STUDY ON INCREASING GAS PRODUCTION OF KHORAT SANDSTONE IN L4/57 BLOCK BY HYDRAULIC FRACTURING AND COMPUTER SIMULATION

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การศึกษาการเพิ่มอัตราการผลิตก๊าซของชั้นหินทรายชุดโคราชในแปลง L4/57 โดยการทำไฮดรอลิคแฟรคเจอริ่งและแบบจำลองคอมพิวเตอร์

นายภานุพงศ์ แก้วหมุด

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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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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ภานุพงศ์ แก้วหมุด : การศึกษาการเพิ่มอัตราการผลิตก๊าซของชั้นหินทรายชุดโคราชในแปลง L4/57 โดยการทำไฮดรอลิคแฟรคเจอริ่งและแบบจำลองคอมพิวเตอร์ (STUDY ON INCREASING GAS PRODUCTION OF KHORAT SANDSTONE IN L4/57 BLOCK BY HYDRAULIC FRACTURING AND COMPUTER SIMULATION) อาจารย์ที่ปรึกษา : ผู้ช่วยศาสตราจารย์ ดร.บัณฑิตา ธีระกุลสถิตย์, 144 หน้า

วัตถุประสงค์ของงานวิจัยนี้คือ 1) ประเมินศักยภาพและความเสี่ยงของปริมาณสำรองปิโตรเลียมแหล่งก๊าซธรรมชาติโดยใช้หลักการของ SPE/AAPG/WPG และวิธีการ Monte Carlo 2) ศึกษาการทำไฮดรอริคแฟรคเจอริงและจำลองโดยใช้โปรแกรมคอมพิวเตอร์ประเมินประสิทธิภาพในการผลิตการผลิต 3) ศึกษาการพัฒนาแหล่งกักเก็บก๊าซในหินทรายชุดโคราช และเปรียบเทียบอัตราการไหลของก๊าซก่อน และหลังการทำไฮดรอริคแฟรคเจอริงโดยใช้ PKN โมเดล และ 4) ประเมินความเสี่ยงในการลงทุนสำหรับวิธีการทำไฮดรอริคแฟรคเจอริงและปริมาณการผลิตปิโตรเลียมโดยใช้โปรแกรมคอมพิวเตอร์ ในการศึกษาครั้งนี้จะขึ้นอยู่กับราคาของก๊าซธรรมชาติ 6 เหรียญสหรัฐต่อล้านบีทียู จากการประเมินชี้ให้เห็นถึงความน่าจะเป็นไปได้มากที่สุดที่จะพบแหล่งสำรองก๊าซธรรมชาติขนาดเล็กที่มีขนาดของแหล่งประมาณ 150 พันล้านลูกบาศก์ฟุต (BCF) ในชั้นหินทรายโคราช โดยหลักการแล้วเราจะทำไฮดรอริคแฟรคเจอริง เพื่อให้อัตราการผลิตดีขึ้นก็ต่อเมื่อค่ารายได้ผลตอบแทน (Initial rate of return, IRR) น้อยกว่า 10% โดยใช้กฎหมายพระราชบัญญัติปิโตรเลียมไทยแลนด์ III (Thailand III) ก่อนการทำให้หินทรายชุดโคราชแตก โดยจำลองการผลิตที่อัตราวันละ 11 ล้านลูกบาศก์ฟุตต่อวัน หลังจากที่ผลิตไปได้ 29 วัน อัตราการผลิตก๊าซก็ได้ลดลงและสิ้นสุดที่ 5.2 ล้านลูกบาศก์ฟุตต่อวัน ในระยะเวลา 20 ปี จะได้อัตราการผลิตรวมทั้งหมด 55.82 พันล้านลูกบาศก์ฟุต คิดเป็นอัตราผลตอบแทน (IRR) ได้ 5.12% หลังจากนั้นได้ทำการจำลองการทำไฮดรอริคแฟรคเจอริง โดยการอัดน้ำด้วยความดันสูงลงไป 1,500 บาร์เรล ได้ทำการผลิตก๊าซที่อัตราวันละ 25 ล้านลูกบาศก์ฟุต สามารถผลิตได้ถึง 1 ปี อัตราการผลิตจึงค่อยลดลงตามธรรมชาติ และสิ้นสุดที่วันละ 5.5 ล้านลูกบาศก์ฟุต ในระยะเวลา 20 ปี จะได้อัตราการผลิตรวมทั้งหมด 93.14 พันล้านลูกบาศก์ฟุต คิดเป็นอัตราผลตอบแทน ได้ 15.73%

สาขาวิชา เทคโนโลยีธรณี

ปีการศึกษา 2560

ลายมือชื่อนักศึกษา ภานุพงศ์ แก้วหมุด

ลายมือชื่ออาจารย์ที่ปรึกษา

PHANUPHONG GAEWMOOD : STUDY ON INCREASING GAS PRODUCTION OF KHORAT SANDSTONE IN L4/57 BLOCK BY HYDRAULIC FRACTURING AND COMPUTER SIMULATION. THESIS ADVISOR : ASST. PROF. BANTITA TERAKULSATIT, Ph.D., 144 PP.

GAS FIELDS RESERVE/ HYDRAULIC FRACTURE/ PRODUCTION EFFICIENCY/ RESERVOIR SIMULATION/ PETROLEUM ECONOMICS

The objectives of this research are to 1) evaluate the potential and risks in the petroleum reserve of a gas field using SPE/AAPG/WPG basis and Monte Carlo Method, 2) study of hydraulic fracturing (HF) and simulation model using computer program, evaluate production efficiency 3) study the development of gas reservoir in Khorat sand and compare the gas flow rate before and after hydraulic fracturing by using PKN model, and 4) evaluate risks in investment for hydraulic fracturing method and petroleum production using a computer program. The study is based on 6 US$/MMBTU of natural gas prices. The assessment indicated the most likely probability to find the small gas field with the reserve of 150 Bcf (billion cubic feet). The Khorat sand gas fields, will need to be fracked with hydraulic fracturing when the IRR is less than 10%. In the NE Thailand and Thailand III, before hydraulic fracturing the Khorat sand gas field starts production of 11 MMSCF/day and lasts for 29 days then declines to end at 5.2 MMSCF/day in the 20th year with the total production of 55.82 MMMSCF, Initial rate of return (IRR) of 5.12%,. After 1500 barrels of fluid hydraulic fracturing, the gas field starts production of 25 MMSCF/day and lasts to 1 years then declines to

end at 5.5 MMSCF/day with the recovery of 93.14 MMMSCF, Initial rate of return of 15.73%.

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS (Continued)

Page

TABLE OF CONTENTS (Continued)

Page

TABLE OF CONTENTS (Continued)

Page

TABLE OF CONTENTS (Continued)

Page

LIST OF TABLES

Table **Page**

LIST OF TABLES (Continued)

Table **Page**

LIST OF FIGURES

LIST OF FIGURES (Continued)

Figure **Page**

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Figure **Page**

SYMBOLS AND ABBREVIATIONS

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

SYMBOLS AND ABBREVIATIONS (Continued)

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

SYMBOLS AND ABBREVIATIONS (Continued)

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

CHAPTER I

INTRODUCTION

1.1 Background and Rational

Unconventional gas mainly includes shale gas, tight gas and coal seam gas. Shale gas is commonly in mudstone, shale and between them the interlayers of sandstone. Tight gas often has been stored in tight sandstone or sometime limestone. Coal bed methane is contained within coal seams (Quanshu et al 2015, and Lange et al, 2013).

Tight gas is the term commonly used to refer to low-permeability reservoirs that produce mainly dry natural gas. Many of the low-permeability reservoirs developed in the past are sandstone, but significant quantities of gas also are produced from low-permeability carbonates, shales, and coal seams. In this paper, production of gas from tight sandstones is the predominant theme. However, much of the same technology applies to tight-carbonate and gas-shale reservoir.

In the 1970s, the U.S. government decided that the definition of a tight gas reservoir is one in which the expected value of permeability to gas flow would be less than 0.1 md. This definition was a political definition that has been used to determine which wells would receive federal and/or state tax credits for producing gas from tight reservoirs (Holditch et al, 2001) (Figure 1.1).

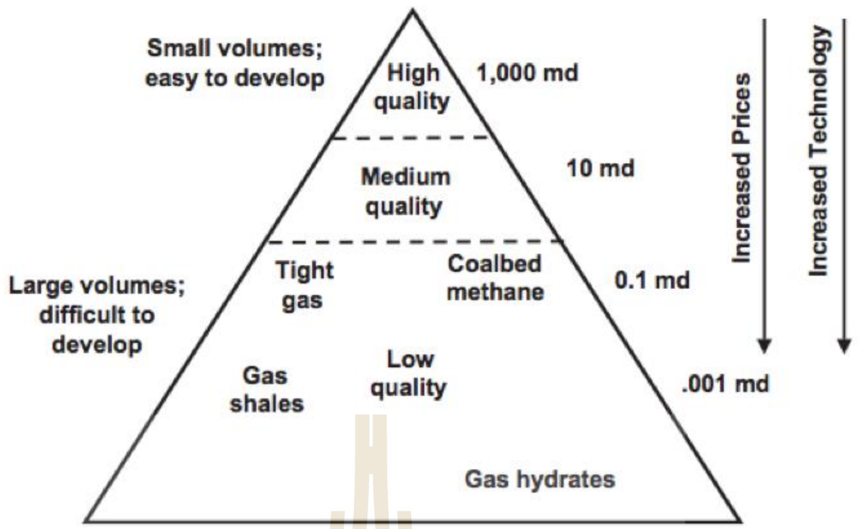

Figure 1.1 Resource triangle for natural gas (Lee, 1982)

In the Northeast, an area of 200,000 km. is a suitable geological formation and reservoir. The rock of Khorat group consists of Phu Phan Member, Phra Wihan Member, Phu Kradung Member and Nam Phong Member combined thickness 2.5-3.0 km. Interbedded with shale and tight-sand throughout the Northeast. Therefore it is appropriate to study the potential for tight-sand gas in Khorat group.

The expected results will be aware of potential resources of natural gas in the tight-sand. Adding new petroleum resources and method in the exploration for the future, the technologies needed to be developed for efficient and low cost operations. Those are expected to be achieved soon, due to the high demand for energy in the future.

1.2 Objectives of the Study

1.2.1 Evaluate the potential and risks in the petroleum reserve of a gas field using SPE/AAPG/WPG basis and Monte Carlo Method.

1.2.2 Study of Hydraulic Fracturing (HF) and Simulation Model using computer program and evaluate production efficiency.

1.2.3 Study and recovery the development of gas reservoir in tight sand and compare the gas flow rate before and after hydraulic fracturing by using PKN model.

1.2.4 Evaluate risks in investment for hydraulic fracturing method and petroleum production using a computer program.

1.3 Scopes and Limitations of the Study

1.3.1 Keep the rock example sand in Khorat group, measuring the porosity, permeability, and stress-strain test data are provided by PTT Exploration and Production Public Company Limited.

1.3.2 Estimate reserves and resources sand in the Northeast.

1.3.3 Study of hydraulic fracturing by computer program, calculate the volume of water, fracture width and performance assessment of fracture.

1.3.4 Reservoir simulation a hydraulic fracturing models, small and very small in the northeast region.

1.3.5 Study in feasibility will be developed based on the results of the model, technical and economics, analysis of risk factors for development and sensitivity study of the risk factors.

1.3.6 Analyze minimum petroleum reserve to develop sand gas field under the petroleum act, fiscal regime, discount rate, threshold internal rate of return, etc.

1.4 Research Methodology

All of summary of research methodology which the description of this research will be conducted as the following steps;

1.4.1 Literature review

The relevant literatures will be studied, reviewed, and collected to be conclusion and data for reference. A review is includes properties of tight sand, type of hydraulic fracture, and computer simulation model.

1.4.2 Collected rock samples

In field work, the geological field trip which studied at the rim of Khorat Plateau is a part of the evaluation of petroleum potential, which has been studied about geological characteristics such as lithology, stratigraphy, structural geology, paleontology. This field trip has collected samples for rock and fluid properties and rock mechanic testing for petroleum reservoir studies.

1.4.3 Rock and Fluid property Test

1.4.3.1 Porosity test

Porosity is define as the ratio of void-space volume (ie. Pore volume) to bulk volume of a material.

Porosity in clean and dried core samples is determinate by a combination of two of the following three physical properties such as Grain volume, Pore volume, and Bulk volume

Grain volume and pore volume can be determined from Helium injection and the application of Boyle's Law. Bulk volume measured by the summation of pore volume and grain volume.

1.4.3.2 Permeability Test

To determine the permeability (using Overburden poro-perme cell) of a core sample air (or nitrogen) at a known initial pressure (upstream pressure) is made to flow through the length of the sample. The sample is sealed along its length so that no air may bypass the sample. The flow rate of air from the other end of the sample is measured. The permeability for that sample is then calculated using Darcy's Law through knowledge of the upstream pressure and flow rate during the test, the atmospheric pressure, the viscosity of air (or nitrogen), and the length and cross sectional area of the sample. Overburden poro-perme cell has been designed to perform porosity and permeability measurements on rock samples under simulated reservoir overburden conditions. It uses an air actuated hydraulic pump to achieve a simulated reservoir confining pressure on the sample. Pressure transducers are used to accurately monitor the pressure of the gas mediums used to measure the parameters of a given sample.

1.4.4 Rock mechanic Data

The testing is to determine the uniaxial compressive strength and the elastic properties, represented by Young's modulus and the Poisson ratio, of cylindrical specimens of intact rock sampled from drill cores. The loading was carried out into the post-failure regime in order to study the mechanical behaviour of the rock after cracking, thereby enabling determination of the brittleness and residual strength.

The data are provided by PTT Exploration and Production Public Company Limited.

1.4.5 Hydraulic Fracturing Simulation by Computer program

From literature review, the computer programs will be used to simulation model the hydraulic fracture of vertical well, the characteristics gas flow regimes and gas flow rate versus time/pressure and considering the effects of length of horizontal well and spacing between the outermost fractures. The calculation will be used reservoir modeling is constructed as hypothetical model by "ECLIPSE Office E100" software.

1.4.6 Analyze and evaluate the potential resource

From the result of the computer simulation, analyze and evaluate the potential resource, evaluate risk in investment for hydraulic fracturing method.

1.5 Expected Results

Chapter I introduce the thesis by briefly describing the background of the problem and the significance of the study. The research objectives, methodology, scope and limitation are identified. Chapter II summarizes results of the literature review to improve an understanding of water-based drilling mud characteristics and the factor that affects to mud properties. Chapter III describes the rock sample and the porosity-permeability measurement. Chapter IV presents the results obtained from a hydraulic fracturing and computer simulation model. Chapter V presents the results obtained from a potential assessment of petroleum reserves and computer simulation. Chapter VI presents the results of petroleum economics analysis. Chapter VII concludes the research results and provides recommendations for future research studies.

CHAPTER II

LITERLATURE REVIEW

There are petroleum exploration well in the northeast of Thailand. Natural gas was discovered in the tight sand of Khorat group such as Daowreang-1, Chonabot-1, Phu wiang-1 and Rattana-1 but the gas was not found are a non-commercial well. Recently, Hydraulic Fracturing methods have been developed successfully. The combination with horizontal drilling made possibility to produce natural gas in tight-sand at lower costs and more gas volume. Therefore, it will increase potential resources of natural gas in tight sands of Khorat group.

Rattanapranudej and Trisarn (2004) measured porosity and permeability of sandstone of the Tertiary (Central Region) is approximately 2 to 36 percent and 0.02 to 23 md respectively at laboratory of Suranaree University of technology.

Trisarn (2010) determined potential and risks assessment of natural gas in Permian rock in the in the northeast of Thailand using a computer program and reported that Chonnabot prospect is 122.43, 470.44 and 1,807.66 BCF; Nam Phong prospect is 456.46, 1,140.73 and 2,850.77 BCF at probability of 95, 50 and 5 respectively.

Trisarn and Wannakomol (2011) showed that the small gas reservoirs named SUT MNE 1 and 2 in the northeast of Thailand which reserve petroleum at 200 and 300 BCF and are worthy for the investment. When the investment is under the Fiscal

Regime Thailand III, the payback percentage rate is 10.16 to 15.58 (Usury Discount Factor 10 percent per year)

Thanapong (2012) measured porosity and permeability in sandstone of the Korat group is approximately 2 to 8 percent and 0.005-1.0 md respectively.

Trisarn and TPI Polene Power., Ltd. (2015) measured porosity and permeability of petroleum exploration well at Chatturat-2 is approximately 3 to 5 percent and 0.05-0.1 md respectively.

2.1 General geology

The simple stratigraphic column of Khorat Plateau as shown in Figure 2.1.

2.1.1 Carboniferous Rocks

2.1.1.1 Wang Saphung Group /Si That Formation

It has been proposed for the near shore sandstone, shale and limestone that exposed along western edge of the Khorat Plateau and distribute mainly in Loei and some part of Udon Thani Provinces. This sequence was interpreted to have been deposited in the passive continental margin.

2.1.2 Permian Rocks

2.1.2.1 Nam Duk Formation

Based on Helmcke and Kraikhong (1982), the stratigraphic succession in Permian Nam Duk Basin is composed of three units; pelagic faceis, flysch facies and molasse facies related to pre-orogenic, syn-orogenic and post-orogenic events. First unit is consists of chert, tuffs, shales, and allodapic limestone (Helmake and Lindenberg, 1983). This facies represent a deep-sea depositional environment.

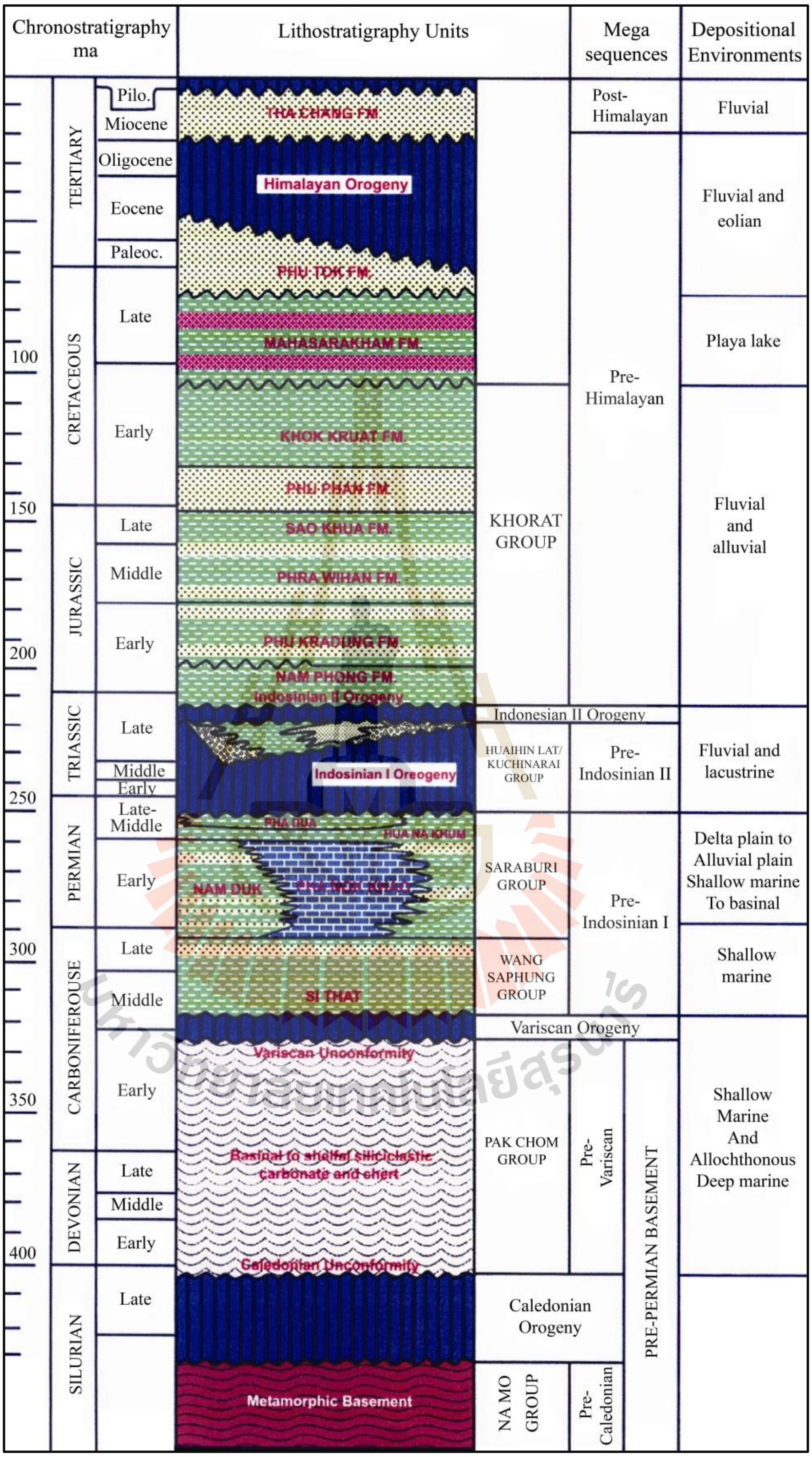

Figure 2.1 Stratigraphy of Khorat Plateau (Sattayarak, 2005)

Second unit is consists of greywacke alternated with shales. The Bouma-cycle can be found which indicated to turbidites.

Third unit is consists of very thick sequence of clastic rocks, mainly sandstones and shales. Some beds are very rich in fossil and plant remains.

2.1.2.2 Pha Nok Khao Formation

It comprises massive to thick-bedded, gray limestone and dolomite. Thin-bedded gray shale and black, nodular or thin-bedded chert may occur locally. It represents all the main environments of shallow carbonate deposition, from reef to back reef, shoal, bio-thermal, lagoonal, intertidal, tidal flat, and beach and supratidal environment.

2.1.2.3 Hua Na Khum Formation

It overlies comformably the Pha Nok Khao Formation. It consists of intercalated light and dark gray siltstone, sandstone, claystone, and limestone. The fossil and sediment structures suggest a shallow platform to maginal marine environment.

2.1.2.4 Pha Dua Formation

It comprised predominantly siltstone and claystone, often tuffaceous, with rare thin beds of sandstone, coal, and limestone (Mouret, 1994). It was deposited mainly in upper delta to alluvial plain environments, with minor interruption of lower delta plain and bay facies.

2.1.3 Triassic Pre-Khorat Rocks

2.1.3.1 Huai Hin Lat Formation

Chonglakmani and Sattayalak (1978) first established the Triassic sediments in the Northeastern Thailand, and subdivided into 5 members which sorted from lower part to upper part, Phu Hai, Sam Khaen Conglomerate, Dat Fa, Phu Hi, and I Mo. Detail description are as follows:

- Phu Hai Member consists mainly of volcanics (e.g. tuff, agglomerate, rhyolite, and andesite) with some intercalations of sandstone, mudstone and conglomerate.

- Sam Khaen Conglomerate Member consists of conglomerate with some intercalation of finer sediments.

- Dat Fa Member consists of gray to black, carbonaceous rich, calcareous, well-bedded shale and argillaceous limestone.

- Phu hi Member consists of gray sandstone, shale and argillaceous limestone with some intercalations of conglomerate beds.

- I Mo Member consists of diorite and its associated volcanic facies intercalated with the well-bedded gray shale, sandstone, and limestone.

2.1.4 Khorat Group

2.1.4.1 Nam Phong Formation

It is characterized by thick to massive resistant beds of reddish brown sandstone, conglomerate and interbedded shale and reddish brown claystone. It was deposited by meandering rivers with associated flood plain and overbank deposits. An oxidizing environment is indicated by the thick red clays deposited in the meandering channel system of the upper part of the unit.

2.1.4.2 Phu Kradung Formation

It is composed of reddish to grey or white thick bed calcareous mudstone/siltstone, limestone, high radioactive reddish brown claystone, siltstone and sandstone. It is interpreted as deposition in a meandering channel system environment.

2.1.4.3 Phra Wihan Formation

It is composed of white, thick and massive bedded, arkosic to ortho-quarzitic and cross-bedded sandstone, interbedded with reddish brown and grey claystone. Small quartz and chert pebbles oriented along cross bedding and bedding plane are normally found in the upper part of formation. It was deposited by an extensive semi-distal braided river system.

2.1.4.4 Sao Khoa Formation

It consists of reddish brown and greenish grey claystone, siltstone, sandstone and calcareous caliche-siltstone-pebbled conglomerate. The depositional environment was a flood plain associated with low energy meandering rivers.

2.1.4.5 Phu Phan Formation

It is characterized by resistant, massive and cross bedded, light coloured sandstone and conglomerate. The depositional environment of the formation is interpreted as a strong, low-sinuosity braided river system.

2.1.4.6 Khok Kruat Formation

It comprised fluviatile redbeds, sandstone, siltstone, claystone and interbedded conglomerate. The depositional environment of the formation was a flood plain with interbedded low energy meandering rivers.

2.1.4.7 Maha Sarakham Formation

It consists of three salt units and two claystone units, the Lower, Middle and Upper Salt with 2 units of claystone in between. It probably was deposited within continental basin.

2.2 Petroleum resources and reserve evaluation

Petroleum Resources and Reserves evaluation using the international standards basis SPE/AAPG/WPG, AAPG (American Association of Petroleum Geologists), SPE (Society of Petroleum Engineers), SPEE (Society of Petroleum Evaluation Engineers) and WPC (World Petroleum Congress).

Petroleum Resources are defined as the total quantities of discovered (including hydrocarbon produced already from known accumulations) and undiscovered petroleum at a specific date in a given area (Figure 2.2).

Discovered Resources comprise the total discovered deliverable petroleum quantities from the start of production to the cease of production, based on current understanding of the quantities in place and the recovery factor. Undiscovered Resources comprise. The total estimated quantities of petroleum to be recoverable from accumulations that remain to be discovered and using statistics, computer program (FASPU) and Monte Carlo simulation to find amount of petroleum. And then, may be used the reservoir simulation.

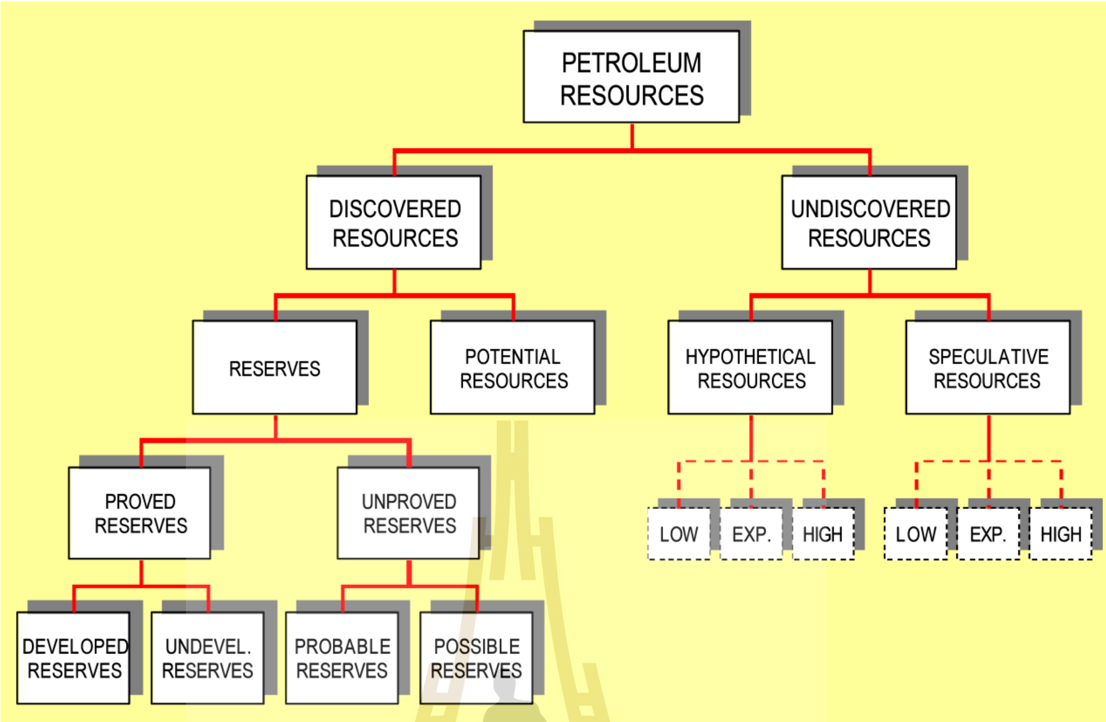

Figure 2.2 Petroleum Resource Classification Chart of Recoverable Resources CCOP

The analysis of a petroleum project depends on the amount of commercially valuable resource that is available. According to the Society of Petroleum Engineers and the World Petroleum Congress (Staff-JPT, 1997), reserves are those quantities of petroleum which are anticipated to be commercially recoverable from known accumulations from a given date forward. Table 2.1 summarizes the SPE/WPC definitions of reserves. The definitions of reserves include both qualitative and quantitative criteria.

Table 2.1 SPE/WPC Reserves definitions

Proved reserves	- Those quantitaties of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given data forward from known reservoirs and under current economic conditions, operating methods, and government regulation. - In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. - There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.
Unproved reserves	Those quantities of petroleum which are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved.
Probable reserves	- Those unproved reserves which analysis of geological and engineering data suggests are more likely that not to be recoverable. - There should be as least a 50% probability (P50) that the quantities actually recovered will equal or exceed the estimate.
Possible reserves	- Those unproved reserves which analysis of geological and engineering data suggests are more likely to be recoverable that probable reserves. - There should be as least a 10% probability (P10) that the quantities actually recovered will equal or exceed the estimate.

2.3 Hydraulic Fracturing

Hydraulic fracturing is a well-stimulation technique in which rock is fractured by a pressurized liquid. The process involves the high-pressure injection of fracking fluid (primarily water, containing sand or other proppants suspended with the aid of thickening agents) into a wellbore to create cracks in the deep-rock formations. The rock was fractured in the direction of a minimum stress. Within the borehole when pressure occurs more than the pressures of the rock can remain, there will occur fractures which is the around boreholes on the rock plane that is perpendicular to the direction of the axis minimum compressive stress occurs and parallel to the plane maximum axis and intermediate compressive stress (Figure 2.3).

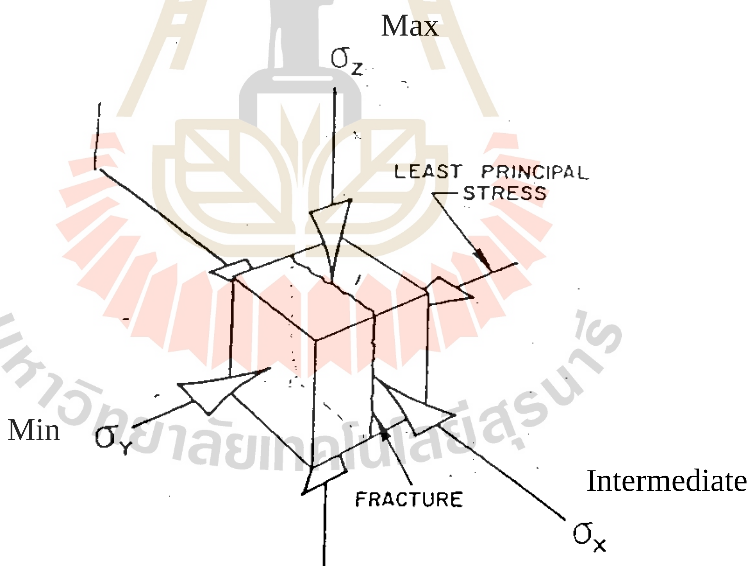

Figure 2.3 Stress element and preferred plane of fracture (Hubbert and Willis, 1957)

If the formations of fractures are deep less than 2000 feet, they will be occur the horizontal fracture. And if the depth is more than 4000 feet, they will be occur the vertical fracture. See in Figure 2.4.

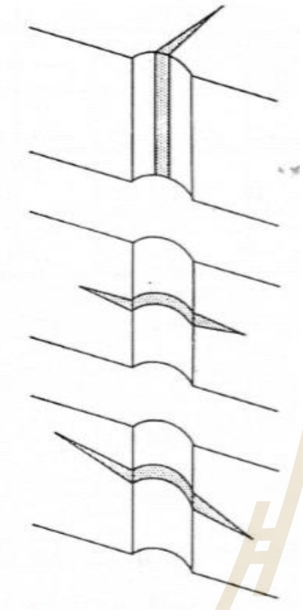

Figure 2.4 Fracture orientations (Craft and Holden, 1962)

The average permeability in rock fracture is more than the original rock is a thousand times, see Figure 2.5 and Figure 2.6.

$$k_{avg} = \frac{k k_{fz} ln(\frac{r_e}{r_w})}{k_{fz} \ln(\frac{r_e}{r_f}) + k ln(\frac{r_f}{r_w})} \tag{2.1}$$

$$k_{fz} = \frac{k_f W + kh}{h} \tag{2.2}$$

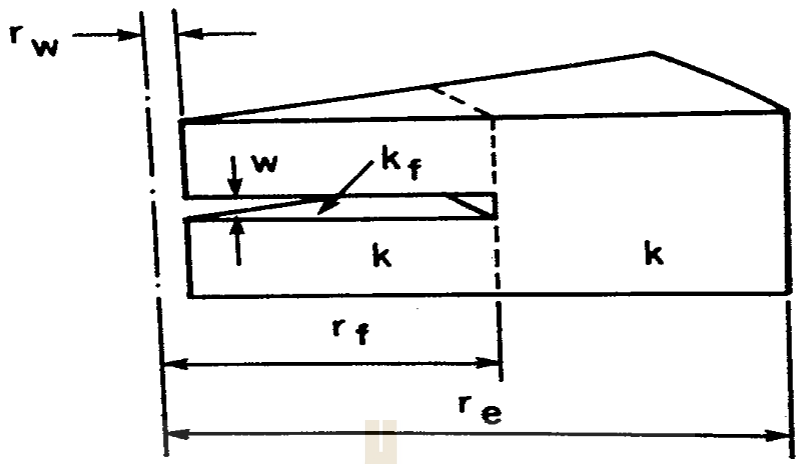

Figure 2.5 Show the average the permeability (Craft and Holden, 1962)

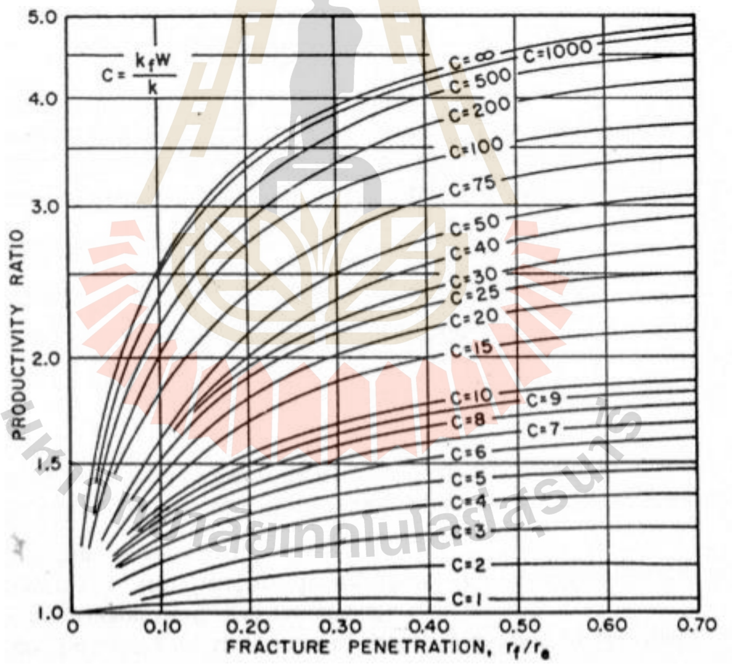

Figure 2.6 Estimate productivity ratio after fracturing (Vertical Fracturing) (Craft and Holden, 1962)

Gas production rate will increase much depends on fracture coefficient capacity length and width of fracture and can calculate the length, width of fracture and volume of mixed solution (Fracturing Fluid) using the PKN model.

2.3.1 Hydraulic Fracture width with the PKN Model

Two-dimensional models are closed-from analytical approximations assuming constant and know fracture height. For a fracture length much larger than the fracture height ($x_f >> h_f$), the Perkins and Kern (1961) and Nordgren (1972) or PKN model is an appropriate approximation.

The PKN model is depicted in Figure 2.7, it has an elliptical shape at the wellbore. The maximum width is at the centerline of this ellipse, with zero width at the top and bottom. For a Newtonian fluid the maximum width, when the fracture-haft length is equal to x_f, is give (in coherent units) by

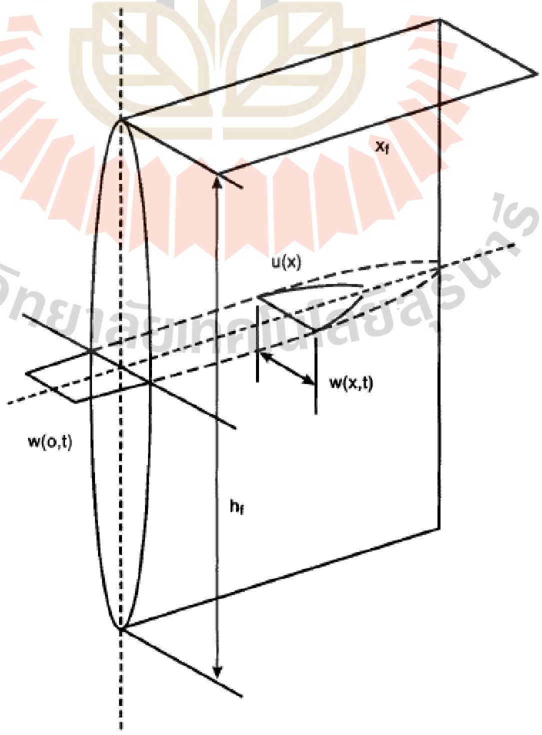

Figure 2.7 The PKN geometry

$$= 2.31[\frac{q_i\mu(1-v)x_f}{G}]^{1/4} \quad (2.3)$$

Where G is the elastic shear modulus and is related to Young's modulus, E, by

$$G = \frac{E}{2(1+v)} \quad (2.4)$$

In Equation (2.3) and (2.4), q_i is the injection rate, μ is the apparent viscosity, and v is the Poisson ratio. Equation (2.3) is particularly useful to understand the relationship among fracture width, treatment variables, and rock properties.

Rock properties have a much larger impact on the fracture width. The Young's modulus of common reservoir rocks may vary by almost two orders of magnitude, from 10^7 psi in tight sand deep sandstones to 2×10^5 psi in diatomite's, coals, and soft chalks. The difference in the fracture widths among these extremes will be more than 2.5 times. The implication is that in stiff rock, where the Young's modulus is large for a give volume of fluid injected, the resulting fracture will be narrow but long. Conversely, in low Young's modulus formations, the same volume of fluid injected would result in wide but short fracture stimulation, since low permeability reservoirs that require long fractures usually have large Young's modulus values.

The corollary is not always true. Low Young's moduli are not necessarily associated with higher permeability formation, although there are several cases where this is true.

The elliptical geometry of the PKN model leads to an expression for the average width by the introduction of a geometric factor. Thus,

$$\bar{w} = 2.31\left[\frac{q_i\mu(1-v)x_f}{G}\right]^{\frac{1}{4}}\left(\frac{\pi}{4}\gamma\right) \tag{2.5}$$

The factor γ is approximately equal to 0.75, and therefore the term in the second set of parentheses is equal to 0.59. In typical oilfield units, where $\bar{w}$ is calculated in inch, q_i is injection rate (bpm), μ is in ft, and G is in psi, Equation (2.5) becomes

For Newtonian fluid:

$$\bar{w} = 0.3\left[\frac{q_i\mu(1-v)x_f}{G}\right]^{\frac{1}{4}}\left(\frac{\pi}{4}\gamma\right) \tag{2.6}$$

For Non-Newtonian fluid:

The expression for the maximum fracture width a non-Newtonian fluid is (in oil/gas field units)

$$w_{max} = 12\left[\left(\frac{128}{3\pi}\right)(n'+1)\left(\frac{2n'+1}{n'}\right)^{n'}\left(\frac{0.9775}{144}\right)\left(\frac{5.61}{60}\right)^{n'}\right]^{\frac{1}{2n'+2}}$$

$$\times\left(\frac{q_i^{n'}K'x_f h_f^{1-n'}}{E}\right)^{\frac{1}{2n'+2}} \tag{2.7}$$

Where w_{max} is in in. The average width can be calculated by multiplying the w_{max} by πγ/4. The quantities $n^{'}$ and K' are the power-law rheological properties of the fracturing fluid.

CHAPTER III

ROCK SAMPLE AND

POROSITY-PERMEABILITY MEASUREMENT

3.1 Rock sample collections

The rock collected area covered Saraburi province, Lopburi Province, Chaiyaphum province, Nakhon Ratchasima Province, Khon Kean Province, Loei Province and Phetchabun Province as shown the route map and geologic map in Figure 3.1 to Figure 3.4 respectively.

Geologically, the geological field trip area consists of four main rock groups as Carboniferous rocks, Permian rocks, Triassic pre-Khorat rocks and Khorat Group. The Carboniferous rocks are called Wang Saphung Group/ Si That Formation which mostly exposed in the northern rim of Khorat Plateau. The Permian rocks are called Pha Nok Khao Formation which was exposed at the northwestern rim of Khorat Plateau. The Triassic pre-Khorat rocks exposed at the northwestern rim of the Khorat Plateau. Finally, the Khorat Group exposed at the Khorat Plateau

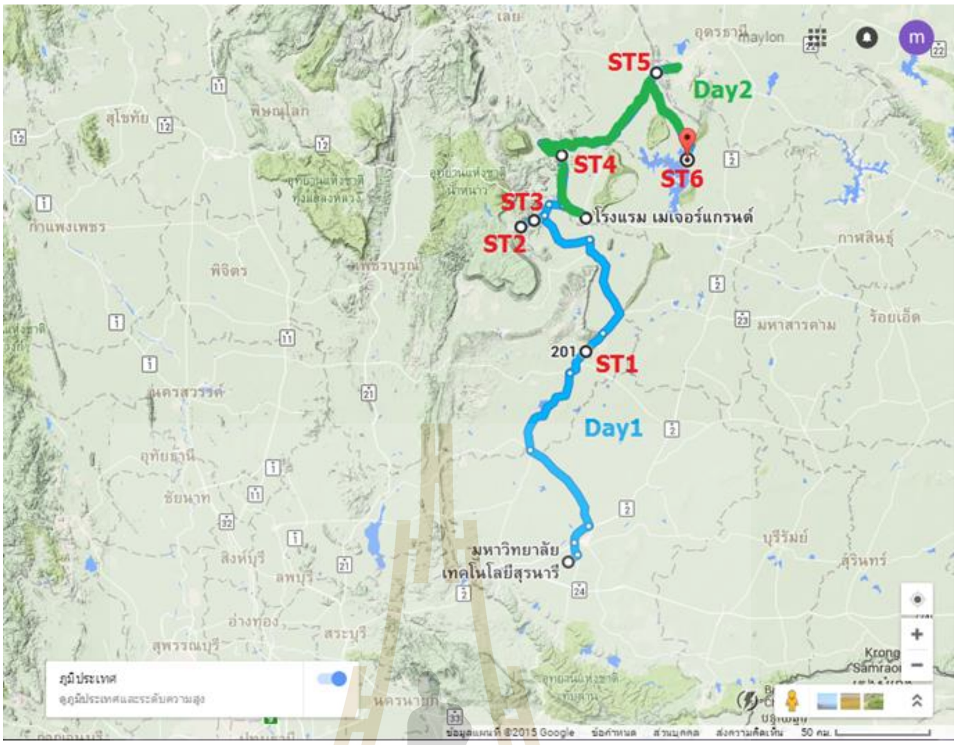

Figure 3.1 The Route map of geological field trip on 2-6 November 2015 (Day 1-2)

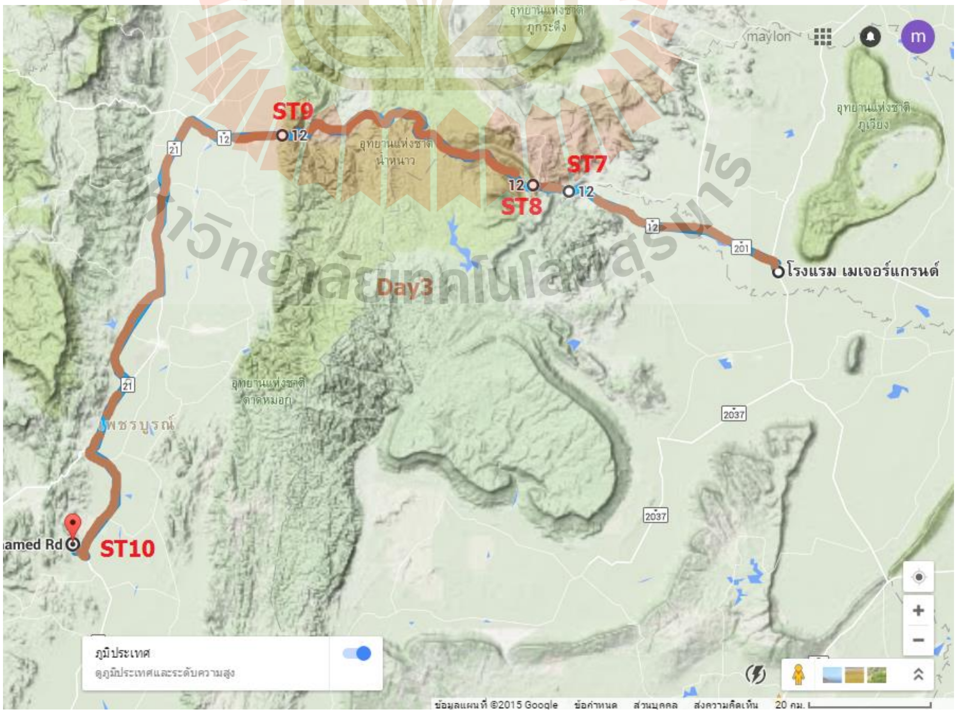

Figure 3.2 The Route map of geological field trip on 2-6 November 2015 (Day 3)

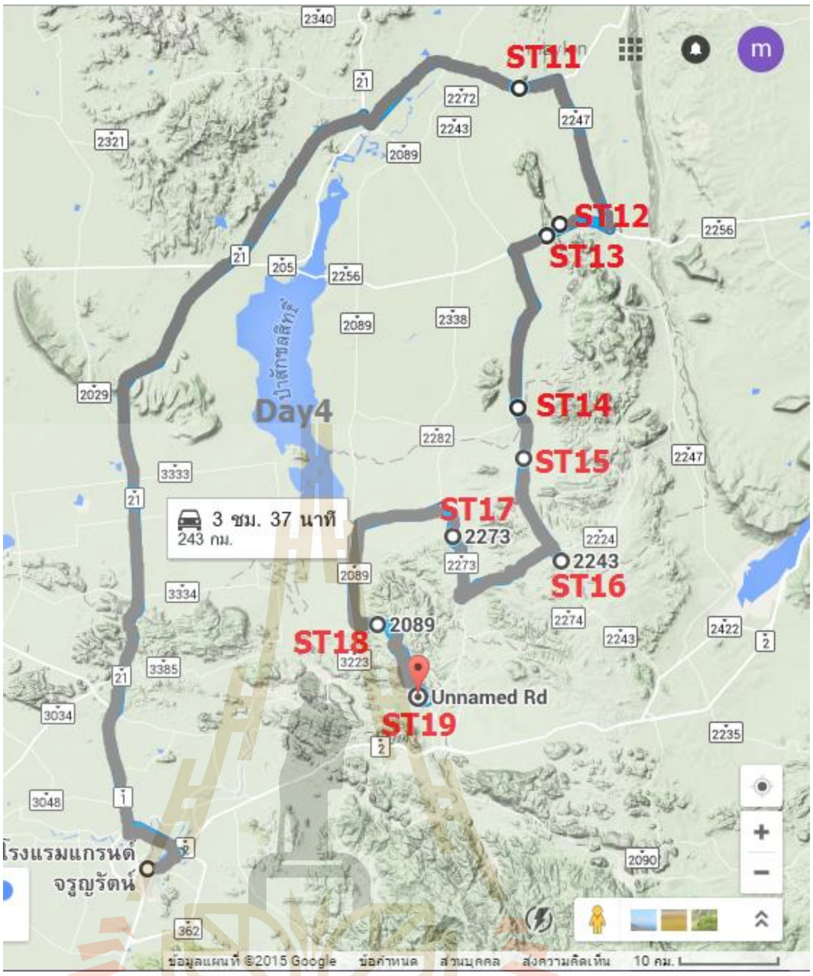

Figure 3.3 The Route map of geological field trip on 2-6 November 2015 (Day 4)

Figure 3.4 The Route map of geological field trip on 2-6 November 2015 (Day 5)

The field trip is separated into 5 days during 2-6 November 2015 the schedule as Table 3.1.

Table 3.1 The schedule of geological field trip 2015

Day 1 November 02, 2015		
Chaiyaphum		
Time	**Stop No.**	**Description**
	-	High Way No.201 CTR-2 and 3 Well, Chaturat, Chaiyaphum
13.00	1	High Way No.201 Km9+900 Huai Rai Khon Swan, Chaiyaphum
16.30	2-1	Rural Road No.2366 Km6+800 (Road to Namprom Dam), Huai Yang, Khon san, Chaiyaphum ; Permain/Hua Na Kham Formation
17.00	2-2	Rural Road No.2366 Km7+020 (Road to Namprom Dam) Huai Yang, Khon san, Chaiyaphum ; Permain/Pha Nok Khao Formation
17.30	3	Rural Road No.2366 Km5+200 (Road to Namprom Dam) Thung Lui Lay, Khon san, Chaiyaphum ; Permain/Pha Nok Khao Formation

Table 3.1 The schedule of geological field trip 2015 (cont.)

Day 2 November 03, 2015		
Khon Khaen, Nong Bua Lum Pho		
Time	**Stop No.**	**Description**
9.00	4	High way No.201 Km 248+500 Jap Poo Lup shrine, Chum Pae, Khon Khaen ; Permain/Pha Nok Khao Formation
12.30	5	High way No.201 Km 81+100 Road cut, Meung, Nong Bua Lum Pho ; Phra Wihan, Phu Ka Dung Formation
14.00	6	High way No.201 Km 52+600 Ubonrat Dam, Ubonrat, Khon Khaen ; Pha Wihan Formation
Day 3 November 04, 2015		
Chaiyaphum, Phetchabun		
Time	**Stop No.**	**Description**
9.30	7	High way No.12 Km 435+100 Pha Tewada, Khon san, Chaiyaphum ; Pha Nok Kao Formation
10.00	8	High way No.12 Km 429+500, Ban Huai Sanam Sai, Nam Nao, Phetchabun ; Nam Phong Formation
11.00	9	High way No.12 Km 438+500, Ban Huai Sanam Sai, Nam Nao, Phetchabun
13.30	10	High way No.12 Km 181+300, Wat Khao Thum Tho, Phetchabun ; Pha Nok Kao Formation

Table 3.1 The schedule of geological field trip 2015 (cont.)

Day 4 November 05, 2015		
Lob Buri, Sara Buri		
Time	**Stop No.**	**Description**
11.00	11	High way No.205 Km262+500, Wat Khao Tambon, Lop Buri
12.00	12	Rural Road No.2256 Km27+800, Wat Sub Krating Wanaram (Khao Somphot area), Lob Buri
12.30	13	Rural Road No.2256 Km28+800, Khao Somphot area, Lob Buri
13.00	14	Rural Road No.2243 Km38+700, Wat Nong Makha, Pathananikom Lob Buri
13.30	15	Rural Road No.2243 Km44+300, Wat sub ta Khian (khao noi), Sara Buri
13.30	16	Rural Road No.2243 Km56, Muak Lek Hill Side, Sara Buri
16.00	17	Rural Road No.2273 Km17+600, Ban Pong Keng, Sara Buri
17.20	18	Rural Road No.2089 Km13+700, Tree Tunnel, Sara Buri
17.50	19	Rural Road No.4029 Km 1, Wat Tham Ratana Prakasit, Sara Buri

Table 3.1 The schedule of geological field trip 2015 (cont.)

Day 5 November 06, 2015		
Sara Buri, Nakhon Ratchasima		
Time	**Stop No.**	**Description**
10.00	20	High way No.2 Km54+600, Slate stone decorate quarry of Khao Ban Dai Ma, Sara Buri
11.30	21	Rural Road No.2235 Km23+600, Small hill near Ozone Farm, Nakhon Ratchasima
11.40	22	Rural Road No.2235 Km23+950, Ban Sup Phlu Rose villas, Nakhon Ratchasima
12.00	23	Rural Road No.2235 Km24, Ban Sup Phlu Rose villas, Nakhon Ratchasima
12.10	24	Rural Road No.2235 Km24+800, Banmai Chaikhao restaurant, Ban Sup Phlu, Nakhon Ratchasima
12.40	25	Rural Road No.2273 Km17+600, Ban Pong Keng, Ban Sup Phlu, Nakhon Ratchasima
13.00	26	Rural Road No.3060 Km44+200, Road cut outcrop, Ban Sup Phlu, Nakhon Ratchasima

Example rock collated

Figure 3.5 Phra Wihan Formation sandstone

Figure 3.6 Sample of Phra Wihan Formation of Khorat Group

Figure 3.7 Mid-Nam Phong red sandstone

Figure 3.8 Sample of Mid-Nam Phong red sandstone

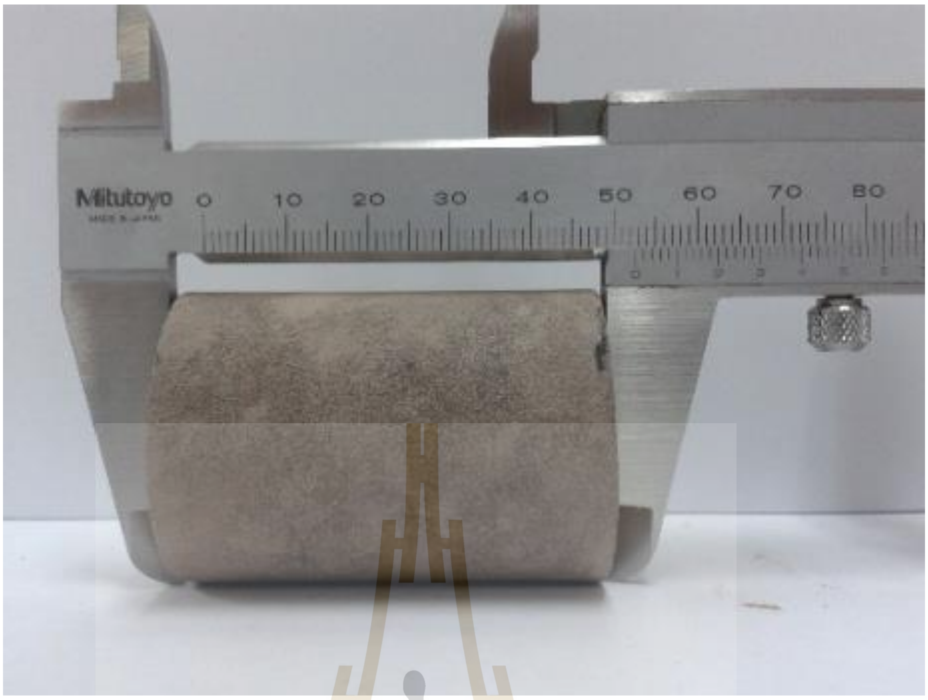

Figure 3.9 Length of core sample

Figure 3.10 Diameter of core sample

3.2 Porosity measurement

Porosity is a measure of the void space within a rock expressed as a fraction (or per cent) of the bulk volume of that rock.

In this research is discussed in the sandstone of Korat group measure by “Porosimeter” equipment from Petroleum engineering and Geotechnology laboratory Suranaree University of Technology.

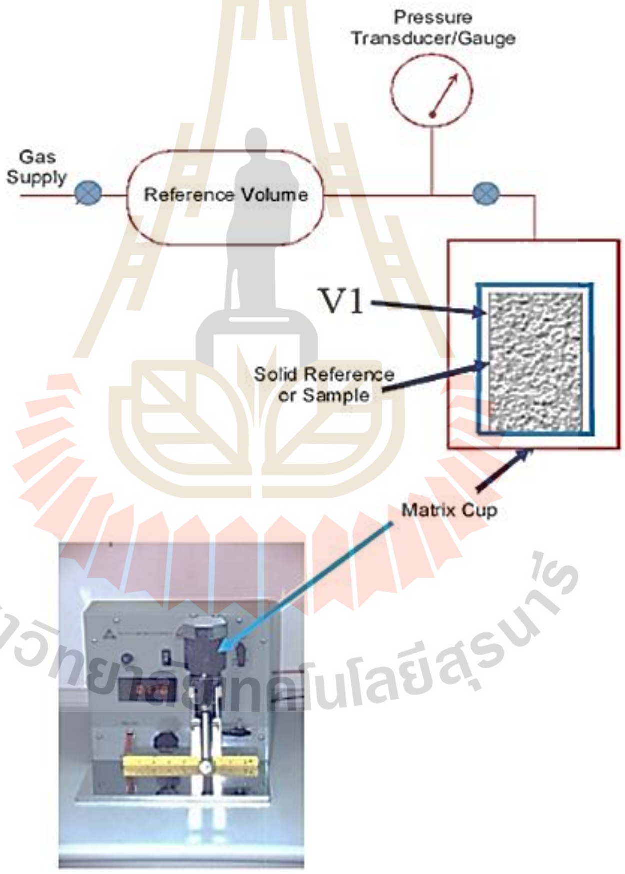

Figure 3.11 Porosimeter (Petroleum engineering and Geotechnology Laboratory, SUT)

3.2.1 Porosity calculations

Grain volume

$$RV = \frac{V_{bil}}{\left(\frac{P_{ob}}{P_b}\right)-\left(\frac{P_{of}}{P_f}\right)} \tag{3.1}$$

or if P_{ob} and P_{of} = 100 psi

$$RV = \frac{P_f}{100} \times \left[\frac{P_b V_{bil}}{P_f - P_b}\right] \tag{3.2}$$

$$GV = V_{bil2} + \left[\left(\frac{P_{of}}{P_f}\right) RV - \left(\frac{P_{os}}{P_s}\right) RV\right] \tag{3.3}$$

Pore volume

$$PV = \frac{P_{os} RV}{P_s - RV - V_{bil}} \tag{3.4}$$

Bulk volume

$$BV = \frac{BV_{Hg}(g)}{Density\ of\ Hg\ (\frac{g}{cm^3})} \tag{3.5}$$

$$BV = L\pi \frac{D^2}{2} \quad ;\ \textit{for whole core samples} \tag{3.6}$$

$$BV = GV + PV \quad ;\ \textit{for vuggy plug samples} \tag{3.7}$$

Porosity

$$\Phi\% = \frac{PV}{BV} \times 100 \tag{3.8}$$

where:

P_{of}, P_{os} = Fill the reference chamber with helium, 100 psig

$P_{f,}$ = Equilibrated pressure, psig

P_s = Pressure to stabilize in matrix cup, psig

P_{ob} = Reference chamber pressure, psig

P_b = The equilibrated pressure of the sample chamber, psig

V_{bil} = Reference volume of billet, cm^3

V_{bil2} = Reference volume of billet remove, cm^3

RV = Reference volume, cm^3

BV = Bulk volume

GV = Grain volume

Table 3.2 Porosity of Khorat sands

No.	Ex.	ID cm	Length cm	Weight gram	Grain Vol. cm3	Bulk Vol. cm3	Pore Vol. cm3	Grain Density g/cc	Bulk Density g/cc	Porosity %
1	PW1	3.74	5.24	133.55	50.12	57.54	7.42	2.66	2.32	12.89
2	PW2	3.75	5.15	127.65	47.51	56.85	9.34	2.68	2.45	16.43
3	PW3	3.73	5.16	130.26	47.56	56.36	8.80	2.74	2.31	15.62
4	PW4	3.74	5.13	129.15	49.10	56.33	7.23	2.63	2.29	12.83
5	PW1(1)	3.70	5.13	128.59	48.63	55.13	6.44	2.64	2.33	11.67
6	PW1(2)	3.70	5.09	126.58	47.95	54.70	6.75	2.64	2.31	12.33
7	PW1(3)	3.70	5.16	127.63	48.25	55.45	7.21	2.62	2.28	12.99
8	PW1(4)	3.70	5.20	128.77	48.70	55.88	7.18	2.64	2.30	12.86
9	PW1(5)	3.70	5.00	124.85	47.02	53.73	6.71	2.66	2.32	12.49
10	PW1(6)	3.70	5.27	131.54	49.70	56.63	6.93	2.65	2.32	12.24
11	PW1(7)	3.70	5.20	130.16	49.15	55.88	6.74	2.65	2.23	12.05
12	PW1(8)	3.70	5.20	124.88	47.07	55.88	8.81	2.65	2.23	15.77
13	PW2 (1)	3.70	5.06	124.30	47.43	54.38	6.94	2.62	2.29	12.77
14	PW2(2)	3.70	4.97	123.32	46.94	53.41	6.47	2.63	2.31	12.12
15	PW2(3)	3.70	5.12	128.95	49.16	55.02	5.87	2.62	2.34	10.66
16	PW2(4)	3.70	5.06	126.18	48.08	54.38	6.30	2.62	2.32	11.59
17	PW2(5)	3.70	5.01	125.19	47.64	53.84	6.20	2.63	2.33	11.52
18	PW2(6)	3.70	5.20	130.89	49.86	55.88	6.02	2.63	2.34	10.78
19	PW2(7)	3.70	5.00	122.62	47.17	53.41	5.24	2.63	2.32	11.68
20	PW2(8)	3.70	4.97	123.83	49.86	55.88	6.02	2.63	2.34	10.78
21	PK1(1)	3.70	4.90	132.53	50.18	52.66	2.48	2.64	2.51	4.71
22	PK1(2)	3.70	5.00	135.50	51.28	53.73	2.45	2.64	2.52	4.56
23	PK1(3)	3.70	5.17	140.05	53.14	55.56	2.52	2.64	2.52	4.36

Table 3.2 Porosity of Khorat sands (cont.)

No.	Ex.	ID cm	Length cm	Weight gram	Grain Vol. cm3	Bulk Vol. cm3	Pore Vol. cm3	Grain Density g/cc	Bulk Density g/cc	Porosity %
24	PK1(4)	3.70	5.16	136.90	53.14	55.45	2.31	2.58	2.47	4.18
25	PK1(5)	3.70	5.17	139.76	51.80	55.56	3.76	2.70	2.52	6.77
26	PK1(6)	3.70	5.20	141.47	53.63	55.88	2.25	2.64	2.53	4.02
27	PK2(1)	3.70	5.30	144.50	53.63	56.96	2.32	2.69	2.54	5.84
28	PK2(2)	3.70	5.25	143.60	53.58	56.42	2.84	2.56	2.68	5.03
29	PK2(3)	3.70	5.27	143.39	54.31	56.63	2.32	2.64	2.53	4.09
30	PK2(4)	3.70	5.30	144.90	54.43	56.96	2.53	2.66	2.54	4.43
31	PK2(5)	3.70	5.33	145.20	54.29	57.28	2.99	2.67	2.53	5.22
32	PP1	3.73	5.13	134.07	49.67	56.03	6.36	2.70	2.39	11.35
33	PP2	3.78	5.22	134.67	50.93	58.55	7.62	2.30	2.64	13.01
34	PP3	3.74	5.22	134.71	50.89	57.32	6.42	2.35	2.65	11.21
35	PP4	3.80	5.23	131.21	50.68	59.28	8.60	2.59	2.21	14.51
36	KK1	3.74	5.24	133.55	49.41	57.54	8.13	2.70	2.32	14.13
37	KK2	3.75	5.15	127.65	58.27	56.58	8.58	2.64	2.25	15.10
38	KK3	3.73	5.16	130.26	49.29	56.36	7.06	2.64	2.31	12.53
39	KK4	3.74	5.13	129.15	48.76	56.33	7.57	2.65	2.29	13.44

Conclusion Khok kruat formation has porosity ranging 12.5-15.10%

Phu phan formation has porosity ranging 11.2-14.51%

Phra Wihan formation has porosity ranging 11.7-16.4%

Phu kradeung formation has porosity ranging 4.09-5.84%

3.3 Permeability measurement

Permeability is the measure of the ability of a porous medium to transmit fluids. The measurement of a porous rock is a measurement of the fluid conductivity of the particular material. Measured permeability is expressed in milliDarcies (mD). A permeability of 1 Darcy (i.e. 1000 mD) is defined as that permeability which will allow the flow of 1 cm^3/sec of fluid of 1 centipoise (cP) viscosity through a cross sectional area of 1 cm^3 under a pressure gradient of 1 atmosphere (atm/sec)

In this research is discussed in the sandstone of Korat group measure by "Overburden poro-perm cell" equipment from Petroleum engineering and Geotechnology laboratory Suranaree University of Technology.

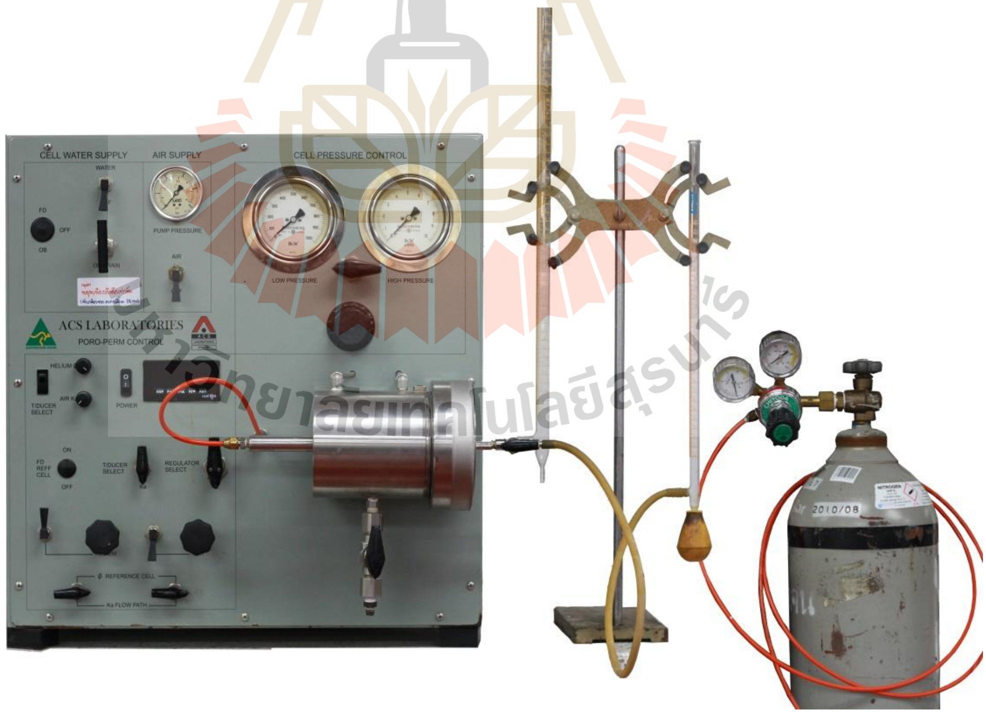

Figure 3.12 Overburden poro-perm cell (Petroleum engineering and Geotechnology Laboratory, SUT)

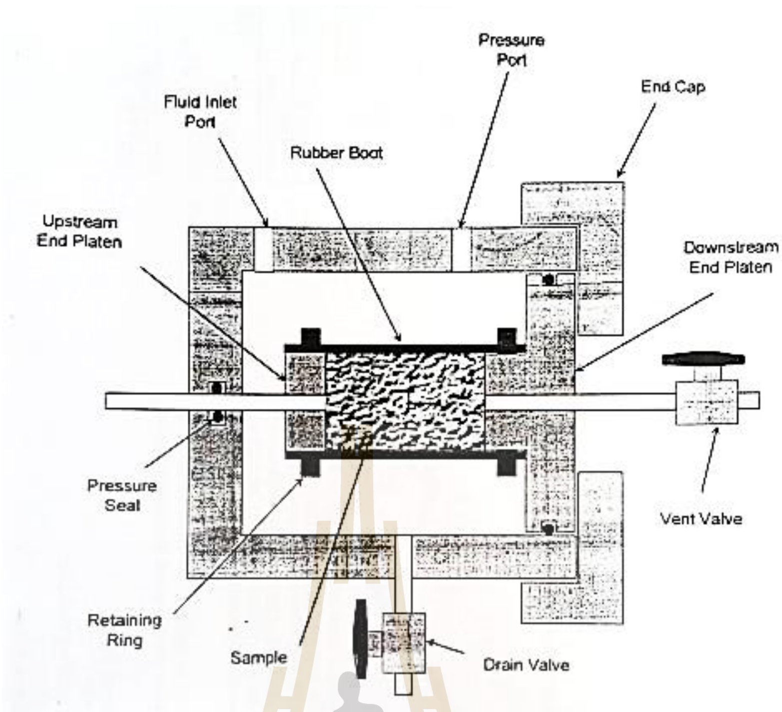

Figure 3.13 Equipment compositions

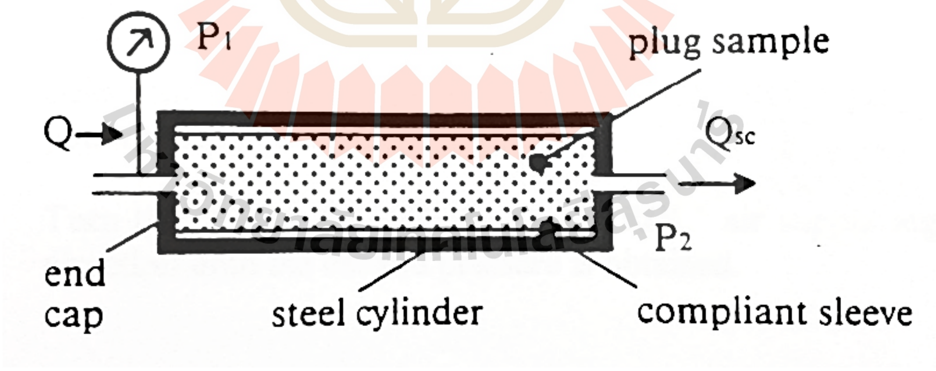

Figure 3.14 Permeability measurement

3.3.1 Permeability calculations

Laboratory calculations

$$A\ (cm^2) = \pi r^2 \qquad (3.9)$$

$$n = (-8x10^{-7} \text{ x } T^2) + (8x10^{-5} \text{ x } T) + 0.0158,\ T \text{ in } {}^oC \qquad (3.10)$$

$$k_{gas} = 0.9716\left[\frac{2000P_b nQL}{[(P_1+P_b)^2-P_b^2]\times A}\right] \qquad (3.11)$$

where:

A = Cylinder cross section area, cm^2

n = Dynamic viscosity, cP

k_{gas} = Permeability, mD

P_c = Overburden Pressure, atm

P_1 = Upstream Pressure, atm

P_b = Barometric Pressure, atm

V = Volume of gas, cm^3

Q = Flow rate, cm^3/sec

Table 3.3 Permeability of Khorat sands

No.	Examples	Id. cm	Length cm	Weight gram	Permeability md.
1	PW1	3.74	5.24	133.551	18.80
2	PW2	3.75	5.15	127.654	222.78
3	PW3	3.73	5.16	130.264	245.93
4	PW4	3.74	5.13	129.148	27.51
5	PW1(1)	3.70	5.13	128.590	2.60
6	PW1(2)	3.70	5.09	126.576	3.09
7	PW1(3)	3.70	5.16	127.627	2.75
8	PW1(4)	3.70	5.20	128.765	2.45
9	PW1(5)	3.70	5.00	124.851	12.49
10	PW1(6)	3.70	5.27	131.536	12.25
11	PW1(7)	3.70	5.20	130.157	12.05
12	PW1(8)	3.70	5.20	124.878	15.77
13	PW2 (1)	3.70	5.06	124.302	6.16
14	PW2 (2)	3.70	4.97	123.315	4.92
15	PW2 (3)	3.70	5.12	128.953	1.29
16	PW2 (4)	3.70	5.06	126.181	3.37
17	PW2 (5)	3.70	5.01	125.193	2.37
18	PW2 (6)	3.70	5.20	130.886	1.66
19	PW2 (7)	3.70	5.00	122.622	8.23
20	PW2 (8)	3.70	4.97	123.827	3.76
21	PK1 (1)	3.70	4.90	132.53	0.17
22	PK1 (2)	3.70	5.00	135.50	0.14
23	PK1 (3)	3.70	5.17	140.05	0.16
24	PK1 (4)	3.70	5.16	136.90	0.18
25	PK1 (5)	3.70	5.17	139.76	0.17
26	PK1 (6)	3.70	5.20	141.47	0.13

Table 3.3 Permeability of Khorat sands (cont.)

No.	Examples	Id. cm	Length cm	Weight gram	Permeability md.
27	PK2 (1)	3.70	5.30	144.50	0.18
28	PK2 (2)	3.70	5.25	143.60	0.15
29	PK2 (3)	3.70	5.27	143.39	0.17
30	PK2 (4)	3.70	5.30	144.90	0.16
31	PK2 (5)	3.70	5.33	145.20	0.15
32	PP1	3.73	5.13	134.067	1.55
33	PP2	3.78	5.22	134.666	0.98
34	PP3	3.74	5.22	134.706	0.91
35	PP4	3.80	5.23	131.214	1.34
36	KK1	3.74	5.24	133.551	0.51
37	KK2	3.75	5.15	127.654	0.56
38	KK3	3.73	5.16	130.264	0.56
39	KK4	3.74	5.13	129.148	0.55

Conclusion Khok kruat formation has permeability ranging 0.51-0.57 mD

Phu phan formation has permeability ranging 0.91-1.55 mD

Phra Wihan formation has permeability is 2.5 mD

Phu kradeung formation has permeability ranging 0.13-0.18 mD

Average permeability at subsurface

$$k_{gas} = 0.0054e^{0.4539\phi} \quad ; \phi = 3.6\%$$

$$= 0.0054e^{0.4539(3.6)}$$

$$= 0.03 \text{ mD}$$

or average permeability ranging 0.03-0.9 mD

CHAPTER IV

HYDRUALIC FRACTURING AND COMPUTER SIMULATION MODEL

4.1 Hydraulic fracturing (HF) the PKN model and hydraulic fracturing pattern

4.1.1 Hydraulic fracturing (HF) the PKN model

The hydraulic fracturing (HF) method is injecting fracturing fluid with high pressure to fracture the formation. If the fracturing zone is more than 3,000 foot depth the vertical fracture occurs.

For calculation, two-dimensional models are closed-from analytical approximations assuming constant and know fracture height. For a fracture length much larger than the fracture height ($x_f >> h_f$), the Perkins and Kern (1961) and Nordgren (1972) or PKN model is an appropriate approximation.

The PKN model is depicted in Figure 4.1, it has an elliptical shape at the wellbore. The maximum width is at the centerline of this ellipse, with zero width at the top and bottom. For a Newtonian fluid the width, when the fracture-haft length is equal to x_f, is give (in coherent units) by

$$W_{(0,t)} = C_2 \left[\frac{(1-v)q_i^2\mu}{Gh_f}\right]^{\frac{1}{5}} \times t^{\frac{1}{5}} \tag{4.1}$$

$$x_f = C_1 [\frac{Gq_i^3}{(1-v)\mu h_f^4}]^{\frac{1}{5}} \times t^{\frac{4}{5}} \tag{4.2}$$

$$G = \frac{E}{2(1+\nu)} \tag{4.3}$$

$$k_f = 7.7(10^{12})w_f^2 \tag{4.4}$$

where:

$W_{(0,t)}$	is width of fracture at injection time, inch
q_i	is the injection rate, bpm
μ	is the apparent viscosity, cp
ν	is the Poisson ratio
G	is the elastic shear modulus, psi
E	is Young's modulus
k_f	is permeability of fracture, md
w_f^2	is width of fracture, ft
t	is inject time, minute

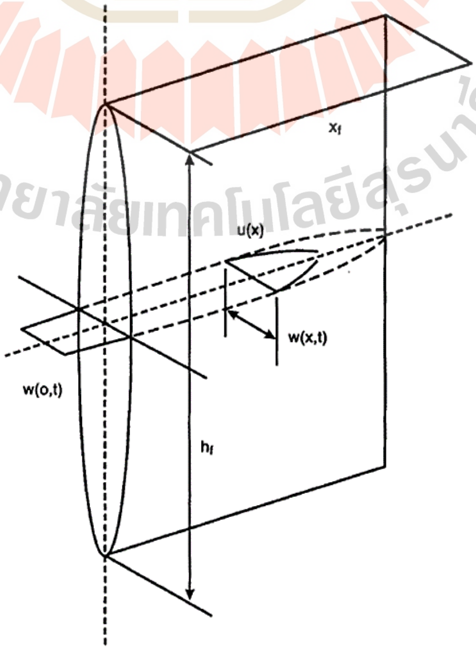

Figure 4.1 The PKN geometry (Perkins and Kern, 1961 and Nordgren, 1972)

Table 4.1 Values for "*C*" (Advance in Hydraulic Fracturing (John et al., 1989)

	One wing	**Two wings**
$\mathbf{C_1}$	0.68	0.45
$\mathbf{C_2}$	2.5	1.89

Table 4.2 The data for calculation at fluid injection 1,500 bbl, injection time 300 minute and infection rate 5 bbl/min

Reservoir area	53,820,000	ft^2			
Reservoir boundary, r_e	7,336	ft.	2,237	m	
Reservoir thickness, h	260	ft.	80	m	
High of fracture, h_f	260	ft.	80	m	
Reservoir pressure	3,600	psi			
Reservoir temperature	266	F			
Injection time, t	300	min.			
Flow rate, q_i	5	bpm.	1.6	m^3/min	
Viscosity of fracture fluid (water), μ	1	cp	1.67×10^{-8}	kPa-min	
Reservoir porosity, ϕ	0.036				
Reservoir permeability, k	0.09	md	0.00009	darcy	
Poisson's Ratio, v	0.43				Ref. company
Young modulus, E	4,757,384.4	kPa	690,000	psi	
ID Pipe	3.875	in.	0.323	ft	

From the data can use to calculate:

Elastic shear modulus:

$$G = \frac{4{,}757{,}384.4}{2(1+0.43)}$$

$$= 1{,}663{,}421.12 \text{ kPa}$$

Length of fracture:

$$L_{(t)} = 0.45\left[\frac{1{,}663{,}421.12(10^2)}{(1-0.43)(1.67\text{x}10^{-8})(80^4)}\right]^{1/5} 300^{1/5}$$

= 796 m. or 2,612 ft. (2 wing)

Width of fracture:

$$W_{(0,t)} = 1.89\left[\frac{(1-0.43)10^3(1.67\text{x}10^{-8})}{1{,}663{,}421.12(80)}\right]^{1/5} 300^{1/5}$$

= 0.00664 m. or 0.02179 ft. or 0.26 in.

Permeability of fracture:

$$k_f = 7.7(10^{12}) \text{ x } 0.02179^2$$

= 3,655,831,561.12 md

Volume of fracturing fluid (water) injection

= 300 min x 5 bbl/min

= 1,500 bbl.

Table 4.3 The summary of calculation results

Elastic shear modulus, G	1,663,421.12	kPa		
Length of fracture, L(t)	796	m	2,612 ft	2 Wing
Width of fracture, W(0,t)	0.00664	m	0.02179 ft	0.26 inch
Permeability of fracture, kf	3,655,831,561.12	md		
Volume of fracturing fluid (water) injection	63,000	gallon	1,500 bbl	

Table 4.4 The data for calculation at fluid injection 5,00 bbl, injection time 500 minute and infection rate 10 bbl/min

Reservoir area	53,820,000	ft^2			
Reservoir boundary, r_e	7,336	ft.	2,237	m	
Reservoir thickness, h	260	ft.	80	m	
High of fracture, h_f	260	ft.	80	m	
Reservoir pressure	3,600	psi			
Reservoir temperature	266	F			
Injection time, t	300	min.			
Flow rate, q_i	10	bpm.	1.6	m^3/min	
Viscosity of fracture fluid (water), μ	1	cp	1.67×10^{-8}	kPa-min	
Reservoir porosity, ϕ	0.036				
Reservoir permeability, k	0.09	md	0.00009	darcy	
Poisson's Ratio, v	0.43				Ref. company
Young modulus, E	4,757,384.4	kPa	690,000	psi	
ID Pipe	3.875	in.	0.323	ft	

From the data can use to calculate:

Elastic shear modulus:

$$G = \frac{4,757,384.4}{2(1+0.43)}$$

$$= 1,663,421.12 \text{ kPa}$$

Length of fracture:

$$L_{(t)} = 0.45[\frac{1,663,421.12(10^2)}{(1-0.43)(1.67x10^{-8})(80^4)}]^{1/5}500^{4/5}$$

= 1,816 m. or 5,985 ft. (2 wing) or 71,820 in.

Width of fracture:

$$W_{(0,t)} = 1.89[\frac{(1-0.43)10^3(1.67x10^{-8})}{1,663,421.12(80)}]^{1/5}500^{1/5}$$

= 0.00971 m. or 0.03184 ft. or 0.38 in.

Permeability of fracture:

$$k_f = 7.7(10^{12})0.03184^2$$

$$= 7,808,177,442.49 \text{ md}$$

Volume of fracturing fluid (water) injection

= 500 min x 10 bbl/min

= 5,000 bbl.

Table 4.5 The summary of calculation results

Elastic shear modulus, G	1,663,421.12	kPa		
Length of fracture, $L_{(t)}$	1,816	m	5,958 ft	2 Wing
Width of fracture, $W_{(0,t)}$	0.00971	m	0.032 ft	0.38 inch
Permeability of fracture, k_f	7,808,177,442.49	md		
Volume of fracturing fluid (water) injection	210,000	gallon	5,000 bbl	

And finally calculation to find the average permeability

$$k_{avg} = \frac{\Sigma k_i A_i}{\Sigma A_i} \tag{4.5}$$

$$= \frac{[3.865\times(146-0.032)\times 52]+[7,808,177,442.49\times 0.032\times 52]}{146\times 52}$$

$$= 1.71\text{x}10^6 \text{ md}$$

4.1.2 Hydraulic fracturing pattern

From the result, using data average permeability, length of fracture and width of fracture input to simulation cell or pattern cell by Microsoft excel as shown in Figure 4.2 to Figure 4.4

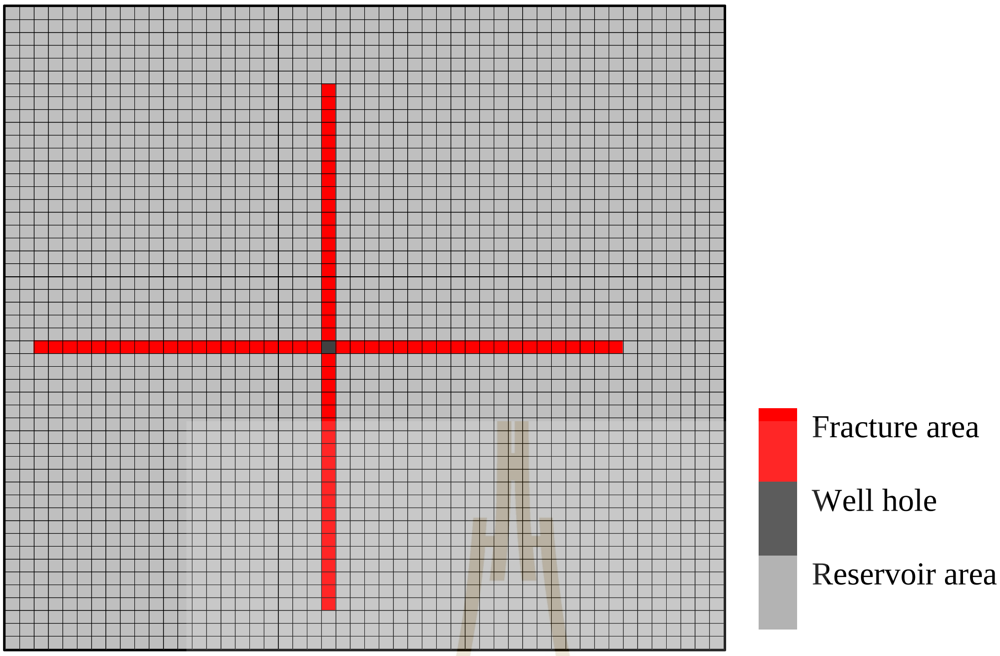

Figure 4.2 The top of hydraulic fracturing pattern with reservoir simulation model (50x50 cell)

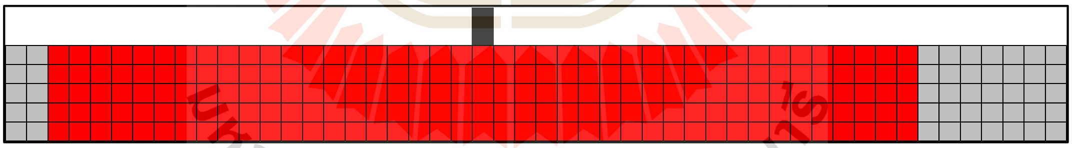

Figure 4.3 Show the fracture area on front view

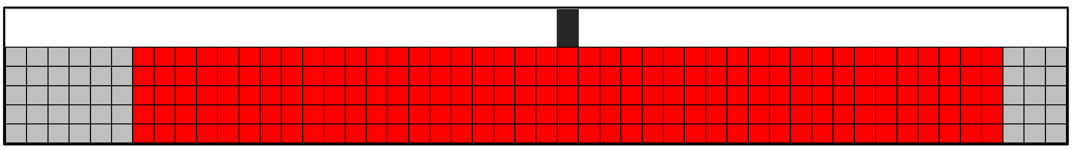

Figure 4.4 Show the fracture area on side view

4.2 Computer simulation model

The Khorat sand gas field simulation by "Eclipse industry-reference reservoir simulator" program with the gas in place of 150 MMSCF is modeled as an anticline (shown in Figure 4.5 to Figure 4.8). The model consists of 50×50 grid blocks in area view and 5 layers includes to 12,500 blocks. Each block has dimension of 7336'×7336'×260' to be 14×10^9 cubic foot.

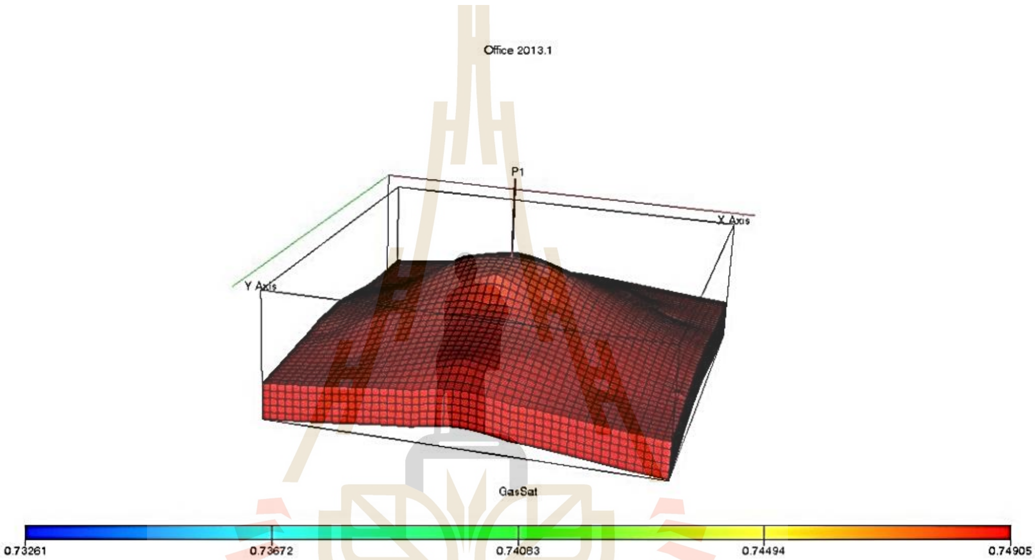

Figure 4.5 Gas saturation in Khorat sand gas field Model (50×50×5 = 12,500 cell)

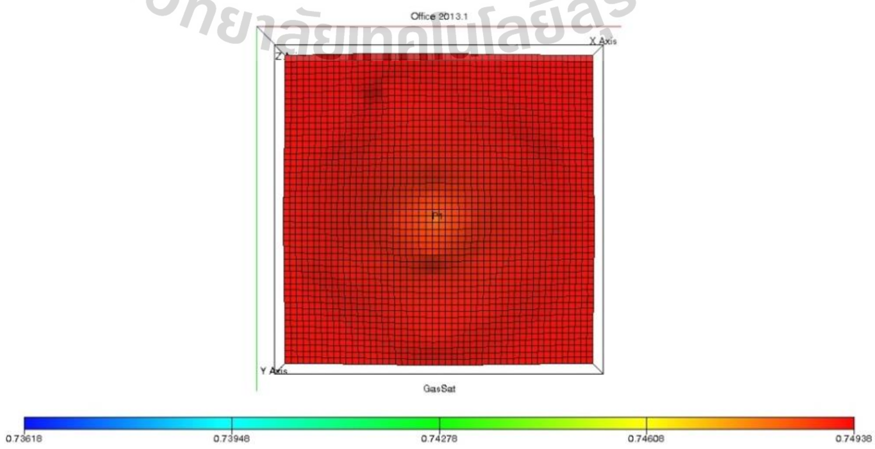

Figure 4.6 The Khorat sand gas field model (Top view)

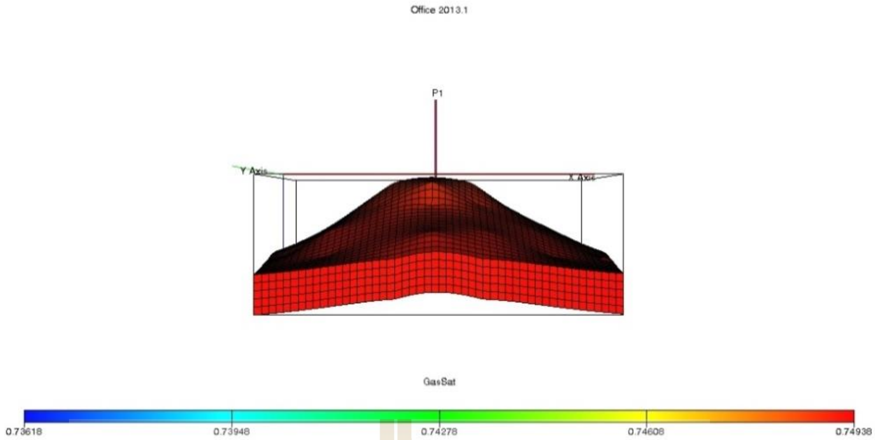

Figure 4.7 The Khorat sand gas field model (Front view)

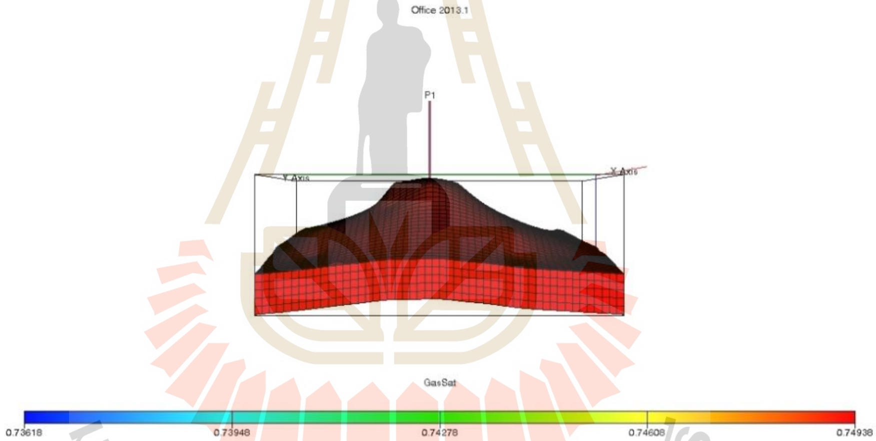

Figure 4.8 The Khorat sand gas field model (Side view)

And finally, the program will process the result, gas in place, gas production rate and pressure drop in reservoir the result will be shown in the next chapter.

CHAPTER V

POTENTIAL ASSESSMENT OF PETROLEUM RESERVE AND COMPUTER SIMULATION RESULT

5.1 The geological assessment of Khorat sand gas field

The result of study on the petroleum system of northeastern region can be summarized as follows:

5.1.1 Source Rocks

The Geochemical data from the Late Triassic Huai Hin Lat Group, the Permian Hua Na Kham and the Pha Nok Khao Formations, and the Late Carboniferous Wang Saphung Group suggest that they contain good to fair source richness.

5.1.2 Reservoir Rocks

The most significant reservoir rocks in the northeastern region are Khorat group sequence including sandstone.

5.1.3 Seal Rocks

Thick sequence of fine and dense rocks on top of saturated hydrocarbon beds in the Northeast is common. They are, for example, the lower part of the Khorat Group which contains a thick and monotonous layer of claystone with argillaceous cement, thus, permeabilities are expected to be very poor.

5.1.4 Trap

The geologic structures and stratigraphic petroleum traps in the northeastern region are successfully tested.

The geologic model used in the assessment of Khorat Plateau Province is that oil and gas generated from source rocks in Paleocene, following Cretaceous burial, migrated upward along faults into Permian carbonate reservoirs and possibly into Triassic sniff clastic reservoirs within structural traps. The probability of these geological variances are tabulated in Table 5.1 and Table 5.2.

Table 5.1 Probability of petroleum geological variances with play level (attributes)

Play attributes	**Probability**	**Descriptions**
1. Hydrocarbon source	0.70	The Late Triassic Huai Hin Lat Group, the Permian Hua Na Kham and the Pha Nok Khao Fm., and the Late Carboniferous Wang Saphung Group suggest that they contain good to fair source richness
2. Timing	1.00	Petroleum originated from source rock and migrated to reservoir (Khorat sand group) at suitable timing. (Late Triassic)
3. Migration	1.00	Migration of petroleum from source rock to reservoir is suitable in both petroleum quantity and migration path
4. Potential Reservoir Facie	0.70	Reservoir has some suitable and enough quantity of porosity and permeability
Marginal Play Probabilities = 0.70×1.00×1.00×0.7 = 0.49		

Table 5.2 Probability of petroleum geological variances within Prospect attributes

Prospect attributes	Probability	Descriptions
5. Trapping Mechanism	0.80	The lower part of the Khorat Group which contains a thick and monotonous layer of claystone with argillaceous cement, thus, permeabilities are expected to be very poor
6. Effective Porosity	0.90	Reservoir has good average porosity (>3%)
7. Hydrocarbon accumulation	0.80	There are suitable trap enough for hydrocarbon accumulation (>17%)
Conditional Deposit Probabilities = 0.80×0.90×0.80 = 0.576		

Petroleum volumetric reserve calculation is assessed with Monte Carlo Simulation by numerical methods using of random numbers and a function of the engineering (area of closure (A), thickness (h), porosity (ϕ), gas saturation (S_g), gas recovery factor (RF) and gas formation volume factor (B_g)).

$$Reserve = \frac{43{,}560 A h \phi S_g}{B_g} \times RF \qquad (5.1)$$

5.2 Petroleum engineering potential assessment of Khorat sand gas field

5.2.1 Evaluate the potential by FASPU

The gas fields are evaluated by FASPU. Evaluation the potential of petroleum resources to separate the probability into 3 levels.

1. High fractile of 95 (F95)
2. Moderate fractile of 50 (F50)
3. Low fractile of 5 (F5)

In play analyzed, the seven fractiles are estimated for all six of the hydrocarbon volume attributes consist of area of closure, reservoir thickness/vertical closure, effective porosity, trap fill, reservoir depth, and hydrocarbon saturation. The probability for each attribute is shown in Table 5.3

Table 5.3 Assessment the hydrocarbon volume attribute probability of the Khorat sand prospect

Attribute			**Probability of Favorable or Present**						
Hydrocarbon Volume Parameter	**Reservoir Lithology**	Sand	X						
		Carbonate	--						
	Hydrocarbon	Gas	1.00						
		Oil	0.00						
	Fractiles / **Attribute**		**Probability of equal to or greater than**						
			100	**95**	**75**	**50**	**25**	**5**	**0**
	Area of Closure (1,000 acres)		6.02	6.41	7.95	9.87	11.79	13.33	13.71
	Reservoir Thickness (feet)		30	38	65	99	133	160	167
	Effective Porosity (%)		2.5	2.7	4	5.1	6.4	9.3	12
	Trap Fill (%)		50	55	60	65	70	80	90
	Reservoir Depth (1,000 feet)		2.50	2.70	3.30	4.40	5.40	6.20	7.20
	HC Saturation (%)		45	47	60	75	90	97	100
No. of drillable prospects (a play characteristic)			**2**	**3**	**3**	**4**	**4**	**5**	**6**

The area of closure on top of the Khorat sand can be taken from the data distribution which is the lognormal distribution type (Table 5.4 and Figure 5.1) because the big or large size prospects usually have the distribution less than the small size prospects.

Table 5.4 Size distributions of area of closure for the Khorat sand play

Area of Closure Class (1,000 acres)	**Frequency**	**Cumulative Greater Than Percent**
6	1	100
6.40	2	95
7.10	1	85
7.80	2	75
8.40	2	65
9.87	1	50
10.25	1	45
11.02	1	35
11.80	0	25
12.56	1	15
13.33	2	5
13.71	1	0

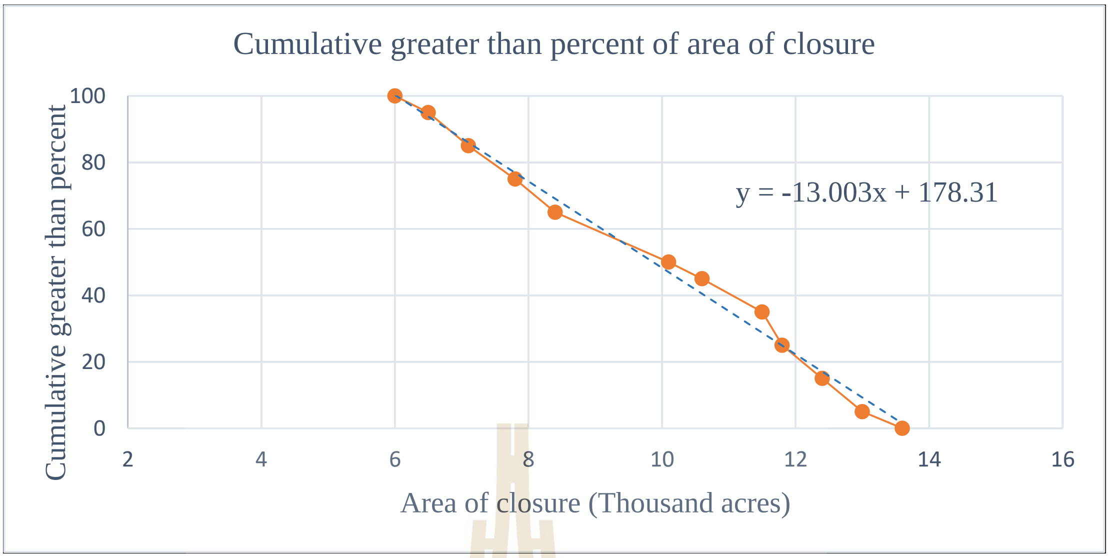

Figure 5.1 Cumulative greater than percent of area of closure for the Khorat sand play

The reservoir thickness/vertical closure can be taken from the data distribution which is the lognormal distribution type (Table 5.5 and Figure 5.2).

Table 5.5 Size distributions of reservoir thickness in percent for the Khorat sand play

Reservoir Thickness Class (ft)	Frequency	Cumulative Greater Than Percent
30	1	100
38	0	95
48	1	87
56	0	81
64	1	75
82	1	63
106	4	46
124	2	33
135.5	0	25
157	2	10
170	0	0

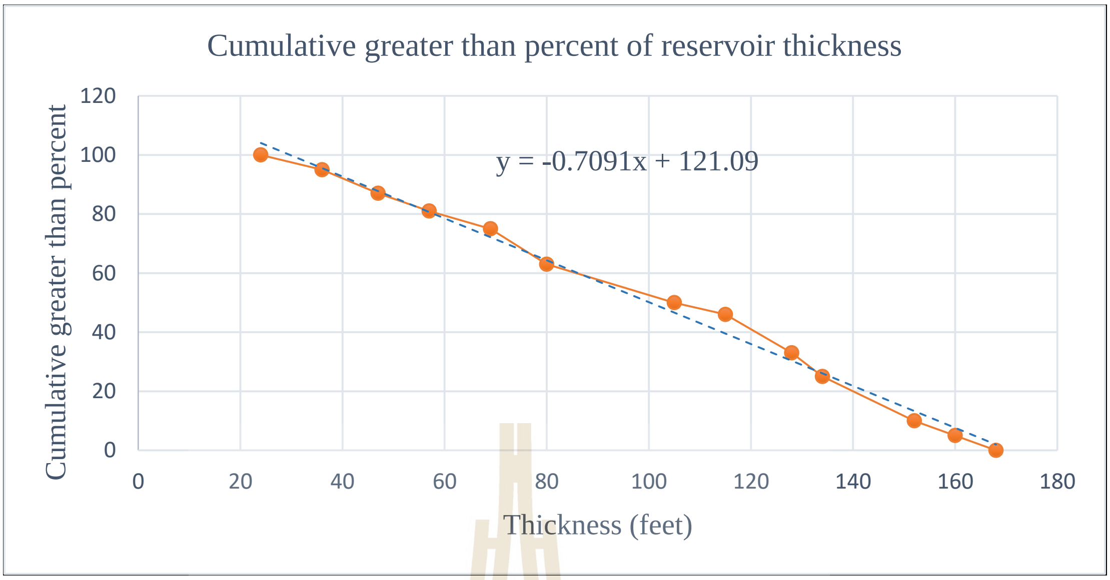

Figure 5.2 Cumulative greater than percent of reservoir thickness for the Khorat sand play

The effective porosity can be taken from the data distribution which is the lognormal distribution type (Table 5.6 and Figure 5.3).

Table 5.6 Size distributions of porosity in percent for the Khorat sand play

Porosity Class (Percent)	Frequency	Cumulative Greater Than Percent
2.5	66	100
5.5	24	62
5.9	14	43
7	6	22
9	2	7
10	3	3
11	2	1
12.5	1	0

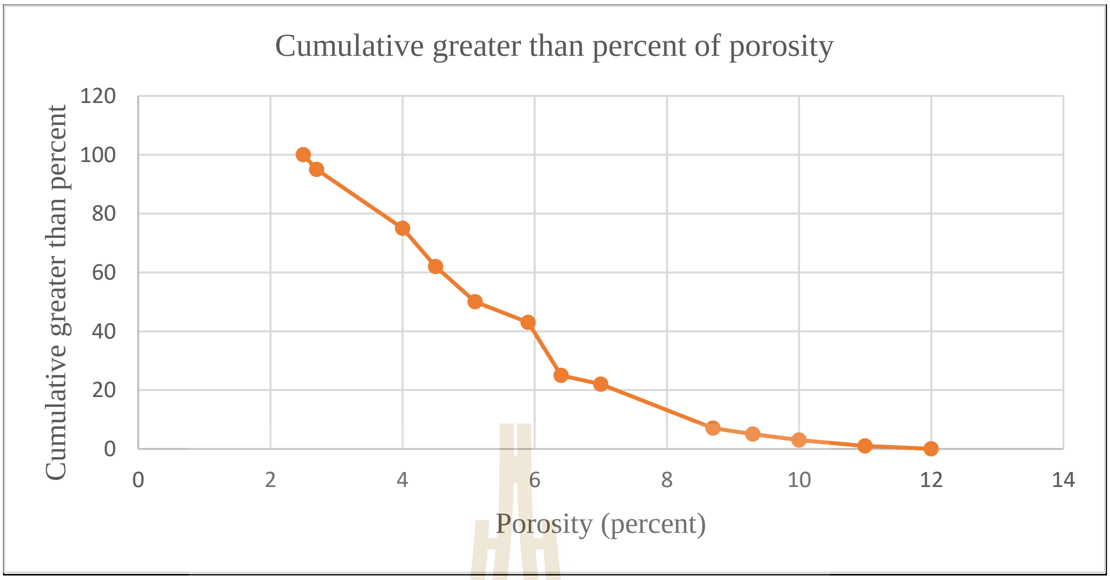

Figure 5.3 Cumulative greater than percent of porosity for the Khorat sand play

The percent of trap fill can be considered from the possible range for trapped hydrocarbon volume as a percentage of the porous volume under the closure. The probability that this minimum value is incorporated into the determination of the hydrocarbon accumulation prospect attribute. As discussed earlier a minimum trap fill of 30 percent has been used in this study.

The hydrocarbon saturation can be taken from the data distribution which is the lognormal distribution type (Table 5.7 and Figure 5.4).

Table 5.7 Size distributions of hydrocarbon saturation in percent for the Khorat sand play

Hydrocarbon Saturation Class (Percent)	Frequency	Cumulative Greater Than Percent
45	3	100
46	2	97
47	4	95
50	2	90
56	5	81
60	5	75
64	2	67
75	2	50
79	6	42
90	3	25
95	4	13
97	10	10
100	11	5

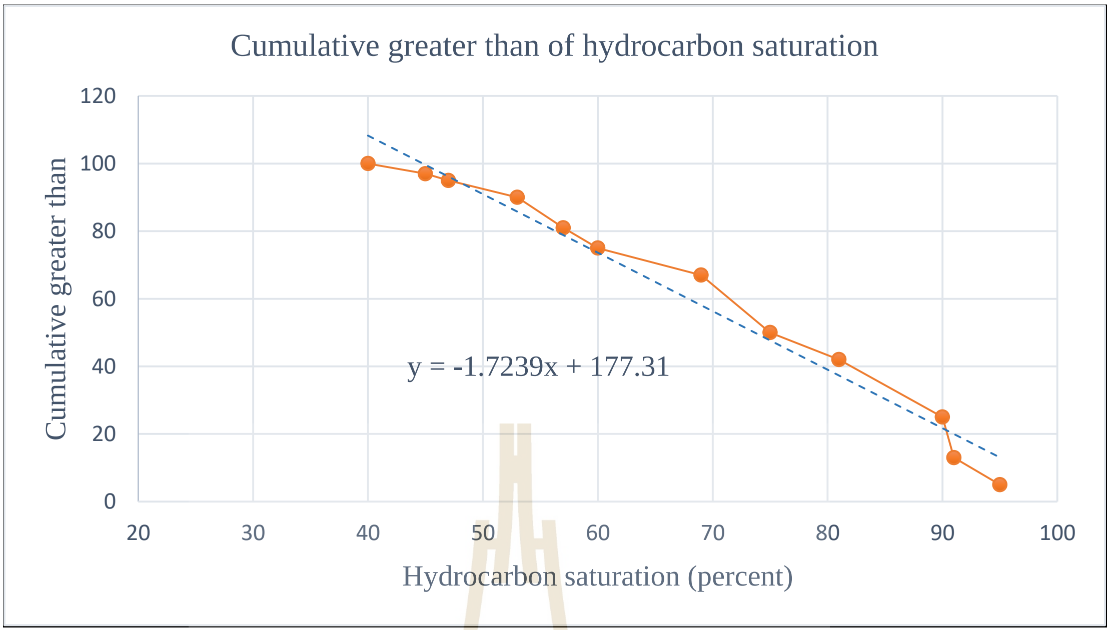

Figure 5.4 Cumulative greater than percent of hydrocarbon saturation for the Khorat sand play

Petroleum reservoir engineering parameter

This section is studied about the reservoir engineering parameters of the Khorat sand prospect, including; original reservoir pressure, reservoir temperature, gas-oil ratio, oil formation volume factor, gas compressibility factor, oil floor depth, and oil and gas recovery factor. Methodology still used the probability theory as in the hydrocarbon approaching.

Original reservoir pressure, Pe

Base on the pressure profile of Chonnabot well, the relationship between the reservoir pressure and depth of reservoir is a linear function (Figure 5.5) (Glumglomjit, 2010).

$$Pe = (0.7166 \text{ x Depth}) + 14.720 \quad (5.2)$$

Where Pe = original reservoir pressure (psi)

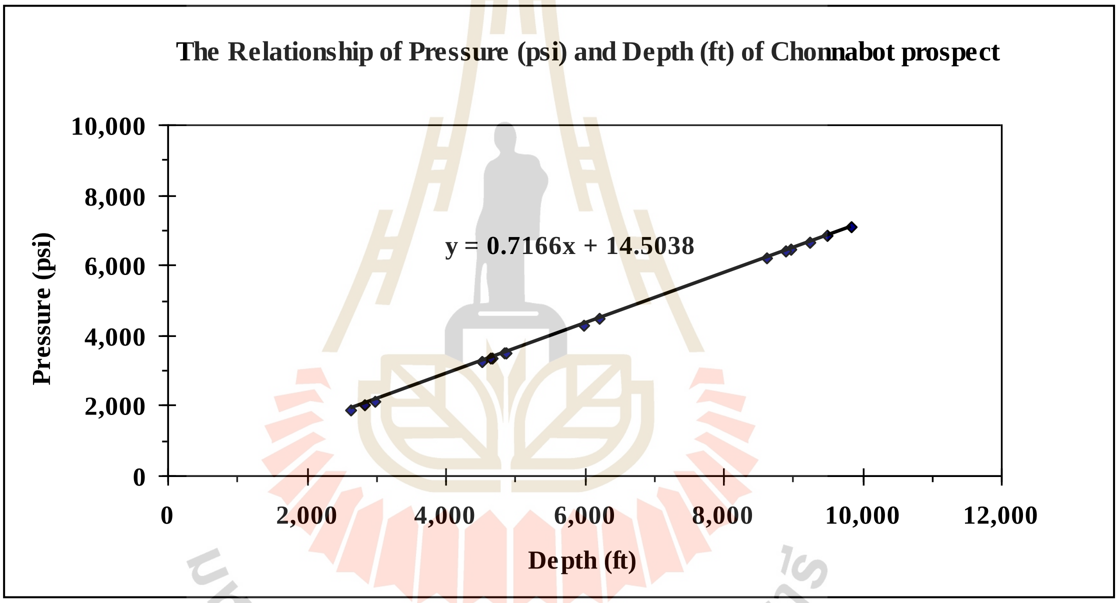

Figure 5.5 Relationship between pressure (psi) and depth (ft) of the Chonnabot prospect (Glumglomjit, 2010)

Reservoir temperature, T

Base on the temperature profile of Chonnabot well, the relationship between the reservoir temperature and depth depicts 1 zone of linear function (Glumglomjit, 2010).

$$T = (0.0267 \text{ x Depth}) + 538.00 \quad (5.3)$$

where : T = reservoir temperature (degree Rankine)

Gas-oil ratio, Rs

Due to there is no any well test data in this area, therefore, this assessment adopted the Rs from the Department of Mineral Fuels (DMF) in the northeastern of Thailand. The study indicated that the relationship between gas-oil ratio and depth of reservoir is a linear function.

$$R_s = (0.00 \text{ x Depth}) + 1.00000 \quad (5.4)$$

where : Rs = gas-oil ratio (Mcf/bbl)

Oil formation volume factor, Bo

As the gas-oil ratio, there is no any well test data in this area, therefore, this assessment adopted Bo from Department of Mineral Fuels (DMF) in the northeastern of Thailand. The study indicated that the relationship between oil formation volume factor and depth of reservoir is a linear function.

$$B_o = (0.00 \text{ x Depth}) + 1.00 \quad (5.5)$$

where : Bo = oil formation volume factor (no unit)

Gas compressibility factor, Z

Gas compressibility factor analysis from Nam Phong–1 well to Nam Phong–4 well that plot with depth of reservoir, it can generated a linear function (Figure 5.6) (Glumglomjit, 2010).

$$Z = (0.00001 \times \text{Depth}) + 1.02384 \qquad (5.6)$$

where : Z = gas compressibility factor (no unit)

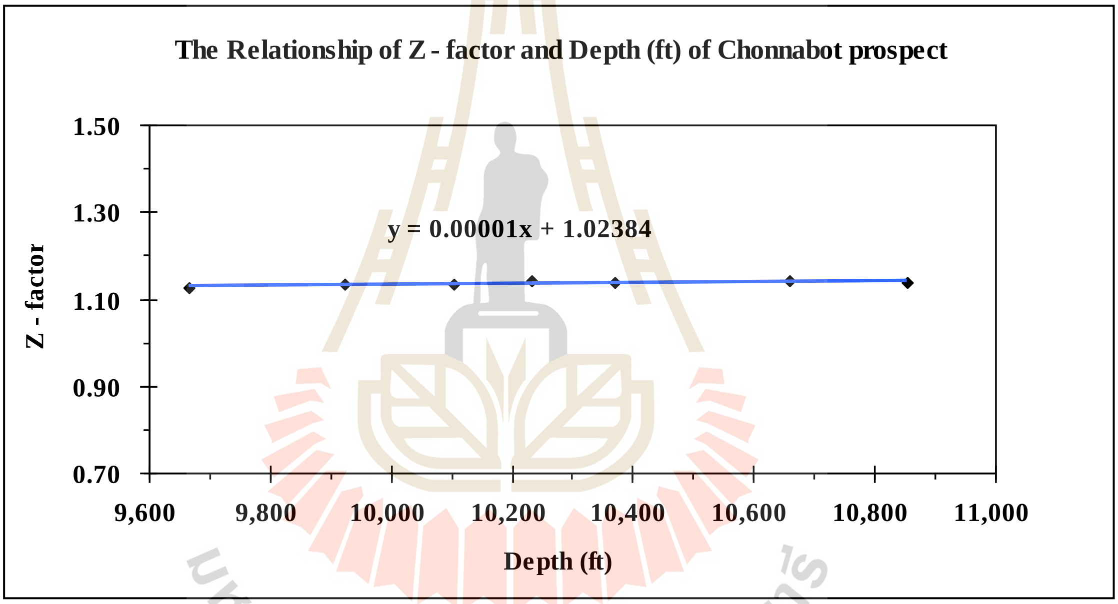

Figure 5.6 Relationship between Z-factor and depth (ft) of the Chonnabot prospect (Glumglomjit, 2010)

Oil floor depth

Oil floor depth is given to be 10,250 feet which is considered from temperature gradient of the Chonnabot well. In assumption of oil will crack and yield gas at above 120 degree Celsius (708 degree Rankine) (Glumglomjit, 2010).

Gas recovery factor

Recovery factor is determined to be 90 percent for gas and 5 percent for oil by production history in the northeastern of Thailand is mainly natural gas from Nam Phong and Sinphuhorm gas fields.

The evaluation of petroleum resources in the Khorat sand gas field by FASPU as shown in Figure 5.7 and Figure 5.8 and Table 5.8.

From the study of the properties of natural gas and reservoir engineering it found that the gas is “Non-Associated gas” non-rerated with oil, Therefore, the potential of natural gas in the Korat sand gas field just considered is free gas.

At high fractile of 95, will be found the gas in place 163.90 Bcf (Billion cubic feet).

Medium fractile of 50, will be found the gas in place 149.26 Bcf

Low fractile of 5, will be found the gas in place 244.41 Bcf

```
FASP:UE  90.7       08/02/18     13:14:13                                   KORAT      Run # 6
==============================================================================================
PLAY : KHORAT SAND GROUP                                          PROJECT : KHORAT SAND
==============================================================================================
                                          INPUT SUMMARY
----------------------------------------------------------------------------------------------
              Play Attribute Probabilities              |          Prospect Attribute Probabilities
--------------------------------------------------------|-------------------------------------
 Hydrocarbon        Timing       Migration    Potential  |  Trapping     Effective    Hydrocarbon
   Source                                     Res. Facies |  Mechanism    Porosity    Accumulation
 -----------    -----------    -----------   -----------|  -----------  -----------  -----------
    0.700          1.000          1.000         0.700       0.800         0.900         0.800

Marginal Play      Conditional Deposit     Reservoir      Hydrocarbon Prob.     Recovery Factors %
 Probability           Probability         Lithology        Gas       Oil         Oil      Free Gas
-------------     -------------------     ---------      -------   -------     --------  --------
    0.490               0.576                 SAND         1.000     0.000        0.00     100.00

  Geologic Variables          F100      F95      F75      F50      F25      F05      F0
--------------------------  -------  -------  -------  -------  -------  -------  -------
Closure (thousand acres)    6.02000  6.41000  7.95000  9.87000  11.7900  13.3300  13.7100
        Thickness (feet)    30.0000  38.0000  65.0000  99.0000  133.000  160.000  167.000
      Porosity (percent)    2.50000  2.70000  4.00000  5.10000  6.40000  9.30000  12.0000
     Trap Fill (percent)    50.0000  55.0000  60.0000  65.0000  70.0000  80.0000  90.0000
   Depth (thousand feet)    2.50000  2.70000  3.30000  4.40000  5.40000  6.20000  7.20000
 HC Saturation (percent)    45.0000  47.0000  60.0000  75.0000  90.0000  97.0000  100.000
     Number of Prospects       2        3        3        4        4        5        6

                          GEOLOGIC VARIABLES and PROBABILITIES OF OCCURRENCE
----------------------------------------------------------------------------------------------
                   Mean     Std. Dev.      "Dry Hole" Risk = 0.7178
                 -------    ---------      Prob. ( Depth <= 10250 feet )  =  1.0000
       Closure   9.86975    2.21883
     Thickness   98.9750    39.2326                         ------------- RESOURCE -------------
      Porosity   5.47750    2.06777                            Oil      NA Gas    AD Gas      Gas
     Trap Fill   65.8750    8.06646                          ------    ------    ------    ------
         Depth   4.41250    1.18975    Cond. Prob. Prospect has 0.0000    0.5760    0.0000    0.5760
 HC Saturation   74.1250    16.4616    Cond. Play Prob.         0.0000    0.9415    0.0000    0.9415
     Prospects   3.50000    0.67082    Uncond. Play Prob.       0.0000    0.4613    0.0000    0.4613
 Accumulations   2.01600    1.00204

Variable     Function        A          B       D(feet)      A         B       D(feet)      A         B
--------     --------    ---------  ---------  ---------  --------- --------- ---------  --------- ---------
Pe           Linear      0.7166000  14.720000
  (PSI)
T            Linear      0.0267000  538.00000
  (Deg Rankine)
Rs           Linear          0.000  1.0000000
  (Thousand CuFt/BBL)
Bo           Linear          0.000  1.0000000
  (no units)
Z            Linear      0.0000100  1.0238400
  (no units)

Depth Floor (feet) =  10250.00
```

Figure 5.7 The result of potential the Khorat sand gas field by FASPU

KHORAT SAND GROUP — ESTIMATED RESOURCES

	Mean	Std. Dev.	F95	F75	F50	F25	F05
OIL (Millions of BBLs)							
Number of Accumulations	0.0	0.0	0	0	0	0	0
Accumulation Size	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. Prospect Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. (B) Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. (A) Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NON-ASSOCIATED GAS (Billions of CuFt)							
Number of Accumulations	2.01600	1.00204	0	1	2	3	4
Accumulation Size	194.990	163.900	44.8405	91.1598	149.264	244.405	496.869
Cond. Prospect Potential	112.314	157.349	0.0	0.0	65.9310	168.656	404.397
Cond. (B) Play Potential	417.534	296.428	119.028	221.269	340.459	523.851	973.817
Cond. (A) Play Potential	393.101	303.863	0.0	200.349	324.006	508.440	956.576
Uncond. Play Potential	192.619	289.585	0.0	0.0	0.0	318.329	750.586
ASSOCIATED-DISSOLVED GAS (Billions of CuFt)							
Number of Accumulations	0.0	0.0	0	0	0	0	0
Accumulation Size	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. Prospect Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. (B) Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cond. (A) Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond Play Potential	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GAS (Billions of CuFt)							
Number of Accumulations	2.01600	1.00204	0	1	2	3	4
Accumulation Size	194.990	163.900	44.8405	91.1598	149.264	244.405	496.869
Cond. Prospect Potential	112.314	157.349	0.0	0.0	65.9310	168.656	404.397
Cond. (B) Play Potential	417.534	296.428	119.028	221.269	340.459	523.851	973.817
Cond. (A) Play Potential	393.101	303.863	0.0	200.349	324.006	508.440	956.576
Uncond. Play Potential	192.619	289.585	0.0	0.0	0.0	318.329	750.586
YIELD FACTORS							
OIL (Thousand BBL / Acre-Ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NON-ASSOCIATED GAS (Million CuFt / Acre-Ft)	0.30301	0.18755	0.10096	0.17547	0.25765	0.37832	0.65750
DISSOLVED GAS (Million CuFt / Acre-Ft)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 5.8 The result of potential the Khorat sand gas field by FASPU (Cont.)

Table 5.8 Petroleum resources in prospect

Level of Confidence	No. of Accumulation	Accumulation Size (Bcf)
High (fractile of 95th)	2	65.43
Medium (fractile of 50th)	4	149.08
Low (fractile of 5th)	6	339.68

5.2.2 Evaluate the potential by MSP program

The program development for evaluate the potential of petroleum resourced call MPS (Monte Carlo Simulation, Swanson's Mean and Probability of Success). Consists of a processing 3 methods, (1) Monte Carlo Simulation method, (2) Swanson's Mean method, (3) Swanson's Mean with Probability of Success method.

The evaluation the potential of petroleum resources processing by Monte Carlo Simulation method to separate the probability into 3 levels.

1. High probability of 90 (P90)
2. Moderate probability of 50 (P50)
3. Low probability of 10 (P10)

The evaluation the potential of petroleum resources processing by Swanson's Mean method to separate the probability into 1 level.

1. Moderate probability of 50 (P50)

The evaluation the potential of petroleum resources processing by Swanson's Mean with Probability of Success method to separate the probability into 1 level.

1. Moderate probability of 50 (P50)

The potential petroleum resources was calculated by Swanson's Mean method using the relationship of 0.30 (P10) + 0.40 (P50) +0.30 (P90).

Table 5.9 Choice of range and distribution of the Khorat sand gas field

Geologic and petroleum engineering variables	Distribution type	Range of variable	
		Low (X_L)	High (X_H)
1. Reservoir area (Acre)	Uniform	1,000	2,600
2. Porosity	Uniform	0.15	0.18
3. Reservoir thickness (ft.)	Uniform	180	200
4. Hydrocarbon saturation	Uniform	0.45	0.75
5. Gas formation volume factor (cu ft/SCF)	Uniform	0.0032	0.0034
6. Recovery factor	Uniform	0.75	0.80

The result evaluation of petroleum resources in the Khorat sand gas field by MSP as shown in Table 5.10.

Table 5.10 The result evaluated of petroleum resources in the Khorat sand gas field by MSP

Level of Probability	**Accumulation Size (Bcf)**		
	Monte Carlo Simulation	**Swanson's Mean**	**Swanson's Mean with Probability of Success**
Probability at 90^{th}	96.91	193.30	-
Probability at 50^{th}	150.13	150.31	158.58
Probability at 10^{th}	202.77	107.42	-

From the study of the properties of natural gas and reservoir engineering it found that the gas is "Non-Associated gas" non-rerated with oil, Therefore, the potential of natural gas in the Korat sand gas field just considered is free gas.

Case 1, processing by Monte Carlo Simulation method (Figure 5.9)

At high probability of 90, will be found the gas in place 96.91 Bcf (billion cubic feet)

Medium probability of 50, will be found the gas in place 150.13 Bcf

Low probability of 10, will be found the gas in place 202.77 Bcf

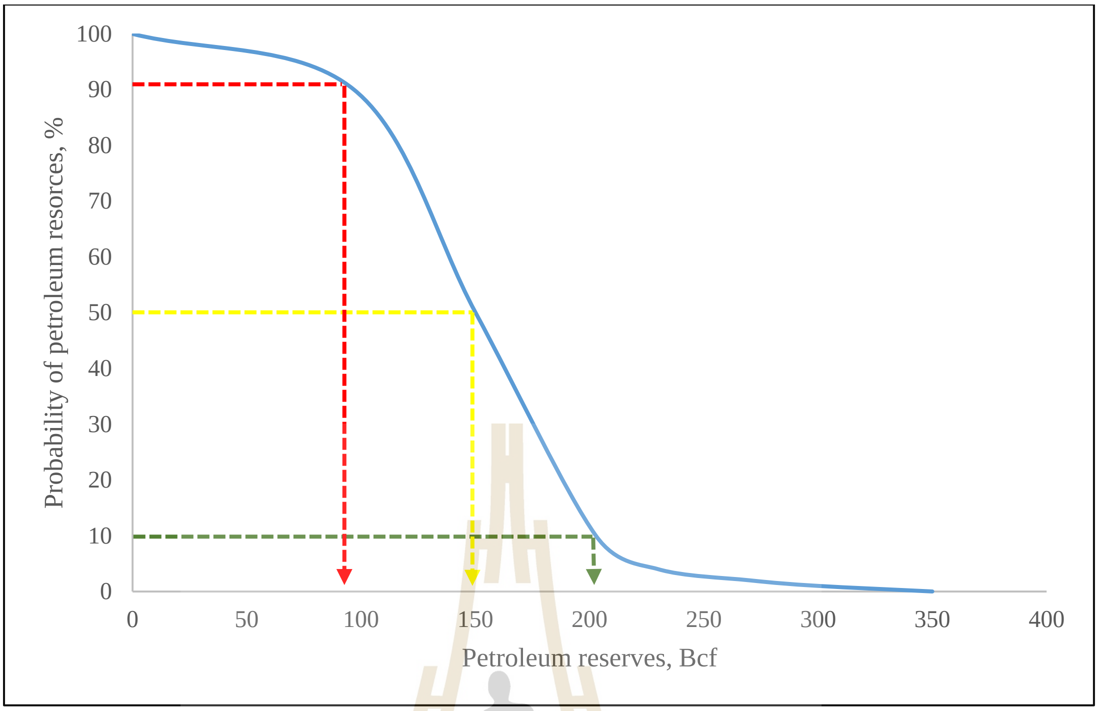

Figure 5.9 The evaluation potential result of the Korat sand gas field by MSP (Case 1)

Case 2, processing by Swanson's Mean method, probability of 50 percent will be found the gas in place 150.31 Bcf (billion cubic feet) (Figure 5.10)

Case 3, processing by Swanson's Mean with Probability of Success method, probability of 50 percent will be found the gas in place 158.58 Bcf (billion cubic feet)

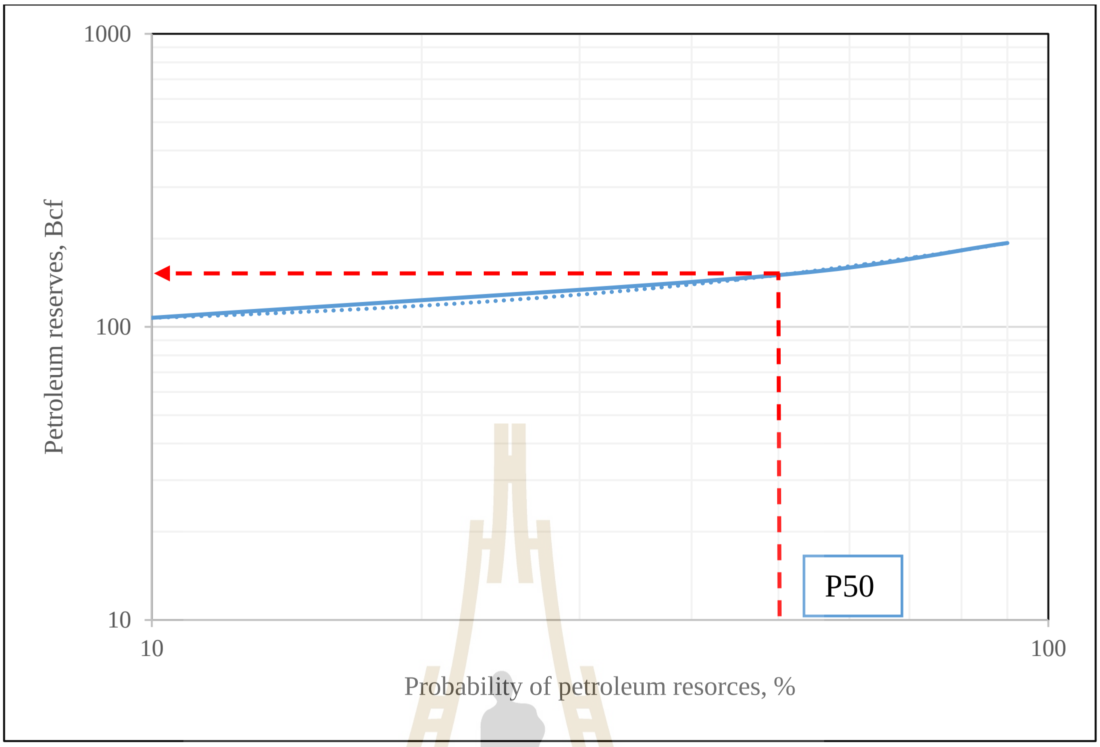

Figure 5.10 The evaluation potential result of the Korat sand gas field by MSP (Case 2)

5.3 The comparison of potential assessment results between the use of MSP and FASPU programs

In the comparison of potential assessment results between the use of MSP program, which was developed, and FASPU that is used as the main program in which the details are shown in Table 5.3 to Table 5.11, it was found that the potential assessment results are satisfactory by comparing the probability of discovery at 95%, 50% and 5% for the FASPU program and the processing of all three subprograms of MSP programs, including (1) Monte Carlo Simulation is the probability of discovery at 90%, 50% and 10% (2) Swanson's Mean is the probability of discovery at 90%, 50% and 10% (3) Swanson's Mean Processing with Probability of Success is the probability of discovery at 50%.

Table 5.11 The comparison of resources' assessment results between the use of MSP and FASPU programs

Programs	Petroleum resources (BCF)		
	P95* (P90)**	**P50**	**P5* (P10**)**
FASPU Program	163.90	149.264	244.41
MSP Program			
- Monte Carlo Simulation	96.91	150.13	202.77
- Swanson's Mean	107.42	150.31	193.30
- Swanson's Mean with Probability of Success	-	158.58	-

As for the reservoir of Khorat sand, the comparison of potential assessment results between the use of MSP and FASPU programs, as shown in detail in Table 5.11, found that the probability of discovery at 95% of FASPU program was 163.90 Bcf (billion cubic feet), and at 90% of MSP program with Monte Carlo Simulation was 96.91 Bcf. The difference was approximately 66.99 Bcf.

The probability of discovery at 50% of FASPU program was 149.26 Bcf, and at 50% of MSP program with Monte Carlo Simulation was 150.13 Bcf. The difference was approximately -0.87 Bcf.

The probability of discovery at 50% of FASPU program was 149.26 Bcf, and at 50% of MSP program with Swanson's Mean was 150.31 Bcf. The difference was approximately -1.05 Bcf.

The probability of discovery at 50% of FASPU program was 149.26 Bcf, and at 50% of MSP program with Swanson's Mean Processing with Probability of Success was 158.58 Bcf. The difference was approximately -9.32 Bcf.

The probability of discovery at 5% of FASPU program was 244.41 Bcf, and at 10% of MSP program with Monte Carlo Simulation was 202.77 Bcf. The difference was approximately 41.64 Bcf.

The probability of discovery at 5% of FASPU program was 244.41 Bcf, and at 10% of MSP program with Swanson's Mean was 193.30 Bcf. The difference was approximately 51.11 Bcf.

5.4 Computer Simulation results

After obtaining the petroleum reserve data from the assessment, use the data obtained to create a computer simulation to simulate the gas production in the Khorat sandstone and take time for production simulation for 20 years with the use of Eclipse program and the results are as follows:

The natural gas production before Hydraulic fracturing (HF) at the production rate of 11,000,000 cubic feet per day cannot achieve the target set since the day of beginning production. However, it can produce less volume in which on the last day of production (20 years) is produced at 5,200,000 cubic feet per day. When it has been producing for a period of 20 years, the total output will be at 55 billion cubic feet. (Figure 5.11 and Figure 5.12).

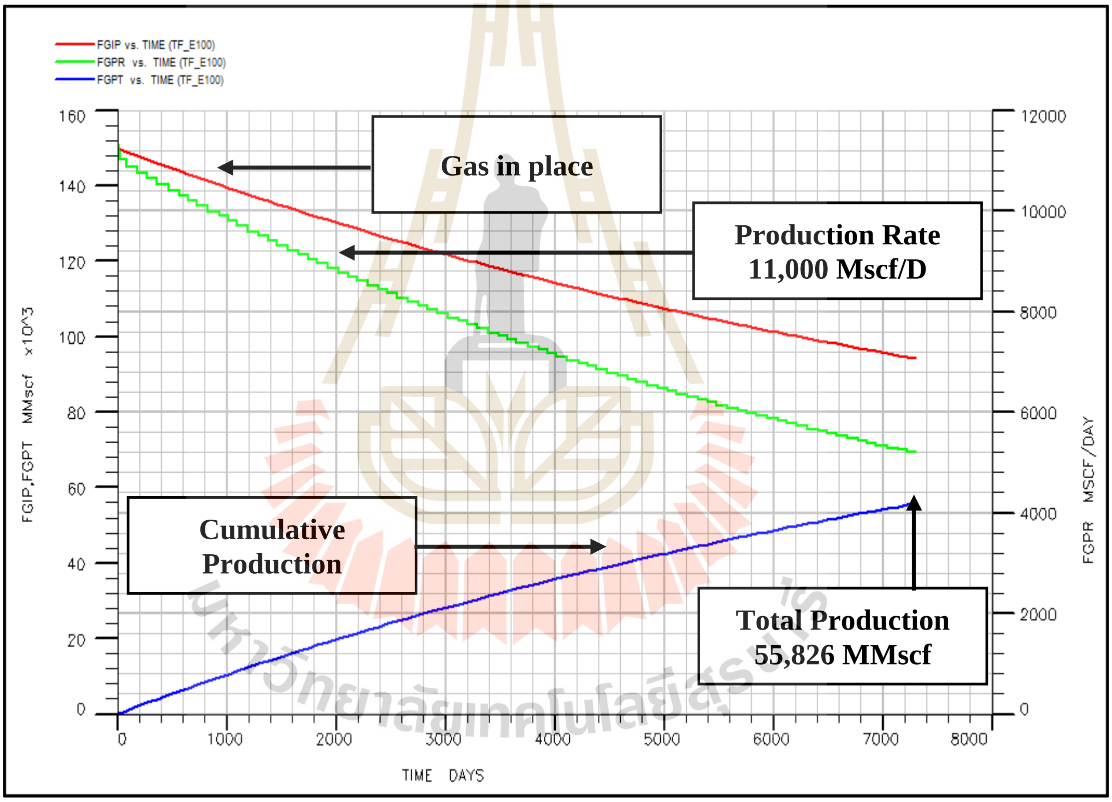

Figure 5.11 This graph shows the relationship between gas availability, production rate, Cumulative production and time before Hydraulic Fracturing

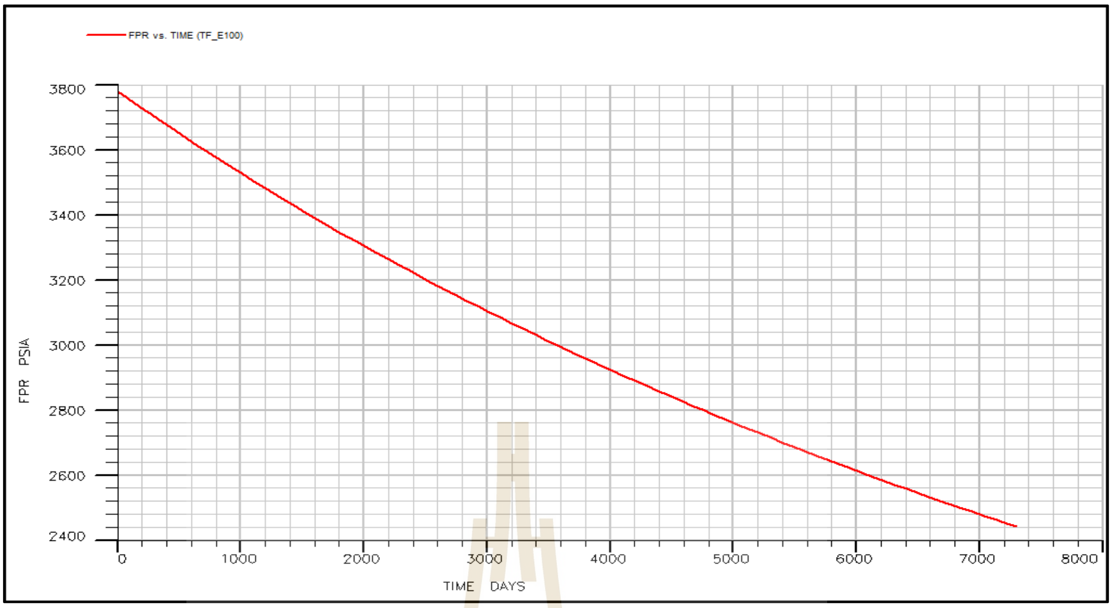

Figure 5.12 The graph showing the relationship between pressure and time indicates the reduction in pressure when starting production until the last day of production (before Hydraulic Fracturing)

After using 1,500 barrels of liquid compression in Hydraulic fracturing, the natural gas production on the first day, with the production rate of 25,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 390 days or about 1 year in which the production rate is gradually decreasing as shown in Figure 5.13. On the last day of production in a period of 20 years with the production rate of 5,500,000 cubic feet per day and the total production rate of 93,142,800 cubic feet (Figure 5.13 and5.14).

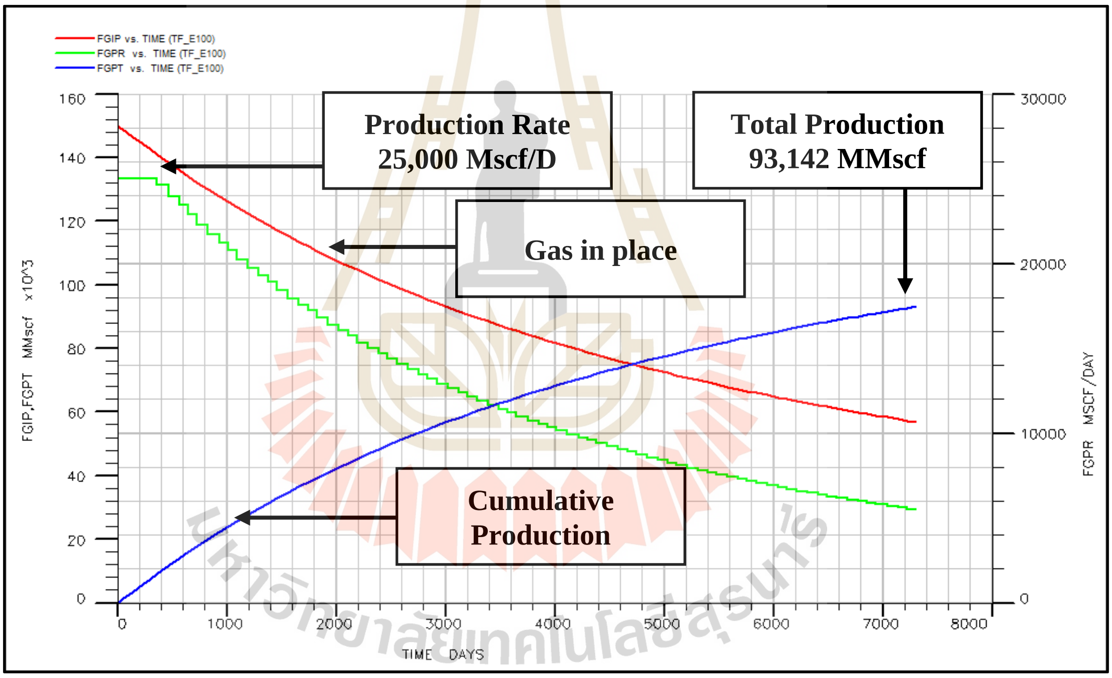

Figure 5.13 This graph shows the relationship between gas availability, production rate, sum of production and time after Hydraulic Fracturing with 1,500 barrels of water injection

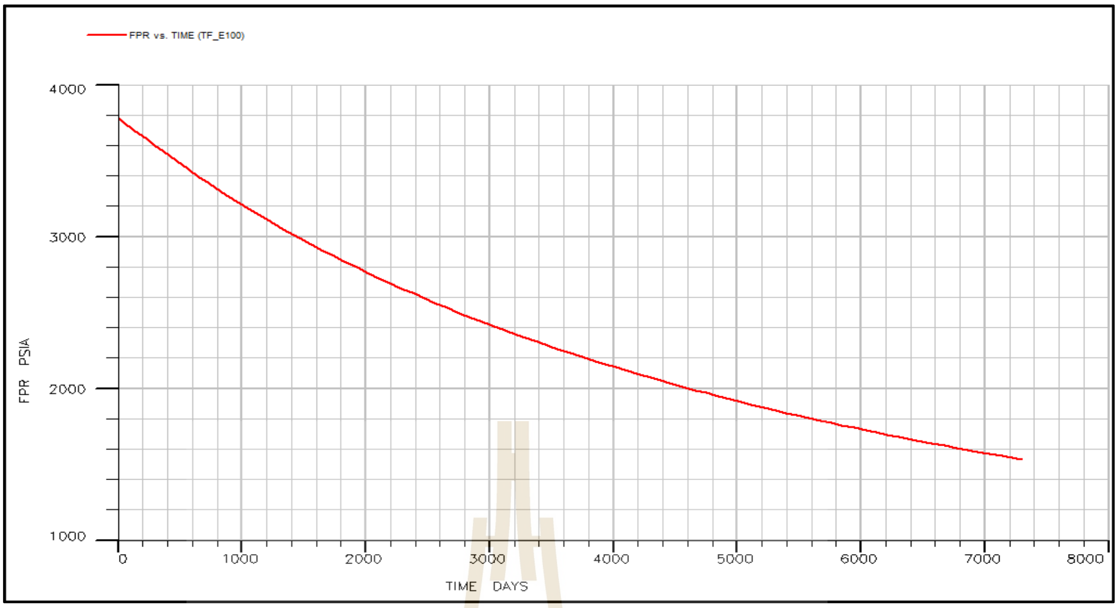

Figure 5.14 The graph showing the relationship between pressure and time indicates the reduction in pressure when starting production until the last day of production (after Hydraulic Fracturing with 1,500 barrels of water injection)

At 5,000 barrels of liquid compression is used in Hydraulic fracturing, the natural gas production on the first day, with the production rate of 30,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 1,200 days or about 3.2 years in which the production rate is gradually decreasing as shown in Figure 5.9. On the last day of production in a period of 20 years with the production rate of 4,687,751 cubic feet per day and the total production rate of 111,429,300 cubic feet (Figure 5.15 and5.16).

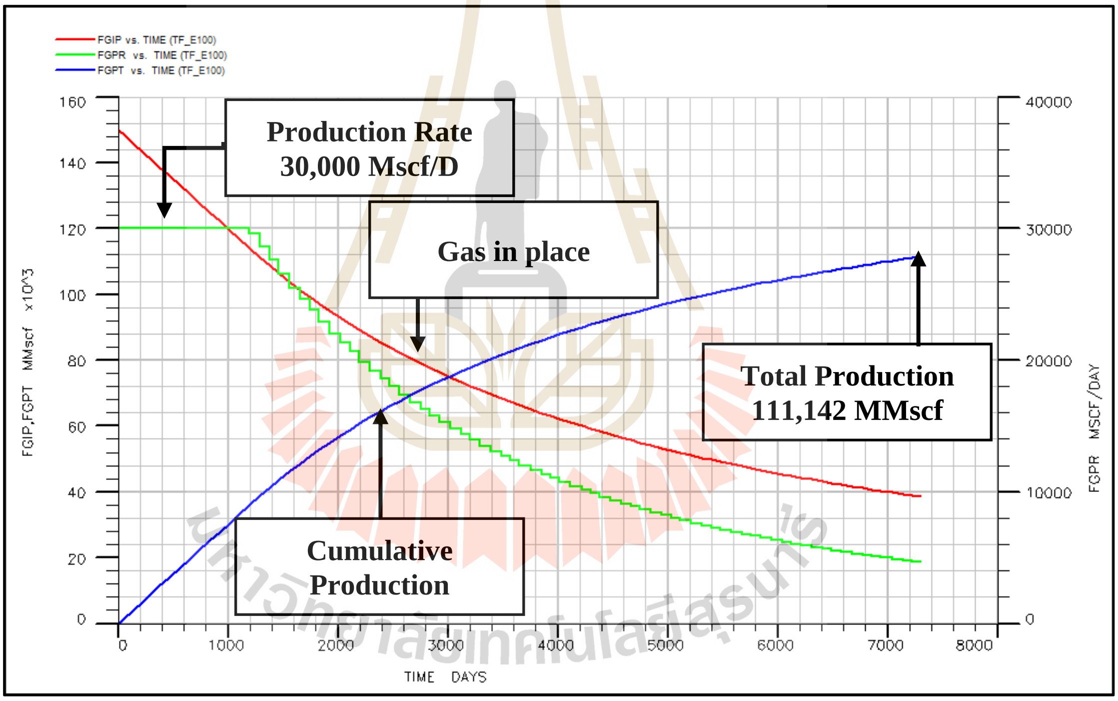

Figure 5.15 This graph shows the relationship between gas availability, production rate, sum of production and time after Hydraulic Fracturing with 5,000 barrels of water injection

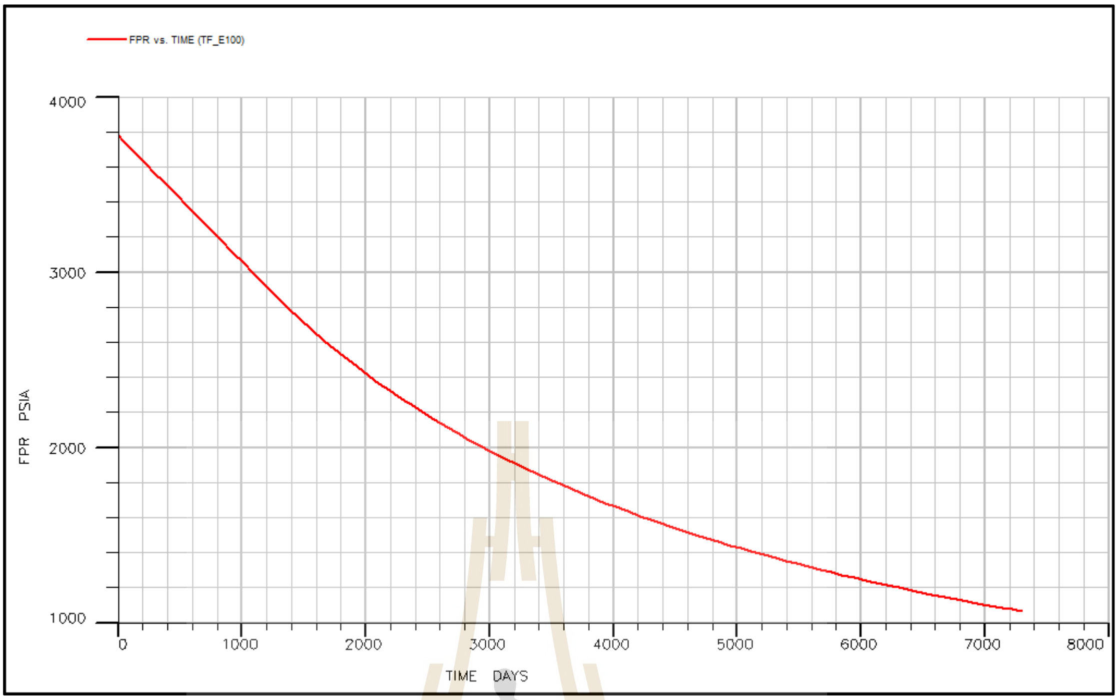

Figure 5.16 The graph showing the relationship between pressure and time indicates the reduction in pressure when starting production until the last day of production (after Hydraulic Fracturing with 5,000 barrels of water injection)

After obtaining the results of production simulation, the numerical results will be applied to economic analysis in the next chapter.

CHAPTER VI

PETROLEUM ECONOMICS ANALYSIS

6.1 Objectives

This study aimed to investigate on and calculate payback period, current earnings, earning per share, and payback rate in order to analyze and forecast the investment alternatives. The study methodologies are as follows:

1. Analysis of Cash flow
2. Analysis of current earnings and payback rates
3. Payback period
4. Net income
5. Comparison of payback rates for selection and opportunity

6.2 Petroleum exploration and development plan

The exploration and development plan for natural gas sources were determined under Petroleum Act Thailand III in which the exploration period is 6 years and can last for another 3 years. The production period is 20 years and can last for another 10 years. However, the exploration and production plan of this study had divided the exploration period into 4 years, and 20 years for the production, totaling 24 years. The details of the exploration and production plan are as follows:

The 1st year; - Request for concession for petroleum exploration in the area.

- 2D-seismic survey

The 2nd year; - 3D-seismic survey

- Drilled 1 exploration well

The 3rd year; - Drilled 1 appraisal well

- Phase 1of Gas pipeline installation

The 4th year; - Drilled 1 development well

- Phase 2 of Gas pipeline installation

- Installation of production equipment

The 5th year; - Started production of natural gas

6.3 Principles of 50 sampling selection of natural gas volume and price

1. Using the gas volume at the probability of 95%, 90%, 85%, 80%, 75%, 70%, 65%, 60%, 55%, 50%, 45%, 40%, 35%, 30%, 25%, 20%, 15%, 10%, and 5% from MSP program to form a new graph with the relationship of the probability and gas volume.

2. Randomly selecting 50 samples of natural gas volume from the graph and designing the production plan by determining a fixed production rate in the first five years in which the total production capacity was 50% of total natural gas volume. Then, the next year's production rate will reduce by 90% of the previous year's production rate.

3. Once the production plans of 50 samples are completed, then randomly select the natural gas price ranging from 3USD-9USD per million BTU to be used in the economic analysis.

4. Analyze 50 samples in terms of Net present value (NPV), discounted internal rate of return (DIRR), and discounted profit to investment ratio (DPIR).

5. Ranking 50 NPV samples in ascending order, and calculating the probability by using the formula of 1-(sequence/50), respectively.

6. Drawing a graph with the relationship between the accumulated probability and NPV.

6.4 Hypothesis in economics studies before Hydraulic Fracturing

The Petroleum economics studies include the hypotheses for analyzing cash flow as follows:

6.4.1 Basis assumptions

1. 150 billion cubic feet of natural gas reserved
2. Number of well
    - Number of exploration well: 1 well
    - Number of appraisal well: 1 well
    - Number of development well: 1 well
3. Initial natural gas production rate is 10% of annual natural gas reserved for 5 years
4. Giving that the heat value of natural gas is approximately 1,000 BTU per cubic foot
5. Interest rate for loans (Discount rate) used in analyzing net present value is 10%
6. Royalty is calculated based on sliding scale, starting at 5%

7. For the Royalty calculation, giving that 10 million BTU of natural gas is equal to 1 barrel of crude oil

8. Petroleum income tax is 50%

6.4.2 Cost assumption

The costs of conducting this study are as follows:

1. The cost of basic investment
   - Asking for the concession of Petroleum exploration: USD0.85 million
   - 2D-seismic survey: USD3.4 million
   - 3D-seismic survey: USD1.7 million
   - The cost of drilling and developing exploration well: USD8.57 million/well
   - The cost of drilling and developing appraisal well: USD4.3 million/well
   - The cost of drilling and developing development well: USD1.43 million/well
   - The cost of installation of gas pipeline and gas production and separation equipment: USD2.86 million
2. The operation costs: USD17 million per billion cubic foot, and escalating at 2% per year
3. Natural gas price: USD6 per million BTU

6.4.3 Other assumptions

1. Natural gas price is fixed throughout the trading contract period
2. The cost of equipment increases at 2% per year in line with inflation
3. The natural gas production will begin in the 5th year of the project

6.4.4 Results of Cash flow analysis

Apply these hypotheses to analyze cash flow at different natural gas volume reserved and prices (as shown in the appendix), and the results are as follows:

An example of cash flow is calculated at natural gas volume of 150 billion cubic feet, and at the natural gas price of USD6 per million BTU.

1. Natural gas production rates shown in Table 6.1
2. Economic impacts of Petroleum industry
   - Gross revenue of gas sales: USD392.42 million
   - Total investment: USD64.72 million, which includes:
     1) Cost of asking for concession and geophysics: USD6 million
     2) Cost of drilling exploration well, development well, production equipment, and gas separation equipment: USD60.57 million
     3) Operation cost: USD336.50 million
   - State revenue
     1) Royalty: USD28.4 million
     2) Income tax: 50% of USD461 million profit

Table 6.1 Natural gas production rates before hydraulic fracturing

Year	Natural gas production rates		
	Mscf/day	**Mscf/month**	**Mscf/year**
1	10,894.31	337,723.74	3,987,319.08
2	10,360.28	321,168.78	3,791,863.6
3	99,45.19	308,300.92	3,639,939.91
4	95,48.54	296,004.99	3,494,768.68
5	91,71.17	284,306.35	3,356,649.26
6	88,13.18	273,208.52	3,225,623.2
7	84,71.85	262,627.42	3,100,698.03
8	81,48.04	252,589.40	2,982,184.57
9	78,40.42	243,053.04	2,869,594.00
10	75,45.30	233,904.43	2,761,581.33
11	72,65.65	225,235.15	2,659,228.00
12	70,01.07	217,033.25	2,562,392.58
13	67,46.37	209,137.50	2,469,171.82
14	6,503.10	201,596.08	2,380,134.41
15	6,273.29	194,472.04	2,296,024.78
16	6,054.45	187,688.09	2,215,930.46
17	5,843.44	181,146.83	2,138,701.34
18	5,641.53	174,887.61	2,064,802.13
19	5,450.58	168,968.22	1,994,915.12
20	5,269.01	163,339.41	1,928,458.87
Total			55,919,981.35

3. With 50% income tax deduction, the net profit will be USD-57.6 million. If it is calculated according to the net present value in the beginning year of the project at the interest rate of 10% (NPV@10%), it will be about USD-18.8 million.
4. The Internal Rate of Return is 15.62%, and the discounted cash flow Internal Rate of Return is 5.11%.
5. Profit to Investment Ratio is 0.30.

Table 6.2 Economic calculation before hydraulic fracturing

No.	Year	Gas Production								Exchange Rate (Baht/$)	Gas Price ($/1,000 SCF)	Gas Production PER year(SCF)	Income (Baht)	Royalty sliding scale (Baht)	2% Escal Factor
		Schedule	Gas in place (SCF)	Cumulative Gas production (SCF)	(SCF/month)	BOE (Barrel/month)	ROYALTY	Royalty(%)	(SCF/day)						
0							CHECK								
1	2011														1.0000
2	2012														1.0200
3	2013														1.0404
4	2014														1.0612
5	2015														1.0824
6	2016														1.1041
7	2017														1.1262
8	2018	0.0400	150,000,000,000	3,695,242,000	307,936,833	51,323	5.000	5.00	10,129,501	35.00	6.00	3,695,242,000	776,000,820	38,800,041	1.1487
9	2019	0.1200	150,000,000,000	7,750,027,000	337,898,750	56,316	5.000	5.00	11,115,090	35.00	6.00	4,054,785,000	1,627,505,670	81,375,284	1.1717
10	2020	0.2100	150,000,000,000	11,383,140,000	302,759,417	50,460	5.000	5.00	9,959,191	35.00	6.00	3,633,113,000	2,390,459,400	119,522,970	1.1951
11	2021	0.3000	150,000,000,000	14,871,330,000	290,682,500	48,447	5.000	5.00	9,561,924	35.00	6.00	3,488,190,000	732,519,900	36,625,995	1.2190
12	2022	0.3900	150,000,000,000	18,230,720,000	279,949,167	46,658	5.000	5.00	9,208,854	35.00	6.00	3,359,390,000	705,471,900	35,273,595	1.2434
13	2023	0.4800	150,000,000,000	21,450,220,000	268,291,667	44,715	5.000	5.00	8,825,384	35.00	6.00	3,219,500,000	676,095,000	33,804,750	1.2682
14	2024	0.5419	150,000,000,000	24,545,000,000	257,898,333	42,983	5.000	5.00	8,483,498	35.00	6.00	3,094,780,000	649,903,800	32,495,190	1.2936
15	2025	0.5926	150,000,000,000	27,521,450,000	248,037,500	41,340	5.000	5.00	8,159,128	35.00	6.00	2,976,450,000	625,054,500	31,252,725	1.3195
16	2026	0.6342	150,000,000,000	30,393,000,000	239,295,833	39,883	5.000	5.00	7,871,573	35.00	6.00	2,871,550,000	603,025,500	30,151,275	1.3459
17	2027	0.6683	150,000,000,000	33,149,540,000	229,711,667	38,285	5.000	5.00	7,556,305	35.00	6.00	2,756,540,000	578,873,400	28,943,670	1.3728
18	2028	0.6963	150,000,000,000	35,803,590,000	221,170,833	36,862	5.000	5.00	7,275,356	35.00	6.00	2,654,050,000	557,350,500	27,867,525	1.4002
19	2029	0.7192	150,000,000,000	38,360,970,000	213,115,000	35,519	5.000	5.00	7,010,362	35.00	6.00	2,557,380,000	537,049,800	26,852,490	1.4282
20	2030	0.7380	150,000,000,000	40,832,000,000	205,919,167	34,320	5.000	5.00	6,773,657	35.00	6.00	2,471,030,000	518,916,300	25,945,815	1.4568
21	2031	0.7534	150,000,000,000	43,207,460,000	197,955,000	32,993	5.000	5.00	6,511,678	35.00	6.00	2,375,460,000	498,846,600	24,942,330	1.4859
22	2032	0.7661	150,000,000,000	45,498,920,000	190,955,000	31,826	5.000	5.00	6,281,414	35.00	6.00	2,291,460,000	481,206,600	24,060,330	1.5157
23	2033	0.7764	150,000,000,000	47,710,450,000	184,294,167	30,716	5.000	5.00	6,062,308	35.00	6.00	2,211,530,000	464,421,300	23,221,065	1.5460
24	2034	0.7849	150,000,000,000	49,850,700,000	178,354,167	29,726	5.000	5.00	5,866,913	35.00	6.00	2,140,250,000	449,452,500	22,472,625	1.5769
25	2035	0.7919	150,000,000,000	51,911,370,000	171,722,500	28,620	5.000	5.00	5,648,766	35.00	6.00	2,060,670,000	432,740,700	21,637,035	1.6084
26	2036	0.7976	150,000,000,000	53,902,260,000	165,907,500	27,651	5.000	5.00	5,457,484	35.00	6.00	1,990,890,000	418,086,900	20,904,345	1.6406
27	2037	0.8023	150,000,000,000	55,826,810,000	160,379,167	26,730	5.000	5.00	5,275,630	35.00	6.00	1,924,550,000	404,155,500	20,207,775	1.6734
28	2038	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
29	2039	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
					4,652,234,167							55,826,810,000	14,127,136,590	706,356,830	
					55,826,810,000										

Table 6.2 Economic calculation before hydraulic fracturing (Cont.)

Investment cost									Depreciation (20%) Tangible Expense (Baht)								
Concession (Baht)	Geological and geophysical surveys (Baht)	Exploration and apprisal wells (Baht)	No. of production wells	Production wells (Baht/Well)	Intangible		Tangible	Pipelines and processing production facilities (Baht)	2018	2019	2020	2021	2022				
					Fraction	(Baht)											
30,000,000																	
	120,000,000																
		300,000,000															
	60,000,000	150,000,000	1	50,000,000	0.80	40,000,000	10,000,000	100,000,000									
			1	50,000,000	0.80	40,000,000	10,000,000	0	22,000,000	120,000,000							
			1	50,000,000	0.80	40,000,000	10,000,000	0		22,000,000	120,000,000	120,000,000					
			0	0	0.80	0	0	0			22,000,000	120,000,000	120,000,000				
			0	0	0.80	0	0	0				22,000,000	120,000,000	120,000,000			
			0	0	0.80	0	0	0					22,000,000	120,000,000	120,000,000		
			0	0	0.80	0	0	0							120,000,000	120,000,000	
			0	0	0.80	0	0	0									120,000,000
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.00	0	0	0									
			0	0	0.00	0	0	0									
30,000,000	180,000,000	450,000,000	3			120,000,000	30,000,000	0									

Table 6.2 Economic calculation before hydraulic fracturing (Cont.)

Depreciation (20%) Tangible Expense (Baht)	Fixed Operation	Operation cost		A(Baht/metre)	SRB RATE(%)	Available for	SRB(Baht)	Total allow expense (Baht)	Taxable income (Baht)	Taxable income (Baht) AFTER SRB	Cumulative taxable income (Baht)	Income tax (Baht)
	Operation cost(Baht)	(Baht/ MMSCF)	(Baht)									
						-30000000		30,000,000	-30,000,000	-30,000,000	-30,000,000	0
						-120000000		120,000,000	-120,000,000	-120,000,000	-150,000,000	0
0						-300000000		300,000,000	-300,000,000	-300,000,000	-450,000,000	0
						0		0	0	0	-450,000,000	0
						0		0	0	0	-450,000,000	0
						0		0	0	0	-450,000,000	0
0						-250000000		250,000,000	-250,000,000	-250,000,000	-700,000,000	0
142,000,000	600,000,000	1,500	606,367,007	1,617	0	-93766228.29		827,167,048	-51,166,228	-51,166,228	-501,166,228	0
262,000,000	600,000,000	1,500	607,126,240	3,191	75	558404146.2		990,501,524	637,004,146	637,004,146	187,004,146	318,502,073
262,000,000	600,000,000	1,500	606,512,860	4,346	75	1323823570	992,867,678	988,035,830	1,402,423,570	409,555,893	-290,444,107	701,211,785
262,000,000	600,000,000	1,500	606,378,126	1,332	0	-251084221.2	0	905,004,121	-172,484,221	-172,484,221	-462,928,329	0
262,000,000	600,000,000	1,500	606,265,469	1,283	0	-276667163.8	0	903,539,064	-198,067,164	-198,067,164	-660,995,492	0
240,000,000	600,000,000	1,500	606,124,657	1,229	0	-275834406.7	0	879,929,407	-203,834,407	-203,834,407	-864,829,899	0
120,000,000	600,000,000	1,500	606,005,142	1,182	0	-144596531.9	0	758,500,332	-108,596,532	-108,596,532	-973,426,431	0
0	600,000,000	1,500	605,891,044	1,136	0	-12089268.85	0	637,143,769	-12,089,269	-12,089,269	-985,515,700	0
0	600,000,000	1,500	605,797,092	1,096	0	-32922867.34	0	635,948,367	-32,922,867	-32,922,867	-1,018,438,567	0
0	600,000,000	1,500	605,676,208	1,052	0	-55746478.06	0	634,619,878	-55,746,478	-55,746,478	-1,074,185,045	0
0	600,000,000	1,500	605,574,466	1,013	0	-76091491.11	0	633,441,991	-76,091,491	-76,091,491	-1,150,276,536	0
0	600,000,000	1,500	605,478,853	976	0	-95281542.58	0	632,331,343	-95,281,543	-95,281,543	-1,245,558,079	0
0	600,000,000	1,500	605,399,736	943	0	-112429251.2	0	631,345,551	-112,429,251	-112,429,251	-1,357,987,330	0
0	600,000,000	1,500	605,294,713	907	0	-131390442.9	0	630,237,043	-131,390,443	-131,390,443	-1,489,377,773	0
0	600,000,000	1,500	605,209,633	875	0	-148063363.2	0	629,269,963	-148,063,363	-148,063,363	-1,637,441,136	0
0	600,000,000	1,500	605,128,471	844	0	-163928235.6	0	628,349,536	-163,928,236	-163,928,236	-1,801,369,372	0
0	600,000,000	1,500	605,062,438	817	0	-178082563	0	627,535,063	-178,082,563	-178,082,563	-1,979,451,935	0
0	600,000,000	1,500	604,971,688	787	0	-193868022.6	0	626,608,723	-193,868,023	-193,868,023	-2,173,319,957	0
0	600,000,000	1,500	604,899,399	760	0	-207716844.1	0	625,803,744	-207,716,844	-207,716,844	-2,381,036,802	0
0	600,000,000	1,500	604,830,865	735	0	-220883140.2	0	625,038,640	-220,883,140	-220,883,140	-2,601,919,942	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
1,550,000,000	12,000,000,000		12,113,994,107				992,867,678	15,150,350,936	-1,023,214,346	-2,016,082,024		1,019,713,858

Table 6.2 Economic calculation before hydraulic fracturing (Cont.)

Income tax (Baht)after SRB	Annual cash flow (Baht)	Cumulative annual cash flow (Baht)	COPANY CASH FLOW(Baht)	Cumulative Company Cash(baht)	SRB(Baht) No special Reduction	Discounted Factor, % 10.00	Discounted cash flow (Baht)	Cumulative discounted cash flow (Baht)
						1		
0	-30,000,000	-30,000,000	-30,000,000	-30,000,000		0.90909091	-27,272,727	-27,272,727
0	-120,000,000	-150,000,000	-120,000,000	-150,000,000		0.82644628	-99,173,554	-126,446,281
0	-300,000,000	-450,000,000	-300,000,000	-450,000,000		0.7513148	-225,394,440	-351,840,721
0	0	-450,000,000	0	-450,000,000		0.68301346	0	-351,840,721
0	0	-450,000,000	0	-450,000,000		0.62092132	0	-351,840,721
0	0	-450,000,000	0	-450,000,000		0.56447393	0	-351,840,721
0	-250,000,000	-700,000,000	-150,000,000	-600,000,000		0.51315812	-76,973,718	-428,814,439
-25,583,114	-25,583,114	-725,583,114	116,416,886	-483,583,114	0	0.46650738	54,309,336	-297,531,385
318,502,073	318,502,073	-407,081,041	580,502,073	96,918,959	477,753,110	0.42409762	246,189,547	-105,651,175
204,777,946	204,777,946	-202,303,095	466,777,946	563,696,905	1,051,817,678	0.38554329	179,963,105	-248,851,334
-86,242,111	-86,242,111	-288,545,205	175,757,889	739,454,795	0	0.3504939	61,602,068	-187,249,266
-99,033,582	-99,033,582	-387,578,787	162,966,418	902,421,213	0	0.31863082	51,926,123	-135,323,143
-101,917,203	-101,917,203	-489,495,991	138,082,797	1,040,504,009	0	0.28966438	39,997,668	-95,325,475
-54,298,266	-54,298,266	-543,794,257	65,701,734	1,106,205,743	0	0.26333125	17,301,320	-78,024,155
-6,044,634	-6,044,634	-549,838,891	-6,044,634	1,100,161,109	0	0.23939205	-1,447,037	-79,471,193
-16,461,434	-16,461,434	-566,300,325	-16,461,434	1,083,699,675	0	0.21762914	-3,582,488	-83,053,680
-27,873,239	-27,873,239	-594,173,564	-27,873,239	1,055,826,436	0	0.19784467	-5,514,572	-88,568,252
-38,045,746	-38,045,746	-632,219,309	-38,045,746	1,017,780,691	0	0.17985879	-6,842,862	-95,411,114
-47,640,771	-47,640,771	-679,860,081	-47,640,771	970,139,919	0	0.16350799	-7,789,647	-103,200,761
-56,214,626	-56,214,626	-736,074,706	-56,214,626	913,925,294	0	0.14864363	-8,355,946	-111,556,707
-65,695,221	-65,695,221	-801,769,928	-65,695,221	848,230,072	0	0.13513057	-8,877,433	-120,434,139
-74,031,682	-74,031,682	-875,801,609	-74,031,682	774,198,391	0	0.12284597	-9,094,494	-129,528,633
-81,964,118	-81,964,118	-957,765,727	-81,964,118	692,234,273	0	0.11167816	-9,153,602	-138,682,235
-89,041,281	-89,041,281	-1,046,807,008	-89,041,281	603,192,992	0	0.1015256	-9,039,969	-147,722,204
-96,934,011	-96,934,011	-1,143,741,020	-96,934,011	506,258,980	0	0.092296	-8,946,621	-156,668,826
-103,858,422	-103,858,422	-1,247,599,442	-103,858,422	402,400,558	0	0.08390545	-8,714,288	-165,383,114
-110,441,570	-110,441,570	-1,358,041,012	-110,441,570	291,958,988	0	0.07627768	-8,424,227	-173,807,341
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
-658,041,012	-1,358,041,012		0.15625		1,529,570,787		126,691,542	

6.5 Hypothesis in economics studies after Hydraulic Fracturing at the water compression of 1,500 barrels

The Petroleum economics studies include the hypotheses for analyzing cash flow as follows:

6.5.1 Basis assumptions

1. 150 billion cubic feet of natural gas reserved
2. Number of well
   - Number of exploration well: 1 well
   - Number of appraisal well: 1 well
   - Number of development well: 1 well
3. Initial natural gas production rate is 10% of annual natural gas reserved for 5 years.
4. Giving that the heat value of natural gas is approximately 1,000 BTU per cubic foot.
5. Interest rate for loans (Discount rate) used in analyzing net present value is 10%.
6. Royalty is calculated based on sliding scale, starting at 5%
7. For the Royalty calculation, giving that 10 million BTU of natural gas is equal to 1 barrel of crude oil.
8. Petroleum income tax is 50%

6.5.2 Cost assumption

The costs of conducting this study are as follows:

1. The cost of basic investment

- Asking for the concession of Petroleum exploration: USD0.85 million
- 2D-seismic survey: USD3.4 million
- 3D-seismic survey: USD1.7 million
- The cost of drilling and developing exploration well: USD8.57 million/well
- The cost of drilling and developing appraisal well: USD4.3 million/well
- The cost of drilling and developing development well: USD1.43 million/well
- The cost of Hydraulic Fracturing: USD2.14 million
- The cost of installation of gas pipeline and gas production and separation equipment: USD2.86 million

2. The operation costs: USD17 million per billion cubic foot, and escalating at 2% per year
3. Natural gas price: USD6 per million BTU

6.5.3 Other assumptions

1. Natural gas price is fixed throughout the trading contract period.
2. The cost of equipment increases at 2% per year in line with inflation.
3. The natural gas production will begin in the 5th year of the project.

6.5.4 Results of Cash flow analysis

Apply these hypotheses to analyze cash flow at different natural gas volume reserved and prices (as shown in the appendix), and the results are as follows:

An example of cash flow is calculated at natural gas volume of 150 billion cubic feet, and at the natural gas price of USD6 per million BTU.

1. Natural gas production rates shown in Table 6.3
2. Economic impacts of Petroleum industry
   - Gross revenue of gas sales: USD 700.71 million
   - Total investment: USD66.53 million, which includes:
     1) Cost of asking for concession and geophysics: USD6 million
     2) Cost of drilling exploration well and development well, cost of production equipment, cost of Hydraulic Fracturing, and cost of gas separation equipment: USD 62.43 million
     3) Operation cost: USD 348.14 million
   - State revenue
     1) Royalty: USD 87.91 million
     2) Income tax: 50% of USD 547.06 million profit
3. With 50% income tax deduction, the net profit will be USD 173.67 million. If it is calculated according to the net present value in the beginning year of the project at the interest rate of 10% (NPV@10%), it will be about USD 97.11 million.

Table 6.3 Natural gas production rate after hydraulic fracturing (injection fluid 1,500 barrels and 300 minute)

Year	Natural gas production rates		
	Mscf/day	Mscf/month	Mscf/year
1	25,000	775,000	9,150,000
2	23,724.29	735,453.05	8,683,090.96
3	21,499.34	666,479.81	7,868,761.64
4	19,530.67	605,450.88	7,148,226.59
5	17,780.91	551,208.44	6,507,815.80
6	16,227.01	503,037.58	5,939,088.95
7	14,849.99	460,349.94	5,435,099.36
8	13,615.35	422,076.13	4,983,221.48
9	12,517.35	388,037.94	4,581,351.19
10	11,526.49	357,321.43	4,218,698.26
11	10,644.90	329,991.96	3,896,034.13
12	9,844.23	305,171.38	3,602,991.18
13	9,127.45	282,951.05	3,340,647.93
14	8,476.00	262,756.03	3,102,216.35
15	7,885.32	244,444.96	2,886,027.59
16	7,352.88	227,939.51	2,691,156.77
17	6,866.04	212,847.51	2,512,973.87
18	6,419.25	198,996.91	2,349,447.38
19	6,014.80	186,458.82	2,201,417.08
20	5,645.59	175,013.40	2,066,287.25
Total			93,164,553.84

4. The Internal Rate of Return is 36.66%, and the discounted cash flow Internal Rate of Return is 24.23%.
5. Profit to Investment Ratio is 3.28.

Table 6.4 Economic calculation after hydraulic fracturing 1, 500 bbl

No.	Year	Gas Production								Exchange Rate (Baht/$)	Gas Price ($/1,000 SCF)	Gas Production PER year(SCF)	Income (Baht)	Royalty sliding scale (Baht)	2% Escal Factor
		Schedule	Gas in place (SCF)	Cumulative Gas production (SCF)	(SCF/month)	BOE (Barrel/month)	ROYALTY	Royalty(%)	(SCF/day)						
0							CHECK								
1	2011														1.0000
2	2012														1.0200
3	2013														1.0404
4	2014														1.0612
5	2015														1.0824
6	2016														1.1041
7	2017														1.1262
8	2018	0.0400	150,000,000,000	9,150,000,000	762,500,000	127,083	6.250	6.25	25,082,237	35.00	6.00	9,150,000,000	1,921,500,000	120,093,750	1.1487
9	2019	0.1200	150,000,000,000	17,829,210,000	723,267,500	120,545	6.250	6.25	23,791,694	35.00	6.00	8,679,210,000	3,744,134,100	234,008,381	1.1717
10	2020	0.2100	150,000,000,000	25,693,990,000	655,398,333	109,233	6.250	6.25	21,559,156	35.00	6.00	7,864,780,000	5,395,737,900	337,233,619	1.1951
11	2021	0.3000	150,000,000,000	32,838,070,000	595,340,000	99,223	6.250	6.25	19,583,553	35.00	6.00	7,144,080,000	1,500,256,800	93,766,050	1.2190
12	2022	0.3900	150,000,000,000	39,359,180,000	543,425,833	90,571	6.250	6.25	17,875,850	35.00	6.00	6,521,110,000	1,369,433,100	85,589,569	1.2434
13	2023	0.4800	150,000,000,000	45,294,290,000	494,592,500	82,432	6.250	6.25	16,269,490	35.00	6.00	5,935,110,000	1,246,373,100	77,898,319	1.2682
14	2024	0.5419	150,000,000,000	50,725,380,000	452,590,833	75,432	6.250	6.25	14,887,856	35.00	6.00	5,431,090,000	1,140,528,900	71,283,056	1.2936
15	2025	0.5926	150,000,000,000	55,704,660,000	414,940,000	69,157	6.250	6.25	13,649,342	35.00	6.00	4,979,280,000	1,045,648,800	65,353,050	1.3195
16	2026	0.6342	150,000,000,000	60,294,530,000	382,489,167	63,748	6.250	6.25	12,581,880	35.00	6.00	4,589,870,000	963,872,700	60,242,044	1.3459
17	2027	0.6683	150,000,000,000	64,509,450,000	351,243,333	58,541	5.000	5.00	11,554,057	35.00	6.00	4,214,920,000	885,133,200	44,256,660	1.3728
18	2028	0.6963	150,000,000,000	68,401,850,000	324,366,667	54,061	5.000	5.00	10,669,956	35.00	6.00	3,892,400,000	817,404,000	40,870,200	1.4002
19	2029	0.7192	150,000,000,000	72,001,300,000	299,954,167	49,992	5.000	5.00	9,866,913	35.00	6.00	3,599,450,000	755,884,500	37,794,225	1.4282
20	2030	0.7380	150,000,000,000	75,347,470,000	278,847,500	46,475	5.000	5.00	9,172,615	35.00	6.00	3,346,170,000	702,695,700	35,134,785	1.4568
21	2031	0.7534	150,000,000,000	78,446,420,000	258,245,833	43,041	5.000	5.00	8,494,929	35.00	6.00	3,098,950,000	650,779,500	32,538,975	1.4859
22	2032	0.7661	150,000,000,000	81,329,220,000	240,233,333	40,039	5.000	5.00	7,902,412	35.00	6.00	2,882,800,000	605,388,000	30,269,400	1.5157
23	2033	0.7764	150,000,000,000	84,017,250,000	224,002,500	37,334	5.000	5.00	7,368,503	35.00	6.00	2,688,030,000	564,486,300	28,224,315	1.5460
24	2034	0.7849	150,000,000,000	86,534,030,000	209,731,667	34,955	5.000	5.00	6,899,068	35.00	6.00	2,516,780,000	528,523,800	26,426,190	1.5769
25	2035	0.7919	150,000,000,000	88,880,600,000	195,547,500	32,591	5.000	5.00	6,432,484	35.00	6.00	2,346,570,000	492,779,700	24,638,985	1.6084
26	2036	0.7976	150,000,000,000	91,079,220,000	183,218,333	30,536	5.000	5.00	6,026,919	35.00	6.00	2,198,620,000	461,710,200	23,085,510	1.6406
27	2037	0.8023	150,000,000,000	93,142,800,000	171,965,000	28,661	5.000	5.00	5,656,743	35.00	6.00	2,063,580,000	433,351,800	21,667,590	1.6734
28	2038	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
29	2039	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
					7,761,900,000							93,142,800,000	25,225,622,100	1,490,374,673	
					93,142,800,000										

Table 6.4 Economic calculation after hydraulic fracturing 1,500 bbl (Cont.)

Investment cost									Depreciation (20%) Tangible Expense (Baht)								
Concession (Baht)	Geological and geophysical surveys (Baht)	Exploration and apprisal wells (Baht)	No. of production wells	Production wells (Baht/Well)	Intangible Fraction	Intangible (Baht)	Tangible	Pipelines and processing production facilities (Baht)	2018	2019	2020	2021	2022				
30,000,000																	
	120,000,000																
		300,000,000															
	60,000,000	150,000,000	1	75,000,000	0.80	60,000,000	15,000,000	100,000,000									
			1	75,000,000	0.80	60,000,000	15,000,000	0	23,000,000	120,000,000							
			1	75,000,000	0.80	60,000,000	15,000,000	0		23,000,000	120,000,000	120,000,000					
			0	0	0.80	0	0	0			23,000,000	120,000,000	120,000,000				
			0	0	0.80	0	0	0				23,000,000	120,000,000	120,000,000			
			0	0	0.80	0	0	0					23,000,000	120,000,000	120,000,000		
			0	0	0.80	0	0	0							120,000,000	120,000,000	
			0	0	0.80	0	0	0									120,000,000
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.00	0	0	0									
			0	0	0.00	0	0	0									
30,000,000	180,000,000	450,000,000	3			180,000,000	45,000,000	0									

Table 6.4 Economic calculation after hydraulic fracturing 1,500 bbl (Cont.)

Depreciation (20%) Tangible Expense (Baht)	Fixed Operation	Operation cost		A(Baht/metre)	SRB RATE(%)	Available for	SRB(Baht)	Total allow expense (Baht)	Taxable income (Baht)	Taxable income (Baht) AFTER SRB	Cumulative taxable income (Baht)
	Operation cost(Baht)	(Baht/ MMSCF)	(Baht)								
						-30000000		30,000,000	-30,000,000	-30,000,000	-30,000,000
						-120000000		120,000,000	-120,000,000	-120,000,000	-150,000,000
0						-300000000		300,000,000	-300,000,000	-300,000,000	-450,000,000
						0		0	0	0	-450,000,000
						0		0	0	0	-450,000,000
						0		0	0	0	-450,000,000
0						-270000000		270,000,000	-270,000,000	-270,000,000	-720,000,000
143,000,000	600,000,000	1,500	615,765,711	4,003	0	939740539.2		938,859,461	982,640,539	982,640,539	532,640,539
263,000,000	600,000,000	1,500	615,253,617	7,341	75	2492972102		1,172,261,998	2,571,872,102	2,571,872,102	2,121,872,102
263,000,000	600,000,000	1,500	614,098,710	9,810	75	4102505571	3,076,879,178	1,214,332,329	4,181,405,571	1,104,526,393	384,526,393
263,000,000	600,000,000	1,500	613,062,890	2,728	0	451527859.5	0	969,828,940	530,427,860	530,427,860	914,954,252
263,000,000	600,000,000	1,500	612,162,271	2,490	0	329781260.3	0	960,751,840	408,681,260	408,681,260	1,323,635,513
240,000,000	600,000,000	1,500	611,290,732	2,266	0	245184049.4	0	929,189,051	317,184,049	317,184,049	1,640,819,562
120,000,000	600,000,000	1,500	610,538,541	2,074	0	302707302.7	0	801,821,597	338,707,303	338,707,303	1,979,526,865
0	600,000,000	1,500	609,855,081	1,901	0	370440668.7	0	675,208,131	370,440,669	370,440,669	2,349,967,533
0	600,000,000	1,500	609,266,041	1,752	0	294364615.2	0	669,508,085	294,364,615	294,364,615	2,644,332,149
0	600,000,000	1,500	608,679,273	1,609	0	232197267.1	0	652,935,933	232,197,267	232,197,267	2,876,529,416
0	600,000,000	1,500	608,175,450	1,486	0	168358350.4	0	649,045,650	168,358,350	168,358,350	3,044,887,766
0	600,000,000	1,500	607,711,351	1,374	0	110378923.6	0	645,505,576	110,378,924	110,378,924	3,155,266,690
0	600,000,000	1,500	607,312,107	1,278	0	60248808.24	0	642,446,892	60,248,808	60,248,808	3,215,515,498
0	600,000,000	1,500	606,907,315	1,183	0	11333209.98	0	639,446,290	11,333,210	11,333,210	3,226,848,708
0	600,000,000	1,500	606,554,044	1,101	0	-31435444.4	0	636,823,444	-31,435,444	-31,435,444	3,195,413,263
0	600,000,000	1,500	606,233,460	1,026	0	-69971474.6	0	634,457,775	-69,971,475	-69,971,475	3,125,441,789
0	600,000,000	1,500	605,953,063	961	0	-103855452.8	0	632,379,253	-103,855,453	-103,855,453	3,021,586,336
0	600,000,000	1,500	605,661,466	896	0	-137520750.9	0	630,300,451	-137,520,751	-137,520,751	2,884,065,585
0	600,000,000	1,500	605,410,604	839	0	-166785913.7	0	628,496,114	-166,785,914	-166,785,914	2,717,279,671
0	600,000,000	1,500	605,179,848	788	0	-193495638.2	0	626,847,438	-193,495,638	-193,495,638	2,523,784,033
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
1,555,000,000	12,000,000,000		12,185,071,575				3,076,879,178	16,070,446,247	9,155,175,853	6,078,296,674	

Table 6.4 Economic calculation after hydraulic fracturing 1,500 bbl (Cont.)

Income tax (Baht)	Income tax (Baht)after SRB	Annual cash flow (Baht)	Cumulative annual cash flow (Baht)	COPANY CASH FLOW(Baht)	Cumulative Company Cash(baht)	SRB(Baht) No special Reduction	Discounted Factor, % 10.00	Discounted cash flow (Baht)	Cumulative discounted cash flow (Baht)
							1		
0	0	-30,000,000	-30,000,000	-30,000,000	-30,000,000		0.90909091	-27,272,727	-27,272,727
0	0	-120,000,000	-150,000,000	-120,000,000	-150,000,000		0.82644628	-99,173,554	-126,446,281
0	0	-300,000,000	-450,000,000	-300,000,000	-450,000,000		0.7513148	-225,394,440	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.68301346	0	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.62092132	0	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.56447393	0	-351,840,721
0	0	-270,000,000	-720,000,000	-175,000,000	-625,000,000		0.51315812	-89,802,671	-441,643,392
491,320,270	491,320,270	491,320,270	-228,679,730	634,320,270	9,320,270	0	0.46650738	295,915,087	-55,925,634
1,285,936,051	1,285,936,051	1,285,936,051	1,057,256,321	1,548,936,051	1,558,256,321	1,928,904,077	0.42409762	656,900,090	305,059,369
2,090,702,786	552,263,196	552,263,196	1,609,519,517	815,263,196	2,373,519,517	3,136,054,178	0.38554329	314,319,254	-127,324,137
265,213,930	265,213,930	265,213,930	1,874,733,447	528,213,930	2,901,733,447	0	0.3504939	185,135,760	57,811,623
204,340,630	204,340,630	204,340,630	2,079,074,077	467,340,630	3,369,074,077	0	0.31863082	148,909,127	206,720,750
158,592,025	158,592,025	158,592,025	2,237,666,102	398,592,025	3,767,666,102	0	0.28966438	115,457,912	322,178,661
169,353,651	169,353,651	169,353,651	2,407,019,753	289,353,651	4,057,019,753	0	0.26333125	76,195,860	398,374,521
185,220,334	185,220,334	185,220,334	2,592,240,087	185,220,334	4,242,240,087	0	0.23939205	44,340,275	442,714,797
147,182,308	147,182,308	147,182,308	2,739,422,395	147,182,308	4,389,422,395	0	0.21762914	32,031,158	474,745,955
116,098,634	116,098,634	116,098,634	2,855,521,028	116,098,634	4,505,521,028	0	0.19784467	22,969,496	497,715,451
84,179,175	84,179,175	84,179,175	2,939,700,204	84,179,175	4,589,700,204	0	0.17985879	15,140,365	512,855,815
55,189,462	55,189,462	55,189,462	2,994,889,665	55,189,462	4,644,889,665	0	0.16350799	9,023,918	521,879,733
30,124,404	30,124,404	30,124,404	3,025,014,070	30,124,404	4,675,014,070	0	0.14864363	4,477,801	526,357,534
5,666,605	5,666,605	5,666,605	3,030,680,675	5,666,605	4,680,680,675	0	0.13513057	765,732	527,123,266
0	-15,717,722	-15,717,722	3,014,962,952	-15,717,722	4,664,962,952	0	0.12284597	-1,930,859	525,192,407
0	-34,985,737	-34,985,737	2,979,977,215	-34,985,737	4,629,977,215	0	0.11167816	-3,907,143	521,285,264
0	-51,927,726	-51,927,726	2,928,049,489	-51,927,726	4,578,049,489	0	0.1015256	-5,271,993	516,013,271
0	-68,760,375	-68,760,375	2,859,289,113	-68,760,375	4,509,289,113	0	0.092296	-6,346,307	509,666,963
0	-83,392,957	-83,392,957	2,775,896,156	-83,392,957	4,425,896,156	0	0.08390545	-6,997,124	502,669,839
0	-96,747,819	-96,747,819	2,679,148,337	-96,747,819	4,329,148,337	0	0.07627768	-7,379,700	495,290,140
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
5,289,120,264	3,399,148,337	2,679,148,337		0.36658		5,064,958,255		1,448,105,317	

6.6 Hypothesis in economics studies after Hydraulic Fracturing at the water inject of 5,000 barrels

The Petroleum economics studies include the hypotheses for analyzing cash flow as follows:

6.6.1 Basis assumptions

1. 150 billion cubic feet of natural gas reserved
2. Number of well
    - Number of exploration well: 1 well
    - Number of appraisal well: 1 well
    - Number of development well: 1 well
3. Initial natural gas production rate is 10% of annual natural gas reserved for 5 years.
4. Giving that the heat value of natural gas is approximately 1,000 BTU per cubic foot.
5. Interest rate for loans (Discount rate) used in analyzing net present value is 10%.
6. Royalty is calculated based on sliding scale, starting at 5%
7. For the Royalty calculation, giving that 10 million BTU of natural gas is equal to 1 barrel of crude oil.
8. Petroleum income tax is 50%.

6.6.2 Cost assumption

The costs of conducting this study are as follows:

1. The cost of basic investment

- Asking for the concession of Petroleum exploration: USD0.85 million
- 2D-seismic survey: USD3.4 million
- 3D-seismic survey: USD1.7 million
- The cost of drilling and developing exploration well: USD8.57 million/well
- The cost of drilling and developing appraisal well: USD4.3 million/well
- The cost of drilling and developing development well: USD2.4 million/well
- The cost of Hydraulic Fracturing: USD2.14 million
- The cost of installation of gas pipeline and gas production and separation equipment: USD2.86 million

2. The operation costs: USD17 million per billion cubic foot, and escalating at 2% per year
3. Natural gas price: USD6 per million BTU

6.6.3 Results of Cash flow analysis

Apply these hypotheses to analyze cash flow at different natural gas volume reserved and prices (as shown in the appendix), and the results are as follows:

An example of cash flow is calculated at natural gas volume of 150 billion cubic feet, and at the natural gas price of USD6 per million BTU.

1. Natural gas production rates shown in Table 6.5

Table 6.5 Natural gas production rate after hydraulic fracturing (at the water inject of 5,000 barrels)

Year	Natural gas production rates		
	Mscf/day	Mscf/month	Mscf/year
1	30,000	900,000	10,980,000
2	30,000	900,000	10,980,000
3	30,000	900,000	10,980,000
4	28,973.39	869,201.85	10,604,262.66
5	25,098.05	752,941.50	9,185,886.30
6	21,710.24	651,307.24	7,945,948.38
7	18,902.28	567,068.40	6,918,234.57
8	16,555.02	496,650.86	6,059,140.52
9	14,583.76	437,513.00	5,337,658.63
10	12,910.96	387,328.92	4,725,412.82
11	11,493.02	344,790.63	4,206,445.68
12	10,276.12	308,283.73	3,761,061.58
13	9,232.06	276,961.83	3,378,934.42
14	8,322.68	249,680.53	3,046,102.54
15	7,536.81	226,104.44	2,758,474.18
16	6,851.37	205,541.16	2,507,602.27
17	6,243.90	187,317.07	2,285,268.29
18	5,710.13	171,304.15	2,089,910.66
19	5,240.36	157,210.85	1,917,972.42
20	4,824.23	144,727.04	1,765,669.96
Total			111,433,985.9

2. Economic impacts of Petroleum industry

- Gross revenue of gas sales: USD866.03 million
- Total investment: USD67.25 million, which includes:
    1) Cost of asking for concession and geophysics: USD6 million
    2) Cost of drilling exploration well and development well, cost of production equipment, cost of Hydraulic Fracturing, and cost of gas separation equipment: USD63.17 million
    3) Operation cost: USD349.09 million
- State revenue
    1) Royalty: USD112.54 million
    2) Income tax: 50% of USD597.66 million profit

3. With 50% income tax deduction, the net profit will be USD268.37 million. If it is calculated according to the net present value in the beginning year of the project at the interest rate of 10% (NPV@10%), it will be about USD144.58 million.

4. The Internal Rate of Return is 41.43%, and the discounted cash flow Internal Rate of Return is 28.58%.

5. Profit to Investment Ratio is 4.55.

Table 6.6 Economic calculation after hydraulic fracturing 5, 000 bbl

No.	Year	Gas Production								Exchange Rate (Baht/$)	Gas Price ($/1,000 SCF)	Gas Production PER year(SCF)	Income (Baht)	Royalty sliding scale (Baht)	2% Escal Factor
		Schedule	Gas in place (SCF)	Cumulative Gas production (SCF)	(SCF/month)	BOE (Barrel/month)	ROYALTY	Royalty(%)	(SCF/day)						
0							CHECK								
1	2011														1.0000
2	2012														1.0200
3	2013														1.0404
4	2014														1.0612
5	2015														1.0824
6	2016														1.1041
7	2017														1.1262
8	2018	0.0400	150,000,000,000	10,980,000,000	915,000,000	152,500	10.000	10.00	30,098,684	35.00	6.00	10,980,000,000	2,305,800,000	230,580,000	1.1487
9	2019	0.1200	150,000,000,000	21,930,000,000	912,500,000	152,083	10.000	10.00	30,016,447	35.00	6.00	10,950,000,000	4,605,300,000	460,530,000	1.1717
10	2020	0.2100	150,000,000,000	32,880,000,000	912,500,000	152,083	10.000	10.00	30,016,447	35.00	6.00	10,950,000,000	6,904,800,000	690,480,000	1.1951
11	2021	0.3000	150,000,000,000	43,484,860,000	883,738,333	147,290	6.250	6.25	29,070,340	35.00	6.00	10,604,860,000	2,227,020,600	139,188,788	1.2190
12	2022	0.3900	150,000,000,000	52,700,960,000	768,008,333	128,001	6.250	6.25	25,263,432	35.00	6.00	9,216,100,000	1,935,381,000	120,961,313	1.2434
13	2023	0.4800	150,000,000,000	60,650,780,000	662,485,000	110,414	6.250	6.25	21,792,270	35.00	6.00	7,949,820,000	1,669,462,200	104,341,388	1.2682
14	2024	0.5419	150,000,000,000	67,571,380,000	576,716,667	96,119	6.250	6.25	18,970,943	35.00	6.00	6,920,600,000	1,453,326,000	90,832,875	1.2936
15	2025	0.5926	150,000,000,000	73,631,870,000	505,040,833	84,173	6.250	6.25	16,613,185	35.00	6.00	6,060,490,000	1,272,702,900	79,543,931	1.3195
16	2026	0.6342	150,000,000,000	78,984,310,000	446,036,667	74,339	6.250	6.25	14,672,259	35.00	6.00	5,352,440,000	1,124,012,400	70,250,775	1.3459
17	2027	0.6683	150,000,000,000	83,709,580,000	393,772,500	65,629	6.250	6.25	12,953,043	35.00	6.00	4,725,270,000	992,306,700	62,019,169	1.3728
18	2028	0.6963	150,000,000,000	87,915,520,000	350,495,000	58,416	5.000	5.00	11,529,441	35.00	6.00	4,205,940,000	883,247,400	44,162,370	1.4002
19	2029	0.7192	150,000,000,000	91,675,670,000	313,345,833	52,224	5.000	5.00	10,307,429	35.00	6.00	3,760,150,000	789,631,500	39,481,575	1.4282
20	2030	0.7380	150,000,000,000	95,062,510,000	282,236,667	47,039	5.000	5.00	9,284,101	35.00	6.00	3,386,840,000	711,236,400	35,561,820	1.4568
21	2031	0.7534	150,000,000,000	98,107,320,000	253,734,167	42,289	5.000	5.00	8,346,519	35.00	6.00	3,044,810,000	639,410,100	31,970,505	1.4859
22	2032	0.7661	150,000,000,000	100,864,400,000	229,756,667	38,293	5.000	5.00	7,557,785	35.00	6.00	2,757,080,000	578,986,800	28,949,340	1.5157
23	2033	0.7764	150,000,000,000	103,370,500,000	208,841,667	34,807	5.000	5.00	6,869,792	35.00	6.00	2,506,100,000	526,281,000	26,314,050	1.5460
24	2034	0.7849	150,000,000,000	105,660,400,000	190,825,000	31,804	5.000	5.00	6,277,138	35.00	6.00	2,289,900,000	480,879,000	24,043,950	1.5769
25	2035	0.7919	150,000,000,000	107,748,700,000	174,025,000	29,004	5.000	5.00	5,724,507	35.00	6.00	2,088,300,000	438,543,000	21,927,150	1.6084
26	2036	0.7976	150,000,000,000	109,665,200,000	159,708,333	26,618	5.000	5.00	5,253,564	35.00	6.00	1,916,500,000	402,465,000	20,123,250	1.6406
27	2037	0.8023	150,000,000,000	111,429,300,000	147,008,333	24,501	5.000	5.00	4,835,800	35.00	6.00	1,764,100,000	370,461,000	18,523,050	1.6734
28	2038	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
29	2039	0.0000	0	0	0	0	0.000	0.00	0	0.00	0.00	0	0	0	0.0000
					9,285,775,000							111,429,300,000	30,311,253,000	2,339,785,298	
					111,429,300,000										

Table 6.6 Economic calculation after hydraulic fracturing 5,000 bbl (Cont.)

Investment cost									Depreciation (20%) Tangible Expense (Baht)								
					Intangible												
Concession (Baht)	Geological and geophysical surveys (Baht)	Exploration and apprisal wells (Baht)	No. of production wells	Production wells (Baht/Well)	Fraction	(Baht)	Tangible	Pipelines and processing production facilities (Baht)	2018	2019	2020	2021	2022				
30,000,000																	
	120,000,000																
		300,000,000															
	60,000,000	150,000,000	1	85,000,000	0.80	68,000,000	17,000,000	100,000,000									
			1	85,000,000	0.80	68,000,000	17,000,000	0	23,400,000	120,000,000							
			1	85,000,000	0.80	68,000,000	17,000,000	0		23,400,000	120,000,000	120,000,000					
			0	0	0.80	0	0	0			23,400,000	120,000,000	120,000,000				
			0	0	0.80	0	0	0				23,400,000	120,000,000	120,000,000			
			0	0	0.80	0	0	0					23,400,000	120,000,000	120,000,000		
			0	0	0.80	0	0	0							120,000,000	120,000,000	
			0	0	0.80	0	0	0									120,000,000
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.80	0	0	0									
			0	0	0.00	0	0	0									
			0	0	0.00	0	0	0									
30,000,000	180,000,000	450,000,000	3			204,000,000	51,000,000	0									

Table 6.6 Economic calculation after hydraulic fracturing 5,000 bbl (Cont.)

Depreciation (20%) Tangible Expense (Baht)	Fixed Operation	Operation cost		A(Baht/metre)	SRB RATE(%)	Available for	SRB(Baht)	Total allow expense (Baht)	Taxable income (Baht)	Taxable income (Baht) AFTER SRB	Cumulative taxable income (Baht)
	Operation cost(Baht)	(Baht/ MMSCF)	(Baht)								
						-30000000		30,000,000	-30,000,000	-30,000,000	-30,000,000
						-120000000		120,000,000	-120,000,000	-120,000,000	-150,000,000
0						-300000000		300,000,000	-300,000,000	-300,000,000	-450,000,000
						0		0	0	0	-450,000,000
						0		0	0	0	-450,000,000
						0		0	0	0	-450,000,000
0						-278000000		278,000,000	-278,000,000	-278,000,000	-728,000,000
143,400,000	600,000,000	1,500	618,918,853	4,804	0	1201881147		1,060,898,853	1,244,901,147	1,244,901,147	794,901,147
263,400,000	600,000,000	1,500	619,244,505	9,030	75	3115105495		1,411,174,505	3,194,125,495	3,194,125,495	2,744,125,495
263,400,000	600,000,000	1,500	619,629,395	12,554	75	5252270605	3,939,202,953	1,573,509,395	5,331,290,605	1,392,087,651	664,087,651
263,400,000	600,000,000	1,500	619,390,898	4,049	0	1126020915	0	1,021,979,685	1,205,040,915	1,205,040,915	1,869,128,566
263,400,000	600,000,000	1,500	617,188,593	3,519	0	854811094.6	0	1,001,549,905	933,831,095	933,831,095	2,802,959,660
240,000,000	600,000,000	1,500	615,123,441	3,035	0	637997371.5	0	959,464,828	709,997,372	709,997,372	3,512,957,032
120,000,000	600,000,000	1,500	613,428,801	2,642	0	593064323.9	0	824,261,676	629,064,324	629,064,324	4,142,021,356
0	600,000,000	1,500	611,995,032	2,314	0	581163937	0	691,538,963	581,163,937	581,163,937	4,723,185,293
0	600,000,000	1,500	610,805,519	2,044	0	442956105.7	0	681,056,294	442,956,106	442,956,106	5,166,141,399
0	600,000,000	1,500	609,730,175	1,804	0	320557356.6	0	671,749,343	320,557,357	320,557,357	5,486,698,755
0	600,000,000	1,500	608,833,997	1,606	0	230251032.9	0	652,996,367	230,251,033	230,251,033	5,716,949,788
0	600,000,000	1,500	608,055,630	1,436	0	142094294.8	0	647,537,205	142,094,295	142,094,295	5,859,044,083
0	600,000,000	1,500	607,400,980	1,293	0	68273600.47	0	642,962,800	68,273,600	68,273,600	5,927,317,683
0	600,000,000	1,500	606,786,641	1,163	0	652953.7639	0	638,757,146	652,954	652,954	5,927,970,637
0	600,000,000	1,500	606,268,220	1,053	0	-56230760.05	0	635,217,560	-56,230,760	-56,230,760	5,871,739,877
0	600,000,000	1,500	605,811,569	957	0	-105844619.5	0	632,125,619	-105,844,619	-105,844,619	5,765,895,258
0	600,000,000	1,500	605,416,412	874	0	-148581362.4	0	629,460,362	-148,581,362	-148,581,362	5,617,313,895
0	600,000,000	1,500	605,038,349	797	0	-188422499.3	0	626,965,499	-188,422,499	-188,422,499	5,428,891,396
0	600,000,000	1,500	604,716,332	732	0	-222374582.1	0	624,839,582	-222,374,582	-222,374,582	5,206,516,814
0	600,000,000	1,500	604,428,115	674	0	-252490165.3	0	622,951,165	-252,490,165	-252,490,165	4,954,026,648
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
1,557,000,000	12,000,000,000		12,218,211,459				3,939,202,953	16,978,996,756	13,332,256,244	9,393,053,290	

Table 6.6 Economic calculation after hydraulic fracturing 5,000 bbl (Cont.)

Income tax (Baht)	Income tax (Baht)after SRB	Annual cash flow (Baht)	Cumulative annual cash flow (Baht)	COPANY CASH FLOW(Baht)	Cumulative Company Cash(baht)	SRB(Baht) No special Reduction	Discounted Factor, % 10.00	Discounted cash flow (Baht)	Cumulative discounted cash flow (Baht)
							1		
0	0	-30,000,000	-30,000,000	-30,000,000	-30,000,000		0.90909091	-27,272,727	-27,272,727
0	0	-120,000,000	-150,000,000	-120,000,000	-150,000,000		0.82644628	-99,173,554	-126,446,281
0	0	-300,000,000	-450,000,000	-300,000,000	-450,000,000		0.7513148	-225,394,440	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.68301346	0	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.62092132	0	-351,840,721
0	0	0	-450,000,000	0	-450,000,000		0.56447393	0	-351,840,721
0	0	-278,000,000	-728,000,000	-185,000,000	-635,000,000		0.51315812	-94,934,252	-446,774,973
622,450,574	622,450,574	622,450,574	-105,549,426	765,850,574	130,850,574	194,516	0.46650738	357,274,945	5,434,223
1,597,062,747	1,597,062,747	1,597,062,747	1,491,513,321	1,860,462,747	1,991,313,321	2,395,594,121	0.42409762	789,017,820	437,177,099
2,665,645,302	696,043,826	696,043,826	2,187,557,146	959,443,826	2,950,757,146	3,998,467,953	0.38554329	369,907,129	-76,867,845
602,520,457	602,520,457	602,520,457	2,790,077,604	865,920,457	3,816,677,604	0	0.3504939	303,499,838	226,631,993
466,915,547	466,915,547	466,915,547	3,256,993,151	730,315,547	4,546,993,151	0	0.31863082	232,701,040	459,333,033
354,998,686	354,998,686	354,998,686	3,611,991,837	594,998,686	5,141,991,837	0	0.28966438	172,349,925	631,682,958
314,532,162	314,532,162	314,532,162	3,926,523,999	434,532,162	5,576,523,999	0	0.26333125	114,425,899	746,108,858
290,581,968	290,581,968	290,581,968	4,217,105,967	290,581,968	5,867,105,967	0	0.23939205	69,563,013	815,671,871
221,478,053	221,478,053	221,478,053	4,438,584,020	221,478,053	6,088,584,020	0	0.21762914	48,200,077	863,871,948
160,278,678	160,278,678	160,278,678	4,598,862,698	160,278,678	6,248,862,698	0	0.19784467	31,710,282	895,582,230
115,125,516	115,125,516	115,125,516	4,713,988,215	115,125,516	6,363,988,215	0	0.17985879	20,706,336	916,288,566
71,047,147	71,047,147	71,047,147	4,785,035,362	71,047,147	6,435,035,362	0	0.16350799	11,616,776	927,905,342
34,136,800	34,136,800	34,136,800	4,819,172,163	34,136,800	6,469,172,163	0	0.14864363	5,074,218	932,979,560
326,477	326,477	326,477	4,819,498,639	326,477	6,469,498,639	0	0.13513057	44,117	933,023,677
0	-28,115,380	-28,115,380	4,791,383,259	-28,115,380	6,441,383,259	0	0.12284597	-3,453,861	929,569,816
0	-52,922,310	-52,922,310	4,738,460,950	-52,922,310	6,388,460,950	0	0.11167816	-5,910,266	923,659,550
0	-74,290,681	-74,290,681	4,664,170,268	-74,290,681	6,314,170,268	0	0.1015256	-7,542,406	916,117,144
0	-94,211,250	-94,211,250	4,569,959,019	-94,211,250	6,219,959,019	0	0.092296	-8,695,321	907,421,823
0	-111,187,291	-111,187,291	4,458,771,728	-111,187,291	6,108,771,728	0	0.08390545	-9,329,220	898,092,603
0	-126,245,083	-126,245,083	4,332,526,645	-126,245,083	5,982,526,645	0	0.07627768	-9,629,683	888,462,920
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
7,517,100,116	5,060,526,645	4,332,526,645		0.41435		6,394,256,590		2,034,755,685	

6.7 Summary of a comparative analysis of Petroleum Economics in the Khorat sand

Economics value analyzed and calculated using the Petroleum Law Thailand III, in which the results of computer modeling and economics computation can indicate that the natural gas production before Hydraulic fracturing (HF) at the production rate of 11,000,000 cubic feet per day cannot achieve the target set since the day of beginning production. However, it can produce less volume in which on the last day of production (20 years) is produced at 5,200,000 cubic feet per day. When it has been producing for a period of 20 years, the total output will be at 55 billion cubic feet as shown in Figure 5.5 in Chapter 5 with IRR of 5.11%. After using 1,500 barrels of liquid compression in Hydraulic fracturing, it caused the cracks in the rock with 2,612 feet long 2 wings, 0.26 inches wide, and 260 feet high, as shown in Table 4.3 in chapter 4. As a result, the natural gas production on the first day, with the production rate of 25,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 390 days or about 1 year in which the production rate is gradually decreasing as shown in Figure 5.7 in chapter 5. On the last day of production in a period of 20 years with the production rate of 5,500,000 cubic feet per day and the total production rate of 93,142,800 cubic feet, the IRR will be at 24.23%. If 5,000 barrels of liquid compression is used in Hydraulic fracturing, it caused the cracks in the rock with 5,690 feet long, 0.38 inches wide, and 260 feet high, as shown in Table 4.5 in chapter 4. As a result, the natural gas production on the first day, with the production rate of 30,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 1,200 days or about 3.2 years in which the production rate is gradually decreasing as shown in Figure 5.9

in chapter 5. On the last day of production in a period of 20 years with the production rate of 4,687,751 cubic feet per day and the total production rate of 111,429,300 cubic feet, the IRR will be at 28.58%.

The summary of analysis results of Petroleum Economics, investment, production rates, returns, and the comparisons in each case are summarized again in the next chapter.

CHAPTER VII

SUMMARY AND RECOMMENDATIONS

The content of this chapter will summarize the estimation of Petroleum resources, the modeling of gas production before and after Hydraulic Fracturing, economics analysis for Khorat sand, as well as the recommendations in conducting the research.

7.1 The estimation of gas volume in Khorat sand

According to the Petroleum potential assessment results mentioned in detail in chapter 7, we can conclude that the Petroleum potential assessment results of both FASPU and MSP at the probability of 50 or P50 had the Petroleum reserved volume (natural gas) in the Khorat sand at approximately 150 billion cubic feet in the area of 1,235.5 acres or about 5 km^2.

7.2 The modeling of gas production before and after Hydraulic Fracturing and the economics analysis

The model simulated Khorat sand stone structure of L4 / 57 concession block where issued by Department of mineral fuels ministry of energy (DMF). And the model cell size is 50x50x5 = 12,500 cells which is equivalent to 5 square kilometers of drainage area and thickness of 80 meters.

The assessment indicates the most likely probability of finding 150 billion cubic feet of natural gas reserved in the Khorat sand. The natural gas reserved in the Khorat sand, must be cracked with Hydraulic fracturing (HF), HF system when there is less than 15% of internal rate of return (IRR) for the development of this natural gas.

Also, it is necessary to use larger amount of liquid used in HF if there is a need to run the operation especially when small and large gas production is unlikely to be of interest in the development of gas resource data.

Economics value analyzed and calculated using the Petroleum Law Thailand III, in which the results of computer modeling and economics computation can indicate that the natural gas production before Hydraulic fracturing (HF) at the production rate of 11,000,000 cubic feet per day cannot achieve the target set since the day of beginning production. However, it can produce less volume in which on the last day of production (20 years) is produced at 5,200,000 cubic feet per day. When it has been producing for a period of 20 years, the total output will be at 55 billion cubic feet as shown in Figure 5.11 in Chapter 5 with IRR of 5.11%. After using 1,500 barrels of liquid compression in Hydraulic fracturing, it caused the cracks in the rock with 2,612 feet long 2 wings, 0.26 inches wide, and 260 feet high, as shown in Table 4.3 in chapter 4. As a result, the natural gas production on the first day, with the production rate of 25,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 390 days or about 1 year in which the production rate is gradually decreasing as shown in Figure 5.13 in chapter 5. On the last day of production in a period of 20 years with the production rate of 5,500,000 cubic feet per day and the total production rate of 93,142,800 cubic feet, the IRR will be at 24.23%. If 5,000 barrels of liquid compression is used in Hydraulic fracturing, it caused the cracks in the rock with 5,690 feet long, 0.38 inches wide, and 260 feet high, as shown in Table 4.5 in chapter 4. As a result, the natural gas production on the first day, with the production rate of 30,000,000 cubic feet per day, can achieve the target set since the day of beginning production until a period of 1,200 days or about 3.2 years in which the production rate is gradually decreasing as shown in Figure 5.9 in chapter 5. On the last day of production in a period of 20 years with the production rate of 4,687,751 cubic feet per day and the total production rate of 111,429,300 cubic feet, the IRR will be at 28.58%.

Therefore, it can be seen that when higher liquid compression is applied in Hydraulic fracturing, there will be the increase in both daily and total production rates as shown in Table 7.1

7.3 Recommendations in conducting the research

1. The Petroleum potential assessment in the Khorat sandstone reservoir, by analyzing geological data and the data obtained from Petroleum engineers in conjunction with the use of FASPU and MSP (Monte Carlo Simulation, Swanson's Mean and Probability of Success) can effectively facilitate the process of Petroleum potential analyzing and assessing. Therefore, the analysis and assessment of these petroleum volumes should be considered in order to develop in line with the current high demand for petroleum.

2. Researchers should have knowledge and understanding about the use of the FASPU program for assessing the amount of petroleum in each source, along with the analysis of geological data and the data obtained from Petroleum engineers.

Table 7.1 Comparison of production rates, investment, and returns

	Production rates $x10^6$ cubic feet/day	Total production rates $x10^9$ cubic feet/20years	% of yields compared to total gas	Investment $x10^6$ $	Investor returns IRR, %	Investor's earnings $x10^6$ $	State revenue $x10^6$ $
Before HF	11	55.6	0.37	64.72	4.41	-38.77	25.84
After HF at compression of 1,500 barrels	10	72.93	0.49	66.53	7.45	7.52	77.78
	15	88.25	0.59	66.53	16.14	51.15	154.80
	20	92.08	0.61	66.53	22.12	66.82	195.43
	25	93.14	0.62	66.53	24.23	74.42	221.29
After HF at compression of 5,000 barrels	10	73.05	0.49	67.25	7.25	7.39	77.90
	15	99.67	0.66	67.25	16.35	80.97	190.13
	20	107.14	0.71	67.25	22.09	105.30	241.09
	30	111.43	0.74	67.25	28.58	120.35	314.99

3. The statistical results of geological data and the data obtained from petroleum engineers can help to determine the appropriate range for the selection and application of data to be used in the processing of the program.

4. Researchers should have knowledge and understanding about the use of Eclipse program for modeling Khorat sandstone reservoir, as well as the simulation of petroleum production.

5. The business investment in the economics assessment of this research was too low compared to the current investment; as a result, the percentage of return is possible.

6. Some imported data may be somewhat difficult to analyze due to unclear limitations of those imported data

7. More appropriate and accurate data are needed to import in to the model which included FASPU, MSP and reservoir simulations.

8. It is expected that this research paper will be useful for those interested in assessing the potential of petroleum in each of the structures for Northeastern Thailand

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APPENDIX A

SIMULATION DATA

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

Pressure (psia)	**FVF (rb/Mscf)**	**Viscosity (cp)**
14.7	247.78568	0.01385764
224.45263	16.161741	0.014077221
434.20526	8.3267534	0.014302277
643.95789	5.6005924	0.014532835
853.71053	4.2177939	0.014768922
1000	3.5987151	0.01493686
1273.2158	2.8269488	0.015257757
1482.9684	2.4301095	0.015510536
1692.7211	2.1336824	0.015768902
1902.4737	1.9044424	0.016032858
2112.2263	1.7223438	0.016302403
2321.9789	1.5745691	0.01657753
2531.7316	1.4525365	0.016858224
2741.4842	1.3502821	0.017144467
2951.2368	1.2635311	0.017436231
3160.9895	1.1891398	0.017733483
3370.7421	1.1247452	0.01803618
3600	1.063674	0.018373196
3790.2474	1.0191082	0.018657706
4000	0.97534584	0.01897641

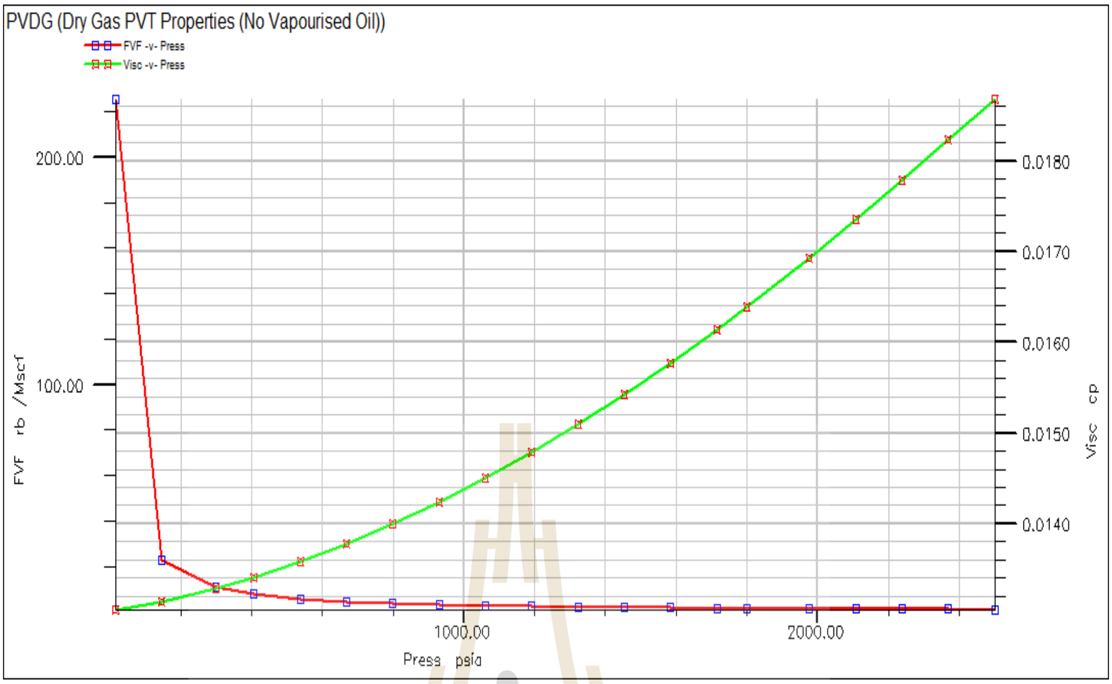

Figure A.1 Graph shows relationship of pressure VS gas formation volume factor and gas viscosity.

APPENDIX B

GAS SATURATION

AFTER 20 YEARS PRODUCTION

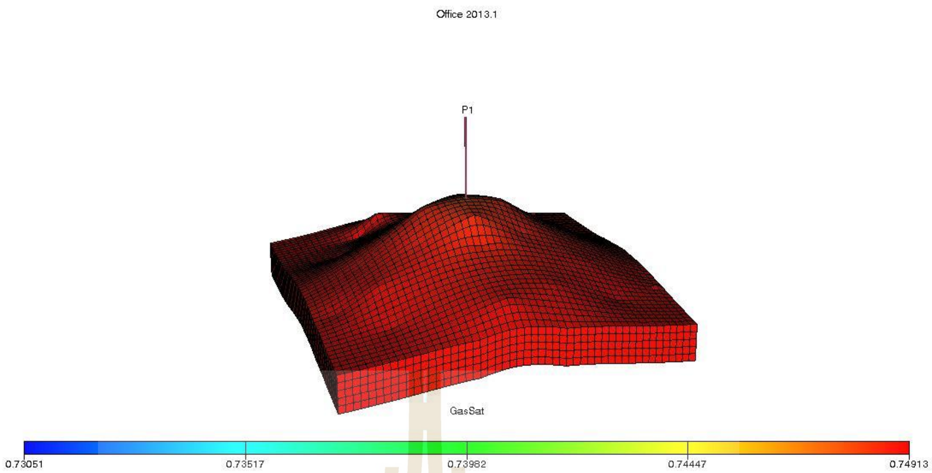

Figure B.1 Gas saturation before hydraulic fracturing and before 20 years production

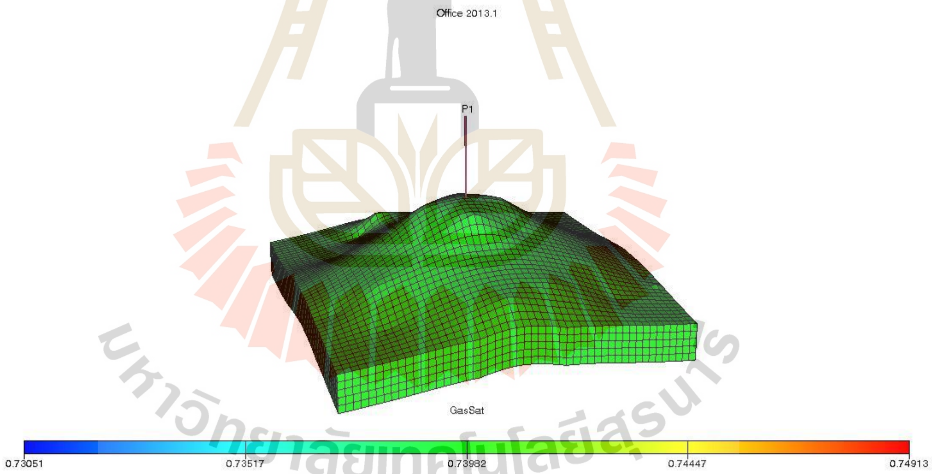

Figure B.2 Gas saturation before hydraulic fracturing and 10 years production

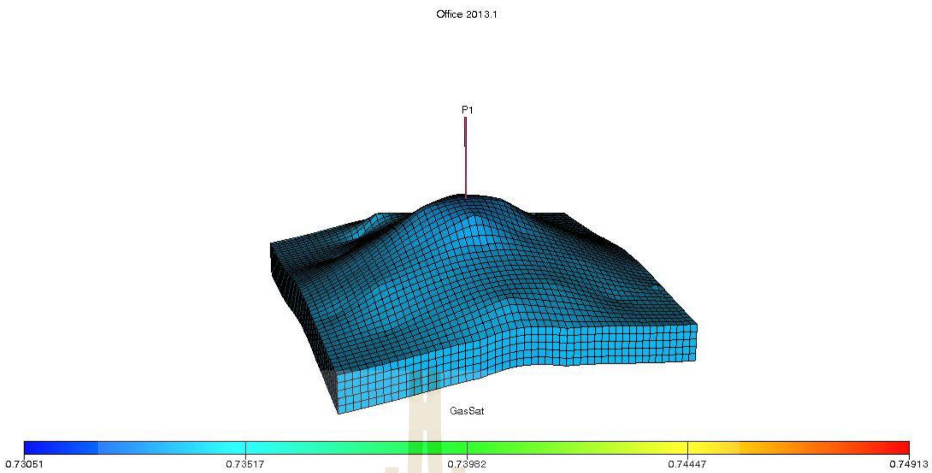

Figure B.3 Gas saturation before hydraulic fracturing and 20 years production

Table B.1 Gas in place, Gas production rate and Gas production total

Year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
0.0	0	149983.7	0	0
0.0	1	149972	11694.68	11.69468
0.0	11	149859	11298.47	124.6794
0.1	29	149654.5	11155.84	329.1823
0.2	84	149048.6	11016.56	935.0313
0.5	184	147961.7	10869.1	2021.941
0.8	275	146985	10752.49	2998.666
1.0	366	146018.4	10640.77	3965.242
1.3	466	144966.4	10520.49	5017.291
1.6	566	143926.1	10401.99	6057.49
1.8	649	143076	10305.36	6907.682
2.0	731	142233.6	10210.24	7750.027
2.3	831	141223.9	10097.12	8759.739
2.6	931	140225.4	9985.208	9758.26
2.8	1014	139409.2	9893.25	10574.45
3.0	1096	138600.5	9802.287	11383.14
3.3	1196	137631.2	9693.538	12352.5
3.6	1296	136672.5	9586.316	13311.13
3.8	1379	135888.9	9498.949	14094.79
4.0	1461	135112.3	9412.621	14871.33
4.3	1561	134181.4	9309.062	15802.24

Table B.1 Gas in place, Gas production rate and Gas production total

Year	**Time Day**	**GIP MMscf**	**GPR Mscf/D**	**GPT MMscf**
4.6	1661	133260.7	9207.139	16722.95
4.8	1744	132503.4	9123.937	17480.24
5.0	1827	131752.9	9041.932	18230.72
5.3	1927	130858.5	8944.475	19125.17
5.6	2027	129973.7	8847.403	20009.91
5.8	2110	129250.4	8768.277	20733.29
6.0	2192	128533.4	8690.055	21450.22
6.3	2292	127673.8	8596.526	22309.87
6.6	2392	126823.3	8504.314	23160.3
6.8	2475	126127.9	8429.198	23855.71
7.0	2557	125438.6	8354.991	24545
7.3	2657	124612.1	8265.926	25371.59
7.6	2757	123794.2	8178.535	26189.44
7.8	2840	123125.3	8107.733	26858.33
8.0	2922	122462.2	8037.736	27521.45
8.3	3022	121666.8	7953.84	28316.83
8.6	3122	120879.8	7870.323	29103.86
8.8	3205	120232.2	7801.639	29751.4
9.0	3288	119590.3	7733.724	30393.3
9.3	3388	118825.1	7652.993	31158.6
9.6	3488	118067.7	7573.371	31915.93

Table B.1 Gas in place, Gas production rate and Gas production total

Year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
9.8	3571	117448.3	7508.464	32535.38
10.0	3653	116834.1	7444.333	33149.54
10.3	3753	116097.3	7367.704	33886.31
10.6	3853	115368.1	7292.052	34615.52
10.8	3936	114771.6	7230.602	35212.04
11.0	4018	114180.1	7170.301	35803.59
11.3	4118	113470.3	7098.063	36513.4
11.6	4218	112767.6	7026.627	37216.06
11.8	4301	112192.7	6967.969	37790.92
12.0	4383	111622.7	6909.776	38360.97
12.3	4483	110938.7	6839.982	39044.97
12.6	4583	110261.6	6770.978	39722.07
12.8	4666	109704.3	6714.363	40279.36
13.0	4749	109151.6	6658.378	40832
13.3	4849	108492.5	6591.825	41491.19
13.6	4949	107839.8	6526.207	42143.81
13.8	5032	107305.8	6472.74	42677.81
14.0	5114	106776.2	6419.963	43207.46
14.3	5214	106140.5	6356.977	43843.16
14.6	5314	105511	6295.064	44472.66
14.8	5397	104995.8	6244.686	44987.85

Table B.1 Gas in place, Gas production rate and Gas production total

Year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
15.0	5479	104484.7	6194.841	45498.92
15.3	5579	103871.2	6134.96	46112.42
15.6	5679	103263.7	6075.66	46719.98
15.8	5762	102766.4	6026.94	47217.21
16.0	5844	102273.2	5978.722	47710.45
16.3	5944	101681.1	5921.003	48302.55
16.6	6044	101094.7	5863.893	48888.94
16.8	6127	100611.9	5816.933	49371.75
17.0	6210	100132.9	5770.479	49850.7
17.3	6310	99561.42	5715.236	50422.22
17.6	6410	98995.34	5660.743	50988.29
17.8	6493	98532	5616.318	51451.64
18.0	6575	98072.27	5572.439	51911.37
18.3	6675	97520.26	5520.121	52463.38
18.6	6775	96973.38	5468.778	53010.26
18.8	6858	96525.67	5426.809	53457.97
19.0	6940	96081.38	5385.314	53902.26
19.3	7040	95547.82	5335.654	54435.82
19.6	7140	95019.17	5286.497	54964.47
19.8	7223	94586.35	5246.278	55397.29
20.0	7305	94156.83	5206.349	55826.81

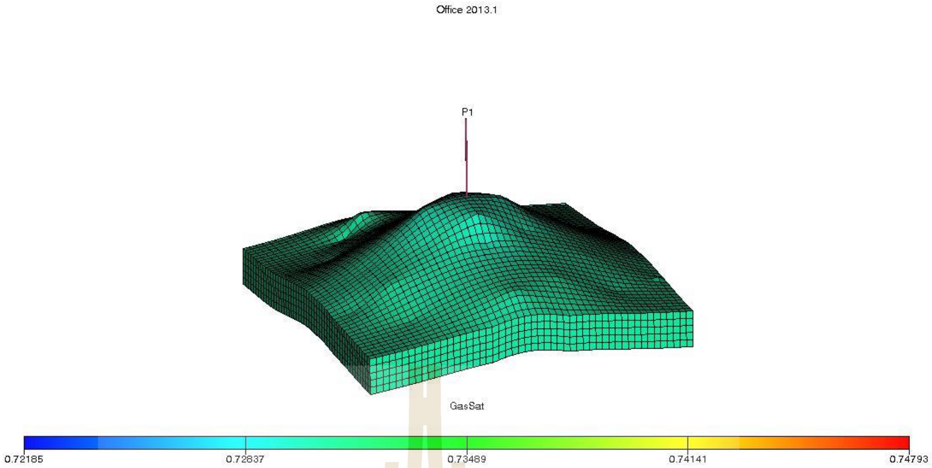

Figure B.4 Gas saturation after hydraulic fracturing 1,500 bbl and 10 years production

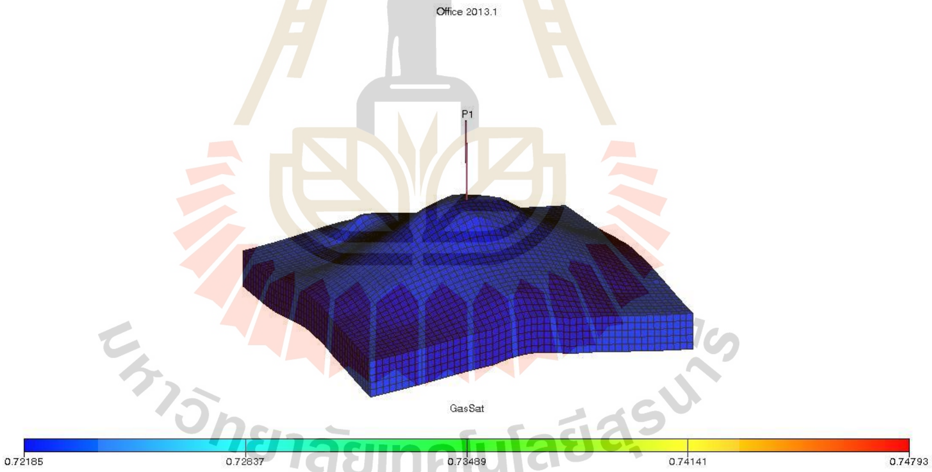

Figure B.5 Gas saturation after hydraulic fracturing 1,500 bbl and 20 years production

Table B.2 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
0.0	0	149983.7	0	0
0.0	1	149958.7	25000	25
0.0	11	149708.7	25000	275
0.1	41	148958.7	25000	1025
0.4	131	146708.7	25000	3275
0.6	231	144208.7	25000	5775
0.8	299	142521.2	25000	7462.5
1.0	366	140833.7	25000	9150
1.3	466	138371.3	24623.94	11612.39
1.6	566	135975.4	23958.33	14008.23
1.8	649	134043.4	23418.29	15940.24
2.0	731	132154.5	22896.61	17829.21
2.3	831	129925.3	22291.31	20058.34
2.6	931	127754.5	21708.32	22229.17
2.8	1014	126003	21230.37	23980.68
3.0	1096	124289.7	20767.39	25693.99
3.3	1196	122266.8	20229.11	27716.9
3.6	1296	120295.6	19711.59	29688.06
3.8	1379	118703.6	19297.19	31280.07
4.0	1461	117145.6	18884.8	32838.07
4.3	1561	115305.3	18403	34678.37

Table B.2 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
4.6	1661	113511.2	17941.08	36472.48
4.8	1744	112052.9	17570.01	37930.79
5.0	1827	110624.5	17209.59	39359.18
5.3	1927	108946	16784.65	41037.65
5.6	2027	107309.1	16369.23	42674.57
5.8	2110	105986	16037.46	43997.66
6.0	2192	104689.4	15716.73	45294.29
6.3	2292	103155.2	15341.35	46828.43
6.6	2392	101657.4	14978.27	48326.26
6.8	2475	100445.9	14685.29	49537.79
7.0	2557	99258.26	14395.09	50725.38
7.3	2657	97852.76	14055.08	52130.89
7.6	2757	96479.96	13728.02	53503.7
7.8	2840	95368.98	13466.41	54614.67
8.0	2922	94278.99	13211.93	55704.66
8.3	3022	92987.7	12912.91	56995.95
8.6	3122	91725.42	12622.9	58258.24
8.8	3205	90697.6	12383.31	59286.05
9.0	3288	89689.13	12150.29	60294.53
9.3	3388	88501.24	11878.86	61482.42
9.6	3488	87339.52	11617.18	62644.13

Table B.2 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
9.8	3571	86398.42	11407.27	63585.23
10.0	3653	85474.2	11202.69	64509.45
10.3	3753	84378.01	10961.93	65605.65
10.6	3853	83305.18	10728.26	66678.47
10.8	3936	82435.77	10538.36	67547.89
11.0	4018	81581.8	10351.06	68401.85
11.3	4118	80568.72	10130.82	69414.93
11.6	4218	79576.93	9917.94	70406.73
11.8	4301	78772.78	9747.269	71210.87
12.0	4383	77982.35	9580.927	72001.3
12.3	4483	77043.86	9384.993	72939.8
12.6	4583	76124.39	9194.621	73859.26
12.8	4666	75374.03	9040.417	74609.62
13.0	4749	74636.18	8889.782	75347.47
13.3	4849	73764.95	8712.337	76218.7
13.6	4949	72911.25	8537.059	77072.41
13.8	5032	72218.57	8396.059	77765.08
14.0	5114	71537.24	8258.55	78446.42
14.3	5214	70727.54	8096.977	79256.11
14.6	5314	69933.53	7940.138	80050.13
14.8	5397	69288.89	7813.824	80694.77

Table B.2 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
15.0	5479	68654.43	7690.347	81329.22
15.3	5579	67899.98	7544.567	82083.67
15.6	5679	67159.71	7402.639	82823.94
15.8	5762	66558.44	7288.172	83425.22
16.0	5844	65966.4	7176.171	84017.25
16.3	5944	65262.02	7043.834	84721.63
16.6	6044	64570.76	6912.626	85412.9
16.8	6127	64005.86	6805.998	85977.79
17.0	6210	63449.62	6701.738	86534.03
17.3	6310	62791.66	6579.55	87191.99
17.6	6410	62145.58	6460.839	87838.07
17.8	6493	61620.45	6365.143	88363.2
18.0	6575	61103.06	6271.488	88880.6
18.3	6675	60486.98	6160.754	89496.67
18.6	6775	59881.7	6052.771	90101.95
18.8	6858	59389.54	5965.561	90594.11
19.0	6940	58904.44	5880.118	91079.22
19.3	7040	58326.54	5779.003	91657.12
19.6	7140	57758.5	5680.332	92225.15
19.8	7223	57296.45	5600.599	92687.2
20.0	7305	56840.85	5522.44	93142.8

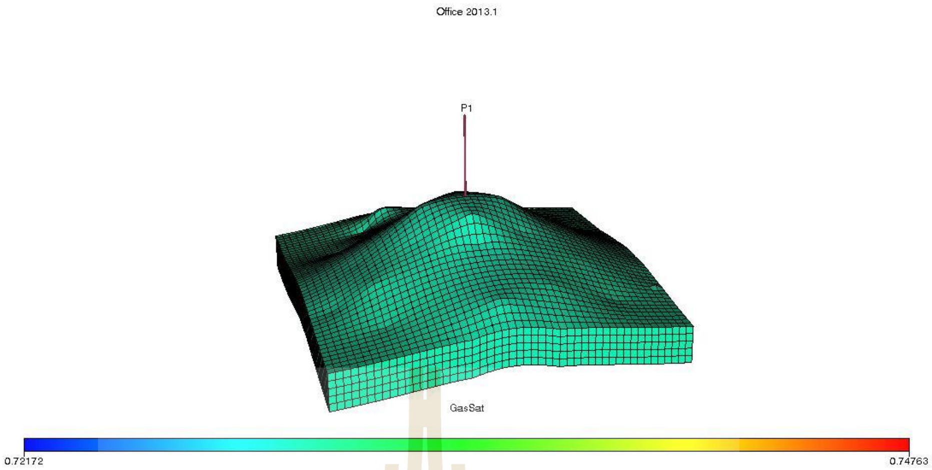

Figure B.6 Gas saturation after hydraulic fracturing 5,000 bbl and 10 years production

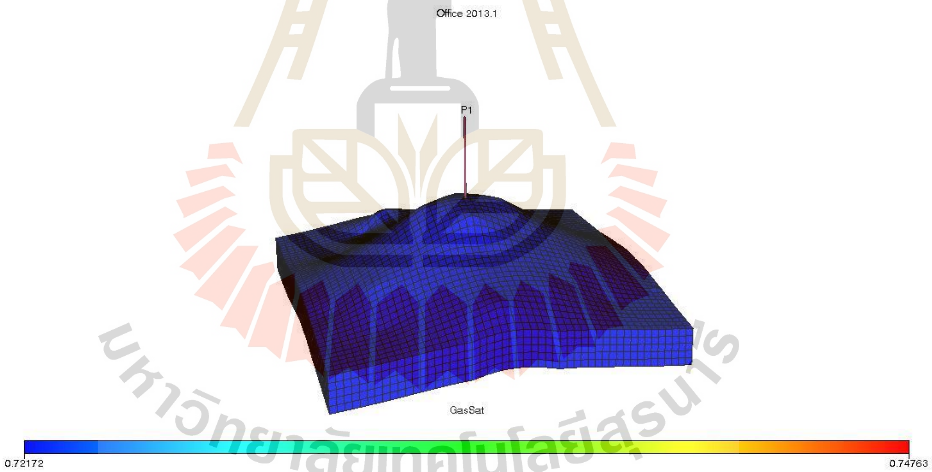

Figure B.7 Gas saturation after hydraulic fracturing 5,000 bbl and 20 years production

Table B.3 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
0.0	0	149983.7	0	0
0.0	1	149953.7	30000	30
0.0	11	149653.7	30000	330
0.1	41	148753.7	30000	1230
0.4	131	146053.7	30000	3930
0.6	231	143053.7	30000	6930
0.8	299	141028.6	30000	8955
1.0	366	139003.7	30000	10980
1.3	466	136003.7	30000	13980
1.6	566	133003.7	30000	16980
1.8	649	130528.7	30000	19455
2.0	731	128053.7	30000	21930
2.3	831	125053.7	30000	24930
2.6	931	122053.7	30000	27930
2.8	1014	119578.7	30000	30405
3.0	1096	117103.7	30000	32880
3.3	1196	114103.7	30000	35880
3.6	1296	111140	29636.31	38843.63
3.8	1379	108778.8	28620.91	41204.86
4.0	1461	106498.8	27636.36	43484.86
4.3	1561	103847.2	26515.76	46136.43

Table B.3 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
4.6	1661	101301.5	25457.73	48682.2
4.8	1744	99258.27	24616.55	50725.38
5.0	1827	97282.7	23802.17	52700.96
5.3	1927	94994.85	22878.48	54988.8
5.6	2027	92794.43	22004.16	57189.22
5.8	2110	91035.96	21314.75	58947.69
6.0	2192	89332.86	20643.58	60650.78
6.3	2292	87345.44	19874.3	62638.21
6.6	2392	85430.87	19145.62	64552.78
6.8	2475	83898.82	18570.4	66084.83
7.0	2557	82412.26	18018.8	67571.38
7.3	2657	80674.96	17373.03	69308.69
7.6	2757	78998.98	16759.8	70984.67
7.8	2840	77656.22	16275.85	72327.42
8.0	2922	76351.78	15811.43	73631.87
8.3	3022	74824.34	15274.48	75159.32
8.6	3122	73348.08	14762.55	76635.57
8.8	3205	72157.2	14347.9	77826.45
9.0	3288	70999.34	13950.14	78984.31
9.3	3388	69649.98	13493.59	80333.67
9.6	3488	68344.18	13058.04	81639.47

Table B.3 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
9.8	3571	67295.39	12712.52	82688.26
10.0	3653	66274.07	12379.7	83709.58
10.3	3753	65074.72	11993.48	84908.93
10.6	3853	63912.67	11620.54	86070.98
10.8	3936	62978.57	11322.38	87005.08
11.0	4018	62068.13	11035.68	87915.52
11.3	4118	60997.83	10702.99	88985.82
11.6	4218	59959.39	10384.41	90024.26
11.8	4301	59123.58	10130.95	90860.06
12.0	4383	58307.98	9886.158	91675.67
12.3	4483	57347.86	9601.227	92635.79
12.6	4583	56415.08	9327.767	93568.58
12.8	4666	55659.16	9107.386	94324.49
13.0	4749	54921.14	8891.866	95062.51
13.3	4849	54056.84	8642.99	95926.81
13.6	4949	53216.42	8404.22	96767.23
13.8	5032	52538.78	8213.879	97444.88
14.0	5114	51876.33	8029.649	98107.32
14.3	5214	51094.86	7814.646	98888.78
14.6	5314	50334.09	7607.752	99649.56
14.8	5397	49720.08	7442.513	100263.6

Table B.3 Gas in place, Gas production rate and Gas production total

year	Time Day	GIP MMscf	GPR Mscf/D	GPT MMscf
15.0	5479	49119.29	7282.348	100864.4
15.3	5579	48409.77	7095.141	101573.9
15.6	5679	47718.3	6914.723	102265.4
15.8	5762	47159.85	6769.114	102823.8
16.0	5844	46613.16	6626.512	103370.5
16.3	5944	45967.16	6460.02	104016.5
16.6	6044	45337.2	6299.633	104646.5
16.8	6127	44825.04	6170.603	105158.6
17.0	6210	44323.27	6045.354	105660.4
17.3	6310	43733.32	5899.551	106250.3
17.6	6410	43157.44	5758.744	106826.2
17.8	6493	42691.65	5645.952	107292
18.0	6575	42234.91	5536.307	107748.7
18.3	6675	41694.13	5407.721	108289.5
18.6	6775	41165.8	5283.384	108817.9
18.8	6858	40738.14	5183.68	109245.5
19.0	6940	40318.49	5086.662	109665.2
19.3	7040	39821.22	4972.751	110162.4
19.6	7140	39334.97	4862.477	110648.7
19.8	7223	38941.12	4773.961	111042.5
20.0	7305	38554.38	4687.751	111429.3

BIOGRAPHY

Mr. Phanuphong Gaewmood was born on the 7th of June 1991 in Chiangrai, Thailand. He earned his high school diploma in science-math from Rajavinit Bangkhen School, and He earned her Bachelor's Degree in Geotechnology, Institute of Engineering at Suranaree University of Technology (SUT) in 2013. After graduation, he continued with him master degree in the School of Geotechnology, Institute of Engineering at Suranaree University of Technology (SUT) with the major in Petroleum Engineering. During 2014-2015 (SUT), His strong background is in drilling and reservoir engineering, and high skill in the areas of reservoir simulation. He was a research assistant at SUT.