ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR OIL FIELD IN PHITSANULOK BASIN

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A Thesis Submitted in Partial Fulfillment of the Requirements for the

Degree of Master of Engineering in Geotechnology

Suranaree University of Technology

Academic Year 2011

การเพิ่มปริมาณการผลิตน้ำมันดิบด้วยวิธีการขับด้วยโพลีเมอร์
สำหรับแหล่งน้ำมันในแอ่งพิษณุโลก

นายจุติกานต์ คณารักษ์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

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ปีการศึกษา 2554

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Suranaree University of Technology has approved this thesis submitted in partial fulfillment of the requirements for a Master's Degree.

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จุติกานต์ คณารักษ์ : การเพิ่มปริมาณการผลิตน้ำมันดิบด้วยวิธีการขับด้วยโพลิเมอร์สำหรับแหล่งน้ำมันในแอ่งพิษณุโลก (ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR OIL FIELD IN PHITSANULOK BASIN) อาจารย์ที่ปรึกษา : รองศาสตราจารย์ เกรียงไกร ไตรสาร, 340 หน้า.

กระบวนการผลิตน้ำมันดิบขั้นปฐมภูมิร่วมกับขั้นทุติยภูมิสำหรับแหล่งน้ำมันในแอ่งพิษณุโลก สามารถผลิตน้ำมันได้ประมาณ 30-50% ของปริมาณสำรองในแหล่งกักเก็บ จะเห็นได้ว่ายังคงมีน้ำมันดิบติดค้างหลงเหลืออยู่ภายในแหล่งกักเก็บอีกเป็นจำนวนหนึ่ง การเพิ่มปริมาณการผลิตน้ำมันดิบโดยวิธีการขับด้วยโพลิเมอร์ จัดได้ว่าเป็นวิธีการหนึ่งที่ได้รับการยอมรับว่าสามารถเพิ่มการผลิตน้ำมันดิบได้สูงขึ้นมากกว่าการผลิตน้ำมันดิบโดยวิธีการขับด้วยน้ำเพียงอย่างเดียวประมาณ 4-7% ของปริมาณสำรองในแหล่งกักเก็บ หัวข้อของการศึกษานี้ประกอบไปด้วย (1) การศึกษาและเปรียบเทียบประสิทธิภาพของการเพิ่มปริมาณการผลิตน้ำมันดิบระหว่างวิธีการขับด้วยน้ำ และวิธีการขับด้วยโพลิเมอร์ โดยใช้แบบจำลองคอมพิวเตอร์ (2) นำผลที่ได้ไปทำการวิเคราะห์ทางด้านเศรษฐศาสตร์ วิเคราะห์กระแสเงินสดร่วมกับอัตราผลตอบแทนเงินลงทุนเพื่อใช้ในการเปรียบเทียบตัดสินใจหาโครงการลงทุนที่มีโอกาสและความเป็นไปได้มากที่สุดโดยอ้างอิงราคาปัจจุบันของน้ำมันดิบดูไบ แบบจำลองโครงสร้างแหล่งกักเก็บจะเป็นแบบประทุนคว่ำ (Anticline structure) โดยแบบจำลองโครงสร้างของแหล่งกักเก็บแบ่งเป็น 3 รูปแบบตามขนาดของปริมาณสำรองที่ 100 30 และ 5 ล้านบาร์เรล (แหล่งกักเก็บที่มีขนาดใหญ่ ขนาดปานกลางและขนาดเล็ก ตามลำดับ) ในการศึกษาสำหรับแต่ละขนาดของแหล่งน้ำมันนั้นจะมีวิธีการผลิตที่หลากหลายรูปแบบเช่น การเปลี่ยนแปลงความเข้มข้นของโพลิเมอร์ และช่วงเวลา ที่เหมาะสมของการเริ่มต้นอัดน้ำหรืออัดโพลิเมอร์ จากผลการทดสอบแบบจำลองพบว่า สำหรับโครงสร้างแหล่งกักเก็บที่มีขนาดใหญ่ การขับด้วยโพลิเมอร์จะมีประสิทธิภาพการผลิตน้ำมันดิบเพิ่มขึ้นมากกว่าการขับด้วยน้ำ อยู่ในช่วง 3.86-7.24%ของปริมาณสำรองในแหล่งกักเก็บ มีอัตราผลตอบแทนภายใน (IRR) ที่ 28.40-43.76% และมีอัตราผลตอบแทนต่อเงินลงทุน (PIR) ที่ 0.37-0.51 จากการพิจาณาผลการประเมินโครงการที่ดีที่สุดคือรูปแบบที่ใช้โพลิเมอร์ความเข้มข้น 1,000 ppm และมีช่วงเวลาของการอัดโพลิเมอร์ 9 ปี คือเริ่มตั้งแต่ปีที่ 3 ถึง 11 ซึ่งทำให้มีกำไรเป็นมูลค่าปัจจุบันสุทธิ (NPV) 170 ล้านดอลลาร์สหรัฐ สำหรับโครงสร้างแหล่งกักเก็บที่มีขนาดปานกลาง การขับด้วยโพลิเมอร์จะมีประสิทธิภาพการผลิตน้ำมันดิบเพิ่มขึ้นมากกว่าการขับด้วยน้ำอยู่ในช่วง 2.42-5.48% ของปริมาณสำรองในแหล่งกักเก็บ มีอัตราผลตอบแทนภายใน (IRR) ที่ 53.91-56.76% และมีอัตราผลตอบแทนต่อเงินลงทุน (PIR) ที่ 0.36-0.40 จากการพิจาณาผลการประเมินโครงการที่ดีที่สุดคือรูปแบบที่ใช้โพลิเมอร์ความเข้มข้น 1,000 ppm และมีช่วงเวลา

ของการอัดโพลิเมอร์ 8 ปี คือเริ่มตั้งแต่ปีที่ 3 ถึง 10 ซึ่งทำให้มีกำไรเป็นมูลค่าปัจจุบันสุทธิ (NPV) 53 ล้านดอลลาร์สหรัฐ และโครงสร้างแหล่งกักเก็บที่มีขนาดเล็ก การขับด้วยโพลิเมอร์จะมีประสิทธิภาพการผลิตน้ำมันดิบเพิ่มขึ้นมากกว่าการขับด้วยน้ำ อยู่ในช่วง 4.39-4.62% ของปริมาณสำรองในแหล่งกักเก็บ มีอัตราผลตอบแทนภายใน (IRR) ที่ 20.95-21.73% และมีอัตราผลตอบแทนต่อเงินลงทุน (PIR) ที่ 0.66-0.76% จากการพิจารณาผลการประเมินโครงการที่ดีที่สุดคือรูปแบบที่ใช้โพลิเมอร์ความเข้มข้น 600 ppm และมีช่วงเวลาของการอัดโพลิเมอร์ 17 ปี คือเริ่มตั้งแต่ปีที่ 4 ถึง 20 ซึ่งทำให้มีกำไรเป็นมูลค่าปัจจุบันสุทธิ (NPV) 15 ล้านดอลลาร์สหรัฐ

สาขาวิชาเทคโนโลยีธรณี ลายมือชื่อนักศึกษา______________________

ปีการศึกษา 2554 ลายมือชื่ออาจารย์ที่ปรึกษา________________

JUTIKARN KANARAK : ENHANCED OIL RECOVERY BY POLYMER FLOODING FOR OIL FIELD IN PHITSANULOK BASIN. THESIS ADVISOR : ASSOC. PROF. KRIANGKRAI TRISARN, 340 PP.

ENHANCED OIL RECOVERY/POLYMER FLOODING/RESERVOIR SIMULATION

Primary and Secondary oil recovery techniques together for oil field in Phitsanulok basin are about 30-50% of the original oil in place (OOIP). Therefore, this leaves the significant amount of oil remaining in the reservoir. Polymer flooding is one of the available technologies that can be used to incremental oil recovery up to 4-5% of OOIP when its compare with the best case of water flooding. This study examines two questions: (1) study and compare of oil recovery efficiency between the best case of waterflooding and polymer flooding by using reservoir simulation technique and, (2) apply the discount cash flow to optimize the polymer flooding selection from each scenario under current Dubai oil prices. Three sizes of oil fields are modeled in anticline reservoir structure with the original oil in place (OOIP) of 100, 30 and 5 million barrels respectively. Each oil field has many production methods by using different polymer concentrations and injection periods. For model A100, oil recovery has increased from waterflooding of 3.86-7.24% OOIP. The polymer flooding has IRR range from 28.40-43.76% and PIR of 0.37-0.51, and the best case is the scenario that used polymer concentration of 1,000 ppm and injection period of 3^{rd}-11^{th}year, that has net present value (NPV) of 170 MMUS$. For model A30, oil recovery has increased from waterflooding of 2.42-5.48% OOIP. The polymer flooding has IRR range from 53.91-56.76% and PIR of 0.36-0.40, and

the best case is the scenario that used polymer concentration of 1,000 ppm and injection period of 3rd-10thyear, that has NPV of 53 MMUS$. For model A05, oil recovery has increased from waterflooding of 4.39-4.62% OOIP. The polymer flooding has IRR range from 20.95-21.73% and PIR of 0.66-0.76, and the best case is the scenario that used polymer concentration of 600 ppm and injection period of 4th-20thyear, that has NPV of 15 MMUS$.

School of Geotechnology Student Signature ____________________

Academic Year 2011 Advisor Signature ____________________

ACKNOWLEDGEMENTS

The author wishes to acknowledge Shulumberger Oversea S.A. who provided reservoir simulation software for Suranaree University of Technology.

The author expresses special gratitude and appreciation to Assoc.Prof. Kriangkrai Trisarn, for his patience, guidance, knowledge and constant support during my graduate study.

The special appreciation is also extending to Asst. Prof. Thara Lekuthai and Dr. Akkhapun Wannakomol, for knowledge and helpful suggestion to steer my research to the right path. The authors wish to special thank to Miss Sonchawan Ak-koson (Senior Geoscientist from Chevron Thailand Company) who gave the valuable suggestion for this research.

Finally, I most gratefully acknowledge my parents and everyone around me for all their help and support throughout the period of this research.

Jutikarn Kanarak

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LIST OF ABBREVIATIONS

BBL, bbl	=	Barrel
bbl/d	=	barrel per day
bbl/ply1kg	=	barrel of oil production per polymer weight 1 kg
BOPD	=	Barrel of oil per day
BS	=	Basal shale
BWPD	=	Barrel of water per day
Capex	=	Capital expense
Conc.	=	Concentration
Cum. Prod.	=	Cumulative production
D, K, L, and M	=	Reservoir sands within the Lan Krabu Formation
FCIR	=	Field polymer injection rate
FCIT	=	Field polymer injection total
FCPR	=	Field polymer production rate
FCPT	=	Field polymer production total
FGIP	=	Field gas in place
FGOR	=	Field gas-oil-ratio
FGPR	=	Field gas production rate
FGPT	=	Field gas production total
FOE	=	Field oil efficiency
FOIP	=	Field oil in place
FOPR	=	Field oil production rate

LIST OF ABBREVIATIONS (Continued)

FOPT	=	Field oil production total
FPR	=	Field pressure
FWCT	=	Field water cut
FWIP	=	Field water in place
FWPR	=	Field water production rate
FWPT	=	Field water production total
Inc.	=	Income
Inj.	=	Injection
LIS	=	Lower intermediate seal
LPTO	=	Lower Pratu Tao
MFS	=	Maximum flooding surface (lacustrine highstand)
MSCF/STB	=	Thousand cubic feet per stock tank barrel
MMbbl	=	Million barrels
MMUS$	=	Million US dallar
MMUS$/well	=	Million US dallar per well
MS	=	Main seal
MSCF	=	Thousand cubic feet
NPV	=	Net present value
Opex	=	Operation expense
P	=	P sands
Pb	=	Bubble point pressure
Ply.	=	Polymer

LIST OF ABBREVIATIONS (Continued)

ppg	=	pound per gallon
ppm	=	Parts per million or milligram versus kilogram
Prod.	=	Production
PTO	=	Pratu Tao
PTT	=	Pre-Tertiary
PV	=	Pore volume
RB	=	Reservoir barrel
RF	=	Recovery factor
Ro	=	Vitrinite reflectance
SCF	=	Standard cubic feet
SCFD	=	Standard cubic feet per day
S-T	=	Sub-Tertiary
STB	=	Stock tank barrel
STOIIP	=	Stock tank of oil initial in place
TD	=	Total depth
TOC	=	Total Organic Carbon
UIS	=	Upper intermediate seal

CHAPTER I

INTRODUCTION

1.1 Problem and Rationale

While the world consumption has rapidly increased, alternative energy becomes ever more important. Crude oil is however a major contribution to the world economy. Therefore, the oil industry must try to invent the new challenges to increase oil productivity. Thailand has strategies for the energy development plan as well. The intensify energy development for greater self-reliance of the country with a view to achieving sufficient and stable energy supply by expediting exploration and development of energy resources at both domestic and international levels. The strategies of Thailand, such as are to promote domestic production of crude oil and condensate, procure natural gas from both domestic and foreign resources to sufficiently meet the demand, develop the electricity supply industry to adequately meet the demand, conduct feasibility study on the development of the nuclear, clean coal and oil shale, etc.

An important energy policy of Thailand is to promote domestic production of crude oil and condensate. That is to be able to produce crude oil and condensate at more than 230,000 barrels/day in 2009 and 250,000 barrels/day in 2011. For the implementation methodology by expedite and promote greater investment in exploration and production (E&P) of crude oil from domestic resources which are a significance reason for this research.

This research study is focused on the Sirikit oil field which is a part of the Phitsanulok basin. Production in the Sirikit oil field of the Phitsanulok basin, Thailand, commenced in 1983. The field has the stock tank oil initial in place (STOIIP) of approximately 800 MMbbl (Ainsworth et al., 1999). To date, proved reserve about 44.77 MMbbl, over 439 wells have been drilled and 192.59 MMbbl oil produced (Department of Mineral Fuels, 2009). The production has used both primary and secondary oil recoveries with the production rate of 22,978 bbl/d (Department of Mineral Fuels, 2010).

In recent years, the oil price in world market is up and the economics of Thailand has developed rapidly over the past few years. A lot of energy resources are required. Therefore, it is necessities to increase the crude oil production of the Sirikit oil field. Most of the Sirikit oil field has been developed secondary oil recovery by waterflooding. When the field life has started to be in the declining phase, the recovery efficiency is low and water cut is over 80% because of heterogeneity of reservoir and high viscosity of oil, enhanced oil recovery (EOR) is the essential process to maintain the field life and increase the oil production. In order to understand EOR and stabilize oil production, EOR is necessary to carried out study. In this study applied EOR process by using polymer agents for injection into the reservoir to obtain high sweep efficiency.

1.2 Objectives of the Study

This study is on the application of the polymer flooding with reference to enhanced oil recovery for the sedimentary sandstone reservoir of the Sirikit oil field in the Phitsanulok basin by carry out from determination of polymer properties to simulation of polymer injection.

1.3 Scopes and Limitations of the Study

1.3.1 Overview on development of oil and gas industry in the Phitsanulok basin.

1.3.2 Collection PVT data of the Sirikit oil field in Phitsanulok basin.

1.3.3 Compile data for polymer characteristics in term of concentration, heat resistance and screen factor from researches in the South East Asia.

1.3.4 Perform the reservoir simulation tests by using the black oil simulation model with polymer option in Eclipse Office.

1.3.5 Economic consideration of an enhanced oil recovery application with polymer flooding will be analyzed and compared with the waterflooding, determine the best Internal Rate of Return (IRR) and Profit to Investment Ratio (PIR).

1.4 Research Methodology

1.4.1 Literature Review

The improve oil recovery processes and characteristics of oil fields in the Phitsanulok basin to select the best solution for an enhanced oil recovery process. Therefore, the important research was done in the Phitsanulok basin to collect data on parameters of the reservoir such as fluid and rock properties, the capacity of oil and gas, etc.

1.4.2 Selection Polymer for Injection

Nowadays, there are a lot of polymer types, which can be used for injection such as xanthan gum, hydrolyzed polyacrylamide, polyacrylamide, polyacrylic acide, polyvinyl alcohol, etc. These belong to two main types of polymer, i.e., synthetic polymer and biopolymer, respectively. In this research don't selected synthetic polymer, and only one type of biopolymer has been used. Some explanation on the synthetic polymer and biopolymer are given below to justify the selection.

- Synthetics polymer is polyacrylamide and hydrolyzed polyacrylamide, which are synthesized from acrylamide molecules. They have high molecular weight up to some million units, and the about one micron size.

Synthetic polymer which has high molecular weight, will make the viscosity and flow resistance higher than the biopolymer that has low molecular weight at the same concentration. Conversely, the synthetic polymers which have high molecular weight will easily become shear degradation due to high rate of flowing.

Although, synthetic polymer has a quite low price with good viscosity in freshwater and absorption in the surface of rock. The weaknesses of these polymers consists in their tendency to be shear degradation at the high rate of injection and their properties would decrease in the saltwater (decrease viscosity).

- Biopolymer (polysaccharide or xanthan gum) is synthetically grown by a microorganism. The xanthan gum is used widely through dissolving in saltwater to create a higher viscosity, while the viscosity in saltwater is less than that of the synthetic polymer. The properties of polymer are constant due to the salinity and hardness, the heating resistance of biopolymer is much higher than the synthetic polymer and it dose not be shear degradation at the high rate. Biopolymer would not be absorbed on the surface of rock and has the injection capability better than that of the synthetic polymer. Therefore, it makes decrease the quantity of polymer injection into reservoir. The price of produced biopolymer is higher than the synthetic polymer.

- Collection data from result of laboratory testing on polymer properties.

According to Thang (2005), the experiment is to examine the polymer properties at high temperature. The tests were carried out are:

1. Heat-resistance of polymer.
2. Screen factor of polymer.

The polymer properties to be determined are:

1. The viscosity versus concentration of polymer solution with different temperature.
2. The screen factor versus concentration of polymer solution with different temperature.

The testing was carried out at different polymer concentrations: 600, 1200, 1,800, 2,400 and 3,000 ppm.

1.4.3 Reservoir Simulation

Reservoir simulation is a technique in which a computer-based mathematical representation of the reservoir construction and then is used to predict its dynamic behavior. The reservoir is gridded up into a number of grid blocks. The reservoir rock properties (porosity, saturation, and permeability), and the fluid properties (viscosity and the PVT properties) are specified for each grid block.

One of the software used in this research is the ECLIPSE OFFICE reservoir simulation software. ECLIPSE OFFICE is licensed and supported by Schlumberger Information Solutions (SIS).

ECLIPSE OFFICE reservoir simulation software offers multiple choices of robust numerical simulation techniques for accurate and fast solutions for all kinds of reservoirs and all degrees of complexity structure, geology, fluids and development scheme.

1.4.4 Building up ECLIPSE Model

The purpose of building up a simulation model for the oil fields in the Phitsanulok basin is to simulate the EOR by polymer flooding. The results from laboratory experiments in physical models permit the research of oil recovery mechanism in one or two dimensions only. For scale-up to three dimensions usage is made of numerical simulator, which also allow incorporation of the effects of reservoir geological heterogeneities. To predict the performance of water and polymer drives for the oil fields in the Phitsanulok basin, we build up simulation ECLIPSE model for a confined well pattern. Three sizes of oilfields are modeled with the oil in place of 100, 30, and 5 million barrels respectively. Many producing, injecting well patterns, and different polymer concentrations are modeled using Eclipse Office to run simulations in each oil field. The simulation pertained to a confined well pattern, the symmetry element being represented by grid of 25 x 25 x 8 blocks (5,000 cells).

- Basic case without polymer injection

The basic case without polymer flooding that is secondary oil recovery by waterflooding only for running reservoir simulation.

- Scenarios of polymer injection

Based on, the basic case model of the oil fields in the Phitsanulok basin process at the beginning, after that applied polymer flooding for the reservoir model to study on EOR with various scenarios of each polymer concentrations.

1.4.5 Analyzing Obtained Data

Considering collected data from previous section, comparing and discussing the result from basic case without polymer injection and scenarios of polymer injection, determining the best Net Present Value (NPV), Internal Rate of Return (IRR) and Profit to Investment Ratio (PIR).

1.5 Expected Results

The following results will be expected by this study:

1.5.1 Oil recovery improvement of oil fields in the Phitsanulok basin by polymer flooding which could have a good economic efficiency.

1.5.2. More oil would be obtained from the polymer flooding than waterflooding alone about 4-5% of OOIP.

1.5.3. The results from simulation model could realize easily and indicate polymer concentration would give the best profit.

1.6 Thesis Contents

Chapter 1 states the problem and rationale, research objectives, scope and limitations of the study, research methodology and expected result. **Chapter 2** summarizes the literature review of the Phitsanulok basin and overview polymer flooding and reservoir simulation method which applied to enhanced oil recovery in oil field of the Phitsanulok basin. **Chapter 3** describes the reservoir simulation data preparations, model characteristics, classification and scenarios description. **Chapter 4** illustrates result of polymer flooding simulation model. **Chapter 5** analyzes result of simulation model in term of economic considerations. Conclusion and discussion for future research needs are given in **Chapter 6**. **Appendix A** illustrated model of polymer flooding in ECLIPSE 100. The simulation input data is shown in **Appendix B** and publication is shown in **Appendix C**

CHAPTER II

LITERLATURE REVIEW

2.1 Review on The Sirikit Oil Field

2.1.1 The Sirikit Oil Field History and Development

The Sirikit oil field is located some 400 km. north of Bangkok in the central plains of Thailand, which presented it is a biggest onshore oil field and encompassed almost the entire Phitsanulok basin (see figure 2.1). The Sirikit oil field, Thailand's first significant oil found, was discovered in late 1981 by Thai Shell Exploration and Production Company, Ltd., with its second exploration well. After deciding to develop the field (named after Thailand's queen), Thai Shell took only one year to design and install the production station, and organize an unconventional evacuation system (road tanker and railways) before oil came on stream in January 1983. A series of facility upgrading kept pace with the production buildup, to a plateau of about 20,000 bbl/d. The crude oil has an attractive refinery yield. Associated gas is sold to the nearly (specially installed) electricity generating station. Gas compression was commissioned in 1985 to increase utilization of gas, which previously was flared.

The field is geologically complex, being very faulted in a lacustrine environment and extremely stratified and heterogeneous in reservoir quality. One of two major reservoirs has a gas cap. After some early surprise in delineating the field, a three-dimensional seismic survey was conducted, which better defined the structure and the reserve potential. Nevertheless, parallel appraisal and development continues on a careful step-by-step approach, using the latest production and pressure data refine the reservoir geologic model. In November 1985, the Petroleum Authority of Thailand became a minority partner, with Shell remaining as operator. Since January 2004, the Petroleum Authority of Thailand Exploration and Production Public Company became only one operator.

According to Morley, Lonnikoff, Pinyochon, and Seusutthiya (2007), recently found a typical infill well production profile displays an average initial rate on the order of 300–800 bbl/d and a two-step decline (see Figure 2.2). In the first three months, decline is very sharp (15–33% per month) and then stabilizes at about 3–5% per month, until the well is shut in for low production. This production behavior is explained by the lack of drive mechanism, the thin bedded nature of the sands, and the relatively poor connectivity caused by stratigraphic and structural compartmentalization. Consequently, despite most sands penetrated by a new well having some level of depletion, the actual primary recovery factor per block never exceeds 18%. The current development plan for the western part of the Sirikit field consists of achieving an infill drilling spacing of approximately 250 m (820 ft) in the main Lan Krabu reservoirs. Once this infill-drilling phase has been completed, water injection activities will start.

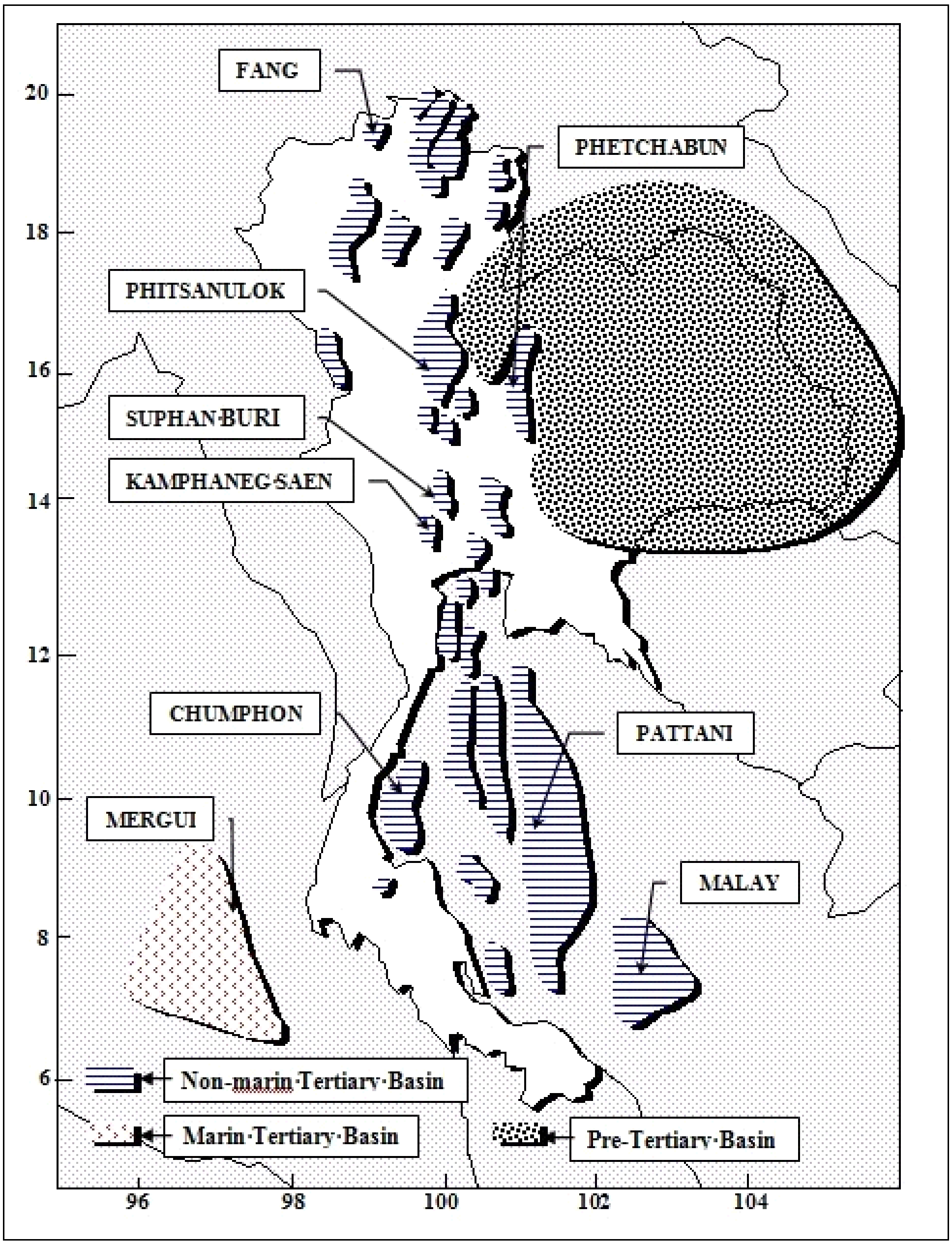


Figure 2.1 Petroleum Bain in Thailand, (After DMR annual report, 1994).

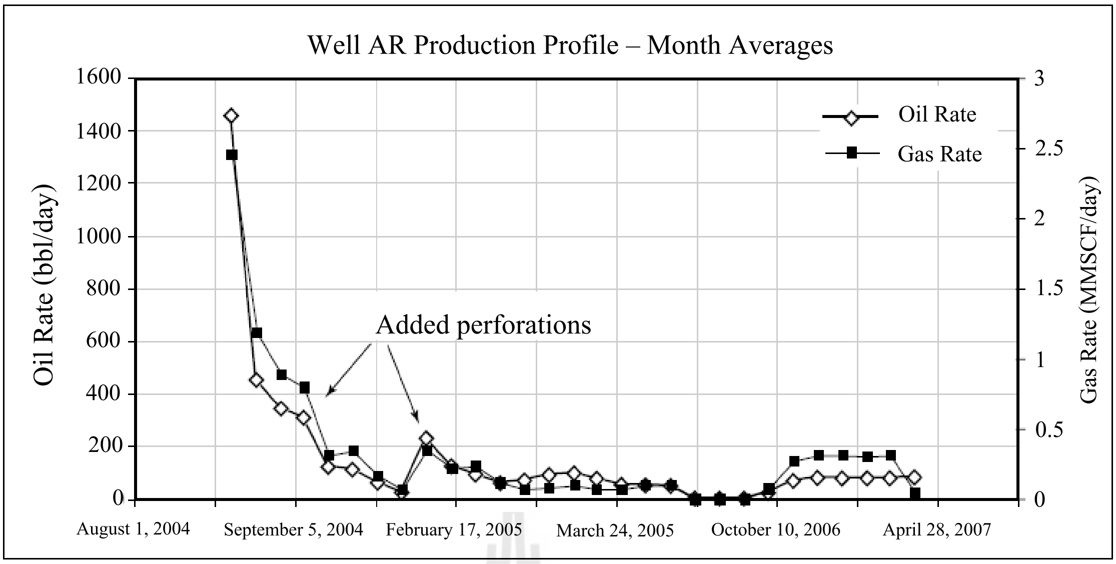


Figure 2.2 Typical production decline curve for a well in the A Block of the Sirikit oil field, (After Morley et al., 2007).

2.1.2 Reservoir Stratigraphy

According to Morley, Lonnikoff, Pinyochon, and Seusutthiya (2007), Lithostratigraphic nomenclature has been applied to the Phitsanulok basin and reflects the typical ranges of facies encountered in continental rifts and half grabens (e.g., Flint et al., 1988). The stratigraphy, particularly the Lan Krabu reservoir interval, has been described in detail by Flint et al. (1988) and, thus, is just summarized here (see Figure 2.3). The earliest stages of the rift (upper Oligocene– lower Miocene) are dominated by coarse immature clastics, deposited as alluvial fans (Sarabop Formation) in alluvial-plain environments (Khom Formation) and fluvial-deltaic to lacustrine environments (Nong Bua Formation).

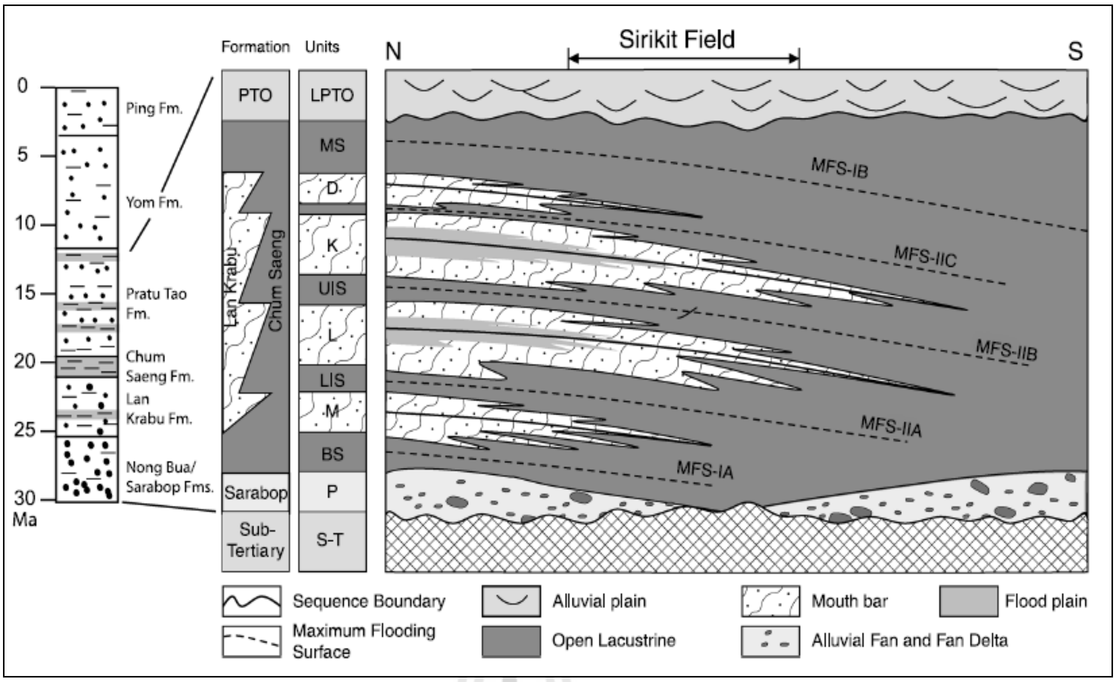


Figure 2.3 Schematic general stratigraphy of the Phitsanulok Basin and detailed schematic stratigraphy of the reservoir section in the Sirikit field area.

During the early Miocene, deposition was dominated by lacustrine (Chum Saeng Formation) and fluviodeltaic (Lan Krabu Formation) conditions. The alternating environments juxtaposed fine-grained lacustrine shales (source and seal) with fluviodeltaic sandstone reservoirs. In Sirikit oil field, the main lacustrine episode occurred after the deposition of the Lan Krabu Formation and forms the main seal (Chum Saeng Formation). Thinner lacustrine shales also punctuate the Lan Krabu Formation;in particular, the lower intermediate seal (LIS) and the upper intermediate seal (UIS) are important. The LIS and UIS separate different reservoir zones within the Lan Krabu Formation (the K, L, and M zones), whereas the basal shale separates the underlying P sands from the Lan Krabu Formation. These zones display different depths to the oil-water contact, indicating significant compartmentalization within the field. In addition to the different oil-water contacts within the main oil-bearing part of the field, there is also a major separation of fluids along a poorly defined northwest southeast–trending zone that divides the oil-bearing Sirikit field in the northern part of the tilted fault block from the gas-producing region to south and west, known as the western gas flank.

The Lan Krabu Formation is a fluviodeltaic sequence that prograded from the north into lacustrine conditions. Hence, there is a general trend to more shale-prone, lacustrine conditions to the south.

2.2 Petroleum resources and potential in the Phitsanulok basin

2.2.1 Basin Type

The Phitsanulok basin is common throughout SE Asia and reveals striking geological similarities. The Phitsanulok basin originated during the early Tertiary as a result of extension rifting related to the collision of India with Asia. The Phitsanulok basin has half graben geometry and show elevated heat flows, typical of lift basins. Strike slip movements are common and lead in combination with extensional faulting to very complex, densely faulted basin margins. The Phitsanulok basin was starting characteristically as narrow, rapidly subsiding rift grabens with fault controlled lacustrine sedimentation. The rifts are then aborted and flexural movements of the cooling phase create larger depressions with mainly alluvial deposits. The Phitsanulok basin was initiated during Paleocene time on an eroded Paleozoic to Mesozoic surface. In Oligocene or early Miocene time a widespread paleo lake Phitsanulok developed for the first time. Fluviolacustrine sands pushed out into the lake particularly from west and north and local source centers in the east (Lan

Krabu formation). During middle Miocene times, channel sands associated with distal alluvial/fluvial plain and ephemeral lacustrine sediments appeared over much of the basin, marking the disappearance of the extensive and permanent lake (Pratu Tao formation).

2.2.2 Source Rock

The sedimentary fill of the Phitsanulok and the other central plain basins consists of a continental series of alluvial plain, fluvial and lacustrine clastic sediments deposited during early to mid Miocene. The major source rocks are the clays of the Chum Saeng formation, which are widespread throughout the basin. Net thickness exceeding 100 m has been encounted adjacent to the Sukhothai depression.

2.2.3 Reservoir

The Lan Krabu fluvio lacustrine sandstones constitute one of the reservoir targets of the basin. The main reservoir targets of the basin. They form the main reservoirs in the Sirikit field where porosities range from 20-30%. Reservoir continuity has proven to be variable. At any particular depth a wide range of porosities are observed. The maximum depth for 12% porosity cut off is 3,900 m. Good lateral continuity exists in distributary channel or composite sand unit whereas mount bar and delta front sands are limited in extent. The sands of the Prato Tao formation are prime reservoir targets in the basin. They are composite, meter beded, sorted, fine to coarse with massive clay interbeds. Porosities can be variable from 12-30%.

2.2.4 Trap and Seal

Clay smear controlled fault seals, the main trapping mechanism in marine deltas, are less well developed in the continental setting of Thailand's intra montane basins (mainly due to different properties of alluvial clays) and across fault leakage is the rule. These factors result in a low retention potential of the basins, with repeated redistribution of hydrocarbon accumulations and the inherent migration loss of a very large part of the generated hydrocarbons.

2.3 EOR Processes

2.3.1 General

According to Green and Willhite (1998), Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Primary production, the initial production stage, resulted form the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of operations, usually was implemented after primary production declined. Traditional secondary recovery processes are waterflooding, pressure maintenance, and gas injection, although the term secondary recovery is now almost synonymous with waterflooding. Tertiary recovery, the third stage of production, was that obtained after waterflooding (or whatever secondary process was used). Tertiary processes used miscible gases, chemicals (such as polymer), and/or thermal energy to displace additional oil after the secondary recovery process became uneconomical.

During the life of a well, there is always a point at which the cost of producing an additional barrel of oil is higher than the price market will pay for that barrel. Production then halts. Under normal circumstances, the well is abandoned, with 70% of the oil left in the ground. This situation has begun to change, especially in the North America. Reserve in the aging oil fields of the US and Canada are declining faster than new oil being added by discoveries. In the US, for example, 75% of the approximately 500 billion barrels of oil discovered were found during of drilling about 70 billion barrels. About 130 billion barrels have been produced to date and up to another 170 billion barrels are considered a long-term target for advanced EOR technology. The situation is similar in Canada. Given the declining reserves and the low probability of locating significant new fields, producers find additional oil in old reservoirs, making North America a proving ground for EOR techniques. Today, it is estimated that North America produces more than half the world's EOR production. An estimate annual worldwide EOR produced is shown in table 2.1.

Table 2.1 Estimated annual worldwide EOR produced, bbl/d (x1000), (After Lake, 1989).

Country	**Thermal**	**Miscible**	**Chemical**	**EOR Total**	**%**
USA	454	191	11.9	656.9	42
Canada	8	127	17.2	152.2	10
Europe	14	3	-	17	1
Venezuela	108	11	-	119	7
Other S.America	2	N/A	N/A	17	1
USSR	20	90	50	160	10
Other (Estimate)	171*	288**	1.5	452.5	29
Total	777	710	80.6	1574.6	100

Remark : * Mainly Duri field (Indonesia)

** Mainly Hassi-Messaoud (Algeria) and Intisar (Libya)

Research and development on many methods indicate that the risk of EOR is being reduced and the potential for EOR profitability increased. Computerized characterization of the reservoir, which quantifies the physical characteristics and dynamic behavior of a field, is becoming one of the most important tools for improved oil recovery. Success of oil recovery depends on applying the energy of injected fluids in the right place, in the right amount and at the right time, a strategy that a well-constructed reservoir simulation can help the development (Thang, 2005).

2.3.2 EOR Process Concepts

According to Lake (1989), EOR is an imprecise term that historically has been used to describe the third step (tertiary recovery) in oil and gas production.

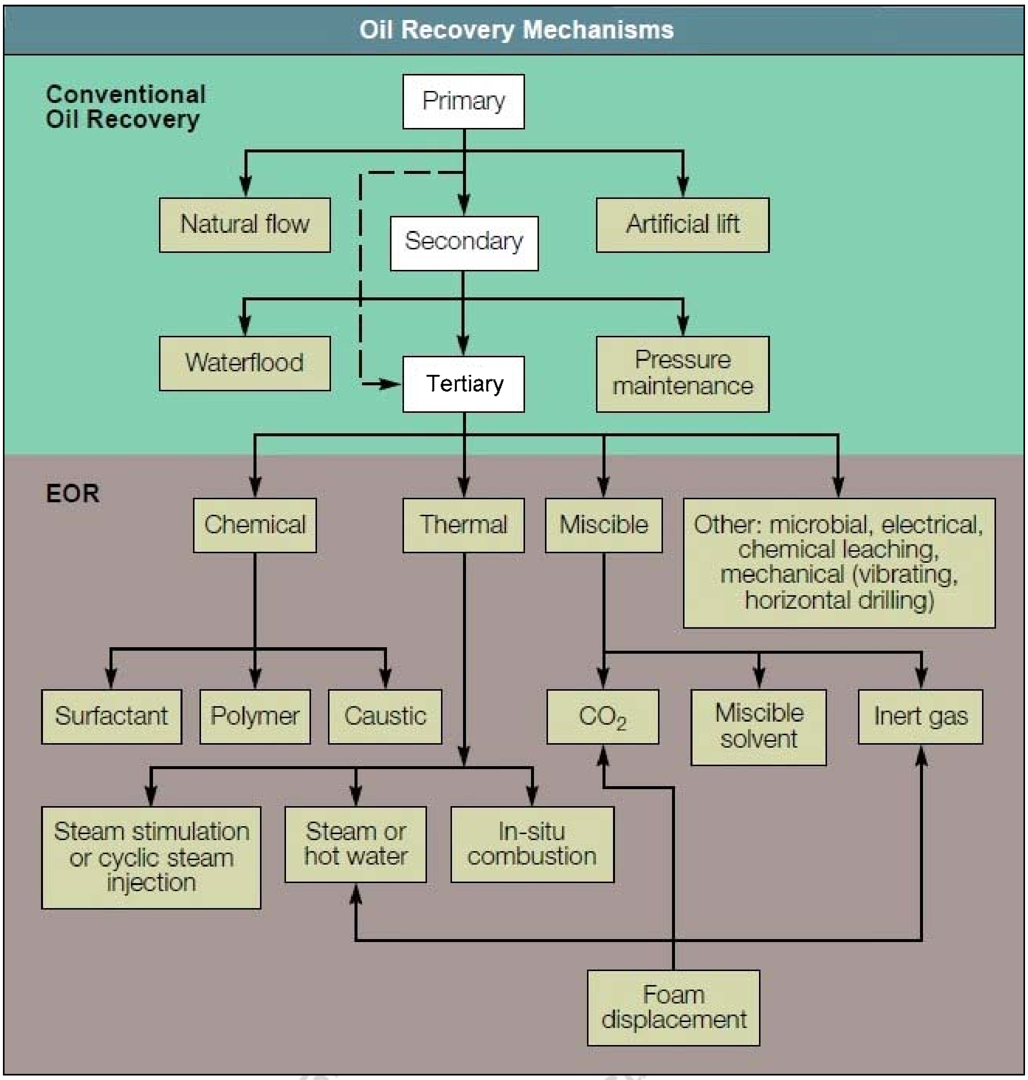


Figure 2.4 Oil Recovery Mechanisms, (After Lake, 1989).

The term "improved oil recovery" (IOR) has come into use to describe all recovery methods other than natural (primary) production, reserving the designation EOR for those processes beyond simple waterflood and gasflood basically, recovery by injection of anything not originally in the reservoir. The three major EOR methods are thermal (application of heat), miscible (mixing of oil with a solvent) and chemical (flooding with chemicals) as shown in Figure 2.4.

Primary recovery, in long accepted practice, is defined as production by natural reservoir pressure, or pumping, until depletion. Until the early 1940s, economics dictated when a well was to be plugged and abandoned, usually after recovery of 10 to 25% of original oil in place (OOIP).

Secondary recovery methods are generally used to repressure the reservoir and drive out some of the remaining oil. Because water is usually readily available and inexpensive, the oldest secondary recovery method is waterflooding, pumping water through injection wells into the reservoir. The water is forced from injection wells through the rock pores, sweeping the oil ahead of it toward production wells. This is practical for light to medium crudes. Over time, the percentage of water in produced fluids-the water cut-steadily increases. Some wells remain economical with a water cut as high as 99%. But at some point, the cost of removing and disposing of water exceeds the income from oil production, and secondary recovery is then halted.

Extensive waterflooding, which began in the 1940s, within a few decades became the established method for secondary oil recovery, usually recovering about another 15% of OOIP. On average, about one-third of OOIP is recovered, leaving two-thirds, or twice as much oil as is produced, in the ground after secondary recovery.

Another recognized secondary recovery technique is injection of a hydrocarbon based gas into an existing gas cap or directly into the oil itself. Gas may be injected over a considerable period of time up to a year while producing wells are shut in, until reservoir pressure is restored and production resumed. Another method is injection of gas to sustain pressure during production. Gas injection requires a nearby source of inexpensive gas in sufficient volume.

While waterflooding is effective in nearly all reservoirs, no single EOR technique is a cure-all. Most reservoirs are complex, as are most EOR processes. Efficient reservoir management treats EOR as a high-cost, high-risk but critical component of a comprehensive plan that spans primary recovery through abandonment.

Once preliminary reservoir information has been assembled and used to select EOR options, engineering project design usually follows several steps as given below (Lake, 1989).

- Laboratory studies test the proposed EOR processes in core floods with samples of reservoir rock and fluids. These small, one-dimensional flow tests in relatively homogeneous media do not always successfully scale up to reservoir dimensions. But if the process fails in the laboratory, it will more than likely fail in the field.

- Fluid-flow simulations, based on a geologic reservoir model, can start with assessment of primary and secondary recovery, matching the production history to determine residual oil and waterflood recovery. Then EOR process-variable sensitivities can be calculated, followed by predictions of EOR recovery, incremental production rate and payout economics. Reservoir geologic models are always constrained by sparse data, simplified concepts of reservoir structure and dynamics, inadequate data for history matching and increasing computational uncertainty as calculations are extrapolated into the future. Consequently, predictions that cover years of EOR performance may be seriously in error. In addition, small-scale heterogeneities, which are difficult to define, are critical to the success of EOR.

- A pilot test of the proposed EOR process is carried out to investigate a novel technique or to confirm expected performance before an expensive, fullscale implementation. Ideally, the pilot test is performed in an area that is geologically similar to the field and large enough to be statistically representative of overall heterogeneity. Monitoring and data acquisition throughout pilot testing provide information needed to plan a full-scale commercial operation.

- Operation consideration for commercial operations, important considerations are secure sources of water and other injectants, storage and transportation facilities (like pipelines), surface processing, separation, recycling and upgrading facilities, and environmental and safety requirements.

The same principles of EOR engineering may not apply to offshore oil fields. Because offshore wells tend to be highly deviated or extended reach, the distance between them is often greater than between onshore wells. This extends the time between EOR initiation and meaningful results and flattens the recovery response. These effects complicate process control and limit the number of EOR techniques that may be applicable. Greater spacing between wells also increases the likelihood of undetectable heterogeneities between wells, impairing simulations of well behavior. Because the number of wells that can be drilled from a platform is fixed, infill drilling, often an important strategy for both secondary recovery and EOR, may not be possible. High costs and extended time before EOR production begins mean that offshore EOR projects must be planned and started early enough so that production increases incrementally before primary and secondary production begins to decline. Otherwise, marginal costs may be too high to sustain profitability. However, this option must be balanced against other risks: insufficient reservoir description at early stages of field production and lack of time to acquire pilot test results to evaluate the EOR process. Cost performance comparison of major EOR methods is presented in Figure 2.5.

Various mechanisms thwart recovery of much of OOIP after secondary recovery. Reservoir geologic heterogeneities may cause a large volume of mobile oil to be bypassed and remain within a field. This is a result of poor sweep efficiency when injected displacement water moves preferentially through higher permeability zones toward the production well. Even in regions that have been swept by large quantities of water, residual, immobile oil is held in the pore spaces by capillary forces. Many techniques have been tried in the laboratory and field in hopes of recovering this additional oil. All employ one or more of three basic mechanisms for improving on water drive alone (Lake, 1989):

- Increase the mobility of the displacement medium by increasing the viscosity of the water, decreasing the viscosity of the oil, or both.
- Extract the oil with a solvent.
- Reduce the interfacial tension between the oil and water.

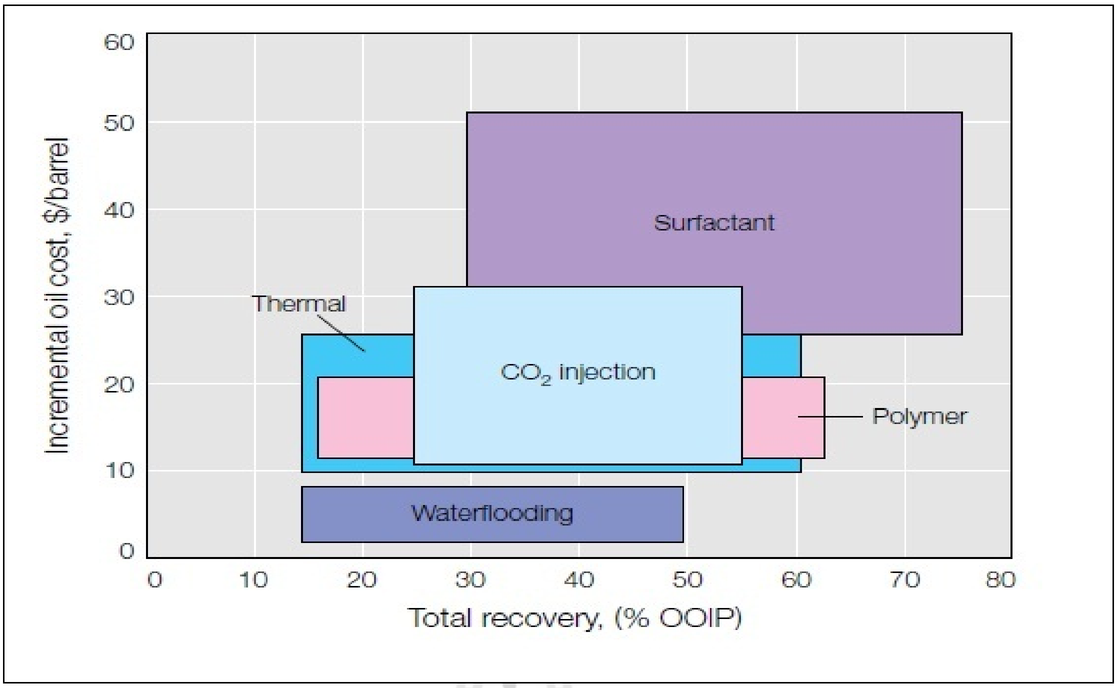


Figure 2.5 Cost performance comparison of major EOR methods (After Lake, 1989).

The three major EOR processes thermal, miscible and chemical are each subdivided in to several categories. Among the three, thermal processes dominate, having the greatest certainty of success and potential application in about 70% of enhanced oil recovery worldwide. Thermal methods also give the highest recoveries at the lowest costs.

The term miscible means the mixing of two fluids for instance, oil and a solvent such as carbon dioxide [CO_2] into a single phase fluid. It may also apply to a continuity between the oil and injected gas, due to a multiphase transition zone between the two. Use of miscible gas drive has grown rapidly in recent years, and today the method accounts for about 18% of EOR applications worldwide. It has been successful at depths greater than 2,000 ft (610 m) for CO_2 and greater than 3,000 ft (915 m) for other gases.

EOR chemical processes, such as surfactant (detergent) flooding, have tantalized the industry with promises of significantly improved recovery. As yet, cost and technical problems have precluded them from mainstream application. Waiting in the wings are processes like microbial EOR (MEOR) and some novel and exotic proposals; these await confirmation by lab and field experimentation and evaluation before taking their place as accepted practice.

Each EOR process is suited to a particular type of reservoir. Because unexpected or unknown reservoir characteristics cause most EOR failures, EOR begins with thorough geologic study. Technical rule of thumb screening criteria are available to aid preliminary evaluation of a reservoir's suitability for EOR as shown in Figure 2.6. After these criteria are applied to a prospect, stringent economic analysis follows, generally through repeated reservoir simulations.

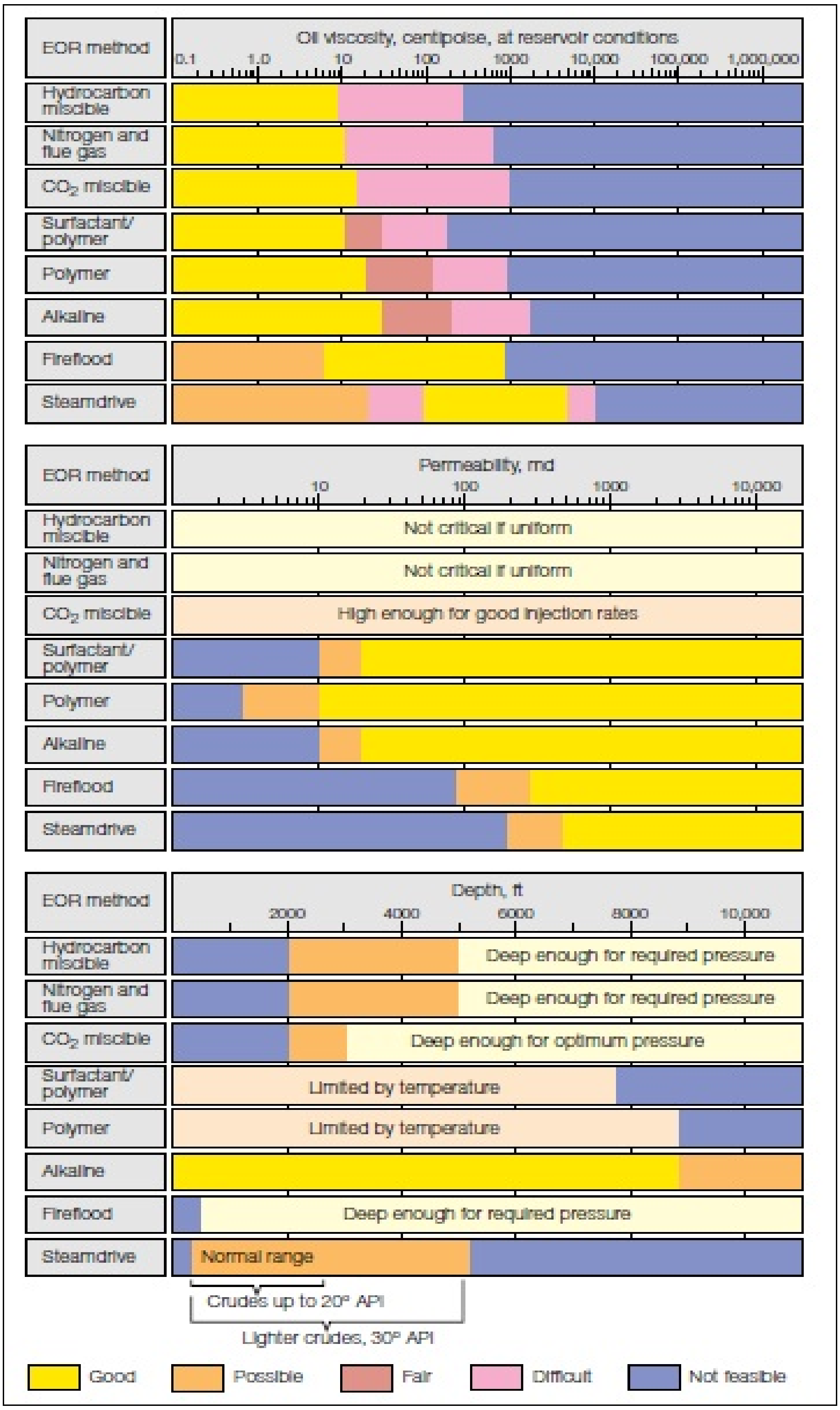


Figure 2.6 Selection of EOR techniques by oil viscosity, permeability and depth, (After Lake, 1989).

2.4 Application of Polymer in EOR

2.4.1 General

The reducing the ratio between the viscosities of the reservoir oil and the injected water ($\mu_{o/}\ \mu_w$) led to an increase in the oil recovery factor $E_{R,o}$ through two mechanisms:

- Modification of the fraction flow curve f_w (S_w) of the water with a gradual transition of the curve shape from concave downwards, through S-shaped, to concave upwards, as $\mu_{o/}\ \mu_w$ decreases. These results in a lower WOR for a given percentage of oil recovered.
- An increase in the areal efficiency E_A and the vertical invasion efficiency E_I as $\mu_{o/}\ \mu_w$ decreases, for a given well distribution and reservoir heterogeneity.

One way to reduce $\mu_{o/}\ \mu_w$ is to increase the temperature of the reservoir. However, the same result can be achieved without altering the temperature, by increasing the water viscosity μ_w through the addition of suitable polymers. These polymer solutions, usually at concentrations of less than 1,000-1,500 ppm (1.0-1.5 kg/m^3 of water), are referred to as "thickened water", and the associated drive process is called polymer flooding.

Moreover, when appropriate chemicals are added, these solutions have the property of gelling when injected in to the reservoir. This produces a semipermanent modification of the permeable zones, thereby reducing reservoir heterogeneity.

There are two broad categories of polymer used in the preparation of thickened water, which are polyacrylamides (PAM) and polysaccharides. The general formulas for the polymers are shown in Figure 2.7.

A Polymer is a large chain molecule formed by thousands of repeating blocks called monomers. Polymers have long been used in the oil and gas industry for drilling and fracturing fluids and water blocking agents. They are also used in the manufacturing of paint and polished. The polysaccharide biopolymers and partially hydrolyzed polyacrylamides are the most commonly used in polymer flooding operation.

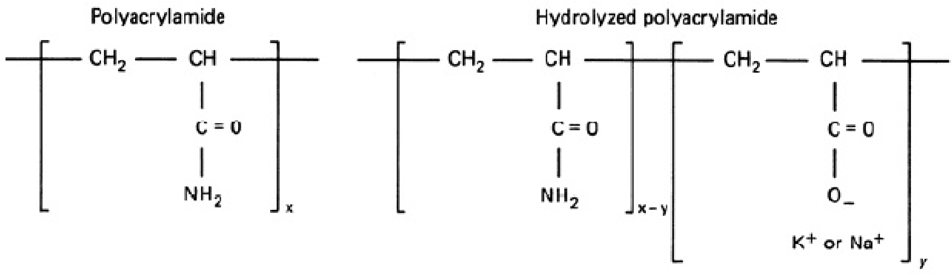
2.4.2 Polyacrylamides (PAM)

Polyacrylamides Polymer are synthetic chemicals which can be tailored to fit a broad range of applications. The molecule is unique in its strong hydrogen bonding, linearity, very high molecular weight, and a high degree of non-Newtonian viscosity. For enhanced oil recovery, the polyacrylamide molecule can be modified by copolymerization with ionic substitutes or by partial hydrolysis of the amid side chain to the carboxylic acid group. The hydrolysis of the side chain amide to a carboxyl group renders that part of the molecule to be a strongly water-soluble moiety. Different grades of polyacrylamides are hydrolyzed to different degrees. Generally, the highest degree of hydrolysis is approximately 35%. As the degree of hydrolysis increases, the water solubility increases and the viscosity of the polymer solution at a given concentration decreases. An increasing number of copolymers of polyacrylamide are becoming available to the industry and more will be available in the future. Some copolymers are manufactured to have utility as industrial flocculants. Also commonly used in these vertical conformance processes are gelled polyacrylamide systems. The hydrolyzed polyacrylamide interacts with polyvalent metals, such as iron, aluminium, and chromium, to form three-dimension gel networks.

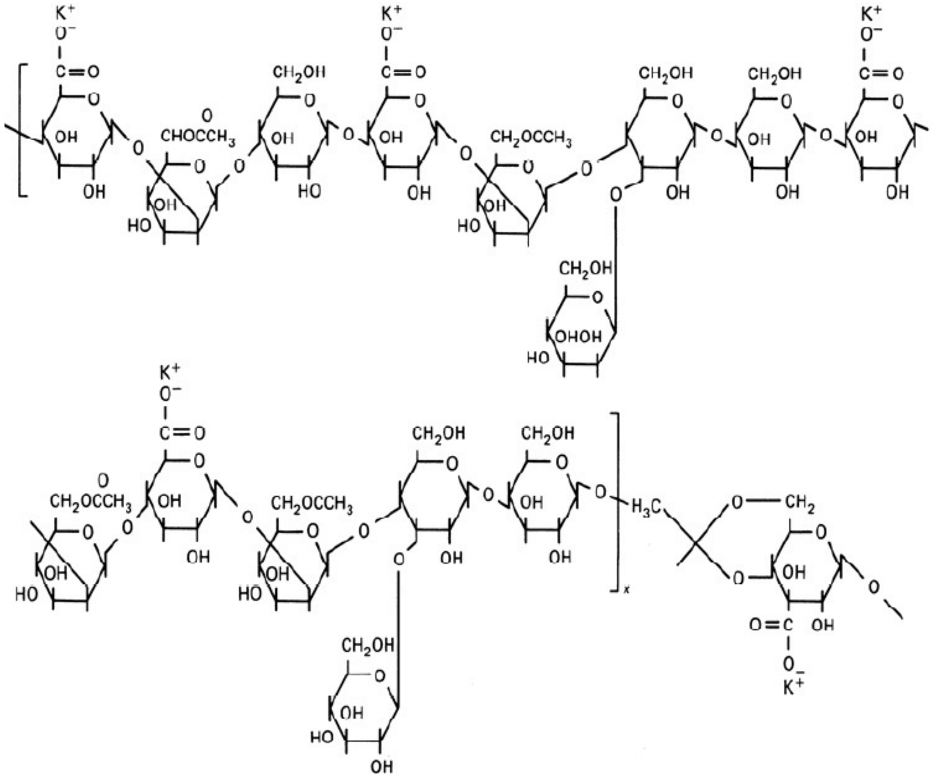
Polyacrylamides are supplied in several forms. Historically, many field polymer projects used solid power, which was then hydrated to form the polymer solution. Because of convenience, however, most field polymer projects today use polyacrylamides supplied in emulsion form as liquids. These materials are available in concentrations ranging from 30 to 50 wt.% solids and offer a fairly efficient and rapid way to get the polyacrylamide into solution. In high-salinity systems, the use of a surfactant to promote hydration may be necessary.

2.4.3 Polysaccharides (biopolymer or xanthan gum)

Polysaccharide, which has found great acceptance in the oilfield. Polysaccharide is a high-molecular-weight, natural carbohydrate. It is a polysaccharide manufactured by a bacterial fermentation process. Commercial polysaccharide is obtained from mutant bacterial strains chosen for field (amount of product produced during fermentation) and polymer functionality (injectivity and high non-Newtonian viscosity). The structure of polysaccharide contains side chains which hold the molecule in rigid, helical structure. Many of the unusual properties of the polymer, stem from its rodlike structure in solution. The side chains shield the backbone of the polymer molecule and protect against enzymatic attack and backbone cleavage. Thermal stability is also improved by this complex structure. Sensitivity to salt is also greatly reduced even though the molecule is anionic in character. Unlike many polysaccharide solutions, the viscosity of which decreases with an increase in temperature, xanthan gum solutions show only a slight decrease in viscosity. This and other characteristics make it a preferred material in EOR applications despite its unusual origin and rather high cost.



(a) Molecular structure of polyacrylamide.



b) Molecular structure of polysaccharide (biopolymer).

Figure 2.7 Molecular structures, (After Lake, 1989).

The synthetic polymer, polyacrylamide, and the biopolymer, xanthan gum, offer the best performance/price ratio of the many types of polymers that have been proposed for EOR operations.

2.4.4 Use of Polymer in EOR

According to Thang (2005), the statistics show the polymer process has been used most widely in all of chemical methods for EOR. Table 2.2 presented for U.S. EOR projects and production, respectively. While the projects are decreasing, EOR production is increasing. In the USSR, the EOR by polymer is the second rank, after the surfactant method. It is proven for the possibility of high commercial of using polymer process. Polymers have been used in oil production in three modes, (Bradley, 1987).

- They have been used as near-well treatments to improve the performance of water injectors or high watercut producers by blocking off high-conductivity zones.
- Polymers also are used as agents that may be crosslinked in situ to plug high-conductivity zones at depth in the reservoir. These processes require that polymer be injected with an inorganic metal cation, which will crosslink subsequently injected polymer molecules with ones already bound to solid surfaces.
- The other mode is use as agents to lower M or λ_D.

The first mode is not truly a chemical flooding process, since the actual oil-displacing agent is not the polymer. The overwhelming majority of polymer EOR projects have been in the third mode, which is the only one emphasized in this study, which deals with the mobility of injected fluid by polymer. This process is often highly efficient when the mobility of oil-water is high and formation has high heterogeneity (capacity and flow properties in the porous medium), (Thang, 2005).

Table 2.2 Active U.S. EOR production, (After Satter and Thaker, 1994).

EOR methods	**barrel/day**						
	1980	**1982**	**1984**	**1986**	**1988**	**1990**	**1992**
Thermal							
Steam	243477	288396	358115	488692	455484	444137	454009
Combustion in-situ	12133	10228	6445	10272	6525	6090	4702
Hot water	-	-	-	705	2896	3985	1980
Total thermal	255610	298624	364560	499669	464905	454212	460691
Chemical							
Miscellar-polymer	930	902	2832	1403	1509	617	254
Polymer	924	2927	10232	15313	20992	11219	1940
Alkaline	550	580	334	185	-	-	-
Surfactant	-	-	-	-	-	20	-
Total chemical	2404	4409	13398	16901	22501	11856	2194
Gas							
Hydrocarbon miscible/immiscible	15448	12515	14439	33767	25935	55386	113072
CO_2 miscible	21532	21953	31300	28440	64192	95591	144973
CO2 immiscible	-	490	702	1349	420	95	95
Nitrogen miscible/ immiscible	2027	1400	7170	18510	19050	22260	22580
Flue gas miscible/ immiscible	35200	35200	29400	26150	21400	17300	11000
Other	600	370	-	-	-	-	6300
Total gas	74807	71928	83011	108216	130997	190632	298020

Table 2.2 Active U.S. EOR production, (After Satter and Thaker, 1994). (Continued)

EOR methods	barrel/day						
	1980	1982	1984	1986	1988	1990	1992
Other							
Carboneted-waterflood	-	-	-	-	-	-	-
Microbial	-	-	-	-	-	-	2
Total other							2
GRAND TOTAL	332821	374961	460969	624786	618403	656700	760907

The polymer flooding into reservoir for control the mobility of injected phase can be shown in Figure 2.8. The figure show a schematic of a typical polymer flood injection sequence: a preflush is usually consisting of a low salinity brine; an oil bank is injected by polymer; a fresh water buffer to protect the polymer solution from backside dilution; and the last are chase or drive water. Many times the freshwater buffer contains polymer in decreasing amounts (a grading or taper) to lessen the effects of unfavorable mobility ratio between the chase water and the polymer solution. Because of the driving nature of the process, polymer floods always are performed through separate sets of injection and production wells.

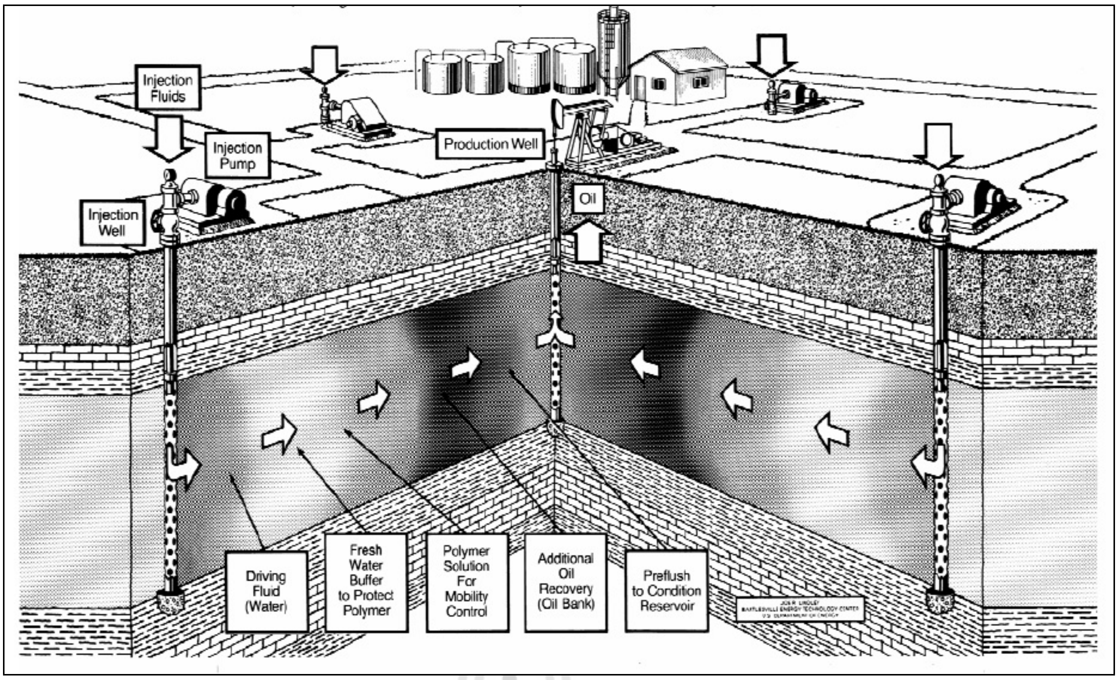


Figure 2.8 Schematic illustration of polymer flooding sequence, (After Lake,1989).

2.5 Recovery Efficiency

The overall recovery efficiency RF of any secondary or tertiary oil recovery method is the product of a combination of three individual efficiency factor as given by Ahmed, (2006).

$$RF = E_D E_A E_V \tag{2.1}$$

And In terms of cumulative oil production as:

$$N_P = N_S\, E_D E_A E_V \tag{2.2}$$

Where: RF = overall recovery efficiency, fraction or percent

N_S = initial oil in place at start of the flood, STB

N_P = cumulative oil produced, STB

E_D = displacement efficiency, fraction or percent

E_A = areal sweep efficiency, fraction or percent

E_V = vertical sweep efficiency, fraction or percent

Displacement efficiency is the fraction of movable oil that has been recovered from the swept zone at any given time. Mathematically for the displacement efficiency is expressed as:

$$E_D = 1 - \frac{S_{or}}{S_{oi}} \tag{2.3}$$

Where: S_{or} = residual oil saturation

S_{oi} = initial oil saturation of reservoir

In general E_AE_V is called the volumetric sweep efficiency and represent the overall fraction of the flood pattern that is contacted by the injected fluid.

Areal sweep efficiency is the ratio of the area swept by water, and the total area contained by the well pattern. It is depends on the geometrical distribution of the wells, production rate and the mobility ratio.

Vertical sweep efficiency or conformance factor is the ratio of the pore space invaded by the injected fluid divided by the pore space enclosed in all layer behind the location of the leading edge (leading areal location) of the front. It is depends on the vertical heterogeneity of the reservoir and the mobility ratio.

The reservoir heterogeneity probably has more influence on the performance of a secondary or tertiary injection project. The most important two types of heterogeneity affecting sweep efficiencies, E_A and E_V, are the reservoir vertical heterogeneity and areal heterogeneity.

- Vertical heterogeneity is the most important parameter for the vertical sweep efficiency. The properties of reservoir in vertical are not same, reservoir is non-homogeneous. While water injected into a stratified system will preferentially enter the layer of highest permeability and will move at a higher-permeability zones, a significant fraction of the less-permeable zones will remain unflooded. Although a flood will continue beyond breakthrough, the economic limit is often reached at an earlier time.

- Areal heterogeneity includes areal variation in formation properties (e.g., h, k, φ, S_{wc}) geometrical factors such as the position, any sealing nature of faults, and boundary conditions due to the presence of an aquifer or gas cap.

The mobility ratio is defined as:

$$M = \frac{\lambda_D}{\lambda d} \tag{2.4}$$

Where: λ_D = mobility of the displacing fluid phase

λ_d = mobility of the displaced fluid phase

For a waterflood where piston-like flow is assumed, with only water flowing behind the front and only oil flowing ahead of the front, therefore;

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}}{k_{ro}} \frac{\mu_o}{\mu_w} \tag{2.5}$$

Where: λ = mobility ratio = $\dfrac{k_r}{\mu}$

k_r = relative permeability

μ = viscosity, cp

w, o = subscripts denoting water and oil, respectively

According to Thang (2005), for the oil-water interface, oil is flowing in the presence of connate water. Behind the interface, water alone is flowing in the presence of residual.

- If mobility ratio M ≤ 1, oil is capable of traveling with a velocity equal to or more than that water. Since water is pushing oil, no tendency for the oil to be by-passed. This sweep results in sharp interface between fluids called piston-like displacement.

- If mobility ratio M > 1, water is capable of traveling faster than oil. As the water is pushing the oil through the reservoir, some of oil will be by-passed.

Figure 2.9 shows comparison areal sweep efficiency at breakthrough as a function of mobility ratio as given by Green and Willhite, (1998).

Consequently, favorable mobility ratio happens when M is less than or equal to one. The addition of certain polymers to injected water can increase oil recovery by providing mobility control and by reducing channeling. Polymer can be injected at different stages of enhanced recovery projects in order to improve the efficiency of oil recovery, and they can be injected in combination with other reactive chemicals for the purpose of restricting flow through high-permeability channels.

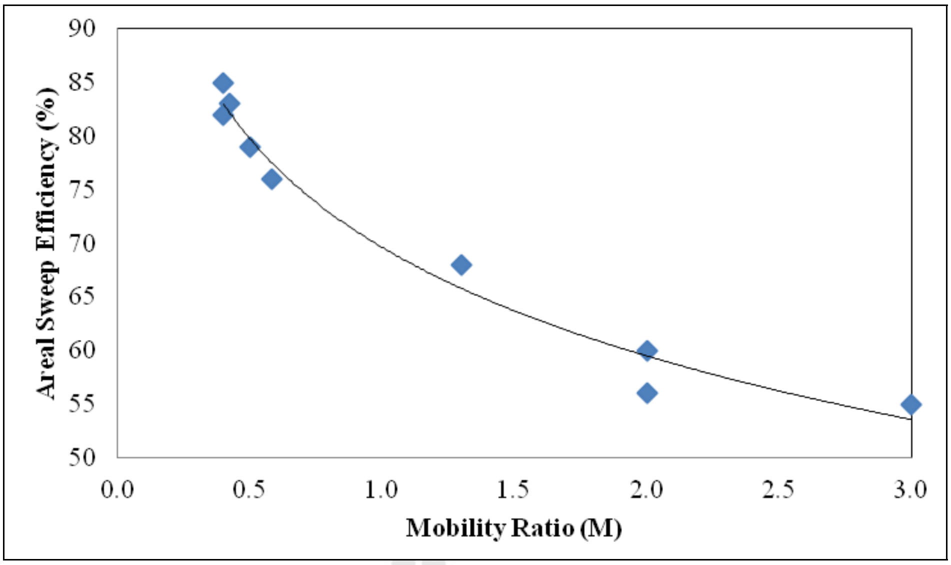


Figure 2.9 Areal sweep efficiency at breakthrough as a function of mobility ratio, (After Green and Willhite,1998).

The addition of the selected polymers to water increases the viscosity, and in some cases it can reduce the permeability of reservoir rock to water. The polymers can interact in the formation to form gels, or they can be used to reduce the mobility of one reactant so that the second reactant can catch up and form a gel plug. Most oil reservoirs are heterogeneous, in some cases the high-permeability channels dominate the flow pattern, but these can be relatively small in cross section. In such cases, a successful plug in the small channel can greatly improve the sweep efficiency of a flood.

The use of polymer solutions for flooding reservoir is simple in principle and quite efficiency in a number of situations. But the application of using polymer on the entire field is not always successful. It still depends on the other factors such as the quality of polymer, reservoir conditions, fluids, interaction between polymer and formation, production processes, and especially the cost of polymer. All these factors will be considered in this study for the Sirikit oil field regarding polymer injection applicability.

2.6 Mechanics of Polymer Solution

The mechanics of polymer solution have important for engineering of petroleum reservoirs, that deals to a great extent with the description of fluid flow in porous media. Therefore, this section includes some basic definitions as well as a discussion of the physical laws of the polymer solution.

2.6.1 Flow of Polymer Solution in Porous Media

Reservoir rock is characterized by presence of solid matrix and a void space. The void space is usually occupied by fluids - water and oil (and/or gas). As a porous media it has two important properties: porosity **(Ø)** and permeability (K). The porosity of a rock is a measurement of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume (V_p) to the total volume (bulk volume, V_b). This important rock property is determined mathematically by the following generalized relationship:

$$\phi = \frac{V_p}{V_b} \tag{2.6}$$

As for geologists there are different concepts of porosity: absolute porosity and effective porosity. For this study means the effective porosity and assume that all pores are interconnected and effective for fluid flow.

Permeability (K) is a property of the porous medium that measures the capacity and ability of reservoir rock to transmit fluids. Henry Darcy first defined this characterization mathematically in 1856. The equation that defines permeability in terms of measurable quantities is called Darcy's Law.

$$V = -\frac{K}{\mu}\frac{dP}{dL} \tag{2.7}$$

Where V = apparent fluid flowing velocity

K = permeability

μ = viscosity of flowing fluid

$\frac{dP}{dL}$ = pressure gradient

Lake (1989) provided the following function to describe the relation of polymer solution viscosity via polymer concentration. $\mu'_1 = \mu_1[1 + a_1C_{41} + a_2C_{41}^2 + a_3C_{41}^3 + \ldots +]$ Where: C_{41} is the polymer concentration in the aqueous phase μ'_1 is the viscosity of polymer solution μ_1 is the solvent viscosity $a_1, a_2, a_3, \ldots$ are constants

When polymer concentration increasing, viscosity of polymer solution increase too. The data of a one type polysaccharide under reservoir condition and their regression line that used in this study as show in Figure 2.10, (Thang, 2005). The relation of polymer solution viscosity via polymer concentration was illustrated in equation as follow;

$$\mu_1' = 0.1041 + 0.002C - 7x10^{-7}C^2 + 8x10^{-11}C^3 \tag{2.8}$$

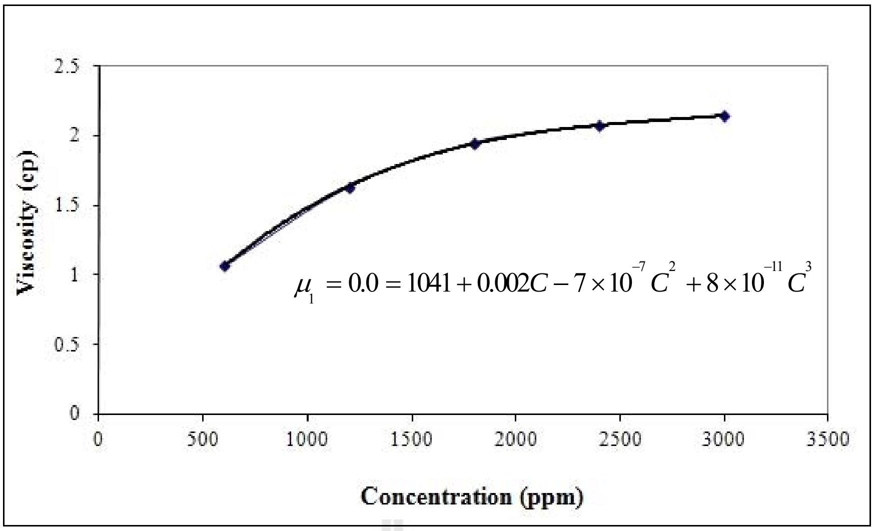


Figure 2.10 The viscosity versus concentration of polymer solution, (After Thang, 2005)

For water and oil the viscosity is, in most cases, a constant value. For polymer solutions this is more or less not the case. The viscosity is in bold outlines a function of the rate of shear strain (shear thinning). Polymer solutions behave as non-Newtonian fluids. All polymer have shear thinning. A fluid whose viscosity decrease with increasing γ is shear thinning as shown in Figure 2.10, (Lake, 1989).

The shear thinning behavior of the polymer solution is caused by the uncoiling of the polymer chains when they are elongated in shear flow, (Lake, 1989). The relationship between polymer solution viscosity and shear rate can be described by a power-law model.

$$\mu'_1 = K_{pl}(\gamma)^{n_{pl}-1} \tag{2.9}$$

Where: μ'_1 is polymer solution viscosity under shear rate γ

K_{pl} and n_{pl} are the power-law coefficient and exponent

For shear thinning fluid, $0 < n_{pl} < 1$. For different polymer, it is different too. It is also a parameter to evaluate the quality of polymer.

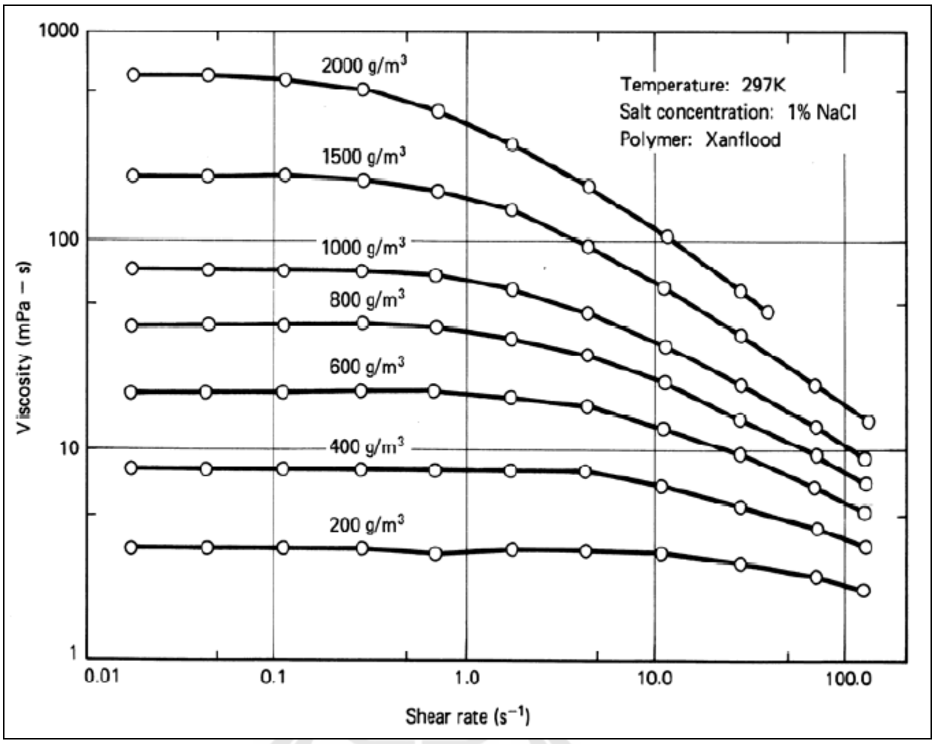


Figure 2.11 The polymer solution viscosity versus shear rate and concentration solution, (After Lake, 1989).

For any polymer product it has a critical shear rate, at this rate polymer chain can be broken and lose its properties forever. Below the critical shear rate, the behavior is partly reversible. With reasonable injection rate the shear rate near wellbore should be controlled under the critical shear rate, so as to avoid polymer molecule's breaking down.

In regard to the viscous flow of a liquid, the rate of shear strain is a function of both flow geometry and flow velocity. For flow in porous media this means that in narrow pores the rate of shear strain is higher than in larger pores, or, in terms of petroleum reservoir engineering, that at the same Darcy velocities the shear rate in low permeable zones is higher than in zones having good permeability.

Usually high permeable zones are preferentially invaded by the flood water during secondary operations or natural water drive, and low permeable zones are not flooded so that oil is left in these parts of a reservoir. During polymer flooding a poor vertical sweep efficiency may be improved, because the polymer solution of course first follows the paths prepared by water and then because of its high viscosity tends to "block" these parts of the reservoir, so that oil that was previously immobile starts flowing. The pressure gradient in the reservoir and especially in those zones where oil was immobile becomes higher in a polymer flood than it was during water drive.

2.6.2 Inaccessible Pore Volume in Polymer Flooding

When performing polymer flooding experiments, many investigators have observed that the polymer breakthrough occurred earlier than the breakthrough of a tracer that was injected along with the polymer. This phenomenon, as shown in Figure 2.11, may be attributed to the fact that some of the pore volume is inaccessible to the polymer solution.

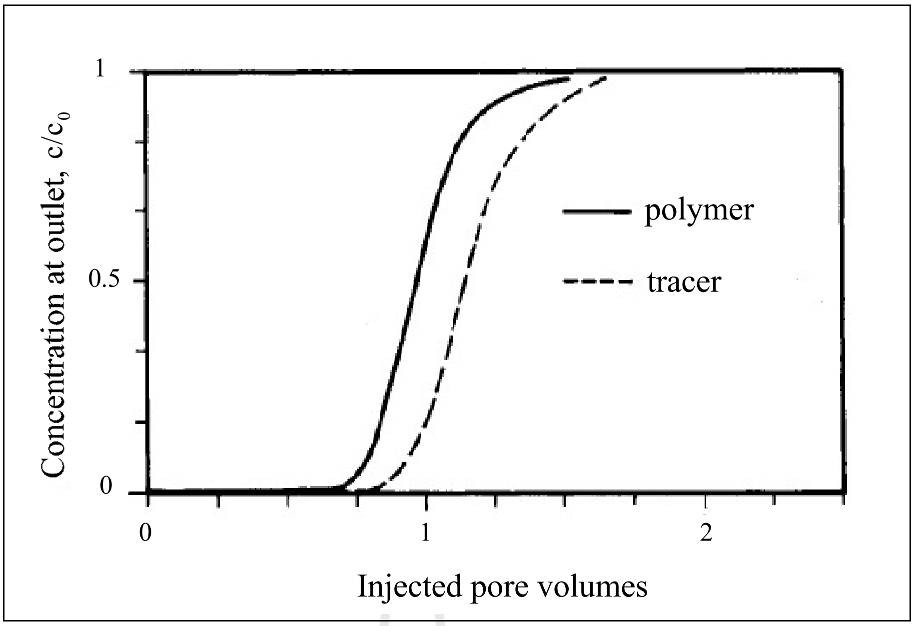


Figure 2.12 Inaccessible pore volume, (After Littmann, 1988).

A reason for this may be that some pores are too small, and that the polymer molecules therefore cannot enter these pores. In order to be able to decide whether or not this is the case, it is necessary to look more closely at the pore sizes of a petroleum reservoir.

As a result, in porous media the saturation of polymer solution is not equal to the saturation of aqueous phase.

$$S_w^* = S_w - S_{IPV} \tag{2.10}$$

Where: S_w is saturation of the whole aqueous phase

S_{IPV} is percentage of inaccessible pore volume in whole effective pore space

S_w^* is saturation of polymer solution

S_{IPV} depends on polymer molecular weight, rock permeability, porosity, and pore size distribution, (Lake, 1989). In ECLIPSE OFFICE PROGRAM it is assumed that it does not exceed the corresponding connate water saturation, (Eclipse Manuals, 2008). The effect of inaccessible pore volume could be covered by the effect of polymer adsorption.

2.6.3 Polymer Retention in Porous Media

All polymers experience retention in porous media because of adsorption on to solid surfaces or trapping within small pores. Polymer retention varies with polymer type, molecular weight, rock composition, brine salinity, brine hardness, flow rate, and temperature, (Lake, 1989).

According to Littmann (1988), Adsorption is the enrichment of a particular component at an interface. This interface may be the interface between two liquid phases, or the interface between a gas or a solid, or between a liquid phase and a solid surface. The enrichment of a component at an interface causes the loss of this component in the continuous phase. The concentration of the component in the continuous phase of a liquid or the partial pressure in a gas phase are in equilibrium with the amount of substance adsorbed. The science that deals with the nature of particles of the size between molecular size and macroscopic size is called the science of colloids. It deals with colloidal particles such as surfactants in interfaces, and also macromolecules, which have a molecular weight of some hundred thousand to several millions. The word colloid is derived from the Greek word for glue. So it is not surprising that materials like polymers for EOR that are used in normal life as glue for wall paper also stick to the solid surface of a sandstone, or that chemicals that are used to form interfaces as surfactants (surface active agents) are also active at the surface of a grain of sand. All substances used for chemical flooding have these properties, and thus they do more or less adsorb. For polymer flooding this means that, due to adsorption, the concentration of polymer in the flood water decreases and thus the viscosity of the displacing phase also decreases.

Table 2.3 Adsorption data, (After Littmann, 1988).

Polymer	**Concentration (kg/m^3)**	**Adsorption (μg/g)**	**Temp. (°C)**	**Adsorbent**	**Salinity of solvent (ppm)**
Xanthan	0.58 (580 ppm)	70	55	Bentheim	-
	0.63 (630 ppm)	83	55	Sandstone	-
	1.35 (1,350 ppm)	151	55	Sandstone	-
	2.45 (2,450 ppm)	114	55	Sandstone	-
	3.10 (3,100 ppm)	123	55	Sandstone	-
		116	56	Res. core	170,000
	0.40 (4,000 ppm)	3	-	-	170,000
	0.05 (500 ppm)	0.4	-	-	170,000
		10	-	Sandstone	100,000

Adsorption mechanisms are divided in to physical and chemical adsorption. Physical adsorption means a relatively weak bond between the surface (adsorbent) and the adsorbed species (adsorptive). The forces are electrostatic. In chemical adsorption a chemical reaction between adsorbent and adsorptive takes place. The values of adsorption of xanthan substance that is injected in to a porous media may be adsorbed, as following Table 2.3.

2.7 Review on polymer injection practice in the world

2.7.1 Polymer Injection at Daqing Oil Field (China)

Daqing oilfield is a large non-marine sandstone reservoir onshore oilfield. This is the largest polymer flooding field in the world. The field has been produced since 1960. The tertiary recovery has been started since 1984 and successfully in 13 field tests in 1989. It has been commercially used in the following years. The results of oil recovery were very good of water-cut dropping and grate oil production increase. The study of polymer injection has been done both in the laboratory to injection testing and in the field (Thang, 2005).

- **Laboratory Studies**

The studies have started since 1985 with two main purposes as follows: selecting the type of polymer and determining the flowing characteristics of the selected polymer.

There are two types of the selected polymer, polyacrylamide and xanthan gum. Due to the characteristics of the field with low temperature and low salinity of formation water, polyacrylamide is more effective at Daqing field than the others. Polyacrylamide has been chosen based on principle of low adsorption and high intrinsic viscosity.

Polymer absorption: The quantity of absorbed polymer determined on sample was 20-25% of the quantity of polymer injection.

Flowing in porous medium: is presented by the parameters such as reducing mobility, reducing permeability, the quantity of absorbed polymer in the sample. All parameters are determined by the experiments of polymer injection on the sample.

- **Preliminary Evaluation**

By modeling method and the results obtained in laboratory, the selected optimum polymer concentration is 915 ppm and the slug size of polymer is 0.5pv. In order to study adequately the application of polymer injection at Daqing field, there are two injections testing, which have been carried out. The first injection testing (PO pilot) was tested on the formation P aiming to determine the effective of polymer. The second injection testing (PT pilot) was tested on the formation P and S aiming to verify the extended polymer injection in entire field.

- **The Result of Injection Testing**

PO pilot: The beginning of water injection in December of 1989 with flow rate of 629 bbl/day at injection wells. The polymer solution has injected since August of 1990 and finished in December of 1991. After 150 days of starting polymer injection, the water cut decreases from 92.6% to 76.6% and production rate increases from 314 bbl/day to 943 bbl/day. In the whole process of injection testing has used 161 tones of polymer and produced 460,000 bbl of oil. Thus, the efficiency of polymer injection is about 2,855 bbl of oil/tones of polymer. Oil recovery increases 7.5% OOIP.

PT pilot: The beginning of water injection was in February of 1990 with flow rate of 1,260 bbl/day. The polymer solution has injected with the same flow rate since October of 1990 and finished in January of 1992. After 200 days of starting polymer injection, the water cut decreases from 92% to 82.6% while production rate increases from 346 to 1,447 bbl/day. PT pilot has used 285 tones of polymer injection and produced 750,000 bbl of oil. Thus, the efficiency of polymer injection about 2,625 bbl of oil/tones of polymer. Oil recovery increases 11.5% OOIP.

CHAPTER III

METHODOLOGY

3.1 Data of Polymer Solution for Injection

Data is collected from the result of laboratory testing on polymer properties. The experiment is to examine the polymer properties at high temperature. The tests that were carried out are:

1. Heat-resistance of polymer
2. Screen factor of polymer

The polymer properties to be determined are:

1. The viscosity versus concentration of polymer solution with changed temperature.
2. The screen factor versus concentration of polymer solution with changed temperature.

The testing was carried out at different polymer concentrations: 600, 1,200, 1,800, 2,400 and 3,000 ppm, dissolved both with the freshwater and brine.

3.1.1 Testing Results for Polymer Properties

According to Thang (2005), the measurement parameters of XCD polymer solution at the different concentrations before and after heating are presented in Table 3.1. The viscosity and screen factor versus concentration with changed temperature. The test of polymer solution have considerable loss of viscosity (plastic and apparent viscosity) and screen factor after heated polymer up to 150º C in the different times. Especially in the polymer samples with low concentration (600 ppm), the capability of increased viscosity and screen factor were almost lost. The problem which has to use high polymer concentration will make increasing the cost price of method and therefore it makes reducing the economic efficiency.

The capability to maintain of plastic viscosity versus the concentration after heating up XCD polymer solution to 150ºC is presented in Figure 3.1 and 3.2. The parameters of plastic viscosity, screen factor high increase with the increasing concentration up to value as 1,200 ppm. At the higher values of concentration more than 1,200 ppm, this increase now were become less and the curves levels off.

In the environment of brine, XCD polymer has a good salt-resistance. The tests with brine solution of 4% NaCl showed that they still maintained the parameters of viscosity, screen factor after heated polymer up to 130ºC.

Table 3.1 Results of test for polymer properties, (After Thang, 2005).

No	Polymer	Conc. ppm	Before heating						Heating temp, °C	Heating time, h	After heating					Viscosity through capilar,μa	Screen factor		Remark
			Temp. °C	PH	V_{300}	V_{600}	μP	μa			Temp. °C	PH	V_{300}	V_{600}	μP		Before heating	After Heating	
1	XCD	600	28.5	8	5	7	2	3.5	130	7	26.0	8	3	4	1	-	1.9	1.1	
2	XCD	600	28.5	8	5	7	2	3.5	150	7	26.0	8	3	4	1	-	1.9	1	
3	XCD	1200	28.5	8	7	9	2	4.5	130	7	28.0	8	3	4.5	1.5	-	2.2	1.1	
4	XCD	1200	28.5	8	7	9	2	4.5	150	7	30.0	8	3	4.5	1.5	-	2.2	1.1	
5	XCD	1800	30.0	8	8	12	4	6	130	7	30.0	8	4	6	2	1.0	2.6	1.3	
6	XCD	1800	30.0	8	8	12	4	6	150	7	30.0	8	3	4.5	1.5	1.0	2.6	1.3	
7	XCD	2400	30.5	8	10	14	4	7	130	7	30.5	8	4	6	2	1.1	4.5	1.4	
8	XCD	2400	30.5	8	10	14	4	7	150	7	30.5	8	3	5	2	1.0	4.5	1.3	
9	XCD	3000	30.5	8	12	17	5	8.5	130	7	30.5	8	5	7	2	1.7	11.4	1.5	
10	XCD	3000	30.5	8	12	17	5	8.5	150	7	30.5	8	3	5	2	1.4	11.4	1.4	
11	XCD	3000	26.0	8	15	20	5	9.8	130	7	26.0	8	4	6	2	-	-	-	Brine
12	XCD	3000	26.0	8	15	20	5	9.8	150	7	26.0	8	3.5	5.5	2	-	-	-	Brine

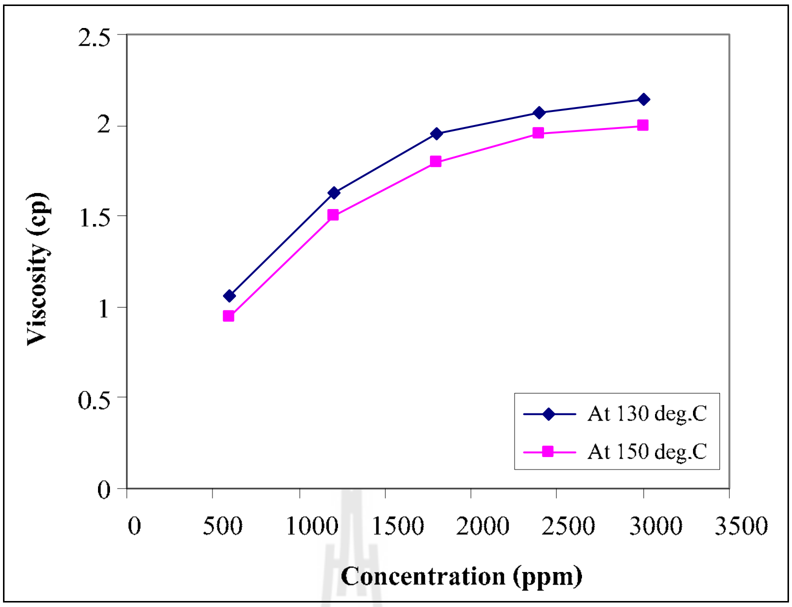


Figure 3.1 The viscosity versus concentration of polymer solution, (After Thang,2005).

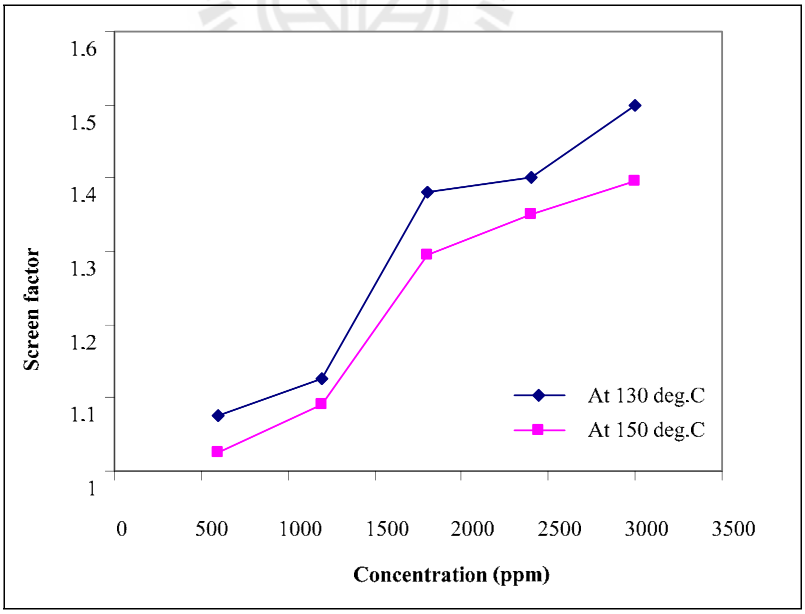


Figure 3.2 The screen factor versus concentration of polymer solution, (After Thang 2005).

At the low polymer concentration, The XCD polymer has not the capability to maintain viscosity, screen factor in a long time when polymer was heated up to 130-150ºC. It is clear that the definition of limitation of the heat resistance for polymers still depends on the purpose of using it in the enhanced oil recovery technique. If the polymer are used for the purpose of well treatment or making gel, then the above solutions can be satisfied up to 150ºC or more than that.

3.2 Simulation Model Construction

For numerical method, the reservoir must be divided into grid cells in space dimension. For each cell the following properties must be specified: porosity, permeability, depth, thickness, etc. This section can be done with Grid in Eclipse.

Fluids PVT properties and rock property must also be set to describe their variation with pressure. This section can be defined with PVT in Office in Eclipse. For multi-phases flow, relative permeability should also be respectively defined for each phase with SCAL section in Eclipse. Initialization of pressure of different cell can be calculated by defining a reference pressure at a depth. Water and oil saturations can be initialized by defining water-oil contact depth. Above this contact, water and oil distribute according to the capillary pressure. In time dimension, the whole process must be divided into time steps, and all production or injection wells should be specified at different time step with Schedule in Office. In the Summary section the output data from simulation process are defined.

The model constructions of reservoir simulation for this study are 3 reserved sizes types as follow:

1. Simulation model of large scale reservoir

   (stock tank of oil initial in placed, STOIIP > 100,000,000 bbl)

2. Simulation model of medium scale reservoir

   (stock tank of oil initial in placed, STOIIP > 30,000,000 bbl)

3. Simulation model of small scale reservoir

   (stock tank of oil initial in placed, STOIIP > 5,000,000 bbl)

The STOIIP sizes and its detail illustrated in Table 3.2-3.3.

Table 3.2 Model structures and STOIIP sizes.

Structure Style	Model No.	Model Name	Aspect STOIIP size (MMBBL)	Model Objective
Anticline	1	A100	109	Large scale case
Anticline	2	A30	32	Medium scale case
Anticline	3	A05	5	Small scale case

Table 3.3 Model sizes and dimensions.

Model	Dimension (ft)	Dimension/grid (ft)	Area (acres)	Thickness (ft)
A100	6,250 x 6,250	250	896.75	100
A30	3,375 x 3,375	135	261.49	160
A05	1,250 x 1,250	50	35.87	56

From the desirable STOIIP, large scale case and medium scale case used 9 production scenarios test of polymer injection to compare the result of production with water injection. For small scale case used 8 production scenarios test of polymer injection to compare the result of production with water injection. All scenarios applied various concentrations of polymer solution injection and difference start times period of 3rd, 4th and 5th year of polymer injection after primary production, see detail in Table 3.4.

Table 3.4 Model scenarios description

Model Name	Scenario No.	Polymer Conc.	Water/Polymer Solution Injection Scenarios	Scenario Name	Project Life Time
A100	1	-	Water injection start 3rd year rate 1,000 bbl/day	A100_ WATER_INJ	25
	2	1,000 ppm	Fresh water inj start 2nd year rate 1,000 bbl/day	A100_ 1000_2INJ	25
			Polymer solution inj start 3rd year rate 1,000 bbl/day		
			Fresh water inj start 12th year rate 1,000 bbl/day		
			Brine inj start 13th year rate 1,000 bbl/day		
	3	1,000 ppm	Fresh water inj start 3rd year rate 1,000 bbl/day	A100_ 1000_3INJ	25
			Polymer solution inj start 4th year rate 1,000 bbl/day		
			Fresh water inj start 13th year rate 1,000 bbl/day		
			Brine inj start 14th year rate 1,000 bbl/day		
	4	1,000 ppm	Fresh water inj start 4th year rate 1,000 bbl/day	A100_ 1000_4INJ	25
			Polymer solution inj start 5th year rate 1,000 bbl/day		
			Fresh water inj start 14th year rate 1,000 bbl/day		
			Brine inj start 15th year rate 1,000 bbl/day		
	5	1,500 ppm	Fresh water inj start 2nd year rate 1,000 bbl/day	A100_ 1500_2INJ	25
			Polymer solution inj start 3rd year rate 1,000 bbl/day		
			Fresh water inj start 12th year rate 1,000 bbl/day		
			Brine inj start 13th year rate 1,000 bbl/day		
	6	1,500 ppm	Fresh water inj start 3rd year rate 1,000 bbl/day	A100_ 1500_3INJ	25
			Polymer solution inj start 4th year rate 1,000 bbl/day		
			Fresh water inj start 13th year rate 1,000 bbl/day		
			Brine inj start 14th year rate 1,000 bbl/day		

Table 3.4 Model scenarios description (Continued)

Model Name	**Scenario No.**	**Polymer Conc.**	**Water/Polymer Solution Injection Scenarios**	**Scenario Name**	**Project Life Time**
	7	1,500 ppm	Fresh water inj start 4th year rate 1,000 bbl/day	A100_ 1500_4INJ	25
			Polymer solution inj start 5th year rate 1,000 bbl/day		
			Fresh water inj start 14th year rate 1,000 bbl/day		
			Brine inj start 15th year rate 1,000 bbl/day		
	8	2,000 ppm	Fresh water inj start 2nd year rate 1,000 bbl/day	A100_ 2000_2INJ	25
			Polymer solution inj start 3rd year rate 1,000 bbl/day		
			Fresh water inj start 12th year rate 1,000 bbl/day		
			Brine inj start 13th year rate 1,000 bbl/day		
	9	2,000 ppm	Fresh water inj start 3rd year rate 1,000 bbl/day	A100_ 2000_3INJ	25
			Polymer solution inj start 4th year rate 1,000 bbl/day		
			Fresh water inj start 13th year rate 1,000 bbl/day		
			Brine inj start 14th year rate 1,000 bbl/day		
	10	2,000 ppm	Fresh water inj start 4th year rate 1,000 bbl/day	A100_ 2000_4INJ	25
			Polymer solution inj start 5th year rate 1,000 bbl/day		
			Fresh water inj start 14th year rate 1,000 bbl/day		
			Brine inj start 15th year rate 1,000 bbl/day		
A30	1	-	Water injection start 3rd year rate 500 bbl/day	A30_ WATER_ INJ	25
	2	1,000 ppm	Fresh water inj start 2nd year rate 500 bbl/day	A30_ 1000_2INJ	25
			Polymer solution inj start 3rd year rate 500 bbl/day		
			Fresh water inj start 11th year rate 500 bbl/day		
			Brine inj start 12th year rate 500 bbl/day		

Table 3.4 Model scenarios description (Continued)

Model Name	Scenario No.	Polymer Conc.	Water/Polymer Solution Injection Scenarios	Scenario Name	Project Life Time
	3	1,000 ppm	Fresh water inj start 3rd year rate 500 bbl/day	A30_ 1000_3INJ	25
			Polymer solution inj start 4th year rate 500 bbl/day		
			Fresh water inj start 12th year rate 500 bbl/day		
			Brine inj start 13th year rate 500 bbl/day		
	4	1,000 ppm	Fresh water inj start 4th year rate 500 bbl/day	A30_ 1000_4INJ	25
			Polymer solution inj start 5th year rate 500 bbl/day		
			Fresh water inj start 13th year rate 500 bbl/day		
			Brine inj start 14th year rate 500 bbl/day		
	5	1,500 ppm	Fresh water inj start 2nd year rate 500 bbl/day	A30_ 1500_2INJ	25
			Polymer solution inj start 3rd year rate 500 bbl/day		
			Fresh water inj start 11th year rate 500 bbl/day		
			Brine inj start 12th year rate 500 bbl/day		
	6	1,500 ppm	Fresh water inj start 3rd year rate 500 bbl/day	A30_ 1500_3INJ	25
			Polymer solution inj start 4th year rate 500 bbl/day		
			Fresh water inj start 12th year rate 500 bbl/day		
			Brine inj start 13th year rate 500 bbl/day		
	7	1,500 ppm	Fresh water inj start 4th year rate 500 bbl/day	A30_ 1500_4INJ	25
			Polymer solution inj start 5th year rate 500 bbl/day		
			Fresh water inj start 13th year rate 500 bbl/day		
			Brine inj start 14th year rate 500 bbl/day		

Table 3.4 Model scenarios description (Continued)

Model Name	Scenario No.	Polymer Conc.	Water/Polymer Solution Injection Scenarios	Scenario Name	Project Life Time
	8	2,000 ppm	Fresh water inj start 2nd year rate 500 bbl/day	A30_ 2000_2INJ	25
			Polymer solution inj start 3rd year rate 500 bbl/day		
			Fresh water inj start 11th year rate 500 bbl/day		
			Brine inj start 12th year rate 500 bbl/day		
	9	2,000 ppm	Fresh water inj start 3rd year rate 500 bbl/day	A30_ 2000_3INJ	25
			Polymer solution inj start 4th year rate 500 bbl/day		
			Fresh water inj start 12th year rate 500 bbl/day		
			Brine inj start 13th year rate 500 bbl/day		
	10	2,000 ppm	Fresh water inj start 4th year rate 500 bbl/day	A30_ 2000_4INJ	25
			Polymer solution inj start 5th year rate 500 bbl/day		
			Fresh water inj start 13th year rate 500 bbl/day		
			Brine inj start 14th year rate 500 bbl/day		
A05	1	-	Water injection start 3rd year rate 200 bbl/day	A05_ WATER_ INJ	20
	2	600 ppm	Fresh water inj start 2nd year rate 200 bbl/day	A05_ 600_2INJ	20
			Polymer solution inj start 3rd year rate 200 bbl/day		
			Polymer solution inj start 8th year rate 250 bbl/day		
	3	600 ppm	Fresh water inj start 3rd year rate 200 bbl/day	A05_ 600_3INJ	20
			Polymer solution inj start 4th year rate 200 bbl/day		
			Polymer solution inj start 9th year rate 250 bbl/day		
	4	800 ppm	Fresh water inj start 2nd year rate 200 bbl/day	A05_ 800_2INJ	20
			Polymer solution inj start 3rd year rate 200 bbl/day		
			Polymer solution inj start 8th year rate 250 bbl/day		

Table 3.4 Model scenarios description (Continued)

Model Name	Scenario No.	Polymer Conc.	Water/Polymer Solution Injection Scenarios	Scenario Name	Project Life Time
	5	800 ppm	Fresh water inj start 3rd year rate 200 bbl/day	A05_ 800_3INJ	20
			Polymer solution inj start 4th year rate 200 bbl/day		
			Polymer solution inj start 9th year rate 250 bbl/day		
	6	1,000 ppm	Fresh water inj start 2nd year rate 200 bbl/day	A05_ 1000_2INJ	20
			Polymer solution inj start 3rd year rate 200 bbl/day		
			Polymer solution inj start 8th year rate 250 bbl/day		
	7	1,000 ppm	Fresh water inj start 3rd year rate 200 bbl/day	A05_ 1000_3INJ	20
			Polymer solution inj start 4th year rate 200 bbl/day		
			Polymer solution inj start 9th year rate 250 bbl/day		
	8	1,200 ppm	Fresh water inj start 2nd year rate 200 bbl/day	A05_ 1200_2INJ	20
			Polymer solution inj start 3rd year rate 200 bbl/day		
			Polymer solution inj start 8th year rate 250 bbl/day		
	9	1,200 ppm	Fresh water inj start 3rd year rate 200 bbl/day	A05_ 1200_3INJ	20
			Polymer solution inj start 4th year rate 200 bbl/day		
			Polymer solution inj start 9th year rate 250 bbl/day		

Remark : From table 3.2 through 3.4 can be summarizing as, three STOIIP reserved sizes of model per a structure style.

3.3 Structure Style of Model

The Anticline structure style are selected to use in this study because of it is a most common structure style that normally appear to a petroleum reservoir, the initial of structural surface data prepared by Suffer Version 7.0 and the result of reservoir structure from reservoir simulator as shown in Figure 3.3-3.5.

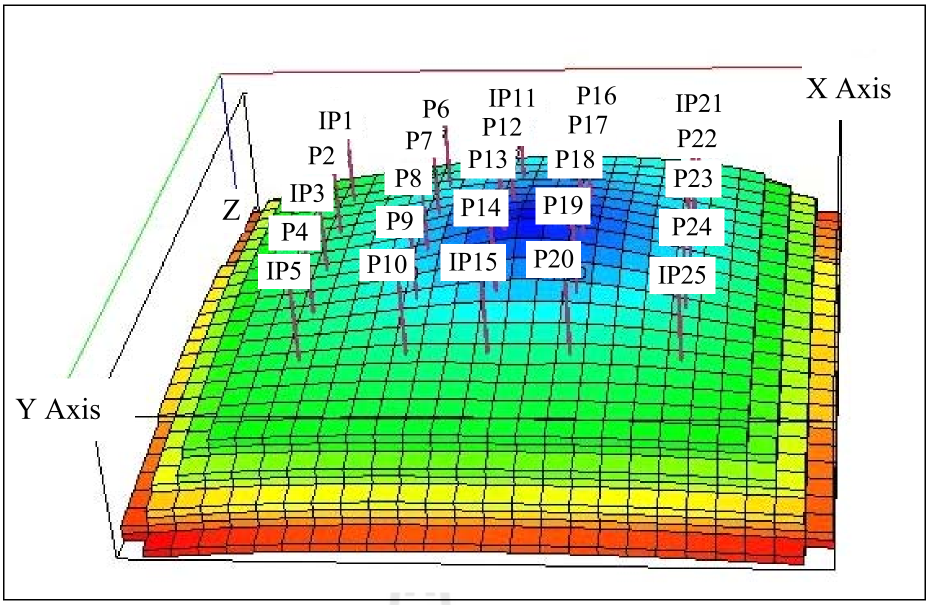


Figure 3.3 Oblique view anticline structure style of model A100

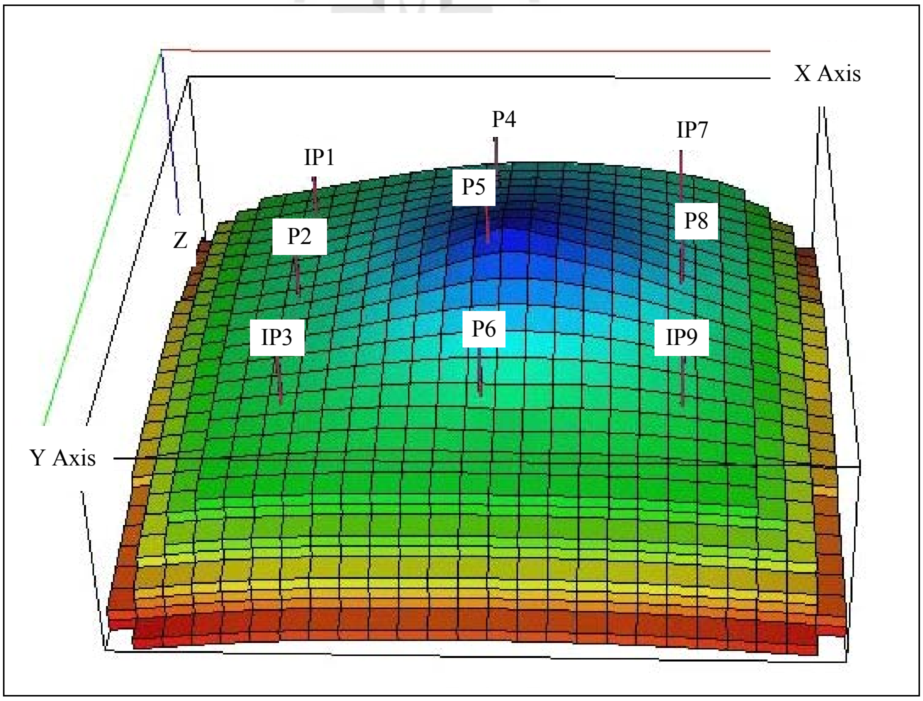


Figure 3.4 Oblique view anticline structure style of model A30

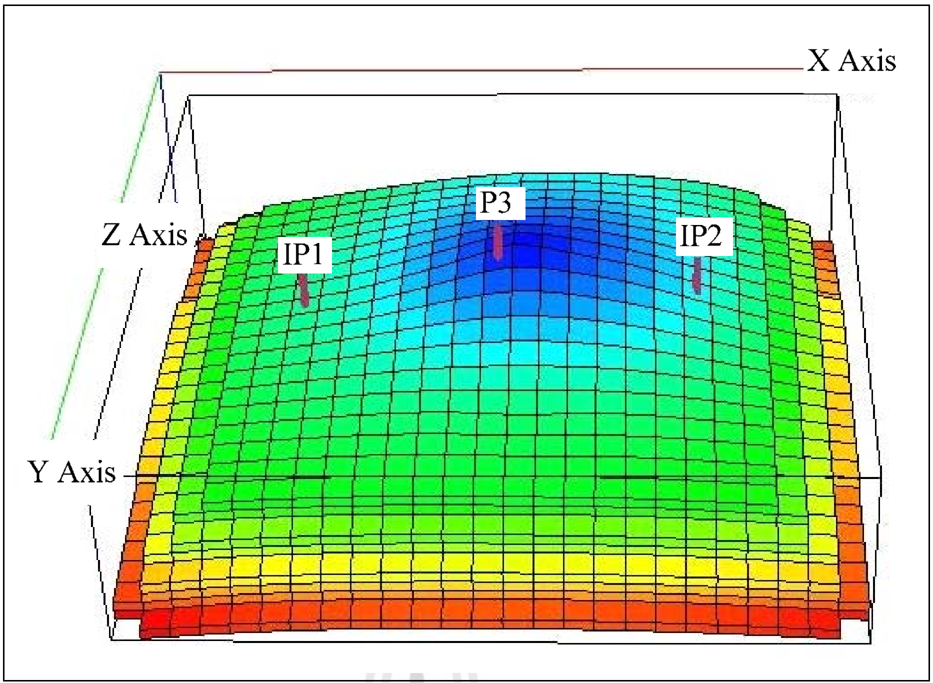


Figure 3.5 Oblique view anticline structure style of model A05

3.4 Reservoir Model Input Parameters

The model input parameter description follow the main input section data of the simulator, Grid section, PVT section, SCAL section, Initialization section and Schedule section, respectively.

3.4.1 Porosity and Permeability Data of Grid Section

Trisarn (2006) found porosity and permeability of the Sirikit L sand as shown in Table 3.5. The x, y, z porosity and x, y permeability set as following table, only z permeability set to 0.1 of represent value.

Table 3.5 Permeability and Porosity for 8 layer selection result, (Trisarn, 2006)

Layer	Porosity (%)	Permeability (md)
1	26.00	586.0
2	25.00	323.5
3	24.00	178.6
4	23.00	98.6
5	22.00	54.5
6	21.00	30.1
7	20.00	16.6
8	19.00	9.2

3.4.2 Reservoir Fluid Properties of PVT Section

This section data is related to PVT section data used in the simulator to indicated fluid properties (fluid formation volume factors, viscosities, densities, gas-oil ratio, and rock and water compressibility) at each phase due to pressure changes after production or injection phase. The reservoir fluid properties are detail as follow:

- Rock type of reservoir — Consolidated sandstone
- Porosity (%) — 19-26%
- Oil gravity, (°API Oil) — 39.4
- Gas specific gravity, (SG Air = 1) — 0.8
- Bubble point pressure, (psi) — 1,800
- Initial static reservoir pressure, (psi) — 3,500
- Reservoir temperature (°F) — 203
- Water density (lb/ft^3) — 62.428
- Water compressibility@3,500 psi — 3.081x10^{-6} psi^{-1}
- Water viscosity (cp) — 0.296
- Oil viscosity (cp) — 2.1-6.7
- Oil formation volume factor (bbl/STB) — 1.055-1.286

3.4.3 Fluid Saturation of SCAL Section

The SCAL section refers to the term of rock properties which is sets of input tables of relative permeability versus saturation. Effectively this defines the connate (or irreducible), critical and maximum saturation of each phase supplies information for defining the transition zone and defines the conditions of flow of phases relative to one another. Fluid saturation is list as follow:

- Initial water saturation 0.3
- Residual oil saturation 0.25
- Gas saturation 0.04

See appendix B for SCAL input data detail.

3.4.4 Fluid Contact of Initialization Section

Initialization refers to defining the initial conditions of the simulation. The initial conditions are defines by specifying the OWC (Oil-Water contact) depths and the pressure at a known depth. ECLIPSE uses this information in conjunction with much of the information from previous stages to calculate the initial hydrostatic pressure gradients in each zone of the reservoir model and allocate the initial saturation of each phase in every grid cell prior to production and injection. The data of equilibration is following:

- Datum depth, (feet) 3,850
- Pressure at datum depth, (psi) 3,500
- Water/Oil contact depth, (feet) 3,915
- The bubble-point at datum depth, (psi) 1,800

3.4.5 Well Data of Schedule Section

Well data provide well and completion locations, production and injection rates of wells and other data such as skin factors, well radius, and well controls, etc. The well data which use in producing wells and injection wells as following;

- Diameter of well bore	0.71	feet
- Skin factor	-1	
- Effective K_h	250	mD
- Datum depth of Production well	3,850	feet
- Datum depth of Injection well	3,850	feet
- Perforation of Production zone	1^{st} - 8^{th} layer	
- Perforation of Injection zone	1^{st} - 8^{th} layer	

3.5 Flood Pattern Design

Polymer flooding pattern design for a comprehensive polymer flooding simulation in this study relies on the reservoir structure, drainage area, number of well, production activity and injection activity. The summary of polymer flooding pattern design, production rate, injection rate number of well and concentration of polymer solution used for each model illustrated in Table 3.6 and Table 3.7.

Table 3.6 Polymer solution flooding pattern design.

Model Name	Pattern	Initial Prod. Well	After well convert		Well Spacing (ft)
			Inj. well	Prod. well	
A100	Peripheral flood	25	8	17	1,000
A30	Peripheral flood	9	4	5	945
A05	Inverted three-spot	3	2	1	350

Table 3.7 Production and injection rate for scenario test.

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A100_WATER_INJ	No injection	25	-	400	-	-	-
	Water injection start 3rd year	17	8	-	1,000	-	-
A100_1000_2INJ	No injection	25		400	-	-	-
	Fresh water inj start 2nd year	17	8	-	1,000	-	-
	Polymer solution inj start 3rd year			-	-	1,000	-
	Fresh water inj start 12th year			-	1,000	-	-
	Brine inj start 13th year			-	-	-	1,000
A100_1000_3INJ	No injection	25		400	-	-	-
	Fresh water inj start 3rd year	17	8	-	1,000	-	-
	Polymer solution inj start 4th year			-	-	1,000	-
	Fresh water inj start 13th year			-	1,000	-	-
	Brine inj start 14th year			-	-	-	1,000
A100_1000_4INJ	No injection	25		400	-	-	-
	Fresh water inj start 4th year	17	8	-	1,000	-	-
	Polymer solution inj start 5th year			-	-	1,000	-
	Fresh water inj start 14th year			-	1,000	-	-
	Brine inj start 15th year			-	-	-	1,000
A100_1500_2INJ	No injection	25		400	-	-	-
	Fresh water inj start 2nd year	17	8	-	1,000	-	-
	Polymer solution inj start 3rd year			-	-	1,000	-
	Fresh water inj start 12th year			-	1,000	-	-
	Brine inj start 13th year			-	-	-	1,000

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A100_1500_3INJ	No injection	25		400	-	-	-
	Fresh water inj start 3^{rd} year	17	8	-	1,000	-	-
	Polymer solution inj start 4^{th} year			-	-	1,000	-
	Fresh water inj start 13^{th} year			-	1,000	-	-
	Brine inj start 14^{th} year			-	-	-	1,000
A100_1500_4INJ	No injection	25		400	-	-	-
	Fresh water inj start 4^{th} year	17	8	-	1,000	-	-
	Polymer solution inj start 5^{th} year			-	-	1,000	-
	Fresh water inj start 14^{th} year			-	1,000	-	-
	Brine inj start 15^{th} year			-	-	-	1,000
A100_2000_2INJ	No injection	25		400	-	-	-
	Fresh water inj start 2^{nd} year	17	8	-	1,000	-	-
	Polymer solution inj start 3^{rd} year			-	-	1,000	-
	Fresh water inj start 12^{th} year			-	1,000	-	-
	Brine inj start 13^{th} year			-	-	-	1,000
A100_2000_3INJ	No injection	25		400	-	-	-
	Fresh water inj start 3^{rd} year	17	8	-	1,000	-	-
	Polymer solution inj start 4^{th} year			-	-	1,000	-
	Fresh water inj start 13^{th} year			-	1,000	-	-
	Brine inj start 14^{th} year			-	-	-	1,000

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A100_2000_4INJ	No injection	25		400	-	-	-
	Fresh water inj start 4th year	17	8	-	1,000	-	-
	Polymer solution inj start 5th year			-	-	1,000	-
	Fresh water inj start 14th year			-	1,000	-	-
	Brine inj start 15th year			-	-	-	1,000
A30_WATER_ INJ	No injection	9	-	1,000	-	-	-
	Water injection start 3rd year	5	4	-	500	-	-
A30_1000_2INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 2nd year	5	4	-	500	-	-
	Polymer solution inj start 3rd year			-	-	500	-
	Fresh water inj start 11th year			-	500	-	-
	Brine inj start 12th year			-	-	-	500
A30_1000_3INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 3rd year	5	4	-	500	-	-
	Polymer solution inj start 4th year			-	-	500	-
	Fresh water inj start 12th year			-	500	-	-
	Brine inj start 13th year			-	-	-	500
A30_1000_4INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 4th year	5	4	-	500	-	-
	Polymer solution inj start 5th year			-	-	500	-
	Fresh water inj start 13th year			-	500	-	-
	Brine inj start 14th year			-	-	-	500

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A30_1500_2INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 2nd year	5	4	-	500	-	-
	Polymer solution inj start 3rd year			-	-	500	-
	Fresh water inj start 11th year			-	500	-	-
	Brine inj start 12th year			-	-	-	500
A30_1500_3INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 3rd year	5	4	-	500	-	-
	Polymer solution inj start 4th year			-	-	500	-
	Fresh water inj start 12th year			-	500	-	-
	Brine inj start 13th year			-	-	-	500
A30_1500_4INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 4th year	5	4	-	500	-	-
	Polymer solution inj start 5th year			-	-	500	-
	Fresh water inj start 13th year			-	500	-	-
	Brine inj start 14th year			-	-	-	500
A30_2000_2INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 2nd year	5	4	-	500	-	-
	Polymer solution inj start 3rd year			-	-	500	-
	Fresh water inj start 11th year			-	500	-	-
	Brine inj start 12th year			-	-	-	500

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A30_2000_3INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 3rd year	5	4	-	500	-	-
	Polymer solution inj start 4th year			-	-	500	-
	Fresh water inj start 12th year			-	500	-	-
	Brine inj start 13th year			-	-	-	500
A30_2000_4INJ	No injection	9		1,000	-	-	-
	Fresh water inj start 4th year	5	4	-	500	-	-
	Polymer solution inj start 5th year			-	-	500	-
	Fresh water inj start 13th year			-	500	-	-
	Brine inj start 14th year			-	-	-	500
A05_WATER_ INJ	No injection	3	-	120	-	-	-
	Water injection start 3rd year	1	2	340	200	-	-
A05_600_2INJ	No injection	3		120	-	-	-
	Fresh water inj start 2nd year	1	2	340	200	-	-
	Polymer solution inj start 3rd year			340	-	200	-
	Polymer solution inj start 8th year			340	-	250	-
A05_600_3INJ	No injection	3		120	-	-	-
	Fresh water inj start 3rd year	1	2	340	200	-	-
	Polymer solution inj start 4th year			340	-	200	-
	Polymer solution inj start 9th year			340	-	250	-

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A05_800_2INJ	No injection	3		120	-	-	-
	Fresh water inj start 2^{nd} year	1	2	340	200	-	-
	Polymer solution inj start 3^{rd} year			340	-	200	-
	Polymer solution inj start 8^{th} year			340	-	250	-
A05_800_3INJ	No injection	3		120	-	-	-
	Fresh water inj start 3^{rd} year	1	2	340	200	-	-
	Polymer solution inj start 4^{th} year			340	-	200	-
	Polymer solution inj start 9^{th} year			340	-	250	-
A05_1000_2INJ	No injection	3		120	-	-	-
	Fresh water inj start 2^{nd} year	1	2	340	200	-	-
	Polymer solution inj start 3^{rd} year			340	-	200	-
	Polymer solution inj start 8^{th} year			340	-	250	-
A05_1000_3INJ	No injection	3		120	-	-	-
	Fresh water inj start 3^{rd} year	1	2	340	200	-	-
	Polymer solution inj start 4^{th} year			340	-	200	-
	Polymer solution inj start 9^{th} year			340	-	250	-
A05_1200_2INJ	No injection	3		120	-	-	-
	Fresh water inj start 2^{nd} year	1	2	340	200	-	-
	Polymer solution inj start 3^{rd} year			340	-	200	-
	Polymer solution inj start 8^{th} year			340	-	250	-

Table 3.7 Production and Injection rate for scenario test (Continued).

Scenario Name	Water/Polymer Solution Injection Scenarios	Number of Production Well	Number of Injection Well	Initial Oil Production (BOPD/Well)	Water Injection (BWPD/Well)	Polymer Solution Injection (BWPD/Well)	Brine Injection (BWPD/Well)
A05_1200_3INJ	No injection	3		120	-	-	-
	Fresh water inj start 3rd year	1	2	340	200	-	-
	Polymer solution inj start 4th year			340	-	200	-
	Polymer solution inj start 9th year			340	-	250	-

CHAPTER IV

RESERVOIR SIMULATION RESULT

From previous chapter, the three reserve sizes of STOIIP (100, 30, and 5 MMBBL) with a structure style (Anticline structure). The large and medium reserve sizes (100 and 30 MMBBL) will be performed by 10 production scenarios. A small reserve size (5 MMBBL) will be performed by 9 production scenarios. Total 29 scenarios, the polymer flooding scenarios start at different of time and different concentration of the polymer solution will be test to observe and compare the results of production efficiency yield from polymer flooding activity and waterflooding scenario (base case) for find the best recovery efficiency. The reservoir simulation results displayed through the cross plot of five main graphs and addition the cross plot of two graphs for results of polymer injection and production. The detail of showing graphs can be illustrated in Table 4.1.

Table 4.1 Graph display parameter description.

Graph	Parameter	Description	Common Refer
1	FGIP	Field Gas in Place	Original of Gas in Place
	FOIP	Field Oil in Place	Original of Oil in Place
	FWIP	Field Water in Place	Original of Water in Place
2	FGPT	Field Gas Production Total	Cumulative Gas Production
	FOPT	Field Oil Production Total	Cumulative Oil Production
	FWPT	Field Water Production Total	Cumulative Water Production
3	FGPR	Field Gas Production Rate	Daily Gas Production Rate
	FOPR	Field Oil Production Rate	Daily Oil Production Rate
	FWPR	Field Water Production Rate	Daily Water production Rate
4	FGOR	Field Gas-Oil-Ratio	Gas-Oil-Ratio (GOR)
	FWCT	Field Water Cut	Water Cut (WCT)
	FPR	Field Pressure	Reservoir Pressure
5	FOE	Field Oil Efficiency	Oil recovery Efficiency
6	FCIR	Field Polymer Injection Rate	Polymer Solution Injection Rate
	FCIT	Field Polymer Injection Total	Polymer Solution Injection Total
7	FCPR	Field Polymer Production Rate	Polymer Solution Production Rate
	FCPT	Field Polymer Production Total	Polymer Solution Production Total

4.1 Reservoir Simulation Result for Model A100

4.1.1 Model A100_WATER_INJ Scenario Result

Model A100_WATER_INJ is waterflooding (base case) and the simulation results as shown in Table 4.2 and Figure 4.1 – 4.6:

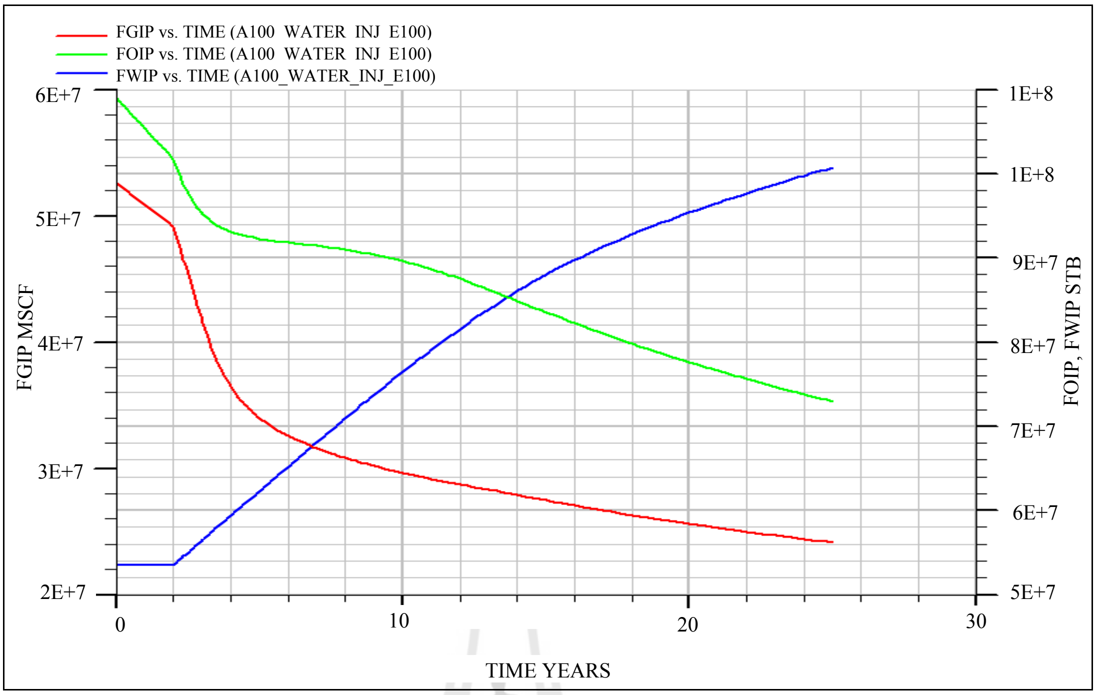


Figure 4.1 Fluid in place profile vs. Time of model A100_WATER_INJ.

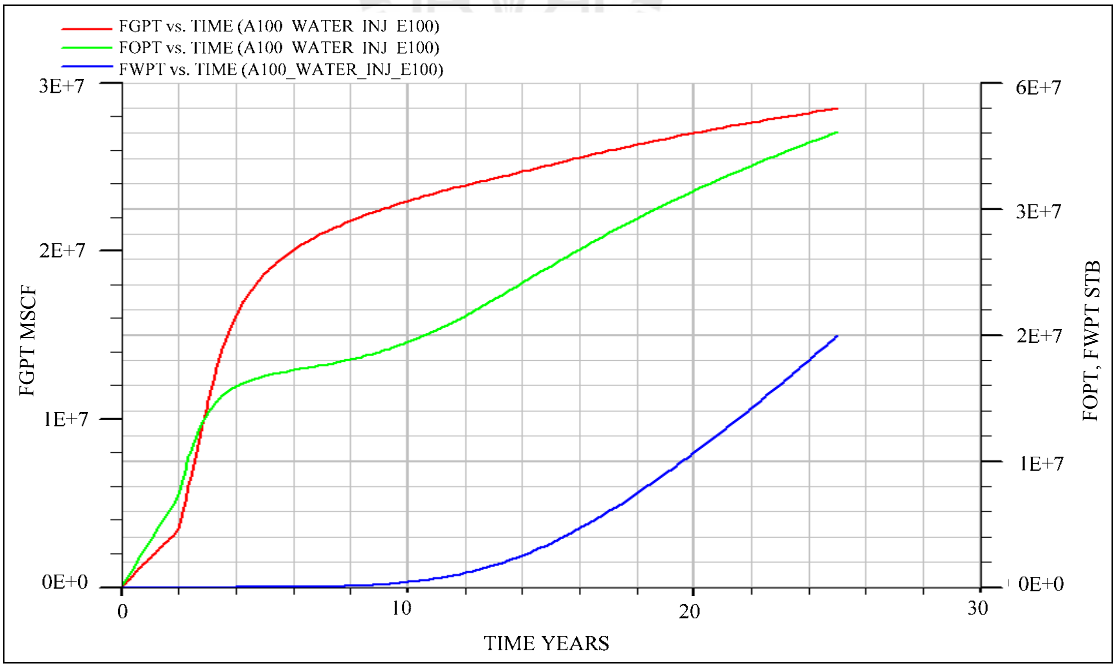


Figure 4.2 Cumulative fluids production profile vs. Time of model A100_WATER_INJ.

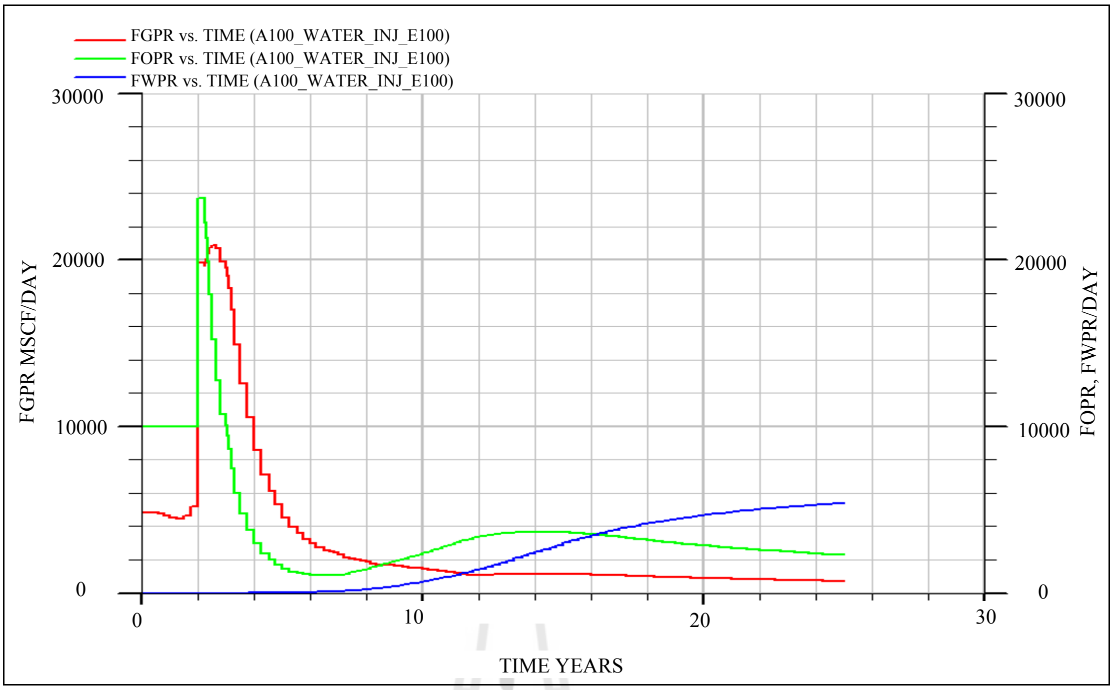


Figure 4.3 Fluids production rate profile vs. Time of model A100_WATER_INJ.

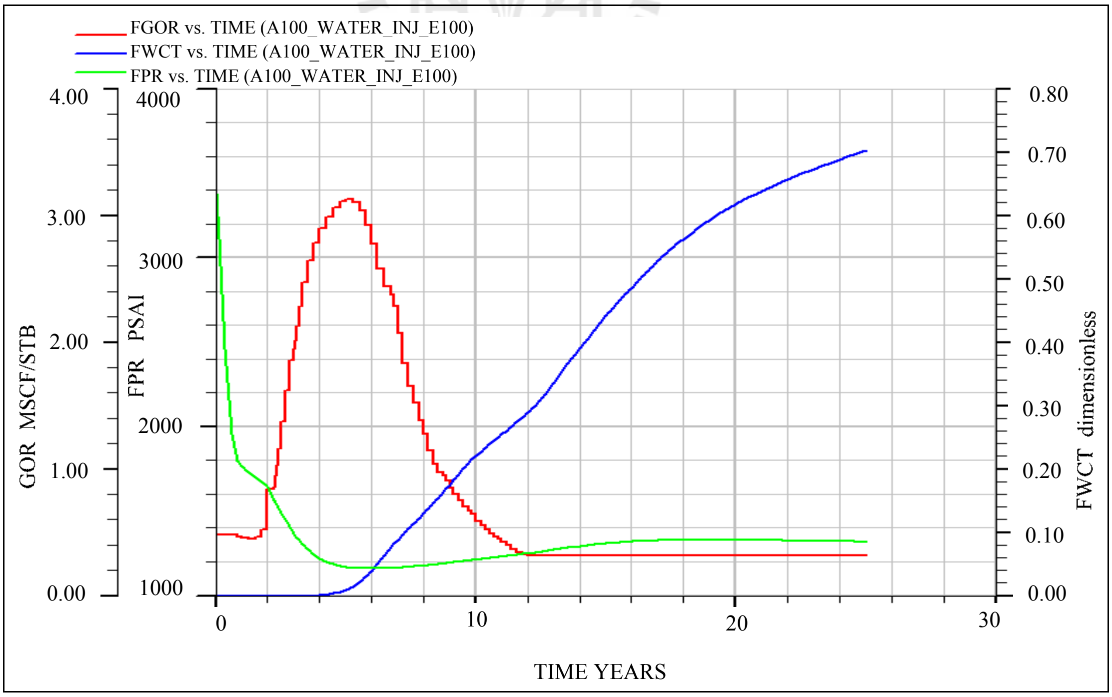


Figure 4.4 GOR, WCT, and Pressure profile vs. Time of model A100_WATER_INJ.

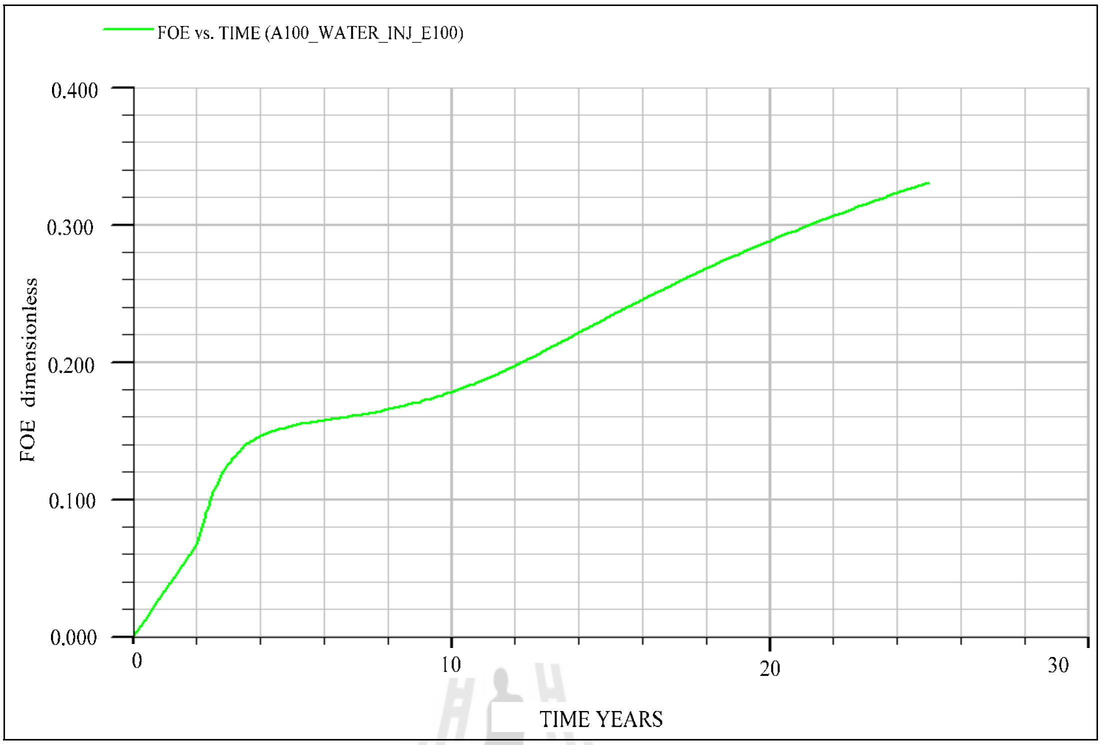


Figure 4.5 Oil recovery efficiency vs. Time of model A100_WATER_INJ.

Table 4.2 Summary detail of graph 4.1, 4.2 and 4.5.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	36,100,988	109,049,300	33.11
Gas (MSCF)	28,479,780	52,615,556	54.13
Water (STB)	19,974,262	53,511,504	37.33

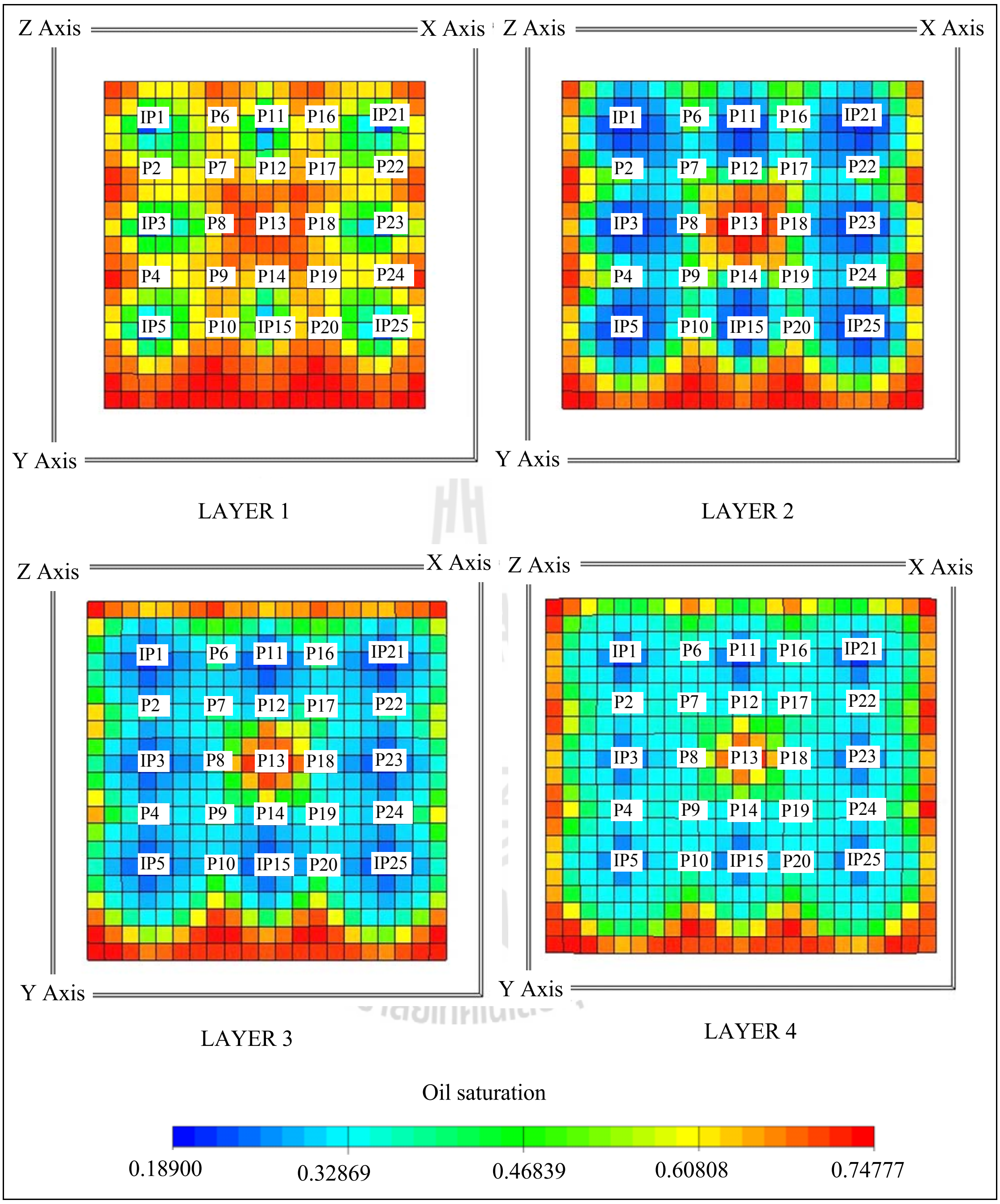


Figure 4.6 Residual oil saturation distribution after waterflooding of model A100_WATER_INJ.

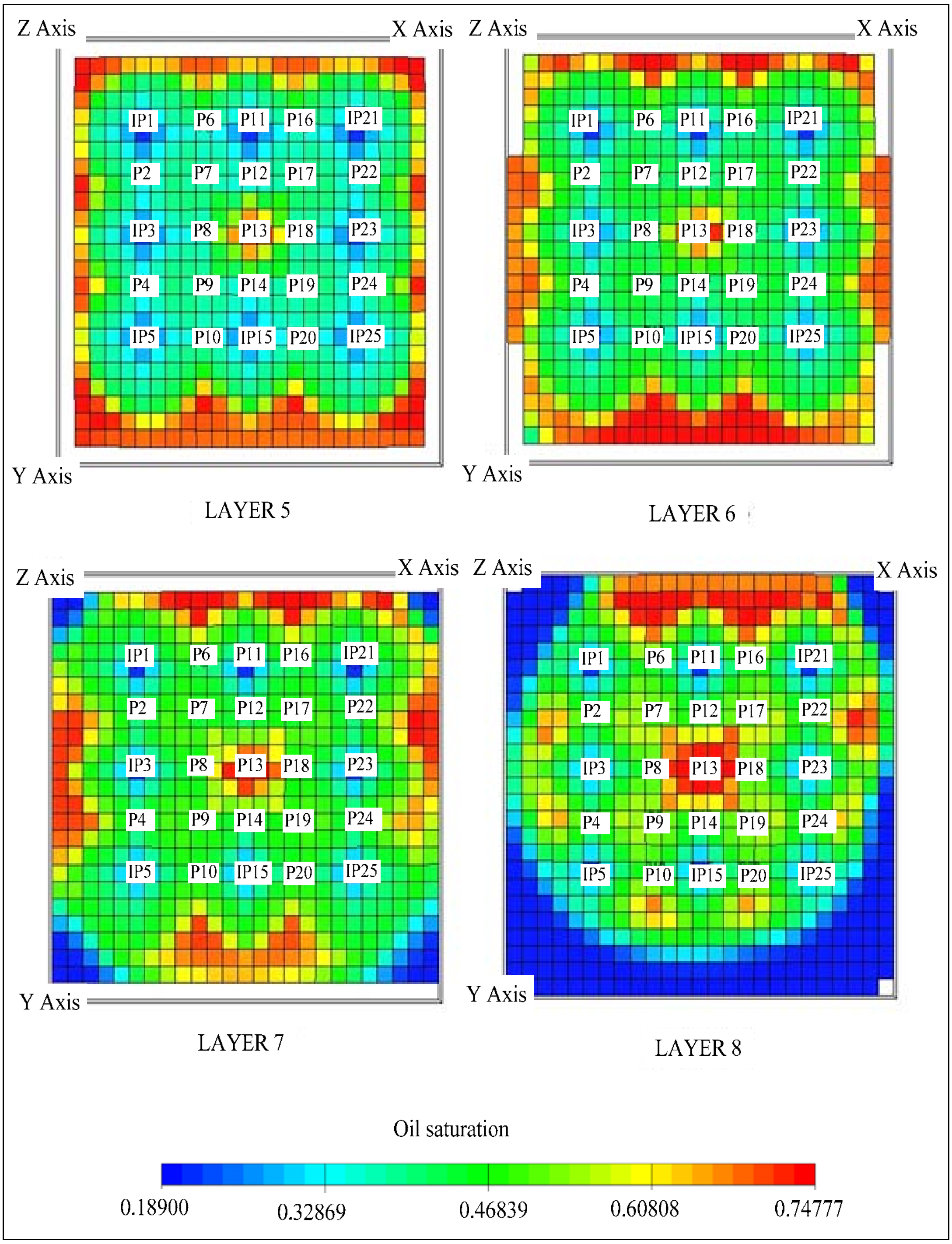


Figure 4.6 Residual oil saturation distribution after waterflooding of model A100_WATER_INJ. (Continued)

4.1.2 Model A100_1000_2INJ Scenario Result

Model A100_1000_2INJ is polymer flooding and the simulation results as shown in Table 4.3, Table 4.4 and Figure 4.7 – 4.13:

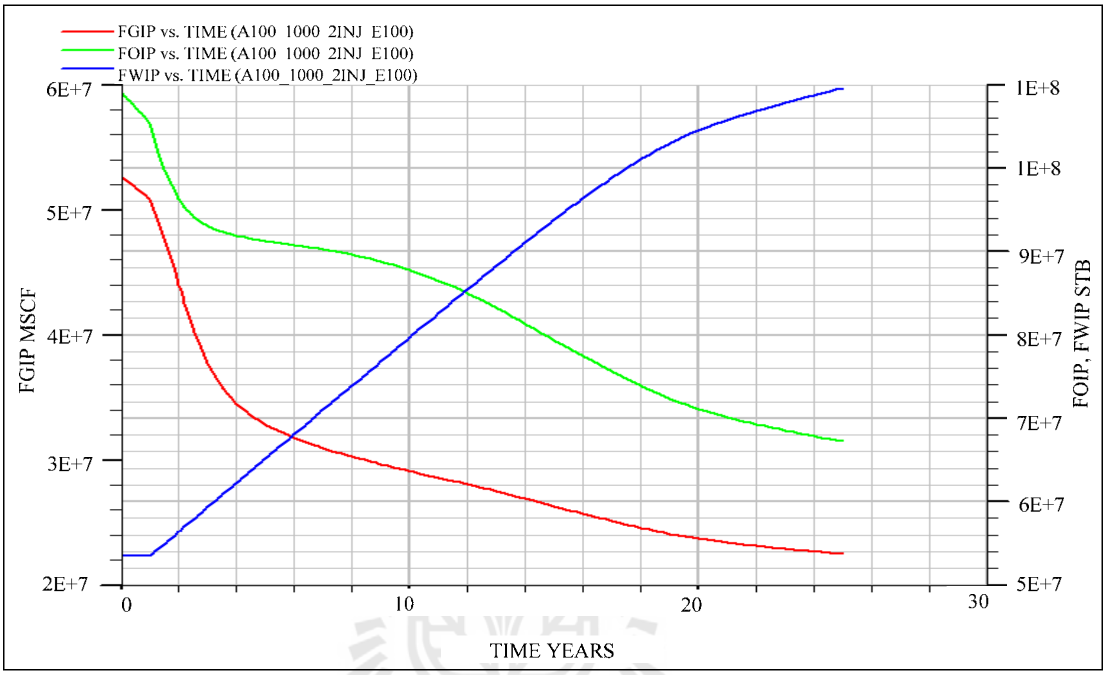


Figure 4.7 Fluid in place profile vs. Time of model A100_1000_2INJ.

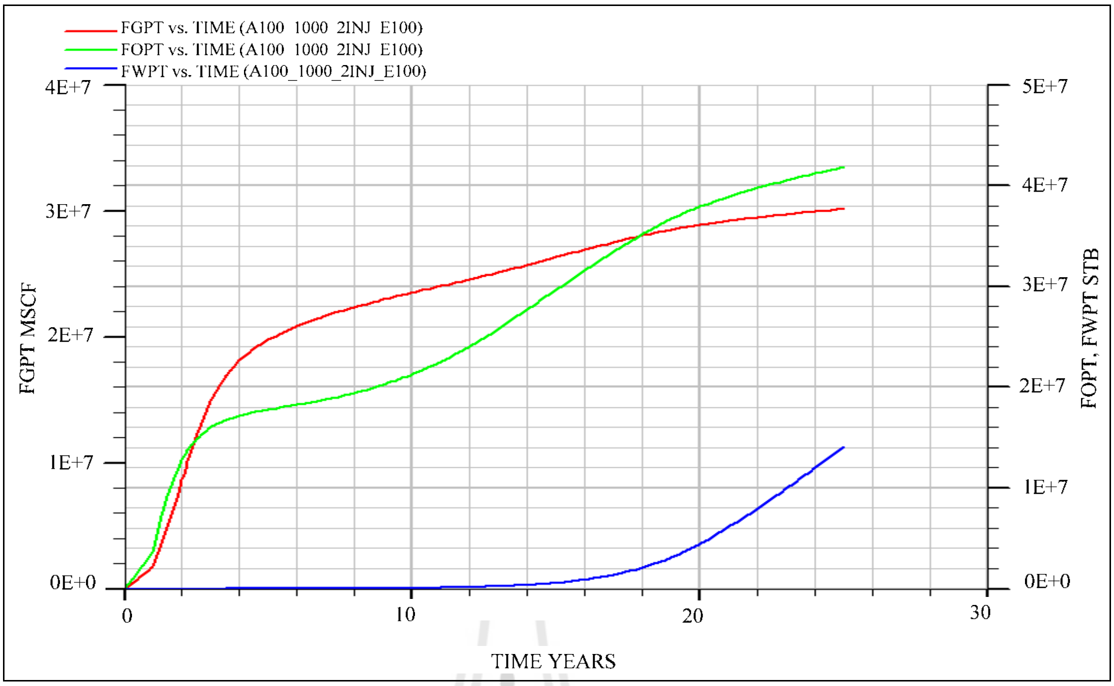


Figure 4.8 Cumulative fluids production profile vs. Time of model A100_1000_2INJ.

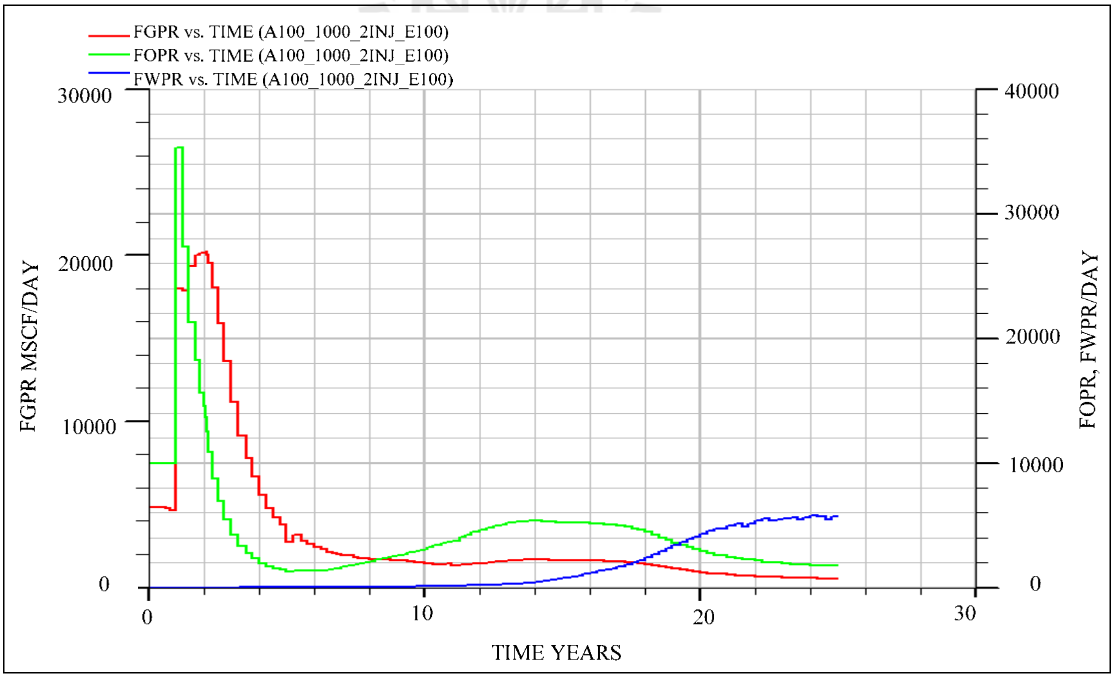


Figure 4.9 Fluids production rate profile vs. Time of model A100_100_2INJ.

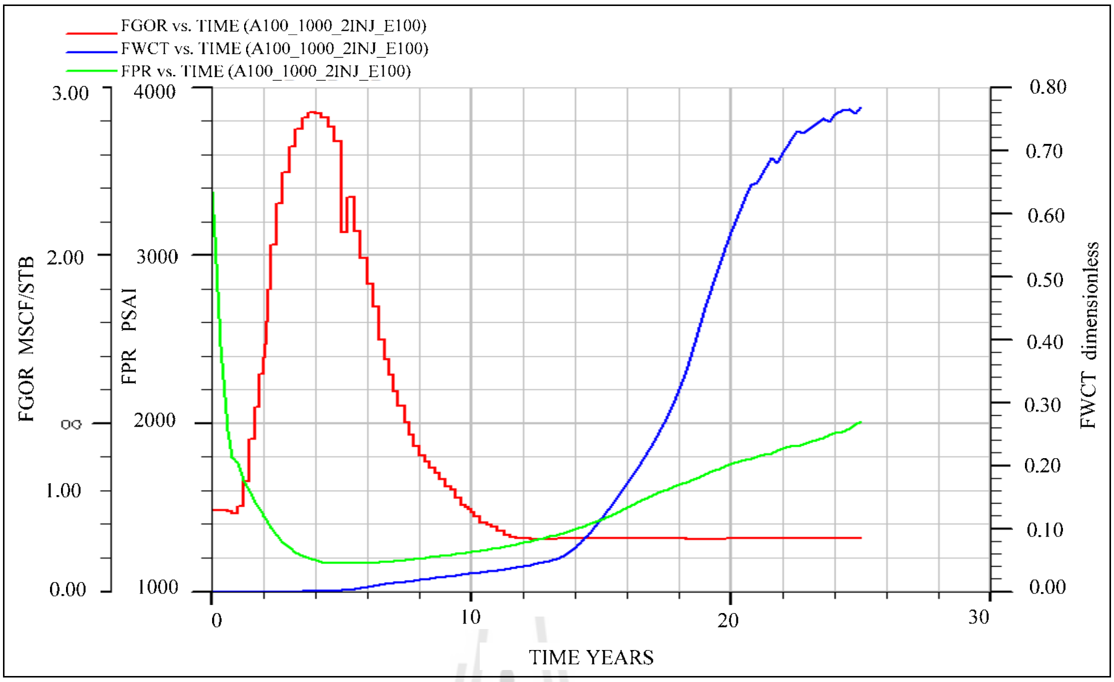


Figure 4.10 GOR, WCT, and Pressure profile vs. Time of model A100_1000_2INJ.

Figure 4.11 Oil recovery efficiency vs. Time of model A100_1000_2INJ.

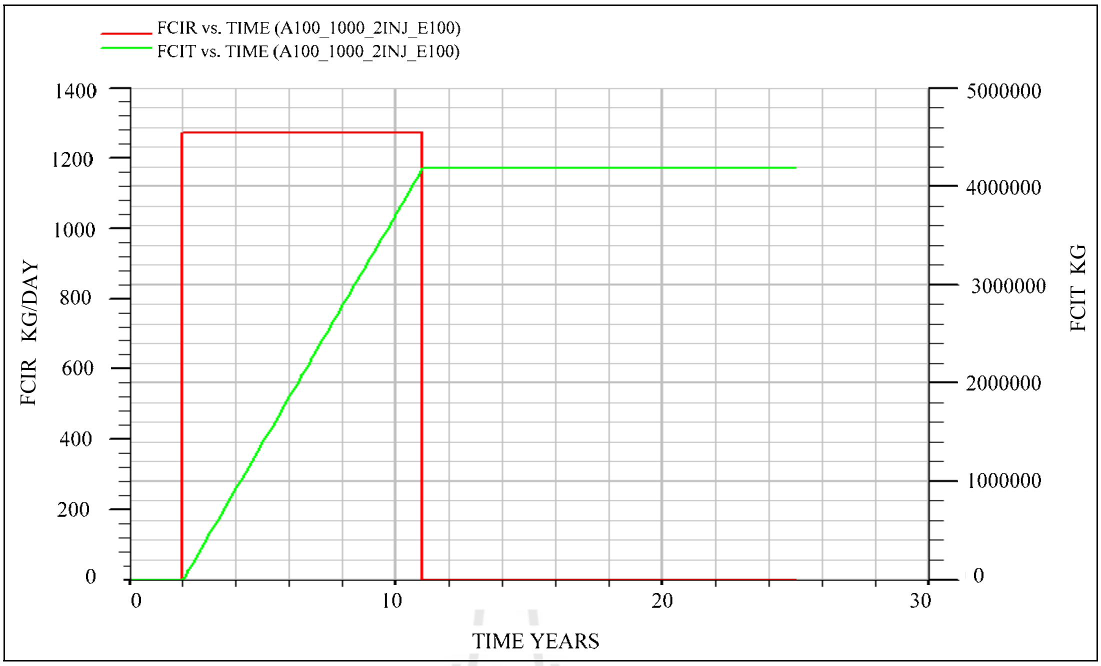


Figure 4.12 CIR and CIT vs. Time of model A100_1000_2INJ.

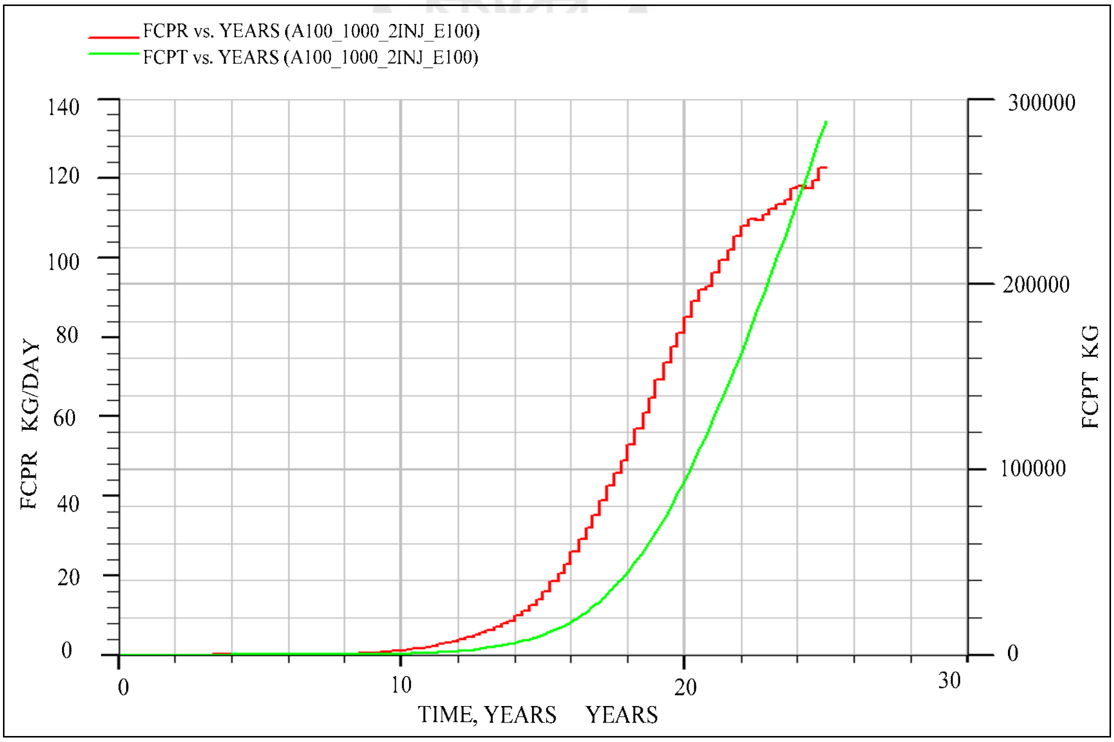


Figure 4.13 CPR and CPT vs. Time of model A100_1000_2INJ.

Table 4.3 Summary detail of graph 4.7, 4.8 and 4.11.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	41,829,864	109,049,300	38.36
Gas (MSCF)	30,135,952	52,615,556	57.28
Water (STB)	14,055,225	53,511,504	26.27

Table 4.4 Summary detail of graph 4.12 and 4.13.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	194,939,500	0.14	4,181

4.1.3 Model A100_1000_3INJ Scenario Result

Model A100_1000_3INJ is polymer flooding and the simulation results as shown in Table 4.5, Table 4.6 and Figure 4.14 – 4.20:

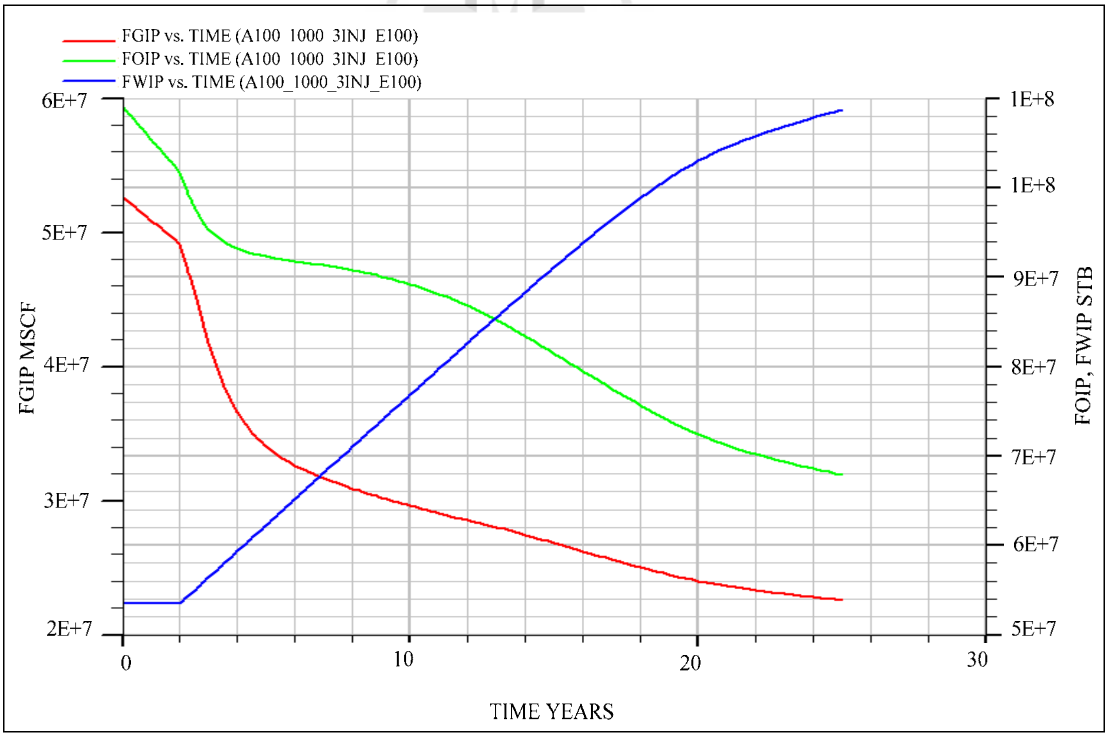


Figure 4.14 Fluid in place profile vs. Time of model A100_1000_3INJ.

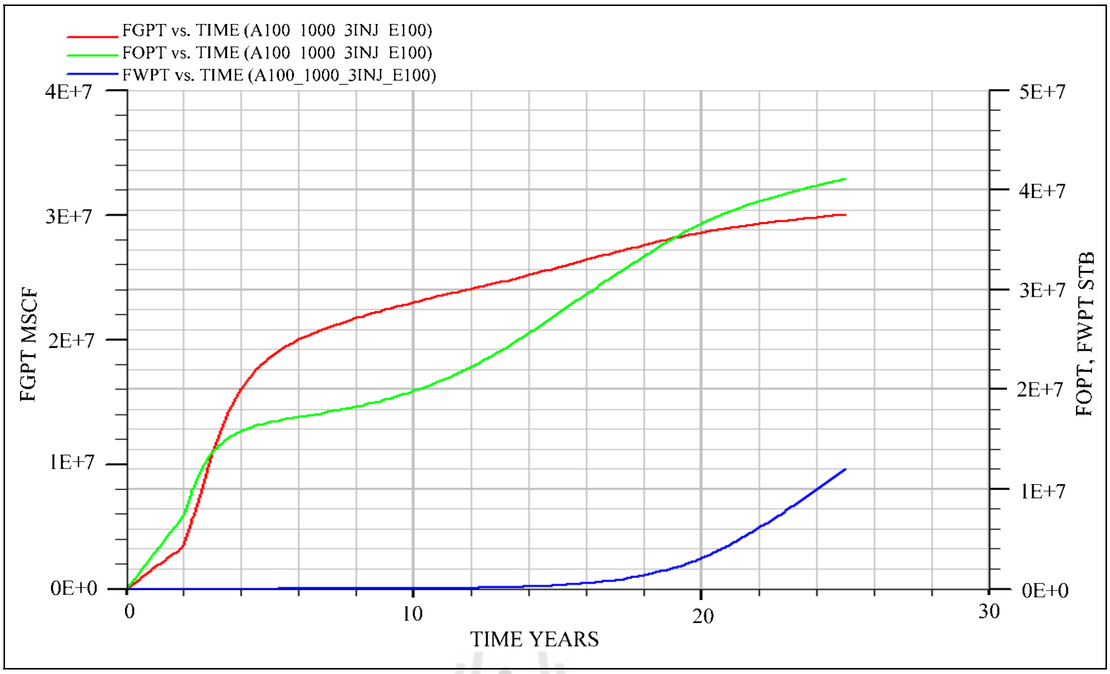


Figure 4.15 Cumulative fluids production profile vs. Time of model A100_1000_3INJ.

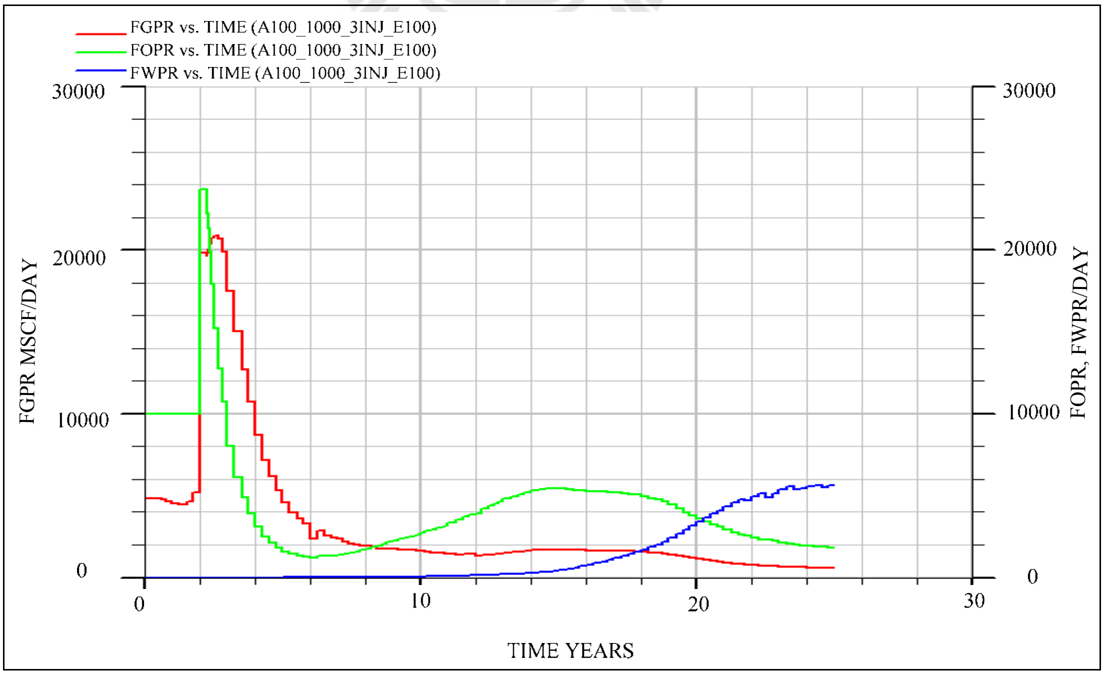


Figure 4.16 Fluids production rate profile vs. Time of model A100_100_3INJ.

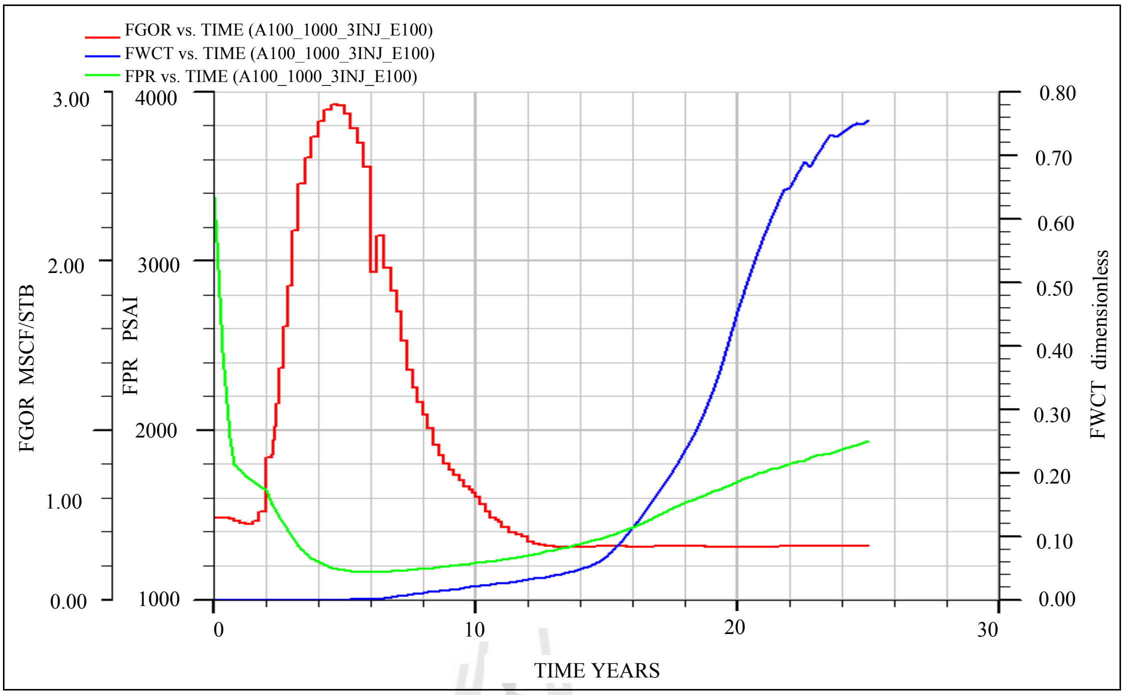


Figure 4.17 GOR, WCT, and Pressure profile vs. Time of model A100_1000_3INJ.

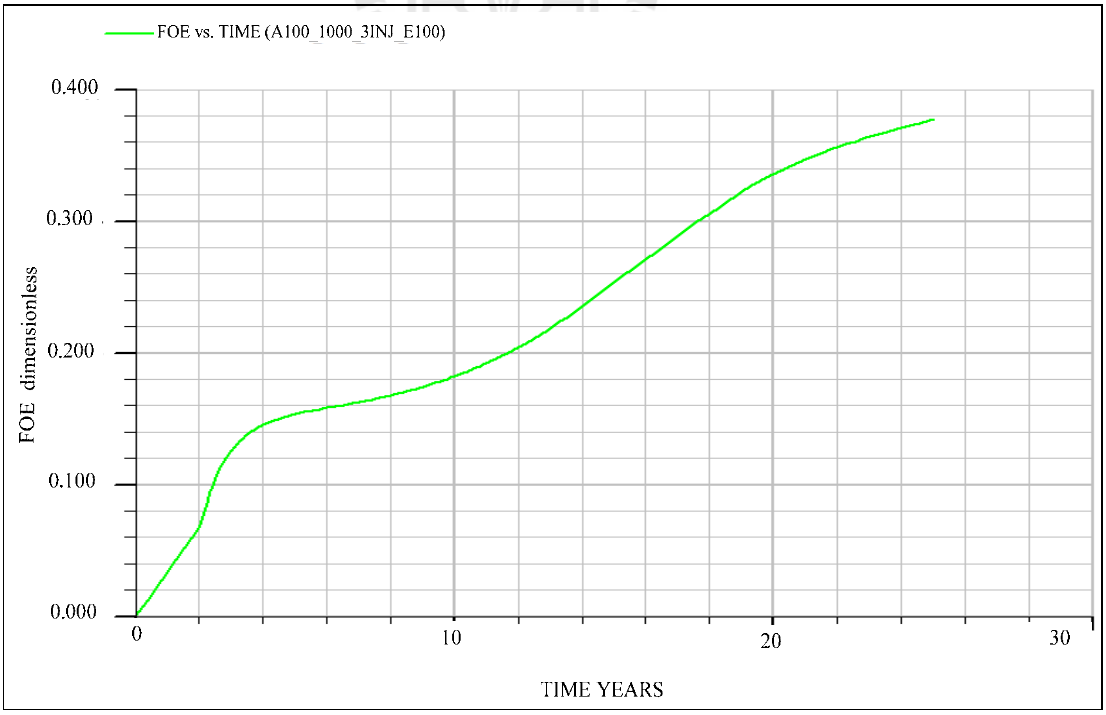


Figure 4.18 Oil recovery efficiency vs. Time of model A100_1000_3INJ.

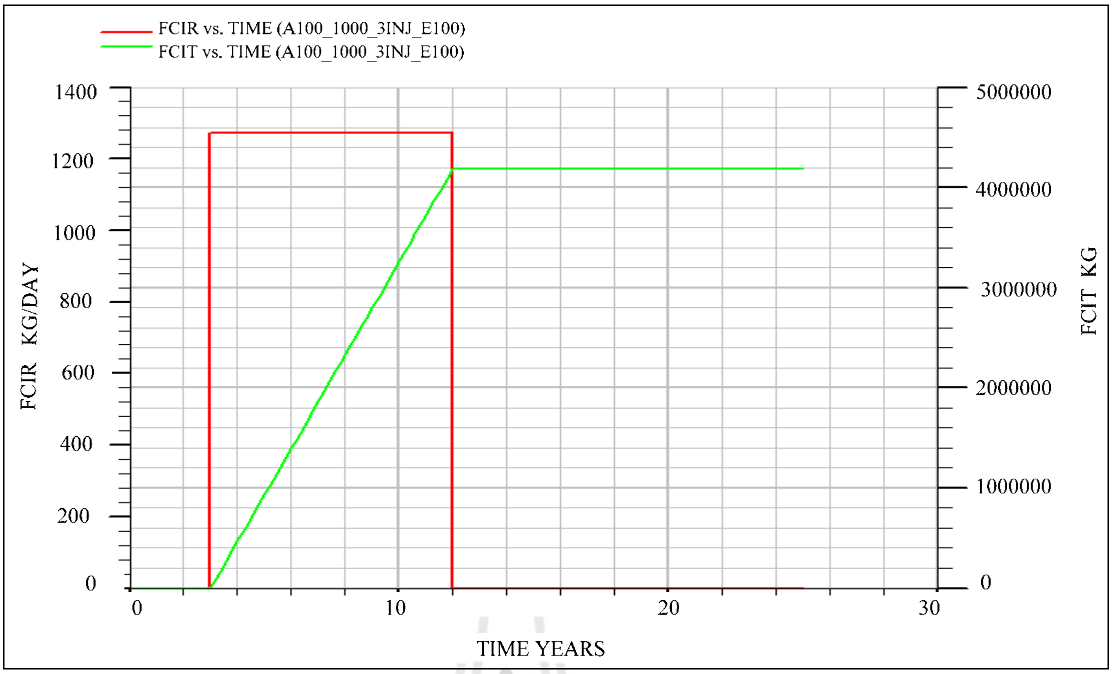


Figure 4.19 CIR and CIT vs. Time of model A100_1000_3INJ.

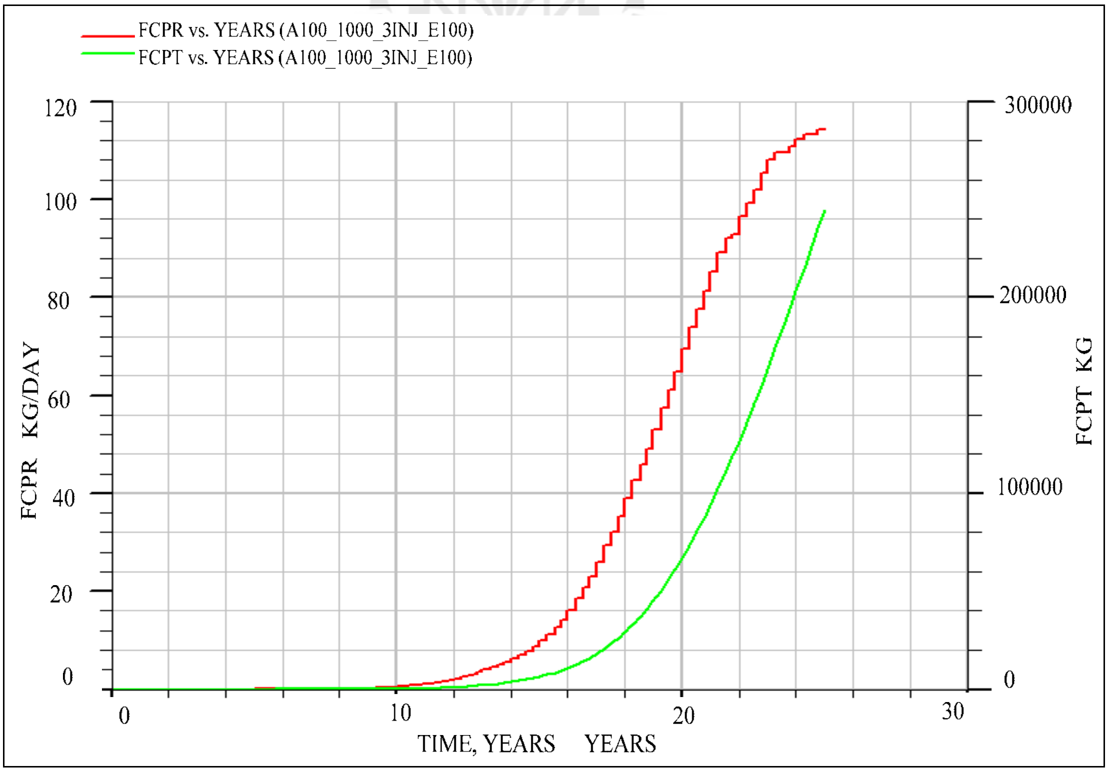


Figure 4.20 CPR and CPT vs. Time of model A100_1000_3INJ.

Table 4.5 Summary detail of graph 4.14, 4.15 and 4.18.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	41,127,388	109,049,300	37.71
Gas (MSCF)	30,013,722	52,615,556	57.04
Water (STB)	12,014,467	53,511,504	22.45

Table 4.6 Summary detail of graph 4.19 and 4.20.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	194,939,500	0.14	4,181

4.1.4 Model A100_1000_4INJ Scenario Result

Model A100_1000_4INJ is polymer flooding and the simulation results as shown in Table 4.7 - 4.8 and Figure 4.21 – 4.27:

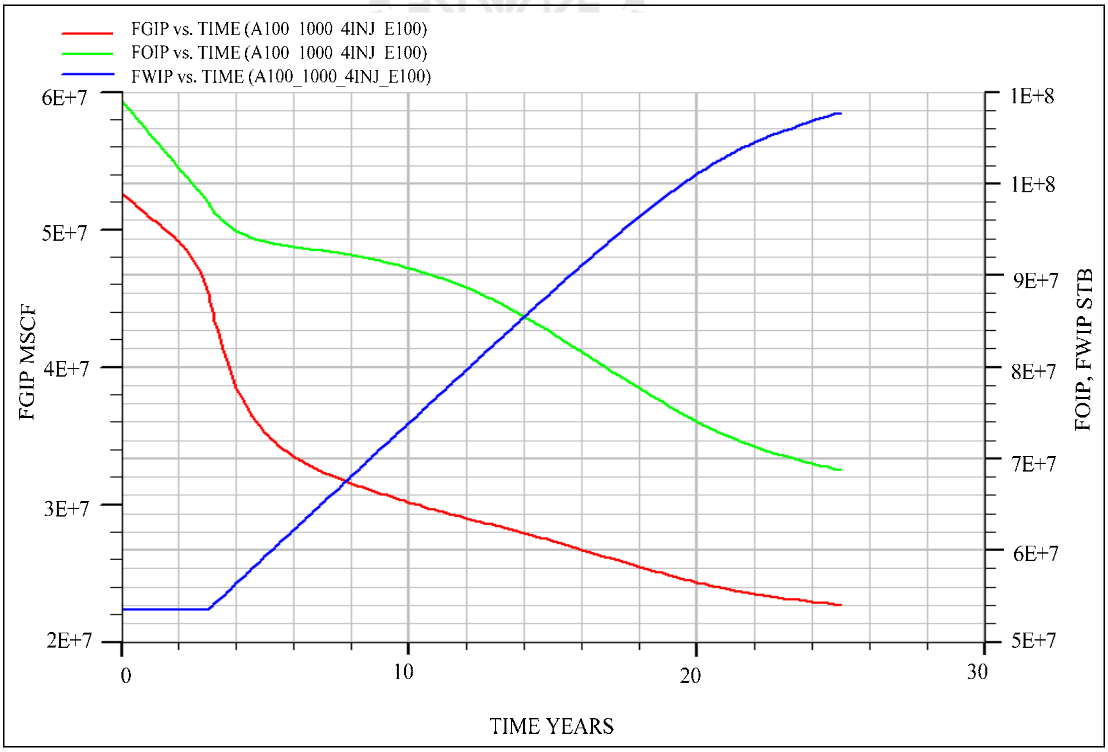


Figure 4.21 Fluid in place profile vs. Time of model A100_1000_4INJ.

Figure 4.22 Cumulative fluids production profile vs. Time of model A100_1000_4INJ.

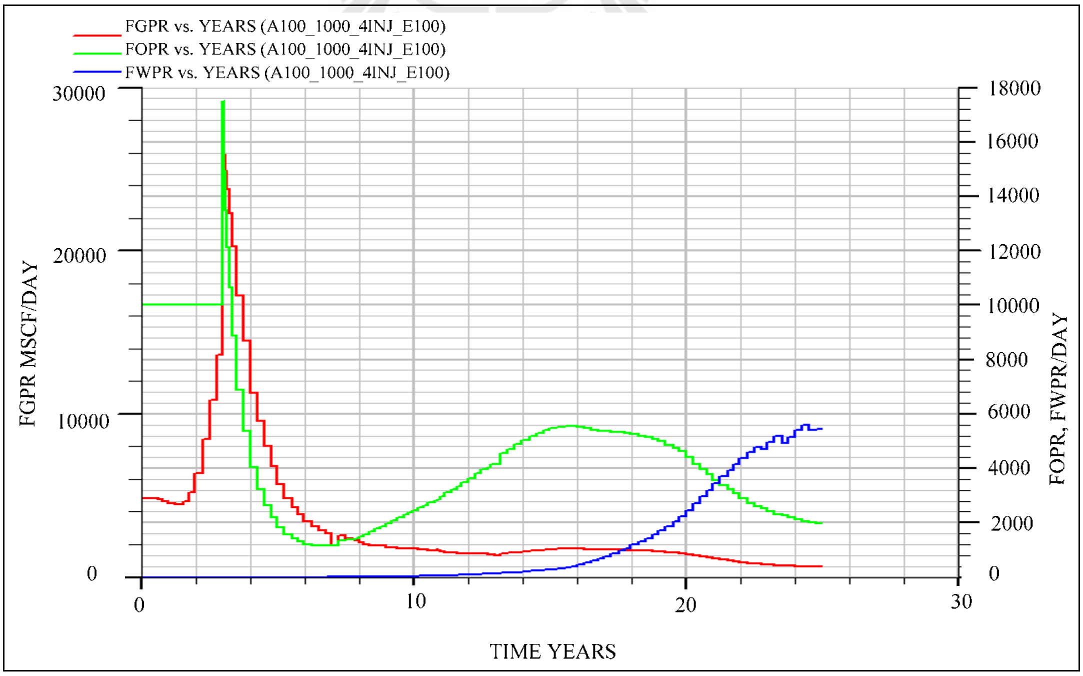


Figure 4.23 Fluids production rate profile vs. Time of model A100_100_4INJ.

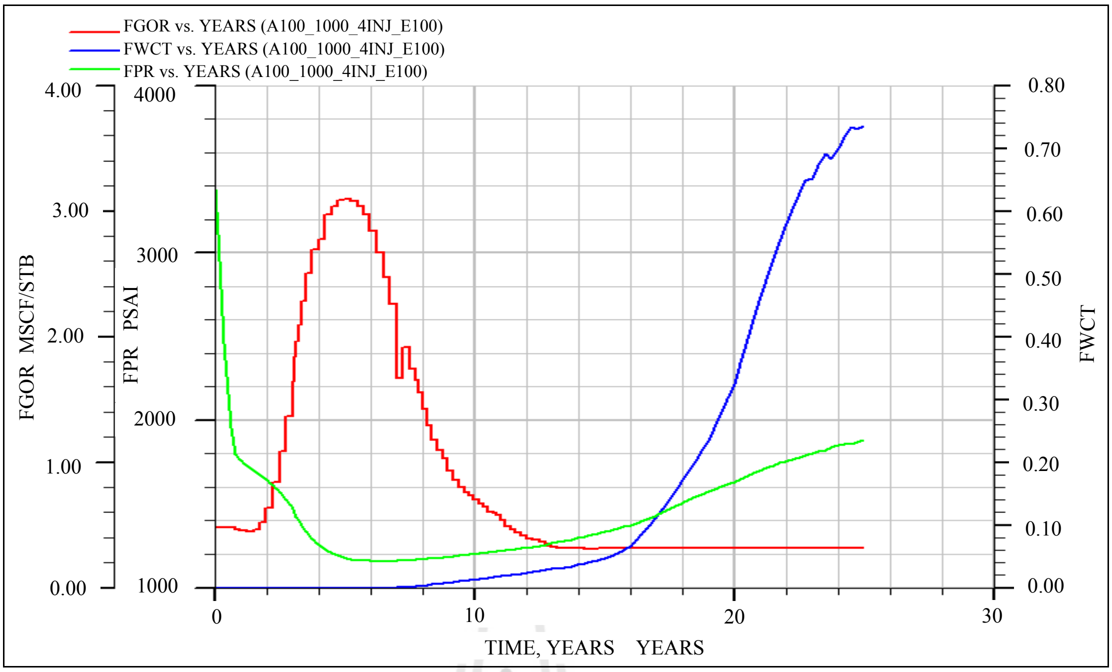


Figure 4.24 GOR, WCT, and Pressure profile vs. Time of model A100_1000_4INJ.

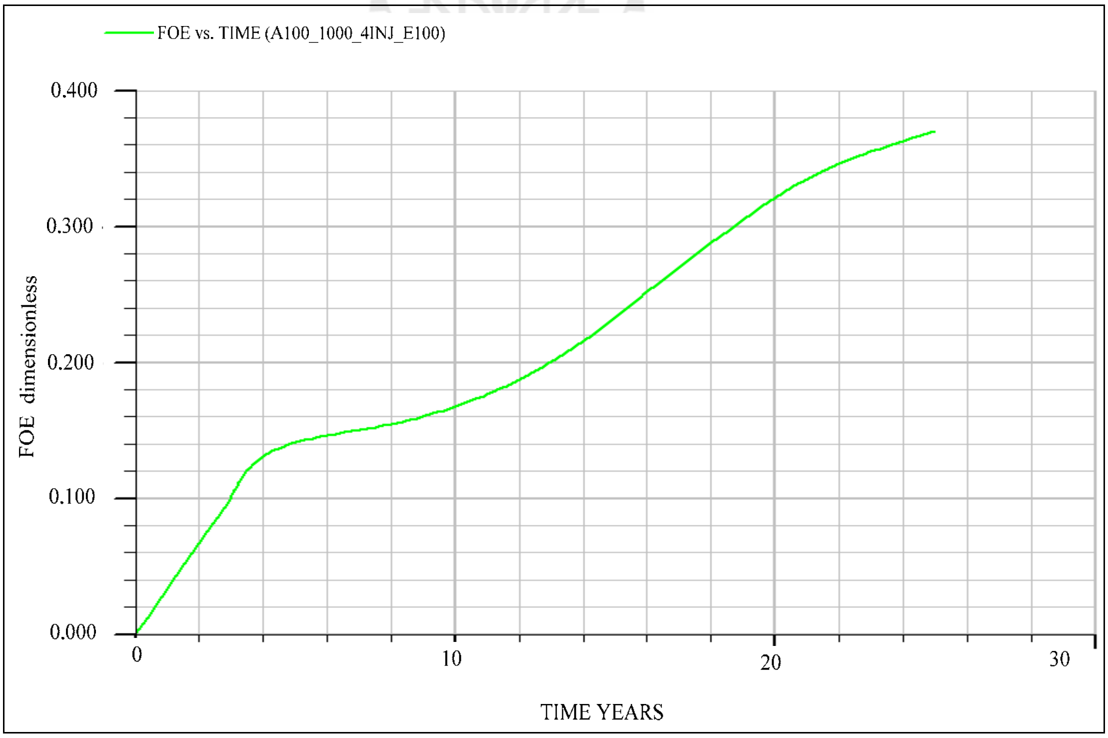


Figure 4.25 Oil recovery efficiency vs. Time of model A100_1000_4INJ.

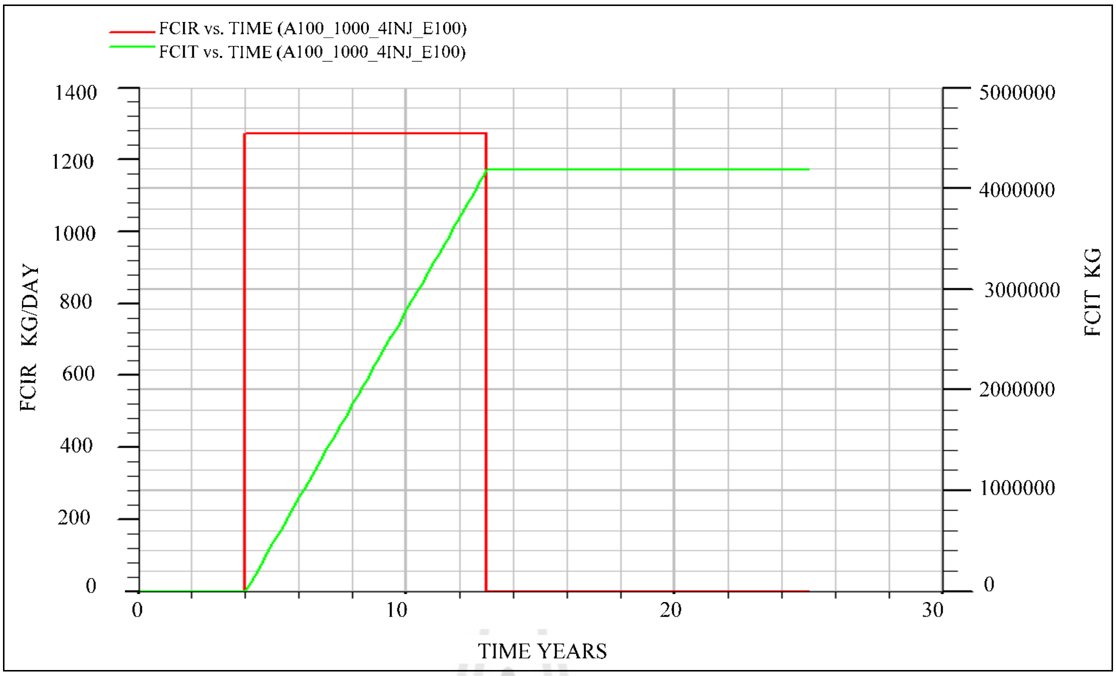


Figure 4.26 CIR and CIT vs. Time of model A100_1000_4INJ.

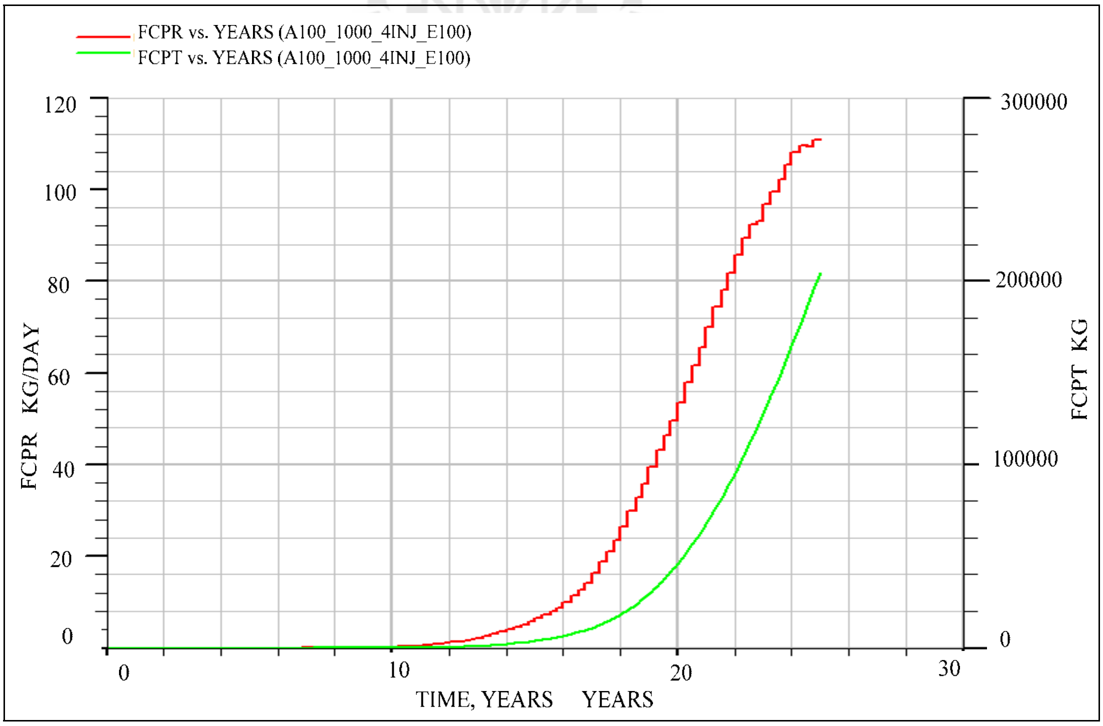


Figure 4.27 CPR and CPT vs. Time of model A100_1000_4INJ.

Table 4.7 Summary detail of graph 4.21, 4.22 and 4.25.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	40,314,836	109,049,300	37.71
Gas (MSCF)	29,930,020	52,615,556	57.04
Water (STB)	10,032,962	53,511,504	22.45

Table 4.8 Summary detail of graph 4.26 and 4.27.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	194,939,500	0.14	4,181

4.1.5 Model A100_1500_2INJ Scenario Result

Model A100_1500_2INJ is polymer flooding and the simulation results as shown in Table 4.9 - 4.10 and Figure 4.28 – 4.34:

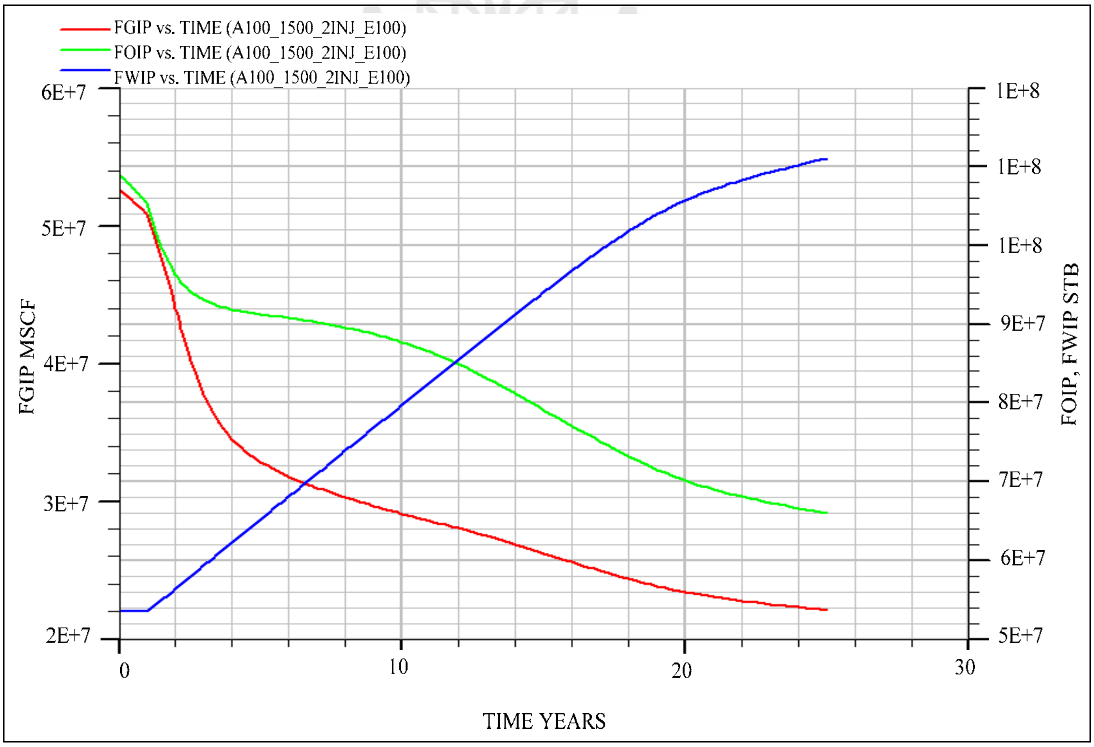


Figure 4.28 Fluid in place profile vs. Time of model A100_1500_2INJ.

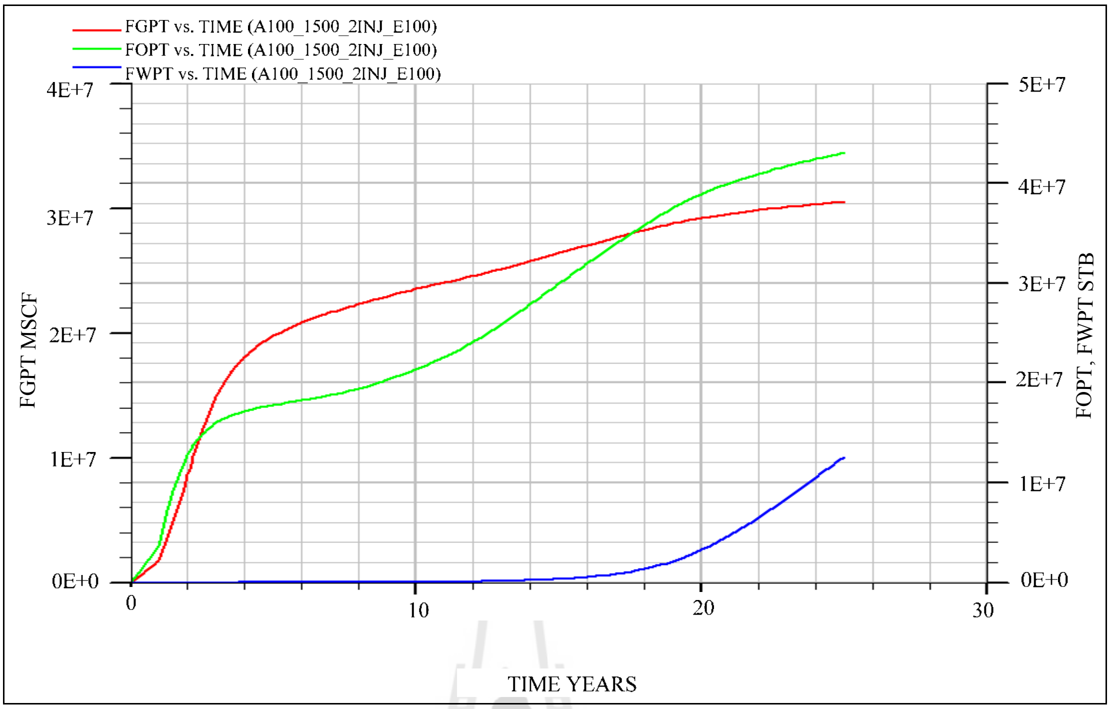


Figure 4.29 Cumulative fluids production profile vs. Time of model A100_1500_2INJ.

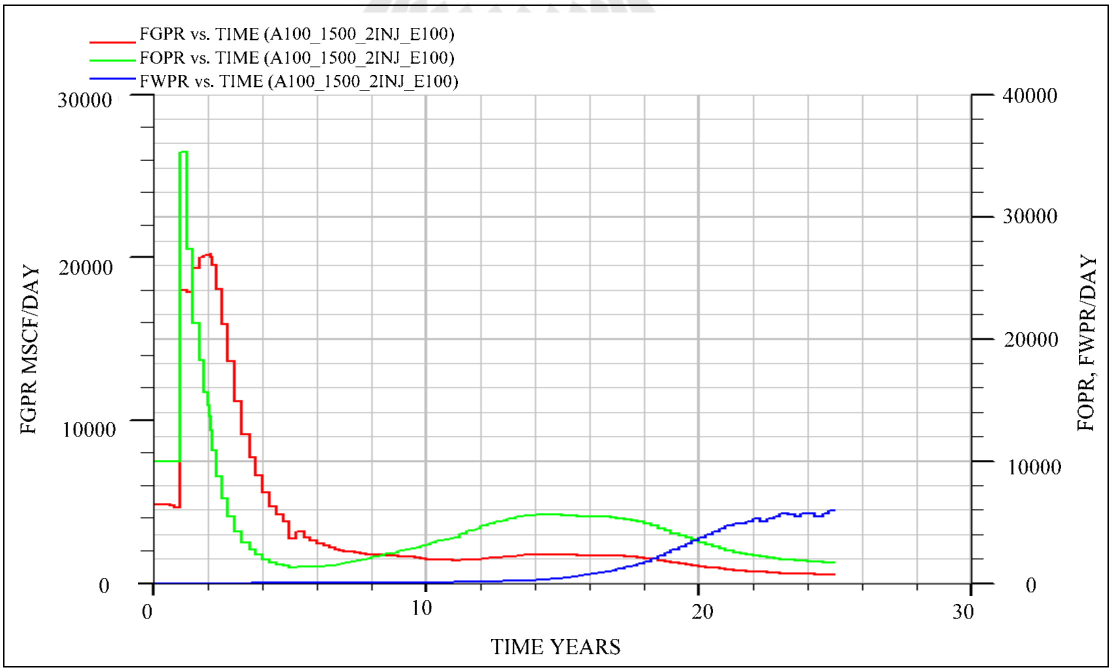


Figure 4.30 Fluids production rate profile vs. Time of model A100_1500_2INJ.

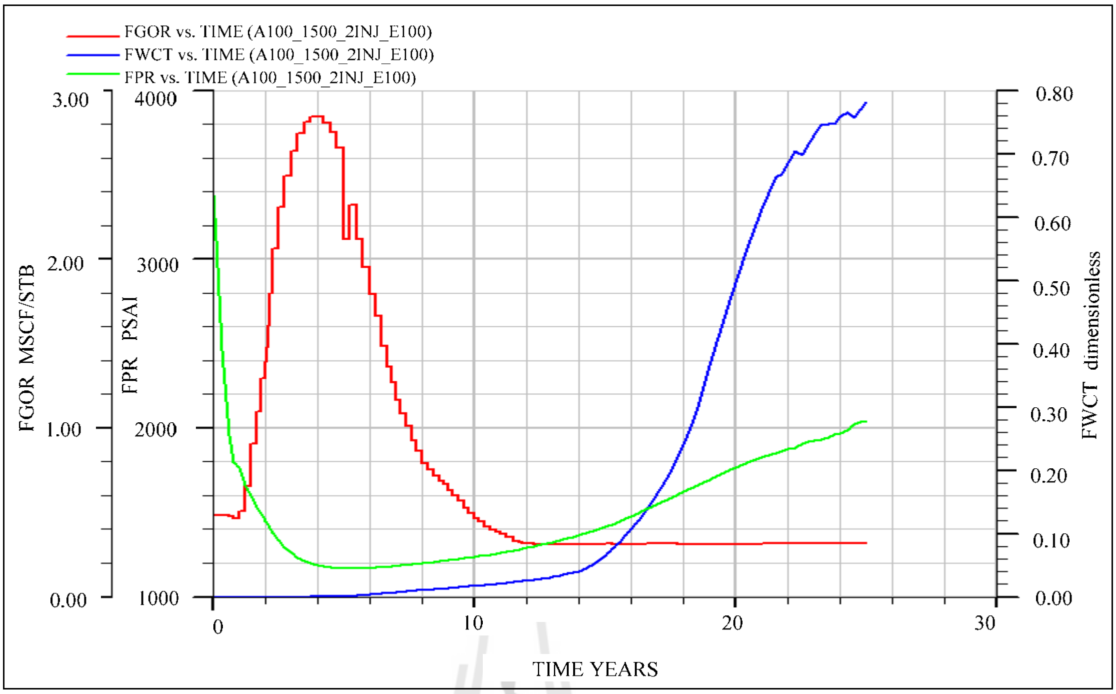


Figure 4.31 GOR, WCT, and Pressure profile vs. Time of model A100_1500_2INJ.

Figure 4.32 Oil recovery efficiency vs. Time of model A100_1500_2INJ.

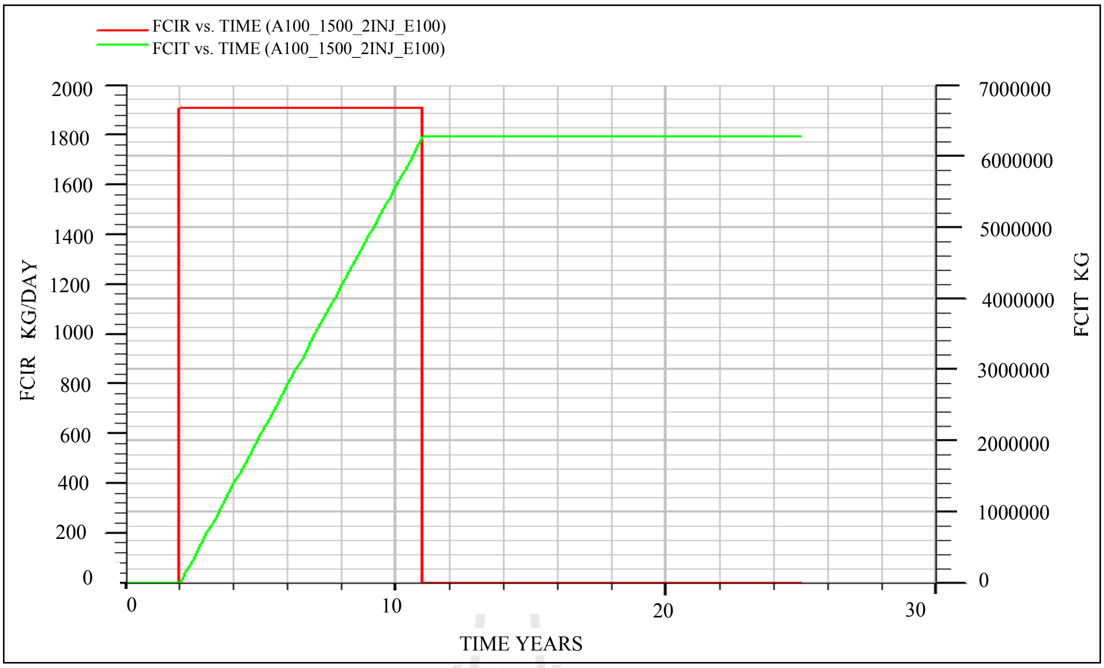


Figure 4.33 CIR and CIT vs. Time of model A100_1500_2INJ.

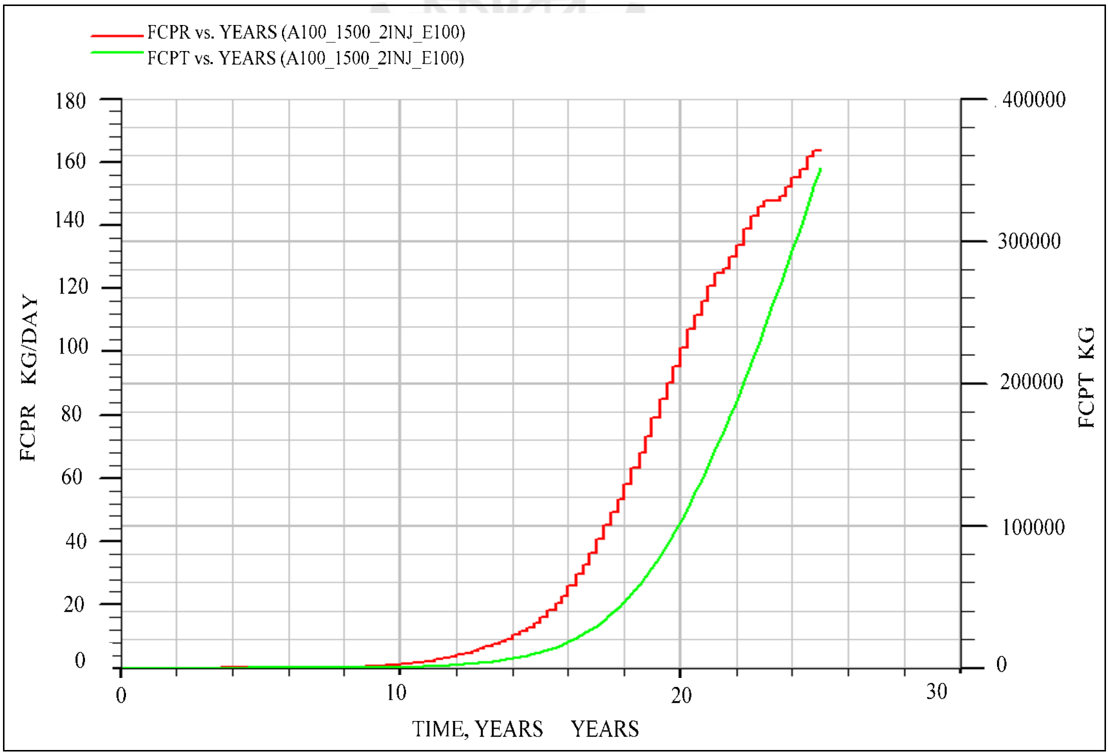


Figure 4.34 CPR and CPT vs. Time of model A100_1500_2INJ.

Table 4.9 Summary detail of graph 4.28, 4.29 and 4.32.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	43,050,272	109,049,300	39.48
Gas (MSCF)	30,510,546	52,615,556	57.99
Water (STB)	12,579,393	53,511,504	23.51

Table 4.10 Summary detail of graph 4.33 and 4.34.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	194,939,500	0.14	6,272

4.1.6 Model A100_1500_3INJ Scenario Result

Model A100_1500_3INJ is polymer flooding and the simulation results as shown in Table 4.11 - 4.12 and Figure 4.35 – 4.41:

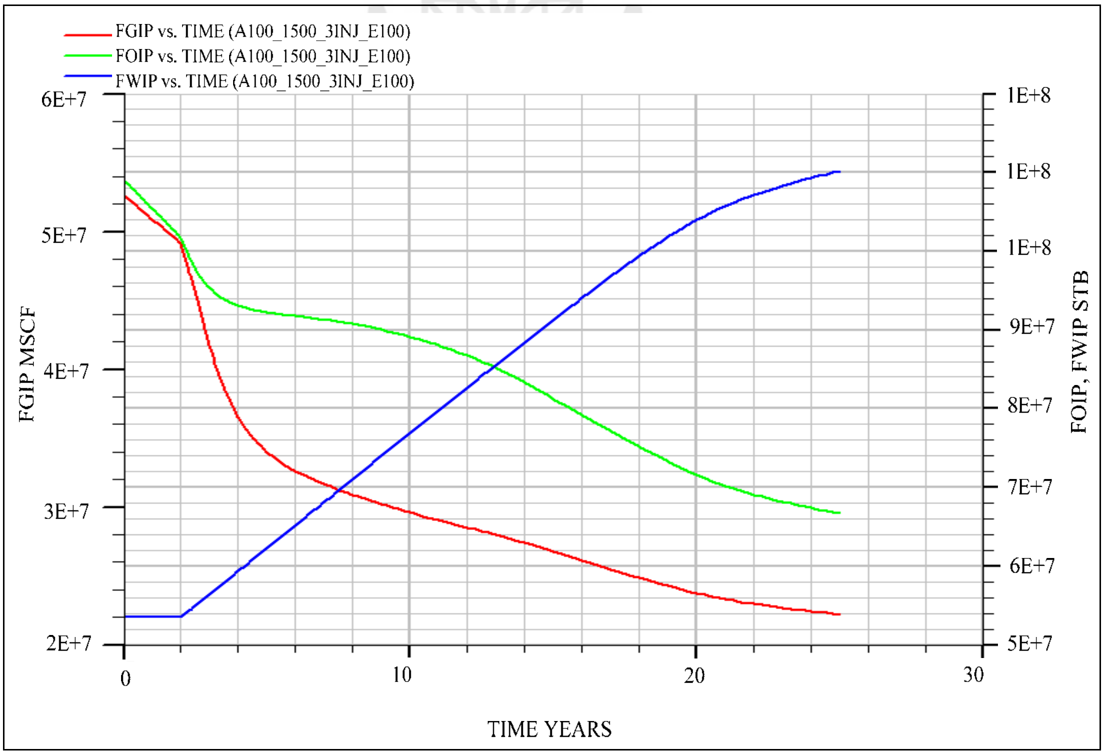


Figure 4.35 Fluid in place profile vs. Time of model A100_1500_3INJ.

Figure 4.36 Cumulative fluids production profile vs. Time of model A100_1500_3INJ.

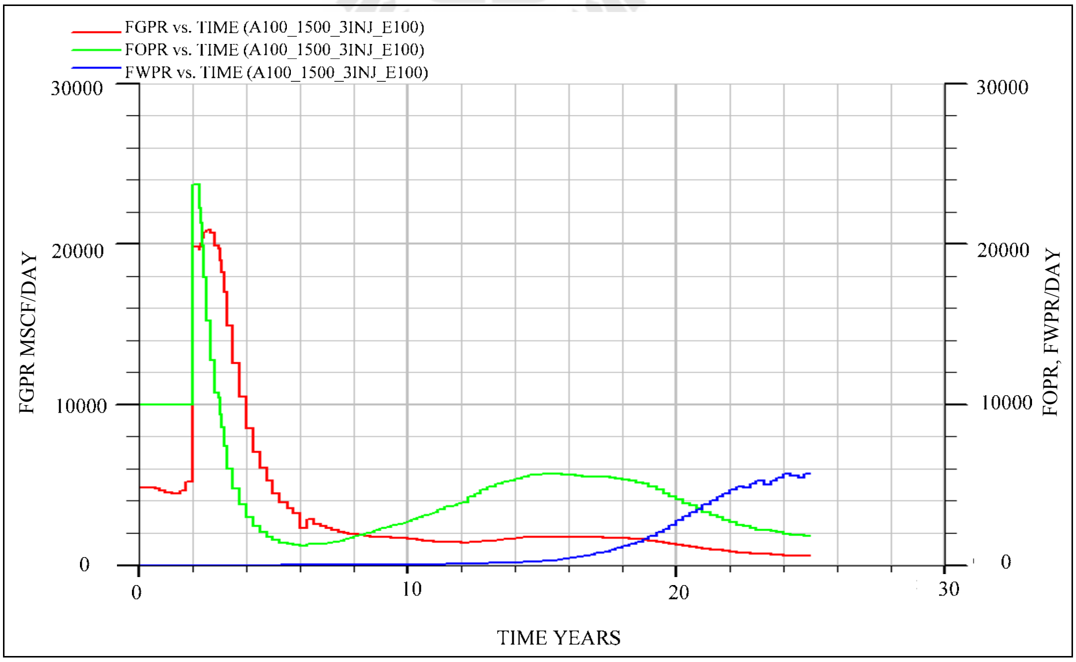


Figure 4.37 Fluids production rate profile vs. Time of model A100_1500_3INJ.

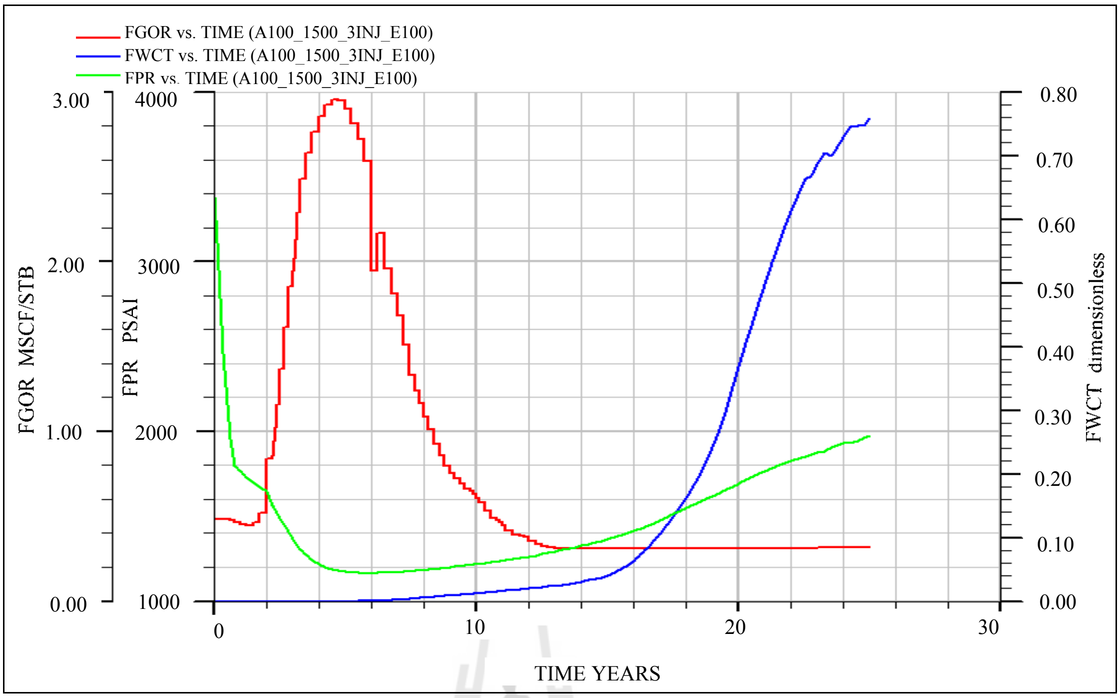


Figure 4.38 GOR, WCT, and Pressure profile vs. Time of model A100_1500_3INJ.

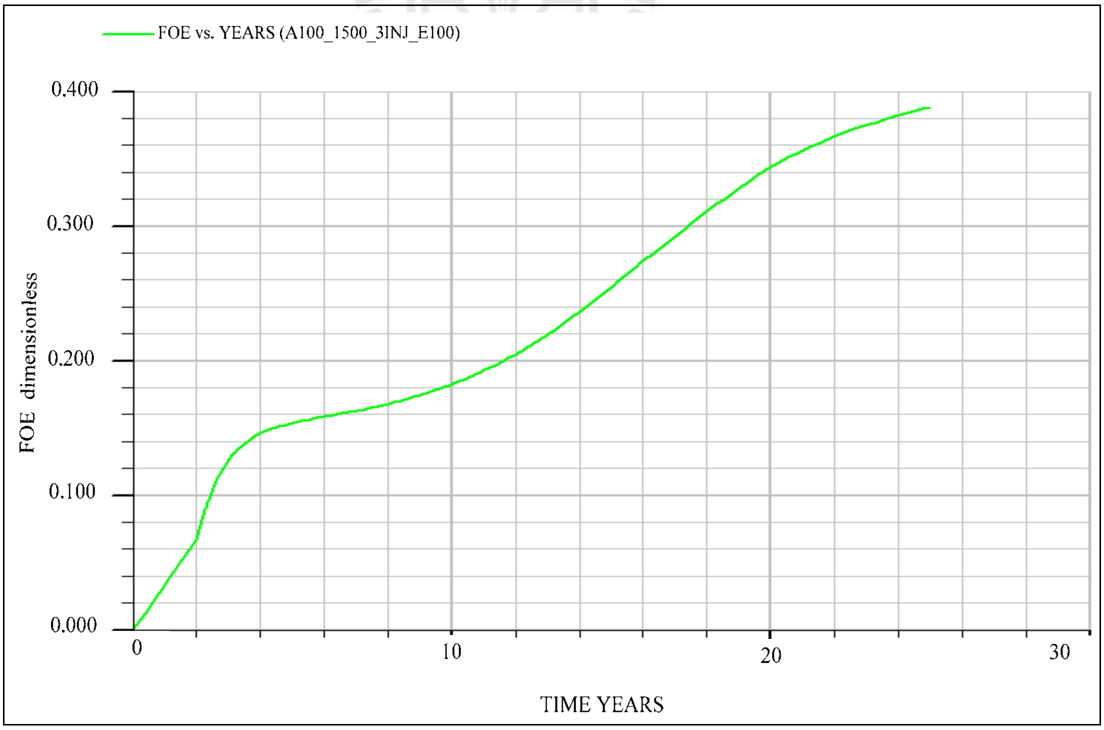


Figure 4.39 Oil recovery efficiency vs. Time of model A100_1500_3INJ.

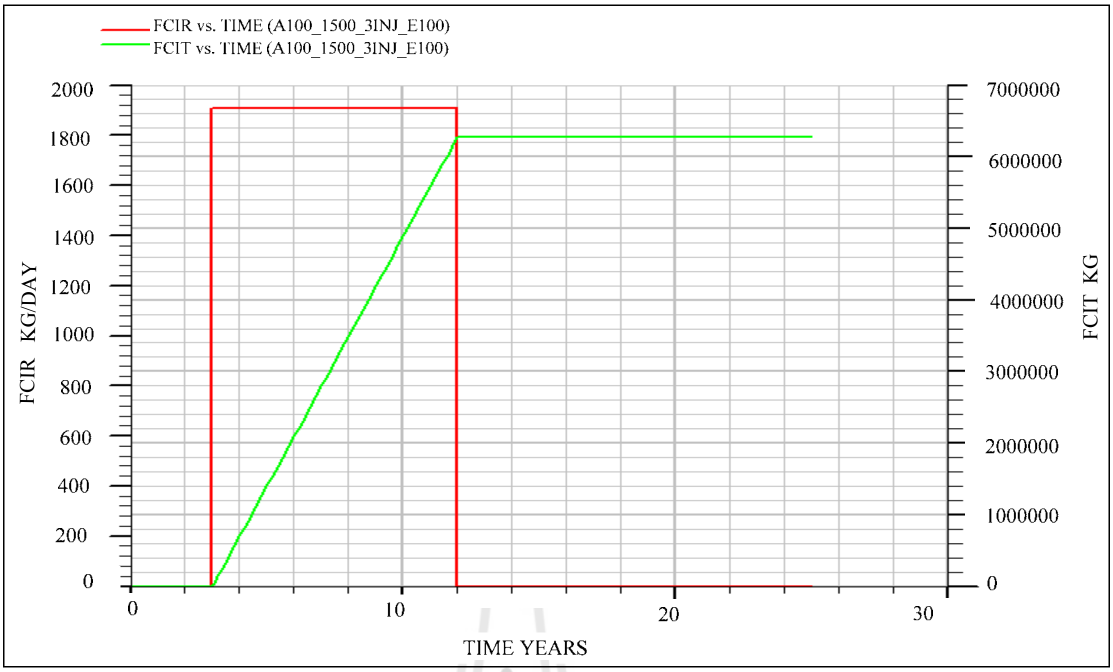


Figure 4.40 CIR and CIT vs. Time of model A100_1500_3INJ.

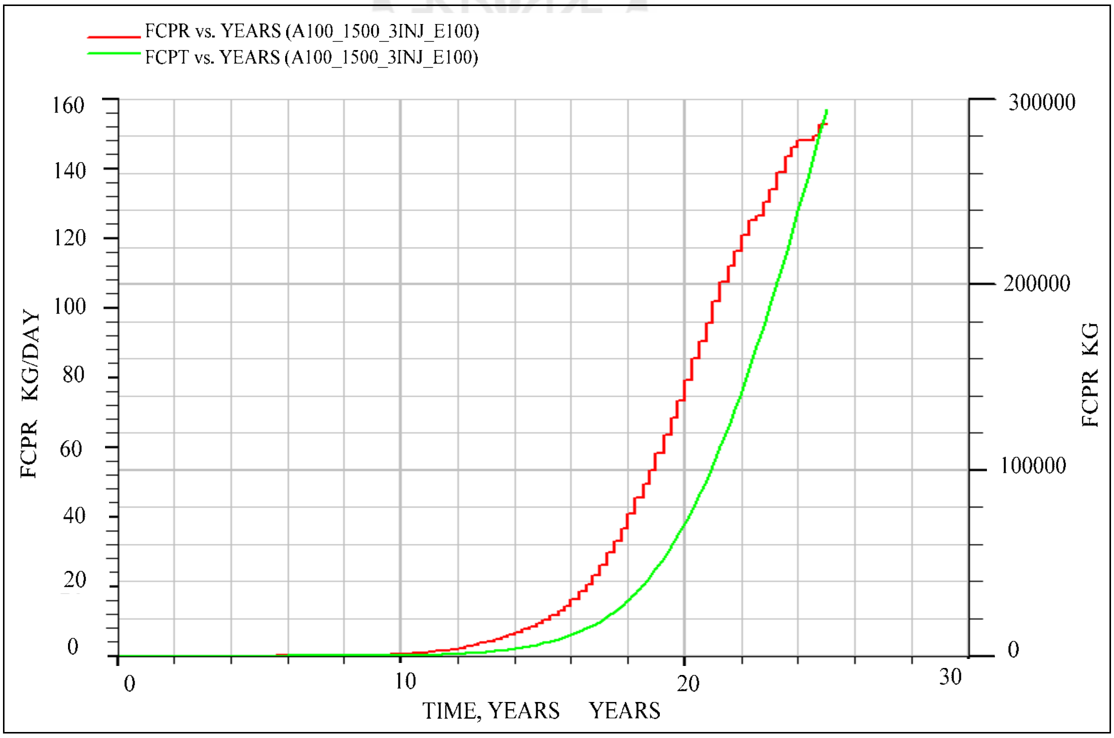


Figure 4.41 CPR and CPT vs. Time of model A100_1500_3INJ.

Table 4.11 Summary detail of graph 4.35, 4.36 and 4.39.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	42,350,996	109,049,300	38.84
Gas (MSCF)	30,405,124	52,615,556	57.79
Water (STB)	10,526,204	53,511,504	19.67

Table 4.12 Summary detail of graph 4.40 and 4.41.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	194,939,500	0.14	6,272

4.1.6 Model A100_1500_4INJ Scenario Result

Model A100_1500_4INJ is polymer flooding and the simulation results as shown in Table 4.13 - 4.14 and Figure 4.42 – 4.48:

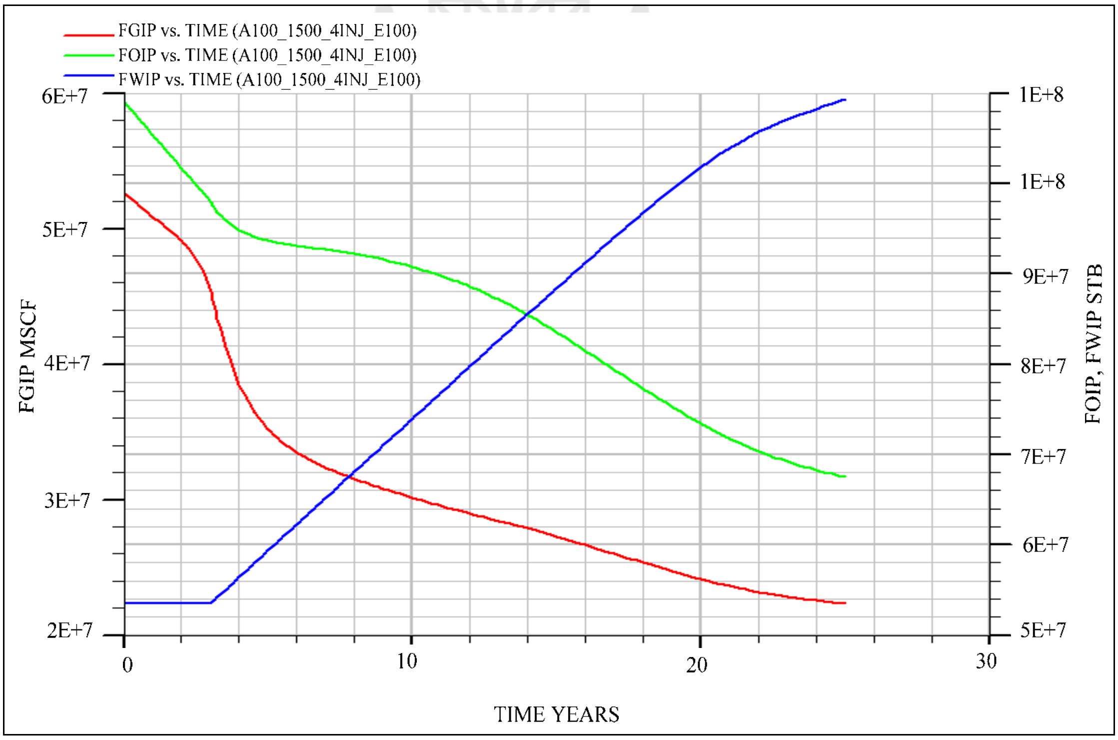


Figure 4.42 Fluid in place profile vs. Time of model A100_1500_4INJ.

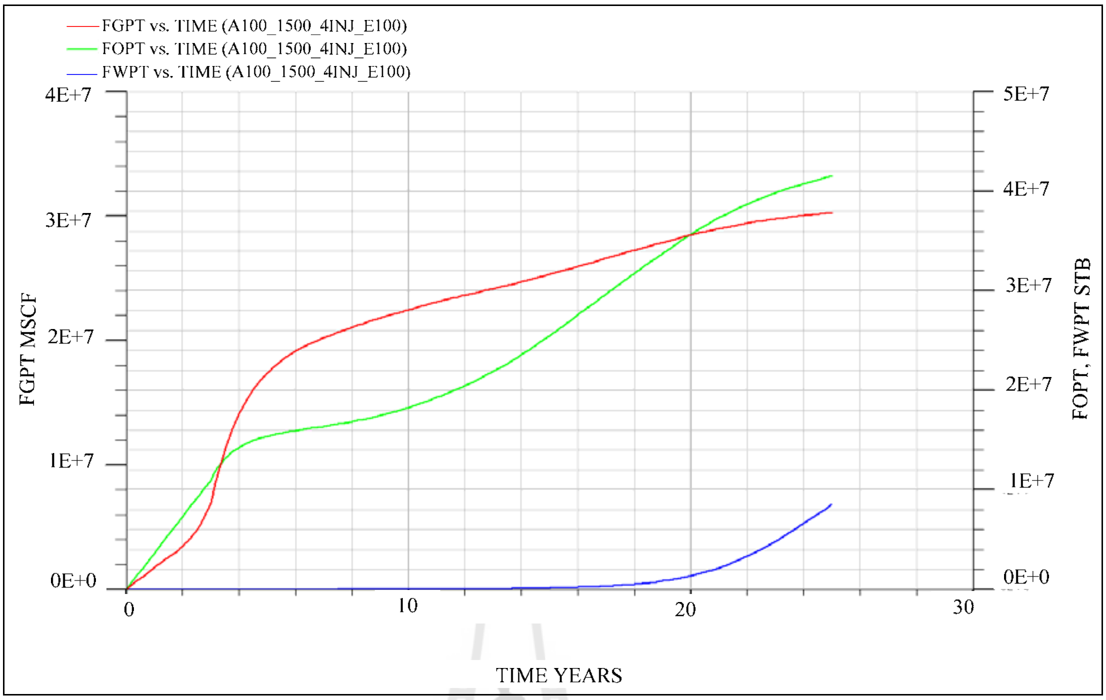


Figure 4.43 Cumulative fluids production profile vs. Time of model A100_1500_4INJ.

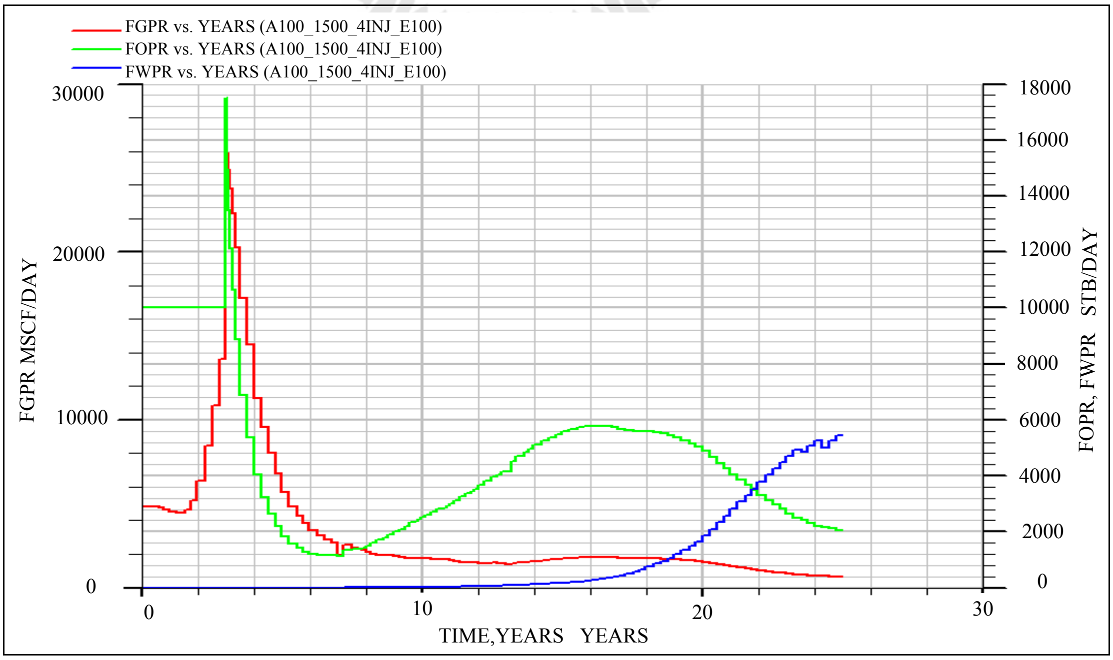


Figure 4.44 Fluids production rate profile vs. Time of model A100_1500_4INJ.

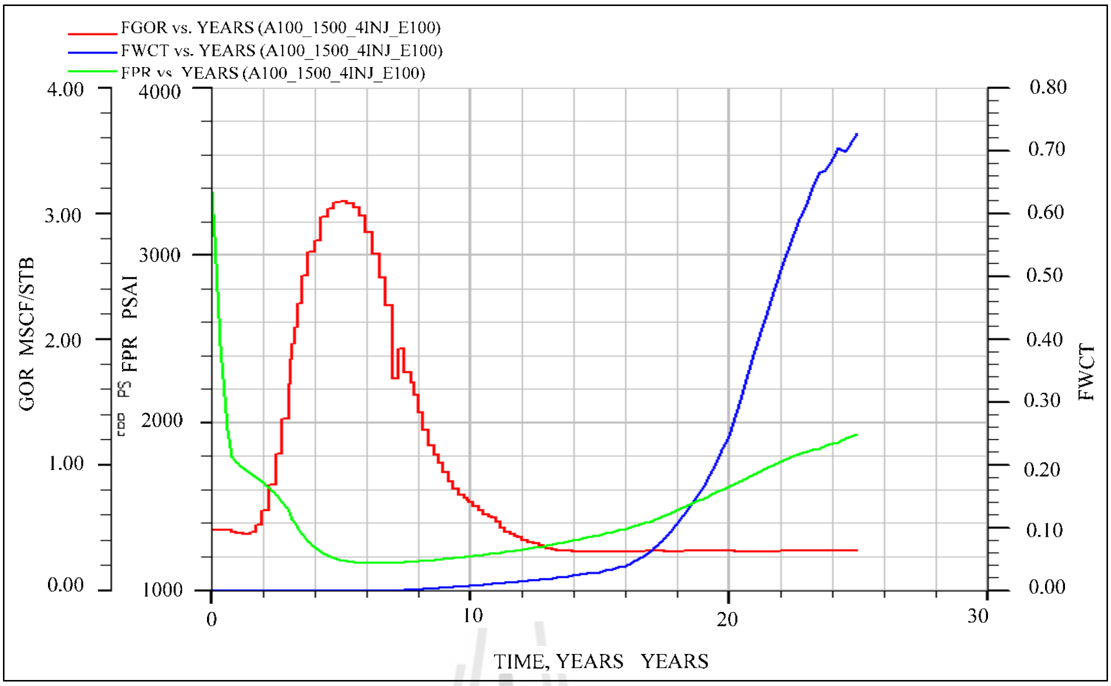


Figure 4.45 GOR, WCT, and Pressure profile vs. Time of model A100_1500_4INJ.

Figure 4.46 Oil recovery efficiency vs. Time of model A100_1500_4INJ.

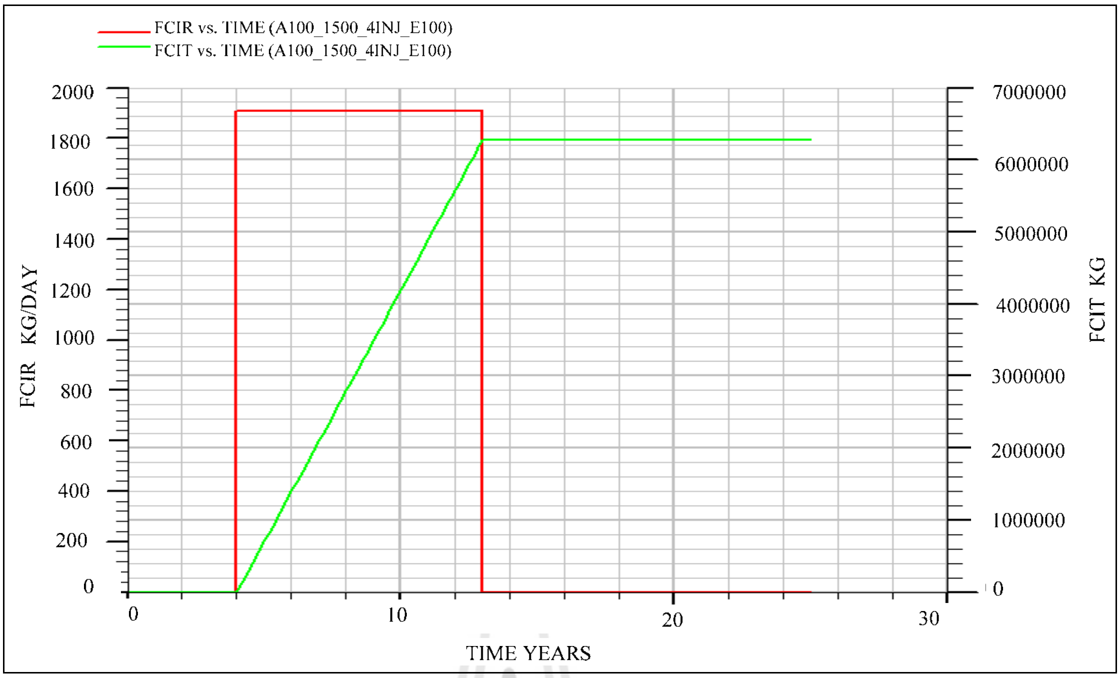


Figure 4.47 CIR and CIT vs. Time of model A100_1500_4INJ.

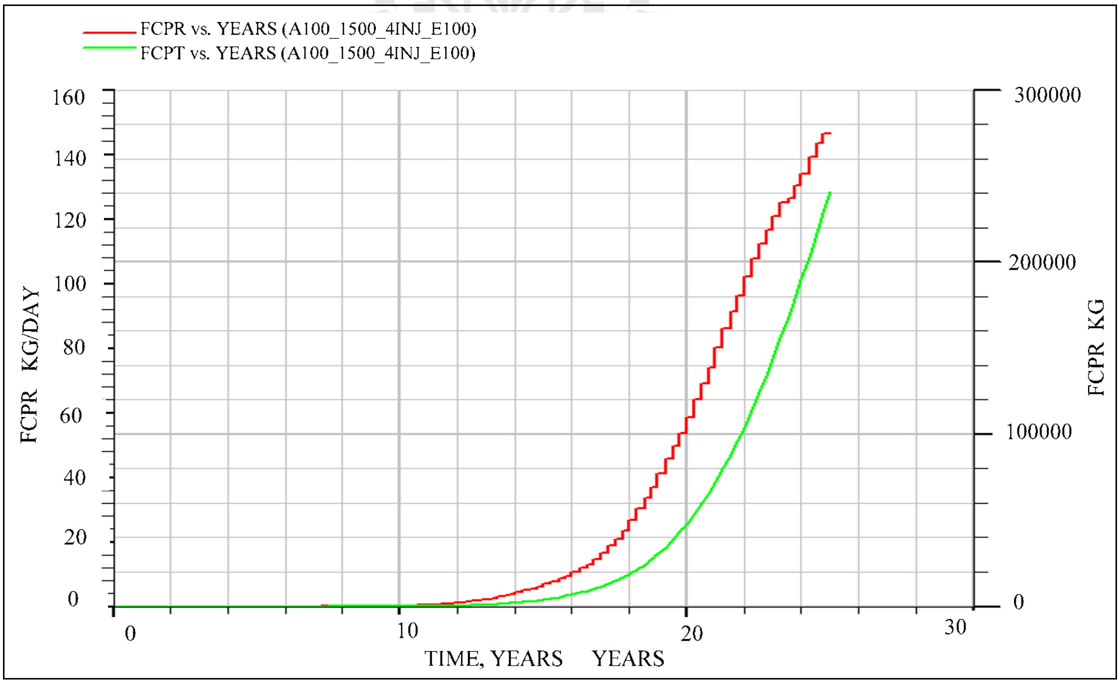


Figure 4.48 CPR and CPT vs. Time of model A100_1500_4INJ.

Table 4.13 Summary detail of graph 4.42, 4.43 and 4.46.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	41,538,904	109,049,300	38.09
Gas (MSCF)	30,312,940	52,615,556	57.61
Water (STB)	8,522,977	53,511,504	15.93

Table 4.14 Summary detail of graph 4.47 and 4.48.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	194,939,500	0.14	6,272

4.1.7 Model A100_2000_2INJ Scenario Result

Model A100_2000_2INJ is polymer flooding and the simulation results as shown in Table 4.15 - 4.16 and Figure 4.49 – 4.55:

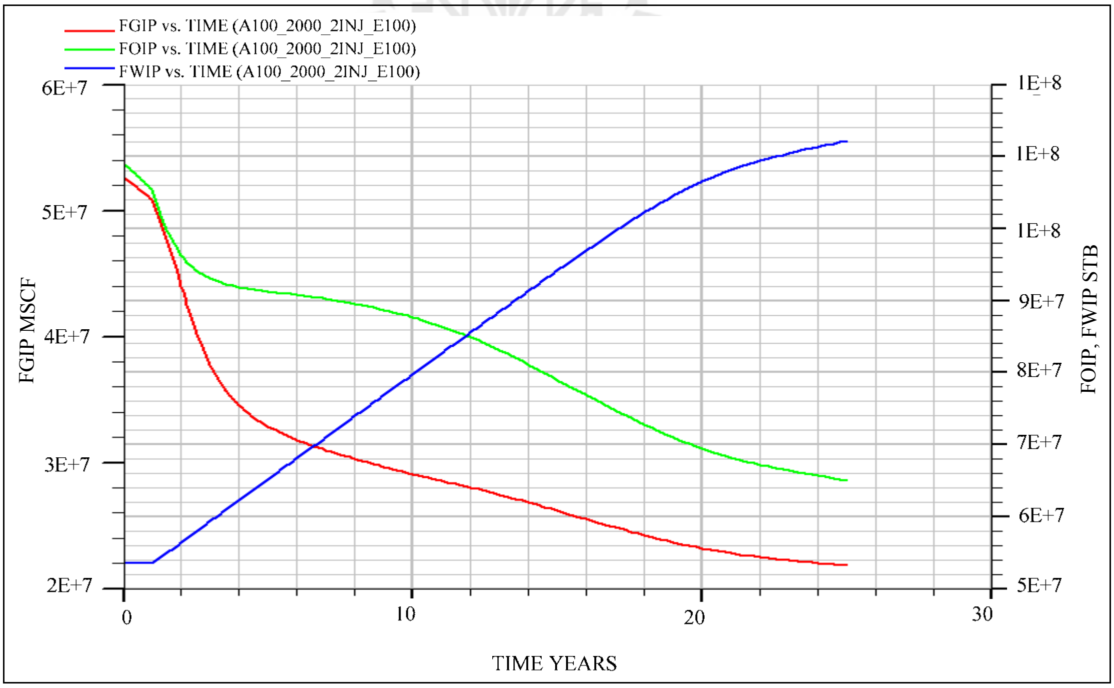


Figure 4.49 Fluid in place profile vs. Time of model A100_2000_2INJ.

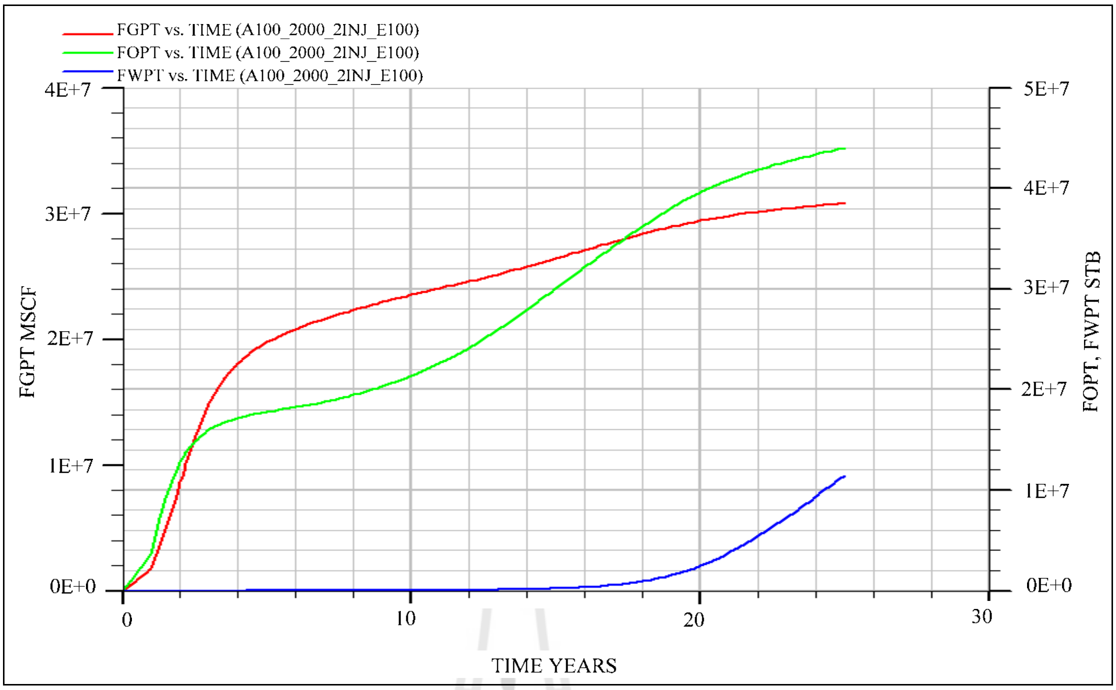


Figure 4.50 Cumulative fluids production profile vs. Time of model A100_2000_2INJ.

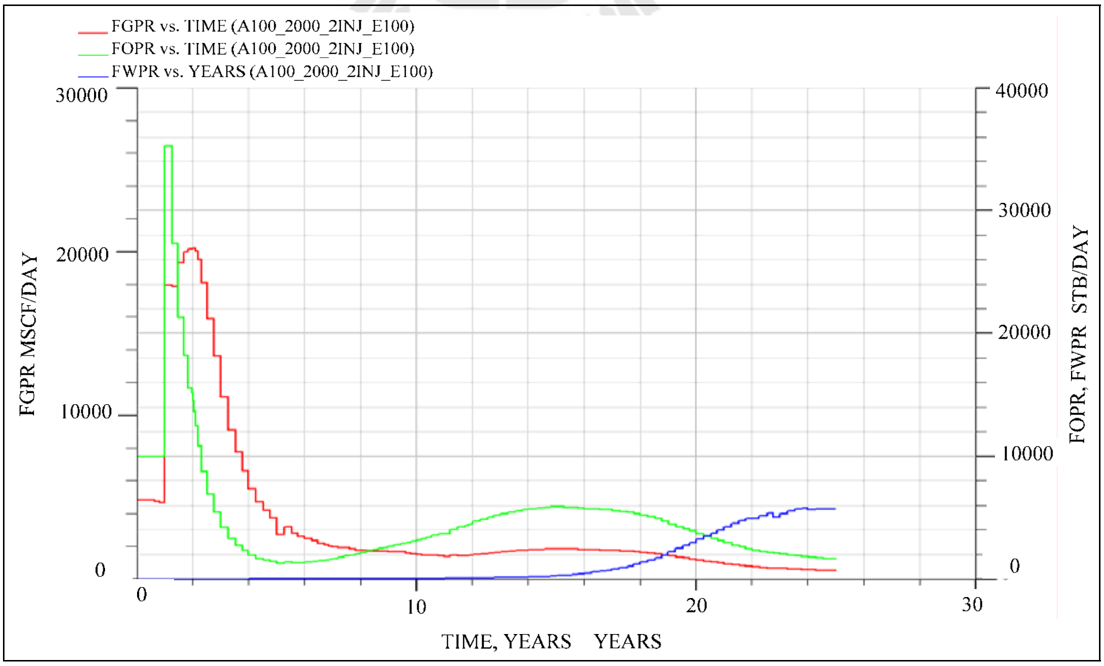


Figure 4.51 Fluids production rate profile vs. Time of model A100_2000_2INJ.

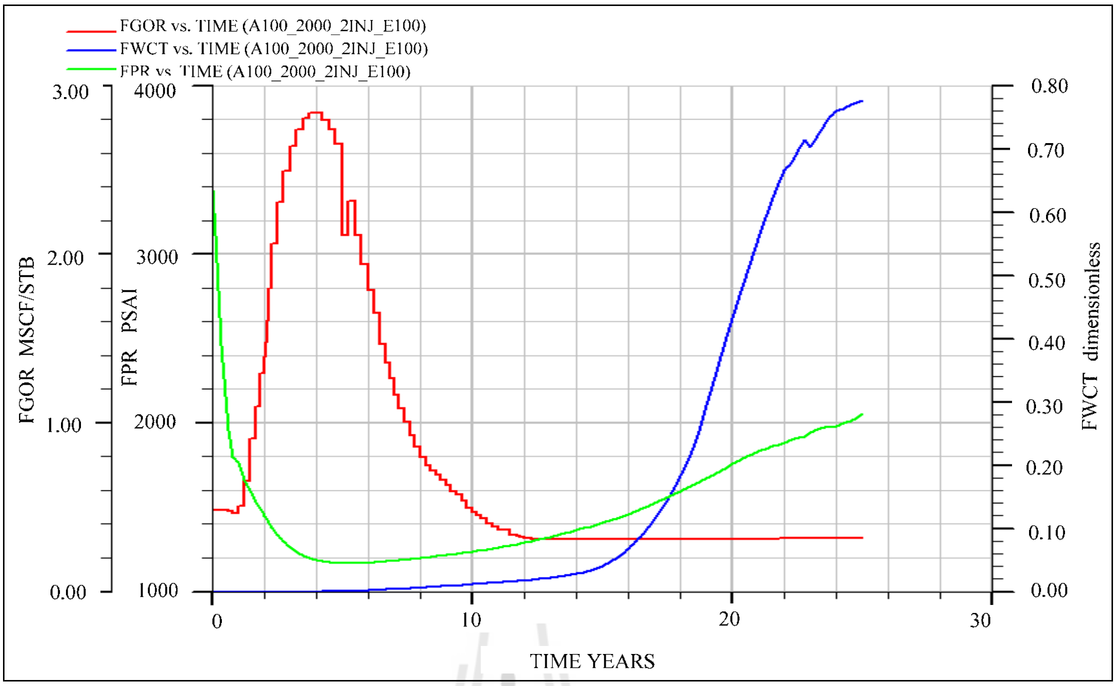


Figure 4.52 GOR, WCT, and Pressure profile vs. Time of model A100_2000_2INJ.

Figure 4.53 Oil recovery efficiency vs. Time of model A100_2000_2INJ.

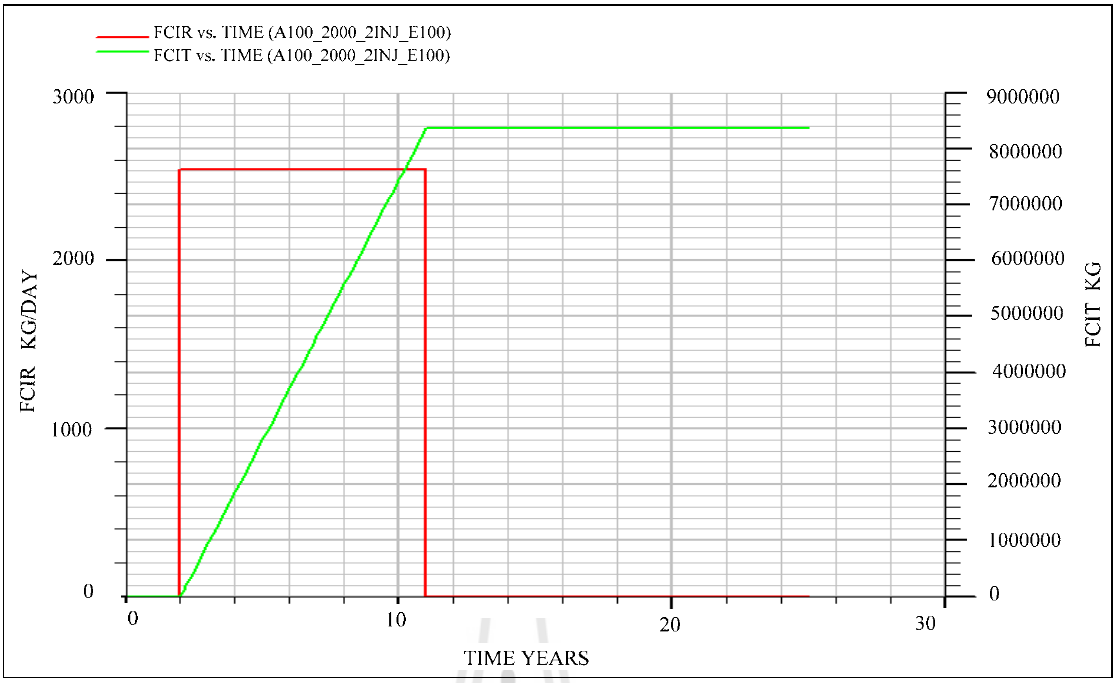


Figure 4.54 CIR and CIT vs. Time of model A100_2000_2INJ.

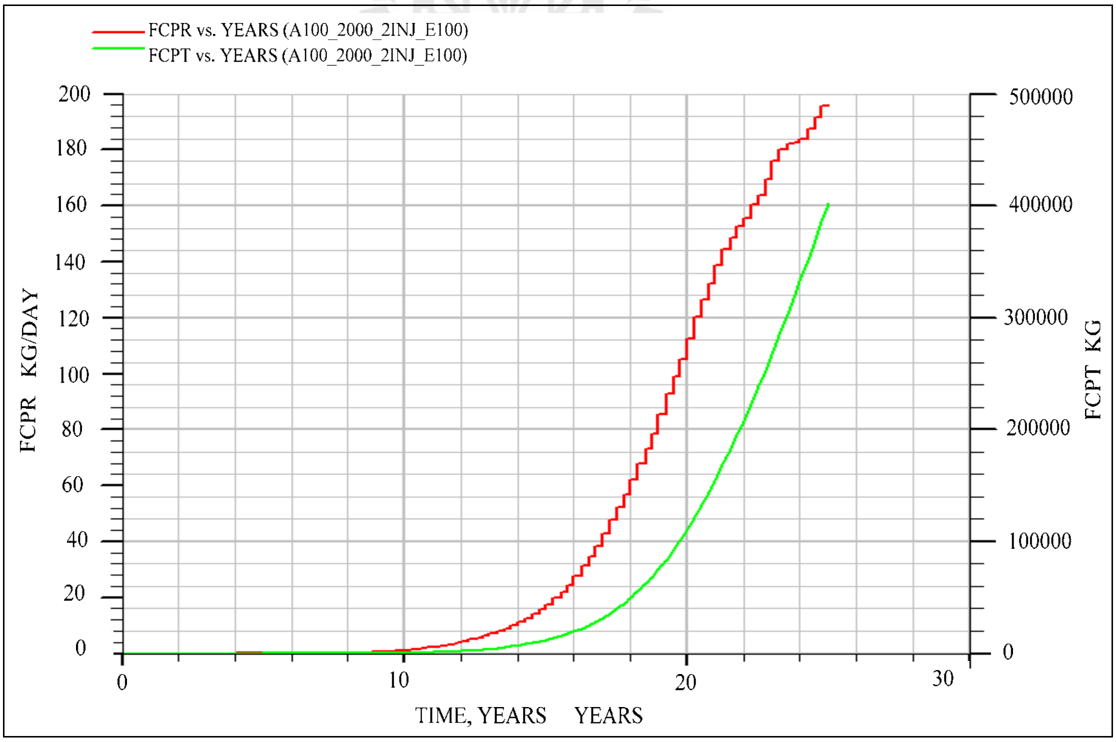


Figure 4.55 CPR and CPT vs. Time of model A100_2000_2INJ.

Table 4.15 Summary detail of graph 4.49, 4.50 and 4.53.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	43,997,032	109,049,300	40.35
Gas (MSCF)	30,808,638	52,615,556	58.55
Water (STB)	11,454,821	53,511,504	21.41

Table 4.16 Summary detail of graph 4.54 and 4.55.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	194,939,500	0.14	8,365

4.1.8 Model A100_2000_3INJ Scenario Result

Model A100_2000_3INJ is polymer flooding and the simulation results as shown in Table 4.17 - 4.18 and Figure 4.56 – 4.62:

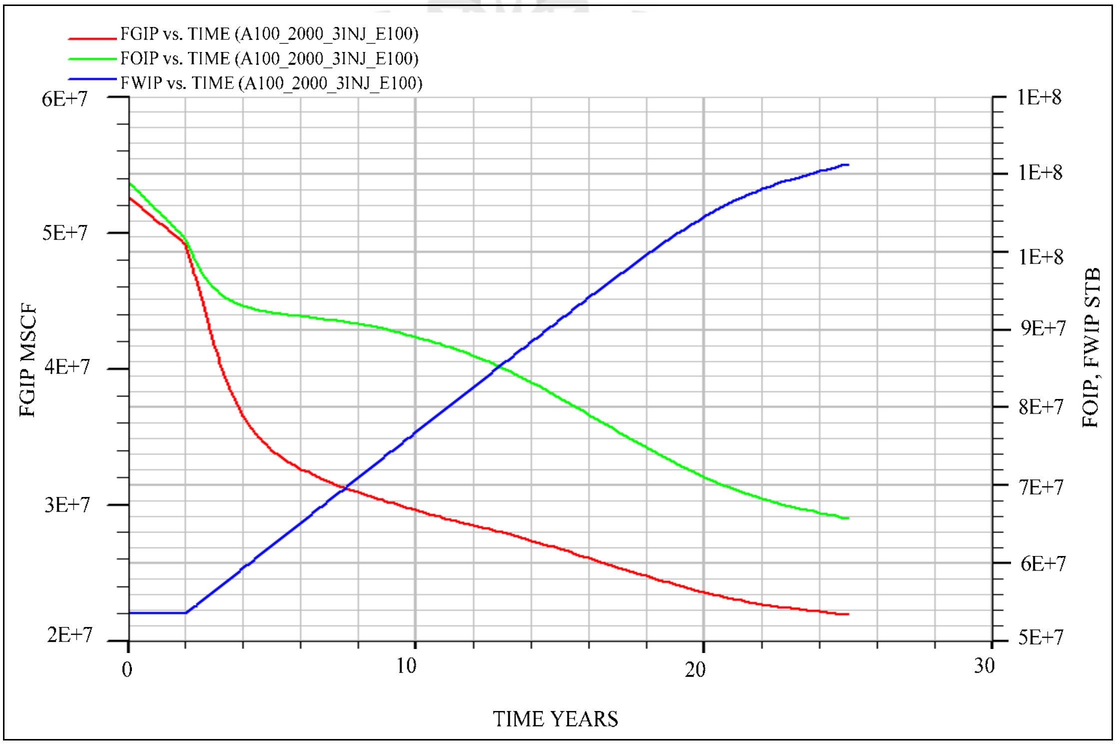


Figure 4.56 Fluid in place profile vs. Time of model A100_2000_3INJ.

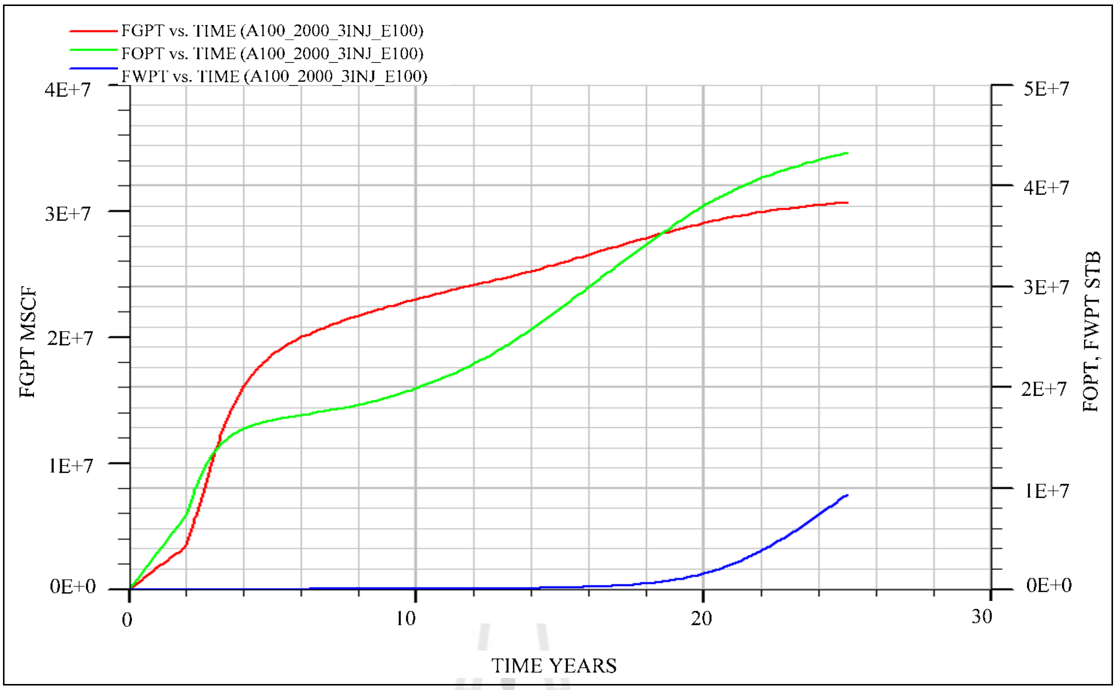


Figure 4.57 Cumulative fluids production profile vs. Time of model A100_2000_3INJ.

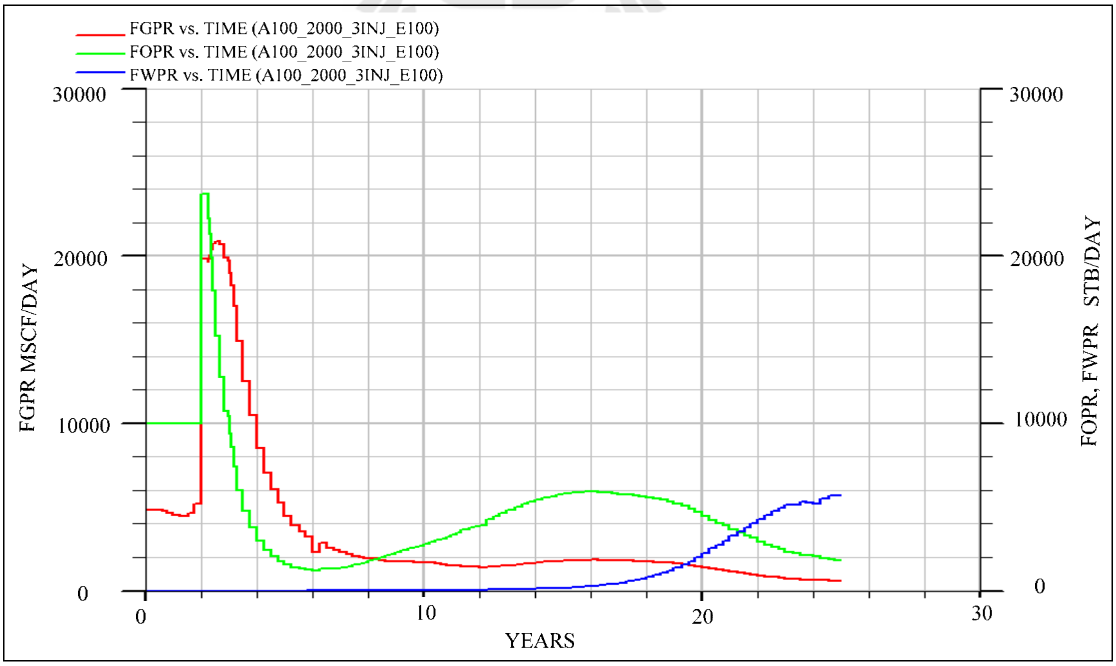


Figure 4.58 Fluids production rate profile vs. Time of model A100_2000_3INJ.

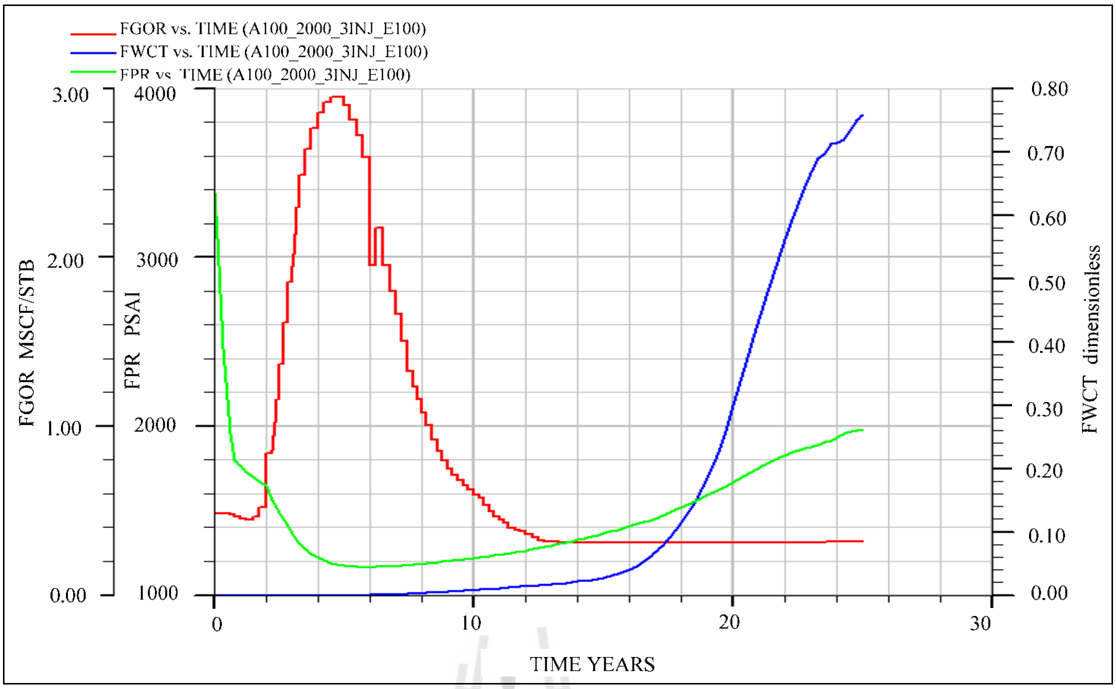


Figure 4.59 GOR, WCT, and Pressure profile vs. Time of model A100_2000_3INJ.

Figure 4.60 Oil recovery efficiency vs. Time of model A100_2000_3INJ.

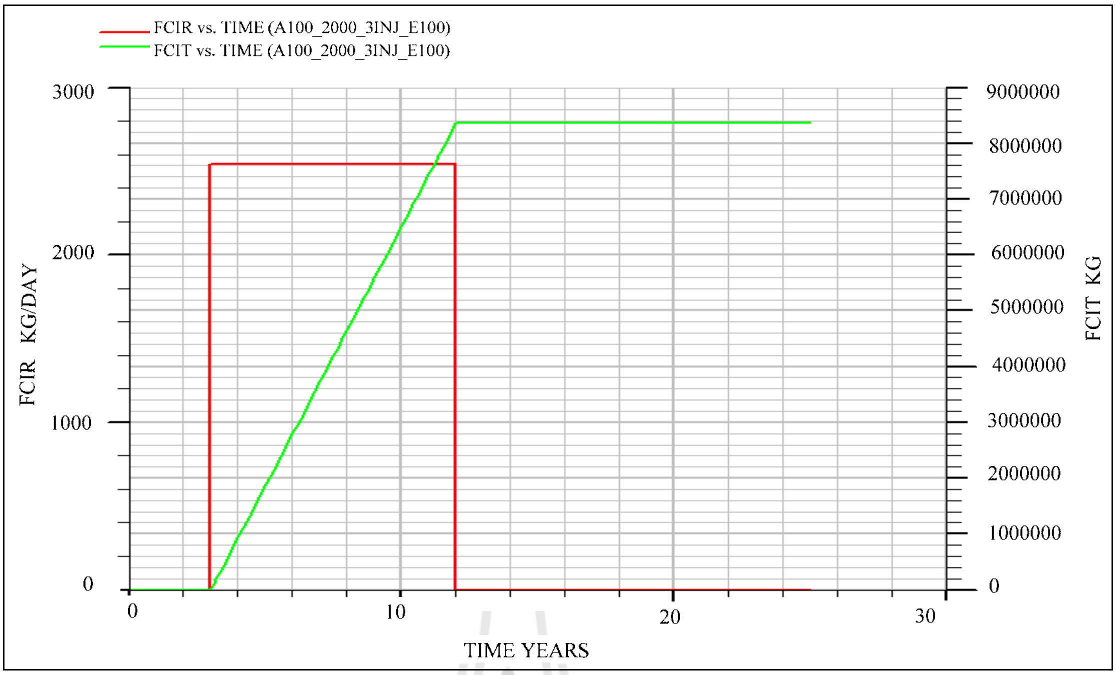


Figure 4.61 CIR and CIT vs. Time of model A100_2000_3INJ.

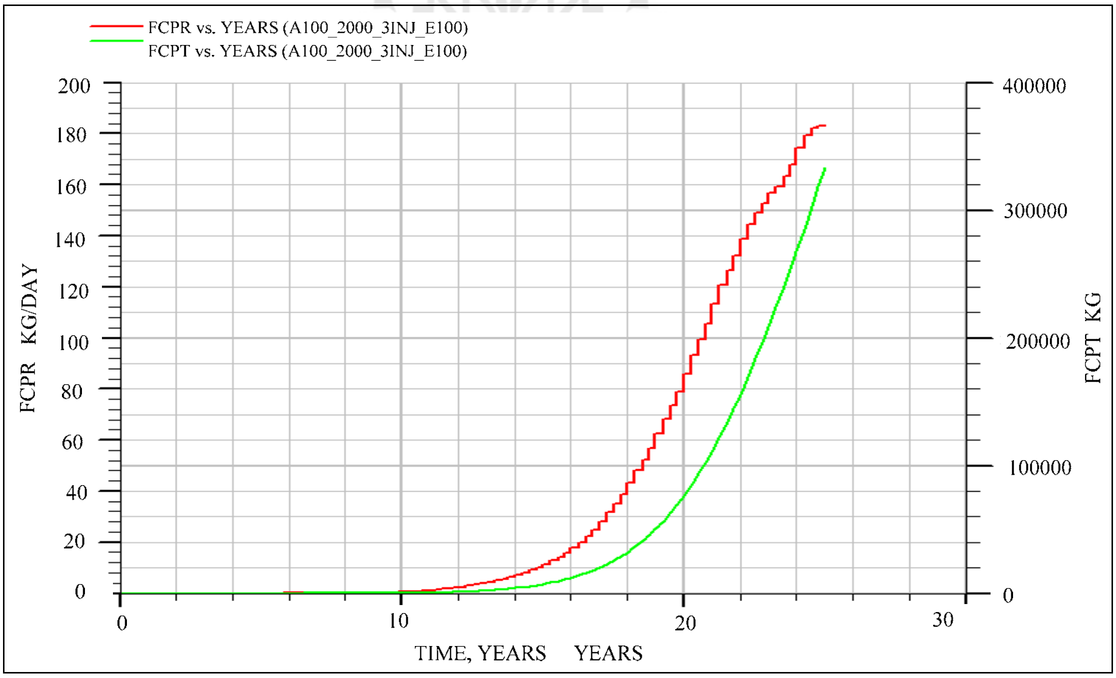


Figure 4.62 CPR and CPT vs. Time of model A100_2000_3INJ.

Table 4.17 Summary detail of graph 4.56, 4.57 and 4.60.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	43,280,728	109,049,300	39.69
Gas (MSCF)	30,700,120	52,615,556	58.35
Water (STB)	9,417,457	53,511,504	17.60

Table 4.18 Summary detail of graph 4.61 and 4.62.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	194,939,500	0.14	8,365

4.1.9 Model A100_2000_4INJ Scenario Result

Model A100_2000_4INJ is polymer flooding and the simulation results as shown in Table 4.19 - 4.20 and Figure 4.63 – 4.69:

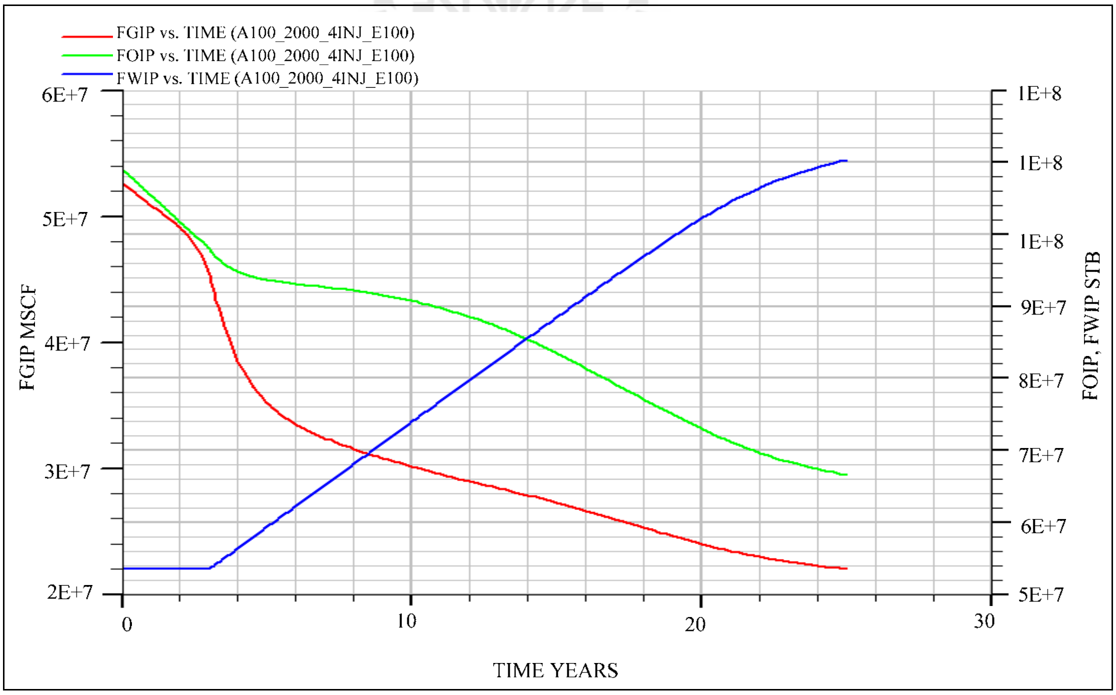


Figure 4.63 Fluid in place profile vs. Time of model A100_2000_4INJ.

Figure 4.64 Cumulative fluids production profile vs. Time of model A100_2000_4INJ.

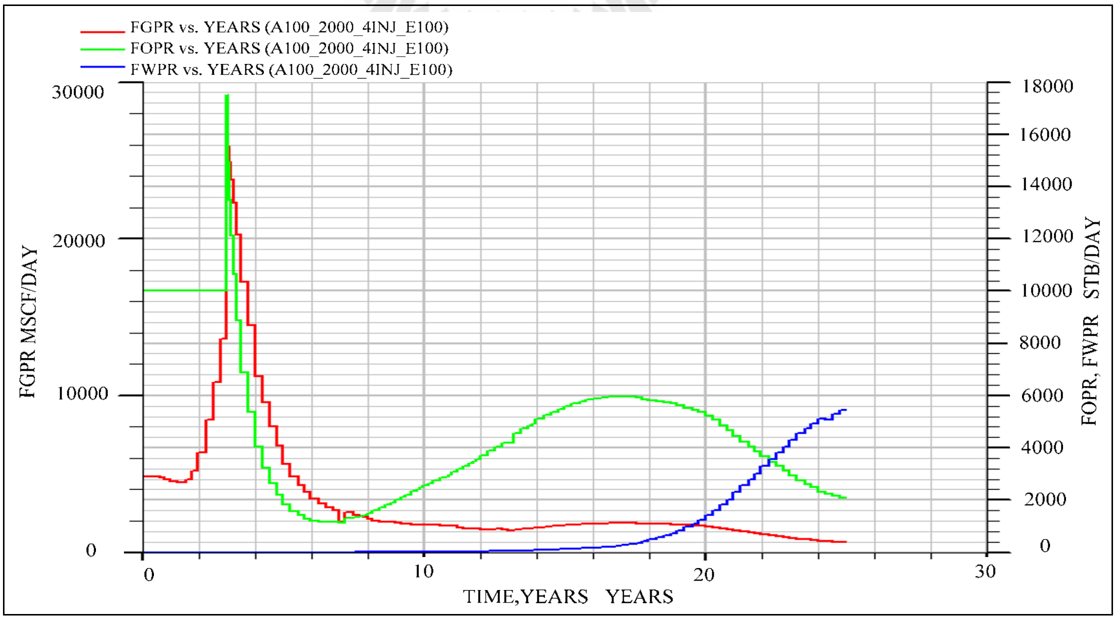


Figure 4.65 Fluids production rate profile vs. Time of model A100_2000_4INJ.

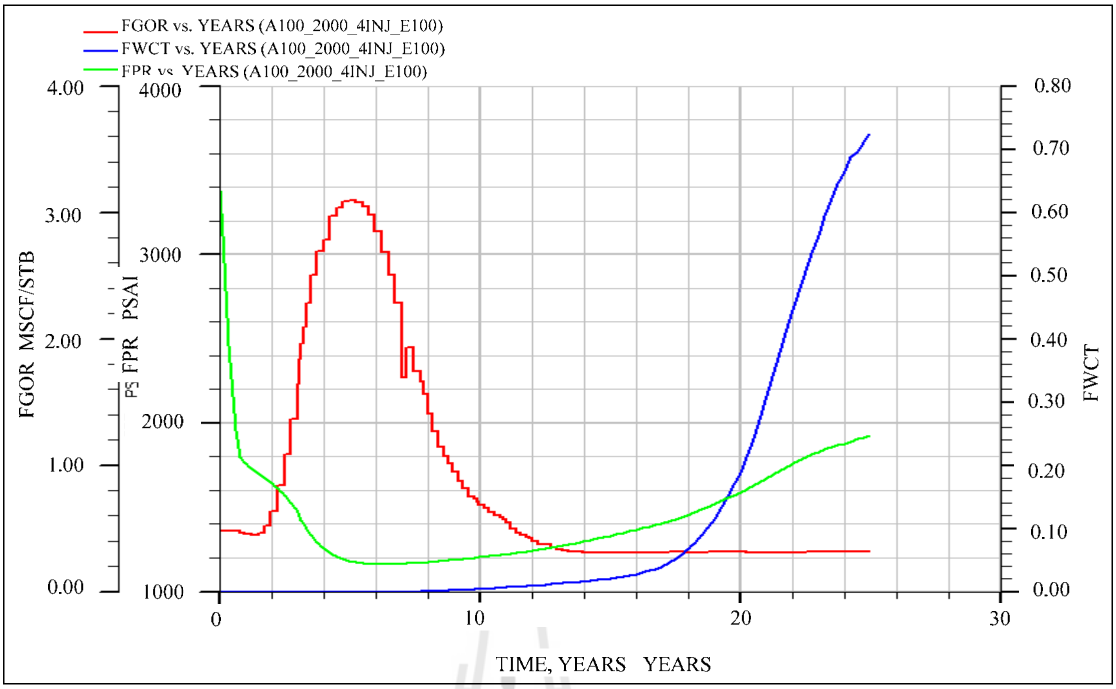


Figure 4.66 GOR, WCT, and Pressure profile vs. Time of model A100_2000_4INJ.

Figure 4.67 Oil recovery efficiency vs. Time of model A100_2000_4INJ.

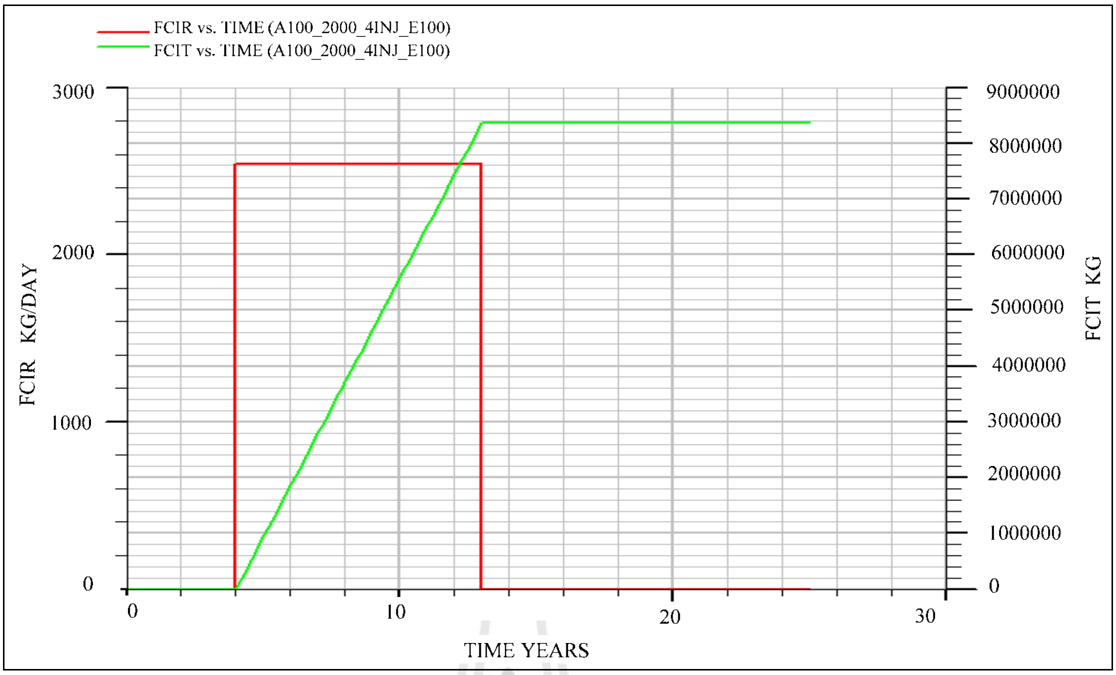


Figure 4.68 CIR and CIT vs. Time of model A100_2000_4INJ.

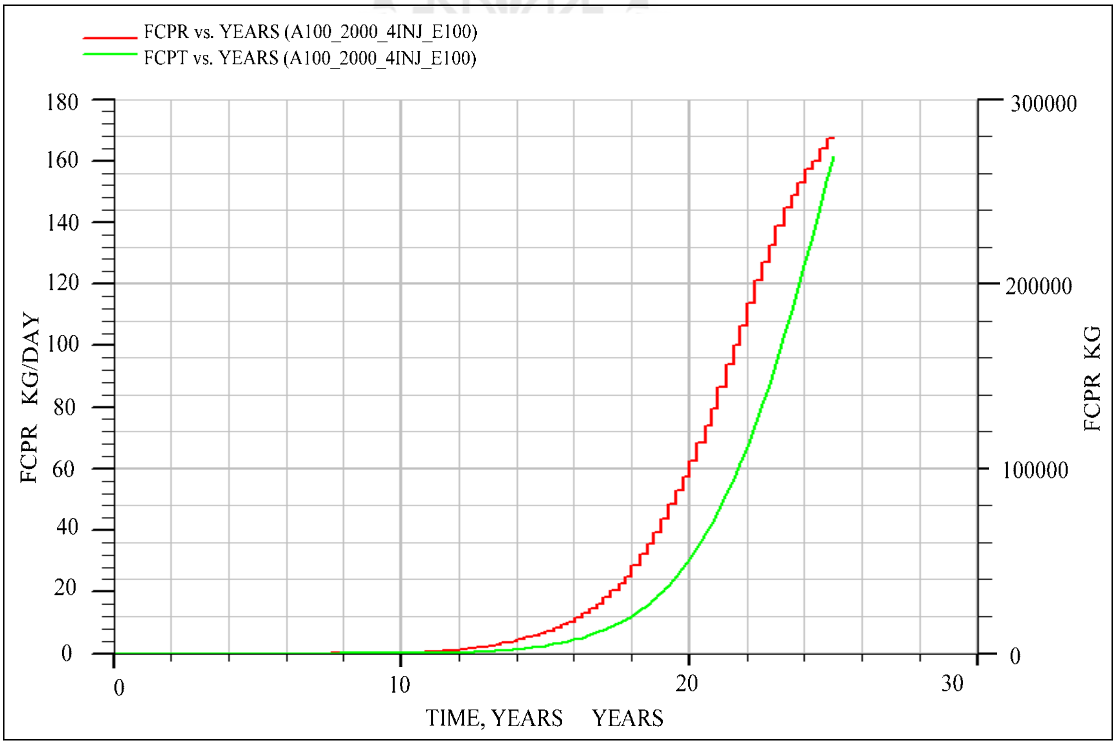


Figure 4.69 CPR and CPT vs. Time of model A100_2000_4INJ.

Table 4.19 Summary detail of graph 4.63, 4.64 and 4.67.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	42,461,376	109,049,300	38.94
Gas (MSCF)	30,607,810	52,615,556	58.17
Water (STB)	7,447,564	53,511,504	13.92

Table 4.20 Summary detail of graph 4.68 and 4.69.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	194,939,500	0.14	8,365

For model A100, the results of reservoir simulation for 10 cases (a base case of waterflooding and nine cases of polymer flooding) of different starting time for polymer injection of 3rd, 4th, and 5th years of production period, for an optimized polymer slug size as 0.14 PV. The processes of reservoir simulation were made for different polymer concentrations of 1,000, 1,500 and 2,000 ppm. The three of different starting times corresponding to the polymer concentrations of 1,000, 1,500 and 2,000 ppm, respectively. These simulations called polymer flooding, running for find the best case oil recovery efficiency. They gave better results than that of the waterflooding as presented in Figure 4.70 – 4.72.

The average of oil production totals and the oil recovery efficiency have increased more than the waterflooding as shown in Table 4.20.

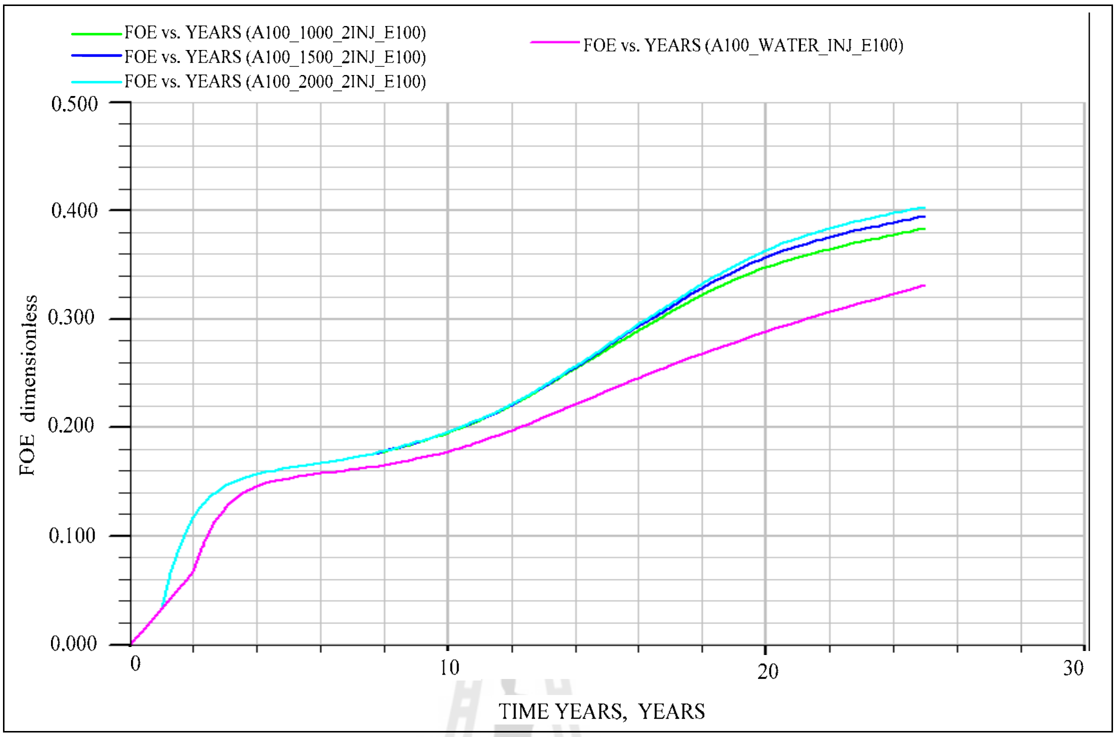


Figure 4.70 Oil recovery efficiency vs. Time of model A100 ply.-start@3rd year.

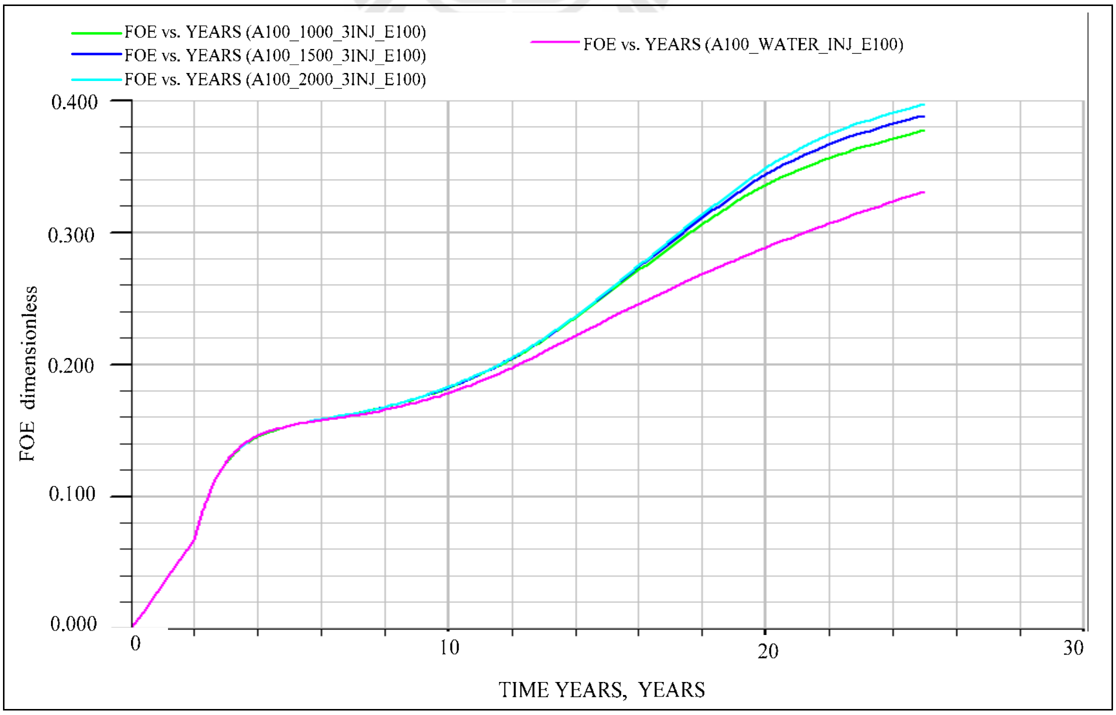


Figure 4.71 Oil recovery efficiency vs. Time of model A100 ply.-start@4th year.

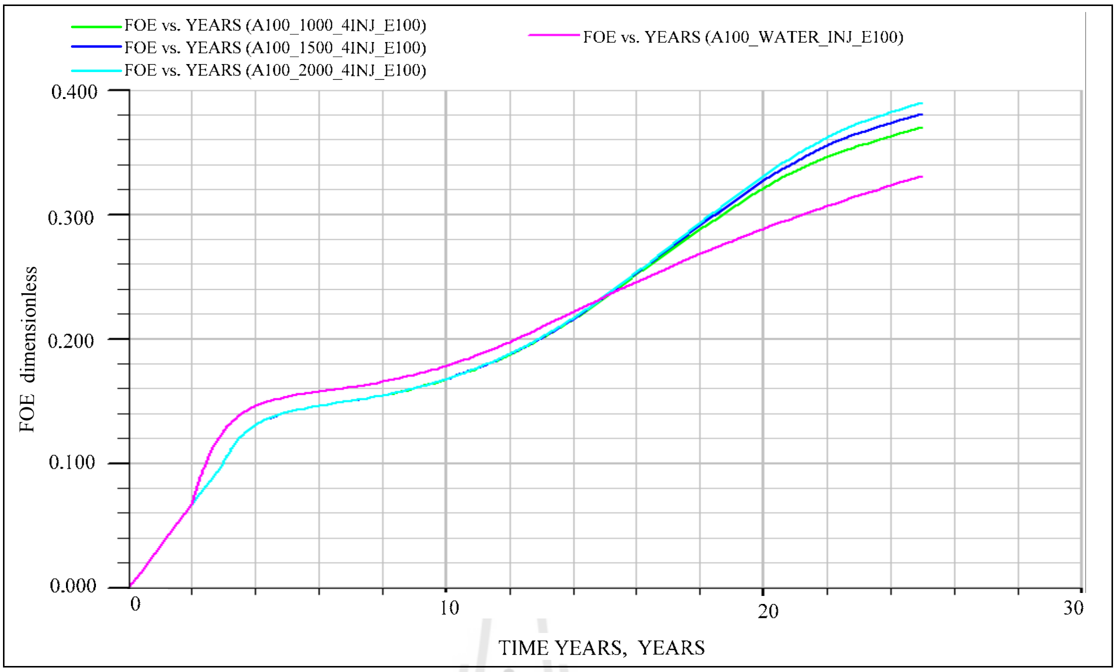


Figure 4.72 Oil recovery efficiency vs. Time of model A100 ply.-start@5th year.

Table 4.21 Cumulative oil production and oil recovery efficiency for A100.

Model Name	Scenario No.	Scenario Name	Polymer Concentration (ppm)	Cum. Oil production (BBL)	Recovery Factor (RF)
A100	1	A100_WATER_INJ	-	36,100,988	33.11
	2	A100_1000_2INJ	1,000	41,829,864	38.36
	3	A100_1000_3INJ	1,000	41,127,388	37.71
	4	A100_1000_4INJ	1,000	40,314,836	36.97
	5	A100_1500_2INJ	1,500	43,050,272	39.48
	6	A100_1500_3INJ	1,500	42,350,996	38.84
	7	A100_1500_4INJ	1,500	41,538,904	38.09
	8	A100_2000_2INJ	2,000	43,997,032	40.35
	9	A100_2000_3INJ	2,000	43,280,728	39.69
	10	A100_2000_4INJ	2,000	42,461,376	38.94

4.2 Reservoir Simulation Result for Model A30

4.2.1 Model A30_WATER_INJ Scenario Result

Model A30_WATER_INJ is waterflooding (base case) and the simulation results as shown in Table 4.22 and Figure 4.73 – 4.78:

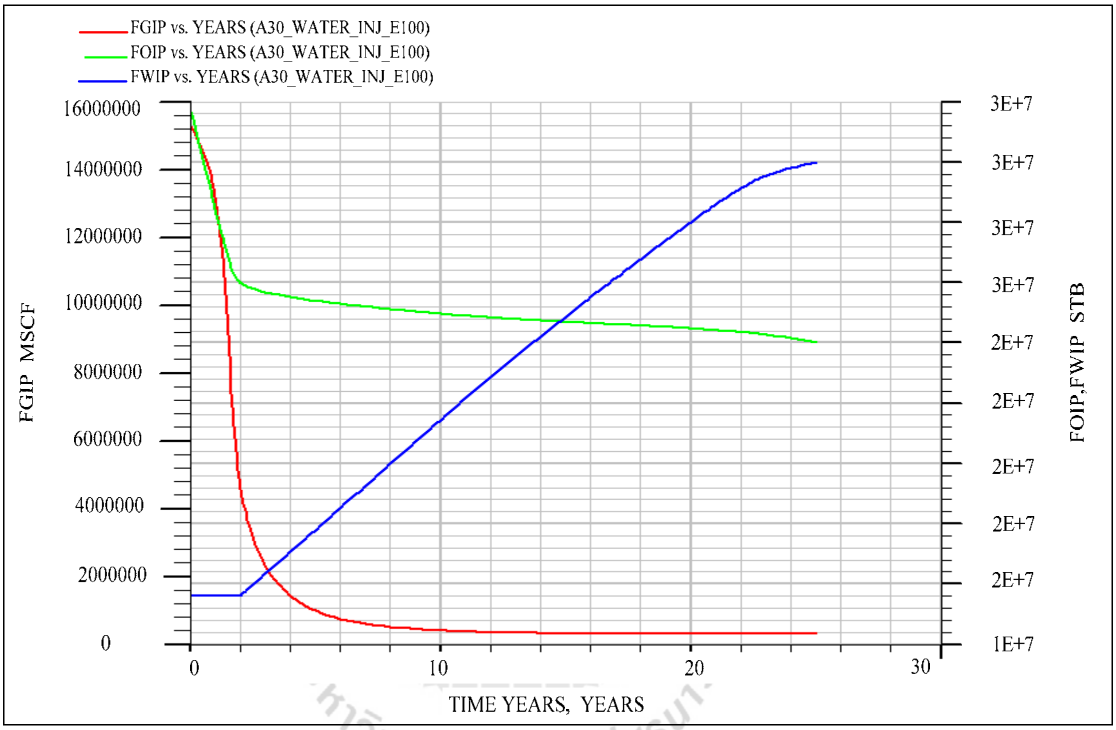


Figure 4.73 Fluid in place profile vs. Time of model A30_WATER_INJ.

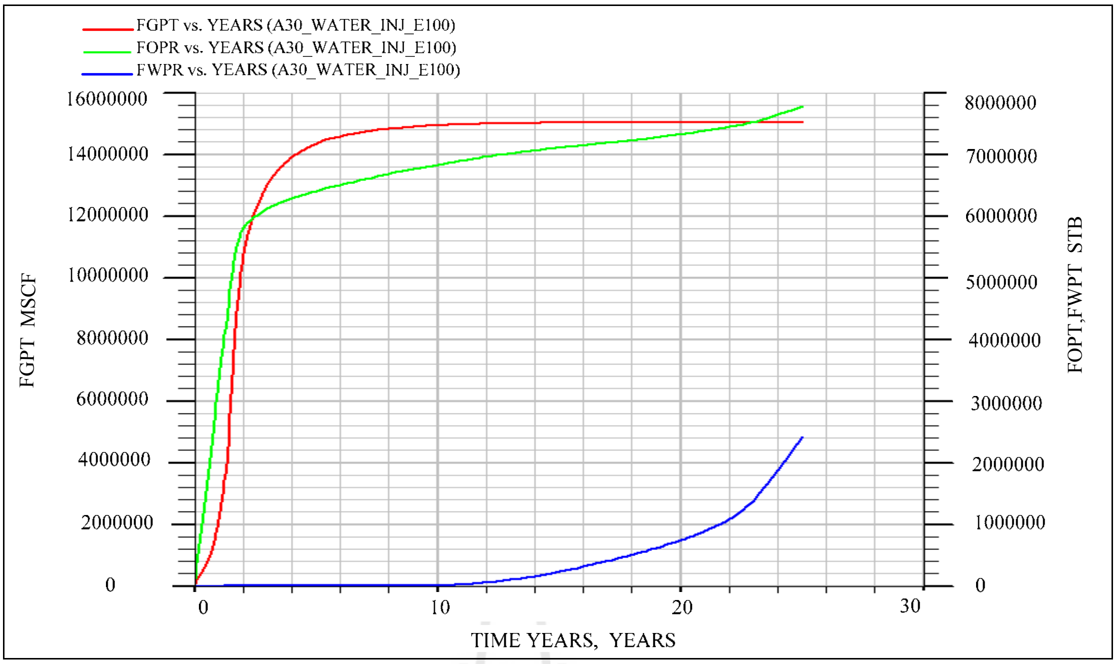


Figure 4.74 Cumulative fluids production profile vs. Time of model A30_WATER_INJ.

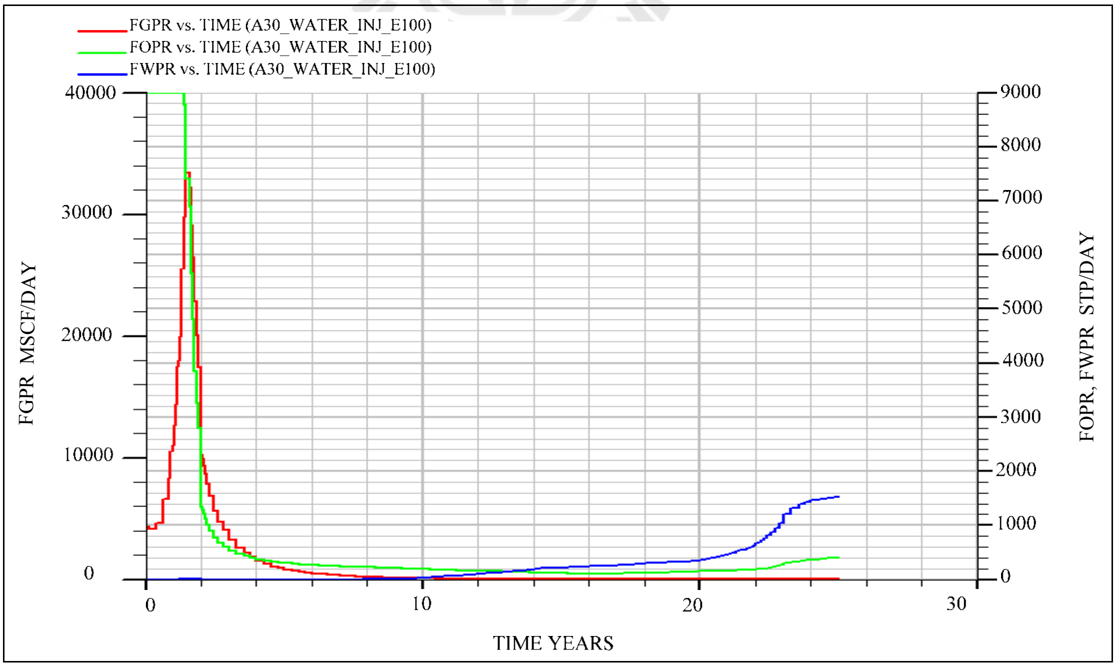


Figure 4.75 Fluids production rate profile vs. Time of model A30_WATER_INJ.

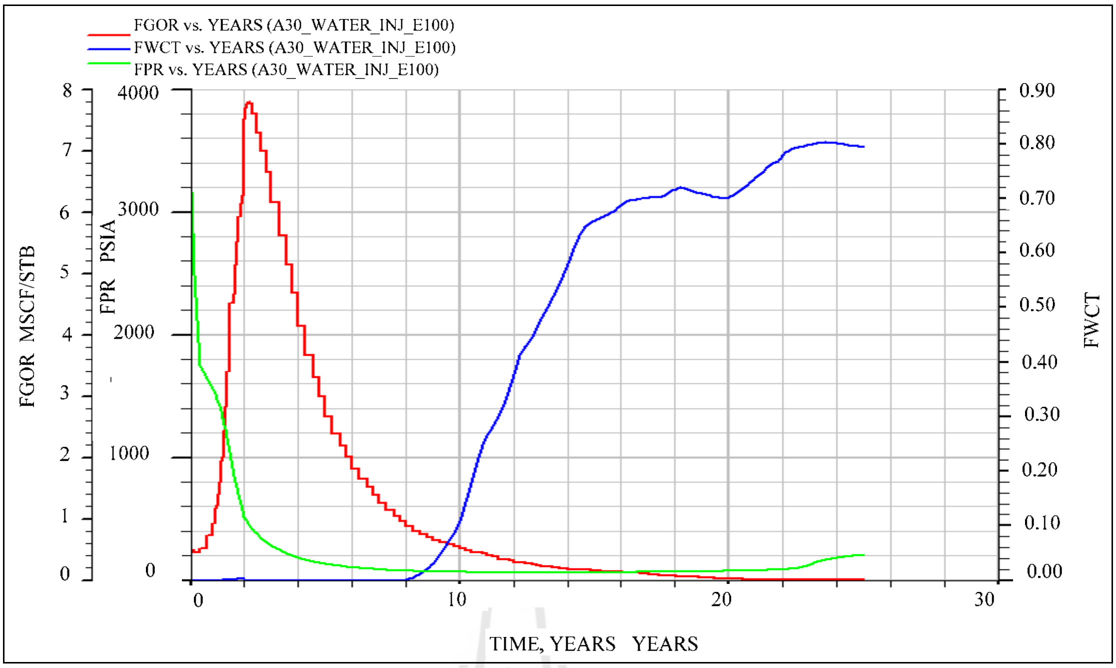


Figure 4.76 GOR, WCT, and Pressure profile vs. Time of model A30_WATER_INJ.

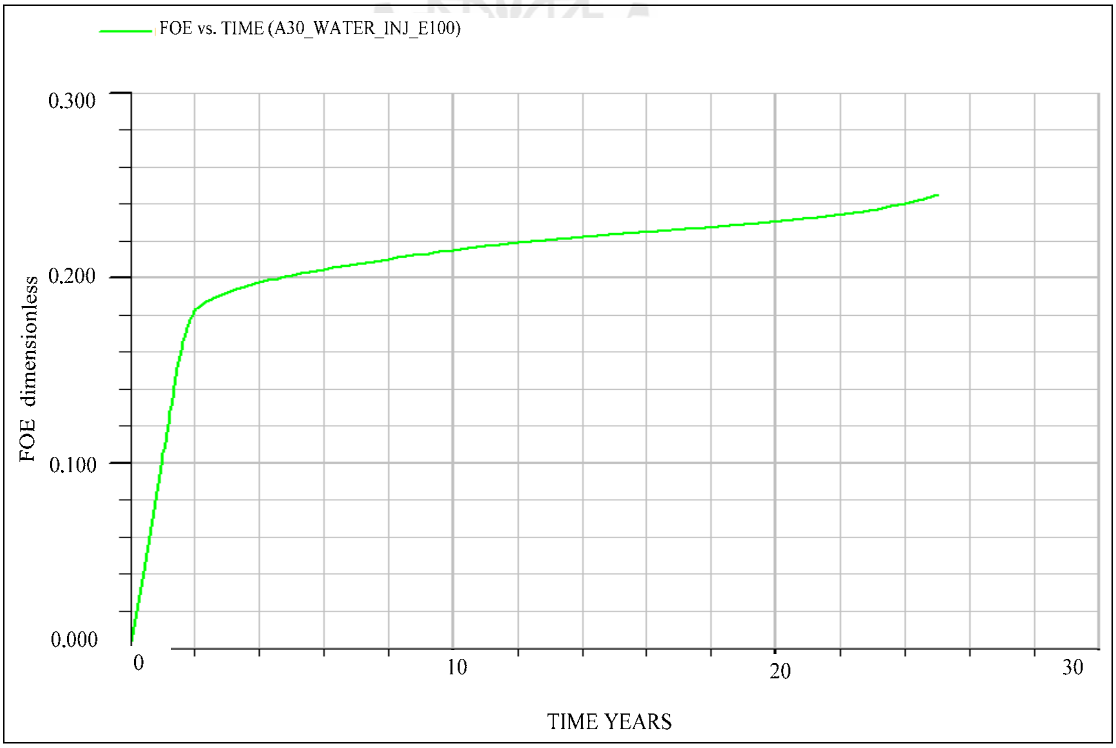


Figure 4.77 Oil recovery efficiency vs. Time of model A30_WATER_INJ.

Table 4.22 Summary detail of graph 4.73, 4.74 and 4.77.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	7,782,724.5	31,798,776	24.47
Gas (MSCF)	15,044,240	15,342,696	98.05
Water (STB)	2,422,689	15,603,954	15.53

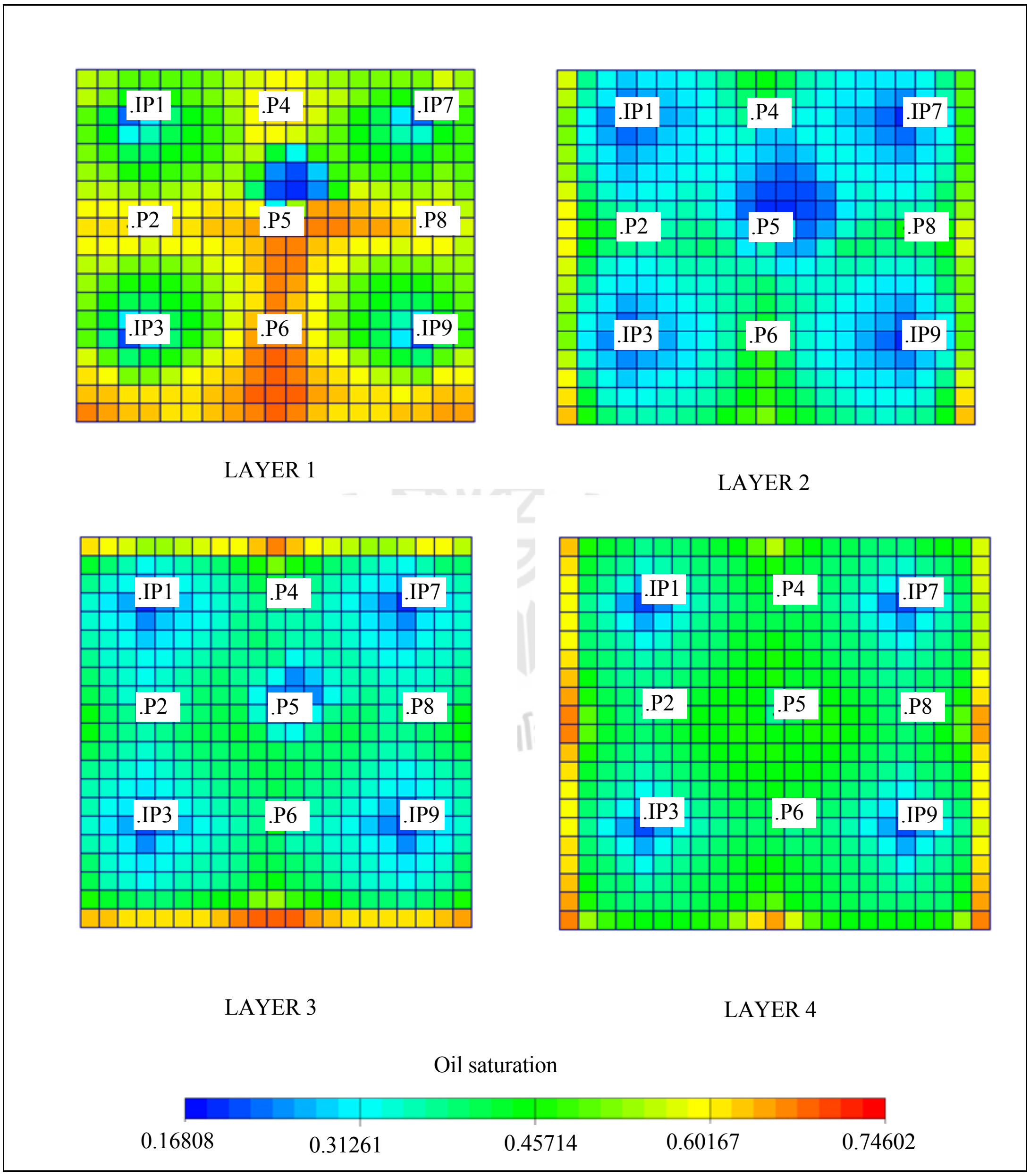


Figure 4.78 Residual oil saturation distribution after waterflooding of model A30_WATER_INJ.

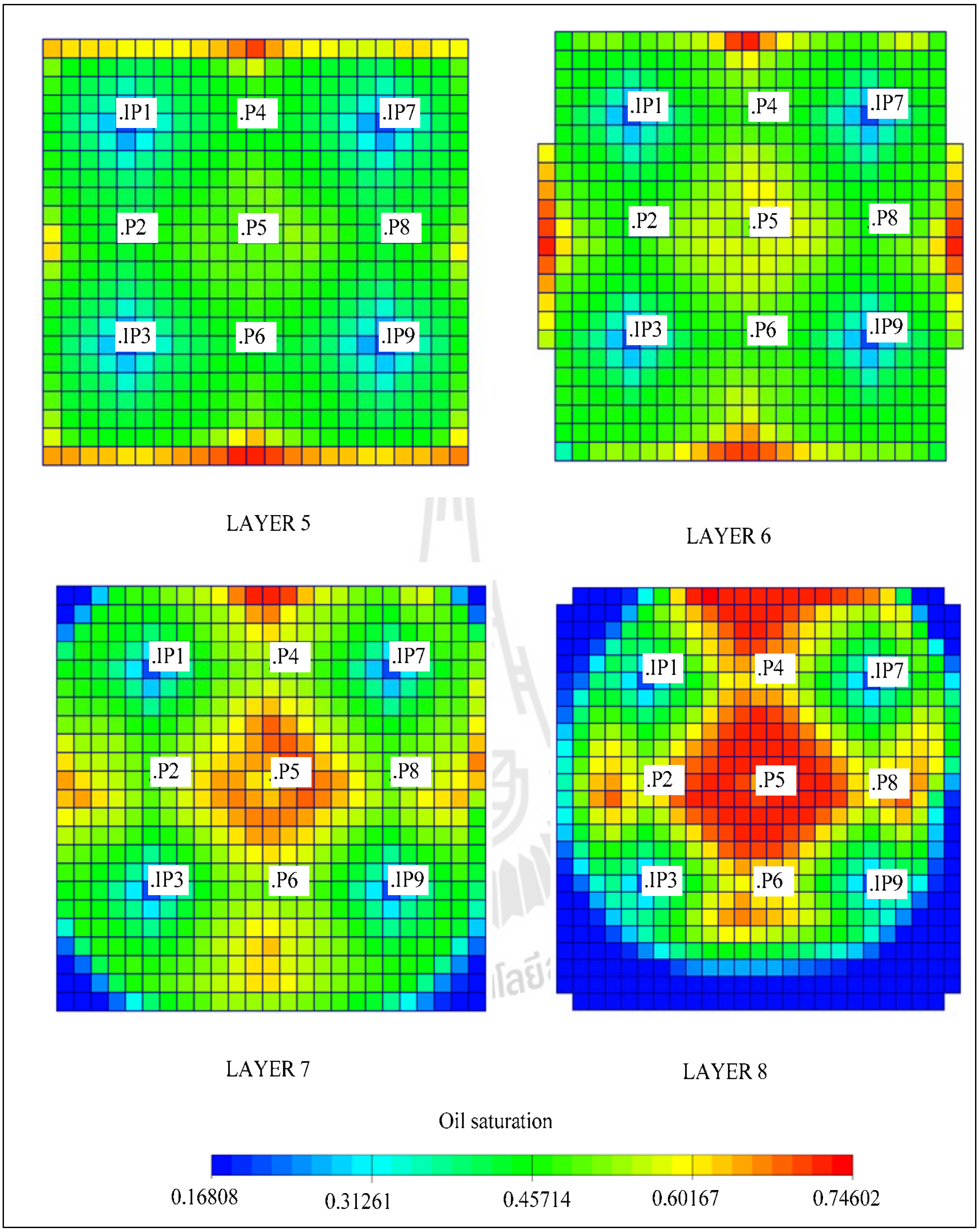


Figure 4.78 Residual oil saturation distribution after waterflooding of model A30_WATER_INJ. (Continued)

4.2.2 Model A30_1000_2INJ Scenario Result

Model A30_1000_2INJ is polymer flooding and the simulation results as shown in Table 4.23-4.24 and Figure 4.79 – 4.85:

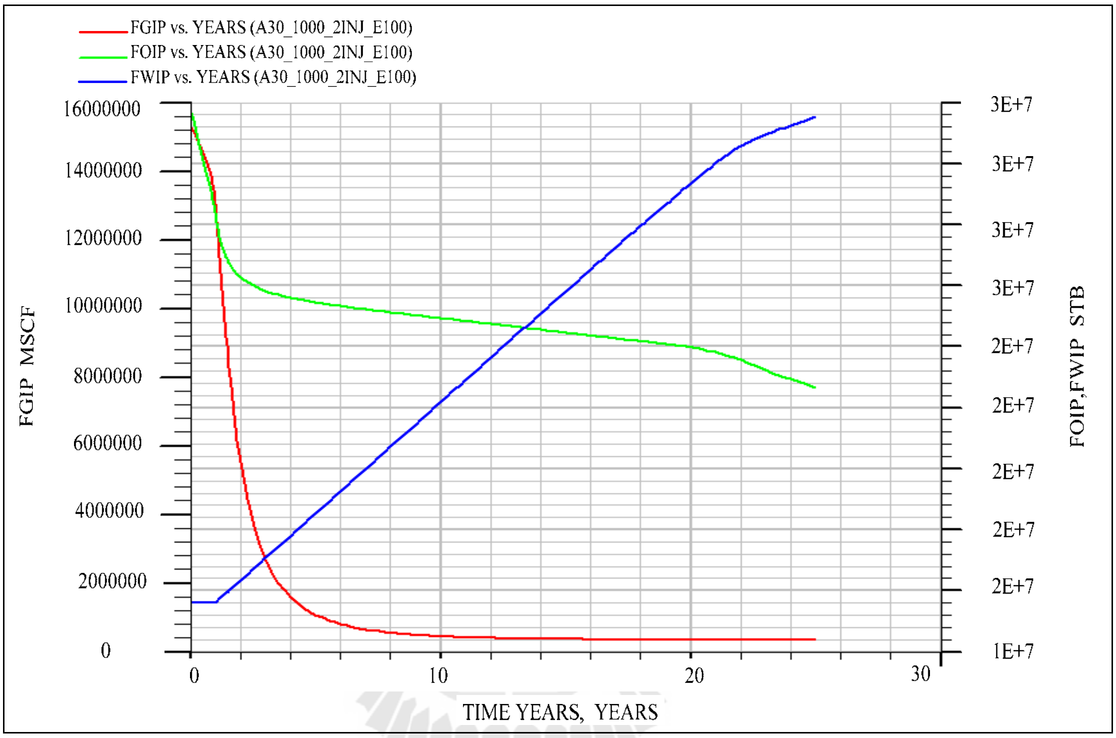


Figure 4.79 Fluid in place profile vs. Time of model A30_1000_2INJ.

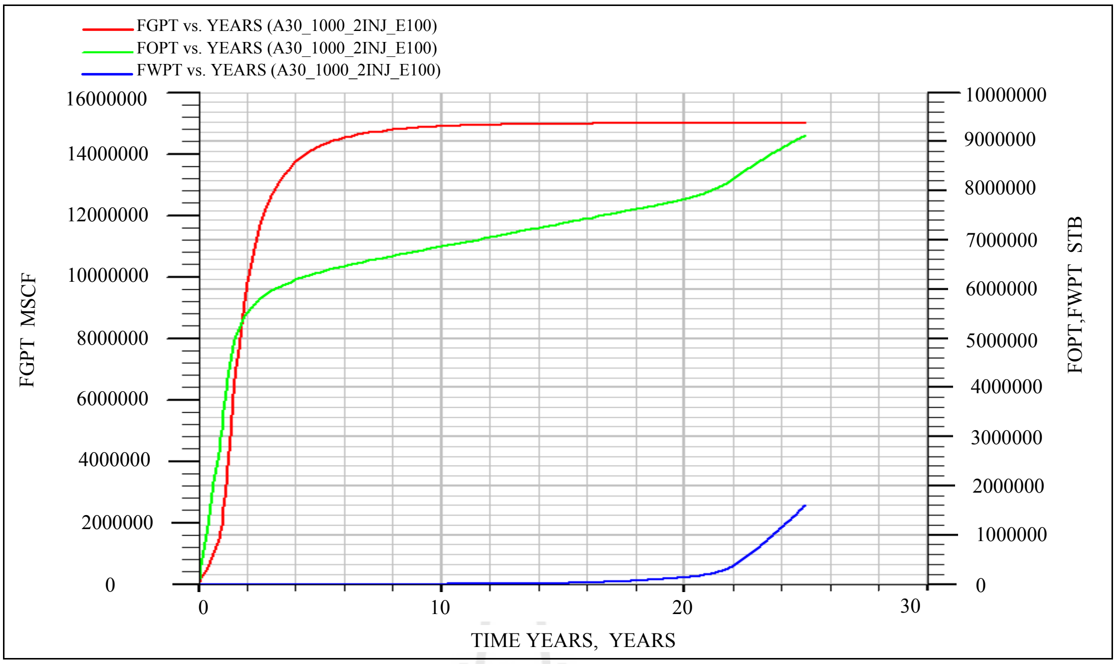


Figure 4.80 Cumulative fluids production profile vs. Time of model A30_1000_2INJ.

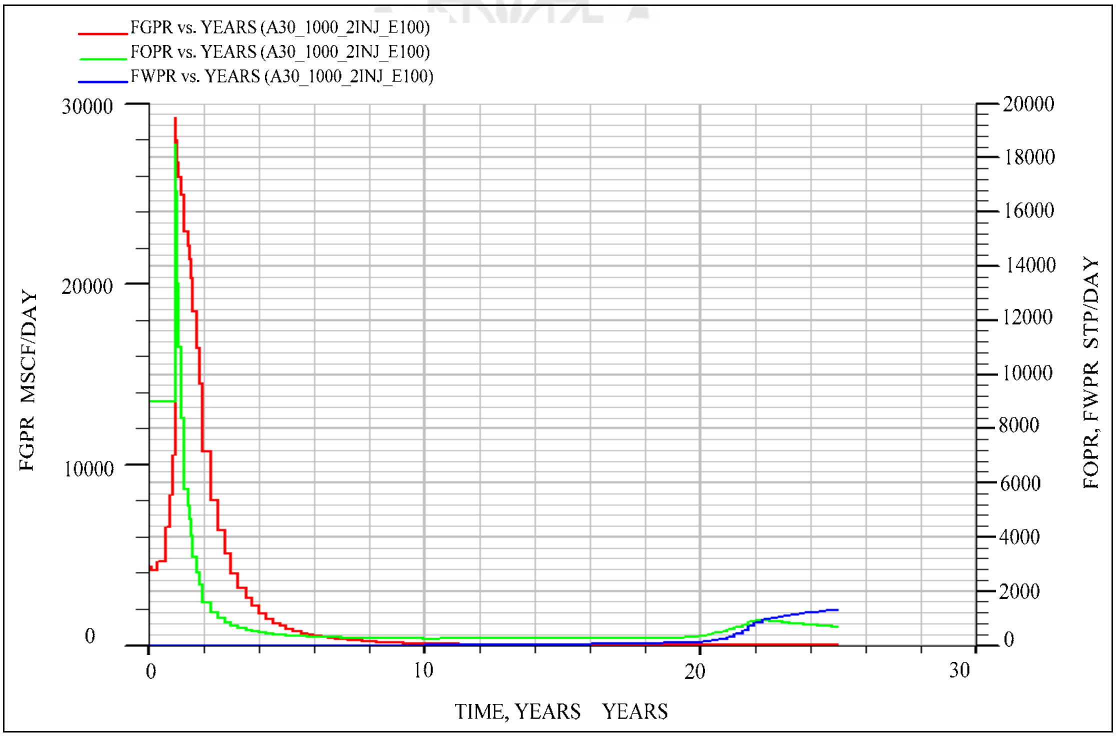


Figure 4.81 Fluids production rate profile vs. Time of model A30_1000_2INJ.

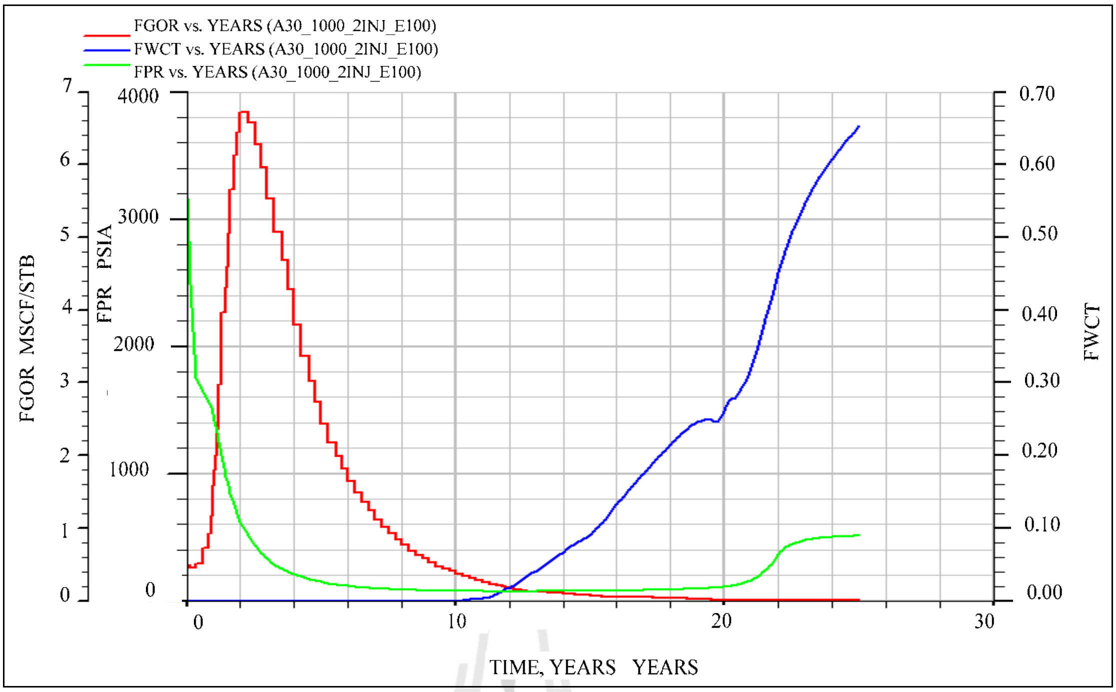


Figure 4.82 GOR, WCT, and Pressure profile vs. Time of model A30_1000_2INJ.

Figure 4.83 Oil recovery efficiency vs. Time of model A30_1000_2INJ.

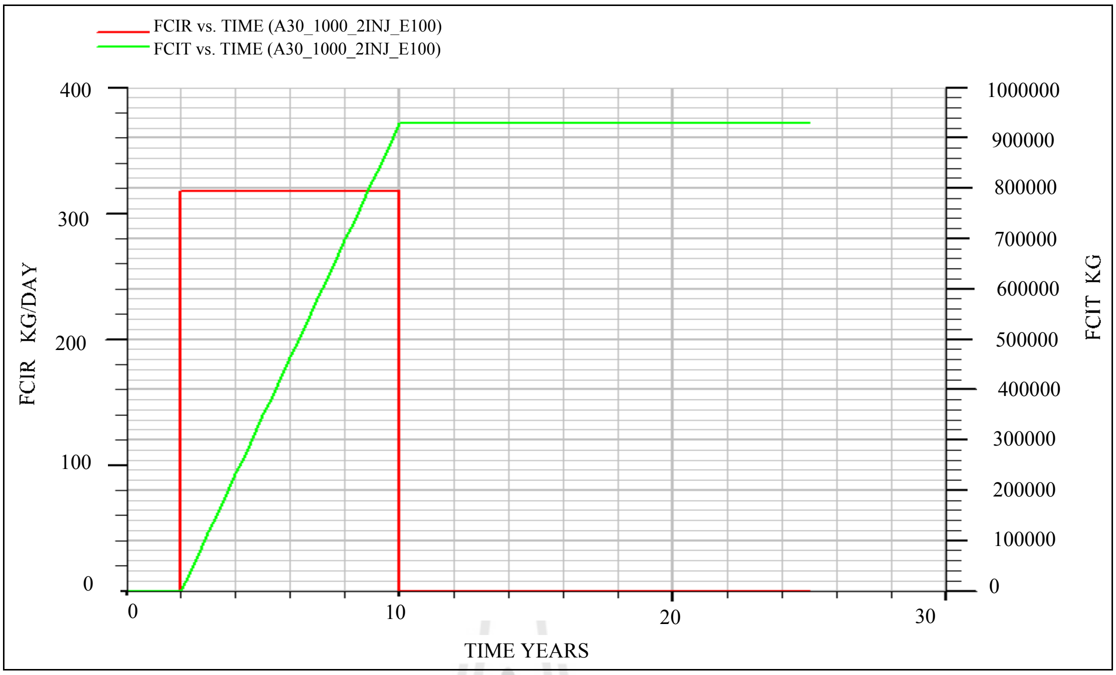


Figure 4.84 CIR and CIT vs. Time of model A30_1000_2INJ.

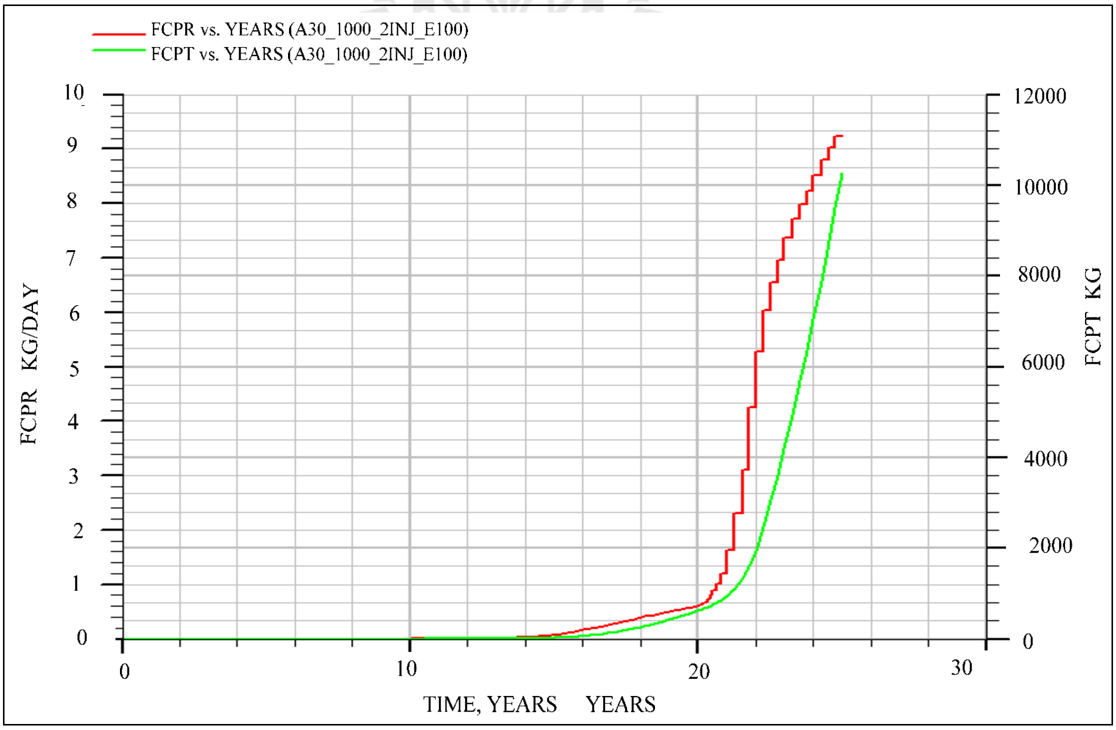


Figure 4.85 CPR and CPT vs. Time of model A30_1000_2INJ.

Table 4.23 Summary detail of graph 4.79, 4.80 and 4.83.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,131,944	31,798,776	28.72
Gas (MSCF)	15,006,740	15,342,696	97.81
Water (STB)	1,610,879	15,603,954	10.32

Table 4.24 Summary detail of graph 4.84 and 4.85.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	56,844,360	0.12	929

4.2.3 Model A30_1000_3INJ Scenario Result

Model A30_1000_3INJ is polymer flooding and the simulation results as shown in Table 4.25-4.26 and Figure 4.86 – 4.92:

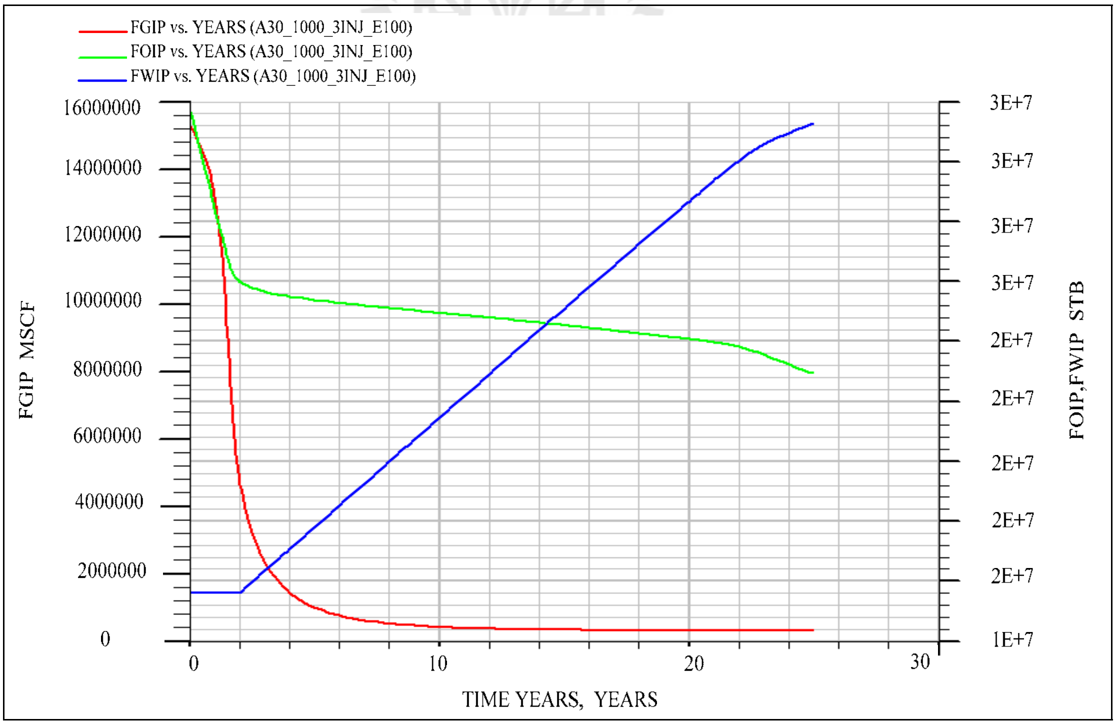


Figure 4.86 Fluid in place profile vs. Time of model A30_1000_3INJ.

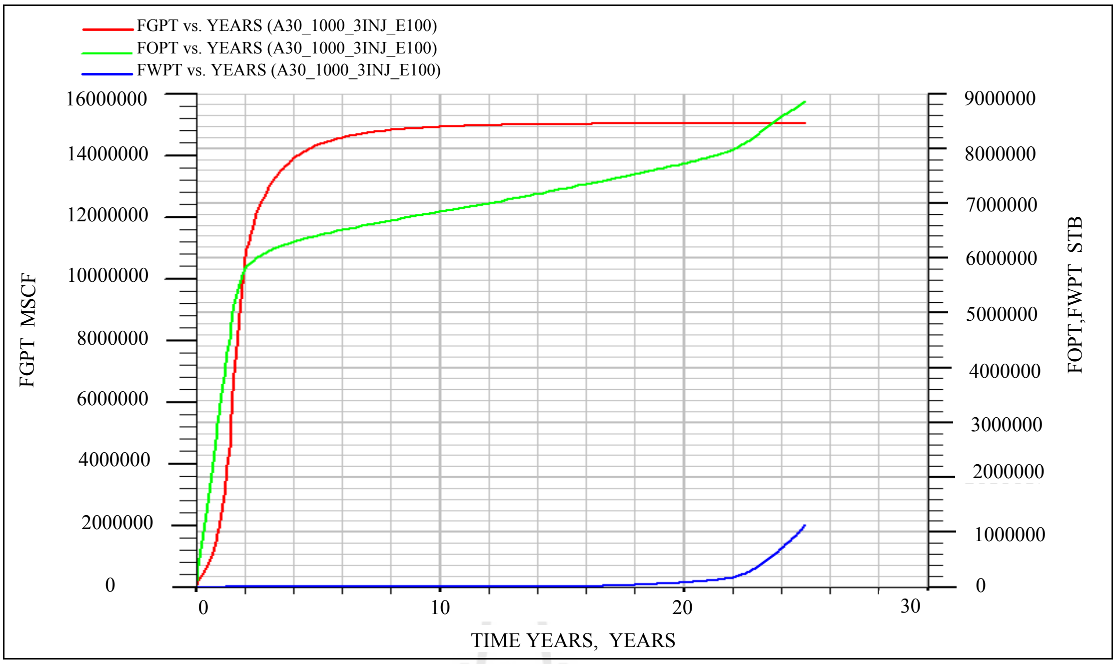


Figure 4.87 Cumulative fluids production profile vs. Time of model A30_1000_3INJ.

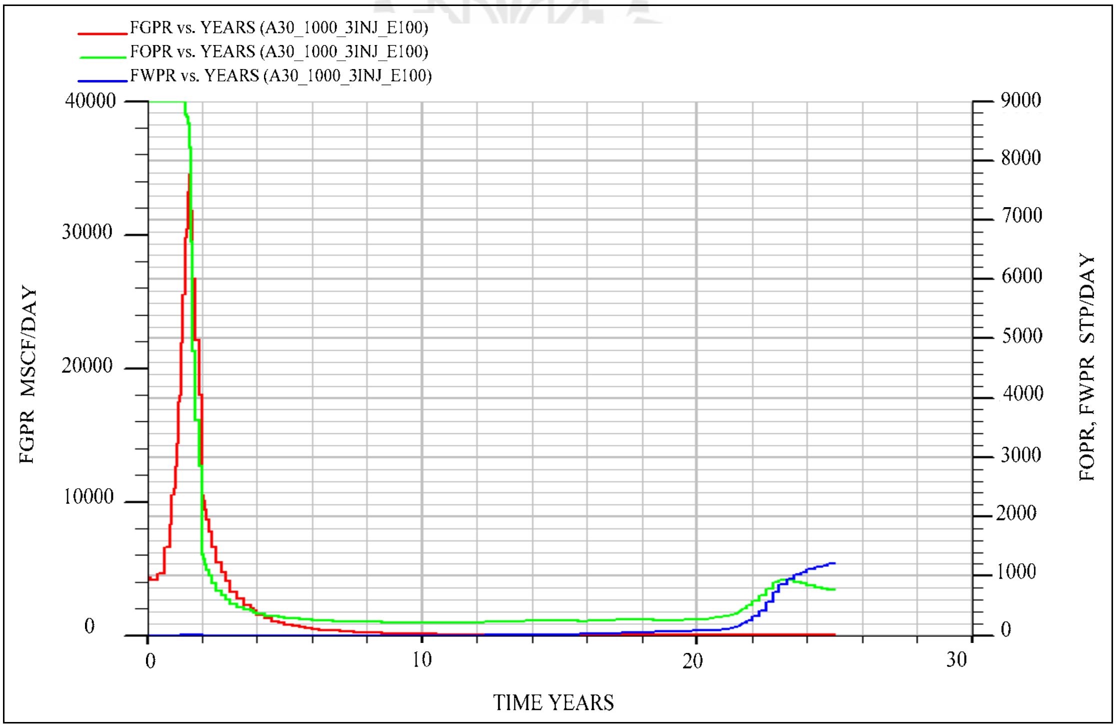


Figure 4.88 Fluids production rate profile vs. Time of model A30_1000_3INJ.

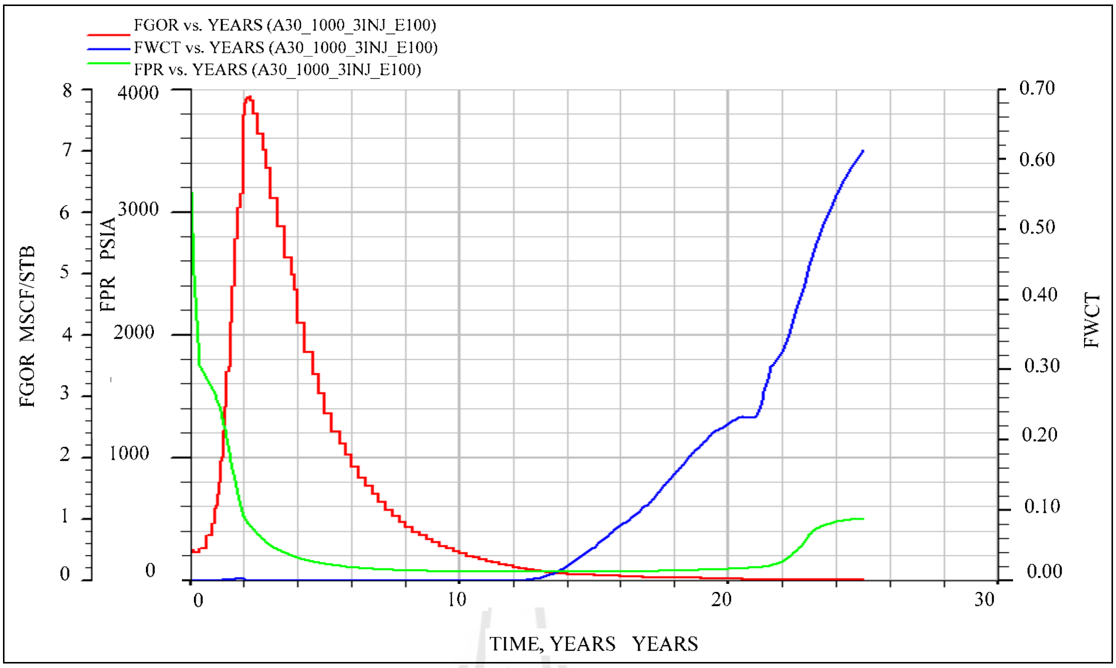


Figure 4.89 GOR, WCT, and Pressure profile vs. Time of model A30_1000_3INJ.

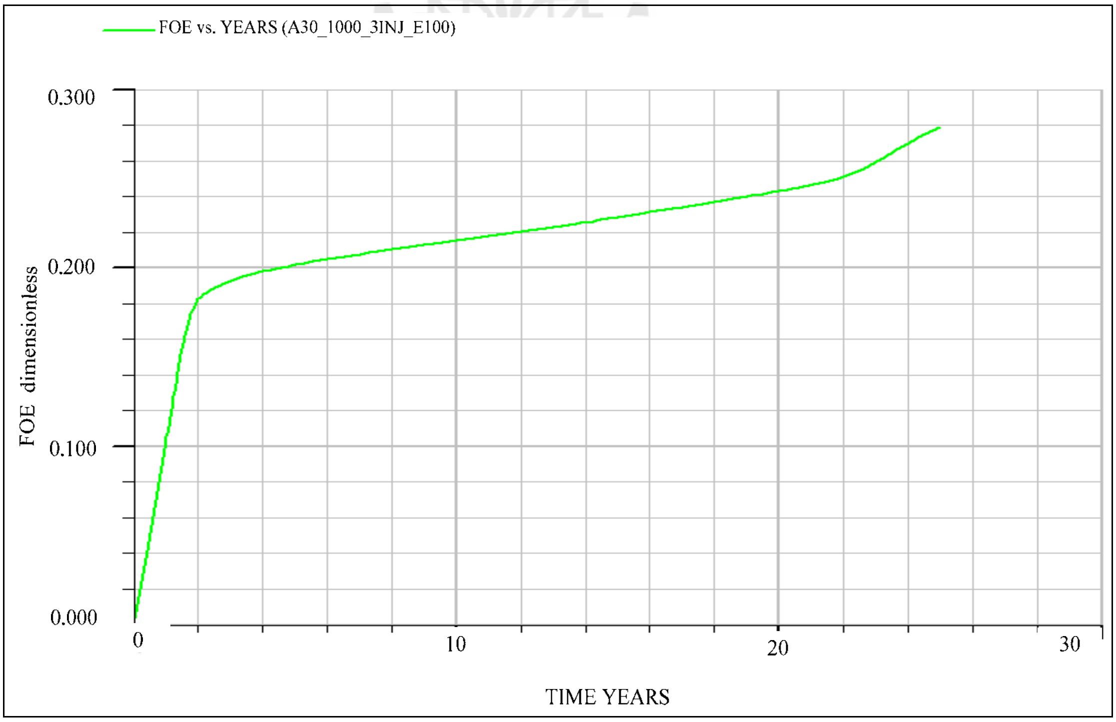


Figure 4.90 Oil recovery efficiency vs. Time of model A30_1000_3INJ.

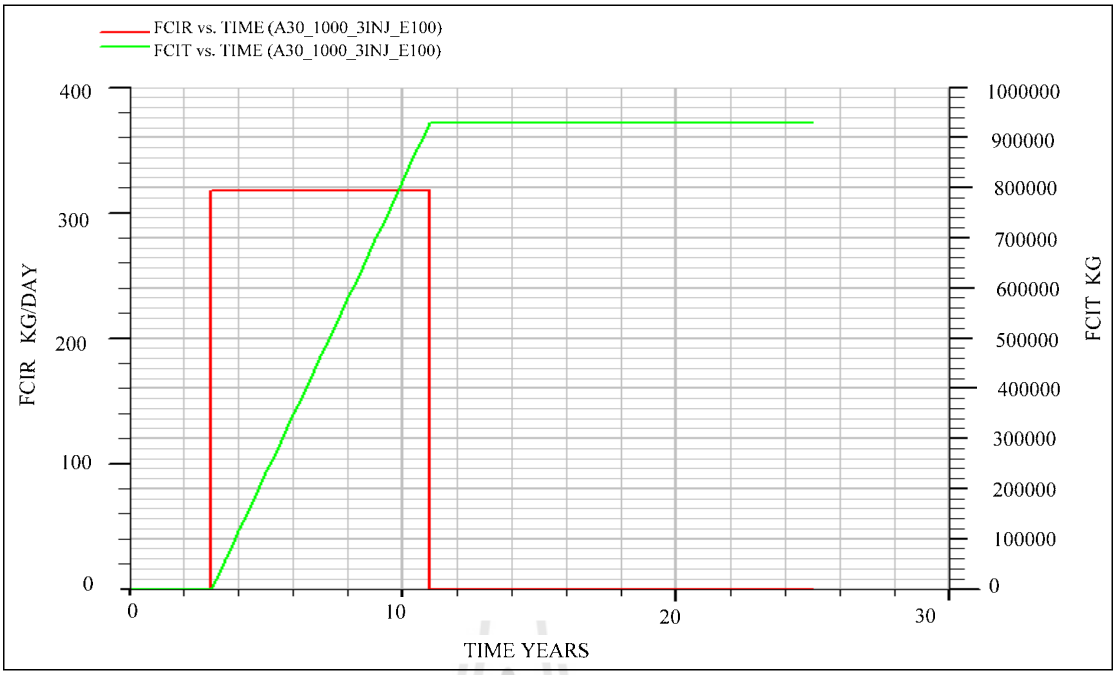


Figure 4.91 CIR and CIT vs. Time of model A30_1000_3INJ.

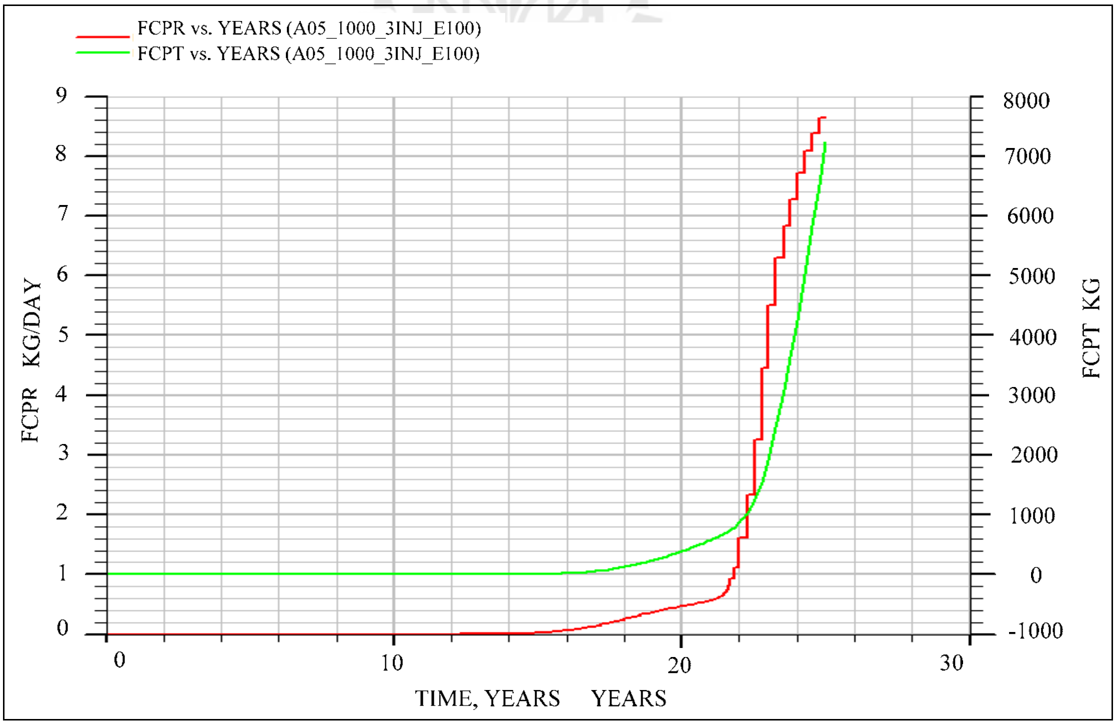


Figure 4.92 CPR and CPT vs. Time of model A30_1000_3INJ.

Table 4.25 Summary detail of graph 4.86, 4.87 and 4.90.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	8,869,303	31,798,776	28.89
Gas (MSCF)	15,040,245	15,342,696	98.03
Water (STB)	1,133,050	15,603,954	7.26

Table 4.26 Summary detail of graph 4.91 and 4.92.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	56,844,360	0.12	929

4.2.4 Model A30_1000_4INJ Scenario Result

Model A30_1000_4INJ is polymer flooding and the simulation results as shown in Table 4.27-4.28 and Figure 4.93 – 4.99:

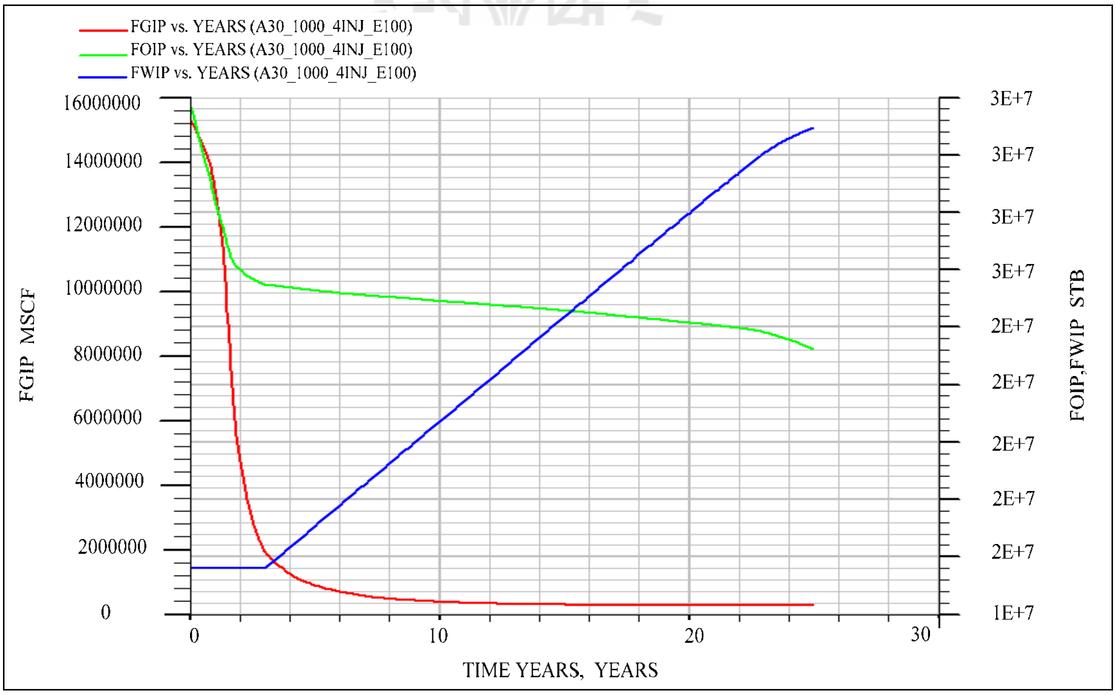


Figure 4.93 Fluid in place profile vs. Time of model A30_1000_4INJ.

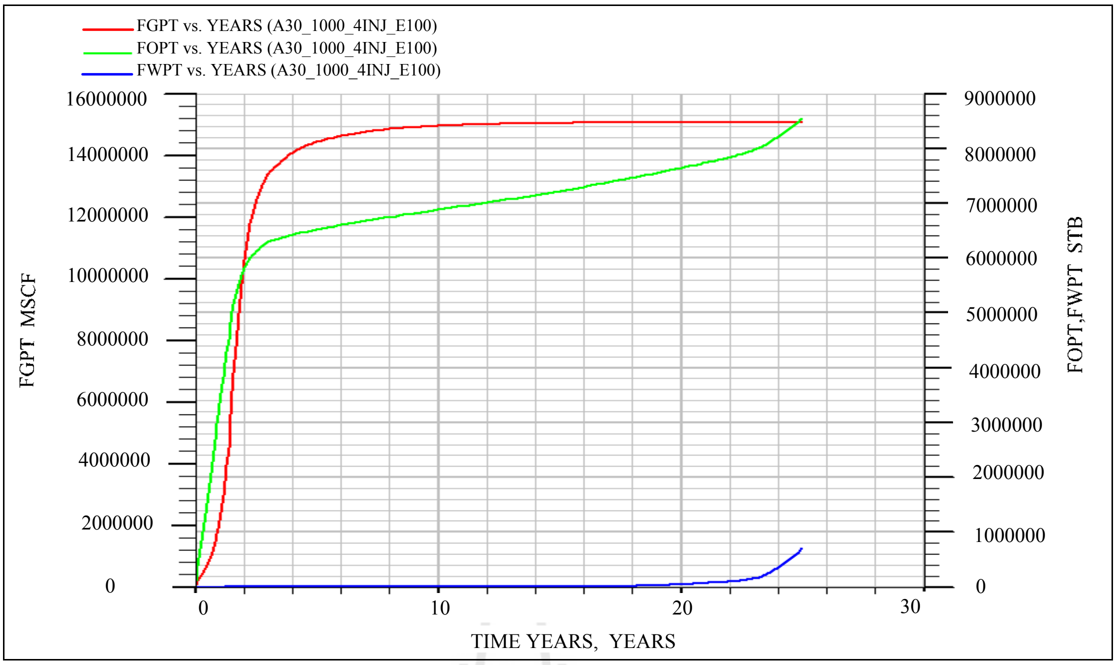


Figure 4.94 Cumulative fluids production profile vs. Time of model A30_1000_4INJ.

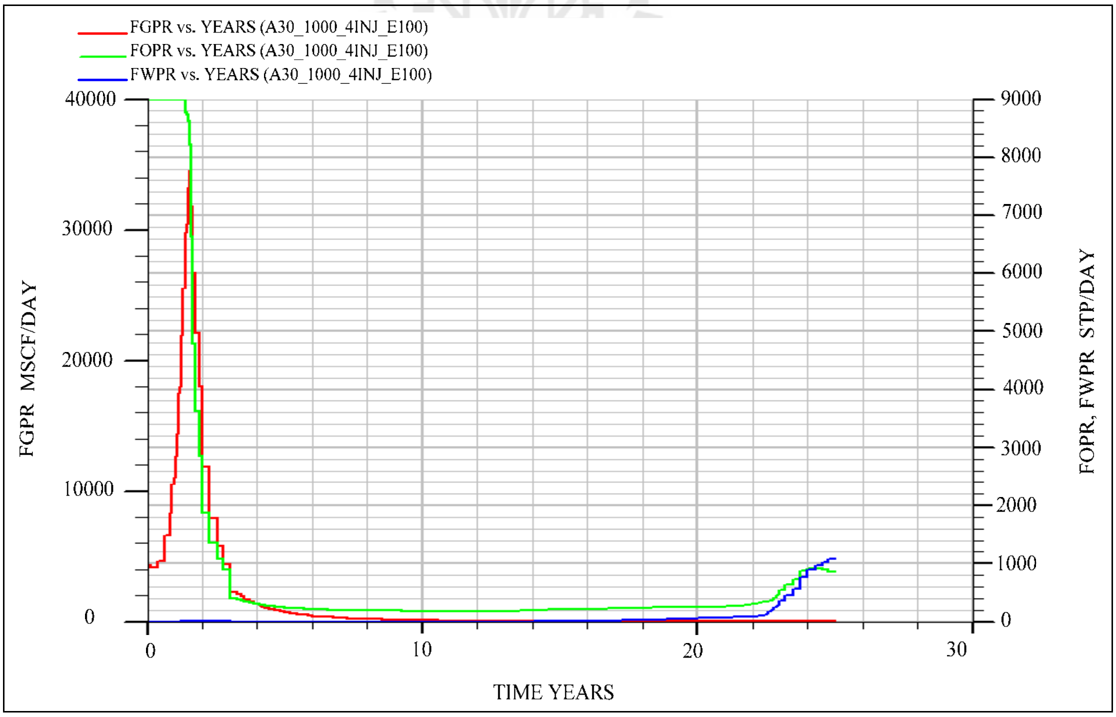


Figure 4.95 Fluids production rate profile vs. Time of model A30_1000_4INJ.

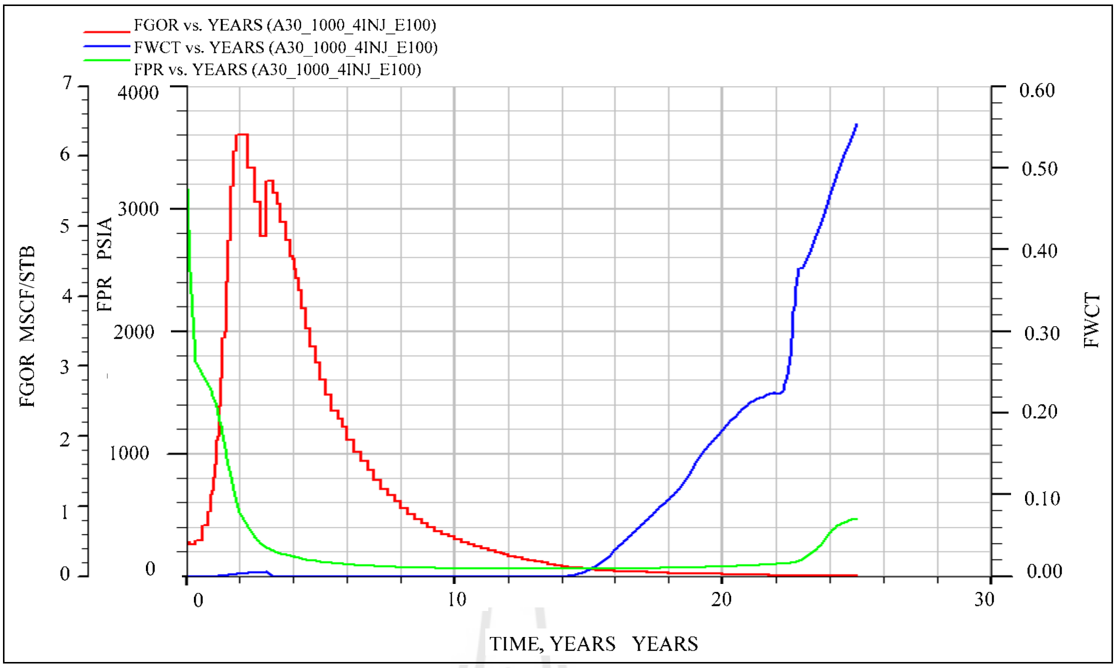


Figure 4.96 GOR, WCT, and Pressure profile vs. Time of model A30_1000_4INJ.

Figure 4.97 Oil recovery efficiency vs. Time of model A30_1000_4INJ.

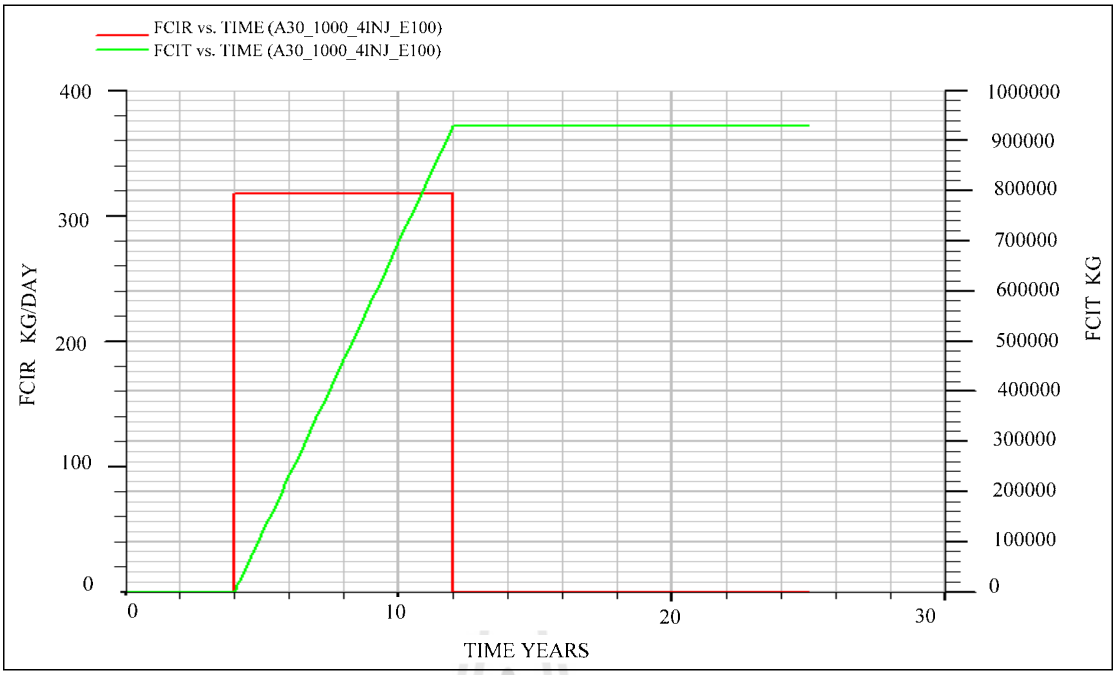


Figure 4.98 CIR and CIT vs. Time of model A30_1000_4INJ.

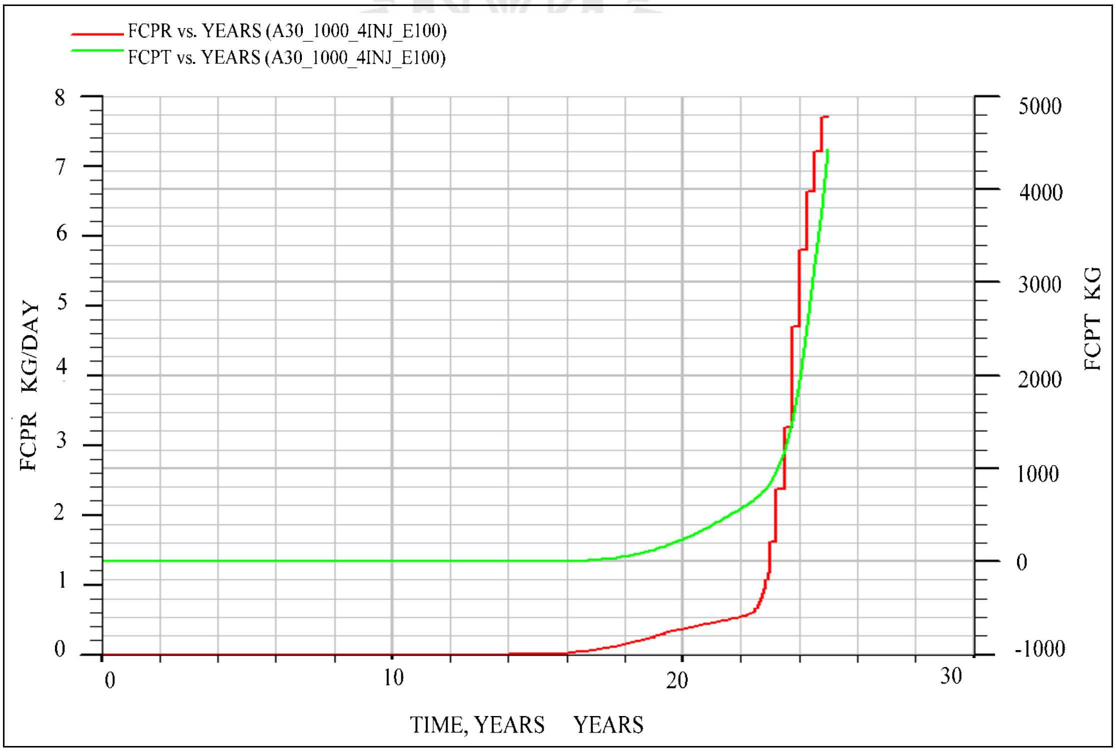


Figure 4.99 CPR and CPT vs. Time of model A30_1000_4INJ.

Table 4.27 Summary detail of graph 4.93, 4.94 and 4.97.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	8,550,628	31,798,776	26.89
Gas (MSCF)	15,077,363	15,342,696	98.27
Water (STB)	712,639	15,603,954	4.57

Table 4.28 Summary detail of graph 4.98 and 4.99.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	56,844,360	0.12	929

4.2.5 Model A30_1500_2INJ Scenario Result

Model A30_1500_2INJ is polymer flooding and the simulation results as shown in Table 4.29-4.30 and Figure 4.100 – 4.106:

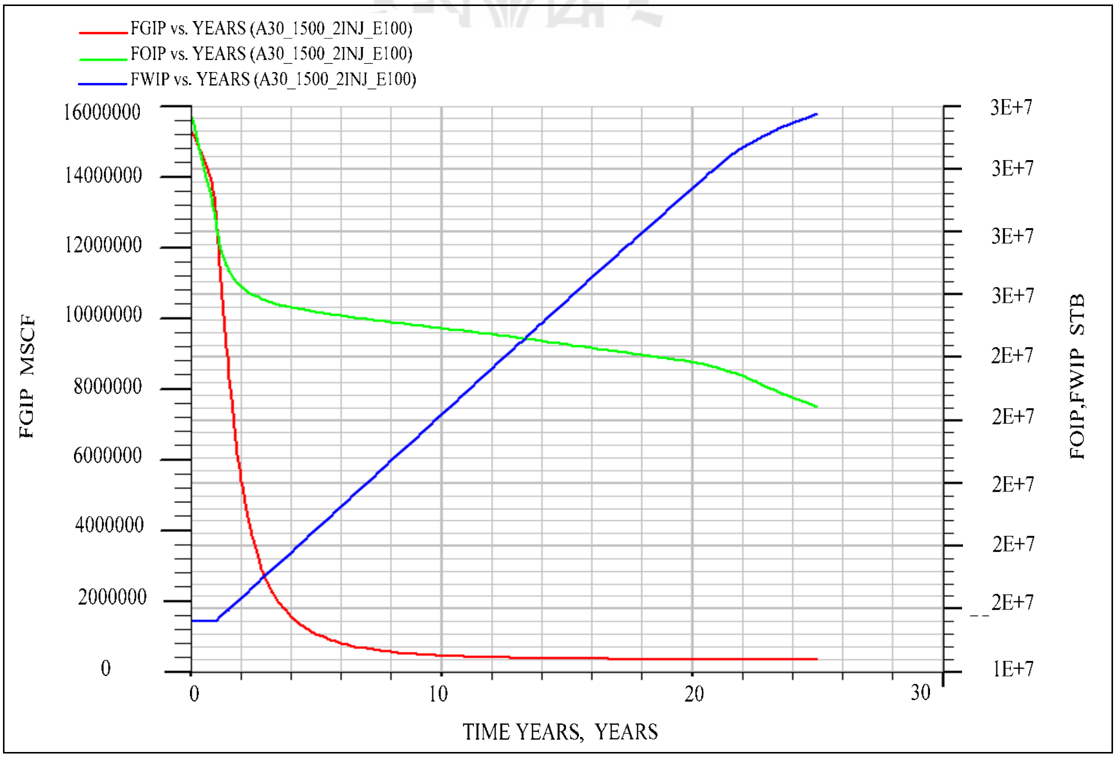


Figure 4.100 Fluid in place profile vs. Time of model A30_1500_2INJ.

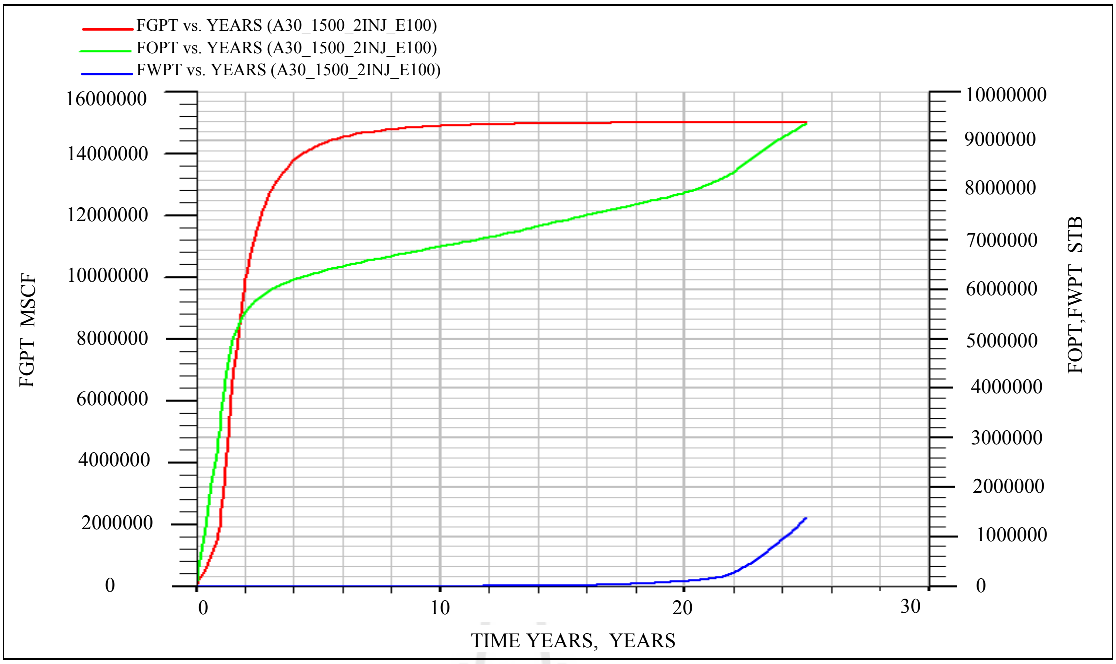


Figure 4.101 Cumulative fluids production profile vs. Time of model A30_1500_2INJ.

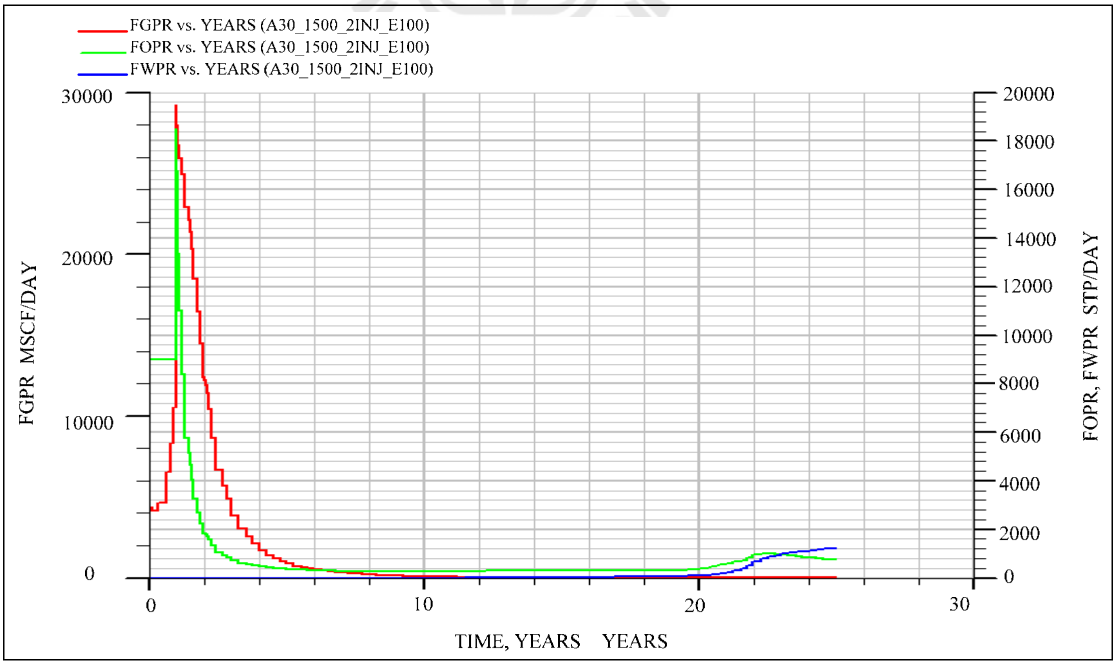


Figure 4.102 Fluids production rate profile vs. Time of model A30_1500_2INJ.

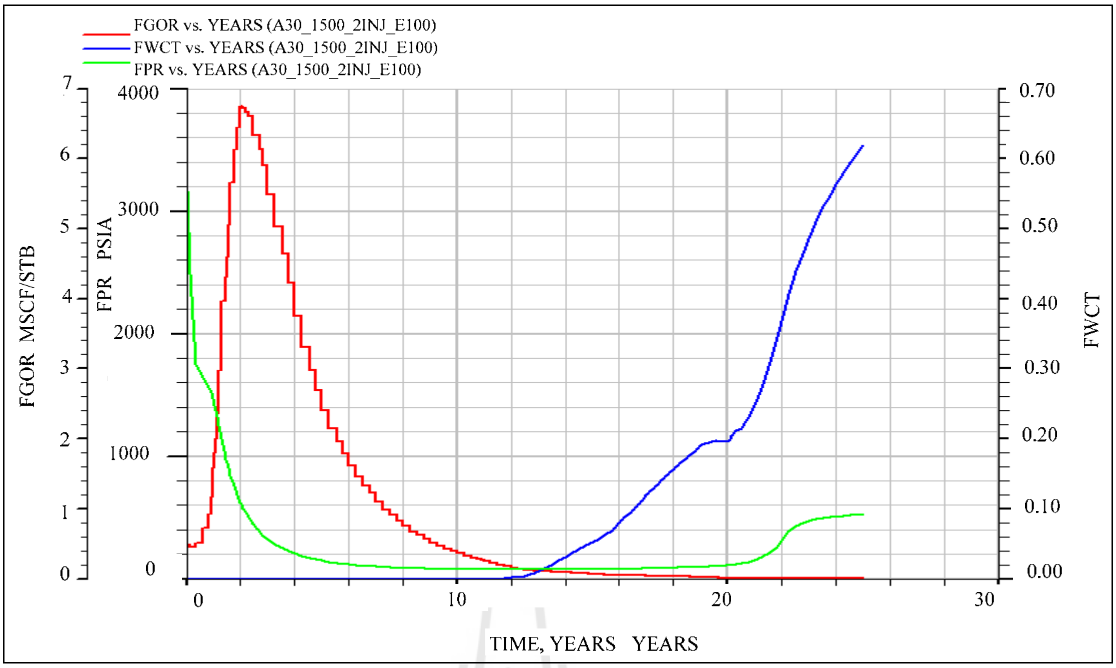


Figure 4.103 GOR, WCT, and Pressure profile vs. Time of model A30_1500_2INJ.

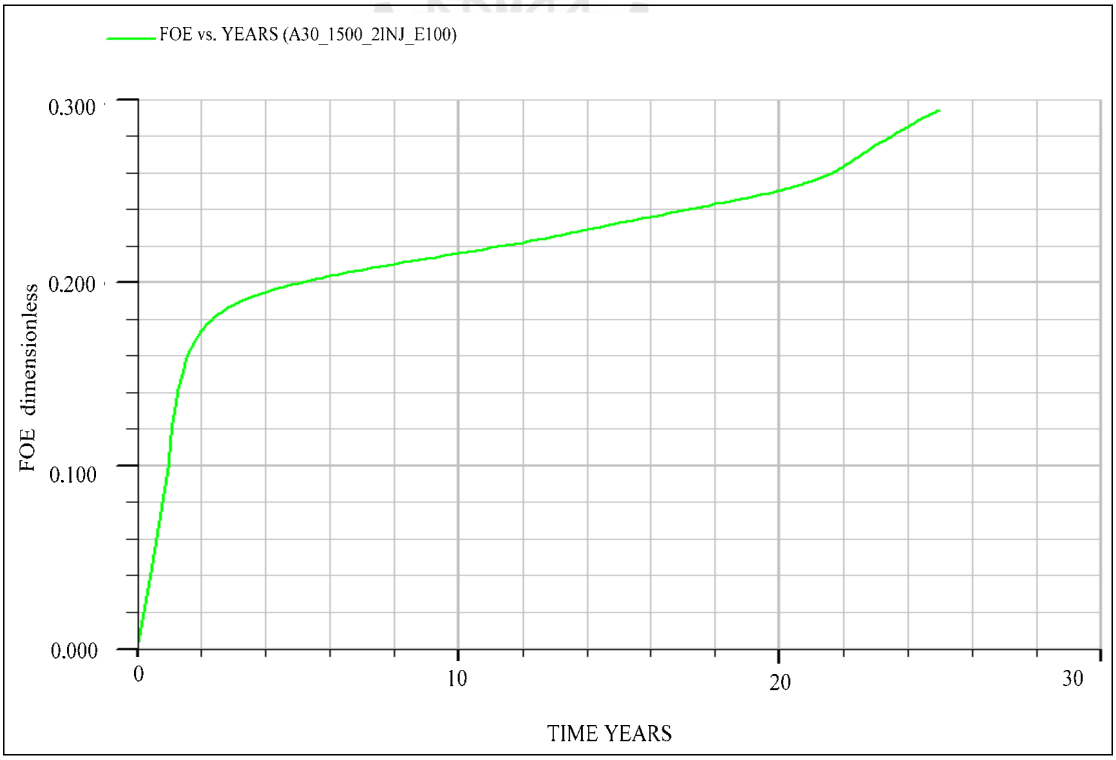


Figure 4.104 Oil recovery efficiency vs. Time of model A30_1500_2INJ.

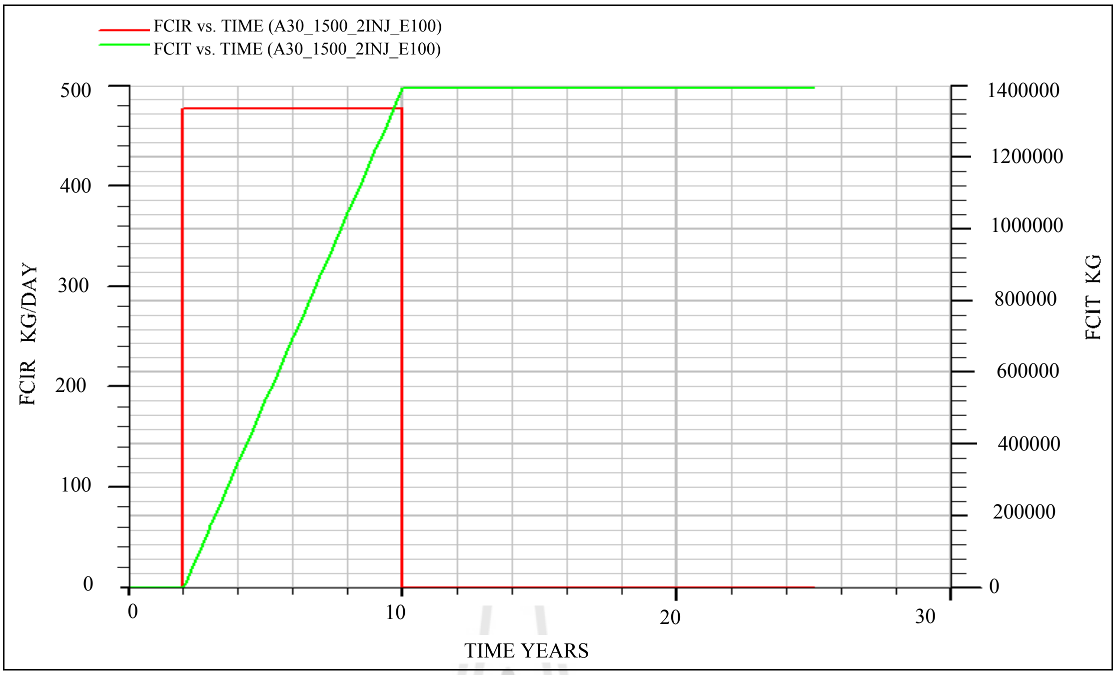


Figure 4.105 CIR and CIT vs. Time of model A30_1500_2INJ.

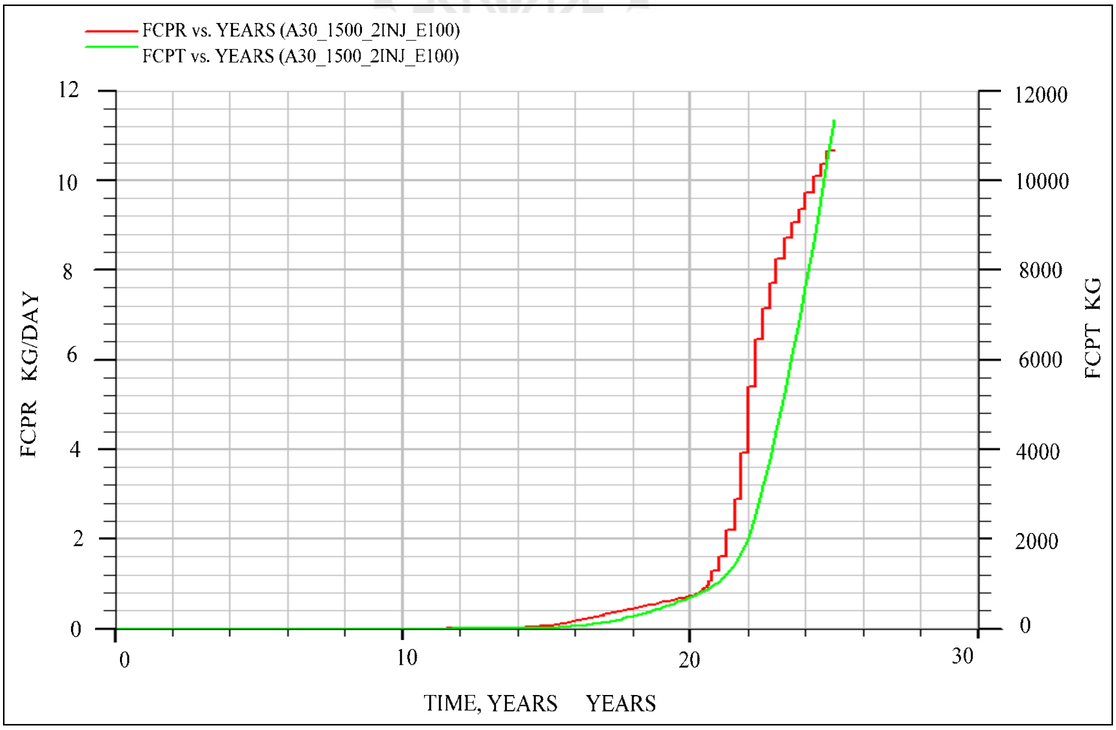


Figure 4.106 CPR and CPT vs. Time of model A30_1500_2INJ.

Table 4.29 Summary detail of graph 4.100, 4.101 and 4.104.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,358,356	31,798,776	29.43
Gas (MSCF)	15,004,653	15,342,696	97.79
Water (STB)	1,377,834	15,603,954	8.83

Table 4.30 Summary detail of graph 4.105 and 4.106.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	56,844,360	0.12	1,394

4.2.6 Model A30_1500_3INJ Scenario Result

Model A30_1500_3INJ is polymer flooding and the simulation results as shown in Table 4.31-4.32 and Figure 4.107 – 4.113:

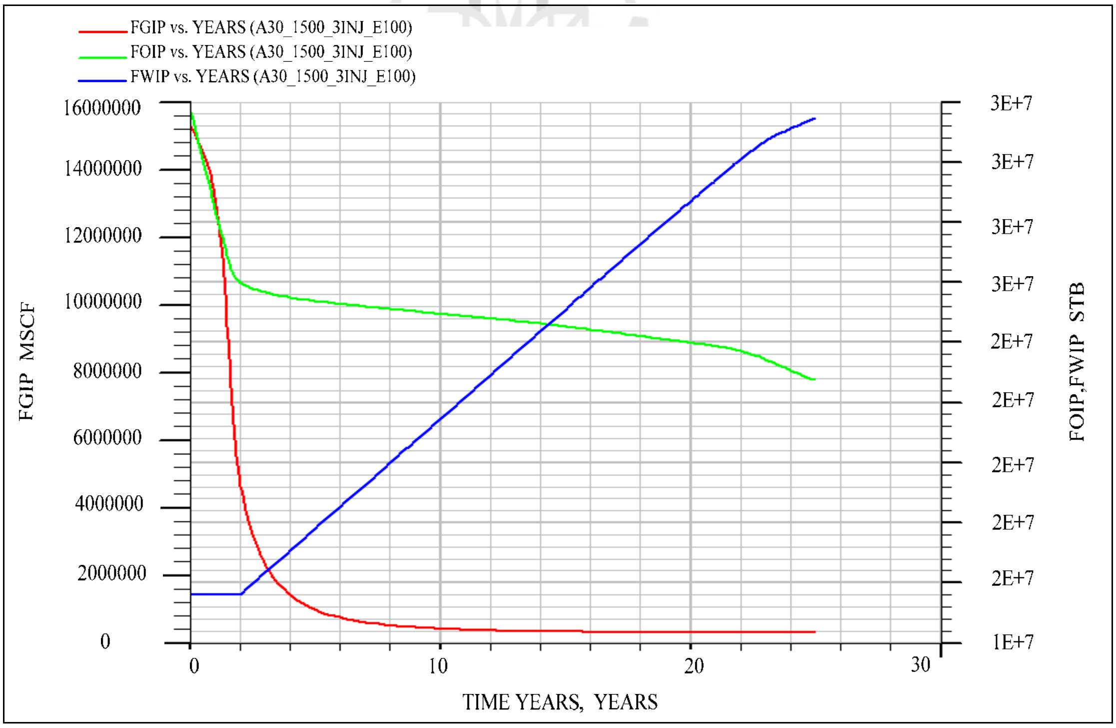


Figure 4.107 Fluid in place profile vs. Time of model A30_1500_3INJ.

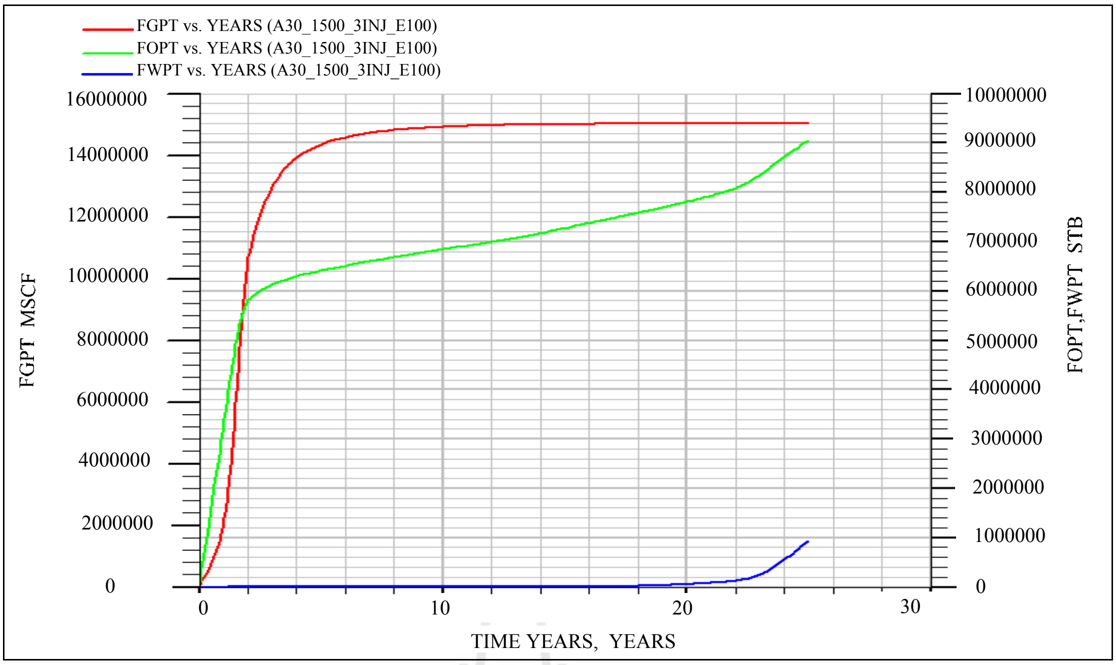


Figure 4.108 Cumulative fluids production profile vs. Time of model A30_1500_3INJ.

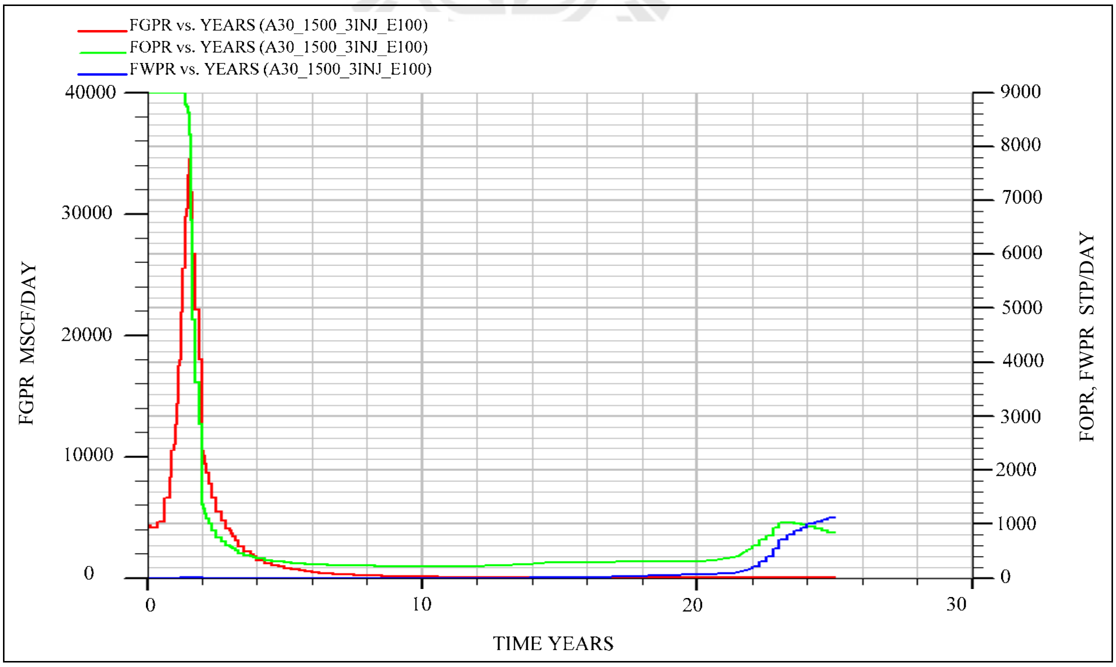


Figure 4.109 Fluids production rate profile vs. Time of model A30_1500_3INJ.

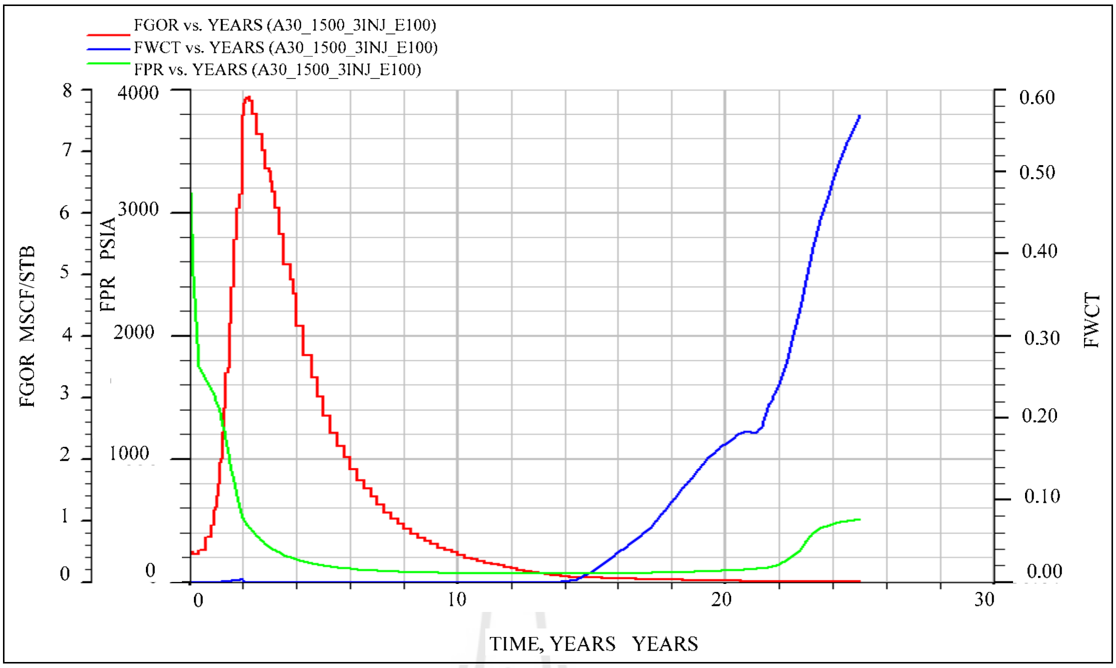


Figure 4.110 GOR, WCT, and Pressure profile vs. Time of model A30_1500_3INJ.

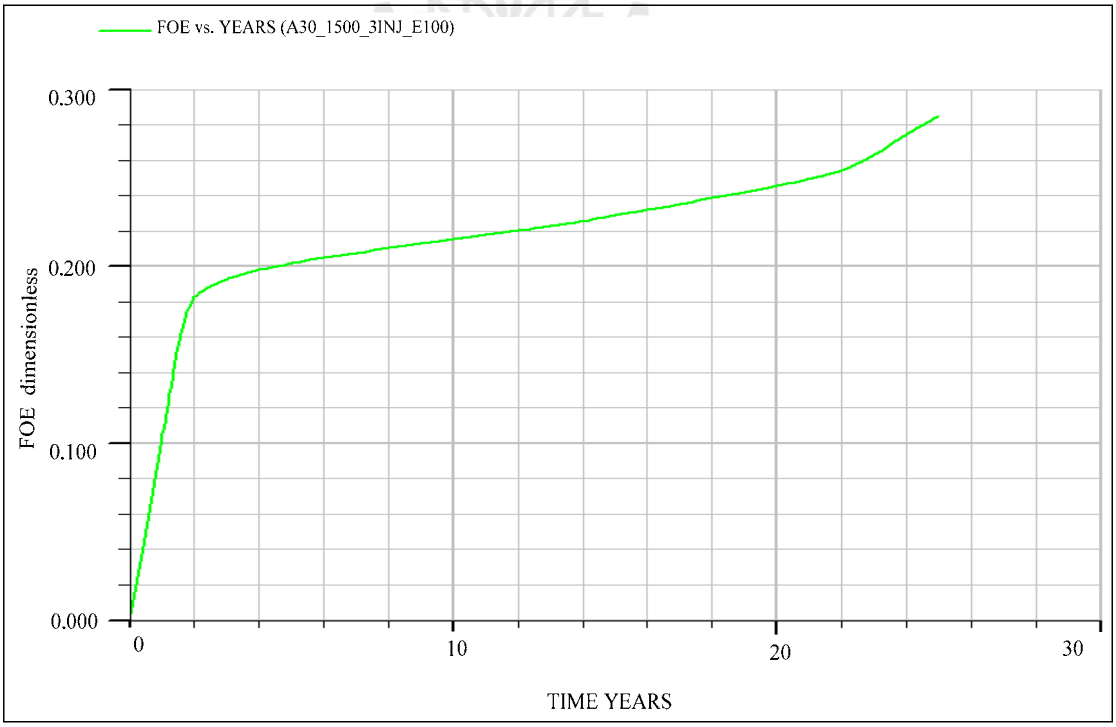


Figure 4.111 Oil recovery efficiency vs. Time of model A30_1500_3INJ.

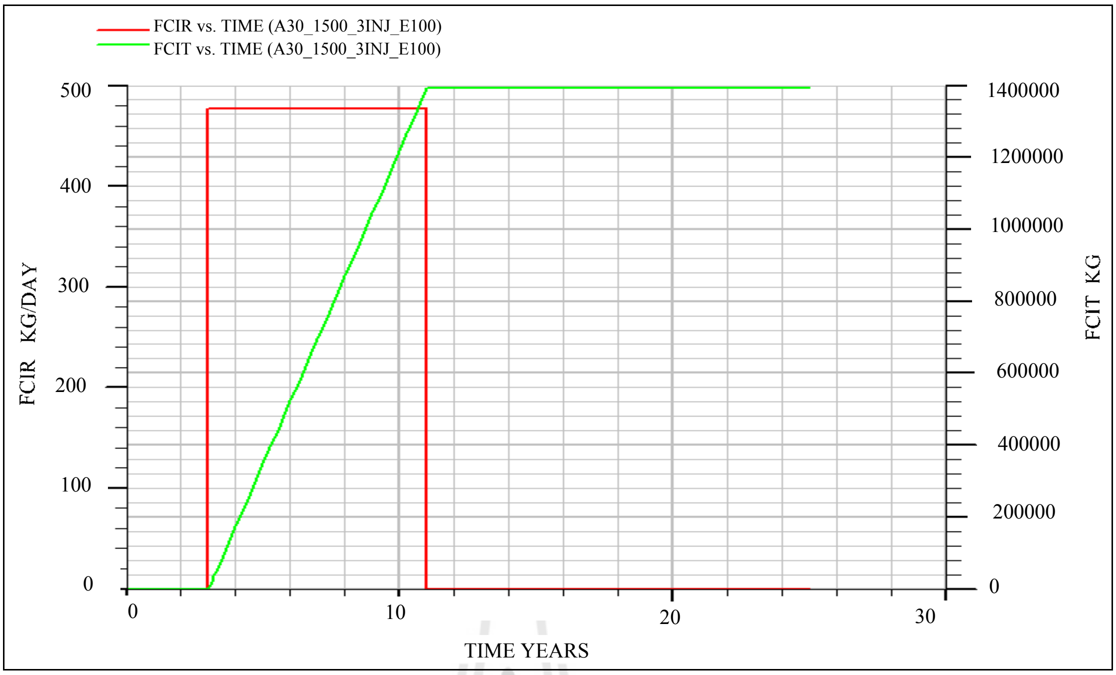


Figure 4.112 CIR and CIT vs. Time of model A30_1500_3INJ.

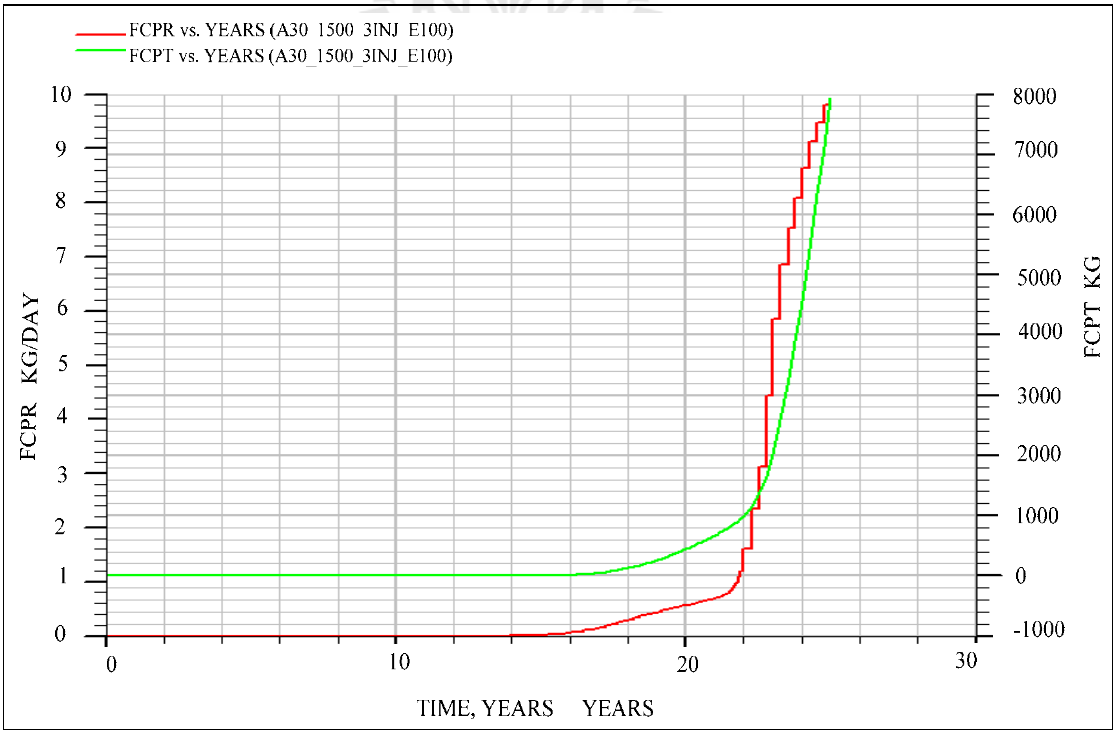


Figure 4.113 CPR and CPT vs. Time of model A30_1500_3INJ.

Table 4.31 Summary detail of graph 4.107, 4.108 and 4.111.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,055,398	31,798,776	28.48
Gas (MSCF)	15,041,798	15,342,696	98.08
Water (STB)	941,149	15,603,954	6.03

Table 4.32 Summary detail of graph 4.112 and 4.113.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	56,844,360	0.12	1,394

4.2.7 Model A30_1500_4INJ Scenario Result

Model A30_1500_4INJ is polymer flooding and the simulation results as shown in Table 4.33-4.34 and Figure 4.114 – 4.120:

Figure 4.114 Fluid in place profile vs. Time of model A30_1500_4INJ.

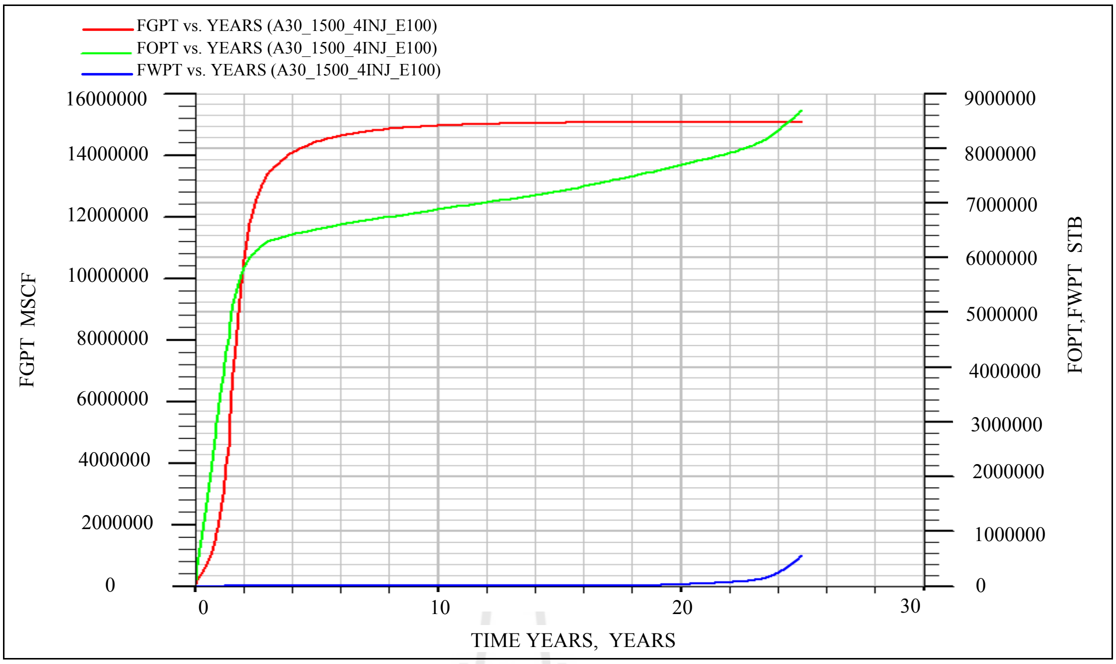


Figure 4.115 Cumulative fluids production profile vs. Time of model A30_1500_4INJ.

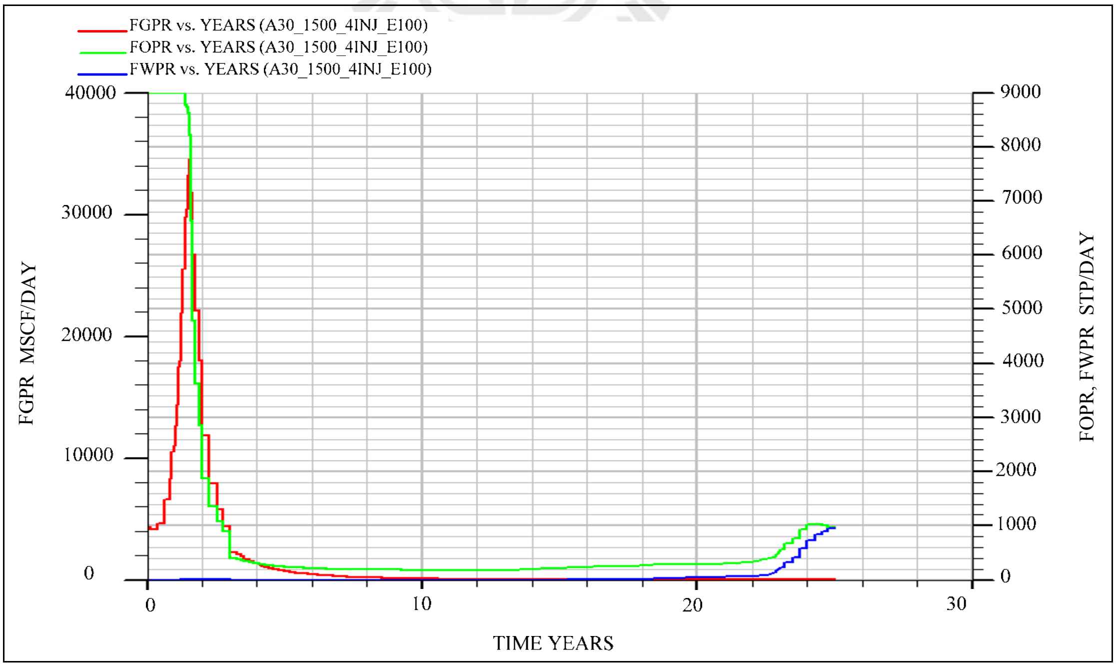


Figure 4.116 Fluids production rate profile vs. Time of model A30_1500_4INJ.

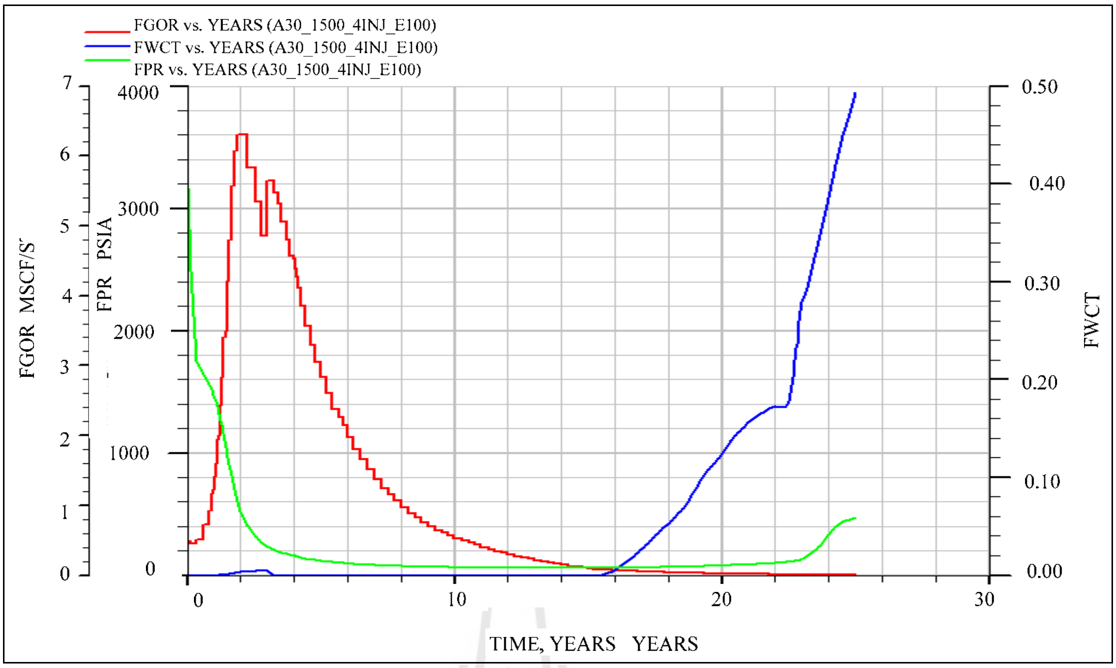


Figure 4.117 GOR, WCT, and Pressure profile vs. Time of model A30_1500_4INJ.

Figure 4.118 Oil recovery efficiency vs. Time of model A30_1500_4INJ.

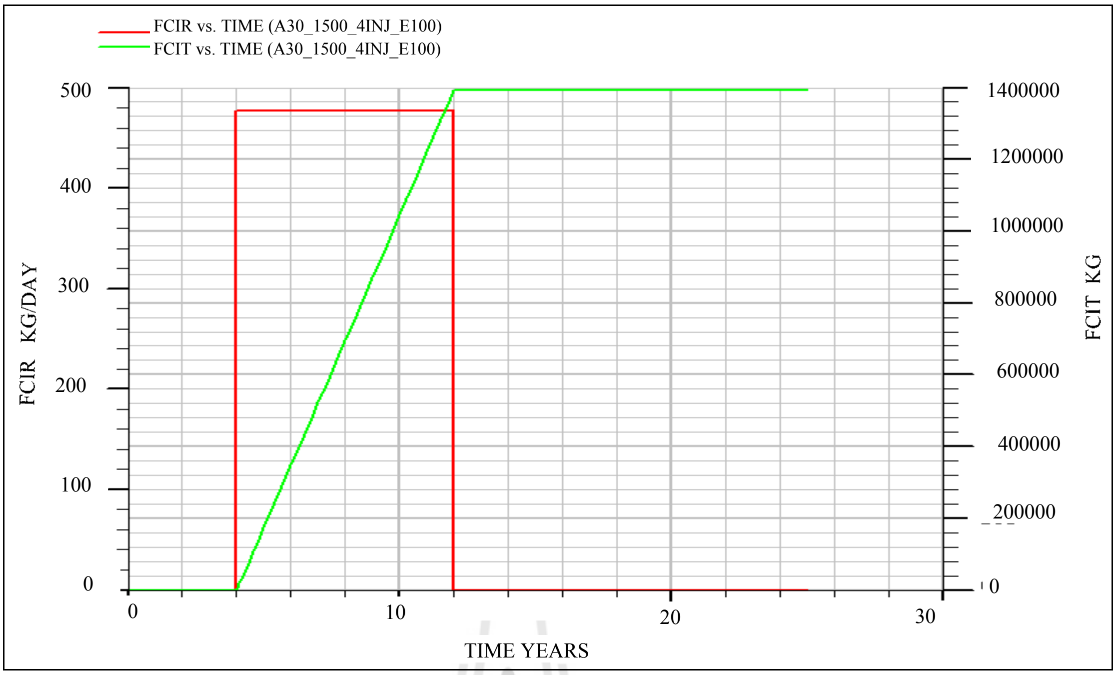


Figure 4.119 CIR and CIT vs. Time of model A30_1500_4INJ.

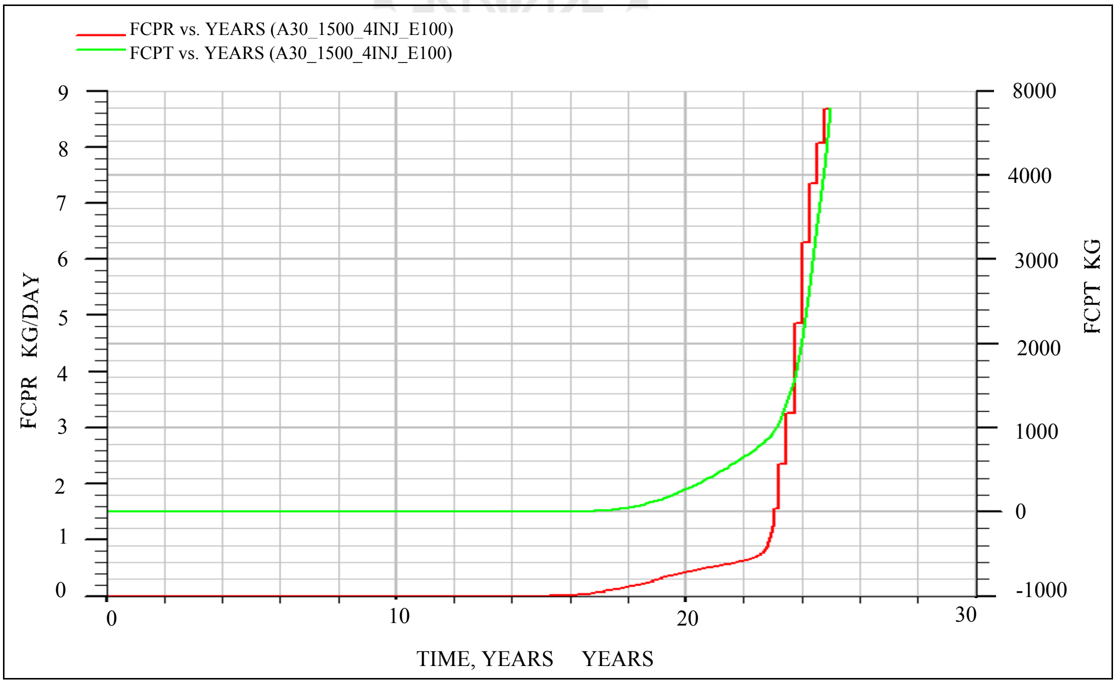


Figure 4.120 CPR and CPT vs. Time of model A30_1500_4INJ.

Table 4.33 Summary detail of graph 4.114, 4.115 and 4.118.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	8,694,523	31,798,776	27.34
Gas (MSCF)	15,080,541	15,342,696	98.29
Water (STB)	563,517	15,603,954	3.61

Table 4.34 Summary detail of graph 4.119 and 4.120.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,500	56,844,360	0.12	1,394

4.2.8 Model A30_2000_2INJ Scenario Result

Model A30_2000_2INJ is polymer flooding and the simulation results as shown in Table 4.35-4.36 and Figure 4.121 – 4.127:

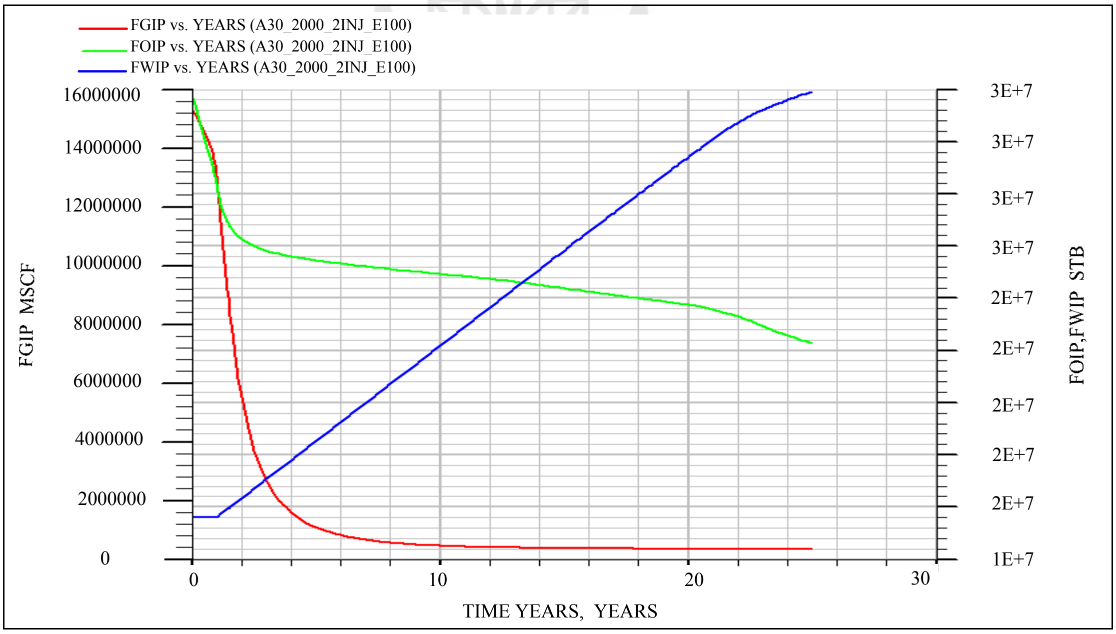


Figure 4.121 Fluid in place profile vs. Time of model A30_2000_2INJ.

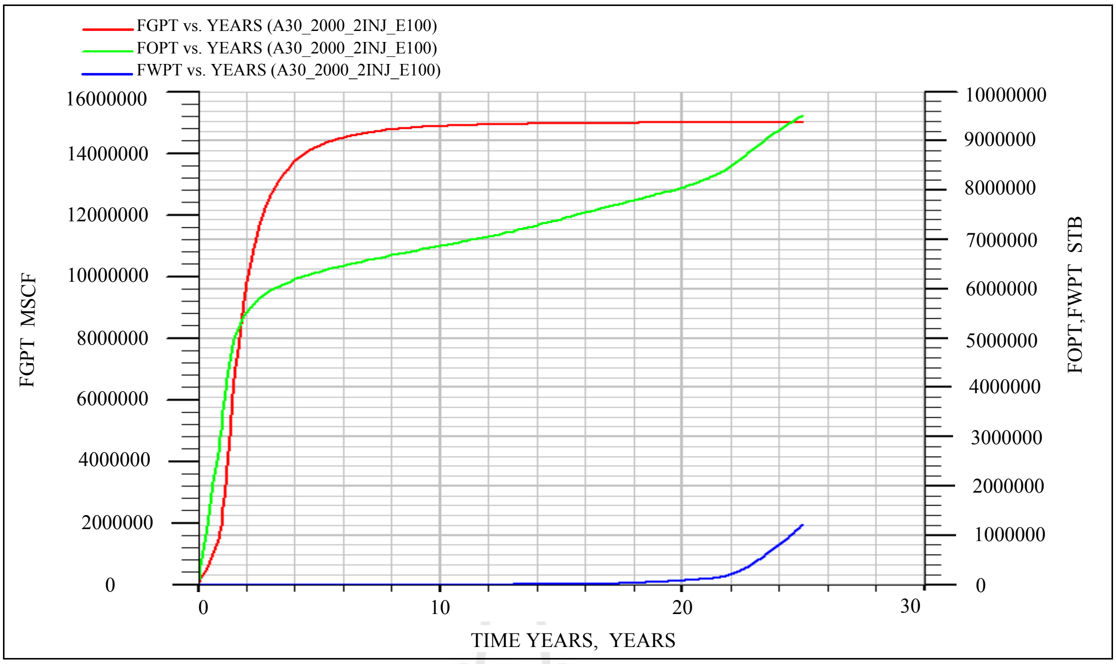


Figure 4.122 Cumulative fluids production profile vs. Time of model A30_2000_2INJ.

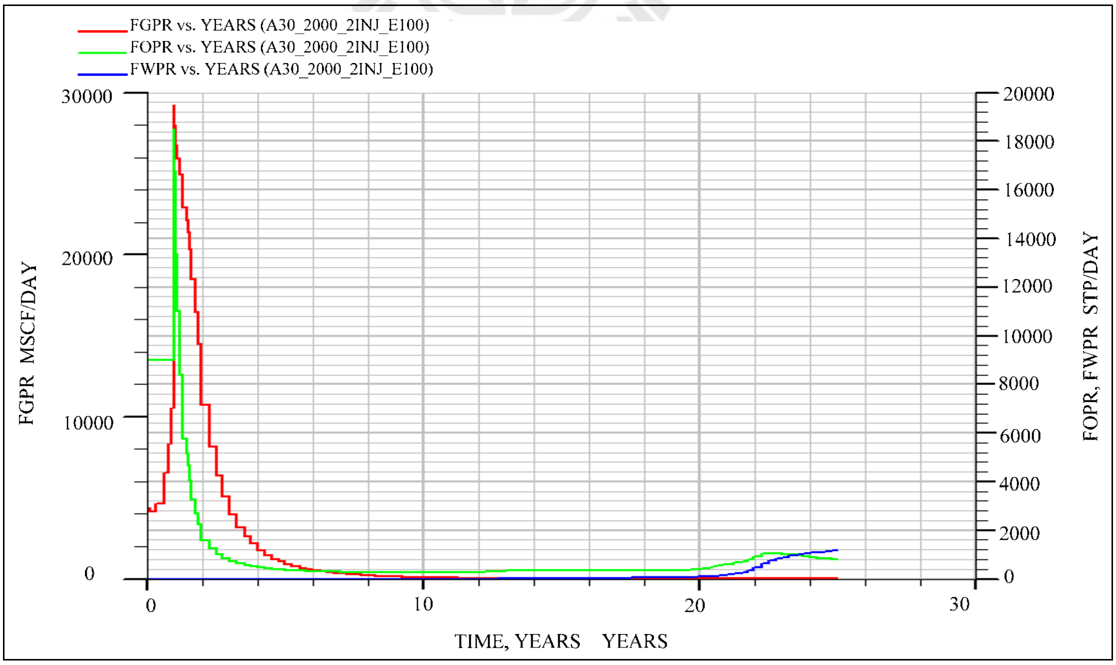


Figure 4.123 Fluids production rate profile vs. Time of model A30_2000_2INJ.

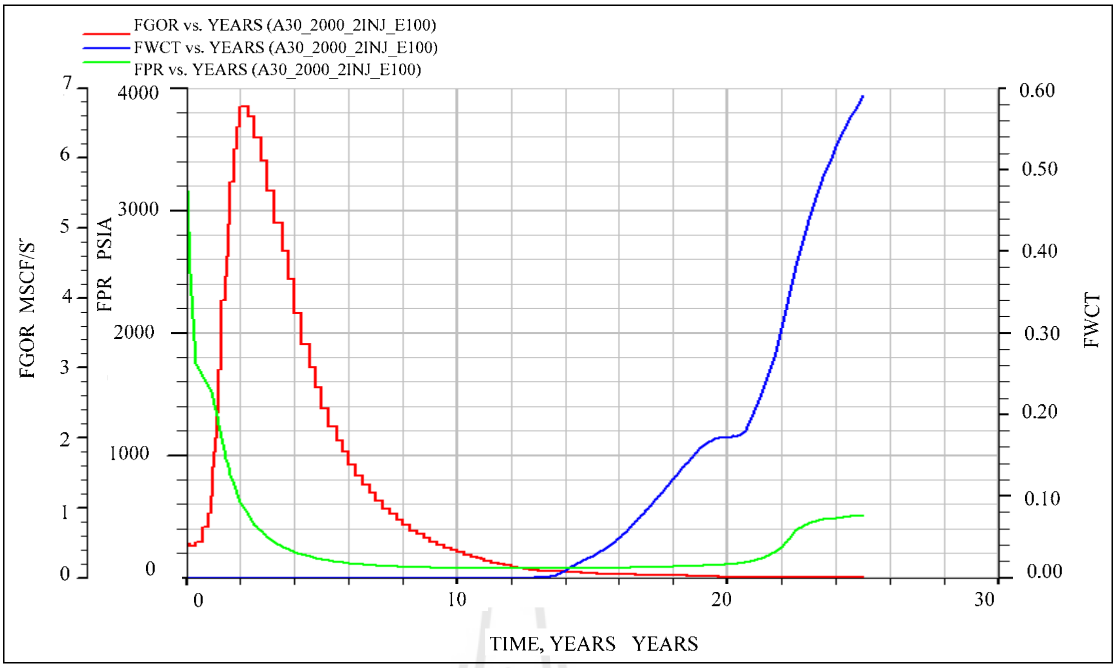


Figure 4.124 GOR, WCT, and Pressure profile vs. Time of model A30_2000_2INJ.

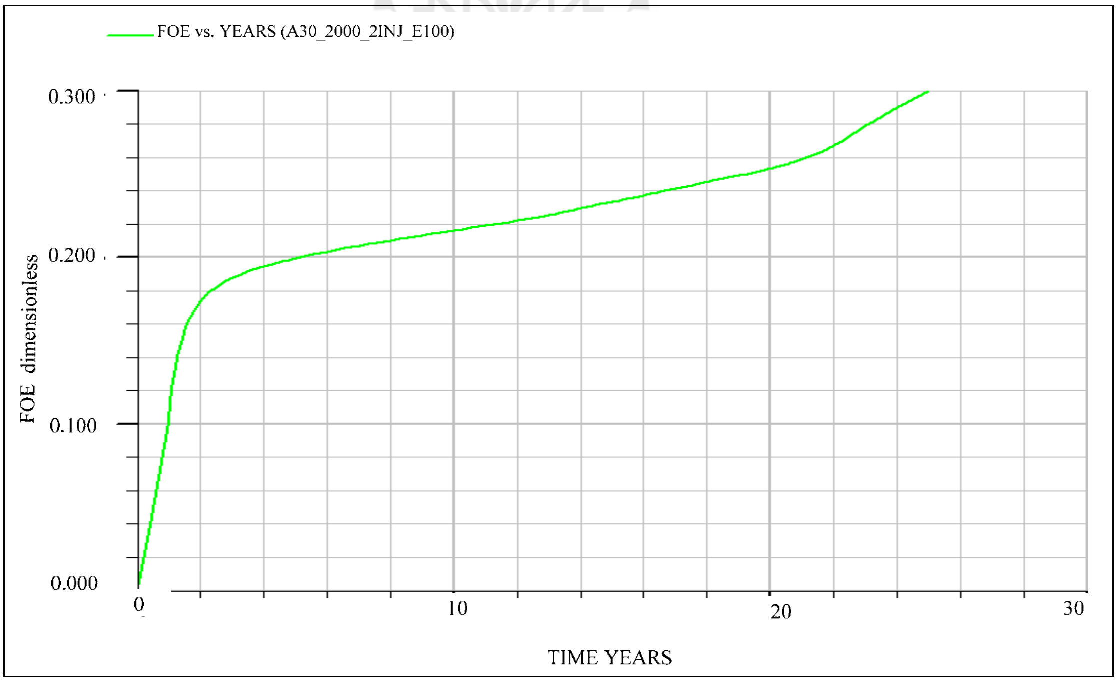


Figure 4.125 Oil recovery efficiency vs. Time of model A30_2000_2INJ.

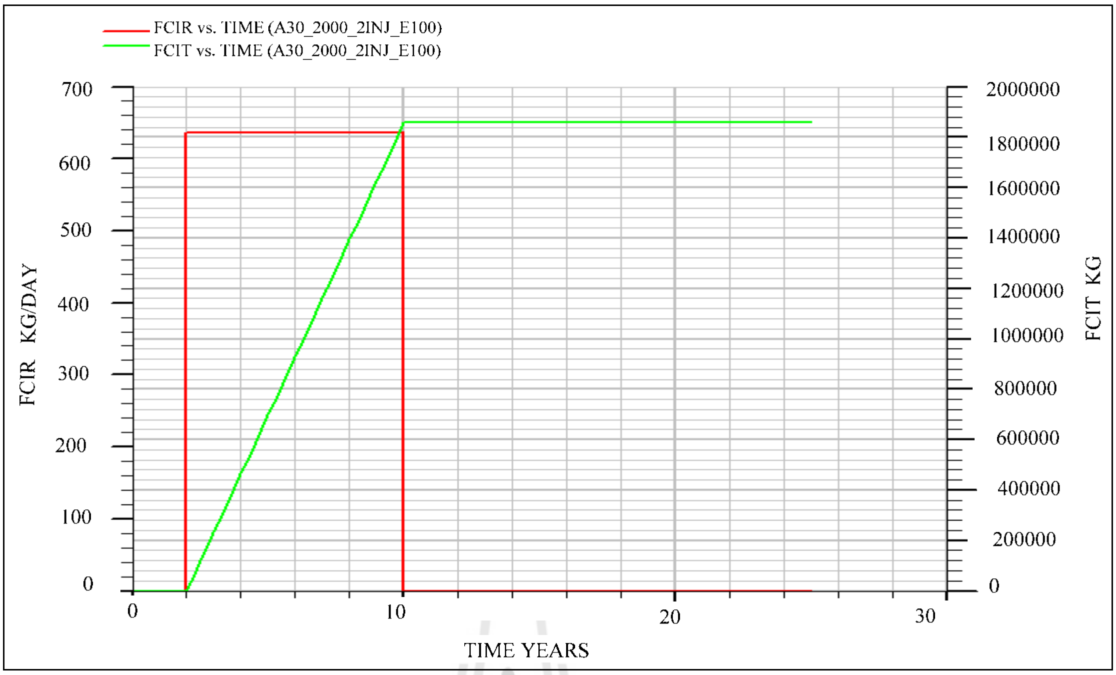


Figure 4.126 CIR and CIT vs. Time of model A30_2000_2INJ.

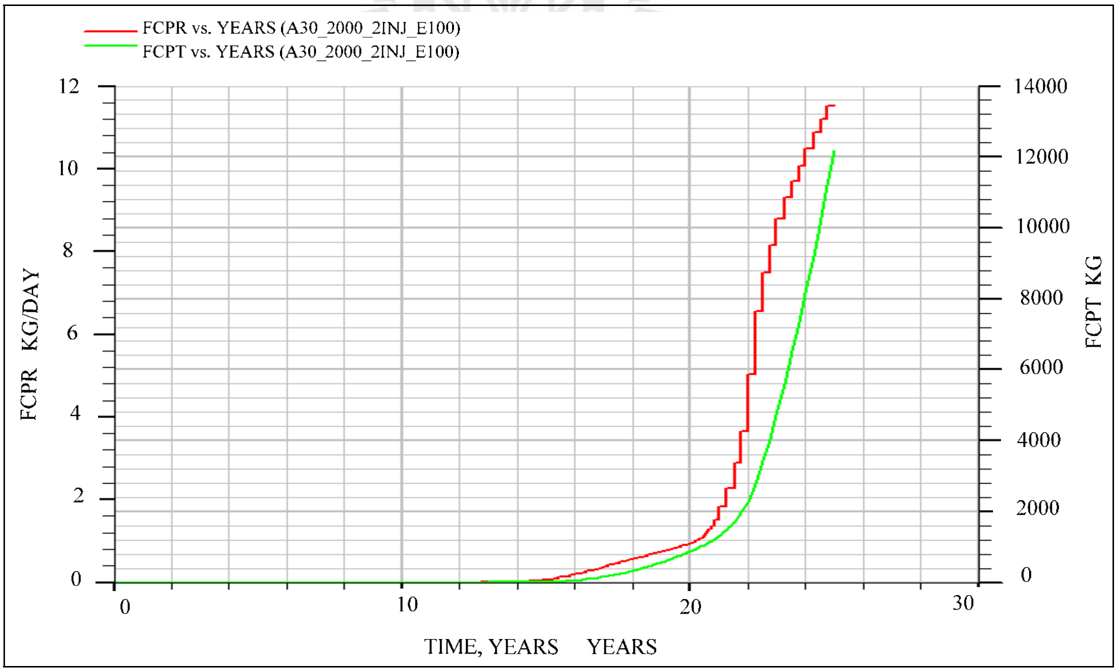


Figure 4.127 CPR and CPT vs. Time of model A30_2000_2INJ.

Table 4.35 Summary detail of graph 4.121, 4.122 and 4.125.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,524,530	31,798,776	29.95
Gas (MSCF)	15,000,739	15,342,696	97.77
Water (STB)	1,214,202	15,603,954	7.78

Table 4.36 Summary detail of graph 4.126 and 4.127.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	56,844,360	0.12	1,858

4.2.9 Model A30_2000_3INJ Scenario Result

Model A30_2000_3INJ is polymer flooding and the simulation results as shown in Table 4.37-4.38 and Figure 4.128 – 4.134:

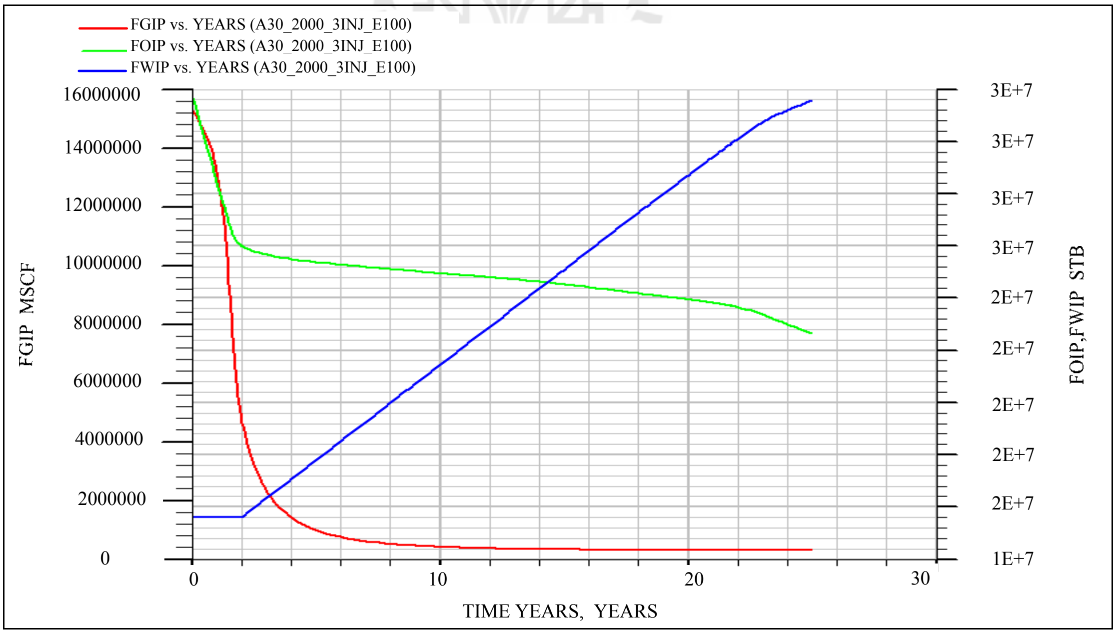


Figure 4.128 Fluid in place profile vs. Time of model A30_2000_3INJ.

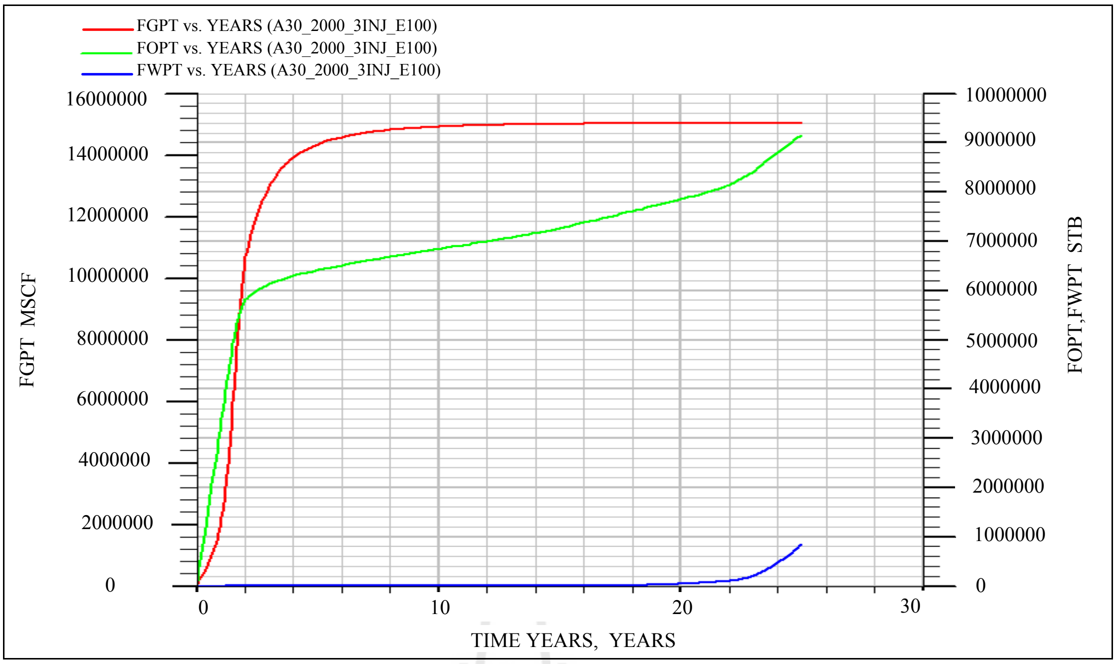


Figure 4.129 Cumulative fluids production profile vs. Time of model A30_2000_3INJ.

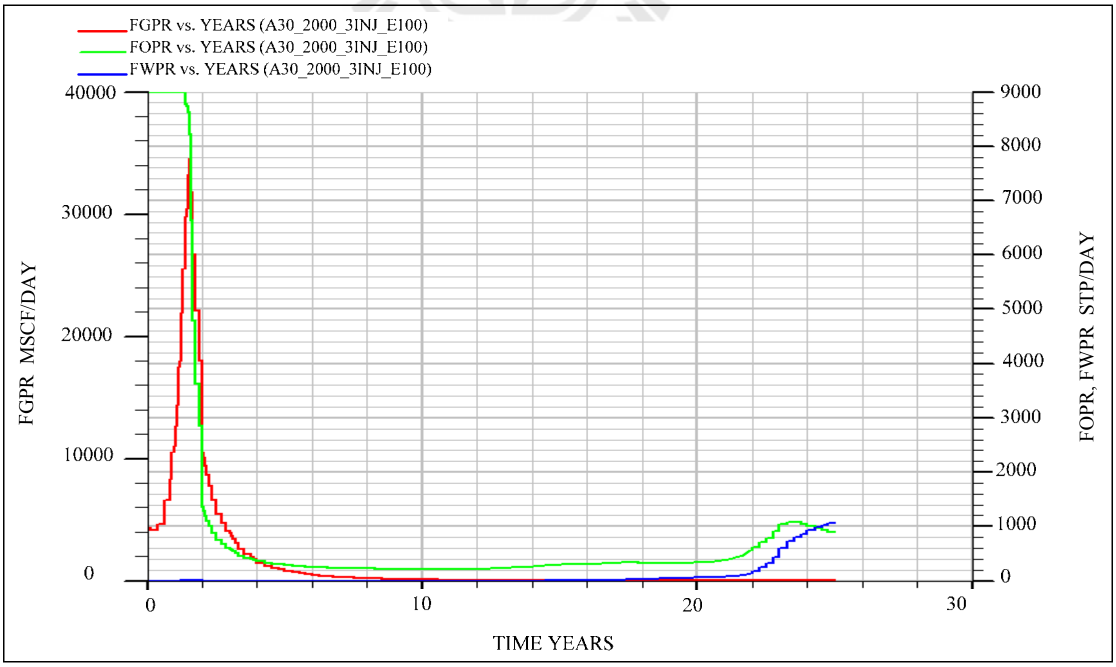


Figure 4.130 Fluids production rate profile vs. Time of model A30_2000_3INJ.

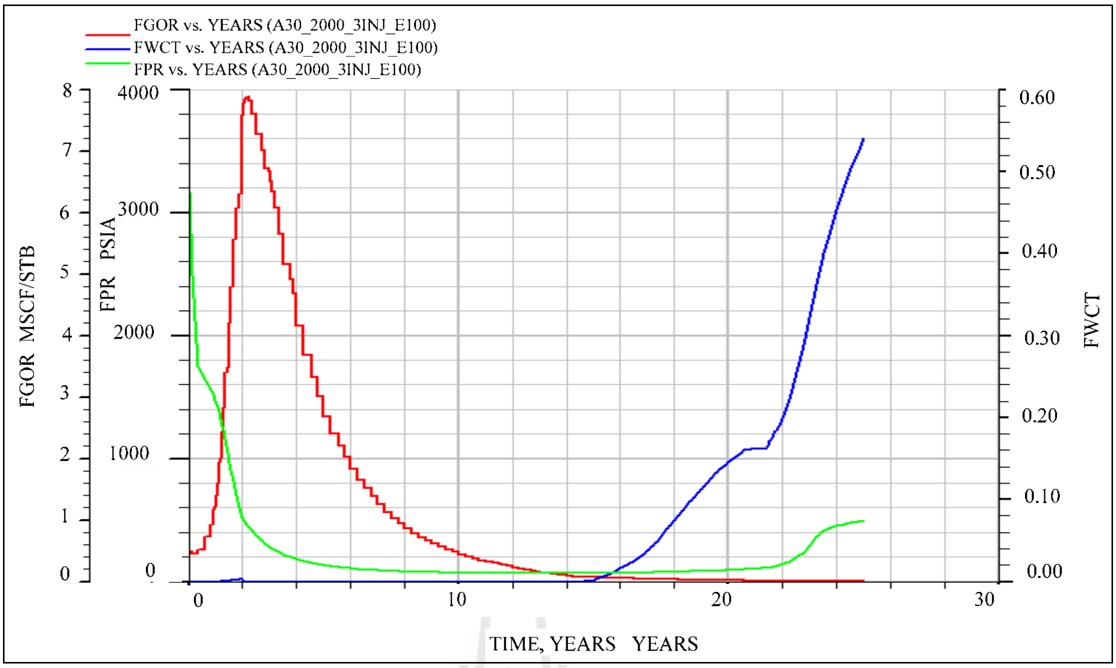


Figure 4.131 GOR, WCT, and Pressure profile vs. Time of model A30_2000_3INJ.

Figure 4.132 Oil recovery efficiency vs. Time of model A30_2000_3INJ.

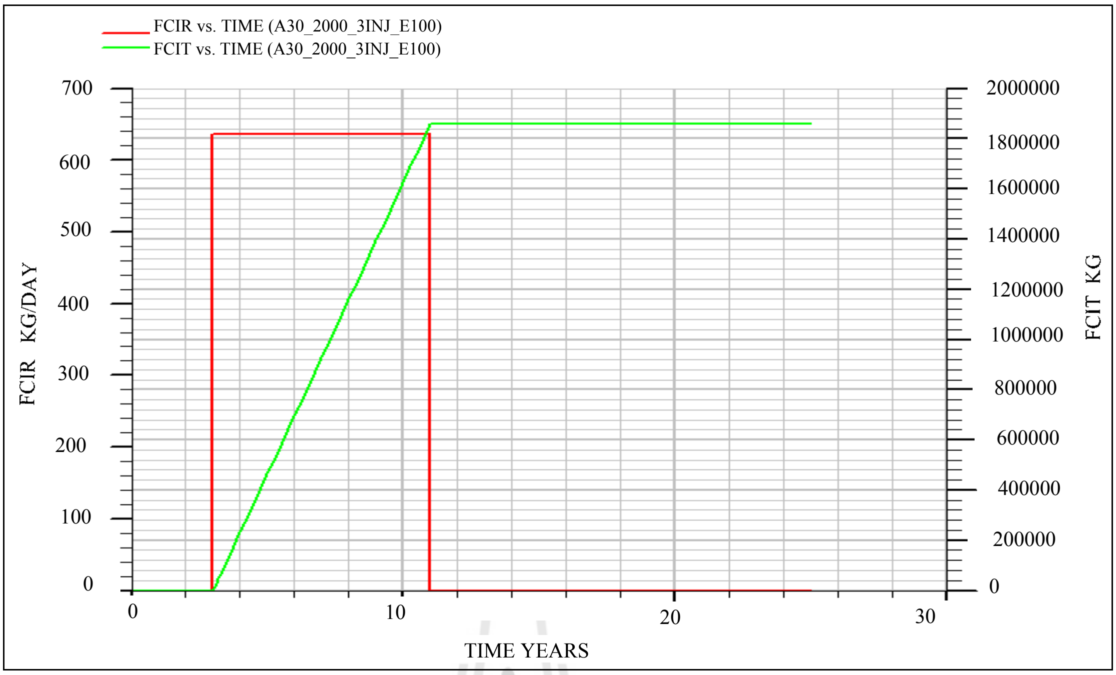


Figure 4.133 CIR and CIT vs. Time of model A30_2000_3INJ.

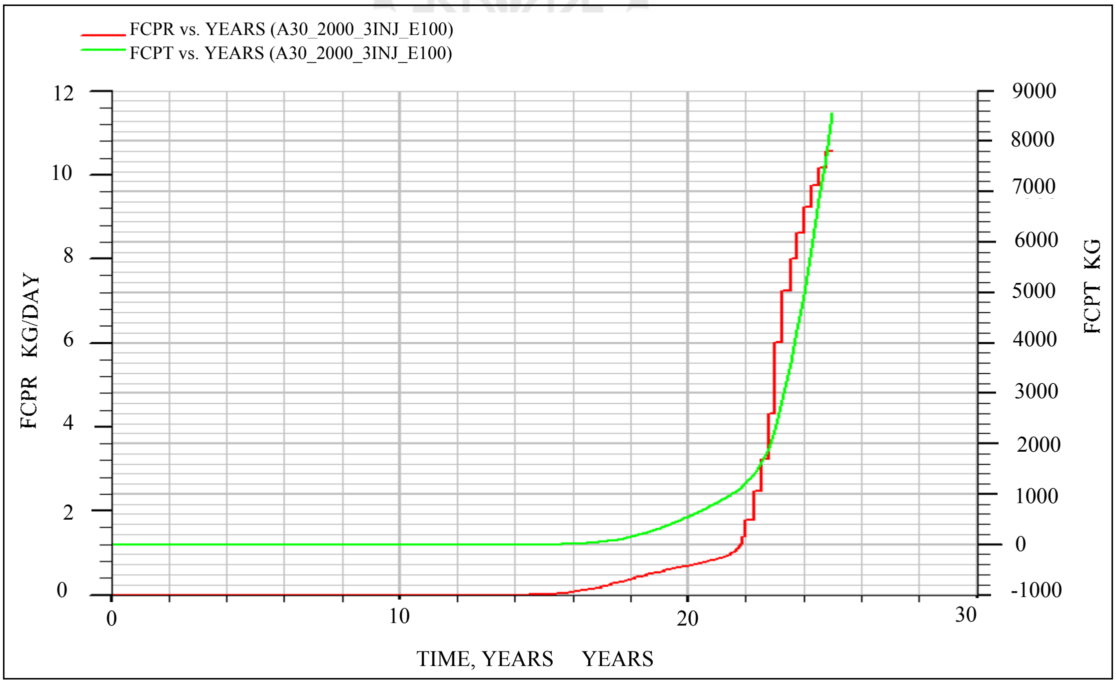


Figure 4.134 CPR and CPT vs. Time of model A30_2000_3INJ.

Table 4.37 Summary detail of graph 4.128, 4.129 and 4.132.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,157,173	31,798,776	28.80
Gas (MSCF)	15,043,579	15,342,696	98.05
Water (STB)	840,166	15,603,954	5.38

Table 4.38 Summary detail of graph 4.133 and 4.134.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	56,844,360	0.12	1,858

4.2.10 Model A30_2000_4INJ Scenario Result

Model A30_2000_4INJ is polymer flooding and the simulation results as shown in Table 4.39-4.40 and Figure 4.135 – 4.141:

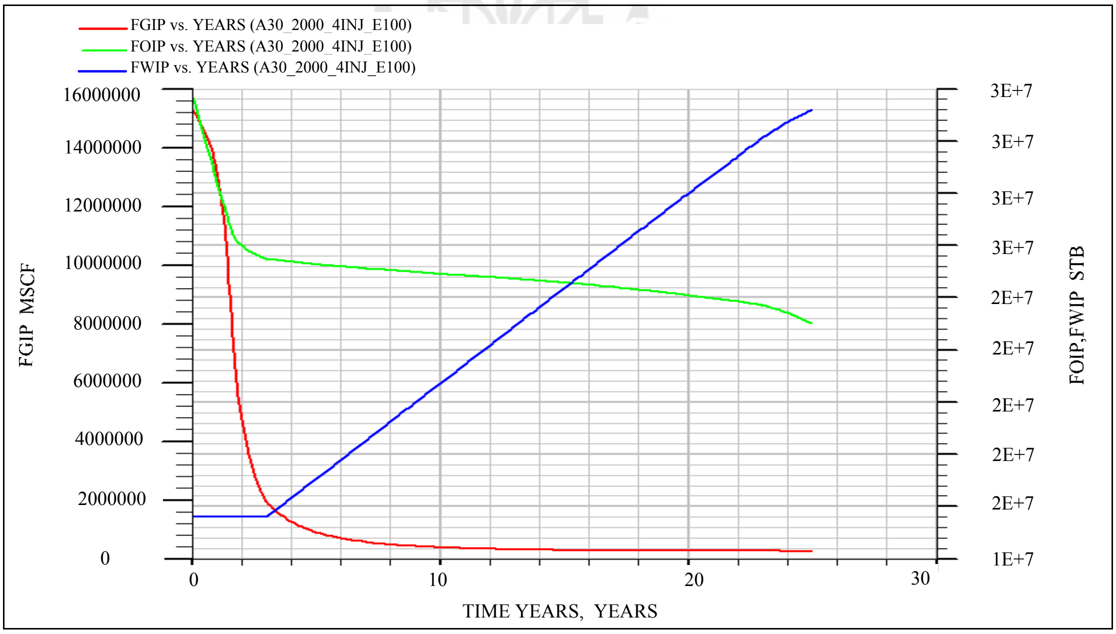


Figure 4.135 Fluid in place profile vs. Time of model A30_2000_4INJ.

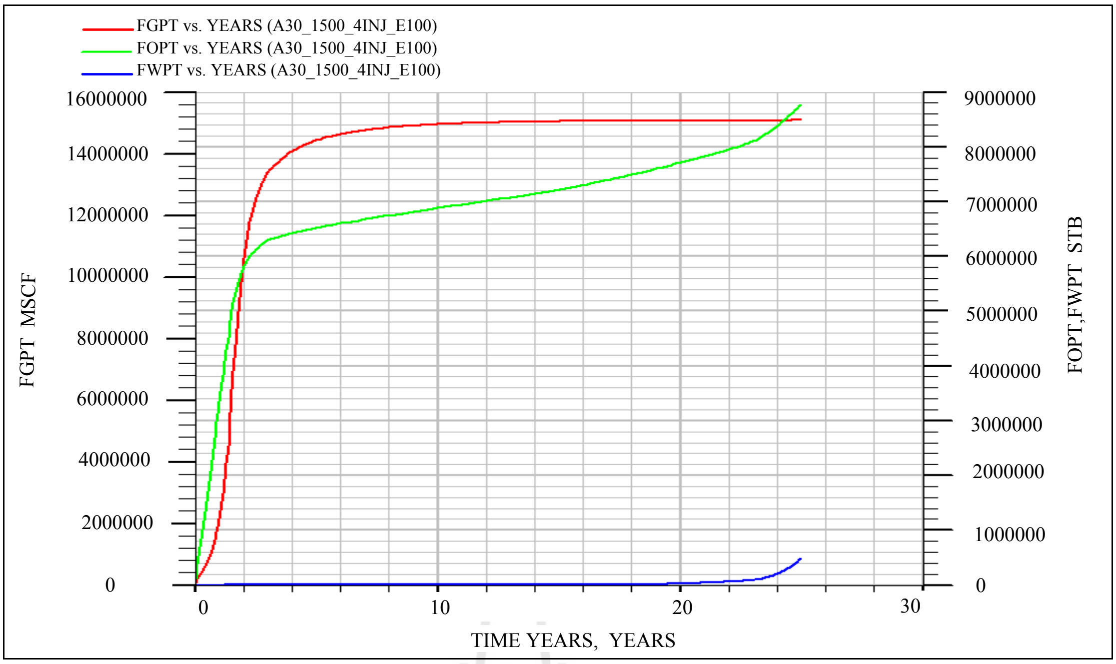


Figure 4.136 Cumulative fluids production profile vs. Time of model A30_2000_4INJ.

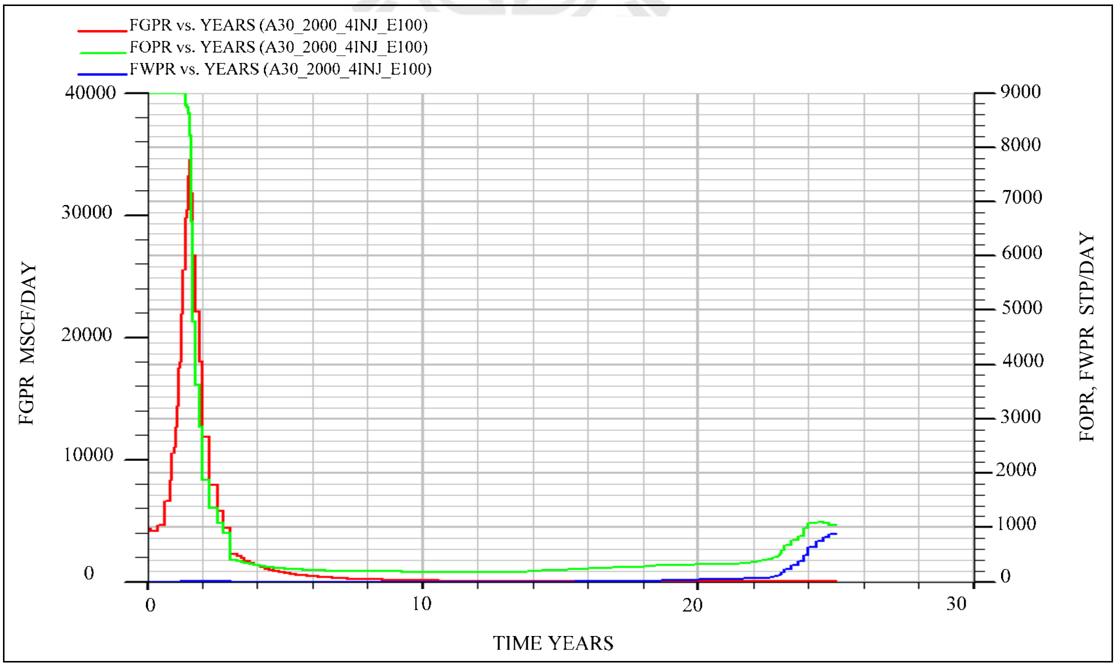


Figure 4.137 Fluids production rate profile vs. Time of model A30_2000_4INJ.

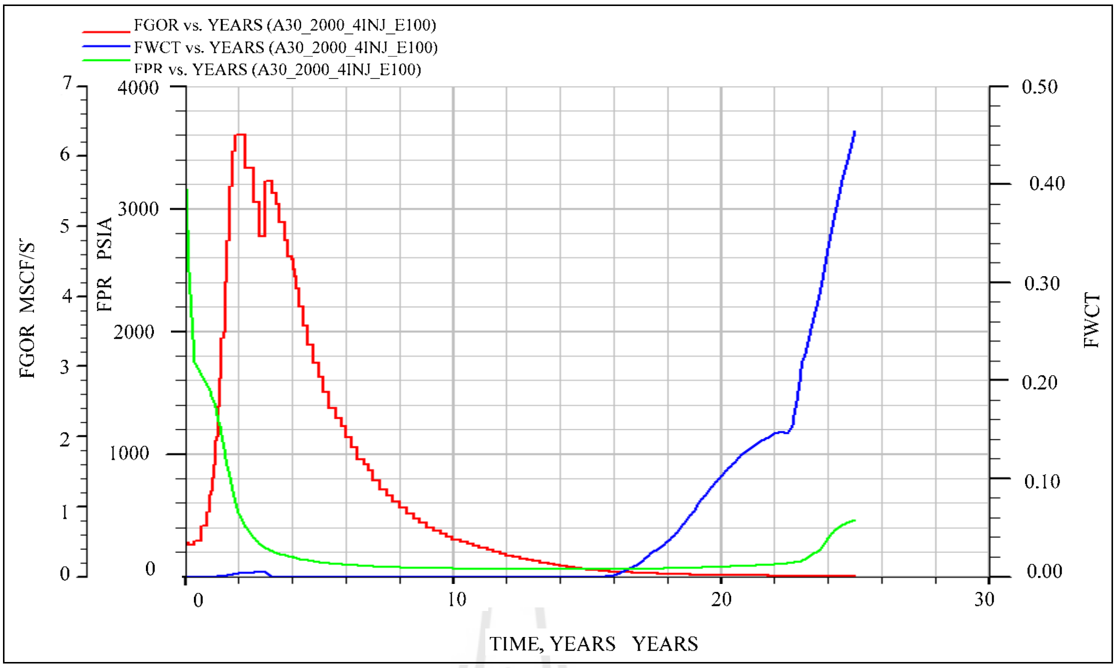


Figure 4.138 GOR, WCT, and Pressure profile vs. Time of model A30_2000_4INJ.

Figure 4.139 Oil recovery efficiency vs. Time of model A30_2000_4INJ.

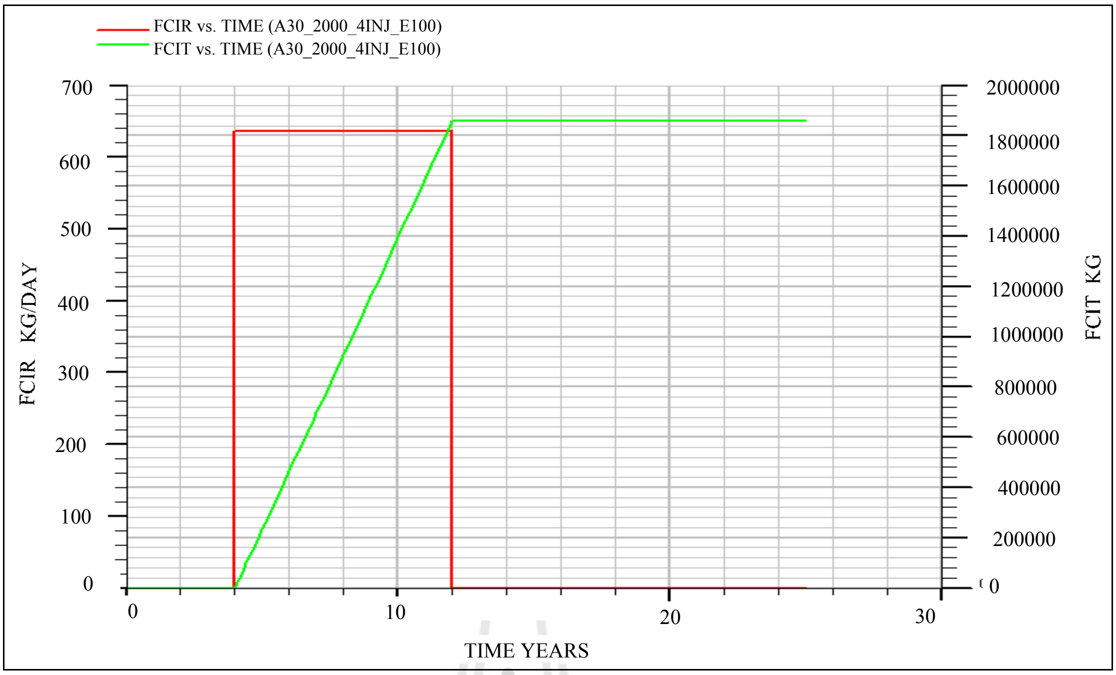


Figure 4.140 CIR and CIT vs. Time of model A30_2000_4INJ.

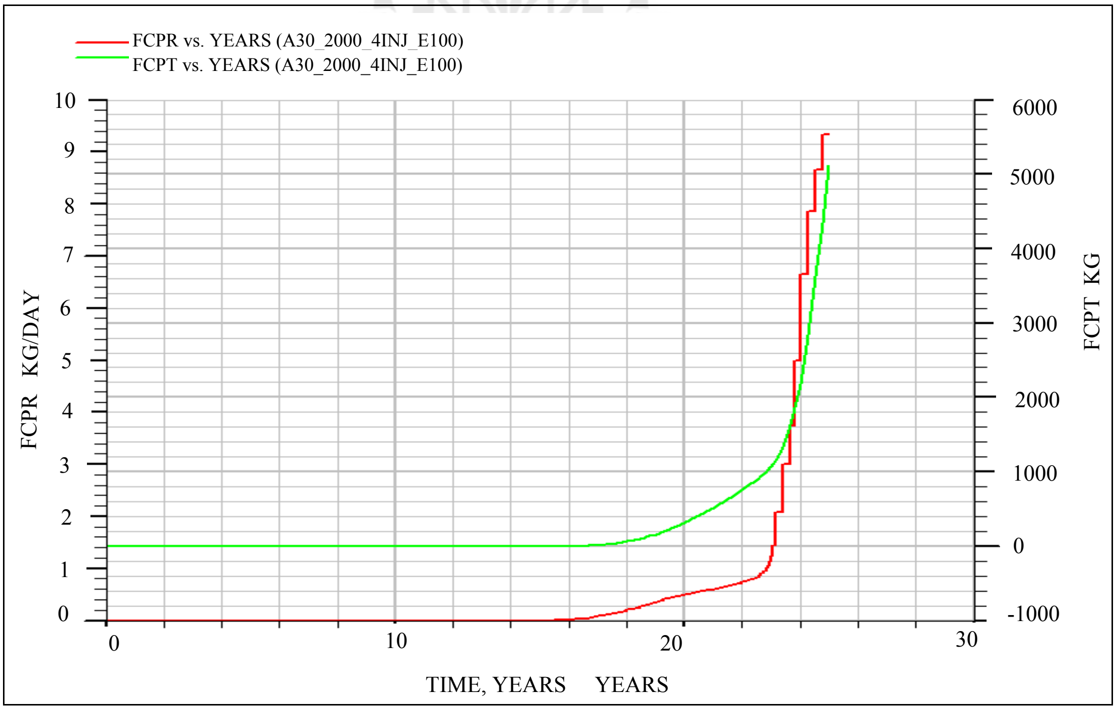


Figure 4.141 CPR and CPT vs. Time of model A30_2000_4INJ.

Table 4.39 Summary detail of graph 4.135, 4.136 and 4.139.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	8,776,165	31,798,776	27.60
Gas (MSCF)	15,083,411	15,342,696	98.31
Water (STB)	482,096	15,603,954	3.09

Table 4.40 Summary detail of graph 4.140 and 4.141.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	2,000	56,844,360	0.12	1,858

For model A30, the results of reservoir simulation for 10 cases (a base case of waterflooding and nine cases of polymer flooding) of different starting time for polymer injection of 3rd, 4th, and 5th years of production period, for an optimized polymer slug size as 0.12 PV. The processes of reservoir simulation were made for different polymer concentrations of 1,000, 1,500 and 2,000 ppm. The three of different starting times corresponding to the polymer concentrations of 1,000, 1,500 and 2,000 ppm, respectively. These simulations called polymer flooding, running for find the best case oil recovery efficiency. They gave better results than that of the waterflooding as presented in Figure 4.142 – 4.144.

The average of oil production totals and the oil recovery efficiency have increased more than the waterflooding as shown in Table 4.41.

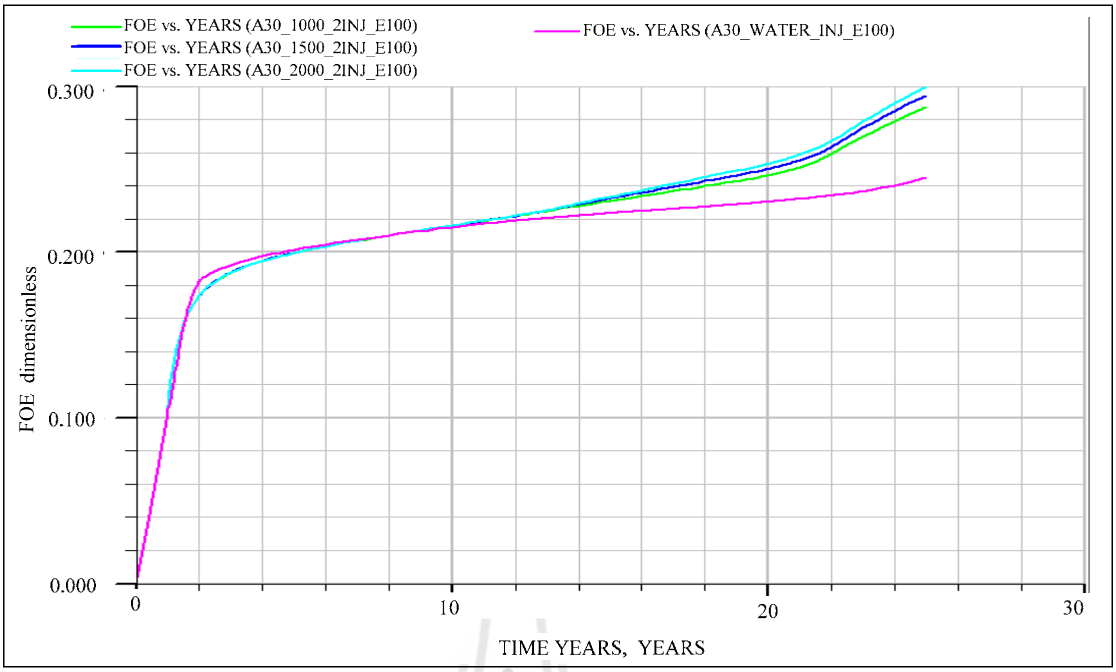


Figure 4.142 Oil recovery efficiency vs. Time of model A30 ply.-start@3rd year

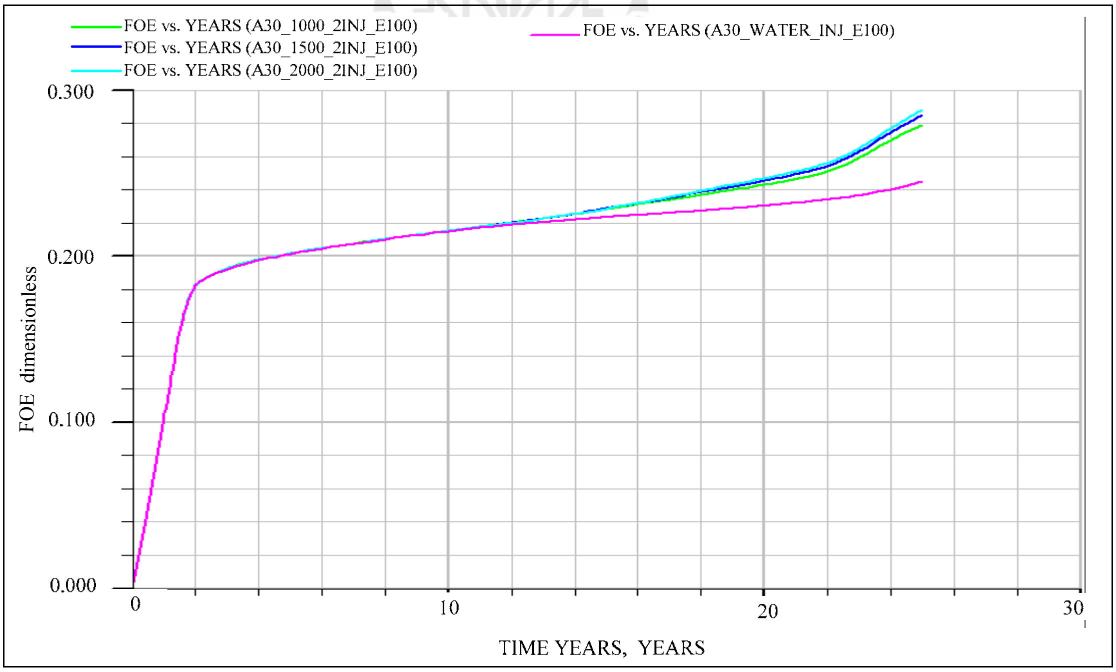


Figure 4.143 Oil recovery efficiency vs. Time of model A30 ply.-start@4th year

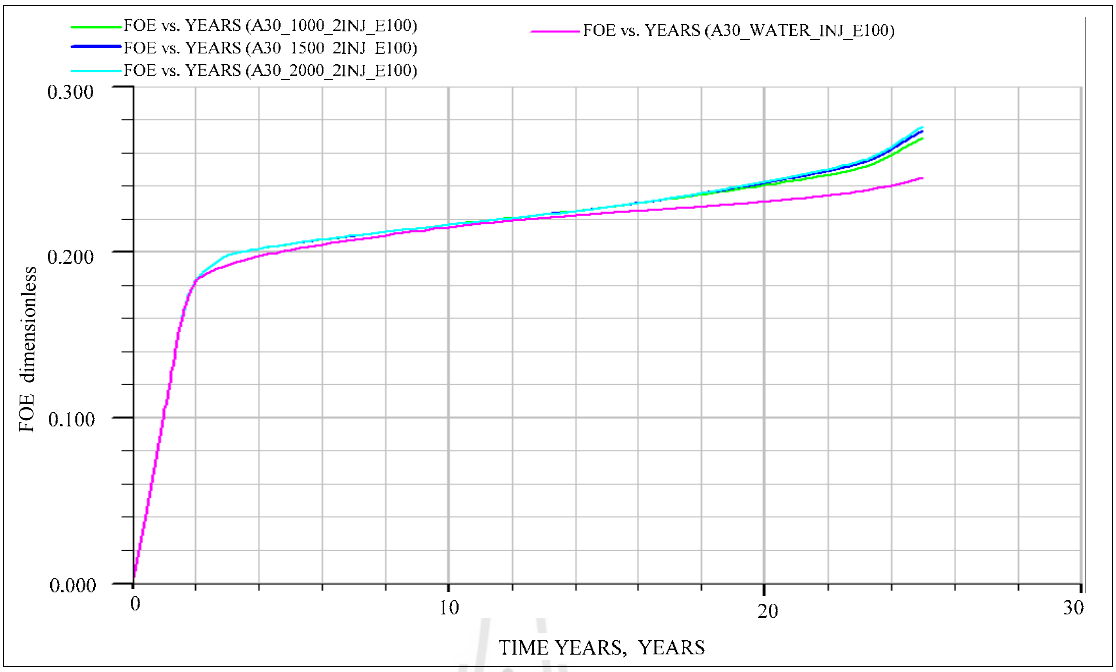


Figure 4.144 Oil recovery efficiency vs. Time of model A30 ply.-start@5th year

Table 4.41 Cumulative oil production and oil recovery efficiency for A30.

Model Name	Scenario No.	Scenario Name	Polymer Concentration (ppm)	Cum. Oil production (BBL)	Recovery Factor (RF)
A30	1	A30_WATER_INJ	-	7,782,724	24.47
	2	A30_1000_2INJ	1,000	9,131,944	28.72
	3	A30_1000_3INJ	1,000	8,869,303	27.89
	4	A30_1000_4INJ	1,000	8,550,628	26.89
	5	A30_1500_2INJ	1,500	9,358,356	29.43
	6	A30_1500_3INJ	1,500	9,055,398	28.48
	7	A30_1500_4INJ	1,500	8,694,523	27.34
	8	A30_2000_2INJ	2,000	9,524,530	29.95
	9	A30_2000_3INJ	2,000	9,157,173	28.80
	10	A30_2000_4INJ	2,000	8,776,165	27.60

4.3 Reservoir Simulation Result for Model A05

4.3.1 Model A05_WATER_INJ Scenario Result

Model A05_WATER_INJ is waterflooding (base case) and the simulation results as shown in Table 4.42 and Figure 4.145 – 4.150:

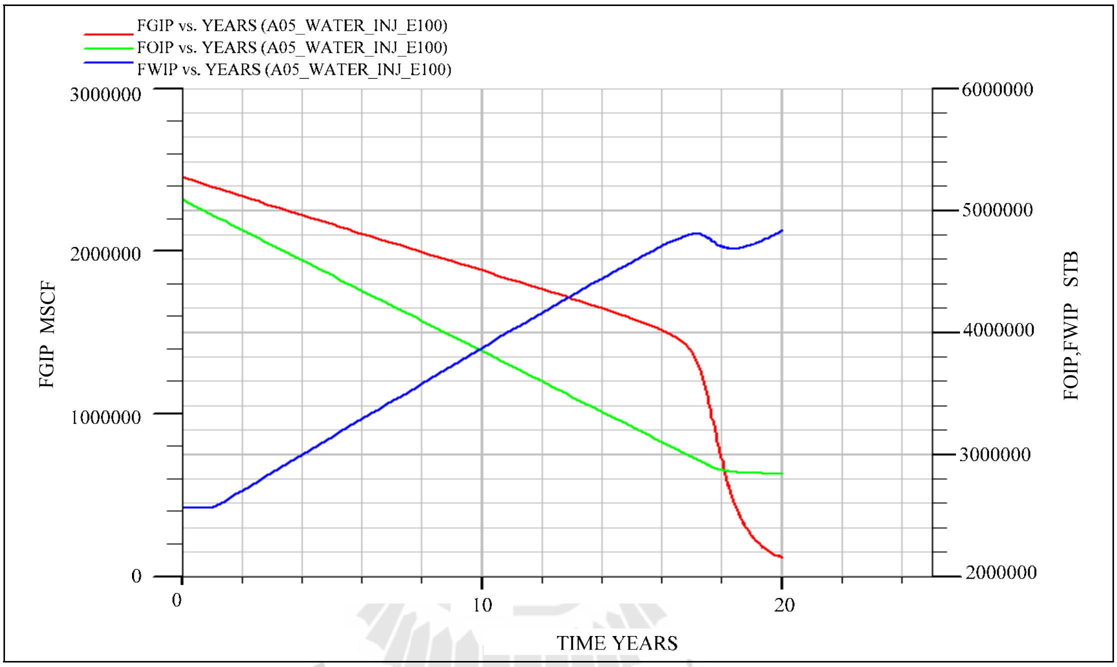


Figure 4.145 Fluid in place profile vs. Time of model A05_WATER_INJ.

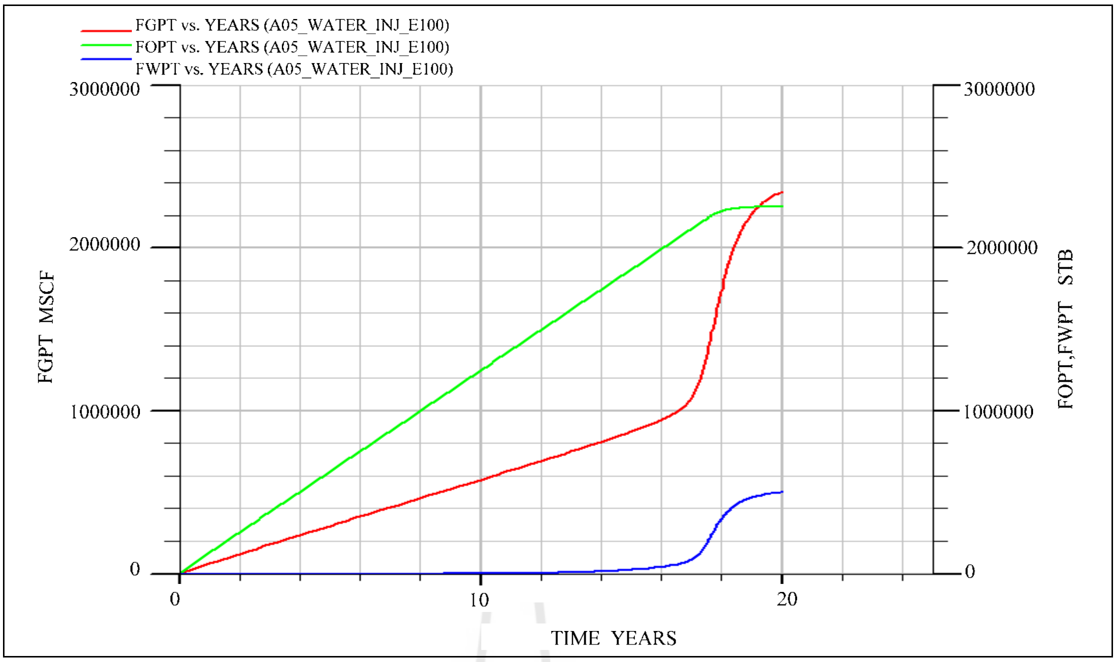


Figure 4.146 Cumulative fluids production profile vs. Time of model A05_WATER_INJ.

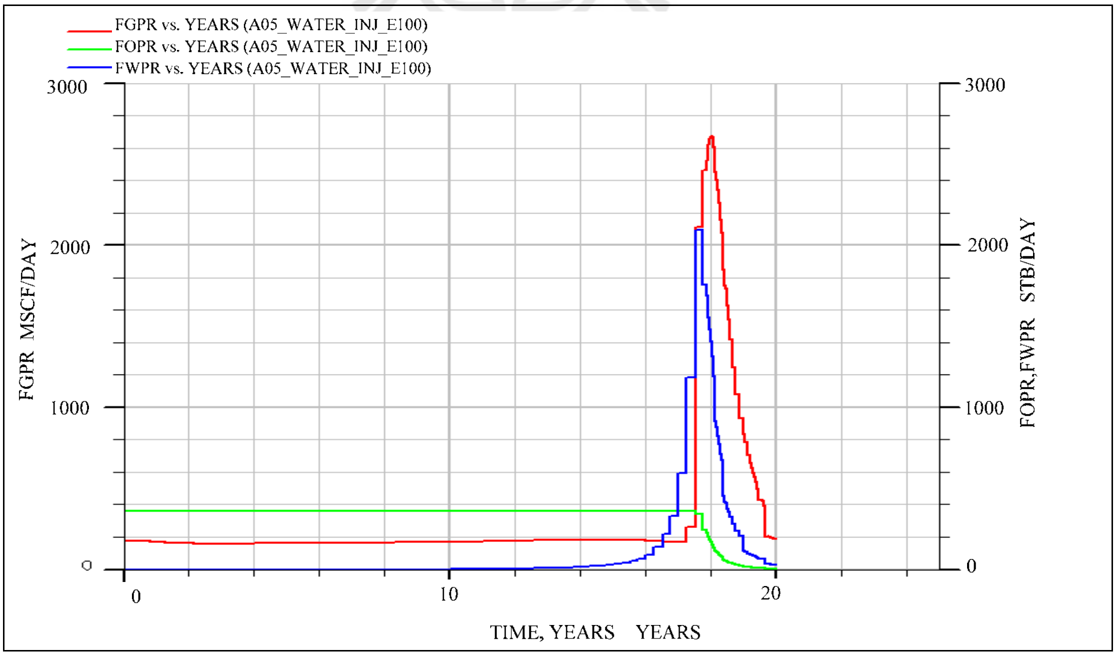


Figure 4.147 Fluids production rate profile vs. Time of model A05_WATER_INJ.

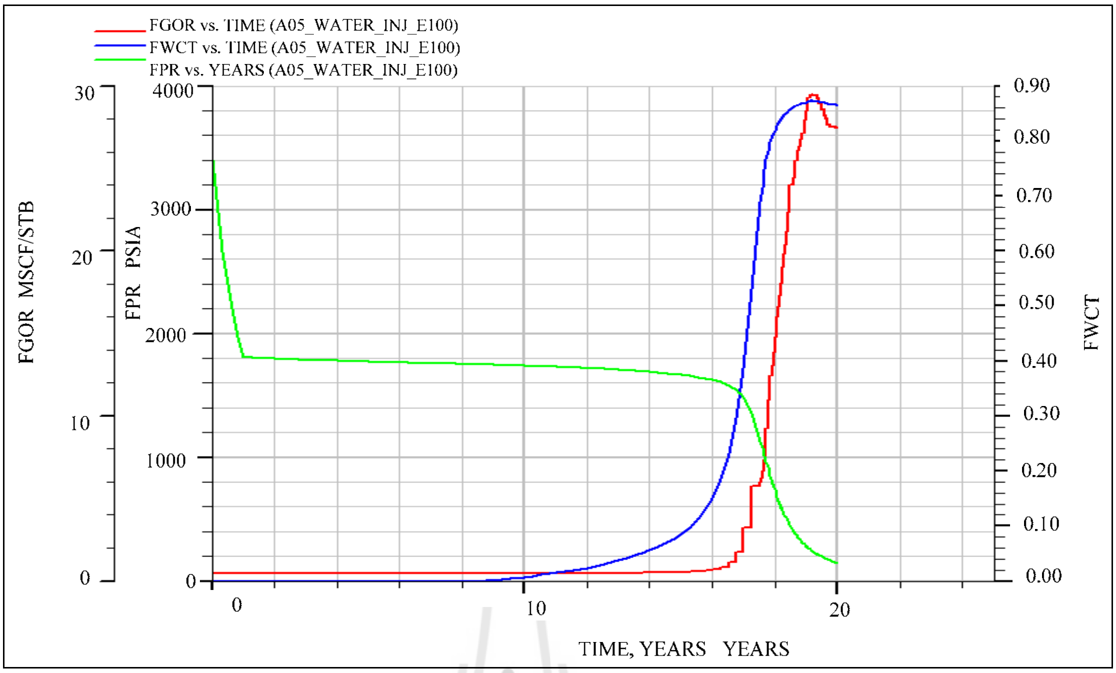


Figure 4.148 GOR, WCT, and Pressure profile vs. Time of model A05_WATER_INJ.

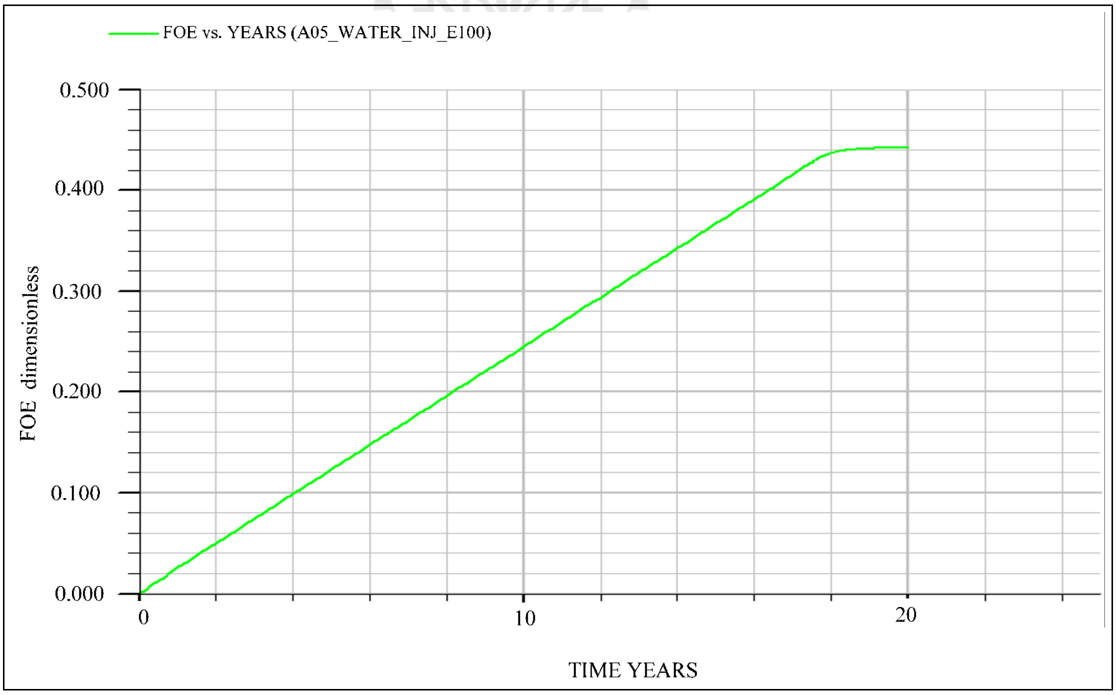


Figure 4.149 Oil recovery efficiency vs. Time of model A05_WATER_INJ.

Table 4.42 Summary detail of graph 4.145, 4.146 and 4.149.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,254,415	5,096,241	44.24
Gas (MSCF)	2,343,730	2,458,902	95.32
Water (STB)	499,766	2,558,227	19.54

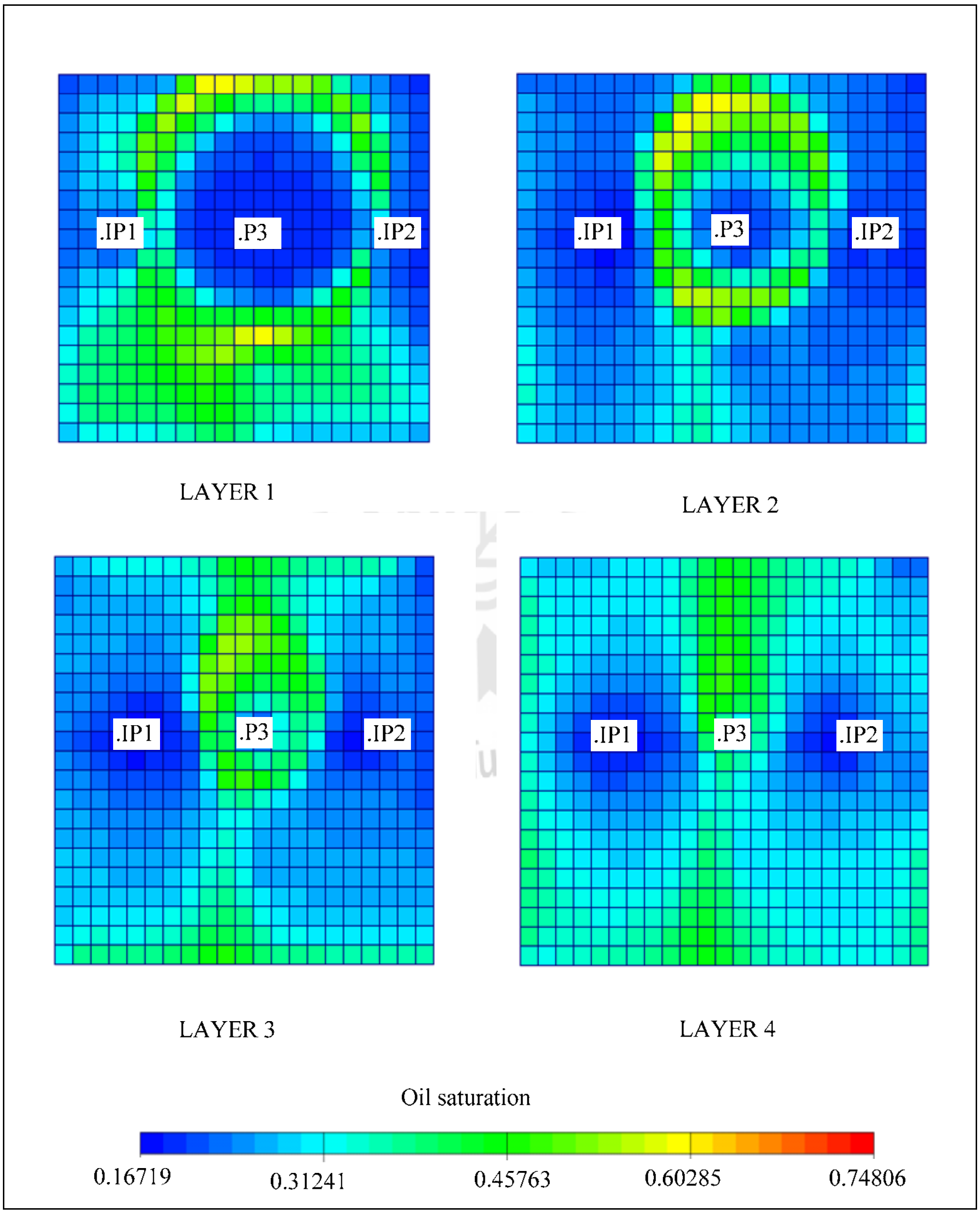


Figure 4.150 Residual oil saturation distribution after waterflooding of model A05_WATER_INJ.

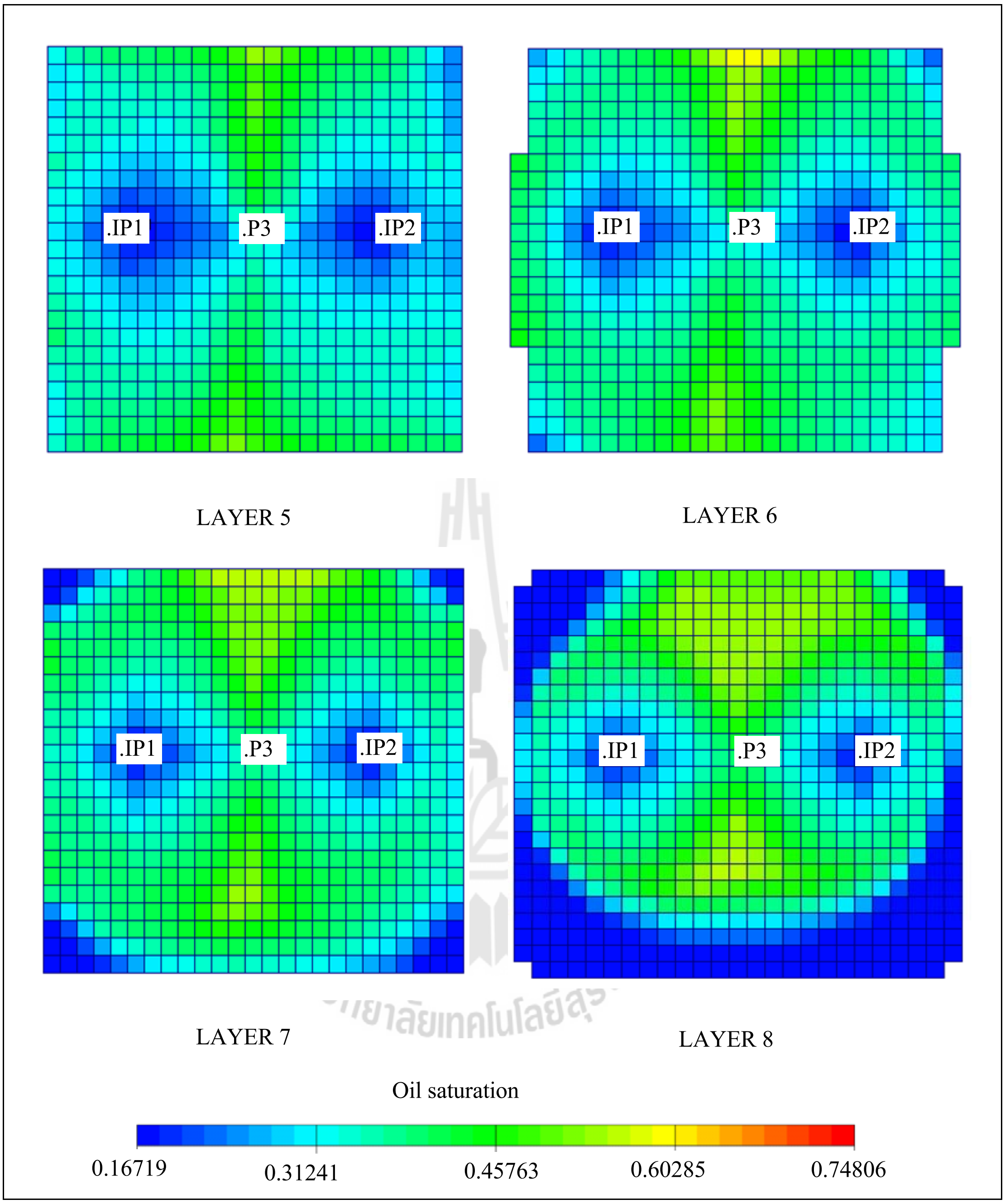


Figure 4.150 Residual oil saturation distribution after waterflooding of model A05_WATER_INJ. (Continued)

4.3.2 Model A05_600_2INJ Scenario Result

Model A05_600_2INJ is polymer flooding and the simulation results as shown in Table 4.43-4.44 and Figure 4.151 – 4.157:

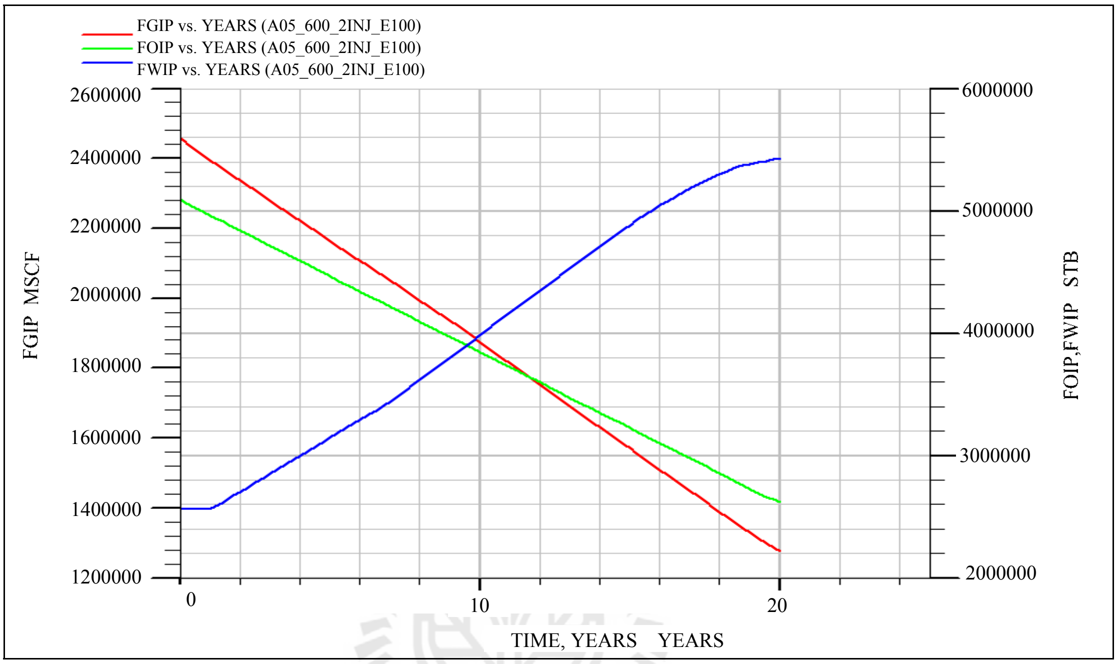


Figure 4.151 Fluid in place profile vs. Time of model A05_600_2INJ.

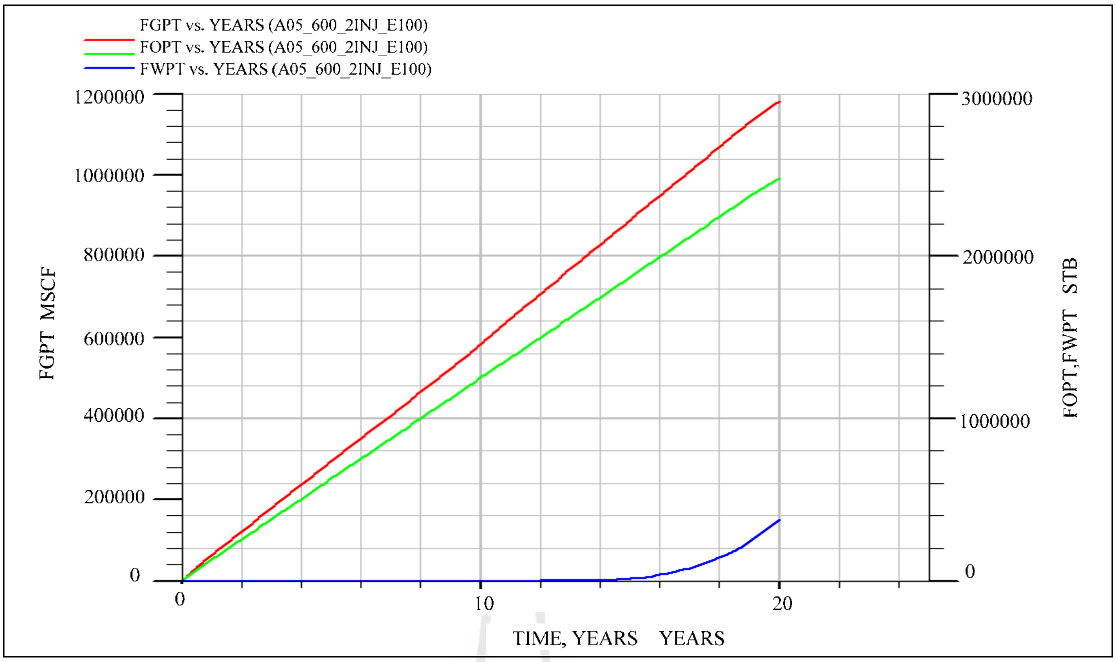


Figure 4.152 Cumulative fluids production profile vs. Time of model A05_600_2INJ.

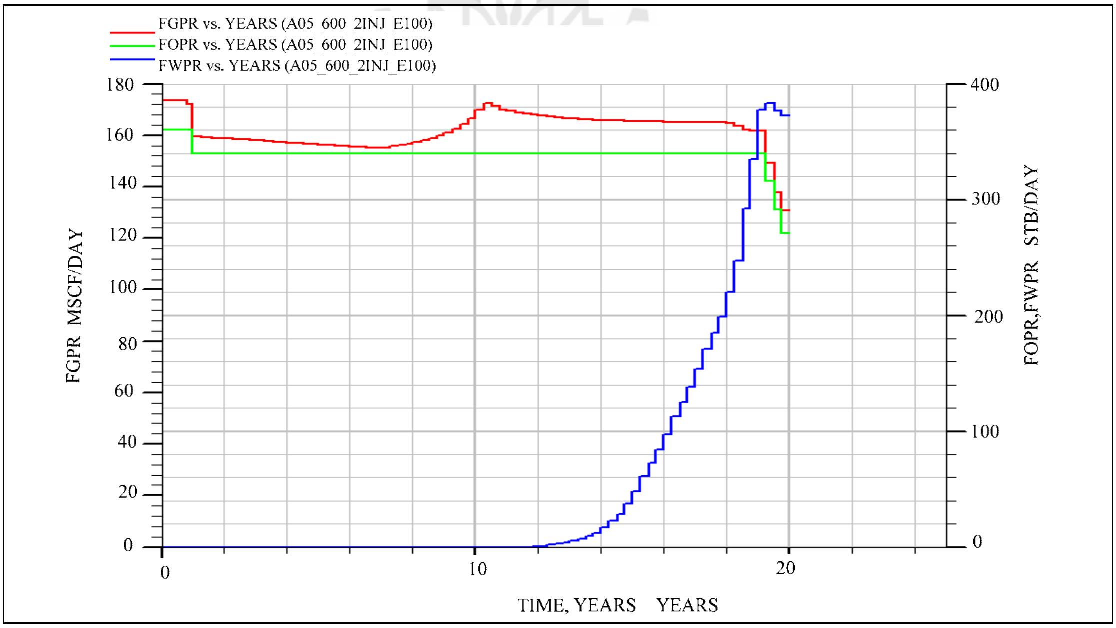


Figure 4.153 Fluids production rate profile vs. Time of model A05_600_2INJ.

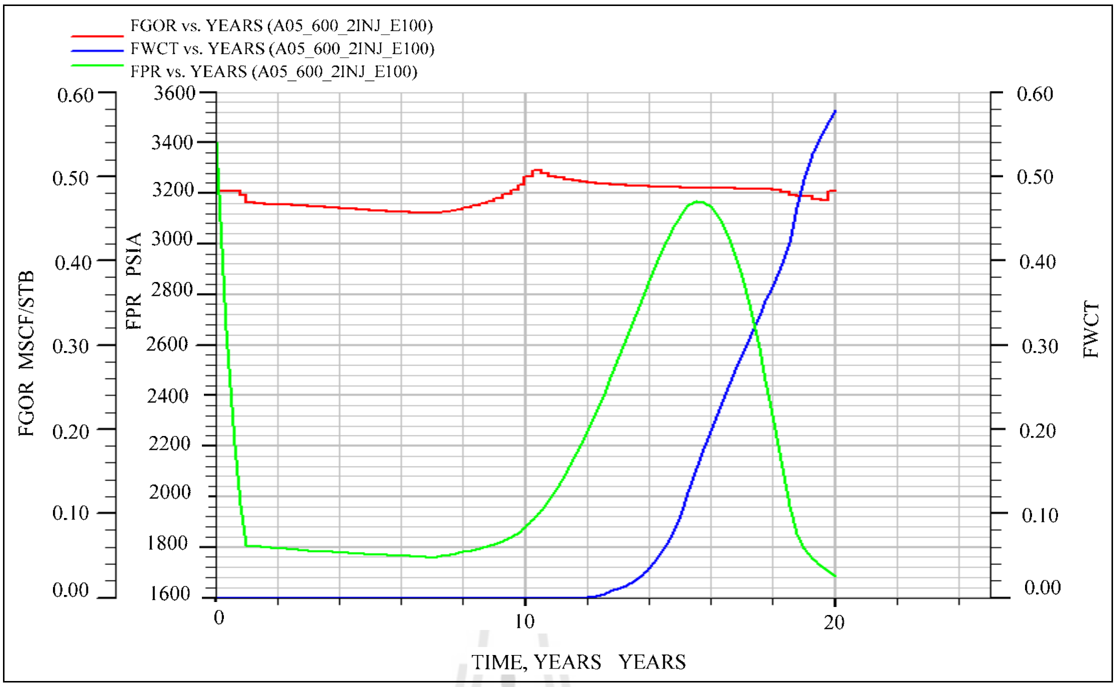


Figure 4.154 GOR, WCT, and Pressure profile vs. Time of model A05_600_2INJ.

Figure 4.155 Oil recovery efficiency vs. Time of model A30_600_2INJ.

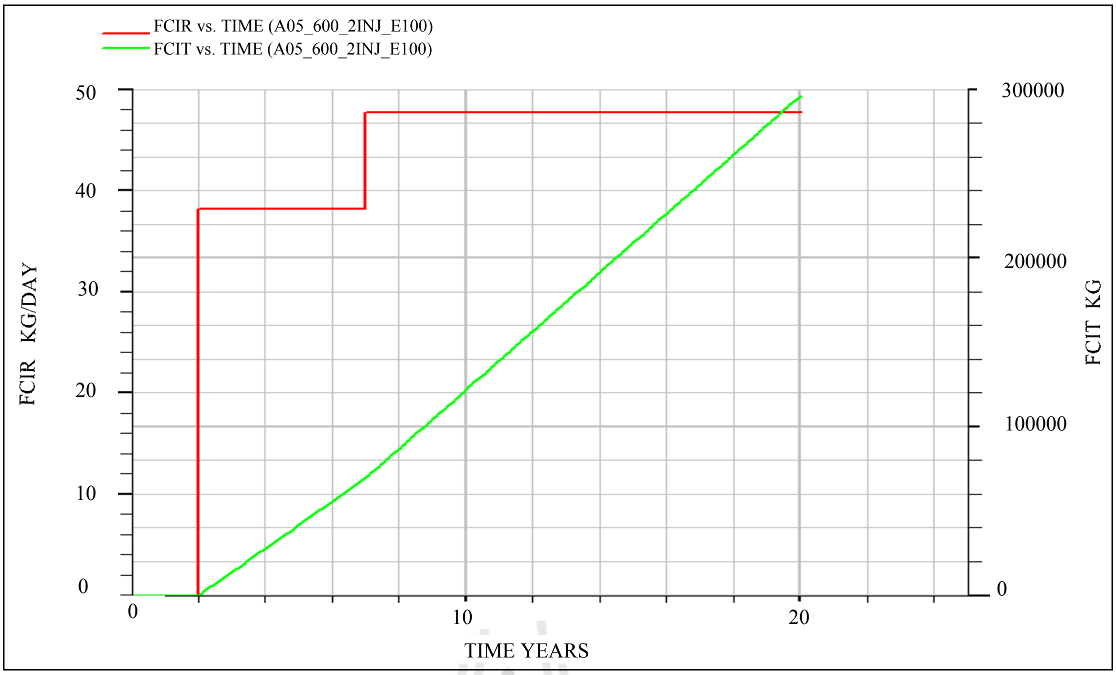


Figure 4.156 CIR and CIT vs. Time of model A05_600_2INJ.

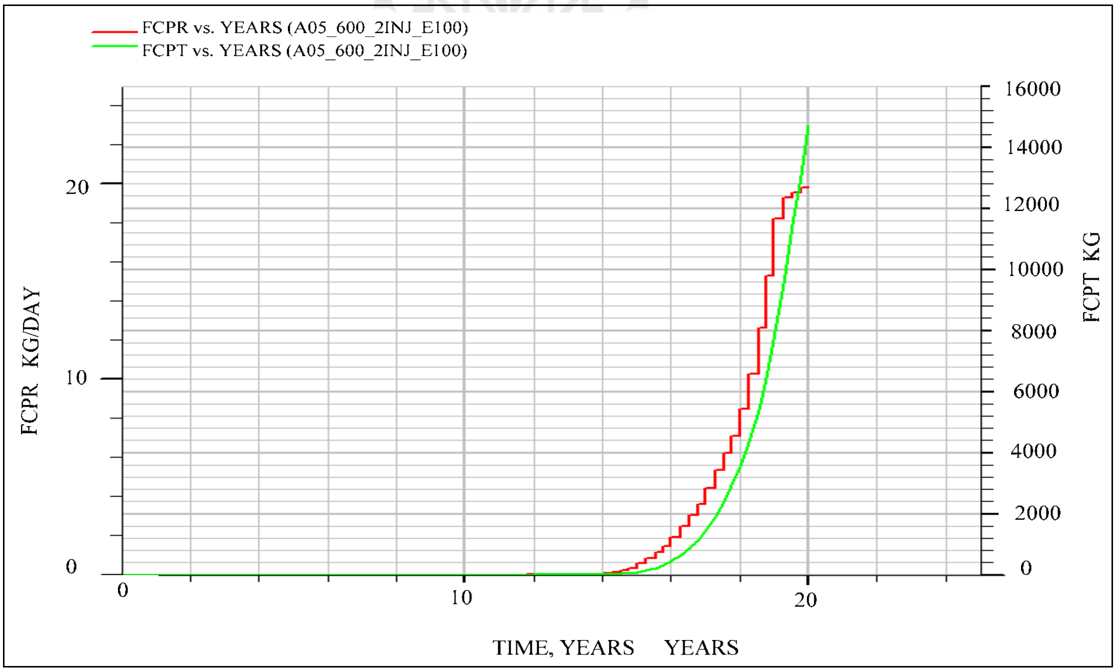


Figure 4.157 CPR and CPT vs. Time of model A05_600_2INJ.

Table 4.43 Summary detail of graph 4.151, 4.152 and 4.155.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,478,934	5,096,241	48.64
Gas (MSCF)	1,182,559	2,458,902	48.09
Water (STB)	380,375	2,558,227	14.87

Table 4.44 Summary detail of graph 4.156 and 4.157.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	600	9,168,827	0.34	296

4.3.3 Model A05_600_3INJ Scenario Result

Model A05_6000_3INJ is polymer flooding and the simulation results as shown in Table 4.45-4.46 and Figure 4.158 – 4.164:

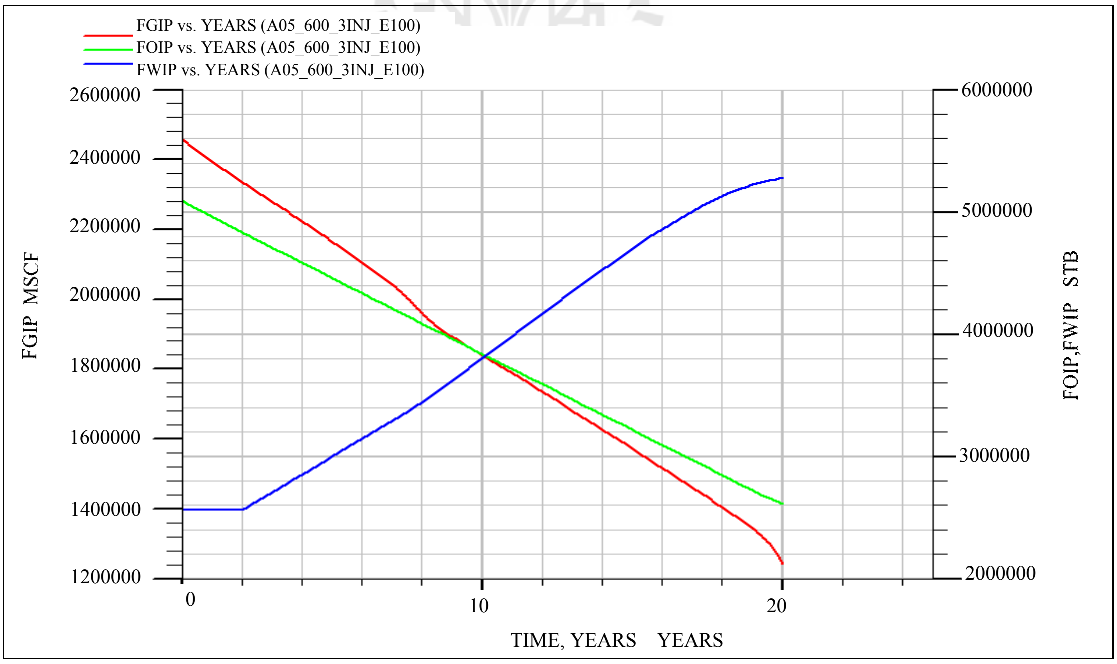


Figure 4.158 Fluid in place profile vs. Time of model A05_600_3INJ.

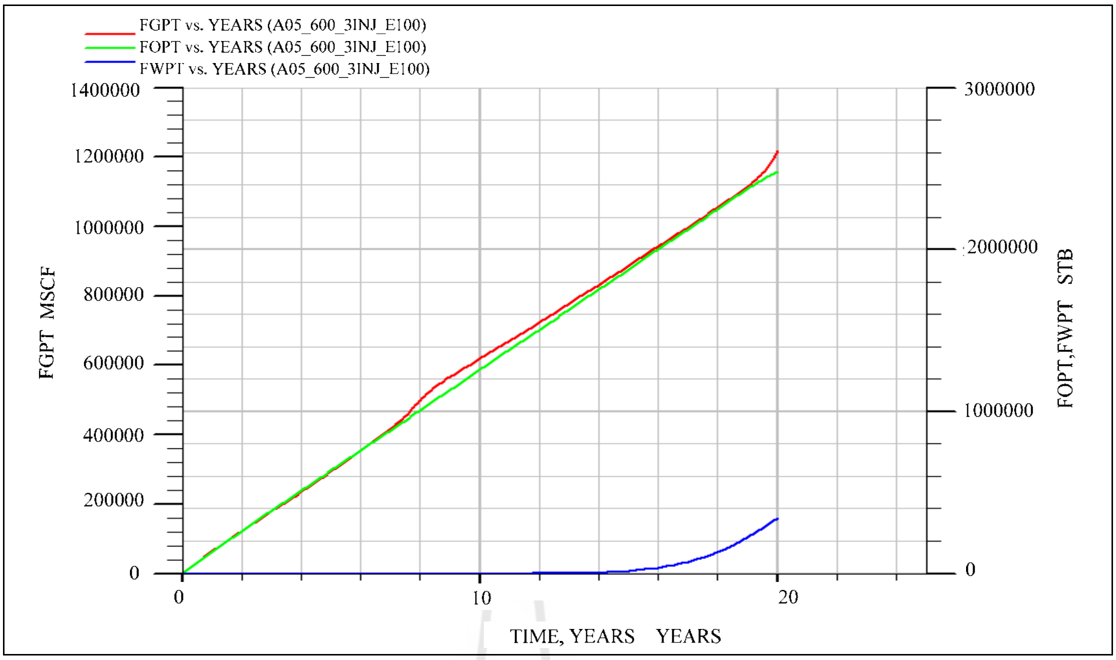


Figure 4.159 Cumulative fluids production profile vs. Time of model A05_600_3INJ.

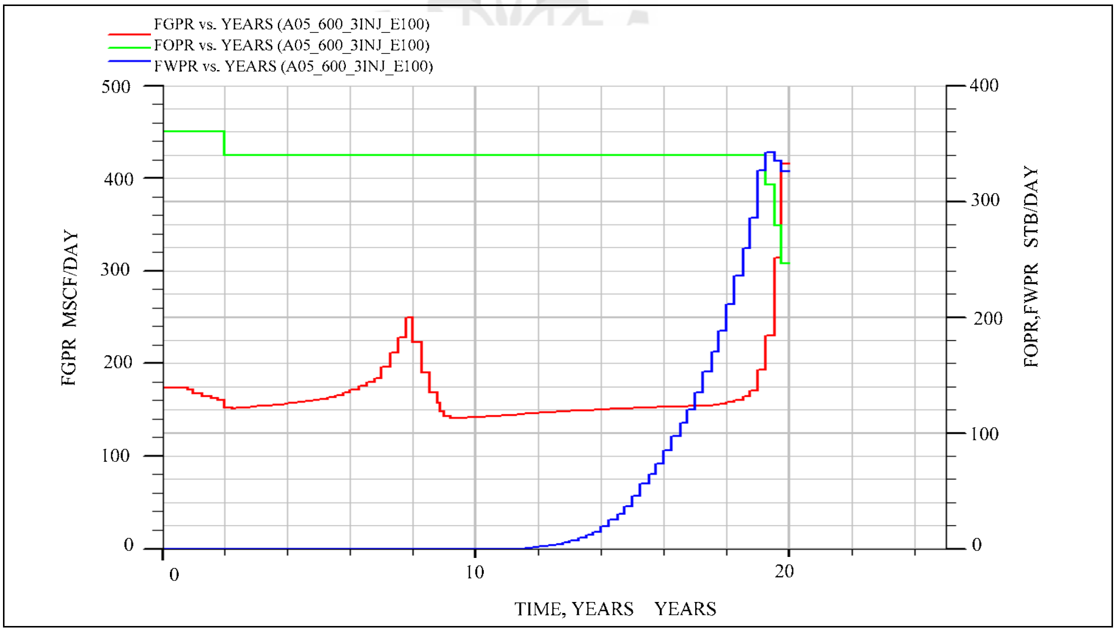


Figure 4.160 Fluids production rate profile vs. Time of model A05_600_3INJ.

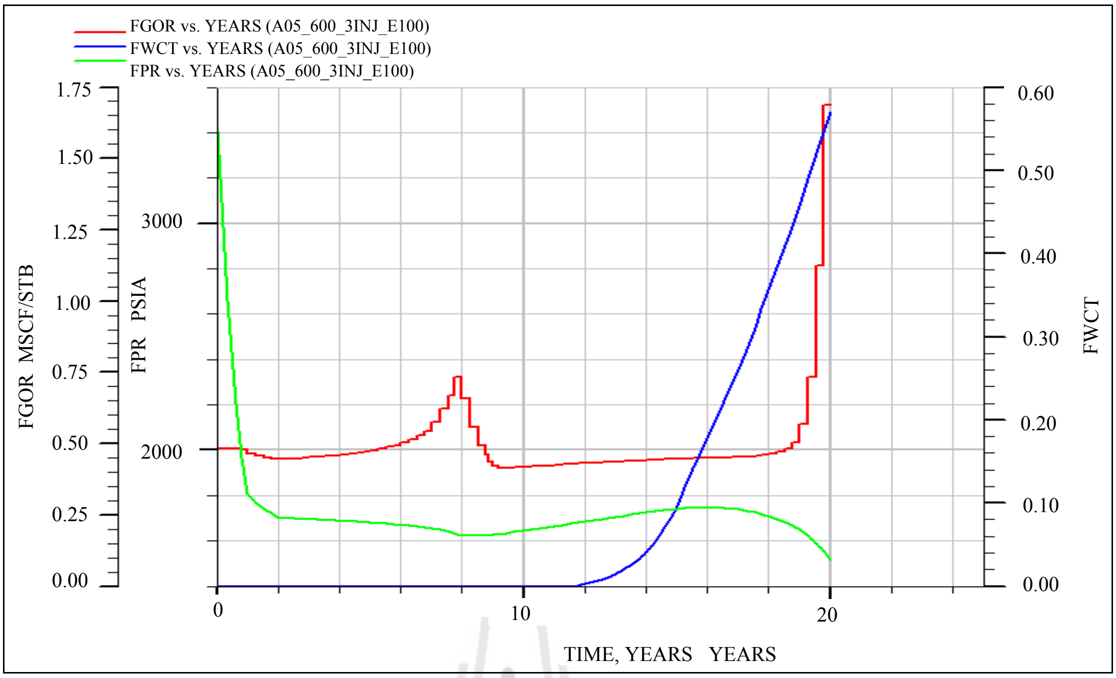


Figure 4.161 GOR, WCT, and Pressure profile vs. Time of model A05_600_3INJ.

Figure 4.162 Oil recovery efficiency vs. Time of model A30_600_3INJ.

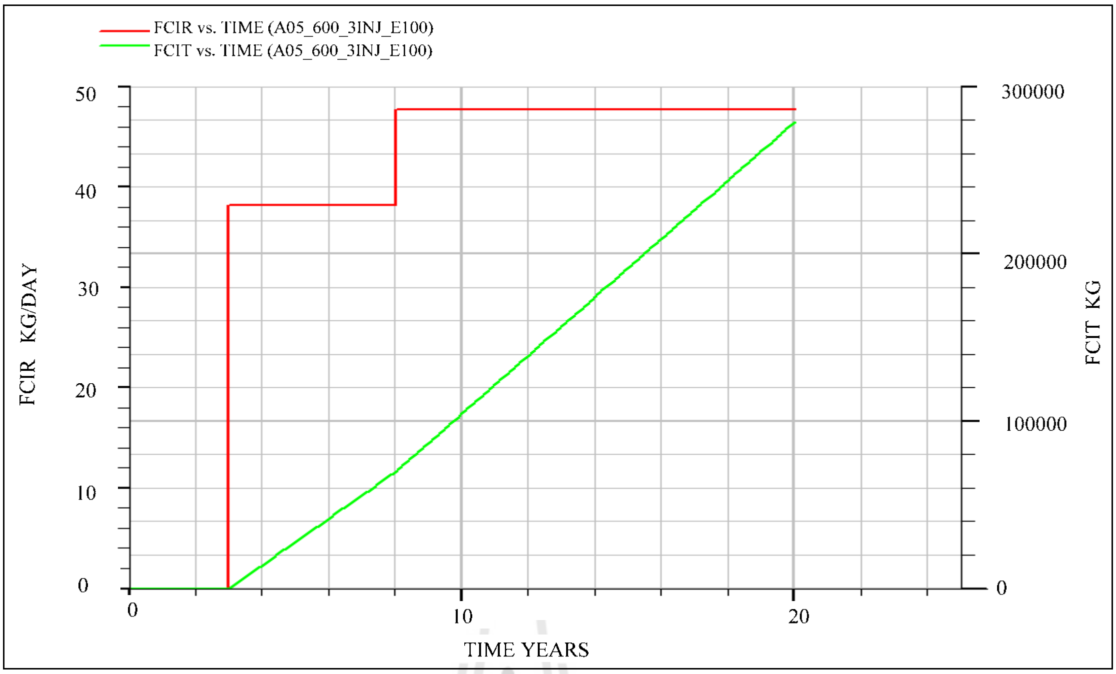


Figure 4.163 CIR and CIT vs. Time of model A05_600_3INJ.

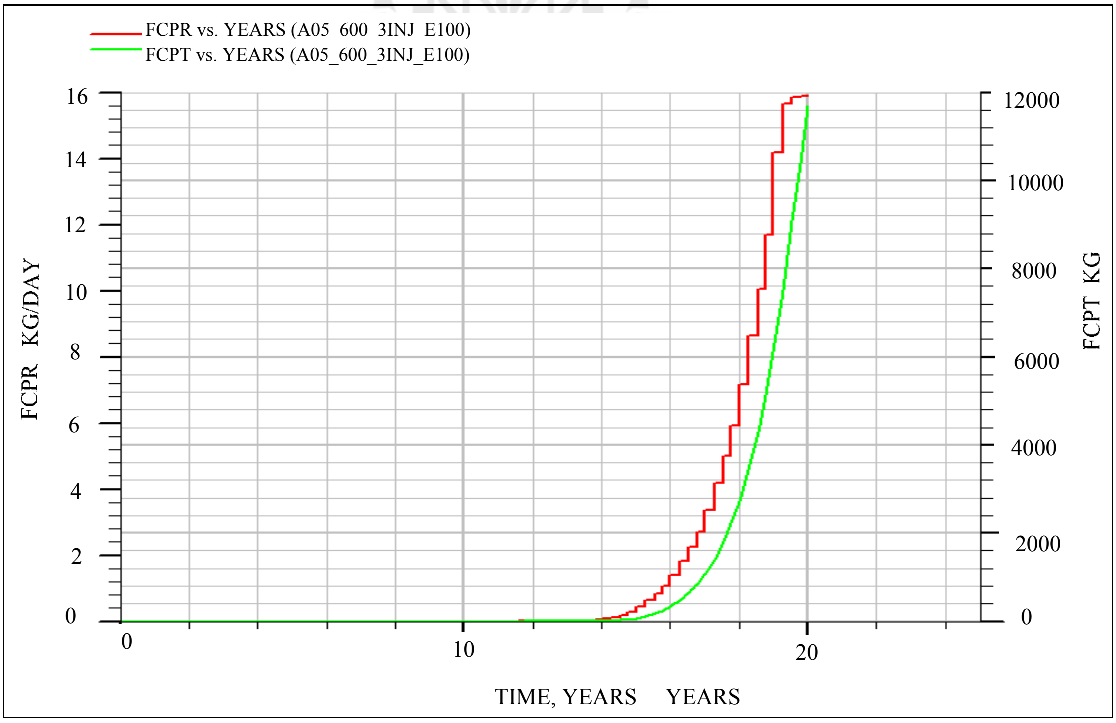


Figure 4.164 CPR and CPT vs. Time of model A05_600_3INJ.

Table 4.45 Summary detail of graph 4.158, 4.159 and 4.162.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,483,015	5,096,241	48.72
Gas (MSCF)	1,216,954	2,458,902	49.49
Water (STB)	343,026	2,558,227	13.41

Table 4.46 Summary detail of graph 4.162 and 4.164.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	600	9,168,827	0.34	279

4.3.4 Model A05_800_2INJ Scenario Result

Model A05_800_2INJ is polymer flooding and the simulation results as shown in Table 4.47-4.48 and Figure 4.165 – 4.171:

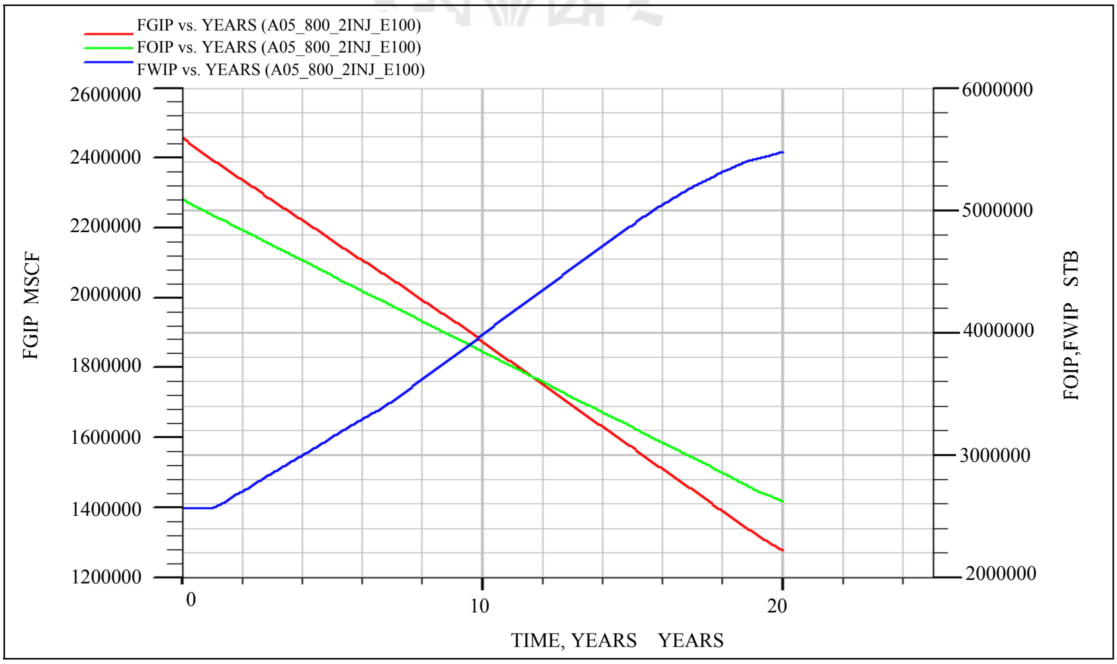


Figure 4.165 Fluid in place profile vs. Time of model A05_800_2INJ.

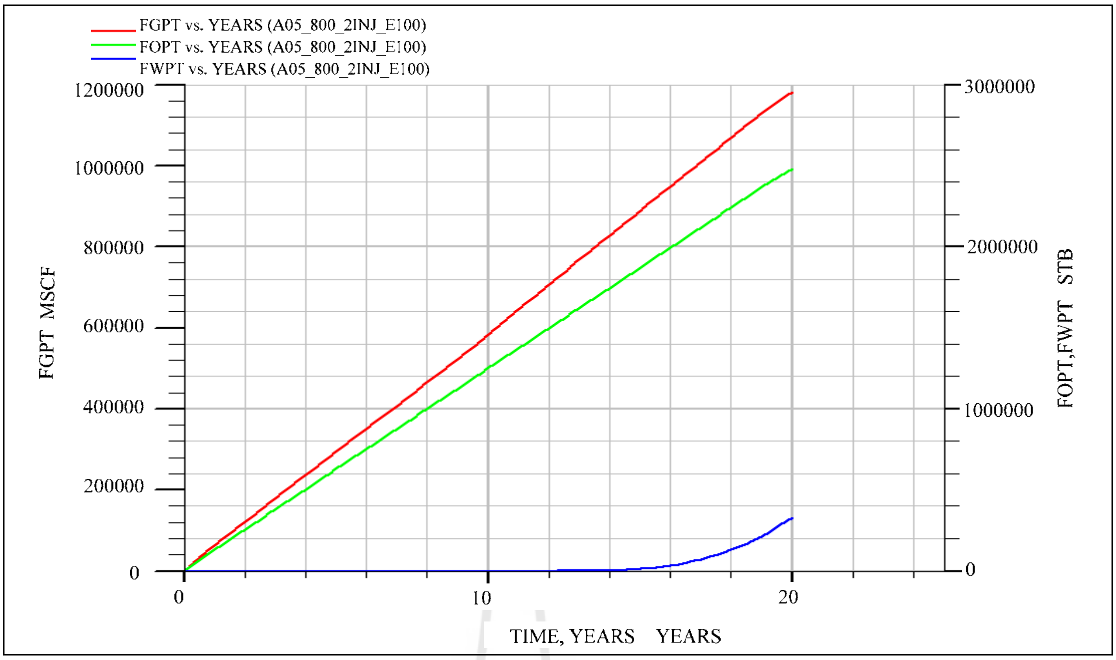


Figure 4.166 Cumulative fluids production profile vs. Time of model A05_800_2INJ.

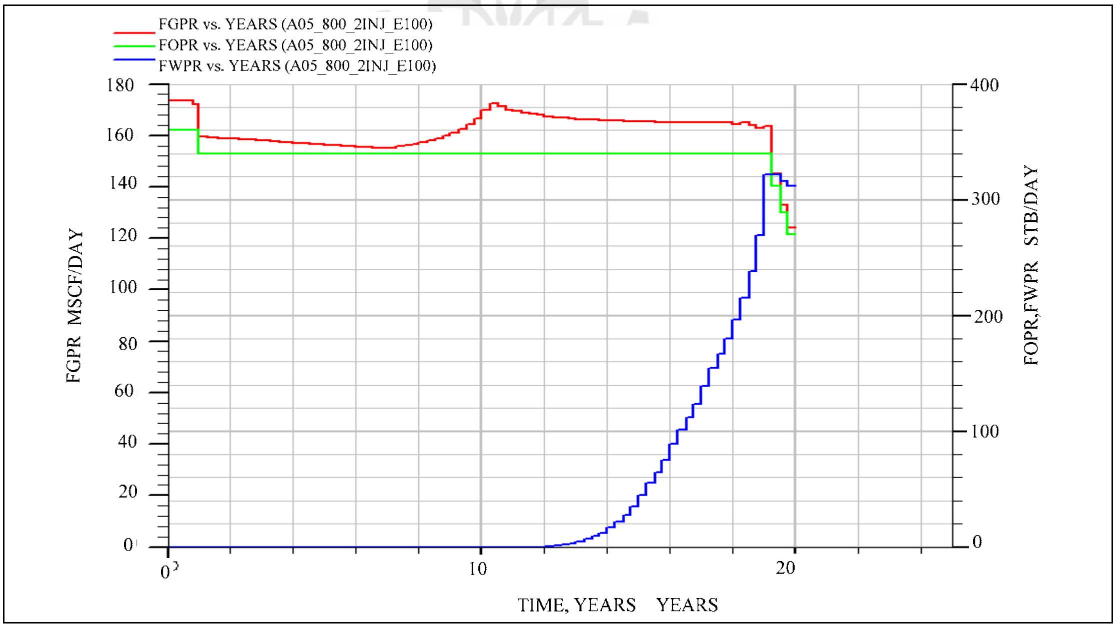


Figure 4.167 Fluids production rate profile vs. Time of model A05_800_2INJ.

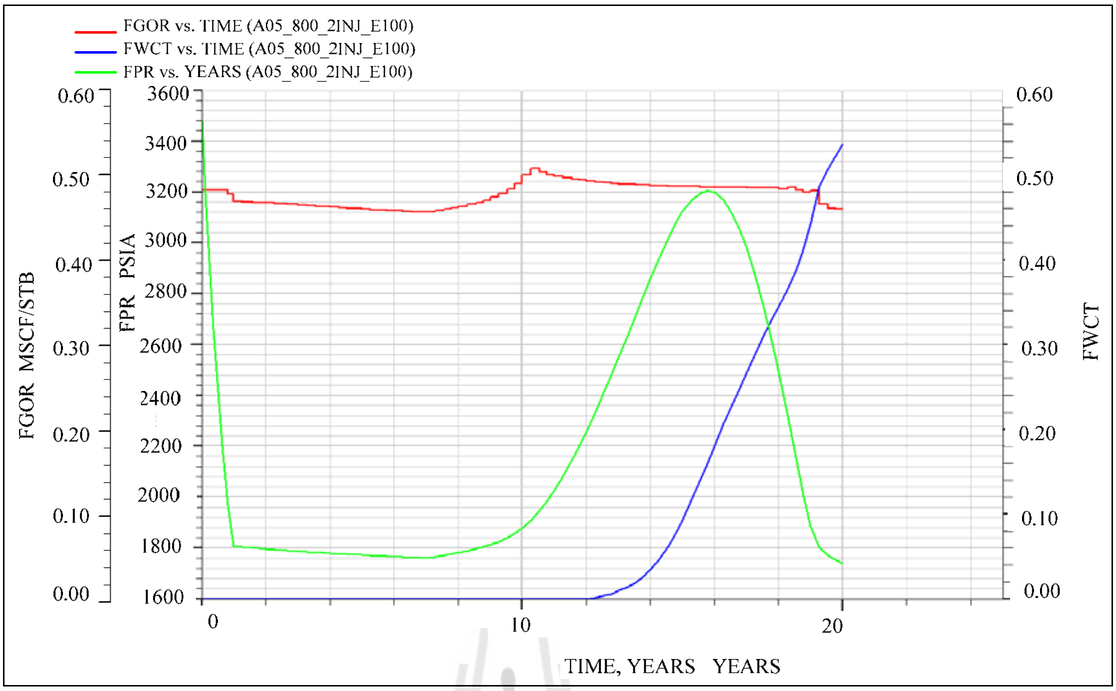


Figure 4.168 GOR, WCT, and Pressure profile vs. Time of model A05_800_2INJ.

Figure 4.169 Oil recovery efficiency vs. Time of model A05_800_2INJ.

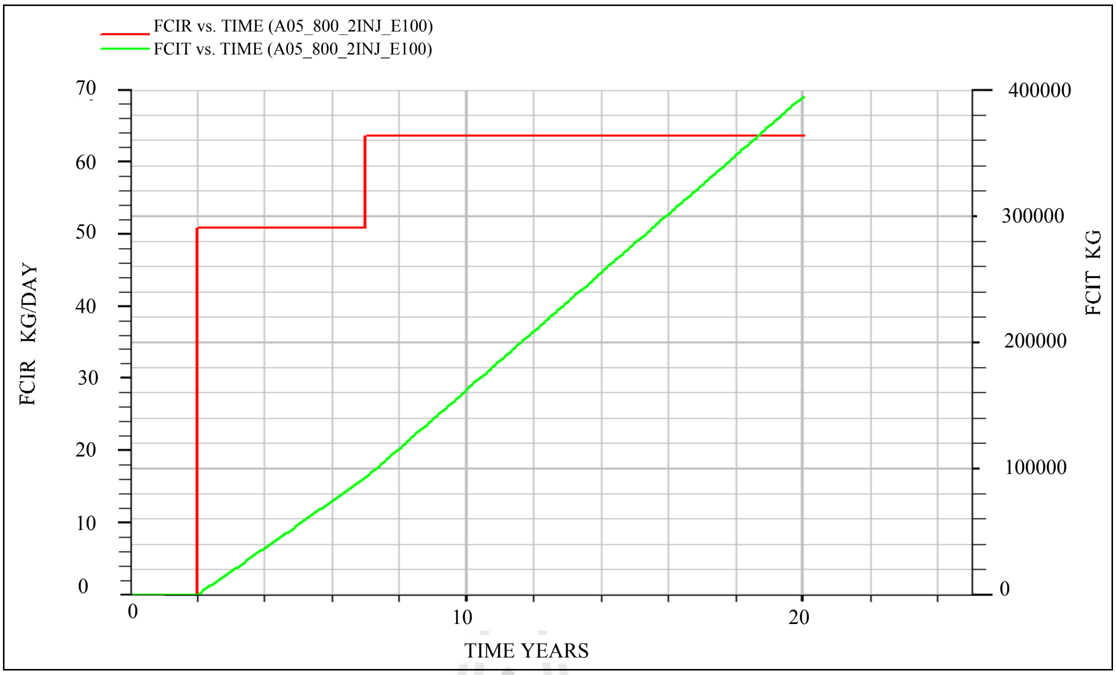


Figure 4.170 CIR and CIT vs. Time of model A05_800_2INJ.

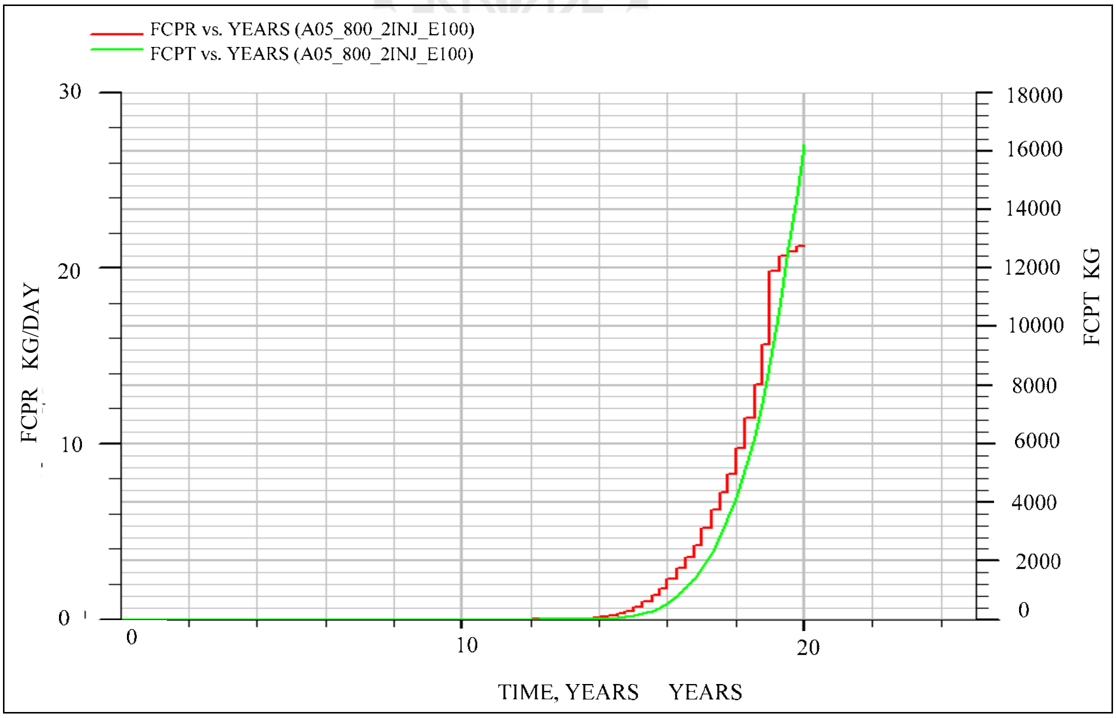


Figure 4.171 CPR and CPT vs. Time of model A05_800_2INJ.

Table 4.47 Summary detail of graph 4.165, 4.166 and 4.169.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,478,150	5,096,241	48.63
Gas (MSCF)	1,181,521	2,458,902	48.05
Water (STB)	329,647	2,558,227	12.89

Table 4.48 Summary detail of graph 4.170 and 4.171.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	800	9,168,827	0.34	395

4.3.5 Model A05_800_3INJ Scenario Result

Model A05_800_2INJ is polymer flooding and the simulation results as shown in Table 4.49-4.50 and Figure 4.172 – 4.178:

Figure 4.172 Fluid in place profile vs. Time of model A05_800_3INJ.

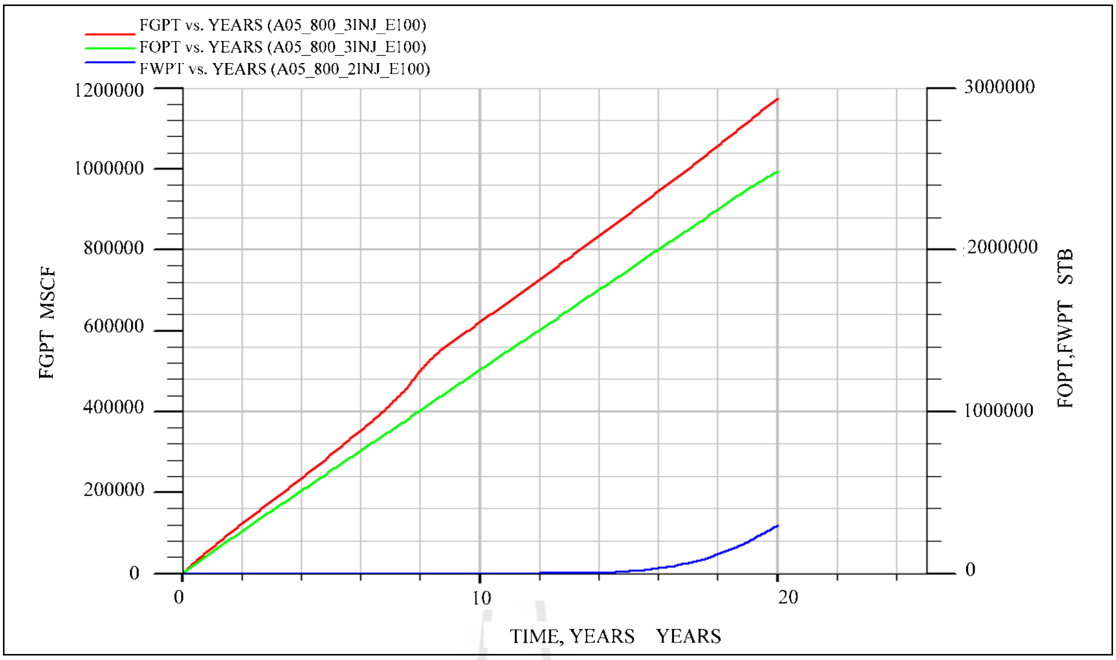


Figure 4.173 Cumulative fluids production profile vs. Time of model A05_800_3INJ.

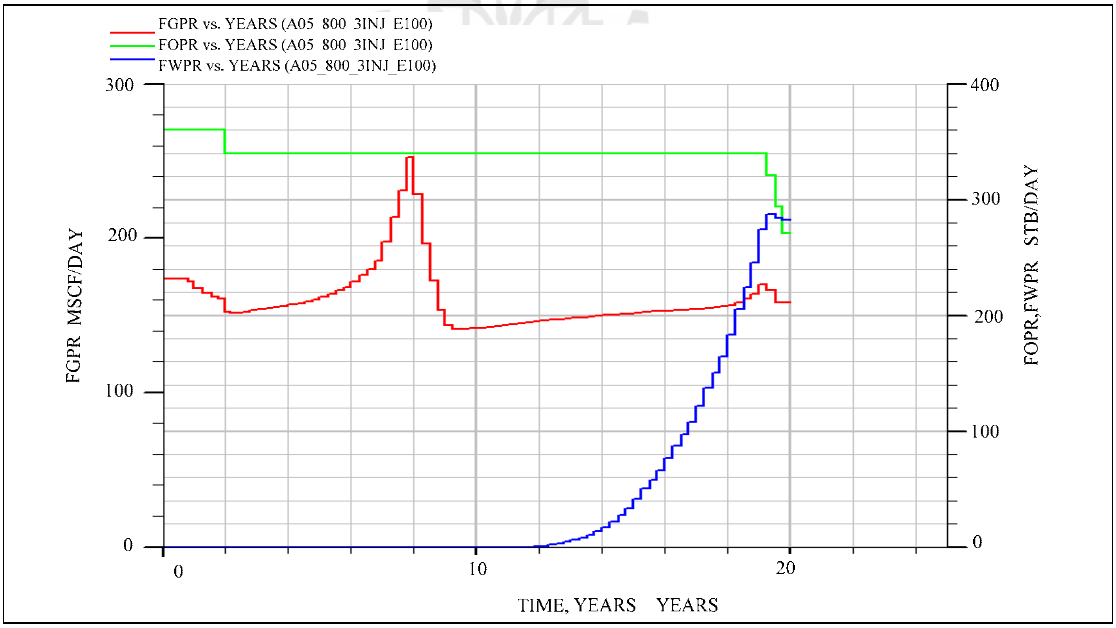


Figure 4.174 Fluids production rate profile vs. Time of model A05_800_3INJ.

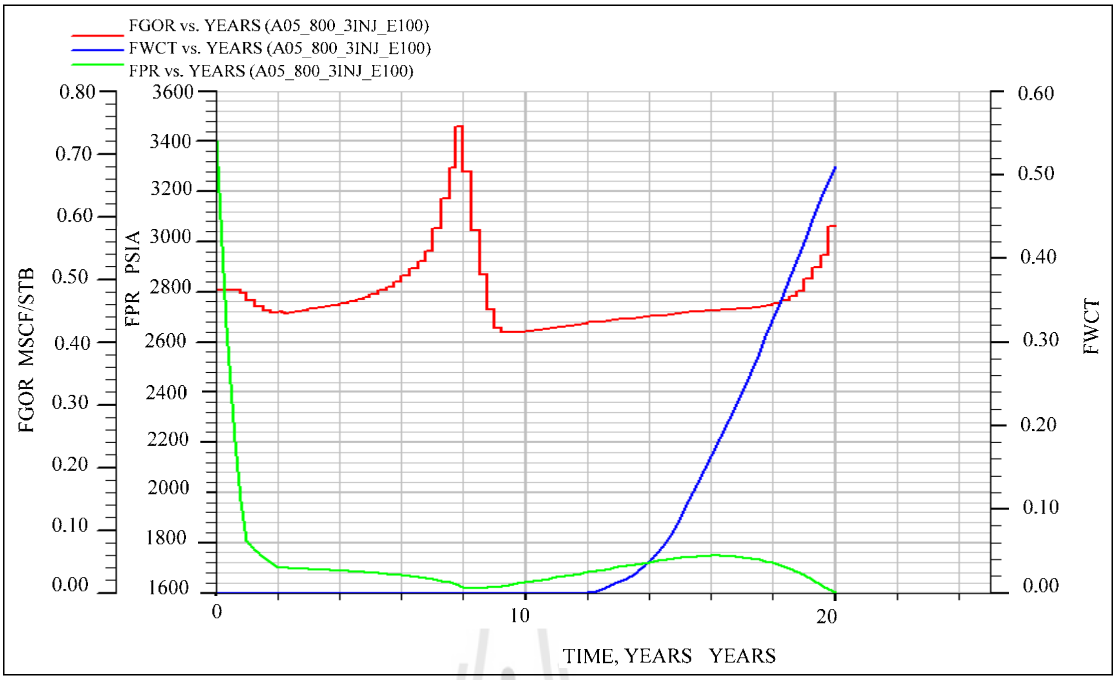


Figure 4.175 GOR, WCT, and Pressure profile vs. Time of model A05_800_3INJ.

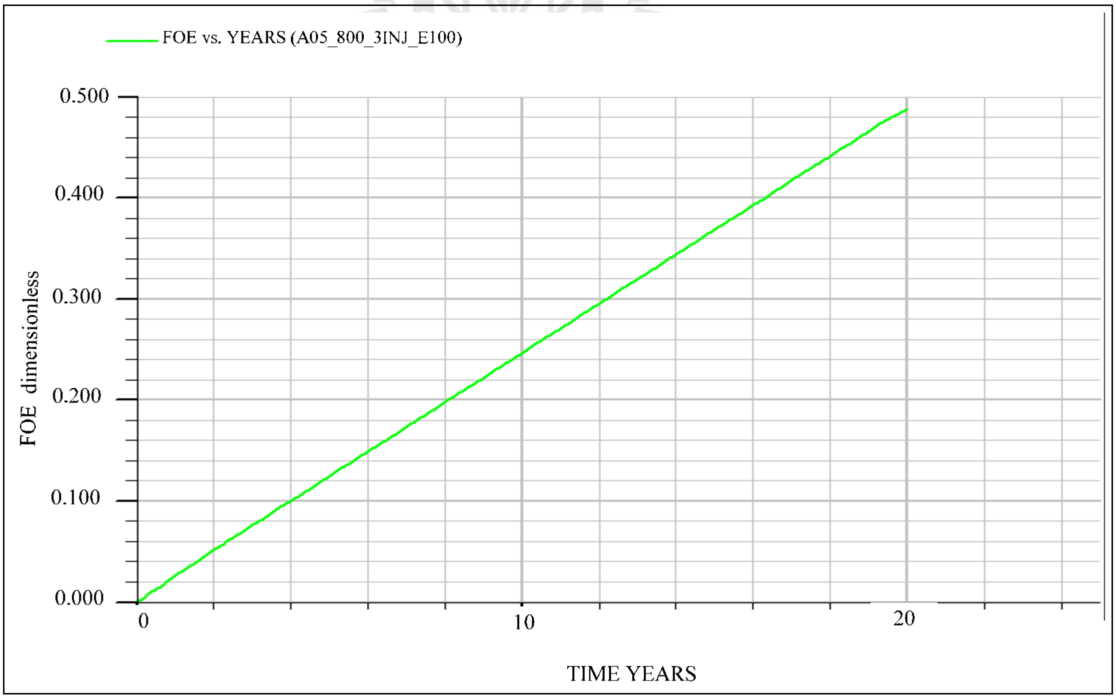


Figure 4.176 Oil recovery efficiency vs. Time of model A05_800_3INJ.

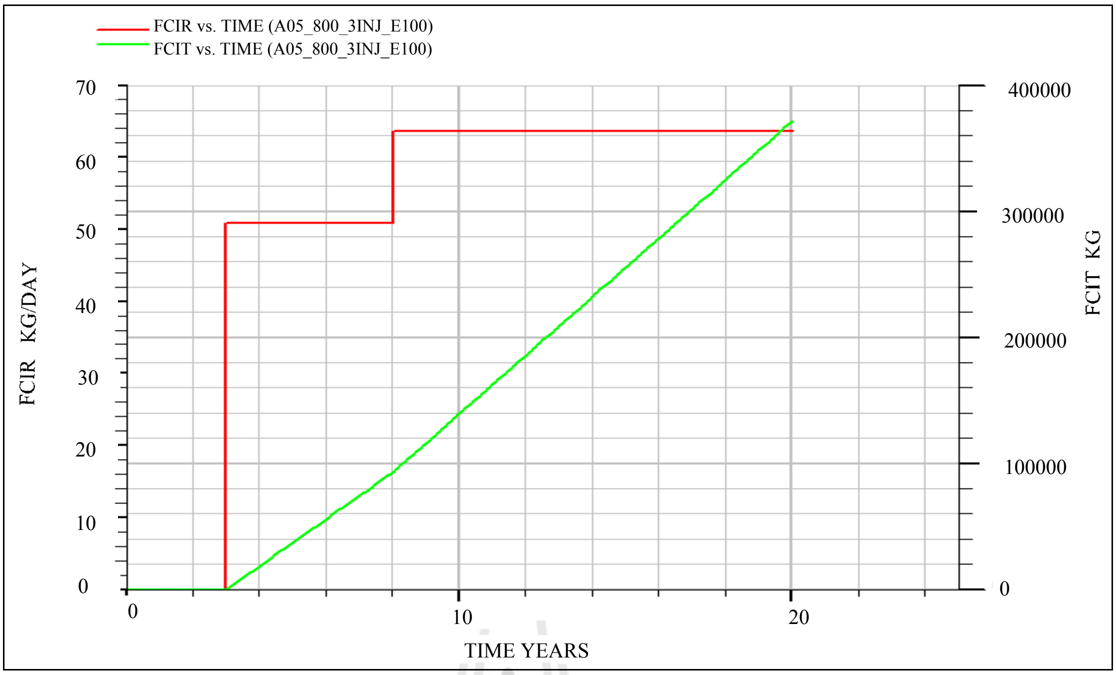


Figure 4.177 CIR and CIT vs. Time of model A05_800_3INJ.

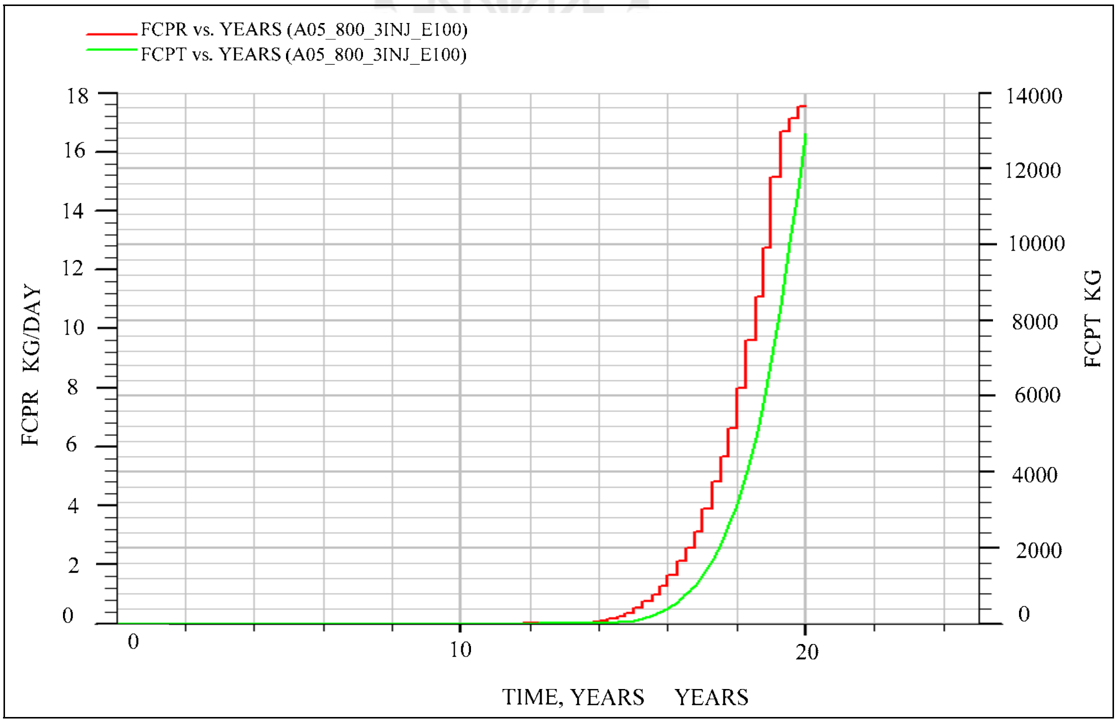


Figure 4.178 CPR and CPT vs. Time of model A05_800_3INJ.

Table 4.49 Summary detail of graph 4.172, 4.173 and 4.176.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,486,937	5,096,241	48.80
Gas (MSCF)	1,175,244	2,458,902	47.80
Water (STB)	298,480	2,558,227	11.67

Table 4.50 Summary detail of graph 4.177 and 4.178.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	800	9,168,827	0.34	372

4.3.6 Model A05_1000_2INJ Scenario Result

Model A05_1000_2INJ is polymer flooding and the simulation results as shown in Table 4.51-4.52 and Figure 4.179 – 4.185:

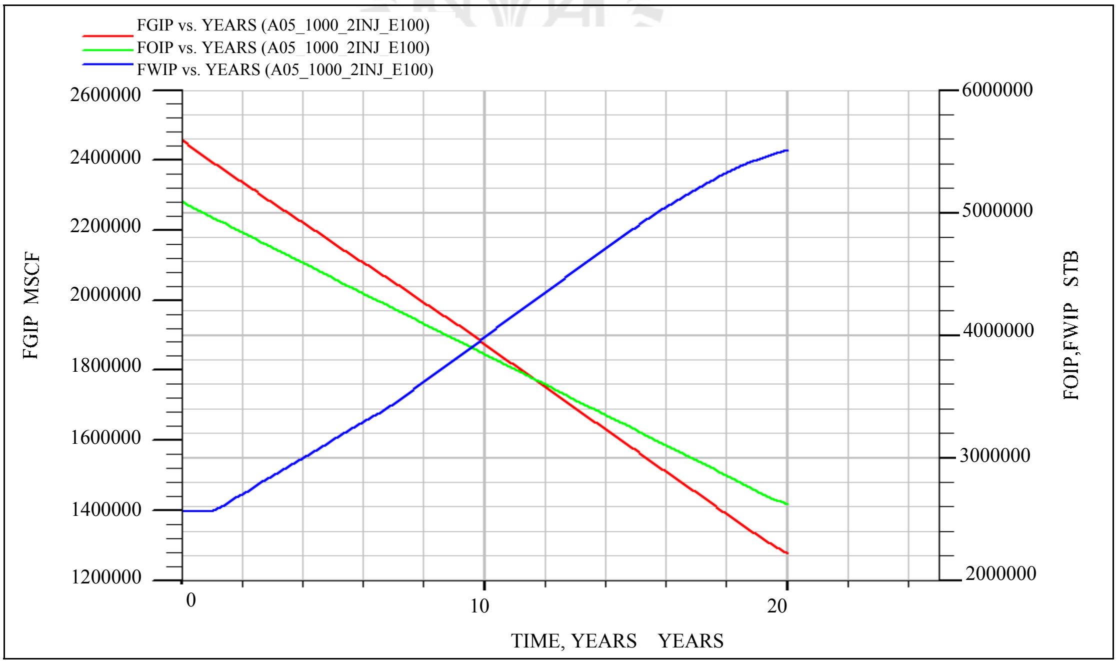


Figure 4.179 Fluid in place profile vs. Time of model A05_1000_2INJ.

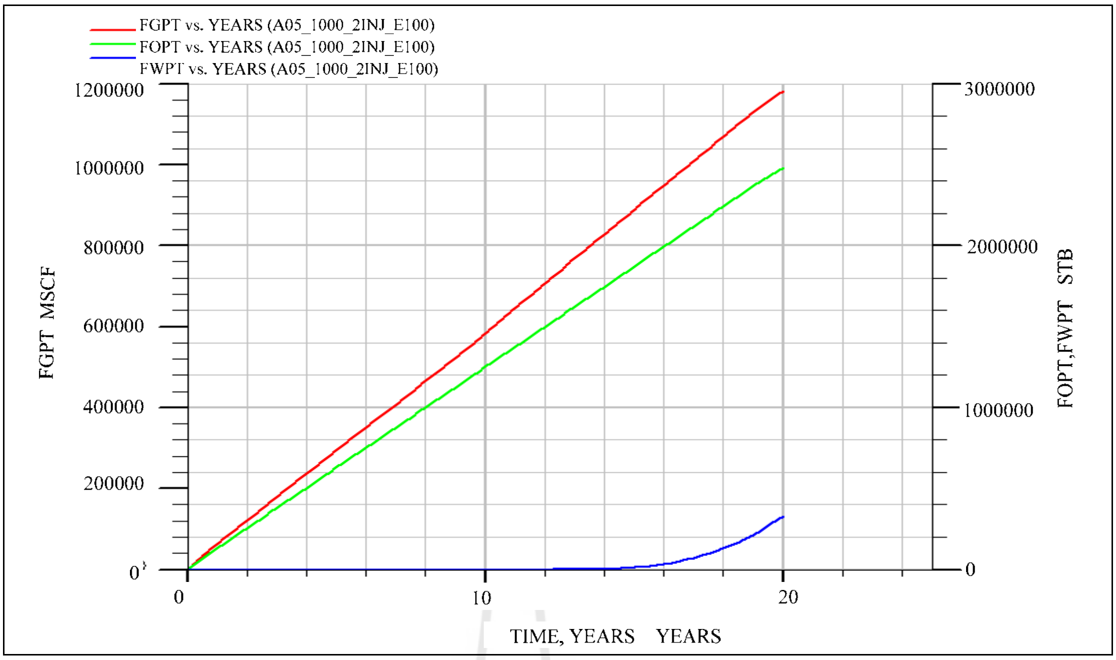


Figure 4.180 Cumulative fluids production profile vs. Time of model A05_1000_2INJ.

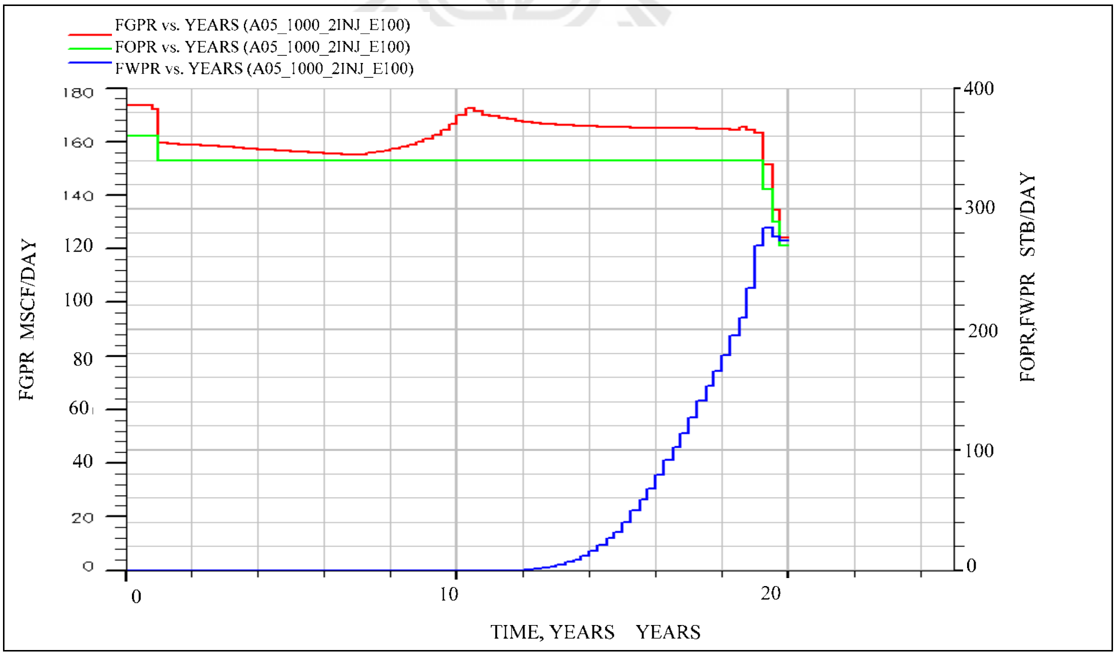


Figure 4.181 Fluids production rate profile vs. Time of model A05_1000_2INJ.

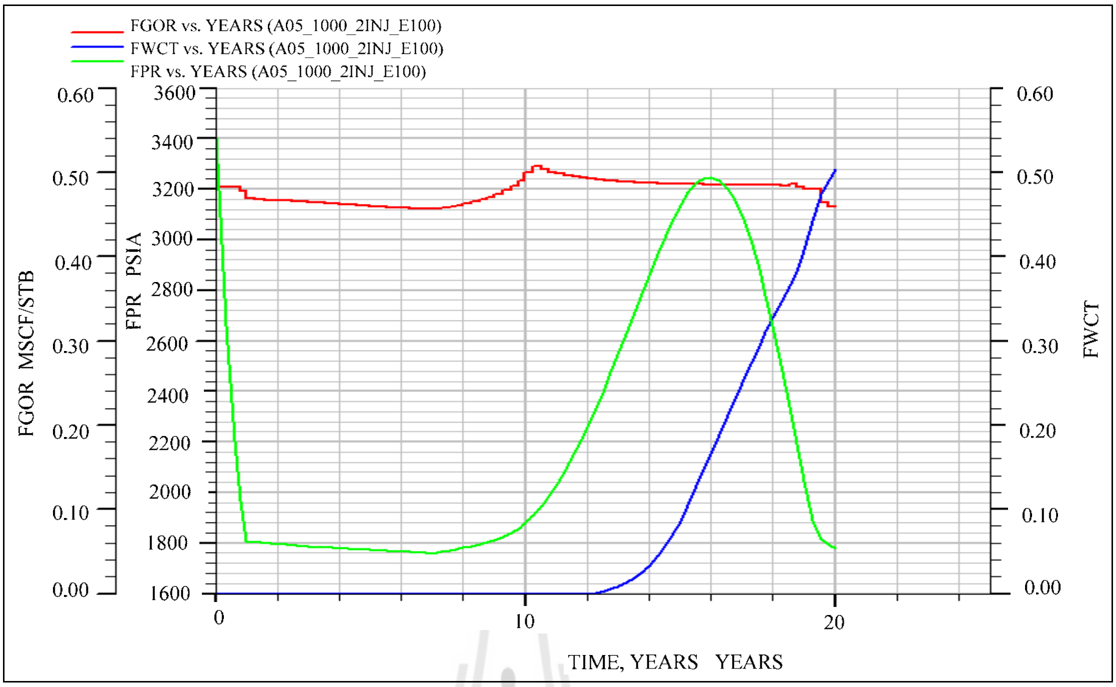


Figure 4.182 GOR, WCT, and Pressure profile vs. Time of model A05_1000_2INJ.

Figure 4.183 Oil recovery efficiency vs. Time of model A05_1200_2INJ.

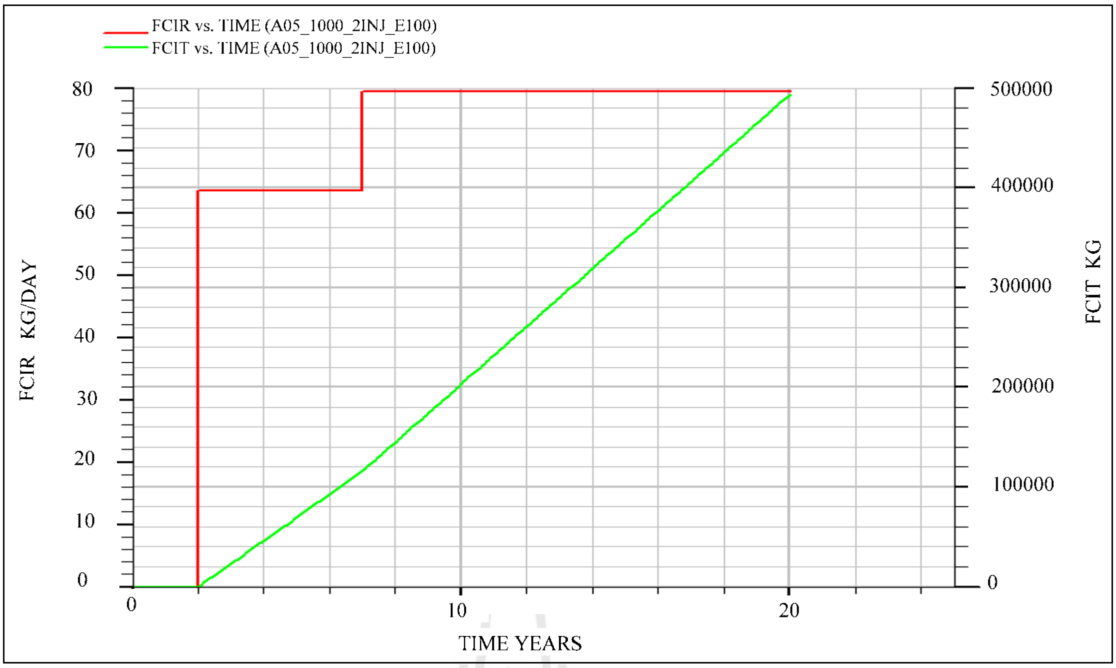


Figure 4.184 CIR and CIT vs. Time of model A05_1000_2INJ.

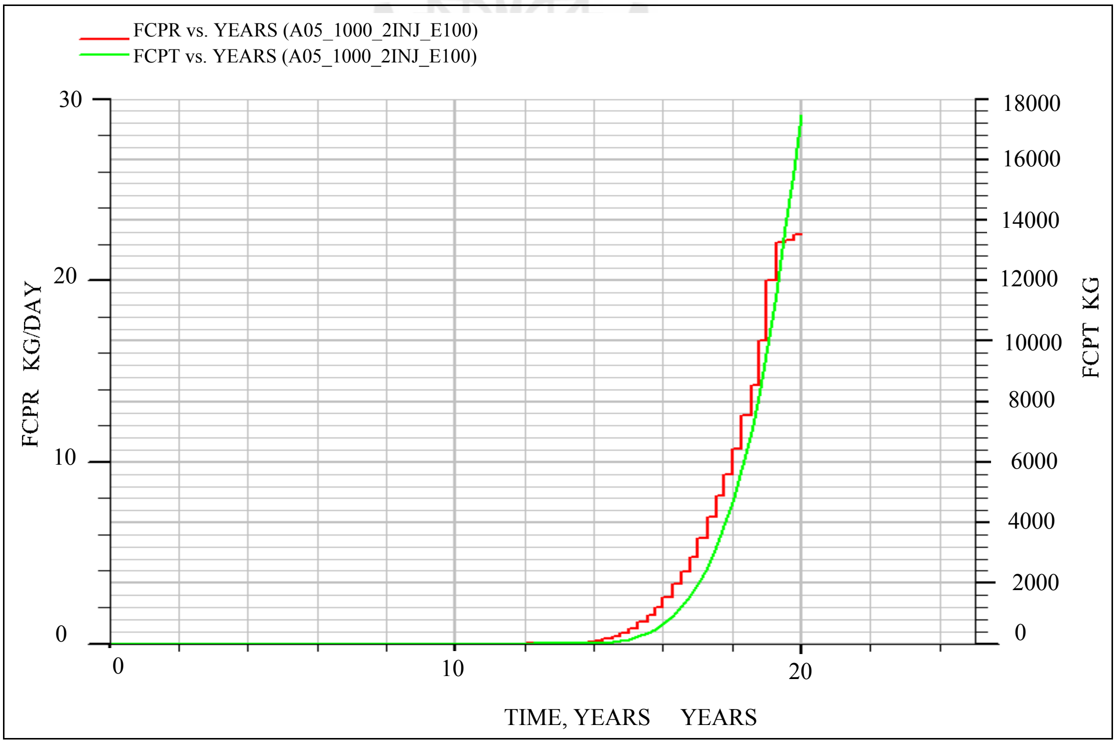


Figure 4.185 CPR and CPT vs. Time of model A05_1000_2INJ.

Table 4.51 Summary detail of graph 4.179, 4.180 and 4.183.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,478,558	5,096,241	48.63
Gas (MSCF)	1,182,180	2,458,902	48.08
Water (STB)	294,037	2,558,227	11.49

Table 4.52 Summary detail of graph 4.184 and 4.185.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	9,168,827	0.34	494

4.3.7 Model A05_1000_3INJ Scenario Result

Model A05_1000_3INJ is polymer flooding and the simulation results as shown in Table 4.53-4.54 and Figure 4.186 – 4.192:

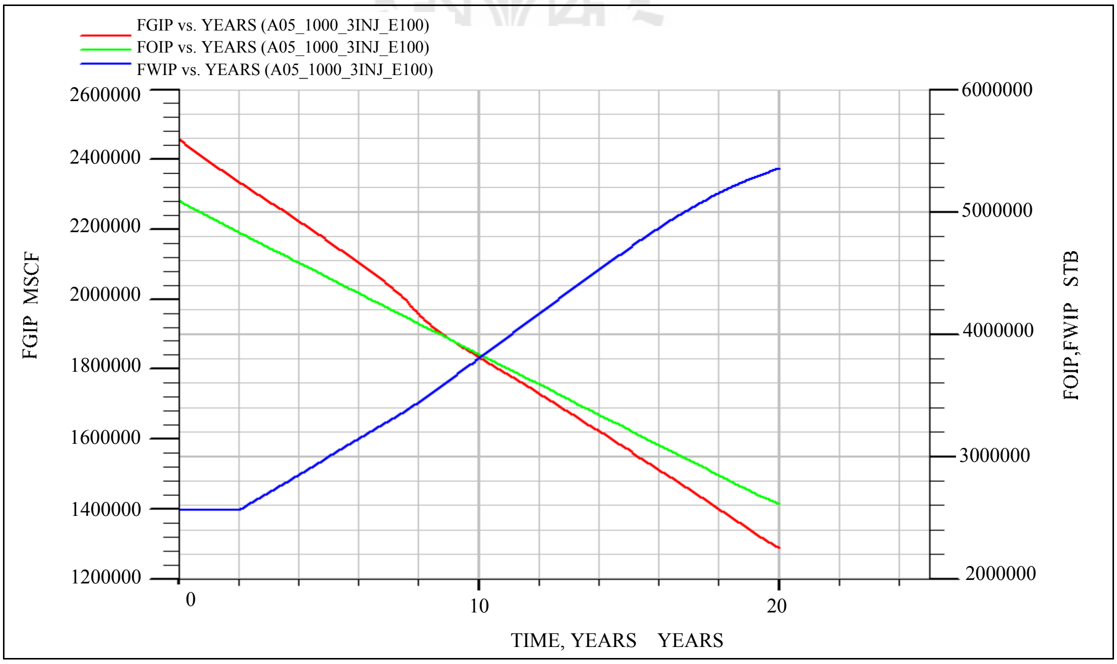


Figure 4.186 Fluid in place profile vs. Time of model A05_1000_3INJ.

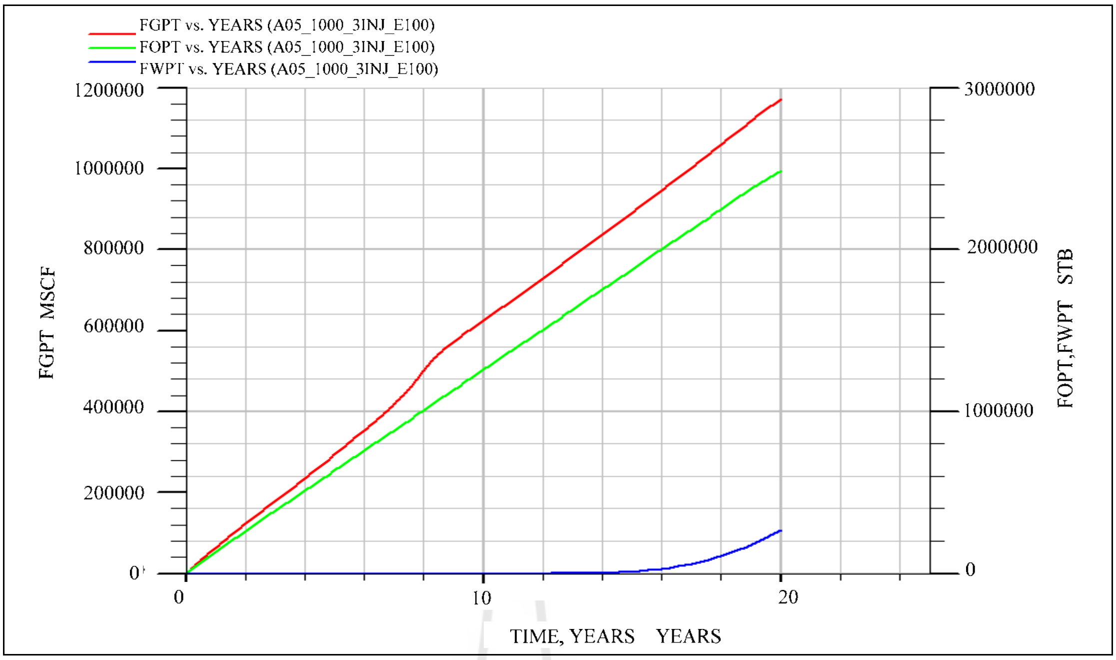


Figure 4.187 Cumulative fluids production profile vs. Time of model A05_1000_3INJ.

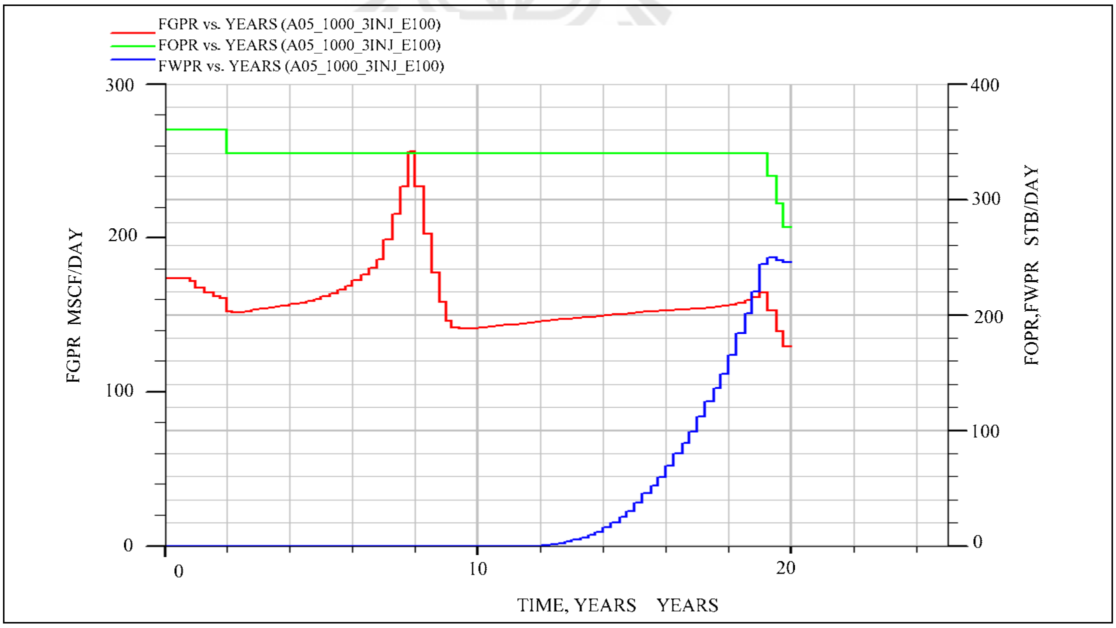


Figure 4.188 Fluids production rate profile vs. Time of model A05_1000_3INJ.

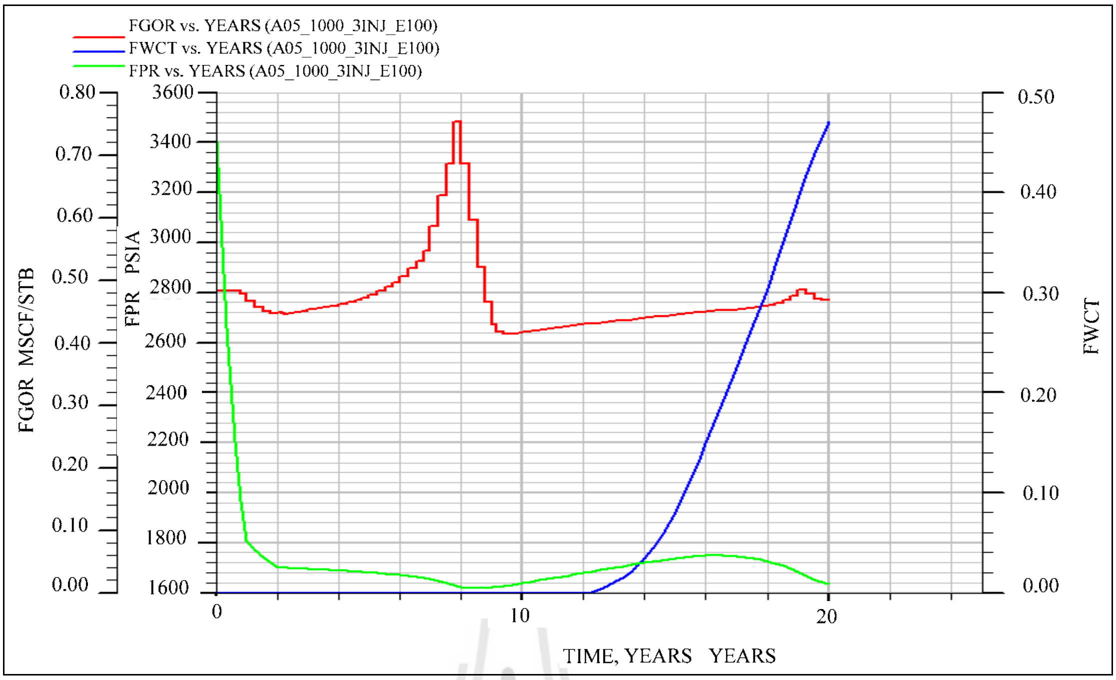


Figure 4.189 GOR, WCT, and Pressure profile vs. Time of model A05_1000_3INJ.

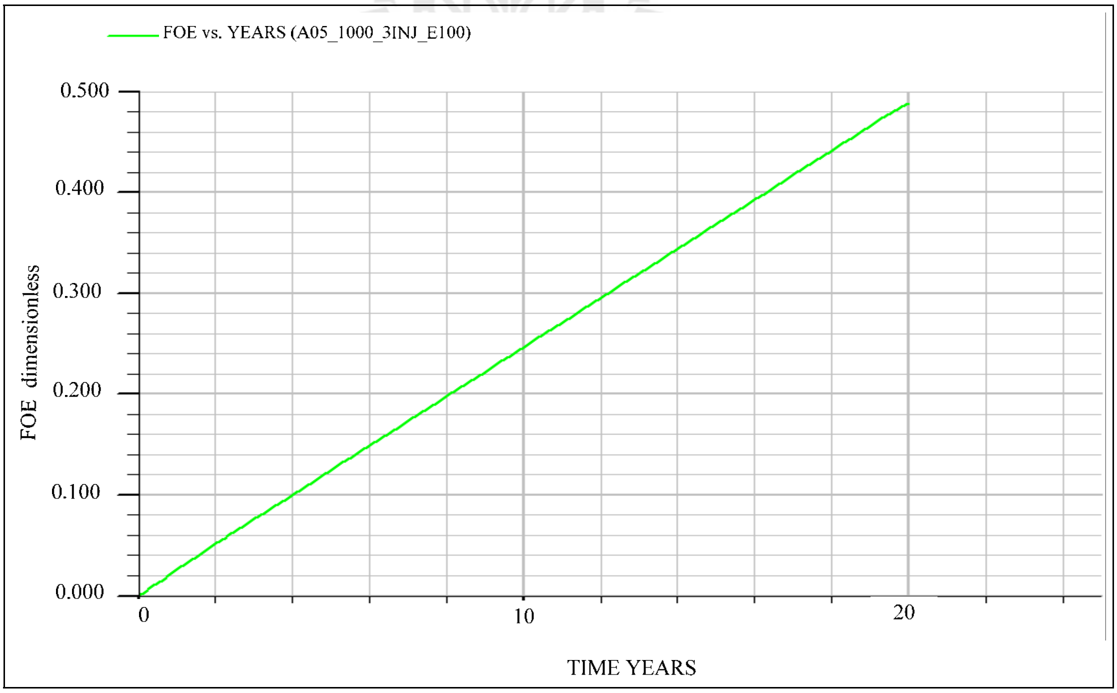


Figure 4.190 Oil recovery efficiency vs. Time of model A05_1000_3INJ.

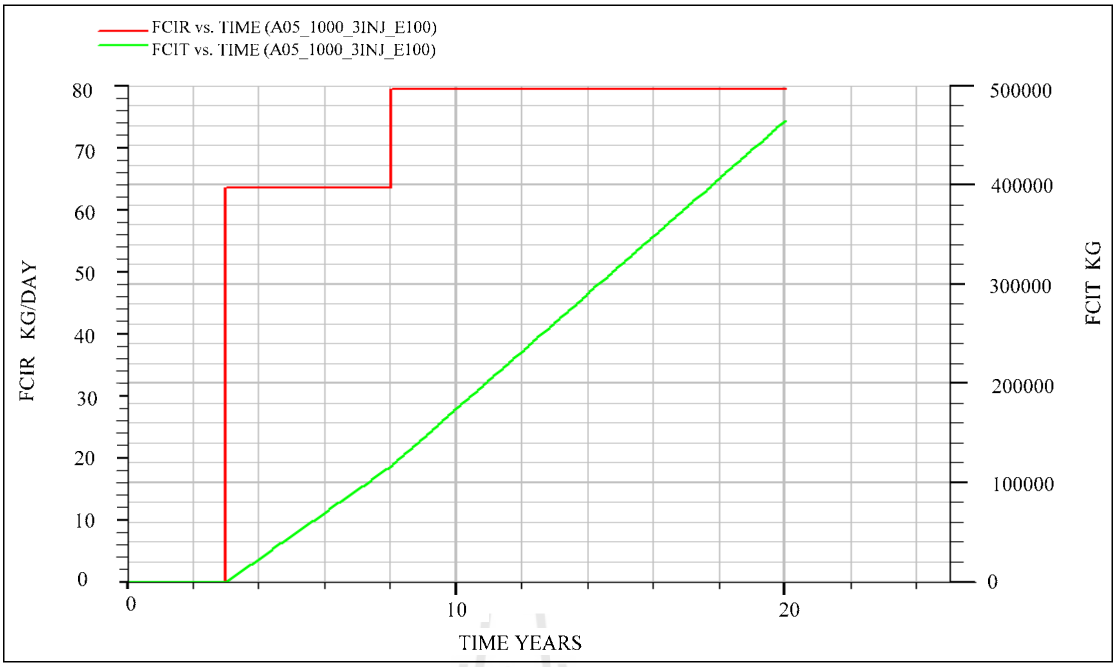


Figure 4.191 CIR and CIT vs. Time of model A05_1000_3INJ.

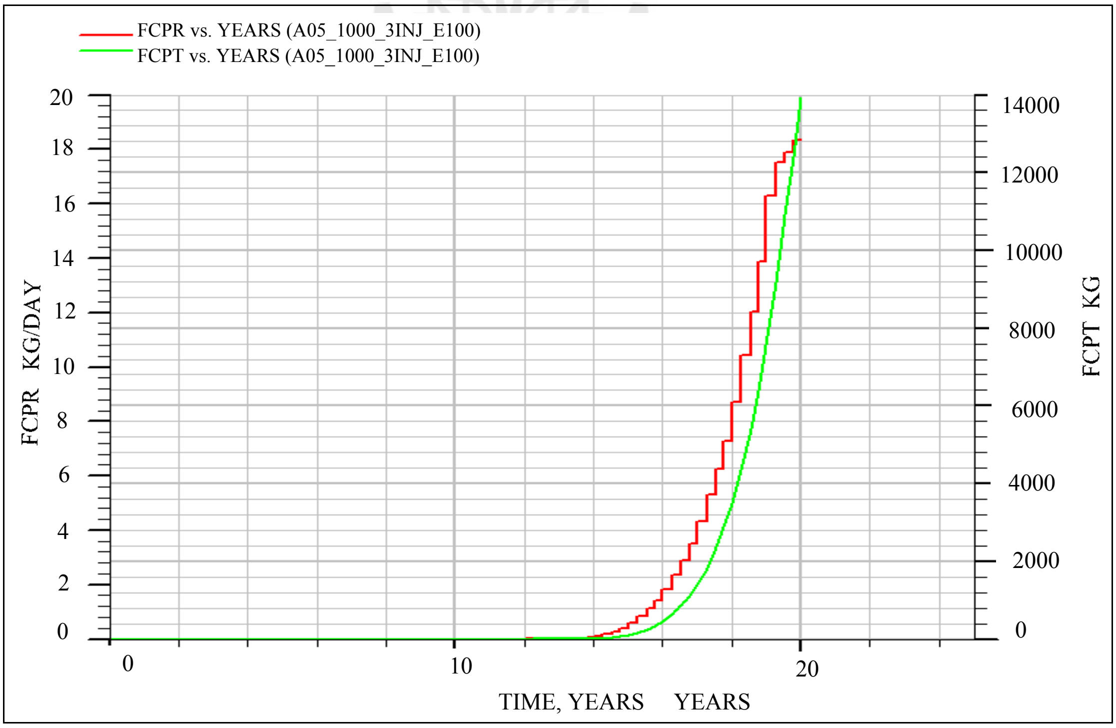


Figure 4.192 CPR and CPT vs. Time of model A05_1000_3INJ.

Table 4.53 Summary detail of graph 4.186, 4.187 and 4.190.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,487,381	5,096,241	48.81
Gas (MSCF)	1,171,144	2,458,902	47.63
Water (STB)	266,581	2,558,227	10.42

Table 4.54 Summary detail of graph 4.191 and 4.192.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,000	9,168,827	0.34	465

4.3.8 Model A05_1200_2INJ Scenario Result

Model A05_1200_2INJ is polymer flooding and the simulation results as shown in Table 4.55-4.56 and Figure 4.193 – 4.199:

Figure 4.193 Fluid in place profile vs. Time of model A05_1200_2INJ.

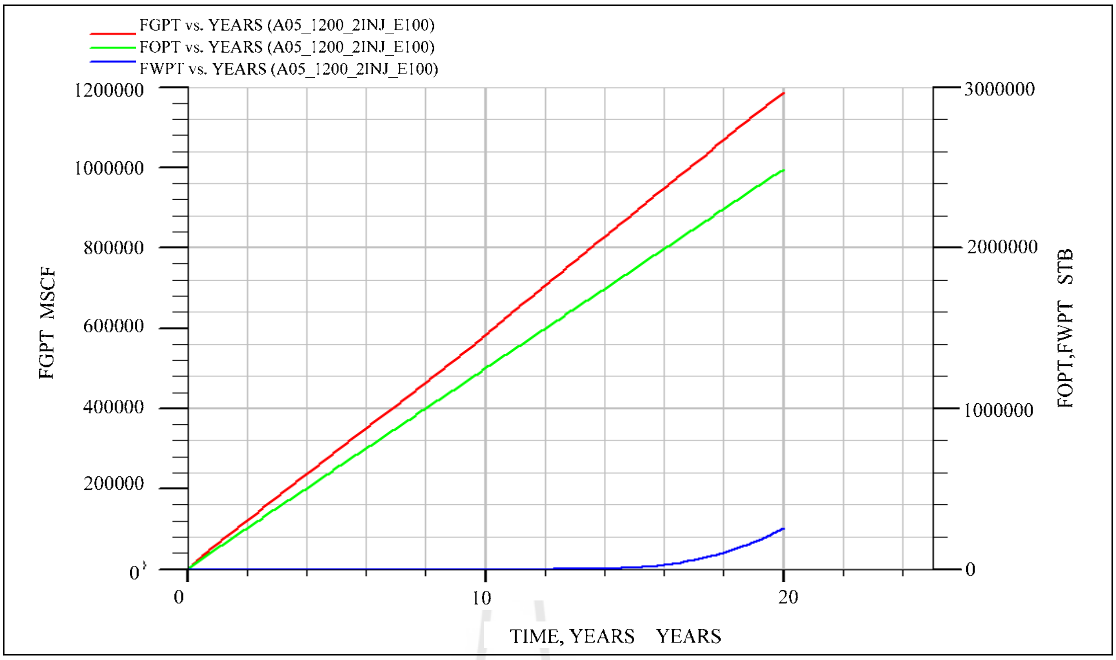


Figure 4.194 Cumulative fluids production profile vs. Time of model A05_1200_2INJ.

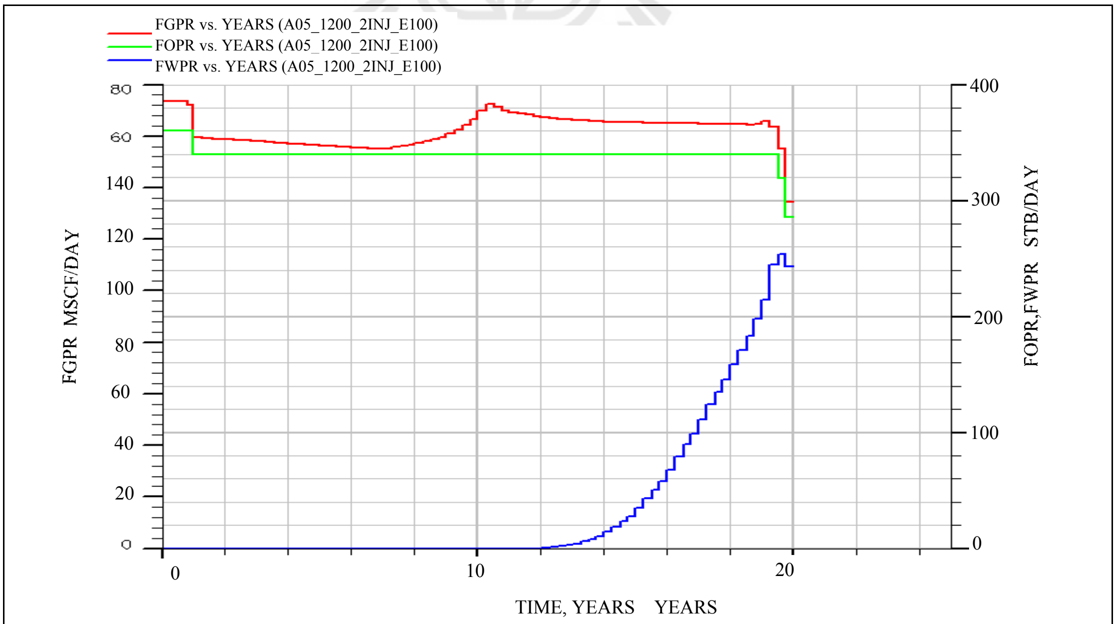


Figure 4.195 Fluids production rate profile vs. Time of model A05_1200_2INJ.

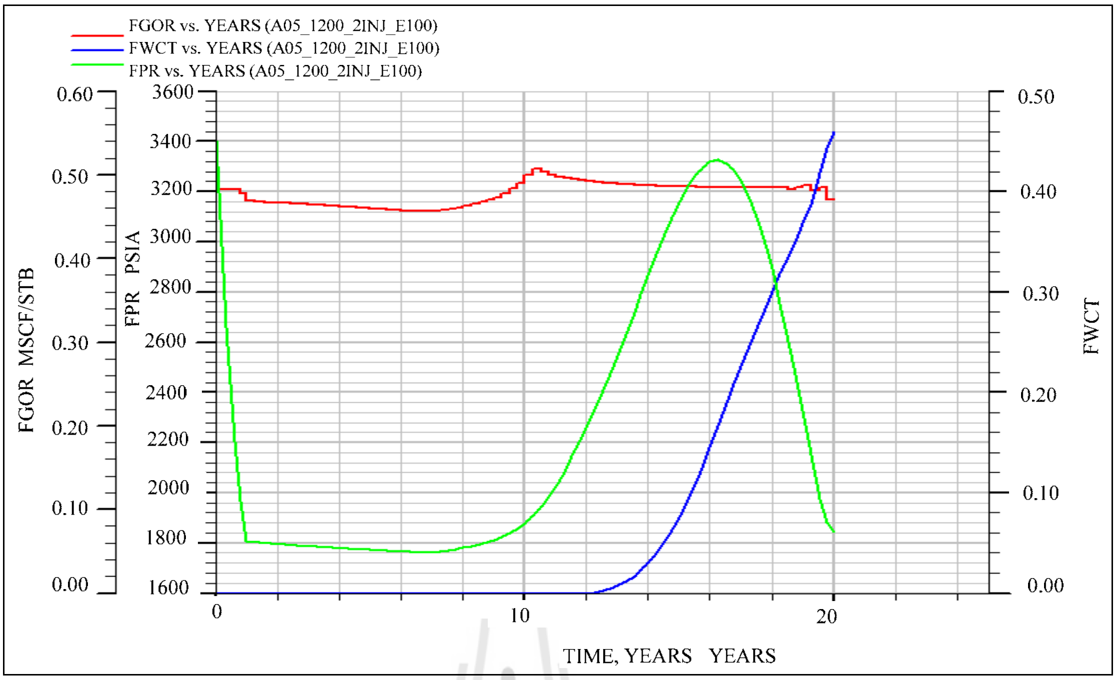


Figure 4.196 GOR, WCT, and Pressure profile vs. Time of model A05_1200_2INJ.

Figure 4.197 Oil recovery efficiency vs. Time of model A05_1200_2INJ.

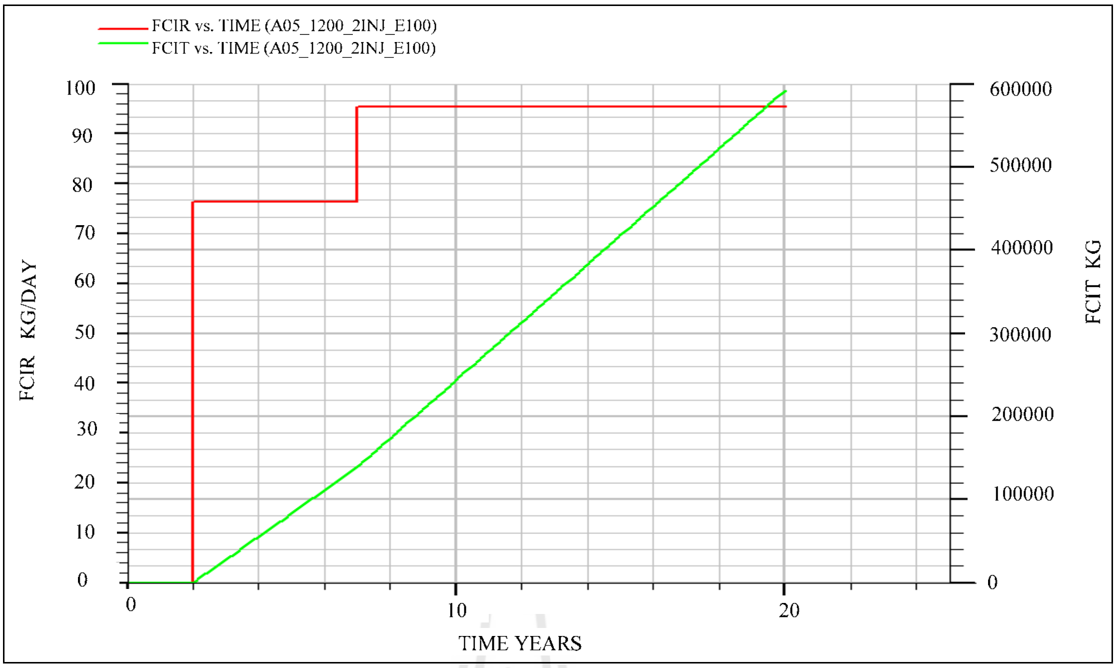


Figure 4.198 CIR and CIT vs. Time of model A05_1200_2INJ.

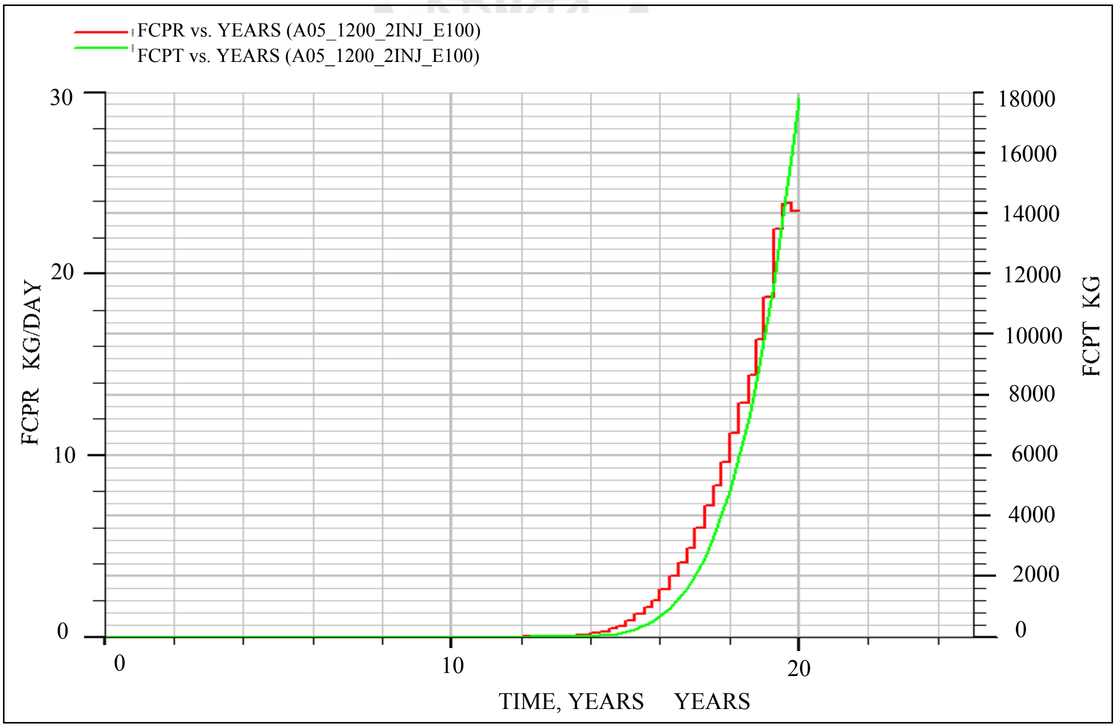


Figure 4.199 CPR and CPT vs. Time of model A05_1200_2INJ.

Table 4.55 Summary detail of graph 4.193, 4.194 and 4.197.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,484,831	5,096,241	48.76
Gas (MSCF)	1,186,075	2,458,902	48.24
Water (STB)	255,696	2,558,227	10.00

Table 4.56 Summary detail of graph 4.198 and 4.199.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,200	9,168,827	0.34	592

4.3.9 Model A05_1200_3INJ Scenario Result

Model A05_1200_3INJ is polymer flooding and the simulation results as shown in Table 4.57-4.58 and Figure 4.200 – 4.206:

Figure 4.200 Fluid in place profile vs. Time of model A05_1200_3INJ.

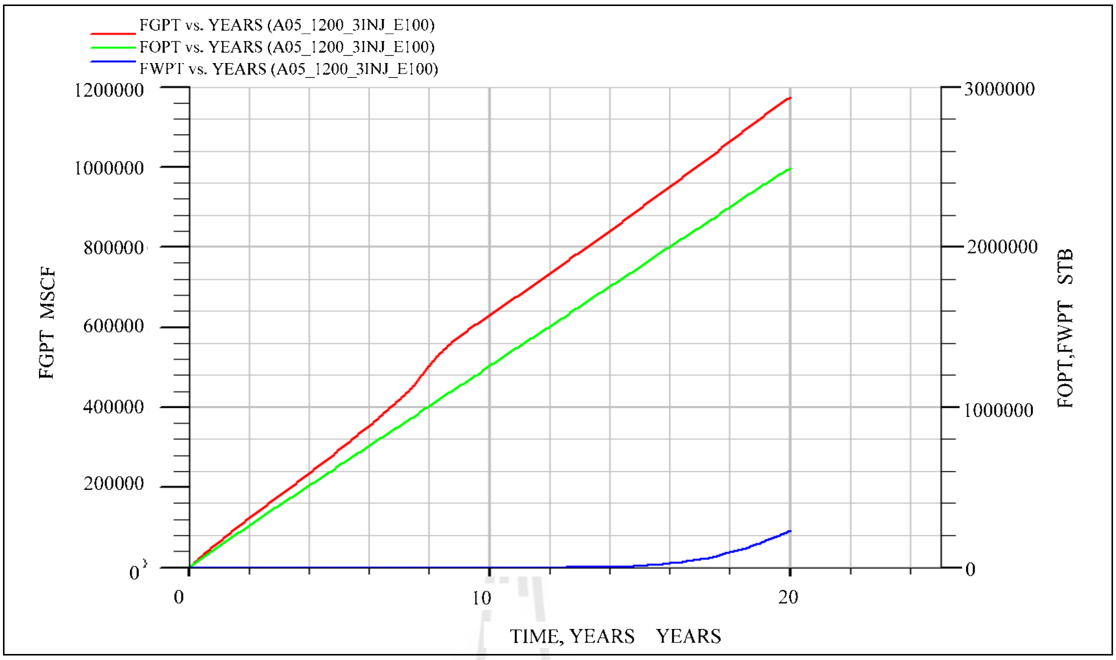


Figure 4.201 Cumulative fluids production profile vs. Time of model A05_1200_3INJ.

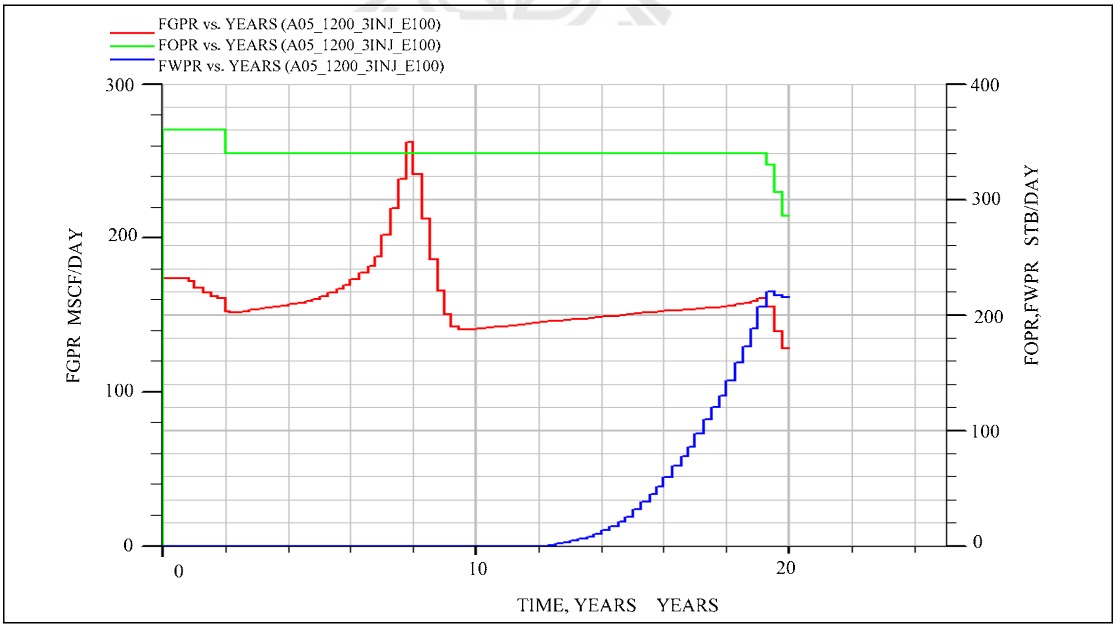


Figure 4.202 Fluids production rate profile vs. Time of model A05_1200_3INJ.

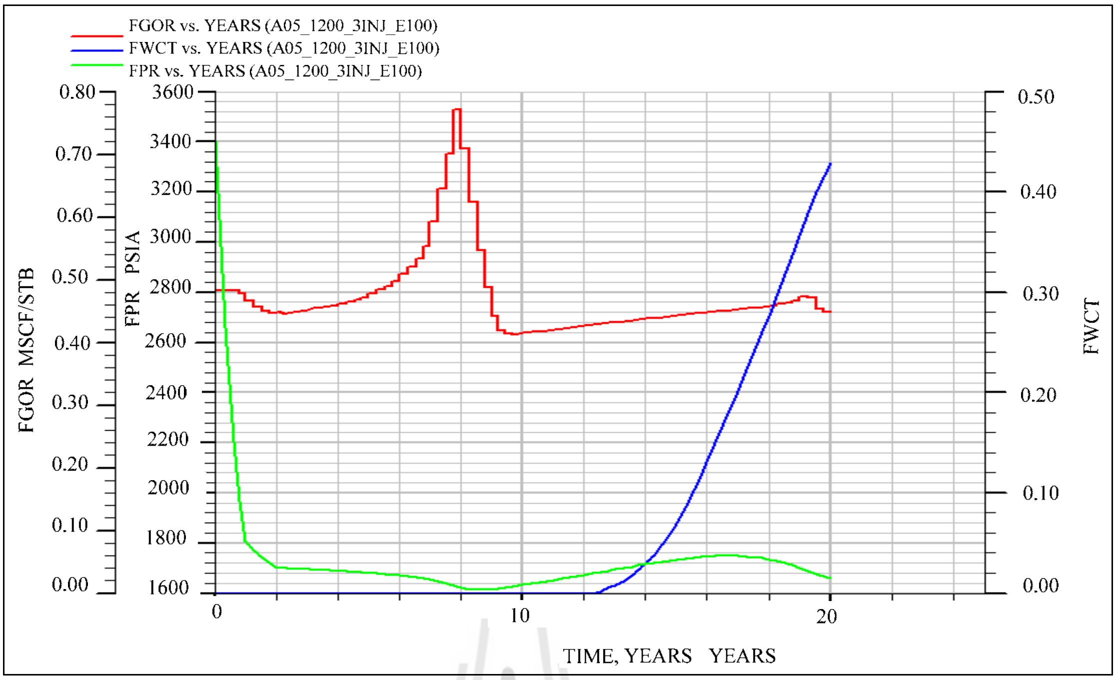


Figure 4.203 GOR, WCT, and Pressure profile vs. Time of model A05_1200_3INJ.

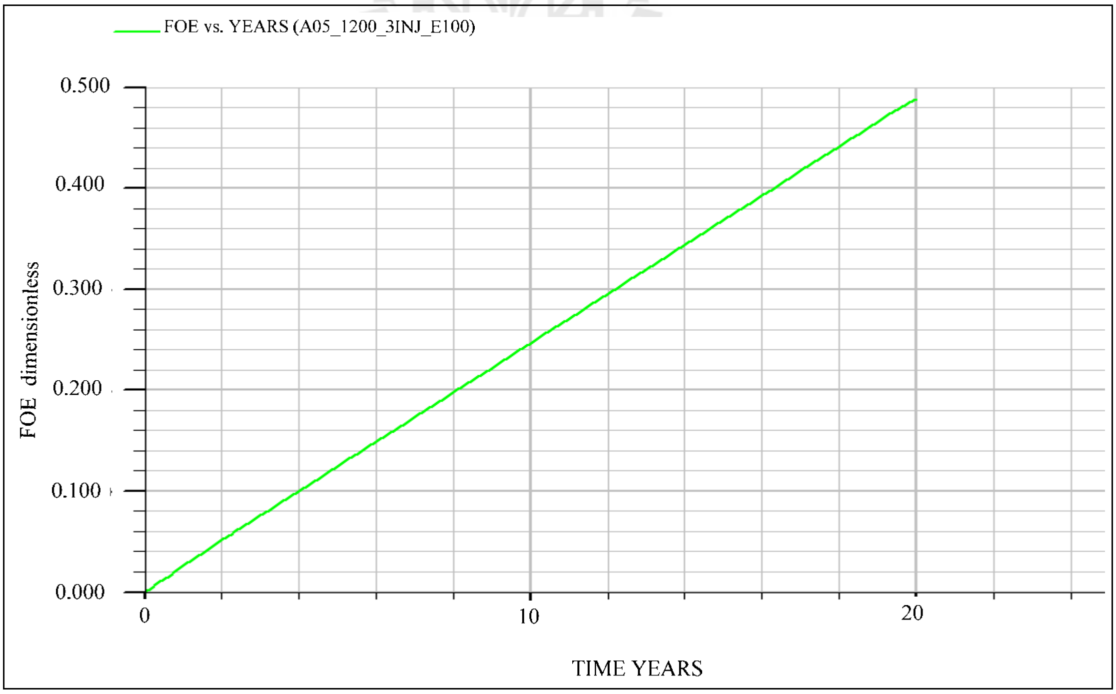


Figure 4.204 Oil recovery efficiency vs. Time of model A05_1200_3INJ.

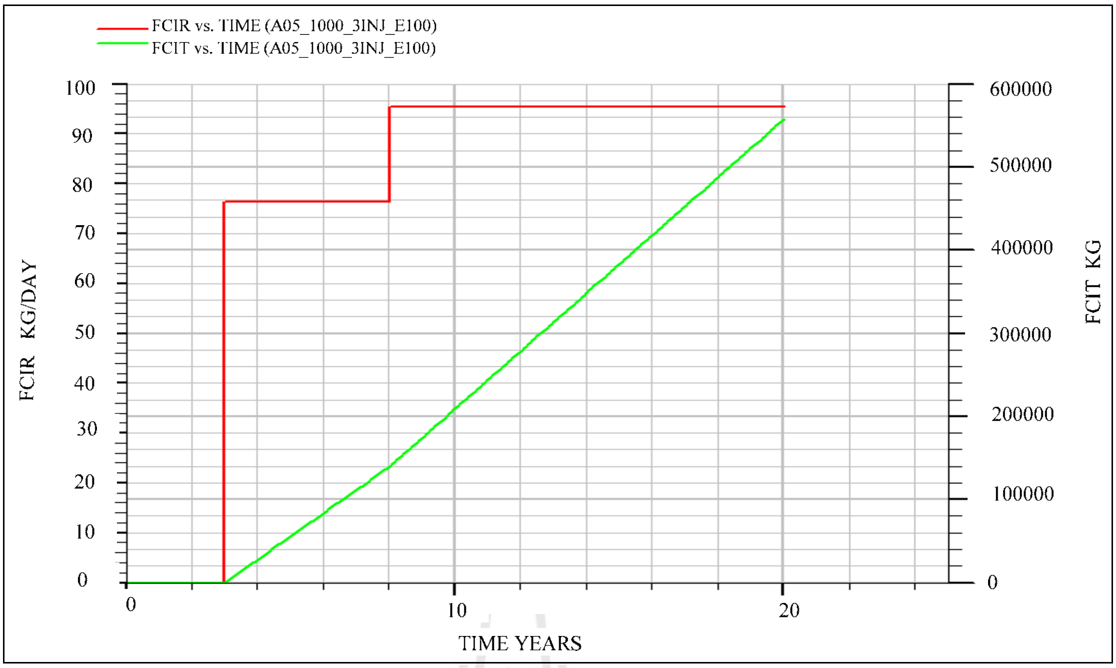


Figure 4.205 CIR and CIT vs. Time of model A05_1200_3INJ.

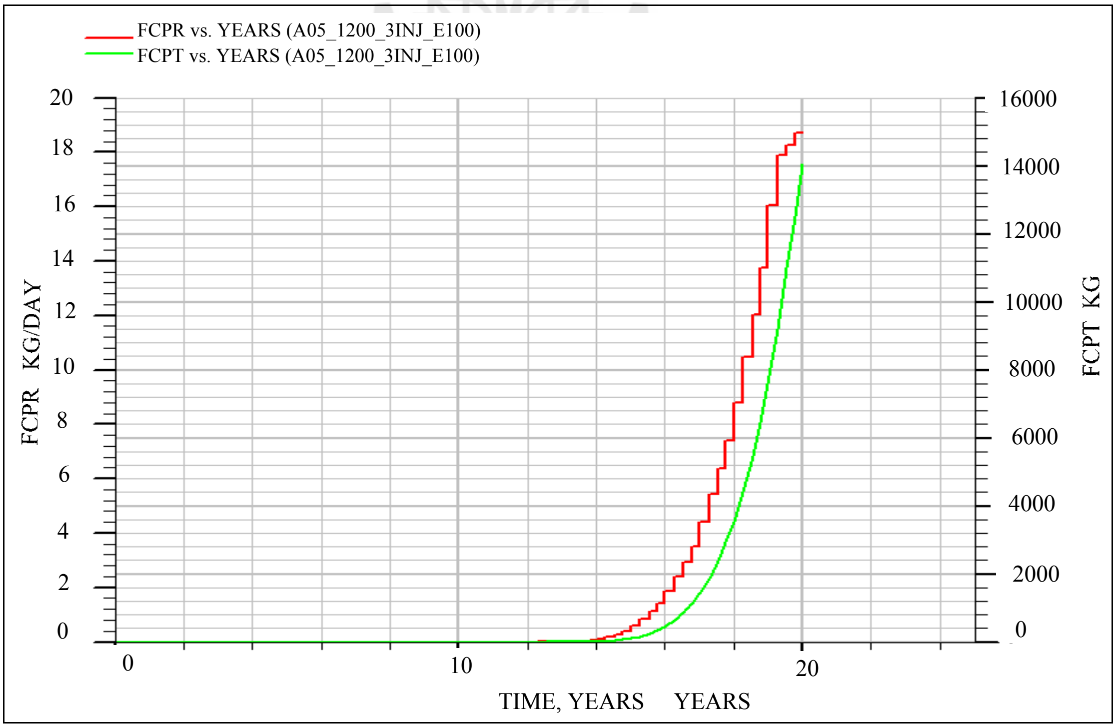


Figure 4.206 CPR and CPT vs. Time of model A05_1200_3INJ.

Table 4.57 Summary detail of graph 4.200, 4.201 and 4.204.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,490,031	5,096,241	48.86
Gas (MSCF)	1,174,179	2,458,902	47.75
Water (STB)	230,765	2,558,227	9.02

Table 4.58 Summary detail of graph 4.205 and 4.206.

Polymer type	Concentration (ppm)	PV reservoir (RB)	Polymer slug size (PV)	Amount of polymer (ton)
XCD	1,200	9,168,827	0.34	557

For model A05, the results of reservoir simulation for nine cases (a base case of waterflooding and eight cases of polymer flooding) of different starting times for polymer injection of 3rd and 4th years of production period, for an optimized polymer slug size as 0.34 PV. The processes of reservoir simulation were made for different polymer concentrations of 600, 800, 1,000 and 1,200 ppm. The two of different starting times corresponding to the polymer concentrations of 600, 800, 1,000 and 1,200 ppm, respectively. These simulations called polymer flooding, running for find the best case oil recovery efficiency. They gave better results than that of the waterflooding as presented in Figure 4.207 – 4.208

The average of oil production totals and the oil recovery efficiency have increased more than the waterflooding as shown in Table 4.59.

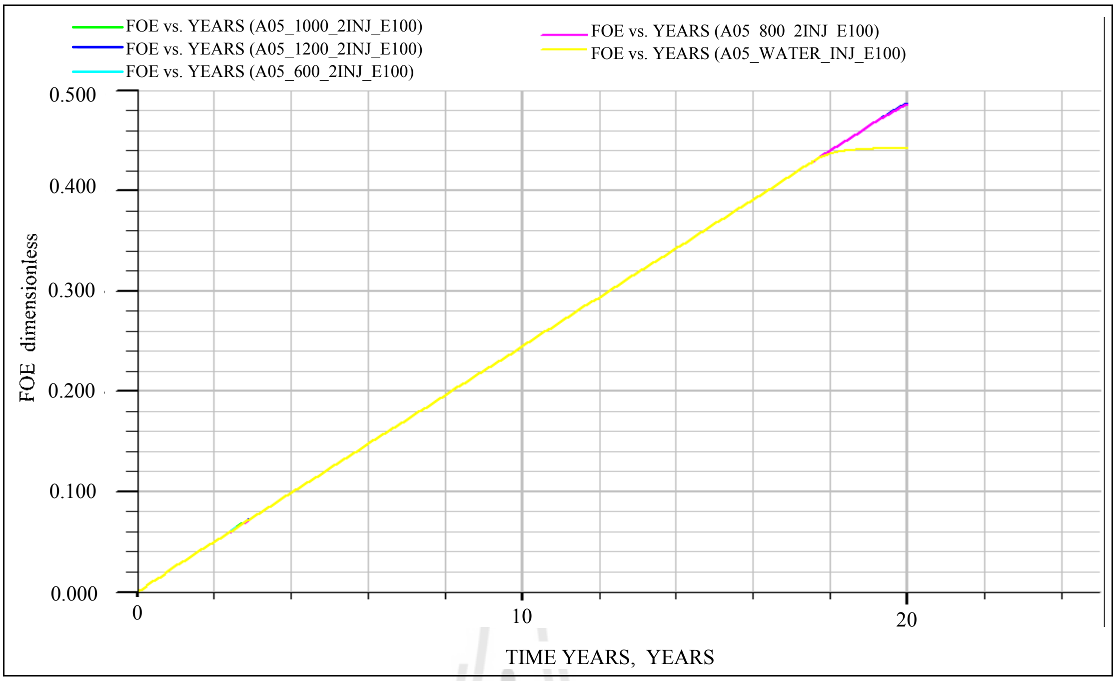


Figure 4.207 Oil recovery efficiency vs. Time of model A05 ply.-start@3rd year.

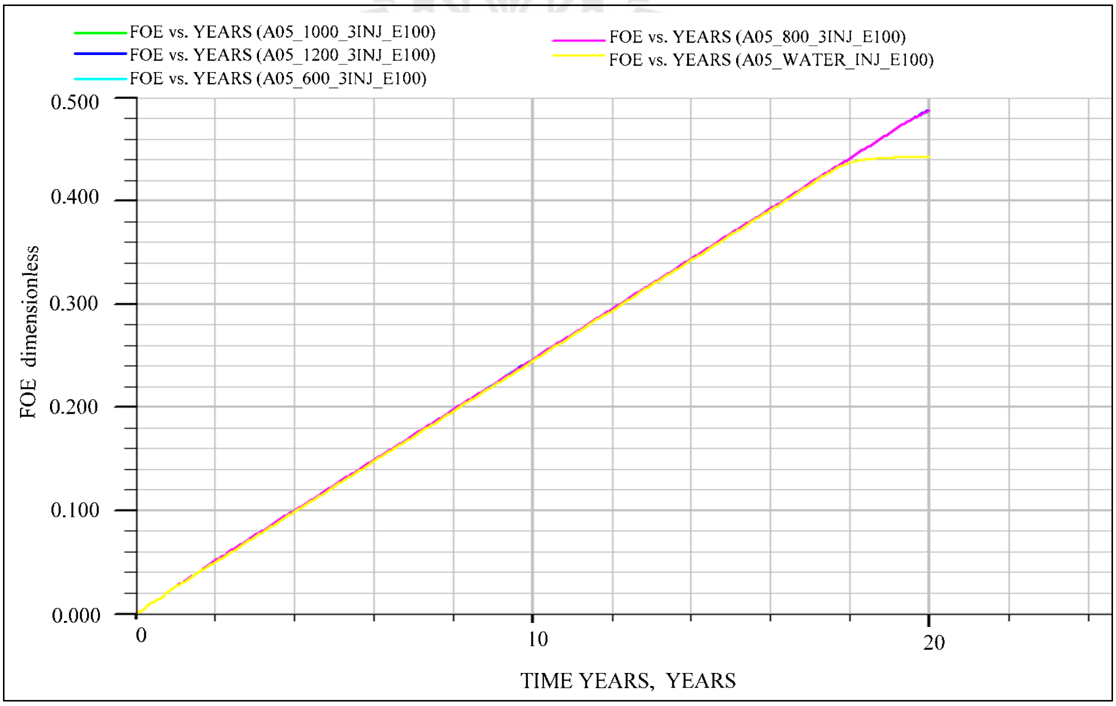


Figure 4.208 Oil recovery efficiency vs. Time of model A05 ply.-start@4th year

Table 4.59 Cumulative oil production and oil recovery efficiency for A05.

Model Name	Scenario No.	Scenario Name	Polymer Concentration (ppm)	Cum. Oil production (BBL)	Recovery Factor (RF)
A05	1	A05_WATER_INJ	-	2,254,415	44.24
	2	A05_600_2INJ	600	2,478,934	48.64
	3	A05_600_3INJ	600	2,483,015	48.72
	4	A05_800_2INJ	800	2,478,150	48.63
	5	A05_800_3INJ	800	2,486,937	48.80
	6	A05_1000_2INJ	1,000	2,478,558	48.63
	7	A05_1000_3INJ	1,000	2,487,381	48.81
	8	A05_1200_2INJ	1,200	2,484,831	48.76
	9	A05_1200_3INJ	1,200	2,490,031	48.86

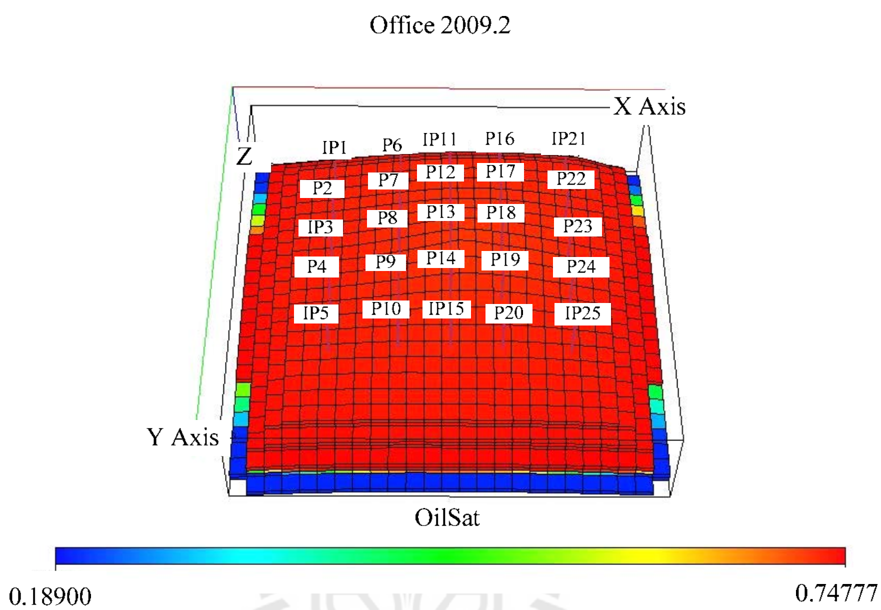
4.4 Reservoir Modeling Design and Model Scenarios Test Results

4.4.1 Simulation Model of Reservoir STOIP = 109 MMBBL

This model has area 39,062,500 ft^2 (896.75 acres), 5,000 grid block and 8 layers@625 cells/layer. The reservoir simulation has 25 production wells. From the base case of reservoir simulation by waterflooding, the performance without polymer flooding are performed by ECLIPSE PROGRAM presented in 3D as shown in Figure 4.209 and polymer flooding in 3D as shown in Figure 4.210.

From Figure 4.209 and 4.210, the top of figure is simulation in 1st year starting time of production. The middle figure shows the front of water movement from the eight injections well in 10th year. The bottom figure shows the development of water that has been wide spread movement from the eight injection wells to the 17 production wells.

The main results of a base case (waterflooding) can be indicated the performance of water cut and oil production versus time as shown in Figure 4.211 and 4.212. The water cut of reservoir increases gradually and starts extremely in 5^{th} year.



1^{st} year (Max, in red color = 0.74777; Min, in blue color = 0.189)

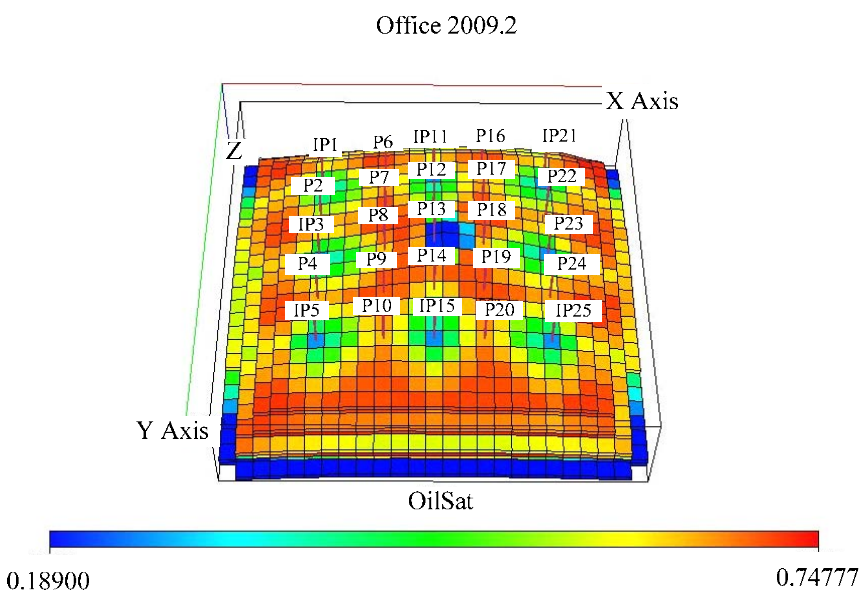
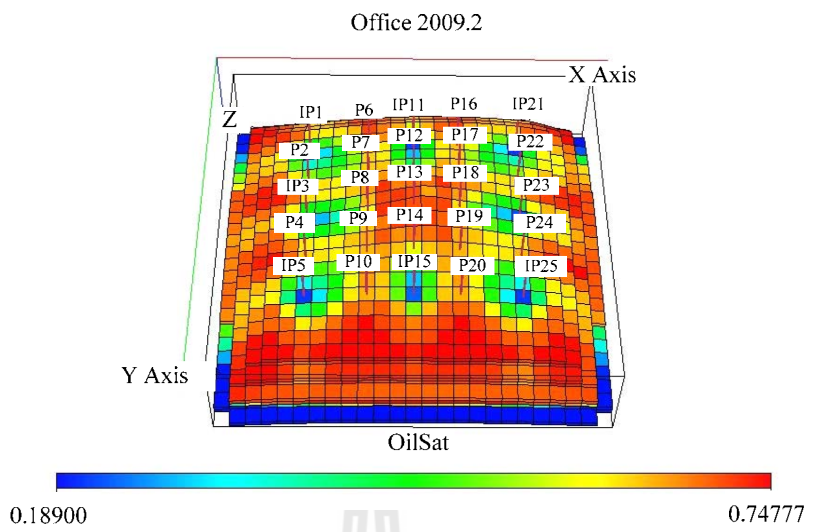


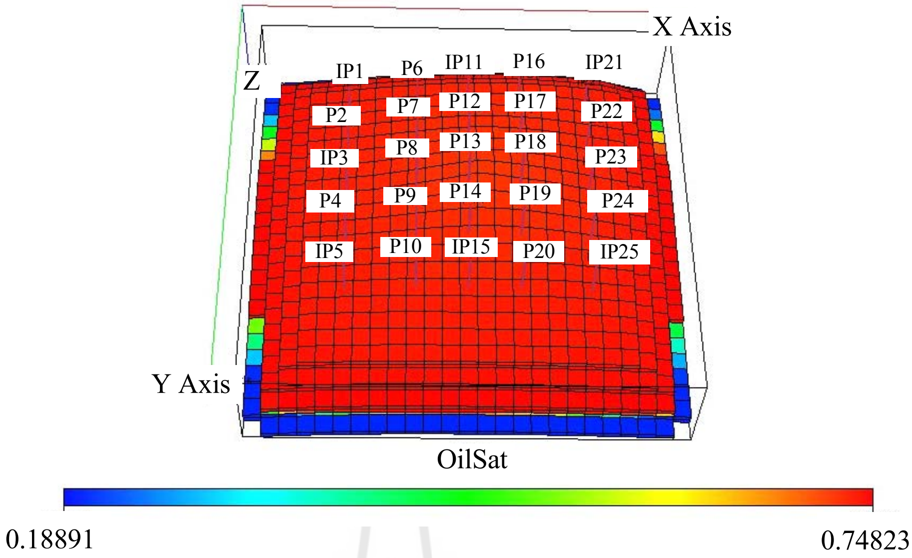
Figure 4.209 The change in oil saturation due to water injection for 1^{st}, 10^{th}, 25^{th} year.



25th year (Max, in red color = 0.74777; Min, in blue color = 0.189)

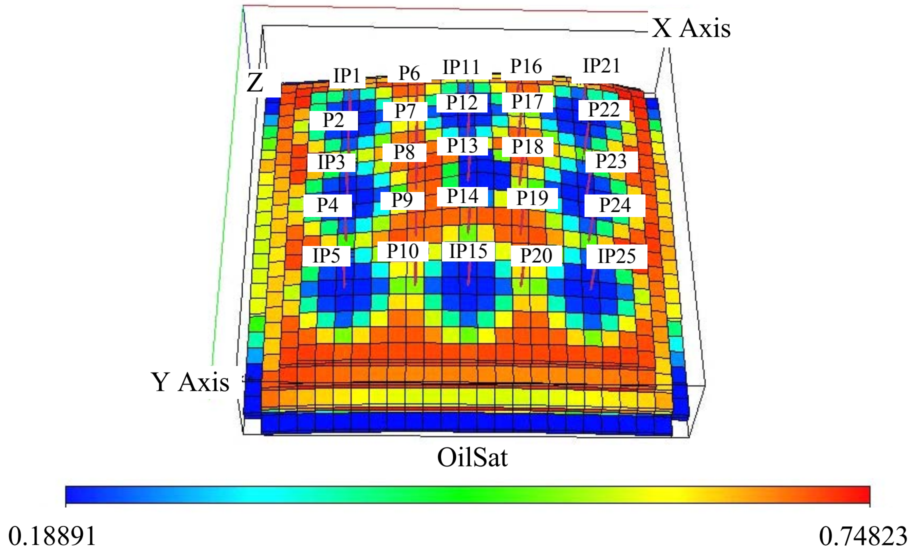
Figure 4.209 The change in oil saturation due to water injection for 1st, 10th, 25th year. (Continued)

Office 2009.2



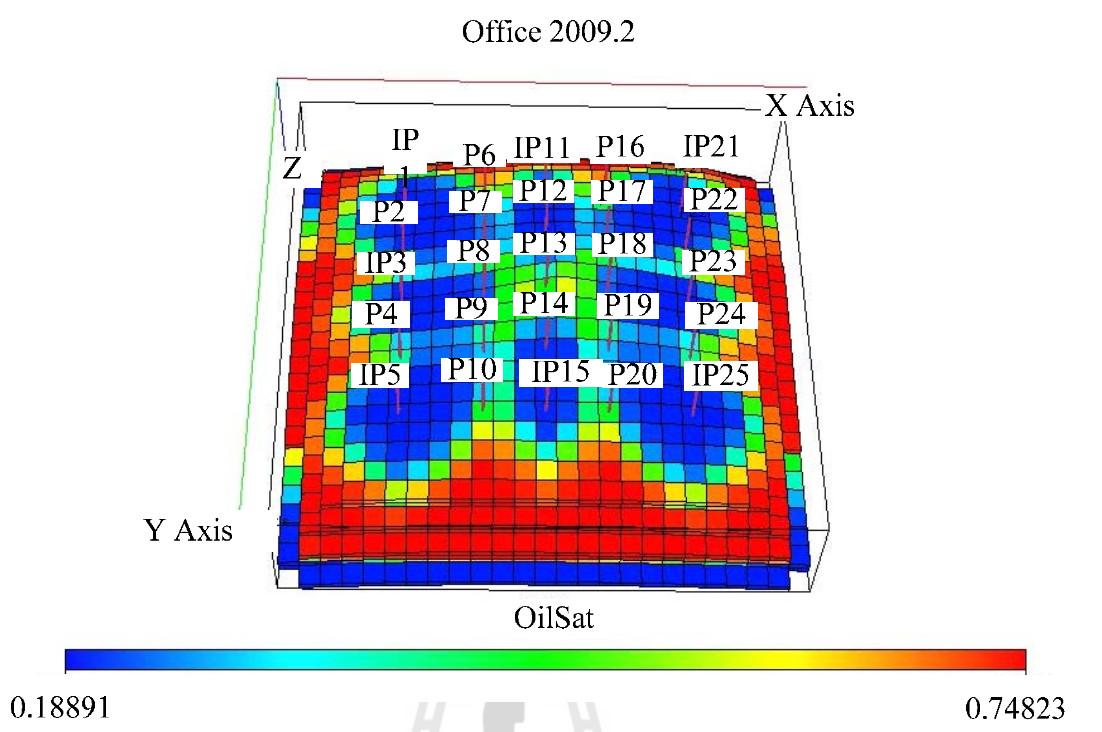
1st year (Max, in red color = 0.74823; Min, in blue color = 0.18891)

Office 2009.2



10th year (Max, in red color = 0.74823; Min, in blue color = 0.18891)

Figure 4.210 The change in oil saturation due to polymer solution injection for 1st,10th,25th year (from the best scenarios A100_1000_2INJ).



25th year (Max, in red color = 0.74823; Min, in blue color = 0.18891)

Figure 4.210 The change in oil saturation due to polymer solution injection for 1st,10th,25th year (from the best scenarios A100_1000_2INJ). (Continued)

While the oil production also increase until 5th year, but it has been declining quickly after 5th year. Therefore, if the reservoir has not applies the other method for enhanced oil recovery such as polymer flooding, the water cut will be increased and also the water production increased too. While the oil production rate and the oil production total will be decreased. Finally, the oil recovery efficiency of waterflooding (base case) is 33.11%, while the oil recovery efficiency of polymer flooding will be increased up to 38.36% in 25th year.

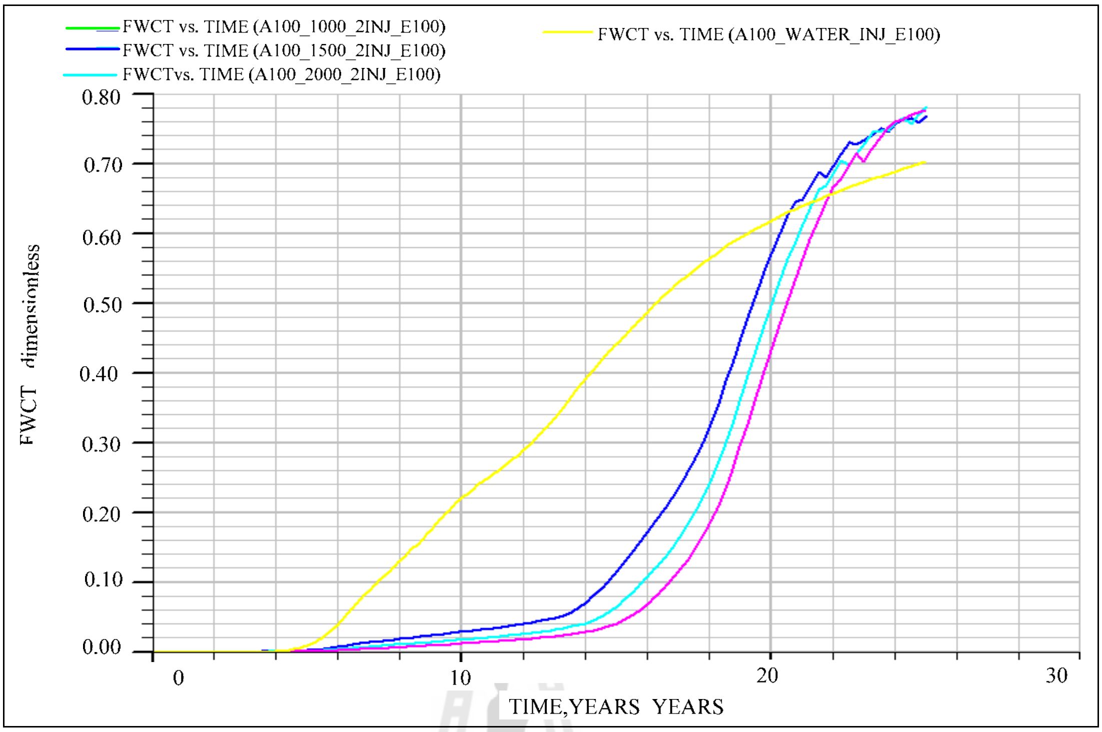


Figure 4.211 Simulation Field Water Cut vs. Time.

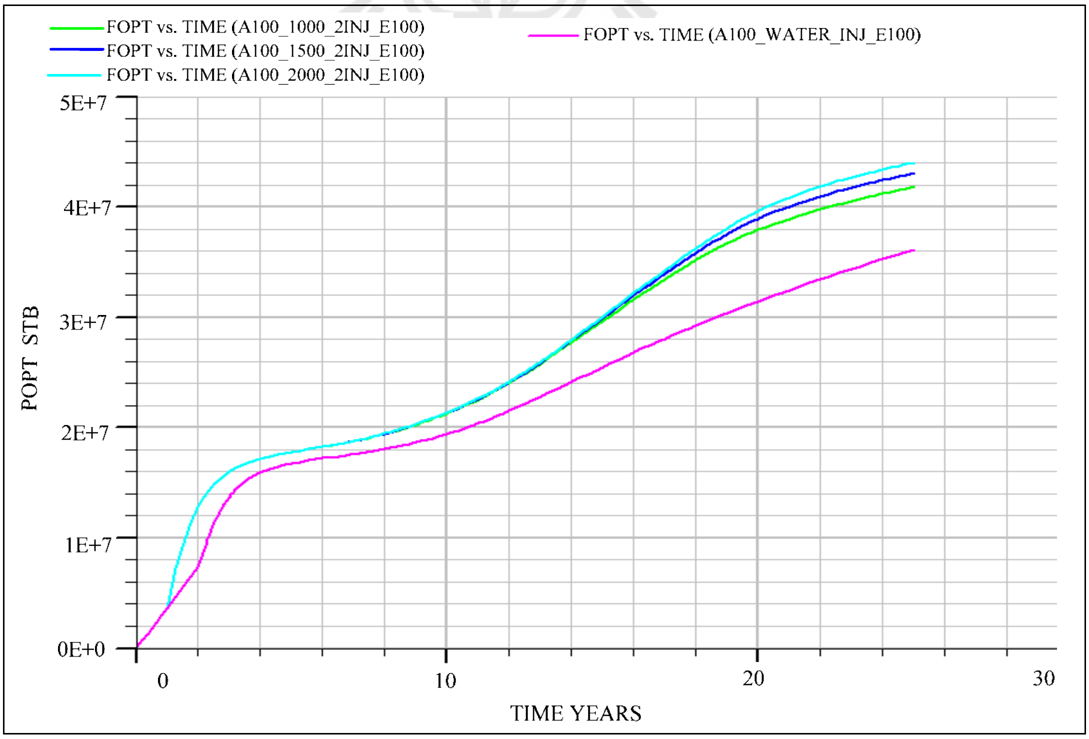


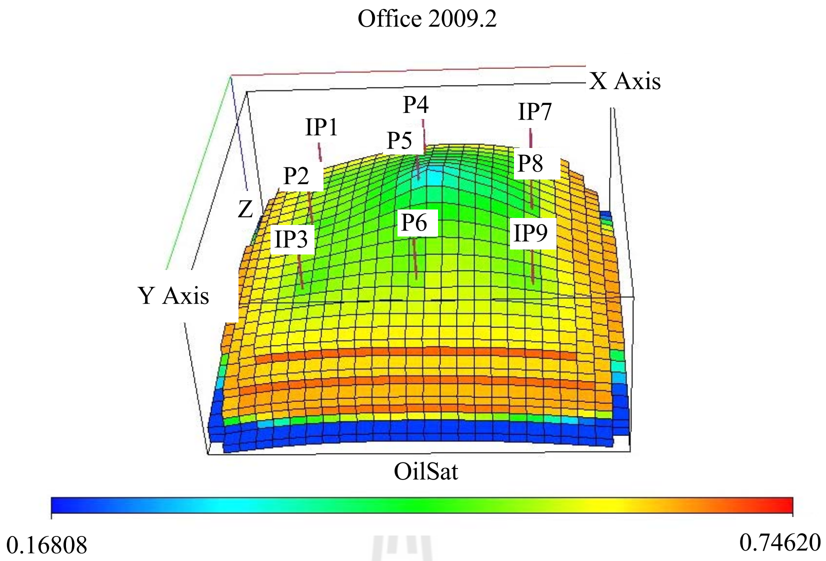
Figure 4.212 Simulation Oil Production Total vs. Time.

4.4.2 Simulation Model of Reservoir STOIP = 32 MMBBL

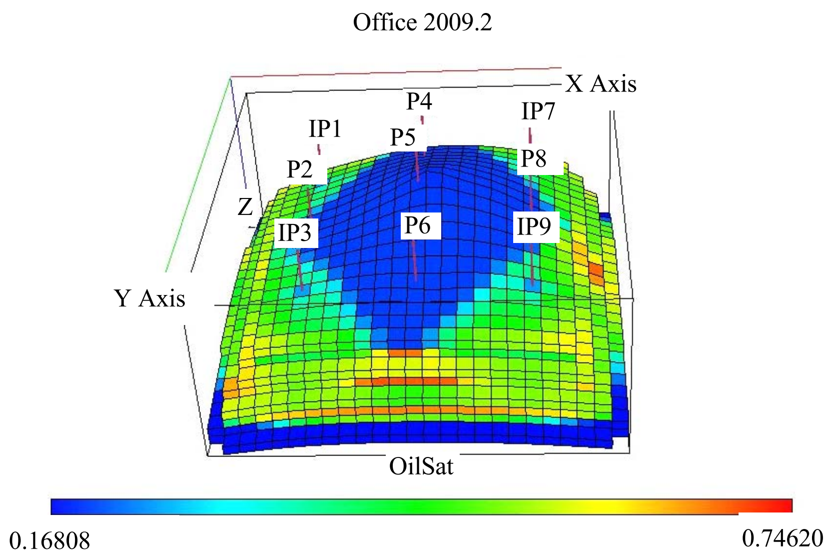
This model has area 11,390,625 ft^2 (261.49 acres), 5,000 grid block and eight layers@625 cells/layer. The reservoir simulation has nine production wells. From the base case of reservoir simulation by waterflooding, the performance without polymer flooding are performed by ECLIPSE PROGRAM presented in 3D as shown in Figure 4.213 and polymer flooding in 3D as shown in Figure 4.214.

From Figure 4.213 and 4.214, the top of figure is simulation in 1^{st} year starting time of production. The middle figure shows the front of water movement from the four injection wells in 10^{th} year. The bottom figure shows the development of water that has been wide spread movement from the four injection wells to the five production wells.

The main results of a base case (waterflooding) can be indicated the performance of water cut and oil production versus time as showed in Figure 4.215 and 4.216. The water cut of reservoir increases gradually and starts extremely in 8^{th} year. While the oil production also increase until 4^{th} year, but it has been declining quickly after 5^{th} year. Therefore, if the reservoir has not apply the other method for enhanced oil recovery such as polymer flooding, the water cut will be increased and also the water production increased too, while the oil production rate and the oil production total will be decreased. Finally, the oil recovery efficiency of waterflooding (base case) is 24.47%, while the oil recovery efficiency of polymer flooding will be increased up to 28.72% in 25^{th} year.

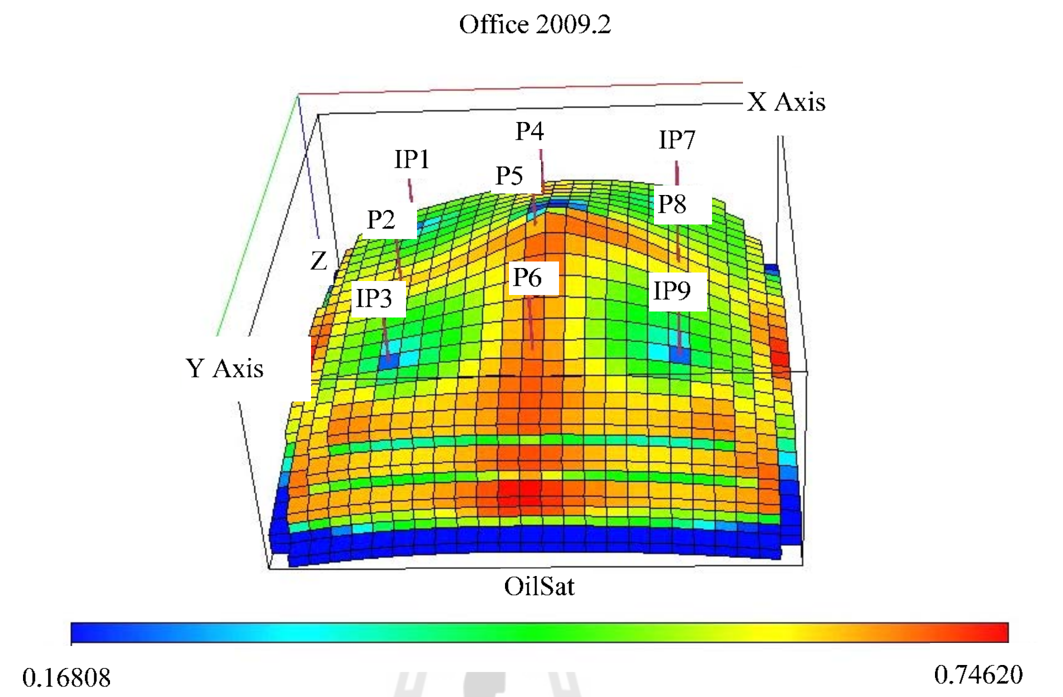


1st year (Max, in red color = 0.74620; Min, in blue color = 0.16808)



10st year (Max, in red color = 0.74620; Min, in blue color = 0.16808)

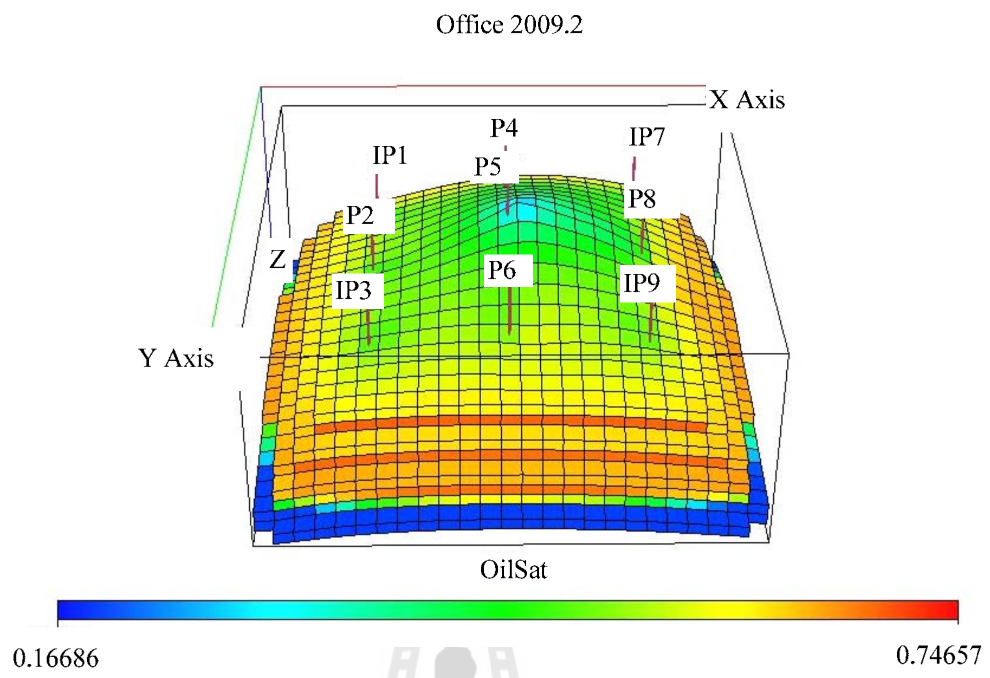
Figure 4.213 The change in oil saturation due to water injection for 1st, 10th, 25th year.



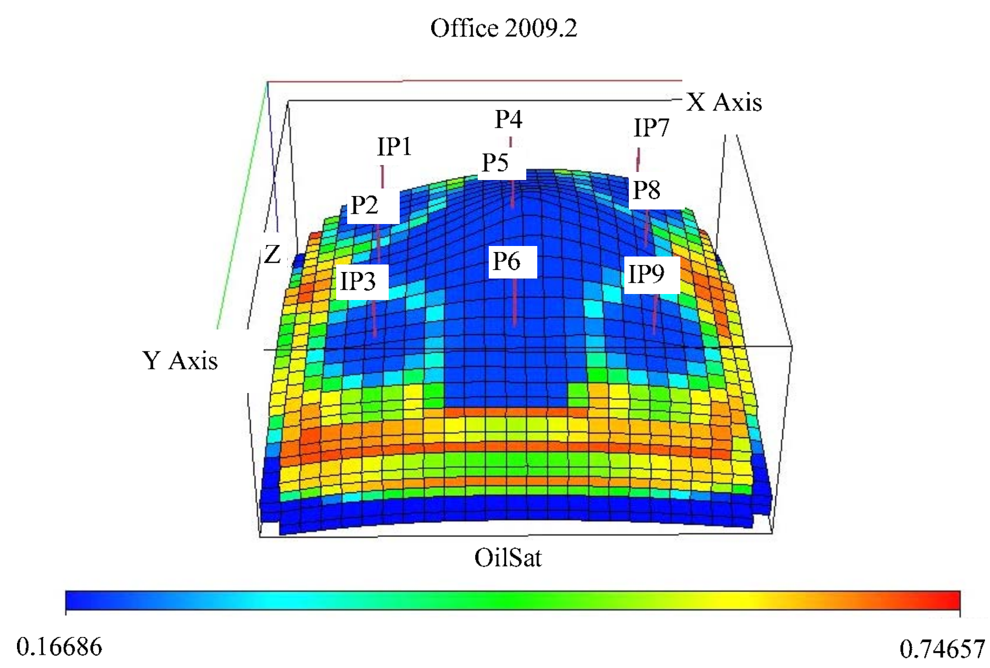
25th year (Max, in red color = 0.74620; Min, in blue color = 0.16808)

Figure 4.213 The change in oil saturation due to water injection for

1st, 10th, 25th year. (Continued)

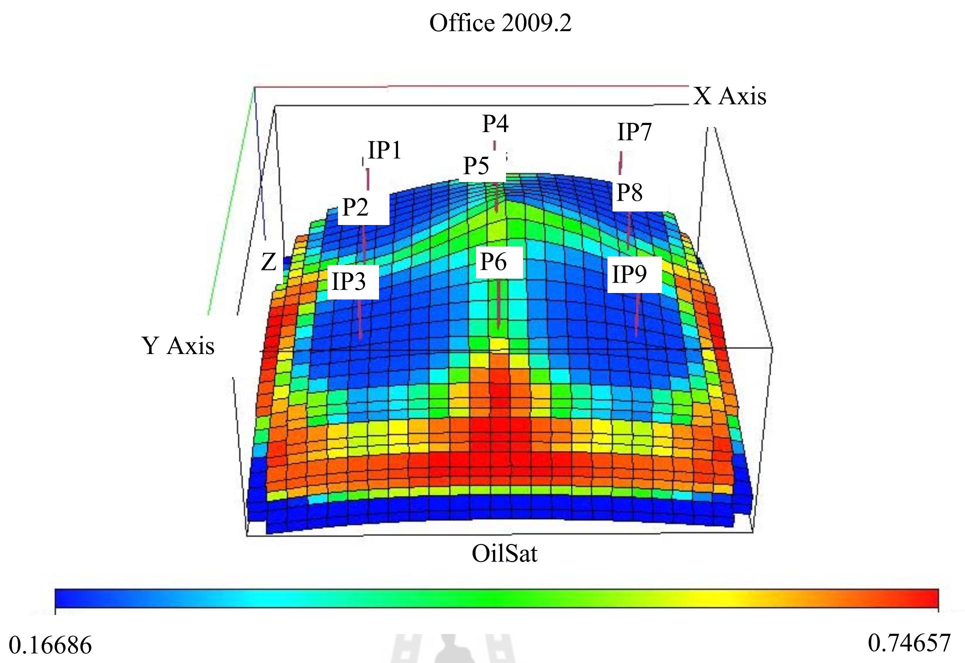


1st year (Max, in red color = 0.74657; Min, in blue color = 0.16686)



10st year (Max, in red color = 0.74657; Min, in blue color = 0.16686)

Figure 4.214 The change in oil saturation due to polymer solution injection for 1st, 10th, 25th year (From the best scenarios A30_1000_2INJ).



25^{th} year (Max, in red color = 0.74657; Min, in blue color = 0.16686)

Figure 4.214 The change in oil saturation due to polymer solution injection for 1^{st}, 10^{th}, 25^{th} year (From the best scenarios A30_1000_2INJ). (Continued)

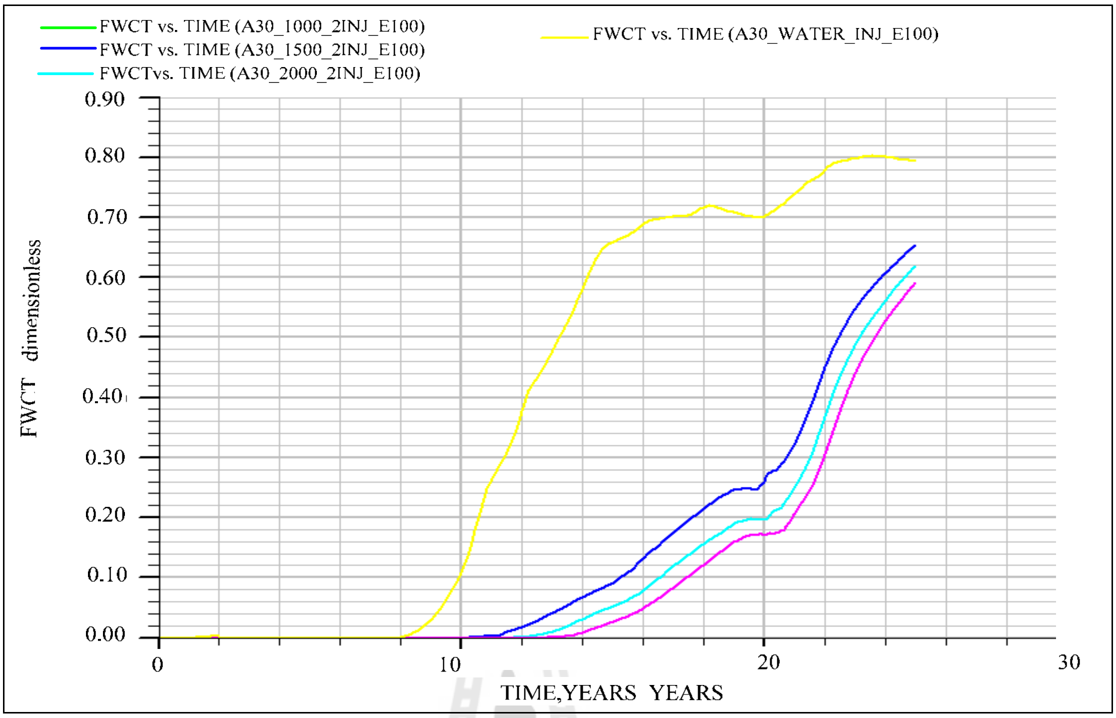


Figure 4.215 Simulation Field Water Cut vs. Time.

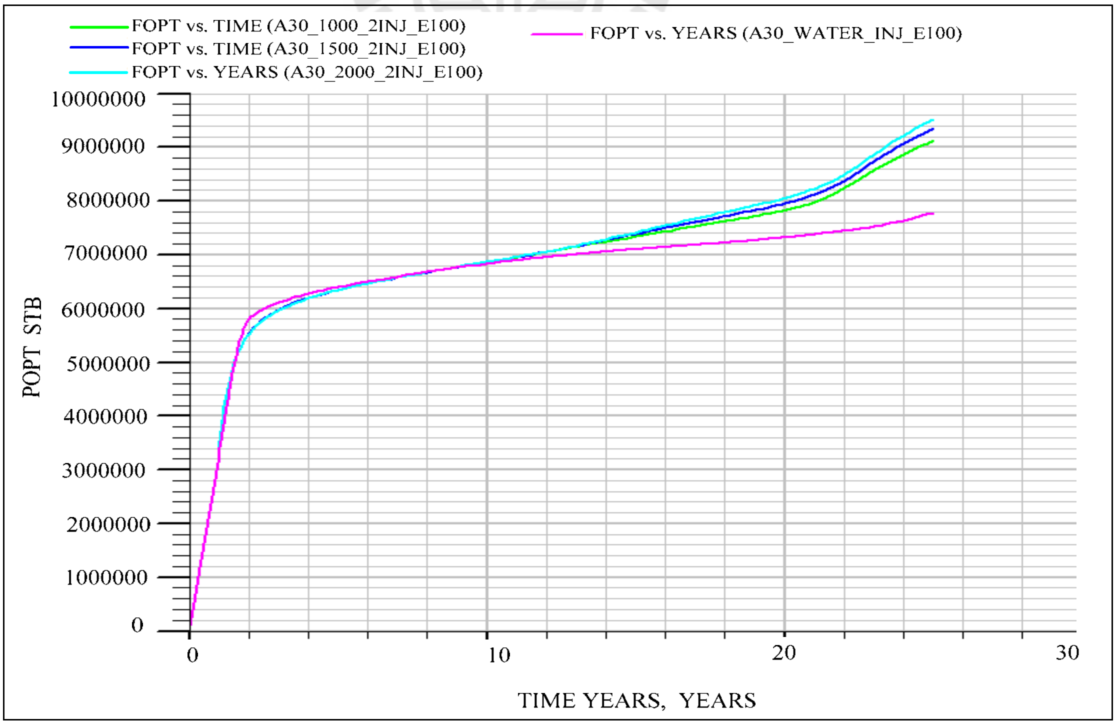


Figure 4.216 Simulation Oil Production Total vs. Time.

4.4.3 Simulation model of reservoir STOIP = 5 MMBBL

This model has area 1,562,500 ft^2 (35.87 acres), 5,000 grid block and 8 layers@625 cells/layer. The reservoir simulation has three production wells. From the base case of reservoir simulation by waterflooding, the performance without polymer flooding are performed by ECLIPSE PROGRAM presented in 3D as shown in Figure 4.217 and polymer flooding in 3D as shown in Figure 4.218.

From Figure 4.217 and 4.218, the top of figure is simulation in 1^{st} year starting time of production. The middle figure shows the front of water movement from the two injection wells in 10^{th} year. The bottom figure shows the development of water that has been wide spread movement from the two injection wells to a production well.

The main results of a base case (waterflooding) can be indicated the performance of water cut and oil production versus time as showed in Figure 4.219 and 4.220. The water cut of reservoir increases gradually and starts extremely in 16^{th} year. While the oil production also increase until 18^{th} year, but it has been declining quickly after 18^{th} year. Therefore, if the reservoir has not apply the other method for enhanced oil recovery such as polymer flooding, the water cut will be increased and also the water production increased too, while the oil production rate and the oil production total will be decreased. Finally, the oil recovery efficiency of waterflooding (base case) is 44.24%, while the oil recovery efficiency of polymer flooding will be increased up to 48.72% in 20^{th} year.

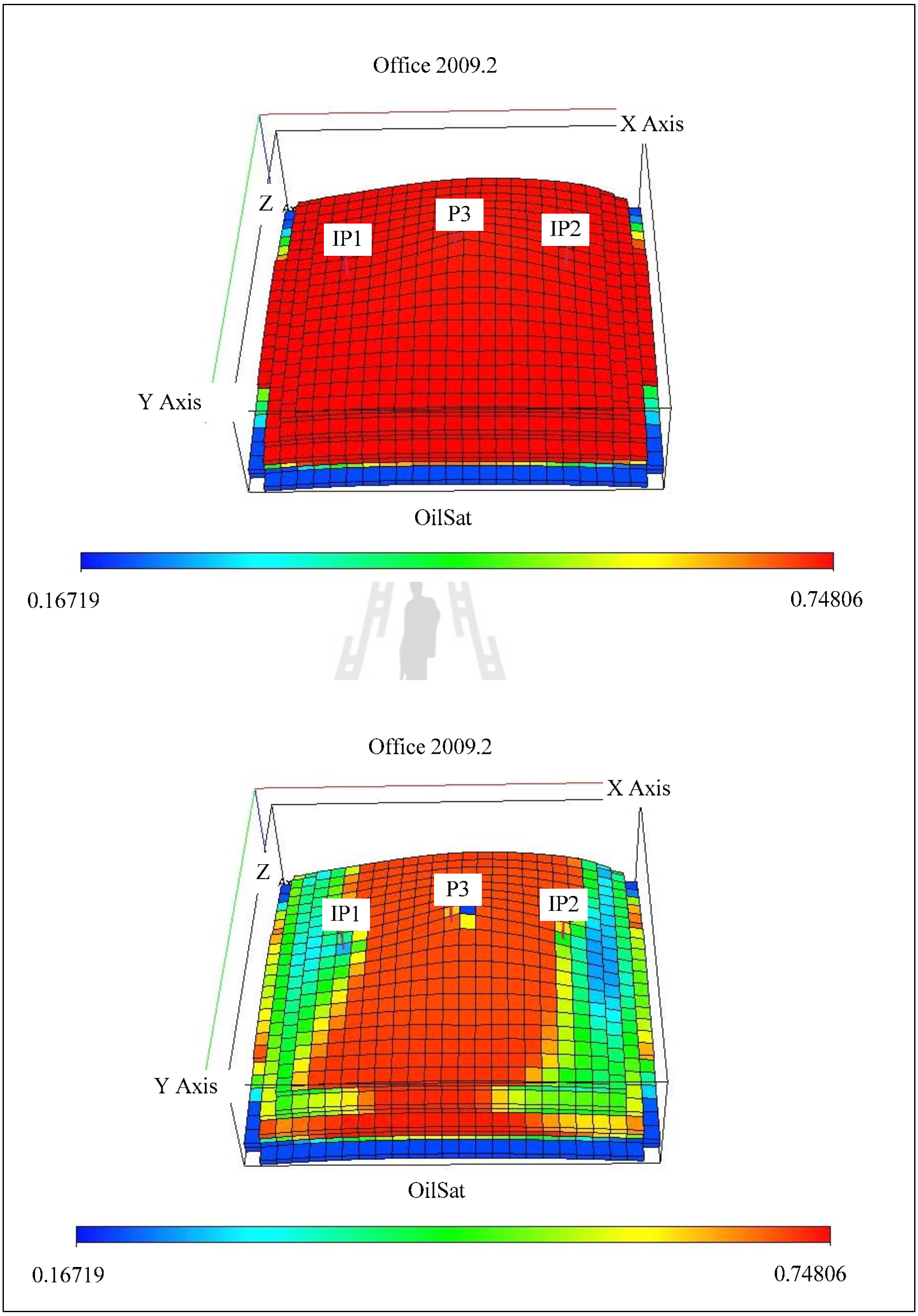
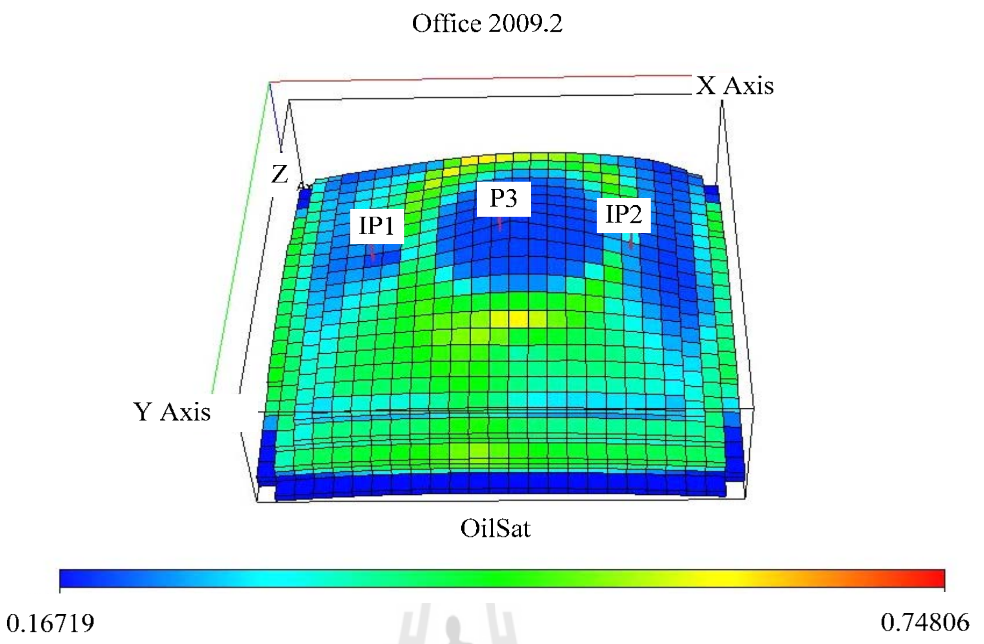
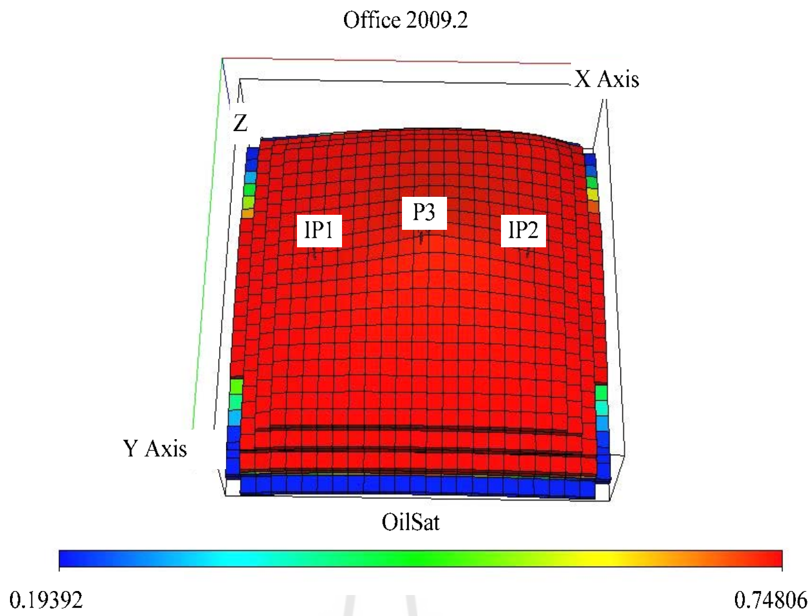


Figure 4.217 The change in oil saturation due to water injection for 1st, 10th, 25th year.

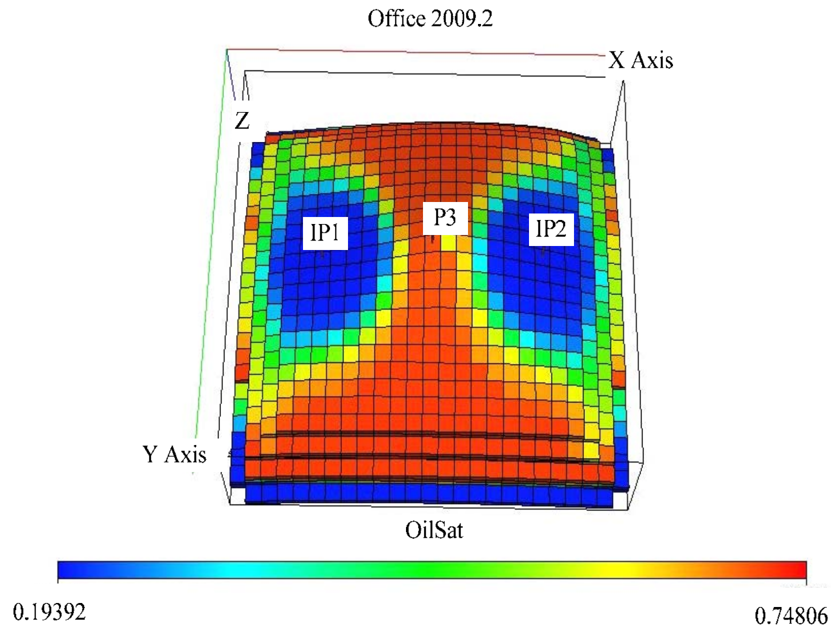


20th year (Max, in red color = 0.74806; Min, in blue color = 0.16719)

Figure 4.217 The change in oil saturation due to water injection for 1^{st}, 10^{th}, 25^{th} year. (Continued)

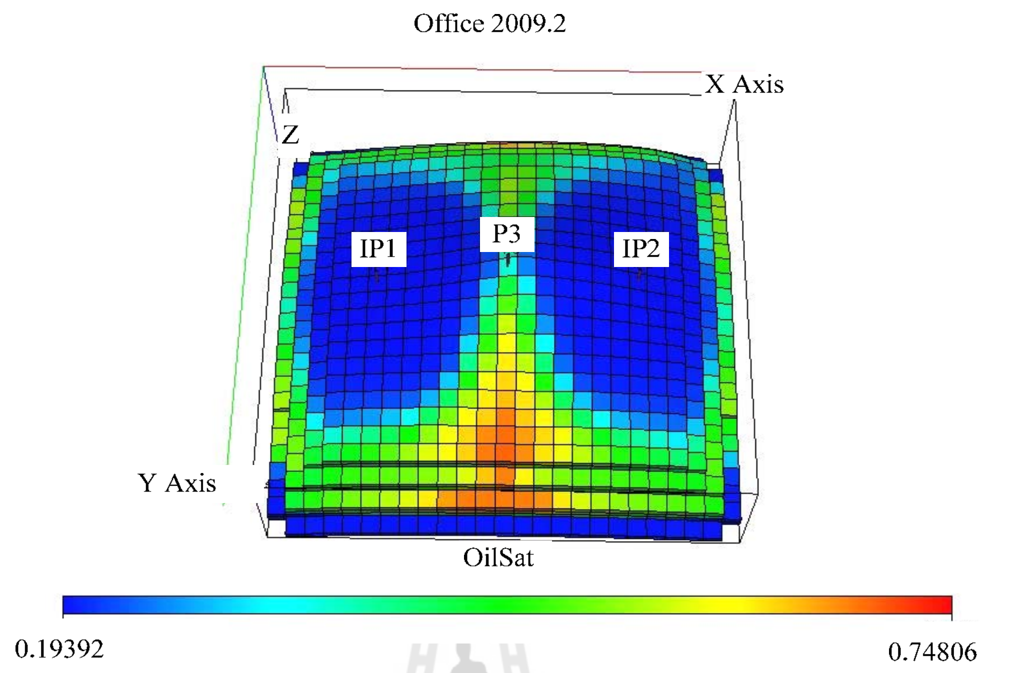


1st year (Max, in red color = 0.74806; Min, in blue color = 0.16719)



10th year (Max, in red color = 0.74806; Min, in blue color = 0.16719)

Figure 4.218 The change in oil saturation due to polymer solution injection for 1st, 10th, 20th year (From the best scenarios A05_600_3INJ).



20th year (Max, in red color = 0.74806; Min, in blue color = 0.16719)

Figure 4.218 The change in oil saturation due to polymer solution injection for 1st, 10th, 20th year (From the best scenarios A05_600_3INJ). (Continued)

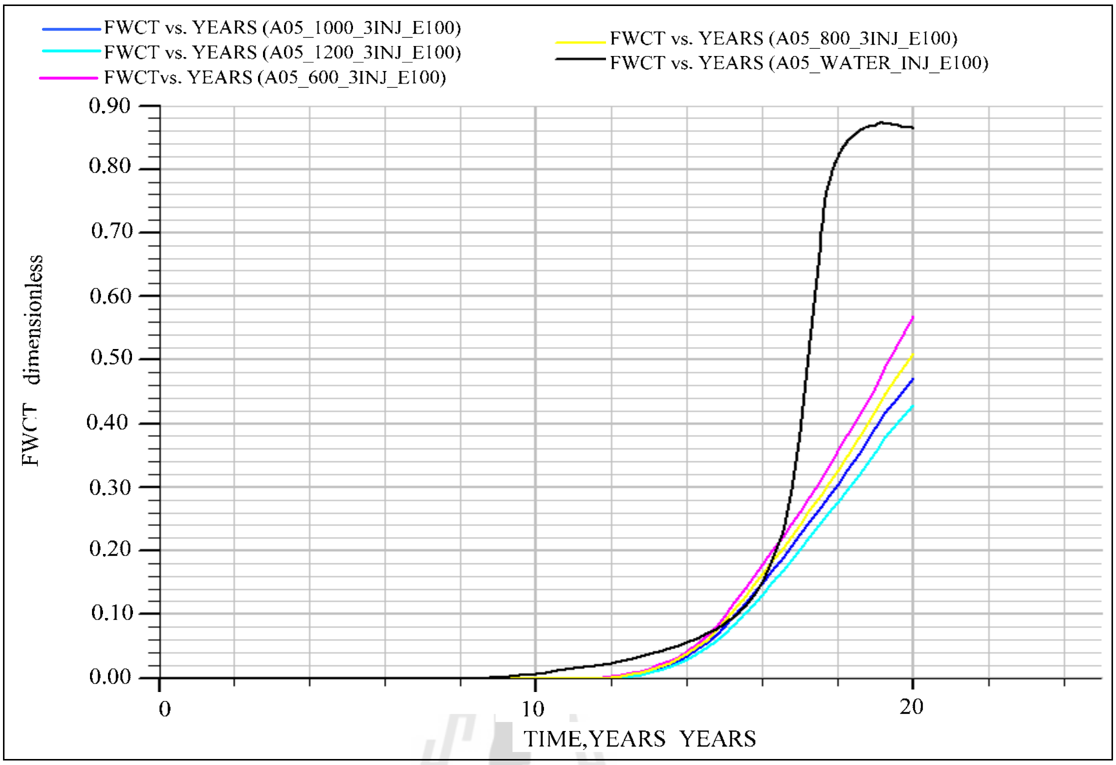


Figure 4.219 Simulation Field Water Cut vs. Time.

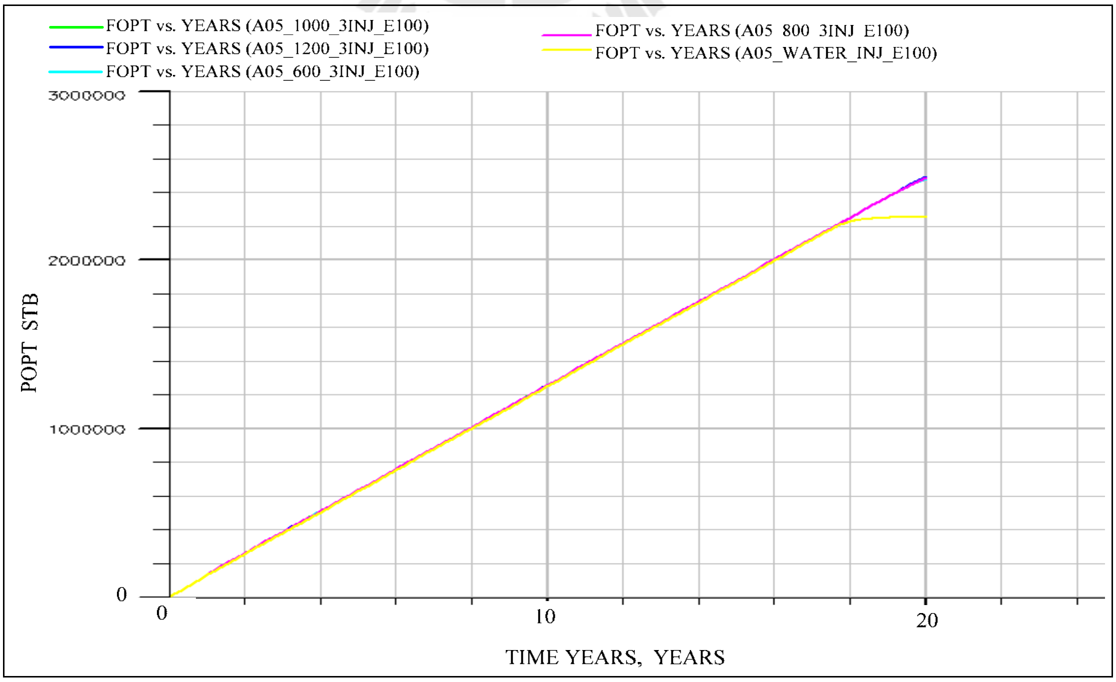


Figure 4.220 Simulation Oil Production Total vs. Time.

CHAPTER V

ECONOMIC ANALYSIS

Economic analysis is the final step in this study on application of enhanced oil recovery by polymer flooding. From the results that obtained of polymer flooding simulation for oil field in the Phitsanulok basin compare with the base case by waterflooding as shown in Table 5.1.

Table 5.1 Summary results of polymer flooding.

Model Name	Scenario No.	Polymer Conc. (ppm)	Cum. Oil production (bbl)	Additional Oil (bbl)	Recovery Factor (RF)	Percentage of Increase Oil (%)	Benefit of Polymer Injection (bbl/ply1kg)
A100	1	-	36,100,988	-	33.11	-	-
	2	1,000	41,829,864	5,728,876	38.36	5.25	1.37
	3	1,000	41,127,388	5,026,400	37.71	4.61	1.20
	4	1,000	40,314,836	4,213,848	36.97	3.86	1.01
	5	1,500	43,050,272	6,949,284	39.48	6.37	1.11
	6	1,500	42,350,996	6,250,008	38.84	5.73	1.00
	7	1,500	41,538,904	5,437,916	38.09	4.99	0.87
	8	2,000	43,997,032	7,896,044	40.35	7.24	0.94
	9	2,000	43,280,728	7,179,740	39.69	6.58	0.86
	10	2,000	42,461,376	6,360,388	38.94	5.83	0.76
A30	1	-	7,782,724	-	24.47	-	-
	2	1,000	9,131,944	1,349,220	28.72	4.24	1.45
	3	1,000	8,869,303	1,086,579	27.89	3.42	1.17
	4	1,000	8,550,628	767,904	26.89	2.41	0.83
	5	1,500	9,358,356	1,575,632	29.43	4.96	1.13
	6	1,500	9,055,398	1,272,674	28.48	4.00	0.91
	7	1,500	8,694,523	911,799	27.34	2.87	0.65
	8	2,000	9,524,530	1,741,806	29.95	5.48	0.94
	9	2,000	9,157,173	1,374,449	28.80	4.32	0.74
	10	2,000	8,776,165	993,441	27.60	3.12	0.53

Table 5.1 Summary results of polymer flooding. (continued)

Model Name	Scenario No.	Polymer Conc. (ppm)	Cum. Oil production (bbl)	Additional Oil (bbl)	Recovery Factor (RF)	Percentage of Increase Oil (%)	Benefit of Polymer Injection (bbl/ply1kg)
A05	1	-	2,254,415	-	44.24	-	-
	2	600	2,478,934	224,519	48.64	4.41	0.76
	3	600	2,483,015	228,600	48.72	4.49	0.82
	4	800	2,478,150	223,735	48.63	4.39	0.57
	5	800	2,486,937	232,522	48.80	4.56	0.63
	6	1,000	2,478,558	224,143	48.63	4.40	0.45
	7	1,000	2,487,381	232,966	48.81	4.57	0.50
	8	1,200	2,484,831	230,416	48.76	4.52	0.39
	9	1,200	2,490,031	235,616	48.86	4.62	0.42

The objective of this chapter is to determine economic parameters that used to analyze project investment possibility including of the net present value (NPV), profit to investment ratio (PIR) and internal rate of return (IRR). The three reserved sizes (three sizes of anticline structure) with various production scenarios for all models were computed and compared to show the best starting time for polymer solution injection activity.

5.1 Exploration and Production Schedule

The exploration period and production region following under the Petroleum Acts “Thailand III” statute are divided into 4 years of exploration period and 25 years of production period for model A100 and A30, 20 years of production period for model A05. The work plan of project can summarize as follow.

1st year: Petroleum concession

2nd year: Geological and geophysical survey

3rd year: Drill exploration well

4th year: Drill development well and prepare to start production plan

5th year: Starting the production plan

5.2 Economic Assumption

5.3.1 Basic assumptions

a. Dubai oil price (US$/bbl) 80

b. Income tax (%) 50

c. Inflation factor (%) 2

d. Discount rate (%) 8

e. Tangible cost (%) 20

f. Intangible cost (%) 80

g. Depreciation of tangible cost (%) 20

h. Sliding scale royalty

Production level (b/d)	Rate (%)
0–2,000	5.00
2,000–5,000	6.25
5,000–10,000	10.00
10,000–20,000	12.50
>20,000	15.00

i. Reserves size (see Table 5.2)

Table 5.2 Reserve size and production planning detail.

Reserves Size (MMSTB)	Model Name	Initial Production Well	Production/Injection Well	Number of Scenario
100	A100	25	17/8	10
30	A30	9	5/4	10
5	A05	3	1/2	9
			Total Scenario	29

5.2.2 Other assumptions

a. The oil price is constant over the production period.

b. Increasing rate of capital expenditure comes from the price increasing of machinery and equipment used in oil industries, and given to two percent per year.

c. Real discount rate of money is 8.00 percent (Bank of Thailand, August 2011).

d. Operating cost is escalated 2 percent each year forward.

e. The expense used in cash flow analysis is list in Table 5.3.

Table 5.3 Cash flow expenditure cost detail.

Expenditure Cost Detail	A100	A30	A05
Concession (MMUS$)	3.75	2.5	0.5
Geological and geophysical survey (MMUS$)	5	4	1
Production facility (MMUS$)	250	100	10
Drilling and completion production well (MMUS$/well)	1.5	1.5	1.5
Drilling exploration & appraisal well (MMUS$)	10.5	6	1
Facility costs of water injection well (US$/well)	60,000	60,000	60,000
Facility costs of polymer injection well (MMUS$/well)	62,000	62,000	62,000
Maintenance costs of water injection well (US$/year)	80,000	60,000	40,000
Maintenance costs of polymer injection well (US$/year)	80,000	60,000	40,000
Cost of polymer including transportation (US$/kg)	7	7	7
Abandonment cost (US$/well)	12,500	12,500	12,500
Operating costs of production well (US$/bbl)	30	25	20
Operating cost of water injection (US$/bbl)	0.5	0.5	0.5
Operational cost of polymer Injection (US$/bbl incremental of oil)	1.0	1.0	1.0

5.3 Cash Flow Summary Results Table

The economic analysis are calculated and analyzed by using Microsoft Excels spreadsheet. The economic summary results of model A100 are illustrated in Table 5.4-5.13, model A30 in Table 5.14-5.23 and model A05 in Table 5.24-5.32, respectively. In Table 5.4-5.32 display undiscounted IRR and PIR at the end of annual cash flow column and discounted value at the end of discount cash flow column. The IRR, PIR and NPV summary results of all scenarios are illustrated in Table 5.33 and 5.34.

Table 5.4 Cash flow summary of base case the 3rd year water injection production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water injection rate at 8,000 BWPD, and recovery factor = 33.11%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@8%)
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.580	122.597	36.500	40.603	40.603	25.587
7	6,413,921	513.114	0.000	218.432	64.139	89.473	89.473	52.207
8	2,207,310	176.585	0.000	77.834	17.658	14.748	14.748	7.968
9	836,766	66.941	0.000	31.216	4.184	15.722	15.722	7.865
10	460,705	36.856	0.000	18.358	1.843	8.280	8.280	3.835
11	387,790	31.023	0.000	16.064	1.551	6.704	6.704	2.875
12	451,560	36.125	0.000	18.759	1.806	7.780	7.780	3.090
13	604,368	48.349	0.000	24.948	2.417	10.492	10.492	3.858
14	770,306	61.624	0.000	31.886	3.852	12.943	12.943	4.407
15	960,258	76.821	0.000	40.048	4.801	15.985	15.985	5.039
16	1,148,080	91.846	0.000	48.428	5.740	18.839	18.839	5.499
17	1,279,504	102.360	0.000	54.809	6.398	20.577	20.577	5.561
18	1,325,226	106.018	0.000	57.825	6.626	20.783	20.783	5.201
19	1,339,056	107.124	0.000	59.580	6.695	20.424	20.424	4.733
20	1,315,686	105.255	0.000	59.745	6.578	19.466	19.466	4.176
21	1,260,766	100.861	0.000	58.491	6.304	18.033	18.033	3.582
22	1,192,944	95.436	0.000	56.577	5.965	16.447	16.447	3.025
23	1,129,544	90.364	0.000	54.775	5.648	14.971	14.971	2.550
24	1,067,596	85.408	0.000	52.933	5.338	13.568	13.568	2.140
25	1,016,148	81.292	0.000	51.509	5.081	12.351	12.351	1.803
26	969,712	77.577	0.000	50.254	4.849	11.237	11.237	1.519
27	928,902	74.312	0.000	49.217	4.645	10.225	10.225	1.280
28	885,980	70.878	0.000	47.997	4.430	9.226	9.226	1.069
29	848,860	67.909	0.000	47.018	4.244	8.323	8.323	0.893
Total	**36,100,988**	**2,888.079**	**307.330**	**1467.827**	**253.792**	**437.203**	**421.927**	**141.937**
						IRR	**44.16%**	**33.49%**
						PIR	**1.373**	**0.462**

Table 5.5 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 38.36%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	9,135,717	730.857	1.076	304.297	91.357	141.704	141.704	89.297
7	3,207,312	256.585	3.259	110.906	25.658	32.533	32.533	18.983
8	1,172,875	93.830	3.250	43.009	5.864	0.000	-9.989	-5.397
9	606,176	48.494	3.250	23.950	2.425	9.337	9.337	4.671
10	480,620	38.450	3.250	19.928	1.922	6.577	6.577	3.046
11	518,912	41.513	3.259	21.734	2.076	7.222	7.222	3.098
12	662,020	52.962	3.250	27.499	2.648	9.782	9.782	3.885
13	838,396	67.072	3.250	34.760	4.192	12.435	12.435	4.572
14	1,019,536	81.563	3.250	42.485	5.098	15.365	15.365	5.231
15	1,247,622	99.810	3.259	52.371	6.238	18.971	18.971	5.980
16	1,506,114	120.489	0.000	62.884	7.531	25.037	25.037	7.308
17	1,771,216	141.697	0.000	75.059	8.856	28.891	28.891	7.808
18	1,924,874	153.990	0.000	83.015	15.399	27.788	27.788	6.954
19	1,935,166	154.813	0.000	85.122	15.481	27.105	27.105	6.281
20	1,900,300	152.024	0.000	85.295	15.202	25.763	25.763	5.527
21	1,856,526	148.522	0.000	85.049	14.852	24.310	24.310	4.829
22	1,750,618	140.049	0.000	81.935	8.753	24.681	24.681	4.540
23	1,514,056	121.124	0.000	72.608	7.570	20.473	20.473	3.487
24	1,221,744	97.740	0.000	60.225	6.109	15.703	15.703	2.476
25	990,188	79.215	0.000	50.257	4.951	12.004	12.004	1.753
26	850,236	68.019	0.000	44.374	4.251	9.697	9.697	1.311
27	749,136	59.931	0.000	40.192	3.746	7.996	7.996	1.001
28	683,144	54.652	0.000	37.610	2.733	7.154	7.154	0.829
29	637,360	50.989	0.000	35.971	2.549	6.234	6.234	0.669
Total	**41,829,864**	**3,346.39**	**337.104**	**1699.060**	**301.962**	**516.764**	**491.499**	**170.314**
						IRR	**55.26%**	**43.76%**
						PIR	**1.458**	**0.505**

Table 5.6 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 37.71%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	6,413,921	513.114	1.076	218.432	64.139	89.373	89.373	52.149
8	2,138,892	171.111	3.250	76.209	17.111	11.423	11.423	6.171
9	881,915	70.553	3.250	33.551	4.410	14.574	14.574	7.290
10	517,286	41.383	3.250	21.149	2.069	7.360	7.360	3.409
11	475,124	38.010	3.259	20.037	1.900	6.309	6.309	2.706
12	550,958	44.077	3.250	23.260	2.204	7.681	7.681	3.050
13	711,606	56.928	3.250	29.837	2.846	10.497	10.497	3.860
14	888,510	71.081	3.250	37.299	4.443	13.044	13.044	4.441
15	1,080,550	86.444	3.259	45.654	5.403	16.064	16.064	5.064
16	1,314,384	105.151	3.250	56.001	6.572	19.664	19.664	5.740
17	1,569,510	125.561	0.000	66.752	7.848	25.481	25.481	6.887
18	1,826,250	146.100	0.000	78.872	14.610	26.309	26.309	6.584
19	1,969,092	157.527	0.000	86.576	15.753	27.599	27.599	6.395
20	1,955,432	156.435	0.000	87.704	15.643	26.543	26.543	5.695
21	1,917,728	153.418	0.000	87.778	15.342	25.149	25.149	4.996
22	1,869,054	149.524	0.000	87.320	14.952	23.626	23.626	4.346
23	1,758,228	140.658	0.000	83.933	8.791	23.967	23.967	4.082
24	1,505,120	120.410	0.000	73.631	7.526	19.626	19.626	3.095
25	1,219,440	97.555	0.000	61.319	6.097	15.070	15.070	2.200
26	987,852	79.028	0.000	51.147	4.939	11.471	11.471	1.551
27	850,108	68.009	0.000	45.261	4.251	9.248	9.248	1.158
28	745,184	59.615	0.000	40.787	3.726	7.551	7.551	0.875
29	681,244	54.500	0.000	38.263	2.725	6.756	6.756	0.725
Total	**41,127,388**	**3,290.191**	**337.096**	**1690.196**	**306.300**	**485.938**	**470.662**	**150.826**
						IRR	**43.94%**	**33.28%**
						PIR	**1.396**	**0.447**

Table 5.7 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 36.97%.

Year	**Cash Flow Summary**							**Discount Cash Flow (NPV@8%)**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	3,660,000	292.800	0.000	123.653	36.600	40.524	40.524	23.645
8	3,297,140	263.771	1.076	115.390	26.377	35.104	35.104	18.966
9	1,128,225	90.258	3.250	42.103	5.641	19.534	19.534	9.772
10	564,025	45.122	3.250	22.717	2.256	8.352	8.352	3.868
11	430,903	34.472	3.259	18.310	1.724	5.492	5.492	2.356
12	481,477	38.518	3.250	20.556	1.926	6.296	6.296	2.500
13	612,848	49.028	3.250	25.965	2.451	8.681	8.681	3.192
14	794,948	63.596	3.250	33.551	3.975	11.410	11.410	3.885
15	973,422	77.874	3.259	41.294	4.867	14.227	14.227	4.485
16	1,177,418	94.193	3.250	50.350	5.887	17.353	17.353	5.065
17	1,414,808	113.185	3.250	61.133	7.074	20.864	20.864	5.639
18	1,684,162	134.733	0.000	72.903	8.421	26.704	26.704	6.683
19	1,911,004	152.880	0.000	84.087	15.288	26.753	26.753	6.199
20	2,015,904	161.272	0.000	90.347	16.127	27.399	27.399	5.878
21	1,990,388	159.231	0.000	91.017	15.923	26.146	26.146	5.194
22	1,946,288	155.703	0.000	90.832	15.570	24.650	24.650	4.534
23	1,892,414	151.393	0.000	90.156	15.139	23.049	23.049	3.926
24	1,756,346	140.508	0.000	85.516	8.782	23.105	23.105	3.644
25	1,496,756	119.740	0.000	74.700	7.484	18.778	18.778	2.742
26	1,214,496	97.160	0.000	62.302	6.072	14.393	14.393	1.946
27	986,036	78.883	0.000	52.085	4.930	10.934	10.934	1.369
28	843,628	67.490	0.000	45.828	4.218	8.722	8.722	1.011
29	742,200	59.376	0.000	41.447	3.711	7.109	7.109	0.763
Total	**40,314,836**	**3,225.187**	**337.096**	**1675.665**	**293.444**	**467.129**	**451.853**	**135.618**
						IRR	**39.15%**	**28.84%**
						PIR	**1.340**	**0.402**

Table 5.8 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 39.48%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	9,135,717	730.857	1.076	304.297	91.357	141.704	141.704	89.297
7	3,207,717	256.617	4.889	111.072	25.662	31.650	31.650	18.467
8	1,172,252	93.780	4.875	43.143	5.861	0.000	-11.795	-6.373
9	605,762	48.461	4.875	24.094	2.423	8.437	8.437	4.220
10	485,378	38.830	4.875	20.260	1.942	5.779	5.779	2.677
11	529,602	42.368	4.889	22.290	2.118	6.536	6.536	2.803
12	676,194	54.096	4.875	28.196	2.705	9.160	9.160	3.637
13	856,532	68.523	4.875	35.622	4.283	11.871	11.871	4.365
14	1,033,846	82.708	4.875	43.215	5.169	14.724	14.724	5.013
15	1,251,514	100.121	4.889	52.704	6.258	18.136	18.136	5.717
16	1,510,290	120.823	0.000	63.052	7.551	25.110	25.110	7.329
17	1,805,194	144.416	0.000	76.458	9.026	29.466	29.466	7.964
18	1,984,444	158.756	0.000	85.517	15.876	28.681	28.681	7.177
19	2,054,556	164.364	0.000	90.238	16.436	28.845	28.845	6.684
20	2,008,412	160.673	0.000	90.020	16.067	27.293	27.293	5.856
21	1,983,134	158.651	0.000	90.693	15.865	26.046	26.046	5.174
22	1,891,088	151.287	0.000	88.322	15.129	23.918	23.918	4.400
23	1,694,316	135.545	0.000	80.968	8.472	23.053	23.053	3.926
24	1,393,688	111.495	0.000	68.360	6.968	18.084	18.084	2.852
25	1,120,672	89.654	0.000	56.553	5.603	13.749	13.749	2.008
26	905,000	72.400	0.000	47.069	4.525	10.403	10.403	1.407
27	782,504	62.600	0.000	41.867	3.913	8.410	8.410	1.053
28	685,704	54.856	0.000	37.741	2.743	7.186	7.186	0.833
29	626,756	50.140	0.000	35.417	2.507	6.108	6.108	0.656
Total	**43,050,272**	**3,444.022**	**351.744**	**1755.697**	**314.959**	**524.347**	**497.275**	**169.315**
						IRR	**54.85%**	**43.38%**
						PIR	**1.414**	**0.481**

Table 5.9 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 38.84%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	6,413,921	513.114	1.076	218.432	64.139	89.373	89.373	52.149
8	2,200,950	176.076	4.875	78.504	17.608	11.697	11.697	6.319
9	855,334	68.427	4.875	32.776	4.277	13.152	13.152	6.579
10	504,337	40.347	4.875	20.847	2.017	6.206	6.206	2.875
11	471,124	37.690	4.889	20.057	1.884	5.332	5.332	2.287
12	553,056	44.244	4.875	23.507	2.212	6.825	6.825	2.710
13	719,590	57.567	4.875	30.313	2.878	9.750	9.750	3.585
14	901,752	72.140	4.875	37.989	4.509	12.384	12.384	4.216
15	1,089,248	87.140	4.889	46.178	5.446	15.313	15.313	4.827
16	1,312,082	104.967	4.875	56.091	6.560	18.720	18.720	5.464
17	1,582,282	126.583	0.000	67.278	7.911	25.697	25.697	6.945
18	1,854,814	148.385	0.000	80.072	14.839	26.737	26.737	6.691
19	2,026,628	162.130	0.000	89.041	16.213	28.438	28.438	6.589
20	2,072,840	165.827	0.000	92.836	16.583	28.204	28.204	6.051
21	2,026,816	162.145	0.000	92.641	16.215	26.645	26.645	5.293
22	1,997,534	159.803	0.000	93.162	15.980	25.330	25.330	4.659
23	1,901,584	152.127	0.000	90.581	15.213	23.166	23.166	3.946
24	1,684,692	134.775	0.000	82.126	8.423	22.113	22.113	3.487
25	1,390,208	111.217	0.000	69.559	6.951	17.353	17.353	2.534
26	1,119,564	89.565	0.000	57.629	5.598	13.169	13.169	1.780
27	906,736	72.539	0.000	48.104	4.534	9.950	9.950	1.246
28	779,992	62.399	0.000	42.569	3.900	7.965	7.965	0.923
29	685,912	54.873	0.000	38.507	2.744	6.811	6.811	0.731
Total	**42,350,996**	**3,388.080**	**351.730**	**1748.223**	**319.634**	**491.884**	**476.608**	**150.245**
						IRR	**43.73%**	**33.08%**
						PIR	**1.355**	**0.427**

Table 5.10 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 38.09%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@8%)
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	3,660,000	292.800	0.000	123.653	36.600	40.524	40.524	23.645
8	3,297,140	263.771	1.076	115.390	26.377	35.104	35.104	18.966
9	1,127,531	90.202	4.875	42.238	5.638	18.628	18.628	9.319
10	562,288	44.983	4.875	22.817	2.249	7.423	7.423	3.438
11	428,493	34.279	4.889	18.388	1.714	4.547	4.547	1.950
12	481,372	38.510	4.875	20.721	1.925	5.396	5.396	2.143
13	619,126	49.530	4.875	26.376	2.477	7.901	7.901	2.905
14	807,170	64.574	4.875	34.202	4.036	10.730	10.730	3.653
15	996,126	79.690	4.889	42.373	4.981	13.724	13.724	4.326
16	1,190,708	95.257	4.875	51.069	5.954	16.679	16.679	4.869
17	1,424,874	113.990	4.875	61.734	7.124	20.128	20.128	5.440
18	1,693,042	135.443	0.000	73.276	8.465	26.851	26.851	6.719
19	1,938,166	155.053	0.000	85.251	15.505	27.149	27.149	6.291
20	2,074,432	165.955	0.000	92.905	16.595	28.227	28.227	6.056
21	2,104,508	168.361	0.000	96.104	16.836	27.710	27.710	5.505
22	2,055,016	164.401	0.000	95.776	16.440	26.093	26.093	4.800
23	2,022,052	161.764	0.000	96.169	16.176	24.710	24.710	4.208
24	1,901,092	152.087	0.000	92.363	15.209	22.258	22.258	3.510
25	1,672,244	133.780	0.000	83.168	8.361	21.125	21.125	3.085
26	1,381,340	110.507	0.000	70.514	6.907	16.543	16.543	2.237
27	1,118,596	89.488	0.000	58.740	5.593	12.577	12.577	1.575
28	902,376	72.190	0.000	48.836	4.512	9.421	9.421	1.092
29	781,212	62.497	0.000	43.484	3.906	7.553	7.553	0.811
Total	**41,538,904**	**3,323.112**	**351.730**	**1734.970**	**306.580**	**472.554**	**457.278**	**134.899**
						IRR	**38.91%**	**28.62%**
						PIR	**1.300**	**0.384**

Table 5.11 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 40.35%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	9,135,717	730.857	1.076	304.297	91.357	141.704	141.704	89.297
7	3,206,994	256.560	6.518	111.167	25.656	30.762	30.762	17.949
8	1,171,551	93.724	6.500	43.240	5.858	0.000	-13.569	-7.331
9	606,086	48.487	6.500	24.229	2.424	7.569	7.569	3.786
10	486,564	38.925	6.500	20.428	1.946	4.928	4.928	2.282
11	534,380	42.750	6.518	22.593	2.138	5.751	5.751	2.466
12	684,258	54.741	6.500	28.628	2.737	8.438	8.438	3.351
13	869,282	69.543	6.500	36.240	4.346	11.228	11.228	4.128
14	1,045,652	83.652	6.500	43.809	5.228	14.057	14.057	4.786
15	1,259,542	100.763	6.518	53.161	6.298	17.393	17.393	5.483
16	1,503,402	120.272	0.000	62.774	7.517	24.991	24.991	7.295
17	1,801,312	144.105	0.000	76.299	9.007	29.400	29.400	7.946
18	2,001,126	160.090	0.000	86.218	16.009	28.931	28.931	7.240
19	2,119,008	169.521	0.000	92.999	16.952	29.785	29.785	6.901
20	2,123,732	169.899	0.000	95.060	16.990	28.924	28.924	6.206
21	2,070,954	165.676	0.000	94.608	16.568	27.250	27.250	5.413
22	1,990,196	159.216	0.000	92.828	15.922	25.233	25.233	4.641
23	1,829,760	146.381	0.000	87.250	14.638	22.246	22.246	3.789
24	1,530,584	122.447	0.000	74.836	7.653	19.979	19.979	3.151
25	1,250,244	100.020	0.000	62.805	6.251	15.482	15.482	2.261
26	988,592	79.087	0.000	51.183	4.943	11.481	11.481	1.552
27	810,648	64.852	0.000	43.280	4.053	8.759	8.759	1.097
28	706,708	56.537	0.000	38.817	2.827	7.447	7.447	0.863
29	620,740	49.659	0.000	35.103	2.483	6.037	6.037	0.648
Total	**43,997,032**	**3,519.763**	**366.383**	**1800.379**	**326.300**	**527.773**	**498.927**	**167.374**
						IRR	**54.44%**	**43.00%**
						PIR	**1.362**	**0.457**

Table 5.12 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 39.69%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@8%)
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	6,413,921	513.114	1.076	218.432	64.139	89.373	89.373	52.149
8	2,199,971	175.998	6.500	78.589	17.600	10.807	10.807	5.839
9	854,535	68.363	6.500	32.869	4.273	12.263	12.263	6.134
10	504,053	40.324	6.500	20.961	2.016	5.326	5.326	2.467
11	470,732	37.659	6.518	20.169	1.883	4.447	4.447	1.907
12	556,230	44.498	6.500	23.754	2.225	6.010	6.010	2.387
13	728,260	58.261	6.500	30.774	2.913	9.037	9.037	3.323
14	918,196	73.456	6.500	38.761	4.591	11.802	11.802	4.018
15	1,101,814	88.145	6.518	46.812	5.509	14.653	14.653	4.619
16	1,320,570	105.646	6.500	56.573	6.603	17.985	17.985	5.250
17	1,572,746	125.820	0.000	66.885	7.864	25.535	25.535	6.901
18	1,853,006	148.240	0.000	79.996	14.824	26.710	26.710	6.684
19	2,041,426	163.314	0.000	89.675	16.331	28.654	28.654	6.639
20	2,135,894	170.872	0.000	95.591	17.087	29.097	29.097	6.243
21	2,139,798	171.184	0.000	97.677	17.118	28.194	28.194	5.601
22	2,083,748	166.700	0.000	97.082	16.670	26.474	26.474	4.870
23	2,000,400	160.032	0.000	95.164	16.003	24.432	24.432	4.161
24	1,817,908	145.433	0.000	88.428	9.090	23.957	23.957	3.778
25	1,522,644	121.812	0.000	75.949	7.613	19.124	19.124	2.793
26	1,245,792	99.663	0.000	63.842	6.229	14.796	14.796	2.000
27	989,588	79.167	0.000	52.264	4.948	10.978	10.978	1.374
28	801,668	64.133	0.000	43.679	4.008	8.223	8.223	0.953
29	707,828	56.626	0.000	39.652	2.831	7.072	7.072	0.759
Total	**43,280,728**	**3,462.458**	**366.365**	**1793.001**	**325.369**	**496.500**	**481.223**	**149.206**
						IRR	**43.44%**	**32.81%**
						PIR	**1.314**	**0.407**

Table 5.13 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (17/8) production/injection well, initial production rate at 10,000 BOPD, water and polymer solution injection rate at 8,000 BWPD, and recovery factor = 38.94%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	3.750	0.000	0.000	0.000	-3.750	-3.472
2	0.000	0.000	5.000	0.000	0.000	0.000	-5.000	-4.287
3	0.000	0.000	10.500	0.000	0.000	0.000	-10.500	-8.335
4	0.000	0.000	287.500	0.000	0.000	0.000	-81.500	-59.905
5	3,650,000	292.000	0.000	118.526	36.500	0.000	85.474	58.172
6	3,650,000	292.000	0.000	120.897	36.500	41.552	41.552	26.185
7	3,660,000	292.800	0.000	123.653	36.600	40.524	40.524	23.645
8	3,297,140	263.771	1.076	115.390	26.377	35.104	35.104	18.966
9	1,126,663	90.133	6.500	42.328	5.633	17.738	17.738	8.874
10	561,162	44.893	6.500	22.899	2.245	6.527	6.527	3.023
11	427,173	34.174	6.518	18.465	1.709	3.644	3.644	1.563
12	479,658	38.373	6.500	20.784	1.919	4.487	4.487	1.782
13	622,380	49.790	6.500	26.630	2.490	7.085	7.085	2.605
14	816,102	65.288	6.500	34.681	4.081	10.013	10.013	3.409
15	1,010,504	80.840	6.518	43.077	5.053	13.096	13.096	4.128
16	1,203,232	96.259	6.500	51.713	6.016	16.015	16.015	4.675
17	1,439,910	115.193	6.500	62.494	7.200	19.499	19.499	5.270
18	1,684,676	134.774	0.000	72.925	8.423	26.713	26.713	6.685
19	1,935,840	154.867	0.000	85.151	15.487	27.115	27.115	6.283
20	2,087,684	167.015	0.000	93.484	16.701	28.414	28.414	6.096
21	2,167,418	173.393	0.000	98.908	17.339	28.573	28.573	5.676
22	2,162,578	173.006	0.000	100.667	17.301	27.520	27.520	5.062
23	2,108,120	168.650	0.000	100.160	16.865	25.812	25.812	4.396
24	2,004,316	160.345	0.000	97.247	16.035	23.532	23.532	3.711
25	1,814,204	145.136	0.000	90.018	9.071	23.024	23.024	3.362
26	1,517,964	121.437	0.000	77.238	7.590	18.305	18.305	2.475
27	1,246,036	99.683	0.000	65.138	6.230	14.157	14.157	1.772
28	986,848	78.948	0.000	53.162	4.934	10.426	10.426	1.209
29	801,768	64.141	0.000	44.558	4.009	7.787	7.787	0.836
Total	**42,461,376**	**3,396.910**	**366.365**	**1780.193**	**312.306**	**476.661**	**461.385**	**133.860**
						IRR	**38.67%**	**28.40%**
						PIR	**1.259**	**0.365**

Table 5.14 Cash flow summary of base case the 3rd year water injection production of model A30, (5/4) production/injection well, initial production rate at 9,000 BOPD, water injection rate at 2,000 BWPD, and recovery factor = 24.47%.

Year	**Cash Flow Summary**							**Discount**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	**Cash Flow (NPV@8%)**
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,515,822	201.266	0.000	69.442	20.127	45.579	45.579	28.722
7	314,245	25.140	0.538	9.327	1.257	0.000	-6.132	-3.578
8	166,208	13.297	0.000	5.261	0.665	0.000	-13.267	-7.168
9	121,913	9.753	0.000	4.069	0.488	2.549	2.549	1.275
10	102,665	8.213	0.000	3.575	0.411	2.065	2.065	0.956
11	91,484	7.319	0.000	3.307	0.366	1.774	1.774	0.761
12	85,617	6.849	0.000	3.190	0.342	1.659	1.659	0.659
13	80,082	6.407	0.000	3.078	0.320	1.504	1.504	0.553
14	72,561	5.805	0.000	2.896	0.290	1.309	1.309	0.446
15	65,272	5.222	0.000	2.715	0.261	1.123	1.123	0.354
16	59,335	4.747	0.000	2.568	0.237	0.971	0.971	0.283
17	54,935	4.395	0.000	2.469	0.220	0.853	0.853	0.231
18	49,078	3.926	0.000	2.313	0.196	0.708	0.708	0.177
19	43,039	3.443	0.000	2.145	0.172	0.563	0.563	0.130
20	39,926	3.194	0.000	2.073	0.160	0.481	0.481	0.103
21	39,423	3.154	0.000	2.096	0.158	0.450	0.450	0.089
22	41,421	3.314	0.000	2.214	0.166	0.467	0.467	0.086
23	45,334	3.627	0.000	2.411	0.181	0.517	0.517	0.088
24	51,265	4.101	0.000	2.691	0.205	0.602	0.602	0.095
25	56,832	4.547	0.000	2.969	0.227	0.675	0.675	0.099
26	62,132	4.971	0.000	3.246	0.249	0.738	0.738	0.100
27	79,819	6.385	0.000	4.052	0.319	1.007	1.007	0.126
28	120,009	9.601	0.000	5.846	0.480	1.637	1.637	0.190
29	139,314	11.145	0.000	6.804	0.557	1.892	1.892	0.203
Total	**7,782,725**	**622.618**	**126.538**	**239.653**	**54.334**	**110.746**	**91.347**	**49.602**
						IRR	**67.86%**	**55.43%**
						PIR	**0.722**	**0.392**

Table 5.15 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A30, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 28.72%.

Year	Cash Flow Summary							Discount Cash Flow
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	(NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,245,243	179.619	0.538	62.442	17.962	39.264	39.264	24.743
7	436,089	34.887	0.815	13.015	1.744	0.000	-1.325	-0.773
8	222,844	17.827	0.813	7.150	0.891	0.000	-11.664	-6.302
9	154,926	12.394	0.813	5.304	0.620	2.780	2.780	1.391
10	125,374	10.030	0.813	4.527	0.501	2.046	2.046	0.948
11	109,413	8.753	0.815	4.133	0.438	1.684	1.684	0.722
12	100,912	8.073	0.813	3.949	0.404	1.454	1.454	0.577
13	96,536	7.723	0.813	3.890	0.386	1.317	1.317	0.484
14	92,277	7.382	0.813	3.830	0.369	1.185	1.185	0.404
15	90,294	7.224	0.000	3.541	0.361	1.661	1.661	0.524
16	92,971	7.438	0.000	3.700	0.372	1.683	1.683	0.491
17	98,496	7.880	0.000	3.964	0.394	1.761	1.761	0.476
18	97,850	7.828	0.000	4.020	0.391	1.708	1.708	0.427
19	93,447	7.476	0.000	3.945	0.374	1.578	1.578	0.366
20	95,257	7.621	0.000	4.088	0.381	1.576	1.576	0.338
21	94,118	7.529	0.000	4.128	0.376	1.513	1.513	0.300
22	93,195	7.456	0.000	4.175	0.373	1.454	1.454	0.267
23	94,897	7.592	0.000	4.326	0.380	1.443	1.443	0.246
24	107,874	8.630	0.000	4.923	0.431	1.638	1.638	0.258
25	158,534	12.683	0.000	7.058	0.634	2.495	2.495	0.364
26	257,893	20.631	0.000	11.275	1.032	4.163	4.163	0.563
27	331,533	26.523	0.000	14.583	1.326	5.307	5.307	0.664
28	295,694	23.656	0.000	13.343	1.183	4.565	4.565	0.529
29	261,283	20.903	0.000	12.112	1.045	3.873	3.873	0.416
Total	**9,131,944**	**730.556**	**133.043**	**296.317**	**58.649**	**127.768**	**114.779**	**53.045**
						IRR	**66.68%**	**54.33%**
						PIR	**0.863**	**0.399**

Table 5.16 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 27.89%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,524,589	201.967	0.000	69.684	20.197	45.773	45.773	28.845
7	319,213	25.537	0.538	9.467	1.277	0.000	-5.894	-3.439
8	166,601	13.328	0.813	5.497	0.666	0.000	-14.286	-7.718
9	119,709	9.577	0.813	4.234	0.479	1.977	1.977	0.989
10	100,274	8.022	0.813	3.738	0.401	1.486	1.486	0.689
11	89,145	7.132	0.815	3.475	0.357	1.194	1.194	0.512
12	83,730	6.698	0.813	3.374	0.335	1.088	1.088	0.432
13	80,985	6.479	0.813	3.355	0.324	0.994	0.994	0.365
14	78,534	6.283	0.813	3.343	0.314	0.907	0.907	0.309
15	77,874	6.230	0.815	3.390	0.311	0.857	0.857	0.270
16	77,251	6.180	0.000	3.171	0.309	1.350	1.350	0.394
17	81,527	6.522	0.000	3.381	0.326	1.407	1.407	0.380
18	86,876	6.950	0.000	3.636	0.348	1.483	1.483	0.371
19	90,988	7.279	0.000	3.857	0.364	1.529	1.529	0.354
20	88,185	7.055	0.000	3.831	0.353	1.436	1.436	0.308
21	90,533	7.243	0.000	3.995	0.362	1.443	1.443	0.287
22	94,934	7.595	0.000	4.241	0.380	1.487	1.487	0.273
23	94,649	7.572	0.000	4.317	0.379	1.438	1.438	0.245
24	95,145	7.612	0.000	4.421	0.381	1.405	1.405	0.222
25	105,454	8.436	0.000	4.924	0.422	1.545	1.545	0.226
26	146,567	11.725	0.000	6.709	0.586	2.215	2.215	0.299
27	265,168	21.213	0.000	11.806	1.061	4.173	4.173	0.522
28	333,106	26.648	0.000	14.940	1.332	5.188	5.188	0.601
29	293,272	23.462	0.000	13.505	1.173	4.392	4.392	0.471
Total	**8,869,303**	**709.544**	**133.043**	**285.185**	**58.716**	**126.390**	**106.210**	**50.830**
						IRR	**67.73%**	**55.31%**
						PIR	**0.798**	**0.382**

Table 5.17 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 26.89%.

Year	**Cash Flow Summary**							**Discount**
	Oil production	**Gross**	**Capex**	**Opex**	**Government take**		**Annual**	**Cash Flow**
	total.	**revenue**			**Royalty**	**Inc. tax**	**cash flow**	**(NPV@8%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,524,589	201.967	0.000	69.684	20.197	45.773	45.773	28.845
7	486,603	38.928	0.000	13.700	1.946	1.371	1.371	0.800
8	128,744	10.300	0.538	4.185	0.515	0.000	-15.088	-8.152
9	96,706	7.736	0.813	3.513	0.387	1.463	1.463	0.732
10	82,777	6.622	0.813	3.167	0.331	1.107	1.107	0.513
11	74,468	5.957	0.815	2.979	0.298	0.884	0.884	0.379
12	70,665	5.653	0.813	2.919	0.283	0.771	0.771	0.306
13	68,545	5.484	0.813	2.910	0.274	0.743	0.743	0.273
14	67,177	5.374	0.813	2.924	0.269	0.684	0.684	0.233
15	65,320	5.226	0.815	2.923	0.261	0.613	0.613	0.193
16	64,738	5.179	0.813	2.960	0.259	0.574	0.574	0.167
17	66,405	5.312	0.000	2.862	0.266	1.092	1.092	0.295
18	68,237	5.459	0.000	2.984	0.273	1.101	1.101	0.276
19	74,260	5.941	0.000	3.260	0.297	1.192	1.192	0.276
20	77,392	6.191	0.000	3.438	0.310	1.222	1.222	0.262
21	80,056	6.404	0.000	3.605	0.320	1.239	1.239	0.246
22	82,677	6.614	0.000	3.777	0.331	1.253	1.253	0.231
23	88,703	7.096	0.000	4.087	0.355	1.327	1.327	0.226
24	91,520	7.322	0.000	4.278	0.366	1.339	1.339	0.211
25	92,950	7.436	0.000	4.421	0.372	1.321	1.321	0.193
26	100,122	8.010	0.000	4.804	0.400	1.403	1.403	0.190
27	131,212	10.497	0.000	6.202	0.525	1.885	1.885	0.236
28	255,181	20.414	0.000	11.615	1.021	3.890	3.890	0.451
29	326,588	26.127	0.000	14.955	1.306	4.933	4.933	0.529
Total	**8,550,628**	**684.050**	**133.043**	**271.047**	**57.441**	**118.804**	**103.715**	**52.533**
						IRR	**69.30%**	**56.76%**
						PIR	**0.780**	**0.395**

Table 5.18 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 29.43%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,404,158	272.333	0.000	92.119	27.233	44.300	88.140	59.987
6	2,126,085	170.087	0.538	59.153	17.009	36.619	36.619	23.076
7	446,423	35.714	1.222	13.338	1.786	0.000	-1.270	-0.741
8	217,980	17.438	1.219	7.043	0.872	0.000	-12.333	-6.663
9	152,553	12.204	1.219	5.267	0.610	2.505	2.505	1.253
10	123,853	9.908	1.219	4.515	0.495	1.791	1.791	0.829
11	108,443	8.675	1.222	4.138	0.434	1.441	1.441	0.618
12	100,476	8.038	1.219	3.971	0.402	1.223	1.223	0.486
13	96,066	7.685	1.219	3.911	0.384	1.086	1.086	0.399
14	92,524	7.402	1.219	3.874	0.370	0.969	0.969	0.330
15	91,431	7.314	0.000	3.578	0.366	1.685	1.685	0.531
16	96,719	7.737	0.000	3.826	0.387	1.762	1.762	0.514
17	108,539	8.683	0.000	4.308	0.434	1.970	1.970	0.532
18	114,846	9.188	0.000	4.615	0.459	2.056	2.056	0.515
19	109,827	8.786	0.000	4.530	0.439	1.908	1.908	0.442
20	111,546	8.924	0.000	4.682	0.446	1.898	1.898	0.407
21	110,969	8.877	0.000	4.754	0.444	1.840	1.840	0.366
22	109,340	8.747	0.000	4.787	0.437	1.761	1.761	0.324
23	109,956	8.796	0.000	4.908	0.440	1.724	1.724	0.294
24	120,332	9.627	0.000	5.414	0.481	1.866	1.866	0.294
25	168,393	13.471	0.000	7.455	0.674	2.672	2.672	0.390
26	256,427	20.514	0.000	11.215	1.026	4.137	4.137	0.559
27	363,268	29.061	0.000	15.910	1.453	5.849	5.849	0.732
28	330,185	26.415	0.000	14.815	1.321	5.139	5.139	0.596
29	288,024	23.042	0.000	13.276	1.152	4.307	4.307	0.462
Total	**9,358,356**	**748.668**	**136.295**	**305.404**	**59.554**	**130.509**	**116.906**	**52.990**
						IRR	**67.31%**	**54.91%**
						PIR	**0.858**	**0.389**

Table 5.19 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 28.48%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,524,589	201.967	0.000	69.684	20.197	45.773	45.773	28.845
7	319,213	25.537	0.538	9.467	1.277	0.000	-5.894	-3.439
8	168,100	13.448	1.219	5.567	0.672	0.000	-14.648	-7.914
9	118,558	9.485	1.219	4.227	0.474	1.733	1.733	0.867
10	99,427	7.954	1.219	3.740	0.398	1.250	1.250	0.579
11	88,406	7.072	1.222	3.481	0.354	0.959	0.959	0.411
12	83,145	6.652	1.219	3.385	0.333	0.858	0.858	0.341
13	80,484	6.439	1.219	3.369	0.322	0.765	0.765	0.281
14	77,930	6.234	1.219	3.353	0.312	0.675	0.675	0.230
15	77,280	6.182	1.222	3.401	0.309	0.625	0.625	0.197
16	77,002	6.160	0.000	3.163	0.308	1.345	1.345	0.392
17	82,091	6.567	0.000	3.401	0.328	1.419	1.419	0.384
18	90,057	7.205	0.000	3.748	0.360	1.548	1.548	0.387
19	100,862	8.069	0.000	4.210	0.403	1.728	1.728	0.400
20	102,663	8.213	0.000	4.358	0.411	1.722	1.722	0.369
21	104,223	8.338	0.000	4.503	0.417	1.709	1.709	0.339
22	110,317	8.825	0.000	4.824	0.441	1.780	1.780	0.327
23	110,033	8.803	0.000	4.911	0.440	1.726	1.726	0.294
24	109,913	8.793	0.000	5.003	0.440	1.675	1.675	0.264
25	118,695	9.496	0.000	5.456	0.475	1.782	1.782	0.260
26	157,037	12.563	0.000	7.138	0.628	2.398	2.398	0.324
27	273,458	21.877	0.000	12.153	1.094	4.315	4.315	0.540
28	369,662	29.573	0.000	16.500	1.479	5.797	5.797	0.672
29	327,258	26.181	0.000	14.984	1.309	4.944	4.944	0.531
Total	**9,055,398**	**724.432**	**136.295**	**292.921**	**59.460**	**128.149**	**107.607**	**50.505**
						IRR	**67.63%**	**55.21%**
						PIR	**0.790**	**0.371**

Table 5.20 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 1,500 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 27.34%.

Year	**Cash Flow Summary**							**Discount**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	**Cash Flow (NPV@8%)**
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,524,589	201.967	0.000	69.684	20.197	45.773	45.773	28.845
7	486,603	38.928	0.000	13.700	1.946	1.371	1.371	0.800
8	128,744	10.300	0.538	4.185	0.515	0.000	-15.088	-8.152
9	96,668	7.733	1.219	3.533	0.387	1.249	1.249	0.625
10	82,713	6.617	1.219	3.187	0.331	0.891	0.891	0.413
11	74,282	5.943	1.222	2.995	0.297	0.665	0.665	0.285
12	70,400	5.632	1.219	2.933	0.282	0.551	0.551	0.219
13	68,212	5.457	1.219	2.922	0.273	0.522	0.522	0.192
14	66,911	5.353	1.219	2.939	0.268	0.464	0.464	0.158
15	64,974	5.198	1.222	2.935	0.260	0.390	0.390	0.123
16	64,041	5.123	1.219	2.961	0.256	0.344	0.344	0.100
17	65,920	5.274	0.000	2.846	0.264	1.082	1.082	0.292
18	67,747	5.420	0.000	2.967	0.271	1.091	1.091	0.273
19	75,620	6.050	0.000	3.309	0.302	1.219	1.219	0.283
20	82,492	6.599	0.000	3.624	0.330	1.323	1.323	0.284
21	89,081	7.126	0.000	3.941	0.356	1.415	1.415	0.281
22	93,164	7.453	0.000	4.174	0.373	1.453	1.453	0.267
23	100,743	8.059	0.000	4.552	0.403	1.552	1.552	0.264
24	105,290	8.423	0.000	4.821	0.421	1.591	1.591	0.251
25	106,541	8.523	0.000	4.968	0.426	1.565	1.565	0.228
26	113,627	9.090	0.000	5.358	0.455	1.639	1.639	0.222
27	143,069	11.445	0.000	6.698	0.572	2.087	2.087	0.261
28	271,568	21.725	0.000	12.314	1.086	4.163	4.163	0.483
29	366,530	29.322	0.000	16.693	1.466	5.581	5.581	0.599
Total	**8,694,523**	**695.562**	**136.295**	**277.133**	**58.016**	**119.603**	**104.515**	**52.217**
						IRR	**69.26%**	**56.72%**
						PIR	**0.767**	**0.383**

Table 5.21 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 29.95%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,245,243	179.619	0.538	62.442	17.962	39.264	39.264	24.743
7	435,763	34.861	1.630	13.061	1.743	0.000	-2.211	-1.290
8	222,568	17.805	1.625	7.199	0.890	0.000	-12.546	-6.778
9	155,024	12.402	1.625	5.364	0.620	2.348	2.348	1.174
10	125,442	10.035	1.625	4.587	0.502	1.612	1.612	0.747
11	109,966	8.797	1.630	4.210	0.440	1.259	1.259	0.540
12	101,745	8.140	1.625	4.036	0.407	1.036	1.036	0.411
13	97,089	7.767	1.625	3.969	0.388	0.892	0.892	0.328
14	93,603	7.488	1.625	3.936	0.374	0.776	0.776	0.264
15	92,455	7.396	0.000	3.612	0.370	1.707	1.707	0.538
16	95,918	7.673	0.000	3.799	0.384	1.745	1.745	0.509
17	108,694	8.695	0.000	4.314	0.435	1.973	1.973	0.533
18	124,737	9.979	0.000	4.962	0.499	2.259	2.259	0.565
19	124,779	9.982	0.000	5.064	0.499	2.210	2.210	0.512
20	127,508	10.201	0.000	5.263	0.510	2.214	2.214	0.475
21	127,795	10.224	0.000	5.379	0.511	2.167	2.167	0.430
22	124,482	9.959	0.000	5.361	0.498	2.050	2.050	0.377
23	123,037	9.843	0.000	5.414	0.492	1.968	1.968	0.335
24	132,232	10.579	0.000	5.883	0.529	2.083	2.083	0.329
25	179,682	14.375	0.000	7.909	0.719	2.874	2.874	0.420
26	253,699	20.296	0.000	11.103	1.015	4.089	4.089	0.553
27	373,399	29.872	0.000	16.334	1.494	6.022	6.022	0.754
28	355,619	28.450	0.000	15.900	1.422	5.563	5.563	0.645
29	309,056	24.724	0.000	14.192	1.236	4.648	4.648	0.499
Total	**9,524,530**	**761.962**	**139.548**	**312.188**	**60.219**	**132.382**	**117.625**	**52.235**
						IRR	**66.22%**	**53.91%**
						PIR	**0.843**	**0.374**

Table 5.22 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and recovery factor = 28.80%.

Year	**Cash Flow Summary**							**Discount**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	**Cash Flow (NPV@8%)**
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,538,745	203.100	0.000	70.074	20.310	46.088	46.088	29.043
7	305,056	24.404	0.538	9.068	1.220	0.000	-6.572	-3.834
8	168,044	13.444	1.625	5.580	0.672	0.000	-15.071	-8.143
9	118,425	9.474	1.625	4.238	0.474	1.520	1.520	0.760
10	99,232	7.939	1.625	3.750	0.397	1.035	1.035	0.479
11	88,208	7.057	1.630	3.490	0.353	0.743	0.743	0.319
12	83,119	6.650	1.625	3.400	0.332	0.646	0.646	0.256
13	80,439	6.435	1.625	3.383	0.322	0.553	0.553	0.203
14	77,765	6.221	1.625	3.364	0.311	0.460	0.460	0.157
15	77,072	6.166	1.630	3.411	0.308	0.409	0.409	0.129
16	76,829	6.146	0.000	3.157	0.307	1.341	1.341	0.391
17	81,183	6.495	0.000	3.370	0.325	1.400	1.400	0.378
18	89,319	7.146	0.000	3.722	0.357	1.533	1.533	0.384
19	101,681	8.134	0.000	4.239	0.407	1.744	1.744	0.404
20	109,221	8.738	0.000	4.597	0.437	1.852	1.852	0.397
21	113,877	9.110	0.000	4.862	0.456	1.896	1.896	0.377
22	121,138	9.691	0.000	5.234	0.485	1.986	1.986	0.365
23	120,222	9.618	0.000	5.305	0.481	1.916	1.916	0.326
24	119,185	9.535	0.000	5.369	0.477	1.845	1.845	0.291
25	127,501	10.200	0.000	5.810	0.510	1.940	1.940	0.283
26	165,381	13.230	0.000	7.480	0.662	2.544	2.544	0.344
27	274,267	21.941	0.000	12.187	1.097	4.329	4.329	0.542
28	387,909	31.033	0.000	17.278	1.552	6.101	6.101	0.707
29	348,360	27.869	0.000	15.903	1.393	5.286	5.286	0.567
Total	**9,157,173**	**732.574**	**139.548**	**297.168**	**59.924**	**128.789**	**107.146**	**49.749**
						IRR	**67.48%**	**55.08%**
						PIR	**0.768**	**0.356**

Table 5.23 Cash flow summary of the 5th year polymer solution injection with the polymer concentrate 2,000 ppm, production of model A100, (5/4) production/injection well, initial production rate at 9,000 BOPD, water and polymer solution injection rate at 2,000 BWPD, and r ecovery factor = 27.60%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	2.500	0.000	0.000	0.000	-2.500	-2.315
2	0.000	0.000	4.000	0.000	0.000	0.000	-4.000	-3.429
3	0.000	0.000	6.000	0.000	0.000	0.000	-6.000	-4.763
4	0.000	0.000	113.500	0.000	0.000	0.000	-31.340	-23.036
5	3,285,000	262.800	0.000	88.895	26.280	41.623	85.463	58.164
6	2,524,589	201.967	0.000	69.684	20.197	45.773	45.773	28.845
7	486,603	38.928	0.000	13.700	1.946	1.371	1.371	0.800
8	128,744	10.300	0.538	4.185	0.515	0.000	-15.088	-8.152
9	96,648	7.732	1.625	3.545	0.387	1.039	1.039	0.520
10	82,658	6.613	1.625	3.198	0.331	0.681	0.681	0.315
11	74,193	5.935	1.630	3.005	0.297	0.453	0.453	0.194
12	70,163	5.613	1.625	2.938	0.281	0.336	0.336	0.133
13	67,977	5.438	1.625	2.928	0.272	0.307	0.307	0.113
14	66,748	5.340	1.625	2.947	0.267	0.251	0.251	0.085
15	64,735	5.179	1.630	2.941	0.259	0.175	0.175	0.055
16	63,597	5.088	1.625	2.960	0.254	0.124	0.124	0.036
17	65,473	5.238	0.000	2.830	0.262	1.073	1.073	0.290
18	67,171	5.374	0.000	2.946	0.269	1.079	1.079	0.270
19	75,303	6.024	0.000	3.297	0.301	1.213	1.213	0.281
20	82,982	6.639	0.000	3.641	0.332	1.333	1.333	0.286
21	91,162	7.293	0.000	4.018	0.365	1.455	1.455	0.289
22	97,587	7.807	0.000	4.342	0.390	1.537	1.537	0.283
23	107,217	8.577	0.000	4.802	0.429	1.673	1.673	0.285
24	113,296	9.064	0.000	5.137	0.453	1.737	1.737	0.274
25	115,867	9.269	0.000	5.343	0.463	1.732	1.732	0.253
26	122,645	9.812	0.000	5.728	0.491	1.797	1.797	0.243
27	151,839	12.147	0.000	7.065	0.607	2.237	2.237	0.280
28	280,208	22.417	0.000	12.683	1.121	4.307	4.307	0.499
29	393,764	31.501	0.000	17.879	1.575	6.024	6.024	0.647
Total	**8,776,165**	**702.093**	**139.548**	**280.635**	**58.343**	**119.328**	**104.239**	**51.746**
						IRR	**69.22%**	**56.68%**
						PIR	**0.747**	**0.371**

Table 5.24 Cash flow summary of base case the 3rd year water injection production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water injection rate at 400 BWPD, and recovery factor = 44.24%.

Year	Cash Flow Summary							Discount Cash Flow
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	(NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	124,100	9.928	0.000	2.740	0.496	2.256	2.256	1.421
7	124,440	9.955	0.145	2.930	0.498	2.149	2.149	1.254
8	124,100	9.928	0.000	2.981	0.496	2.123	2.123	1.147
9	124,100	9.928	0.000	3.040	0.496	3.184	3.184	1.593
10	124,100	9.928	0.000	3.101	0.496	3.153	3.153	1.461
11	124,440	9.955	0.000	3.172	0.498	3.131	3.131	1.343
12	124,100	9.928	0.000	3.249	0.496	3.091	3.091	1.228
13	124,100	9.928	0.000	3.314	0.496	3.059	3.059	1.125
14	124,100	9.928	0.000	3.381	0.496	3.026	3.026	1.030
15	124,440	9.955	0.000	3.457	0.498	3.000	3.000	0.946
16	124,100	9.928	0.000	3.517	0.496	2.957	2.957	0.863
17	124,100	9.928	0.000	3.587	0.496	2.922	2.922	0.790
18	124,100	9.928	0.000	3.659	0.496	2.886	2.886	0.722
19	124,440	9.955	0.000	3.742	0.498	2.858	2.858	0.662
20	124,100	9.928	0.000	3.807	0.496	2.812	2.812	0.603
21	124,100	9.928	0.000	3.883	0.496	2.774	2.774	0.551
22	107,041	8.563	0.000	3.444	0.428	2.346	2.346	0.431
23	24,361	1.949	0.000	0.957	0.097	0.447	0.447	0.076
24	4,654	0.372	0.000	0.354	0.019	0.000	0.000	0.000
Total	**2,254,416**	**180.353**	**17.145**	**61.161**	**9.018**	**48.174**	**44.855**	**14.260**
						IRR	**31.46%**	**21.72%**
						PIR	**2.616**	**0.832**

Table 5.25 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 600 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.64%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	124,100	9.928	0.269	2.865	0.496	2.156	2.156	1.359
7	124,440	9.955	0.098	2.987	0.498	2.072	2.072	1.209
8	124,100	9.928	0.098	3.039	0.496	2.033	2.033	1.098
9	124,100	9.928	0.098	3.100	0.496	3.093	3.093	1.547
10	124,100	9.928	0.098	3.162	0.496	3.062	3.062	1.418
11	124,440	9.955	0.098	3.233	0.498	3.063	3.063	1.314
12	124,100	9.928	0.122	3.315	0.496	2.997	2.997	1.190
13	124,100	9.928	0.122	3.382	0.496	2.964	2.964	1.090
14	124,100	9.928	0.122	3.449	0.496	2.930	2.930	0.998
15	124,440	9.955	0.122	3.528	0.498	2.904	2.904	0.915
16	124,100	9.928	0.122	3.589	0.496	2.861	2.861	0.835
17	124,100	9.928	0.122	3.660	0.496	2.825	2.825	0.763
18	124,100	9.928	0.122	3.734	0.496	2.788	2.788	0.698
19	124,440	9.955	0.122	3.818	0.498	2.758	2.758	0.639
20	124,100	9.928	0.122	3.885	0.496	2.713	2.713	0.582
21	124,100	9.928	0.122	3.962	0.496	2.674	2.674	0.531
22	124,100	9.928	0.122	4.041	0.496	2.634	2.634	0.485
23	124,440	9.955	0.122	4.133	0.498	2.601	2.601	0.443
24	112,034	8.963	0.122	3.824	0.448	2.284	2.284	0.360
Total	**2,478,934**	**198.315**	**19.343**	**69.552**	**9.916**	**51.411**	**48.093**	**14.489**
						IRR	**30.90%**	**21.21%**
						PIR	**2.486**	**0.749**

Table 5.26 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 600 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.72%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	131,400	10.512	0.000	2.902	0.526	2.452	2.452	1.545
7	124,440	9.955	0.269	2.930	0.498	2.137	2.137	1.247
8	124,100	9.928	0.098	3.040	0.496	2.033	2.033	1.098
9	124,100	9.928	0.098	3.101	0.496	3.092	3.092	1.547
10	124,100	9.928	0.098	3.163	0.496	3.061	3.061	1.418
11	124,440	9.955	0.098	3.235	0.498	3.038	3.038	1.303
12	124,100	9.928	0.098	3.313	0.496	3.010	3.010	1.195
13	124,100	9.928	0.122	3.383	0.496	2.963	2.963	1.090
14	124,100	9.928	0.122	3.451	0.496	2.929	2.929	0.997
15	124,440	9.955	0.122	3.529	0.498	2.903	2.903	0.915
16	124,100	9.928	0.122	3.590	0.496	2.860	2.860	0.835
17	124,100	9.928	0.122	3.662	0.496	2.824	2.824	0.763
18	124,100	9.928	0.122	3.735	0.496	2.787	2.787	0.698
19	124,440	9.955	0.122	3.820	0.498	2.758	2.758	0.639
20	124,100	9.928	0.122	3.886	0.496	2.712	2.712	0.582
21	124,100	9.928	0.122	3.964	0.496	2.673	2.673	0.531
22	124,100	9.928	0.122	4.043	0.496	2.633	2.633	0.484
23	124,440	9.955	0.122	4.135	0.498	2.600	2.600	0.443
24	108,816	8.705	0.122	3.724	0.435	2.212	2.212	0.349
Total	**2,483,016**	**198.641**	**19.220**	**69.450**	**9.932**	**51.679**	**48.360**	**14.693**
						IRR	**31.47%**	**21.73%**
						PIR	**2.516**	**0.764**

Table 5.27 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 800 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.63%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	124,100	9.928	0.269	2.865	0.496	2.156	2.156	1.359
7	124,440	9.955	0.130	2.987	0.498	2.056	2.056	1.199
8	124,100	9.928	0.130	3.039	0.496	2.017	2.017	1.090
9	124,100	9.928	0.130	3.100	0.496	3.077	3.077	1.539
10	124,100	9.928	0.130	3.162	0.496	3.046	3.046	1.411
11	124,440	9.955	0.130	3.233	0.498	3.047	3.047	1.307
12	124,100	9.928	0.163	3.315	0.496	2.977	2.977	1.182
13	124,100	9.928	0.163	3.382	0.496	2.944	2.944	1.082
14	124,100	9.928	0.163	3.449	0.496	2.910	2.910	0.991
15	124,440	9.955	0.163	3.528	0.498	2.883	2.883	0.909
16	124,100	9.928	0.163	3.589	0.496	2.840	2.840	0.829
17	124,100	9.928	0.163	3.660	0.496	2.804	2.804	0.758
18	124,100	9.928	0.163	3.734	0.496	2.768	2.768	0.693
19	124,440	9.955	0.163	3.818	0.498	2.738	2.738	0.634
20	124,100	9.928	0.163	3.884	0.496	2.692	2.692	0.578
21	124,100	9.928	0.163	3.962	0.496	2.653	2.653	0.527
22	124,100	9.928	0.163	4.041	0.496	2.614	2.614	0.481
23	124,440	9.955	0.163	4.133	0.498	2.581	2.581	0.440
24	111,251	8.900	0.163	3.799	0.445	2.247	2.247	0.354
Total	**2,478,151**	**198.252**	**20.034**	**69.526**	**9.913**	**51.049**	**47.731**	**14.376**
						IRR	**30.81%**	**21.12%**
						PIR	**2.383**	**0.718**

Table 5.28 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 800 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.80%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	131,400	10.512	0.000	2.902	0.526	2.452	2.452	1.545
7	124,440	9.955	0.269	2.930	0.498	2.137	2.137	1.247
8	124,100	9.928	0.130	3.040	0.496	2.016	2.016	1.089
9	124,100	9.928	0.130	3.101	0.496	3.076	3.076	1.539
10	124,100	9.928	0.130	3.163	0.496	3.045	3.045	1.410
11	124,440	9.955	0.130	3.235	0.498	3.022	3.022	1.296
12	124,100	9.928	0.130	3.313	0.496	2.994	2.994	1.189
13	124,100	9.928	0.163	3.383	0.496	2.943	2.943	1.082
14	124,100	9.928	0.163	3.451	0.496	2.909	2.909	0.990
15	124,440	9.955	0.163	3.529	0.498	2.883	2.883	0.909
16	124,100	9.928	0.163	3.590	0.496	2.839	2.839	0.829
17	124,100	9.928	0.163	3.662	0.496	2.803	2.803	0.758
18	124,100	9.928	0.163	3.736	0.496	2.767	2.767	0.692
19	124,440	9.955	0.163	3.820	0.498	2.737	2.737	0.634
20	124,100	9.928	0.163	3.886	0.496	2.691	2.691	0.577
21	124,100	9.928	0.163	3.964	0.496	2.652	2.652	0.527
22	124,100	9.928	0.163	4.043	0.496	2.613	2.613	0.481
23	124,440	9.955	0.163	4.135	0.498	2.580	2.580	0.439
24	112,738	9.019	0.163	3.848	0.451	2.279	2.279	0.359
Total	**2,486,938**	**198.955**	**19.871**	**69.579**	**9.948**	**51.438**	**48.120**	**14.608**
						IRR	**31.40%**	**21.67%**
						PIR	**2.422**	**0.735**

Table 5.29 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.63%.

Year	**Cash Flow Summary**							**Discount**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	**Cash Flow (NPV@8%)**
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	124,100	9.928	0.269	2.865	0.496	2.156	2.156	1.359
7	124,440	9.955	0.163	2.987	0.498	2.039	2.039	1.190
8	124,100	9.928	0.163	3.039	0.496	2.001	2.001	1.081
9	124,100	9.928	0.163	3.100	0.496	3.060	3.060	1.531
10	124,100	9.928	0.163	3.162	0.496	3.029	3.029	1.403
11	124,440	9.955	0.163	3.233	0.498	3.031	3.031	1.300
12	124,100	9.928	0.203	3.315	0.496	2.957	2.957	1.174
13	124,100	9.928	0.203	3.382	0.496	2.923	2.923	1.075
14	124,100	9.928	0.203	3.449	0.496	2.890	2.890	0.984
15	124,440	9.955	0.204	3.528	0.498	2.863	2.863	0.903
16	124,100	9.928	0.203	3.589	0.496	2.820	2.820	0.823
17	124,100	9.928	0.203	3.660	0.496	2.784	2.784	0.752
18	124,100	9.928	0.203	3.734	0.496	2.747	2.747	0.688
19	124,440	9.955	0.204	3.818	0.498	2.718	2.718	0.630
20	124,100	9.928	0.203	3.884	0.496	2.672	2.672	0.573
21	124,100	9.928	0.203	3.962	0.496	2.633	2.633	0.523
22	124,100	9.928	0.203	4.041	0.496	2.594	2.594	0.477
23	124,440	9.955	0.204	4.133	0.498	2.560	2.560	0.436
24	111,658	8.933	0.203	3.812	0.447	2.235	2.235	0.353
Total	**2,478,558**	**198.285**	**20.725**	**69.539**	**9.914**	**50.712**	**47.394**	**14.268**
						IRR	**30.71%**	**21.03%**
						PIR	**2.287**	**0.688**

Table 5.30 Cash flow summary of the 4th year polymer solution injection with the polymer concentrate 1,000 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.81%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	131,400	10.512	0.000	2.902	0.526	2.452	2.452	1.545
7	124,440	9.955	0.269	2.930	0.498	2.137	2.137	1.247
8	124,100	9.928	0.163	3.040	0.496	2.000	2.000	1.081
9	124,100	9.928	0.163	3.101	0.496	3.060	3.060	1.531
10	124,100	9.928	0.163	3.163	0.496	3.029	3.029	1.403
11	124,440	9.955	0.163	3.235	0.498	3.005	3.005	1.289
12	124,100	9.928	0.163	3.313	0.496	2.978	2.978	1.183
13	124,100	9.928	0.203	3.383	0.496	2.923	2.923	1.075
14	124,100	9.928	0.203	3.451	0.496	2.889	2.889	0.983
15	124,440	9.955	0.204	3.529	0.498	2.862	2.862	0.902
16	124,100	9.928	0.203	3.591	0.496	2.819	2.819	0.823
17	124,100	9.928	0.203	3.662	0.496	2.783	2.783	0.752
18	124,100	9.928	0.203	3.736	0.496	2.746	2.746	0.687
19	124,440	9.955	0.204	3.820	0.498	2.717	2.717	0.629
20	124,100	9.928	0.203	3.886	0.496	2.671	2.671	0.573
21	124,100	9.928	0.203	3.964	0.496	2.632	2.632	0.523
22	124,100	9.928	0.203	4.043	0.496	2.592	2.592	0.477
23	124,440	9.955	0.204	4.135	0.498	2.559	2.559	0.436
24	113,181	9.054	0.203	3.862	0.453	2.268	2.268	0.358
Total	**2,487,381**	**198.990**	**20.521**	**69.594**	**9.950**	**51.122**	**47.804**	**14.511**
						IRR	**31.33%**	**21.61%**
						PIR	**2.329**	**0.707**

Table 5.31 Cash flow summary of the 3rd year polymer solution injection with the polymer concentrate 1,200 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.76%.

Year	**Cash Flow Summary**							**Discount**
	Oil production total.	**Gross revenue**	**Capex**	**Opex**	**Government take**		**Annual cash flow**	**Cash Flow (NPV@8%)**
					Royalty	**Inc. tax**		
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	124,100	9.928	0.269	2.865	0.496	2.156	2.156	1.359
7	124,440	9.955	0.196	2.988	0.498	2.023	2.023	1.180
8	124,100	9.928	0.195	3.039	0.496	1.984	1.984	1.072
9	124,100	9.928	0.195	3.100	0.496	3.044	3.044	1.523
10	124,100	9.928	0.195	3.162	0.496	3.013	3.013	1.396
11	124,440	9.955	0.196	3.234	0.498	3.014	3.014	1.293
12	124,100	9.928	0.244	3.316	0.496	2.936	2.936	1.166
13	124,100	9.928	0.244	3.382	0.496	2.903	2.903	1.067
14	124,100	9.928	0.244	3.450	0.496	2.869	2.869	0.977
15	124,440	9.955	0.244	3.528	0.498	2.842	2.842	0.896
16	124,100	9.928	0.244	3.589	0.496	2.799	2.799	0.817
17	124,100	9.928	0.244	3.661	0.496	2.763	2.763	0.747
18	124,100	9.928	0.244	3.734	0.496	2.727	2.727	0.682
19	124,440	9.955	0.244	3.819	0.498	2.697	2.697	0.625
20	124,100	9.928	0.244	3.885	0.496	2.651	2.651	0.569
21	124,100	9.928	0.244	3.963	0.496	2.613	2.613	0.519
22	124,100	9.928	0.244	4.042	0.496	2.573	2.573	0.473
23	124,440	9.955	0.244	4.134	0.498	2.540	2.540	0.433
24	117,931	9.434	0.244	4.011	0.472	2.354	2.354	0.371
Total	**2,484,831**	**198.786**	**21.416**	**69.746**	**9.939**	**50.502**	**47.184**	**14.179**
						IRR	**30.62%**	**20.95%**
						PIR	**2.203**	**0.662**

Table 5.32 Cash flow summary of the 4th polymer solution injection with the polymer concentrate 1,200 ppm, production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water and polymer solution injection rate at 400 BWPD, and recovery factor = 48.86%.

Year	Cash Flow Summary							Discount
	Oil production total.	Gross revenue	Capex	Opex	Government take		Annual cash flow	Cash Flow (NPV@8%)
					Royalty	Inc. tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0.000	0.000	0.500	0.000	0.000	0.000	-0.500	-0.463
2	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.857
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.794
4	0.000	0.000	14.500	0.000	0.000	0.000	-5.780	-4.248
5	131,400	10.512	0.000	2.845	0.526	0.000	4.962	3.377
6	131,400	10.512	0.000	2.902	0.526	2.452	2.452	1.545
7	124,440	9.955	0.269	2.930	0.498	2.137	2.137	1.247
8	124,100	9.928	0.195	3.040	0.496	1.984	1.984	1.072
9	124,100	9.928	0.195	3.101	0.496	3.043	3.043	1.522
10	124,100	9.928	0.195	3.163	0.496	3.012	3.012	1.395
11	124,440	9.955	0.196	3.235	0.498	2.989	2.989	1.282
12	124,100	9.928	0.195	3.314	0.496	2.961	2.961	1.176
13	124,100	9.928	0.244	3.384	0.496	2.902	2.902	1.067
14	124,100	9.928	0.244	3.451	0.496	2.868	2.868	0.977
15	124,440	9.955	0.244	3.530	0.498	2.842	2.842	0.896
16	124,100	9.928	0.244	3.591	0.496	2.799	2.799	0.817
17	124,100	9.928	0.244	3.663	0.496	2.763	2.763	0.747
18	124,100	9.928	0.244	3.736	0.496	2.726	2.726	0.682
19	124,440	9.955	0.244	3.821	0.498	2.696	2.696	0.625
20	124,100	9.928	0.244	3.887	0.496	2.651	2.651	0.569
21	124,100	9.928	0.244	3.964	0.496	2.612	2.612	0.519
22	124,100	9.928	0.244	4.044	0.496	2.572	2.572	0.473
23	124,440	9.955	0.244	4.136	0.498	2.539	2.539	0.432
24	115,831	9.266	0.244	3.899	0.463	2.330	2.330	0.367
Total	**2,490,031**	**199.202**	**21.172**	**69.633**	**9.960**	**50.878**	**47.559**	**14.424**
						IRR	**31.26%**	**21.54%**
						PIR	**2.246**	**0.681**

Table 5.33 Undiscounted and discounted cash flow summary of all scenarios.

Model	Polymer Conc. (ppm)	Period of Water/Ply Injection Scenarios	Oil Recovery Factor (%)	IRR Undiscount (%)	PIR Undiscount (Fraction)	IRR With 8% Discount (%)	PIR With 8% Discount (Fraction)
A100	Water inj.	3^{rd}-25^{th}	33.11	44.16	1.37	33.49	0.46
	1,000	3^{rd}-11^{th}	38.36	55.26	1.46	43.76	0.51
	1,000	4^{th} -12^{th}	37.71	43.94	1.40	33.28	0.45
	1,000	5^{th} -13^{th}	36.97	39.15	1.34	28.84	0.4
	1,500	3^{rd}-11^{th}	39.48	54.85	1.41	43.38	0.48
	1,500	4^{th} -12^{th}	38.84	43.73	1.36	33.08	0.43
	1,500	5^{th} -13^{th}	38.09	38.91	1.30	28.62	0.38
	2,000	3^{rd}-11^{th}	40.35	54.44	1.36	43.00	0.46
	2,000	4^{th} -12^{th}	39.69	43.44	1.31	32.81	0.41
	2,000	5^{th} -13^{th}	38.94	38.67	1.26	28.40	0.37
A30	Water inj.	3^{rd}-25^{th}	24.47	67.86	0.72	55.43	0.39
	1,000	3^{rd}-10^{th}	28.72	66.68	0.86	54.33	0.40
	1,000	4^{th} -11^{th}	27.89	67.73	0.80	55.31	0.38
	1,000	5^{th} -12^{th}	26.89	69.30	0.78	56.76	0.39
	1,500	3^{rd}-10^{th}	29.43	67.31	0.86	54.91	0.39
	1,500	4^{th} -11^{th}	28.48	67.63	0.79	55.21	0.37
	1,500	5^{th} -12^{th}	27.34	69.26	0.77	56.72	0.38
	2,000	3^{rd}-10^{th}	29.95	66.22	0.84	53.91	0.37
	2,000	4^{th} -11^{th}	28.80	67.48	0.77	55.08	0.36
	2,000	5^{th} -12^{th}	27.60	69.22	0.75	56.68	0.37
A05	Water inj.	3^{rd}-20^{th}	44.24	31.46	2.62	21.72	0.83
	600	3^{rd}-20^{th}	48.64	30.90	2.49	21.21	0.75
	600	4^{th} -20^{th}	48.72	31.47	2.52	21.73	0.76
	800	3^{rd}-20^{th}	48.63	30.81	2.38	21.12	0.72
	800	4^{th} -20^{th}	48.80	31.40	2.42	21.67	0.74
	1,000	3^{rd}-20^{th}	48.63	30.71	2.29	21.03	0.69
	1,000	4^{th} -20^{th}	48.81	31.33	2.33	21.61	0.71
	1,200	3^{rd}-20^{th}	48.76	30.62	2.20	20.95	0.66
	1,200	4^{th} -20^{th}	48.86	31.26	2.25	21.54	0.68

Table 5.34 Net present value and incremental NPV summary of all scenarios.

Model	Polymer Conc. (ppm)	Period of Water/Ply Injection Scenarios	Oil Recovery Factor (%)	Capital Cost (MMUS$)	NPV (8%Disc.) (MMUS$)	Incremental NPV (8%Disc.) (MMUS$)
A100	Water inj.	3rd-25th	33.11	307.33	141.94	-
	1,000	3rd-11th	38.36	337.1	170.31	28.37
	1,000	4th -12th	37.71	337.1	150.83	8.89
	1,000	5th -13th	36.97	337.1	135.62	-6.32
	1,500	3rd-11th	39.48	351.74	169.31	27.37
	1,500	4th -12th	38.84	351.73	150.25	8.31
	1,500	5th -13th	38.09	351.73	134.9	-7.04
	2,000	3rd-11th	40.35	366.38	167.37	25.43
	2,000	4th -12th	39.69	366.37	149.21	7.27
	2,000	5th -13th	38.94	366.37	133.86	-8.08
A30	Water inj.	3rd-25th	24.47	126.54	49.6	-
	1,000	3rd-10th	28.72	133.04	53.05	3.45
	1,000	4th -11th	27.89	133.04	50.83	1.23
	1,000	5th -12th	26.89	133.04	52.53	2.93
	1,500	3rd-10th	29.43	136.29	52.99	3.39
	1,500	4th -11th	28.48	136.29	50.51	0.91
	1,500	5th -12th	27.34	136.29	52.22	2.62
	2,000	3rd-10th	29.95	139.55	52.24	2.64
	2,000	4th -11th	28.80	139.55	49.75	0.15
	2,000	5th -12th	27.60	139.55	51.75	2.15
A05	Water inj.	3rd-20th	44.24	17.15	14.26	-
	600	3rd-20th	48.64	19.34	14.49	0.23
	600	4th -20th	48.72	19.22	14.69	0.43
	800	3rd-20th	48.63	20.03	14.38	0.12
	800	4th -20th	48.80	19.87	14.61	0.35
	1,000	3rd-20th	48.63	20.72	14.27	0.01
	1,000	4th -20th	48.81	20.52	14.51	0.25
	1,200	3rd-20th	48.76	21.42	14.18	-0.08
	1,200	4th -20th	48.86	21.17	14.42	0.16

CHAPTER VI

CONCLUSIONS AND DISCUSSIONS

6.1 Introduction

This chapter concludes the study in term of reservoir modeling design, results of model scenarios test, and economic evaluation of polymer flooding simulation model for oil field in the Phitsanulok basin. Finally, discussion about study results, problems, and given the possible idea for future works.

6.2 Conclusions of Reservoir Modeling Scenarios Test

The heterogeneity of the geological conditions in the reservoirs causes the oil fields to have a high water cut stage, and low oil recovery efficiency using the waterflooding method. The main physical effect of polymer solution method is reservoir pressure support and sweep efficiency improvement. The application of the polymer flooding method in the three reserved sizes of the oil fields with the various polymer concentrations by the reservoir simulation, the results found the polymer flooding can increase the oil recovery more than using the traditional waterflooding method only. Due to the polymer solution can improve the water swept coefficient and the volumetric sweep efficiency that the results of oil recovery efficiency, the improvement of mobility ratio and the remaining reservoir pressure at the end of project life as shown in Table 6.1 and Figure 6.1. Figure 6.1 shows which improves the mobility ratio of the displacing fluids to avoid fingering and taking advantage of the increased reservoir pressure from the injected polymer solution. Finally, those have reduced the water cut in the oil reservoirs of heterogeneous geological condition and increased oil recovery. The “Xanthan Gum” polymer solution is used in these oil fields simulation. The reservoir with quite high temperature assures that this polymer solution can increase the water viscosity. Therefore, the mobility ratio between polymer solutions and oil will be decreased.

Table 6.1 Oil recovery efficiency, mobility ratio and pressure at the end of project life.

Model	Scenario No.	Polymer Conc. (ppm)	Period of Water/Ply Injection Scenarios	Oil Recovery Factor (%)	Mobility Ratio	Pressure at The End of Project Life (psia)	Incremental Oil Recovery (%OOIP)	Benefit of Polymer (bbl/kg)
A100	1	Water	3rd-25th	33.11	1.136	1,319	-	-
	2	1,000	3rd-11th	38.36	0.370	2,009	5.25	1.37
	3	1,000	4th -12th	37.71	0.370	1,939	4.60	1.20
	4	1,000	5th -13th	36.97	0.370	1,884	3.86	1.01
	5	1,500	3rd-11th	39.48	0.206	2,044	6.37	1.11
	6	1,500	4th -12th	38.84	0.206	1,972	5.73	1.00
	7	1,500	5th -13th	38.09	0.206	1,929	4.93	0.87
	8	2,000	3rd-11th	40.35	0.176	2,052	7.24	0.94
	9	2,000	4th -12th	39.69	0.176	1,981	6.58	0.86
	10	2,000	5th -13th	38.94	0.176	1,922	5.83	0.76
A30	1	Water	3rd-25th	24.47	1.136	207	-	-
	2	1,000	3rd-10th	28.72	0.370	512	4.25	1.45
	3	1,000	4th -11th	27.89	0.370	500	3.42	1.17
	4	1,000	5th -12th	26.89	0.370	473	2.42	0.83
	5	1,500	3rd-10th	29.43	0.206	523	4.96	1.13
	6	1,500	4th -11th	28.48	0.206	512	4.01	0.91
	7	1,500	5th -12th	27.34	0.206	475	2.87	0.65
	8	2,000	3rd-10th	29.95	0.176	510	5.48	0.94
	9	2,000	4th -11th	28.80	0.176	490	4.33	0.74
	10	2,000	5th -12th	27.60	0.176	461	3.13	0.53
A05	1	Water	3rd-20th	44.24	1.136	144	-	-
	2	600	3rd-20th	48.64	0.462	1,685	4.40	0.76
	3	600	4th -20th	48.72	0.462	1,513	4.48	0.82
	4	800	3rd-20th	48.63	0.423	1,749	4.39	0.57
	5	800	4th -20th	48.80	0.423	1,616	4.56	0.63
	6	1,000	3rd-20th	48.63	0.370	1,780	4.39	0.45
	7	1,000	4th -20th	48.81	0.370	1,634	4.57	0.50
	8	1,200	3rd-20th	48.76	0.264	1,844	4.52	0.39
	9	1,200	4th -20th	48.86	0.264	1,661	4.62	0.42

The results show the scenarios of polymer injection that could have high performance oil recovery efficiency when compared to the best case of water injection. All scenarios have more incremental of oil from the polymer injection than that would be gained from the water injection alone. For Model A100, oil recovery has increased 5.25, 4.60, 3.86, 6.37, 5.73, 4.98, 7.24, 6.58, and 5.83% of OOIP for polymer injection scenario 2 to 10 respectively. Model A30, oil recovery has increased 4.25, 3.42, 2.42, 4.96, 4.01, 2.87, 5.48, 4.33, and 3.13% of OOIP for polymer injection scenario 2 to 10 respectively. Model A05, oil recovery has increased 4.40, 4.48, 4.39, 4.56, 4.39, 4.57, 4.52, and 4.62 % of OOIP for polymer injection scenario 2 to 9 respectively.

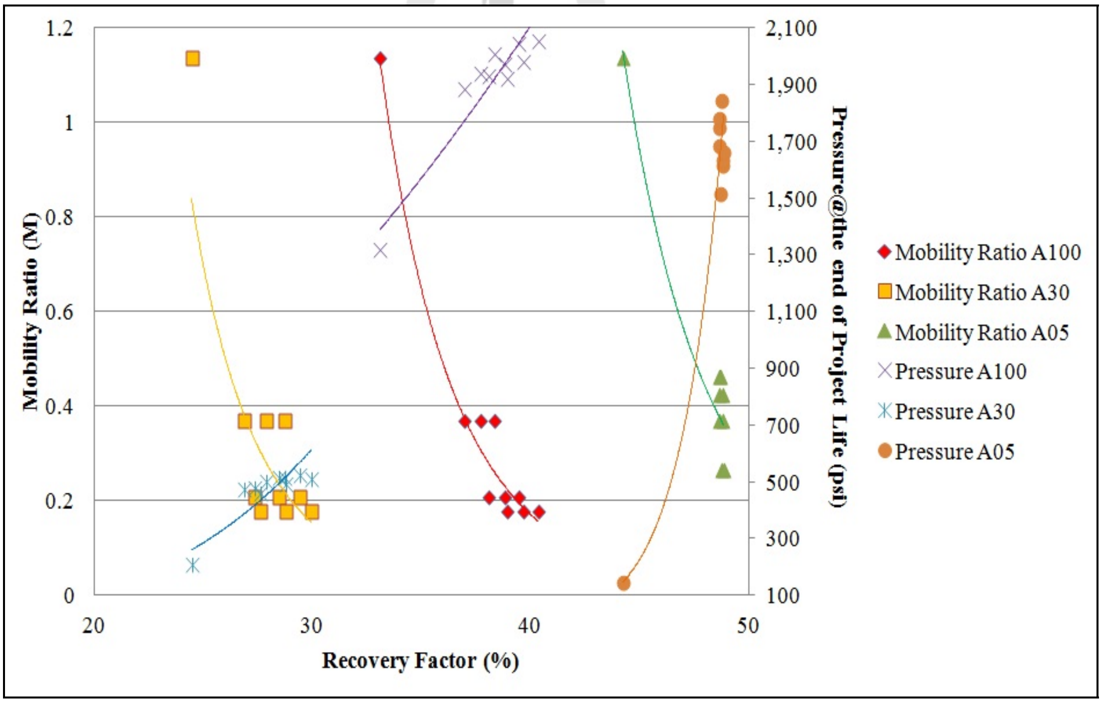


Figure 6.1 Relationship of Recovery Factor, Mobility Ratio and Remaining Reservoir Pressure.

Consequently, model A100 with the 1,000 ppm polymer solution injection and inject period of 3rd-11th year, there is an increased profit of 1,370 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 5.25% OOIP more than the waterflooding. For model A30, with the 1,000 ppm polymer solution injection and injection period of 3rd-10th year, there is an increased profit of 1,450 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 4.25% OOIP more than the waterflooding. For model A05, with the 600 ppm polymer solution injection and injection period of 4th-20th year, there is an increased profit of 820 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 4.48% OOIP more than the waterflooding.

6.3 Economic Evaluation

From the result of polymer flooding in each model is compared to the best case of the waterflooding which is used the same water injection rate (displacing phase). The results of economic evaluation are shown in Table 6.2.

The economic evaluation shows the results of cash flow analysis. This table contains for Internal Rate of Return (IRR), Profit to Investment Ratio (PIR) and Net Present Value (NPV). For model A100, scenario of water injection has the IRR after tax and 8% discounted of 33.49% and PIR of 0.46, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 28.40-43.76% and PIR of 0.37-0.51. Accordingly, the best operation case for model A100 is the scenario that used the polymer concentration of 1,000 ppm and the time interval of injection 3rd-11th year, that has the best NPV of 170 MMUS$.

For model A30, scenario of water injection has the IRR after tax and 8% discounted of 55.43% and PIR of 0.39, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 53.91-56.76% and PIR of 0.36-0.40. Accordingly, the best case for model A30 is the scenario that used the polymer concentration of 1,000 ppm and the time interval of injection 3rd-10th year, that has the best NPV of 53 MMUS$.

For model A05, scenario of water injection has the IRR after tax and 8% discounted of 21.72% and PIR of 0.83, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 20.95-21.73% and PIR of 0.66-0.76. Accordingly, the best operation case for model A05 is the scenario used the polymer concentration of 600 ppm and the time interval of injection 4th-20th year, that has the best NPV of 14.7 MMUS$.

Table 6.2 Economic evaluation results summary.

Model	Scenario No.	Polymer Conc. (ppm)	Period of Water/Ply Injection Scenarios	Capital Cost (MMUS$)	NPV with 8% Discounted (MMUS$)	IRR with 8% Discounted (%)	PIR with 8% Discounted (Fraction)
A100	1	Water	3rd-25th	307.33	141.94	33.49	0.46
	2	1,000	3rd-11th	337.10	170.31	43.76	0.51
	3	1,000	4th -12th	337.10	150.83	33.28	0.45
	4	1,000	5th -13th	337.10	135.62	28.84	0.4
	5	1,500	3rd-11th	351.74	169.31	43.38	0.48
	6	1,500	4th -12th	351.73	150.25	33.08	0.43
	7	1,500	5th -13th	351.73	134.9	28.62	0.38
	8	2,000	3rd-11th	366.38	167.37	43.00	0.46
	9	2,000	4th -12th	366.37	149.21	32.81	0.41
	10	2,000	5th -13th	366.37	133.86	28.40	0.37

Table 6.2 Economic evaluation results summary. (Continued)

Model	Scenario No.	Polymer Conc. (ppm)	Period of Water/Ply Injection Scenarios	Capital Cost (MMUS$)	NPV with 8% Discounted (MMUS$)	IRR with 8% Discounted (%)	PIR with 8% Discounted (Fraction)
A30	1	Water	3^{rd}-25^{th}	126.54	49.60	55.43	0.39
	2	1,000	3^{rd}-10^{th}	133.04	53.05	54.33	0.4
	3	1,000	4^{th} -11^{th}	133.04	50.83	55.31	0.38
	4	1,000	5^{th} -12^{th}	133.04	52.53	56.76	0.39
	5	1,500	3^{rd}-10^{th}	136.29	52.99	54.91	0.39
	6	1,500	4^{th} -11^{th}	136.29	50.51	55.21	0.37
	7	1,500	5^{th} -12^{th}	136.29	52.22	56.72	0.38
	8	2,000	3^{rd}-10^{th}	139.55	52.24	53.91	0.37
	9	2,000	4^{th} -11^{th}	139.55	49.75	55.08	0.36
	10	2,000	5^{th} -12^{th}	139.55	51.75	56.68	0.37
A05	1	Water	3^{rd}-20^{th}	17.15	14.26	21.72	0.83
	2	600	3^{rd}-20^{th}	19.34	14.49	21.21	0.75
	3	600	4^{th} -20^{th}	19.22	14.69	21.73	0.76
	4	800	3^{rd}-20^{th}	20.03	14.38	21.12	0.72
	5	800	4^{th} -20^{th}	19.87	14.61	21.67	0.74
	6	1,000	3^{rd}-20^{th}	20.72	14.27	21.03	0.69
	7	1,000	4^{th} -20^{th}	20.52	14.51	21.61	0.71
	8	1,200	3^{rd}-20^{th}	21.42	14.18	20.95	0.66
	9	1,200	4^{th} -20^{th}	21.17	14.42	21.54	0.68

6.4 Discussions

- The results of reservoir simulation can be indicated that enhanced oil recovery by the polymer flooding technique improved oil recovery efficiency (compare to the water injection) of the oil field in the Phitsanulok basin.

- From the economic analysis, the large scale reservoir model A100 that has the 3^{rd}-11^{th} of polymer injection scenario with the polymer concentration 1,000 ppm, the medium scale reservoir model A30 that has 3^{rd}-10^{th} of polymer injection scenario with the polymer concentration 1,000 ppm and the small scale reservoir model A05 the 4^{th}-20^{th} of polymer injection scenario with the polymer concentration 600 ppm are the best case of operation and development for each reserved sizes of reservoir, due to the recovery efficiency and economic evaluation are more favorable than the others.

- The results showed the polymer injection would not economic efficiency at the high polymer concentrations of 1,500 and 2,000 ppm caused from the big consumed amount of polymer. These cases should be applied only when the oil price increases higher than 100 US$/bbl and a sufficiently of high injection rate within a reasonable time.

- The low polymer concentration, the capabilities of polymer pumping will operate easier than at the high polymer concentration and would spend less than to buy polymer for injection.

- The late time of polymer injection would not economic efficiency because maintenance pressure of reservoir is case of necessity.

- The simulation process, in order to simplify the problem, the injection and production rate specification has been set unchangeable. The oil field application can be changing the production rate of different production wells. Consequently, the oil can be more recovered in the edge area.

- If polymer slug size is very small, that is almost no enhanced oil recovery. Most of polymer has been adsorbed on the pore surface of the rock when oil was flowing from the injection well to the production well.

- Reliability of simulation result depends of the data confidential of rock and fluid properties collected from the oil field.

- Heterogeneity effect of porosity and absolute permeability variation need to apply and test for individual productive reservoir to make a reliable result of the simulation result.

- A reservoir with the aquifer may become difficult to be flooded, due to the flow of polymer solution in the reservoir could not be regulated.

- In a small geometry reservoir that has only a small oil bearing zone, the economic design of a flooding may be not possible, due to it is very to be flooded with respect to the control of chemical loss.

- Polymer flooding in reservoirs that have the low permeability should not be excluded if a sufficiently high injection rate can be achieved and the necessary amount of polymer solution can be injected within a reasonable time.

- The reservoirs that have a high vertical permeability where polymer flooding may have the most benefit.

- The limit for injection pressure is given by that pressure attained when the reservoir is fractured.

- The earlier of a polymer project is started that has the better performance than injected later.

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APPENDIX A

MODEL OF POLYMER FLOODING IN ECLIPSE 100

A.1 Model of polymer flooding in ECLIPSE 100

The simulator suite ECLIPSE consists of two separate simulators: ECLIPSE 100, specializing in black oil modeling, and ECLIPSE 300, specializing in compositional modeling. This study introduces only one special option of the ECLIPSE 100 polymer flood model. All parameters and functions it needs are input through keywords.

A.1.1 The mathematical model of polymer flood option in ECLIPSE

The Polymer Flood option uses a fully implicit five component model (oil/ water/ gas/polymer/ brine) to allow the detailed mechanisms involved in polymer displacement process to be studied. The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black- oil equations are therefore used to describe the hydrocarbon phases in the model. The equations are as follows:

Oil: $$\frac{d}{dt}\left[\frac{VS_o}{B_r B_o}\right] = \sum\left[\frac{Tk_{rw}}{B_o \mu_o}(\delta P_o - \rho_o g D_z)\right] - Q_o \qquad \text{(A.1)}$$

Water: $$\frac{d}{dt}\left[\frac{VS_w}{B_r B_w}\right] = \sum\left[\frac{Tk_{rw}}{B_w \mu_{w,eff} R_{kw}}(\delta P_w - \rho_w g D_z)\right] + Q_w \qquad \text{(A.2)}$$

Polymer: $$\frac{d}{dt}\left[\frac{VS_w^* C_p}{B_r B_w}\right] + \frac{d}{dt}\left[V\rho_r C_a \frac{1-\phi}{\phi}\right] = \sum\left[\frac{Tk_{rw} C_p}{B_w \mu_{p,eff} R_{kw}}(\delta P_w - \rho_w g D_z)\right] + Q_w C_{pi} \qquad \text{(A.3)}$$

$$\text{Brine:} \frac{d}{dt}\left[\frac{VS_wC_n}{B_rB_w}\right] = \sum\left[\frac{Tk_{rw}C_n}{B_w\mu_{s,eff}\ R_{kw}}(\delta P_w - \rho_w g D_z)\right] + Q_wC_{ni} \tag{A.4}$$

$$S_w^* = S_w - S_{dpv} \tag{A.5}$$

Where: S_{dpv} denotes the dead pore space within each grid cell

C_a denotes the adsorption isotherm which is a function of the local polymer solution concentration

ρ_r denotes the mass density of the rock formation

ϕ denotes the porosity

ρ_w denotes the water density

ρ_o denotes the oil density

$\sum$ denotes the sum over neighboring cells

R_{kw} denotes the relative permeability reduction factor for the aqueous phase due to polymer retention

C_p, C_n denote the local concentration of polymer and sodium chloride in the aqueous phase

μ_{eff} denotes the effective viscosity of the water, polymer and salt components

B denotes the formation volume factor of rock, oil and water

V denotes the pore volume in the grid sell

T Transmissibility

D_z Depth difference

The model makes the assumption that the density and formation volume factor of the aqueous phase are independent of the local polymer and sodium chloride concentrations. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components of the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations.

The principal effects of polymer and brine on the flow of the aqueous phase are represented by equations (A.1) to (A.5) above. The fluid viscosities $(\mu_{w,eff}, \mu_{p,eff}, \mu_{s,eff})$ are dependent on the local concentrations of salt and polymer in the solution. Polymer adsorption is represented by the additional mass accumulation term on the left hand side of the equation (A-3). The adsorption term requires the user to specify the adsorption isotherm C_a as a function of the local polymer concentration for each rock species. The effect of pore blocking and adsorption on the aqueous phase relative permeability is treated through the term R_{kw} requires the input of a residual resistance factor for each rock type.

The equations solved by the ECLIPSE polymer model are a discretized form of the differential equations (A.1) to (A.5). In order to avoid numerical stability problems which could be triggered by strong changes in the aqueous phase properties over a timestep (resulting from large changes in the local polymer/sodium chloride concentrations) a fully implicit time discretization is used. The ECLIPSE polymer flood model is therefore free from this type of instability.

A.1.2 Treatment of Fluid Viscosities in ECLIPSE Polymer Flood Model

The viscosity terms used in the fluid flow equations contain the effects of a change in the viscosity of the aqueous phase due to the presence of polymer and salt in the solution. However, to incorporate the effects of physical dispersion at the leading edge of the slug and also the fingering effects at the rear edge of the slug, the fluid components are allocated effective viscosity values which are calculated by using the Todd-Longstaff technique.

To get the effective polymer viscosity, it is required to enter the viscosity of a fully mixed polymer solution as an increasing function of the polymer concentration in solution $(\mu_m(C_p))$. The viscosity of the solution at the maximum polymer concentration also needs to be specified and denotes the injected polymer concentration in solution (μ_p). The effective polymer viscosity is calculated as follows:

$$\mu_{p,eff} = \mu_m(C_p)^{\omega} \mu_p^{(1-\omega)} \tag{A.6}$$

Where: ω is the Todd-Longstaff mixing parameter

The mixing parameter is useful in modeling the degree of segregation between the water and the injected polymer solution. If ω=1, then the polymer solution and water are fully mixed in each block. If ω= 0, the polymer solution is completely segregated from the water. The partially mixed water viscosity is calculated in an analogous manner by using the fully mixed polymer viscosity and the pure water viscosity (μ_w),

$$\mu_{w,e} = \mu_w^{(1-w)} \mu_m \left(C_p\right)^{\omega} \tag{A.7}$$

In order to calculate the effective water viscosity to be inserted into (A.7), the total water equation is written as the sum of contributions from the polymer solution and the pure water. The following expression then gives the effective water viscosity to be inserted into (A.7):

$$\frac{1}{\mu_{w,eff}} = \frac{1-\overline{C}}{\mu_{w,e}} + \frac{\overline{C}}{\mu_{p,eff}} \tag{A.8}$$

$$\overline{C} = \frac{C_p}{C_{p,\max}} \tag{A.9}$$

Where : $\overline{C}$ is the effective saturation for the injected polymer solution within the total aqueous phase in the cell

If the salt-sensitive option is active, the above expressions are still suitable for the effective polymer and water viscosity terms. The injected salt concentration needs to be specified in order to evaluate the maximum polymer solution viscosity $\left(\mu_p\right)$. The effective salt component viscosity to be used in (3.4) is set equal to the effective water viscosity.

A.1.3 Treatment of Polymer Adsorption

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes.

The adsorption model can handle both stripping and desorption effects. The user specifies an adsorption isotherm, which tabulates the saturated rock adsorbed concentration versus the local polymer concentration in solution.

There are currently two adsorption models, which can be selected. The first model ensures that each grid cell retraces the adsorption isotherm as the polymer concentration rises and falls in the cell. The second model assumes that the adsorbed polymer concentration on the rock may not decrease with time, and hence does not allow for any desorption. More complex models of the desorption process can be implemented if required.

A.1.4 Treatment of permeability reductions and dead pore volume

The adsorption process causes a reduction in the permeability of the rock to the passage of the aqueous phase and is directly correlated with the adsorbed polymer concentration. In order to compute the reduction in rock permeability, the user is required to specify the residual resistance factor (RRF) for each rock type. The actual resistance factor can then be calculated:

$$R_{kw} = 1.0 + (RRF - 1.0)\frac{C_a}{C_{a,\max}} \tag{A.10}$$

The value of the maximum adsorbed concentration (μ_p) depends on the rock type and needs to be specified by the user. Alternative expressions for the resistance factor can also be implemented if required. The dead pore space is specified by the user for each rock type. It represents the amount of total pore space in each grid cell which is inaccessible to the polymer solution. The effect of the dead pore space within each cell is to cause the polymer solution to travel at a greater velocity than inactive tracers embedded in the water. The ECLIPSE model assumes that the dead pore space for each rock type does not exceed the corresponding irreducible water saturation.

A.1.5 Treatment of the Shear Thinning Effect

The shear thinning of polymer has the effect of reducing the polymer viscosity at higher flow rates. ECLIPSE assumes that shear rate is proportional to the flow velocity. This assumption is not valid in general, for example, a given flow in a low permeability rock will have to pass through smaller pore throats than the same flow in a high permeability rock, and consequently the shear rate will be higher in the low permeability rock. For a single reservoir, however, this assumption is probably reasonable. The flow velocity is calculated as:

$$v = B_w \frac{F_w}{\phi A} \tag{A.11}$$

Where: F_w is the water flow rate on surface units

B_w is the water formation volume factor

ϕ is the average porosity of the two cells

A is the flow area between two cells

The reduction in the polymer viscosity is assumed to be reversible, and is given by:

$$\mu = \mu_w\left[(P-1)M + 1\right] \tag{A.12}$$

Where: μ_w is the viscosity of water with no polymer present

P is the viscosity multiplier assuming no shear effect (entered using the PLYVISC or PLYVISCS keywords)

M is the shear thinning multiplier supplied in the PLYSHEAR keyword

The well inflows are treated in a manner analogous to the treatment of block to block flows. The viscosity of the polymer solution flowing into the well is calculated, assuming a velocity at a representative radius from the well. The representative radius is:

$$R_r = e^{\left(\ln\left(R_w\right)+\ln\left(Ra\right)\right)/2} \tag{A.13}$$

Where: R_w is well bore radius (taken from diameter input in COMPDAT)

R_a is area equivalent radius of the grid block in which the well is completed

In the present version of ECLIPSE, the radial inflow equation is not integrated over distance from the well to account for the local viscosity reduction due the local velocity.

APPENDIX B

RESERVOIR SIMULATION INPUT DATA

B.1 Reservoir Simulation Input Data

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-- ---------------------------------------------------------------------------
-- Office Simulation File (DATA) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: Sirikit100MMbbl_INJ_PLY_E100.DATA
-- Created on: 28-Feb-2011 at: 03:22:10
--
-- *********************************************************************
-- *  WARNING
-- *  THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
-- *  ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*********************************************************************
RUNSPEC

TITLE
Sirikit Oil Field

START
1 'JAN' 1990 /

FIELD

GAS

OIL

WATER

DISGAS

NSTACK
50 /

RPTRUNSP

ENDSCALE
'NODIR' 'REVERS' 1 20 /

MONITOR

RSSPEC

NOINSPEC

MSGFILE
1 /

GASFIELD
'NO'  'NO' /

POLYMER

DISPDIMS
1 2 1 /

DIMENS
25 25 8 /

SCDPDIMS
0 0 0 0 0 /

EQLDIMS
1 100 100 1 20 /

REGDIMS
1 1 0 0 /
```

```
TABDIMS
1 1 20 20 1 20 20 1 /

WELLDIMS
26 9 3 26 /

GRID

GRIDFILE
2 /

INIT

INCLUDE
'Sirikit100MMbbl_gopp.INC'  /

INCLUDE

'Sirikit100MMbbl_ggo.INC'  /

INCLUDE
'Sirikit100MMbbl_gpro.INC'  /

INCLUDE
'Sirikit100MMbbl_goth.INC'  /

PROPS

INCLUDE
'Sirikit100MMbbl_INJ_PLY_pvt.INC'  /

INCLUDE
'Sirikit100MMbbl_INJ_PLY_scal.INC'  /

SOLUTION

INCLUDE
'Sirikit100MMbbl_init.INC'  /

SUMMARY

INCLUDE
'Sirikit100MMbbl_INJ_PLY_sum.INC'  /

SCHEDULE

INCLUDE
'Sirikit100MMbbl_INJ_PLY_sch.INC'  /

END
--
-- ---------------------------------------------------------------------------
-- Office PVTN (PVTN) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: Sirikit100MMbbl_INJ_PLY_pvt.INC
-- Created on: 13-Oct-2010 at: 16:56:39


**********************************************************************
-- *    WARNING
-- *    THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
- *    ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID     DATA.

**********************************************************************
-- OFFICE-PVTN-HEADER-DATA
-- Off PVTN PVT Tables:         1         1
-- Off PVTN  "PVT 1"
-- Off PVTN Rock Tables:         1         1
```

```
-- Off PVTN  "Rock Compact 1"
-- Off PVTN Miscible Tables:         1         1
-- Off PVTN  "Miscible 1"
-- Off PVTN Correlation Data:        33         1
-- Off PVTN  "PVT 1"
-- Off PVTN  "CUSTOMIZED"
-- Off PVTN  "SET VALUE FOR STANDARD_TEMPERATURE TO 59.9999999999999 IN F;"
-- Off PVTN  "SET VALUE FOR STANDARD_PRESSURE TO 14.7 IN psia;"
-- Off PVTN  "SET VALUE FOR POROSITY TO 0.2 IN dimensionless;"
-- Off PVTN  "SET VALUE FOR REF_PRESSURE TO 3500 IN psia;"
-- Off PVTN  "SET VALUE FOR ROCK_TYPE TO CONSOLIDATED_SANDSTONE;"
-- Off PVTN  "SET VALUE FOR GAS_GRAVITY TO 0.8 IN sg_Air_1;"
-- Off PVTN  "SET VALUE FOR OIL_GRAVITY TO 39.4 IN APIoil;"
-- Off PVTN  "SET VALUE FOR BUBBLE_POINT TO 1800 IN psia;"
-- Off PVTN  "SET VALUE FOR SALINITY TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR TEMPERATURE TO 203 IN F;"
-- Off PVTN  "SET VALUE FOR N2 TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR H2S TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR CO2 TO 0 IN fraction;"
-- Off PVTN  "SET CORRELATION FOR ROCK TO NEWMAN;"
-- Off PVTN  "SET CORRELATION FOR OIL_RS TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR OIL_PB TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR OIL_VISCOSITY TO BEGGS;"
-- Off PVTN  "SET CORRELATION FOR OIL_COMPRESSIBILITY TO VASQUEZ;"
-- Off PVTN  "--SET CORRELATION FOR NONE TO UNSET;"
-- Off PVTN  "SET CORRELATION FOR OIL_FVF TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR GAS_CRIT_PROPS TO THOMAS;"
-- Off PVTN  "SET CORRELATION FOR GAS_ZFACTOR TO HALL;"
-- Off PVTN  "SET CORRELATION FOR GAS_FVF TO IDEAL_GAS;"
-- Off PVTN  "SET CORRELATION FOR GAS_VISCOSITY TO LEE;"
-- Off PVTN  "SET CORRELATION FOR WATER_VISCOSITY TO
    MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_COMPRESSIBILITY TO
    MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_FVF TO MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_DENSITY TO FVF_
    RATIO;"
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-- Off PVTN  "SET VALUE FOR MAX_PRESSURE TO 3500 IN psia;"
-- Off PVTN  "SET VALUE FOR TABLE_LENGTH TO 20;"
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PLYMAX
--
-- Polymer/Salt Concentrations
--
  1.40223937628393 3.50559844070981
/
PLYSHEAR
--
-- Polymer Shear Thinning Data
--
        0        1
  3.28083989501312      0.8
  9.84251968503937     0.75
  19.6850393700787      0.7
  32.8083989501312     0.68
/
PLYVISC
--
-- Polymer Solution Viscosity Function
--
        0        1
      0.35       48
  0.526000007011197      100
/
DENSITY
--
-- Fluid Densities at Surface Conditions
--
```

```
51.637497914955 62.4279737253144 0.0499423789802515
/
PVTO
-- Live Oil PVT Properties (Dissolved Gas)
    0.00147       14.70      1.0709      1.2585
                 198.14      1.0550      1.3038
                 381.57      1.0544      1.3837
                 565.01      1.0542      1.4867
                 748.45      1.0541      1.6103
                 931.88      1.0540      1.7541
                1115.32      1.0540      1.9188
                1298.76      1.0539      2.1054
                1482.19      1.0539      2.3152
                1665.63      1.0539      2.5498
                1800.00      1.0539      2.7384
                2032.51      1.0539      3.1008
                2215.94      1.0539      3.4211
                2399.38      1.0539      3.7741
                2582.82      1.0538      4.1619
                2766.25      1.0538      4.5869
                2949.69      1.0538      5.0514
                3133.13      1.0538      5.5575
                3316.56      1.0538      6.1077
                3500.00      1.0538      6.7042
    0.03380      198.14      1.0856      1.0751
                 381.57      1.0763      1.0959
                 565.01      1.0731      1.1278
                 748.45      1.0715      1.1686
                 931.88      1.0705      1.2170
                1115.32      1.0698      1.2723
                1298.76      1.0693      1.3342
                1482.19      1.0690      1.4026
                1665.63      1.0687      1.4774
                1800.00      1.0685      1.5362
                2032.51      1.0683      1.6460
                2215.94      1.0681      1.7400
                2399.38      1.0680      1.8405
                2582.82      1.0679      1.9477
                2766.25      1.0678      2.0615
                2949.69      1.0677      2.1823
                3133.13      1.0676      2.3099
```

	3316.56	1.0676	2.4445
	3500.00	1.0675	2.5862
0.07444	381.57	1.1044	0.9243
	565.01	1.0973	0.9411
	748.45	1.0937	0.9642
	931.88	1.0915	0.9928
	1115.32	1.0901	1.0262
	1298.76	1.0890	1.0639
	1482.19	1.0883	1.1059
	1665.63	1.0876	1.1518
	1800.00	1.0873	1.1879
	2032.51	1.0868	1.2553
	2215.94	1.0864	1.3127
	2399.38	1.0861	1.3739
	2582.82	1.0859	1.4389
	2766.25	1.0857	1.5076
	2949.69	1.0855	1.5800
	3133.13	1.0853	1.6562
	3316.56	1.0852	1.7362
	3500.00	1.0851	1.8199
0.11946	565.01	1.1257	0.8111
	748.45	1.1196	0.8255
	931.88	1.1160	0.8442
	1115.32	1.1135	0.8667
	1298.76	1.1118	0.8925
	1482.19	1.1104	0.9213
	1665.63	1.1094	0.9532
	1800.00	1.1088	0.9783
	2032.51	1.1079	1.0252
	2215.94	1.1073	1.0652
	2399.38	1.1069	1.1078
	2582.82	1.1065	1.1530
	2766.25	1.1061	1.2007
	2949.69	1.1058	1.2509
	3133.13	1.1055	1.3036
	3316.56	1.1053	1.3588
	3500.00	1.1051	1.4164
0.16762	748.45	1.1490	0.7246
	931.88	1.1435	0.7374
	1115.32	1.1398	0.7533
	1298.76	1.1372	0.7720

	1482.19	1.1352	0.7931
	1665.63	1.1336	0.8165
	1800.00	1.1327	0.8351
	2032.51	1.1314	0.8699
	2215.94	1.1305	0.8997
	2399.38	1.1298	0.9315
	2582.82	1.1292	0.9652
	2766.25	1.1287	1.0007
	2949.69	1.1282	1.0381
	3133.13	1.1278	1.0774
	3316.56	1.1274	1.1184
	3500.00	1.1271	1.1612
0.21829	931.88	1.1740	0.6568
	1115.32	1.1688	0.6684
	1298.76	1.1651	0.6823
	1482.19	1.1623	0.6983
	1665.63	1.1601	0.7163
	1800.00	1.1588	0.7306
	2032.51	1.1570	0.7575
	2215.94	1.1558	0.7806
	2399.38	1.1548	0.8053
	2582.82	1.1539	0.8315
	2766.25	1.1532	0.8592
	2949.69	1.1525	0.8884
	3133.13	1.1520	0.9190
	3316.56	1.1514	0.9509
	3500.00	1.1510	0.9842
0.27105	1115.32	1.2006	0.6022
	1298.76	1.1956	0.6128
	1482.19	1.1918	0.6252
	1665.63	1.1889	0.6393
	1800.00	1.1871	0.6507
	2032.51	1.1846	0.6721
	2215.94	1.1830	0.6905
	2399.38	1.1817	0.7103
	2582.82	1.1805	0.7314
	2766.25	1.1795	0.7536
	2949.69	1.1786	0.7771
	3133.13	1.1779	0.8017
	3316.56	1.1772	0.8274
	3500.00	1.1766	0.8542

0.32563	1298.76	1.2285	0.5573
	1482.19	1.2236	0.5671
	1665.63	1.2198	0.5784
	1800.00	1.2175	0.5875
	2032.51	1.2143	0.6049
	2215.94	1.2122	0.6200
	2399.38	1.2104	0.6361
	2582.82	1.2089	0.6534
	2766.25	1.2076	0.6717
	2949.69	1.2065	0.6910
	3133.13	1.2055	0.7113
	3316.56	1.2046	0.7325
	3500.00	1.2038	0.7546
0.38181	1482.19	1.2578	0.5197
	1665.63	1.2529	0.5289
	1800.00	1.2500	0.5363
	2032.51	1.2459	0.5506
	2215.94	1.2432	0.5631
	2399.38	1.2410	0.5766
	2582.82	1.2391	0.5910
	2766.25	1.2374	0.6063
	2949.69	1.2360	0.6225
	3133.13	1.2347	0.6395
	3316.56	1.2336	0.6573
	3500.00	1.2325	0.6758
0.43944	1665.63	1.2883	0.4877
	1800.00	1.2846	0.4939
	2032.51	1.2795	0.5058
	2215.94	1.2762	0.5163
	2399.38	1.2734	0.5277
	2582.82	1.2710	0.5399
	2766.25	1.2689	0.5528
	2949.69	1.2671	0.5666
	3133.13	1.2655	0.5810
	3316.56	1.2641	0.5962
	3500.00	1.2628	0.6120
0.48249	1800.00	1.3114	0.4672
	2032.51	1.3053	0.4777
	2215.94	1.3015	0.4870
	2399.38	1.2982	0.4970
	2582.82	1.2955	0.5079

```
                    2766.25          1.2931          0.5195
                    2949.69          1.2910          0.5318
                    3133.13          1.2891          0.5447
                    3316.56          1.2875          0.5583
                    3500.00          1.2860          0.5725
/
PVDG
--
-- Dry Gas PVT Properties (No Vapourised Oil)
--
       14.70        226.6988          0.0128
      198.14         16.4361          0.0130
      381.57          8.3420          0.0132
      565.01          5.5087          0.0135
      748.45          4.0690          0.0138
      931.88          3.2006          0.0142
     1115.32          2.6225          0.0146
     1298.76          2.2121          0.0151
     1482.19          1.9079          0.0157
     1665.63          1.6752          0.0163
     1800.00          1.5377          0.0168
     2032.51          1.3480          0.0178
     2215.94          1.2309          0.0185
     2399.38          1.1353          0.0193
     2582.82          1.0564          0.0202
     2766.25          0.9908          0.0210
     2949.69          0.9356          0.0219
     3133.13          0.8890          0.0227
     3316.56          0.8491          0.0236

     3500.00          0.8148          0.0244
/

PVTW
--
-- Water PVT Properties
--
   3500 1.0220300723725 3.080179e-006 0.296407629534231 3.827219e-006
/
ECHO
ROCK
--
-- Rock Properties
--
   3500 1.52989636834116e-006
/



ECHO
TLMIXPAR
--
-- Todd-Longstaff Mixing Parameters
--
     1     1*
/
--
```

```
-- ---------------------------------------------------------------------------
-- Office SCAL (SCAL) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: Sirikit100MMbbl_INJ_PLY_scal.INC
-- Created on: 13-Oct-2010 at: 15:19:53
--
*******************************************************************
-- *   WARNING
-- *   THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
-- *   ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*******************************************************************
--
-- OFFICE-SCAL-HEADER-DATA
-- Off SCAL Saturation Tables:        1        1

-- Off SCAL  "Saturation 1"
-- Off SCAL End Point Tables:        1        1
-- Off SCAL  "End Points 1"
-- Off SCAL Petro Elastic Tables:        1        1
-- Off SCAL  "Petro-elastic 1"
ECHO
PLYROCK
--
-- Polymer Rock Properties
--
     0.15       1 981.567       1            3e-005
/

PLYADS
--
-- Polymer Adsorption Functions
--
          0          0
          0.35       3e-005
          0.7        3e-005
/

--        0.3        0.0        0.5
--        0.4        0.0        0.3
--        0.48       0.0        1*
--        0.5        0.218  0.16
--        0.6        0.352  0.1
--
-- Water Saturation Functions
--
SWFN
--
-- Water Saturation Functions
--
          0.25                  0          1
          0.3        0                     0.5
          0.4        0.04       0.2
          0.5        0.11       0.1
          0.6        0.2        0.05
          0.7        0.3        0.03
          0.75       0.44       0.01
          0.8        0.68                  0
/

-- SIMILARLY FOR GAS
--
--  SGAS   KRG    PCOG

--
-- Gas Saturation Functions
--
SGFN
--
```

```
-- Gas Saturation Functions
--
        0           0           0
         0.04                   0                       0.015
         0.15       0.022       0.036
         0.2        0.05        0.086
         0.3                    0.113       0.167
         0.4        0.21        0.276
         0.5        0.4         0.4
         0.6        0.45        0.5
         0.7        0.55        0.6
         0.75       0.6         0.65
/
-- OIL RELATIVE PERMEABILITY IS TABULATED AGAINST OIL SATURATION
-- FOR OIL-WATER AND OIL-GAS-CONNATE WATER CASES
--
--  SOIL    KROW    KROG
--
-- Oil Saturation Functions
--
SOF3

--
-- Oil Saturation Functions
--
         0                      0           0
         0.2        0           0
         0.3        0.01        0.03
         0.4        0.03        0.04
         0.45       0.05        0.07
         0.5        0.1         0.12
         0.55       0.15        0.17
         0.6        0.2         0.25
         0.65       0.6         0.62
         0.7        0.8         0.82
         0.75                   1           1
/  --
--
-- ---------------------------------------------------------------------------
-- Office INIT (INIT) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------

--
-- File: Sirikit100MMbbl_INJ_PLY_init.INC
-- Created on: 12-Oct-2010 at: 19:09:15
--
*********************************************************************
-- *  WARNING
-- *  THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
-- *  ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*********************************************************************
--
-- OFFICE-INIT-HEADER-DATA
-- ---------------------------------------------------------------------------
-- Office INIT Keywords
-- ---------------------------------------------------------------------------
ECHO
PBVD
--
-- Bubble Point v Depth
--
       3850       1800
       3900       1800
/

EQUIL
--
-- Equilibration Data Specification
--
```

```
   3850   3500   3915     1*     1*     1*     1     1*     5     1*     1*
/   --
--
-- ----------------------------------------------------------------------------
-- Office Summary (SUM) Data Section Version 2009.2 Oct 16 2009
-- ----------------------------------------------------------------------------
--
-- File: Sirikit100MMbbl_INJ_PLY_sum.INC
-- Created on: Oct-13-2010 at: 15:09:24
--
**********************************************************************
-- *  WARNING
-- *  THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
-- *  ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
**********************************************************************
ALL
FGPR
FGPT
FGPTF
FGPTS
FOE
FOIP
FOIPL
FOPT
RUNSUM
SEPARATE
TIMESTEP
WGPTS
 /
WOPP
 /
WOPT
 /
FCPR
FCIR
FCPT
FCIT
--
-- ----------------------------------------------------------------------------
-- End of Office Summary (SUM) Data Section
-- ----------------------------------------------------------------------------
--
-- ----------------------------------------------------------------------------
-- Office Schedule (SCHED) Data Section Version 2009.2 Oct 16 2009
-- ----------------------------------------------------------------------------
--
-- File: Sirikit100MMbbl_INJ_PLY_sch.INC
-- Created on: 28-Feb-2011 at: 03:21:58
--
 **********************************************************************
-- *    WARNING
-- *    THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
-- *    ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
          DATA.
**********************************************************************
-- Off SCHED Units: "FIELD"
-- Off SCHED Wells:       25
-- Off SCHED Well: 1 6 6 100 11 0 8
-- Off SCHED Name: "IP1" ""
-- Off SCHED Completion: 1 6 6 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 6 6 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 6 6 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 6 6 4
-- Off SCHED LGR:""
```

```
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 6 6 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 6 6 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 6 6 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 6 6 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 2 6 12 100 11 0 8
-- Off SCHED Name: "IP3" ""
-- Off SCHED Completion: 1 6 12 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 6 12 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 6 12 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 6 12 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 6 12 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 6 12 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 6 12 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 6 12 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 3 6 18 100 11 0 8
-- Off SCHED Name: "IP5" ""
-- Off SCHED Completion: 1 6 18 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 6 18 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 6 18 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 6 18 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 6 18 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 6 18 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 6 18 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 6 18 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 4 10 9 100 10 0 8
-- Off SCHED Name: "P7" ""
-- Off SCHED Completion: 1 10 9 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 2 10 9 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 10 9 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 10 9 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 10 9 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 10 9 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 10 9 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 10 9 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 5 10 15 100 10 0 8
-- Off SCHED Name: "P9" ""
-- Off SCHED Completion: 1 10 15 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 10 15 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 10 15 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 10 15 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 10 15 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 10 15 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 10 15 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 10 15 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 6 13 6 100 11 0 8
-- Off SCHED Name: "IP11" ""
-- Off SCHED Completion: 1 13 6 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 13 6 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 6 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 6 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 6 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 6 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 6 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 8 13 6 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 7 13 12 100 10 0 8
-- Off SCHED Name: "P13" ""
-- Off SCHED Completion: 1 13 12 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 13 12 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 12 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 12 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 12 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 12 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 12 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 13 12 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 8 13 18 100 11 0 8
-- Off SCHED Name: "IP15" ""
-- Off SCHED Completion: 1 13 18 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 13 18 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 18 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 18 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 18 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 18 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 18 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 13 18 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 9 16 9 100 10 0 8
-- Off SCHED Name: "P17" ""
-- Off SCHED Completion: 1 16 9 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 16 9 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 16 9 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 16 9 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 16 9 5
```

```
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 16 9 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 16 9 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 16 9 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 10 16 15 100 10 0 8
-- Off SCHED Name: "P19" ""
-- Off SCHED Completion: 1 16 15 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 16 15 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 16 15 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 16 15 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 16 15 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 16 15 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 16 15 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 16 15 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 11 20 6 100 11 0 8
-- Off SCHED Name: "IP21" ""
-- Off SCHED Completion: 1 20 6 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 20 6 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 20 6 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 20 6 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 20 6 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 20 6 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 20 6 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 20 6 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 12 20 12 100 11 0 8
-- Off SCHED Name: "IP23" ""
-- Off SCHED Completion: 1 20 12 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 20 12 2
```

```
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 20 12 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 20 12 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 20 12 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 20 12 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 20 12 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 20 12 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 13 20 18 100 11 0 8
-- Off SCHED Name: "IP25" ""
-- Off SCHED Completion: 1 20 18 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 20 18 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 20 18 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 20 18 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 20 18 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 20 18 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 20 18 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 20 18 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 14 6 9 100 10 0 8
-- Off SCHED Name: "P2" ""
-- Off SCHED Completion: 1 6 9 1
-- Off SCHED LGR:""
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-- Off SCHED Completion: 2 6 9 2
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-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 6 9 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 6 9 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 6 9 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 6 9 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 6 9 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 8 6 9 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 15 6 15 100 10 0 8
-- Off SCHED Name: "P4" ""
-- Off SCHED Completion: 1 6 15 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 6 15 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 6 15 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 6 15 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 6 15 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 6 15 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 6 15 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 6 15 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 16 10 6 100 10 0 8
-- Off SCHED Name: "P6" ""
-- Off SCHED Completion: 1 10 6 1
-- Off SCHED LGR:""
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-- Off SCHED Completion: 2 10 6 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 10 6 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 10 6 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 10 6 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 10 6 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 10 6 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 10 6 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 17 10 12 100 10 0 8
-- Off SCHED Name: "P8" ""
-- Off SCHED Completion: 1 10 12 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 10 12 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 10 12 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 10 12 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 5 10 12 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 10 12 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 10 12 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 10 12 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 18 10 18 100 10 0 8
-- Off SCHED Name: "P10" ""
-- Off SCHED Completion: 1 10 18 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 10 18 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 10 18 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 10 18 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 10 18 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 10 18 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 10 18 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 10 18 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 19 13 9 100 10 0 8
-- Off SCHED Name: "P12" ""
-- Off SCHED Completion: 1 13 9 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 13 9 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 9 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 9 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 9 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 9 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 9 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 13 9 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 20 13 15 100 10 0 8
-- Off SCHED Name: "P14" ""
-- Off SCHED Completion: 1 13 15 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 2 13 15 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 15 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 15 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 15 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 15 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 15 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 13 15 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 21 16 6 100 10 0 8
-- Off SCHED Name: "P16" ""
-- Off SCHED Completion: 1 16 6 1
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-- Off SCHED Completion: 2 16 6 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 16 6 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 16 6 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 16 6 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 16 6 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 16 6 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 16 6 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 22 16 12 100 10 0 8
-- Off SCHED Name: "P18" ""
-- Off SCHED Completion: 1 16 12 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 16 12 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 16 12 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 16 12 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 16 12 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 16 12 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 16 12 7
-- Off SCHED LGR:""
```

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-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 16 12 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 23 16 18 100 10 0 8
-- Off SCHED Name: "P20" ""
-- Off SCHED Completion: 1 16 18 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 16 18 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 16 18 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 16 18 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 16 18 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 16 18 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 16 18 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 16 18 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 24 20 9 100 10 0 8
-- Off SCHED Name: "P22" ""
-- Off SCHED Completion: 1 20 9 1
-- Off SCHED LGR:""
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-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 20 9 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 20 9 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 20 9 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 20 9 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 20 9 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 20 9 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 25 20 15 100 10 0 8
-- Off SCHED Name: "P24" ""
-- Off SCHED Completion: 1 20 15 1
-- Off SCHED LGR:""
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-- Off SCHED Completion: 2 20 15 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 20 15 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 20 15 4
-- Off SCHED LGR:""
```

```
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 20 15 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 20 15 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 20 15 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 20 15 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Groups:        2
-- Off SCHED Group: "1"
-- Off SCHED Group: "2"
-- Off SCHED Times:        26
-- Off SCHED Date: 1 1 1990 0
-- Off SCHED Time: 0 0
-- Off SCHED Date: 1 1 1991 0
-- Off SCHED Time: 365 365
-- Off SCHED Date: 1 1 1992 0
-- Off SCHED Time: 365 730
-- Off SCHED Date: 1 1 1993 0
-- Off SCHED Time: 366 1096
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-- Off SCHED Time: 365 1826
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-- Off SCHED Time: 365 2191
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-- Off SCHED Date: 1 1 1999 0
-- Off SCHED Time: 365 3287
-- Off SCHED Date: 1 1 2000 0
-- Off SCHED Time: 365 3652
-- Off SCHED Date: 1 1 2001 0
-- Off SCHED Time: 366 4018
-- Off SCHED Date: 1 1 2002 0
-- Off SCHED Time: 365 4383
-- Off SCHED Date: 1 1 2003 0
-- Off SCHED Time: 365 4748
-- Off SCHED Date: 1 1 2004 0
-- Off SCHED Time: 365 5113
-- Off SCHED Date: 1 1 2005 0
-- Off SCHED Time: 366 5479
-- Off SCHED Date: 1 1 2006 0
-- Off SCHED Time: 365 5844
-- Off SCHED Date: 1 1 2007 0
-- Off SCHED Time: 365 6209
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-- Off SCHED Time: 365 6574
-- Off SCHED Date: 1 1 2009 0
-- Off SCHED Time: 366 6940
-- Off SCHED Date: 1 1 2010 0
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-- Off SCHED Date: 1 1 2011 0
-- Off SCHED Time: 365 7670
-- Off SCHED Date: 1 1 2012 0
-- Off SCHED Time: 365 8035
-- Off SCHED Date: 1 1 2013 0
-- Off SCHED Time: 366 8401
-- Off SCHED Date: 1 1 2014 0
-- Off SCHED Time: 365 8766
-- Off SCHED Date: 1 1 2015 0
-- Off SCHED Time: 365 9131
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```
-- Off SCHED END: 1 1 2015
ECHO
RPTSCHED
'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'RESTART=2' 'FIP=2' 'WELLS=2' /

TUNING
1 100 10 7* /
11* /
10* /
WELSPECS
'IP1' '1' 6 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
WELSPECS
'IP3' '1' 6 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
 WELSPECS
'IP5' '1' 6 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
 WELSPECS
'P7' '2' 10 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
 WELSPECS
'P9' '2' 10 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'IP11' '1' 13 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
 WELSPECS
'P13' '2' 13 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
  WELSPECS
'IP15' '1' 13 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P17' '2' 16 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
 WELSPECS
'P19' '2' 16 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

WELSPECS
'IP21' '1' 20 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'IP23' '1' 20 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'IP25' '1' 20 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
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WELSPECS
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WELSPECS
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 /
WELSPECS
'P8' '2' 10 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P10' '2' 10 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P12' '2' 13 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P14' '2' 13 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
```

```
 /
WELSPECS
'P16' '2' 16 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P18' '2' 16 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P20' '2' 16 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P22' '2' 20 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P24' '2' 20 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
COMPDAT
'P*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /
WCONPROD
'P*' 'OPEN' 1* 400 8* 6* 1* /
 /
WECON
'P*' 2* 0.9 2* 'CON' 'NO' 1* 'RATE' 1* 'NONE' 2* /
 /
COMPDAT
'IP*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /
WCONPROD
'IP*' 'OPEN' 1* 400 8* 6* 1* /
 /
WECON
'IP*' 2* 0.9 2* 'NONE' 'NO' 1* 'RATE' 1* 'NONE' 2* /
/
TSTEP
365 /
WELSPECS
'IP1' '1' 6 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
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WELSPECS
'IP5' '1' 6 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P7' '2' 10 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P9' '2' 10 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'IP11' '1' 13 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P13' '2' 13 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'IP15' '1' 13 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P17' '2' 16 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P19' '2' 16 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'IP21' '1' 20 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
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WELSPECS
'IP23' '1' 20 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'IP25' '1' 20 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P2' '2' 6 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P4' '2' 6 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P6' '2' 10 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P8' '2' 10 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
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WELSPECS
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WELSPECS
'P14' '2' 13 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
WELSPECS
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WELSPECS
'P18' '2' 16 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P20' '2' 16 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P22' '2' 20 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'P24' '2' 20 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
COMPDAT
'P*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /
WCONPROD
'P*' 'OPEN' 6* 1140 3* 6* 1* /
 /
WECON
'P*' 2* 0.9 2* 'CON' 'NO' 1* 'RATE' 1* 'NONE' 2* /
 /
COMPDAT
'IP*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /
WCONINJE
'IP*' 'WATER' 'OPEN' 'RATE' 1000 9* /
 /
WECONINJ
'IP*' 100 'RATE' /
 /
TSTEP
365 /
WELSPECS
'IP1' '1' 6 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'IP3' '1' 6 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
WELSPECS
'IP5' '1' 6 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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WELSPECS
'P7' '2' 10 9 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
WELSPECS
'P9' '2' 10 15 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
WELSPECS
'IP11' '1' 13 6 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
WELSPECS
'P13' '2' 13 12 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
/
WELSPECS
'IP15' '1' 13 18 3850 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
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B.2 Graph of Input Parameter Display

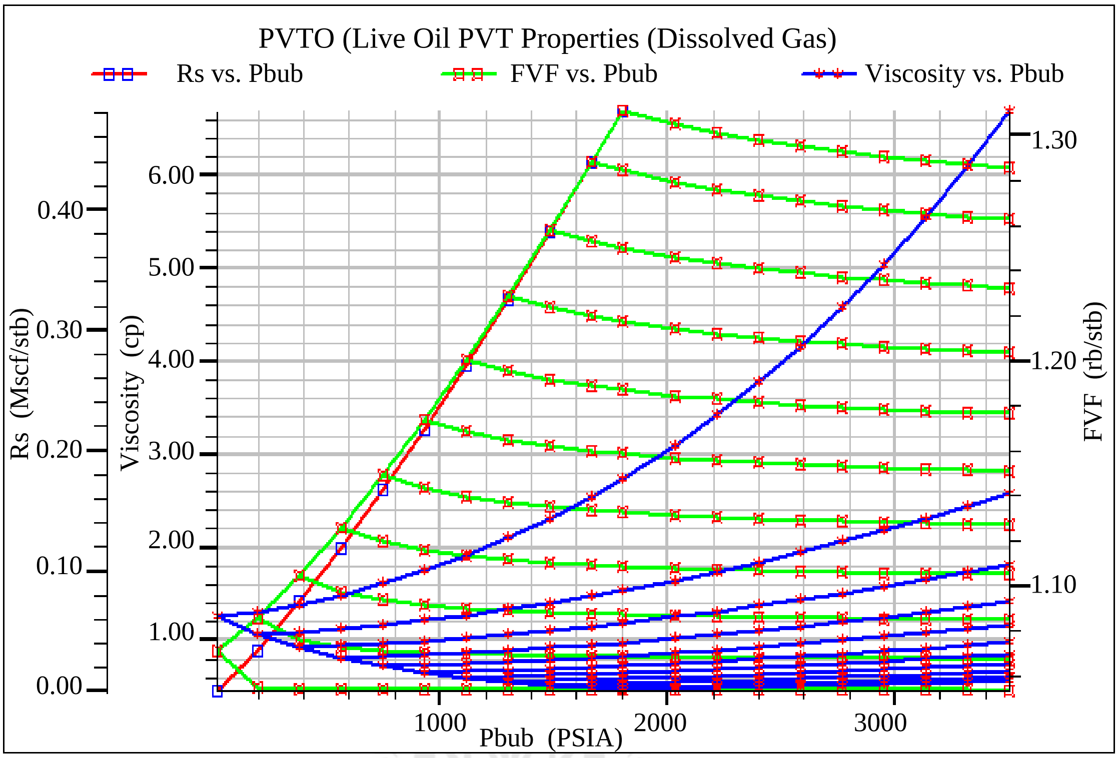


Figure B.1 Live Oil PVT Properties (Dissolved Gas) graph display result from Sirikit100MMbbl_INJ_PLY_pvt.INC input data section.

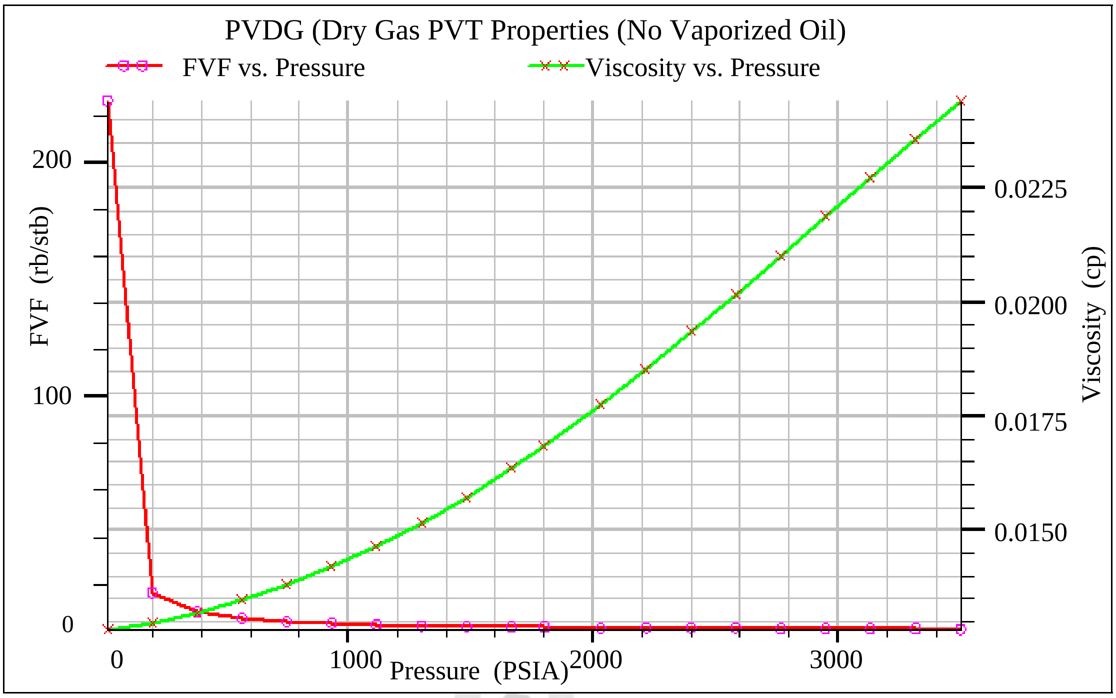


Figure B.2 Dry Gas PVT Properties (Dissolved Gas) graph display result from Sirikit100MMbbl_INJ_PLY_pvt.INC input data section.

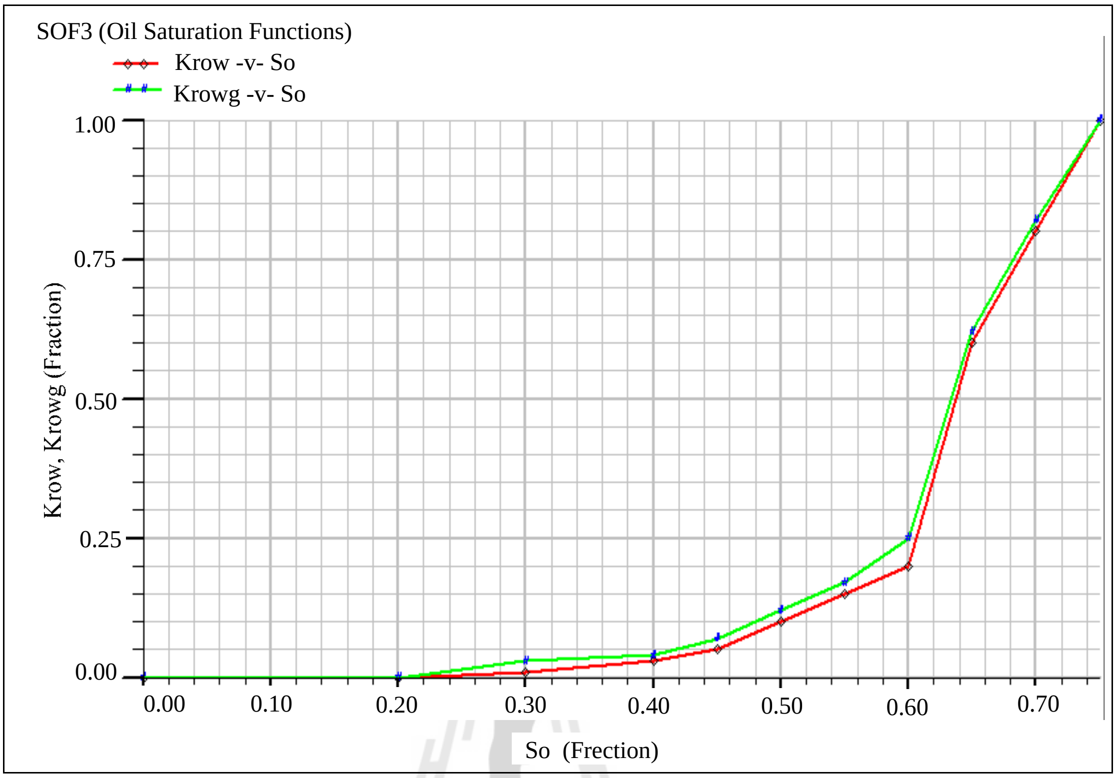


Figure B.3 Oil saturation functions graph display result from Sirikit 100MMbbl_INJ_PLY_scal.INC input data section.

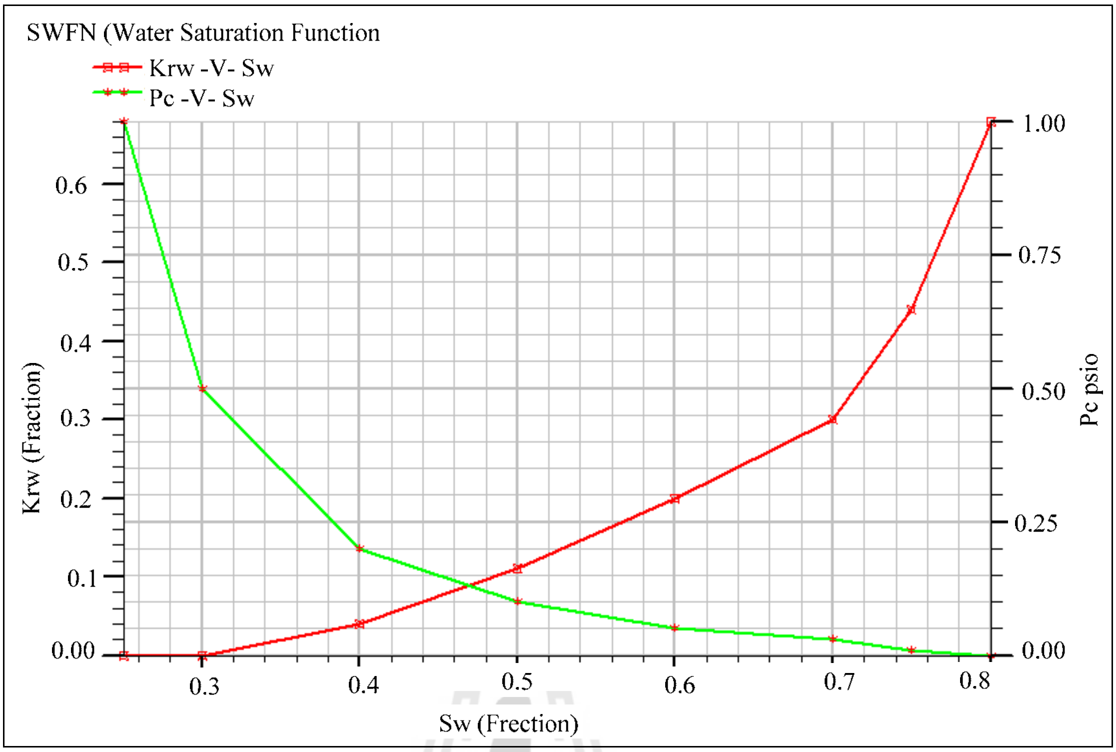


Figure B.4 Water saturation functions graph display result from Sirikit 100MMbbl_INJ_PLY_scal.INC input data section.

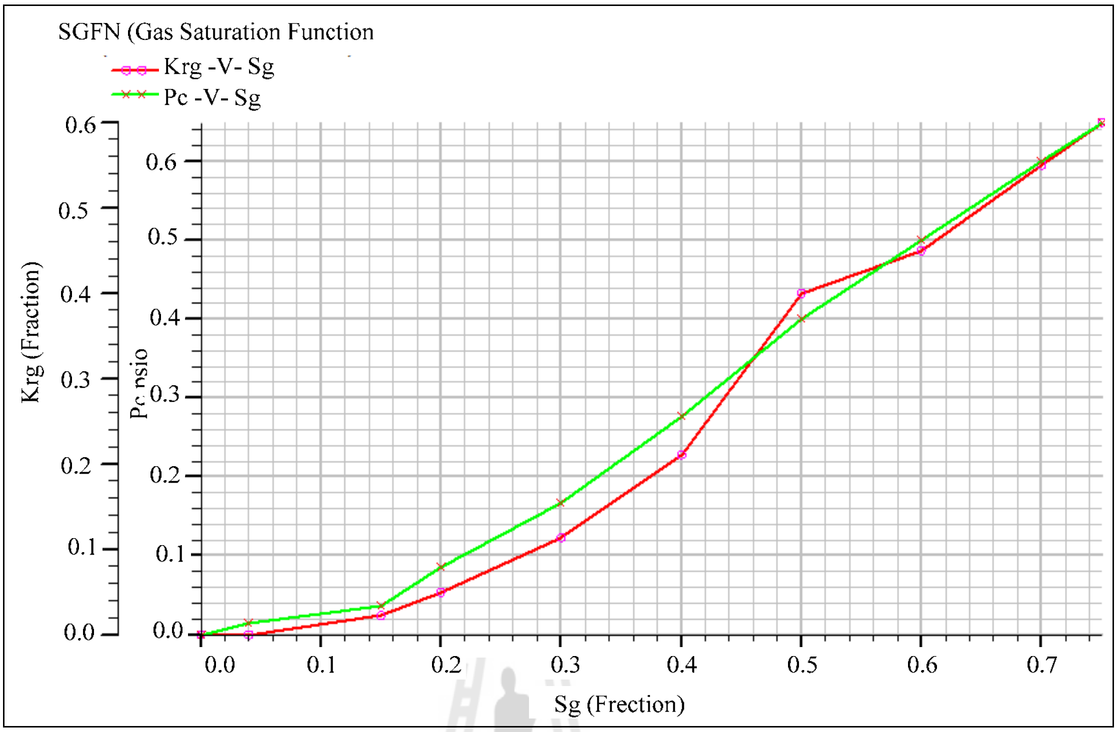


Figure B.5 Gas saturation functions graph display result from Sirikit 100MMbbl_INJ_PLY_scal.INC input data section.

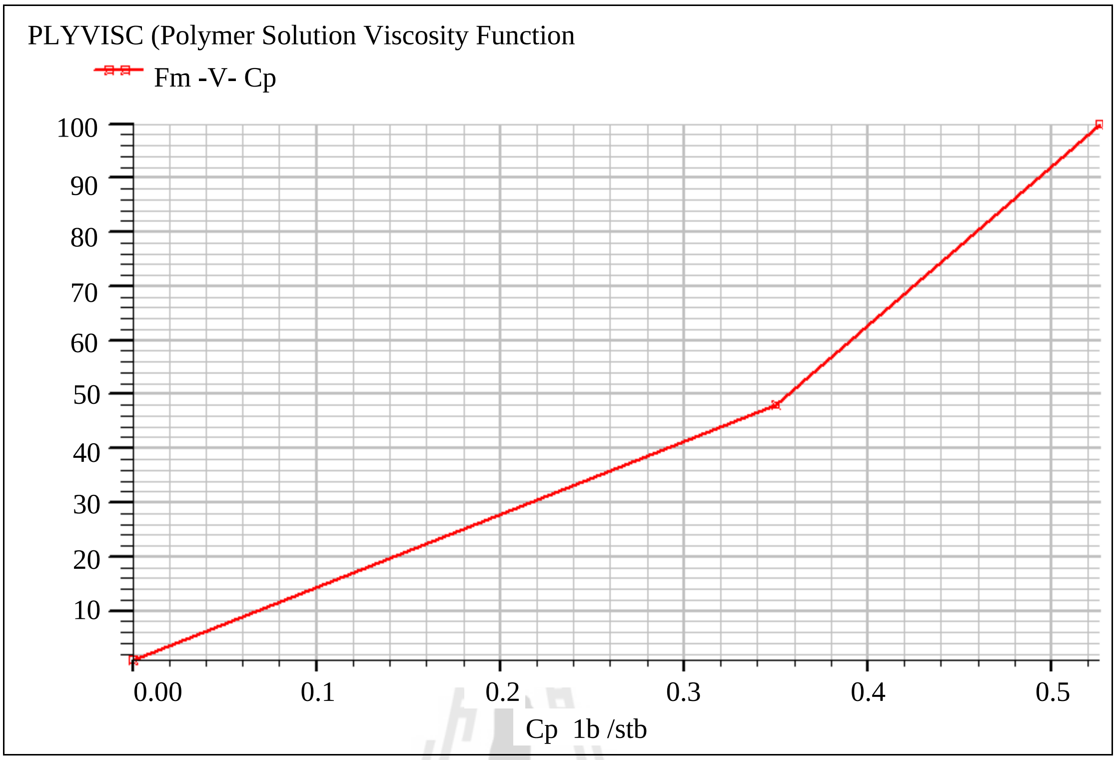


Figure B.6 Polymer solution viscosity function graph display result from Sirikit100MMbbl_INJ_PLY_scal.INC input data section.

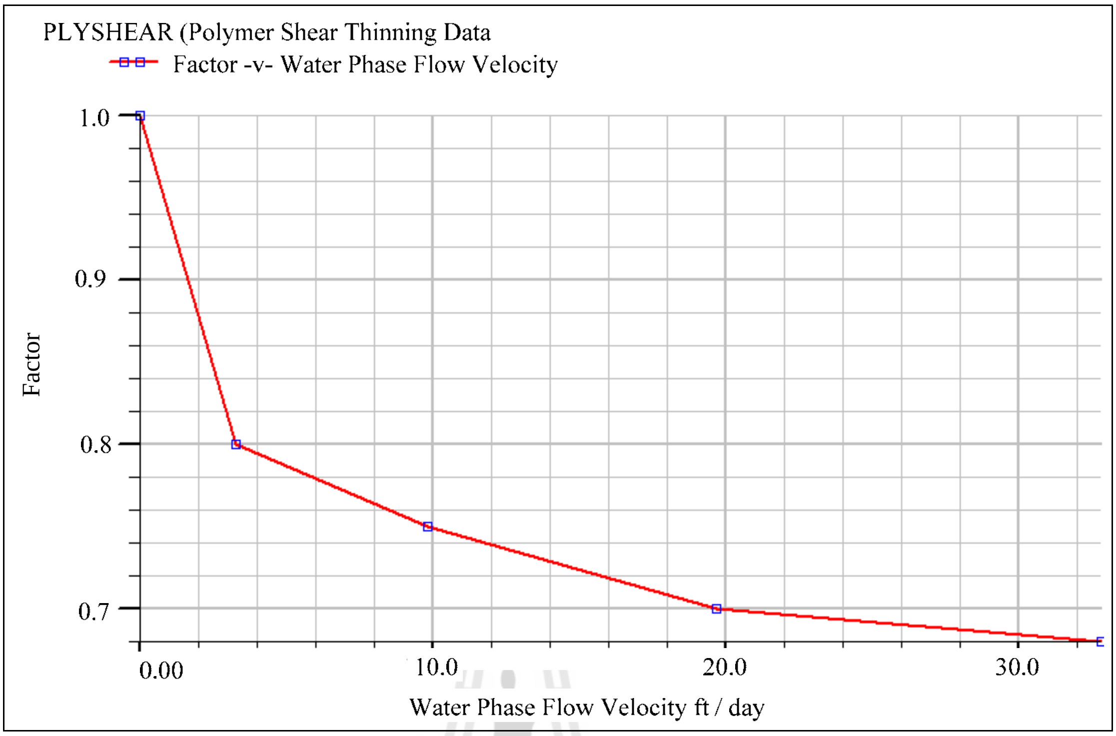


Figure B.7 Polymer shear thinning data graph display result from Sirikit 100MMbbl_INJ_PLY_scal.INC input data section.

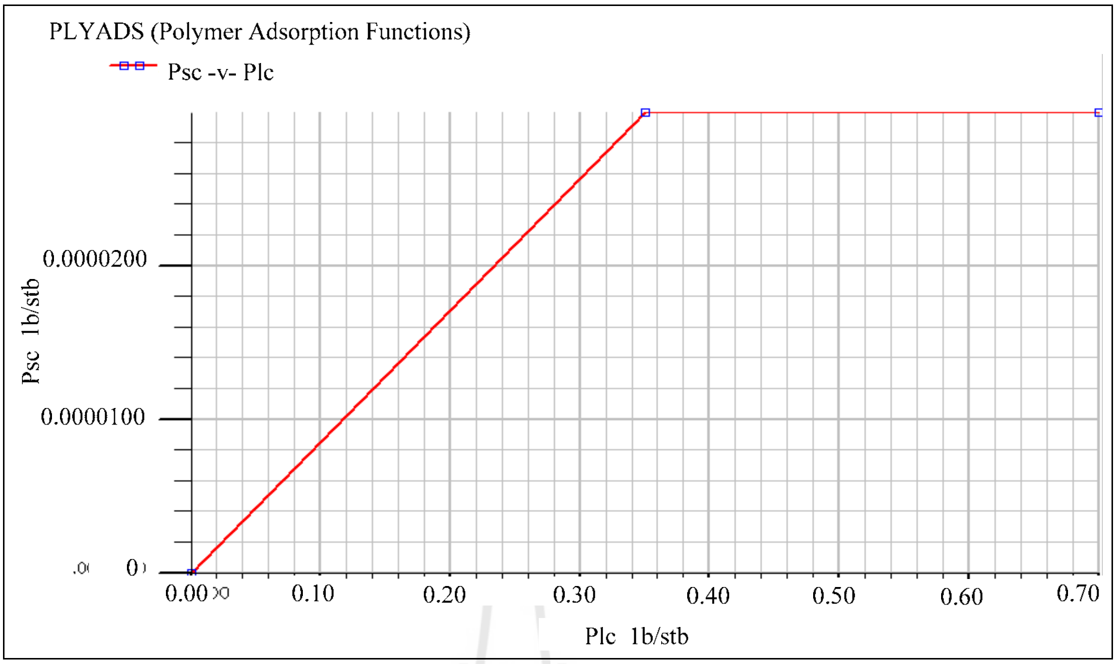


Figure B.8 Polymer adsorption function graph display result from Sirikit 100MMbbl_INJ_PLY_scal.INC input data section.

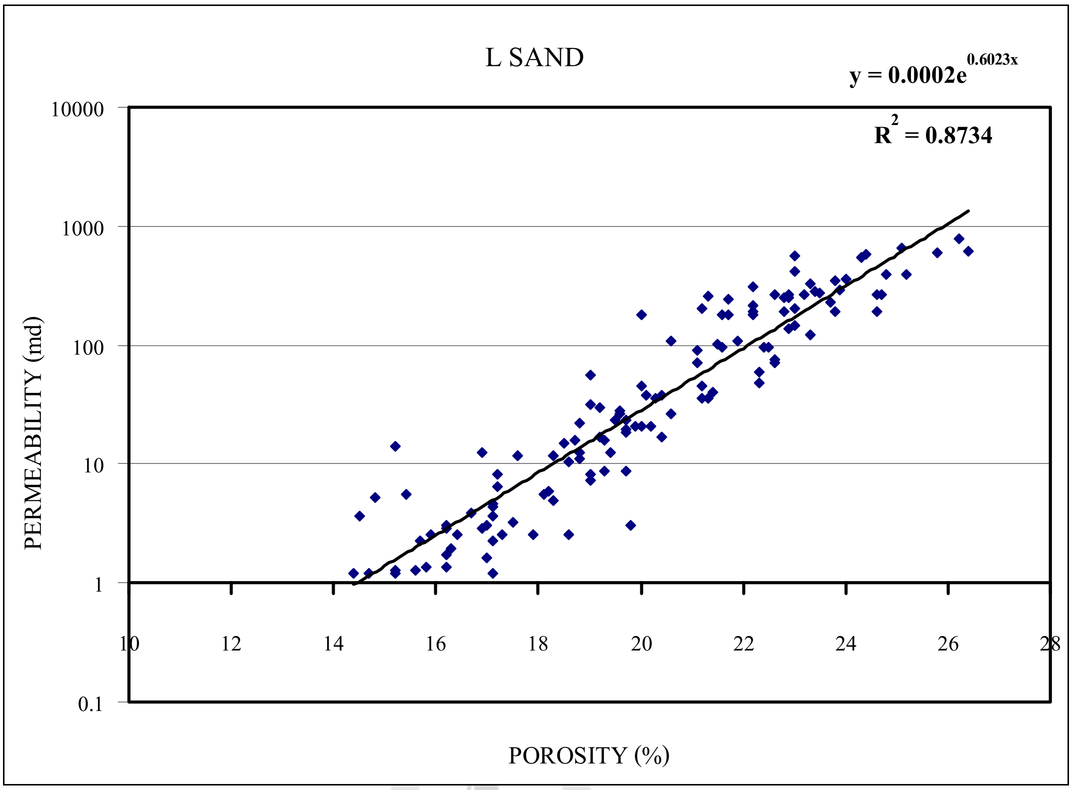


Figure B.9 Sirikit field review of atmospheric k/ø trend (L sand), (After Thai Shell Exploration and Production Co., Ltd.).

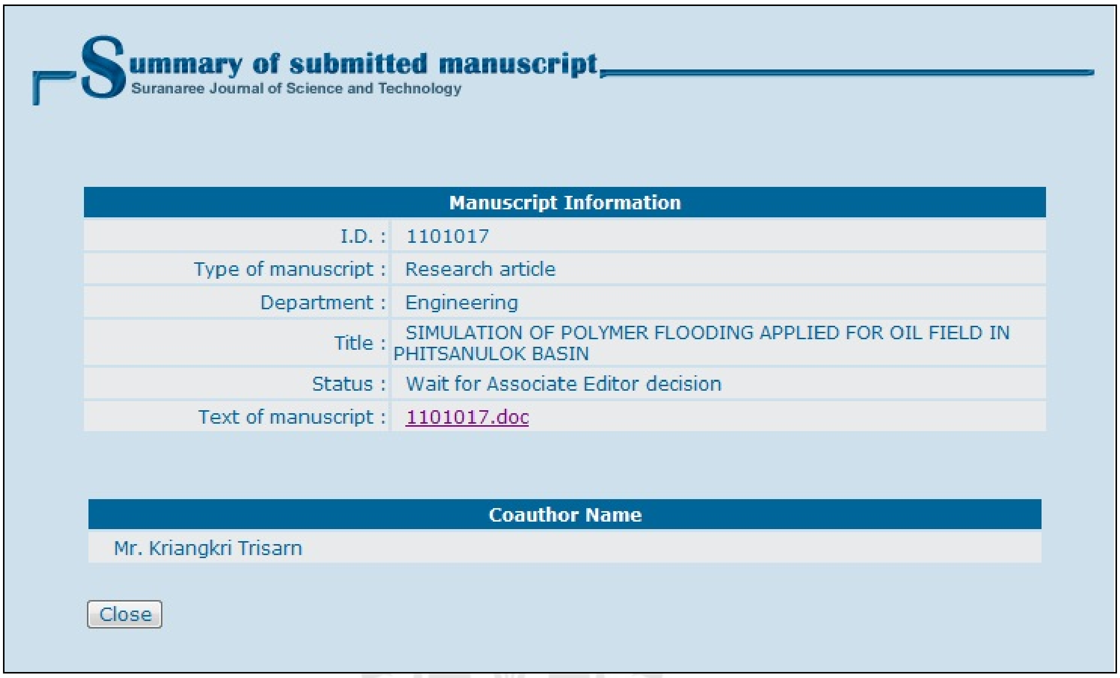
APPENDIX C

TECHNICAL PUBLICATION

TECHNICAL PUBLICATION

Kanarak, J., and Trisarn, K. (2011). **Simulation of polymer flooding applied for oil field in phitsanulok basin**, Suranaree Journal of Science and Technology, Suranaree University of Technology, *Nakhon Ratchasima, Thailand.*(submit)

Status of submitted manuscript


Summary of submitted manuscript
Suranaree Journal of Science and Technology

Manuscript Information	
I.D. :	1101017
Type of manuscript :	Research article
Department :	Engineering
Title :	SIMULATION OF POLYMER FLOODING APPLIED FOR OIL FIELD IN PHITSANULOK BASIN
Status :	Wait for Associate Editor decision
Text of manuscript :	1101017.doc

Coauthor Name
Mr. Kriangkri Trisarn

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SIMULATION OF POLYMER FLOODING APPLIED FOR OIL FIELD IN PHITSANULOK BASIN

Jutikarn Kanarak* and Kriangkri Trisarn

Running head: Simulation of Polymer Flooding in Phitsanulok Basin

Abstract

This paper examines two questions: (1) study and compare of oil recovery efficiency between the best case of waterflooding and polymer flooding by using reservoir simulation technique and, (2) apply the discount cash flow to optimize the polymer flooding selection from each scenario under current Dubai oil prices. Three sizes of oil fields are modeled in anticline reservoir structure with the original oil in place (OOIP) of 100, 30 and 5 million barrels respectively. Each oil field has many production methods by using different polymer concentrations and injection periods. The large size reservoir of model A100, oil recovery has increased from waterflooding of 3.86-7.24% OOIP. The polymer flooding has IRR range from 28.40-43.76% and PIR of 0.37-0.51, and the best case is the scenario that used polymer concentration of 1,000 ppm and injection period of 3rd-11thyear, that has net present value (NPV) of 170 MMUS$. The medium size reservoir of model A30, oil recovery has increased from waterflooding of 2.42-5.48% OOIP. The polymer flooding has IRR range from 53.91-56.76% and PIR of 0.36-0.40, and the best case is the scenario that used polymer concentration of 1,000 ppm and injection period of 3rd-10thyear, that has NPV of 53 MMUS$. The

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small size reservoir of model A05, oil recovery has increased from waterflooding of 4.39-4.62% OOIP. The polymer flooding has IRR range from 20.95-21.73% and PIR of 0.66-0.76, and the best case is the scenario that used polymer concentration of 600 ppm and injection period of 4th-20thyear, that has NPV of 15 MMUS$.

Keywords: Recovery efficiency, Polymer flooding, Waterflooding, Reservoir simulation

Introduction

The oil field in Phitsanulok Basin, located in the central part of Thailand. This study focused on Sirikit oil field where it is a part of the Phitsanulok Basin. The Sirikit oil field has been produced by primary and secondary oil recoveries together with the production of 22978 bbl/d (Department of Mineral Fuels., 2009). For secondary recovery, water injection has been applied to maintain reservoir pressure with some successes; it is still water breakthrough due to high mobility ratio and heterogeneity of geology that has actually occurred as high water cut stage. It causes poor performance of waterflooding. In order to improve the oil recovery, the polymer flooding is an attractive alternative to conventional waterflooding. Minor modifications need to be made to a waterflooding to enable polymer injection and recovery of additional oil. Additional polymers with flood water can increase the viscosity of the displacing phase (aqueous phase). The increased viscosity of water during polymer flooding causes the change of water-oil fractional flow and the improvement in vertical and areal sweep efficiency. Thus more oil is recovered.

Characteristics of Petroleum Reservoirs

The Sirikit field is a main oil field in the Phitsanulok Basin that is the area of this study. The basin is an extensional Oligocene structure. The main reservoir intervals lie within the Oligocene-Miocene fluvio-lacustrine Lan Krabu Formation (Figure 1). The major reservoir facies are interpreted to be lacustrine mouth bars and fluvial distributary channels. The central area of the field is intensely faulted, whereas the western and eastern flanks are relatively undeformed. The field has an estimated STOIIP (stock tank oil initially in place) of some 800 MMbbl (million barrels). The main reservoirs contain undersaturated, light oil (39.4°API), and the initial reservoir pressure of 3500 psi at depth of 3850 m. The bubble point is lower 1800 psi (Trisarn, 2006). Production started during 1982, and reservoir pressure quickly dropped to below bubble point, which resulted in higher producing gas/oil ratios (GOR) and lower oil rates. The reservoir drive energy was determined to be limited to solution gas expansion, which is aided by gas-cap expansion in some reservoirs. To preserve this energy and to optimize oil recovery, GOR limitations were set for the different reservoirs. As early as 1982, a water injection scheme was suggested for the Sirikit oil field. Consequently, in 1995 full-scale water injection commenced on the eastern, unfaulted flank of the field (Bruce *et al.*, 1999). This study was the field development that investigated into optimizing recovery and identifying unswept oil volumes are considered.

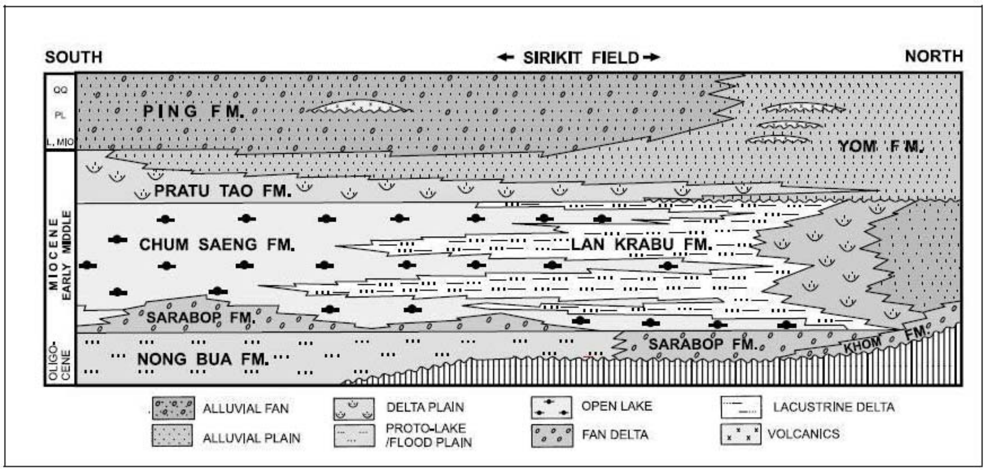

Figure 1. Schematic general stratigraphy of the Phitsanulok Basin and the Sirikit field. The strata of interest are the Oligocene-Miocene lacustrine deltaics of the Lan Krabu Formation (Bruce, *et.al.*, 1999).

Enhanced Oil Recovery

The increase oil recovery efficiency by polymer flooding is proven workable a widespread distribution, especially in the North America and China. In China, the study on enhanced oil recovery by chemical flooding has been carried out for more than 20 years (Han *et al.*, 1999) and used both types of polymer which are Polyacrylamide (PAM) and Polysaccharide (Biopolymer or Xanthan Gum). The results from China oil field can be proven that the polymer flooding technique can increase the oil recovery of the various reservoir types. This study used the Xanthan Gum for polymer flooding method, which has good performance more than the Polyacrylamide for high temperature in the reservoir.

The objective of polymer flooding is to reduce mobility ratio based on increasing the water viscosity. In some cases, the polymer solution reduces the permeability of the reservoir rock to water. The mobility ratio between the displacing phase (polymer solution) and the displaced phase (oil) will be decreased, therefore, the oil water contact will move steady in the formation from injection well to production well.

The polymer flooding into reservoir for control the mobility of injected phase can be shown in Figure 2. The figure show a schematic of a typical polymer flood injection sequence: a preflush is usually consisting of low salinity brine; an oil bank is injected by polymer; a fresh water buffer to protect the polymer solution from backside dilution; and the last are drive water.

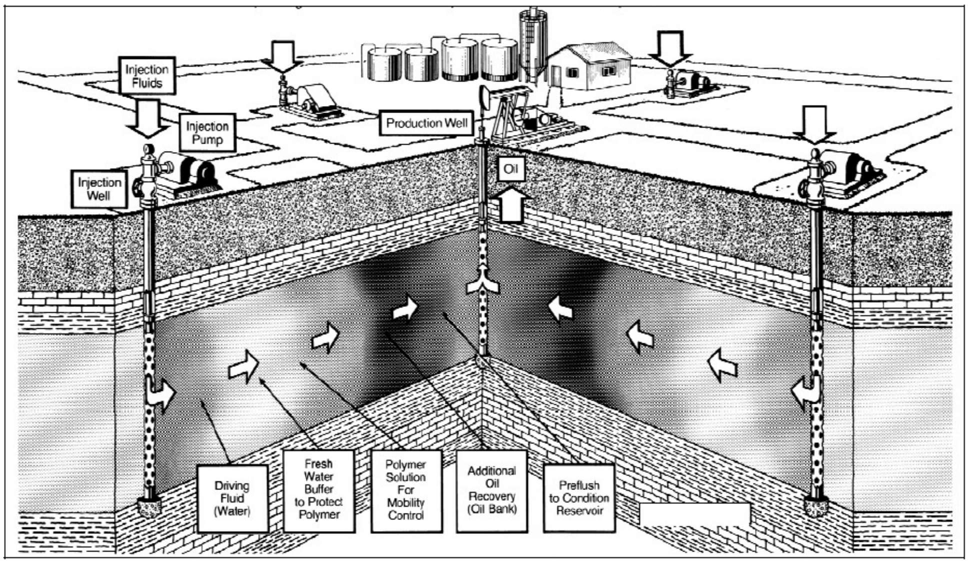

Figure 2. Schematic illustration of polymer flooding sequence, (Lake, 1989).

Reservoir Simulation Model design

The performance prediction of water and polymer injection for the fields was built from the ECLIPSE OFFICE simulator model which confined well pattern. Three sizes of oil fields are modeled with the oil in place of 100, 30 and 5 million barrels respectively. Model sizes and dimensions are shown Table 1. Each oil field has many production methods that use different polymer concentrations and various times interval for injection. The properties of the reservoir are summarized in Table 2. The simulation pertained to a confined well pattern, the symmetry element being represented by grid block of, 25 x 25 x 8 blocks (5000 cells) for all models, which are shown in Figure 3. Polymer flooding pattern design for a comprehensive of the flooding simulation which relies on the reservoir structure, drainage area, number of well, production and injection activity. The summary of water and polymer injection rate for each scenario is illustrated in Table 3.

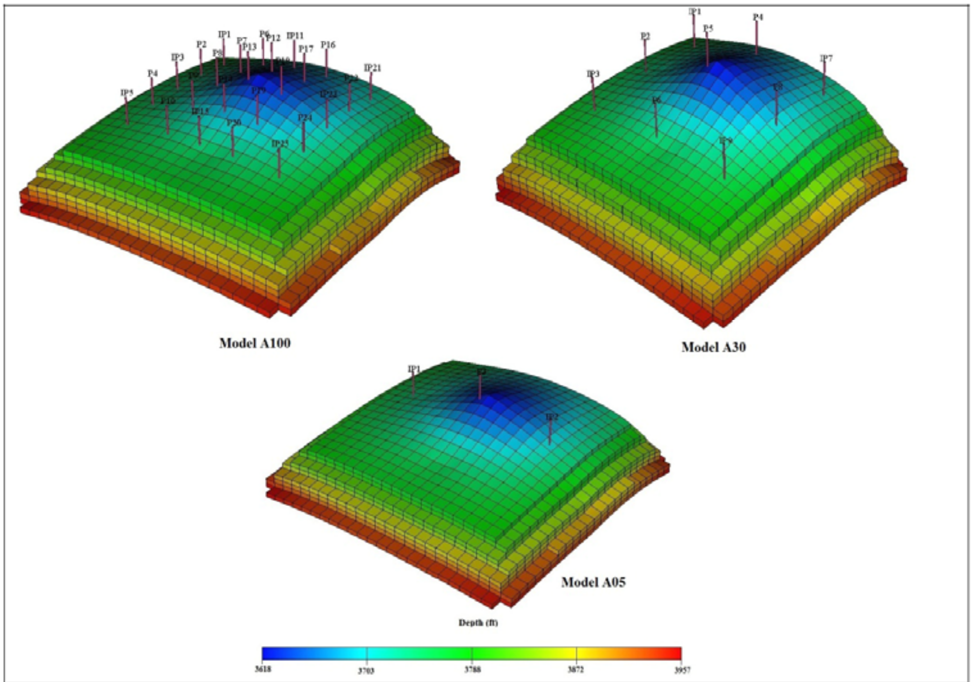

Figure 3. The model structure and confined well pattern of three reserve sizes.

Table 1. Model sizes and dimensions

Model	Dimension (ft)	Horizontal grid dimension (ft)	Area (acres)	Thickness (ft)
A100	6,250 x 6,250	250	896.75	100
A30	3,375 x 3,375	135	261.49	160
A05	1,250 x 1,250	50	35.87	56

Table 2. Summary of reservoir and fluid properties

Parameter	Properties
Depth	3,850 ft
Temperature	203°F
Rock type	Consolidated Sandstone
Porosity	19-26%
Oil gravity	39.4°API
Oil viscosity	2.1 cp
Permeability	9.2-586 md
Average k_v / k_h	0.10
Datum depth	3,850 ft
Initial static reservoir pressure	3,500 psi
Oil formation volume factor	1.055-1.286 bbl/STB
Dissolved gas specific gravity	0.8
Bubble point pressure	1,800 psi
Water-oil contact depth	3,915 ft

Table 3. Injection rate of scenarios test

Model	Injection scenarios	Water injection (BWPD/well)	Polymer/water Injection (BWPD/well)
A100	Waterflooding	1,000	-
	Preflush by water		1,000
	Polymer injection		1,000
	Driving water		1,000
A30	Waterflooding	500	-
	Preflush by water		500
	Polymer injection		500
	Driving water		500
A05	Waterflooding	200	-
	Preflush by water		200
	Polymer injection		200
	Driving water		-

The structural of model A100 shows peripheral flood injection pattern. There are 17 production wells and 8 injection wells located in and around the reservoir boundary, respectively. The appropriate spacing of each well is approximately 1000 ft. Model A30 shows peripheral flood injection pattern. There are 5 production wells and 4 injection wells located in and around the reservoir boundary, respectively. The appropriate spacing of each well is approximately 945 ft. Model A05 shows inverted three-spot flood injection pattern. There are a production well and 2 injection wells located at reservoir crest and down dip of the reservoir boundary, respectively. The appropriate spacing of each well is approximately 350 ft.

The production and injection wells are located in the updip and downdip structure, respectively. The appropriate numbers of well are considered to optimum oil recovery, injection of polymer slug, polymer concentration and economic evaluation.

The structure model for the Sirikit oil field is very important for maximal improvement oil recovery. The field is geologically complex, being very faulted in a lacustrine environment and heterogeneity of the various reservoirs. Trisarn (2006) found vertical heterogeneity of porosity and permeability of the Sirikit L sand as shown in Figure 4.

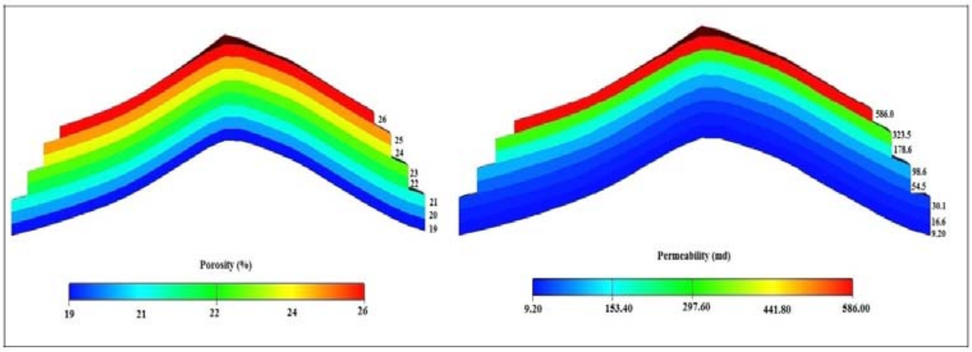

Figure 4. The reservoir sections show the vertical heterogeneities of reservoir.

Results and Discussion of Polymer Flooding Simulation

The base case from the waterflooding of each model was tested which need to found the best case as well as the highest oil recovery from the waterflooding. The results found, all models of the waterflooding that have highest oil recovery can be started within a reasonable time on 3rd year and water flood must be injected into the reservoir until the end of project life, for reservoir pressure support.

The results of analysis obtained from the best scenario of the waterflooding (base case) and the application of the polymer flooding technique in the three reserved sizes of oil field with different polymer concentrations and various times interval for injection are shown in Table 4.

Table 4. Basic data of polymer flooding

Model	Pattern	Injector/ Producer	Distance between injector and producer (ft)	Scenario No.	Polymer concentration (ppm)	Date of water/ polymer injection	Quantity of injected polymer (ton x pv)	Incremental oil recovery (%OOIP)
A100	Peripheral flood	8/17	1,000	1	Water inj. (no-polymer)	3rd-25th	-	-
				2	1,000	3rd-11th	4,181x0.14	5.25
				3	1,000	4th -12th	4,181x0.14	4.60
				4	1,000	5th -13th	4,181x0.14	3.86

				5	1,500	3^{rd}-11^{th}	6,272x0.14	6.37
				6	1,500	4^{th} -12^{th}	6,272x0.14	5.73
				7	1,500	5^{th} -13^{th}	6,272x0.14	4.98
				8	2,000	3^{rd}-11^{th}	8,365x0.14	7.24
				9	2,000	4^{th} -12^{th}	8,365x0.14	6.58
				10	2,000	5^{th} -13^{th}	8,365x0.14	5.83
A30	Peripheral flood	4/5	945	1	Water inj. (no- polymer)	3^{rd}-25^{th}	-	-
				2	1,000	3^{rd}-10^{th}	929x0.12	4.25
				3	1,000	4^{th} -11^{th}	929x0.12	3.42
				4	1,000	5^{th} -12^{th}	929x0.12	2.42
				5	1,500	3^{rd}-10^{th}	1,394x0.12	4.96
				6	1,500	4^{th} -11^{th}	1,394x0.12	4.01
				7	1,500	5^{th} -12^{th}	1,394x0.12	2.87
				8	2,000	3^{rd}-10^{th}	1,858x0.12	5.48
				9	2,000	4^{th} -11^{th}	1,858x0.12	4.33
				10	2,000	5^{th} -12^{th}	1,858x0.12	3.13
A05	Inverted three-spot	2/1	350	1	Water inj. (no-polymer)	3^{rd}-20^{th}	-	-
				2	600	3^{rd}-20^{th}	296x0.34	4.40
				3	600	4^{th} -20^{th}	279x0.34	4.48
				4	800	3^{rd}-20^{th}	395x0.34	4.39
				5	800	4^{th} -20^{th}	372x0.34	4.56
				6	1,000	3^{rd}-20^{th}	494x0.34	4.39
				7	1,000	4^{th} -20^{th}	465x0.34	4.57
				8	1,200	3^{rd}-20^{th}	592x0.34	4.52
				9	1,200	4^{th} -20^{th}	557x0.34	4.62

There shows the scenarios of polymer injection that could have high performance oil recovery efficiency when compared to the best case of water injection. All scenarios have more incremental of oil from the polymer injection than that would be gained from the water injection alone. For Model A100, oil recovery has increased 5.25, 4.60, 3.86, 6.37, 5.73, 4.98, 7.24, 6.58 and 5.83% of OOIP in scenario 2 to 10 respectively. Model A30, oil recovery has increased 4.25, 3.42, 2.42, 4.96, 4.01, 2.87, 5.48, 4.33 and 3.13% of OOIP in scenario 2 to 10 respectively. Model A05, oil recovery has increased 4.40, 4.48, 4.39, 4.56, 4.39, 4.57, 4.52 and 4.62% of OOIP in scenario 2 to 9 respectively.

The results show that the polymer flooding can improve the water swept coefficient and the volumetric sweep efficiency, consequently, water cut in reservoir decreased. As a result, the polymer flooding method can successfully adjust the mobility ratio between polymer solution and oil phase in the reservoir that is effectively prompt of oil recovery efficiency, which are shown Figure 5-7.

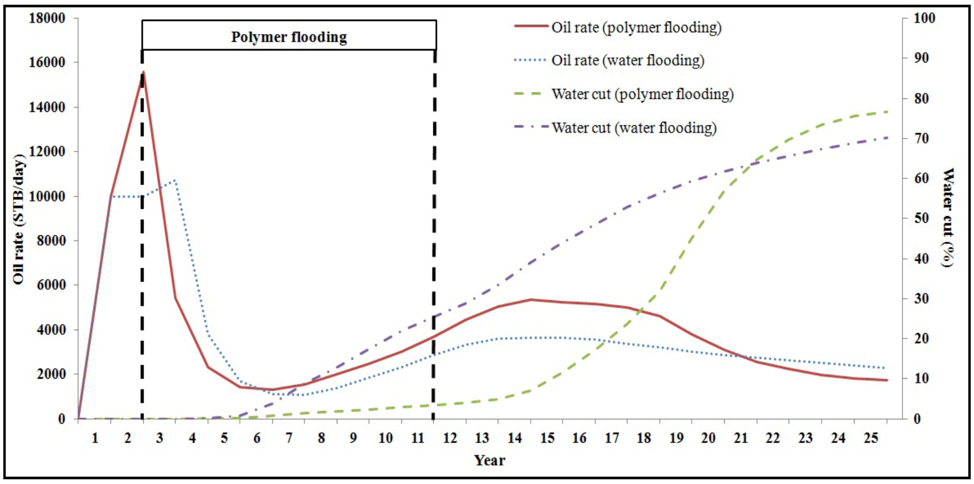

Figure 5. Production performance, Model A100-polymer 1,000 ppm-injected 3rd-11th year.

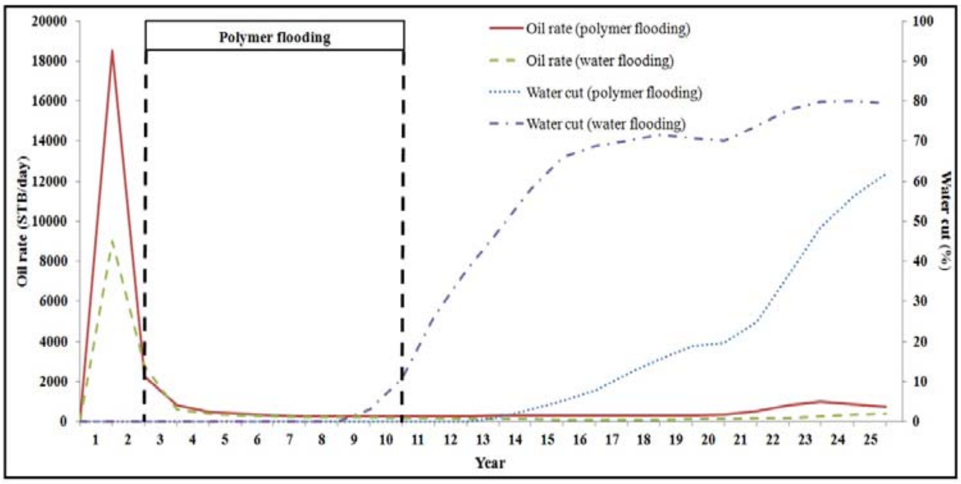

Figure 6. Production performance, Model A30-polymer

1,000 ppm-injected 3rd-10th year.

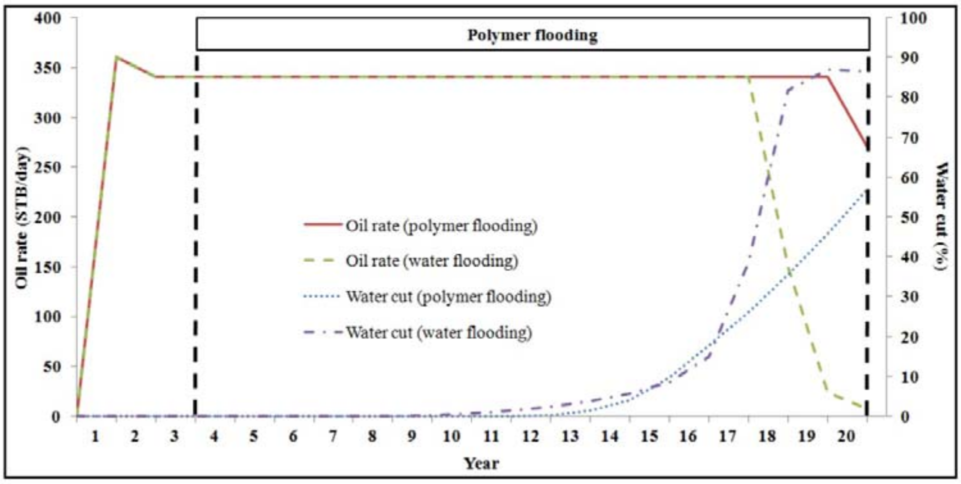

Figure 7. Production performance, Model A05-polymer

600 ppm-injected 4th-20th year.

The effects of reducing the water cut and increasing the oil production rate are observed at all scenarios in each model. For example, model A100 with polymer concentration of 1,000 ppm and a time interval injection of 3rd-11th year, the oil production rate increases after injection of polymer solution on June 6th year, and at the end of polymer flooding on 11th year, the water cut of that reservoir decreases from 25.5% to 3.4% with a production rate increases from 2849 to 3667 bbl/day and the polymer flooding can maintains oil production rate more than receives from the waterflooding until June 21th year.

Comparison between the waterflooding and polymer flooding from model A100, the oil saturation distribution after polymer flooding by injection polymer concentration of 1000 ppm with injection slug size of 0.12 pore volume (PV) has been selected to compare with the waterflooding (Figure 8-9). Before polymer flooding, the oil saturation in all layers has been still very high. From the waterflooding, the oil saturation has been decreased in small area around the wells only. After polymer flooding, in the most area where is oil in placed can be controlled by the injection wells and the production wells, the reservoir oil saturation has been decreased to the residual oil saturation, that is more oil has been produced.

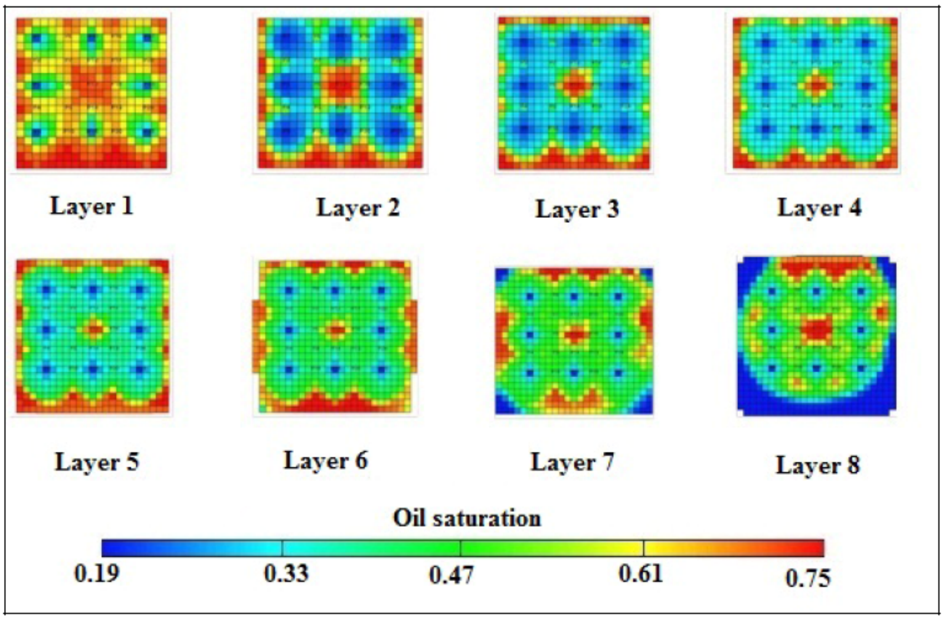

Figure 8. Oil saturation distribution after waterflooding@the end of project life, Model A100-no polymer injection.

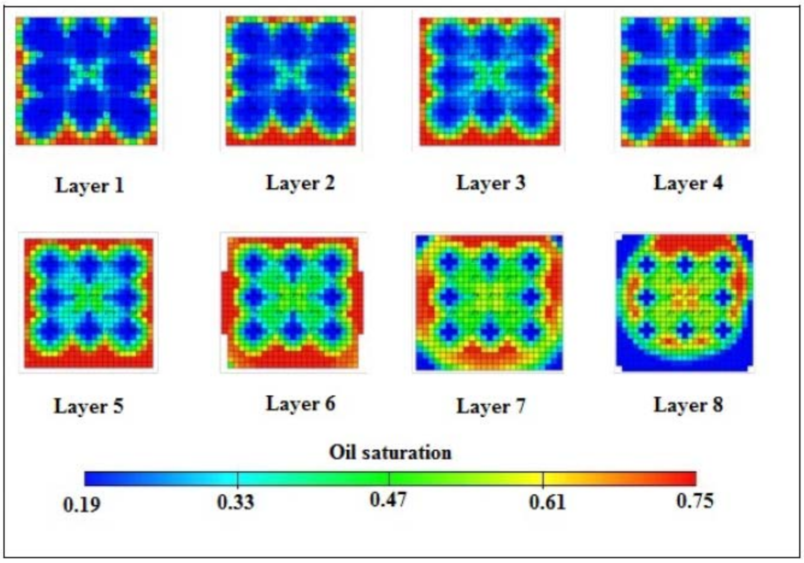

Figure 9. Oil saturation distribution after polymer flooding@the end of project life, Model A100-polymer 1,000 ppm-injection 3rd-11th year.

The comparison shows that oil saturation from polymer flooding has been apparently decreased, especially in the upper six layers. The polymer flooding has taken clearly effect on improving volumetric driving efficiency. On the other hand, the two lower layers have not effectiveness by polymer flooding because a reservoir with the aquifer may become difficult to be flooded, due to the flow of polymer solution in the reservoir could not be regulated and that is difficult respect to control of chemical loss.

The increasing of polymer concentration can increase the oil recovery, however, the concentration of polymer need to be adjusted to the suitable injection rate to prevent the extreme adsorption mechanism on the rock surface and undesired blocking zones. If polymer slug size is very small, that is almost no enhanced oil recovery. Most of polymer has been adsorbed on the pore surface of the rock. In addition, the polymer injection with too high concentration more than appropriate concentration will make the larger particle size which plug in pore spaces. The oil recovery will be decrease due to the inaccessible pore volume that solid particle of polymer cannot flow through.

The polymer injection within a reasonable time will make the highest oil recovery. The main important to improvement oil recovery is to maintain pressure in the reservoir for the stable pressure drop which control the oil optimum flow rate base on the Darcy's Law. Therefore, the polymer injection in the early stage of a water flood is important as mention above and the simulation also provide the suitable time period to start polymer injection.

The small reservoir geometry that has only a small oil bearing zone, such as model A05, the economic design of a flooding may be not possible. Due to it is very difficult to be flooded with respect to the control of chemical loss. Thus model A05 need to be used to the lower polymer concentration injection with a long period of time, to prevent an adsorption and undesired blocking zone. The effect of polymer injection with incremental of oil recovery are shown in Figure 10.

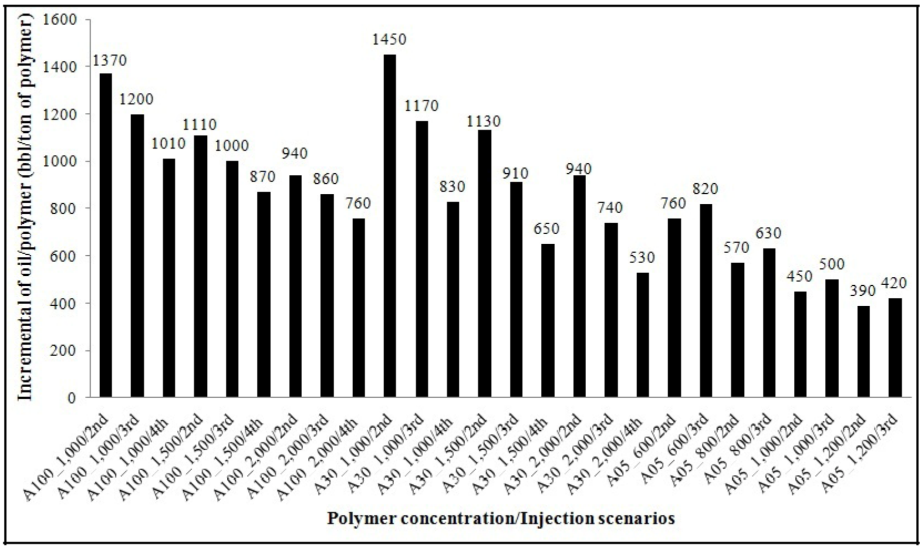

Figure 10. Effect of polymer injection (barrel oil/ton of polymer).

Economic Evaluation

Economic evaluation is the final step in this study on the application of polymer flooding for the enhanced oil recovery. The objective of economic evaluation is the commerciality of each model project as the result from the reservoir simulation. Table 5 lists the economic evaluation parameters used in this study.

Table 5. Economic evaluation parameter

Project parameters	A100	A30	A05
Dubai oil price (US$/bbl)	80	80	80
Income tax (%)	50	50	50
Inflation rate (%)	2	2	2
Real discount rate (%)	8	8	8
Sliding scale royalty (%)			
Production level (bbl/day)			
0-2,000	5	5	5
2,000-5,000	6.25	6.25	6.25
5,000-10,000	10	10	10
10,000-20,000	12.5	12.5	12.5
>20,000	15	15	15
Concession (MMUS$)*	3.75	2.50	0.50
Geological and geophysical survey (MMUS$)	5	4	1
Production facility (MMUS$)	250	100	10
Drilling exploration & appraisal well (MMUS$)	10.5	6	1
Drilling and completion production well (MMUS$/well)	1.5	1.5	1.5
Facility cost of water injection well (US$/well)	60,000	60,000	60,000
Facility cost of polymer injection well (US$/well)	62,000	62,000	62,000
Maintenance cost of water injection well (US$/year)	80,000	60,000	40,000
Maintenance cost of polymer injection well (US$/year)	80,000	60,000	40,000

Abandonment cost (US$/well)	12,500	12,500	12,500
Operating cost of production well (US$/bbl)	30	25	20
Operating cost of water injection (US$/bbl)	0.5	0.5	0.5
Operating cost of polymer injection (US$/bbl)	1.0	1.0	1.0
Polymer purchasing price including transportation (US$/kg)	7	7	7

*MMUS$ = Million US Dollar

From the result of polymer flooding in each model is compared to the best case of the waterflooding which is used the same water/polymer solution injection rate (displacing phase). The results of economic evaluation are shown in Table 6. This table contains for net present value (NPV), internal rate of return (IRR) and profit to investment ratio (PIR). For model A100, scenario of water injection has the IRR after tax and 8% discounted of 33.49% and PIR of 0.46, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 28.40-43.76% and PIR of 0.37-0.51. Accordingly, the best operation case for model A100 is the scenario that used the polymer concentration of 1000 ppm and the time interval of injection 3^{rd}-11^{th} year, that has the best NPV of 170 MMUS$.

Model A30, scenario of water injection has the IRR after tax and 8% discounted of 55.43% and PIR of 0.39, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 53.91-56.76% and PIR of 0.36-0.40. Accordingly, the best case for model A30 is the scenario that used the polymer concentration of 1,000 ppm and the time interval of injection 3^{rd}-10^{th} year, that has the best NPV of 53 MMUS$.

Model A05, scenario of water injection has the IRR after tax and 8% discounted of 21.72% and PIR of 0.83, while scenarios of polymer injection have the IRR after tax and 8% discounted range from 20.95-21.73% and PIR of 0.66-0.76.

Accordingly, the best operation case for model A05 is the scenario used the polymer concentration of 600 ppm and the time interval of injection 4th-20th year, that has the best NPV of 15 MMUS$.

Table 6. Economic evaluation results summary

Model	Scenario No.	Time of water/ polymer injection (year)	Amount of polymer (ton)	Capital cost (MMUS$)	NPV with8% discounted (MMUS$)	IRR with8% discounted (%)	PIR with8% discounted (Fraction)
A100	1	23	-	307.33	141.94	33.49	0.46
	2	9	4,181	337.10	170.31	43.76	0.51
	3	9	4,181	337.10	150.83	33.28	0.45
	4	9	4,181	337.10	135.62	28.84	0.40
	5	9	6,272	351.74	169.31	43.38	0.48
	6	9	6,272	351.73	150.25	33.08	0.43
	7	9	6,272	351.73	134.90	28.62	0.38
	8	9	8,365	366.38	167.37	43.00	0.46
	9	9	8,365	366.37	149.21	32.81	0.41
	10	9	8,365	366.37	133.86	28.40	0.37
A30	1	23	-	126.54	49.60	55.43	0.39
	2	8	929	133.04	53.05	54.33	0.40
	3	8	929	133.04	50.83	55.31	0.38
	4	8	929	133.04	52.53	56.76	0.39
	5	8	1,394	136.29	52.99	54.91	0.39
	6	8	1,394	136.29	50.51	55.21	0.37
	7	8	1,394	136.29	52.22	56.72	0.38
	8	8	1,858	139.55	52.24	53.91	0.37
	9	8	1,858	139.55	49.75	55.08	0.36
	10	8	1,858	139.55	51.75	56.68	0.37
A05	1	18	-	17.15	14.26	21.72	0.83
	2	18	296	19.34	14.49	21.21	0.75
	3	17	279	19.22	14.69	21.73	0.76
	4	18	395	20.03	14.38	21.12	0.72
	5	17	372	19.87	14.61	21.67	0.74
	6	18	494	20.72	14.27	21.03	0.69
	7	17	465	20.52	14.51	21.61	0.71

8	18	592	21.42	14.18	20.95	0.66
9	17	557	21.17	14.42	21.54	0.68

Conclusions and Recommendations

The heterogeneity of the geological conditions in the reservoirs causes the oil fields to have a high water cut stage, and low oil recovery efficiency using the waterflooding method. The application of the polymer flooding method in the different size of oil fields with the various polymer concentrations by the reservoir simulation, the results found the polymer flooding can increase the oil recovery more than using the traditional waterflooding method only, due to the polymer solution can improve the water swept coefficient and the volumetric sweep efficiency. Finally, those have reduced the water cut in the oil reservoirs of heterogeneous geological condition. The "Xanthan Gum" polymer solution is used in these oil fields simulation. The reservoir with quite high temperature assures that this polymer solution can increase the water viscosity. Therefore, the mobility ratio between polymer solutions and oil will be decreased.

Consequently, Model A100 with the 1000 ppm polymer solution injection and inject period of 3^{rd}-11^{th} year, there is an increased profit of 1370 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 5.25% OOIP more than the waterflooding. For Model A30, with the 1000 ppm polymer solution injection and injection period of 3^{rd}-10^{th} year, there is an increased profit of 1450 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 4.25% OOIP more than the waterflooding. For Model A05, with the 600 ppm polymer solution injection and injection period of 4^{th}-20^{th} year, there is an increased profit of 820 barrel of oil production per ton of polymer injected, and the oil recovery efficiency will be increased 4.48% OOIP more than the waterflooding.

The polymer flooding would not economic efficiency when the field used excess concentration of polymer, due to the big consumed amount of polymer. Thus the polymer flooding will make not profitable as well as the higher cost than the waterflooding.

The heterogeneity effect of porosity and absolute permeability variation need to apply and test for individual productive reservoir to make a reliable result of the simulation result.

The simulation models used in this study appear to be conceptual model not the real performance of oil field in the Phitsanulok Basin.

Acknowledgement

The authors wish to special thank to Asst. Prof. Thara Lekuthai who gave the valuable suggestion for this research. Also, we would like to acknowledge the School of Geotechnology, Suranaree University of Technology for all supports.

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During 2009-2011, he studied for master's degree in the School of Geotechnology, Institute of Engineering at SUT with the major in Petroleum Engineering. His strong background is in drilling engineering, reservoir management and high skill in reservoir simulation.