COMPARISON OF THE OIL RECOVERY BETWEEN WATER FLOODING AND POLYMER FLOODING FOR SUPHAN BURI BASIN

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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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การวิจัยนี้ใช้หลักการผลิตน้ำมันดิบด้วยวิธีการขับด้วยน้ำและพอลิเมอร์เพื่อเพิ่มปริมาณการผลิตน้ำมันดิบซึ่งติดค้างหลงเหลืออยู่ภายในแหล่งกักเก็บของแอ่งสุพรรณบุรี จุดประสงค์การศึกษานี้ประกอบไปด้วย (1) ศึกษาทฤษฎีเกี่ยวกับวิธีการขับน้ำมันด้วยน้ำและการขับด้วยพอลิเมอร์ (2) เปรียบเทียบการผลิตน้ำมันดิบด้วยวิธีการขับน้ำมันด้วยน้ำและการขับด้วยพอลิเมอร์โดยใช้แบบจำลองคอมพิวเตอร์เปรียบเทียบประสิทธิภาพการผลิตน้ำมันของแหล่งกักเก็บในแอ่งสุพรรณบุรี (3) ทำการวิเคราะห์ทางด้านเศรษฐศาสตร์เพื่อใช้ในการตัดสินใจหาโครงการลงทุนที่มีโอกาสและความเป็นไปได้มากที่สุดที่จะนำวิธีการดังกล่าวนี้ไปใช้ในการประกอบการจริง โดยแหล่งกักเก็บที่ใช้ในการวิจัยเป็นแหล่งกักเก็บที่มีคุณสมบัติและขนาดเหมือนกันทุกประการนำมาเปรียบเทียบกันโดยทำการเปลี่ยนชนิดของการอัด (อัดด้วยน้ำหรือพอลิเมอร์)และปีที่ทำการอัดด้วยการวางรูปแบบตำแหน่งหลุมผลิตต่อหลุมที่ทำการอัดใช้เป็นแบบ Direct Line Drive และ Staggered Line Drive โดยทำการรวบรวมข้อมูลทางด้านธรณีฟิสิกส์และคุณสมบัติของของไหลในแหล่งกักเก็บ ค่าความพรุน ค่าความซึมผ่านได้และความดันของแหล่งกักเก็บนั้นได้ทำการรวบรวมมาจากบทความที่เผยแพร่ต่าง ๆ รวมทั้งใช้ค่าที่ได้จากการคำนวณเชิงทฤษฎี โดยแหล่งกักเก็บมีขนาดประมาณ 6.48 ล้านบาร์เรลทำการอัดด้วยน้ำหรือพอลิเมอร์ด้วยอัตราคงที่ในปีที่ 1, 3 และ 5 โดยผลจากการทดสอบแบบจำลองพบว่าการผลิตในขั้นปฐมภูมิ (ไม่มีการอัดน้ำหรือพอลิเมอร์) สามารถผลิตน้ำมันดิบได้ 25.55-26.05% ของปริมาณสำรองทั้งหมด กรณีศึกษาที่ทำการขับน้ำมันด้วยน้ำในปีที่ 1, 3 และ 5 ทำให้ประสิทธิภาพการขับน้ำมันเพิ่มเป็น 47.96-49.28%, 45.07-40.46% และ 40.35-40.46% ของปริมาณสำรองตามลำดับ กรณีศึกษาที่ทำการขับน้ำมันด้วยพอลิเมอร์ในปีที่ 1, 3 และ 5 ทำให้ประสิทธิภาพการขับน้ำมันเพิ่มเป็น 52.61-55.03%, 48.58-51.14% และ 43.09-44.19% ของปริมาณสำรองตามลำดับ เมื่อทำการเปรียบเทียบกรณีศึกษาระหว่างการขับน้ำมันด้วยน้ำและการขับน้ำมันด้วยพอลิเมอร์พบว่าการขับน้ำมันด้วยพอลิเมอร์มีประสิทธิภาพสูงกว่าทั้งทางด้านการผลิตน้ำมันและทางด้านเศรษฐศาสตร์ และพบว่าการขับน้ำมันด้วยพอลิเมอร์ในปีที่ 1 จะทำให้ได้ค่าประสิทธิภาพทางการผลิตและผลวิเคราะห์ทางด้านเศรษฐศาสตร์สูงที่สุด

สาขาวิชา เทคโนโลยีธรณี ลายมือชื่อนักศึกษา__________

ปีการศึกษา 2556 ลายมือชื่ออาจารย์ที่ปรึกษา__________

THEERADECH THONGSUMRIT : COMPARISON OF THE OIL RECOVERY BETWEEN WATER FLOODING AND POLYMER FLOODING FOR SUPHAN BURI BASIN. THESIS ADVISOR : ASSOC. PROF. KRIANGKRAI TRISARN, 128 PP.

SUPHAN BURI BASIN /WATER FLOODING /POLYMER FLOODING/ RESERVOIR SIMULATION

This research utilized water and polymer flooding to improve oil recovery by reducing the residual oil left in the reservoir of Suphan Buri Basin of Thailand. The objectives of this study are, 1) to study the theory of water and polymer flooding, 2) to compare between water and polymer flooding cases by using reservoir simulation to simulate the improve oil recovery factor in the reservoirs of Suphan Buri Basin, and 3) to study economics of both methods to find the best case. The same reservoir will be compared by changing different types of well injection (water and polymer) and years to inject with direct line drive and staggered line drive flood patterns. Physical properties of the reservoir rock and fluids, porosity, permeability, and reservoir pressure were collected from literature review and theoretical assumptions. The reserve size of reservoir is around 6.48 million barrels injected with constant rate at the 1st, 3rd and 5th year. The results of reservoir simulation show the primary production (no injection) about 25.55-26.05% of oil in place. Case studies which applied by water flooding technique, the 1st, 3rd and 5th year of water injection, the recoveries increased to 47.96-49.28%, 45.07-46.20% and 40.35-40.46%, respectively. Case studies which applied by polymer flooding technique, the 1st, 3rd and 5th years of polymer injection, the recoveries increased to 52.61-55.03%, 48.58-51.14% and 43.09-44.19%, respectively. Comparing between water and polymer flooding case studies, polymer flooding has oil recovery efficiency and economic values more favorable than water flooding, the 1^{st} year of polymer injection presented itself the best operation cases of every case in development plan.

School of Geotechnology Student Signature ___________________

Academic Year 2013 Advisor Signature ___________________

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SYMBOLS AND ABBREVIATIONS

bbl	=	Barrel
bbl/d	=	Barrel per day
CAPEX	=	Capital expense
Disc.	=	Discount
EOR	=	Enhanced oil recovery
FCIT	=	Field polymer injection total
FGIP	=	Field gas in place
FGPR	=	Field gas production rate
FGPT	=	Field gas production total
FOE	=	Field oil efficiency
FOIP	=	Field oil in place
FOPR	=	Field oil production rate
FOPT	=	Field oil production total
FPR	=	Field pressure
FVF	=	Formation volume factor
FWIP	=	Field water in place
FWPR	=	Field water production rate
FWPT	=	Field water production total
GOGD	=	Gas/oil gravity drainage
HPAM	=	Hydrolyses polyacrylamides
IRR	=	Internal Rate of Return

SYMBOLS AND ABBREVIATIONS (Continued)

Inc.	=	Income
Inj.	=	Injection
MSCF/STB	=	Thousand cubic feet per stock tank barrel
MMBBL	=	Million barrels
MMSTB	=	Million stock tank barrels
MMUS$	=	Million US dollar
MMUS$/well	=	Million US dollar per well
MSCF	=	Thousand cubic feet
NPV	=	Net present value
OPEX	=	Operation expense
OOIP	=	Original oil in place
Pbub	=	Bubble point pressure
PIR	=	Profit investment ratio
Ply.	=	Polymer
ppm	=	Parts per million
Prod.	=	Production
RB	=	Reservoir barrel
RF	=	Recovery factor
SCF	=	Standard cubic feet
SCFD	=	Standard cubic feet per day
STB	=	Stock tank barrel
STOIIP	=	Stock tank of oil initial in place

SYMBOLS AND ABBREVIATIONS (Continued)

Visc.	=	Viscosity
TSCF	=	Trillions of standard cubic feet
WOC	=	Oil/water contact

CHAPTER I

INTRODUCTION

1.1 Rationale

Oil recovery operations traditionally have been subdivided in to three stages: primary, secondary and tertiary. The primary production is the initial production stage, results from the use of natural energy present in a reservoir as main source of energy for the displacement of oil to producing wells. These natural energy sources are solution-gas drive, gas-cap drive, natural water drive, fluid and rock expansion, and gravity drainage. Some artificial lifts may be applied to the primary stage. The secondary recovery is the second stage of operations, usually was implemented after primary production decline. Traditional secondary recovery processes are water flooding, pressure maintenance, and gas injection to displace oil toward producing wells. The secondary recovery is now almost synonymous with water flooding. The tertiary recovery is the third stage of production, is that obtained after water flooding (or whatever secondary process was used). Because of such situations, the term “tertiary recovery” fell into disfavor in petroleum engineering literature and the designation of “enhanced oil recovery” (EOR) became more accepted. The process is used miscible gases, chemicals, polymer and/or thermal energy to displace additional oil. (Green and Willhite, 1998).

These research studies focus on the U-Thong oil field that is a part of the Suphan Buri Basin. The reservoir has low pressure, production requires an artificial lift system by using the sucker rod pump to pump crude oil to the surface. This research is to improve oil recovery by reducing the residual oil left in the reservoir. The two methods used in this study are the water flooding and polymer flooding techniques. The simulation software named “Eclipse” will be used to design the reservoir pattern and find efficiency for comparing economics.

1.2 Objectives of the Study

This study is on the application of the water flooding and polymer flooding for the reservoir of the U-Thong oil field in the Suphan Buri Basin by using the reservoir simulation. Efficiency of crude oil recovery and economics will be compared to find the best method for the reservoir.

1.3 Scopes and Limitations of the Study

2.3.1 Collect and study data of reservoir in U-Thong oil field.

2.3.2 Find oil recovery efficiency for water flooding and polymer flooding by using simulation program in the Eclipse Office when changes the reservoir data, year to injected.

2.3.3 Analyze data and compare economics of water flooding and polymer flooding. Determine the best Internal Rate of Return (IRR) and Net Present Value (NPV) and Profit to Investment Ratio (PIR).

1.4 Research Methodology

1.4.1 Literature Review

The review include detail of Suphan Buri Basin overview, geological information and stratigraphy, theory of water and polymer flooding, and case studies of water and polymer flooding. Literature review has been carried out to study the state-of-art of water and polymer flooding technique.

1.4.2 Data Collection and Preparation

The sources of reservoir modeling data and some additional geological data are provided by PTT Exploration and Production Public Company Limited, the published documents, such as American Association of Petroleum Geologist (AAPG), Society of Petroleum Engineers (SPE).

1.4.3 Reservoir Simulation

The reservoir simulators are complex computer program that simulate multiphase displacement processed in two or three dimensions. Reservoir modeling is constructed as hypothetical model by “ECLIPSE Office E100”, black oil simulation software must be done for these studies, and then used to predict its dynamic behavior. It solves the fluid-flow equation by using numerical techniques to estimate saturation distribution, pressure distribution, and flow of each phase at discrete points in a reservoir. The reservoir rock properties (porosity, saturation and permeability), the fluid properties (viscosity and the PVT properties) and other necessary data were collected and obtained from literature reviewing, concessionaire result and theoretical assumptions. Data are also based on U-Thong oil field in Suphan Buri Basin.

1.4.4 Economic Evaluation

Economic evaluation is calculated from results of reservoir simulator. This calculated from the reservoir simulator's results; optimum oil, gas and water production rate, cumulative oil production recovery, such as capital costs, operating costs, anticipated revenues, contract terms, fiscal (tax) structure, forecast oil prices, the timing of the project, and the expectation of the company in the investment. Different method of water and polymer flooding scenarios were analyzed to determine the potentially most economically viable project, time to start water or polymer injection for each reservoir, were simulated and analyzed to determine the suitable time that meet the economic criteria for each projects.

1.5 Expected Results

The research involves improving of the oil recovery and minimizing oil left in the reservoir by using water and polymer flooding techniques. Simulation results are useful as supporting information to study improved oil recovery in onshore fields in Thailand. The research will be informatively support for the oil companies to increase oil reserves for the country. The economic analysis of the simulation results can apply to advice management on the attractiveness of such investment opportunities, to assist in selecting the best method, and lead to maximize the value of the existing assets by water and polymer flooding project.

1.6 Thesis Contents

Chapter 1 states the rationale, research objectives, scope and limitations of the study, research methodology and expected result. **Chapter 2** summarizes results of the literature review of Suphan Buri Basin overview, water and polymer flooding and reservoir simulation method. **Chapter 3** describes the reservoir simulation data preparations, model characteristics, classification and case study description. **Chapter 4** illustrates result of water and 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** illustrates simulation data. **Appendix B** illustrated polymer data. The changes of oil saturation are shown in **Appendix C.**

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CHAPTER II

LITERLATURE REVIEW

2.1 U-Thong oil field

In 1993 Petroleum Authority of Thailand Exploration and Production Public Company Limited, or PTTEP, purchased the petroleum exploration and production business from BP Petroleum Development Co., Ltd. (Thailand) to produce crude oil in the area with covering Suphan Buri and Nakhon Pathom provinces, became known as the PTTEP1 project. This project started with two oil including fields U-Thong and Kamphaeng Saen. In 2002 Sang Kajai was discovered in Suphan Buri province. This is considered the first project that has been explored, developed, produced, and operated by a Thai company. The U-Thong field is 80 km north-west of Bangkok. Covering an area of approximately 5.06 square kilometers in Suan Taeng subdistrict, Mueang and U-Thong district, Suphan Buri province. The field has nine production wells and one injection well (Figure 2.1).

2.2 Basin type

The Suphan Buri Basin is an onshore Tertiary rift basin with over three kilometers of sediment fills (Pisutha-arnond *et al.*, 2000). The basin is a simple rift basin with western thickening halfgraben geometry. The boundary fault has a maximum displacement in its central part (O'Leary and Hill, 1989 and Seusuthya and Morley, 2004). The basin formed on the N-S trending suture zone between Shan-Thai and Indochina continental blocks. The suture is believed to have developed in the Early to Middle Triassic (Win, T. N., 2007).

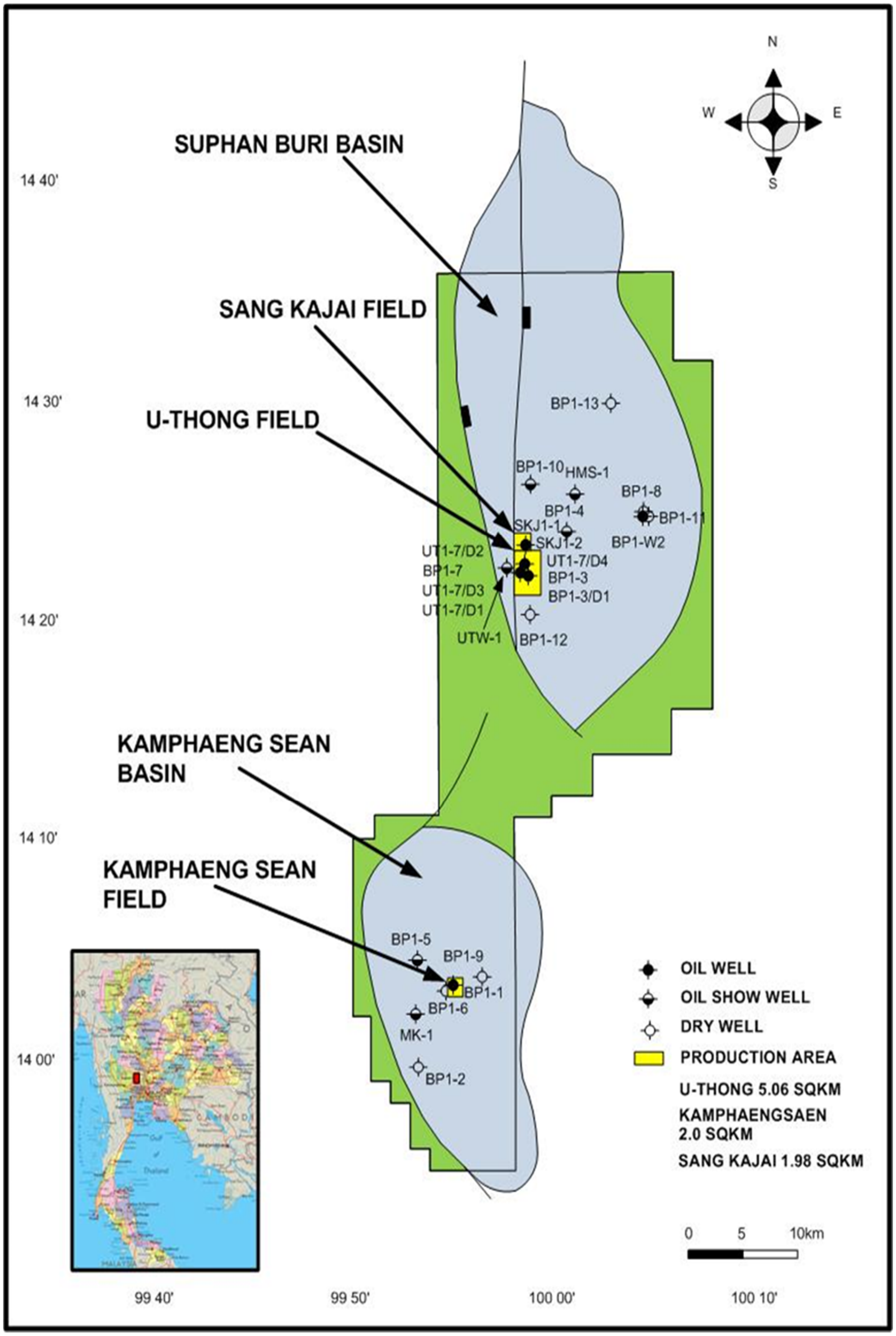


Figure2.1 Location map of Suphan Buri Basin (modified after PTTEP, 2006).

A Syn- rift sediments are late Oligocene-Miocene age (O'Leary and Hill, 1989). Two strike-slip fault zones occur north and south of the basin (Figure 2.2): the Mae Ping fault zone locates in the north and the Three-Pagoda fault zone locates in the south of basin (Buayai, 2005).

2.3 Stratigraphy

The stratigraphic analysis of Suphan Buri Basin is initially established by BP in 1987 based on the seismic sequence stratigraphy and stratigraphic wells. The basin fill was interpreted to comprise sandstone, conglomerate and mudstone that were deposited in alluvial fans and fringes, deltas, lakes, fluvial channels and flood-plains. BP has identified eight Tertiary depositional sequences from bottom to top as shown in Figure 2.3 and explained below (Gawthorpe, 1987).

Sequence 90 (S90): represents the basement, which consists of sandstone, mudstone and carbonate or metasedimentary of Pre-Tertiary age.

Sequence 80 (S80): consists of predominantly coarse-grained alluvial fan sandstones and conglomerates of marginal reservoir quality, fining upwards into shallow lacustrine mudstones with thin intervals of prograding, good reservoir quality, alluvial fan sandstones.

Sequence 70 (S70): predominantly consists of lacustrine mudstones with occasional thin turbiditic sandstones. This sequence is regarded as the principal source for hydrocarbons in the basin.

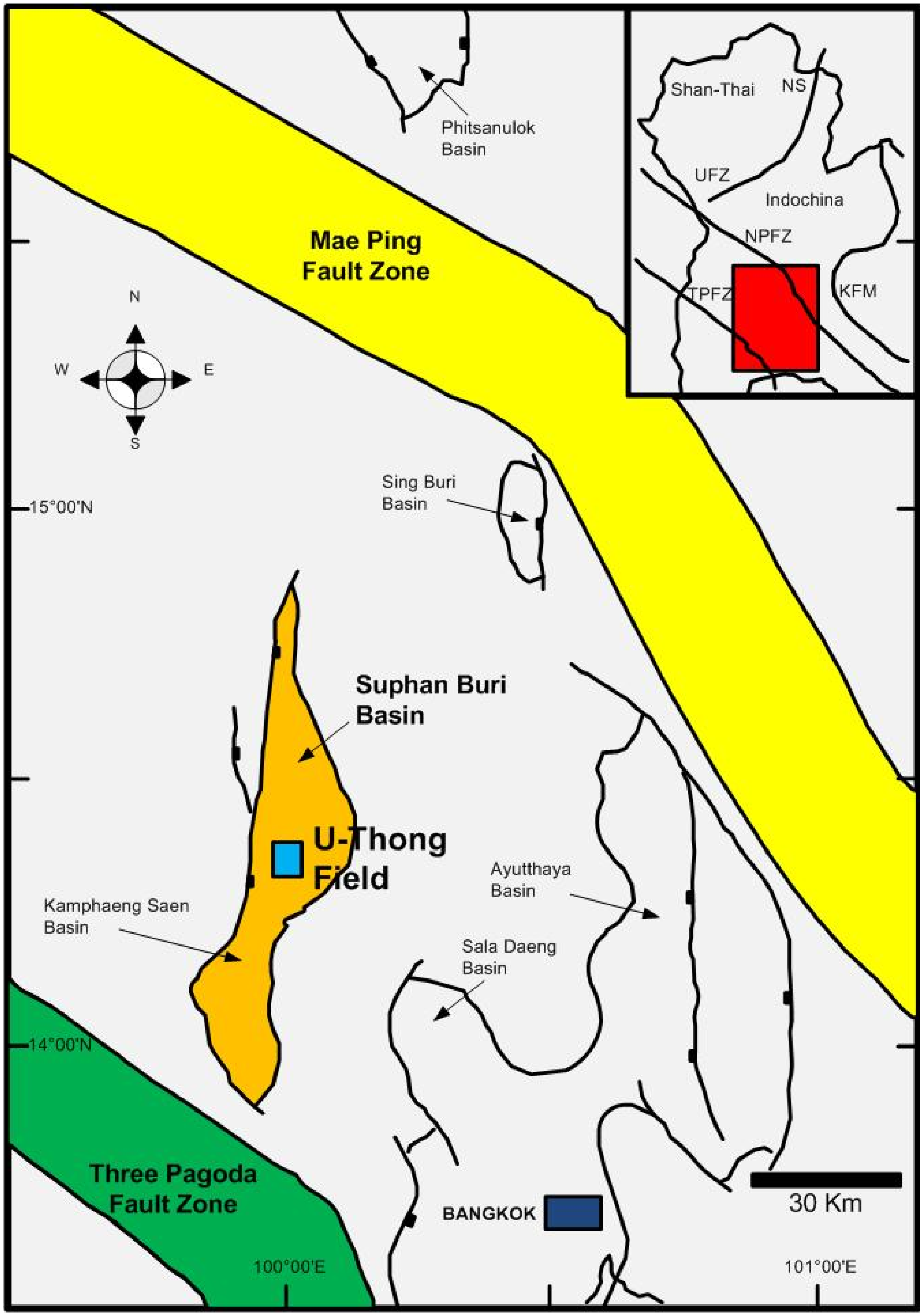


Figure 2.2 Location and structural features of U-Thong Oil Field, Suphan Buri Basin (modified after Jantarangsi, 1999).

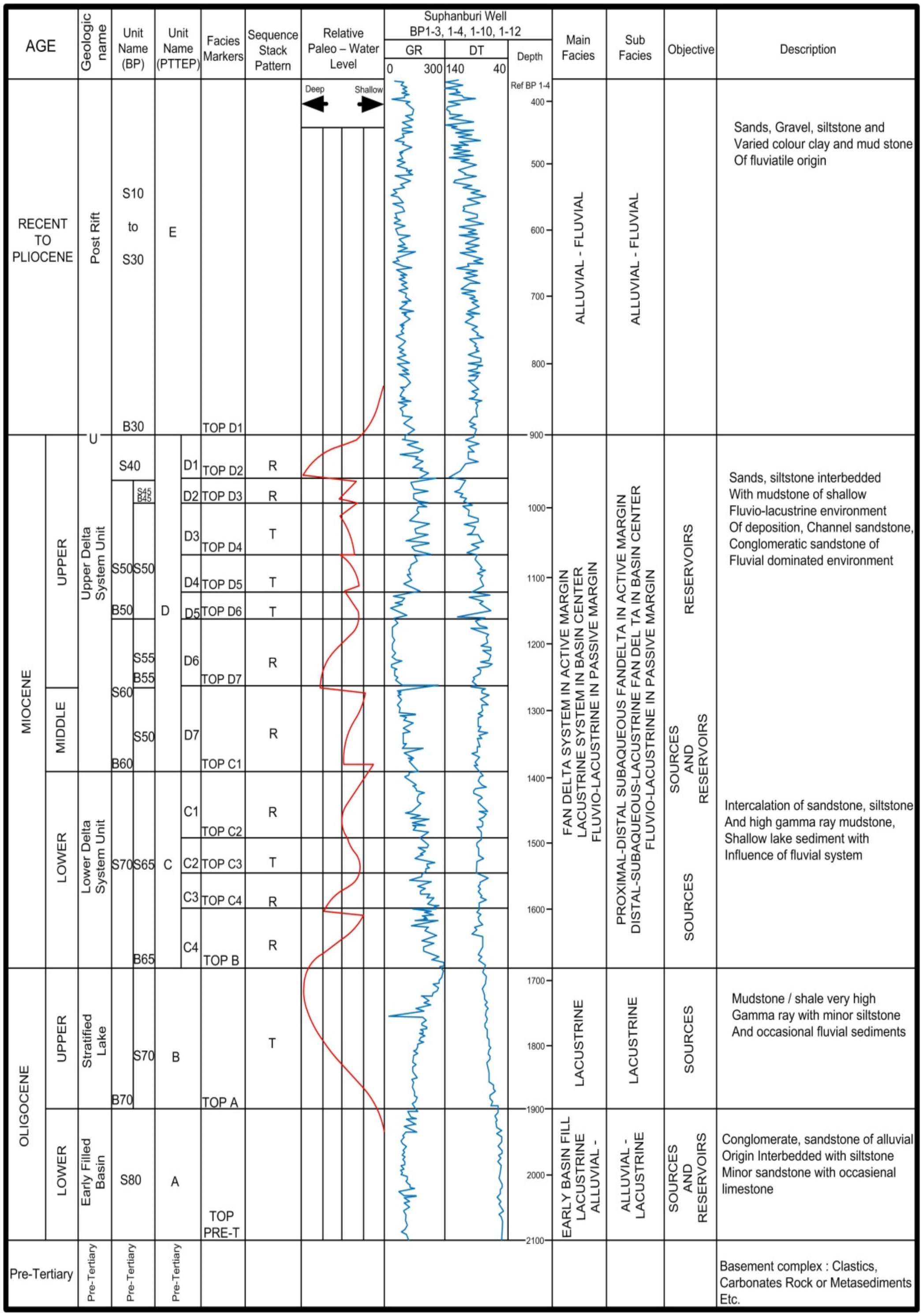


Figure 2.3 General Stratigraphy of the Suphan Buri Basin

(Tongpenyai *et al.*, 2000).

Sequence S60: was interpreted as a shoaling-upward deposit of a shallow lacustrine to fluvial flood-plain environment. It consists of siltstone and minor sandstone. Well data show no reservoir potential.

Sequence 60 (S60): is interpreted as a shoaling-upward deposit of a shallow lacustrine to fluvial flood-plain environment. It predominantly consists of siltstones and minor sandstones. Well data show no reservoir potential.

Sequence 50 (S50): predominantly consists of mudstones with minor siltstones, which are interpreted as shallow lacustrine deposits with moderate clastic input.

Sequence 40 (S40): mainly comprises mudstones and shales, which are interpreted as lacustrine deposits.

Sequences 30-10 (S30-S10): are interpreted as alluvial flood-plain deposits (sequence S30), and predominantly fluvial channel/flood-plain in sequences S20 and

In 1993, PTTEP revised the stratigraphy into five units, namely A, B, C, D and E units starting from bottom up to top as illustrated in Figure 3. Detailed descriptions of each unit are discussed as follows (Tongpenyai *et al.*, 2000);

Unit A: This unit consists mainly of early basin fill sediments which comprises mainly of sandstones and conglomerates with interbedded siltstones, mudstones, and occasional limestones. In terms of seismic characters, this unit shows a pattern of discontinuous reflectors and interfaces with low amplitude contrasts between the overlying and underlying sequences.

Unit B: It is believed to be deposited during a period of stratified lake environment. The sediments are mainly composed of lacustrine mudstones with minor siltstones and occasional fluvial sediments. The upper part of this unit grades into fluvial-lacustrine sediments, which is characterized by a pattern of low amplitude with poor to moderate continuity of seismic reflectors.

Unit C: Unit C is interpreted as lacustrine fan deltaic environment, lower lacustrine unit with an overall regressive stacked pattern. The sediments are composed of the intercalation of sandstones, siltstones and mudstones. The seismic character is easily recognized by its very high amplitude and good continuity, overlying a low amplitude interval of unit B.

Unit D: This is a main reservoir interval of U-Thong oil field. It is an upper lacustrine fan deltaic unit (or an upper regressive stacked pattern). The unit contains predominantly sandstone and siltstones with interbedded shallow lacustrine mudstones. Unit D is subdivided into D1 to D7. In D2 unit is subdivided into 3 reservoir units (KR1-1, KR1-2 and KR1-3. The D3 unit is subdivided into 7 reservoir units (KR2-1, KR2-2, KR2-3, KR2-4, KR2-5, KR2-6 and KR2-7). For the different intervals between top of D2 (top of KR1-1) and top of D3 (top of KR2-1), they are about 33 m. The main sediment supply for U-Thong area is believed to come from west-southwest of the Suphan Buri.

Unit E: This unit is the uppermost Cenozoic sediment, which comprises mostly of unconsolidated sands, gravel, and varied color clays of fluviatile origin with occasional limestone. The lower boundary of this unit is easily identified by a contrast between the high amplitude, good continuity seismic characters of the underlying unit and its low amplitude, poor continuity seismic character of the E unit itself.

Ronghe and Surarat (2002) classified two styles of sand distribution in unit D based on the interpretation of seismic impedance. These styles are axial deposits comprising channel sourced deltas (prograded from south to north, down plunge into the basin) and boundary fault-induced deposit comprising fan deltas (transported perpendicular to the fault). Sand-filled feeder canyon transported sediments northeastward downslope to merge with the rift-floor fan delta deposit.

As per interpretation of seismic images, the coarse-grained sediment was transported from two sources: from the south and from the west across the boundary fault. O'Leary and Hill (1989) made the paleogeography reconstruction. They proposed that fluvial systems drained the western highlands and fed into the Suphan Buri Basin show in Figure 2.4

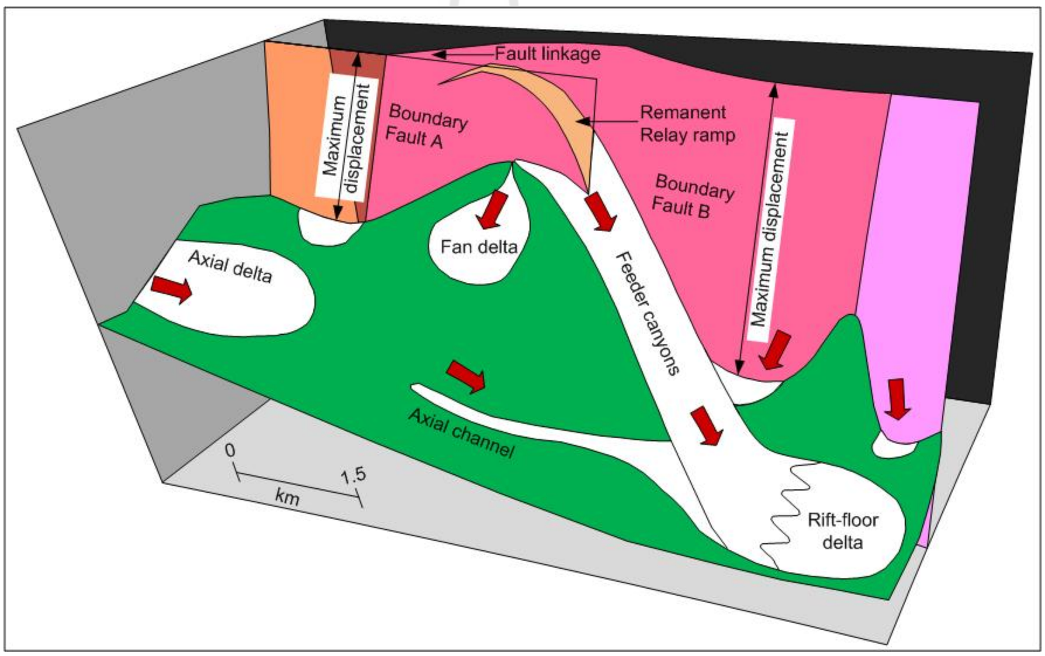


Figure 2.4 Summary Geological model of Suphan Buri basin.

(modified after Ronghe and Surarat, 2002).

2.4 Water flooding

Secondary recovery actually consists of replacing the natural reservoir drive or enhancing it with an artificial, or induced, drive. Generally the use of injected water or natural gas into the production reservoir is the most common method. When water is used it is referred to as water flooding. The first known water flooding was by accident, an abandoned oil well was being used as a disposal salt water well when it was noticed that production of nearby wells was increasing as more water was being dumped. Some of the first water flooding was accomplished by drilling a well (Figure 2.5), or a series of wells, on the perimeter of the reservoir and injecting water under pressure (Bill and Kenneth, 1992).

A method used water to inject into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. Potential problems associated with water flooding techniques include inefficient recovery due to variable permeability, or similar conditions affecting fluid transport within the reservoir, and early water breakthrough that may cause production and surface processing problems (Schlumberger Oilfield Glossary, 2000).

2.5 Case Study of Water Flooding

2.5.1 Suphan Buri Basin, U-Thong field

Suphan Buri Basin, U-Thong Field is the studied area to improve oil recovery by water flooding. It is constructed as hypothetical model while its geological, petrophysical and production data are based on the data from this field. The reservoir simulation study is divided into 5 cases; case 1 has no water injection and four cases which have water injection in different flood patterns. For three years, it can be produced about 0.58 MMSTB or 10% of original oil in place (OOIP).

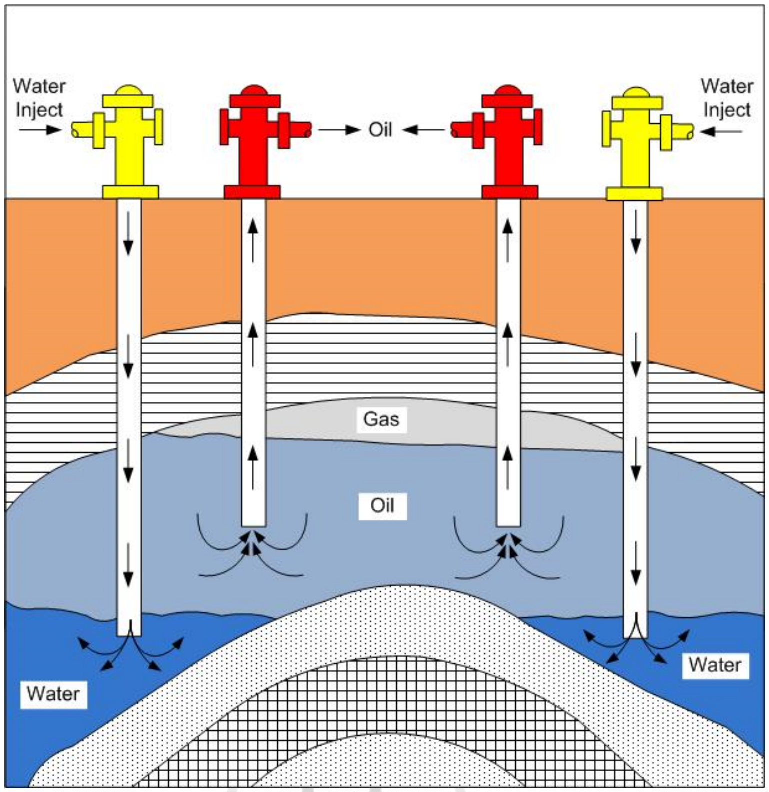


Figure 2.5 Water flooding method (modified after Berger & Anderson, 1992).

After that, the field has been continued to produce oil for 15 years. For case 1 without waterflooding, it can be produced oil recovery factor by 11.93%. The other 4 cases with waterflooding production, they are increased to 17.59%, 34.69%, 36.10%, and 36.55%, respectively. It shows that case 1 has no water injection; it provides the minimum of oil recovery factor. On the other hands, cases 4 and 5 which have four injection wells, they can be produced a largest amount of oil production about 3.20 and 3.23 MMSTB. In four cases of waterflooding, they can be calculated the displacement efficiencies about 0.55, 0.58, 0.60, and 0.59, respectively.

In economic analysis, for cases 4 and 5 can be produced maximum of oil production but there is higher investment than other cases. As a result, they are not suitable for development. Therefore, case 3 is the best case operation in development plan due to economic values which are more favorable than the other cases. The benefits of this study will improve the knowledge of waterflooding including the ability to use reservoir simulation. The simulation model and results can be applied for study of improving oil recovery by water flooding in other fields (Rattanapranudej, 2004).

2.5.2 The Sirikit oil field

The oilfields in the Sirikit area are situated within Phitsanulok Basin. The basin has an areal extent in order of 6,000 square kilometers formed as a result of the relative movement of the Shan Tai and Indonesian blocks. The Sirikit oil field is geologically very complex. The geological complexity is a product of the multiphased structural history and the interaction between faulting and deposition through time. The water flooding is one of the successful projects which have been developed in the Sirikit oil fields. The water flood project started as early as 1983. A small pilot project in a small area of LKU-E block was designed to test the viability of injecting water into the complex sand shale inter-bedded layers of the Lan Krabu formations. It was proved that the pilot test could maintain pressure under a non-fracturing condition. So it was indicated that the water flooding of Lan Krabu reservoir was feasible. The water flooding project had studies again during 1993-1994. It gave a boost to the confidence in recovery factor of the field, which increased over 20% for the first time. The discovery of oil in Pradu Tao and Yom reservoirs during 1997-1998 gave another upgrade to the recovery factor to a level of around 25%. The implement of the previous water flood project encountered many operational difficulties, but proved water flood to be a technically viable secondary recovery technique in the Sirikit complex reservoirs. Reviews and studies of reservoir performances and simulations of the Sirikit reservoirs indicated that a reserves volume is recoverable only through water flood of the Sirikit reservoirs. Recent disappointing results of new infill wells confirmed that the plans to drill hundreds of infill wells would not be as effective as water flooding. With the advanced of computer modeling techniques compared to 10 years ago, the confidence of successfully implementing water flooding projects in the Sirikit field has been reviewed (Wongsirasawad, 2002).

2.5.3 The Jay-LEC field

The Jay-LEC Field has produced from the Smackover carbonate and Norphlet sand formations at depth about 15,400 ft. An oil/water contact is located at a sub-sea depth of 15,480 ft. More than 90% of the oil in place is in Smackover. The reservoir study indicated that natural water drive would not be effective source of reservoir energy. Thus, water flood was selected among other possible processes to maintain pressure for increasing oil recovery. The water flooding plan in Smackover formation was developed by using a two-dimensional (2-D) simulation to compare alternative flooding schemes. Four water flood plans were evaluated: (1) peripheral flood, (2) five-spot pattern (3) a 3:1 staggered line-drive pattern and (4) a combination of peripheral wells and five-spot patterns. From the results of the 2D simulator indicated that the peripheral flood was not effective. For the remaining three water flooding plans, the 3:1 staggered line-drive plan was recovered more than 200 MMBBL. The 3:1 plan yielded 9.8 MMBBL incremental oil recoveries over the five-spot plan and 14.4 MMBBL over the combination pattern. Moreover the 3:1 plan also has advantages for development plan and economic potential (Willhite, 1986).

2.5.4 The Mean field

The Means field in Andrews County, Texas, was discovered in 1934 and developed on 40-acre spacing in early 1950's. Production is from the Grayburg and San Andres formation at depths ranging from 4,200 to 4,800 ft. The Grayburg is about 400 ft. thick with the basal 100 to 200 ft. considered gross pay. Production from Grayburg was by solution-gas drive with the bubble point at the original reservoir pressure of 1,850 psi. The waterflood program was initiated after the operators in the area authorized a major reservoir study to evaluate secondary recovery. Highlights of this study included one of Humble's first full-field computer simulations. For this study, additional data had to be accumulated, including logging, fluid sampling and core data. It was recommended that waterflooding should be initiated on a peripheral pattern that would encompass the more prolific Lower San Andres. A five-spot pattern was implemented later when needed. For the Grayburg, a lease-line pilot with the portion of the field west of the unit was recommended. In 1963, the field was unitized and water injection began with 36 wells, forming a peripheral pattern. The reservoir study was reviewed again in 1969 due to the peripheral injection pattern could no longer provide sufficient pressure support. Barber (Stile and Magruder, 1992) reported the results of a detailed engineering and geologic study conducted during 1968-1969 to determine a new depletion plan more consistent with capacity production. Analysis of pressure data from the pressure observation wells indicated that parts of the South Dome were not receiving adequate pressure support from the peripheral injectors. This study recommended interior injection with a three-to one-line drive following implementation of this program. Production increased from 13,000 bbl/d in 1970 to more than 18,000 bbl/d in 1972. After peaking in 1972, production began to decline again. An in-depth reservoir study indicated that all the pay was not being flooded effectively by the three-to-one line drive pattern. Hence the geologic study provided that the basis for a secondary surveillance program and later to design and implement of the CO_2 tertiary project (Stiles and Magruder, 1992).

2.5.5 The Fahud field

A fracture model was constructed for the Natih-E reservoir unit of the Fahud field in north Oman. The fracture model indicates that the current gas/oil gravity drainage (GOGD) recovery mechanism is an inefficient oil recovery method for a large part of the lower Natih-E. The optimum well pattern for a waterflood development within two Natih-E subunits is proposed on the basis of simulation results. Nicholls et al (2000) studies the fracture modeling and they expected that the oil recovery is increased from 17 % under GOGD to 40% for the waterflood. A fracture model that includes information from well production and injection performance, borehole-image data, structural map, and fault data has been constructed foe the Natih-E containing sparse and widely spaced fractures. A pilot water injection cell of two horizontal procedures and one injector well oriented parallel to the bedding strike has shown that water injection is a viable alternative to GOGD (Nicholls et al, 2000).

2.5.6 The Statfjord Field

The Statfjord field is the largest producing oil field in Europe. The field was discovered in March 1974. The Statfjord field, which is 15 miles long and averages 2.5 miles in width, is located in a westerly tilted and eroded Jurassic fault block. About 75% of the main recoverable reserves are located in the middle Jurassic Brent group, while the remaining 25% is in the Lower Jurassic/ Upper Triassic Statfjord formation. The estimated ultimate recovery is around 3,000 MMBBL of oil and 3.0 TSCF of gas. Both Brent and Statfjord reservoir contain highly under saturated low sulfur crude oil. The one of reservoir development strategy is to develop the upper and lower Brent as separate reservoirs with pressure maintenance by water injection. The Brent reservoir had a common initial oil/water contact (WOC) and equal reservoir pressure. The original reservoir pressure was 5,561 psia, about 1,550 psia higher than the bubble point pressure. The average reservoir pressure is maintained at around 4,500 psia by balancing total fluid production with water injection. All wells are anticipated to produce with flowing BHP above the BP. In fact, the minimum reservoir pressure was reached in late 1986 if there is no waterflood. The maximum oil production is around 630,000 STB/D and 1,050,000 B/D of water is injected into the Brent reservoir (Haugen et al, 1988).

2.6 Polymer flooding

Polymer flooding is a type of chemical flooding to control drive-water mobility and fluid flow patterns in reservoirs. Polymer-long, chainlike, high-weight molecules have three important oil recovery properties. They increase water viscosity, decrease effective rock permeability and are able to change their viscosity with the flow rate. Small amounts of water-dissolved polymer increase the viscosity of water. This higher viscosity slows the progress of the water flow through a reservoir and makes it less likely to bypass the oil in low permeability rock (Gerding, 1986). The figure 2.6 (Bradley, 1987) 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.

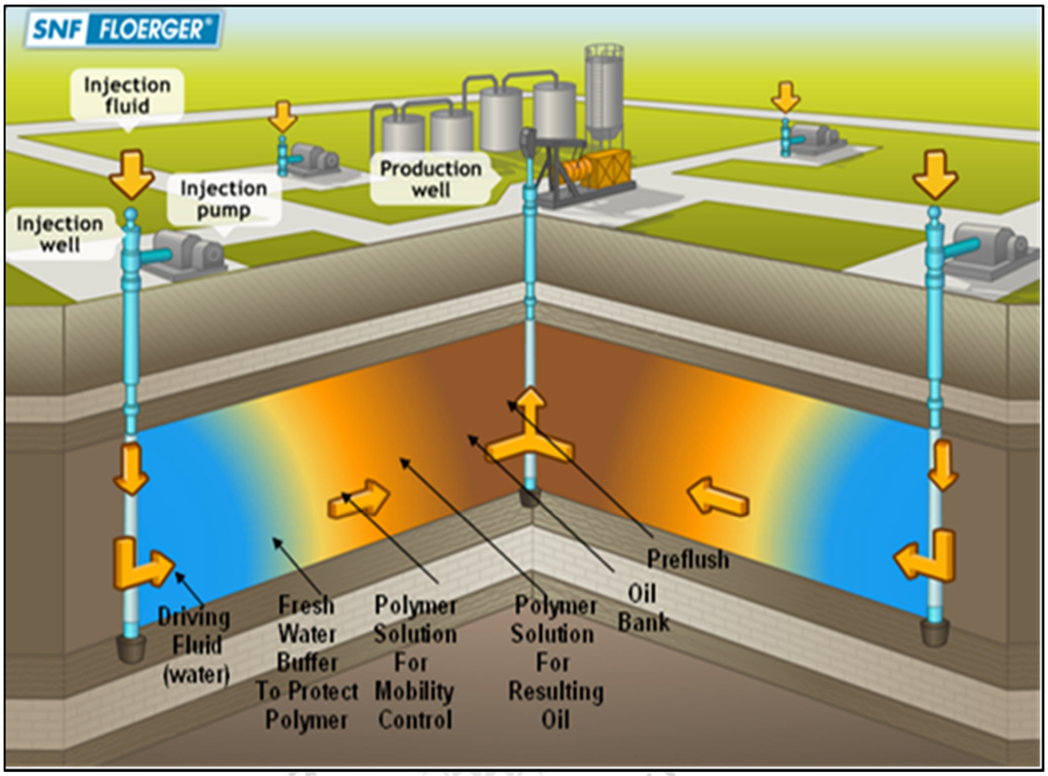


Figure 2.6 Polymer flooding method (Bradley, 1987).

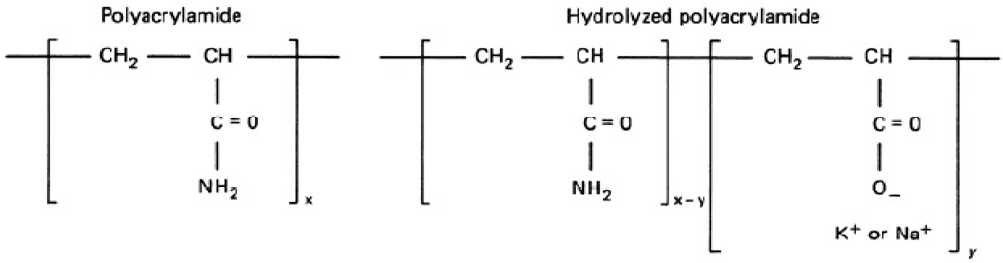
2.6.1 Polymer type

According to Noianusontigul (2008), several polymers have been considered for polymer flooding; Xanthan gum, hydrolyzed polyacrylamide (HPAM), copolymers (a polymer consisting of two or more different types of monomers) of acrylic acid and acrylamide, copolymers of acrylamide and 2-acrylamide 2-methy l propane sulfonate (AM/AMPS), hydroxyethylcellulose (HEC), carboxymethylhydroxyethylcellulose (CMHEC), polyacrylamide (PAM), polyacrylic acid, glucan, dextran polyethylene oxide (PEO), and polyvinyl alcohol. Although only the first three have actually been used in the field, there are many potentially suitable chemicals, and some may prove to be more effective than those new used. Polymer can be commercially categorized in two types:

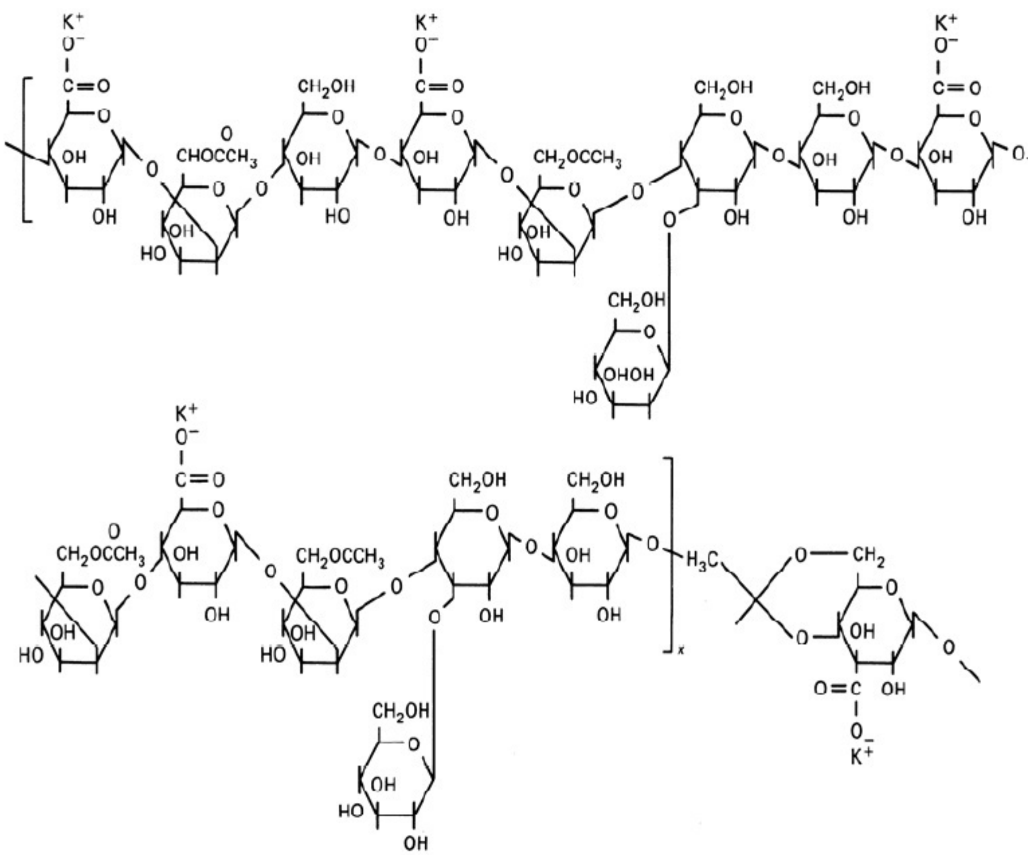
2.6.1.1 Polyacrylamides (PAM)

These polymers' monomeric unit is the acrylamide molecule (Figure 2.7a). When used in polymer flooding, polyacrylamides have undergone partial hydrolysis, which causes anionic (negatively charged) carboxyl (-COO-) to be scattered along the backbone chain. For this reason these polymers are called partially hydrolyses polyacrylamides (HPAM). Typical degrees of hydrolysis are 30-35% of the acrylamide monomers; hence the HPAM molecule is negatively charged, which accounts for many of its physical properties. This degree of hydrolysis has been selected to optimize certain properties such as water solubility, viscosity, and retention. If hydrolysis is too small, the polymers will not be water-soluble. If it is too large, the polymers will be too sensitive to salinity and hardness.

The viscosity-increasing feature of HPAM lies in its large molecular weight. This feature is accentuated by the anionic repulsion between polymer molecules and between segments in the same molecule. The repulsion cause the molecule in solution to elongate and snag on those similarly elongated, an effect that accentuates the mobility reduction at higher concentrations.



(a) Molecular structure of polyacrylamide.



(b) Molecular structure of polysaccharide (biopolymer).

Figure 2.7 Molecular structures, (Lake, 1989).

If the brine salinity or hardness is high, this repulsion is greatly decreased through ionic shielding since the freely rotating carbon-carbon bonds allow the molecule to coil up. The shielding causes a corresponding decrease in the effectiveness of the polymer since snagging is greatly reduced. Almost all HPAM properties show a large sensitivity to salinity and hardness, which is an obstacle to use HPAM in many reservoirs; on the other hand, HPAM is inexpensive and relatively resistant to bacterial attack, and it exhibits permanent permeability reduction.

2.6.1.2 Polysaccharides

Another widely used polymer, a biopolymer, is xanthan gum (corn sugar gum). This kind of polymer is formed from the polymerization of saccharide molecule (Figure 2.7b), a bacterial fermentation process. This process leaves substantial debris in the polymer product that must be removed before the polymer is injected. The polymer is also susceptible to bacterial attack after it has been introduced into the reservoir. The disadvantages are also offset by the insensitivity of polysaccharide properties to brine salinity and hardness. The polysaccharide molecule is relatively non-ionic and, therefore, free of the ionic shielding effects of HPAM. Polysaccharides are more branched than HPAM, and the oxygen-ringed carbon bond does not rotate fully; hence the molecule increase brine viscosity by snagging and adding a more rigid structure to the solution. Polysaccharides do not exhibit permeability reduction. Molecule weights of polysaccharides are generally around 2 million.

From the study in thermal and rheological of polysaccharides, at 55 and 65ºC an increase in viscosity values was observed. This behavior is interesting for polymer flooding operations into the reservoir, temperatures are in this level or still higher, the cost of polymer could be reduced. Xanthan is supplied as a dry powder or as a concentrated broth. It is often chosen for a field application when no fresh water is available for flooding. Some permanent shear loss of viscosity could occur for polyacrylamide, but not for polysaccharide at the wellbore. It is an advantage in offshore operations.

HPAM is less expensive per unit amount than polysaccharides, but between compared on a unit volume of mobility reduction, particularly at high salinities, the costs are close enough so that the preferred polymer for given application is site specific (Manning et. al., 1983).

2.6.2 Polymer flow behavior in porous media

2.6.2.1 Polymer retention

According to Maheshwari (2011), retention of polymer in a reservoir includes adsorption, mechanical trapping, and hydrodynamic retention. Adsorption refers to the interaction between polymer molecules and the solid surface. This interaction causes polymer molecules to be bound to the surface of the solid, mainly by physical adsorption, and hydrogen bonding. Mechanical entrapment and hydrodynamic retention are related and occur only in flow-through porous media. Retention by mechanical entrapment occurs when larger polymer molecules become lodged in narrow flow channels. The level of polymer retained in a reservoir rock depends on permeability of the rock, nature of the rock (sandstone, carbonate, minerals, or clays), polymer type, polymer molecular weight, polymer concentration, brine salinity, and rock surface.

2.6.2.2 Inaccessible pore volume

When size of polymer molecules is larger than some pores in a porous medium, the polymer molecules cannot flow through those pores. The volume of those pores that cannot be accessed by polymer molecules is called inaccessible pore volume (IPV). The inaccessible pore volume is a function of polymer molecular weight, medium permeability, porosity, salinity, and pore size distribution. In extreme cases, IPV can be 30% of the total pore volume.

2.6.2.3 Permeability reduction and the resistance factor

Polymer adsorption/retention causes the reduction in apparent permeability. Therefore, rock permeability is reduced when a polymer solution is flowing through it, compared with the permeability when water is flowing. This permeability reduction is defined by the permeability reduction factor:

$$R_k = \frac{k_w}{k_p} \tag{2.1}$$

where R_k = Permeability reduction factor

k_w = Rock permeability when water flows

kp = Rock permeability when aqueous polymer solution flows

The resistance factor is defined as the ratio of mobility of water to the mobility of a polymer solution flowing under the same conditions

$$R_f = \frac{\frac{k_w}{\mu_w}}{\frac{k_p}{\mu_w}} \tag{2.2}$$

where Rf = The resistance factor

μ_o, μ_w = viscosity of oil and water, cp

The residual resistance factor is the ratio of the mobility of water before to that after the injection of polymer solution

$$R_{rf} = \left(\frac{\frac{k_w}{\mu_w}}{\frac{k_p}{\mu_w}}\right) a \tag{2.3}$$

where R_{rf} = The residual resistance factor

Residual resistance factor is a measure of the tendency of the polymer to adsorb and thus partially block the porous medium. Permeability reduction depends on the type of polymer, the amount of polymer retained, the pore-size distribution, and the average size of the polymer relative to pores in the rock.

2.6.2.4 Relative permeability in polymer flooding

Some of the researchers have proved from their experiments that polymer flooding does not reduce residual oil saturation in a micro scale. The polymer function is to increase displacing fluid viscosity and thus to increase sweep efficiency. Also, fluid viscosities do not affect relative permeability curves. Therefore, it is believed that the relative permeability in polymer flooding and in water flooding after polymer flooding are the same as those measured in waterflooding before polymer flooding.

2.6.2.5 Polymer rheology in porous media

The rheological behavior of fluids can be classified as Newtonian and Non-Newtonian. Water is a Newtonian fluid in that the flow rate varies linearly with the pressure gradient, thus viscosity is independent of flow rate. Polymers are Non-Newtonian fluids.

Rheological behavior can be expressed in the terms of apparent viscosity which can be defined as:

$$\mu = \frac{\tau}{\gamma} \tag{2.4}$$

where τ = shear stress

γ = shear rate

The apparent viscosity of polymer solutions used in EOR processes decreases as shear rate increases. Fluids with this rheological characteristic are said to be shear thinning. Materials that exhibit shear thinning effect are called pseudo plastic. Polysaccharides such as Xanthan are not shear sensitive and even high shear rate is employed to Xanthan solutions to obtain proper mixing, while polyacrylamides are more shears sensitive. Most significant change in polymer mobility occurs near the wells where fluid viscosities are large.

2.7 Case study of polymer flooding

2.7.1 Polymer injection at Daqing oil field (China)

Daqing oil field is a large non-marine sandstone reservoir onshore oil field. 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 (Liu He et al., 2009). The study of polymer injection has been done both in the laboratory to injection testing and in the field (Thang, 2005).

The studies have started since 1985 with two main purposes as follows: 1) Selecting the type of polymer, 2) 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. The quantity of absorbed polymer determined on sample was 20-25 % of the quantity of polymer injection. The test was conducted in two adjacent blocks, PO and PT.

PO pilot: The beginning of water injection in December of 1989 with flow rate of 629 bbl/d 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/d to 943 bbl/d. 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/d. 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 bbl/d to 1,447 bbl/d. PT pilot has used 285 tones of polymer injection and produced 750,000 bbl of oil. The efficiency of polymer injection about 2,625 bbl of oil/tones of polymer. Oil recovery increases 11.5% OOIP.

2.7.2 Feasibility study of secondary polymer flooding in Henan oil field (China)

Henan oil field is the second largest oil field in Henan Province, People's Republic of China. It is located in Nanyang region. The field was discovered in 1970s. It has accumulated proven oil reserves of 2.7 billion tons. It is operated by Sinopec Henan oil field Company, a subsidiary of Sinopec (Wikipedia, 2012). During 1996 to 2006, polymer flooding was implemented in Henan oil field, with average 70 mPa.s of crude oil viscosity and reservoir temperature of 55˚C, polymer of 0.42PV to 0.44PV was injected with above 8% of enhanced recovery. In the next water flooding, water cut arise rapidly, and part of lower permeability zones were not development, therefore it is necessary to employ relay technology to retain yield. In the other hand, the total produced degree is less than 35%, that is to say, more than 65% of residual crude oil still exists in underground, and both vertical and plane heterogeneity are serious. Therefore, according to characteristic of crude oil and formation, a series of laboratory experiments to study the feasibility of secondary polymer flooding were carried, including microscopic mechanism study and macroscopic physical modeling. In addition, the polymer concentration must be optimized to ensure recovery effect and economics. Filed trial with above optimum parameters was implemented. Up to 2008.12, water cut decreased from 92% to 83%, and cumulative increased crude oil of above 50000 tones.

2.8 Recovery efficiency

A key factor in the design of a water or polymer flooding is the estimation of the oil recovery. This factor indicates the portion of the initial oil in place that can be economically recovered by water injection. In equation form, the oil recovery by water or polymer flooding can be expressed by

$$Np = NE_AE_VE_D \tag{2.5}$$

where Np = Cumulative Water flooding Recovery, bbl

N = Oil in Place at Start of Injection, bbl

E_A = Areal Sweep Efficiency, Fraction

E_V = Vertical Sweep Efficiency, Fraction

E_D = Displacement Efficiency, Fraction

2.8.1 The displacement efficiency

The displacement efficiency E_D is the fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Because an injection fluid (water or polymer) will always leave behind some residual oil, E_D will always be less than 1, the displacement efficiency can be expressed by

$$E_D = \frac{\text{Volume of oil at start of flood - Remaining oil volume}}{\text{Volume of oil at start of flood}} \tag{2.6}$$

$$E_D = \frac{(\text{Pore volume})(\frac{\bar{S}_{oi}}{B_{oi}}) - (\text{Pore volume})(\frac{\bar{S}_o}{B_o})}{(\text{Pore volume})(\frac{\bar{S}_{oi}}{B_{oi}})} \tag{2.7}$$

Or

$$E_D = \frac{(\frac{\bar{S}_{oi}}{B_{oi}}) - (\frac{\bar{S}_o}{B_o})}{(\frac{\bar{S}_{oi}}{B_{oi}})} \tag{2.8}$$

where $\bar{S}_{oi}$ = volumetric average oil saturation at the beginning of the water or polymer flooding, where the average pressure is $\bar{p}_1$, fraction

$\overline{S}_o$ = volumetric average oil saturation at a particular point during the water or polymer flooding

B_{oi} = oil FVF at pressure is pressure is $\overline{p}_1$, bbl/STB

B_o = oil FVF at a particular point during the water or polymer flooding, bbl/STB

When the oil saturation in the PV swept by water or polymer flooding is reduced to the residual saturation (S_{or}),

$$E_D = 1 - \left(\frac{S_{or}}{\overline{S}_{oi}}\right)\left(\frac{B_{oi}}{B_o}\right) \tag{2.9}$$

This becomes

$$E_D = 1 - \left(\frac{S_{or}}{\overline{S}_{oi}}\right) \tag{2.10}$$

Where S_{or} = residual oil, fraction

$\overline{S}_{oi}$ = volumetric average oil saturation at the beginning of the water or polymer flooding, where the average pressure is $\overline{p}_1$, fraction

2.8.2 The areal sweep efficiency

The areal sweep efficiency E_A is defined as the fraction of the total flood pattern that is contacted by the displacing fluid. It increases steadily with injection from zero at the start of the flood until breakthrough occurs, after which E_A continues to increase at a slower rate.

The areal sweep efficiency depends basically on the following three main factors:

- Mobility ratio M
- Flood pattern
- Cumulative fluid injected

2.8.3 The vertical sweep efficiency

The vertical sweep efficiency, E_V, is defined as the fraction of the vertical section of the pay zone that is the injection fluid. This particular sweep efficiency depends primarily on (1) the mobility ratio and (2) total volume injected. As a consequence of the nonuniform permeability, any injected fluid will tend to move through the reservoir with an irregular front. In the more permeable portions, the injected water will travel more rapidly than in the less permeable zone.

2.8.4 The mobility ratio

The mobility of a fluid is the effective relative permeability of that fluid divided by its viscosity. For an injection scheme, the mobility ratio (M) is the ratio of the mobility of the displacing fluid behind the flood front to that of the displaced fluid ahead of the flood front.

The mobility of any fluid λ is defined as the ratio of the effective permeability of the fluid to the fluid viscosity,

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o} \tag{2.11}$$

$$\lambda_w = \frac{k_w}{\mu_w} = \frac{kk_{rw}}{\mu_w} \tag{2.12}$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{kk_{rg}}{\mu_g} \tag{2.13}$$

where $\lambda_o, \lambda_w, \lambda_g$ = mobility of oil, water, and gas, respectively

μ_o, μ_w, μ_g = viscosity of oil, water, and gas, cp

k_o, k_w, k_g = effective permeability to oil, water, and gas, respectively

k_{ro}, k_{rw} = relative permeability to oil, water, and gas, respectively

k = absolute permeability

for water flooding,

$$M = \frac{\lambda_w}{\lambda_o} = \left(\frac{k_{rw}}{\mu_w}\right)\left(\frac{\mu_o}{k_{ro}}\right) \tag{2.14}$$

simplifying gives

$$M = \left(\frac{k_{rw}}{k_{ro}}\right)\left(\frac{\mu_o}{\mu_w}\right) \tag{2.15}$$

If mobility ratio $M \leq 1$, oil is capable of traveling with a velocity equal to or more than that water. 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.

CHAPTER III

RESERVOIR SIMULATION

3.1 General

Reservoir simulation is a technique in which a computer-based mathematical representation of the reservoir is constructed and then use to predict its dynamic behavior. Simulation is the only way to describe quantitatively the flow of multi-phases in a heterogeneous reservoir having a production schedule determined not only by the properties of the reservoir, but also by market demand, investment strategy, and government regulations. The reservoir is a gridded up into a number of grid blocks. The reservoir rock properties (porosity, saturation and permeability) and the fluid properties (viscosity and PVT data) are applied for each grid block. (Noianusontikul, 2008)

According to Tuan (2005), in the U-Thong oil, there are two main production zones: Upper zone (layer KR1-1 to KR2-5), and Lower zone (layers KR2-6 to KR2-8). Recovery factor of the upper zone is 5 percent and the lower zone is 30 percent. This difference in recovery factor because the Upper zone is believed to have a depletion drive mechanism and Lower zone is believed to have a water drive mechanism. In this study is applied from Lower zone only.

3.2 Reservoir simulation model

This study used black-oil reservoir simulation by Eclipse Office E100 to simulate all type of reservoir (primary, secondary and tertiary productions) which based on available data of U-Thong oil field and some of data assumptions. The structure of reservoir simulation is show in figure 3.1-3.2 and the detail summarize as follow:

- Model dimension (long, wide, thick)	2500, 2500, 133 feet
- Scale grid (x, y, z)	25,25,6 (3,750 grid blocks)
- Structure style	Monocline
- Unit	Field
- Geometry type	Conner Point
- Grid type	Cartesian

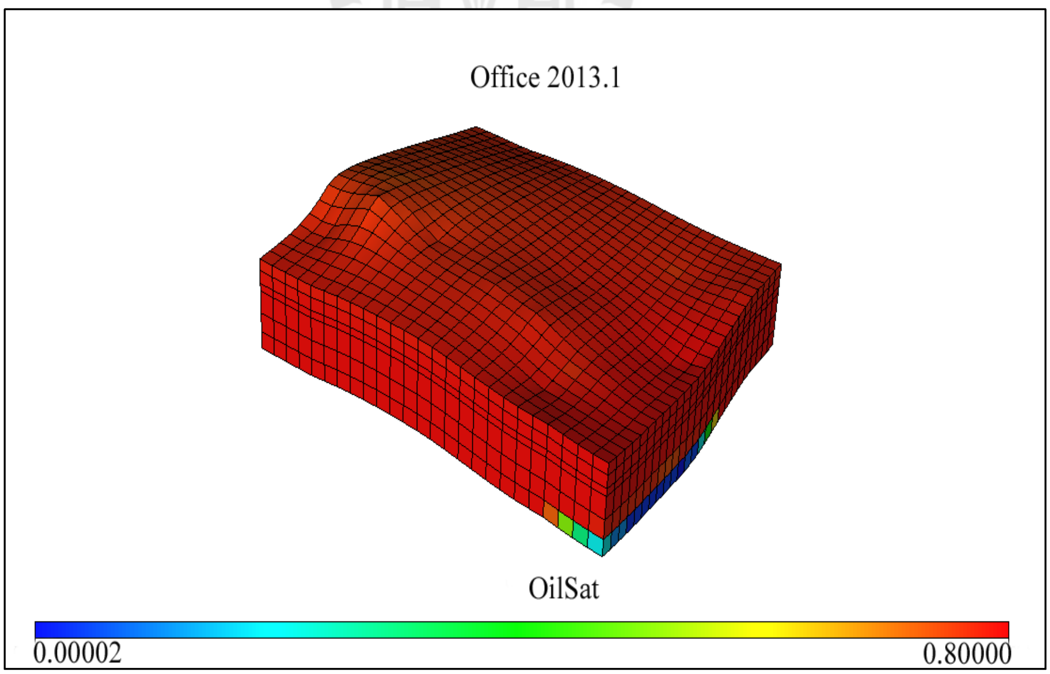


Figure 3.1 Reservoir structure model.

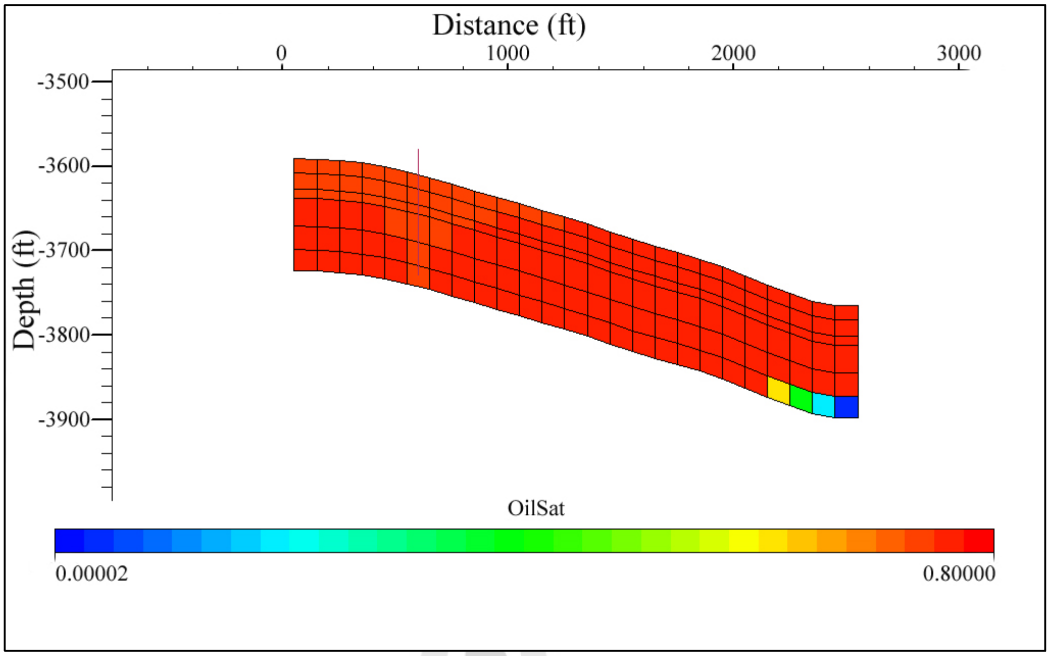


Figure 3.2 Cross-section of reservoir model.

3.3 Data input for the reservoir model

The data input in the reservoir model are received from available data of U-Thong oil field data. The main input section data of the simulation are Grid section, PVT section, SCAL section, Fluid Initialization section and Schedule section. Some data are assumed for using in this study because they are not available from U-Thong data.

3.3.1 Grid section data

The data input in this section are grid block corner, grid block coordinate lines, porosity and permeability distribution, and net-to-gross ratio. The data for Grid section is following:

-Depth of top surface, (feet)	3,586
-Net-to-gross ratio	0.18 – 1.00

According to Htoo (2009) from 4 wells test, the effective porosity of reservoir units at 22% in KR1-1 and decreases with burial depth to an average value of 12% in unit KR2-8B (see figure A.1 in appendix A). According to Rattanapranudej (2004) using an equation from porosity-permeability scatter program to generate a geo-statistical permeability distribution. This equation is following as:

$$\text{Log}(k) = 0.2023 \times Ø - 2.3475 \tag{5.1}$$

The porosity and permeability of Suphan Buri basin as show in Table 3.1. The x, y, z, porosity and x, y permeability set as following table, only z permeability set to 0.1 of represent value.

Table 3.1 Porosity and permeability for all layers.

Layer	Porosity (%)	Permeability (md)
1	15	362.74
2	14	227.67
3	13.7	197.98
4	13.3	164.32
5	13	142.89
6	12	89.68

3.3.2 PVT section data

The PVT section data are the fluid properties include fluid formation volume factors, viscosities, densities, gas-oil ratio, and rock and water compressibility. The data input for PVT section are detail as follow:

- Rock type of reservoir	Consolidated Sandstone
- Oil gravity, (API Oil)	33
- Gas gravity, (SG Air = 1)	0.74
- Bubble point pressure, (psi)	300
- Referenced pressure, (psi)	1,800
- Standard temperature, (ºF)	60
- Standard pressure, (psi)	14.7

3.3.3 Scal section data

The SCAL section refers to the term of rock properties, which is the 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	0.2
- Critical water saturation	0.3
- Gas saturation	0.04
- Critical water saturation	0.1

The Table A.1, A.2 and figure A.2, A.3 of PVT and fluid saturation are shown in Appendix A.

3.3.4 Fluid initialization section data

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 are following:

- Datum depth, (feet)	3,850
- Pressure at datum depth, (psi)	1,800
- Water/Oil contact depth, (feet)	3,875
- The bubble-point at datum depth, (psi)	300

3.3.5 Well data of schedule section data

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 (feet)	0.71
- Skin factor	-1
- Effective K_h (mD)	250
- Perforation of production zone (layer)	1^{st} - 6^{th}
- Perforation of injection zone (layer)	1^{st} - 6^{th}

3.3.6 Type of polymer for injection

The Xanthan Gum (XCD) polymer concentration 600 ppm is used in this study. XCD polymer has a good salt-resistance. The reservoir has a high temperature this polymer can increase the water viscosity but the mobility ratio between polymer solution and oil will be decrease. After study enhanced oil recovery by polymer flooding for oil field in Phisanulok basin (Kanarak, 2008) the reservoir model name A05 is nearby this study. The polymer concentration 600 ppm is the best case and development for each reserved sizes of reservoir. Recovery efficiency and economic evaluation is more favorable than the others concentrations.

The data of polymer for injection showed in Appendix B.

3.4 Case of study

In this study the reservoir size is 6.478 MMBBL with the monocline structure style. Use two flood pattern (staggered line and direct line drive) to compare the result of production with primary production (natural flow), secondary production (water injection) and the tertiary production (polymer injection).Water and polymer inject at a difference times of the 1st, 3rd and 5th year of constant production rate at 600 bbl/d and constant injection rate at 500 bbl/d. Case study model show in Table 3.2 and flood pattern show in Figure 3.3 – 3.4.

Table 3.2 Case study model.

Case	Flood pattern	Type to inject	Year to inject	Initial Pro. Well	After well convert	
					Inj. Well	Pro. Well
1	Staggered line	-	no	3	0	3
2	Direct line	-	no	4	0	4
3	Staggered line	Water	1^{st}	1	2	1
4	Direct line	Water	1^{st}	2	2	2
5	Staggered line	Water	3^{rd}	3	2	1
6	Direct line	Water	3^{rd}	4	2	2
7	Staggered line	Water	5^{th}	3	2	1
8	Direct line	Water	5^{th}	4	2	2
9	Staggered line	Fresh water	1^{st}	1	2	1
		Polymer	2^{nd}			
10	Direct line	Fresh water	1^{st}	2	2	2
		Polymer	2^{nd}			
11	Staggered line	Fresh water	3^{rd}	3	2	1
		Polymer	4^{th}			
12	Direct line	Fresh water	3^{rd}	4	2	2
		Polymer	4^{th}			
13	Staggered line	Fresh water	5^{th}	3	2	1
		Polymer	6^{th}			
14	Direct line	Fresh water	5^{th}	4	2	2
		Polymer	6^{th}			

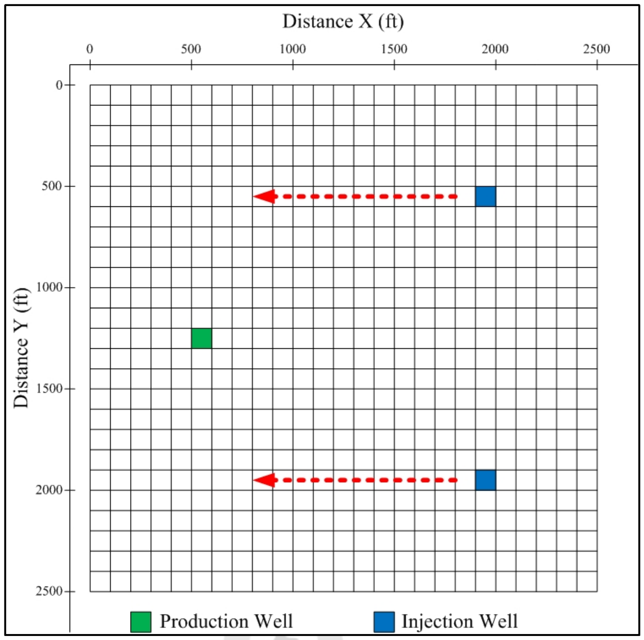


Figure 3.3 Staggered line drive pattern.

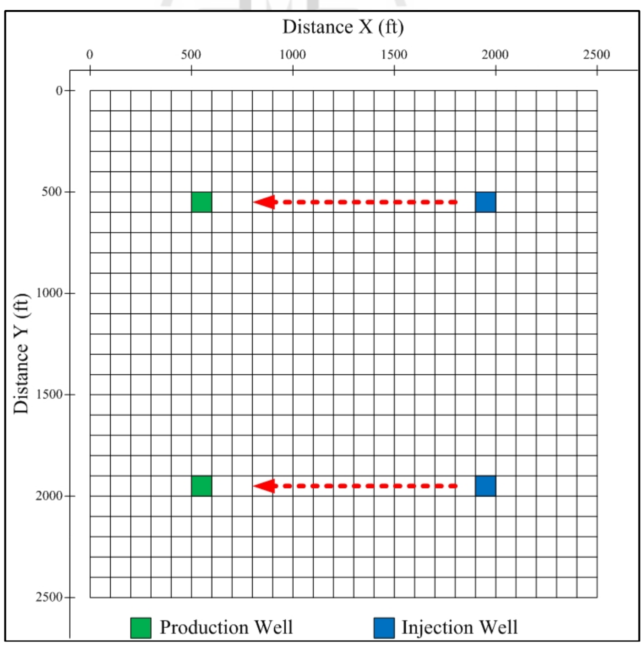


Figure 3.4 Direct line drive pattern.

CHAPTER IV

RESERVOIR SIMULATION RESULTS

This chapter shows reservoir simulation results of the all case study (total 14 cases). These results show graphs with 3 phases of fluids (oil, water, and gas). The graphs show field fluid in place (volume in the reservoir), field cumulative production (production efficiency), field production rate (production profile), field pressure, field oil efficiency and field polymer injection total. Total 14 case studies simulation run results displayed through the cross plot of 4 main graphs (Figures 1 - 4) to observed fluids production behavior from reservoir by natural flow and after applied water and polymer flooding, but Figure 5 (field polymer injection total) are shown in cases study 9 – 14 only. Detail of the presented graphs can be illustrated in Table 4.1.

Table 4.1 Display parameter description.

Figure	Parameters	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	FPR	Field Pressure	Reservoir Pressure
	FOE	Field Oil Efficiency	Oil Recovery Efficiency
5	FCIT	Field Polymer Injection Total	Polymer Solution Injection Total

4.1 Reservoir simulation results

4.1.1 Model case 1 result

Model case 1 staggered line drive pattern, natural flow produced with no water injection. Production period is 20 years start by 3 production wells at initial oil production rate 200 bbl/d/well. The simulation results show in Figures 4.1 – 4.4:

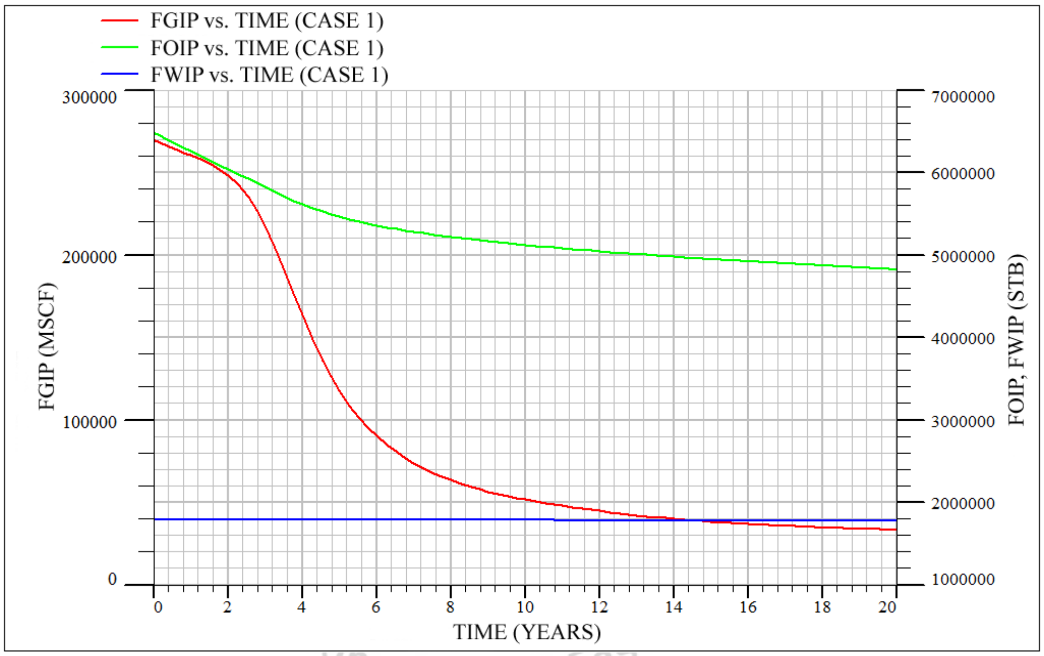


Figure 4.1 Fluid in place profile vs. time of model case 1.

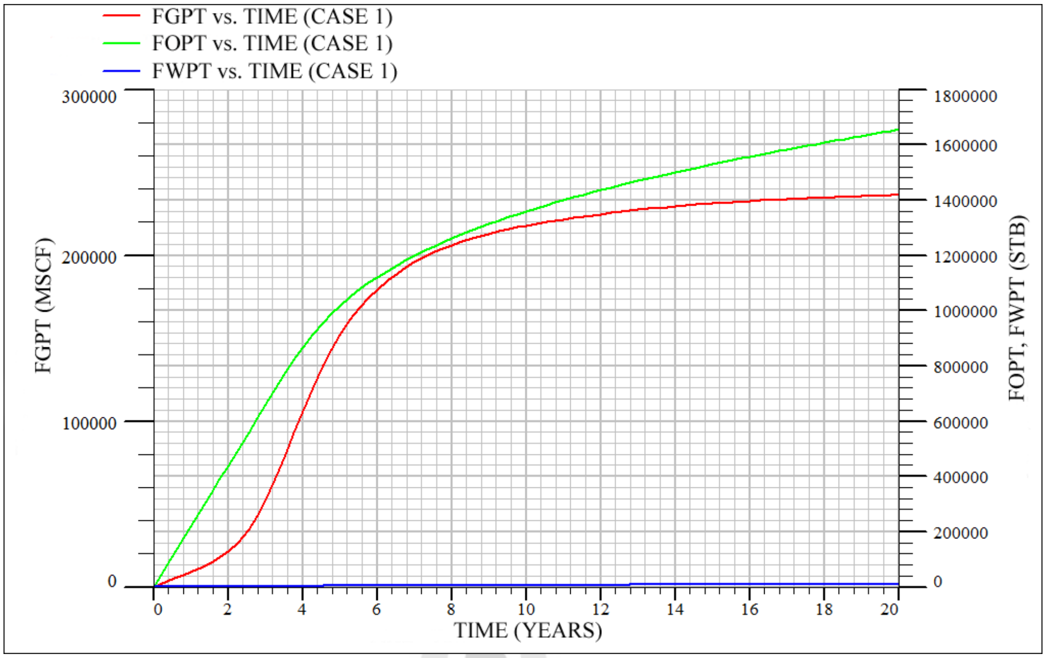


Figure 4.2 Cumulative fluids production profile vs. time of model case 1.

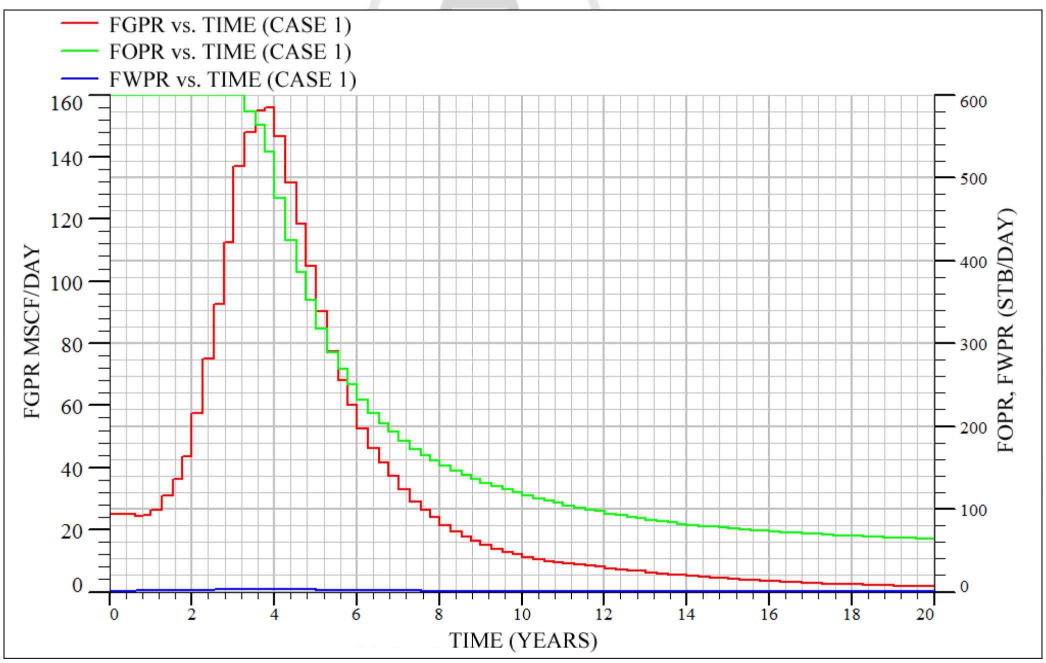


Figure 4.3 Fluids production rate profile vs. time of model case 1.

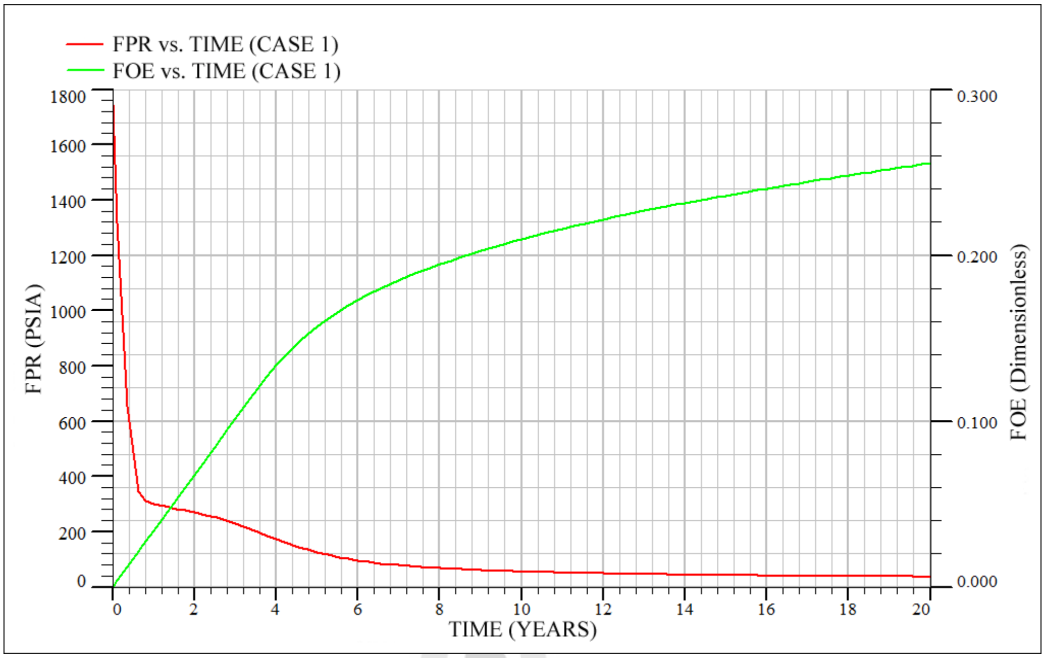


Figure 4.4 Field pressure and oil recovery efficiency vs. time of model case 1.

4.1.2 Model case 2 result

Model case 2 direct line drive pattern, natural flow produced with no water injection. Production period is 20 years start by 4 production wells at initial oil production rate 150 bbl/d/well. The simulation results show in Figures 4.5 – 4.8:

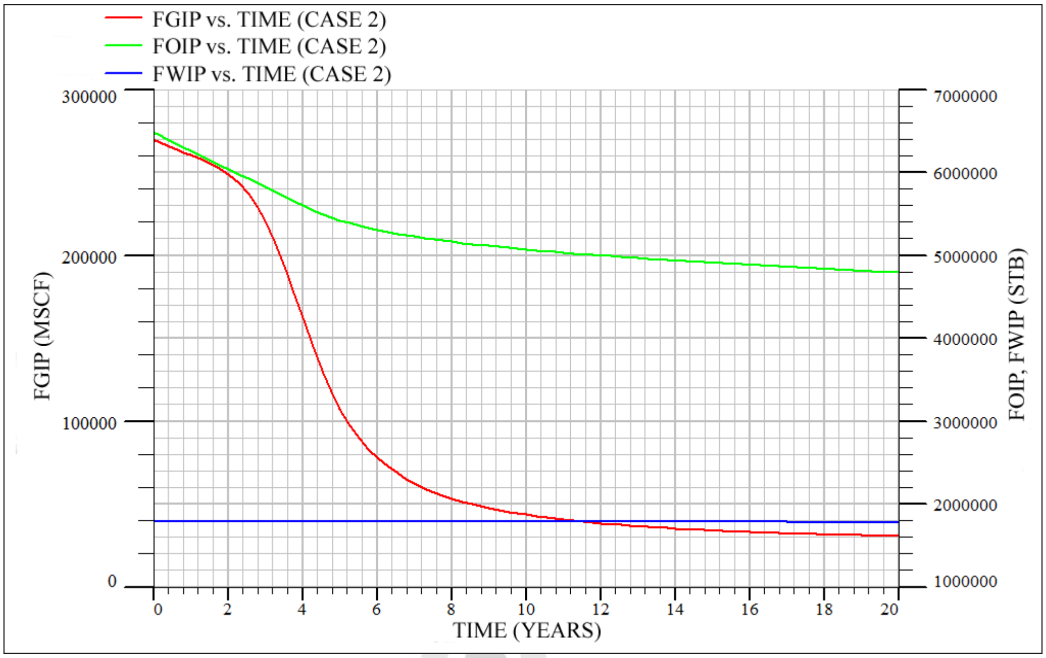


Figure 4.5 Fluid in place profile vs. time of model case 2.

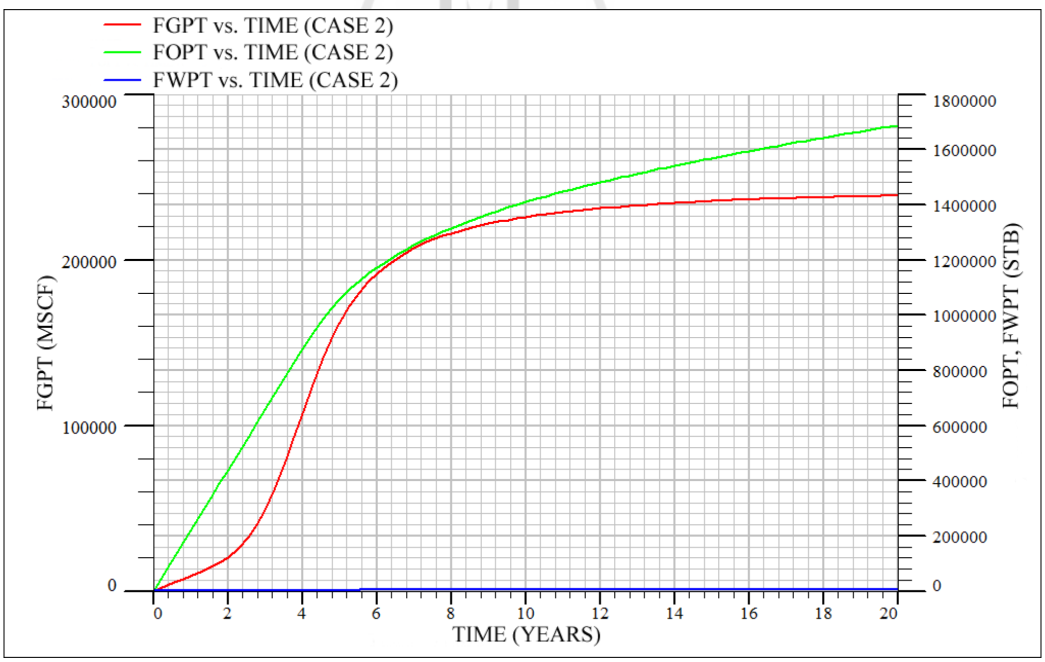


Figure 4.6 Cumulative fluids production profile vs. time of model case 2.

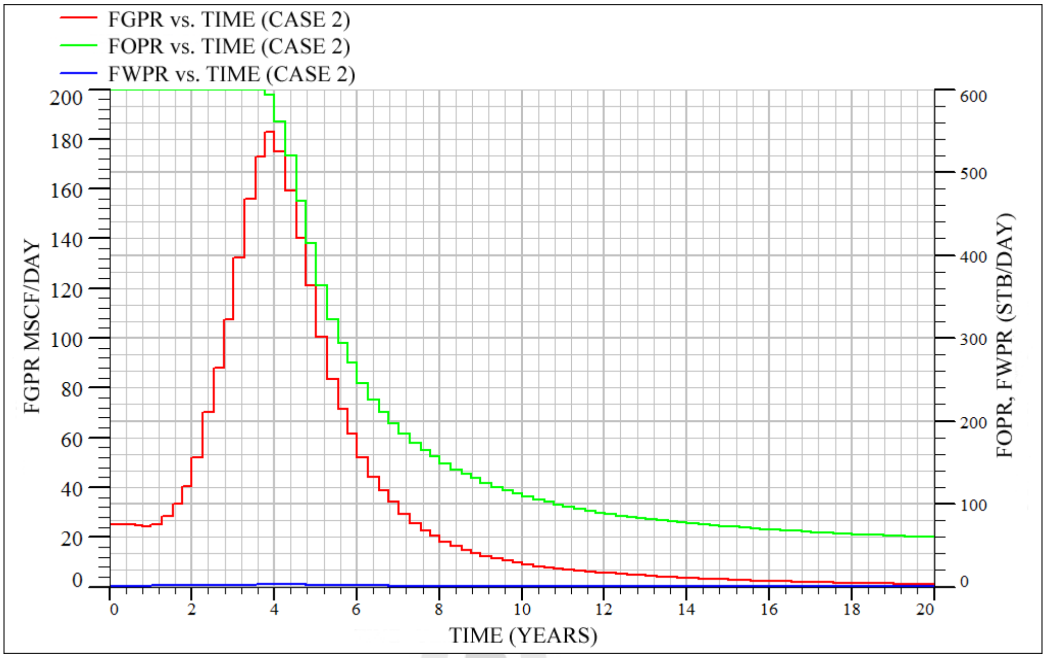


Figure 4.7 Fluids production rate profile vs. time of model case 2.

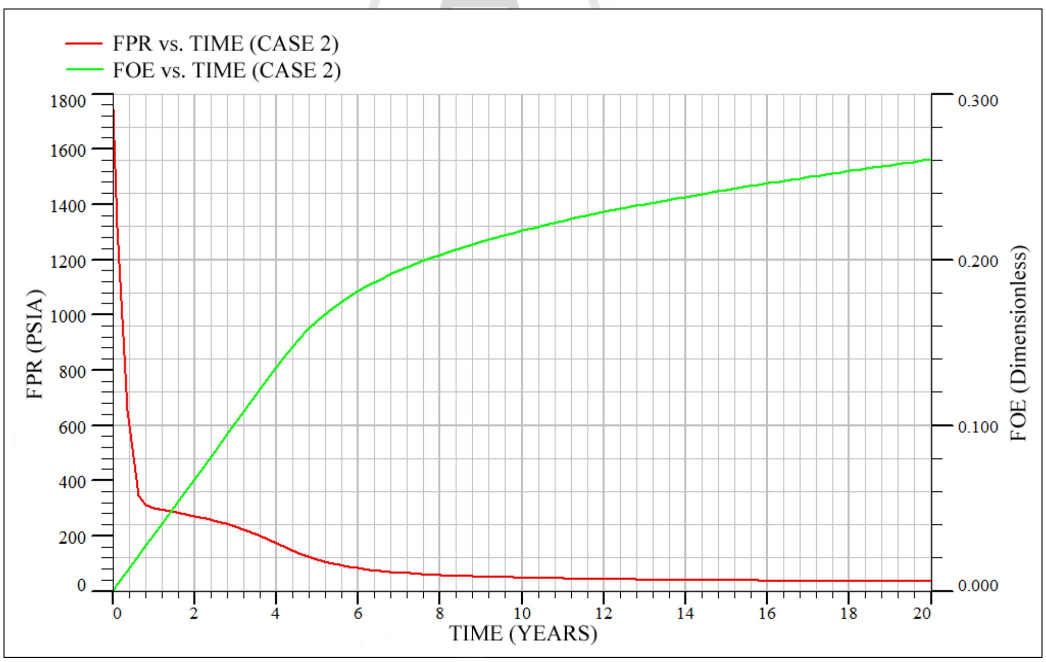


Figure 4.8 Field pressure and oil recovery efficiency vs. time of model case 2.

4.1.3 Model case 3 result

Model case 3 staggered line drive pattern, produced with water injection at the 1st year. Production period is 20 years start by 1 production well at initial oil production rate 600 bbl/d and 2 injection wells at water injection rate 250 bbl/d/well. The simulation results show in Figures 4.9 – 4.12:

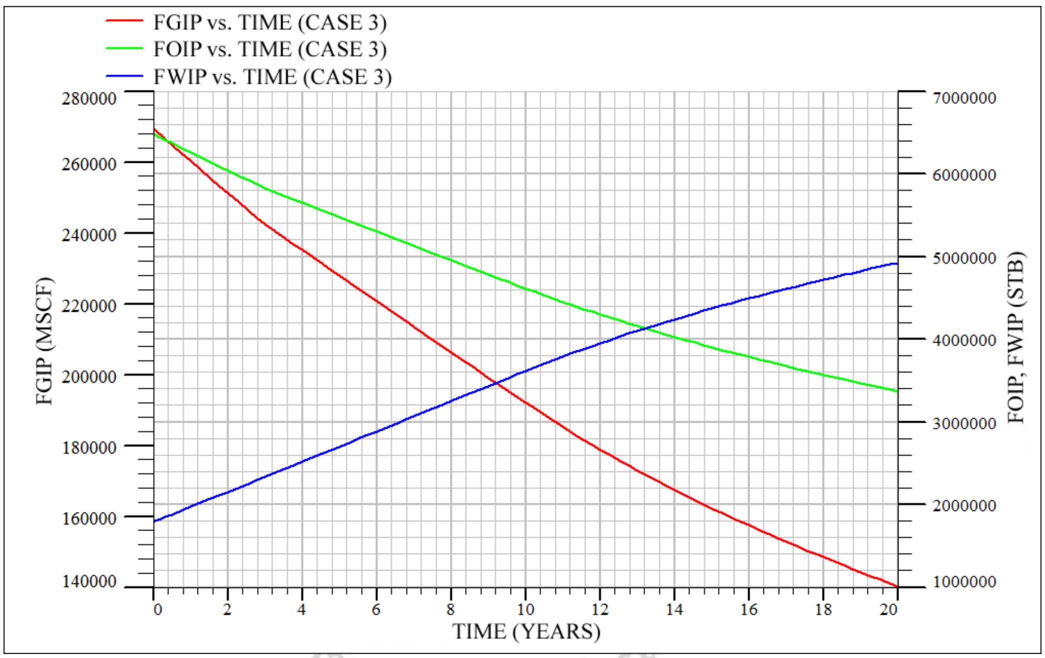


Figure 4.9 Fluid in place profile vs. time of model case 3.

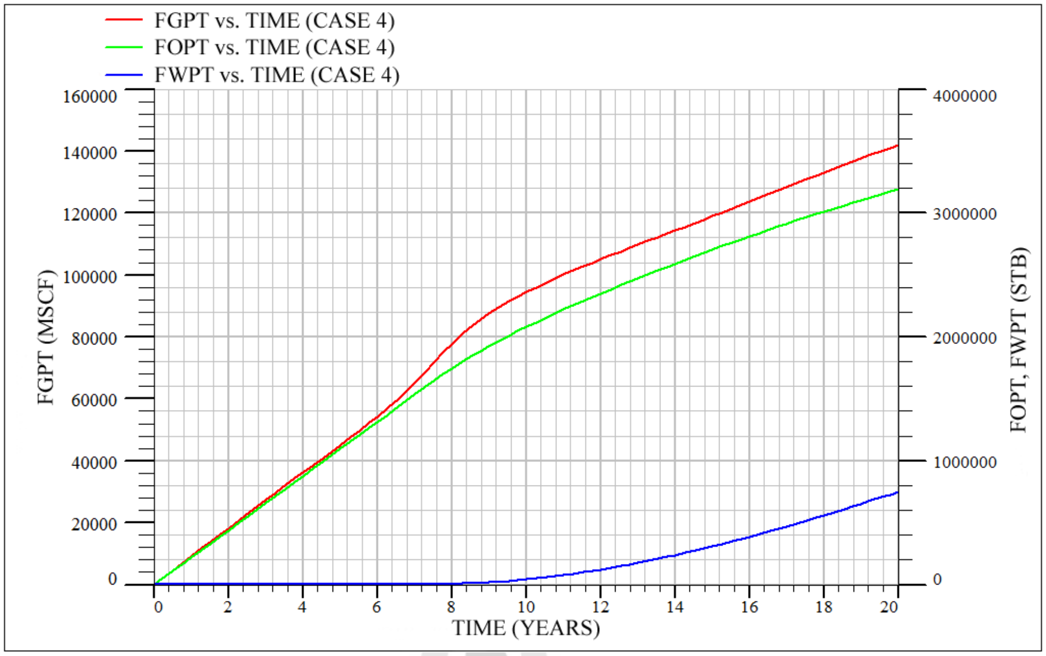


Figure 4.10 Cumulative fluids production profile vs. time of model case 3.

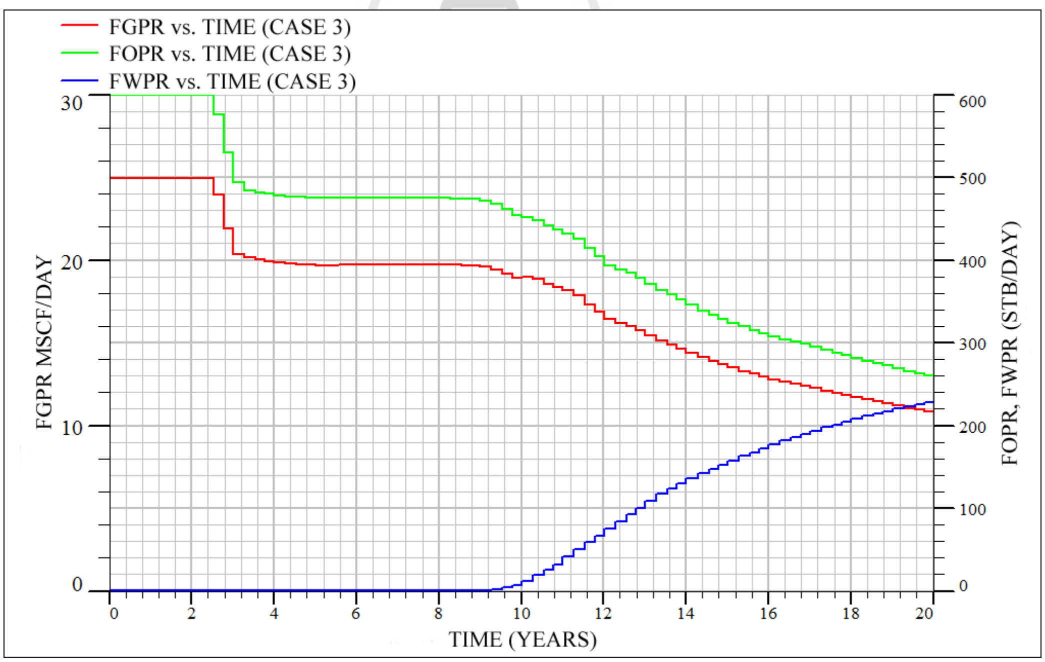


Figure 4.11 Fluids production rate profile vs. time of model case 3.

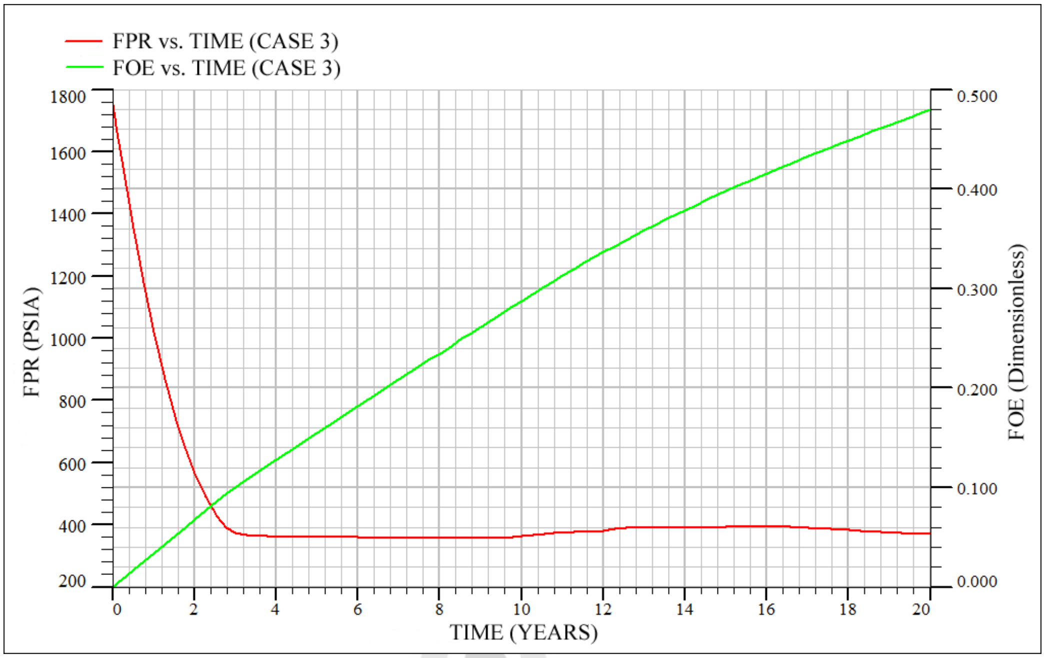


Figure 4.12 Field pressure and oil recovery efficiency vs. time of model case 3.

4.1.4 Model case 4 result

Model case 4 direct line drive pattern, produced with water injection at the 1st year. Production period is 20 years start by 2 production wells at initial oil production rate 300 bbl/d/well and 2 injection wells at water injection rate 250 bbl/d/well. The simulation results show in Figures 4.13 – 4.16:

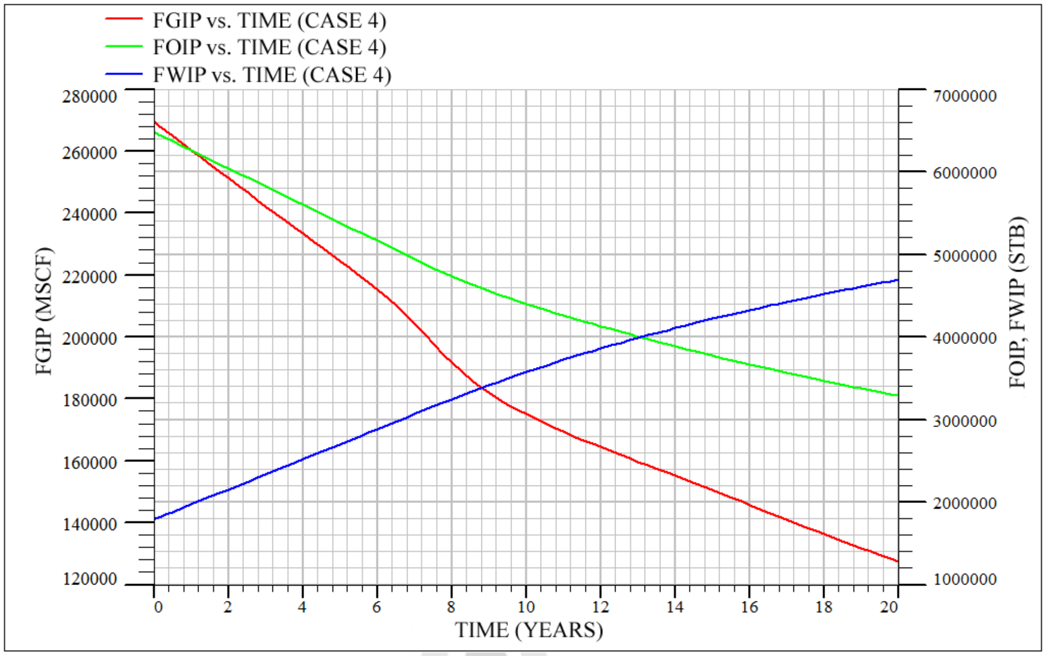


Figure 4.13 Fluid in place profile vs. time of model case 4.

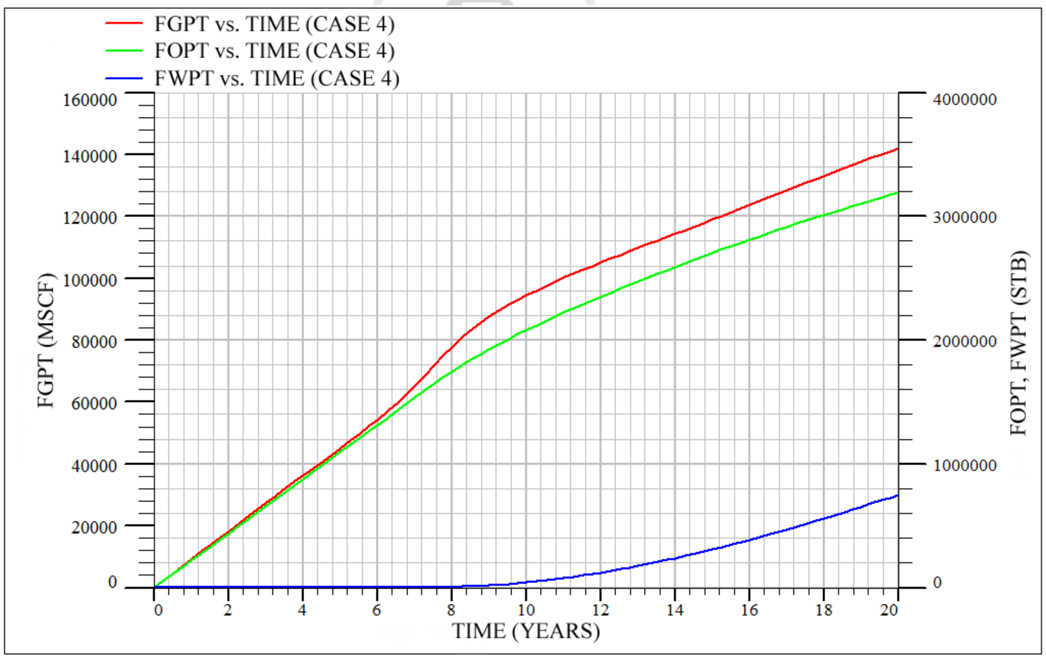


Figure 4.14 Cumulative fluids production profile vs. time of model case 4.

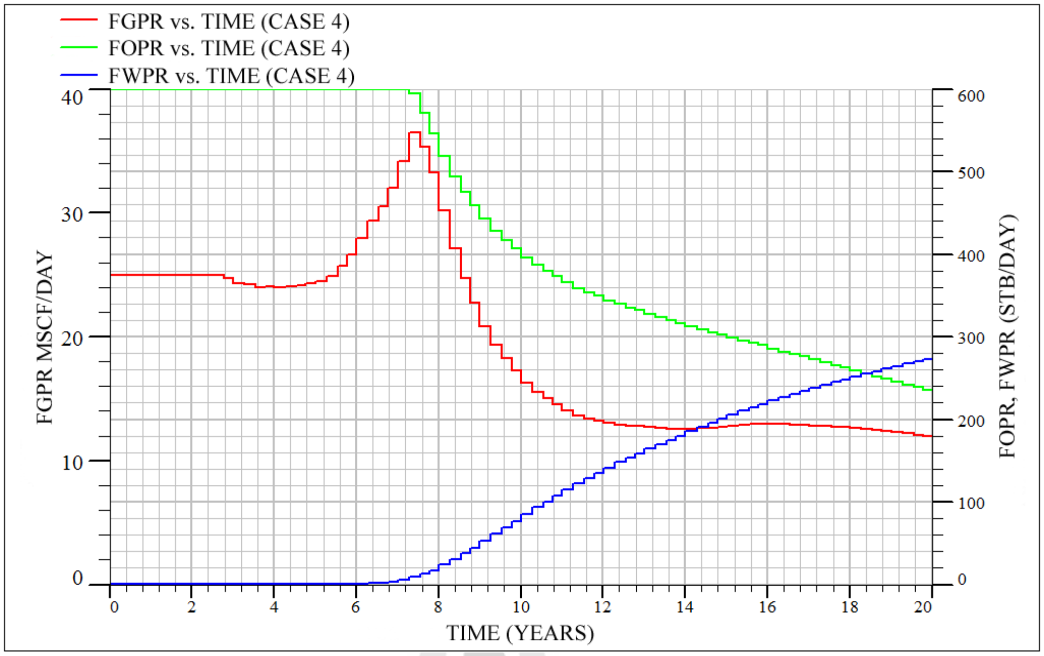


Figure 4.15 Fluids production rate profile vs. time of model case 4.

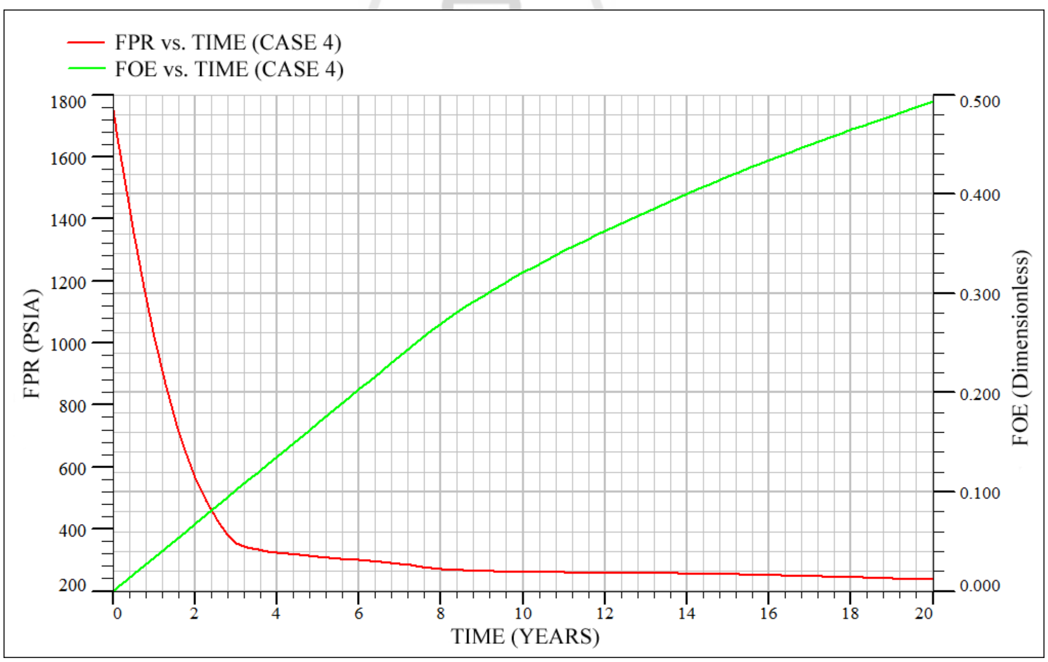


Figure 4.16 Field pressure and oil recovery efficiency vs. time of model case 4.

4.1.5 Model case 5 result

Model case 5 staggered line drive pattern, produced with water injection at the 3rd year. Production period is 20 years start by 3 production wells at initial oil production rate 200 bbl/d/well. After 2 years of production period, start water injection by converted 2 production wells to injection well with water injection rate 250 bbl/d/well. The remaining production well produced at rate 600 bbl/d. The simulation results show in Figures 4.17 – 4.20:

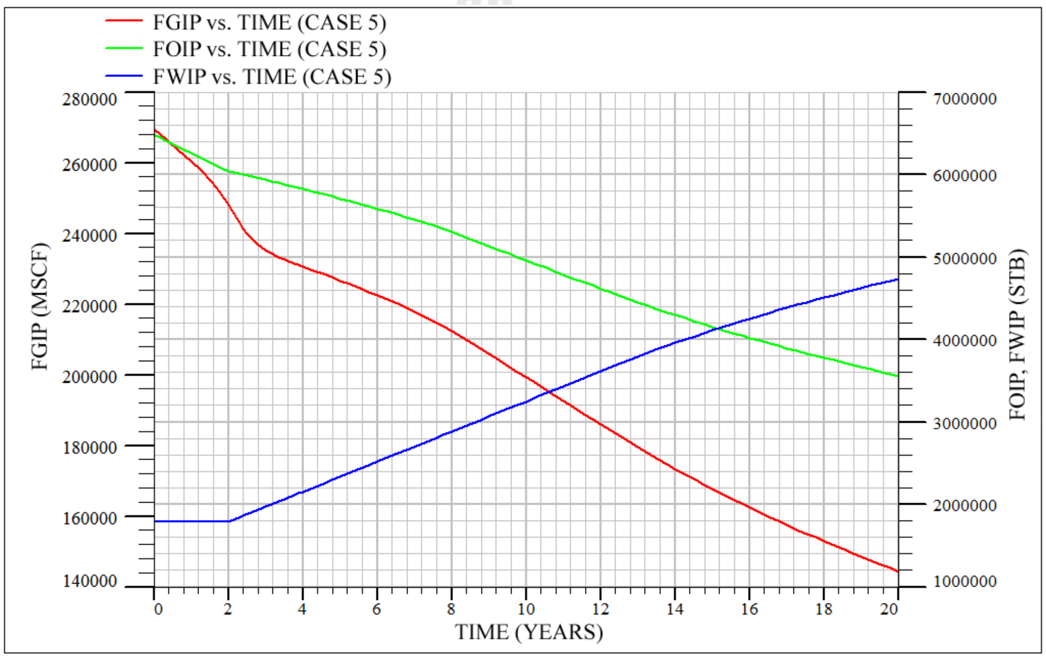


Figure 4.17 Fluid in place profile vs. time of model case 5.

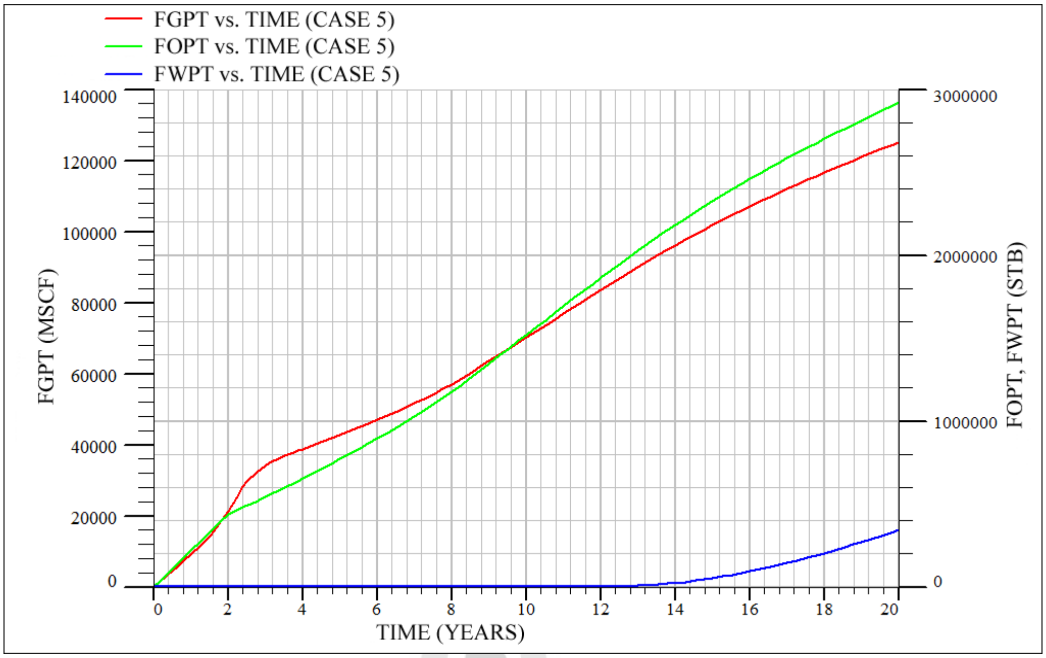


Figure 4.18 Cumulative fluids production profile vs. time of model case 5.

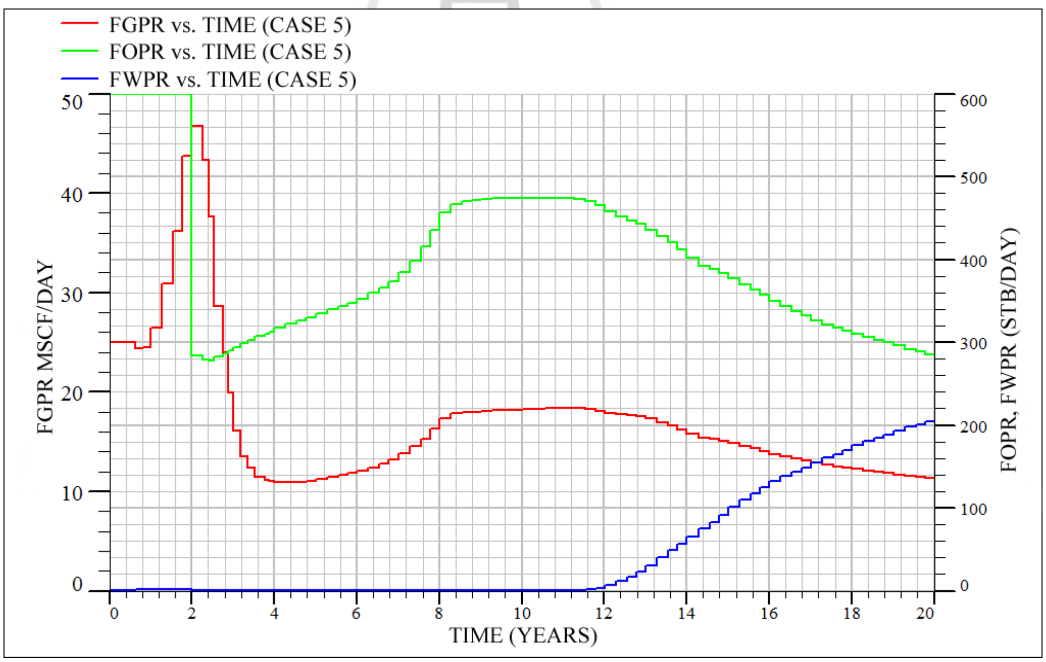


Figure 4.19 Fluids production rate profile vs. time of model case 5.

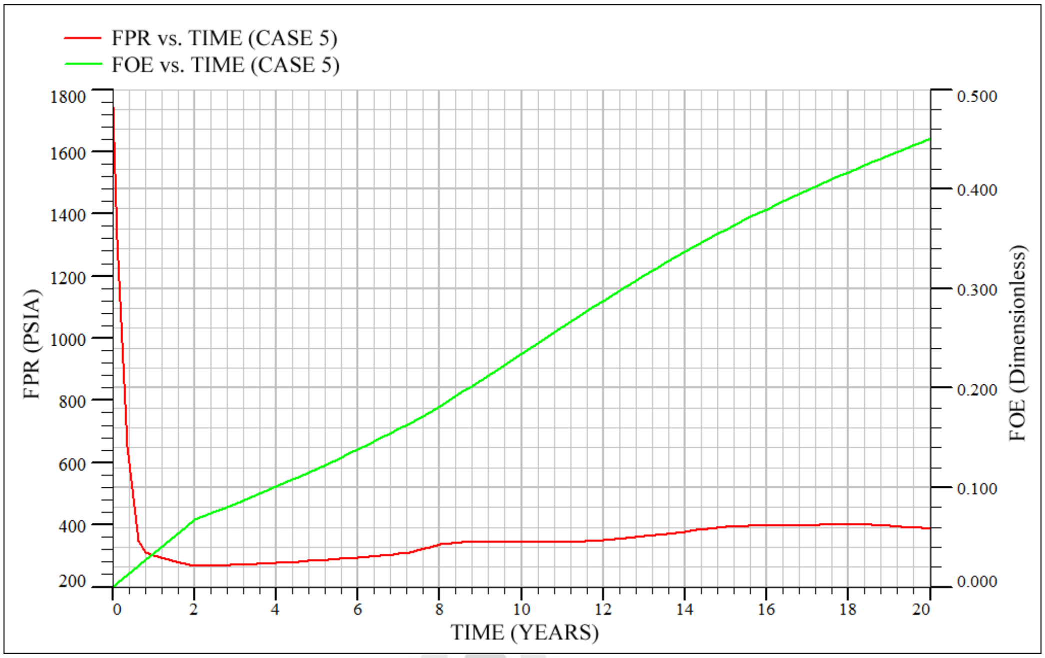


Figure 4.20 Field pressure and oil recovery efficiency vs. time of model case 5.

4.1.6 Model case 6 result

Model case 6 direct line drive pattern, produced with water injection at the 3rd year. Production period is 20 years start by 4 production wells at initial oil production rate 150 bbl/d/well. After 2 years of production period, start water injection by converted 2 production wells to injection well with water injection rate 250 bbl/d/well. The remaining 2 production wells produced at rate 300 bbl/d/well. The simulation results show in Figures 4.21 – 4.24:

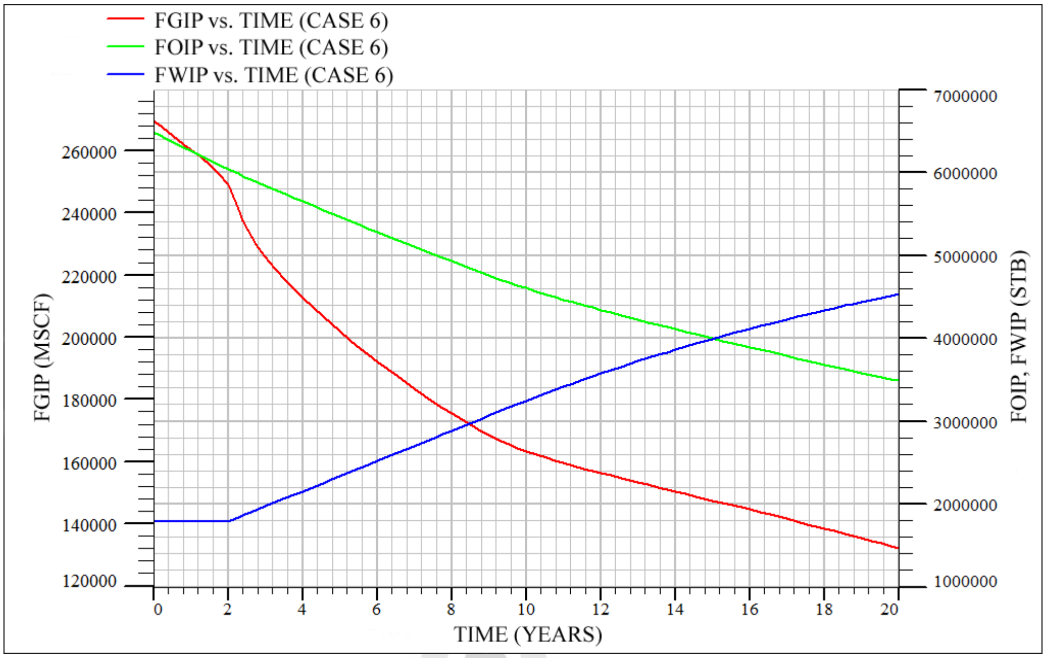


Figure 4.21 Fluid in place profile vs. time of model case 6.

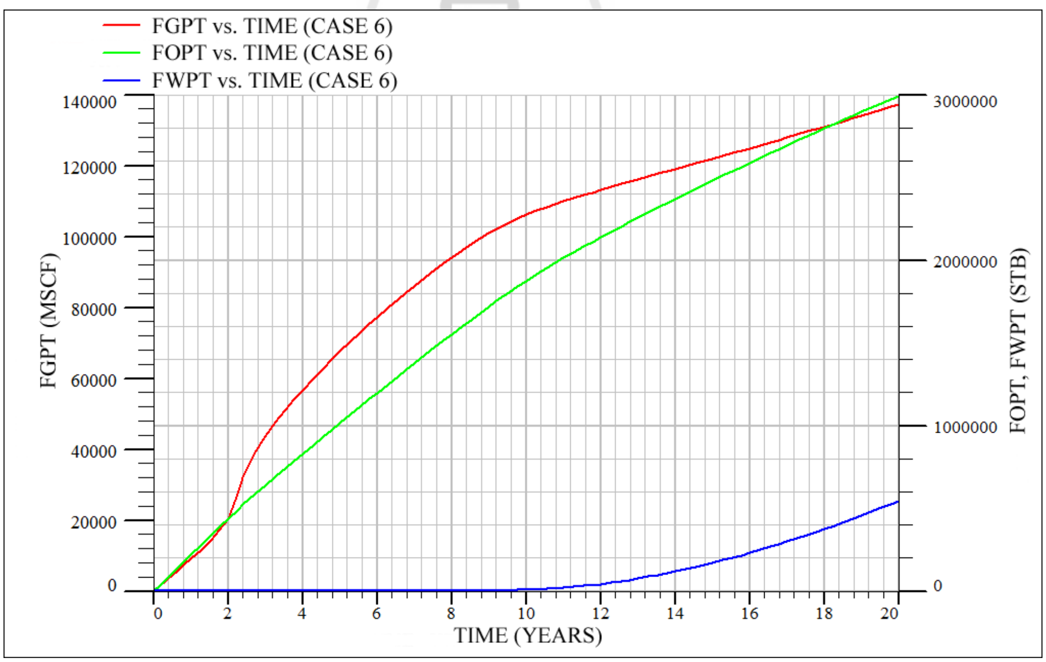


Figure 4.22 Cumulative fluids production profile vs. time of model case 6.

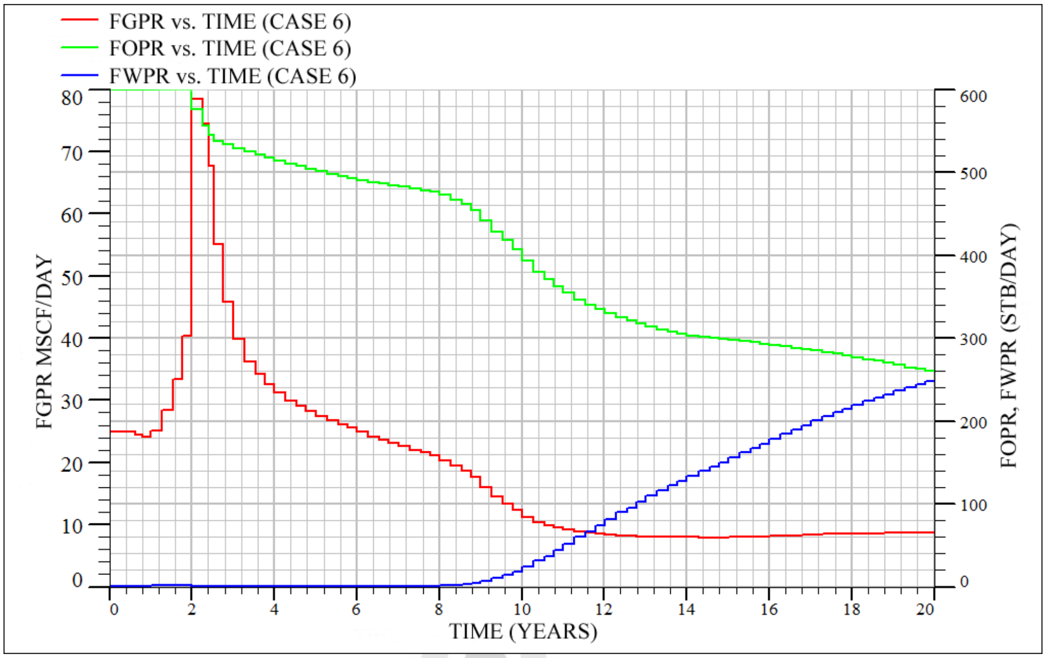


Figure 4.23 Fluids production rate profile vs. time of model case 6.

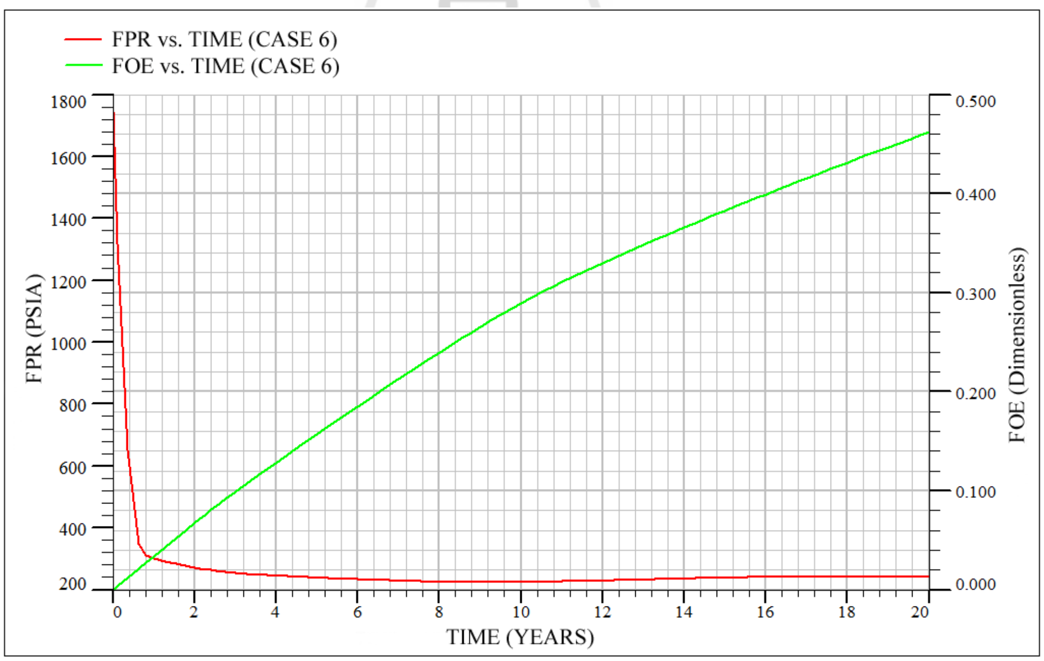


Figure 4.24 Field pressure and oil recovery efficiency vs. time of model case 6.

4.1.7 Model case 7 result

Model case 7 staggered line drive pattern, produced with water injection at the 5th year. Production period is 20 years start by 3 production wells at initial oil production rate 200 bbl/d/well. After 4 years of production period, start water injection by converted 2 production wells to injection well with water injection rate 250 bbl/d/well. The remaining production well produced at rate 600 bbl/d. The simulation results show in Figures 4.25 – 4.28:

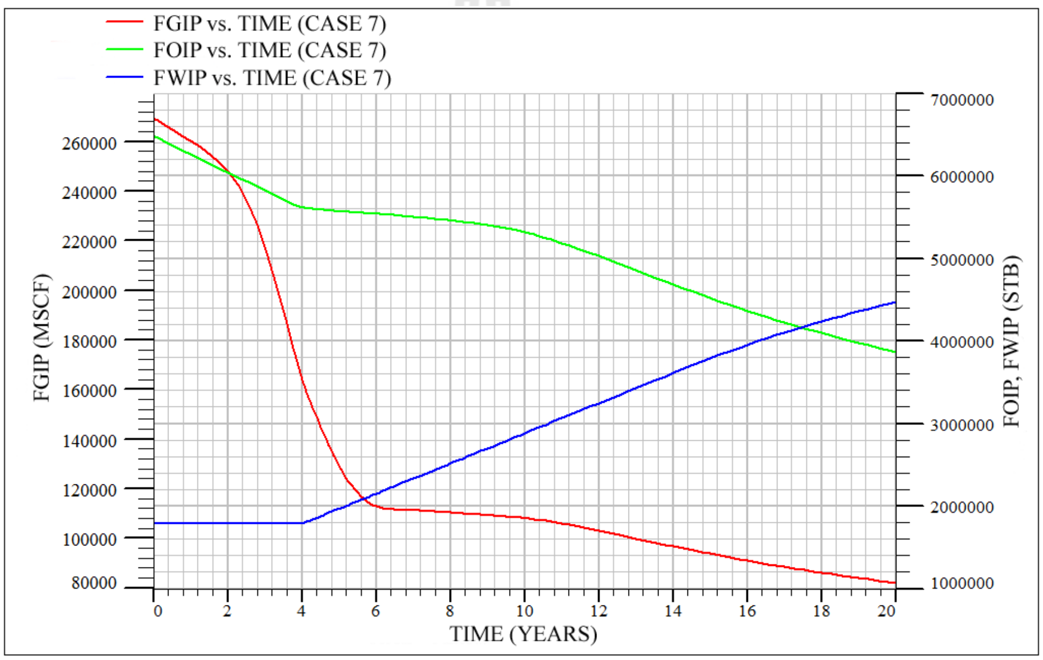


Figure 4.25 Fluid in place profile vs. time of model case 7.

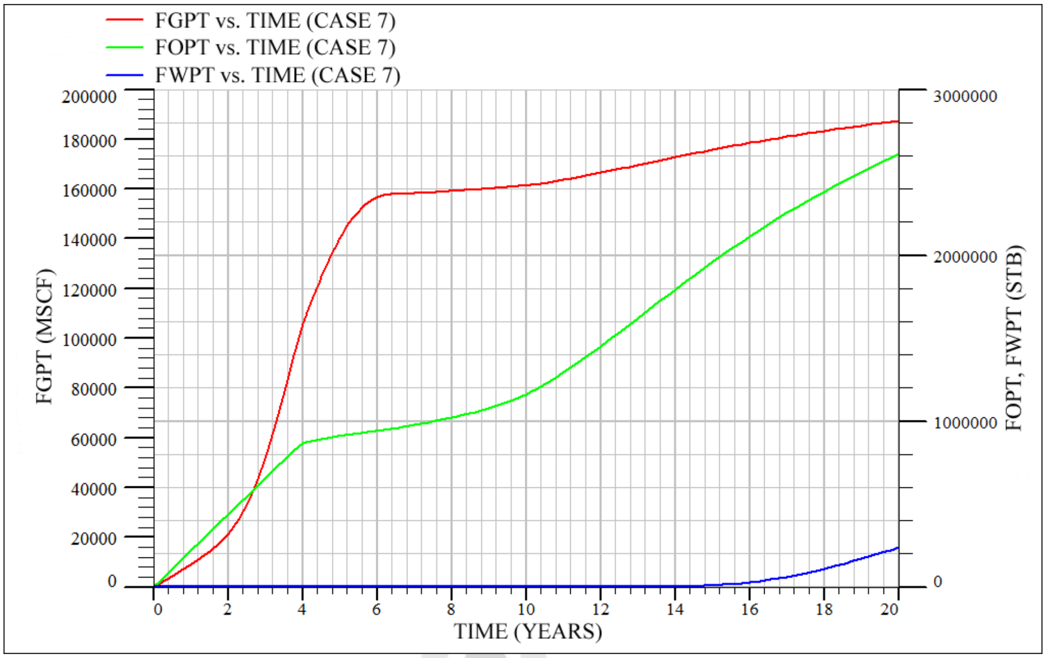


Figure 4.26 Cumulative fluids production profile vs. time of model case 7.

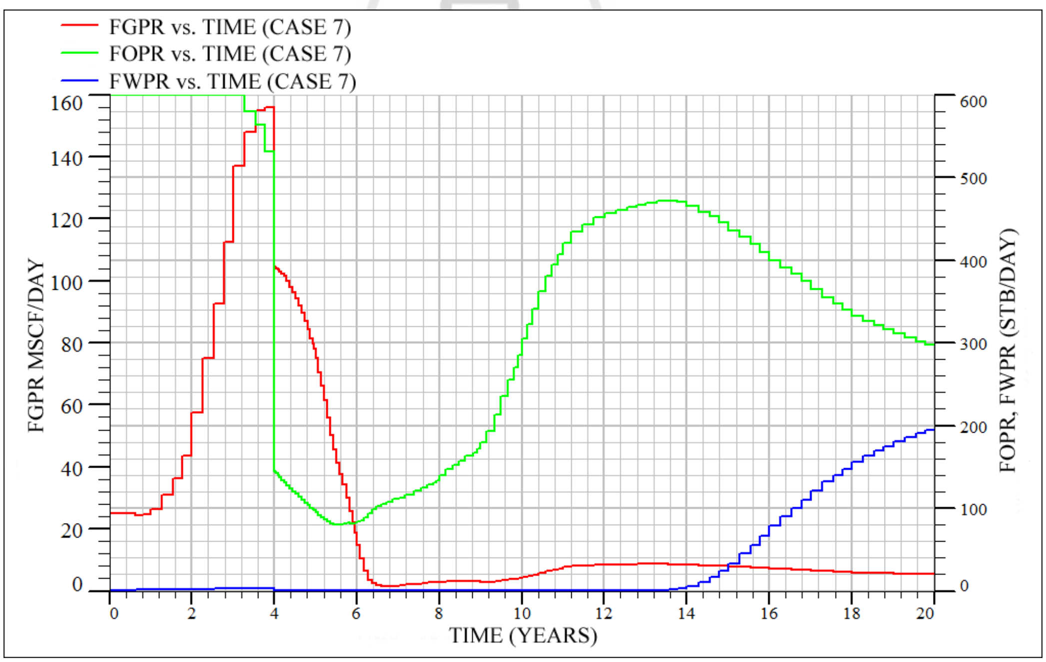


Figure 4.27 Fluids production rate profile vs. time of model case 7.

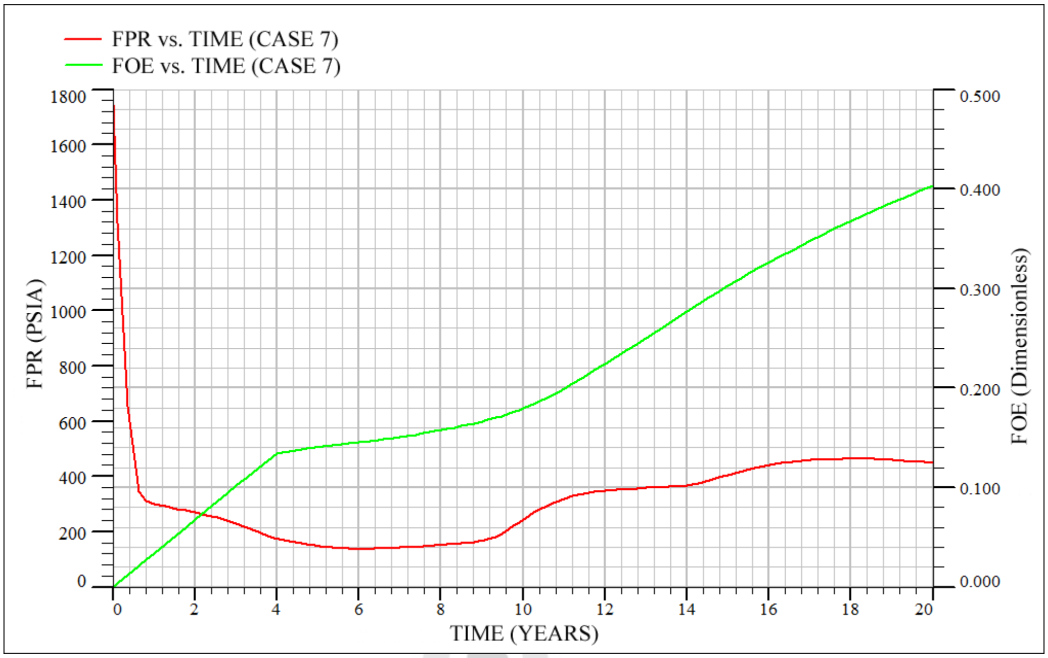


Figure 4.28 Field pressure and oil recovery efficiency vs. time of model case 7.

4.1.8 Model case 8 result

Model case 8 direct line drive pattern, produced with water injection at the 5th year. Production period is 20 years start by 4 production wells at initial oil production rate 150 bbl/d/well. After 4 years of production period, start water injection by converted 2 production wells to injection well with water injection rate 250 bbl/d/well. The remaining 2 production wells produced at rate 300 bbl/d/well. The simulation results show in Figures 4.29 – 4.32:

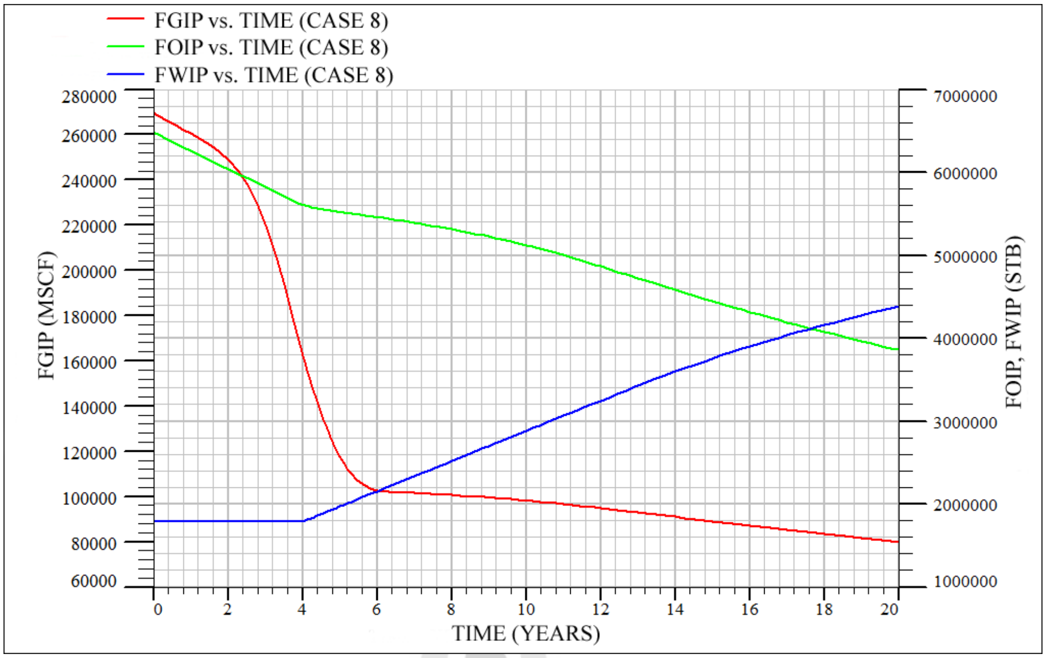


Figure 4.29 Fluid in place profile vs. time of model case 8.

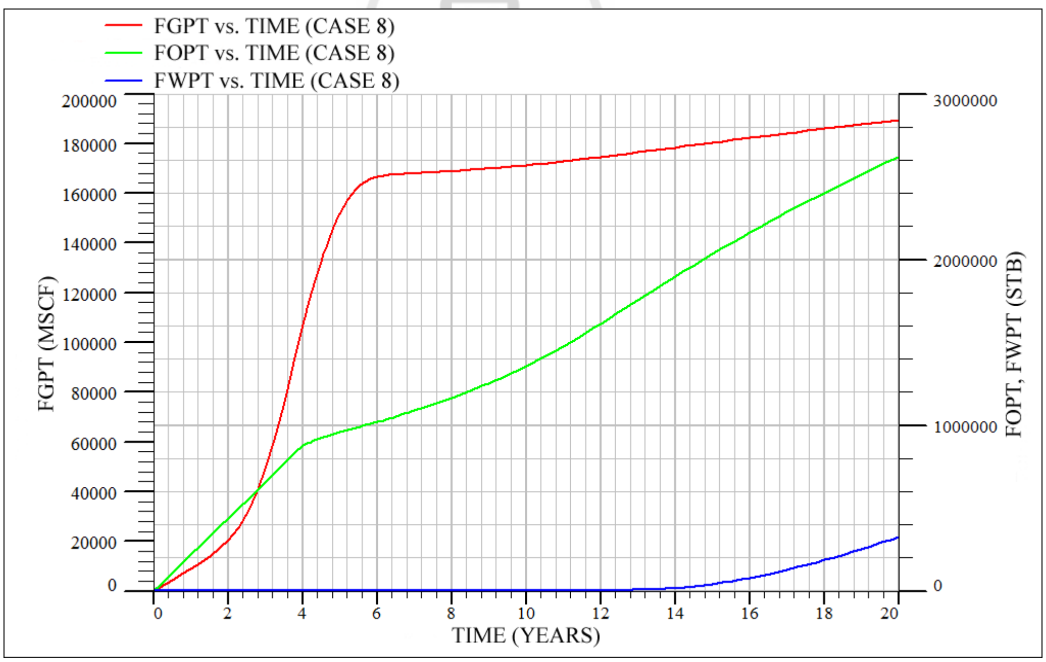


Figure 4.30 Cumulative fluids production profile vs. time of model case 8.

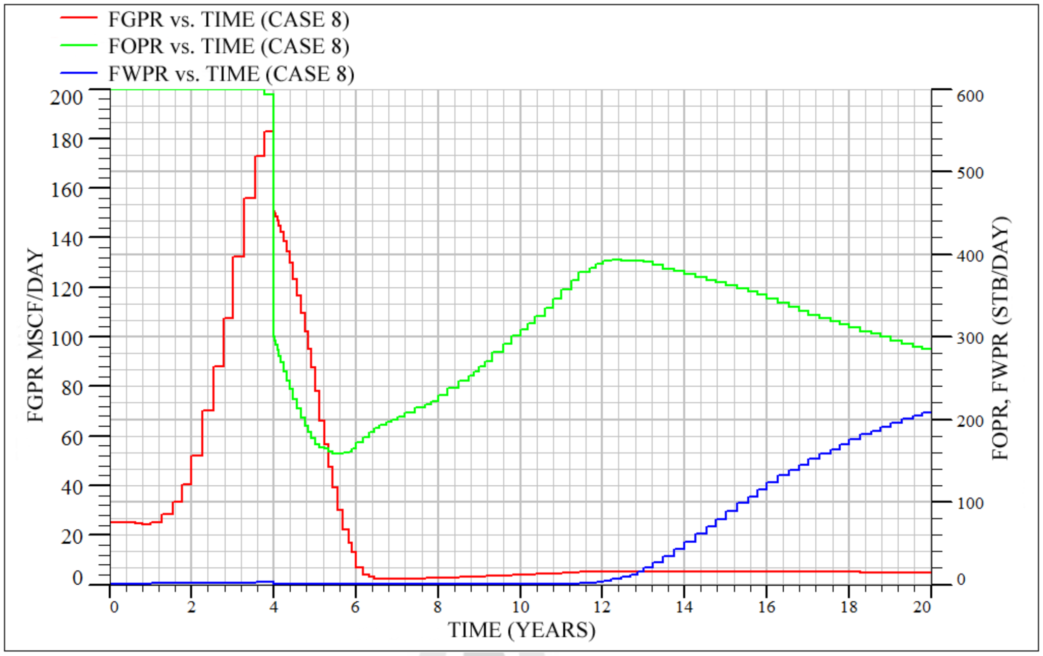


Figure 4.31 Fluids production rate profile vs. time of model case 8.

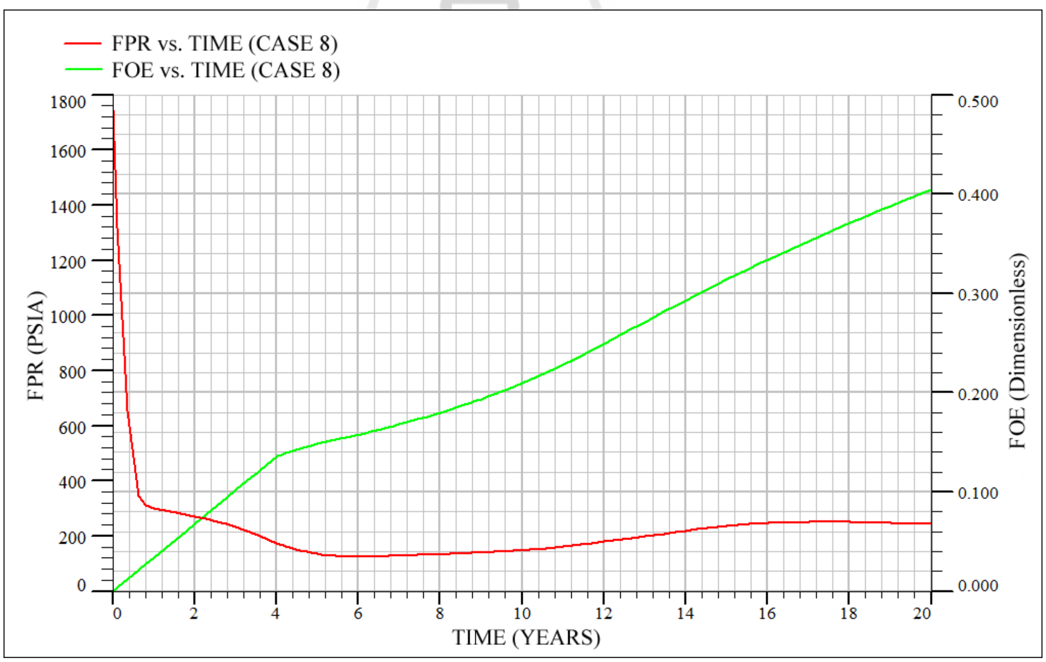


Figure 4.32 Field pressure and oil recovery efficiency vs. time of model case 8.

4.1.9 Model case 9 result

Model case 9 staggered line drive pattern, produced with water injection at the 1st year and polymer injection at the 2nd year. Production period is 20 years start by 1 production well at initial oil production rate 600 bbl/d and 2 injection wells at water and polymer injection rate 250 bbl/d/well. The simulation results show in Figures 4.33 – 4.37:

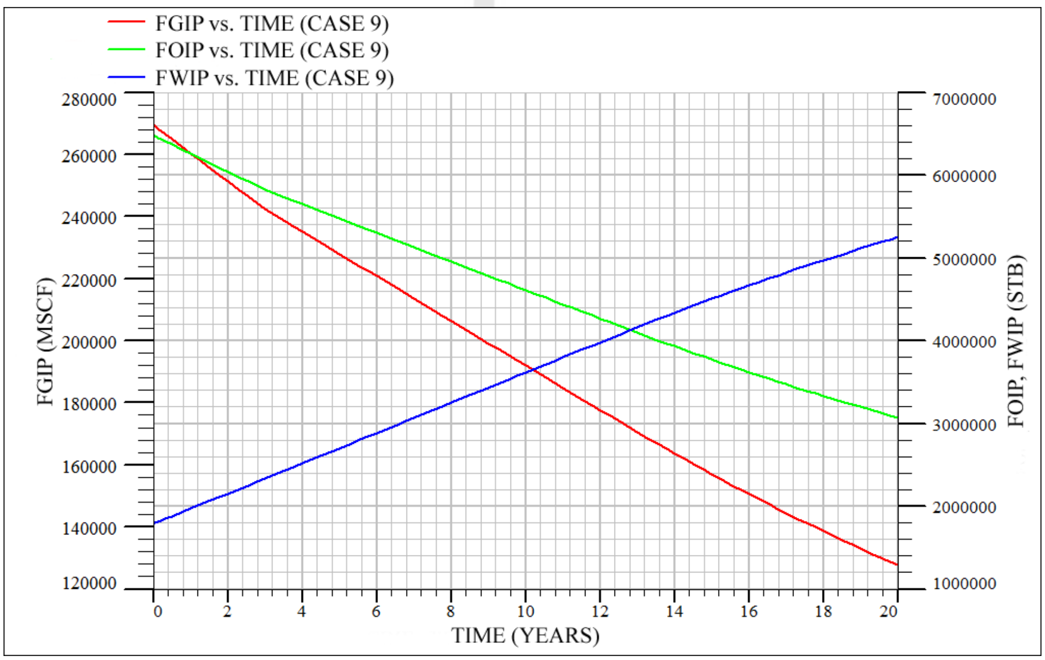


Figure 4.33 Fluid in place profile vs. time of model case 9.

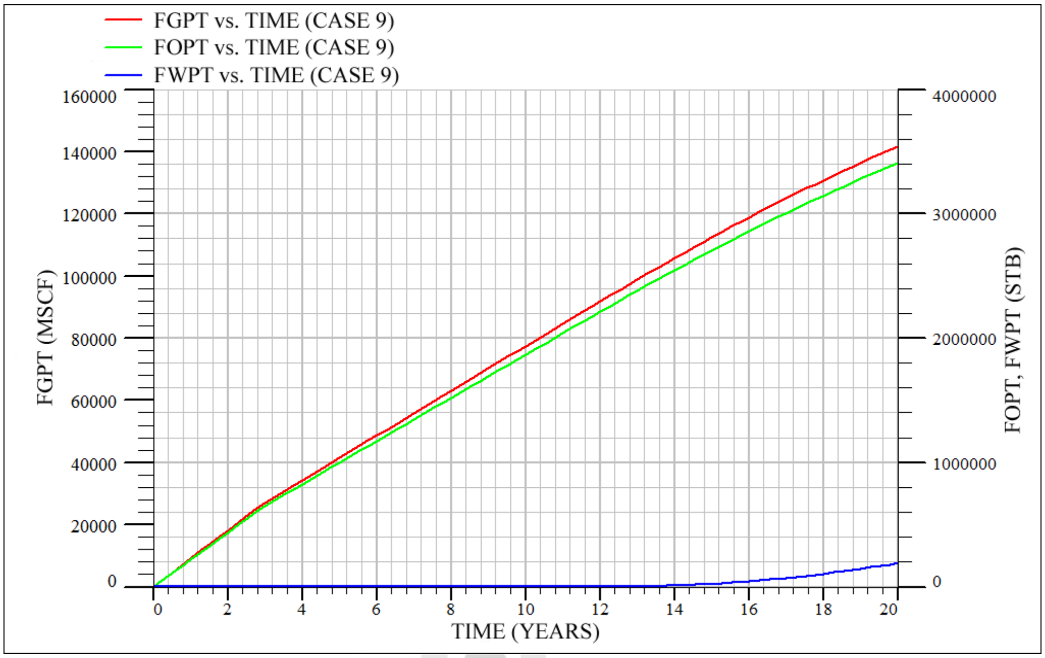


Figure 4.34 Cumulative fluids production profile vs. time of model case 9.

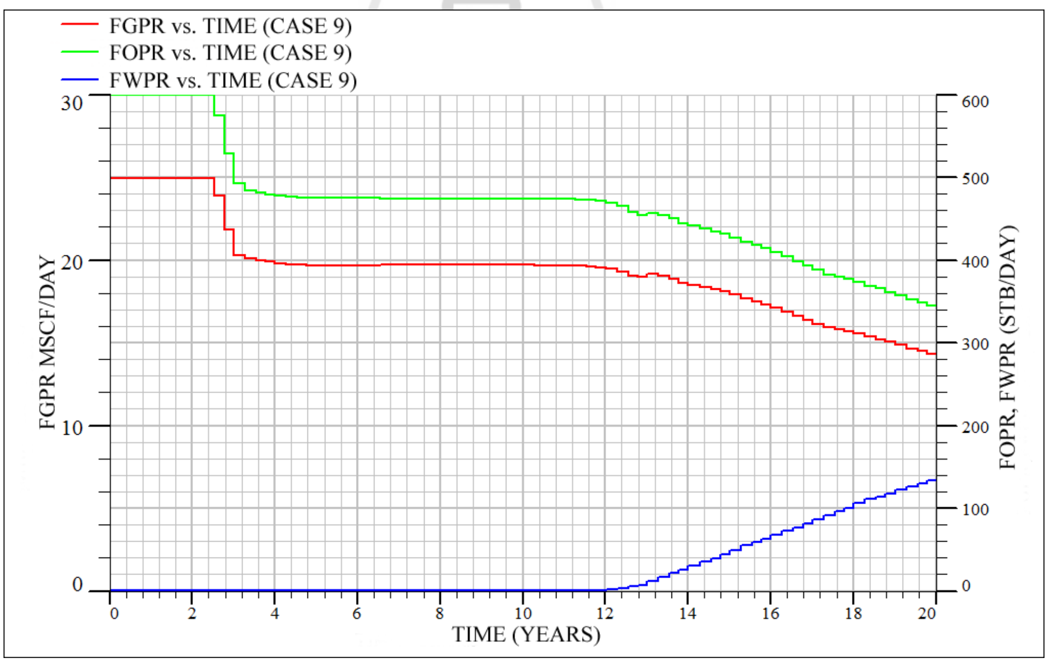


Figure 4.35 Fluids production rate profile vs. time of model case 9.

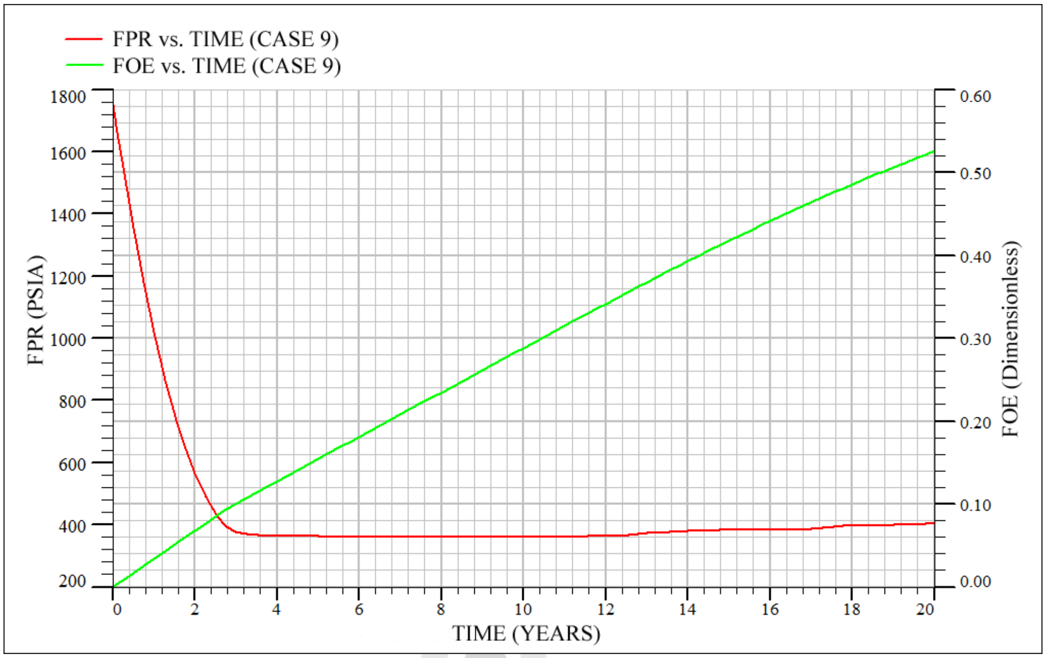


Figure 4.36 Field pressure and oil recovery efficiency vs. time of model case 9.

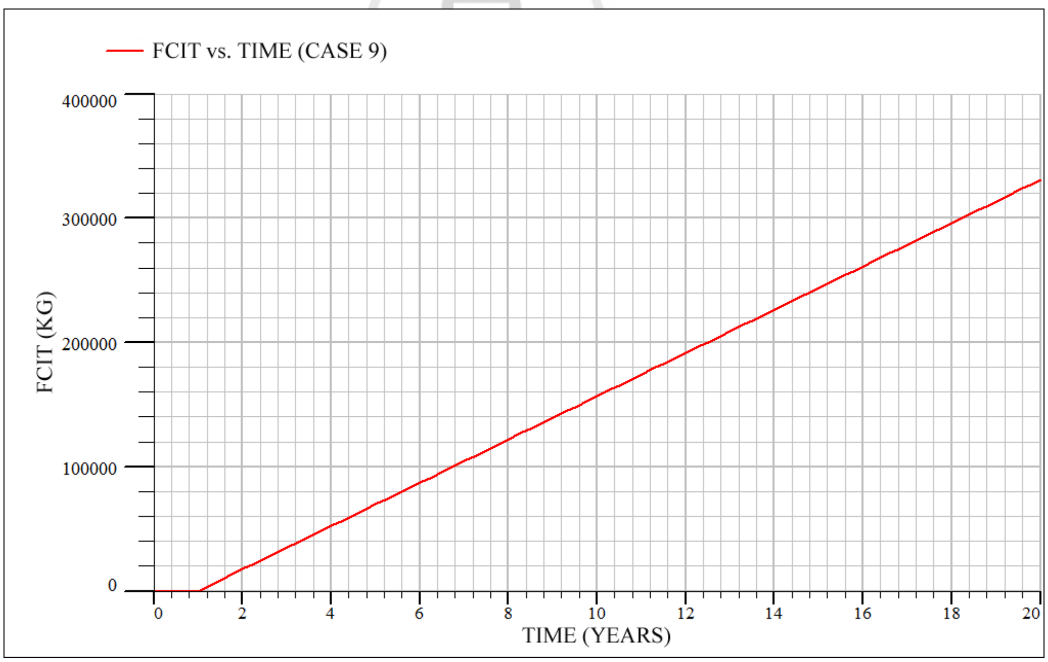


Figure 4.37 Field polymer injection total vs. time of model case 9.

4.1.10 Model case 10 result

Model case 10 direct line drive pattern, produced with water injection at the 1st year and polymer injection at the 2nd year. Production period is 20 years start by 2 production wells at initial oil production rate 300 bbl/d/well and 2 injection wells at water and polymer injection rate 250 bbl/d/well. The simulation results show in Figures 4.38 – 4.42:

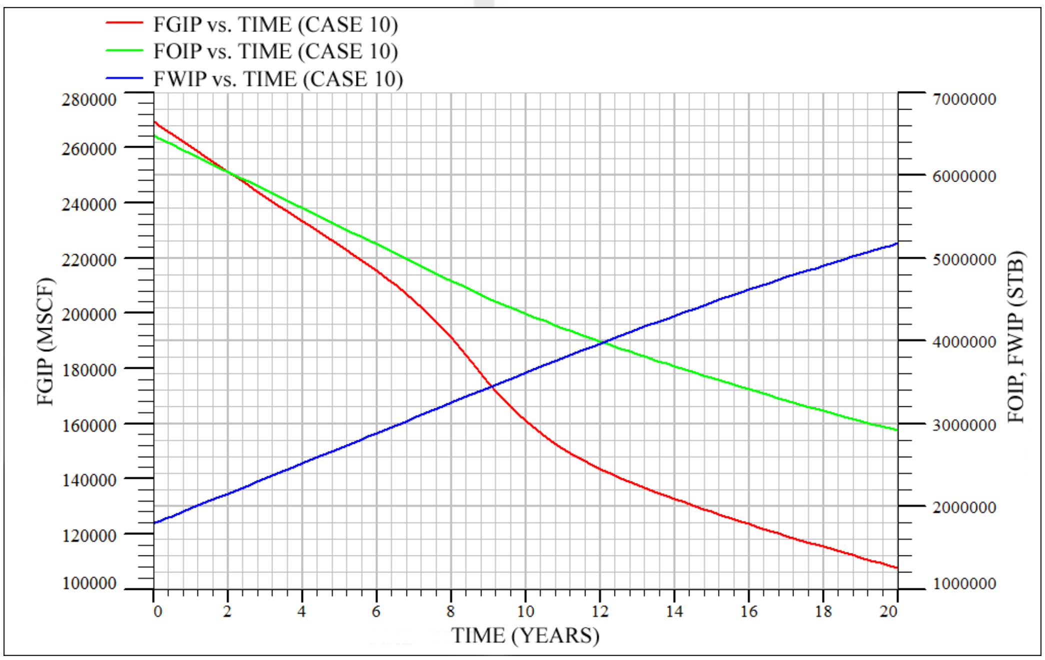


Figure 4.38 Fluid in place profile vs. time of model case 10.

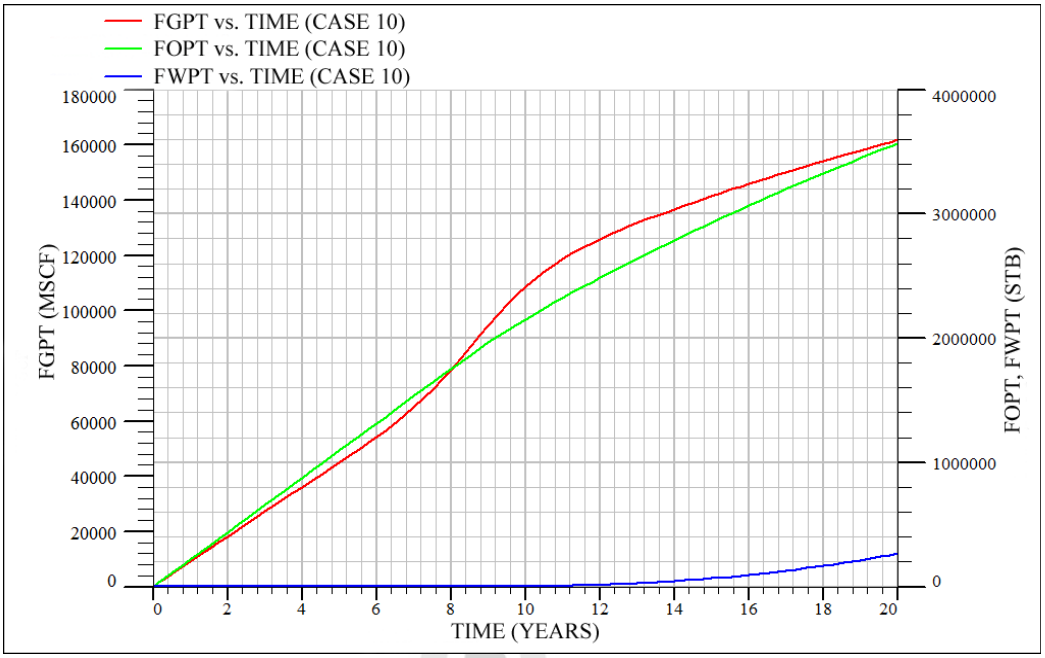


Figure 4.39 Cumulative fluids production profile vs. time of model case 10.

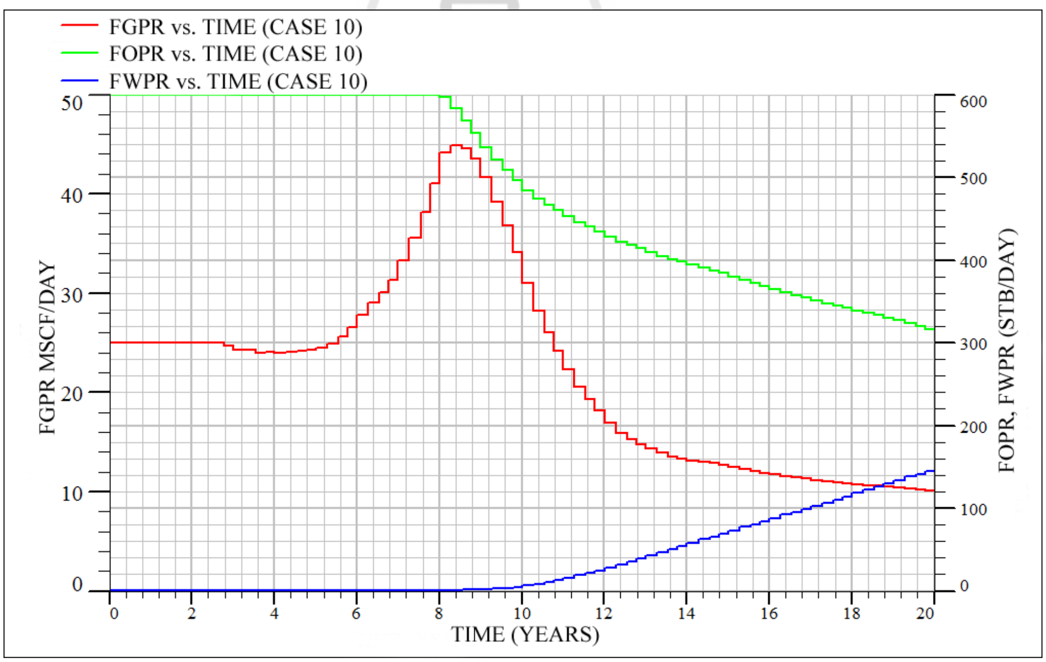


Figure 4.40 Fluids production rate profile vs. time of model case 10.

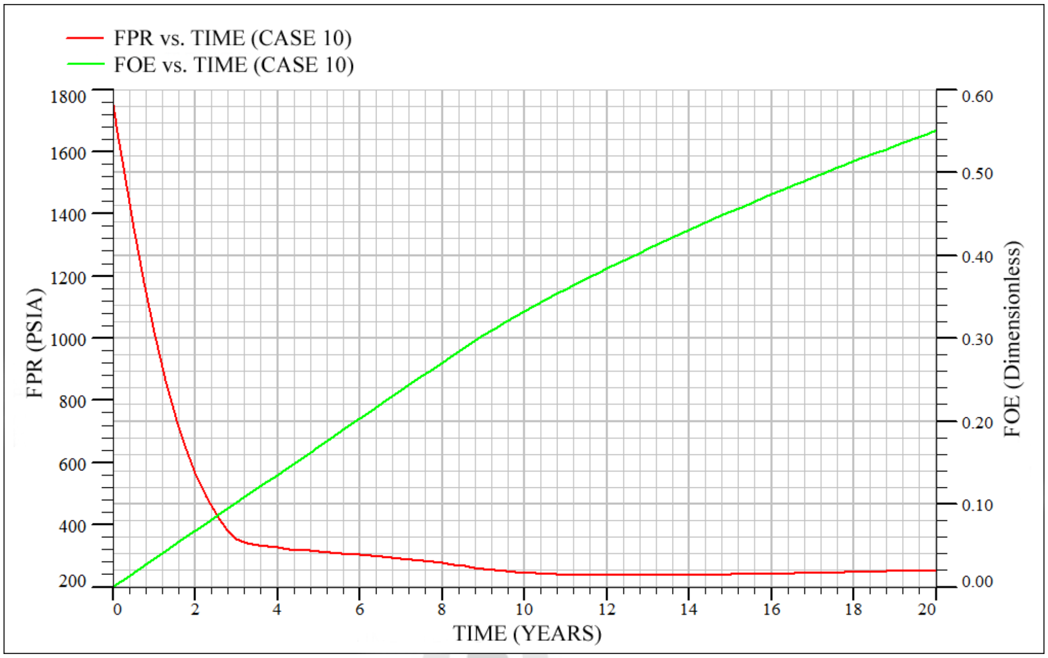


Figure 4.41 Field pressure and oil recovery efficiency vs. time of model case 10.

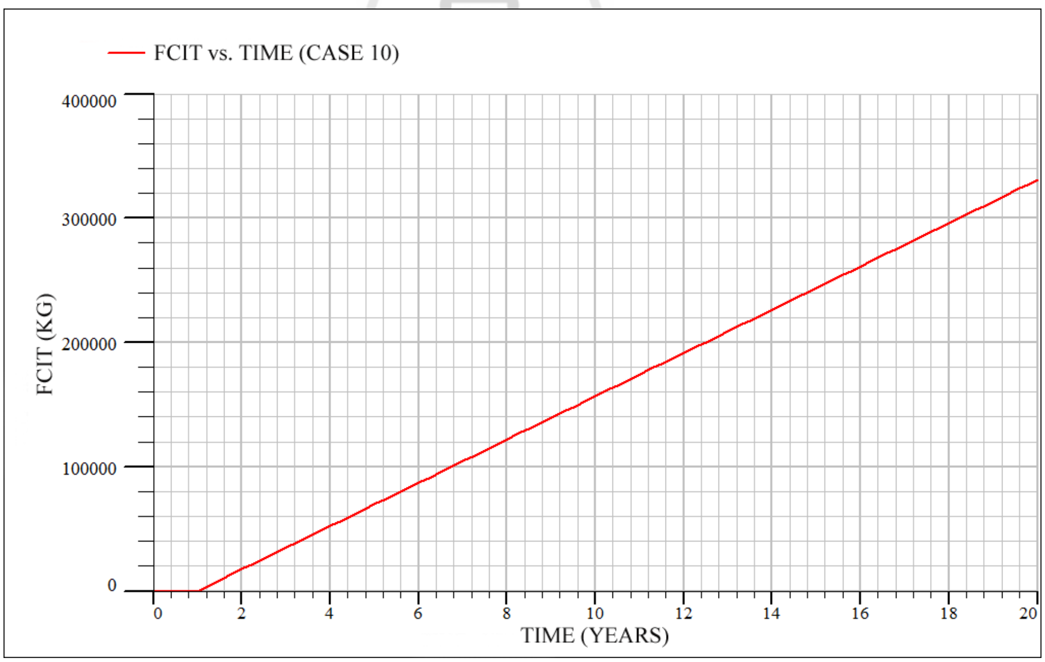


Figure 4.42 Field polymer injection total vs. time of model case 10.

4.1.11 Model case 11 result

Model case 11 staggered line drive pattern, produced with water injection at the 3rd year and polymer injection at the 4th year. Production period is 20 years start by 3 production wells at initial oil production rate 200 bbl/d/well. After 2 years of production period, start water injection by converted 2 production wells to injection well with water and polymer at injection rate 250 bbl/d/well. The remaining production well produced at rate 600 bbl/d. The simulation results show in Figures 4.43 – 4.47:

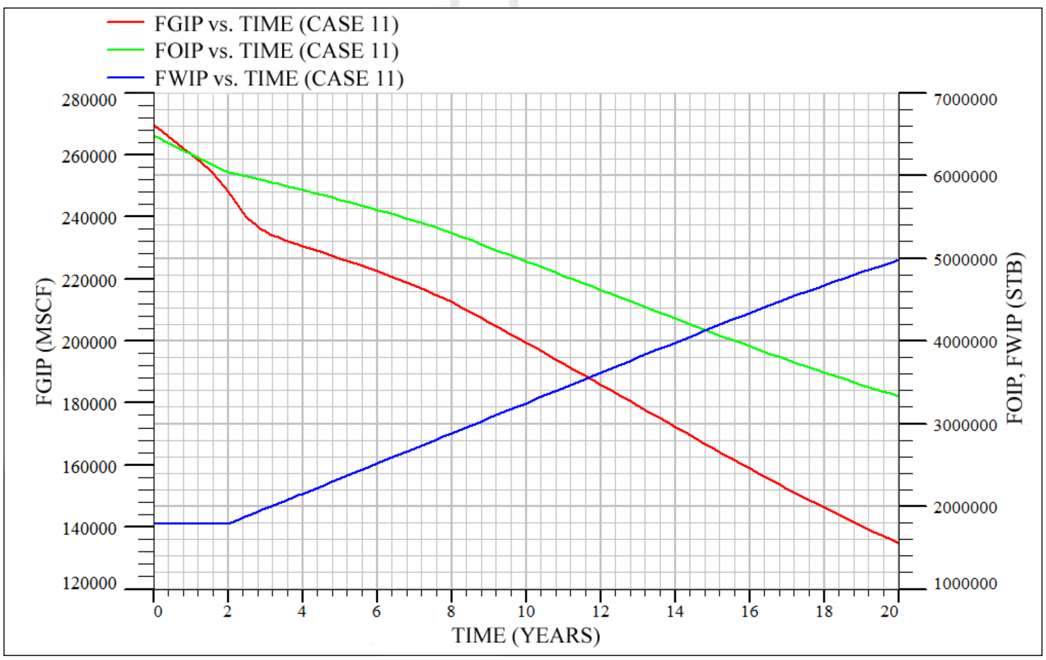


Figure 4.43 Fluid in place profile vs. time of model case 11.

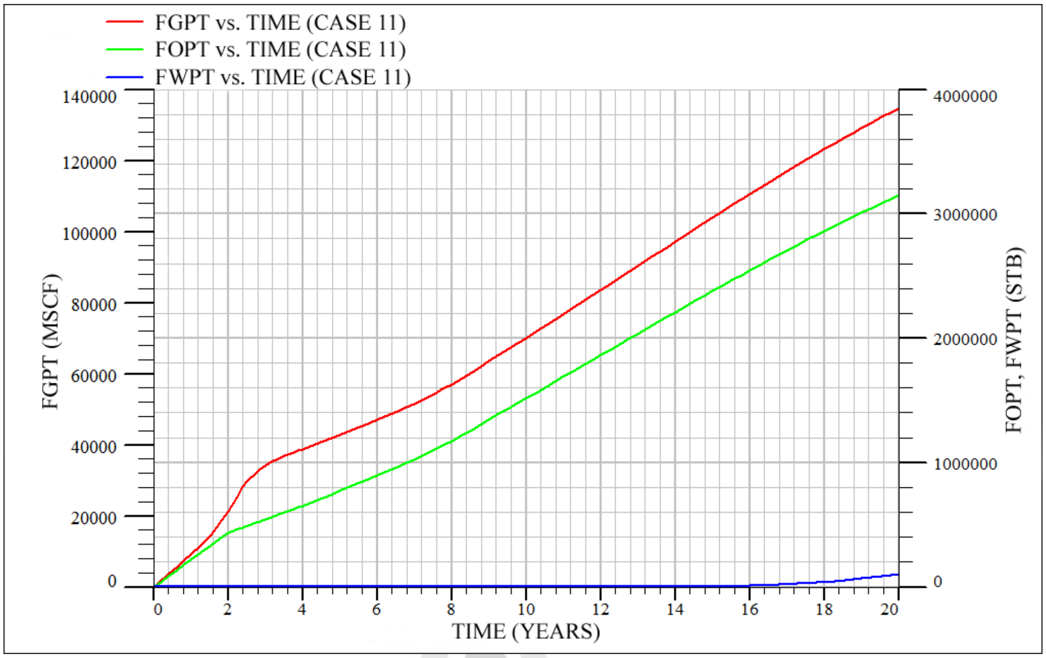


Figure 4.44 Cumulative fluids production profile vs. time of model case 11.

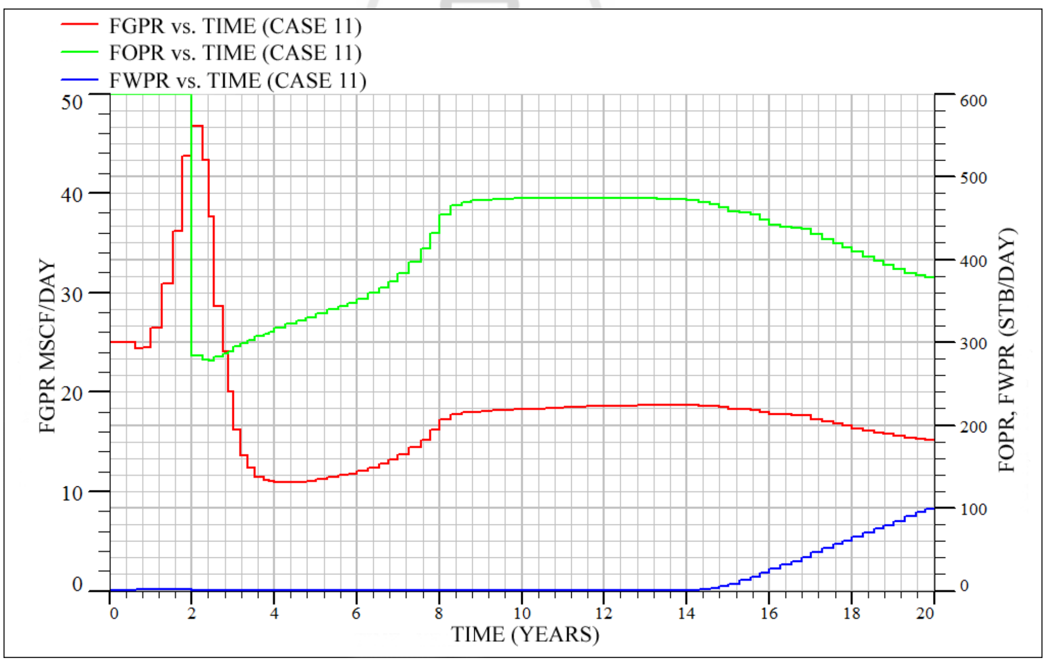


Figure 4.45 Fluids production rate profile vs. time of model case 11.

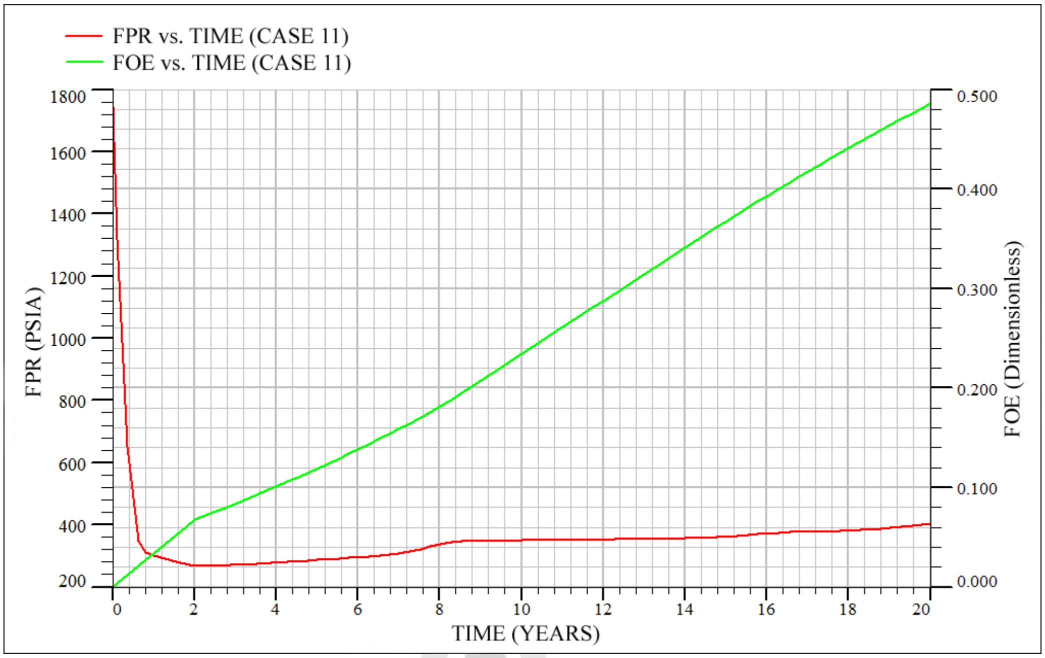


Figure 4.46 Field pressure and oil recovery efficiency vs. time of model case 11.

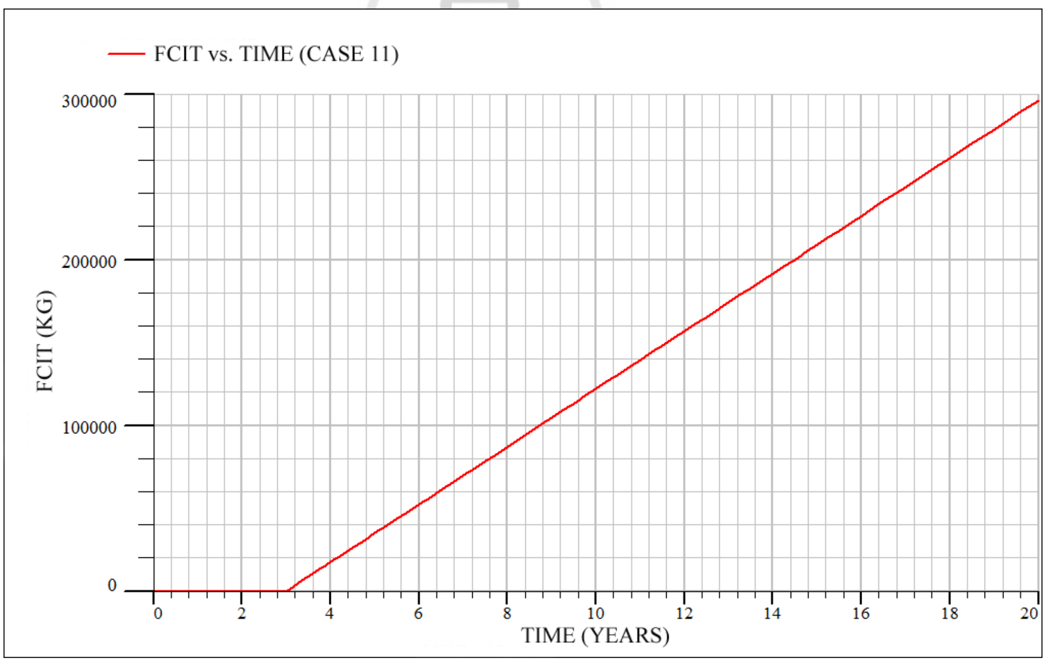


Figure 4.47 Field polymer injection total vs. time of model case 11.

4.1.12 Model case 12 result

Model case 12 direct line drive pattern, produced with water injection at the 3rd year and polymer injection at the 4th year. Production period is 20 years start by 4 production wells at initial oil production rate 150 bbl/d/well. After 2 years of production period, start water injection by converted 2 production wells to injection well with water and polymer at injection rate 250 bbl/d/well. The remaining production well produced at rate 300 bbl/d/well. The simulation results show in Figures 4.48 – 4.52:

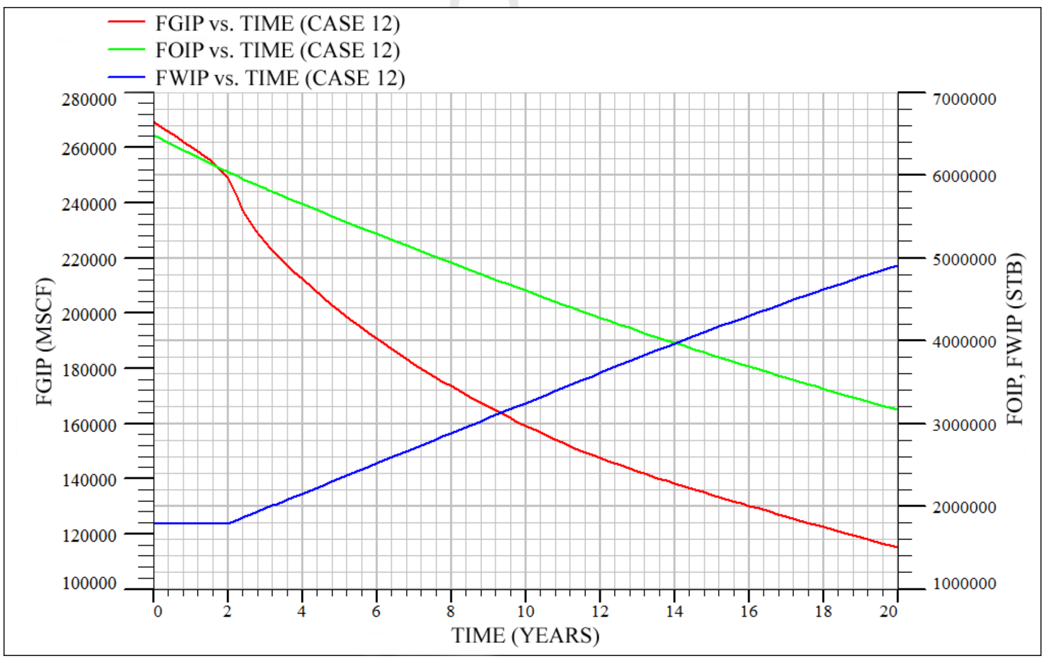


Figure 4.48 Fluid in place profile vs. time of model case 12.

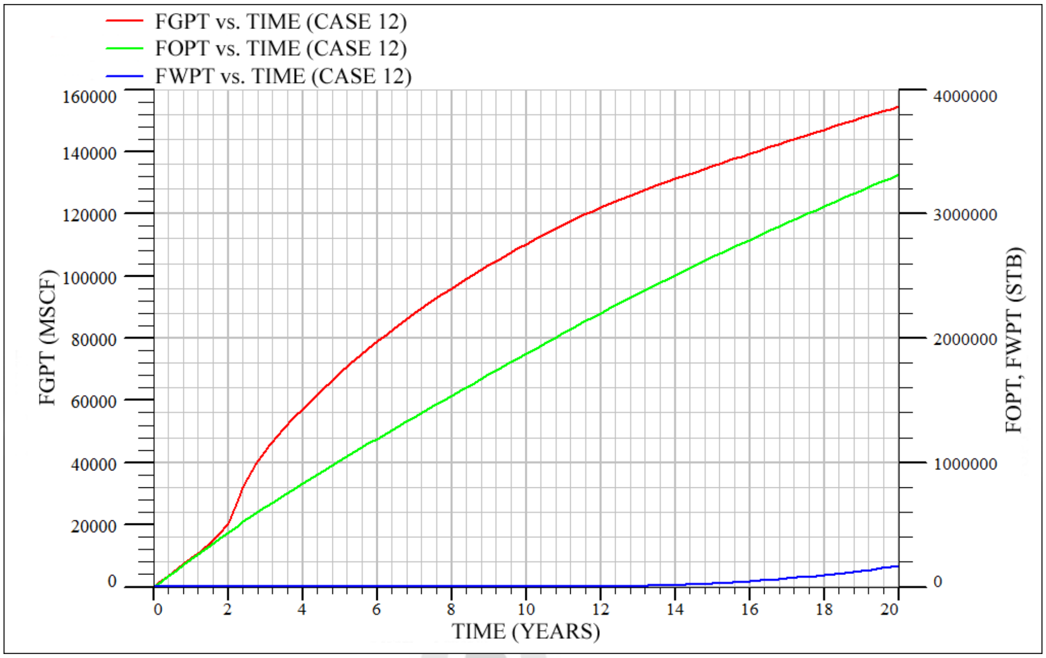


Figure 4.49 Cumulative fluids production profile vs. time of model case 12.

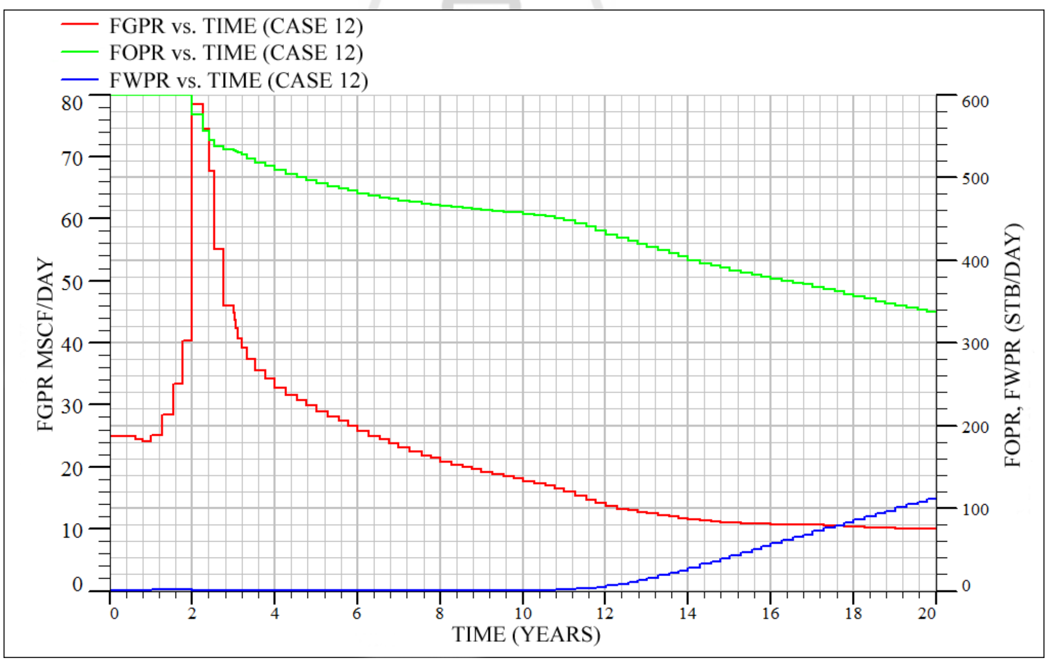


Figure 4.50 Fluids production rate profile vs. time of model case 12.

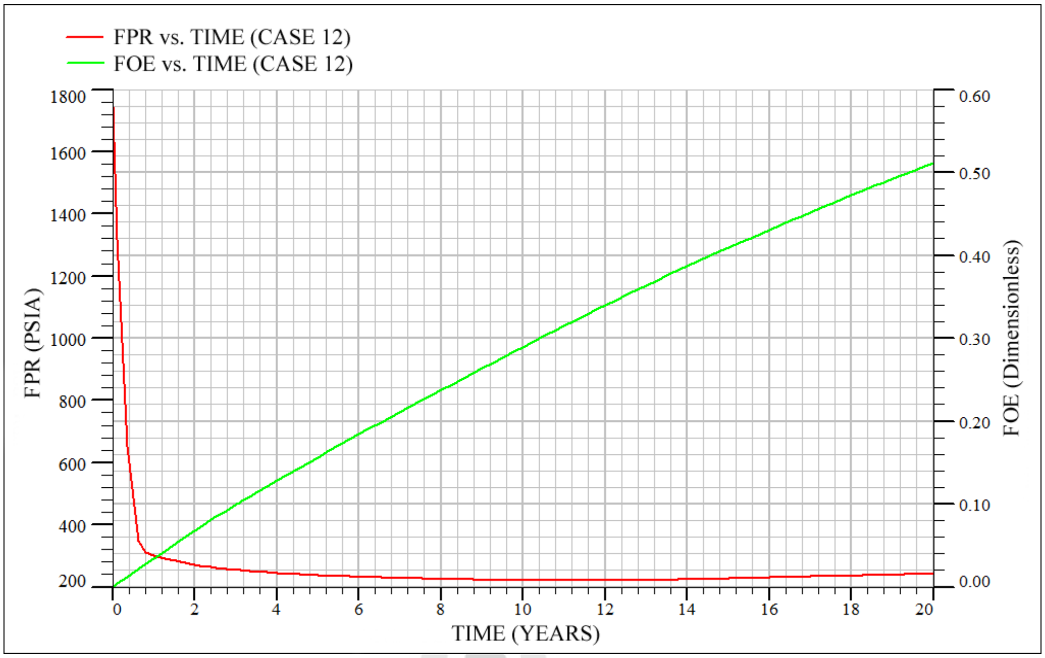


Figure 4.51 Field pressure and oil recovery efficiency vs. time of model case 12.

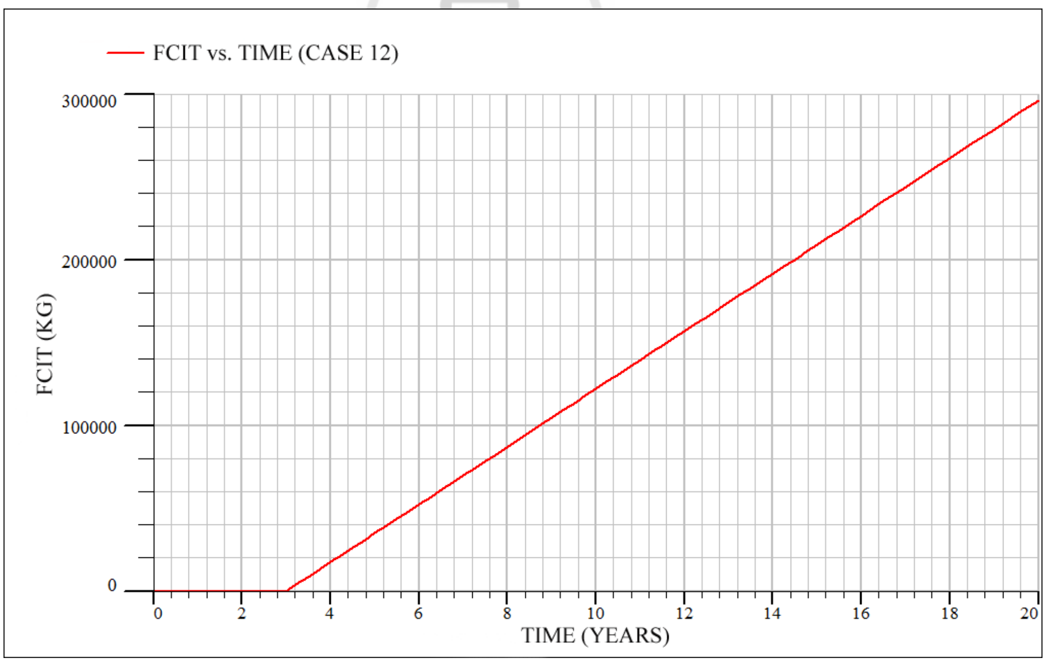


Figure 4.52 Field polymer injection total vs. time of model case 12.

4.1.13 Model case 13 result

Model case 13 staggered line drive pattern, produced with water injection at the 5th year and polymer injection at the 6th year. Production period is 20 years start by 3 production wells at initial oil production rate 200 bbl/d/well. After 4 years of production period, start water injection by converted 2 production wells to injection well with water and polymer at injection rate 250 bbl/d/well. The remaining production well produced at rate 600 bbl/d. The simulation results show in Figures 4.53 – 4.57:

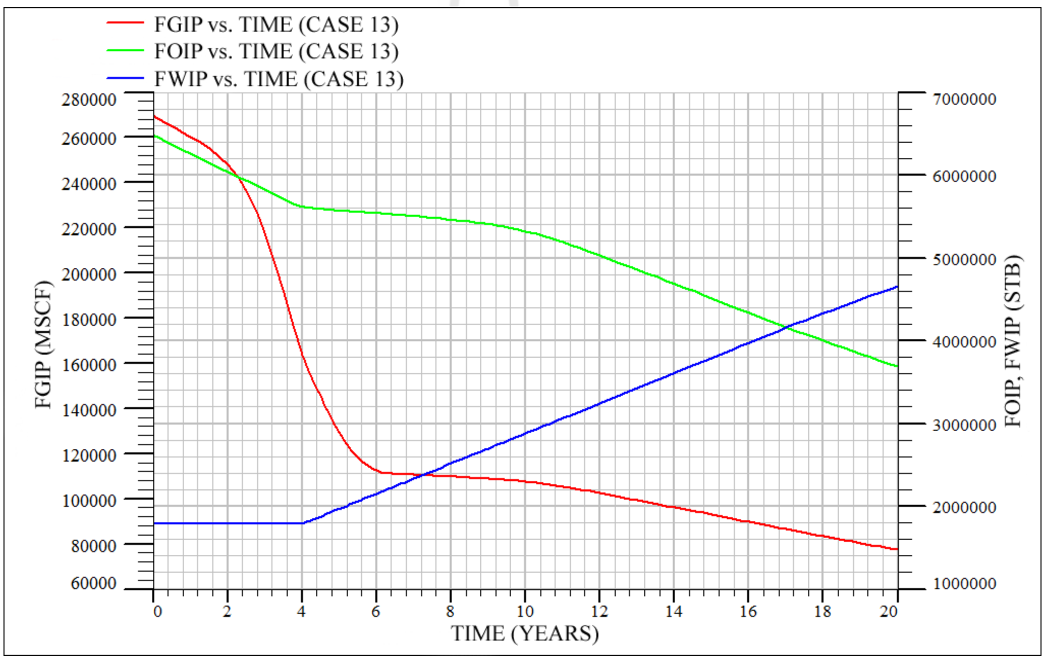


Figure 4.53 Fluid in place profile vs. time of model case 13.

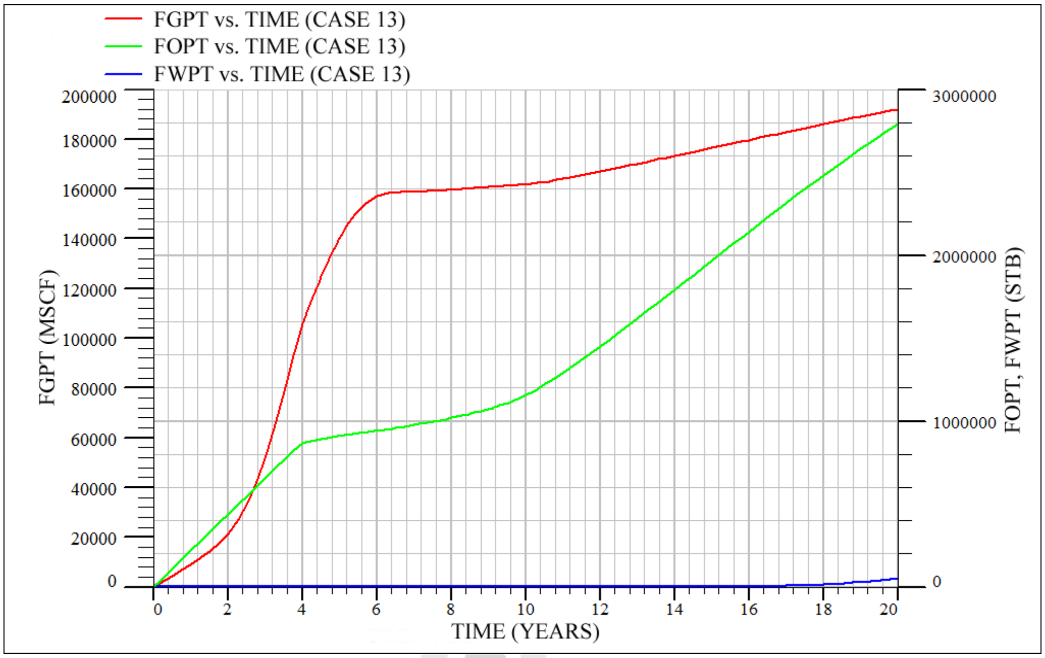


Figure 4.54 Cumulative fluids production profile vs. time of model case 13.

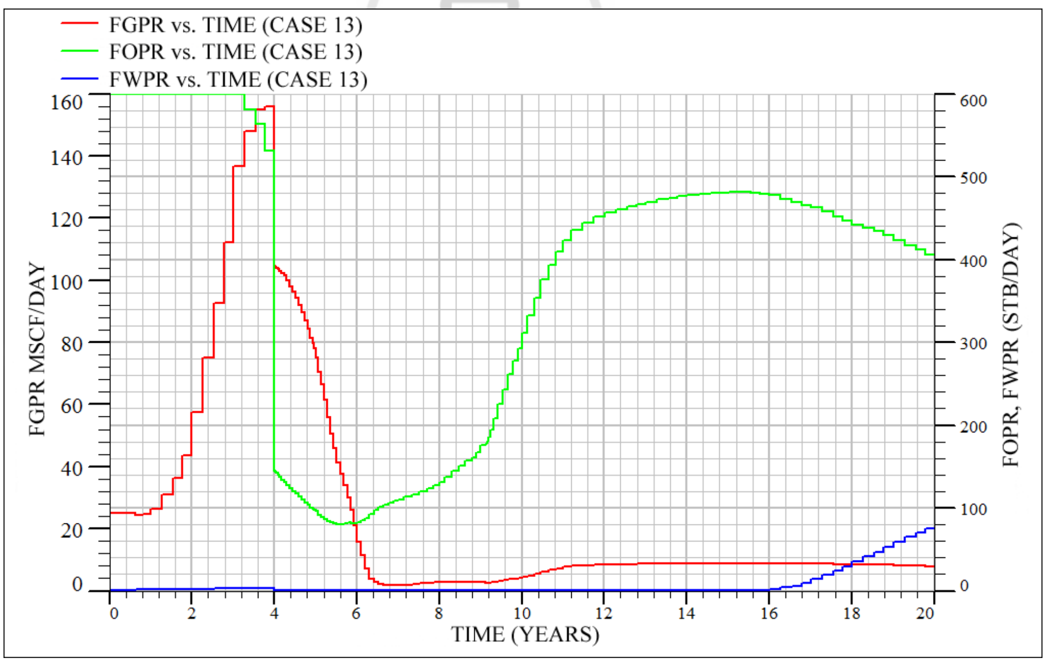


Figure 4.55 Fluids production rate profile vs. time of model case 13.

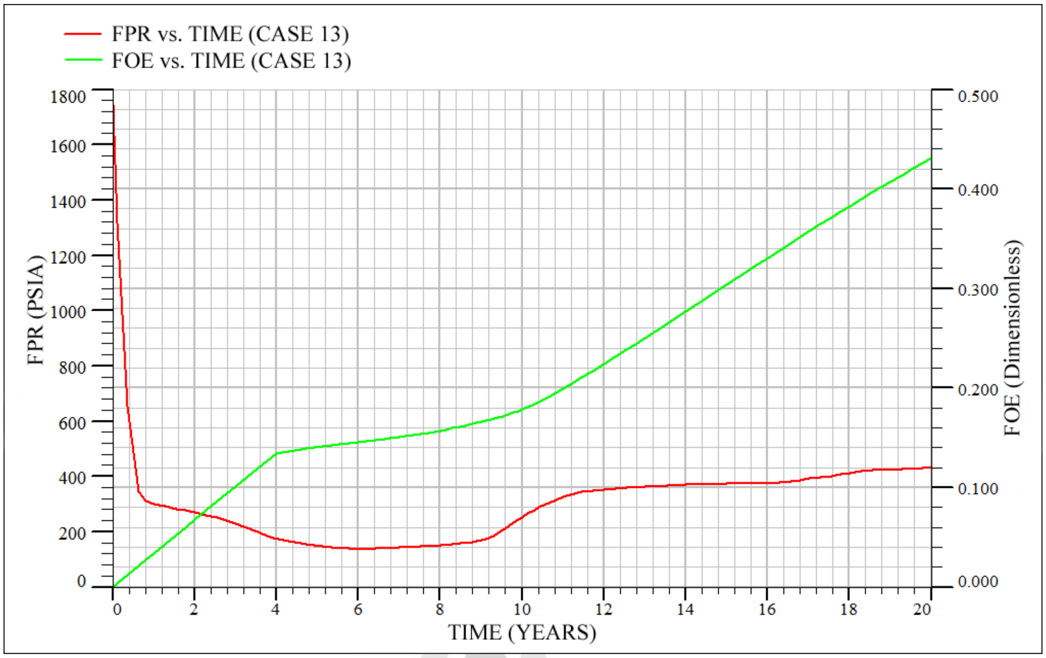


Figure 4.56 Field pressure and oil recovery efficiency vs. time of model case 13.

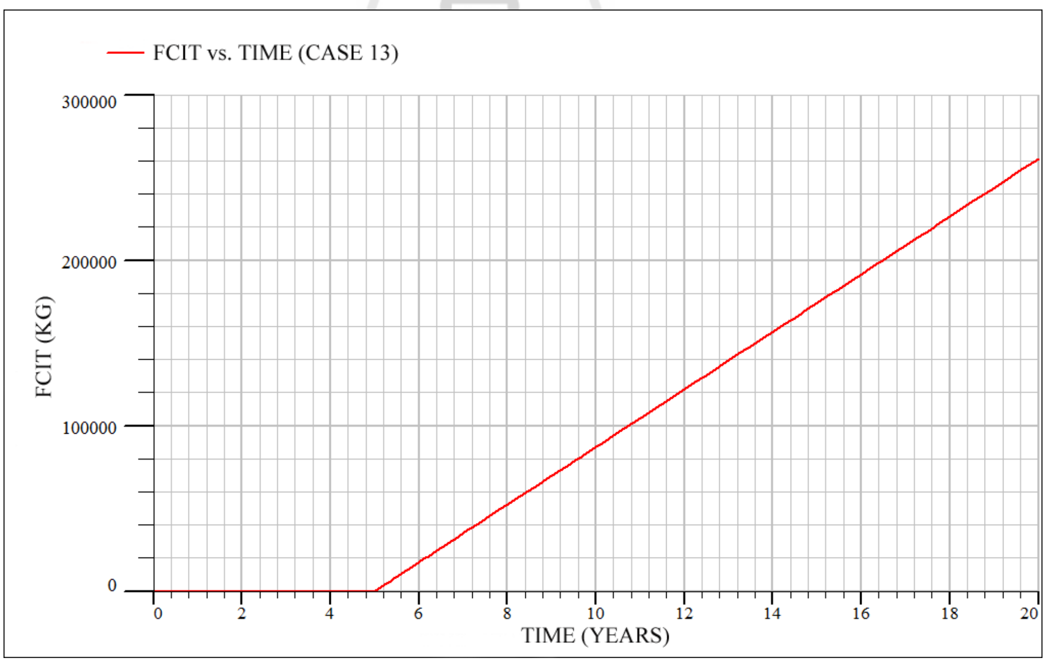


Figure 4.57 Field polymer injection total vs. time of model case 13.

4.1.14 Model case 14 result

Model case 14 direct line drive pattern, produced with water injection at the 5th year and polymer injection at the 6th year. Production period is 20 years start by 4 production wells at initial oil production rate 150 bbl/d/well. After 4 years of production period, start water injection by converted 2 production wells to injection well with water and polymer at injection rate 250 bbl/d/well. The remaining production well produced at rate 300 bbl/d/well. The simulation results show in Figures 4.58 – 4.62:

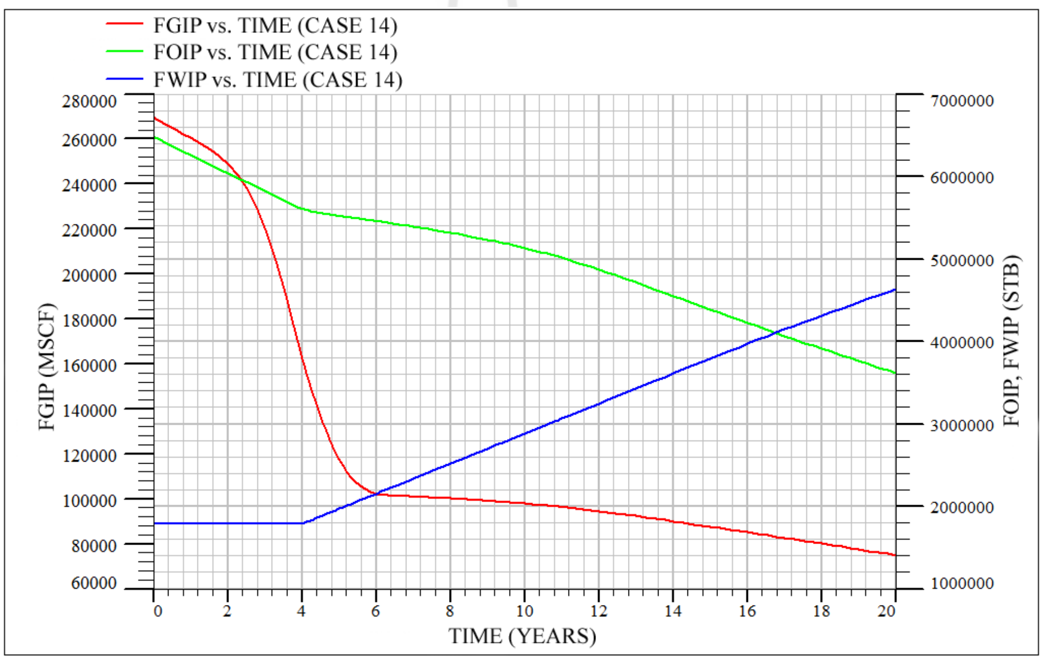


Figure 4.58 Fluid in place profile vs. time of model case 14.

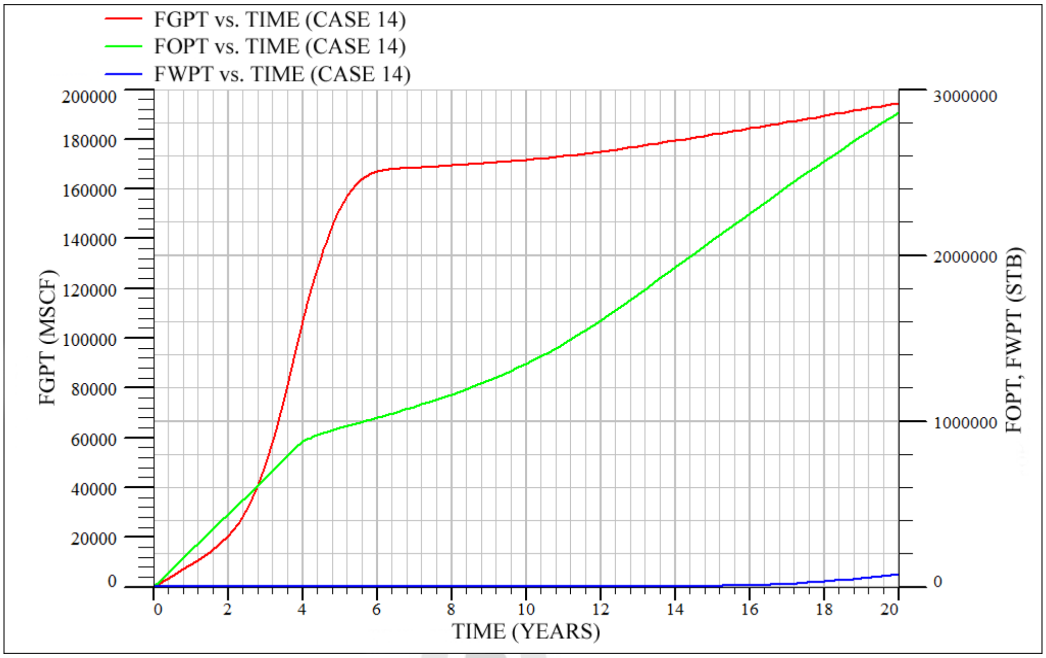


Figure 4.59 Cumulative fluids production profile vs. time of model case 14.

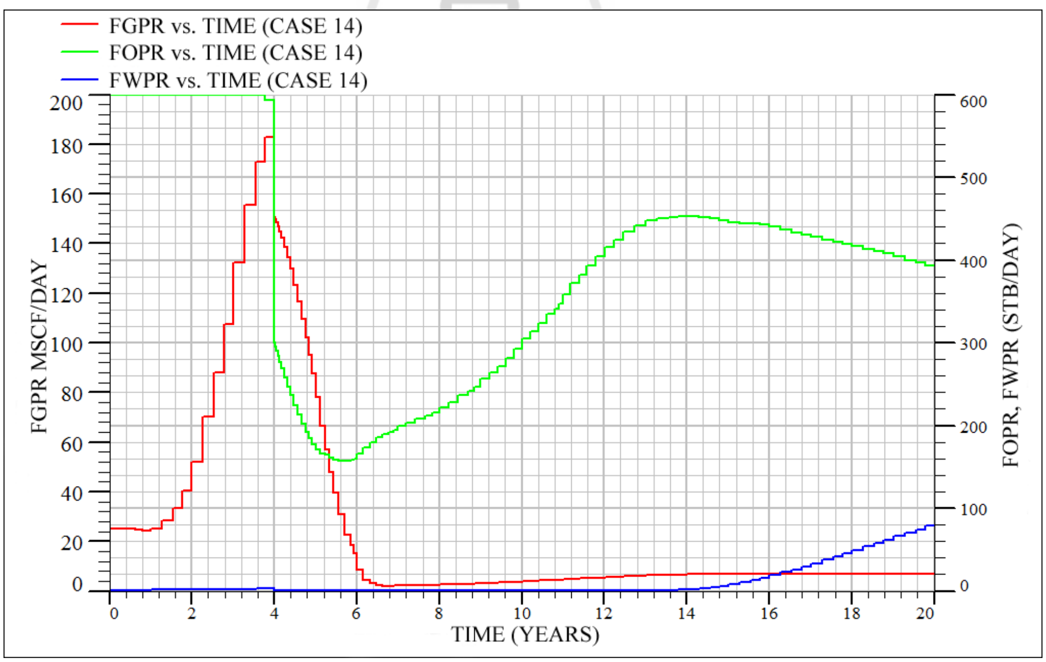


Figure 4.60 Fluids production rate profile vs. time of model case 14.

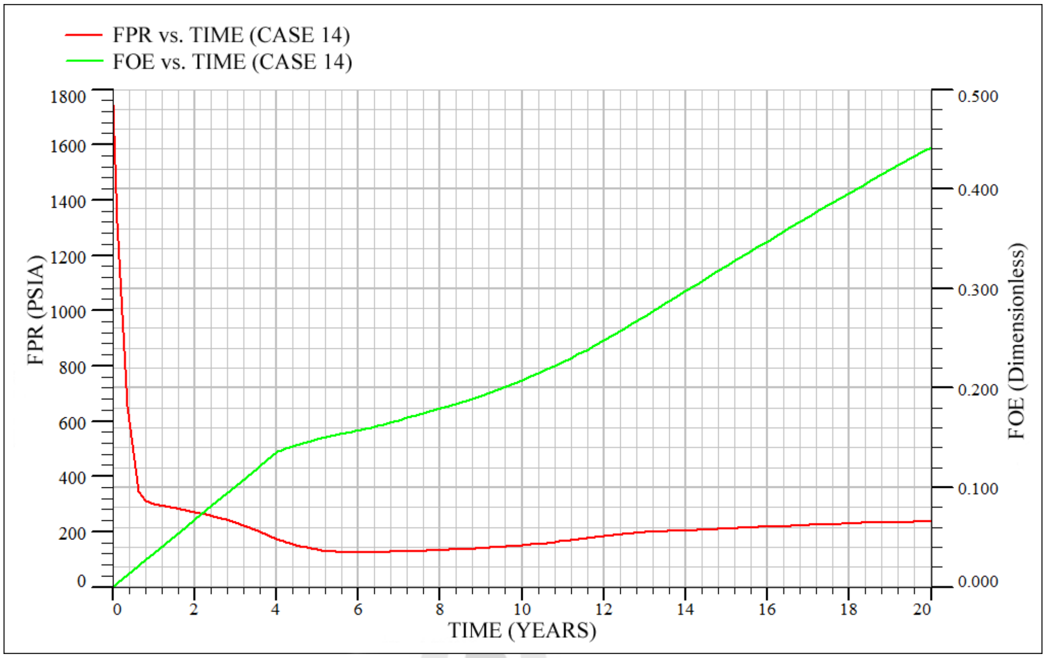


Figure 4.61 Field pressure and oil recovery efficiency vs. time of model case 14.

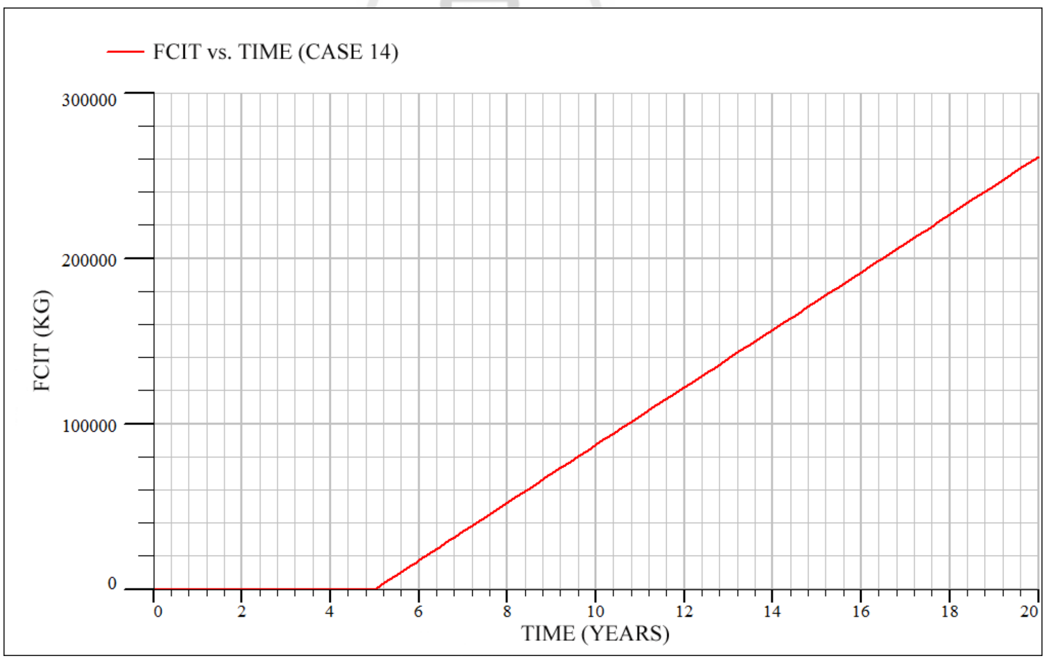


Figure 4.62 Field polymer injection total vs. time of model case 14.

4.2 Summary of oil recovery results

The reserved size of reservoir is 6,478,346 bbl. Summary of oil recovery results are shown in Table 4.2.

Table 4.2 Summary of oil recovery results.

Case study	Flood pattern	Type of fluid to inject	Year to inject	Product rate (bbl)	Inject rate (bbl)	Cum. Oil Production (MMbbl)	Amount of polymer to inject (ton)	RF (%)
1	Staggered line	No inject	-	600	0	1.655	-	25.55
2	Direct line	No inject	-	600	0	1.687	-	26.05
3	Staggered line	Water	1st	600	500	3.107	-	47.96
4	Direct line	Water	1st	600	500	3.192	-	49.28
5	Staggered line	Water	3rd	600	500	2.920	-	45.07
6	Direct line	Water	3rd	600	500	2.993	-	46.20
7	Staggered line	Water	5th	600	500	2.614	-	40.35
8	Direct line	Water	5th	600	500	2.621	-	40.46
9	Staggered line	Polymer	1st	600	500	3.408	331	52.61
10	Direct line	Polymer	1st	600	500	3.565	331	55.03
11	Staggered line	Polymer	3rd	600	500	3.147	296	48.58
12	Direct line	Polymer	3rd	600	500	3.313	296	51.14
13	Staggered line	Polymer	5th	600	500	2.792	261	43.09
14	Direct line	Polymer	5th	600	500	2.863	261	44.19

CHAPTER V

ECONOMIC ANALYSIS

5.1 Objective

This chapter objective is to determine economic parameters that used to analyze project investment possibility including of the net present value (NPV), profit investment ratio (PIR) and internal rate of return (IRR). Compare with all cases study to find the best case for the Suphan Buri Basin.

5.2 Exploration and production schedule

The exploration and production period are following under the Petroleum Acts "Thailand III" statute are divided into 4 years of exploration period and 20 years of production period. 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

5.3 Economic assumption

5.3.1 Basic assumptions

a. Oil price (US$)	95
b. Income tax (%)	50

c. Escalation factor (%) 2

d. Discount rate (%) 7.5

e. Tangible cost (%) 20

f. Intangible cost (%) 80

g. Depreciation of tangible cost (%) 20

i. 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

5.3.2 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. The central bank discount rate of Thailand is 7.5 % (Bank of Thailand, November 2013).

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

e. The expense used in cash flow analysis is list in Table 5.1.

Table 5.1 Cash flow expenditure cost detail.

Expenditure Cost Detail	All Case Study
Concession (MMUS$)	0.5
Geological and geophysical survey (MMUS$)	2
Production facility (MMUS$)	20
Drilling and completion production well (MMUS$/well)	2
Drilling and completion injection well (MMUS$/well)	1.5
Drilling exploration & appraisal well (MMUS$)	1
Facility costs of water injection well (US$/well)	63,500
Facility costs of polymer injection well (US$/well)	65,000
Maintenance costs of water injection well (US$/year)	42,500
Maintenance costs of polymer injection well (US$/year)	42,500
Cost of polymer including transportation (US$/kg)	7
Abandonment cost (US$)	12,500
Operating costs of production well (US$/bbl)	20
Operating cost of water injection (US$/bbl)	0.5
Operational cost of polymer Injection (US$/bbl incremental of oil)	1.0

5.4 Cash flow summary results table

The economic analysis is calculated and analyzed by using Microsoft Excels spreadsheet. The economic summary results of all case studies are illustrated in Tables 5.2-5.15. In Tables 5.2-5.15 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 of all case studies are illustrated in Table 5.16.

Table 5.2 Cash flow summary of case 1. Recovery factor = 25.55%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	26.000	0.000	0.000	0.000	-9.040	-6.769
5	219,000	20.805	0.000	4.741	1.040	0.000	10.784	7.511
6	219,000	20.805	0.000	4.836	1.040	5.344	5.344	3.463
7	219,600	20.862	0.000	4.946	1.043	5.316	5.316	3.204
8	208,236	19.782	0.000	4.784	0.989	4.885	4.885	2.739
9	150,842	14.330	0.000	3.535	0.716	5.039	5.039	2.628
10	103,573	9.839	0.000	2.476	0.492	3.436	3.436	1.667
11	77,728	7.384	0.000	1.895	0.369	2.560	2.560	1.155
12	62,001	5.890	0.000	1.542	0.295	2.027	2.027	0.851
13	52,582	4.995	0.000	1.334	0.250	1.706	1.706	0.666
14	45,833	4.354	0.000	1.186	0.218	1.475	1.475	0.536
15	40,848	3.881	0.000	1.078	0.194	1.304	1.304	0.441
16	36,739	3.490	0.000	0.989	0.175	1.163	1.163	0.366
17	33,380	3.171	0.000	0.916	0.159	1.048	1.048	0.307
18	30,759	2.922	0.000	0.861	0.146	0.957	0.957	0.260
19	28,918	2.747	0.000	0.826	0.137	0.892	0.892	0.226
20	27,343	2.598	0.000	0.797	0.130	0.836	0.836	0.197
21	26,103	2.480	0.000	0.776	0.124	0.790	0.790	0.173
22	25,068	2.381	0.000	0.760	0.119	0.751	0.751	0.153
23	24,228	2.302	0.000	0.749	0.115	0.719	0.719	0.136
24	23,619	2.244	0.000	0.745	0.112	0.693	0.693	0.122
Total	**1,655,401**	**157.263**	**29.500**	**39.771**	**7.863**	**40.943**	**39.186**	**17.033**
						IRR	**39.73%**	**29.98%**
						PIR	**1.328**	**0.577**

Table 5.3 Cash flow summary of case 2. Recovery factor = 26.05%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	28.000	0.000	0.000	0.000	-10.720	-8.027
5	219,000	20.805	0.000	4.741	1.040	0.000	10.704	7.456
6	219,000	20.805	0.000	4.836	1.040	5.304	5.304	3.437
7	219,600	20.862	0.000	4.946	1.043	5.276	5.276	3.180
8	208,236	19.782	0.000	4.784	0.989	4.845	4.845	2.716
9	150,842	14.330	0.000	3.535	0.716	5.039	5.039	2.628
10	103,573	9.839	0.000	2.476	0.492	3.436	3.436	1.667
11	77,728	7.384	0.000	1.895	0.369	2.560	2.560	1.155
12	62,001	5.890	0.000	1.542	0.295	2.027	2.027	0.851
13	52,582	4.995	0.000	1.334	0.250	1.706	1.706	0.666
14	45,833	4.354	0.000	1.186	0.218	1.475	1.475	0.536
15	40,848	3.881	0.000	1.078	0.194	1.304	1.304	0.441
16	36,739	3.490	0.000	0.989	0.175	1.163	1.163	0.366
17	33,380	3.171	0.000	0.916	0.159	1.048	1.048	0.307
18	30,759	2.922	0.000	0.861	0.146	0.957	0.957	0.260
19	28,918	2.747	0.000	0.826	0.137	0.892	0.892	0.226
20	27,343	2.598	0.000	0.797	0.130	0.836	0.836	0.197
21	26,103	2.480	0.000	0.776	0.124	0.790	0.790	0.173
22	25,068	2.381	0.000	0.760	0.119	0.751	0.751	0.153
23	24,228	2.302	0.000	0.749	0.115	0.719	0.719	0.136
24	23,619	2.244	0.000	0.745	0.112	0.693	0.693	0.122
Total	**1,655,401**	**157.263**	**31.500**	**39.771**	**7.863**	**40.823**	**37.306**	**15.646**
						IRR	**35.04%**	**25.62%**
						PIR	**1.184**	**0.497**

Table 5.4 Cash flow summary of case 3. Recovery factor = 47.96%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	22.131	0.000	0.000	0.000	-5.706	-4.273
5	219,000	20.805	0.000	4.886	1.040	0.783	9.989	6.958
6	219,000	20.805	0.000	4.984	1.040	5.338	5.338	3.459
7	211,752	20.116	0.000	4.920	1.006	5.042	5.042	3.039
8	177,053	16.820	0.000	4.221	0.841	3.826	3.826	2.145
9	174,036	16.533	0.000	4.235	0.827	5.736	5.736	2.992
10	173,472	16.480	0.000	4.306	0.824	5.675	5.675	2.753
11	173,857	16.516	0.000	4.402	0.826	5.644	5.644	2.548
12	173,331	16.466	0.000	4.477	0.823	5.583	5.583	2.344
13	173,072	16.442	0.000	4.560	0.822	5.530	5.530	2.160
14	169,398	16.093	0.000	4.556	0.805	5.366	5.366	1.950
15	162,801	15.466	0.000	4.473	0.773	5.110	5.110	1.727
16	153,269	14.561	0.000	4.306	0.728	4.763	4.763	1.498
17	141,083	13.403	0.000	4.057	0.670	4.338	4.338	1.269
18	132,095	12.549	0.000	3.887	0.627	4.017	4.017	1.093
19	123,479	11.730	0.000	3.719	0.587	3.713	3.713	0.940
20	116,058	11.026	0.000	3.576	0.551	3.449	3.449	0.812
21	110,569	10.504	0.000	3.485	0.525	3.247	3.247	0.711
22	105,853	10.056	0.000	3.411	0.503	3.071	3.071	0.626
23	101,066	9.601	0.000	3.332	0.480	2.895	2.895	0.549
24	96,844	9.200	0.000	3.266	0.460	2.737	2.737	0.483
Total	**3,107,086**	**295.173**	**25.631**	**83.056**	**14.759**	**85.864**	**85.864**	**32.779**
						IRR	**50.24%**	**39.76%**
						PIR	**3.350**	**1.279**

Table 5.5 Cash flow summary of case 4. Recovery factor = 49.28%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	24.131	0.000	0.000	0.000	-7.386	-5.531
5	219,000	20.805	0.000	4.886	1.040	0.000	10.693	7.448
6	219,000	20.805	0.000	4.984	1.040	5.298	5.298	3.433
7	219,600	20.862	0.000	5.097	1.043	5.268	5.268	3.175
8	219,000	20.805	0.000	5.185	1.040	5.197	5.197	2.914
9	219,000	20.805	0.000	5.289	1.040	7.238	7.238	3.775
10	219,000	20.805	0.000	5.394	1.040	7.185	7.185	3.486
11	219,600	20.862	0.000	5.517	1.043	7.151	7.151	3.227
12	211,584	20.101	0.000	5.428	1.005	6.834	6.834	2.869
13	178,490	16.957	0.000	4.697	0.848	5.706	5.706	2.228
14	155,135	14.738	0.000	4.187	0.737	4.907	4.907	1.783
15	140,717	13.368	0.000	3.890	0.668	4.405	4.405	1.489
16	130,390	12.387	0.000	3.690	0.619	4.039	4.039	1.270
17	123,336	11.717	0.000	3.570	0.586	3.781	3.781	1.106
18	117,558	11.168	0.000	3.479	0.558	3.565	3.565	0.970
19	112,627	10.700	0.000	3.409	0.535	3.378	3.378	0.855
20	107,476	10.210	0.000	3.326	0.511	3.187	3.187	0.750
21	102,533	9.741	0.000	3.246	0.487	3.004	3.004	0.658
22	97,566	9.269	0.000	3.160	0.463	2.823	2.823	0.575
23	92,636	8.800	0.000	3.071	0.440	2.645	2.645	0.501
24	88,132	8.373	0.000	2.991	0.419	2.482	2.482	0.437
Total	**3,192,379**	**303.276**	**27.631**	**84.495**	**15.164**	**88.090**	**87.897**	**34.418**
						IRR	**48.99%**	**38.59%**
						PIR	**3.181**	**1.246**

Table 5.6 Cash flow summary of case 5. Recovery factor = 45.07%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	26.000	0.000	0.000	0.000	-9.040	-6.769
5	219,000	20.805	0.000	4.741	1.040	0.000	10.784	7.511
6	219,000	20.805	0.000	4.836	1.040	5.344	5.344	3.463
7	103,560	9.838	0.156	2.483	0.492	1.286	1.286	0.775
8	110,899	10.535	0.000	2.701	0.527	1.521	1.521	0.853
9	118,052	11.215	0.000	2.923	0.561	3.853	3.853	2.009
10	124,306	11.809	0.000	3.131	0.590	4.031	4.031	1.956
11	132,565	12.594	0.000	3.395	0.630	4.284	4.284	1.934
12	148,372	14.095	0.000	3.856	0.705	4.767	4.767	2.002
13	169,932	16.144	0.000	4.480	0.807	5.428	5.428	2.120
14	172,832	16.419	0.000	4.645	0.821	5.477	5.477	1.990
15	173,499	16.482	0.000	4.755	0.824	5.451	5.451	1.842
16	171,806	16.322	0.000	4.805	0.816	5.350	5.350	1.682
17	164,411	15.619	0.000	4.698	0.781	5.070	5.070	1.483
18	154,995	14.725	0.000	4.528	0.736	4.730	4.730	1.287
19	143,329	13.616	0.000	4.286	0.681	4.325	4.325	1.095
20	134,139	12.743	0.000	4.103	0.637	4.001	4.001	0.942
21	124,531	11.830	0.000	3.900	0.592	3.670	3.670	0.804
22	116,817	11.098	0.000	3.744	0.555	3.399	3.399	0.693
23	111,232	10.567	0.000	3.646	0.528	3.196	3.196	0.606
24	106,393	10.107	0.000	3.567	0.505	3.018	3.018	0.532
Total	**2,919,671**	**277.369**	**29.656**	**79.222**	**13.868**	**78.203**	**76.446**	**25.807**
						IRR	**35.95%**	**26.46%**
						PIR	**2.578**	**0.870**

Table 5.7 Cash flow summary of case 6. Recovery factor = 46.20%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	28.000	0.000	0.000	0.000	-10.720	-8.027
5	219,000	20.805	0.000	4.741	1.040	0.000	10.704	7.456
6	219,000	20.805	0.000	4.836	1.040	5.304	5.304	3.437
7	201,391	19.132	0.156	4.687	0.957	4.559	4.559	2.748
8	191,097	18.154	0.000	4.544	0.908	4.178	4.178	2.343
9	185,807	17.652	0.000	4.511	0.883	6.116	6.116	3.190
10	181,365	17.230	0.000	4.495	0.861	5.924	5.924	2.874
11	178,398	16.948	0.000	4.513	0.847	5.794	5.794	2.615
12	174,937	16.619	0.000	4.517	0.831	5.636	5.636	2.366
13	169,385	16.092	0.000	4.466	0.805	5.410	5.410	2.113
14	154,894	14.715	0.000	4.180	0.736	4.899	4.899	1.780
15	138,164	13.126	0.000	3.823	0.656	4.323	4.323	1.461
16	125,693	11.941	0.000	3.563	0.597	3.890	3.890	1.223
17	117,973	11.207	0.000	3.423	0.560	3.612	3.612	1.056
18	112,908	10.726	0.000	3.349	0.536	3.420	3.420	0.930
19	110,089	10.458	0.000	3.336	0.523	3.300	3.300	0.835
20	107,756	10.237	0.000	3.334	0.512	3.195	3.195	0.752
21	105,538	10.026	0.000	3.335	0.501	3.095	3.095	0.678
22	103,035	9.788	0.000	3.326	0.489	2.986	2.986	0.608
23	99,866	9.487	0.000	3.295	0.474	2.859	2.859	0.542
24	96,526	9.170	0.000	3.256	0.458	2.728	2.728	0.481
Total	**2,992,819**	**284.318**	**31.656**	**79.529**	**14.216**	**81.230**	**77.714**	**28.461**
						IRR	**38.41%**	**28.76%**
						PIR	**2.455**	**0.899**

Table 5.8 Cash flow summary of case 7. Recovery factor = 40.35%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	26.000	0.000	0.000	0.000	-9.040	-6.769
5	219,000	20.805	0.000	4.741	1.040	0.000	10.784	7.511
6	219,000	20.805	0.000	4.836	1.040	5.344	5.344	3.463
7	219,600	20.862	0.000	4.946	1.043	5.316	5.316	3.204
8	208,236	19.782	0.000	4.784	0.989	4.885	4.885	2.739
9	43,698	4.151	0.286	1.181	0.208	1.369	1.369	0.714
10	30,620	2.909	0.000	0.892	0.145	0.936	0.936	0.454
11	36,336	3.452	0.000	1.049	0.173	1.115	1.115	0.503
12	44,548	4.232	0.000	1.274	0.212	1.373	1.373	0.577
13	56,661	5.383	0.000	1.607	0.269	1.753	1.753	0.685
14	82,984	7.884	0.000	2.320	0.394	2.585	2.585	0.939
15	131,603	12.502	0.000	3.650	0.625	4.114	4.114	1.390
16	159,992	15.199	0.000	4.487	0.760	4.976	4.976	1.565
17	168,447	16.002	0.000	4.808	0.800	5.197	5.197	1.520
18	171,768	16.318	0.000	4.998	0.816	5.252	5.252	1.429
19	166,790	15.845	0.000	4.956	0.792	5.049	5.049	1.278
20	154,566	14.684	0.000	4.698	0.734	4.626	4.626	1.089
21	141,500	13.443	0.000	4.404	0.672	4.183	4.183	0.916
22	128,478	12.205	0.000	4.097	0.610	3.749	3.749	0.764
23	118,423	11.250	0.000	3.868	0.563	3.410	3.410	0.646
24	111,462	10.589	0.000	3.727	0.529	3.166	3.166	0.558
Total	**2,613,711**	**248.303**	**29.786**	**71.322**	**12.415**	**68.398**	**66.642**	**22.174**
						IRR	**37.30%**	**27.72%**
						PIR	**2.237**	**0.744**

Table 5.9 Cash flow summary of case 8. Recovery factor = 40.46%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	28.000	0.000	0.000	0.000	-10.720	-8.027
5	219,000	20.805	0.000	4.741	1.040	0.000	10.704	7.456
6	219,000	20.805	0.000	4.836	1.040	5.304	5.304	3.437
7	219,600	20.862	0.000	4.946	1.043	5.276	5.276	3.180
8	218,474	20.755	0.000	5.019	1.038	5.189	5.189	2.910
9	84,090	7.989	0.286	2.127	0.399	2.718	2.718	1.418
10	59,199	5.624	0.000	1.575	0.281	1.884	1.884	0.914
11	68,560	6.513	0.000	1.835	0.326	2.176	2.176	0.982
12	77,578	7.370	0.000	2.095	0.368	2.453	2.453	1.030
13	88,375	8.396	0.000	2.411	0.420	2.782	2.782	1.087
14	103,369	9.820	0.000	2.847	0.491	3.241	3.241	1.177
15	119,589	11.361	0.000	3.333	0.568	3.730	3.730	1.261
16	136,421	12.960	0.000	3.852	0.648	4.230	4.230	1.330
17	143,057	13.590	0.000	4.111	0.680	4.400	4.400	1.287
18	140,385	13.337	0.000	4.119	0.667	4.275	4.275	1.163
19	135,655	12.887	0.000	4.066	0.644	4.088	4.088	1.035
20	130,138	12.363	0.000	3.987	0.618	3.879	3.879	0.913
21	123,653	11.747	0.000	3.874	0.587	3.643	3.643	0.798
22	117,137	11.128	0.000	3.754	0.556	3.409	3.409	0.694
23	111,518	10.594	0.000	3.655	0.530	3.205	3.205	0.607
24	106,276	10.096	0.000	3.563	0.505	3.014	3.014	0.531
Total	**2,621,075**	**249.002**	**31.786**	**70.746**	**12.450**	**68.899**	**65.382**	**22.182**
						IRR	**34.75%**	**25.35%**
						PIR	**2.057**	**0.698**

Table 5.10 Cash flow summary of case 9. Recovery factor = 52.61%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	22.131	0.000	0.000	0.000	-5.706	-4.273
5	219,000	20.805	0.000	4.886	1.040	0.783	9.989	6.958
6	219,000	20.805	0.122	5.048	1.040	5.244	5.244	3.398
7	211,016	20.046	0.122	4.969	1.002	4.923	4.923	2.968
8	177,356	16.849	0.122	4.295	0.842	3.741	3.741	2.098
9	173,845	16.515	0.122	4.299	0.826	5.634	5.634	2.939
10	173,288	16.462	0.122	4.371	0.823	5.573	5.573	2.704
11	173,207	16.455	0.122	4.457	0.823	5.526	5.526	2.494
12	173,650	16.497	0.122	4.557	0.825	5.496	5.496	2.308
13	173,157	16.450	0.122	4.636	0.822	5.435	5.435	2.123
14	173,106	16.445	0.122	4.727	0.822	5.387	5.387	1.957
15	173,004	16.435	0.122	4.819	0.822	5.336	5.336	1.803
16	172,995	16.435	0.122	4.915	0.822	5.288	5.288	1.662
17	168,676	16.024	0.122	4.895	0.801	5.103	5.103	1.492
18	164,837	15.659	0.122	4.885	0.783	4.935	4.935	1.342
19	159,213	15.125	0.122	4.823	0.756	4.712	4.712	1.193
20	154,023	14.632	0.122	4.768	0.732	4.505	4.505	1.061
21	146,633	13.930	0.122	4.643	0.697	4.234	4.234	0.927
22	139,411	13.244	0.122	4.517	0.662	3.971	3.971	0.809
23	134,164	12.746	0.122	4.445	0.637	3.771	3.771	0.715
24	128,415	12.199	0.122	4.353	0.610	3.557	3.557	0.627
Total	**3,407,994**	**323.759**	**27.948**	**93.309**	**16.188**	**93.157**	**93.157**	**34.305**
						IRR	**49.91%**	**39.45%**
						PIR	**3.333**	**1.227**

Table 5.11 Cash flow summary of case 10. Recovery factor = 55.03%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	24.131	0.000	0.000	0.000	-7.386	-5.531
5	219,000	20.805	0.000	4.886	1.040	0.000	10.693	7.448
6	219,000	20.805	0.122	5.052	1.040	5.202	5.202	3.371
7	219,000	20.805	0.122	5.153	1.040	5.152	5.152	3.105
8	219,600	20.862	0.122	5.270	1.043	5.120	5.120	2.871
9	219,000	20.805	0.122	5.361	1.040	7.141	7.141	3.725
10	219,000	20.805	0.122	5.469	1.040	7.087	7.087	3.439
11	219,000	20.805	0.122	5.578	1.040	7.032	7.032	3.174
12	219,600	20.862	0.122	5.704	1.043	6.996	6.996	2.937
13	210,511	19.999	0.122	5.588	1.000	6.644	6.644	2.595
14	188,645	17.921	0.122	5.134	0.896	5.885	5.885	2.138
15	172,247	16.363	0.122	4.804	0.818	5.310	5.310	1.794
16	162,408	15.429	0.122	4.635	0.771	4.950	4.950	1.556
17	153,644	14.596	0.122	4.487	0.730	4.629	4.629	1.354
18	147,324	13.996	0.122	4.400	0.700	4.387	4.387	1.193
19	142,070	13.497	0.122	4.338	0.675	4.181	4.181	1.058
20	137,047	13.019	0.122	4.278	0.651	3.984	3.984	0.938
21	131,362	12.479	0.122	4.195	0.624	3.769	3.769	0.825
22	126,557	12.023	0.122	4.133	0.601	3.583	3.583	0.730
23	122,181	11.607	0.122	4.081	0.580	3.412	3.412	0.647
24	117,909	11.201	0.122	4.028	0.560	3.246	3.246	0.572
Total	**3,565,104**	**338.685**	**29.948**	**96.576**	**16.934**	**97.710**	**97.516**	**36.939**
						IRR	**48.88%**	**38.49%**
						PIR	**3.256**	**1.233**

Table 5.12 Cash flow summary of case 11. Recovery factor = 48.58%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	26.000	0.000	0.000	0.000	-9.040	-6.769
5	219,000	20.805	0.000	4.741	1.040	0.000	10.784	7.511
6	219,000	20.805	0.000	4.836	1.040	5.344	5.344	3.463
7	103,267	9.810	0.156	2.477	0.491	1.276	1.276	0.769
8	111,171	10.561	0.122	2.772	0.528	1.436	1.436	0.805
9	118,028	11.213	0.122	2.988	0.561	3.758	3.758	1.960
10	124,310	11.809	0.122	3.198	0.590	3.937	3.937	1.910
11	132,139	12.553	0.122	3.453	0.628	4.175	4.175	1.885
12	148,228	14.082	0.122	3.922	0.704	4.667	4.667	1.959
13	169,469	16.100	0.122	4.539	0.805	5.317	5.317	2.077
14	172,576	16.395	0.122	4.710	0.820	5.371	5.371	1.952
15	172,838	16.420	0.122	4.812	0.821	5.333	5.333	1.802
16	173,510	16.483	0.122	4.926	0.824	5.306	5.306	1.668
17	172,853	16.421	0.122	5.006	0.821	5.236	5.236	1.531
18	172,682	16.405	0.122	5.101	0.820	5.181	5.181	1.409
19	170,781	16.224	0.122	5.150	0.811	5.071	5.071	1.283
20	166,173	15.786	0.122	5.118	0.789	4.878	4.878	1.148
21	160,173	15.216	0.122	5.042	0.761	4.646	4.646	1.017
22	154,338	14.662	0.122	4.966	0.733	4.421	4.421	0.901
23	146,460	13.914	0.122	4.822	0.696	4.137	4.137	0.784
24	140,246	13.323	0.122	4.723	0.666	3.906	3.906	0.689
Total	**3,147,241**	**298.988**	**31.729**	**87.300**	**14.949**	**83.396**	**81.640**	**26.754**
						IRR	**35.80%**	**26.32%**
						PIR	**2.573**	**0.843**

Table 5.13 Cash flow summary of case 12. Recovery factor = 51.14%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	28.000	0.000	0.000	0.000	-10.720	-8.027
5	219,000	20.805	0.000	4.741	1.040	0.000	10.704	7.456
6	219,000	20.805	0.000	4.836	1.040	5.304	5.304	3.437
7	200,861	19.082	0.156	4.675	0.954	4.541	4.541	2.737
8	190,903	18.136	0.122	4.610	0.907	4.075	4.075	2.285
9	183,487	17.431	0.122	4.528	0.872	5.942	5.942	3.099
10	178,156	16.925	0.122	4.491	0.846	5.720	5.720	2.775
11	174,128	16.542	0.122	4.483	0.827	5.555	5.555	2.507
12	171,705	16.312	0.122	4.512	0.816	5.431	5.431	2.280
13	169,135	16.068	0.122	4.537	0.803	5.303	5.303	2.071
14	167,470	15.910	0.122	4.585	0.795	5.204	5.204	1.891
15	165,576	15.730	0.122	4.627	0.786	5.097	5.097	1.723
16	161,878	15.378	0.122	4.620	0.769	4.934	4.934	1.551
17	155,208	14.745	0.122	4.529	0.737	4.678	4.678	1.368
18	149,659	14.218	0.122	4.464	0.711	4.460	4.460	1.213
19	144,180	13.697	0.122	4.397	0.685	4.246	4.246	1.075
20	140,292	13.328	0.122	4.372	0.666	4.084	4.084	0.961
21	136,423	12.960	0.122	4.344	0.648	3.923	3.923	0.859
22	132,622	12.599	0.122	4.316	0.630	3.766	3.766	0.767
23	128,457	12.203	0.122	4.273	0.610	3.599	3.599	0.682
24	124,799	11.856	0.122	4.244	0.593	3.448	3.448	0.608
Total	**3,312,938**	**314.729**	**33.729**	**90.187**	**15.736**	**89.309**	**85.793**	**30.317**
						IRR	**38.32%**	**28.67%**
						PIR	**2.544**	**0.899**

Table 5.14 Cash flow summary of case 13. Recovery factor = 43.09%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	26.000	0.000	0.000	0.000	-9.040	-6.769
5	219,000	20.805	0.000	4.741	1.040	0.000	10.784	7.511
6	219,000	20.805	0.000	4.836	1.040	5.344	5.344	3.463
7	219,000	20.805	0.000	4.933	1.040	5.296	5.296	3.192
8	208,832	19.839	0.000	4.798	0.992	4.905	4.905	2.750
9	43,698	4.151	0.286	1.181	0.208	1.369	1.369	0.714
10	30,636	2.910	0.122	0.957	0.146	0.843	0.843	0.409
11	35,352	3.358	0.122	1.091	0.168	0.989	0.989	0.446
12	43,284	4.112	0.122	1.310	0.206	1.237	1.237	0.519
13	54,242	5.153	0.122	1.614	0.258	1.580	1.580	0.617
14	83,787	7.960	0.122	2.411	0.398	2.514	2.514	0.914
15	133,312	12.665	0.122	3.767	0.633	4.071	4.071	1.376
16	160,837	15.280	0.122	4.583	0.764	4.905	4.905	1.542
17	168,378	15.996	0.122	4.881	0.800	5.097	5.097	1.490
18	172,541	16.391	0.122	5.095	0.820	5.177	5.177	1.408
19	174,912	16.617	0.122	5.265	0.831	5.199	5.199	1.316
20	175,814	16.702	0.122	5.397	0.835	5.174	5.174	1.218
21	172,012	16.341	0.122	5.392	0.817	5.005	5.005	1.096
22	166,044	15.774	0.122	5.318	0.789	4.773	4.773	0.972
23	159,138	15.118	0.122	5.211	0.756	4.515	4.515	0.855
24	151,868	14.427	0.122	5.087	0.721	4.249	4.249	0.749
Total	**2,791,685**	**265.210**	**31.615**	**77.868**	**13.261**	**72.242**	**70.485**	**22.790**
						IRR	**37.19%**	**27.62%**
						PIR	**2.229**	**0.721**

Table 5.15 Cash flow summary of case 14. Recovery factor = 44.19%.

Year	Cash flow summary							Discount cash flow (NPV@ 7.5%)
	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	0.500	0.000	0.000	0.000	-0.500	-0.465
2	0.000	0.000	2.000	0.000	0.000	0.000	-2.000	-1.731
3	0.000	0.000	1.000	0.000	0.000	0.000	-1.000	-0.805
4	0.000	0.000	28.000	0.000	0.000	0.000	-10.720	-8.027
5	219,000	20.805	0.000	4.741	1.040	0.000	10.704	7.456
6	219,000	20.805	0.000	4.836	1.040	5.304	5.304	3.437
7	219,000	20.805	0.000	4.933	1.040	5.256	5.256	3.168
8	219,070	20.812	0.000	5.033	1.041	5.209	5.209	2.921
9	84,092	7.989	0.286	2.127	0.399	2.719	2.719	1.418
10	58,841	5.590	0.122	1.636	0.279	1.776	1.776	0.862
11	66,557	6.323	0.122	1.857	0.316	2.014	2.014	0.909
12	75,798	7.201	0.122	2.124	0.360	2.297	2.297	0.964
13	85,226	8.096	0.122	2.406	0.405	2.582	2.582	1.008
14	99,688	9.470	0.122	2.828	0.474	3.024	3.024	1.098
15	118,235	11.232	0.122	3.374	0.562	3.587	3.587	1.212
16	140,195	13.318	0.122	4.033	0.666	4.249	4.249	1.336
17	156,644	14.881	0.122	4.565	0.744	4.725	4.725	1.382
18	164,489	15.626	0.122	4.876	0.781	4.924	4.924	1.339
19	164,606	15.638	0.122	4.977	0.782	4.878	4.878	1.235
20	162,493	15.437	0.122	5.015	0.772	4.764	4.764	1.122
21	158,920	15.097	0.122	5.009	0.755	4.606	4.606	1.009
22	154,546	14.682	0.122	4.976	0.734	4.425	4.425	0.901
23	150,474	14.295	0.122	4.950	0.715	4.254	4.254	0.806
24	145,877	13.858	0.122	4.904	0.693	4.069	4.069	0.717
Total	**2,862,749**	**271.961**	**33.615**	**79.200**	**13.598**	**74.662**	**71.146**	**23.273**
						IRR	**34.67%**	**25.28%**
						PIR	**2.116**	**0.692**

Table 5.16 Cash flow summary of all case studies.

Case study	Type of fluid to inject	Year to inject	Oil Recovery Factor (%)	IRR Undiscount (%)	PIR Undiscount (Fraction)	IRR (7.5%Disc) (%)	PIR (7.5%Disc) (Fraction)	NPV (7.5%Disc) (MMUS$)
1	No inject	-	25.55	39.73	1.328	29.98	0.577	17.03
2	No inject	-	26.05	35.04	1.184	25.62	0.497	15.65
3	Water	1^{st}	47.96	50.24	3.350	39.76	1.279	32.78
4	Water	1^{st}	49.28	48.99	3.181	38.59	1.246	34.42
5	Water	3^{rd}	45.07	35.95	2.578	26.46	0.870	25.81
6	Water	3^{rd}	46.20	38.41	2.455	28.76	0.899	28.46
7	Water	5^{th}	40.35	37.30	2.237	27.72	0.744	22.17
8	Water	5^{th}	40.46	34.75	2.057	25.35	0.698	22.18
9	Polymer	1^{st}	52.61	49.91	3.333	39.45	1.227	34.31
10	Polymer	1^{st}	55.03	48.88	3.256	38.49	1.233	36.94
11	Polymer	3^{rd}	48.58	35.80	2.573	26.32	0.843	26.75
12	Polymer	3^{rd}	51.14	38.32	2.544	28.67	0.899	30.32
13	Polymer	5^{th}	43.09	37.19	2.229	27.62	0.721	22.79
14	Polymer	5^{th}	44.19	34.67	2.116	25.28	0.692	23.27

CHAPTER VI

CONCLUSIONS AND DISCUSSIONS

6.1 Introduction

This chapter concludes the research study in term of reservoir model case study, and economic evaluation of water and polymer flooding simulation model for oil field in Suphan Buri Basin. Finally, discussion on the research results, problems, and given the recommendation for future works.

6.2 Conclusions of case study results

The recovery factor of primary production in this reservoir model is low. The effect of water and polymer flooding method are increase reservoir pressure and oil recovery. The advantage of polymer solution, improve the swept coefficient, volumetric sweep efficiency and decrease the mobility ratio.

The study focuses on monocline structure style with 6 layers. Used the reservoir and fluid data from data of U-Thong oil field, but some data are not available so they are assumed by based on U-Thong data. The reserved size of reservoir is around 6.48 MMBBL. The porosity ranges from 12 to 15%, and the permeability from of 89.68 to 362.74 md. The study uses reservoir simulation to evaluate 14 case studies for oil recovery with two patterns, staggered line and direct line drive. All cases have the same total production rate at 600 bbl/day and production life time 20 years. Cases 3 to 14 have an injection rate at 500 bbl/d. The XCD polymer (Xanthan gum) concentration 600 ppm is used in these simulation. The result show cases of polymer flooding that have high performance oil recovery efficiency when compared with water flooding. Case 1-2 show oil recovery from natural flow (no water or polymer injection) can produce 25.55 and 26.05% of oil in place. Case 3-8 show applied water flooding, the 1st, 3rd and 5th year of water injection, the recoveries increased to 47.96%, 49.28%, 45.07%, 46.20%, 40.35% and 40.46% respectively. Case 9-14 show applied polymer flooding, the 1st, 3rd and 5th year of polymer injection, the recoveries increased to 52.61%, 55.03%, 48.58%, 51.14%, 43.09% and 44.19% respectively. Summary of reservoir simulation results is shown in Figure 6.1 and Table 6.1.

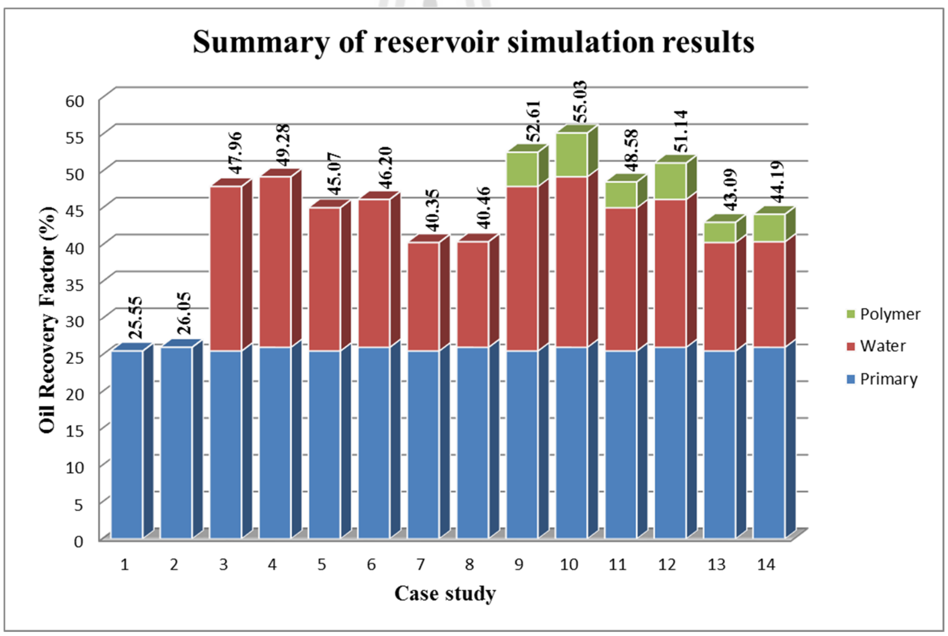


Figure 6.1 Summary of reservoir simulation results.

Table 6.1 Summary of reservoir simulation results.

Case	Flood pattern	Type to inject	Year to inject	Pro. Rate (bbl/d)	Inj. Rate (bbl/d)	RF (%)
1	Staggered line	-	no	600	500	25.55
2	Direct line	-	no	600	500	26.05
3	Staggered line	Water	1st - 20th	600	500	47.96
4	Direct line	Water	1st - 20th	600	500	49.28
5	Staggered line	Water	3rd - 20th	600	500	45.07
6	Direct line	Water	3rd - 20th	600	500	46.20
7	Staggered line	Water	5th - 20th	600	500	40.35
8	Direct line	Water	5th - 20th	600	500	40.46
9	Staggered line	Fresh water	1st	600	500	52.61
		Polymer	2nd - 20th			
10	Direct line	Fresh water	1st	600	500	55.03
		Polymer	2nd - 20th			
11	Staggered line	Fresh water	3rd	600	500	48.58
		Polymer	4th - 20th			
12	Direct line	Fresh water	3rd	600	500	51.14
		Polymer	4th - 20th			
13	Staggered line	Fresh water	5th	600	500	43.09
		Polymer	6th - 20th			
14	Direct line	Fresh water	5th	600	500	44.19
		Polymer	6th - 20th			

6.3 Economic analysis

Economic analysis in this study is based on a constant oil price rate through the project life time (95$/BBL), the 7.5% discounted rate. Economic results show summary of all case studies, IRR range from 25.28-39.45%, and PIR range from 0.497-1.279 fraction. The best operation case for this study is the case 10, used polymer flooding start to inject at 1st year with direct line drive pattern. That has the best NPV is 36.94 MMUS$. The economic results summary of all case studies are shown in Figures 6.2-6.4.

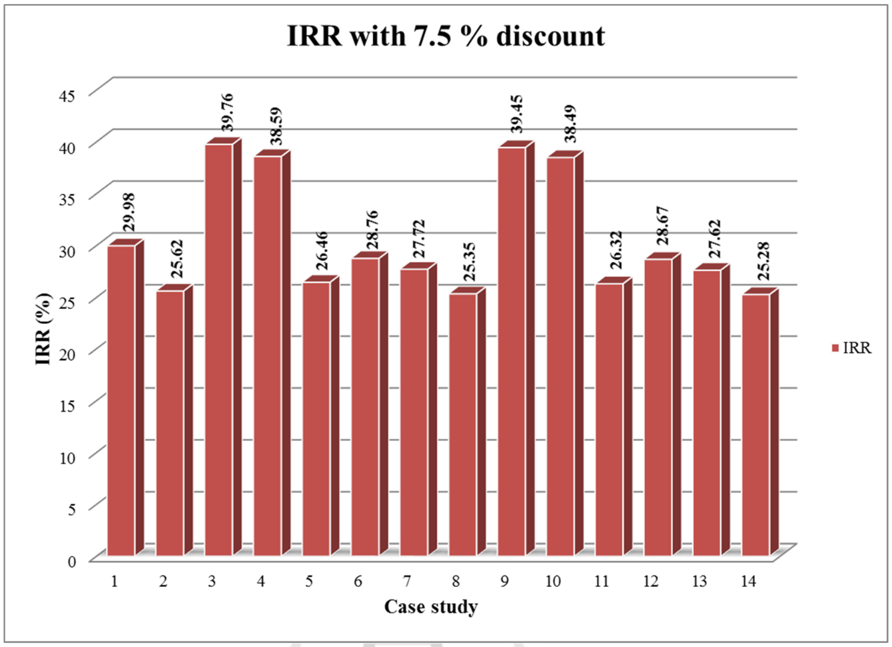


Figure 6.2 Summary of IRR results.

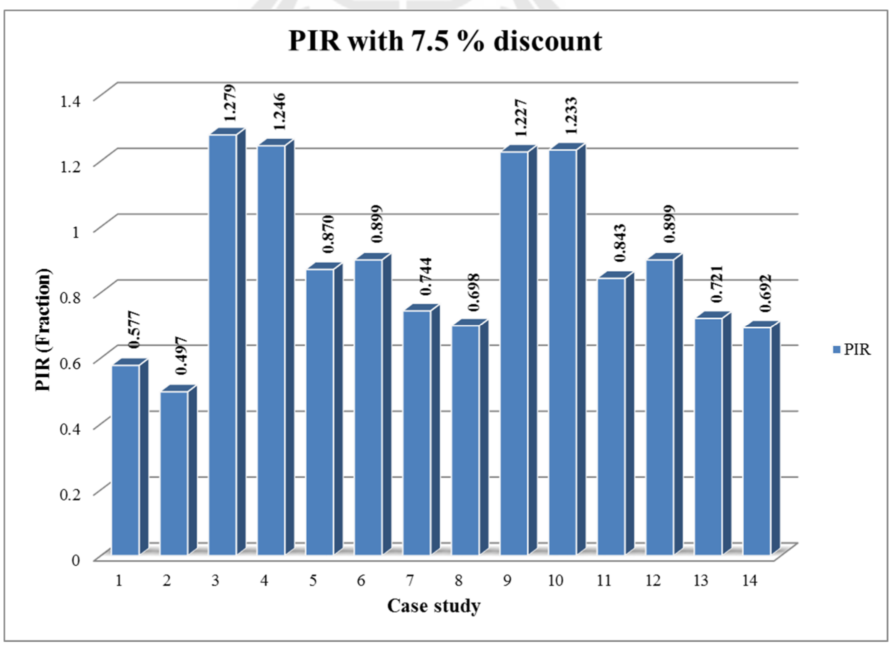


Figure 6.3 Summary of PIR results.

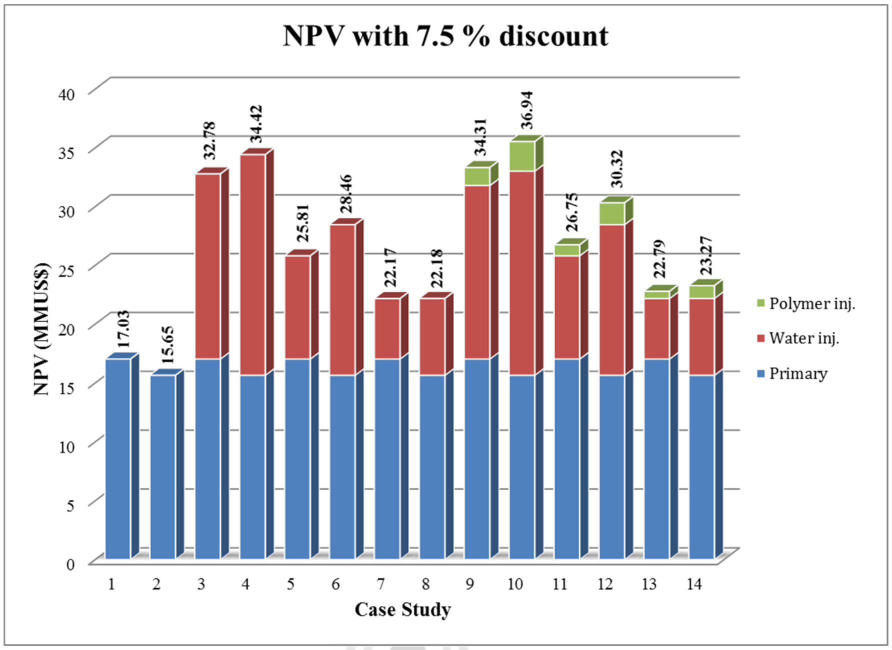


Figure 6.4 Summary of NPV results.

6.4 Discussions

- The reservoir simulation results indicated that the polymer flooding technique can increase oil recovery efficiency by comparing with natural flow and water flooding of U-Thong oil field in Suphan Buri Basin.
- The best case of this study is case 10, polymer flooding technique injection at the 1st year with direct line drives (2 production wells and 2 injection wells). It can provides the best of oil recovery and best values of economics. The summary of oil recovery factor and NPV result is 55.03% and 35.53 MMUS$.
- Comparing with all cases study, the 1st year of injection (water and polymer) are the best case of operation, improved efficiency and economic values are more favorable than the others. The 1st year of

injection cases (water and polymer) is the best cases when compared with the 3rd and 5th year, but in a real field operation may be the 3th or 5th year, because of water and polymer flooding projects need time to collect the reservoir properties data and history of production rates.

- The history matching should be compared with the real field and the reservoir simulation because it is necessary step for more accuracy of results, but the production rates couldn't access in the oil field for this study. More reservoir properties data obtain be more accuracy of results are.
- 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.
- For future study, the locations of production and injection wells can be changed to be five, seven and nine spot to find oil recovery efficiency and economic values for Suphan Buri basin. The researcher should understand in reservoir simulation and reservoir characteristics of this field before running reservoir simulation. Reliability of simulation results depends on the accuracy of the input data of simulators.

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APPENDIX A

SIMULATION DATA

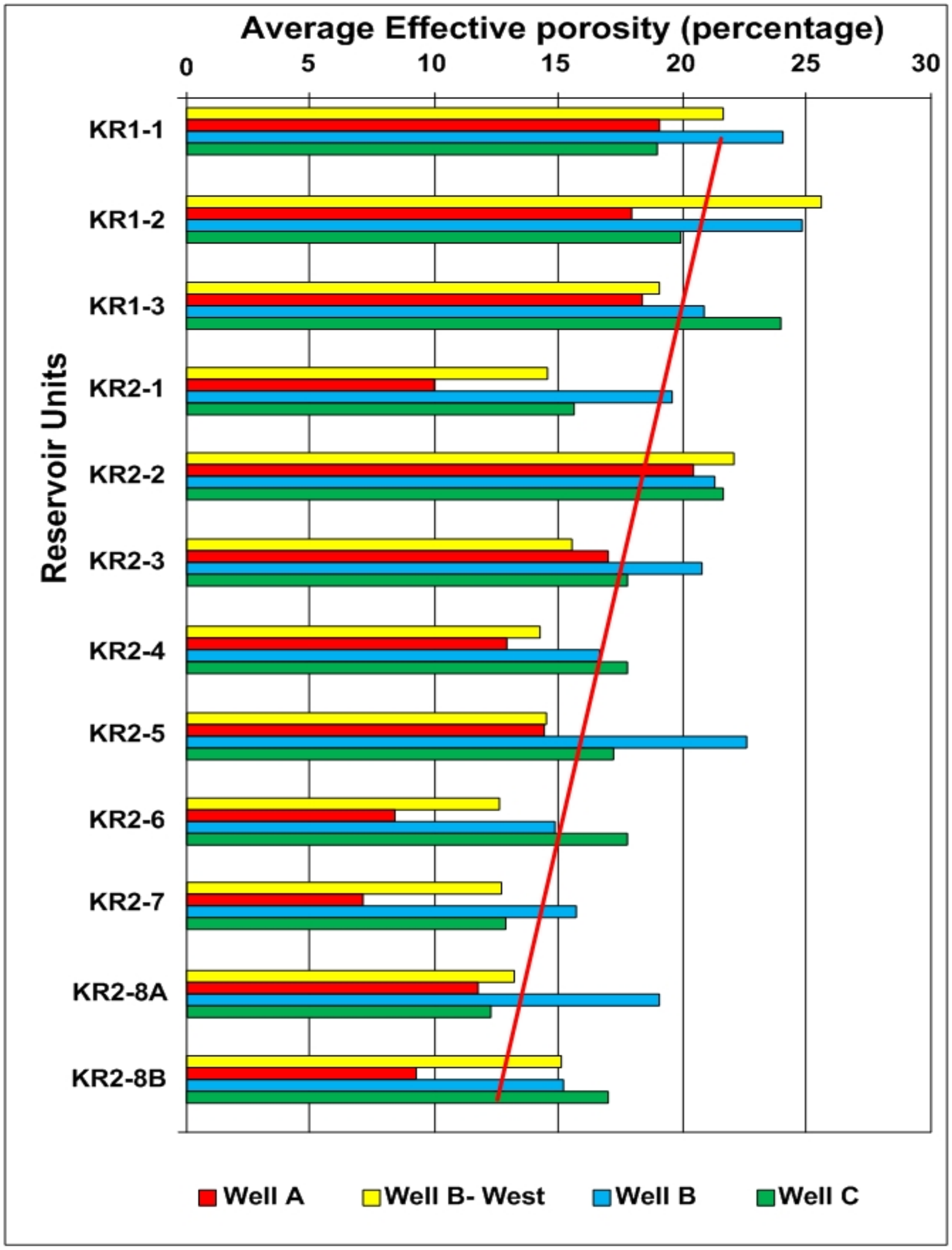

Figure A.1 Comparison of average effective porosities. Red line indicates the Decreasing trend of porosity with burial depth

(modified after by Aung Kyaw Htoo, 2009)

Table A.1 PVTO (The Oil Properties).

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.001098929	14.7	1.0690455	2.0525159
	145.50526	1.0542012	2.0975871
	300	1.0533484	2.193711
	407.11579	1.0531372	2.2780557
	537.92105	1.0529934	2.3977334
	668.72632	1.0529058	2.5345923
	799.53158	1.052847	2.6882334
	930.33684	1.0528046	2.8587427
	1061.1421	1.0527727	3.0465045
	1191.9474	1.0527478	3.2521059
	1322.7526	1.0527279	3.4762823
	1453.5579	1.0527115	3.719884
	1584.3632	1.0526978	3.9838542
	1715.1684	1.0526862	4.2692135
	1800	1.0526796	4.4662229
	1976.7789	1.0526677	4.9085038
	2107.5842	1.0526601	5.2647716
	2238.3895	1.0526534	5.647088
	2369.1947	1.0526475	6.0567249
	2500	1.0526422	6.4949846
0.017394905	145.50526	1.0759539	1.854182
	300	1.0669216	1.8840161
	407.11579	1.0646954	1.9150471
	537.92105	1.0631818	1.961891
	668.72632	1.0622615	2.0172401
	799.53158	1.0616427	2.0802459
	930.33684	1.0611982	2.1503911
	1061.1421	1.0608633	2.2273566
	1191.9474	1.0606021	2.3109508
	1322.7526	1.0603925	2.4010686
	1453.5579	1.0602207	2.4976661
	1584.3632	1.0600773	2.6007435
	1715.1684	1.0599558	2.7103333
	1800	1.0598864	2.7849133
	1976.7789	1.059761	2.9492948
	2107.5842	1.0596818	3.0788283
	2238.3895	1.0596118	3.2151896
	2369.1947	1.0595495	3.3584814
	2500	1.0594938	3.5088103

Table A.1 PVTO (The Oil Properties). (Continued)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.041593119	300	1.086339	1.6318195
	407.11579	1.0813253	1.6475368
	537.92105	1.0779247	1.6734954
	668.72632	1.0758597	1.7057359
	799.53158	1.0744726	1.7434819
	930.33684	1.0734767	1.7862249
	1061.1421	1.0727269	1.8336179
	1191.9474	1.072142	1.8854187
	1322.7526	1.0716731	1.9414569
	1453.5579	1.0712887	2.0016126
	1584.3632	1.0709678	2.0658029
	1715.1684	1.070696	2.1339719
	1800	1.0705409	2.1802913
	1976.7789	1.0702604	2.28212
	2107.5842	1.0700833	2.3620702
	2238.3895	1.0699268	2.445935
	2369.1947	1.0697877	2.5337202
	2500	1.0696631	2.6254361

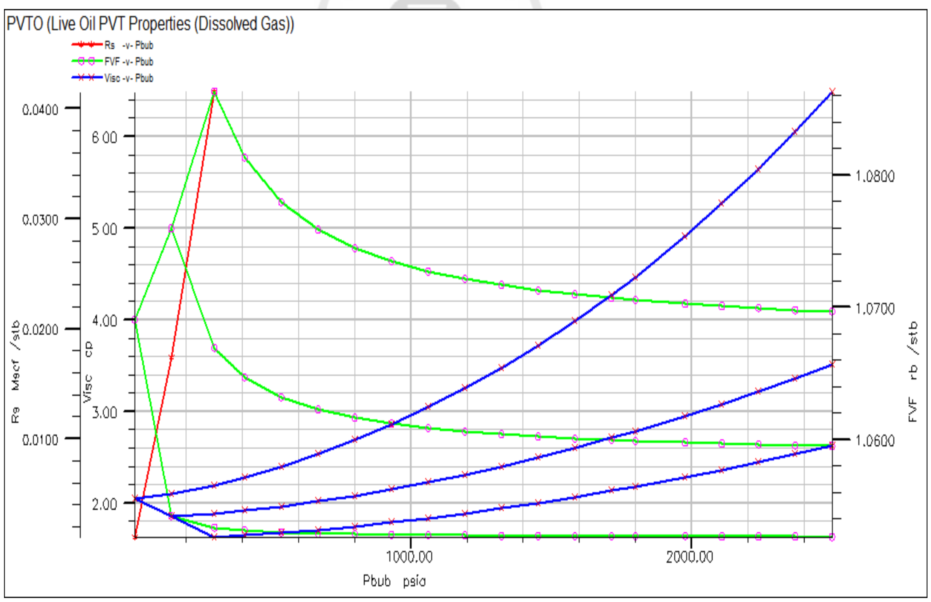

Figure A.2 Graph shows relationship of bubble-point pressure, (Pbub) VS oil formation volume factor, (FVF) and solution gas-oil ratio, (Rs).

Table A.2 PVDG (The Dry Gas PVT Property).

Pressure (psia)	FVF (rb /Mscf)	Visc (cp)
14.7	225.76409	0.013055067
145.50526	22.51986	0.013134663
300	10.762904	0.013279531
407.11579	7.8524134	0.013403079
537.92105	5.8728986	0.013576538
668.72632	4.6703478	0.013773436
799.53158	3.8636279	0.01399302
930.33684	3.2859652	0.014234895
1061.1421	2.852823	0.014498816
1191.9474	2.5167748	0.014784555
1322.7526	2.2491514	0.01509181
1453.5579	2.0315971	0.015420141
1584.3632	1.8518087	0.015768922
1715.1684	1.7012232	0.016137309
1800	1.6161983	0.016386205
1976.7789	1.4646702	0.016928389
2107.5842	1.3707341	0.017348283
2238.3895	1.2892371	0.017782248
2369.1947	1.2181028	0.018228503
2500	1.1556753	0.018685204

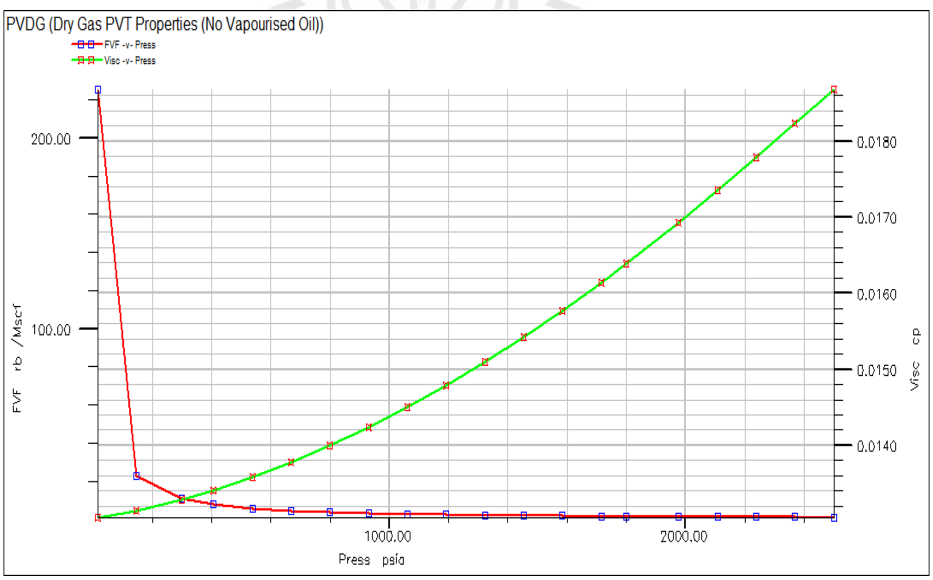

Figure A.3 Graph shows relationship of pressure VS gas formation volume factor and gas viscosity.

APPENDIX B

POLYMER DATA

Data of polymer solution for injection

According to Kanarak (2011), 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.

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 B1. 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.

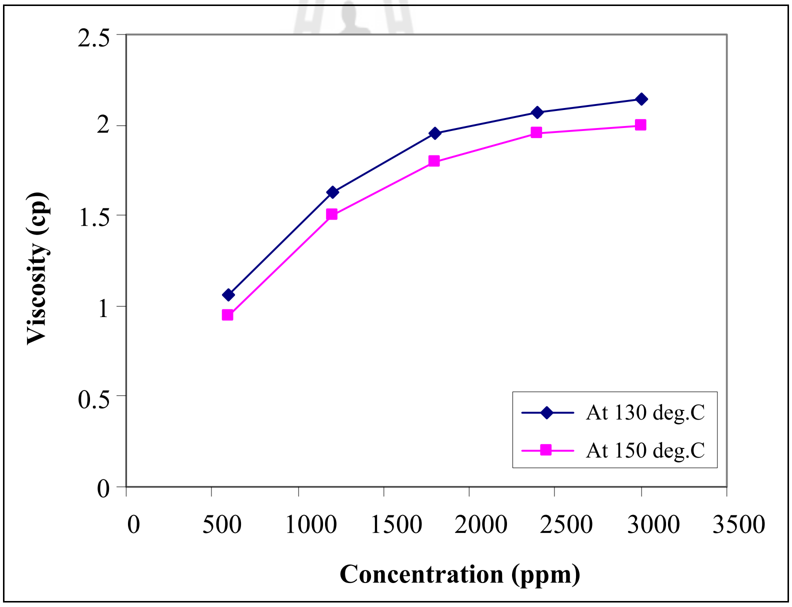

Figure B.1 The viscosity versus concentration of polymer solution, (After Thang, 2005).

Table B.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

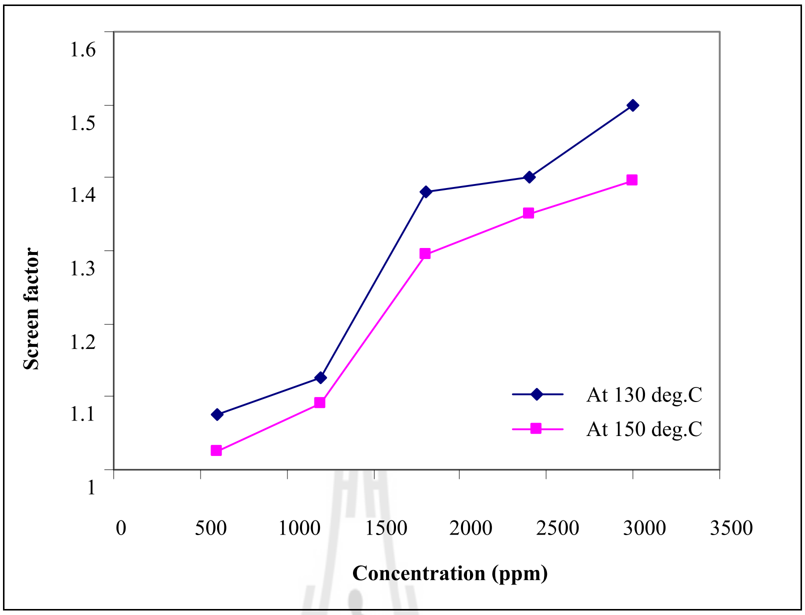

Figure B.2 The screen factor versus concentration of polymer solution, (After Thang 2005).

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.

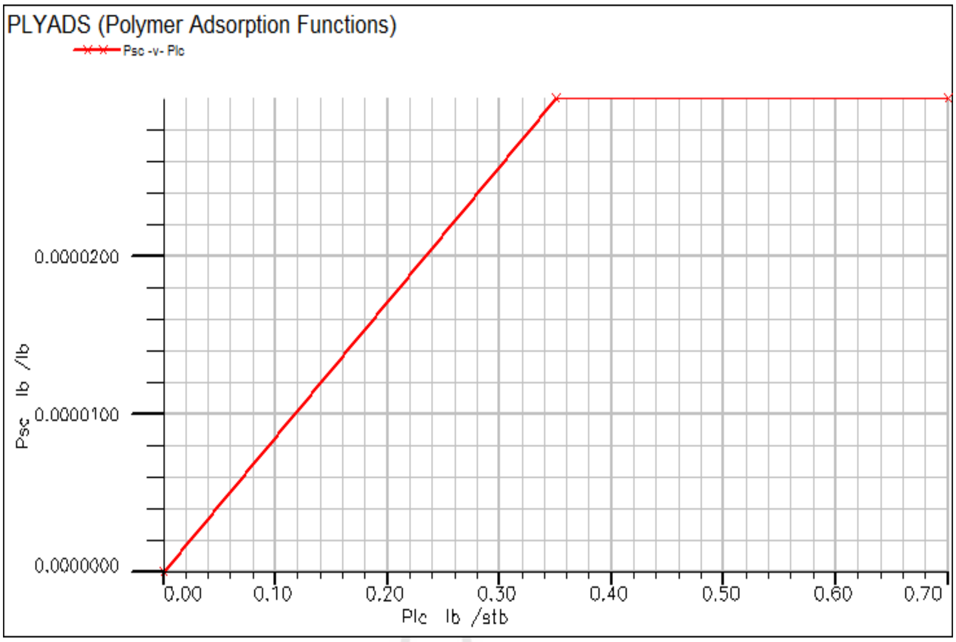

Figure B.3 Polymer adsorption function graph display result from Suphan Buri basin input data section

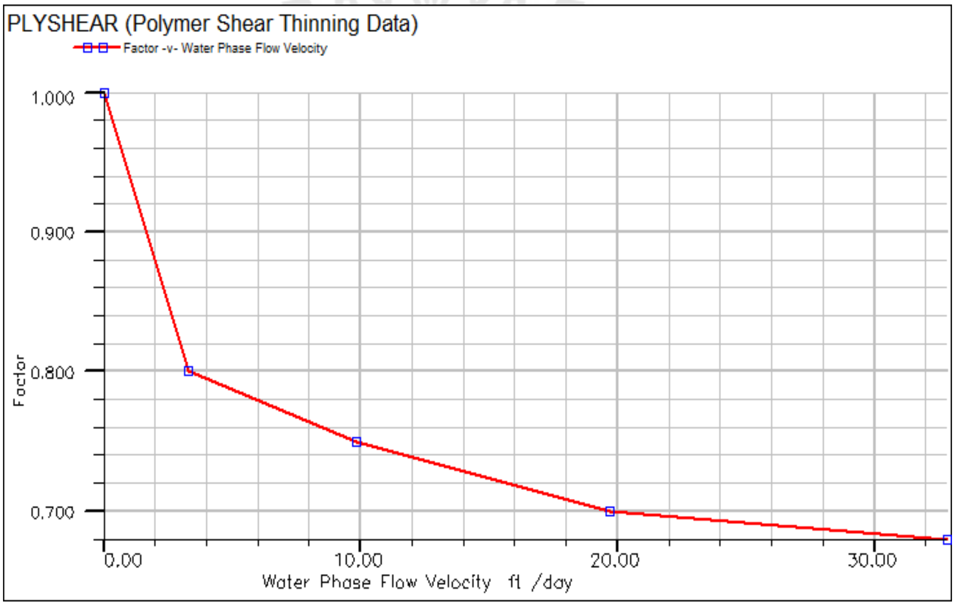

Figure B.4 Polymer shear thinning data graph display result from Suphan Buri basin input data section

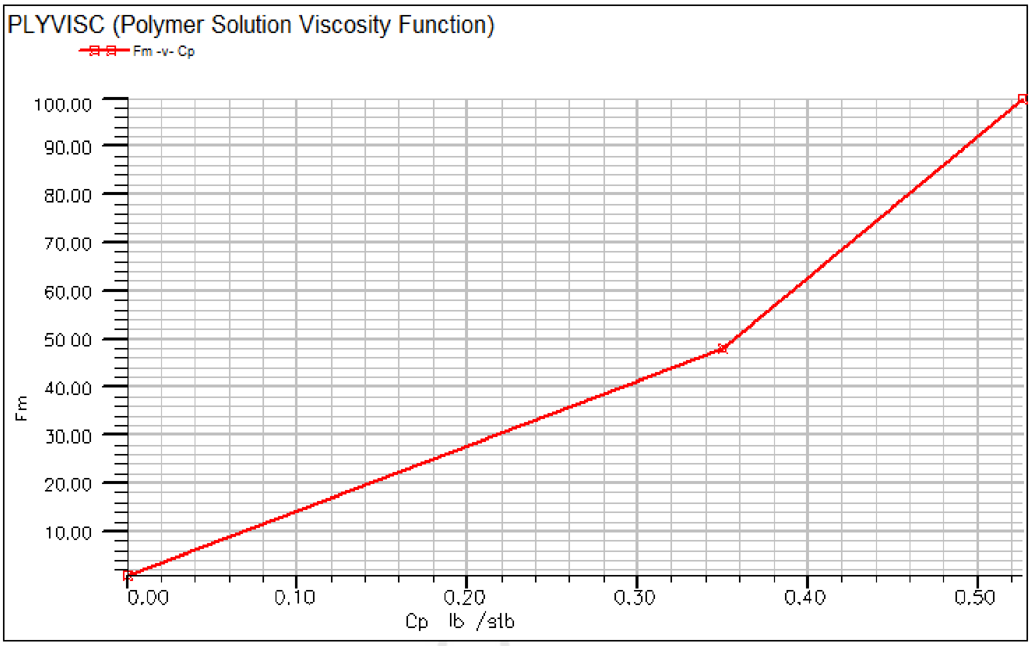

Figure B.5 Polymer solution viscosity function graph display result from Suphan Buri basin input data section

APPENDIX C

OIL SATURATION

AFTER 20 YEARS PRODUCTION

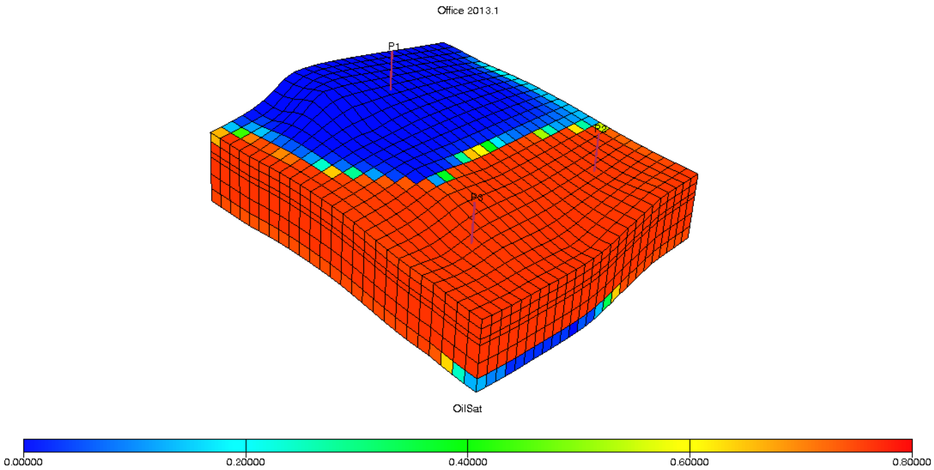

Figure C.1 Oil saturation after 20 years production of case study 1 production with natural flow by staggered line drive pattern (3 production wells)

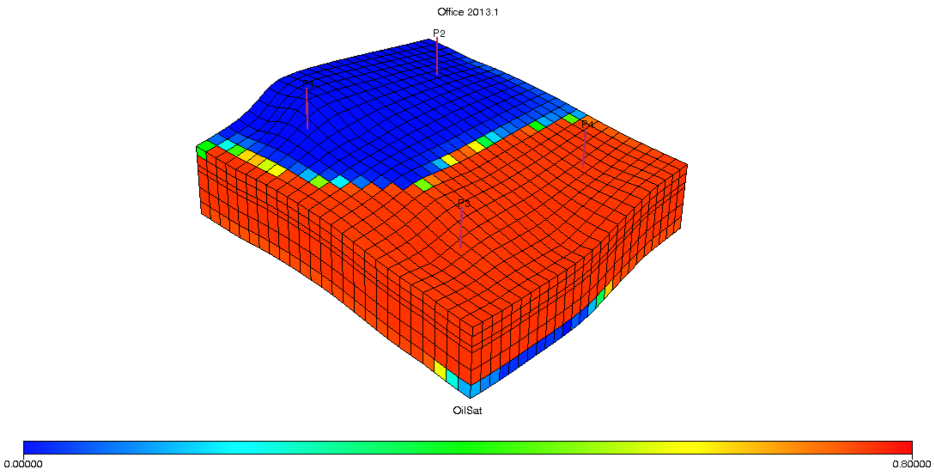

Figure C.2 Oil saturation after 20 years production of case study 2 production with natural flow by direct line drive pattern (4 production wells)

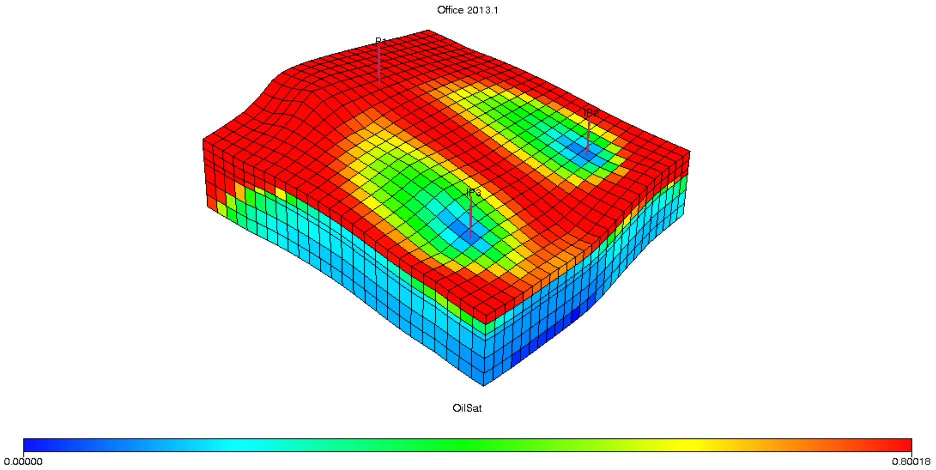

Figure C.3 Oil saturation after 20 years production of case study 3 start with water flooding at the 1st year by staggered line drive pattern (1 production well, 2 injection wells)

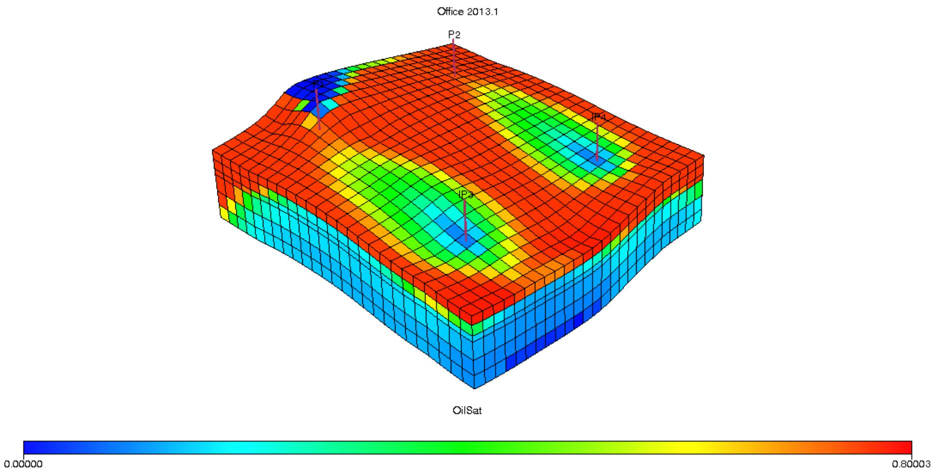

Figure C.4 Oil saturation after 20 years production of case study 4 start with water flooding at the 1st year by direct line drive pattern (2 production well, 2 injection wells)

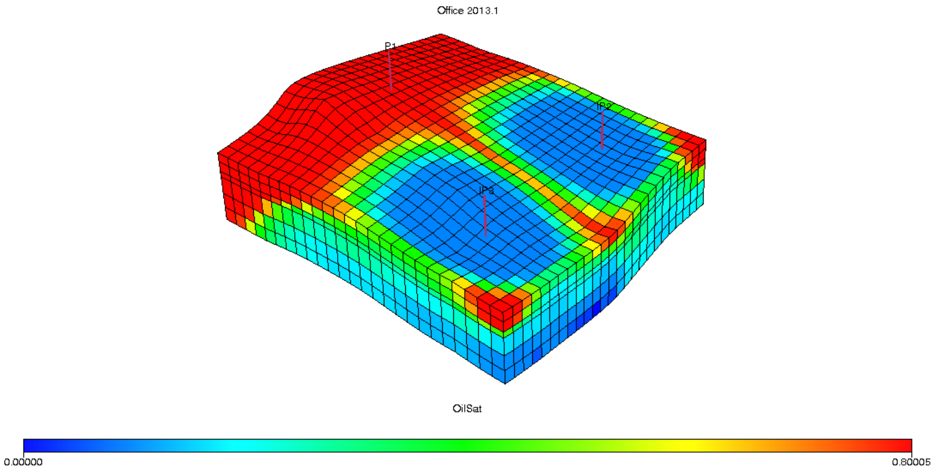

Figure C.5 Oil saturation after 20 years production of case study 9 start with polymer flooding at the 1st year by staggered line drive pattern (1 production well, 2 injection wells)

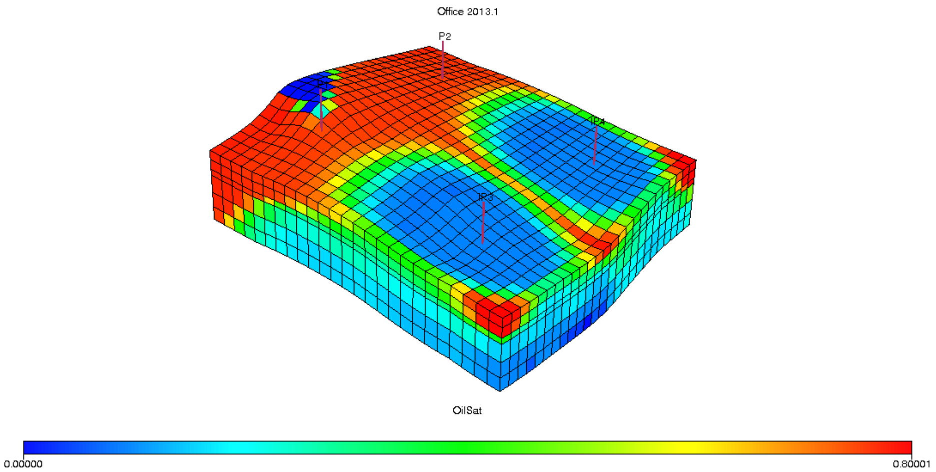

Figure C.6 Oil saturation after 20 years production of case study 10 start with polymer flooding at the 1st year by direct line drive pattern (2 production well, 2 injection wells)

BIOGRAPHY

Mr. Theeradech Thongsumrit was born on the 14th of September 1982 in Angthong province. He earned his high school diploma in science-math from Angthong Patthamaroj Wittayakom School in 2000 and his bachelor's degree in Transportation Engineering from Faculty of Transportation Engineering, Suranaree University of Technology (SUT) in 2007. After graduation, he has been worked about highway engineering, traffic engineering and road safety until 2011.

During 2011-2014, 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 and reservoir engineering, and high skill in the areas of reservoir simulation.