COMPUTER SIMULATION OF POLYMER FLOODING IN MAESOON OIL FIELD

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การจำลองทางคอมพิวเตอร์ของการขับน้ำมันโดยใช้พอลิเมอร์ในแหล่งน้ำมันแม่สูน

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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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การศึกษานี้ใช้กระบวนการขับน้ำมันโดยใช้น้ำและพอลิเมอร์เพื่อมาช่วยเพิ่มประสิทธิภาพการผลิตน้ำมันในแหล่งน้ำมันแม่สูน วัตถุประสงค์ในการศึกษานี้จะศึกษา 1) ศึกษากระบวนการขับน้ำมันโดยใช้น้ำและพอลิเมอร์ 2) เปรียบเทียบประสิทธิภาพการผลิตน้ำมันของการใช้กระบวนการขับน้ำมันโดยใช้น้ำและพอลิเมอร์ 3) เปรียบเทียบการผลิตน้ำมันเมื่อทำการเปลี่ยนความเข้มข้นของพอลิเมอร์ 4) ประเมินค่าทางด้านเศรษฐศาสตร์เพื่อค้นหาตัวเลือกที่ดีที่สุดสำหรับการลงทุนและกำไรมากที่สุดในการดำเนินงานจริง การจำลองชั้นกักเก็บน้ำมันเป็นการจำลองจากชั้นหินกักเก็บจริง โดยใช้ข้อมูลจากสื่อสิ่งพิมพ์ซึ่งครอบคลุมข้อมูลทางธรณีวิทยา ธรณีฟิสิกส์ และชั้นหินกักเก็บข้อมูลบางอย่างมาจากการประเมินและคำนวณจากวิธีการต่างๆ ตามทฤษฎี รูปแบบที่ใช้ในการจำลองนี้ใช้หลุมผลิต 1 หลุมและหลุมอัด 2 หลุม โดยมีอัตราการผลิตคงที่ที่ 200 บาร์เรลต่อวัน โดยใช้พอลิเมอร์ความเข้มข้น 600 ppm, 1,000 ppm และ 1,500 ppm โดยทำการอัดทั้งในกระบวนการขับน้ำและพอลิเมอร์และใช้อัตราการอัด 150 และ 300 บาร์เรลต่อวัน ทำการอัดด้วยน้ำและพอลิเมอร์ ในปีที่ 1, 3 และ 5 ของการผลิต โดยกรณีที่ดีที่สุดของการขับน้ำมันด้วยน้ำ คือ การอัดน้ำในปีที่ 1 ในอัตรา 150 บาร์เรลต่อวัน ตัวแปรการกู้คืนน้ำมันได้ 21.725% มูลค่าปัจจุบันสุทธิ คือ 2.809 ล้านเหรียญสหรัฐ ส่วนผลของการขับน้ำมันโดยพอลิเมอร์ คือ การอัดพอลิเมอร์ในปีที่ 1 (ความเข้มข้นของพอลิเมอร์ 600 ppm และอัตราการอัด 300 บาร์เรลต่อวัน) เป็นวิธีที่ดีที่สุด ตัวแปรการกู้คืนน้ำมันได้ 26.72% มูลค่าปัจจุบันสุทธิ คือ 8.905 ล้านเหรียญสหรัฐ จากผลการศึกษาเมื่อพิจารณาจากผลรวมการผลิตน้ำมันทั้งหมด จะพบว่ากรณีการศึกษาของความเข้มข้นที่ 1,500 ppm ของพอลิเมอร์ คือ กรณีที่ดีที่สุด เพราะความหนืดของพอลิเมอร์สูงขึ้นกว่ากรณีอื่นๆ ทำให้น้ำมันที่หลงเหลืออยู่ถูกขับไปยังหลุมทำให้ได้ปริมาณน้ำมันเพิ่มขึ้นซึ่งแสดงในค่าผลรวมการผลิตทั้งหมด และเมื่อพิจารณาจากผลการประเมินทางด้านเศรษฐศาสตร์ กรณีศึกษาที่ความเข้มข้น 600 ppm ของพอลิเมอร์ คือ กรณีที่ดีที่สุด เพราะความเข้มข้นของพอลิเมอร์ที่ใช้จะต่ำกว่าส่งผลให้ใช้พอลิเมอร์ดังกล่าวน้อยลงกว่า ซึ่งค่าใช้จ่ายที่ได้จากการคำนวณจะถูกกว่ากรณีอื่นๆ จากผลการประเมินของทั้งจากผลรวมการผลิตน้ำมันทั้งหมดและการประเมินทางด้านเศรษฐศาสตร์ พบว่าค่อนข้างขัดแย้งกันและยากต่อการตัดสินใจ อย่างไรก็ตามกรณีความเข้มข้นที่ 1,000 ppm ของพอลิเมอร์จะค่อนข้าง

ความเหมาะสมเพราะยังคงแสดงค่าที่สูงของตัวแปรการกู้คืนน้ำมันและค่าอัตราการผลิต ยิ่งไปกว่านั้นยังแสดงผลประเมินทางเศรษฐศาสตร์ที่สูงเป็นอันดับที่สองด้วย

สาขาวิชา เทคโนโลยีธรณี

ปีการศึกษา 2560

ลายมือชื่อนักศึกษา______________________

ลายมือชื่ออาจารย์ที่ปรึกษา______________________

SUCHET NILLAPHAN : COMPUTER SIMULATION OF POLYMER FLOODING IN MAESOON OIL FIELD. THESIS ADVISOR : ASST. PROF. AKKHAPUN WANNAKOMOL, Ph.D., 237 PP.

MAESOON OIL FIELD / WATER FLOODING / POLYMER FLOODING / SIMULATION

This study applies water and polymer flooding to increase the oil production efficiency in Maesoon oil fields. The purposes of this study are to (1) Study of water and polymer flooding (2) Compare the oil production efficiency between water and polymer flooding (3) Compare the oil production efficiency with a variation of polymer concentration (4) Evaluate the economics to find the best option for investment and most profitable in actual operation. The reservoir simulation is modeled as the actual oil reservoir by using information from all publications which have included geological, geophysical and reservoir data. Some data are estimated and calculated from theoretical method. The stagged line drive pattern is applied for injection and production wells. The production-fixed rate of 200 bbl/d, 600 ppm, 1,000 ppm and 1,500 ppm of polymer concentrations are used in experiment. Each of concentration is injected in rate of 150 and 300 bbl/d to the well. Firstly, the water is injected in the 1st, 3rd and 5th year, while the polymer are injected in the 1st, 3rd and 5th year of production as well. The best case in the 1st year in water flooding at injection rate 150 bbl/d, as the summary of the oil recovery factor of 21.725%, net present value is 2.809 MMUS$. The results of this research revealed that polymer flooding in 1st year (concentration 600 ppm in injection rate 300 bbl/d) is the best method, as the summary of the oil recovery factor of 26.72%, net present value is 8.095 MMUS$. Form the research results can be concluded that the polymer concentration of 1,500 ppm is the best case depending on the cumulative oil production. Because the viscosity of polymer is higher than others. The remaining oil is swept to the well then the production is higher as shown in the cumulative oil production. The economic evaluation, the case of 600 ppm polymer concentration is the best case. Because the polymer concentration is lower affecting to the lower polymer volume is used. That the calculated cost of this lower concentration case is cheaper than others. Both the cumulative oil production and economic evaluations are contrasted and hard for consideration. However, the case of 1,000 ppm polymer concentration is quite proper. Due to it is still high in recovery factor and production rate moreover, it is 2nd best case of both economic evaluations.

School of Geotechnology Student's Signature SUCHET NILLAPHAN

Academic Year 2017 Advisor's 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

SYMBOLS AND ABBREVIATIONS (Continued)

IRR	=	Internal Rate of Return
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
OWC	=	Oil/water contact
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

SYMBOLS AND ABBREVIATIONS (Continued)

SCFD	=	Standard cubic feet per day
STB	=	Stock tank barrel
STOIIP	=	Stock tank of oil initial in place
TSCF	=	Trillions of standard cubic feet
Visc.	=	Viscosity

CHAPTER I

INTRODUCTION

1.1 Rationale and background

Oil recovery operations traditionally have been subdivided into 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 a 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 (Don, Green and Paul Willhite, 1998). The final stage in this study is the use of polymer flooding in increasing oil production.

Thailand oil source countries are smaller and therefore less oil production and thus adopt water flooding in increasing oil production, but the leading polymer flooding used very little. This study chose to apply polymer flooding to improve oil production rate in Thailand. By studying Maesoon oil field which is located in a Fang oil field study in order to be able to compare the polymer flooding could increase oil production rate is more than letting the natural production. The simulation software named "Eclipse100" will be used to design the reservoir pattern and find efficiency for comparing economics.

1.2 Objectives of the study

This study is intended to inform the work of the polymer flooding that can improve the performance of oil production in the Maesoon oil field. The program, namely "Eclipse100" is selected to run the reservoir simulation. This study applies water and polymer flooding to increase the oil production efficiency in Maesoon oil fields. The purposes of this study are to (1) Study of water and polymer flooding (2) Compare the oil production efficiency between water and polymer flooding (3) Compare the oil production efficiency with a variation of polymer concentration (4) Evaluate the economics to find the best option for investment and most profitable in actual operation. After many performance simulation have been run, the efficiency comparison comes from oil production, and economic principles determine the best method of Maesoon oil field.

1.3 Scopes and limitations of the study

1.3.1 Collect and study data of reservoir in Maesoon oil field.

1.3.2 Find oil reserve and recovery efficiency for water flooding and polymer flooding by using a simulation program, namely Eclipse100 when changes the reservoir data, year to inject and rate of injections.

1.3.3 Analyze data and compare the economics of water flooding and polymer flooding. Determine the best Internal Rate of Return (IRR) and Net Present Value (NPV).

1.4 Research methodology

1.4.1 Literature review

The review includes details of Maesoon oil field in Fang 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 the American Association of Petroleum Geologist (AAPG), Society of Petroleum Engineers (SPE).

1.4.3 Reservoir simulation

The reservoir simulators or complex computer program that simulate multiphase displacement processed in two or three dimensions. Reservoir modeling is constructed as a hypothetical model by "ECLIPSE Office E100", simulation software must be done in these studies, and then used to predict its dynamic behavior. It solves the fluid flow equation by using numerical techniques to estimate the 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 Maesoon oil field in Fang Basin.

1.4.4 Economic evaluation

Economic evaluation is calculated from the 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 projects, 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 project.

1.5 Expected results

The following expectative results this study is:

1. Find the oil reserve and recovery efficiency in the Maesoon oil field.

2. Find the best method and economically in Maesoon oil field with water flooding or polymer flooding.

3. Improve knowledge of water and polymer flooding.

4. Assist in planning and energy management, alternative fuel and energy for utilization in the future.

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 Fang Basin and Mae Soon oil field 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 the result of water and polymer flooding simulation model. **Chapter 5** analyzes result of simulation model in term of economic considerations. Conclusion and discussion of future research needs are given in **Chapter 6**. **Appendix A** illustrates simulation data. **Appendix B** illustrated polymer data. Economic data are shown in **Appendix C**. Reservoir simulation result are shown in **Appendix D**.

CHAPTER II

LITERLATURE REVIEW

2.1 Maesoon oil field

Maesoon oil field was found and developed following Chaiprakarn oil field, which is drilled for exploration in 1963. Crude oil in the oil field is paraffinic base and then called Maesoon crude oil. There is an oil layer at 2,200 feet of depth with can be produced oil about 50 bbl per day. From 1963 to 2010 Maesoon oil field has been developing. There were 84 exploration wells and about 33 wells were developed to be productive well. Almost of oil layer have a depth range between 2,000 to 3,000 feet.

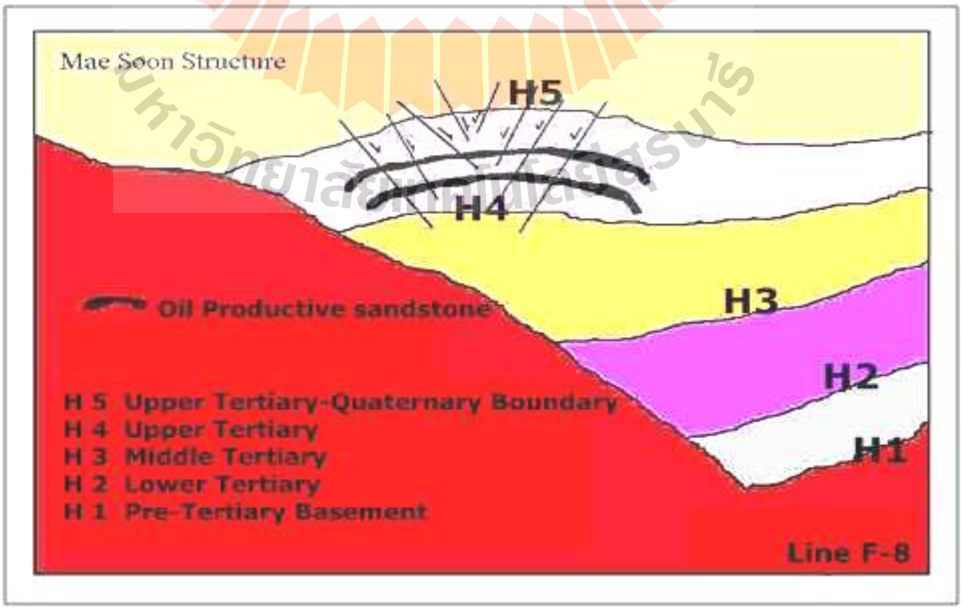


Figure 2.1 Structural stratigraphic in Maesoon oil field (Chananchida, 2012)

Maesoon oil field is a potential source of petroleum; oil-drilling exploration and development holes, the most oil production in Fang district, Chiang Mai Province.

2.2 Fang basin

The Fang Oilfield is located in Fang intermontane basin, Northern Thailand. It is approximately 150 kilometer north of Chiang Mai or 850 kilometer from Bangkok, the capital of Thailand. The surface area is approximately 600 square kilometer (width 12 and length 50 kilometer), probably the smallest intermontane basin in which petroleum has been discovered in the country. The basin lies NE-SW with an elongated shape and is surrounded by older formations of rocks from Cambrian and Igneous rocks to more recent sediments. The highest peak is around 2,000 meter and the basin is about 450 meter above mean sea level.

People living in the area are Thai citizens and also more than 10 groups of minority hill tribes including Chinese, Mong, Muser, E-koe, Palong, Dai Yai, Karen, Yao, Wa, Lisor and local northern people with different dialects and cultures.

The area is hilly with green mountain forest and beautiful nature. As such, Fang is one of the most attractive places for both Thai and foreign tourists who visit all year long. During December and January, some days the temperature might drop down to 5-10°C and sometimes even as low as 0°C on the peak of Doi Angkang. Such climatic conditions are rarely found in other places of the country.

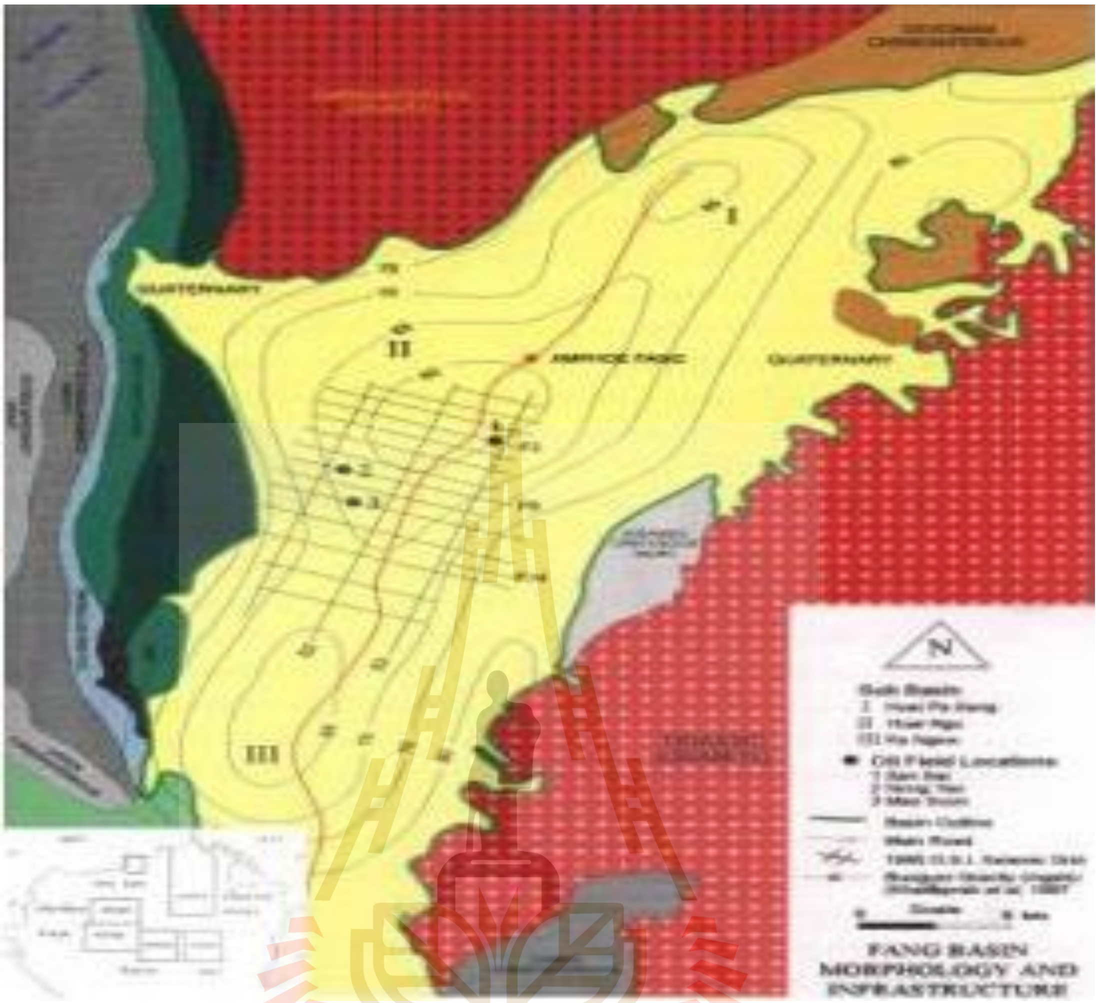


Figure 2.2 Geomorphology and geologic setting of the Fang basin

Agriculture and commerce are the main economies in the region. Among most popular fruits from this area are lychees and honey oranges which are very tasty. On the top of Doi Angkang where the Royal King's project station is located, many plants, floras and vegetables from cold countries are planted aimed at reducing drug activities previously common in the area. The main oil production operated from the sandstone of the Mae Sod Formation in the Mae Soon, San Sai, Nong Yao, Sam Jang and Ban Thi structures. Most oil fields in Fang basin were belonging to and operated by the Department of Defence Energy, and produced by natural flows which now are expelled by low differential pressures and finally resulted in lower production efficiency. Present day, the sucker rod pumping units is used to improve oil recovery of these oil fields. These oil fields have a long history of operation and production in some tracts has decreased, with many wells currently exhibiting water cut increases. In order to reduce operating expenditures on electricity for sucker rod pumping unit, intermit operation is selected to study in this research. The methods of intermit operation have been to build up the pressure in a well by shutting in well for 12 hours and then open hole for normal flow for 12 hours. As a result, work hours of sucker rod pump are reduced. Moreover, the useful life of sucker rod pumping unit could also be extended and this can also reduce its maintenance and spare part costs. The total production from the Fang basin is approximately 9 million barrels (MMbbl) from the following 7 reservoirs since early 1960 to the present day.

I. Chaiprakarn Reservoir (abandoned 1984), II. Maesoon Reservoir, III. Pongnok Reservoir (abandoned 1985), IV. Sansai Reservoir, V. Nongyao Reservoir, VI. Sanjang Reservoir, VII. Banthi Reservoir.

2.3 Statigraphy

2.3.1 Stratigraphy of Fang basin

Based on the characteristics of seismic reflections, seven seismic sequences have been identified and described successively upward as follows.

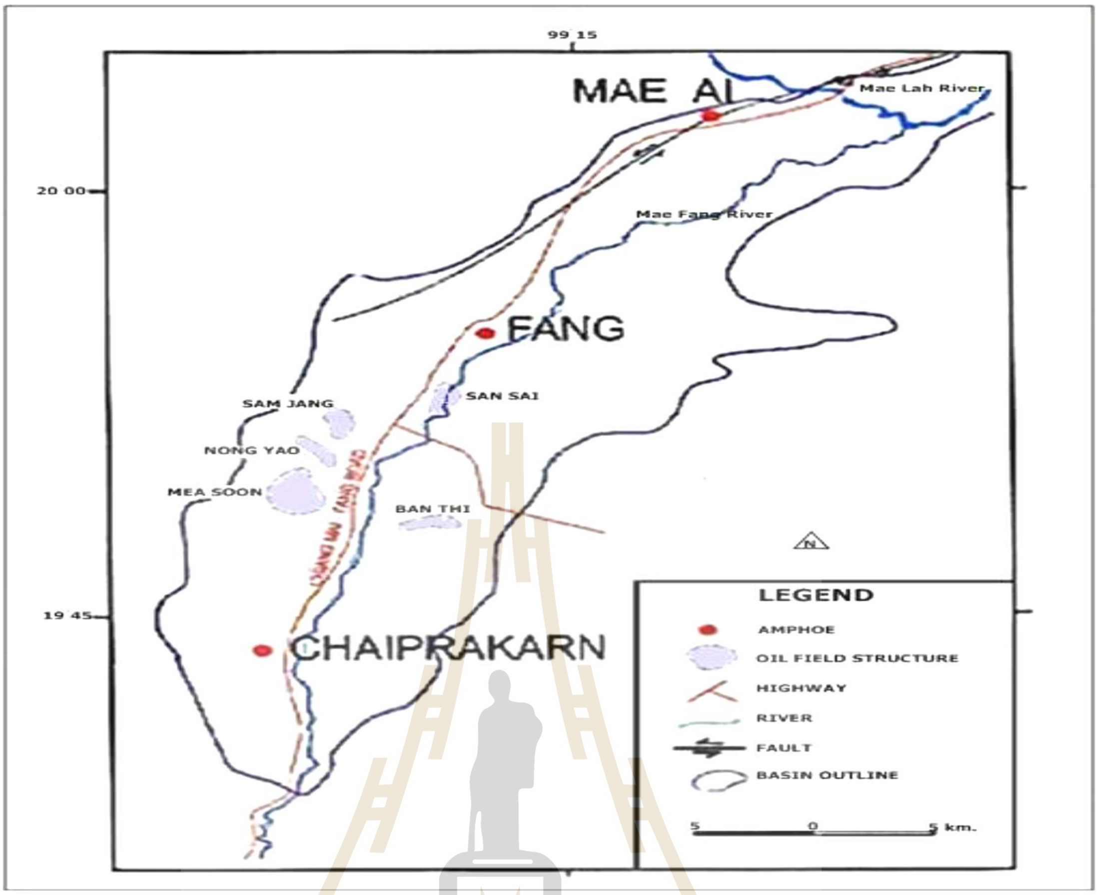


Figure 2.3 Oil fields in the Fang basin (Defense Energy Department, 2004)

The Pre-Tertiary basement is characterized by chaotic and discontinuous reflections with moderate to low amplitude and low continuity. It is tilted to the west and the upper part of the unit has irregular reflections that are cut by east-dipping faults.

Sequence 1 consists of weak seismic reflections with low to moderate amplitude and poor continuity. The amplitude the upper boundary increases eastward. The unit is the thickest in the northeastern part of the area.

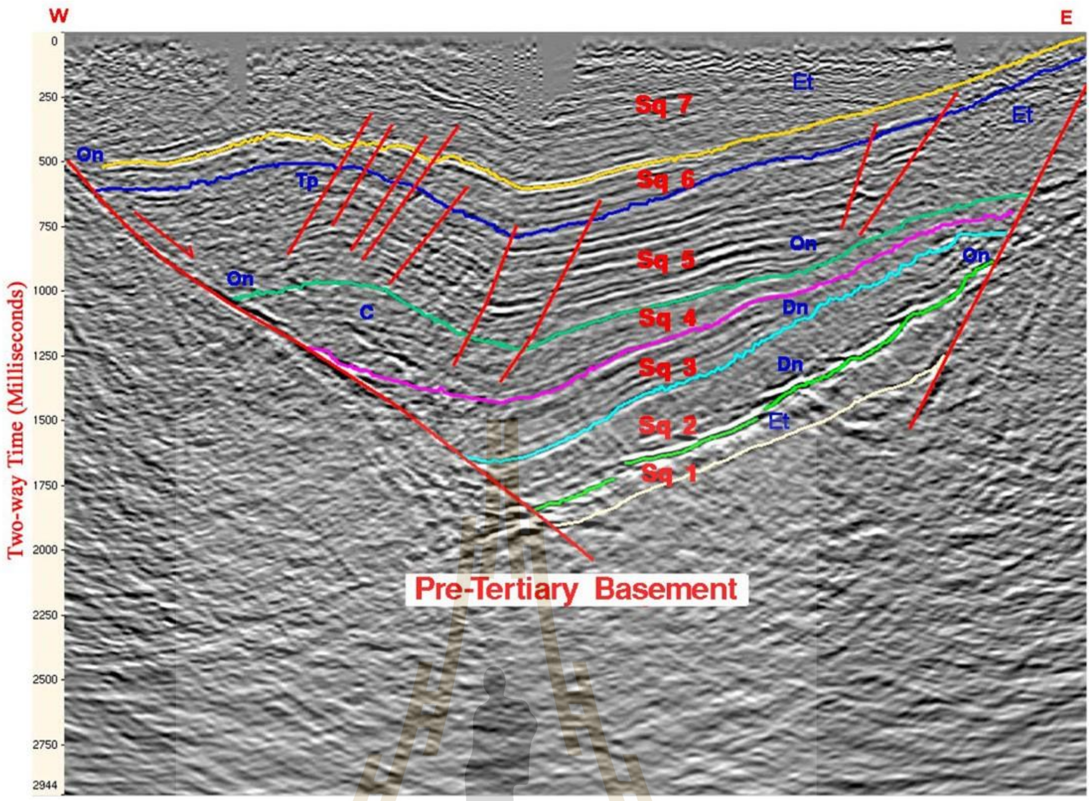


Figure 2.4 Interpretation of a seismic profile across the study area with 8 seismic units Basement and Sq1 to Sq7. On = onlap; Dn = downlap; Tp = Toplap; Et = erosional truncation; C = Clinoform

Sequence 2 the seismic reflections have moderate to high amplitude and poor to moderate continuity. The unit is the thickest in the northeastern part of the area. In the east, the upper boundary features toplap and erosional truncation. The lower boundary is characterized by westward downlap of seismic reflections. Inter nally, reflection configuration can be described as sigmoid to oblique clinoforms. The unit pinches out eastward onto the lower boundary and thins toward the west.

Sequence 3 consists of chaotic seismic reflections with poor continuity. It pinches out eastward and thickens toward the western basin-bounding fault. Internal reflections are sub-parallel with moderate to low amplitude and onlap onto the lower boundary. The upper boundary is a concordant reflection with moderate to strong amplitude.

Sequence 4 has similar seismic characteristics to those of Sequences 2 and 3. It is a prograding unit that thins eastward and thickens toward the western basin-bounding fault. The seismic reflections within the unit have high amplitude.

Sequence 5 can be separated into five subsequences: 5I, 5H, 5G, 5F and 5E, successively upward. Most reservoirs of the Fang oil fields are located within Sequence 5. The seismic reflections in the unit are sub- parallel and have moderate to high amplitude with moderate to good continuity. The reflections onlap onto the lower boundary at the western and eastern margins of the basin. The upper boundary is characterized by erosional truncation in the east and toplap in the west. Strong reflections occur near the basin margins and become less prominent in the basin centre.

Sequence 6 consists of seismic reflections inside the unit with low to medium amplitude and moderate continuity. The reflections onlap onto the lower boundary at both basin margins. The upper boundary is characterized by erosional truncation over most of the area.

Sequence 7 consists of seismic reflections with low amplitude and moderate to poor continuity. The reflections are better resolved in the basin centre. At the basin margin, they appear to onlap onto the lower boundary. In the western half of the basin, erosional truncation characterizes the upper part of the unit.

2.3.2 Depositional Environments

Depositional environments of the basin fills were interpreted from analysis of seismic reflections in combination with well data. This information is considered crucial in predicting the possibility and suitability of a prospected area. Depositional environments for the seven seismic units are discussed as follows.

In general all of the seismic units represent sediment that was deposited in a continental environment including purely fluvial and lacustrine conditions as well as the transition between the two regimes.

Based on well information, the Pre-Tertiary basement consists of weathered andesite and Permian limestone. The sandstone in Sequence 1 has been described as poorly sorted, angular and rich in feldspar and rock fragments. This information and its seismic characteristics of low to moderate amplitude and poor continuity indicate that the unit was probably deposited in a fluvial environment with the sediment sources at the basin margins. The upper boundary has very strong amplitude and corresponds to bituminous shale and lignite, which are regarded as good source rocks in the eastern part of the Fang basin. Well information reveals that Sequence 2 consists of a series of sandstone inter-bedded with shale. The sandstone is grayish and well- sorted with sub-angular to sub-rounded grains. The alternation of sandstone and shale provides seismic reflections with moderate to high amplitudes and poor to moderate continuity. Clinoform seismic configuration indicates a westward-directed prograding unit.

The sub-parallel to chaotic reflections with poor continuity of Sequence 3 can be interpreted to represent deposition in a low energy environment or a lake where mud dominated. The strong reflection at the upper unit boundary corresponds to coal that indicates a possible swampy environment, especially along the lake margins.

Clinoform configuration in seismic profiles of Sequence 4 indicates a westward directed prograding unit. Strong reflections within the unit correspond to alternation of sandstone and shale. Data from wells show that the sandstone is moderately sorted with angular to sub-rounded grains. Sequence 5 comprises sandstone inter-bedded with shale. The sandstone forms reservoirs in the western part and the eastern part of the Fang basin. The internal reflections are sub-parallel and onlap onto both the western and eastern basin margins. The strong seismic amplitudes at the basin margins that decrease toward the basin centre can be interpreted as a transition from alternating sandstone and shale in the shallower part to dominantly shale in the deeper part of the basin. This information suggests that the sediment was supplied by sources on the basin flanks.

Sequence 6 consists of dominantly shale inter-bedded by minor sandstone. The upper boundary of the unit shows erosional truncation that can be interpreted as an unconformity corresponding to a seismic reflection with have moderate to low amplitude and moderate to low continuity. Sequence 7 is the youngest sequence. Seismic reflections in this sequence have low amplitude and moderate to poor continuity that probably correspond to alternating sandstone and shale layers. At the basin margins, they appear to onlap onto the lower boundary and the reflections are better resolved in the basin centre. Therefore, the sediment has been interpreted as being supplied from the basin margins. In the western half of the basin, erosional truncation characterizes the upper part of the unit. This erosion was probably a result of local or regional uplift of the basin (Nuntajun, 2009).

2.3.3 Subsurface Lithostratigraphy

From the geological data there are 2 major formations from the upper zone of Maefang formation to lower zones of Maesod formation as follows:

Maefang Formation (Quaternary + Recent)

The post-rift of Maefang formation overlies discordantly above the Maesod formation. The thickness of the Maefang formation from the surface varies from 1,000-1,800 feet. The minimum thickness is found on top of the Maesoon structure. The thickness will increase down dip from the crest of the structure.

Maefang formation is mainly composed of coarse clastic sediments of soil, lateritic sands, loose sands, gravels, cobbles and pebbles, carbonized woods and clay on the top and towards the basin edge. Sizes of sands vary from coarse to very coarse grains, roundness from angular to sub-angular, poorly sorted and inter-bedded with reddish clays. While down dip towards the central basin clay-shale and arkosic sandstone are inter-bedded. This formation overlies discordantly with the Maesod formation. The Maefang formation shows energetic alluvial and fluvial deposits.

Maesod Formation (Middle Tertiary)

The Maesod formation is composed of brown to gray shale, yellowish mud stone generally inter-bedded with sand and sandstone with a series of channels of sand paleodelta and fluvial sand.

Basal conglomerate lies unconformity with Pre-Tertiary rocks and continues with sequences of lacustrine shale and mudstone. The color of the sediments indicates a reducing environment in the central, deeper part of the basin while an oxidizing environment develops in the shallow part of basin. Organic shale in the central part of the basin plays an important role as a potential source of rocks. The upper part of the Tertiary sediments is inter-bedded with 4 packages of sand which are important reservoir rocks in the Fang basin. Only 2 packages of sands have been proven to be producing sands. The sand thickness varies from 1-10 meter.

The thickness of the Maesod formation varies from the margin of the basin towards the centre of the basin. At the Maesoon structure the thickness is approximately 3,500 feet or total thickness (Maefang + Maesod formation) 5,000 feet from the surface. Seismic interpretations indicate that the thickest part of the Maesod formation might reach up to 8,000 feet at the deepest part of the basin.

Basement (Pre-Tertiary)

The age of the basement of the Fang basin ranges from Mesozoic continental clastics to Cambrian marine clastics.

2.3.4 Oil Reservoir

Within the Fang basin, all productions come from the Maesod formation. The current producing reservoirs are distributed into widespread sections of the sorted sands and coarse clastics in some cases.

Reservoir distribution

Generally, inter-bedded sand and sandstones in the upper zones of the Maesod formation are dominant reservoir rocks in the Maesoon reservoir and others.

The sand member which gives the lowest production includes 4 layers of sand. The thickness of each sand layer varies from 5-45 feet. The depth of this sand is about 2,386-2,487 feet which is the main producer of wells. The thickest part of this sand is in a North-South direction. Porosity decreases towards the margin of the reservoir.

The sand member gives the highest production includes 5 sands, 5-15 feet in thickness for each sand, with a total thickness of about 55 feet. The depth is about 2,160-2,255 feet. Most of the old wells are from this sand 2,300 feet in depth. The thickness of the sand varies from place to place. The trend in thickness North-South is 55 feet and decreasing to 10-15 feet at the edge of reservoir.

Reservoir Properties

Cores analysis from some wells shows interesting results of porosity up to 25%, permeability higher than 200 milliDarcy (mD), some loose clastics as high as 2,000-3,000 mD found in the well IF 26 Table 2.1 Reservoir properties.

Table 2.1 Reservoir properties

Well	Depth (ft)	Permeability (mD)	Porosity (%)	Fluid saturation (%)		Density (gm/cc)
				Oil (Sor)	Wat (Sw)	
BS-110	2,755	231	25.7	6.1	54.4	2.67
IF-26 1)	2,581	2,390	25.4	17.5	33.0	2.65
2)	2,587	3,440	26.7	20.5	34.7	2.64

Fluid Properties

Physical properties of oil from Maesoon, Pongnok, and Lankrabreau are quite similar with a very high content of paraffin wax up to 18% shown on the Table 2.2

Table 2.2 Physical properties and composition of crude oil in Maesoon oil field, Pong Nok oil field, and Lankrabue oil field

Properties	Maesoon oil field	Pong Nok oil field	Lankrabue oil field
API. Gravity	30.8	37.6	38.2
Pour Point	95°F	92°F	90°F
Sulfur (%)	0.18	0.16	0.5
Paraffin wax (%wt)	18	18.62	14.5-20
Specific gravity	0.872	0.873	-
Color	Brownish black	Brownish black	Brownish black

Reserve Estimation

The Maesoon reservoir has produced a total of 7 MMbbl since 1963. Production started from 100 barrel per day up to nearly 1,000 barrels per day at the peak of production (Table 2.3). The mature reservoir needs to maintain pressure to extend the life of the reservoir.

From the decline curve the life of the Maesoon reservoir will terminate in the next 4-5 years. Secondary recovery will be needed for this reservoir to prolong production (Settakul, 2009).

Table 2.3 Reserve estimation

Field	Probable (MMbbl)	Proven (MMbbl)	Recoverable (MMbbl)
Maesoon	23.0 - 30.0	10.0 - 15.0	8.00
Sansai	20.0	7.0	3.00
Nongyao	5.0	3.0	2.00
Samjang	5.0	1.5	0.75
Pongnok	6.0	3.0	1.50
Banthi	8.0	3.0	1.50
Chiprakarn	4.5	1.5	1.00

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).

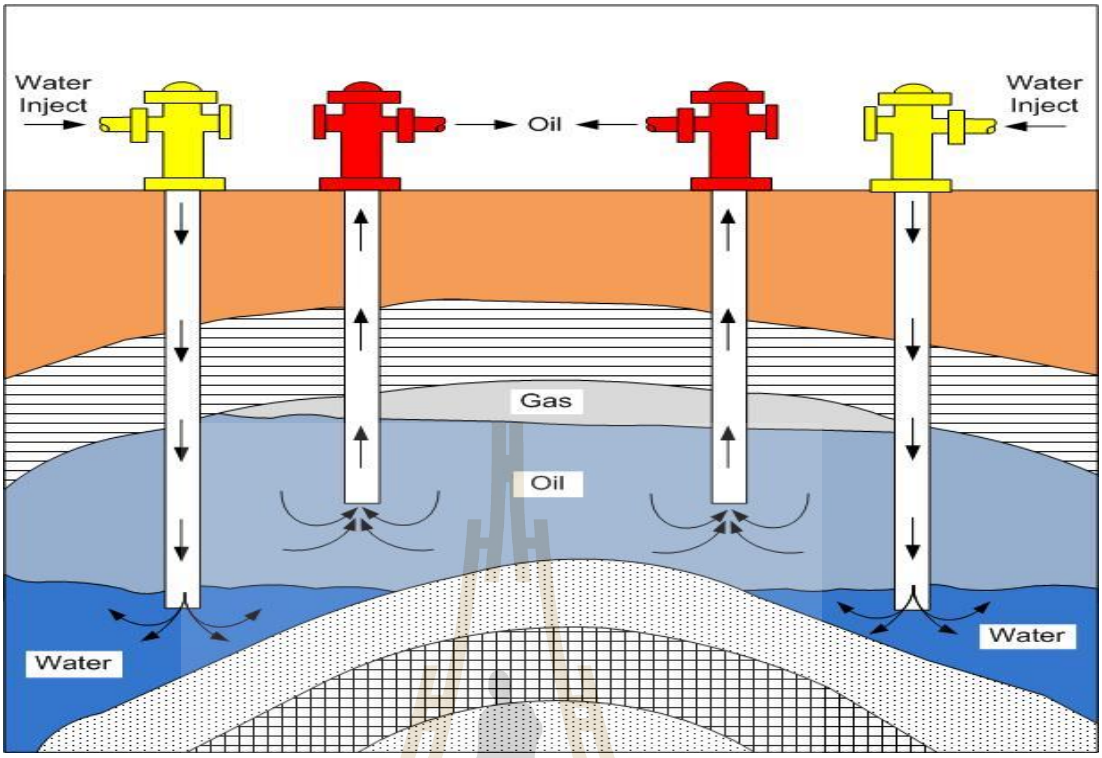


Figure 2.5 Water flooding method showing two water injection wells and two well productions (Thongsumrit, 2012)

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, 2009).

2.5 Case study of water flooding

2.5.1 Jay-LEC Field:

The Jay-LEC field has produced from the Smackover carbonate and Norphlet sand formations at depth about 15,400 feet. An oil/water contact is located at a sub-sea depth of 15,480 ft. More than 90% of the oil in place are in Smackover. The reservoir study indicated that the natural water drive would not be an 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 (2D) 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).

2.5.2 Fahud field

A fracture model was constructed for the Natih-E reservoir unit of the Fahud Field in northern 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 water flood 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 percent under GOGD to 40 percent of the water flood. 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).

2.5.3 Sirikit oil field

The oil fields 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 oilfield 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 oilfields. 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 LanKrabu 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 LanKrabu reservoir was feasible. The water flooding project had studied again during 1993-1994. It gave a boost to the confidence in recovery factor of the field, which increased over 20 percent 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 percent. 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 reserve volume is recoverable only through the 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).

2.6 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 show a schematic of a typical polymer flood injection sequence: a preflush is usually consists 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 chased or drive water. Many times the freshwater buffer contains polymer in decreasing amounts (a grading or taper) to lessen the effects of the 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.

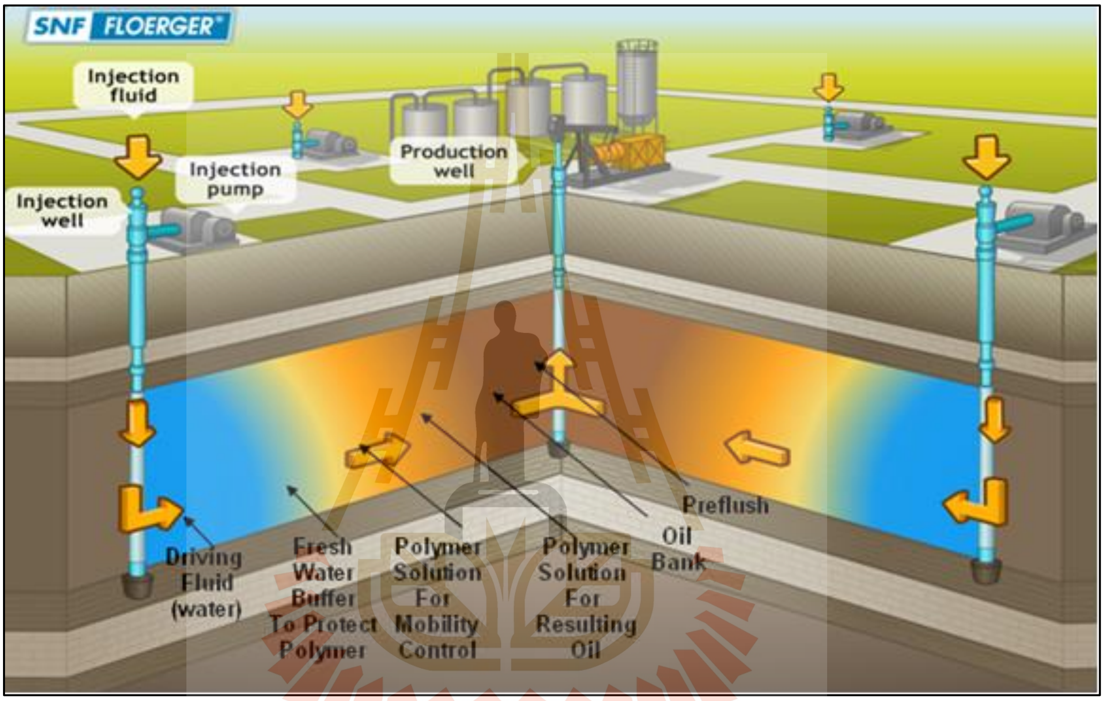


Figure 2.6 Polymer flooding method (Bradley, 1987)

2.6.1 Polymer type

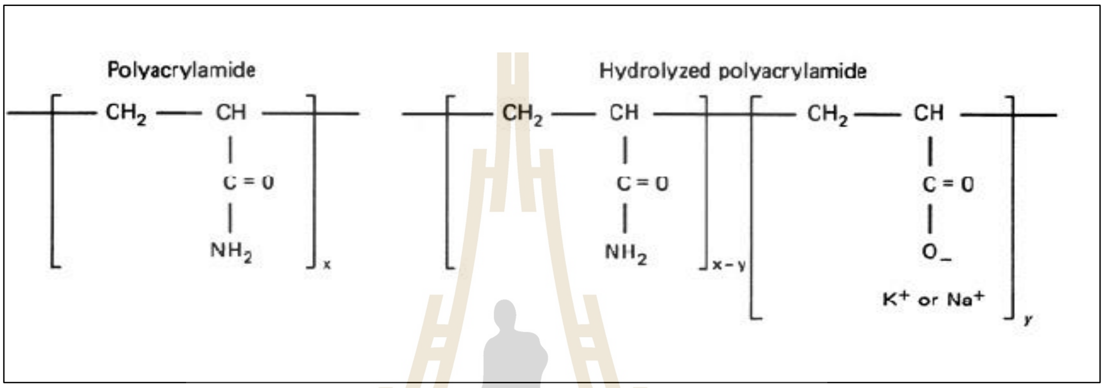
According to Noianusontigul (2008), several polymers have been considered for polymer flooding; Xanthan gum, hydrolyzed polyacrylamide (HPAM), copolymers (a polymer consisting of two or more different types of monomers) of acrylic acid and acrylamide, copolymers of acrylamide and 2-acrylamide 2-methyl propane sulfonate (AM/AMPS), hydroxyethylcellulose (HEC), carboxymethylhydroxy ethylcellulose (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)

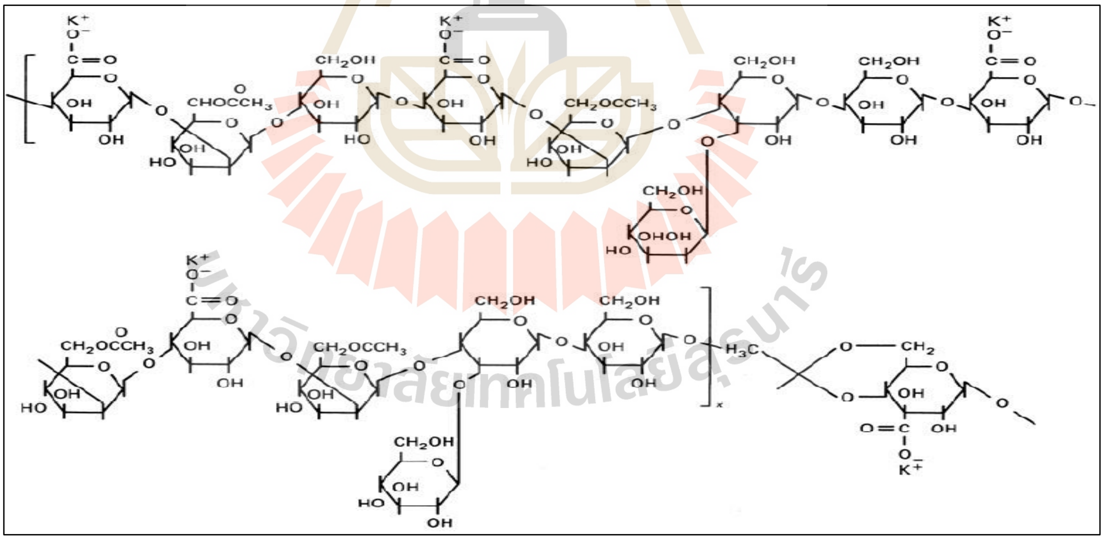
These polymers' monomeric unit is the acrylamide molecule (Figure 2.7a). When used in polymer flooding, polyacrylamides have undergone partial hydrolysis, which causes anionic (negatively charged) carboxyl (-COO-) to be scattered along the backbone chain. For this reason these polymers are called partially 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 causes the molecule in solution to elongate and snug on those similarly elongated, an effect that accentuates the mobility reduction at higher concentrations.

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 a permanent permeability reduction.



(a) Molecular structure of polyacrylamide



(b) Molecular structure of polysaccharide (biopolymer)

Figure 2.7 Molecular structures (Lake, 1989)

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 a permeability reduction. Molecular weights of polysaccharides are generally around 2 million.

From the study in thermal and rheological of polysaccharides, at 55^{o}C 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

k_p = 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.

$$Rf = \frac{\frac{kw}{\mu w}}{\frac{kp}{\mu w}} \tag{2.2}$$

where Rf = Resistance factor

μo, μw = 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.

$$Rrf = \left(\frac{\frac{kw}{\mu w}}{\frac{kp}{\mu w}}\right) a \tag{2.3}$$

where R_{rf} = 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 water flooding 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 Feasibility study of secondary polymer flooding in Henan Oilfield

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 Oilfield Company, a subsidiary of Sinopec (Wikipedia, 2012). During 1996 to 2006, polymer flooding was implemented in Henan Oilfield, with average 70 mPa.s of crude oil viscosity and reservoir temperature of 55˚C, polymer of 0.42 PV to 0.44 PV was injected with above 8% of enhanced recovery. In the next water flooding, water cut rises rapidly, and part of the lower permeability zone was not developing, therefore it is necessary to employ relay technology to retain yield. On 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. Water cuts decreased from 92% to 83%, and cumulative increased crude oil of above 50,000 tons.

2.7.2 Polymer flooding in a large field in south oman

This large sandstone field was discovered in 1956s. The oil is heavy (22°API) and viscous (90 cp). The field is highly heterogeneous with sand diamictite and shale bodies. However, the main reservoir units the net-sand/gross-reservoir ratio approaches 1.0 and the permeability can be many darcies.

The crude oil and the resulting poor mobility ratio with the displacing water, the achievable recovery by water flooding were estimated at 20 to 30%. The Phase-I project consists of polymer injection in 27 existing injection wells, with the aim to increase recovery by approximately 10% of the targeted area. Polymer injection takes place through 20 inverted nine spot patterns, four inverted five spot patterns all with vertical injectors and three patterns with horizontal injectors. Initial polymer injection took place in February 2010, and the project was fully commissioned in April 2010. The polymer injection rate is approximately 13,000

m^3/d in 15 cp polymer viscosity at the wellhead. This project is the first full scale polymer plant in Oman and the Middle East, and is one of very few full scale polymer applications in the world (Faisal, Henri, and Pradeep, 2012).

2.7.3 Reduced well spacing combined with polymer flooding improves oil recovery from marginal reservoirs

In continental, multilayer, heterogeneous sandstone oil fields, some reservoirs with poor connectivity and low permeability have low recovery factors. The low degree of layer connection and inner-layer interferences lead to poor water flooding efficiency, to improve oil recovery and increase recoverable reserves, infill wells were drilled to improve reservoir connectivity and a polymer solution was injected. Average incremental oil per day for a single well was 1.83 times original production. Water cut decreased 10.2%, and oil recovery increased more than 10% (Sui, and Bai, 2006).

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

$$Np = N * E_A * E_V * E_D \tag{2.5}$$

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

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

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

or

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

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

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

Boi = oil FVF at pressure is pressure is $\bar{p}1$, bbl/STB

Bo = 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 (Sor),

$$E_D = 1 - \left(\frac{Sor}{\overline{S}oi}\right)\left(\frac{Boi}{Bo}\right) \tag{2.9}$$

This becomes

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

where Sor = 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 non-uniform 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,

$$\lambda o = \frac{ko}{\mu o} = \frac{kkro}{\mu o} \tag{2.11}$$

$$\lambda w = \frac{kw}{\mu w} = \frac{kkrw}{\mu w} \tag{2.12}$$

$$\lambda g = \frac{kg}{\mu g} = \frac{kkrg}{\mu g} \tag{2.13}$$

where λ_o, λ_w, λ_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,

$$M = \frac{\lambda w}{\lambda o} = \left(\frac{krw}{\mu w}\right)\left(\frac{\mu o}{kro}\right) \tag{2.14}$$

simplifying gives

$$M = \left(\frac{krw}{kro}\right)\left(\frac{\mu o}{\mu w}\right) \tag{2.15}$$

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.

3.2 Reservoir simulation model

This study used dead-oil reservoir simulation by Eclipse Office E100 to simulate all types of reservoir (primary, secondary and tertiary productions) which based on available data on Mae Soon oil field and some of data assumptions. The structure of reservoir simulation is shown in figure 3.1 to 3.2 and the detail summarize as follows:

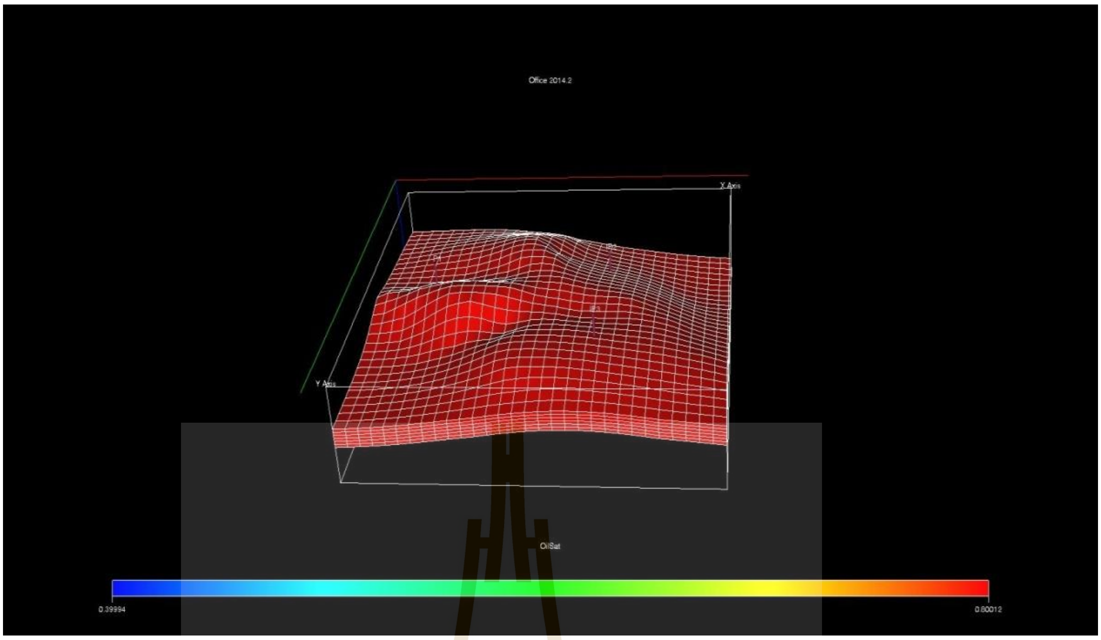


Figure 3.1 Reservoir Structure model

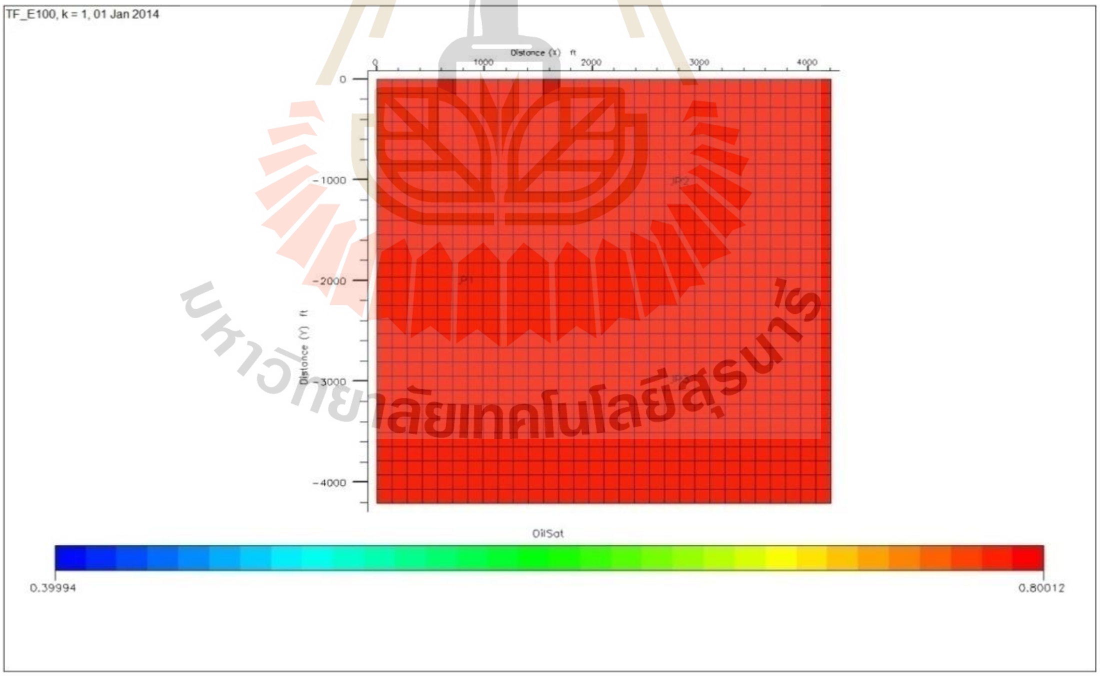


Figure 3.2 2D Reservoir model

- Model dimension (long, wide, thick)	4200, 4200, 105 feet
- Scale grid (x, y, z)	30, 30, 6 (5,400 grid blocks)
- Structure style	Monocline
- Unit	Field
- Geometry type	Conner Point
- Grid type	Cartesian

3.3 Data input for the reservoir model

The data input in the reservoir model are received from available data of Mae Soon oil field data. The main input data section 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 for Mae Soon data.

3.3.1 Grid section data

The data input in this section is used keyword type Properties and geometry. Properties is input data active grid block, permeability distribution, porosity and net to gross thickness ratios. Geometry is an input data grid block coodinate line and grid block corners. The data for Grid section is following:

- Net-to-gross ratio	0.18 – 1.00

Table 3.1 Permeability and porosity for 6 layers

Layer	Porosity (%)	Permeability (md)
1	29.00	230
2	27.00	190
3	25.00	170
4	23.00	150
5	21.00	120
6	19.00	100

3.3.2 PVT section data

The PVT section data are used keyword Polymer shear thinning data, Polymer solution viscosity function, Water PVT properties, Dry gas PVT, Dead oil PVT and fluid Density. The data input for PVT section are detail as follow:

- Rock type of reservoir	Consolidated Sandstone
- Oil gravity, (API Oil)	35.1
- Gas gravity, (SG Air = 1)	0.881
- Bubble point pressure, (psi)	14.7
- Salinity	0.00016
- Referenced pressure, (psi)	900
- Standard temperature, (°F)	60
- Standard pressure, (psi)	14.7
- Reservoir temperature, (°F)	170
- Fraction hydrogen sulfide	0.33

- Fraction carbon dioxide 0.03
- Fraction nitrogen 0.04

3.3.3 Scal section data

The SCAL section data use keyword Polymer adsorption function, Oil saturation, Gas saturation, Water saturation and Polymer rock properties. The data input for PVT section are detail as follow:

- Initial water saturation 0.2
- Oil saturation 0.1
- Gas saturation 0.04
- Polymer adsortion function 0.35

The Table A.1, A.2 of PVT Dry gas property and Dead oil PVT property are shown in Appendix A.

3.3.4 Fluid initialization section data

Initialization refers to the initial conditions of the simulation. The initial conditions are defined 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 calibration are as follows:

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

3.3.5 Well data about schedule section data

Well data provides well and completion locations, production and injection rates of wells and other data, the use keyword Well specification, Well completion data, Production well control, Production well economic limits, 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 Kh (mD)	250
- Perforation of production zone (layer)	1st - 6th
- Perforation of injection zone (layer)	1st - 6th

3.3.6 Type of polymer for injection

The Xanthan Gum (XCD) polymer concentration 1,000 and 1,500 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. This study is comparison different of polymer concentration for use is the best case and development for each reserved sizes of the reservoir. Recovery efficiency and economic evaluations are more favorable than the others concentrations. 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 in Appendix B. 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 3.3 and 3.4. 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.

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.

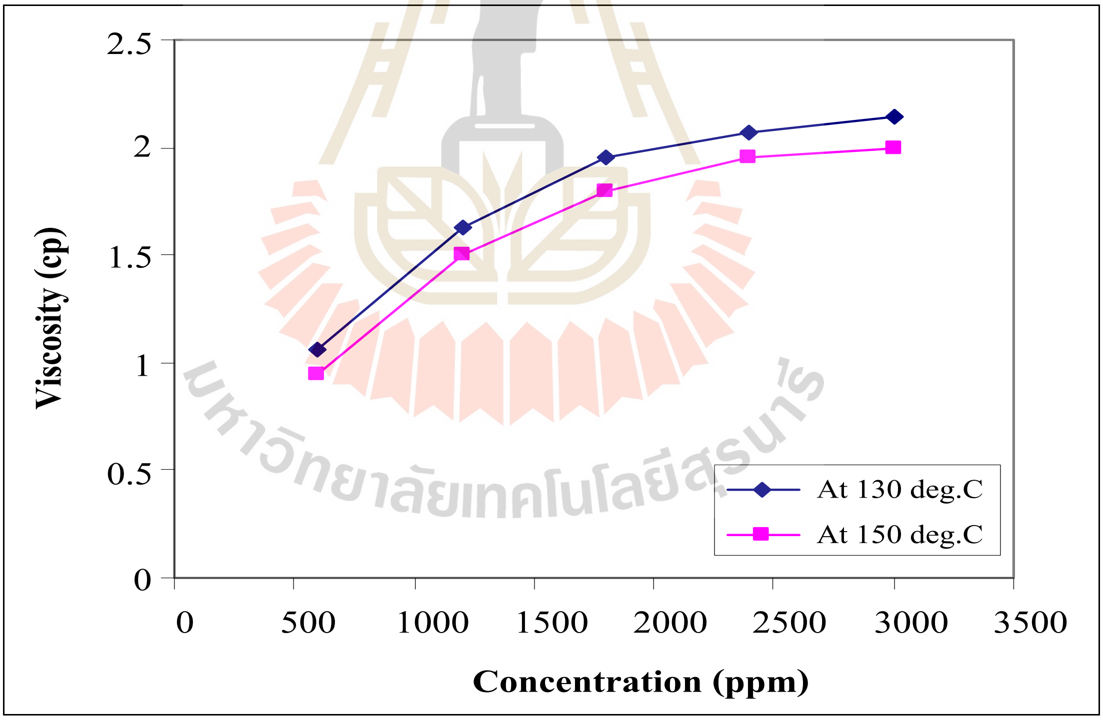


Figure 3.3 The viscosity versus concentration of polymer solution (Thang, 2005)

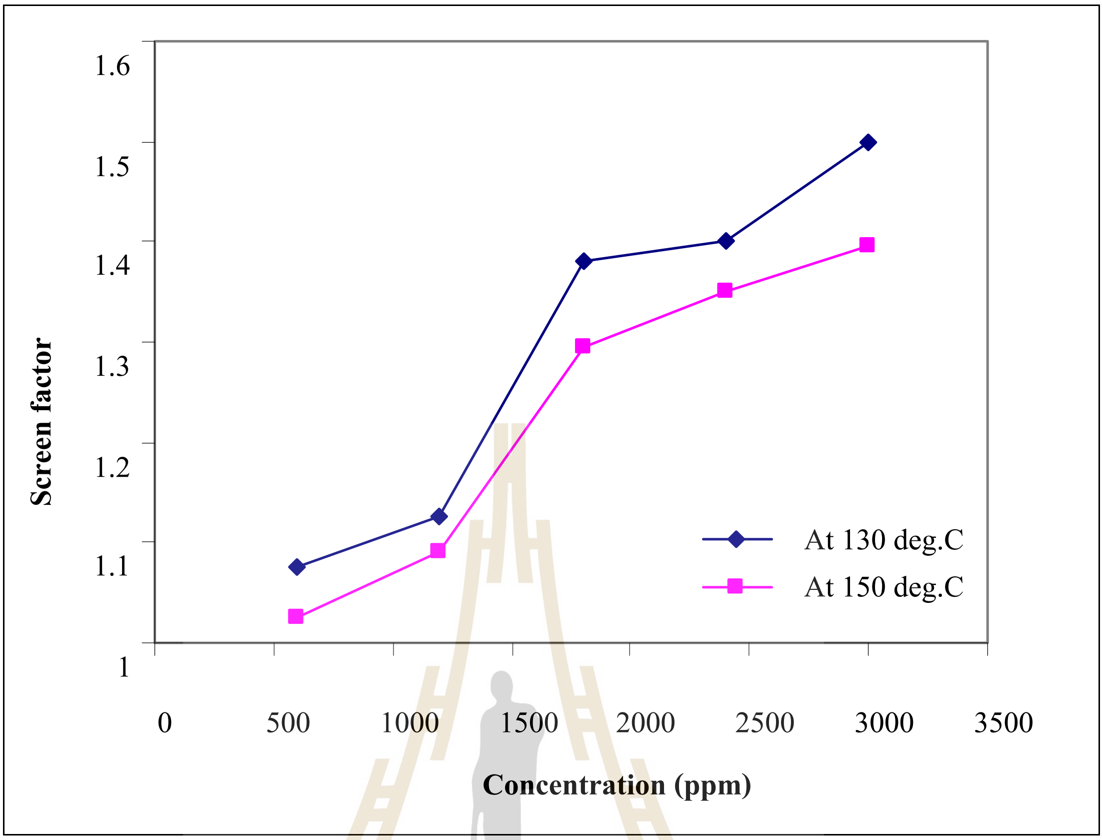


Figure 3.4 The screen factor versus concentration of polymer solution (Thang, 2005)

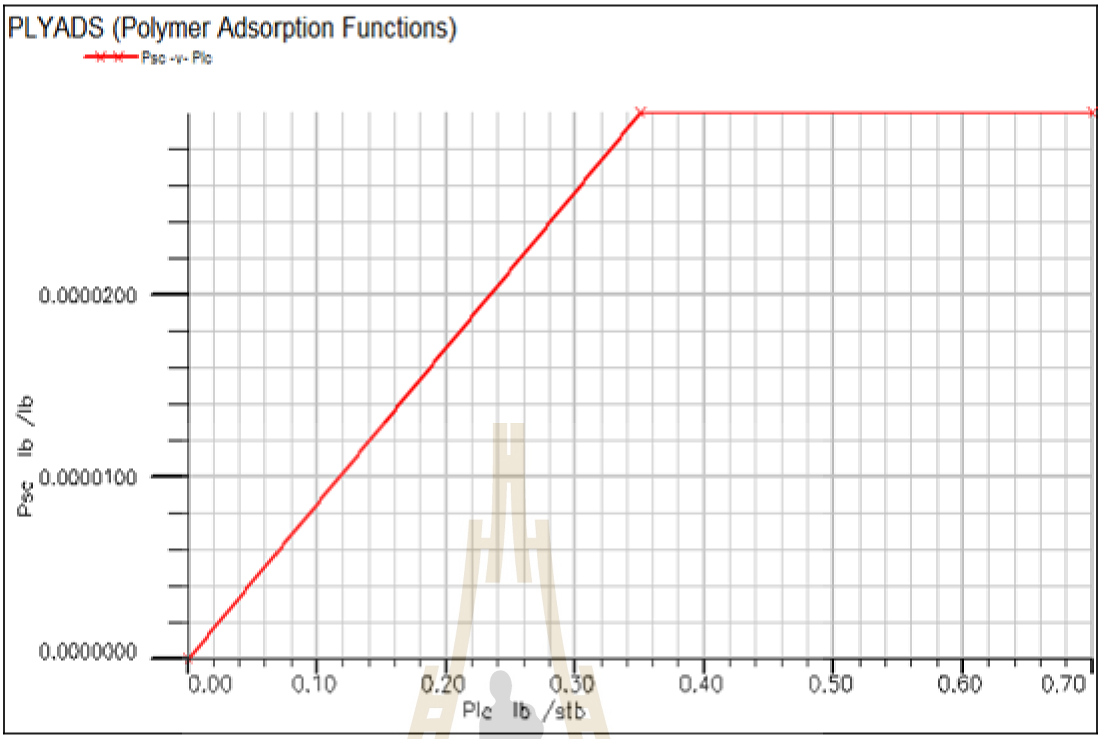


Figure 3.5 Polymer adsorption function graph display result

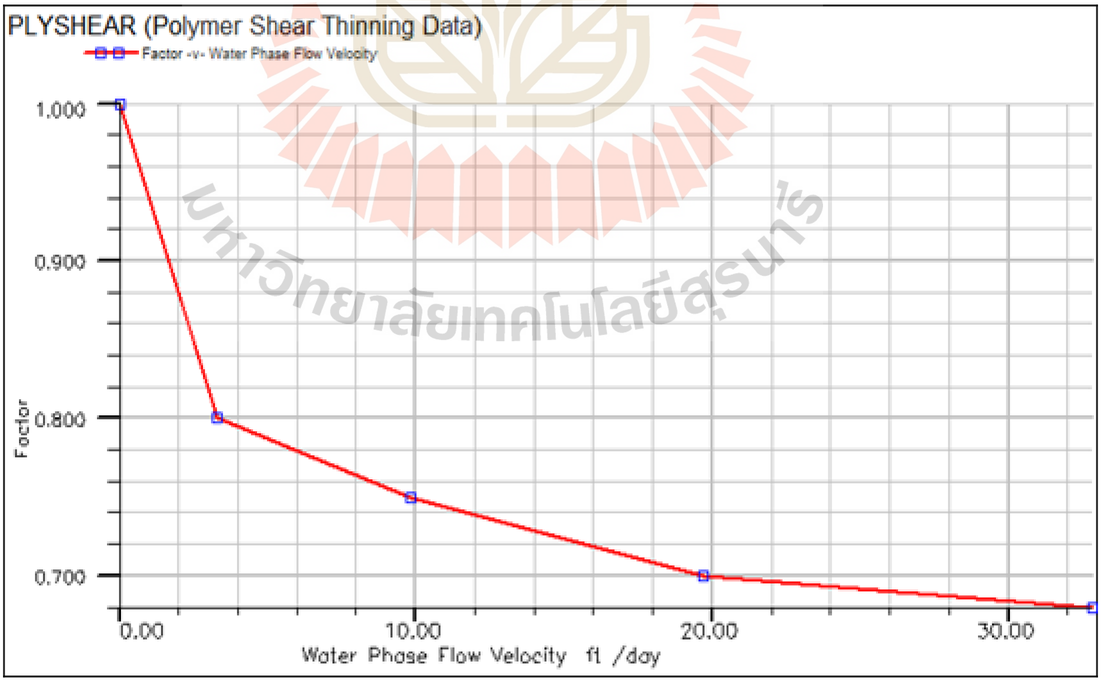


Figure 3.6 Polymer shear thinning data graph display result

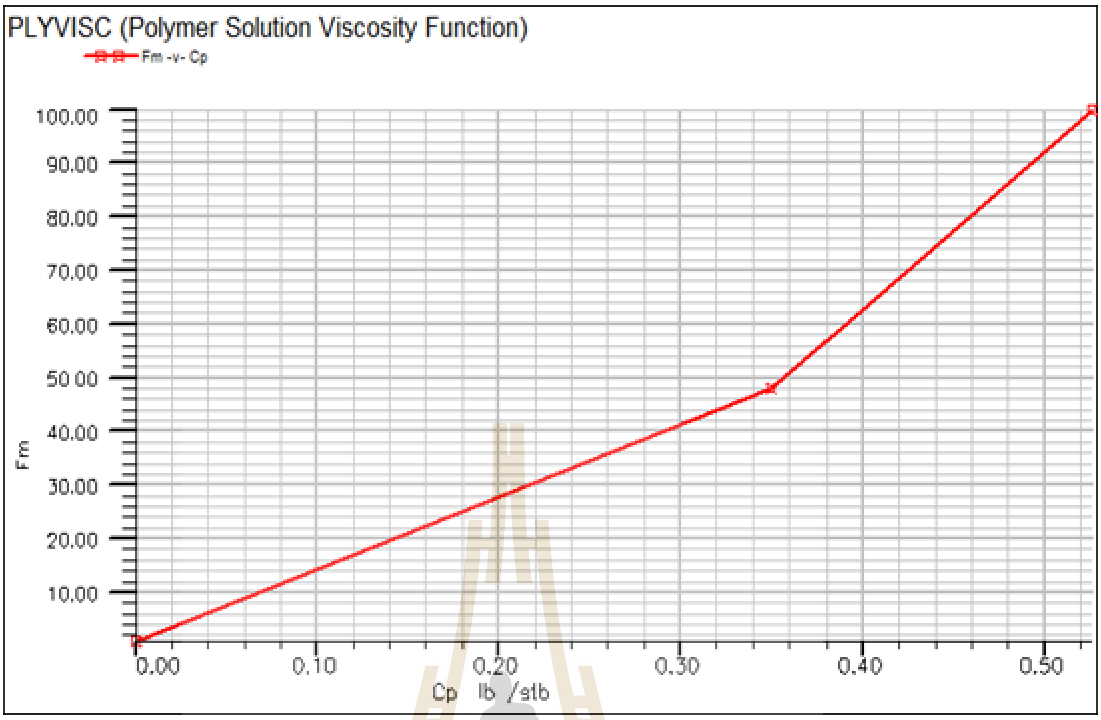


Figure 3.7 Polymr solution viscosity function graph display

3.4 Case of study

In this study the reservoir is the monocline structure style, using flood pattern staggered line drive to compare the result of production with primary production (water injection) and secondary production (polymer injection). Water and polymer was injected in the 1st, 3rd and 5th with the constant production rates of 200 bbl/d, and constant injection rate of 150 bbl/d and 300 bbl/d, and use concentration in polymer is 600 ppm, 1,000 ppm and 1500 ppm, case study model is shown in Table 3.2 and flood pattern is shown in Figure 3.8.

Table 3.2 Case study model

Case	**Time (year)**	**Injection rate (bbl/D)**	**Case No.**
Water flooding	1st	150	1
		300	2
	3rd	150	3
		300	4
	5th	150	5
		300	6
Polymer flooding 600 ppm	1st	150	7
		300	8
	3rd	150	9
		300	10
	5th	150	11
		300	12
Polymer flooding 1000 ppm	1st	150	13
		300	14
	3rd	150	15
		300	16
	5th	150	17
		300	18
Polymer flooding 1500 ppm	1st	150	19
		300	20
	3rd	150	21
		300	22
	5th	150	23
		300	24

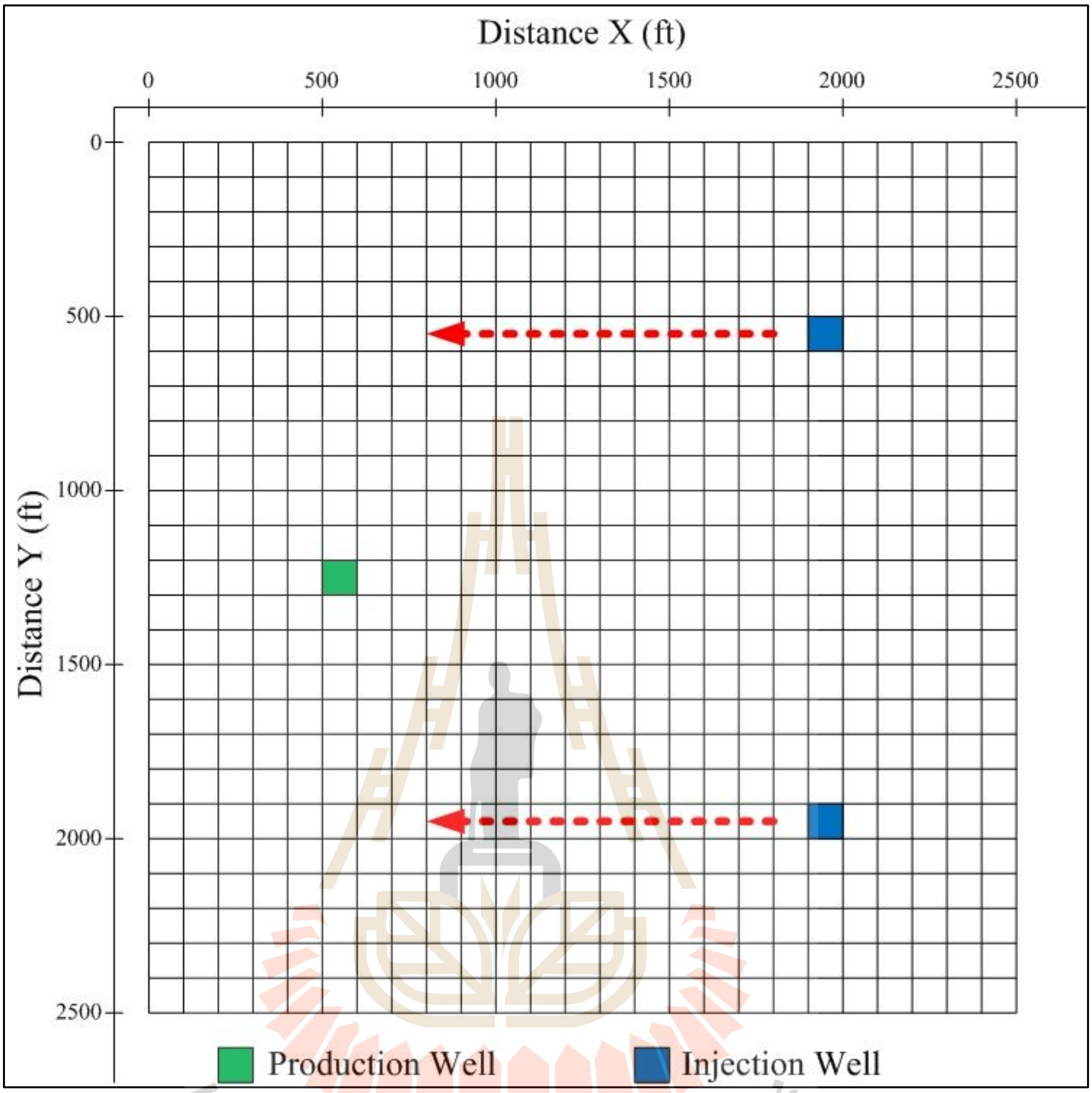


Figure 3.8 Staggered line drive pattern

CHAPTER IV

RESERVOIR SIMULATION RESULTS

4.1 Reservoir simulation result

This chapter shows reservoir simulation results of the total 24 cases studies, comprising of graphs with 2 phases of fluids (oil and water) because there is little gas production in dead oil reservoir. The graphs show field fluid in place (a volume in the reservoir), field cumulative production (production efficiency), field production rate (production profile), field pressure, field oil efficiency and field polymer injection total. Result from running simulations of the 24 case studies to explain fluid behavior water flooding and polymer flooding methods. The result is shown in Table 4.1.

Table 4.1 Reservoir simulation results

Case study	Type of fluid to inject	year to inject	Product rate (bbl)	Inject rate (bbl)	Concen. (ppm)	Cum. Oil production (MMbbl)	Amount of polymer to inject (ton)	RF (%)
1	Water	1st	200	150	-	1.461	-	21.725
2	Water	1st	200	300	-	1.461	-	21.725
3	Water	3rd	200	150	-	1.242	-	19.738
4	Water	3rd	200	300	-	1.242	-	19.737
5	Water	5th	200	150	-	1.096	-	18.427
6	Water	5th	200	300	-	1.096	-	18.427
7	Polymer	1st	200	150	600	1.245	97.990	20.734
8	Polymer	1st	200	300	600	1.604	197.310	26.72
9	Polymer	3rd	200	150	600	1.140	87.690	18.999
10	Polymer	3rd	200	300	600	1.559	176.560	25.978
11	Polymer	5th	200	150	600	1.036	77.365	17.259
12	Polymer	5th	200	300	600	1.093	155.775	18.226
13	Polymer	1st	200	150	1000	1.257	99.320	20.944
14	Polymer	1st	200	300	1000	1.604	198.637	26.72
15	Polymer	3rd	200	150	1000	1.151	84.468	19.175
16	Polymer	3rd	200	300	1000	1.560	174.936	25.995
17	Polymer	5th	200	150	1000	1.045	77.172	17.412
18	Polymer	5th	200	300	1000	1.094	154.343	18.226

Table 4.1 Reservoir simulation results (cont.)

Case study	Type of fluid to inject	year to inject	Product rate (bbl)	Inject rate (bbl)	Concen. (ppm)	Cum. Oil production (MMbbl)	Amount of polymer to inject (ton)	RF (%)
19	Polymer	1st	200	150	1500	1.269	99.053	21.145
20	Polymer	1st	200	300	1500	1.604	196.803	26.72
21	Polymer	3rd	200	150	1500	1.161	88.634	19.352
22	Polymer	3rd	200	300	1500	1.561	176.101	26.012
23	Polymer	5th	200	150	1500	1.054	78.201	17.565
24	Polymer	5th	200	300	1500	1.093	155.372	18.227

4.2 Water flooding result

The reservoir simulation result is a comparison case in water flooding is inject rate 150 bbl/d and 300 bbl/d in year inject to 1st, 3rd and 5th. The result in water flooding is shown Figure 4.1 and 4.2.

Choose case 1 in water flooding because use production rate 200 bbl/d, the result came out with similar values. In use inject year 1st, 3rd and 5th.

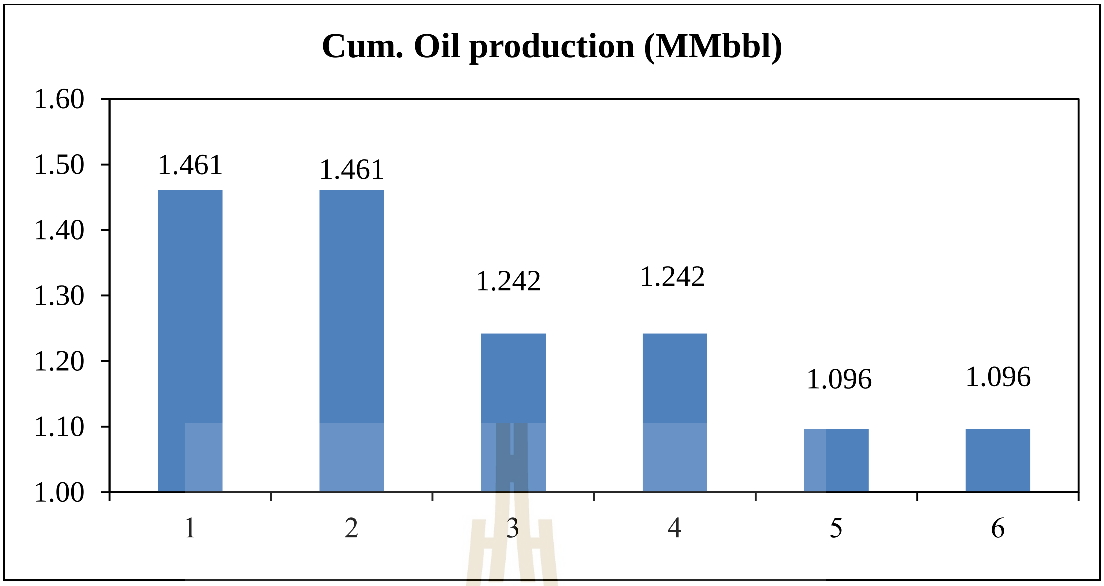


Figure 4.1 Cumulative oil production in water flooding

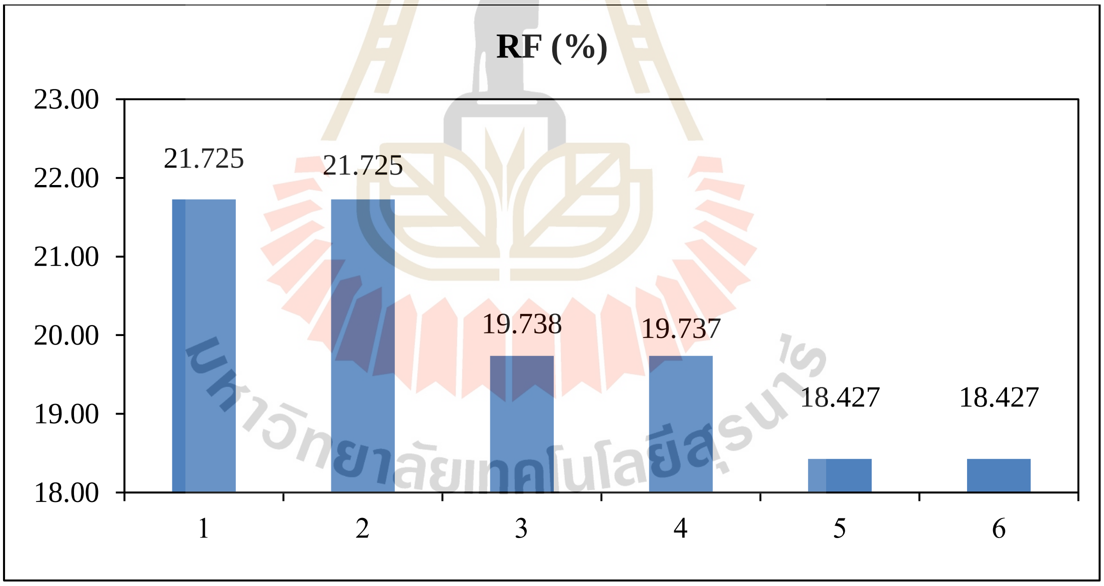


Figure 4.2 Recovery factor in water flooding

4.3 Polymer flooding result

The reservoir simulation result is a comparison case in polymer flooding is concentration 600 ppm is inject rate 150 bbl/d and 300 bbl/d at production rate 200 bbl/d. In use inject year 1st, 3rd and 5th. The result is shown in Figure 4.3 and Figure 4.4.

The reservoir simulation result is a comparison case in polymer flooding is concentration 1,000 ppm is inject rate 150 bbl/d and 300 bbl/d at production rate 200 bbl/d. In use inject year 1st, 3rd and 5th. The result is shown in Figure 4.5 and Figure 4.6.

The reservoir simulation result is a comparison case in polymer flooding is concentration 1,500 ppm is inject rate 150 bbl/d and 300 bbl/d at production rate 200 bbl/d. In use inject year 1st, 3rd and 5th. The result is shown in Figure 4.7 and Figure 4.8.

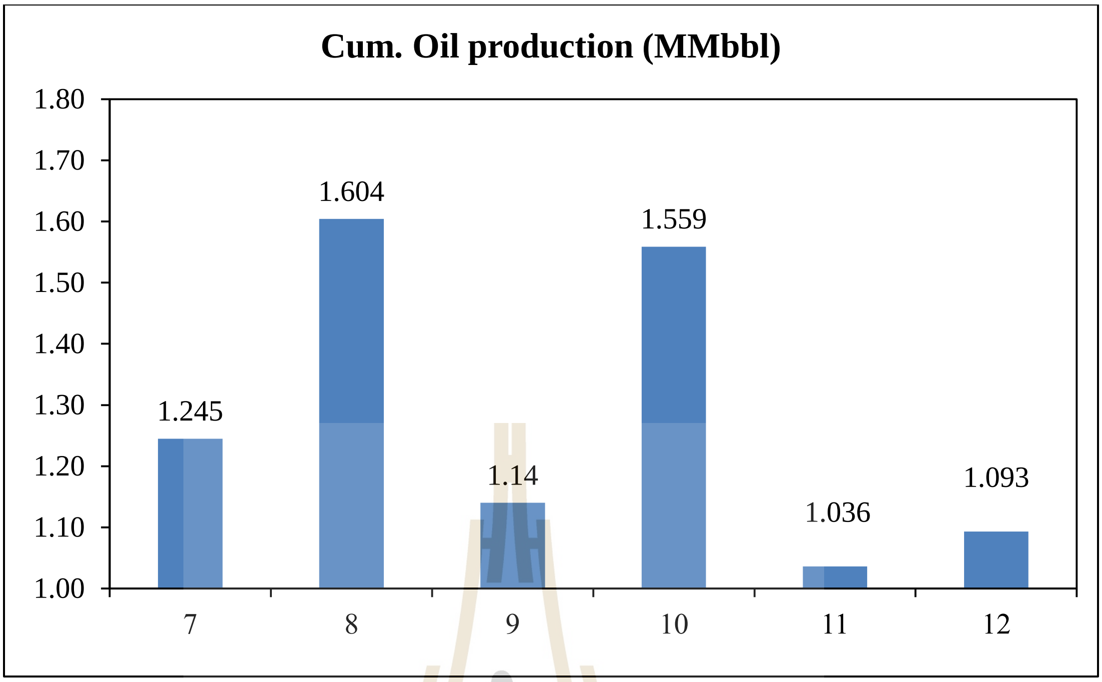


Figure 4.3 Cumulative oil production in polymer flooding at concentration 600 ppm

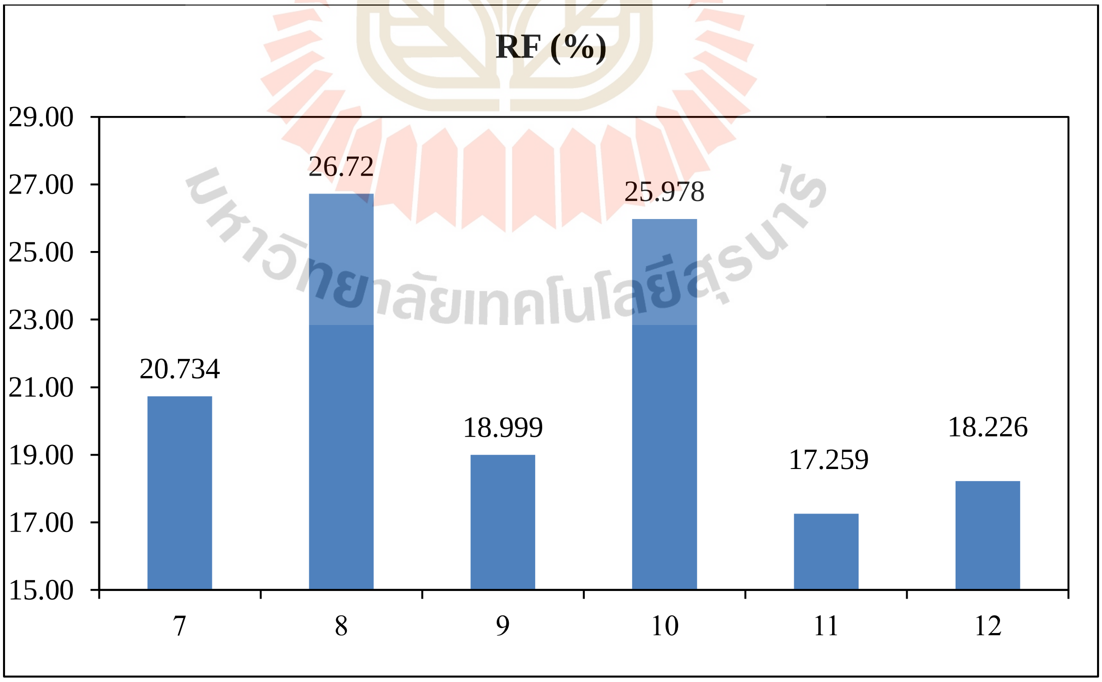


Figure 4.4 Recovery factor in polymer flooding at concentration 600 ppm

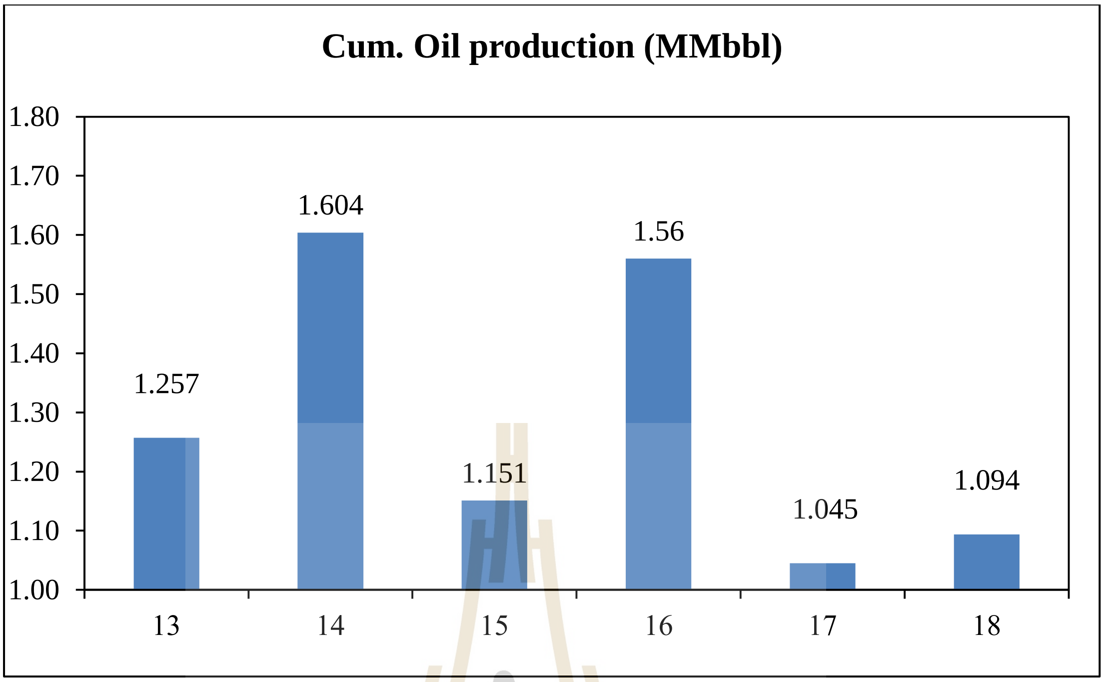


Figure 4.5 Cumulative oil production in polymer flooding at concentration 1,000 ppm

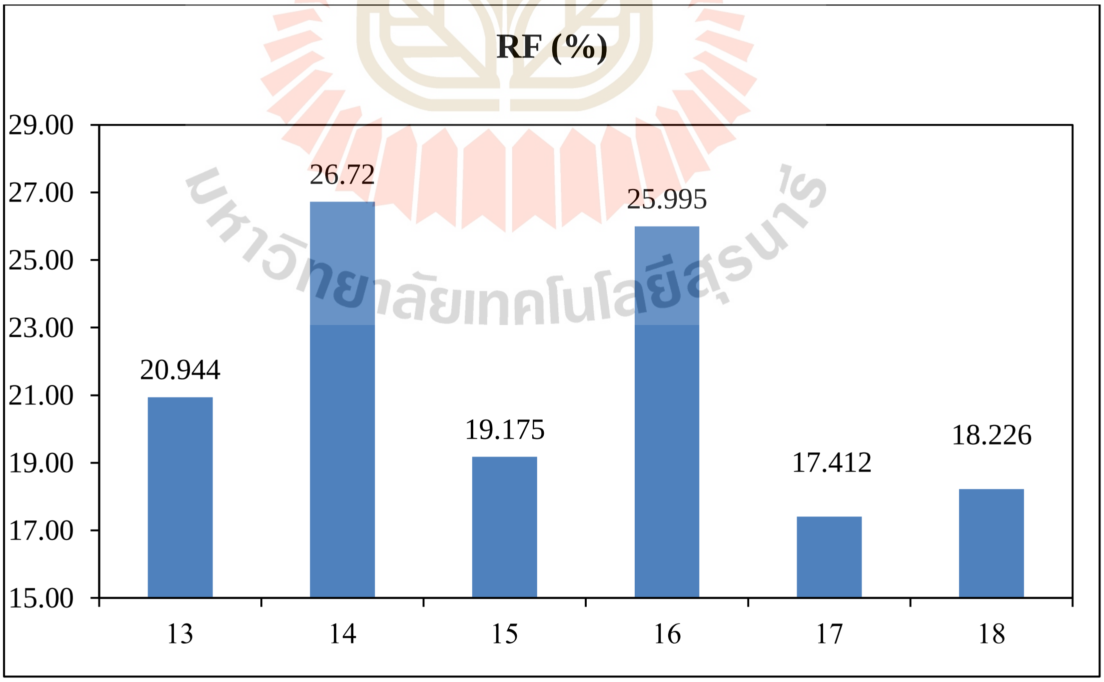


Figure 4.6 Recovery factor in polymer flooding at concentration 1,000 ppm

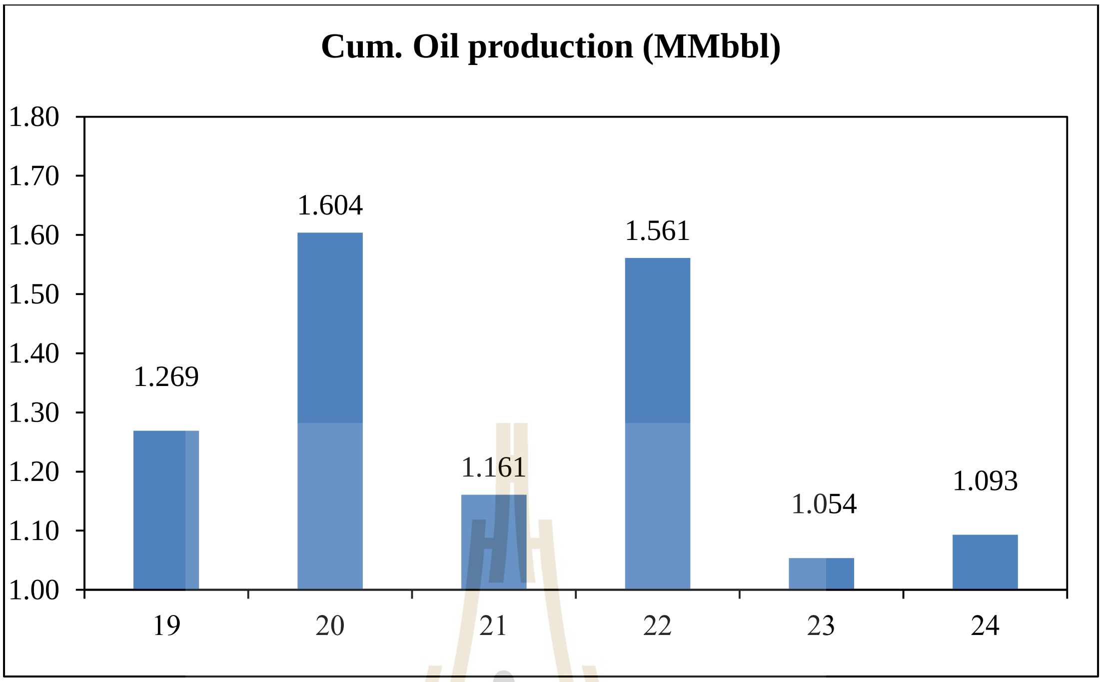


Figure 4.7 Cumulative oil production in polymer flooding at concentration 1,500 ppm

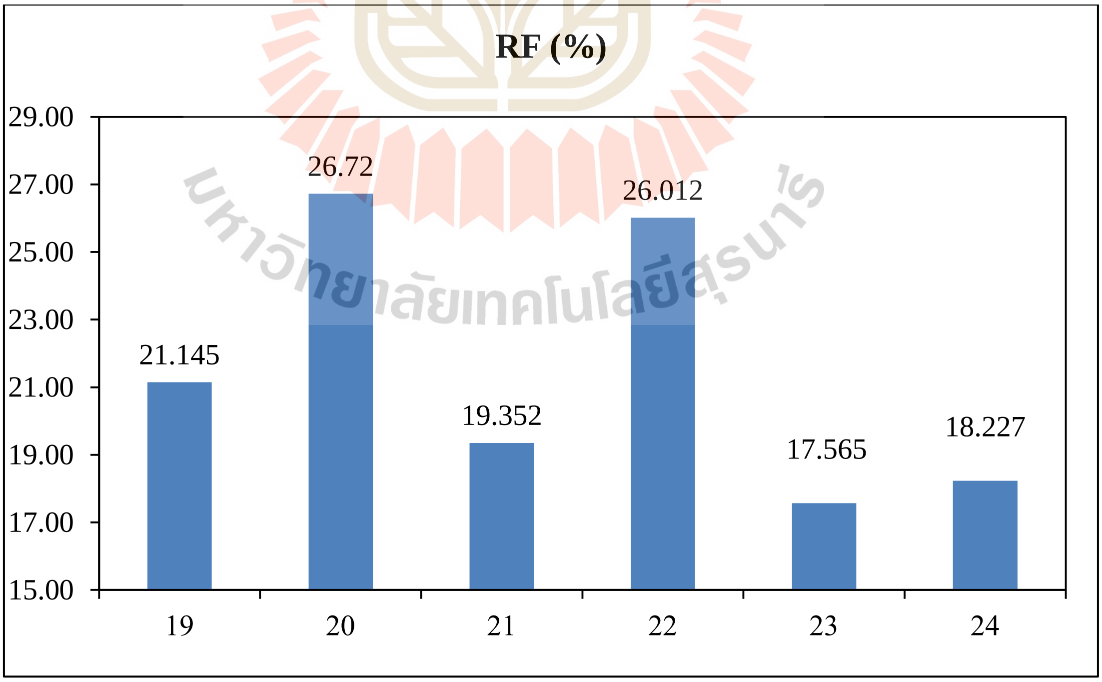


Figure 4.8 Recovery factor in polymer flooding at concentration 1,500 ppm

4.4 Comparison result in change year to inject in water and polymer flooding

The all case use injection rate 150 bbl/d in first year to inject, the case use comparison is case 1, case 7, case 13 and case 19. The result is shown Figure 4.9 and Figure 4.10. Choose case 1 is water flooding injection rate 150 bbl/d and production rate 200 bbl/d are best in production oil.

The all case use injection rate 300 bbl/d in first year to inject, the case use comparison is case 2, case 8, case 14 and case 20. The result is shown in Figure 4.11 and Figure 4.12.

The all case use injection rate 150 bbl/d in third year to inject, the case use comparison is case 3, case 9, case 15 and case 21. The result is shown in Figure 4.13 and Figure 4.14.

The all case use injection rate 300 bbl/d in third year to inject, the case use comparison is case 4, case 10, case 16 and case 22. The result is shown in Figure 4.15 and Figure 4.16.

The all case use injection rate 150 bbl/d in fifth year to inject, the case use comparison is case 5, case 11, case 17 and case 23. The result is shown in Figure 4.17 and Figure 4.18.

The all case use injection rate 300 bbl/d in fifth year to inject, the case use comparison is case 6, case 12, case 18 and case 24. The result is shown in Figure 4.19 and Figure 4.20.

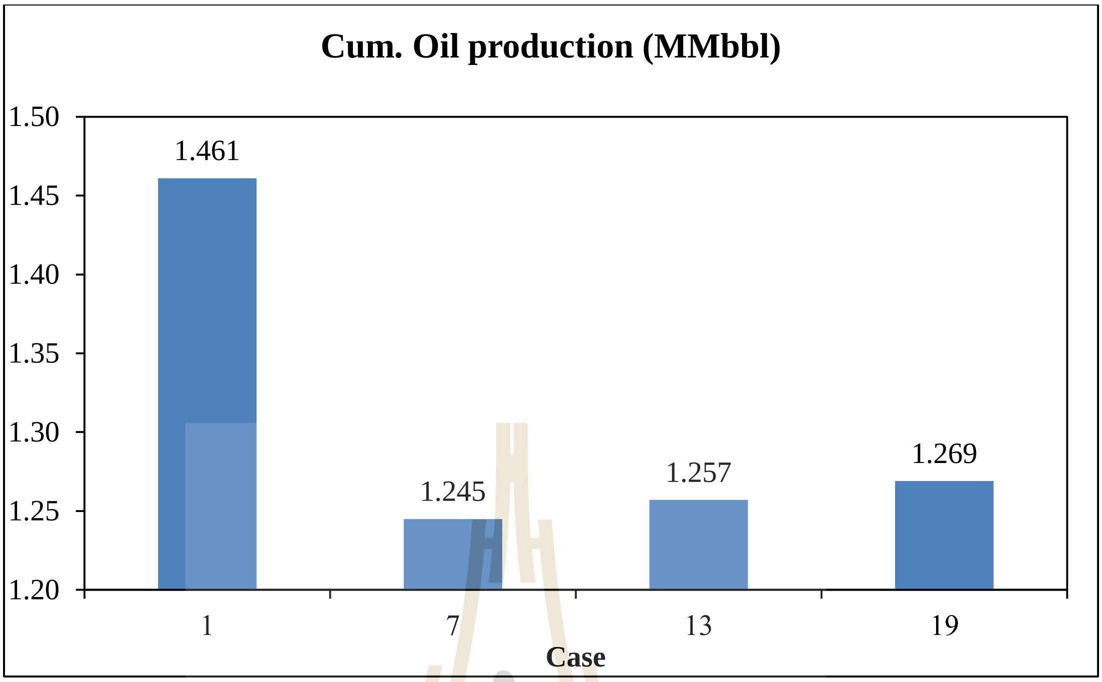


Figure 4.9 Cumulative oil production is use inject rate 150 bbl/d in first year to inject

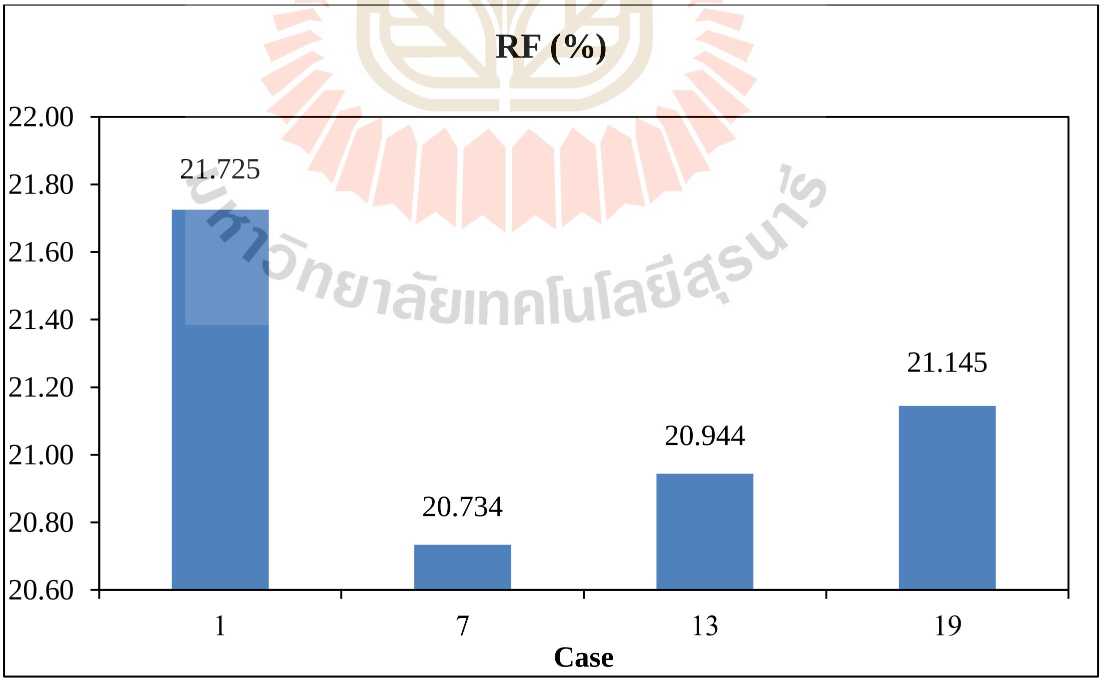


Figure 4.10 Recovery factor is use inject rate 150 bbl/d in first year to inject

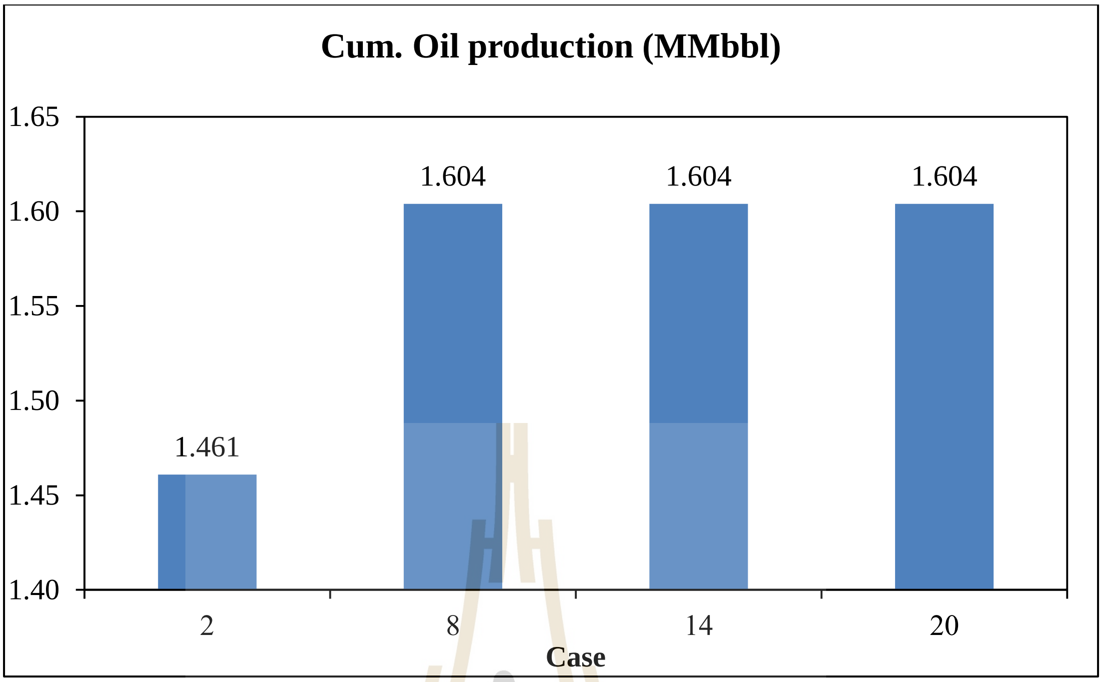


Figure 4.11 Cumulative oil production is use inject rate 300 bbl/d in first year to inject

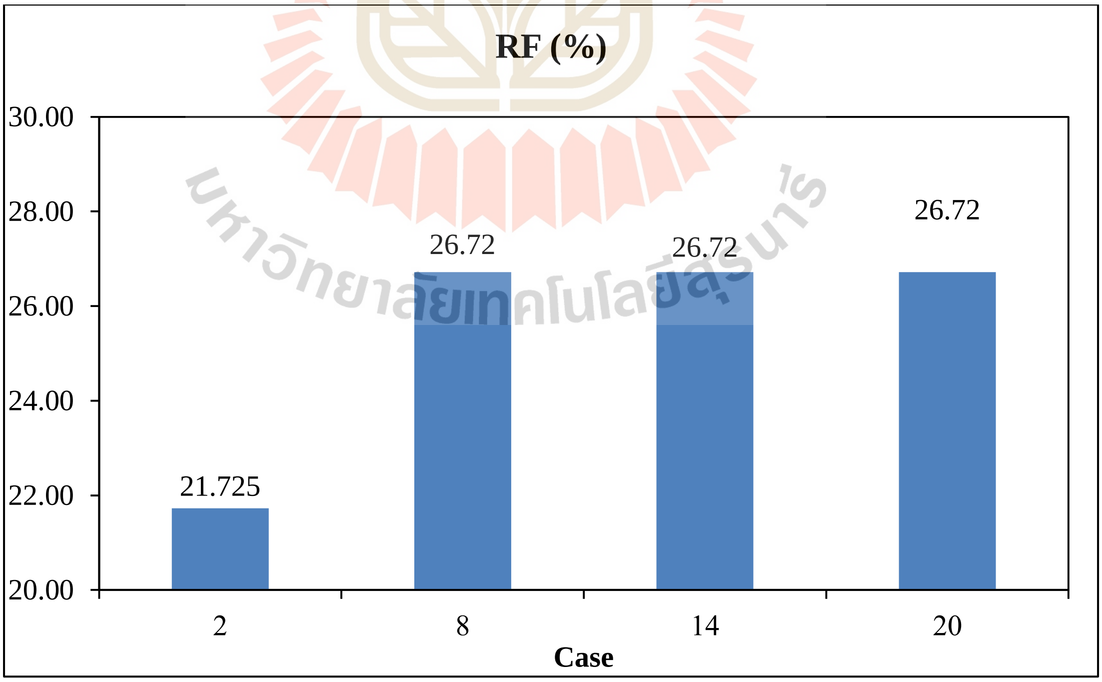


Figure 4.12 Recovery factor is use inject rate 300 bbl/d in first year to inject

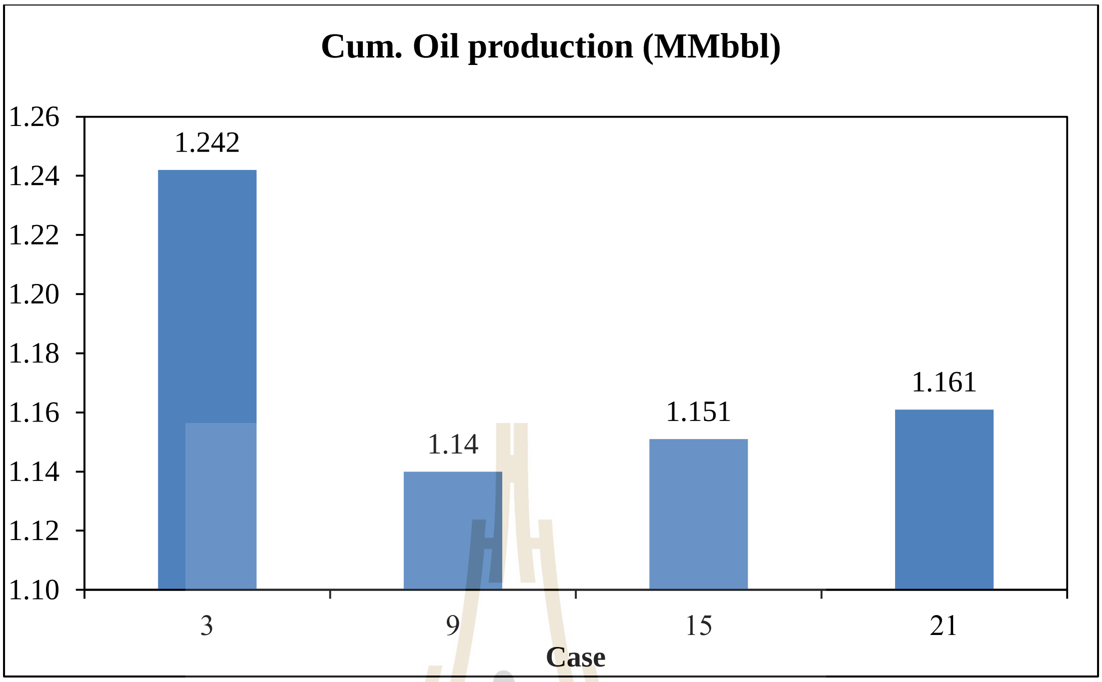


Figure 4.13 Cumulative oil production is use inject rate 150 bbl/d in third year to inject

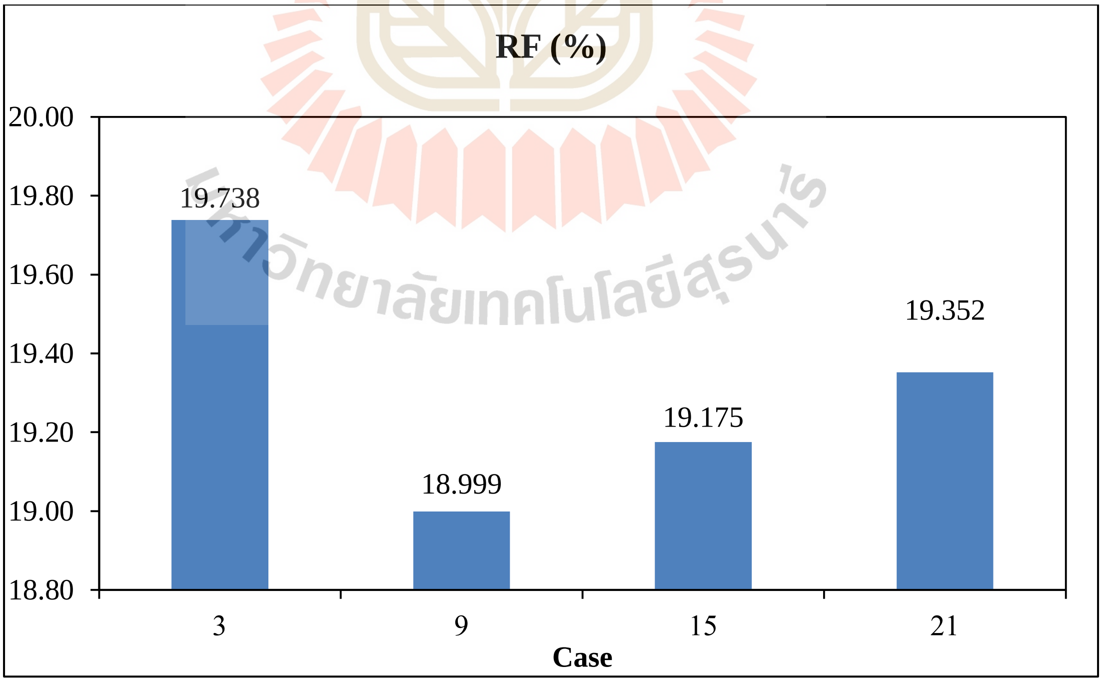


Figure 4.14 Recovery factor is use inject rate 150 bbl/d in third year to inject

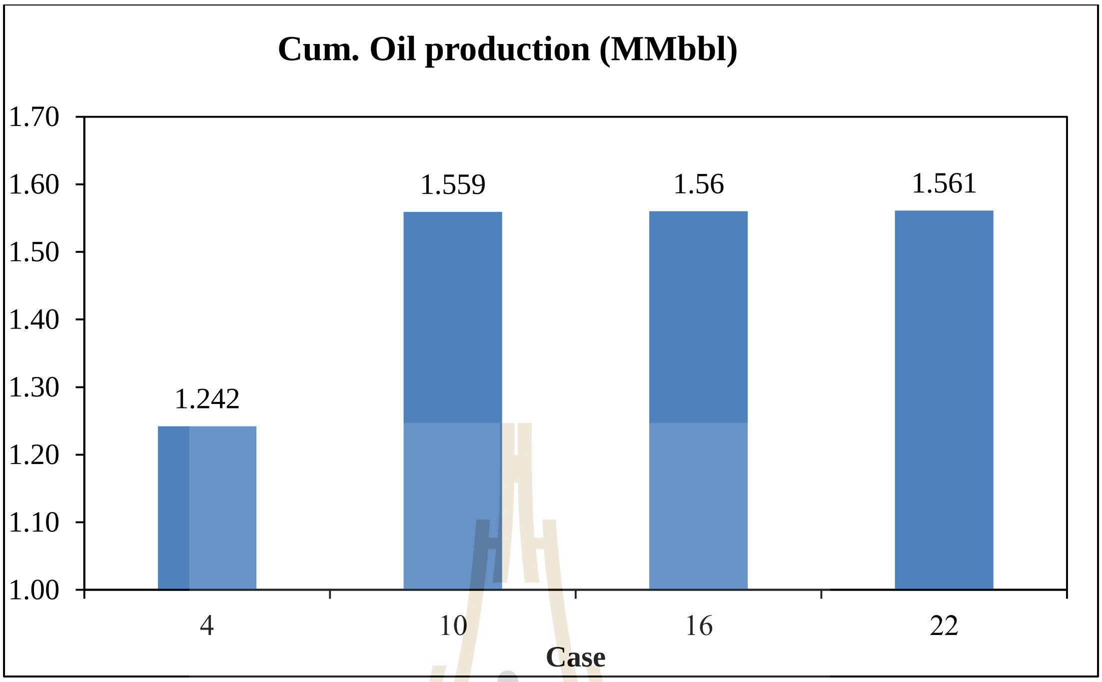


Figure 4.15 Cumulative oil production is use inject rate 300 bbl/d in third year to inject

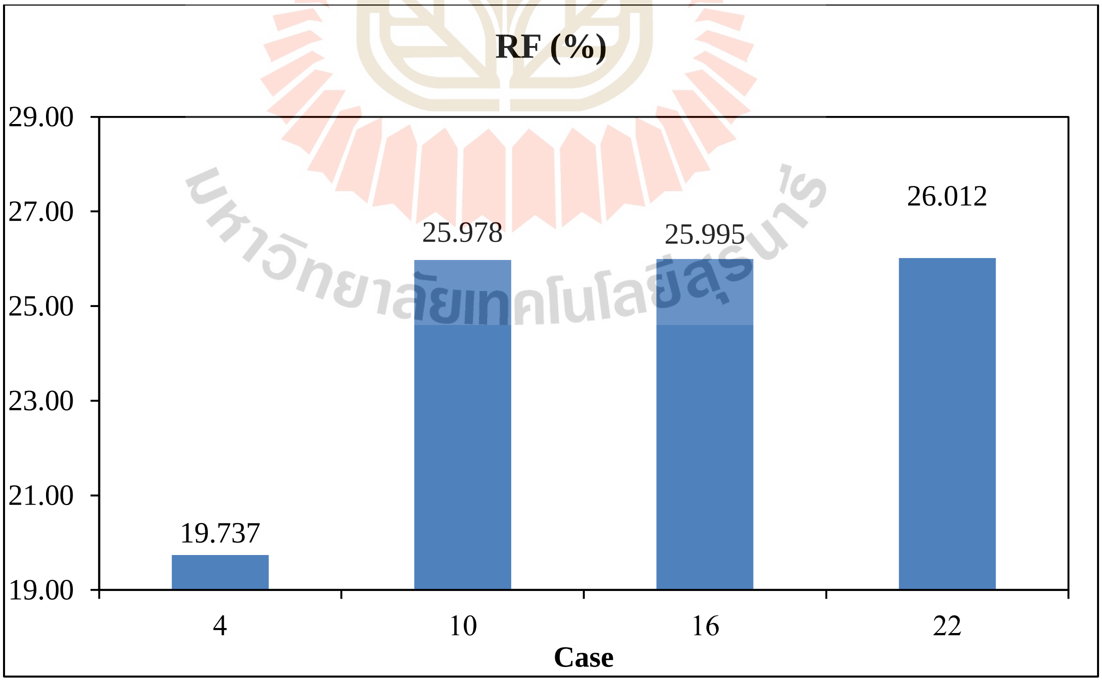


Figure 4.16 Recovery factor is use inject rate 300 bbl/d in third year to inject

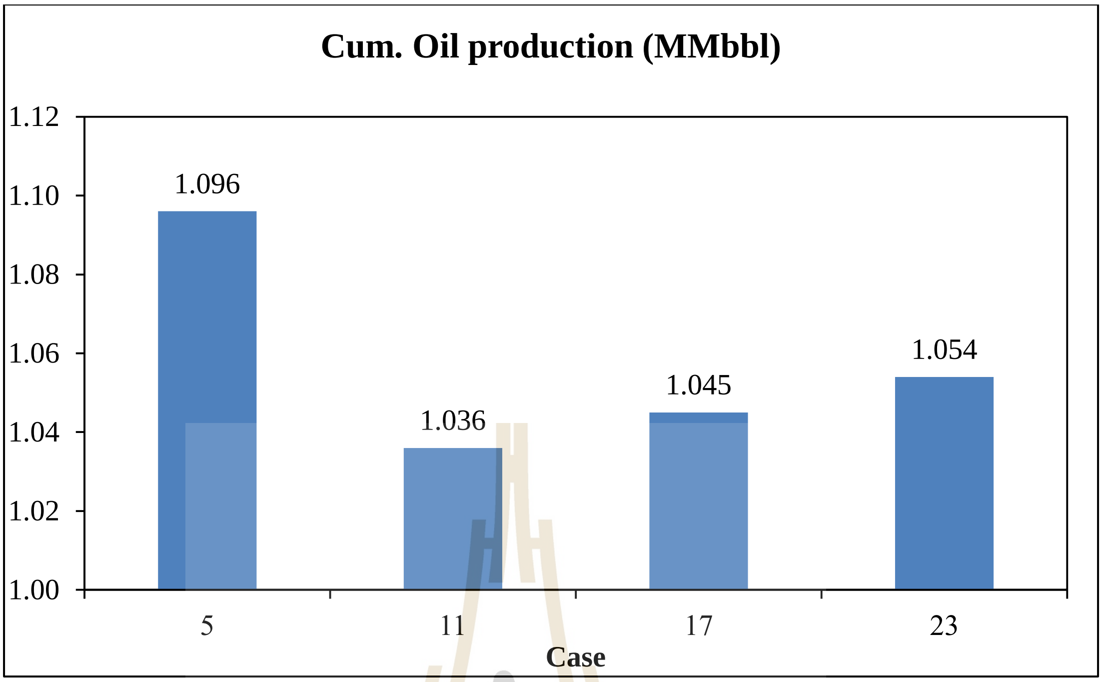


Figure 4.17 Cumulative oil production is use inject rate 150 bbl/d in fifth year to inject

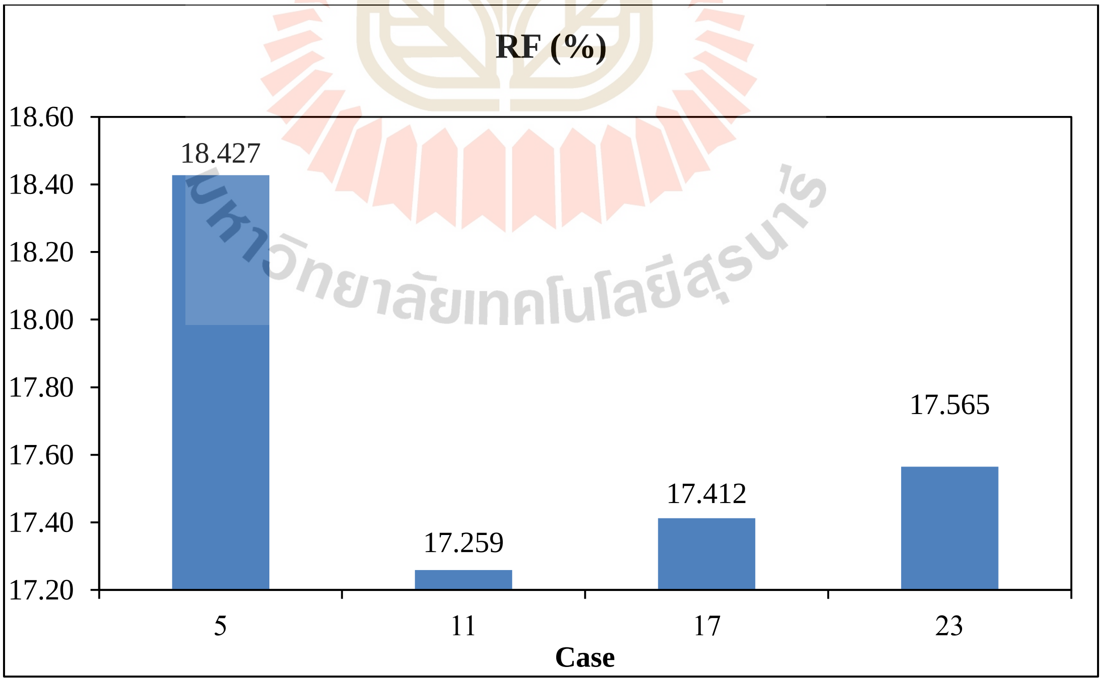


Figure 4.18 Recovery factor is use inject rate 150 bbl/d in fifth year to inject

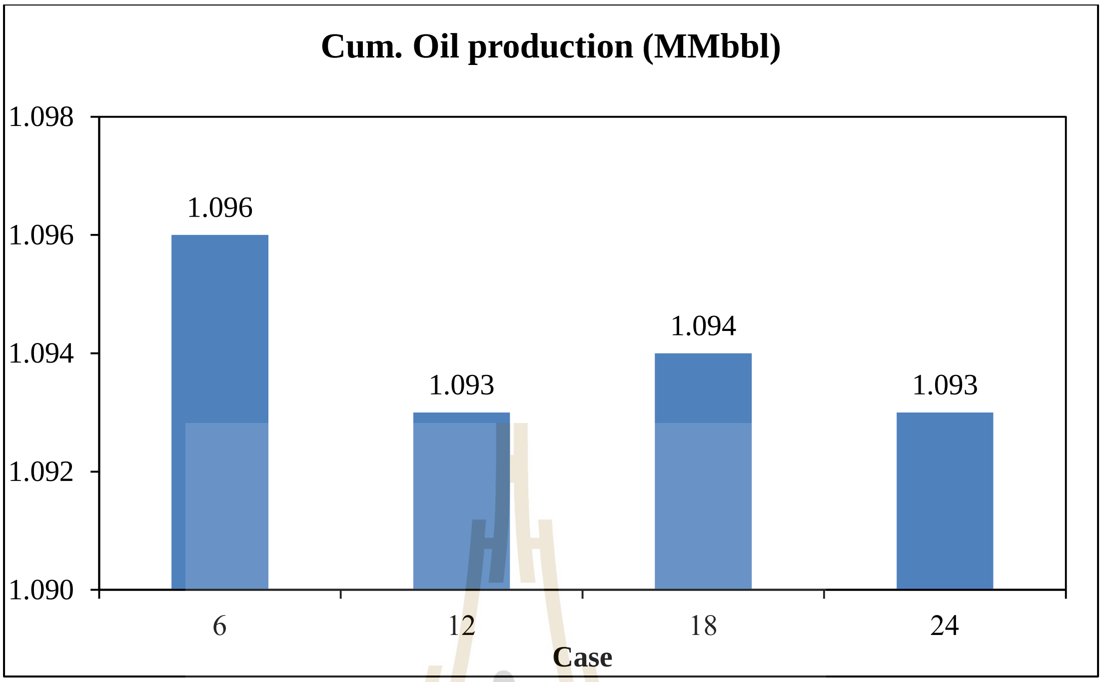


Figure 4.19 Cumulative oil production is use inject rate 300 bbl/d in fifth year to inject

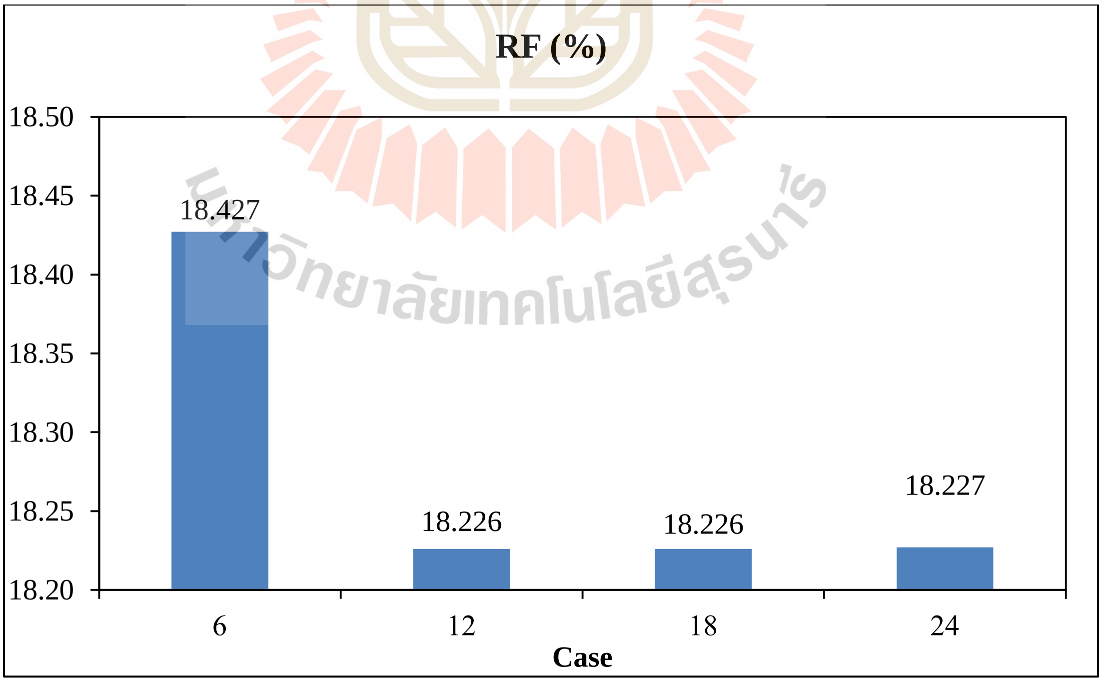


Figure 4.20 Recovery factor is use inject rate 300 bbl/d in fifth year to inject

4.5 Conclusion simulation result

- The water flooding can choose case 1 and 2 at first year to injection in rate 150 bbl/d 300 bbl/d the result values is similar. The result is cumulative oil production 1.461 and recovery factor 21.725%

- The polymer flooding at concentration 600 ppm can choose case 8 at first year to inject in rate 300 bbl/d. The result is cumulative oil production 1.604 MMbbl and recovery factor 26.72%

- The polymer flooding at concentration 1,000 ppm can choose case 8 at first year to inject in rate 300 bbl/d. The result is cumulative oil production 1.604 MMbbl and recovery factor 26.72%

- The polymer flooding at concentration 1,500 ppm can choose case 8 at first year to inject in rate 300 bbl/d. The result is cumulative oil production 1.604 MMbbl and recovery factor 26.72%

- The best case in first year to inject at rate 150 bbl/d can choose case 1 is water flooding , the best case in first year to inject at rate 300 bbl/d can choose case 8, case 14 or case 20 in polymer flooding because the result values is similar.

- The best case in third year to inject at rate 150 bbl/d can choose case 4 is water flooding, the best case in third year to inject at rate 300 bbl/d can choose case 22 in polymer flooding at concentration 1,500 ppm.

- The best case in fifth year to inject at rate 150 bbl/d and 300 bbl/d can choose case 5 or case 6 is water flooding because the result values is similar.

CHAPTER V

ECONOMIC ANALYSIS

5.1 Objective

This chapter objective is to determine economic parameters that used to analyze project investment possibility, including on 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 Mae Soon oil field.

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 the project can summarize as follows.

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

Table 5.1 Basic assumptions

Oil price (US$/bbl)	85
Income tax (%)	50
Escalation factor (%)	2
Discount rate (%)	7.5
Tangible cost (%)	20
Intangible cost (%)	80
Depreciation of tangible cost (%)	20
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

5.3.1 Other assumptions

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

b. The increasing rate of capital expenditure comes from the increasing price 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 5.2.

Table 5.2 Cash flow expenditures

Expenditures	For All Case
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$/kg)	5
Abandonment cost (US$)	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 Table of cash flow summary

The economic analysis is calculated and analyzed by the Microsoft Excel spreadsheet. The economic summary results of all case studies are illustrated in Tables C.1-C.24 in Appendix C.These table display undiscounted IRR and PIR at the end of an 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 5.3.

Table 5.3 Cash flow summary of all case studies

Cash flow summary result							
Case	**Type to inject**	**Concentration (ppm)**	**IRR Undiscount (%)**	**PIR Undiscount (Fraction)**	**IRR 7.5% Disc (%)**	**PIR 7.5% Disc (Fraction)**	**NPV 7.5% Disc (MMUS$)**
1	Water	-	10.7	0.839	2.98	0.11	2.809
2	Water	-	10.54	0.825	2.83	0.104	2.668
3	Water	-	3.16	0.348	-	-0.209	-5.364
4	Water	-	3.06	0.336	-	-0.213	-5.469
5	Water	-	0.9	0.107	-	-0.341	-8.746
6	Water	-	0.81	0.096	-	-0.345	-8.83
7	Polymer	600	16.31	0.701	8.2	0.168	4.427
8	Polymer	600	21.68	1.048	13.19	0.3	8.095
9	Polymer	600	14.93	0.575	6.91	0.123	3.23
10	Polymer	600	19.95	0.923	11.59	0.246	6.62
11	Polymer	600	4.01	0.288	-	-0.112	-2.932

Table 5.3 Cash flow summary of all case studies (cont.)

Cash flow summary result							
Case	**Type to inject**	**Concentration (ppm)**	**IRR Undiscount (%)**	**PIR Undiscount (Fraction)**	**IRR 7.5% Disc (%)**	**PIR 7.5% Disc (Fraction)**	**NPV 7.5% Disc (MMUS$)**
12	Polymer	600	4.5	0.32	-	-0.095	-2.544
13	Polymer	1000	16.52	0.714	8.39	0.173	4.554
14	Polymer	1000	21.68	1.048	13.19	0.299	8.091
15	Polymer	1000	8.36	0.381	0.08	0.017	0.521
16	Polymer	1000	13.39	0.714	5.48	0.136	4.193
17	Polymer	1000	1.77	0.129	-	-0.188	-5.703
18	Polymer	1000	2.12	0.151	-	-0.174	-5.385
19	Polymer	1500	16.72	0.727	8.58	0.178	4.681
20	Polymer	1500	21.67	1.047	13.18	0.299	8.087
21	Polymer	1500	8.5	0.39	0.93	0.02	0.605
22	Polymer	1500	13.41	0.714	5.5	0.136	4.206
23	Polymer	1500	1.87	0.136	-	-0.186	-5.635
24	Polymer	1500	2.11	0.151	-	-0.174	-5.386

5.5 Economic Analysis

Economic analysis in this study base on the constant oil price rates of 85 $/bbl. In case 1 - 24 as the IRRs result of all case studies range from 0.81 to 21.68%, while the PIRs range from 0.096 to 1.048 fractions, at discount 7.5% in case 1 - 24 as the DIRRs result of all case studies range from 0 to 13.19%, while the DPIRs range from

-0.345 to 0.3 fractions, while the DNPVs range from -8.83 to 8.095 MMUS$. In production rate 200 bbl the best cases in this study is case 8 of which employs the polymer flooding at concentration 600 ppm in the staggered line drive pattern at the first year of injection, the use injection rate of 300 bbl/d. Its best NPV at discount 7.5% is 8.095 MMUS$. In this study is a case summary of the economic results of all case studies are shown in Figures 5.1-5.3.

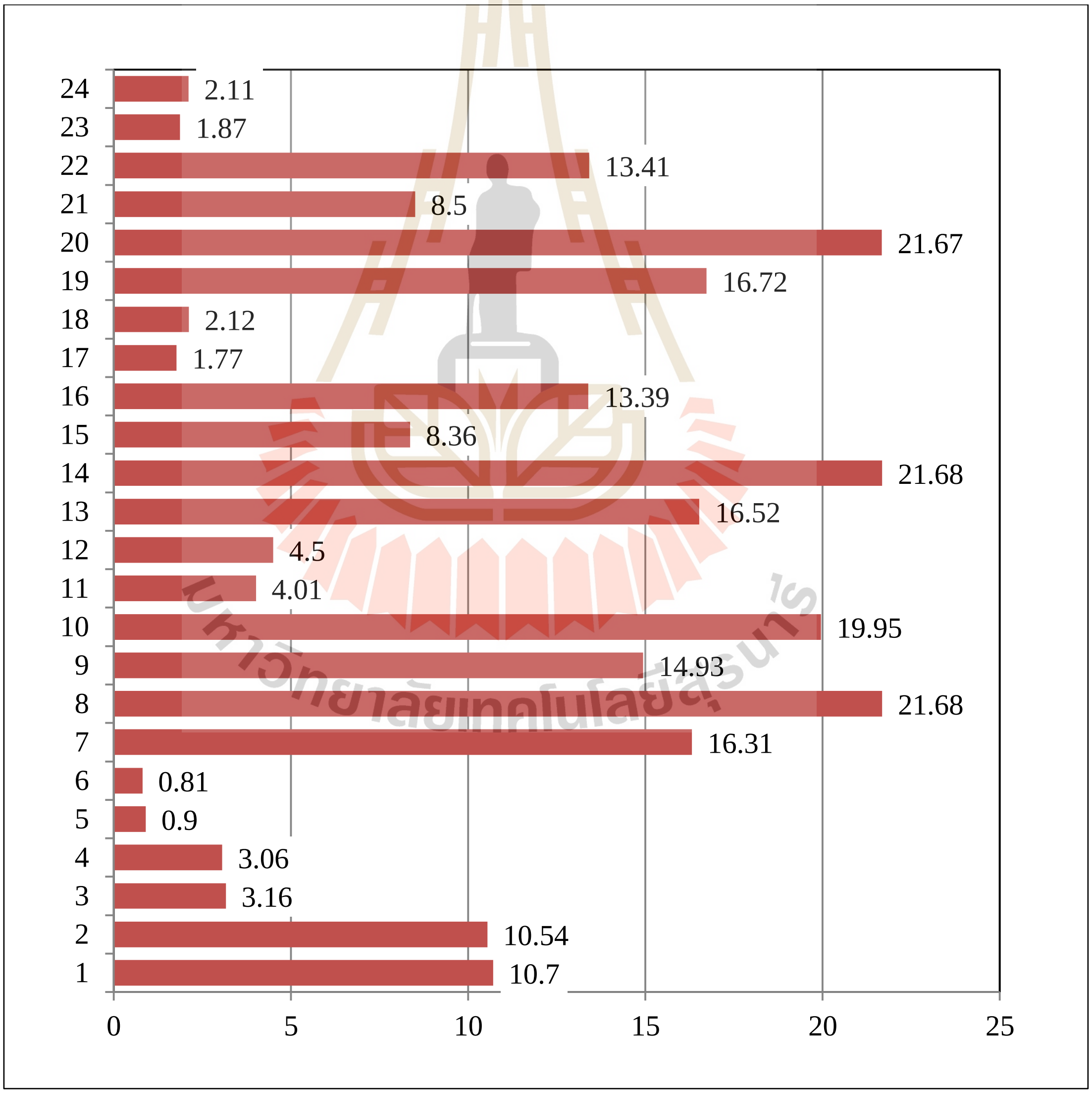


Figure 5.1 Summary of IRR Results, Oil price 85 $/bbl

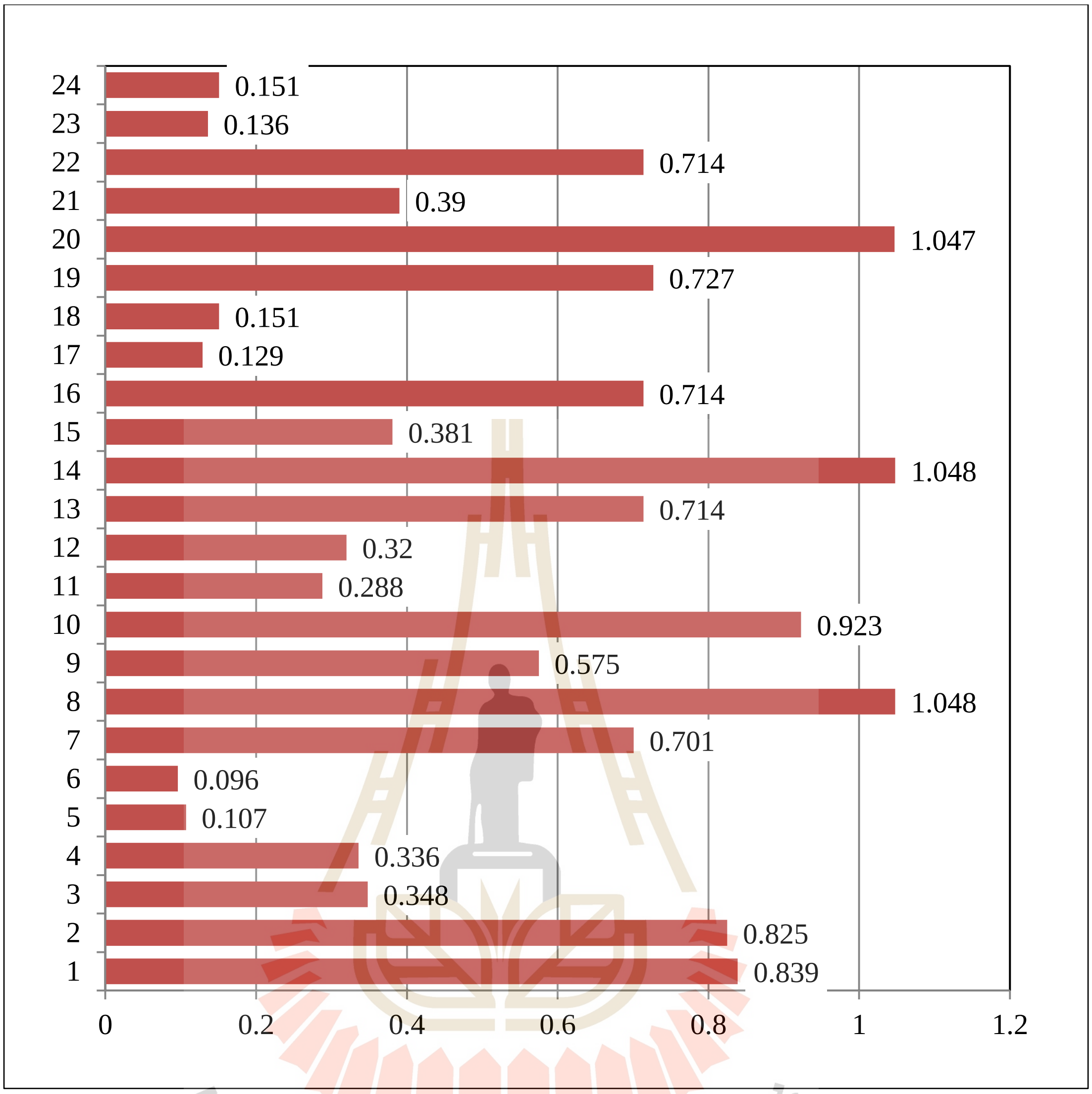


Figure 5.2 Summary of PIR Results, Oil price 85 $/bbl

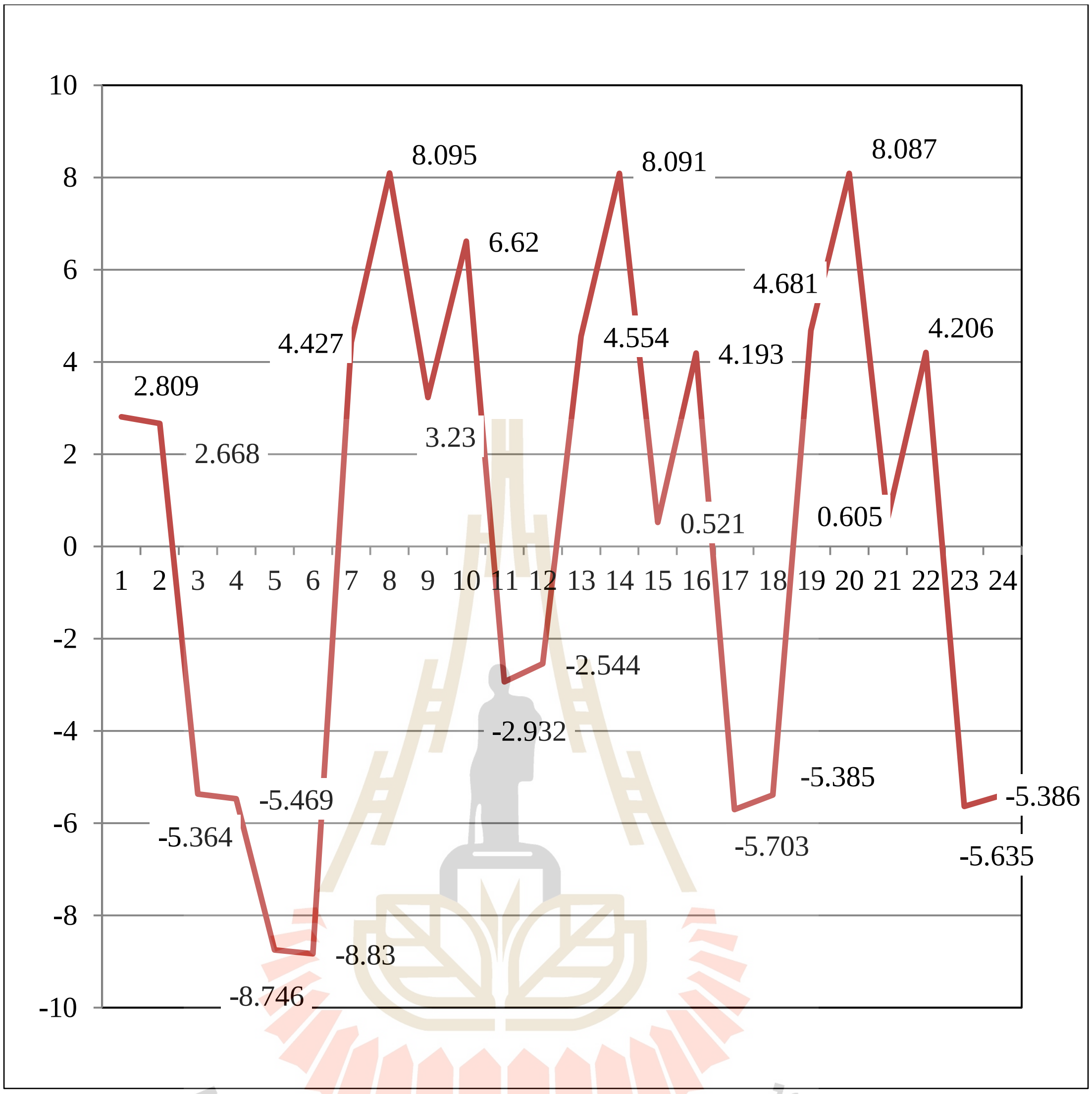


Figure 5.3 Summary of NPV Results, Oil price 85 $/bbl

CHAPTER VI

CONCLUSIONS AND DISCUSSIONS

6.1 Introduction

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

6.2 Conclusions of case study results

This study process of water flooding and polymer flooding, but focuses the polymer flooding method.

The study focuses on monocline structure style with 6 layers. Used the reservoir and fluid data from data of Maesoon oil field, but some data are not available so they are assumed by based on Maesoon data. The porosity ranges from 19 to 29%, and the permeability from about 100 to 230 mD. The study uses reservoir simulation to evaluate 24 case studies for oil recovery with staggered line drive patterns. Cases 1 to 24 have the same total production rate of 200 bbl/day at inject rate 150 bbl/d and 300 bbl/d in production life time 20 years, case 1 to 6 in water flooding at 1st, 3rd and 5th year to inject, case 7 to 12 in polymer flooding at concentration 600 ppm, case 13 to 18 in polymer flooding at concentration 1,000 ppm, case 19 to 24 in polymer flooding at concentration 1,500 ppm. This study used the XCD polymer (Xanthan gum) is three polymer concentrations.

The result show cases of polymer flooding some case that have high performance oil recovery efficiency when compared with water flooding, case 1 to 6 show oil recovery from water flooding can best produce 21.725% in case 1 and case 2. Case 7 to 12 show applied polymer flooding, the 1st, 3rd and 5th year of polymer injection and use polymer concentration at 600 ppm, the best recoveries increased to 26.72% in case 8. Case 13 to 18 show applied polymer flooding, the 1st, 3rd and 5th year of polymer injection and use polymer concentration at 1,000 ppm, the best recoveries increased to 26.72% in case 14. Case 19 to 24 show applied polymer flooding, the 1st, 3rd and 5th year of polymer injection and use polymer concentration at 1,500 ppm, the best recoveries increased to 26.72% in case 20. In economic evaluation case 1 to 6 best NPVs is 2.809 MMUS$ in case 1, case 7 to 12 best NPVs is 8.095 MMUS$ in case 7, case 13 to 18 best NPVs is 8.091 MMUS$, case 19 to 24 best NPVs is 8.087 MMUS$ in case 20. Consider its techniques can choose a case, polymer concentration 1,500 ppm because increase viscosity in production rates it best. If consider it economic can choose a case, polymer concentration 600 ppm because low cost on to inject polymer. But if consider to both result can choose a case, polymer concentration 1,000 ppm because the result medium in techniques and economic. Summary of reservoir simulation results is shown in Figure 6.1 and Table 6.1 and shown cash flow summary result in Figure 6.2 and Table 6.2.

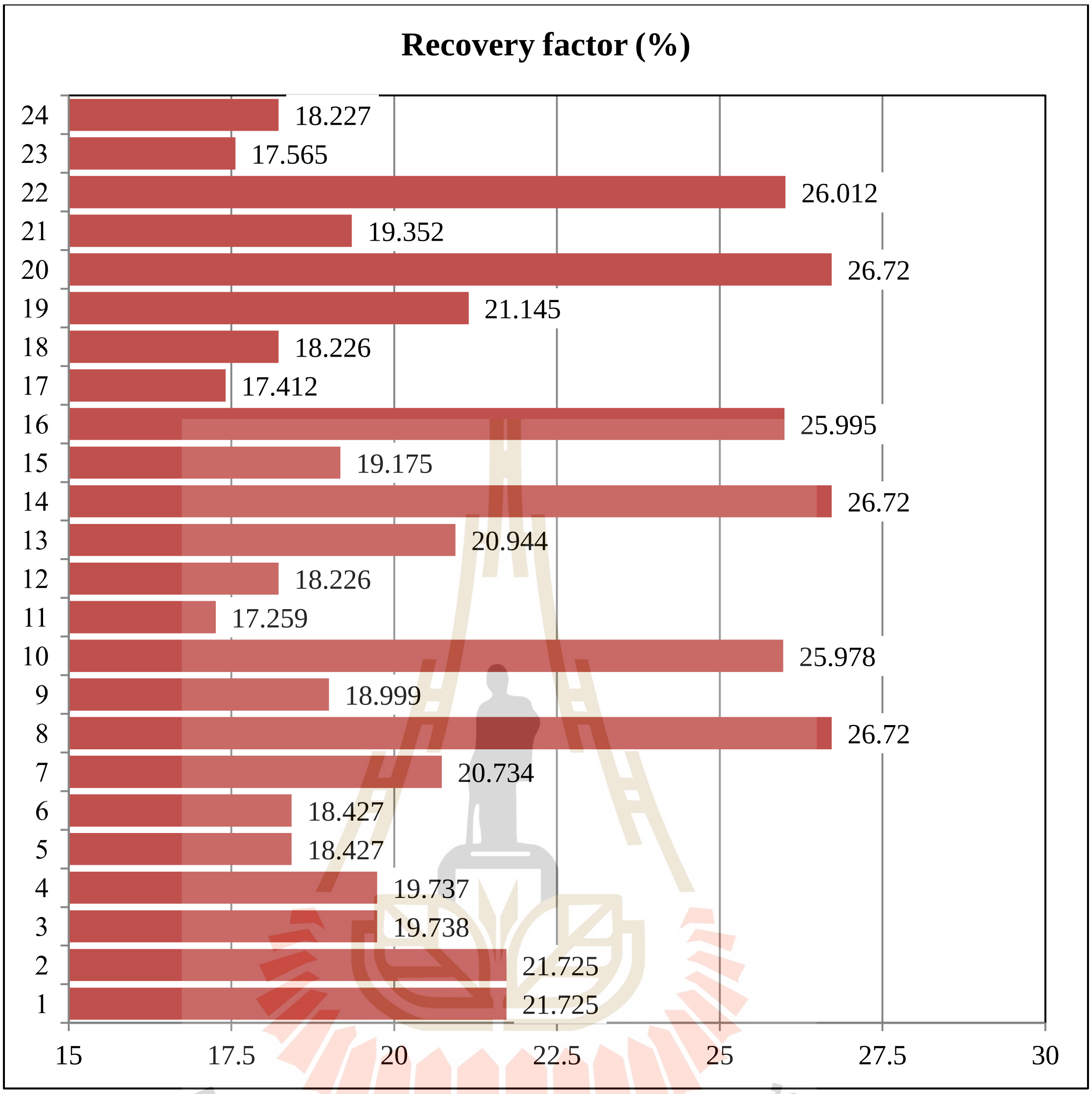


Figure 6.1 Summary of reservoir simulation results

Table 6.1 summary of reservoir simulation result

Case study	Type of fluid to inject	Year to inject	Product rate (bbl)	Inject rate (bbl)	Concentration (ppm)	Cum. Oil production (MMbbl)	Amount of polymer to inject (ton)	RF (%)
1	Water	1st	200	150	-	1.461	-	21.725
2	Water	1st	200	300	-	1.461	-	21.725
3	Water	3rd	200	150	-	1.242	-	19.738
4	Water	3rd	200	300	-	1.242	-	19.737
5	Water	5th	200	150	-	1.096	-	18.427
6	Water	5th	200	300	-	1.096	-	18.427
7	Polymer	1st	200	150	600	1.245	97.990	20.734
8	Polymer	1st	200	300	600	1.604	197.310	26.72
9	Polymer	3rd	200	150	600	1.140	87.690	18.999
10	Polymer	3rd	200	300	600	1.559	176.560	25.978
11	Polymer	5th	200	150	600	1.036	77.365	17.259
12	Polymer	5th	200	300	600	1.093	155.775	18.226
13	Polymer	1st	200	150	1000	1.257	99.320	20.944
14	Polymer	1st	200	300	1000	1.604	198.637	26.72
15	Polymer	3rd	200	150	1000	1.151	84.468	19.175
16	Polymer	3rd	200	300	1000	1.560	174.936	25.995
17	Polymer	5th	200	150	1000	1.045	77.172	17.412
18	Polymer	5th	200	300	1000	1.094	154.343	18.226

Table 6.1 summary of reservoir simulation result (cont.)

Case study	**Type of fluid to inject**	**Year to inject**	**Product rate (bbl)**	**Inject rate (bbl)**	**Concentration (ppm)**	**Cum. Oil production (MMbbl)**	**Amount of polymer to inject (ton)**	**RF (%)**
19	Polymer	1st	200	150	1500	1.269	99.053	21.145
20	Polymer	1st	200	300	1500	1.604	196.803	26.72
21	Polymer	3rd	200	150	1500	1.161	88.634	19.352
22	Polymer	3rd	200	300	1500	1.561	176.101	26.012
23	Polymer	5th	200	150	1500	1.054	78.201	17.565
24	Polymer	5th	200	300	1500	1.093	155.372	18.227

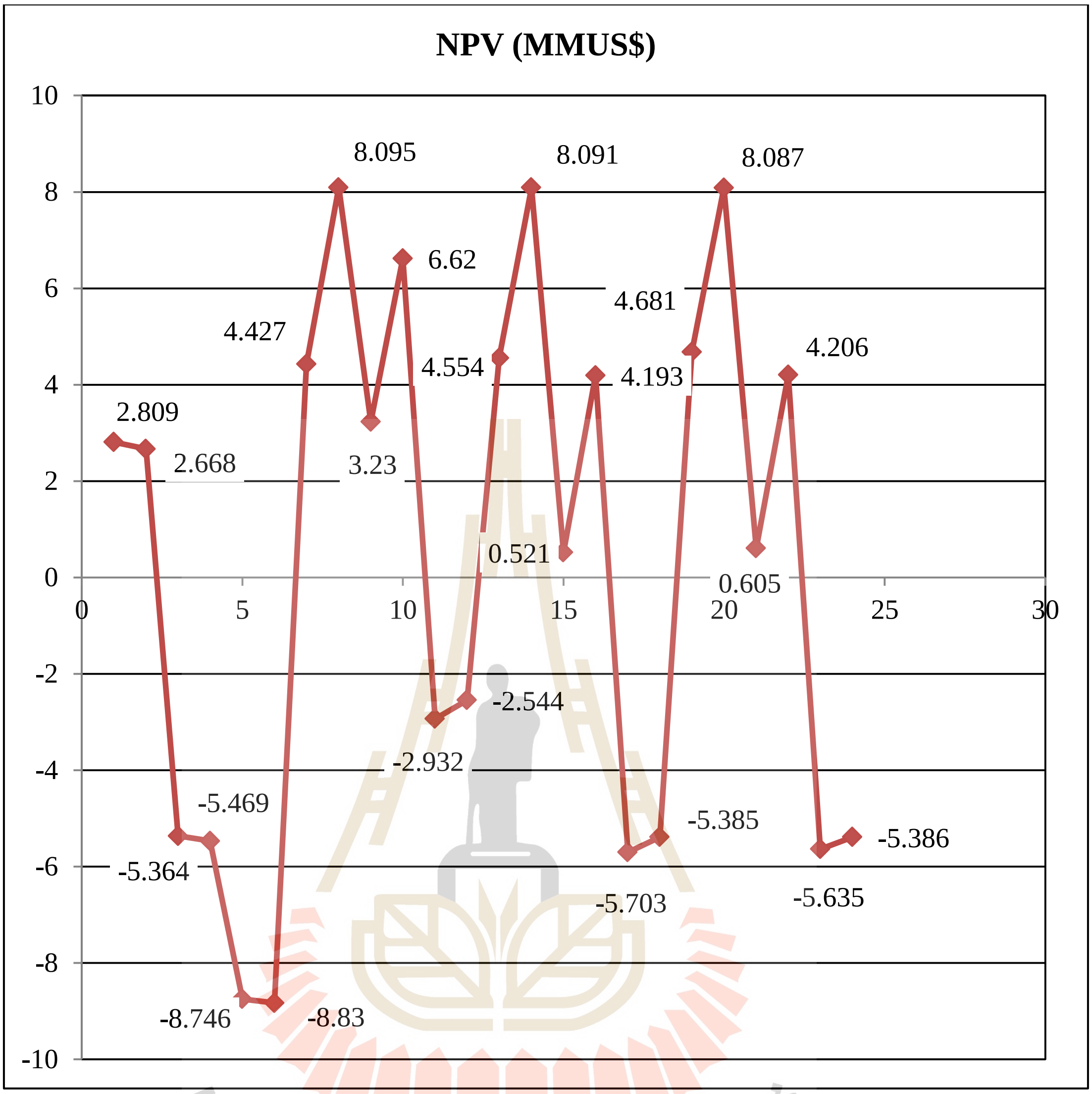


Figure 6.2 cash flow summary result

Table 6.2 Cash flow summary result

Cash flow summary result							
Case	**Type to inject**	**Concentration (ppm)**	**IRR Undiscount (%)**	**PIR Undiscount (Fraction)**	**IRR 7.5% Disc (%)**	**PIR 7.5% Disc (Fraction)**	**NPV 7.5% Disc (MMUS$)**
1	Water	-	10.7	0.839	2.98	0.11	2.809
2	Water	-	10.54	0.825	2.83	0.104	2.668
3	Water	-	3.16	0.348	-	-0.209	-5.364
4	Water	-	3.06	0.336	-	-0.213	-5.469
5	Water	-	0.9	0.107	-	-0.341	-8.746
6	Water	-	0.81	0.096	-	-0.345	-8.83
7	Polymer	600	16.31	0.701	8.2	0.168	4.427
8	Polymer	600	21.68	1.048	13.19	0.3	8.095
9	Polymer	600	14.93	0.575	6.91	0.123	3.23
10	Polymer	600	19.95	0.923	11.59	0.246	6.62
11	Polymer	600	4.01	0.288	-	-0.112	-2.932
12	Polymer	600	4.5	0.32	-	-0.095	-2.544
13	Polymer	1000	16.52	0.714	8.39	0.173	4.554
14	Polymer	1000	21.68	1.048	13.19	0.299	8.091
15	Polymer	1000	8.36	0.381	0.08	0.017	0.521
16	Polymer	1000	13.39	0.714	5.48	0.136	4.193
17	Polymer	1000	1.77	0.129	-	-0.188	-5.703
18	Polymer	1000	2.12	0.151	-	-0.174	-5.385

Table 6.2 Cash flow summary result (cont.)

Cash flow summary result							
Case	**Type to inject**	**Concentration (ppm)**	**IRR Undiscount (%)**	**PIR Undiscount (Fraction)**	**IRR 7.5% Disc (%)**	**PIR 7.5% Disc (Fraction)**	**NPV 7.5% Disc (MMUS$)**
19	Polymer	1500	16.72	0.727	8.58	0.178	4.681
20	Polymer	1500	21.67	1.047	13.18	0.299	8.087
21	Polymer	1500	8.5	0.39	0.93	0.02	0.605
22	Polymer	1500	13.41	0.714	5.5	0.136	4.206
23	Polymer	1500	1.87	0.136	-	-0.186	-5.635
24	Polymer	1500	2.11	0.151	-	-0.174	-5.386

6.3 Discussions

1. The reservoir simulation result indicates that the polymer flooding technique has the most potential in increasing oil recovery of Maesoon oil field in Fang basin compared to the water flooding techniques

2. In polymer flooding method, change the value of the concentration of the polymer is 600 ppm, 1000 ppm and 1500 ppm. Form the research results can be concluded that the polymer concentration of 1,500 ppm is the best case depending on the cumulative oil production. Because the viscosity of polymer is higher than others. The remaining oil is swept to the well then the production is higher as shown in the cumulative oil production. The economic evaluation, the case of 600 ppm polymer concentration is the best case. Because the polymer concentration is lower affecting to the lower polymer volume is used. That the calculated cost of this lower concentration

case is cheaper than others. Both the cumulative oil production and economic evaluations are contrasted and hard for consideration. However, the case of 1,000 ppm polymer concentration is proper. Due to it is still high in recovery factor and production rate moreover, it is 2nd best case of both evaluations.

3. The best case of this study is case use injection rate 150 bbl are choosing polymer flooding at concentration 1,500 ppm. During the first year to inject, at the oil price rate 85$/bbl, the NPVs is 4.681 MMUS$. The best case use injection rate 300 bbl are choosing polymer flooding at concentration 600 ppm. During the first year to inject, the NPVs is 8.095 MMUS$. Why the choose polymer flooding at concentration 600 ppm because the rate in polymer inject is low compared to the each case in polymer flooding for decrease cost inject polymer.

4. In all cases, in the fifth year of injection, in water and polymer flooding are should choose not to do because to be produced, but not worth the cost to do. In water flooding at third year to inject should not to do. Polymer flooding is the best techniques in improving efficiency of oil recovery and economic values. But in the real field operation, it is unlikely that the operation can take place in the first year because water and polymer flooding projects require at least 3 to 5 years in collecting data of reservoir properties and history of production rates.

5. History matching should be compared to the real field and the reservoir simulation because it is crucial in producing more accurate results. The study also finds that the more reservoir properties data obtained, the more accurate the results are. However, production rates are not included in this study due to the inaccessibility

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

7. For future study, the locations of production and injection wells can be changed to five spot, seven spot, and nine spot, and peripheral flood patterns in order to find oil recovery efficiency and economic values in Maesoon oil field. It is suggested that the researchers should have sufficient understanding of program application (ECLIPSE and Surfer) in order to input data into the simulations and produce highly accurate results.

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APPENDIX A

SIMULATION DATA

Table A.1 PVDG (The Dry Gas PVT property)

PVDG (Dry gas PVT properties (No vapoursed oil))					
Pressure (psia)	**FVF (rb/Mscf)**	**Viscosity (cp)**	**Pressure (psia)**	**FVF (rb/Mscf)**	**Viscosity (cp)**
14.7	215.05354	0.01267968	954.33158	3.3286206	0.01357113
108.66316	29.078567	0.01276601	1048.2947	3.0354079	0.01366388
202.62632	15.589737	0.01285294	1142.2579	2.7910519	0.01375733
296.58947	10.649988	0.01294048	1236.2211	2.5844068	0.01385148
390.55263	8.0888839	0.01302865	1330.1842	2.4074748	0.01394635
484.51579	6.5225623	0.01311744	1424.1474	2.2543676	0.01404194
578.47895	5.4662877	0.01320686	1518.1105	2.1206536	0.01413827
672.44211	4.7062572	0.01329694	1612.0737	2.0029337	0.01423534
766.40526	4.1335156	0.01338767	1706.0368	1.8985567	0.01433317
900	3.5264576	0.01351781	1800	1.8054244	0.01443177

Table A.2 PVDO (The Dead Oil PVT property)

PVDO (Dead oil PVT Properties (No Dissolved Gas))					
Pressure (psia)	**FVF (rb/Mscf)**	**Viscosity (cp)**	**Pressure (psia)**	**FVF (rb/Mscf)**	**Viscosity (cp)**
14.7	1.0588915	2.1112164	954.33158	1.0491988	2.1112164
108.66316	1.0523605	2.1112164	1048.2947	1.0491624	2.1112164
202.62632	1.0507048	2.1112164	1142.2579	1.0491321	2.1112164
296.58947	1.0500988	2.1112164	1236.2211	1.0491063	2.1112164
390.55263	1.0497845	2.1112164	1330.1842	1.0490842	2.1112164
484.51579	1.0495922	2.1112164	1424.1474	1.049065	2.1112164
578.47895	1.0494624	2.1112164	1518.1105	1.0490482	2.1112164
672.44211	1.0493689	2.1112164	1612.0737	1.0490333	2.1112164
766.40526	1.0492983	2.1112164	1706.0368	1.0490201	2.1112164
900	1.0492233	2.1112164	1800	1.0490082	2.1112164

APPENDIX B

POLYMER DATA

Table B.1 Results of test for polymer properties (After Thang, 2005)

No	Polymer	Conc. ppm	Before heating						Heating temp, °C	Heating time, h
			Temp. °C	PH	V_{300}	V_{600}	µP	µa		
1	XCD	600	28.5	8	5	7	2	3.5	130	7
2	XCD	600	28.5	8	5	7	2	3.5	150	7
3	XCD	1200	28.5	8	7	9	2	4.5	130	7
4	XCD	1200	28.5	8	7	9	2	4.5	150	7
5	XCD	1800	30.0	8	8	12	4	6	130	7
6	XCD	1800	30.0	8	8	12	4	6	150	7
7	XCD	2400	30.5	8	10	14	4	7	130	7
8	XCD	2400	30.5	8	10	14	4	7	150	7
9	XCD	3000	30.5	8	12	17	5	8.5	130	7
10	XCD	3000	30.5	8	12	17	5	8.5	150	7
11	XCD	3000	26.0	8	15	20	5	9.8	130	7
12	XCD	3000	26.0	8	15	20	5	9.8	150	7

Table B.1 Results of test for polymer properties (After Thang, 2005) (cont.)

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

APPENDIX C

CASH FLOW SUMMARY

C.1 Cash flow summary result 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 C.1 - C.24. In Tables C.1 - C.24 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 C.25.

Table C.1 Cash flow summary of case 1

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	73,200	6.222	0.000	1.660	0.311	0.000	0.144	0.101
6	73,000	6.205	0.000	1.689	0.310	0.050	0.050	0.032
7	73,000	6.205	0.000	1.723	0.310	0.033	0.033	0.020
8	73,000	6.205	0.000	1.757	0.310	0.016	0.016	0.009
9	73,200	6.222	0.000	1.797	0.311	2.057	2.057	1.073
10	73,000	6.205	0.000	1.828	0.310	2.033	2.033	0.986
11	73,000	6.205	0.000	1.865	0.310	2.015	2.015	0.909
12	73,000	6.205	0.000	1.902	0.310	1.996	1.996	0.838
13	73,200	6.222	0.000	1.945	0.311	1.983	1.983	0.774
14	73,000	6.205	0.000	1.979	0.310	1.958	1.958	0.711
15	73,000	6.205	0.000	2.019	0.310	1.938	1.938	0.655
16	73,000	6.205	0.000	2.059	0.310	1.918	1.918	0.603
17	73,200	6.222	0.000	2.106	0.311	1.903	1.903	0.556
18	73,000	6.205	0.000	2.142	0.310	1.876	1.876	0.510
19	73,000	6.205	0.000	2.185	0.310	1.855	1.855	0.469
20	73,000	6.205	0.000	2.229	0.310	1.833	1.833	0.432
21	73,200	6.222	0.000	2.279	0.311	1.816	1.816	0.398
22	73,000	6.205	0.000	2.319	0.310	1.788	1.788	0.364
23	73,000	6.205	0.000	2.365	0.310	1.765	1.765	0.334
24	73,000	6.205	0.000	2.412	0.310	1.741	1.741	0.307
Total	**1,461,000**	**124.185**	**25.631**	**40.262**	**6.209**	**30.572**	**21.511**	**2.809**
						IRR	**10.70%**	**2.98%**
						PIR	**0.839**	**0.110**

Table C.2 Cash flow summary of case 2

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	73,200	6.222	0.000	1.690	0.311	0.000	0.115	0.080
6	73,000	6.205	0.000	1.719	0.310	0.035	0.035	0.022
7	73,000	6.205	0.000	1.754	0.310	0.017	0.017	0.011
8	73,000	6.205	0.000	1.789	0.310	0.000	0.000	0.000
9	73,200	6.222	0.000	1.829	0.311	2.041	2.041	1.064
10	73,000	6.205	0.000	1.861	0.310	2.017	2.017	0.979
11	73,000	6.205	0.000	1.898	0.310	1.998	1.998	0.902
12	73,000	6.205	0.000	1.936	0.310	1.979	1.979	0.831
13	73,200	6.222	0.000	1.980	0.311	1.965	1.965	0.768
14	73,000	6.205	0.000	2.014	0.310	1.940	1.940	0.705
15	73,000	6.205	0.000	2.055	0.310	1.920	1.920	0.649
16	73,000	6.205	0.000	2.096	0.310	1.899	1.899	0.597
17	73,200	6.222	0.000	2.143	0.311	1.884	1.884	0.551
18	73,000	6.205	0.000	2.181	0.310	1.857	1.857	0.505
19	73,000	6.205	0.000	2.224	0.310	1.835	1.835	0.464
20	73,000	6.205	0.000	2.269	0.310	1.813	1.813	0.427
21	73,200	6.222	0.000	2.320	0.311	1.795	1.795	0.393
22	73,000	6.205	0.000	2.360	0.310	1.767	1.767	0.360
23	73,000	6.205	0.000	2.407	0.310	1.744	1.744	0.330
24	73,000	6.205	0.000	2.456	0.310	1.720	1.720	0.303
Total	**1,461,000**	**124.185**	**25.631**	**40.983**	**6.209**	**30.227**	**21.135**	**2.668**
						IRR	**10.54%**	**2.83%**
						PIR	**0.825**	**0.104**

Table C.3 Cash flow summary of case 3

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	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.860
6	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.661
7	200	0.017	0.000	0.052	0.001	0.000	-4.142	-2.497
8	72,800	6.188	0.000	1.753	0.309	0.010	0.010	0.006
9	73,200	6.222	0.000	1.797	0.311	2.057	2.057	1.073
10	73,000	6.205	0.000	1.828	0.310	2.033	2.033	0.986
11	73,000	6.205	0.000	1.865	0.310	2.015	2.015	0.909
12	73,000	6.205	0.000	1.902	0.310	1.996	1.996	0.838
13	73,200	6.222	0.000	1.945	0.311	1.983	1.983	0.774
14	73,000	6.205	0.000	1.979	0.310	1.958	1.958	0.711
15	73,000	6.205	0.000	2.019	0.310	1.938	1.938	0.655
16	73,000	6.205	0.000	2.059	0.310	1.918	1.918	0.603
17	73,200	6.222	0.000	2.106	0.311	1.903	1.903	0.556
18	73,000	6.205	0.000	2.142	0.310	1.876	1.876	0.510
19	73,000	6.205	0.000	2.185	0.310	1.855	1.855	0.469
20	73,000	6.205	0.000	2.229	0.310	1.833	1.833	0.432
21	73,200	6.222	0.000	2.279	0.311	1.816	1.816	0.398
22	73,000	6.205	0.000	2.319	0.310	1.788	1.788	0.364
23	73,000	6.205	0.000	2.365	0.310	1.765	1.765	0.334
24	73,000	6.205	0.000	2.412	0.310	1.741	1.741	0.307
Total	**1,241,800**	**105.553**	**25.631**	**35.237**	**5.278**	**30.484**	**8.923**	**-5.364**
						IRR	**3.16%**	**-**
						PIR	**0.348**	**-0.209**

Table C.4 Cash flow summary of case 4

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	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.860
6	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.661
7	200	0.017	0.000	0.053	0.001	0.000	-4.143	-2.497
8	72,800	6.188	0.000	1.784	0.309	0.000	-0.012	-0.006
9	73,200	6.222	0.000	1.829	0.311	2.041	2.041	1.064
10	73,000	6.205	0.000	1.861	0.310	2.017	2.017	0.979
11	73,000	6.205	0.000	1.898	0.310	1.998	1.998	0.902
12	73,000	6.205	0.000	1.936	0.310	1.979	1.979	0.831
13	73,200	6.222	0.000	1.980	0.311	1.965	1.965	0.768
14	73,000	6.205	0.000	2.014	0.310	1.940	1.940	0.705
15	73,000	6.205	0.000	2.055	0.310	1.920	1.920	0.649
16	73,000	6.205	0.000	2.096	0.310	1.899	1.899	0.597
17	73,200	6.222	0.000	2.143	0.311	1.884	1.884	0.551
18	73,000	6.205	0.000	2.181	0.310	1.857	1.857	0.505
19	73,000	6.205	0.000	2.224	0.310	1.835	1.835	0.464
20	73,000	6.205	0.000	2.269	0.310	1.813	1.813	0.427
21	73,200	6.222	0.000	2.320	0.311	1.795	1.795	0.393
22	73,000	6.205	0.000	2.360	0.310	1.767	1.767	0.360
23	73,000	6.205	0.000	2.407	0.310	1.744	1.744	0.330
24	73,000	6.205	0.000	2.456	0.310	1.720	1.720	0.303
Total	**1,241,800**	**105.553**	**25.631**	**35.867**	**5.278**	**30.175**	**8.603**	**-5.469**
						IRR	**3.06%**	**-**
						PIR	**0.336**	**-0.213**

Table C.5 Cash flow summary of case 5

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	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.860
6	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.661
7	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.475
8	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.302
9	200	0.017	0.000	0.055	0.001	0.000	-0.038	-0.020
10	72,800	6.188	0.000	1.823	0.309	2.028	2.028	0.984
11	73,000	6.205	0.000	1.865	0.310	2.015	2.015	0.909
12	73,000	6.205	0.000	1.902	0.310	1.996	1.996	0.838
13	73,200	6.222	0.000	1.945	0.311	1.983	1.983	0.774
14	73,000	6.205	0.000	1.979	0.310	1.958	1.958	0.711
15	73,000	6.205	0.000	2.019	0.310	1.938	1.938	0.655
16	73,000	6.205	0.000	2.059	0.310	1.918	1.918	0.603
17	73,200	6.222	0.000	2.106	0.311	1.903	1.903	0.556
18	73,000	6.205	0.000	2.142	0.310	1.876	1.876	0.510
19	73,000	6.205	0.000	2.185	0.310	1.855	1.855	0.469
20	73,000	6.205	0.000	2.229	0.310	1.833	1.833	0.432
21	73,200	6.222	0.000	2.279	0.311	1.816	1.816	0.398
22	73,000	6.205	0.000	2.319	0.310	1.788	1.788	0.364
23	73,000	6.205	0.000	2.365	0.310	1.765	1.765	0.334
24	73,000	6.205	0.000	2.412	0.310	1.741	1.741	0.307
Total	**1,095,600**	**93.126**	**25.631**	**31.685**	**4.656**	**28.412**	**2.743**	**-8.746**
						IRR	**0.90%**	**-**
						PIR	**0.107**	**-0.341**

Table C.6 Cash flow summary of case 6

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	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.860
6	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.661
7	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.475
8	0	0.000	0.000	0.000	0.000	0.000	-4.106	-2.302
9	200	0.017	0.000	0.055	0.001	0.000	-0.039	-0.020
10	72,800	6.188	0.000	1.856	0.309	2.011	2.011	0.976
11	73,000	6.205	0.000	1.898	0.310	1.998	1.998	0.902
12	73,000	6.205	0.000	1.936	0.310	1.979	1.979	0.831
13	73,200	6.222	0.000	1.980	0.311	1.965	1.965	0.768
14	73,000	6.205	0.000	2.014	0.310	1.940	1.940	0.705
15	73,000	6.205	0.000	2.055	0.310	1.920	1.920	0.649
16	73,000	6.205	0.000	2.096	0.310	1.899	1.899	0.597
17	73,200	6.222	0.000	2.143	0.311	1.884	1.884	0.551
18	73,000	6.205	0.000	2.181	0.310	1.857	1.857	0.505
19	73,000	6.205	0.000	2.224	0.310	1.835	1.835	0.464
20	73,000	6.205	0.000	2.269	0.310	1.813	1.813	0.427
21	73,200	6.222	0.000	2.320	0.311	1.795	1.795	0.393
22	73,000	6.205	0.000	2.360	0.310	1.767	1.767	0.360
23	73,000	6.205	0.000	2.407	0.310	1.744	1.744	0.330
24	73,000	6.205	0.000	2.456	0.310	1.720	1.720	0.303
Total	**1,095,600**	**93.126**	**25.631**	**32.251**	**4.656**	**28.129**	**2.460**	**-8.830**
						IRR	**0.81%**	**-**
						PIR	**0.096**	**-0.345**

Table C.7 Cash flow summary of case 7

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	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	66,589	5.660	0.036	1.594	0.283	0.000	-0.359	-0.233
7	60,428	5.136	0.036	1.487	0.257	0.000	-0.750	-0.452
8	57,322	4.872	0.036	1.446	0.244	0.000	-0.959	-0.538
9	55,283	4.699	0.036	1.427	0.235	1.501	1.501	0.783
10	54,138	4.602	0.036	1.428	0.230	1.454	1.454	0.705
11	53,439	4.542	0.036	1.439	0.227	1.420	1.420	0.641
12	53,150	4.518	0.036	1.461	0.226	1.397	1.397	0.587
13	52,732	4.482	0.036	1.480	0.224	1.371	1.371	0.536
14	52,561	4.468	0.036	1.505	0.223	1.352	1.352	0.491
15	52,455	4.459	0.036	1.532	0.223	1.334	1.334	0.451
16	52,537	4.466	0.036	1.565	0.223	1.321	1.321	0.415
17	52,352	4.450	0.036	1.591	0.222	1.300	1.300	0.380
18	52,324	4.448	0.036	1.622	0.222	1.283	1.283	0.349
19	52,308	4.446	0.036	1.654	0.222	1.267	1.267	0.321
20	52,442	4.458	0.036	1.691	0.223	1.254	1.254	0.295
21	52,292	4.445	0.036	1.720	0.222	1.233	1.233	0.270
22	52,291	4.445	0.036	1.755	0.222	1.216	1.216	0.248
23	52,289	4.445	0.036	1.790	0.222	1.198	1.198	0.227
24	52,431	4.457	0.036	1.830	0.223	1.184	1.184	0.209
Total	**1,244,986**	**105.824**	**26.317**	**34.686**	**5.291**	**21.084**	**18.447**	**4.427**
						IRR	**16.31%**	**8.20%**
						PIR	**0.701**	**0.168**

Table C.8 Cash flow summary of case 8

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	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	73,000	6.205	0.073	1.766	0.310	0.000	-0.050	-0.032
7	73,000	6.205	0.073	1.801	0.310	0.000	-0.085	-0.051
8	73,200	6.222	0.073	1.842	0.311	0.000	-0.110	-0.062
9	73,000	6.205	0.073	1.874	0.310	1.974	1.974	1.030
10	73,000	6.205	0.073	1.911	0.310	1.955	1.955	0.949
11	73,000	6.205	0.073	1.950	0.310	1.936	1.936	0.874
12	73,200	6.222	0.073	1.994	0.311	1.922	1.922	0.807
13	73,000	6.205	0.073	2.028	0.310	1.897	1.897	0.741
14	73,000	6.205	0.073	2.069	0.310	1.877	1.877	0.682
15	73,000	6.205	0.073	2.110	0.310	1.856	1.856	0.627
16	73,200	6.222	0.073	2.158	0.311	1.840	1.840	0.578
17	73,000	6.205	0.073	2.196	0.310	1.813	1.813	0.530
18	73,000	6.205	0.073	2.240	0.310	1.791	1.791	0.487
19	73,000	6.205	0.073	2.284	0.310	1.769	1.769	0.448
20	73,200	6.222	0.073	2.336	0.311	1.751	1.751	0.412
21	73,000	6.205	0.073	2.377	0.310	1.723	1.723	0.377
22	73,000	6.205	0.073	2.424	0.310	1.699	1.699	0.346
23	73,000	6.205	0.073	2.473	0.310	1.675	1.675	0.317
24	73,200	6.222	0.073	2.529	0.311	1.655	1.655	0.292
Total	**1,603,622**	**136.308**	**27.012**	**45.029**	**6.815**	**29.133**	**28.319**	**8.095**
						IRR	**21.68%**	**13.19%**
						PIR	**1.048**	**0.300**

Table C.9 Cash flow summary of case 9

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	18.615	0.000	4.741	0.931	0.000	8.837	6.156
6	131,429	11.171	0.000	2.902	0.559	1.802	1.802	1.168
7	73,626	6.258	0.000	1.658	0.313	0.090	0.090	0.055
8	12,325	1.048	0.036	0.412	0.052	0.000	-3.559	-1.996
9	18,143	1.542	0.036	0.556	0.077	0.436	0.436	0.228
10	24,090	2.048	0.036	0.710	0.102	0.600	0.600	0.291
11	30,083	2.557	0.036	0.870	0.128	0.762	0.762	0.344
12	36,013	3.061	0.036	1.035	0.153	0.918	0.918	0.386
13	40,953	3.481	0.036	1.181	0.174	1.045	1.045	0.408
14	44,758	3.804	0.036	1.303	0.190	1.138	1.138	0.413
15	47,376	4.027	0.036	1.398	0.201	1.196	1.196	0.404
16	49,260	4.187	0.036	1.477	0.209	1.232	1.232	0.387
17	50,267	4.273	0.036	1.534	0.214	1.245	1.245	0.364
18	50,998	4.335	0.036	1.585	0.217	1.248	1.248	0.340
19	51,464	4.374	0.036	1.630	0.219	1.245	1.245	0.315
20	51,911	4.412	0.036	1.676	0.221	1.240	1.240	0.292
21	51,956	4.416	0.036	1.711	0.221	1.224	1.224	0.268
22	52,080	4.427	0.036	1.748	0.221	1.210	1.210	0.247
23	52,156	4.433	0.036	1.786	0.222	1.195	1.195	0.226
24	52,347	4.449	0.036	1.828	0.222	1.182	1.182	0.208
Total	**1,140,233**	**96.920**	**26.244**	**31.740**	**4.846**	**19.009**	**15.081**	**3.230**
						IRR	**14.93%**	**6.91%**
						PIR	**0.575**	**0.123**

Table C.10 Cash flow summary of case 10

Year	Cash flow summary							Discount cash flow
	Oil production total	Gross revenue	CAPEX	OPEX	Government take		Annual cash flow	(NPV@7.5%)
					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	18.615	0.000	4.741	0.931	0.000	8.837	6.156
6	131,429	11.171	0.000	2.902	0.559	1.802	1.802	1.168
7	73,626	6.258	0.000	1.658	0.313	0.090	0.090	0.055
8	16,901	1.437	0.073	0.649	0.072	0.000	-3.463	-1.942
9	35,377	3.007	0.073	1.095	0.150	0.845	0.845	0.441
10	59,888	5.090	0.073	1.702	0.255	1.530	1.530	0.743
11	73,000	6.205	0.073	2.056	0.310	1.883	1.883	0.850
12	73,200	6.222	0.073	2.103	0.311	1.868	1.868	0.784
13	73,000	6.205	0.073	2.139	0.310	1.841	1.841	0.719
14	73,000	6.205	0.073	2.182	0.310	1.820	1.820	0.661
15	73,000	6.205	0.073	2.226	0.310	1.798	1.798	0.608
16	73,200	6.222	0.073	2.276	0.311	1.781	1.781	0.560
17	73,000	6.205	0.073	2.315	0.310	1.753	1.753	0.513
18	73,000	6.205	0.073	2.362	0.310	1.730	1.730	0.471
19	73,000	6.205	0.073	2.409	0.310	1.707	1.707	0.432
20	73,200	6.222	0.073	2.464	0.311	1.687	1.687	0.397
21	73,000	6.205	0.073	2.506	0.310	1.658	1.658	0.363
22	73,000	6.205	0.073	2.556	0.310	1.633	1.633	0.333
23	73,000	6.205	0.073	2.608	0.310	1.607	1.607	0.305
24	73,200	6.222	0.073	2.667	0.311	1.586	1.586	0.280
Total	**1,559,021**	**132.517**	**26.867**	**45.616**	**6.626**	**28.620**	**24.788**	**6.620**
						IRR	**19.95%**	**11.58%**
						PIR	**0.923**	**0.246**

Table C.11 Cash flow summary of case 11

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	54,750	4.654	0.000	1.185	0.233	0.000	-0.870	-0.606
6	54,750	4.654	0.000	1.209	0.233	0.000	-0.894	-0.579
7	54,750	4.654	0.000	1.233	0.233	0.000	-0.918	-0.553
8	54,900	4.667	0.000	1.261	0.233	0.000	-0.934	-0.524
9	54,750	4.654	0.000	1.283	0.233	1.569	1.569	0.818
10	44,198	3.757	0.036	1.190	0.188	1.171	1.171	0.568
11	46,946	3.990	0.036	1.281	0.200	1.237	1.237	0.558
12	48,965	4.162	0.036	1.357	0.208	1.280	1.280	0.538
13	50,064	4.255	0.036	1.412	0.213	1.297	1.297	0.507
14	50,871	4.324	0.036	1.461	0.216	1.305	1.305	0.474
15	51,383	4.368	0.036	1.504	0.218	1.305	1.305	0.441
16	51,852	4.407	0.036	1.547	0.220	1.302	1.302	0.409
17	51,920	4.413	0.036	1.579	0.221	1.289	1.289	0.377
18	52,053	4.425	0.036	1.615	0.221	1.276	1.276	0.347
19	52,140	4.432	0.036	1.649	0.222	1.262	1.262	0.319
20	52,334	4.448	0.036	1.688	0.222	1.251	1.251	0.294
21	52,224	4.439	0.036	1.718	0.222	1.231	1.231	0.270
22	52,245	4.441	0.036	1.754	0.222	1.215	1.215	0.247
23	52,259	4.442	0.036	1.789	0.222	1.197	1.197	0.227
24	52,413	4.455	0.036	1.830	0.223	1.183	1.183	0.209
Total	**1,035,768**	**88.040**	**26.172**	**29.545**	**4.402**	**20.372**	**7.549**	**-2.932**
						IRR	**4.01%**	**-**
						PIR	**0.288**	**-0.112**

Table C.12 Cash flow summary of case 12

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	54,750	4.654	0.000	1.185	0.233	0.000	-0.870	-0.606
6	54,750	4.654	0.000	1.209	0.233	0.000	-0.894	-0.579
7	54,750	4.654	0.000	1.233	0.233	0.000	-0.918	-0.553
8	54,900	4.667	0.000	1.261	0.233	0.000	-0.934	-0.524
9	54,750	4.654	0.000	1.283	0.233	1.569	1.569	0.818
10	52,732	4.482	0.073	1.427	0.224	1.379	1.379	0.669
11	54,750	4.654	0.073	1.505	0.233	1.422	1.422	0.642
12	54,900	4.667	0.073	1.539	0.233	1.411	1.411	0.592
13	54,750	4.654	0.073	1.565	0.233	1.391	1.391	0.543
14	54,750	4.654	0.073	1.597	0.233	1.376	1.376	0.500
15	54,750	4.654	0.073	1.629	0.233	1.360	1.360	0.460
16	54,900	4.667	0.073	1.666	0.233	1.347	1.347	0.424
17	54,750	4.654	0.073	1.695	0.233	1.327	1.327	0.388
18	54,750	4.654	0.073	1.728	0.233	1.310	1.310	0.356
19	54,750	4.654	0.073	1.763	0.233	1.293	1.293	0.327
20	54,900	4.667	0.073	1.803	0.233	1.279	1.279	0.301
21	54,750	4.654	0.073	1.834	0.233	1.257	1.257	0.275
22	54,750	4.654	0.073	1.871	0.233	1.239	1.239	0.252
23	54,750	4.654	0.073	1.908	0.233	1.220	1.220	0.231
24	54,900	4.666	0.073	1.951	0.233	1.204	1.204	0.212
Total	**1,093,732**	**92.967**	**26.721**	**31.652**	**4.648**	**21.384**	**8.561**	**-2.544**
						IRR	**4.50%**	**#NUM!**
						PIR	**0.320**	**-0.095**

Table C.13 Cash flow summary of case 13

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	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	66,794	5.677	0.037	1.599	0.284	0.000	-0.348	-0.226
7	60,817	5.169	0.037	1.496	0.258	0.000	-0.728	-0.439
8	57,822	4.915	0.037	1.458	0.246	0.000	-0.931	-0.522
9	55,846	4.747	0.037	1.440	0.237	1.516	1.516	0.791
10	54,754	4.654	0.037	1.443	0.233	1.471	1.471	0.714
11	54,090	4.598	0.037	1.456	0.230	1.438	1.438	0.649
12	53,811	4.574	0.037	1.478	0.229	1.415	1.415	0.594
13	53,411	4.540	0.037	1.497	0.227	1.390	1.390	0.543
14	53,250	4.526	0.037	1.523	0.226	1.370	1.370	0.498
15	53,153	4.518	0.037	1.551	0.226	1.352	1.352	0.457
16	53,237	4.525	0.037	1.584	0.226	1.339	1.339	0.421
17	53,054	4.510	0.037	1.611	0.225	1.318	1.318	0.386
18	53,031	4.508	0.037	1.642	0.225	1.302	1.302	0.354
19	53,017	4.506	0.037	1.675	0.225	1.285	1.285	0.325
20	53,151	4.518	0.037	1.712	0.226	1.271	1.271	0.299
21	53,001	4.505	0.037	1.742	0.225	1.251	1.251	0.274
22	52,998	4.505	0.037	1.777	0.225	1.233	1.233	0.251
23	52,998	4.505	0.037	1.812	0.225	1.215	1.215	0.230
24	53,142	4.517	0.037	1.853	0.226	1.201	1.201	0.212
Total	**1,256,997**	**106.845**	**26.326**	**35.019**	**5.342**	**21.367**	**18.791**	**4.554**
						IRR	**16.52%**	**8.39%**
						PIR	**0.714**	**0.173**

Table C.14 Cash flow summary of case 14

Year	Cash flow summary							Discount cash flow
	Oil production total	Gross revenue	CAPEX	OPEX	Government take		Annual cash flow	(NPV@7.5%)
					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	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	73,000	6.205	0.073	1.766	0.310	0.000	-0.051	-0.033
7	73,000	6.205	0.073	1.802	0.310	0.000	-0.086	-0.052
8	73,200	6.222	0.073	1.842	0.311	0.000	-0.111	-0.062
9	73,000	6.205	0.073	1.874	0.310	1.974	1.974	1.029
10	73,000	6.205	0.073	1.912	0.310	1.955	1.955	0.948
11	73,000	6.205	0.073	1.950	0.310	1.936	1.936	0.874
12	73,200	6.222	0.073	1.994	0.311	1.922	1.922	0.807
13	73,000	6.205	0.073	2.029	0.310	1.896	1.896	0.741
14	73,000	6.205	0.073	2.069	0.310	1.876	1.876	0.682
15	73,000	6.205	0.073	2.111	0.310	1.855	1.855	0.627
16	73,200	6.222	0.073	2.159	0.311	1.839	1.839	0.578
17	73,000	6.205	0.073	2.196	0.310	1.813	1.813	0.530
18	73,000	6.205	0.073	2.240	0.310	1.791	1.791	0.487
19	73,000	6.205	0.073	2.285	0.310	1.768	1.768	0.448
20	73,200	6.222	0.073	2.337	0.311	1.750	1.750	0.412
21	73,000	6.205	0.073	2.377	0.310	1.722	1.722	0.377
22	73,000	6.205	0.073	2.425	0.310	1.698	1.698	0.346
23	73,000	6.205	0.073	2.473	0.310	1.674	1.674	0.317
24	73,200	6.222	0.073	2.529	0.311	1.654	1.654	0.292
Total	**1,603,622**	**136.308**	**27.021**	**45.038**	**6.815**	**29.125**	**28.308**	**8.091**
						IRR	**21.68%**	**13.19%**
						PIR	**1.048**	**0.299**

Table C.15 Cash flow summary of case 15

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	18.615	0.000	4.741	0.931	0.000	8.703	6.062
6	131,429	11.171	0.000	2.902	0.559	1.735	1.735	1.124
7	73,626	6.258	0.156	1.658	0.313	0.000	-0.004	-0.002
8	12,381	1.052	0.037	0.414	0.053	0.000	-3.717	-2.084
9	18,313	1.557	0.037	0.561	0.078	0.428	0.428	0.223
10	24,400	2.074	0.037	0.717	0.104	0.595	0.595	0.289
11	30,567	2.598	0.037	0.882	0.130	0.775	0.775	0.350
12	36,672	3.117	0.037	1.052	0.156	0.936	0.936	0.393
13	41,710	3.545	0.037	1.200	0.177	1.066	1.066	0.416
14	45,533	3.870	0.037	1.323	0.194	1.158	1.158	0.421
15	48,152	4.093	0.037	1.419	0.205	1.216	1.216	0.411
16	50,032	4.253	0.037	1.498	0.213	1.253	1.253	0.394
17	51,013	4.336	0.037	1.555	0.217	1.264	1.264	0.370
18	51,739	4.398	0.037	1.606	0.220	1.268	1.268	0.345
19	52,203	4.437	0.037	1.652	0.222	1.264	1.264	0.320
20	52,634	4.474	0.037	1.697	0.224	1.258	1.258	0.296
21	52,676	4.477	0.037	1.732	0.224	1.242	1.242	0.272
22	52,796	4.488	0.037	1.771	0.224	1.228	1.228	0.250
23	52,869	4.494	0.037	1.808	0.225	1.212	1.212	0.230
24	53,061	4.510	0.037	1.851	0.226	1.199	1.199	0.211
Total	**1,150,806**	**97.818**	**30.278**	**32.041**	**4.891**	**19.096**	**11.539**	**0.521**
						IRR	8.36%	0.80%
						PIR	0.381	0.017

Table C.16 Cash flow summary of case 16

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	18.615	0.000	4.741	0.931	0.000	8.703	6.062
6	131,429	11.171	0.000	2.902	0.559	1.735	1.735	1.124
7	73,626	6.258	0.156	1.658	0.313	0.000	-0.004	-0.002
8	16,969	1.442	0.073	0.551	0.072	0.000	-3.520	-1.974
9	35,698	3.034	0.073	1.000	0.152	0.892	0.892	0.465
10	60,518	5.144	0.073	1.614	0.257	1.587	1.587	0.770
11	73,000	6.205	0.073	1.950	0.310	1.936	1.936	0.874
12	73,200	6.222	0.073	1.994	0.311	1.922	1.922	0.807
13	73,000	6.205	0.073	2.029	0.310	1.896	1.896	0.741
14	73,000	6.205	0.073	2.069	0.310	1.876	1.876	0.682
15	73,000	6.205	0.073	2.111	0.310	1.855	1.855	0.627
16	73,200	6.222	0.073	2.159	0.311	1.839	1.839	0.578
17	73,000	6.205	0.073	2.196	0.310	1.813	1.813	0.530
18	73,000	6.205	0.073	2.240	0.310	1.791	1.791	0.487
19	73,000	6.205	0.073	2.285	0.310	1.768	1.768	0.448
20	73,200	6.222	0.073	2.337	0.311	1.750	1.750	0.412
21	73,000	6.205	0.073	2.377	0.310	1.722	1.722	0.377
22	73,000	6.205	0.073	2.425	0.310	1.698	1.698	0.346
23	73,000	6.205	0.073	2.473	0.310	1.674	1.674	0.317
24	73,200	6.222	0.073	2.529	0.311	1.654	1.654	0.292
Total	**1,560,039**	**132.603**	**30.900**	**43.640**	**6.630**	**29.410**	**22.050**	**4.193**
						IRR	13.39%	5.48%
						PIR	0.714	0.136

Table C.17 Cash flow summary of case 17

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	54,750	4.654	0.000	1.185	0.233	0.000	-1.004	-0.699
6	54,750	4.654	0.000	1.209	0.233	0.000	-1.028	-0.666
7	54,750	4.654	0.000	1.233	0.233	0.000	-1.052	-0.634
8	54,900	4.667	0.000	1.261	0.233	0.000	-1.068	-0.599
9	54,750	4.654	0.286	1.283	0.233	1.557	1.557	0.812
10	44,350	3.770	0.037	1.194	0.188	1.175	1.175	0.570
11	47,300	4.021	0.037	1.290	0.201	1.246	1.246	0.563
12	49,452	4.203	0.037	1.370	0.210	1.294	1.294	0.543
13	50,643	4.305	0.037	1.427	0.215	1.313	1.313	0.513
14	51,492	4.377	0.037	1.478	0.219	1.322	1.322	0.480
15	52,044	4.424	0.037	1.522	0.221	1.322	1.322	0.447
16	52,530	4.465	0.037	1.565	0.223	1.320	1.320	0.415
17	52,610	4.472	0.037	1.599	0.224	1.306	1.306	0.382
18	52,755	4.484	0.037	1.635	0.224	1.294	1.294	0.352
19	52,841	4.492	0.037	1.670	0.225	1.280	1.280	0.324
20	53,040	4.508	0.037	1.709	0.225	1.269	1.269	0.299
21	52,931	4.499	0.037	1.740	0.225	1.249	1.249	0.273
22	52,954	4.501	0.037	1.776	0.225	1.232	1.232	0.251
23	52,969	4.502	0.037	1.812	0.225	1.215	1.215	0.230
24	53,123	4.515	0.037	1.853	0.226	1.200	1.200	0.212
Total	**1,044,935**	**88.819**	**30.334**	**29.810**	**4.441**	**20.594**	**3.901**	**-5.703**
						IRR	**1.77%**	**-**
						PIR	**0.129**	**-0.188**

Table C.18 Cash flow summary of case 18

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	54,750	4.654	0.000	1.185	0.233	0.000	-1.004	-0.699
6	54,750	4.654	0.000	1.209	0.233	0.000	-1.028	-0.666
7	54,750	4.654	0.000	1.233	0.233	0.000	-1.052	-0.634
8	54,900	4.667	0.000	1.261	0.233	0.000	-1.068	-0.599
9	54,750	4.654	0.286	1.283	0.233	1.557	1.557	0.812
10	52,785	4.487	0.073	1.429	0.224	1.380	1.380	0.670
11	54,750	4.654	0.073	1.505	0.233	1.421	1.421	0.642
12	54,900	4.667	0.073	1.539	0.233	1.410	1.410	0.592
13	54,750	4.654	0.073	1.566	0.233	1.391	1.391	0.543
14	54,750	4.654	0.073	1.597	0.233	1.375	1.375	0.500
15	54,750	4.654	0.073	1.629	0.233	1.359	1.359	0.459
16	54,900	4.667	0.073	1.666	0.233	1.347	1.347	0.423
17	54,750	4.654	0.073	1.695	0.233	1.326	1.326	0.388
18	54,750	4.654	0.073	1.729	0.233	1.309	1.309	0.356
19	54,750	4.654	0.073	1.764	0.233	1.292	1.292	0.327
20	54,900	4.667	0.073	1.803	0.233	1.278	1.278	0.301
21	54,750	4.654	0.073	1.835	0.233	1.257	1.257	0.275
22	54,750	4.654	0.073	1.871	0.233	1.238	1.238	0.252
23	54,750	4.654	0.073	1.909	0.233	1.220	1.220	0.231
24	54,900	4.667	0.073	1.952	0.233	1.204	1.204	0.212
Total	**1,093,785**	**92.972**	**30.883**	**31.661**	**4.649**	**21.366**	**4.673**	**-5.385**
						IRR	**2.12%**	**-**
						PIR	**0.151**	**-0.174**

Table C.19 Cash flow summary of case 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	22.131	0.000	0.000	0.000	-5.706	-4.273
5	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	66,998	5.695	0.037	1.604	0.285	0.000	-0.337	-0.218
7	61,211	5.203	0.037	1.506	0.260	0.000	-0.706	-0.426
8	58,323	4.957	0.037	1.469	0.248	0.000	-0.903	-0.506
9	56,413	4.795	0.037	1.454	0.240	1.532	1.532	0.799
10	55,373	4.707	0.037	1.458	0.235	1.488	1.488	0.722
11	54,727	4.652	0.037	1.472	0.233	1.455	1.455	0.657
12	54,485	4.631	0.037	1.495	0.232	1.434	1.434	0.602
13	54,091	4.598	0.037	1.515	0.230	1.408	1.408	0.550
14	53,940	4.585	0.037	1.541	0.229	1.389	1.389	0.504
15	53,849	4.577	0.037	1.570	0.229	1.371	1.371	0.463
16	53,940	4.585	0.037	1.604	0.229	1.357	1.357	0.427
17	53,757	4.569	0.037	1.631	0.228	1.337	1.337	0.391
18	53,736	4.568	0.037	1.663	0.228	1.320	1.320	0.359
19	53,722	4.566	0.037	1.696	0.228	1.303	1.303	0.330
20	53,862	4.578	0.037	1.734	0.229	1.289	1.289	0.304
21	53,710	4.565	0.037	1.764	0.228	1.268	1.268	0.278
22	53,708	4.565	0.037	1.799	0.228	1.250	1.250	0.255
23	53,707	4.565	0.037	1.835	0.228	1.232	1.232	0.234
24	53,852	4.577	0.037	1.876	0.229	1.218	1.218	0.215
Total	**1,269,025**	**107.867**	**26.335**	**35.353**	**5.393**	**21.651**	**19.136**	**4.681**
						IRR	**16.72%**	**8.58%**
						PIR	**0.727**	**0.178**

Table C.20 Cash flow summary of case 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	22.131	0.000	0.000	0.000	-5.706	-4.273
5	215,622	18.328	0.000	4.668	0.916	0.000	8.637	6.016
6	73,000	6.205	0.074	1.767	0.310	0.000	-0.052	-0.033
7	73,000	6.205	0.074	1.802	0.310	0.000	-0.087	-0.052
8	73,200	6.222	0.074	1.843	0.311	0.000	-0.112	-0.063
9	73,000	6.205	0.074	1.875	0.310	1.973	1.973	1.029
10	73,000	6.205	0.074	1.912	0.310	1.954	1.954	0.948
11	73,000	6.205	0.074	1.951	0.310	1.935	1.935	0.873
12	73,200	6.222	0.074	1.995	0.311	1.921	1.921	0.807
13	73,000	6.205	0.074	2.029	0.310	1.896	1.896	0.740
14	73,000	6.205	0.074	2.070	0.310	1.876	1.876	0.681
15	73,000	6.205	0.074	2.111	0.310	1.855	1.855	0.627
16	73,200	6.222	0.074	2.159	0.311	1.839	1.839	0.578
17	73,000	6.205	0.074	2.197	0.310	1.812	1.812	0.530
18	73,000	6.205	0.074	2.241	0.310	1.790	1.790	0.487
19	73,000	6.205	0.074	2.285	0.310	1.768	1.768	0.447
20	73,200	6.222	0.074	2.337	0.311	1.750	1.750	0.412
21	73,000	6.205	0.074	2.378	0.310	1.722	1.722	0.377
22	73,000	6.205	0.074	2.425	0.310	1.698	1.698	0.346
23	73,000	6.205	0.074	2.474	0.310	1.674	1.674	0.317
24	73,200	6.222	0.074	2.530	0.311	1.654	1.654	0.292
Total	**1,603,622**	**136.308**	**27.030**	**45.047**	**6.815**	**29.117**	**28.298**	**8.087**
						IRR	**21.67%**	**13.18%**
						PIR	**1.047**	**0.299**

Table C.21 Cash flow summary of case 21

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	18.615	0.000	4.741	0.931	0.000	8.703	6.062
6	131,429	11.171	0.000	2.902	0.559	1.735	1.735	1.124
7	73,626	6.258	0.156	1.658	0.313	0.000	-0.004	-0.002
8	12,435	1.057	0.037	0.415	0.053	0.000	-3.714	-2.083
9	18,483	1.571	0.037	0.565	0.079	0.432	0.432	0.225
10	24,715	2.101	0.037	0.725	0.105	0.604	0.604	0.293
11	31,062	2.640	0.037	0.895	0.132	0.788	0.788	0.356
12	37,342	3.174	0.037	1.069	0.159	0.955	0.955	0.401
13	42,473	3.610	0.037	1.220	0.181	1.086	1.086	0.424
14	46,314	3.937	0.037	1.344	0.197	1.179	1.179	0.428
15	48,922	4.158	0.037	1.440	0.208	1.237	1.237	0.418
16	50,784	4.317	0.037	1.519	0.216	1.272	1.272	0.400
17	51,770	4.400	0.037	1.576	0.220	1.284	1.284	0.375
18	52,482	4.461	0.037	1.628	0.223	1.287	1.287	0.350
19	52,936	4.500	0.037	1.673	0.225	1.282	1.282	0.324
20	53,366	4.536	0.037	1.719	0.227	1.276	1.276	0.300
21	53,403	4.539	0.037	1.755	0.227	1.260	1.260	0.276
22	53,513	4.549	0.037	1.793	0.227	1.246	1.246	0.254
23	53,584	4.555	0.037	1.831	0.228	1.229	1.229	0.233
24	53,775	4.571	0.037	1.874	0.229	1.216	1.216	0.214
Total	**1,161,412**	**98.720**	**30.286**	**32.343**	**4.936**	**19.368**	**11.813**	**0.605**
						IRR	8.50%	0.93%
						PIR	0.390	0.020

Table C.22 Cash flow summary of case 22

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	18.615	0.000	4.741	0.931	0.000	8.703	6.062
6	131,429	11.171	0.000	2.902	0.559	1.735	1.735	1.124
7	73,626	6.258	0.156	1.658	0.313	0.000	-0.004	-0.002
8	17,036	1.448	0.074	0.552	0.072	0.000	-3.517	-1.972
9	36,019	3.062	0.074	1.008	0.153	0.900	0.900	0.470
10	61,162	5.199	0.074	1.629	0.260	1.605	1.605	0.779
11	73,000	6.205	0.074	1.951	0.310	1.935	1.935	0.873
12	73,200	6.222	0.074	1.995	0.311	1.921	1.921	0.807
13	73,000	6.205	0.074	2.029	0.310	1.896	1.896	0.740
14	73,000	6.205	0.074	2.070	0.310	1.876	1.876	0.681
15	73,000	6.205	0.074	2.111	0.310	1.855	1.855	0.627
16	73,200	6.222	0.074	2.159	0.311	1.839	1.839	0.578
17	73,000	6.205	0.074	2.197	0.310	1.812	1.812	0.530
18	73,000	6.205	0.074	2.241	0.310	1.790	1.790	0.487
19	73,000	6.205	0.074	2.285	0.310	1.768	1.768	0.447
20	73,200	6.222	0.074	2.337	0.311	1.750	1.750	0.412
21	73,000	6.205	0.074	2.378	0.310	1.722	1.722	0.377
22	73,000	6.205	0.074	2.425	0.310	1.698	1.698	0.346
23	73,000	6.205	0.074	2.474	0.310	1.674	1.674	0.317
24	73,200	6.222	0.074	2.530	0.311	1.654	1.654	0.292
Total	**1,561,071**	**132.691**	**30.908**	**43.673**	**6.635**	**29.430**	**22.072**	**4.206**
						IRR	13.41%	5.50%
						PIR	0.714	0.136

Table C.23 Cash flow summary of case 23

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	54,750	4.654	0.000	1.185	0.233	0.000	-1.004	-0.699
6	54,750	4.654	0.000	1.209	0.233	0.000	-1.028	-0.666
7	54,750	4.654	0.000	1.233	0.233	0.000	-1.052	-0.634
8	54,900	4.667	0.000	1.261	0.233	0.000	-1.068	-0.599
9	54,750	4.654	0.286	1.283	0.233	1.557	1.557	0.812
10	44,503	3.783	0.037	1.198	0.189	1.179	1.179	0.572
11	47,653	4.051	0.037	1.299	0.203	1.256	1.256	0.567
12	49,941	4.245	0.037	1.382	0.212	1.307	1.307	0.549
13	51,209	4.353	0.037	1.442	0.218	1.328	1.328	0.519
14	52,126	4.431	0.037	1.494	0.222	1.339	1.339	0.486
15	52,704	4.480	0.037	1.540	0.224	1.340	1.340	0.453
16	53,221	4.524	0.037	1.584	0.226	1.338	1.338	0.421
17	53,306	4.531	0.037	1.618	0.227	1.325	1.325	0.387
18	53,453	4.543	0.037	1.655	0.227	1.312	1.312	0.357
19	53,545	4.551	0.037	1.691	0.228	1.298	1.298	0.329
20	53,749	4.569	0.037	1.730	0.228	1.286	1.286	0.303
21	53,640	4.559	0.037	1.762	0.228	1.266	1.266	0.277
22	53,663	4.561	0.037	1.798	0.228	1.249	1.249	0.254
23	53,678	4.563	0.037	1.834	0.228	1.232	1.232	0.233
24	53,834	4.576	0.037	1.876	0.229	1.217	1.217	0.215
Total	**1,054,125**	**89.601**	**30.342**	**30.075**	**4.480**	**20.828**	**4.136**	**-5.635**
						IRR	**1.87%**	**-**
						PIR	**0.136**	**-0.186**

Table C.24 Cash flow summary of case 24

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	54,750	4.654	0.000	1.185	0.233	0.000	-1.004	-0.699
6	54,750	4.654	0.000	1.209	0.233	0.000	-1.028	-0.666
7	54,750	4.654	0.000	1.233	0.233	0.000	-1.052	-0.634
8	54,900	4.667	0.000	1.261	0.233	0.000	-1.068	-0.599
9	54,750	4.654	0.286	1.283	0.233	1.557	1.557	0.812
10	52,852	4.492	0.074	1.431	0.225	1.382	1.382	0.670
11	54,750	4.654	0.074	1.506	0.233	1.421	1.421	0.641
12	54,900	4.667	0.074	1.540	0.233	1.410	1.410	0.592
13	54,750	4.654	0.074	1.566	0.233	1.391	1.391	0.543
14	54,750	4.654	0.074	1.598	0.233	1.375	1.375	0.500
15	54,750	4.654	0.074	1.630	0.233	1.359	1.359	0.459
16	54,900	4.667	0.074	1.667	0.233	1.346	1.346	0.423
17	54,750	4.654	0.074	1.696	0.233	1.326	1.326	0.388
18	54,750	4.654	0.074	1.729	0.233	1.309	1.309	0.356
19	54,750	4.654	0.074	1.764	0.233	1.292	1.292	0.327
20	54,900	4.667	0.074	1.804	0.233	1.278	1.278	0.301
21	54,750	4.654	0.074	1.835	0.233	1.256	1.256	0.275
22	54,750	4.654	0.074	1.872	0.233	1.238	1.238	0.252
23	54,750	4.654	0.074	1.909	0.233	1.219	1.219	0.231
24	54,900	4.667	0.074	1.953	0.233	1.203	1.203	0.212
Total	**1,093,852**	**92.977**	**30.891**	**31.670**	**4.649**	**21.360**	**4.668**	**-5.386**
						IRR	**2.11%**	**#DIV/0!**
						PIR	**0.151**	**-0.174**

Table C.25 Cash flow summary of all case studies

Cash flow summary result							
Case	Type to inject	Concentration (ppm)	IRR Undiscount (%)	PIR Undiscount (Fraction)	IRR 7.5% Disc (%)	PIR 7.5% Disc (Fraction)	NPV 7.5% Disc (MMUS$)
1	Water	-	10.7	0.839	2.98	0.11	2.809
2	Water	-	10.54	0.825	2.83	0.104	2.668
3	Water	-	3.16	0.348	-	-0.209	-5.364
4	Water	-	3.06	0.336	-	-0.213	-5.469
5	Water	-	0.9	0.107	-	-0.341	-8.746
6	Water	-	0.81	0.096	-	-0.345	-8.83
7	Polymer	600	16.31	0.701	8.2	0.168	4.427
8	Polymer	600	21.68	1.048	13.19	0.3	8.095
9	Polymer	600	14.93	0.575	6.91	0.123	3.23
10	Polymer	600	19.95	0.923	11.59	0.246	6.62
11	Polymer	600	4.01	0.288	-	-0.112	-2.932
12	Polymer	600	4.5	0.32	-	-0.095	-2.544
13	Polymer	1000	16.52	0.714	8.39	0.173	4.554
14	Polymer	1000	21.68	1.048	13.19	0.299	8.091
15	Polymer	1000	8.36	0.381	0.08	0.017	0.521
16	Polymer	1000	13.39	0.714	5.48	0.136	4.193
17	Polymer	1000	1.77	0.129	-	-0.188	-5.703
18	Polymer	1000	2.12	0.151	-	-0.174	-5.385
19	Polymer	1500	16.72	0.727	8.58	0.178	4.681
20	Polymer	1500	21.67	1.047	13.18	0.299	8.087
21	Polymer	1500	8.5	0.39	0.93	0.02	0.605
22	Polymer	1500	13.41	0.714	5.5	0.136	4.206
23	Polymer	1500	1.87	0.136	-	-0.186	-5.635
24	Polymer	1500	2.11	0.151	-	-0.174	-5.386

APPENDIX D

RESERVOIR SIMULATION RESULT

Graph descriptions are shown in Table D.1

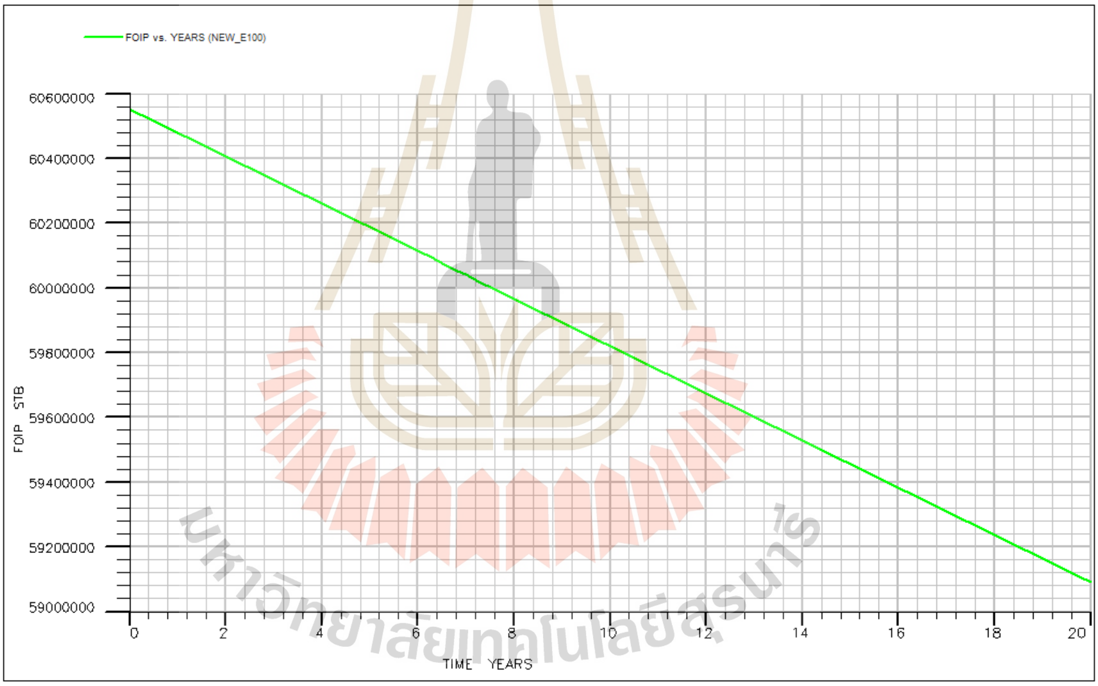
Table D.1 Display parameter description

Fig.	Parameters	Description	Common Refer
1	FOIP	Field Oil in Place	Original of Oil in Place
	FWIP	Field Water in Place	Original of Water in Place
2	FOPT	Field Oil Production Total	Cumulative Oil Production
	FWPT	Field Water Production Total	Cumulative Water Production
3	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

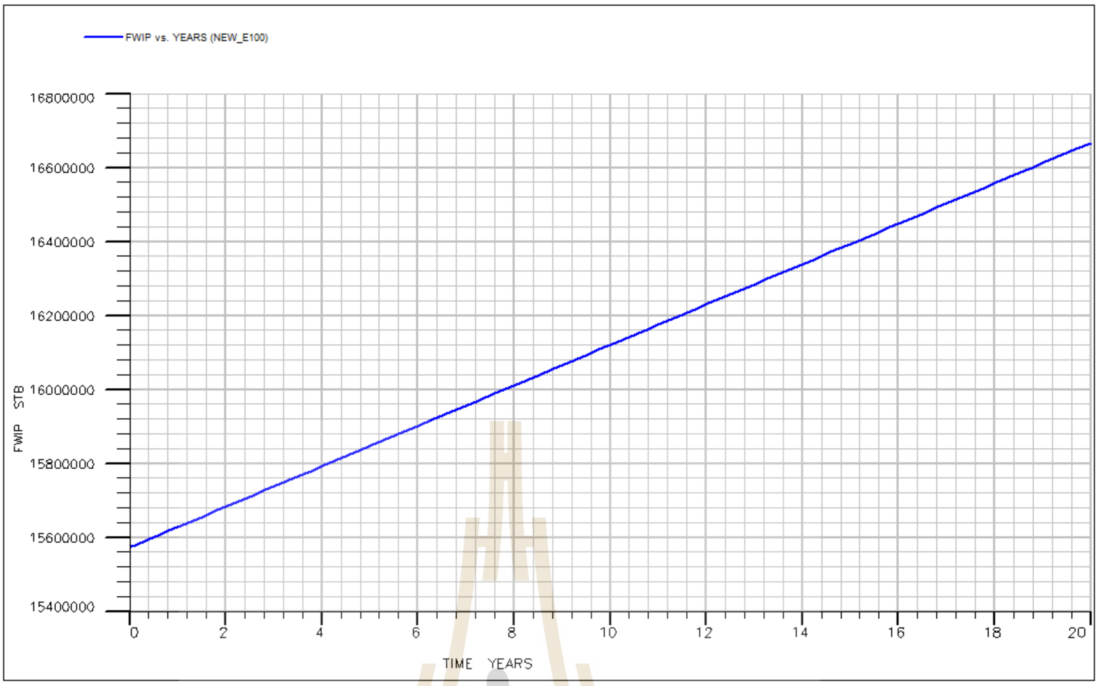
D.1 Reservoir simulation result for case water flooding

D.1.1 Result of Model Case 1

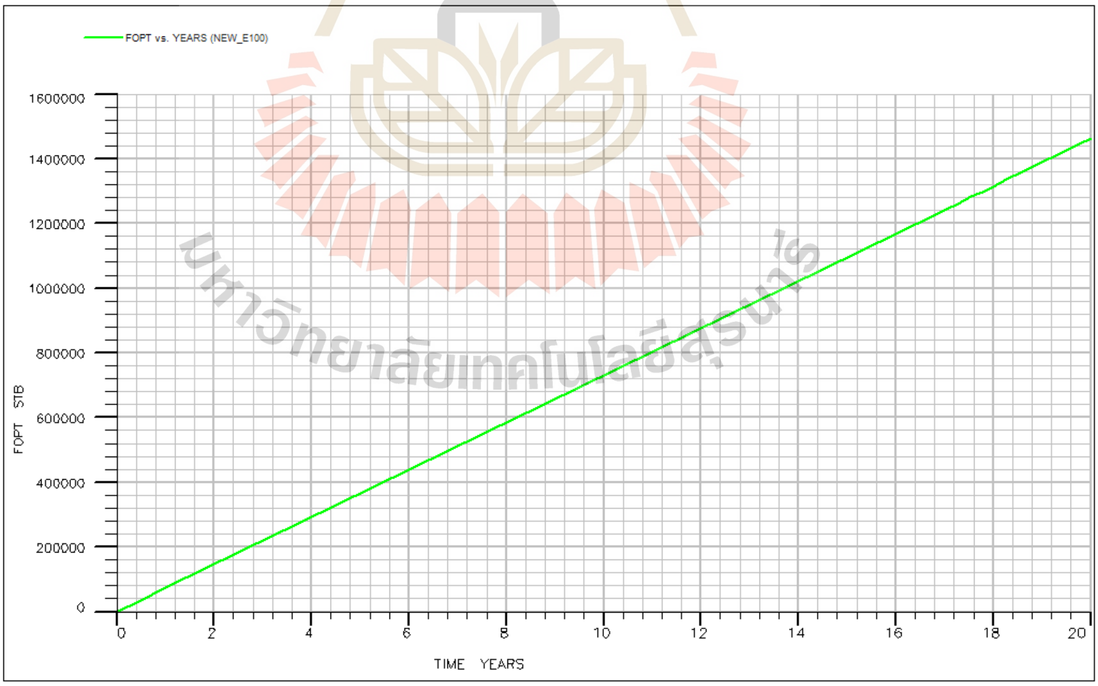
Model case 1 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 150 bbl/d. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.1 - D.7:



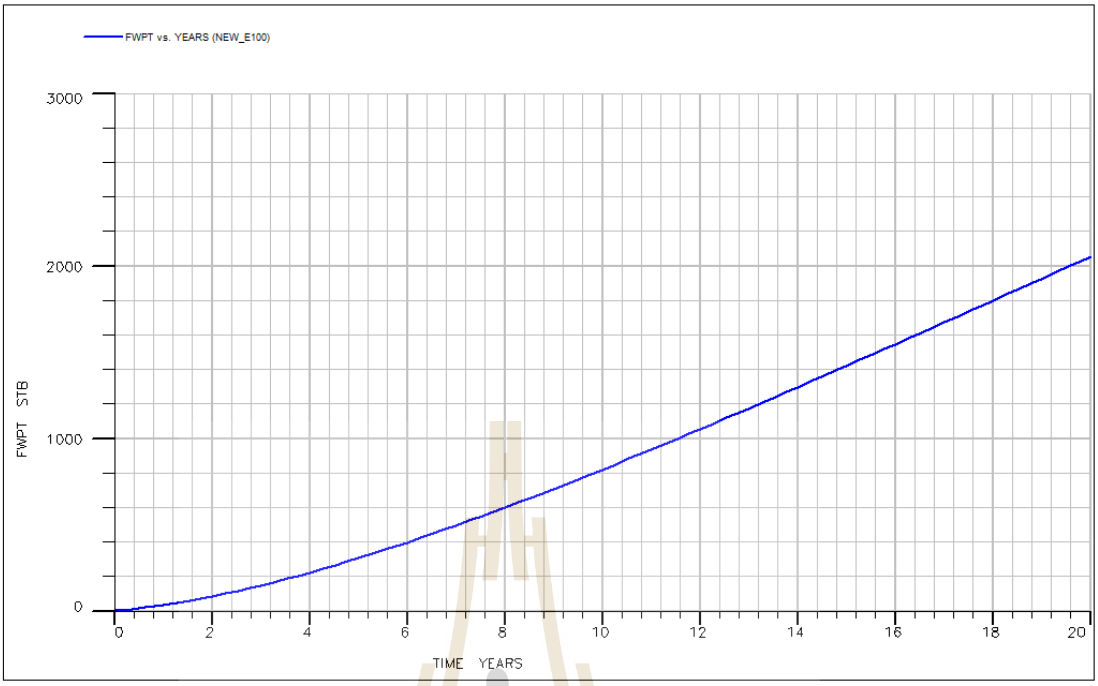
Figures D.1 Oil in place Vs. time of model case 1



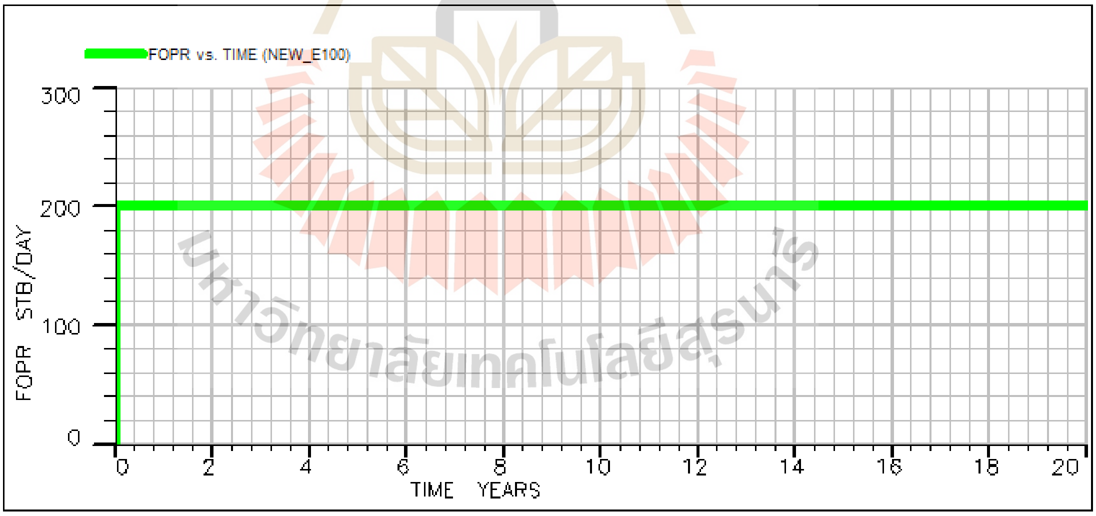
Figures D.2 Water in place Vs. time of model case 1



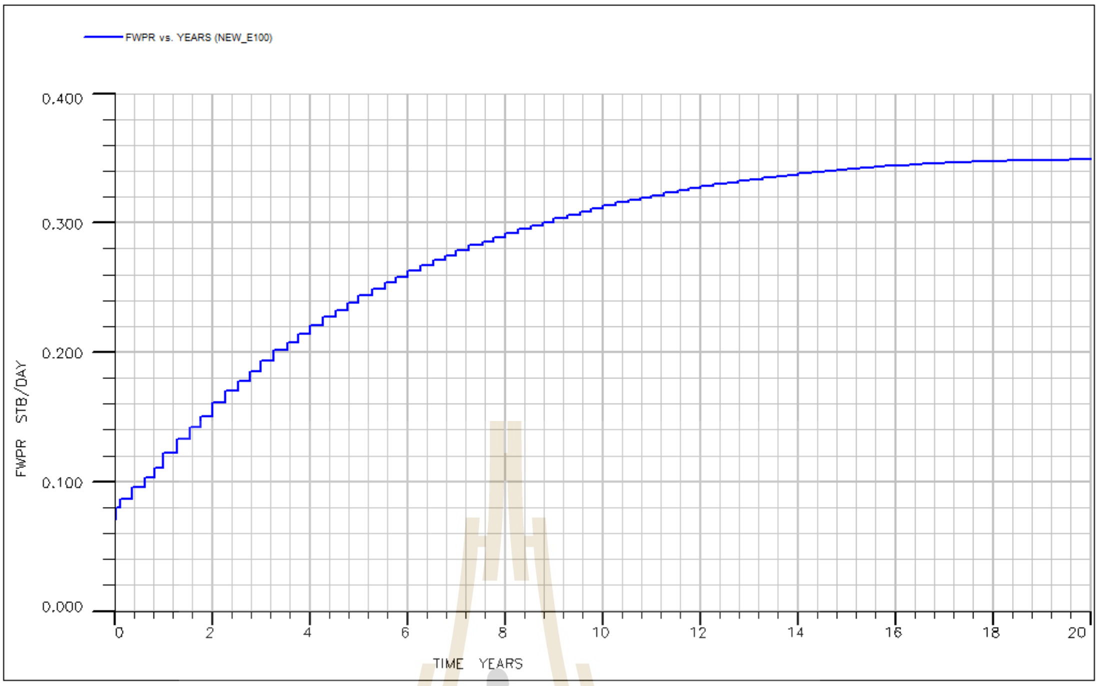
Figures D.3 Oil production total Vs. time of model case 1



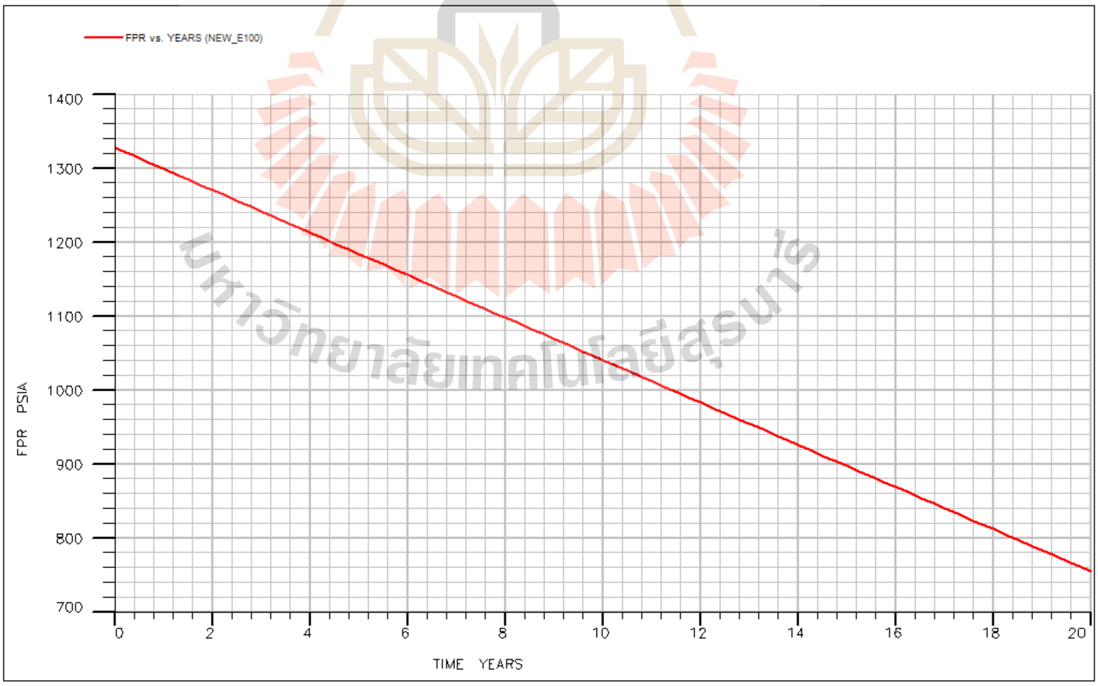
Figures D.4 Water production total Vs. time of model case 1



Figures D.5 Oil production rate Vs. time of model case 1



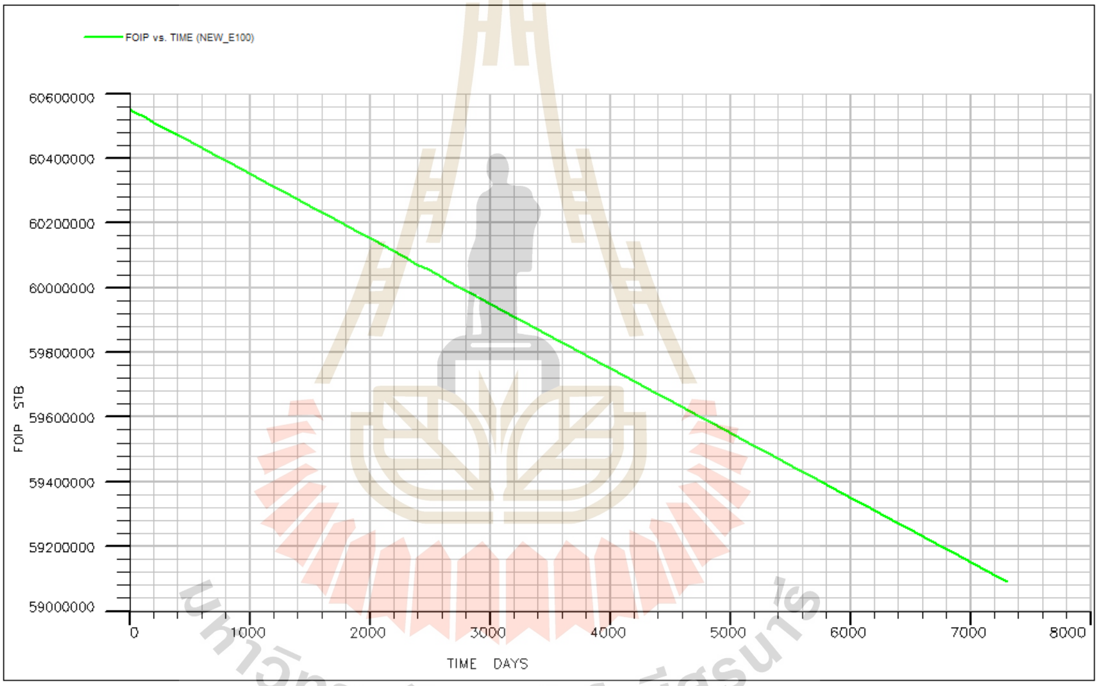
Figures D.6 Water production rate Vs. time of case 1



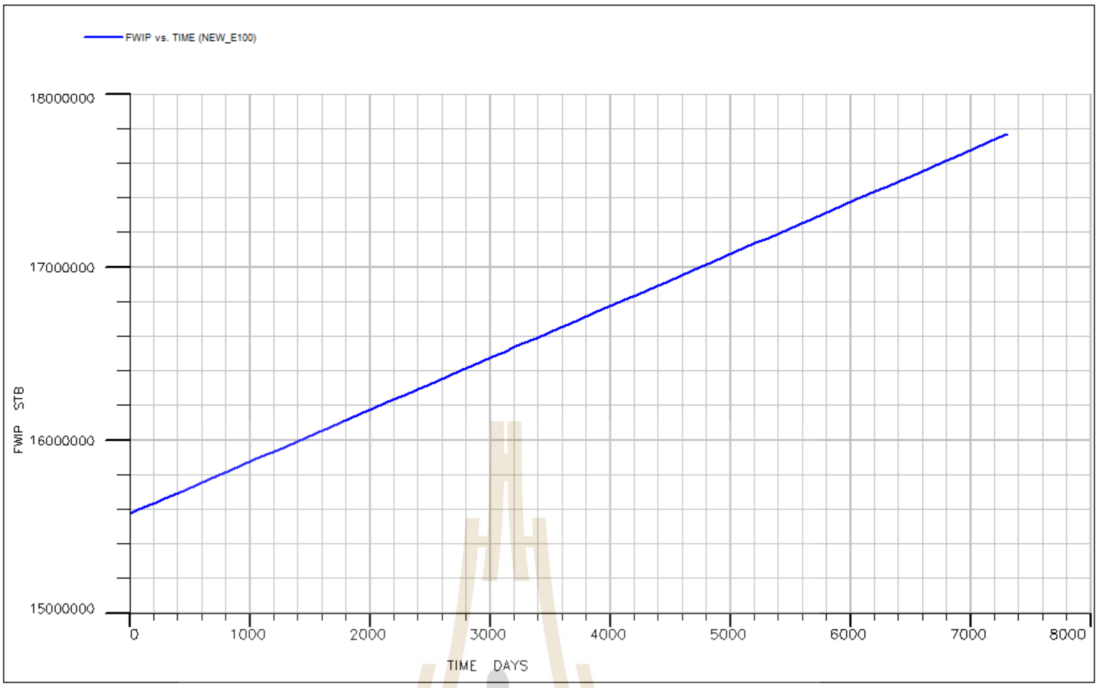
Figures D.7 Field pressure Vs. time of model case 1

D.1.2 Result of Model Case 2

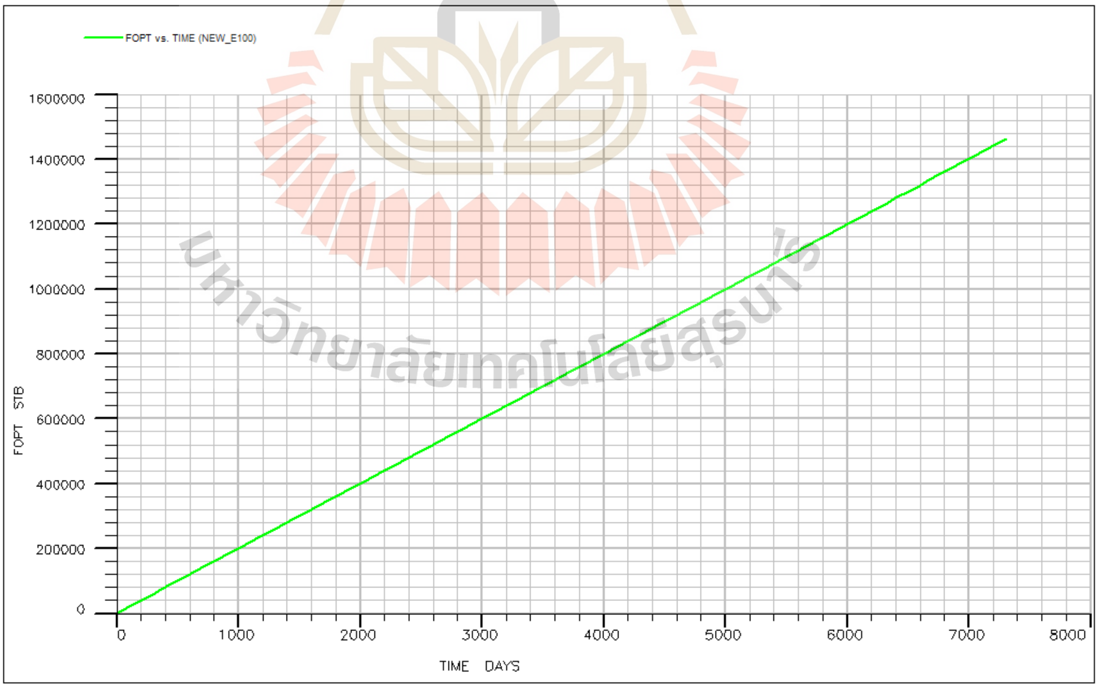
Model case 2 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 300 bbl/d. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.8 - D.14:



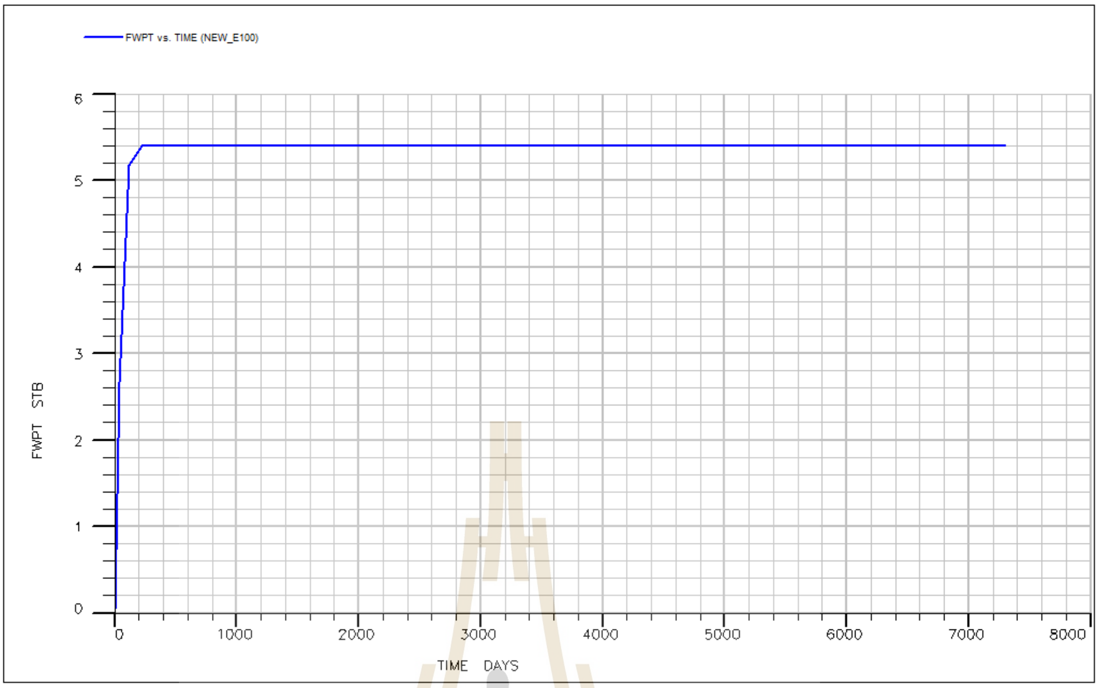
Figures D.8 Oil in place Vs. time of model case 2



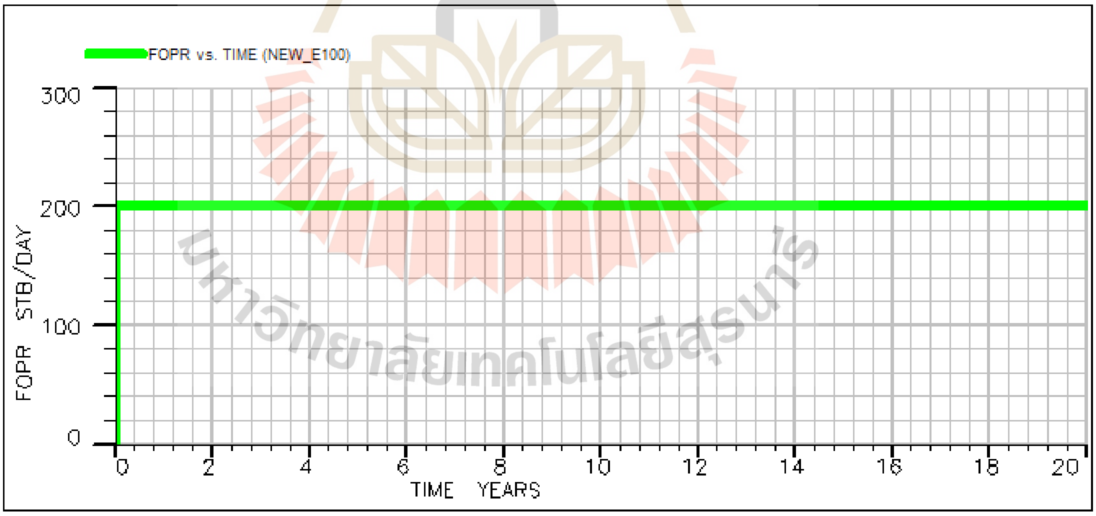
Figures D.9 Water in place Vs. time of model case 2



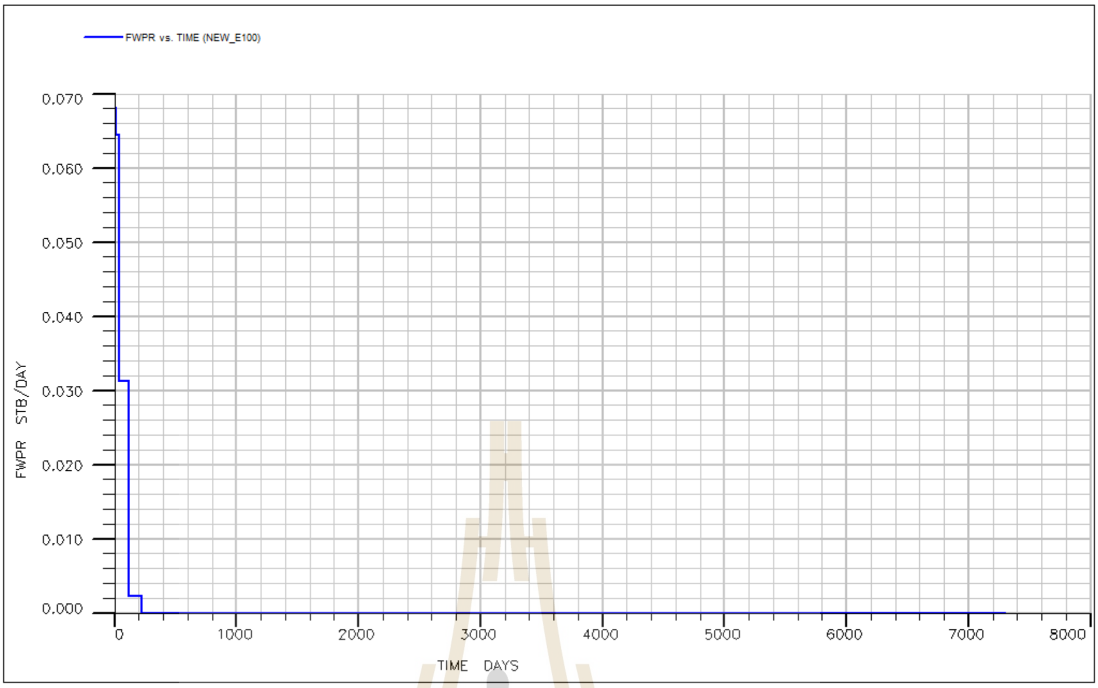
Figures D.10 Oil production total Vs. time of model case 2



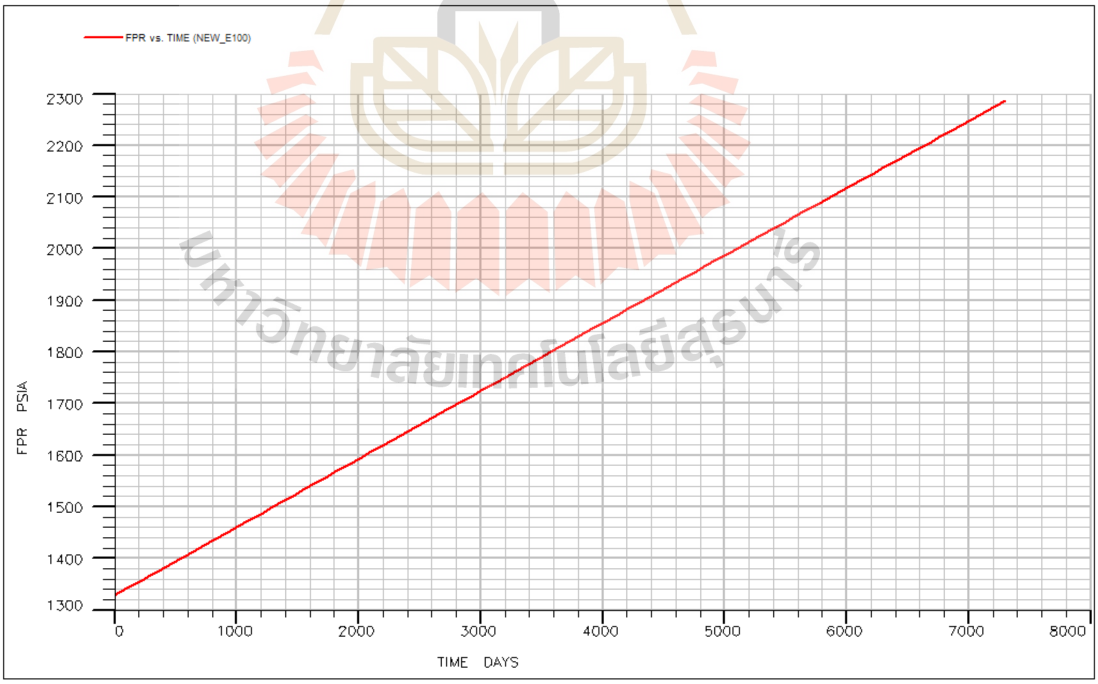
Figures D.11 Water production total Vs. time of model case 2



Figures D.12 Oil production rate Vs. time of model case 2



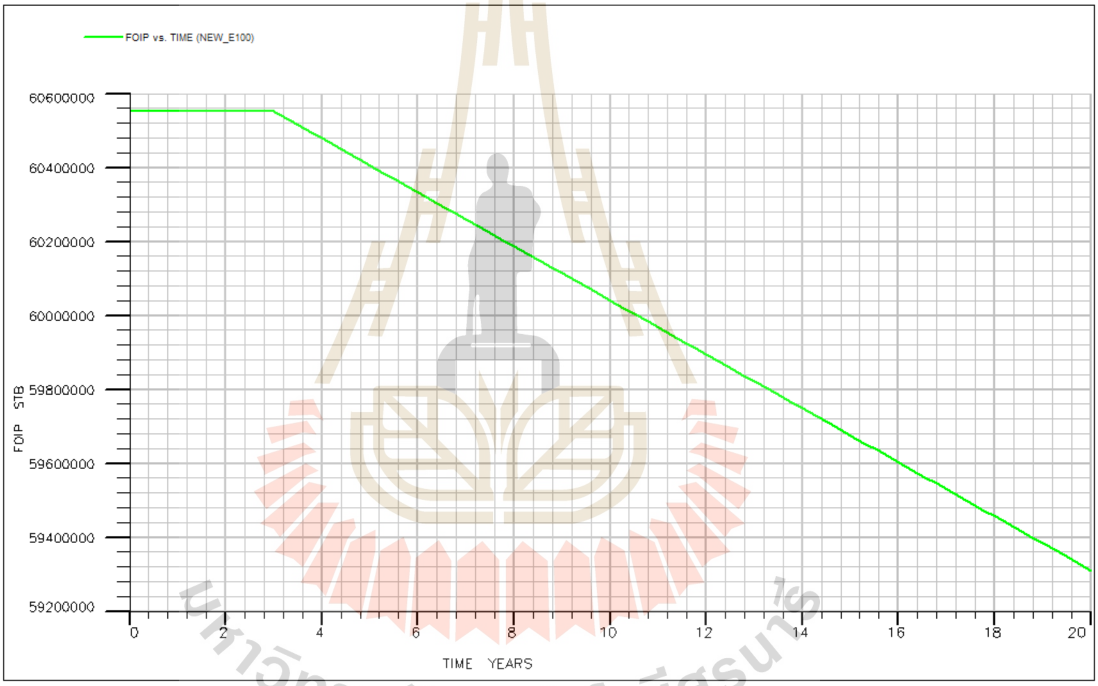
Figures D.13 Water production rate Vs. time of case 2



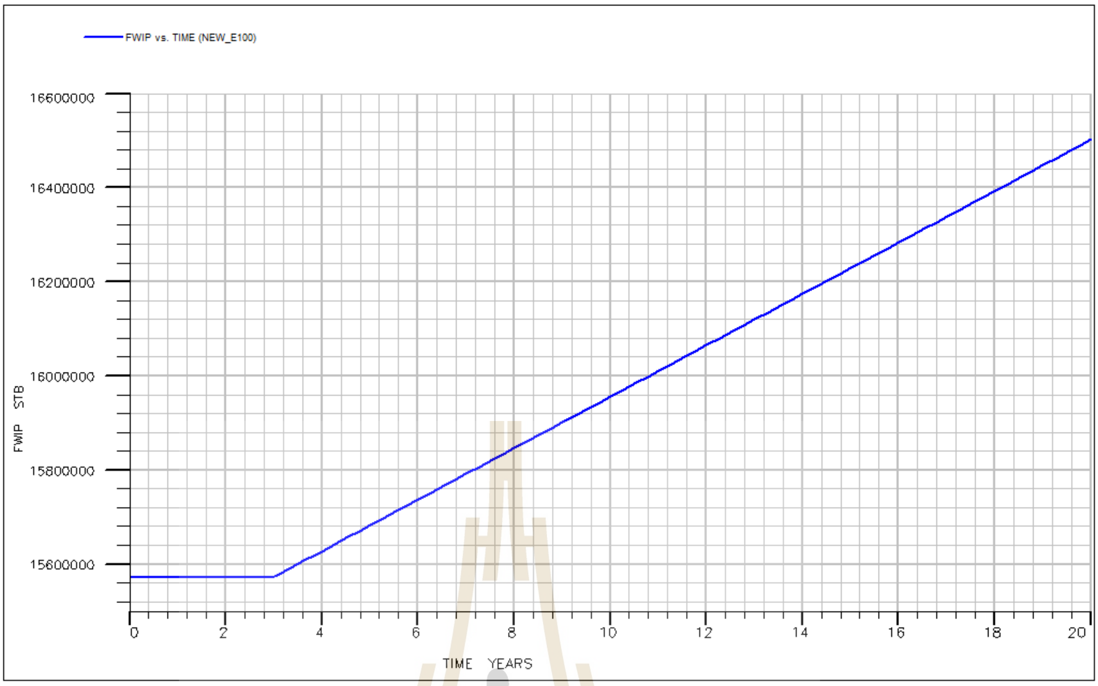
Figures D.14 Field pressure Vs. time of model case 2

D.1.3 Result of Model Case 3

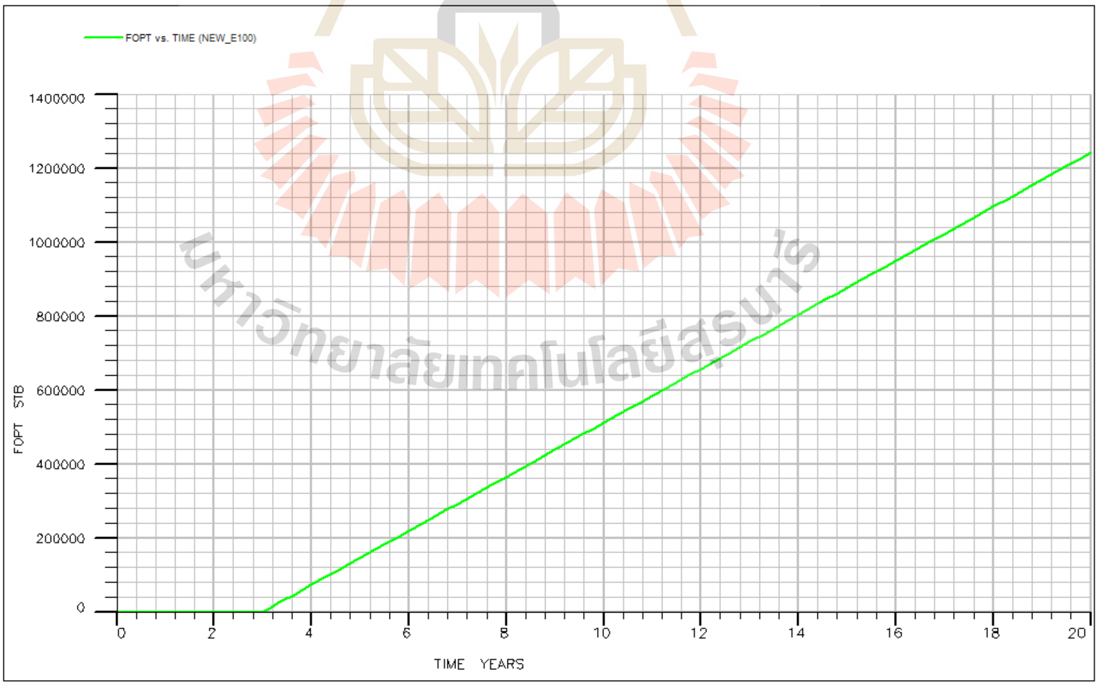
Model case 3 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 150 bbl/d. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.15 - D.21:



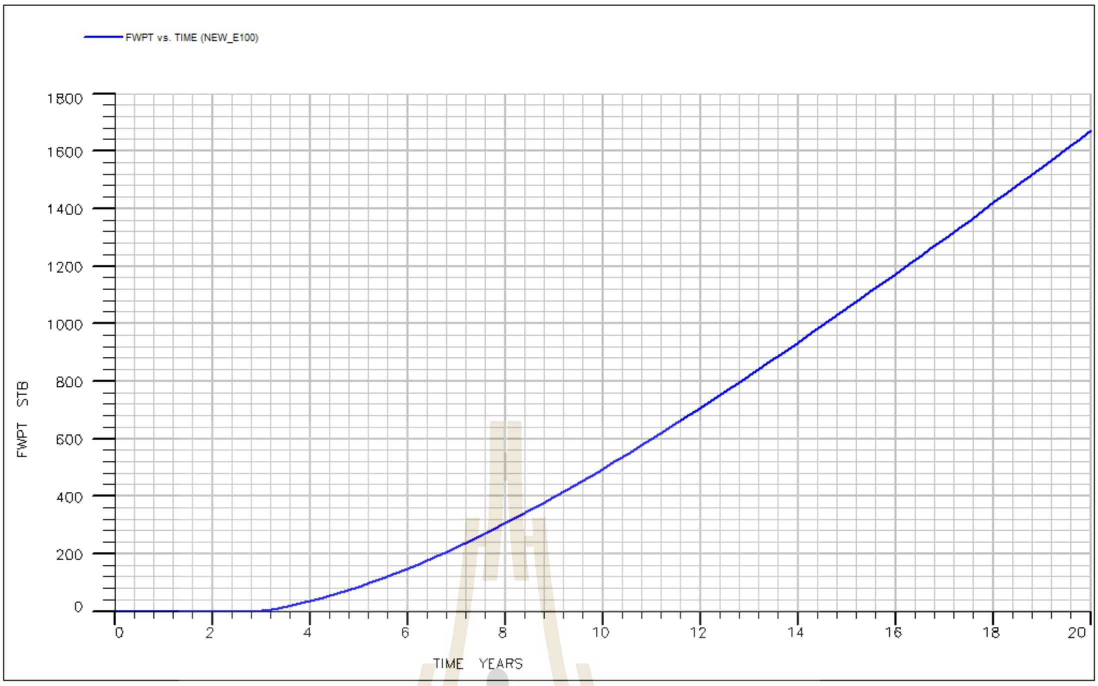
Figures D.15 Oil in place Vs. time of model case 3



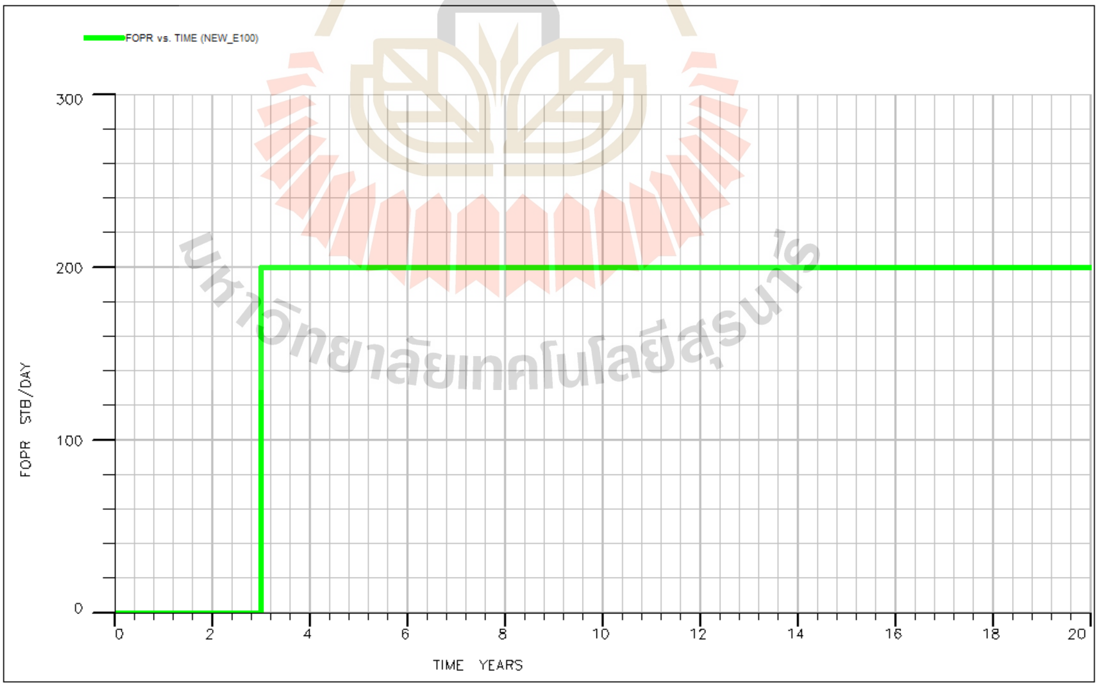
Figures D.16 Water in place Vs. time of model case 3



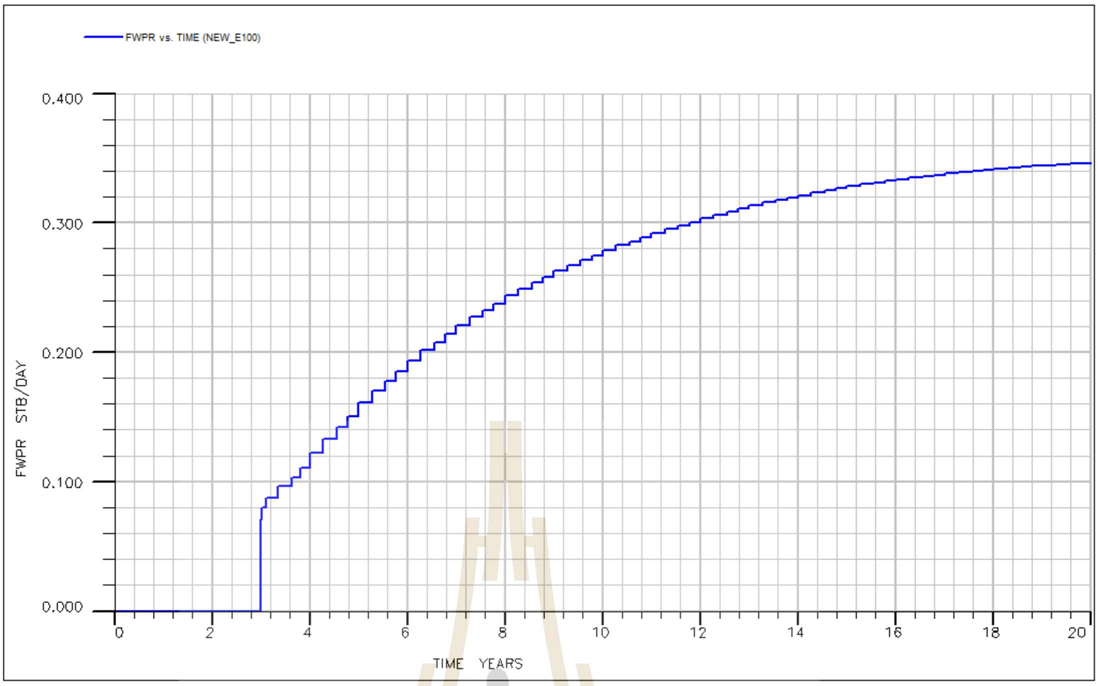
Figures D.17 Oil production total Vs. time of model case 3



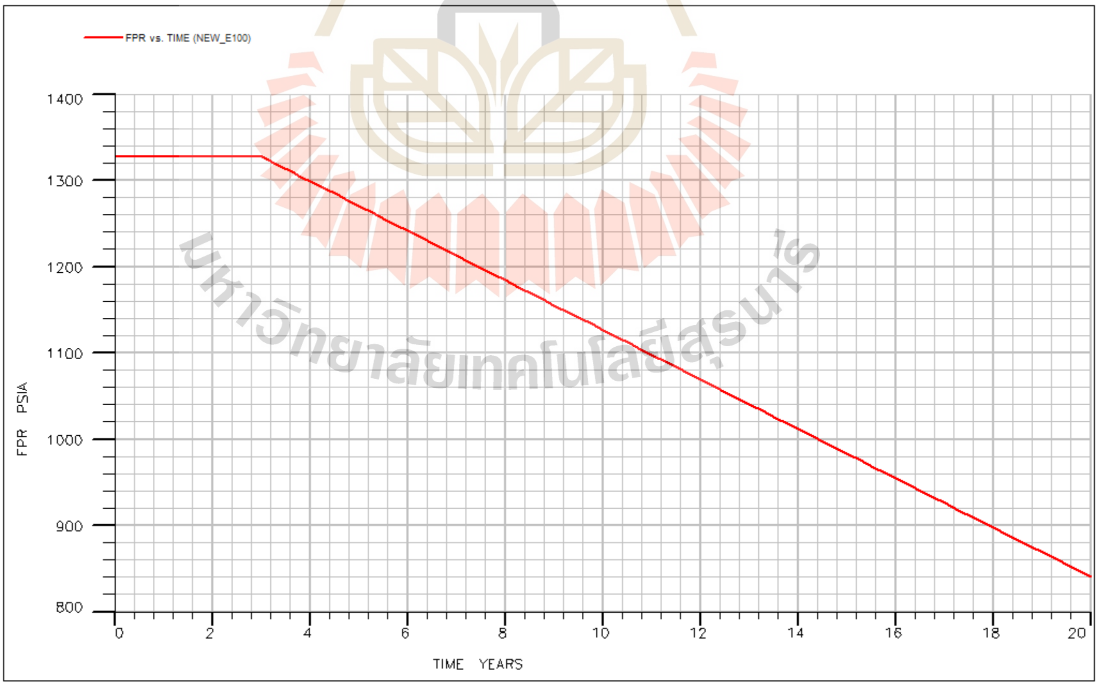
Figures D.18 Water production total Vs. time of model case 3



Figures D.19 Oil production rate Vs. time of model case 3



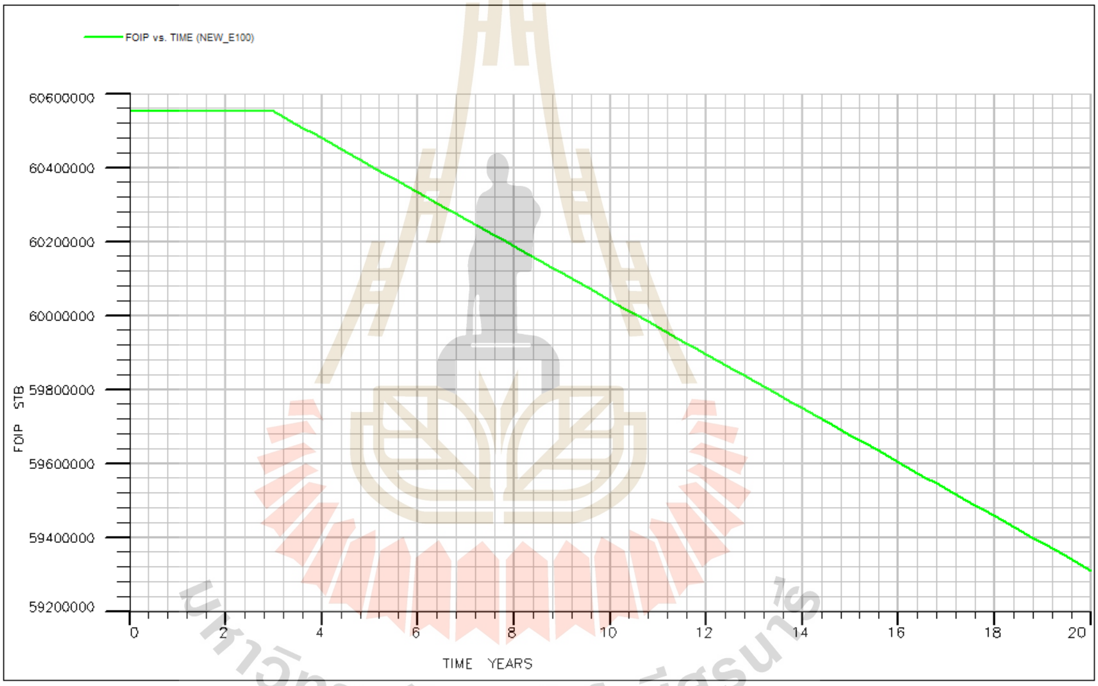
Figures D.20 Water production rate Vs. time of case 3



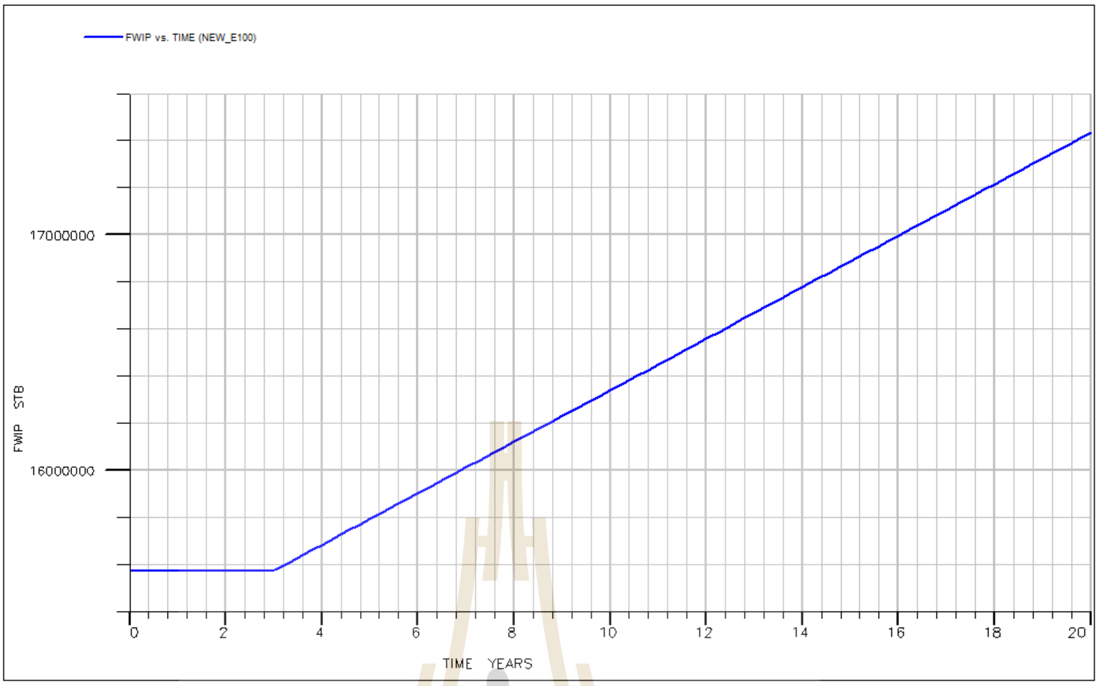
Figures D.21 Field pressure Vs. time of model case 3

D.1.4 Result of Model Case 4

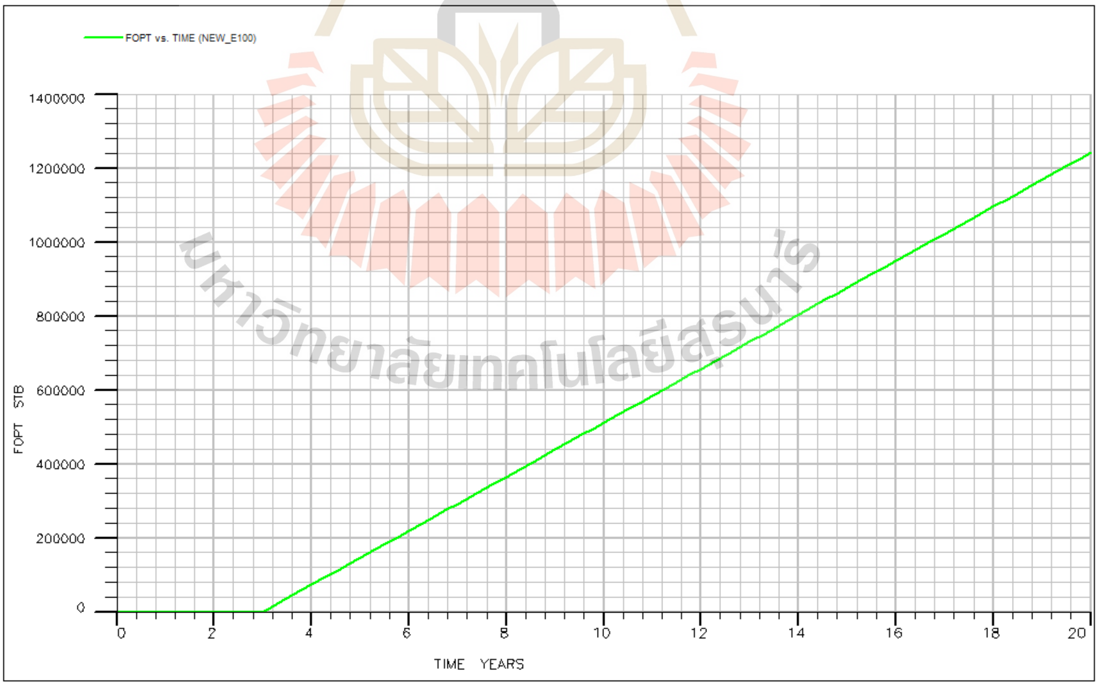
Model case 4 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 300 bbl/d. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.22 - D.28:



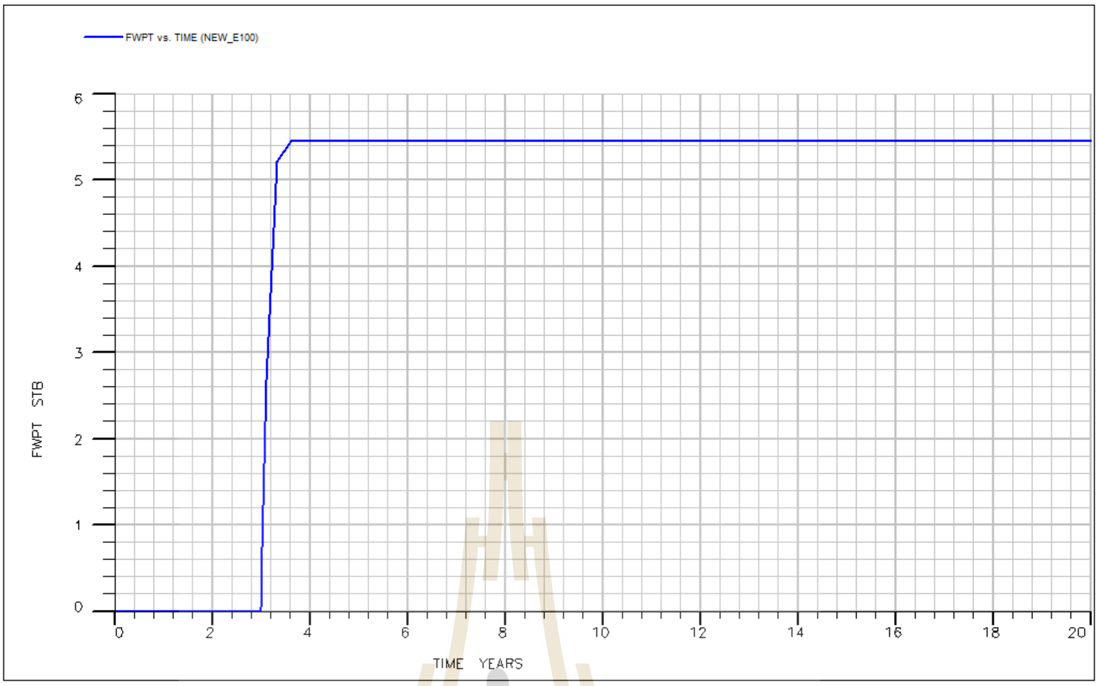
Figures D.22 Oil in place Vs. time of model case 4



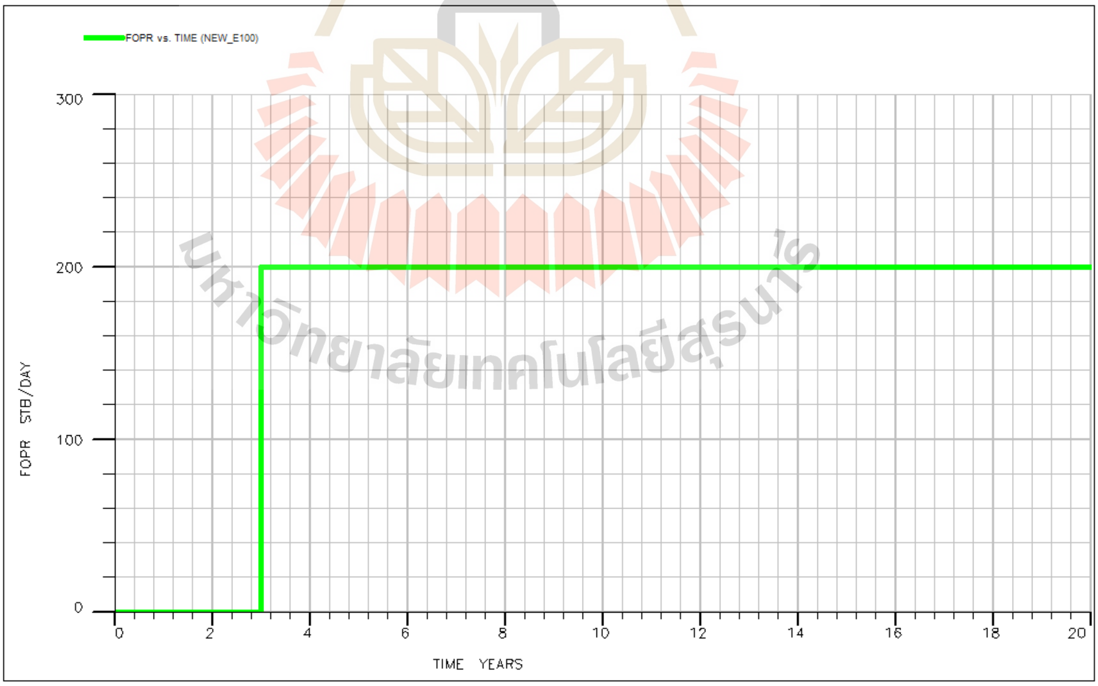
Figures D.23 Water in place Vs. time of model case 4



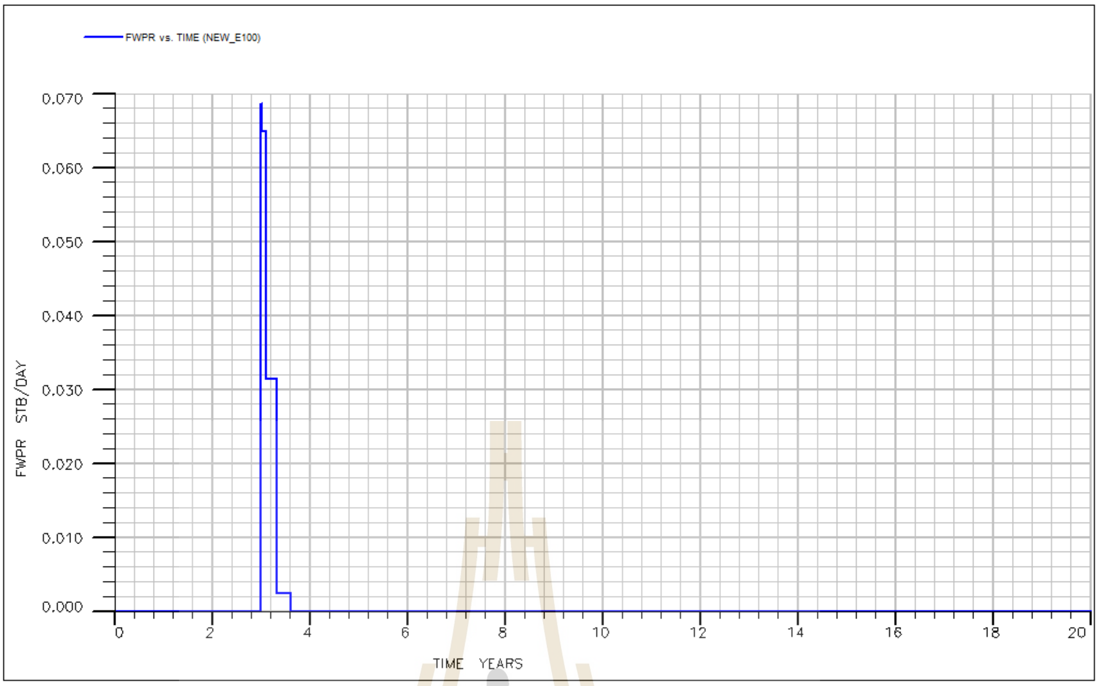
Figures D.24 Oil production total Vs. time of model case 4



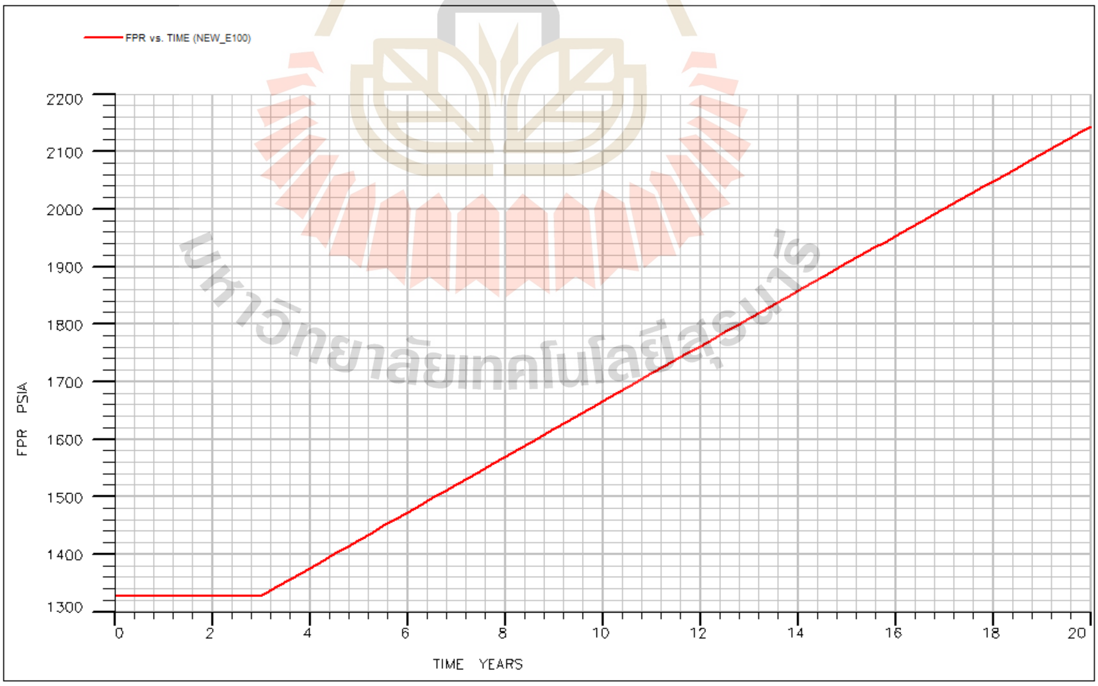
Figures D.25 Water production total Vs. time of model case 4



Figures D.26 Oil production rate Vs. time of model case 4



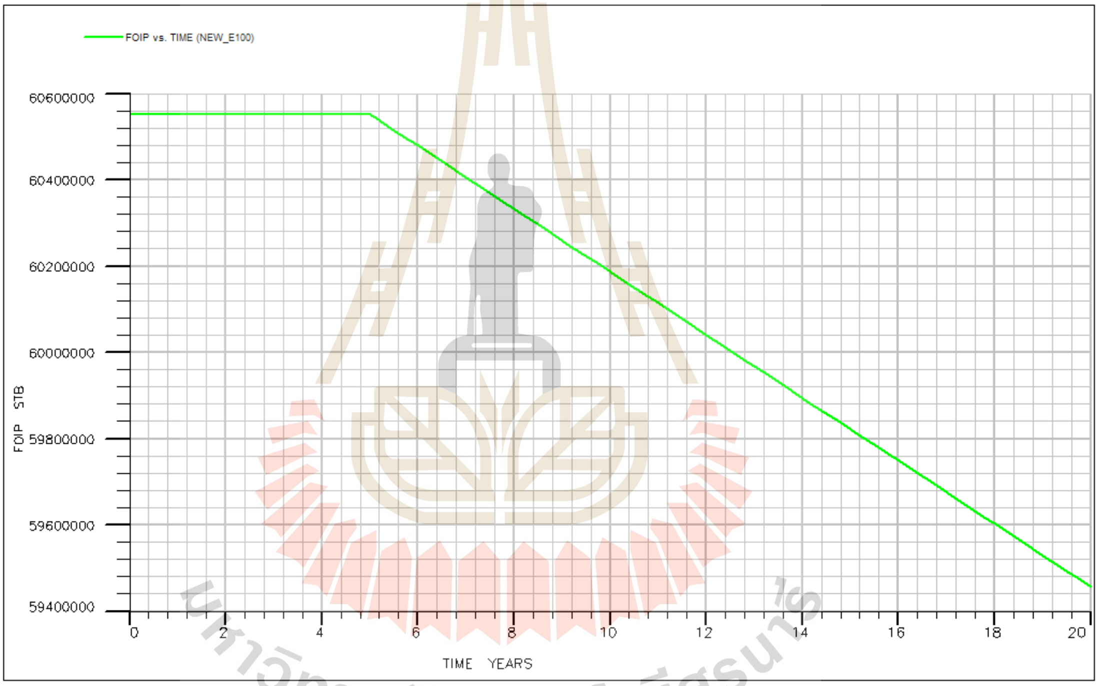
Figures D.27 Water production rate Vs. time of case 4



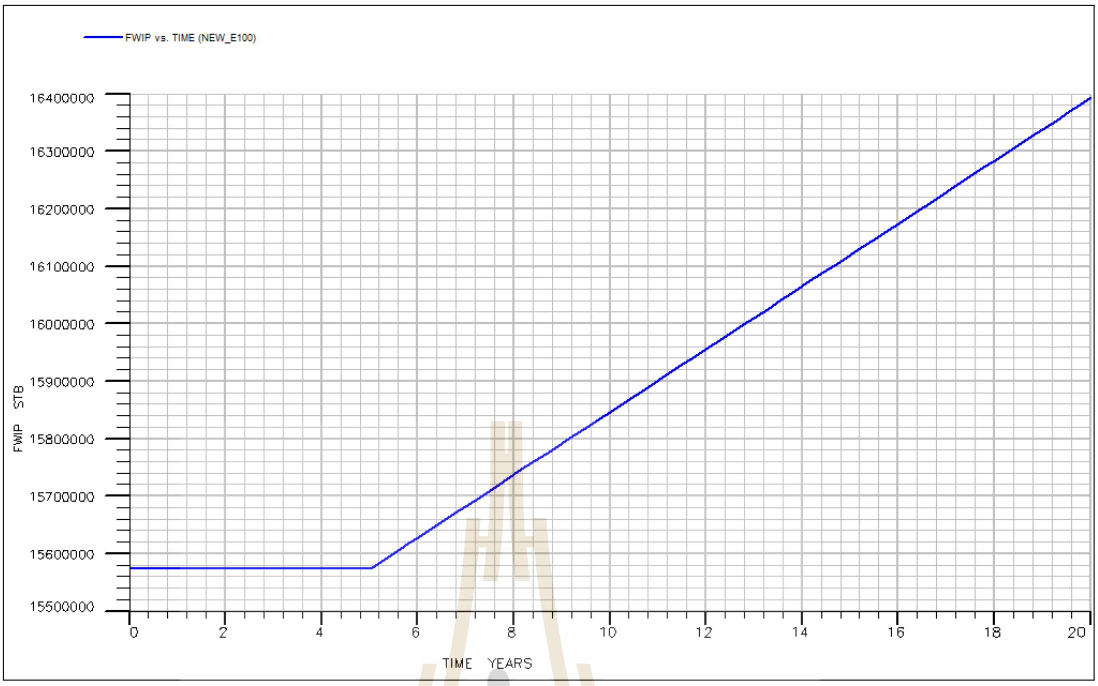
Figures D.28 Field pressure Vs. time of model case 4

D.1.5 Result of Model Case 5

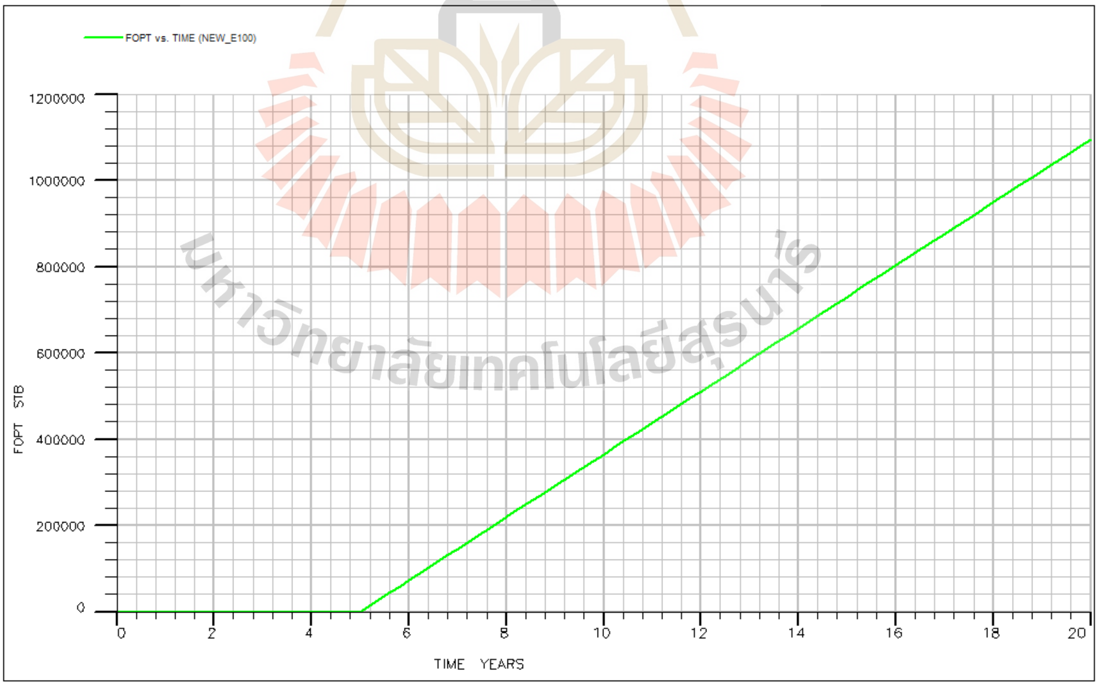
Model case 5 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 150 bbl/d. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.29 - D.35:



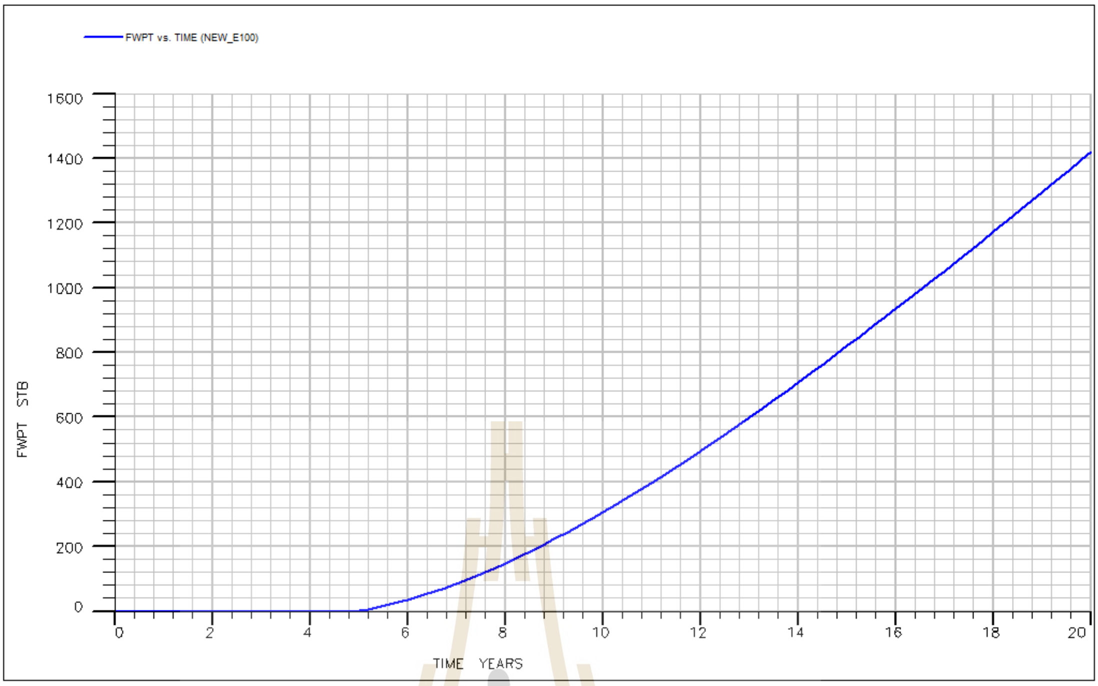
Figures D.29 Oil in place Vs. time of model case 5



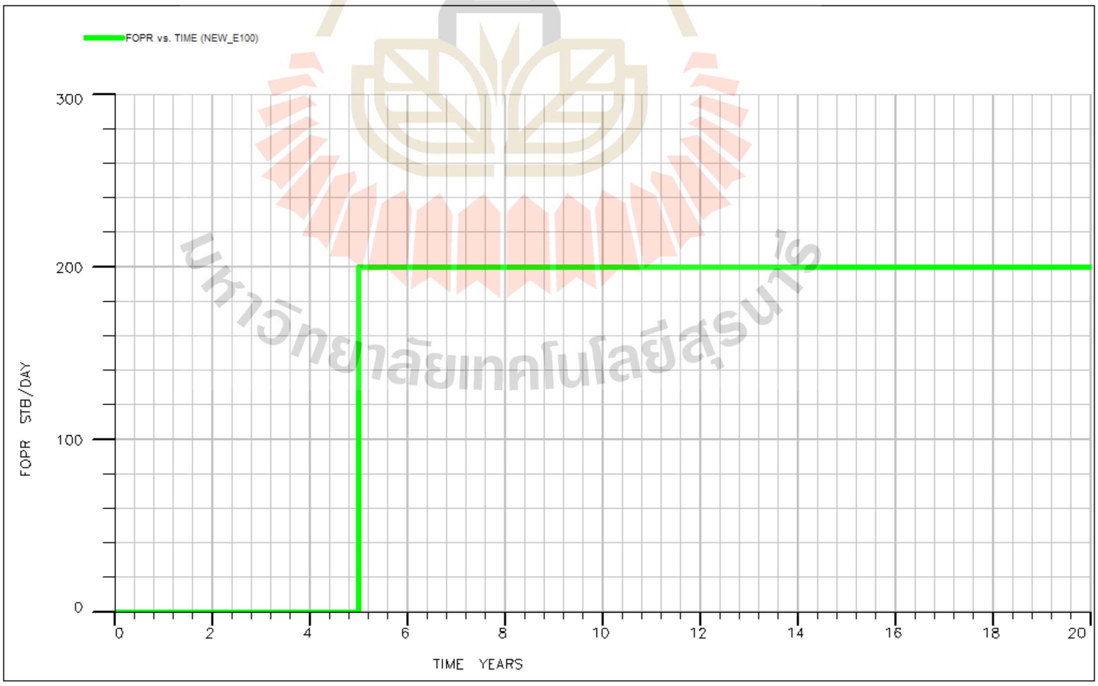
Figures D.30 Water in place Vs. time of model case 5



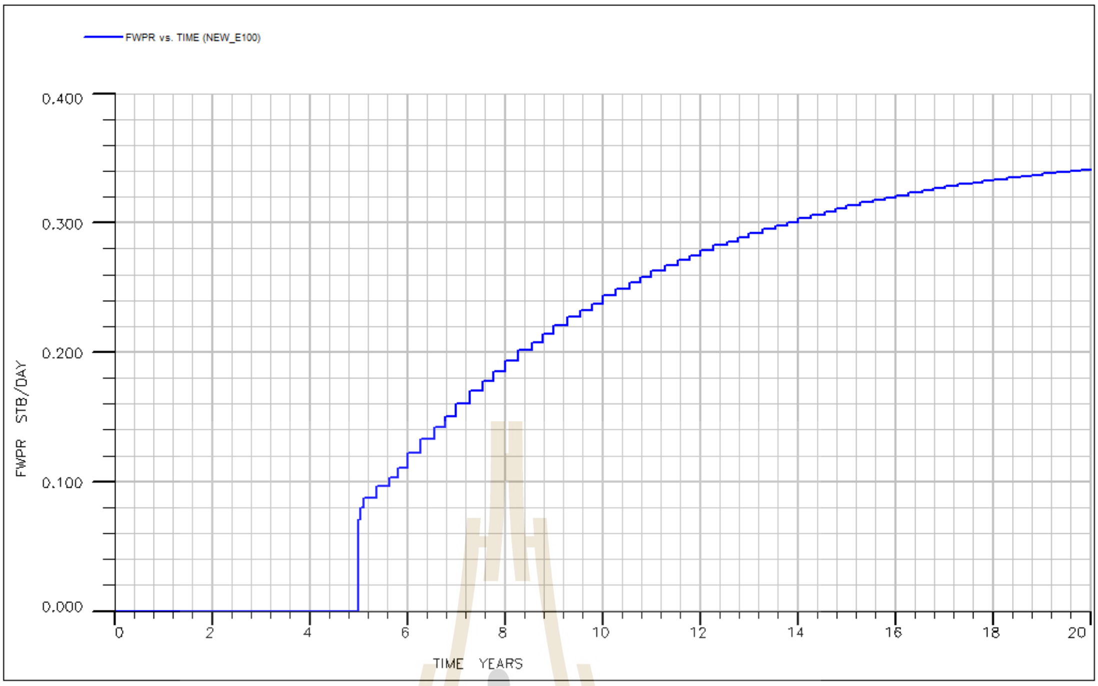
Figures D.31 Oil production total Vs. time of model case 5



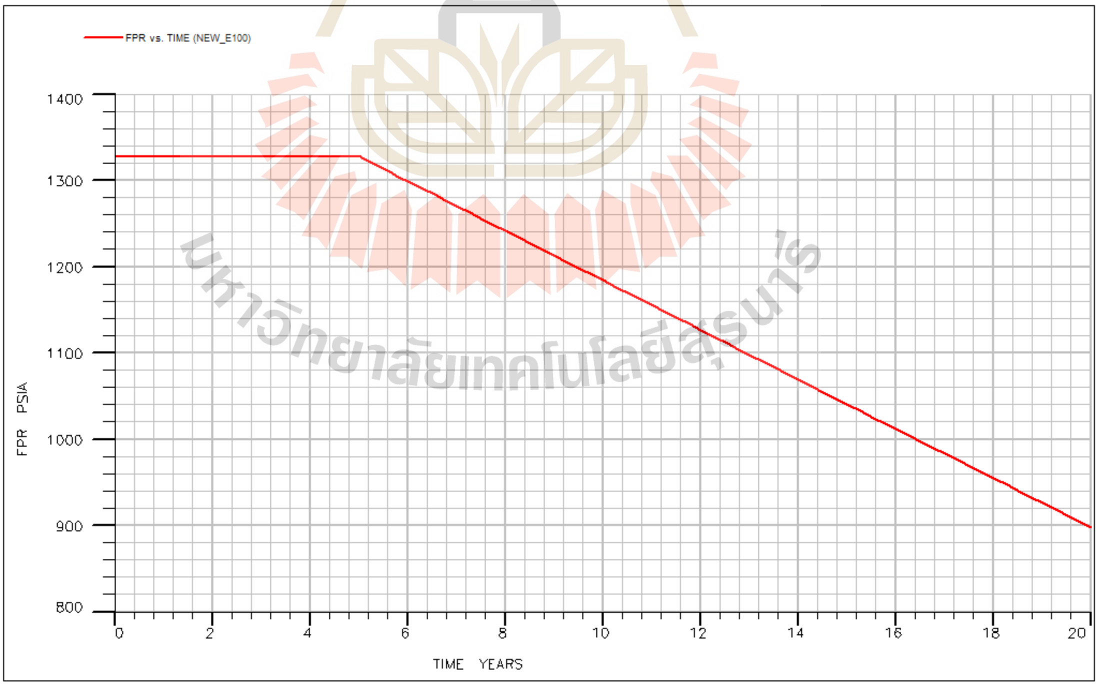
Figures D.32 Water production total Vs. time of model case 5



Figures D.33 Oil production rate Vs. time of model case 5



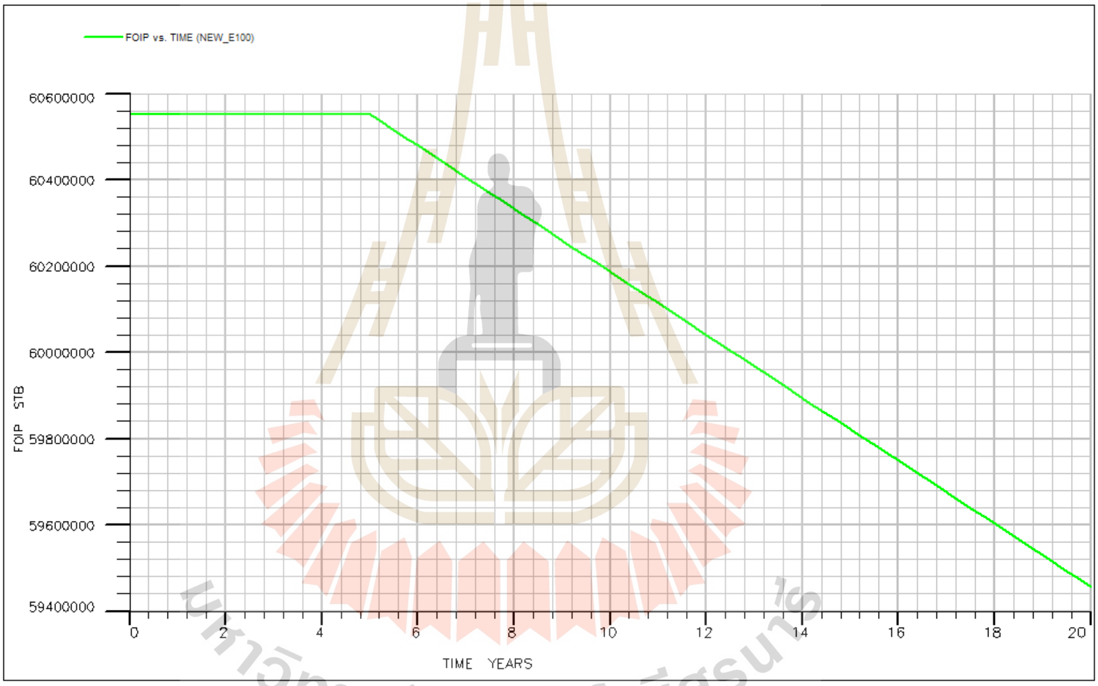
Figures D.34 Water production rate Vs. time of case 5



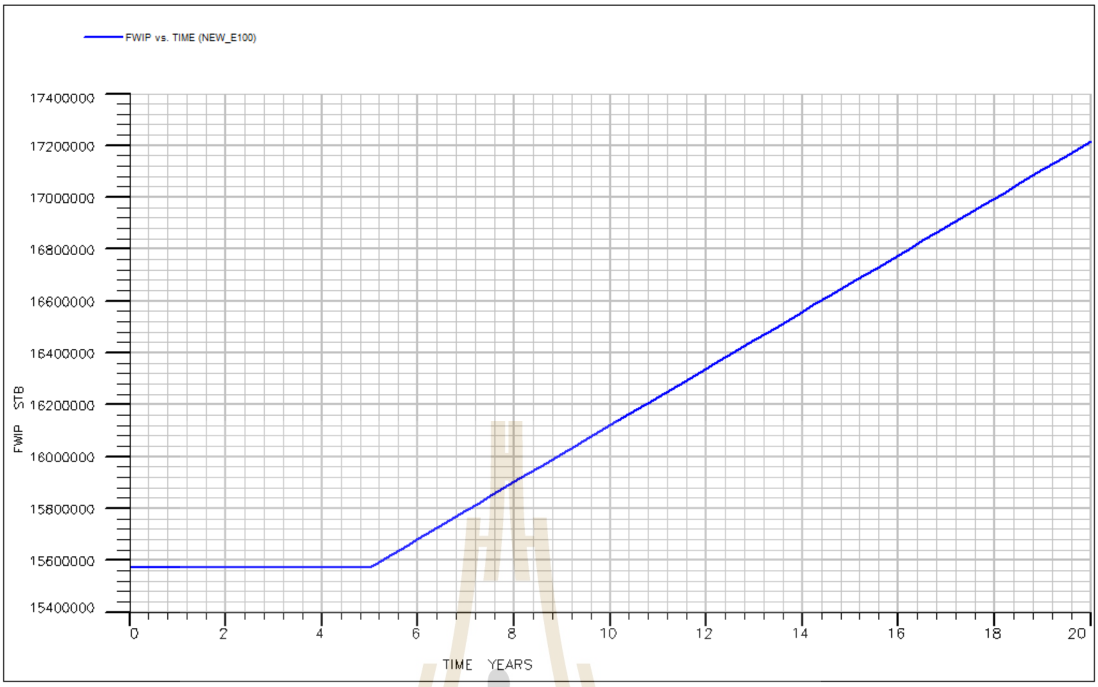
Figures D.35 Field pressure Vs. time of model case 5

D.1.6 Result of Model Case 6

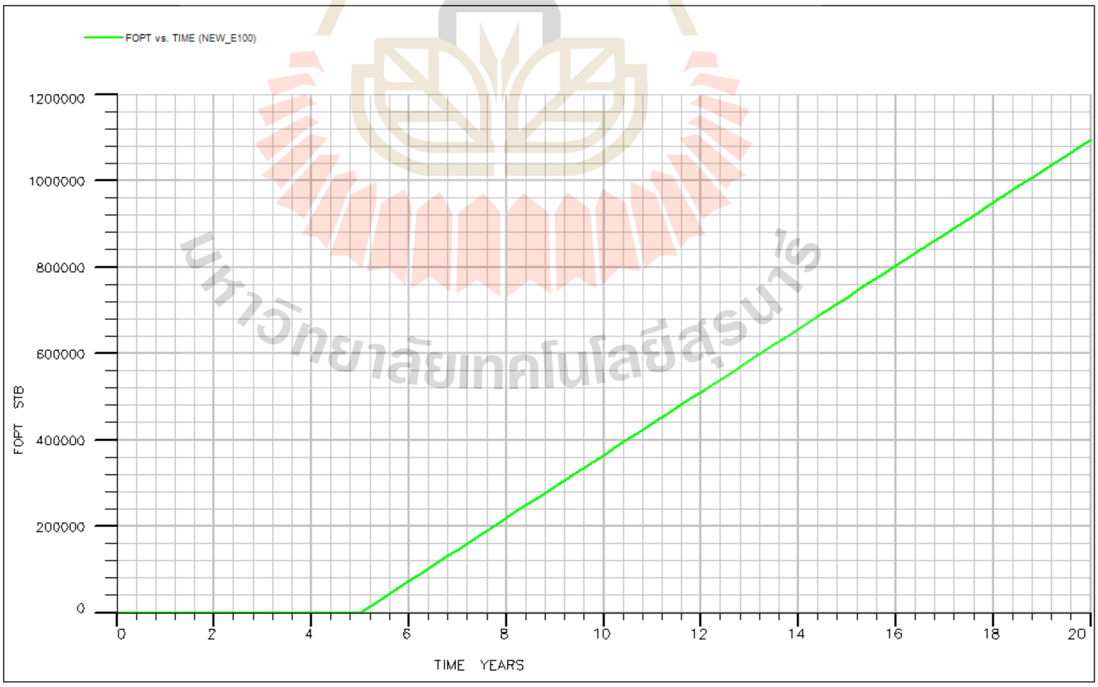
Model case 6 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the water injection rate of 300 bbl/d. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.36 - D.42:



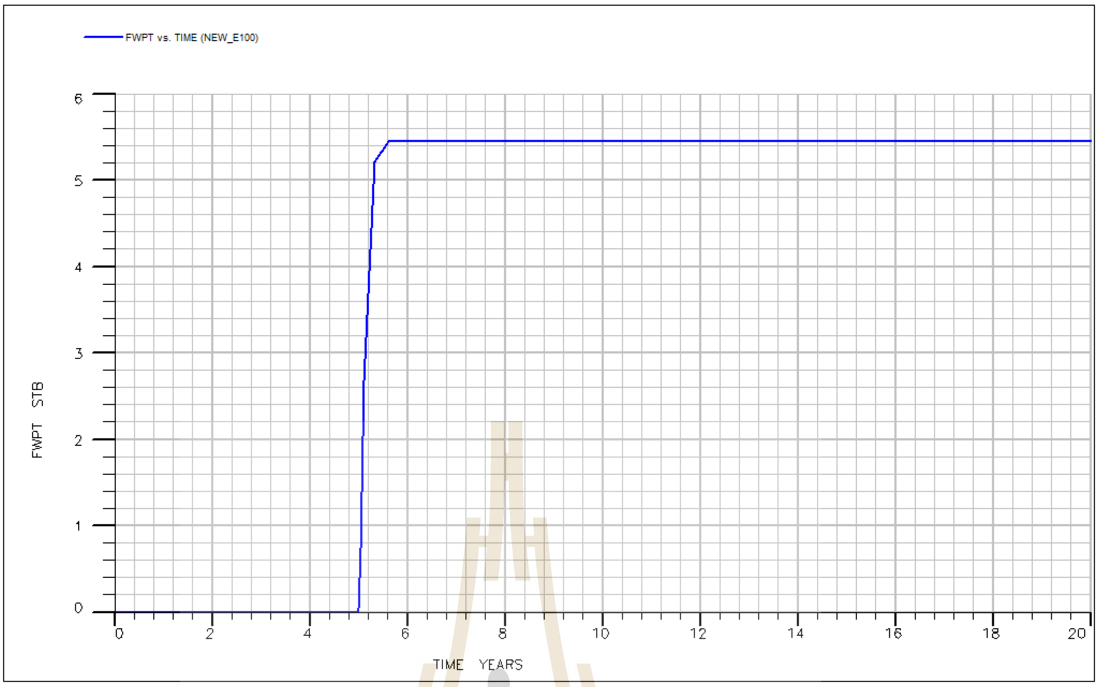
Figures D.36 Oil in place Vs. time of model case 6



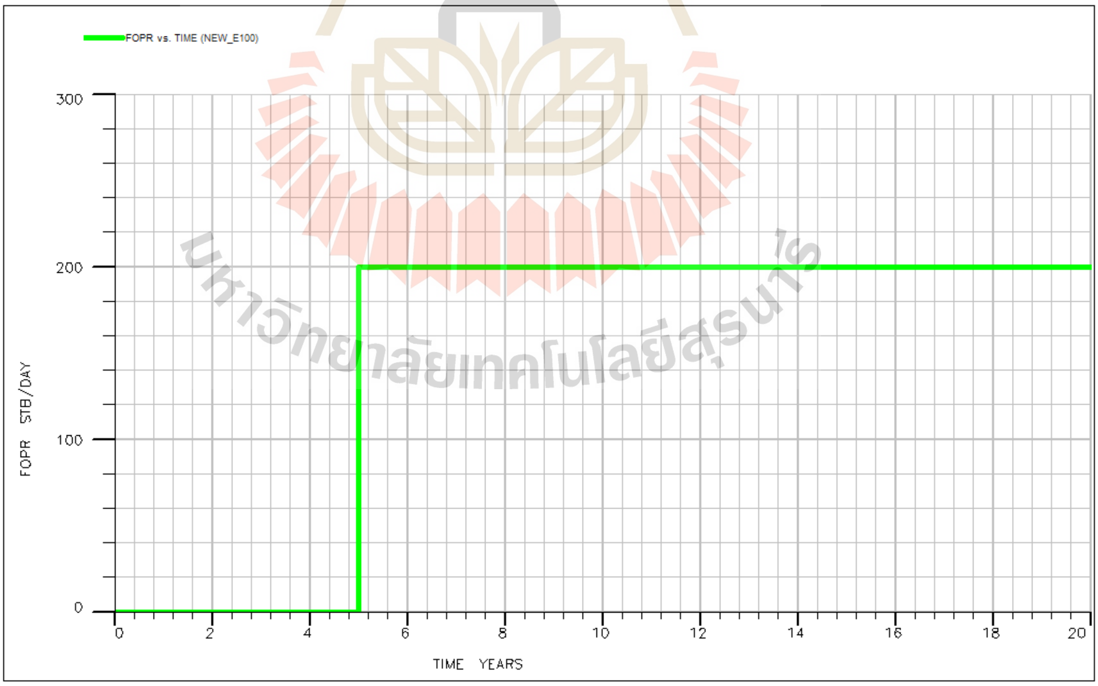
Figures D.37 Water in place Vs. time of model case 6



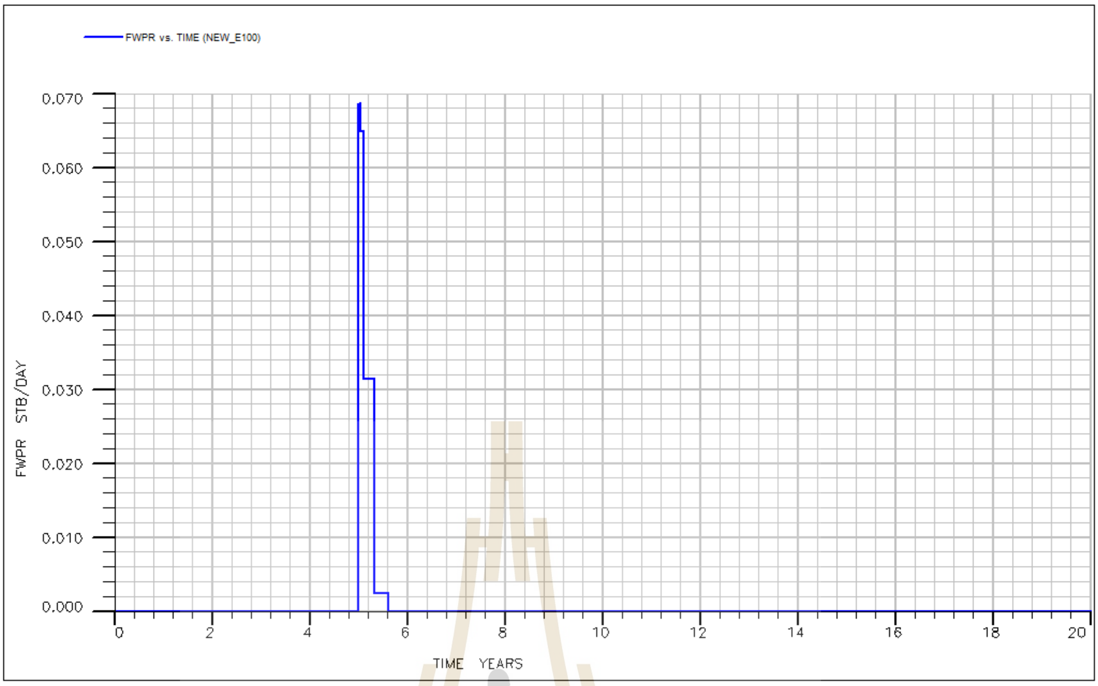
Figures D.38 Oil production total Vs. time of model case 6



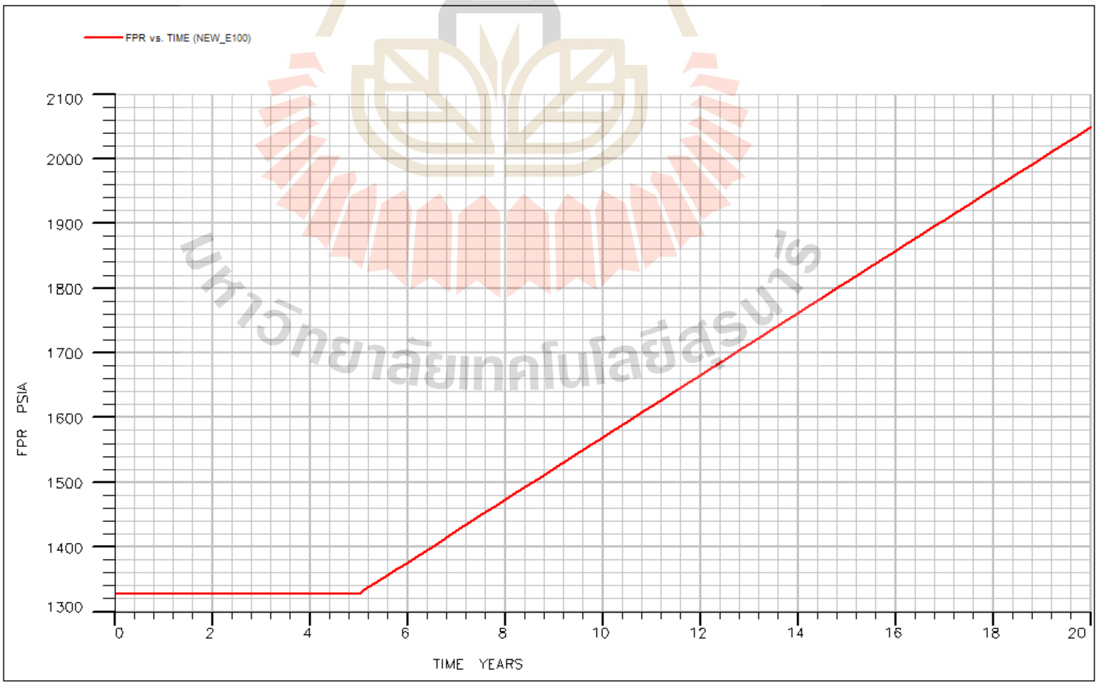
Figures D.39 Water production total Vs. time of model case 6



Figures D.40 Oil production rate Vs. time of model case 6



Figures D.41 Water production rate Vs. time of case 6

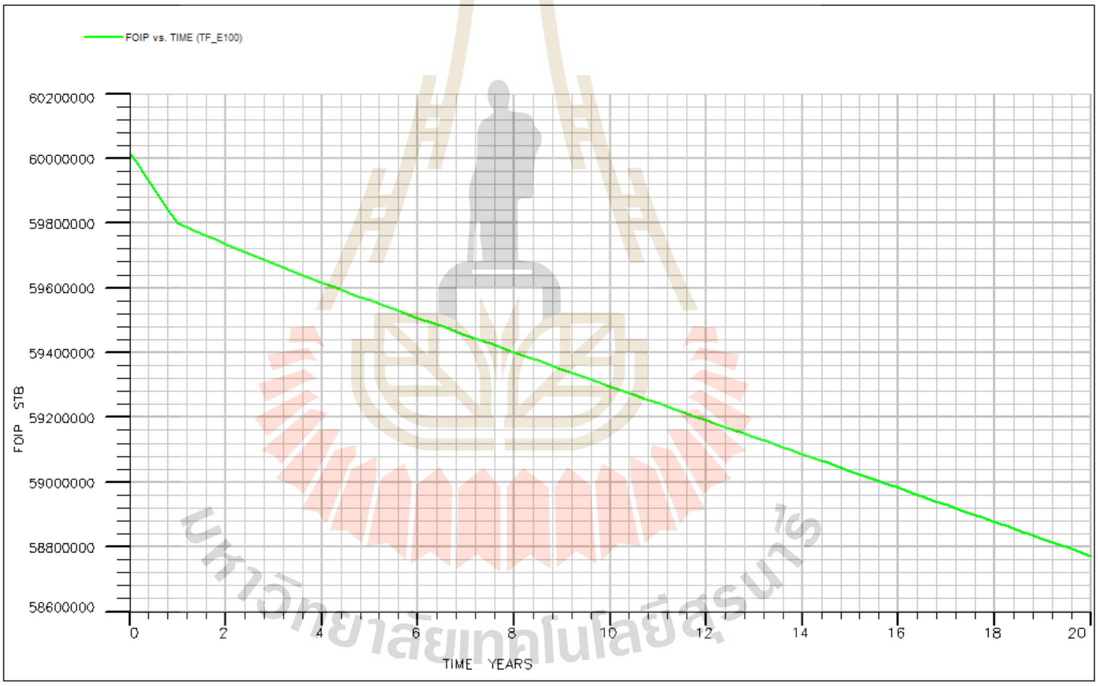


Figures D.42 Field pressure Vs. time of model case 6

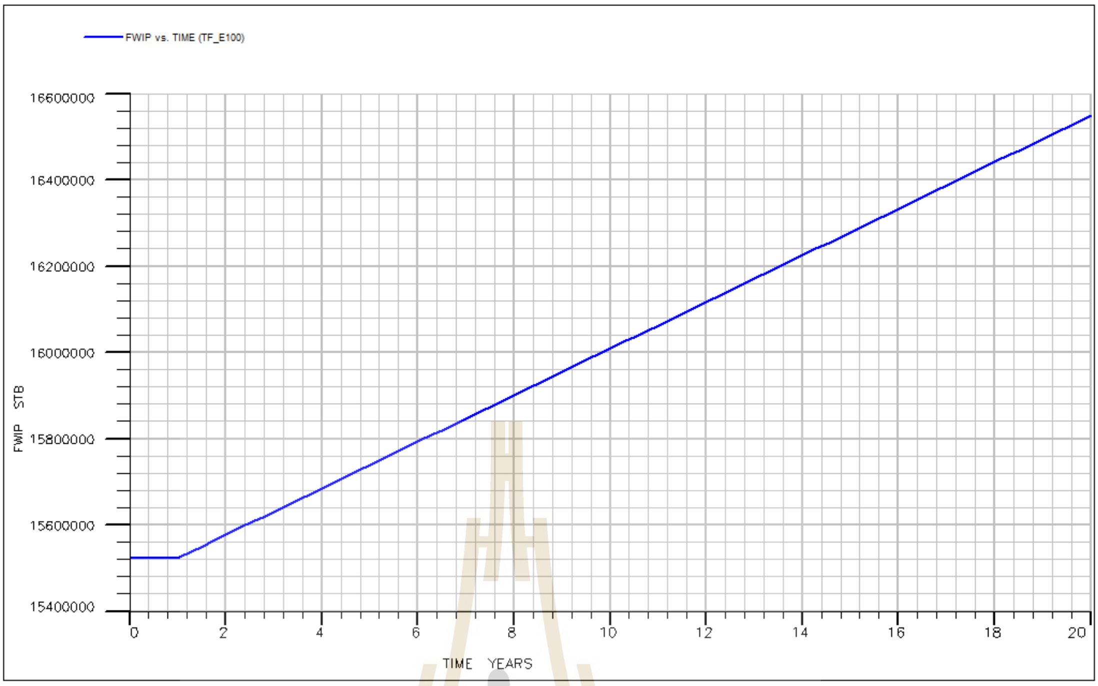
D.2 Reservoir simulation result for case polymer flooding concentration 600 ppm

D.2.1 Result of Model Case 7

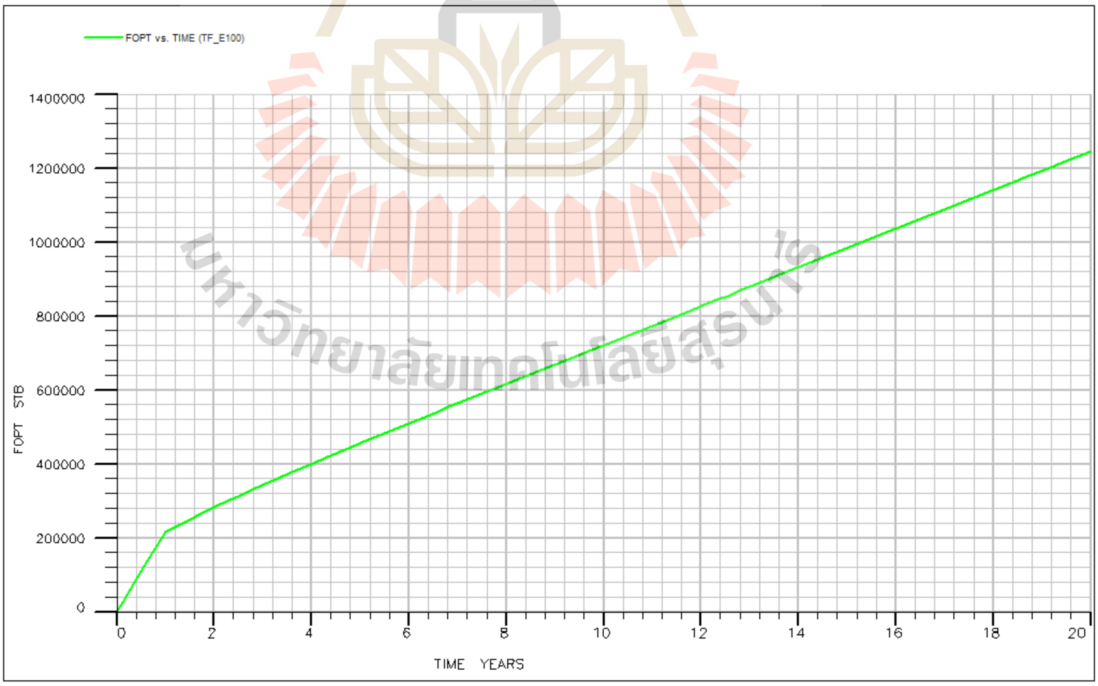
Model case 7 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.44 - D.52:



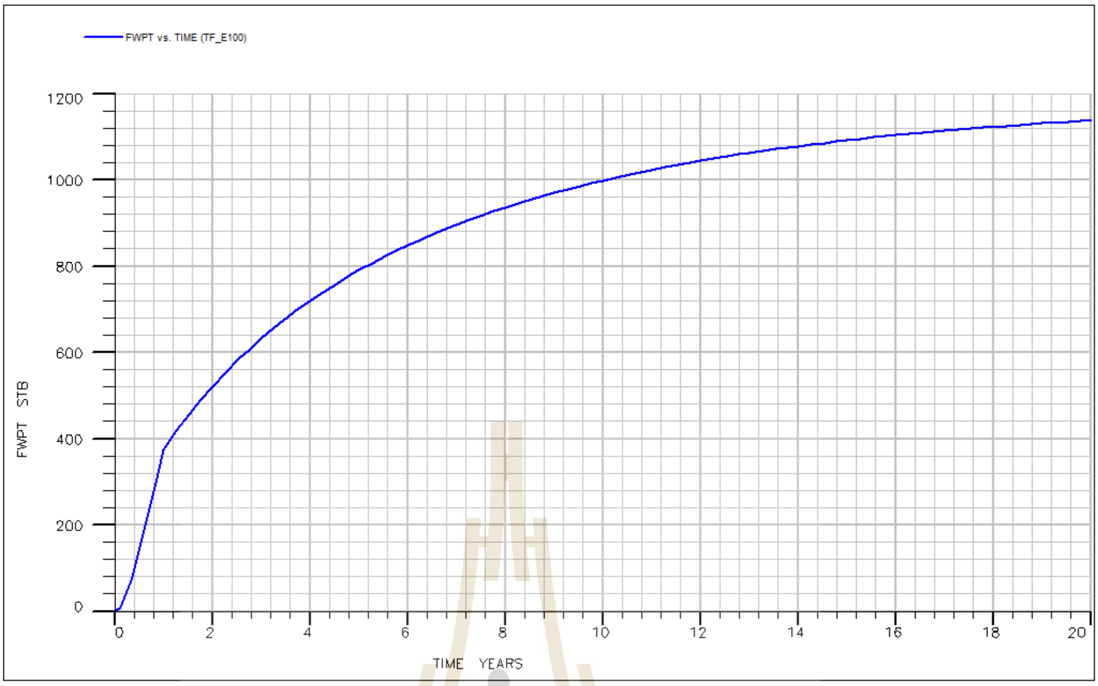
Figures D.44 Oil in place Vs. time of model case 7



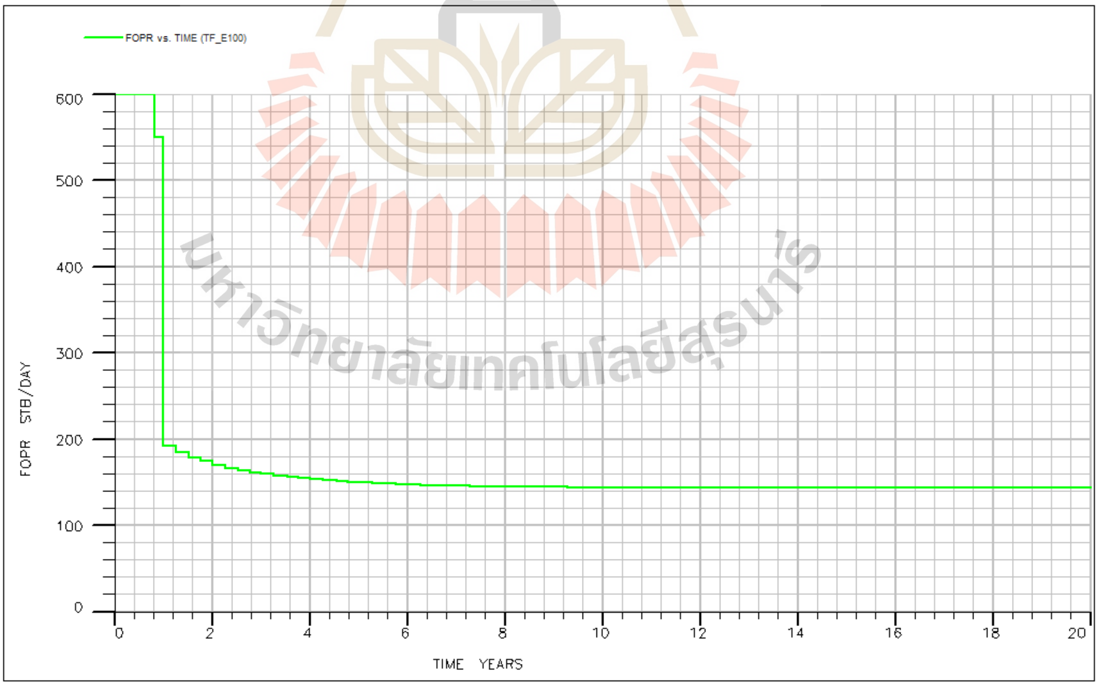
Figures D.45 Water in place Vs. time of model case 7



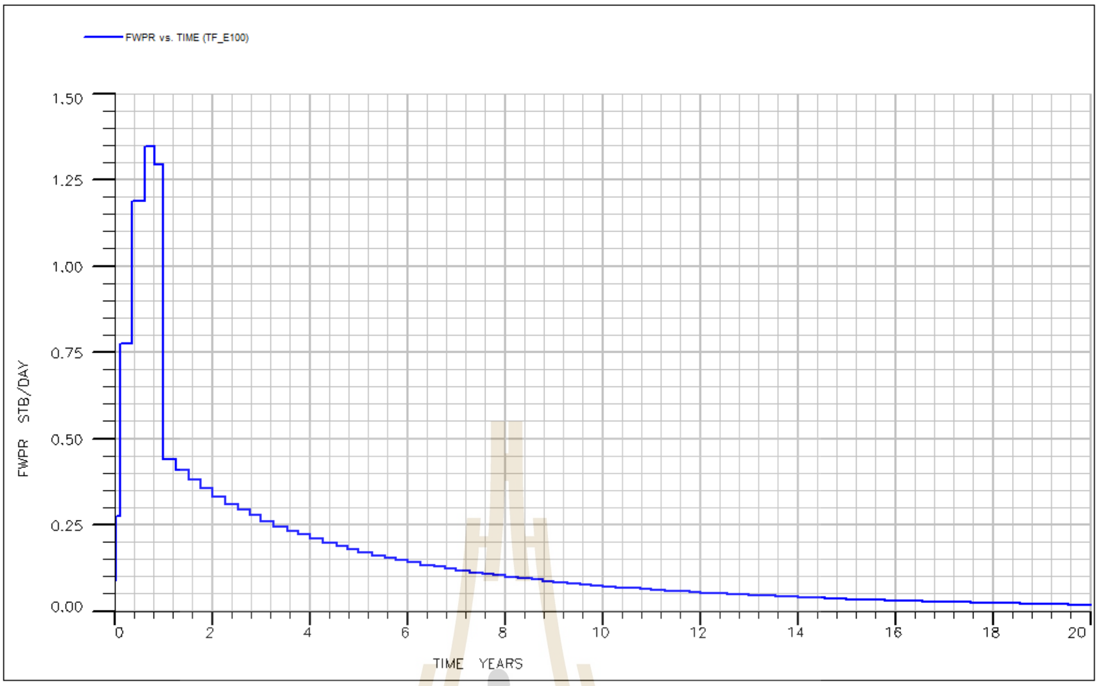
Figures D.46 Oil production total Vs. time of model case 7



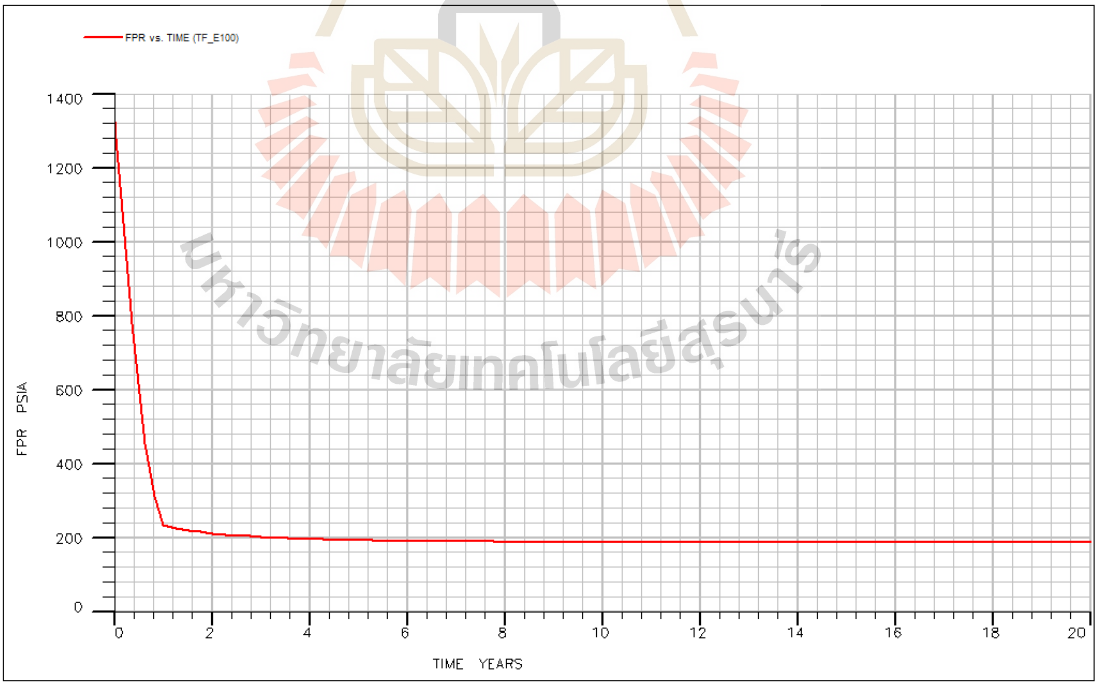
Figures D.47 Water production total Vs. time of model case 7



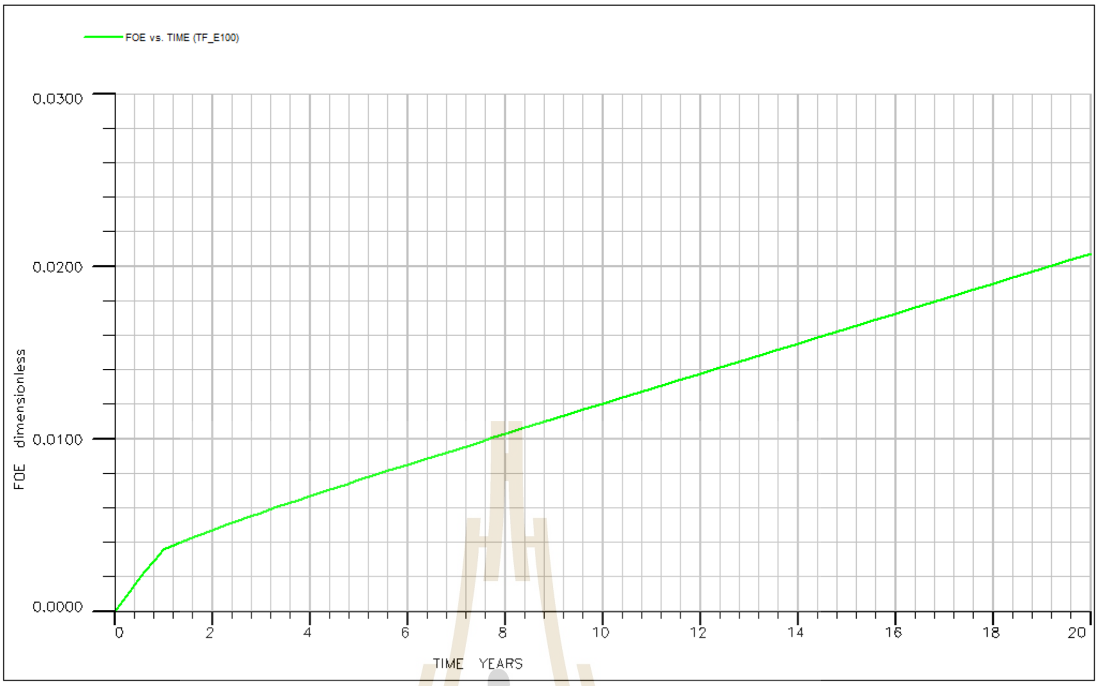
Figures D.48 Oil production rate Vs. time of model case 7



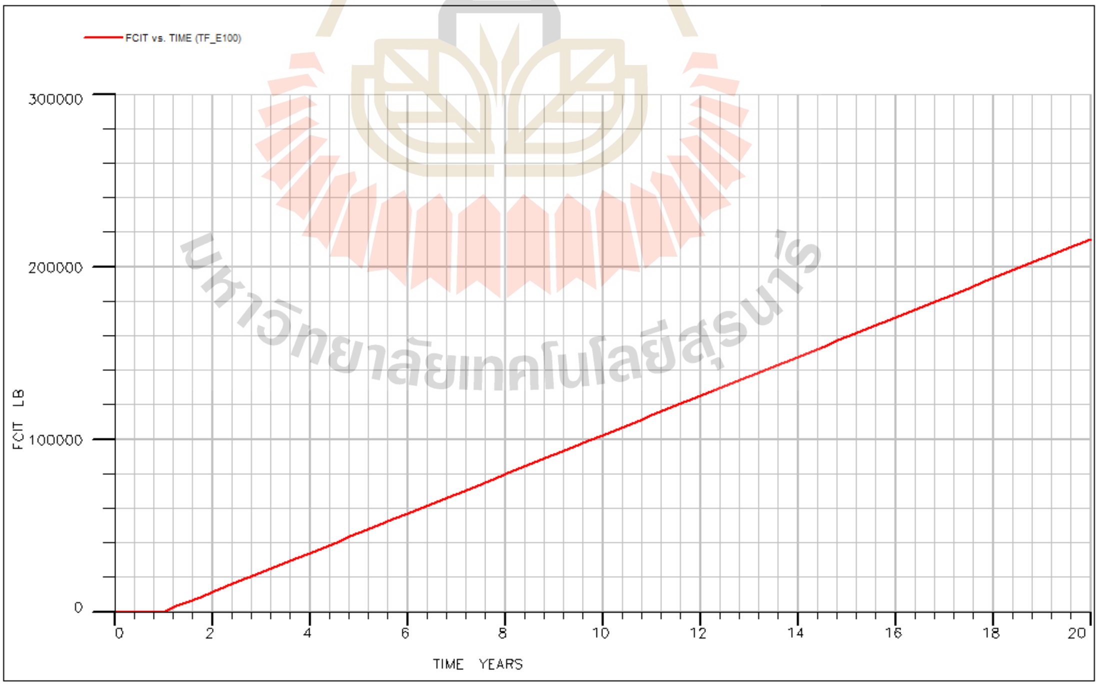
Figures D.49 Water production rate Vs. time of case 7



Figures D.50 Field pressure Vs. time of model case 7



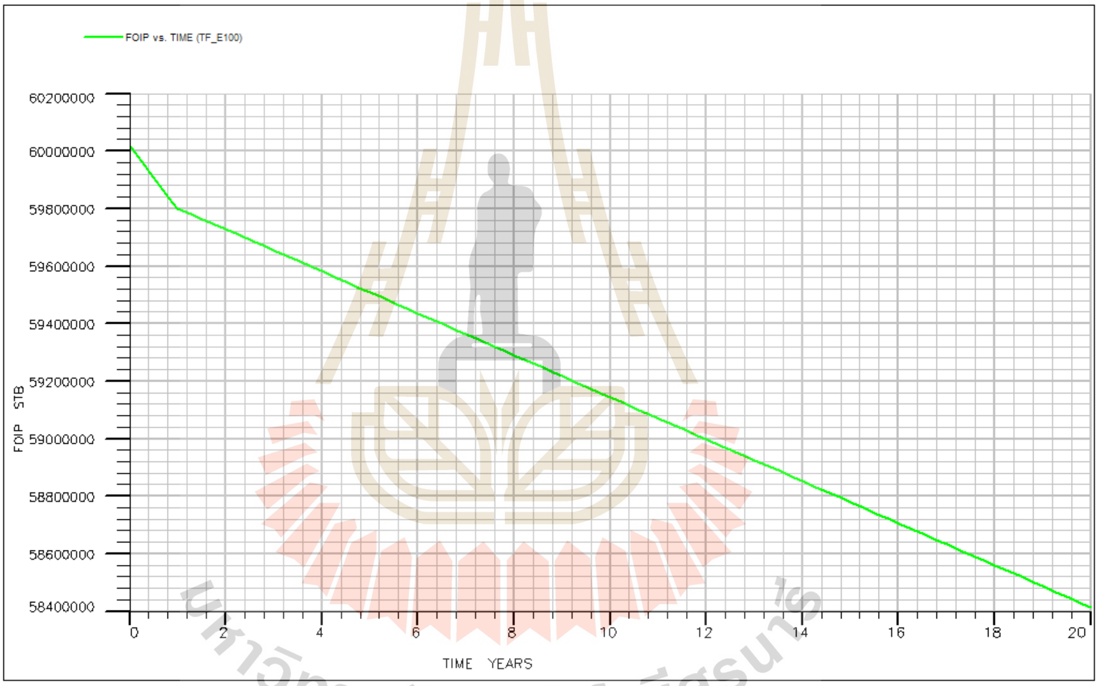
Figures D.51 Oil efficiency Vs. time of model case 7



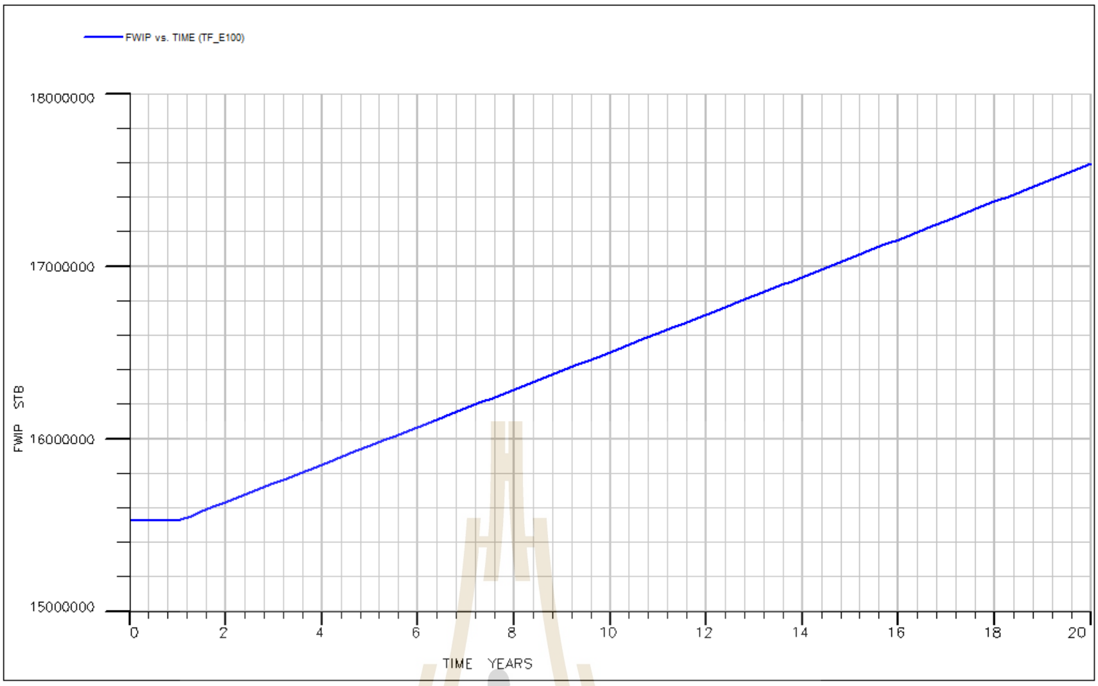
Figures D.52 Polymer injection total Vs. time of model case 7

D.2.2 Result of Model Case 8

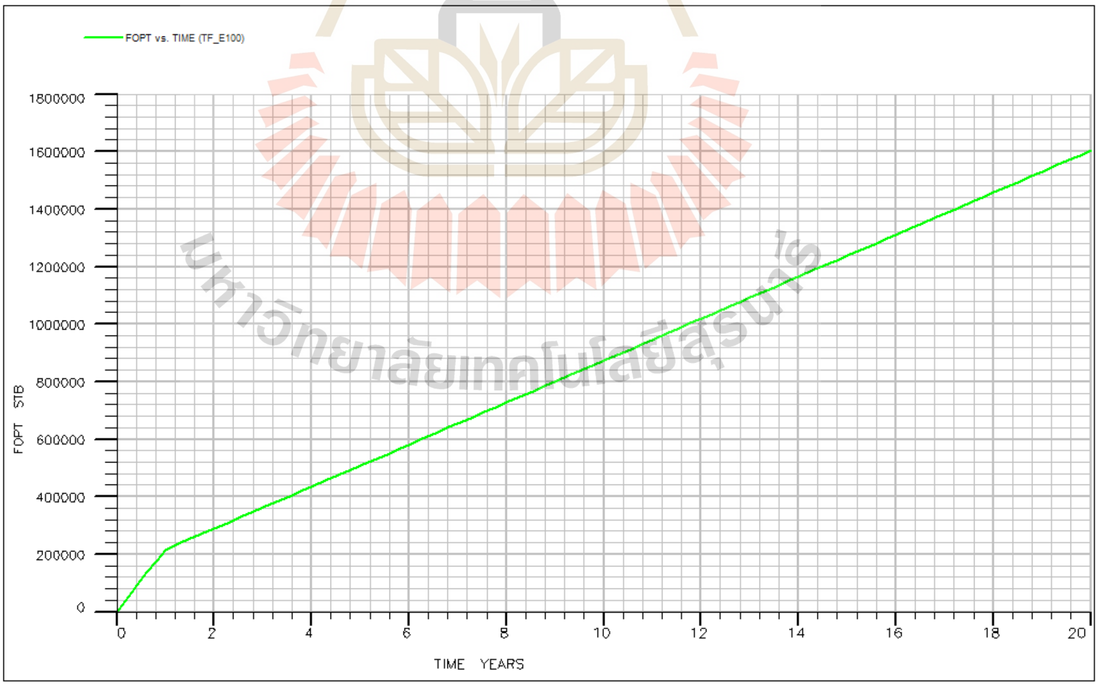
Model case 8 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.53 - D.61:



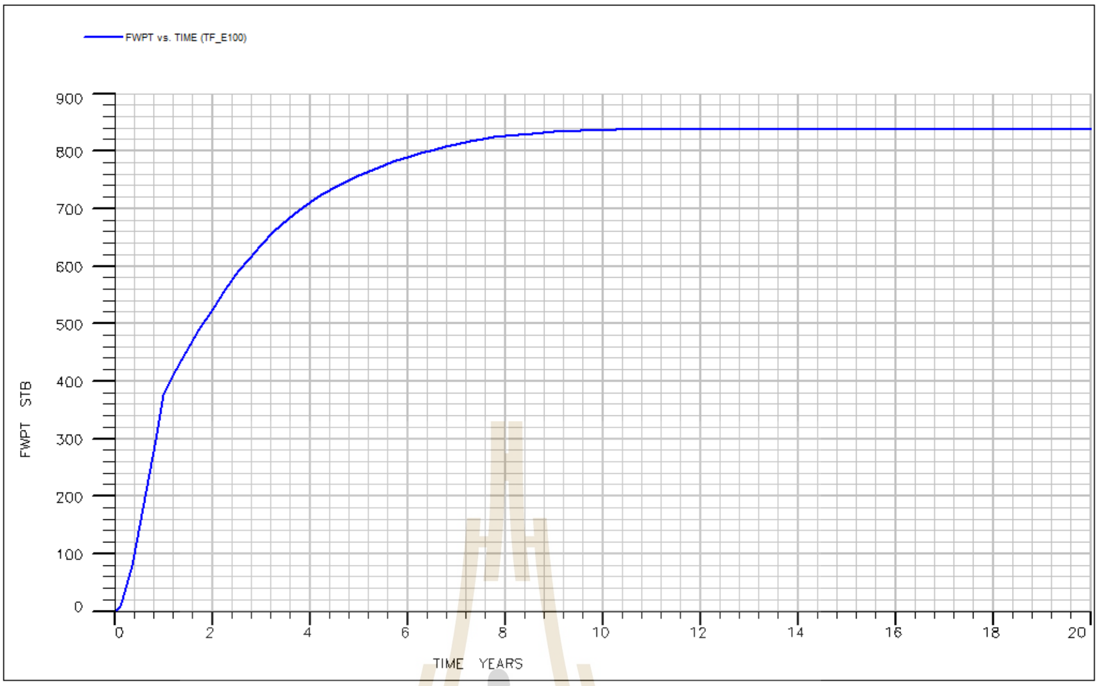
Figures D.53 Oil in place Vs. time of model case 8



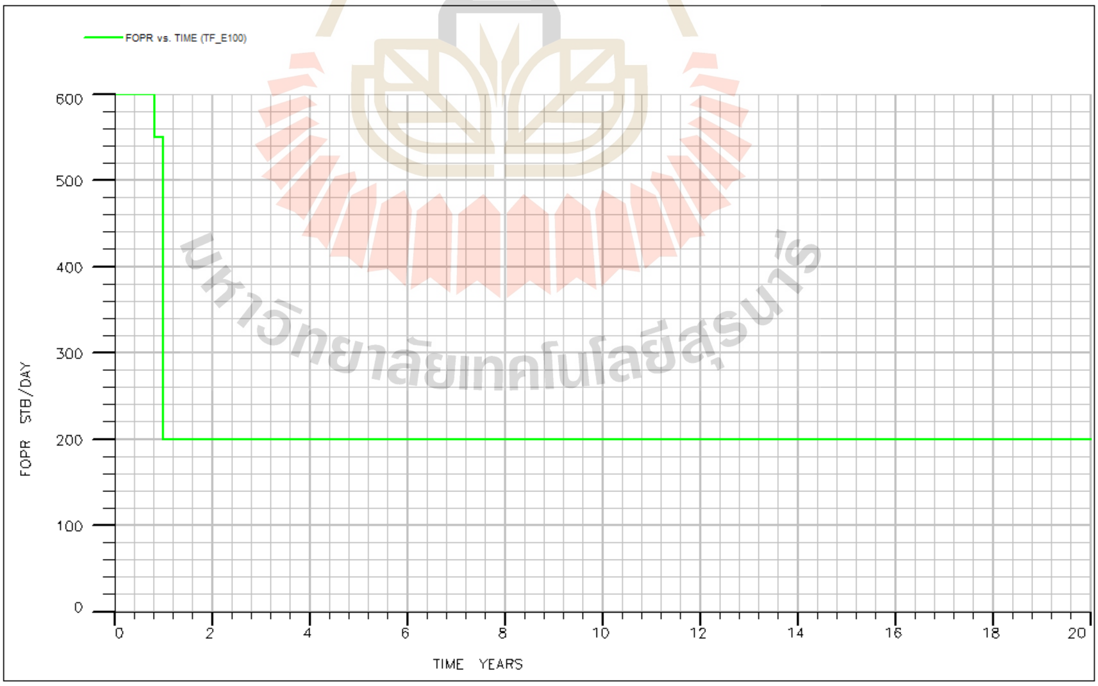
Figures D.54 Water in place Vs. time of model case 8



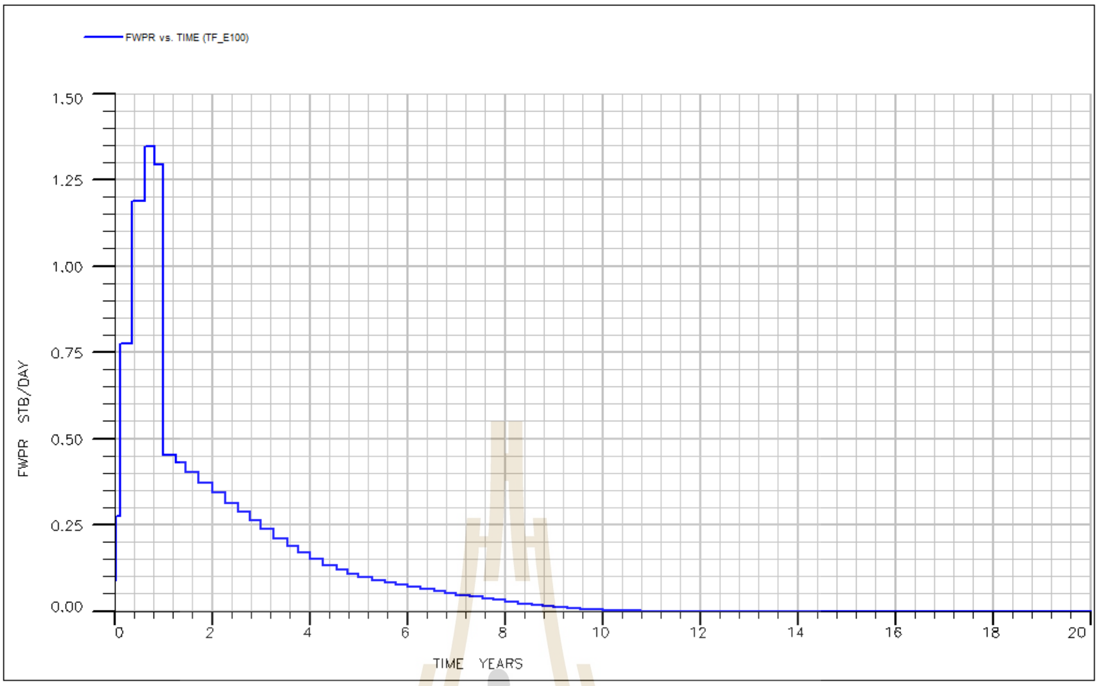
Figures D.55 Oil production total Vs. time of model case 8



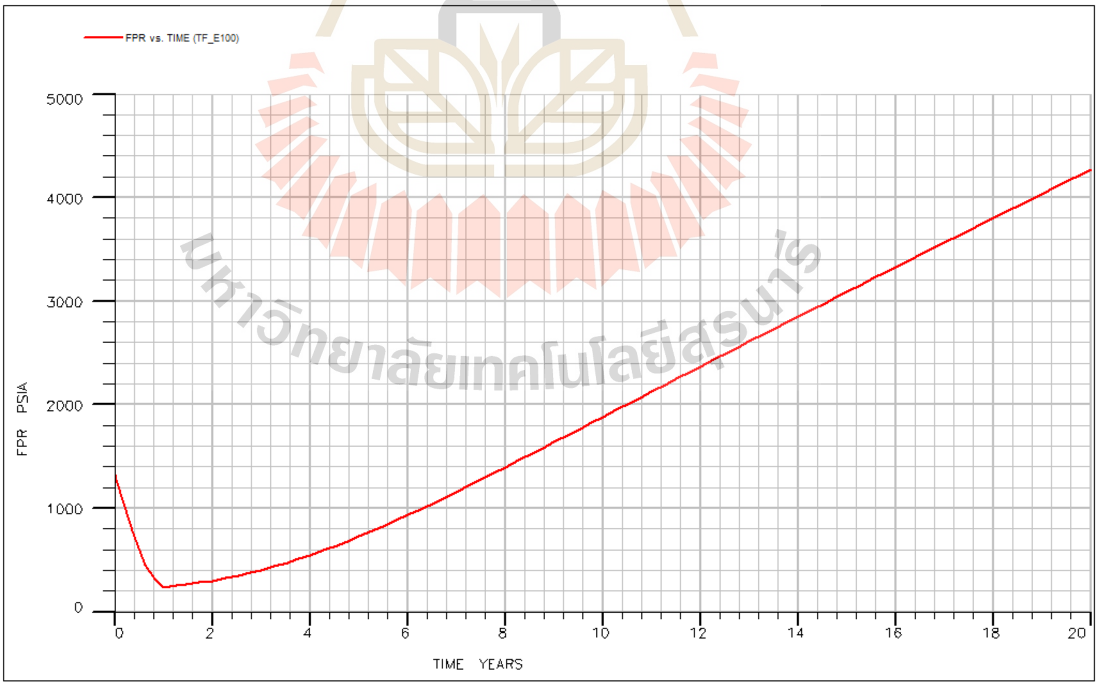
Figures D.56 Water production total Vs. time of model case 8



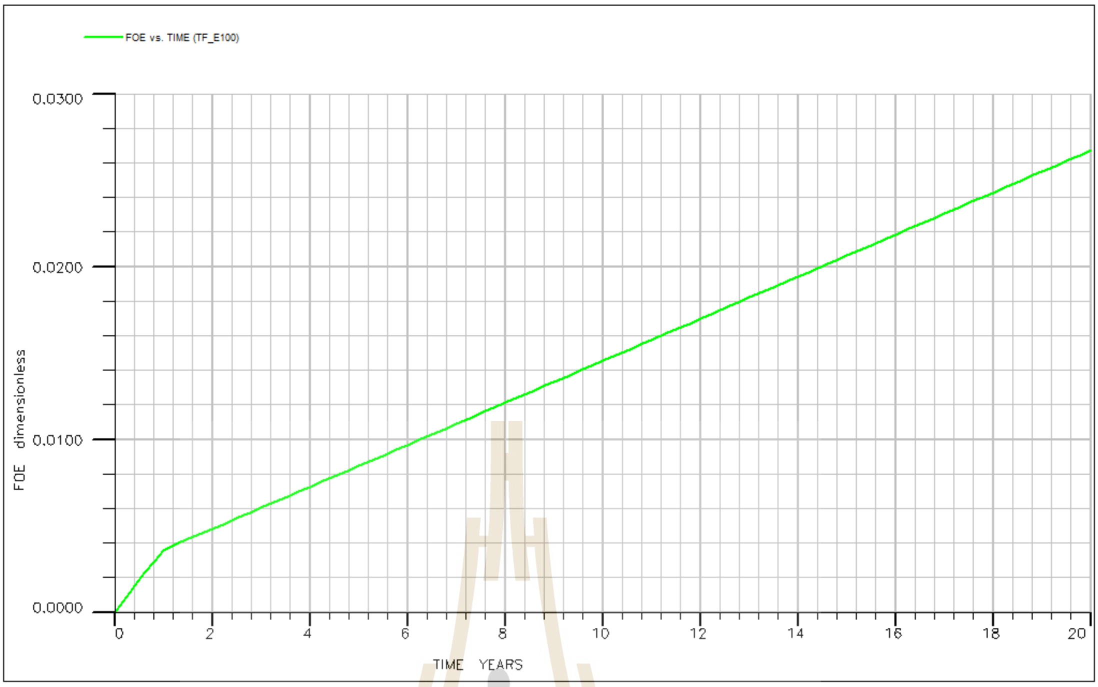
Figures D.57 Oil production rate Vs. time of model case 8



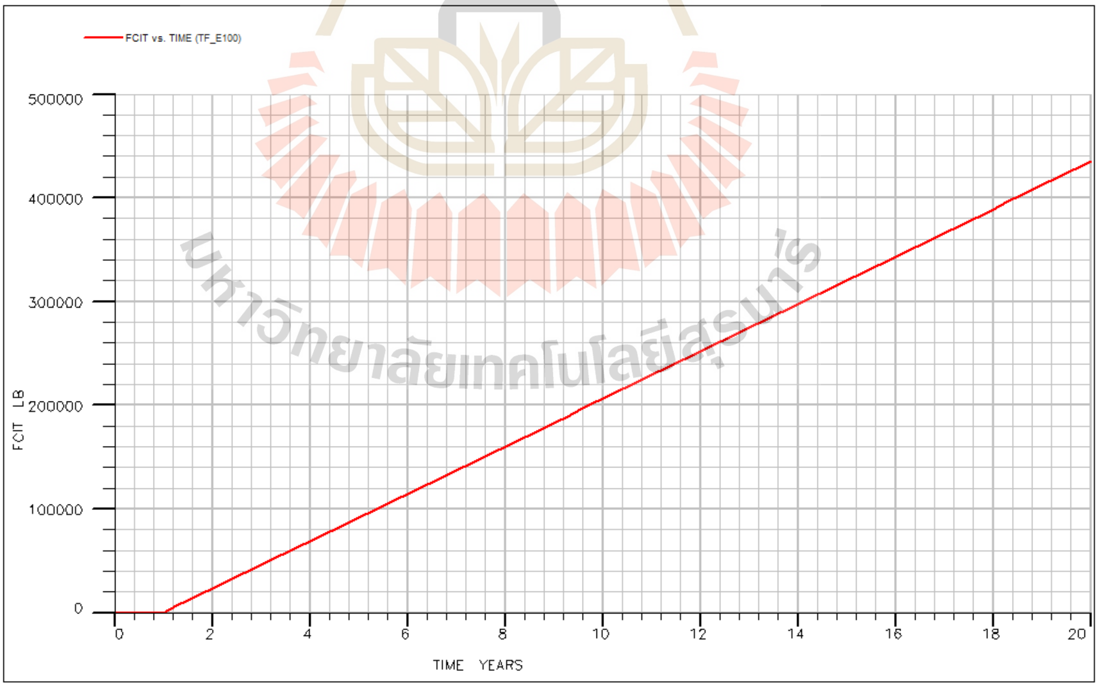
Figures D.58 Water production rate Vs. time of case 8



Figures D.59 Field pressure Vs. time of model case 8



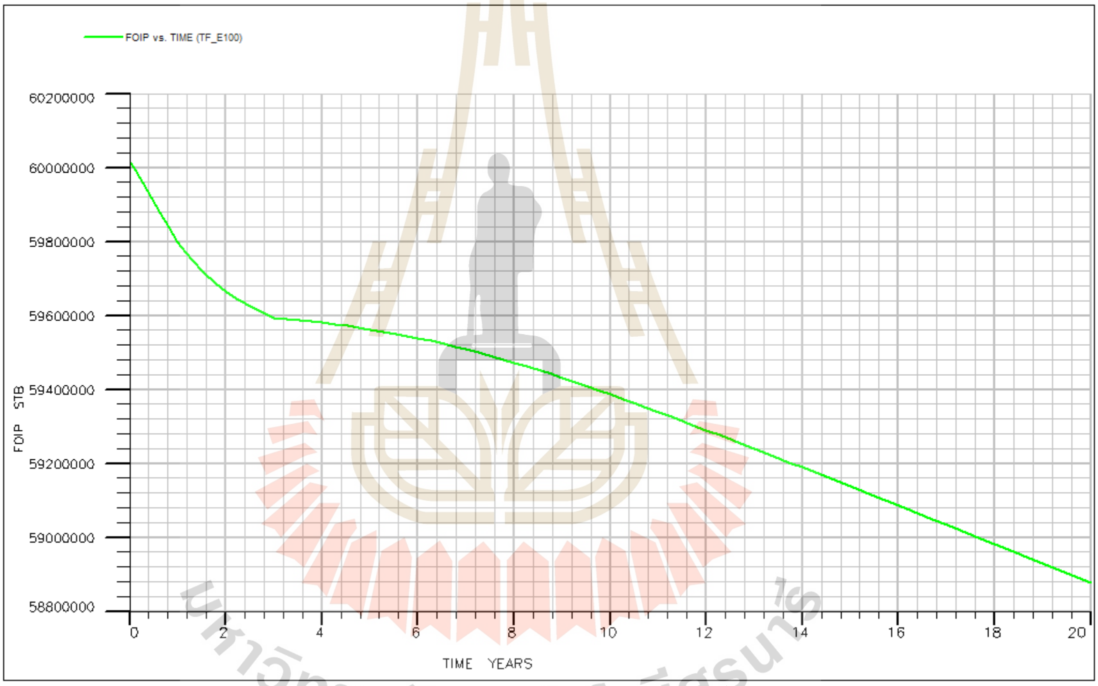
Figures D.60 Oil efficiency Vs. time of model case 8



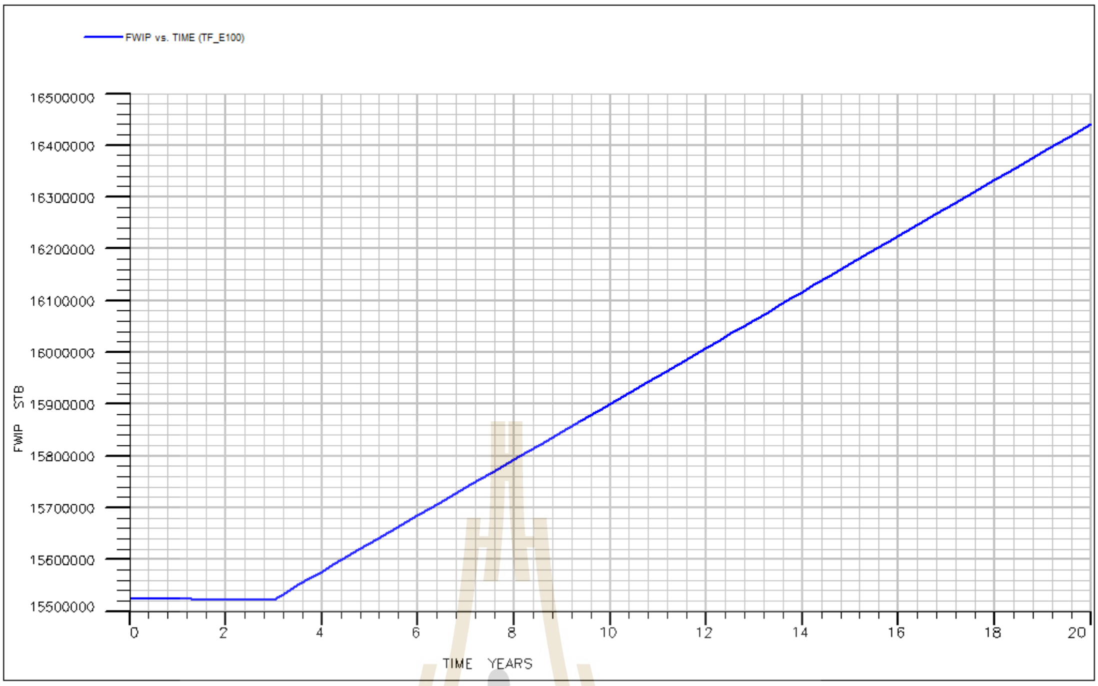
Figures D.61 Polymer injection total Vs. time of model case 8

D.2.3 Result of Model Case 9

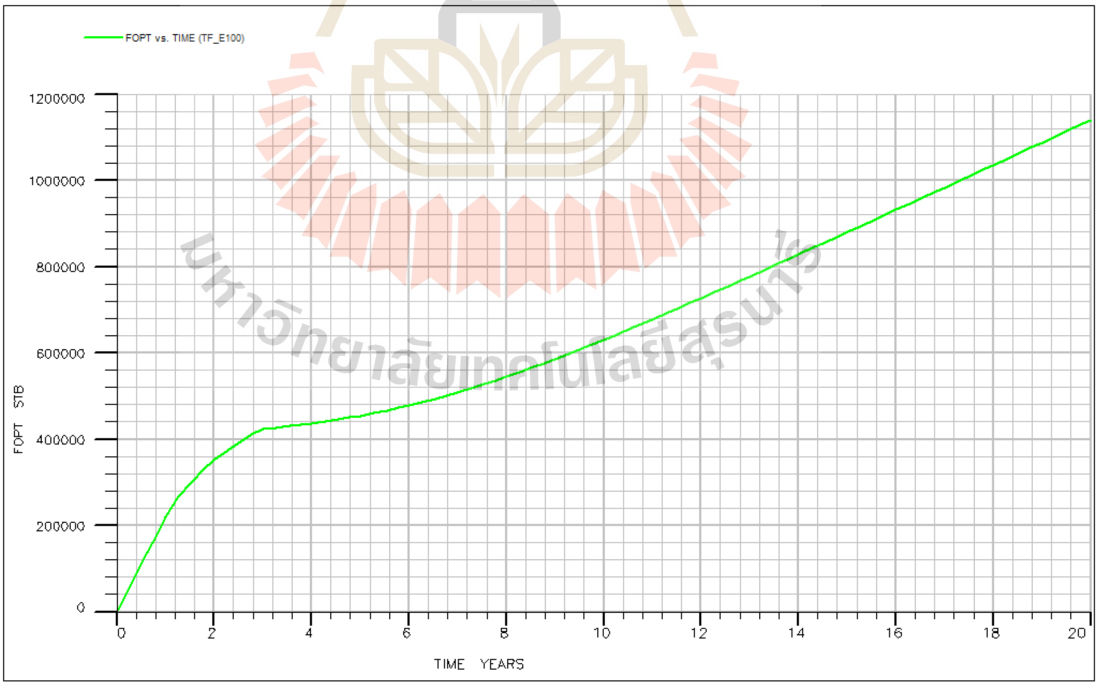
Model case 9 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.62 - D.70:



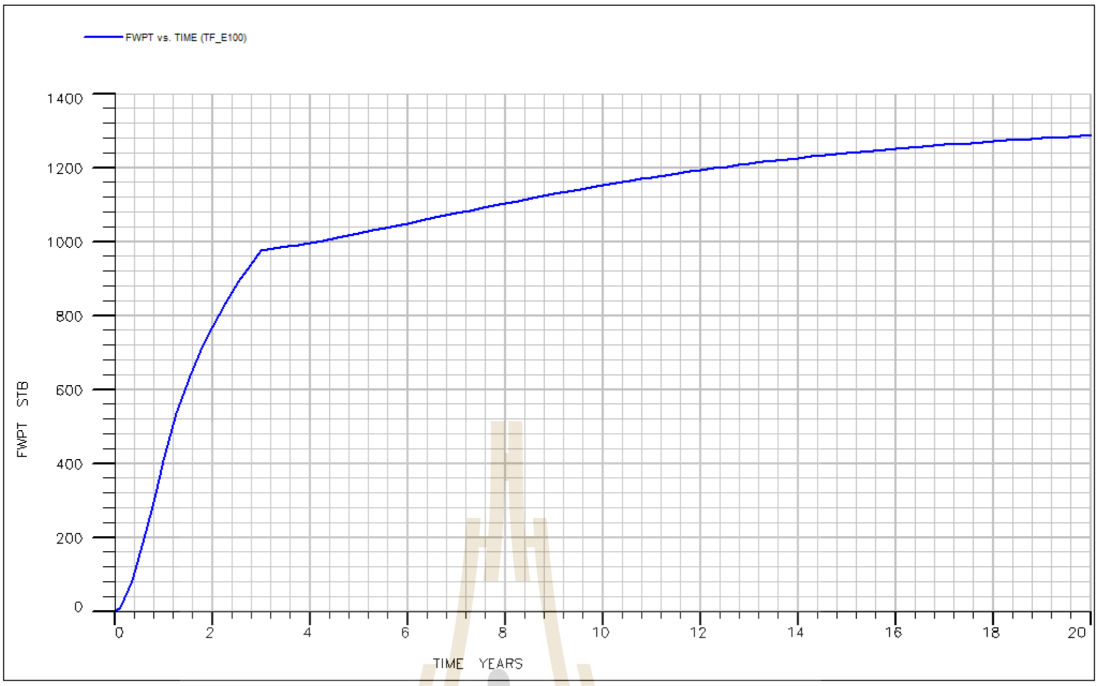
Figures D.62 Oil in place Vs. time of model case 9



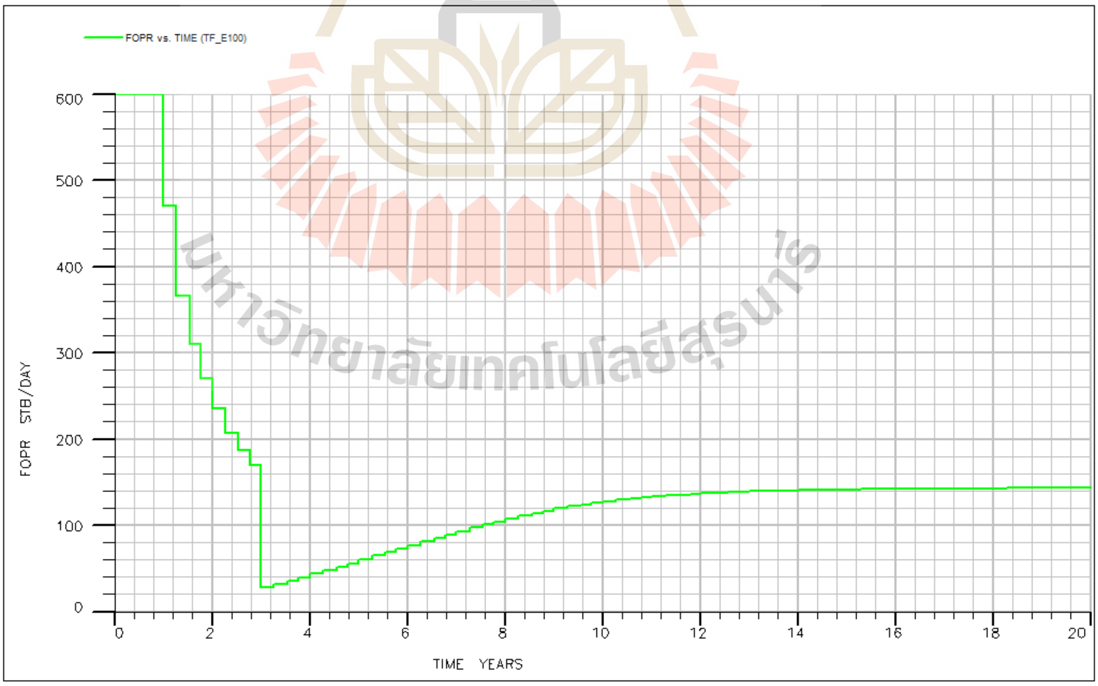
Figures D.63 Water in place Vs. time of model case 9



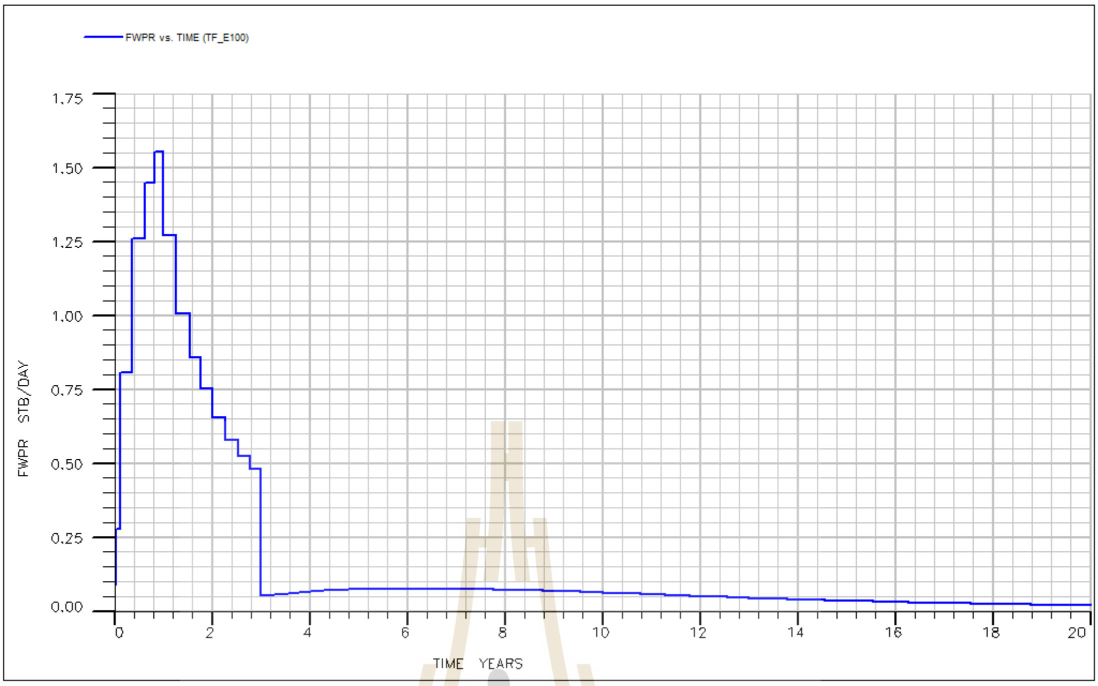
Figures D.64 Oil production total Vs. time of model case 9



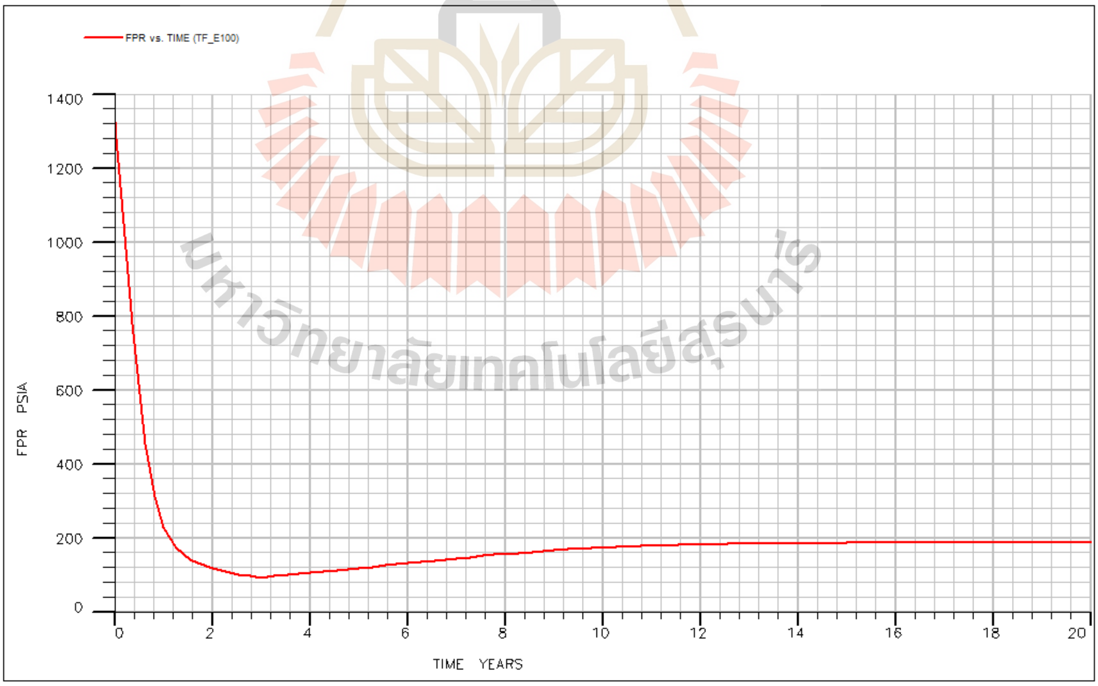
Figures D.65 Water production total Vs. time of model case 9



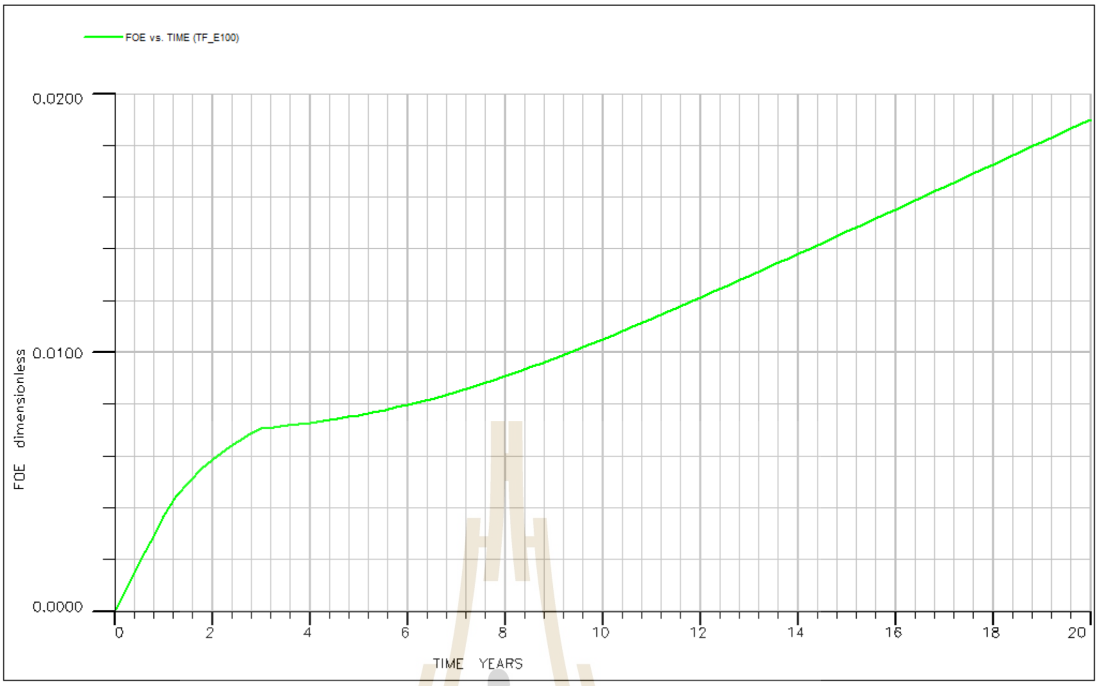
Figures D.66 Oil production rate Vs. time of model case 9



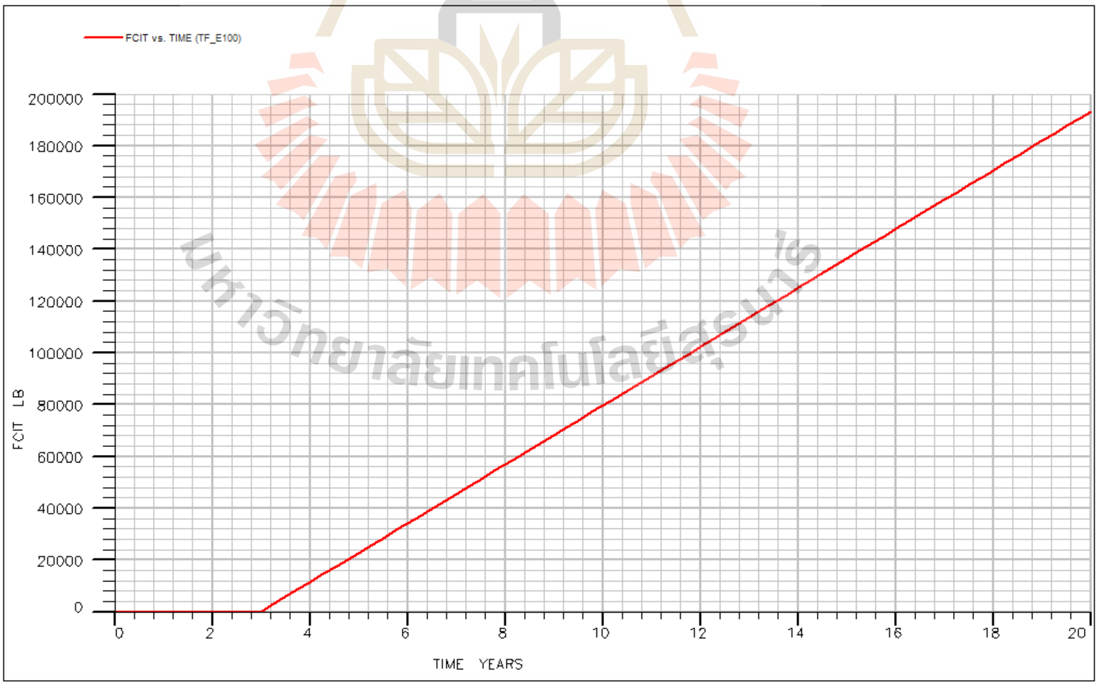
Figures D.67 Water production rate Vs. time of case 9



Figures D.68 Field pressure Vs. time of model case 9



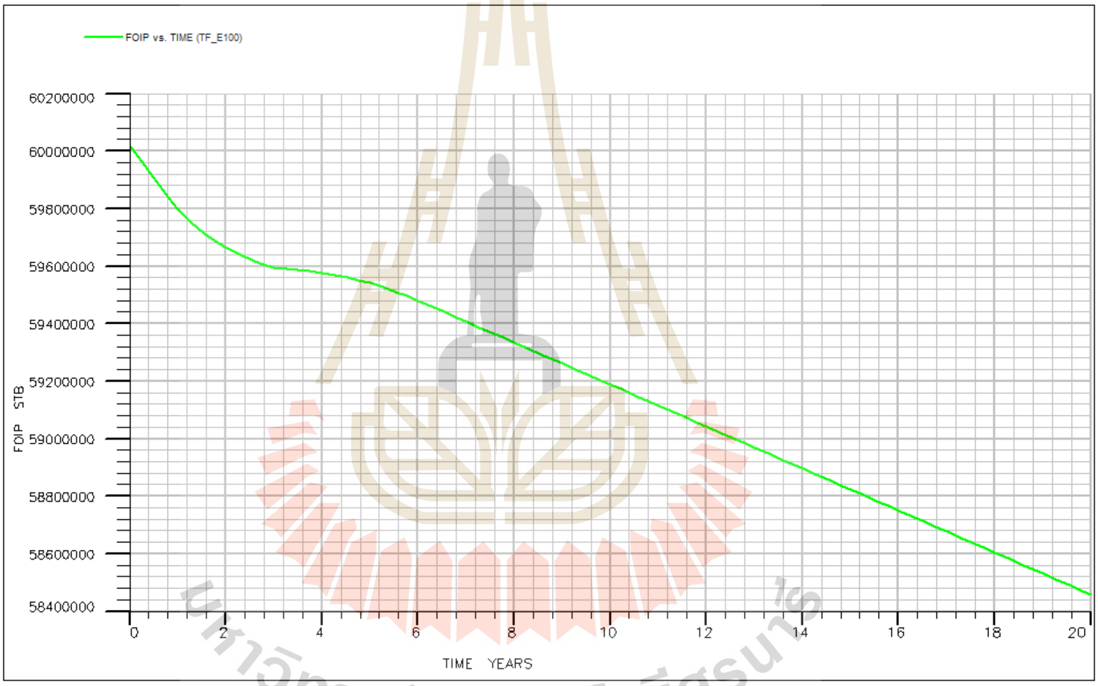
Figures D.69 Oil efficiency Vs. time of model case 9



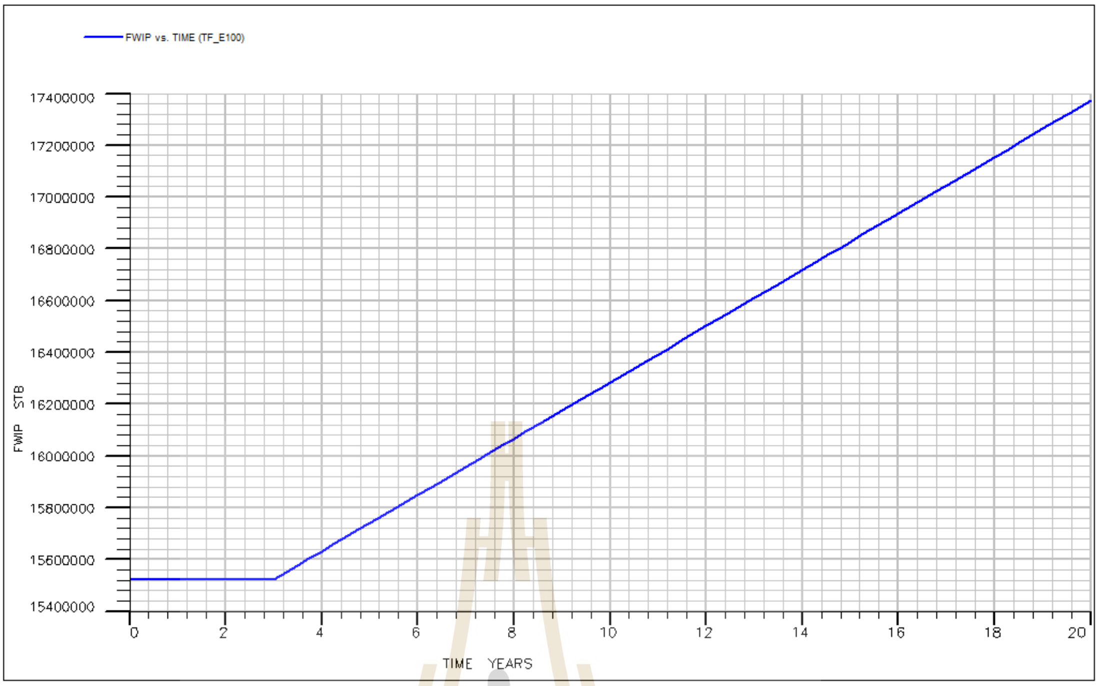
Figures D.70 Polymer injection total Vs. time of model case 9

D.2.4 Result of Model Case 10

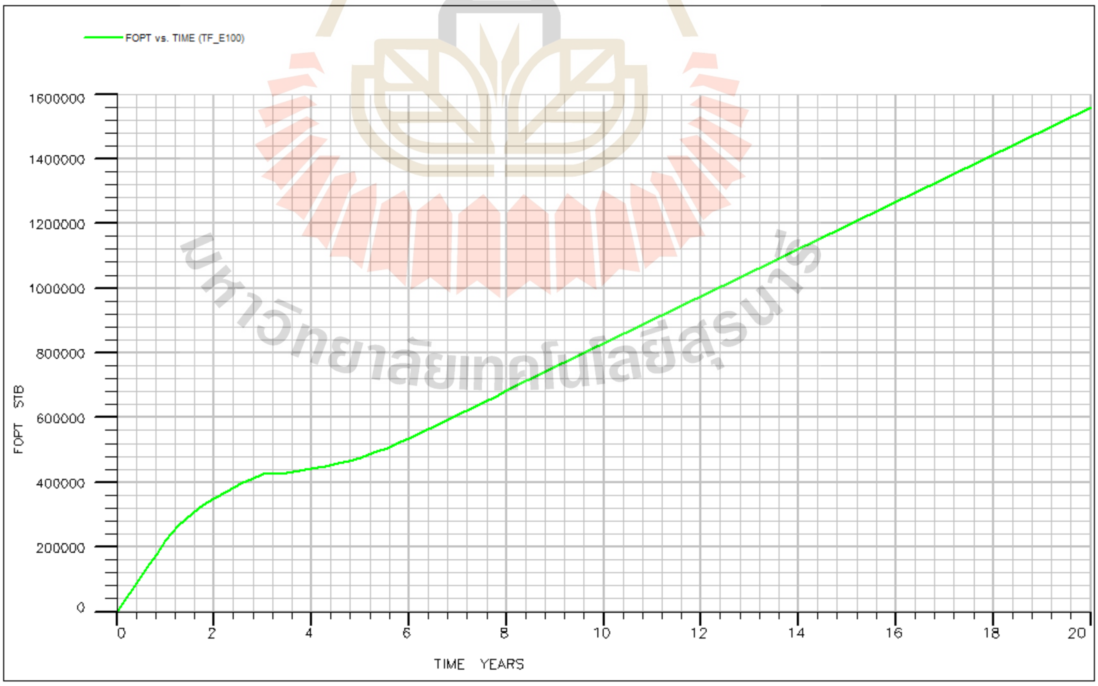
Model case 10 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.71 - D.79:



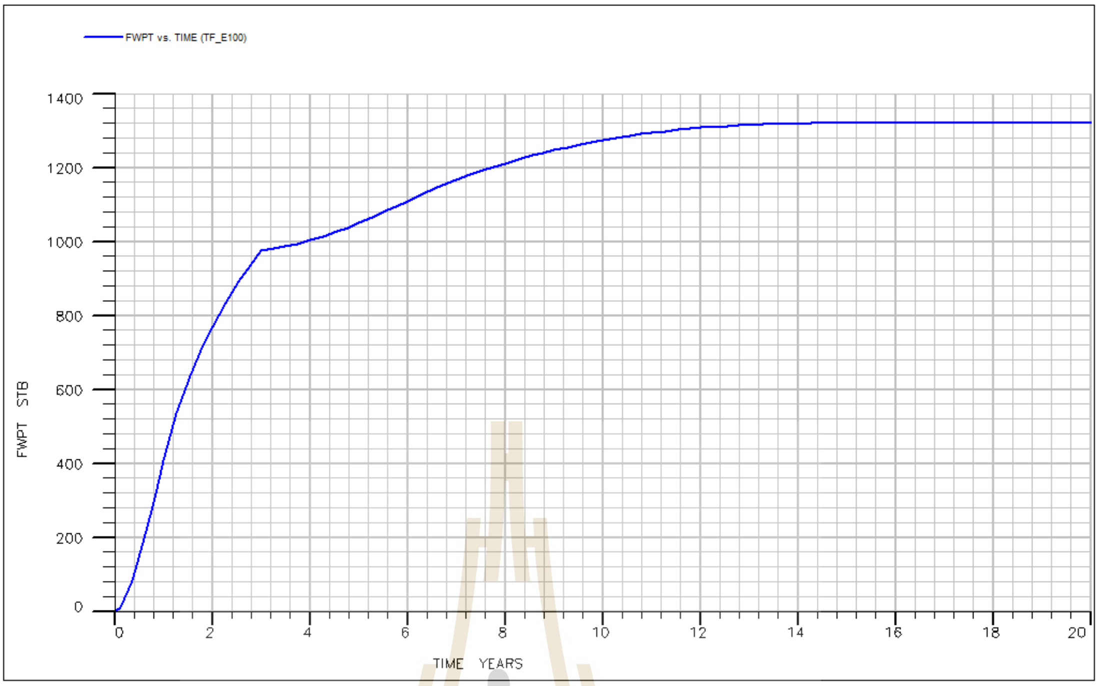
Figures D.71 Oil in place Vs. time of model case 10



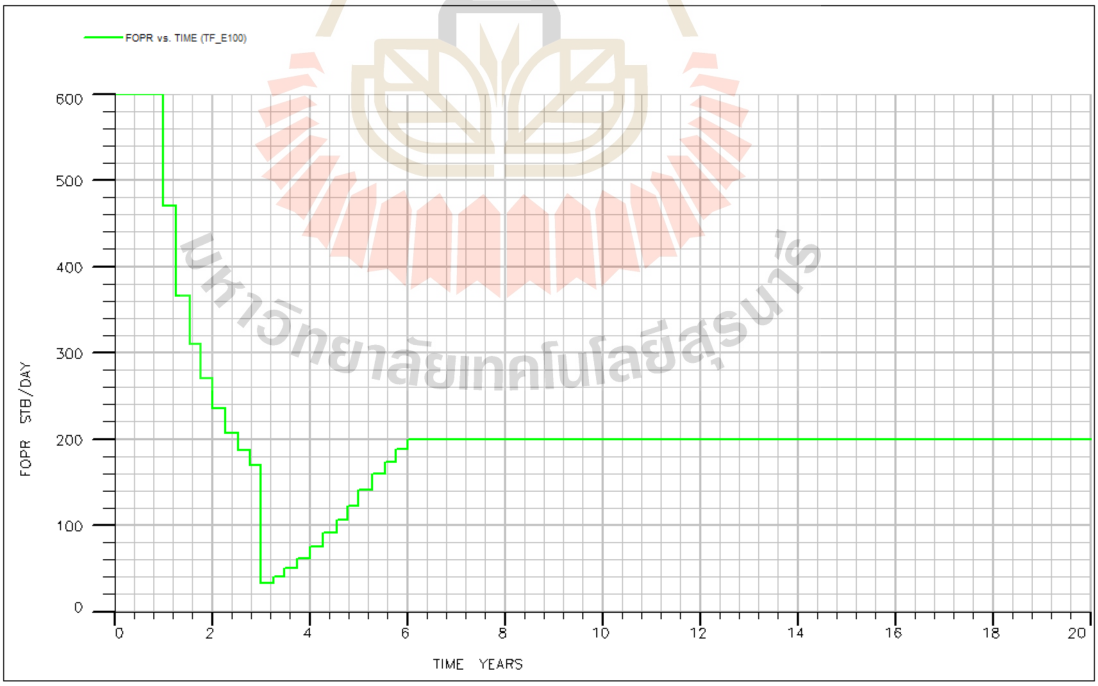
Figures D.72 Water in place Vs. time of model case 10



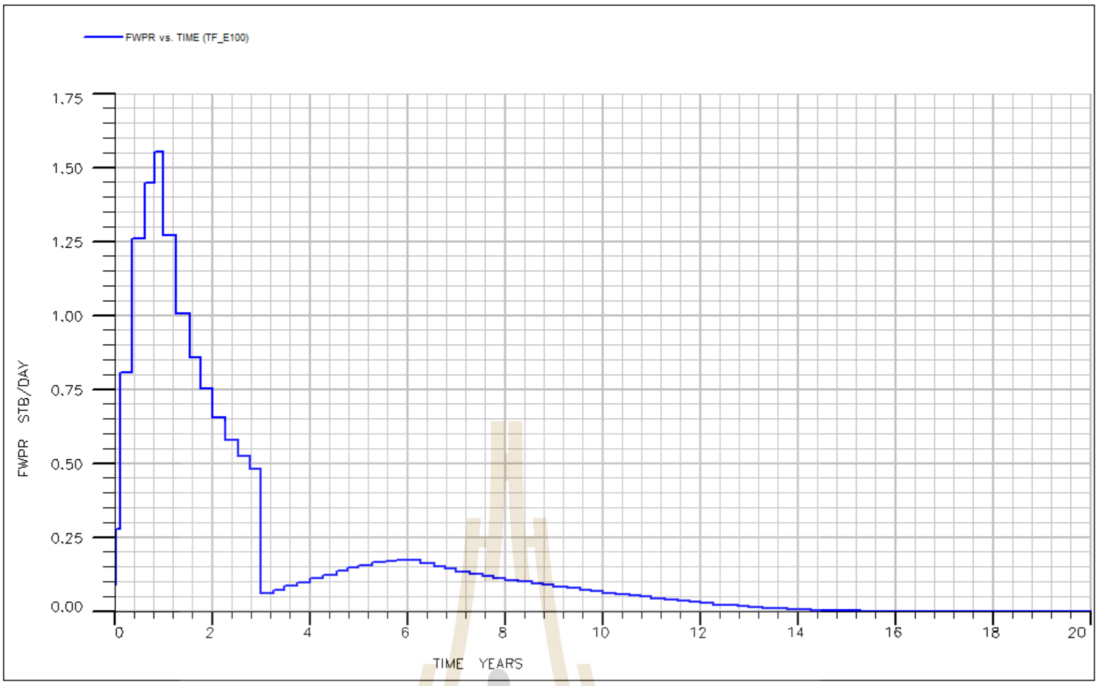
Figures D.73 Oil production total Vs. time of model case 10



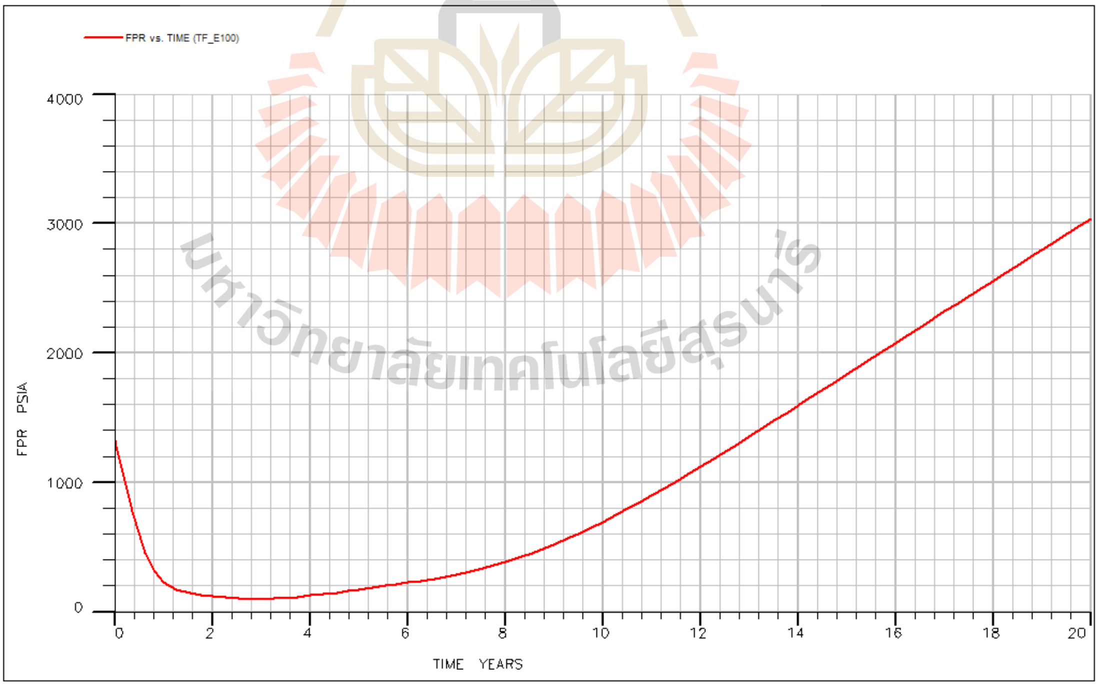
Figures D.74 Water production total Vs. time of model case 10



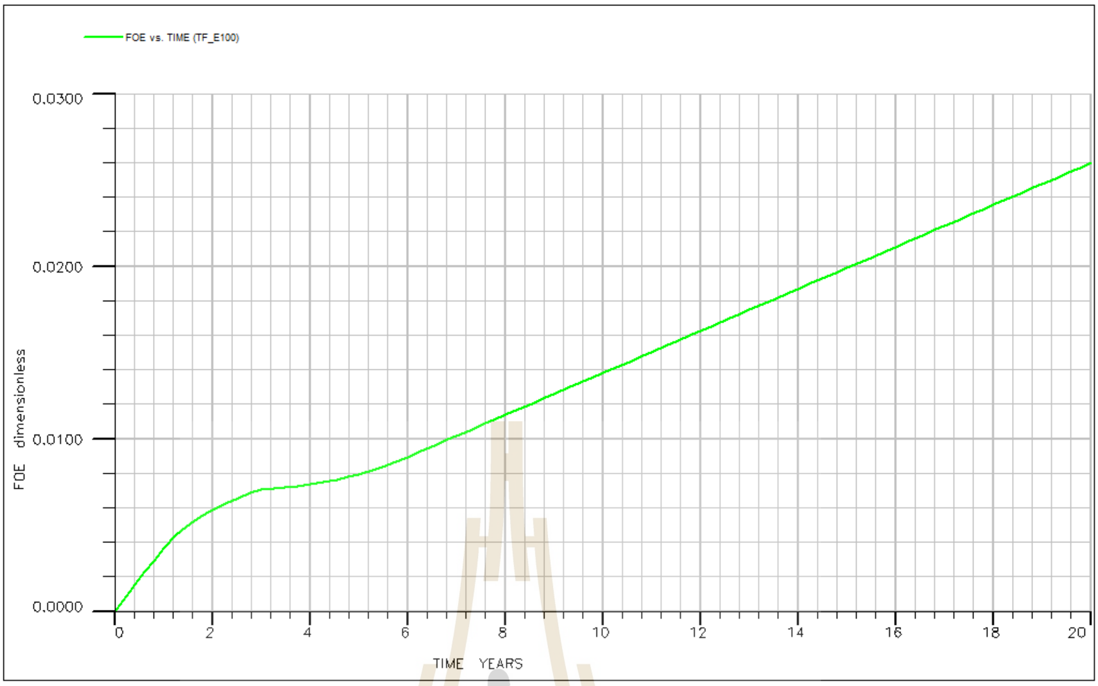
Figures D.75 Oil production rate Vs. time of model case 10



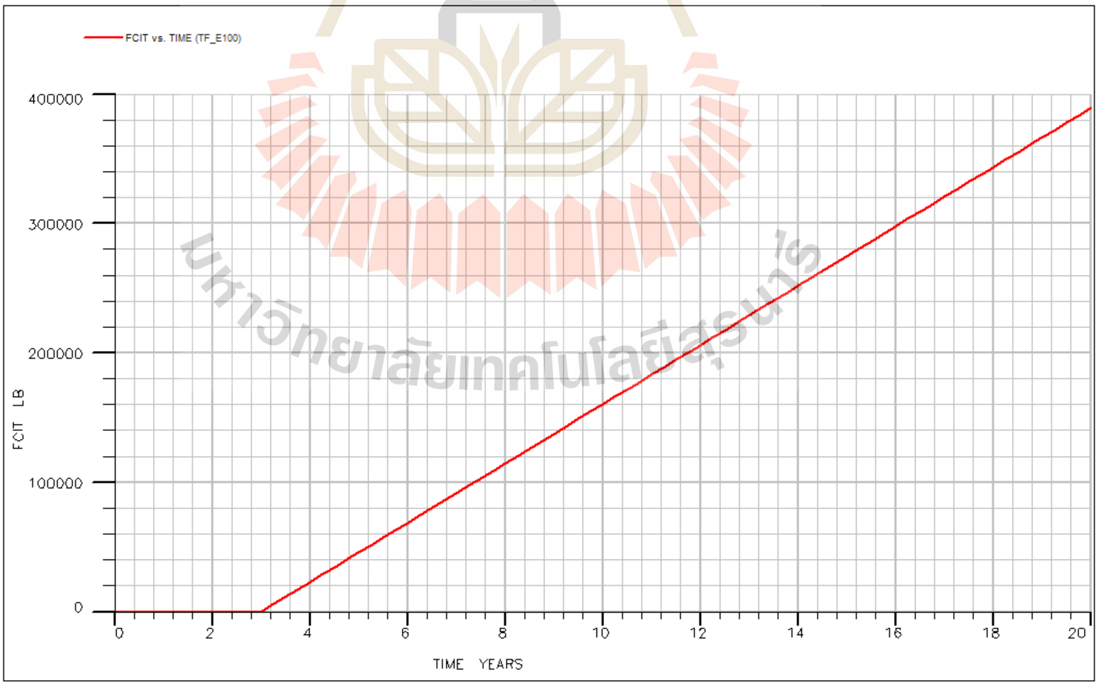
Figures D.76 Water production rate Vs. time of case 10



Figures D.77 Field pressure Vs. time of model case 10



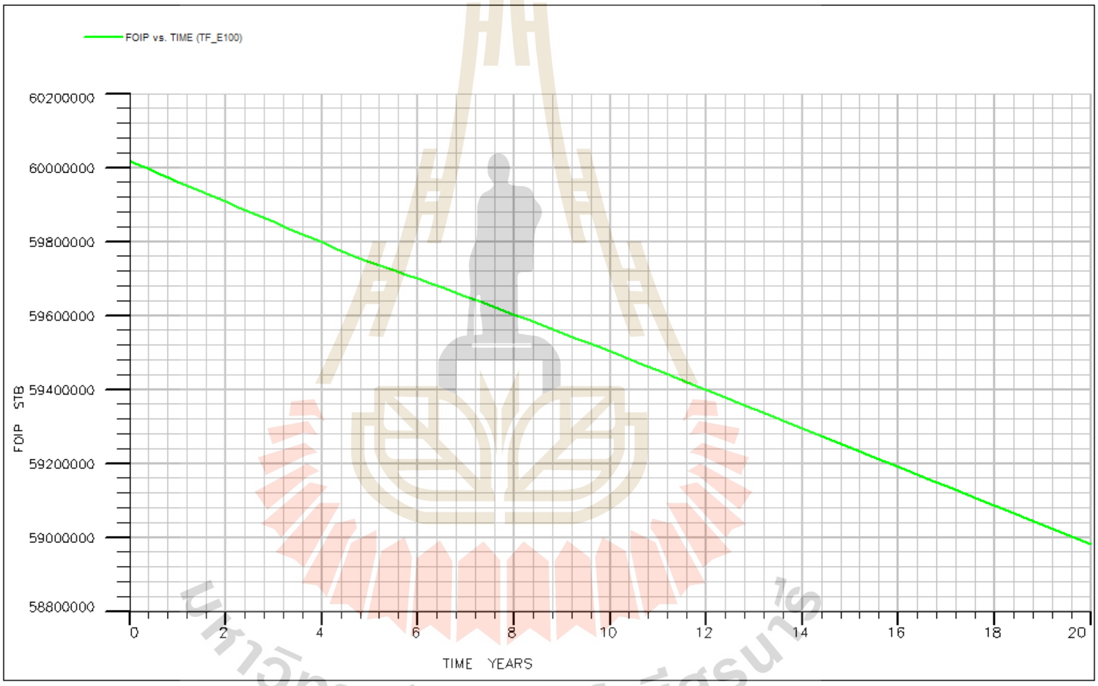
Figures D.78 Oil efficiency Vs. time of model case 10



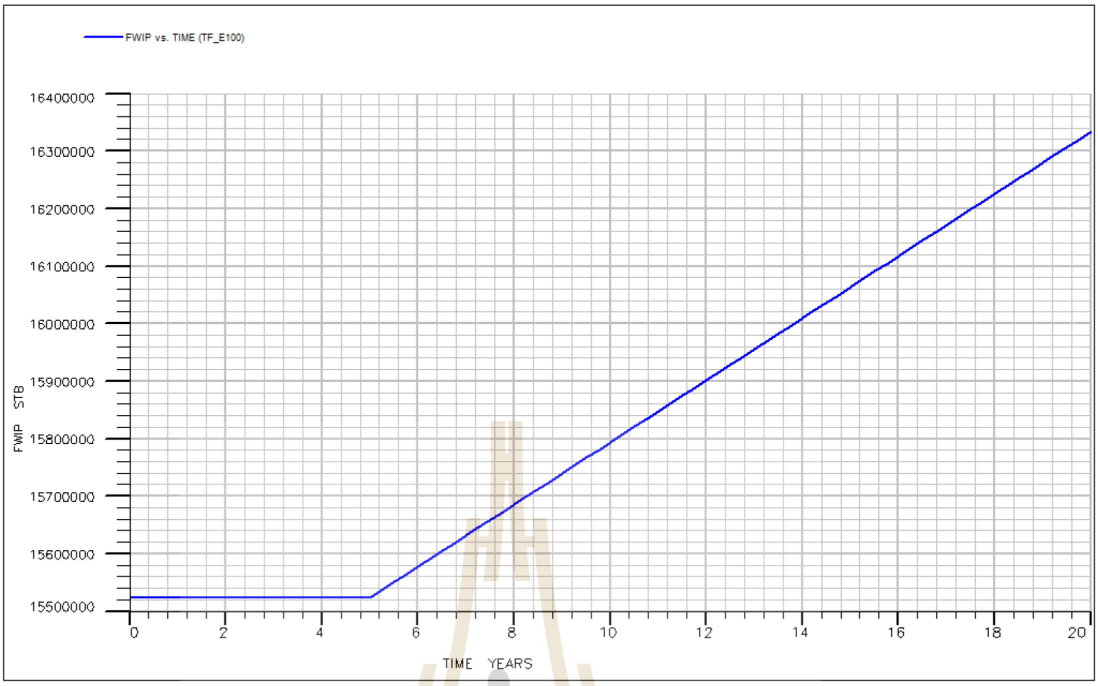
Figures D.79 Polymer injection total Vs. time of model case 10

D.2.5 Result of Model Case 11

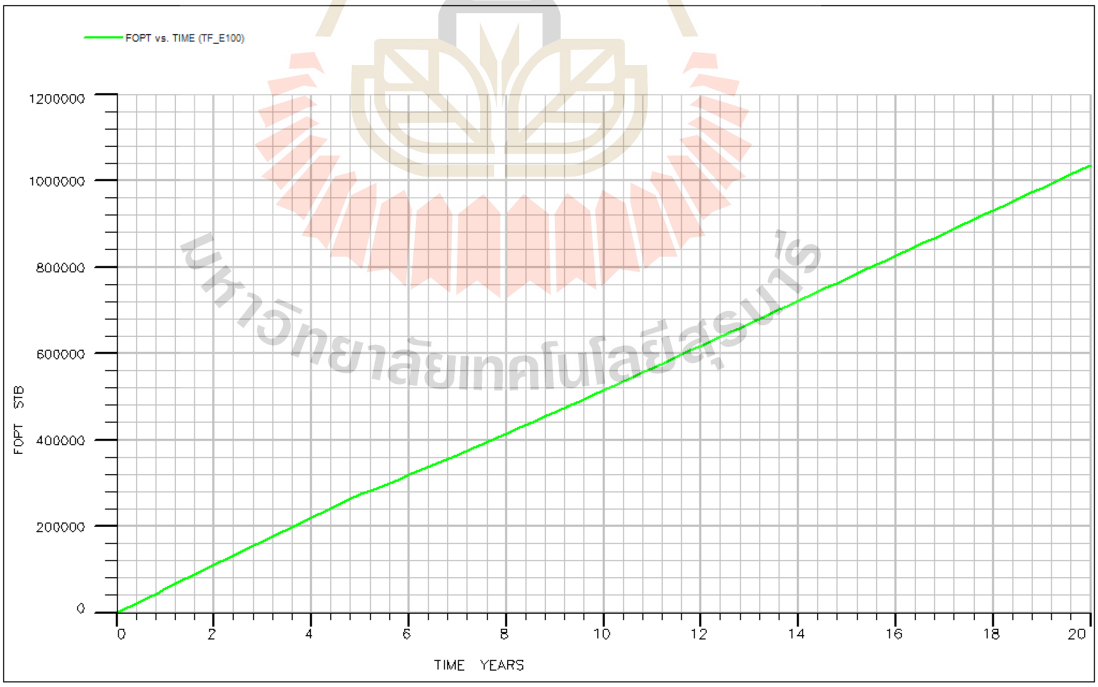
Model case 11 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.80 - D.88:



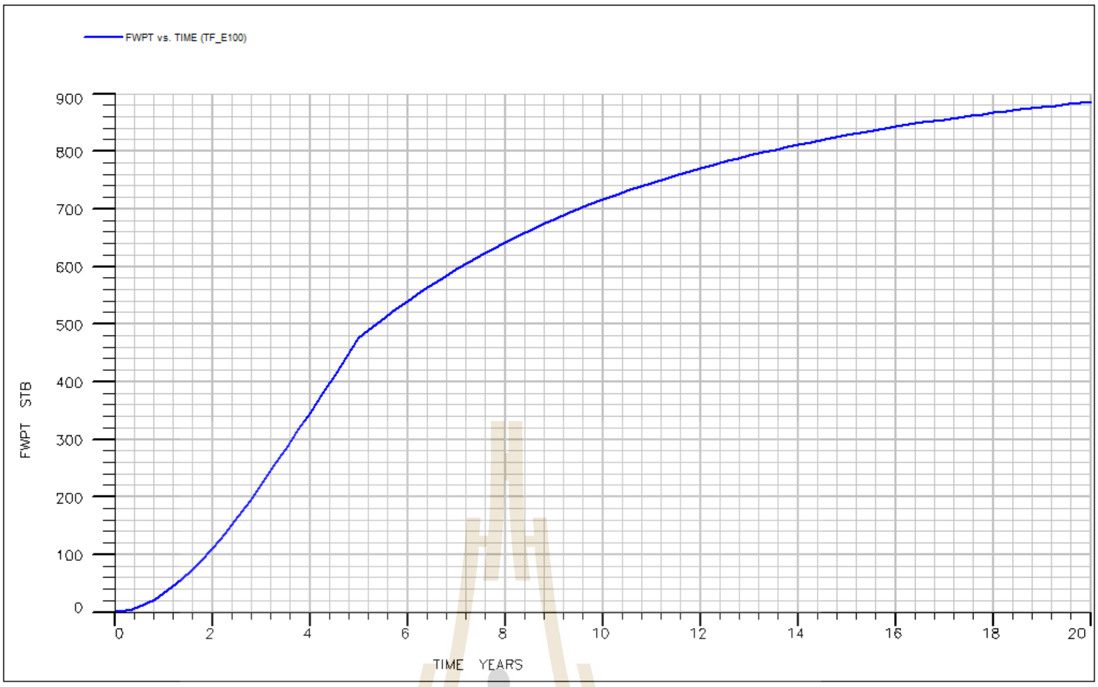
Figures D.80 Oil in place Vs. time of model case 11



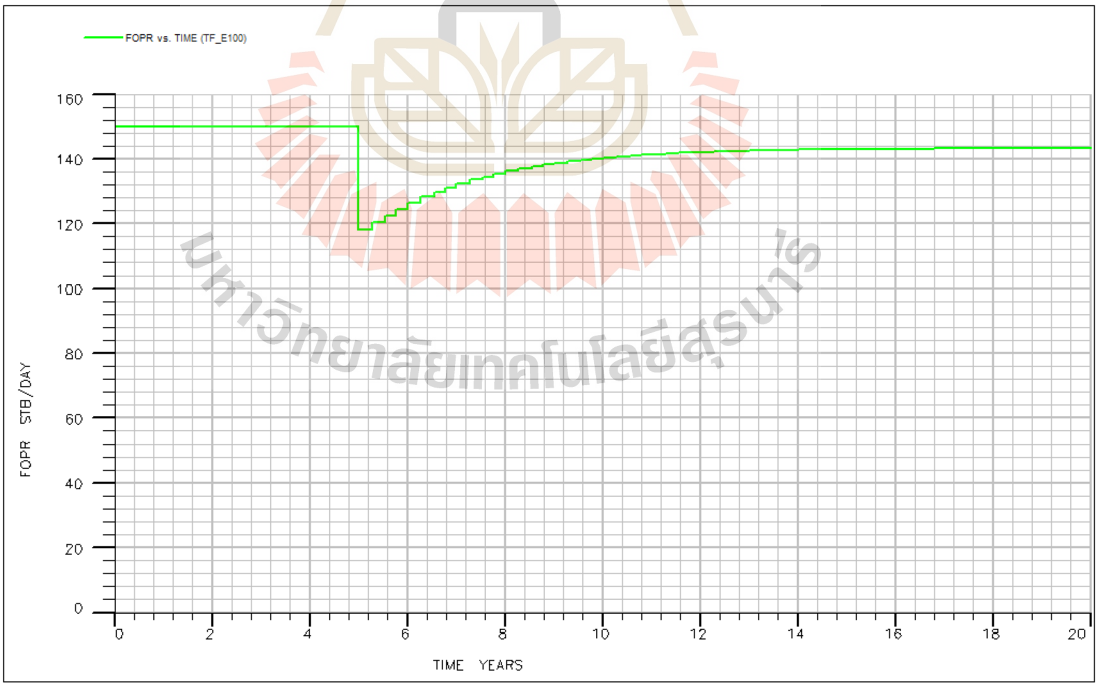
Figures D.81 Water in place Vs. time of model case 11



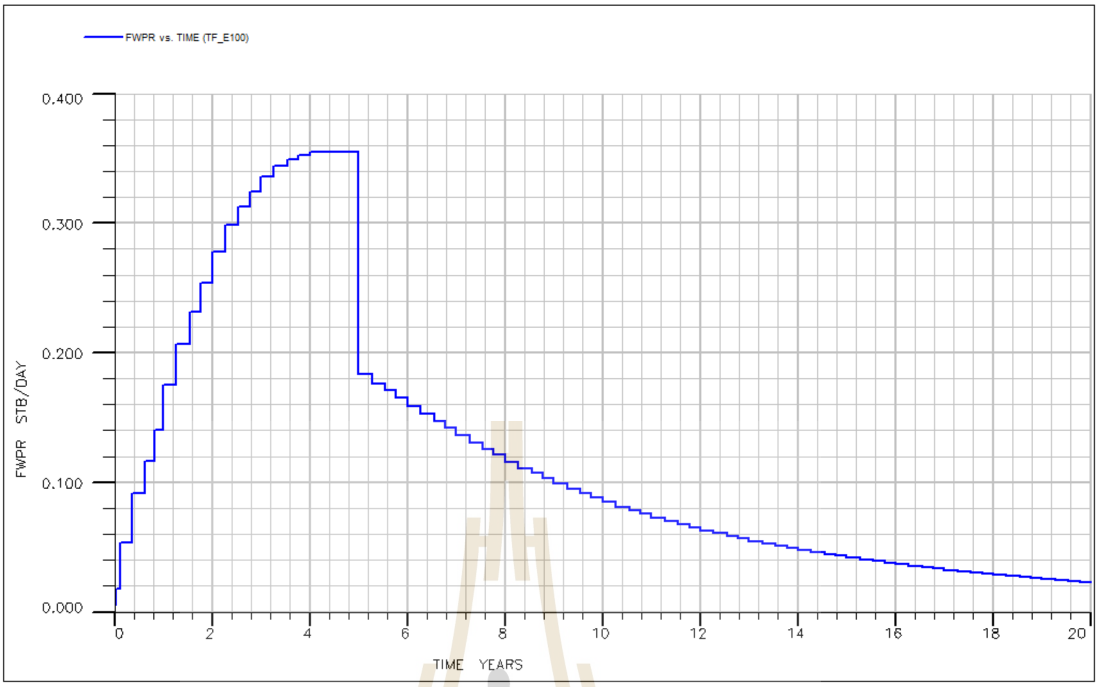
Figures D.82 Oil production total Vs. time of model case 11



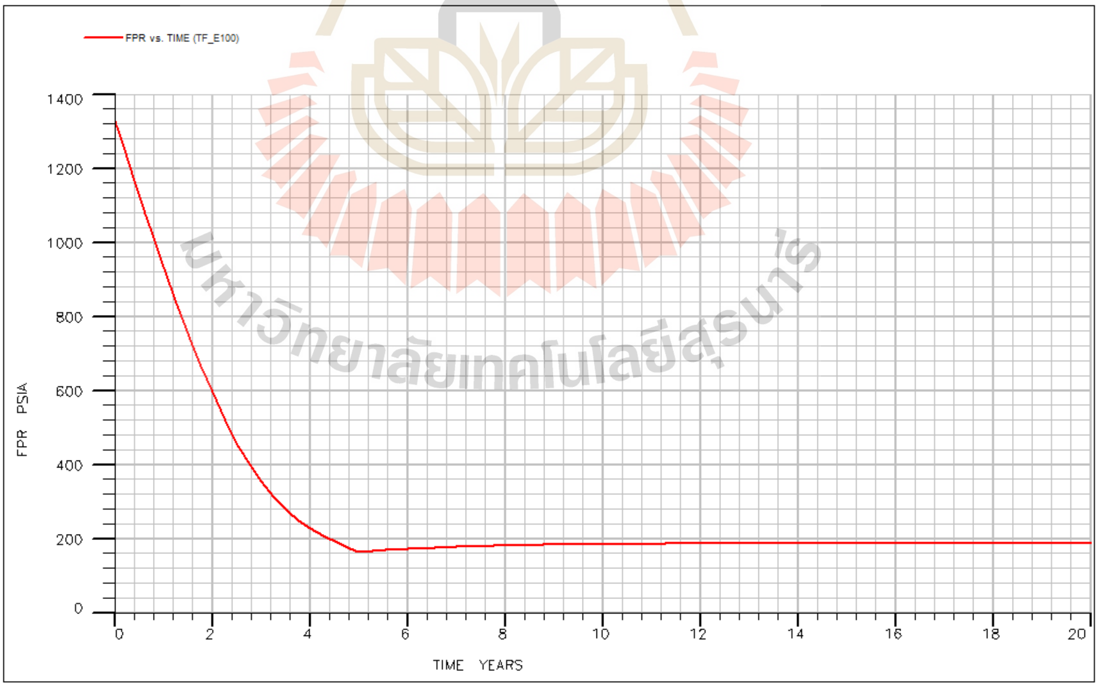
Figures D.83 Water production total Vs. time of model case 11



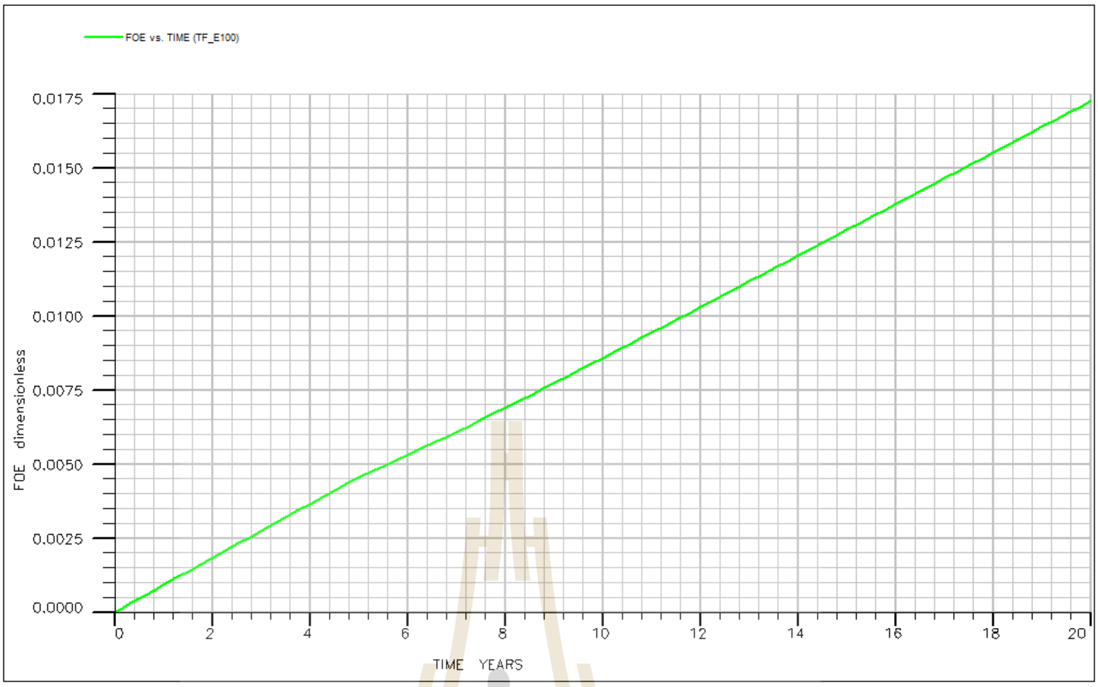
Figures D.84 Oil production rate Vs. time of model case 11



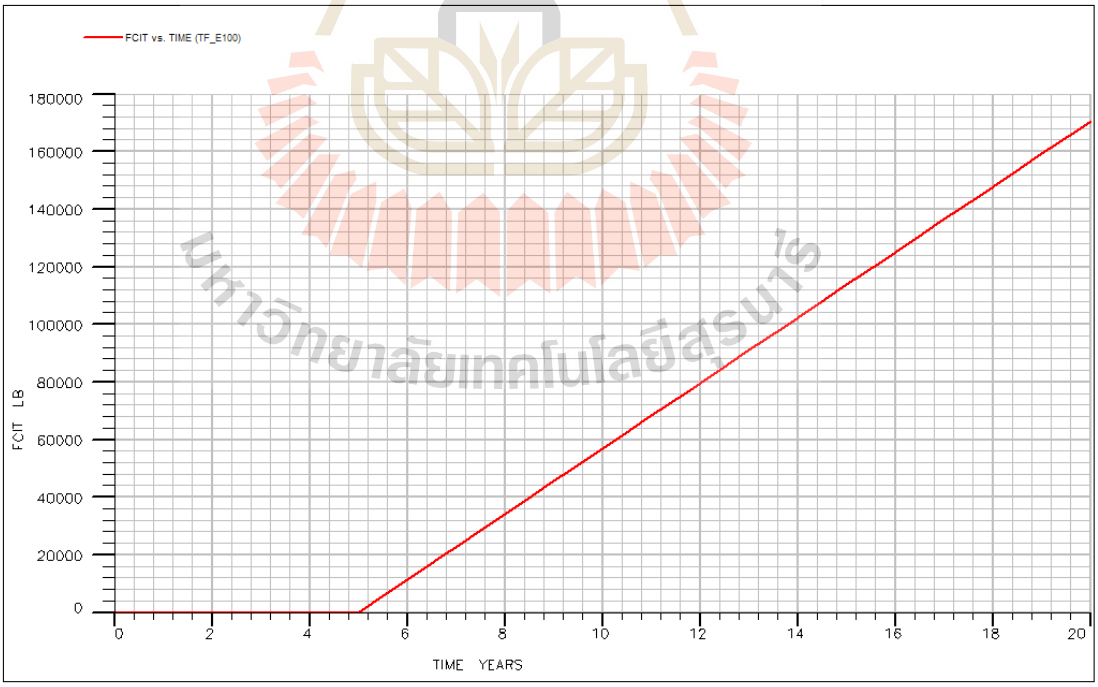
Figures D.85 Water production rate Vs. time of case 11



Figures D.86 Field pressure Vs. time of model case 11



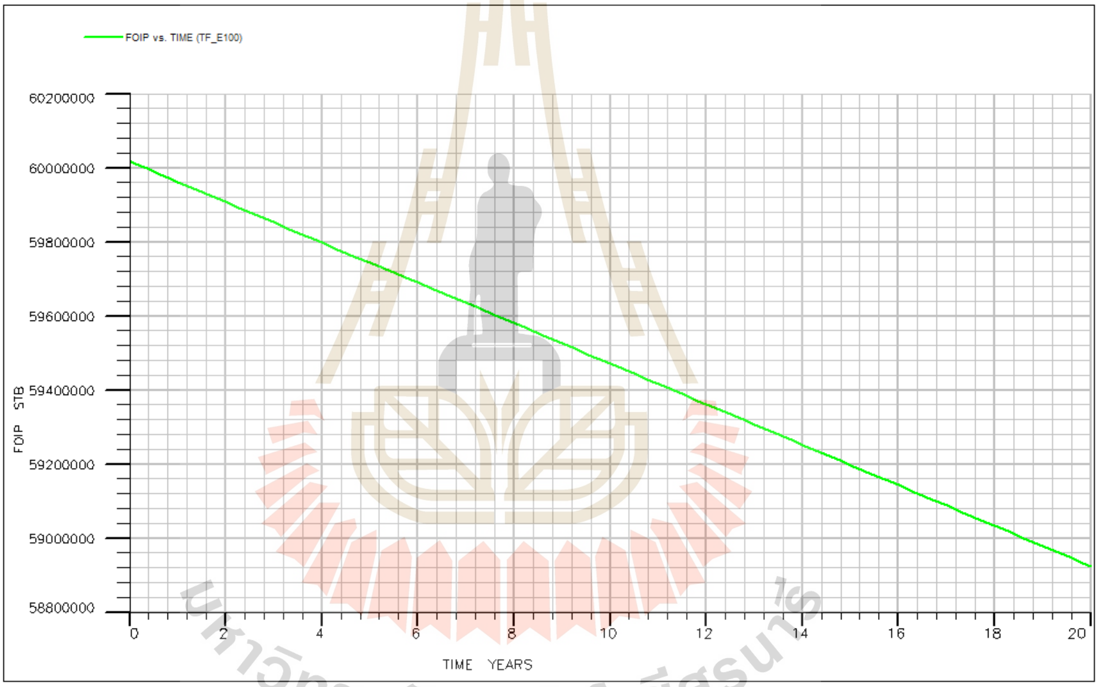
Figures D.87 Oil efficiency Vs. time of model case 11



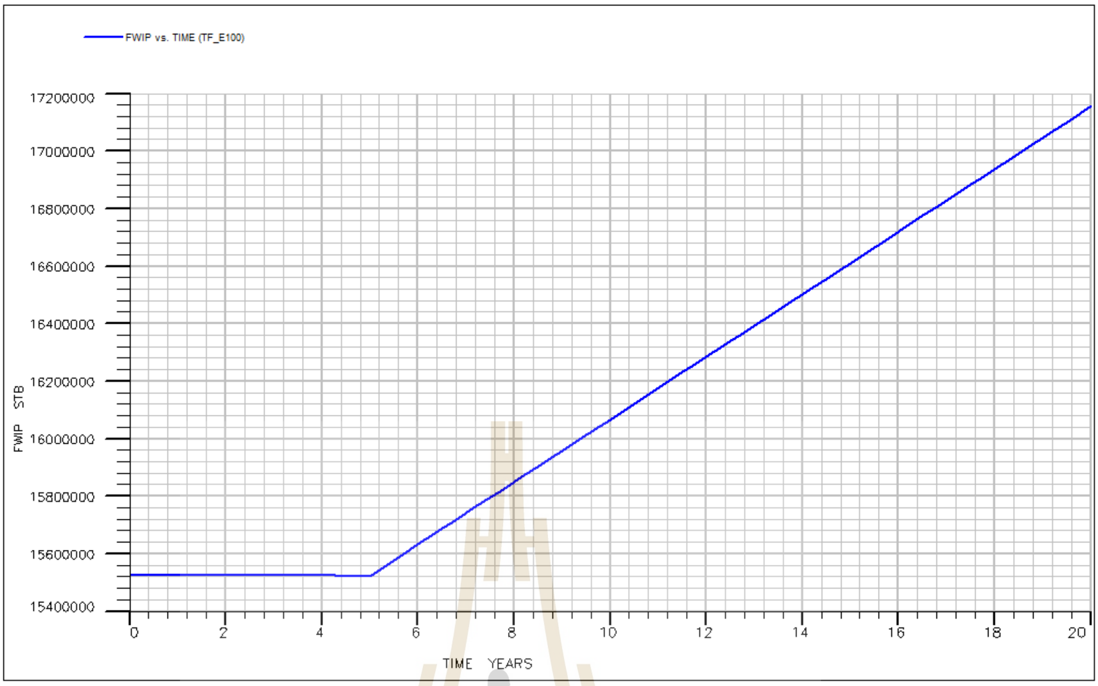
Figures D.88 Polymer injection total Vs. time of model case 11

D.2.5 Result of Model Case 12

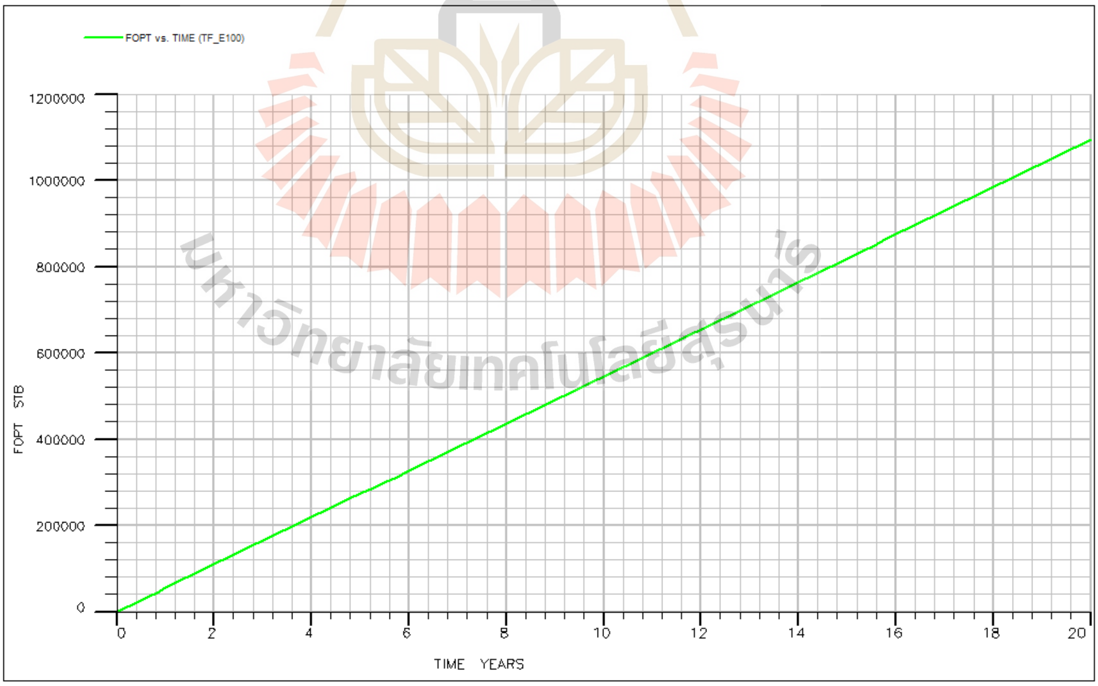
Model case 12 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 600 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.89 - D.97:



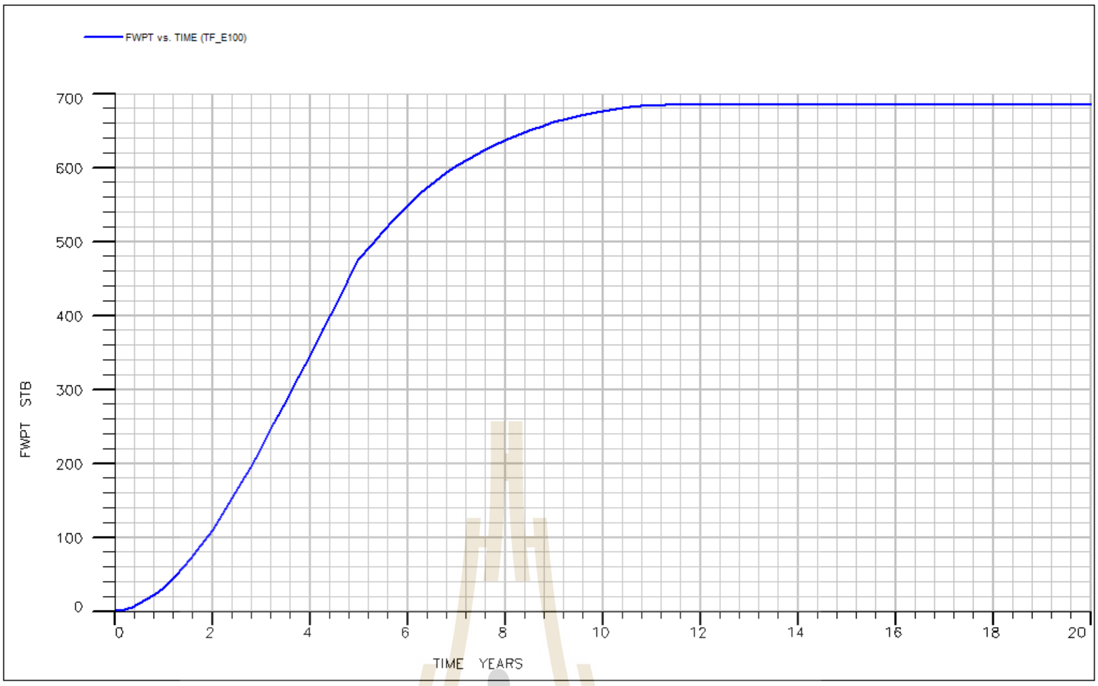
Figures D.89 Oil in place Vs. time of model case 12



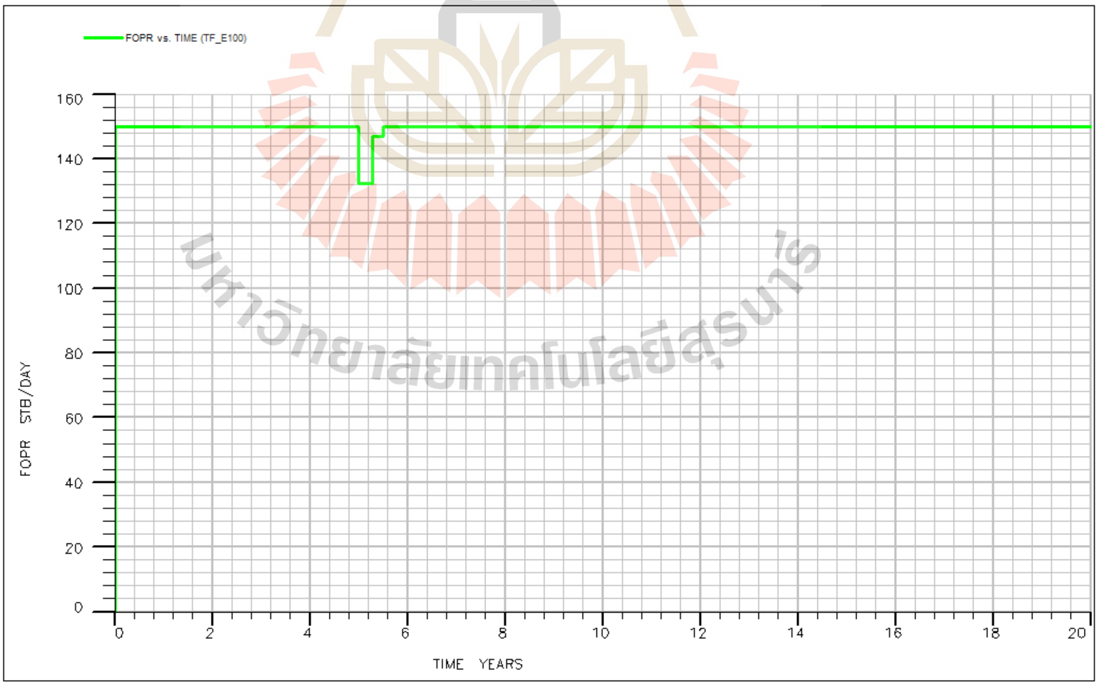
Figures D.90 Water in place Vs. time of model case 12



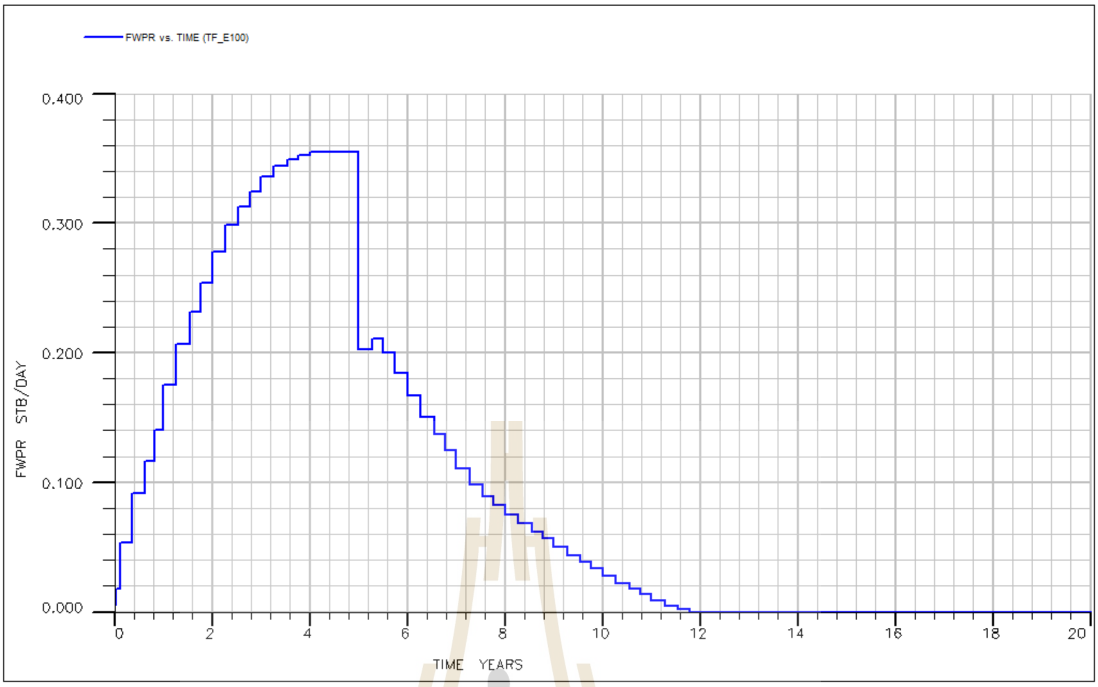
Figures D.91 Oil production total Vs. time of model case 12



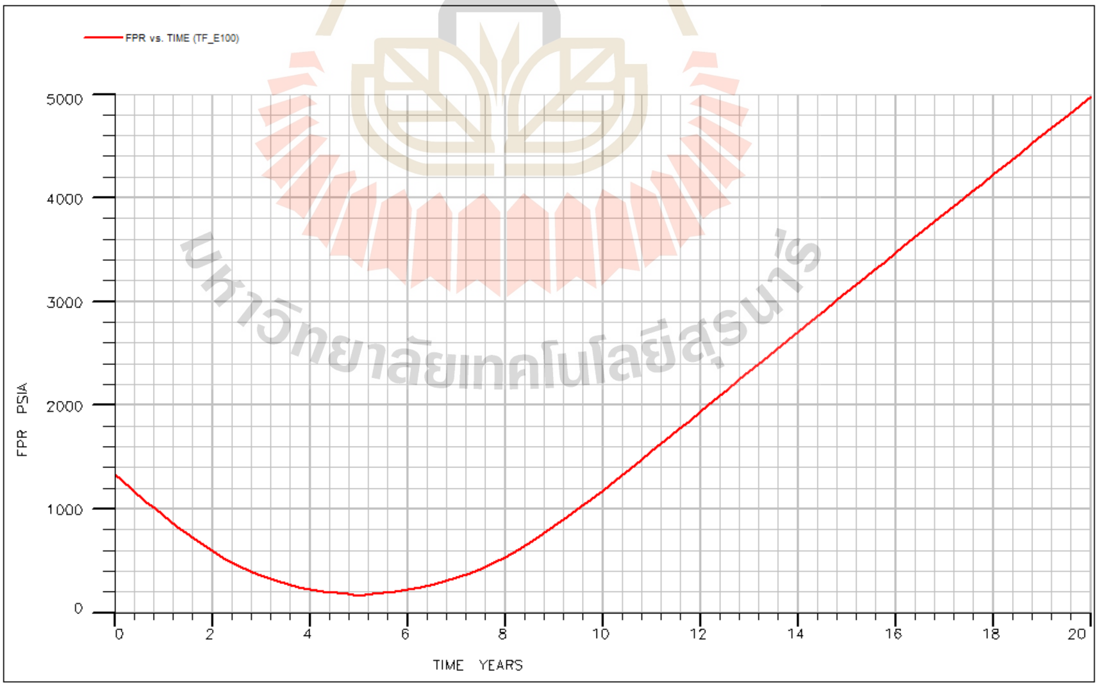
Figures D.92 Water production total Vs. time of model case 12



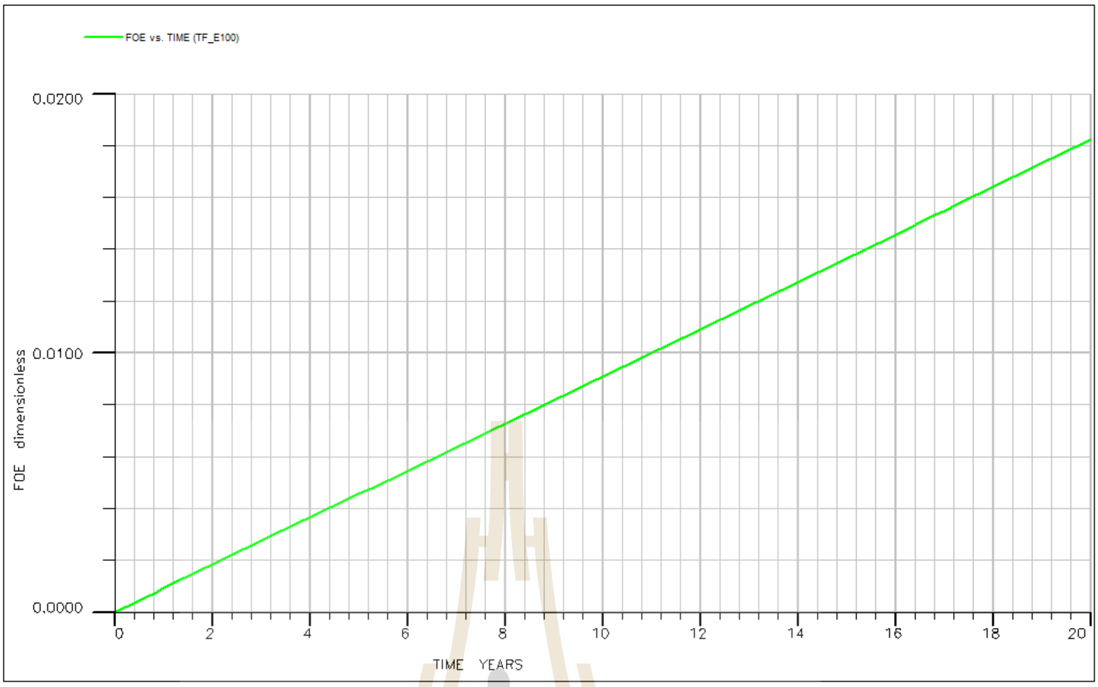
Figures D.93 Oil production rate Vs. time of model case 12



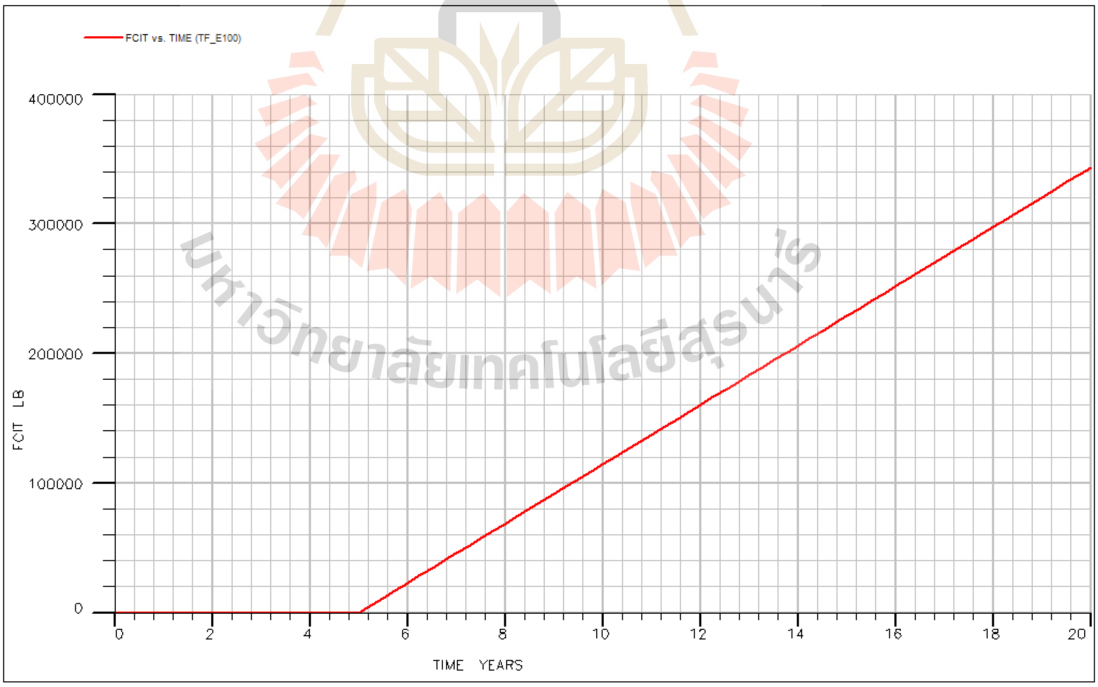
Figures D.94 Water production rate Vs. time of case 12



Figures D.95 Field pressure Vs. time of model case 12



Figures D.96 Oil efficiency Vs. time of model case 12

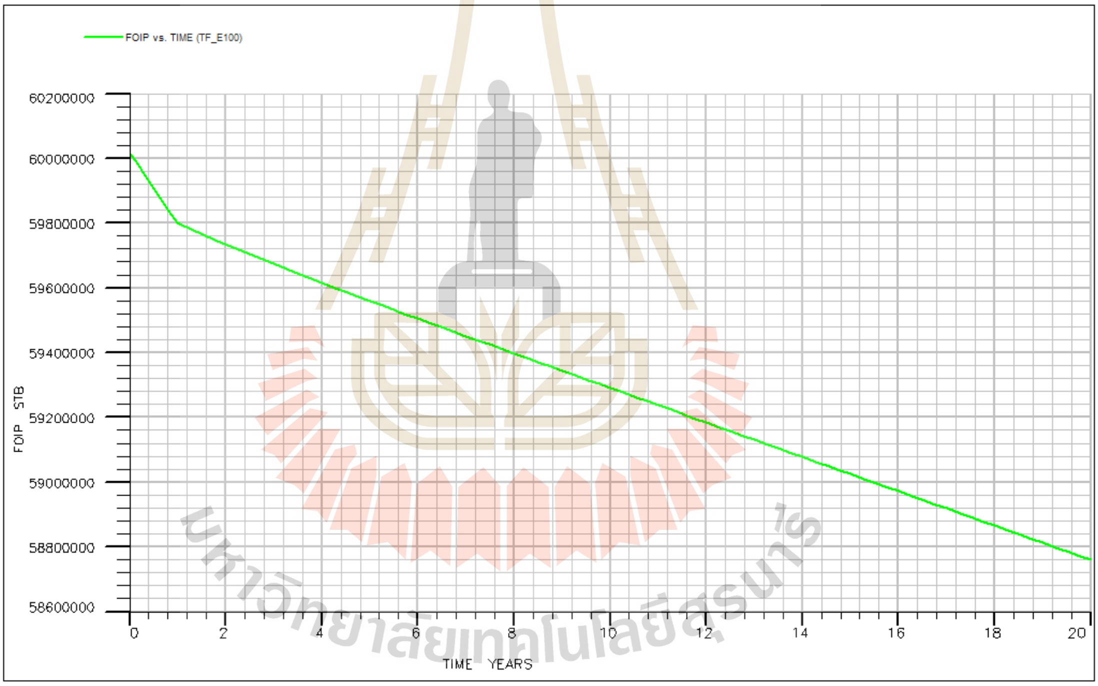


Figures D.97 Polymer injection total Vs. time of model case 12

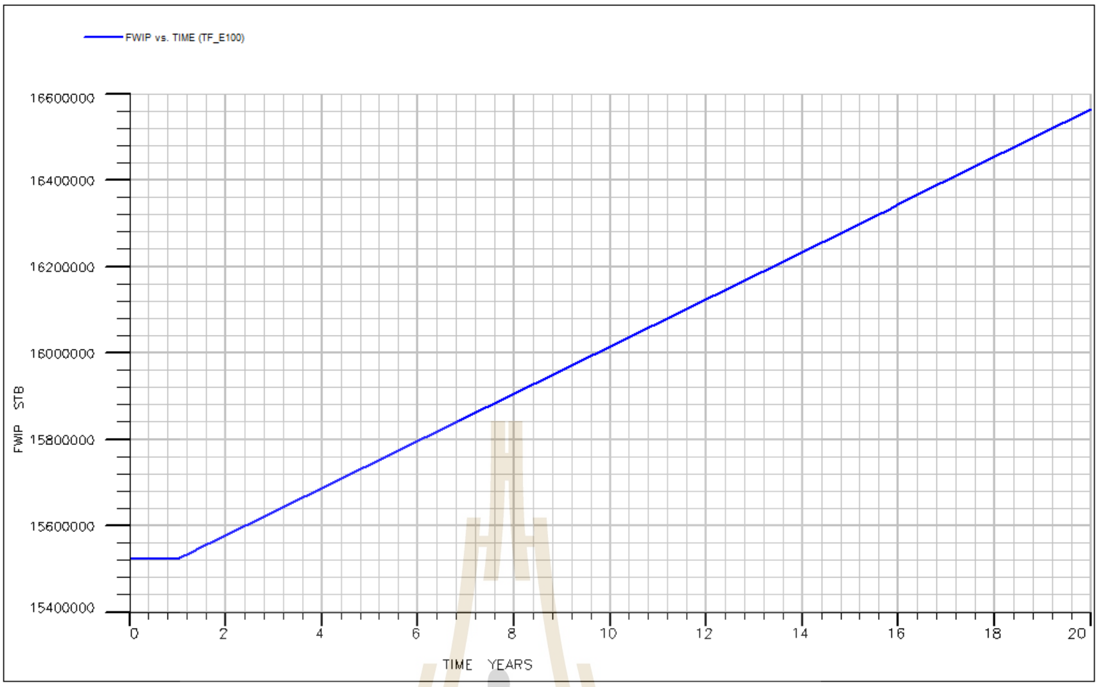
D.3 Reservoir simulation result for case polymer flooding concentration 1000 ppm

D.3.1 Result of Model Case 13

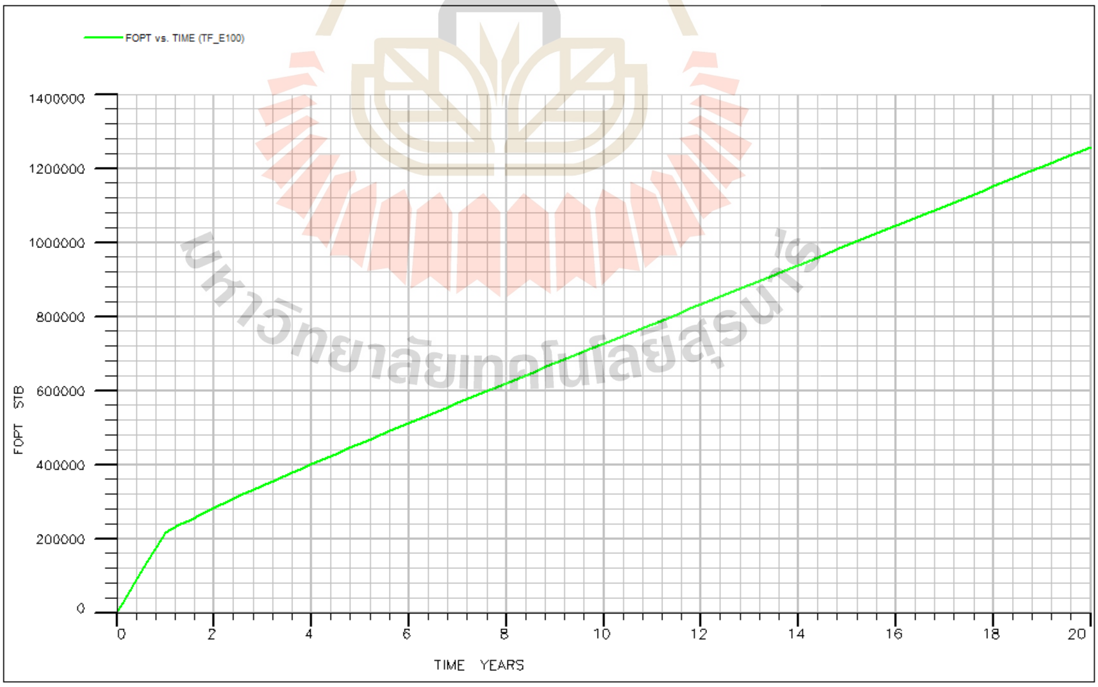
Model case 13 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.98 - D.106:



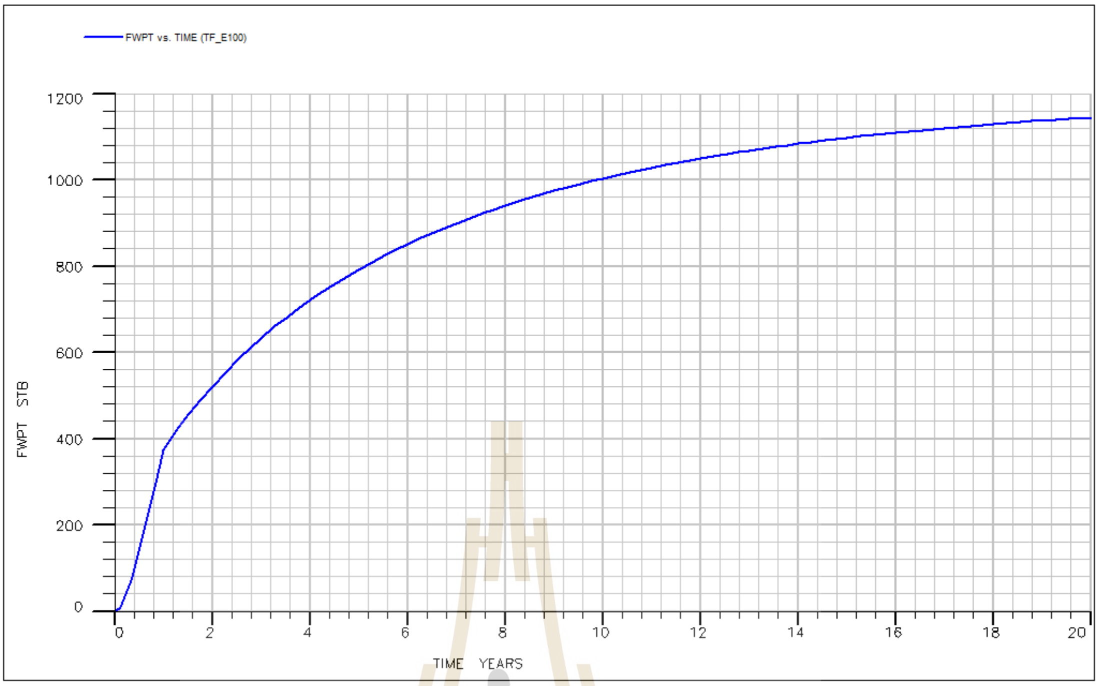
Figures D.98 Oil in place Vs. time of model case 13



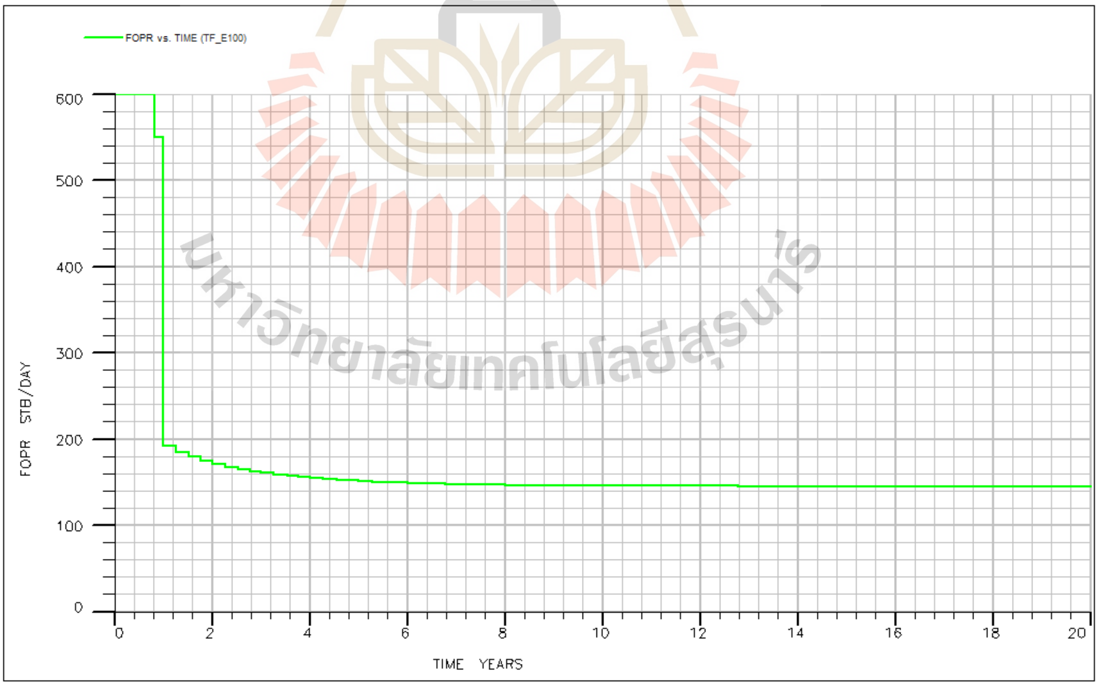
Figures D.99 Water in place Vs. time of model case 13



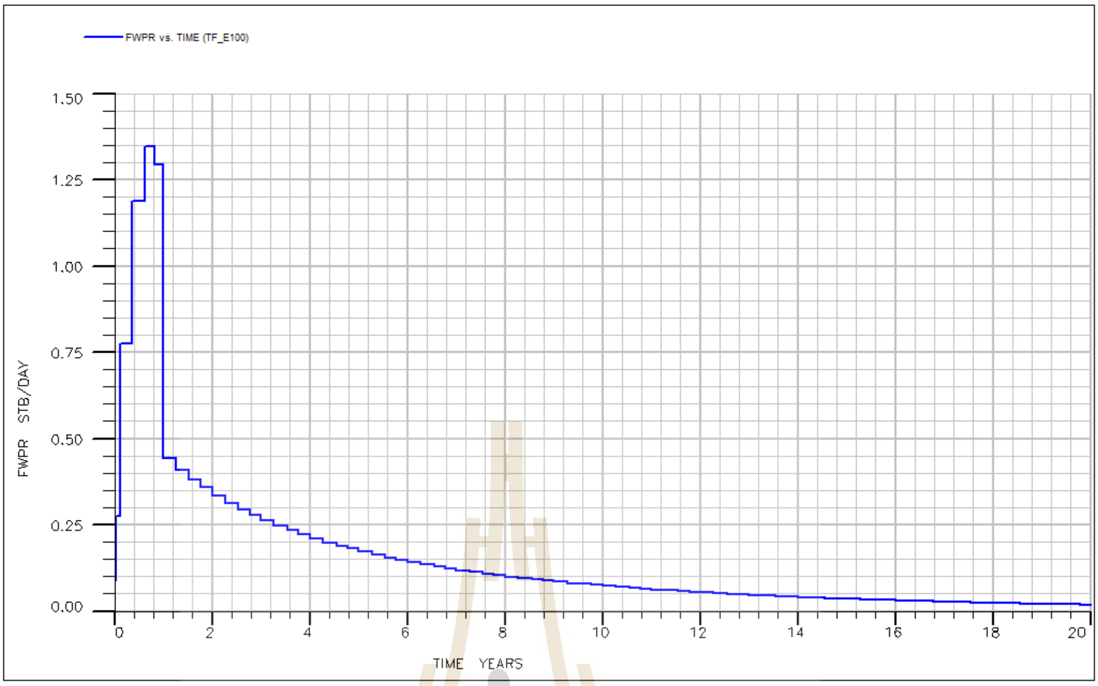
Figures D.100 Oil production total Vs. time of model case 13



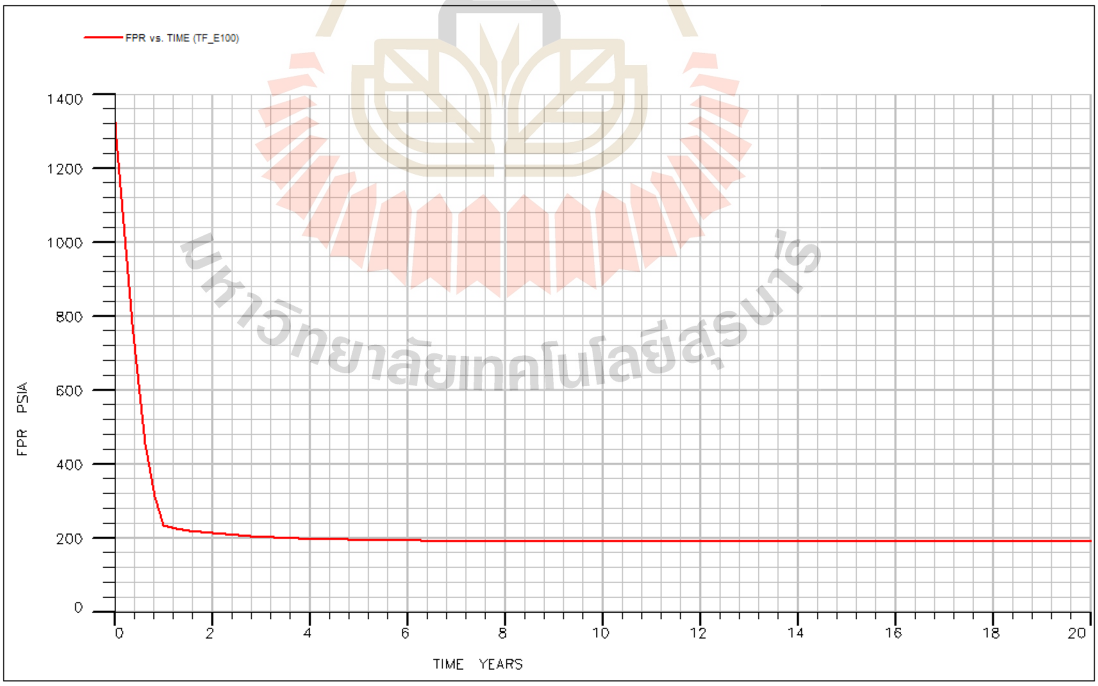
Figures D.101 Water production total Vs. time of model case 13



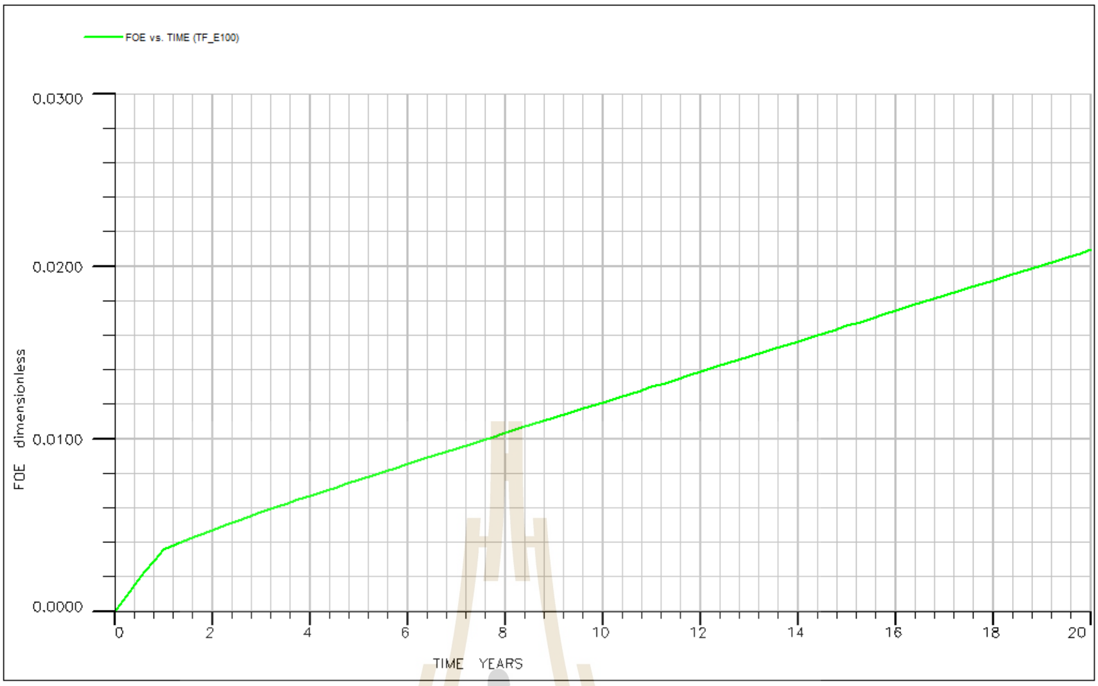
Figures D.102 Oil production rate Vs. time of model case 13



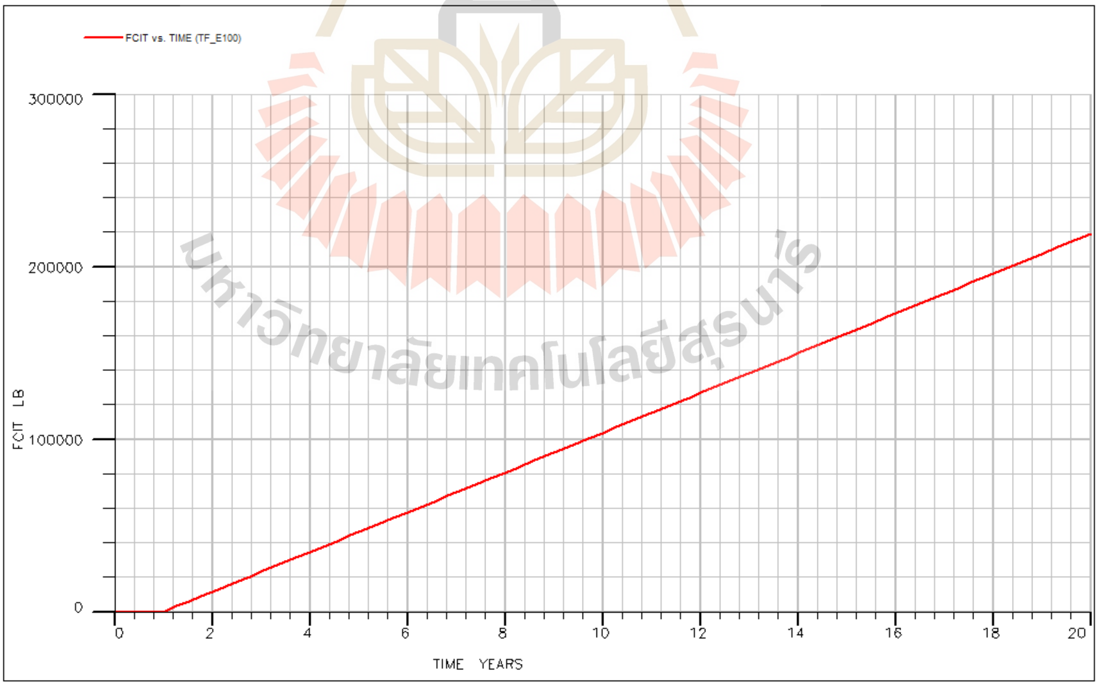
Figures D.103 Water production rate Vs. time of case 13



Figures D.104 Field pressure Vs. time of model case 13



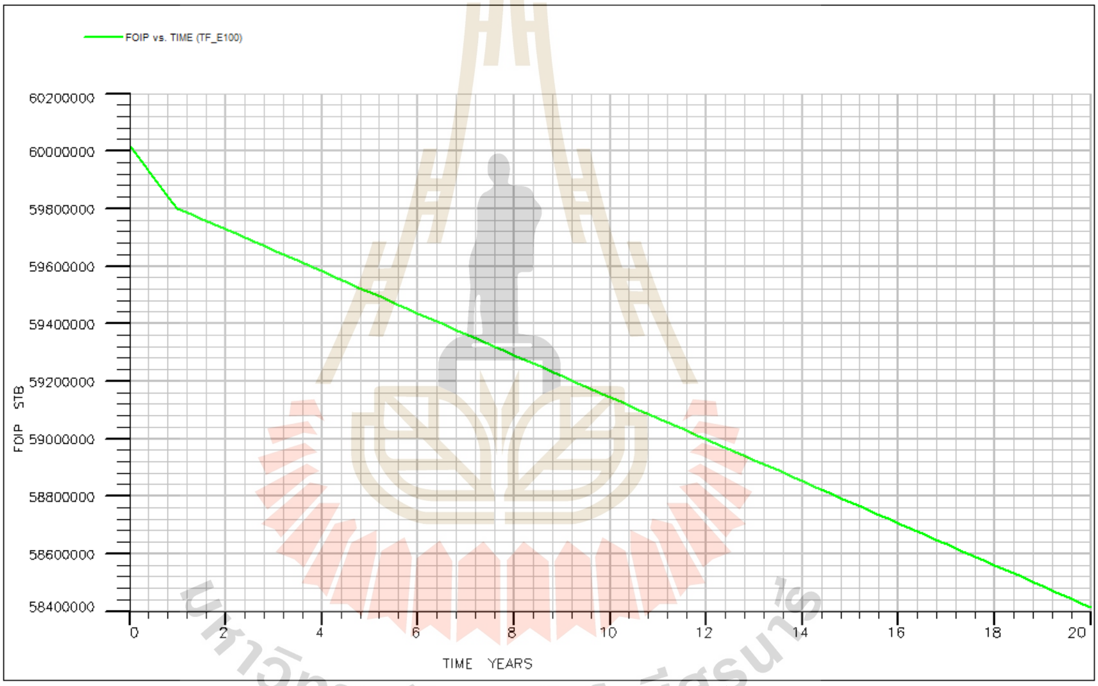
Figures D.105 Oil efficiency Vs. time of model case 13



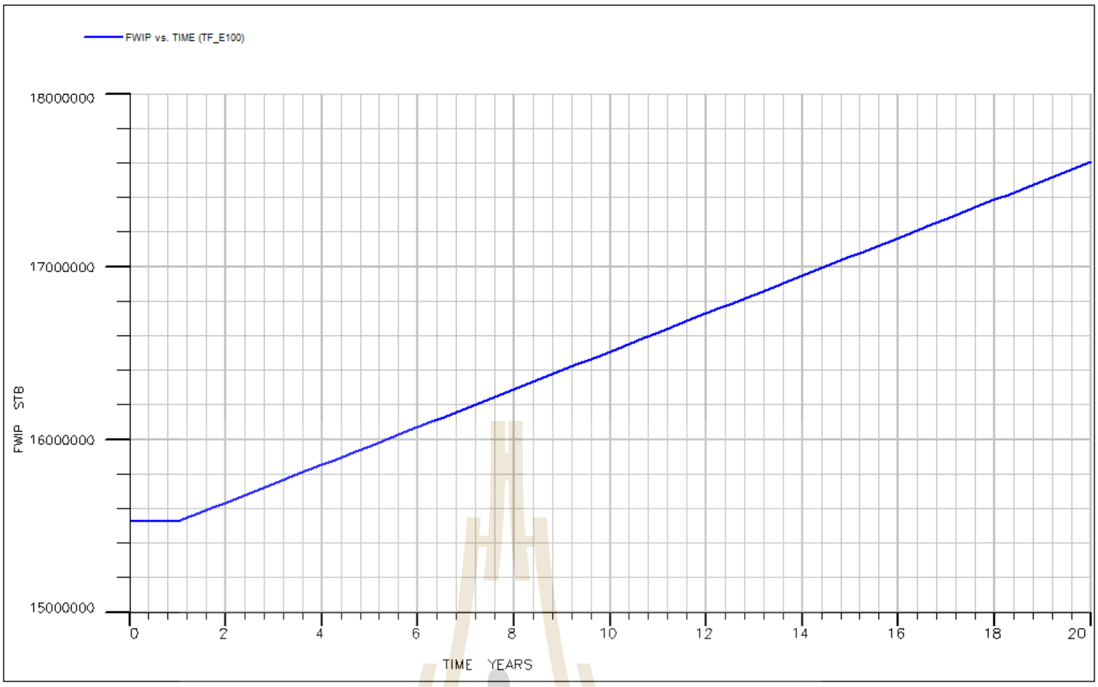
Figures D.106 Polymer injection total Vs. time of model case 13

D.3.2 Result of Model Case 14

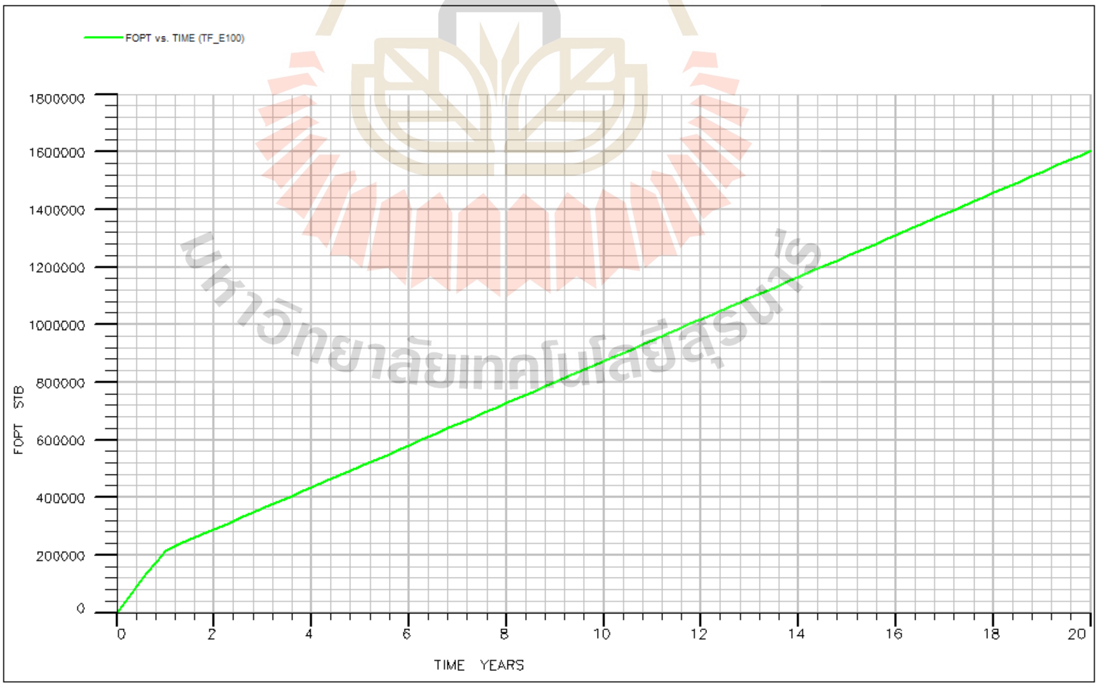
Model case 14 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.107 - D.115:



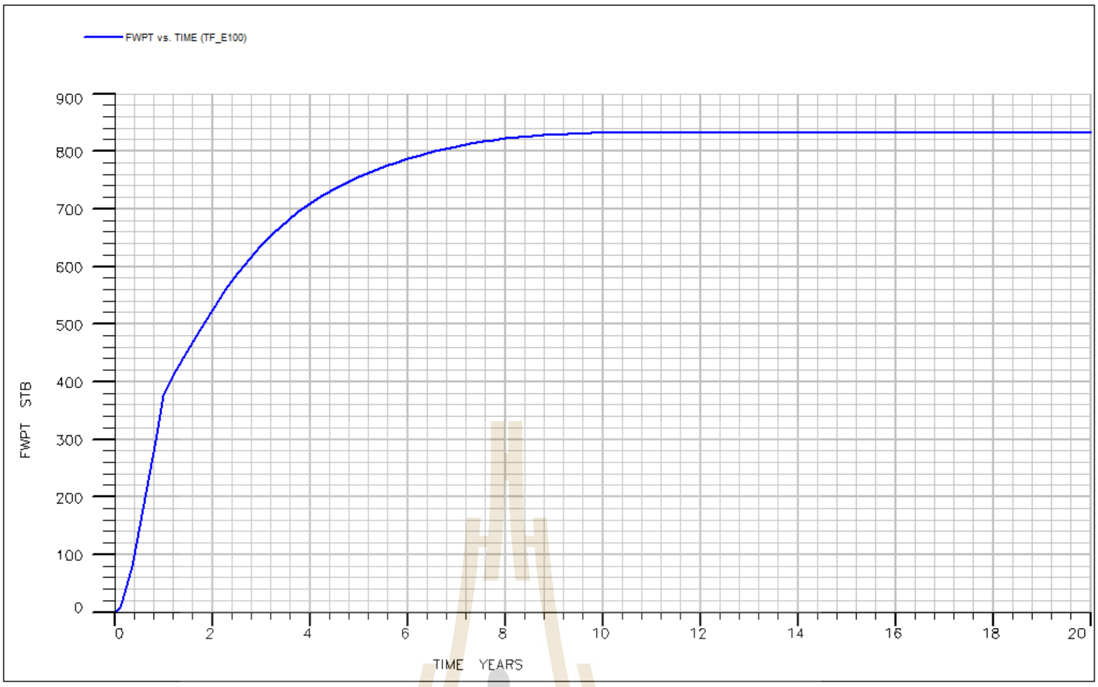
Figures D.107 Oil in place Vs. time of model case 14



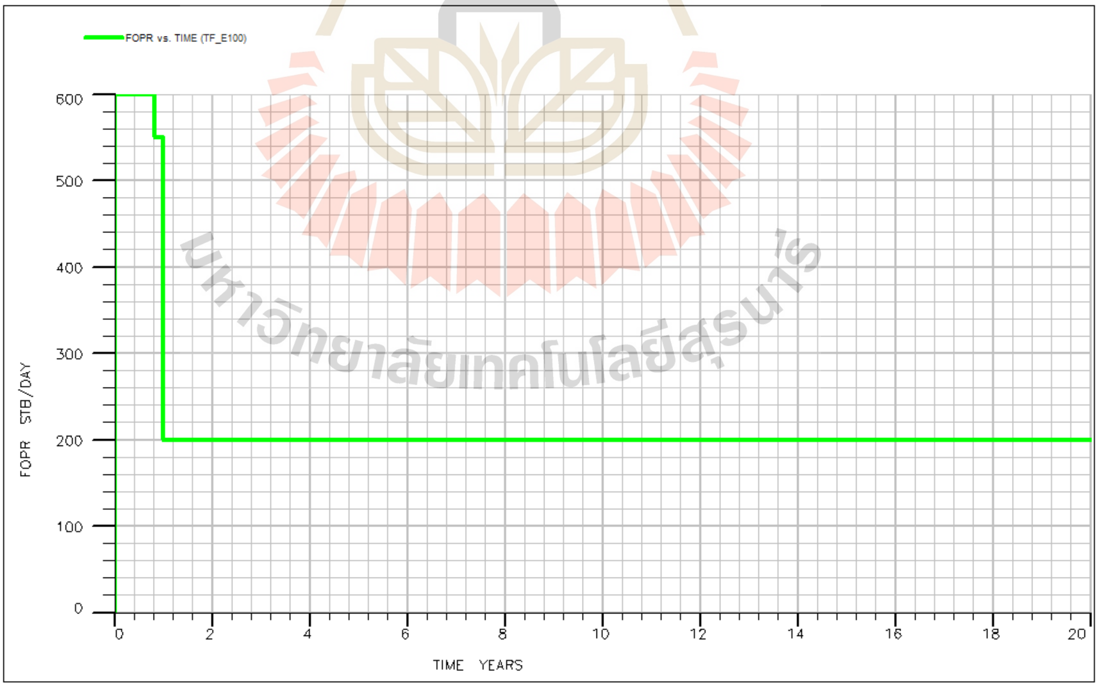
Figures D.108 Water in place Vs. time of model case 14



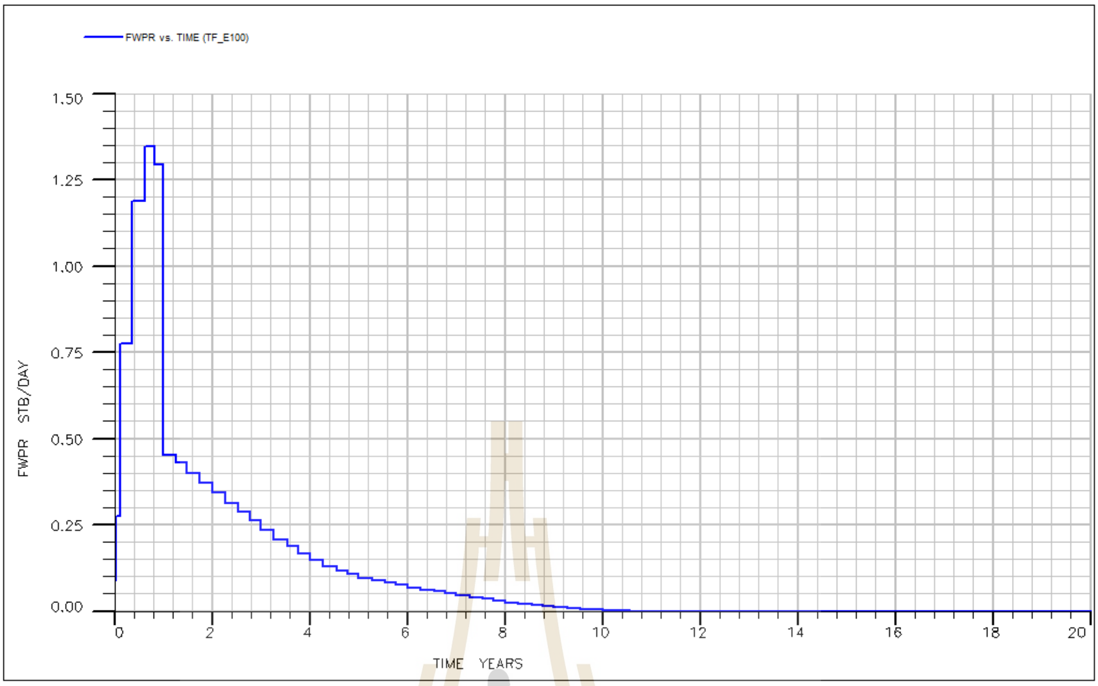
Figures D.109 Oil production total Vs. time of model case 14



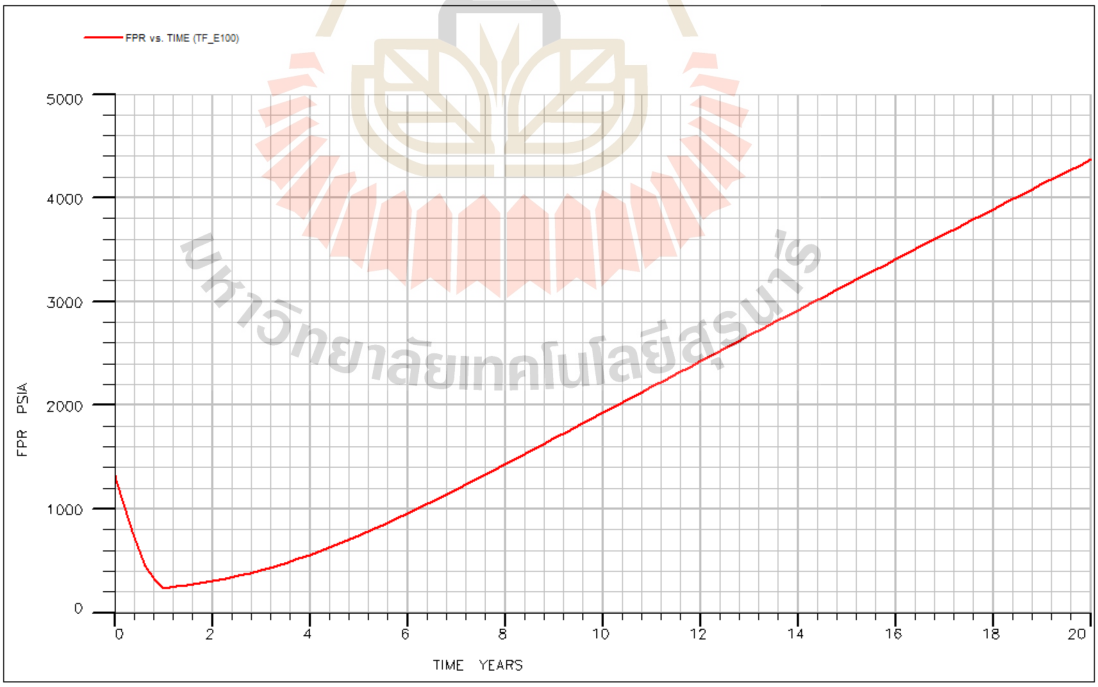
Figures D.110 Water production total Vs. time of model case 14



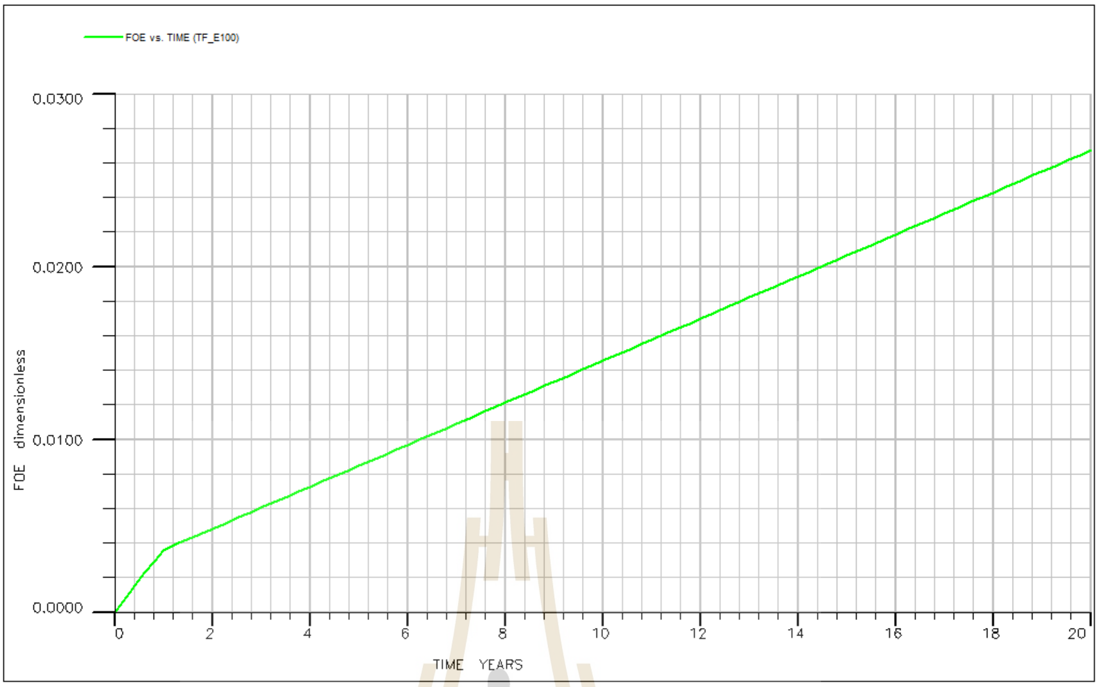
Figures D.111 Oil production rate Vs. time of model case 14



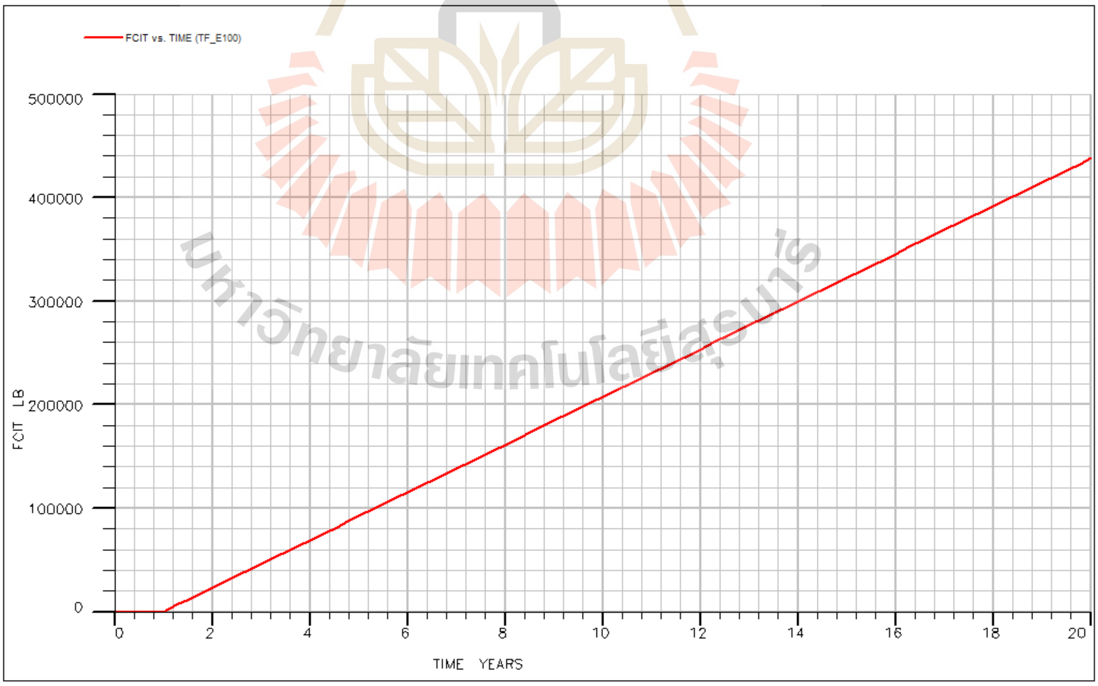
Figures D.112 Water production rate Vs. time of case 14



Figures D.113 Field pressure Vs. time of model case 14



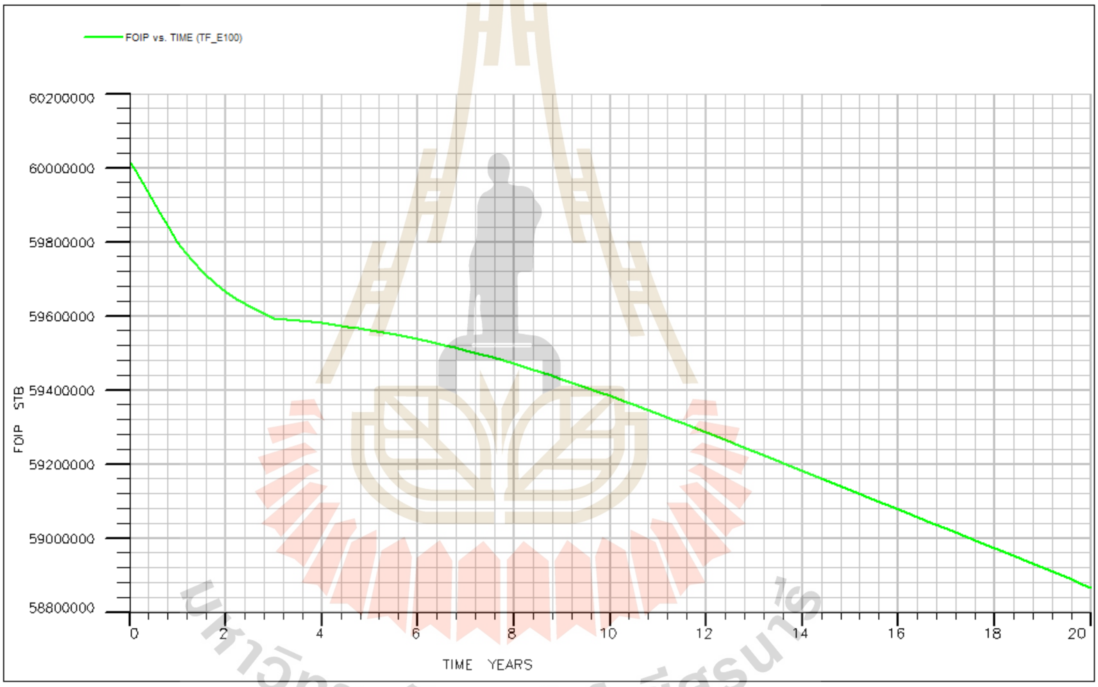
Figures D.114 Oil efficiency Vs. time of model case 14



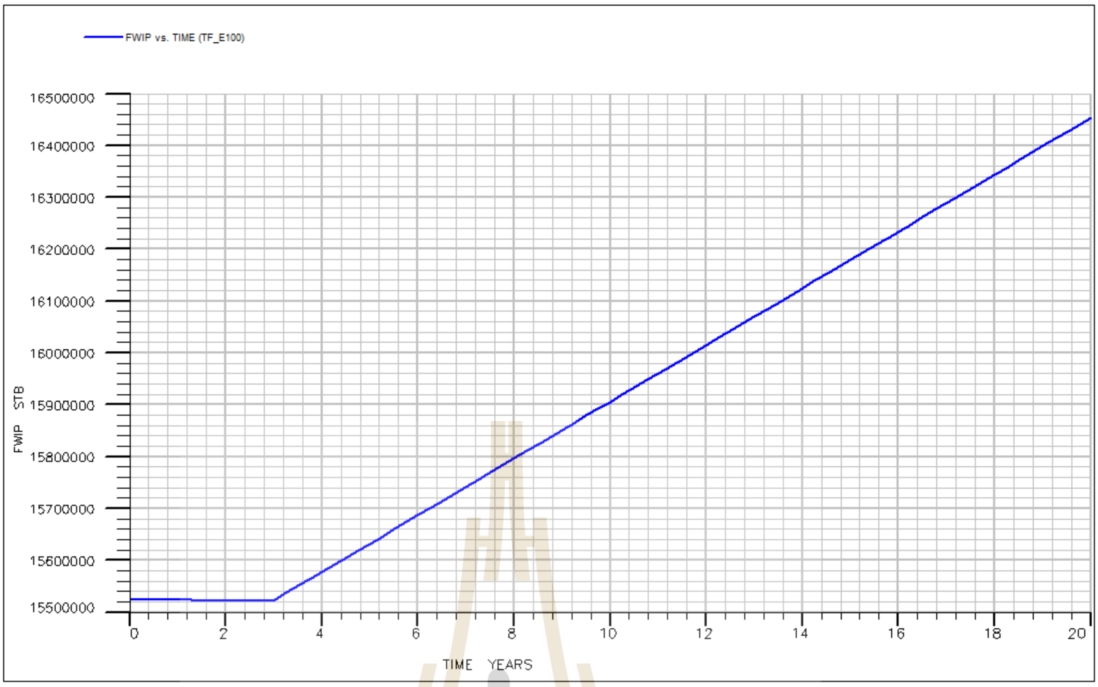
Figures D.115 Polymer injection total Vs. time of model case 14

D.3.3 Result of Model Case 15

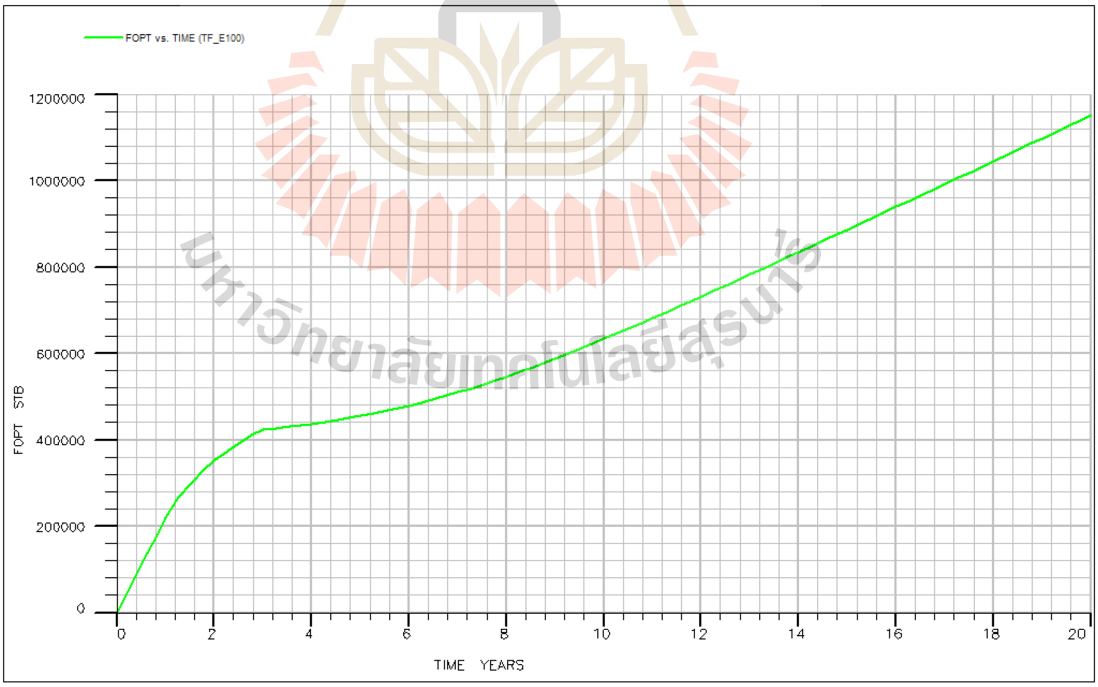
Model case 15 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.116 - D.124:



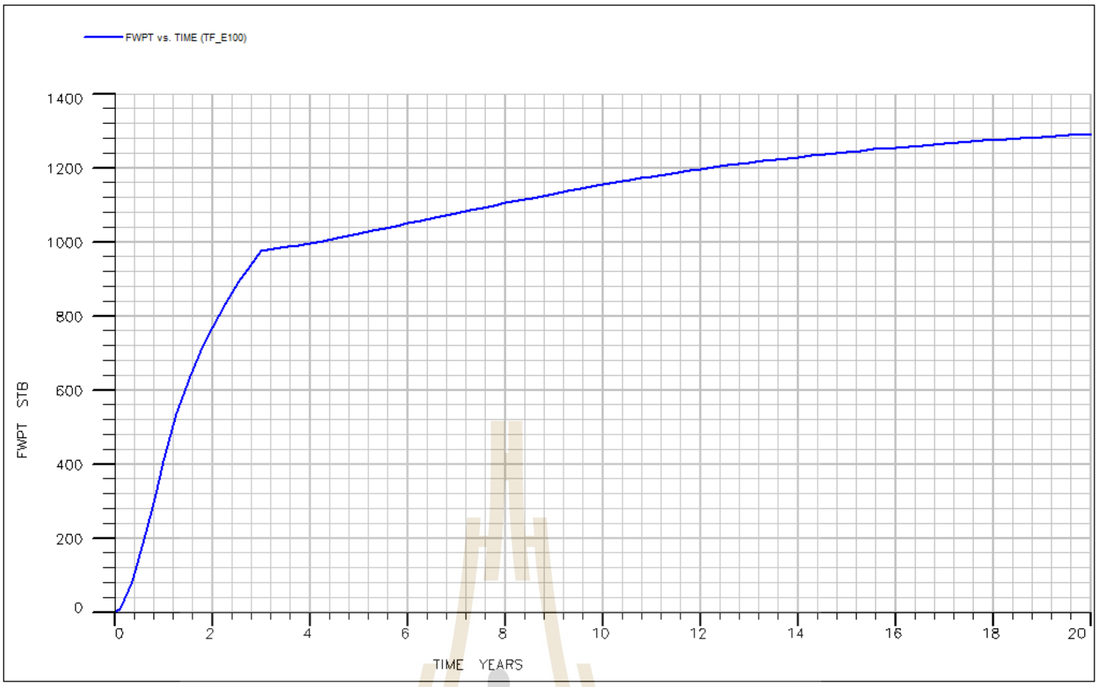
Figures D.116 Oil in place Vs. time of model case 15



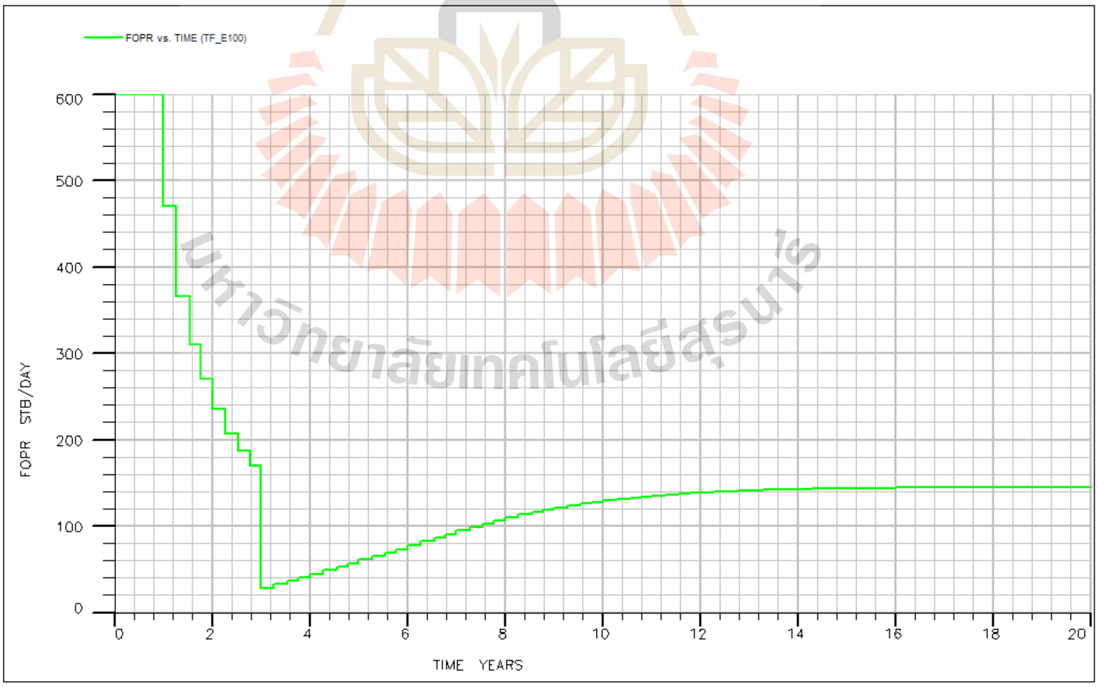
Figures D.117 Water in place Vs. time of model case 15



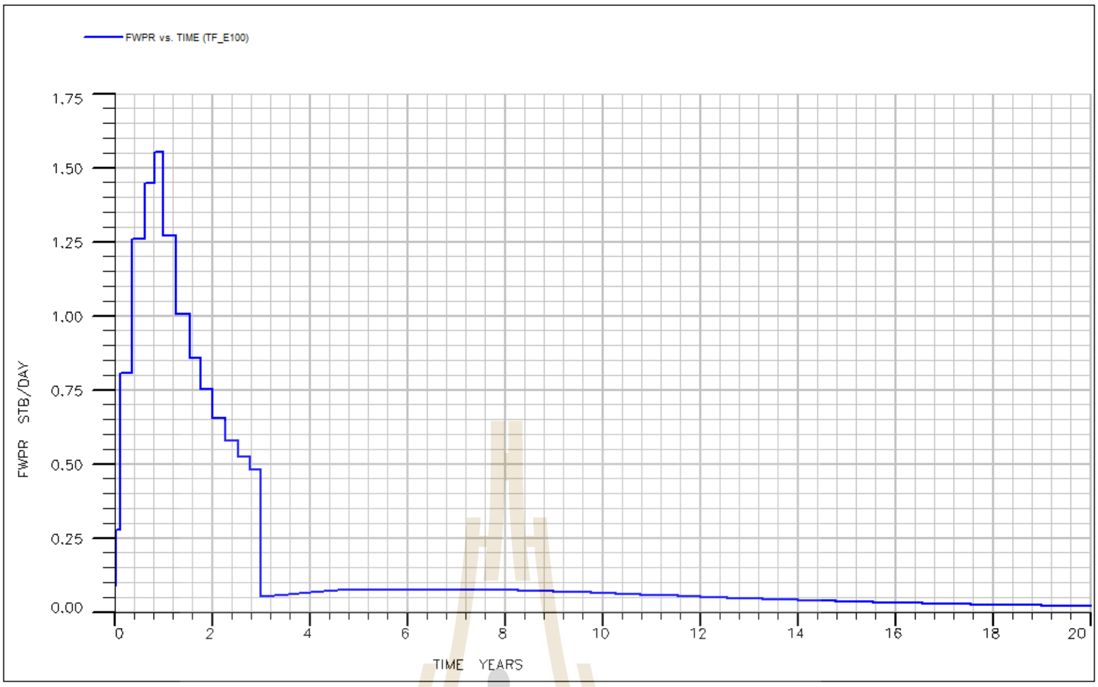
Figures D.118 Oil production total Vs. time of model case 15



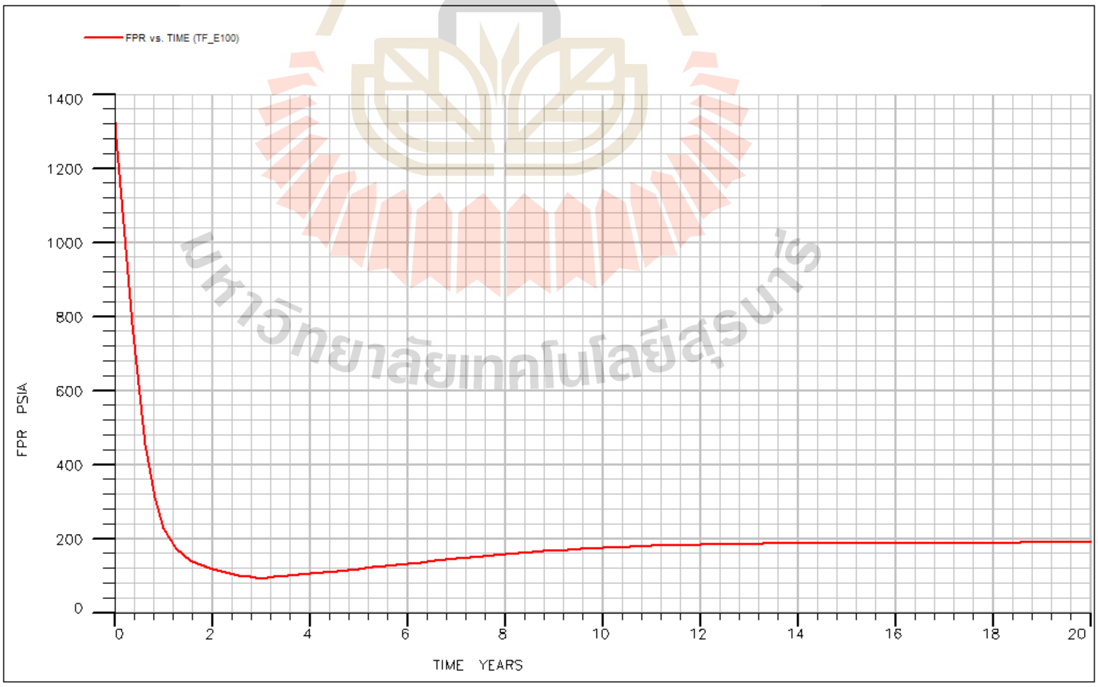
Figures D.119 Water production total Vs. time of model case 15



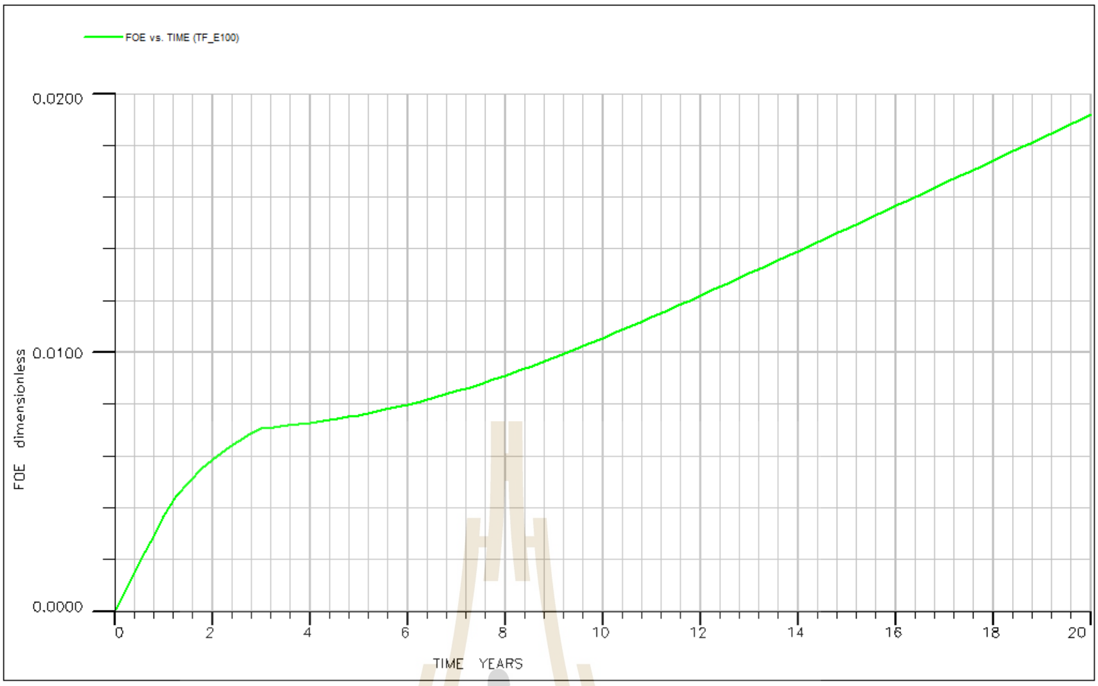
Figures D.120 Oil production rate Vs. time of model case 15



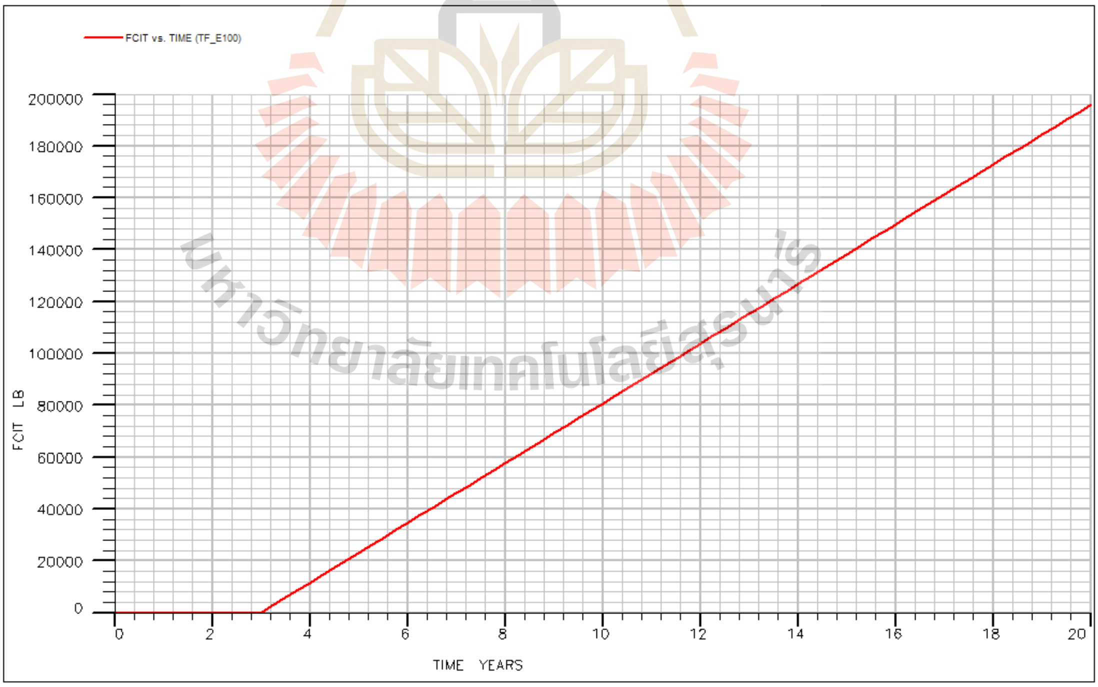
Figures D.121 Water production rate Vs. time of case 15



Figures D.122 Field pressure Vs. time of model case 15



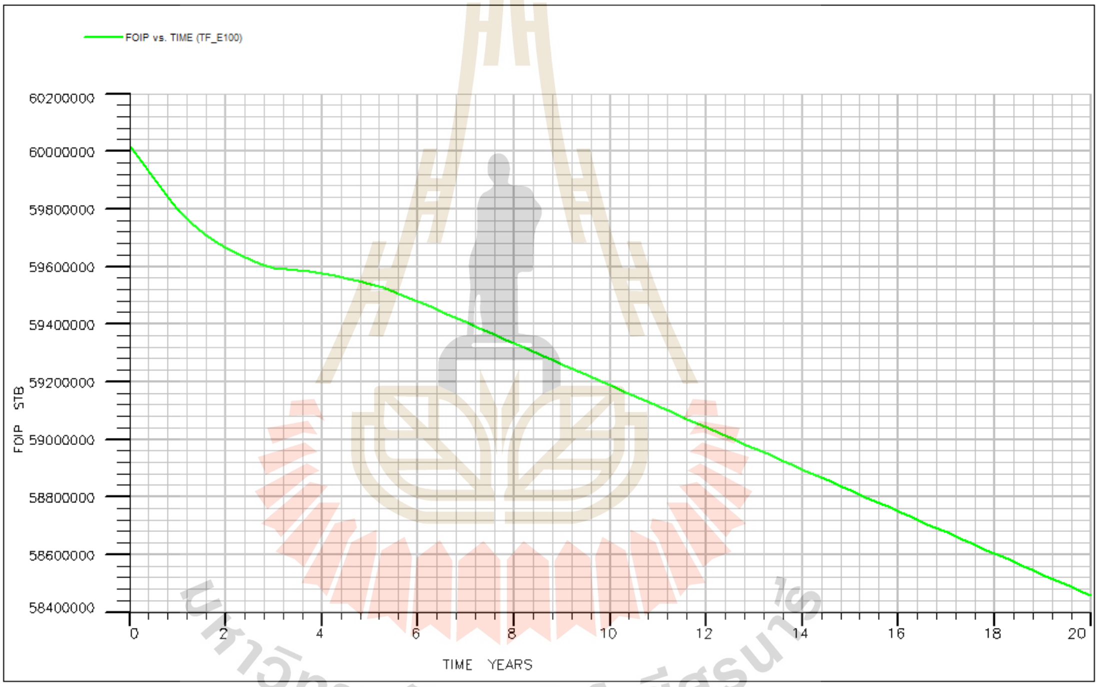
Figures D.123 Oil efficiency Vs. time of model case 15



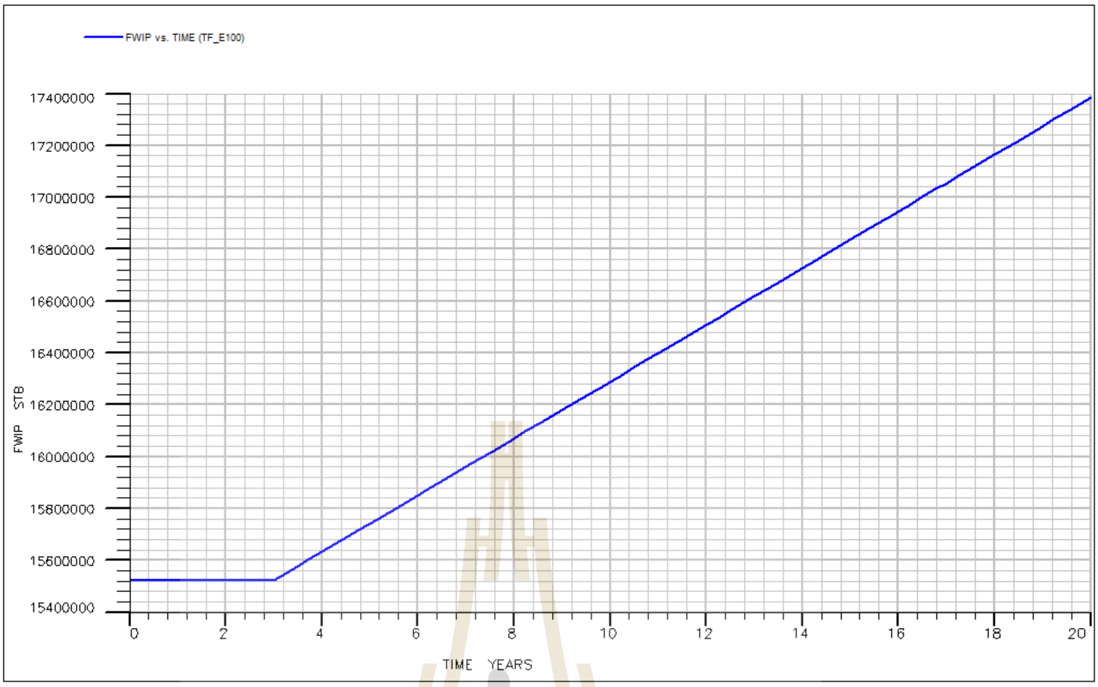
Figures D.124 Polymer injection total Vs. time of model case 15

D.3.4 Result of Model Case 16

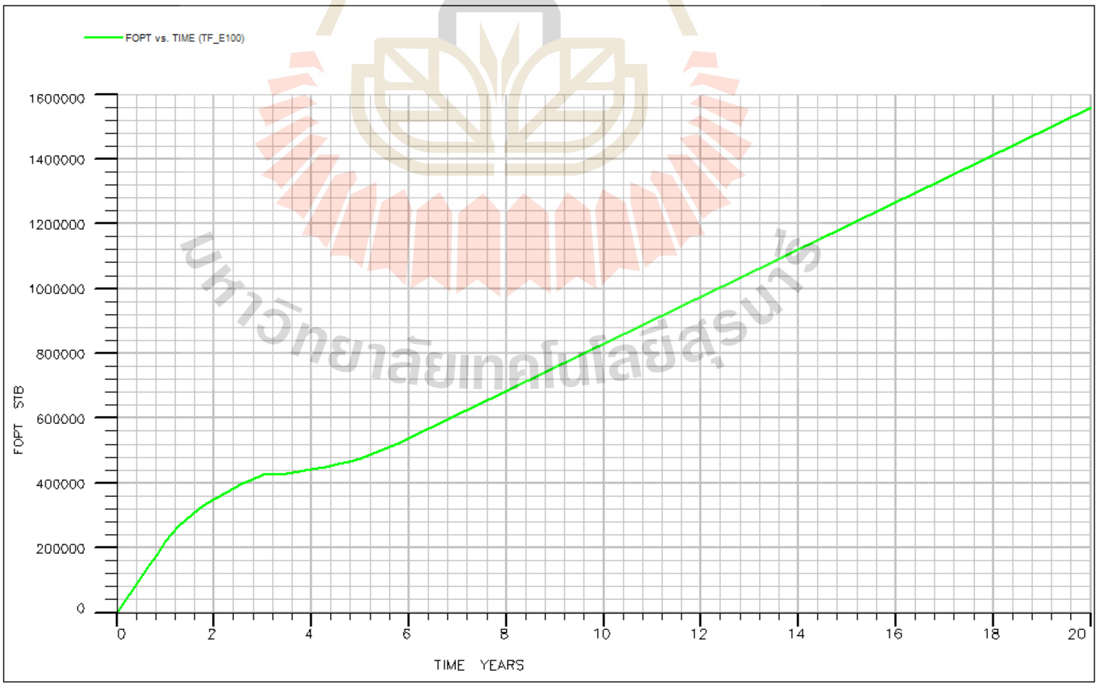
Model case 16 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.125 - D.133:



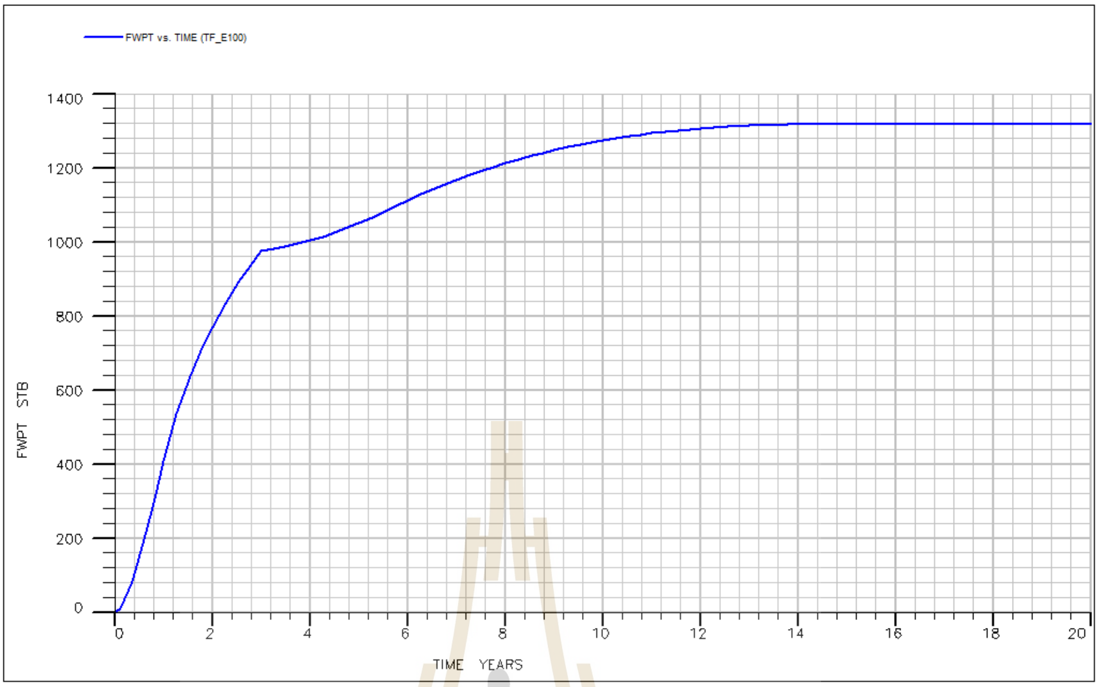
Figures D.125 Oil in place Vs. time of model case 16



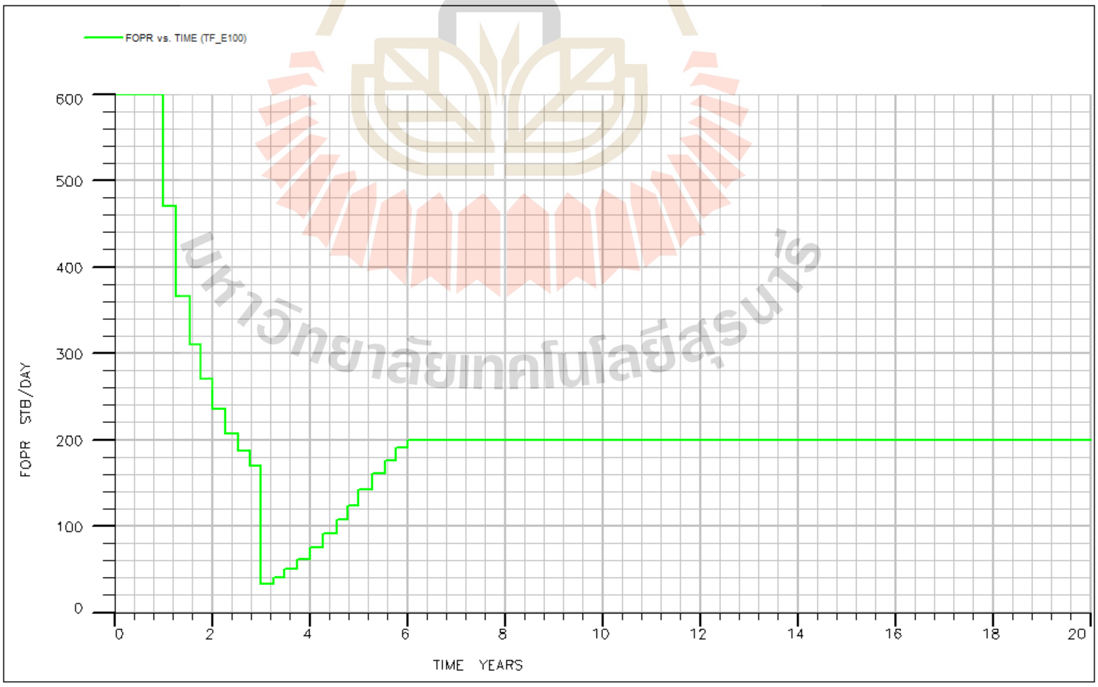
Figures D.126 Water in place Vs. time of model case 16



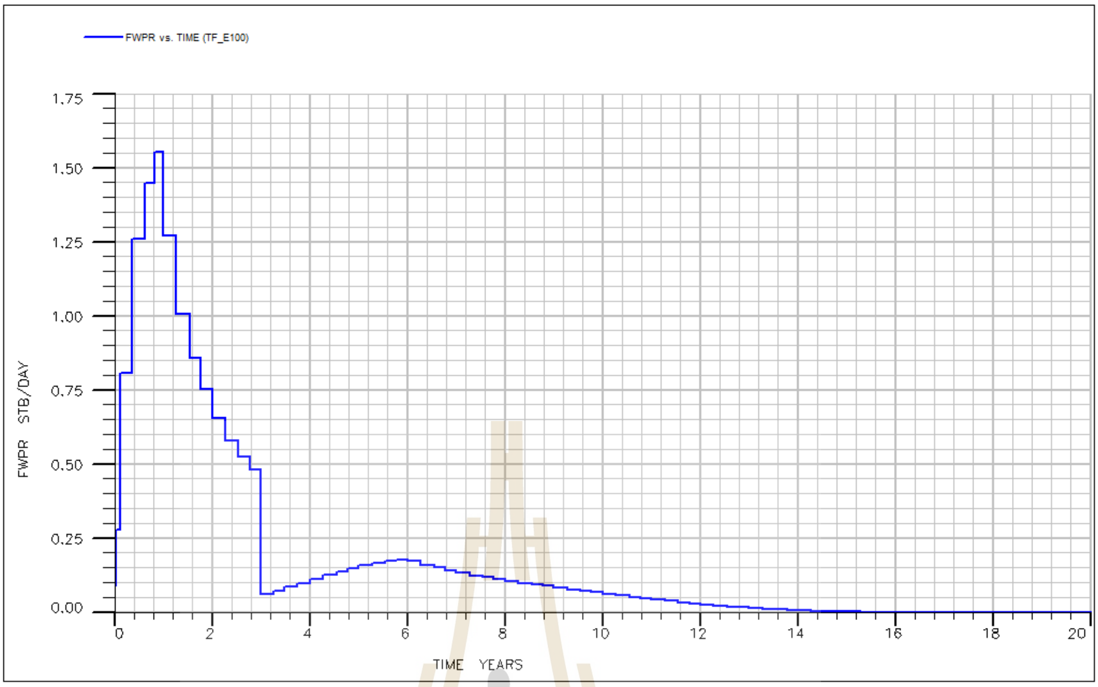
Figures D.127 Oil production total Vs. time of model case 16



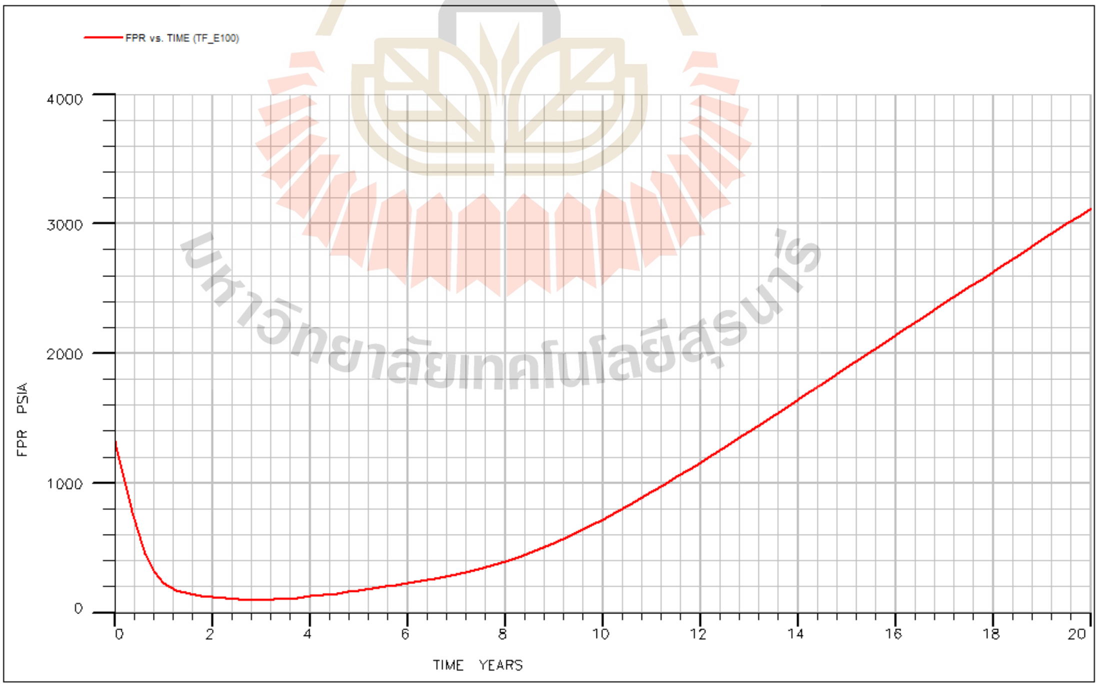
Figures D.128 Water production total Vs. time of model case 16



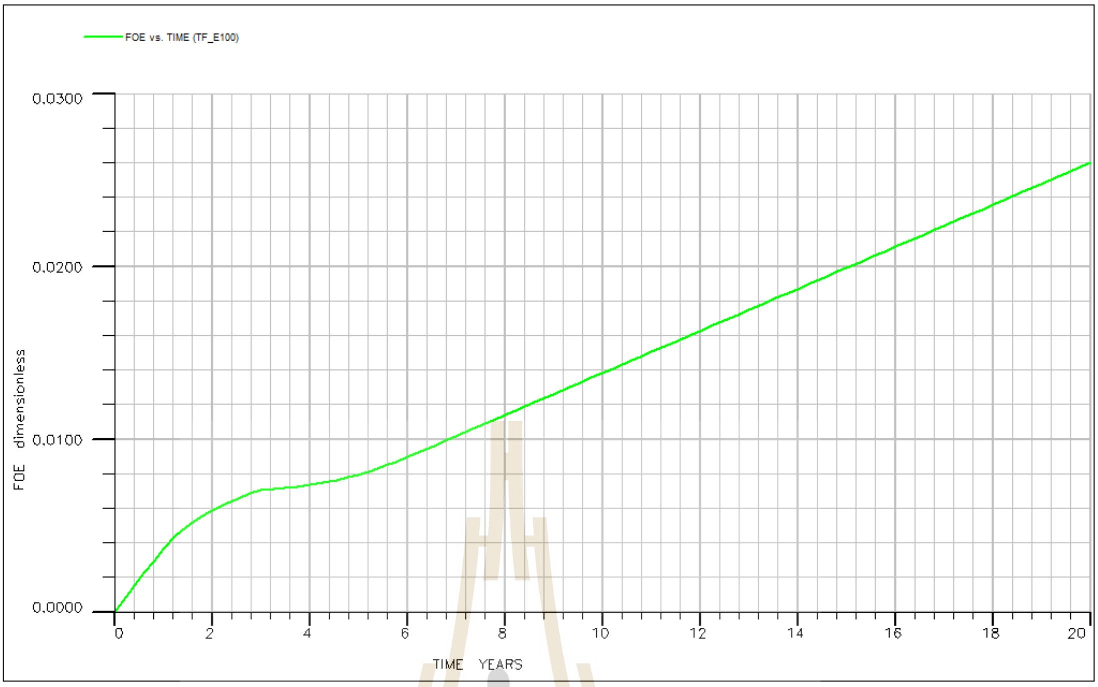
Figures D.129 Oil production rate Vs. time of model case 16



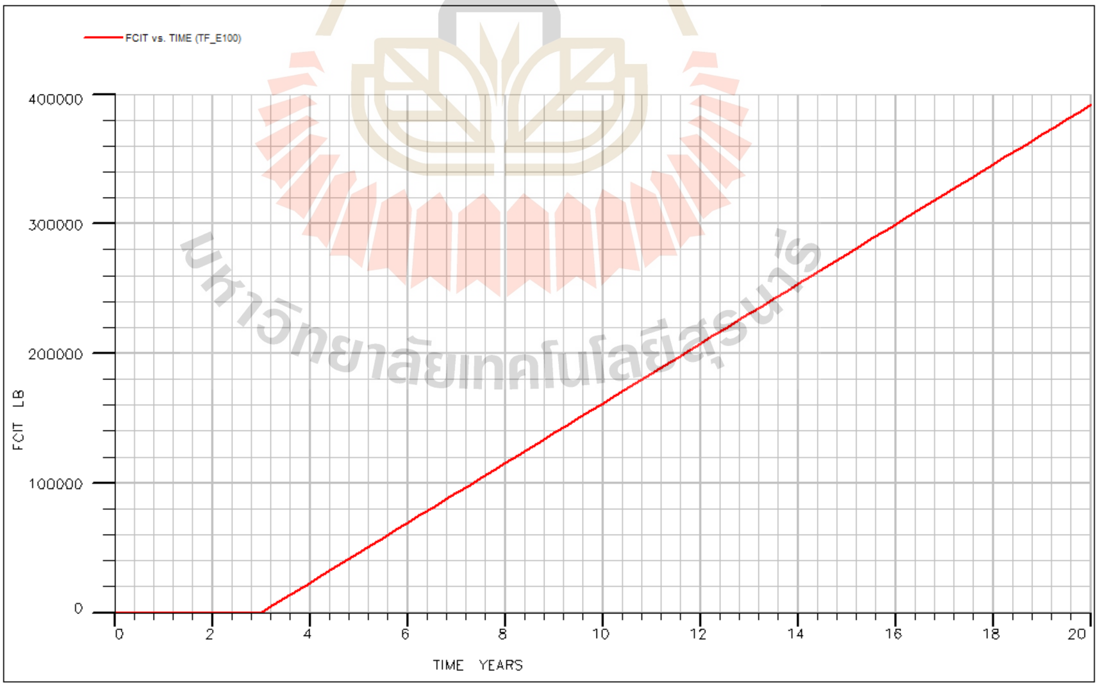
Figures D.130 Water production rate Vs. time of case 16



Figures D.131 Field pressure Vs. time of model case 16



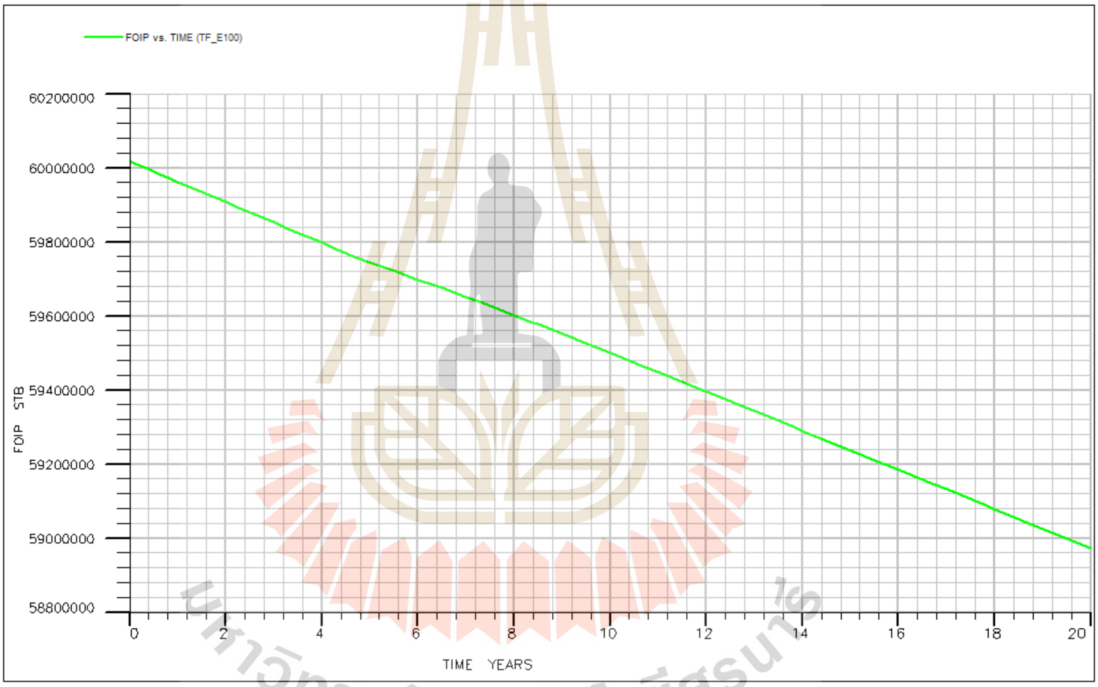
Figures D.132 Oil efficiency Vs. time of model case 16



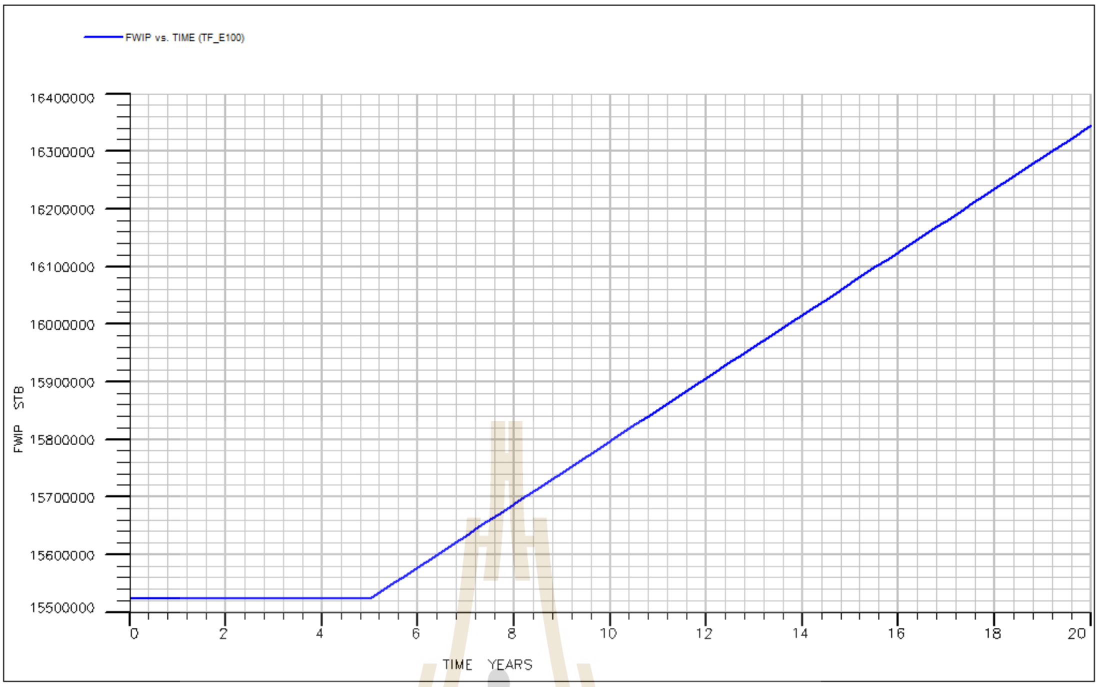
Figures D.133 Polymer injection total Vs. time of model case 16

D.3.5 Result of Model Case 17

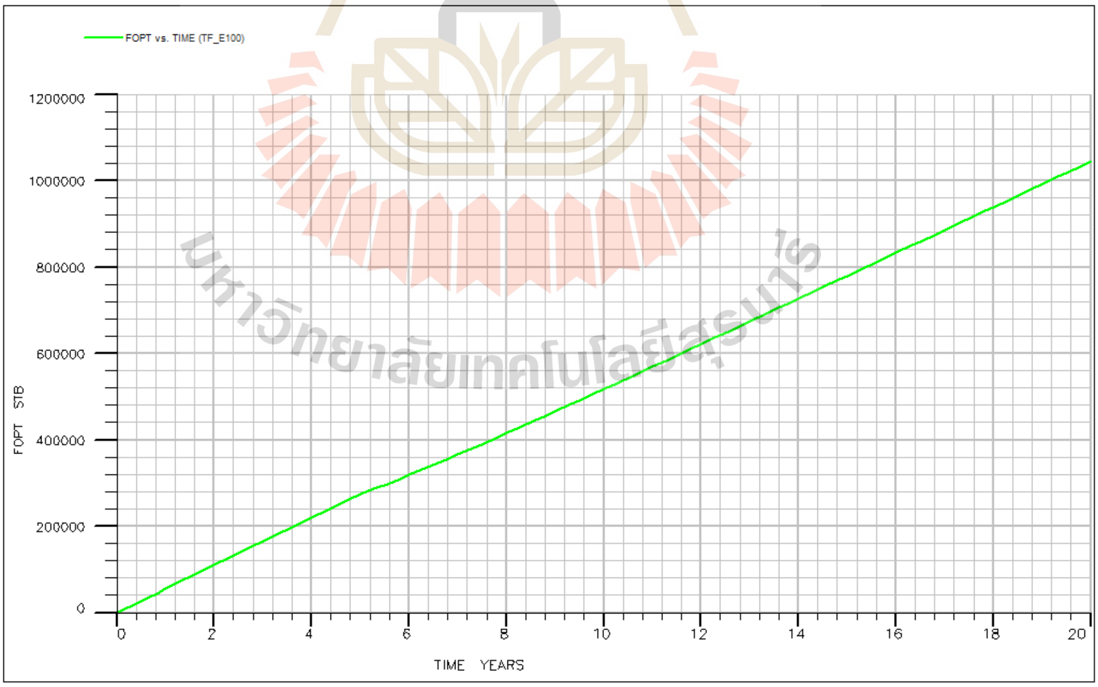
Model case 17 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.134 - D.142:



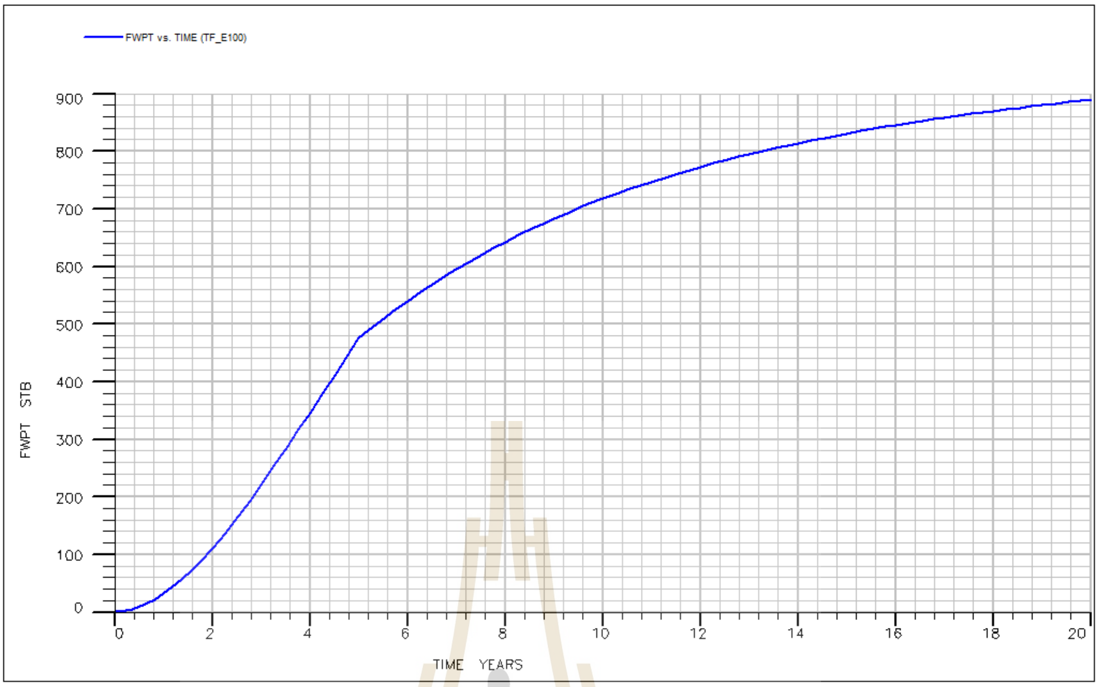
Figures D.134 Oil in place Vs. time of model case 17



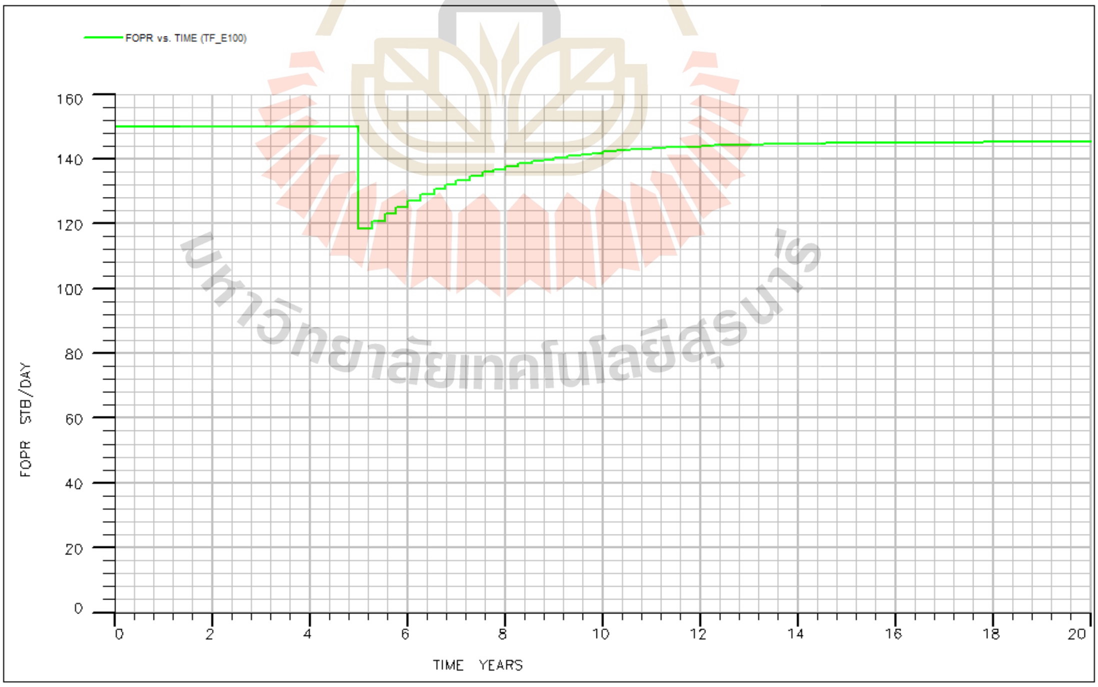
Figures D.135 Water in place Vs. time of model case 17



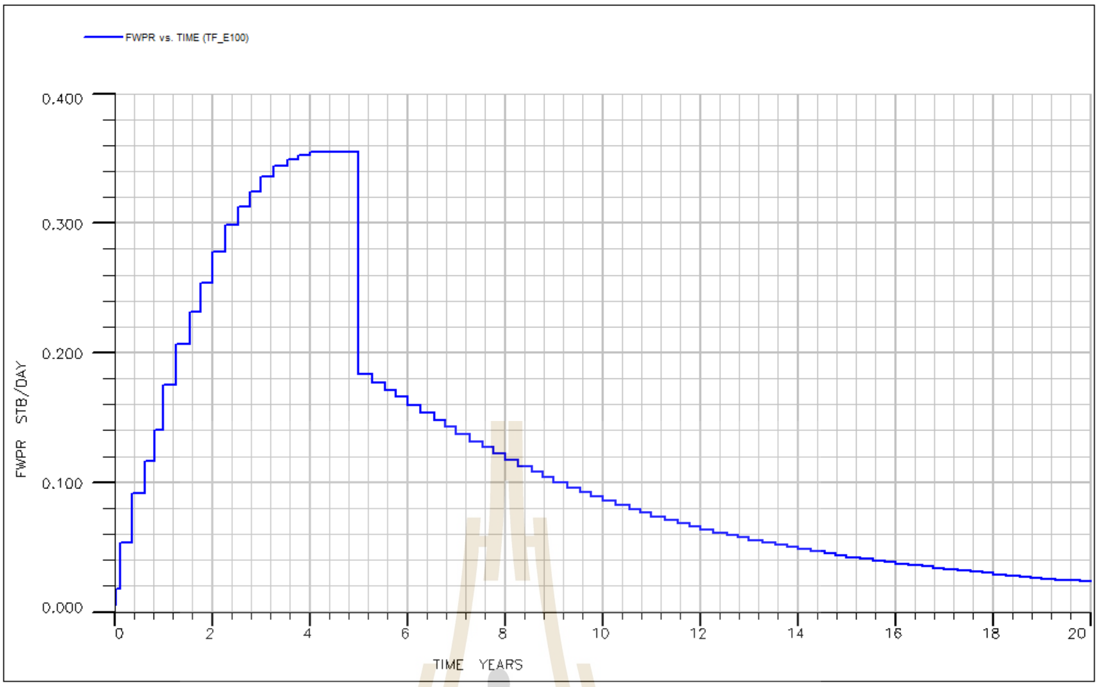
Figures D.136 Oil production total Vs. time of model case 17



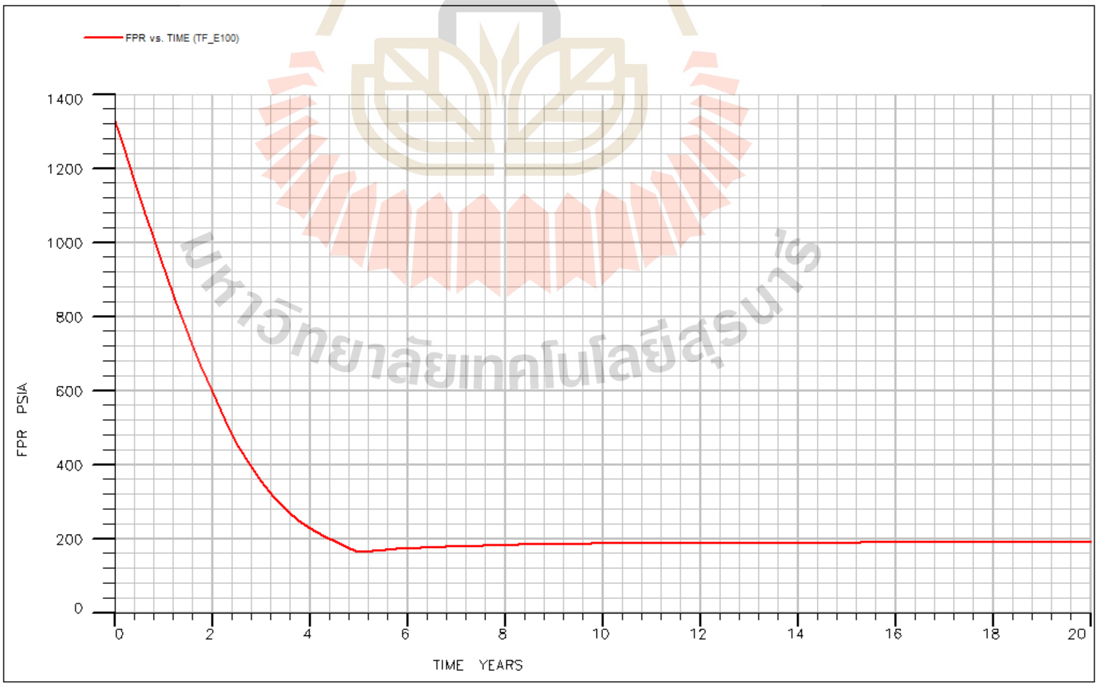
Figures D.137 Water production total Vs. time of model case 17



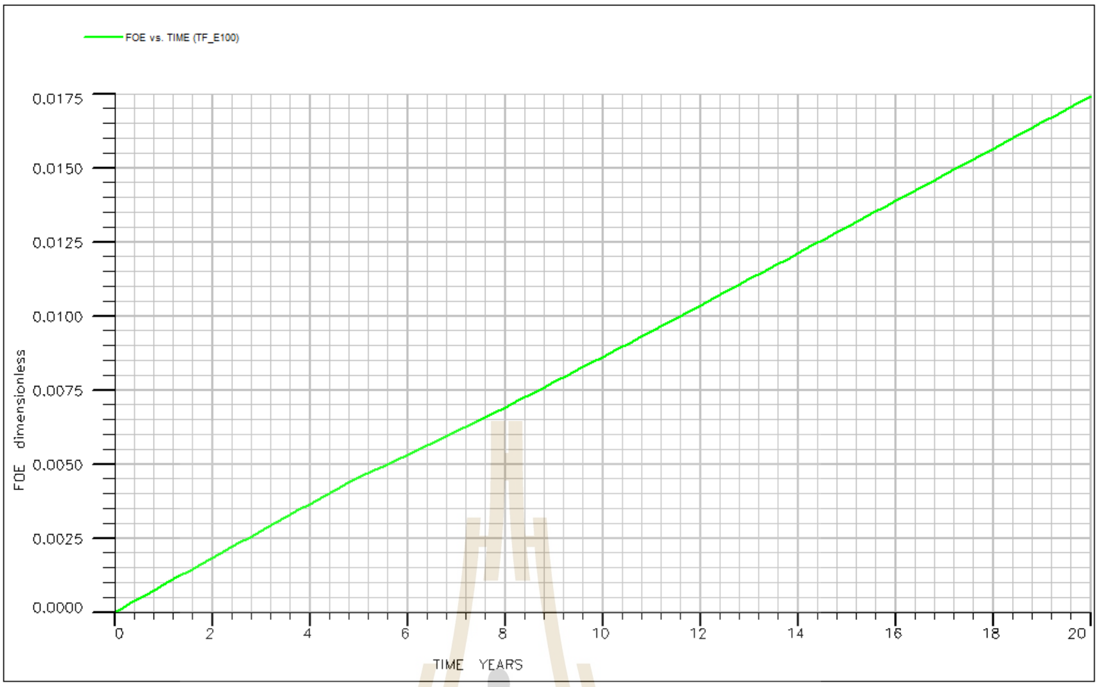
Figures D.138 Oil production rate Vs. time of model case 17



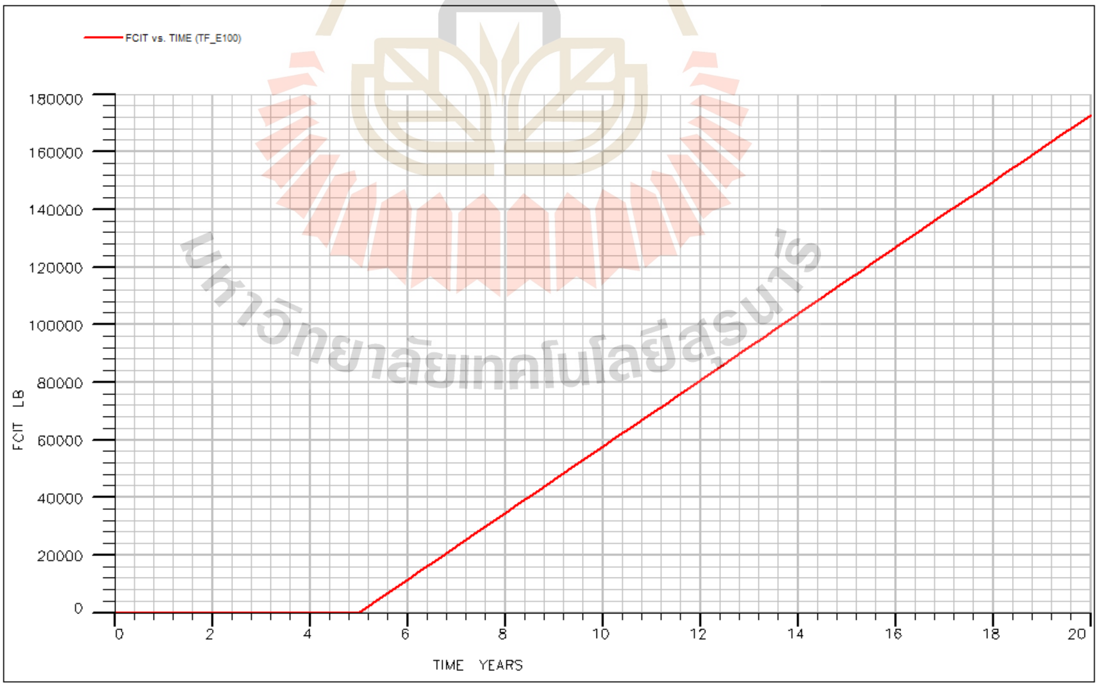
Figures D.139 Water production rate Vs. time of case 17



Figures D.140 Field pressure Vs. time of model case 17



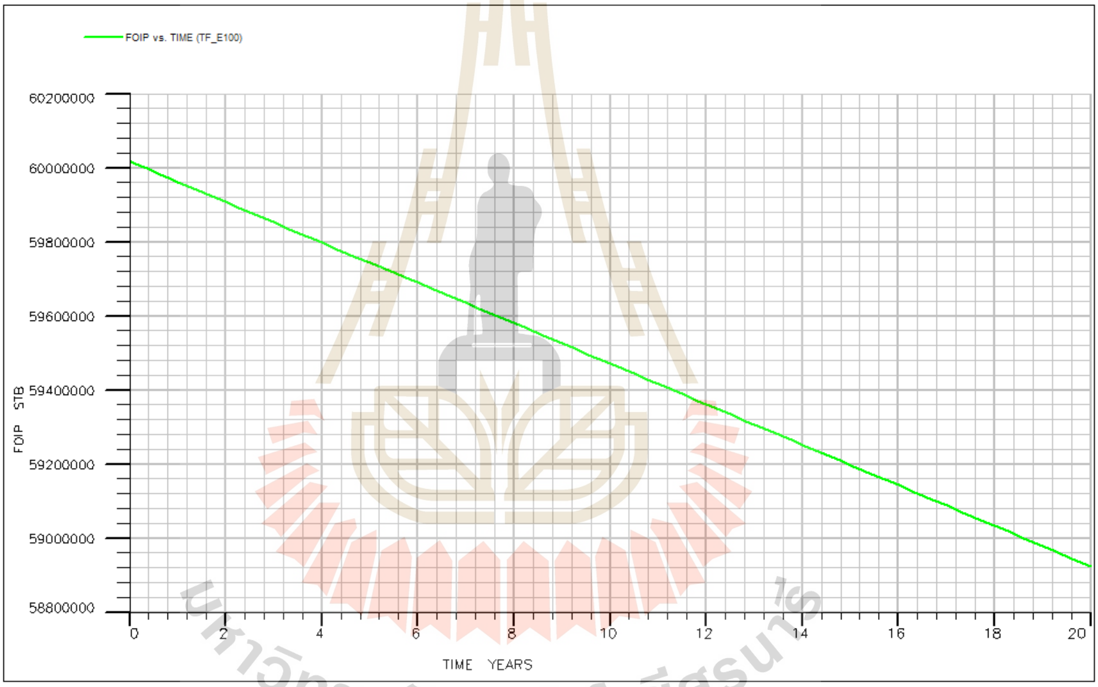
Figures D.141 Oil efficiency Vs. time of model case 17



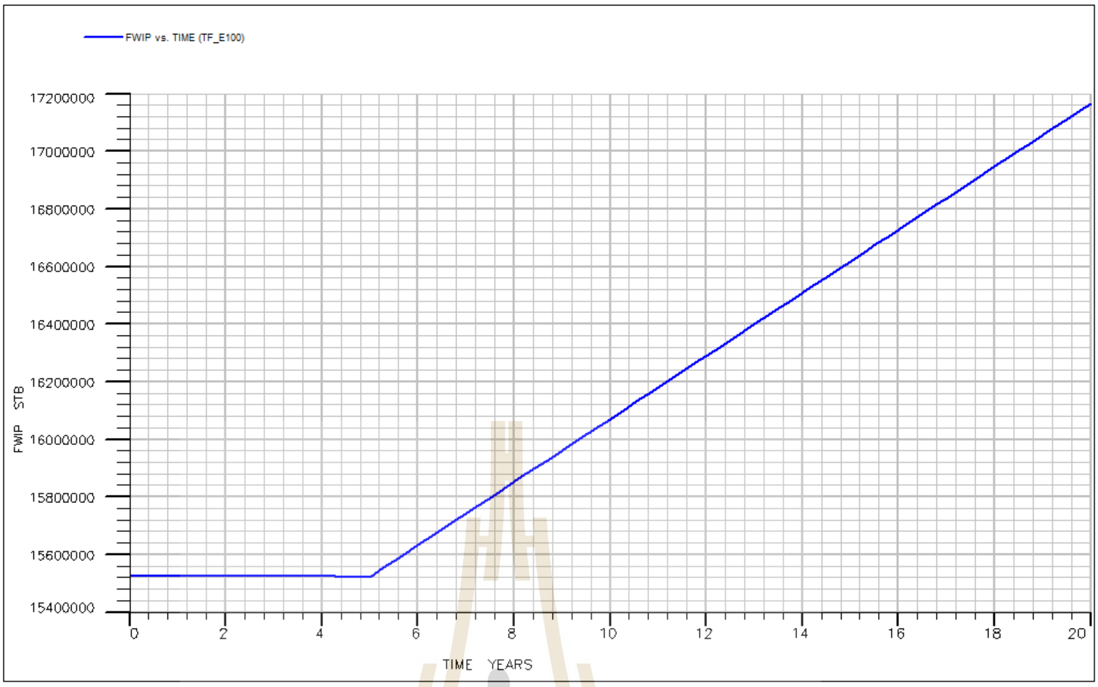
Figures D.142 Polymer injection total Vs. time of model case 17

D.3.6 Result of Model Case 18

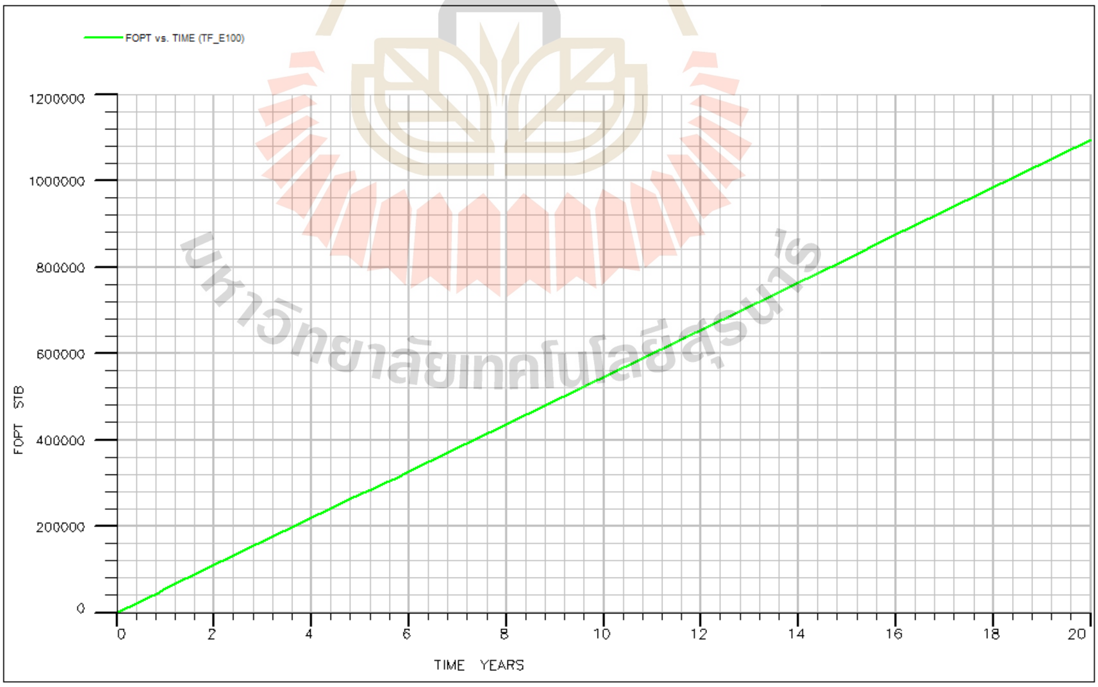
Model case 18 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1000 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.143 - D.151:



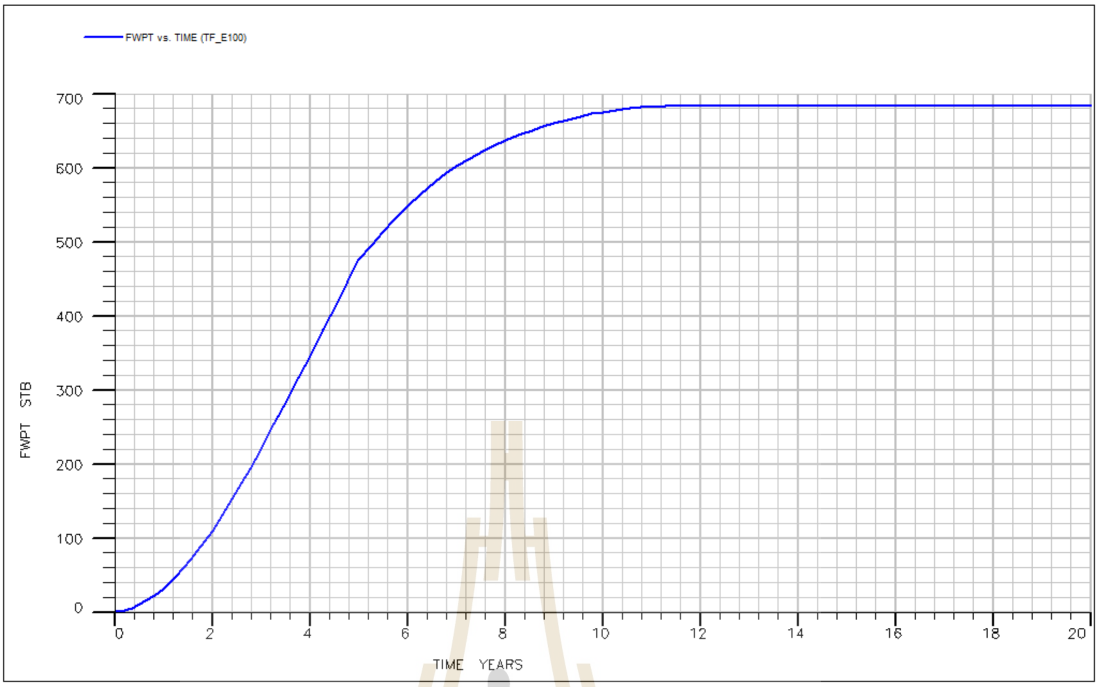
Figures D.143 Oil in place Vs. time of model case 18



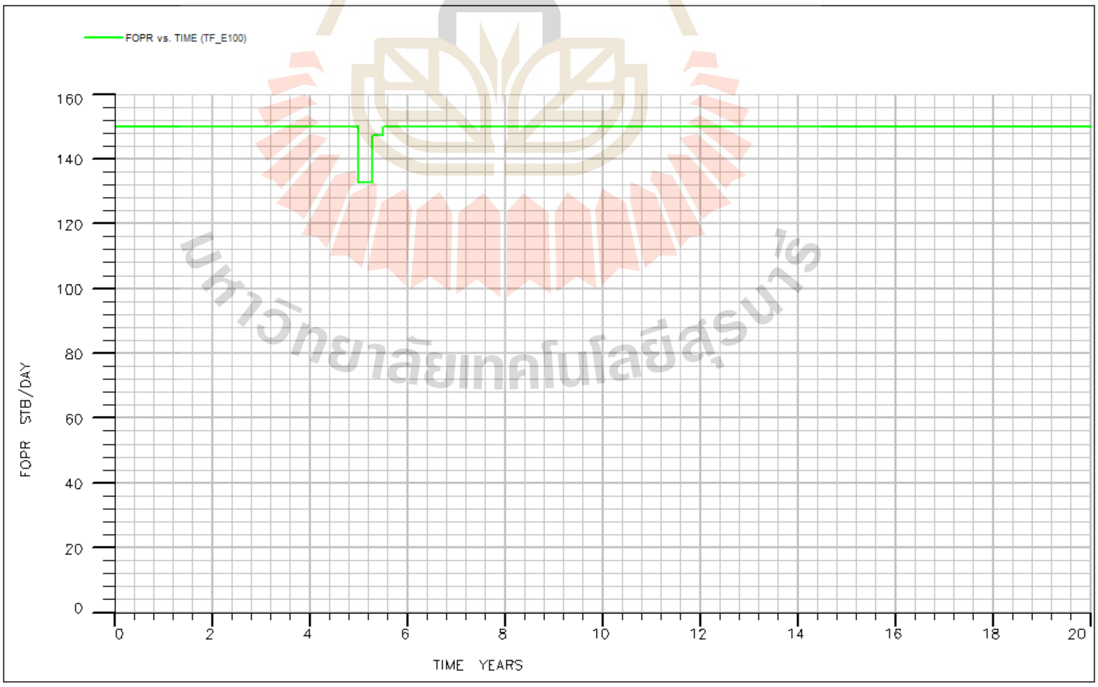
Figures D.144 Water in place Vs. time of model case 18



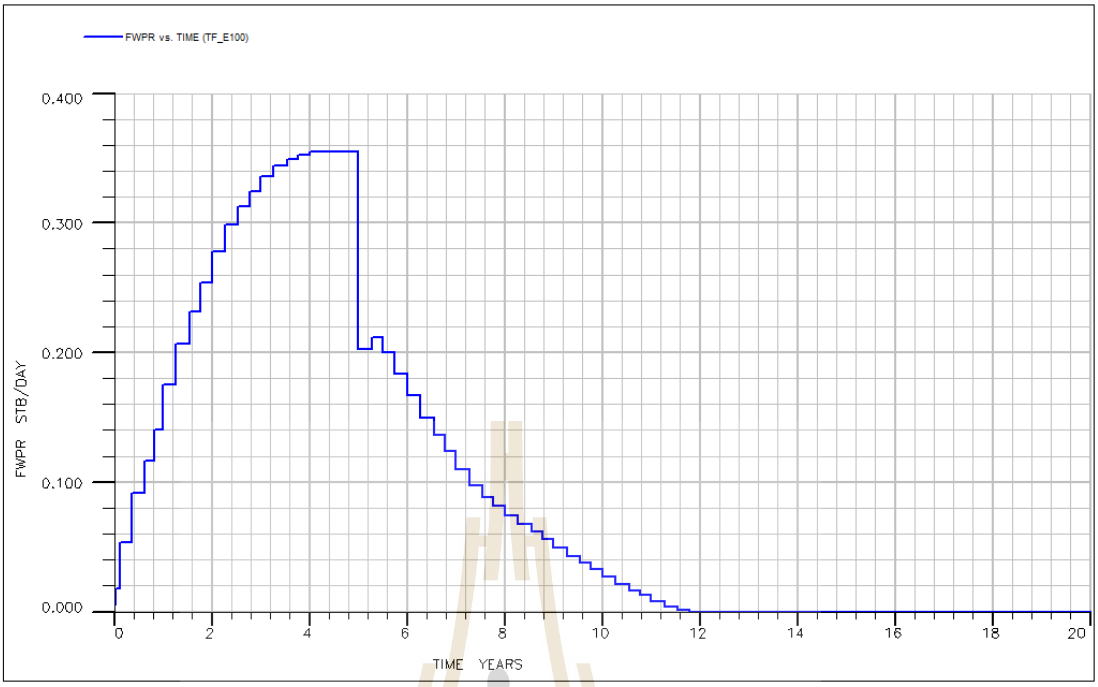
Figures D.145 Oil production total Vs. time of model case 18



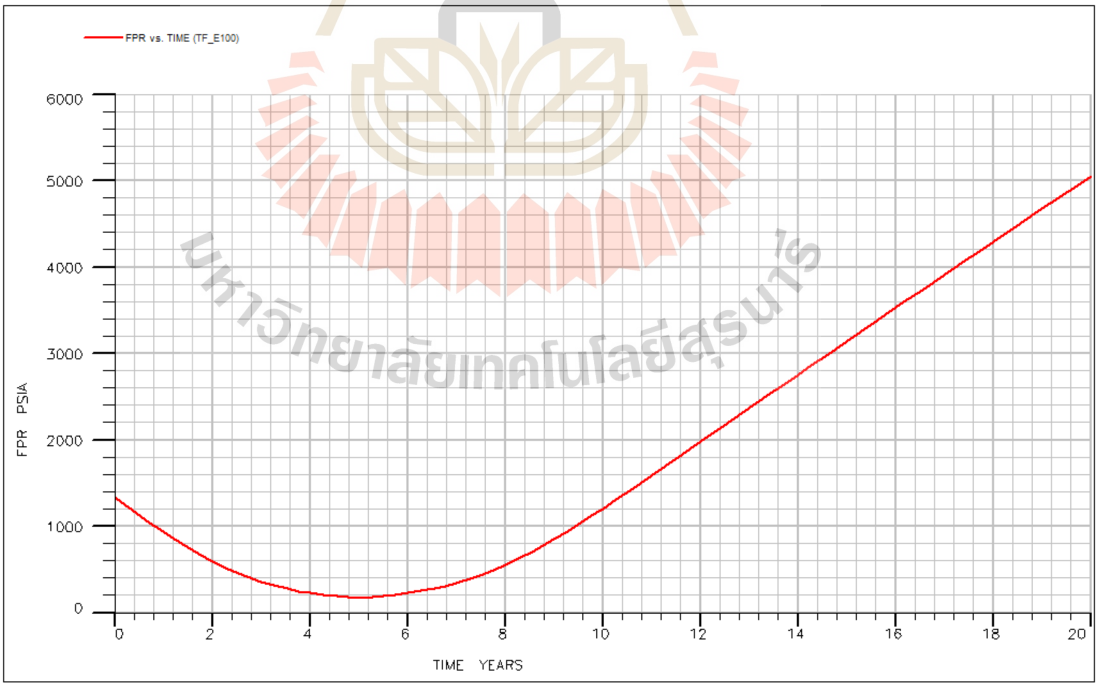
Figures D.146 Water production total Vs. time of model case 18



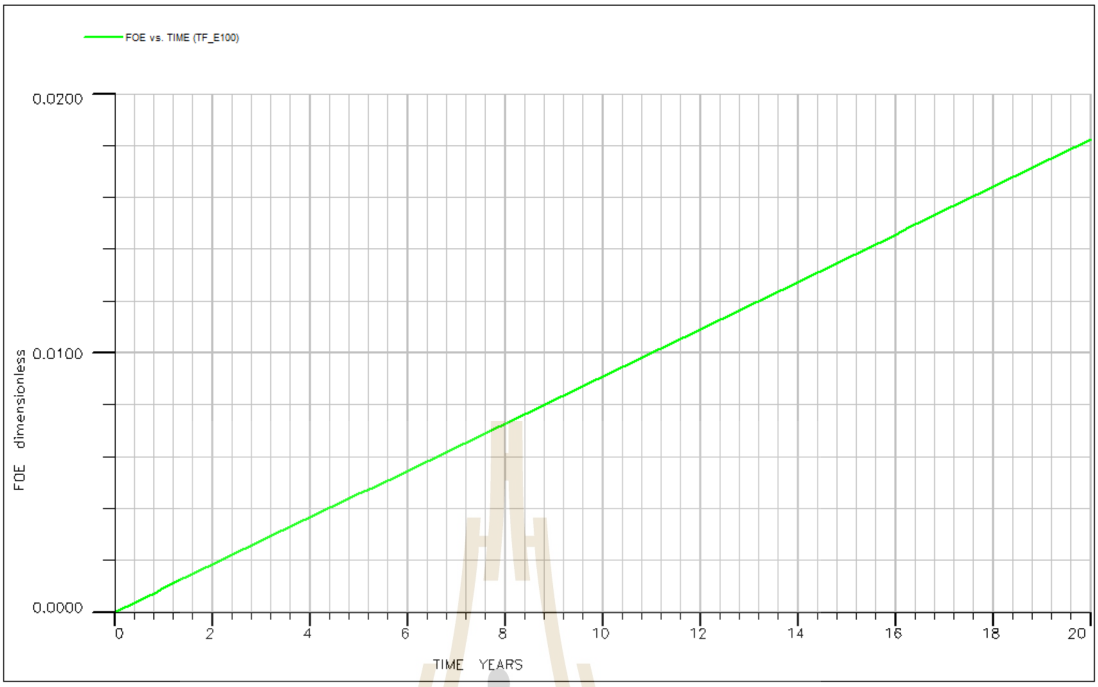
Figures D.147 Oil production rate Vs. time of model case 18



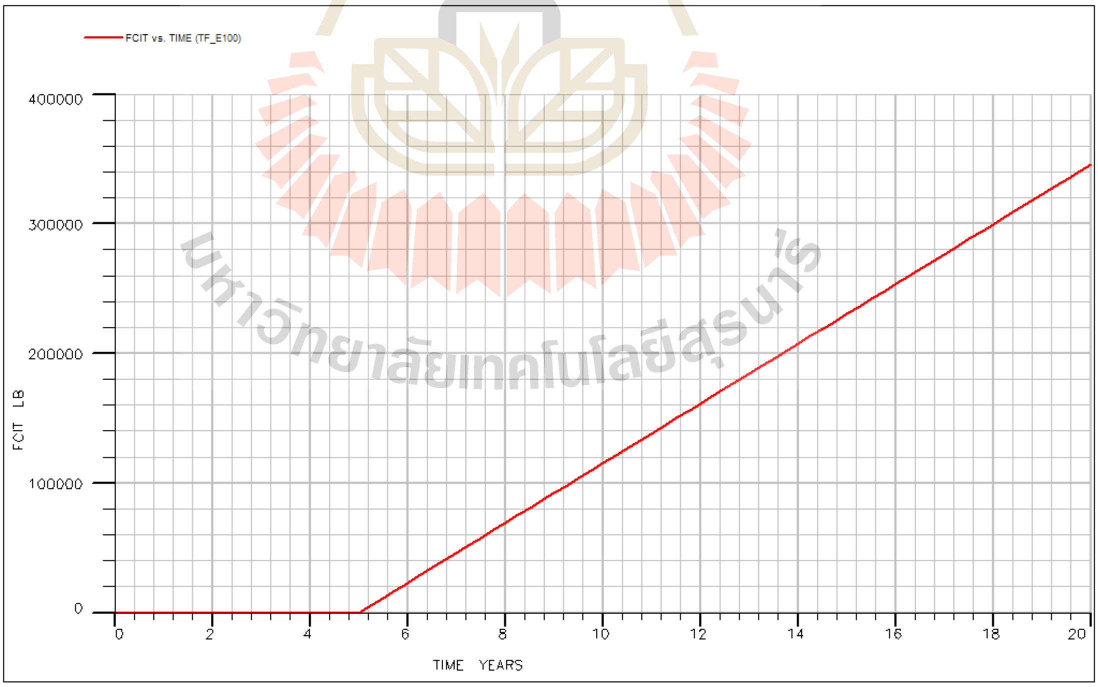
Figures D.148 Water production rate Vs. time of case 18



Figures D.149 Field pressure Vs. time of model case 18



Figures D.150 Oil efficiency Vs. time of model case 18

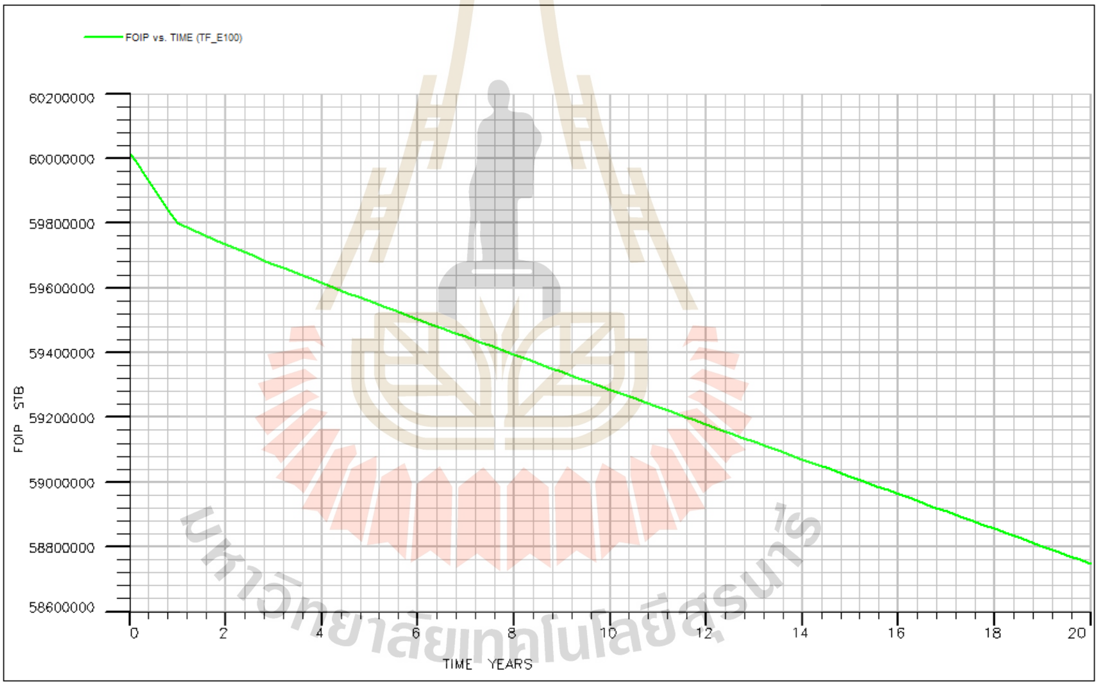


Figures D.151 Polymer injection total Vs. time of model case 18

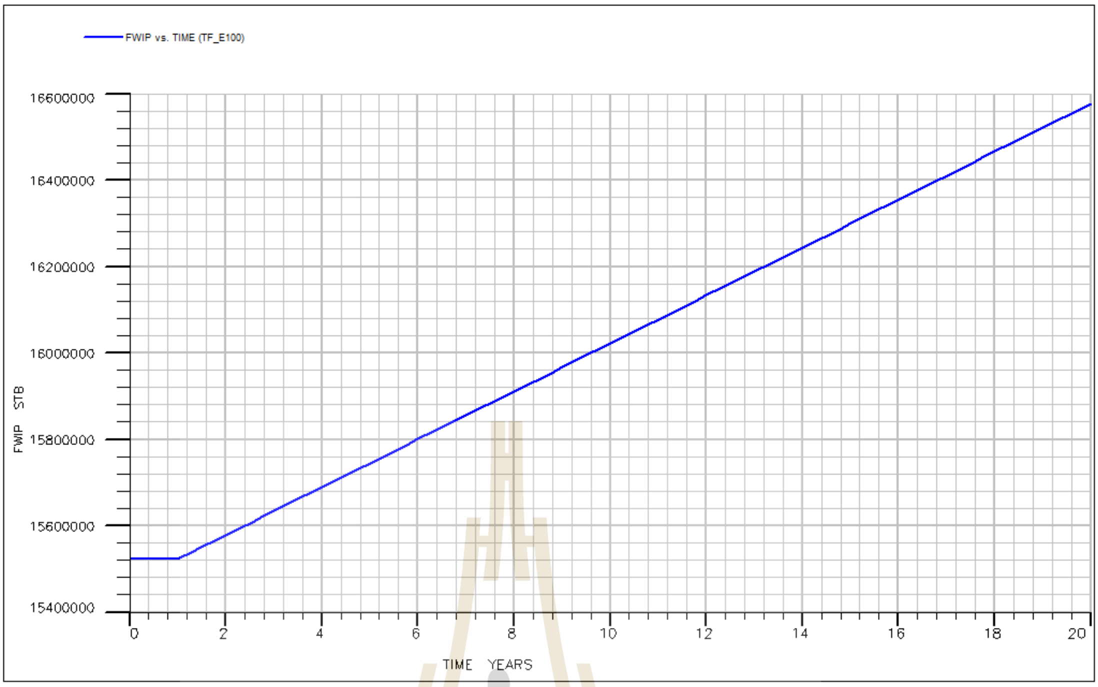
D.4 Reservoir simulation result for case polymer flooding concentration 1500 ppm

D.4.1 Result of Model Case 19

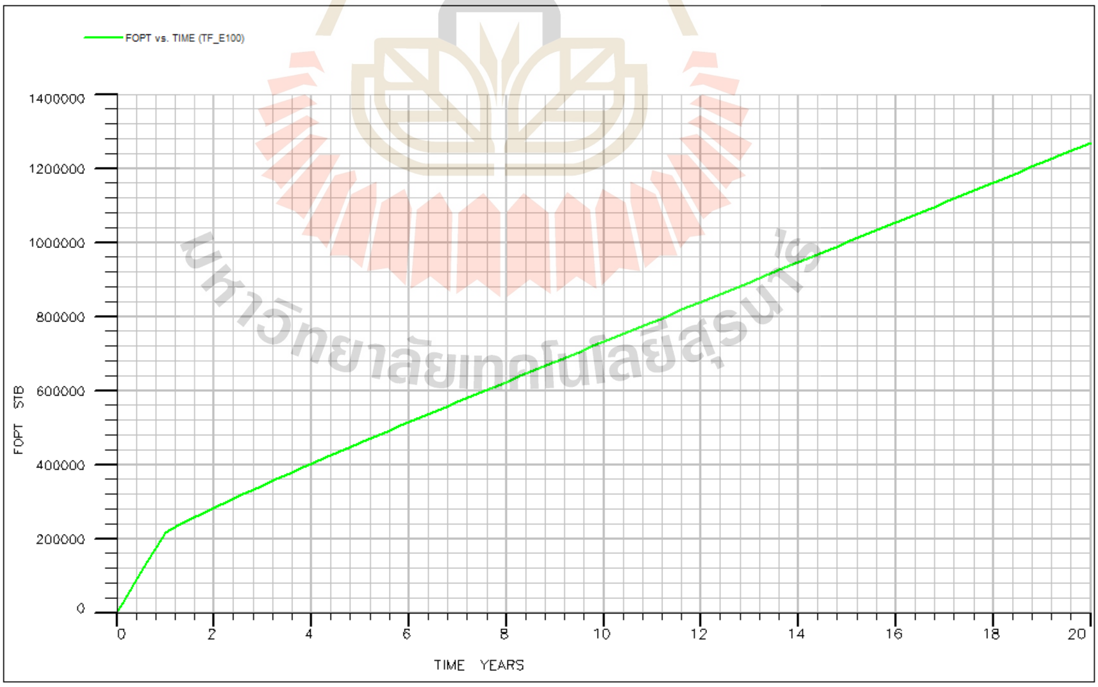
Model case 19 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.152 - D.160:



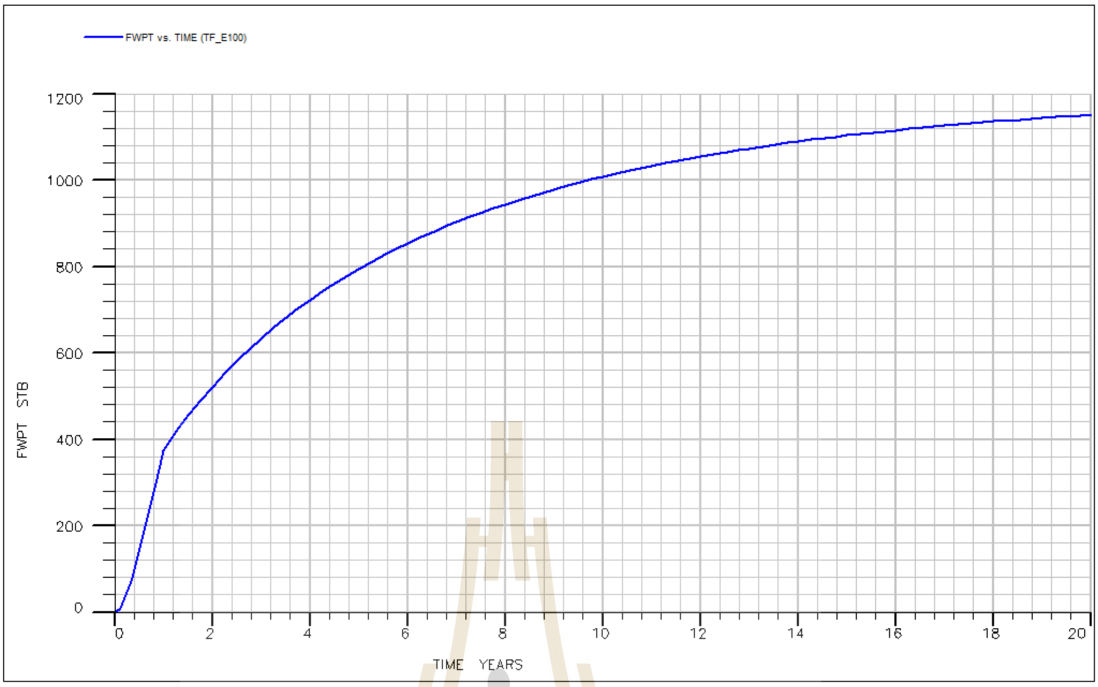
Figures D.152 Oil in place Vs. time of model case 19



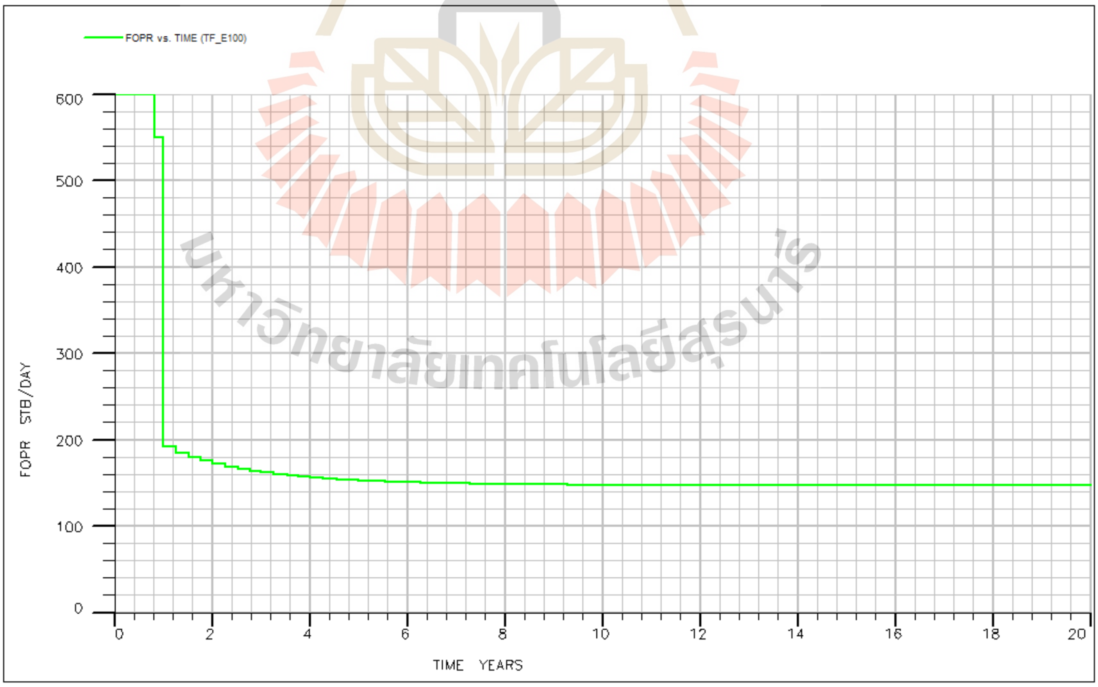
Figures D.153 Water in place Vs. time of model case 19



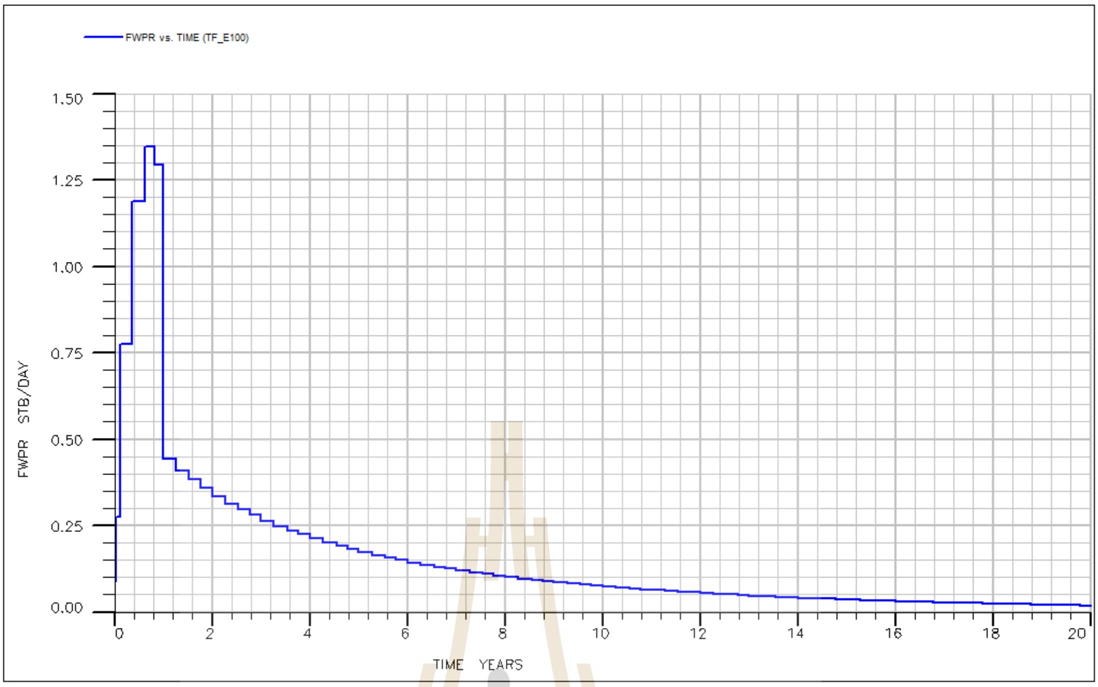
Figures D.154 Oil production total Vs. time of model case 19



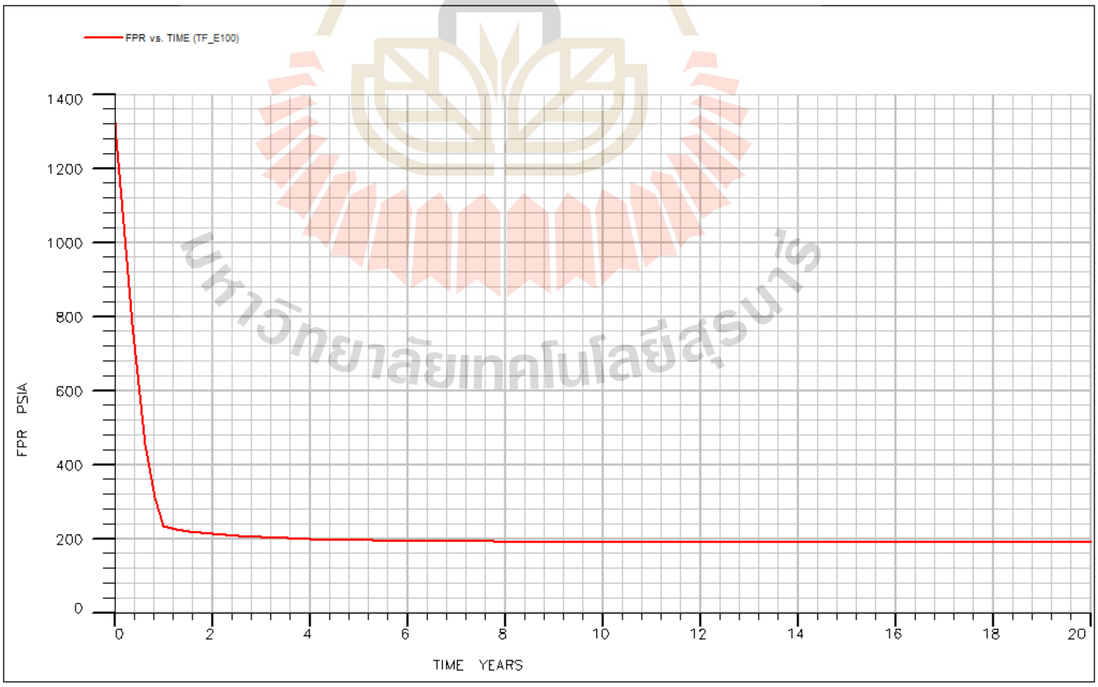
Figures D.155 Water production total Vs. time of model case 19



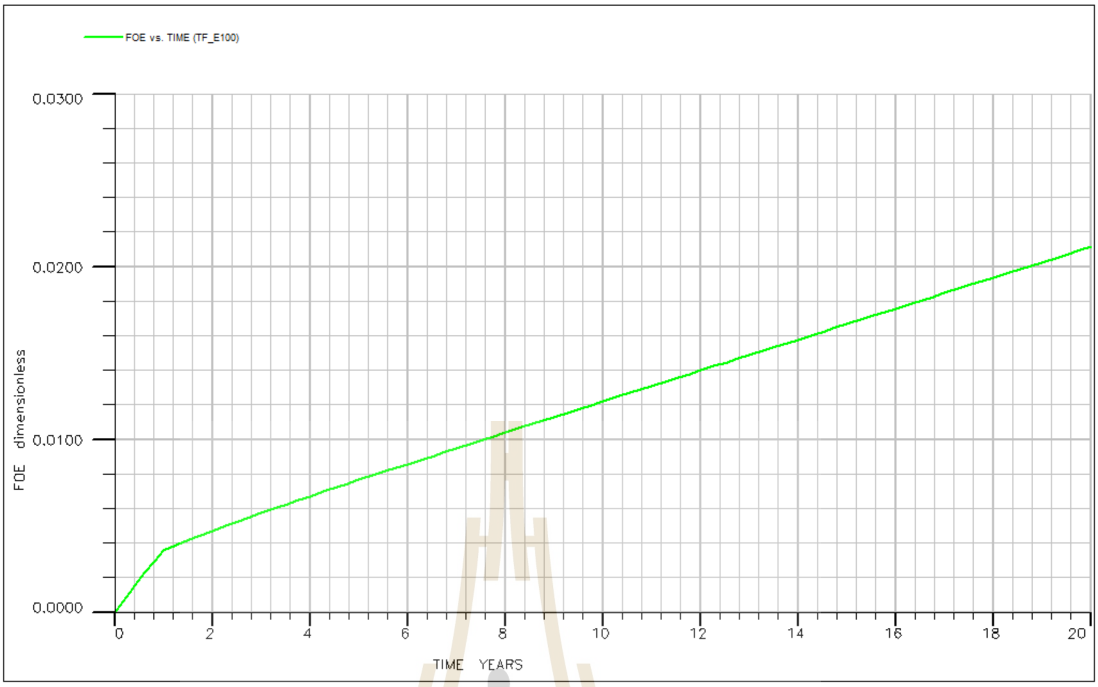
Figures D.156 Oil production rate Vs. time of model case 19



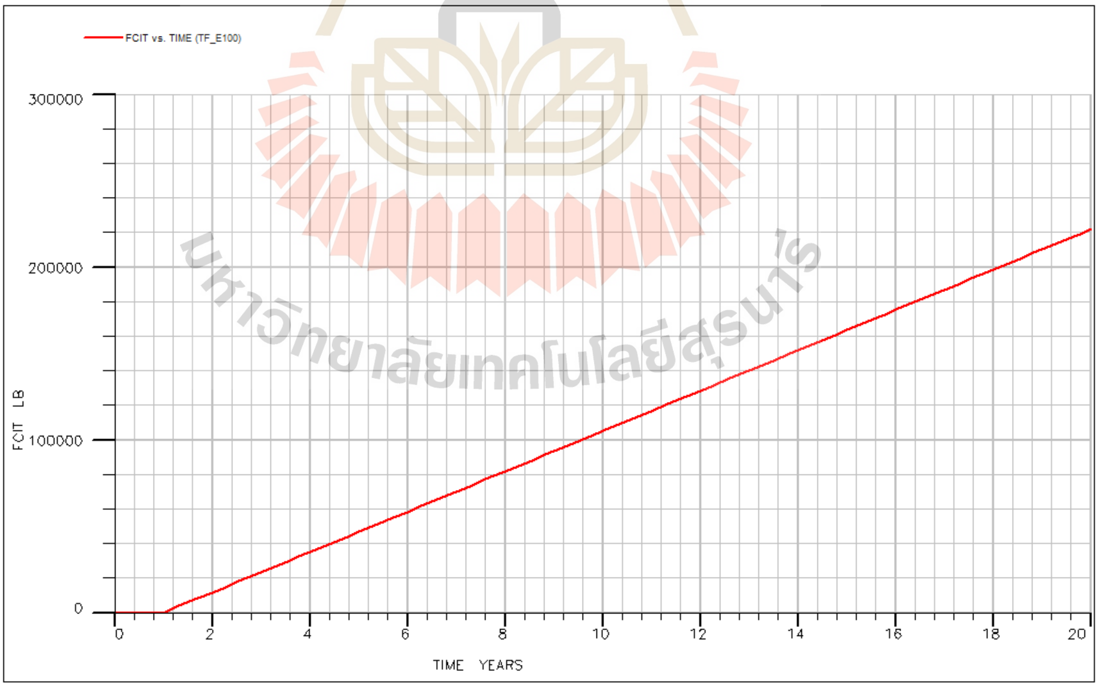
Figures D.157 Water production rate Vs. time of case 19



Figures D.158 Field pressure Vs. time of model case 19



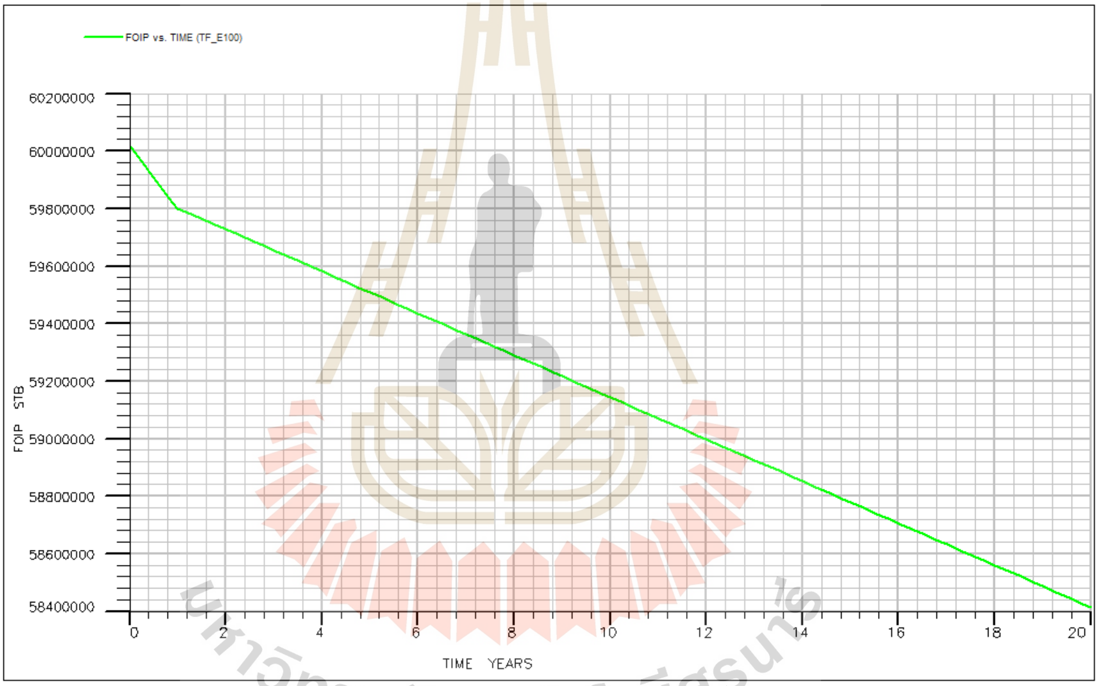
Figures D.159 Oil efficiency Vs. time of model case 19



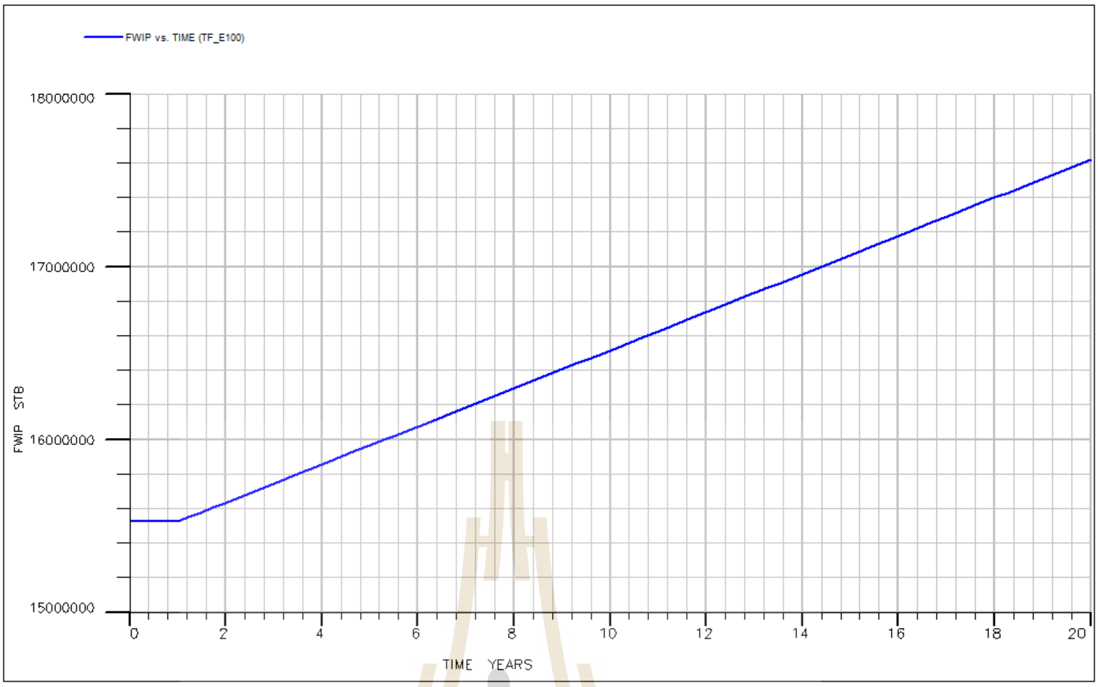
Figures D.160 Polymer injection total Vs. time of model case 19

D.4.2 Result of Model Case 20

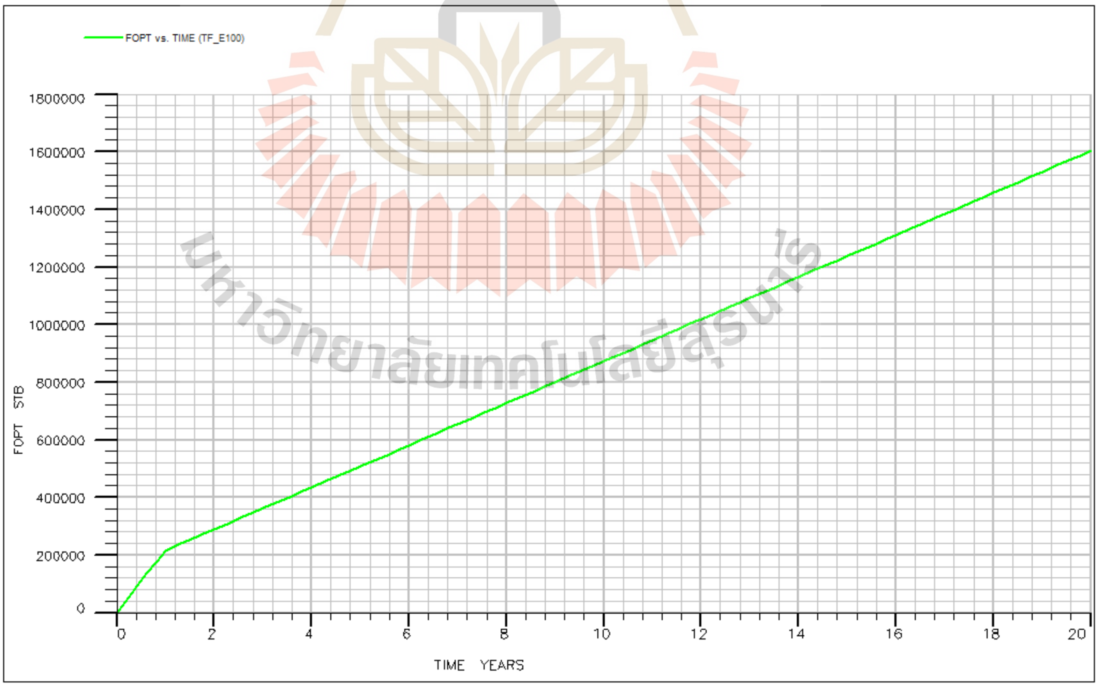
Model case 20 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the first year. The production period is 20 years. The simulation results are shown in Figures D.161 - D.169:



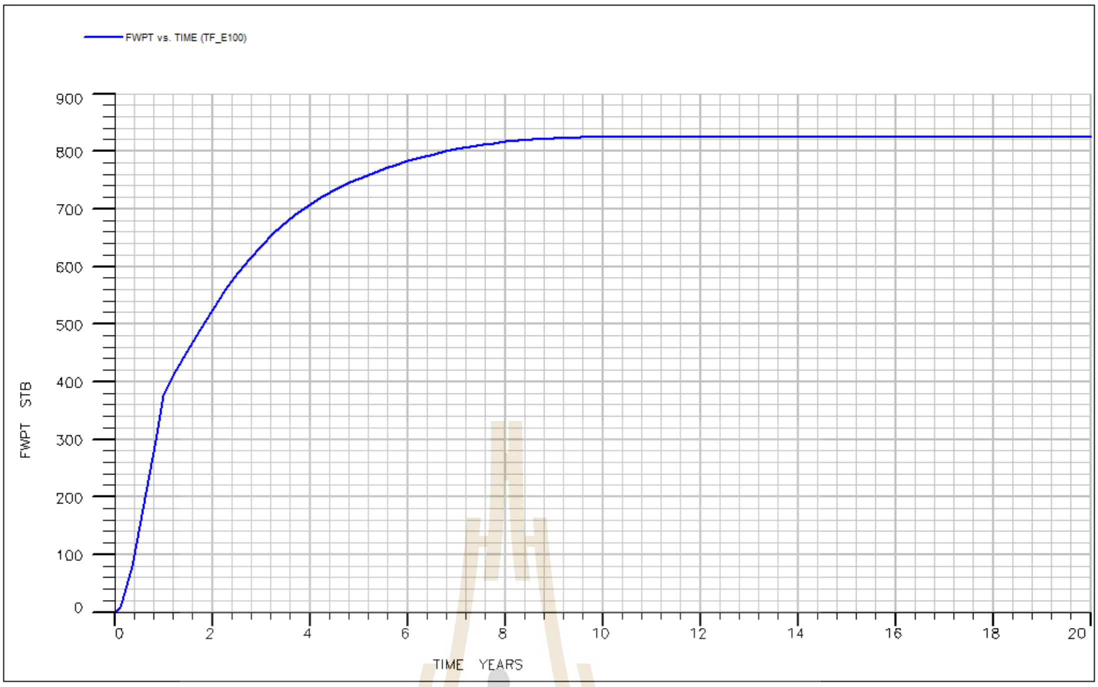
Figures D.161 Oil in place Vs. time of model case 20



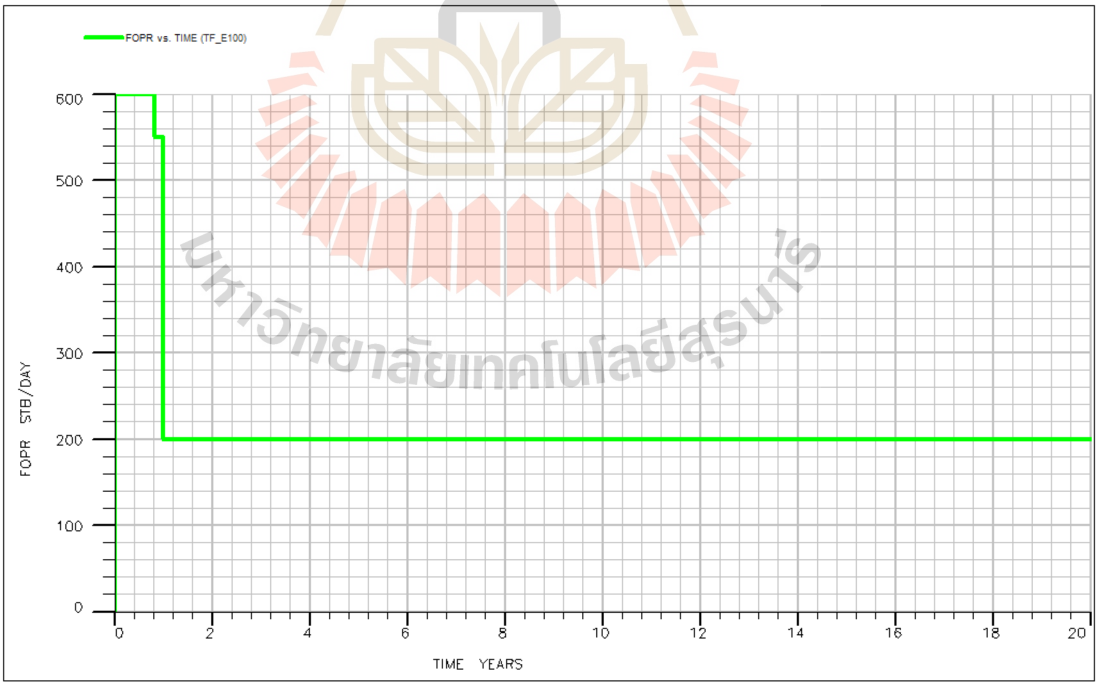
Figures D.162 Water in place Vs. time of model case 20



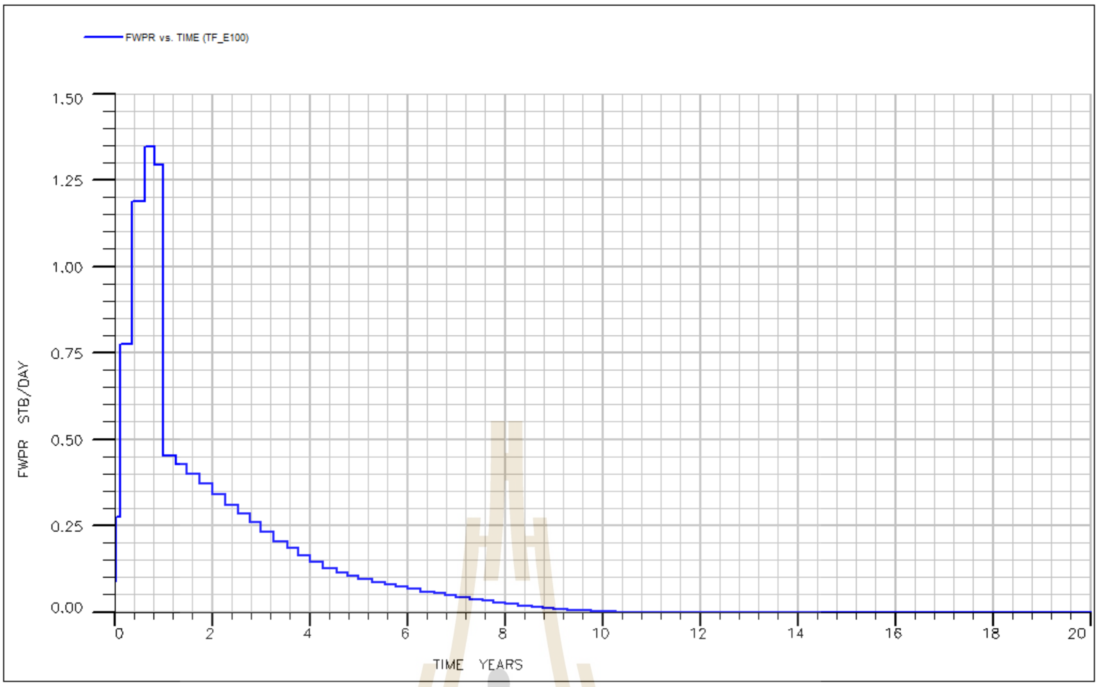
Figures D.163 Oil production total Vs. time of model case 20



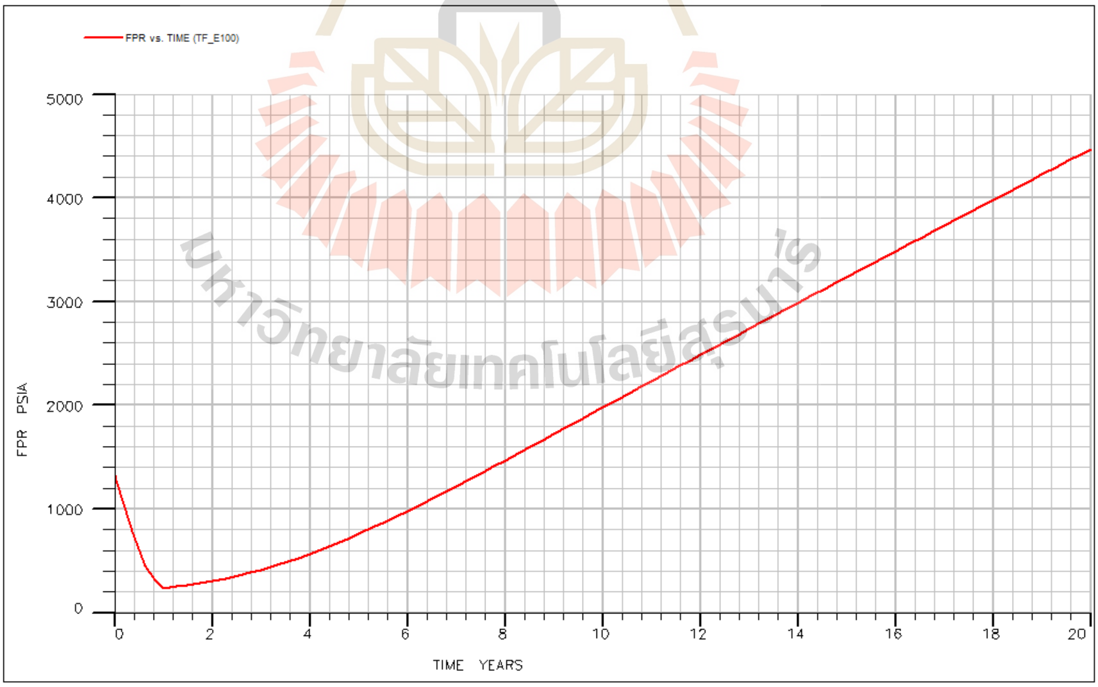
Figures D.164 Water production total Vs. time of model case 20



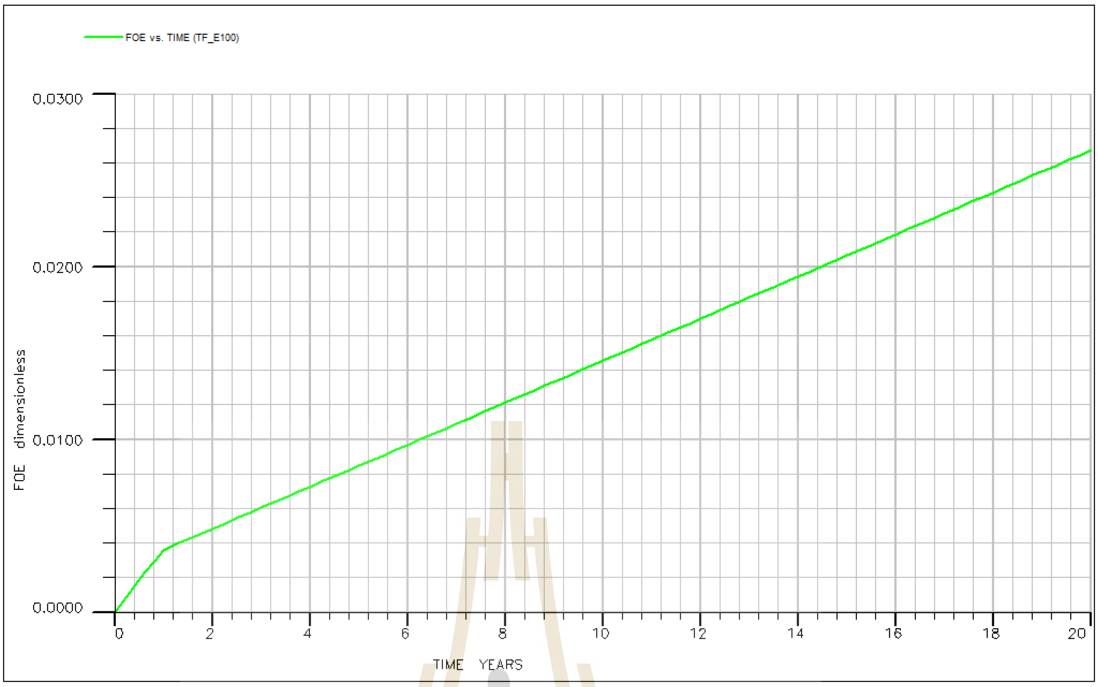
Figures D.165 Oil production rate Vs. time of model case 20



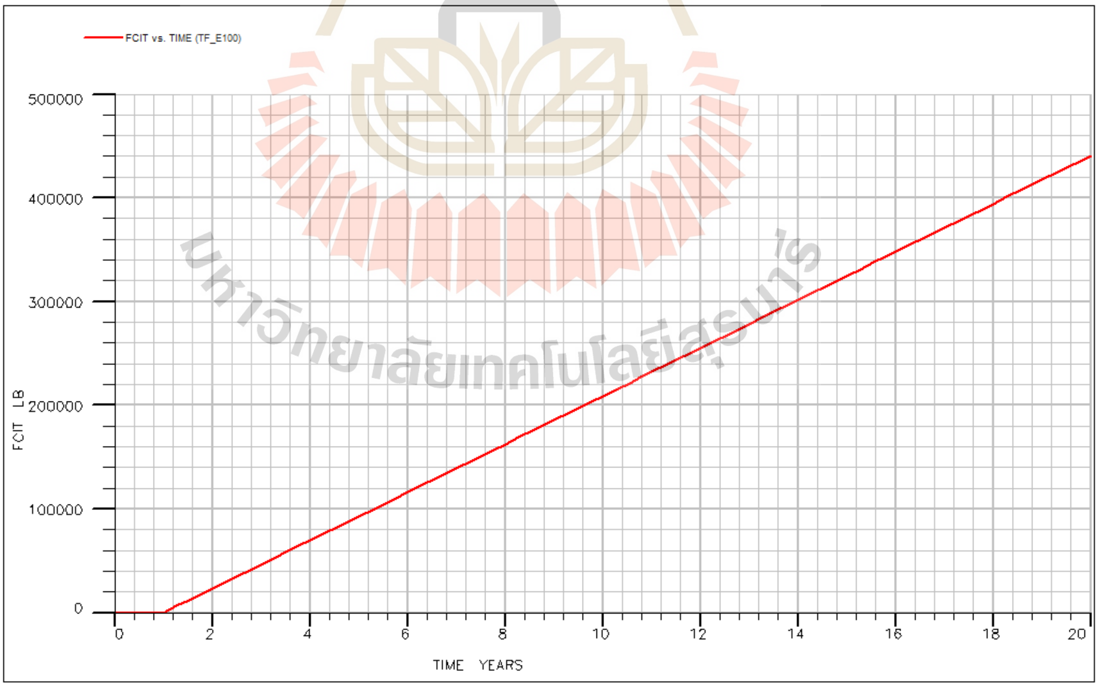
Figures D.166 Water production rate Vs. time of case 20



Figures D.167 Field pressure Vs. time of model case 20



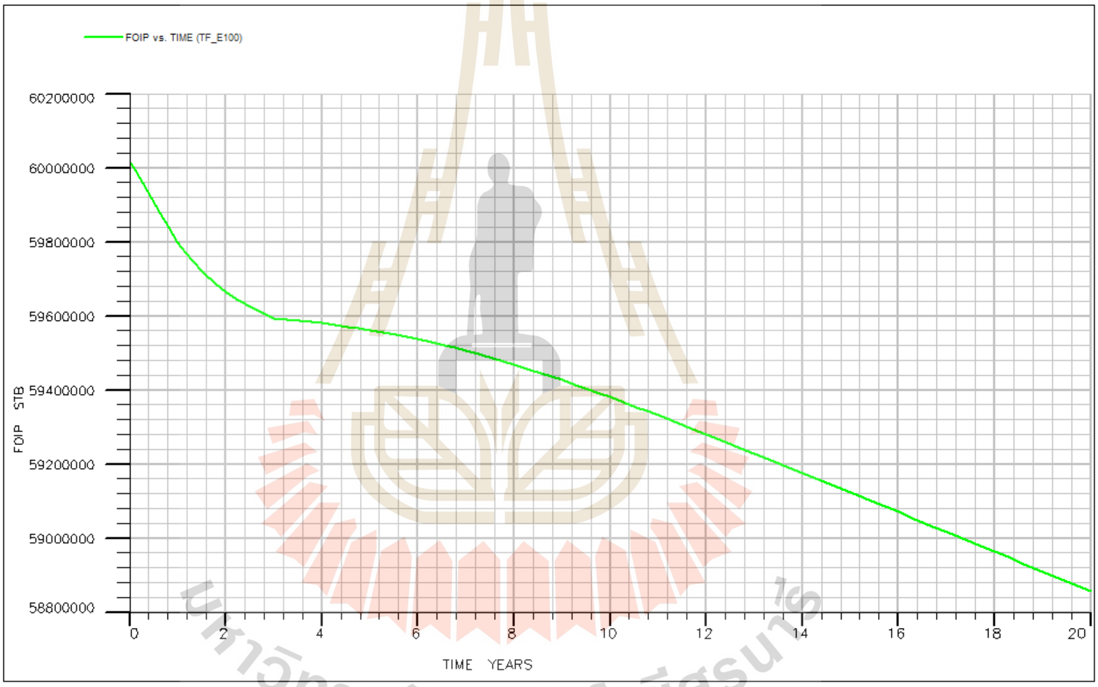
Figures D.168 Oil efficiency Vs. time of model case 20



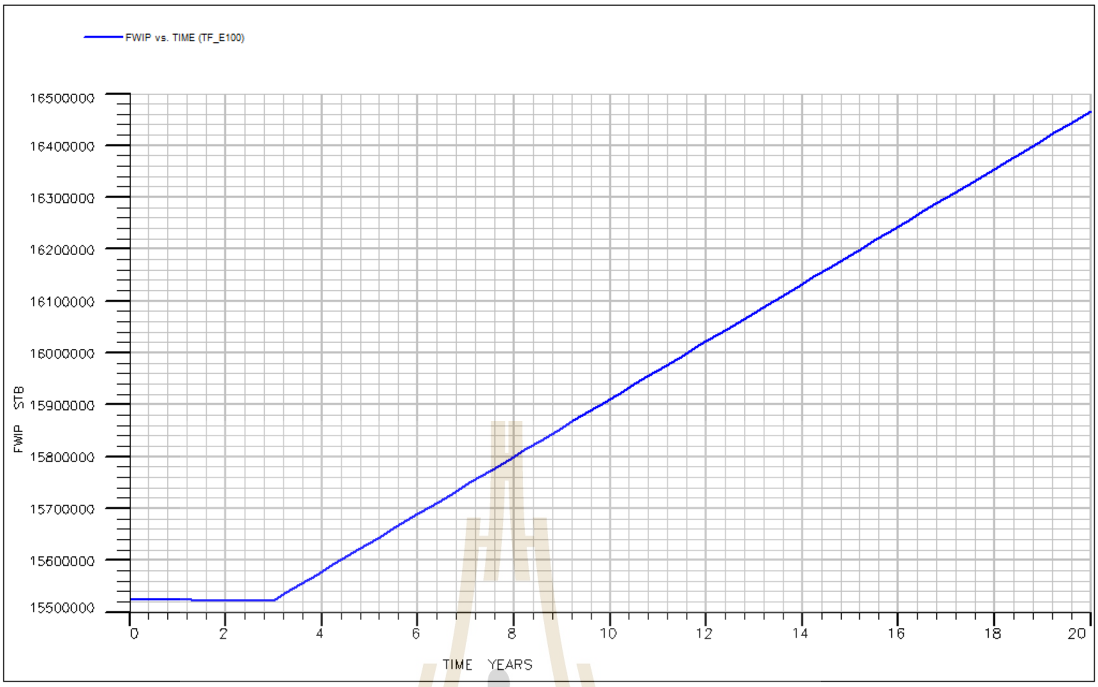
Figures D.169 Polymer injection total Vs. time of model case 20

D.4.3 Result of Model Case 21

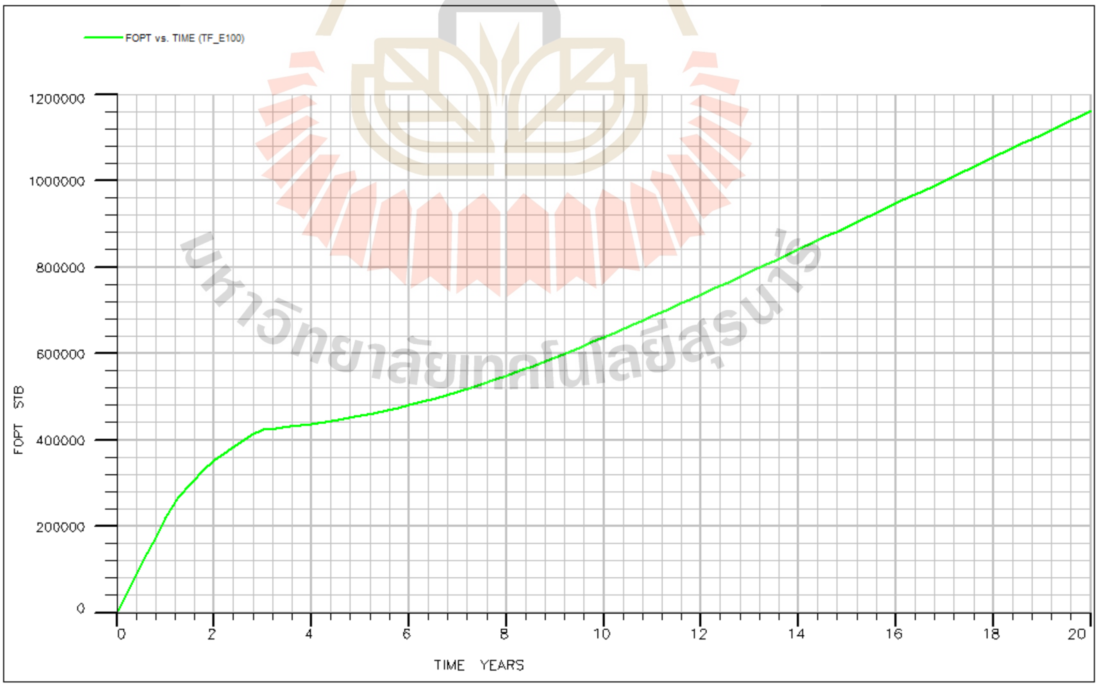
Model case 21 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.170 - D.178:



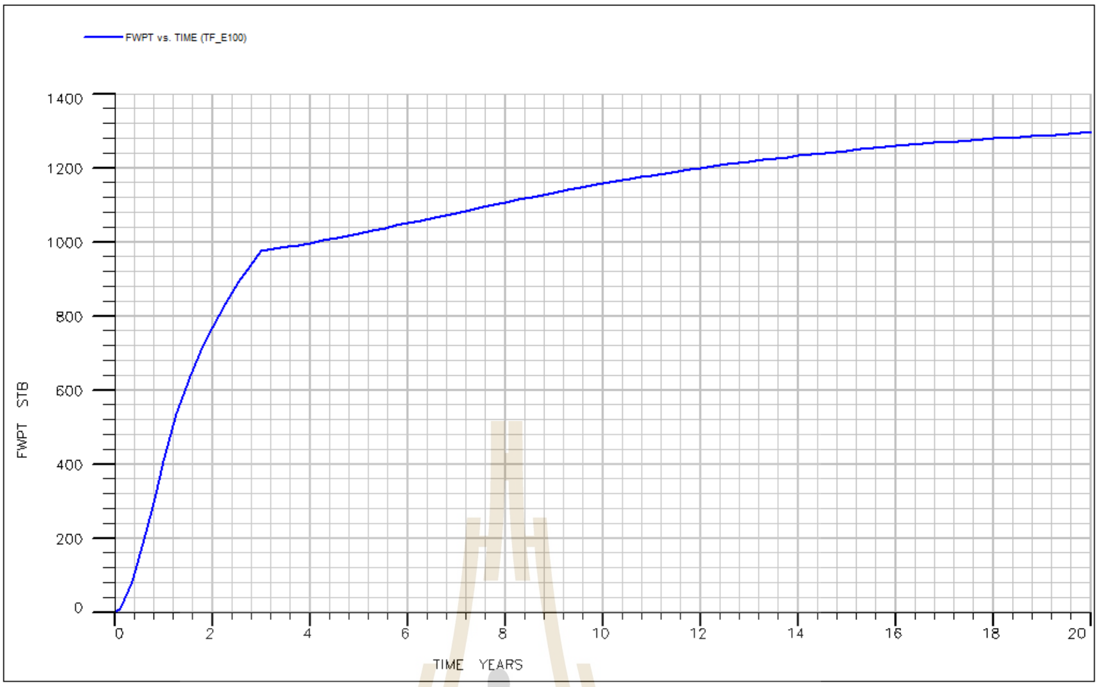
Figures D.170 Oil in place Vs. time of model case 21



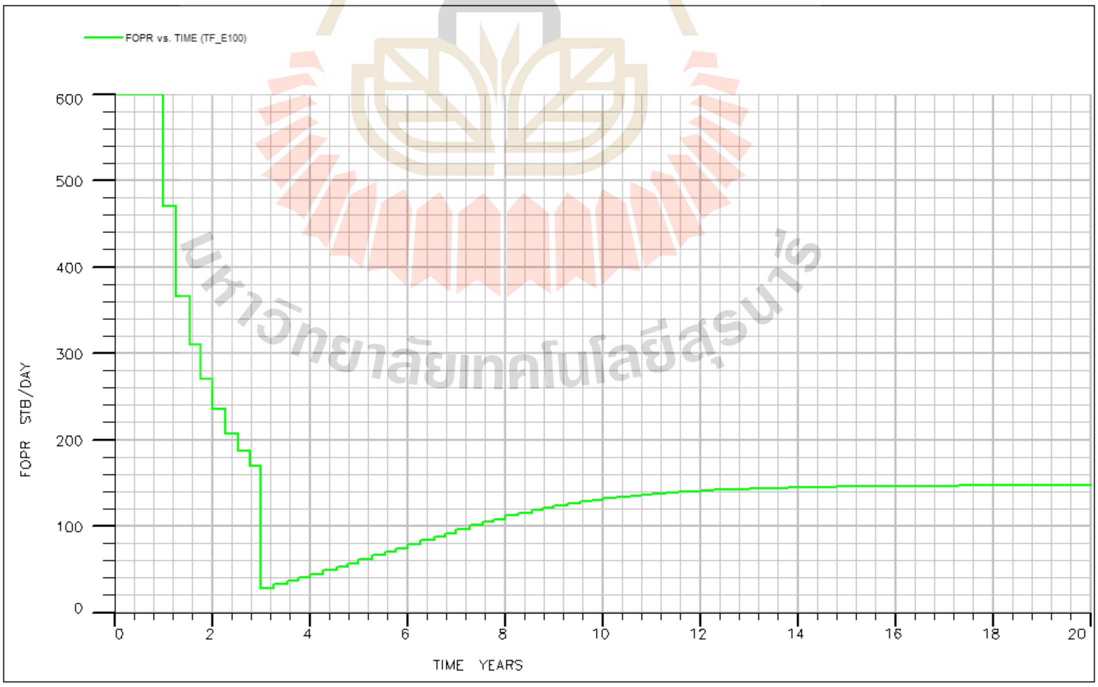
Figures D.171 Water in place Vs. time of model case 21



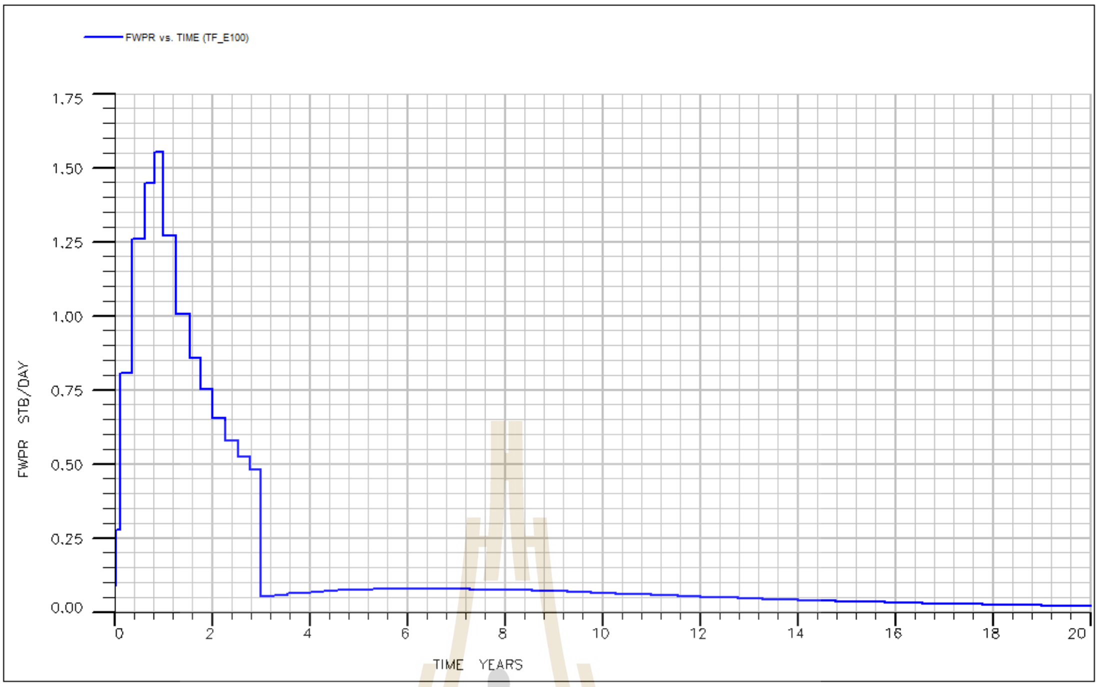
Figures D.172 Oil production total Vs. time of model case 21



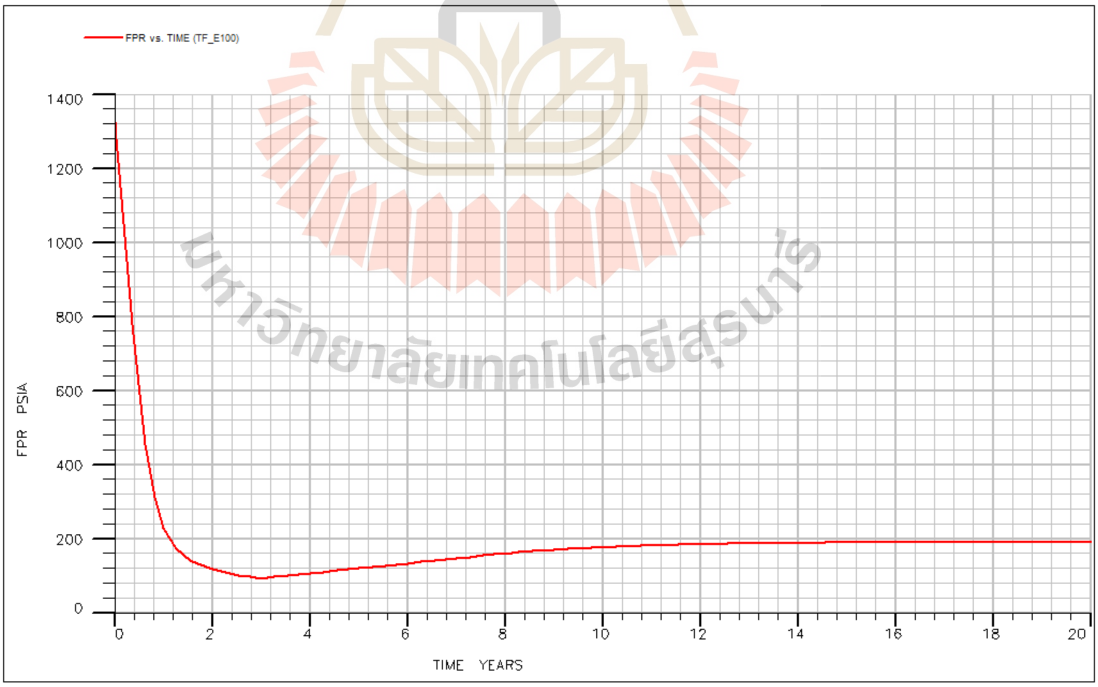
Figures D.173 Water production total Vs. time of model case 21



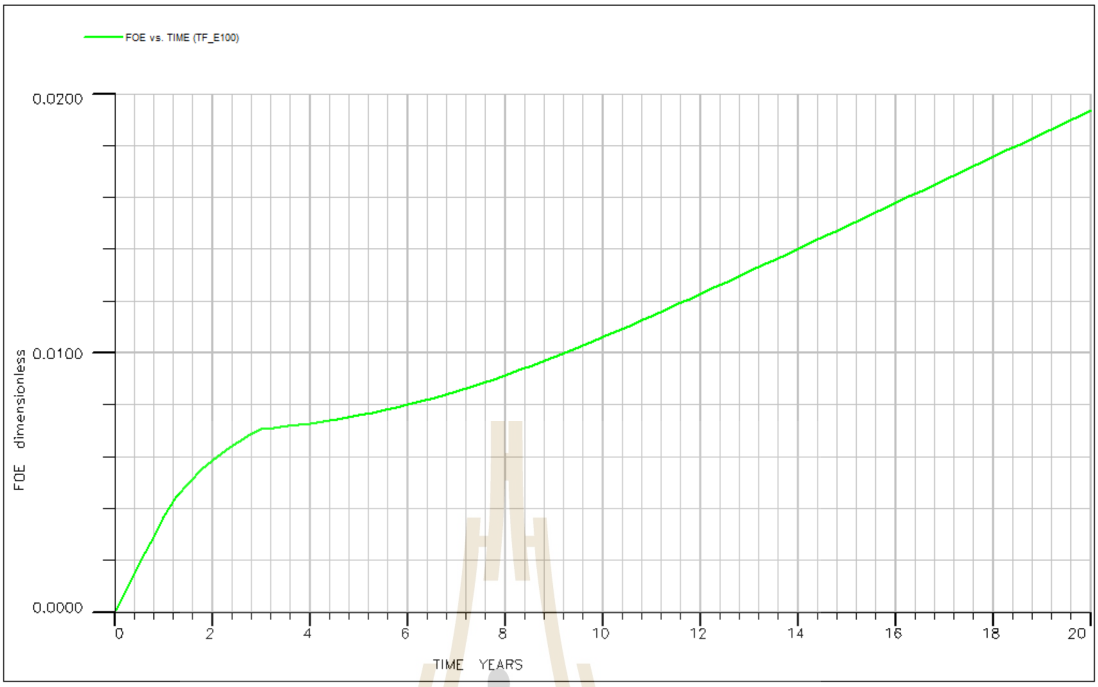
Figures D.174 Oil production rate Vs. time of model case 21



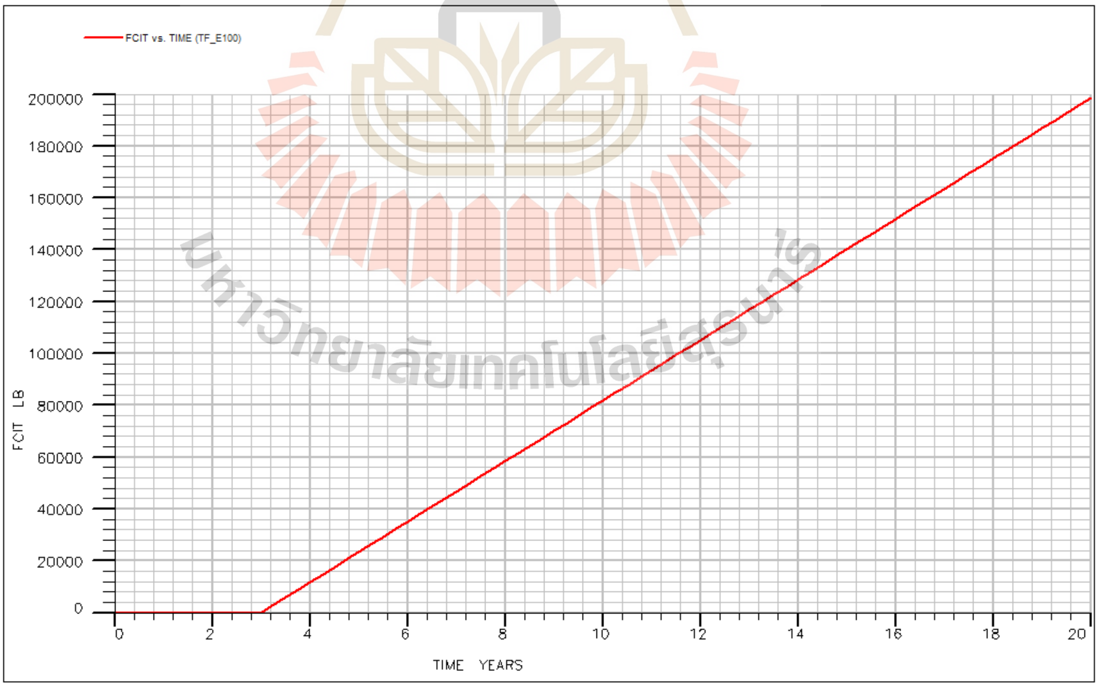
Figures D.175 Water production rate Vs. time of case 21



Figures D.176 Field pressure Vs. time of model case 21



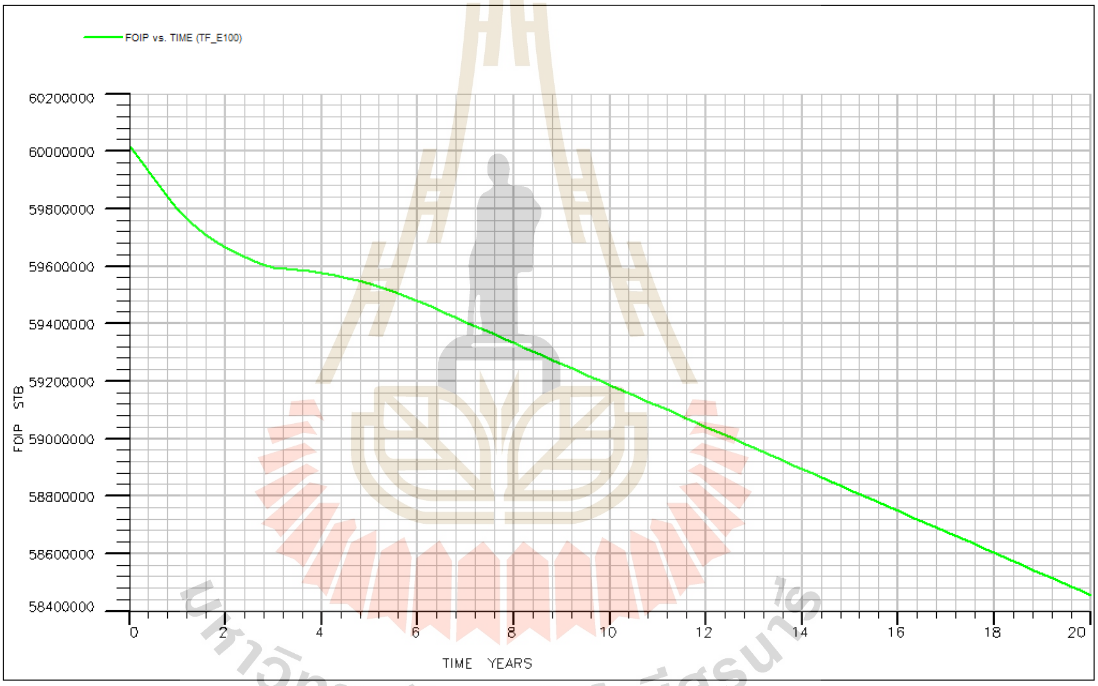
Figures D.177 Oil efficiency Vs. time of model case 21



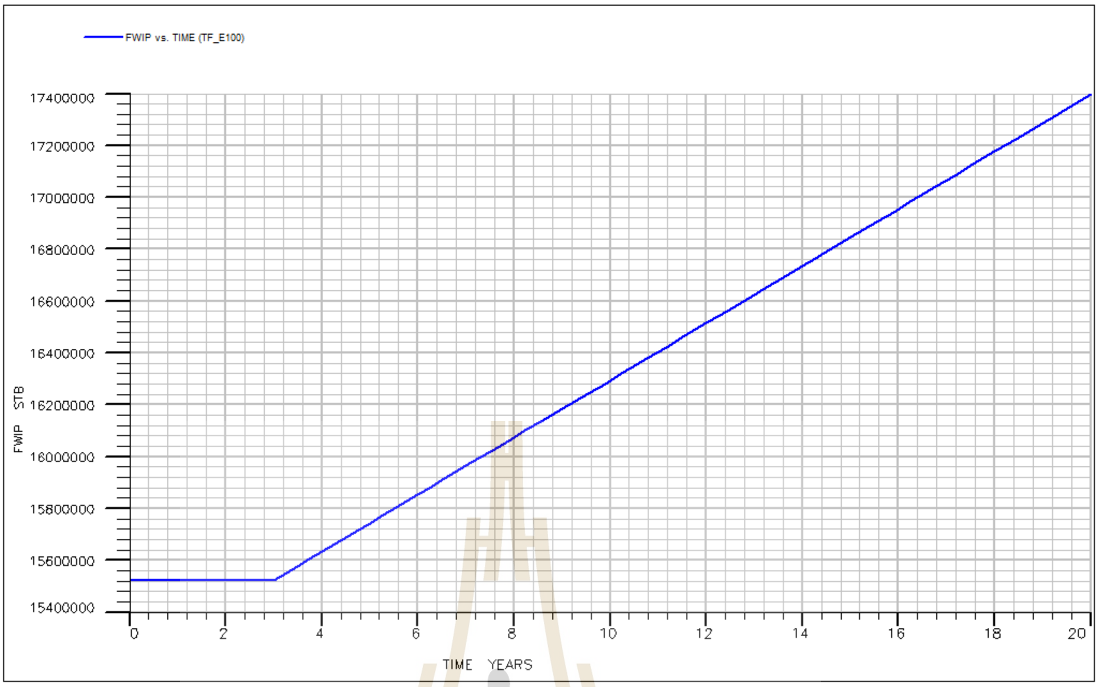
Figures D.178 Polymer injection total Vs. time of model case 21

D.4.4 Result of Model Case 22

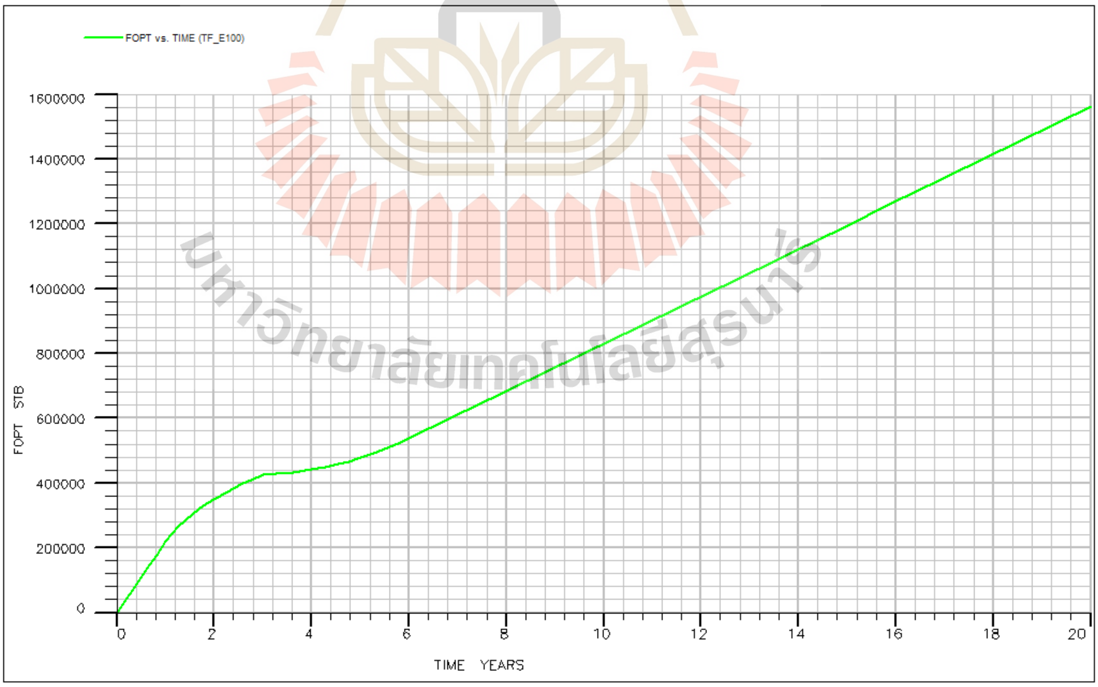
Model case 22 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the third year. The production period is 20 years. The simulation results are shown in Figures D.179 - D.187:



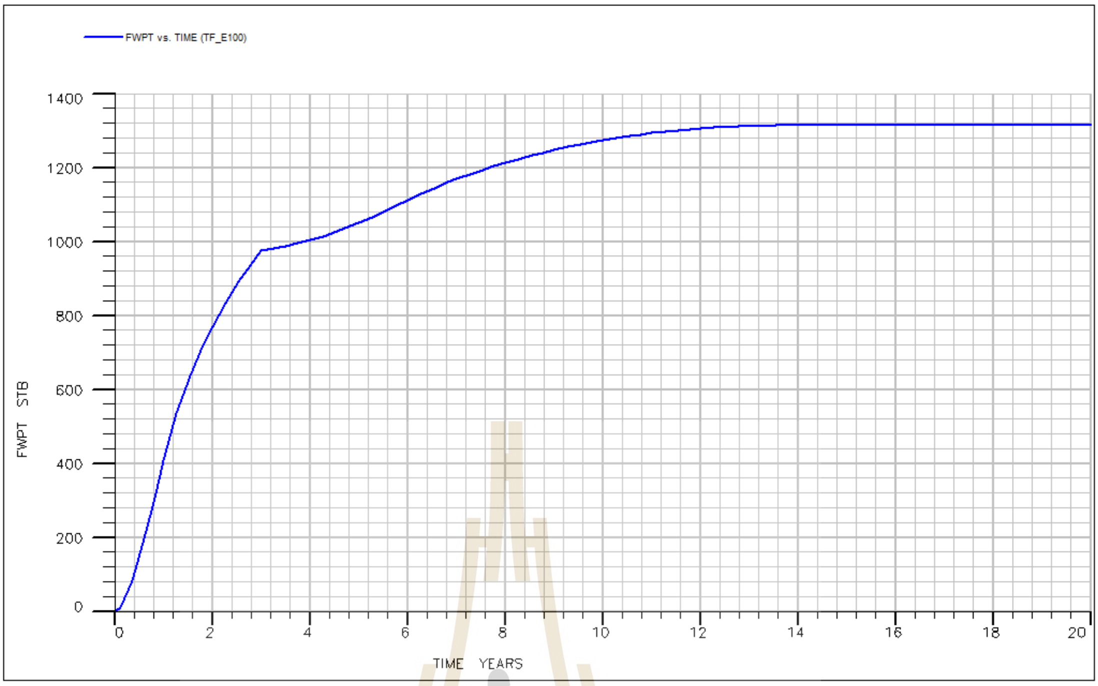
Figures D.179 Oil in place Vs. time of model case 22



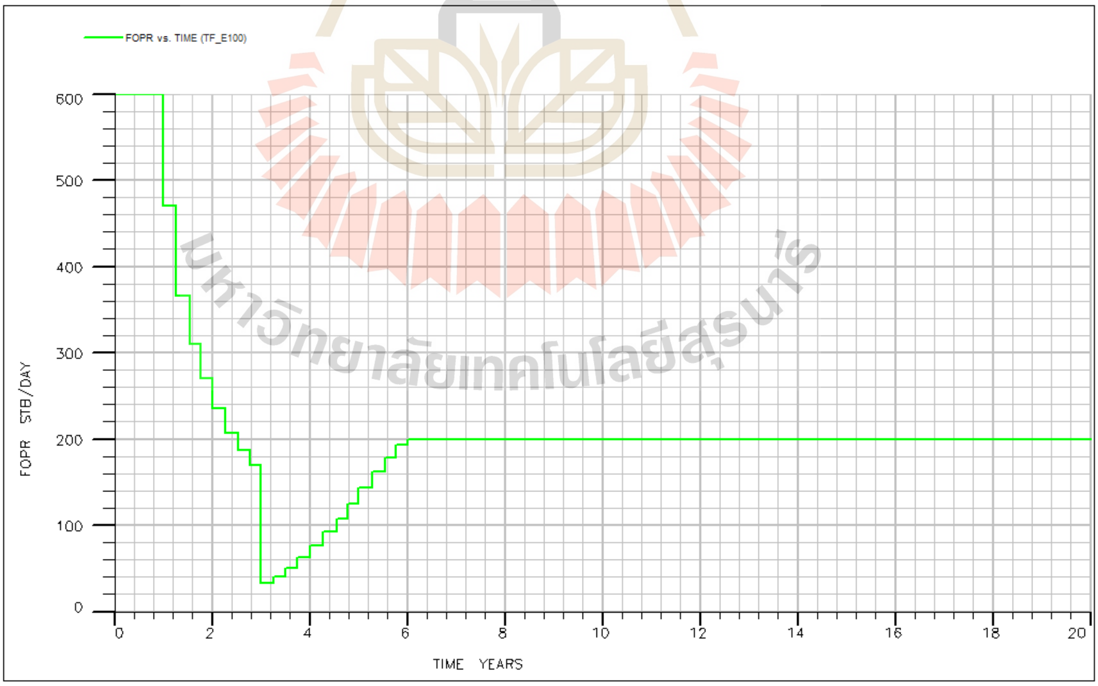
Figures D.180 Water in place Vs. time of model case 22



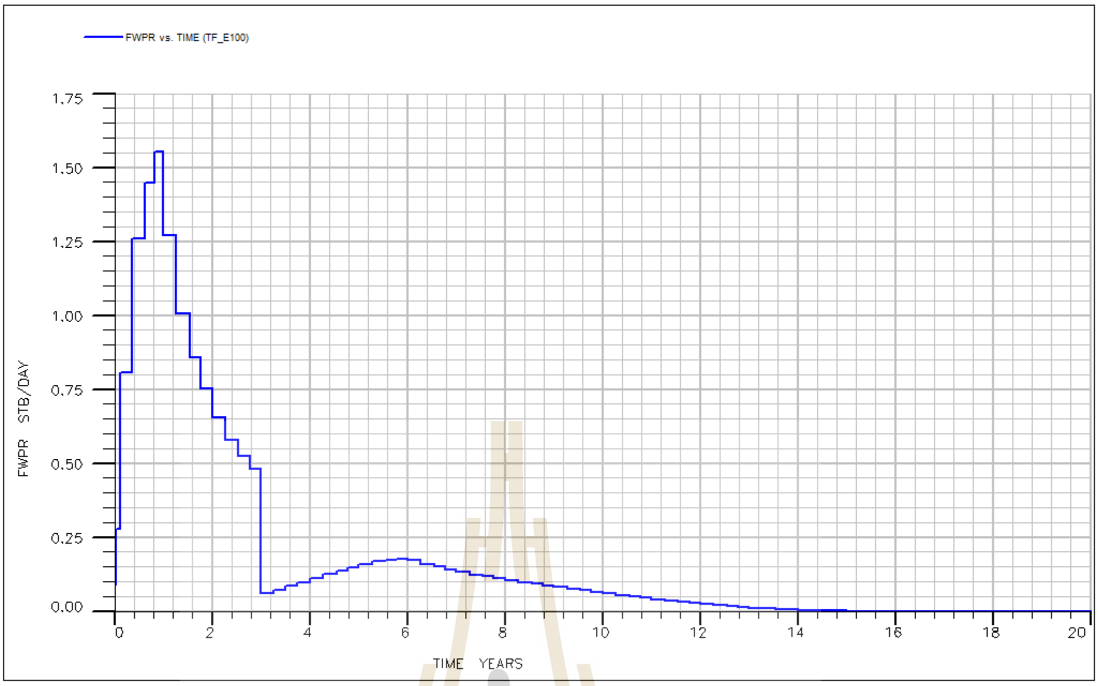
Figures D.181 Oil production total Vs. time of model case 22



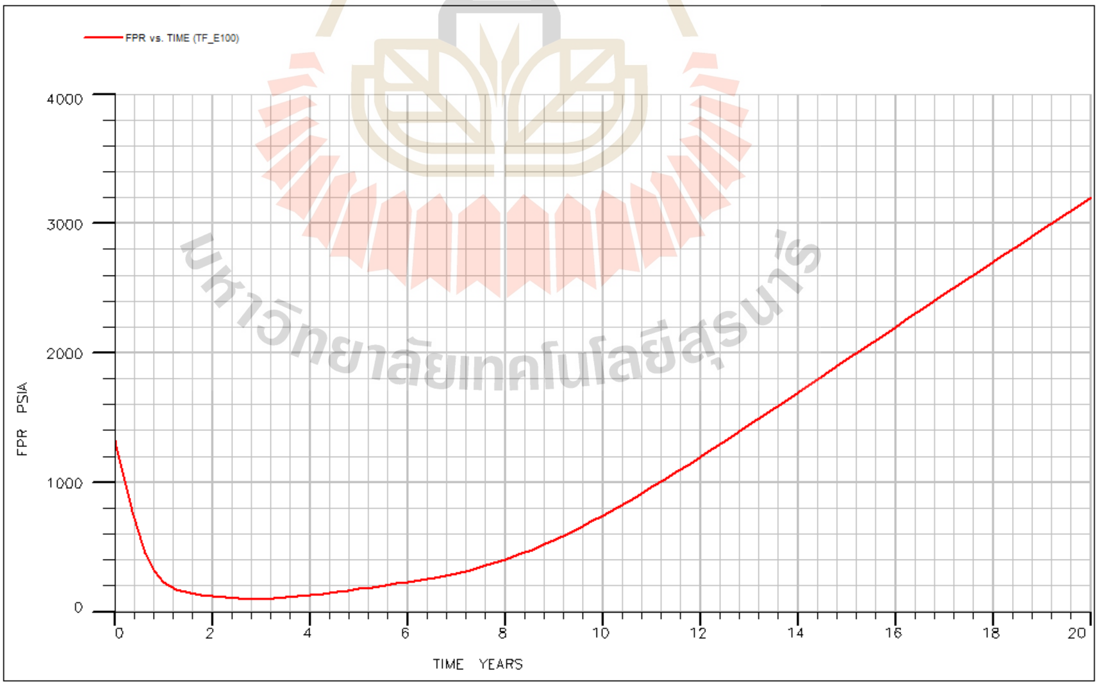
Figures D.182 Water production total Vs. time of model case 22



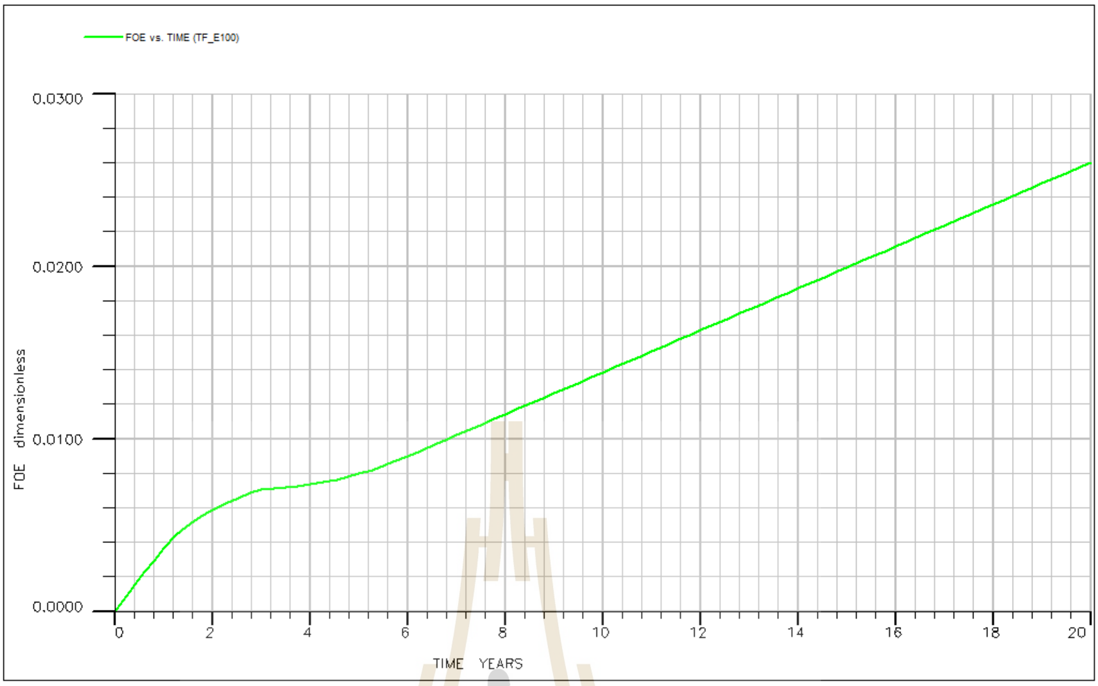
Figures D.183 Oil production rate Vs. time of model case 22



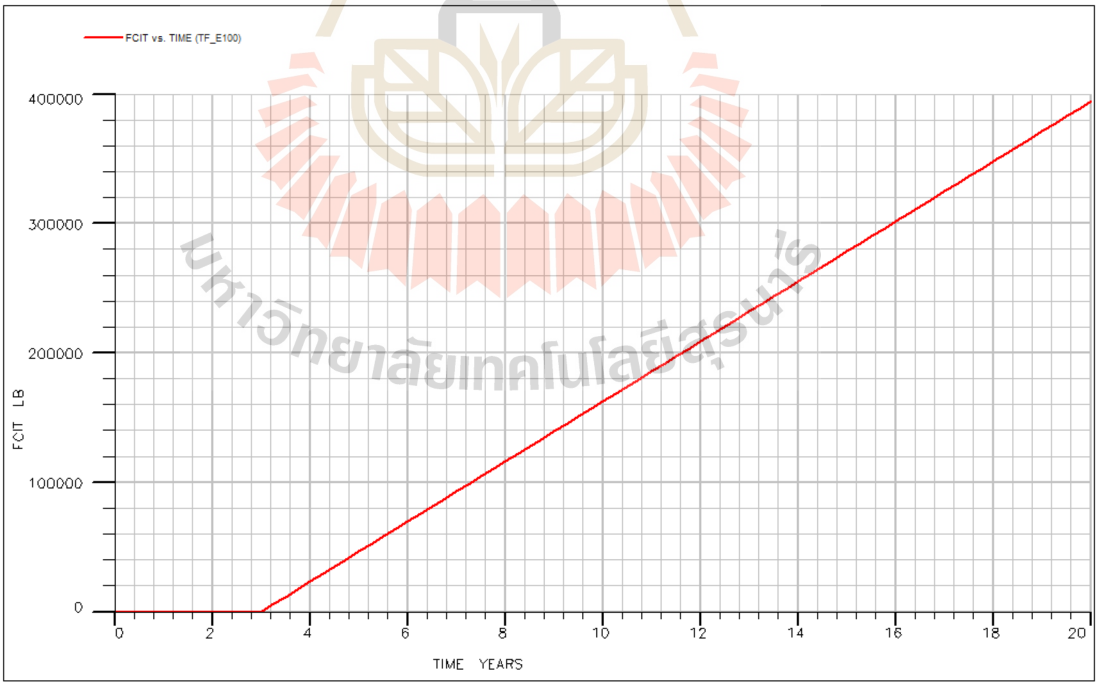
Figures D.184 Water production rate Vs. time of case 22



Figures D.185 Field pressure Vs. time of model case 22



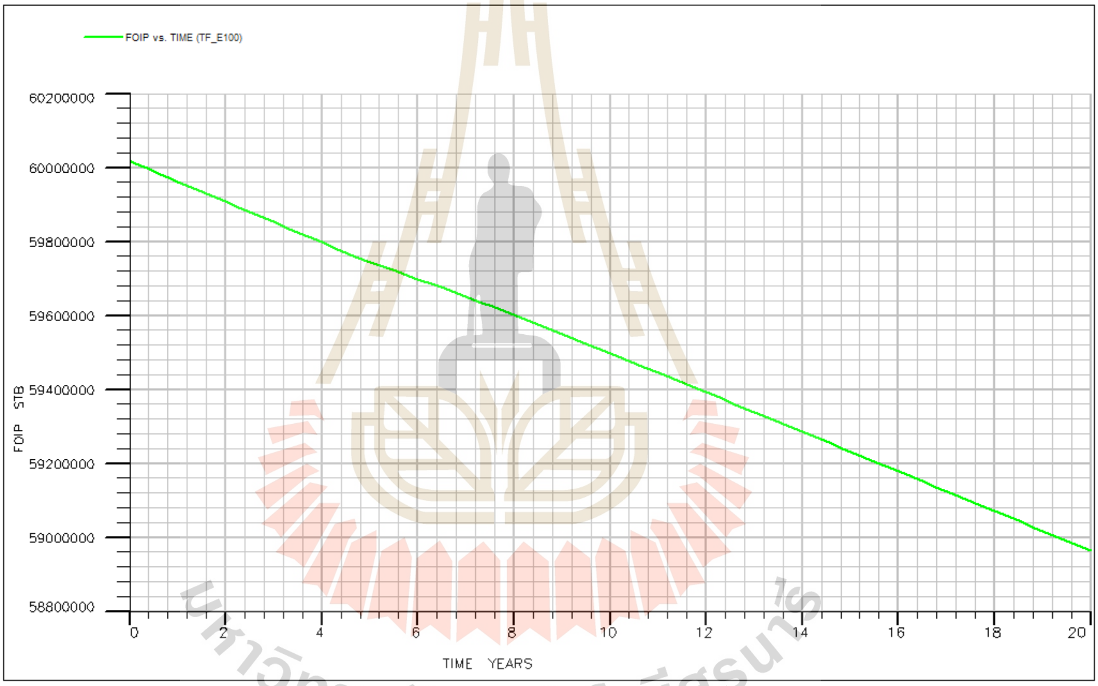
Figures D.186 Oil efficiency Vs. time of model case 22



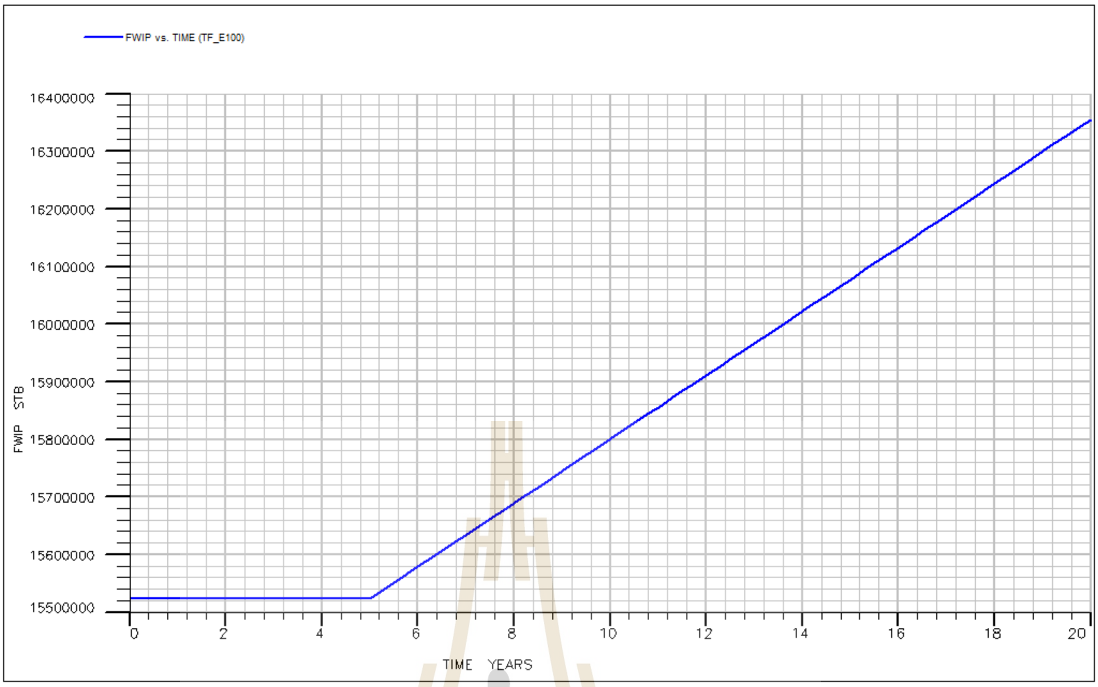
Figures D.187 Polymer injection total Vs. time of model case 22

D.4.5 Result of Model Case 23

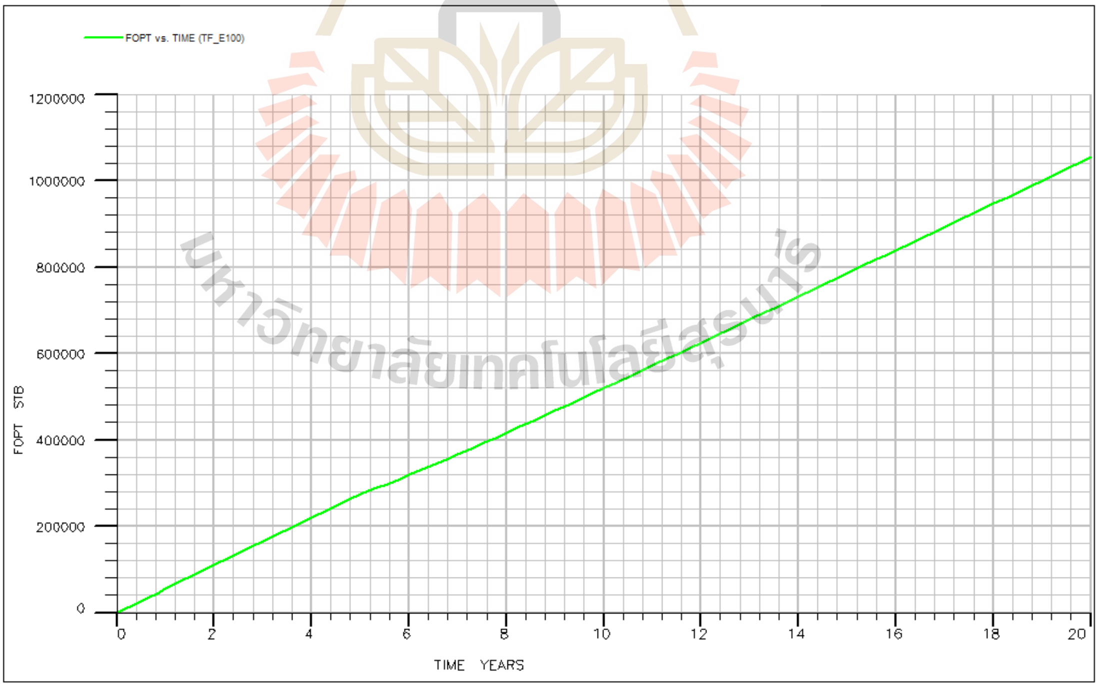
Model case 23 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 150 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.188 - D.196:



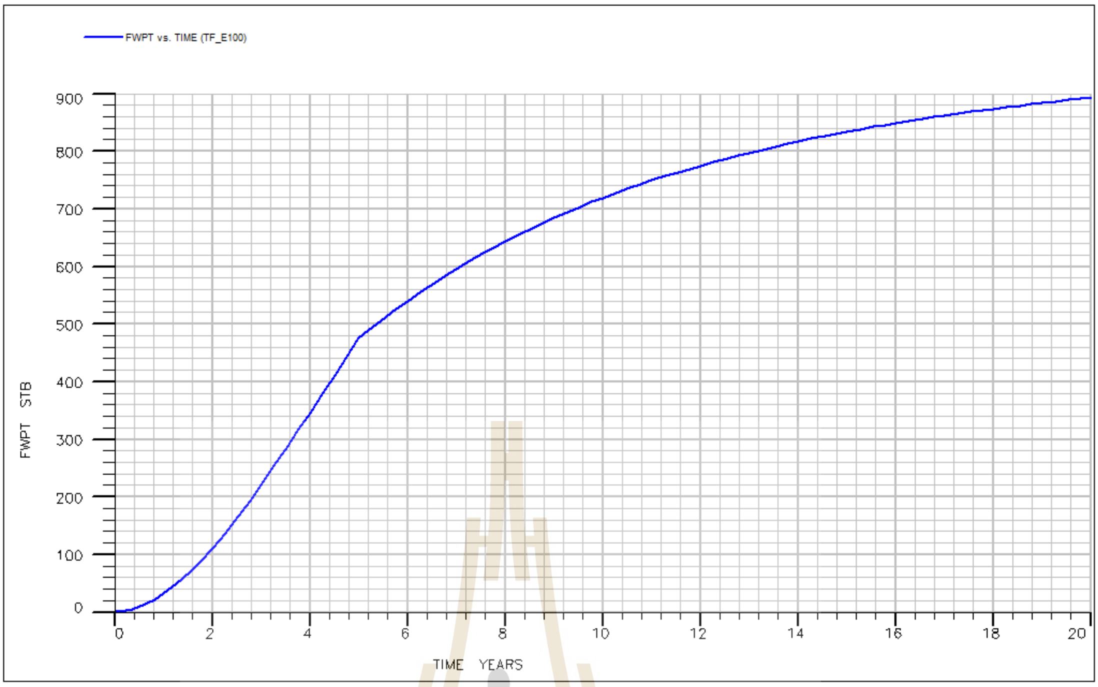
Figures D.188 Oil in place Vs. time of model case 23



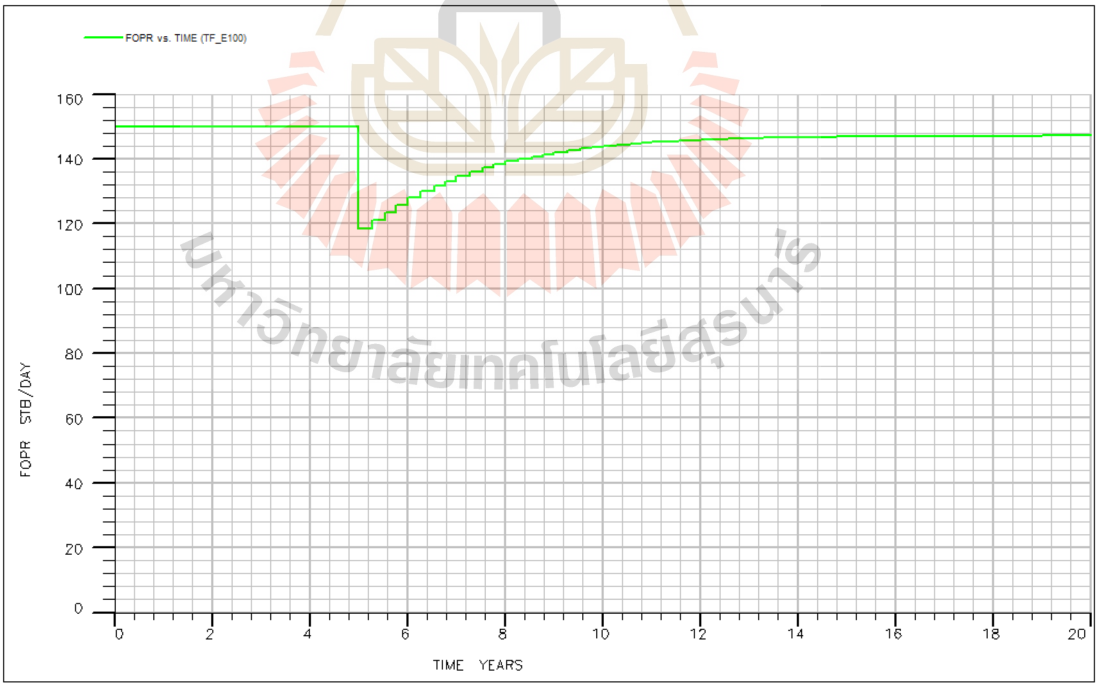
Figures D.189 Water in place Vs. time of model case 23



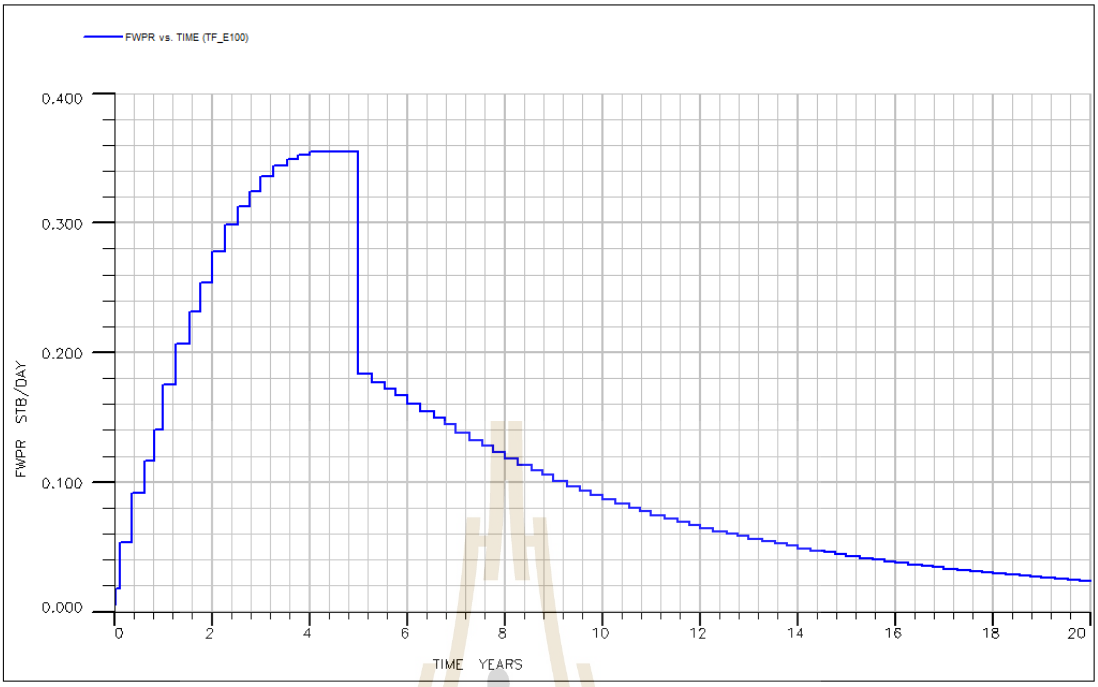
Figures D.190 Oil production total Vs. time of model case 23



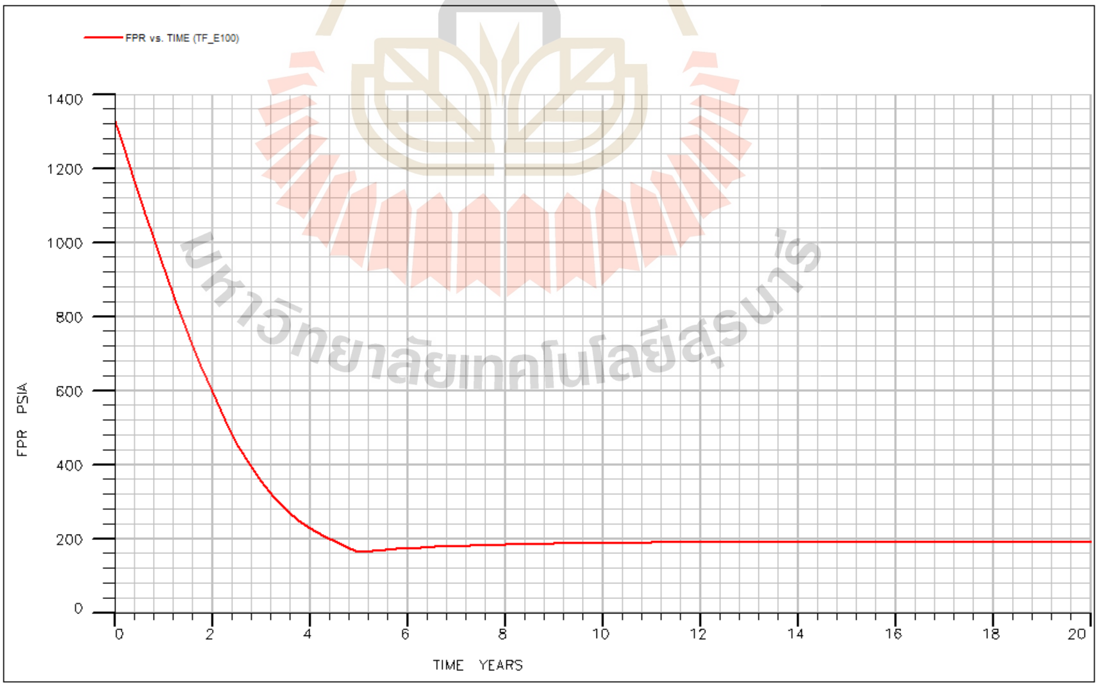
Figures D.191 Water production total Vs. time of model case 23



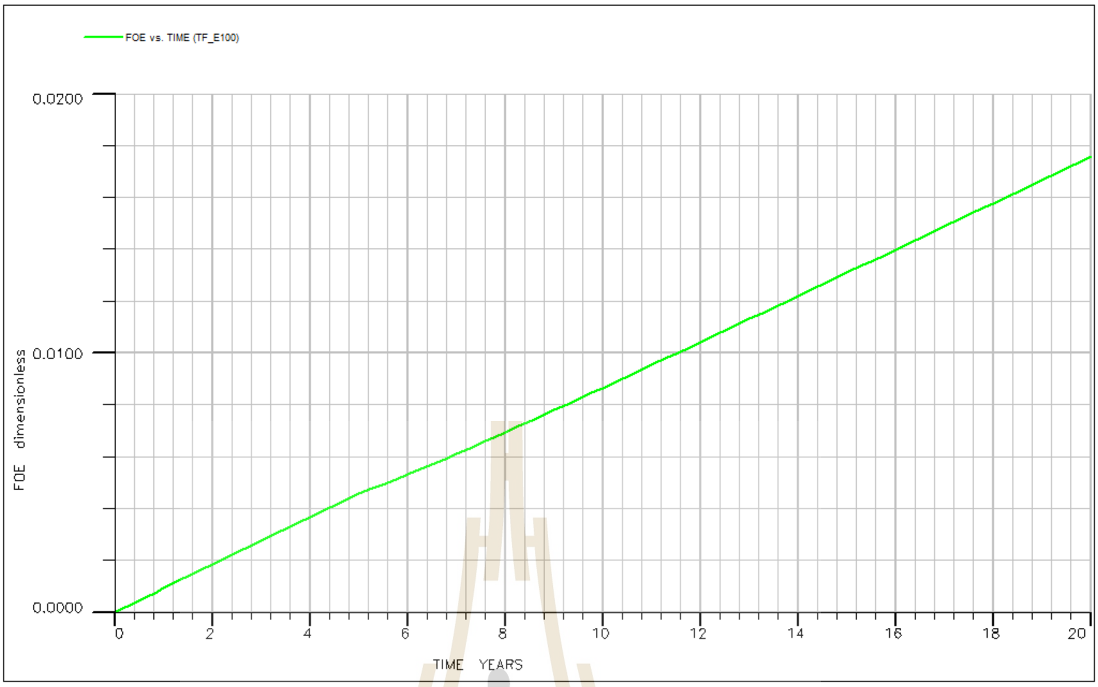
Figures D.192 Oil production rate Vs. time of model case 23



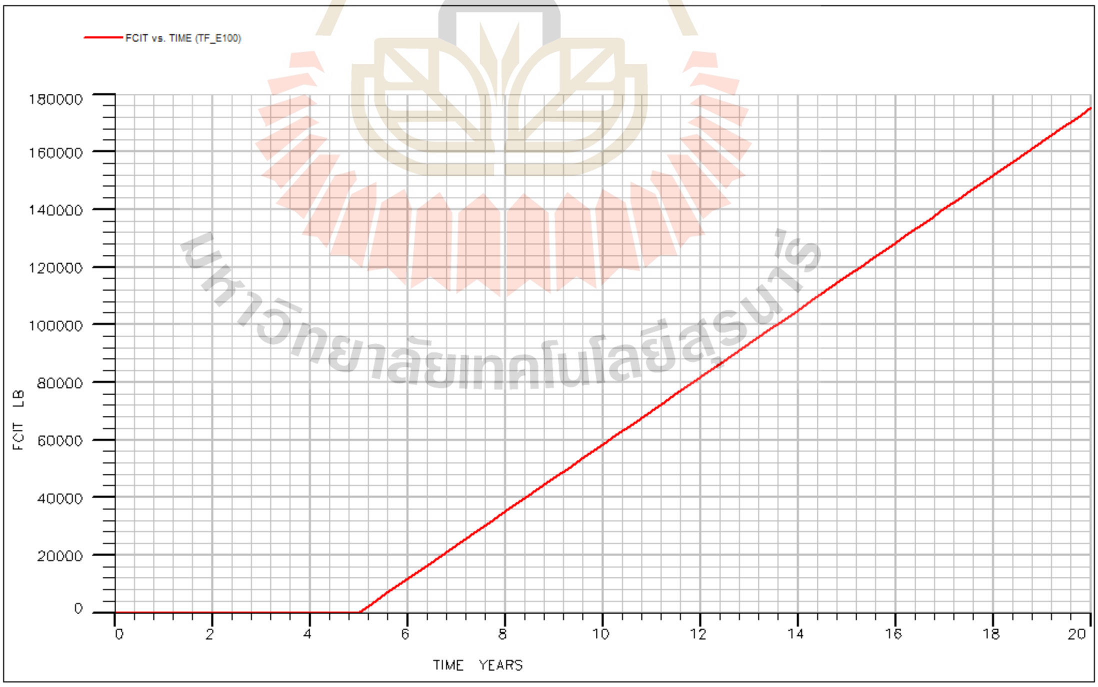
Figures D.193 Water production rate Vs. time of case 23



Figures D.194 Field pressure Vs. time of model case 23



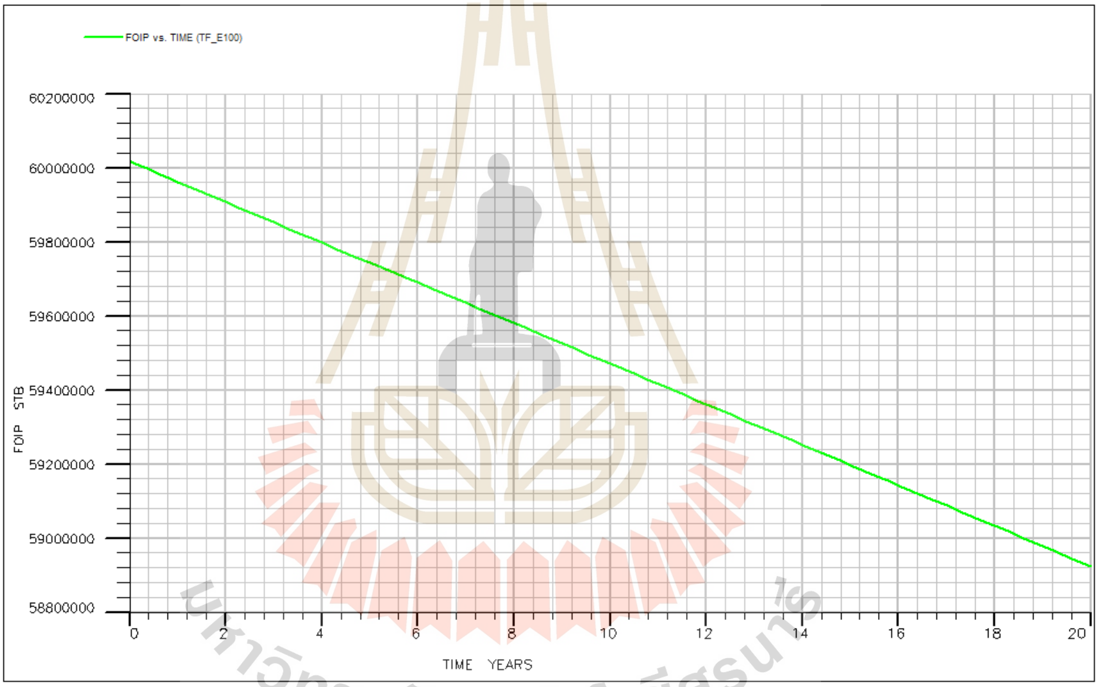
Figures D.195 Oil efficiency Vs. time of model case 23



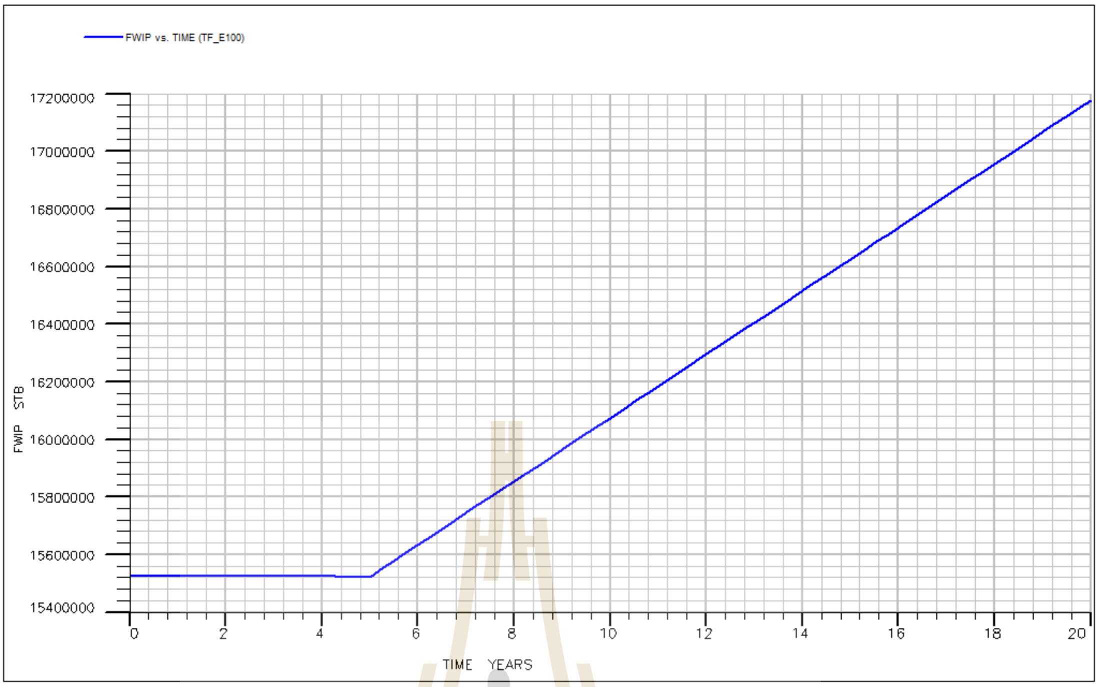
Figures D.196 Polymer injection total Vs. time of model case 23

D.4.6 Result of Model Case 24

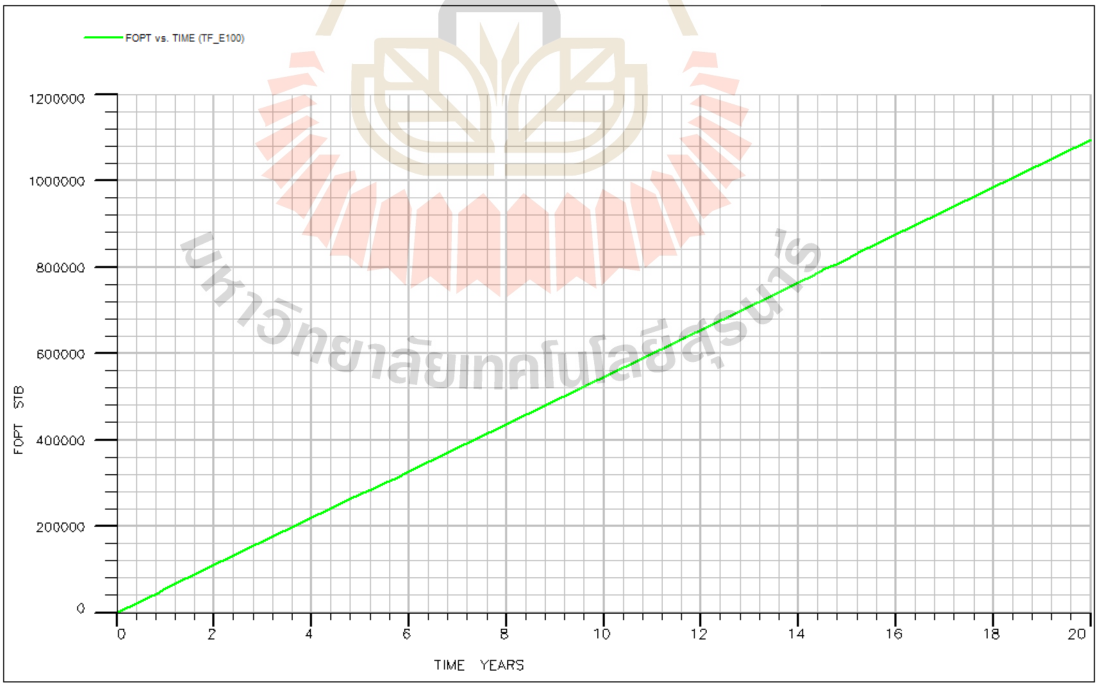
Model case 24 The production is commenced in 1 production wells at the initial oil production rate of 200 bbl/d and 2 injection well at the polymer injection rate of 300 bbl/d in concentration 1500 ppm. Employs the staggered line drive pattern and injection method in the fifth year. The production period is 20 years. The simulation results are shown in Figures D.197 - D.205:



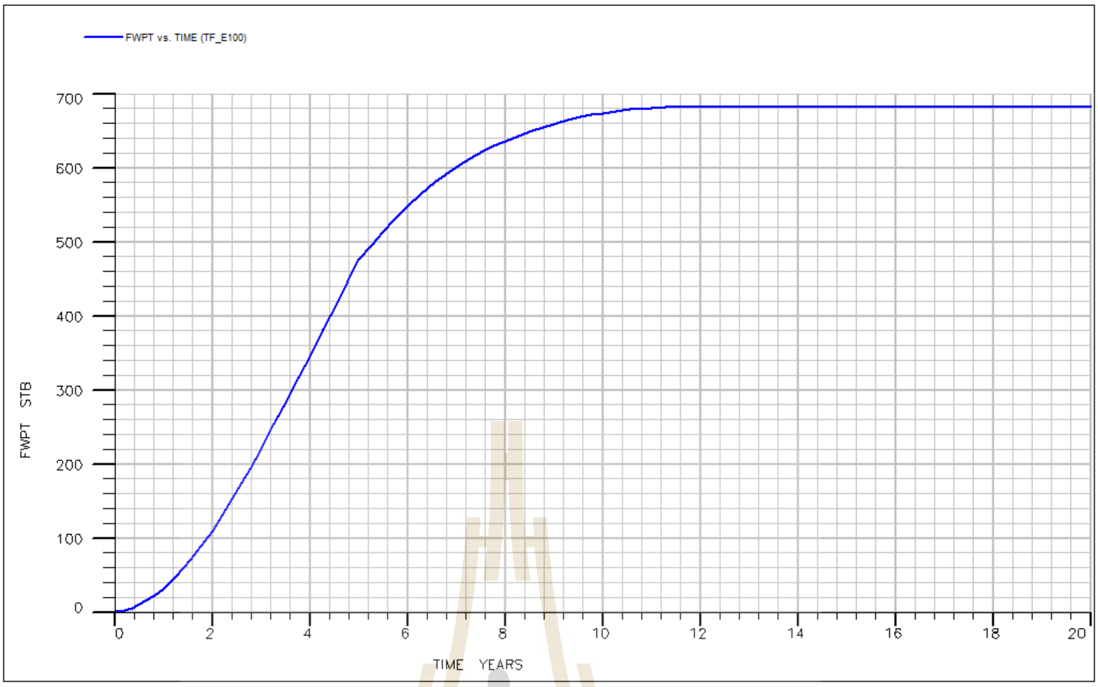
Figures D.197 Oil in place Vs. time of model case 24



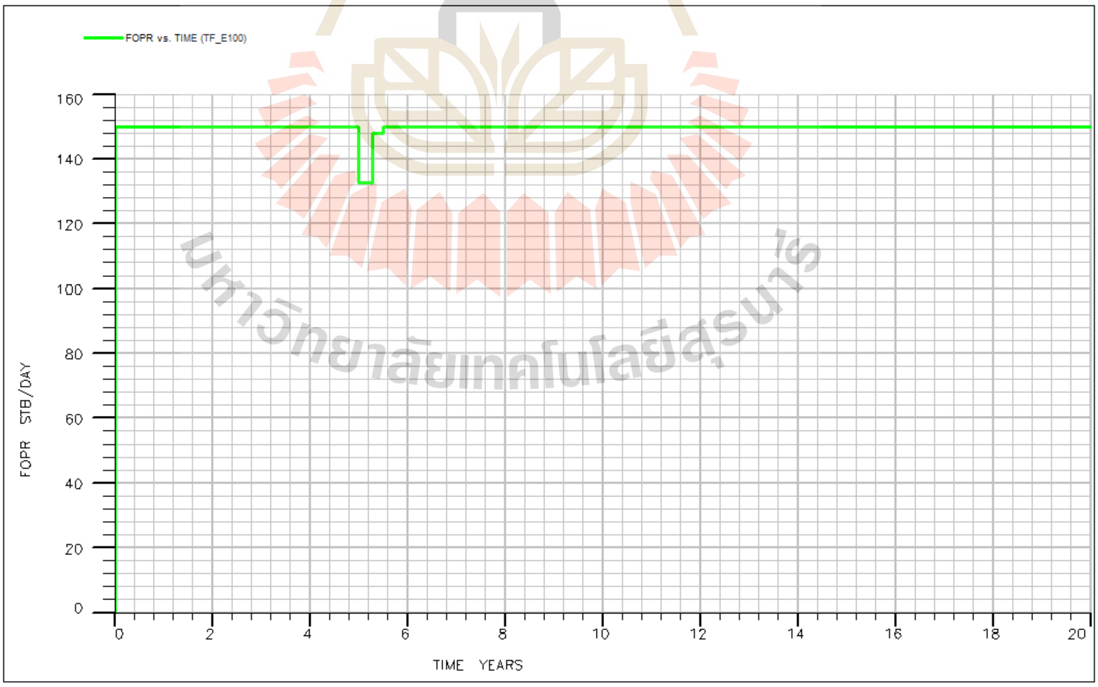
Figures D.198 Water in place Vs. time of model case 24



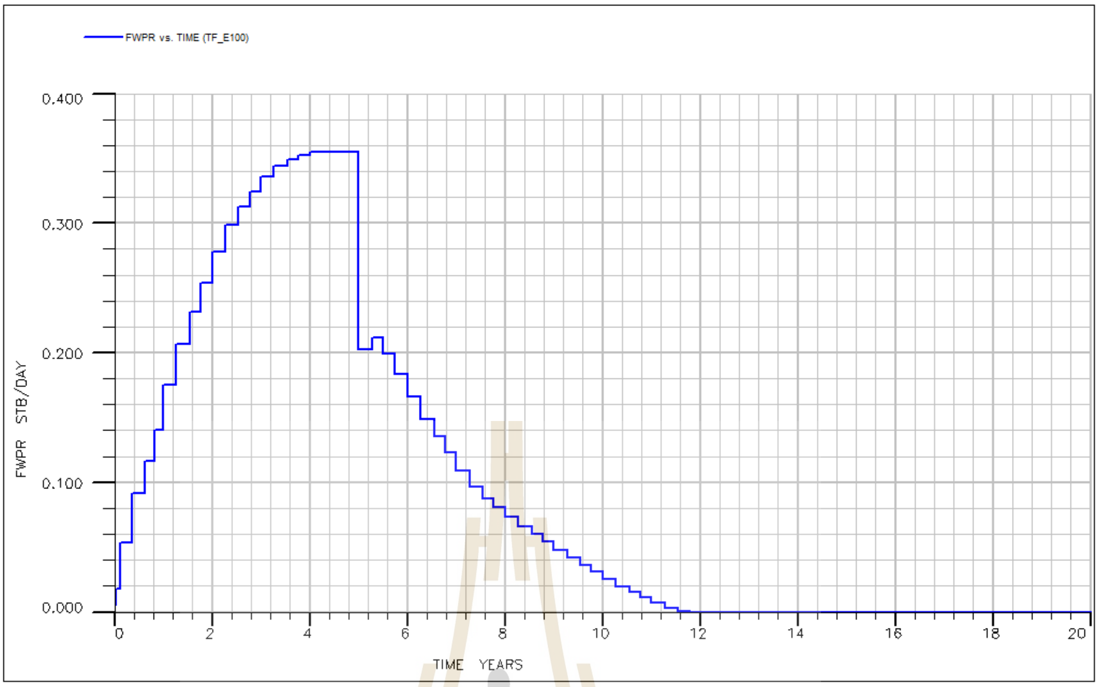
Figures D.199 Oil production total Vs. time of model case 24



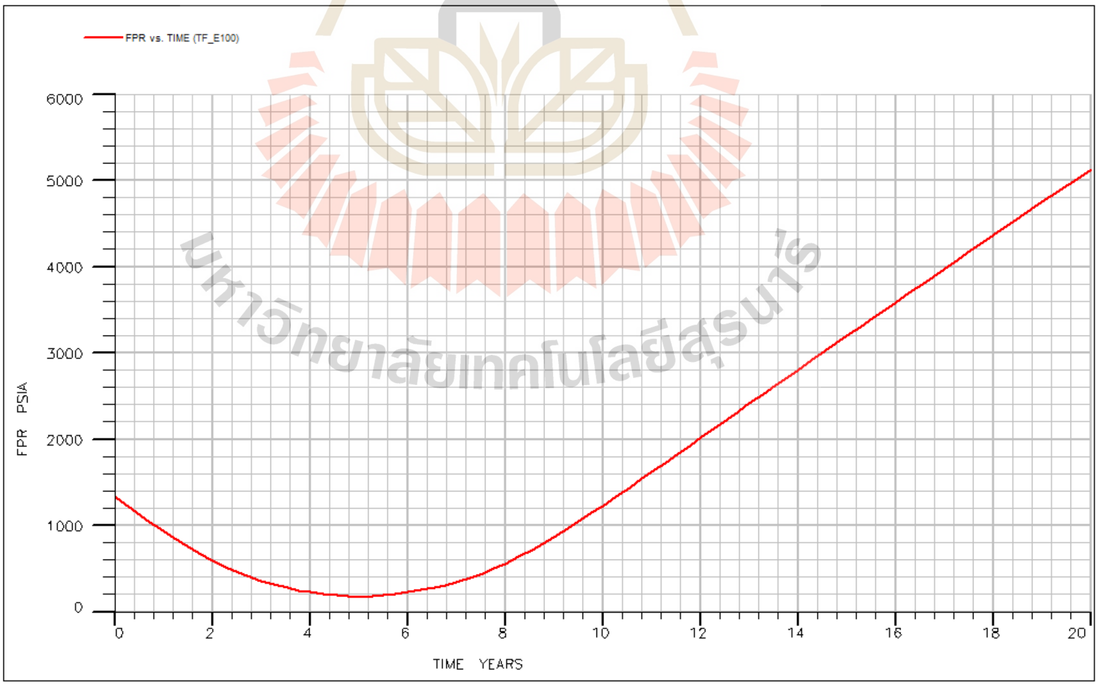
Figures D.200 Water production total Vs. time of model case 24



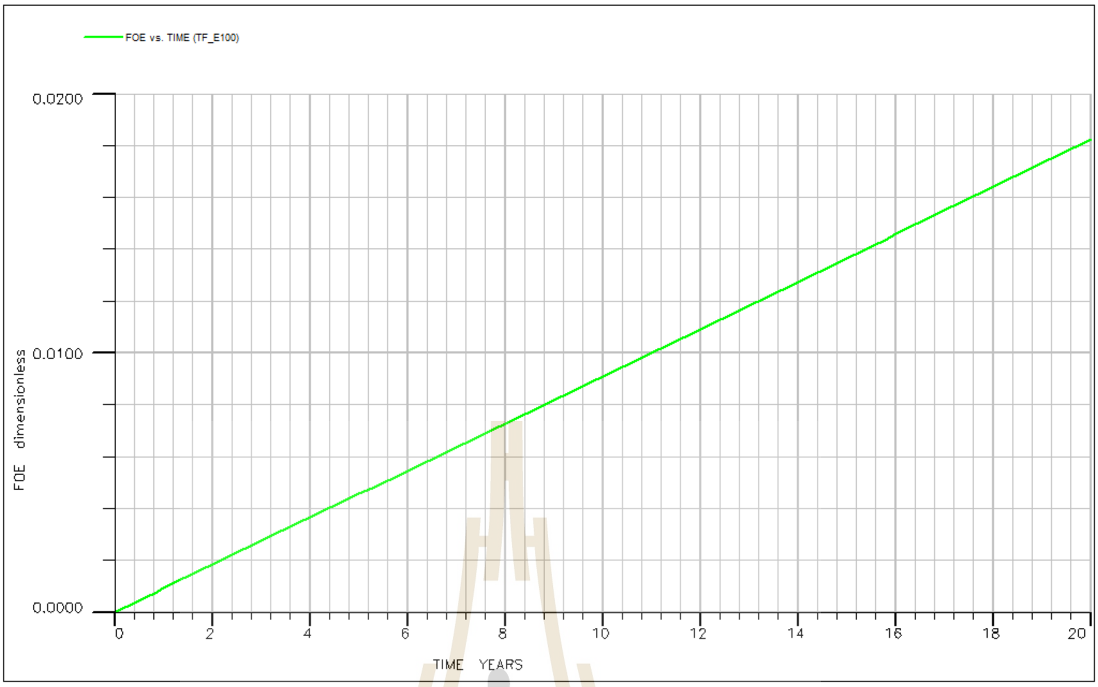
Figures D.201 Oil production rate Vs. time of model case 24



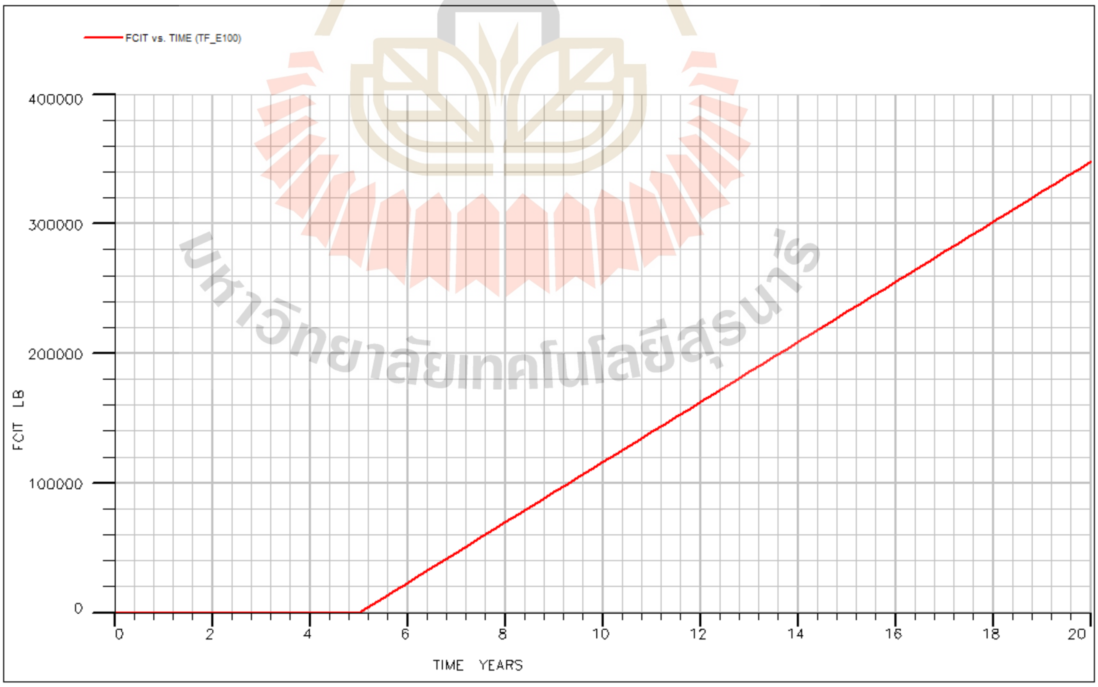
Figures D.202 Water production rate Vs. time of case 24



Figures D.203 Field pressure Vs. time of model case 24



Figures D.204 Oil efficiency Vs. time of model case 24



Figures D.205 Polymer injection total Vs. time of model case 24

BIOGRAPHY

Mr. Suchet Nillaphan was born on the 20th January 1989 in Saraburi. Graduated from Pibul Wittayalai School in 2007, he continued to pursue a bachelor's degree at Suranaree University of Technology (SUT). In 2012, he earned his degree in the School of Geotechnology.

From 2012-2017, he has studied for a master's degree in the School of Geotechnology, Institute of Engineering at Suranaree University of Technology with the major in Petorleum Engineering.