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Department of Petroleum Engineering

Developing a Sudanese oil field

Reservoir and Production Engineering Aspects

تطوير حقل نفط سوداني

إعتبارات هندسة المكامن والانتاج

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مشروع تخرج مقدم إلي كلية هندسة وتكنولوجيا النفط – جامعة السودان للعلوم والتكنولوجيا

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سورة طه (110)

DEDICATION

This work is dedicated

To the people who helped and supported us in all aspects of life;

Our parents

To those who stand by our side during the whole journey;

Our brothers & sisters

To those who gave us a lot of lessons to learn, and inspired us to get involved in a beautiful world of science,

Our teachers

To those who have a hand in this success

Our friends

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Abstract

Field development planning comprises a great amount of investments and involves a high number of parameters related to the geological and structural characteristics of the reservoir, to the operational scheduling and the economic scenario. The importance of this problem demands the elaboration of methodologies that can help in the management decision making process, leading to better recovery strategies that increase both reserves and profitability of reservoirs.

The main objective of this work is to employ an efficient optimization technique to identify a sound field development plan for Haraz field. Optimized parameters include number of well, well placement, Production scheme for all wells and network design regardless of economic evaluation.

Two major scenarios were implemented to the model by using dynamic numerical reservoir simulator (ECLIPSE). In the first scenario the field was developed by implemented several vertical wells (2, 4, 6, 8) to the base case (2vertical well), in the second scenario the field was developed by implemented 3 horizontal wells to the base case (2vertical well).

The result shows that the best scenario is to implement 8 vertical wells (2 wells in base case) and the optimum cumulative oil production is 3.05 MMBO with recovery factor = 14.6%.

The optimization in this study was based only on the recovery factor, oil production rate and the cumulative production during the simulation time.

The best scenario (8 vertical wells) is used in constructing production network system to connect the wells by using steady-state production network simulator (PIPESIM). The network system will allow producer to interact with production facilities to make a stable system in producing fluid.

التجريد

التخطيط التطويري للحقول النفطية يتضمن قدرا كبيرا من الاستثمارات، و يشتمل على عدد من العوامل المتعلقة بالخصائص الجيولوجية و التركيبية للمكمن، إلى الجدولة الزمنية للعمليات والسيناريو الاقتصادي. تكمم أهمية هذه المشكلة في أنها تتطلب وضع منهجيات مفصلة يمكن أن تساعد في عملية اتخاذ القرارات الإدارية، مما يؤدي إلى استراتيجيات إستخلاص أفضل تزيد من الاحتياطي القابل للإستخلاص و ربحية المكامن.

الهدف الأساسي من هذه الدراسة توظيف آلية مثلى لتعيين خطة تطوير جيدة لحقل حراز و ذلك بتحقيق الأمثلية لعدة معاملات تشمل عدد الآبار، وضع الآبار، خطة الإنتاج لكل الآبار، و تصميم شبكة الإنتاج مع عدم الأخذ في الإعتبار للتقييم الإقتصادي.

تم تطبيق سيناريوهان رئيسيان على النموذج باستخدام برنامج محاكي الخزانات العددية الديناميكية (ECLIPSE). طور الحقل في السيناريو الأول بتطبيق عدة آبار عمودية (2,4,6,8) على الوضع الأساسي (بئرين رأسيين) ، أما السيناريو في الثاني فطور الحقل بتطبيق 3 آبار أفقية على الوضع الأساسي (بئرين رأسيين) .

النتائج بينت أن أفضل سيناريو تم تنفيذه هو 8 آبار عمودية (يحتوي بئرين الوضع الأساسي) وإنتاج النفط التراكمي الأمثل هو 3.05 مليون برميل نفط مع معامل استخلاص 14.6٪.

وأستند الإختيار الأمثل على أساس معامل الاستخلاص، معدل إنتاج النفط والإنتاج التراكمي.

أستخدم السيناريو الأفضل (8 آبار عمودية) في إنشاء شبكة الإنتاج لربط الآبار باستخدام برنامج محاكاة شبكة الإنتاج المستقر (PIPESIME). شبكة الانتاج تسمح لأبآر الأنتاج بالتفاعل مع مرافق الإنتاج لجعل النظامس مستقر في إنتاج الموائع.

Nomenclature:

FDP	Field Development Plan
NPV	Net Present Value
GOR	Gas Oil Ratio
DST	Drill Stem Test
DFL	Dynamic Fluid Level
OWC	Oil Water Contact
OOIP	Oil Initial In Place
RF	Recovery Factor
ECL	Exploration Consultants Ltd
TD	Total Depth
GNPOC	Greater Nile Petroleum Operation Company
GOR	Gas Oil Ratio
PCP	Progressive Cavity Pump
PI	Productivity index
OGM	Oil Gathering Manifold
FPF	Field Processing Facility

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CHAPTER 1

GENERAL INTRODUCTION

Chapter 1

General Introduction

1.1. Introduction:

Field Development Planning is the daunting process of evaluating multiple development options for a field and selecting the best option based on assessing tradeoffs among multiple factors: Net present value, typically the key driver of decisions for publicly-traded operators.

Field development plans (FDPs) give you the best technical solutions for field optimization. FDPs comprise all activities and processes required to develop a field: environmental impact, geophysics, geology, reservoir and production engineering, infrastructure, well design and construction, completion design, surface facilities, and economics and risk assessment.

Reservoir development plans are developed by using reservoir simulation software such as Eclipse 2011. The aim of reservoir development plan is to accelerate oil production with maximum recovery factors and at minimum cost possible. To achieve this objective, placement of additional infill wells and new perforations in the existing wells is inevitable (Keng , et al., 2011). However, oil production depending only on natural reservoir energy (primary oil recovery techniques) can recover about 30% to 50% of the original oil in place (Lyons, 1996). This is due to the fact that once reservoir pressure falls below the oil bubble point pressure, gas that was initially dissolved in the oil comes out of solution and flow preferentially towards production wells since it is less viscous than oil. Consequently, oil production rate and oil recovery factor are lowered. To avoid this, water and/or gas injection is usually applied to maintain reservoir pressure above the bubble point for improved oil production (Muggeridge, et al., 2013)

Forecasting optimal number, type, subsurface locations, and design parameters for a new set of wells, considering field uncertainty, is a complex and often a time-consuming set of challenges for field development planning. But it is a necessary and critical part of the field development planning workflow. Sub-optimal decisions on the number of wells, the size and well configuration, the processing capacity of facilities, etc. which are made early in the field life may constrain field operations for years. The problem is often addressed through a tedious process of locating one well at a time in a static model, and then validating a set of well locations through case studies with reservoir simulation; then repeating this process until some convergence to a "good" set of wells is reached. With only a small number of cases investigated, there may be little confidence by an asset team that an overlooked alternative could be more attractive. The problem of locating many wells simultaneously when formulated as an optimization problem that it can result in innumerable solution combinations. Thus, a practical procedure for locating many wells in a full-field development plan has been elusive.

This current work, will present a framework for optimizing many well locations with design constraints simultaneously. Rather than solve the full problem all at once, the method identifies a set of target and well plan locations based on the static reservoir model and then uses the locations to "seed" the global optimization as initial guesses. The locations are risked, based on subsurface uncertainty, through analysis of the statistical character of the oil recovery or net present value within the optimization procedure. The mean recovery can be maximized with requirements on the statistical risk, e.g., the standard deviation. A key to the success of the optimization is efficiently running optimizer simulations on a computer cluster or grid.

1.2. General Background about the Field:

Located far west of BLK-4, 180 km NW Heglig, 3 km SE of Suttaib. Haraz consists of 6 reservoirs with different rock and fluid properties.

The Depth of Reservoir varies 1390 to 1480 m. Nayil is the main reservoir and is divided into sub units.

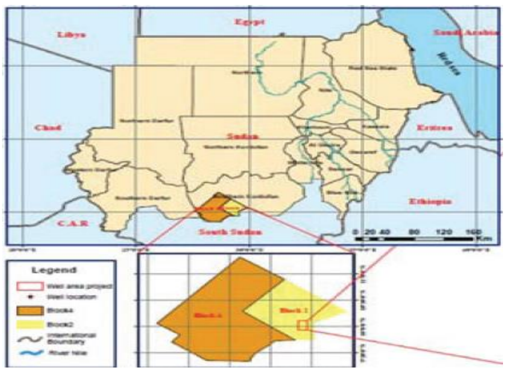

Fig 1.1 Location Map of Block 4

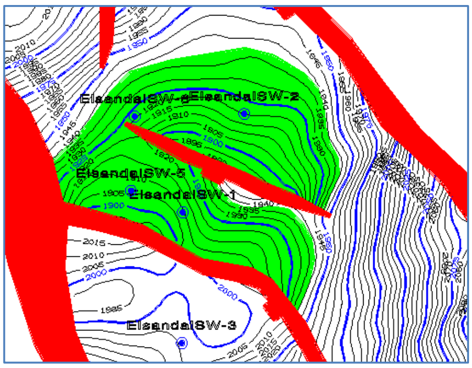

Fig 1.2 Structural Map of Haraz Field

First discovery in HZ-01 was in 2003. Potential was confirmed by drilling and testing HZ-02 in 2004.

Oil has moderate to high viscosity, and Low GOR. Well Productivity is moderate from DST.

Initial Field Development Plan for field carried out in 2007, FDP was carried out on 2007 and accordingly 2 wells HZ-01 & 2 were tied- in 2009. FDP predicted complete depletion after less than 3 years and producing 0.8 MMSTB. Currently the field Np is 0.5 MMSTB without significant pressure depletion as indicated by DFL. The summary of Haraz field presented through Table 1.1

Table 1.1: Haraz field Summary

Total drilled wells	2
Total wells at field from simulation	2(the existing wells only)
Formation	Nayil-A (OWC 1398.5 mKB) And two OWC- at, 1381,1469.6 mKB)for L.Nayil-C1,L.Nayil-C2
OOIP	7.2 MMstb
Cumm. Oil	0.8 MMstb
Recovery Factor	%11.4 (base Case with constrains)
Average Wcut for first 6 months	3 %
Average daily oil rate for first 6 months	1085 stbd
Oil viscosity @res. Cond	30-32-7.5(Hz1) cp L-Nayil-c2, L-Nayil-c1, L-Nayil-A,
PCP Intake Depth	6.67 cp @ RES. T160.5F(Hz2) Nayil-A,

1.3. Problem Statement:

Haraz field with recoverable oil reserve of about 7.2 MMstb. The existing plan has recovery factor about %11.4 of the recoverable reserve equivalent to 0.8 MMstb , leaving about 6.4 MMstb oil in the ground. Therefore, there is a need to simulate and analyses alternative reservoir development plan that can improve oil production.

1.4. Research Objective:

The main objective of this study is to determine the best alternative reservoir development plan to improve oil production from Haraz field, without considering economic estimation, that plan include:

- Perform well placement optimization.
- Estimate the recovery factor (RF) for the reservoir.
- Select the production scheme for all field wells.
- Design a surface facility connecting all field wells

CHAPTER 2

THEORETICAL BACKGROUND AND LITERATURE REVIEW

Chapter 2

Theoretical Background and Literature Review

2.1: Theoretical background:

Production strategy optimization has a great importance in the oil industry and must be applied to achieve different objectives. Sometimes, the main purpose of this process is to select an adequate production strategy to be applied in the reservoir development planning. In other instances, the objective is to utilize a detailed optimization procedure in order to obtain accurate results to support complex decisions.

The objectives are established by the management regarding the importance of the project and the technical and economic resources available and the decision making process must lead to lucrative results and high revenues, considering the physical and operational restrictions for each particular project. Hence, it is very important to develop new procedures to minimize risks and maximize profits in recovery strategy arrangements.

The use of reservoir simulation is very important to provide reliable production forecast and correct predictions for field recovery potential. However, during the initial field development phase the amount of available information for the reservoir is very restricted and it is very difficult to obtain a correct reservoir model. Therefore, the use of simplified simulation models provides more appropriate and lead to better results.

(C. C. Mezzomo and D. J. Schiozer) proposed a methodology including a robust optimization procedure that uses the production/injection forecasts generated by reservoir simulation for the evaluation of an objective-function (NPV). This methodology helps in the decision making process granting a correct evaluation of relevant parameters in field recovery planning and it provides adequate solutions using a small number of simulation runs. Some examples based on different offshore fields were selected in order to validate the methodology and the results are presented. It can be shown the importance of reservoir simulation in field development planning to determine an adequate amount of producer and injector wells and propose a suitable scheduling. The procedure can be refined to increase the accuracy of the solutions and can also be adapted to define production strategies for field development under uncertainty. In this case different strategies are proposed for each geological model generated. Integration of Field Development Plan is shown in Fig 2.1 (Mezzomo, 8th October, 2000)

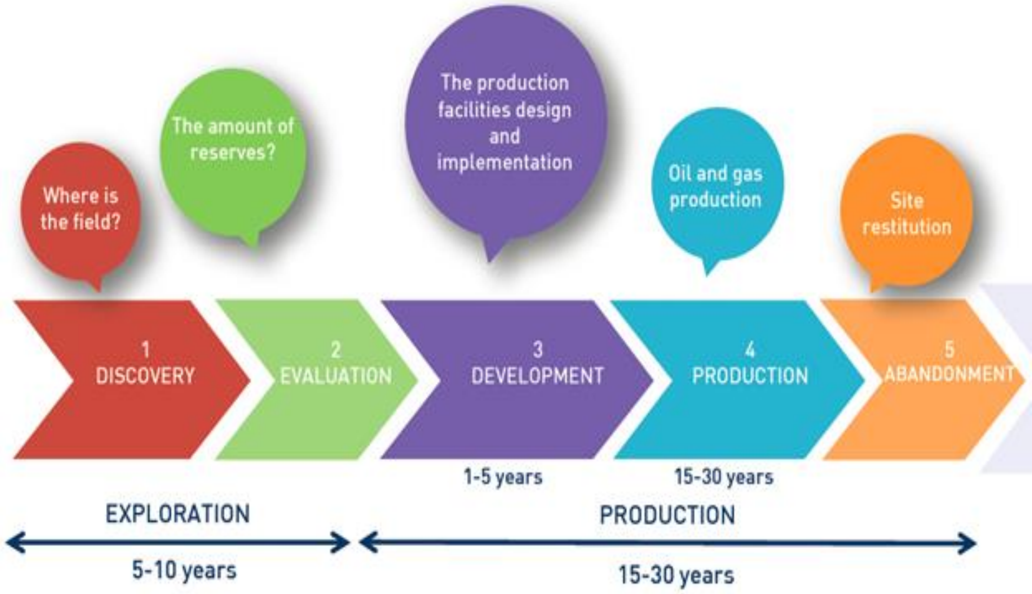

Fig 2.1: Integration of Field Development Plan

2.2. Literature Review:

The planning of adequate recovery strategies for petroleum reservoirs has a great economic importance in oil industry and several studies have been performed in order to develop efficient procedures for this optimization problem.

Arps et *alli* [1967] participated of a study, organized by the *American Petroleum Institute*, with the objective of developing equations for the assessment of recovery factors for petroleum fields. The well spacing was one of the most studied parameters. However, from the analysis of 312 different reservoirs they concluded that there was no mathematical relationship between recovery factor and well spacing. The purpose of their work was to develop a methodology for field recovery planning through an analysis preceding the stage involving simulation, but it was not possible to obtain satisfactory results. (Mezzomo, 8th October, 2000)

Davis and Shepler [1969] verified that the well spacing initially used to develop a petroleum field, in general, isn't the most adequate spacing. The ideal well spacing depends on characteristics of each reservoir. Thus beig necessary to take into account the uncertainties related to the geological model and the dynamic behavior of the economic and technological scenario (Mezzomo, 8th October, 2000).

Reservoir simulation became an important tool for the development and management of petroleum reservoirs. Accurate reservoir performance predictions can be obtained through numerical simulation using a previously built geological model that comprises several parameters obtained through reservoir characterization. The simulation model is the most important tool for the evaluation of an objective-function that represents the global objective of the project (Mezzomo, 8th October, 2000).

Using numerical simulation, Nystad [1985], Damsleth *et alli* [1992], Beckner and Song [1995] among others authors developed methods for optimization problems related to the development and management of petroleum reservoirs. These works presented the following common features: They required some previously established simplifications and the number of simulations runs performed and evaluated parameters was small. The objectives of such works were the evaluation of the most important parameters in the assessment of the objective-function and their optimization (Beckner, Oct. 5-8, 1997).

Pedroso and Schiozer [2000] developed a methodology for the optimization of the number of producer wells and their location in a reservoir in development stage (Pedroso JR., 2000).

Mezzomo and Schiozer [2000] developed a procedure for primary recovery strategies optimization, comprising only vertical producer wells. In order to expand the scope of that procedure, compassing a greater number of reservoirs, this work developed a more flexible and adaptable methodology, including water injection with producer and injector vertical and horizontal wells (Mezzomo, 8th October, 2000).

Nogueira and Schiozer (2009) proposed a methodology to optimize the number and placement of wells in a field through two optimization stages. The procedure started by creating reservoir sub-regions equal to the maximum number of wells. Then, a search for the optimum location of a single well was performed in each sector. The second stage aimed to optimize well quantity through sequential exclusion of wells obtained from the first stage. After a new optimum number of wells is reached, the first stage is performed again until no improvement in the objective function is observed. This strategy showed efficiency when tested on a heterogeneous synthetic model with light oil. They optimized both vertical and horizontal wells in separate studies. They also concluded that the proposed modularization of the problem speeds up the optimization process for their problem of consideration (Schiozer, 2009)

Field development plan consist several steps there is many Literature Review for according to this step:

2.2.1 Improving Oil Recovery by Infill Well Drilling

Infill well drilling is the technique of increasing oil recovery by increasing number of wells in an area to get access into the un-swept areas of a reservoir. In heterogeneous reservoirs, modification to well patterns and adding number of wells improves oil recovery significantly. However, infill wells can be more expensive than fluid injection processes (Alusta, et al., 2011). To determine the un-swept areas for the infill well locations, prediction simulation of the base case is run so as to identify the remaining oil saturated areas at the end of simulation period. Required number of infill wells is determined based on the identified oil saturation locations (Thang, et al., 2010).

2.2.2 Estimation of Infill Well Performance

According to (Gao & McVay, 2004) infill well performance is estimated by using reservoir simulation model where forecast is made on the base case and then a new infill well is placed in the un-swept areas of the reservoir. Forecast of the new infill well is done and compared with the base case results to get the additional oil production from the new well.

2.2.3 Types of Wells and their Performance

Production or injection wells can be vertical, horizontal or deviated wells. Due to technological and economic constraints, vertical wells were preferred. Nevertheless, increase in drilling technology and the need to reduce cost of drilling many vertical wells to hit the reservoir, horizontal wells and deviated wells are now becoming popular in the petroleum industry (Wagenhofer & Hatzignatiou, 1996)

2.2.4 Well Placement Optimization

Since well performance depends on well location, well placement should be given special attention in analysing reservoir development plans. This is due to the fact that, wrong decision on well location results into wastage of money and recovery (Ermolaev & Kuvichko, 2013). Optimum well placement can be done by using simulators since they are capable of analysing complex interactions of parameters affecting reservoir development decisions like reservoir and fluid properties, well surface networks and economic factors (Badru & Kabir, 2003).

Optimal well placement determines the oil recovery factor for a given oil production technique. Economically, well spacing should be small to get access to the large area of the reservoir to attain highest recovery factors and net present value (NPV) (Abeeb & Carlos, 2014). However, for matured fields, well spacing should be managed to avoid collision with the existing wells. To avoid well collisions, an ‘Oriented Separation Factor’’ greater than 1.5 is required (Okafor & Moore, 2009).

CHAPTER 3

RESEARCH METHODOLOGY

Chapter 3

Research Methodology

3.1. Research Methodology:

(Mezzomo, 8th October, 2000) use a methodology in a field development plan using reservoir simulation the same methodology will be used to develop Haraz oil field.

In order to develop a methodology to the optimization problem of recovery strategy planning for different reservoirs, it is necessary to evaluate several parameters mainly related to the geological model and operational conditions.

3.2. Methodology Description:

Depending on the objectives defined for the project and the time available to the decision making process, some of these steps can be simplified or discarded:

3.2.1. Recovery Strategy Assessment:

In this first step, a study based on field data is performed for the assessment of relevant geological and physical reservoir parameter, that will be used for the definition of basic important parameters related to recovery strategy like well type (producer or injector) and geometry (vertical or horizontal).

3.2.2. Production Patterns Evaluation:

The second step comprises an evaluation of several production patterns proposed according to the recovery method and the well type and geometry established in the previous step. The production patterns are defined based on field characteristics the technical resources available.

During this stage, simulation runs are performed to access the recovery potential for each pattern proposed for the field. At this stage all wells comprised by the defined patterns must be opened simultaneously at the initial time of the simulation runs in order to obtain a correct evaluation of their production/injection performance. The best patterns are retained and submitted to the optimization procedure in the next step.

The software package had been used in this step is ECLIPSE dynamic numerical reservoir simulator. ECLIPSE is an oil and gas dynamic reservoir simulator originally developed by Exploration Consultants Ltd. (ECL) and currently owned and marketed by Schlumberger. The simulator provides the industry with the most complete and reliable set of numerical solutions for accurate prediction of dynamic behavior for all reservoir types and available development alternatives (Schlumberger, 2011). ECLIPSE allows modeling of flow and fluid interactions in the reservoir as well as in the production string provided VLP tables are entered into the model.

ECLIPSE used to estimate and calculate a lot of variables for particular grid or whole model such as :

X variables are pressure P and two saturations for a three phase black oil study. The water saturation *Sw* and either *Sg* , *Rs* ,*Rv*, or are chosen to complete the set. For a 3 component black oil system (oil, water, gas), the residual R and the solution, X, are 3 component vectors in each grid block. By default, the solution procedure is fully implicit;

$$R = \begin{bmatrix} R_o \\ R_w \\ R_g \end{bmatrix}$$ [EQ 3.1]

and the Jacobian, $J = \frac{dR}{dX}$, takes the form

$$\frac{dR_i}{dX_j} = \begin{bmatrix} \frac{dR_o}{dP_o} & \frac{dR_o}{dS_w} & \frac{dR_o}{dS_g} \\ \frac{dR_w}{dP_o} & \frac{dR_w}{dS_w} & \frac{dR_w}{dS_g} \\ \frac{dR_g}{dP_o} & \frac{dR_g}{dS_w} & \frac{dR_g}{dS_g} \end{bmatrix}_{ij}$$ [EQ 3.2]

The mass change during the time step, , is then proportional to

$$dM = M_{t+dt} - M_t$$ [EQ 3.3]

with
$$M = \mathrm{PV} \begin{bmatrix} \frac{S_o}{B_o} + \frac{R_v S_g}{B_g} \\ \frac{S_w}{B_w} \\ \frac{S_g}{B_g} + \frac{R_s S_o}{B_o} \end{bmatrix}$$ [EQ 3. 4]

where

PV is the pore volume

Bo is the oil formation volume factor

Bw is the water formation volume factor

Bg is the gas formation volume factor

Rs is the solution gas/oil ratio

Rv is the vapor oil/gas ratio.

When Sg is zero the solution variable becomes Rs (undersaturated oil) and when So is zero the solution variable becomes Rv (undersaturated gas). Terms in the Jacobian are adjusted in accordance with the change of variable. No approximations are made in evaluating the Jacobian in ECLIPSE 2011. Great care is taken to compute all derivatives to ensure quadratic convergence of Newton's method.

Material balance

If the residuals are summed over all cells in the reservoir, the flow terms cancel, because the flow out of one cell is always equal and opposite in sign to the corresponding flow into its neighboring cell. Thus the sum of the residuals for each phase or component corresponds to the net mass accumulation within the reservoir less the net influx through wells. This is the material balance error. For a three-component system we have

$$\sum_i (R_o)_i = \sum_i \left(\frac{dM_o}{dt}\right)_i + \sum_i (Q_o)_i$$

$$\sum_i (R_w)_i = \sum_i \left(\frac{dM_w}{dt}\right)_i + \sum_i (Q_w)_i$$

$$\sum_i (R_g)_i = \sum_i \left(\frac{dM_g}{dt}\right)_i + \sum_i (Q_g)_i \qquad \text{[EQ 3.5]}$$

where

Σi refers to the sum over all reservoir cells and

(*Ro*)*i* is the oil residual in cell i etc.

In ECLIPSE 100 the material balance errors are converted to meaningful, problem independent, numbers by scaling to equivalent field saturation values:

$$\mathrm{MB}_o = \overline{B_o} dt \left\{ \left(\sum_i (R_o)_i \right) \Big/ \left(\sum_i (\mathrm{PV})_i \right) \right\}$$

$$\mathrm{MB}_w = \overline{B_w} dt \left\{ \left(\sum_i (R_w)_i \right) \Big/ \left(\sum_i (\mathrm{PV})_i \right) \right\}$$

$$\mathrm{MB}_g = \overline{B_g} dt \left\{ \left(\sum_i (R_g)_i \right) \Big/ \left(\sum_i (\mathrm{PV})_i \right) \right\}$$

[EQ 3.6]

where is *Bo* the average oil formation factor etc.

The numerical values of MBo, MBw and MBg are computed after each Newton iteration and the material balance errors are considered to be sufficiently small if they are all less than 1.0E-7 .

MB values are printed out in the summary of each Newton iteration. Conventional material balance accounts in conventional units can also be printed at each report time.

The flow rate into cell i from a neighboring cell n, , *Fni* is

$$F_{ni} = T_{ni} \begin{bmatrix} \dfrac{k_{ro}}{B_o \mu_o} & 0 & \dfrac{R_v k_{rg}}{B_g \mu_g} \\ 0 & \dfrac{k_{rw}}{B_w \mu_w} & 0 \\ \dfrac{R_s k_{ro}}{B_o \mu_o} & 0 & \dfrac{k_{rg}}{B_g \mu_g} \end{bmatrix}_u \times \begin{bmatrix} dP_{oni} \\ dP_{wni} \\ dP_{gni} \end{bmatrix}$$

[EQ 3.7]

where

$$dP_{oni} = P_{on} - P_{oi} - \rho_{oni} G (D_n - D_i)$$

$$dP_{wni} = P_{wn} - P_{wi} - \rho_{wni} G (D_n - D_i)$$

$$= P_{on} - P_{oi} - \rho_{wni} G (D_n - D_i) - P_{cown} + P_{cowi}$$

$$dP_{gni} = P_{gn} - P_{gi} - \rho_{gni} G (D_n - D_i)$$

$$= P_{on} - P_{oi} - \rho_{gni} G (D_n - D_i) + P_{cogn} - P_{cogi}$$

Tni is the transmissibility between cells n and i,

Kr is the relative permeability

(*kro* is the relative permeability of oil etc.),

μ is the viscosity (μ*w* is the viscosity of water etc.), *dP* is the potential difference

(*dPgni* is the gas potential difference between cells n and i),

is the fluid density

(ρ*oni* is the density of oil at the interface between cells n and i),

G is the acceleration due to gravity

(0.0000981 in metric units, 0.00694 in field units and 0.000968 in lab units),

D is the cell center depth.

3.2.3. Estimation of the Approximate Number of Wells:

As stated before, the patterns retained in the previous stage are then submitted to an optimization procedure.

The optimization procedure will provide the ideal number of wells for these selected recovery patterns and it must take into account the relevant reservoir parameters, the number of required simulation runs and the desired quality for the results.

As in the previous stage, throughout this optimization procedure all wells must start to produce simultaneously in order to obtain a correct evaluation of the potential of each well and an accurate value for their objective-function. This optimization procedure must be adapted to attend the operational restrictions imposed to the project.

ECLIPSE dynamic numerical reservoir simulator is also used in this step.

3.3. Production Scheme:

After the simulations run finished and the estimation of the total wells number concluded a production scheme will be evaluated to assist the best production scenario for the field. Production rate from oil fields is reduced due to various parameters with time. So it is necessary to use some methods to compensate the reduction of production rate.

Artificial lift refers to use of artificial means to increase the flow of liquids, such as crude oil or water, from a production well and is the most suitable way to increase production rate. It is achieved by the reduction of downhole pressure. Artificial lift includes five methods and it is very important to select the best method, considering the field conditions.

Based on the All Methods Comparison Table 3.2 and according to the basic data for the field the best method for the initial production will be selected.

Table 3.1: Artificial lift selection criteria

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Production rate	Less than 1000 B/D	The full range of production rates can be handled. An AOF production rate cannot be achieved with gas lift because as much drawdown as for an ESP cannot be achieved.	The full range of production rates can be handled. When unconstrained an ESP can be designed to produce the full well potential to the surface (AOF), thus achieving higher flow rates than with gas lift.	Rate is dependent on setting depth, the deeper the setting depth the lesser rates. Generally PCP is suitable for low rate wells.	Rate is dependent on setting depth. Feasible for low rates (<100 B/D) and low GOR (<250). Typically are used with 1.5-in nominal tubing.	The full range of production rates can be handled. Less than 50 B/D up to 15000 B/D with adequate flowing bottom hole pressure, tubular size, and horsepower. Guideline as below: Piston Hydraulic lift: 50 to 4000 BFPD. Jet Hydraulic lift: >15,000 BFPD of total fluid. AOF production rate cannot be achieved.
	1000 to 10,000 B/D			Up to 4000 b/d at 3000 feet	Up to 2000 b/d at 4000 feet. Restricted to shallow depths using large plungers. In general, due to efficiency, rod pump is not recommended as a lift mechanism of choice on high producing wells.	
	Greater than 10,000 B/D			Not available.	Not available.	
Well depth	Less than 2500 ft	Not restricted by well depth. The benefit of gas lift will be larger with greater depth, as there is more fluid to 'lighten' to enable increased well productivity.	Not restricted by well depth. The benefit of ESP will be larger with greater depth as there is more fluid head to overcome to enable increased well productivity.	Pump must be landed below dynamic fluid level. Optimal to have intake below perforations, which will allow natural gas separation and vent to annulus. Depth is tied to dynamic fluid level.	Pump must be landed below dynamic fluid level. Optimal to have intake below perforations, which will allow natural gas separation and vent to annulus. Depth is tied to dynamic fluid level.	Not restricted by well depth. However, limited by power- fluid pressure or horsepower as depth increases. A practical depth of 20,000 ft is *possible*. Guideline as below: Piston Hydraulic lift: up to 17,000 ft TVD. Jet Hydraulic lift: up to 20,000 ft TVD.
	22500 to 7500 ft					
	Greater than 7500 ft			Maximum 8000 feet.	Maximum 14,000 ft TVD. Due to excessive polished rod load, depth is limited. Rods or structure may limit rate at depth. H_2S limits depth at which a large volume pump can be set. Effectively, about 500 B/D at 7,500 ft TVD and 150 B/D at 14,000 ft TVD.	
Oil Gravity		No limitations. Preferable > 15 °API.	No limitat ions. Preferable > 12 °API.	Not used for oil with gravity greater than 40 degrees API due to high aromatic content (C6 to C9 should be under 20%) that will deteriorate elastomers. Preferable < 30 °API.	> 8 °API.	> 8 to 45 °API.
Fluid viscosity	Less than 100 cp gas free viscosity at reservoir temperature	Recommended	Recommended	Recommended	Recommended	Recommended
	100 to 500 cp gas free viscosity at reservoir temperature	Recommended	Efficiency of ESP will be reduced.	Recommended. Pump efficiency will increase as viscosity increases.	Good for < 200 cp fluids and low rate. Rod fall problem for high rates. Higher rates may require diluents to lower viscosity.	Recommended
	Greater than 500 cp gas free viscosity at reservoir temperature	Has been used with success up to 1000 cp but little case history for very high viscosity.	Not recommended. Pump efficiency is reduced, motors cool poorly in the high viscous fluid, more power is required to pump high viscous fluid and emulsions form. A mixture of ESP and progressive cavity pump technology is a potential alternative.	Recommended for all high viscosity crude. Up to 80,000 cp.	Not recommended, as pump efficiency will reduce.	Mixture of power and producing fluid is not a major issue in Jet pump. The system is capable of handling high-viscosity fluid. Production with up to 800 cp possible. Oil power fluid in the range of >24°API and <50 cp could be used. If waterpower fluid is used, it will reduce friction losses.

3.4. Network Design:

Pipesim will be used to develop a simple network connection for the field wells. The software package had been used in this step PIPESIM steady-state production network simulator. PIPESIM is also owned and maintained by Schlumberger, it is a steady-state flow simulator, which can be used to perform well modeling, artificial lift design, nodal analysis, pipeline, and process equipment simulation (Schlumberger, 2017). In the current analysis, PIPESIM is used to model the fluid flow both from the bottom of the tubing up to separator entry.
A small study, which compares the fluid modeling in the production string with ECLIPSE (using VLP tables) and PIPESIM, has also been performed.

PIPESIM will be used to develop many parameter and correlation for the wells and the flow of fluid such as :

Productivity index (PI)

PI is one of a number of methods that can be used to specify the Inflow performance relationship (IPR) for a completion. It can be regarded as a simplified version of the Pseudo-steady state or Transient IPRs.

Liquid PI:

The (straight line) productivity index relationship for liquid reservoirs is perhaps the simplest and most widely used IPR equation. It states that rate is directly proportional to pressure drawdown between the bottom hole and the reservoir.

$$QL = JL\,.(Pws - Pwf) \qquad \text{[EQ 3.8]}$$

Where:

QL is the stock-tank oil rate

Pws is the well static (or reservoir) pressure

Pwf is the well flowing (or bottom hole) pressure

JL is the liquid productivity index

Single phase flow correlations

See also: SPHASE Single Phase Flow Options

The steady-state pressure gradient in single phase sections is given by the equation:

$$\frac{dP}{dL} = (\frac{dP}{dL})elev + (\frac{dP}{dL})fric + (\frac{dP}{dL})acc \qquad \text{[Eq. 3.9]}$$

where elevation, friction and acceleration components of the pressure drop are:

$$\left(\frac{dP}{dL}\right) elev = -\rho g \sin\theta \qquad \text{[Eq. 3.10]}$$

$$\left(\frac{dP}{dL}\right) fric = -\frac{f\rho v^2}{2D} \qquad \text{[Eq. 3.11]}$$

$$\left(\frac{dP}{dL}\right) acc = -\rho v \frac{dv}{dL} \qquad \text{[Eq. 3.12]}$$

Where

f	is the friction factor	$dimensionless$
ρ	is the fluid density	lb/ft^3
v	is the fluid velocity	ft/s
g	is the gravitational acceleration	ft/s^2
θ	is the angle of the pipe to the horizontal	$degrees$
D	is the pipe diameter	ft
L	is the length of the pipe	ft

There are a number of different ways of calculating the friction factor, which usually depends on the Reynolds number:

$$Re = \frac{\rho v D}{\mu} \qquad \text{[Eq. 3.13]}$$

Dead oil viscosity

The correlations available for calculating dead oil viscosity are:

Beggs and Robinson

Dead oil viscosity is calculated as follows:

$$\mu_{od} = 10^{x} - 1$$

Where $x = yT^{-1.163}$ And $y = 10^{z}$ And

$$z = 3.0324 - 0.02023 \cdot g_{API}$$

Data used to develop correlation

The Beggs-Robinson dead oil viscosity correlation was developed using temperature data above 70F.

The Beggs-Robinson correlation, when applied to lower temperatures tends to overpredict viscosity and may display asymptotic behavior which worsens with decreasing API gravity and temperature. To address this, extrapolation to temperatures lower than 70F are performed by tuning the Users Data equation using Beggs and Robinson calculations at 70F and 80F.

However, as a best practice user data should be used to calibrate dead oil viscosity, especially for low API oils are modeled at temperatures lower than 70F.

CHAPTER 4
RESULTS & DISCUSSION

Chapter
Results & Discussion

4.1. Initial Fluid In-place:

After all reservoir properties are available, initialization was conducted by using black oil simulator (eclipse 2011) and resulting initial fluid in place of “Haraz” Reservoir as shown in Table 4.1

Table 4.1: Initial Oil in Place

Region	**Oil(MMSTB)**
Region 1	4.35
Region 2	1.17
Region 3	2.99
Region 4	8.06
Region 5	2.56
Region 6	1.62
Total	20.76

4.2. Development Plan Selection:

To find the best scenario of development of “Haraz” field, couples black-oil reservoir simulation cases have been run in order to get the best recovery factor. In this selection phase, to simplify the development selection, drilling schedule is ignored and wells are assumed to be initially produced at the same time. The trial cases are based on the following strategy of development.

The model was already built and calibrated with the production test from two drilled wells; to focus on the topic on hand these results will be used as the basic of this study.

4.2.1. Model History Matching:

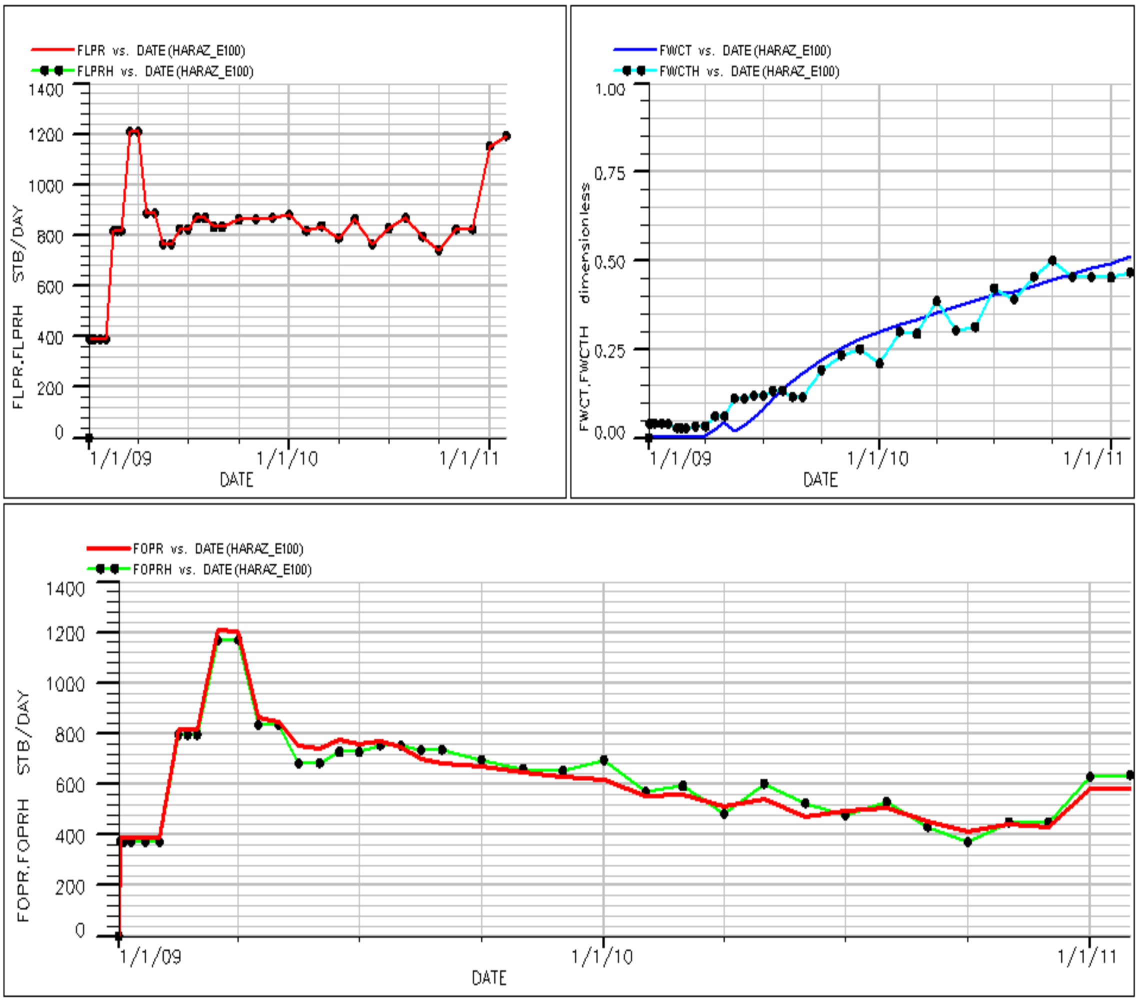

Fig 4.1: Model History Matching

4.2.2. Before the Design

There are two wells already drilled in the field and have been tested, there results will be used as a base for the reservoir engineering and the selection of the production scheme.

Well-1 was drilled to the TD of 3050 on October 5th, 2004. On October 26th, 2004, commenced testing operation. Two zones were tested: Nayil-D tested 100% formation water while Nayil-C2(1473.5-1476.0 mKB), Lower Nayil-C1(1465.0-1467.0mKB), and Lower Nayil-A(1394.0-1401.0mKB) was tested 100% oil, oil gravity 26.0API. The well was suspended on March 4th, 2003. Well-1 is shown in next figure .

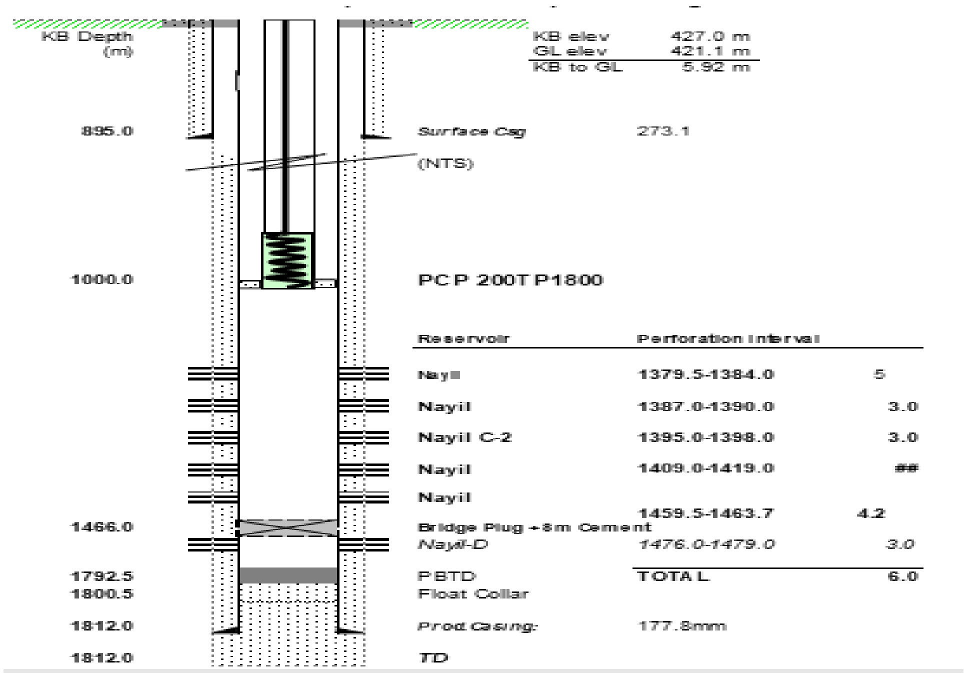

Fig 4.2: Well-1

Well-2 was drilled to the TD of 3050 on October 5th, 2004. On October 26th, 2004, commenced testing operation. Two zones were tested: Nayil-D tested 100% formation water while Nayil-C2(1473.5-1476.0 mKB), Lower Nayil-C1(1465.0-1467.0mKB), and Lower Nayil-A(1394.0-1401.0mKB) was tested 100% oil, oil gravity 26.0API. The well was suspended on March 4th, 2003. Well-2 is shown in figure below:

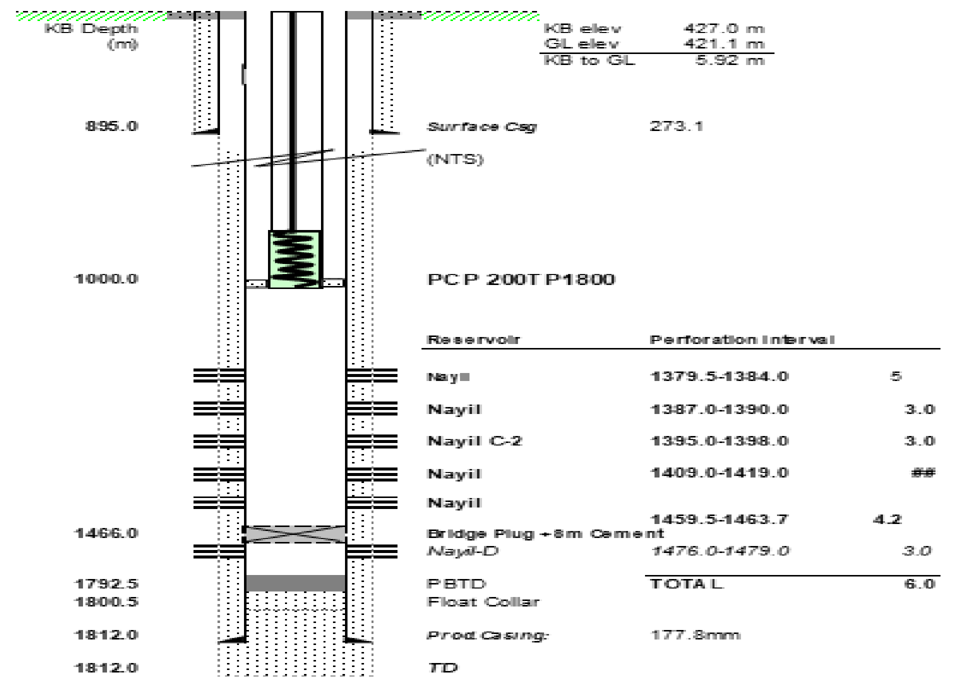

Fig 4.3: Well-2

4.2.3 Production Test Results:

The production test results for the both wells are shown in the Table 4.2 and Table 4.2 below

Table 4.2: Production Test Results For Well-1

WELL TEST ANALYSIS RESULTS

HARAZ -1 (18/2/2003 - 4/3/2003)

Test No.	Reservoir	Perf. Interval m-KB	Choke 1/64 "	Q STB/D	WC %	FWHP psig	GOR scf/STB	S.G. °API	P. Pt. ° F	Pwf psia	Tr °F	Pi psia	Visc. cP	k mD	Ri m	S -	PI STB/D/psi	Dp %	25%Dp STB/D	ϕ %	h m
1	Zarqa	2094.0 - 2096.0	96	Swabbed 223.1 bbls of formation water						-	-	-	-	-	-	-	-	-	-	-	-
2	L.Nayil- C2	1473.5 - 1476.0	96	541.9	0	0	0	26.62	96.8	1333.9	173	1758.81	30 / 60 C	2040	N/A	-4.58	1.3	24.2	561	27	2.5
3	L. Nayil-C1	1465.0 - 1467.0	96	388.4	0	0	0	26.23	82.4	1099.2	172	1721.24	32 / 60 C	1820	N/A	-1.17	0.6	36.1	269	25	2.5
4	L. Nayil-A	1394.0 - 1401.0	96	525.6	0	0	0	26.04	41<	1255.7	168	1615.5	7.4 / 64 C	848	N/A	-2.67	1.5	22.3	590	21	6
				1455.9													3.4				

Table 4.3: Production Test Results for Well-2

WELL TEST ANALYSIS RESULTS

4586.614173 0.03499

Haraz -2 (27/10/2004 - 2/11/2004)

Test No.	Reservoir	Perf. Interval m-KB	Choke 1/64 "	Qo STB/D	WC %	FWHP psig	Gas Rate MMSCF/D	Gas Gravity	GOR scf/STB	S.G. °API	P. Pt. ° F	Pwf psia	Tr °F	Pi psia	Visc. cP	k mD	Ri m	S -	PI STB/D/ps	Dp %	25%Dp STB/D	ϕ %	h m
1	Nayil -C2	1476.0 -1479.0	96	0	100	0	Swabbed a total of 253.0 bbl of new formation water (wet zone).			-	-	0	165	-	-	-	-	-	-	-	-	20	3
3	Nayil -A	1395.0 - 1398.0	96	900	0	0	Swabbed a total of 305.0 bbl of clean oil (average rate per day of oil from influx calcualtion is 900 bbl/d).			22	<41	0	160.5	1650	6.67@Res. Tem.	750	Fault	0.5	0.5	100.0	225	24	3

4.2.4. Reservoir Simulation Model:

Standard case with two drilled wills will be used as a basic scenario for the further development and infill wells, the perforation specification will be chosen from the interpreted well log analysis.

The simulation model used in this study was constructed by Greater Nile Petroleum Operation Company (GNPOC).

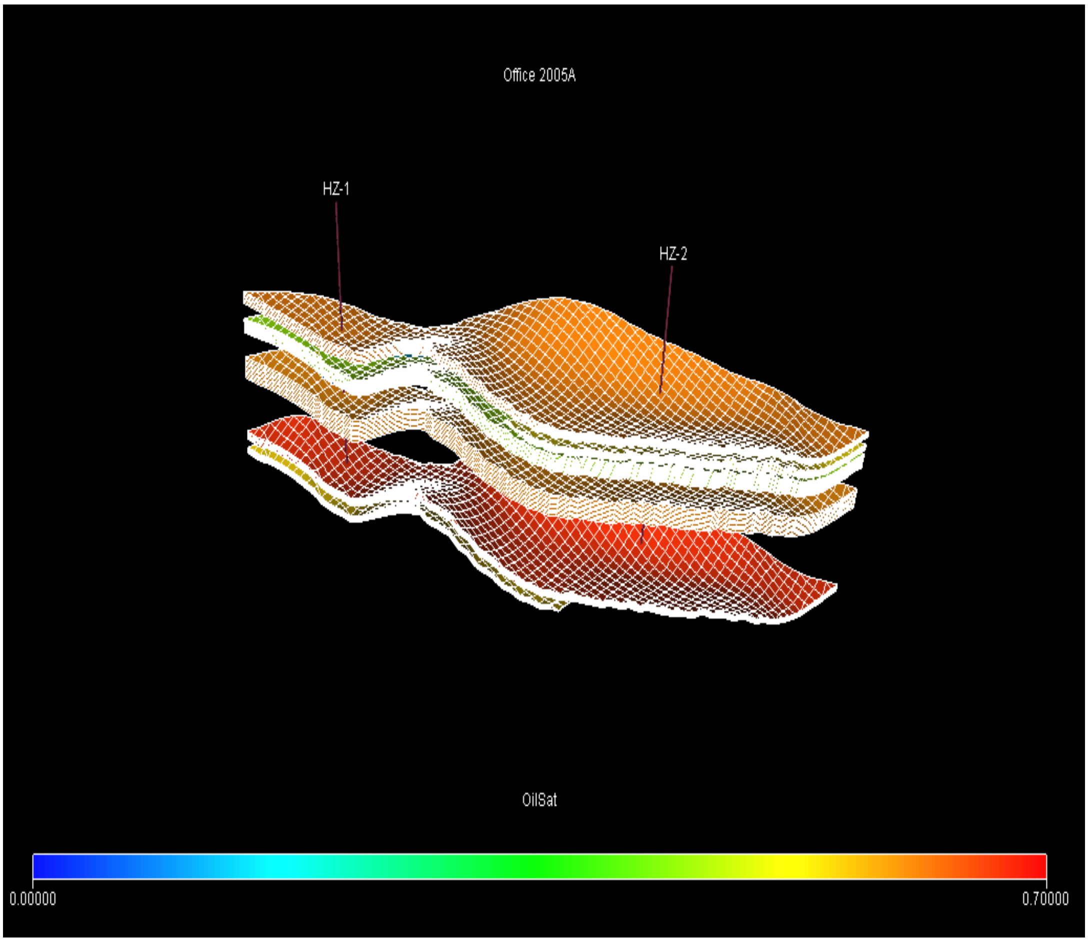

Fig 4.4: Reservoir Simulation Model

- Cells Number: 36×63×70=158760 cells
- The fine model was used.
- Vertical direction: 0 .5~1.5m (except shale)

4.2.5. Case of Vertical Wells:

A first development cases that has been run is cases of the simplest development plan which are developing the field by implemented several vertical wells (2, 4, 6, 8) to the base case (2vertical well),

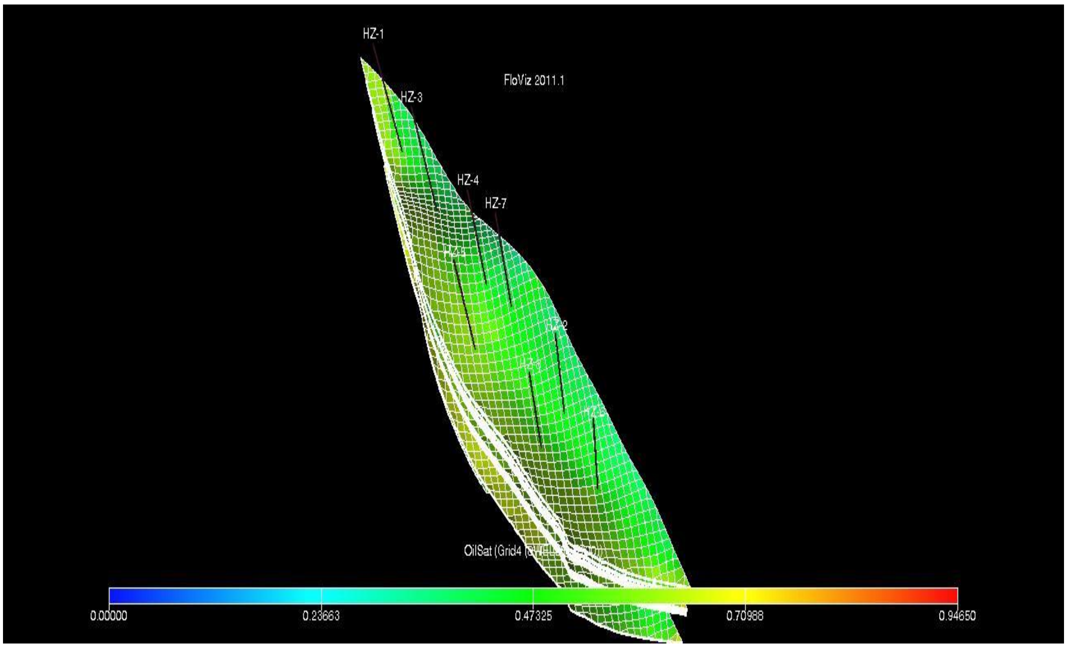

Fig 4.5: Vertical Well Position Selection

The vertical well positions have been chosen based on the best structural position and also considering the drainage area of each wells in such that each well doesn't interference with another wells drainage. To find the best location and also the optimum number of well, a package of reservoir simulation cases has been run by combining number of well from 3 well to maximum possible well number. The most optimum recovery factor will be selected as the best location and also the most optimum well number of vertical well cases.

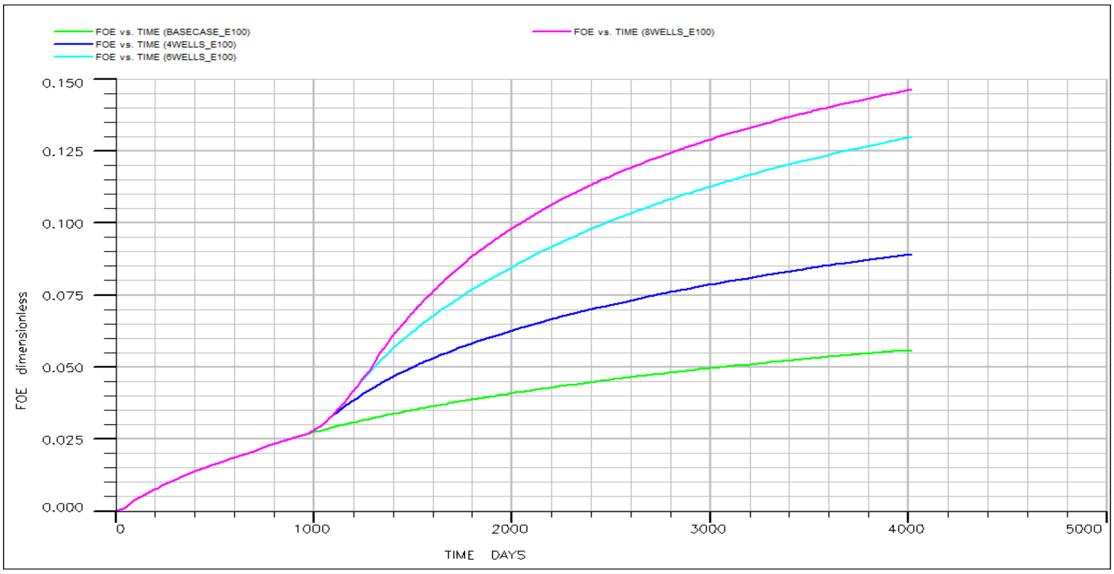

Fig 4.6: Recovery Factor for Vertical Wells Cases

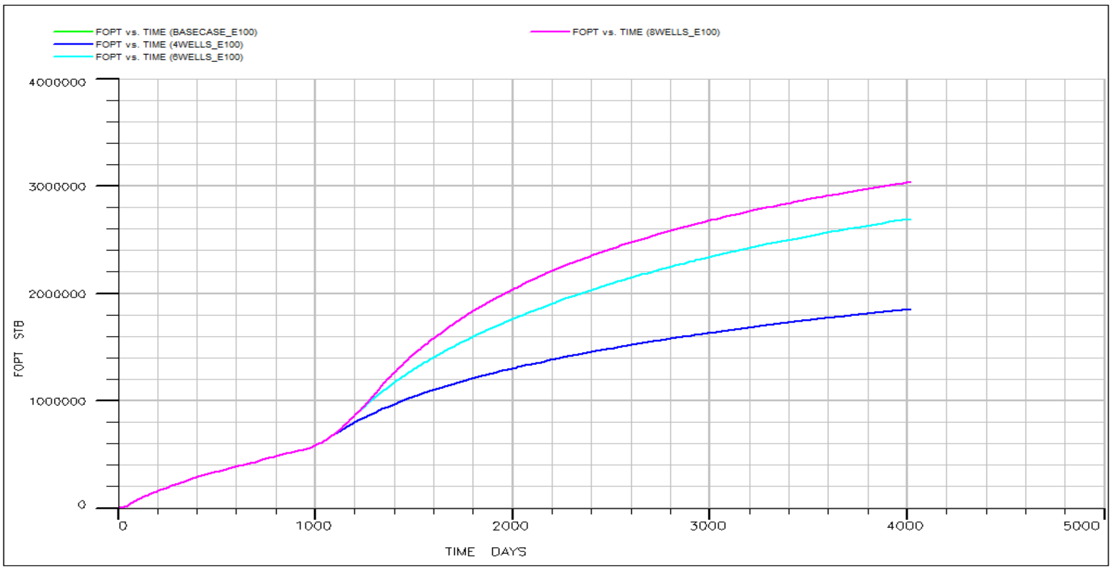

Fig 4.7 Cumulative Oil Production of Vertical Wells Cases

Based on the chart, the optimum number of vertical well is 8 wells (2wells base case) and the optimum cumulative oil production is 3.05 MMBO (recovery factor = 14.6%).

4.2.6. Case of Horizontal Well:

There is l possibility of increasing recovery factor by applying horizontal wells in the development strategy. In the other hand, horizontal well is also important in reducing the well number. The idea of positioning horizontal wells is to cover area that is also covered by vertical wells in previous development strategy. As shown in Figure 3 horizontal wells are enough to drain most of the reservoir areas.

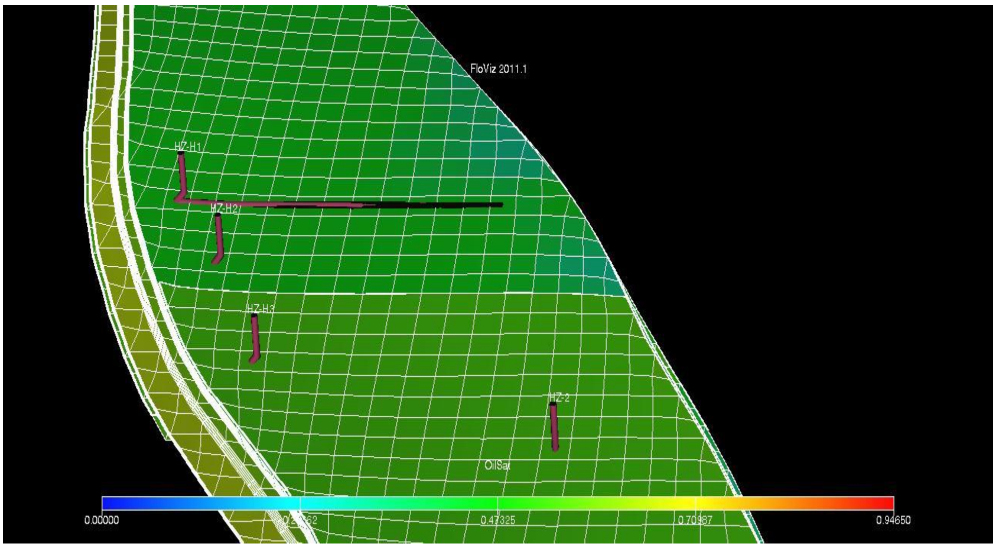

Fig 4.8: Horizontal Wells Positions

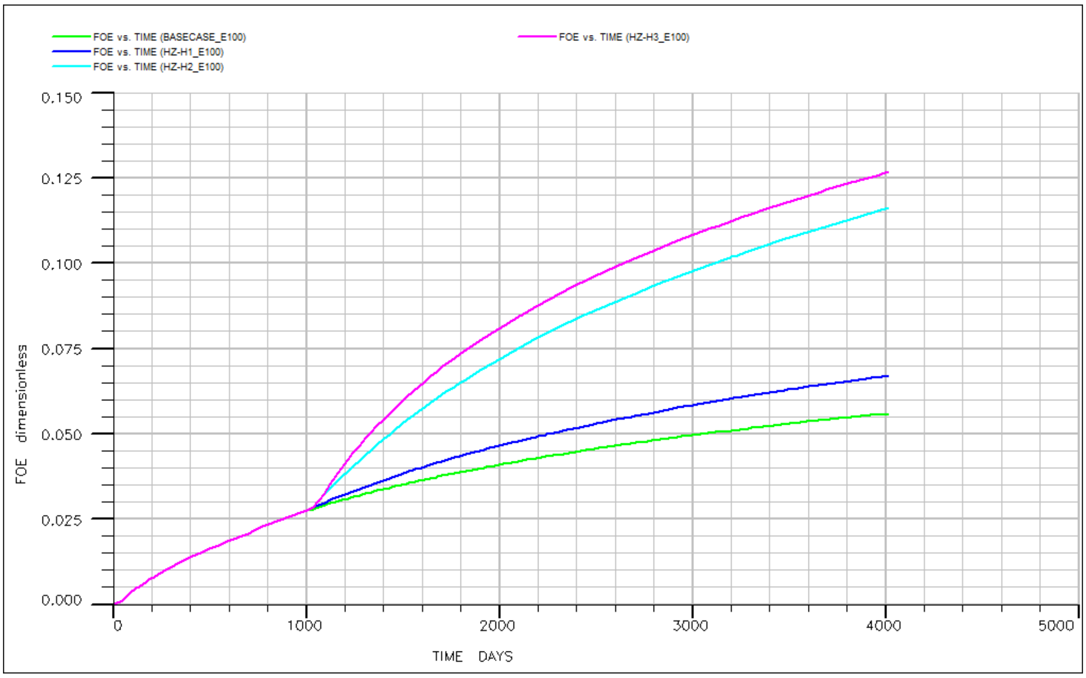

Fig 4.9: Recovery Factor for Horizontal Wells

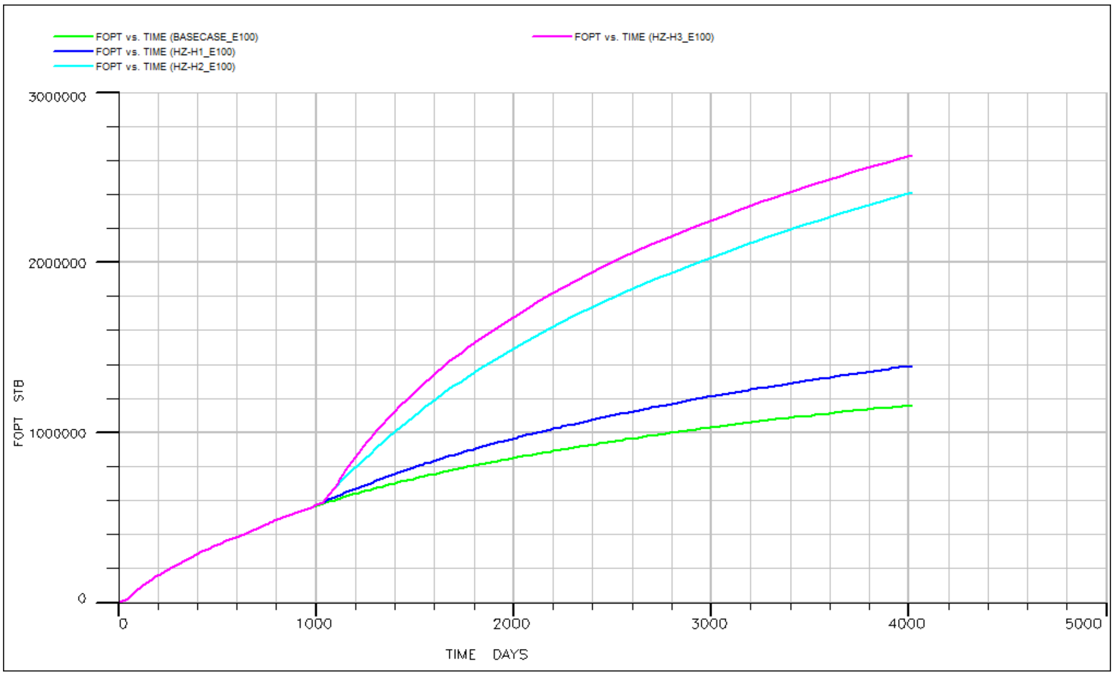

Fig 4.10: Cumulative Oil Production of Horizontal Wells

Based on the chart, there are 2 vertical well (base case) and 3 horizontal well and the cumulative oil production is 2.63 MMBO (recovery factor = 12.7%).

4.3. Selected Development Plan:

The result of above development plan selection is summarized in Table 4.5. Reviewing the table, it is clearly that from the number of well and also recovery factor point of view, the recommended strategy to be proposed as final development plan would be vertical wells. This development plan is selected since it has the highest recovery factor, and also the suitable number of well required.

Table 4.5: Development Plan Selection Summary

Development Plan	Well Requirement	Cum. Oil (MMBO)	RF (%)
Vertical Wells	8 Vertical Wells	3.05	14.6
Vertical Wells With Horizontal Wells	2 Vertical Wells , 3 Horizontal Wells	2.63	12.7

Common completion type of casing and perforated would be recommended to be applied in these vertical wells. This type of completion will allows well intervention in case of well problems occur during production periods. Perforation Interval shown in Table 4.6

Table 4.6: Well Perforation Interval

Name	Top MD (ft)	Bottom MD (ft)
HZ-01	4479	4730
HZ-02	4442	4690
HZ-03	4502	4764
HZ-04	4436	4706
HZ-05	4440	4680
HZ-06	4470	4725
HZ-07	4481	4690
HZ-08	4433	4661

4.4. Production Network System:

The second important step in building an appropriate development plan of a field is constructing production network system to be connected to the proposed wells that has been discussed. The network system will allow producer to interact with production facilities to make a stable system in producing fluid.

4.4.1. Pipesim Simplified Model:

To get the optimum size of each surface facility unit, the network system of "Haraz" Field is simplified in PIPESIM model to simulate the flow correlation between all units (wells, pipeline, and other connected units) by combining all flow parameters including pressure, temperature, and flow rate. By simulating the network, we can optimize the each facility unit to get the best operating condition which at the end will increase the oil production.

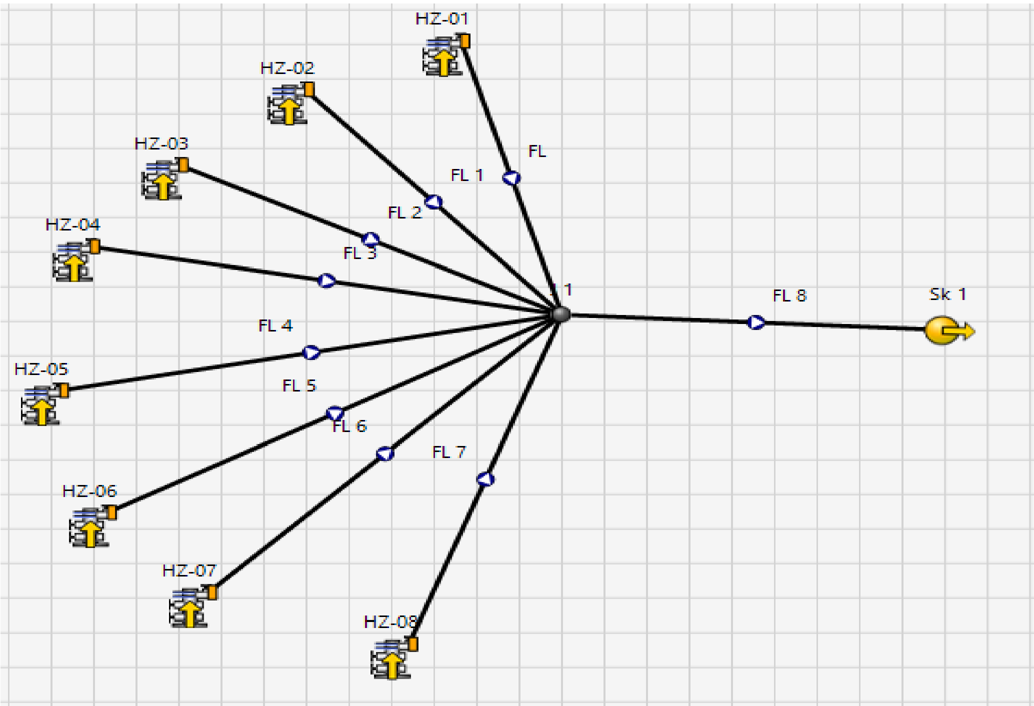

Figure 4.11: Production Network System (PIPESIM)

4.4.2. Network system stimulation:

- **Fluid Properties**

Fluid properties used for PIPESIM simulation are based on the Eclipse simulation result that has been run and detail discussed. To get a rough estimation of the future actual condition, initial fluid condition will be used in this PIPESIM simulation.

Based on eclipse simulation results, initial fluid properties of all wells are equal as shown in Table 4.7

Table 4.7: Fluid Properties

Fluid Properties	**Value**
Water Cut (%)	0
GOR (scf/stb)	0
Oil gravity (deg API)	26

- **Production String Design**

<u>Typical well configuration:</u>

The typical well completion of proposed wells is shown in Figure 4.12 It is recommended to complete the well by using common casing-cemented and perforation. It is fast and less complicated option for vertical well.

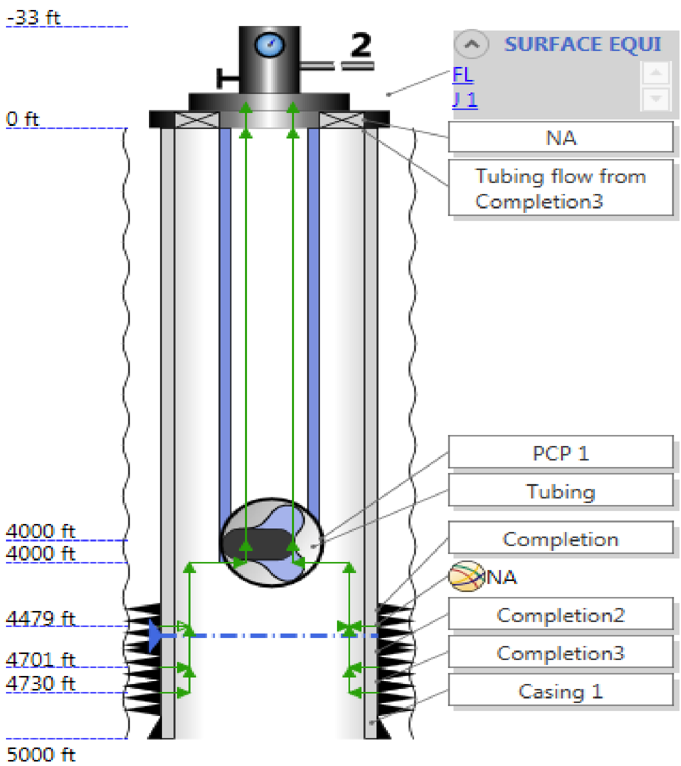

Fig 4.12: Typical Well Configuration

<u>Optimization Procedure</u>:

There are few procedures that are necessary to be done to evaluate our well configuration on affecting the productivity.

1. Setting up the initial wellbore configuration:

The Figure shows the Pipesim dialog of tubing setup. All data regarding initial tubing configuration, and downhole equipment's. Based on the screening criteria of artificial left methods and according to the basic data for the field the best method for the initial production is PCP .

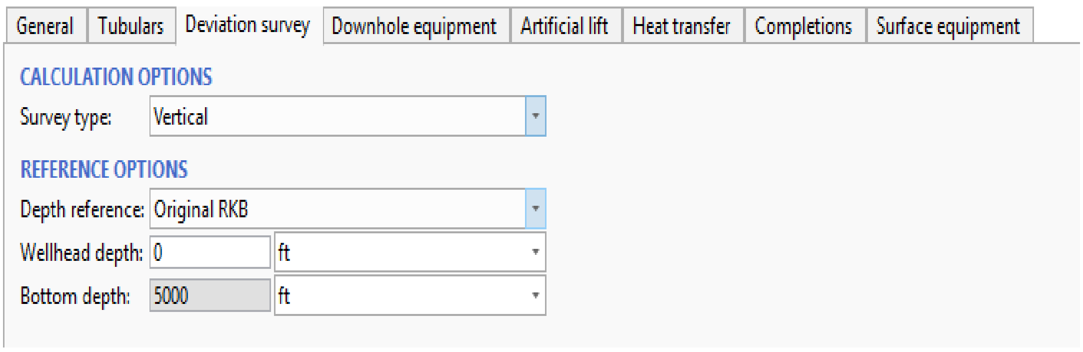

Figure 4.13: Pipesim Dialog HZ-01

2. Setting up the completion:

The completion setting requires data of static pressure, temperature, and PI model. The static pressure is taken from eclipse initial data at the oil water contact which is 1614 psi. Temperature reservoir is also using simplified geothermal survey data at that water contact which is 248 deg F.The following Table 4.8 shows the PI for all proposed wells .

Table 4.8: PI of Wells

Well Name	**PI, stb/day/psi**
HZ-01	2.08
HZ-02	0.88
HZ-03	0.99
HZ-04	0.74
HZ-05	0.84
HZ-06	0.47
HZ-07	0.34
HZ-08	0.63

3. Running system analysis with sensitivity:

The final important step of well production string optimization is running the well model using various sensitivity parameters. Water cut will be varied from 1 – 90%, while tubing inner diameter sensitivity data will use the commercially available.

The following Fig 4.14 shows the typical dialog of sensitivity of system analysis in Pipesim for HZ-01. The inlet pressure is set at 1705 psi, consistent with bottom hole flowing pressure constraint in Eclipse data file. The outlet pressure (well head) is set at 250 psi.

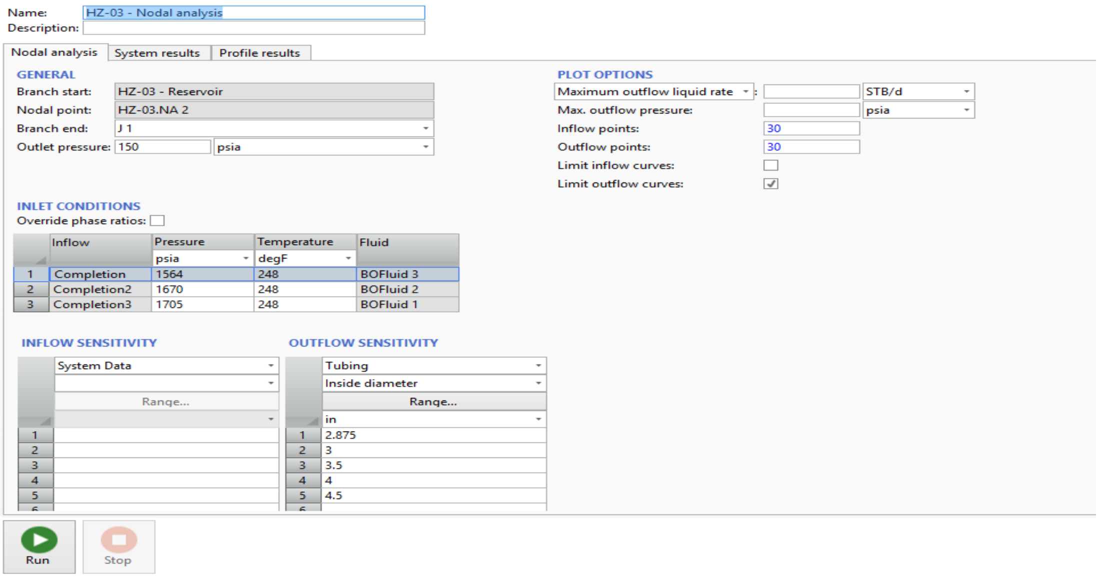

Fig 4.14: System Analysis (Pipesim Dialog)

- **Flowline sizing:**

Table 4.9 shows that pipes used in this system.

Table 4.9: Flowline sizing

	Name	Hor. distance	Elev. diff.	Undulation	ID	Wall thickness	Roughness
		m	ft		in	in	in
1	FL	800	0	0	4	0.5	0.001
2	FL 1	150	0	0	4	0.5	0.001
3	FL 2	700	0	0	4	0.5	0.001
4	FL 3	400	0	0	4	0.5	0.001
5	FL 4	310	0	0	4	0.5	0.001
6	FL 5	400	0	0	4	0.5	0.001
7	FL 6	650	0	0	4	0.5	0.001
8	FL 7	250	0	0	4	0.5	0.001
9	FL 8	3000	0	0	12	0.5	0.001

4.4.3. Production Network Summary:

The final goal of this production system optimization is that all facility units must be able to flow at stable condition which also means completed by Pipesim engine without error. Detail stream of each unit in production network system of “Haraz” Field is shown in Table 4.10

Table 4.10: Final Well Operating Condition

Well Name	Temp (F)	Pressure (psi)	Liquid rate(STB/d)	Reservoir rate	Water cut (%)
HZ-01	248	250	335	214	0
HZ-02	248	210	288	177	0
HZ-03	248	145	529	537	0
HZ-04	248	210	522	422	0
HZ-05	248	210	790	600	0
HZ-06	248	195	327	336	0
HZ-07	248	194	283	251	0
HZ-08	284	210	513	586	0

HZ-01 is taken as example of pressure distribution along a well is show for each well

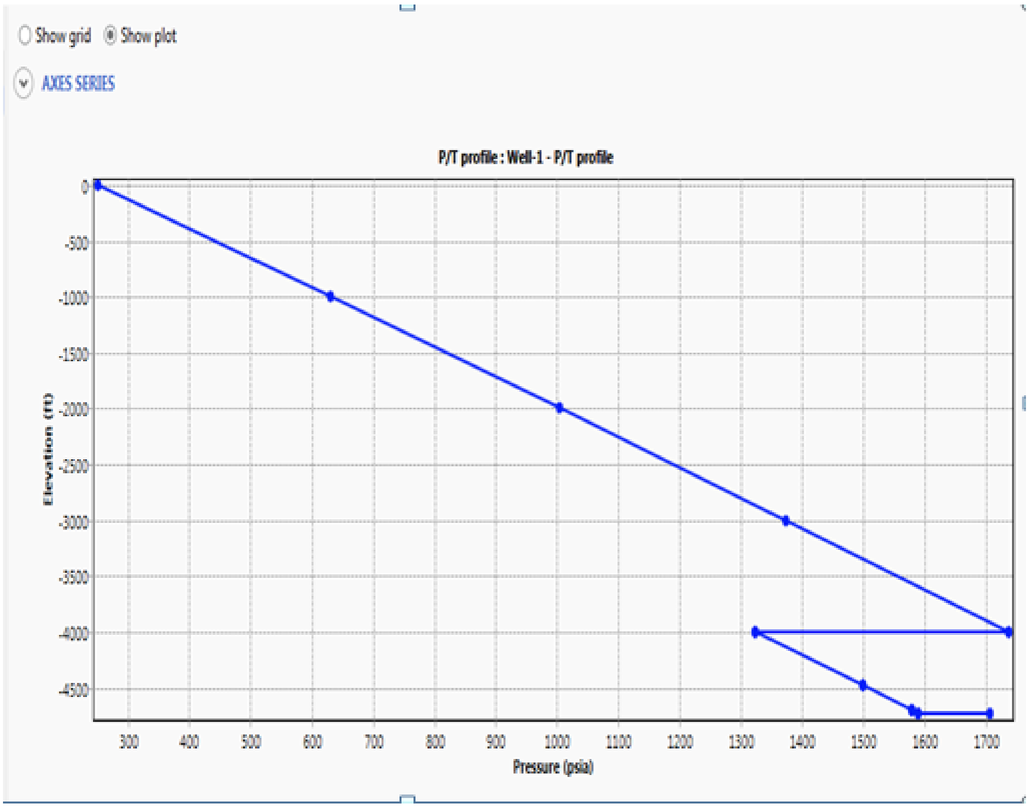

Fig 4.15: Pressure distribution of HZ-01

4.4.4 Result:

The cumulative liquid rate from Pipesim is shown in Table 4.11 **.**

Table 4.11: liquid Flow Rate from Pipesim

Name	ST liquid rate STB/d
PCP 1	343.0306
PCP 2	293.7835
PCP 3	535.7742
PCP 4	531.9638
PCP 5	805.4932
PCP 6	332.1764
PCP 7	288.4529
PCP 8	522.1268
Sk 1	3652.792
HZ-01	343.0306
HZ-02	293.7835
HZ-03	535.7742
HZ-04	531.9638
HZ-05	805.4932
HZ-06	332.1764
HZ-07	288.4529
HZ-08	522.1268

The pressure distribution of the wells across the distance is show in the flowing figure

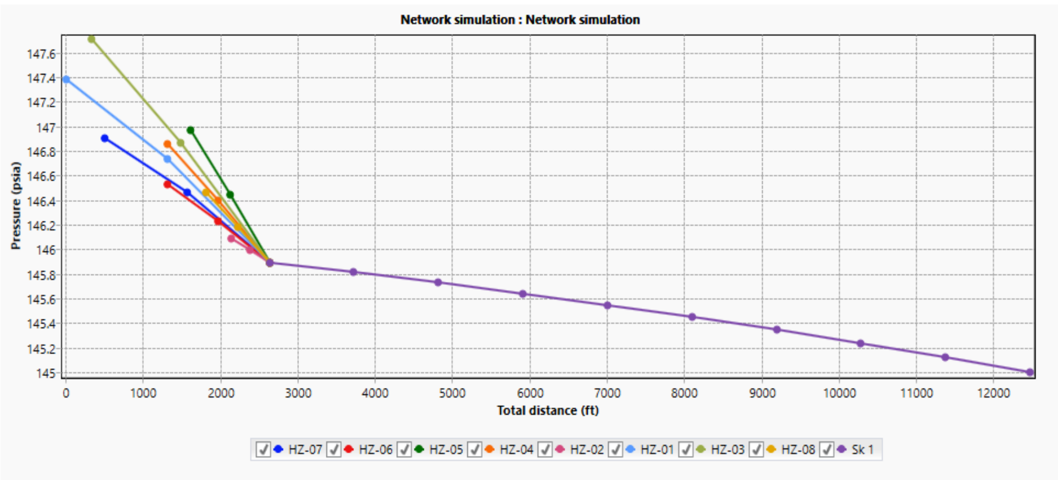

Fig 4.16: Network Stimulation

These results are the guidance to design the field surface facility with the consideration of the other parameters such as cost analysis and future development plans.

CHAPTER 5
CONCLUSION AND RECOMMENDATIONS

Chapter 5

Conclusion and Recommendations

5.1 Conclusion:

This study provides an initial attempt to integrate the reservoir and production aspect as a part of the major FDP, based on the reservoir simulation results obtained from this study; the following conclusion can be given about alternative reservoir development plans to be applied in Haraz field:

- Estimation of the recovery factor (RF) for the two scenarios was done, case one has RF = 14.6 % and case two has RF = 12.7%
- For the well placement optimization, it is best to use case 1 (with 8 vertical wells) as the alternative plan to develop Haraz field than case 2 which used 2 vertical wells and 3 horizontal wells.
- The production scheme was designed according to reservoir simulation data, all the wells considered to operate with PCP pump and 3.5 in tubing.
- The surface facility was designed to connect all the wells to a single OGM which will connect them to the nearest FPF.

5.2 Recommendations:

1. Implement more infill drilling with cost consideration for most recovery factor.
2. Shut in the high water cut layers could add more resources to the field recovery and need more investigation.
3. After the reservoir pressure decreased using water flooding is essential to recover the pressure and produce more oil from this field.
4. Coupling the reservoir aspects with the production will give a clear view on the field best management scenario and will help to minimize the economic risk, an advanced approach will include analyzing the economic feasibility to get the optimum production scenario but it's beyond our scope here.

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