BOTTOM WATERFLOODING SIMULATION MODEL

IN PHITSANULOK BASIN OF THAILAND

Narin Yaemphiphat

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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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การวิจัยนี้มีวัตถุประสงค์หลักเพื่อทำการสร้างแบบจำลองเพื่อใช้ในการทดสอบการเพิ่มปริมาณการผลิตน้ำมันโดยการขับด้วยน้ำจากด้านล่างของแหล่งน้ำมันในแอ่งพิษณุโลกของประเทศไทย ทั้งนี้สืบเนื่องจากการการใช้พลังงานของประเทศได้เพิ่มขึ้นอย่างต่อเนื่อง คาดการณ์ได้ว่าความต้องการด้านพลังงานในอนาคตก็ยังคงสูงขึ้นเช่นกัน เพื่อจัดการกับความต้องการดังกล่าวรวมทั้งเพื่อรักษาระดับการพัฒนาเศรษฐกิจให้เป็นไปอย่างยั่งยืน กระบวนการผลิตน้ำมันขั้นทุติยภูมิจึงต้องนำมาพิจารณาใช้งานในการเพิ่มอัตราการผลิตน้ำมันให้เพียงพอต่อความต้องการใช้งานและความมั่นคงทางพลังงานของประเทศ หัวข้อการศึกษานี้ประกอบไปด้วย (1) เพื่อศึกษาและสรุปประวัติการสำรวจและผลิตปิโตรเลียมของประเทศไทยโดยสังเขป (2) เพื่อจำลองและทดสอบผลของการเพิ่มขึ้นของการผลิตน้ำมันโดยการขับด้วยน้ำจากด้านล่างของแหล่งกักเก็บน้ำมันในแอ่งพิษณุโลกของประเทศไทย (3) ทำการเปรียบเทียบผลที่ได้กับการศึกษาของบริษัทผู้ผลิตในพื้นที่ ทั้งนี้รวมไปถึงการวิเคราะห์ทางด้านเศรษฐศาสตร์เพื่อการเปรียบเทียบตัดสินใจ การพิจารณาถึงโอกาสและความเป็นไปได้ที่จะนำวิธีการดังกล่าวนี้ไปใช้ในการประกอบการจริง โดยข้อมูลทางธรณีฟิสิกส์และคุณสมบัติของของไหลในแหล่งกักเก็บนั้นได้ทำการรวบรวมมาจากบทความเผยแพร่ต่าง ๆ รวมทั้งใช้ค่าที่ได้จากการคำนวณเชิงทฤษฎี เพื่อใช้ในการสร้างแบบจำลองดังกล่าว การจัดทำแบบจำลองจะเน้นโครงสร้างของแหล่งกักเก็บแบบประทุนคว่ำ (Anticline structure) และแบบลาดเอียงแนวเทเดียว (Monocline structure) โดยแต่ละแบบของโครงสร้างยังแบ่งเป็น 3 กรณีศึกษาตามขนาดปริมาณสำรองของน้ำมันที่ 20 10 และ 5 ล้านบาร์เรล (เป้าหวังระดับสูง ระดับกลาง และระดับมาตรฐาน ตามลำดับ) และสำหรับทุกกรณีศึกษาจะแบ่งรูปแบบการวางแผนการผลิตเป็น 4 รูปแบบ (ผลิตโดยไม่มีการอัดน้ำ ทำการอัดน้ำหลังจากทำการผลิตไปแล้ว 2 4 และ 8 ปี) รูปแบบการวางตำแหน่งหลุมผลิตต่อหลุมอัดน้ำใช้เป็นแบบ Direct Line Drive และ Staggered Line Drive โดยใช้อัตราการอัดน้ำคงที่ต่อทุกรูปแบบการผลิตเพื่อศึกษาถึงลักษณะของอัตราการผลิตของของไหล ณ เวลาที่เริ่มการอัดน้ำที่ต่างกัน ผลจากการทดสอบแบบจำลองพบว่าประสิทธิภาพที่ได้จากการผลิตแบบใช้แรงขับตามธรรมชาติ (ไม่มีการอัดน้ำ) อยู่ที่ช่วง 21.97-27.62% ของปริมาณสำรองของน้ำมัน ส่วนกรณีการผลิตที่มีการอัดน้ำเพื่อทำการขับน้ำมันด้วยน้ำจากด้านล่างหลังจากผ่านการผลิตโดยใช้แรงขับตามธรรมชาติในปีที่ 2 4 และ 8 นั้นได้ประสิทธิภาพออกมาที่ 54.34-57.75% 50.26-56.17% และ 44.96-51.34% ตามลำดับ เมื่อทำการ

เปรียบเทียบโดยใช้การอัดน้ำช่วยกับการไม่อัดน้ำพบว่าการเริ่มอัดน้ำหลังจากทำการผลิตไปแล้ว 2 ปี จะทำให้ได้ค่าประสิทธิภาพการผลิตสูงที่สุด และมีลักษณะของค่าผลกำไรต่อเงินลงทุนที่สูงกว่ากรณีอื่น ๆ ทั้งหมดในเชิงเศรษฐศาสตร์

สาขาวิชาเทคโนโลยีธรณี ลายมือชื่อนักศึกษา ______________________

ปีการศึกษา 2552 ลายมือชื่ออาจารย์ที่ปรึกษา________________

NARIN YAEMPHIPHAT : BOTTOM WATERFLOODING SIMULATION MODEL IN PHITSANULOK BASIN OF THAILAND. THESIS ADVISOR : ASSOC. PROF. KRIANGKRAI TRISARN, 271 PP.

IMPROVE OIL RECOVERY/SECONDARY/BOTTOM WATERFLOODING/ RESERVOIR SIMULATION

The primary objective of this research is to stimulate the improving of oil recovery scenarios in Phitsanulok Basin of Thailand by bottom waterflooding reservoir simulation model. The nation's energy consumption has risen dramatically and it is expected that future energy demand will keep on increasing. To cope with the increasing demand and maintain sustainable economic growth, the secondary oil recovery process can be performed to ensure that petroleum supply of the country is secured and meets the demand. The research effort includes (1) study and review Thailand oil production history, (2) simulate the improve oil recovery technique by bottom waterflooding method in the reservoirs of Phitsanulok Basin, central Thailand, 3) compare the results with previous studies of oil companies, including economic analysis to consider the feasibility of project and it's realizable. Physical properties of the reservoir rock and fluids, e.g. permeability, porosity, and reservoir pressure, collected from literature review and theoretical assumptions, to analyze and input to a reservoir simulation model. The reservoir simulation study is focused on anticline and monocline structure styles, each structure is divide into 3 main cases according to the volume of oil in place of 20, 10, and 5 million barrels (high, medium, and base case respectively), for all cases include 4 production scenarios test applied (no water injection, 2^{nd} year, 4^{th} year, and 8^{th} year after natural flow production periods of the water injection). Direct line drive and staggered line drive flood pattern are used to perform the bottom waterflooding technique which constant water injection rate to observe the fluids production behavior at the specific time to start water injection. The results of reservoir simulation show significantly that natural flow mechanism (no water injection) can produced 21.97-27.62% of oil in place and the other cases which applied bottom waterflooding technique, the 2^{nd}, 4^{th} and 8^{th} year of water injection scenarios, the recoveries increased to 54.34-57.75%, 50.26-56.17% and 44.96-51.34% respectively. To compare with natural flow production and waterflooding scenarios, the 2^{nd} water injection presented itself the best operation scenarios of every case in development plan due to the recovery efficiency and economic values are more favorable than the others.

School of Geotechnology | Student Signature ____________________

Academic Year 2009 | Advisor Signature ____________________

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LIST OF ABBREVIATIONS

BBL, bbl	=	Barrel
BOPD	=	Barrel of oil per day
BWPD	=	Barrel of water per day
Capex	=	Capital expense
Cum. Prod.	=	Cumulative production
FGIP	=	Field gas in place
FGPR	=	Field gas production rate
FGOR	=	Field gas-oil-ratio
FGPT	=	Field gas production total
FOIP	=	Field oil in place
FOPR	=	Field oil production rate
FOPT	=	Field oil production total
FPR	=	Field pressure
FWCT	=	Field water cut
FWIP	=	Field water in place
FWPR	=	Field water production rate
FWPT	=	Field water production total
Inc.	=	Income
Inj.	=	Injection

LIST OF ABBREVIATIONS (Continued)

MSCF/STB	=	Thousand cubic feet per stock tank barrel
MMbbl	=	Million barrels
MMUS$	=	Million US$
MMUS$/well	=	Million US$ per well
MSCF	=	Thousand cubic feet
NPV	=	Net present value
Opex	=	Operation expense
Pb	=	Bubble point pressure
Prod.	=	Production
ppg	=	pound per gallon
RF	=	Recovery factor
Ro	=	vitrinite reflectance
SCF	=	Standard cubic feet
SCFD	=	Standard cubic feet per day
STB	=	Stock tank barrel
STOIIP	=	Stock tank of oil initial in place
TD	=	total depth
TOC	=	Total Organic Carbon

CHAPTER I

INTRODUCTION

1.1 Problem and Rationale

Petroleum energy is so essential to human lives and represents a significant part of the cost of production for agricultural, industrial, and transport sectors, it is vital to the economic of the nation. Thailand's energy consumption had risen dramatically (60% of imported and 40% of indigenous production) and it is expected that future energy demand will keep on increasing. To cope with the increasing demand and maintain sustainable economic growth, the secondary oil recovery process can be performed to ensure that petroleum supply of the country is secured and meets the demand. To perform this task, production planning and implementation must also carefully be done such that petroleum produced can be maximized under technical, economical and time constraints.

Since the primary depletion mechanism reach its mature stage and the remaining oil still left in a reservoir, the Enhanced Oil Recovery (EOR), a method that refers to any method used to recover more oil from a reservoir than would be produced by primary recovery, have been developed and applied to mature and depleted oil reservoir. These methods can be improving more oil recovery about 20 to 30 percent of primary production stage (normally 10-20%). One of the most famous secondary recovery methods is waterflooding, the most successful and widely used commercial recovery process. This is because water is available and inexpensive when it relates to other fluid. Additionally, waterflooding involves low capital investment and operating costs and favorable economics (Thakur, G.C., and Satter, A.,1998).

The secondary recovery process usually has an uncertain parameter that cause of unexpected results while operating the project. This can be achieve by reservoir simulation or reservoir modeling, one of the most powerful techniques currently available for reservoir management and development tool, has been studies to consider the petroleum production and development plan. This technique provides opportunity to produce the reservoir several times to examine alternatives before commencing. Not only primary production examine but also field development too, especially waterflooding project can be modeled and simulated to studies the suitable flooding pattern, optimum water injection rate, optimum oil production rate, optimum time to start water injection and other necessary project requirement.

1.2 Research Objectives

The primary objective of this research is to simulate the improving of oil recovery in Phitsanulok Basin of Thailand by bottom waterflooding reservoir simulation model. The bottom waterflooding is the process to injecting water through a water injection well, direct into the water production zone in the reservoir to force through the pore spaces and sweeps some residual oil toward the producing wells. The objectives of studies are (1) to study and review Thailand oil production history, (2) to simulate the improve oil recovery technique by bottom waterflooding method in the reservoirs of Phitsanulok Basin, central Thailand, 3) to compare the results with previous studies of oil companies, including economic analysis to considerate the possible of project feasibility and it’s realizable.

1.3 Scopes and Limitations of the Study

Phitsanulok Basin, Sirikit oil field is the studied area to improve oil recovery by bottom waterflooding technique. The reservoir modeling constructed as hypothetical model, consists of two possible trapping structures, anticline structure and monocline structure with various initial of oil in place sizes. Both of static and dynamic model parameters such as geological parameters, petrophysical parameters, reservoir fluid properties and historical production data are based on data from the existing field. This reservoir model is used to analyze characteristics and behaviors of reservoir process throughout the bottom waterflooding operations that cannot be easily observed.

1.4 Research Methodology

1.4.1 Literature Review

The review will include detail of Phitsanulok Basin overview, consists of tectonic setting and structural evolution, depositional setting and stratigraphy, and hydrocarbon habitat. Some of various waterflooding problems that have been investigated by concessionaires or researchers and their methodology to solving the existing problems are reviewing next and finally, the Thailand exploration and production data will summarize to overviews the country’s petroleum activity up to date.

1.4.2 Data Collection and Preparation

The sources of reservoir modeling data were obtained from the published document such as American Association of Petroleum Geologist (AAPG), Social Petroleum Engineering (SPE), Journal of Petroleum Technology (JPT), technical report and conference papers.

1.4.3 Reservoir Modeling and Simulation

The 5,000 grid block reservoir modeling is constructed as hypothetical model by “ECLIPSE Office E100”, black oil simulation software must be done for these studies, and then used to predict its dynamic behavior. 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. However, these data are also based on Sirikit oil field that represented itself the biggest field in Phitsanulok Basin.

1.4.4 Economic Evaluation

The economic model is constructed for evaluate of feasibility studies to investment or divestment the projects. This calculated from the reservoir simulator’s results; optimum oil, gas and water production rate, cumulative oil production recovery and the gathering of much information, 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. The difference bottom waterflooding scenarios depended on time to start water injection for each reservoir sizes, were simulated and analyzed to determine the suitable time that meet the economic criteria for each projects.

1.5 Expected Results

The research involves in improving of the oil recovery and minimizing oil left in the reservoir by using bottom waterflooding technique. The simulation results represent the alternate solution of waterflooding techniques which can be performing secondary recovery project in the onshore oilfield of Thailand. The economic analysis of the simulation results can apply to advice management on the attractiveness of such investment opportunities, to assist in selecting the best options, and lead to maximize the value of the existing assets by bottom waterflooding project.

1.6 Thesis Contents

Chapter 1 states the problem and rationale, research objectives, scope and limitations of the study, research methodology and expected result. **Chapter 2** summarizes results of the literature review of Phitsanulok Basin overview, waterflood and reservoir simulation method which applied to bottom waterflooding technique and Thailand's petroleum exploration and production history were summarizes at the end of chapter. **Chapter 3** describes the reservoir simulation data preparations, model characteristics, classification and scenarios description. **Chapter 4** illustrates result of bottom waterflooding simulation model. **Chapter 5** analyzes result of simulation model in term of economic considerations. Conclusion and discussion for future research needs are given in **Chapter 6**. **Appendix A** illustrates waterflood design and basic theory. **Appendix B** illustrated reservoir simulation theory. **Appendix C** has shown the full details of base case's economic analysis calculation. The simulation input data is shown in **Appendix D** and publication is shown in **Appendix E.**

CHAPTER II

LITERATURE REVIEW

2.1 Tectonic Setting and Structural Evolution of Phitsanulok Basin

2.1.1 Regional Tectonic

In response to India's collision with Asia during the Tertiary Himalayan Orogeny, intracratonic extensional and transitional basins develop through out Southeast Asia. The onshore Tertiary basins of Thailand (Figure 2.1) are aligned in a board north-south trending belt that corresponds to a Late Paleozoic suture zone between the Shan Thai craton to the west and the Indochaina craton to the east. This suture was reactivated by Tertiary Himalayan tectonism, causing extensional and transitional basin to develop within a regionally extensive strike-slip system. The common tectonic origin for these Tertiary basins has led to many similarities in age, basin fill, structural style and hydrocarbon habitats (Burri, 1989).

2.1.2 Main Structural Elements

Within this north-south trending zone, the Phitsanulok Basin is the largest Tertiary basin of onshore Thailand. It developed as an asymmetric half-graben, due to east west extension along the Western Boundary Fault System, with associated sinistral strike-slip movement on Uttradit and Ping Fault Systems, to the north and southwest respectively. To the east lies the dextral Phetchabun Fault System (Figure 2.2).

The half-graben geometry of the Phitsanulok Basin is illustrated by Figure 2.3, which shows the western Boundary Fault flanking the Sukhothai Depression, the main basin depocentre. To the east is the intensely wrench-faulted monocline of the Eastern Flank. At basement level, more than 10 km of extension has occurred on the Western Boundary Fault, with up to 8 km of throw from the axis of the Sukhothai Depression to basement outcrops to the west. To keep peace with this rapid tertiary subsidence, sedimentation rates reach up to 1 meter per 1,000 years.

2.1.3 Structural Development

The structural development of the Phitsanulok Basin can be subdivided into four main tectonic phases (Figure 2.5). During phase 1, from Late Oligocene to early Middle Miocene, rapid extension took place along the Western Boundary Fault, and in some places was accommodated by the development of smaller antithetic normal faults on the eastern flank of the basin. Unrestricted strike-slip movement occurred along the Ping, Uttaradit and Phetchabun Fault System during this period (Figure 2.5A).

Structural Phase 2 and 3 took place in the early Middle Miocene and late Middle Miocene respectively. During phase 2, extension continued in the northern, central and southeast parts of the basin. Only in the southwestern Phitsanulok Basin did inversion commence, due to the blockage of sinistral movements on the Ping Fault (Figure 2.5B). During phase 3, extension continued in the north, and resulted in continued rapid subsidence of the Sukhothai Depression. Meanwhile, inversion became more widespread in the south, as sinistral movement on the Uttaradit fault zone become blocked (Figure 2.5C)

Finally, in Late Miocene to recent times (structural phase 4) dextral movement on the Phetchabun fault system became blocked, extensional tectonics ceased, and slow, uniform subsidence took place across the basin. The transpressional tectonic setting of this phase caused structural inversion, and a system of young dextral faults developed across the Eastern Flank of the basin, parallel to the Petchabun Fault System (Figure 2.5D). As a result of this late dextral transpression, complex riedel fault patterns developed at Tertairy level, particularly on the Eastern Flank of the basin. Localized basaltic volcanism accompanied this transpressional phase.

Fault patterns in the Phitsanulok basin are the product of the successive tectonic phase. The resulting trap geometries are often complex, and fault reactivation has had a direct impact on hydrocarbon retention in fault bounded traps. Ninety-eight percent of the hydrocarbon discovered to date in the Phitsanulok Basin is confirmed to the Sirikit and Pru Kratiam structural highs, of which certainly the former pre-dates the first oil generation in the basin. The remaining 2% of the basin's hydrocarbon are found scattered in a small accumulations on the Eastern Flank of the basin, where traps were formed only during late tectonic activity, and retention in any pre-existing traps suffered from fault reactivation.

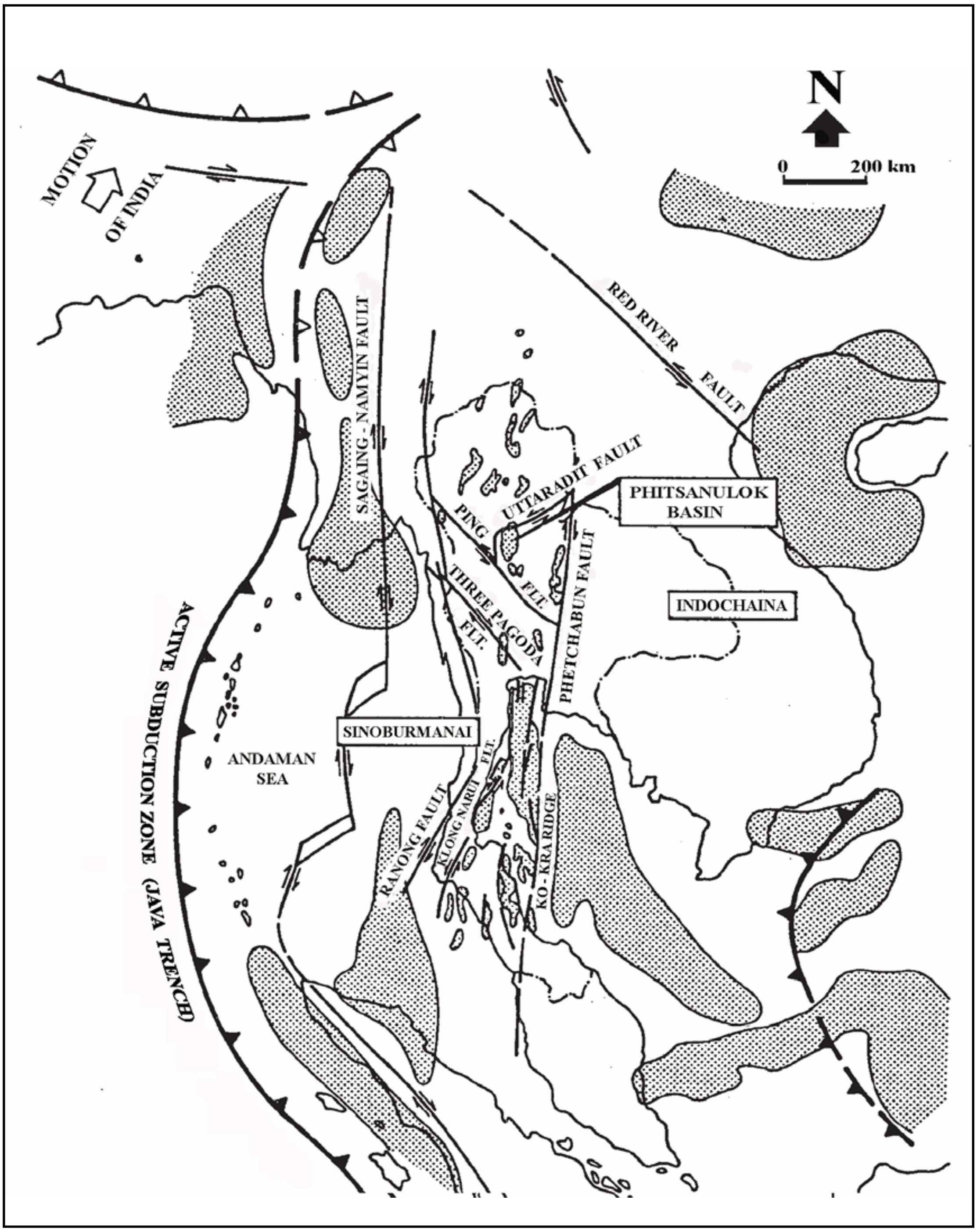

Figure 2.1 Regional tectonic setting and Tertiary Basins of Thailand,

(After Ball, A.A., 1992).

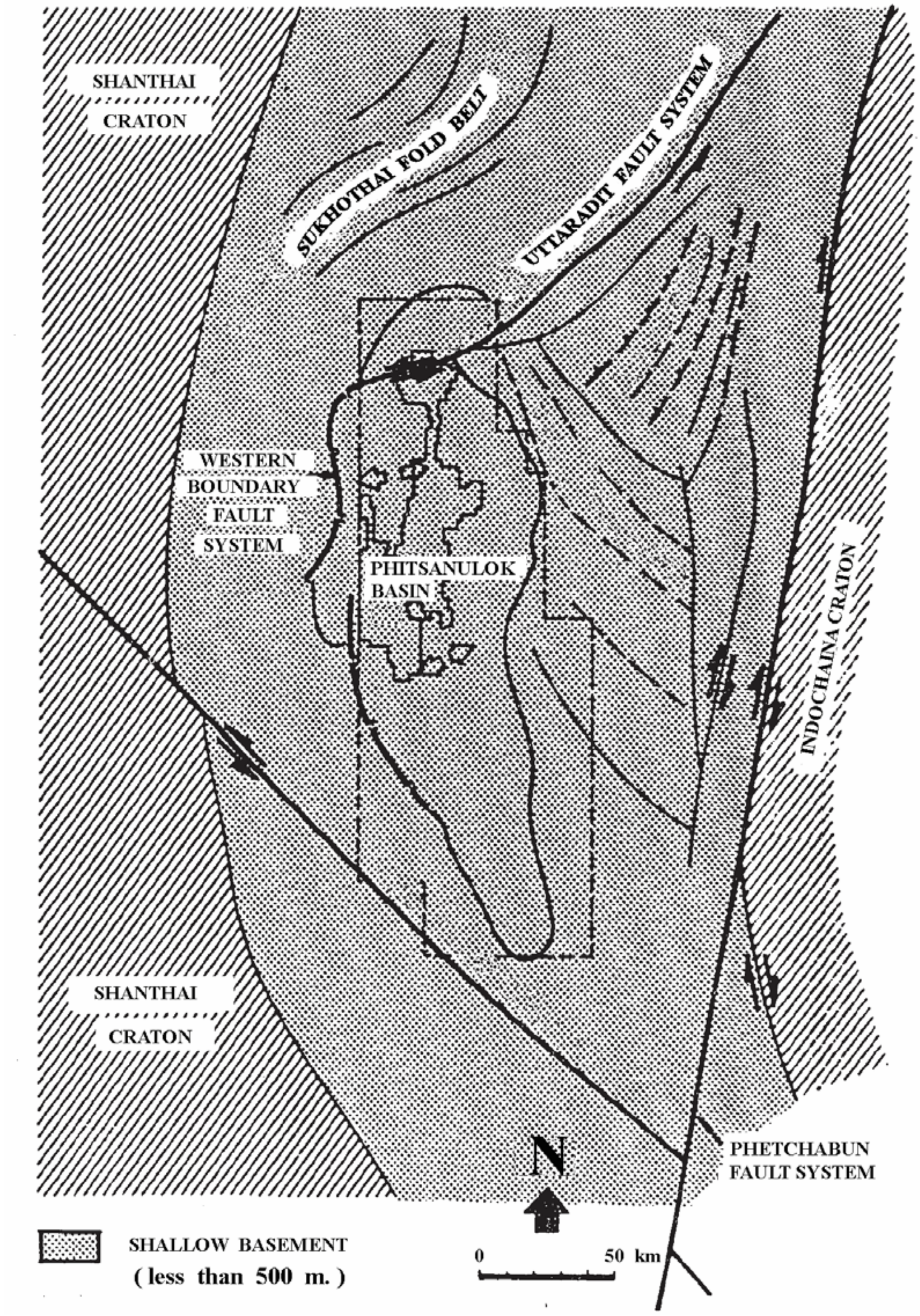

Figure 2.2 Phitsanulok Basin tectonic setting, (After Ball, A.A., 1992).

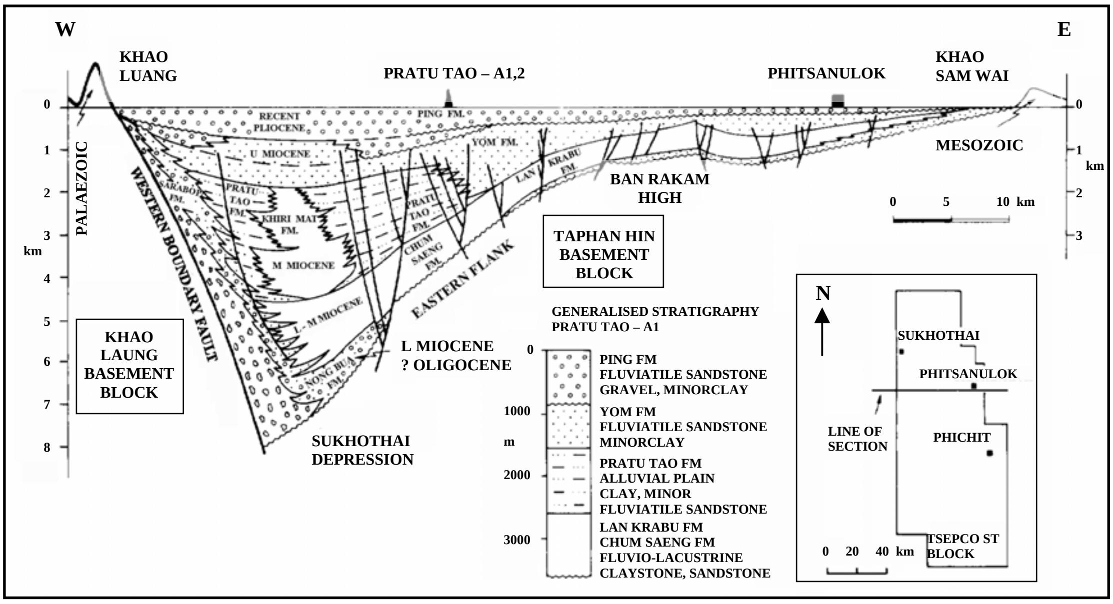

Figure 2.3 E-W Regional cross-section of Phitsanulok Basin,

(After Knox and Wakefield, 1983).

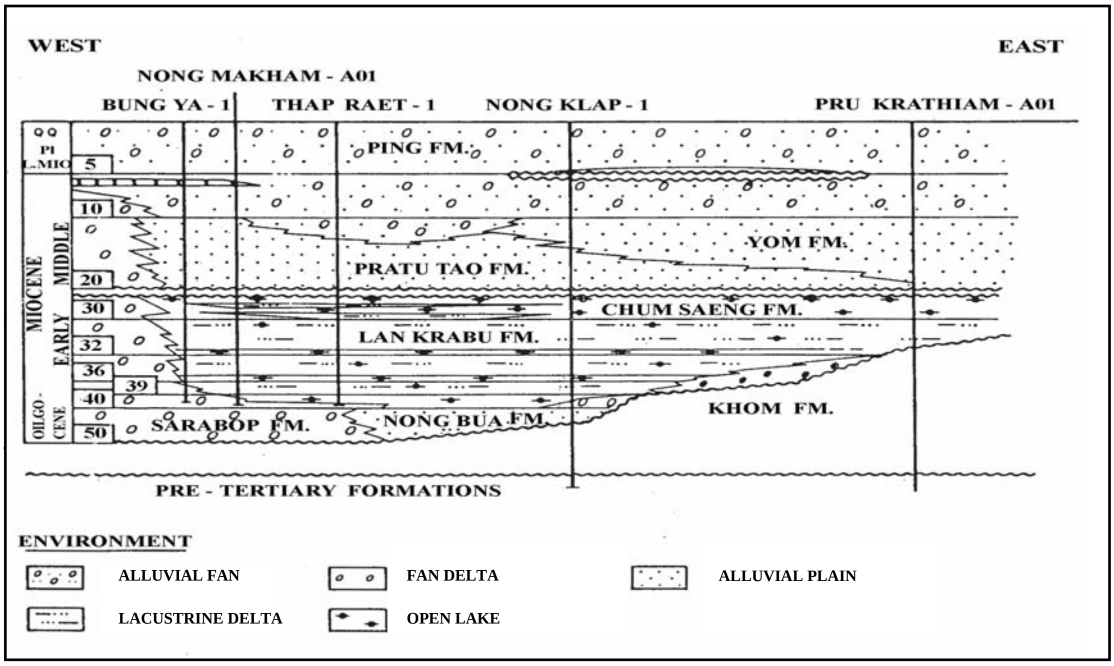

Figure 2.4 Phitsanulok Basin chronostratigraphic cross-section,

(After Ball, A.A., 1992).

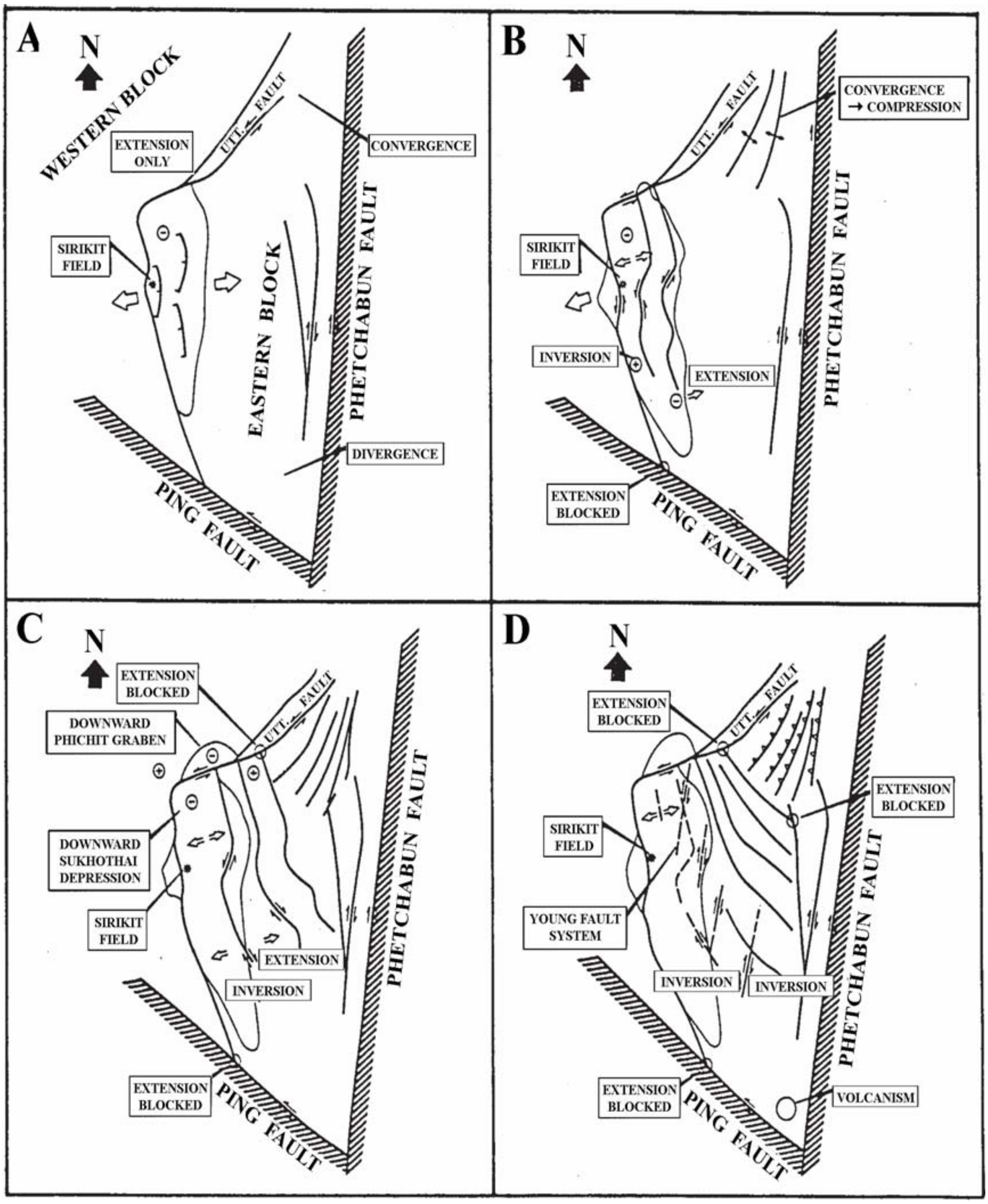

Figure 2.5 Phitsanulok Basin structure evolution, (After Ball, A.A., 1992).

2.2 Depositional Setting and Stratigraphy

The Tertiary stratigraphy of the Phitsanulok Basin has been subdivided by Thai Shell into eight lithostratigraphic units which together comprise the Oligocene to Recent Phitsanulok Group (Figure 2.4). The lithostratigraphic units were deposited in five main environments within a fluvio-lacustrine depositional system. These main depositional environments are illustrated schematically in Figure 2.6. Adjacent to the Western Boundary Fault, alluvial fans and fan deltas were shed basinwards, while fluvial deposits accumulated on an alluvial plain. Further downstream, lacustrine deltas prograded into a well-developed open lacustrine setting that occupied the rapidly subsiding central portions of the basin.

During the basin's early depositional history in the Oligocene, alluvial fans and fan deltas of the Sarabop Formation were shed from the Western Boundary Fault, while an alluvial plain occupied the basin axis. Several fault blocks were emergent at this time, including the Sirikit High, which was a palaeo-structure from early in the basin's history.

By the end of Oligocene times, open lacustrine conditions were established across the basin for the first time. At its maximum extent, the fresh-water Lake Phitsanulok covered an area up to 4,000 km^2 to a shallow depth, not exceeding 50 m. At the same time, fan deltas continued to shed from the Western Boundary Fault, while lacustrine deltas developed in the north. This was the first of several phases of lake expansion, during which organic-rich lacustrine claystone if the Chum Saeng Formation were deposited. Phases of lacustrine transgression were due to variations in base level, subsidence and sedimentation rates and possibly climate.

These transgressive phases were interspersed with periods of rapid delta progadation, giving rise to an alternation of transgressive/regressive lacustrine depositional sequences.

One such phase of delta progradation took place in the mid Early Miocene, when lacustrine deltas prograded southward and occupied much of the northern and central parts of the Phitsanulok Basin. Lacustrine conditions prevailed only in the southern basin at this time. These deltaic deposits comprised sandstones and interbedded claystones of the Lan Krabu Formation, and constitute one of the main hydrocarbon reservoir in the basin. By the end of the early Miocene, open lake conditions were reestablished over the central basin area. Organic-rich lacustrine claystones of the Chum Saeng Formation deposited in this period form the main seal and source rock to the Lan Krabu Formation.

From Middle Miocene times the regional tectonic regime became transpressioal, and alluvial deposits of the Pratu Tao and Yom Formations accumulated across the basin, to the exclusion of any further lacustrine sedimentation. The alluvial depositional setting established in Middle Miocene times has persisted until the present day, with little variation.

The chronostratigraphy of Tertiary lacustrine basins is difficult to define in an absolute sense, because of the scarcity of age-diagnostic biostratigraphic control. Chronostratigraphy in the Phitsanulok Basin is based on K-Ar whole rock dating of a few basaltic lava flows in the upper part of the basin fill, and the recognition of a limited number of ages-diagnostic palynomorphs.

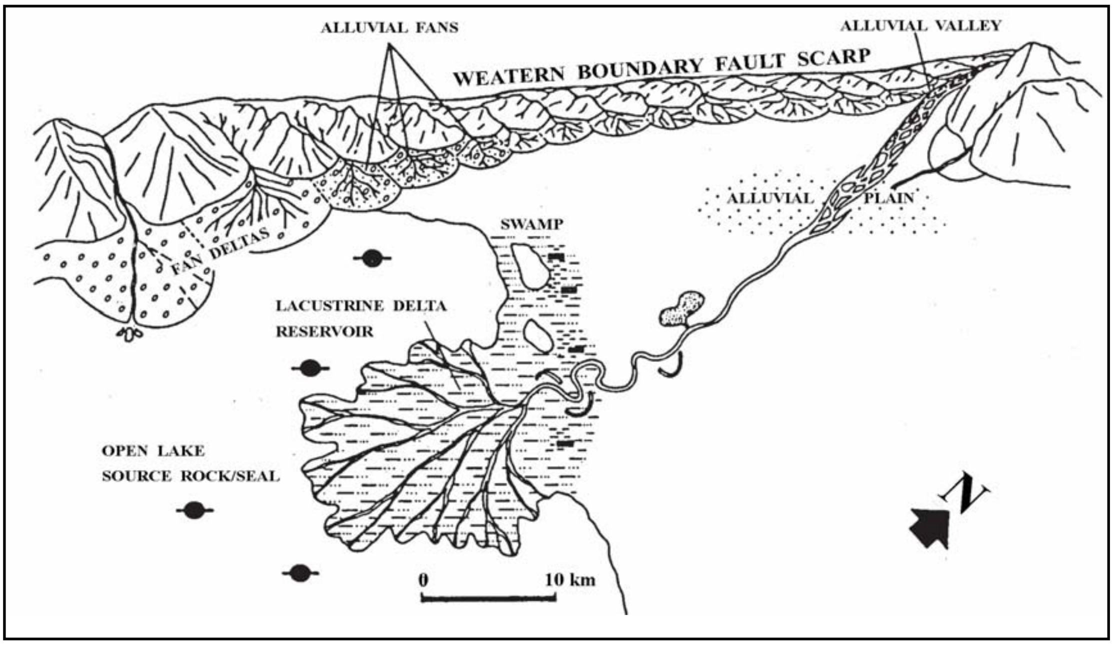

Figure 2.6 Schematic depositional environments of Phitsanulok Basin, (After Knox and Wakefield, 1983).

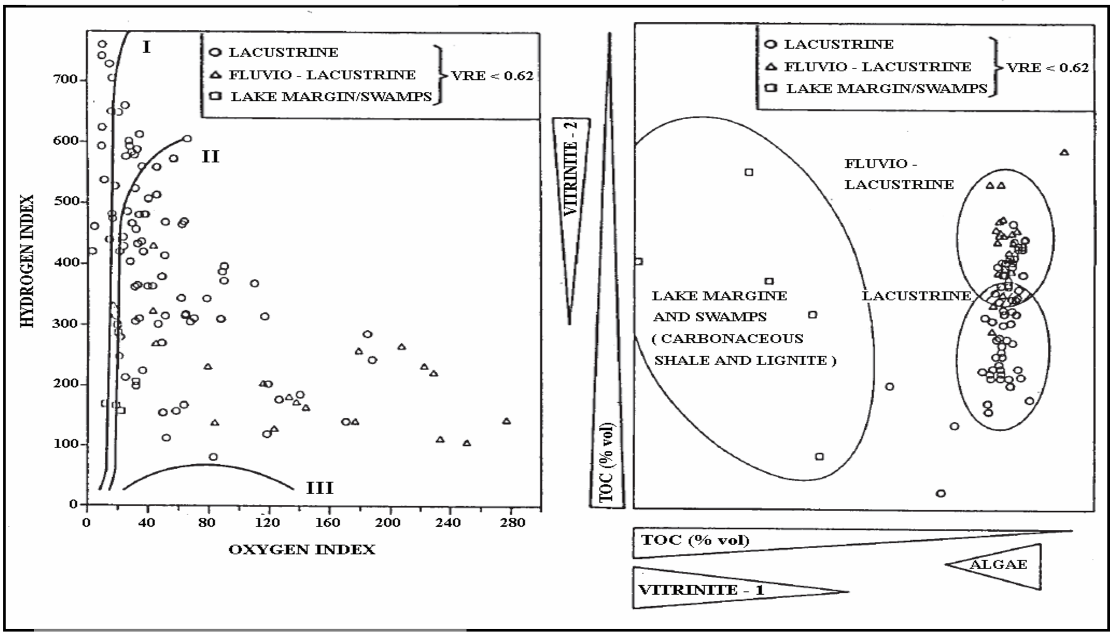

Figure 2.7 A. HI/OI plot., B. Maceral Analyses, (After Ball, A.A., 1992).

2.3 Hydrocarbon Habitat

2.3.1 Source Rocks

Source rocks in the Phitsanulok Basin were deposited in three environments. In order of importance, these environments are:

- open lacustrine environment
- fluvio-lacustrine environment
- marginal lacustrine swamp

The most volumetrically significant source rocks are lacustrine claystones of the Chum Saeng Formation. A plot of hydrogen and oxygen indices (Figure 2.7A) shows that the Chum Saeng Formation contains excellent type I algal/lacustrine source rocks. By comparison, the fluvio-lacustrine and marginal swamp deposits contain fair type II and III source rocks. Maceral compositions of these three groups are illustrated by Figure 2.7B. The lacustrine source rocks contain mainly algae organic matter. Fluvio-lacustrine source rocks form a continuous spectrum with the lacustrine claystones, but have lower total organic content (TOC), a lesser algal component and higher vitrinite. The coaly marginal swamp deposits have a discrete range of compositions, and are characterized by high TOC and high vitrinite.

Thick intervals of high quality algal lacustrine source rocks have accumulated in the Chum Saeng Formation. Gross source rock thicknesses of 400 m are commonly encountered in wells, and average net-to-gross ratios lie in the range 50-80%. In the Sukhothai Depression, seismo-stratigraphic interpretation has show that lacustrine source rock thickness may exceed 1,000 m. Based on an extensive data base of geochemical analyses, it has been established that hydrocarbon yields from these lacustrine source rock can range up to 170 kg/m^3, with an average in the range 20-40 kg/m^3. These data clearly indicate the outstanding richness and volumes of lacustrine source rocks in the Phitsanulok Basin.

By comparison, fluvio-lacustrine claystones of the Lan Krabu Formation are qualitatively and quantitatively less important, but still have significant source potential. From well data, gross fluvio-lacustrine source rock thicknesses are commonly in the range 150-300 m., with average net-to-gross ratios of 30-50%. Geochemical data indicate average hydrocarbon yields in the range 20-30 kg/m^3 for these fluvio-lacustrine claystones.

These source rocks have produced a light (40° API), waxy, low-sulphur, high pour-point oil in the Sirikit Field. Reservoirs shallower than about 1,200 m contain heavy (8° to 23° API) biodegraded oil.

2.3.2 Organic Maturity and Hydrocarbon Migration

Mature source rocks occur mainly in the northern part of the basin. The main source rock intervals are currently in the gas window within the central Sukhothai Depression, and in the oil window on its flank. Elsewhere, over a considerable area of the Phitsanulok Basin, the main source rock horizons are immature. Thus, consideration of access to a mature hydrocarbon kitchen area is important for prospect appraisal and ranking in the basin.

The Sirikit Field is situated directly to the south of the Sukhothai Depression, and is well-placed to have received hydrocarbon charge from mature kitchen areas. Detailed mapping has shown that the main reservoirs of the Sirikit Field (“K” and “L” sands) drain present-day kitchen area of 14-21 km^2 in area. These relatively small kitchen areas emphasize the lacustrine source rock richness, as they have yield a STOIIP of almost 800 million barrels in the Sirikit Field. Considering that the Phitsanulok Basin has a total kitchen area of about 800 km^2, it is likely that several billions of barrels of oil have been generated altogether in the Phitsanulok Basin.

The distribution of oil accumulations and hydrocarbon migration is predominantly lateral migrate. Vertical migration may occur along fault planes, especially when reactivated, and is inferred to have taken place in the Sirikit Field, based in the distribution of hydrocarbons. The dense north-south fault pattern on the Eastern Flank of the basin has caused migrating hydrocarbons to be deflected towards the north and south, leaving a shadow zone in the east.

2.3.3 Reservoir/Seal Pairs

The fluvio-lacustrine Tertiary fill of the Phitsanulok Basin offers numerous opportunities to develop potential reservoir/seal pairs, although reservoir quality and distribution are often variable due to rapid lateral and vertical facies changes. A representative log correlation (Figure 2.8) illustrates the main occurrence of Tertiary reservoir and seal in the basin.

Deltaic sandstones of the Lan Krabu Formation sealed by lacustrine claystones of Chum Saeng Formation, from the main reservoir/seal pairs. Due to cyclic delta progradation and lacustrine transgression in this interval, the Lan Krabu Formation contains four reservoir units separated by intraformational seals. From youngest to oldest, these are the “D”, “K”, “L”, and “M” sands. Of these reservoirs, the “K” and “L” sands are laterally continuous over much of the basin, and contain the majority of the Phitsanulok Basin’s reserves. The “K” and “L” sand are quartz litharenites of metamorphic and sedimentary provenance, and have net-to-gross ratios in the range 10-35%. Individual sand bodies are generally less than 7 m. thick, and comprise relatively continuous distributary mouth bars, of 2-3 km. lateral extent, and discontinuous channel sands (Flint et al., 1988).

The oldest Tertiary reservoirs are Oligocene alluvial deposits; seal by the first lacustrine flooding even of Chum Saeng Formation. Potential reservoirs also occur in fluvial sandstones of the Middle Miocene Pratu Tao and Yom Formations. These intervals have fair to good reservoir properties, and compared with the Lan Krabu Formation they show less rapid deterioration with depth. However, Pratu Tao and Yom sands rely on thin and laterally discontinuous intraformational seals, and therefore traps at this level may be easily breached. These sands also require long vertical migration of hydrocarbons to charge them, and are therefore less important reservoirs.

Highly indurate Pre-Tertiary sedimentary, metasedimentary and volcanic strata may constitute fractured reservoirs in buried hill traps in the Phitsanulok Basin, sealed by Tertairy claystones. To date one well in the Sirikit Field has encountered good oil production from a fracture Pre-Tertiary reservoir.

2.3.4 Trap Configuration

The trapping configuration of hydrocarbon accumulations in the Phitsanulok Basin is controlled critically in most cases by the complex fault patterns, as exemplified by the Sirikit Field. The Sirikit Field is a tilted fault block bounded by the Western Sirikit Fault and Ket Kason Boundary Fault. In between, the field is broken into numerous compartments by rather intense wrench related faulting (Figure 2.9).

Due to lateral and vertical facies changes as well as rapid variations in fault throw along strike, fault juxtaposition of reservoirs against interbedded claystones can only trap limited hydrocarbon columns. Retention of longer columns depends critically on clay smear along fault planes. Fault sealing potential depends on factors like adjacent clay bed thickness, fault throw direction and the post-or syn-depositional nature of the faults. Thus, clay smear is and important factor, especially in the deltaic “L” sand of the Sirikit Field. Soft lacustrine clay adjacent to the “L” sand at Sirikit Field have good smear potential, allowing the accumulation of a 600 m. hydrocarbon column. Detailed investigations of fluid contact have shown that they are largely controlled by fault seal failure, as the trap is not filled to its lowest structural spill point. Clay smear also plays an important part in this upthrown fault trap at Pru Krathiam-B01, where a 95 m oil column in deltaic “K” sand is sealed laterally by clay smear from overlying lacustrine deposits and by juxtraposition against the same clays across the fault.

A distinctive trap type in the Phitsanulok Basin and in many other Tertiary lacustrine basins of Southeast Asia is the Pre-Tertiary buried hill trap. These traps are sealed by draped Tertiary lacustrine claystones over a Pre-Tertiary palaeotopographic feature (i.e. a buried hill).

A critical point to address in relation to hydrocarbon habitat and trap configuration is trap definition. In order to resolve the complex fault pattern and image valid structure for drilling, 3D seismic data were recorded in the Pretu Tao, Lan Krabu and Lam Khun areas. Early exploration results in the Phitsanulok Basin highlighted the inadequacy of 2D seismic data set in this complex structural setting, as fault miscorrelations undoubtedly contributed to non-optimum placement of some exploration wells.

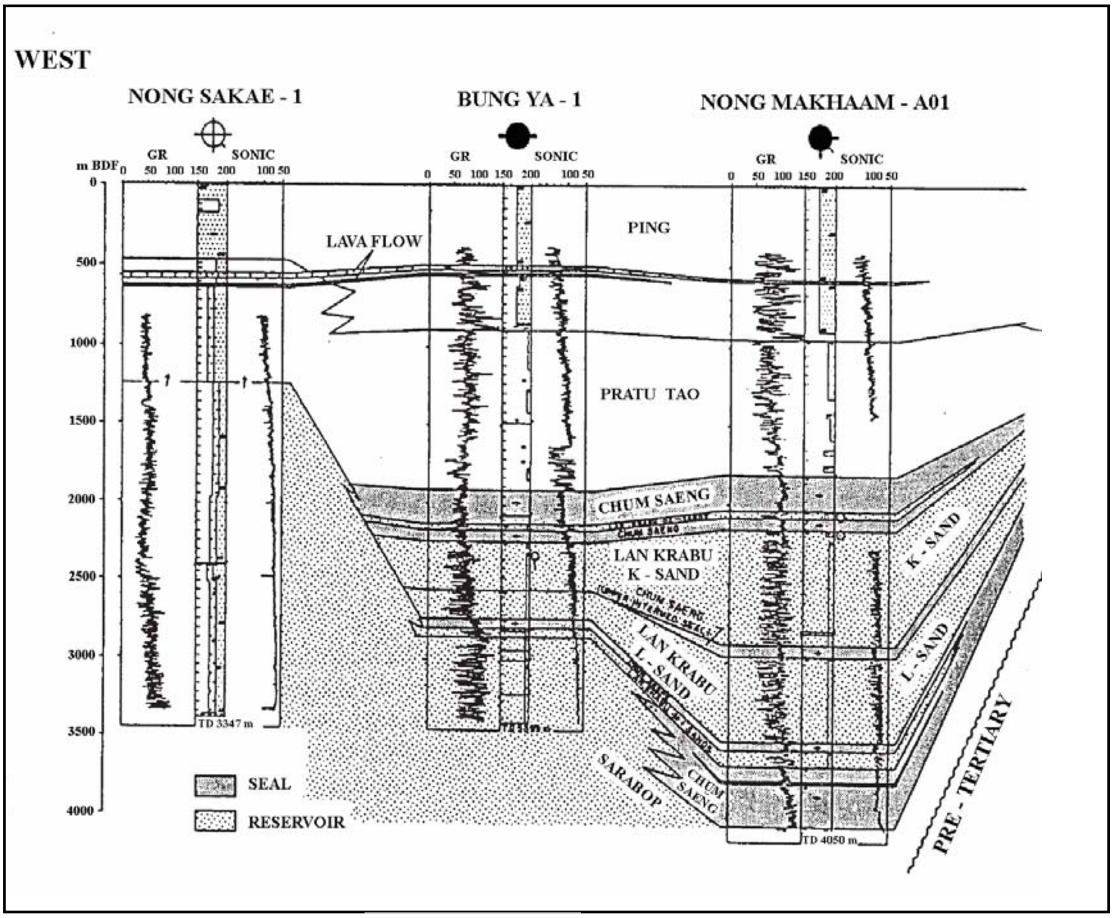

Figure 2.8 Log Correlation showing reservoir/seal pairs, (After Ball, A.A., 1992).

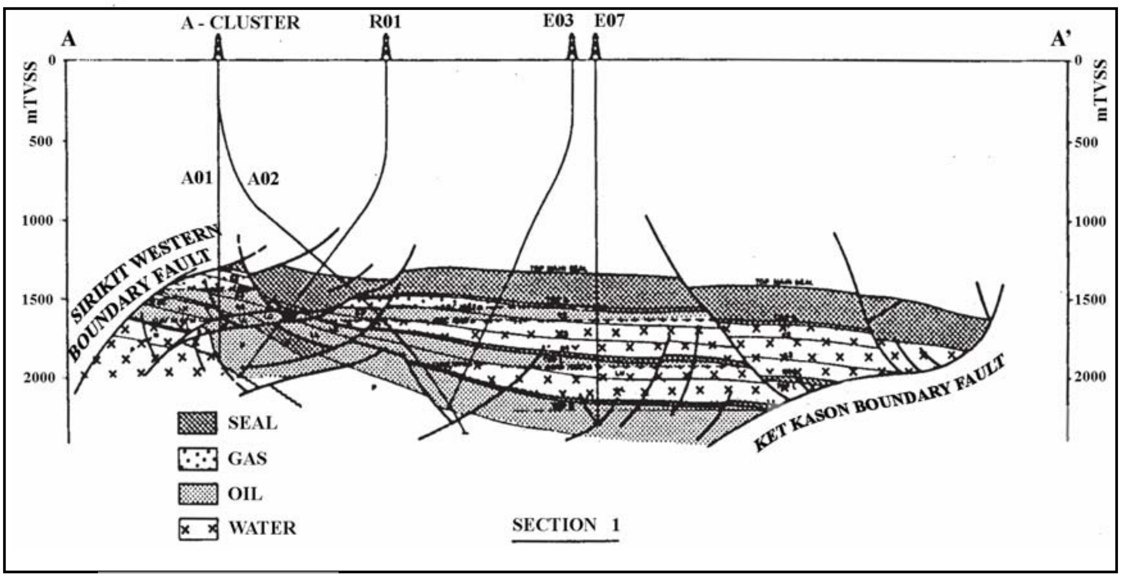

Figure 2.9 Sirikit Field geological cross-section, (After Ball, A.A., 1992).

2.4 Case Study of Waterflooding in Development Plans

In early 1880, Carll discovered that it might be possible to increase oil recovery by injecting water to displace oil in the reservoir (Willhite, 1986). Waterflooding began accidentally producing in Bradford Field, PA in 1880's. Many wells were abandoned in Bradford Field by pulling casing without plugging while in some wells casings were left in the wells, thus they were corroded. Therefore, water from shallow horizons could enter the producing interval. The practical water injection began, perhaps as early as 1890, when operators realized that water entering the productive formation was stimulating oil production. Then in 1907, the practice of water injection had an impact on oil production from the Bradford Field. The first flooding pattern was a circle flood and it was developed continuously until the present there are many patterns which use in waterflooding.

Waterflooding, called secondary recovery because the process yields a second batch of oil after a field was depleted by primary production. The slow growth of water injection was caused by several factors. In the early days, waterflooding was understood poorly. Interest in waterflooding developed in the late 1940's and early 1950's as reservoir approached economic limits and operators needed to increase reserves. Nowadays waterflooding is practiced extensively throughout the world. In the U.S. as much as half of the current oil production is thought to be the result of water injection.

2.4.1 The Sirikit Oil Field (Wongsirasawad, 2002):

The oilfields in the Sirikit Area are situated within Phitsanulok Basin. The basin has an areal extent in order of 6,000 km^2 formed as a result of the relative movement of the Shan Tai and Indonesian Blocks. The main reservoir formations are Lan Krabu (LKU) and Pratu Tao (PTO) formations. The Sirikit oilfield is geologically very complex. The geological complexity is a product of the multi-phased structural history and the interaction between faulting and deposition through time. However, the complexity and uncertainties of the Sirikit oilfield will always be the key factor to determine the successful projects in the future. The waterflooding is one of the successful projects which have been developed in the Sirikit oilfields. The waterflood project started as early as 1983. A small pilot project in a small area of LKU-E block was designed to test the viability of injecting water into the complex sand shale inter-bedded layers of the Lan Krabu formations. It was proved that the pilot test could maintain pressure under a non-fracturing condition. So it was indicated that the waterflooding of Lan Krabu reservoir was feasible. However, the waterflooding study was initiated lower than plan due to problems with deliverability pf source-water. Moreover, the responded in the reservoirs were very slow. The waterflooding project had studies 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 Pratu 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 waterflood project encountered many operational difficulties, but proved waterflood to be a technically viable secondary recovery technique in the Sirikit complex reservoirs. Reviews and studies of reservoir performances and simulations of the Sirikit reservoirs indicated that a reserves volume is recoverable only through waterflood 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 waterflooding. With the advanced of computer modeling techniques compared to 10 years ago, the confidence of successfully implementing waterflooding projects in the Sirikit Field has been reviewed.

2.4.2 The Benchamas Oilfield (Graves et al, 2001):

Benchamas Development in the Gulf of Thailand is an oil play predominantly gas condensate region. This development is unique in that the operator has significant oil reserves of high pour-point crude oil in several zones. The project has developed as a waterflood with horizontal and monobore producers and injectors. The initial phases of horizontal producers were completed with sand exclusion capability, consisting of multi-layered sintered screens. This has so far proved to be effective. The Benchamas waterflood project is comprised of eight stacked in sandstone reservoirs. This sandstone is fluvial channels and is discontinuous. The waterflood is designed to maintain oil viscosity and gas cap location in order to maximize recovery. The economic impact of this waterflood is estimated to increase the recovery from 12-18% (primary) to 25-35% of the OOIP.

2.4.3 The Intistar "A" Field (DesBrisay, 1972):

Intistar "A" Field has been selected to studied waterflooding plan by limiting the geology of the reservoir. In this field, unique geology properties permitted the use of a bottom-water drive to deplete the reservoir. The carbonate reef reservoir is at depths of 8,900 to 10,000 ft. This reservoir has gross thickness about 1,002 ft. at the thickest point. Log analyses indicated that the oil column was essentially continuous from the oil/water contact (OWC) to the top of the reef. Primary recovery from this reservoir was below because the oil was highly under-saturated. Although there was OWC at the base of the reef, all of the reservoir energy was not supplied by the aquifer. The reservoir energy was thought to be limited to fluid and rock expansion in addition with solution gas drive. A bottom-water injection program was started for pressure maintenance in this field. Water was injected below the OWC in the 29 wells. For a bottom-water flood to be effective, the reservoir must have good communication in horizontal and vertical directions with no barriers to vertical flow. The ratio of vertical to horizontal permeability was about 0.75, which indicated good communication in both horizontal and vertical directions. Reservoir pressure declined rapidly with fluid withdrawal before water injection; it had decreased from 4,352 to 3,700 psig. And cumulative production was 40 MMBBL. The pressure decline had changed in about 2 years after water injection began in 1968. This study also included reservoir pressure computed in December, 1982 using a reservoir simulator. At end of 1983, the field had produced 683 MMBBL of oil and 1.17 MMMBBL of water had been injected. Ultimate recovery is estimated to be 750 MMBBL which is almost 50 percent of the stock-tank oil original oil in place.

2.4.4 The Statfjord Field (Haugen et al, 1988):

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

2.4.5 The Mean Field (Stiles and Magruder, 1992):

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

2.4.6 The Glenn Pool Field (Kerr et al, 1999):

Glenn Pool field is a large, mature producing area covering 27,440 acre in portions of Tulsa and Creek counties, northeastern Oklahoma. Discovered in 1905, the field has produced 336 MMBBL (million barrels) of oil from the Middle Pennsylvanian (Desmoinesian) Bartlesville sandstone, locally known as the Glenn sand, at depths of 1,400-1,900 ft (427-579 m). Intensive early field development on close spacing caused production to peak in 1908. Continued high levels of oil production in the following decades, coupled with gas flaring, resulted in a rapid loss of energy in the solution-gas–driven reservoir. Despite gas injection beginning in 1940, and waterflooding since 1944, combined primary and limited enhanced recovery has produced perhaps one-third of the original oil in place (OOIP) after nine decades of continual production. Recent analysis suggests that enhanced recovery has been limited due to significant reservoir heterogeneity. For these and other reasons, the Bartlesville reservoir in Glenn Pool field has been chosen for inclusion within the U.S. Department of Energy's (DOE) Class I Oil Recovery Field Demonstration program to improve present and future recovery from mature fields producing from fluvial-deltaic reservoirs. The initial focus of the DOE-sponsored Class I study was the William Berryhill Self unit, a 160 acre lease located in the southeastern portion of the field. Production from the lease began in 1906 and had recovered 1.81 MMBBL of oil, or 13.8% of the estimated 13.009 MMBBL of OOIP, by 1945. Subsequent recovery efforts, including recompletions, resulted in incremental production of 0.95 MMBBL of oil, or 7.3% of OOIP. Thus, a total of 10.34 MMBBL of oil, or 79%

of OOIP, remains within the reservoir. Secondary recovery began with gas reinjection (1945-1954), producing an additional 0.23 MMBBL of oil. A pilot waterflood program, initiated in 1954, had good success, and subsequent continuation of waterflooding resulted in incremental recovery of 0.41 MMBBL of oil through 1977. In 1978, a redrill program was begun, based on a 10 acre five-spot pattern, with the objective of containing injected fluids in the upper portion of the reservoir, above the flushed zone. In contrast to previous wells in the unit and to other productive tracts in Glenn Pool, the redrills were selectively perforated, resulting in an initial rapid increase in production and a fairly steep decline thereafter. The redrill program with continued waterflooding resulted in incremental recovery of 0.31 MMBBL of oil through 1993. Total recovery, prior to initiation of the study, was 2.76 MMBBL of oil, or 21.07% of OOIP. Original reservoir pressure is calculated at 600-700 psi; current pressures are in the neighborhood of 100 psi. When this Self unit project was initiated, unit production was 15 BOPD with 99% water cut. Currently, injection pressures and water production range from 50 to 700 psi and 40 to 1000 BOPD, respectively.

2.4.7 The Minas Field (Bou-Mikael et at, 2001):

Minas Field, located in the Central Sumatra basin, is a faulted anticline approximately 28 km long by 10 km wide. The field was discovered in 1944 and placed on production in 1952. Minas has produced to date 4.27 billion barrels of oil or ~51% of original oil in place (OOIP). The reservoir is divided into two segments, called the Main segment (MS) and Northwest Segment (NWS). The reservoir consists of five major sand bodies which have an average total gross thickness of approximately 260 feet and lie at a depth of about 2000 feet sub-sea.

Early production history suggested strong aquifer support, but by the mid 1960s reservoir pressure had declined significantly and in 1970 a peripheral water injection program was initiated in the field’s western flank. The injection program was later expanded to the field’s entire periphery. In the early 1990’s Minas tested a pattern waterflood program that was later expanded to cover the entire high graded area of the MS of the reservoir. The pattern waterflood was implemented using 71-acre, inverted 7-spot patterns (24-acre well spacing) and conducted in four consecutive phases beginning in 1993 and ending in 1998. Expansion of pattern waterflood to the Northwest Segment is currently being re-evaluated in comparison with continuing the peripheral flood. This was prompted by the PWF performance in the MS. Infill drilling on 24-acre well spacing outside the pattern waterflood area is also underway to drain bypassed oil that can not be recovered with existing wells. Current field production is ~130,000 BOPD at water cut of 97.5%. Produced water is currently being recycled back into the reservoir for waterflooding purposes. Current field development and recovery processes are expected to produce ~55 % of the original oil in place. Remaining oil recoverable by secondary means ranges between 3% and 5% of the OOIP. A significant volume of oil will remain in the ground after waterflooding, which is now the target of various tertiary EOR processes. In 1994, a tertiary screening effort identified two potentially viable applications for the Minas field. Light oil steam flood (LOSF) and surfactant/polymer flood processes were selected for further evaluation.

2.4.8 **The Meren Field** (Thakur, 2004):

Thakur (2004) described the waterflood surveillance to improve oil recovery and maintain pressure reservoir in Meren Field. Meren Field is located in

OML-95 of the Niger Delta. The primary production is gas cap expansion, solution gas drive and water drive. The drive mechanism was dependent on the location of the reservoirs. The ultimate recovery factor from the primary depletion was estimated as 27%. The study used reservoir simulation techniques available the (2-D areal and 2-D cross-sectional) and analytical methods to evaluate different schemes for optimizing oil recovery. From results of reservoir simulator passed on the observed trends. The current ultimate recovery factor is estimated at 59%, which is significantly higher than estimated recovery of 45-52% used to justify the project.

2.4.9 The Yakin Field (Kojuro et at, 1998):

The Yakin Central field was put on production in October 1976 from four wells on four single-well platforms. The initial rate was 500 BOPD and increased to 5,270 BOPD as a peak production which occurred in December 1977 from eleven wells on the 7 (seven) platforms. Of this 4,300 BOPD in oil production came from seven wells producing from the 23-8 sand reservoir. In 1980, production rapidly declined to less than 1,000 BOPD and had been on a steady decline ever since. By December 1989, prior to the initiation of a Pilot Waterflood the average daily production rate was only 349 BOPD, coming from the wells Y-9 and Y-11 only. About 27.2 percent of the total OOIP had been produced by depletion drive mechanism supplemented by a weak water drive before the start of water injection. The Yakin water injection Pilot was developed in late 1988 to test the feasibility of a waterflood project in the 23-8 sand. A small area of 28 acres in Yakin Central, having representative reservoir rock and fluid properties, was chosen. Down-dip Y-8 well was selected as an injector and three up-dip wells, Y-2, Y-4, and Y-9 were chosen as producers, properly located inside the Pilot area. The wells irregular configuration roughly conforms to a quarter of a 9-spot pattern. An irregular injection system was a result of the geologic conditions. By this scheme, no additional capital investment would be producer. The watered out Y-8 well, structurally low in the pilot area, was selected as a water injection well. It was re-completed with a gravel pack after adding perforation intervals over the complete sand interval in the underlying aquifer. Minor workovers were also made in two out of the three producers to install new Electric Submersible Pump (ESPs). The calculated incremental oil recovery due to waterflood process was 0.78 MMSTB oil for 1.0 PV, with an upside potential of 1.53 MMMSTB oil at 1.5 PV (additional 6.4 percent of the primary recovery).

2.5 Thailand Exploration and Production History

2.5.1 Exploration and Production History

Thailand exploration and production history can be summarized as follows:

- On 26 March 1971 the first Petroleum Act was promulgated and given by His Majesty King Bhumibol Adulyadej.
- The first-ever petroleum field in Thailand was found in Fang, Chiang Mai long before 1971.
- The first round of petroleum concession bidding was announced on 13 September 1971 and 9 awarders were received altogether 22 blocks. Until 2008, 62 concessions with 80 blocks were still held, Table 2.1 illustrated for more detail, the petroleum concessions maps of Thailand illustrated in figure 2.10-2.12, petroleum production history from 1981-2008 are shown in figure 2.13-2.15.

Table 2.1 Total petroleum concessions in Thailand (as of Dec., 2008), (After DMF annual report, 2008).

Area	Concessions	Blocks	Exploration (km^2)	Production (km^2)	Reserve (km^2)
Onshore	30	39	117,613.2	733.8	984.6
Gulf of Thailand	31	38	147,676.8	15,238.8	5,825.6
Andaman Sea	1	3	68,820.0	-	-
Total	62	80	334,110.0	15,972.6	6,810.2

Table 2.2 Onshore oil field production summary, (After DMF annual report, 2008).

Field Name	Gross Prod. Rate (BOPD)	Prod. Well (well)	Total Prod. (well)
Sirikit et al.	21,293	313	439
U-Thong	302	9	11
Sangkrajai	78	2	2
Bung Ya	843	24	27
Bung Muang	221	19	25
Bung Ya and Nong Sa	486	16	18
Wichian Buri	89	6	14
Nasanun	480	3	3
Si Thep	4	1	1
Nasanun East	11,351	6	12
Fang	1,221	52	54

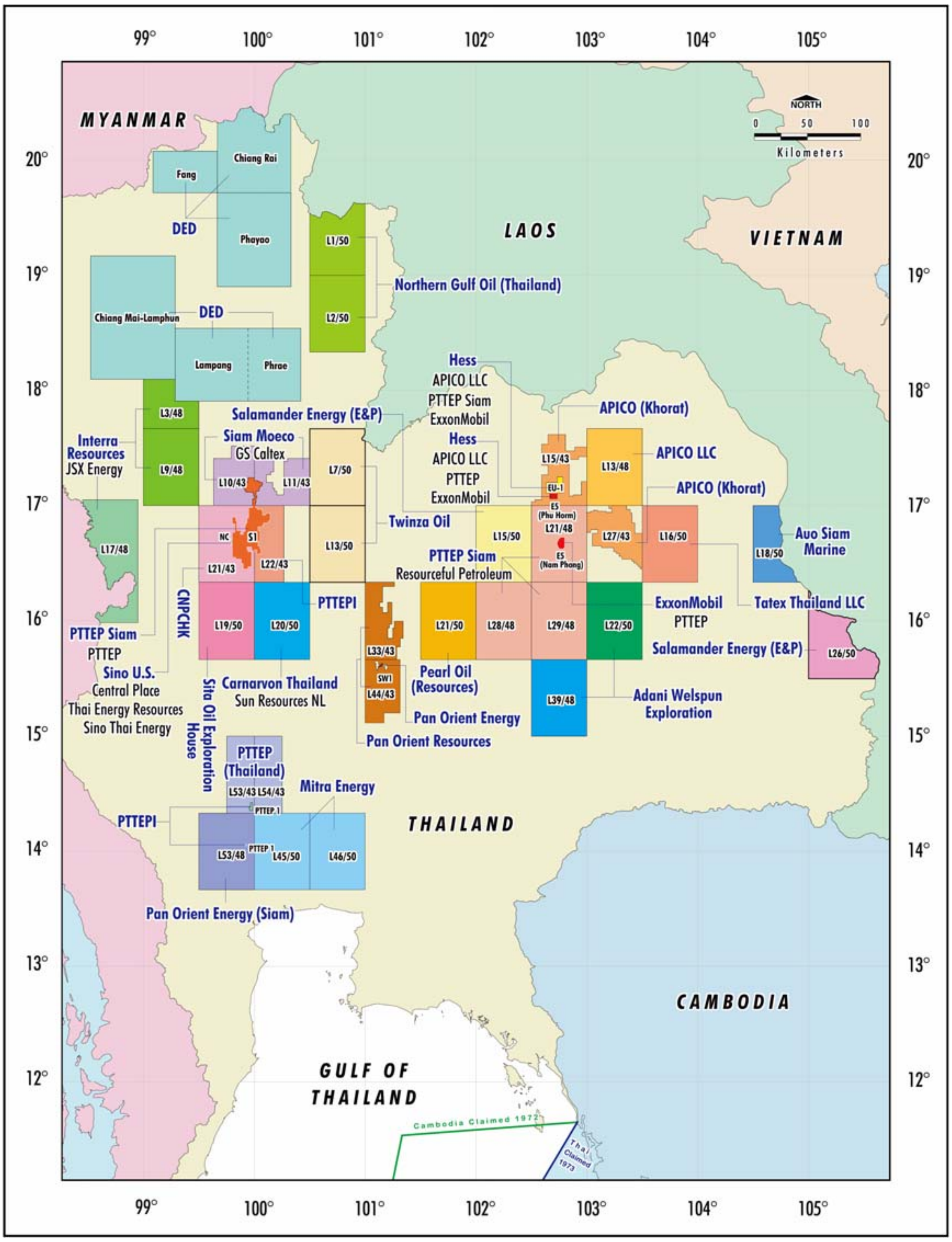

Figure 2.10 Onshore Petroleum Concession Map of Thailand,

(After DMF annual report, 2008).

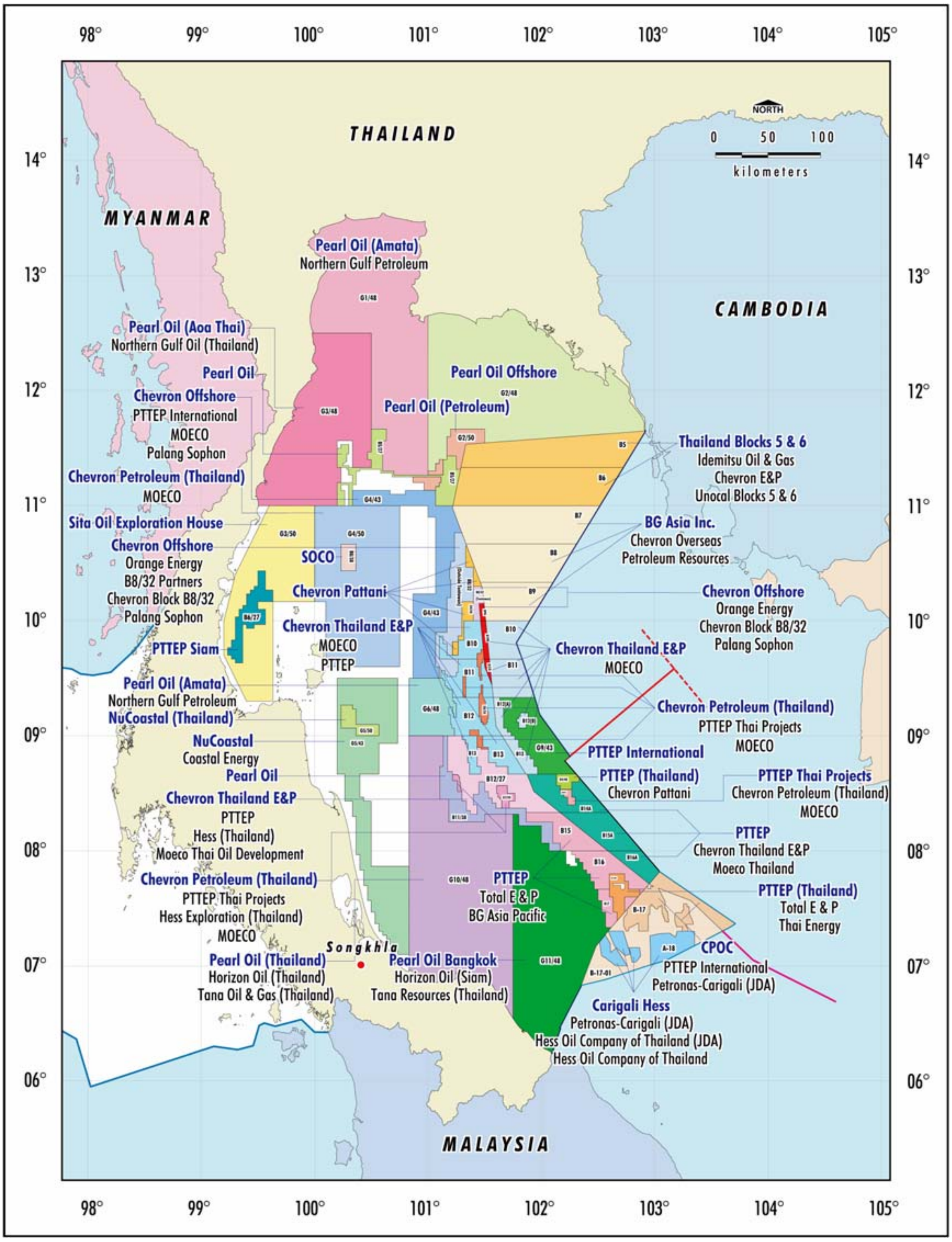

Figure 2.11 Offshore Petroleum Concession Map of Thailand,

(After DMF annual report, 2008).

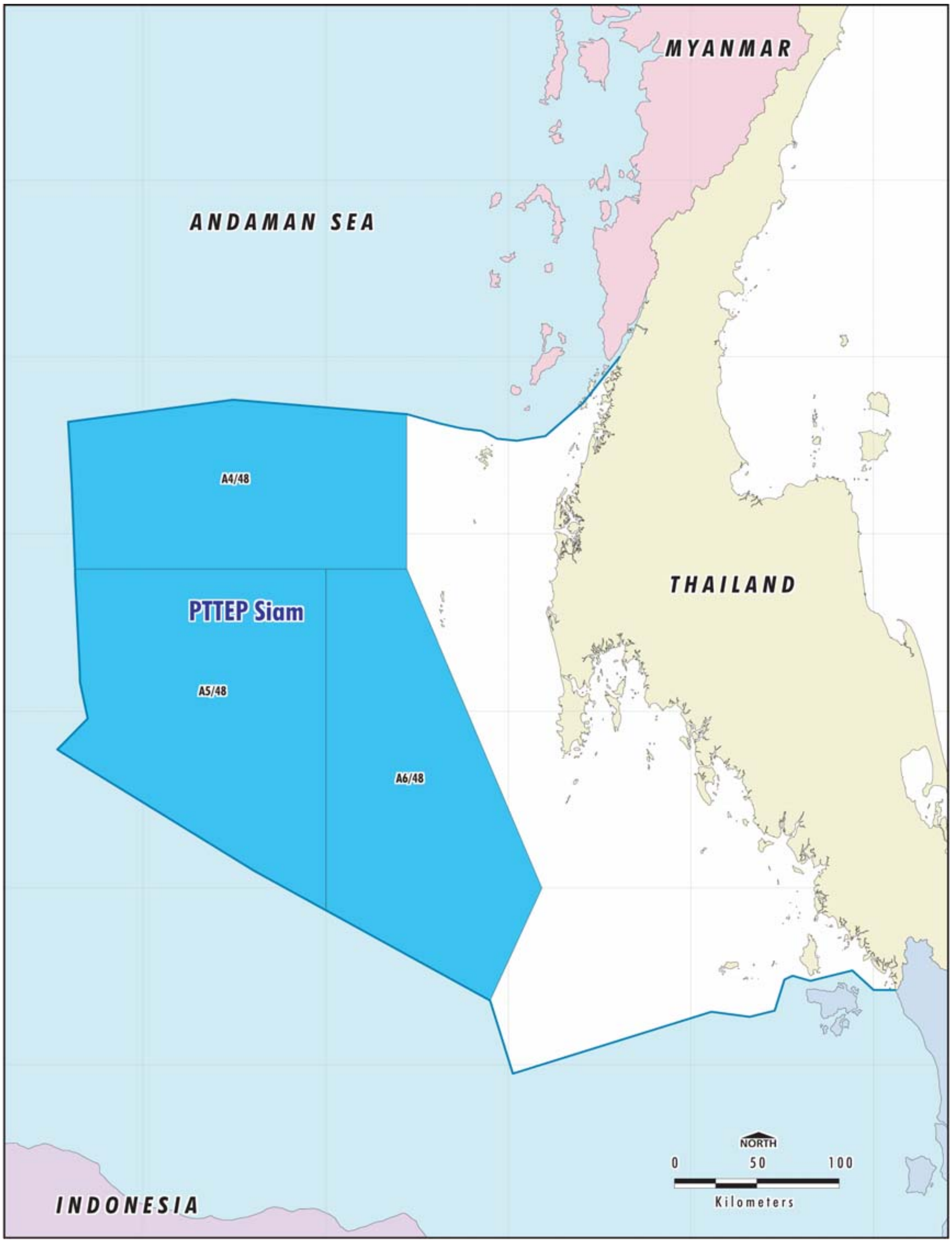

Figure 2.12 Offshore Petroleum Concession Map of Thailand, (Andaman Sea), (After DMF annual report, 2008).

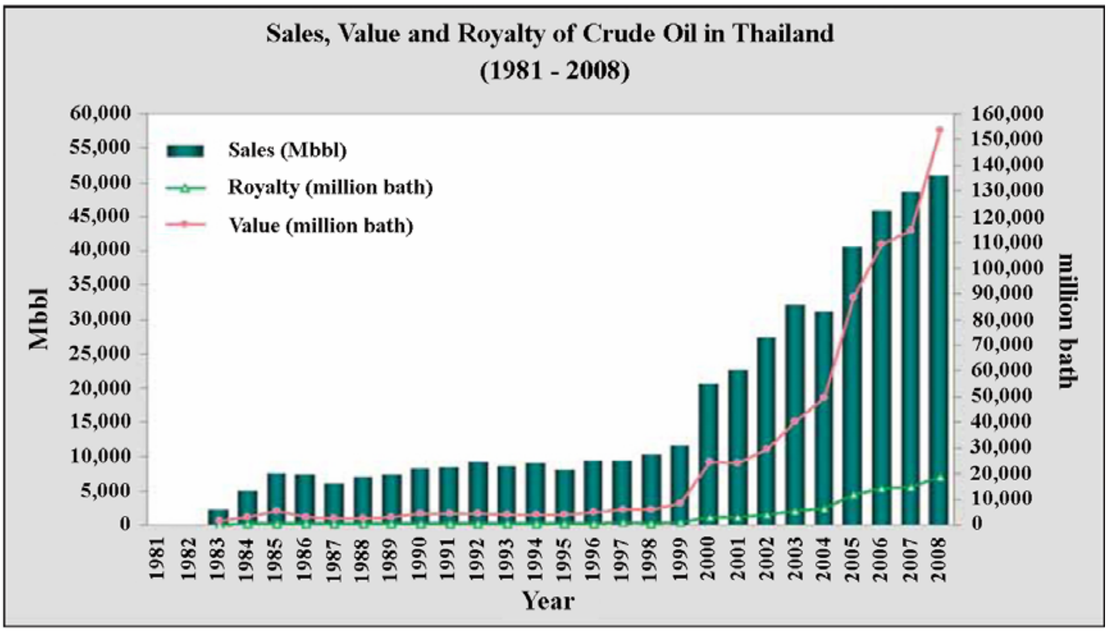

Figure 2.13 Crude oil production history in Thailand,

(After DMF annual report, 2008).

Figure 2.14 Condensate production history in Thailand,

(After DMF annual report, 2008).

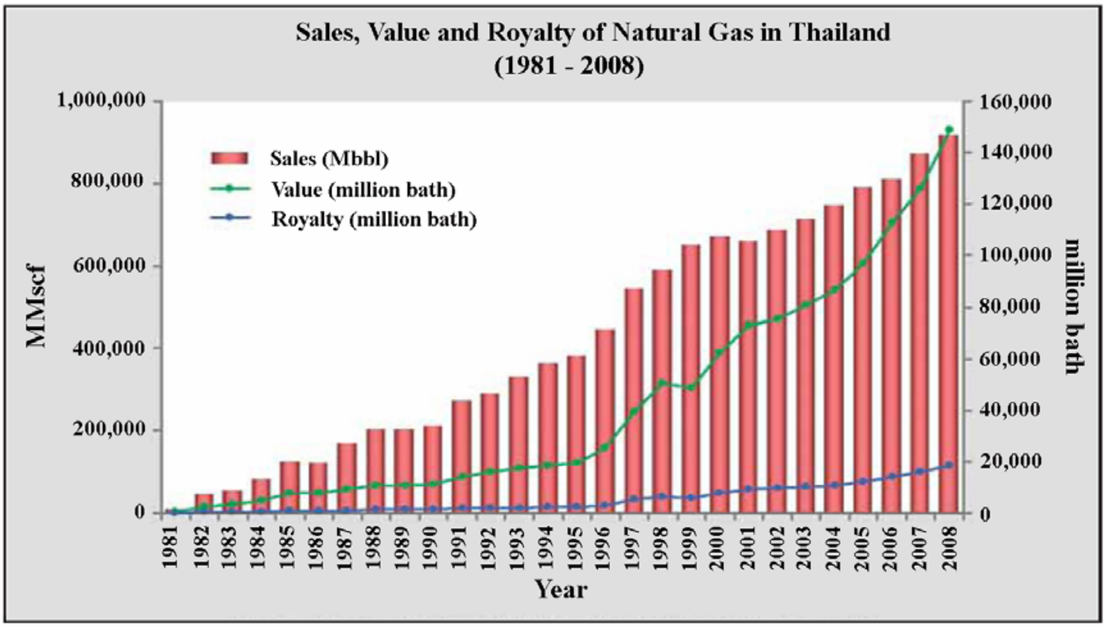

Figure 2.15 Natural gas production history in Thailand,

(After DMF annual report, 2008).

Table 2.3 Proved Reserve and Petroleum Cumulative Production

(as of Dec., 2008), (After DMF annual report, 2008).

Petroleum Type	**Reserve**	**Cumulative Production**
Natural Gas (Tcf)	12.0	11.978
Condensate (MMBBL)	270.8	353.804
Crude Oil (MMBBL)	182.9	454.087
Total (MMBOE)	2,500.0	

2.5.2 Sirikit Field Overview (S1 Project)

The sirikit field is located some 400 km. north of Bangkok in the central plains of Thailand, which presented it is a biggest onshore oil field and encompassed almost the entire Phitsanulok Basin (see figure 2.16). The field was discovered by Shell on 1981 and now operated by the Thai oil company, PTT Exploration and Production (PTTEP). The detail of this field can summarize as follow:

Concessions:	Block S1, Concession Number 1/2522/16 awarded on March 15, 1979 under Thailand I
Area:	1,328 square kilometers
Location:	Sukhothai, Phitsanulok and Kamphaengpet provinces, Thailand
Operator:	PTT Exploration and Production Plc.
Phase:	Production
Petroleum Field:	Sirikit (three adjacent areas), Sirikit West, Pru Krathiam, Wat Taen, Thap Raet, Pratu Tao, Nong Tum, Sirikit East, Nong Makham East, Sirikit-T, Nong Makham, Pradu Tao South and Sirikit West (Extension)
Type of Petroleum:	Crude oil, LNG, Natural gas
Production Start – up:	December, 1982

Commercially viable volume of crude was found December 1981 at “Lan Krabu-A01” exploration well, located in Lan Krabu District of Kampaengphet Province, production started the following year. The oil field was given the name

"Sirikit" after permission had been given by Her Majesty Queen Sirikit who also graciously presided over the opening ceremony on January 12, 1983. PTTEP entered into a joint venture with Thai Shell on October 21, 1985. In January 1, 2004, PTTEP, which had held a 25% stake in concession block S1 or Sirikit oil field since 1985, purchased the rest of the shares from Thai Shell Exploration and Production Co., Ltd. becoming the sole owner of the largest onshore oil field in Thailand. PTTEP Siam Ltd., a subsidiary was set up to operate it. Additional highlights are as follow:

2009 Activities:

- Excellent production performance achieving cumulative production 190 MMBBL
- 1 Exploration well (PTO-AK)
- S1 EOR Study
- 3D Seismic Acquisition & Processing
- 1 Exploration well (NKM5)
- Accelerate waterflood project to maximize productive volume

2008 Activities:

- Implement and accelerate waterflood project
- Maximize production volume by infill development wells / workover
- Successful implement waterflood program to maximize production volume (Phase1 in L-Block)
- Write off SPA-B-01 in Quarter 3
- Acquire 3D Seismic acquisition
- Implement and accelerate waterflood project

- Maximize production volume by infill development wells/workover

2007 Activities:

- Produced 20,501 BPD of crude, 50 MMSCFD of gas, and 265 TPD of LPG on average
- 37 development wells, two exploration wells, and five appraisal wells were drilled during the year
- The project acquired 1.982 square kilometers to bring the total production area to 309 square kilometers
- A new gas-lift compressor unit (K-3850) was installed at the production station to boost the gas-lift capacity from 27 to 40 MMSCFD

2006 Activities:

- Yield on average of 18,800 BPD of oil, 58 MMSCFD of gas, and 264 TPD of LPG
- Drilled 36 development wells, eight appraisal wells, one water source well, and one water injector well
- New production areas, West Flank Region (99 sq.km.) and Nong Tum South (19 sq.km.), were approved, bringing the total production area to 308 sq.km.
- Signed a gas sales agreement (GSA) with Ratchaburi Energy Co., Ltd. for the PTO-A flared gas to fuel power generation

2005 Activities:

- The S1 Project on average produced 18,000 BPD of crude oil, 59 MMSCFD of natural gas and 275 tons per day (TPD) of LPG
- In a move to maximize the value of its production, PTTEP signed a memorandum for feasibility study and development for electricity generation from Pratu Tao-A flared gas with Ratchaburi Energy

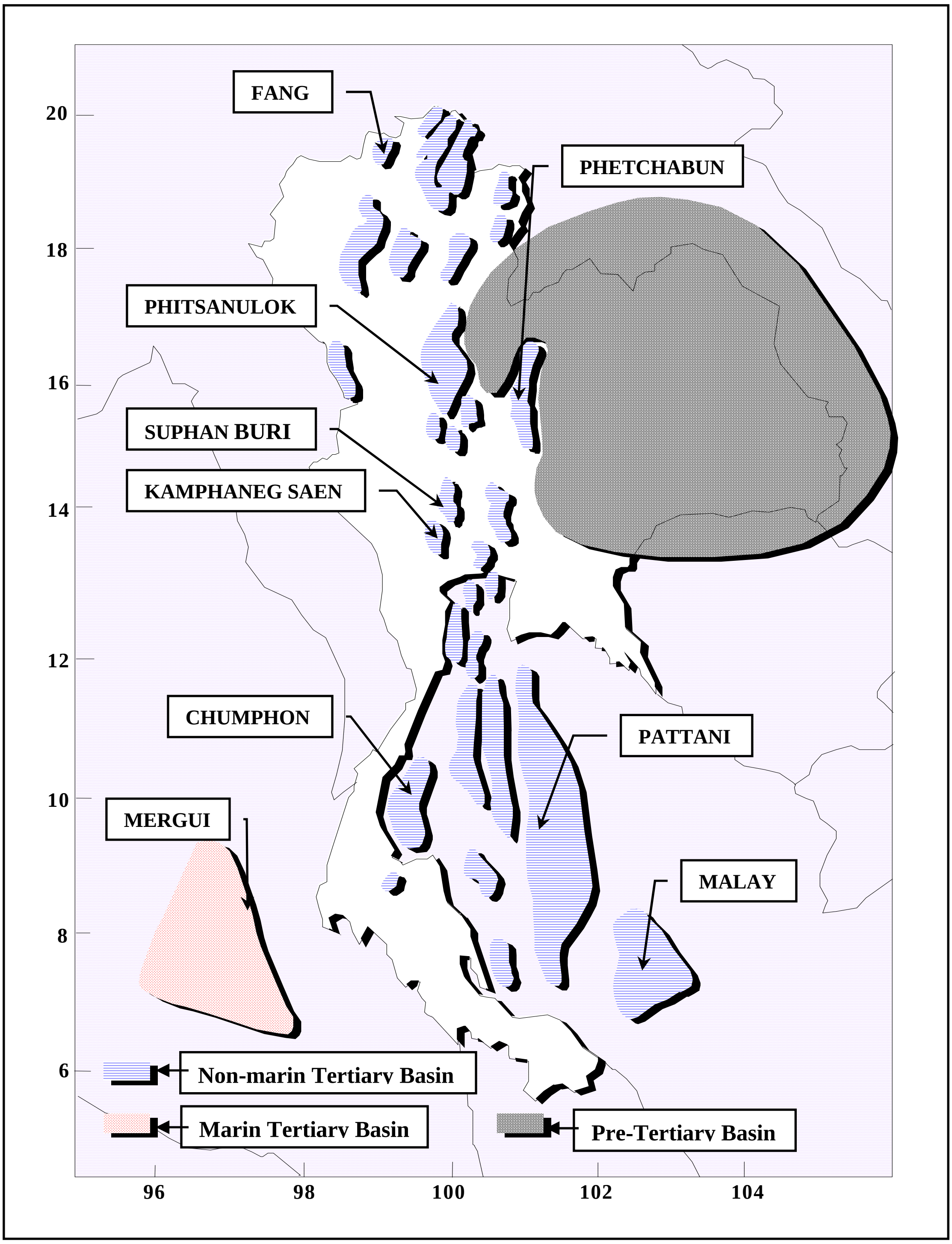

Figure 2.16 Petroleum Bain in Thailand, (After DMR annual report, 1994).

CHAPTER III

MODEL DEFINITION AND WATERFLOOD DESIGN

3.1 Objective

The main objective of this chapter is to detail a reservoir simulation modeling data requirement in term of static (reservoir structure and rock properties) and dynamic (fluid saturation, pressure, and fluid flow rate) properties of reservoir, and describe about reservoir simulation scenarios test selection. The additional description is waterflood design of water injection rate and flood pattern selection.

3.2 Basic Model Definition

In this study used black oil reservoir simulator (Eclipse Office E100) of total 5,000 grid blocks to stimulated primary production scenarios and secondary production scenarios by applied the bottom waterflooding technique, the detail summarize as follow:

-	Simulator	Black Oil
-	Model dimension (x, y, z)	25, 25, 8 (5,000 grid blocks)
-	Unit	Field
-	Grid Type	Cartesian
-	Geometry Type	Conner Point
-	Solution Type	Fully – Implicit

3.3 Structure Style of Model

The Anticline (Ax-Model) and Monocline (Mx-Model) structure style are selected to use in this study because of it is a most common structure style that normally appear to a petroleum reservoir, the initial of structural surface data prepared by Suffer Version 7.0 and the result of reservoir structure from reservoir simulator as show in figure 3.1-3.4.

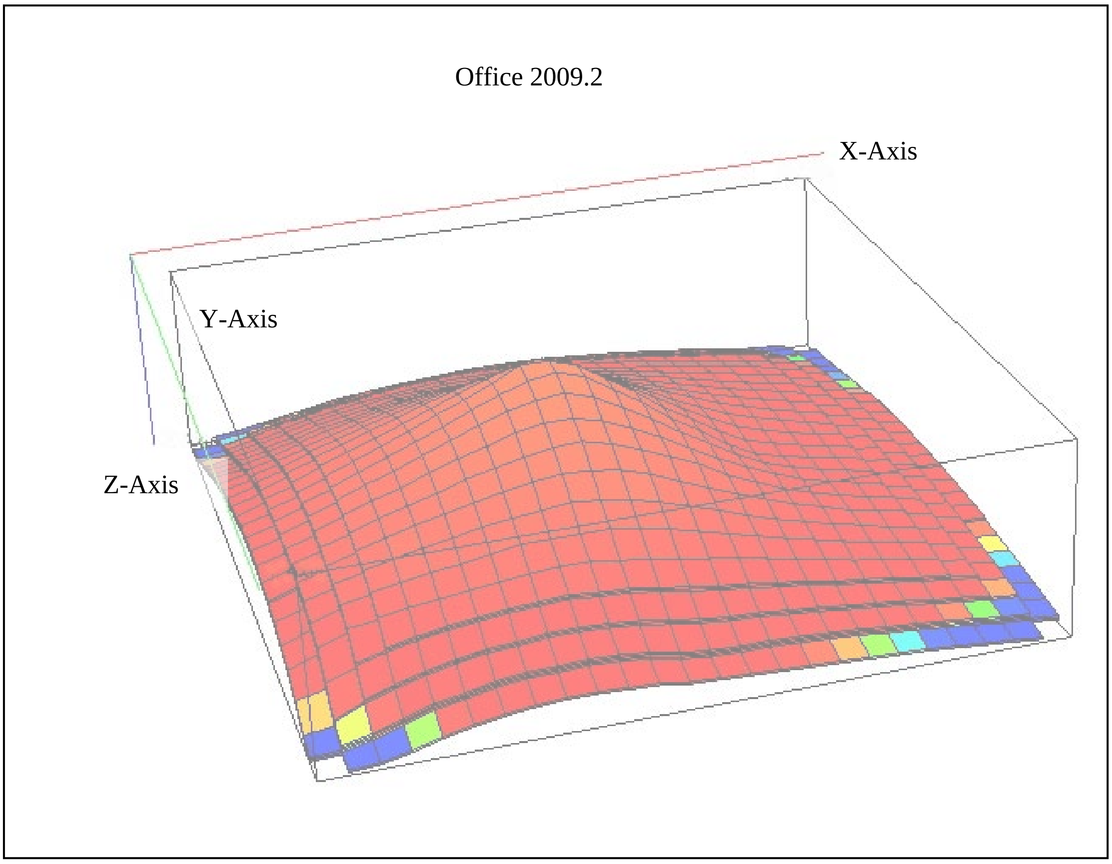

Figure 3.1 Oblique view of monocline structure style.

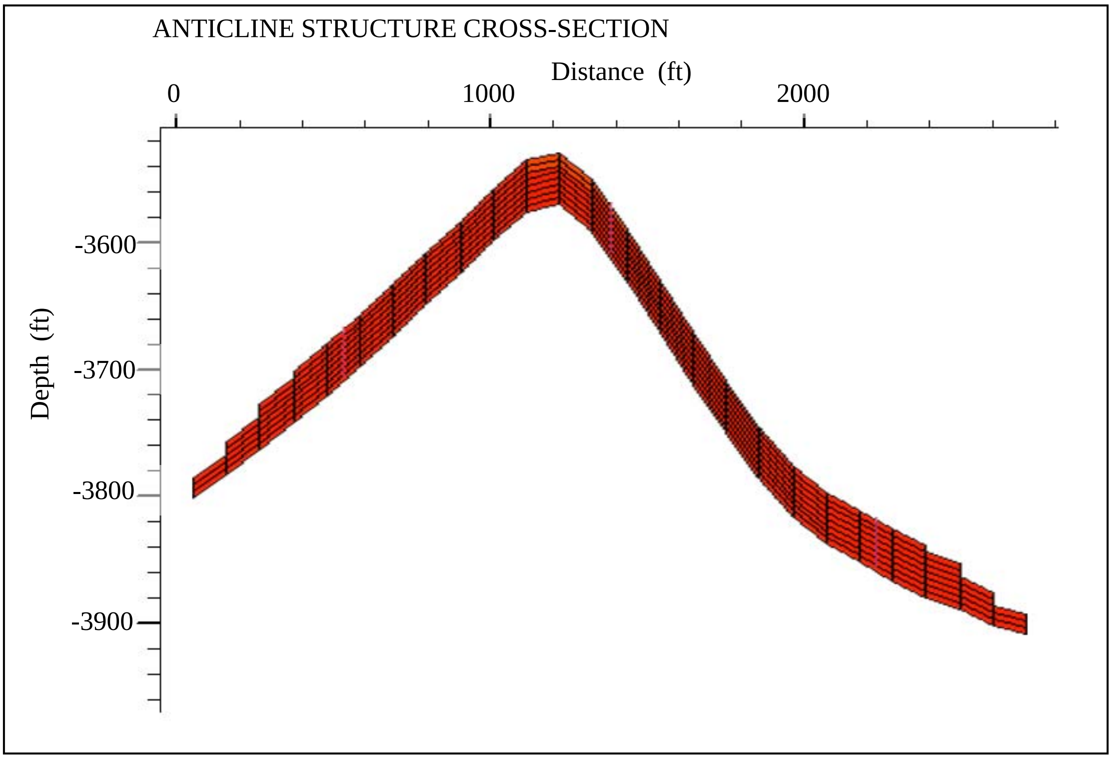

Figure 3.2 Cross-section view of anticline structure style.

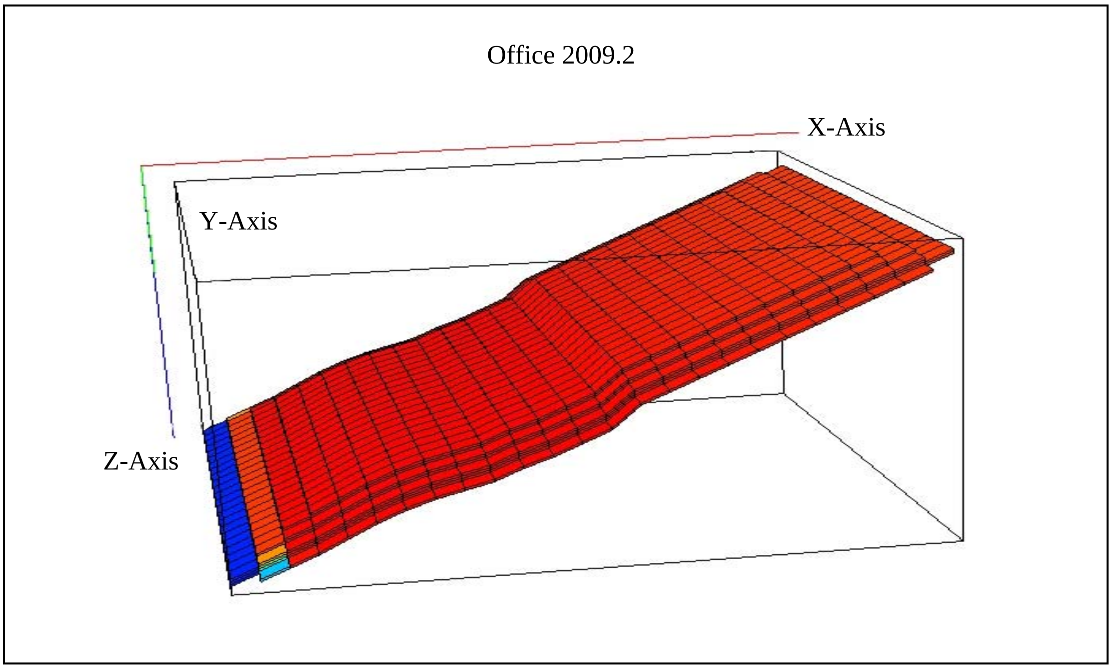

Figure 3.3 Oblique view of monocline structure style.

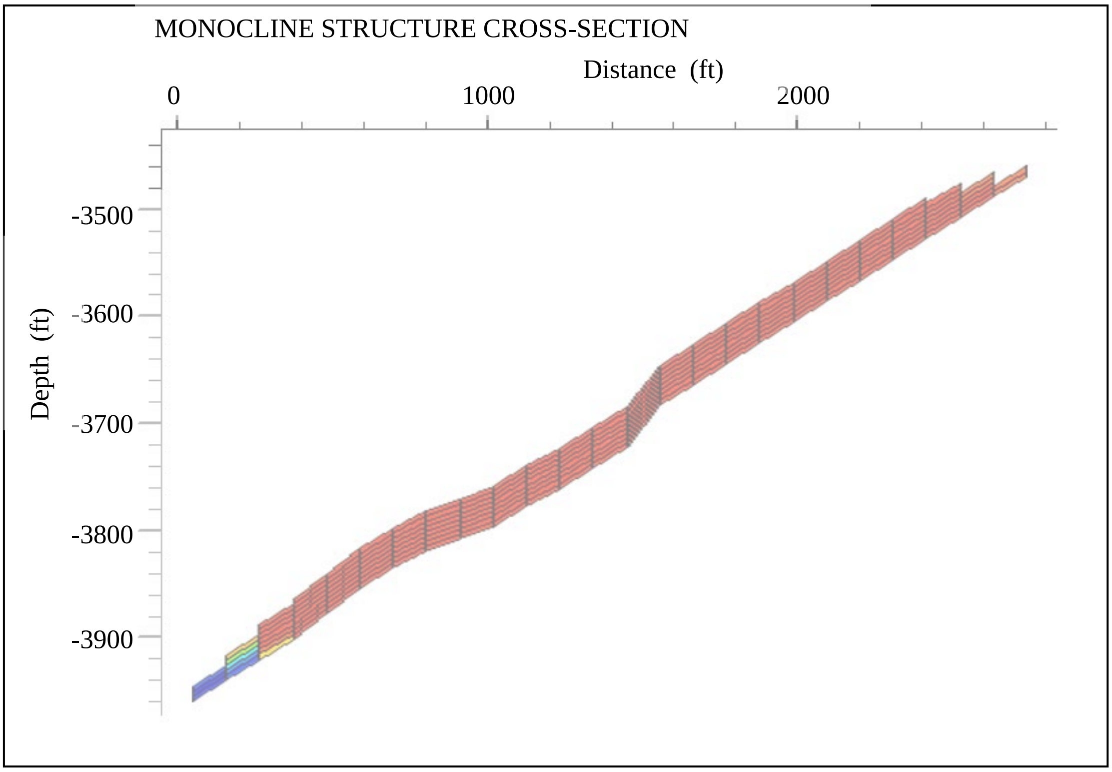

Figure 3.4 Cross-section view of monocline structure style.

3.4 Reservoir Model Input Parameters

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

3.4.1 Porosity and Permeability Data of Grid Section

Porosity and permeability of the model obtained from atmospheric k/ø trend relationship of some cores sample in the Sirikit L sand plot (see figure D.6 in appendix D), from this plot the equation become;

$$k = 0.0002 \, \mathrm{EXP}\,(0.6023\, ø) \tag{3.1}$$

From reservoir grid dimension of 8 layer (z-direction) that mention before, porosity rang selection with 0.25 descending from top to bottom give the permeability (Eq. 3.1) as show in Table 3.1. The x, y, z porosity and x, y permeability set as following table, only z permeability set to 0.1 of represent value.

Table 3.1 Permeability and Porosity for 8 layer selection result.

Layer	Porosity (%)	Permeability (md)
1	23.00	207.62
2	22.75	178.60
3	22.50	153.63
4	22.25	132.16
5	22.00	113.68
6	21.75	97.79
7	21.50	84.12
8	21.25	72.36

3.4.2 Reservoir Fluid Properties of PVT Section

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

- Rock Type of Reservoir — Consolidated Sandstone
- Average porosity (%) — 22.125
- Oil gravity, (API Oil) — 39.4
- Gas gravity, (SG Air = 1) — 0.8
- Bubble – point pressure, (psi) — 1,800
- Reference pressure, (psi) — 3,500
- Reservoir temperature (°F) — 202

3.4.3 Fluid Saturation of SCAL Section

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

- Water saturation 0.3
- Residual oil saturation 0.25
- Gas saturation 0.04

See appendix D for SCAL input data detail.

3.4.4 Fluid Contact of Initialization Section

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

- Datum depth, (feet) 3,900
- Pressure at datum depth, (psi) 3,500
- Water/Oil contact depth, (feet) 3,915
- The bubble-point at datum depth, (psi) 1,800

3.4.5 Well Data of Schedule Section

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

-	Diameter of well bore	0.71	feet
-	Skin factor	-1	
-	Effective K_h	250	mD
-	Datum depth of Production well	3,915	feet
-	Datum depth of Injection well	3,950	feet
-	Perforation of Production zone	1^{st} - 6^{th}	layer
-	Perforation of Injection zone	7^{th} - 8^{th}	layer

3.5 Simulation Scenarios Selection

From structure style and reservoir input parameters that described above, result to select the original of oil in place (or stock tank of oil initial in placed, STOIIP) to performed the simulation tests. In this study selected 3 reserved sizes to cover the possible base case (5 MMBBL) to high case of 4 times size of base case (20 MMBBL). The STOIIP sizes and its detail illustrated in Table 3.2-3.3. From the desirable STOIIP, this study used 4 production scenarios test to compare the result of production with primary production only (no water injection) to 3 secondary production scenarios (applied water injection) at a difference times of the 2^{nd}, 4^{th} and 8^{th} after primary production to start water injection, see detail in Table 3.4.

Table 3.2 Model structures and STOIIP sizes.

Structure Style	Model No.	Model Name	Aspect STOIIP size (MMBBL)	Model Objective
Anticline	1	A20	20	High case
Anticline	2	A10	10	Medium case
Anticline	3	A05	5	Base case
Monocline	4	M20	20	High case
Monocline	5	M10	10	Medium case
Monocline	6	M05	5	Base case

Table 3.3 Model sizes and dimensions.

Model	Dimension (ft)	Dimension/grid (ft)	Area (acres)	Thickness (ft)
A20	4,500 x 4,500	108	464.88	56
A10	3,450 x 3,450	138	273.24	48
A05	2,675 x 2,675	107	164.27	40
M20	4,500 x 4,500	108	464.88	56
M10	3,450 x 3,450	138	273.24	48
M05	2,650 x 2650	106	161.21	40

Table 3.4 Model scenarios description.

Model Name	Scenario No.	Water Injection Scenarios	Scenario Name	Project Life Time
A20	1	Natural flow (no inj)	A20_no inj	20
	2	Water injection after 2nd year	A20_2 inj	25
	3	Water injection after 4th year	A20_4 inj	25
	4	Water injection after 8th year	A20_8 inj	25
A10	5	Natural flow (no inj)	A10_no inj	20
	6	Water injection after 2nd year	A10_2 inj	25
	7	Water injection after 4th year	A10_4 inj	25
	8	Water injection after 8th year	A10_8 inj	25
A05	9	Natural flow (no inj)	A05_no inj	15
	10	Water injection after 2nd year	A05_2 inj	25
	11	Water injection after 4th year	A05_4 inj	25
	12	Water injection after 8th year	A05_8 inj	25
M20	13	Natural flow (no inj)	M20_no inj	20
	14	Water injection after 2nd year	M20_2 inj	25
	15	Water injection after 4th year	M20_4 inj	25
	16	Water injection after 8th year	M20_8 inj	25
M10	17	Natural flow (no inj)	M10_no inj	20
	18	Water injection after 2nd year	M10_2 inj	25
	19	Water injection after 4th year	M10_4 inj	25
	20	Water injection after 8th year	M10_8 inj	25
M05	21	Natural flow (no inj)	M05_no inj	15
	22	Water injection after 2nd year	M05_2 inj	25
	23	Water injection after 4th year	M05_4 inj	25
	24	Water injection after 8th year	M05_8 inj	25

From table 3.2 through 3.4 can be summarizing as, 2 structure style, 3 STOIIP sizes of model per structure style and 4 production scenarios per STOIIP size model to total 24 scenarios test.

3.6 Flood Pattern Design

Waterflood pattern design for a comprehensive waterflood simulation in this study relies on the reservoir structure, drainage area, number of well, production activity and injection activity, see appendix A for additional information. The summary of waterflood pattern design, production rate, injection rate and number of well used for each model illustrated in Table 3.5.

Table 3.5 Waterflood pattern design.

Model Name	Initial Prod. Well	After well convert		Flood Pattern	Well Spacing (ft)
		Inj. well	Prod. well		
A20	6	4	2	Direct Line	1,440
A10	4	2	2	Staggered Line	1,104
A05	3	2	1	Direct Line	856
M20	6	3	3	Direct Line	2,160
M10	4	2	2	Direct Line	1,656
M05	3	2	1	Staggered Line	1,204

Table 3.6 Production and Injection rate for scenario test.

Model Name	Scenario No.	Water Injection Scenario	Initial Oil Production Rate/Well (BOPD/Well)	Water Injection Rate/Well (BWPD/Well)	Initial Inj./Prod. Raio (Fraction)
A20	1	(no inj)	130	-	-
	2	2nd	280	550	1.31
	3	4th	240	550	1.53
	4	8th	160	550	2.29
A10	5	(no inj)	90	-	-
	6	2nd	190	500	1.32
	7	4th	170	500	1.47
	8	8th	110	500	2.27
A05	9	(no inj)	150	-	-
	10	2nd	120	250	1.39
	11	4th	80	250	2.08
	12	8th	45	250	3.70
M20	13	(no inj)	150	-	-
	14	2nd	280	600	1.07
	15	4th	240	600	1.25
	16	8th	160	600	1.88
M10	17	(no inj)	110	-	-
	18	2nd	190	450	1.18
	19	4th	175	450	1.29
	20	8th	125	450	1.80
M05	21	(no inj)	160	-	-
	22	2nd	130	225	1.15
	23	4th	80	225	1.88
	24	8th	65	225	2.31

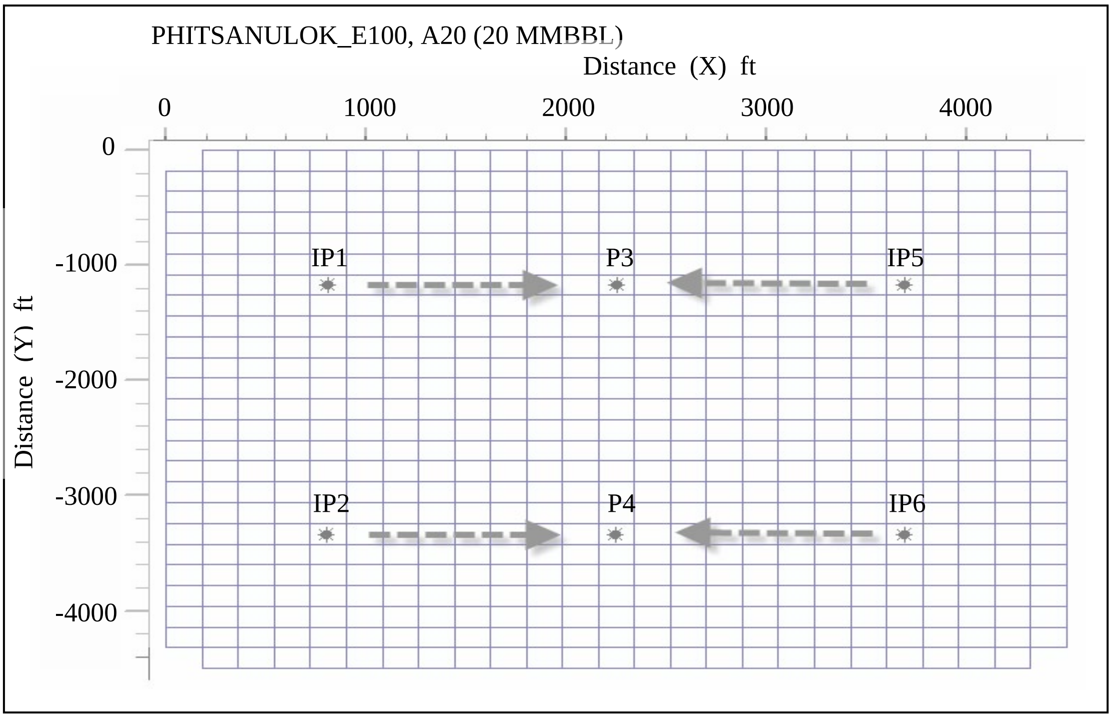

Figure 3.5 Model A20 Flood pattern design (P = Production, IP = Injection).

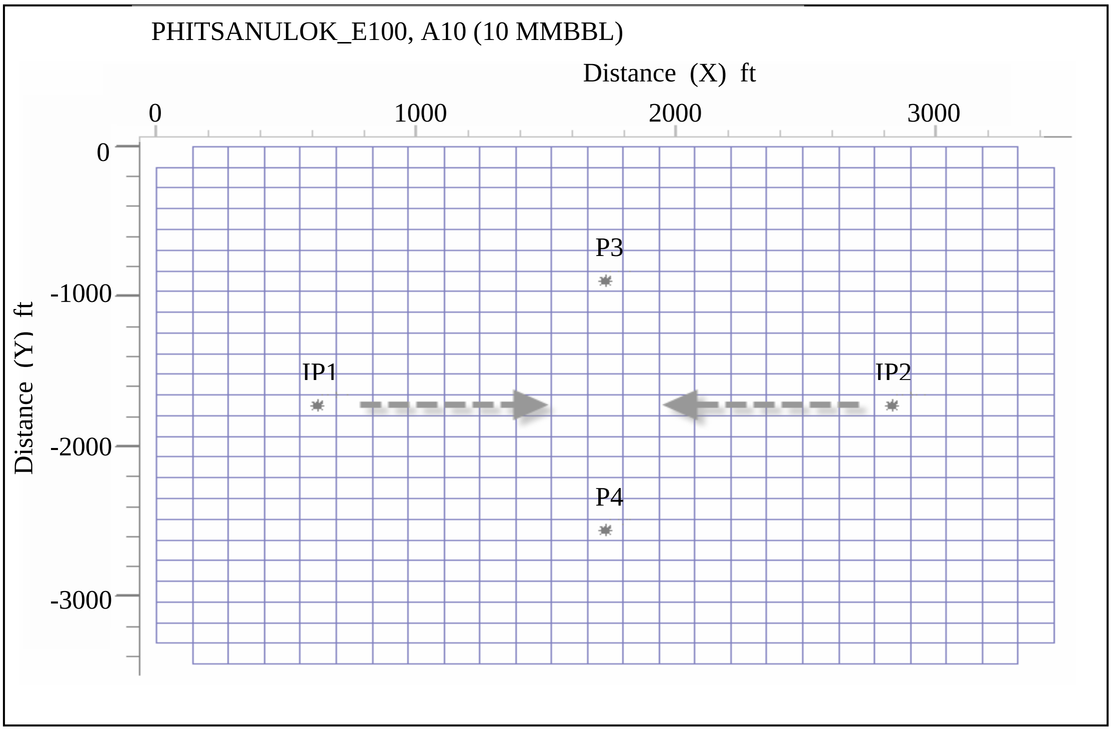

Figure 3.6 Model A10 flood pattern design (P = Production, IP = Injection).

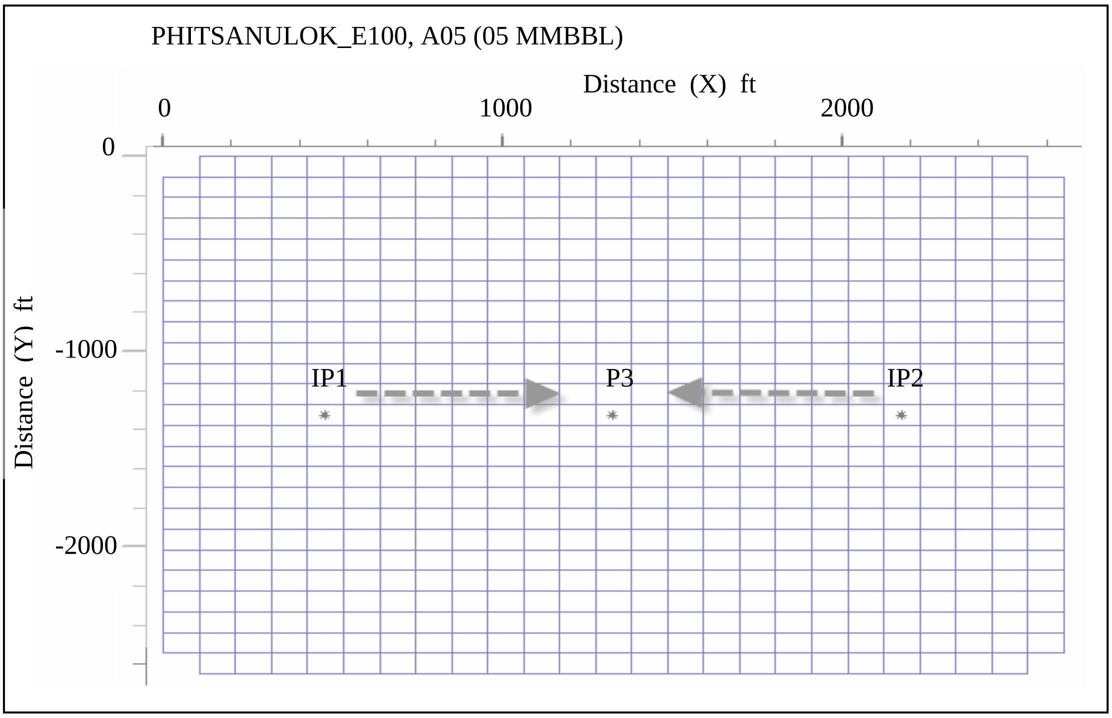

Figure 3.7 Model A05 Flood pattern design (P = Production, IP = Injection).

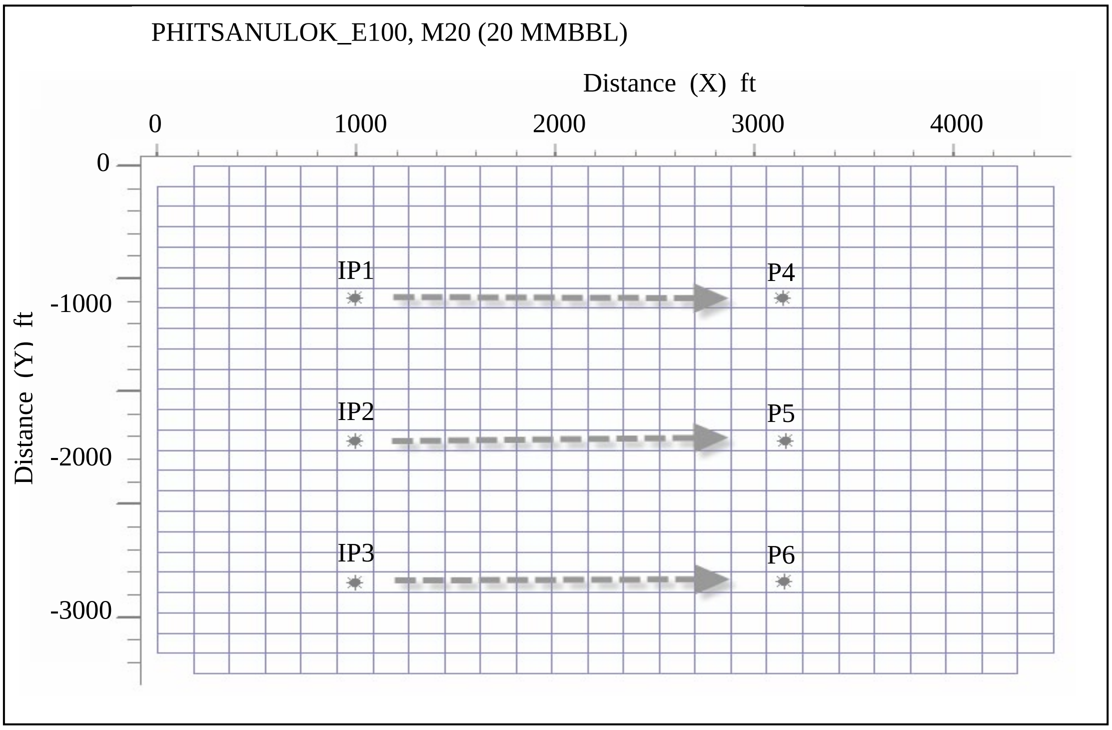

Figure 3.8 Model M20 flood pattern design (P = Production, IP = Injection).

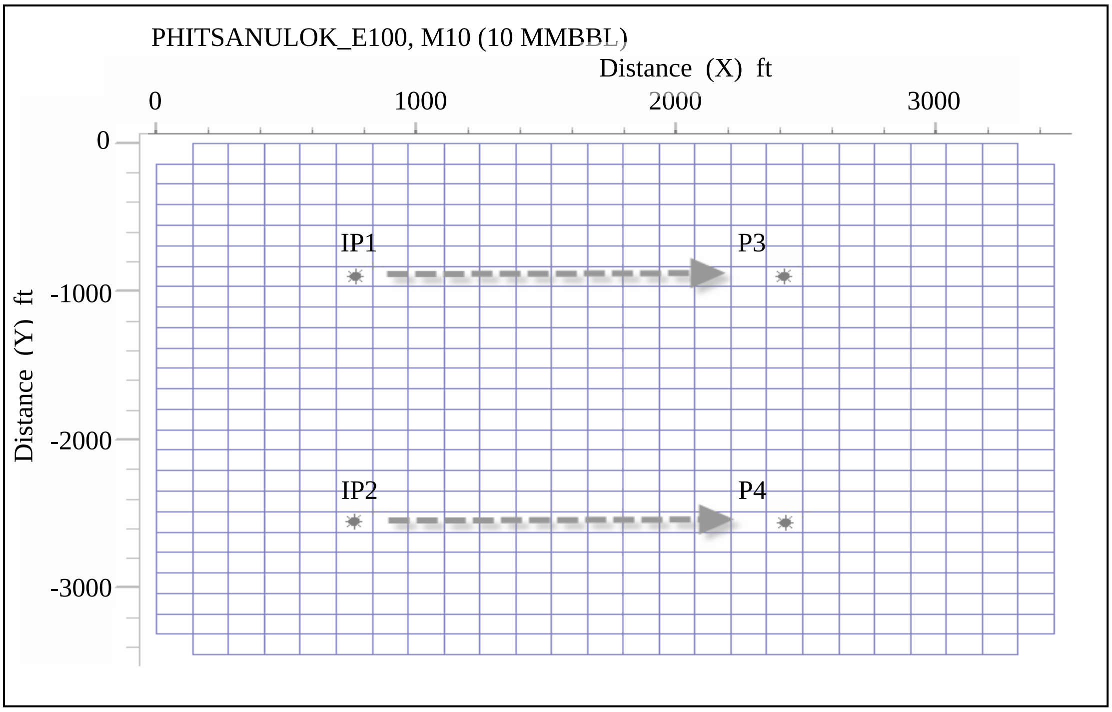

Figure 3.9 Model M10 flood pattern design (P = Production, IP = Injection).

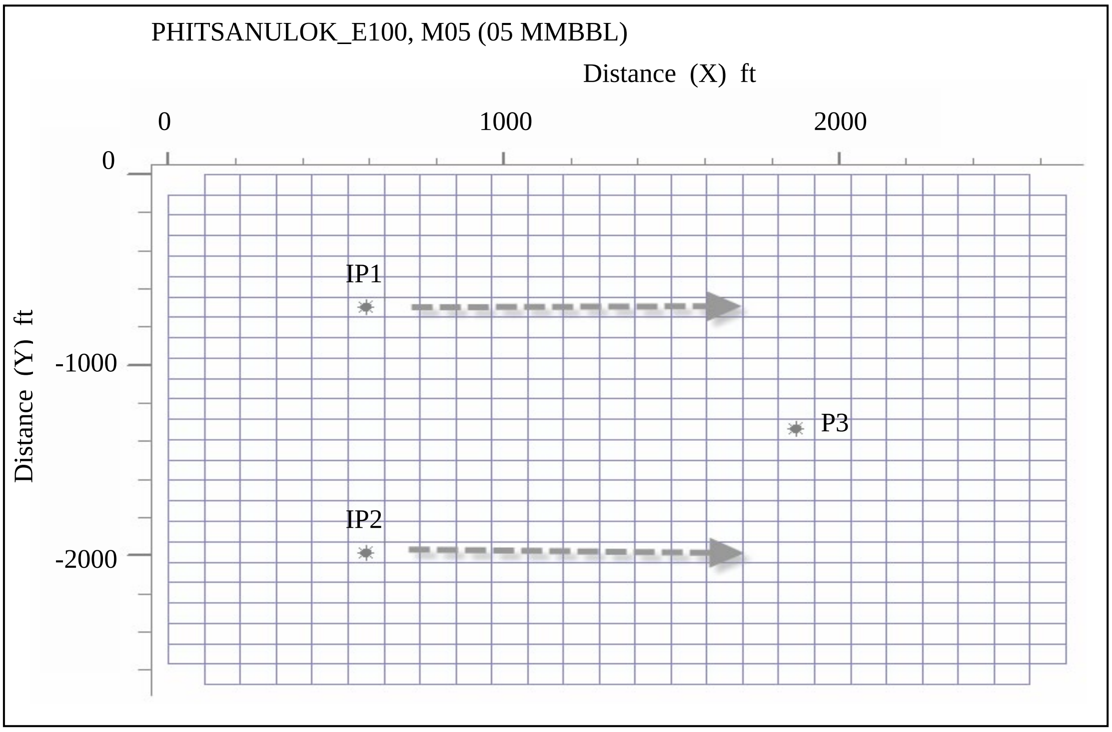

Figure 3.10 Model M05 Flood pattern design (P = Production, IP = Injection).

CHAPTER IV

RESERVOIR SIMULATION RESULT

4.1 Objective

The objective of this chapter is to illustrated reservoir simulation results of the bottom waterflooding technique. These results focus on 4 main graph which 3 phase of fluids represent (oil, water, and gas), field fluid in place (show oil, gas, and water volume represent in the reservoir), field cumulative production (show production efficiency), field production rate (show production profile), and cross plot of pressure, gas-oil-ratio, and water cut (show fluids represented and its effected by waterflood activity at each stage of pressure profile). Detail of the presented graphs will be described to figure out its trend through the production period.

4.2 Production Scenarios

As described in previous chapter, the 3 sizes of STOIIP (20, 10, and 5 MMBBL) with 2 structure style (Anticline, A-model and Monocline, M-model Structure) will be performed and tested by 4 production scenarios, natural flow (no water injection), 2nd year, 4th year, and 8th year after natural flow production periods of the water injection . The water injection scenarios start at different of time will be test to observe and compare the results of production efficiency yield from waterflood activity, because in a real production operation can not fixed a certain waterflood activity schedule until its reach the necessary of operation data criteria (especially, reservoir connectivity), see appendix A. The detail of production scenarios are illustrated in Table 4.1.

Table 4.1 Production scenarios detail.

Model Name	Scenario No.	Water Injection Scenario	Gross Oil Production Rate (BOPD)	Gross Water Injection Rate (BWPD)	Initial Inj./Prod. Ratio (Fraction)
A20	1	(no inj)	780	-	-
	2	2nd year	1,680	2,200	1.31
	3	4th year	1,440	2,200	1.53
	4	8th year	960	2,200	2.29
A10	5	(no inj)	360	-	-
	6	2nd year	760	1,000	1.32
	7	4th year	680	1,000	1.47
	8	8th year	440	1,000	2.27
A05	9	(no inj)	300	-	-
	10	2nd year	360	500	1.39
	11	4th year	240	500	2.08
	12	8th year	135	500	3.70
M20	13	(no inj)	900	-	-
	14	2nd year	1,680	1,800	1.07
	15	4th year	1,440	1,800	1.25
	16	8th year	960	1,800	1.88
M10	17	(no inj)	440	-	-
	18	2nd year	760	900	1.18
	19	4th year	700	900	1.29
	20	8th year	500	900	1.80
M05	21	(no inj)	320	-	-
	22	2nd year	390	450	1.15
	23	4th year	240	450	1.88
	24	8th year	195	450	2.31

Table 4.1 Production scenarios detail (Continued).

No.	Scenario Name.	Oil Production Rate/Well (BOPD/Well)	Water Injection Rate/Well (BWPD/Well)	Total Initial Prod. Well (Well)	Inj./Prod. Well After Convert (Well/Well)
1	A20_no inj	130	-	6	-
2	A20_2 inj	280	550	6	4/2
3	A20_4 inj	240	550	6	4/2
4	A20_8 inj	160	550	6	4/2
5	A10_no inj	90	-	4	-
6	A10_2 inj	190	500	4	2/2
7	A10_4 inj	170	500	4	2/2
8	A10_8 inj	110	500	4	2/2
9	A05_no inj	150	-	2	-
10	A05_2 inj	120	250	3	2/1
11	A05_4 inj	80	250	3	2/1
12	A05_8 inj	45	250	3	2/1
13	M20_no inj	150	-	6	-
14	M20_2 inj	280	600	6	3/3
15	M20_4 inj	240	600	6	3/3
16	M20_8 inj	160	600	6	3/3
17	M10_no inj	110	-	4	-
18	M10_2 inj	190	450	4	2/2
19	M10_4 inj	175	450	4	2/2
20	M10_8 inj	125	450	4	2/2
21	M05_no inj	160	-	2	-
22	M05_2 inj	130	225	3	2/1
23	M05_4 inj	80	225	3	2/1
24	M05_8 inj	65	225	3	2/1

4.3 Reservoir Simulation Result

This section illustrated and describes results from the bottom waterflooding simulation model in Phitsanulok Basin. Production scenarios performed with no water injection and water injection scenarios to compare the recovery efficiency gained from each run. Total 24 scenarios simulation run results displayed through the cross plot of 4 main graphs to observed fluids production behavior from reservoir before and after applied bottom waterflooding. Detail of showing graphs are described in Table 4.2.

Table 4.2 Graph display parameter description.

Graph	Parameter	Description	Common Refer
1	FGIP	Field Gas in Place	Original of Gas in Place
	FOIP	Field Oil in Place	Original of Oil in Place
	FWIP	Field Water in Place	Original of Water in Place
2	FGPT	Field Gas Production Total	Cumulative Gas Production
	FOPT	Field Oil Production Total	Cumulative Oil Production
	FWPT	Field Water Production Total	Cumulative Water Production
3	FGPR	Field Gas Production Rate	Daily Gas Production Rate
	FOPR	Field Oil Production Rate	Daily Oil Production Rate
	FWPR	Field Water Production Rate	Daily Water production Rate
4	FGOR	Field Gas-Oil-Ratio	Gas-Oil-Raio (GOR)
	FWCT	Field Water Cut	Water Cut (WCT)
	FPR	Field Pressure	Reservoir Pressure

4.3.1 Model A20_no inj Scenario Result

Model A20 natural flow produced with no water injection through the production period (20 years). Production schedule start by 6 production wells at initial oil production rate 130 BOPD/well (Gross 780 BOPD), the simulation results show in figure 4.1 – 4.4:

Table 4.3 Summary detail of graph 4.1 and 4.2.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,052,435	20,197,464	25.02
Gas (MSCF)	9,482,403	9,745,141	97.30
Water (STB)	-	9,052,867	-

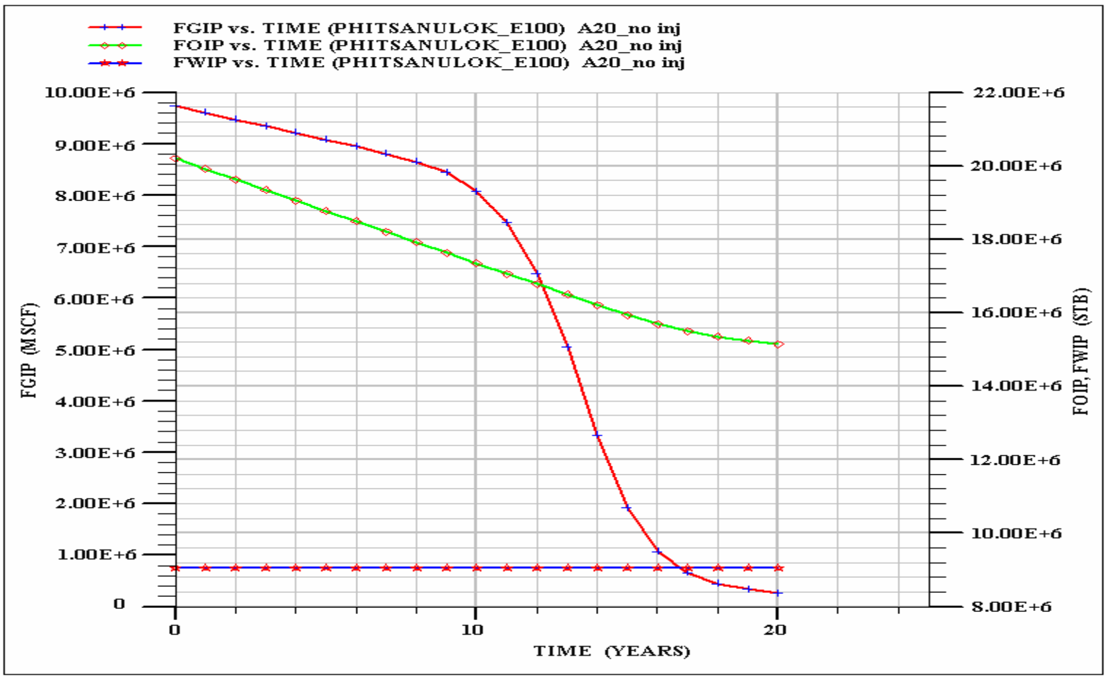

Figure 4.1 Fluid in place profile vs. Time of model A20_no inj.

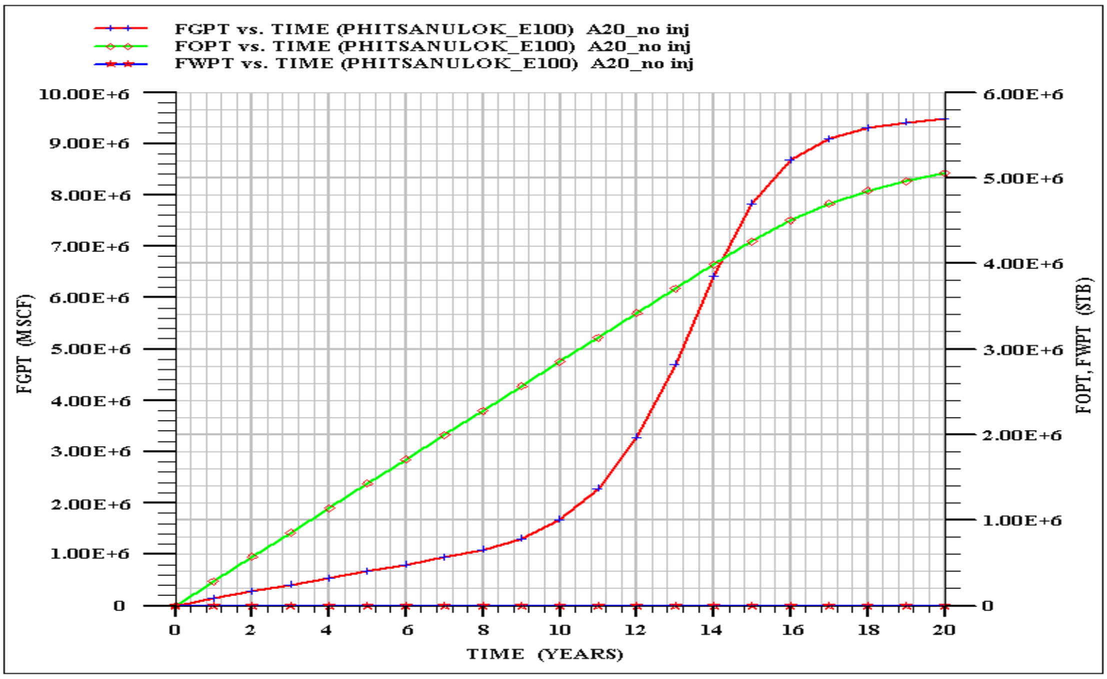

Figure 4.2 Cumulative fluids production profile vs. Time of model A20_no inj.

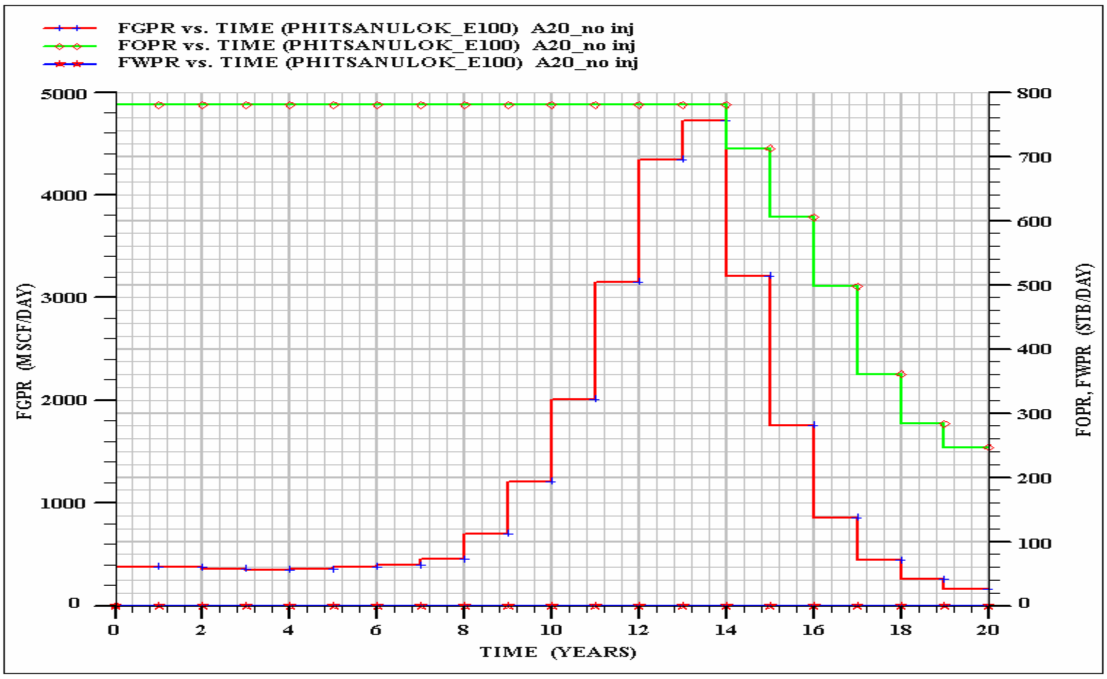

Figure 4.3 Fluids production rate profile vs. Time of model A20_no inj.

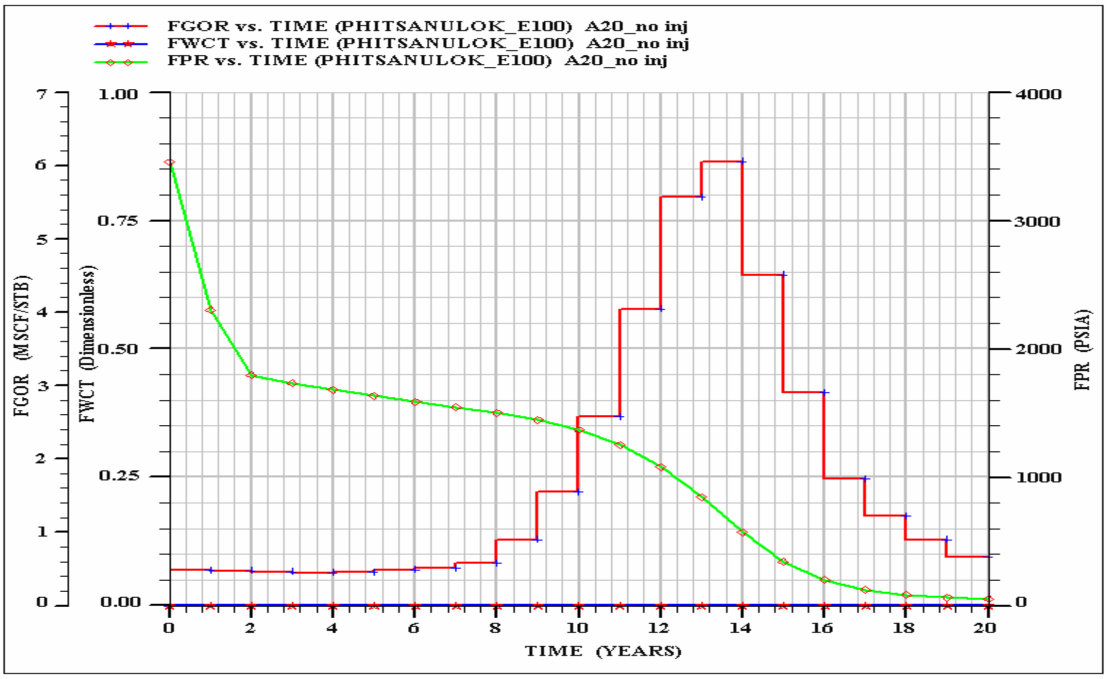

Figure 4.4 GOR, WCT, and Pressure profile vs. Time of model A20_no inj.

Figure 4.3, show gross oil production (FPOR) keep a steady rate at 780 BOPD from starting production to the 14th year, after that decreases gradually to 246 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.4). Gross gas production rate (FGPR) remain constant around 400 MSCFD until the 8th year, it increase suddenly to 4,722 MSCFD at the 14th year, and then drop rapidly to 163 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.2 Model A20_2 inj Scenario Result

Model A20_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.5 – 4.8):

- 6 production wells at initial oil production rate 280 BOPD/well (gross 1,680 BOPD)
- after 2 years of production period, start water injection by converted 4 production well to injection well with 550 BWPD/well injection rate (gross 2,200 BWPD)
- 2 remaining production well produced at rate 840 BOPD/well to maintain initial gross production rate

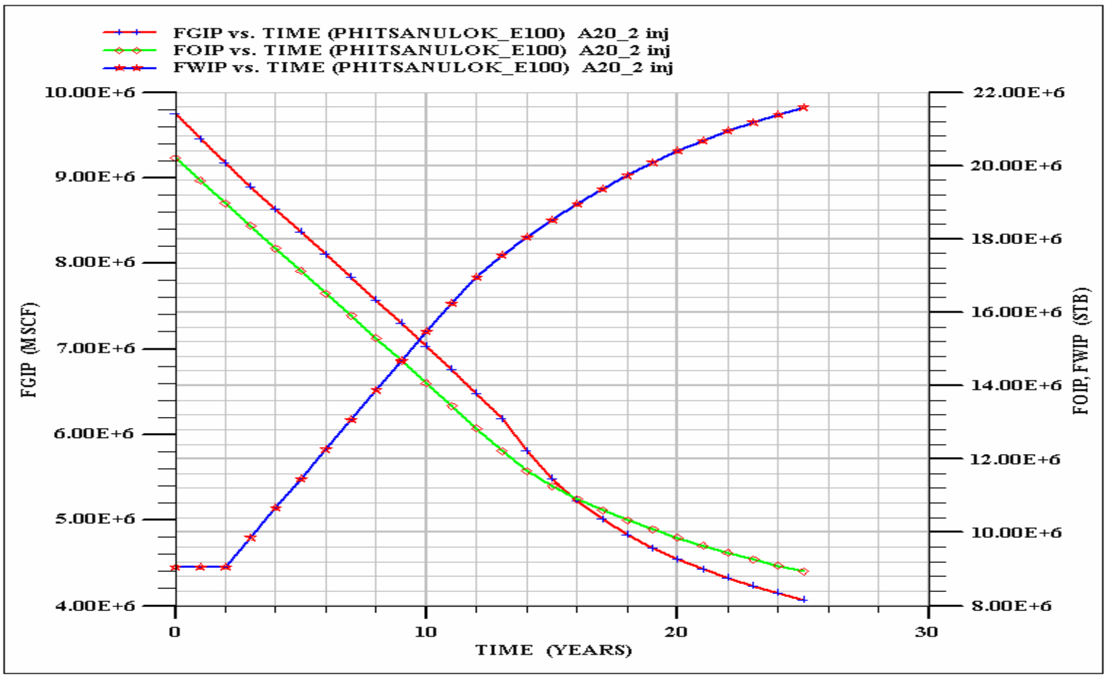

Figure 4.5 Fluid in place profile vs. Time of model A20_2 inj.

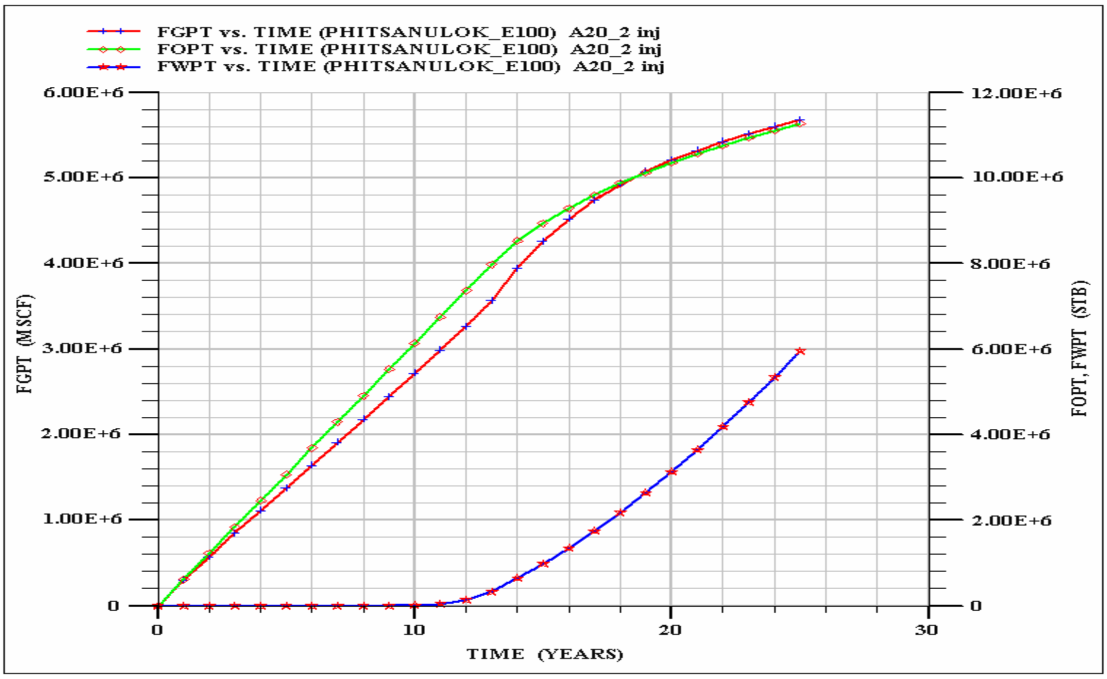

Figure 4.6 Cumulative fluids production profile vs. Time of model A20_2 inj.

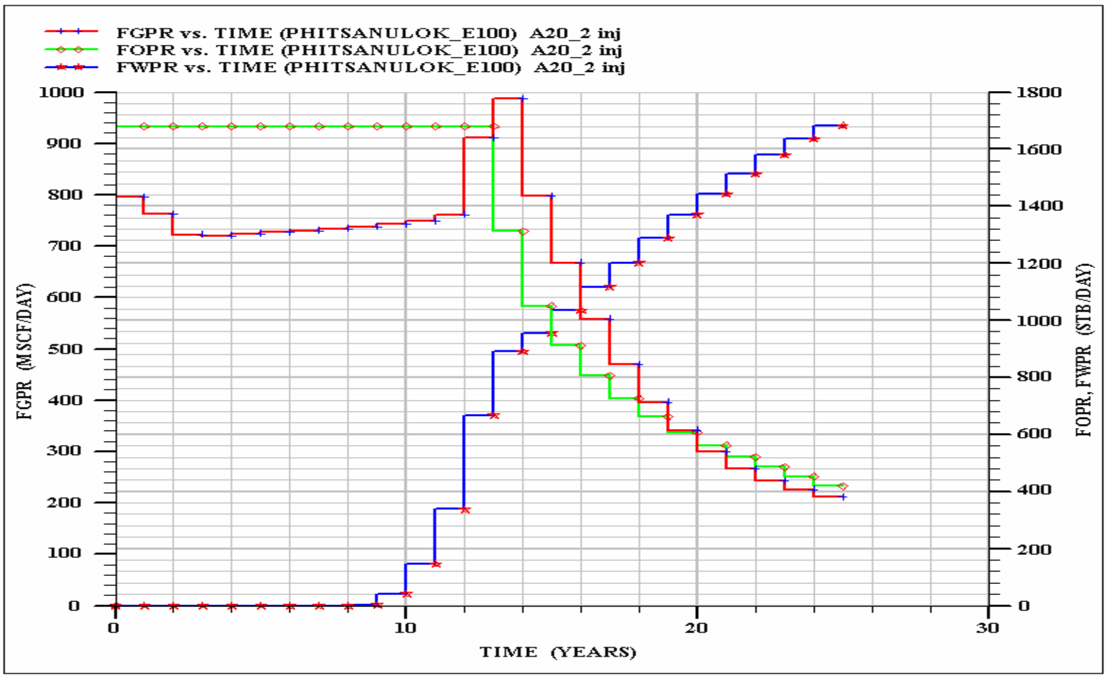

Figure 4.7 Fluids production rate profile vs. Time of model A20_2 inj.

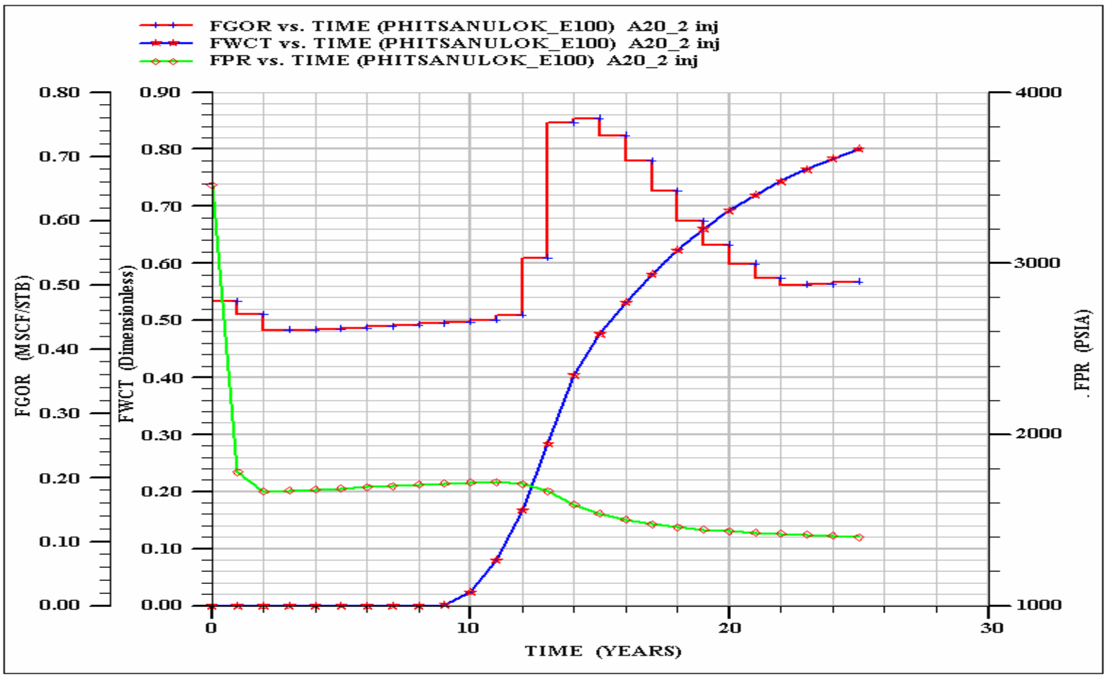

Figure 4.8 GOR, WCT, and Pressure profile vs. Time of model A20_2 inj.

Table 4.4 Summary detail of graph 4.5 and 4.6.

Fluid type	**Cumulative production**	**Initial fluid in place**	**RF (%)**
Oil (STB)	11,264,666	20,197,464	55.77
Gas (MSCF)	5,676,151	9,745,141	58.24
Water (STB)	5,950,624	9,052,867	65.73

Figure 4.7, show FOPR remain constant rate at 1,680 BOPD over the first 13 years, cause by a long FPR maintenance from water injection activity (see figure 4.8), beyond this point, it decreases dramatically to 420 BOPD at the end of production period due to WCT start breakthroughs at 9th year. with a rapid high rate. Suddenly WCT reach, FPR drop moderately and changes slightly through the end.

4.3.3 Model A20_4 inj Scenario Result

Model A20_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.9 – 4.12):

- 6 production wells at initial oil production rate 240 BOPD/well (gross 1,440 BOPD)
- after 4 years of production period, start water injection by converted 4 production well to injection well with 550 BWPD/well injection rate (gross 2,200 BWPD)
- 2 remaining production well produced at rate 720 BOPD/well to maintain initial gross production rate

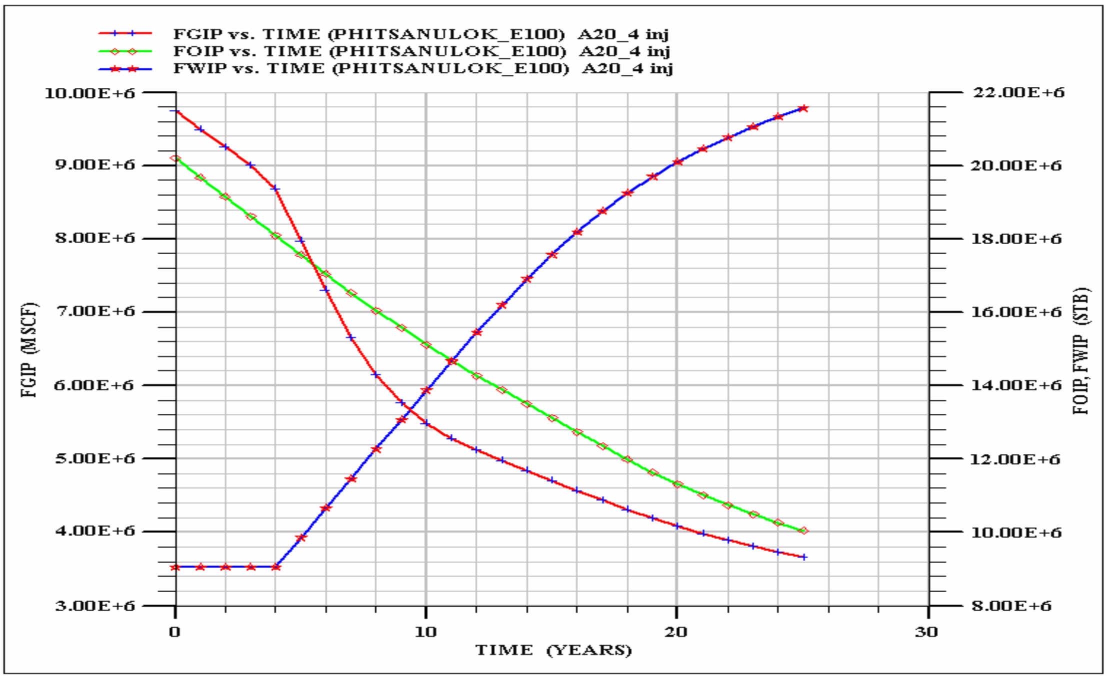

Figure 4.9 Fluid in place profile vs. Time of model A20_4 inj.

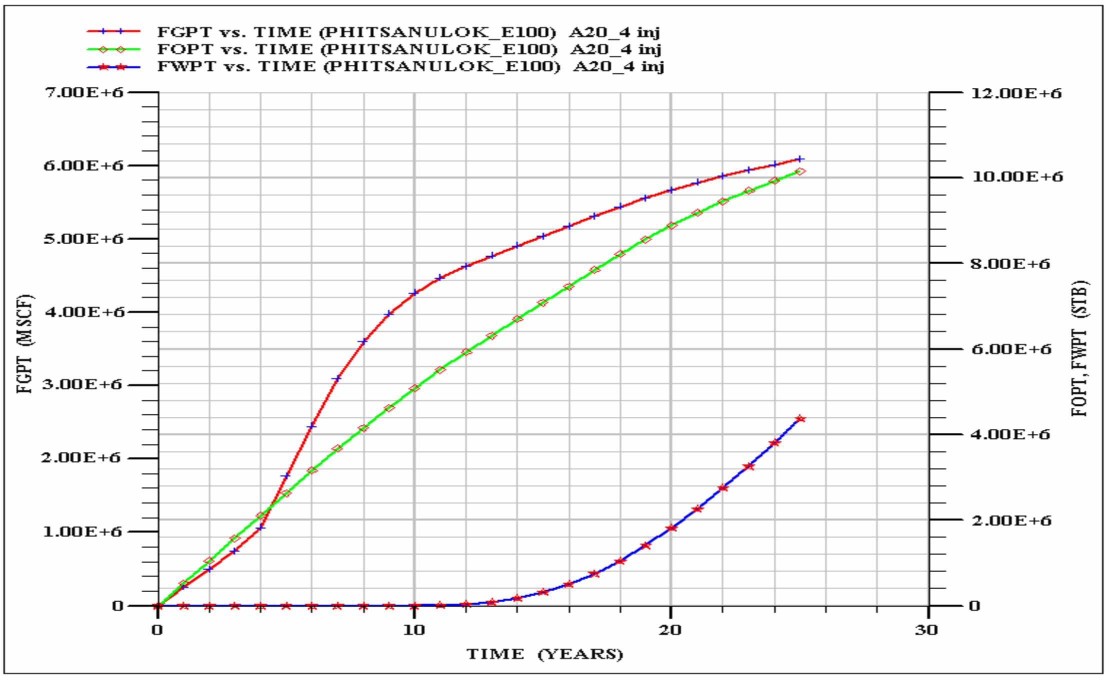

Figure 4.10 Cumulative fluids production profile vs. Time of model A20_4 inj.

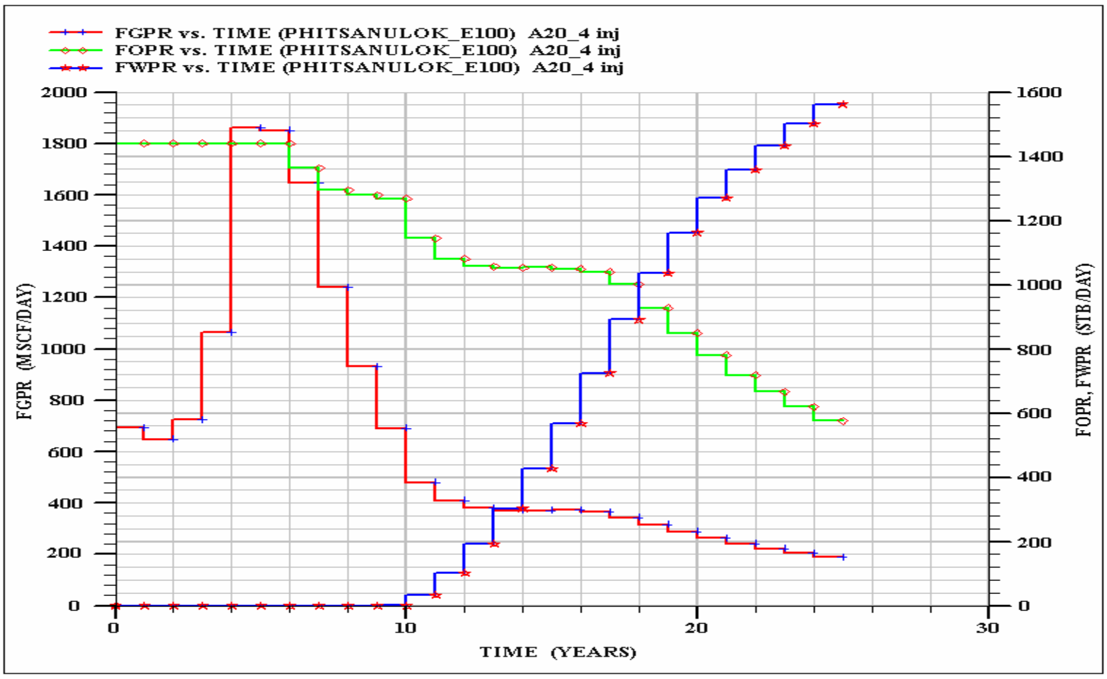

Figure 4.11 Fluids production rate profile vs. Time of model A20_4 inj.

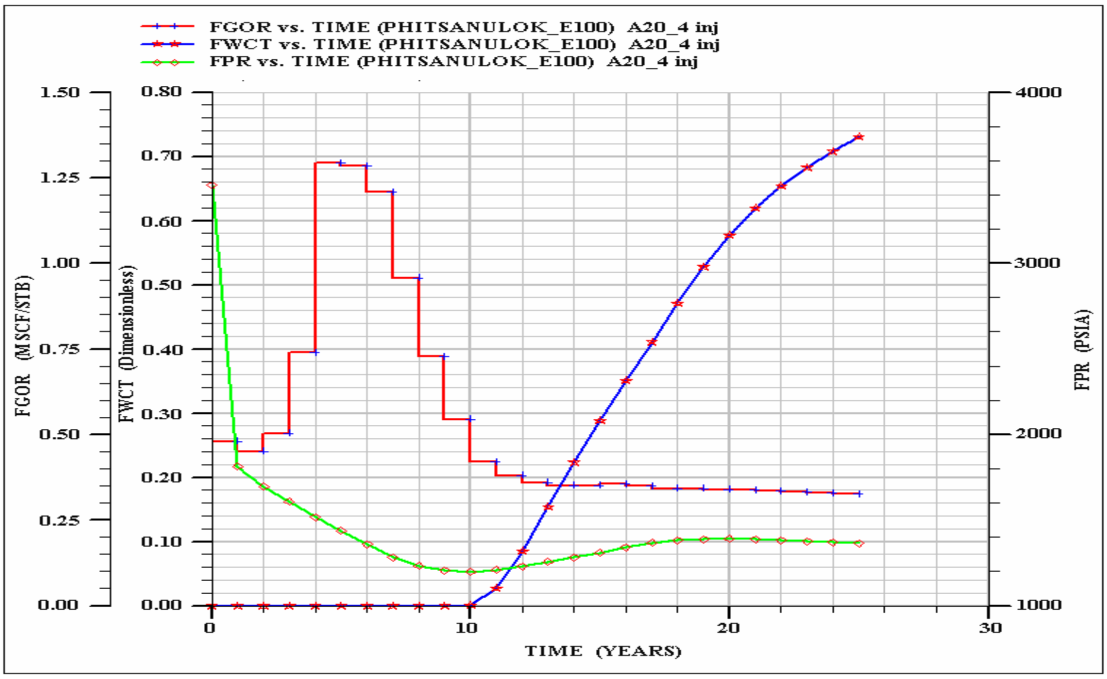

Figure 4.12 GOR, WCT, and Pressure profile vs. Time of model A20_4 inj.

Table 4.5 Summary detail of graph 4.9 and 4.10.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	10,151,359	20,197,464	50.26
Gas (MSCF)	6,085,160	9,745,141	62.44
Water (STB)	4,364,221	9,052,867	48.20

Figure 4.11, show FOPR remain constant rate at 1,440 BOPD over the first 6 years, after that decreases gradually to 1,144 BOPD at the 11th year and keep constant rate around 1,050 BOPD to the 18th year, beyond this point, it drop steadily to 576 BOPD at the end. This production trend effected by FPR (see figure 4.12) drop slightly till the 10th year, after that it improve slowly and flattened out through the end of production period (starting effected by WCT at 9th year).

4.3.4 Model A20_8 inj Scenario Result

Model A20_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.13 – 4.16):

- 6 production wells at initial oil production rate 160 BOPD/well (gross 960 BOPD)
- after 8 years of production period, start water injection by converted 4 production well to injection well with 550 BWPD/well injection rate (gross 2,200 BWPD)
- 2 remaining production well produced at rate 480 BOPD/well to maintain initial gross production rate

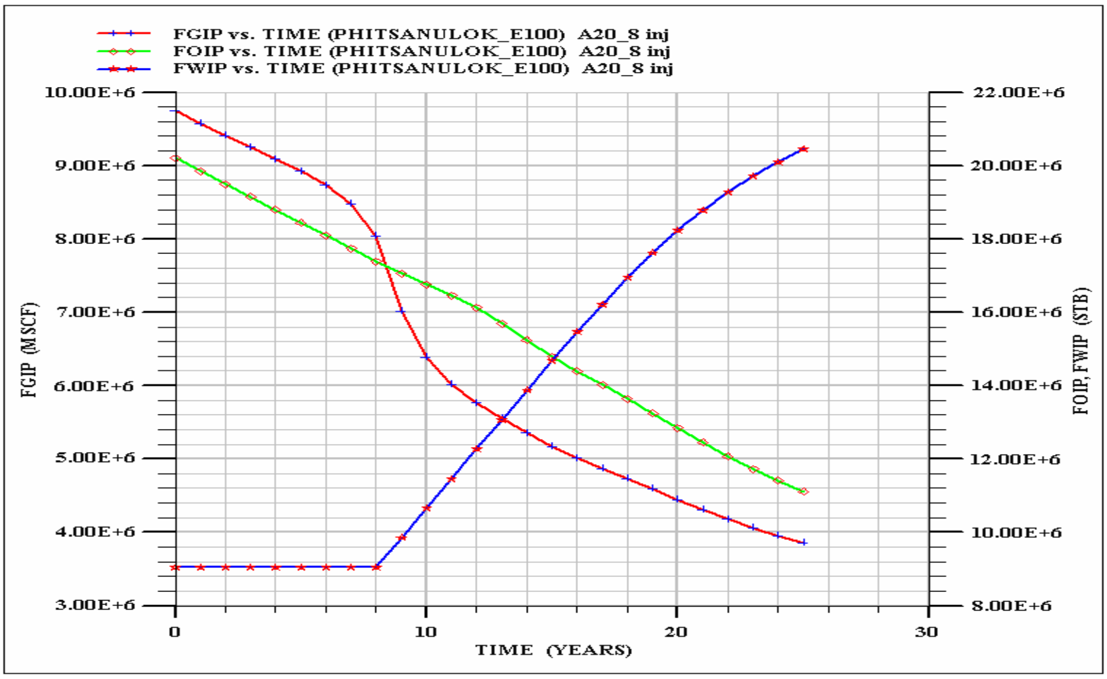

Figure 4.13 Fluid in place profile vs. Time of model A20_8 inj.

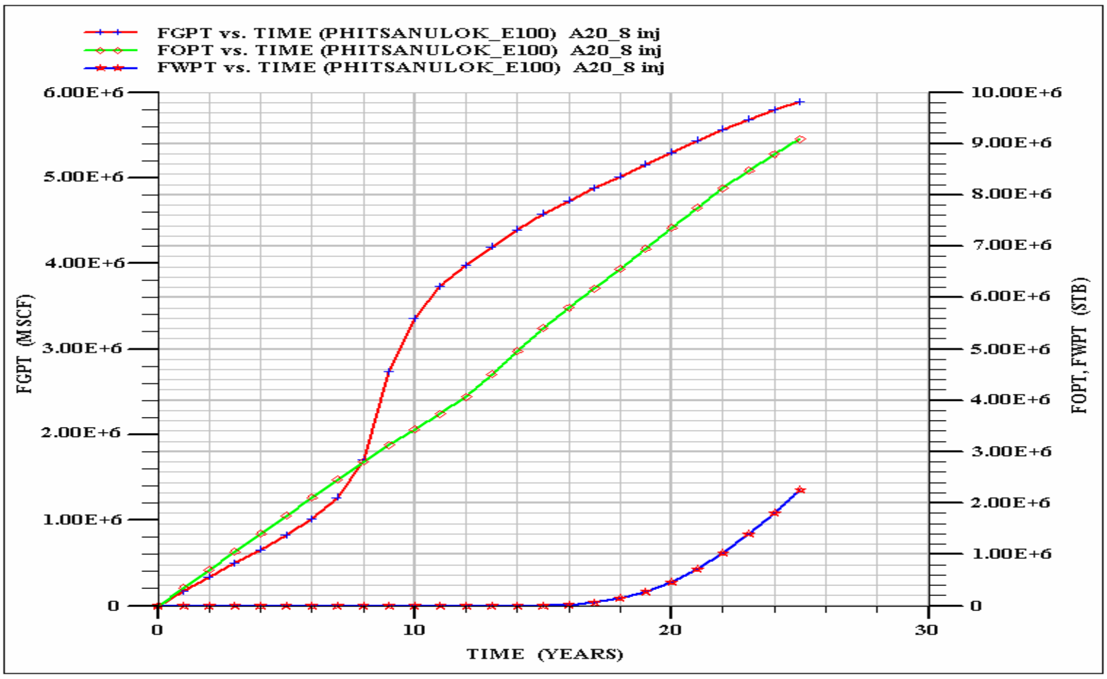

Figure 4.14 Cumulative fluids production profile vs. Time of model A20_8 inj.

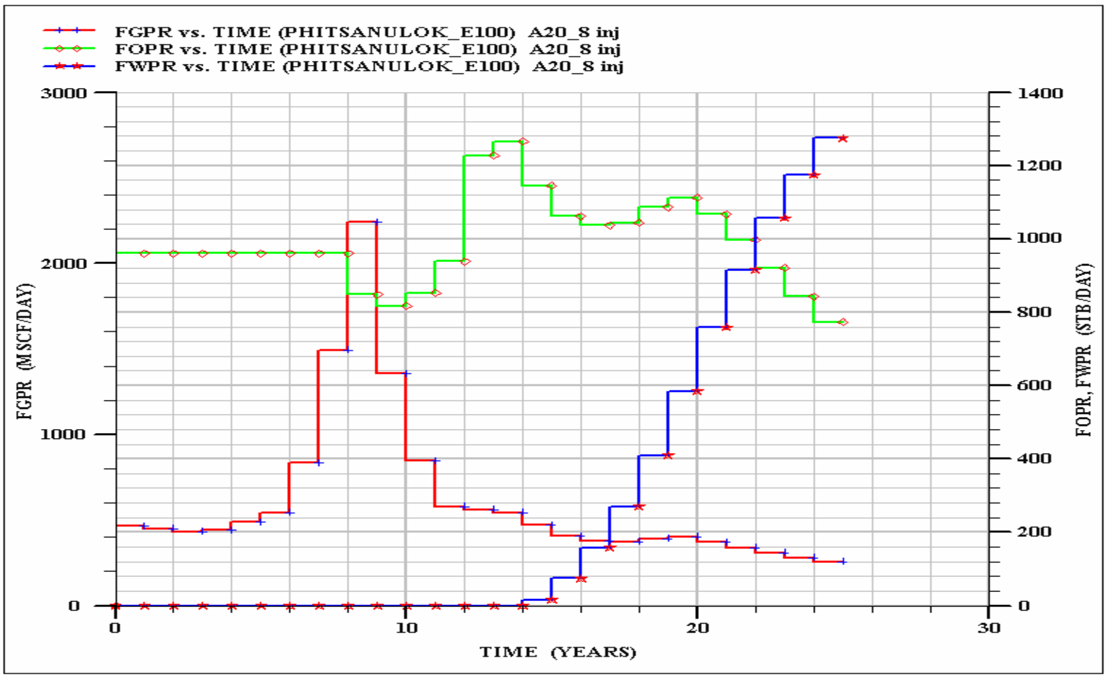

Figure 4.15 Fluids production rate profile vs. Time of model A20_8 inj.

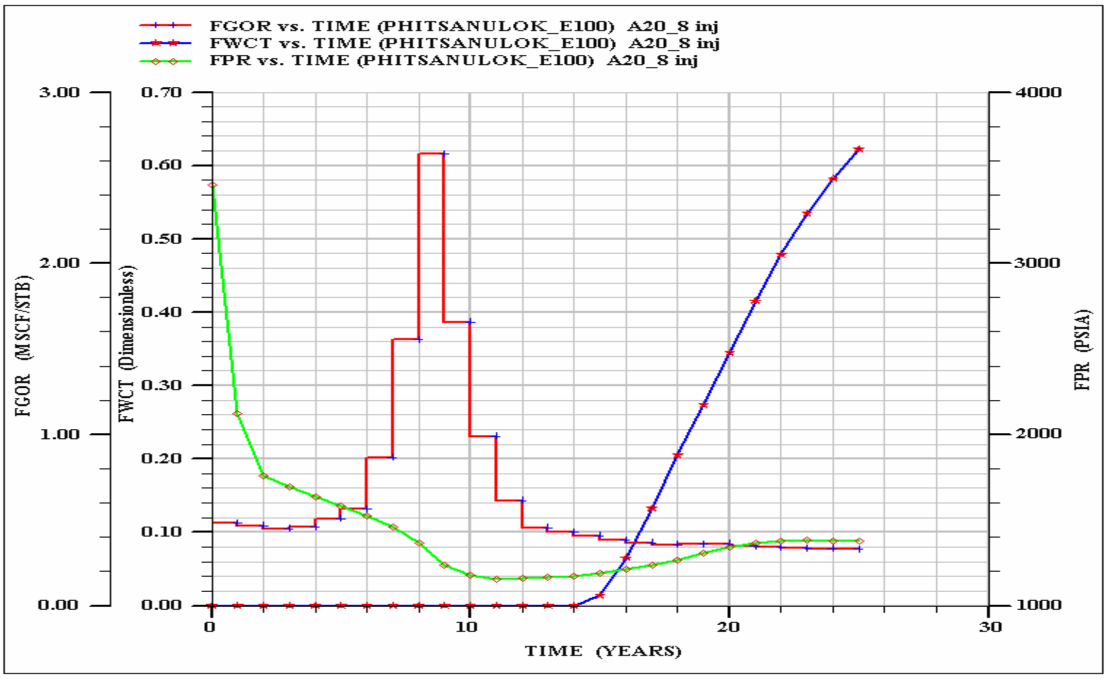

Figure 4.16 GOR, WCT, and Pressure profile vs. Time of model A20_8 inj.

Table 4.6 Summary detail of graph 4.13 and 4.14.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	9,082,409	20,197,464	44.96
Gas (MSCF)	5,885,775	9,745,141	60.39
Water (STB)	2,259,092	9,052,867	24.95

Figure 4.15, show FOPR remain constant rate at 960 BOPD over the first 8 years, after that decreases slightly, until the water injection reach and FPR improve (see figure 4.16), it jumped suddenly to 1,227 BOPD at the 13th year and fluctuated around 1,100 BOPD to the 21st year, and drop steadily to 773 BOPD at the end (WCT breakthrough at 15th year, because of late water injection).

4.3.5 Model A10_no inj Scenario Result

Model A10 natural flow produced with no water injection through the production period (20 years). Production schedule start by 4 production wells at initial oil production rate 90 BOPD/well (Gross 360 BOPD), the simulation results show in figure 4.17 – 4.20:

Table 4.7 Summary detail of graph 4.17 and 4.18.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,224,570	10,126,692	21.97
Gas (MSCF)	4,798,227	4,886,061	98.20
Water (STB)	-	4,625,127	-

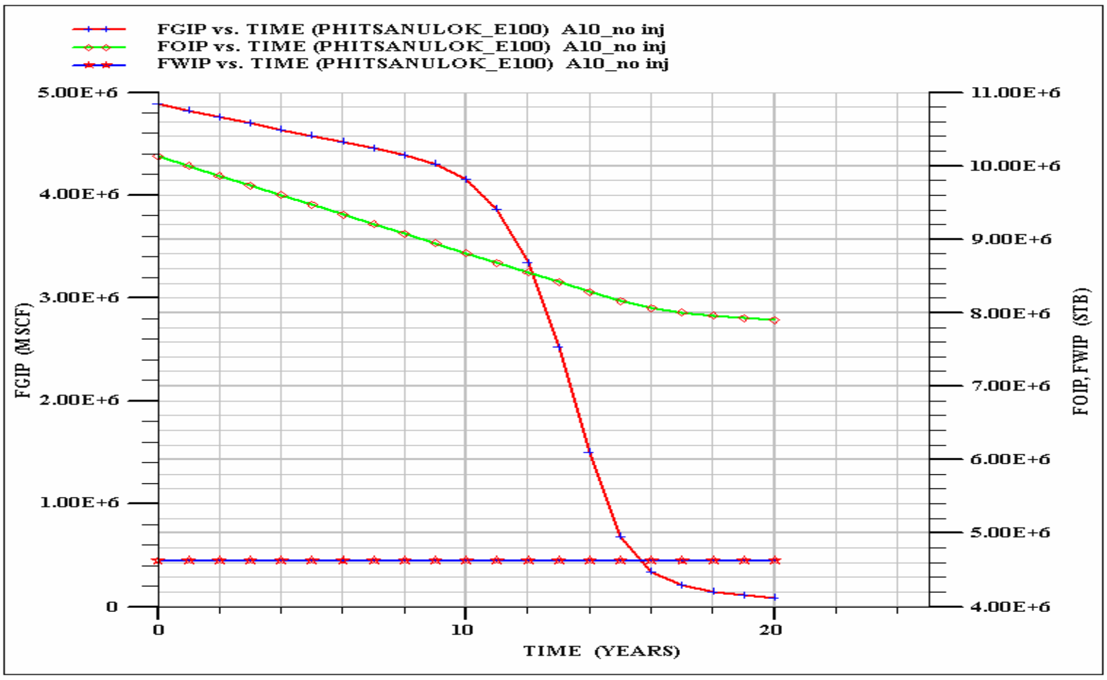

Figure 4.17 Fluid in place profile vs. Time of model A10_no inj.

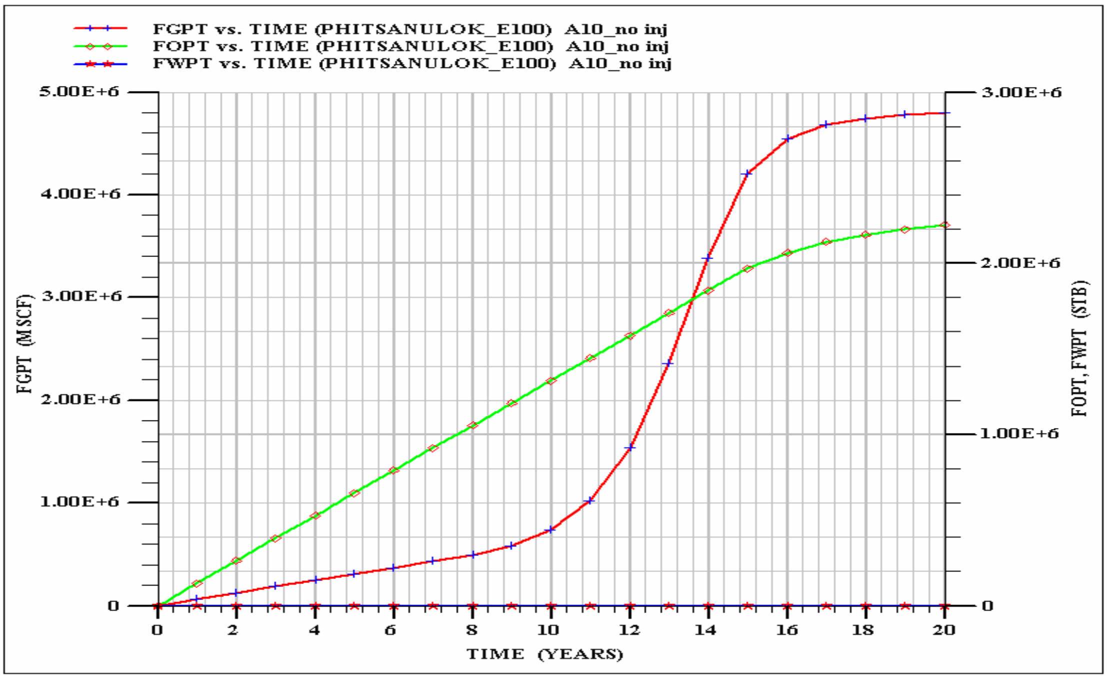

Figure 4.18 Cumulative fluids production profile vs. Time of model A10_no inj.

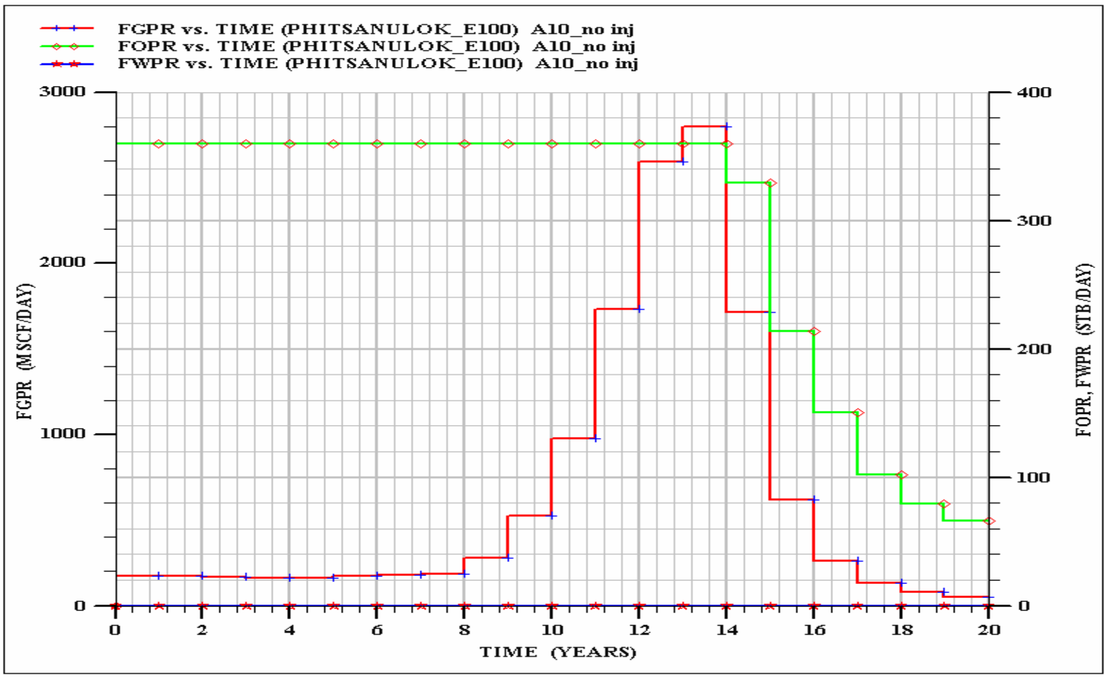

Figure 4.19 Fluids production rate profile vs. Time of model A10_no inj.

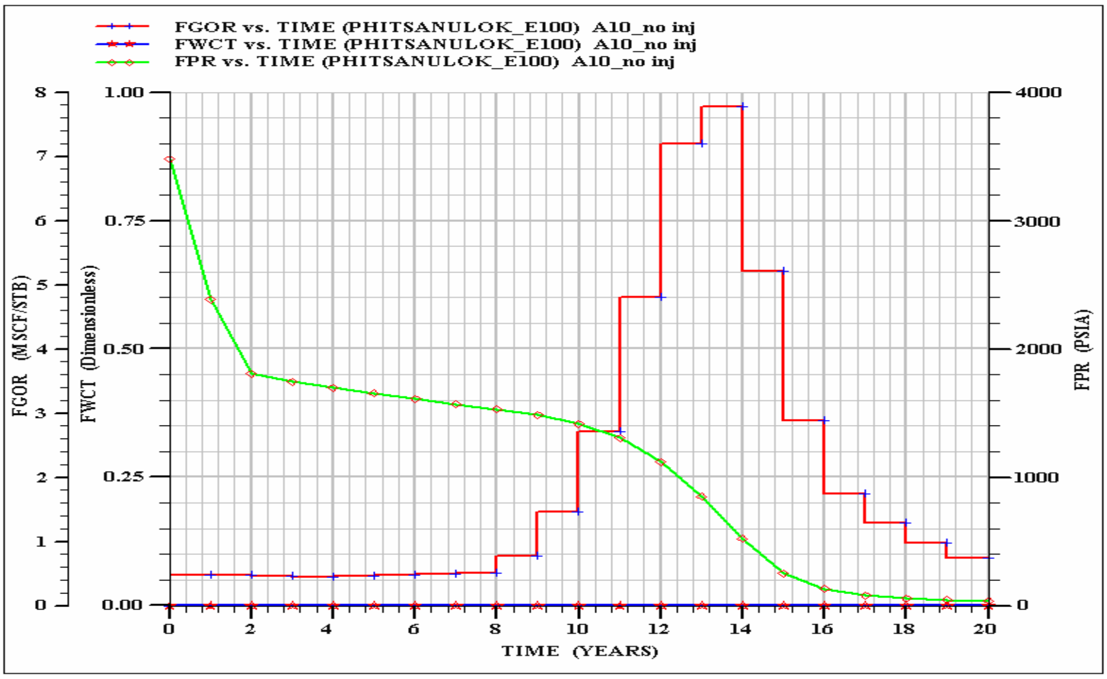

Figure 4.20 GOR, WCT, and Pressure profile vs. Time of model A10_no inj.

Figure 4.19, show gross oil production (FOPR) keep a steady rate at 360 BOPD from starting production to the 14th year, after that drop sharply to 66 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.20). Gross gas production rate (FGPR) fluctuate slightly around 180 MSCFD until the 8th year, it increase suddenly to 2,796 MSCFD at the 14th year, and then drop rapidly to 49 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.6 Model A10_2 inj Scenario Result

Model A10_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.21 – 4.24):

- 4 production wells at initial oil production rate 200 BOPD/well (gross 800 BOPD)
- after 2 years of production period, start water injection by converted 2 production well to injection well with 500 BWPD/well injection rate (gross 1,000 BWPD)
- 2 remaining production well produced at rate 400 BOPD/well to maintain initial gross production rate

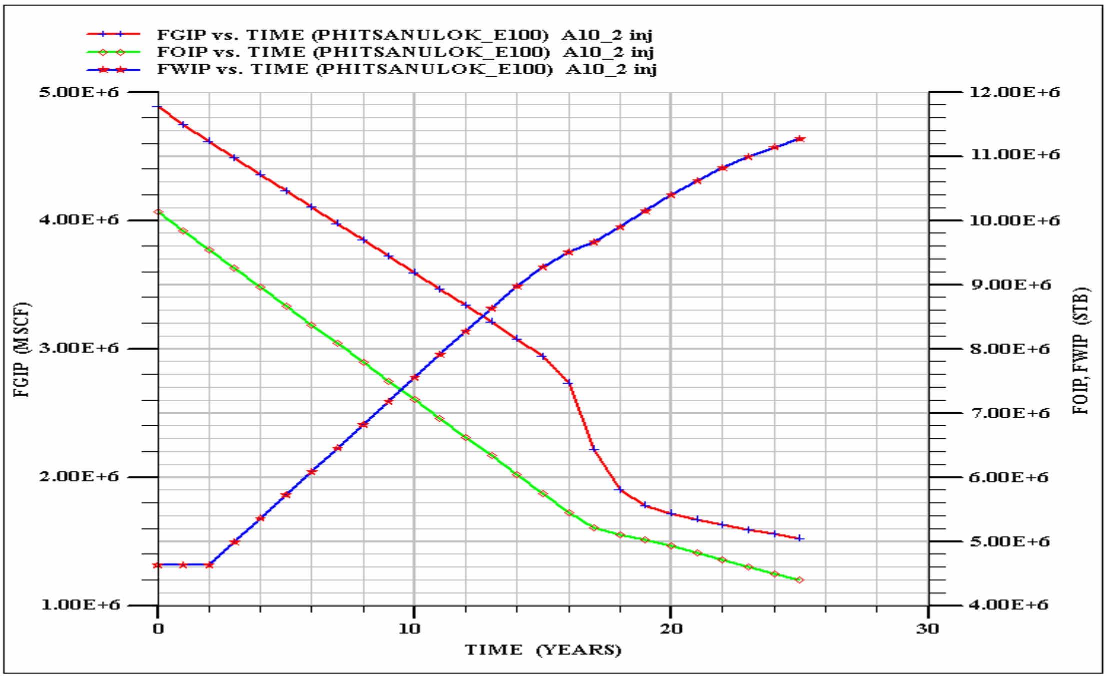

Figure 4.21 Fluid in place profile vs. Time of model A10_2 inj.

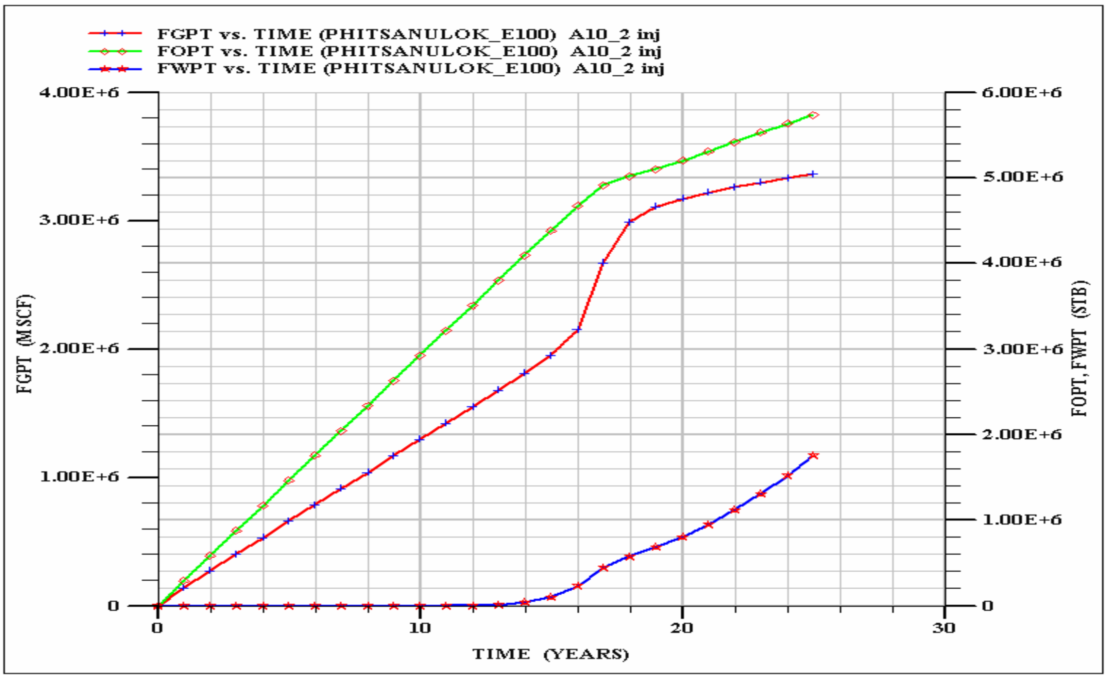

Figure 4.22 Cumulative fluids production vs. Time of model A10_2 inj.

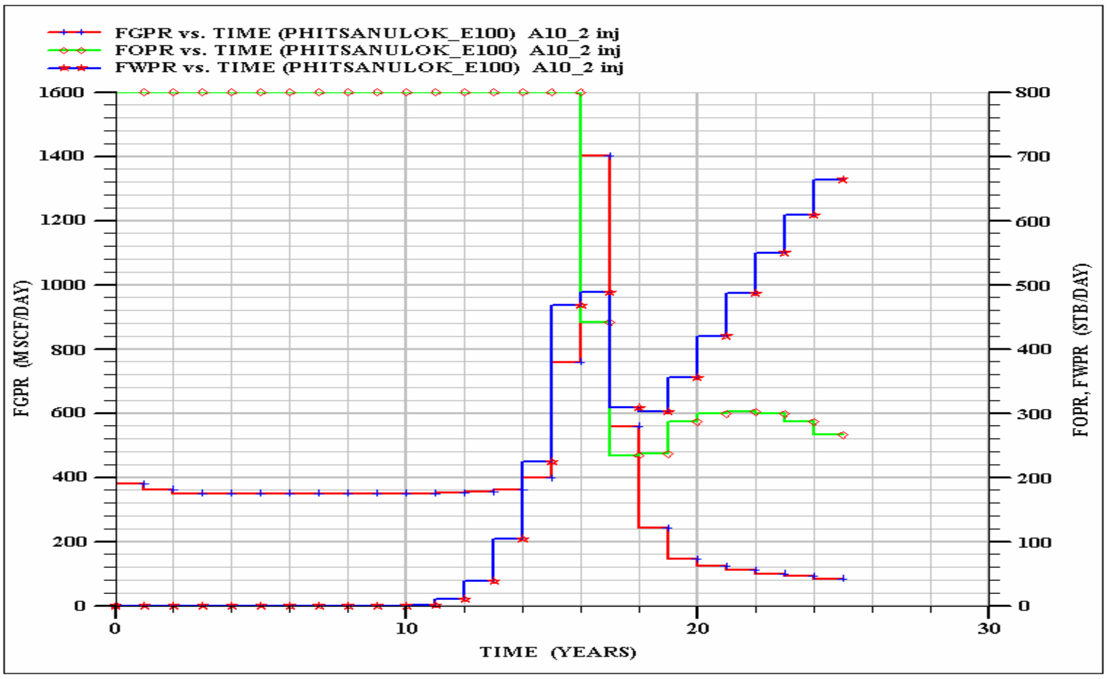

Figure 4.23 Fluids production rate profile vs. Time of model A10_2 inj.

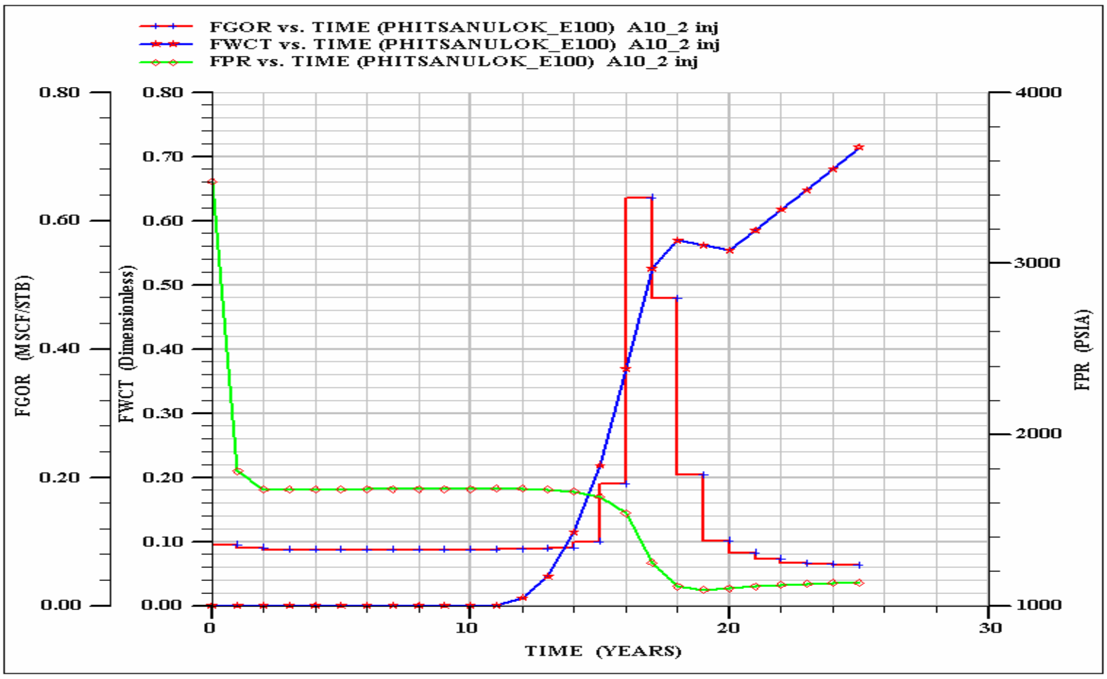

Figure 4.24 GOR, WCT, and Pressure profile vs. Time of model A10_2 inj.

Table 4.8 Summary detail of graph 4.21 and 4.22.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,733,226	10,126,692	56.61
Gas (MSCF)	3,363,101	4,886,061	68.83
Water (STB)	1,756,893	4,625,127	37.99

Figure 4.23, show FOPR remain constant rate at 800 BOPD over the first 16 years, cause by a long FPR maintenance around 1,700 psia nearly the bubble point pressure (see figure 4.24), beyond this point, it drop rapidly to 233 BOPD and then recover gradually to 265 BOPD at the end of production period. The high rate of WCT encounters at 16th year has a significant play to FOPR sharply change.

4.3.7 Model A10_4 inj Scenario Result

Model A10_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.25 – 4.28):

- 4 production wells at initial oil production rate 170 BOPD/well (gross 680 BOPD)
- after 4 years of production period, start water injection by converted 2 production well to injection well with 550 BWPD/well injection rate (gross 1,000 BWPD)
- 2 remaining production well produced at rate 340 BOPD/well to maintain initial gross production rate

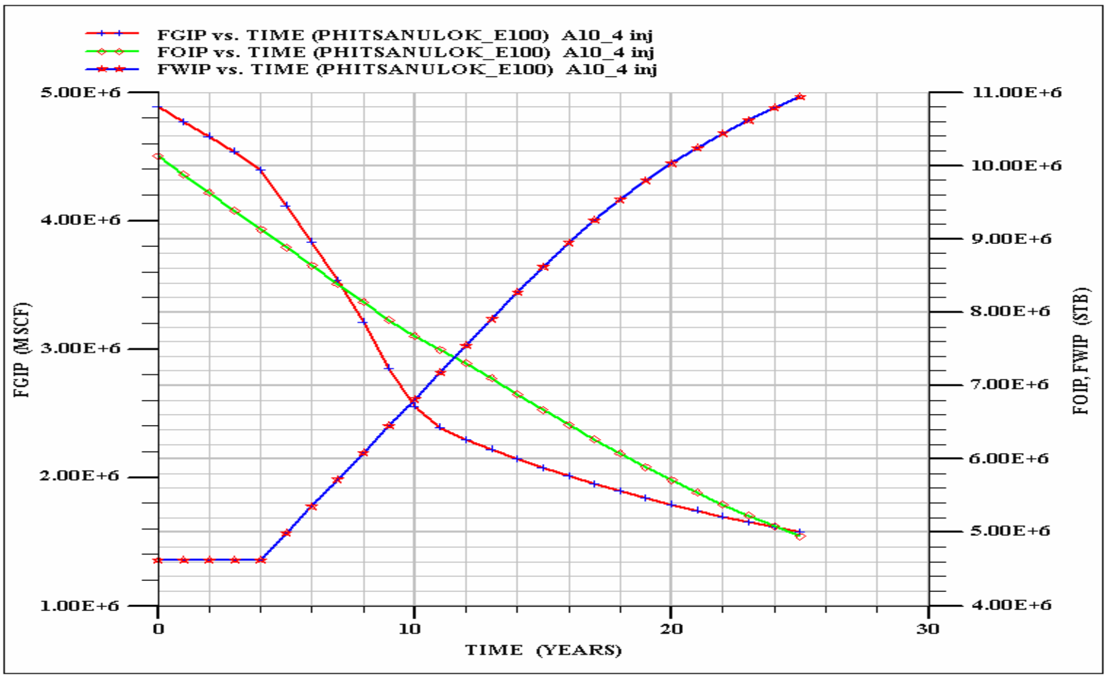

Figure 4.25 Fluid in place profile vs. Time of model A10_4 inj.

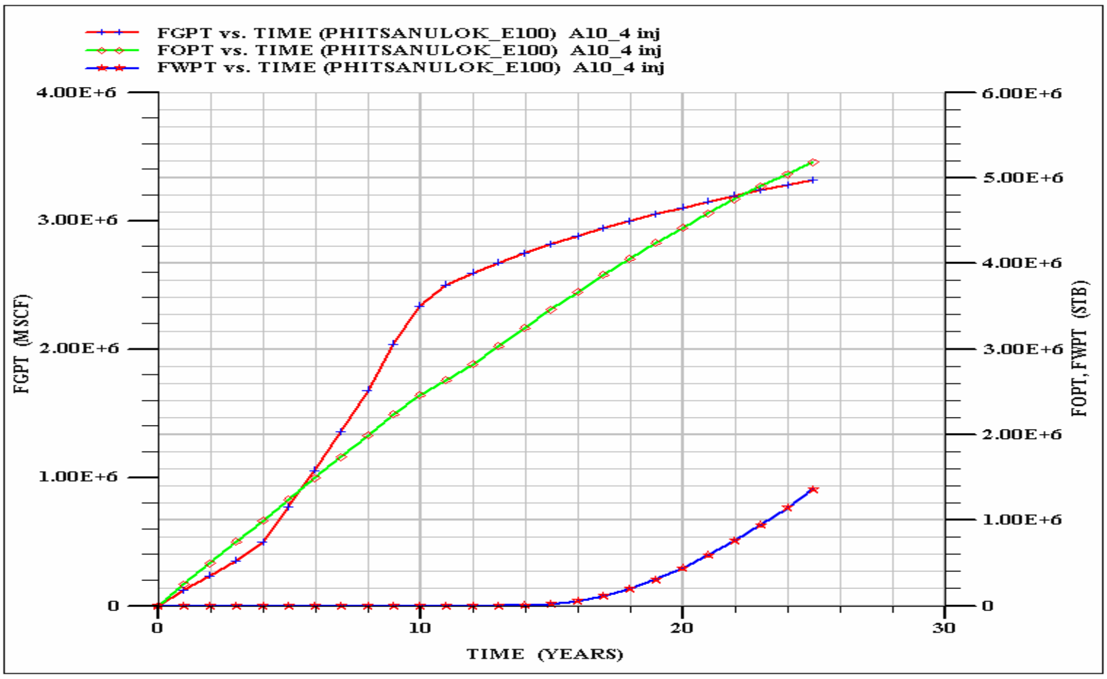

Figure 4.26 Cumulative fluids production profile vs. Time of model A10_4 inj.

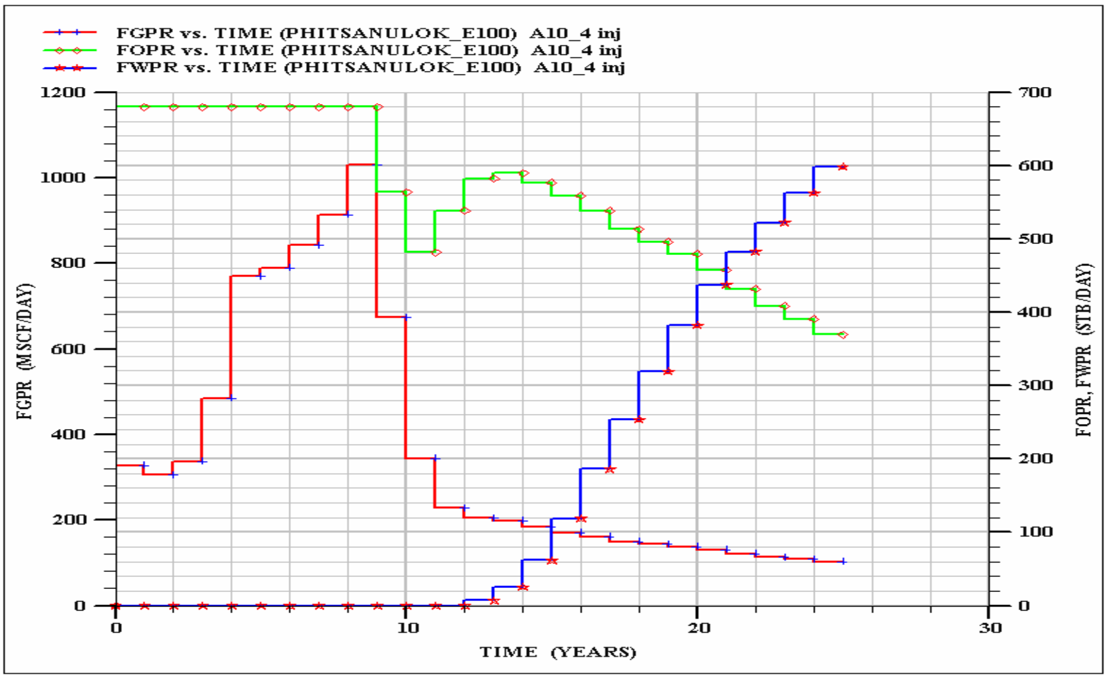

Figure 4.27 Fluids production rate profile vs. Time of model A10_4 inj.

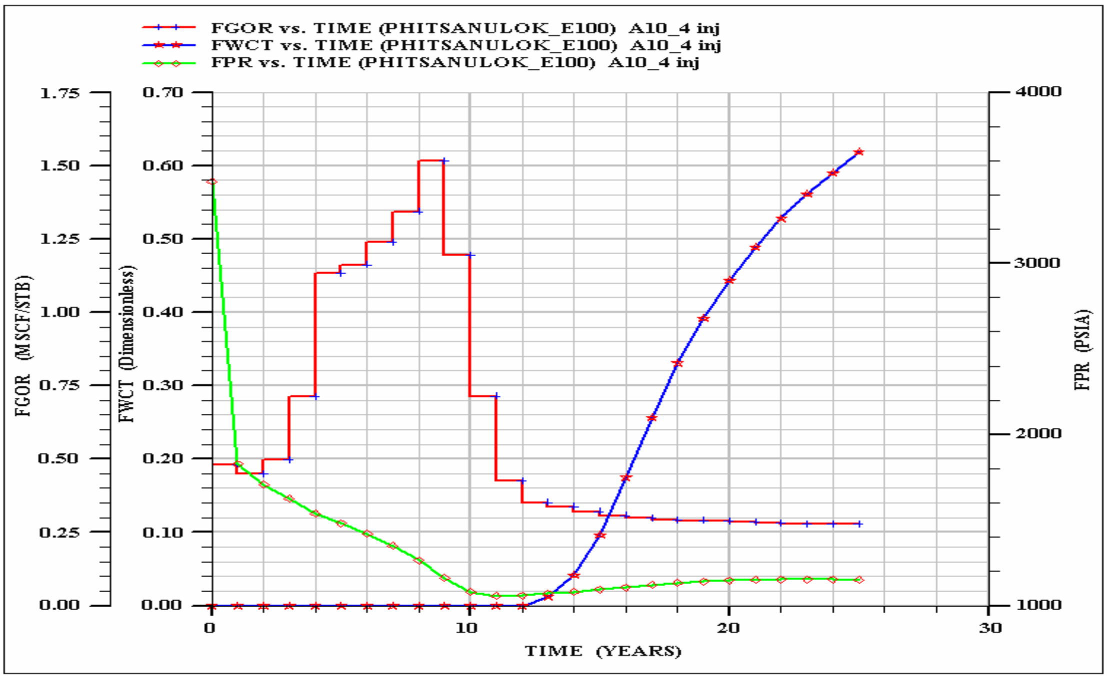

Figure 4.28 GOR, WCT, and Pressure profile vs. Time of model A10_4 inj.

Table 4.9 Summary detail of graph 4.25 and 4.26.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,182,266	10,126,692	51.17
Gas (MSCF)	3,313,526	4,886,061	67.82
Water (STB)	1,359,471	4,625,127	29.39

Figure 4.27, show FOPR remain constant rate at 680 BOPD over the first 9 years, after that drop suddenly to 481 BOPD at the 11th year, and then recover to 589 BOPD at the 14th year, beyond this point, it decrease slightly to 369 BOPD at the end. This production trend effected by FPR (see figure 4.28) drop moderately till the 11th year, after that it improve slightly through the end of production period (starting effected by WCT at 13th year.).

4.3.8 Model A10_8 inj Scenario Result

Model A10_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.29 – 4.32):

- 4 production wells at initial oil production rate 110 BOPD/well (gross 440 BOPD)
- after 8 years of production period, start water injection by converted 4 production well to injection well with 500 BWPD/well injection rate (gross 1,000 BWPD)
- 2 remaining production well produced at rate 220 BOPD/well to maintain initial gross production rate

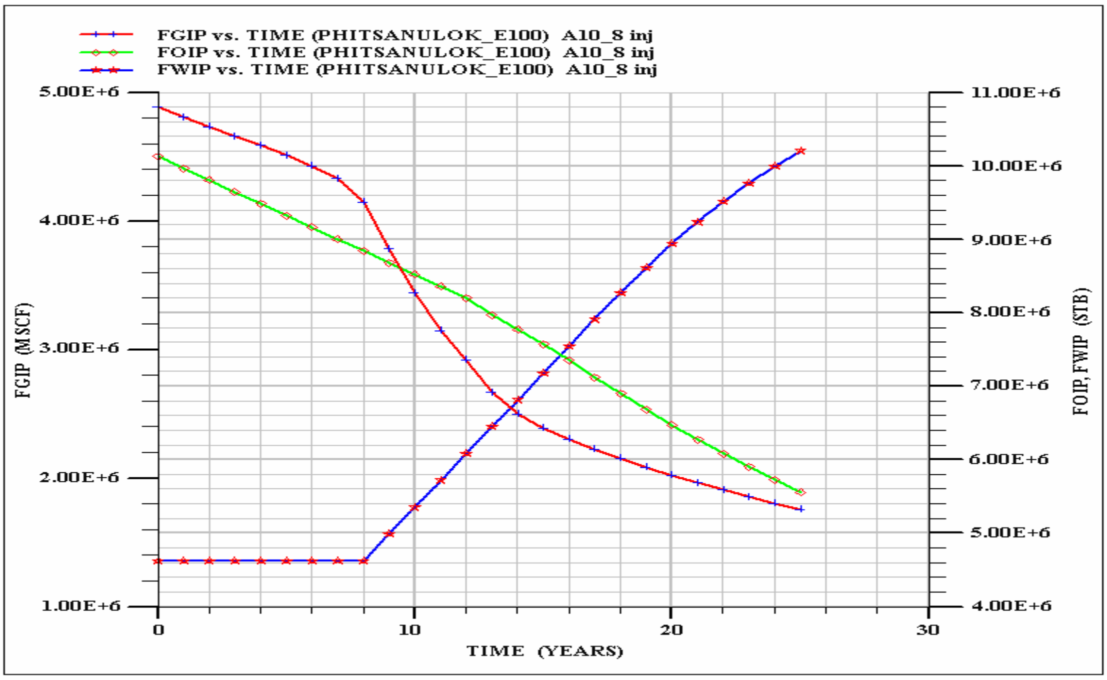

Figure 4.29 Fluid in place profile vs. Time of model A10_8 inj.

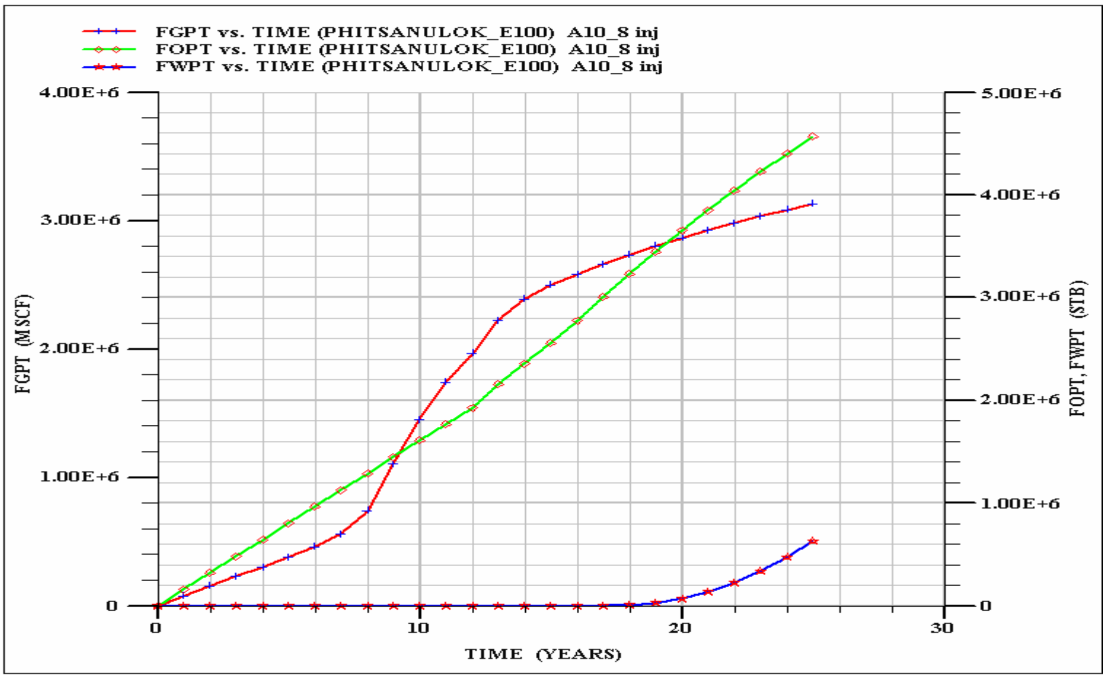

Figure 4.30 Cumulative fluids production profile vs. Time of model A10_8 inj.

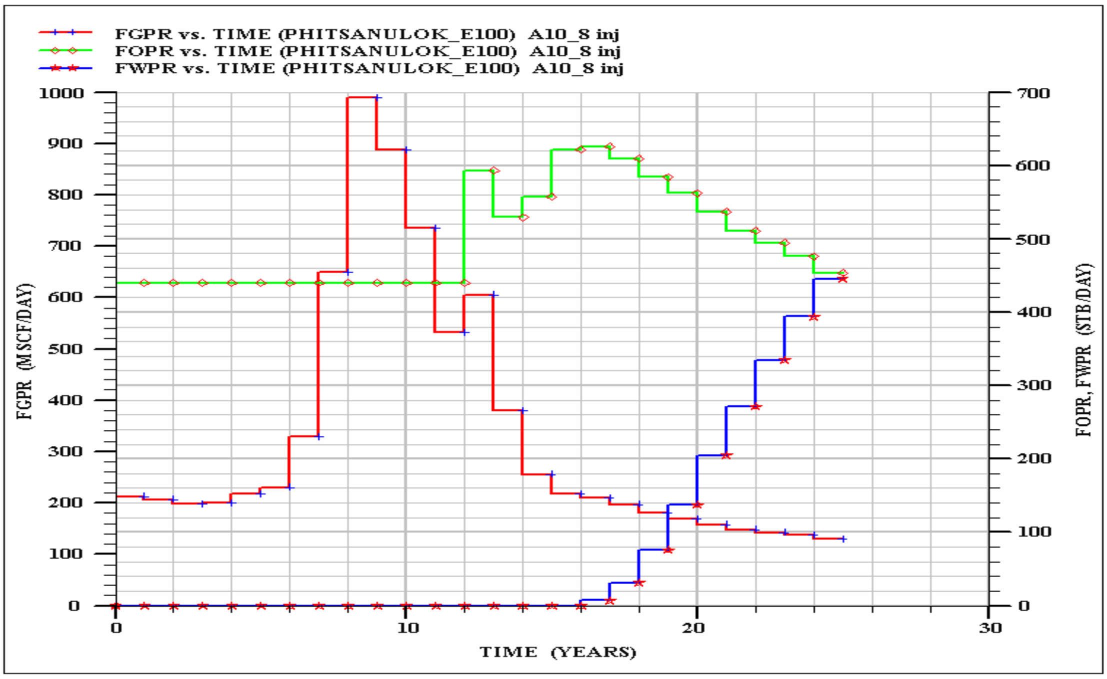

Figure 4.31 Fluids production rate profile vs. Time of model A10_8 inj.

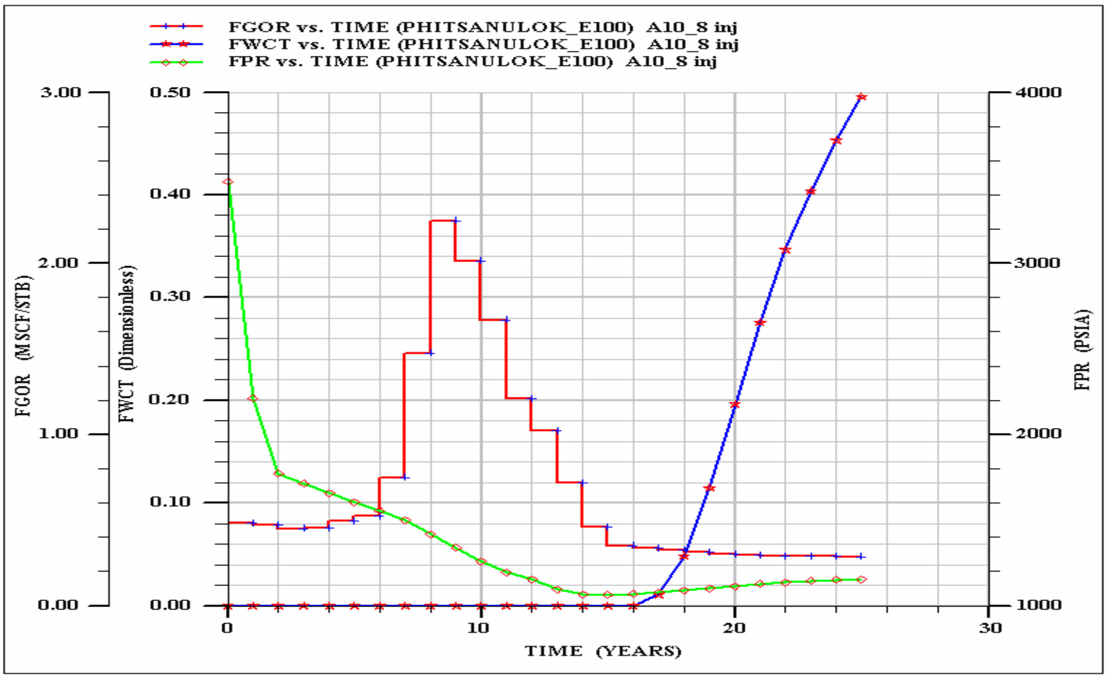

Figure 4.32 GOR, WCT, and Pressure profile vs. Time of model A10_8 inj.

Table 4.10 Summary detail of graph 4.29 and 4.30.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	4,570,141	10,126,692	45.13
Gas (MSCF)	3,130,704	4,886,061	64.07
Water (STB)	630,155	4,625,127	13.62

Figure 4.31, show FOPR remain constant rate at 440 BOPD over the first 13 years, until the water injection reach and FPR improve (see figure 4.32), it jumped suddenly to 593 BOPD at the 14th year, then fluctuated and reach a peak of 625 BOPD at 18th year, and decrease gradually to 435 BOPD at the end (WCT breakthrough at 17th year, because late of water injection).

4.3.9 Model A05_no inj Scenario Result

Model A05 natural flow produced with no water injection through the production period (15 years). Production schedule start by 2 production wells at initial oil production rate 150 BOPD/well (Gross 300 BOPD), the simulation results show in figure 4.33 – 4.36:

Table 4.11 Summary detail of graph 4.33 and 4.34.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	1,183,511	5,011,563	23.62
Gas (MSCF)	2,371,869	2,418,046	98.09
Water (STB)	-	2,232,949	-

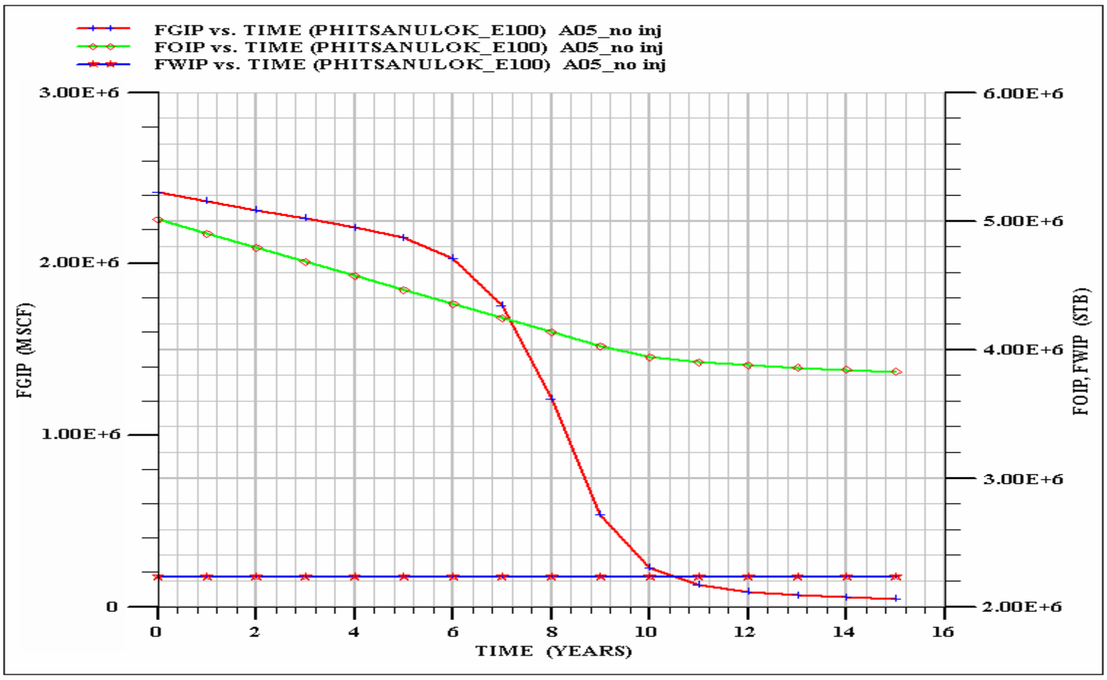

Figure 4.33 Fluid in place profile vs. Time of model A05_no inj.

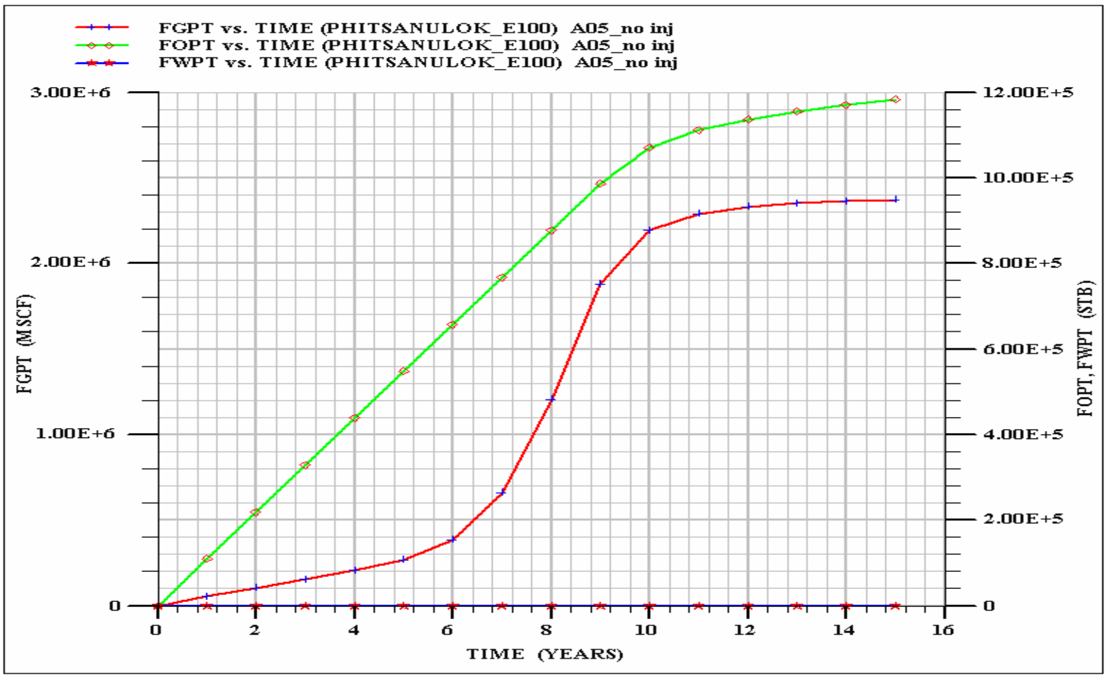

Figure 4.34 Cumulative fluids production profile vs. Time of model A05_no inj.

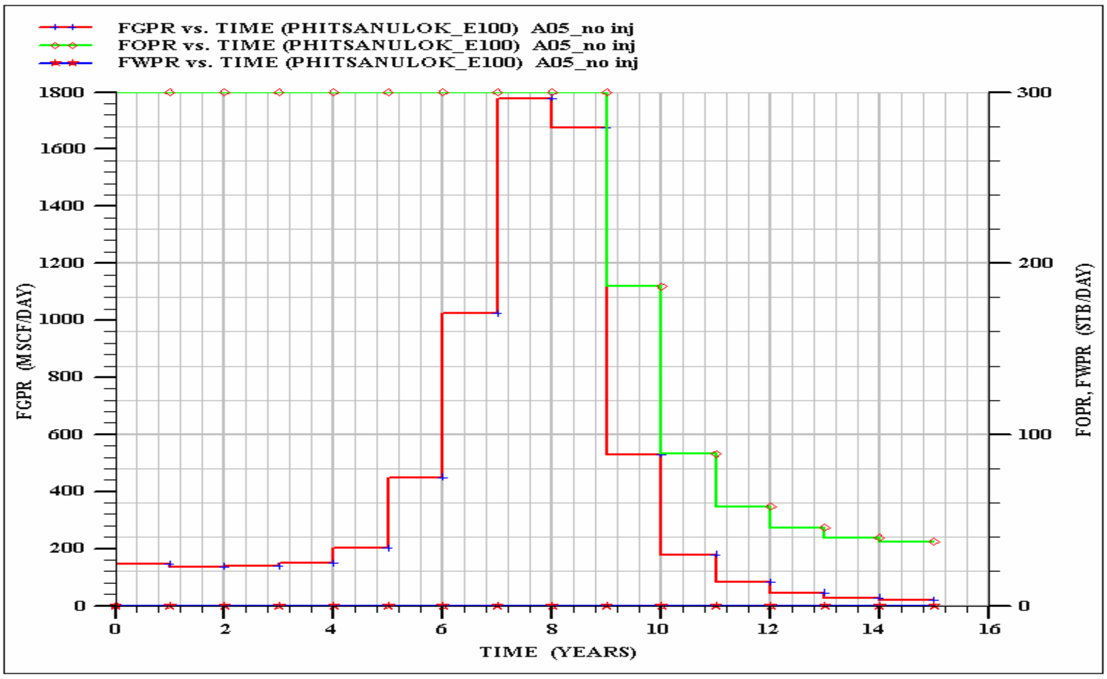

Figure 4.35 Fluids production rate profile vs. Time of model A05_no inj.

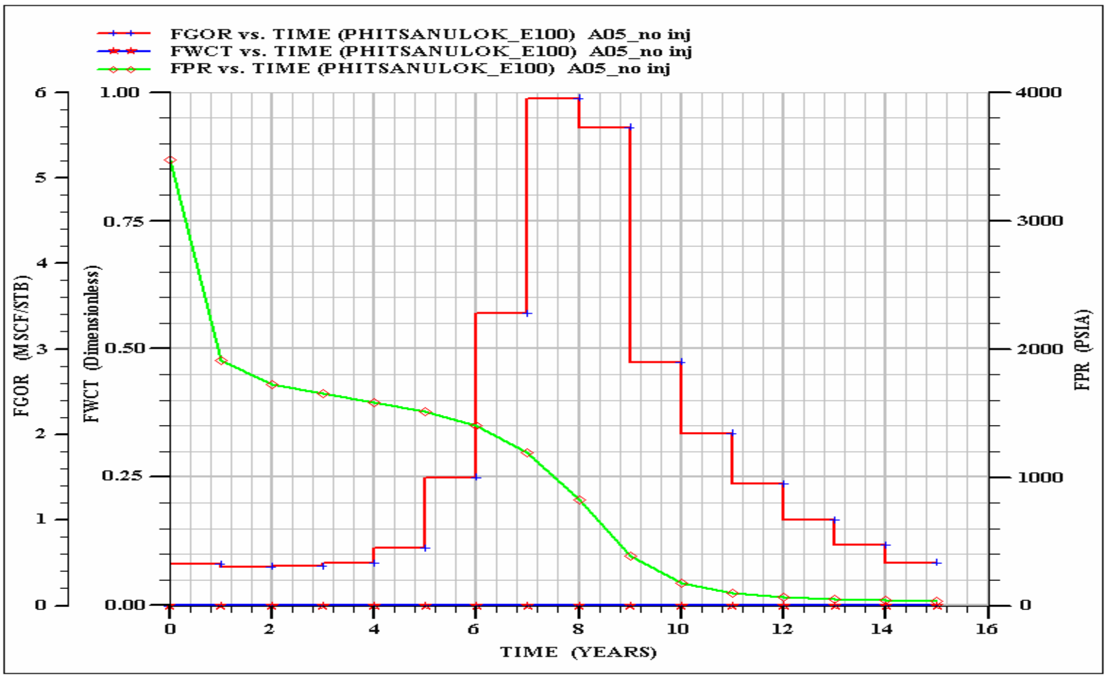

Figure 4.36 GOR, WCT, and Pressure profile vs. Time of model A05_no inj.

Figure 4.35, show gross oil production (FOPR) keep a steady rate at 150 BOPD from starting production to the 9th year, after that drop gradually to 37 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.36). Gross gas production rate (FGPR) fluctuate slightly around 150 MSCFD until the 4th year, it increase suddenly to 1,779 MSCFD at the 8th year, and then drop rapidly to 18 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.10 Model A05_2 inj Scenario Result

Model A05_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.37 – 4.40):

- 3 production wells at initial oil production rate 120 BOPD/well (gross 360 BOPD)
- after 2 years of production period, start water injection by converted 2 production well to injection well with 250 BWPD/well injection rate (gross 500 BWPD)
- 1 remaining production well produced at rate 360 BOPD/well to maintain initial gross production rate

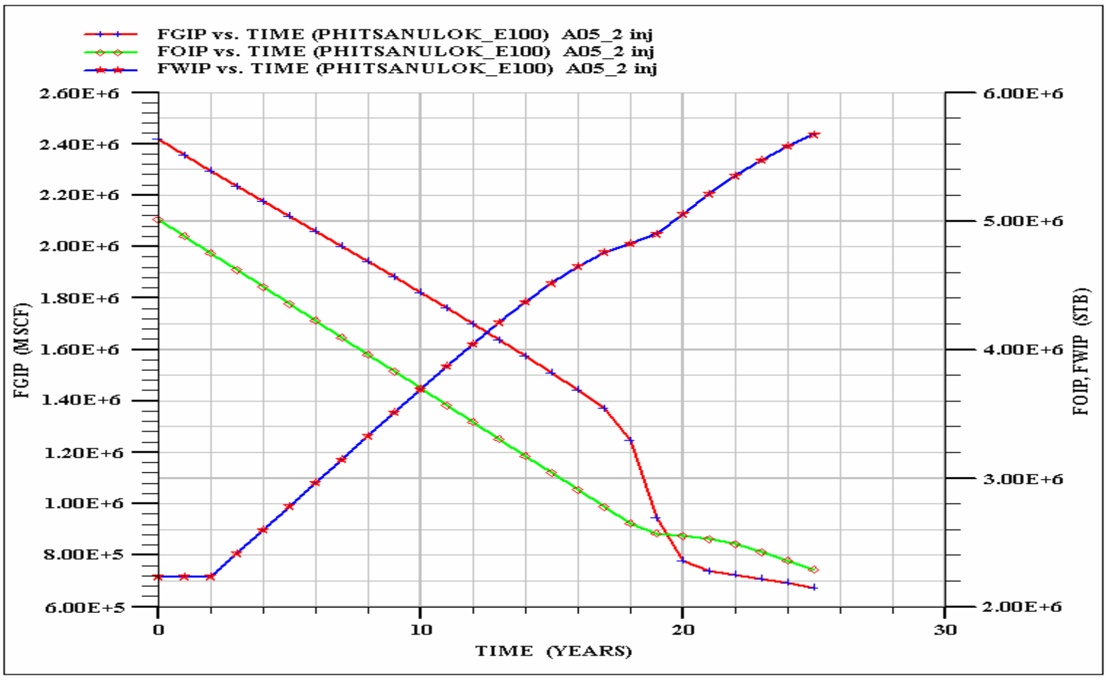

Figure 4.37 Fluid in place profile vs. Time of model A05_2 inj.

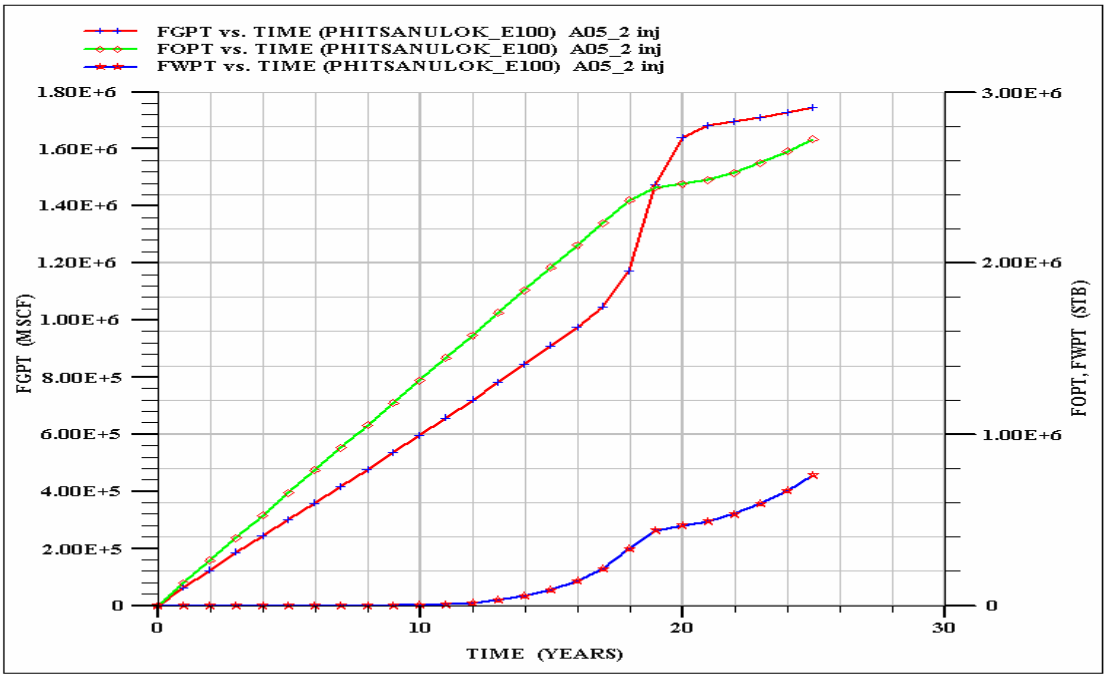

Figure 4.38 Cumulative fluids production vs. Time of model A05_2 inj.

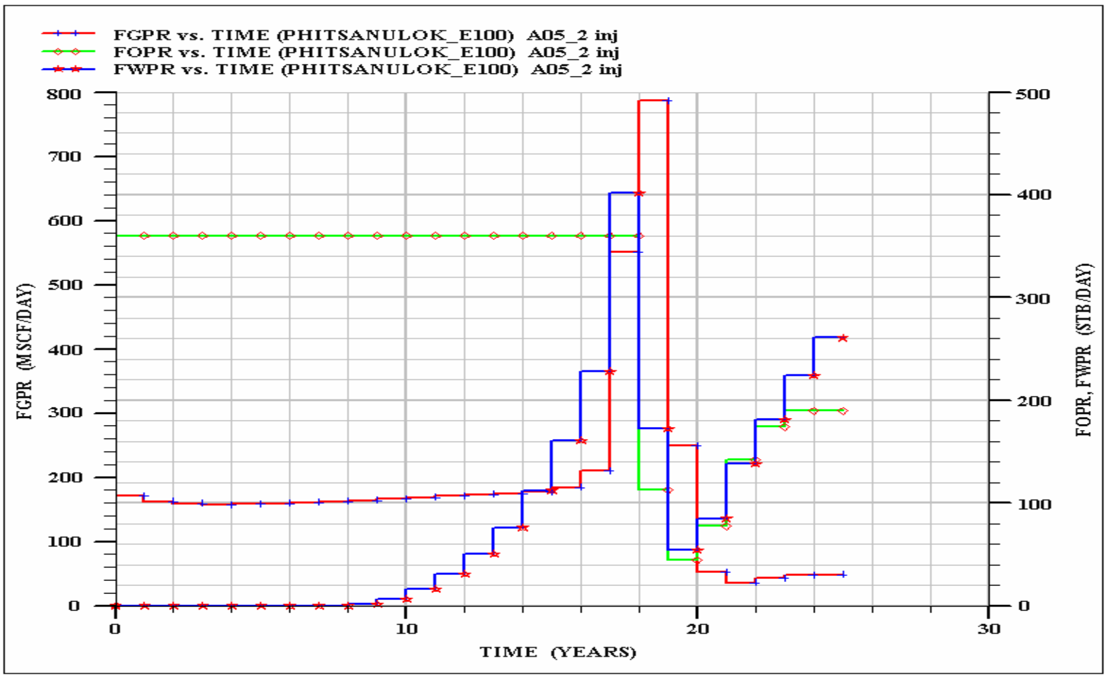

Figure 4.39 Fluids production rate profile vs. Time of model A05_2 inj.

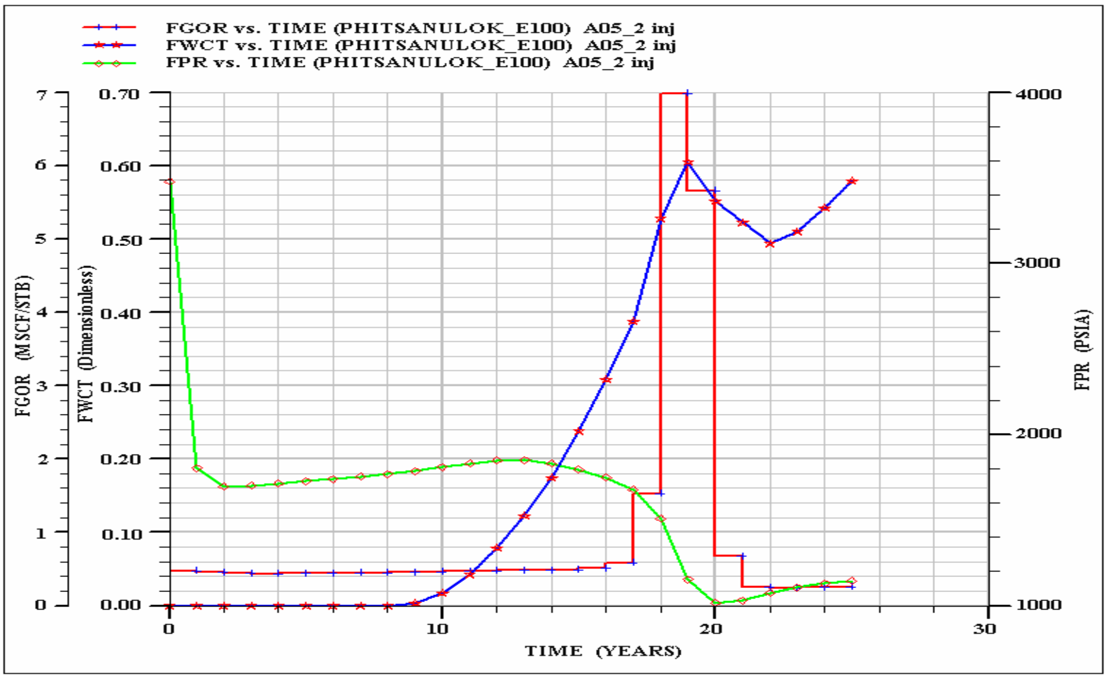

Figure 4.40 GOR, WCT, and Pressure profile vs. Time of model A05_2 inj.

Table 4.12 Summary detail of graph 4.37 and 4.38.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,723,317	5,011,563	54.34
Gas (MSCF)	1,743,869	2,418,046	72.12
Water (STB)	760,869	2,232,949	34.07

Figure 4.39, show FOPR remain constant rate at 360 BOPD over the first 18 years, cause by a long FPR maintenance around 1,700-1,800 (P_b) psia (see figure 4.40), beyond this point, it bottom out to 43 BOPD and then recover moderately to 265 BOPD at the end of production period. The high rate of WCT encounters at 19th year has a significant play to FOPR sharply change.

4.3.11 Model A05_4 inj Scenario Result

Model A05_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.41 – 4.44):

- 3 production wells at initial oil production rate 80 BOPD/well (gross 240 BOPD)
- after 4 years of production period, start water injection by converted 2 production well to injection well with 250 BWPD/well injection rate (gross 500 BWPD)
- 1 remaining production well produced at rate 240 BOPD/well to maintain initial gross production rate

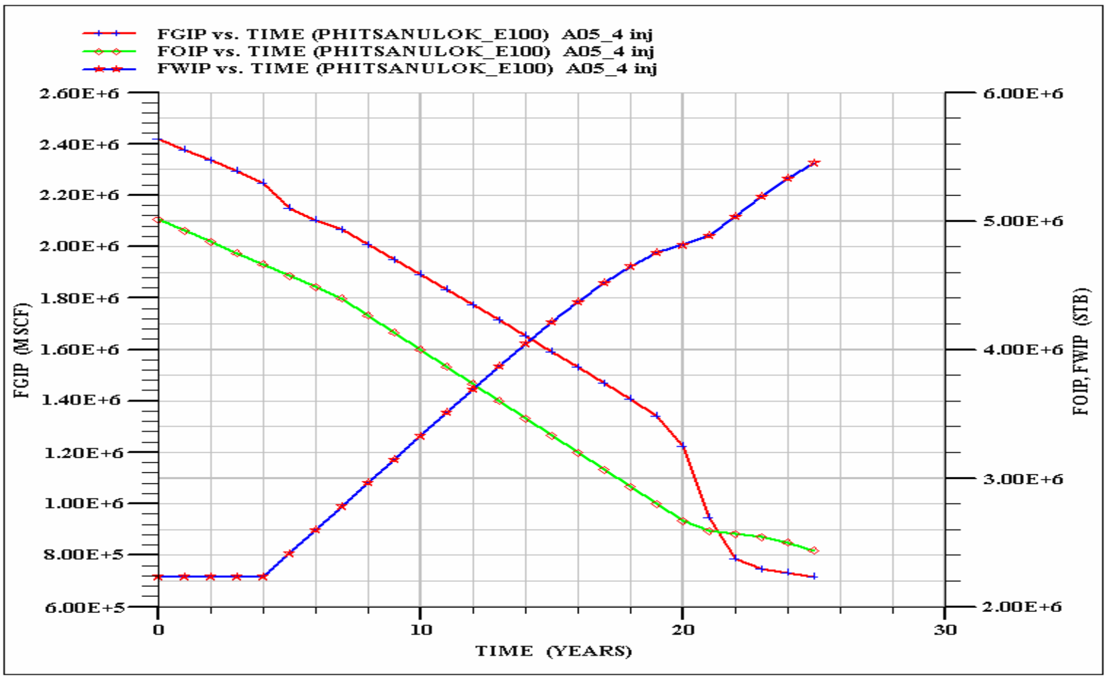

Figure 4.41 Fluid in place profile vs. Time of model A05_4 inj.

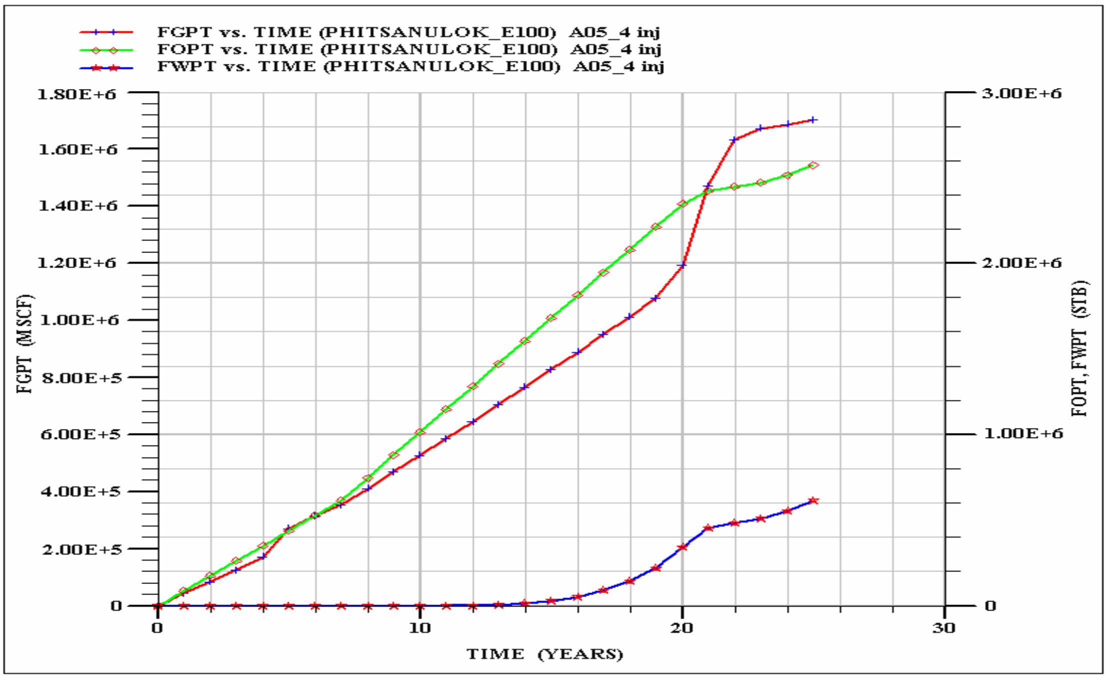

Figure 4.42 Cumulative fluids production profile vs. Time of model A05_4 inj.

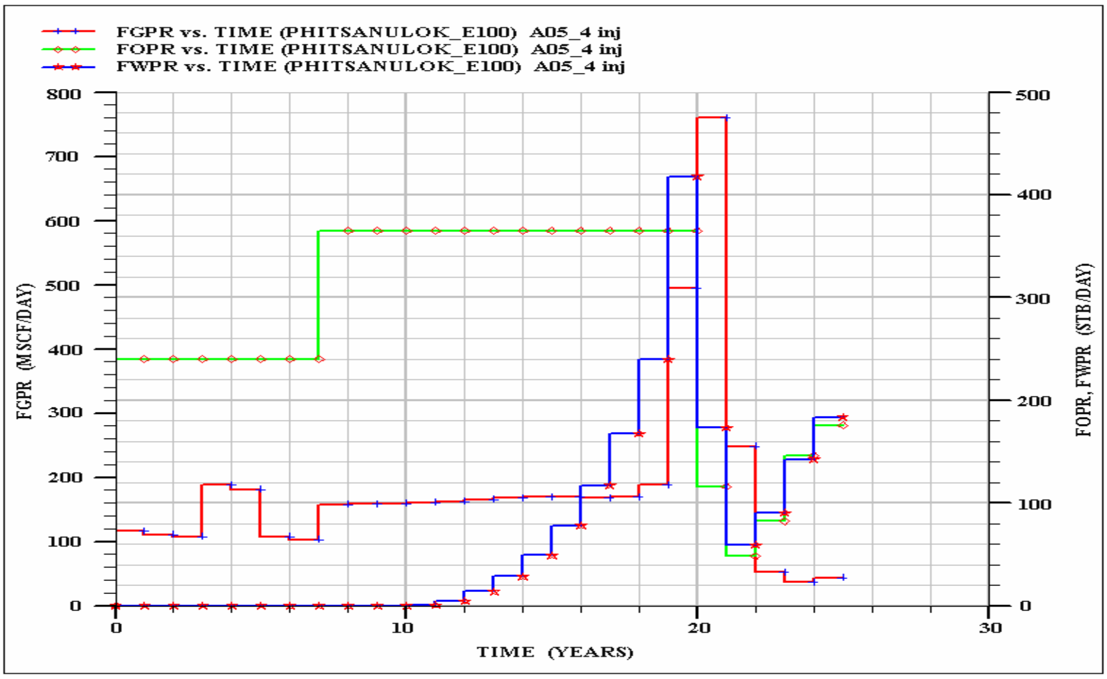

Figure 4.43 Fluids production rate profile vs. Time of model A05_4 inj.

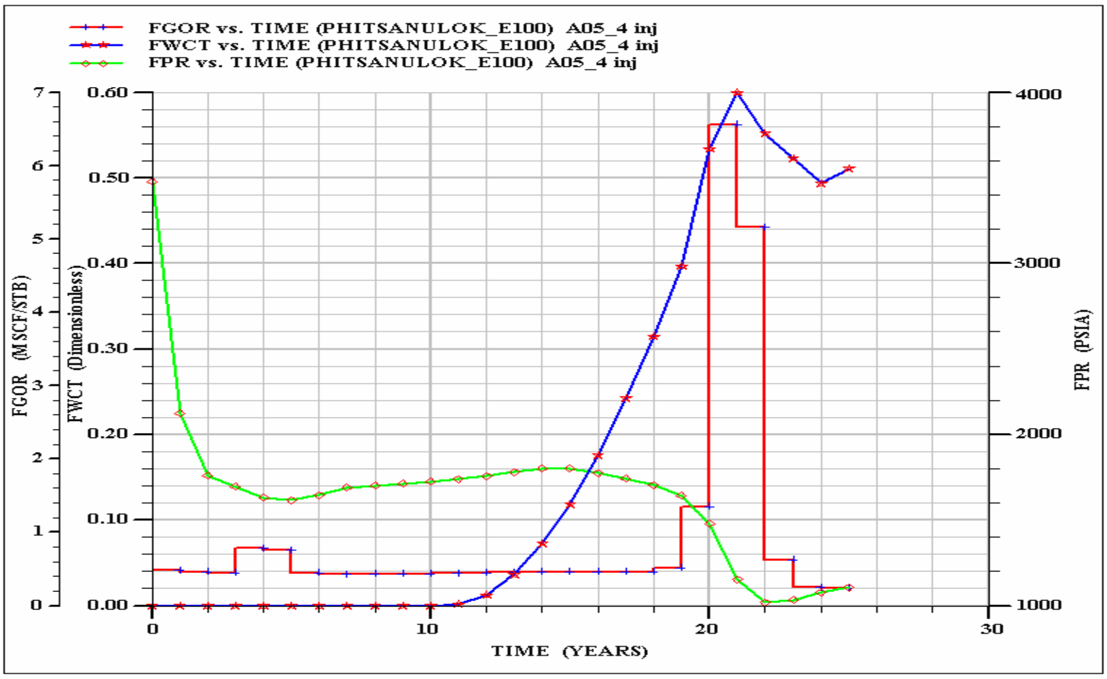

Figure 4.44 GOR, WCT, and Pressure profile vs. Time of model A05_4 inj.

Table 4.13 Summary detail of graph 4.41 and 4.42.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,574,744	5,011,563	51.38
Gas (MSCF)	1,701,966	2,418,046	70.39
Water (STB)	615,139	2,232,949	27.55

Figure 4.43, show FOPR remain constant rate at 240 BOPD over the first 7 years, after that jump suddenly to 365 BOPD at the 8th year and stay the same rate through the 20th year, next it drop rapidly to 48 BOPD and recover to 175 BOPD at the end. This production trend effected by FPR (see figure 4.44) improved and maintained around 1,600-1,800 (P_b) psia till the 20th year, after that it drop rapidly through the end of production period (starting effected by WCT at 11th year.).

4.3.12 Model A05_8 inj Scenario Result

Model A05_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.45 – 4.48):

- 3 production wells at initial oil production rate 45 BOPD/well (gross 135 BOPD)
- after 8 years of production period, start water injection by converted 2 production well to injection well with 250 BWPD/well injection rate (gross 500 BWPD)
- 1 remaining production well produced at rate 135 BOPD/well to maintain initial gross production rate

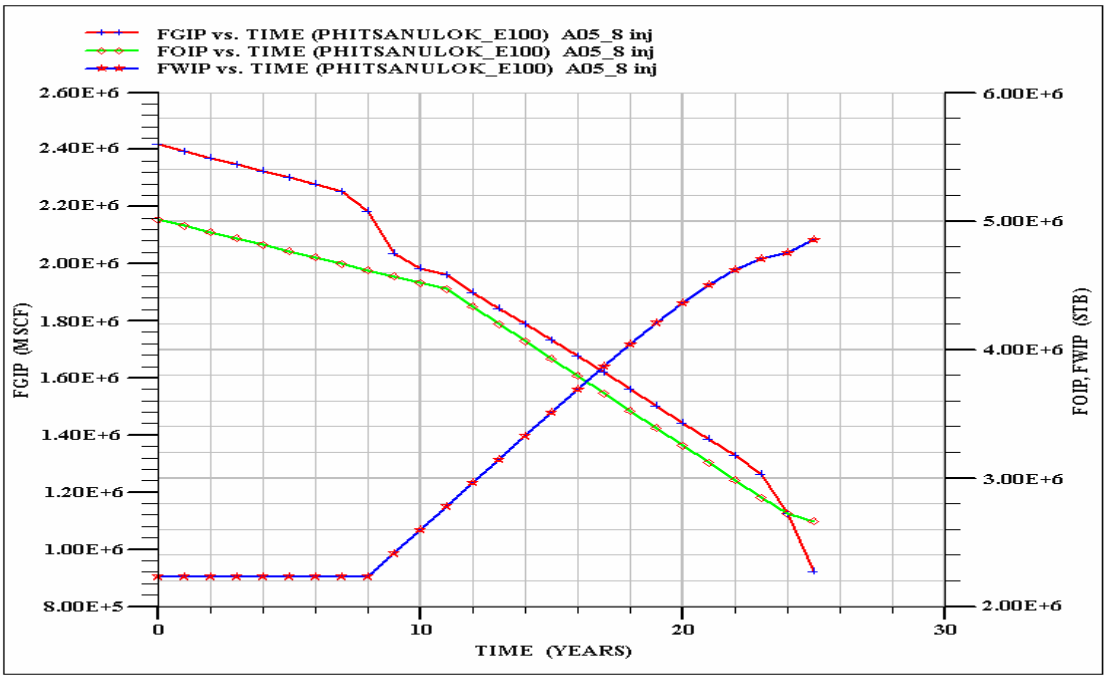

Figure 4.45 Fluid in place profile vs. Time of model A05_8 inj.

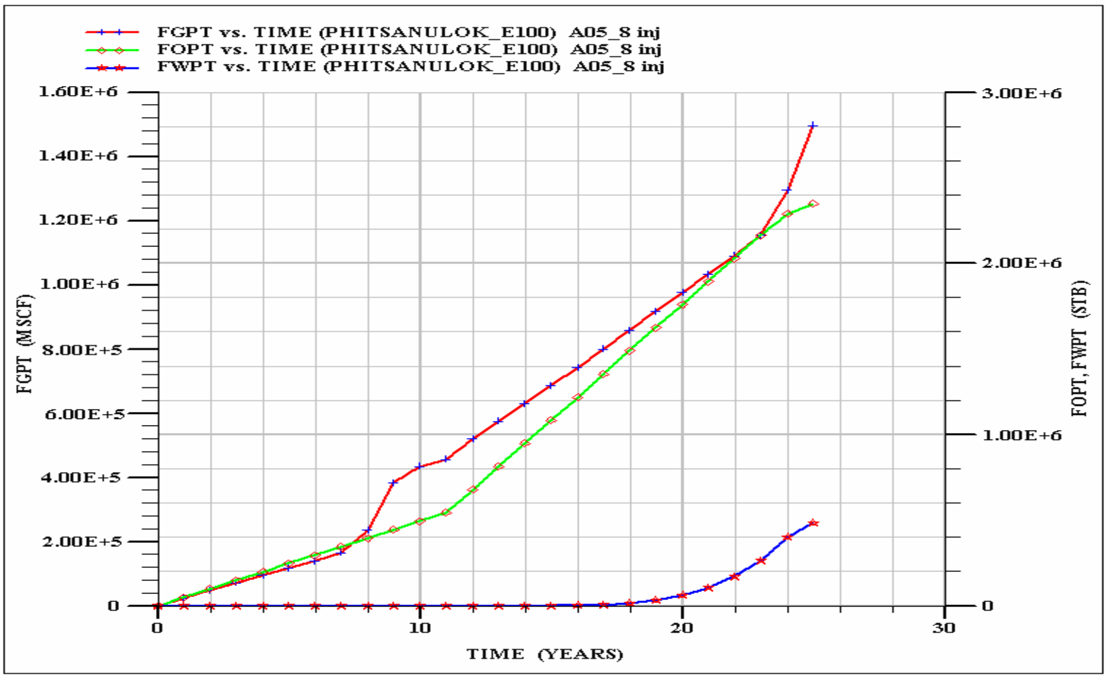

Figure 4.46 Cumulative fluids production profile vs. Time of model A05_8 inj.

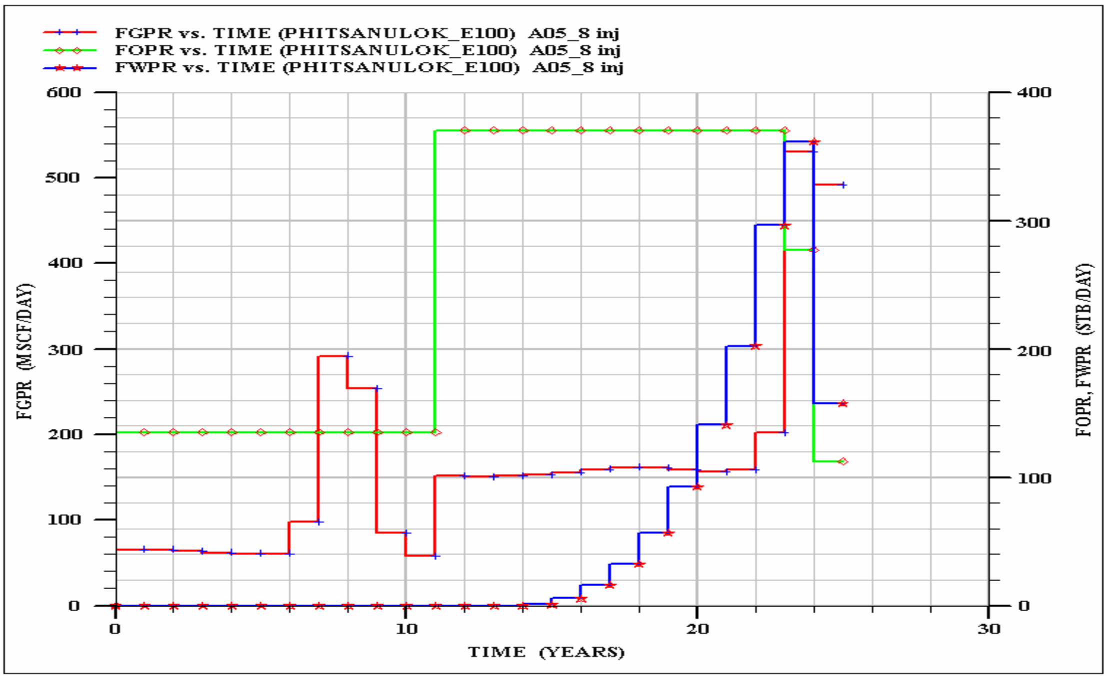

Figure 4.47 Fluids production rate profile vs. Time of model A05_8 inj.

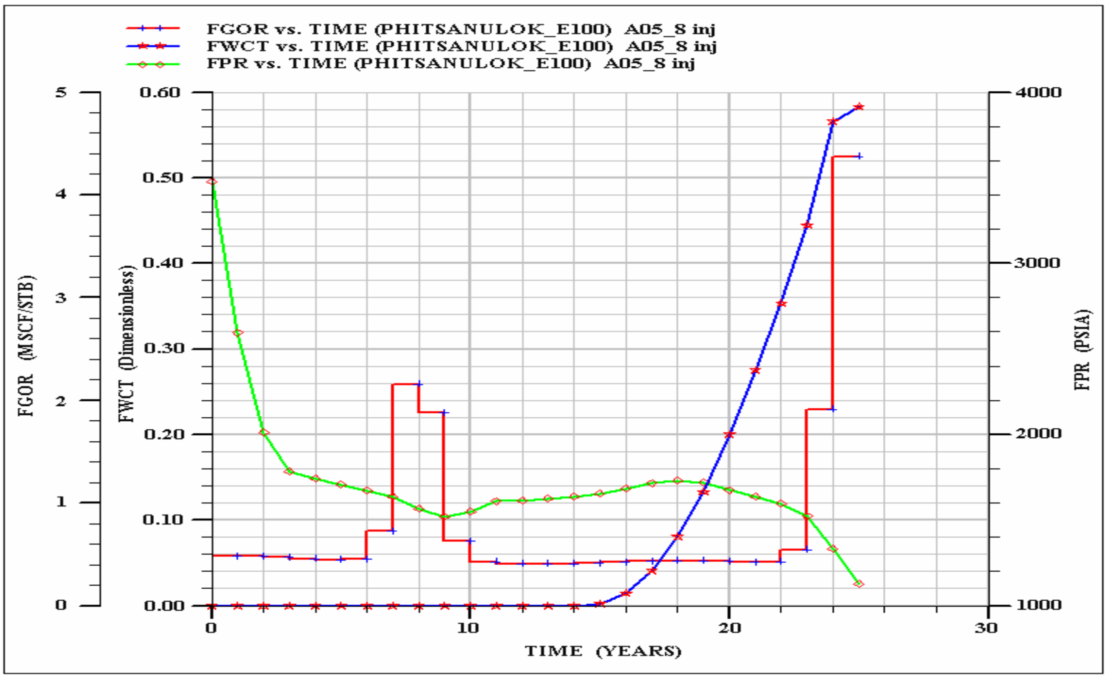

Figure 4.48 GOR, WCT, and Pressure profile vs. Time of model A05_8 inj.

Table 4.14 Summary detail of graph 4.45 and 4.46.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,348,090	5,011,563	46.85
Gas (MSCF)	1,496,092	2,418,046	61.87
Water (STB)	481,591	2,232,949	21.57

Figure 4.47, show FOPR remain constant rate at 135 BOPD over the first 11 years, after that jump suddenly to 370 BOPD at the 12th year and stay the same rate through the 23rd year, next it drop rapidly to 112 BOPD at the end. This production trend effected by FPR (see figure 4.48) improved and maintained around 1,600-1,700 psia (P_b = 1,800 psia) till the 23rd year, after that it drop gradually through the end of production period (starting effected by WCT at 15th year).

4.3.13 Model M20_no inj Scenario Result

Model M20 natural flow produced with no water injection through the production period (20 years). Production schedule start by 6 production wells at initial oil production rate 150 BOPD/well (Gross 900 BOPD), the simulation results show in figure 4.49 – 4.52:

Table 4.15 Summary detail of graph 4.49 and 4.50.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,486,531	20,088,216	27.31
Gas (MSCF)	9,561,241	9,692,430	98.65
Water (STB)	-	9,186,909	-

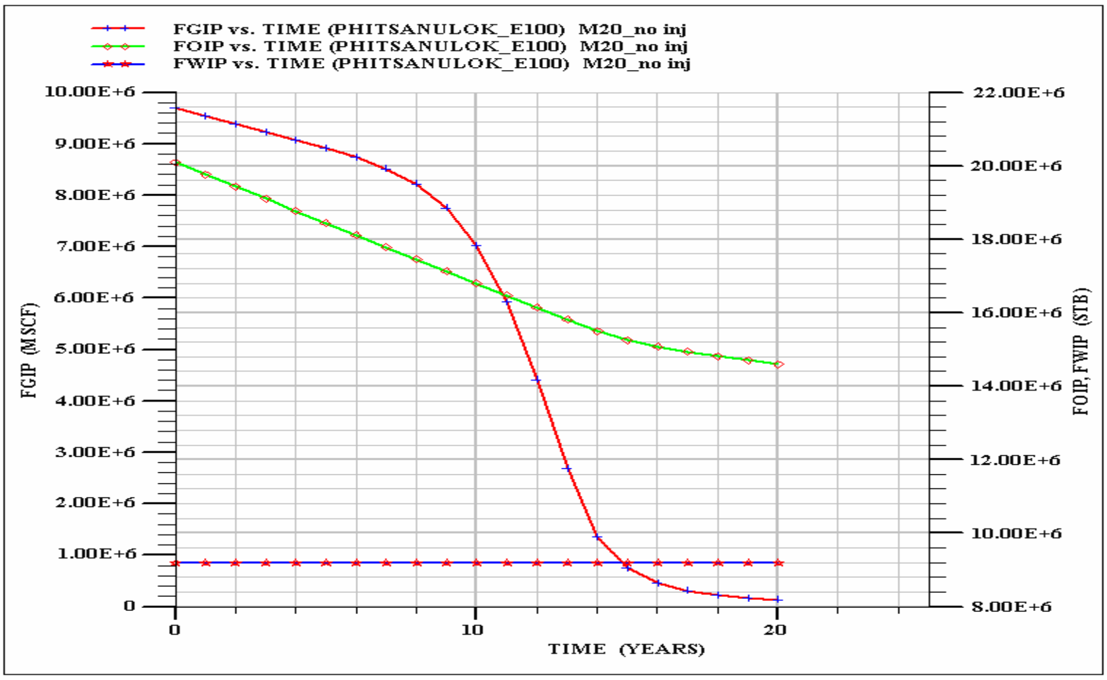

Figure 4.49 Fluid in place profile vs. Time of model M20_no inj.

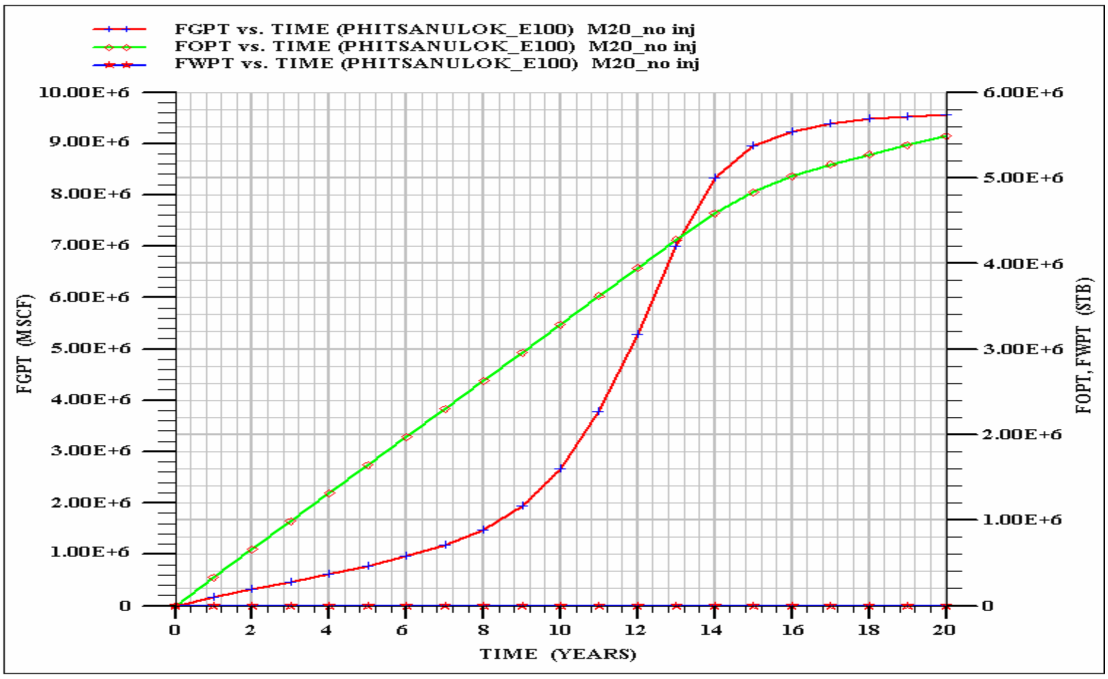

Figure 4.50 Cumulative fluids production profile vs. Time of model M20_no inj.

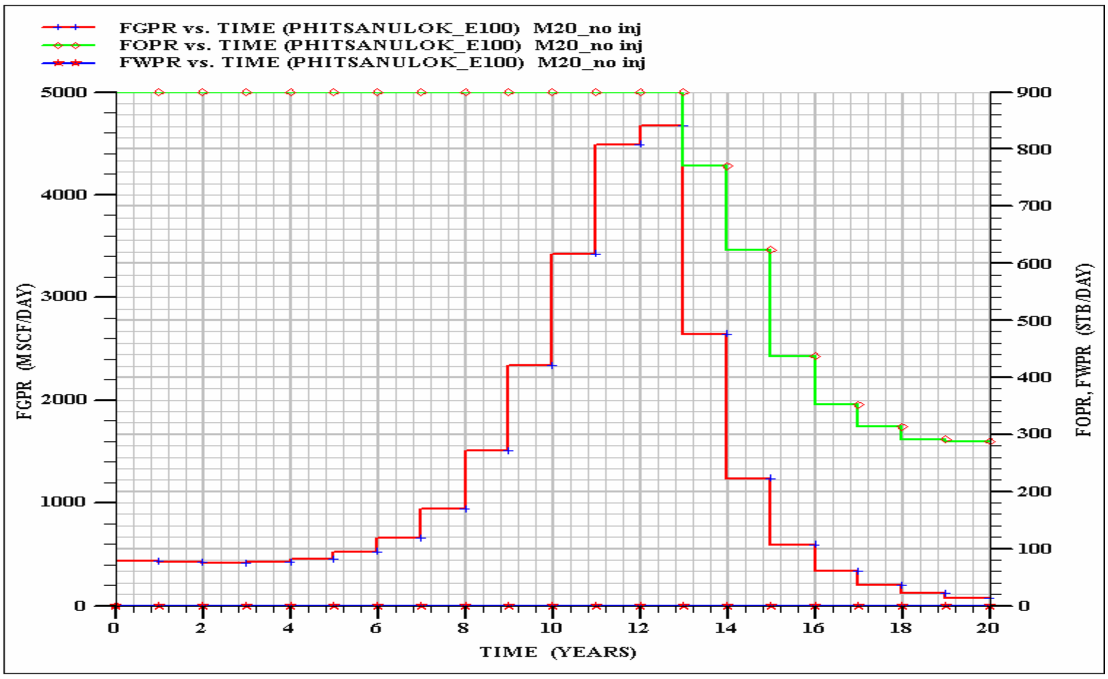

Figure 4.51 Fluids production rate profile vs. Time of model M20_no inj.

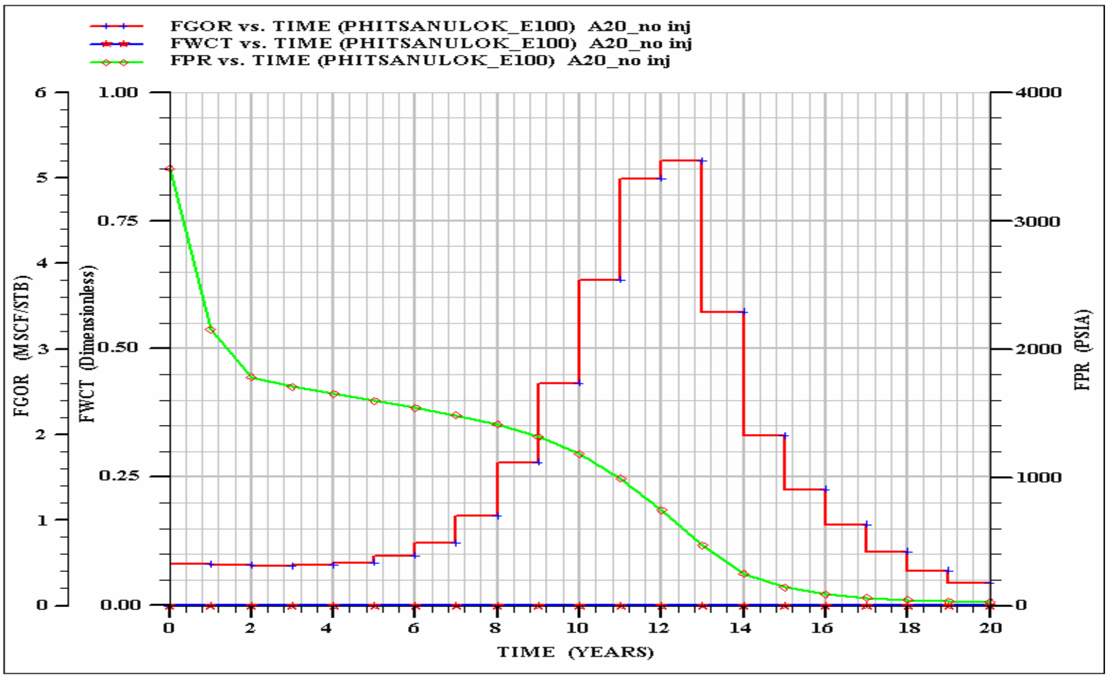

Figure 4.52 GOR, WCT, and Pressure profile vs. Time of model M20_no inj.

Figure 4.51, show gross oil production (FPOR) keep a steady rate at 900 BOPD from starting production to the 13th year, after that decreases gradually to 288 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.52). Gross gas production rate (FGPR) remain constant around 420 MSCFD until the 5th year, it increase suddenly to 4,676 MSCFD at the 13th year, and then drop rapidly to 77 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.14 Model M20_2 inj Scenario Result

Model M20_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.53 – 4.56):

- 6 production wells at initial oil production rate 280 BOPD/well (gross 1,680 BOPD)
- after 2 years of production period, start water injection by converted 3 production well to injection well with 600 BWPD/well injection rate (gross 1,800 BWPD)
- 3 remaining production well produced at rate 560 BOPD/well to maintain initial gross production rate

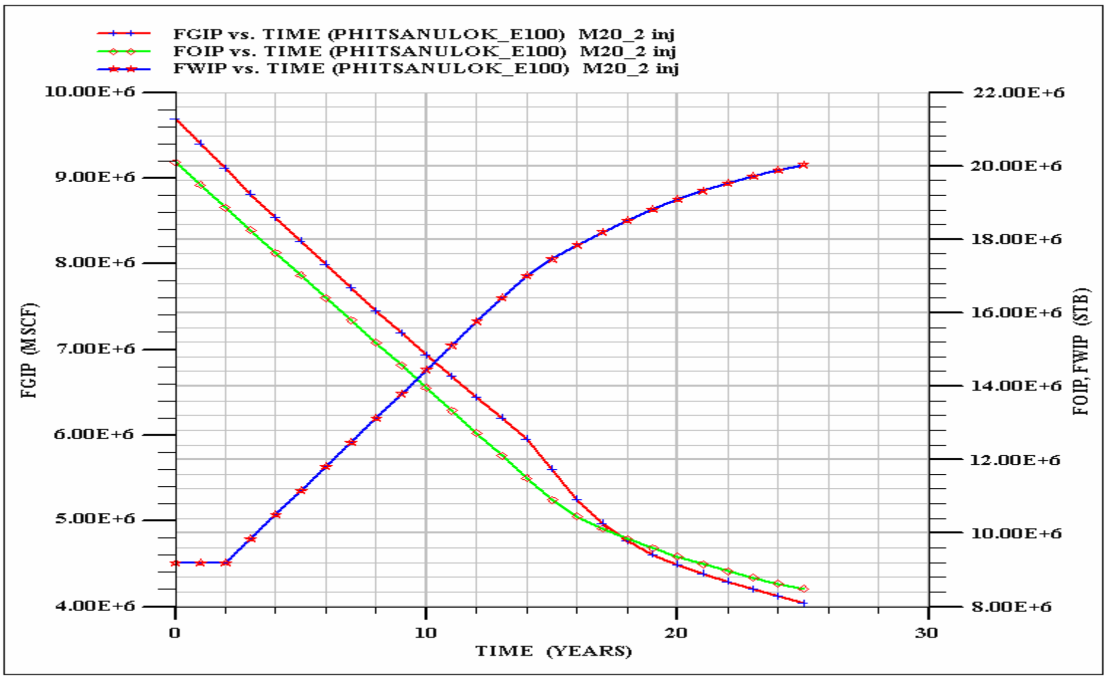

Figure 4.53 Fluid in place profile vs. Time of model M20_2 inj.

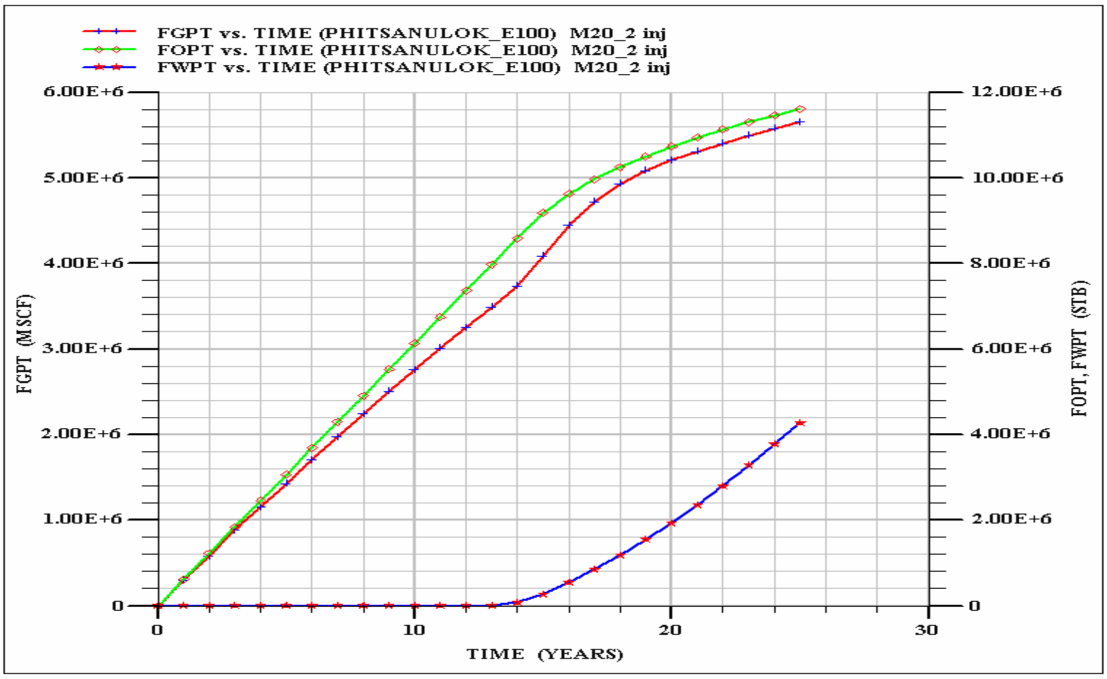

Figure 4.54 Cumulative fluids production profile vs. Time of model M20_2 inj.

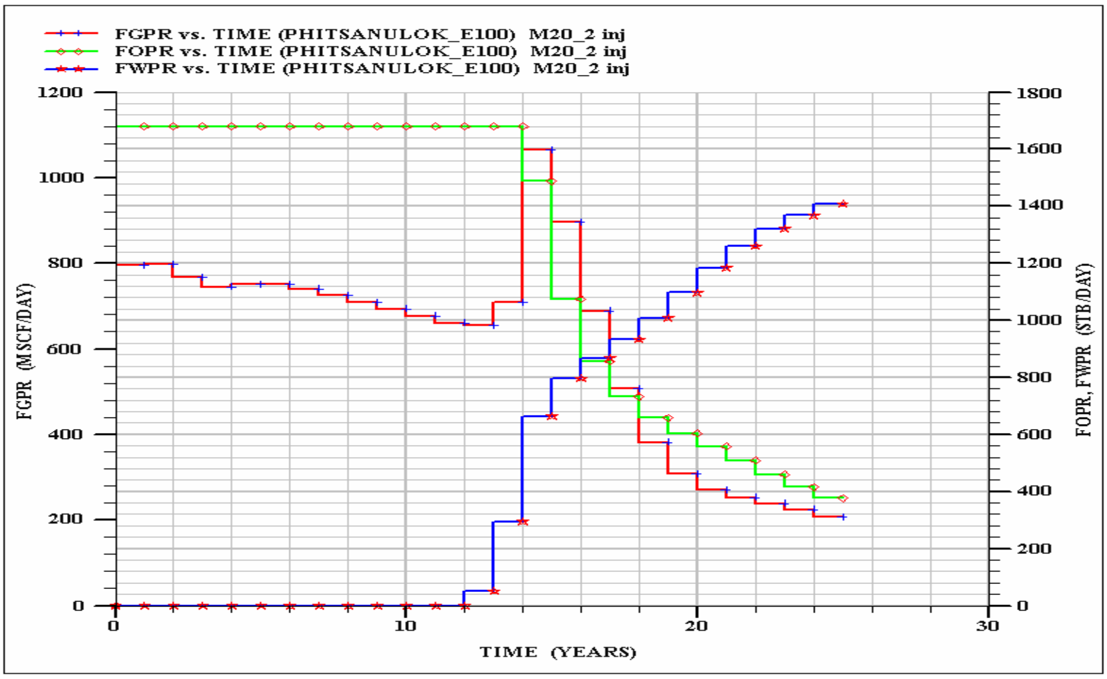

Figure 4.55 Fluids production rate profile vs. Time of model M20_2 inj.

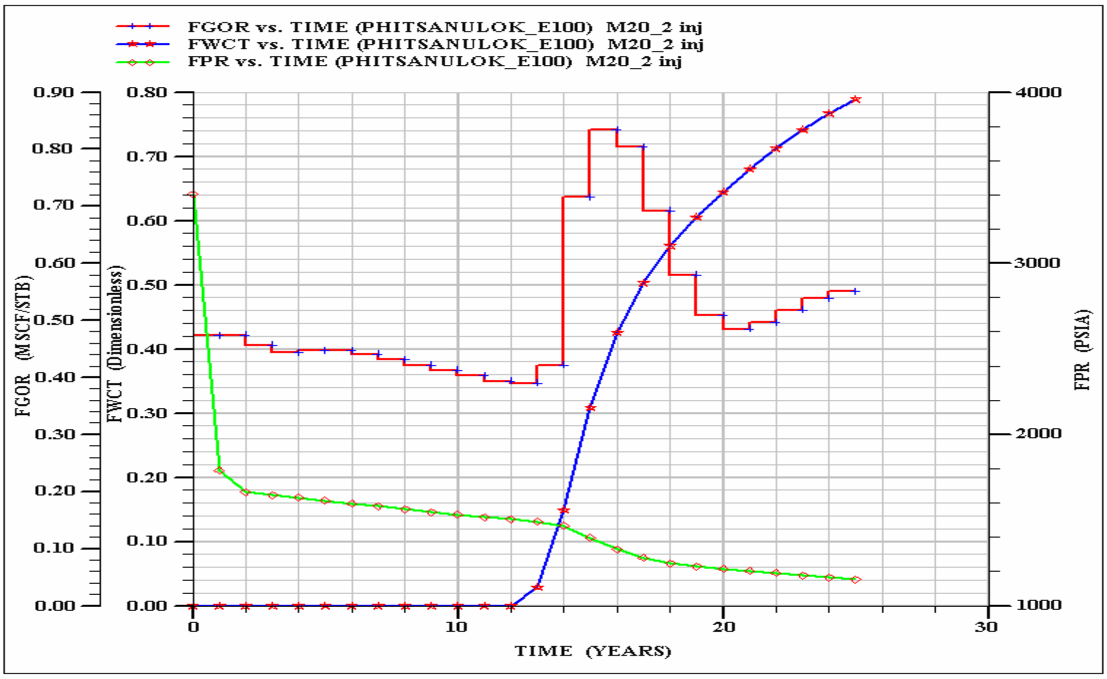

Figure 4.56 GOR, WCT, and Pressure profile vs. Time of model M20_2 inj.

Table 4.16 Summary detail of graph 4.53 and 4.54.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	11,602,345	20,088,216	57.76
Gas (MSCF)	5,652,545	9,692,430	58.32
Water (STB)	4,282,326	9,186,909	46.61

Figure 4.55, show FOPR remain constant rate at 1,680 BOPD over the first 14 years, cause by a long FPR maintenance from water injection activity (see figure 4.56), beyond this point, it decreases dramatically to 376 BOPD at the end of production period due to WCT start breakthroughs at 13th year with a rapid high rate. Suddenly WCT reach, FPR drop moderately and changes slightly through the end.

4.3.15 Model M20_4 inj Scenario Result

Model M20_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.57 – 4.60):

- 6 production wells at initial oil production rate 240 BOPD/well (gross 1,440 BOPD)
- after 4 years of production period, start water injection by converted 3 production well to injection well with 600 BWPD/well injection rate (gross 1,800 BWPD)
- 3 remaining production well produced at rate 480 BOPD/well to maintain initial gross production rate

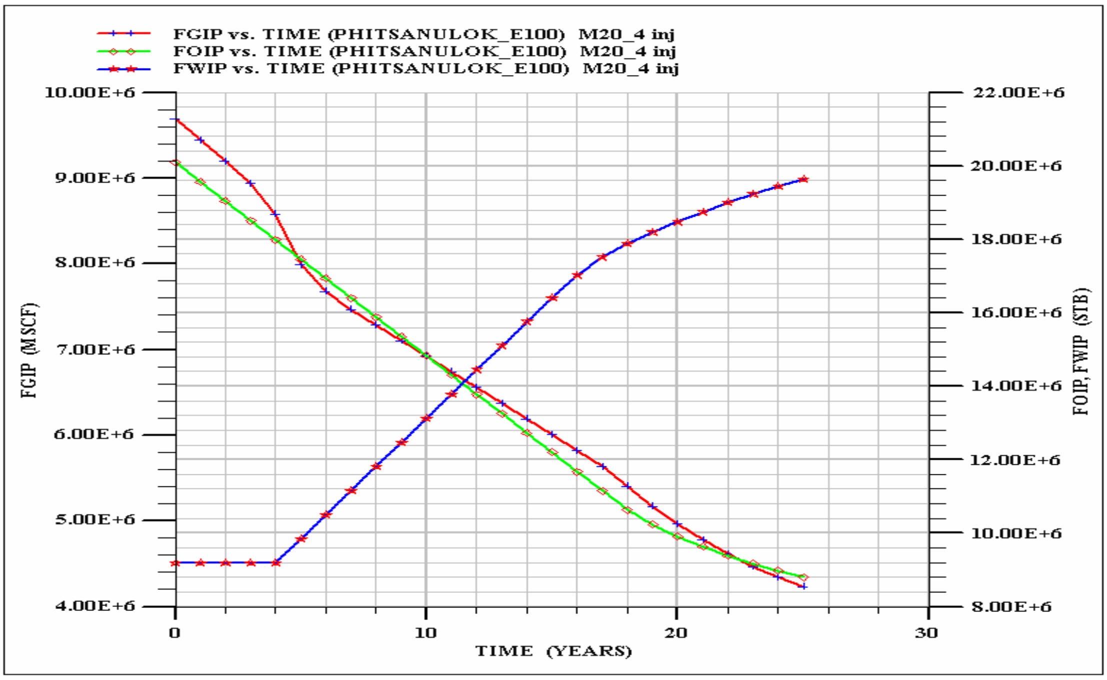

Figure 4.57 Fluid in place profile vs. Time of model M20_4 inj.

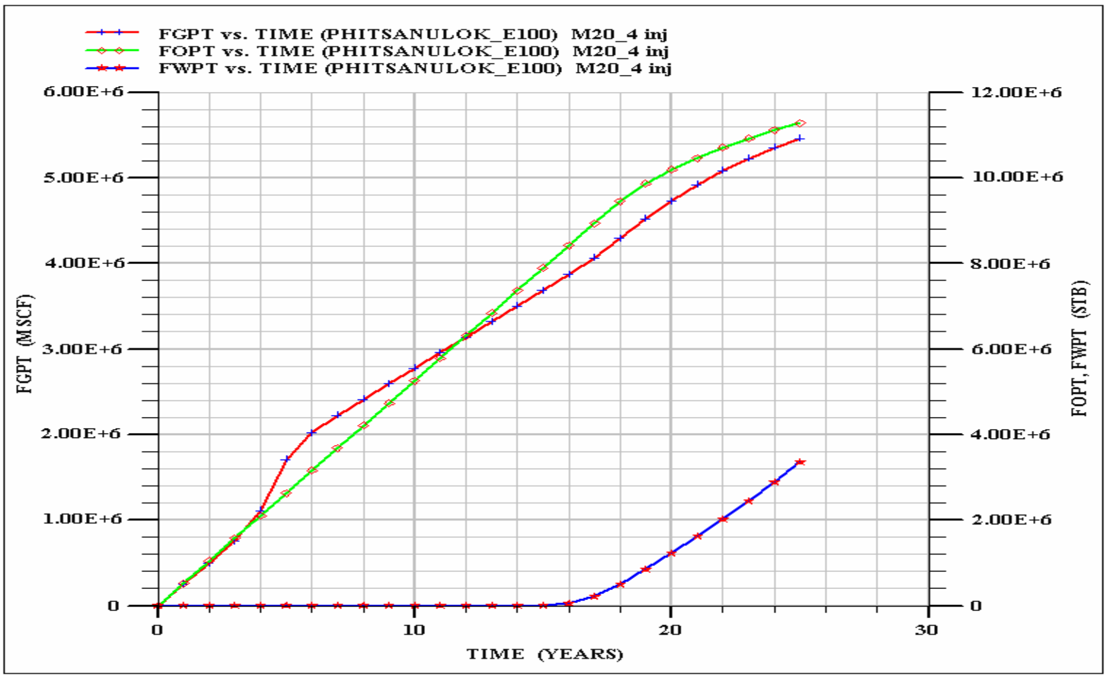

Figure 4.58 Cumulative fluids production profile vs. Time of model M20_4 inj.

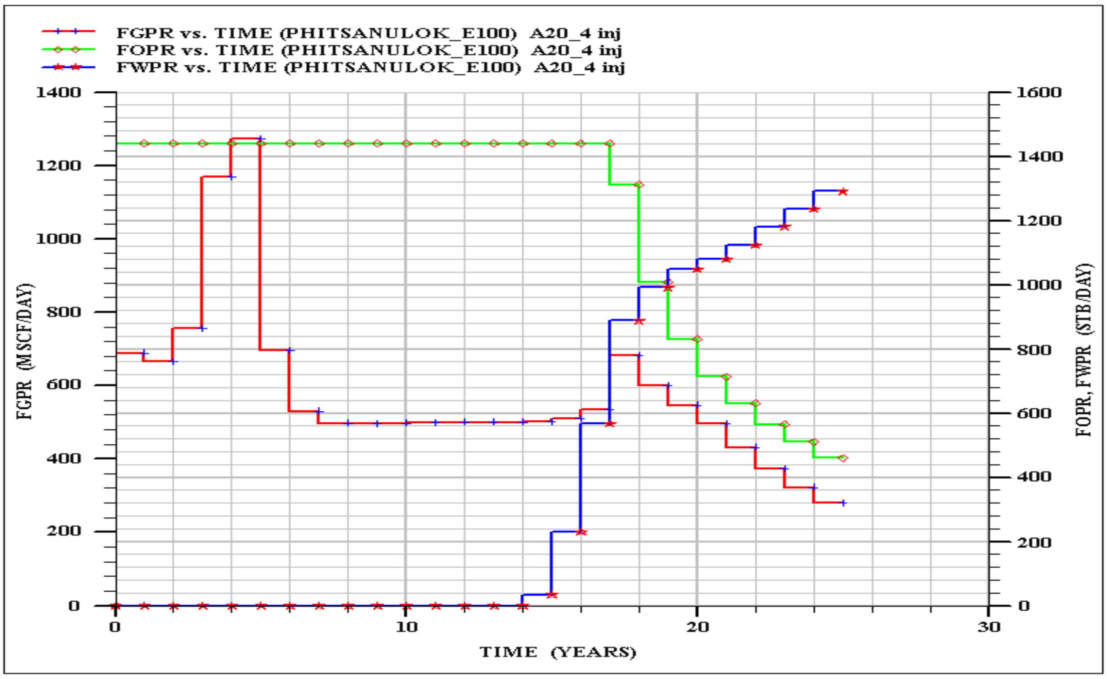

Figure 4.59 Fluids production rate profile vs. Time of model M20_4 inj.

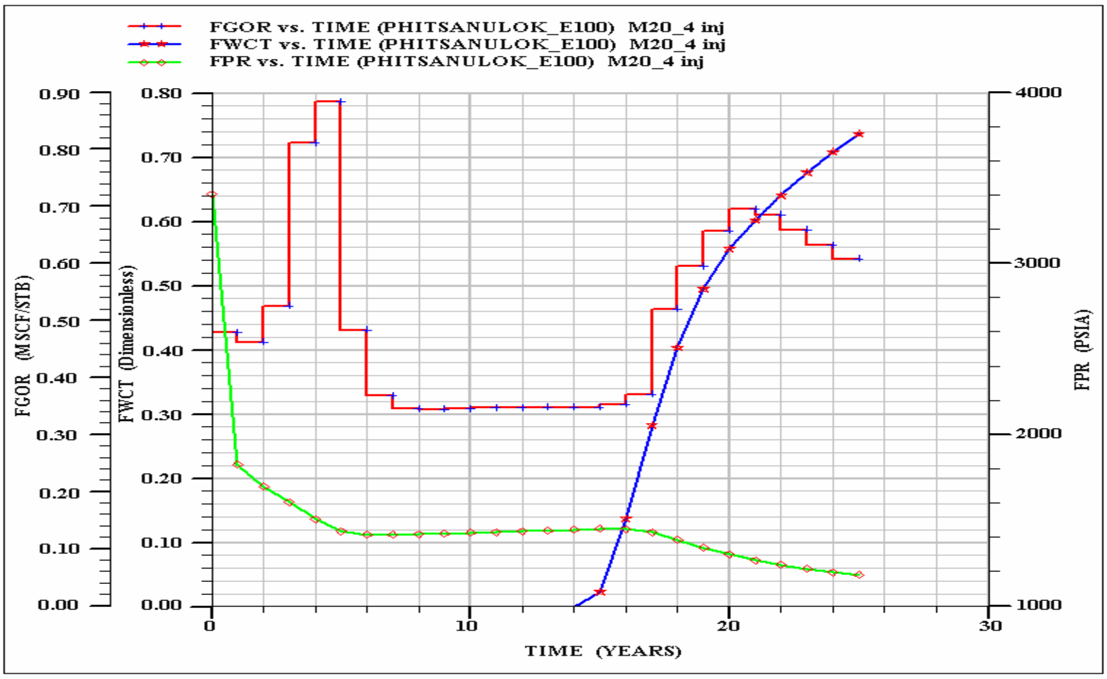

Figure 4.60 GOR, WCT, and Pressure profile vs. Time of model M20_4 inj.

Table 4.17 Summary detail of graph 4.57 and 4.58.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	11,283,936	20,088,216	56.17
Gas (MSCF)	5,458,164	9,692,430	56.31
Water (STB)	3,354,161	9,186,909	36.51

Figure 4.11, show FOPR remain constant rate at 1,440 BOPD over the first 17 years, after that decreases rapidly to 460 BOPD at the end. This production trend effected by FPR (see figure 4.12) drop slightly till the 4th year, after that it improve slowly and flattened out through the end of production period (starting effected by WCT at 15th year).

4.3.16 Model M20_8 inj Scenario Result

Model M20_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.61 – 4.64):

- 6 production wells at initial oil production rate 160 BOPD/well (gross 960 BOPD)
- after 8 years of production period, start water injection by converted 3 production well to injection well with 600 BWPD/well injection rate (gross 1,800 BWPD)
- 3 remaining production well produced at rate 320 BOPD/well to maintain initial gross production rate

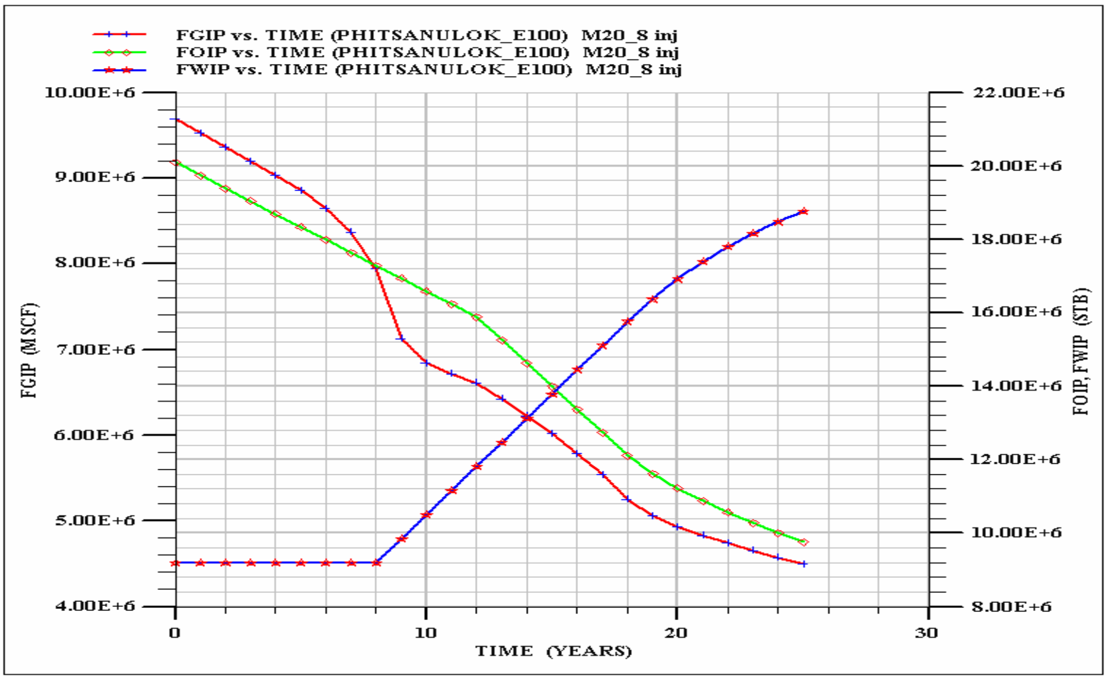

Figure 4.61 Fluid in place profile vs. Time of model M20_8 inj.

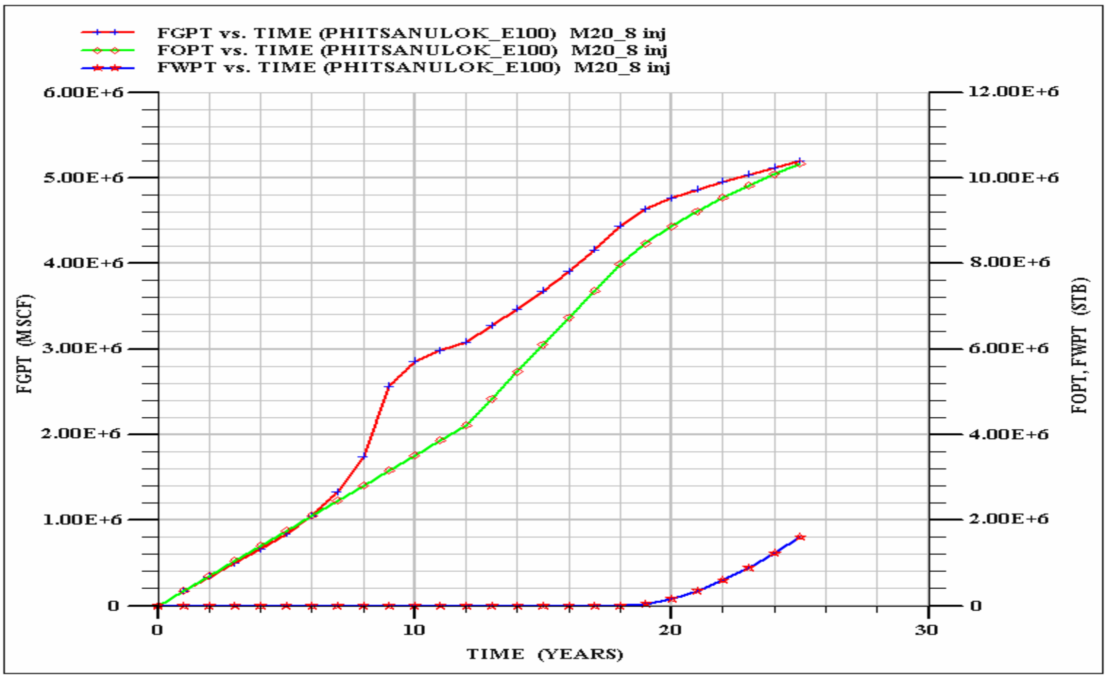

Figure 4.62 Cumulative fluids production profile vs. Time of model M20_8 inj.

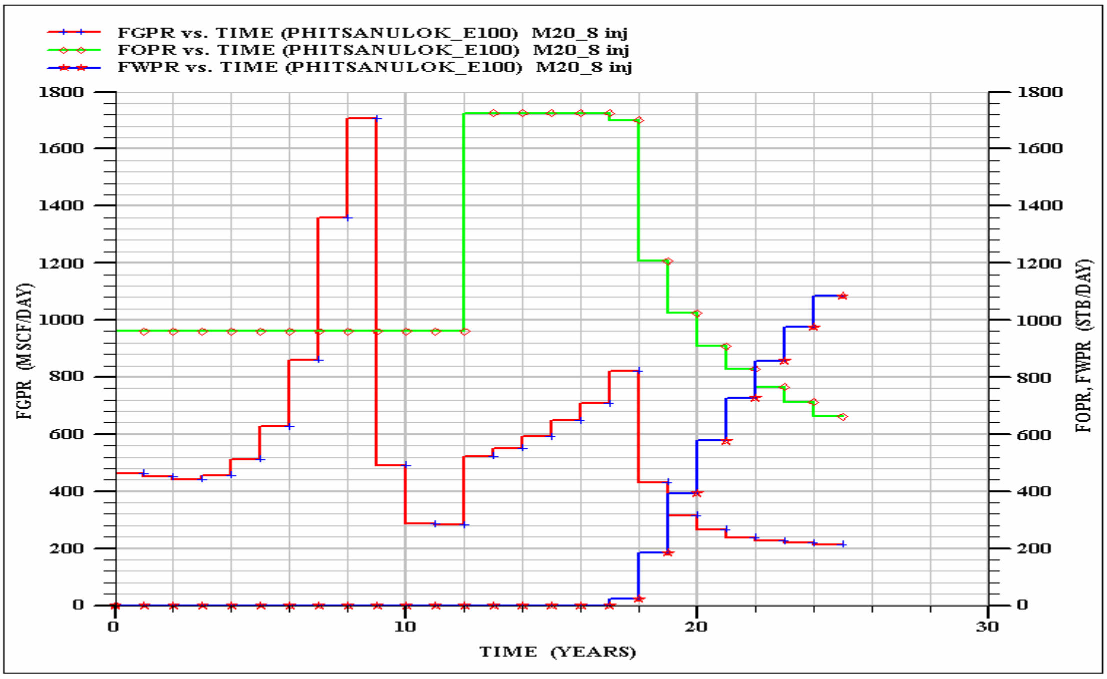

Figure 4.63 Fluids production rate profile vs. Time of model M20_8 inj.

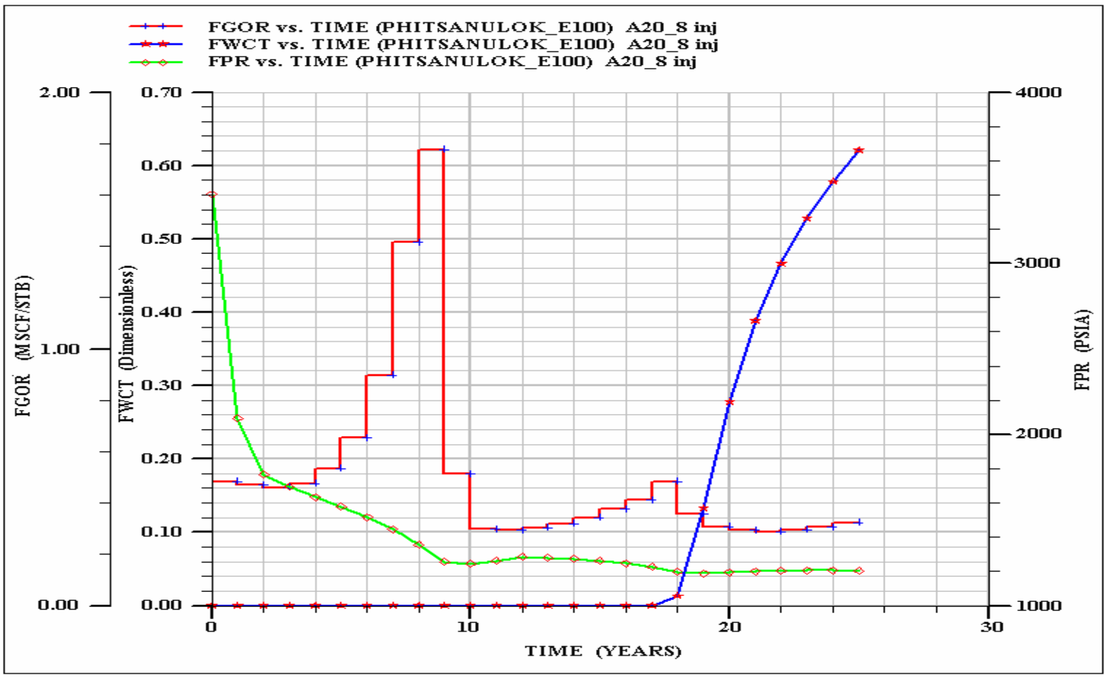

Figure 4.64 GOR, WCT, and Pressure profile vs. Time of model M20_8 inj.

Table 4.18 Summary detail of graph 4.61 and 4.62.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	10,331,622	20,088,216	51.43
Gas (MSCF)	5,197,031	9,692,430	53.62
Water (STB)	1,610,721	9,186,909	17.53

Figure 4.63, show FOPR remain constant rate at 960 BOPD over the first 12 years, until the water injection reach and FPR improve (see figure 4.64), it jumped suddenly to 1,725 BOPD at the 13th year and stay the same rate through the 17th year, then drop suddenly to 662 BOPD at the end (WCT breakthrough at 18th year, because late of water injection).

4.3.17 Model M10_no inj Scenario Result

Model M10 natural flow produced with no water injection through the production period (20 years). Production schedule start by 4 production wells at initial oil production rate 110 BOPD/well (Gross 440 BOPD), the simulation results show in figure 4.65 – 4.68:

Table 4.19 Summary detail of graph 4.65 and 4.66.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,781,504	10,069,492	27.62
Gas (MSCF)	4,786,027	4,858,462	98.51
Water (STB)	-	4,696,308	-

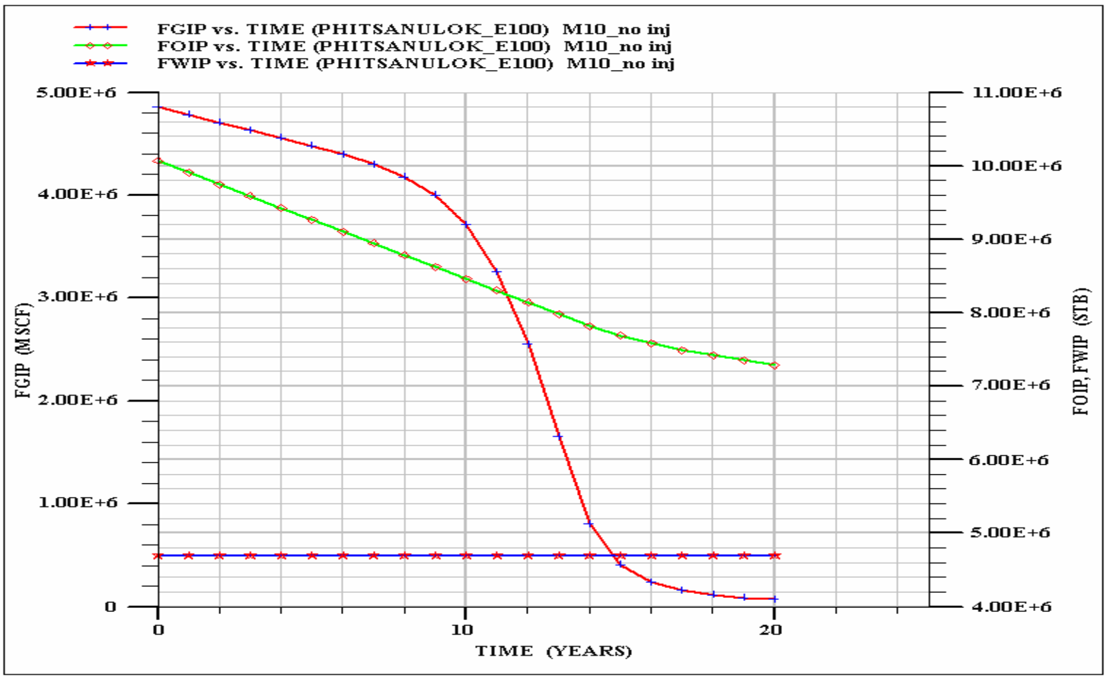

Figure 4.65 Fluid in place profile vs. Time of model M10_no inj.

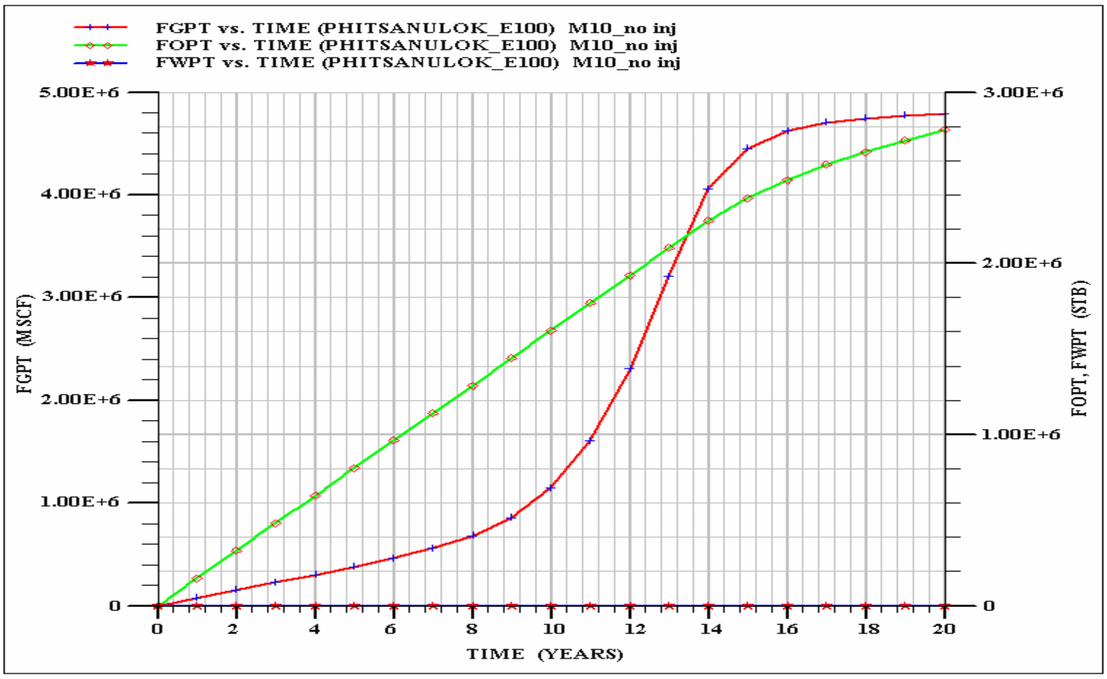

Figure 4.66 Cumulative fluids production profile vs. Time of model M10_no inj.

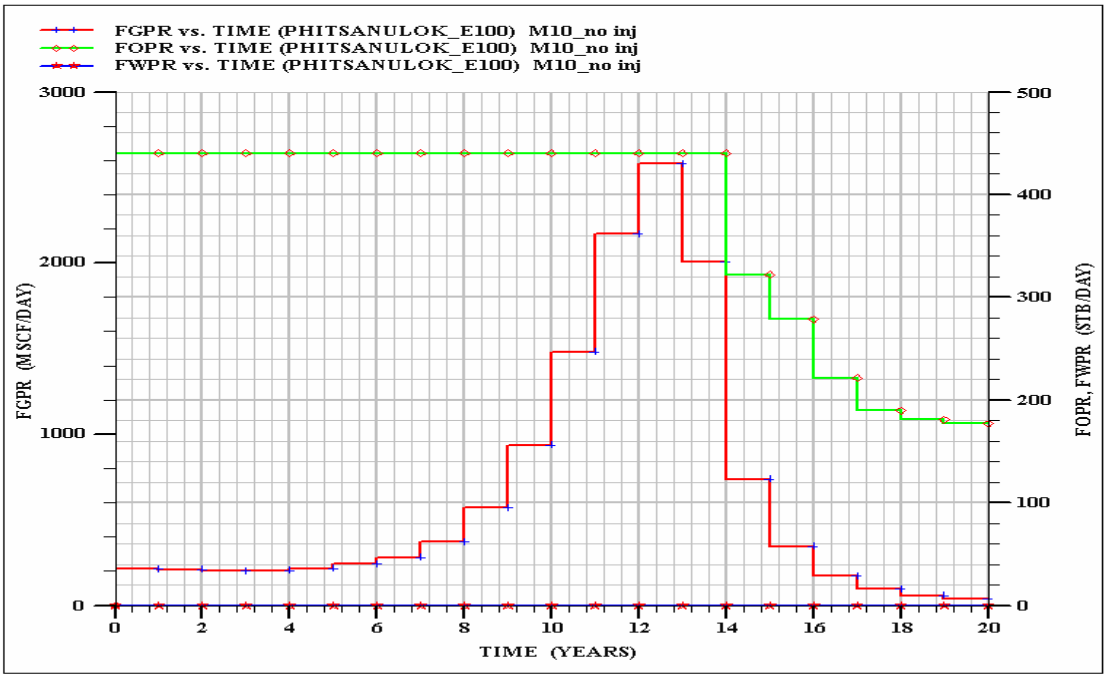

Figure 4.67 Fluids production rate profile vs. Time of model M10_no inj.

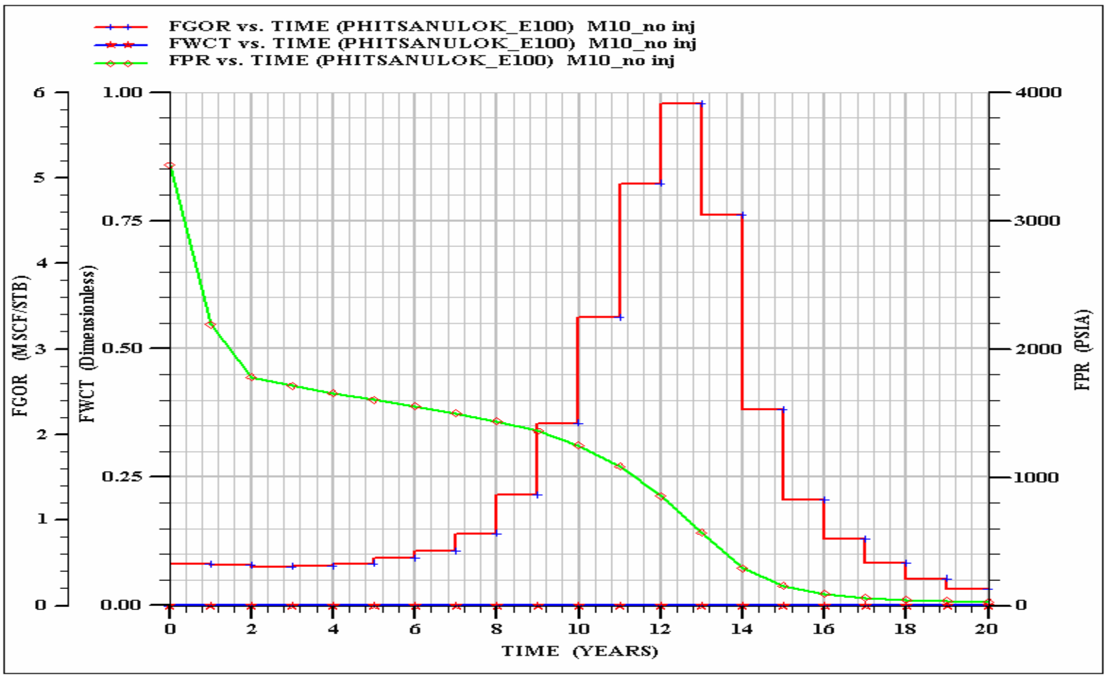

Figure 4.68 GOR, WCT, and Pressure profile vs. Time of model M10_no inj.

Figure 4.67, show gross oil production (FOPR) keep a steady rate at 440 BOPD from starting production to the 14th year, after that drop gradually to 177 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.68). Gross gas production rate (FGPR) fluctuate slightly around 200 MSCFD until the 5th year, it increase suddenly to 2,580 MSCFD at the 13th year, and then drop rapidly to 35 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.18 Model M10_2 inj Scenario Result

Model M10_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.69 – 4.72):

- 4 production wells at initial oil production rate 190 BOPD/well (gross 760 BOPD)
- after 2 years of production period, start water injection by converted 2 production well to injection well with 450 BWPD/well injection rate (gross 900 BWPD)
- 2 remaining production well produced at rate 380 BOPD/well to maintain initial gross production rate

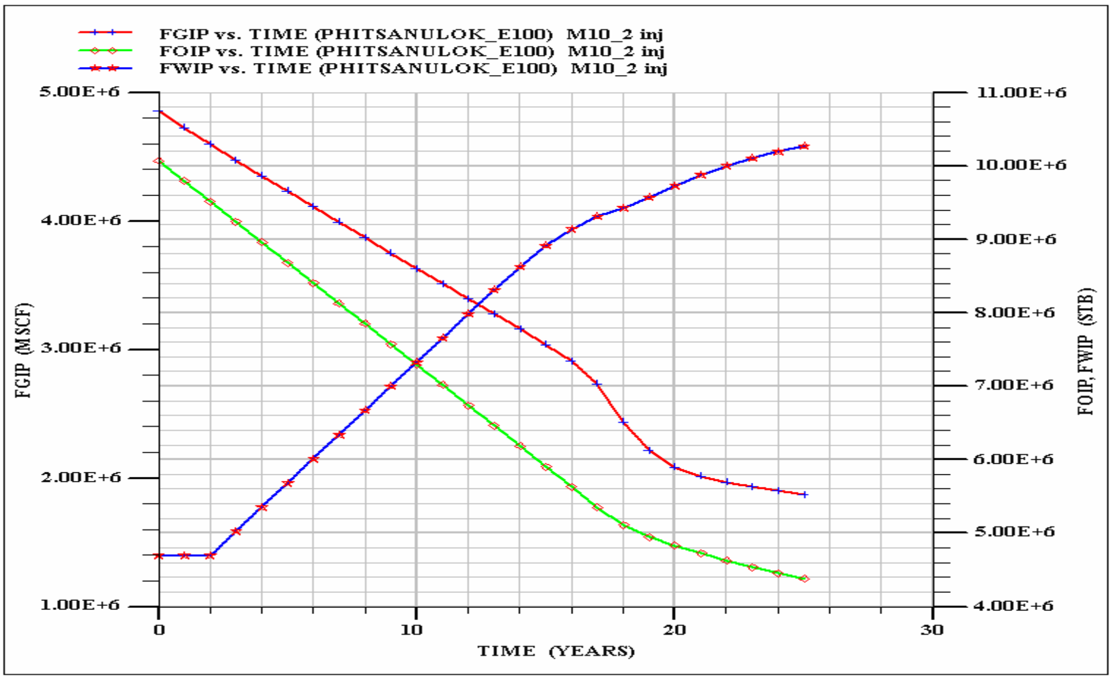

Figure 4.69 Fluid in place profile vs. Time of model M10_2 inj.

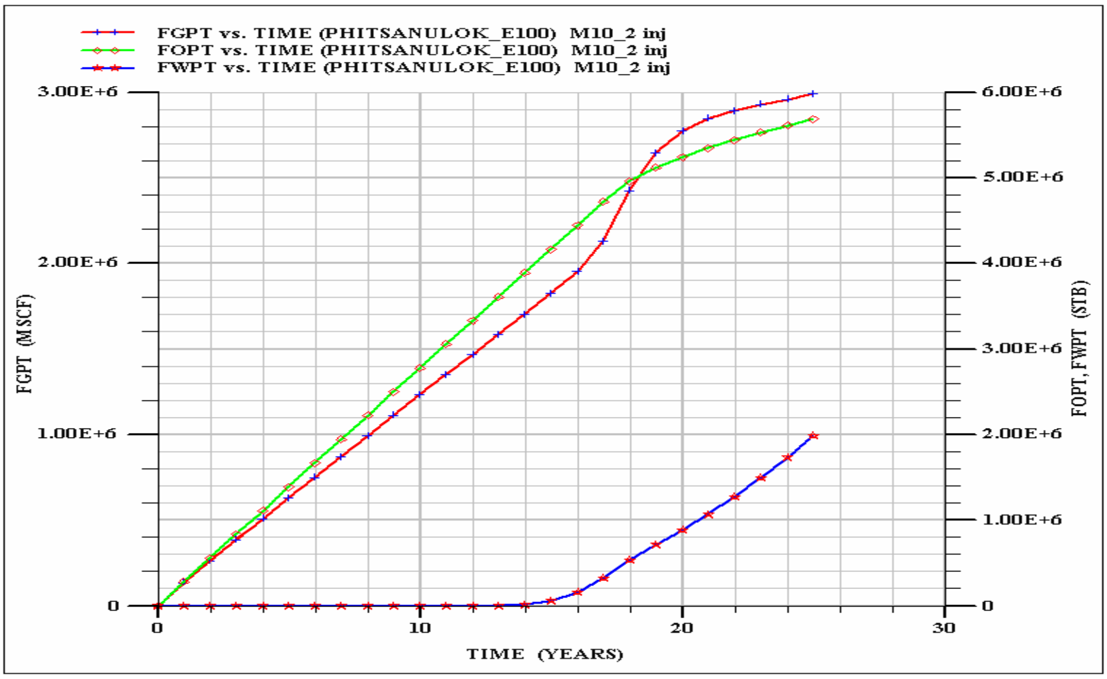

Figure 4.70 Cumulative fluids production vs. Time of model M10_2 inj.

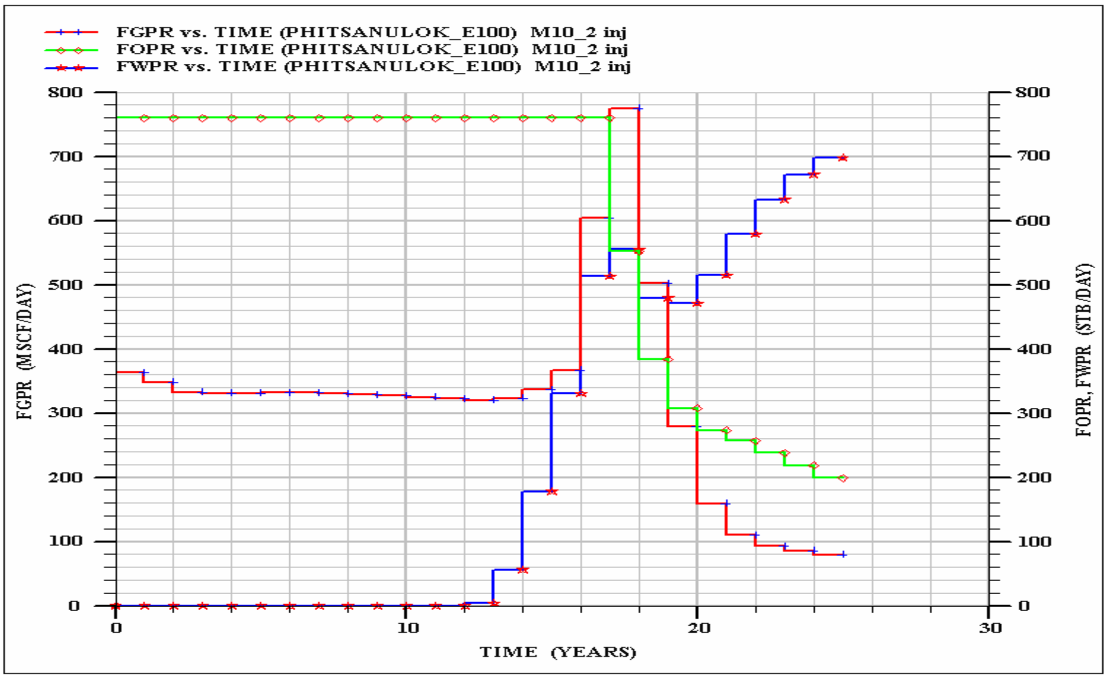

Figure 4.71 Fluids production rate profile vs. Time of model M10_2 inj.

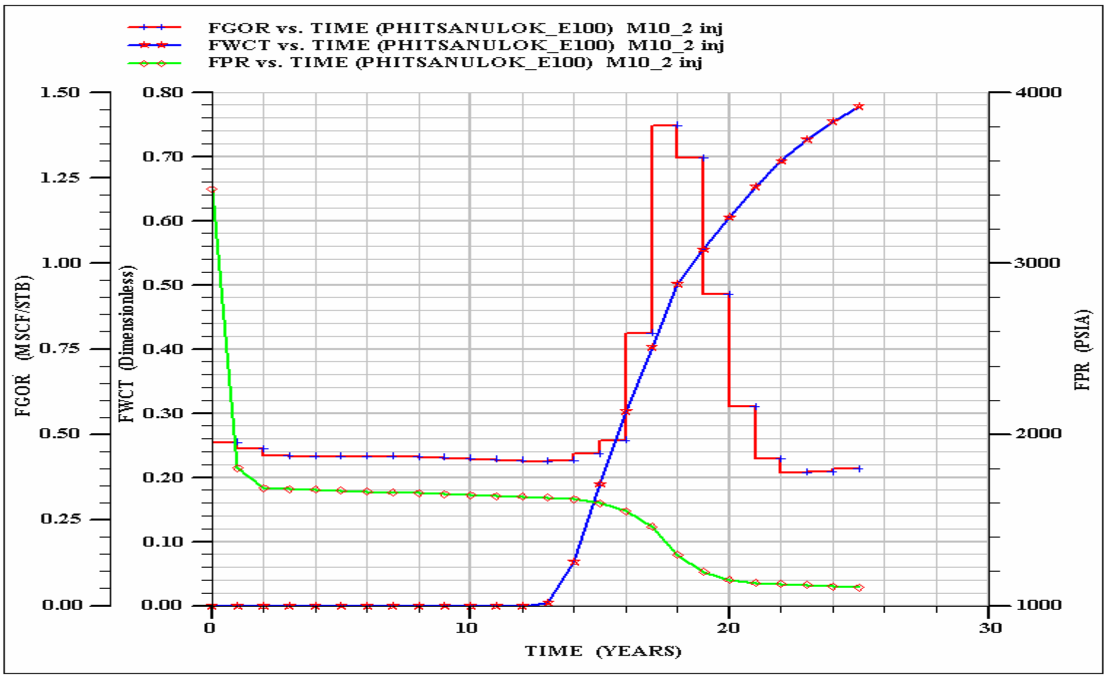

Figure 4.72 GOR, WCT, and Pressure profile vs. Time of model M10_2 inj.

Table 4.20 Summary detail of graph 4.69 and 4.70.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,687,946	10,069,492	56.49
Gas (MSCF)	2,988,709	4,858,462	61.52
Water (STB)	1,985,805	4,696,308	42.28

Figure 4.71, show FOPR remain constant rate at 760 BOPD over the first 17 years, cause by a long FPR maintenance around 1,600-1,700 psia nearly the bubble point pressure (see figure 4.72), beyond this point, it drop gradually to 199 BOPD at the end of production period due to WCT start breakthroughs at 13th year with a rapid high rate. Suddenly WCT reach, FPR drop moderately and changes slightly through the end.

4.3.19 Model M10_4 inj Scenario Result

Model M10_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.73 – 4.76):

- 4 production wells at initial oil production rate 175 BOPD/well (gross 700 BOPD)
- after 4 years of production period, start water injection by converted 2 production well to injection well with 450 BWPD/well injection rate (gross 900 BWPD)
- 2 remaining production well produced at rate 350 BOPD/well to maintain initial gross production rate

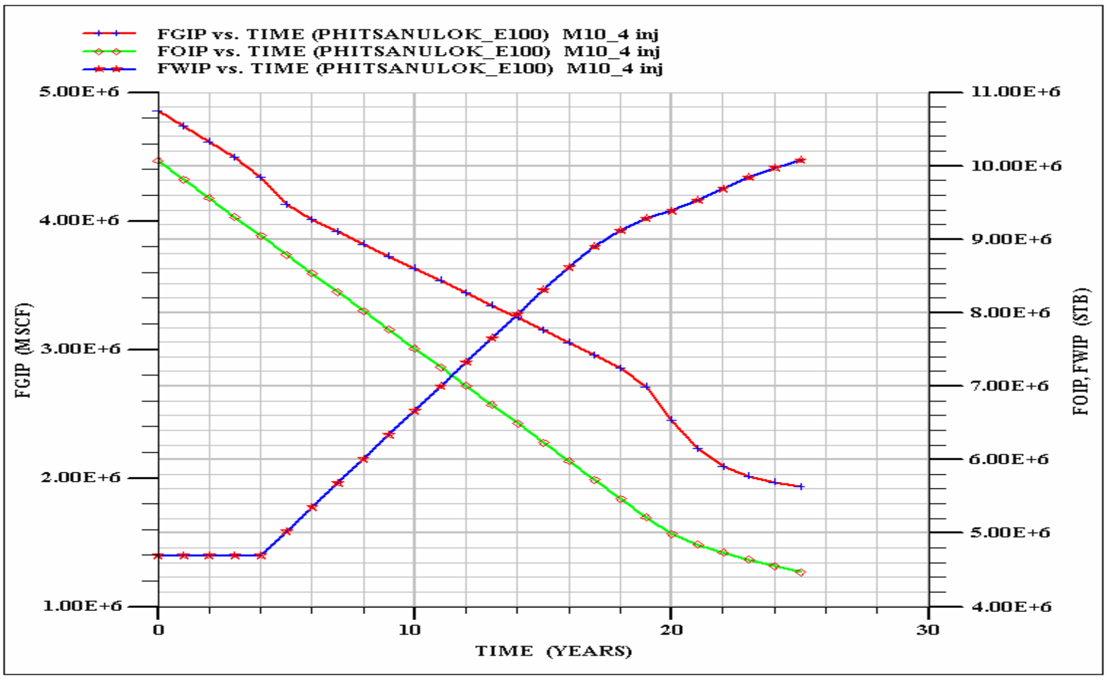

Figure 4.73 Fluid in place profile vs. Time of model M10_4 inj.

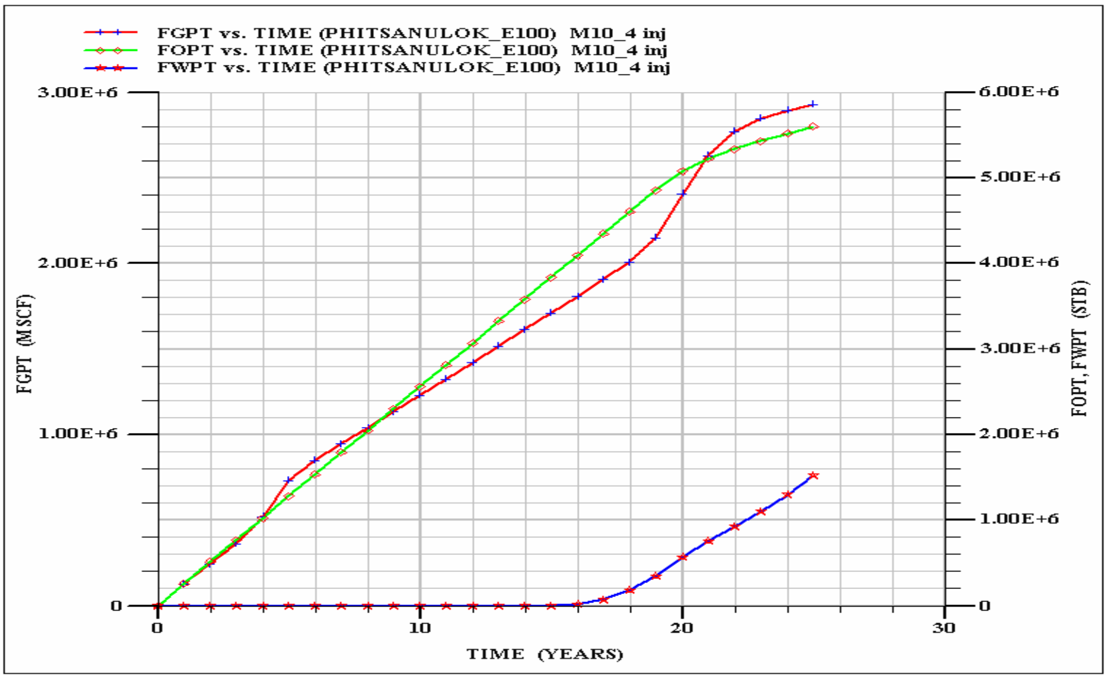

Figure 4.74 Cumulative fluids production profile vs. Time of model M10_4 inj.

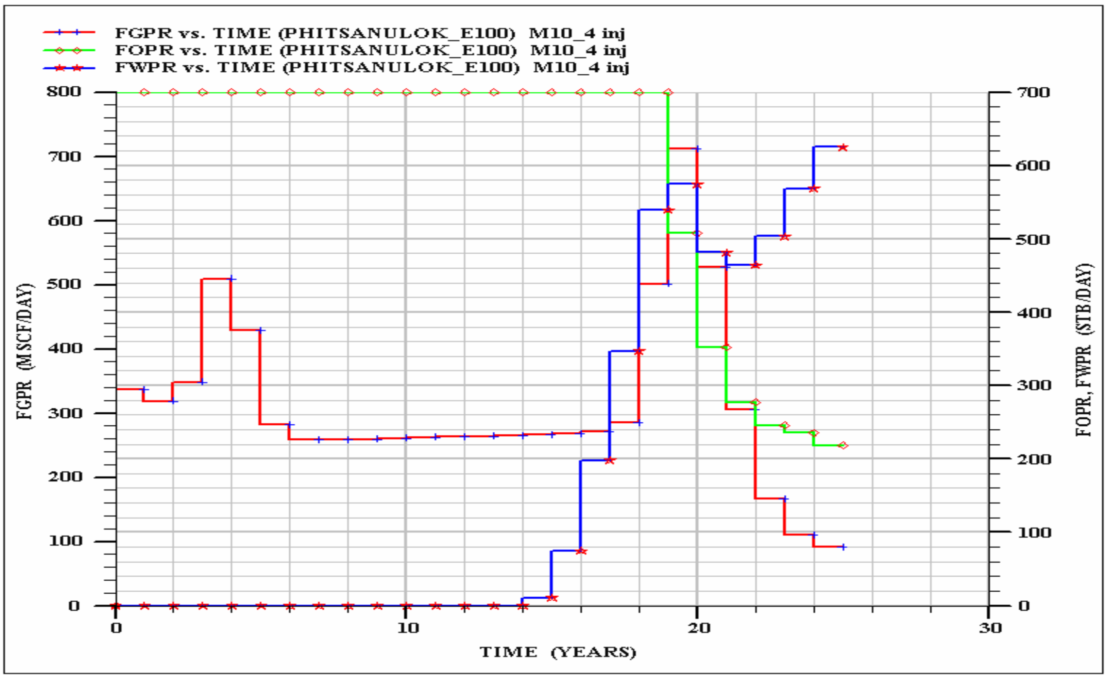

Figure 4.75 Fluids production rate profile vs. Time of model M10_4 inj.

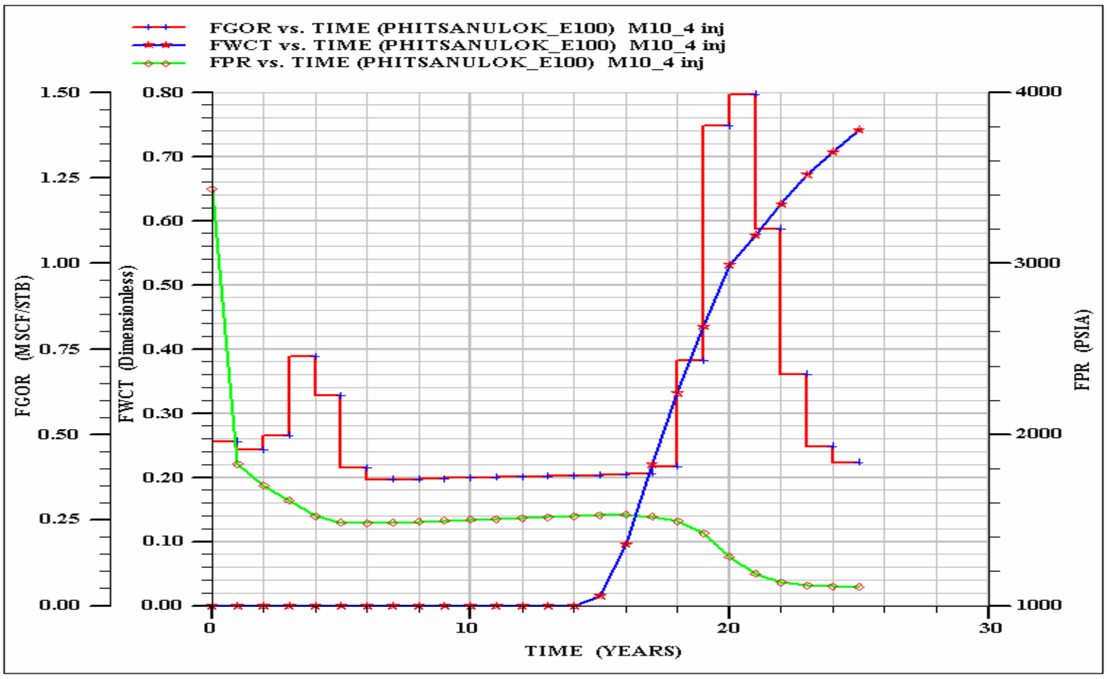

Figure 4.76 GOR, WCT, and Pressure profile vs. Time of model M10_4 inj.

Table 4.21 Summary detail of graph 4.73 and 4.74.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,598,326	10,069,492	55.60
Gas (MSCF)	2,927,517	4,858,462	60.26
Water (STB)	1,520,618	4,696,308	32.38

Figure 4.75, show FOPR remain constant rate at 680 BOPD over the first 19 years, after that sharply change for next 3 years, then decrease slightly to 218 BOPD at the end of production period. This production trend effected by FPR (see figure 4.76) maintain significantly around 1,400-1,500 psia, after that it decrease steadily through the end of production period (starting effected by WCT at 15th year).

4.3.20 Model M10_8 inj Scenario Result

Model M10_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.77 – 4.80):

- 4 production wells at initial oil production rate 125 BOPD/well (gross 500 BOPD)
- after 8 years of production period, start water injection by converted 4 production well to injection well with 450 BWPD/well injection rate (gross 900 BWPD)
- 2 remaining production well produced at rate 250 BOPD/well to maintain initial gross production rate

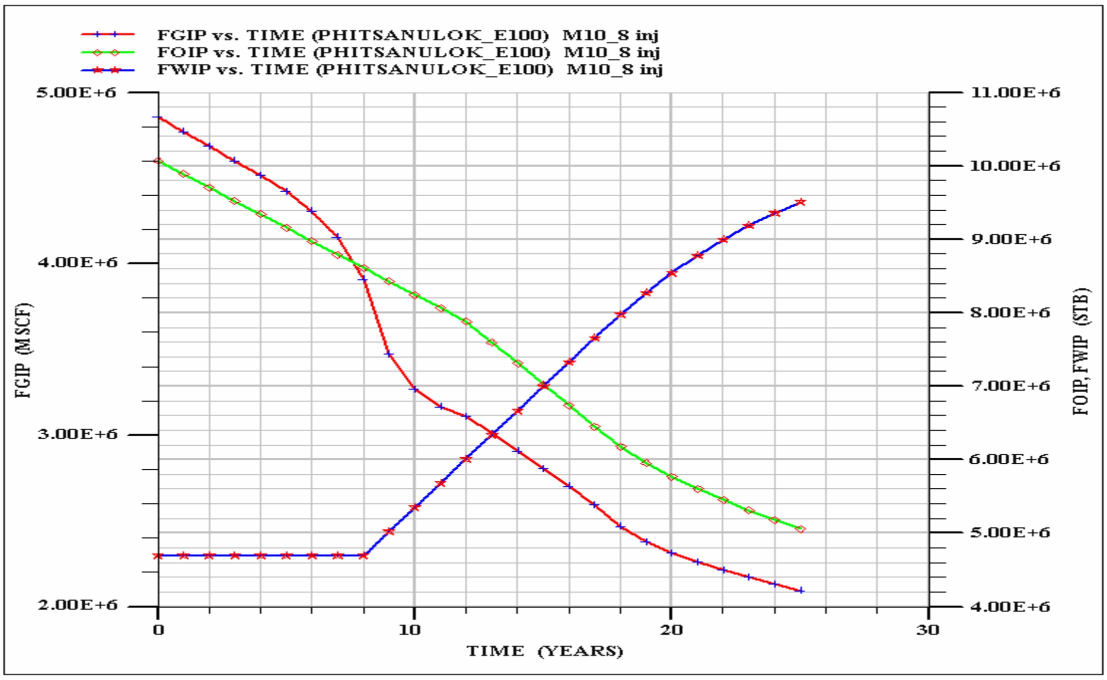

Figure 4.77 Fluid in place profile vs. Time of model M10_8 inj.

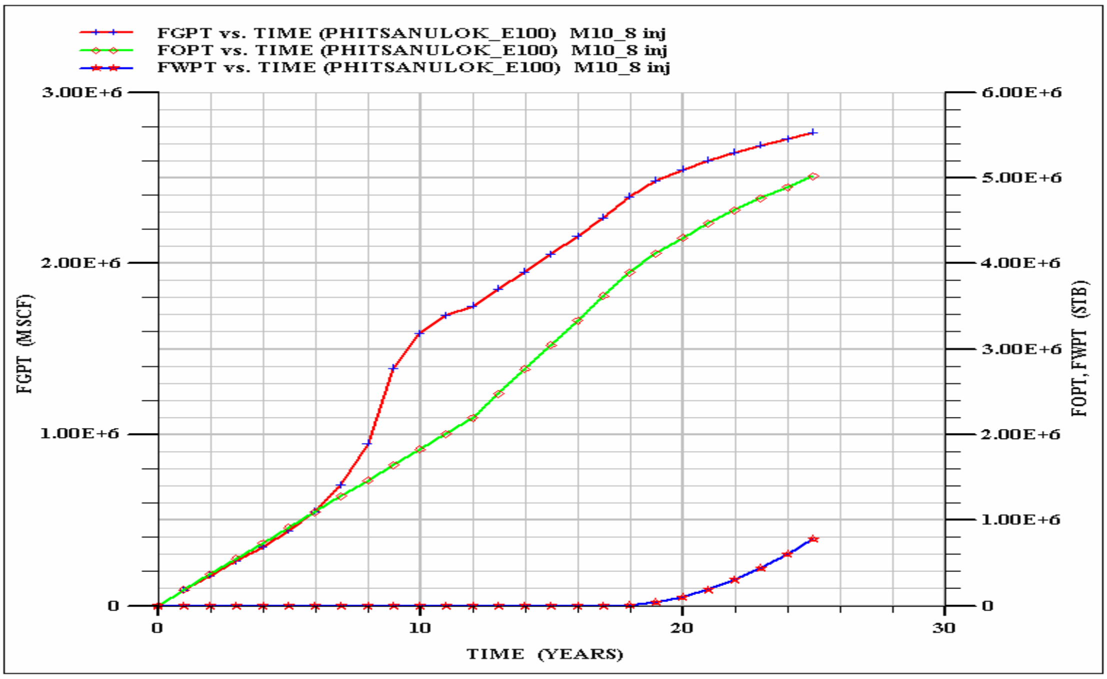

Figure 4.78 Cumulative fluids production profile vs. Time of model M10_8 inj.

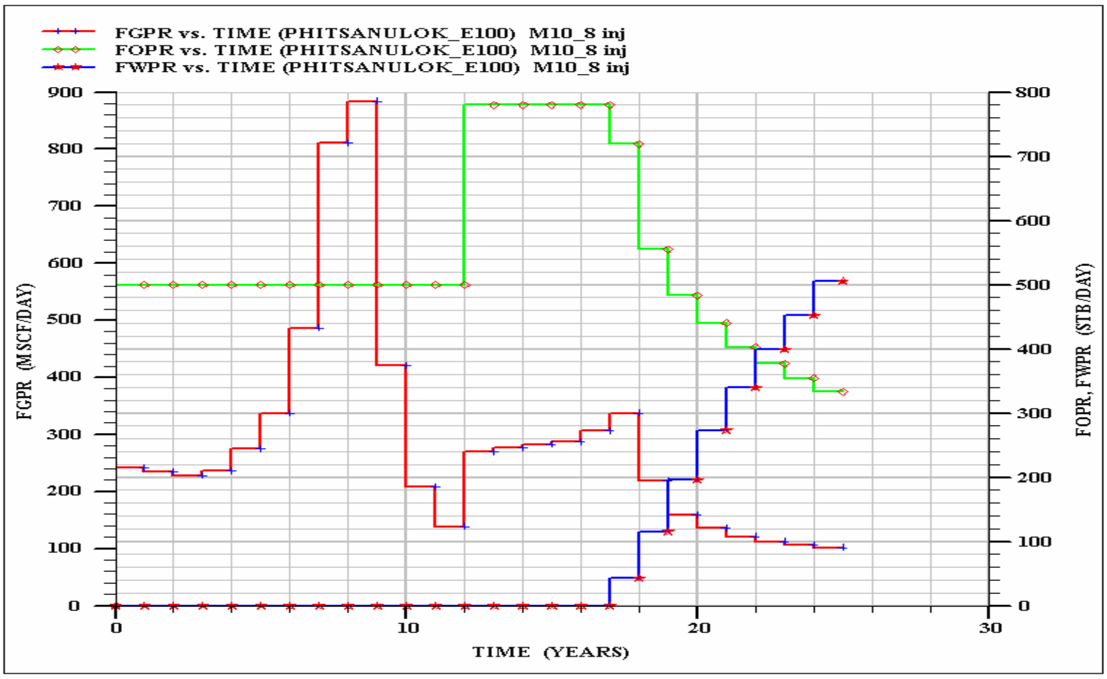

Figure 4.79 Fluids production rate profile vs. Time of model M10_8 inj.

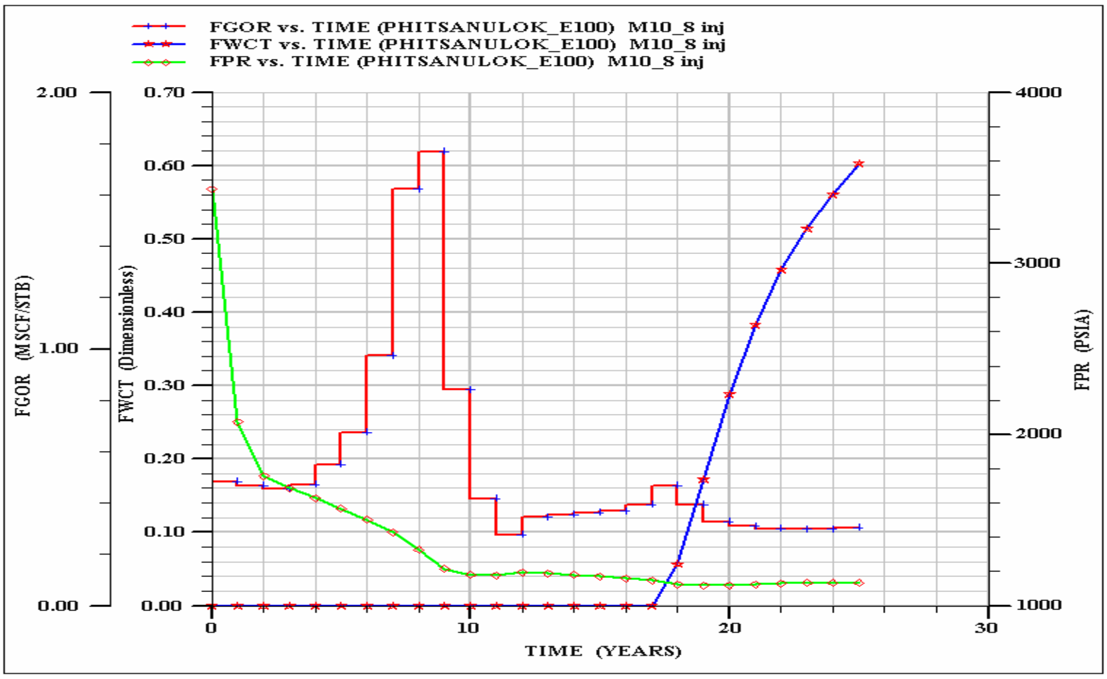

Figure 4.80 GOR, WCT, and Pressure profile vs. Time of model M10_8 inj.

Table 4.22 Summary detail of graph 4.77 and 4.78.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	5,016,365	10,069,492	49.82
Gas (MSCF)	2,764,795	4,858,462	56.91
Water (STB)	777,300	4,696,308	16.55

Figure 4.79, show FOPR remain constant rate at 500 BOPD over the first 12 years, until the water injection reach and FPR improve (see figure 4.80), it jumped suddenly to 780 BOPD at the 14th year and keep this rate for next 4 years, then decrease gradually to 333 BOPD at the end (WCT breakthrough at 18th year, because late of water injection).

4.3.21 Model M05_no inj Scenario Result

Model M05 natural flow produced with no water injection through the production period (15 years). Production schedule start by 2 production wells at initial oil production rate 160 BOPD/well (Gross 320 BOPD), the simulation results show in figure 4.81 – 4.84:

Table 4.23 Summary detail of graph 4.81 and 4.82.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	1,352,225	5,023,991	26.92
Gas (MSCF)	2,376,430	2,424,042	98.04
Water (STB)	-	2,380,078	-

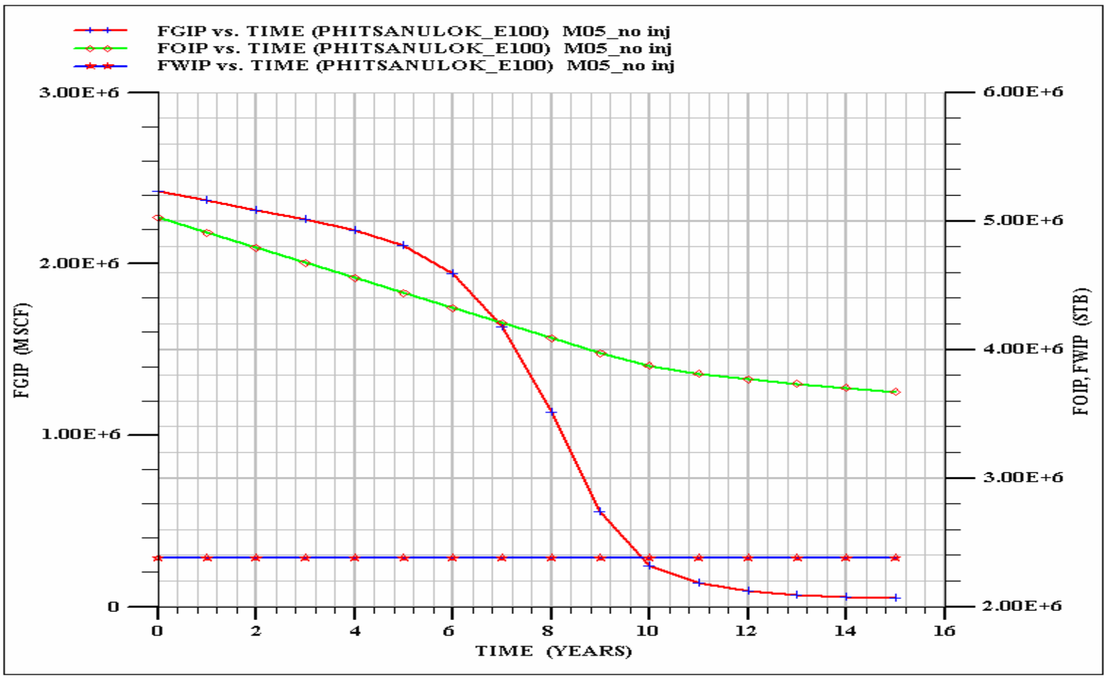

Figure 4.81 Fluid in place profile vs. Time of model M05_no inj.

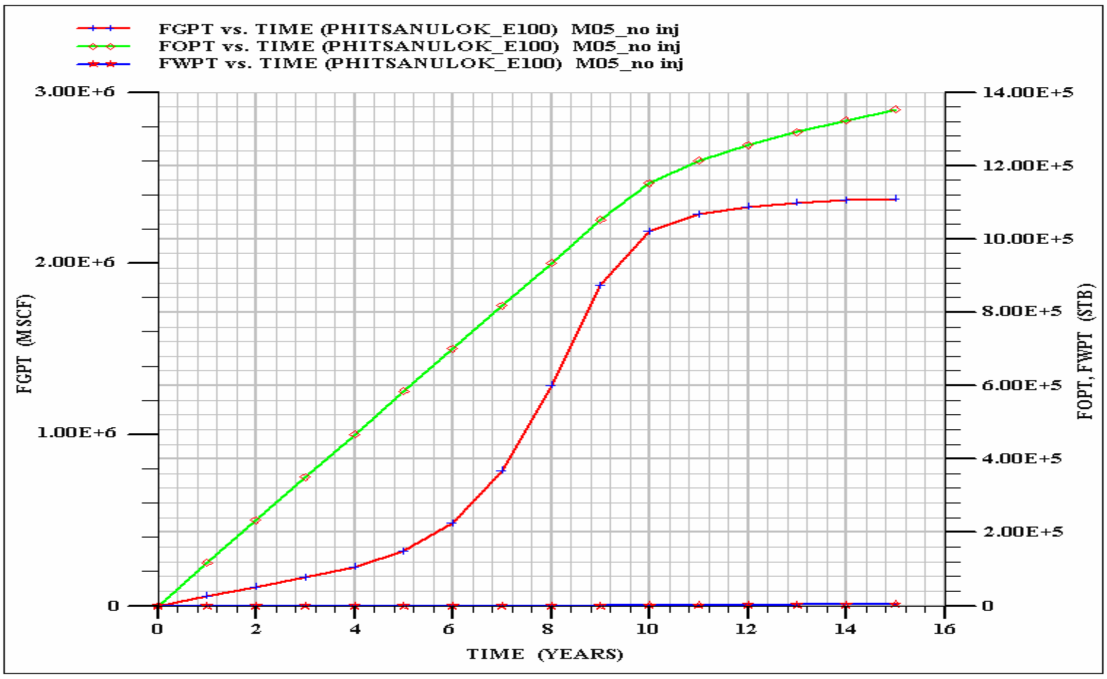

Figure 4.82 Cumulative fluids production profile vs. Time of model M05_no inj.

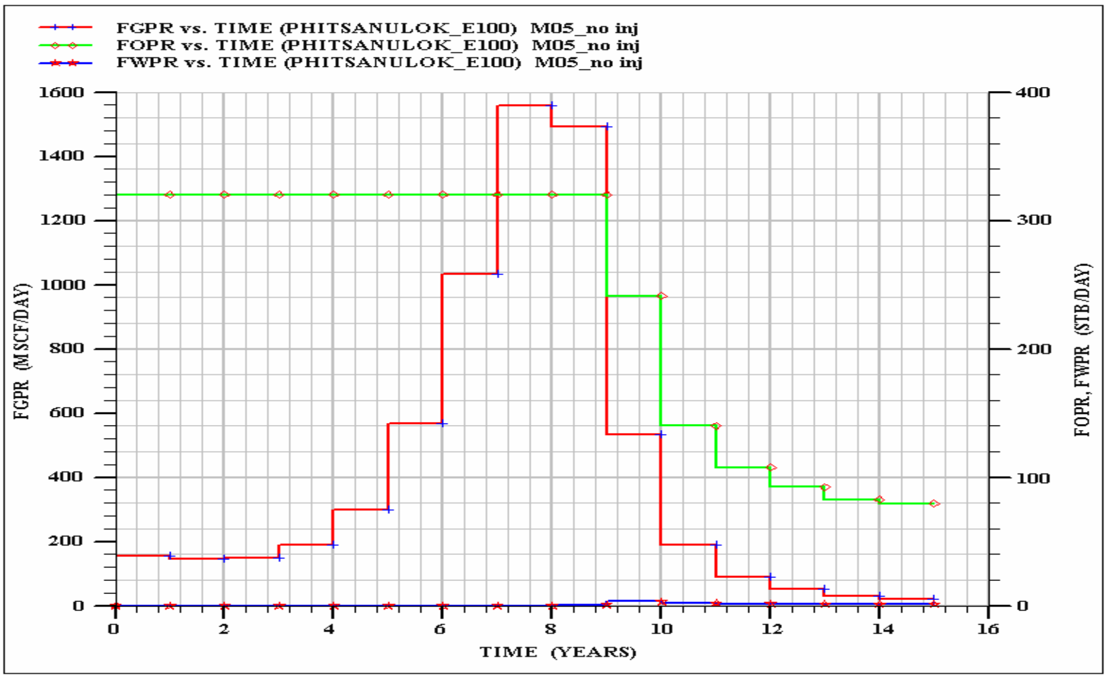

Figure 4.83 Fluids production rate profile vs. Time of model M05_no inj.

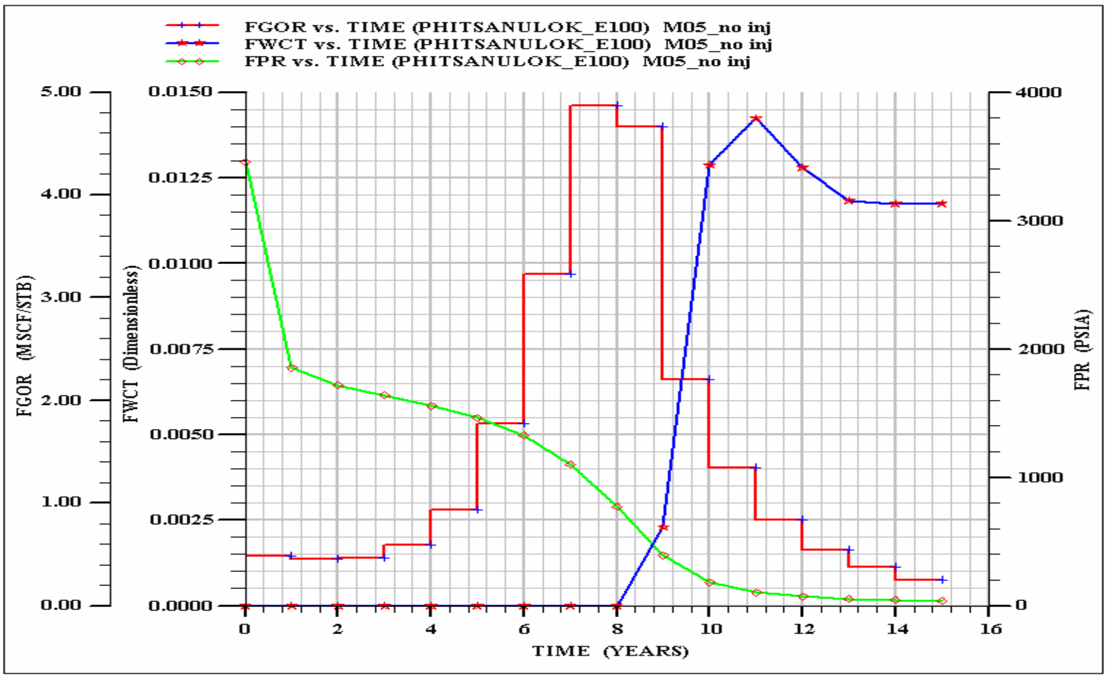

Figure 4.84 GOR, WCT, and Pressure profile vs. Time of model M05_no inj.

Figure 4.83, show gross oil production (FOPR) keep a steady rate at 320 BOPD from starting production to the 9th year, after that decrease steadily to 79 BOPD at the final due to reservoir pressure (FPR) drop significantly (see figure 4.84). Gross gas production rate (FGPR) fluctuate slightly around 150 MSCFD until the 4th year, it increase suddenly to 1,558 MSCFD at the 8th year, and then drop rapidly to 20 MSCFD at the end. This means, solution gas drive present during production period (no water production).

4.3.22 Model M05_2 inj Scenario Result

Model M05_2 inj produced with applied water injection after natural flow production for 2 years, production schedule detail summarize as follow (simulation result show in figure 4.85 – 4.88):

- 3 production wells at initial oil production rate 130 BOPD/well (gross 390 BOPD)
- after 2 years of production period, start water injection by converted 2 production well to injection well with 225 BWPD/well injection rate (gross 450 BWPD)
- 1 remaining production well produced at rate 390 BOPD/well to maintain initial gross production rate

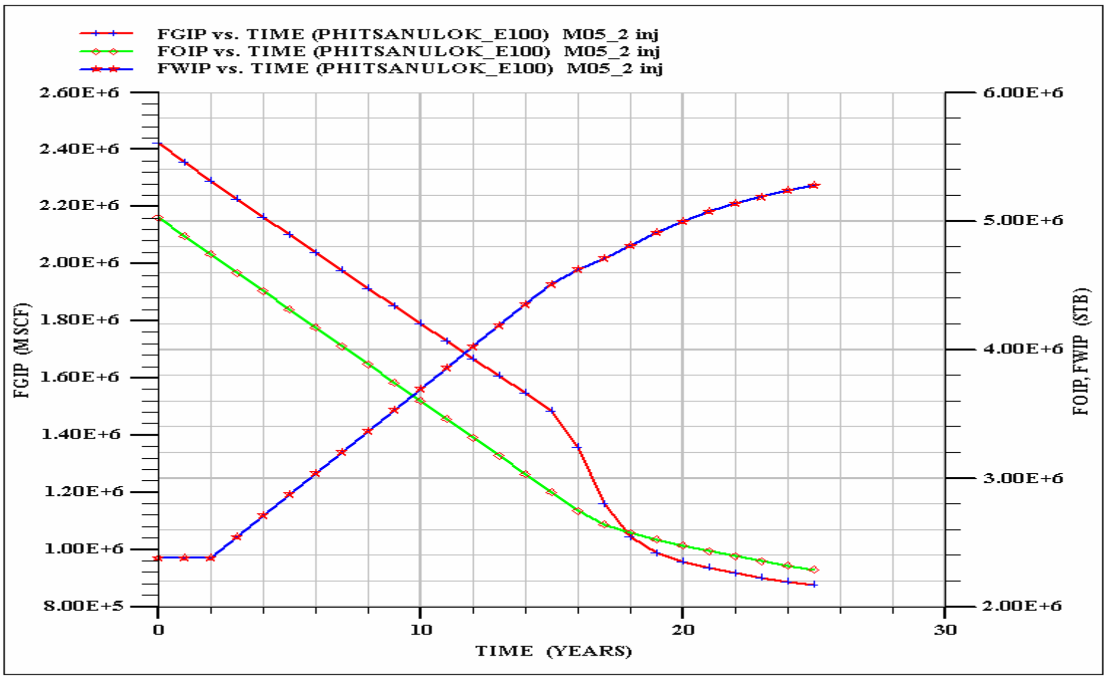

Figure 4.85 Fluid in place profile vs. Time of model M05_2 inj.

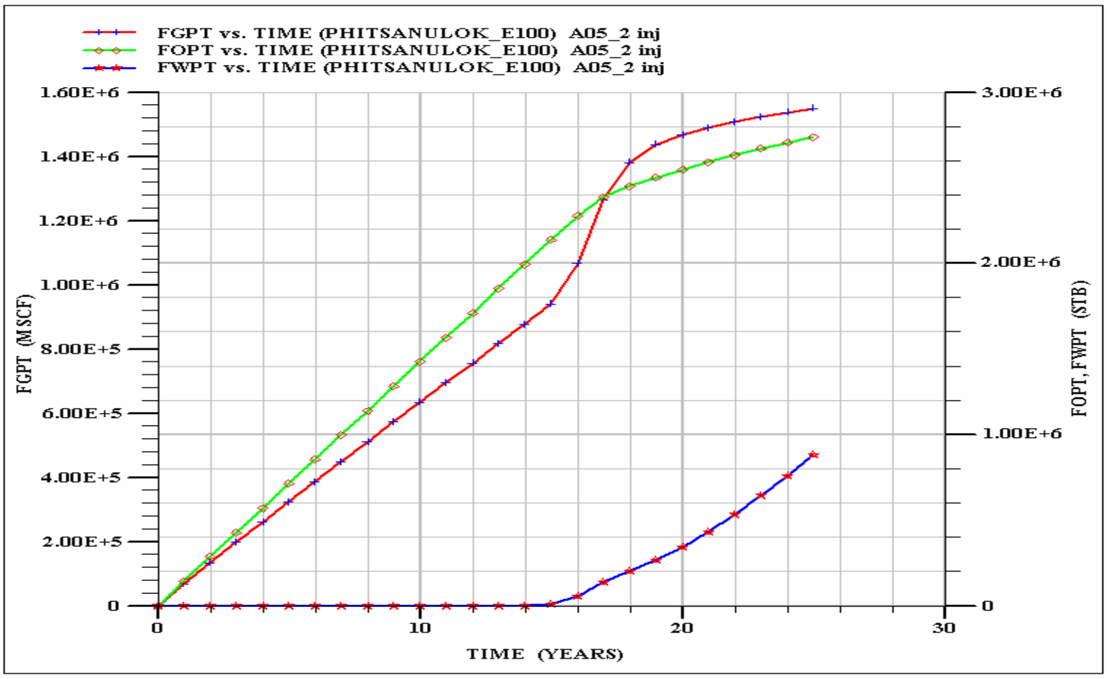

Figure 4.86 Cumulative fluids production vs. Time of model M05_2 inj.

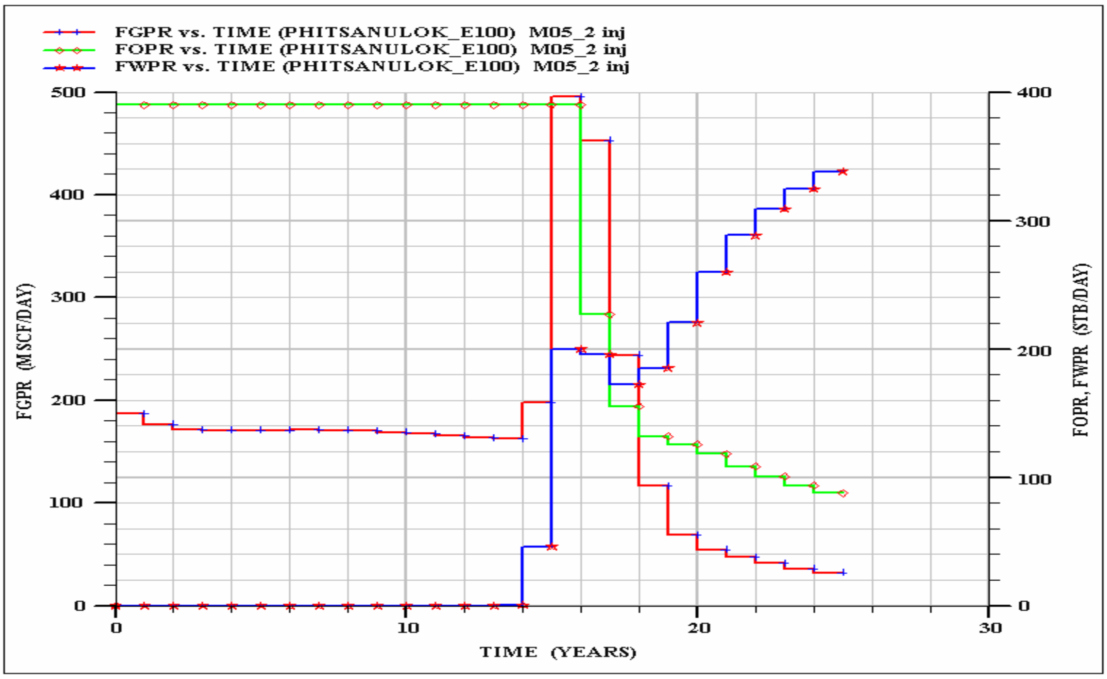

Figure 4.87 Fluids production rate profile vs. Time of model M05_2 inj.

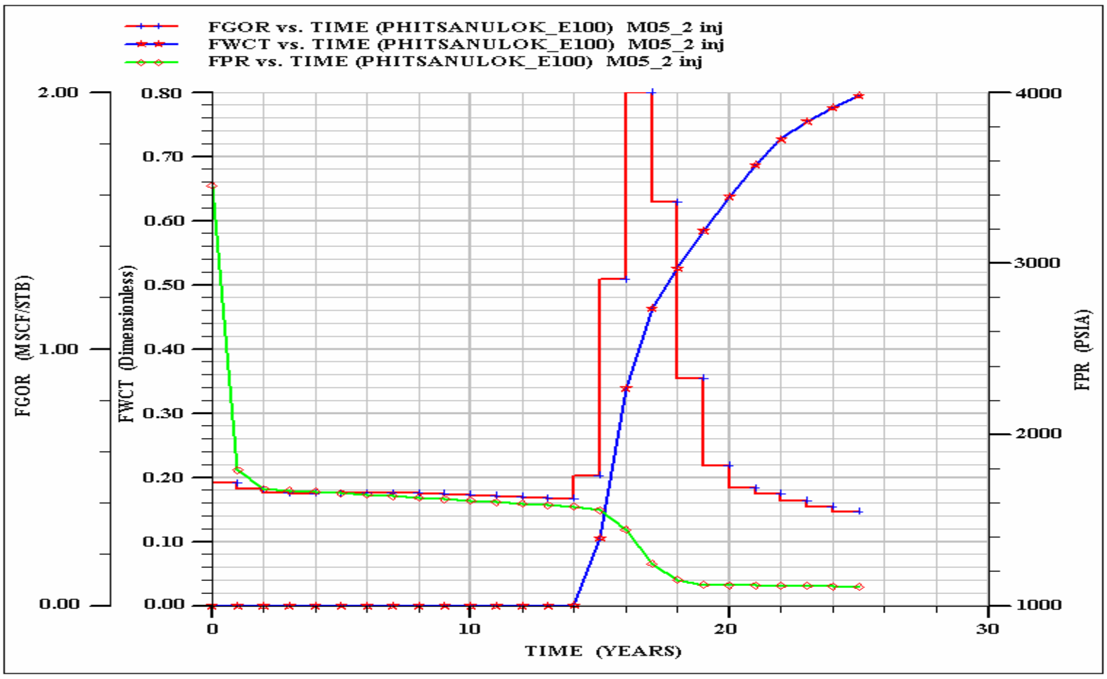

Figure 4.88 GOR, WCT, and Pressure profile vs. Time of model M05_2 inj.

Table 4.24 Summary detail of graph 4.85 and 4.86.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,738,695	5,023,991	54.51
Gas (MSCF)	1,548,448	2,424,042	63.88
Water (STB)	881,436	2,380,078	37.03

Figure 4.39, show FOPR remain constant rate at 360 BOPD over the first 16 years, cause by a long FPR maintenance around 1,600-1,700 psia (see figure 4.40), beyond this point, it drop suddenly for next 2 years and then decrease gradually to 88 BOPD at the end of production period due to the rapid WCT encountered at 14th year.

4.3.23 Model M05_4 inj Scenario Result

Model M05_4 inj produced with applied water injection after natural flow production for 4 years, production schedule detail summarize as follow (simulation result show in figure 4.89 – 4.92):

- 3 production wells at initial oil production rate 80 BOPD/well (gross 240 BOPD)
- after 4 years of production period, start water injection by converted 2 production well to injection well with 225 BWPD/well injection rate (gross 450 BWPD)
- 1 remaining production well produced at rate 240 BOPD/well to maintain initial gross production rate

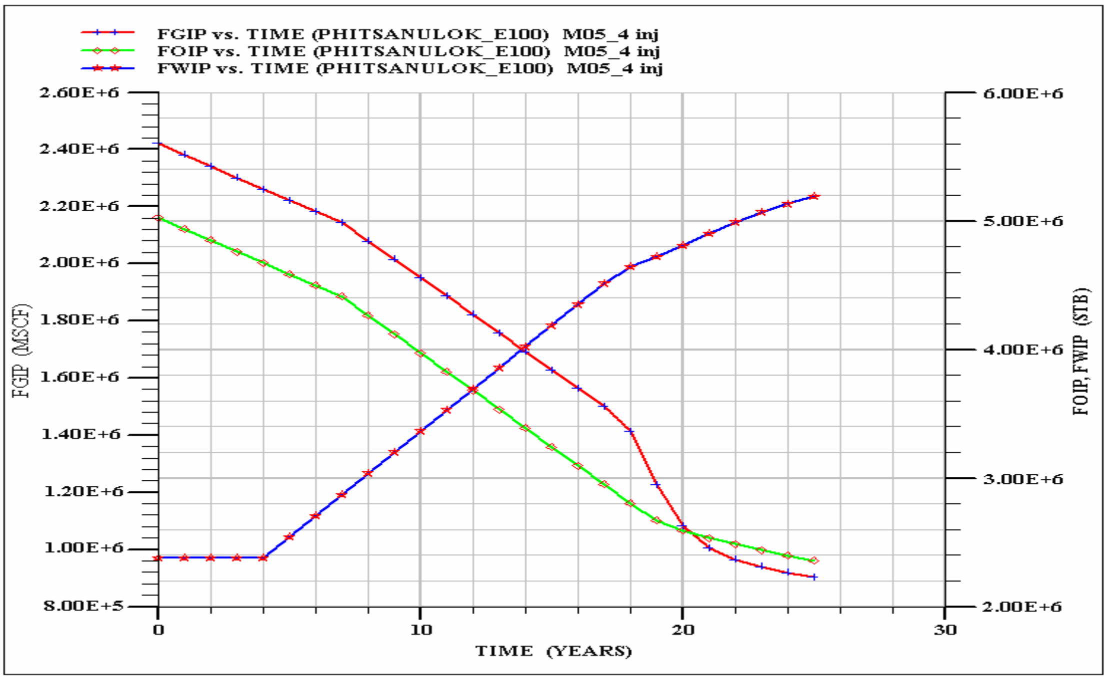

Figure 4.89 Fluid in place profile vs. Time of model M05_4 inj.

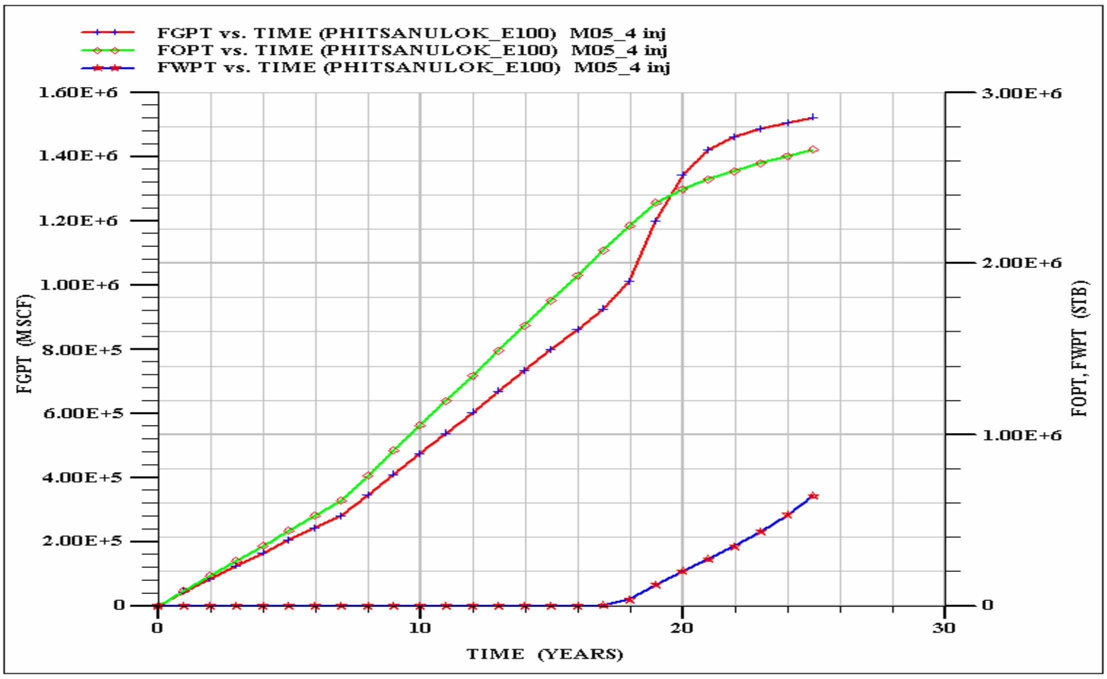

Figure 4.90 Cumulative fluids production profile vs. Time of model M05_4 inj.

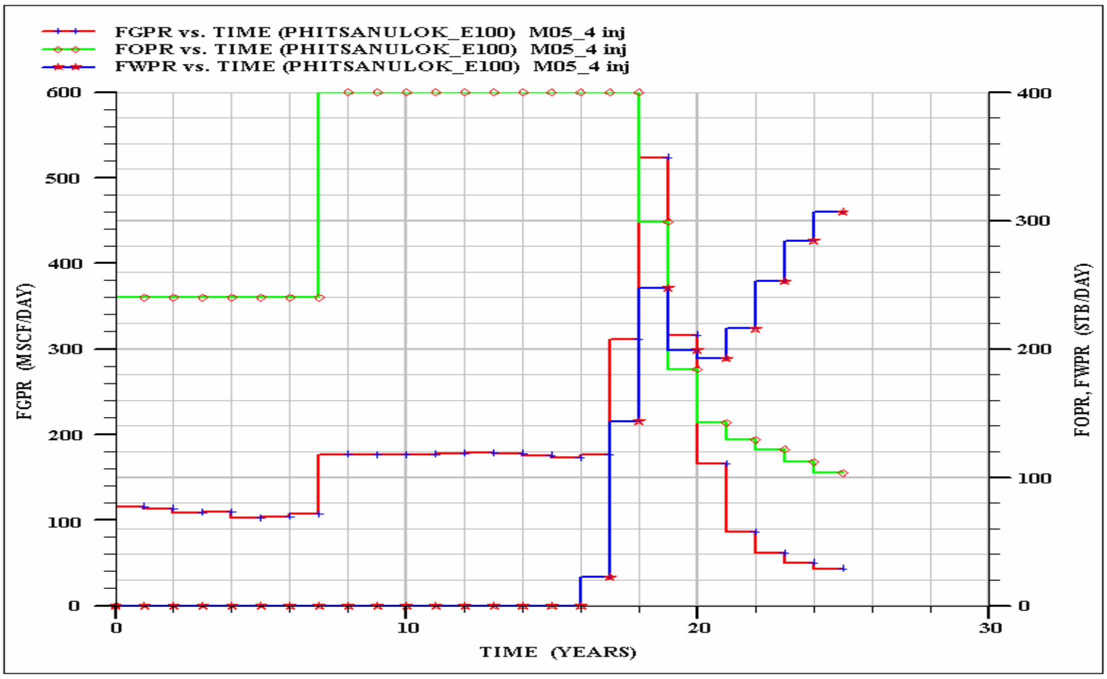

Figure 4.91 Fluids production rate profile vs. Time of model M05_4 inj.

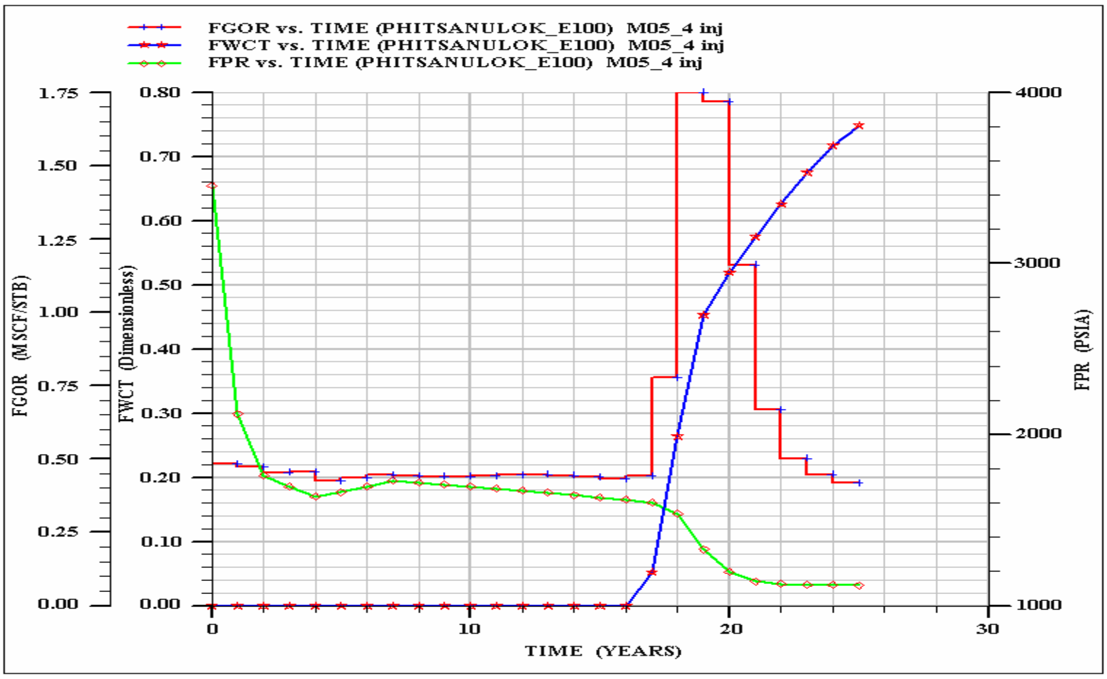

Figure 4.92 GOR, WCT, and Pressure profile vs. Time of model M05_4 inj.

Table 4.25 Summary detail of graph 4.89 and 4.90.

Fluid type	Cumulative production	Initial fluid in place	RF (%)
Oil (STB)	2,665,606	5,023,991	53.06
Gas (MSCF)	1,521,261	2,424,042	62.76
Water (STB)	642,253	2,380,078	26.98

Figure 4.91, show FOPR remain constant rate at 240 BOPD over the first 7 years, after that jump suddenly to 400 BOPD at the 8th year and stay the same rate through the 18th year, next it drop rapidly to 184 BOPD and decrease to 103 BOPD at the end. This production trend effected by FPR (see figure 4.92) improved and maintained around 1,600-1,700 psia till the 18th year, after that it drop and flatted out through the end of production period (starting effected by WCT at 17th year).

4.3.24 Model M05_8 inj Scenario Result

Model M05_8 inj produced with applied water injection after natural flow production for 8 years, production schedule detail summarize as follow (simulation result show in figure 4.93 – 4.96):

- 3 production wells at initial oil production rate 65 BOPD/well (gross 195 BOPD)
- after 8 years of production period, start water injection by converted 2 production well to injection well with 225 BWPD/well injection rate (gross 450 BWPD)
- 1 remaining production well produced at rate 195 BOPD/well to maintain initial gross production rate

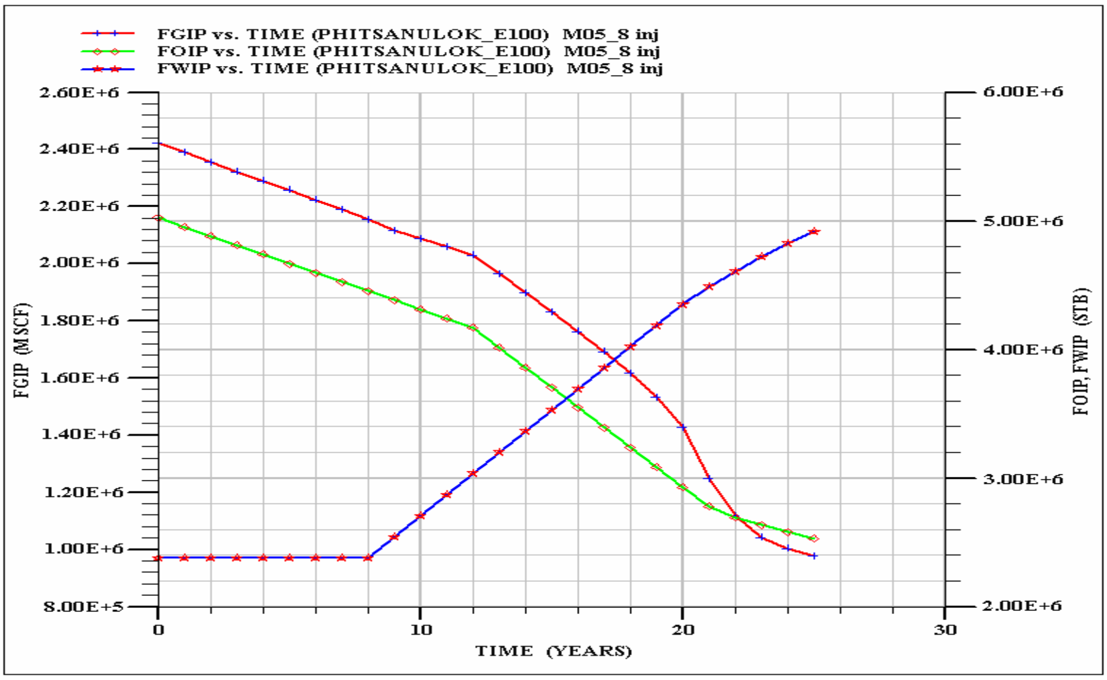

Figure 4.93 Fluid in place profile vs. Time of model M05_8 inj

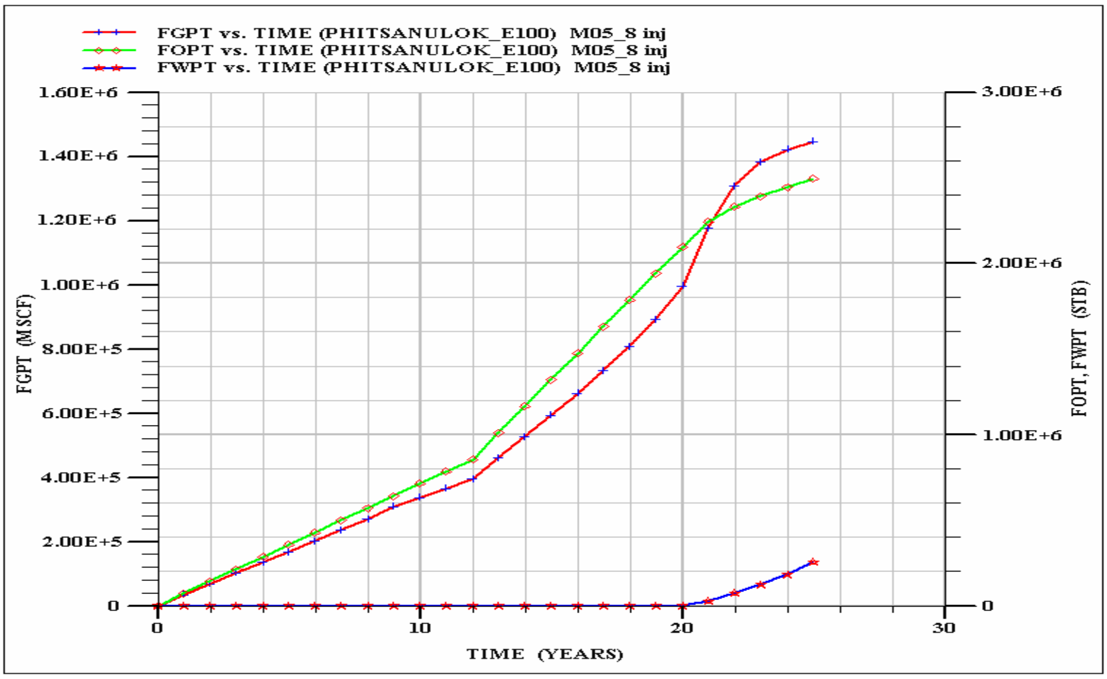

Figure 4.94 Cumulative fluids production profile vs. Time of model M05_8 inj.

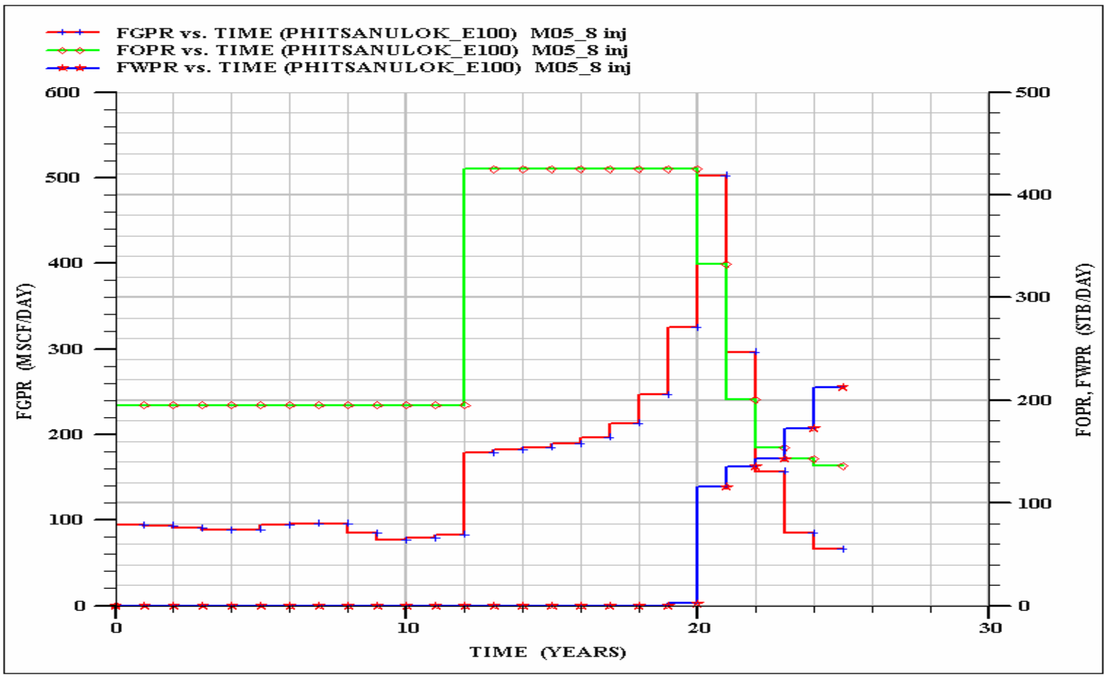

Figure 4.95 Fluids production rate profile vs. Time of model M05_8 inj.

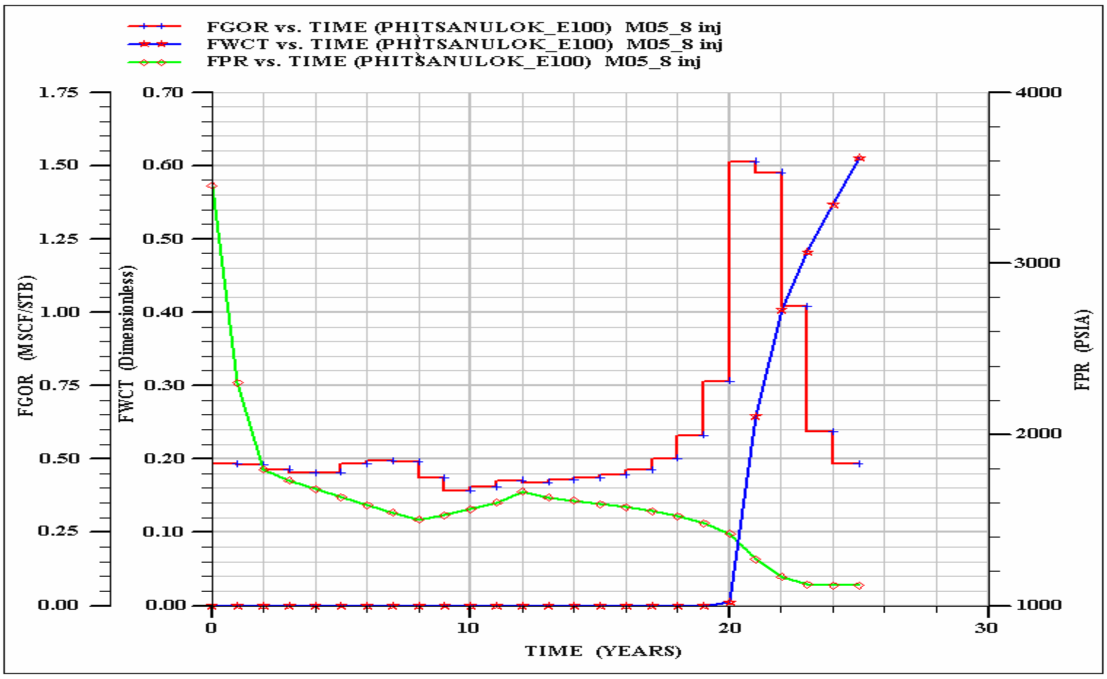

Figure 4.96 GOR, WCT, and Pressure profile vs. Time of model M05_8 inj.

Table 4.26 Summary detail of graph 4.93 and 4.94.

Fluid type	**Cumulative production**	**Initial fluid in place**	**RF (%)**
Oil (STB)	2,495,011	5,023,991	49.66
Gas (MSCF)	1,446,826	2,424,042	59.69
Water (STB)	254,455	2,380,078	10.69

Figure 4.95, show FOPR remain constant rate at 195 BOPD over the first 12 years, after that jump suddenly to 425 BOPD at the 13th year and stay the same rate through the 20th year, next it drop rapidly to 135 BOPD at the end. This production trend effected by FPR (see figure 4.96) improved and maintained around 1,500-1,600 psia till the 18th year, after that it drop gradually through the end of production period (starting effected by WCT at 20th year).

Table 4.27 Reservoir Simulation Result Summary.

Model Name	Scenario No.	Scenario Name.	Cum. Oil Production per Year (BBL)	Cum. Water Production per Year (BBL)	Recover Factor (RF) (%)
A20	1	A20_no inj	5,052,435	-	25.02
	2	A20_2 inj	11,264,666	5,950,624	55.78
	3	A20_4 inj	10,151,359	4,364,221	50.26
	4	A20_8 inj	9,082,409	2,259,092	44.96
A10	5	A10_no inj	2,224,570	-	21.97
	6	A10_2 inj	5,733,226	1,756,893	56.61
	7	A10_4 inj	5,182,266	1,359,471	51.17
	8	A10_8 inj	4,570,141	630,155	45.13
A05	9	A05_no inj	1,183,511	-	23.62
	10	A05_2 inj	2,723,317	760,869	54.34
	11	A05_4 inj	2,574,744	615,139	51.38
	12	A05_8 inj	2,348,090	481,591	46.85
M20	13	M20_no inj	5,486,531	-	27.31
	14	M20_2 inj	11,602,345	4,282,326	57.76
	15	M20_4 inj	11,283,936	3,354,161	56.17
	16	M20_8 inj	10,331,622	1,610,721	51.43
M10	17	M10_no inj	2,781,504	-	27.62
	18	M10_2 inj	5,687,946	1,985,805	56.49
	19	M10_4 inj	5,598,326	1,520,618	55.60
	20	M10_8 inj	5,016,365	777,300	49.82
M05	21	M05_no inj	1,352,225	-	26.92
	22	M05_2 inj	2,738,695	881,436	54.51
	23	M05_4 inj	2,665,606	642,253	53.06
	24	M05_8 inj	2,495,011	254,455	49.66

CHAPTER V

ECONOMIC ANALYSIS

5.1 Objective

The objective of this chapter is to determine economic parameters that used to analyze project investment possibility including of the net present value (NPV), profit investment ratio (PIR) and internal rate of return (IRR). The 6 STOIIP size (3 size of each monocline and anticline structure) with 4 production scenarios per size were compute and compare to show the best time to start water injection activity.

5.2 Exploration and Production Schedule

The exploration period and production region following under the Petroleum Acts "Thailand III" statute are divided into 4 years of exploration period and 25 years of production period. The work plan of project can summarize as follow.

1st year: Petroleum concession

2nd year: Geological and geophysical survey

3rd year: Drill exploration well

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

5th year: Starting the production plan

The production plan divided into 4 scenarios:

- Natural flow (no water injection activity applied)
- Applied water injection after 2nd, 4th, and 8th year of production period

5.3 Economic Assumption

5.3.1 Basic assumptions

a.	Oil price (US$)	70
b.	Income tax (%)	50
c.	Escalation factor (%)	2
d.	Discount rate (%)	10
e.	Tangible cost (%)	20
f.	Intangible cost (%)	80
g.	Depreciation of tangible cost (%)	20
h.	Reserve size (see Table 5.1)	

Table 5.1 Reserve size and production planning detail.

Reserve Size (MMSTB)	Model Name	Initial Production Well	Production/Injection Well	Number of Scenario
20	A20	6	2/4	4
10	A10	4	2/2	4
5	A05	3	1/2	4
20	M20	6	3/3	4
10	M10	4	2/2	4
5	M05	3	1/2	4
			Total Scenario	24

i. Sliding scale royalty

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

5.3.2 Other assumptions

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

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

c. Discount rate of money is 10.00 percent (Bank of Thailand, January 2009).

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 expenditure cost detail.

Expenditure Cost Detail	A20/M10	A10/M10	A05/M05
Production facility (MM US$)	25	12	5
Drilling and completion production well (MM US$)	1.5	1.5	1.5
Drilling exploration well (MM US$)	1	1	1
Facility costs of production well (MM US$)	0.35	0.35	0.35
Facility costs of injection well (MM US$)	0.25	0.25	0.25
Maintenance costs of injection well (MM US$)	0.12	0.12	0.12
Abandonment cost (MM US$)	0.0125	0.0125	0.0125
Operational costs of Production well (US$/bbl)	20	20	20
Operational cost of Injection water (US$/bbl)	0.5	0.5	0.5

5.3 Cash Flow Summary Results Table

The economic analysis are calculated and analyzed by using Microsoft Excels spreadsheet. The economic summary results of model A20 are illustrated in Table 5.3-5.6, model A10 in Table 5.7-5.10, model A05 in Table 5.11-5.14, model M20 in Table 5.15-5.18, model M10 in Table 5.19-5.22, and model M05 in Table 5.23-5.26, respectively. In Table 5.3-5.26 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 and PIR summary results of all scenarios are illustrated in Table 5.27.

Table 5.3 Cash flow summary of natural flow production of model A20, 6 production well, initial production rate at 780 BOPD, and recovery factor = 25.02%.

Year	Cash Flow Summary							Discount Cash Flow
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	(NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	284,700	19.929	0.000	6.163	0.996	0.000	7.409	4.601
6	284,700	19.929	0.000	6.287	0.996	0.000	7.286	4.113
7	284,700	19.929	0.000	6.412	0.996	0.148	7.013	3.599
8	285,480	19.984	0.000	6.559	0.999	3.533	3.533	1.648
9	284,700	19.929	0.000	6.671	0.996	6.131	6.131	2.600
10	284,700	19.929	0.000	6.805	0.996	6.064	6.064	2.338
11	284,700	19.929	0.000	6.941	0.996	5.996	5.996	2.101
12	285,480	19.984	0.000	7.099	0.999	5.943	5.943	1.894
13	284,700	19.929	0.000	7.221	0.996	5.856	5.856	1.696
14	284,700	19.929	0.000	7.366	0.996	5.783	5.783	1.523
15	284,700	19.929	0.000	7.513	0.996	5.710	5.710	1.367
16	285,480	19.984	0.000	7.684	0.999	5.650	5.650	1.230
17	284,700	19.929	0.000	7.817	0.996	5.558	5.558	1.100
18	284,700	19.929	0.000	7.973	0.996	5.480	5.480	0.986
19	271,117	18.978	0.000	7.744	0.949	5.142	5.142	0.841
20	242,417	16.969	0.000	7.063	0.848	4.529	4.529	0.673
21	194,032	13.582	0.000	5.766	0.679	3.568	3.568	0.482
22	150,382	10.527	0.000	4.559	0.526	2.721	2.721	0.334
23	112,048	7.843	0.000	3.464	0.392	1.993	1.993	0.223
24	94,301	6.601	0.000	2.974	0.330	1.648	1.648	0.167
Total	**5,052,435**	**353.670**	**43.000**	**130.083**	**17.684**	**81.452**	**81.452**	**17.557**
						IRR	23.51%	12.28%
						PIR	1.894	0.814

Table 5.4 Cash flow summary of the 2nd water injection production of model A20, (2/4) production/injection well, initial production rate at 1,680 BOPD, water injection rate at 2,200 BWPD, and recovery factor = 55.78%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	613,200	42.924	0.000	13.275	2.146	0.291	21.851	13.568
6	613,200	42.924	0.000	13.540	2.146	10.939	10.939	6.175
7	613,200	42.924	1.050	15.962	2.146	9.603	9.603	4.928
8	614,880	43.042	0.000	16.283	2.152	9.523	9.523	4.443
9	613,200	42.924	0.000	16.538	2.146	12.020	12.020	5.098
10	613,200	42.924	0.000	16.836	2.146	11.871	11.871	4.577
11	613,200	42.924	0.000	17.145	2.146	11.716	11.716	4.106
12	614,880	43.042	0.000	17.493	2.152	11.698	11.698	3.727
13	613,200	42.924	0.000	17.768	2.146	11.505	11.505	3.332
14	613,200	42.924	0.000	18.092	2.146	11.343	11.343	2.987
15	613,200	42.924	0.000	18.426	2.146	11.176	11.176	2.675
16	614,880	43.042	0.000	18.803	2.152	11.043	11.043	2.403
17	613,200	42.924	0.000	19.101	2.146	10.839	10.839	2.144
18	544,875	38.141	0.000	17.537	1.907	9.348	9.348	1.681
19	413,968	28.978	0.000	14.121	1.449	6.704	6.704	1.096
20	351,112	24.578	0.000	12.535	1.229	5.407	5.407	0.804
21	307,559	21.529	0.000	11.460	1.076	4.497	4.497	0.608
22	275,239	19.267	0.000	10.677	0.963	3.813	3.813	0.468
23	249,741	17.482	0.000	10.074	0.874	3.267	3.267	0.365
24	229,487	16.064	0.000	9.600	0.803	2.830	2.830	0.287
25	211,144	14.780	0.000	9.170	0.739	2.435	2.435	0.225
26	195,486	13.684	0.000	8.808	0.684	2.096	2.096	0.176
27	181,926	12.735	0.000	8.502	0.637	1.798	1.798	0.137
28	169,961	11.897	0.000	8.227	0.595	1.538	1.538	0.107
29	157,528	11.027	0.000	7.927	0.551	1.274	1.274	0.080
Total	**11,264,666**	**788.527**	**44.050**	**347.903**	**39.426**	**178.574**	**178.574**	**50.241**
						IRR	44.97%	31.79%
						PIR	4.054	1.141

Table 5.5 Cash flow summary of the 4th water injection production of model A20, (2/4) production/injection well, initial production rate at 1,440 BOPD, water injection rate at 2,200 BWPD, and recovery factor = 50.26%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	525,600	36.792	0.000	11.379	1.840	0.000	18.214	11.309
6	525,600	36.792	0.000	11.606	1.840	7.320	10.666	6.021
7	525,600	36.792	0.000	11.838	1.840	8.877	8.877	4.555
8	527,040	36.893	0.000	12.108	1.845	8.790	8.790	4.101
9	525,600	36.792	1.050	14.485	1.840	10.109	10.109	4.287
10	525,600	36.792	0.000	14.742	1.840	10.005	10.005	3.857
11	513,500	35.945	0.000	14.715	1.797	9.617	9.617	3.371
12	481,133	33.679	0.000	14.167	1.684	8.814	8.814	2.808
13	467,838	32.749	0.000	14.081	1.637	8.415	8.415	2.438
14	467,285	32.710	0.000	14.317	1.635	8.379	8.379	2.206
15	434,675	30.427	0.000	13.715	1.521	7.596	7.596	1.818
16	404,132	28.289	0.000	13.130	1.414	6.872	6.872	1.496
17	387,388	27.117	0.000	12.901	1.356	6.430	6.430	1.272
18	384,104	26.887	0.000	13.035	1.344	6.254	6.254	1.125
19	384,629	26.924	0.000	13.283	1.346	6.147	6.147	1.005
20	385,048	26.953	0.000	13.524	1.348	6.041	6.041	0.898
21	380,836	26.659	0.000	13.637	1.333	5.844	5.844	0.790
22	371,211	25.985	0.000	13.586	1.299	5.550	5.550	0.682
23	349,225	24.446	0.000	13.150	1.222	5.037	5.037	0.562
24	321,260	22.488	0.000	12.495	1.124	4.434	4.434	0.450
25	294,091	20.586	0.000	11.839	1.029	3.859	3.859	0.356
26	270,388	18.927	0.000	11.265	0.946	3.358	3.358	0.282
27	250,263	17.518	0.000	10.790	0.876	2.926	2.926	0.223
28	233,139	16.320	0.000	10.384	0.816	2.560	2.560	0.178
29	216,177	15.132	0.000	9.969	0.757	2.203	2.203	0.139
Total	**10,151,359**	**710.595**	**44.050**	**320.141**	**35.530**	**155.437**	**155.437**	**40.273**
						IRR	39.85%	27.14%
						PIR	3.529	0.914

Table 5.6 Cash flow summary of the 8th water injection production of model A20, (2/4) production/injection well, initial production rate at 960 BOPD, water injection rate at 2,200 BWPD, and recovery factor = 44.96%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@10%)
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	350,400	24.528	0.000	7.586	1.226	0.000	10.356	6.430
6	350,400	24.528	0.000	7.737	1.226	0.000	10.204	5.760
7	350,400	24.528	0.000	7.892	1.226	4.525	5.525	2.835
8	351,360	24.595	0.000	8.072	1.230	4.967	4.967	2.317
9	350,400	24.528	0.000	8.211	1.226	7.545	7.545	3.200
10	350,400	24.528	0.000	8.375	1.226	7.463	7.463	2.877
11	350,400	24.528	0.000	8.543	1.226	7.379	7.379	2.586
12	351,360	24.595	0.000	8.737	1.230	7.314	7.314	2.330
13	329,191	23.043	1.050	10.565	1.152	5.538	5.538	1.604
14	300,814	21.057	0.000	10.010	1.053	4.897	4.897	1.290
15	303,930	21.275	0.000	10.264	1.064	4.874	4.874	1.167
16	328,703	23.009	0.000	11.100	1.150	5.279	5.279	1.149
17	434,911	30.444	0.000	14.206	1.522	7.258	7.258	1.436
18	456,444	31.951	0.000	15.061	1.598	7.646	7.646	1.375
19	445,054	31.154	0.000	15.009	1.558	7.294	7.294	1.193
20	397,010	27.791	0.000	13.873	1.390	6.264	6.264	0.931
21	380,420	26.629	0.000	13.625	1.331	5.836	5.836	0.789
22	378,703	26.509	0.000	13.813	1.325	5.685	5.685	0.698
23	389,356	27.255	0.000	14.391	1.363	5.750	5.750	0.642
24	404,506	28.315	0.000	15.120	1.416	5.890	5.890	0.598
25	396,282	27.740	0.000	15.126	1.387	5.613	5.613	0.518
26	374,663	26.226	0.000	14.687	1.311	5.114	5.114	0.429
27	346,751	24.273	0.000	14.019	1.214	4.520	4.520	0.345
28	319,001	22.330	0.000	13.315	1.117	3.949	3.949	0.274
29	291,552	20.409	0.000	12.594	1.020	3.397	3.397	0.214
Total	**9,082,409**	**635.769**	**44.050**	**291.930**	**31.788**	**134.000**	**134.000**	**27.032**
						IRR	28.62%	16.92%
						PIR	3.042	0.614

Table 5.7 Cash flow summary of natural flow production of model A10, 4 production well, initial production rate at 360 BOPD, and recovery factor = 21.97%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	131,400	9.198	0.000	2.845	0.460	0.000	3.253	2.020
6	131,400	9.198	0.000	2.902	0.460	0.000	3.197	1.804
7	131,400	9.198	0.000	2.960	0.460	0.000	3.139	1.611
8	131,760	9.223	0.000	3.027	0.461	0.122	2.973	1.387
9	131,400	9.198	0.000	3.079	0.460	2.829	2.829	1.200
10	131,400	9.198	0.000	3.141	0.460	2.799	2.799	1.079
11	131,400	9.198	0.000	3.204	0.460	2.767	2.767	0.970
12	131,760	9.223	0.000	3.277	0.461	2.743	2.743	0.874
13	131,400	9.198	0.000	3.333	0.460	2.703	2.703	0.783
14	131,400	9.198	0.000	3.400	0.460	2.669	2.669	0.703
15	131,400	9.198	0.000	3.468	0.460	2.635	2.635	0.631
16	131,760	9.223	0.000	3.547	0.461	2.608	2.608	0.568
17	131,400	9.198	0.000	3.608	0.460	2.565	2.565	0.508
18	131,400	9.198	0.000	3.680	0.460	2.529	2.529	0.455
19	128,225	8.976	0.000	3.663	0.449	2.432	2.432	0.398
20	93,521	6.546	0.000	2.725	0.327	1.747	1.747	0.260
21	61,776	4.324	0.000	1.836	0.216	1.136	1.136	0.154
22	43,129	3.019	0.000	1.307	0.151	0.780	0.780	0.096
23	31,484	2.204	0.000	0.973	0.110	0.560	0.560	0.063
24	25,755	1.803	0.000	0.812	0.090	0.450	0.450	0.046
Total	**2,224,570**	**155.720**	**23.000**	**56.783**	**7.786**	**34.075**	**34.075**	**6.460**
						IRR	19.45%	8.59%
						PIR	1.482	0.281

Table 5.8 Cash flow summary of the 2nd water injection production of model A10, (2/2) production/injection well, initial production rate at 760 BOPD, water injection rate at 1,000 BWPD, and recovery factor = 56.61%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	292,000	20.440	0.000	6.321	1.022	0.000	10.457	6.493
6	292,000	20.440	0.000	6.448	1.022	4.173	6.157	3.475
7	292,000	20.440	0.525	7.213	1.022	4.720	4.720	2.422
8	292,800	20.496	0.000	7.367	1.025	4.682	4.682	2.184
9	292,000	20.440	0.000	7.489	1.022	5.915	5.915	2.508
10	292,000	20.440	0.000	7.631	1.022	5.843	5.843	2.253
11	292,000	20.440	0.000	7.777	1.022	5.770	5.770	2.022
12	292,800	20.496	0.000	7.945	1.025	5.763	5.763	1.836
13	292,000	20.440	0.000	8.076	1.022	5.671	5.671	1.643
14	292,000	20.440	0.000	8.230	1.022	5.594	5.594	1.473
15	292,000	20.440	0.000	8.388	1.022	5.515	5.515	1.320
16	292,800	20.496	0.000	8.569	1.025	5.451	5.451	1.186
17	292,000	20.440	0.000	8.712	1.022	5.353	5.353	1.059
18	292,000	20.440	0.000	8.878	1.022	5.270	5.270	0.948
19	292,000	20.440	0.000	9.050	1.022	5.184	5.184	0.848
20	292,800	20.496	0.000	9.246	1.025	5.113	5.113	0.760
21	238,326	16.683	0.000	7.804	0.834	4.022	4.022	0.544
22	104,639	7.325	0.000	3.901	0.366	1.529	1.529	0.188
23	82,953	5.807	0.000	3.302	0.290	1.107	1.107	0.124
24	98,091	6.866	0.000	3.837	0.343	1.343	1.343	0.136
25	107,567	7.530	0.000	4.211	0.376	1.471	1.471	0.136
26	109,926	7.695	0.000	4.366	0.385	1.472	1.472	0.124
27	109,831	7.688	0.000	4.443	0.384	1.430	1.430	0.109
28	106,614	7.463	0.000	4.414	0.373	1.338	1.338	0.093
29	100,081	7.006	0.000	4.268	0.350	1.194	1.194	0.075
Total	**5,733,226**	**401.326**	**23.525**	**167.887**	**20.066**	**94.924**	**94.924**	**24.813**
						IRR	40.72%	27.93%
						PIR	4.035	1.055

Table 5.9 Cash flow summary of the 4th water injection production of model A10, (2/2) production/injection well, initial production rate at 680 BOPD, water injection rate at 1,000 BWPD, and recovery factor = 51.17%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	248,200	17.374	0.000	5.373	0.869	0.000	8.492	5.273
6	248,200	17.374	0.000	5.481	0.869	2.218	6.166	3.481
7	248,200	17.374	0.000	5.590	0.869	4.138	4.138	2.123
8	248,880	17.422	0.000	5.718	0.871	4.096	4.096	1.911
9	248,200	17.374	0.525	6.462	0.869	4.959	4.959	2.103
10	248,200	17.374	0.000	6.584	0.869	4.911	4.911	1.893
11	248,200	17.374	0.000	6.710	0.869	4.848	4.848	1.699
12	248,880	17.422	0.000	6.852	0.871	4.799	4.799	1.529
13	248,200	17.374	0.000	6.965	0.869	4.720	4.720	1.367
14	220,187	15.413	0.000	6.372	0.771	4.135	4.135	1.089
15	180,076	12.605	0.000	5.435	0.630	3.270	3.270	0.783
16	186,879	13.082	0.000	5.718	0.654	3.355	3.355	0.730
17	207,129	14.499	0.000	6.381	0.725	3.696	3.696	0.731
18	214,338	15.004	0.000	6.704	0.750	3.775	3.775	0.679
19	213,275	14.929	0.000	6.801	0.746	3.691	3.691	0.603
20	207,430	14.520	0.000	6.758	0.726	3.518	3.518	0.523
21	199,396	13.958	0.000	6.647	0.698	3.306	3.306	0.447
22	190,526	13.337	0.000	6.504	0.667	3.083	3.083	0.379
23	183,140	12.820	0.000	6.400	0.641	2.890	2.890	0.323
24	177,944	12.456	0.000	6.355	0.623	2.739	2.739	0.278
25	170,099	11.907	0.000	6.223	0.595	2.544	2.544	0.235
26	161,183	11.283	0.000	6.048	0.564	2.336	2.336	0.196
27	152,279	10.659	0.000	5.864	0.533	2.131	2.131	0.163
28	145,474	10.183	0.000	5.741	0.509	1.967	1.967	0.136
29	137,754	9.643	0.000	5.579	0.482	1.791	1.791	0.113
Total	**5,182,266**	**362.759**	**23.525**	**155.266**	**18.138**	**82.915**	**82.915**	**19.641**
						IRR	35.56%	23.24%
						PIR	3.525	0.835

Table 5.10 Cash flow summary of the 8th water injection production of model A10, (2/2) production/injection well, initial production rate at 440 BOPD, water injection rate at 1,000 BWPD, and recovery factor = 45.13%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	160,600	11.242	0.000	3.477	0.562	0.000	4.563	2.833
6	160,600	11.242	0.000	3.546	0.562	0.000	4.494	2.537
7	160,600	11.242	0.000	3.617	0.562	0.520	3.903	2.003
8	161,040	11.273	0.000	3.700	0.564	2.185	2.185	1.019
9	160,600	11.242	0.000	3.763	0.562	3.458	3.458	1.467
10	160,600	11.242	0.000	3.839	0.562	3.421	3.421	1.319
11	160,600	11.242	0.000	3.915	0.562	3.382	3.382	1.185
12	161,040	11.273	0.000	4.005	0.564	3.352	3.352	1.068
13	160,600	11.242	0.525	4.743	0.562	2.906	2.906	0.842
14	160,600	11.242	0.000	4.831	0.562	2.875	2.875	0.757
15	160,600	11.242	0.000	4.921	0.562	2.830	2.830	0.677
16	161,040	11.273	0.000	5.023	0.564	2.793	2.793	0.608
17	227,016	15.891	0.000	6.927	0.795	4.035	4.035	0.798
18	202,529	14.177	0.000	6.373	0.709	3.548	3.548	0.638
19	196,480	13.754	0.000	6.321	0.688	3.372	3.372	0.551
20	219,290	15.350	0.000	7.104	0.768	3.739	3.739	0.556
21	229,535	16.067	0.000	7.543	0.803	3.860	3.860	0.522
22	224,295	15.701	0.000	7.528	0.785	3.694	3.694	0.454
23	216,821	15.177	0.000	7.441	0.759	3.489	3.489	0.390
24	208,636	14.605	0.000	7.323	0.730	3.275	3.275	0.333
25	199,246	13.947	0.000	7.161	0.697	3.045	3.045	0.281
26	189,551	13.269	0.000	6.978	0.663	2.813	2.813	0.236
27	182,742	12.792	0.000	6.884	0.640	2.634	2.634	0.201
28	176,818	12.377	0.000	6.811	0.619	2.474	2.474	0.172
29	168,662	11.806	0.000	6.656	0.590	2.280	2.280	0.144
Total	**4,570,141**	**319.910**	**23.525**	**140.429**	**15.995**	**69.980**	**69.980**	**12.443**
						IRR	24.64%	13.31%
						PIR	2.975	0.529

Table 5.11 Cash flow summary of natural flow production of model A05, 2 production well, initial production rate at 300 BOPD, and recovery factor = 23.62%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	8.000	0.000	0.000	0.000	-3.520	-2.404
5	109,500	7.665	0.000	2.371	0.383	0.000	3.791	2.354
6	109,500	7.665	0.000	2.418	0.383	0.758	2.986	1.686
7	109,500	7.665	0.000	2.466	0.383	1.848	1.848	0.948
8	109,800	7.686	0.000	2.523	0.384	1.830	1.830	0.854
9	109,500	7.665	0.000	2.566	0.383	2.358	2.358	1.000
10	109,500	7.665	0.000	2.617	0.383	2.332	2.332	0.899
11	109,500	7.665	0.000	2.670	0.383	2.306	2.306	0.808
12	109,800	7.686	0.000	2.730	0.384	2.286	2.286	0.728
13	109,500	7.665	0.000	2.777	0.383	2.252	2.252	0.652
14	84,143	5.890	0.000	2.177	0.294	1.709	1.709	0.450
15	41,744	2.922	0.000	1.102	0.146	0.837	0.837	0.200
16	24,549	1.718	0.000	0.661	0.086	0.486	0.486	0.106
17	17,998	1.260	0.000	0.494	0.063	0.351	0.351	0.070
18	15,142	1.060	0.000	0.424	0.053	0.291	0.291	0.052
19	13,836	0.969	0.000	0.395	0.048	0.262	0.262	0.043
Total	**1,183,511**	**82.846**	**10.500**	**28.391**	**4.142**	**19.906**	**19.906**	**6.414**
						IRR	32.96%	20.87%
						PIR	1.896	1.065

Table 5.12 Cash flow summary of the 2nd water injection production of model A05, (1/2) production/injection well, initial production rate at 360 BOPD, water injection rate at 500 BWPD, and recovery factor = 54.34%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	131,400	9.198	0.000	2.845	0.460	0.000	4.713	2.927
6	131,400	9.198	0.000	2.902	0.460	1.045	3.612	2.039
7	131,400	9.198	0.525	3.413	0.460	2.010	2.010	1.032
8	131,760	9.223	0.000	3.485	0.461	1.998	1.998	0.932
9	131,400	9.198	0.000	3.543	0.460	2.548	2.548	1.080
10	131,400	9.198	0.000	3.610	0.460	2.514	2.514	0.969
11	131,400	9.198	0.000	3.679	0.460	2.480	2.480	0.869
12	131,760	9.223	0.000	3.757	0.461	2.502	2.502	0.797
13	131,400	9.198	0.000	3.820	0.460	2.459	2.459	0.712
14	131,400	9.198	0.000	3.893	0.460	2.423	2.423	0.638
15	131,400	9.198	0.000	3.967	0.460	2.385	2.385	0.571
16	131,760	9.223	0.000	4.052	0.461	2.355	2.355	0.513
17	131,400	9.198	0.000	4.120	0.460	2.309	2.309	0.457
18	131,400	9.198	0.000	4.198	0.460	2.270	2.270	0.408
19	131,400	9.198	0.000	4.279	0.460	2.229	2.229	0.365
20	131,760	9.223	0.000	4.371	0.461	2.195	2.195	0.326
21	131,400	9.198	0.000	4.444	0.460	2.147	2.147	0.290
22	131,400	9.198	0.000	4.529	0.460	2.104	2.104	0.259
23	75,232	5.266	0.000	2.880	0.263	1.061	1.061	0.119
24	21,684	1.518	0.000	1.245	0.076	0.099	0.099	0.010
25	21,011	1.471	0.000	1.244	0.074	0.076	0.076	0.007
26	41,631	2.914	0.000	1.942	0.146	0.413	0.413	0.035
27	59,787	4.185	0.000	2.586	0.209	0.695	0.695	0.053
28	67,783	4.745	0.000	2.906	0.237	0.801	0.801	0.056
29	69,548	4.868	0.000	3.022	0.243	0.801	0.801	0.051
Total	**2,723,317**	**190.632**	**12.525**	**84.733**	**9.532**	**41.921**	**41.921**	**10.216**
						IRR	34.32%	22.11%
						PIR	3.347	0.816

Table 5.13 Cash flow summary of the 4th water injection production of model A05, (1/2) production/injection well, initial production rate at 240 BOPD, water injection rate at 500 BWPD, and recovery factor = 51.38%.

Year	**Cash Flow Summary**							**Discount**
	Cum. Oil	**Gross**	**Capex**	**Opex**	**Government Take**		**Annual**	**Cash Flow**
	Prod.	**Revenue**			**Royalty**	**Inc. Tax**	**Cash Flow**	**(NPV@10%)**
	(bbl/year)	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**	**MMUS$**
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	87,600	6.132	0.000	1.896	0.307	0.000	2.749	1.707
6	87,600	6.132	0.000	1.934	0.307	0.000	2.711	1.530
7	87,600	6.132	0.000	1.973	0.307	0.426	2.246	1.153
8	87,840	6.149	0.000	2.018	0.307	1.322	1.322	0.617
9	87,600	6.132	0.525	2.516	0.307	1.592	1.592	0.675
10	87,600	6.132	0.000	2.563	0.307	1.581	1.581	0.610
11	87,600	6.132	0.000	2.611	0.307	1.557	1.557	0.546
12	133,590	9.351	0.000	3.803	0.468	2.490	2.490	0.794
13	133,225	9.326	0.000	3.866	0.466	2.447	2.447	0.709
14	133,225	9.326	0.000	3.940	0.466	2.460	2.460	0.648
15	133,225	9.326	0.000	4.015	0.466	2.422	2.422	0.580
16	133,590	9.351	0.000	4.101	0.468	2.391	2.391	0.520
17	133,225	9.326	0.000	4.170	0.466	2.345	2.345	0.464
18	133,225	9.326	0.000	4.250	0.466	2.305	2.305	0.415
19	133,225	9.326	0.000	4.331	0.466	2.264	2.264	0.370
20	133,590	9.351	0.000	4.424	0.468	2.230	2.230	0.331
21	133,225	9.326	0.000	4.498	0.466	2.181	2.181	0.295
22	133,225	9.326	0.000	4.585	0.466	2.137	2.137	0.263
23	133,225	9.326	0.000	4.673	0.466	2.093	2.093	0.234
24	133,590	9.351	0.000	4.774	0.468	2.055	2.055	0.209
25	77,717	5.440	0.000	3.069	0.272	1.050	1.050	0.097
26	22,830	1.598	0.000	1.325	0.080	0.096	0.096	0.008
27	22,618	1.583	0.000	1.342	0.079	0.081	0.081	0.006
28	44,010	3.081	0.000	2.095	0.154	0.416	0.416	0.029
29	60,744	4.252	0.000	2.715	0.213	0.662	0.662	0.042
Total	**2,574,744**	**180.232**	**12.525**	**81.490**	**9.012**	**38.603**	**38.603**	**7.551**
						IRR	25.62%	14.20%
						PIR	3.082	0.603

Table 5.14 Cash flow summary of the 8th water injection production of model A05, (1/2) production/injection well, initial production rate at 135 BOPD, water injection rate at 500 BWPD, and recovery factor = 46.85%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	49,275	3.449	0.000	1.067	0.172	0.000	1.030	0.640
6	49,275	3.449	0.000	1.088	0.172	0.000	1.009	0.569
7	49,275	3.449	0.000	1.110	0.172	0.000	0.987	0.506
8	49,410	3.459	0.000	1.135	0.173	0.000	0.971	0.453
9	49,275	3.449	0.000	1.155	0.172	0.000	2.122	0.900
10	49,275	3.449	0.000	1.178	0.172	0.469	1.630	0.629
11	49,275	3.449	0.000	1.201	0.172	1.038	1.038	0.364
12	49,410	3.459	0.000	1.229	0.173	1.029	1.029	0.328
13	49,275	3.449	0.530	1.737	0.172	0.705	0.705	0.204
14	49,275	3.449	0.000	1.768	0.172	0.704	0.704	0.186
15	49,275	3.449	0.000	1.800	0.172	0.688	0.688	0.165
16	135,420	9.479	0.000	4.151	0.474	2.377	2.377	0.517
17	135,050	9.454	0.000	4.220	0.473	2.330	2.330	0.461
18	135,050	9.454	0.000	4.301	0.473	2.340	2.340	0.421
19	135,050	9.454	0.000	4.383	0.473	2.299	2.299	0.376
20	135,420	9.479	0.000	4.478	0.474	2.264	2.264	0.337
21	135,050	9.454	0.000	4.553	0.473	2.214	2.214	0.299
22	135,050	9.454	0.000	4.640	0.473	2.170	2.170	0.267
23	135,050	9.454	0.000	4.730	0.473	2.126	2.126	0.237
24	135,420	9.479	0.000	4.832	0.474	2.087	2.087	0.212
25	135,050	9.454	0.000	4.913	0.473	2.034	2.034	0.188
26	135,050	9.454	0.000	5.008	0.473	1.987	1.987	0.167
27	135,050	9.454	0.000	5.105	0.473	1.938	1.938	0.148
28	125,734	8.801	0.000	4.884	0.440	1.738	1.738	0.121
29	58,351	4.085	0.000	2.632	0.204	0.624	0.624	0.039
Total	**2,348,090**	**164.366**	**12.530**	**77.295**	**8.218**	**33.161**	**33.161**	**3.435**
						IRR	15.88%	5.34%
						PIR	2.647	0.274

Table 5.15 Cash flow summary of natural flow production of model M20, 6 production well, initial production rate at 900 BOPD, and recovery factor = 27.31%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@10%)
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	328,500	22.995	0.000	7.112	1.150	0.000	9.374	5.820
6	328,500	22.995	0.000	7.254	1.150	0.000	9.231	5.211
7	328,500	22.995	0.000	7.399	1.150	3.066	6.021	3.090
8	329,400	23.058	0.000	7.568	1.153	4.489	4.489	2.094
9	328,500	22.995	0.000	7.698	1.150	7.074	7.074	3.000
10	328,500	22.995	0.000	7.852	1.150	6.997	6.997	2.698
11	328,500	22.995	0.000	8.009	1.150	6.918	6.918	2.425
12	329,400	23.058	0.000	8.191	1.153	6.857	6.857	2.185
13	328,500	22.995	0.000	8.332	1.150	6.756	6.756	1.957
14	328,500	22.995	0.000	8.499	1.150	6.673	6.673	1.757
15	328,500	22.995	0.000	8.669	1.150	6.588	6.588	1.577
16	329,400	23.058	0.000	8.867	1.153	6.519	6.519	1.419
17	328,500	22.995	0.000	9.019	1.150	6.413	6.413	1.269
18	311,792	21.825	0.000	8.732	1.091	6.001	6.001	1.079
19	244,039	17.083	0.000	6.971	0.854	4.629	4.629	0.757
20	187,227	13.106	0.000	5.455	0.655	3.498	3.498	0.520
21	137,591	9.631	0.000	4.089	0.482	2.530	2.530	0.342
22	118,935	8.325	0.000	3.605	0.416	2.152	2.152	0.264
23	108,199	7.574	0.000	3.345	0.379	1.925	1.925	0.215
24	105,549	7.388	0.000	3.329	0.369	1.845	1.845	0.187
Total	**5,486,531**	**384.057**	**43.000**	**139.994**	**19.203**	**90.930**	**90.930**	**21.909**
						IRR	27.02%	15.48%
						PIR	2.115	1.016

Table 5.16 Cash flow summary of the 2nd water injection production of model M20, (3/3) production/injection well, initial production rate at 1,680 BOPD, water injection rate at 1,800 BWPD, and recovery factor = 57.76%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@10%)
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	613,200	42.924	0.000	13.275	2.146	0.291	21.851	13.568
6	613,200	42.924	0.000	13.540	2.146	10.939	10.939	6.175
7	613,200	42.924	0.788	15.205	2.146	10.013	10.013	5.138
8	614,880	43.042	0.000	15.525	2.152	9.927	9.927	4.631
9	613,200	42.924	0.000	15.777	2.146	12.426	12.426	5.270
10	613,200	42.924	0.000	16.072	2.146	12.278	12.278	4.734
11	613,200	42.924	0.000	16.377	2.146	12.126	12.126	4.250
12	614,880	43.042	0.000	16.724	2.152	12.083	12.083	3.850
13	613,200	42.924	0.000	16.996	2.146	11.891	11.891	3.444
14	613,200	42.924	0.000	17.316	2.146	11.731	11.731	3.089
15	613,200	42.924	0.000	17.645	2.146	11.566	11.566	2.769
16	614,880	43.042	0.000	18.021	2.152	11.434	11.434	2.488
17	613,200	42.924	0.000	18.316	2.146	11.231	11.231	2.222
18	613,200	42.924	0.000	18.662	2.146	11.058	11.058	1.989
19	596,265	41.739	0.000	18.535	2.087	10.558	10.558	1.726
20	441,250	30.888	0.000	14.366	1.544	7.488	7.488	1.113
21	338,566	23.700	0.000	11.582	1.185	5.466	5.466	0.739
22	282,324	19.763	0.000	10.089	0.988	4.343	4.343	0.533
23	248,656	17.406	0.000	9.233	0.870	3.651	3.651	0.408
24	228,225	15.976	0.000	8.751	0.799	3.213	3.213	0.326
25	209,743	14.682	0.000	8.312	0.734	2.818	2.818	0.260
26	192,211	13.455	0.000	7.883	0.673	2.450	2.450	0.206
27	174,467	12.213	0.000	7.430	0.611	2.086	2.086	0.159
28	158,194	11.074	0.000	7.000	0.554	1.760	1.760	0.122
29	142,604	9.982	0.000	6.578	0.499	1.453	1.453	0.092
Total	**11,602,345**	**812.164**	**43.788**	**339.210**	**40.608**	**194.279**	**194.279**	**53.344**
						IRR	45.49%	32.27%
						PIR	4.437	1.218

Table 5.17 Cash flow summary of the 4th water injection production of model M20, (3/3) production/injection well, initial production rate at 1,440 BOPD, water injection rate at 1,800 BWPD, and recovery factor = 56.17%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@10%)
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	525,600	36.792	0.000	11.379	1.840	0.000	18.214	11.309
6	525,600	36.792	0.000	11.606	1.840	7.320	10.666	6.021
7	525,600	36.792	0.000	11.838	1.840	8.877	8.877	4.555
8	527,040	36.893	0.000	12.108	1.845	8.790	8.790	4.101
9	525,600	36.792	0.788	13.724	1.840	10.521	10.521	4.462
10	525,600	36.792	0.000	13.979	1.840	10.412	10.412	4.014
11	525,600	36.792	0.000	14.241	1.840	10.281	10.281	3.603
12	527,040	36.893	0.000	14.539	1.845	10.179	10.179	3.243
13	525,600	36.792	0.000	14.774	1.840	10.014	10.014	2.901
14	525,600	36.792	0.000	15.050	1.840	9.951	9.951	2.621
15	525,600	36.792	0.000	15.334	1.840	9.809	9.809	2.348
16	527,040	36.893	0.000	15.657	1.845	9.696	9.696	2.110
17	525,600	36.792	0.000	15.910	1.840	9.521	9.521	1.884
18	525,600	36.792	0.000	16.209	1.840	9.372	9.372	1.686
19	525,600	36.792	0.000	16.516	1.840	9.218	9.218	1.507
20	527,040	36.893	0.000	16.866	1.845	9.091	9.091	1.351
21	525,600	36.792	0.000	17.141	1.840	8.906	8.906	1.203
22	513,968	35.978	0.000	17.111	1.799	8.534	8.534	1.048
23	404,072	28.285	0.000	14.038	1.414	6.416	6.416	0.717
24	326,113	22.828	0.000	11.838	1.141	4.924	4.924	0.500
25	275,240	19.267	0.000	10.419	0.963	3.942	3.942	0.364
26	240,457	16.832	0.000	9.466	0.842	3.262	3.262	0.274
27	214,700	15.029	0.000	8.776	0.751	2.751	2.751	0.210
28	193,882	13.572	0.000	8.219	0.679	2.337	2.337	0.162
29	174,544	12.218	0.000	7.690	0.611	1.959	1.959	0.123
Total	**11,283,936**	**789.876**	**43.788**	**334.427**	**39.494**	**186.084**	**186.084**	**46.361**
						IRR	40.57%	27.79%
						PIR	4.250	1.059

Table 5.18 Cash flow summary of the 8th water injection production of model M20, (3/3) production/injection well, initial production rate at 960 BOPD, water injection rate at 1,800 BWPD, and recovery factor = 51.43%.

Year	Cash Flow Summary							Discount Cash Flow
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	(NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.818
2	0	0.000	4.000	0.000	0.000	0.000	-4.000	-3.306
3	0	0.000	3.000	0.000	0.000	0.000	-3.000	-2.254
4	0	0.000	34.000	0.000	0.000	0.000	-12.560	-8.579
5	350,400	24.528	0.000	7.586	1.226	0.000	10.356	6.430
6	350,400	24.528	0.000	7.737	1.226	0.000	10.204	5.760
7	350,400	24.528	0.000	7.892	1.226	4.525	5.525	2.835
8	351,360	24.595	0.000	8.072	1.230	4.967	4.967	2.317
9	350,400	24.528	0.000	8.211	1.226	7.545	7.545	3.200
10	350,400	24.528	0.000	8.375	1.226	7.463	7.463	2.877
11	350,400	24.528	0.000	8.543	1.226	7.379	7.379	2.586
12	351,360	24.595	0.000	8.737	1.230	7.314	7.314	2.330
13	350,400	24.528	0.788	10.330	1.226	6.392	6.392	1.852
14	350,400	24.528	0.000	10.517	1.226	6.317	6.317	1.664
15	350,400	24.528	0.000	10.710	1.226	6.221	6.221	1.489
16	351,360	24.595	0.000	10.928	1.230	6.144	6.144	1.337
17	629,625	44.074	0.000	18.767	2.204	11.477	11.477	2.271
18	629,625	44.074	0.000	19.122	2.204	11.374	11.374	2.046
19	629,625	44.074	0.000	19.488	2.204	11.191	11.191	1.830
20	631,350	44.195	0.000	19.905	2.210	11.040	11.040	1.641
21	629,625	44.074	0.000	20.232	2.204	10.819	10.819	1.462
22	627,644	43.935	0.000	20.557	2.197	10.591	10.591	1.301
23	486,553	34.059	0.000	16.589	1.703	7.884	7.884	0.880
24	398,937	27.926	0.000	14.135	1.396	6.197	6.197	0.629
25	344,381	24.107	0.000	12.643	1.205	5.129	5.129	0.473
26	312,646	21.885	0.000	11.835	1.094	4.478	4.478	0.376
27	287,888	20.152	0.000	11.226	1.008	3.959	3.959	0.302
28	267,634	18.734	0.000	10.736	0.937	3.531	3.531	0.245
29	248,409	17.389	0.000	10.262	0.869	3.129	3.129	0.197
Total	**10,331,622**	**723.214**	**43.788**	**313.134**	**36.161**	**165.066**	**165.066**	**32.374**
						IRR	29.43%	17.66%
						PIR	3.770	0.739

Table 5.19 Cash flow summary of natural flow production of model M10, 4 production well, initial production rate at 440 BOPD, and recovery factor = 27.62%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	160,600	11.242	0.000	3.477	0.562	0.000	4.563	2.833
6	160,600	11.242	0.000	3.546	0.562	0.000	4.494	2.537
7	160,600	11.242	0.000	3.617	0.562	0.520	3.903	2.003
8	161,040	11.273	0.000	3.700	0.564	2.185	2.185	1.019
9	160,600	11.242	0.000	3.763	0.562	3.458	3.458	1.467
10	160,600	11.242	0.000	3.839	0.562	3.421	3.421	1.319
11	160,600	11.242	0.000	3.915	0.562	3.382	3.382	1.185
12	161,040	11.273	0.000	4.005	0.564	3.352	3.352	1.068
13	160,600	11.242	0.000	4.074	0.562	3.303	3.303	0.957
14	160,600	11.242	0.000	4.155	0.562	3.262	3.262	0.859
15	160,600	11.242	0.000	4.238	0.562	3.221	3.221	0.771
16	161,040	11.273	0.000	4.335	0.564	3.187	3.187	0.694
17	160,600	11.242	0.000	4.409	0.562	3.135	3.135	0.620
18	160,600	11.242	0.000	4.498	0.562	3.091	3.091	0.556
19	130,805	9.156	0.000	3.736	0.458	2.481	2.481	0.406
20	106,716	7.470	0.000	3.109	0.374	1.994	1.994	0.296
21	89,803	6.286	0.000	2.669	0.314	1.652	1.652	0.223
22	72,371	5.066	0.000	2.194	0.253	1.309	1.309	0.161
23	66,907	4.684	0.000	2.069	0.234	1.190	1.190	0.133
24	65,183	4.563	0.000	2.056	0.228	1.139	1.139	0.116
Total	**2,781,504**	**194.705**	**23.000**	**71.403**	**9.735**	**45.283**	**45.283**	**10.076**
						IRR	24.24%	12.95%
						PIR	1.969	0.438

Table 5.20 Cash flow summary of the 2nd water injection production of model M10, (2/2) production/injection well, initial production rate at 760 BOPD, water injection rate at 900 BWPD, and recovery factor = 56.49%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	277,400	19.418	0.000	6.005	0.971	0.000	9.802	6.086
6	277,400	19.418	0.000	6.125	0.971	3.522	6.160	3.477
7	277,400	19.418	0.525	6.848	0.971	4.417	4.417	2.267
8	278,160	19.471	0.000	6.995	0.974	4.382	4.382	2.044
9	277,400	19.418	0.000	7.110	0.971	5.619	5.619	2.383
10	277,400	19.418	0.000	7.246	0.971	5.551	5.551	2.140
11	277,400	19.418	0.000	7.385	0.971	5.481	5.481	1.921
12	278,160	19.471	0.000	7.544	0.974	5.477	5.477	1.745
13	277,400	19.418	0.000	7.669	0.971	5.389	5.389	1.561
14	277,400	19.418	0.000	7.816	0.971	5.316	5.316	1.400
15	277,400	19.418	0.000	7.967	0.971	5.240	5.240	1.254
16	278,160	19.471	0.000	8.139	0.974	5.179	5.179	1.127
17	277,400	19.418	0.000	8.274	0.971	5.086	5.086	1.006
18	277,400	19.418	0.000	8.433	0.971	5.007	5.007	0.901
19	277,400	19.418	0.000	8.596	0.971	4.926	4.926	0.805
20	278,160	19.471	0.000	8.783	0.974	4.857	4.857	0.722
21	277,400	19.418	0.000	8.929	0.971	4.759	4.759	0.643
22	242,139	16.950	0.000	8.032	0.847	4.035	4.035	0.496
23	159,215	11.145	0.000	5.623	0.557	2.482	2.482	0.277
24	121,075	8.475	0.000	4.525	0.424	1.763	1.763	0.179
25	103,555	7.249	0.000	4.046	0.362	1.420	1.420	0.131
26	95,787	6.705	0.000	3.865	0.335	1.252	1.252	0.105
27	89,460	6.262	0.000	3.725	0.313	1.112	1.112	0.085
28	82,628	5.784	0.000	3.559	0.289	0.968	0.968	0.067
29	75,248	5.267	0.000	3.367	0.263	0.819	0.819	0.052
Total	**5,687,946**	**398.156**	**23.525**	**166.606**	**19.908**	**94.059**	**94.059**	**23.728**
						IRR	39.03%	26.39%
						PIR	3.998	1.009

Table 5.21 Cash flow summary of the 4th water injection production of model M10, (2/2) production/injection well, initial production rate at 700 BOPD, water injection rate at 900 BWPD, and recovery factor = 55.60%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	255,500	17.885	0.000	5.531	0.894	0.000	8.820	5.476
6	255,500	17.885	0.000	5.642	0.894	2.544	6.165	3.480
7	255,500	17.885	0.000	5.755	0.894	4.298	4.298	2.206
8	256,200	17.934	0.000	5.886	0.897	4.256	4.256	1.985
9	255,500	17.885	0.525	6.597	0.894	5.134	5.134	2.178
10	255,500	17.885	0.000	6.722	0.894	5.084	5.084	1.960
11	255,500	17.885	0.000	6.851	0.894	5.020	5.020	1.759
12	256,200	17.934	0.000	6.998	0.897	4.970	4.970	1.583
13	255,500	17.885	0.000	7.114	0.894	4.889	4.889	1.416
14	255,500	17.885	0.000	7.249	0.894	4.871	4.871	1.283
15	255,500	17.885	0.000	7.389	0.894	4.801	4.801	1.149
16	256,200	17.934	0.000	7.548	0.897	4.745	4.745	1.033
17	255,500	17.885	0.000	7.673	0.894	4.659	4.659	0.922
18	255,500	17.885	0.000	7.820	0.894	4.585	4.585	0.825
19	255,500	17.885	0.000	7.971	0.894	4.510	4.510	0.737
20	256,200	17.934	0.000	8.143	0.897	4.447	4.447	0.661
21	255,500	17.885	0.000	8.278	0.894	4.356	4.356	0.589
22	255,500	17.885	0.000	8.437	0.894	4.277	4.277	0.525
23	255,500	17.885	0.000	8.600	0.894	4.195	4.195	0.469
24	221,665	15.517	0.000	7.698	0.776	3.521	3.521	0.358
25	146,751	10.273	0.000	5.435	0.514	2.162	2.162	0.200
26	109,708	7.680	0.000	4.322	0.384	1.487	1.487	0.125
27	93,153	6.521	0.000	3.849	0.326	1.173	1.173	0.089
28	87,593	6.131	0.000	3.728	0.307	1.048	1.048	0.073
29	82,157	5.751	0.000	3.607	0.288	0.928	0.928	0.059
Total	**5,598,326**	391.883	23.525	164.842	19.594	91.961	91.961	21.992
						IRR	36.81%	24.37%
						PIR	3.909	0.935

Table 5.22 Cash flow summary of the 8th water injection production of model M10, (2/2) production/injection well, initial production rate at 500 BOPD, water injection rate at 900 BWPD, and recovery factor = 49.82%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.909
2	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.653
3	0	0.000	2.000	0.000	0.000	0.000	-2.000	-1.503
4	0	0.000	18.000	0.000	0.000	0.000	-7.440	-5.082
5	182,500	12.775	0.000	3.951	0.639	0.000	5.545	3.443
6	182,500	12.775	0.000	4.030	0.639	0.000	5.466	3.086
7	182,500	12.775	0.000	4.110	0.639	1.979	3.407	1.748
8	183,000	12.810	0.000	4.204	0.641	2.663	2.663	1.242
9	182,500	12.775	0.000	4.277	0.639	3.930	3.930	1.667
10	182,500	12.775	0.000	4.362	0.639	3.887	3.887	1.499
11	182,500	12.775	0.000	4.449	0.639	3.843	3.843	1.347
12	183,000	12.810	0.000	4.551	0.641	3.809	3.809	1.214
13	182,500	12.775	0.525	5.262	0.639	3.375	3.375	0.978
14	182,500	12.775	0.000	5.361	0.639	3.338	3.338	0.879
15	182,500	12.775	0.000	5.462	0.639	3.287	3.287	0.787
16	183,000	12.810	0.000	5.577	0.641	3.246	3.246	0.706
17	284,700	19.929	0.000	8.475	0.996	5.179	5.179	1.025
18	284,700	19.929	0.000	8.638	0.996	5.148	5.148	0.926
19	284,700	19.929	0.000	8.805	0.996	5.064	5.064	0.828
20	285,480	19.984	0.000	8.996	0.999	4.994	4.994	0.742
21	284,700	19.929	0.000	9.146	0.996	4.893	4.893	0.661
22	279,664	19.576	0.000	9.170	0.979	4.714	4.714	0.579
23	219,142	15.340	0.000	7.476	0.767	3.548	3.548	0.396
24	185,559	12.989	0.000	6.559	0.649	2.890	2.890	0.293
25	166,376	11.646	0.000	6.067	0.582	2.499	2.499	0.231
26	151,766	10.624	0.000	5.702	0.531	2.195	2.195	0.184
27	140,925	9.865	0.000	5.448	0.493	1.962	1.962	0.150
28	132,700	9.289	0.000	5.268	0.464	1.778	1.778	0.123
29	124,455	8.712	0.000	5.080	0.436	1.598	1.598	0.101
Total	**5,016,365**	**351.146**	**23.525**	**150.425**	**17.557**	**79.819**	**79.819**	**15.688**
						IRR	28.00%	16.36%
						PIR	3.393	0.667

Table 5.23 Cash flow summary of natural flow production of model M05, 2 production well, initial production rate at 320 BOPD, and recovery factor = 26.92%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	8.000	0.000	0.000	0.000	-3.520	-2.404
5	116,800	8.176	0.000	2.529	0.409	0.000	4.119	2.557
6	116,800	8.176	0.000	2.579	0.409	1.083	2.985	1.685
7	116,800	8.176	0.000	2.631	0.409	2.008	2.008	1.031
8	117,120	8.198	0.000	2.691	0.410	1.989	1.989	0.928
9	116,800	8.176	0.000	2.737	0.409	2.515	2.515	1.067
10	116,800	8.176	0.000	2.792	0.409	2.488	2.488	0.959
11	116,800	8.176	0.000	2.848	0.409	2.460	2.460	0.862
12	117,120	8.198	0.000	2.912	0.410	2.438	2.438	0.777
13	116,800	8.176	0.000	2.963	0.409	2.402	2.402	0.696
14	100,105	7.007	0.000	2.590	0.350	2.034	2.034	0.535
15	61,588	4.311	0.000	1.625	0.216	1.235	1.235	0.296
16	42,584	2.981	0.000	1.146	0.149	0.843	0.843	0.183
17	35,560	2.489	0.000	0.976	0.124	0.694	0.694	0.137
18	31,265	2.189	0.000	0.876	0.109	0.602	0.602	0.108
19	29,282	2.050	0.000	0.836	0.102	0.555	0.555	0.091
Total	**1,352,225**	**94.656**	**10.500**	**32.730**	**4.733**	**23.346**	**23.346**	**7.476**
						IRR	35.14%	22.86%
						PIR	2.223	1.242

Table 5.24 Cash flow summary of the 2nd water injection production of model M05, (1/2) production/injection well, initial production rate at 390 BOPD, water injection rate at 450 BWPD, and recovery factor = 54.51%.

Year	Cash Flow Summary							Discount Cash Flow
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	(NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	142,350	9.965	0.000	3.082	0.498	0.000	5.205	3.232
6	142,350	9.965	0.000	3.143	0.498	1.534	3.609	2.037
7	142,350	9.965	0.525	3.641	0.498	2.260	2.260	1.160
8	142,740	9.992	0.000	3.719	0.500	2.247	2.247	1.048
9	142,350	9.965	0.000	3.781	0.498	2.793	2.793	1.184
10	142,350	9.965	0.000	3.854	0.498	2.756	2.756	1.063
11	142,350	9.965	0.000	3.928	0.498	2.719	2.719	0.953
12	142,740	9.992	0.000	4.012	0.500	2.740	2.740	0.873
13	142,350	9.965	0.000	4.079	0.498	2.693	2.693	0.780
14	142,350	9.965	0.000	4.158	0.498	2.654	2.654	0.699
15	142,350	9.965	0.000	4.238	0.498	2.614	2.614	0.626
16	142,740	9.992	0.000	4.329	0.500	2.581	2.581	0.562
17	142,350	9.965	0.000	4.402	0.498	2.532	2.532	0.501
18	142,350	9.965	0.000	4.487	0.498	2.490	2.490	0.448
19	142,350	9.965	0.000	4.574	0.498	2.446	2.446	0.400
20	142,740	9.992	0.000	4.673	0.500	2.410	2.410	0.358
21	107,303	7.511	0.000	3.710	0.376	1.713	1.713	0.231
22	64,415	4.509	0.000	2.481	0.225	0.901	0.901	0.111
23	50,301	3.521	0.000	2.091	0.176	0.627	0.627	0.070
24	46,644	3.265	0.000	2.014	0.163	0.544	0.544	0.055
25	44,245	3.097	0.000	1.974	0.155	0.484	0.484	0.045
26	40,964	2.868	0.000	1.902	0.143	0.411	0.411	0.034
27	37,688	2.638	0.000	1.828	0.132	0.339	0.339	0.026
28	35,195	2.464	0.000	1.775	0.123	0.283	0.283	0.020
29	32,780	2.295	0.000	1.724	0.115	0.228	0.228	0.014
Total	**2,738,695**	**191.709**	**12.525**	**83.597**	**9.585**	**43.001**	**43.001**	**11.233**
						IRR	36.93%	24.48%
						PIR	3.433	0.897

Table 5.25 Cash flow summary of the 4th water injection production of model M05, (1/2) production/injection well, initial production rate at 240 BOPD, water injection rate at 450 BWPD, and recovery factor = 53.06%.

Year	Cash Flow Summary							Discount Cash Flow (NPV@10%)
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	87,600	6.132	0.000	1.896	0.307	0.000	2.749	1.707
6	87,600	6.132	0.000	1.934	0.307	0.000	2.711	1.530
7	87,600	6.132	0.000	1.973	0.307	0.426	2.246	1.153
8	87,840	6.149	0.000	2.018	0.307	1.322	1.322	0.617
9	87,600	6.132	0.525	2.498	0.307	1.601	1.601	0.679
10	87,600	6.132	0.000	2.545	0.307	1.590	1.590	0.613
11	87,600	6.132	0.000	2.593	0.307	1.566	1.566	0.549
12	146,400	10.248	0.000	4.103	0.512	2.766	2.766	0.881
13	146,000	10.220	0.000	4.172	0.511	2.719	2.719	0.787
14	146,000	10.220	0.000	4.252	0.511	2.728	2.728	0.718
15	146,000	10.220	0.000	4.334	0.511	2.687	2.687	0.643
16	146,400	10.248	0.000	4.428	0.512	2.654	2.654	0.578
17	146,000	10.220	0.000	4.502	0.511	2.603	2.603	0.515
18	146,000	10.220	0.000	4.589	0.511	2.560	2.560	0.460
19	146,000	10.220	0.000	4.678	0.511	2.516	2.516	0.411
20	146,400	10.248	0.000	4.779	0.512	2.478	2.478	0.368
21	146,000	10.220	0.000	4.860	0.511	2.425	2.425	0.328
22	146,000	10.220	0.000	4.954	0.511	2.378	2.378	0.292
23	133,619	9.353	0.000	4.667	0.468	2.109	2.109	0.236
24	79,766	5.584	0.000	3.058	0.279	1.123	1.123	0.114
25	56,455	3.952	0.000	2.366	0.198	0.694	0.694	0.064
26	48,556	3.399	0.000	2.151	0.170	0.539	0.539	0.045
27	45,383	3.177	0.000	2.085	0.159	0.466	0.466	0.036
28	42,391	2.967	0.000	2.021	0.148	0.399	0.399	0.028
29	38,798	2.716	0.000	1.933	0.136	0.323	0.323	0.020
Total	**2,665,606**	**186.592**	**12.525**	**83.392**	**9.330**	**40.673**	**40.673**	**8.076**
						IRR	26.13%	14.67%
						PIR	3.247	0.645

Table 5.26 Cash flow summary of the 8th water injection production of model M05, (1/2) production/injection well, initial production rate at 195 BOPD, water injection rate at 450 BWPD, and recovery factor = 49.66%.

Year	Cash Flow Summary							Discount
	Cum. Oil Prod.	Gross Revenue	Capex	Opex	Government Take		Annual Cash Flow	Cash Flow (NPV@10%)
					Royalty	Inc. Tax		
	(bbl/year)	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1	0	0.000	0.500	0.000	0.000	0.000	-0.500	-0.455
2	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.826
3	0	0.000	1.000	0.000	0.000	0.000	-1.000	-0.751
4	0	0.000	9.500	0.000	0.000	0.000	-4.780	-3.265
5	71,175	4.982	0.000	1.541	0.249	0.000	2.012	1.249
6	71,175	4.982	0.000	1.572	0.249	0.000	1.981	1.118
7	71,175	4.982	0.000	1.603	0.249	0.000	1.950	1.001
8	71,370	4.996	0.000	1.640	0.250	0.295	1.631	0.761
9	71,175	4.982	0.000	1.668	0.249	1.533	1.533	0.650
10	71,175	4.982	0.000	1.701	0.249	1.516	1.516	0.584
11	71,175	4.982	0.000	1.735	0.249	1.499	1.499	0.525
12	71,370	4.996	0.000	1.775	0.250	1.486	1.486	0.473
13	71,175	4.982	0.525	2.274	0.249	1.167	1.167	0.338
14	71,175	4.982	0.000	2.316	0.249	1.158	1.158	0.305
15	71,175	4.982	0.000	2.360	0.249	1.137	1.137	0.272
16	71,370	4.996	0.000	2.408	0.250	1.119	1.119	0.244
17	155,125	10.859	0.000	4.753	0.543	2.732	2.732	0.540
18	155,125	10.859	0.000	4.845	0.543	2.736	2.736	0.492
19	155,125	10.859	0.000	4.939	0.543	2.689	2.689	0.440
20	155,550	10.889	0.000	5.046	0.544	2.649	2.649	0.394
21	155,125	10.859	0.000	5.131	0.543	2.592	2.592	0.350
22	155,125	10.859	0.000	5.230	0.543	2.543	2.543	0.312
23	155,125	10.859	0.000	5.332	0.543	2.492	2.492	0.278
24	155,550	10.889	0.000	5.448	0.544	2.448	2.448	0.249
25	146,934	10.285	0.000	5.277	0.514	2.247	2.247	0.207
26	86,401	6.048	0.000	3.393	0.302	1.176	1.176	0.099
27	61,193	4.284	0.000	2.614	0.214	0.727	0.727	0.055
28	53,313	3.732	0.000	2.394	0.187	0.576	0.576	0.040
29	50,634	3.544	0.000	2.345	0.177	0.511	0.511	0.032
Total	**2,495,011**	**174.651**	**12.525**	**79.340**	**8.733**	**37.027**	**37.027**	**5.714**
						IRR	21.11%	10.10%
						PIR	2.956	0.456

Table 5.27 Economic analysis cash flow summary of all scenarios.

Model	Water Injection Scenarios	Initial Oil Production Rate (BOPD)	Water Injection Rate (BOPD)	IRR With 10% Discount (%)	PIR With 10% Discount (Fraction)	Oil Recovery Factor (%)
A20	(no inj)	780	-	12.28	0.814	25.02
	2nd year	1,680	2,200	31.79	1.141	55.78
	4th year	1,440	2,200	27.14	0.914	50.26
	8th year	960	2,200	16.92	0.614	44.96
A10	(no inj)	360	-	8.59	0.281	21.97
	2nd year	760	1,000	27.93	1.055	56.61
	4th year	680	1,000	23.24	0.835	51.17
	8th year	440	1,000	13.31	0.529	45.13
A05	(no inj)	300	-	20.87	1.065	23.62
	2nd year	360	500	22.11	0.816	54.34
	4th year	240	500	14.20	0.603	51.38
	8th year	135	500	5.34	0.274	46.85
M20	(no inj)	900	-	15.48	1.016	27.31
	2nd year	1,680	1,800	32.27	1.218	57.76
	4th year	1,440	1,800	27.79	1.059	56.17
	8th year	960	1,800	17.66	0.739	51.43
M10	(no inj)	440	-	12.95	0.438	27.62
	2nd year	760	900	26.39	1.009	56.49
	4th year	700	900	24.37	0.935	55.60
	8th year	500	900	16.36	0.667	49.82
M05	(no inj)	320	-	22.86	1.242	26.92
	2nd year	390	450	24.48	0.897	54.51
	4th year	240	450	14.67	0.645	53.06
	8th year	195	450	10.10	0.456	49.66

Table 5.28 Undiscount and discount cash flow summary of all scenarios.

Model	Water Injection Scenarios	IRR Undiscount (%)	PIR Undiscount (Fraction)	IRR With 10% Discount (%)	PIR With 10% Discount (Fraction)	Oil Recovery Factor (%)
A20	(no inj)	23.51	1.894	12.28	0.814	25.02
	2nd year	44.97	4.054	31.79	1.141	55.78
	4th year	39.85	3.529	27.14	0.914	50.26
	8th year	28.62	3.042	16.92	0.614	44.96
A10	(no inj)	19.45	1.482	8.59	0.281	21.97
	2nd year	40.72	4.035	27.93	1.055	56.61
	4th year	35.56	3.525	23.24	0.835	51.17
	8th year	24.64	2.975	13.31	0.529	45.13
A05	(no inj)	32.96	1.896	20.87	1.065	23.62
	2nd year	34.32	3.347	22.11	0.816	54.34
	4th year	25.62	3.082	14.20	0.603	51.38
	8th year	15.88	2.647	5.34	0.274	46.85
M20	(no inj)	27.02	2.115	15.48	1.016	27.31
	2nd year	45.49	4.437	32.27	1.218	57.76
	4th year	40.57	4.250	27.79	1.059	56.17
	8th year	29.43	3.770	17.66	0.739	51.43
M10	(no inj)	24.24	1.969	12.95	0.438	27.62
	2nd year	39.03	3.998	26.39	1.009	56.49
	4th year	36.81	3.909	24.37	0.935	55.60
	8th year	28.00	3.393	16.36	0.667	49.82
M05	(no inj)	35.14	2.223	22.86	1.242	26.92
	2nd year	36.93	3.433	24.48	0.897	54.51
	4th year	26.13	3.247	14.67	0.645	53.06
	8th year	21.11	2.956	10.10	0.456	49.66

CHAPTER VI

CONCLUSIONS AND DISCUSSIONS

6.1 Introduction

This chapter concludes the research study in term of reservoir modeling design, results of model scenarios test, and economic evaluation of bottom waterflooding simulation model in Phitsanulok Basin. Finally, discussion about research results, problems, and given the possible idea for future works.

6.2 Reservoir modeling design and model scenarios test results

The main propose of this research study is to simulate the bottom waterflooding technique and observed oil recovery improvements from water injection activity for oil fields in Phitsanulok Basin. The study focus on anticline and monocline structure style, each structure is divide into 3 main cases according to the volume of oil in place of 20, 10, and 5 million barrels (high, medium, and base case respectively), for all cases include 4 production scenarios test applied (no water injection, 2nd year, 4th year, and 8th year after natural flow production periods of the water injection). The results of reservoir simulation show that natural flow mechanism (no water injection) can produce 21.97-27.62% of oil in place and the other cases which applied bottom waterflooding technique, the 2nd, 4th and 8th year of water injection scenarios, the recoveries increased to 54.34-57.75%, 50.26-56.17% and 44.96-51.34% respectively. The bottom water injections lead to 3 difference production profile due to the stating time of water injection as follow:

- maintain production rate over the half way of production life time (25 years), and then gradually decline for the 2nd year of water injection.
- maintain production rate, then slightly fluctuate or increase nearly 2 time and keep constant at this rate, after that suddenly decline for the 4th year of water injection.
- maintain production rate and increase suddenly to 2 or 3 time and keep constant at this rate for a long periods, after that suddenly decline for the 8th year of water injection.

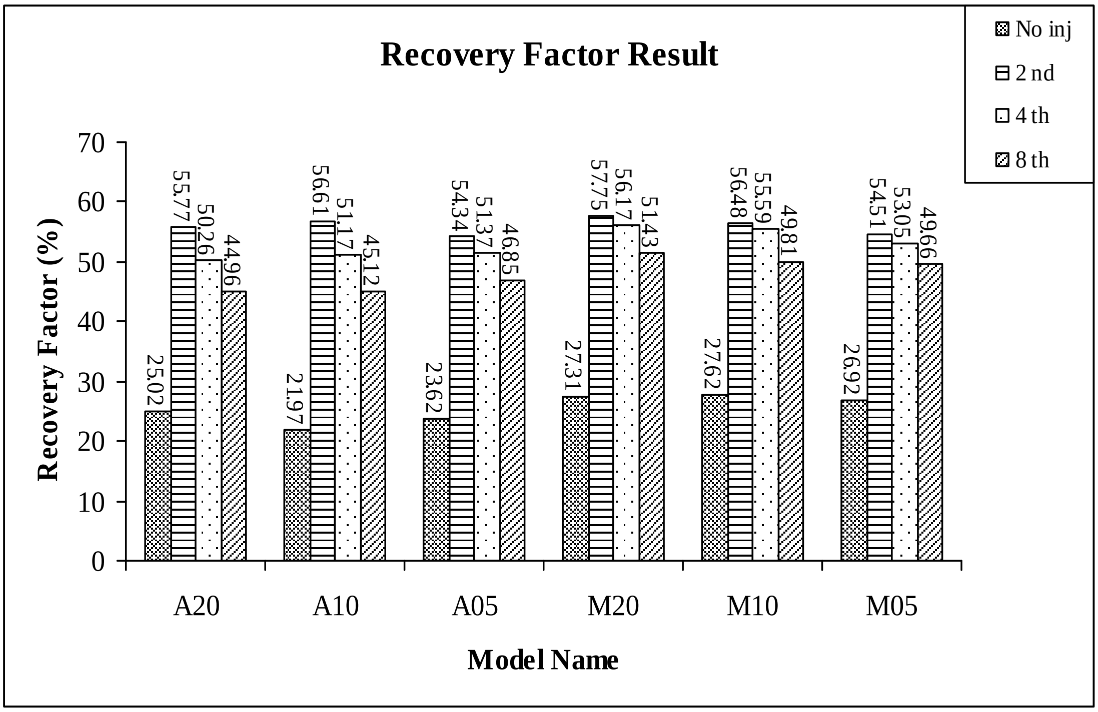

Figure 6.1 Recovery efficiency of model testing results.

6.3 Economic analysis

Economic analysis in this study performed for each scenario to considerate the possible of project feasibility and it's realizable to operate in the real oil field. This analysis base on a constant oil price rate through the project life time (70$/BBL), the 10% discounted economic results show that natural flow mechanism (no water injection) gained 8.59-22.86% of IRR (PIR 0.281-1.242), the 2nd year of water injection scenarios gained 27.41-36.05% of IRR (PIR 0.904-1.281), the 4th year of water injection scenarios gained 17.51-31.24% of IRR (PIR 0.679-1.117), and the 8th year of water injection scenarios gained 6.92-20.70% of IRR (PIR 0.334-0.786). The economic results summary data of every scenario are show in figure 6.2 and 6.3.

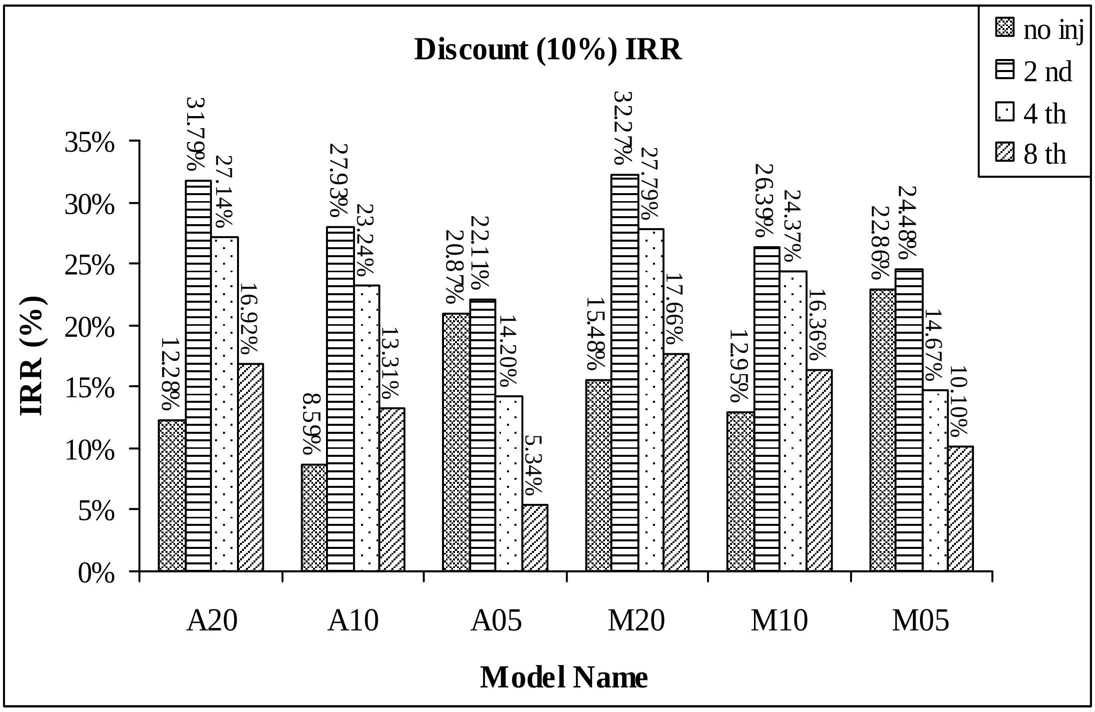

Figure 6.2 Discount IRR of model testing results.

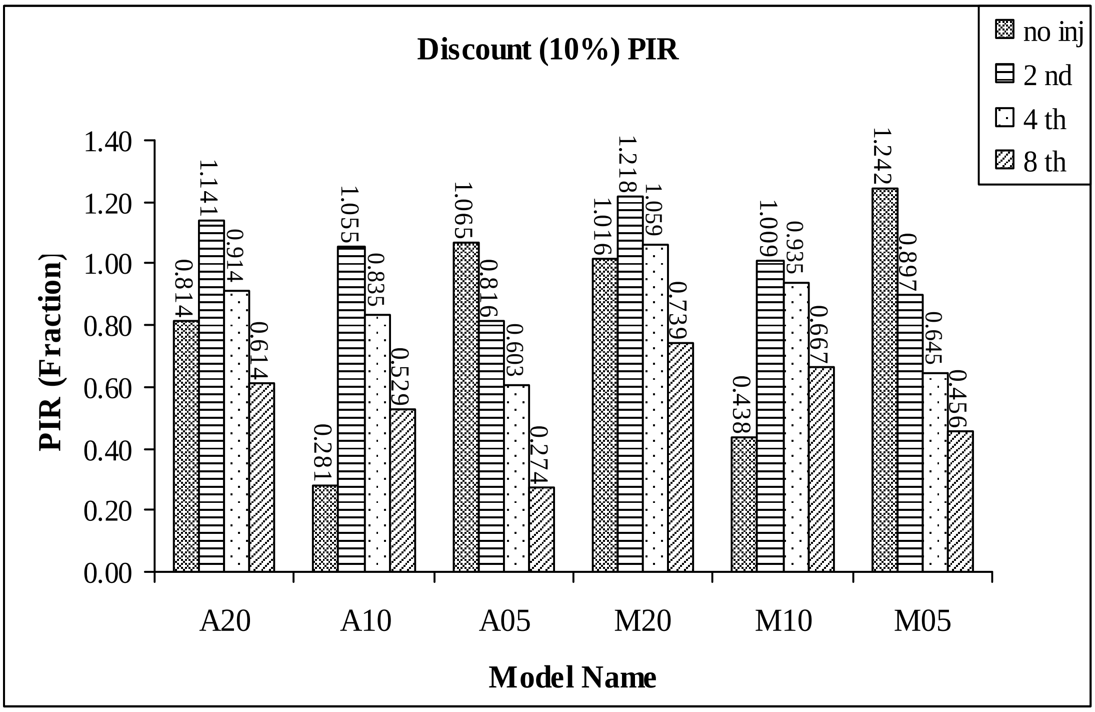

Figure 6.3 Discount PIR of model testing results.

6.4 Discussions

- The reservoir simulation result indicated that the bottom waterflooding technique improved oil recovery efficiency (compare to no water injection) of oil field in Phitsanulok Basin.
- To compare with the natural flow drive mechanism (no water injection), the 2nd of water injection scenarios of every cases are the best case of operation and development due to the recovery efficiency and economic values are more favorable than the others.
- Although, the 2nd of water injection scenarios represent itself is the best scenarios, but a suitable of time to start waterflooding project in a real field operation may be the 4th or 8th year, because of the every

waterflooding projects need time to collected the necessary reservoir properties data, production history, etc., especially the connectivity between injection and production well, to ensure that the projects meet its high success level.

- The production life time and production schedule adjustable of 5 MMBBL STOIIP size (base case) can be aspect that the projected will gain a better figure of economic value.
- Proper of injection and production rate applied in the simulation test of each reservoir size represented a reliable fluid production profile conducted in the real field (water cut effected from improper injection rate).
- Reliability of simulation result depends of the data confidential of rock and fluid properties collected from the oil field.
- Heterogeneity effect of porosity and absolute permeability variation need to apply and test for individual productive reservoir to make a reliable result of the simulation result.

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APPENDIX A

WATERFLOOD DESIGN AND BASIC CONCEPT

A.1 Bottom Waterflooding Concept

When hydrocarbons are produced from a reservoir the fluid pressure decreases due to the volume changes. As the reservoir pressure is the force pushing the hydrocarbons up to the surface, production rates will start to fall off at the wellheads. Nevertheless, there are mechanisms of natural energy inherent within the reservoir itself, which help to reduce the rate of pressure decline in the wells (Figure A.1). The magnitude of this reservoir energy can have a significant influence on primary recovery factors (Levorsen, 1967; Sills, 1992). A major source of energy is supplied by a large water aquifer in direct contact with an oil zone. This is known as water drive. As the oil is produced and the pressure drops, the low-pressure area resulting from production spreads outward into the aquifer. Water has a small compressibility, and the aquifer water will expand as the pressure decreases, flowing into the pore space previously occupied by the oil. Because water compressibility is small, a large aquifer is required for the increase in the volume of the water to be big enough to significantly compress and displace the oil toward the production wells. The volume of aquifer should be at least 10 times the volume of the oil in the oil leg (Jahn et al., 1998). If the water is part of an artesian system with free flowing water, this can also provide a significant source of energy. The primary recovery of oil from water drive reservoirs can be high (35–75%), (Clark, 1969).

In this study the bottom waterflooding or vertical waterflooding is the process to injecting water through a water injection well, direct into the water production zone in the reservoir to force through the pore spaces and sweeps some residual oil toward the producing wells (Figure A.2).

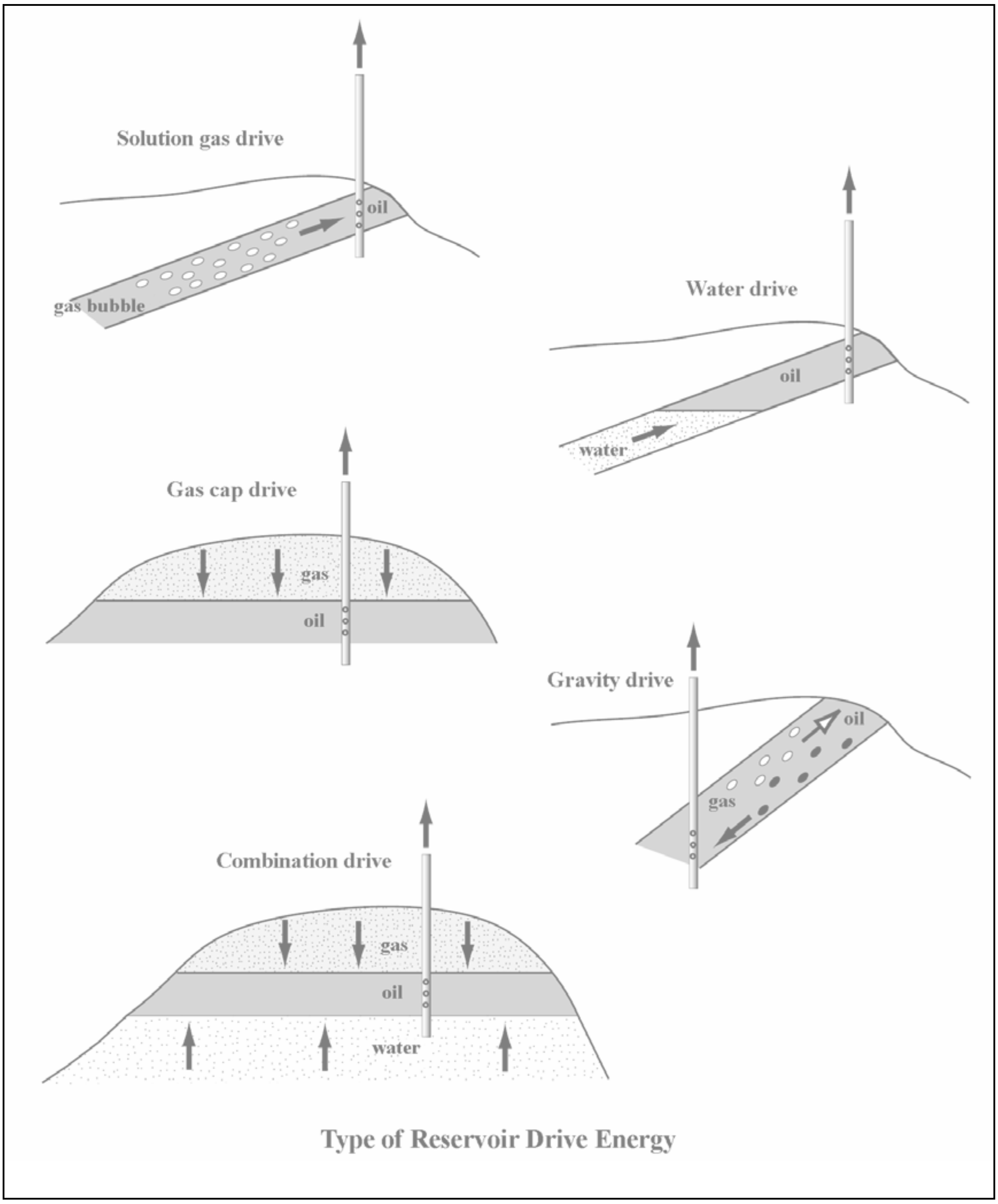


Figure A.1 Various mechanisms of natural reservoir drive energy,

(After Shepherd, 2009).

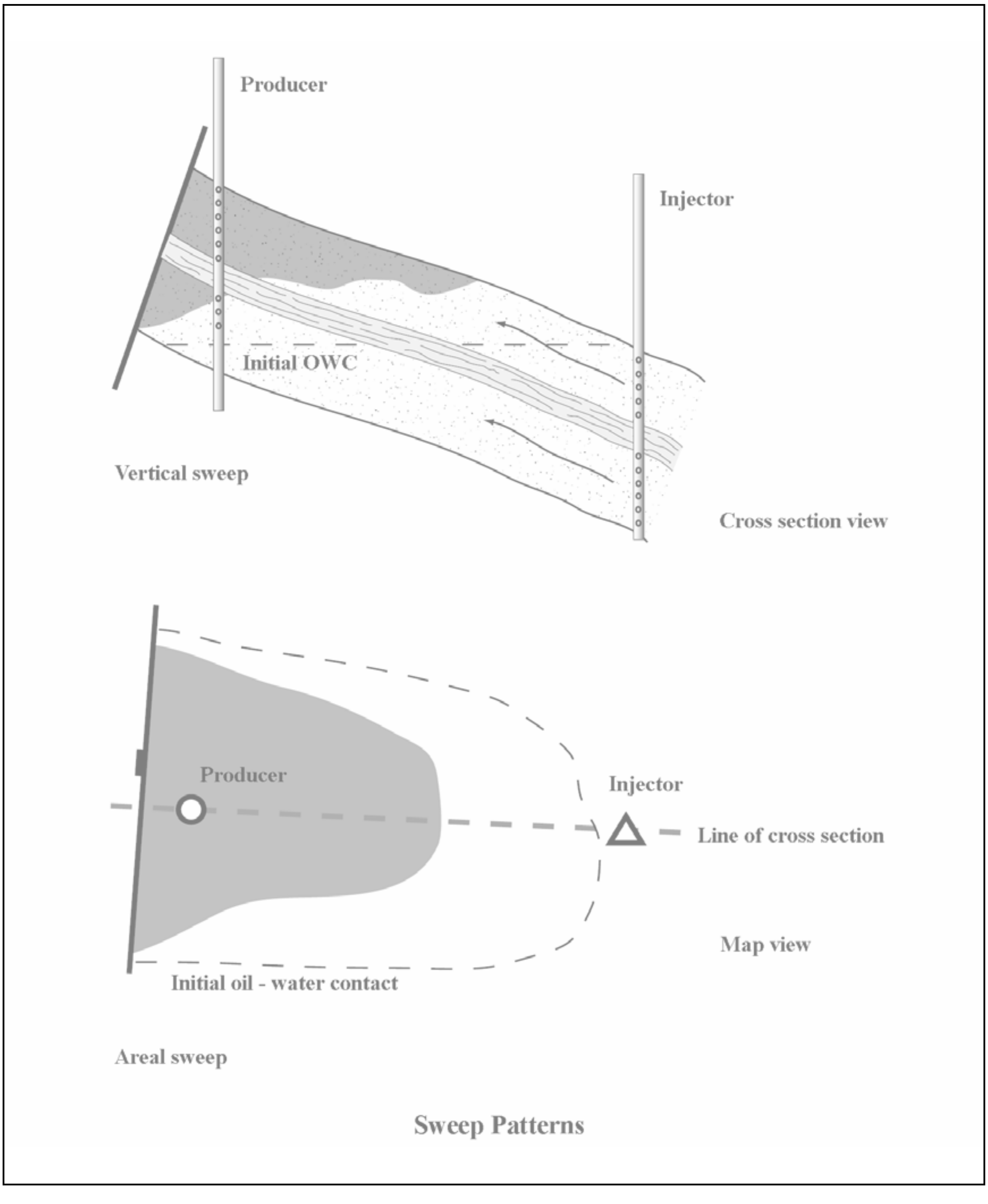


Figure A.2 Bottom waterflooding sweep or vertical sweep concept,

(After Shepherd, 2009)

A.2 Waterfloods Design

Ganesh C. Thakur and Abdus Satter, 1998, describe the design and operation process for waterflooding, called "a five phase" as follow.

A.2.1 Phase 1: Conceptual Design to Identify and Frame Opportunity

The first step in conceptual design is to identify the business opportunities (declining reserve, emphasis on replacing or increasing reserve, reservoir performance under primary depletion, successfully waterfloods in the same or similar reservoirs). The next step is to form a task force to perform a quick waterflood feasibility study to add probable reserves. The study should include an integrated approach, involving various pertinent functions, and develop:

- Location of field (onshore/offshore)
- Reservoir characteristics, depth, thickness, temperature, oil gravity and viscosity
- Probable injection pattern and alternatives
- Approximate value of rates and pressure (injection and production fluids)
- Water source, quality, and compatibility
- Project life
- Assimilate information available for the project, reservoir, wells, and facilities.
- Rough cost estimates for pump system, water source and treating, modification of existing facilities, drilling and completing well, changing well equipment, operation

- Coarse economic screening to determine economic feasibility using reasonable estimates for parameters

The result of this phase is to determine the potential economic attractiveness of the project.

A.2.2 Phase 2: Generate and Select Alternative

The second phase steps are:

- Collect, select, validate, consolidate, manage and store information of reservoir study and asset development planning (see Table A.1 and A.2)
- Perform a study and look at several development alternatives (for more detailed study) generating the following:
  - Reservoir description
  - Drilling and production performance analysis
  - Waterflood performance prediction utilizing reservoir simulation and/or classical methods
  - Waterflood analysis of similar fields, if available
  - Overall integrated waterflood system
  - Economic analysis and risk assessment, clearly identifying economic drivers and destroyers
  - Initiate unitization proceedings, involving other partner
  - Plan a pilot study and/or injectivity test, if necessary

A.2.3 Phase 3: Develop Preferred Alternative

The third phase involves performing a detailed evaluation of prefer waterflood alternatives (e.g. 5-spot, 9-spot, line drive, peripheral flood, etc), utilizing core and log information, completion data, production performance analysis (oil, water, GOR), pressure performance analysis, reservoir fluid analysis, operating costs, laboratory and pilot test results, etc. See Table A.3 for a detailed description of waterflood design. The key concept in design and management includes the following information:

- Illustration of typical flood patterns
- Checklist for estimating waterflood performance
- Process for waterflood management
- Screening criteria for evaluating empirical performance factors
- Guidelines for calculating oil saturation
- Table of potential waterflood problems with probable causes and solution
- Select best alternative for detailed design and development, and develop detailed waterflood design plans and estimate development costs
- Perform detailed risk and environmental assessments
- Negotiate unitization parameters, if necessary
- Perform economic and risk analysis, and develop an expected value of the project
- Seek management approval and government approval

- Develop and document waterflood assessment plan, including metrics

A.2.4 Phase 4: Implement Waterflood and Its Management Plan

- Complete detailed design, sizing and selection of materials and equipment
- implement asset management plan
- Finalize waterflood operating plan and schedule
- Develop waterflood surveillance and monitoring plan
- Select operating team and train

A.2.5 Phase 5: Operate, Monitor and Evaluate Waterflood

- Monitor reservoir, wells and facilities performance
- Evaluate performance against metrics
- Modify “living” reservoir model as additional data are obtained from operational and evaluation of results
- Revision of plan and strategies based upon actual performance
- Identify new opportunities for expansion
- Plan exit strategies for terminating the waterflood at some point in time

Table A.1 Step-by-step of waterflood design methodology,
(After Thakur, G.C., 1992).

Step-by-step of waterflood design methodology
1. Review previous study 2. Review field development and performance, including primary, secondary, and enhanced recovery operations, paying particular attention to - drive mechanisms - production and pressure history (deduce past performance) - recovery factors - mobility ratio and sweep efficiency - well spacing and drainage - wells and facility conditions - lease line migration - IPR curve/individual well performance 3. Establish geological parameters, including - general reservoir configuration - fluid distribution and movement in the reservoir - variation in pore space properties - continuity and thickness - porosity - thickness and structure maps - rock type, porosity and permeability cut offs - fluid contacts - 3-D description of reservoir - vertical stratification

Table A.1 Step-by-step of waterflood design methodology (Continued).

Step-by-step of waterflood design methodology
4. Determine "pay". Compare log and core data with DST (Drill Stem Test) and RFT (Repeat Formation Test) data. 5. Estimate OOIP (original oil in place) and OOGIP (original gas in place) 6. Review database and monitoring program, including - logging, well testing - injection profiles - completion/workover records - PVT analysis - relative permeability, capillary pressure, coreflood and wettability test - surface facility data - pattern performance monitoring (area flood balance and vertical conformance monitoring) - interwell tracer - well performance 7. Use simulators to perform history matching 8. Estimate reserves (original and remaining) and forecast production - geology and formation evaluation data - drive mechanisms - fluid properties - relative permeability and residual saturation data - Reserve

Table A.2 Type of information, (After Thakur, G.C., 1992).

Type of information list
1. Field Information: - Physical description of the reservoir - Surrounding environment 2. Geological and Engineering: - Physical boundaries 3. Reservoir Characteristic: - Pay quality and continuity - Zone and Heterogeneous effects - Permeability direction - Fracture orientation - Unusual completions 4. Primary Operations History: - Primary recovery data - Production equipment installed - Well-completion data 5. Waterflood Layout: - Potential pattern selection - Selection of well and spacing - Production loss from injection wells - Possible expansion - Terrain and topography 6. Pilot Tests

Table A.3 Waterflood design, (After Thakur, G.C., 1992).

Waterflood design detail
1. Evaluate the Reservoir - Reservoir characterization - Formation evaluation 2. Select Potential Flooding Plans - Peripheral flood - Pattern configuration - Aquifer injection - Well spacing 3. Estimate Injection/Production Rates - Injectivity test - Empirical correlations (Rules of Thumb) - Local experience 4. Forecast oil recovery over the life of the project for each flooding plan - Material balance - Empirical correlations - Analytical model - Reservoir simulators 5. Preliminary facilities design - Estimate fluid volume and rates for sizing equipment and fluid handling system - Identify compatible water source or injection - Arrange for disposal of produce water

Table A.3 Waterflood design (Continued).

Waterflood design detail
6. Estimate capital expenditures and future operating expense - Facility - Well - Lifting costs - Treating costs handling 7. Conduct decision analysis and economic evaluation 8. Identify variable that may cause uncertainty - Original oil in place - Sweep efficiency - Injection rates - Reservoir discontinuities

A.3 Basic Theoretical Aspects of Waterflooding

A.3.1 Immiscible Displacement Theory

Darcy's law as shown below is the basic equation to describe the flow of fluids through porous media:

$$q = -\frac{kA}{\mu}\left(\frac{dp}{ds} - \frac{\rho g}{1.0133}\frac{dz}{ds}\times 10^{-6}\right) \qquad \text{(A.1)}$$

where:

A = the cross-sectional area of rock and pore, in the direction of flow, cm^3

$\frac{dp}{ds}$ = pressure gradient along the direction of flow, $\frac{atm}{cm}$

$\frac{dz}{ds}$ = gradient in the vertical direction

g = acceleration due to gravity, $\frac{cm}{sec^2}$

μ = viscosity of flowing fluid, centipoises (cp)

ρ = density of flowing fluid, $\frac{g}{cm^3}$

q = flow of fluid, $\frac{cm^3}{sec}$

Displacement of oil from a porous medium by immiscible water can be described by the fractional flow equation, and frontal advance theory.

Applying Darcy's law separately to oil and water flows, and considering viscous, gravitational, and capillary effects, the fractional flow equation of water displacing oil in practical units is:

$$f_w = \frac{1 + 0.001127 \dfrac{kk_{ro}}{\mu_o} \dfrac{A}{q_t} \left[\dfrac{\partial p_c}{\partial L} - \Delta\rho \sin\alpha_d \right]}{1 + \dfrac{\mu_w}{\mu_o} \dfrac{k_{ro}}{k_{rw}}} \tag{A.2}$$

where:

A	=	Area, sq. ft.
f_w	=	fraction of water flowing
k	=	absolute permeability, md
k_{ro}	=	relative permeability to oil
k_{rw}	=	relative permeability to water
μ_o	=	oil viscosity, cp
μ_w	=	water viscosity, cp
L	=	distance along direction of flow, ft
p_c	=	capillary pressure $= p_o - p_w$, psi
q_t	=	total flow rate $= q_o + q_w$, $\dfrac{B}{day}$
$\Delta\rho$	=	water-oil density difference $= p_w - p_o$, $\dfrac{gm}{cc}$
α_d	=	angle of formation dip to the horizon, degree

The fractional flow of water for given rock and fluid properties and flooding conditions is a function of water saturation only because the relative permeability and capillary pressure are function only.

Neglecting gravity and capillary effects, the above fractional flow equation is reduced to:

$$f_w = \frac{1}{1 + \frac{\mu_w}{\mu_o}\frac{k_{ro}}{k_{rw}}} \tag{A.3}$$

Using the oil water relative permeability data shown in Figure A.3, calculated fractional flow curve is shown in Figure A.4.

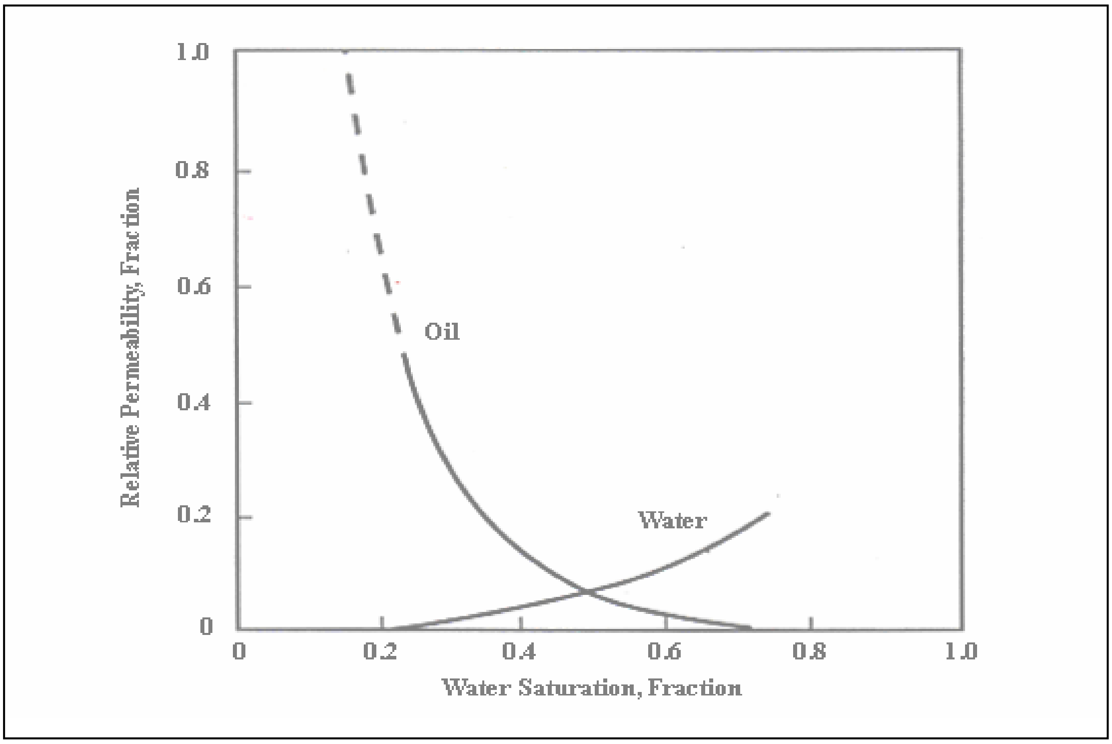


Figure A.3 Oil-Water Relative Permeability, (Thakur, 1998).

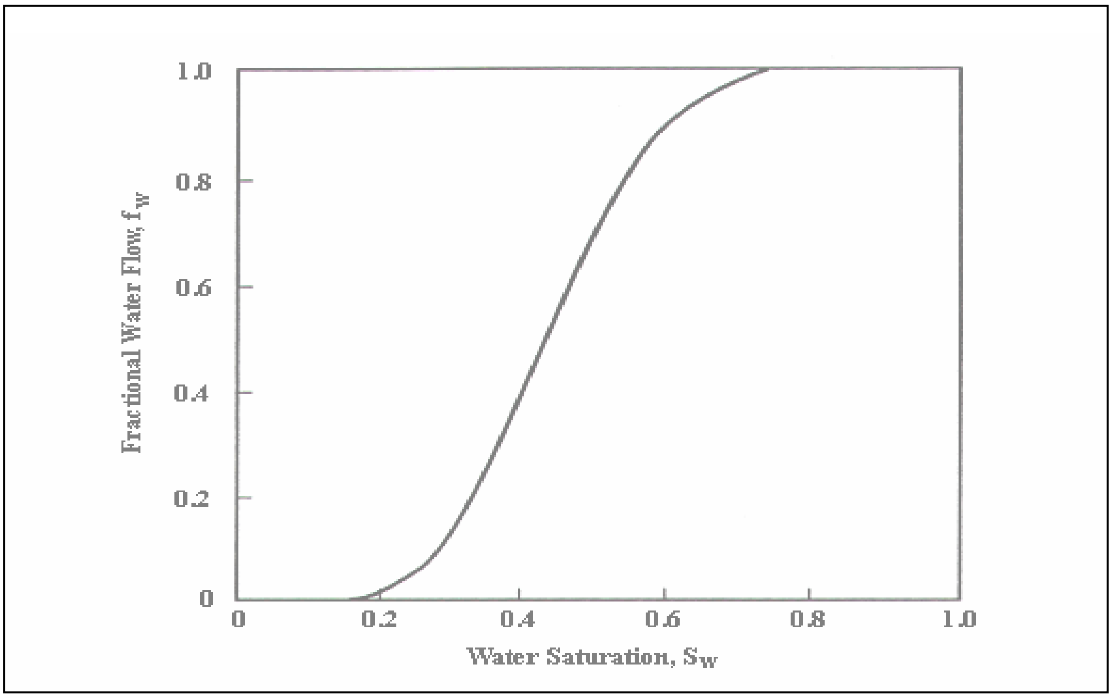


Figure A.4 Fractional Water Flow, (Thakur, 1998).

The linear frontal advance equation for water, based upon conservation of mass and assuming incompressible fluid, is given by:

$$\left(\frac{\partial x}{\partial t}\right)_{S_w} = \frac{q_t}{A\varphi}\left(\frac{\partial f_w}{\partial S_w}\right)_t \tag{A.4}$$

The frontal advance equation can be used to derive the expression for average water saturation as follows:

At breakthrough: $$\overline{S}_{wbt} - S_{wc} = \left(\frac{\partial S_w}{\partial f_w}\right)_f = \frac{S_{wf} - S_{wc}}{f_{wf}} \tag{A.5}$$

After breakthrough: $$\overline{S}_w - S_{w2} = \frac{1 - f_{w2}}{\left(\frac{\partial f_w}{\partial S_w}\right)S_{w2}} \tag{A.6}$$

where:

f_{wf} = fraction of water flowing at the flood front

f_{wf2} = fraction of water flowing at the producing end of the system

$\overline{S}_w$ = average water saturation after breakthrough, fraction

S_{wf} = water saturation at the flood front, fraction

$\overline{S}_{wbt}$ = average water saturation at breakthrough, fraction

S_{wc} = connate water saturation, fraction

S_{w2} = water saturation at the producing end of the system, fraction

Figure A.5 present graphical solutions for average water saturation at end after water breakthrough. The average water saturations can be used to calculate displacement efficiencies before and after breakthrough.

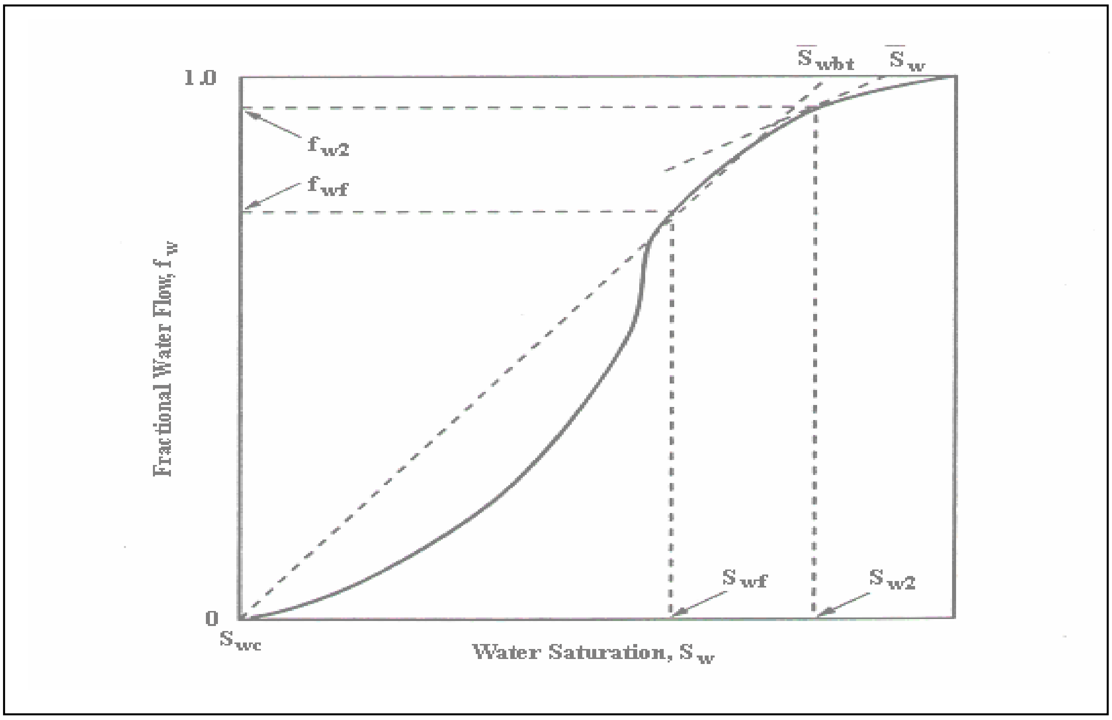


Figure A.5 Determination of average Water Saturation at Breakthrough, (Thakur, 1998)

Displacement efficiency (E_D) that is governed by rock and fluid properties is given by:

$$E_D = \frac{\frac{S_{oi}}{B_{oi}} - \frac{S_{or}}{B_{or}}}{\frac{S_{oi}}{B_{oi}}} \qquad (A.7)$$

where:

S_o	=	oil saturation function, fraction
B_o	=	oil formation volume factor, RB/STB
i, r	=	subscribes denoteing initial (before flooding) and residual (after flooding) condition, respectively

If oil and water are the only fluids present in the formation, ($S_o = 1 - S_w$), then assuming B_{or} is approximately equal to B_{oi}, oil displacement efficiency can be re-expressed as:

$$E_D = \frac{S_{wor} - S_{wi}}{1 - S_{wi}} \qquad \text{(A.8)}$$

when:

B_{oi} = B_{or}

S_{wor} = water saturation at the residual oil saturation which can be determined from the fractional flow curve for a given fractional water flow

Recovery efficiency (E_R), the overall waterflood recovery efficiency is given by

$$E_R = E_D \times E_v \qquad \text{(A.9)}$$

where:

E_R = overall recovery efficiency, fraction or %

E_D = displacement efficiency within the volume swept by water, fraction or %

E_v = volumetric actually, the fraction of the reservoir volume actually swept by water, fraction or %

Volumetric sweep efficiency (E_A) is defined by:

$$E_v = E_A \times E_I \tag{A.10}$$

where:

E_A	=	areal sweep efficiency, fraction
E_I	=	vertical or invasion sweep efficiency, fraction

A.3.2 Waterflood Pattern

Selection of the waterflooding plan is determined by factors that often unique to each reservoir. Pattern flooding, an alternative to pressure maintenance, may be selected because reservoir properties will not permit waterflooding through edge wells at desired injection rated. In pattern flooding, injection and withdrawal rates ate determined by well spacing as well as reservoir properties. The selection of possible waterflooding depends on existing wells that generally must be used because of economics. Finally, selected flooding pattern to use waterflooding a reservoir must be determined by comparison of the economics of alternative flooding schemes. Injection-production well arrangements are shown in Figure A.6-A.7 and their characteristics are given in Table A.4.

Table A.4 Well patterns characteristic.

Pattern	Producer/Injectors Ratio	Drilling pattern	E_A, %
Direct Line Drive	1	Rectangle	56
Staggered Line drive	1	Offset line of well	78
5-spot	1	Square	72
Normal 7-spot	1/2	Equilateral triangle	-
Inverted 7-spot	2	Equilateral triangle	-
Normal 9-spot	1/3	Square	~80
Inverted 9-spot	3	Square	-

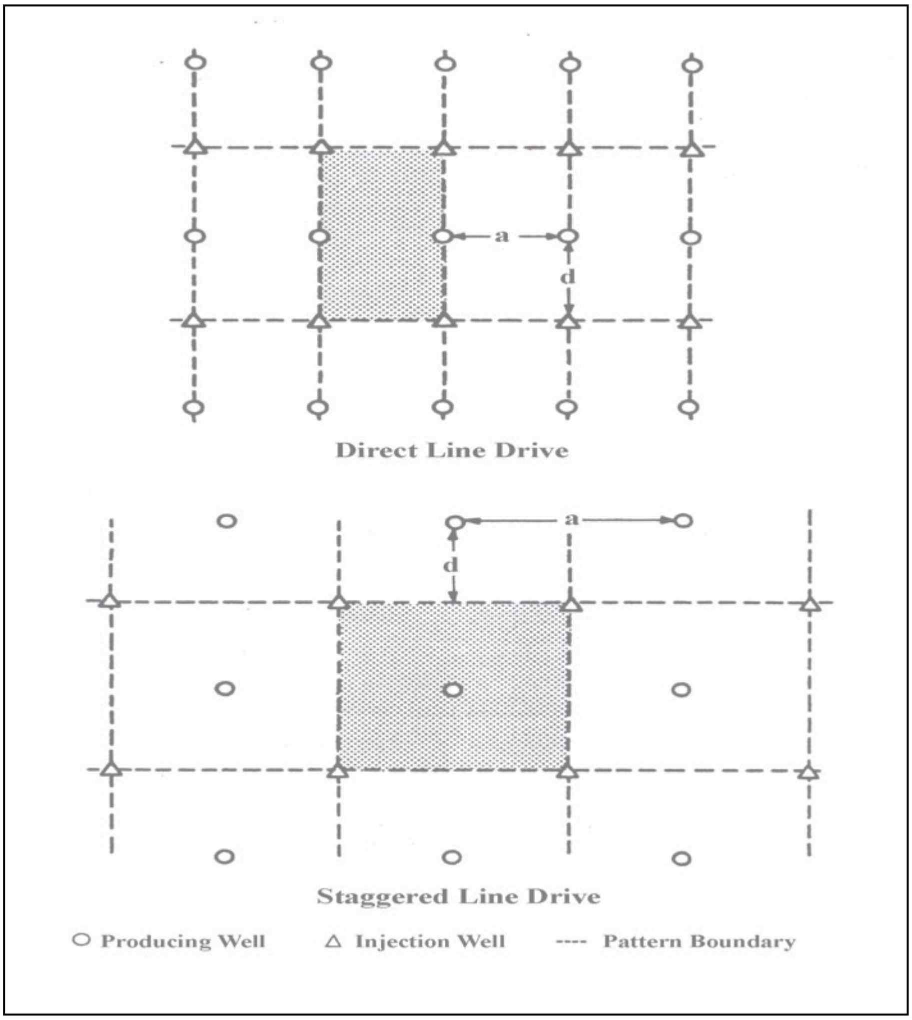


Figure A.6 Well distances in line drive pattern.

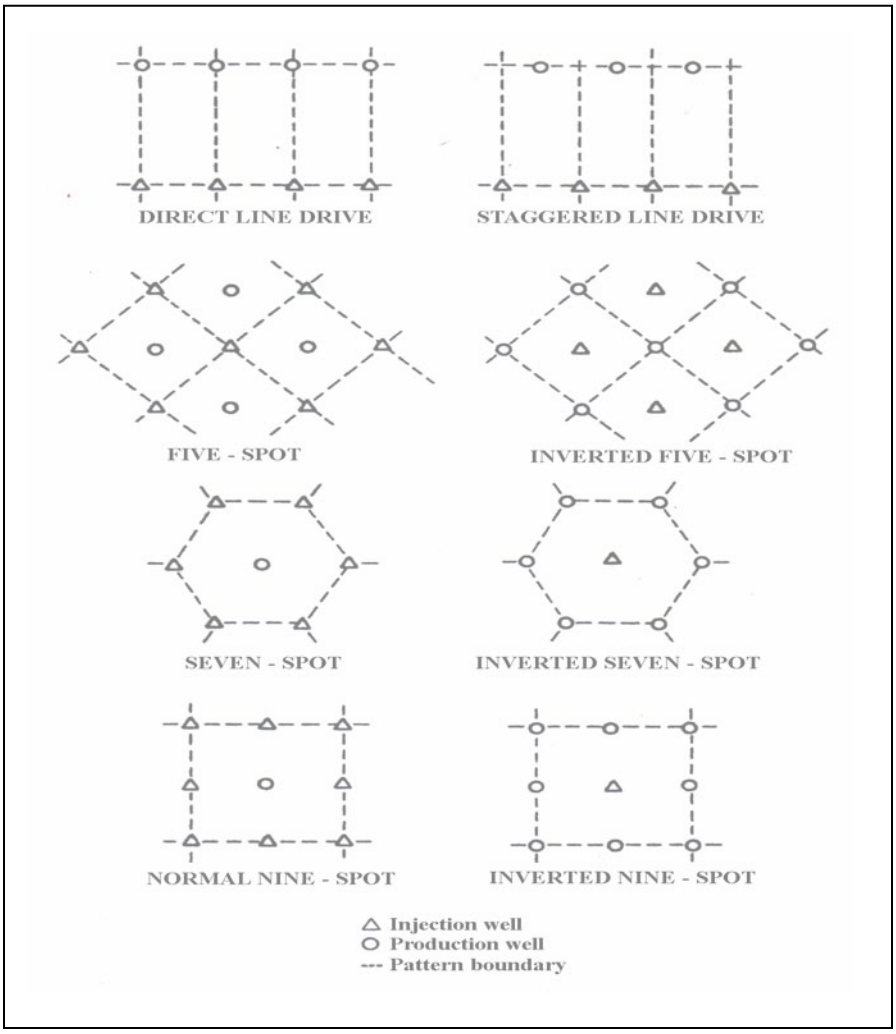


Figure A.7 Well location in flood patterns.

APPENDIX B

RESERVOIR SIMULATION THEORY

B.1 General Description

Reservoir simulation is an area of reservoir engineer in which computer model are used to predict the flow behavior of fluids (typically; oil, water, and gas) through porous media. Reservoir simulation models are used by oil and gas companies in the development of new fields. Also, models are used in developed fields where production forecasts are needed to help make investment decisions. As building and maintaining a robust, reliable model of a field is often time-consuming and expensive; models are typically only constructed where large investment decisions are at stake. For new fields, models may help development by identifying the number of wells required, the optimal completion of wells, the present and future needs for artificial lift, and the expected production of oil, water and gas.

For ongoing reservoir management, models may help in improved oil recovery by hydraulic fracturing. Highly deviated or horizontal wells can also be represented. Specialized software may be used in the design of hydraulic fracturing, and then the improvements in productivity can be included in the field model. Also, future improvement in oil recovery with pressure maintenance by re-injection of produced gas or by water injection into an aquifer can be evaluated. Waterflooding resulting in the improved displacement of oil is commonly evaluated using reservoir simulation.

Traditional finite difference simulators dominate both theoretical and practical work in reservoir simulation. Conventional fundamental simulation is underpinned by three physical concepts: conservation of mass, isothermal fluid phase behavior, and the Darcy's approximation of fluid flow through porous media.

B.2 Type of Models Based on Reservoir Geometry

Reservoir simulation model classified according to the geometry of the reservoir fall into three main categories (G.L. Chierici,1995):

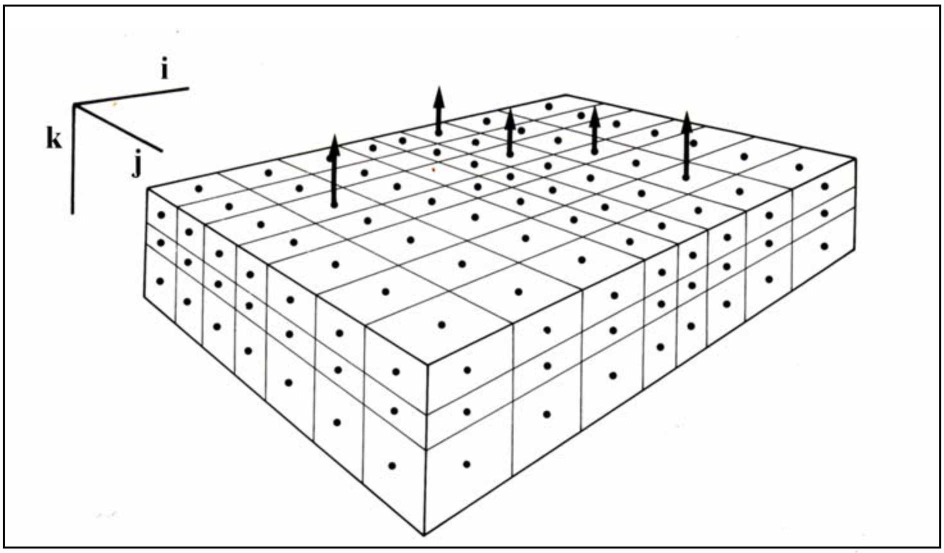
B.2.1 One-dimensional (1-D):

- Horizontal
- Inclined
- Vertical
- Curvilinear coordinates
- Radial

B.2.2 Two-dimensional (2-D):

- Horizontal
- Vertical (a cross section of the reservoir)
- Radial

B.2.3 Three-dimensional (3-D)



Fiure B.1 Three-dimensional model, (After Chierici, G.L.,1995).

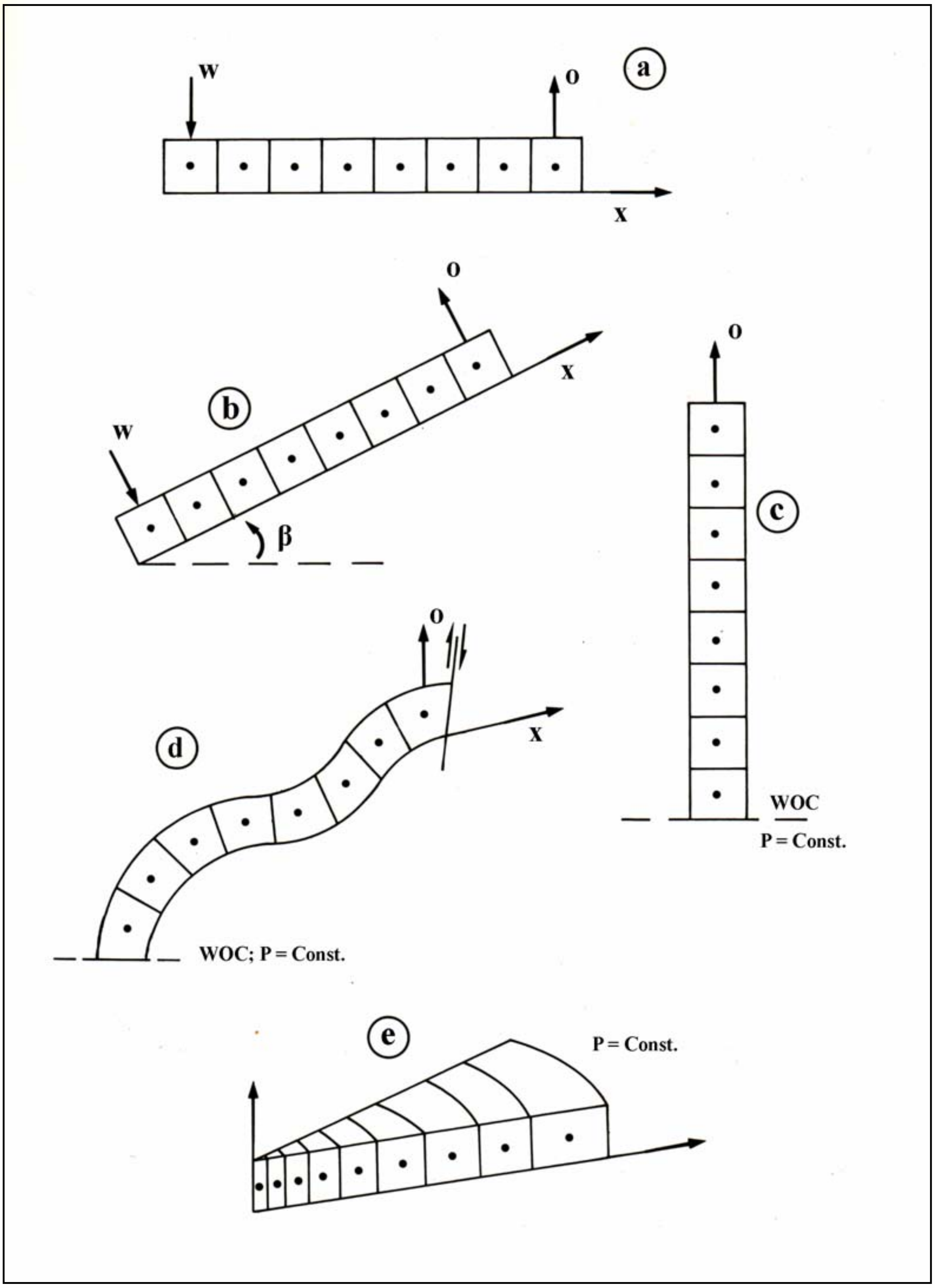


Figure B.2 One-dimensional models, a. horizontal, b. inclinal, c. vertical, d. curvilinear coordinates, e. radial (After Chierici, G.L.,1995).

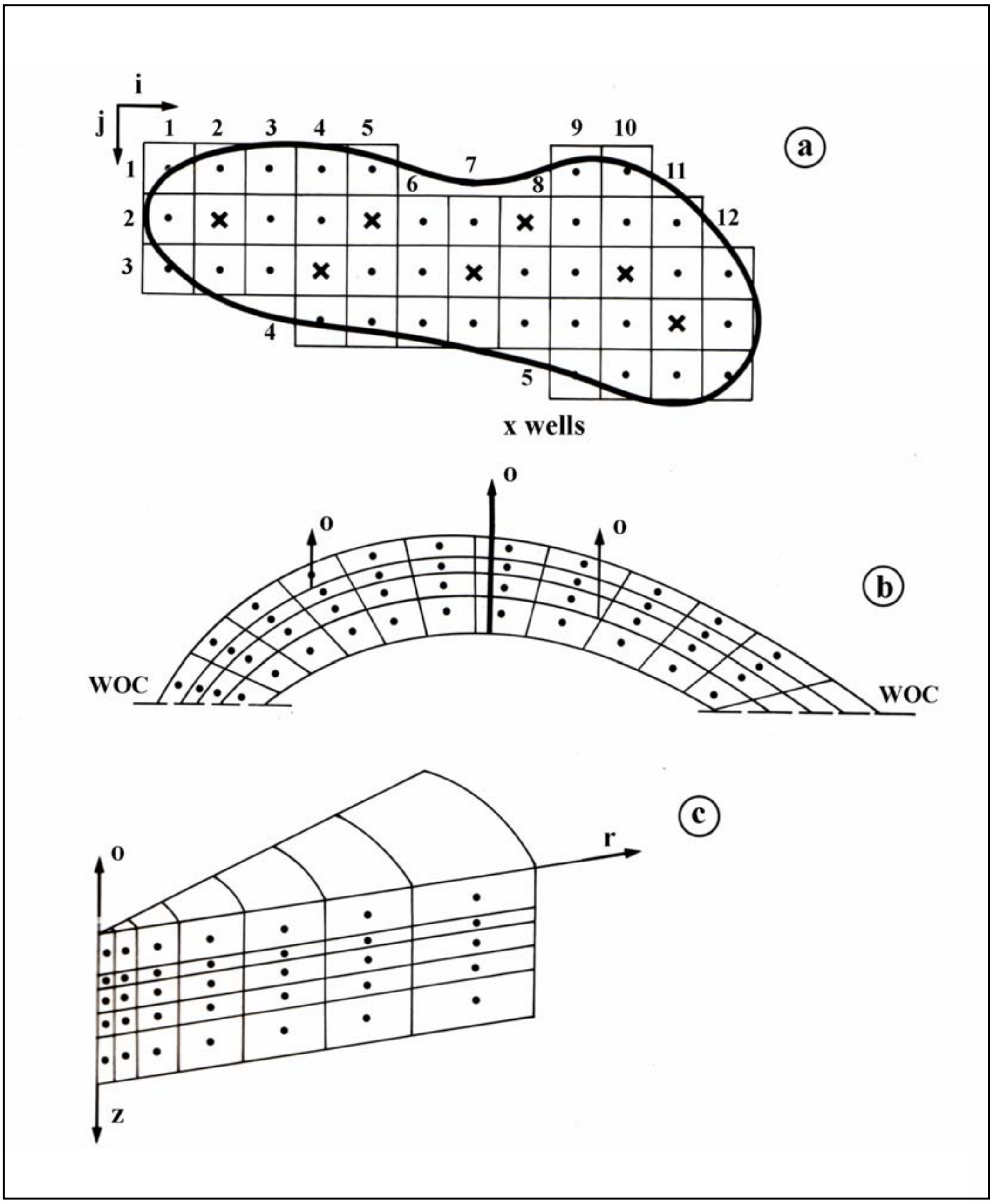


Figure B.3 Two-dimensional models, a. horizontal, b. reservoir cross-section, c. radial, (After Chierici, G.L.,1995).

B.3 Type of Numerical Simulator

B.3.1 Black oil simulator

Theses simulators consist of three phase flows: oil, gas, and water, although additional gas or aqueous phase may be include allow different properties. The simulators employ standard PVT properties of formation volume factors and solution gas and are the most common type of simulator.

B.3.2 Compositional simulator

These simulators are similar to black oil simulators as far as dimensions and solution techniques are concerned; the similarity ceases, for while volume factors and solution gas effect are employed in a black oil model, a compositional model employs Equation of State (EOS) with fugacity constraints, and uses equilibrium values, densities and several varying components (including non – hydrocarbon). Considerable time is required in the phase package (i.e., matching lab data with simulator requirements) before the actual model can be run. It is reasonable to state that this type of model requires additional expertise to be useful (Leonard F. Koederitz, 2005).

B.4 Data Requirements for Reservoir Modeling

Variables required for assignment to each cell (location dependent):

- Length
- Width
- Thickness
- Porosity
- Absolute permeability (directional)

- Elevation
- Pressure
- Fluids Saturation

Variables required as a function of pressure:

- Solution gas-oil ratio
- Formation volume factors
- Viscosity
- Density
- Compressibility

Variable required as a function of saturation:

- Relative permeability
- Capillary pressure

Well data:

- Production (or injection) rate
- Location in grid system
- Production limitation

B.5 Theoretical Development

Flow Equation

Total Differential:

$$Q = f(x, y, z)$$

$$dQ = \frac{\partial Q}{\partial x}dx + \frac{\partial Q}{\partial y}dy + \frac{\partial Q}{\partial z}dz$$

Where $\frac{\partial Q}{\partial x}$ represents the changes in Q with respect to x.

Addition:

$$\frac{\partial(A+B)}{\partial x} = \frac{\partial A}{\partial x} + \frac{\partial B}{\partial x}$$

Multiplication:

$$\frac{\partial(AB)}{\partial x} = A\frac{\partial B}{\partial x} + B\frac{\partial A}{\partial x}$$

Constant:

$$\frac{\partial(1)}{\partial x} = 0$$

Reciprocal:

$$\frac{\partial\left(\frac{1}{x}\right)}{\partial x} = \frac{-1}{x^2}$$

Finite-Difference Approximation:

$$\frac{\partial A}{\partial x} \approx \frac{A_2 - A_1}{x_2 - x_1}$$

Simplified Theoretical development of Three-Phase, Three-Dimensional Flow Equation

Base on the continuity equation, a general expression for the mass balance of a flowing system can be written as:

$$\text{Flow in} - \text{flow out} - \text{production} = \text{accumulation} \tag{B.1}$$

where

$$\text{flow in } = Q_x + Q_y + Q_z \tag{B.2}$$

and

$$\text{flow out} = \text{flow in } + \Delta x \frac{\partial Q_x}{\partial x} + \Delta y \frac{\partial Q_y}{\partial y} + \Delta z \frac{\partial z}{\partial z} \tag{B.3}$$

For oil and water phases, substitute Darcy's law for the velocity terms

$$Q_x = -0.00113 \frac{kk_r}{\mu B} A_x \frac{\partial \Phi}{\partial x} \tag{B.4}$$

where the cross-sectional area open to flow is defined as

$$A_x = \Delta y \Delta z \tag{B.5}$$

Substituting Eq. (B.5) into (B.4) and then, (B.4) into (B.3) yields (with minor rearrangement) flow in – flow out

$$= 0.00113\Delta x\Delta y\Delta z\left[\frac{\partial}{\partial x}\left(\frac{kk_r}{\mu B}\frac{\partial\Phi}{\partial x}\right)+\frac{\partial}{\partial y}\left(\frac{kk_r}{\mu B}\frac{\partial\Phi}{\partial y}\right)\right.$$

$$\left.+\frac{\partial}{\partial z}\left(\frac{kk_r}{\mu B}\frac{\partial\Phi}{\partial z}\right)\right] \tag{B.6}$$

The bulk volume is

$$V_b = \Delta x\Delta y\Delta z \tag{B.7}$$

and may be substituted in Eq. (B.6).

The production term is defined as q and only exits for cells with wells. Injection is treated just like production with the exception that sign is reversed.

The accumulation term represents the change in a cell with respect to time

$$\text{accumulation} = \frac{\partial}{\partial t}\left(\frac{SV_b\phi}{5.615B}\right) \tag{B.8}$$

By substituting Eq. (B.6) and B.(8) into Eq. (B.1), and using the definition of production, for the oil phase:

$$0.00113V_b\left[\frac{\partial}{\partial x}\left(\frac{kk_{ro}}{\mu_o B_o}\frac{\partial\Phi_o}{\partial x}\right)+\frac{\partial}{\partial y}\left(\frac{kk_{ro}}{\mu_o B_o}\frac{\partial\Phi_o}{\partial y}\right)\right.$$

$$\left.+\frac{\partial}{\partial z}\left(\frac{kk_{ro}}{\mu_o B_o}\frac{\partial\Phi_o}{\partial z}\right)\right]-q_o = \frac{\partial}{\partial t}\left(\frac{S_oV_b\phi}{5.615B_o}\right) \tag{B.9}$$

The water phase equation is identical to Eq. (B.9) expect all “o” subscripts become “w”.

For the gas phase, accounting for the dissolved gas (in oil) and free gas,

flow in – flow out

$$= 0.00113V_b\left[\frac{\partial}{\partial x}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial x}\right)+\frac{\partial}{\partial y}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial y}\right)\right.$$

$$+\frac{\partial}{\partial z}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial z}\right)+\frac{\partial}{\partial x}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial x}\right)$$

$$\left.+\frac{\partial}{\partial y}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial y}\right)+\frac{\partial}{\partial z}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial z}\right)\right] \tag{B.10}$$

Also, defining the total gas production,

$$\text{gas production} = q_g + q_o R_s \tag{B.11}$$

and the accumulation term as in Eq. (B.8), the total gas phase equation becomes

$$0.00113V_b\left[\frac{\partial}{\partial x}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial x}\right)+\frac{\partial}{\partial y}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial y}\right)\right.$$

$$+\frac{\partial}{\partial z}\left(\frac{kk_{rg}}{\mu_g B_g}\frac{\partial \Phi_g}{\partial z}\right)+\frac{\partial}{\partial x}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial x}\right)$$

$$\left.+\frac{\partial}{\partial y}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial y}\right)+\frac{\partial}{\partial z}\left(\frac{kk_{ro}R_s}{\mu_o B_o}\frac{\partial \Phi_o}{\partial z}\right)\right]-\left(q_g + q_o R_s\right)$$

$$= \frac{\partial}{\partial t}\left(\frac{S_g V_b \phi}{5.615 B_g}+\frac{S_o R_s V_b \phi}{5.615 B_o}\right) \tag{B.12}$$

To account for capillary pressure and gravity effect, the oil potential may be defined (for an incompressible fluid) as

$$\Phi_o = P_o - \frac{\rho_o D}{144} \tag{B.13}$$

The water-oil capillary pressure is

$$P_{c_{wo}} = P_o - P_w \tag{B.14}$$

so the water potential (in terms of oil pressure) is

$$\Phi_w = P_o - P_{c_{wo}} - \frac{\rho_w D}{144} \tag{B.15}$$

Similarly, the gas-oil capillary pressure is

$$P_{c_{go}} = P_g - P_o \tag{B.16}$$

resulting in the gas potential

$$\Phi_g = P_o + P_{c_{go}} - \frac{\rho_g D}{144} \tag{B.17}$$

Rewrite Eq. (B.9) for the water phase considering only the x-direction and sub substituting Eq. (B.15) for the water potential

$$0.00113V_b\left[\frac{\partial}{\partial x}\left(\frac{kk_{rw}}{\mu_w B_w}\frac{\partial\left(P_o - P_{c_{wo}} - \frac{\rho_w D}{144}\right)}{\partial x}\right) - q_w\right.$$

$$= \frac{\partial}{\partial t}\left(\frac{S_w V_b \phi}{5.615 B_w}\right) \tag{B.18}$$

To simplify matters, define mobility,

$$M_w = \frac{kk_{rw}}{\mu_w B_w} \tag{B.19}$$

and divide both side of Eq. (B.18) by bulk volume (since $\frac{\partial V_b}{\partial t} = 0$),

$$0.00113\left[\frac{\partial}{\partial x}\left(M_w \frac{\partial\left(P_o - P_{c_{wo}} - \frac{\rho_w D}{144}\right)}{\partial x}\right) - \frac{q_w}{V_b}\right.$$

$$= \frac{\partial}{\partial t}\left(\frac{S_w \phi}{5.615 B_w}\right) \tag{B.20}$$

Work with the left side of Eq. (B.20), excluding the production term. Define the partial differential by a finite-difference approximation

$$\frac{\partial A}{\partial x} \approx \frac{A_2 - A_1}{x_2 - x_1} \tag{B.21}$$

so that the left side of Eq. (B.20) becomes

$$\frac{0.00113}{\Delta x_i}\left[M_{w_{i+\frac{1}{2}}}\left(\frac{\partial\left(P_o - P_{c_{wo}} - \dfrac{\rho_w D}{144}\right)}{\partial x}\right)_{1+\frac{1}{2}}\right.$$

$$\left. - M_{w_{i-\frac{1}{2}}}\left(\frac{\partial\left(P_o - P_{c_{wo}} - \dfrac{\rho_w D}{144}\right)}{\partial x}\right)_{1-\frac{1}{2}}\right] \tag{B.22}$$

The potential term using the partial of sum,

$$\frac{\partial\left(P_o - P_{c_{wo}} - \dfrac{\rho_w D}{144}\right)}{\partial x} = \frac{\partial P_o}{\partial x} - \frac{\partial P_{c_{wo}}}{\partial x} - \frac{\partial\left(\dfrac{\rho_w D}{144}\right)}{\partial x} \tag{B.23}$$

and the gravity term is the partial of a product

$$\frac{\partial\left(\dfrac{\rho_w D}{144}\right)}{\partial x} = \frac{\rho_w}{144}\frac{\partial D}{\partial x} + \frac{D}{144}\frac{\partial \rho_w}{\partial x} + \rho_w D\frac{\partial \dfrac{1}{144}}{\partial x}$$

$$= \frac{\rho_w}{144}\frac{\partial D}{\partial x} + \frac{D}{144}\frac{\partial \rho_w}{\partial x} \tag{B.24}$$

A common simplifying assumption is that the gravity term is primarily a function of height and may be approximated (for an incompressible fluid) by

$$\partial\left(\frac{\rho_w D}{144}\right) \approx \frac{\rho_w}{144}\frac{\partial D}{\partial x} \tag{B.25}$$

Using the finite difference approximation for $M_{i+\frac{1}{2}}$ (at the right interface of a cell),

$$\left(\frac{\partial P_o}{\partial x}\right)_{i+\frac{1}{2}} \approx \frac{P_{o_{i+1}} - P_{o_i}}{\frac{\Delta x_{i+1} + \Delta x_i}{2}} \tag{B.26}$$

Similarly, for $M_{i-\frac{1}{2}}$ (at the left interface of a cell),

$$\left(\frac{\partial P_o}{\partial x}\right)_{i-\frac{1}{2}} \approx \frac{P_{o_i} - P_{o_{i-1}}}{\frac{\Delta x_i + \Delta x_{i-1}}{2}} \tag{B.27}$$

Substitute these terms into Eq. (B.22),

$$\frac{0.00113}{\Delta x_i}\left[M_{w_{i+\frac{1}{2}}} \frac{P_{o_{i+1}} - P_{o_i} - P_{c_{wo_{i+1}}} + P_{c_{wo_i}} - \frac{\rho_w}{144}\left(D_{i+1} - D_i\right)}{\frac{\Delta x_{i+1} + \Delta x_i}{2}}\right.$$

$$\left. - M_{w_{i-\frac{1}{2}}} \frac{P_{o_i} - P_{o_{i-1}} - P_{c_{wo_i}} + P_{c_{wo_{i-1}}} - \frac{\rho_w}{144}\left(D_i - D_{i-1}\right)}{\frac{\Delta x_i + \Delta x_{i-1}}{2}}\right] \tag{B.28}$$

Eq. (B.28) can be expanded to include the y and z directions, and the oil and gas phase equations.

Now, work with the right side of Eq. (B.20),

$$\frac{\partial}{\partial t}\frac{S_w\phi}{5.615B_w}=\frac{1}{5.615}\left(\frac{\phi}{B_w}\frac{\partial S_w}{\partial t}+S_w\phi\frac{\partial\frac{1}{B_w}}{\partial t}+\frac{S_w}{B_w}\frac{\partial\phi}{\partial t}\right) \tag{B.29}$$

and applying the chain rule

$$\frac{\partial A}{\partial t}=\frac{\partial A}{\partial P}\frac{\partial P}{\partial t} \tag{B.30}$$

to the last two terms of (B.29),

$$\frac{\phi}{5.615B_w}\frac{\partial S_w}{\partial t}+\left(\frac{S_w\phi}{5.615}\frac{\partial\frac{1}{B_w}}{\partial P_o}+\frac{\frac{S_w}{B_w}}{5.615}\frac{\partial\phi}{\partial P_o}\right)\frac{\partial P_o}{\partial t} \tag{B.31}$$

Employing the chain rule and the reciprocal derivative definition,

$$\frac{\partial\frac{1}{B_w}}{\partial P_o}=\frac{\partial\frac{1}{B_w}}{\partial B_w}\frac{\partial B_w}{\partial P_o}=-\frac{1}{B_w^2}\frac{\partial B_w}{\partial P_o} \tag{B.32}$$

Using the definition of water compressibility

$$c_w=-\frac{1}{B_w}\frac{\partial B_w}{\partial P_o} \tag{B.33}$$

and formation compressibility

$$c_f=\frac{1}{\phi}\frac{\partial\phi}{\partial P_o} \tag{B.33a}$$

Eq. (B.31) can be written as

$$\frac{\phi}{5.615B_w}\frac{\partial S_w}{\partial t}+\frac{S_w\phi c_w+S_w\phi c_f}{5.615B_w}\frac{\partial P_o}{\partial t} \tag{B.34}$$

Multiply the entire water phase equation by its formation volume factor, Eq. (B.34) simplifies to

$$\frac{\phi}{5.615}\frac{\partial S_w}{\partial t}+\frac{S_w\phi c_w+S_w\phi c_f}{5.615}\frac{\partial P_o}{\partial t} \tag{B.35}$$

Add the three phase equations together, the sum of the first term of each phase in Eq. (B.35) will be

$$\frac{\phi}{5.615}\left(\frac{\partial S_w}{\partial t}+\frac{\partial S_o}{\partial t}+\frac{\partial S_g}{\partial t}\right)=\frac{\phi}{5.615}\frac{\partial\left(S_w+S_o+S_g\right)}{\partial t} \tag{B.36}$$

However, the sum of the saturation is equation is equal to one,

$$S_w+S_o+S_g=1 \tag{B.37}$$

and the derivative of a constant is equal to zero

$$\frac{\partial\left(S_w+S_o+S_g\right)}{\partial t}=\frac{\partial(1)}{\partial t}=0 \tag{B.38}$$

so neglecting the first term in Eq. (B.35) when solving for pressure in an IMPES formulation. Again, using the finite difference approximation,

$$\frac{\partial P_o}{\partial t} \approx \frac{P_o^{t+\Delta t} - P_o^t}{\Delta t} \tag{B.39}$$

the water phase equation in the x direction become

$$\frac{0.00113 B_{wi}}{\Delta x_i}\left[M_{w_{i+\frac{1}{2}}} \frac{P_{o_{i+1}} - P_{o_i} - P_{c_{wo_{i+1}}} + P_{c_{wo_i}} - \frac{\rho_w}{144}\left(D_{i+1} - D_i\right)}{\frac{\Delta x_{i+1} + \Delta x_i}{2}} \right.$$

$$\left. - M_{w_{i-\frac{1}{2}}} \frac{P_{o_i} - P_{o_{i-1}} - P_{c_{wo_i}} + P_{c_{wo_{i-1}}} - \frac{\rho_w}{144}\left(D_i - D_{i-1}\right)}{\frac{\Delta x_i + \Delta x_{i-1}}{2}} \right] - \frac{q_w B_w}{V_b}$$

$$= \frac{S_w \phi c_w + S_w \phi c_f}{5.615} \frac{P_o^{t+\Delta t} - P_o^t}{\Delta t} \tag{B.40}$$

This result in one equation for each cell in the model and in adding the phase equations together (and eliminating the saturation derivative with respect to time), constructed the IMPES formulation.

If maintain separate phase equations, the solution process have a fully implicit formulation with three equations per cell; in this formulation, the saturation derivatives with respect to time cannot be eliminated and must be approximated using a finite difference.

Nomenclature:

A	=	area, ft^2
B	=	formation volume factor, RVB/STB for liquids, RVB/MCF for gas
b	=	bulk
c	=	compressibility, 1/psi
D	=	depth, ft
f	=	formation
g	=	gas
i, j, k	=	indices of direction location
k	=	absolute permeability, md
k_r	=	relative permeability
o	=	oil
P	=	pressure, psi
Q, q	=	rate (+ for production, - for injection), STB/day for liquids, MCF/day for gas
S	=	saturation function
V	=	volume, ft^3
w	=	water
x	=	length, ft
y	=	width, ft
z	=	thickness, ft
Δx	=	cell length, ft
Δy	=	cell width, ft
Δz	=	cell thickness, ft

Δt	=	timestep, days
μ	=	viscosity, cp
ρ	=	density, lb/ft^3
Φ	=	potential, psi
Ø	=	porosity, fraction

APPENDIX C

BASE CASE ECONOMIC ANALYSIS

CALCULATION DETAIL

Table C.1 Model M05_no inj economic analysis calculation detail.

1	2	3	4	5	6	7	8
					CAPEX		
No. of Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
				1.0000	500,000		
				1.0200		1,000,000	
				1.0404			1,000,000
0	0	0	0	1.0612			
1	116,800	8,176,000	408,800	1.0824			
2	233,600	8,176,000	408,800	1.1041			
3	350,400	8,176,000	408,800	1.1262			
4	467,520	8,198,400	409,920	1.1487			
5	584,320	8,176,000	408,800	1.1717			
6	701,120	8,176,000	408,800	1.1951			
7	817,920	8,176,000	408,800	1.2190			
8	935,040	8,198,400	409,920	1.2434			
9	1,051,840	8,176,000	408,800	1.2682			
10	1,151,945	7,007,336	350,367	1.2936			
11	1,213,533	4,311,167	215,558	1.3195			
12	1,256,117	2,980,894	149,045	1.3459			
13	1,291,678	2,489,228	124,461	1.3728			
14	1,322,942	2,188,536	109,427	1.4002			
15	1,352,225	2,049,754	102,488	1.4282			
Total	**1,352,225**	**94,655,715**	**4,732,786**				

Table C.1 Model M05_no inj economic analysis calculation detail (continued).

1	9	10	11	12	13	14	15
No. of Year	CAPEX						
	No. of Production Well	No. of Injection Well	Water Injection Rate (bbl/year)	Drilling and completion cost of production well (US$)	(US$)	Facility cost of production well (US$)	Abandonment cost (US$)
				INTANG	TANG		
0	2	0	0	2,400,000	600,000	5,000,000	-
1	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-
Total				**2,400,000**	**600,000**	**5,000,000**	

Table C.1 Model M05_no inj economic analysis calculation detail (continued).

1	16	17	18	19	20
	CAPEX		**OPEX**		
No. of Year	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense (US$)**	**Operation cost of production well (US$)**	**Maintenance cost of water injection facility (US$)**	**Operation cost of water injection (US$)**
0	-	1,120,000	0	-	-
1	-	1,120,000	2,528,562	-	-
2	-	1,120,000	2,579,133	-	-
3	-	1,120,000	2,630,715	-	-
4	-	1,120,000	2,690,681	-	-
5	-	0	2,736,996	-	-
6	-	0	2,791,736	-	-
7	-	0	2,847,571	-	-
8	-	0	2,912,480	-	-
9	-	0	2,962,613	-	-
10	-	0	2,589,925	-	-
11	-	0	1,625,284	-	-
12	-	0	1,146,255	-	-
13	-	0	976,336	-	-
14	-	0	875,565	-	-
15	-	0	836,444	-	-
Total		**5,600,000**	**32,730,296**		

Table C.1 Model M05_no inj economic analysis calculation detail (continued).

1	**21**	**22**	**23**	**24**	**25**	**26**
No. of Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(10%) Discount factor**	**Discount cash flow (US$)**
					1	
	500,000	-500,000	0	-500,000	0.909	-454,545
	1,000,000	-1,000,000	0	-1,000,000	0.826	-826,446
	1,000,000	-1,000,000	0	-1,000,000	0.751	-751,315
0	3,520,000	-3,520,000	0	-3,520,000	0.683	-2,404,207
1	4,057,362	4,118,638	0	4,118,638	0.621	2,557,350
2	4,107,933	4,068,067	1,083,353	2,984,714	0.564	1,684,793
3	4,159,515	4,016,485	2,008,242	2,008,242	0.513	1,030,546
4	4,220,601	3,977,799	1,988,899	1,988,899	0.467	927,836
5	3,145,796	5,030,204	2,515,102	2,515,102	0.424	1,066,649
6	3,200,536	4,975,464	2,487,732	2,487,732	0.386	959,128
7	3,256,371	4,919,629	2,459,815	2,459,815	0.350	862,150
8	3,322,400	4,876,000	2,438,000	2,438,000	0.319	776,822
9	3,371,413	4,804,587	2,402,294	2,402,294	0.290	695,859
10	2,940,291	4,067,045	2,033,522	2,033,522	0.263	535,490
11	1,840,842	2,470,325	1,235,162	1,235,162	0.239	295,688
12	1,295,299	1,685,595	842,797	842,797	0.218	183,417
13	1,100,798	1,388,430	694,215	694,215	0.198	137,347
14	984,992	1,203,544	601,772	601,772	0.180	108,234
15	938,932	1,110,822	555,411	555,411	0.164	90,814
Total	**45,463,081**	**46,692,634**	**23,346,317**	**23,346,317**		**7,475,610**

Table C.2 Model M05_2 inj economic analysis calculation detail.

1	2	3	4	5	6	7	8
					CAPEX		
No. of Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
				1.0000	500,000		
				1.0200		1,000,000	
				1.0404			1,000,000
0	0	0	0	1.0612			
1	142,350	9,964,500	498,225	1.0824			
2	142,350	9,964,500	498,225	1.1041			
3	142,350	9,964,500	498,225	1.1262			
4	142,740	9,991,800	499,590	1.1487			
5	142,350	9,964,500	498,225	1.1717			
6	142,350	9,964,500	498,225	1.1951			
7	142,350	9,964,500	498,225	1.2190			
8	142,740	9,991,800	499,590	1.2434			
9	142,350	9,964,500	498,225	1.2682			
10	142,350	9,964,500	498,225	1.2936			
11	142,350	9,964,500	498,225	1.3195			
12	142,740	9,991,800	499,590	1.3459			
13	142,350	9,964,500	498,225	1.3728			
14	142,350	9,964,500	498,225	1.4002			
15	142,350	9,964,500	498,225	1.4282			
16	142,740	9,991,800	499,590	1.4568			
17	107,303	7,511,231	375,562	1.4859			
18	64,415	4,509,029	225,451	1.5157			
19	50,301	3,521,035	176,052	1.5460			
20	46,644	3,265,101	163,255	1.5769			
21	44,245	3,097,164	154,858	1.6084			
22	40,964	2,867,501	143,375	1.6406			
23	37,688	2,638,160	131,908	1.6734			
24	35,195	2,463,650	123,183	1.7069			
25	32,780	2,294,579	114,729	1.7410			
Total	**2,738,695**	**191,708,650**	**9,585,433**				

Table C.2 Model M05_2 inj economic analysis calculation detail (continued).

1	9	10	11	12	13	14	15
	CAPEX						
No. of Year	**No. of Production Well**	**No. of Injection Well**	**Water Injection Rate (bbl/year)**	**Drilling and completion cost of production well (US$)**	**(US$)**	**Facility cost of production well (US$)**	**Abandonment cost (US$)**
				INTANG	TANG		
0	3	-	0	3,600,000	900,000	5,000,000	0
1	-	-	0	-	-	-	-
2	-	-	0	-	-	-	-
3	-	2	329,400	-	-	-	25,000
4	-	-	328,500	-	-	-	-
5	-	-	328,500	-	-	-	-
6	-	-	328,500	-	-	-	-
7	-	-	329,400	-	-	-	-
8	-	-	328,500	-	-	-	-
9	-	-	328,500	-	-	-	-
10	-	-	328,500	-	-	-	-
11	-	-	329,400	-	-	-	-
12	-	-	328,500	-	-	-	-
13	-	-	328,500	-	-	-	-
14	-	-	328,500	-	-	-	-
15	-	-	329,400	-	-	-	-
16	-	-	328,500	-	-	-	-
17	-	-	328,500	-	-	-	-
18	-	-	328,500	-	-	-	-
19	-	-	329,400	-	-	-	-
20	-	-	328,500	-	-	-	-
21	-	-	328,500	-	-	-	-
22	-	-	328,500	-	-	-	-
23	-	-	329,400	-	-	-	-
24	-	-	328,500	-	-	-	-
25	-	-	328,500	-	-	-	-
Total			**7,560,900**	**3,600,000**	**900,000**	**5,000,000**	**25,000**

Table C.2 Model M05_2 inj economic analysis calculation detail (continued).

1	16	17	18	19	20
	CAPEX		**OPEX**		
No. of Year	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense (US$)**	**Operation cost of production well (US$)**	**Maintenance cost of water injection facility (US$)**	**Operation cost of water injection (US$)**
0	0	1,180,000	0	0	0
1	-	1,180,000	3,081,684	0	0
2	-	1,180,000	3,143,318	0	0
3	500,000	1,280,000	3,206,184	270,279	164,700
4	-	1,280,000	3,279,268	275,685	164,250
5	-	100,000	3,335,714	281,198	164,250
6	-	100,000	3,402,429	286,822	164,250
7	-	100,000	3,470,477	292,559	164,700
8	-	0	3,549,585	298,410	164,250
9	-	0	3,610,684	304,378	164,250
10	-	0	3,682,898	310,466	164,250
11	-	0	3,756,556	316,675	164,700
12	-	0	3,842,185	323,008	164,250
13	-	0	3,908,321	329,469	164,250
14	-	0	3,986,487	336,058	164,250
15	-	0	4,066,217	342,779	164,700
16	-	0	4,158,905	349,635	164,250
17	-	0	3,188,941	356,627	164,250
18	-	0	1,952,624	363,760	164,250
19	-	0	1,555,271	371,035	164,700
20	-	0	1,471,067	378,456	164,250
21	-	0	1,423,313	386,025	164,250
22	-	0	1,344,126	393,745	164,250
23	-	0	1,261,356	401,620	164,700
24	-	0	1,201,477	409,653	164,250
25	-	0	1,141,405	417,846	164,250
Total	**500,000**	**6,400,000**	**72,020,492**	**7,796,187**	**3,780,450**

Table C.2 Model M05_2 inj economic analysis calculation detail (continued).

1	21	22	23	24	25	26
No. of Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(10%) Discount factor**	**Discount cash flow (US$)**
					1	
	500,000	-500,000	0	-500,000	0.909	-454,545
	1,000,000	-1,000,000	0	-1,000,000	0.826	-826,446
	1,000,000	-1,000,000	0	-1,000,000	0.751	-751,315
0	4,780,000	-4,780,000	0	-4,780,000	0.683	-3,264,804
1	4,759,909	5,204,591	0	5,204,591	0.621	3,231,641
2	4,821,543	5,142,957	1,533,774	3,609,183	0.564	2,037,290
3	5,444,388	4,520,112	2,260,056	2,260,056	0.513	1,159,766
4	5,498,792	4,493,008	2,246,504	2,246,504	0.467	1,048,011
5	4,379,388	5,585,112	2,792,556	2,792,556	0.424	1,184,316
6	4,451,726	5,512,774	2,756,387	2,756,387	0.386	1,062,707
7	4,525,961	5,438,539	2,719,270	2,719,270	0.350	953,087
8	4,511,835	5,479,965	2,739,983	2,739,983	0.319	873,043
9	4,577,537	5,386,963	2,693,481	2,693,481	0.290	780,206
10	4,655,839	5,308,661	2,654,331	2,654,331	0.263	698,968
11	4,736,156	5,228,344	2,614,172	2,614,172	0.239	625,812
12	4,829,033	5,162,767	2,581,383	2,581,383	0.218	561,784
13	4,900,264	5,064,236	2,532,118	2,532,118	0.198	500,966
14	4,985,020	4,979,480	2,489,740	2,489,740	0.180	447,802
15	5,071,921	4,892,579	2,446,289	2,446,289	0.164	399,988
16	5,172,379	4,819,421	2,409,710	2,409,710	0.149	358,188
17	4,085,380	3,425,851	1,712,925	1,712,925	0.135	231,469
18	2,706,085	1,802,944	901,472	901,472	0.123	110,742
19	2,267,058	1,253,977	626,989	626,989	0.112	70,021
20	2,177,028	1,088,073	544,036	544,036	0.102	55,234
21	2,128,446	968,718	484,359	484,359	0.092	44,704
22	2,045,496	822,005	411,002	411,002	0.084	34,485
23	1,959,584	678,576	339,288	339,288	0.076	25,880
24	1,898,563	565,087	282,544	282,544	0.069	19,593
25	1,838,230	456,349	228,175	228,175	0.063	14,384
Total	**103,207,562**	**86,001,088**	**43,000,544**	**43,000,544**		**11,232,975**

Table C.3 Model M05_4 inj economic analysis calculation detail.

1	2	3	4	5	6	7	8
					CAPEX		
No. of Year	**Oil production total (bbl/year)**	**Income (US$)**	**Royalty sliding scale (US$)**	**(2%) Escalate Factor**	**Concession (US$)**	**Geological and geophysical surveys (US$)**	**Exploration and appraisal well (US$)**
				1.0000	500,000		
				1.0200		1,000,000	
				1.0404			1,000,000
0	0	0	0	1.0612			
1	87,600	6,132,000	306,600	1.0824			
2	87,600	6,132,000	306,600	1.1041			
3	87,600	6,132,000	306,600	1.1262			
4	87,840	6,148,800	307,440	1.1487			
5	87,600	6,132,000	306,600	1.1717			
6	87,600	6,132,000	306,600	1.1951			
7	87,600	6,132,000	306,600	1.2190			
8	146,400	10,248,000	512,400	1.2434			
9	146,000	10,220,000	511,000	1.2682			
10	146,000	10,220,000	511,000	1.2936			
11	146,000	10,220,000	511,000	1.3195			
12	146,400	10,248,000	512,400	1.3459			
13	146,000	10,220,000	511,000	1.3728			
14	146,000	10,220,000	511,000	1.4002			
15	146,000	10,220,000	511,000	1.4282			
16	146,400	10,248,000	512,400	1.4568			
17	146,000	10,220,000	511,000	1.4859			
18	146,000	10,220,000	511,000	1.5157			
19	133,619	9,353,316	467,666	1.5460			
20	79,766	5,583,585	279,179	1.5769			
21	56,455	3,951,829	197,591	1.6084			
22	48,556	3,398,941	169,947	1.6406			
23	45,383	3,176,775	158,839	1.6734			
24	42,391	2,967,335	148,367	1.7069			
25	38,798	2,715,825	135,791	1.7410			
Total	**2,665,606**	**186,592,406**	**9,329,620**				

Table C.3 Model M05_4 inj economic analysis calculation detail (continued).

1	9	10	11	12	13	14	15
	CAPEX						
No. of Year	No. of Production Well	No. of Injection Well	Water Injection Rate (bbl/year)	Drilling and completion cost of production well (US$)	(US$)	Facility cost of production well (US$)	Abandonment cost (US$)
				INTANG	TANG		
0	3	-	0	3,600,000	900,000	5,000,000	0
1	-	-	0	-	-	-	-
2	-	-	0	-	-	-	-
3	-	-	0	-	-	-	-
4	-	-	0	-	-	-	-
5	-	2	328,500	-	-	-	25,000
6	-	-	328,500	-	-	-	-
7	-	-	329,400	-	-	-	-
8	-	-	328,500	-	-	-	-
9	-	-	328,500	-	-	-	-
10	-	-	328,500	-	-	-	-
11	-	-	329,400	-	-	-	-
12	-	-	328,500	-	-	-	-
13	-	-	328,500	-	-	-	-
14	-	-	328,500	-	-	-	-
15	-	-	329,400	-	-	-	-
16	-	-	328,500	-	-	-	-
17	-	-	328,500	-	-	-	-
18	-	-	328,500	-	-	-	-
19	-	-	329,400	-	-	-	-
20	-	-	328,500	-	-	-	-
21	-	-	328,500	-	-	-	-
22	-	-	328,500	-	-	-	-
23	-	-	329,400	-	-	-	-
24	-	-	328,500	-	-	-	-
25	-	-	328,500	-	-	-	-
Total			**6,903,000**	**3,600,000**	**900,000**	**5,000,000**	**25,000**

Table C.3 Model M05_4 inj economic analysis calculation detail (continued).

1	16	17	18	19	20
	CAPEX		**OPEX**		
No. of Year	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense (US$)**	**Operation cost of production well (US$)**	**Maintenance cost of water injection facility (US$)**	**Operation cost of water injection (US$)**
0	0	1,180,000	0	0	0
1	-	1,180,000	1,896,421	0	0
2	-	1,180,000	1,934,350	0	0
3	-	1,180,000	1,973,037	0	0
4	-	1,180,000	2,018,011	0	0
5	500,000	100,000	2,052,747	281,198	164,250
6	-	100,000	2,093,802	286,822	164,250
7	-	100,000	2,135,678	292,559	164,700
8	-	100,000	3,640,600	298,410	164,250
9	-	100,000	3,703,266	304,378	164,250
10	-	0	3,777,331	310,466	164,250
11	-	0	3,852,878	316,675	164,700
12	-	0	3,940,702	323,008	164,250
13	-	0	4,008,534	329,469	164,250
14	-	0	4,088,705	336,058	164,250
15	-	0	4,170,479	342,779	164,700
16	-	0	4,265,543	349,635	164,250
17	-	0	4,338,966	356,627	164,250
18	-	0	4,425,746	363,760	164,250
19	-	0	4,131,439	371,035	164,700
20	-	0	2,515,643	378,456	164,250
21	-	0	1,816,077	386,025	164,250
22	-	0	1,593,235	393,745	164,250
23	-	0	1,518,878	401,620	164,700
24	-	0	1,447,115	409,653	164,250
25	-	0	1,350,948	417,846	164,250
Total	**500,000**	**6,400,000**	**72,690,132**	**7,250,224**	**3,451,500**

Table C.3 Model M05_4 inj economic analysis calculation detail (continued).

1	21	22	23	24	25	26
No. of Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(10%) Discount factor**	**Discount cash flow (US$)**
					1	
	500,000	-500,000	0	-500,000	0.909	-454,545
	1,000,000	-1,000,000	0	-1,000,000	0.826	-826,446
	1,000,000	-1,000,000	0	-1,000,000	0.751	-751,315
0	4,780,000	-4,780,000	0	-4,780,000	0.683	-3,264,804
1	3,383,021	2,748,979	0	2,748,979	0.621	1,706,900
2	3,420,950	2,711,050	0	2,711,050	0.564	1,530,317
3	3,459,637	2,672,363	426,196	2,246,167	0.513	1,152,639
4	3,505,451	2,643,349	1,321,675	1,321,675	0.467	616,571
5	2,929,795	3,202,205	1,601,102	1,601,102	0.424	679,024
6	2,951,474	3,180,526	1,590,263	1,590,263	0.386	613,115
7	2,999,537	3,132,463	1,566,232	1,566,232	0.350	548,955
8	4,715,660	5,532,340	2,766,170	2,766,170	0.319	881,387
9	4,782,894	5,437,106	2,718,553	2,718,553	0.290	787,468
10	4,763,047	5,456,953	2,728,477	2,728,477	0.263	718,493
11	4,845,253	5,374,747	2,687,374	2,687,374	0.239	643,336
12	4,940,361	5,307,639	2,653,820	2,653,820	0.218	577,548
13	5,013,253	5,206,747	2,603,374	2,603,374	0.198	515,064
14	5,100,013	5,119,987	2,559,994	2,559,994	0.180	460,437
15	5,188,958	5,031,042	2,515,521	2,515,521	0.164	411,308
16	5,291,828	4,956,172	2,478,086	2,478,086	0.149	368,352
17	5,370,844	4,849,156	2,424,578	2,424,578	0.135	327,635
18	5,464,756	4,755,244	2,377,622	2,377,622	0.123	292,081
19	5,134,840	4,218,476	2,109,238	2,109,238	0.112	235,556
20	3,337,528	2,246,057	1,123,028	1,123,028	0.102	114,016
21	2,563,943	1,387,886	693,943	693,943	0.092	64,048
22	2,321,178	1,077,763	538,882	538,882	0.084	45,215
23	2,244,037	932,738	466,369	466,369	0.076	35,574
24	2,169,385	797,950	398,975	398,975	0.069	27,666
25	2,068,835	646,990	323,495	323,495	0.063	20,393
Total	**102,746,476**	**81,345,930**	**40,672,965**	**40,672,965**		**8,075,986**

Table C.4 Model M05_8 inj economic analysis calculation detail.

1	2	3	4	5	6	7	8
					CAPEX		
No. of Year	Oil production total (bbl/year)	Income (US$)	Royalty sliding scale (US$)	(2%) Escalate Factor	Concession (US$)	Geological and geophysical surveys (US$)	Exploration and appraisal well (US$)
				1.0000	500,000		
				1.0200		1,000,000	
				1.0404			1,000,000
0	0	0	0	1.0612			
1	71,175	4,982,250	249,113	1.0824			
2	71,175	4,982,250	249,113	1.1041			
3	71,175	4,982,250	249,113	1.1262			
4	71,370	4,995,900	249,795	1.1487			
5	71,175	4,982,250	249,113	1.1717			
6	71,175	4,982,250	249,113	1.1951			
7	71,175	4,982,250	249,113	1.2190			
8	71,370	4,995,900	249,795	1.2434			
9	71,175	4,982,250	249,113	1.2682			
10	71,175	4,982,250	249,113	1.2936			
11	71,175	4,982,250	249,113	1.3195			
12	71,370	4,995,900	249,795	1.3459			
13	155,125	10,858,750	542,938	1.3728			
14	155,125	10,858,750	542,938	1.4002			
15	155,125	10,858,750	542,938	1.4282			
16	155,550	10,888,500	544,425	1.4568			
17	155,125	10,858,750	542,938	1.4859			
18	155,125	10,858,750	542,938	1.5157			
19	155,125	10,858,750	542,938	1.5460			
20	155,550	10,888,500	544,425	1.5769			
21	146,934	10,285,380	514,269	1.6084			
22	86,401	6,048,091	302,405	1.6406			
23	61,193	4,283,524	214,176	1.6734			
24	53,313	3,731,896	186,595	1.7069			
25	50,634	3,544,394	177,220	1.7410			
Total	**2,495,011**	**174,650,735**	**8,732,537**				

Table C.4 Model M05_8 inj economic analysis calculation detail (continued).

1	9	10	11	12	13	14	15
	CAPEX						
No. of Year	**No. of Production Well**	**No. of Injection Well**	**Water Injection Rate (bbl/year)**	**Drilling and completion cost of production well**		**Facility cost of production well (US$)**	**Abandonment cost (US$)**
				(US$)	**(US$)**		
				INTANG	TANG		
0	3	-	0	3,600,000	900,000	5,000,000	0
1	-	-	0	-	-	-	-
2	-	-	0	-	-	-	-
3	-	-	0	-	-	-	-
4	-	-	0	-	-	-	-
5	-	-	0	-	-	-	-
6	-	-	0	-	-	-	-
7	-	-	0	-	-	-	-
8	-	-	0	-	-	-	-
9	-	2	328,500	-	-	-	25,000
10	-	-	328,500	-	-	-	-
11	-	-	329,400	-	-	-	-
12	-	-	328,500	-	-	-	-
13	-	-	328,500	-	-	-	-
14	-	-	328,500	-	-	-	-
15	-	-	329,400	-	-	-	-
16	-	-	328,500	-	-	-	-
17	-	-	328,500	-	-	-	-
18	-	-	328,500	-	-	-	-
19	-	-	329,400	-	-	-	-
20	-	-	328,500	-	-	-	-
21	-	-	328,500	-	-	-	-
22	-	-	328,500	-	-	-	-
23	-	-	329,400	-	-	-	-
24	-	-	328,500	-	-	-	-
25	-	-	328,500	-	-	-	-
Total			**5,588,100**	**3,600,000**	**900,000**	**5,000,000**	**25,000**

Table C.4 Model M05_8 inj economic analysis calculation detail (continued).

1	16	17	18	19	20
	CAPEX		**OPEX**		
No. of Year	**Facility cost of injection well (US$)**	**Total Depreciation (20%) tangible expense (US$)**	**Operation cost of production well (US$)**	**Maintenance cost of water injection facility (US$)**	**Operation cost of water injection (US$)**
0	0	1,180,000	0	0	0
1	-	1,180,000	1,540,842	0	0
2	-	1,180,000	1,571,659	0	0
3	-	1,180,000	1,603,092	0	0
4	-	1,180,000	1,639,634	0	0
5	-	0	1,667,857	0	0
6	-	0	1,701,214	0	0
7	-	0	1,735,239	0	0
8	-	0	1,774,792	0	0
9	500,000	100,000	1,805,342	304,378	164,250
10	-	100,000	1,841,449	310,466	164,250
11	-	100,000	1,878,278	316,675	164,700
12	-	100,000	1,921,092	323,008	164,250
13	-	100,000	4,259,068	329,469	164,250
14	-	0	4,344,249	336,058	164,250
15	-	0	4,431,134	342,779	164,700
16	-	0	4,532,140	349,635	164,250
17	-	0	4,610,152	356,627	164,250
18	-	0	4,702,355	363,760	164,250
19	-	0	4,796,402	371,035	164,700
20	-	0	4,905,734	378,456	164,250
21	-	0	4,726,682	386,025	164,250
22	-	0	2,835,010	393,745	164,250
23	-	0	2,048,036	401,620	164,700
24	-	0	1,819,978	409,653	164,250
25	-	0	1,763,107	417,846	164,250
Total	**500,000**	**6,400,000**	**70,454,538**	**6,091,235**	**2,794,050**

Table C.4 Model M05_8 inj economic analysis calculation detail (continued).

1	21	22	23	24	25	26
No. of Year	**Total allow expense (US$)**	**Taxable income (US$)**	**Income tax (US$)**	**Annual cash flow (US$)**	**(10%) Discount factor**	**Discount cash flow (US$)**
					1	
	500,000	-500,000	0	-500,000	0.909	-454,545
	1,000,000	-1,000,000	0	-1,000,000	0.826	-826,446
	1,000,000	-1,000,000	0	-1,000,000	0.751	-751,315
0	4,780,000	-4,780,000	0	-4,780,000	0.683	-3,264,804
1	2,969,955	2,012,295	0	2,012,295	0.621	1,249,477
2	3,000,772	1,981,478	0	1,981,478	0.564	1,118,493
3	3,032,205	1,950,045	0	1,950,045	0.513	1,000,682
4	3,069,429	1,926,471	295,145	1,631,326	0.467	761,026
5	1,916,970	3,065,280	1,532,640	1,532,640	0.424	649,989
6	1,950,327	3,031,923	1,515,962	1,515,962	0.386	584,469
7	1,984,351	2,997,899	1,498,949	1,498,949	0.350	525,373
8	2,024,587	2,971,313	1,485,656	1,485,656	0.319	473,376
9	2,648,083	2,334,167	1,167,084	1,167,084	0.290	338,063
10	2,665,277	2,316,973	1,158,486	1,158,486	0.263	305,066
11	2,708,765	2,273,485	1,136,742	1,136,742	0.239	272,127
12	2,758,146	2,237,754	1,118,877	1,118,877	0.218	243,500
13	5,395,724	5,463,026	2,731,513	2,731,513	0.198	540,415
14	5,387,494	5,471,256	2,735,628	2,735,628	0.180	492,027
15	5,481,551	5,377,199	2,688,600	2,688,600	0.164	439,608
16	5,590,449	5,298,051	2,649,025	2,649,025	0.149	393,761
17	5,673,967	5,184,783	2,592,392	2,592,392	0.135	350,311
18	5,773,302	5,085,448	2,542,724	2,542,724	0.123	312,363
19	5,875,075	4,983,675	2,491,838	2,491,838	0.112	278,284
20	5,992,864	4,895,636	2,447,818	2,447,818	0.102	248,516
21	5,791,226	4,494,154	2,247,077	2,247,077	0.092	207,396
22	3,695,410	2,352,681	1,176,341	1,176,341	0.084	98,701
23	2,828,533	1,454,991	727,496	727,496	0.076	55,492
24	2,580,476	1,151,420	575,710	575,710	0.069	39,922
25	2,522,423	1,021,971	510,986	510,986	0.063	32,212
Total	**98,097,359**	**74,053,376**	**37,026,688**	**37,026,688**		**5,713,537**

APPENDIX D

RESERVOIR SIMULATION INPUT DATA

D.1 Reservoir Simulation Input Data

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-- Office Simulation File (DATA) Data Section Version 2009.2 Oct 16 2009
-- ----------------------------------------------------------------------
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-- File: PHITSANULOK_E100.DATA
-- Created on: 03-May-2010 at: 15:51:11
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*****************************************************************
-- *                    WARNING                    *
-- *       THIS FILE HAS BEEN AUTOMATICALLY GENERATED.      *
-- *    ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.      *
-- *****************************************************************
--

RUNSPEC

TITLE
Phitsanulok Basin Reservoir Simulation Model

START
1 'JAN' 2005 /

FIELD

GAS

OIL

WATER

DISGAS

NSTACK
50 /

ENDSCALE
'NODIR' 'REVERS' 1 20 /

MONITOR
```

```
RSSPEC

NOINSPEC

MSGFILE
1 /

GASFIELD
'NO'  'NO' /

DIMENS
25 25 8 /

EQLDIMS
1 100 100 1 20 /

REGDIMS
1 1 0 0 /

TABDIMS
1 1 20 20 1 20 20 1 /

WELLDIMS
 7 9 3 7 /


GRID

GRIDFILE
2 /

INCLUDE
'PHITSANULOK_GOPP.INC'  /

INCLUDE
'PHITSANULOK_GGO.INC'  /

INCLUDE
'PHITSANULOK_GPRO.INC'  /


PROPS

INCLUDE
'PHITSANULOK_PVT.INC'  /
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INCLUDE
'PHITSANULOK_SCAL.INC'  /
SOLUTION

INCLUDE
'PHITSANULOK_INIT.INC'  /


SUMMARY

INCLUDE
'PHITSANULOK_SUM.INC'  /


SCHEDULE

INCLUDE
'PHITSANULOK_SCH.INC'  /


END

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-- ---------------------------------------------------------------------------
-- Office PVTN (PVTN) Data Section Version 2009.2 Oct 16 2009
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-- File: PHITSANULOK_PVT.INC
-- Created on: Mar-12-2010 at: 11:33:50
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-- *****************************************************************
-- *                          WARNING                          *
-- *          THIS FILE HAS BEEN AUTOMATICALLY GENERATED.          *
-- *        ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.       *
-- *****************************************************************
--
-- OFFICE-PVTN-HEADER-DATA
-- Off PVTN PVT Tables:        1        1
-- Off PVTN  "PVT 1"
-- Off PVTN Rock Tables:        1        1
-- Off PVTN  "Rock Compact 1"
-- Off PVTN Correlation Data:        32        1
-- Off PVTN  "PVT 1"
-- Off PVTN  "SET VALUE FOR STANDARD_TEMPERATURE TO
59.9999999999999 IN F;"
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-- Off PVTN  "SET VALUE FOR STANDARD_PRESSURE TO 14.7 IN psia;"
-- Off PVTN  "SET VALUE FOR POROSITY TO 0.2 IN dimensionless;"
-- Off PVTN  "SET VALUE FOR REF_PRESSURE TO 3500 IN psia;"
-- Off PVTN  "SET VALUE FOR ROCK_TYPE TO
CONSOLIDATED_SANDSTONE;"
-- Off PVTN  "SET VALUE FOR GAS_GRAVITY TO 0.8 IN sg_Air_1;"
-- Off PVTN  "SET VALUE FOR OIL_GRAVITY TO 39.4 IN APIoil;"
-- Off PVTN  "SET VALUE FOR BUBBLE_POINT TO 1800 IN psia;"
-- Off PVTN  "SET VALUE FOR SALINITY TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR TEMPERATURE TO 203 IN F;"
-- Off PVTN  "SET VALUE FOR N2 TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR H2S TO 0 IN fraction;"
-- Off PVTN  "SET VALUE FOR CO2 TO 0 IN fraction;"
-- Off PVTN  "SET CORRELATION FOR ROCK TO NEWMAN;"
-- Off PVTN  "SET CORRELATION FOR OIL_RS TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR OIL_PB TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR OIL_VISCOSITY TO BEGGS;"
-- Off PVTN  "SET CORRELATION FOR OIL_COMPRESSIBILITY TO
VASQUEZ;"
-- Off PVTN  "--SET CORRELATION FOR NONE TO UNSET;"
-- Off PVTN  "SET CORRELATION FOR OIL_FVF TO STANDING;"
-- Off PVTN  "SET CORRELATION FOR GAS_CRIT_PROPS TO THOMAS;"
-- Off PVTN  "SET CORRELATION FOR GAS_ZFACTOR TO HALL;"
-- Off PVTN  "SET CORRELATION FOR GAS_FVF TO IDEAL_GAS;"
-- Off PVTN  "SET CORRELATION FOR GAS_VISCOSITY TO LEE;"
-- Off PVTN  "SET CORRELATION FOR WATER_VISCOSITY TO MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_COMPRESSIBILITY TO
MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_FVF TO MEEHAN;"
-- Off PVTN  "SET CORRELATION FOR WATER_DENSITY TO FVF_RATIO;"
-- Off PVTN  "SET VALUE FOR MIN_PRESSURE TO 14.7 IN psia;"
-- Off PVTN  "SET VALUE FOR MAX_PRESSURE TO 3500 IN psia;"
-- Off PVTN  "SET VALUE FOR TABLE_LENGTH TO 20;"
ECHO
DENSITY
--
-- Fluid Densities at Surface Conditions
--
 51.637497914955 62.4279737253144 0.0499423789802515
/

PVTO
--
-- Live Oil PVT Properties (Dissolved Gas)
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0.00147	14.70	1.0709	1.2585
	198.14	1.0550	1.3038
	381.57	1.0544	1.3837
	565.01	1.0542	1.4867
	748.45	1.0541	1.6103
	931.88	1.0540	1.7541
	1115.32	1.0540	1.9188
	1298.76	1.0539	2.1054
	1482.19	1.0539	2.3152
	1665.63	1.0539	2.5498
	1800.00	1.0539	2.7384
	2032.51	1.0539	3.1008
	2215.94	1.0539	3.4211
	2399.38	1.0539	3.7741
	2582.82	1.0538	4.1619
	2766.25	1.0538	4.5869
	2949.69	1.0538	5.0514
	3133.13	1.0538	5.5575
	3316.56	1.0538	6.1077
	3500.00	1.0538	6.7042
0.03380	198.14	1.0856	1.0751
	381.57	1.0763	1.0959
	565.01	1.0731	1.1278
	748.45	1.0715	1.1686
	931.88	1.0705	1.2170
	1115.32	1.0698	1.2723
	1298.76	1.0693	1.3342
	1482.19	1.0690	1.4026
	1665.63	1.0687	1.4774
	1800.00	1.0685	1.5362
	2032.51	1.0683	1.6460
	2215.94	1.0681	1.7400
	2399.38	1.0680	1.8405
	2582.82	1.0679	1.9477
	2766.25	1.0678	2.0615
	2949.69	1.0677	2.1823
	3133.13	1.0676	2.3099
	3316.56	1.0676	2.4445
	3500.00	1.0675	2.5862
0.07444	381.57	1.1044	0.9243
	565.01	1.0973	0.9411

	748.45	1.0937	0.9642
	931.88	1.0915	0.9928
	1115.32	1.0901	1.0262
	1298.76	1.0890	1.0639
	1482.19	1.0883	1.1059
	1665.63	1.0876	1.1518
	1800.00	1.0873	1.1879
	2032.51	1.0868	1.2553
	2215.94	1.0864	1.3127
	2399.38	1.0861	1.3739
	2582.82	1.0859	1.4389
	2766.25	1.0857	1.5076
	2949.69	1.0855	1.5800
	3133.13	1.0853	1.6562
	3316.56	1.0852	1.7362
	3500.00	1.0851	1.8199
0.11946	565.01	1.1257	0.8111
	748.45	1.1196	0.8255
	931.88	1.1160	0.8442
	1115.32	1.1135	0.8667
	1298.76	1.1118	0.8925
	1482.19	1.1104	0.9213
	1665.63	1.1094	0.9532
	1800.00	1.1088	0.9783
	2032.51	1.1079	1.0252
	2215.94	1.1073	1.0652
	2399.38	1.1069	1.1078
	2582.82	1.1065	1.1530
	2766.25	1.1061	1.2007
	2949.69	1.1058	1.2509
	3133.13	1.1055	1.3036
	3316.56	1.1053	1.3588
	3500.00	1.1051	1.4164
0.16762	748.45	1.1490	0.7246
	931.88	1.1435	0.7374
	1115.32	1.1398	0.7533
	1298.76	1.1372	0.7720
	1482.19	1.1352	0.7931
	1665.63	1.1336	0.8165
	1800.00	1.1327	0.8351
	2032.51	1.1314	0.8699
	2215.94	1.1305	0.8997

	2399.38	1.1298	0.9315
	2582.82	1.1292	0.9652
	2766.25	1.1287	1.0007
	2949.69	1.1282	1.0381
	3133.13	1.1278	1.0774
	3316.56	1.1274	1.1184
	3500.00	1.1271	1.1612
0.21829	931.88	1.1740	0.6568
	1115.32	1.1688	0.6684
	1298.76	1.1651	0.6823
	1482.19	1.1623	0.6983
	1665.63	1.1601	0.7163
	1800.00	1.1588	0.7306
	2032.51	1.1570	0.7575
	2215.94	1.1558	0.7806
	2399.38	1.1548	0.8053
	2582.82	1.1539	0.8315
	2766.25	1.1532	0.8592
	2949.69	1.1525	0.8884
	3133.13	1.1520	0.9190
	3316.56	1.1514	0.9509
	3500.00	1.1510	0.9842
0.27105	1115.32	1.2006	0.6022
	1298.76	1.1956	0.6128
	1482.19	1.1918	0.6252
	1665.63	1.1889	0.6393
	1800.00	1.1871	0.6507
	2032.51	1.1846	0.6721
	2215.94	1.1830	0.6905
	2399.38	1.1817	0.7103
	2582.82	1.1805	0.7314
	2766.25	1.1795	0.7536
	2949.69	1.1786	0.7771
	3133.13	1.1779	0.8017
	3316.56	1.1772	0.8274
	3500.00	1.1766	0.8542
0.32563	1298.76	1.2285	0.5573
	1482.19	1.2236	0.5671
	1665.63	1.2198	0.5784
	1800.00	1.2175	0.5875
	2032.51	1.2143	0.6049
	2215.94	1.2122	0.6200

	2399.38	1.2104	0.6361
	2582.82	1.2089	0.6534
	2766.25	1.2076	0.6717
	2949.69	1.2065	0.6910
	3133.13	1.2055	0.7113
	3316.56	1.2046	0.7325
	3500.00	1.2038	0.7546
0.38181	1482.19	1.2578	0.5197
	1665.63	1.2529	0.5289
	1800.00	1.2500	0.5363
	2032.51	1.2459	0.5506
	2215.94	1.2432	0.5631
	2399.38	1.2410	0.5766
	2582.82	1.2391	0.5910
	2766.25	1.2374	0.6063
	2949.69	1.2360	0.6225
	3133.13	1.2347	0.6395
	3316.56	1.2336	0.6573
	3500.00	1.2325	0.6758
0.43944	1665.63	1.2883	0.4877
	1800.00	1.2846	0.4939
	2032.51	1.2795	0.5058
	2215.94	1.2762	0.5163
	2399.38	1.2734	0.5277
	2582.82	1.2710	0.5399
	2766.25	1.2689	0.5528
	2949.69	1.2671	0.5666
	3133.13	1.2655	0.5810
	3316.56	1.2641	0.5962
	3500.00	1.2628	0.6120
0.48249	1800.00	1.3114	0.4672
	2032.51	1.3053	0.4777
	2215.94	1.3015	0.4870
	2399.38	1.2982	0.4970
	2582.82	1.2955	0.5079
	2766.25	1.2931	0.5195
	2949.69	1.2910	0.5318
	3133.13	1.2891	0.5447
	3316.56	1.2875	0.5583
	3500.00	1.2860	0.5725

```
/

PVDG
--
-- Dry Gas PVT Properties (No Vapourised Oil)
--

     14.70     226.6988     0.0128
    198.14      16.4361     0.0130
    381.57       8.3420     0.0132
    565.01       5.5087     0.0135
    748.45       4.0690     0.0138
    931.88       3.2006     0.0142
   1115.32       2.6225     0.0146
   1298.76       2.2121     0.0151
   1482.19       1.9079     0.0157
   1665.63       1.6752     0.0163
   1800.00       1.5377     0.0168
   2032.51       1.3480     0.0178
   2215.94       1.2309     0.0185
   2399.38       1.1353     0.0193
   2582.82       1.0564     0.0202
   2766.25       0.9908     0.0210
   2949.69       0.9356     0.0219
   3133.13       0.8890     0.0227
   3316.56       0.8491     0.0236
   3500.00       0.8148     0.0244

/

PVTW
--
-- Water PVT Properties
--
3500 1.0220300723725 3.080178583e-006 0.296407629534231
3.82721871239781e-006
/

ECHO
ROCK
--
-- Rock Properties
--
3500 1.52989636834116e-006
/
--
-- ---------------------------------------------------------------------------
-- Office SCAL (SCAL) Data Section Version 2009.2 Oct 16 2009
```

```
-- ------------------------------------------------------------------------------
--
-- File: PHITSANULOK_SCAL.INC
-- Created on: 23-Mar-2010 at: 12:27:56
--
--
*******************************************************************
-- *                    WARNING                   *
-- *          THIS FILE HAS BEEN AUTOMATICALLY GENERATED.     *
-- *       ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.     *
-- *****************************************************************
--
-- OFFICE-SCAL-HEADER-DATA
-- Off SCAL Saturation Tables:      1      1
-- Off SCAL  "Saturation 1"
-- Off SCAL End Point Tables:      1      1
-- Off SCAL  "End Points 1"
-- Off SCAL Petro Elastic Tables:      1      1
-- Off SCAL  "Petro-elastic 1"
ECHO
--   0.3            0.0            0.5
--   0.4            0.0            0.3
--   0.48           0.0            1*
--   0.5            0.218          0.16
--   0.6            0.352          0.1
--
-- Water Saturation Functions
--
SWFN
--
-- Water Saturation Functions
--
        0.25           0              2
        0.3            0              1
        0.4            0.04           0.4
        0.5            0.11           0.2
        0.6            0.2            0.1
        0.7            0.3            0.06
        0.75           0.44           0.02
        0.8            0.68           0
/

-- SIMILARLY FOR GAS
--
--  SGAS   KRG    PCOG
--
-- Gas Saturation Functions
```

```
--
SGFN
--
-- Gas Saturation Functions
--
        0           0           0
        0.04        0           0.03
        0.15        0.02        0.115
        0.2         0.05        0.172
        0.3         0.11        0.334
        0.4         0.21        0.552
        0.5         0.31        0.76
        0.6         0.41        1
        0.7         0.52        1.22
        0.75        0.6         1.35
/

-- OIL RELATIVE PERMEABILITY IS TABULATED AGAINST OIL
SATURATION
-- FOR OIL-WATER AND OIL-GAS-CONNATE WATER CASES
--
--  SOIL     KROW     KROG
--
-- Oil Saturation Functions
--
SOF3
--
-- Oil Saturation Functions
--
        0           0           0
        0.2         0           0
        0.3         0.01        0.03
        0.4         0.04        0.07
        0.45        0.06        0.12
        0.5         0.09        0.17
        0.55        0.15        0.25
        0.6         0.26        0.37
        0.65        0.48        0.56
        0.7         0.75        0.78
        0.75        1      1
/
--
-- ---------------------------------------------------------------------------
-- Office INIT (INIT) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: PHITSANULOK_INIT.INC
-- Created on: Mar-12-2010 at: 11:34:39
```

```
--
-- ****************************************************************
-- *                          WARNING                          *
-- *           THIS FILE HAS BEEN AUTOMATICALLY GENERATED.      *
-- *       ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.      *
--
****************************************************************
--
-- OFFICE-INIT-HEADER-DATA
--
--
-- ---------------------------------------------------------------------------
-- Office INIT Keywords
-- ---------------------------------------------------------------------------
--
ECHO
PBVD
--
-- Bubble Point v Depth
--
     3850      1800
     3900      1800
/

EQUIL
--
-- Equilibration Data Specification
--
 3850   3500   3915    1*    1*    1*    1    1*    5    1*    1*
/
--
-- ---------------------------------------------------------------------------
-- Office Summary (SUM) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: PHITSANULOK_SUM.INC
-- Created on: Mar-12-2010 at: 11:35:42
--
--
****************************************************************
-- *                          WARNING                          *
-- *           THIS FILE HAS BEEN AUTOMATICALLY GENERATED.      *
-- *       ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.      *
--
****************************************************************
--
```

```
ALL
FGPR
FGPT
FGPTF
FGPTS
FOE
FOIP
FOIPL
FOPT
RPTONLY
RUNSUM
SEPARATE
TIMESTEP
WGPTS
 /
WOPP
 /
WOPT
 /
--
-- ---------------------------------------------------------------------------
-- End of Office Summary (SUM) Data Section
-- ---------------------------------------------------------------------------
--
--
-- ---------------------------------------------------------------------------
-- Office Schedule (SCHED) Data Section Version 2009.2 Oct 16 2009
-- ---------------------------------------------------------------------------
--
-- File: PHITSANULOK_SCH.INC
-- Created on: 31-Mar-2010 at: 14:20:12
--
--
*****************************************************************
-- *                    WARNING                    *
-- *          THIS FILE HAS BEEN AUTOMATICALLY GENERATED.      *
-- *      ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID
DATA.      *
--
*****************************************************************
--
-- Off SCHED Units: "FIELD"
-- Off SCHED Wells:        3
-- Off SCHED Well: 1 5 13 100 11 0 8
-- Off SCHED Name: "IP1" ""
-- Off SCHED Completion: 1 5 13 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
```

```
-- Off SCHED Completion: 2 5 13 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 5 13 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 5 13 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 5 13 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 5 13 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 5 13 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 5 13 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 2 21 13 100 11 0 8
-- Off SCHED Name: "IP2" ""
-- Off SCHED Completion: 1 21 13 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 21 13 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 21 13 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 21 13 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 21 13 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 21 13 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 21 13 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 21 13 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Well: 3 13 13 100 10 0 8
```

```
-- Off SCHED Name: "P3" ""
-- Off SCHED Completion: 1 13 13 1
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 2 13 13 2
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 3 13 13 3
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 4 13 13 4
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 5 13 13 5
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 6 13 13 6
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 7 13 13 7
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Completion: 8 13 13 8
-- Off SCHED LGR:""
-- Off SCHED Compdat: 0.70999998 -1
-- Off SCHED Groups:          2
-- Off SCHED Group: "1"
-- Off SCHED Group: "2"
-- Off SCHED Times:         26
-- Off SCHED Date: 1 1 2005 0
-- Off SCHED Time: 0 0
-- Off SCHED Date: 1 1 2006 0
-- Off SCHED Time: 365 365
-- Off SCHED Date: 1 1 2007 0
-- Off SCHED Time: 365 730
-- Off SCHED Date: 1 1 2008 0
-- Off SCHED Time: 365 1095
-- Off SCHED Date: 1 1 2009 0
-- Off SCHED Time: 366 1461
-- Off SCHED Date: 1 1 2010 0
-- Off SCHED Time: 365 1826
-- Off SCHED Date: 1 1 2011 0
-- Off SCHED Time: 365 2191
-- Off SCHED Date: 1 1 2012 0
-- Off SCHED Time: 365 2556
-- Off SCHED Date: 1 1 2013 0
-- Off SCHED Time: 366 2922
-- Off SCHED Date: 1 1 2014 0
```

```
-- Off SCHED Time: 365 3287
-- Off SCHED Date: 1 1 2015 0
-- Off SCHED Time: 365 3652
-- Off SCHED Date: 1 1 2016 0
-- Off SCHED Time: 365 4017
-- Off SCHED Date: 1 1 2017 0
-- Off SCHED Time: 366 4383
-- Off SCHED Date: 1 1 2018 0
-- Off SCHED Time: 365 4748
-- Off SCHED Date: 1 1 2019 0
-- Off SCHED Time: 365 5113
-- Off SCHED Date: 1 1 2020 0
-- Off SCHED Time: 365 5478
-- Off SCHED Date: 1 1 2021 0
-- Off SCHED Time: 366 5844
-- Off SCHED Date: 1 1 2022 0
-- Off SCHED Time: 365 6209
-- Off SCHED Date: 1 1 2023 0
-- Off SCHED Time: 365 6574
-- Off SCHED Date: 1 1 2024 0
-- Off SCHED Time: 365 6939
-- Off SCHED Date: 1 1 2025 0
-- Off SCHED Time: 366 7305
-- Off SCHED Date: 1 1 2026 0
-- Off SCHED Time: 365 7670
-- Off SCHED Date: 1 1 2027 0
-- Off SCHED Time: 365 8035
-- Off SCHED Date: 1 1 2028 0
-- Off SCHED Time: 365 8400
-- Off SCHED Date: 1 1 2029 0
-- Off SCHED Time: 366 8766
-- Off SCHED Date: 1 1 2030 0
-- Off SCHED Time: 365 9131
-- Off SCHED END: 1 1 2030

ECHO

RPTSCHED
'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'RESTART=2' 'FIP=2' 'WELLS=2' /

TUNING
1 100 10 7* /
11* /
10* /

WELSPECS
'IP1' '1' 5 13 3950 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /
```

```
WELSPECS
'IP2' '1' 21 13 3950 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

WELSPECS
'P3' '2' 13 13 3915 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

COMPDAT
'P*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /

WCONPROD
'P*' 'OPEN' 1* 120 8* 6* 1* /
 /

WECON
'P*' 2* 0.9 2* 'CON' 'NO' 1* 'RATE' 1* 'NONE' 2* /
 /

COMPDAT
'IP*' 2* 1 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /

WCONPROD
'IP*' 'OPEN' 1* 120 8* 6* 1* /
 /

WECON
'IP*' 2* 0.9 2* 'NONE' 'NO' 1* 'RATE' 1* 'NONE' 2* /
 /

TSTEP
365 /

TSTEP
365 /

WELSPECS
'IP1' '1' 5 13 3950 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

WELSPECS
'IP2' '1' 21 13 3950 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

WELSPECS
```

```
'P3' '2' 13 13 3915 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD' /
 /

COMPDAT
'P*' 2* 1 6 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /

WCONPROD
'P*' 'OPEN' 1* 360 4* 1000 3* 6* 1* /
 /

WECON
'P*' 2* 0.9 2* 'CON' 'NO' 1* 'RATE' 1* 'NONE' 2* /
 /

COMPDAT
'IP*' 2* 7 8 'OPEN' 2* 0.71 250 -1 1* 'Z' 1* /
 /

WCONINJE
'IP*' 'WATER' 'OPEN' 'RATE' 250 9* /
 /

WECONINJ
'IP*' 100 'RATE' /
 /

TSTEP
365 /
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366 /
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D.2 Graph of Input Parameter Display

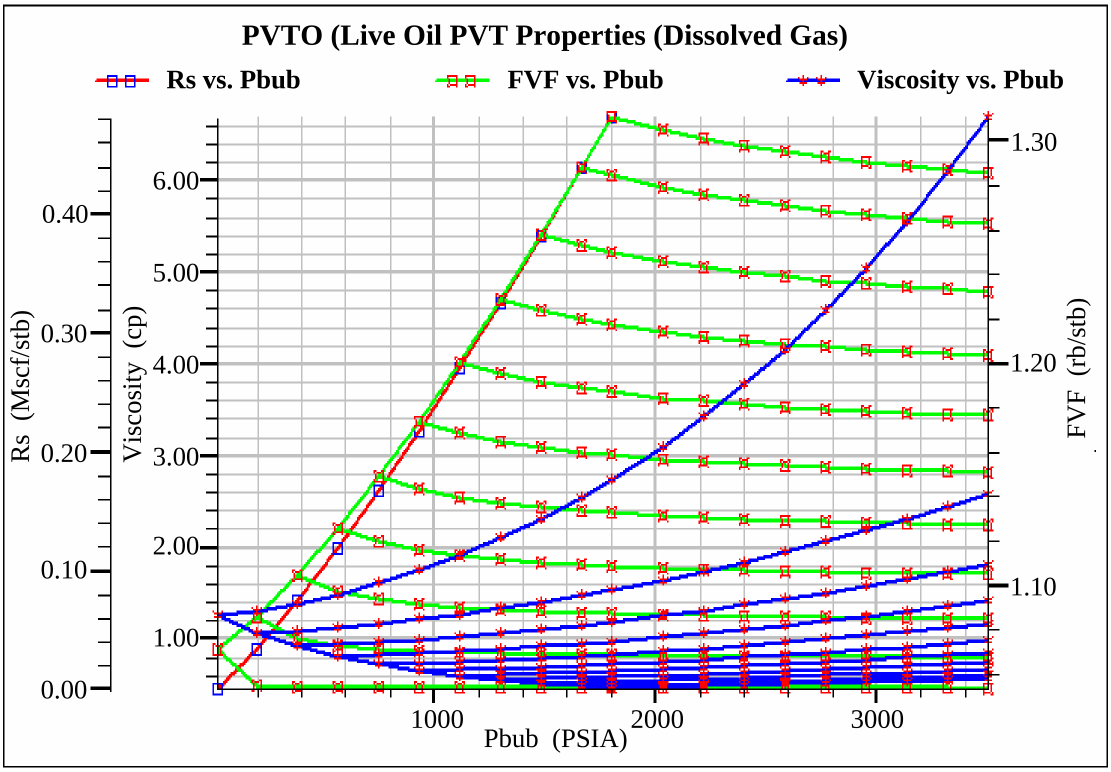

Figure D.1 Live Oil PVT Properties (Dissolved Gas) graph display result from PHITSANULOK_PVT.INC input data section.

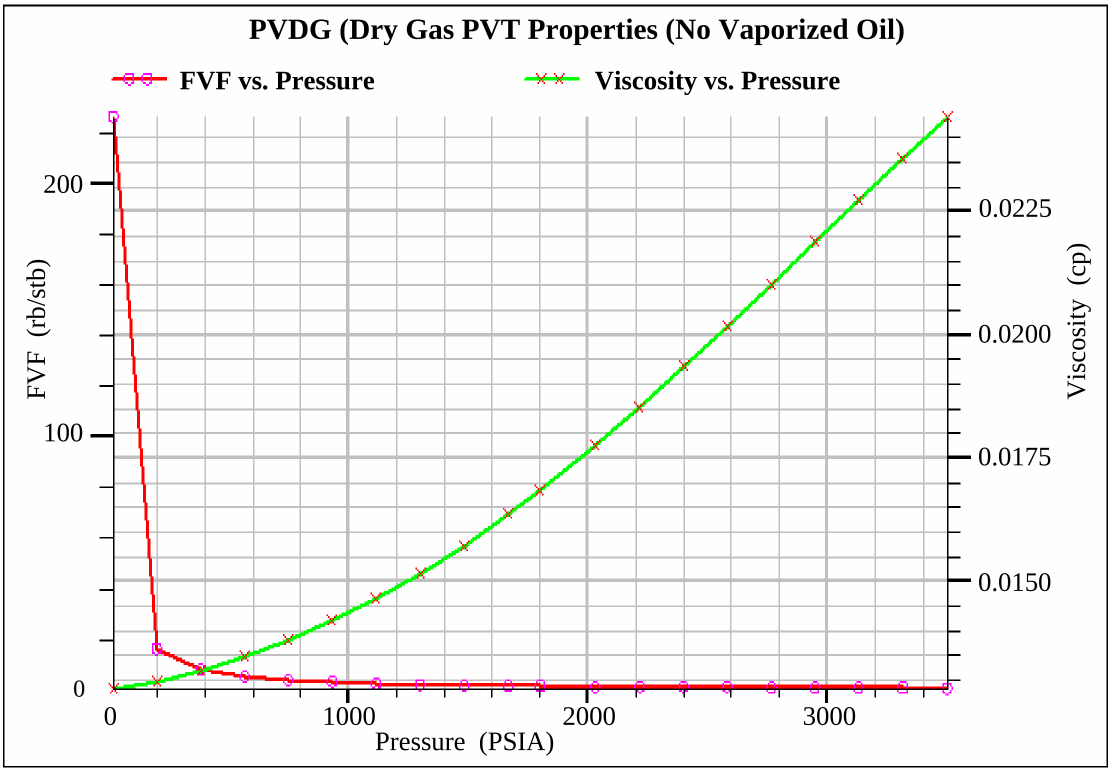

Figure D.2 Dry Gas PVT Properties (Dissolved Gas) graph display result from PHITSANULOK_PVT.INC input data section.

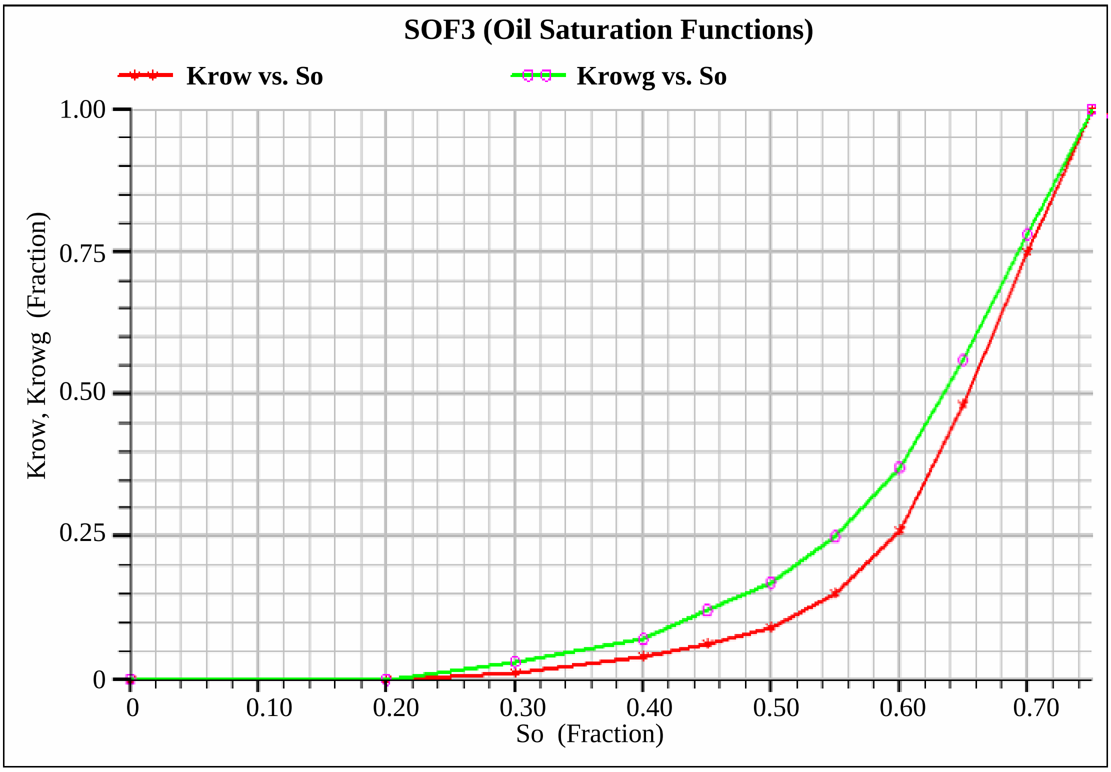

Figure D.3 Oil saturation functions graph display result from PHITSANULOK_SCAL.INC input data section.

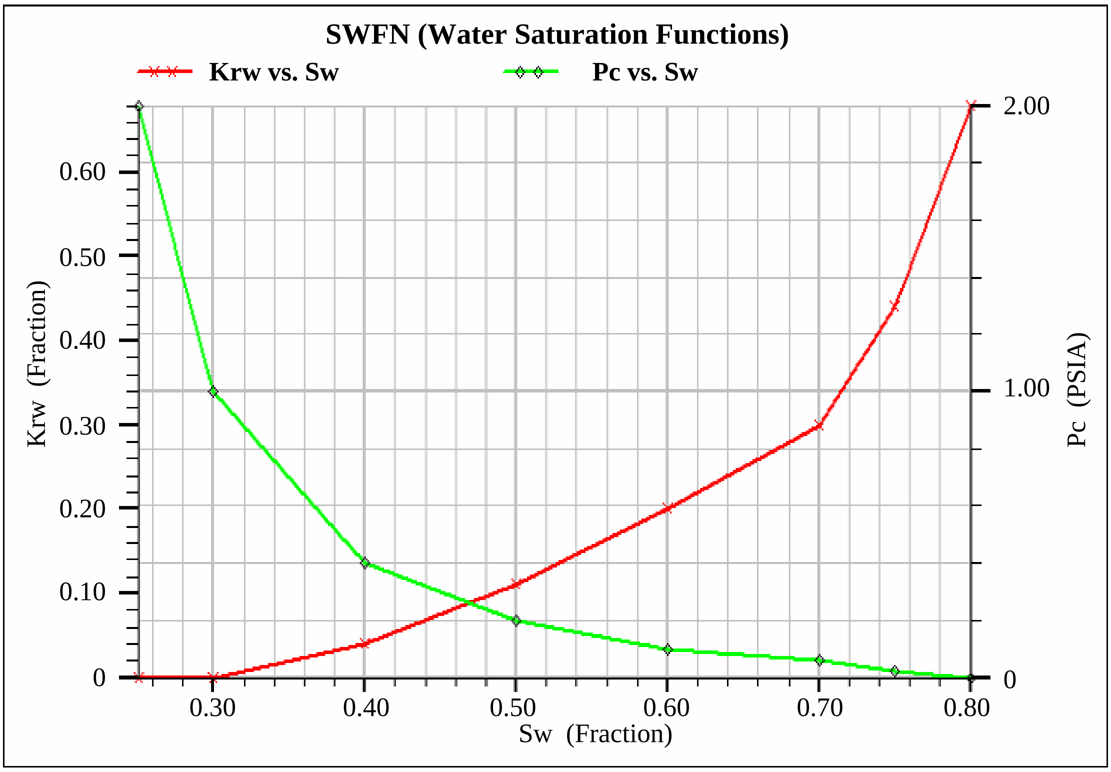

Figure D.4 Water saturation functions graph display result from PHITSANULOK_SCAL.INC input data section.

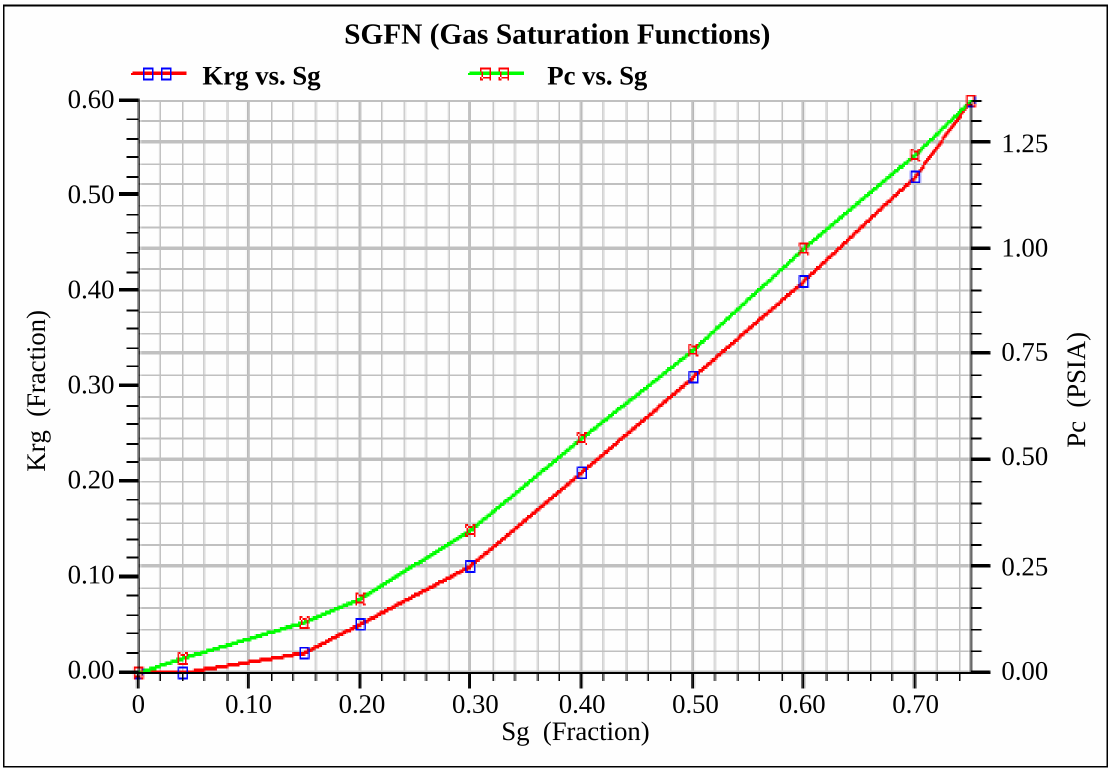

Figure D.5 Gas saturation functions graph display result from PHITSANULOK_SCAL.INC input data section.

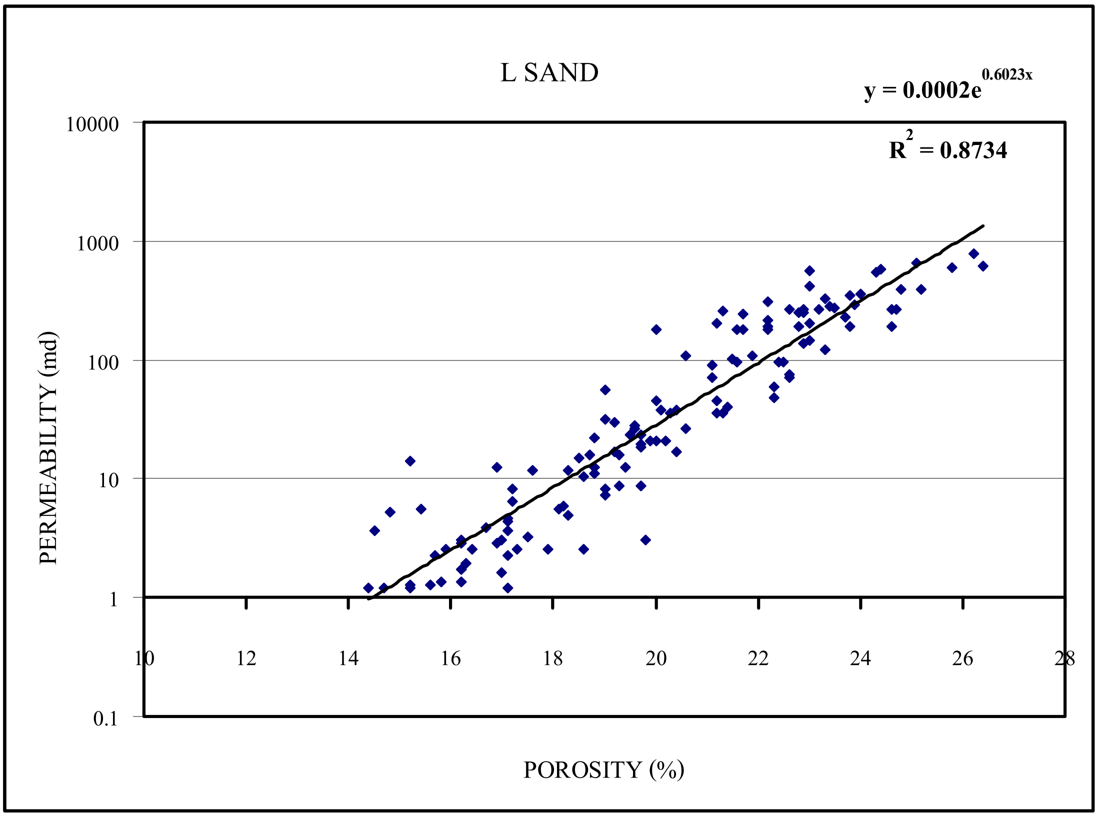

Figure D.6 Sirikit field review of atmospheric k/ø trend (L sand),

(After Thai Shell Exploration and Production Co., Ltd.).

APPENDIX E

PUBLICATION

Bottom Waterflooding Simulation Model of Monocline Structure in Phitsanulok Basin

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Abstract

The petroleum demand of Thailand is continuously increased, due to the increasing growth rate of the industrial output index. It is important to look for additional petroleum supply this high demand. Though reserves of hydrocarbon in Thailand are limited, some residual oil from primary productions still left in the reservoir. This remaining oil can be recovered by secondary oil recovery technique. Phitsanulok basin located in the central part of Thailand, one of the most important petroleum production fields, is an interested to perform and improve oil recovery by secondary oil recovery technique. The objectives of this research are 1) study comparisons of bottom waterflooding projects focus on monocline reservoir structure by using reservoir simulation technology to estimate waterflood performance; 2) economic consideration regarding to flooding pattern, optimum time to start water injection, optimum injection and production rate for suitable development plane. The method used in this study is the bottom waterflooding technique which is the one of the effective enhanced oil recovery techniques. Physical properties of the reservoir rock and fluids, e.g. permeability, porosity, and reservoir pressure, will be collected, analyzed, and input to a reservoir simulation software, ECLIPSE, for simulating the bottom waterflooding model. The reservoir simulation study is divided into 4 main cases up to the volume of oil in place (30, 20, 10 and 5 million barrels), for all cases include 4 production periods schedule per case (no water injection, 2nd, 4th and 8th year periods of water injection) by using the line drive pattern but different in water injection time periods. For the cases that produce by natural flow mechanism (no water injection) can be produce 19.26-22.44% of oil recovery factor and the other cases with bottom waterflooding production technique, the 2nd, 4th and 8th water injection period, the recoveries increased to 51.42-53.56%, 50.04-52.38% and 44.61-48.45% respectively. From the result of reservoir simulation the 2nd year periods of water injection is the best operation case in development plan due to the recovery and economic values are more favorable than the others.

Keyword: Improve oil recovery, Secondary, Bottom waterflooding, Reservoir simulation

1. Introduction

The petroleum demand in Thailand is continuously increased, reflected by the increasing growth rate of the industrial output index. The industrial sectors which have a high growth rate include the construction material sector, the automobile and transportation equipment sector. The indigenous petroleum production is accounted about 40 percent of petroleum consumption in Thailand. Oil fields exploration and production development are moderately successful but it is not enough for consumption. In primary recovery, oil production will be about 10 – 30 percent of original oil in place and some residual oil still left in the reservoir. Due to the oil price are increased but the reserve of hydrocarbon in Thailand are limited and petroleum consumption demand remaining high, so the conservation of this reserve is important. This can be achieved either by discovery of new oil field or by increasing the recovery from the large quantity of residual oil left in oil reservoirs. Phitsanulok basin of Thailand is one of the most important petroleum production fields that interested to improve oil recovery by secondary oil recovery technique. Bottom waterflooding is the immiscible fluid displacement technique that normally used in enhanced oil recovery process. This is because of water is generally available, low capital investment and operating costs than the other fluid, its easy to injected and high efficiency in displacement oil. Therefore this method should be operated to improve and develop oil fields.

2. Reservoir Simulation Model Design

The reservoir modeling is divided in to 4 main cases up to a reservoir size that have the volume of oil in place (STOIIP) 30, 20, 10 and 5 million barrel (MMBBL). For all cases have 4 productions time periods schedule simulation test; no water injection, 2nd, 4th and 8th year periods of water injection with 25 years of production life time. The models are described as a regular Cartesian coordinate that has 25×25×8 (5,000) grid blocks, see figure 1.

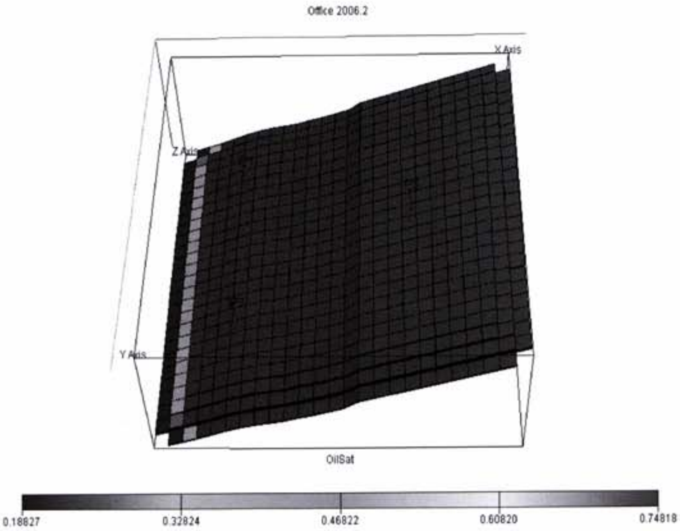

Figure 1 Show M05 Model Structure

These test operated by the black oil reservoir simulation software "Eclipse Office E100 version 2006.2". Some of model characteristics for each model design are discussed as follow.

M30 model of STOIIP 30 MMBBL

- Production area = 633 acres (27,562,500 ft^2)
- Thickness = 64 feet
- No. of production well = 8 wells

- No. of production/injection well = 4/4 wells
- Well spacing = 2,310 feet

M20 model of STOIIP 20 MMBBL

- Production area = 491 acres (21,390,625 ft^2)
- Thickness = 56 feet
- No. of production well = 6 wells
- No. of production/injection well = 2/4 wells
- Well spacing = 2,035 feet

M10 model of STOIIP 10 MMBBL

- Production area = 281 acres (12,250,000 ft^2)
- Thickness = 48 feet
- No. of production well = 4 wells
- No. of production/injection well = 2/2 wells
- Well spacing = 1,540 feet

M05 model of STOIIP 5 MMBBL

- Production area = 164 acres (7,155,625 ft^2)
- Thickness = 40 feet
- No. of production well = 3 wells
- No. of production/injection well = 1/2 wells
- Well spacing = 1,177 feet

3. Reservoir Simulation Input Data

The in put data for each model were collected and obtained from literature reviewing, concessionaire result and theoretical assumptions. However, these data are also based on Sirikit oil field composed of reservoir fluids and rock properties such as porosity, permeability, pressure, etc. The input data for the Eclipse Office E100 are classified in section of Grid, PVT, SCAL, Initialization and Schedule section data.

Grid Section Data

- Porosity (ϕ) = 18 – 25%
- Permeability (k) = 10 – 692 mD
- $k_v = 0.1k_h$

PVT Section Data

- ^{o}API oil gravity = 39.4 ^{o}API
- Solution gas gravity = 0.8
- Bubble point pressure = 1,800 psi
- Reference pressure = 3,500 psi

- Porosity = 20%
- Reservoir temperature = 203 °F
- Rock type = Consolidated Sandstone

SCAL Section Data

This section refers to the relative permeability versus fluid saturation function that provide by Corey's correlation.

Initialization Section Data

- Datum depth = 3,850 ft
- Pressure at datum depth = 3,500 psi
- Bubble point at datum depth = 1,800 psi
- Water-oil contact depth = 3,915

Schedule Section Data

- Diameter of well bore = 0.71 ft
- Skin factor = -1
- Effective k_h = 250 mD
- Production life time = 25 years

4. Results of Reservoir Simulation

The full detail of reservoir simulation results are illustrated in table 1 and the brief discussion of M05 model are described for example as follows.

- No water injection scenario; the oil production rate was maintained at 135 barrels/day for fourteen years and then declined to 91 barrels/day (BOPD) at the end of production life time (25 years). The cumulative oil production is 1.128 million barrels (MMBBL) with the recovery factor of 22.44%, see figure 2.

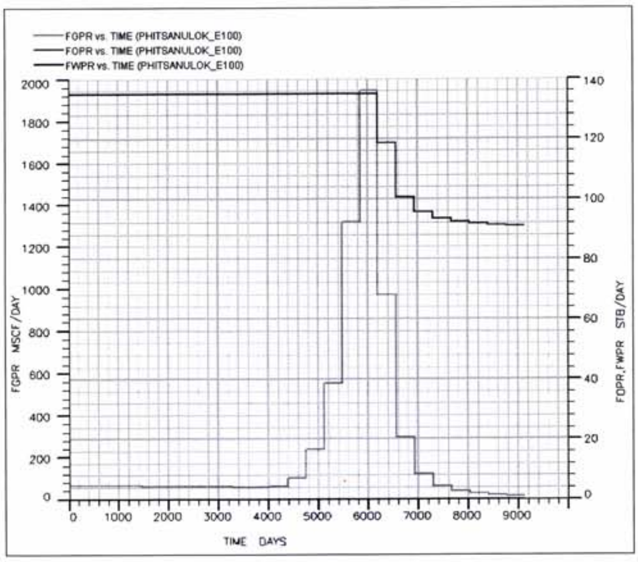

Figure 2 No Water Injection Scenario, Oil production rate vs. Time of M05 Model

Table 1: Reservoir simulation results summary

Model	Year of starting water injection	No. of oil producing wells befor/after water injection	No. of water injection wells	Total oil production (million barrels)	Oil recovery factor (%)
M30	- (no injection)	8/8	0	5.796	19.26
	2nd	8/4	4	15.473	51.42
	4th	8/4	4	15.058	50.04
	8th	8/4	4	13.425	44.61
M20	- (no injection)	6/6	0	4.040	19.77
	2nd	6/3	3	10.942	53.56
	4th	6/3	3	10.554	51.66
	8th	6/3	3	9.607	47.02
M10	- (no injection)	4/4	0	2.152	21.51
	2nd	4/2	2	5.267	52.66
	4th	4/2	2	5.239	52.38
	8th	4/2	2	4.720	47.19
M05	- (no injection)	3/3	0	1.128	22.44
	2nd	3/1	2	2.634	52.42
	4th	3/1	2	2.571	51.16
	8th	3/1	2	2.435	48.45

- The 2nd water injection scenario; the oil production rate was start at 390 BOPD and maintained this rate due to waterflood schedule for fourteen years and then declined to 95 BOPD at the end of production life time. The cumulative oil production is 2.634 MMBBL with the recovery factor of 52.42%, see figure 3.

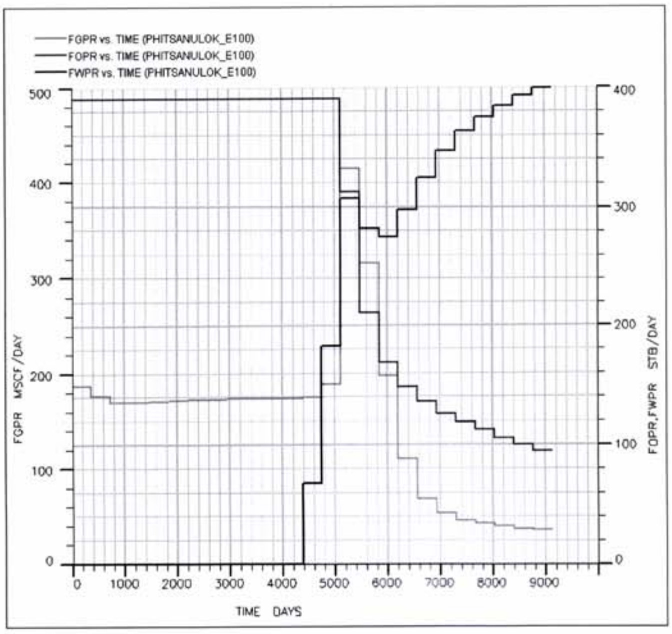

Figure 3: 2nd Water Injection Scenario, Oil production rate vs. Time of M05 Model

- The 4th water injection scenario; the oil production rate was start at 240 BOPD and maintained at this rate for seven years, after that due to waterflood schedule the production rate increased to 400 BOPD for next ten years and then declined to 105 BOPD at the end of production life time. The cumulative oil production is 2.571 MMBBL with the recovery factor of 51.16%, see figure 4.

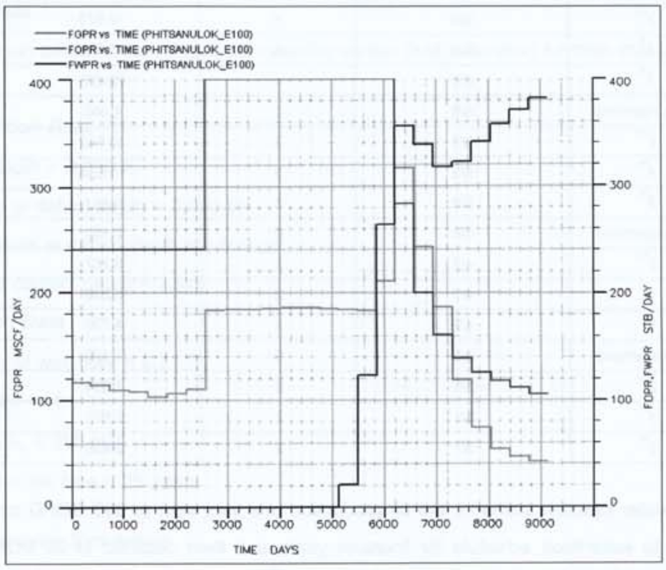

Figure 4 4th Water Injection Scenario, Oil production rate vs. Time of M05 Model

- The 8th water injection scenario; the oil production rate was start at 180 BOPD and maintained at this rate for eleven years, after that due to waterflood schedule the production rate increased to 400 BOPD for next nine years and then declined to 133 BOPD at the end of production life time. The cumulative oil production is 2.435 MMBBL with the recovery factor of 48.45%, see figure 5.

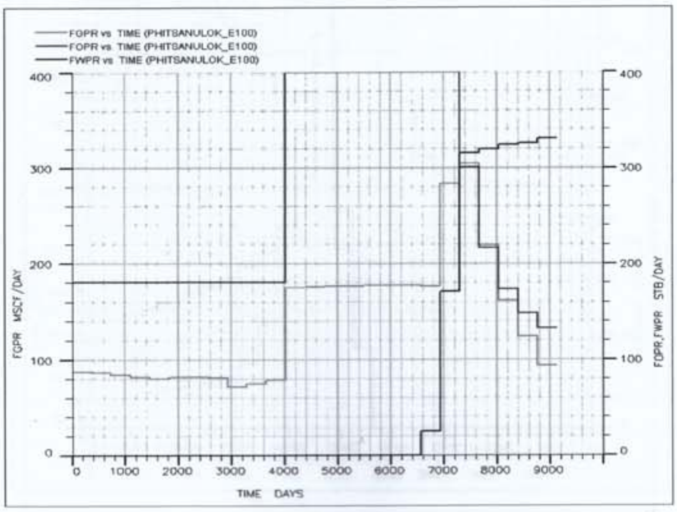

Figure 5 8th Water Injection Scenario, Oil production rate vs. Time of M05 Model

5. Economic Evaluation

The objective of an economic evaluation is to study the commerciality of the project for each bottom waterflooding model which results from reservoir simulation. The economic evaluation parameters are listed in table 2 and the other assumptions are described as follow.

Table 2 Economic evaluation parameter

Parameter	M30	M20	M10	M05
Concession application (MM$)	2.5	1.5	0.5	0.25
Geological and Geophysical Exploration (MM$)	4	3	1	0.5
Exploration and Appraisal Well (MM$)	4	3	2	1
Facility Cost of Production Well (MM$)	35	25	12	5
Note: (MM$) = million USD				

- Drilling and Completion Cost of Production Well = 1,500,000 $/well
- Well Abandonment Cost = 6,000 $/well
- Facility Cost of Injection Well = 60,000 $/well
- Maintenance Cost of Water Injection Facility = 72,000 $/well/year
- Production Operation Cost = 20 $/barrel
- Oil price = 60 $/barrel
- Discounted Rate (Interest rate) = 10%
- Escalation = 2%
- Income Tax = 50%
- Sliding Scale Royalty

(Production Level)	(Rate)(%)
0 – 2,000 BOPD	5.00
2,000 – 5,000 BOPD	6.25
5,000 – 10,000 BOPD	10.00
10,000 – 20,000 BOPD	12.50
> 20,000 BOPD	15.00

Table 3 shows the results of cash flow analysis. This table contains of internal rate of return (IRR) and profit to investment ratio (PIR). For no water injection or primary recovery scenarios, the IRR after tax and 10% discounted range from 0.61 – 1.90% with PIR of 0.037 – 0.099. If the bottom waterflooding technique is include, the IRR after tax and 10% discounted range from 6.91% – 30.53% with PIR of 0.302 – 0.982. The best operation case is the 2nd year period of water injection scenario for every model.

Table 3 Economic evaluation results summary

Model	Year of starting water injection	Initial Oil Production Rate (BOPD)	Injection Rate (BWPD)	IRR Before Discounted	PIR Before Discounted	IRR with 10% Discounted	PIR with 10% Discounted
M30	- (no injection)	720	0	11.54%	1.0135	1.40%	0.0989
	2nd	2,320	2,400	39.86%	3.4187	27.14%	0.9104
	4th	1,920	2,400	34.65%	3.3041	22.41%	0.7785
	8th	1,200	2,400	22.52%	2.7210	11.38%	0.4422
M20	- (no injection)	510	0	11.19%	0.9644	1.08%	0.0749
	2nd	1,800	1,950	43.59%	3.4393	30.53%	0.9821
	4th	1,380	1,950	34.77%	3.1945	22.51%	0.7630
	8th	840	1,950	22.17%	2.7023	11.06%	0.4384
M10	- (no injection)	280	0	12.09%	1.0086	1.90%	0.0613
	2nd	760	1,000	37.67%	3.0715	25.15%	0.7893
	4th	680	1,000	34.19%	3.0095	21.99%	0.7090
	8th	420	1,000	21.40%	2.4961	10.36%	0.3903
M05	- (no injection)	135	0	10.67%	0.9911	0.61%	0.0371
	2nd	390	500	35.10%	2.8050	22.82%	0.7240
	4th	240	500	23.84%	2.6317	12.58%	0.5002
	8th	180	500	17.61%	2.3513	6.91%	0.3021

6. Conclusions

Reservoir simulation or reservoir modeling is one of the most powerful techniques currently available to the reservoir engineer. The bottom waterflooding modeling for secondary oil recovery project can be achieved by reservoir simulation. In this study, the oil recovery from primary recovery only ranged from 19.26 – 22.44%, when including bottom waterflooding technique the oil recovery increased to 51.42-53.56%, 50.04-52.38% and 44.61-48.45% for the 2nd, 4th and 8th water injection periods respectively. The bottom waterflooding yields high recovery due to the higher specific gravity of water yields higher oil displacement efficiency by displacing up from the bottom. The earlier water injection is used (after starting oil production) the more oil recovery there is, because of the reservoir pressure is still high allowing more oil displacement efficiency. The internal rate of return of the bottom waterflooding project seems to be less compared to the primary oil recovery alone, but the net present value profit and net present value profit to investment ratio will be higher in water injection projects. When primary production has been underway for some time, converting suitable producing wells to water injection wells at a suitable time might cost less money and earn considerable profits.

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