APPLICATION OF INFLOW CONTROL DEVICE (ICD) FOR OPTIMIZING HORIZONTAL WELL PERFORMANCE

Final Year Project II

Final Report

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Application of Inflow Control Device (ICD) for Optimizing Horizontal Well Performance

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CERTIFICATION OF ORIGINALITY

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

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ABSTRACT

Horizontal and multilateral wells are shaping the development of the oil and gas industry due to its increased reservoir contact. The horizontal well drilling technology was established about ten to fifteen years ago and has since become a method for improving hydrocarbon recovery. With its horizontal nature, the presence of a strong aquifer and gas cap facilitate the possibility of early water and gas breakthrough through a situation known as “heel toe effect” which is a result of frictional losses. Reservoir heterogeneities results into variations in permeability along the length of the wellbore causing unequal influx of the inflowing fluids around the vicinity of the wellbore. The unequal influx contributes to early water and gas breakthrough because the fluids flowing in the zones with higher permeability (thief zones) move faster than those moving in the low permeability zones, thereby allowing the low viscosity fluids to bypass the high viscosity fluids making the well uneconomical.

This research paper studies the application of Inflow Control Devices (ICDs) as a means of eradicating or at least delaying the water/gas breakthrough. A simulation method has been identified by the author after a thorough review of literature. The implementation of ICDs is expected to improve hydrocarbon recovery and delay water/gas production. The multi-segment well model in the ECLIPSE Black Oil Simulator is used to represent a horizontal well divided into segments with ICD installed in some of the suitable segments. A set of data is used to demonstrate and address the problem of unequal influx of fluid and early breakthrough or higher production of water and gas.

Two cases of different model dimensions have been discussed in this study and both cases show that proper application of ICD to the segments that provide optimum oil recovery and reduced water and gas production at the same time will improve performance of horizontal wells. The two cases also showed that oil production may decrease at the beginning when using ICD because of the additional pressure drop created by forcing the fluids to flow through the device. However, the rate will increase eventually over time and higher recovery will be achieved.

Key words: ICD, Horizontal well, Performance, Multi-segment well model.

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CHAPTER 1

INTRODUCTION

1.1. Background of Study

Horizontal wells are currently widely used to maximize the contact within the reservoir. In other words, horizontal wells are used to reach wells that cannot be reached by the conventional vertically drilled wells. These wells are basically drilled to reach targets beneath adjacent lands, reduce the footprint of gas field development, to increase the length of the pay zone and to intersect fractures among others.

Inflow control devices are choking control devices that provide an additional pressure drop at the wellbore. These devices are introduced to equalize inflow flux at the heel of the horizontal well and delay production of water and gas. The first application of inflow control device (ICD) was witnessed in the Troll oil field in Norway.

1.2. Problem Statement

Horizontal wells are associated with various problems since they are drilled at an angle making them susceptible to early water/gas breakthrough mostly motivated by factors such as frictional pressure drop, permeability variations along the wellbore and "heel toe effect". These result to uneven flow sweep at the wellbore leading to low oil production, sharp oil production rate declines, and short economic production life of the well.

Since the main objective of the engineer and the operating company is to produce oil but not water and gas, there is a need to develop a device that will control and stop or minimize these problems.

1.3. Objectives

The main objectives of this study are to apply ICD in horizontal wells to;

- Achieve equal or uniform flux along the length of the horizontal well.
- Delay premature breakthrough of water and gas as well as improve reservoir fluid recovery.

The bottom-line of the study is to mitigate the heel toe effect of horizontal wells and improve hydrocarbon recovery through the application of inflow control devices.

1.4.Scope of the Study

The general aim of this study is to model and simulate the performance of horizontal wells with ICD and without ICD to justify the significance of the application of ICD for optimizing horizontal wells performance.

CHAPTER 2
LITERATURE REVIEW

2.1.Literature Review

With current efforts of maximizing contact with reservoir quality rock in either single or multiple reservoirs, horizontal and multilateral completions are proven superior to the conventional completion solutions as reported by El-Khelaiwi and Davies [1].

Horizontal wells are first drilled as early as 1927 but the major application of drilling horizontal well came into effect in the 1980s initially with short well lengths, about 250ft long [11]. In 1985, the first medium radius horizontal well was drilled using a downhole mud motor. This has triggered the use of horizontal well to a higher level. Nowadays, horizontal well drilling has become a common practice and the medium radius drilling technique is the most commonly used technique.

Horizontal wells are applied in vast reservoir types including low permeability, naturally fractured, carbonate reservoirs. But most of the horizontal wells are drilled in clastic reservoirs. Horizontal wells have also been used to produce thin zones, formations with water and gas coning problems, water flooding, heavy oil reservoirs, gas reservoirs and in enhanced oil recovery (EOR) methods such as thermal and CO_2 flooding and used to improve well economics.

Since horizontal wells are drilled at an angle, there usually occur problems of gas and water conning at the heel of the well due to frictional pressure drop, variation of the permeability along the well, and or pressure drop along the completion’s flow path due to friction losses usually known as “heel-toe effect.” It has been found from previous researches that installation of Inflow ICD mitigates such problems. ICD is usually installed as a part of the sand face completion hard ware. It was proposed in the early 90s as solution to the above problems associated to horizontal and multilateral wells. The use of ICD is currently gaining more and more popularity and applications in different reservoirs [2]. Notable application of ICDs is in the Troll oilfield located in the North Sea

80km west from the Norwegian west coast. This was presented in a case study by Henriksen and Gule [3]. They argued that technical and functional description, qualification, computer modeling and production experience verifies that completions with ICDs yield higher volumetric oil recovery from each well as compared to the more conventional sand control completion methods.

Several studies had been carried out on the application of ICD as a smart way of completions. These studies include the work by Birchenko [4] which focused on how to make a choice between active (Inflow Control Valve, ICV) and passive (ICD) inflow control completions. This study enumerated the areas of application of ICVs and ICDs with the major aspects dictating the choice between ICV and ICD completions. Although the application areas of ICV and ICD technologies have developed up to the extent that they overlap, they pointed out that ICDs are appropriate for mitigating the "heel toe effect" while also noting that ICD has greater advantage in terms of simpler design, installation and lower cost. This, according to their study, is due to the fact that the ICV's reduced inner flow conduit increases the heel toe effect and the design and installation of ICV is quite complex as compared to that of ICD.

A similar study on understanding the roles of ICD in Optimizing horizontal-well performance by Fernandes et al. stressed that even though the detail structure of designing ICD varies, the principle for different inflow devices is the same, which is to restrict flow by creating additional pressure drop and therefore balancing or equalizing the wellbore pressure drop to achieve an evenly distributed flow profile along a horizontal well [5]. This study showed that ICD is now widely considered by the oil and gas industry as a solution to the pressure inequality near the wellbore vicinity of horizontal wells. However, they emphasized that careful observation has to be taken in determining as well as knowing the reservoir condition and the well structure together with the completion design because once the ICDs are installed, the location of the ICD as well as the relationship between the rate and the pressure will remain fixed. Since the reservoir may change with time, the impact of the ICD will also depend on time.

Another application of ICD was in in the SS field presented by Rahimah et al [6]. The SS field is in offshore East Malaysia currently with 3 horizontal producers and 3 water injectors. According to the paper, SS field has significant development challenges making early water and gas breakthrough inevitable which led to the implementation of horizontal wells and Inflow Control devices were the solution for the mitigation of the early water and gas breakthrough. Through the dynamic and static computer modeling, they were able to adequately place the horizontal wells, quantify the value of implementing ICD, compare production performance before and after ICD and achieve the bottom-line which is approval from management. The paper reported that ICD yielded significant benefits in suppressing the gas influx and balances the flow influx heterogeneity along the horizontal well length which resulted favorably in delaying gas and water breakthrough to optimize recovery. Generally, the paper concluded that the application of ICD proved valuable to horizontal well optimization by reducing the risks of having early gas and water coning and that is important to make in depth feasibility studies to avoid misplacement of the device.

The flow rate per joint of an ICD restricts the applicability of the device. In a paper presented by McKenzie and [7], they reported that the maximum flow rate per ICD should not exceed the erosion velocity since the erosion velocity is the function of the fluid properties, the flow area and the ICD material. Therefore, there is a need to consider the minimum flow per joint because if the well production is very low, it will make the ICD function like a normal screen since no additional pressure drop is created (i.e. $\Delta p = 0$ through the screen). To avoid this scenario, it is recommended to operate within the envelope of the minimum and maximum flow rates per joint as in the figure shown below. This plot in the figure can also be used to identify the wells which can benefit from the application of ICD and determine the minimum well length or the reservoir contact needed for the ICD to function properly as reported by the study.

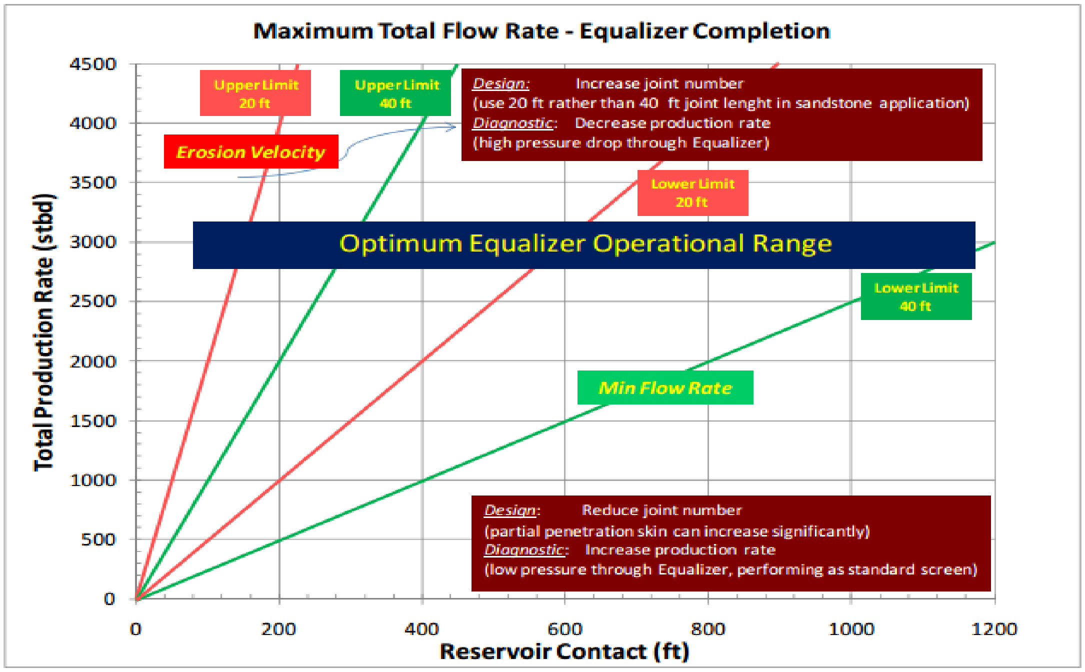

Figure 2.1: ICD operation envelope as a function of the flow rate per joint [7]

The design and application of ICDs revolves around the pressure transient behavior of the horizontal wells since the additional pressure drop is the driving factor. It is important to know the transient behavior of the well before and after the ICD application. In a similar study by experts from Schlumberger, they observed that frictional pressure losses along the wellbore and through the completed intervals (multi-segmented intervals) and ICD dramatically alter the reservoir fluid inflow distribution along the wellbore [8]. In order to have a considerable insight on the inflow profiles of fluids along the wellbore, the evaluation of the transient performance of the horizontal well with ICD is significant.

2.2.Types of Inflow Control Device

Several types of ICD are present with different principles and uses. In a recent study on the design, implementation and use of ICD for improving the production performance of horizontal wells presented by Minulina et al., They noted that all ICD type designs are based on the principle of pressure equalization along the wellbore and balancing inflow along the well path which is achieved by including choking devices that create additional pressure drop between the reservoir wellbore annulus and the wellbore [9]. They described the most commonly used ICD types as below.

2.2.1. Channel Type ICD

This ICD type achieves the pressure equalization by friction forces which are in built-in channels. This type of ICD is based on the Poiseuille's law which states that the pressure drop in a laminar fluid flowing in a tube is proportional to the fluid viscosity and the length of the channel. This is given by [9];

$$\Delta P = \frac{128uLQ}{\pi d^4} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2.1)$$

Where: Δ**P** is the pressure drop; **L** is the length of the pipe; **μ** is the dynamic viscosity

Q is the flow rate; **d** is the diameter

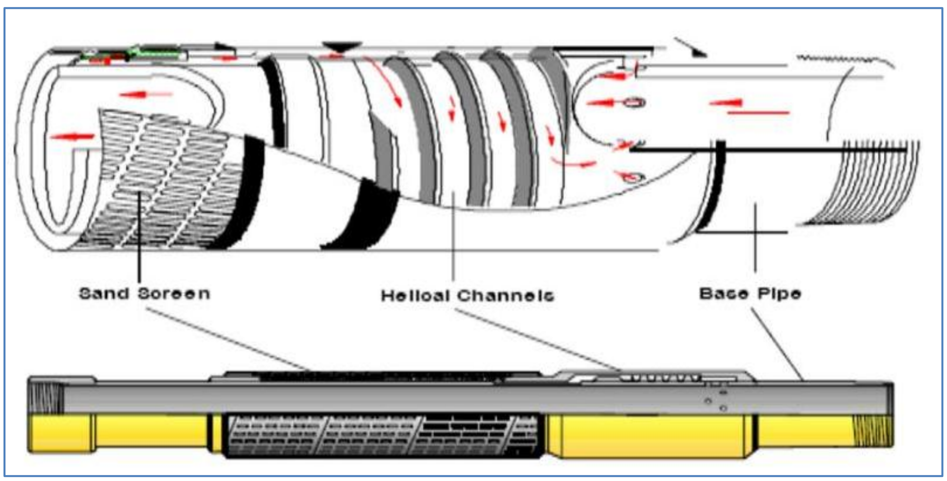

Figure 2.2: Channel type ICD [9]

The Channel type ICD is excellent in corrosion eradication and has a limitation in that it cannot be adjusted at the rig site and is sensitive to changes in fluid viscosity.

2.2.2. Nozzle Type ICD

The nozzle type ICD has a prefabricated number of nozzles ranging from 1 to 4 in each section. The pressure drop is achieved when the fluid enters through the nozzle.

This is according to Bernoulli's law which describes the physical phenomena as [9]

$$\Delta P = \rho.\frac{v^2}{2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2.2)$$

$v = \frac{q}{A}$ ………………………………………………………………………………... (2.3)

Where:

ΔP is the pressure drop, **ρ** is the flow rate of the fluid, **v** is the velocity of the fluid **A** is the cross-sectional area of the pipe

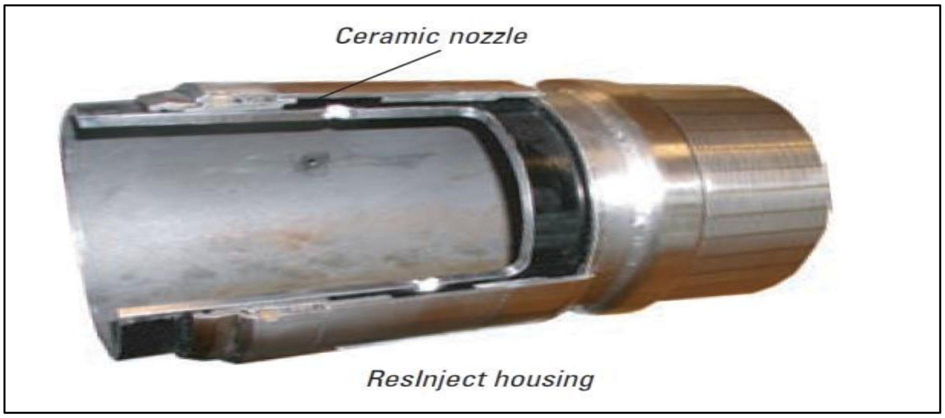

Figure 2.3: Housing unit section of Nozzle type ICD [9]

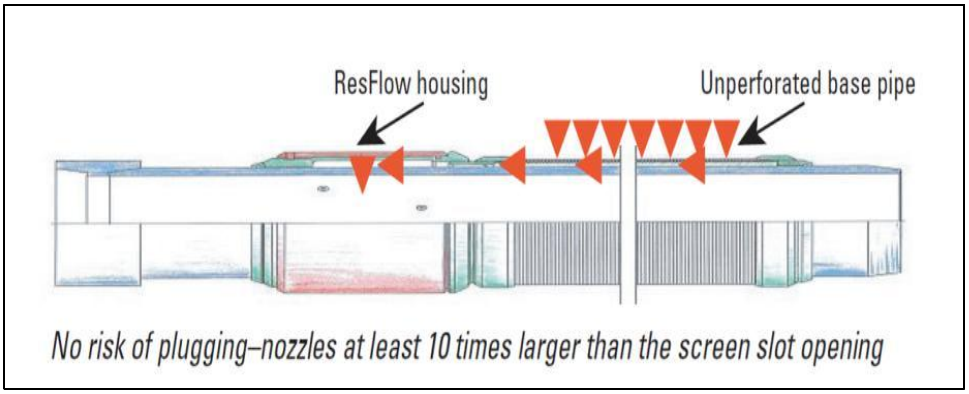

Figure 2.4: Flow pattern in Nozzle ICD [9]

Unlike the channel type ICD, the nozzle type ICD is adjustable at the rig site and the pressure drop is insensitive to fluid viscosity although it depends on the fluid viscosity.

2.2.3. Orifice Type ICD

This ICD type has a number of orifices integrated into the device to provide restrictions. The pressure drop is achieved as the fluid flows through the restriction which can be adjusted by varying the number of open orifices. These orifices with known diameters and flow characteristics are installed around the pipe within the ICD chamber, prefabricated before delivery. The Orifice type ICD is non-adjustable at the rig site and are known to be erosion prone due to higher fluid velocities required to create the instantaneous pressure drop.

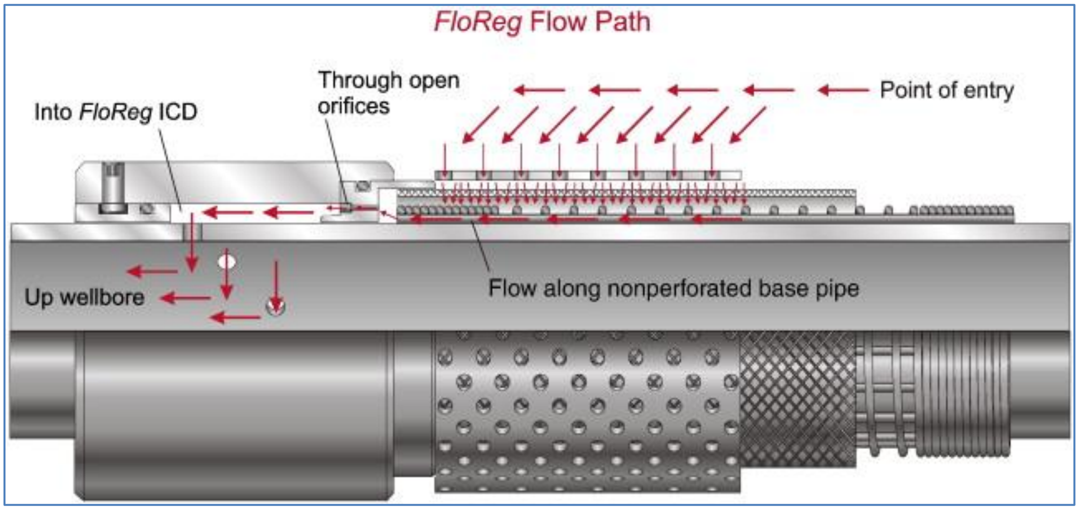

Figure 2.5: Orifice type ICD for water injectors [16]

2.3.Application of ICD with other Control Devices

However, several published papers have presented different applications of ICDs since its first application in the Troll field. For example, in Al-Khelaiwi et al paper, they presented other applications such as [1];

2.3.1. Application of ICDs with Stand Alone Screens (SAS) in horizontal wells

This is applied in long horizontal wells like in the well M-22 in the Troll field which had a horizontal well length of 3,619 meters and completed with 279 jointed SAS with ICD.

2.3.2. Integration of ICD with Annular Isolation

The integration of ICDs with annular isolation is employed to prevent annular flow which may occur due to variations in permeability, hole size, or undulations along the wellbore even if ICD is installed. Annular isolation is always necessary to guarantee the full benefits of ICD implementation. For example, the Z-23 in Zulu field in Saudi Arabia was completed with four mechanical External Casing Packers (ECPs) in conjunction with a single strength channel type ICD to segment a 2200ft length.

2.3.3. Integration of ICD with Artificial Lift

Practically, the application of Artificial Lift methods is to revive dead or low flow rate wells to increase production by increasing the pressure drop at the wellbore which is desirable in vertical wells. However, in horizontal wells, this could further worsen the effect of the pressure drop along the wellbore which encourage water or gas coning. This is mitigated by integrating ICD with artificial lift as witnessed at the Z and M fields and at the Troll and Grane fields in the Norwegian shelf of the North Sea.

2.3.4. Integration of ICD with Gravel Pack

For wells with high sand production, ICD can be combined with gravel pack to minimize both the problem of sand and water or gas breakthrough such as in the Etame oil field at offshore Gabon where ICD was combined with gravel pack in ET-6H well.

2.3.5. Integration of ICD with Multilateral, Intelligent Completion

This involves the combination of Inflow Control Valve and ICD in multilateral wells. The ICV is installed together with the ICD at the mouth of each lateral to avoid the potential of water breakthrough in one lateral before the other lateral in multilateral wells completed in different reservoir facies. In the Z field in offshore Saudi Arabia, an integrated ICD completion with level 4 multilateral junctions equipped with ICV was employed to control the production from each lateral well.

CHAPTER 3

METHODOLOGY

3.1.Research Methodology

The study investigates the reservoir performance through a comparison of base case model without ICD and a model with ICD employed. Therefore, two project phases were involved. Part one dealt with researching of the principles, application and industry best practices of ICD installation and part two focused on creating two dynamic and static reservoir models for predicting or forecasting the future well performances, quantifying the value of ICD implementation, appraisal and comparison of the production performance before and after the installation of ICD. The author used the ECLIPSE multi segment model feature in ECLIPSE 100 to divide the horizontal well length into a number of segments which include the annulus, the tubing and the ICD length.

Several assumptions were made in order to model and simulate the impact of ICD using the multisegment model. These assumptions include [18];

i. Flow through the reservoir can be described by Darcy law and the inflow into the well is steady or pseudo-steady.
ii. The distance between the well and the reservoir boundary is much longer than the well length (or parallel to the well).
iii. Friction and acceleration pressure losses between the toe and the heel are small compared to the drawdown.
iv. The fluid is incompressible.
v. No fluid in the annulus parallel to the base pipe.
vi. The ICDs installed are of the same strength.

The first part which is primarily research was achieved through literature and industry papers while the second part which involves model creation and simulation was achieved using Schlumberger Eclipse Simulator and data from literature.

3.2. The Multi-segment Model

The multi-segment well model is a special extension available in both Eclipse (100) and Eclipse (300) which is for black oil and compositional model respectively. This special extension is specifically designed for multi-lateral and horizontal wells although it can still be used for more detailed analysis of fluid flow in standard vertical wells. Like any standard well model, the equations are solved fully implicitly and simultaneously with the reservoir equations to ensure stability and meet the exact operating targets [13].

In this project, the wellbore length was divided into a number of 1-dimensional segments to obtain the detailed description of the fluid flowing conditions within the well. The segments were isolated from each other by packers. Each of the segments had their own set of independent variables. Since the author was using ECLIPSE 100, the number of the independent variables per segments was four which were the fluid pressure, the total flow rate and the flowing fractions of water and gas. The variables within each segment were evaluated by material balance equations for each phase or component and a pressure drop equation that takes into account the local hydrostatic, friction and acceleration pressure gradients. For better accuracy and ability to model the choke, the pressure drop was derived from pre-calculated vertical flow performance (VFP) tables [14]. The figure below shows a multi-segment model taken from literature.

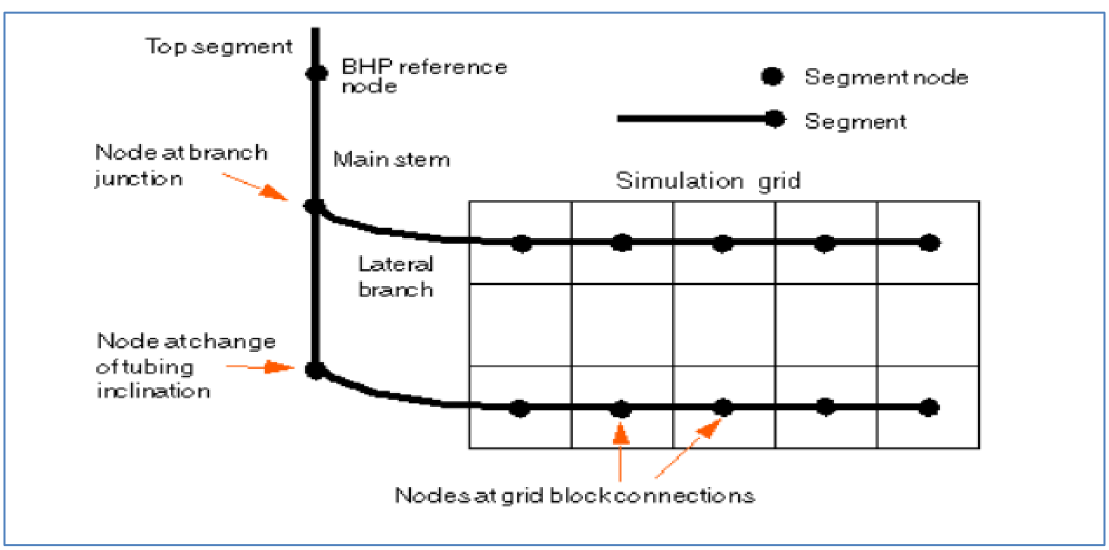

Figure 3.1: Multi-segment well model [13]

The flow between a grid block and its associated segment is given by the following equation [13].

$$q_{pj} = T_{wj}\left(P_j + H_{cj} - P_n - H_{nc}\right) \quad \text{(3.1)}$$

Where:

- q_{pj} = Volumetric flow rate of phase p in connection j (stb).
- T_{wj} = Connection transmissibility factor.
- M_{pj} = Phase mobility at the connection.
- P_j = pressure in the grid block containing the connection.
- H_{cj} = Hydrostatic pressure head between connection's depth and the center depth of the grid.
- P_n = Pressure at the associated segment's node n.
- H_{nc} = hydrostatic pressure head between the segment node and the connection depth (i.e. center depth is not necessarily equal to the segment node).

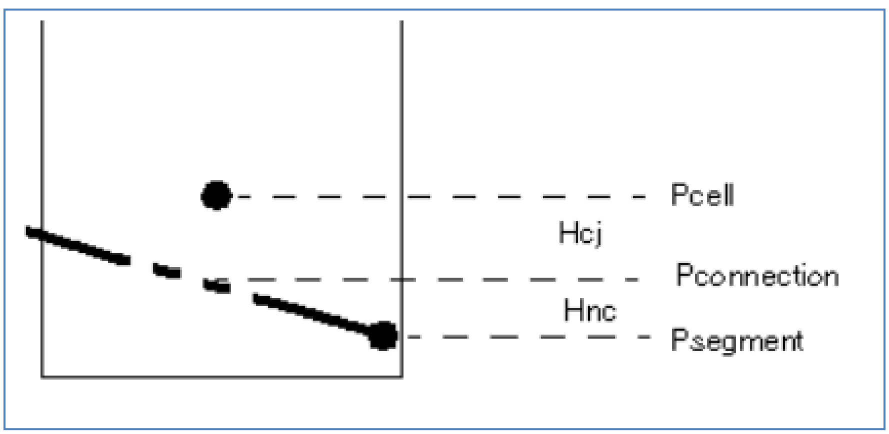

Figure 3.2: Hydrostatic head Components [13]

3.2.1. Inflow Control Device (ICD)

An inflow control device is a permanent hardware installed upon completion of a well based on initial reservoir conditions and simulation prediction of reservoir performance. It is not adjustable and irretrievable.

3.2.2. How ICD Works

ICDs work by imposing an additional pressure drop between the sand face and the tubing with the aim of equalizing drawdown throughout the length of the wellbore. The retard or slow down the fluid flow in the fastest zones (thief zones) leading to a more uniform fluid inflow profile along the length of the wellbore.

The mechanism by which this additional pressure drop is achieved varies for different devices from simple flow control valves to complicated smart devices that are capable of changing their response according to the properties of the inflowing fluid. Due to the increased pressured drop introduced by ICD, wells may begin to produce at lower rates than when there is no ICD and gradually increase over time. This can be illustrated in the figure below.

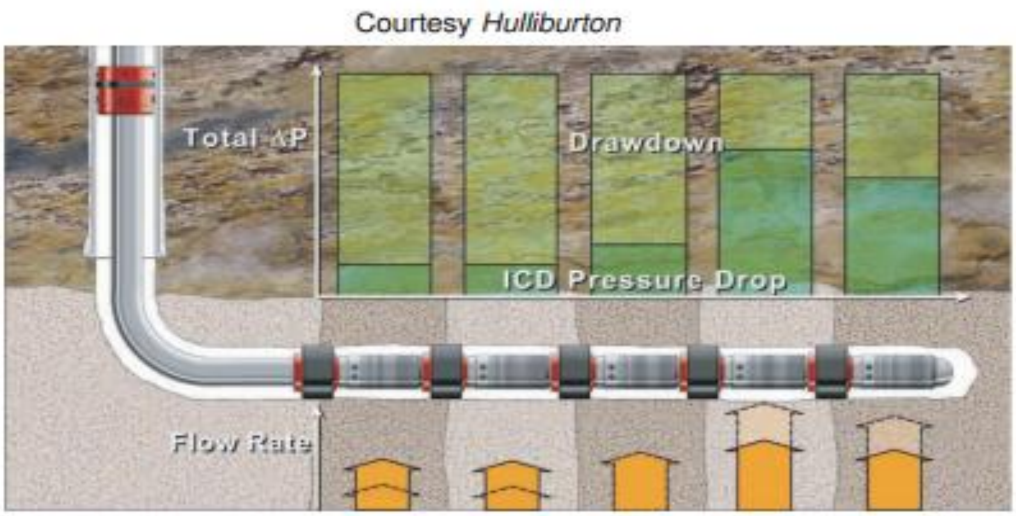

Figure 3.3: ICD segments illustrating the additional pressure drop created by the ICD [18]

From figure 3.3, the green zone represents the additional pressure drop created by ICD between the sand face and the tubing, and the grey-yellowish zone shows the drawdown from the sand face totaling to one even pressure drop in all the segments which contributes to uniform influx of the fluids.

Four ICD types that can be easily modeled in ECLIPSE Reservoir simulator include;

1. Sub critical valve: additional pressure drop created by constriction – its magnitude depends upon both the size of the constriction and the velocity of inflowing fluid.

2. Labyrinth Device: forces the inflowing fluid to flow through a system of channels before it enters the tubing – the pressure drop depends on the length of the flow path through the channels and the velocity of the inflowing fluid.
3. Spiral ICD: additional pressure drop is created by forcing the inflowing fluid to flow through a spiral before it enters the tubing.
4. Autonomous ICD: Same mechanism as spiral ICD.

The equation for the additional pressure for the Spiral and Autonomous ICDs are given by the equations below [17].

$$\boldsymbol{\delta PSICD = \left(\frac{\rho_{cal}\cdot\ u_{mix}}{\rho_{mix}\cdot u_{cal}}\right)^{1/4} a_{sicd}q^2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \mathbf{(3.2)}$$

$$\boldsymbol{\delta PAICD = \left(\frac{\rho_{mix}^2}{\rho_{cal}}\right)\left(\frac{u_{cal}}{u_{mix}}\right)^{y} a_{Aicd}q^x} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \mathbf{(3.3)}$$

$\boldsymbol{\rho_{mix}}$ = Density of fluid mixture flowing through the device. This is calculated from saturated weighted average of the density of the individual phases.

$\boldsymbol{\rho_{cal}}$ = Density of the fluid used to calibrate the device during laboratory experiments.

$\boldsymbol{u_{mix}}$ = Viscosity of the fluid mixture flowing through the device. This can be calculated from either the averaging method or by a more sophisticated calculation which assumes that the oil and water form an emulsion.

$\boldsymbol{\alpha}$ **=** the device strength calibrated from the lab. **q** = the volumetric flow rate through the device. **x** = user defined exponent measured during calibration. **y** = user defined exponent measured during calibration.

The pressure drop depends on a combination of the fluid properties and the device variables. The pressure drop across ICD segment increases with the fluid flow rate which helps to retard or slow down flow in the fastest zones (thief zones).

3.3. The Reservoir and Well Model

To demonstrate the significance of the application of ICD, two models were created representing a reservoir with thin layer of 20 feet. Water injection had been performed for pressure maintenance. The model represents a reservoir with 15x1x20 grids and thicknesses with varying horizontal and vertical permeability values. The first multi-segment well model was run without ICD and the results were compared with the second model with ICD. Some of the data were assumed for the purpose of this study. The reservoir and fluid properties are given for two different cases in the respective sections in Chapter 4.

The base case model without ICD was created by using the multi-segment well model described above to divide the production well into 25 segments with three branches and the injection well was divided into 24 segments with two branches. The segment properties and dimensions are given in the table below.

Table 3.1: Summary of segments and branches

Property	Production well	Injection well
Number of segments	25	24
Number of branches	4	3

The simulator will calculate the flow of the fluid from segment to segment throughout the horizontal well length.

The Spiral (SICD) was applied into the multi-segment well model to restrict flow in those segments with high permeability so that the inflow of the fluid is balanced. This was enabled in the simulator by a special keyword (WSEGSICD) to designate some of the segments to represent the SICD and impose an additional pressure drop between the sand face and the tubing. The pressure drop across the SICD depends on the viscosity and density of the fluid flowing through it and it is given by the **equation 3.2** above. The viscosity of the mixture is given by **equation 3.4** below.

$$u_{mix} = \alpha_o u_o + \alpha_w u_w + \alpha_g u_g \quad \text{(3.4)}$$

Where:
$u_{o,w,g}$ = the viscosities of oil, water and gas.

$\alpha_{o,w,g}$ = the volume fractions of the free oil, water and gas.

3.4. Project Activities

The activities involved in this project ranges from doing research on the project to data collection, model creation and results analysis. These are summarized in the table below.

Table 3.2: Project Activities for FYP2

Activities	Description
Research and Review Literatures	- Identifying the problem - Suggest a solution - Establish firm objectives - Extract relevant parameters and procedures - Adopt a methodology
Preparation of Data Model Creation	- Look for data in published papers - Create Multi-segment well model - Incorporate ICD into the multi-segment well model and create model to be used by E100
Running the model in Simulator, Check for consistency and convergence	- Export the model into the E100 and run model - Check for errors and problems - Check for convergence and consistency - Modify control values to suit the project study
Analyse the Results	- Discuss and scrutinize the findings from the results - Draw a conclusion from the results.
Report Writing	Compilation of all works into a final report

3.5. Project Flow Chart

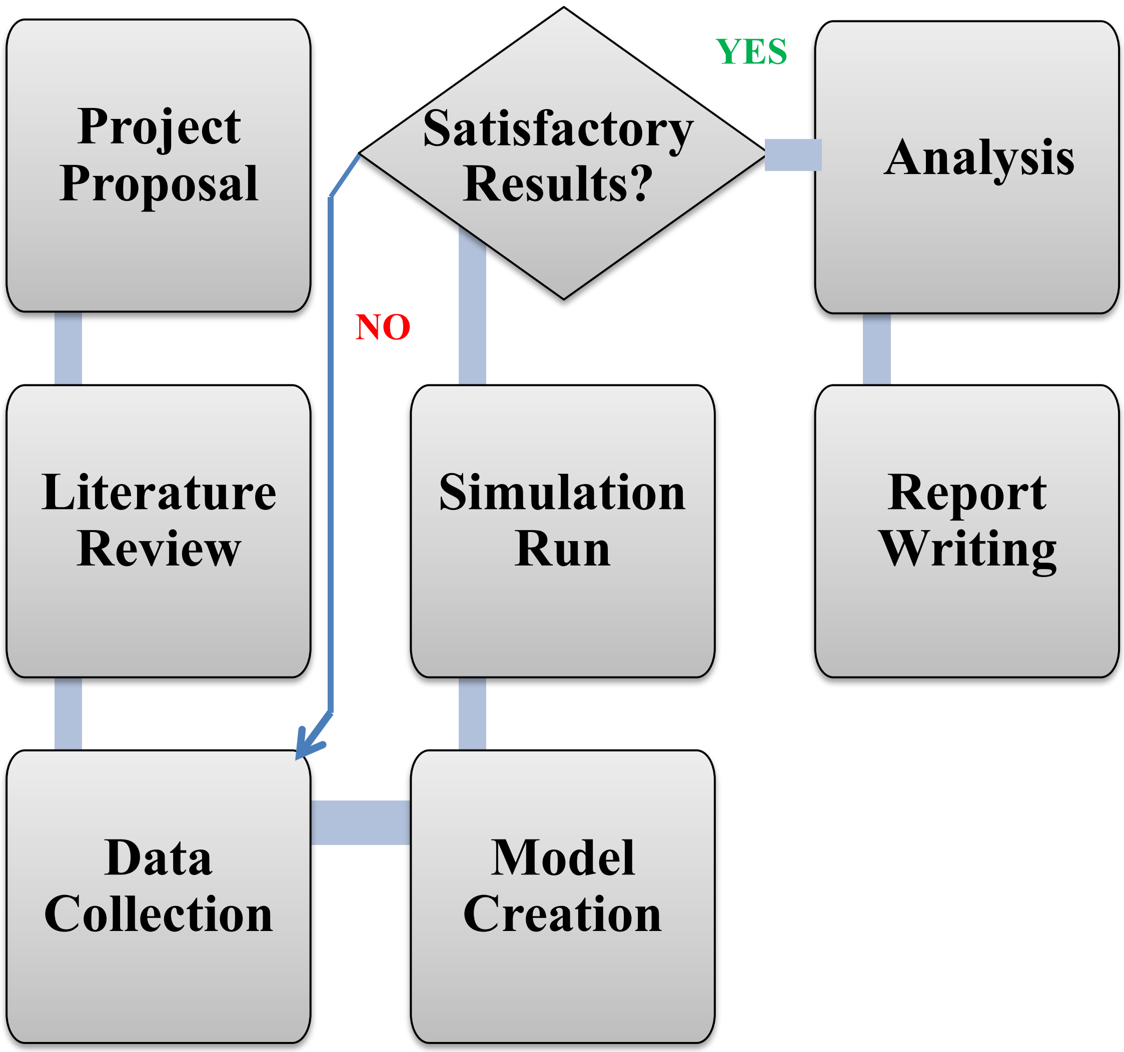

Figure 3.4: Project process flow chart

3.6. Gantt chart and Key Milestones for FYP2 (semester 2)

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

Figure 3.5: Gantt chart and Milestones for FYP2 as per the FYP Guideline

3.7.Equipment and Data Required for the Project

The Schlumberger Reservoir Simulator (ECLIPSE Black Oil, E100) is used in this project. The data for this project were taken from various papers and some of them were assumed since the data were needed as an example for demonstrating the significance of ICD application. There are limitations to the data and these limitations are discussed in the proceeding chapters.

CHAPTER 4
RESULTS AND DISCUSSION

To illustrate the effect of ICD on the reservoir performance, two models were considered for study with different reservoir rock and fluid properties. The data used were taken from literature and were assumed to be appropriate for this study. The two models both show a positive effect of applying ICD in a completion for better performances. As discussed before, the major functions of ICD are;

1. To redistribute the flowing pressure in the wellbore by creating an additional pressure drop to balance the reservoir drawdown along the wellbore and subsequently achieve evenly distributed flow rate along the horizontal well.
2. To restrict high permeability channels or high drawdown spots (thief zones) at the heel of the well and along the well length in order to delay early water or gas breakthrough since they are not the fluids we want to produce. The reservoir heterogeneity and are well identified before any completion is applied in the field.

The two cases were aimed to justify the above functions of ICD in horizontal well completions. Both cases were pressure supported by water injection and it was assumed that some of the injected water was produced with the oil, thereby increasing the water cut of the completion.

4.1. Case One

The first case consisted of a reservoir with 300 cells (15x1x20 dimensions) [15]. This reservoir was having an initial pressure of 3000psi and was expected to produce to a maximum rate of 650stb/d. The well has three branches. The first branch has 10 segments ranging from segment 2 to 12 as the top branch. The second branch consists of 5 segments ranging from 13 to 17 making the middle branch. The third and last branch consists of 6 segments ranging from 18 to 24 at the bottom. All branches were in the horizontal direction and no inclined branch or segments for simplicity. The reference depth or the depth to the nodal point of the top segment was taken to be 7010 ft. and the length down the tubing to the nodal point of the top segment (the distance between the bottom hole pressure reference depth, 7010, and the tubing head) was 20 ft. A tubing size of 4.5 inches (0.375 ft.) was applied with an effective absolute roughness of 0.001. The cross sectional area for a segment is given by;

$$\pi\left(\frac{D^2}{4}\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (4.1)$$

Where D = the tubing diameter.

Therefore, the cross sectional area for the segment was calculated to be 15.9 square inches (0.11 square feet).

The volume of the segment is given by the cross sectional area multiplied by the length of the segment (A.L). For the top segment, the length of each segment was given to be 50 ft. Hence, the volume of a single segment in the top branch can be calculated to be 5.5 cubic feet (795 cubic inches). Some of the necessary rock and fluid properties are presented in tables 4.1 and 4.2 below.

Table 4.1: Data taken from Anna et al. [15], with some modified.

Property	**Value**
Block dimensions	15x1x20
Size of reservoir grid blocks*	200x100x20ft^3
Reservoir initial water saturation, swi	0.12
Total well length*	1000 ft.
Well roughness	0.001
Size of segment*	100 ft.
Reservoir temperature at top boundary	160 degF

Table 4.2: Data taken from Preston Fernandes et al. [5]

Property	Value
Horizontal permeability*	2000 md
Vertical Permeability	20 md
Average reservoir pressure*	3000 psi
Pressure at heel*	2700 psi
Reference depth*	7010
Water oil contact*	7990
Oil viscosity	2 cp
Oil density	40 lb/ft^3
Tubing diameter	4.5 in
Gas viscosity	0.02 cp

The asterisk * shows modified and added data for the project.

There were two sets of results for this case. The first results were from the base case without ICD and the second results were from the base case with ICD.

4.1.1. Segment GOR and Water cut

Water cut is the ratio of water produced compared to the total volume of liquids produced. Here it is the ratio of the water produced to the oil produced at the surface. Therefore, a water cut of 0.5 means 50% of the liquids produced is water and the rest if oil. Water cut is a problem in reservoirs with strong aquifers or aquifers supported by water injection.

Like the water cut, gas oil ratio (GOR) is the ratio of the amount of gas produced to that of the oil produced. GOR may occur due to the presence of gas in solution with oil and the pressure drops below bubble point where the gas starts to escape from the oil and subsequently produced together with the oil or when there is a gas cap on top of the oil zone and the gas is penetrating or coning through the oil into the production tubing.

The amount of water and gas produced immensely influence the production performance and the overall economic decisions of the well, as well as the whole field.

To determine the segments suitable for the application of ICD, the base case model without ICD was run and the results of the segments which produce most of the water and gas are shown in the figure 4.1.

It can be clearly observed from the figure that segments 1, 3, 13, 14, 15, 16and 17 were the most suitable for applying ICD to reduce gas and water production because they have higher water cut. The rest of the segments have low water production and gas production but the fluid inflow is variable which qualify them for ICD as well. Here, ICD was applied to the segments which will optimize oil recovery and reduce unwanted fluid production at the same time. ICD was not applied to segments 1 to 3 because they are located at the top segment near to the heel of the well and putting ICD there will instead push more water or gas towards production. No pressure losses were calculated from the top segments because the mult-isegment model does not calculate pressure losses above the nodal point of the top segment. Instead, the pressure losses between the bottom hole pressure reference depth and the tubing head were handled by the vertical flow performance (VFP) tables.

It is also recommended in the simulator not to include an ICD in the top segments (1 and 2) because once we restrict the top segments, the flow into the liner will be blocked and this will lead to low fluid recovery.

The question remains whether to install ICD for all segments ranging from 5 to 25 or just select some of them. Here, some of the segments have ICD while others were left without ICD as discussed above.

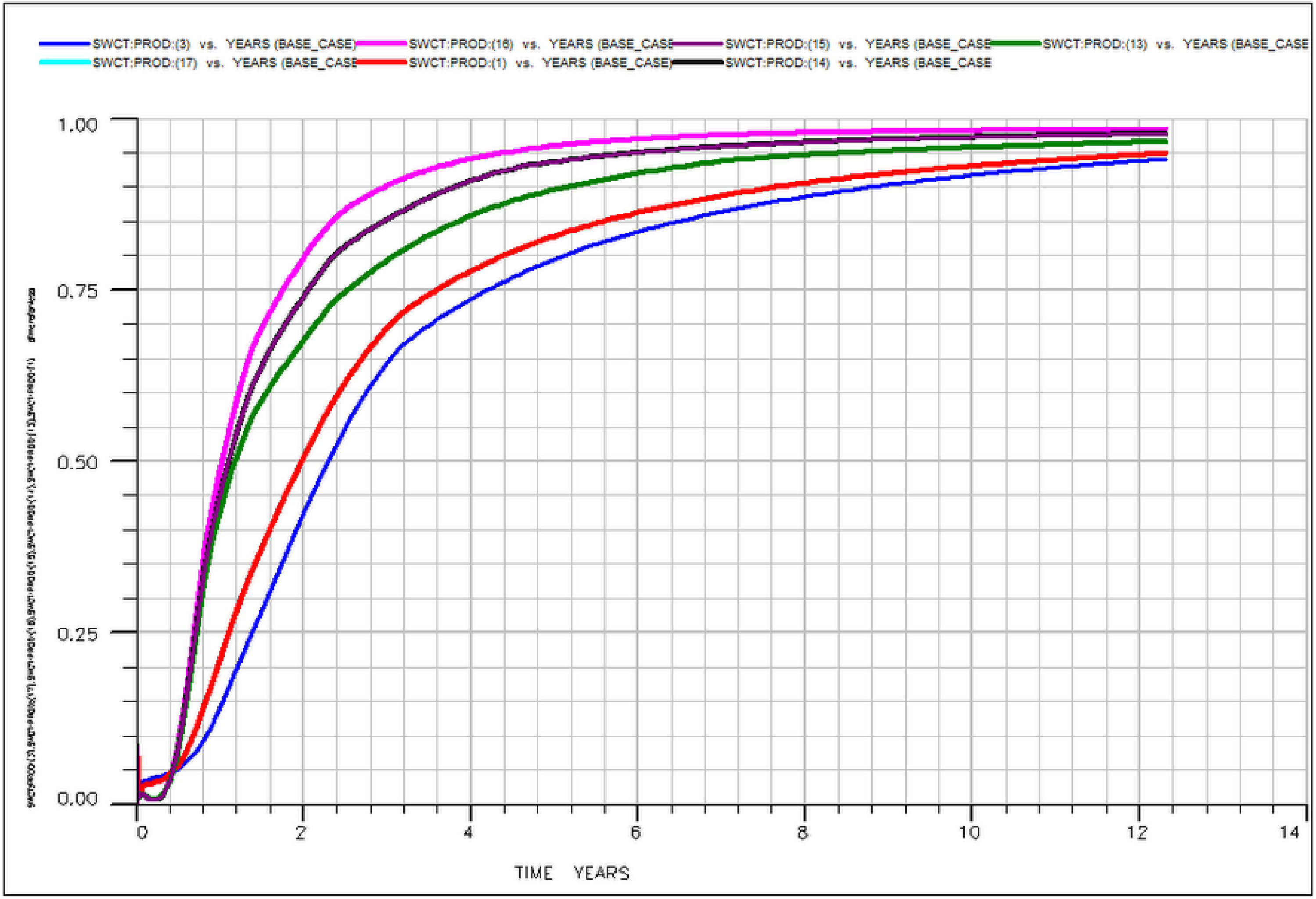

Figure 4.1: GOR and water cut for every segment in the base case

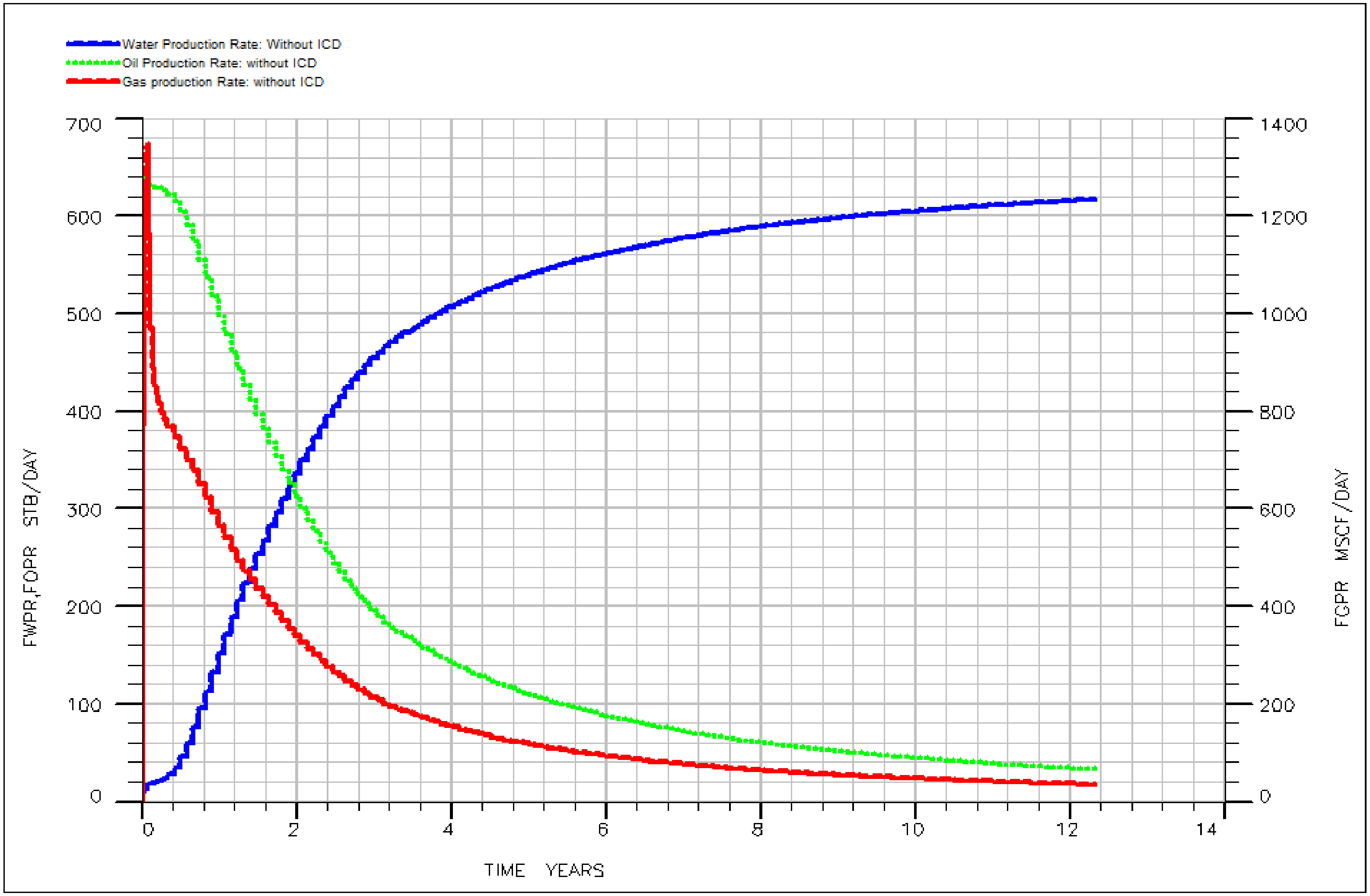

Figure 4.2: Annual Oil, water and gas production for base case (without ICD)

4.1.2. Base Case (without ICD) Production Rates for Case One

Results from the base case without ICD shows that the well starts producing with high rates and declines until lower rates the end of production year. From graph in figure 4.2, production began with 620 STB/D in the first day of production and declines to 500 STB/D after a year of production. In the third year, the oil production rate dropped to only 190 STB/D and at the end of production, the oil rate was only around 40 STB/D. The well also started with high gas rates and low water rates. But water increased rapidly and the gas rate decreased with time. The water production rate became higher than oil production in the second year and continued to rise until the last year of production. The gas production rate kept decreasing, showing that there was gas dissolved in the oil and when the pressure dropped below bubble point, the gas started to escape. However, after the implementation of water injection to maintain the pressure of the reservoir above the bubble point, the gas declined and consequently, some of the injected water penetrates through the oil into the production liner by the process of fingering resulting to high water production rates.

Higher water production may be the result of some zones having faster fluid inflow than the other zones and water, because of its higher density and low viscosity, breaks through the oil so easily. The uneven inflow distribution let to the decrease in oil production rates and higher water production. From table 4.3 below, total cumulative oil production of 721872 STB was recovered while cumulative water production was 2203128 STB, which was higher than the total oil produced. The pressure increased, demonstrating the support offered by the water injection program. In general, gas production was not a major problem in this well because its production was considered low and could be handled in the surface facilities. Therefore, the main mission remains to improve the inflow distribution and reduce or delay water production and if possible, increase the oil production. Table 4.3 shows results of the base case without ICD.

Table 4.3: Production rates for base case without ICD (Simulated)

TIME	YEAR	Oil Rate	Gas rate	Water Rate	Cum. Oil	Cum. Water	GOR
DAYS	YEAR	STB/D	MSCF/D	STB/D	STB	STB	MSCF/STB
1	0.003	594.7499	594.7639	55.25005	594.7499	55.25005	1.000023
750	2.0533	313.1326	339.898	336.8674	369912.2	117587.8	1.085476
1110	3.039	195.8681	213.7527	454.1319	457478.6	264021.4	1.09131
1470	4.024	143.7855	154.9961	506.2145	516828.2	438671.8	1.077968
1830	5.010	111.3233	118.6299	538.6768	561862.1	627637.9	1.065635
2220	6.078	87.84339	92.94745	562.1566	600048.1	842951.9	1.058104
2580	7.063	72.15463	76.02178	577.8453	628478	1048522	1.053595
2940	8.049	60.7084	63.84494	589.2916	652120.5	1258880	1.051666
3300	9.034	52.06255	54.72628	597.9374	672233.6	1472766	1.051164
3660	10.02	45.06068	47.36242	604.9393	689568.4	1689432	1.051081
4020	11.00	39.31342	41.3339	610.6866	704636.9	1908363	1.051394
4410	12.07	34.18361	35.96579	615.8164	718859	2147641	1.052136
4500	12.32	33.13748	34.87265	616.8625	721872.4	2203128	1.052363

4.1.3. Base Case with ICD Production Rates for Case One

The application of ICD was expected to improve the sweep efficiency and delay or reduce the production of water or gas. These were evaluated here by observing the performance of the well. From the graphs in figure 4.3a and 4.3b, Oil production started with a rate of 260 STB/D and increased up to a maximum of 440 STB/D within a year. It started to decline thereafter until 200 STB/D in the fourth year. It kept declining to a rate of 65 STB/D in the end year (12.25 years). During the start of production, water production rate was as low as 100 STB/D and increased until the water rate equals the oil rate at 3 years at the rate of 250 STB/D. More water continued to break through until it reaches a maximum of 520 STB/D in the end of production year. This higher rate of water production was the result of the water from the injection coning through the oil into the wellbore. As discussed above, gas production was considered low and manageable. The field pressure was increased from 3160 psi to a constant pressure of 3530 psi from the beginning of production till the end year of production. Some of the results for the ICD case are presented in table 4.4 below.

Table 4.4: Production results for the base case with ICD (Simulated)

TIME	YER	Oil Rate	Gas Rate	Water Rate	Cum. Oil	Cum. Water	GOR
DAY	**YEAR**	**STB/D**	**MSCF/D**	**STB/D**	**STB**	**STB**	**MSCF/STB**
1	0.00	405.94	431.74	118.35	405.94	118.3522	1.06
750	2.05	376.37	413.68	177.79	297688.00	99544.48	1.10
1110	3.04	257.61	278.80	253.23	409450.40	179050.3	1.08
1470	4.02	193.90	209.02	322.87	488901.30	284069.6	1.08
1830	5.01	151.30	163.12	377.81	549632.40	411261.8	1.08
2220	6.08	125.06	134.46	418.49	602557.00	568127.2	1.08
2580	7.06	108.48	116.02	443.11	644310.20	723648.8	1.07
2940	8.05	93.69	99.72	464.60	680406.20	887474.6	1.06
3300	9.03	81.09	85.95	482.63	711612.40	1058345	1.06
3660	10.02	70.69	74.68	497.35	738713.00	1235055	1.06
4020	11.01	62.41	65.77	509.01	762489.40	1416458	1.05
4410	12.07	55.28	58.14	519.03	785282.60	1617147	1.05
4500	12.32	53.83	56.59	521.06	790170.10	1663982	1.05

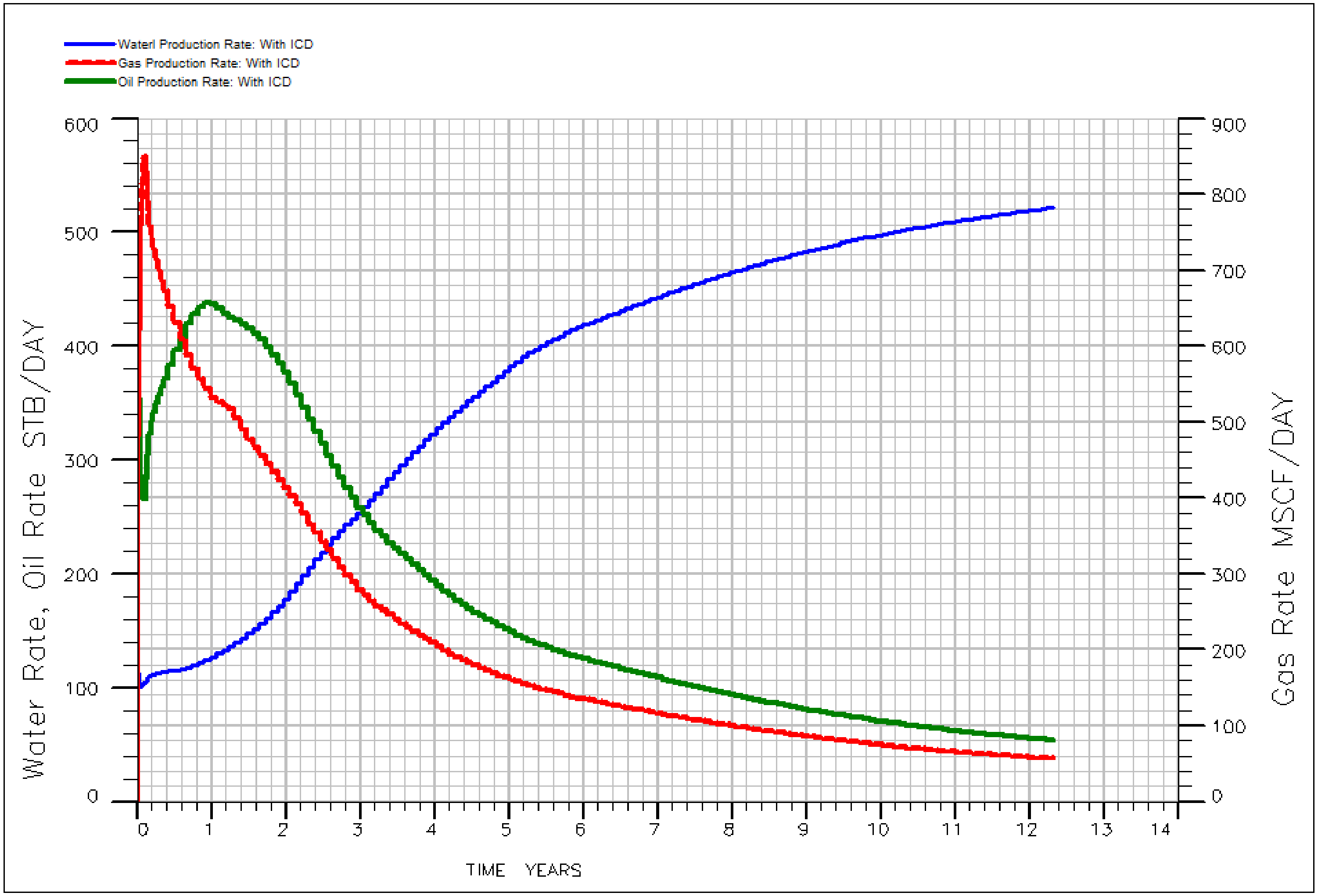

Figure 4.3a: Production rates for the base case with ICD for case one

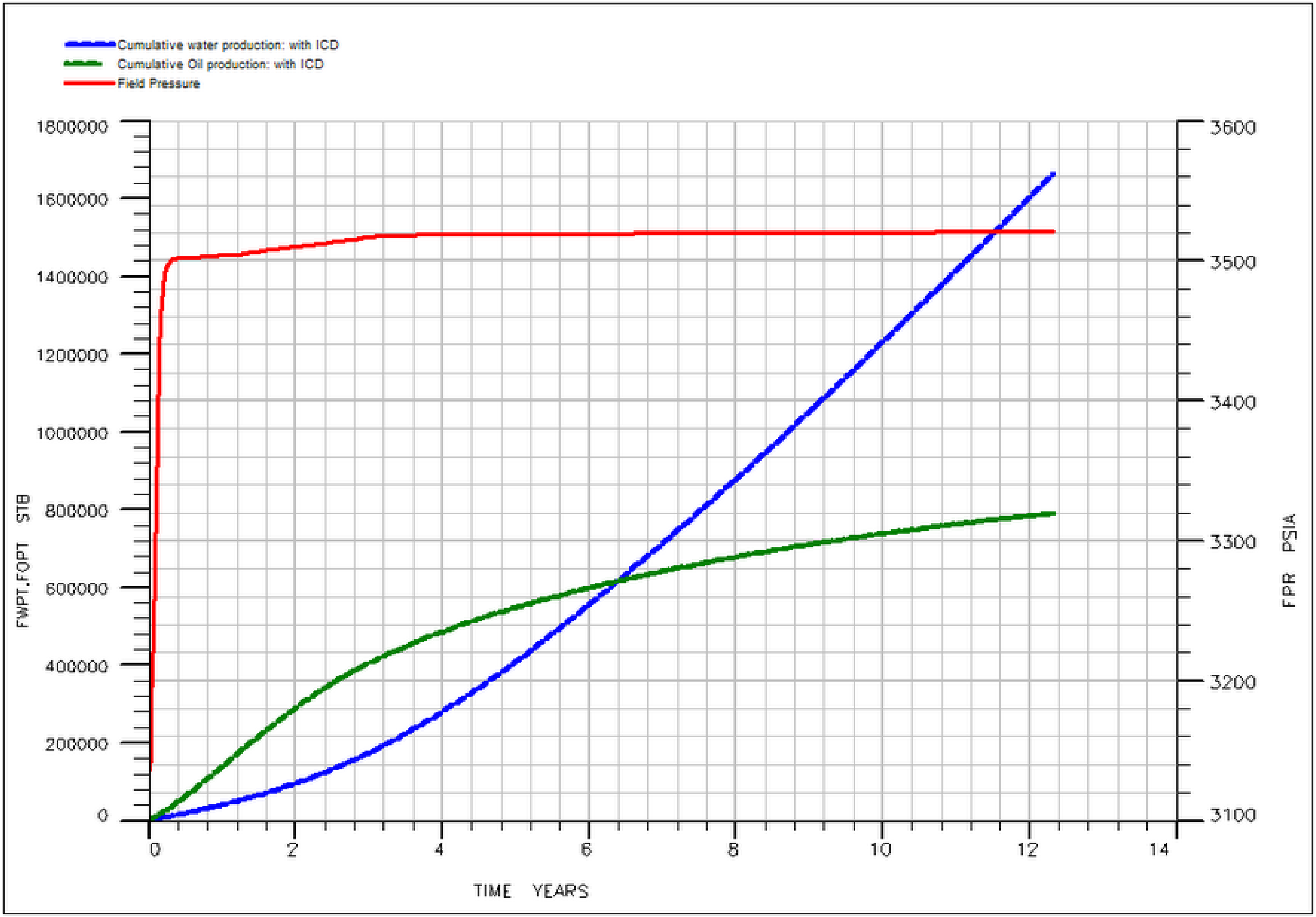

Figure 4.3b: Field pressur and cummulative productions as a function of time

4.1.4. Comparison between the Base Case Results and the ICD case Results

To clearly identify and illustrate the effect of the application of ICD in this well, let us look at a comparative view of the two results. The figure 4.4 below shows the results of the annual fluid production rates for both cases (base case and ICD case).

When we produced without ICD, the production began with a high rate of 640STB/D and declined rapidly until a rate of 200 STB/D in 3 years and continued to decrease until 40 STB/D at the end of production year 12. Water started with a low production rate of 20 STB/D and increased until water rate became equal to the oil rate at the second year with a rate of 330 STB/D with a maximum rate of 620 STB/D at the end of production year 12. While with ICD, production began with an oil rate of 260 STB/D and water rate of 100 STB/D. The oil rate decreased while the water rate increased until the rate of water equaled that of oil in 3 years with at a rate of 260 STB/D. Water continued to increase until a rate of 520 STB/D and oil decreased until a rate of 60 STB/D at the end of production (12.2 years).

Looking at figure 4.4b and 4.4c which shows the water cut, GOR, cumulative oil and cumulative water respectively, it was observed that the field water cut was reduced. The GOR was not highly affected but it was reduced as well. It is also evident that the oil recovery was improved as it can be seen that the total volume of oil produced at the end of production in the case without ICD was only 736739 STB as compared to the ICD case with about 801572 STB. This gave a difference of 64833 STB extra volumes of oil recovered due to the application of ICD. That is a percentage increase of 8%.

The increase in oil and reduction in the water rate was due to the additional pressure drop created by the ICD when the fluids were flowing through the device. This means that the model was able to demonstrate the objective of improving inflow distribution and sweep performance as well as reducing water/gas production in the well. Table 4.5a shows the summary of the comparative analysis of the two results.

Table 4.5: Comparative analysis of the Base case without ICD and the one with ICD (simulated results)

Property	**Year**	**Base Case (No ICD)**	**Base Case (with ICD)**	**Comment**
Oil Rate (STB/D)	1	500	420	Oil rate was low for ICD in the beginning because of the restriction, and it was improved from the third year and remained above the base case rate until end of production.
	3	195	275	
	6	87	125	
	12	40	55	
Water Rate (STB/D)	1	140	120	Water production was immensely reduced throughout the production period. This is due to even influx of the inflowing fluids by the additional pressure drop created by ICD.
	3	460	260	
	6	560	420	
	12	620	520	
Gas Rate (MSCF/D)	1	600	520	Gas production was reduced but it started to increase, insignificantly. Still manageable level
	3	210	280	
	6	80	130	
	12	40	50	
Cum. Oil (STB)	1	253438	1535560	The total volume of oil produced at the end of production is much higher than when no ICD is used. Over 8% increase in oil production.
	3	477407	430255	
	6	612967	612967	
	12	736739	807466	
Cum. Water (STB)	1	23575	23575	Total water volumes produced are reduced as compared to without ICD. Total decrease of 23.94%. Very successful in terms of water production reduction.
	3	271120	182711	
	6	848723	577603	
	12	2139000	1626720	

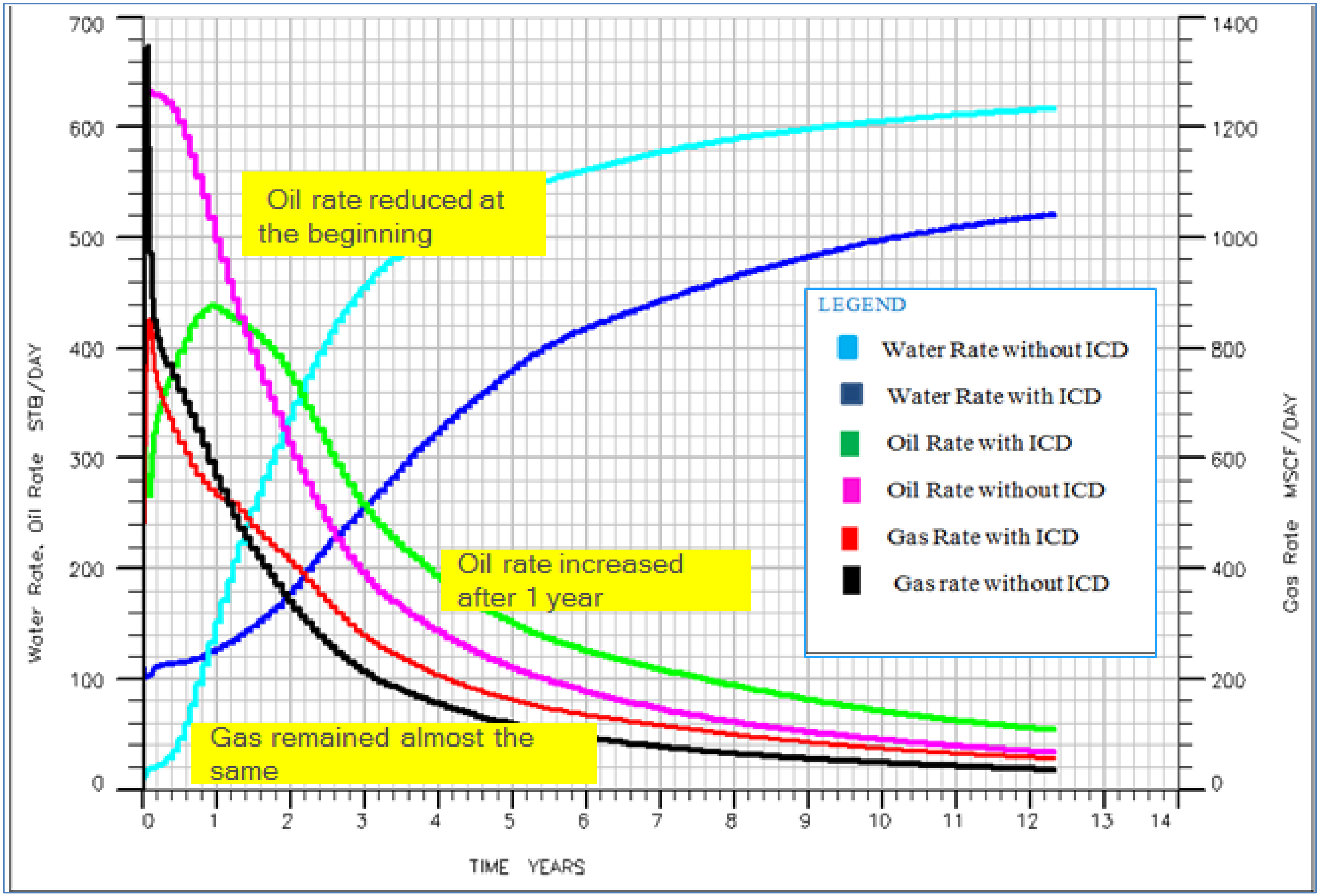

Figure 4.4a: Production Rates for both cases (with and without ICD)

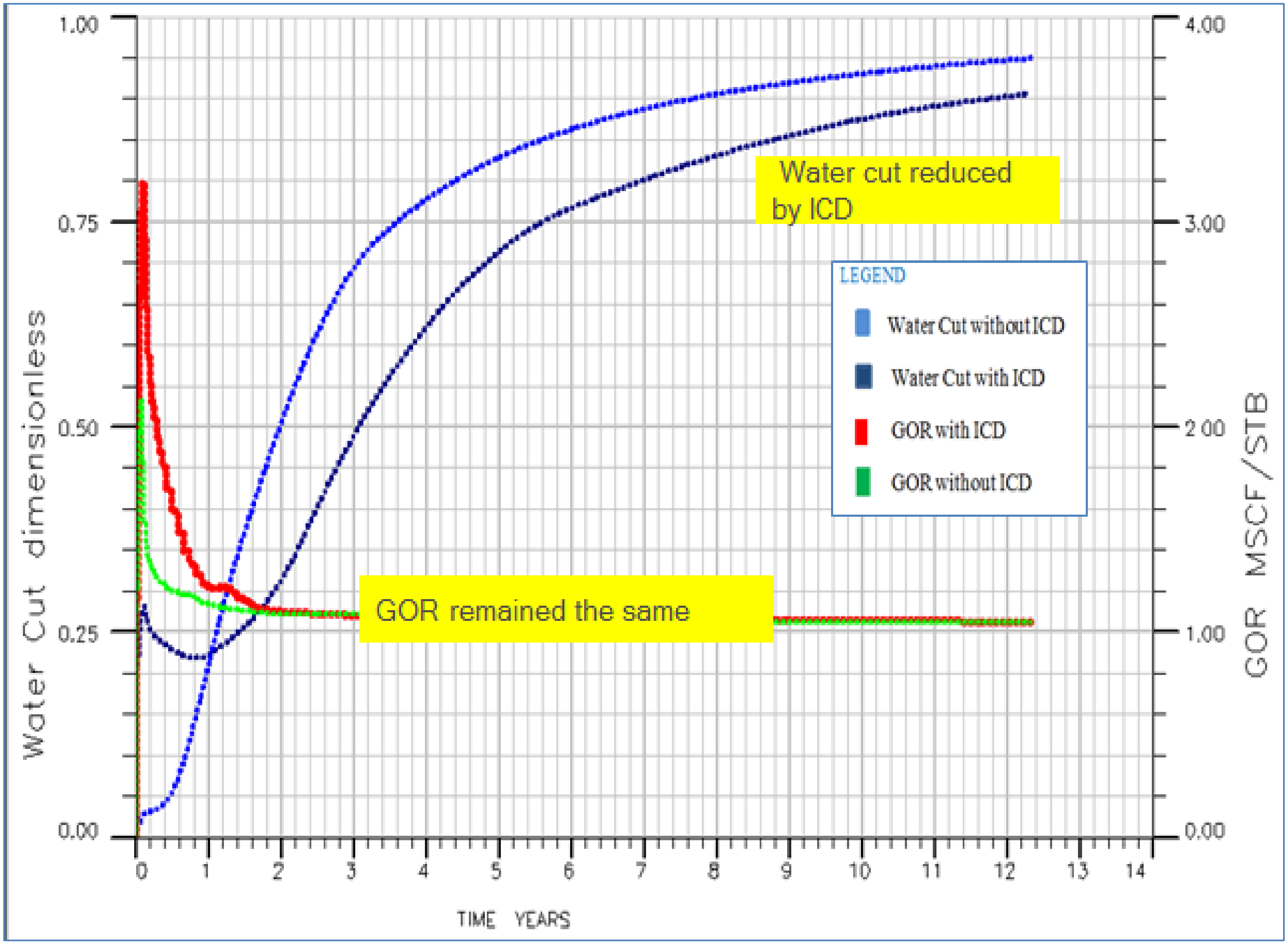

Figure 4.4b: Water cut (WWCT) and gas oil ratio for both cases

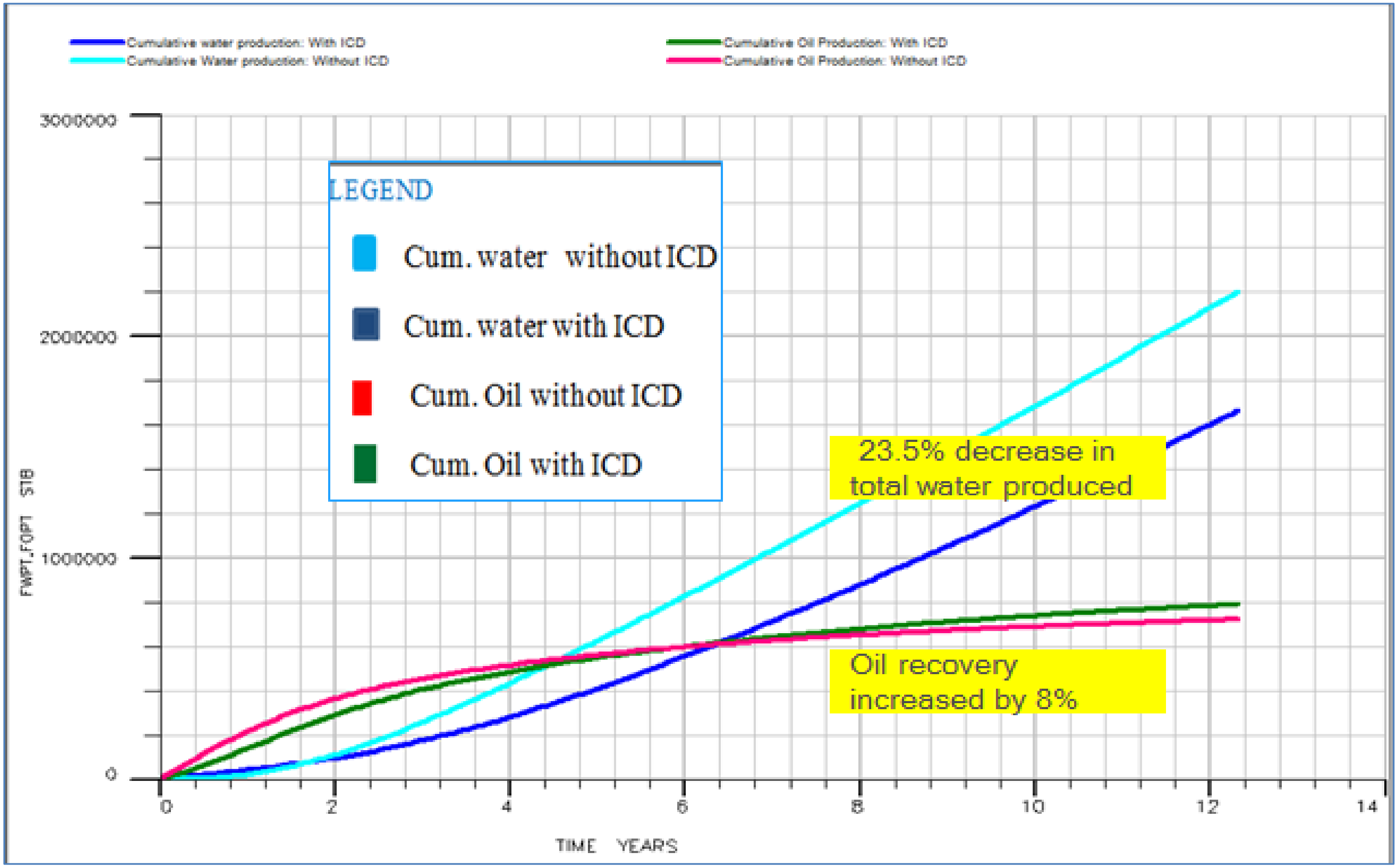

Figure 4.4 c: Annual Cumulative production for both cases (with and without ICD)

In conclusion, the application of the inflow control device has improved the well performance by reducing the production of the unwanted fluids (water and gas) as well as equalizing the distribution of the fluids to be produced at the vicinity of the wellbore. Although the oil production rate was reduced at the start of production, it increased over time and better cumulative oil production was achieve. Therefore, our objective of achieving evenly distributed inflow at the wellbore area while reducing water and gas production has been addressed for case one. ICD can be a tool for production performance optimization.

4.2. Case Two

The second case consists of a model of 500 grid cells (10x5x10). Each grid has the dimensions of 200x200x50 ft. with initial water saturation of 0.22 and a high permeability of 2000 md to demonstrate the existence of thief zones and heterogeneity. The vertical permeability was 50 md and initial pressure of 3000 psi. Some of the reservoir and fluid properties are shown in the table below.

Table 4.6a: Reservoir rock and fluid properties for case II [5]

Property	**Value**
Model dimensions	10x5x10
Grid size	200x200x50 ft
Initial pressure	3000 psi
Reference depth	7020 ft
Reference pressure	2700 psi
Permeability in x and y direction	2000 md
Permeability in Z direction	50 md
Oil density	45 lb/cu.ft
Water density	63 lb/cu.ft
Gas density	0.702 lb/cu.ft

Continuation: Table 4.6

Water viscosity	0.96 cp
Oil viscosity	2.1 cp
Oil FVF	1.21 rb/stb
Water FVF	1 cp
WOC	7990 ft
GOC	7020 ft
Well Length	822 ft
ICD strength	0.0002 psi/(ft/day)^2
Segment length	20 ft

The model consists of one horizontal well and one injection well. Like the first case, the production well was divided into 25 segments and three main branches with 15 nodes. The injection was divided into 24 segments. The injection well was used for pressure maintenance and specifically in this study to demonstrate the existence of a strong water drive which results to higher water production rates.

4.2.1. Base case II Results

As in the first case, both the production and injection wells were divided into segments and it was run normally without ICD. The production rates are published in the table below.

Table 4.6b: Production rates and cumulative volumes for Case II without ICD (Simulated)

YEAR	Oil rate (STB/D)	Gas rate (MSCF/D)	Water rate (STB/D)	Cum. Oil (STB)	Cum. Water (STB)	GOR MSCF/STB
0	0.52	0.53	649.48	0.52	649.48	1.01
2	72.95	84.42	577.05	36871.42	528628.60	1.12
4	95.88	109.87	554.12	89605.11	865894.90	1.14
6	100.83	116.44	549.17	161148.5	1262352	1.15
8	99.27	115.65	550.73	233381.9	1658118	1.17
10	94.94	111.49	555.06	303337.8	2056162	1.18
12	89.23	105.57	560.77	372339.8	2474660	1.19
12.32	88.31	104.84	561.69	382978.6	2542022	1.19

From the table above, the well started producing at an oil rate of 0.52 STB/D and increased to 72.95 in the second year while water started at a higher rate of 649.48 STB/D and increased to 577 STB/D. This was considered very high water production. Most of the water might have come from the injection well due to the effect of fingering because of viscosity and mobility differences. The water was able to cut through the oil into the producing liner. The oil rate reached a maximum of 100 STB/D in the sixth year and started to decrease in a stabilized manner until it reached a production rate of 88 STB/D at the end of production. The water increased as the oil rate decreased leading to higher cumulative water production and higher water cut. The gas was also increasing as the oil was decreasing. This means that there was gas in solution with the oil and the reservoir pressure had started to decline to below the bubble point pressure. The overall performance of the well in terms of production rates can be observed in the proceeding figures 4.5a to 4.5c below.

4.2.2. Results for Case II with ICD

The segments with high water cut and suitable for ICD application were identified to be segments 5, 6, 7, 8, 13, and 14. Spiral ICD of 0.0002 psi/(ft/day)^2 was applied and the results are given the table below.

Table 4.6c: Production performance results for ICD Case II (Simulated)

YEAR	Oil Rate (STB/D)	Gas Rate (MSCF/D)	Water Rate (STB/DAY)	Cum. Oil (STB)	Cum. Water (STB)	GOR (MSCF/STB)
0	264.73	286.14	385.27	264.73	0.53	1.08
2	338.46	380.41	311.54	319841.40	84.42	1.12
4	276.79	317.37	373.21	503797.20	109.87	1.15
6	201.67	235.74	448.33	675756.10	116.44	1.17
8	153.41	182.05	496.59	800258.90	115.65	1.19
10	131.58	158.11	518.42	901343.80	111.49	1.20
12	113.61	137.91	536.39	993080.50	105.57	1.21
12.3	111.50	135.5047	538.50	1003179	1921821	1.22

It can be observed from the above table that the production was improved. When using ICD, the well started producing at the rate 264.3 STB/D as opposed to 0.53 STB/D without ICD. Its maximum was at the second year (338 STB/D) and decreased in a stabilized manner until 111 STB/D as compared to 88 STB in the end of production. The cumulative oil produced increased from 382978.6 STB to 1003179 STB with ICD, a massive increase of 62%. The water production was also reduced from 649.48 STB/D in the start of production without ICD to 286.14 STB/D with ICD. Total water produced at the end of production was also reduced.

Notably, the gas rate was not improved by ICD as it increased, even though it was an insignificant increase. This may be a result of poor pressure maintenance by water injection. Since water injection was not the objective of this study, it is only provided to illustrate the pressure of strong water source and was not discussed here.

When ICD was applied to all the segments, the oil production rate decreased badly and the water cut was reduced to minimum. That means more unwanted restriction was provided which subsequently lowered the recovery although water cut will be minimum. For this analysis, the ICD application in the selected segments was considered the optimum strategy for oil recovery with ICD. More comparative analysis and discussions were provided in the proceeding subsection below with graphical illustrations.

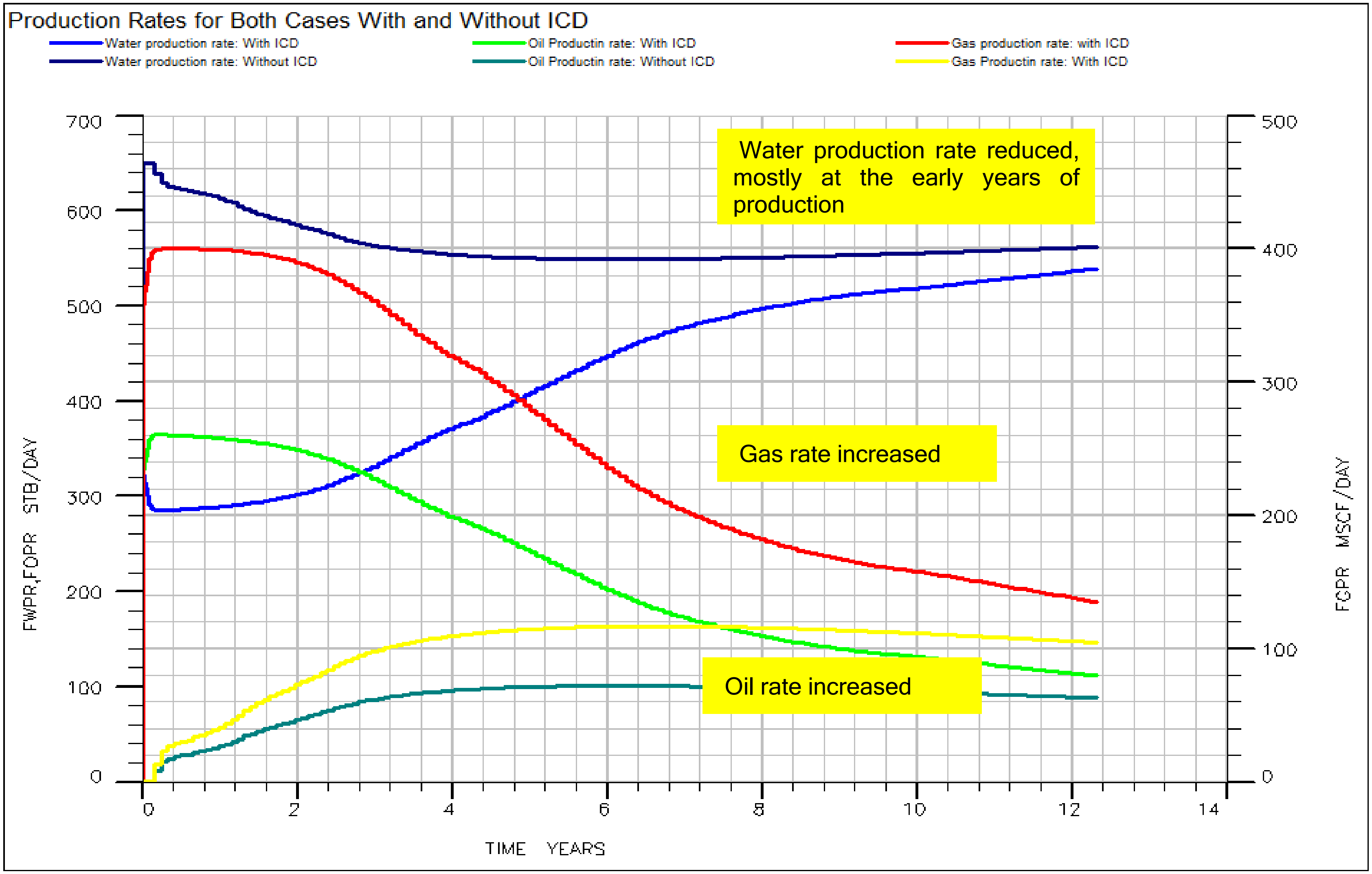

Figure 4.5a: Production rates for Case II with and without ICD

4.2.3. Comparison Between Base Case and ICD Case for Case Two

Figure 4.5a above shows the production rates for Case II with and without ICD. It can clearly be seen that the improved to higher rates and the water rate was reduced to lesser than when we produced without ICD. The increment in the oil production rate was the result of even inflow redistribution at the wellbore vicinity by the additional restriction and pressure drop provided by the ICD. The restriction also resulted into reduced water production, although the gas production increased. The increment in gas production by the application of ICD provides evident that the gas in solution escapes faster with the additional pressure by ICD because the pressure maintenance strategy was not very successful.

Figure 4.5b below shows the water cut and gas oil ratio for the Case II with and without ICD. It was illustrated graphically that the water cut was decreased into a very low value that made the application of ICD very successful here and desirable for application in the industry. The gas oil ratio increased but not very much. That means this was still considered insignificant increase and can be improved into a better desirable lower ratio.

Figure 4.5c below illustrates the cumulative volumes of fluid produced for Case II with and without ICD. It was evident that the production with ICD was much better than that without ICD. The STOIP was given in figure 4.5d and demonstrated that ICD application was successful in this case. The OOIP was 7.49 MSTB and 1003179 STB was produced. Therefore, 13.57 % of the OOIP was produced with ICD. Without ICD, only 382978.6 STB was recovered, resulting to only 5.11% recovery. In general, an incredible increase of 62.31% in oil production was achieved by the application of ICD. More comparisons are provided and illustrated for better understanding in a summarized way in table 4.6d below.

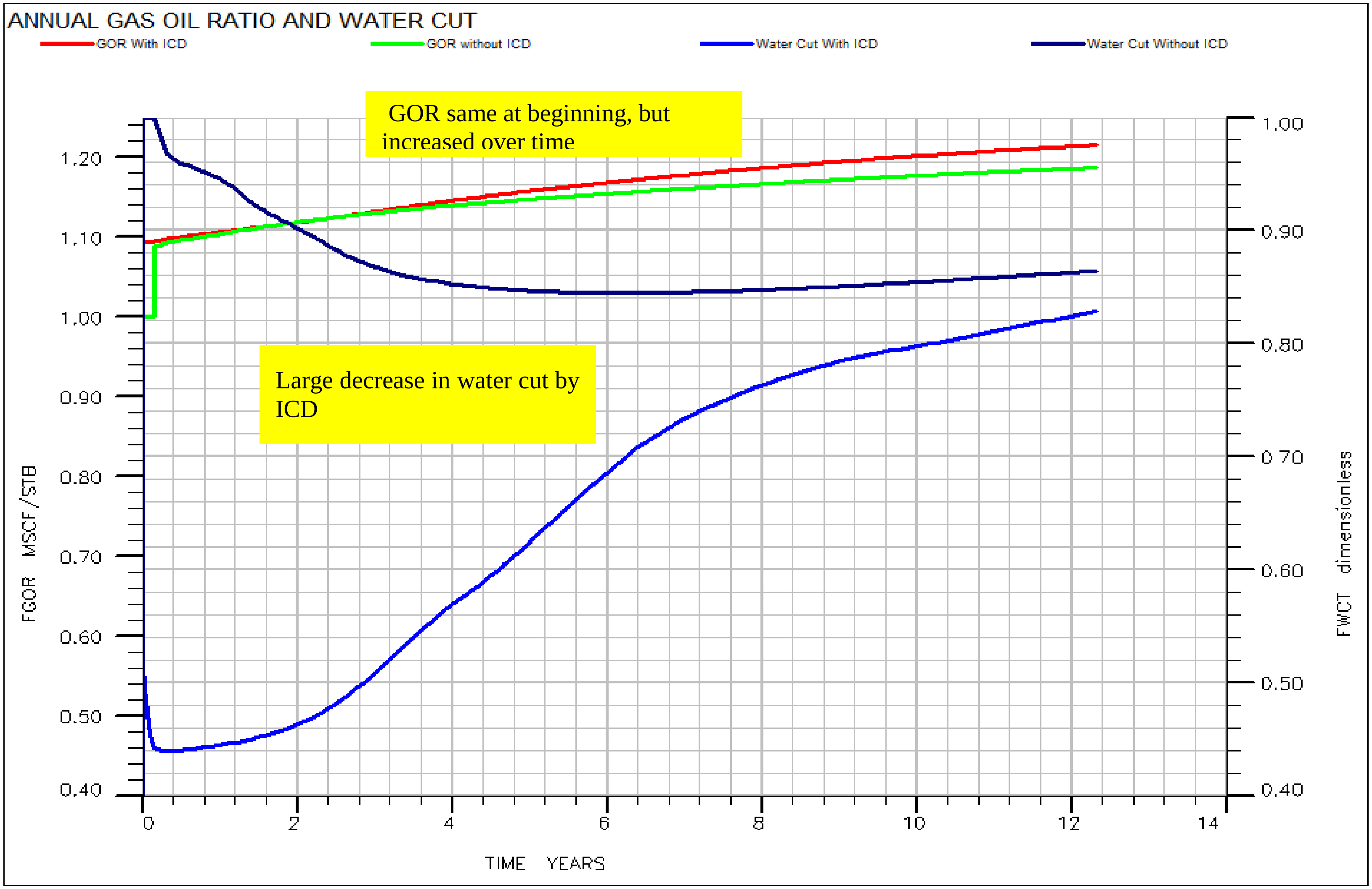

Figure 4.5b: Annual Water cut and GOR for Case II with and without ICD

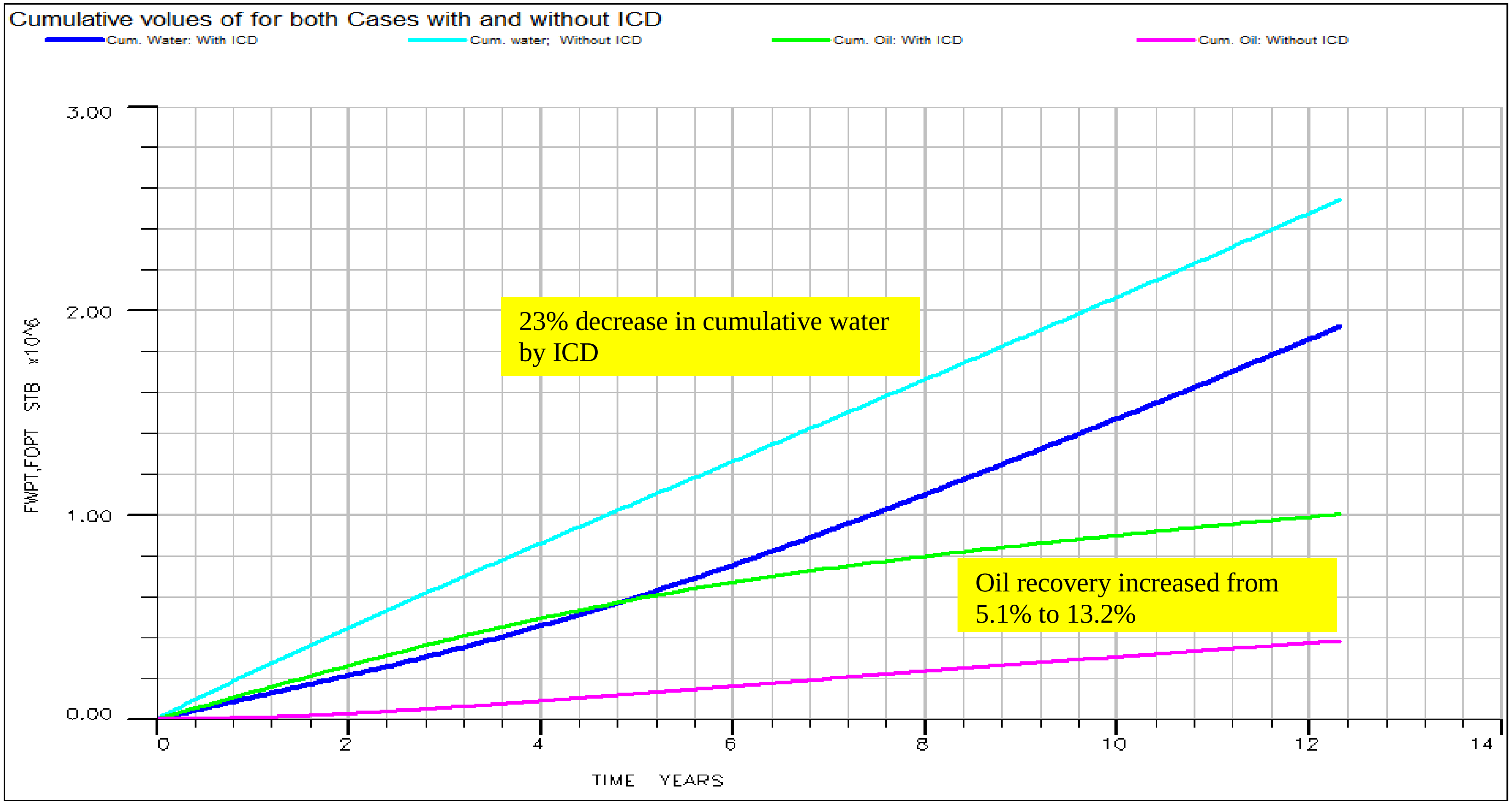

Figure 4.5c: Annual Cumulative fluid volumes produced for Case II with and without ICD

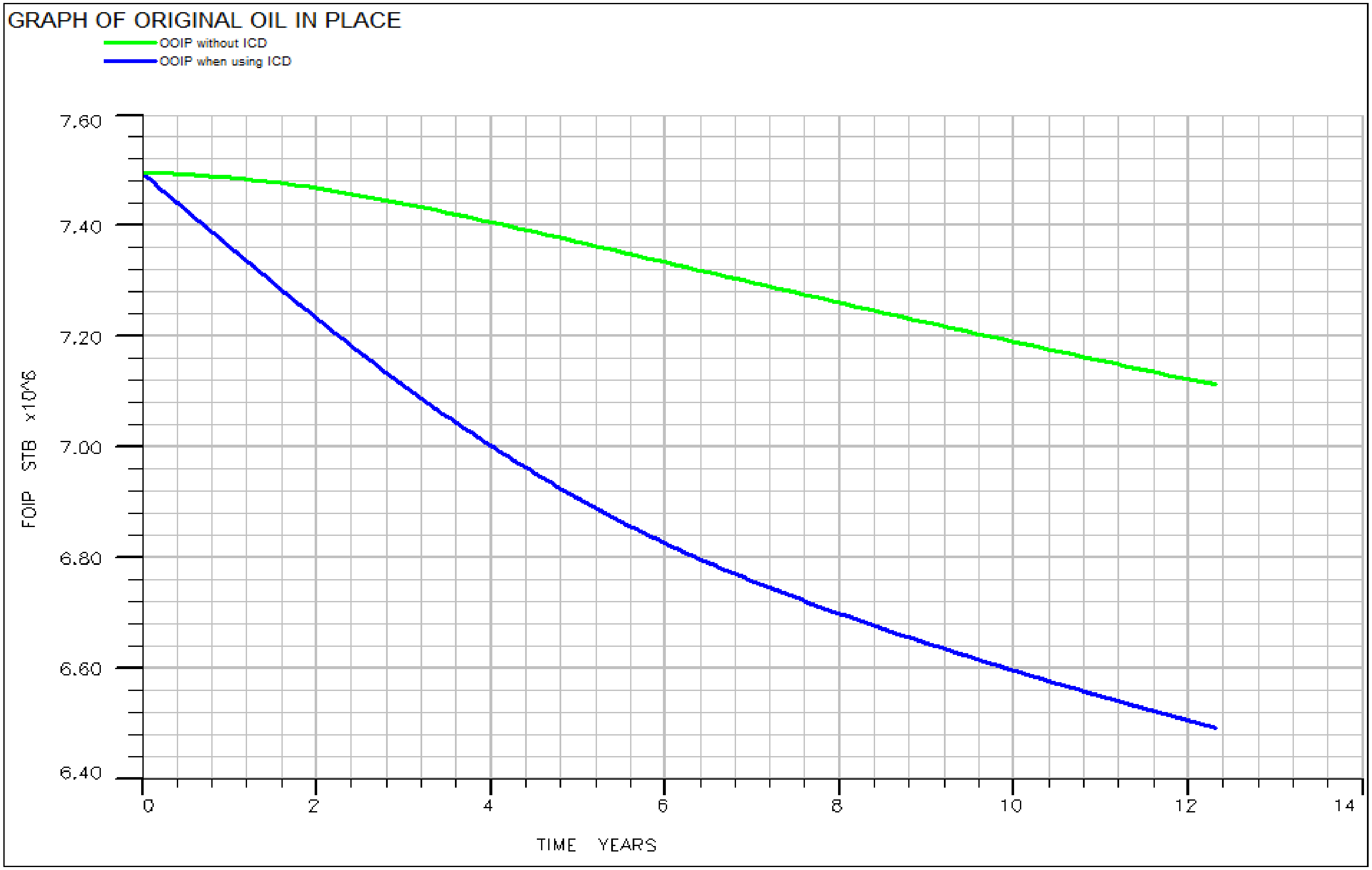

Figure 4.6d: Graph of OIIP vs. production years for Case II with and without ICD

Table 4.6d: Comparative analysis for Case II with and without ICD (Simulated)

YEARS	Cum. Oil (STB)		Cum. Water (STB)		GOR (MSCF/STB)		Recovery (%)	
	Base Case	ICD	Base case	ICD	Base Case	ICD	Base case	ICD
1	9272.612	140630.8	244227.4	112869.2	1.01	1.08	1.104	1.878
2	36871.42	319841.40	528628.60	84.42	1.12	1.12	0.492	4.270
4	89605.11	503797.20	865894.90	109.87	1.14	1.15	1.196	6.726
6	161148.5	675756.10	1262352.0	116.44	1.15	1.17	2.152	9.022
8	233381.9	800258.90	1658118.0	115.65	1.17	1.19	3.116	10.684
10	303337.8	901343.80	2056162	111.49	1.18	1.20	4.050	12.034
12	372339.8	993080.50	2474660	105.57	1.19	1.21	4.971	13.259
12.32	382978.6	1003179.00	2542022	1921821	1.19	1.22	5.113	13.394

This shows a massive increase in recovery. 13.39% was considered high as compared to 5.11% without ICD. This was especially quite good for primary recovery and given the fact that ICDs are not as expensive as EOR methods. The application of ICD to Case II of this study was successful. This rhymed with the objectives of the study which were to reduce water/gas production and increasing oil recovery by even distribution of the inflow in the vicinity of the wellbore.

In general, for the two cases presented above, there was increase in oil recovery as well as decrease in the unwanted fluid production (water and gas). This demonstrated that the application of ICD was having a positive impact on horizontal well performance when properly optimized. Choosing the segments to install the ICD was very crucial to obtain the best recovery strategy. As it was only simulation, it was important to do “try and error” in placing the ICDs to various segments and find the best segments that improves oil production as well as decrease water and gas production for an overall better recovery.

CHAPTER 5
CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

Horizontal wells are currently widely used in the oil and gas industry as a way of improving oil recovery due to high world demand for oil. From the results, the basic idea for the application of ICD was witnessed. It was apparent that ICD can improve the flux efficiency of horizontal well as well as reducing the production of water and gas. From the two cases presented above, the objectives of this study have been achieved. It is worth noting that the use of simulation tools can enhance the optimization of horizontal wells by ICD modeling. The multi-segment well model in the ECLIPSE Black Oil simulator is very essential to ICD modeling. Table 5 presents a summary of the study in a conclusive manner with respect to the objectives.

Table 5: Conclusive remarks

Base Case (without ICD)	**Base Case (with ICD)**
Low oil recovery.	High Oil recovery
Unequal influx at the heel of the well depicted by low oil rates and high water production	Equalized influx at the heel of the well resulting to higher oil recovery.
Higher Water and gas production	Reduced water and gas production

5.2 Limitations

There are some limitations in the study of ICD application as a student since there was no practical data provided. Usually, actual reservoir data are required to simulate the effect of ICD on horizontal well performance. Given the time and the current circumstance, partial data from literature have been used and other data were assumed to meet the objective of the study.

The ECLISPE Simulator was also challenging software which requires a lot of time and expertise and there is a need for proper training for the engineer for better simulation.

5.3 Recommendations

The use of actual reservoir data may enhance the study of ICD application and students interested in ICD study may need to get a proper knowledge of the simulator.

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APPENDICES

Appendix 1: Case One Model (without ICD)

```
=================
RUNSPEC
TITLE
3D - 3 Phase Model
--       Number of cells
--      NX      NY      NZ
--      --      --      --
DIMENS
              15       1       20/

-- Phases
OIL
WATER
GAS
DISGAS
/
-- Units
FIELD
/
TABDIMS
--#Sat tabs #pvt tabs  #Sat nodes #Pnodes #FIP  NRPVT
   1      1      15      15      2 15 /
EQLDIMS
--Number of equilibration regions
 2 /
-- Maximum well/connection/group values
--      #wells   #cons/w   #grps   #wells/grp
--    ------ ------- ----- ----------
WELLDIMS
          2    25     3     1 /
VFPPDIMS
 6 3 3 3 1 1 /
VFPIDIMS
 6 3 2 /
WSEGDIMS
--#msw   #segments/well   #Branches
   2     25        6 /
-- Unified output files
UNIFOUT

NSTACK
60/
-- Simulation start date
START
 1 Jan 2008 /
==========================
GRID
EQUALS
 'DX'    200 /
 'DY'    100 /
 'PERMX'  2000  /
 'PERMZ'  20  /
 'DZ'    20  /
 'PORO'   0.2 /
 'TOPS'   7000   1 15  1 1  1   1 /
 'DZ'    200    1 15  1 1  15  15 /
 'PORO'   0.0    1 15  1 1  15  15 /
 /
COPY
  PERMX PERMY /
 /
RPTGRID
 -- Report Levels for Grid Section Data
 /
-- Output file with geometry and rock properties (.INIT)
INIT
==========================
PROPS
-- Densities in lb/ft3
--        Oil     Wat     Gas
--        ---     ---     ---
DENSITY
          45           63.02   0.0702 /
-- PVT data for water
--     P      Bw      Cw       Vis Viscosibility
--    ----    ----    -----    -----   -------------
PVTW
      3000      1.00341    3.0D-6   0.96     0.0 /
-- Rock compressibility
--       P       Cr
--     ----     -----
ROCK
      3000   4.0D-6  /
PVDG
 400  5.9   0.013
 800  2.95  0.0135
```

```
1200  1.96  0.014
1600  1.47  0.0145
2000  1.18  0.015
2400  0.98  0.0155
2800  0.84  0.016
3200  0.74  0.0165
3600  0.65  0.017
4000  0.59  0.0175
4400  0.54  0.018
4800  0.49  0.0185
5200  0.45  0.019
5600  0.42  0.0195 /
PMAX
 7000 /
PVCO
400  0.165   1.012    1.17   5.0E-5  1*
800  0.335   1.0255   1.14     2*
1200 0.500   1.038    1.11     2*
1600 0.665   1.051    1.08     2*
2000 0.828   1.063    1.06     2*
2400 0.985   1.075    1.03     2*
2800 1.130   1.087    1.00     2*
3200 1.270   1.0985   0.98     2*
3600 1.390   1.11     0.95     2*
4000 1.500   1.12     0.94     2*
4400 1.600   1.13     0.92     2*
4800 1.676   1.14     0.91     2*
5200 1.750   1.148    0.9      2*
5600 1.810   1.155    0.89     2*
/
-- Water, Gas and oil rel perms & capillary pressures
SWFN
-- Sw    Krw    Pcow
 0.22   0.0    6.30
 0.3    0.07   3.60
 0.4    0.15   2.70
 0.5    0.24   2.25
 0.6    0.33   1.80
 0.8    0.65   0.90
 0.9    0.83   0.45
 1.0    1.0    0.0   /
SGFN
-- Sg    Krg    Pcgo
 0.0  0.0     0.0
 0.04  0.0    0.2
 0.1  0.022   0.5
 0.2  0.1     1.0
 0.3  0.24    1.5
 0.4  0.34    2.0
 0.5  0.42    2.5
 0.6  0.5     3.0
 0.7  0.8125  3.5
 0.78  1.0    3.9   /
SOF3
-- So   Krow    Krog
 0.0  0.0     0.0
 0.2  0.0     0.0
 0.38  1*     0.0
 0.4  0.0048  1*
 0.48  1*     0.02
 0.5  0.0649  1*
 0.58  1*     0.1
 0.6  0.125   1*
 0.68  1*     0.33
 0.7  0.4     1*
 0.74  1*     0.6
 0.78  1.0    1.0   /
--SWOF
--  0.22  0     1.0     3.5
--  0.3   0.07  0.4     2
--  0.4   0.15  0.125   1.5
--  0.5   0.24  0.0649  1.25
SOLUTION
-- Initial equilibration conditions
--    Datum   Pi@datum    WOC    Pc@WOC
--    -----   --------   -----   ------
EQUIL
    7020.00    2700.00   7990.00   0.0000    7020.00   .00000   0   0   5 /
    7200.00    3700.00   7300.00   .00000 7000.00   .00000    1   0   5 /

RSVD     2 TABLES     3 NODES IN EACH      FIELD    12:00 17 AUG 83
   7000.0  1.0000
   7990.0  1.0000
/
   7000.0  1.0000
   7400.0  1.0000
/
RPTRST
-- Restart File Output Control
'BASIC=2' 'FLOWS' 'POT' 'PRES' /
RPTSOL
--
-- Initialisation Print Output
'PRES'  'SOIL'  'SWAT'  'SGAS'  'RS'  'RESTART=1'   'FIP=2'   'EQUIL'  'RSVD' /
==========================
SUMMARY
```

```
-- Field average pressure
FPR
-- Bottomhole pressure of all wells
WBHP
/
-- Field Oil Production Rate
FOPR
--Field gas production
FGPR
-- Field Water Production Rate
FWPR
-- Field Oil Production Total
FOPT
-- Field Water Production Total
FWPT
-- field Recovery factor
FOE
--Field Water cut
FWCT
--Field GOR
FGOR
-- Water cut in PROD
WWCT
PROD /
WOPR/
FOIP
SOFR
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SOFRF
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SOFRS
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SWFR
 'PROD' 1 /
 /
SGFR
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SGFRF
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SGFR
 'PROD' 1 /
 'PROD' 2 /
 'PROD' 3 /
 'PROD' 10 /
 'PROD' 13 /
 'PROD' 18 /
 'PROD' 20 /
 'PROD' 22 /
 'PROD' 23 /
 /
SWCT
 'PROD' 1 /
 'PROD' 3 /
```

```
 'PROD' 13 /
 'PROD' 14 /
 'PROD' 15 /
 'PROD' 16 /
 'PROD' 17 /
 /
SGOR
 'PROD' 1 /
 'PROD' 23 /
 'PROD' 25 /
 'PROD' 25 /
 /
SPR
 'PROD' /
 /
SPRDH
 'PROD' 2 /
 'PROD' 3 /
 /
SPRDF
 'PROD' /
/

SWFR
 'WINJ' 1 /
 'WINJ' 4 /
 'WINJ' 5 /
 /
SWCT
 'WINJ' 4 /
 /
SGOR
 'WINJ' 4 /
 /
SPR
 'WINJ' /
 /
SPRDH
 'WINJ' 2 /
 'WINJ' 3 /
 /

SPRDF
 'WINJ' /
 /
RUNSUM
-- CPU usage
TCPU
-- Create Excel readable Run Summary file (.RSM)
EXCEL
==========================
SCHEDULE
DEBUG
  1 3  /
DRSDT
  1.0E20  /
RPTSCHED
  'PRES' 'SWAT' 'SGAS' 'RESTART=1' 'RS' 'WELLS=2' 'SUMMARY=2'
  'CPU=2' 'WELSPECS' 'NEWTON=2' /
NOECHO
--PRODUCTION WELL VFP TABLE 1
VFPPROD

  1    7.0000E+03   'LIQ'   'WCT' 'GOR'  'thp'  'iglr' 'field' /
  2.00000E+00   6.00000E+02 1.40000E+03  2.00000E+03
  4.00000E+03  6.00000E+03
 /
  2.00000E+02   5.00000E+02 1.00000E+03
 /
  .00000E+00   4.00000E-01 8.00000E-01
 /
  1.00000E+00   2.00000E+00 4.00000E+00
 /
  .00000E+00
 /
  1   1   1   1   1.97594E+03 1.37517E+03   7.75232E+02 7.31301E+02
   8.63600E+02 1.07507E+03
   /
  2   1   1   1   2.24076E+03 2.05768E+03   2.00844E+03 1.95077E+03
   1.91803E+03 1.99808E+03
   /
  3   1   1   1   2.71295E+03 2.70532E+03   2.71278E+03 2.72263E+03
   2.78084E+03 2.87541E+03
   /

  1   2   1   1   2.34711E+03 1.96200E+03   1.80998E+03 1.63946E+03
   1.53864E+03 1.65905E+03
   /
  2   2   1   1   2.61779E+03 2.49181E+03   2.45750E+03 2.45608E+03
```

2.49589E+03
2.53344E+03

/

3 2 1 1 3.09452E+03
3.09009E+03 3.09663E+03
3.10603E+03

3.15875E+03
3.24354E+03

/

1 3 1 1 2.85373E+03
2.68696E+03 2.63428E+03
2.62542E+03

2.66829E+03
2.70294E+03

/

2 3 1 1 3.14219E+03
3.09125E+03 3.08104E+03
3.08301E+03

3.12402E+03
3.20092E+03

/

3 3 1 1 3.63367E+03
3.63377E+03 3.64044E+03
3.64886E+03

3.69552E+03
3.76936E+03

/

1 1 2 1 1.90703E+03
4.23900E+02 4.91041E+02
5.61854E+02

8.41860E+02
1.14254E+03

/

2 1 2 1 2.13732E+03
1.51748E+03 1.10210E+03
1.13989E+03

1.31168E+03
1.53169E+03

/

3 1 2 1 2.52712E+03
2.36101E+03 2.32094E+03
2.26533E+03

2.32880E+03
2.47300E+03

/

1 2 2 1 2.24180E+03
1.37824E+03 7.45545E+02
7.21454E+02

9.51216E+02
1.21802E+03

/

2 2 2 1 2.47044E+03
2.06424E+03 1.91696E+03
1.78107E+03

1.76738E+03
1.92943E+03

/

3 2 2 1 2.87369E+03
2.74718E+03 2.72192E+03
2.72627E+03

2.78577E+03
2.89035E+03

/

1 3 2 1 2.75731E+03
2.35384E+03 2.23030E+03
2.18779E+03

2.01332E+03
2.05525E+03

/

2 3 2 1 3.02294E+03
2.83361E+03 2.77281E+03
2.76184E+03

2.80340E+03
2.86235E+03

/

3 3 2 1 3.47670E+03
3.41854E+03 3.40882E+03
3.41186E+03

3.45913E+03
3.54604E+03

/

1 1 3 1 1.87259E+03
3.91529E+02 5.70235E+02
7.19731E+02

1.21992E+03
1.71171E+03

/

2 1 3 1 2.11457E+03
8.41615E+02 9.39654E+02
1.03956E+03

1.43521E+03
1.86682E+03

/

3 1 3 1 2.50409E+03
1.83217E+03 1.79926E+03
1.85238E+03

2.09347E+03
2.40294E+03

/

1 2 3 1 2.22684E+03
5.02107E+02 5.73039E+02
6.81812E+02

1.06856E+03
1.47815E+03

/

2 2 3 1 2.45705E+03
1.54829E+03 1.10263E+03
1.17176E+03

1.46382E+03
1.80211E+03

/

3 2 3 1 2.83378E+03
2.42600E+03 2.30007E+03
2.22995E+03

2.38437E+03
2.65017E+03

/

1 3 3 1 2.73870E+03
1.91960E+03 1.48679E+03
1.24203E+03

1.23967E+03
1.44955E+03

/

2 3 3 1 2.98935E+03
2.50931E+03 2.37089E+03
2.32059E+03

2.18865E+03
2.28214E+03

/

3 3 3 1 3.40018E+03
3.17167E+03 3.10777E+03
3.09743E+03

3.14591E+03
3.22270E+03

/

--INJECTION WELL VFP TABLE 1

VFPINJ

1 7.0000E+03 'WAT' /

2.00000E+00 6.00000E+02 1.40000E+03 2.00000E+03

4.00000E+03 6.00000E+03

/

5.00000E+02

/

1 3.49209E+03 3.48640E+03 3.46590E+03 3.44178E+03

3.30981E+03 3.10032E+03

/

--INJECTION WELL VFP TABLE 2

VFPINJ

2 6.90000E+03 'GAS' /

1.00000E+00 3.00000E+02 7.00000E+02 1.00000E+03

2.00000E+03 3.00000E+03

/

1.00000E+03 2.00000E+03 3.00000E+03

/

1 1.31963E+03 1.31781E+03 1.31049E+03 1.30133E+03

1.24694E+03 1.15029E+03

/

2 2.73750E+03 2.73671E+03 2.73365E+03 2.72991E+03

2.70847E+03 2.67303E+03

/

3 3.92693E+03 3.92631E+03 3.92396E+03 3.92110E+03

3.90493E+03 3.87853E+03

/

ECHO

-- Location of wellhead and pressure gauge

-- Well Well Location BHP Pref.

-- name group I J datum phase

-- ----- ---- - - ----- -----

WELSPECS

PROD G1 1 1 7030 OIL 0.0 STD STOP YES 0 AVG 0 /

WINJ G2 15 1 7030 WAT 0.0 STD STOP YES 0 AVG 0 /

/

-- Completion interval

-- Well Location Interval Status Well

-- name I J K1 K2 O or S ID

-- ---- - - -- -- ------ ------

COMPDAT

'PROD' 1 1 2 2 3* 0.2 3* 'X' /

'PROD' 2 1 2 2 3* 0.2 3* 'X' /

'PROD' 3 1 2 2 3* 0.2 3* 'X' /

'PROD' 4 1 2 2 3* 0.2 3* 'X' /

'PROD' 5 1 2 2 3* 0.2 3* 'X' /

'PROD' 1 1 5 5 3* 0.2 3* 'X' /

'PROD' 2 1 5 5 3* 0.2 3* 'X' /

'PROD' 3 1 5 5 3* 0.2 3* 'X' /

'PROD' 4 1 5 5 3* 0.2 3* 'X' /

'PROD' 5 1 5 5 3* 0.2 3* 'X' /

'PROD' 1 1 10 10 3* 0.2 3* 'X' /

'PROD' 2 1 10 10 3* 0.2 3* 'X' /

'PROD' 3 1 10 10 3* 0.2 3* 'X' /

'PROD' 4 1 10 10 3* 0.2 3* 'X' /

'PROD' 5 1 10 10 3* 0.2 3* 'X' /

'WINJ' 15 1 2 2 3* 0.2 3* 'X' /

'WINJ' 14 1 2 2 3* 0.2 3* 'X' /

'WINJ' 13 1 2 2 3* 0.2 3* 'X' /

'WINJ' 12 1 2 2 3* 0.2 3* 'X' /

'WINJ' 11 1 2 2 3* 0.2 3* 'X' /

'WINJ' 15 1 20 20 3* 0.2 3* 'X' /

'WINJ' 14 1 20 20 3* 0.2 3* 'X' /

'WINJ' 13 1 20 20 3* 0.2 3* 'X' /

'WINJ' 12 1 20 20 3* 0.2 3* 'X' /

'WINJ' 11 1 20 20 3* 0.2 3* 'X' /

/

WELSEGS

-- Name Dep 1 Tlen 1 Vol 1

'PROD' 7010 20 0.31 'INC' /

-- First Last Branch Outlet Length Depth Diam Ruff Area Vol

-- Seg Seg Num Seg Chang

-- Main Stem

2 12 1 1 20 20 0.375 1.E-3 1* 1* /

-- Top Branch

13 13 2 2 50 0 0.375 1.E-3 1* 1* /

14 17 2 13 100 0 0.375 1.E-3 1* 1* /

-- Bottom Branch

18 18 3 9 50 0 0.375 1.E-3 1* 1* /

19 22 3 18 100 0 0.375 1.E-3 1* 1* /

23 23 4 12 50 0 0.375 1.E-3 1* 1* /

24 25 4 23 100 0 0.375 1.E-3 1* 1* /

/

COMPSEGS

-- Name

'PROD' /

-- I J K Brn Start End Dirn End

-- No Length Length Penet Range

-- Top Branch

1 1 2 2 30 1* 'X' 10 /

-- Middle Branch

1 1 5 3 170 1* 'X' 10 /

-- Bottom Branch

1 1 10 4 230 1* 'X' 10 /

/

WELSEGS

-- Name Dep 1 Tlen 1 Vol 1

'WINJ' 7010 20 0.31 'INC' /

-- First Last Branch Outlet Length Depth Diam Ruff Area Vol

-- Seg Seg Num Seg Chang

-- Main Stem

2 14 1 1 20 20 0.375 1.E-3 1* 1* /

-- Top Branch

15 15 2 2 50 0 0.375 1.E-3 1* 1* /

16 19 2 15 100 0 0.375 1.E-3 1* 1* /

-- Bottom Branch

20 20 3 14 50 0 0.375 1.E-3 1* 1* /

21 24 3 20 100 0 0.375 1.E-3 1* 1* /

/

COMPSEGS

-- Name

'WINJ' /

-- I J K Brn Start End Dirn End

-- No Length Length Penet Range

-- Top Branch

15 1 2 2 30 1* 'X' 8 /

-- Bottom Branch

15 1 20 3 270 1* 'X' 8 /

/

WSEGITER

--MXSIT NR FR FI

70 100 0.8 10/

WEFAC

'*' 1.0 /

/

-- Production control

-- Well Status Control Oil Wat Gas Liq Resv BHP

-- name mode rate rate rate rate rate limit

-- ---- ------ ------ ---- ---- ---- -- -- ---- -----

WCONPROD

'PROD' 'OPEN' 'LRAT' 3* 650 1* 1000 0.0 1/

/

WCONINJE

'WINJ' 'WAT' 'OPEN' 'RESV' 1* 2000 3500 1* 1 /

/

WVFPEXP

'*' 'EXP' /

/

TUNING

/

/

30 40 50 20 30 /

NUPCOL

100/

DEBUG

6* 1/

-- Number and size (days) of timesteps

TSTEP

150*30

-- 2 18 80 100 2*500

/

END