.41	240579.8	43773.77
		2:1	Full	78	32672.36	141099.6	83882.26
H-V	1	1:1	Full	83.2	34826.02	190191.9	75380.18
		1:2	Full	82.3	34448.36	233766.2	45797.4
		2:1	Full	83	34754.21	139592.8	99031.79
H-H	1	1:1	Full	78.6	32919.63	171492.2	81892.02
		1:2	Full	79.3	33205.97	224030	49195.51
		2:1	Full	75.3	31525.81	120220.9	112042.3

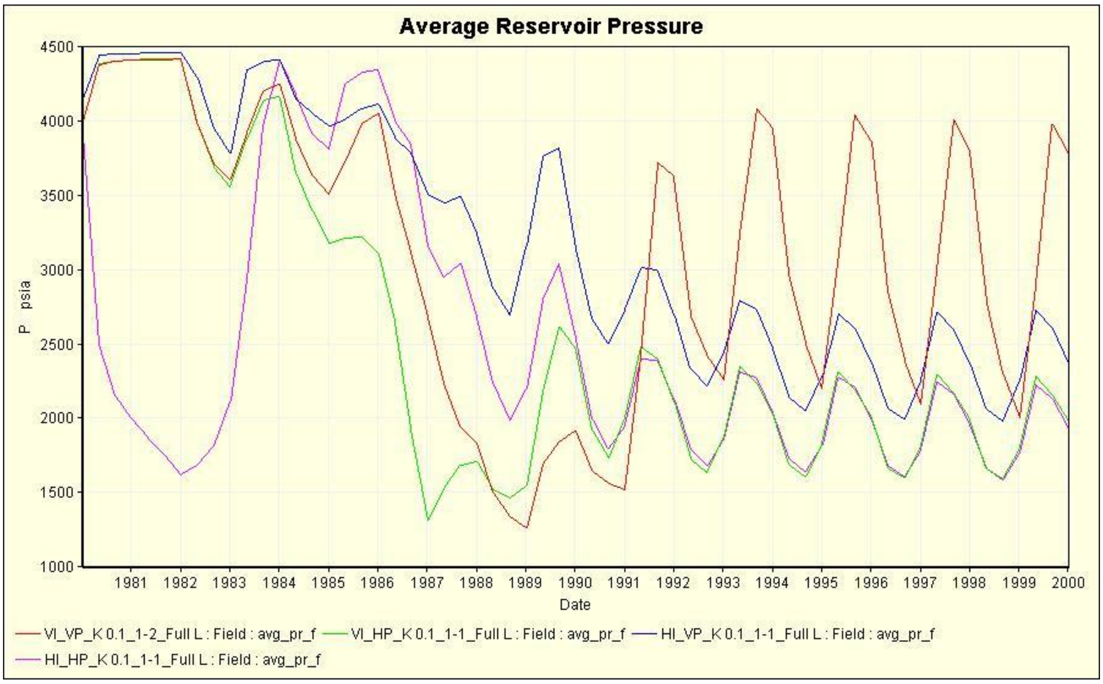
A-3) Numerical Results for the Effect of Well Length on Oil Recovery for all Well Configuration Design

Well Configuration	Permeability Ratio (md)	WAG Ratio	Well Length (ft)	Oil Recovery (%)	Cumulative Oil Production (MSTB)	Cumulative Gas Production (mmscf)	Cumulative Water Production (MSTB)
VI-VP	1	1:1	Full	80.3	33627.68	169537	53091.75
		1:1	Half	80.5	33701.65	182893.8	36601.12
VI-HP	1	1:1	Full	79.5	33305.55	192241	73611.72
		1:1	Half	78.4	32848.22	193951.6	48998.17
HI-VP	1	1:1	Full	83.2	34826.02	190191.9	75380.18
		1:1	Half	82.5	34537.87	187867.3	71666.28
HI-HP	1	1:1	Full	78.6	32919.63	171492.2	81892.02
		1:1	Half	77.6	32488.05	176406.1	80632.96

A-4) Cumulative Oil Production vs. Pore Volume Injected for Each Well Configuration.



A-5 Average Reservoir Pressure



A-6 Simulation deck for VI-VP of 1 anisotropy ratio, 1:1 WAG Ratio and full well length

```
/         ===================================================================
          INPUT    DATA                                                     /
          ===================================================================

TITLE:    SPE      5TH      COMPARATIVE   SOLUTION     "PROJECT,"    CASE    "1,"
          Feb.     "10,"    1989
IDATE:    1        JAN      1980
SDATE:    0        YEARS
IMPL      IMPES
CNAME:    C1       C3       C6       C10      C15      C20      WATR   /
SCMP:     SOLV     -        injected fluid
          0.77     0.2      0.03     /
SCMP:     ROIL     -        reservoir oil
          0.5      0.03     0.07     0.2      0.15     0.05     /
LUMP:     C2-6     C3       C6       /
LUMP:     C7+      C10      C15      C20      /
STREAM

/         ===================================================================
          FLUID    EOS
/         ===================================================================

PRINT     ALL
WATR:
          2*62.4   3.30E-06 4000     0.7      /
EQUATION           OF       STATE    IS       PENG-ROBINSON (PR79)
/         SGR's    calculated        by       equation  of      state
PROP:     MW       TC       PC       ACF      ZC       SGR
          C1       16.04    343      667.8    0.013    0.29     0.29832  /       C1
```

```
        C3      44.1    665.7   616.3   0.1524  0.277   0.54914 /       C3
        C6      86.18   913.4   436.9   0.3007  0.264   0.65778 /       C6
        C10     142.29  1111.8  304     0.4885  0.257   0.67168 /       C10
        C15     206     1270    200     0.65    0.245   0.57818 /       C15
        C20     282     1380    162     0.85    0.235   0.59965 /       C20
        /end
TEMP:   160
INTERACTION     PARAMETERS

        C1      C15     0.05    /       CIJ
        C1      C20     0.05    /       CIJ
        C3      C15     0.005   /       CIJ
        C3      C20     0.005   /       CIJ
/end

TEMP:   60
INTERATION      PARAMETERS      -       DUPLICATE       ABOVE
/end

/       ========================================================================
        RELATIVE PERMEABILITY
/       ========================================================================

WETTABILITY     -       WATER   WET



KRWO:   sw      krw     krow

        0.2     0       1       /
        0.2899  0.0022  0.6769  /
        0.3778  0.018   0.4153  /
        0.4667  0.0607  0.2178  /
        0.5556  0.1438  0.0835  /
        0.6444  0.2809  0.0123  /
        0.7     0.4089  0       /
        0.7333  0.4855  0       /
        0.8222  0.7709  0       /
        0.9111  1       0       /
        1       1.3     0       /
        /end

KRGO:   sg      krg     krog
        0       0       1       /
        0.05    0       0.88    /
        0.0889  0.001   0.7023  /
        0.1778  0.01    0.4705  /
        0.2667  0.03    0.2963  /
        0.3556  0.05    0.1715  /
        0.4444  0.1     0.0878  /
        0.5333  0.2     0.037   /
        0.6222  0.35    0.011   /
        0.65    0.39    0       /
        0.7111  0.56    0       /
        0.8     1       0       /
        /end

        ========================================================================
        GRID    DATA
        ========================================================================
```

```
SIZE      7      7      3      cartesian
HORIZONTAL       -      BLOCK  CENTERED
VERTICAL         FLOW   -      BLOCK  CENTERED
DATUM     8400
PRINT     GRID   MAP    /      DEPTH  THIC   PORO   K-X    K-Y    K-Z    T-X    T-Y
          T-Z    PVOL
X-DIRECTION      GRID   SPACING
CONSTANT:
          3500   /      total  x-length
Y-DIRECTION      GRID   SPACING
CONSTANT:
          3500   /      total  y-length
DEPTH     1      ST     LAYER  MIDDLE
CONSTANT
          8335
THICKNESS
ZVARIABLE
          20     30     50     /
POROSITY         UNIFORM
CONSTANT
          0.3
K_X
ZVARIABLE
          500    500    500    /
K_Y
ZVARIABLE
          500    500    500    /
K_Z
ZVARIABLE
          500    500    500    /
CROCK     UNIFORM       -      ROCK   COMPRESSIBILITY
CONSTANT:
          5.00E-06
REFERENCE        PRESSURE      -      UNIFORM
CONSTANT:
          4000
/         ====================================================================
INITIALIZATION   -      NONEQUILIBRIUM
/         ====================================================================

F(DEPTH)         T      P      SW     COMPOSITION
          8335   1*     3984.3 2*     0.2    ROIL   /
          8360   1*     3990.3 /
          8400   1*     4000   /
          /end
SEPA      ALL    EOS    ZFAC
60        14.7   /
/         The    above  K-values and  the    specific gravities (see  PROP)
/         came   from   the    EOS.
/         ====================================================================
RECURRENT        DATA
/         ====================================================================

RATES     0.25   YEARS
FREQUENCY        1      1      1      /
ARRAY     EQUA   MONTHS
4         /
GENERAL:         PRESSURE      CPU_TIME      FLIP   RESTARTS      /
SATURATION:      OIL    GAS    WATR   /
DELT:     6      DAYS
DTMX:     DAYS   DAYS
```

```
0       6       /
10000   6       /
/

WELL    I-1     INJECTS SOLV    QLIM=120000     PMAX=3500
RADI    0.25    /
CIJK
1       1       1       z       0.25    1*      1*      1*      /
1       1       2       z       0.25    1*      1*      1*      /
1       1       3       z       0.25    1*      1*      1*      /
/
WELL    P-1     PRODUCE         OIL     QLIM=12000      PMIN=1000
RADI    0.25    /
CIJK
7       7       1       z       0.25    1*      1*      1*      /
7       7       2       z       0.25    1*      1*      1*      /
7       7       3       z       0.25    1*      1*      1*      /
/

READ:   2       YEAR    -------------------------
DELT:   1.5     manual  time    step    reduction
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   3       YEAR    -------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   4       YEAR    -------------------------

DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   5       YEAR    -------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   6       YEAR    -------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   7       YEAR    -------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   8       YEAR    -------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   9       YEAR    -------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   10      YEAR    ------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   11      YEAR    ------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   12      YEAR    ------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   13      YEAR    ------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   14      YEAR    ------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   15      YEAR    ------------------------
DELT:   3
```

```
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   16      YEAR    ------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   17      YEAR    ------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   18      YEAR    ------------------------
DELT:   1.5
WELL    I-1     INJECTS WATR    QLIM=35865.4795  PMAX=4500
READ:   19      YEAR    ------------------------
DELT:   3
WELL    I-1     INJECTS SOLV    QLIM=51280.3538  PMAX=4500
READ:   20      YEAR    ------------------------
DELT:   3

STOP    ----------------------  END     OF      MODEL   RUN     ------------------------
```