Study on Pumping System Design for Water Injection

by

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Mechanical Engineering Programme
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in partial fulfilment of the requirement for the
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Approved by,

(AP Dr. Razali Hamzah)
Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

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.

LUIS-CASIANO NDONG MIKUE

ABSTRACT

The Objective of this project is to study the types of water injection pumping system and their performance, related to deepwater reservoirs and to analyze the pressure maintenance effectiveness using ECLPISE100 reservoir simulator.

Producing hydrocarbons from deepwater reservoirs is a challenge faced by most oil and gas companies to sustain for high and long production life. For effective pressure maintenance, a good pumping system design is critical due to very high pressures associated with deepwater reservoirs. A good design of the pumping system together with the injection wells location could provide good results for pressure maintenance and lead to higher production rates.

The Scope of Study was to do a literature review of water injection facilities assessment, their performance and problems associated with their operations. Literature review of the types water injection pumps used and their trend in the future and finally a simulation work using ECLIPSE100.

The methods used to achieve the objectives of this project are, a) Conducting literature review of work pertinent on water injection, b) Communicating with companies specialized in oil and gas pumping systems c) case study was conducted by doing the simulation work on Gelama Merah reservoir model using ECLIPSE100, Black oil simulator where water injection wells and production wells were designed on the model to run the simulation.

This study concluded that, the main water injection types suitable for water injection are a) Multistaged Centrifugal pumps and b) Reciprocating Positive Displacement Pumps. Due to the trend of usage on the market, most of the Oil and gas companies tend to use Multistaged Centrifugal pumps, due to several advantages over the reciprocating pumps such as the cost of maintenance and space available on the platform for pumps for offshore operations. Using Line drive injection pattern for Water injection, suitable pressure maintenance can be achieved. The ratio between the water injected and oil produced for equals number of wells of producers and injectors is 2STB (I/P=2). Use of miscible gas injection to the reservoir could improve the pressure maintenance this is due to the high production of this gas as obtained in the field production.

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LIST OF ABBREVIATIONS

BOPD	Barrels of Oil per day
CP	Centrifugal Pump
DC	Double Casing
FOPR	Field Oil Production rate
FGPR	Field Gas Production Rate
FGOR	Field Gas oil Ratio
FPR	Field Pressure rate
FWIR	Field Water injection rate
GPM	Gallons per Minute (US)
LWD	Logging While Drilling
MWD	Measurement while drilling
NPSH	Net Positive Suction Head
NPSHA	Net positive Suction Head available
NPSHR	Net positive Suction head required
PD	Positive Displacement
WBHP	Well Borehole Pressure
WI	Well injection
WOPR	Well Oil Production Rate
WWIR	Well Water injection rate
STB	Standard Barrel

CHAPTER 1
INTRODUCTION

1.1 Background of study

Water injection, also called waterflooding, is a method where water is injected back into the reservoir usually for pressure maintenance and thereby stimulates production [1]. The important of water injection for reservoir pressure maintain in the oil and gas industry, has been crucial for many decades. The correct design of the injection facilities depend on the physical characteristics and properties of the reservoir we need to perform the injection. In order to perform the injection, new injection wells are drilled. According to the type of petroleum fluids found and their properties such as the density and the porosity of the rocks, it would be possible to apply the water injection or steam injection for improved oil recovery. Basically the processes involved are, to sweep of mobile oil from injection well to Production well, no loss of oil by maintaining reservoir pressure above the bubble point and to reduced or no requirement for artificial lift.

This Project Use ECLIPSE100 Simulator to a reservoir model Injection system to analyze on how it can meet the current demand for deep water high pressure reservoirs injection Pumping system. An injection System in which the injection wells are located in a straight line parallel to the production wells which the injected fluid creates a nearly linear frontal movement [2].

1.2 Problem statement

Producing Hydrocarbons from deepwater reservoirs is a challenge for most of major oil and gas companies. Therefore, being the Seawater as the main water source for water injection, it must be properly treated before being injected to the reservoir. With the need of pressure maintenance for longer period for deepwater reservoirs, a good pumping system design is critical to meet the injection objective of provide high pressure enough to the reservoir system and thereby stimulate the production. A good design of the Pumping system together with the injection wells location, could give good results for the field and leading to higher production rates. Using ECLIPSE100 we can simulate different types of arrangements of the injection wells and Production wells. But due to the time constraint and the limitation of the simulation models, in this project only Line drive water injection pattern is performed.

1.3 Objectives

The Objectives of this project are:

a) To study the types of water injection pumping system and asses their performance related to deepwater oil and gas reservoirs.
b) To analyze the pressure maintenance effectiveness of a reservoir system using ECLIPSE100 reservoir simulator.
c) To recommend a practical pumping system design applicable for high pressure deepwater reservoir systems.

1.4 Scope of study

a) Literature review of water injection facilities, their performance and problems associated with their operation.
b) Literature review of the Types of Water Injection Pumps used and their trend in the future
c) Pressure maintenance effectiveness on a reservoir using ECLIPSE100 on Gelama Merah reservoir model.

CHAPTER 2
LITERATURE REVIEW

2.1 Deepwater Reservoir System

A Petroleum reservoir or an oil and gas system is a subsurface pool of hydrocarbons contained in porous rock formations. The naturally occurring hydrocarbons are trapped by overlying rock formations with lower permeability. A deepwater reservoir is referring as offshore reservoirs for water too deep for a freestanding steel platform of about 400 m depth or more [3].

Deepwater reservoirs, those in water depths ranging from 1000 m to more 3000 m often consist of young turbidite sediments associated with early hydrocarbons charge, overpressure buildup, and seal with retarded diagenesis. Deepwater sands maintain shallow properties even at great depths (e.g. 18000 ft) but these weekly cemented sands with a history of progressive compaction and cementation differ from surface sediments [4].

2.1.2 Deepwater Reservoir Characterization

Knowing how the reservoir will change during its productive life forms the basis of an optimal production strategy. The answers many in near real time com from interpretation of a dynamic reservoir model built on seismic, log, test, and production data [5].

a) Logging While Drilling and Measurements While Drilling (LWD and MWD)

Looking ahead of the bit enables real-time steering changes that keep the well path on target. A geomechanical model updated in real time with petrophysical information can drive decisions to improve drilling performance, avoid surprises, and reduce risks. Scope technologies deliver downhole drilling data and enable formation evaluation while drilling.

b) **Wireline Logging and Formation Sampling,** Petrophysical data from wireline logs are used to populate the Petrel geological model, create the ECLIPSE reservoir engineering model, and improve the dynamic mechanical 3D earth model. Data from Scanner Family services characterize the fluids and rock matrix for a better understanding of the reservoir. Formation pressures can be acquired while drilling with the StethoScope service or on wireline with the MDT Modular Formation Dynamics Tester. Minimally contaminated fluid samples can be acquired quickly with the Quicksilver Probe tool, analyzed downhole, and retrieved for PVT analysis. Oilphase-DBR services include PVT analyses and flow assurance studies.

c) **Well Testing,** Well tests are vital for field development decisions, delivering information on reservoir compartmentalization, reserves volumes, production potential, permeability, and viscosity. Proven SenTREE high-pressure subsea well control systems reliably establish the environment needed to acquire test data [5].

2.2 Water Injection Facilities

Water injection is a relatively low cost and efficient means of improving oil production from a depleted field which is used widely [6]. Normally the treated water is injected under pressure into the flanks of the oil bearing strata through proposed drilled wells. Water displaced any remaining particles of oil and reduces free space, thus maintaining the reservoir pressure, see Figure 2.1. In this figure we see three reservoir fluids, gas, oil and water in stratigraphic form. The Injection wells are located at the two sides of the Production wells or Producers. The water injected by the injectors displaced the oil the producers by occupying the pores volumes left by the Produced oil and gas. Normally at the end of the injection process the water will occupy most the area occupied by oil before, remaining only a residual oil layer at the upper layer of the reservoir. In order to achieve this objective, the water injection process requires treatment and injection facilities. The water injection system will consist of water lift pumps, coarse filtration, fine filtration, deaeration system, booster pumps and injection pumps [6]

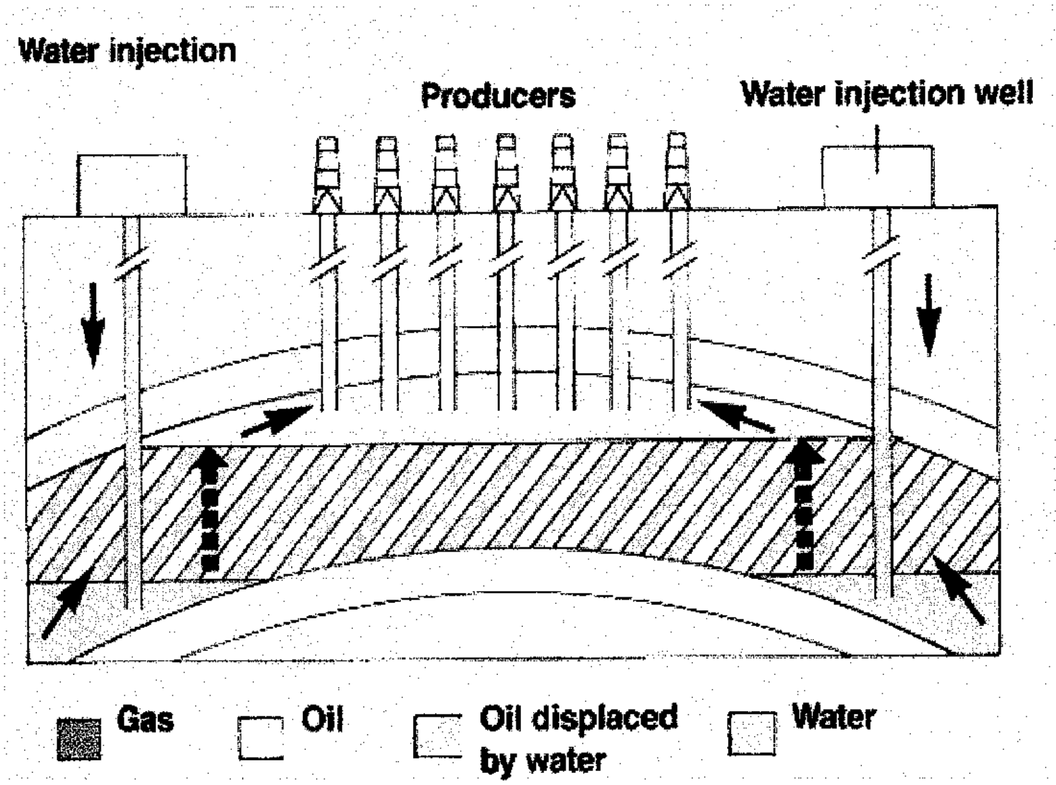

Figure 2.1 Water Injection System [6]

2.2.1 Sea Water Lift Pumps

The sea water lift pumps are pumps that lift the water at certain depth from sea water surface and then transfer it to the following facilities for treatment. Usually the lift pumps are multistaged centrifugal submersible pumps installed within separate caissons. The sea water can be drawn from a depth of 20m below sea water surface. The material of the pumps casings can be Cu-Ni alloys materials with impeller material of Al-Bronze. The Sea water lift pumps can operate with three or four injection pumps at ½ of the full capacity of each pump in order to drawn the optimum water required for injection [6].

2.2.2 Coarse filtration

a) Sedimentation,

Sometimes in the land operations the water source may contain a high concentration of coarse particles. These can be removed by allowing the water to stay stagnant for a period of time and allowing the solids to settle. Stokes Law describes the settling process; it is a function of the particle diameter and density hence in a continuous process the required residence time to clarify the liquid at any depth can be calculated from the time required for particles originally at the to the top to settle to this depth.
Hydrocyclones can be used to speed up the removal of these solids particles. Hydrocyclones have become the standard device for cleaning oily water; they work by using centrifugal force to increase the effect of gravity. They have proven to be compact, efficient, and with increasing use of floating production and storage vessels to develop marginal oils fields-operate independently of platform motion [7].

b) Coagulation/Flocculation

The separation of solid material can be enhanced by artificially increasing their size and their ability to coalesce. This can be done by chemical flocculation. This process uses chemical such as Ferrous Sulphate, which forms a voluminous precipitates in contact with water.
This precipitate has the ability to coagulate into large flocks and, in the process, destabilize any suspended particles at the same time. A Flocculation unit consists of a mixing chamber and a flock growth chamber as shown figure 2.2. This growth chamber gives the microflocs, formed in mixing chamber, the opportunity to collide, grow and form large flocs.
This process can be speeded up by the addition of floc growth catalyst. The flocs are subsequently removed from the water stream by settling (gravity separation) or by flotation [7].

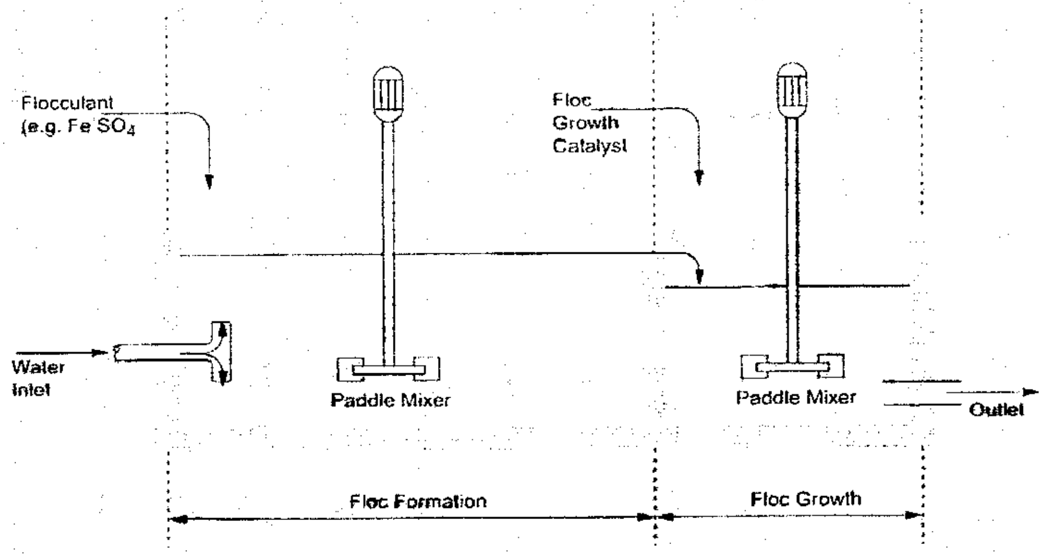

Figure 2.2: Flocculation Unit [7]

2.2.3 Fine Filtration

The Filters must clean the water and remove any impurities, such as shells and algae. [1]. Typical filtration is to 2 micrometers. Sand filters are the easiest to use, because there is an automatic system with Delta P which cleans the filter with a backwash when the sand filter is dirty. The sand filters have different beds with various sizes of sands granules. The sea water traverses the first, finest, layer of sand down to the coarsest and to clean the filter, the process is inverted. After the water is filtered it continues on to fill the de-oxygenation tower [1]. Besides the Sand filters, the fine filtration process can be done by single and dual media filters, diatomaceous Earth(DE) filters and the cartridge filters. Single and Dual Media filters consist of pressure vessel filled with a filter medium. The advantage of DE filters is that are lighter than single or mixed media filters. Cartridge filters units consist of one or more cartridges mounted over a perforated pipe support. The flow direction is from the outside (greatest surface area, where the filtration takes place) to the inside. A wide range of particles sizes can be removed [7]

2.2.4 Deaeration Systems

The presence of oxygen in concentrations greater than 0.005 g/m^3(5ppb) in water flood operations can cause severe corrosion and plugging of the formation by corrosion products [7]. Bacterial growth in the reservoir can produce toxic hydrogen sulfide, a source of serious production problems, and block the pores in the rock. Oxygen can be removed from the water by the following methods:

a) Gas Stripping

Removal of oxygen by gas stripping is based on lowering of the solubility of oxygen in water by reducing the oxygen partial vapour pressure. According to Henry's Law, gas's solubility is proportional to the vapour pressure of the gas over the water. Oxygen for the water may be stripped by passing a (low oxygen content) stripping gas trough the water in co-current or counter-current flow [7]. Gas stripping is normally performed in towers containing packing or perforated trays. The water runs into the top of the tower and the stripping gas is fed in at the bottom of the tower. The gas bubbles up through the water, the trays or packing provide good contact between the water and the gas, eventually removing oxygen present in the water which goes to the vent gas exit (Figure 2.3a).

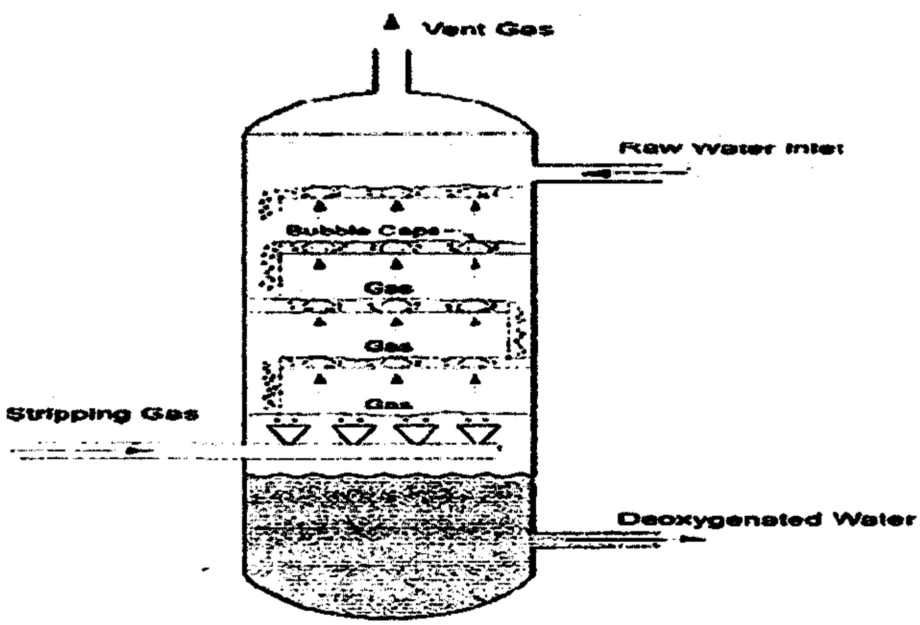

Figure 2.3a: Gas Stipping deaerator [7]

b) Vacuum Deaeration

The principle of vacuum deaeration is to reduce the partial pressure of oxygen by boiling the water. At a temperature of 15°C, water boils at a pressure of about 0.017Atm and the residual water oxygen content is reduced to 150 ppb [7]. Vacuum deaeration is the most common deaeration technology. Packed towers are continuously evacuated by specially selected vacuum systems, reducing the oxygen partial pressure to create a driving force for mass transfer from the liquid to the gas phase.

Water enters at the top of the deaeration tower. It is distributed evenly across the vessel cross-section. The water trickles down over a bed of polypropylene mass transfer packing where it is broken up into thin films, thereby forming a large interfacial area between the water and the surrounding vapour phase. A vacuum system extracts all gases from the vapour phase, thereby lowering the partial pressure oxygen in the vapour phase to near zero. This creates a driving force for oxygen molecules dissolved in the water to diffuse to the liquid surface and on into the vapour phase, thereby reducing the concentration of oxygen in the water (Figure 2.3b) [20]

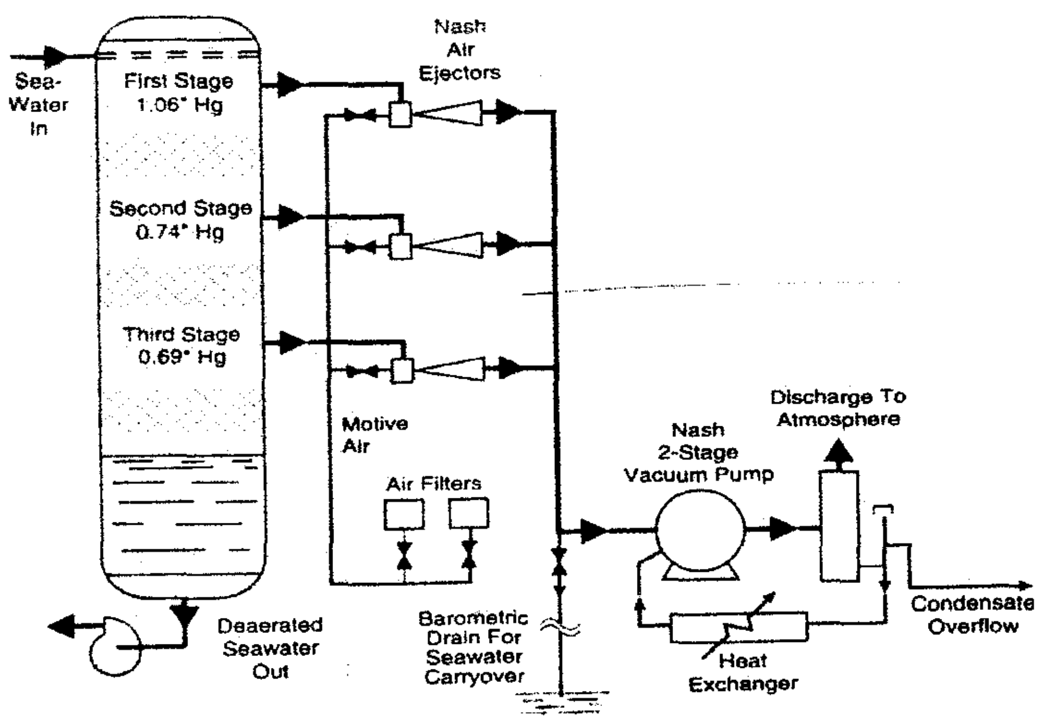

Figure 2.3b: Vacuum Deaeration System [19]

c) Chemical Treatment With Oxygen Scavengers

Oxygen removal to the required 5ppb level is rarely possible. Oxygen scavengers are used to achieve this very low value. Oxygen scavengers remove oxygen form water by chemical reaction. A large number of chemical compounds can be used for this purpose. Selection of appropriate compounds should be based on cost, compatibility of these compounds or their reaction products with other additives used (bactericides, corrosion inhibitors, etc) and ease of handling. Sodium Sulphide is the scavenger most frequently used in water flooding [7]

2.2.5 Hydrogen Sulphide Removal

Hydrogen sulphide is highly corrosive a well as representing a safety hazard. It can be removed in a similar manner to oxygen ,mechanical removal by vacuum or counter current gas stripping; chemical removal by the addition of oxidizing agents e.g. chlorine, potassium permanganate etc [7].

2.2.6 Booster Pumps

Self-priming pumps create and maintain a sufficient vacuum level to draw fluid into an inlet with no external assistance. For water injection systems, Booster pumps are used to provide a sufficient a net positive suction head for the water injection pumps. Priming introduces fluid in the into the pumping system chamber to create the pressure differential needed for pumping at a rated service [6]. Booster pumps are centrifugal pumps made of aluminum, brass, bronze, cast iron, plastic, or stainless steel. Power sources include AC or DC voltage; pneumatic or hydraulic systems; gasoline, diesel fuel, or natural gas; steam or water. Booster pumps include a pump stator / rotor assembly that is mounted either vertically or horizontally, depending on the orientation of the media. Close-coupled pumps mount the pump end on the motor shaft. Frame-mounted pumps mount the pump end on a bearing frame that is coupled to the motor [16].

2.3 Types of Water Injection Pumps

Two types of pumps may be used for water injection:

a) Reciprocating positive displacement pumps

b) Centrifugal Pumps.

2.3.1 Reciprocating Positive Displacement Pumps

These pumps increase pressure by trapping a fixed volume of fluid at suction pressure and then compressing that fluid to a discharge pressure. There is no flow until the discharge valve opens [8]. Historically, PD Pumps have been ruggedly built to stand up the use of Waterflood installation. A PD pump usually is the 'Best' candidate for low-volume, high pressure floods. However the evaluator must be aware of the limitations of this type of pump. The injection rate is a function of pump speed (in RPM) and plunger size (diameter and Area). Although both can be changed to cover a broad range, any specific plunger size has a definite pressure limitation. The Engineer must evaluate the effect of both the injection pressure and the rate on pump design [8].

Reciprocating pumps use a piston and a cylinder arrangement with suction and discharge valves integrated into the pump. Pumps in this category range from having one cylinder (simplex), to in some cases four cylinders (quad) or more. Most reciprocating-type pumps are "duplex" (two) or "triplex" (three) cylinder. The Pumps can be powered by air. Stream or through a belt drive from engine or motor. Citronelle oil field (Alabama) uses different types of Triplex pumps for water injection and for artificial lifting since 1962. Other oil fields in the Persian Gulf and Mexico gulf has been used pistons pumps since 1950s [23].

2.3.2 Triplex Piston Pumps and Plunger Pumps

Piston pumps and plunger pumps are reciprocating pumps that use a plunger or piston to move media through a cylindrical chamber. The plunger or piston is actuated by a steam powered, pneumatic, hydraulic, or electric drive. Piston pumps and plunger pumps are also called well service pumps, high pressure pumps, or high viscosity pumps.

Piston pumps and plunger pumps use a cylindrical mechanism to create a reciprocating motion along an axis, which then builds pressure in a cylinder or working barrel to force gas or fluid through the pump. The pressure in the chamber actuates the valves at both the suction and discharge points. Piston pumps are used in lower pressure applications. The volume of the fluid discharged is equal to the area of the plunger or piston. The capacity of the piston pumps and plunger pumps can be calculated with the area of the piston or plunger, the number of pistons or plungers, the displacement of the stroke, and the speed of the drive. The power from the drive is proportional to the capacity of the pump [21].

CAT Manufactures triplex high-pressure piston pumps that use a dynamic seal that moves through a cylinder and feature a patented sleeved-piston rod and UNIFLOW design. The piston pumps provide easy wet-end service, strong suction and a very smooth flow. These piston pumps are available with Brass or 316SS manifolds with 304SS valve assemblies. Triplex high-pressure plunger pumps feature static Lo-Pressure and Hi-Pressure seals supported by adapters or seal cases. Triplex plunger pumps permit higher pressures up to 7000 psi, various drive options and liquid-end construction. The triplex plunger pumps are available with Brass, Nickel Aluminum Bronze, 316SS and Duplex SS heads with matching valve assemblies and various elastomer options for liquid compatibility. These triplex plunger pumps are rated from 5 to 320 GPM or 1,744.32 m^3/day and pressure rates up to 7000 psi [22].

Reciprocating PD pumps have the following advantages and disadvantages:

a) High Efficiency and flexibility

b) Able to operate over a wide range of pressure head

c) Able to operate over a wide range of flowrate within their hydraulic power

d) They can be designed to operate at pressures above 2,857psi (200 bars) or at rates of around 1,000 m^3/day

Disadvantages:

a) Their principal disadvantage is their requirement for frequent Maintenance, especially when corrosive or sand-bearing fluids are being pumped [8].

b) Their weight and size sometimes is unsuitable for offshore operations.

2.3.3 Centrifugal Pumps

Centrifugal pumps increase pressure by increasing the velocity of the fluid within the pump and converting the energy to a pressure increase at the pump discharge [8].
They may be mounted horizontally or vertically and are generally use when rates of the order of several thousand m^3/day (e.g. 2,000m^3/day) are required at pressures lower than 1,428.57psi (100 bars). The centrifugal have the following advantages and disadvantages compared with reciprocating units:

***Advantages*:**

a) A centrifugal pump increases pressure by greatly increasing the velocity of the liquid as it passes through the impeller and then converting that velocity head to pressure.
b) Doubling the speed would quadruple the pressure because the discharge pressure is a function of the rotating speed squared. However, this relationship makes the power requirement a cubic function of the speed.
c) Increases a centrifugal pump speed increases the rate if the pressure is held constant. If the rate is held constant, speed increase will cause the pressure to increases as a squared function.

***Disadvantages*:**

a) The greatest disadvantage of centrifugal pumps is their low efficiency compared with PD pumps.
b) Centrifugal pumps are not designed to be effective at low rates and high discharge heads
c) Where a PD pump generates the discharge pressure in one stage, a centrifugal can be multistaged. For example, a pump capable of 3,500 to 4000 psi discharge pressure may have 10 stages.

A centrifugal pump will operate at the point where the head curve intersects the system curve. This may not be intended condition. Therefore, the design must anticipate this point. The system curve is the result of all pressure requirements downstream of the pump discharge flange, including valves, fittings, pipe, elevation changes, and wellhead pressure.

The head rate curve is a function of the difference in pressure between the suction and the discharge flanges at various flow rates. Figure 2.4 shows that as a pump speeds are varied, the intersection with the system curve changes. The system curve can be moved upward to decrease flow at reduced speed, but generally cannot be moved downward.
A centrifugal pump should never be operated to the right of the vendor's published curve without the manufacturer's concurrence. The pump is not designated for that area, so the curves cannot be extrapolated [8].

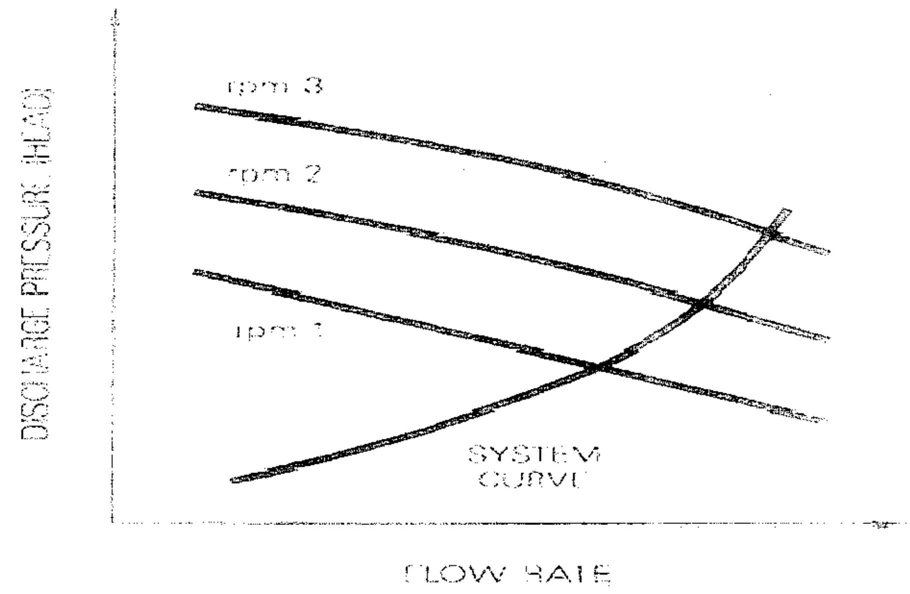

Figure 2.4: Typical Centrifugal Pump Curve [8]

2.4 Net Positive Suction Head (NPSH)

The Net Positive Suction Head (NPSH) is an external force on pressure that a pump is required to push fluid into the suction to maintain an adequate pressure [8]. The effect of having inadequate NPSH available is cavitation and pressure pulses in the pump. Cavitation occurs when the suction pressure drops low enough to cause the liquid to flash to a gaseous phase. The subsequent collapse of the vapour bubble causes a brief but energetic pressure pulse in the system. These pulsations can cause problems ranging for noise to severe damage to the pump and piping [8].

There are two types of NPSH to be considered in pumping system design:

a) **NPSHR** is a function of the pump design and flow rate. NPSHR is a measured in psia for reciprocating pumps. Manufacturers will normally supply this value for their pumps. NPSHR is determined by testing to find the pressure at which cavitation starts to a given flow rate.

For Centrifugal pumps, NPSHR is determined by some test methods as the pressure at which the total dynamic head drop 3% for the maximum obtained efficiency. NPSHR increases with flow rate. A good conservative design criterion is two add 3 to 10% to the manufacturer's maximum value of NPSHR.

b) **NPSHA** is a function of the suction system design for the pump to operate satisfactory, NPSHA must exceed NPSHR. NPSHA can be calculated using various parameters:

$$NPSHA = Pa + Pz - Pvp - Pf - Pac \quad \text{...(1)}$$

Where;

P_a =	Pressure exerted at water surface
P_z =	Pressure head from the surface of water
P_{vp} =	Vapour pressure of water of system temperature
P_f =	flowing frictional pressure losses, and
P_{ac} =	Acceleration pressure losses.

Acceleration pressure losses (P_{ac}) are a function of the action of the pump plungers. As the pump plunger starts its suction stroke, it accelerates to the midpoint of the stroke, and then decelerates to come to rest at the end of the stroke.

P_{ac} can be calculated by the following formula:

$$Pac = (LvNC)/(Kg) \ldots\ldots (2)$$

Where;

L =	length of suction piping
N =	pump speed (RPM)
V=	Velocity of fluid (ft/sec)
C =	Constant based on pump type
K =	constant based on fluid type, 1.4 for water, 2.5 for hot oil, and
g =	acceleration of gravity

2.5 Centrifugal Pump Efficiency

Flow in the impeller of the pump or casing passage is accompanied by frictional losses which are proportional to the square of the flow velocity relative to the passage walls. All losses result in a conversion of mechanical energy into thermal (internal) energy. The enthalpy, kinetic energy, and potential energy are changed by the work input, gH_{in}, and the balance of these energies is expressed by:

$$hs + \frac{V2s}{2} + ZsG + gHin = Hd + \frac{V2d}{2} + Zdg \quad \ldots\ldots (4)$$

Where the subscripts **s** and **d** refer to properties at the suction and discharge flanges of the pump casing. Usually the Practical performance parameter as determined by test is the overall pump efficiency **η**, defined by:

$$\eta = \frac{mgH}{P} \ldots\ldots (5)$$

Where **P** is the power of the motor driving the pump as determined by dynamometer test. The so called total head is determined from steady-flow energy terms at the suction and discharge sides of the pump.

Another expression of the total efficiency of the pump is:

$\eta = \eta_m * \eta_v * \eta_H$ ....(6)

Where η_m, is the mechanical efficiency accounts for frictional losses occurring between moving mechanical parts, which are typically bearings and seal, as well as for disk friction, and is defines by:

$\eta_m = [(M+ML)\, gHin] / P$ .... (7)

η_v, is the volumetric efficiency of the pump defined by:

$\eta_v = 1-(C/Q^n)$ ....(8)

Where C and n are constants which depend on the dimensional specific speed Ns and Q is the capacity of the Pump. Equation (8) shows that volumetric efficiencies range from 0.99 for large pumps to 0.85 for pumps for low capacity.

η_H, is the hydraulic efficiency, which is defined by:

$\eta_H = (H/ H_{in}) = (H_{in}-H_L)/ H_{in}$ ....(9)

or

$\eta_H = 1-(0.8/Q^{1.4})$ ....(10)

Where Q, is the capacity in GPM. To the equation (9) the hydraulic losses, represented by 1- η_H, vary from 30% for pumps of 50gpm capacity to 8% for pumps of 10,000 GPM capacities.

2.6 Water injection Sources

The sources of water used for water injection are mainly from the reservoir produced water and the seawater.

2.6.1 Produced Water

The produced water is often used as an injection fluid because this reduces the potential of causing formation damage due to incompatible fluids, although the risk of scaling or corrosion in injection flowlines or tubing remains.

Also, the produced water, being contaminated with hydrocarbons and solids, must be disposed of in some manner, and disposal to sea or river will require a certain level of clean-up of the water stream first. However, the processing required to render produced water fit for reinjection may be equally costly. As the volume of water being produced are never sufficient o replace all the production volumes of the reservoir fluids, additional "make-up' water must be provided. Mixing waters from different spurces exacerbates the risk of scaling [9].

2.6.2 Seawater

Is obviously the most convenient source for offshore production facilities and it may be pumped inshore for use in land fields. Where possible, the water intake is placed at the sufficient depth to reduce the concentration of algae; however, filtering, deoxygenation and biociding is generally required [9].

2.7 Injection Well Location

The relative location of injection and production wells depends on the geology of the reservoir, its type, and the volume of hydrocarbons-bearing rock required to be swept in a time limited by economics. This Lead to two types of injection well location:

- Central and peripheral flooding, in which the injectors are grouped together
- Pattern flooding, in which the injectors are distributed amongst the production wells [10].

2.7.1 Central and Peripheral Flooding

This type of injection occurs in the following cases:

a) Reservoir with a gas-cap in which gas injection is taking place. If the reservoir is fairly regular anticlinal structure, the injection wells are normally grouped in a cluster around the top of the anticline

b) Anticlinal reservoir with an underlying aquifer in which water injection is taking place. In this case the injectors will form a ring around the reservoir

c) Monoclinal reservoir with a gas-cap or aquifer undergoing gas o water injection. The injectors are grouped in one or more lines located towards the bas of the reservoir in the case of water injection, towards the top in the case of gas injection

2.7.2 Pattern Flooding

Pattern flooding is principally employed in reservoirs having a small dip and large surface area. In order to ensure a uniform sweep the injection wells are distributed amongst the production wells. This is done by either converting existing production wells into injectors or by drilling infill injection wells [10].

The most common Patterns are the following:

a) **Direct Line Drive,** The lines of injection and production wells are directly opposed. The system is characterised by the two parameters, the spacing between wells of the same type "**a**" and the spacing between lines of injection and the production wells "**d**".

b) **Staggered line Drive,** the wells are in lines as before, the injectors and producers being no longer directly opposed but literally displaced, normally by a distance of **a/2**

c) **Five-Spot,** This is a particular case of staggered line drive in which d/a =1/2, and is the most well-known pattern. Each injection well is located at the centre of a square defined by four production wells. In all the above patterns the injection and production wells are equal in number (I/P = 1).

d) **Seven-Spot,** The injection wells are located at the corners of a hexagon with a production well at its centre. There are twice as many injection wells as production wells (I/P=2)

e) **Nine-Spot,** The pattern is similar to that of a five-spot, but with an extra injection well drilled at the middle of each side of the square. There are three times as many injections as production wells (I/P =3), see figure 2.5

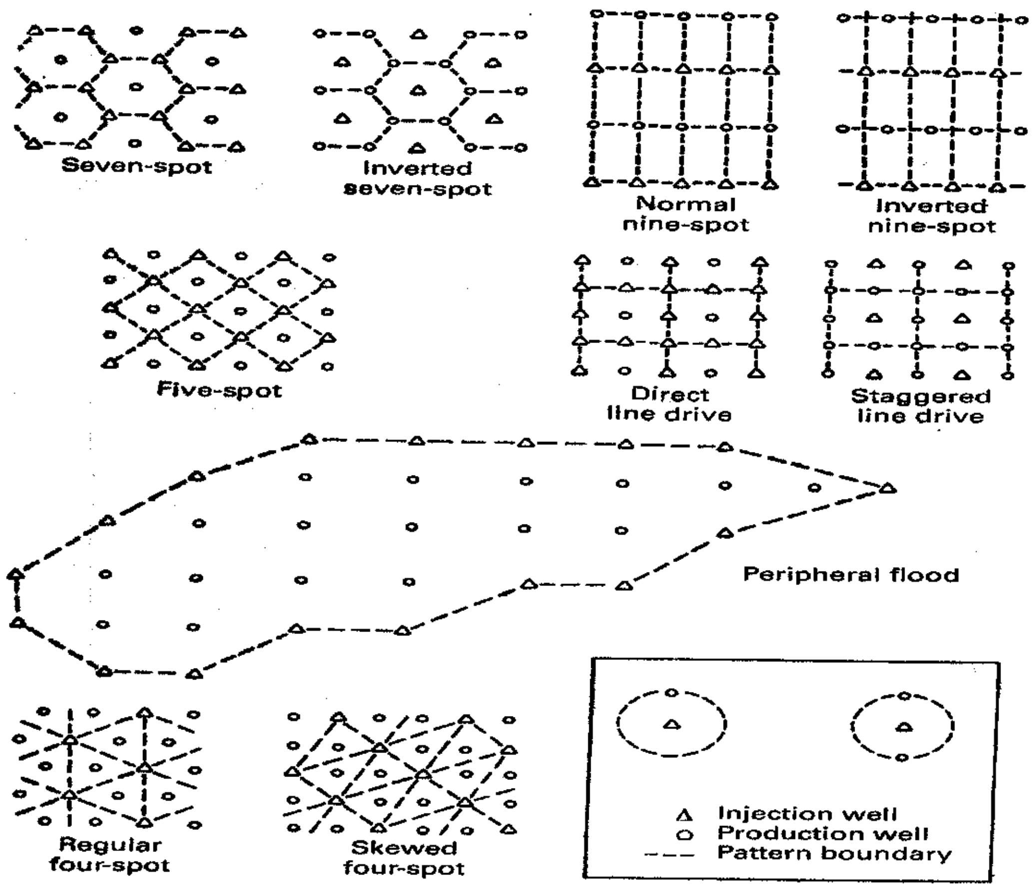

Figure 2.5: Water injection patterns [11]

2.8 Water Injection Mobility ratio (M)

Mobility ratio is the ratio of the mobility of the displacing fluid to that of the displaced fluid [10]. The displacing fluid is water and the displaced fluid is oil or oil with solution with gas.

The mobility ration of water injection is defined as:

$$M = \frac{Kw * \mu o}{\mu w * Ko} = \frac{Krw * \mu o}{\mu w * Kro} \quad \text{(11)}$$

Where;

K_w = Effective permeability to water (md)

K_o = Effective permeability to oil (md)

K_{rw} = Relative Permeability to oil (fraction)

μ_w = Water viscosity (cp)

μ_o = Oil Viscosity (cp)

By conventional use, mobility ratios less than unity (M<1) are termed "favorable", and the greater than unity are (M>1) "unfavorable". One way to reduce the mobility ratio is to thick the water, for example, by addition of polymers **[11]**

2.9 Efficiency of oil displacement by Water (f_w)

Efficiency of oil displacement by water is defined as the ration of the superficial area displaced by the water over the reservoir area. The area displaced by the water increases with time as the injection continue, but never becomes equal to the area of the reservoir, even long after the initial breakthrough of the front at the production wells [10].

The fractional flow "fw" equation of a horizontal reservoir being either very thin or subject to high flow rates is in a simplified form as:

$$fw = \frac{1}{1 + \mu w * Kro / \mu o * Krw} \quad \text{(12)}$$

2.10 ECLIPSE Reservoir Engineering Software

Eclipse reservoir Simulators have been the benchmark for commercial reservoir simulation for over 25 years because of their breath of capabilities, parallel scalability, utility computing, and unmatched platform coverage. The difficulty in preparing input into and analyzing the results from the reservoir simulation has historically been a lack of integration between the pre-and post processing tools and the need for many manual times consuming data transfers and formatting steps.

As a result, reservoir simulation has not been utilized in many business decisions where it would have added tremendous value [12].

The Software uses the following reservoir models:

- Black-Oil
- Compositional
- Thermal
- Streamlines
- Add-on options

In this project only the Black oil was used in order to meet the objectives of the project.

2.10.1 Black Oil Reservoir Model

The ECLIPSE Black oil simulator uses a three-component model for reservoir situations in which oil reserves and oil recovery need to be known but the effects of fluid phase composition on flow behavior do not need to be considered. The black-oil model assumes that the reservoir fluids consist of three components (water, oil, and gas) in a three-phase system (liquid, gas, and gas in solution), with components miscible in all proportions. Four components can also be considered for modeling reservoir recovery mechanisms when injected fluids are miscible with hydrocarbons in the reservoir [13]. Besides that, ECLIPSE100 Black oil simulation provides a fully 3D fully implicit three-phase simulation.

CHAPTER 3

METHODOLOGY/ PROJECT WORK

3. PROJECT WORK

3.1 Research methodology

The research methodology for the project consists primarily of three parts, which are:

3.1.1 Conducting literature review of work pertinent to the area of the study, i.e. Types of Water Injection Pumps.

→ Deepwater Reservoirs

→ Water Injection facilities

→ Relationship between the water Injection Pumps and high pressure Reservoirs

3.1.2 Conducting Simulation work on GELAMA MERAH reservoir model using ECLIPSE100.

→ Effect of pressure maintenance of the field with few water injection wells and more Production wells

→ Effect of Production rate as the injection rate increase

→ Effect of Pressure of the field as the number of injection wells is equal to the Production wells

3.1.3 Analyzing and discussing the experimental Results:

→ Draw conclusions and recommendations on the suitable Pumping systems and the reservoir pressure maintenance.

→ Final report of the Research project

3.2 Tools and Equipment used

Due to the nature of this project, no specific equipment is required apart from that offered in the office workstation. The followings Microsoft application software's were essential:

a) Microsoft Office
b) Microsoft Power Point
c) Adobe Acrobat reader
d) Internet Explorer

Besides these computers programs, reservoir simulation software was used. The reservoir simulator used was ECLIPSE100, which is used at the computer Laboratory at the university.

CHAPTER 4
RESULTS AND DISCUSSION

4.1 Results of Types of Water Injection Pumps

4.1.1 Water Injection Pumps

Water injection pumps are either of one of two general types:

a) Reciprocating Positive displacement (PD) pumps
b) Centrifugal Pumps.

4.1.2 PD Pumps

The Reciprocating PD pumps can be used for low pressure high flow rates for water injection and at constant rates for high injection pressures. Based on the literature reviewed, the common reciprocating PD pumps used are Duplex and Triplex Pistons or plunger Pumps. Triplex Pistons pumps fabricated by CAT Pumps, meet pressure ranges from 1,000 to 7,000 psi at flow rates from 5 to 320 GPM or 1,744.3 m^3/day.

4.1.3 Centrifugal Pumps (CP)

The following Centrifugal pumps can be used for High pressure high flow rates for water injection:

a) Horizontal multistage double casing (back to back design)
b) Horizontal multistage double casing (inline design)

Horizontal multistaged centrifugal pumps are high pressure pumps used for water injection at different rates and head according to the requirement of the field. The next section discusses more about these centrifugal pumps.

4.1.4 CP Horizontally Multistage Double Casing

Centrifugal pumps are the most practical and reliable water injection pumps used nowadays in the industry, due to their easy maintenance and easy to adapt at different requirements compared to reciprocating PD pumps. Centrifugal pumps are electric motor driven capable of generating water pressure up to 6,250psi with heads for about 8,280 ft. The Table 1 of the operating data summarizes the capability for this pump. These pumps are manufactured by many companies such as SULZER pumps, which is one the major player of this industry [17].

Table 1: CP Horizontal Multistage Pump Operating Data

Units	SI Units	U.S. Units
Capacities	Up to 590 m3/h	Up to 2,600 gpm
Heads	Up to 2,525 m	Up to 8,280 ft.
Pressures	Up to 425 bar	Up to 6,250 psi
Temperatures	-28 to 425 degree Celsius	-20o to 800 degree Far.
Speeds	Up to 7,200 RPM	Up to 7,200 RPM

From Table 1 we can see that these pumps are suitable for high pressure up to 6250 psi, speed up to 7,200RPM, temperatures up to 800°F. The CP's rotating element is housed in horizontally split inner case, which is itself contained in a cast or forged outer barrel. This design provides for easy maintenance and element removal without piping disturbance. Suction and discharge nozzles are normally positioned at the top centerline, but can be rotated to meet specific application requirements.

For each injection pump, the discharged volumes at a pre-determined injection pressure well Head Injection Pressure (WHIP) should never exceed fracture pressure of the formation. Pumping Capacity is equal to the sum of all pumps capacity at that injection pressure. Most of Centrifugal pumps are designed for specific operating conditions and may not be suited for any other without loss of performance or damage.

PETRONAS Carigali's Angsi field uses four CP injection pumps, (see Appendix B).

These injections pumps are designed to provide flow rate of treated seawater 510 m^3/h at a back pressure of 11,800 kpa (1711.4 psi) with 3 units on line and one unit on standby, which is the maximum design of Angsi water injection management Plant. The water injection pump is taking suction directly from vacuum Deaerator which is design to locate at high level to provide NPSH require for the pump to prevent from pump cavitations. Other examples are the LL-5 Flank Waterflood at Lake Maracaibo (Venezuela) where each of eight injection wells has its own injection station capable of delivering 60,000B/D water. Many others fields from the Gulf of Mexico and the North Sea uses the split barrel multistaged centrifugal pumps [8].

4.1.5 CP Horizontal multistage Double Casing Design Features

a) Compliance with API 610 9th Edition (ISO 13709) requirements
b) Hot alignment feature for temperatures above 250°F (120°C) Forged outer case and end covers
c) Designed to accommodate temperatures between -20°F (-29°C) to 800°F (425°C)
d) Pump feet located on horizontal centerline
e) Inner bundle arrangement (rotating element & volute case) for Suction end closure design requires no heavy bolting ease of changeouts
f) Seal chambers for single/double seals to API 610 9th Edition (ISO 13709) Table 6
g) Tapered shaft extension per API 610 (ISO 13709)
h) Flanged stationary wear parts to control interstage leakage
i) Large shaft diameter with
j) Double volute inner case for radial thrust balance•
k) Replaceable or integral impeller hub and eye rings
l) Dynamically balanced impellers and rotating element
m) Rotation counterclockwise, as viewed from the driver

4.1.6 Pumps Selection Parameters

A number of Parameters enter into the choice of Waterflood pressure pumps, such as:

a) **Prime mover to be used,** there are several types of prime movers: Natural-gas-fueled, internal-combustion engines(either naturally aspired or turbocharged), electric motors, diesel or gasoline-fired engines; and natural-gas fired turbines

b) **Injection rates and Pressure required throughout the Waterflood life,** before reservoir fill-up, water is usually injected at low pressure and maximum achievable rates. As the flood progresses, the actual injection rate may decrease, in some cases to less than half the initial value.

c) **Future flood expansion,** this refers to the requirements of the reservoir for higher injection volumes in the future. So the current design must meet the future changes on the facilities.

d) **Injection-water quality,** asses the concentration of chemicals and substances not suitable for the water injection. Certain injection pumps are very sensitive to sand or other chemicals that can be found in the water.

e) **Space available for pump**

The space for the facilities is very important especially for offshore operations. The space availability is limited due to the nature of the environment; therefore injection pumps that required less space are suitable. PD pumps take more space compared to CP with the same capacities.

f) **Pump efficiency**

The efficiency of a hydraulic pump is the output power of the pump over the initial energy or power required to run the pump. The parameters that affect the efficiency of a pump are the flow rate, the density of the fluid and the head difference of the pump.

g) Maintenance Cost

The maintenance cost of the pumps is highly considered during the selection of the pump. The cost of maintenance of a Centrifugal pump depends on the Capacity of the pump, the fluid properties and the quality of the materials design for the pump. Generally CP pumps are cost saved of maintenance compared to their counterpart PD pumps.

4.1.7 Relationship of Injection Pumps and Reservoir Performance

Reciprocating positive displacement pumps and centrifugal pumps can be used for water injection based on the selection parameters mentioned. The reservoir performance will depend on the injection rates and the at desired head requirements. For high deepwater reservoirs flexibility on injection rates and pressure rates of the fluids injected are important parameters that the pumps need to meet for long production life of the reservoir. In addition to that the Maintenance cost of the pumps is also a critical parameter to select a suitable injection pump. One of the most important factor in oil and gas industry is to produce hydrocarbons efficiently at the lowest cost is possible. The cost of production comprises the initial cost of development of the field or capital expenditure, CAPEX and the Operation expenditures, OPEX. According to SPE (Ref.8) the Reciprocating PD pumps require frequent maintenance as compared to the centrifugal pumps. This makes these injection pumps very unsuitable for many oil corporations due to their high cost as result of the maintenance of the pumps. For same pressure rates and injection rates PD pumps have higher efficiency than the Centrifugal pumps

The investment for PD pumps is greater because of the higher unit weight and size. As a rule of thumb, the maintenance cost for a PD pump is about three times that of a centrifugal on a per-unit power basis. Most problems with a PD pump can be avoided by selecting a pump that will operate at conservative speeds, carefully designing the piping system, and using maintenance practices that preserve the alignment of the plunger and stuffing box. This alignment is important because packing problems can be significant. As with most equipment, operation problems can be significant [8].

4.1. 8 Pumping system Failure considerations

The Pumping system design for water injection must meet a desirable operations condition to avoid frequent downtime of the equipments. The downtime of the injection system due to a failure of the injection pump will have a serious impact on the reservoir if good maintenance methods are not been used. The downtime state of the pumping system will lead to a depletion of pressure of the reservoir if another alternative for pressure maintenance is not being implemented. For deepwater reservoirs this requirement is very critical, because the failure of the equipments will cause a reduction in the injection rates of the water into the reservoir, reduction of borehole pressure of the production wells and thus lead to a production decrease of the hydrocarbons.
In the 1950s and earlier, most floods used small PD pumps. Since then, design has tended toward use of a split-case multistage, centrifugal pump in large volume applications. Centrifugal pump usually are not competitive in high pressure, low rate applications. But a centrifugal pump is capable of a wide range of injection rates without changing the equipment. A PD pump, particularly when driven by an electric motor, has little flexibility without recycling water and consequently, wasting energy. Besides that a failure of a PD pump would cost higher. Whether a PD or a centrifugal is chosen, future expansion must also be considered [8]. The Operators of the pumps must have a high reliable system in order to response to any failure or downtime of the components of the injection system. One way of having a high reliable system to have a half or full back up system of the injection pumps while the system is online, in order to avoid greater pressure losses during production.

4.2 Simulation Work Results and Discussion

4.2.1 Line Drive Injection with Three Injection wells

The first results of the simulation with ECLIPSE100 are obtained simulating three water injection wells and fifteen production wells at a simulation time of about 3500 days or about 10 years. Figure 4.1 shows the injectors rates of the three injection wells which are WI1, WI2 and WI3. The Properties of the Gelama Merah reservoir Model are given in APPENDIX C.

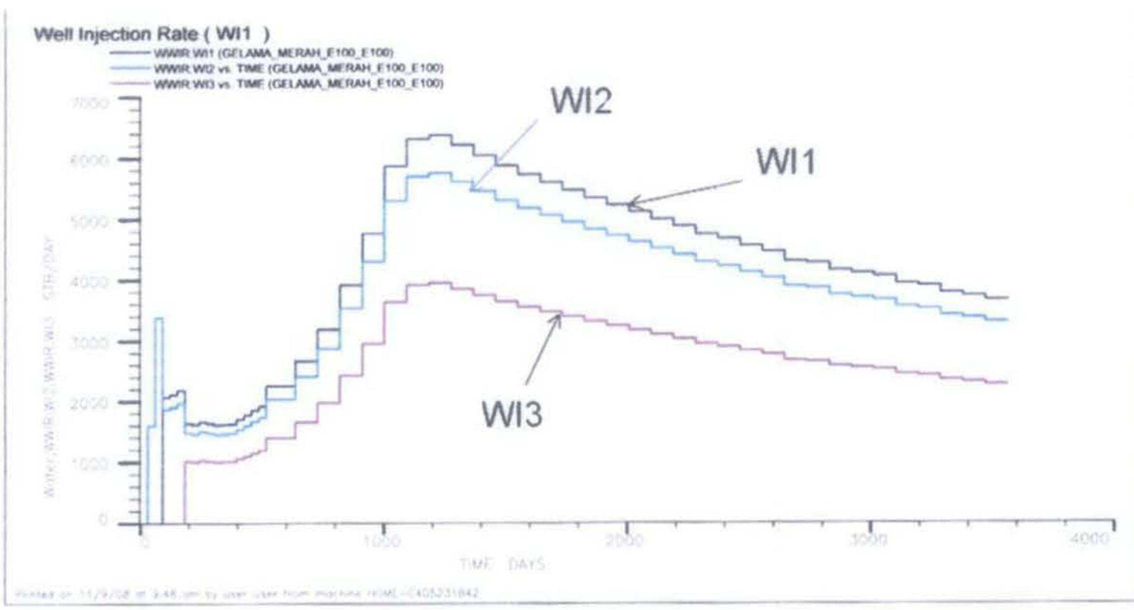

Figure 4.1: Wells Injection rates for three Injection wells Vs. Time

We see that the maximum rate in Figure 4.1, is 6,600 STB/Day of water for the well number one (WI1) and minimum injection rate is about 3,800 STB/Day for well number three (WI3). The Water injection performed for this first simulation is not at constant rate for all the wells. The reason for this is due to the requirement of each location of the wells in the field. Each location on the field requires different rate of injection. The injection rate decreases as the life of the reservoir growth. Only three was used because the idea was to analyze the reservoir behaviour when we have more production wells than the water injection wells.

4.2.2 Wells Borehole pressure Profile for Injectors and producers

Wells borehole pressure profile for the injectors is shown Figure 4.2. The WBHP is consistent to all the three wells. From this figure, we see that the pressure changes from 2,200psi to 1,800psi. The Maximum pressure of model for the field is 2,200psia therefore the WBHP must not exceed this pressure limit in order to avoid overpressures in the reservoir. The pressure profiles for the three wells are almost the same, which appear to follow a linear trend throughout the injection process for all the wells.

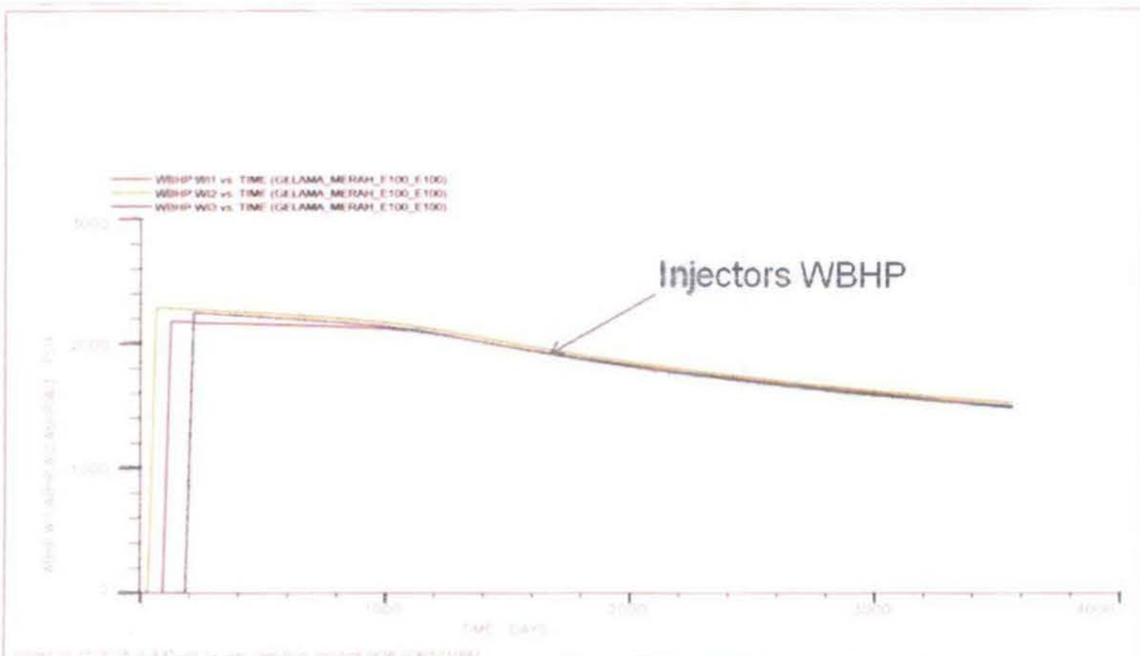

Figure 4.2: Injectors wells borehole pressure Profile

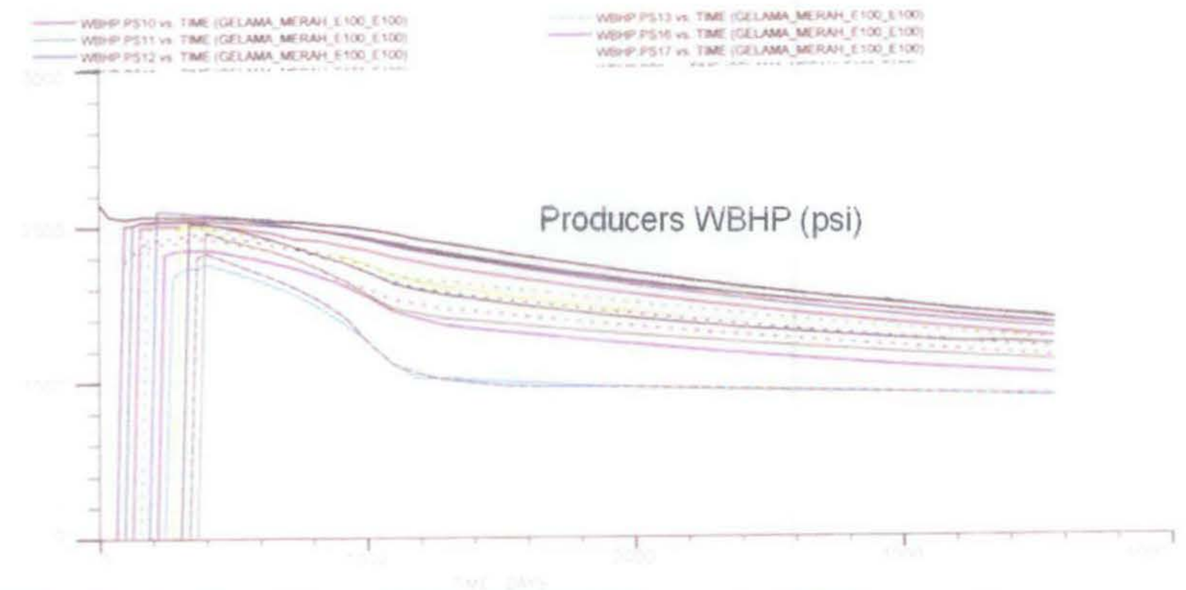

Figure 4.3: Production wells borehole pressure Profile (for 15 wells)

In figure 4.3, we have the production wells borehole pressure profile for fifteen wells. The WBHP profile shows a consistency for all the wells for about 40 days of production. The pressure of the wells starts to decrease after of about 200 days. Pressure drop in some wells is faster than others due to the different fluids migration in different locations in the reservoir. The overall pressure drop ranges from 2200psi to 1,600psi at the top part of the profile and from 1600psi to about 1000psi to the lowest part of the profile. The pressure drop of the wells appears to follow a nonlinear trend at the beginning of production and a linear trend by the end of production.

4.2.3 *Wells Oil Production Rate*

The wells Oil Production rate for the fifteen wells are shown in figure 4.4. In this figure the maximum production rate is 3,150 STB/Day, of "PS19" well. Different wells produce at the different rates due to the location of the wells in the reservoir. The trend shows that, the production profiles drops at the beginning of the production. The high production of the wells at the early days is related to high pressure of the reservoir at the production. The pressure of most of the wells decrease as the year of the reservoir increases as show at after 1,200 days of production.

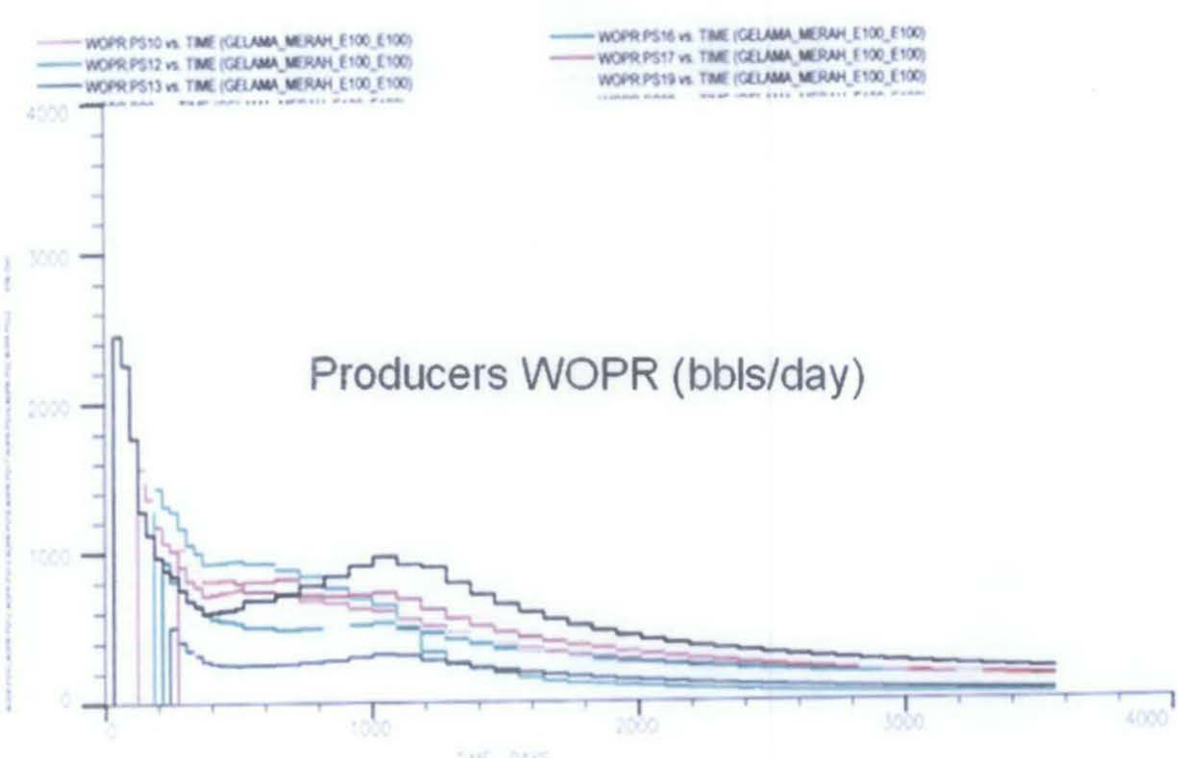

Figure 4.4: wells Oil Production rate profile

4.2.4 Field Oil Production Rate (FOPR)

Figure 4.5, shows the Field Oil Production Rate (FOPR), Field Gas Production Rate (FGPR) and Field Water injection rate plotted against the time. In Figure 4.5 the field Oil production rate has a constant rate 10,000 STB/Day for the first 3 years, then it start to decline until it ends with a production of 2,000 STB/Day. The Field Production declines as the Injection rate declines.. The water injection rate reaches to maximum of 16,000 STB/day of water while the field gas production rate reaches to about 30,000 MSCF/day. This high production of gas could lead to high depletion of the field pressure.

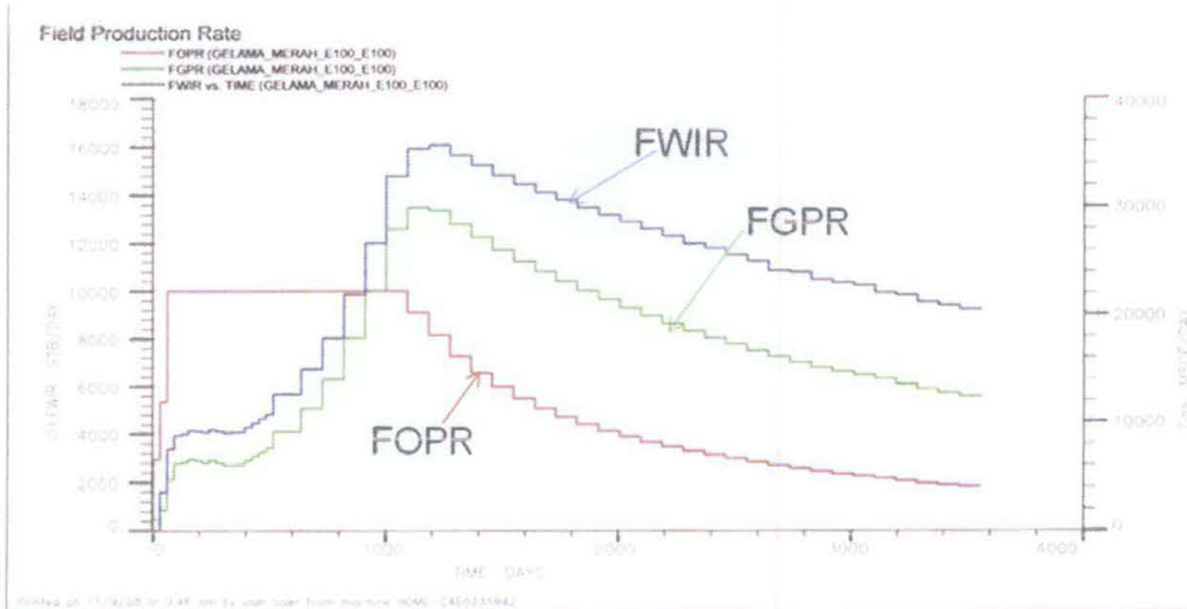

Figure 4.5: FOPR-FGPR and FWIR vs. TIME

4.2.5 Water Injection with Nine Injection wells

The Second Simulation work was done with nine production wells and Nine Injection wells. Figure 4.6 shows the wells injection rate profile for a period of more than sixteen years. The maximum rate is about 2,800 STB/Day of water by the WI1 and WI5 wells. The injection rates decrease as the reservoir life increases.

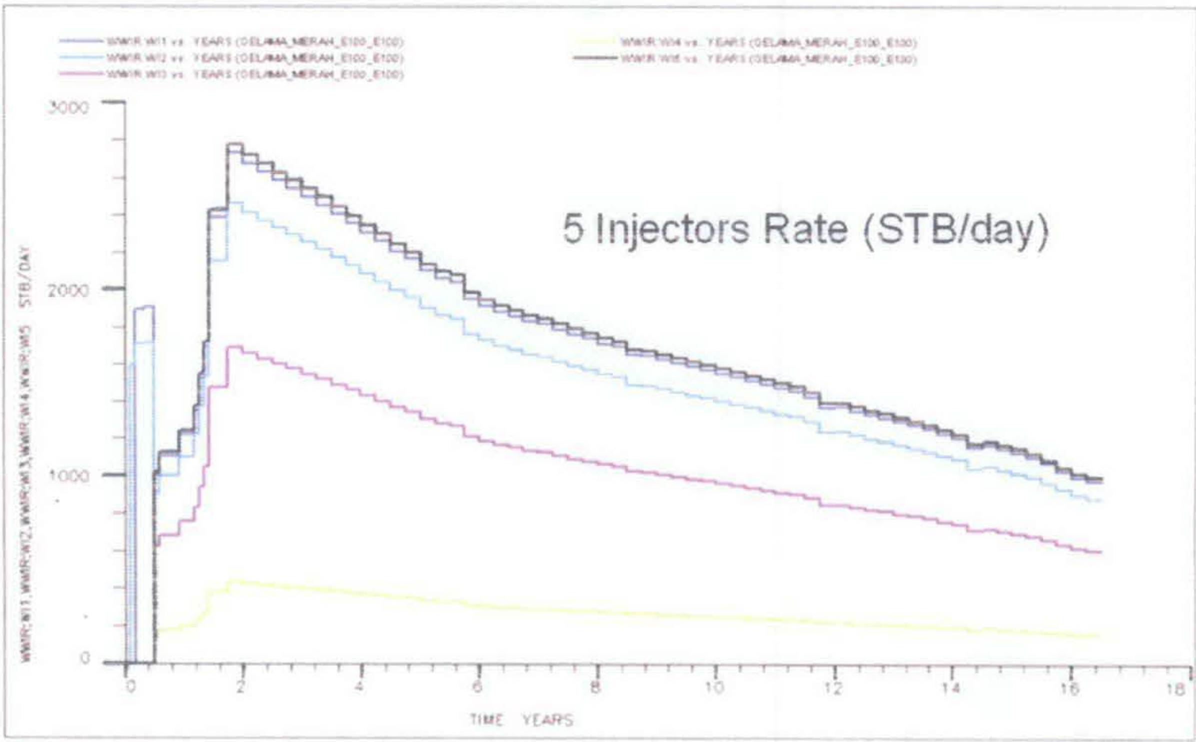

Figure 4.6: wells Injection rate Profile1 (five wells)

Figure 4.7 and Figure 4.8 also show the injection rate profile of the remaining injection wells. WI6 well in Figure 4.7 (blue plot) has the lowest rate of the simulation, about 100 STB/Day of water. In Figure 4.6, shows the Wells Water injection Rate (WWIR) profile for WI1, WI2, W13, WI4 and WI5 injection wells.

Figure 4.7, shows the WWIR profile of WI6, WI7, and WI8 injection wells at a simulation time of about 16 years.

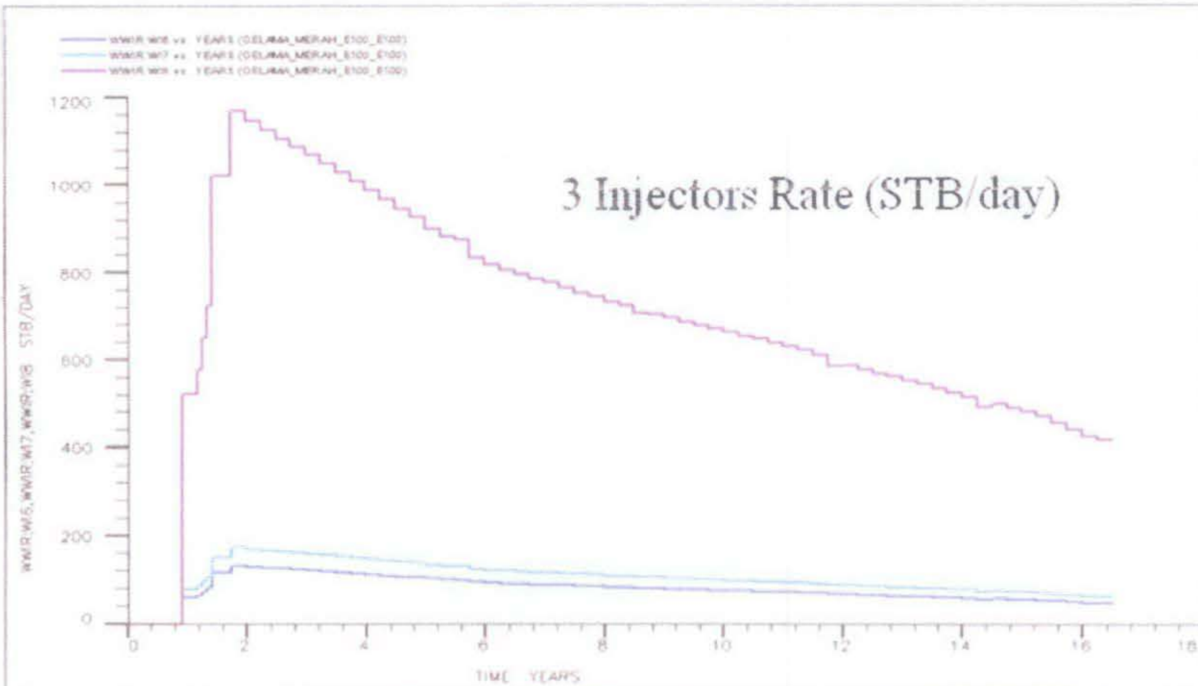

Figure 4.7: wells Injection rate Profile2 (3 wells)

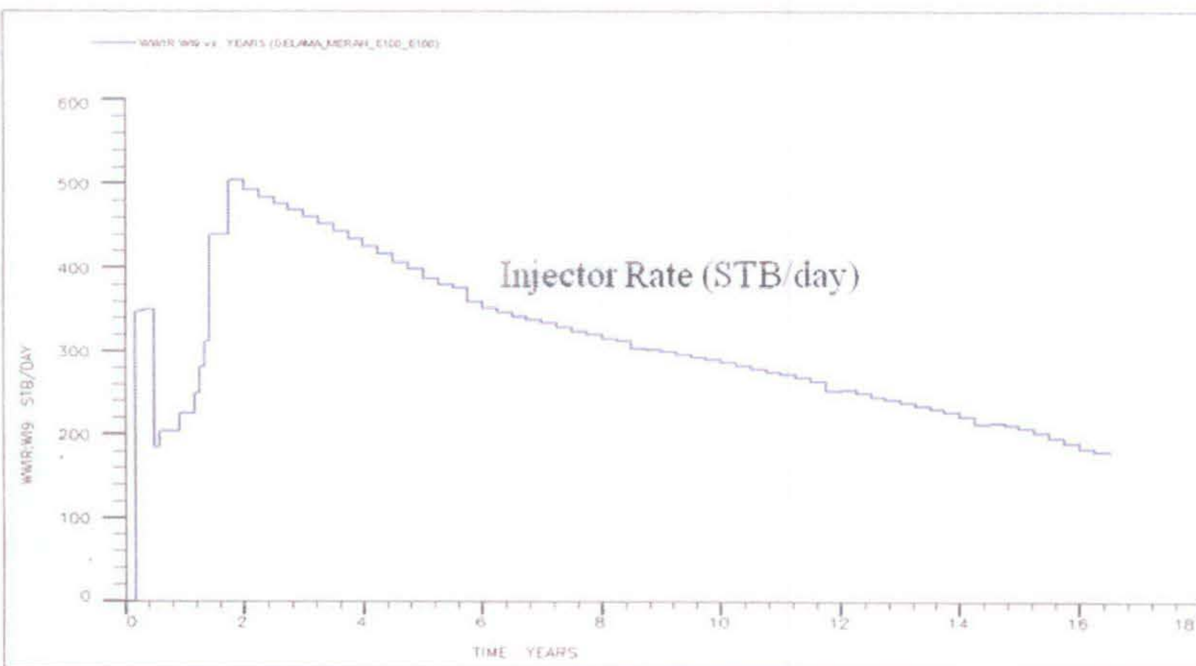

Figure 4.8: wells Injection rate Profile3 (one well)

4.2.6 WBHP for Nine production wells

The wells borehole pressure profile for four production wells is shown in Figure 4.9, three production wells in Figure 4.10 and two production wells in Figure 4.11. The borehole pressure depletion for the nine wells ranges from 2,200 psia of the maximum pressure of the field until it reaches about 1,200 psia. Meaning that the pressure profile of all the wells is consistent to one trend. If we compared it with Figure 4.2 for pressure profiles for fifteen production wells, we see that the decline is lower than the previous simulation, which reflects the influence of the injection fluids by the injectors in the field.

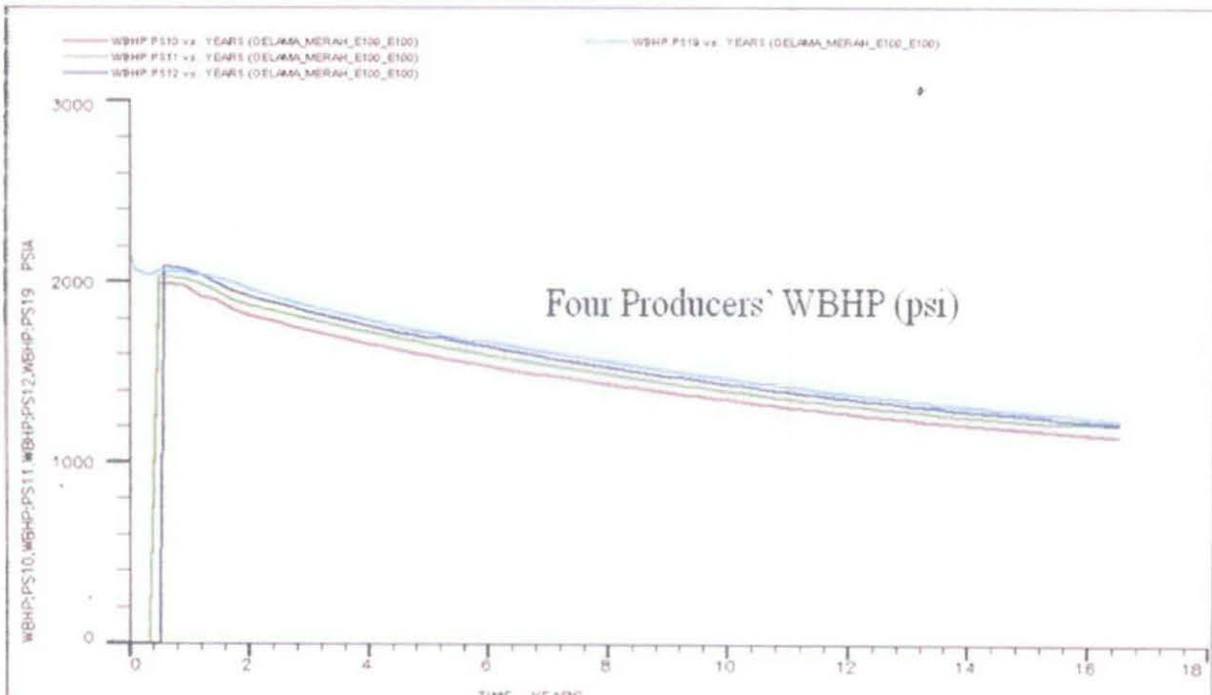

Figure 4.9: Production wells Pressure profile1 (four wells)

Figure 4.10, shows the well borehole pressure profile for three production wells (**PS2, PS4 and PS6**).

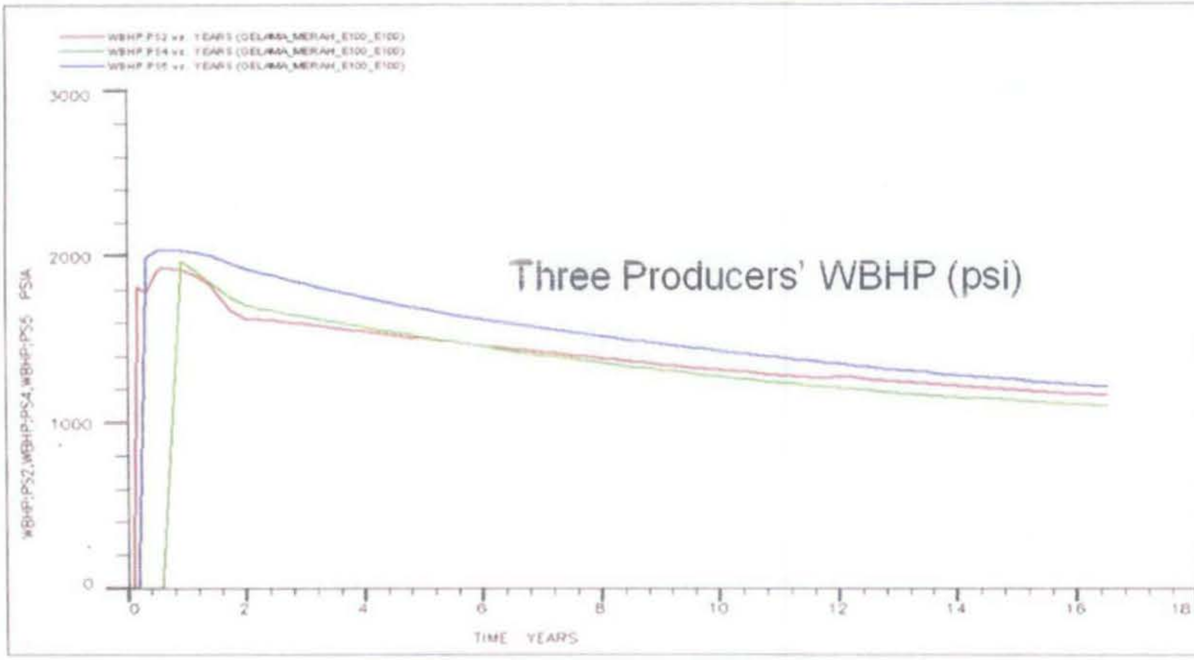

Figure 4.10: Production wells Pressure profile2 (three wells)

Figure 4.11, shows the well borehole pressure profile for two production wells (**PS8** andPS9)

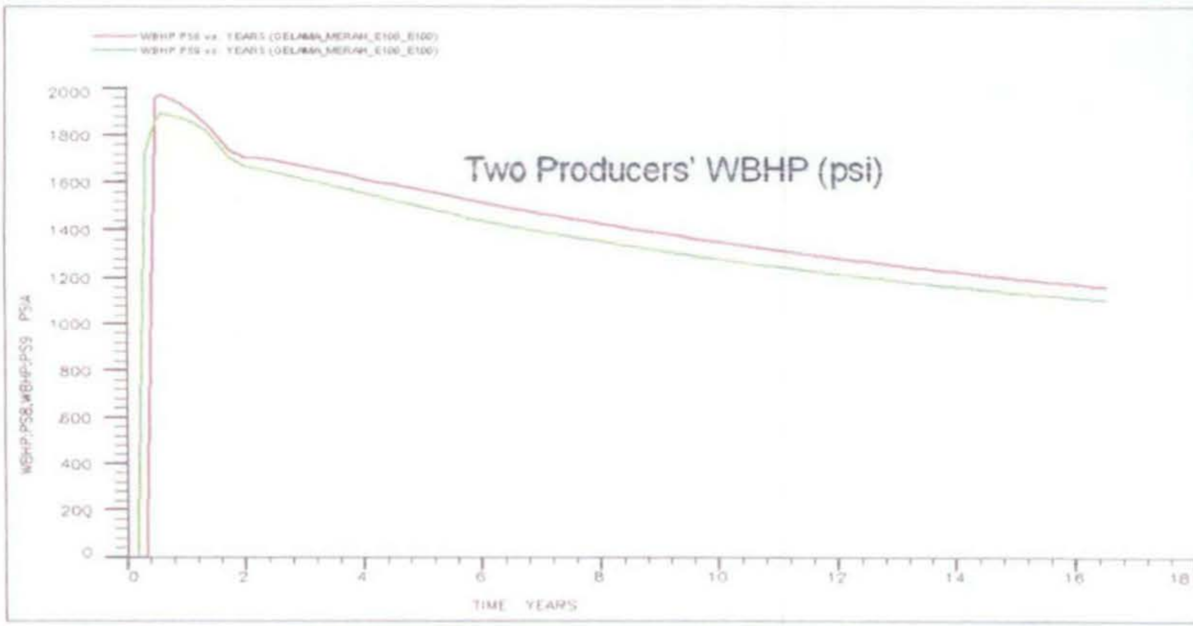

Figure 4.11: Production wells Pressure profile3 (2 wells)

4.2.7 Field Oil Production Rate

The field Oil Production Profile rate is shown in Figure 4.12 of the production rate and Injection rate. In Figure 4.12 the FOPR reaches at a maximum value of 10,000 STB/day of oil, while the FWIR reaches at a maximum of 12,000 STB/Day of water. This values shows that the injected at the end of second year is higher than the FOPR. We see that the trend of FOPR is constant for the first two years of injection before drop at the end of the second year. The FOPR declines faster as the FWIR declines as well. This fast decline of the FOPR could be due to the distance between the injection wells and the production wells in the reservoir. This distance will influence in order to obtain front drive of the Injection wells to the production wells.

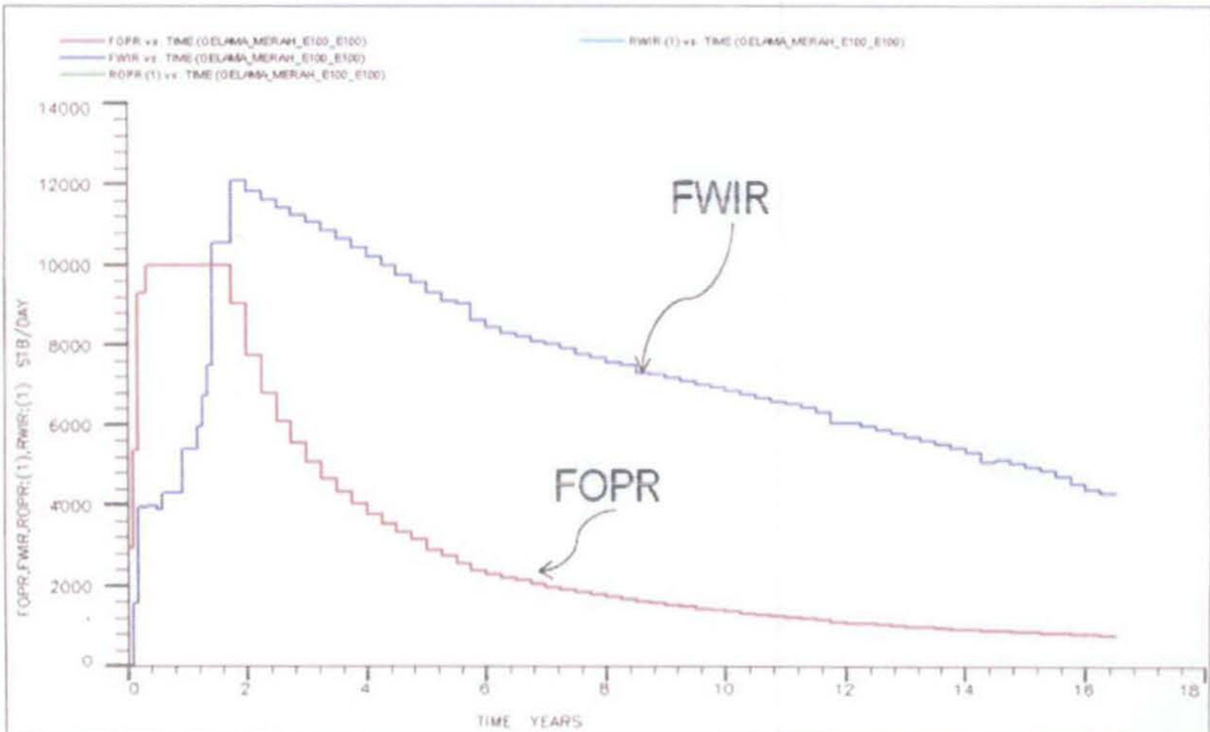

Figure 4.12: Field Oil Production rate and Injection rate Profile

Figure 4.13 Shows the FOPR and Field gas Production rate (FGPR) for nine production wells and nine Water injection wells.

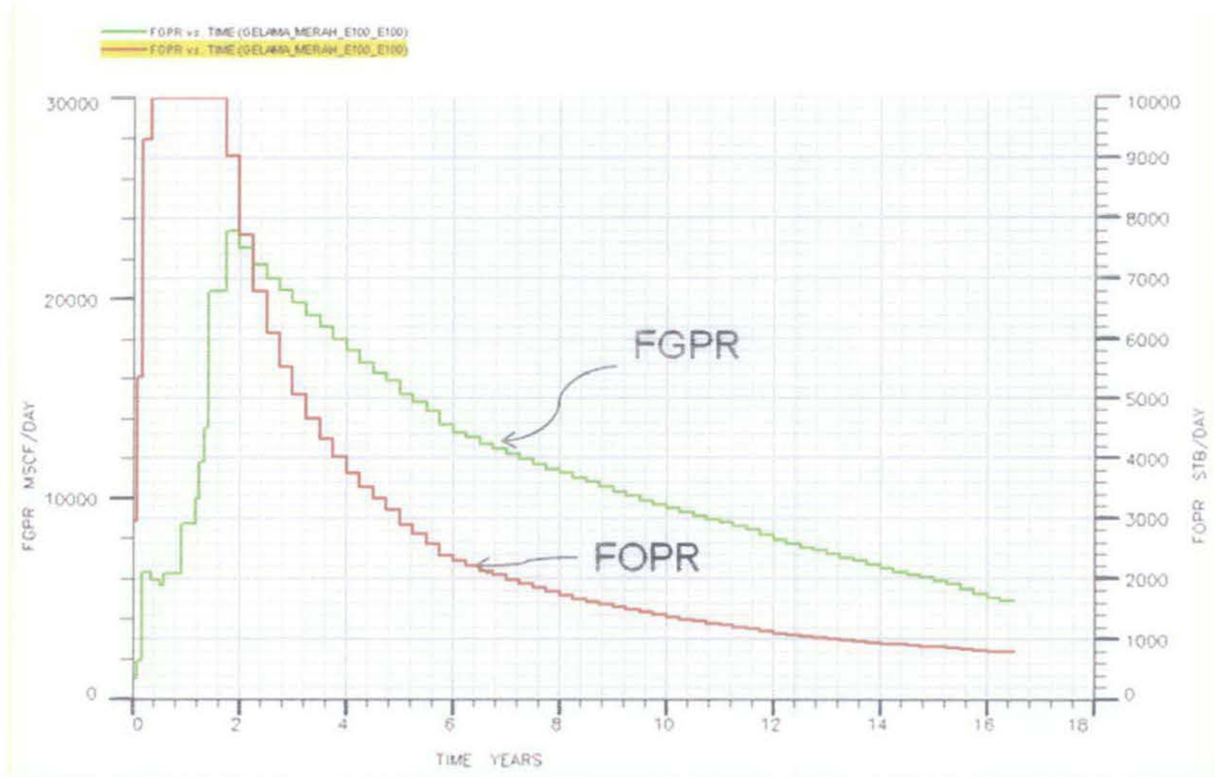

Figure 4.13: FGPR -FOPR- vs. TIME

In Figure 4.13 of FGPR and FOPR, the two plots show a fast decline after two years of production. The maximum FGPR is 7,800MSCF/day while the FOPR reaches a maximum of 10,000 STB/day. The FGPR increases for the first two years up to the maximum value before declining at the beginning of year three of production.

In Figure 4.14 we can see the FOPR, Field Gas oil ratio (FGOR) and Field Pressure rate (FPR).The FRP declines as the FORP declines, meaning that the withdrawal of this reservoir fluids influence directly for the pressure depletion of the reservoir. The field needed more fluids to replace the rock voidage created by the produced fluids. Increasing the number of the injection wells is one option, but we can maintain the pressure longer by injecting gas and water at the same time. Because getting back to Figure 4.12, the Water injection rate is higher than the oil production rate at all the times of the years of production.

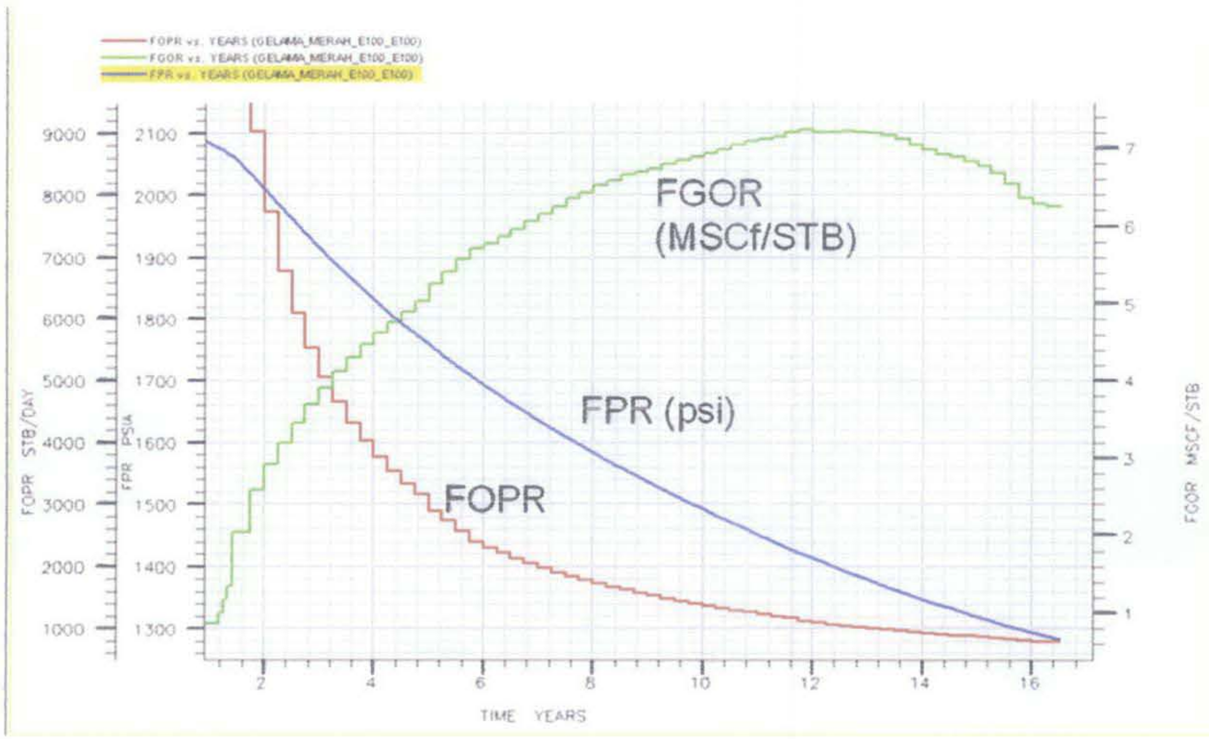

Figure 4.14: FOPR-FGOR-FPR- vs. TIME

The FGOR increases as the production declines over the years. This rising of the FGOR is due to the expansion of the gas in the field and leads to high production of this solution gas as the oil production rate declines. High Production of solution gas leads to fast decline of the FPR. The FPR in Figure 4.14 shows a linear drop as the FGOR increases with a negative slope of 55.55psi/year approximately.

Normally for black oil reservoir, reservoir pressure decreases as liquid is removed from the reservoir. At pressures above the bubble point, the oil, water and reservoir rock must expand to fill the void created by the removal of liquid. The rock and remaining liquids are not very compressible. So a large decrease in pressure is necessary to allow the rock and remaining liquids to expand enough replace a relatively small amount of oil produced. Thus as long as the reservoir pressure is above bubble point, pressure decreases rapidly during production. At Pressures below bubble point, gas forms in the pore space. This free gas occupies considerably more space as a gas than it did as a liquid. Also, the gas readily expands as pressure decreases further. The forming and expanding gas replaces most of the void created by production. Reservoir pressure does not decrease as rapidly as it does when pressure is above the bubble point [18].

Figure 4.15 shows the Field water injection total and field oil production total for nine producers and nine water injectors. From these graphs we can see that the water injected in the field is more than the oil produced for a period of sixteen years. Though the water injected is more than the oil produced by the producers, but the expansion of the liquids is not sufficient enough to boost up the production of the field. Figure 4.15 shows that the FWIT by beginning of year seventeen is about 54MMSTB of water, while the FOPT is 28MMSTB of oil. This shows that the ratio between the water injected and the oil produced is about 1.93 or 2 barrels of water per one produced barrel of oil on the field.

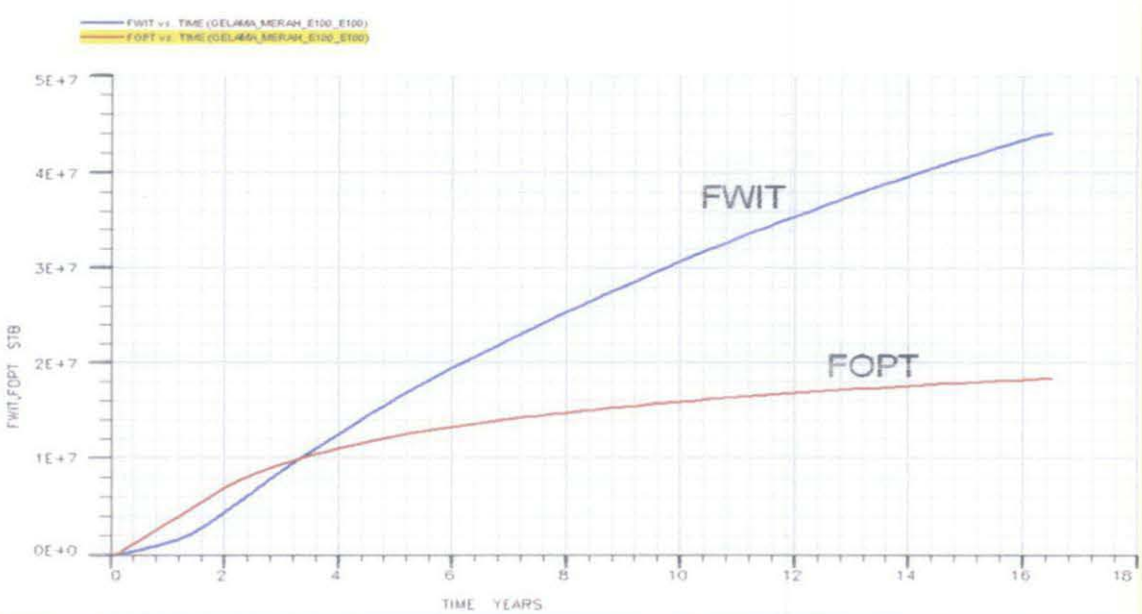

Figure 4.15 Field Water injection total and Field Oil Production total

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5. 1 CONCLUSION

The following conclusions could be drawn from the study conducted:

a) Multistage Centrifugal Pumps are the type of injection pumps suitable for high pressure and high flow rate reservoirs due to their reliability and low maintenance cost as compared to the Positive displacement reciprocating pumps.

b) Pressure Maintenance is achieved with the Line Drive water Injection Pattern used in this project. This process might be improved by combining with other patterns of injection and by considering not injecting only water but also injecting miscible gas.

c) The Wells borehole pressure is improved when injecting equal number of water injection wells and producers. The ratio between the injected water and the Oil produced is about two (I/P =2 STB) barrels of water per 1STB of oil produced, which is not typical for line drive injection pattern.

5.2 RECOMMENDATIONS

a) Combining Line drive injection with staggered injection should be analyzed.
b) Further studies on the use of the Simulation software is required to better use and interpretation of the results obtained for each simulation work.

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APPENDICES

APPENDIX A: PUMPS SEGMENT Matrix by SULZER Pumps [9]

Product Types		Oil & Gas	Hydrocarbon Processing	Pulp & Paper	Power Generation	Water & Wastewater	Food, Metals & Fertilizers
Single Stage Pumps	AHLSTAR™ A Series		●	●	●	●	●
	AHLSTAR™ N Series		●	●			●
	AHLSTAR™ W Series		●	●	●		●
	AHLSTAR™ E Series		●	●	●		●
	CPT		●	●	●		●
	Z Series		●	●	●	●	●
	OHH/OHHL	●	●				
	OHM/OHC	●	●				
	BBS	●	●				
	HLTE		●				
	HZB				●		
Two Stage Pumps	BBT/BBT-D		●				
	LSP/LST			●			
Barrel Pumps	GSG	●	●		●		●
	HPT				●		
	HPcp/HPcpV	●					
	CP	●	●		●		
	MPP	●					
Ring Section Pumps	M Series			●	●	●	●
	HPP/HPT			●	●	●	●
	HPH/HPL					●	●
	TUP					●	
Axial Split Pumps	MSD	●	●		●		
	SM/SMN/SMH Series	●	●	●	●	●	●
	HSB	●	●				
	ZPP			●	●		
	HPDM	●				●	
Vertical Pumps	AHLSTAR™ NVP/NVT		●	●	●	●	●
	AHLSTAR™ NKP/T,WKP/T			●			●
	B Series	●	●		●	●	
	JD	●	●	●	●	●	●
	JF	●	●	●	●		●
	JM		●	●	●	●	●
	JP		●	●	●	●	●
	JS	●	●	●	●	●	●
	JT	●	●	●	●	●	●
	OHV	●	●				
	VCR	●	●				
	TTMCM		●				
	APV/NPV				●	●	
MC® Products	MC® Pumping System			●			
	AHLMIX™ Chemical Mixer			●			
	MC® Discharge Scraper			●			
	MC® Flow Discharger			●			
Agitators	SALOMIX® SL/ST			●			●
	SALOMIX® L Series			●			●
	SALOMIX® TES, VULCA			●			
Service	Service products available for all segments.						

APPENDIX B: DIFFERENT TYPES OF INJECTION PUMPS

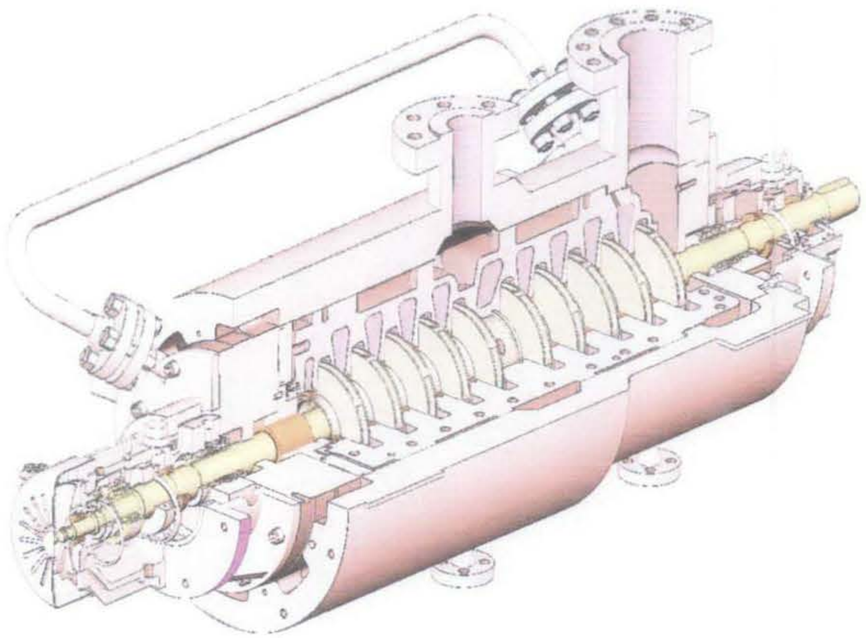

Figure B1: CP Horizontal Double Casing Radially Split Multistage Pump [9]

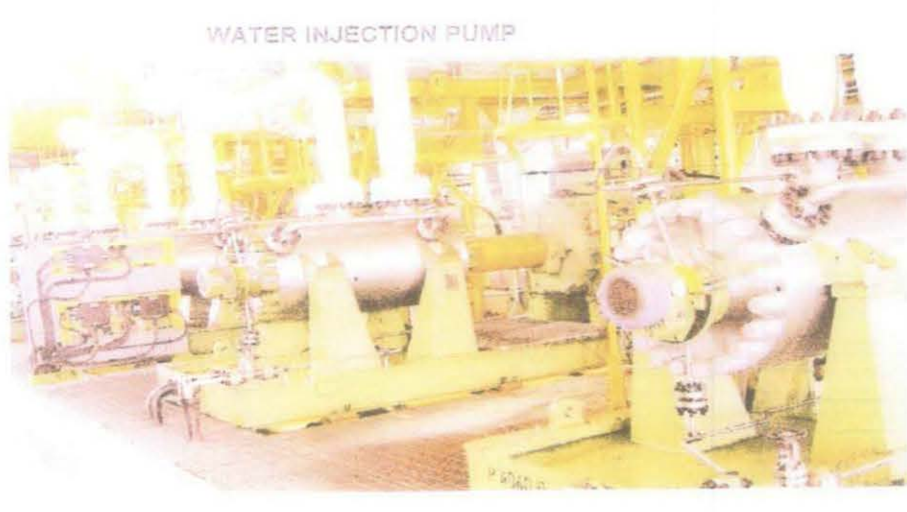

Figure B2: CP horizontal Pumps used in Angsi Field, Malaysia [19]

APPENDIX C: GELAMA MERAH RESERVOIR PVT PROPERTIES

Table C: Gelama Merah Reservoir Model PVT Properties

Parameter	Unit	Description
Gas oil Contact (GOC) depth	Feet (ft)	4815.945
Water Oil Contact(WOC) depth	Feet	4948.163
Reservoir Thickness	Feet	132.218
Maximum Reservoir Pressure	psi	2200
Number of cells	----	53x44x104
permeability	md	20-200 (average)
Live Oil Properties		
Oil Density	lb /cu ft	51.85
Oil Viscosity	Centipoises (cp)	2.938
Oil Saturation, So	Percentage (%)	0.37328 Or 37.328 %
Oil Volume Factor, Bo	Rb/STB	1.15
Specific Gravity	(Oil density/Water Density)	0.83
API Gravity	Degree API	38.87
Dry Gas Properties		
Gas density	lb/cu ft	0.0522
Gas Saturation, Sg	Percentage (%)	0.56 or 56.0%
Gas viscosity	cp	0.0266
Water Properties		
Water Volume Factor, Bw	Rb/STB	1.0
Pressure at Water level	psi	(1874 to 21116.463)
Water Viscosity	Centipoises (cp)	3.561e-006
Water Density	lb/cu ft	62.43
Water Saturation	Percentage (%)	0.18664 or 18.6%
Reservoir Rock Properties		
Average Pressure,	Psia	1874
Porosity	%	20

APPENDIX D: 3D Views of the Simulation Work

Figure D1: Top View of the Reservoir Model Before well designs

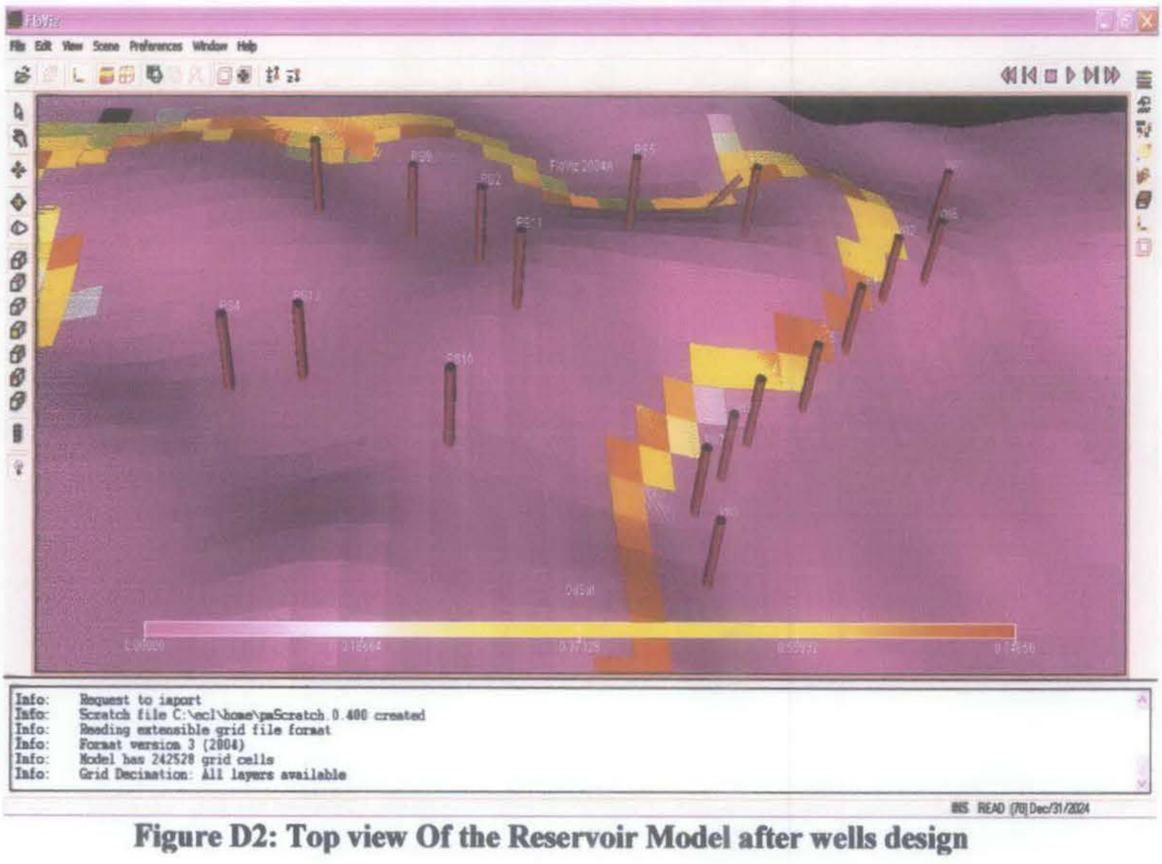

Figure D2: Top view Of the Reservoir Model after wells design

APPENDIX D: 3D Views of the Simulation Work (continue)

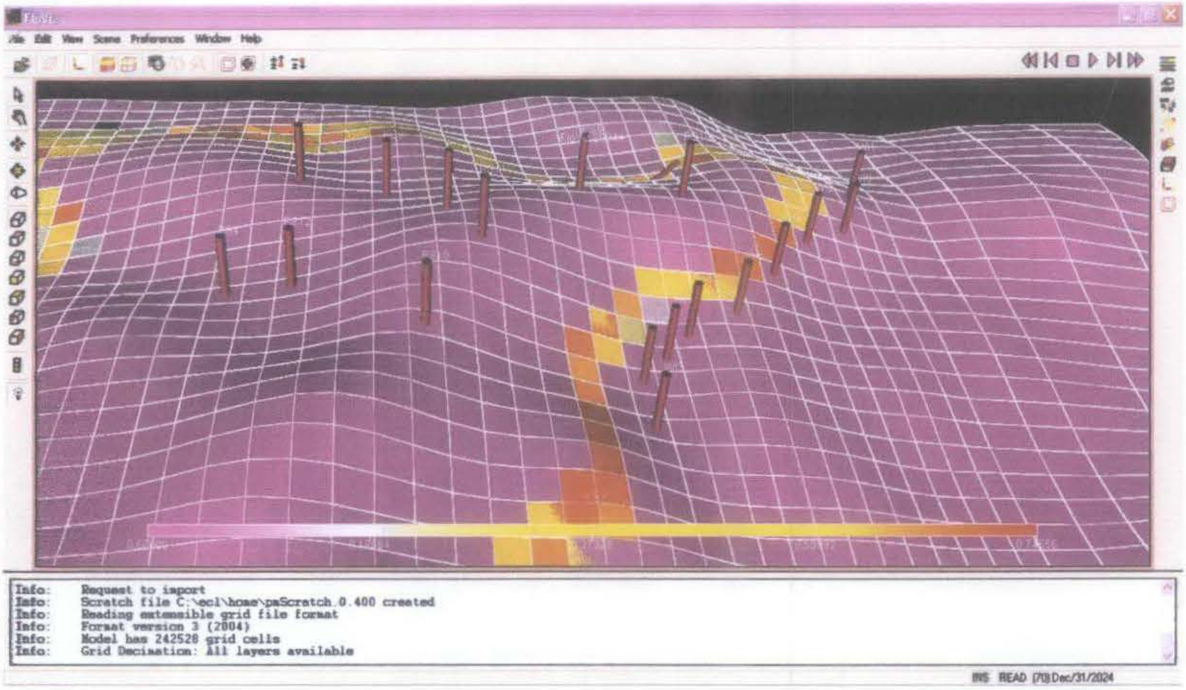

Figure D3: Grid view of the Reservoir Model

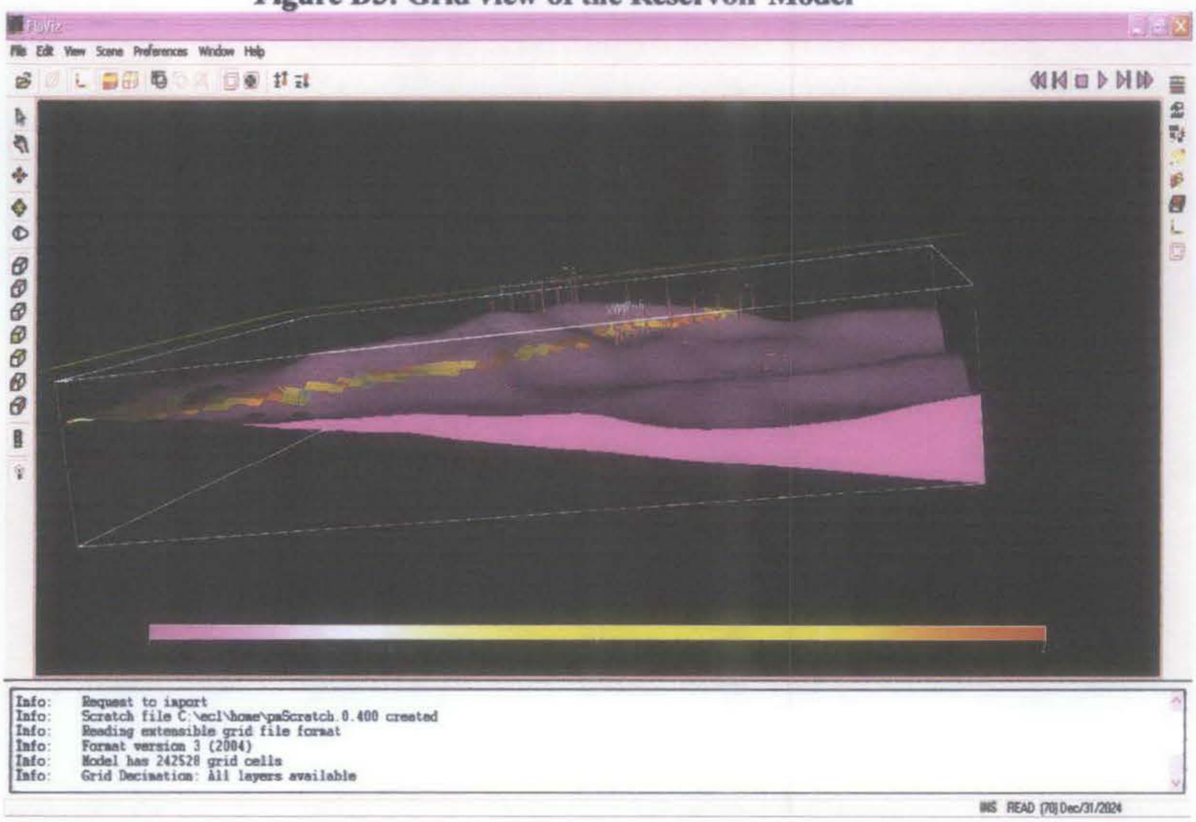

Figure D4: Side View of the Reservoir Model

APPENDIX D: 3D Views of the Simulation Work (continue)

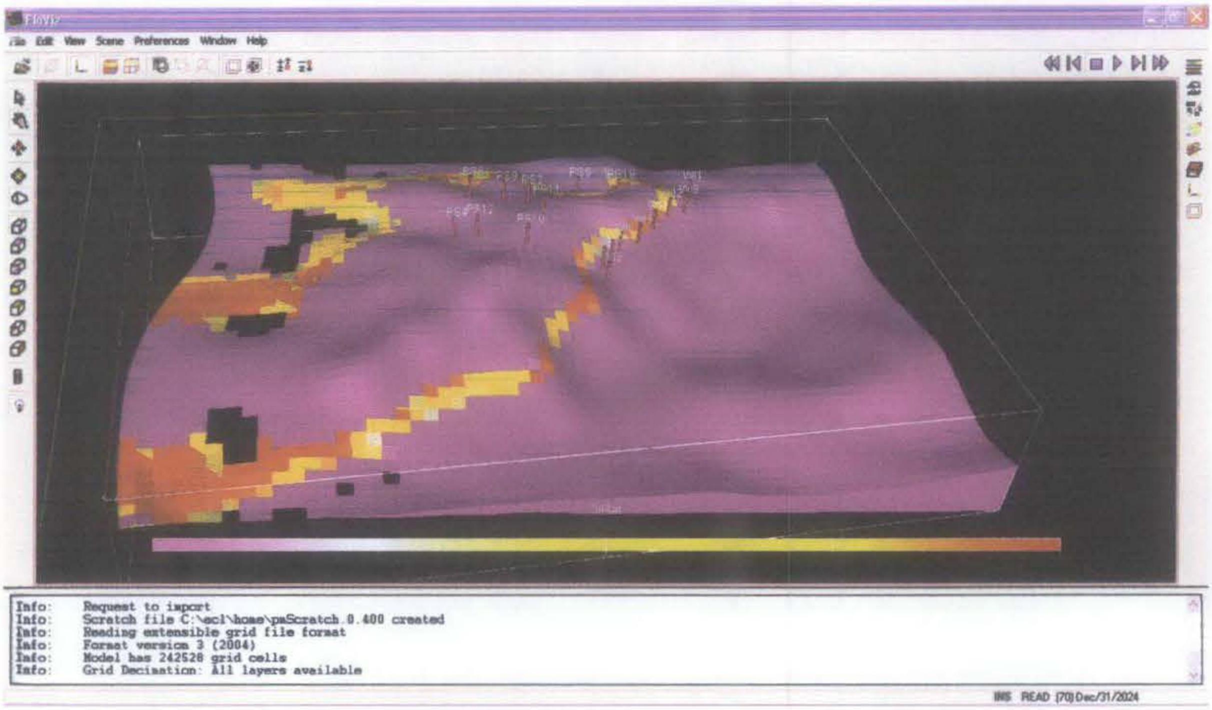

Figure D5: Top view of The Model

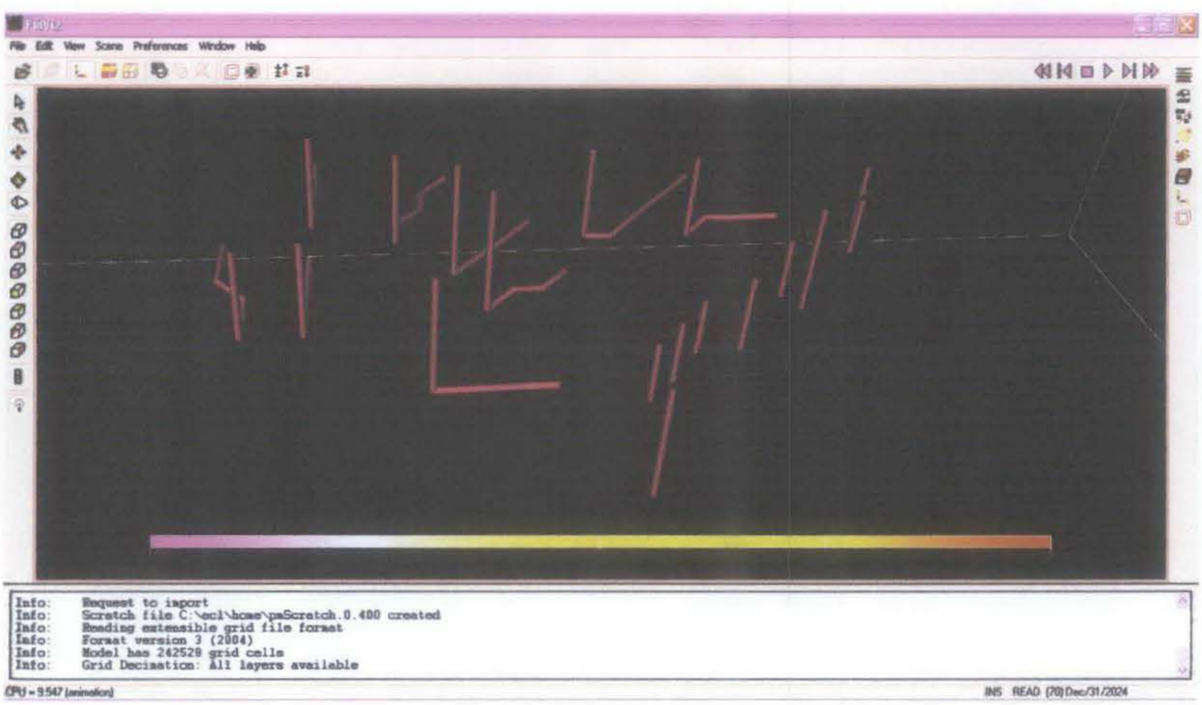

Figure D6: Wells Layout of the Model