UNDISCOVERED PETROLEUM RESOURCES AND PETROLEUM ECONOMICS POTENTIAL ASSESSMENT OF SIKHIU PROSPECT, NORTHEAST THAILAND

PORNCHAYA PHUMIPHAN

A Thesis Submitted in Partial Fulfillment of the Requirements for the Degree of Doctor of Philosophy in Geotechnology

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การประเมินศักยภาพทรัพยากรปิโตรเลียมที่ยังไม่ค้นพบและเศรษฐศาสตร์ปิโตรเลียมของเป้ากักเก็บสีคิ้ว ภาคตะวันออกเฉียงเหนือ ประเทศไทย

นางสาวพรชญา ภูมิพันธุ์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรดุษฎีบัณฑิต
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มหาวิทยาลัยเทคโนโลยีสุรนารี
ปีการศึกษา 2566

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Suranaree University of Technology has approved this thesis submitted in partial fulfillment of the requirements for the Degree of Doctor of Philosophy.

Thesis Examining Committee

....

(Asst. Prof. Dr. Yupa Thasod)

Chairperson

....

(Asst. Prof. Dr. Akkhapun Wannakomol)

Member (Thesis Advisor)

....

(Asst. Prof. Dr. Prachya Tepnarong)

Member

....

(Asst. Prof. Dr. Bantita Terakulsatit)

Member

....

(Asst. Prof. Dr. Decho Phueakphum)

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คำสำคัญ: ทรัพยากรไฮโดรคาร์บอนที่ยังไม่ถูกค้นพบ/ เป้ากักเก็บสีคิ้ว/ เศรษฐศาสตร์ปิโตรเลียม/ ระบบข้อผูกพันด้านการเงินแบบไทยแลนด์ III และสัญญาแบ่งปันผลผลิต

การศึกษาครั้งนี้มีวัตถุประสงค์เพื่อประเมินทรัพยากรไฮโดรคาร์บอนที่ยังไม่ถูกค้นพบ และเพื่อประเมินศักยภาพทางเศรษฐศาสตร์ปิโตรเลียมของเป้ากักเก็บสีคิ้ว ซึ่งอยู่ในแอ่งซับพลูทางภาคตะวันออกเฉียงเหนือของประเทศไทย การประเมินทรัพยากรไฮโดรคาร์บอนที่ยังไม่ถูกค้นพบได้ถูกทำการวิเคราะห์โดยใช้โปรแกรม FASPU การวิเคราะห์เป้ากักเก็บปิโตรเลียม และทฤษฎีความน่าจะเป็น โดยการประเมินได้ใช้ข้อมูลที่เกี่ยวข้องที่มีการเผยแพร่และข้อมูลที่ได้มาจากกรมเชื้อเพลิงธรรมชาติ (DMF) เป้ากักเก็บสีคิ้วยังคงไม่ได้รับการทดสอบและถูกจัดอยู่ในเป้ากักเก็บที่เป็นแบบเพอร์เมียนคาร์บอเนต ข้อมูลนำเข้าที่ใช้ในการประเมินประกอบไปด้วยข้อมูลทางธรณีวิทยาและวิศวกรรม จากการประเมินพบว่าปริมาณทรัพยากรก๊าซธรรมชาติโดยประมาณแตกต่างกันไปตามระดับความเชื่อมั่นที่แตกต่างกัน ดังนี้: ขนาด 4.84 พันล้านลูกบาศก์ฟุต (ความเชื่อมั่นสูงมาก F95) ขนาด 10.31 พันล้านลูกบาศก์ฟุต (ความเชื่อมั่นสูง F75) ขนาด 17.45 พันล้านลูกบาศก์ฟุต (ความเชื่อมั่นปานกลาง F50) ขนาด 29.52 พันล้านลูกบาศก์ฟุต (ความเชื่อมั่นต่ำ F25) ขนาด 62.90 พันล้านลูกบาศก์ฟุต (ความเชื่อมั่นต่ำมาก F05) และขนาด 23.64 พันล้านลูกบาศก์ฟุต ที่ค่าเฉลี่ยเลขคณิต ตามลำดับ ผลการประเมินทางเศรษฐศาสตร์ปิโตรเลียมพบว่าในกรณีพื้นฐานนั้นระบบข้อผูกพันด้านการเงินแบบสัญญาแบ่งปันผลผลิต (PSC) ให้ผลตอบแทนสูงกว่าและมีระยะเวลาคืนทุนสั้นกว่าระบบข้อผูกพันด้านการเงินแบบไทยแลนด์ III (Thailand III) สำหรับการวิเคราะห์ความอ่อนไหวต่อราคาก๊าซพบว่าระบบข้อผูกพันด้านการเงินแบบสัญญาแบ่งปันผลผลิตจะมีความน่าสนใจทางการเงินมากกว่าเมื่อราคาก๊าซค่อนข้างต่ำ เนื่องจากมีการแบ่งปันค่าใช้จ่ายกับรัฐบาลจึงส่งผลให้คู่สัญญามีรายได้เพิ่มขึ้น ในทางกลับกันเมื่อราคาก๊าซสูงขึ้น รัฐจะได้รับส่วนแบ่งการผลิตที่สูงขึ้นในระบบข้อผูกพันด้านการเงินแบบสัญญาแบ่งปันผลผลิต ส่งผลให้รายได้ของคู่สัญญาลดลง ทำให้ระบบข้อผูกพันด้านการเงินแบบไทยแลนด์ III มีความน่าสนใจทางการเงินมากกว่า สำหรับการวิเคราะห์ความอ่อนไหวต่อต้นทุนหลุมพบว่าระบบข้อผูกพันด้านการเงินแบบสัญญาแบ่งปันผลผลิตให้ผลตอบแทนดีกว่าระบบข้อผูกพันด้านการเงินแบบไทยแลนด์ III ทั้งในด้านมูลค่าปัจจุบันสุทธิ (NPV) อัตราผลตอบแทน (IRR) ความสามารถ

ในการทำกำไร (PIR) และระยะเวลาคืนทุน (payback period) อันเป็นผลมาจากการแบ่งปันค่าใช้จ่ายร่วมกับรัฐซึ่งเป็นประโยชน์ต่อคู่สัญญา ดังนั้นเป้ากักเก็บสีคิ้วจึงแสดงให้เห็นถึงศักยภาพทางเศรษฐศาสตร์ในการสำรวจและพัฒนาปิโตรเลียม

สาขาวิชา เทคโนโลยีธรณี

ปีการศึกษา 2566

ลายมือชื่อนักศึกษา พรชญา ภูมิพันธ์

ลายมือชื่ออาจารย์ที่ปรึกษา

PORNCHAYA PHUMIPHAN: UNDISCOVERED PETROLEUM RESOURCES AND PETROLEUM ECONOMICS POTENTIAL ASSESSMENT OF SIKHIU PROSPECT, NORTHEAST THAILAND. THESIS ADVISOR: ASST. PROF. AKKHAPUN WANNAKOMOL, Ph.D., 235 PP.

Keyword: UNDISCOVERED HYDROCARBON RESOURCE/ SIKHIU PROSPECT/ PETROLEUM ECONOMICS/ THAILAND III AND PRODUCTION SHARING CONTRACT FISCAL REGIME

The objectives of this study are to assess the undiscovered hydrocarbon resource and to evaluate the petroleum economics potential of the Sikhiu prospect in the Sap Phlu Basin, northeast Thailand. The assessment of undiscovered hydrocarbon resources was analyzed using the FASPU program, play analysis, and probability theory approach. The assessment relied on relevant published data and from the Department of Mineral Fuels (DMF). The Sikhiu prospect remains untested and is categorized as a Permian Carbonate Play. The input data are geological and engineering parameters. Estimated natural gas resources vary across different confidence levels, as follows: 4.84 Bcf (very high confidence, F95), 10.31 Bcf (high confidence, F75), 17.45 Bcf (medium confidence, F50), 29.52 Bcf (low confidence, F25), 62.90 Bcf (very low confidence, F05), and 23.64 Bcf at the arithmetic mean respectively. The economically evaluated results indicated that the PSC fiscal regime offers higher returns and a shorter payback period than the Thailand III fiscal regime at the base case. For gas price sensitivity analysis, The PSC fiscal regime will be more financially attractive when gas prices are relatively low because of cost-sharing with the government, resulting in increased revenue for contractors. Conversely, when gas prices rise the state receives a higher production share in the PSC fiscal regime, resulting in lower revenue for the contractor, making the Thailand III fiscal regime more fiscally attractive. For the well cost sensitivity analysis, it was found that the PSC fiscal regime gave better returns than the Thailand III fiscal regime in terms of NPV, IRR, PIR, and payback period at every well cost. This is a result of cost sharing with the state which is beneficial to the contractor. Therefore, the Sikhiu prospect demonstrates economically viable in petroleum exploration and development.

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Student's Signature พรชญา ภูมิพันธุ์
Advisor's Signature

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Pornchaya Phumiphan

TABLE OF CONTENTS

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 TABLES (Continued)

Table **Page**

LIST OF TABLES (Continued)

Table Page

LIST OF TABLES (Continued)

Table Page

LIST OF TABLES (Continued)

Table Page

LIST OF TABLES (Continued)

Table **Page**

LIST OF TABLES (Continued)

Table Page

LIST OF TABLES (Continued)

Table **Page**

LIST OF FIGURES

Figure Page

LIST OF FIGURES (Continued)

Figure **Page**

LIST OF FIGURES (Continued)

Figure **Page**

LIST OF FIGURES (Continued)

Figure **Page**

SYMBOLS AND ABBREVIATIONS

AAPG	=	American Associated Petroleum Geologists
Bcf	=	Billion cubic feet
Bo	=	Oil formation volume factor
BTU	=	British thermal unit
CAPEX	=	Capital expenditure
CCOP	=	Coordination Committee for Coastal and offshore Geoscience Programmers in East and Southeast Asia
DMF	=	Department of Mineral Fuels
F	=	Trap fill
°F/100 ft	=	Fahrenheit degree per 100 feet
FASPU	=	Fast Appraisal System for Petroleum Universal
H	=	Reservoir thickness
IRR	=	Internal rate of return
Mcf/bbl	=	Thousand cubic feet per barrel
MMSCF	=	Million cubic feet
MMSCF/day	=	Million cubic feet per day
MMSCF/month	=	Million cubic feet per month
MMSCF/year	=	Million cubic feet per year
MMUS$	=	Million US$
MMUS$/km	=	Million US$ per kilometer
MMUS$/well	=	Million US$ per well
NPV	=	Net present value
OPEC	=	Operational expenditure
PA	=	Petroleum Act
Pe	=	Original reservoir pressure
PIR	=	Profit to investment ratio
PITA	=	Petroleum Income Tax Act

SYMBOLS AND ABBREVIATIONS (Continued)

PSC	=	Production sharing contract
psi	=	Pound per square inch
°R	=	Degrees Rankine
Rs	=	Gas-oil ratio
SC	=	Service Contracts
Sh	=	Hydrocarbon saturation
SPE	=	Society of petroleum Engineers
SPEE	=	Society of petroleum Evaluation Engineers
SRB	=	Special Remuneratory Benefits
T	=	Reservoir temperature
TOC	=	Total organic carbon
US$/MMSCF	=	US$ per Million cubic feet
WPC	=	World Petroleum Congressses
Z	=	Gas compressibility factor

CHAPTER I
INTRODUCTION

1.1 Background and Rationale

Currently, Thailand's daily crude oil consumption stands at around 1.5 million barrels of crude oil equivalence. Of this demand, approximately 60% is imported from the Middle East. However, Thailand still relies primarily on natural gas, which accounts for 43% of its primary commercial energy, 69% of which comes from indigenous gas sources (Department of Mineral Fuels [DMF], 2023). Over the past decade, Thailand has consistently developed its discovered oil and gas fields. However, the petroleum reserves from these fields are now in the depletion phase, rendering them inadequate to meet the increasing demand for energy. Therefore, promoting domestic petroleum exploration and production investment is critical, especially for the new, undiscovered/ untested oil and gas fields.

In the past, the explorations of petroleum in Northeastern of Thailand were executed with exploration drilling more than 30 wells. At the present, Nam Phong, Sin Phu Horm and Dong Mun gas fields have been developed in commerciality.

Thailand has a lot of marginal fields could not be developed in the past, but nowadays technology and petroleum prices are very high, that makes the marginal fields can be possible. Chantong (2007) suggested that Sikhiu prospect was very interested area and high petroleum potential. The outcrop and subsurface data seismic profile indicated that petroleum system was good, the structure can be petroleum potential and there is a possibility to petroleum exploration and production.

In Thailand a concession system and production sharing contract (PSC) system were applied for the allocation and granting of petroleum exploration and production rights. The concessionaire or contractors must be processed in accordance with the rule under Department of Mineral Fuel, Ministry of Energy and must share income to the state through petroleum fiscal regime consisting of royalty, petroleum income tax, Special remuneratory benefits (SRB) and production sharing for production sharing contract (PSC) fiscal regime according to the Petroleum Act (PA) and the Petroleum Income Tax Act (PITA) (Sirasoontorn and Suksai, 2013).

In 2020, operations were carried out 38 concession covering 45 exploration blocks in the production period, 2 exploration blocks in the exploration period, 12 exploration blocks operation suspend (the Cambodia – Thailand overlapping areas), and two production sharing contact (PSC) covering two exploration blocks, namely offshore Gulf of Thailand G1/61 and G2/61 (Department of Mineral Fuels [DMF], 2020).

Currently, the production sharing contact (PSC) are applied only offshore and quite large reserves. For onshore and marginal field, there is no study. In this study aim to assessment of petroleum and economics under Thailand III and production sharing contract system (PSC) for marginal field at Sikhiu prospect, northeast Thailand, which is a very interesting area having high petroleum potential and one of the untested petroleum prospects. Therefore, the results and findings of this study may help increase the amount of natural gas reserves in Thailand to benefit the country's energy security in the future.

1.2 Research Objectives

1) To assess the undiscovered petroleum resource of Sikhiu prospect.

2) To evaluate the economical potential of petroleum resource of Sikhiu prospect performed under of Thailand III and production sharing contact (PSC) fiscal regime.

1.3 Scope and Limitations

1) The study was performed by using the existing and published data that provided by Department of Mineral Fuels (DMF), Thailand.

2) The assessment of undiscovered petroleum potential was conducted by Fast Appraisal System for Petroleum Universal (FASPU) program and followed the Coordination Committee for Coastal and offshore Geoscience Programmers in East and

Southeast Asia (CCOP) Guidelines based on the well data available, petroleum engineering information.

3) The assessment of petroleum potential was conducted only in Permian carbonate play/ reservoir of Sikhiu prospect within the Sap Phlu Basin.

4) The exploration and production work were planned under Thailand III and PSC fiscal regime within 6 years.

1.4 Research Methodology

The research methodology summary comprises six steps, which had been undertaken as outlined below:

1.4.1 Literature Review

The relevant literature will be thoroughly studied, comprising an extensive review, summarized and collected to be conclusion and data for reference. The summary of the literature review was included in the thesis, encompassing the petroleum exploration and production history of Thailand, general geology, stratigraphy, petroleum province, petroleum prospect in both Triassic and Permian basin play, exploration history of Sikhiu prospect, petroleum system of northeastern Thailand, petroleum potential and risk assessment, types of petroleum arrangements and Petroleum Acts of Thailand.

1.4.2 Data Collection and Analysis

Geological characteristics with similar attributes had been categorized into play types for conducting petroleum play analysis. The play analysis aims to estimate undiscovered oil and gas resources at the play scale was then applied.

1.4.3 Undiscovered Petroleum Resource Assessment

The assessment of undiscovered petroleum resources within the Sikhiu prospect had been conducted using the FASPU program. Estimates of hydrocarbon resources, including oil, non-associated gas, associated-dissolved gas, and total gas, were computed utilizing probability distributions.

1.4.4 Petroleum Economics

The petroleum economics of the calculated undiscovered petroleum resources from the previous steps was then evaluated. The results of cash flow analysis were studied and analyzed to determine the base case of net income, internal rate of return (IRR), profit to investment ratio (PIR) and payback period under Thailand III and production sharing contract (PSC) fiscal regime for comparison.

1.4.5 Discussion and Conclusion

The results from petroleum potential assessment and petroleum economic potential under Thailand III and PSC fiscal regime were then concluded and discussed.

1.4.6 Thesis Writing

All research activities, methods, and results were documented and complied in the thesis. The research or findings were then published in the international journals.

1.5 Thesis Contents

Chapter I introduce the thesis by briefly describing the rationale and background and the significance of the study. The research objectives, research methodology, scope and limitation are identified. Chapter II summarizes results of the literature review. Chapter III describes the method of the study. Chapter IV presents the results and discussion of geological model and petroleum reservoir engineering parameter for undiscovered petroleum resources assessment, petroleum economics potential and also comparison under Thailand III and PSC fiscal regime. Chapter V reports conclusions and provides recommendations for future research studies.

CHAPTER II

LITERATURE REVIEW

2.1 Introduction

This chapter comprises literature review of petroleum geology and petroleum potential. The related knowledge were categorized into groups including petroleum exploration and production history of Thailand, general geology, stratigraphy, petroleum province, petroleum prospects in both Triassic and Permian basin play, exploration history of Sikhiu prospect, petroleum system of northeastern Thailand, petroleum potential and risk assessment, types of petroleum arrangement and petroleum act of Thailand, respectively.

2.2 Petroleum Geology and Petroleum Potential

2.2.1 Petroleum Exploration and Production History of Thailand

Oil exploration in Thailand commenced in 1921 within the northern Fang Basin, where reports of oil seepages had surfaced. In the beginning, exploration of petroleum was conducted by the Military fuel Division. In 1962, Union Oil (Unocal) was given permission to explore the Khorat Plateau region. Unfortunately, due to the absence of well-defined petroleum regulations, significant exploration efforts did not take place. Simultaneously, some stratigraphic wells were drilled in the vicinity of Bangkok (CCOP, 2002)

In 1964, numerous foreign companies submitted applications for offshore exploration. This marked the recognition of the Petroleum Act as Thailand I. During this period, the first round of licenses for offshore blocks was granted to companies such as Tenneco, Pan Ocean, Conoco, Triton, BP, Union, Amoco and Gulf. Concurrently, Union and Meridian were also allocated blocks in the Khorat Plateau region.

In 1971, Union conducted the inaugural deep well drilling operation on the Khorat Plateau, referred to as Kuchinarai–1. Simultaneously, Conoco embarked on the first offshore well drilling named Surat – 1. Unfortunately, both of these exploration wells proved unsuccessful in encountering hydrocarbons.

In January 1973, Union was discovered hydrocarbon in offshore area in Pattani Basin. The discovery was later named Erawan. Another pivotal discovery occurred in May 1973 in the Malay Basin when Tenneco abandoned wildcat 15-B-1X, which turned out to be an oil and gas well. Subsequent drilling efforts by BP and Texas Pacific confirmed the existence of a substantial gas reservoir, which was later designated as the "B" structure. Presently, Total operates this field as the Bongkot Field, and production rates are highly impressive.

In 1979, Shell was awarded large blocks in the Phitsanulok Basin, while Esso secured significant areas in the Khorat Plateau. By 1981, Esso made a noteworthy discovery with the identification of the Nam Phong gas field, while Shell discovered the Sirikit (also known as Lan Krabue) oil and gas field in the same year.

Thailand II fiscal regime became effective in 1982 due to high global oil prices. Under this new regime, the cost recovers 20% of annual gross revenue, along with an escalated royalty rate that paralleled increased production rates. However, because of a significant drop in oil prices in 1985, Thailand II had a brief existence as it had been specifically tailored for medium and large-sized oil fields.

In June 1987, Shell achieved a significant discovery with the Nang Nuan–1 well in B6/27, marking the first noteworthy oil discovery in the Gulf of Thailand. This discovery occurred within the Chumphon Basin and led to the commencement of production in January 1988, establishing it as Thailand's sole offshore oil-producing field.

In November 1988, the British independent company Premier Consolidated accomplished an oil discovery at Songkhla–1 in B11/27. This event marked the first discovery in the Songkhla Basin, followed by another oil discovery at Bua Ban–1 within the same basin in April 1990. Despite their size not being significant, these fields were noteworthy.

In 1989, Thailand introduced a new fiscal regime known as Thailand III during the 13th Licensing Round. One of its primary alterations was the adaptation of the royalty rate into a sliding scale, facilitating commercial production for all field sizes.

The three concessionaires who had previously operated under Thailand II terms successfully transitioned to Thailand III, while those originally under Thailand I were content to remain under the previous terms.

In 2000, Thailand actively conducted petroleum exploration both onshore and offshore, encompassing the Gulf of Thailand and the Andaman Sea, where no petroleum drilling had taken place for a decade. Unocal Andaman carried out drilling for five exploratory wells in block W9/38. However, only a small trace of gas was discovered in the Kantang-1A well (CCOP, 2002).

By the end of 2020, Thailand had drilled a total of 12,634 wells, which included 630 exploratory wells, 865 appraisal wells, and 11,139 development wells. Since 1971, there have been 23 completed rounds of concession bidding, resulting in the awarding of 25 concessions. The primary operators consist of PTTEP, Unocal, Chevron, ESSO, and Thai Shell. There are more than 21 fields currently in production, yielding hydrocarbons, with several development projects in the planning stages (DMF, 2020).

2.2.2 General Geology

The nnortheastern region of Thailand is situated between latitude 14°-19° N and longitude 101°-106° E, covering an area approximately 200,000 square kilometers and about one third of the area of the country (Sattayarak, 2005). It comprises the Khorat Plateau which is bounded on the North and East by the People Republic of Laos and the Western part is connected to central and northern Thailand. The southern part is bounded by Democratic Kampuchea. The Khorat Plateau is consisted of two fold belts; The N-S treading Loei - Phetchabun fold belt and the NW-SE trending Phu Phan Anticline. The basin extends into Laos, and the structure can be categorized into five basins; Sakon Nakhon Subbasin, Khon Kaen Subbasin, Ubon Subbasin, Vientiane Subbasin, and Savannakhet Subbasin (Piyasin, 1995). The stratigraphic sequences of the Khorat Plateau region range in age from the Early Paleozoic to the Neogene. Most of the area of the Khorat Plateau consists of Khorat Group rocks. Based on drilled wells data, the Khorat Group rocks are the Late Triassic to Early Cretaceous sediments. The overlying Late Tertiary Tha Chang, the Late Cretaceous - Middle Eocene Mahasarakham and Phu Tok formations, and the underlying Late Triassic Huai Hin Lat (Kuchinarai Group) are excluded from the Khorat Group rocks (GMT Cooporation Ltd., and SUT, 1999; Sattayarak, 2005; Atop, 2006; Chantong, 2007; Glumglomjit, 2010; Minezaki, 2019).

2.2.3 Stratigraphy

Chantong (2007) established the lithostratigraphy, depositional characteristics, and hydrocarbon system of the Khorat Plateau have been established (Figure 2.1) through the integration of seismic stratigraphy, tectono-stratigraphy, well data, prior research, and an analysis of the region's tectonic history. This analysis identifies six tectono-stratigraphic units. The Pre-Caledonian and Pre-Variscan Megasequences, representing the Early to Late Carboniferous age, constitute the basement of the region. The Pre-Indosinian I Megasequence, categorized as a pre-rift Megasequence, spans from the Late Carboniferous to Late Permian age. The Pre-Indosinian II Megasequence encompasses both the syn-rift and earliest post-rift Megasequences, occurring during the Triassic period. The Pre-Himalayan Megasequence is associated with post-rift and post-inversion Megasequences, extending from the Late Triassic to Early Late Cretaceous age. The Post-Himalayan Megasequence is Middle Miocene in age. Details of lithostratigraphy and petroleum system of northeastern region of Thailand are summarized and listed as follows;

2.2.3.1 Pre-Caledinian Megasequence (Pre-Permian basement)

The Pre-Caledonian Megasequence comprises a metamorphic basement that is differentiated from the overlying non-metamorphosed sequence. Rocks older than the Late Carboniferous in the Loei - Phetchabun fold belt and the Khorat Plateau area are recognized as part of the basement layer.

The Na Mo Group, dating back to the Middle Silurian period, represents the most ancient metamorphic basement and exposed in the Loei province along the northwestern edge of the Khorat Plateau. These low-grade metamorphic rocks, found in the upper greenschist facies, consist of phyllite, chlorite, schist, metatuff, and quartzite.

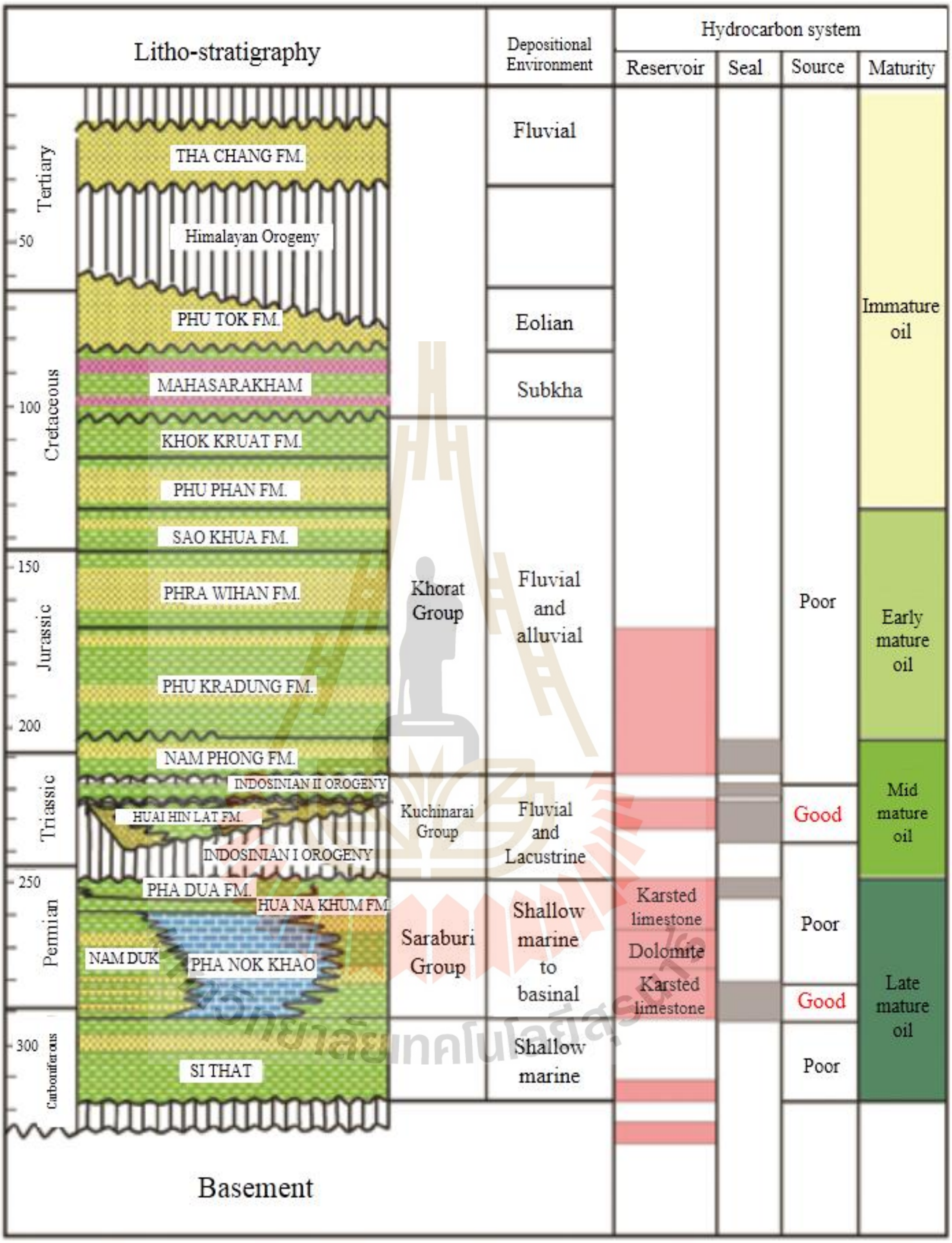


Figure 2.1 Lithostratigraphy and petroleum system of northeastern region of Thailand (modified after Chantong, 2007).

2.2.3.2 Pre-Variscan Megasequence (Pre-Permian basement)

The Pre-Variscan Megasequence comprises the Pak Chom Group, which lies beneath the Variscan unconformity. Stratigraphically, the Variscan Orogeny is dated to the Early to Middle Carboniferous period. Rocks that predate the Late Carboniferous are regarded as the basement in both the Loei-Phetchabun fold belt and the Khorat Plateau area.

The Pak Chom Group, dating from the Late Silurian to Early Carboniferous, primarily comprises shallow marine sedimentary of limestone, greywacke, shale, conglomerate, and tuff. Notably, the sequence also contains radiolarian chert indicative of a deep-sea facies suggested allochthonous content. The Pak Chom Group uncomformably overlies the Na Mo Group.

2.2.3.3 Pre-Indosinian I Megasequence

The Pre-Indosinian I megasequence unconformably is overlies the Pre-Varisan Megasequence. It is below the Indosinian I unconformity, which is dated from the Late Carboniferous to the Late Permian period. The Pre-Indosinian I megasequence can be subdivided into two groups in ascending order: the Si That Group and the Saraburi Group.

The Si That Group

The Si That Group, referred to as the pre-rift megasequence, is exclusively encountered in subsurface data, situated beneath the Phu Phan range. Comprising sediments from a shallow marine depositional environment known as the R-Sarn sea, these sediments were laid down during the Late Carboniferous to Late Permian period. The Si That Group can be categorized into three distinct formations: Si That, Dong Mun, and Lam Pao formations.

The Si That formation deposite during the Late Carboniferous to Early Permian period. Informally referred to as the "Lower Clastics," this rock unit comprises grey to dark shale interbedded with limestone, dolomite, and siltstone with some conglomerate in the lower part of the formation.

The Dong Mun formation is identified as originating from the Early to Middle Permian period. This rock unit primarily comprises carbonate rock, encompassing mudstone and dolomite. The limestone within it exhibits shades of pale yellow and brown. Meanwhile, the dolomite ranges from light grey to dark grey and also exhibits a moderate level of hardness.

The Lam Pao formation is identified as Late Permian. This rock unit comprises of interbedded limestone, claystone, and siltstone. The limestone are mudstone and wackstone, with colors ranging from brown to medium grey and dark grey. They are rich in calcareous content. Claystones in this formation exhibit a light grey. The siltstone displays of grey to dark grey, possesses a moderate level of hardness, and argillaceous.

The Saraburi Group

The Saraburi Group is described as a pre-rift megasequence, composed of sediments deposited in a range of shallow to deep marine environments, specifically the Nam Duk sea, during the Early to Late Permian period. Saraburi Group is extensively exposed along the western border of the Khorat Plateau, extending from Loei, Petchabun to Saraburi province. The carbonate sequence is comprises of limestone, dolomite, and clastic sediment of shale, sandstone, and siltstone. The Saraburi Group can be divided into three formations as follow;

The Nam Duk formation is characterized as originating from the Early to Middle Permian period. This rock unit is comprised of pelagic shale, sandstone, limestone, as well as lenticular and bedded limestone, with a minor amount of chert. This rock sequence is indicative of a deep-sea basin depositional environment.

The Pha Nok Khao formation is categorized as having formed during the Early to Middle Permian period. This formation consists predominantly of shallow-marine massive and thick-bedded limestones, fractured dolomites, and thin-bedded shales (Chaodumrong and Burrett, 2014).

The Hua Na Kham formation is identified as originating from the Late Permian period. These outcrops are located along the northern edge of the Khorat Plateau. This rock unit conformably overlays the Pha Nok Khao formation and has informally name "Upper Clastics." The Upper Clastics are consist of conglomeratic sandstone, light grey to grey shale, siltstone, and sandstone with minor limestone beds. The fossils including fusulinids within the limestone suggests that the sedimentary sequence of this formation was deposited in a shallow platform marginal marine environment.

2.2.3.4 Pre-Indosinian II Megasequence

The Pre-Indosinian II Megasequence unconformably is ovelies Pre-Indosinian I Megasequences. This geological arrangement can be further divided into the Kuchinarai Group.

The Kuchanarai Group

The Kuchinarai Group is defined as the syn-rift megasequence. There are contains coarse, fluvial, alluvial-fans sandstones and organic-rich lacustrine shales interbedded with volcaniclastic rocks (Minezaki, 2019). This group can be divided into three parts. The lower part is made of basal conglomerate. The middle part is consisted of dark lacustrine shale with minor amount of siltstone, and sandstone. Light to moderate dark grey, red brown to rust brown claystone, and shale is the upper part.

The Huai Hin Lat Formation classified as the earliest post-rift megasequence. Primarily comprising claystone, and siltstone interbedded claystone, siltstone, chert, and quartz-conglomerate. Its deposition during the Late Triassic is supported by evidence from plant remains, pollen, spores, and conchostracan fossils.

2.2.3.5 Pre-Himalayan Megasequence

The Pre-Himalayan Megasequence comprises sedimentary units situated between the Indosinian II and the Himalayan unconformity. There are comprised of the Khorat and Phon Hong Groups.

The Khorat Group

The Khorat Group is classified as a post-rift megasequence, characterized by substantial deposits of red clays, conglomerates (continental sediments), siltstone, and sandstone that accumulated during the Jurassic to Cretaceous period. The geological unit is present in both the Loei-Phetchabun fold belt and the Khorat Plateau, and it can be subdivided into six formations.

The Nam Phong formation represents the lowest unit. It can be divided into two parts. The upper part is primarily composed of siltstone, with minor of sandstone and claystone, occasionally interspersed with thin layers of limestone. The lower part consists of red-brown sandstone, claystone, and siltstone.

The Phu Kradung formation comprises interbedded of sandstone and siltstone, occasionally punctuated by limestone lenses, concretions, and thin layers of claystone. The sandstone ranges from light grey, light to medium brown, red brown, medium green to off white with varicoloured grains.

The Phra Wihan formation is composed of cross-bedded with quartz sandstone, interspersed with thin bed of siltstone, and occasionally containing thin beds of claystone and nodular limestone. The sandstone varies in color, ranging from off-white to grayish-green and varing of grain size.

The Sao Khua formation comprises interbedded of sandstone and siltstone, with minor claystones, with occasional nodular limestone occurrences towards the base. The deposition of this formation predominantly occurred in a low-energy environment.

The Phu Phan formation consists of fine to medium-grained sandstone interbedded with siltstone. The sandstone displays colors ranging from off-white to light grey, grey-green, reddish-brown, and occasionally light brown. It is moderately hard, with a sub-angular texture, some micaceous, and traces of siltstone and limestone lithoclasts.

The Khok Kruat formation is composed of interbedded reddish-brown sandstone, siltstone, and claystone, occasionally containing conglomerate layers (Meesook, 2011; Racey et al., 2009). The sandstone is very fine to medium-grained, with a rounded to sub-rounded texture. It is friable, with a silty/argillaceous matrix, and exhibits fair to poor visible porosity.

The Phon Hong Group

The Phon Hong Group is characterized as a post-inversion megasequence, composed primarily of hypersaline lacustrine and Aeolian sediments deposited during the Early Late Cretaceous period. This group can be further categorized into the Maha Sarakham and Phu Tok Formations.

The Maha Sarakham formation comprises anhydrite and salt in lower part and siltstone and shale in upper part and. This formation consists of three layers of halite, with minor occurrences of anhydrite separating within claystone. The halite is clear translucent appearance, varying from white to occasional grayish, orange, to pink hues. It is brittle, elongated, and exhibits a coarse to granular size. The anhydrite present in this formation is typically white, light grey, or pale red, and has a very fine to finely crystalline. It is brittle and ranges from blocky to sub-blocky in shape.

The Phu Tok formation comprises massive reddish sandstone, claystone, and siltstone, indicated in an Aeolian depositional environment. The sandstones display high angles and large-scale cross-bedding, interbedded with fine-grained channelized deposits. These features are interpreted as indicative of deposition by both streams and wind.

2.2.3.6 Post-Himalayan Megasequence

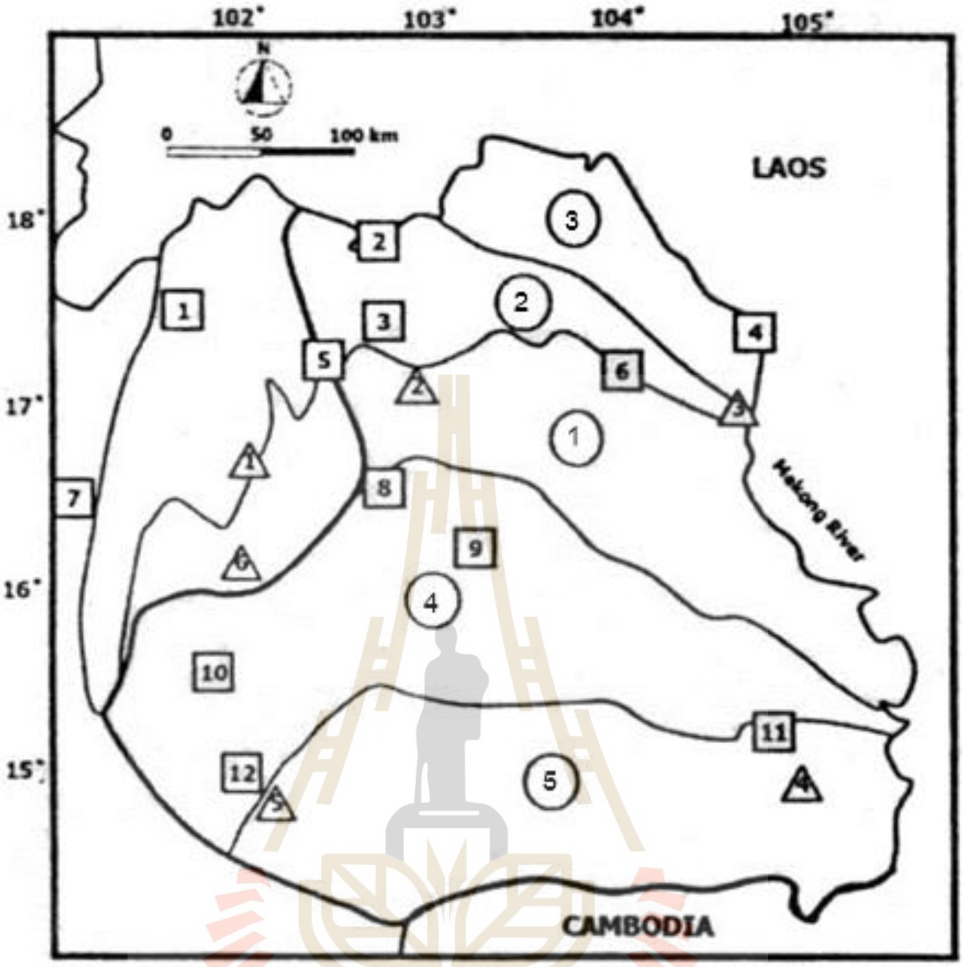
The Post-Himalayan Megasequence comprises rocks between the Himalayan unconformity and the base of Quaternary sediments, and includes the Tha Chang formation.

The Tha Chang formation comprises semi-consolidated to consolidated, mudstone, and conglomerate. Vertebrate fossils within this formation indicated a Middle Miocene age.

The Quaternary sediments, located beneath the soil cover along the edge of the Khorat Plateau, consist of gravel beds and lateritic soil layers. These gravel beds contain petrified wood specimens dating back to the Late Cretaceous to Early Quaternary period.

2.2.4 Petroleum Province

The petroleum province of the Khorat Plateau can be subdivided into five regions based on their geologic structures, geology, and geomorphology. This division excludes the western part, which encompasses the Loei, Phetchabun, and Chumphae areas. A study of the geological structures and prospects has been conducted in the Khorat Plateau to evaluate the petroleum potential of each regions (Sattayarak, 2005). The specifics of each province are detailed in Figure 2.2 as follows:



1 Petroleum Province: 1. Phu phan Anticlinorium 2. Nong Khai-Tat Phanom Area 3. Phon Phisai-Nakhon Phanom Area 4. Khon Kaen-Ubon Area 5. Chok Chai-Det Udom Area

1 Changwat/Province: 1. Loei 2. Nong Khai 3. Udon Thani 4. Nakhon Phanom 5. Nong Bua Lamphu 6. Sakon Nakhon 7. Petchabun 8. Khon Kaen 9. Maha Sarakham 10. Chaiyaphum 11. Ubon Ratchathani 12. Nakhon Ratchasima

1 Amphoe/District: 1. Chum Phae 2. Khoa saun Kwang 3. Tat Phanom 4. Det Udom 5. Chok Chai 6. Phu Kiew

Figure 2.2 Petroleum Provinces, Northeastern Region (Sattayarak, 2005).

1) Phu Phan Anticlinorium

The Phu Phan Range comprises of complex anticlines and synclines treding NW-SE. It covers from Khao Nam Phong in the west, through Khao Suan Khwang, Khao Phu Phan, and Pha Taem to the east. Beneath this area, there are underlying geological formations including the Permo-Carboniferous formation, Triassic Pre-Khorat formation, and minor folding of Jurassic-Cretaceous redbeds in the upper part.

2) Nong Khai-Tat Phanom Area

The Nong Khai-Tat Phanom region is located in north of Phu Phan Range from Nong Khai to Udon Thani and Nakhon Phanom. This area is covered by the Phu Tok and Mahasarakham Formations as younger rock units. These overlays the redbeds of the Khorat Group, which includes the lower part of the Triassic.

3) Phon Pisai-Nakhon Phanom Area

The Phon Pisai-Nakhhon Phanom area is located in north of Nong Khai–Tat Phanom region. The data obtained from drilling indicated that the underlying units are thick sandstone belonging to the Phu Tok Formation, which was deposited through eolian processes. Beneath these sandstone units lie the rock salt formations of the Mahasarakham Formation, followed by the redbeds of the Khorat Group, all resting atop the basement rocks.

4) Khon Kaen–Ubon Area

The Khon Kaen-Ubon region covers mainly Khon Kaen and Ubon Ratchathani Province, extending in an east-west direction. Its geological stratigraphy closely resembles that of the Nong Khai-Tat Phanom region. But the thickness of the Khorat Group and the overlying sediments are much greater.

5) Chok Chai-Det Udom Area

The region is covered by gravel beds and basalt, which overlie the redbeds of the Khorat Group and the basement rocks. The pre-Khorat unit is found in some places based on the well data.

2.2.5 Petroleum System of Northeastern Thailand

The important parameters for hydrocarbon exploration are source, reservoir, and seal. Moreover, the maturation of petroleum for generates. The petroleum system of northeast Thailand are summarized as follows:

1) Source Rocks and Source Rocks Maturity

The result of geochemical data indicates that the Triassic Pre-Khorat sediments, the Permo-Carboniferous carbonates and shale contain a good to fair source richness (Sattayarak, Srikulwong, and Pum-In, 1989; Chinoroje and Cole, 1995; Piyasin, 1995). Chantong (2007) discussed the Huai Hin Lat Formation consists of lacustrine grey shales, mudstones, and limestones of good source quality. Geochemical analyses of these sediments from both surface samples and exploration well samples in the Khorat Plateau have total organic carbon (TOC) values from 0.2-5.76% and Ro values from 0.9-20.52% (Chantong, 2007). Arsairai (2014) discussed the Ban Nong Sai section in Sap Phlu Basin show the present-day total organic carbon in the range of 1.9-7.1% and the original total organic carbon values range from 5.1-10.7%. The study of gas analysis in Dao Ruang-1well by Chinoroje and Cole (1995) indicates that methane and ethane carbon isotopes comes from organic-rich lacustrine shale and coals of the Triassic Pre-Khorat.

Several Permian rock samples from the surface and exploration wells show TOC of 0.29-1.59% (Thongboonruang, 2008). The potential source is restricted chiefly to Permian shales intercalated within the Pha Nok Khao Formation (Piyasin, 1995). The lower part of the Pha Nok Khao Formations in Dao Ruang-1 contains fair source richness (TOC 0.5-1 percent) in limestones. It contains kerogen type III and is gas-prone (Chinoroj and Cole, 1995). Geochemical analysis of these sediments shows that they are very mature to overmature. Maturation modeling using the present-day geothermal gradient of 1.20°F/100 ft (Sattayarak et al., 1989) suggested that oil could probably be generated in the Jurassic after the deposition of the lower part of the Khorat Group.

2) Reservoir Rocks

Based on the available data, it can be indicated that Permian carbonates are significant reservoirs within the Khorat Plateau and are typically the primary targets (GMT Cooporation Ltd., and SUT, 1999; Atop, 2006; Chantong, 2007; Chantong, Srisuwon, Kaewkor, Praipipan, and Ponsri, 2013; Minezaki, 2019). The properties and characteristics of the Permian carbonate reservoirs in the Khorat Plateau are summarized below;

- The deposition of carbonates took place on the isolated platforms. Within the cores, it was observed that the lithofacies of the carbonates are primarily characterized by fossiliferous packstone and grainstone, with wackestone and mudstone being less commonly found.
- Low porosity and low permeability are considered standard characteristics of these carbonates. In general, the porosity ranges from 0 to 18% (with an average of 4.0%).
- They were subjected to deep burial, multiphase karstification, and deep erosion.
- The mud-rich lithofacies (mudstone and wackestone) exhibit higher porosity values compared to the grain-rich lithofacies (packstone, grainstone, and boundstone). By lithology, the dolomite appears to have higher porosity than limestone (Kozar, Crandall, and Hall, 1992)
- The permeability of the carbonates seems to be primarily dependent on the presence of microfractures. The existence of these open microfractures is likely the cause of the favorable gas flow rate observed in the Nam Phong Structure within the Khorat Plateau.

3) Trap and Seal

In northeastern Thailand, the geological structures that are considered suitable for petroleum traps are:1) the angular unconformity between the Saraburi and the Huai Hin Lat Formation and 2) The anticlinal structures that were formed during the Tertiary period.

2.2.6 Petroleum Prospects in Both Triassic and Permian Basin Play

Both Triassic & Permian basins play is the target and has not been tested. This formation can be deposited in Triassic and Permian basin in the same area. Chantong (2007) suggested that both Triassic & Permian basins play can be divided into three groups as follow:

1) Permian pinch out: It is the target in Saraburi Group or older (thin formation) and disappears in the basement. Lower section was strong reflector and it could be Si That Formation. This target does not have fault control. The examples for this target are Ubon, Det Udom and Nong Ngu Luam structure.

2) Permian underneath very thick graben: It is the half-graben basin in Triassic, which in southwest of Khorat plateau. Kuchinarai Group had been deposited in half-graben and it was very thick. The reflect under Kuchinarai Group similar to Saraburi group. This target was not tested but predicted to be the petroleum potential area because of there have source rock (Kuchinarai Group) and reservoir rock (Saraburi Group) in the same area. Moreover, Kuchinarai group is good trap. These targets are complex structure and difficult to scope the area. So, this area could be study more. The examples for this target are Lam Phra Phloeng, Sikhiu, Dan Khun Tod, Don Phrai and Lam Nang Rong structure.

3) Very complex structure (cannot be defined): This target is underneath of Khorat Group with very complex structure and fault lines cutting across. From seismic data, the reflector is not well defined. It can be Kuchinarai Group (Triassic period) or Saraburi Group (Permian period) or older (Pre-Permian). The seismic reprocessing is the way for well-defined structure. The examples of this target are Sida, At Samat, Puthai Song, Phayakkhaphum Phisai, Kaset Pasai, Chaturaphak Phiman, Mancha Kiri, Nong Khaman, Chumphon Buri, West Sri Sa Ket and East Sri Sa Ket structure.

2.2.7 Exploration History in the Sikhiu Prospect

Block L21/57 in Petroleum Bidding Round 21^{st} (Figure 2.3 and Figure 2.4) consists of at least 2 prospects which are Sikhiu and Don Phrai. It is located in Nakhon Ratchasima province. It covers the area of 2,935.89 km^2 (Department of Mineral Fuels [DMF], 2014). The Sikhiu prospect (the studied prospect) is located in the vicinity of Sikhiu district, in the Nakhon Ratchasima province, southwestern part of the Khorat Plateau between latitudes 14°55΄0″ to 15°05΄0″ North and longitudes 101°45΄0″ to 102° 00΄0″ East (Figure 2.5). No wells have been drilled in this block up to date. The nearest wells are on Chonnabot prospect.

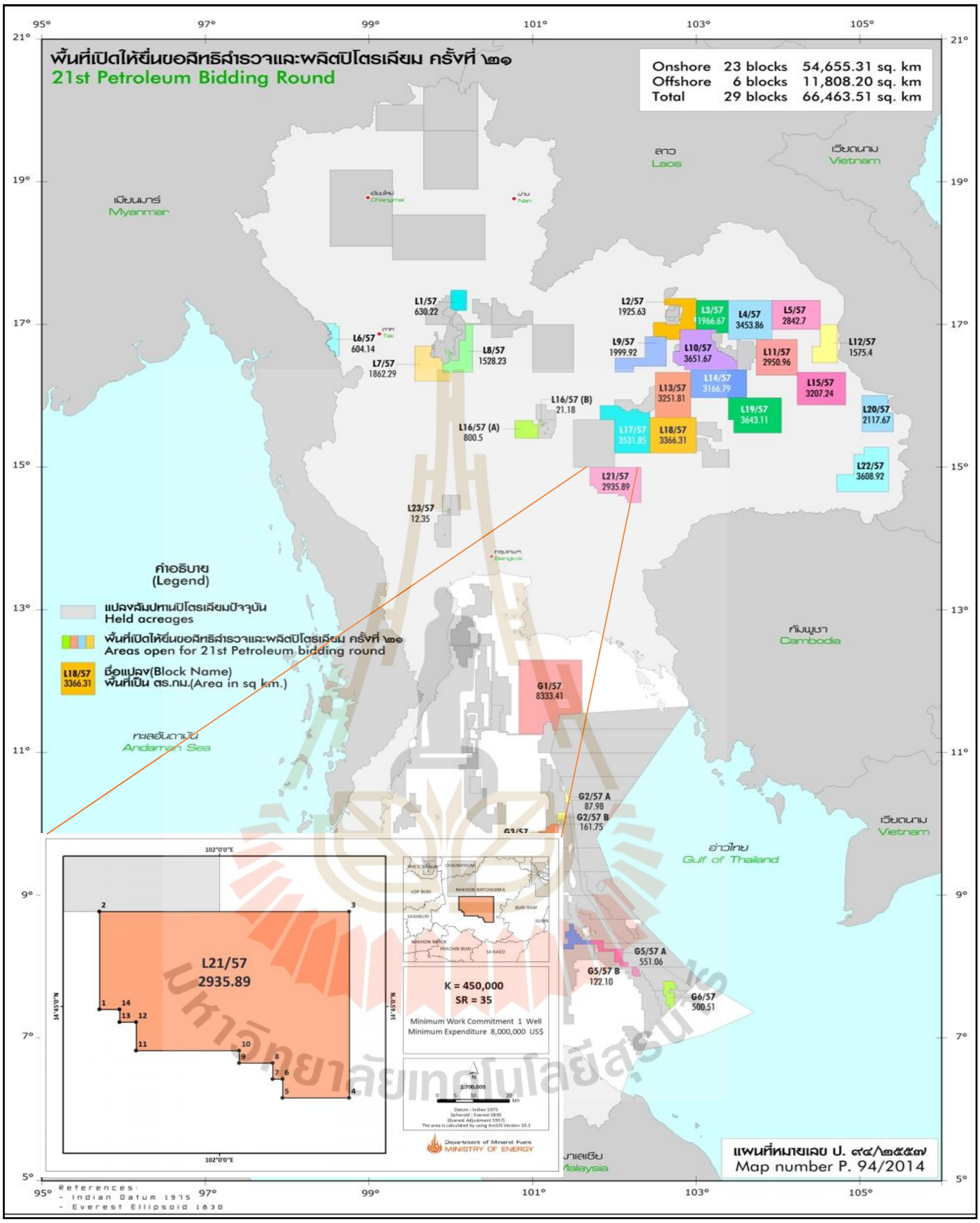


Figure 2.3 Petroleum Bidding Round 21st (DMF, 2014).

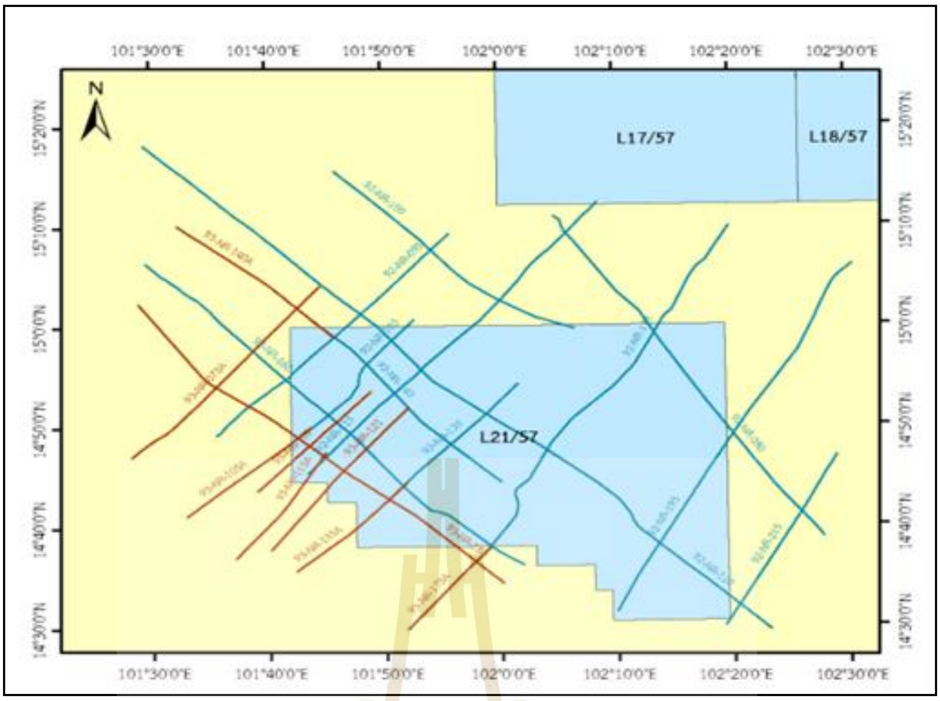


Figure 2.4 Geographic location of block L21/57 and 2D seismic survey lines which pass through and nearby the block (DMF, 2014).

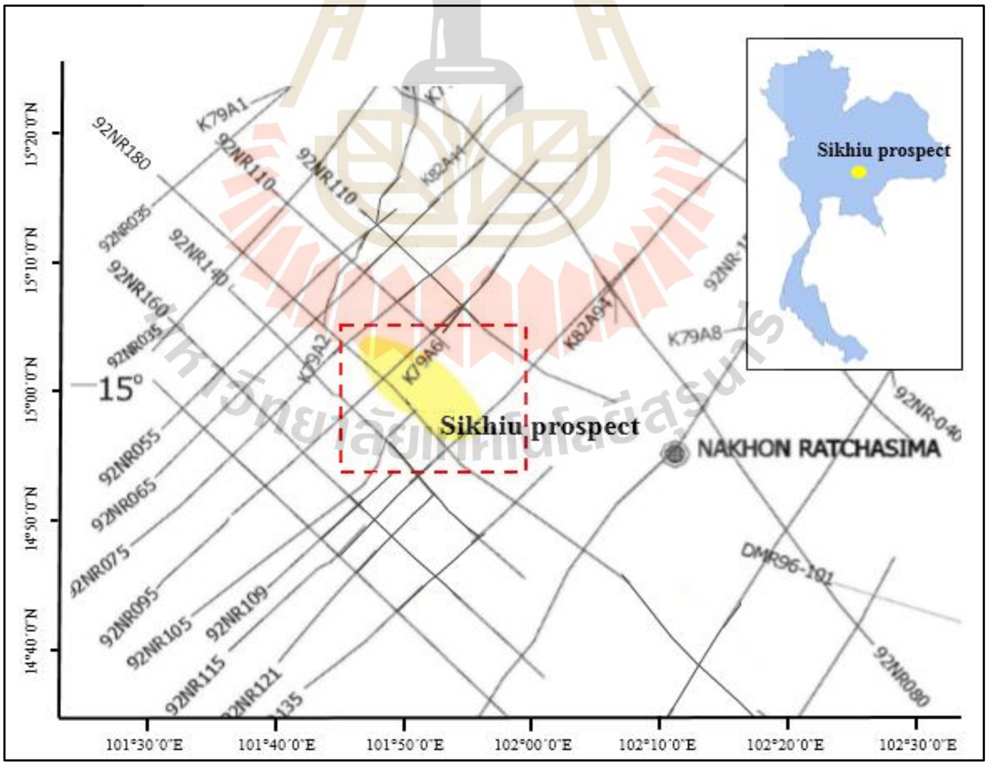


Figure 2.5 Sikhiu prospect location and nearby 2D seismic lines (modified after Chantong, 2007).

2.2.7.1 Seismic Interpretation of Sikhiu Prospect

The seismic section depicted in Figure 2.6 is of the 2D seismic line 92NR180. The expected exploration play of Sikhiu prospect (the studied prospect) is the Lower-Middle Permian carbonate reservoir of the Pha Nok Khao Formation. Seismic profile (Figure 2.6) shows planar tilted extensional fault block which produced horst and graben geometries. For the Pha Nok Khao play, it was shortening by imbricated thrusts which can be the trap for this play. The top of Pha Nok Khao Formation is marked by light blue horizon and the bottom of this formation is marked by dark blue horizon. The detachment layer of the imbricated thrusts may sit within Si That Formation (DMF, 2014).

2.2.7.2 Subsurface Geology of Sikhiu Prospect

Chantong, Chantraprasert, and Kolae (2008) suggested that the outcrop in this study area are Permian carbonate rocks and Triassic Pre-Khorat rocks, which are important to petroleum system and can be connected to subsurface rocks. The data of 2D seismic can be defined the rocks as follows.

1. Permian carbonate rocks

In the southwest of Sap Phlu Basin discovered Permian limestone with low porosity, coral reef, algae and sponge. This Permian limestone connected to subsurface to confirm that underneath of Sap Phlu Basin is likely Permian limestone and can be reservoir.

2. Triassic Pre-Khorat rocks

Basal conglomerate of the Triassic Sap Phlu Basin are found resting unconformably on top of the Permian strata. Pebbles are mostly limestone in both lime mud and sandy matrixed.

2.1 Conglomerate; clasts consist of limestone, chert, volcanic rock, granite. Size of clasts are 5x10 cm to 15x30 cm Very poorly sorted, subangular-subrounded, mud support. Matrix is lime mud, white-yellow. Limestone clasts; light grey. Most clasts are mudstone. Found some fusulinid grainstone. Chert clasts; dark grey. Volcanic clast; greenish grey. Orientation of bed 70/130. Thickness is 30 metres.

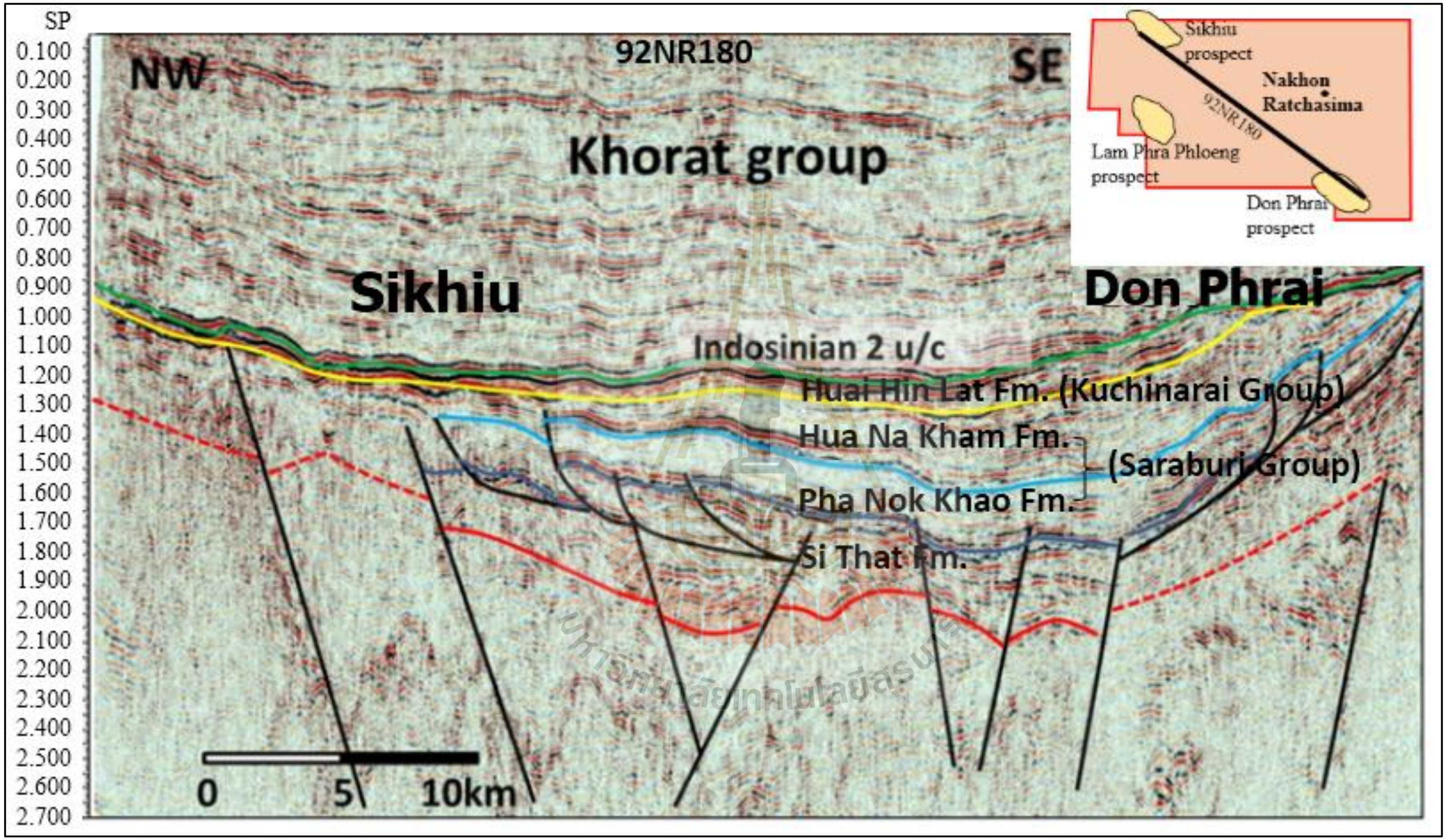


Figure 2.6 Seismic lithostratigraphic of Sikhiu prospect on the seismic profile along the 92NR180 seismic survey line (modified after Department of Mineral Fuels [DMF], 2019).

2.2 Sandstone; greenish grey, fine grained, calcareous cement and well bedded.

2.3 Sandstone/shale; sandstone, medium-coarse grained. Mud pebble, cross bedding and graded bedding. Shale- grey, thin bedded 1-2 cm found Euestheria sp. This is the middle part; thickness is 2 meters.

2.4 Shale/sandstone; shale, grey, lamination in thin bedded and sandstone, thin bedded. Show graded bedding of sandstone, which is the upper part. Thickness is 5 meters.

2.2.7.3 Relationship between 2D Seismic Profile and Surface Geology

Result of 2D seismic profile interpretation indicated that underneath Khorat group in the middle part is Triassic pre-Khorat rock, which very thick because there is middle of basin. Left side or southwest of basin found outcrop at Sap Phlu Basin. Underneath could be Permo-carboniferous rock, which confirm from surface geology data (Figure 2.7).

If comparing the Sap Phlu Basin with Sattayarak's model, tends are in the same direction which is Triassic pre-Khorat half graben. The sediment deposit in lake and has fault line in southwest of basin, nearby there are Permian carbonate rock (Figure 2.8).

The structure of Sap Phlu Basin had NW-SE trending and very thick in the northeast, the outcrop shows basal conglomerate and lacustrine shale. So, outcrop can connect to subsurface data-seismic profile, which are important to petroleum system.

2.2.7.4 Structural Map from 2D Seismic Data

After interpreting 2D seismic data cover the Sap Phlu Basin and nearby, map shows the thickness of Triassic pre-Khorat rocks (Isochron map) and shows Time-structure map of Top Permian rocks can be generated as depicted in Figure 2.9 and Figure 2.10 respectively. Based on the established maps of Chantong et al. (2008), the Triassic pre-Khorat rocks have very thick in the northeast. It's can be good source rock and the petroleum can migrate to highest area in the southwest of the Permo-Caboniferous rocks.

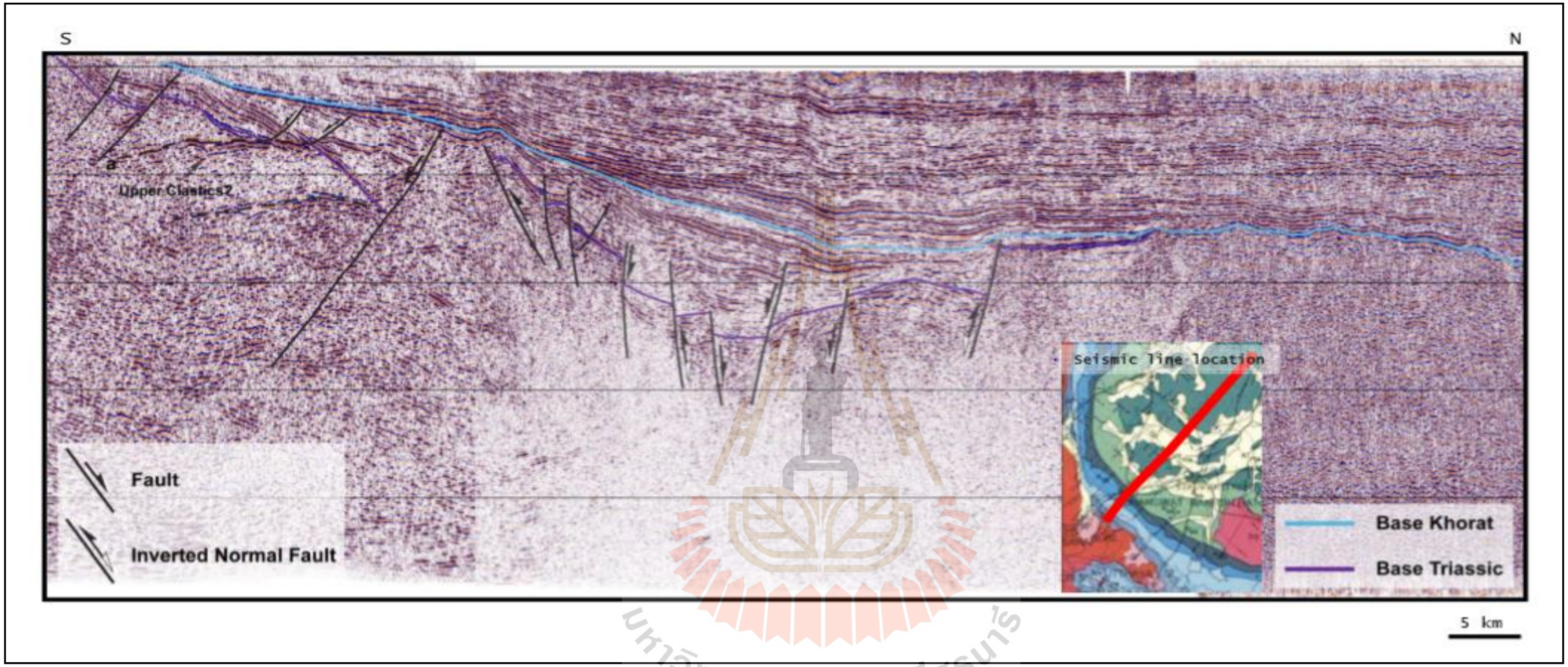


Figure 2.7 The Sap Phlu half-graben containing Traissic lacustrine sedimentary strata underlain by Permian succession (Chantong et al., 2008).

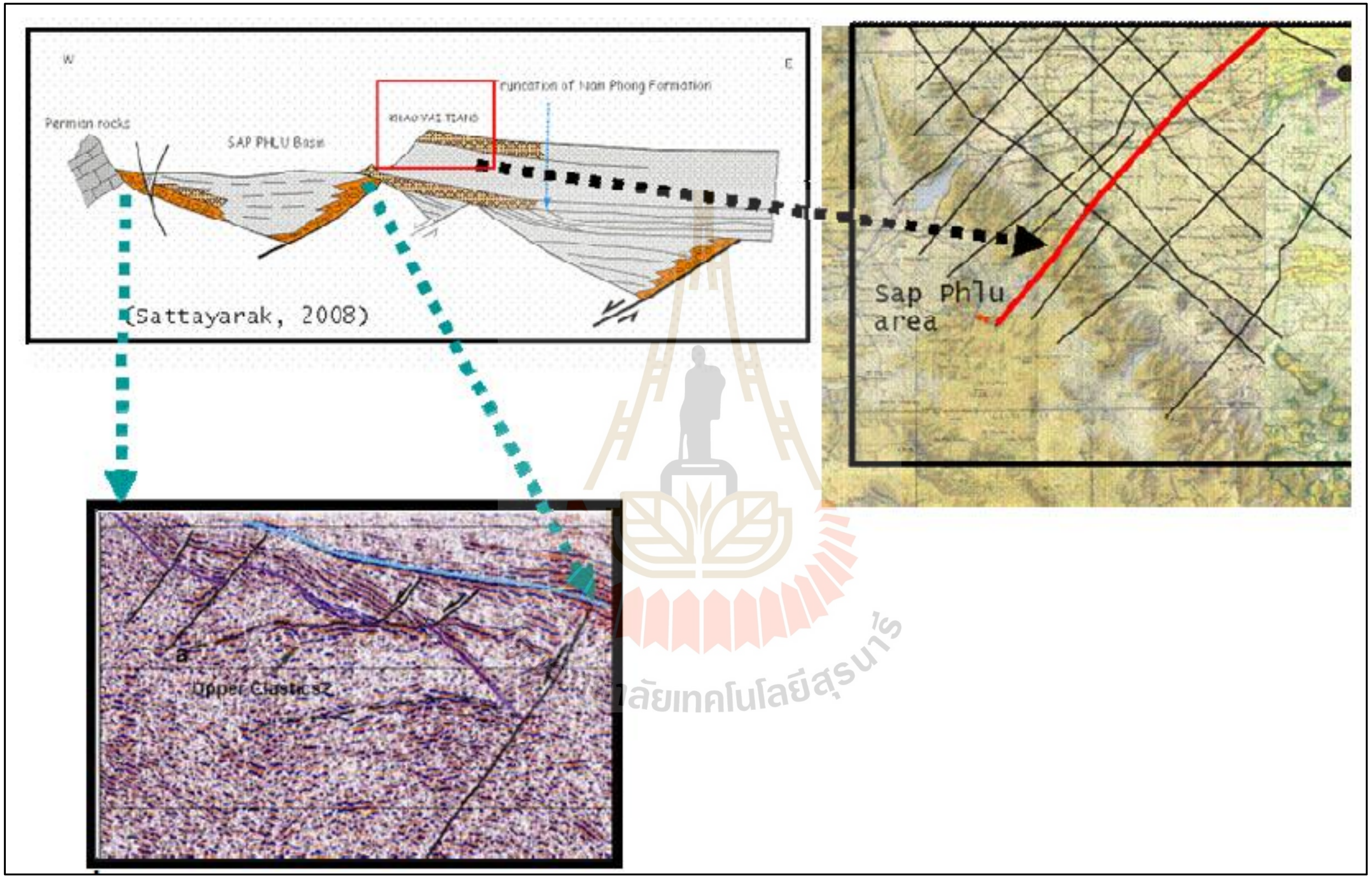


Figure 2.8 Relationship between 2D seismic profile and surface geology (Chantong et al., 2008)

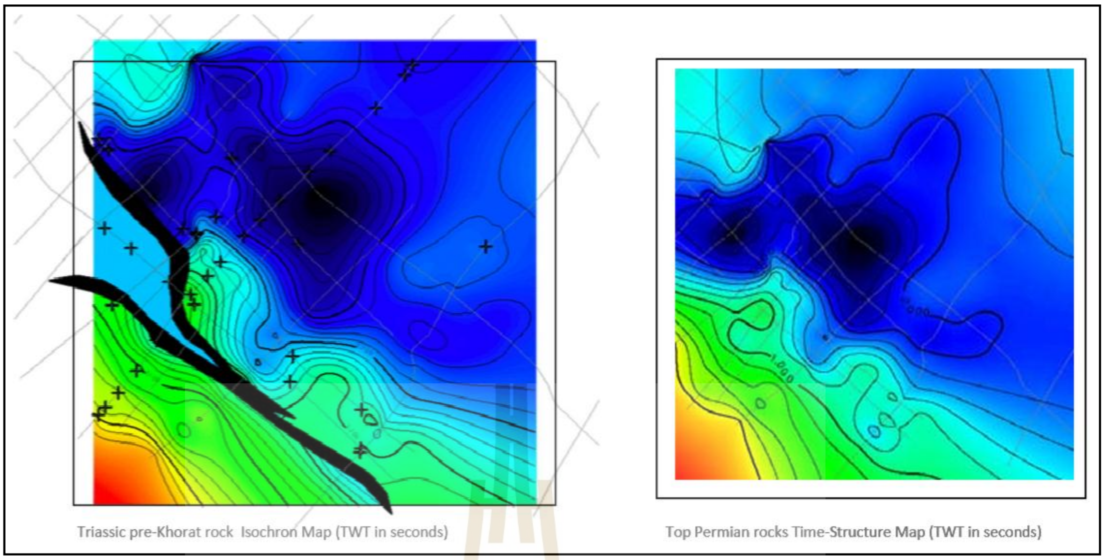


Figure 2.9 Triassic Pre-Khorat rocks isochron and Top Permian rocks Time-structure map (Chantong et al., 2008).

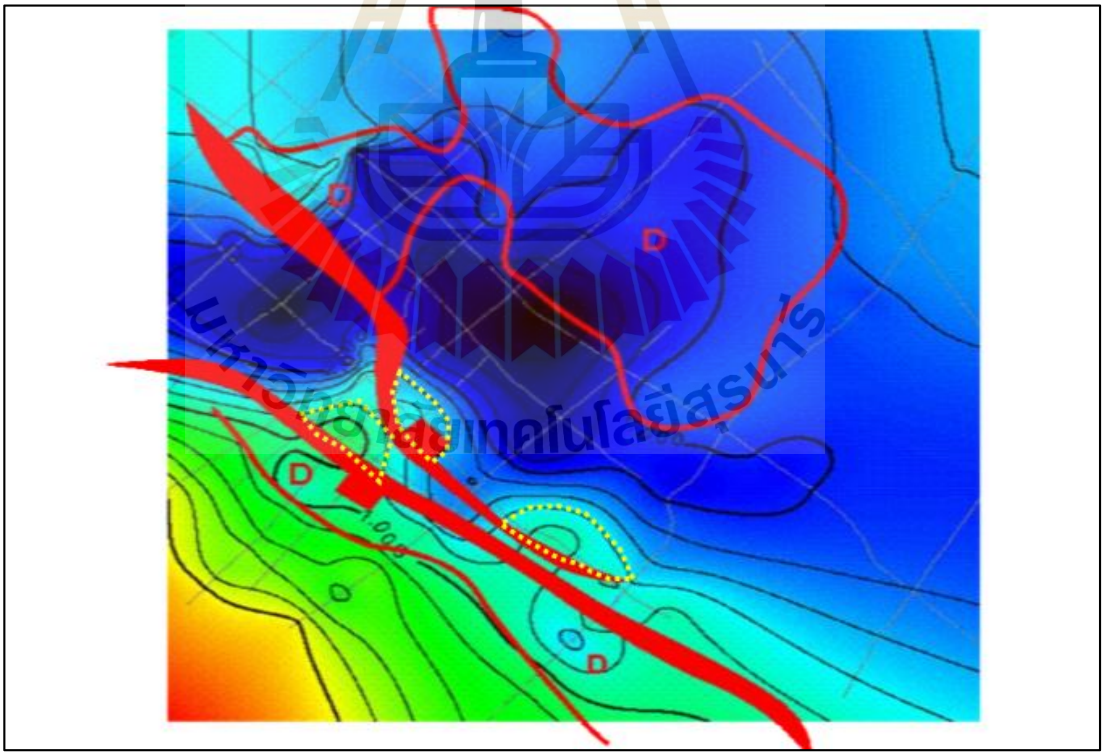


Figure 2.10 Triassic faults and depocenters over Top Permian Time-structure map (modified after Chantong et al., 2008).

2.3 Petroleum Economics

2.3.1 Petroleum Potential and Risk Assessment

WPC (World Petroleum Congresses), AAPG (American Associated Petroleum Geologists), SPE (Society of Petroleum Engineers), and SPEE (Society of petroleum Evaluation Engineers) have collaborated to develop an international standard system for classification and definition of petroleum resources and reserves as depicted in Figure 2.11 (CCOP, 2000).

Petroleum resources refer to the complete volumes of hydrocarbons, including discovered and undiscovered petroleum.

Discovered resources refer to the quantities of petroleum (such as oil or natural gas) that have been identified, located, and confirmed to exist in specific subsurface reservoirs or fields, according to current understanding of the quantities in place and the recovery factor.

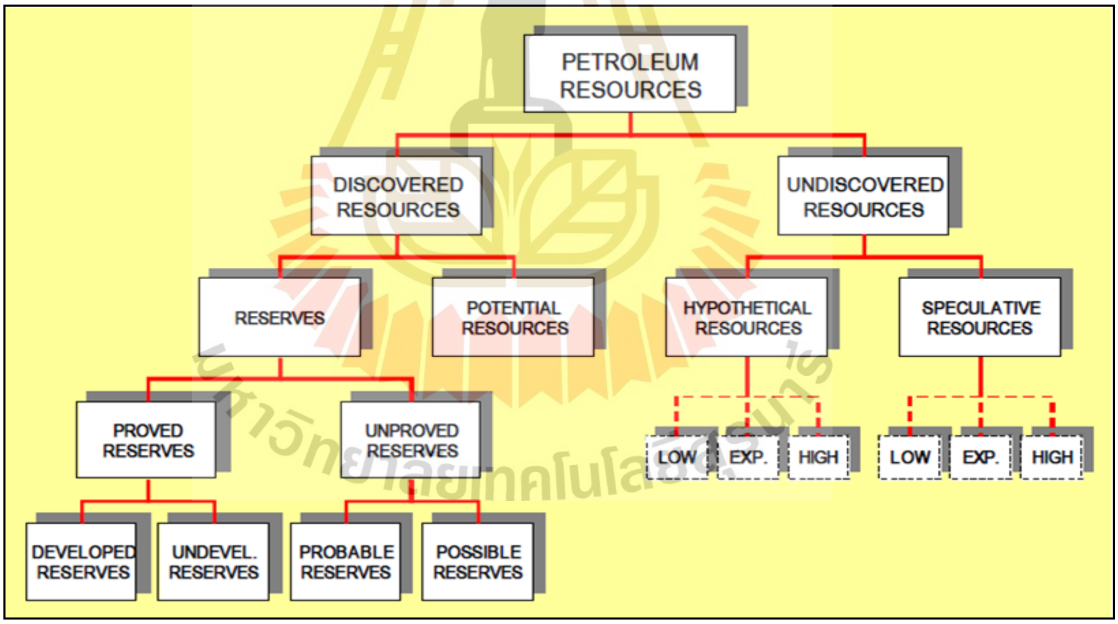


Figure 2.11 CCOP Petroleum resource classification chart of recoverable resources. (CCOP, 2000).

Undiscovered resources refer to the estimated quantities of hydrocarbons that are believed to exist in a particular geographical area but have yet to be found or proven through exploration and drilling. Undiscovered resources are determined through the analysis of geophysical, geological, and geochemical data.

These data are compiled into geological models and maps to define hydrocarbon plays. The discovery of petroleum accumulations within these plays depends on the presence of specific geological conditions. In this study, the total estimated volumes of recoverable petroleum from undiscovered accumulations are calculated using statistical methods, computer programs (FASPU), or Monte Carlo simulations.

The Fast Appraisal System for Petroleum Universal (FASPU) program is software system used in the oil and gas industry. It is designed to perform rapid and comprehensive assessments of petroleum resources and reserves, aiding in the evaluation of hydrocarbon potential within specific geological areas or reservoirs. FASPU typically integrates various data by using a play analysis method, which is a general term of geologic model and the probabilistic method, to generate estimates of undiscovered hydrocarbons resource. (Crovelli and Balay, 1994).

Trisarn (2010) calculated the potential and risk assessment of petroleum resources in the northeast Thailand using a FASPU program. He concluded that the petroleum resources potential of Chonnabot formation are 122-234, 403-622 and 833-1808 Bcf. Namphong formation are 420-456, 819-1264 and 2084-2851 Bcf. And the petroleum resources of Permian formation are 6,498-14,831, 40,645-70,564 and 252,860-307,507 Bcf. In the probability of 90, 50 and 10 respectively.

Glumglomjit (2010) studied on petroleum potential assessment of Chonnabot prospect by using FASPU program. Results of the study indicated that the undiscovered petroleum resource can be summarized as follows; 1) the quantity of oil accumulation is 41.1835 MMbbl but the chance of discovery is only 5 percent. 2) The quantities of non-associated gas accumulation are varying size as 122.433, 270.895, 470.444, 816.987 and 1,807.66 Bcf. In the probability of 95, 75, 50, 25 and 5 respectively (Table 2.1).

Table 2.1 Results of undiscovered hydrocarbon resource assessment of the Chonnabot prospect, Carbonate Play (Glumglomjit, 2010).

Result	Mean	F95	F75	F50	F25	F05
Oil resource (MMbbl)						
Number of accumulations	0.161	0	0	0	0	1
Accumulation size	15.015	2.815	6.212	10.768	18.664	41.184
Unconditional play potential	1.958	0	0	0	0	13.877
Non-associated gas resource (Bcf)						
Number of accumulations	4.479	3	4	4	5	7
Accumulation size	657.53	122.43	270.9	470.44	816.99	1,807.66
Unconditional play potential	2,345.50	0	1,250.23	2,232.27	3,337.20	5,644.70

Note F = fractile

Mean = arithmetic mean

2.3.2 Types of Petroleum Arrangements

The petroleum arrangements can be categorized into two system; there are concessionary system and contractual system (Figure 2.12). The different between these two systems is, under concessionary system, all of concessionaires are subject to the same conditions in term of the contractual as well as the fiscal and the mineral rights to be transfer to private companies. On the contrary, contractual system, each contractor might be subject to difference conditions and the ownership of mineral resource remains with the state (Chotipanvittayakul and Mantajit, 2011).

The contractual system divided into two sub-main arrangements, production sharing contract (PSC) and service contracts (SC). The difference of these two sub-main arrangements is the production sharing contract receives compensation in term of production. In contrast, the service contractor receives compensation in cash. (Chotipanvittayakul and Mantajit, 2011).

2.3.2.1 Concessionary Contract

Concession contract is a grant of an exclusive right to explore and develop petroleum under given area of a specific time (Chotipanvittayakul and Mantajit, 2011). The petroleum vested in the state is transferred to company once petroleum enters the drilling well. In return, oil companies pay royalties and taxes to the state. A modern concession has developed to allow state involvement in operation, smaller area of granted blocks and shorter duration of concessions.

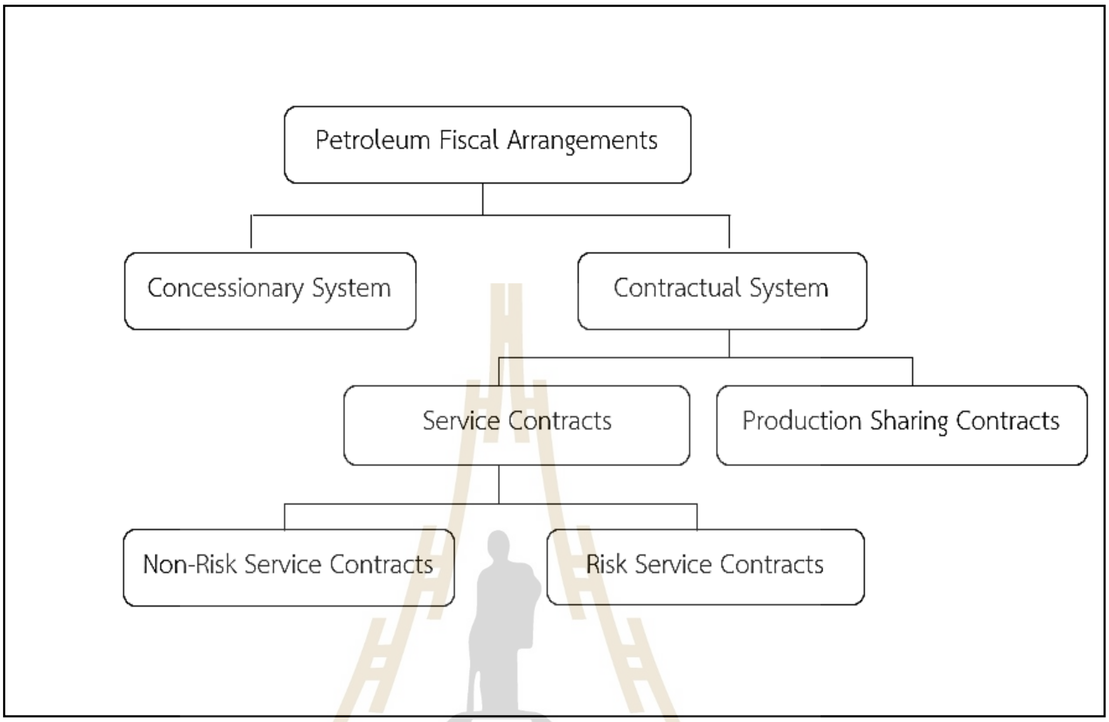


Figure 2.12 Petroleum Arrangements (Chotipanvittayakul and Mantajit, 2011).

2.3.2.2 Production Sharing Contract (PSC)

In production sharing contract, Oil company operates at its sole risk and expense, but it entitles to the cost recovery from the production. After the cost recovery is recouped, the production will be allocated to the companies according to the percentage agreed in contract, not the whole production (profit oil). Additionally, income tax is levied upon the company profit on profit oil.

2.3.2.3 Service Contract

The contractor provides service and know-hoe technology without the control power in the operation, and receives fee in return. The service contract can be divided into non-risk service contract (pure service contract) and risk service contract.

Non-risk service contact: Oil company receives the flat fee for reward. This is not contingent on whether the discovery is successfully made.

Risk service contract: Only if the commercial production is carried out, Oil Company is able to claim its reimbursement and service fee.

2.3.3 Petroleum Act of Thailand

2.3.3.1 Thailand I

In 1967, the Thai government implemented a concession system outlined in a document titled "Consideration Bases in Applying for Petroleum Exploration and/or Production." The Ministry of National Development invited exploration applications, which led to the Council of Ministers granting exploration rights to six oil companies. In 1968, abbreviated agreements were executed with these companies. These agreements stipulated that the Ministry would grant concession agreements once a new petroleum law was enacted (Chandler MHM Ltd., 2019)

In 1971, Thailand promulgated the original Petroleum Act (PA) (Thailand I) and Petroleum Income Tax Act (PITA). The PA established a concession system based on the Consideration Bases, and nine Ministerial Regulations were issued in 1971 dealing with major subjects under that act. The PITA established an income tax system applicable only to concessionaires, with tax rates ranging from 50% and 60%. A tax rate of 50% was specifically mandated by a Royal Decree. Three Ministerial Regulations were issued in 1971 under the PITA (Chandler MHM Ltd., 2019). The essences of Thailand I are summarized and presented in Table 2.2

2.3.3.2 Thailand II

In 1982, amid increasing oil prices, a set of new terms known as "conditions of bidding" were established for onshore blocks. These terms led to the granting of additional concessions. However, as oil prices subsequently declined and small, less productive fields were discovered, these terms discouraged further onshore exploration and production activities. Under the new regime, cost recovery was limited to 20% of annual gross revenue, and royalty rates were raised in proportion to production rate increases. From the reasons mentioned above, Thailand I was later revised to become the Thailand II petroleum act (Chandler MHM Ltd., 2019).

Table 2.2 Summary of the essences of Thailand I petroleum act (Chandler MHM Ltd., 2019).

Contract Terms	
Contract Type	Concession system
Contract Period (years)	
Exploration period	8 years + 4 years renewal period.
Production period	30 years +10 years from end of the exploration period.
Contract Area	
Relinquishment	50% after 5 years (35% in deep water) 25% after 8 years (40% in deep water)
Fiscal Terms	
Royalty	12.5% in cash (8.75% in deep water), and 1/7 in kind.
Petroleum Income Tax	Income tax on profits 50% to 60% (presently 50%); or 35% on profits plus 23.08% remittance tax under 1979 Royal Decree.
Work expenditure	Work and financial obligations are fixed for first 3 years, and second 5 years.
Operating costs	Company responsibility.
Bonuses	According to application for concession, referred to as special benefits.
Capital cost recovery	Amortized over 5 to 10 years

2.3.3.3 Thailand III

Thailand III was implemented in 1989, significantly changing the petroleum fiscal regime. One notable change was the royalty rate adjustment, which was restructured into a sliding scale. This modification aimed to facilitate commercial production across fields of varying sizes (Figure 2.13).

In the Thailand III concession system, the concessionaire will obtain income as the residual amount from the revenue after deducting royalties, special remuneratory benefits (SRB), and taxes. On the other hand, the government will generate income through royalties, which follow a sliding scale, petroleum income tax at 50% of the net profit, and SRB. The essences of the Thailand III petroleum act are summarized and presented in Table 2.3.

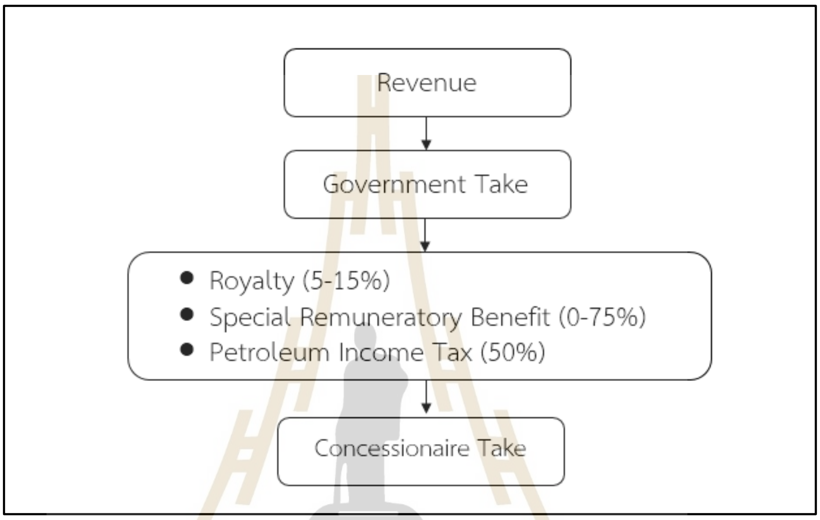


Figure 2.13 Flowchart of Thailand III fiscal regime (DMF, 2019).

Table 2.3 Thailand III fiscal regime, which contains the following key terms (Chandler MHM Ltd., 2019).

Contract Terms	
Contract Type	Concession system
Contract Period (years)	
Exploration period	3 + 3 (with 3 years extendable)
Production period	20 (with 10 years extendable) starting immediately after the end of the exploration period.
Contract Area	
Exploration Block	Area relinquishment is 50% at the end of year 4 and another 25% at the end of year 6.
Production Area	With commercial discovery, production area will be delineated and production can start right away even in the exploration period.

Table 2.3 Thailand III fiscal regime, which contains the following key terms (Chandler MHM Ltd., 2019) (Continued).

Fiscal Terms	
Royalty	To be paid in a sliding scale rate corresponding with the revenue from petroleum sold or disposed of as follows: Up to 60,000 barrels per month. ....5.00 % 60,000 – 150,000 barrels per month....... 6.25 % 150,000 – 300,000 barrels per month.... 10.00 % 300,000 – 600,000 barrels per month......12.50 % over 600,000 barrels per month .... 15.00 % In deep water blocks, royalty is 70% of the above rates.
Petroleum Income Tax	50% of net profit of the company
Special remuneratory benefit	(SRB) is designed for extra government's take from windfall profit which will only be used if: all capital cost (plus special reduction) is recovered, and annual revenue become drastically high compared with the investment (i.e., unusual high oil price)

2.3.3.4 Production Sharing Contract (PSC)

The contract governing the exploration blocks made available for bidding, granting the right to explore and produce petroleum, is structured as a production sharing contract (PSC), inclusive of the following terms and conditions (Figure 2.14).

In the production sharing contract (PSC) fiscal regime, the contractor earns income from the cost recovery and the contractor's production sharing portion. The cost recovery portion allows the contractor to recover their incurred costs. Additionally, the contractor shares in the production of the project. Conversely, the government generates income from royalties at 10% of gross revenue, production sharing and petroleum income tax at a rate of 20%. The main issues of the PSC systems are summarized and showed in Table 2.4.

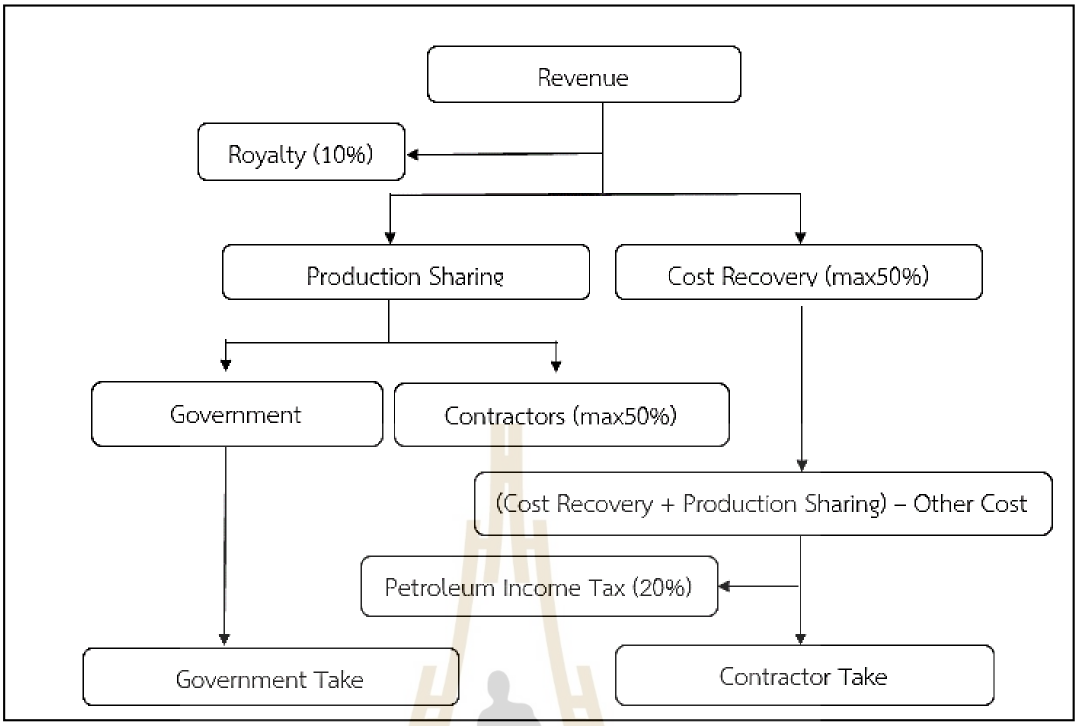


Figure 2.14 Flowchart of PSC fiscal regime (DMF, 2019).

Table 2.4 The main issues of the production sharing contract (PSC) fiscal regime (Chandler MHM Ltd., 2019).

Contract Terms	
Contract Period (years)	
Exploration Production	3 (with 3 years extendable). 20 (with 10 years extendable) starting immediately after the end of the exploration period.
Contract Area	
Exploration Block	Area relinquishment at the end of exploration period: Exploration period extended 25% of remaining area (excluding production area) Exploration period not extended
Exploration Block	All of remaining area (excluding production area)
Production Area	Upon commercial discovery, a production area can be delineated. Once the production area is delineated,

Table 2.4 The main issues of the production sharing contract (PSC) fiscal regime (Chandler MHM Ltd., 2019) (Continued).

Production Area	the production may be started even during petroleum exploration period.
Fiscal Terms	
Royalty	To be paid at 10% of the gross petroleum production.
Cost Recovery	To be recovered at a maximum of 50% of the annual gross petroleum production.
Percentage of Contractors' Share of profit petroleum	The remainder of gross production after royalty and cost recovery, "petroleum profit", shall be divided to contractor at a maximum of 50% of the total petroleum profit.
Petroleum Income Tax	20% of net profit of the company as stated in Petroleum Income Tax Act

Though there is a comparative study on petroleum resources management among Thailand I, Thailand III, and the production sharing contract (PSC) of Vietnam, Cambodia, and Malaysia-Thailand of Chaisinboon (1996), this kind of comparative study has not been done before in a small onshore gas fields of Thailand up to date.

In order to develop and promote the exploration and production activities of the indigenous natural, especially from the small onshore gas fields, this study therefore choose the untested Sikhiu prospect (a marginal field) to assess its undiscovered petroleum resources from its Permian carbonate rocks and its petroleum economics potential running under Thailand III and production sharing contract (PSC) fiscal regime for comparison. Therefore, the results and findings of this study may help increase the amount of natural gas reserves in Thailand to benefit the country's energy security in the future.

CHAPTER III

RESEARCH METHODOLOGY

3.1 Introduction

Estimating of undiscovered hydrocarbon resources in the Sikhiu prospects is conducted through a geostatistical system, utilizing the Fast Appraisal System for Petroleum Universal (FASPU) program. This system is designed for play analysis, incorporating a reservoir engineering geological model and probabilistic methodology. The geological model is a specialized probability model that employs reservoir engineering equations. The probabilistic methodology is an analytical approach derived from probability theory. Through this process, estimates of crude oil, non-associated gas, associated-dissolved gas, and total gas are calculated as probability distributions.

3.2 Method of Petroleum Resource Assessment

The assessment of undiscovered hydrocarbon resources in the Permian carbonate rocks was carried out using FASPU program, which involves play analysis and analytic methods.

Play analysis is a general term for various geologic models and probabilistic methods of analyzing a geologic play for hydrocarbon potential assessment. Most of the input parameters within these geological models are represented as probability distributions (Crovelli and Balay, 1986). Consequently, the uncertainties related to these input parameters and the resulting estimates of resources can be quantified in terms of probability distributions.

The FASPU program utilized parameters from petroleum geology and petroleum reservoir engineering to assess undiscovered hydrocarbon resources.

The probability of discovery within the plays assessed by the FASPU program is related to three petroleum geology parameters: play, prospect, and hydrocarbon volume attributes. All prospects share a common geological mechanism for petroleum occurrences within a geological play. A play should represent a group of prospects within specific geographic and stratigraphic limits with similar geological characteristics regarding sources, reservoirs, and traps. The play attributes' probability reflects the hydrocarbon source's favorability, the migration timing from the source rock to the reservoir, the effectiveness of the migration path, and the potential reservoir facies. The prospect attributes indicate the favorability of the trapping mechanism, effective porosity (greater than 3 percent), and the accumulation of hydrocarbons. The hydrocarbon volume attributes include factors such as closure area (in thousand acres), trap fill (as a percentage), effective porosity (as a percentage), reservoir depth (in thousand feet), reservoir thickness (in feet), hydrocarbon saturation (as a percentage), and the number of drillable prospects.

The petroleum reservoir engineering parameters encompass the essential factors for calculating hydrocarbon volume. These factors include oil and gas recovery factors (expressed as a percentage), original reservoir pressure (measured in psi), oil floor depth (in feet), gas compressibility factor, reservoir temperature (in °R), oil formation volume factor, and gas-oil ratio (expressed in Mcf/bbl.).

The Department of Mineral Fuels (DMF) in Thailand provided and assisted in gathering the required petroleum geology and engineering parameters from the well summary reports of drilled wells in the Khorat Plateau, specifically Chonnabot-1, Nam Phong-1, Phu Wiang-1, and Dao Ruang-1.

The FASPU program utilizes reservoir engineering equations to calculate the in-place volumes of oil in Equation 3.1 and non-associated gas in Equation 3.2.

Oil in place in MMbbl unit

$$= \frac{7{,}758 * 1{,}000 * A * F * H * P * Sh}{Bo} \qquad (3.1)$$

Non-associated gas in place in Bcf Unit

$$= \frac{1{,}537.7 * 1{,}000 * A * F * H * P * Sh * Pe}{T * Z} \qquad (3.2)$$

A is area of closure (Thousand acres)

H is reservoir thickness (feet)

F is trap fill (decimal fraction)

P is effective reservoir porosity (decimal fraction)

Sh is hydrocarbon saturation (decimal fraction)

Pe is the original reservoir pressure (psi)

Bo is oil formation volume factor (no unit)

T is reservoir temperature (degree Rankine)

Z is the gas compressibility factor (no unit)

To create a generalized geologic model, a range of mathematical functions must be available for modeling five geological variables: original reservoir pressure (Pe), reservoir temperature (T), gas-oil ratio (Rs), oil formation volume factor (Bo), and gas compressibility factor (Z) as functions of depth. Four mathematical functions will be established: zoned linear, exponential, power, and logarithmic. Zoned linear refers to piece-wise linear functions with up to four zones or levels, each with three transition depths. Each of the four mathematical function types is defined by two parameters, A and B, except for zoned linear, which has a set of A and B coefficients for each zone. These mathematical functions Equation 3.3, 3.4, 3.5, and 3.6 can be derived from the following:

1) Zoned Linear Function : (A x Depth) + B (3.3)

 Maximum of 4 zoned with three transition depths (feet)

2) Exponential Function : A x [exp (B x Depth)] (3.4)

3) Power Function : A x (Depth x B) (3.5)

4) Logarithmic Function : A x [Ln (B x Depth)] (3.6)

When evaluating the play, the following procedure is employed: for each of the five geological variables, a specific type of function is chosen, and values for the parameters A and B are assigned.

The equations for oil and non-associated gas in place are composed of a series of factors that depend on the hydrocarbon volume attributes. These attributes are considered continuous independent random variables, except for effective porosity, which exhibits a nearly perfect positive correlation with hydrocarbon saturation. Geologists typically make subjective judgments to determine the probability distribution for an attribute. This is based on available geological and geophysical data and the expertise and knowledge of experts who may use analog data and geological extrapolations when data is unavailable.

The probability distribution for each attribute is described by complementary cumulative fractiles (25th, 5th, and 0th). For example, the 5th fractile represents an attribute value with at least a five percent chance of being equal to or greater than that value. In each play analyzed, seven fractiles are estimated for all six hydrocarbon volume attributes, except for hydrocarbon saturation, where the seven fractiles depend on the expected reservoir lithology.

Furthermore, the study estimates the probabilities of hydrocarbon types, determining oil or non-associated gas accumulation. However, if the reservoir depth exceeds a specified threshold known as the oil floor depth, the accumulation is assumed to be non-associated gas. This oil floor depth, along with recovery factors for oil and gas, is assigned in the case of recoverable estimates and is set at 100 percent for each in the case of in-place estimates.

The number of drillable prospects within the play is considered a discrete random variable, and seven fractiles are estimated.

Probability assessments for the three attribute sets are formulated by experts well-versed in the geological aspects of the specific area under consideration. These experts initially conduct a comprehensive review of all pertinent data related to the evaluation, pinpoint the principal plays within the assessment region, and subsequently evaluate each recognized play. All geological information essential for applying this model to a play is documented on a primary oil and gas appraisal data form (Figure 3.1) and an additional data form (Figure 3.2). The details from these data forms are then input into computer data files, which serve as the basis for a computer program employing an analytical method.

Evaluator: ______________________ Play Name: ______________

Data Evaluated: ______________________

Attribute			Probability of Favorable or Present							Comments
Play Attributes	Hydrocarbon Source									
	Timing									
	Migration									
	Potential Reservoir Facies									
	Marginal Play Probability									
Prospect Attributes	Trapping Mechanism									
	Effective Porosity (>3%)									
	Hydrocarbon Accumulation									
	Conditional Deposit Probability									
Hydrocarbon Volume Parameter	Reservoir Lithology	Sand								
		Carbonate								
	Hydrocarbon	Gas								
		Oil								
		Probability of equal to or greater than								
	Attribute	100	95	75	50	25	5	0		
	Area of closure (1,000 acres)									
	Reservoir Thickness									
	Effective Porosity (%)									
	Trap Fill (%)									
	Reservoir Depth (1,000 feet)									
	HC Saturation (%)									
No. of drillable prospects (a play characteristic)										

Figure 3.1 Oil and gas appraisal data form used in the play analysis (Crovelli and Balay, 1994).

ADDENDUM DATA FORM FASPU

Geological Variables

Four Types of Mathaematical Functions

1.Zone Linear Functions : A * Depth +B

Maximum of 4 zones with transition depths (feet)

2. Exponential Function : A * exp (B * Depth)

3. Power Function : A * Depth * B

4. Logarithmic Function : A * Ln (B*Depth)

For each of the five geological variables below, select one type of function and assign values for the

Pe	Original Reservoir Pressure (Psi)
T	Reservoir Temperature (degree Rankine)
Rs	Gas-Oil Ratio (Thousand CuFt/bbl)
Bo	Oil Formation Volume Factor (no unit)
Z	Gas Compressibility Factor (no unit)

	Parameters										
Variable Function	A	B	D	A	B	D	A	B	D	A	B
Pe											
T											
Rs											
Bo											
Z											

Oil Floor Depth (feet) : ______

Oil Recovery Factor (percent) : ______

Gas Recovery Factor (percent) : ______

Figure 3.2 Addendum oil and gas appraisal data form used in the play analysis (Crovelli and Balay, 1994).

3.2.1 Analytical Method of Play Analysis

An analytical approach based on probability theory principles offers a cost-effective alternative to time-consuming Monte Carlo simulations for petroleum play analysis (Crovelli, 1987). It systematically navigates geological models, computes means and variances of random variables, and determines probabilities. The lognormal distribution models unknown distributions for probability fractiles. Oil, non-associated gas, dissolved gas, and gas resources are individually assessed using separate methodologies. Figure 3.3 presents a simplified flowchart of the analytical process. Details of the fundamental steps are given in Appendix A.

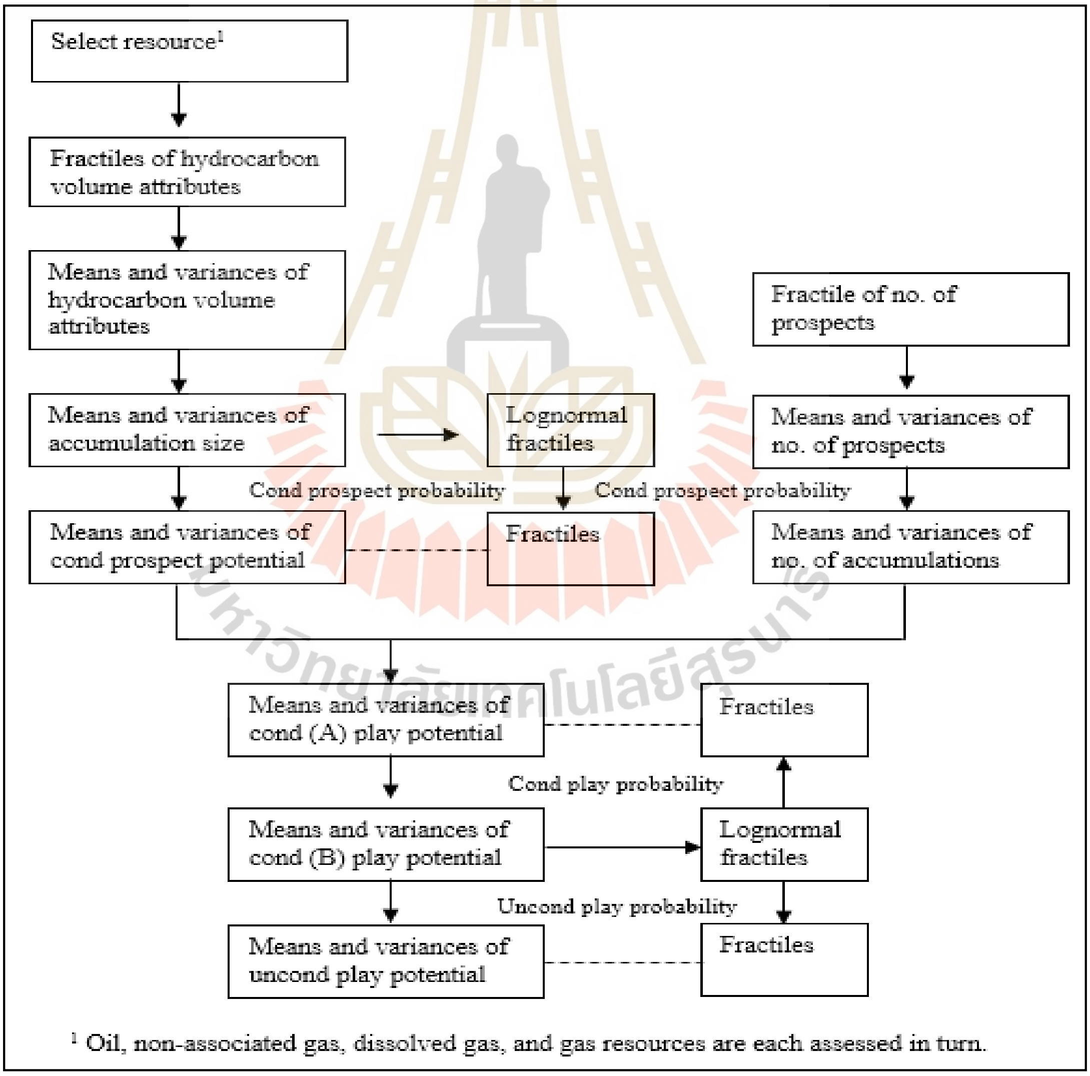


Figure 3.3 The analytic method of the play analysis flow chart to assess the undiscovered hydrocarbon resources (Crovelli and Balay, 1994)

3.2.2 Petroleum Play Analysis

Play analysis is a quantitative method used to estimate undiscovered oil and gas resources within a specific geological region, known as a "play." A play encompasses a collection of prospects within a defined geographic and stratigraphic area where various geological conditions align, allowing for the potential discovery of hydrocarbons. These geological conditions involve suitable reservoir rocks, traps, mature source rocks, migration pathways, and timing (CCOP, 1990). Most variables incorporated into this model are expressed in a probabilistic form, representing either the probability of occurrence or a probability distribution. Probabilities are assigned to various geological attributes that are essential for the creation and accumulation of hydrocarbons. In this appraisal method, geologists use their expertise to assess the geological factors required to develop a hydrocarbon accumulation. They also quantitatively evaluate these geological factors to determine the accumulation's potential size.

The probability of favorable play attributes

The play attributes include four characteristics that define a particular geological play: hydrocarbon source, timing, migration, and potential facies. These attributes determine whether the conditions within the play are conducive to the presence of hydrocarbons. For each of these four play attributes, a value must be assigned, ranging from 0 (indicating absence or unfavorable conditions) to 1.0 (indicating certain presence or favorable conditions). The definitions of these attributes are as follows:

The presence of a hydrocarbon source refers to the likelihood of a rock unit having generated and released oil in quantities sufficient to create one or more accumulations within the play. This probability factor is assessed by considering specific source rock criteria, such as organic richness (total organic carbon), kerogen type, and thermal maturity. When known hydrocarbon accumulations exist within the play, this probability factor is assigned a value of 1.

The timing of hydrocarbon migration from the source to the trap is the probability of a favorable relationship between the timing of trap formation and the timing of hydrocarbon movement into or through the play. This probability factor relied on knowledge of the time of trap formation and the time of hydrocarbon generation from source rocks or maturity of source rocks. If known hydrocarbon accumulations are present within the play, this probability factor is assigned a value of 1.

The presence of a potential migration pathway refers to the probability of hydrocarbons effectively moving through pathways that could be permeable clastic or carbonate rocks, fractures, or faults. This probability assessment relies on structural and stratigraphic data, which help deduce the existence of geologically favorable conduits. If known hydrocarbon accumulations are present within the play, this probability factor is typically assigned a value of 0.9.

The presence of potential reservoir facies refers to the probability of occurrence of rock formations that contain permeability and porosity to host producible hydrocarbon accumulations. This probability assessment relies on reservoir data from the play, projections from nearby areas, and analog comparisons. In many marine environments, the probability of potential reservoir facies is typically assigned a value of 0.9 because marine gas can create reservoirs by mechanically displacing sediments. If known hydrocarbon accumulations are already present within the play, this probability factor is also set at 0.9.

The marginal play probability is determined by multiplying the probabilities of hydrocarbon source, timing, migration, and potential facies. This factor indicates the probability that all four of these play attributes are favorable in some of the play, although not necessarily in all areas. If an oil or natural gas accumulation has been discovered within the play, it indicates favorable play attributes and the marginal play probability is at 0.81. However, if no oil or natural gas accumulation has been found in the play, the marginal play probability is less than 1.

The probability of favorable prospect attributes

The prospect attributes comprise three specific characteristics that define the characteristics of a prospect within a play: trapping mechanism, effective porosity, and hydrocarbon accumulation. Assessing these attributes involves assigning a single value on a scale from 0 (total certainty that the attribute is absent) to 1 (total certainty that the attribute is present) to represent the probability that the attribute is generally favorable in a prospect chosen at random within the play area.

The presence of a trapping mechanism refers to the probability of occurrence a stratigraphic or structural configuration that serves as a trap for migrating hydrocarbons. This probability factor is assessed using regional geological data, including geological mapping, projections from adjacent regions, seismic data, and relevant analog comparisons. This probability factor is also set at 1.

Effective porosity represents the probability of substantial interconnected void spaces within the potential reservoir facies that can accommodate hydrocarbons. The assessment of this attribute involves estimating the probability that the porosity in the prospect equals or exceeds 3 percent, as defined by the effective porosity volume parameter. This probability factor is determined using data from core measurements, well-log analyses, projections from nearby regions, and comparisons with analogous geological settings. This probability factor is set at 0.8.

Hydrocarbon accumulation represents the probability of a specific combination of hydrocarbon source, timing, and migration occurring in a randomly selected prospect within the play, resulting in a hydrocarbon charge equal to or greater than the minimum required size. This probability factor is assessed by the play's structural, stratigraphic, and thermal history. This probability factor is assigned a value of 1.

The conditional deposit probability is derived by multiplying the trapping mechanism, effective porosity, and hydrocarbon accumulation probabilities. The conditional deposit probability is 0.80. As a guide, the conditional deposit probability should not exceed the success ratio calculated from the drilling results.

The unconditional play probability is calculated as the product of the marginal play probability and the conditional deposit probability. It represents the probability that at least one undrilled prospect within the play contains hydrocarbon accumulations of the minimum size.

Reservoir parameters

The assessments are unaffected by the lithology of the reservoir. The probability that an accumulation is a gas accumulation depends on the hydrocarbon type. The probability that the accumulation involves oil build-up is one minus this probability. Organic material type, seismic observation, thermal maturity, and hydrocarbon type observed in wells and seeps are the basis for estimating the hydrocarbon mix.

Hydrocarbon volume parameters

During hydrocarbon volume assessment, marginal play and conditional deposit probabilities are assumed to be 1.0. These parameters include area of closure, net reservoir thickness, effective porosity, trap fill, reservoir depth, and hydrocarbon saturation, which define the probability range for reservoir characteristics determining hydrocarbon volume in a play. Evaluation involves recording estimates at seven fractiles (probability levels) from 0 to 100 percent, with intermediate values indicating relative confidence in potential reservoir volume exceeding recorded fractiles.

Notably, the minimum threshold values, typically set at the 100th fractile unless a higher value is chosen, are incorporated into prospect attribute judgments and the distribution of the number of drillable prospects. These threshold values are intentionally selected to be economically conservative, ensuring that economic considerations do not unduly influence the evaluation process. Additionally, while the number of drillable structures is technically a play attribute, it is closely related to the hydrocarbon volume parameters and will be discussed. This comprehensive assessment process aids in refining our understanding of the potential hydrocarbon resources within a given geological play.

The closure area serves to estimate the potential range for the area of the prospective reservoir located within a trap above the spill point. A vital threshold value for this parameter is set at a minimum of 120 acres and is utilized at the 100th fractile level. This minimal value holds particular significance, especially concerning the parameter related to the number of drillable prospects. The data for assessing this parameter may encompass seismic mapping, surface geologic mapping, and comparisons with analogous cases.

Another essential hydrocarbon volume parameter, reservoir thickness, endeavors to estimate the possible range for the thickness of the reservoir. In cases where the structural amplitude is less than the individual reservoir thickness, it describes the vertical closure extent. The thickness value characterizes the maximum thickness of a single reservoir or multiple stacked reservoirs possessing an effective porosity of at least 3 percent or the specified minimum threshold value. At the 100th fractile level, the minimum value for this parameter is established at 100 feet or approximately 30 meters. The evaluation of this parameter relies on various data sources, including projections from adjacent areas, surface and subsurface geological maps, seismic records, and analog comparison.

The hydrocarbon volume parameter, effective porosity, represents the average value denoting the extent of interconnected void spaces within the available reservoir rock. A minimum threshold for this parameter is set at 3 percent to be employed at the 100th fractile level. The probability of attaining this minimum value is integrated into assessing effective porosity within the prospect attribute. Data sources contributing to the evaluation of this parameter encompass measurements from well cores, projections from nearby regions, well log calculations, and analog comparison.

Trap fill is to estimate the potential range for the volume of trapped hydrocarbons as a percentage of the porous volume under closure. At the 100th fractile level, a minimum value of 30 percent is established. The probability of achieving this minimum value determines hydrocarbon accumulation within the prospect attribute. The evaluation of this parameter is based on data related to the porosity and permeability of the reservoir rock, source rock richness and thermal maturation, structural size, hydrocarbon drainage area, and comparisons with analogous scenarios.

Reservoir Depth endeavors to estimate the plausible range for the depth required to penetrate the potential reservoir. For this parameter, a minimum value of 11400 feet or approximately 3400 meters is set to be utilized at the 100th fractile. The data sources contributing to the assessment of this parameter include seismic records, projections from nearby regions, and comparative analysis with analogous cases.

Hydrocarbon saturation estimates the potential hydrocarbon saturation within the reservoir, presented as a percentage of the porous volume, for the prospects situated within the play. Hydrocarbon saturation is calculated as one minus the water saturation. A minimum value of 60 percent is utilized at the 100th fractile level. The probability of attaining this minimum value is integrated into calculating hydrocarbon accumulation within the prospect attribute.

The number of drillable prospect parameters offers insights into the conceivable range of values for the number of viable drilling targets that would be considered in the event of comprehensive exploration of the play. This assessment considers the presence of at least three prospects with the minimum accumulation size. The distribution of this parameter also considers the probability that the reservoir formation might be absent in certain portions of the play area. The evaluation of this parameter is enriched by utilizing surface and subsurface mapping, seismic records, and analog comparisons drawn from more extensively studied areas with similar geological characteristics.

3.3 Petroleum Economics

The petroleum economics of the undiscovered hydrocarbon resource of Sikhiu prospect from the FASPU program will be evaluated. The selected evaluations and analyses are as follows:

1. Cash flow analysis
2. Internal rate of return (IRR)
3. Profit to investment ratio (PIR)
4. Payback period
5. Sensitivity analysis
6. Comparison of Thailand III fiscal regime and product sharing contract (PSC) fiscal regime

The essences different fiscal terms between Thailand III and production sharing contract (PSC) system are presented in Table 3.1

Table 3.1 The essences different fiscal terms between Thailand III and production sharing contract (PSC) system.

Fiscal regime	Royalty (%)	Petroleum income tax (%)	Production sharing (%)	Cost recovery (%)
Thailand III	5	50	-	-
Production sharing contract	10	20	50	50

3.3.1 Petroleum Exploration and Development Plan

The exploration and development plan for natural gas in this study was determined under the Thailand III and production sharing contract (PSC) fiscal regime. The exploration and production plan of this study had divided the exploration period into 1 year and 5 years for production, resulting in a total duration of 6 years. The details of the exploration and production plans are outlined as follows:

The 1st year; - Geophysical surveys: 2D seismic survey
- Drilled 1 exploration well and 2 appraisal/ production well

The 2nd year; - Start production of natural gas up to the 6th year of the work plans

3.3.2 Hypothesis in Economics Studies

3.3.2.1 Basis Assumption of Economic Study

1. Gas resource size: 17.446 billion cubic feet
2. Number of exploration wells: 1
3. Number of appraisal/ production wells: 2
4. Heating value of gas: 1,000 BTU per cubic feet
5. Discount rate of money: 7.04 %
6. Escalation factor: 2 %
7. Tangible cost: 80 %
8. Intangible cost: 20 %

Note: The discount rate 7.04% is the average minimum retail rate (MRR) of Thai commercial banks in July 2023.

3.3.2.2 Cost Assumption of Economic Study

- Capital cost

1. Seismic survey 2D: 0.3 MMUS$
2. Exploration well: 4 MMUS$/well
3. Appraisal and production well: 4 MMUS$/well

- Operation cost: 400 US$/MMSCF
- Natural gas price: 3.435 US$/MMBTU (average 10 years)

Note: Detail of the average 10 years gas price calculation is presented in Appendix B

3.3.2.3 Other Assumptions of This Study

1. The study area is marginal fields.
2. The production plan will start in the second year and five years for the production period.
3. The natural gas price is constant over the contract.
4. The increasing rate of capital expenditure comes from the price increase of machinery and other equipment used in petroleum industries and is given 2% per year.
5. This study does not consider signature bonuses, production bonuses, or special remuneration benefits (SRB).

Net present value (NPV), profit to investment ratio (PIR), internal rate of return (IRR), and payback period are calculated by Equations 3.7, 3.8, 3.9, and 3.10, respectively;

Net present value (NPV) is a financial metric that calculates the present value of expected future cash flows generated by a project or investment. This calculation accounts for the time value of money.

$$NPV = A \times (1+i)^{-n} \tag{3.7}$$

Where A is the net cash flow

n is the amount of year

i is the discount rate

Profit to investment ratio (PIR) is the ratio of the sum of net cash flow divided by the sum of CAPEX.

$$PIR = \Sigma \text{ (Net Cash Flow)}/ \Sigma \text{ (CAPEX)} \qquad (3.8)$$

Internal rate of return (IRR) using trial and error to find i value. The i value makes the lower equation to be zero when replacing i on the equation.

$$0 = (-C) + A (1+i)^{-1}+A (1+i)^{-2}+...+A (1+i)^{-n} \qquad (3.9)$$

When C is a negative net cash flow value

A is the net cash flow value

i is the assumed discount rate value

The payback period is the length of time it takes to recover the cost of an investment or the length of time an investor needs to reach a breakeven point.

$$P = C/R \qquad (3.10)$$

When C is cost of investment

R is the annual cash flow

CHAPTER IV

RESULTS AND DISCUSSION

4.1 Introduction

From the study of the literature review, information concerning petroleum geology, including source, reservoir, seal, trap, and petroleum engineering data from the northeastern region, as well as the potential of Sikhiu prospect for petroleum resources, has been analyzed and summarized in the initial part of this section. The data gathered from petroleum geology and petroleum engineering analyses have been utilized in the evaluation of undiscovered petroleum resources using the FASPU program. The assessment outcomes are presented in section 4.2.

The evaluation of undiscovered petroleum resources has been further subjected to an analysis of petroleum economic potential. This began with establishing a basic scenario or base case using average gas prices and an average discounted rate. Subsequently, a sensitivity analysis was conducted on the revenue side by altering gas prices and on the expenditure side by modifying well costs. The analysis of petroleum economic potential in this study was carried out under both the Thailand III and PSC fiscal regimes to compare the project's performance under the fiscal regimes of both systems. The study outcomes and the evaluation of petroleum economic potential in this research have been presented and analyzed in section 4.3 accordingly.

4.2 Undiscovered Hydrocarbon Resource Assessment of the Sikhiu Prospect

1) Source rocks and source rocks maturity

The analysis of various Permian rock samples gathered from surface outcrops and exploration wells revealed total organic carbon (TOC) spanning from 0.29 to 1.59 percent (Thongboonruang, 2008). The potential source predominantly originates from the Permian shales interbedded within the Pha Nok Khao Formation

(Piyasin, 1995). The lower Pha Nok Khao Formations in Dao Ruang-1 displayed fair source richness (TOC 0.5-1 percent) within limestones. These limestones contain kerogen type III and are characterized as gas-prone (Chinoroj and Cole, 1995). Geochemical analysis has determined that these sediments have reached a state of very mature to overmature. Maturation modeling, utilizing the present-day geothermal gradient of 1.20°F/100 ft (Sattayarak et al., 1989), has suggested that oil could have been generated during the Jurassic period following the deposition of the lower part of the Khorat Group.

2) Reservoir rocks

Based on the available data, it can be indicated that Permian carbonates are significant reservoirs within the Khorat Plateau and are typically the primary targets (GMT Cooporation Ltd. and SUT, 1999; Atop, 2006; Chantong, 2007; Chantong et al., 2013; Minezaki, 2019). These Permian carbonate rocks were deposited in isolated platforms and exhibited a range of lithofacies, including fossiliferous packstone and grainstone with wackestone and mudstone being less commonly found. These carbonates demonstrate typical characteristics of having low porosity and permeability. In general, porosity ranges from 0 to 18%, with an average value of 4.0%. Mud-rich lithofacies like mudstone and wackestone often exhibit higher porosity than grain-rich lithofacies like packstone, grainstone, and boundstone. Additionally, within the carbonate reservoirs, the presence of dolomite often corresponds to higher porosity levels than limestone (Kozar et al., 1992). The carbonates' permeability seems to primarily depend on the presence of microfractures. The existence of these open microfractures is likely the cause of the favorable gas flow rate observed in the Nam Phong Structure within the Khorat Plateau.

3) Trap and seal

In northeastern Thailand, the geological structures considered suitable for petroleum traps are: 1) the angular unconformity between the Saraburi and the Huai Hin Lat Formation and 2) The anticlinal structures formed during the Tertiary period.

4) Geologic attributes

Play attributes

The probability for each play attribute can be defined and analyzed using data from petroleum geology, geochemistry, geophysics, and petroleum reservoir engineering derived from the existing well drilling records.

According to the study of Chantong (2007), the Sikhiu prospect is categorized as a Permian Carbonate Play. The main seal for this play type will be the Khorat Group, and the main reservoir will be the Permian Saraburi Group. Sources can originate from either the Permian Group itself or the Triassic Group. A fair to excellent organic richness is contained within these Permian carbonate rocks. A late to overmature oil stage was indicated by the thermal maturity of these carbonate source rocks (Sattayarak et al., 1989; Chinoroje and Cole, 1995; Piyasin, 1995; Thongboonruang, 2008). Therefore, a probability of 1.00 is assigned to the existence of a hydrocarbon source. Similarly, a probability of 1.00 is assigned to the favorable timing for hydrocarbon migration from the source to the reservoir, considering that they are local sources. However, the potential migration path is assigned a probability of 0.90, as the fractured carbonate reservoir is expected (GMT Cooporation Ltd. and SUT, 1999; Atop, 2006; Minezaki, 2019). Due to the influence of numerous tectonics, the fractures and microfractures in these carbonate reservoirs were partly filled with calcite. As a result, a probability of 0.90 is assigned to the favorable potential reservoir facies. Consequently, the marginal play probability of the Sikhiu prospect is determined to be 0.81 (1x1x0.9x0.9).

Prospect attributes

In the Sikhiu prospect, an unconformity between the Permian Saraburi Group and the Triassic Huai Hin Lat Formation is clearly depicted in the seismic profile (CCOP, 1990; Atop, 2006). Therefore, a probability of 1.0 is assigned to the existence of a trapping mechanism. High average porosity in the Permian carbonate rocks on the Khorat Plateau has been indicated by data from previously drilled wells (Esso Exploration and Production Korat Inc, 1982). Therefore, the probability of effective porosity is given 0.80. Since reservoir and source rocks in the Sikhiu prospect are the same Permian carbonate rocks, the probability of petroleum accumulation is

1.00. Consequently, the conditional deposit probability of the Sikhiu prospect is equal to 0.80 (1x0.8x1). The probability of favorable of each play and prospect attribute is summarized and shown in Table 4.1.

Table 4.1 Probability of favorable for each input play and prospect attribute of the Sikhiu prospect (Permian Carbonate Play).

Input	Attribute	Probability of favorable
Play attributes	1. Hydrocarbon source	1
	2. Timing	1
	3. Migration	0.9
	4. Potential reservoir facies	0.9
	Marginal Play Probabilities = 0.81 (1 x 2 x 3 x 4)	
Prospect attributes	5. Trapping mechanism	1
	6. Effective porosity (>3%)	0.8
	7. Hydrocarbon accumulation	1
	Conditional Deposit Probabilities = 0.80 (5 x 6 x 7)	

Available petroleum geology and engineering parameters were collected from available drilled wells data and estimated by the authors (Table 4.2). The complementary cumulative plots of these available data were used for generating the probability distribution for each hydrocarbon volume attribute. As a result, the favorable value at the fractiles of 100th, 95th, 75th, 25th, 5th, and 0th of all six hydrocarbon volume attributes, equal to or greater than at seven fractiles, can be estimated (Table 4.3).

Reservoir engineering parameters

This study adopted the results of the study of Glumglomjit (2010) for this assessment. In his study the required reservoir engineering parameters were plotted with depth. Then the relationship between depth and these essential reservoir engineering parameters is established based on the four types of mathematic functions of the FASPU program. The summary and demonstration of these relationships are presented in Table 4.4.

Table 4.2 Raw data of required hydrocarbon volume parameters.

Hydrocarbon volume parameters	Wells /Source of data	Range of data
1. Area of closure (1,000 acres)	Structural contour map of Sikhiu prospect (Chantong, 2007)	0.119-0.302
2. Reservoir thickness (ft)	Chonnabot-1, Phu Wiang-1	103-322
3. Effective porosity (%)	Chonnabot-1, Phu Wiang-1	0.00-17.00
4. Trap fill (%)	Determined by the assessors	30-80
5. Reservoir depth (1,000 ft)	Chonnabot-1, Phu Wiang-1	11.4-16.4
6. Hydrocarbon saturation (%)	Nam Phong-1, Chonnabot-1, Phu Wiang-1	3.0-90.0
7. No. of drillable prospects	Structural contour map of Sikhiu prospect (Chantong, 2007)	3-5

Table 4.3 Hydrocarbon volume parameters of the Sikhiu prospect (Permian Carbonate Play).

Hydrocarbon volume parameters	**Reservoir lithology**	Carbonate					
	Hydrocarbon type Prob %	Gas 98 Oil 2					
Attribute	**Probability (equal to or greater than)**						
	100	**95**	**75**	**50**	**25**	**5**	**0**
Closure area (1,000 acres)	0.12	0.125	0.151	0.235	0.345	0.432	0.451
Reservoir thickness (ft)	100	120	205	234	256	323	340
Effective porosity (%)	3	3.14	3.71	4.61	7	13.1	18
Trap fill (%)	30	35	40	45	50	70	80
Depth of reservoir (1,000 ft)	11.4	11.65	12.65	13.9	15.15	16.15	16.4
HC Saturation (%)	60	64	72	82	86	89	90
No. of drillable prospects	3	3	3	4	4	5	5

Table 4.4 Engineering parameters input data for hydrocarbon resource assessment of the Sikhiu prospect (Permian Carbonate Play).

Original reservoir pressure (psi)	=	(0.7166 x Depth)+14.5038
Reservoir temperature (°R)	=	(0.0267 x Depth)+538.00 (from 0-2,300 ft)
	=	(0.0068 x Depth)+579.00 (from 2,300-5,500 ft)
	=	(0.0115 x Depth)+537.00 (below 5,500 ft)
Gas-oil ratio (Mcf/bbl)	=	0.0056146
Oil formation volume factor	=	1
Gas compressibility factor	=	(0.00001 x Depth)+1.02384
Oil floor depth	=	14,870 ft
Oil recovery factor (%)	=	5
Gas recovery factor (%)	=	90

Estimating the undiscovered hydrocarbon resource quantities of the Sikhiu prospect (Permian Carbonate Play) by the FASPU program is a complementary cumulative probability. These distributions summarize the estimates range as a single probability curve in an "equal to or greater than" format. Consequently, the estimated undiscovered resources are reported at the arithmetic mean and the five confidence levels, as shown in Table 4.5. Details of the steps of calculation are given in the Appendix A.

Table 4.5 Results of a hydrocarbon resource assessment of the Sikhiu prospect (Permian Carbonate Play).

Result	Mean	F95	F75	F50	F25	F05
Oil resource						
Number of accumulations	0.039	0	0	0	0	0
Accumulation size (MMbbl)	0.54	0.11	0.24	0.4	0.67	1.43
Unconditional play potential	0.017	0	0	0	0	0

Table 4.5 Results of a hydrocarbon resource assessment of the Sikhiu prospect (Permian Carbonate Play) (Continue).

Non-associated Gas resource						
Number of accumulations	2.8	1	2	3	3	4
Accumulation size (Bcf)	23.641	4.84	10.31	17.45	29.52	62.9
Unconditional play potential	53.628	0	23.98	47.24	75.01	136.97

Note: F = fractile

Mean = arithmetic mean

Petroleum potential assessment of the Sikhiu prospect was performed by using the FASPU computer program, and the results of the accumulation size of non-associated gas resources can be summarized in 5 levels as follows;

- Very high confidence at fractile of 95 percent chance of discovery; the accumulation size is 4.84 Bcf (from 1 accumulation).

- High confidence at the fractile of 75 percent chance of discovery; the accumulation size is 10.31 Bcf (from 2 accumulations).

- Medium confidence (most likely) at the fractile 50 percent chance of discovery; the accumulation size is 17.45 Bcf (from3 accumulations)

- Low confidence at the fractile 25 percent chance of discovery; the accumulation size 29.52 Bcf (from 3 accumulations).

- Very low confidence at fractile 5 percent chance of discovery; the accumulation size 62.90 Bcf (from 4 accumulations).

However, the findings from the geochemical investigations conducted by Chantong (2007) and Thongboonruang (2008) on the Permian carbonate source rocks in the Khorat Plateau indicate that there is no chance of discovering oil resources within the Permian carbonate play of the Sikhiu prospect and the possible generated natural gas could be only non-associated gas.

4.3 Petroleum Economics

The petroleum economics potential assessment was performed using medium confidence (most likely) at the fractile 50 percent chance of discovering of the calculated undiscovered petroleum resources resulted from FASPU program, 17.45 Bcf, under Thailand III and production sharing contract (PSC) fiscal regime for comparison.

The production start in the 2nd year of the work plan with a production rate of 9.556 MMSCF/D for five years. The calculated production rate profile is presented in Table 4.6 and Figure 4.1.

Table 4.6 Natural Gas production rates of Sikhiu prospect.

Year	Natural gas production rates	
	MMSCF/day	MMSCF/year
1	0	0
2	9.556	3,488
3	9.556	3,488
4	9.556	3,488
5	9.556	3,488
6	9.556	3,488
Total		17,440

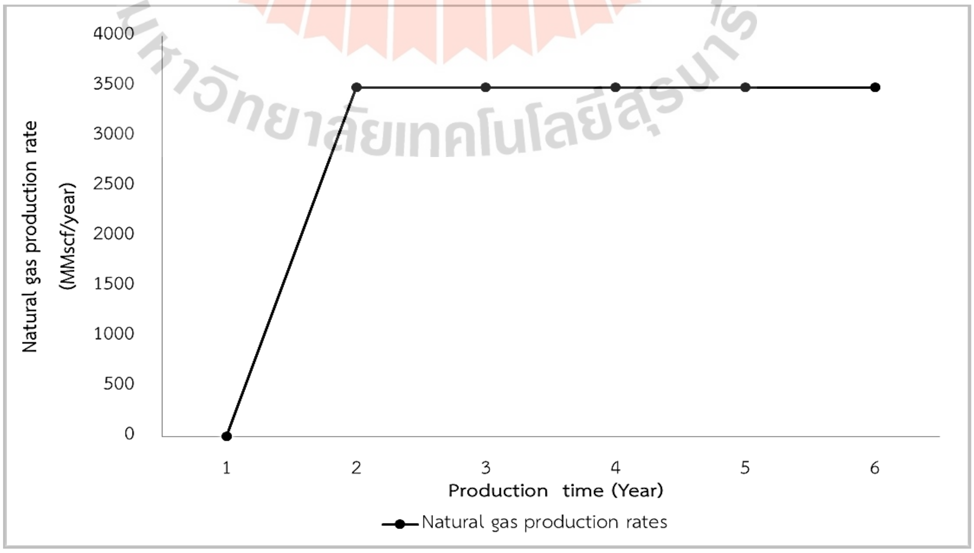


Figure 4.1 Sikhiu prospect production rate profile.

Financial parameters such as NPV, IRR, PIR, and payback period between Thailand III and production sharing contract (PSC) fiscal regime are mainly compared in this study. For establishing the base case, the cash flow analysis of the undiscovered natural gas resource size is 17.45 Bcf, the average gas price in 10 years is 3.435 US$/MMBTU (Appendix B), and the gas production rate started at 9.556 MMSCF/D are assigned.

4.3.1 Cash Flow Analysis

Based on seismic profile line 92NR180, the two-way travel time for the Pha Nok Khao Formation is 1.3 ms. According to Satarugsa (2007), the average seismic velocity of the Khorat Group is 2400 m/s. The average well cost in northeast Thailand is 3.195 MMUS$/km. (Appendix C). Therefore, the well cost of this study is 4.985 MMUS$/well. For comparison, the project net income (annual cash flow) of each year was then converted to its corresponded present (discounted) value (PV).

1) Thailand III fiscal regime

- Net income

In the base case run under Thailand III fiscal regime, the results (Table 4.7) indicated that gross sale revenue is 59.91 MMUS$, total investment cost is 23.56 MMUS$, CAPEX (capital expenditure) is 16.58 MMUS$, OPEX (operating expenditure) is 6.98 MMUS$. Government take is 26.22 MMUS$ (royalty cost 3.00 MMUS$ and Income tax at 50 percent is 23.22 MMUS$). The project earned the profit of 10.13 MMUS$, payout in the 5th year of the production. The net present value (NPV) at discount rate 7.04% is 5.89 MMUS$.

- Internal rate of return (IRR)

The internal rate of return after tax of the Thailand III fiscal regime is 21.95%.

- Profit to investment ratio (PIR)

The profit to investment ratio of the Thailand III fiscal regime is 0.61.

- Payback period

The payback period of the Thailand III fiscal regime is 3.92 years (Table 4.8).

Table 4.7 The base case run under Thailand III fiscal regime summary.

YEAR	CASH FLOW SUMMARY					ANNUAL CASH FLOW	DISCOUNTED CASH FLOW (NPV@7.04%)
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE			
				ROYALTY	INCOME TAX		
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26
2024	11.98	0.00	1.40	0.60	3.54	6.45	6.02
2025	11.98	0.00	1.40	0.60	4.76	5.22	4.56
2026	11.98	0.00	1.40	0.60	4.76	5.22	4.26
2027	11.98	0.00	1.40	0.60	4.76	5.22	3.98
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33
TOTAL	59.91	16.58	6.98	3.00	23.22	10.13	5.89

IRR =21.95%   PIR = 0.61

Table 4.8 Payback period of the base case run under Thailand III fiscal regime.

System		Thailand III fiscal regime	
Year	CPEX	Annual cash flow	Cumulative annual cash flow
1	16.46	0	0
2		6.45	6.45
3		5.22	11.67
4		5.22	16.89
5		5.22	22.12
6		3.40	25.51
Payback period (years)			3.92

2) Production sharing contract (PSC) fiscal regime

- **Net income**

For the base case run under production sharing contract (PSC) fiscal regime, the results (Table 4.9) indicated that, gross sale revenue is 59.91 MMUS$, the total investment cost is 23.56 MMUS$, CAPEX (capital expenditure) is 16.58 MMUS$, OPEX (operating expenditure) is 6.98 MMUS$, as same as Thailand III fiscal regime. Government takes is 28.97 MMUS$ (royalty cost at 10 percent is 5.99 MMUS$, income tax at 20 percent is 7.74 MMUS$ and production sharing maximum 50 percent is 15.24 MMUS$). The project earned the profit of 15.68 MMUS$, payout in the 5^{th} year of the production, and net present value (NPV) at discount rate 7.04% is 10.23 MMUS$.

- **Internal rate of return (IRR)**

The internal rate of return after tax of the production sharing contract fiscal regime is 30.35%

- **Profit to investment ratio (PIR)**

The profit to investment ratio of the production sharing contract fiscal regime is 0.95

- **Payback period**

The payback period of the production sharing contract fiscal regime is 3.54 years (Table 4.10).

Table 4.9 The base case run under production sharing contract (PSC) fiscal regime summary.

YEAR	CASH FLOW SUMMARY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV7.04%)
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE				
				ROYALTY	INC. TAX	SHARE		
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28
2027	11.98	0.00	1.40	1.20	1.54	3.06	6.18	4.71
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81
TOTAL	59.91	16.58	6.98	5.99	7.74	15.24	15.68	10.23

IRR = 30.35% PIR = 0.95

Table 4.10 Payback period of the base case run under production sharing contract (PSC) fiscal regime.

System		PSC fiscal regime	
Year	CAPEX	Annual cash flow (contractor take)	Cumulative annual cash flow
1	16.46	0.00	0.00
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		6.18	25.59
6		5.35	30.94
Payback period (years)			3.54

These results of the base case demonstrate that the PSC fiscal regime offers higher returns and a shorter payback period than the Thailand III fiscal regime. The IRR and NPV values indicate that the investment opportunity is more attractive under the PSC fiscal regime, with the project expected to generate higher cash flows and profitability over the assessment period. The PIR also indicates that the project's returns exceed the investment costs to a greater extent under the PSC fiscal regime.

4.3.2 Sensitivity Analysis

To study the relationship among the studied economical parameters, this study performed some sensitivity analyses by varying the gas prices and well costs of the tested projects respectively.

4.3.2.1 Sensitivity Analysis of Gas Price

In order to perform the sensitivity analysis on the gas price, the gas prices were set to vary between -50 to +200 percent of the average gas price 3.435 US$/MMBTU, well cost was fixed at 4.985 MMUS$/well, and undiscovered natural gas resource is 17.45 Bcf. Results of the tests are presented in the Appendix D and some essences results are as follows;

1) Thailand III fiscal regime

- Net income

If the gas price falls below -26.70% of the base price, it becomes evident that the company's NPV turns negative. Furthermore, as the gas price rises, the NPV experiences a substantial increase. A detailed breakdown of net income and net present value can be found in Table 4.11, while Figure 4.2 visually illustrates these observations.

Table 4.11 Net income and net present value of the project run under Thailand III fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	Thailand III	
		Net income (MMUS$)	NPV (MMUS$)
1.72	-50	-3.34	-5.14
2.58	-25	3.39	0.37
3.44	Base price	10.13	5.89
4.29	25	16.87	11.42
5.15	50	23.62	16.94
6.01	75	30.35	22.45
6.87	100	37.09	27.98
7.72	125	43.83	33.50
8.59	150	50.57	39.02
9.45	175	57.31	44.54
10.31	200	64.05	50.06

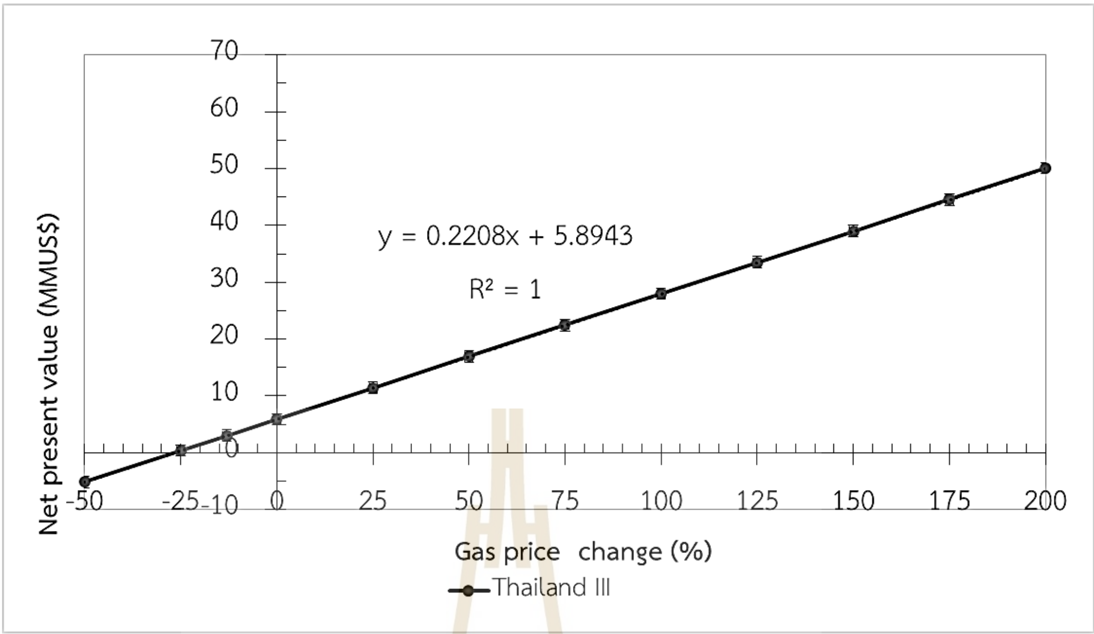


Figure 4.2 Relationship between net present value (MMUS$) and gas price change (%) of the project run under Thailand III fiscal regime.

The relationship between gas price and net present value (NPV) in the Thailand III fiscal regime can be represented by a linear function, as shown in Equation 4.1.

$$y = 0.2208x + 5.8943 \qquad (4.1)$$

When y is net present value (MMUS$),

x is gas price change (percent)

- **Internal rate of return (IRR)**

In the scenario where the gas price falls below -38.16% of the base price, an intriguing observation emerges: the internal rate of return (IRR) exhibits a negative value from the company's perspective. Conversely, with a rise in the gas price, there is a remarkable increase in the IRR. These findings are graphically illustrated in Figure 4.3 and further detailed in Table 4.12.

Table 4.12 Internal rate of return of the project run under Thailand III fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	IRR (%) Thailand III
1.72	-50	-9.26
2.58	-25	8.06
3.44	Base price	21.95
4.29	25	34.24
5.15	50	45.61
6.01	75	56.37
6.87	100	66.73
7.72	125	76.80
8.59	150	86.65
9.45	175	96.31
10.31	200	105.85

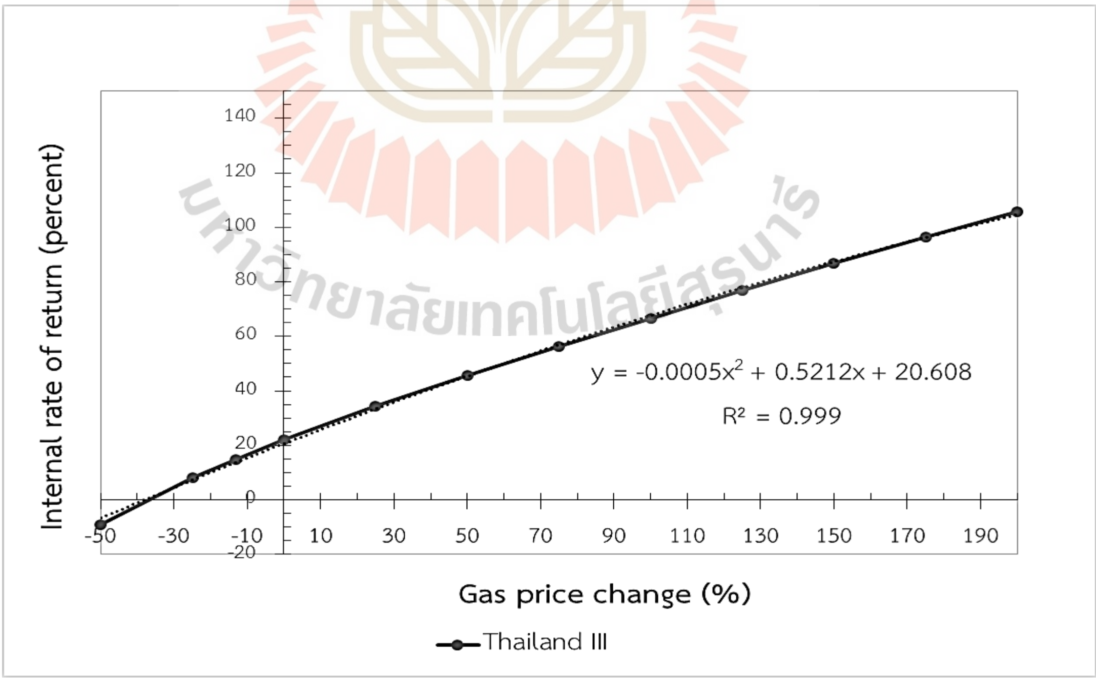


Figure 4.3 Relationship between internal rate of return (%) and gas price change (%) of the project run under Thailand III fiscal regime.

The relationship between the internal rate of return (IRR) and gas price in the Thailand III fiscal regime is depicted by a polynomial function, as expressed in Equation 4.2.

$$y = -0.0005x^2 + 0.5212x + 20.608 \quad (4.2)$$

When y is internal rate of return (percent)

x is gas price change (percent)

- **Profit to investment ratio (PIR)**

The Profit to investment ratio (PIR) exhibits a notable increase as the gas price rises. However, it's important to note that when the gas price falls below -37.47% of the base price, the PIR turns negative. Detailed PIR data can be found in Table 4.13, and for a visual representation, refer to Figure 4.4.

Table 4.13 Profit to investment ratio of the project run under Thailand III fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	PIR of Thailand III
1.72	-50	-0.2
2.58	-25	0.2
3.44	Base price	0.61
4.29	25	1.02
5.15	50	1.42
6.01	75	1.83
6.87	100	2.24
7.72	125	2.64
8.59	150	3.05
9.45	175	3.46
10.31	200	3.86

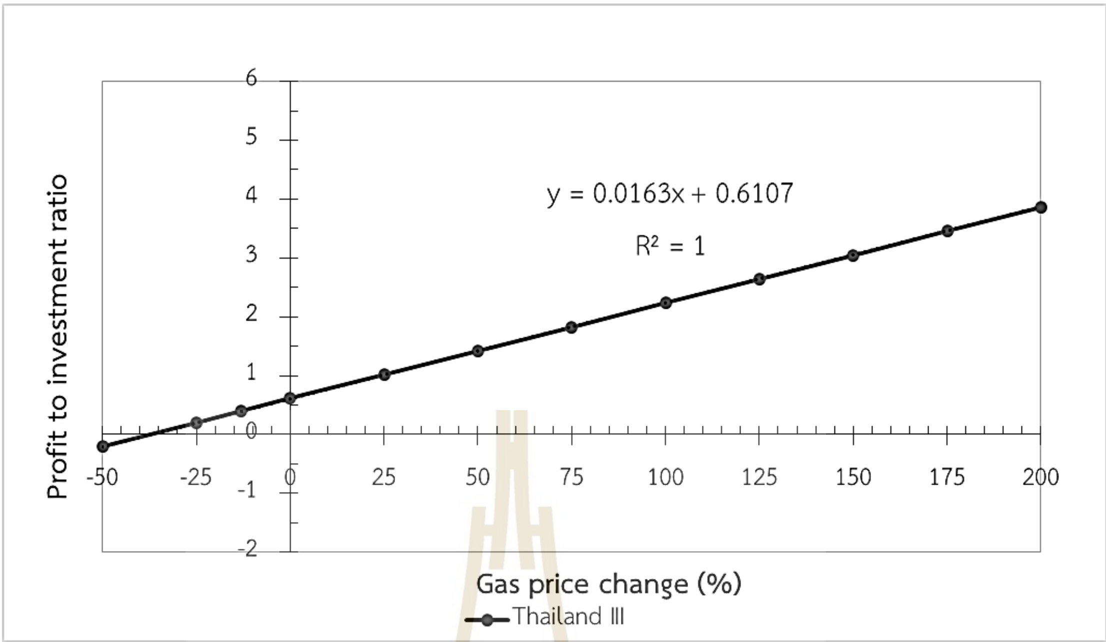


Figure 4.4 Relationship between profit to investment ratio and gas price change (%) of the project run under Thailand III fiscal regime.

The profit to investment ratio's (PIR) association with gas price changes in the Thailand III fiscal regime follows a linear function, as detailed in Equation 4.3.

$$y = 0.0163x + 0.6107 \tag{4.3}$$

When y is profit to investment ratio

x is gas price change (percent)

- **Payback period**

As the gas price rises, there is a corresponding decrease in the payback period. Specifically, if the gas price is 33.5% lower than the base price within the Thailand III fiscal regime, the project is projected to achieve a payback period of 6 years. The detailed calculations for the payback period can be referenced in Appendix Table D4. For a more comprehensive visual representation of these payback period dynamics, please consult Table 4.14 and Figure 4.5.

Table 4.14 Payback period of the project run under Thailand III fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	Payback Period (years) Thailand III
2.28	-33.5	6
2.58	-25	4.93
3.44	Base price	3.92
4.29	25	3.32
5.15	50	2.92
6.01	75	2.64
6.87	100	2.44
7.72	125	2.27
8.59	150	2.14
9.45	175	2.04
10.31	200	1.96

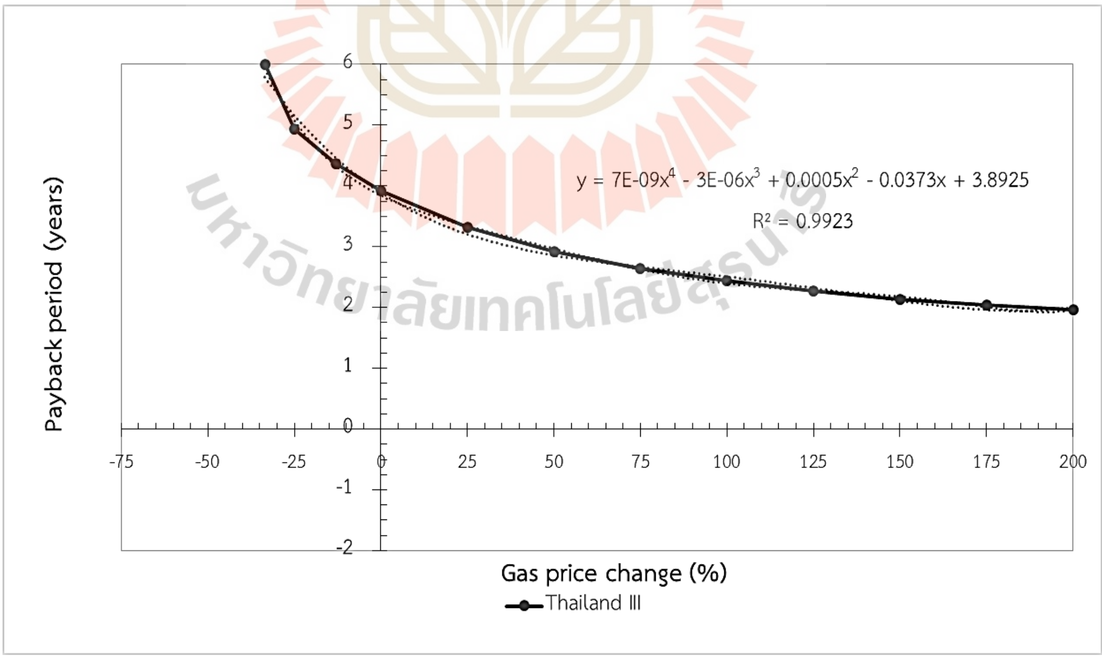


Figure 4.5 Relationship between payback period (years) and gas price change (%) of the project run under Thailand III fiscal regime.

The payback period's correlation with gas price fluctuations in the Thailand III fiscal regime can be described through a polynomial function, as illustrated in Equation 4.4.

$$y = 7E\text{-}09x^4 - 3E\text{-}06x^3 + 0.0005x^2 - 0.0373x + 3.8925 \tag{4.4}$$

When y is payback period (years)

x is gas price change (percent)

2) Production sharing contract (PSC) fiscal regime

- Net income

If the gas price falls below -42.41% of the base price, it becomes apparent that the net present value on the company's side plunges into negative territory. Conversely, with an increase in gas price, the net present value experiences a noteworthy upsurge. For a detailed breakdown of net income and net present value figures, kindly refer to Table 4.15 and Figure 4.6.

Table 4.15 Net income and net present value of the project run under PSC fiscal regime at various gas prices.

Gas price	Gas Price	PSC	
(US$/MMBTU)	Change (%)	Net income (MMUS$)	NPV (MMUS$)
1.72	-50	0.92	-2.00
2.58	-25	9.00	4.62
2.99	-13.08	12.86	7.78
3.44	Base price	15.68	10.23
4.29	25	21.08	14.81
5.15	50	26.47	19.32
6.01	75	31.86	23.81
6.87	100	37.25	28.26
7.72	125	42.64	32.71
8.59	150	48.04	37.16
9.45	175	53.42	41.61
10.31	200	58.82	46.06

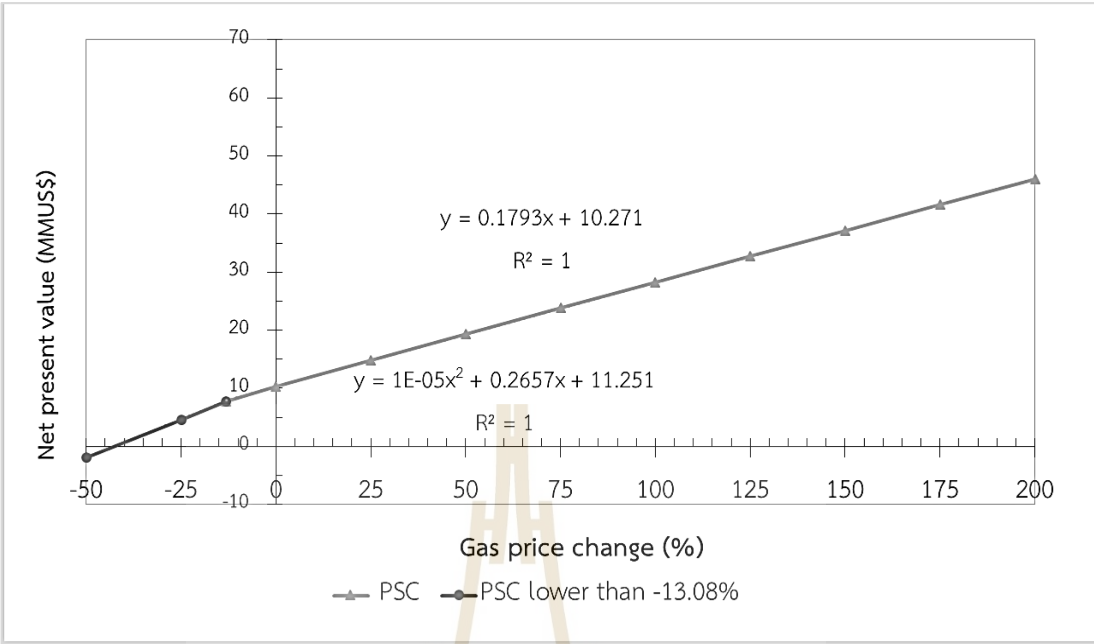


Figure 4.6 Relationship between net present value (MMUS$) and gas price change (%) of the project run under PSC fiscal regime.

When the gas price below -13.08% of the base price, the connection between net present value and the percentage change in gas price under the PSC fiscal regime is best described by a polynomial function, denoted as Equation 4.5. Conversely, if the gas price surpasses -13.08% of the base price, a linear function equation, referred to as Equation 4.6, effectively characterizes this relationship.

$$y = 1E\text{-}05x^2 + 0.2657x + 11.251 \tag{4.5}$$

$$y = 0.1793x + 10.271 \tag{4.6}$$

When y is net present value (MMUS$)

x is gas price change (percent)

The reason for the relationship between NPV and changes in gas price being polynomial and linear functions as described in Equations 4.5 and 4.6, respectively, is due to cost bank (Table 4.16).

Table 4.16 Cumulative cost bank of the project run under PSC fiscal regime at various gas prices.

Years	Cost Bank											
	Gas price change (%)											
	-50	-25	-13.08	0	25	50	75	100	125	150	175	200
2023	15.26	15.26	15.26	15.26	15.26	15.26	15.26	15.26	15.26	15.26	15.26	15.26
2024	13.95	12.61	11.96	11.26	9.91	8.56	7.22	5.87	4.52	3.17	1.82	0.48
2025	12.65	9.96	8.67	7.26	4.57	1.87	0.00	0.00	0.00	0.00	0.00	0.00
2026	11.35	7.31	5.38	3.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	10.05	4.66	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	9.95	3.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Remark number in the table is cumulative cost bank of each gas price change.

Based on the analysis of sensitivity to changes in gas prices under the PSC fiscal regime, with a maximum cost recovery set at 50%, it was found that the company can achieve the fastest return on investment in the third year of the project when the gas price is at 75% of the base price, as shown in Table 4.16. However, this period extends to the project's fourth year when the gas price falls within 25-50% of the base price and extends even further to the project's fifth year at the base price. When the gas price falls to a minimum of -13.08% of the base price, the company can recover all costs within the 6-year project timeframe. Nevertheless, if the gas price drops below -13.08% of the base price, the company can only recover some costs within six years. For instance, when the gas price is at -25% of the base price, the company cannot achieve a cost recovery of 3.21 MMUS$. Furthermore, if the gas price drops to -50% of the base price, the company cannot attain a cost recovery of 9.95 MMUS$.

- **Internal rate of return (IRR)**

The internal rate of return (IRR) experiences a significant and noteworthy increase as the gas price rises. The specific IRR values are presented in Table 4.17, and for a visual representation, please refer to Figure 4.7.

The relationship between IRR and the percentage change in gas price under the PSC fiscal regime can be expressed using a polynomial function, Equation 4.7, for lower gas prices and a polynomial function, Equation 4.8, for higher gas prices.

$$y = -0.0016x^2 + 0.5117x + 31.544 \tag{4.7}$$

$$y = -0.0002x^2 + 0.4154x + 30.375 \tag{4.8}$$

When y is internal rate of return (percent)

x is gas price change (percent)

Table 4.17 Internal rate of return (IRR) of the project run under PSC fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	IRR (%) PSC
1.72	-50	1.99
2.58	-25	17.76
2.99	-13.08	24.58
3.44	Base price	30.35
4.29	25	40.93
5.15	50	50.98
6.01	75	60.79
6.87	100	69.98
7.72	125	79.12
8.59	150	88.24
9.45	175	97.36
10.31	200	106.51

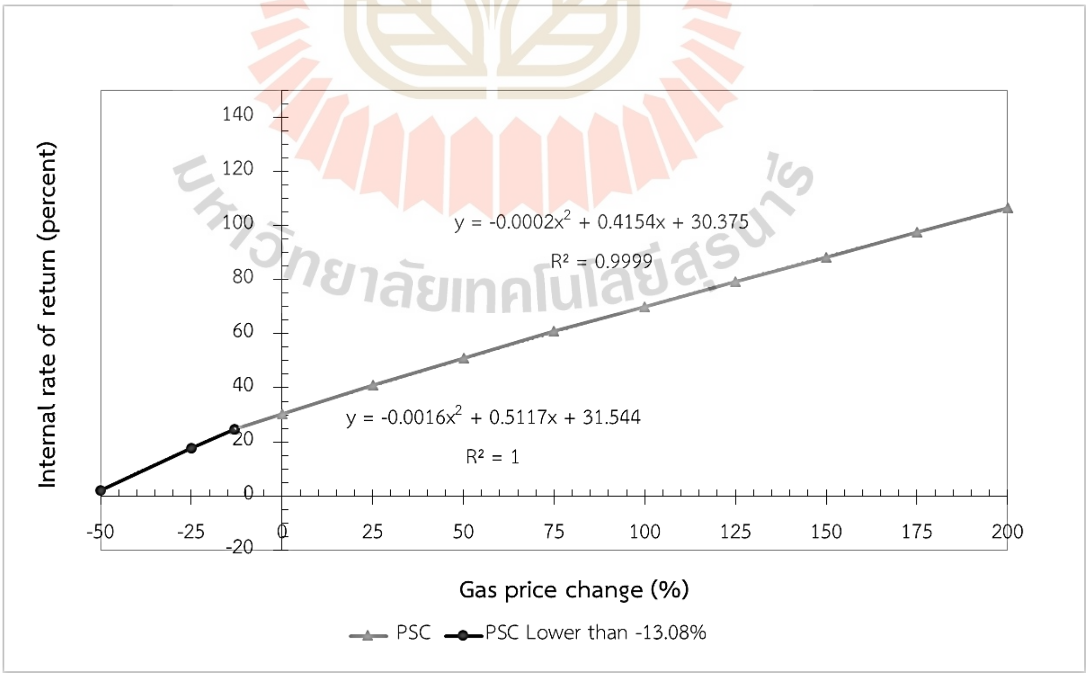


Figure 4.7 Relationship between internal rate of return (%) and gas price change (%) of the project run under PSC fiscal regime.

- **Profit to investment ratio (PIR)**

` With the rise in gas prices, there is a marked and substantial increase in the profit to investment ratio (PIR). Detailed PIR values can be found in Table 4.18, and for a visual representation, please consult Figure 4.8.

The PIR's relationship with the percentage change in gas price under the PSC fiscal regime can be depicted as a linear function, Equation 4.9, for lower gas prices and another linear function, Equation 4.10, for higher gas prices.

$$y = 0.0195x + 1.0308 \quad (4.9)$$

$$y = 0.013x + 0.946 \quad (4.10)$$

When y is profit to investment ratio

x is gas price change (percent)

Table 4.18 Profit to investment ratio (PIR) of the project run under PSC fiscal regime at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	PIR of PSC
1.72	-50	0.06
2.58	-25	0.54
2.99	-13.08	0.78
3.44	Base price	0.95
4.29	25	1.27
5.15	50	1.60
6.01	75	1.92
6.87	100	2.25
7.72	125	2.57
8.59	150	2.90
9.45	175	3.22
10.31	200	3.55

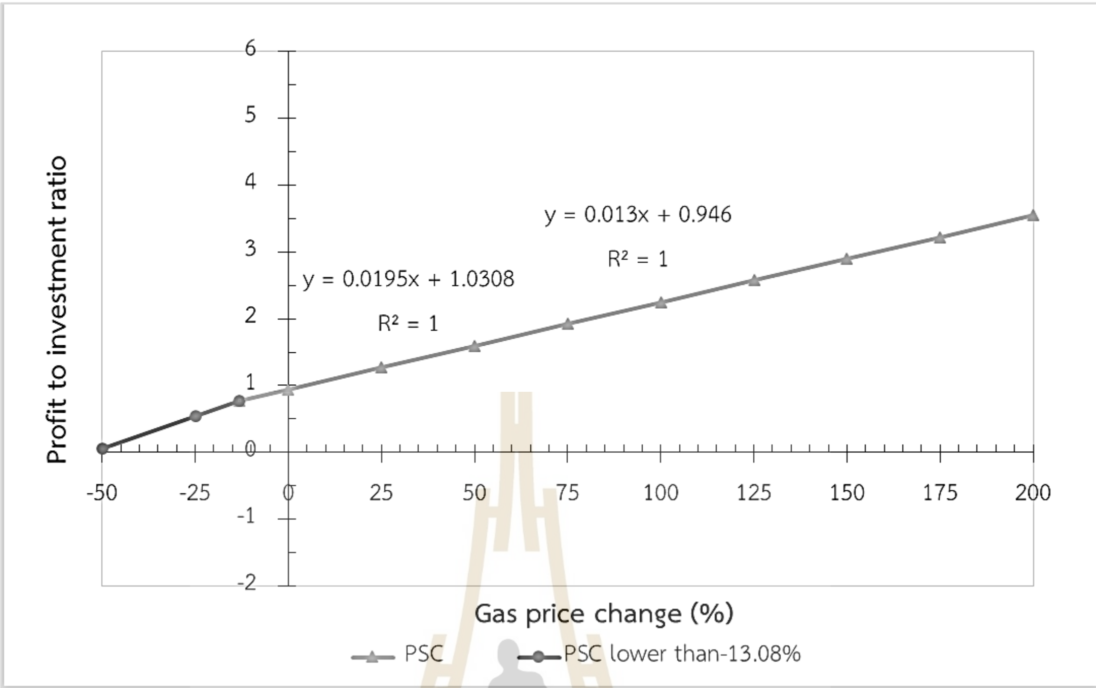


Figure 4.8 Relationship between profit to investment ratio and gas price change (%) of the project run under PSC fiscal regime.

- Payback period

As gas prices rise, the payback period decreases. Specifically, when the gas price is 49.1% lower than the base price in the PSC fiscal regime, the project's payback period is reduced to 6 years. This data is presented in Table 4.19 and Figure 4.9. The comprehensive payback period calculation is provided in Appendix Table D32.

To analyze the payback period in the PSC fiscal regime, Equation 4.11, a polynomial function, is employed.

$$y = 5E\text{-}09x4 - 2E\text{-}06x3 + 0.0003x2 - 0.0282x + 3.5087 \quad (4.11)$$

When y is payback period (years)

x is gas price change (percent)

Table 4.19 Payback period of the project run under PSC at various gas prices.

Gas price (US/MMBTU)	Gas Price Change (%)	Payback Period (years) PSC
1.748	-49.1	6
2.282	-33.5	4.83
2.58	-25	4.39
2.99	-13.08	3.93
3.44	0	3.54
4.29	25	3.04
5.15	50	2.7
6.01	75	2.47
6.87	100	2.31
7.72	125	2.16
8.59	150	2.02
9.45	175	1.93
10.31	200	1.85

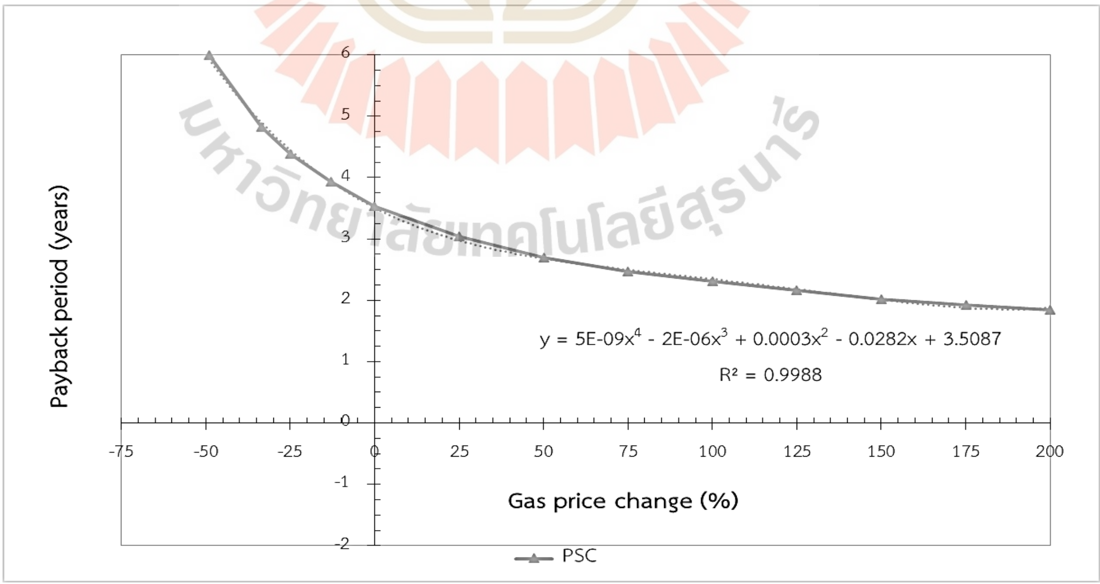


Figure 4.9 Relationship between payback period (years) and gas price change (%) of the project run under PSC fiscal regime.

3) Comparison between Thailand III and production sharing contract fiscal regime.

- Net income

The cash flow analysis revealed that when the gas price is lower than 106.8% of the base price, the PSC fiscal regime yields a higher net present value than the Thailand III fiscal regime. Conversely, when the gas price exceeds 106.8% of the base price, the net present value of the Thailand III regime surpasses that of the PSC fiscal regime. At a gas price at 106.8% of the base price, both fiscal regimes exhibit an equal net present value of 29.45 MMUS$ (The cash flow analysis shown in Appendix Table D19 and Table D47). The net income and net present value of the project run under Thailand III and PSC fiscal regime are presented in Table 4.20 and Figure 4.10.

Table 4.20. Net income and net present value of the project run under Thailand III and PSC fiscal regimes at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	Thailand III		PSC	
		Net income (MMUS$)	NPV (MMUS$)	Net income (MMUS$)	NPV (MMUS$)
1.72	-50	-3.34	-5.14	0.92	-2.00
2.58	-25	3.39	0.37	9.00	4.62
2.99	-13.08	6.61	3.00	12.86	7.78
3.44	Base price	10.13	5.89	15.68	10.23
4.29	25	16.87	11.42	21.08	14.81
5.15	50	23.62	16.94	26.47	19.32
6.01	75	30.35	22.45	31.86	23.81
6.87	100	37.09	27.98	37.25	28.26
7.10	106.8	38.90	29.45	38.69	29.45
7.72	125	43.83	33.50	42.64	32.71
8.59	150	50.57	39.02	48.04	37.16
9.45	175	57.31	44.54	53.42	41.61
10.31	200	64.05	50.06	58.82	46.06

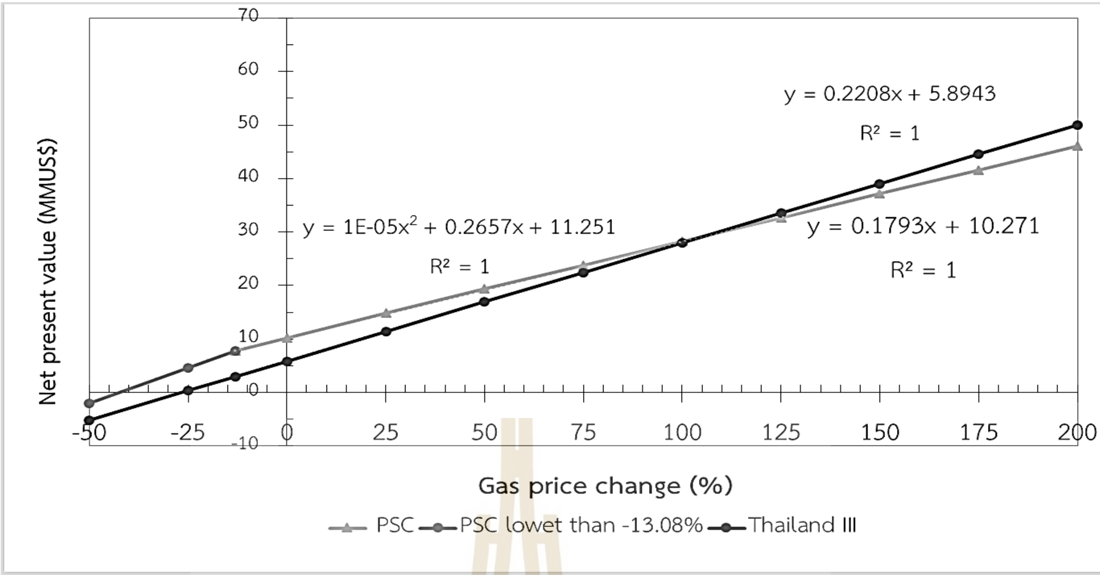


Figure 4.10 Relationship between net present value (MMUS$) and gas price change (%) of the project run under Thailand III and PSC fiscal regimes.

The connection between the net present value (NPV) and changes in gas price can be characterized using a linear function, as denoted by Equation 4.1, as previously discussed for the Thailand III fiscal regime. Conversely, when investigating the PSC fiscal regime, the relationship can be represented by a polynomial function labeled as Equation 4.5 for gas prices below -13.08% of the base price. In contrast, when gas prices exceed -13.08% of the base price, this relationship can be described by a linear function referred to as Equation 4.6, as mentioned earlier.

The company's profits from both fiscal regimes exhibit different slopes, which leads to the intersection of the lines on the graph. The slope of the graph results from government takes, which affects the remaining revenue as shown in the table. Under the Thailand III fiscal regime, the government take consists of a fixed royalty cost of 5% and a fixed income tax of 50%. On the other hand, the government take in the PSC fiscal regime has a fixed government royalty at 10%, a fixed income tax at 20%, and production sharing set at 50%. This difference in government take causes the graph to intersect at 106.8% of the base price.

The analysis of the graph indicates that the Thailand III fiscal regime has a steeper slope than the PSC fiscal regime. This conclusion is derived from observing the changes in slope based on the government take values.

The study found that when the gas prices are low, the contractor in the PSC fiscal regime earns more net present value than the Thailand III fiscal regime because of the capital expenditure and operational expenditure (CAPEX and OPEX). In the PSC fiscal regime, the state serves as the co-investor. As a result, the contractor receives cost recovery, leading to higher income for the contractor. In contrast, the concessionaire must be the sole investor in the Thailand III fiscal regime, leading to lower income than in the PSC fiscal regime.

When the gas price exceeds 106.8% of the base price, it was observed that the concessionaire in the Thailand III fiscal regime would receive a greater net present value than the PSC fiscal regime. As gas prices increase, the PSC fiscal regime generates more revenue for the government, as depicted in Figure 4.11 and Table 4.21 Consequently, the contractor receives a reduced share.

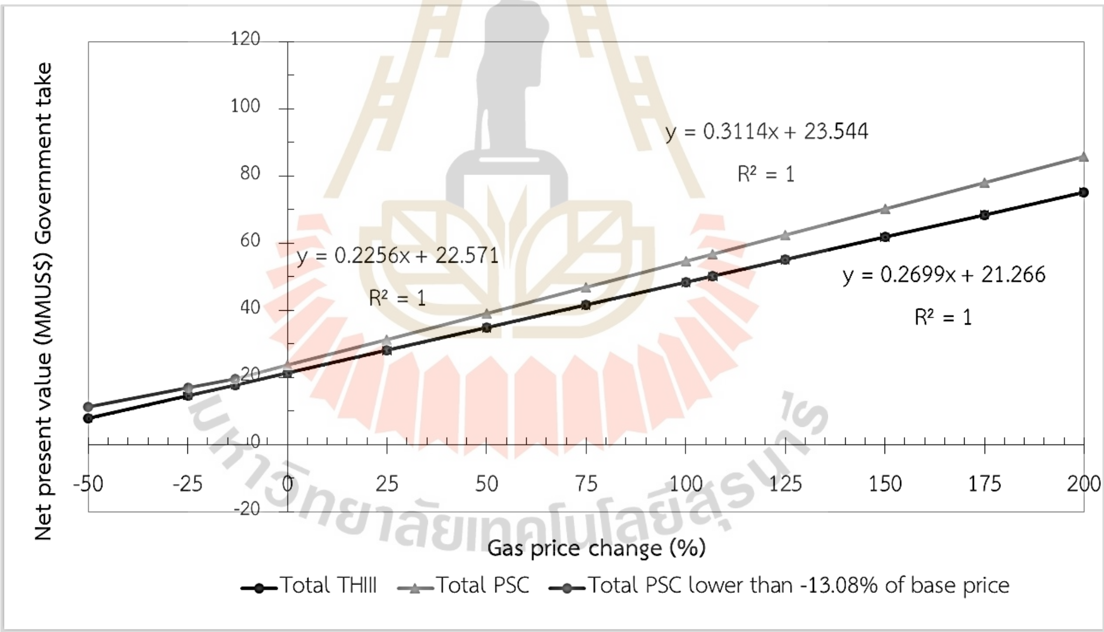


Figure 4.11 Relationship between net present value (MMUS$) and gas price change (%) of government's take (total) between Thailand III and PSC fiscal regimes.

A linear function can aptly illustrate the relationship between net present value (NPV) and changes in the government's take from gas price fluctuations. In the context of the Thailand III fiscal regime, this relationship is presented in Equation 4.12. For the PSC fiscal regime, when gas prices below -13.08%

Table 4.21 Government take, and contractor take under Thailand III and PSC fiscal regimes at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	Government Take (MMUS$)							Contractor Take (MMUS$)	
		Thailand III			PSC					
		Royalty (5%)	Income Tax (50%)	Total	Royalty (10%)	Income Tax (20%)	Production Sharing (50%)	Total	TH III	PSC
1.72	-50	1.23	6.55	7.78	2.45	3.31	5.52	11.29	-5.14	-2.00
2.58	-25	1.84	12.68	14.52	3.68	4.97	8.28	16.93	0.37	4.62
2.99	-13.08	2.13	15.60	17.74	4.27	5.76	9.60	19.62	3.00	7.78
3.44	0	2.45	18.81	21.27	4.91	6.37	12.31	23.59	5.89	10.23
4.29	25	3.07	24.95	28.02	6.13	7.52	17.63	31.28	11.42	14.81
5.15	50	3.68	31.08	34.77	7.36	8.64	23.03	39.04	16.94	19.32
6.01	75	4.29	37.21	41.51	8.59	9.77	28.45	46.81	22.45	23.81
6.87	100	4.91	43.35	48.26	9.81	10.88	33.94	54.63	27.98	28.26
7.72	125	5.52	49.48	55.01	11.04	11.99	39.42	62.45	33.50	32.71
8.59	150	6.13	55.62	61.76	12.27	13.10	44.90	70.27	39.02	37.16
9.45	175	6.75	61.75	68.50	13.49	14.22	50.37	78.08	44.54	41.61
10.31	200	7.36	67.89	75.25	14.72	15.33	55.85	85.90	50.06	46.06

of the base price, the corresponding relationship is expressed through Equation 4.13. Conversely, if gas prices exceed -13.08% of the base price, it is represented by Equation 4.14.

$$y = 0.2699x + 21.268 \quad (4.12)$$

$$y = 0.2256x + 22.571 \quad (4.13)$$

$$y = 0.3114x + 23.549 \quad (4.14)$$

When y is net present value (MMUS$)

x is gas price change (percent)

From the Figure 4.11, it is observed that when gas prices increase, the net revenue on the government side also increases. The net revenue increase under the PSC fiscal regime is also higher than the Thailand III fiscal regime, as shown in the equation above.

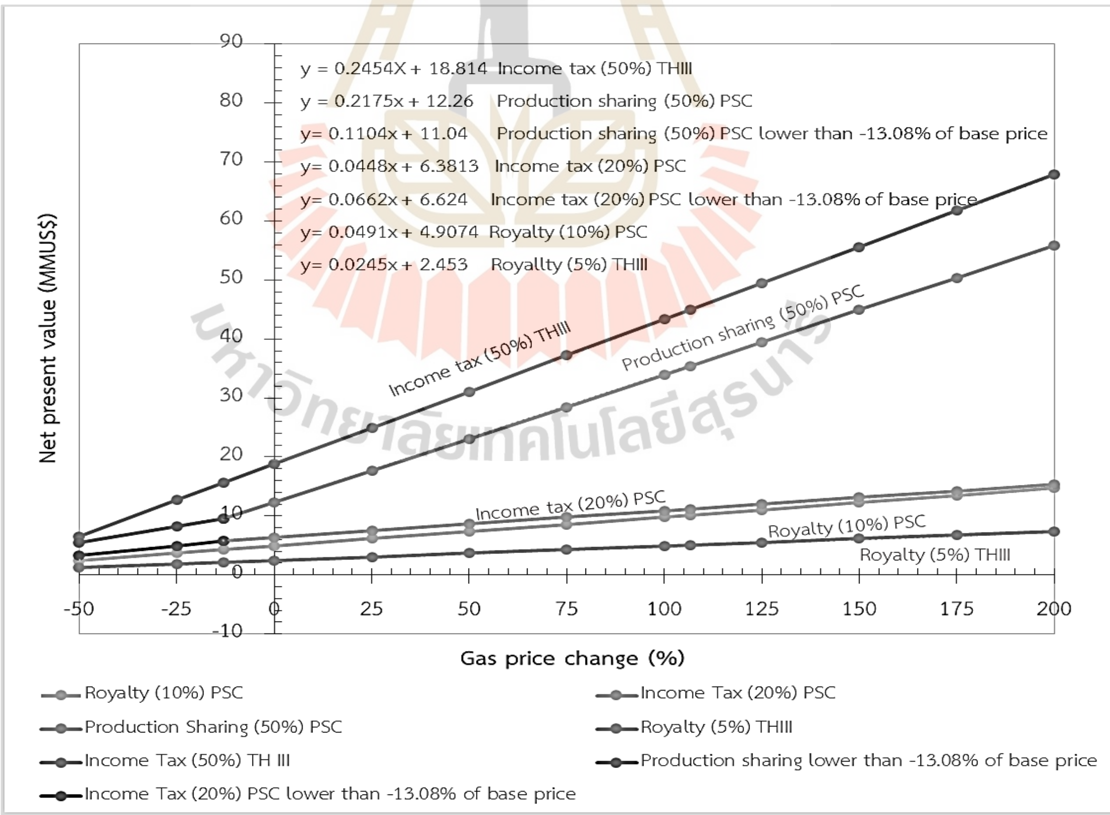


Figure 4.12 Comparison of government takes between Thailand III and PSC fiscal regimes.

In Figure 4.12, it can be seen that the income tax (50%) of the Thailand III fiscal regime has the highest net present value, followed by royalty (5%), and for the PSC fiscal regime, the production sharing (50%) has the highest value. This is followed by income tax (20%) and royalty (10%). As gas prices increase, the net present value of these values will also increase accordingly, as indicated by the following equation.

The relationship between the net present value (NPV) and changes in the government's take due to gas price fluctuations can be effectively depicted using a linear function equation. For the Thailand III fiscal regime, Equation 4.15 represents the income tax (50%), while Equation 4.16 represents the royalty (5%). In the case of the PSC fiscal regime, when gas prices are lower than -13.08% of the base price, the relationship is delineated through Equations 4.17 and 4.18, representing production sharing (50%) and income tax (20%) respectively. When gas prices exceed -13.08% of the base price, production sharing (50%), income tax (20%), and royalty (10%) are encapsulated in Equations 4.19, 4.20, and 4.21, respectively.

$$y = 0.2454x + 18.814 \tag{4.15}$$

$$y = 0.0245x + 2.453 \tag{4.16}$$

$$y = 0.1104x + 11.04 \tag{4.17}$$

$$y = 0.0662x + 6.624 \tag{4.18}$$

$$y = 0.2175x + 12.26 \tag{4.19}$$

$$y = 0.0448x + 6.3813 \tag{4.20}$$

$$y = 0.0491x + 4.9074 \tag{4.21}$$

When y = net present value (MMUS$)

x = gas price change (percent)

When examining only the royalty and income tax of both fiscal regimes, as shown in Figure 4.13, it is evident that the net present value of the Thailand III fiscal regime exceeds that of the PSC fiscal regime. However, when considering production sharing, the state revenue in the PSC fiscal regime surpasses the Thailand III fiscal regime. Therefore, the proportion of production sharing emerges as a crucial factor influencing higher government revenue and leading to a significant decrease in company earnings.

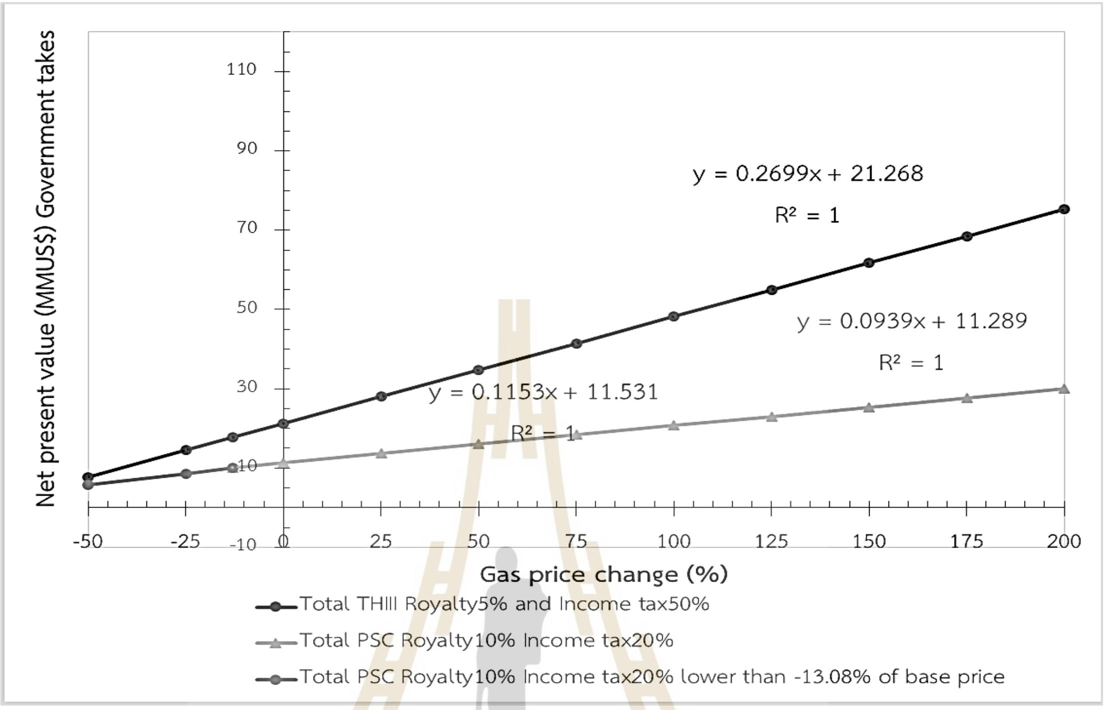


Figure 4.13 Comparison of only royalty and income taxes from Thailand III and PSC fiscal regimes.

Moreover, the relationship between NPV and the percentage change in gas price with respect to the government's take (comprising royalty and income taxes) can be described using linear function Equation 4.22 for the Thailand III fiscal regime and polynomial functions (Equations 4.23 and 4.24) for the PSC fiscal regime under different gas price scenarios.

$$y = 0.2699x + 21.268 \tag{4.22}$$

$$y = 0.1153x + 11.531 \tag{4.23}$$

$$y = 0.0939x + 11.289 \tag{4.24}$$

When y is net present value (MMUS$)

x is gas price change (percent)

Another influential factor to consider is cost recovery. When examining cost recovery, it becomes evident that as the percentage of cost recovery decreases, the net present value (NPV) is reduced under the PSC fiscal regime.

Conversely, when the cost recovery percentage increases, the company's NPV increases, the maximum cost recovery value is 50%. As depicted in Table 4.22 and Figure 4.14

When the cost recovery rate in the PSC fiscal regime is set at 19.7%, both the PSC and Thailand III fiscal regimes yield an equivalent net present value of 5.89 MMUS$ (Appendix Table F3).

Table 4.22 Net present value of the project run under PSC fiscal regime at various cost recovery.

Cost recovery (%)	Net present value (MMUS$) PSC
0	2.41
10	4.18
19.7	5.89
20	5.94
30	7.71
40	9.48
50	10.23

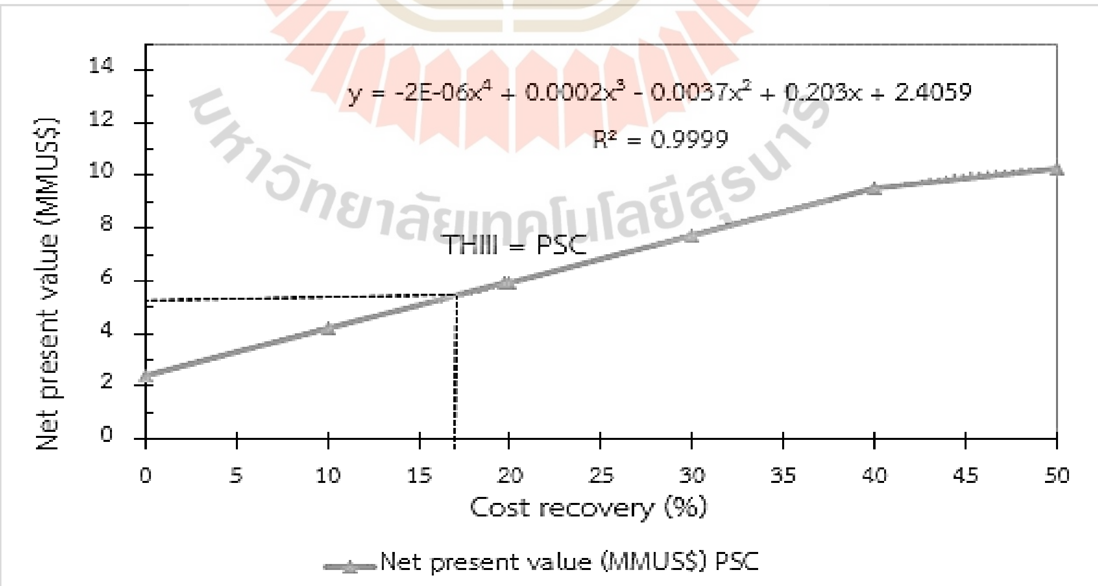


Figure 4.14 Relationship between net present value (MMUS$) and cost recovery (%) of the project run under PSC fiscal regime.

In addition, Equation 4.25, a polynomial function, is utilized to model the relationship between NPV and cost recovery changes in the PSC fiscal regime.

$$y = -2E\text{-}06x^4 + 0.0002x^3 - 0.0037x^2 + 0.203x + 2.4059 \quad (4.25)$$

When y is net present value (MMUS$)

x is cost recovery (%)

- **Internal rate of return (IRR)**

According to the analysis of the internal rate of return (IRR), it was determined that the PSC fiscal regime demonstrates a higher IRR than the Thailand III fiscal regime. The IRR between Thailand III and PSC fiscal regimes are presented in Figure 4.15 and Table 4.23.

The relationship between the internal rate of return (IRR) and gas price can be expressed through a polynomial function equation. In the context of the Thailand III fiscal regime, this relationship is articulated using Equation 4.2, as previously mentioned. Similarly, for the PSC fiscal regime, Equation 4.7 represents the relationship when gas prices are below -13.08% of the base price. Conversely, if gas prices surpass -13.08% of the base price, the relationship is captured by Equation 4.8, as discussed earlier.

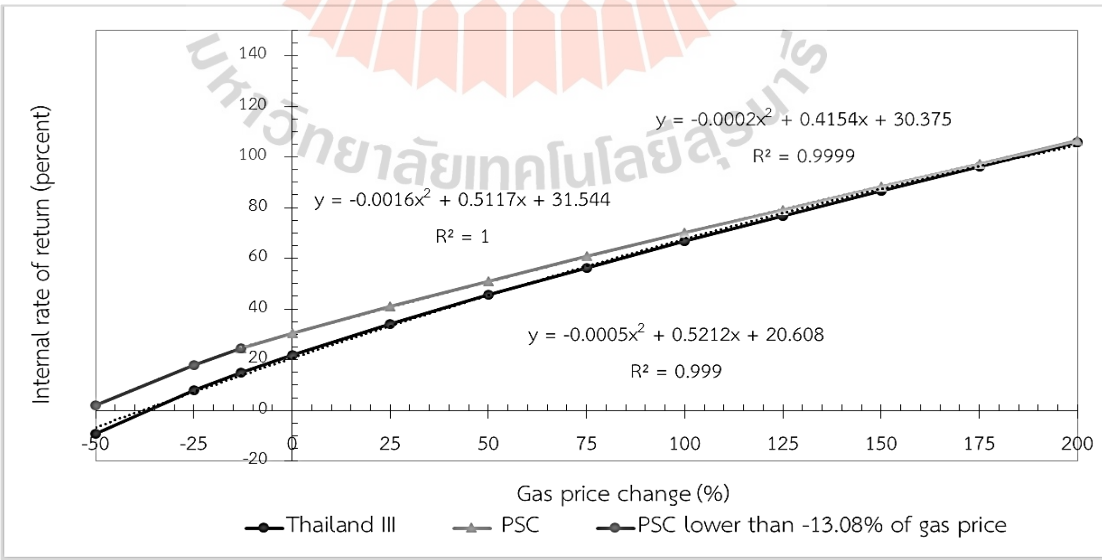


Figure 4.15 Relationship between internal rate of return (%) and gas price change (%) of the project run under Thailand III and PSC fiscal regimes.

Table 4.23 Internal rate of return of the project run under Thailand III and PSC fiscal regimes at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	IRR (%)	
		Thailand III	PSC
1.72	-50	-9.26	1.99
2.58	-25	8.06	17.76
2.99	-13.08	14.95	24.58
3.44	Base price	21.95	30.35
4.29	25	34.24	40.93
5.15	50	45.61	50.98
6.01	75	56.37	60.79
6.87	100	66.73	69.98
7.72	125	76.80	79.12
8.59	150	86.65	88.24
9.45	175	96.31	97.36
10.31	200	105.85	106.51

As mentioned, the contractor in the PSC fiscal regime earns more IRR than the Thailand III fiscal regime because of the capital expenditure and operational expenditure (CAPEX and OPEX). In the PSC fiscal regime, where the state serves as the co-investor. As a result, the contractor receives cost recovery, leading to higher income for the contractor. In contrast, the concessionaire must be the sole investor in the Thailand III fiscal regime, leading to lower income than in the PSC fiscal regime.

- **Profit to investment ratio (PIR)**

The analysis of the profit to investment ratio (PIR) determined that when the gas price is lower than 101.6% of the base price, the PSC fiscal regime exhibits a higher PIR than the Thailand III fiscal regime. Conversely, if the gas price exceeds 101.6% of the base price, the PIR of Thailand III is higher than that of the PSC fiscal regime. Notably, when the gas price reaches 101.6% of the base price, both fiscal regimes yield the same PIR of 2.27. The PIR between Thailand III and PSC fiscal regimes are presented in Table 4.24 and Figure 4.16.

Table 4.24 Profit to investment of the project run under Thailand III and PSC fiscal regimes at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	PIR	
		Thailand III	PSC
1.72	-50	-0.2	0.06
2.58	-25	0.2	0.54
2.99	-13.08	0.4	0.78
3.44	Base price	0.61	0.95
4.29	25	1.02	1.27
5.15	50	1.42	1.60
6.01	75	1.83	1.92
6.87	100	2.24	2.25
7.72	125	2.64	2.57
8.59	150	3.05	2.90
9.45	175	3.46	3.22
10.31	200	3.86	3.55

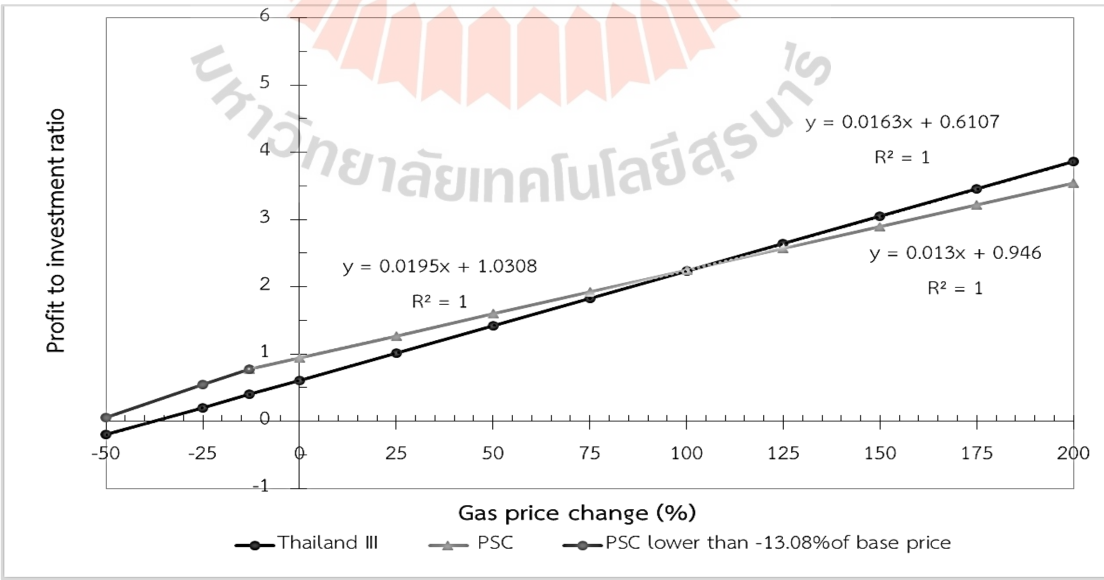


Figure 4.16 Relationship between profit to investment ratio and gas price change (%) of the project run under Thailand III and PSC fiscal regimes.

Utilizing a linear function equation, it becomes evident that there exists a correlation between the profit to investment ratio (PIR) and gas price. In the case of the Thailand III fiscal regime, Equation 4.3 illustrates this relationship, as previously noted. When gas prices dip below -13.08% of the base price within the PSC fiscal regime, the associated relationship is presented in Equation 4.9. Conversely, if gas prices exceed -13.08% of the base price in the PSC fiscal regime, it is portrayed through Equation 4.10, as mentioned earlier.

When gas prices are low, the profit to investment ratio (PIR) in the PSC fiscal regime will be higher than the Thailand III fiscal regime, which is the same reason for both the net present value.

When gas prices are high, the profit to investment ratio (PIR) in the Thailand III fiscal regime will be higher than the PSC fiscal regime. This is due to the production sharing, which affects the net present value.

A positive NPV, IRR, and PIR in this scenario indicate that the project's cash flows, even with the reduced gas price up to -25% of the base price, are sufficient to cover the initial investment and generate a positive return. A positive NPV, IRR, and PIR imply that the investment remains financially feasible, despite the decrease in gas price.

- **Payback period**

The payback period of the PSC fiscal regime is consistently shorter than Thailand III fiscal regime across all gas price percentages. According to the designed production plan, when the gas price is 33.5% lower than the base price in the Thailand III fiscal regime or the gas price is 49.1% lower than the base price in the PSC fiscal regime, the project will have a payback period of 6 years (Table 4.25 and Figure 4.17). The reason for the more significant decline in gas prices within the PSC fiscal regime than Thailand III fiscal regime is attributed to the government take, as described in the NPV, IRR, and PIR discussions.

The polynomial function equations introduced previously serve as effective tools to define the relationship between the payback period and gas price. Equation 4.4 aptly captures this relationship within the Thailand

III fiscal regime, while Equation 4.11 serves the same purpose within the context of the PSC fiscal regime.

Table 4.25 Payback period of the project run under Thailand III and PSC fiscal regimes at various gas prices.

Gas price (US$/MMBTU)	Gas Price Change (%)	Payback Period (years)	
		Thailand III	PSC
1.748	-49.1	-	6
2.282	-33.5	6	4.83
2.58	-25	4.93	4.39
2.99	-13.08	4.37	3.93
3.44	Base price	3.92	3.54
4.29	25	3.32	3.04
5.15	50	2.92	2.7
6.01	75	2.64	2.47
6.87	100	2.44	2.31
7.72	125	2.27	2.16
8.59	150	2.14	2.02
9.45	175	2.04	1.93
10.31	200	1.96	1.85

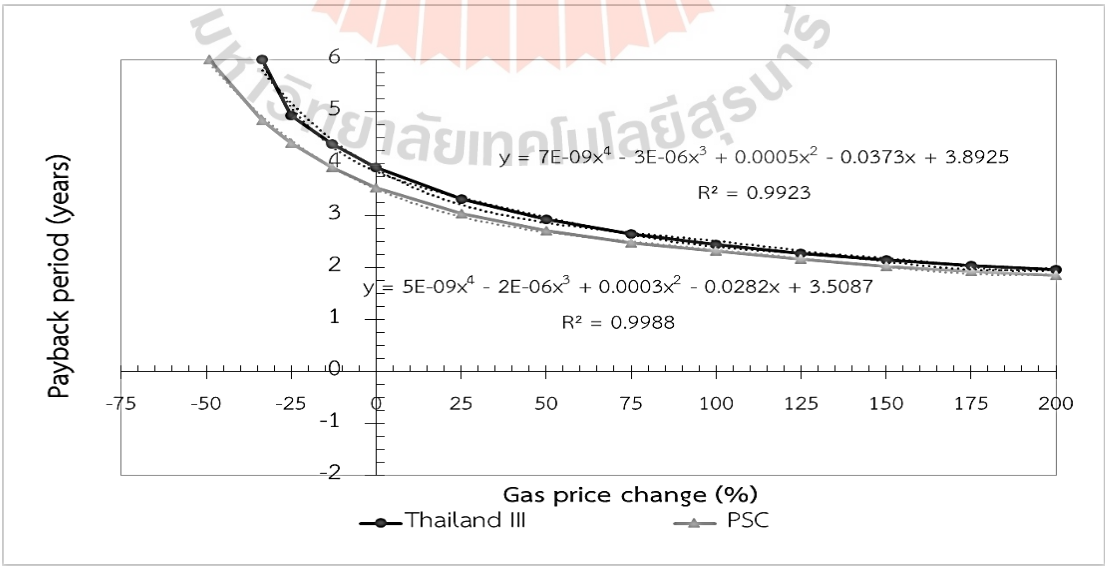


Figure 4.17 Relationship between payback period (years) and gas price change (%) of the project run under Thailand III and PSC fiscal regimes.

4.3.2.2 Sensitivity Analysis of Well Cost

To study the effect of the well cost, the biggest cost of the project, the base case was set up with the average gas price at 3.435 US$/MMBTU and the undiscovered natural gas resource estimated at 17.45 Bcf. Well costs varying from 3 to 7 MMUS$ per well were used to perform sensitivity analyses for the project both run under Thailand III and PSC fiscal regime for comparison. Results of the tests are presented in the Appendix E.

1) **Thailand III fiscal regime**

- **Net income**

In the analysis of net present value (NPV), it's evident that greater well costs correspond to diminished NPV figures, whereas reduced well costs correlate with elevated NPV figures. This observation aligns with the conventional understanding that increased costs can have an adverse effect on the project's overall profitability. The relevant net income and net present value data can be found in Table 4.26 and Figure 4.18 for reference.

Table 4.26 Net income and net present value of the project run under Thailand III fiscal regime at various well cost.

Well cost (MMUS$/well)	Thailand III	
	Net income (MMUS$)	NPV (MMUS$)
3.00	13.71	9.79
4.00	11.91	7.83
5.00	10.11	5.86
6.00	8.31	3.90
7.00	6.51	1.94

The correlation between the net present value (NPV) and the cost of wells under the Thailand III fiscal regime can be elegantly expressed using a linear equation, as denoted by Equation 4.26.

$$y = -1.963x + 15.679 \tag{4.26}$$

When y is net present value (MMUS$)

x is well cost (MMUS$/well)

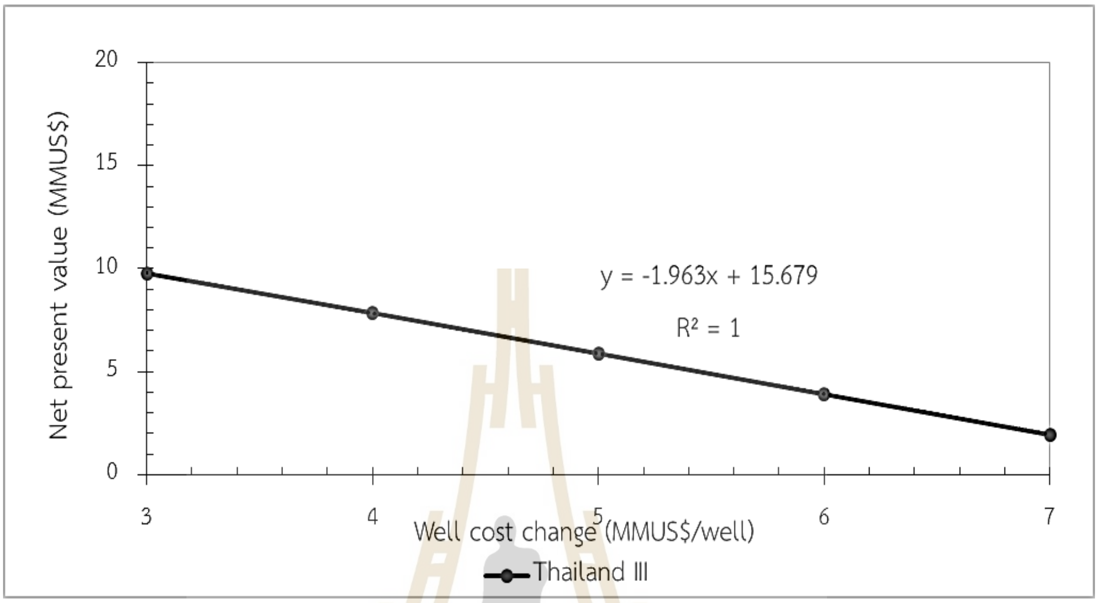


Figure 4.18 Relationship between net present value (MMUS$) and well cost change (MMUS$/well) of the project run under Thailand III fiscal regime.

- **Internal rate of return (IRR)**

In the analysis of the internal rate of return (IRR), it became evident that an escalation in well cost was inversely proportional to the IRR. Further insights into the internal rate of return can be gleaned from Table 4.27, while Figure 4.19 provides a graphical representation of these findings.

Table 4.27 Internal rate of return of the project run under Thailand III fiscal regime at various well cost.

Well cost (MMUS$/well))	**Internal rate of return (%)**
	Thailand III
3.00	44.20
4.00	30.66
5.00	21.84
6.00	15.54
7.00	10.76

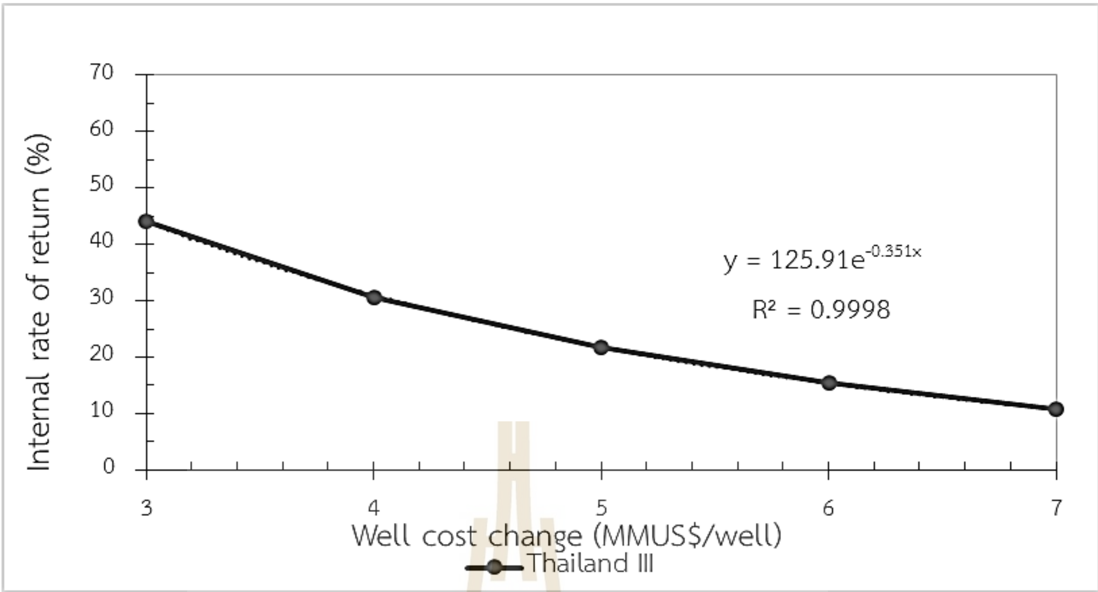


Figure 4.19 Relationship between internal rate of return (%) and well cost change (MMUS$/well) of the project run under Thailand III fiscal regime.

Mathematical representations in the form of exponential equations aptly depict the connection between the internal rate of return (IRR) and well costs for the Thailand III fiscal regimes, as Equation 4.27.

$$y = 125.91e^{-0.351x} \tag{4.27}$$

When y is internal rate of return (percent)

x is well cost (MMUS$/well)

- **Profit to investment ratio (PIR)**

During the analysis of the profit to investment ratio (PIR), it was noted that an increase in well cost was associated with a decrease in PIR, mirroring the trends observed in the internal rate of return (IRR) analysis. Comprehensive data regarding the profit to investment ratio can be accessed in Table 4.28, while Figure 4.20 visually represents these insights.

Table 4.28 Profit to investment ratio of the project run under Thailand III fiscal regime at various well cost.

Well cost (MMUS$/well))	Profit to investment ratio Thailand III
3.00	1.29
4.00	0.87
5.00	0.61
6.00	0.42
7.00	0.29

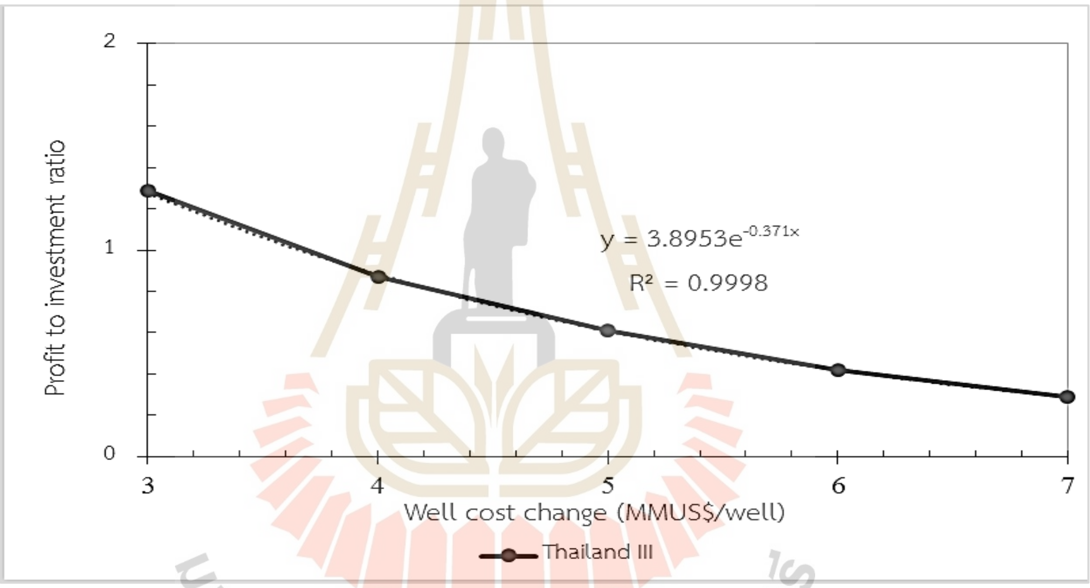


Figure 4.20 Relationship between profit to investment ratio and well cost change (MMUS$/well) of the project run under Thailand III fiscal regime.

The intricate interplay between the PIR and well costs in the Thailand III fiscal regimes can be vividly conveyed through exponential equations. Equation 4.28 characterizes this relationship for the Thailand III fiscal regime.

$$y = 3.8953e^{-0.371x} \tag{4.28}$$

When y is profit to investment ratio

x is well cost (MMUS$/well)

- **Payback period**

The examination of the payback period under the Thailand III fiscal regime revealed that higher well costs are associated with a prolonged payback period. Detailed information regarding the payback period is documented in Table 4.29, and Figure 4.21 provides a graphical representation of these findings.

Table 4.29 Payback period of the project run under Thailand III fiscal regime at various well cost.

Well cost (MMUS$/well))	Payback period (years)
	Thailand III
3.00	3.05
4.00	3.51
5.00	3.92
6.00	4.30
7.00	4.64

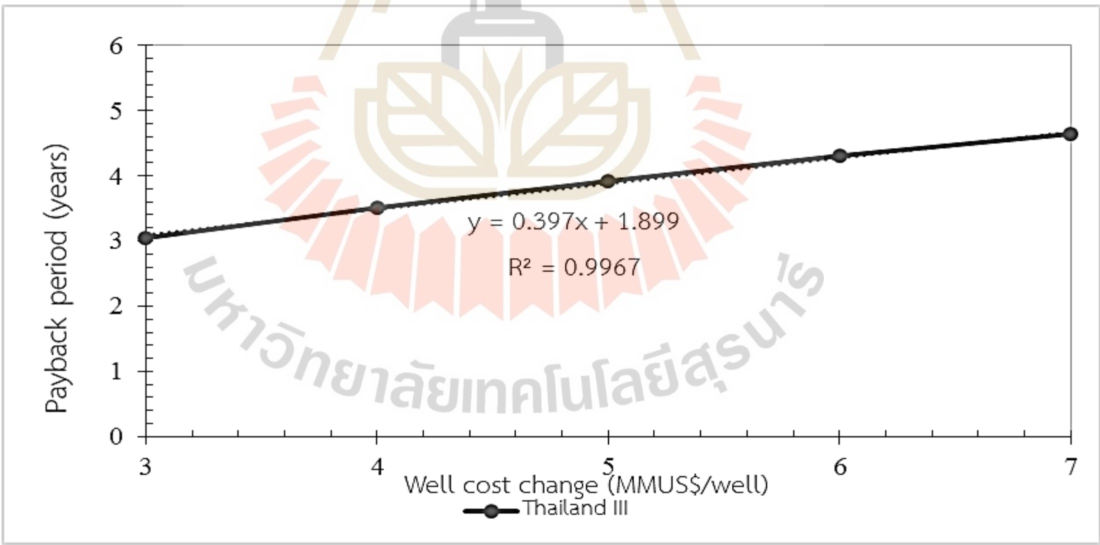


Figure 4.21 Relationship between payback period (years) and well cost change (MMUS$/well) of the project run under Thailand III fiscal regime.

In the context of the Thailand III fiscal regime, the link between well cost and payback period can be concisely depicted through a linear equation, as denoted by Equation 4.29.

$$y = 0.397x + 1.899 \tag{4.29}$$

When y is payback period

x is well cost (MMUS$/well

2) **Production sharing contract (PSC) fiscal regime**

- **Net income**

In the assessment of net present value (NPV), it becomes evident that an upsurge in well costs exerts a direct influence on NPV, resulting in a reduction in its value. Detailed data on net income and net present value can be found in Table 4.30, while Figure 4.22 visually represents these findings.

Table 4.30 Net income and net present value of the project run under PSC fiscal regime at various well cost.

Well cost (MMUS$/well)	PSC	
	Net income (MMUS$)	NPV (MMUS$)
3.00	19.26	14.31
4.00	17.46	12.28
5.00	15.66	10.19
6.00	13.86	8.06
7.00	11.05	5.20

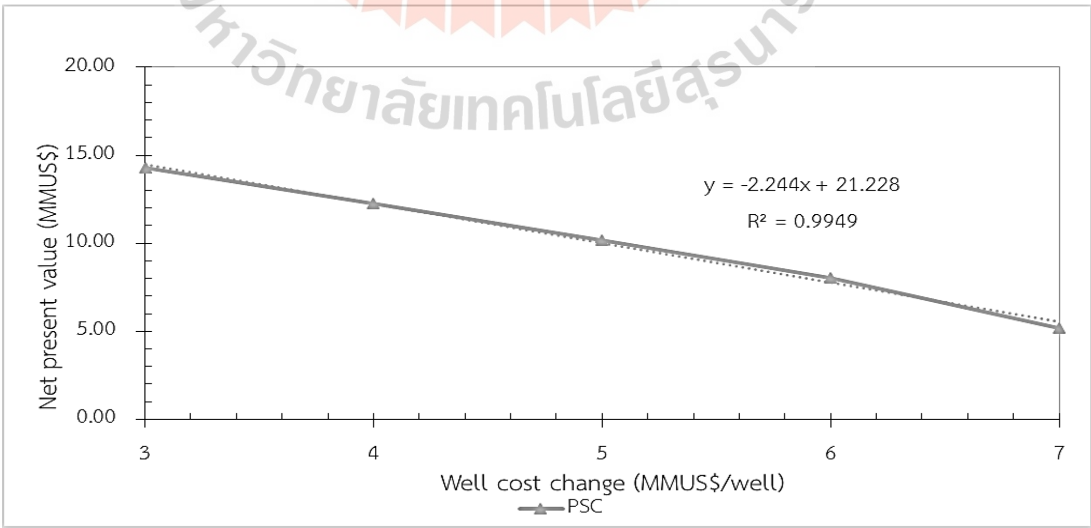


Figure 4.22 Relationship between net present value (MMUS$) and well cost change (MMUS$/well) of the project run under PSC fiscal regime.

When considering the PSC fiscal regime, the connection between well cost and net present value finds clear expression in Equation 4.30, which is a linear function equation.

$$y = -2.244x + 21.228 \quad (4.30)$$

When y is net present value (MMUS$)

x is well cost (MMUS$/well)

- **Internal rate of return (IRR)**

In the analysis of internal rate of return (IRR), a recurring observation is that an increase in well drilling costs consistently leads to a reduction in internal rate of return (IRR). This relationship is documented in Table 4.31 and visually represented Figure 4.23.

Table 4.31 Internal rate of return of the project run under PSC fiscal regime at various well cost.

Well cost (MMUS$/well))	**Internal rate of return (%)**
	PSC
3.00	58.66
4.00	41.38
5.00	30.21
6.00	22.4
7.00	15.77

Equationally capturing the interplay between internal rate of return and well cost for the PSC fiscal regime, Equation 4.31 is presented as an exponential function.

$$y = 153.62e^{-0.324x} \quad (4.31)$$

When y is internal rate of return (percent)

x is well cost (MMUS$/well)

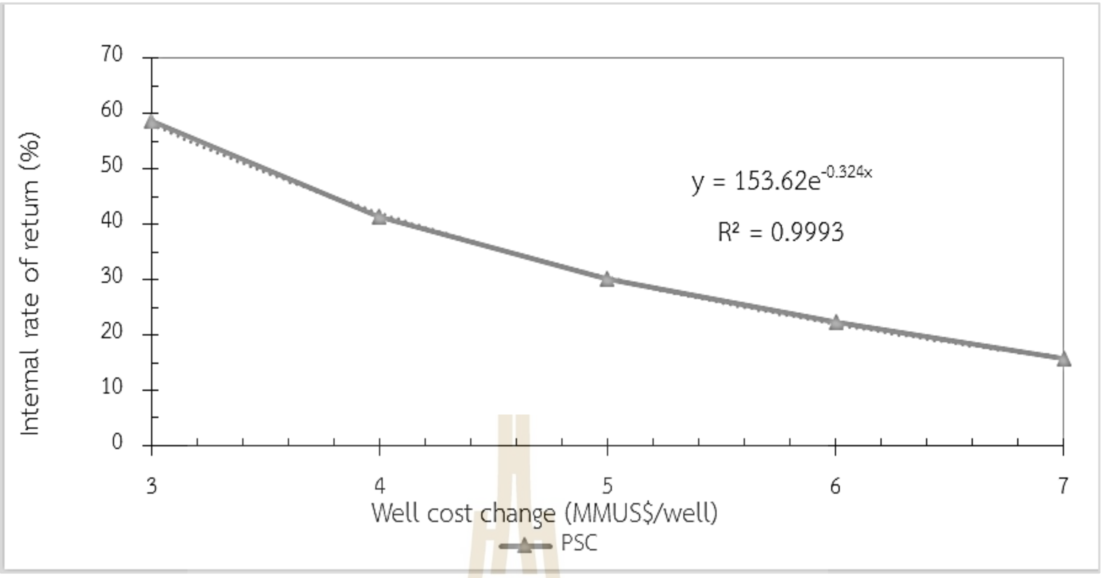


Figure 4.23 Relationship between Internal rate of return (%) and well cost change (MMUS$/well) of the project run under PSC fiscal regime.

- **Profit to investment ratio (PIR)**

The correlation between well costs and the profit to investment ratio is a fundamental aspect of investment analysis. Generally, higher drilling costs are associated with a lower PIR, as illustrated in Table 4.32 and Figure 4.24 for the PSC fiscal regime.

Table 4.32 Profit to investment ratio of the project run under PSC fiscal regime at various well cost.

Well cost (MMUS$/well))	Profit to investment ratio PSC
3.00	1.81
4.00	1.28
5.00	0.94
6.00	0.71
7.00	0.49

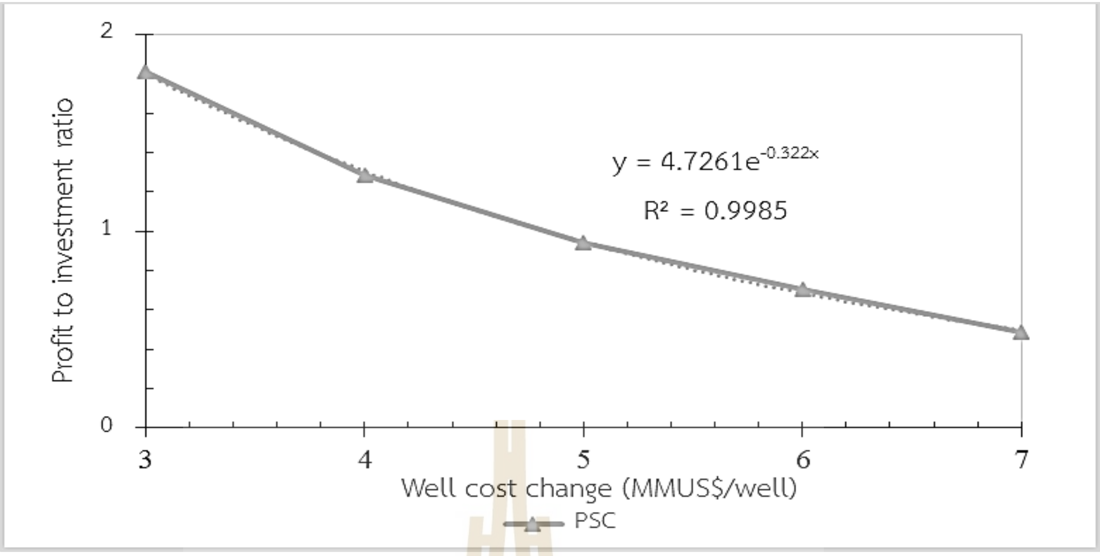


Figure 4.24 Relationship between profit to investment ratio and well cost change (MMUS$/well) of the project run under PSC fiscal regime.

In the realm of the PSC fiscal regime, the relationship between profit to investment ratio and well cost can be effectively conveyed using Equation 4.32, which is formulated as an exponential function.

$$y = 4.7261e^{-0.322x} \tag{4.32}$$

When y is Profit to investment ratio

x is well cost (MMUS$/well)

- **Payback period**

Through an examination of the payback period, it was noted that higher well costs are associated with a prolonged payback period. The specific payback period data can be located in Table 4.33 and visualized in Figure 4.25.

The association between well cost and payback period for the PSC fiscal regime is succinctly represented through a linear equation, as seen in Equation 4.33.

$$y = 0.464x + 1.23 \tag{4.33}$$

When y is payback period (year)

x is well cost (MMUS$/well)

Table 4.33 Payback period of the project run under PSC fiscal regime at various well cost.

Well cost (MMUS$/well))	Payback period (years)
	PSC
3.00	2.62
4.00	3.09
5.00	3.55
6.00	4.01
7.00	4.48

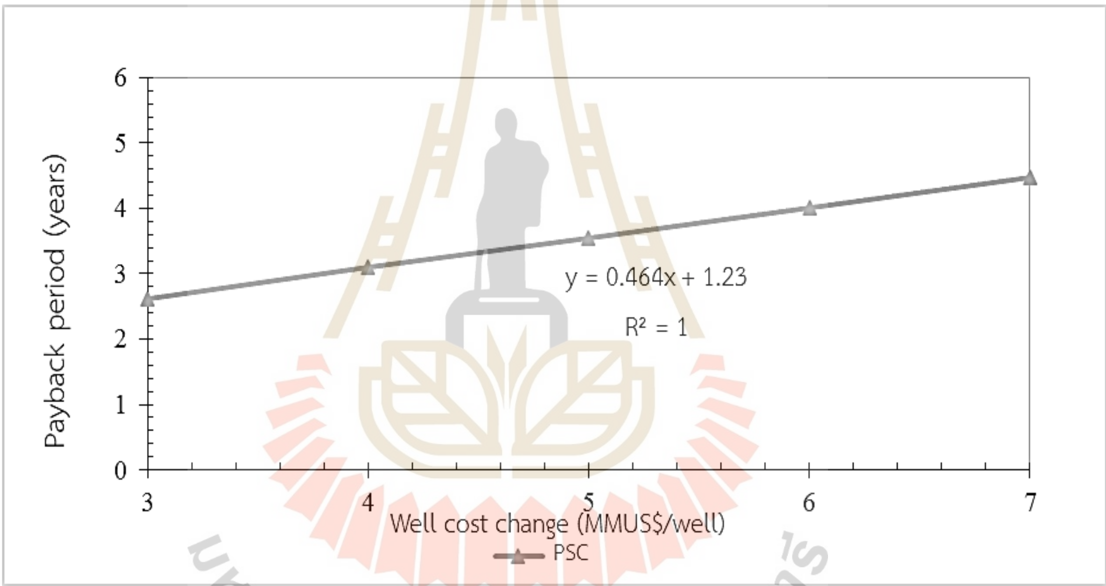


Figure 4.25 Relationship between payback period (years) and well cost change (MMUS$/well) of the project run under PSC fiscal regime.

3) Comparison between Thailand III and production sharing contract fiscal regime

- **Net income**

In the net present value (NPV) analysis, higher well costs are associated with lower NPV values, while lower well costs are linked to higher NPV values. This relationship aligns with the general principle that higher costs can negatively impact the project's overall profitability. However, if comparing Thailand III and PSC fiscal regimes, the NPV analysis showed that the PSC fiscal regime consistently yields higher values than the Thailand III fiscal regime, regardless of any changes in well cost. This finding suggests that under different well cost scenarios, the PSC fiscal regime remains more financially advantageous, generating higher net present values for the investment in the Sikhiu prospect. The net income and net present value of Thailand III and PSC fiscal regime are presented in Table 4.34 and Figure 4.26.

In the PSC fiscal regime, the contractor earns a higher net present value (NPV) than the Thailand III fiscal regime due to the sharing of capital expenditure (CAPEX) and operational expenditure (OPEX) with the state, where the state acts as a co-investor. This arrangement allows the contractor to benefit from cost recovery, resulting in higher income. On the other hand, in the Thailand III fiscal regime, the concessionaire bears all the investment burden as the sole investor, leading to lower income than in the PSC fiscal regime.

The connection between well cost and net present value (NPV) can be effectively demonstrated through a linear function. Specifically, Equation 4.26 captures this relationship within the Thailand III fiscal regime, while Equation 4.30 provides a comprehensive representation within the PSC fiscal regime, as mentioned previously.

Table 4.34 The net income and net present value of the project run under the Thailand III and PSC fiscal regimes at various well cost prices.

Well cost (MMUS$/well)	Thailand III		PSC	
	Net income (MMUS$)	NPV (MMUS$)	Net income (MMUS$)	NPV (MMUS$)
3.00	13.71	9.79	19.26	14.31
4.00	11.91	7.83	17.46	12.28
5.00	10.11	5.86	15.66	10.19
6.00	8.31	3.90	13.86	8.06
7.00	6.51	1.94	11.05	5.20

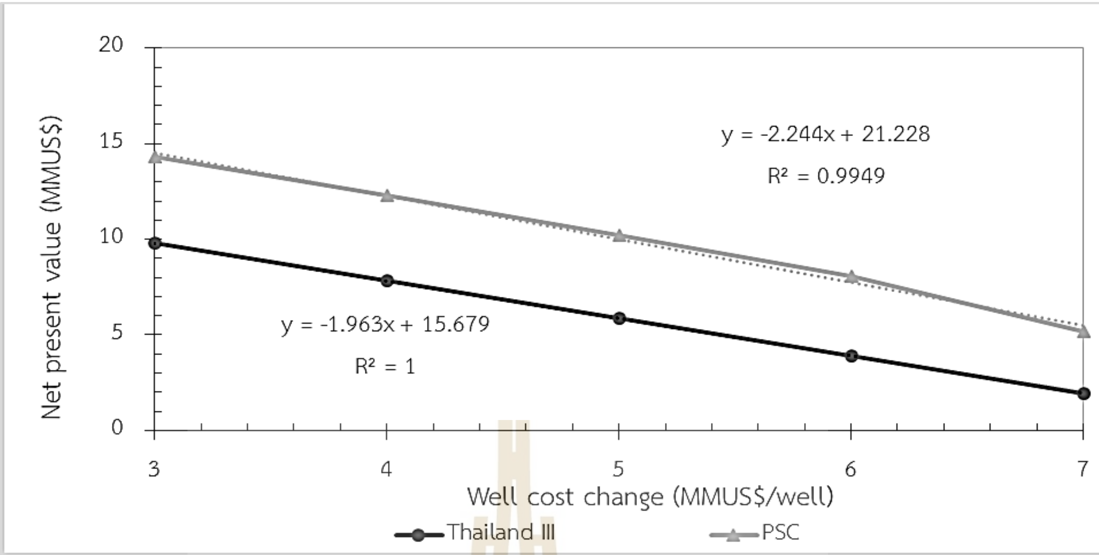


Figure 4.26 Relationship between net present value (MMUS$) and well cost change (MMUS$/well) of Thailand III and PSC fiscal regimes.

- **Internal rate of return (IRR)**

The IRR analysis determined that the PSC fiscal regime consistently demonstrates a higher IRR than the Thailand III fiscal regime, regardless of any changes in well cost. This similarity in results is also observed in the net present value (NPV) analysis. As depicted in Table 4.35 and Figure 4.27.

Table 4.35 The internal rate of return (IRR) of the project run under Thailand III and PSC fiscal regimes at various well cost prices.

Well cost (MMUS$/well))	Internal rate of return (%)	
	Thailand III	PSC
3.00	44.20	58.66
4.00	30.66	41.38
5.00	21.84	30.21
6.00	15.54	22.4
7.00	10.76	15.77

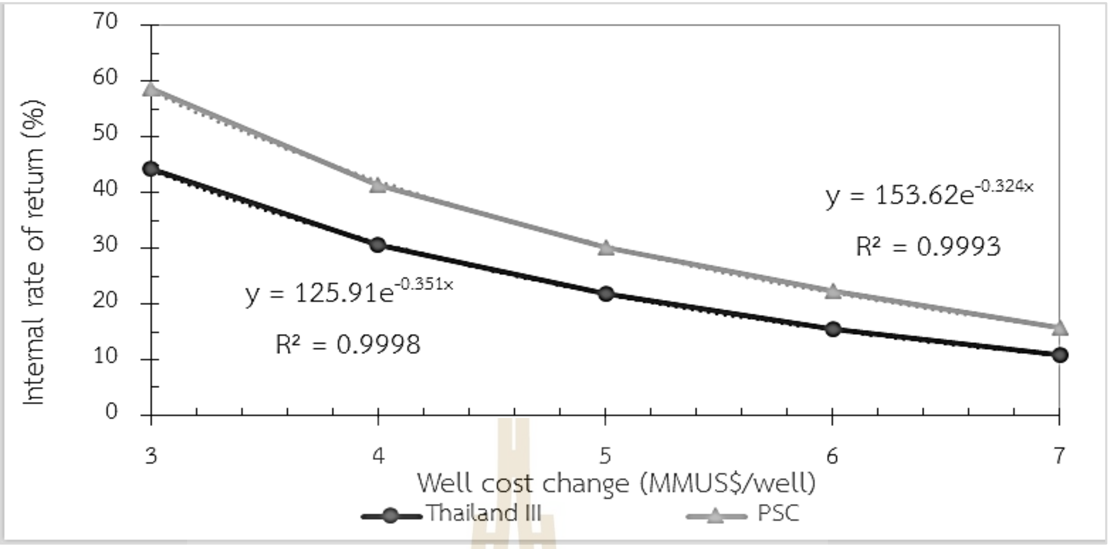


Figure 4.27 Relationship between internal rate of return (%) and well cost change (MMUS$/well) of the project run under Thailand III and PSC fiscal regimes.

The relationship between internal rate of return (IRR) and well cost in both the Thailand III and PSC fiscal regimes can be expressed mathematically as exponential function equations. Equation 4.27 pertains to the Thailand III fiscal regime, while Equation 4.31 is applicable to the PSC fiscal regime. It's important to note that these equations have been previously introduced.

- **Profit to investment ratio (PIR)**

The analysis of the profit to investment ratio (PIR) determined that the PSC fiscal regime consistently yields a higher PIR than the Thailand III fiscal regime, regardless of any changes in well cost. This similarity in results is also observed in the net present value (NPV) and internal rate of return (IRR) analysis (Table 4.36 and Figure 4.28).

To mathematically depict the association between profit to investment ratio and well cost within both the Thailand III and PSC fiscal regimes, exponential function equations are utilized. Equation 4.28 corresponds to the Thailand III fiscal regime, while Equation 4.32 is specific to the PSC fiscal regime. As previously discussed, these equations provide a mathematical representation of this relationship.

Table 4.36 The profit to investment ratio (PIR) of the project run under the Thailand III and PSC fiscal regimes at various well cost prices.

Well cost (MMUS$/well))	Profit to investment ratio	
	Thailand III	PSC
3.00	1.29	1.81
4.00	0.87	1.28
5.00	0.61	0.94
6.00	0.42	0.71
7.00	0.29	0.49

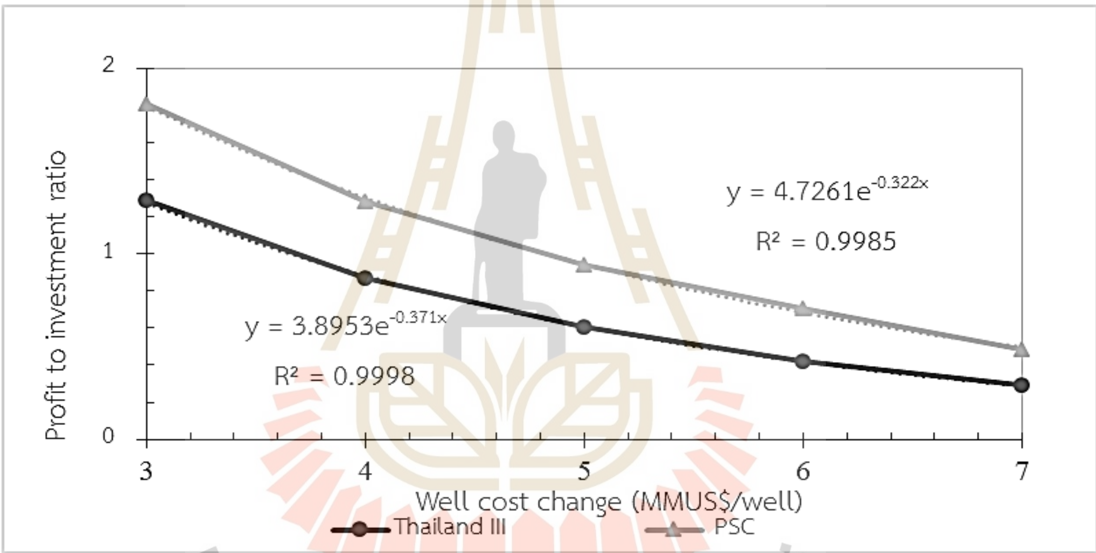


Figure 4.28 Relationship between profit to investment and well cost change (MMUS$/well) of the project run under Thailand III and PSC fiscal regimes.

- **Payback period**

According to the payback period analysis, it was determined that the PSC fiscal regime exhibits a consistently shorter payback period than Thailand III across various changes in well costs. This outcome can be attributed to the fact that in the PSC fiscal regime, the government shares the operational expenditure (OPEX) and capital expenditure (CAPEX) with the company. This cooperative investment approach allows the company to receive more funds, resulting in a shorter payback period. In contrast, the payback period may be extended in the Thailand III fiscal regime, where the company bears all the expenses independently (Table 4.37 and Figure 4.29).

Table 4.37 The payback period of the project run under Thailand III and PSC fiscal regimes at various well cost prices.

Well cost (MMUS$/well))	Payback period (years)	
	Thailand III	PSC
3.00	3.05	2.62
4.00	3.51	3.09
5.00	3.92	3.55
6.00	4.30	4.01
7.00	4.64	4.48

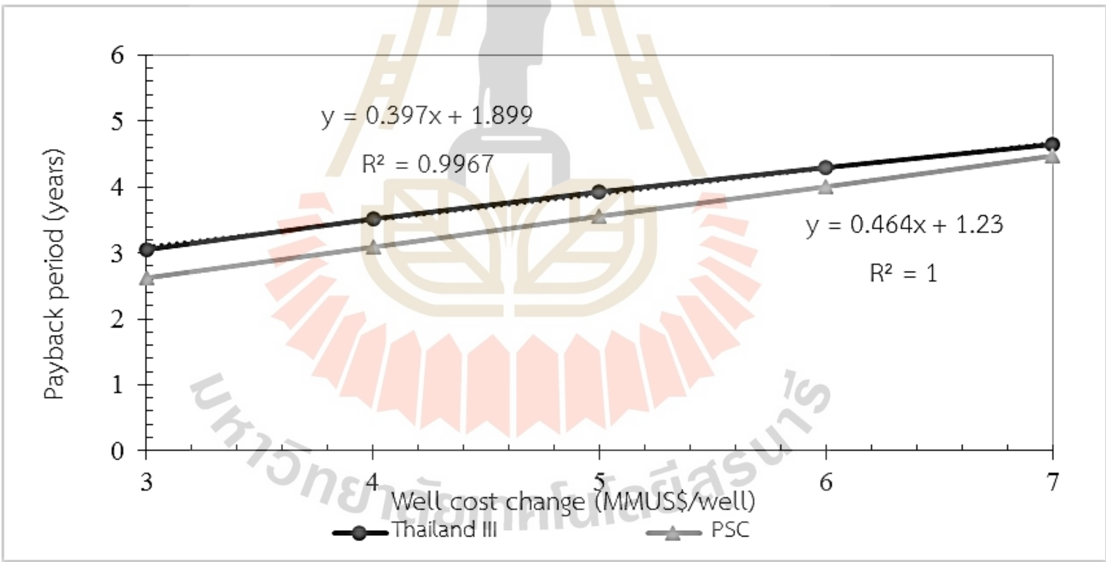


Figure 4.29 Relationship between payback period (years) and well cost change (MMUS$/well) of the project run under Thailand III and PSC fiscal regimes.

Figure 4.29, presented as a graph, illustrates the relationship between payback period and well cost for both the Thailand III and PSC fiscal regimes. This relationship is succinctly summarized by the linear function equations mentioned earlier. Equation 4.29 applies to the Thailand III fiscal regime, while Equation 4.33 is relevant to the PSC fiscal regime.

CHAPTER V

CONCLUSIONS AND RECOMMENDATION

5.1 Conclusions

The objectives of this study are to assess the undiscovered petroleum resources and to evaluate petroleum economics potential of the Sikhiu prospect located in the Sap Phlu basin, northeast Thailand. The research findings have been presented in two main parts, focusing on the undiscovered hydrocarbon resource assessment and the economics potential of the prospect.

5.1.1 Undiscovered Petroleum Resources of Sikhiu Prospect

Based on the available data, which includes relevant surface and subsurface geology, seismic data, and drilled well information provided by the Department of Mineral Fuels (DMF), as well as the published literature, the untested (undrilled) Sikhiu prospect is classified as a Permian Carbonate Play. The main seals for this prospect are the Khorat Group rocks, while the reservoir is situated in the Permian Saraburi Group. The hydrocarbon sources originate from the Permian Group itself. An essential characteristic of these Permian carbonate rocks is their fair to excellent organic richness, indicating the potential for hydrocarbon generation. Additionally, the thermal maturity assessment of these carbonate source rocks suggests they have reached a late to overmature oil stage. These geological features contribute to the Sikhiu prospect's highly favorable petroleum geology system.

According to the available input geological and engineering parameter data, the estimated undiscovered hydrocarbon resources of the Sikhiu prospect resulted from FASPU calculation consist solely of non-associated gas. The estimated gas resources vary across different confidence levels, as follows: 4.84 Bcf (very high confidence, F95), 10.31 Bcf (high confidence, F75), 17.45 Bcf (medium confidence, F50), 29.52 Bcf (low confidence, F25), 62.90 Bcf (very low confidence, F05), and 23.64 Bcf at the arithmetic mean respectively.

The estimates of undiscovered hydrocarbon resources of the untested Sikhiu prospect from this study are novel since this prospect has never been assessed. Thailand must promote investment in domestic petroleum exploration and production, especially from the new and undiscovered/untested oil and gas field, to respond to its high domestic energy demand. Therefore, the results of this study can enhance the domestic natural gas supply to ensure the sustainability of the energy supply security of Thailand in the near future.

5.1.2 Petroleum Economics

The research delves into the economic aspects of petroleum exploration and production in the Sikhiu prospect. The study compares the fiscal regimes of Thailand III and the production sharing contract (PSC), examining the implications on petroleum economics. Additionally, sensitivity analyses are performed to assess the impact of fluctuations in gas prices and well costs on the project's financial viability.

5.1.2.1 Cash Flow Analysis

The financial metrics for the Thailand III fiscal regime are calculated based on the given data, including the undiscovered natural gas resource size of 17.45 Bcf, the well cost of 4.985 MMUS$/well, an average gas price of 3.435 US$/MMBTU over ten years, and an initial gas production rate of 9.556 MMSCF/D. The calculated values are as follows: a net present value (NPV) at a discount rate of 7.04% of 5.89 MMUS$, an internal rate of return (IRR) after tax of 21.95%, profit to investment ratio (PIR) of 0.61, and payback period of 3.92 years

When applying the production sharing contract (PSC) fiscal regime, the economic analysis reveals a NPV at a discount rate of 7.04% of 10.23 MMUS$, an IRR of 30.35%, a PIR of 0.95, and payback period of 3.54 years.

These results demonstrate that the PSC fiscal regime offers higher returns and a shorter payback period than the Thailand III fiscal regime. The IRR and NPV values indicate that the investment opportunity is more attractive under the PSC fiscal regime, with the project expected to generate higher cash flows and profitability over the assessment period.

5.1.2.2 Sensitivity Analysis

- Sensitivity analysis of gas price

Based on the sensitivity analysis, where gas prices vary between -50% to +200% of 3.435 US$/MMBTU, well cost remains at 4.985 MMUS$/well, and undiscovered natural gas resource size is 17.45 Bcf, the following conclusions can be drawn:

1) Net income

When the gas price is lower than 106.8% of the base price, the PSC fiscal regime yields a higher net present value than the Thailand III fiscal regime. This indicates that the project is more financially attractive under the PSC regime when gas prices are relatively lower. The higher net present value in the PSC fiscal regime results from the contractor benefiting from shared capital expenditure (CAPEX) and operational expenditure (OPEX) with the state, where the state acts as a co-investor. This arrangement allows the contractor to benefit from cost recovery, resulting in higher income. On the other hand, in the Thailand III fiscal regime, the concessionaire bears all the investment burden as the sole investor, leading to lower income than in the PSC fiscal regime.

Conversely, when the gas price exceeds 106.8% of the base price, the NPV of the Thailand III fiscal regime surpasses that of the PSC fiscal regime. In this scenario, the Thailand III regime proves to be more financially advantageous for the project. The higher net present value in the Thailand III fiscal regime results from the PSC fiscal regime generating more revenue for the government. Consequently, the contractor receives a reduced share. Moreover, the one that affects this outcome is production sharing.

At a gas price of 106.8% of the base price, both fiscal regimes exhibit an equal net present value of 29.45 MMUS$. This threshold represents the intersection point where both regimes' financial attractiveness becomes equal.

The analysis of sensitivity to changes in gas prices under the PSC fiscal regime, with a maximum cost recovery set at 50%, it was found that the contractor can achieve the fastest return on investment in the third year of the project when the gas price is at 75% of the base price and when the gas price falls to a minimum of -13.08% of the base price, the contractor can recover all costs within the 6-year project timeframe. Nevertheless, if the gas price drops below -13.08% of the base price, the contractor can only recover some costs within six years.

When examining cost recovery, it becomes evident that as the percentage of cost recovery decreases, the NPV is reduced under the PSC fiscal regime. Conversely, when the cost recovery percentage increases, the contractor's NPV increases. When the cost recovery rate in the PSC fiscal regime is set at 19.7%, both the PSC and Thailand III fiscal regimes yield an equivalent net present value of 5.89 MMUS$.

2) Internal rate of return (IRR)

The production sharing contract fiscal regime demonstrates a higher IRR than the Thailand III fiscal regime which is the same reason for the net present value.

3) Profit to investment ratio (PIR)

When the gas price is lower than 101.6% of the base price, the PSC fiscal regime exhibits a higher PIR than the Thailand III fiscal regime. Conversely, if the gas price exceeds 101.6% of the base price, the PIR of Thailand III is higher than the PSC fiscal regime, which is the same reason for the NPV and IRR. Notably, when the gas price reaches 101.6% of the base price, both fiscal regimes yield the same PIR of 2.27.

4) Payback period

The payback period of the PSC fiscal regime is consistently shorter than the Thailand III fiscal regime across all gas price percentages. According to the designed production plan, when the gas price is 33.5% lower than the base price in the Thailand III fiscal regime or the gas price is 49.1% lower than the base price in the PSC fiscal regime, the project will have a payback period of 6 years. The reason for the more significant decline in gas prices within the PSC fiscal regime than Thailand III fiscal regime is attributed to cost recovery, as described in the NPV discussions.

- Sensitivity analysis of well cost

The sensitivity analysis, with the gas price remaining constant at 3.435 US$/MMBTU and the undiscovered natural gas resource estimated at 17.45

Bcf, the results of varying well costs from 3 to 7 MMUS$ per well are as follows:

1) Net income

The NPV analysis showed that higher well costs are associated with lower NPV values, while lower well costs are linked to higher NPV values and the PSC fiscal regime consistently yields higher values than the Thailand III fiscal regime, regardless of any changes in well cost.

In the PSC fiscal regime, the contractor earns a higher net present value (NPV) than the Thailand III fiscal regime due to the sharing of capital expenditure (CAPEX) and operational expenditure (OPEX) with the state, where the state acts as a co-investor. This arrangement allows the contractor to benefit from cost recovery, resulting in higher income. On the other hand, in the Thailand III fiscal regime, the concessionaire bears all the investment burden as the sole investor, leading to lower income than in the PSC fiscal regime.

2) Internal rate of return (IRR)

The internal rate of return (IRR) analysis determined that the PSC fiscal regime consistently demonstrates a higher IRR than the Thailand III fiscal regime, regardless of any changes in well cost. This similarity in results is also observed in the NPV analysis.

3) Profit to investment ratio (PIR)

The analysis of the profit to investment ratio (PIR) determined that the PSC fiscal regime consistently yields a higher PIR than the Thailand III fiscal regime, regardless of any changes in well cost. This similarity in results is also observed in the NPV and IRR analysis.

4) Payback period

According to the payback period analysis, it was determined that the PSC fiscal regime exhibits a consistently shorter payback period than Thailand III across various changes in well costs. This similarity in results is also observed in the NPV, IRR, and PIR analysis.

5.2 Recommendations for Further Research

The reliability of estimates for undiscovered hydrocarbon assessment is influenced not only by the accuracy and quantity of input parameters, geological models, and play types but also by geological uncertainty. This uncertainty comprises two key elements, the uncertainty involved in interpreting the geological play and the uncertainty involved in the areal extent of the different play attributes.

In order to assess the amount of the undiscovered petroleum resources in Sikhiu prospect to be more accurate and reliable, data from seismic surveys from exploration lines that pass through or nearby Sikhiu prospect should be reprocessed and interpreted for having more accurate petroleum geology and engineering data from what was used in this study. If the results of the amount of this calculated undiscovered petroleum resources are more accurate, the results of the petroleum economics assessment will also be accurate and reliable as well.

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APPENDIX

APPENDIX A

Analysis Method of Play Analysis

The basic steps of the analytic method of the play analysis are;

1) Select the play

2) Oil is the first resource to be assessed

3) The following volume attributed are estimated: 1) area of closure, 2) thickness of reservoir, 3) effective porosity, 4) trap fill, 5) Depth of reservoir, 6) hydrocarbon saturation. Determine the mean and variance from the estimated seven fractiles, assuming a uniform distribution between fractile, that is, a piecewise uniform probability density function. Recall that the hydrocarbon saturation distribution depends on whether the estimated reservoir lithology is sandstone or carbonate. Calculate the mean and variance of the product of effective porosity and hydrocarbon saturation, assuming they possess near perfect position correlation. Also compute the mean and variance for the reciprocal of the oil formation volume factor, which is a function of reservoir depth.

4) Compute the mean and variance of accumulation size of oil in place using a reservoir engineering equation. The equation involves the product of the constant, are of closure, reservoir thickness, trap fill, effective porosity, hydrocarbon saturation, and the reciprocal of the oil formation volume factor. Various laws of expectation and variance are involved in the calculations.

5) Model the accumulation size distribution by the lognormal probability distribution with mean and variance from step 4. Calculation various lognormal fractiles of the accumulation size for oil.

6) Compute the probability that a prospect has an oil accumulative, given the play is favorable. This is called the conditional prospect probability of oil. This probability is the product of the conditional deposit probability, the probability that the reservoir depth is less than the oil floor depth, and the hydrocarbon type probability of oil.

7) Compute the mean and variance of the conditional prospect potential for oil, which is the quantity of oil in a prospect, given the play is favorable. They are derived by applying the conditional prospect probability of oil to the mean and variance of the accumulation size of oil.

8) Compute various fractiles of the conditional prospect potential for oil by a transformation to appropriate lognormal fractiles of the accumulation size of oil using the conditional prospect probability of oil.

9) Compute the mean and variance of the number of prospect from the estimated seven fractiles, assuming a uniform distribution between fractiles.

10) Compute the mean and variance of the oil accumulations, given the play is favorable. They are derived by applying the conditional prospect probability of oil to the mean and variance of the number of prospects.

11) Compute the mean and variance of the conditional (A) play potential for oil, which is the quantity of oil in the play, given the play is favorable. They are determined from the probability theory of the expectation and variance of a random number (number of prospects) of random variables (conditional prospect potential).

12) Compute the conditional play probability of oil, which is the probability that a favorable play has at least one oil accumulation, and is a function of the conditional prospect probability of oil and the number of prospects distribution.

13) Compute the mean and variance of the conditional (B) play potential for oil, which is the quantity of oil in the play, given the play is favorable and there is at least one oil accumulation within the play. They are obtained by applying the conditional play probability of oil to the mean and variance of the conditional (A) play potential for oil,

14) Compute the unconditional play probability of oil, which is the probability that the play has at least one oil accumulation, and is the product of the conditional play probability of oil and the marginal play probability.

15) Compute the mean and variance of the unconditional play potential for oil, which is the quantity of oil in the play. They are derived by applying the unconditional play probability of oil to the mean and variance of the conditional (B) play potential for oil.

16) Model the probability distribution of the conditional (B) play potential for oil by the lognormal distribution with mean and variance from step 13. Calculate various lognormal fractiles.

17) Compute various fractiles of the conditional (A) play potential for oil by a transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the conditional play probability of oil.

18) Compute various fractiles of the unconditional play potential for oil by transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the unconditional play probability of oil.

19) Non-associated gas is the second resource to be assessed. Repeat step 3 through 18, substituting non-associated gas for oil, with two basic modifications as follows. A different reservoir engineering equation is used to calculate the accumulation size of non-associated gas is equal to the condition deposit probability minus the conditional prospect probability of oil.

20) Associated-dissolved gas is the third resource to be assessed, repeat steps 3 through 18, substitution associated-dissolved gas for oil with two basic modifications as follows. The reservoir engineering equation for the accumulation size of oil in place is multiplied by a gas-oil ratio, which is a function of reservoir depth. The conditional prospect probability of dissolved gas is the same as the conditional prospect probability of oil.

21) Gas is the fourth resource to be assessed. Repeat step 4 through 18, substituting gas for oil, with two basic modifications as follows. Replace step 4 to compute the mean and variance of the accumulation size of gas in place by using conditional probability theory and conditional on the type of gas. Th
prospect probability of gas is the same as the conditional deposit probal

APPENDIX B

Average Gas Price Calculation

Table B1 Average gas price 10 years.

Years	Jan	Feb	Mar	April	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Average
2013	3.33	3.33	3.81	4.17	4.04	3.83	3.62	3.43	3.62	3.68	3.64	4.24	3.73
2014	4.71	6	4.9	4.66	4.58	4.59	4.05	3.91	3.92	3.78	4.12	3.48	4.39
2015	2.99	2.87	2.83	2.61	2.85	2.78	2.84	2.77	2.66	2.34	2.09	1.93	2.63
2016	2.28	1.99	1.73	1.92	1.92	2.59	2.82	2.82	2.99	2.98	2.55	3.59	2.52
2017	3.3	2.85	2.88	3.1	3.15	2.98	2.98	2.9	2.98	2.88	3.01	2.82	2.99
2018	3.87	2.67	2.69	2.8	2.8	2.97	2.83	2.96	3	3.28	4.09	4.04	3.17
2019	3.11	2.69	2.95	2.65	2.64	2.4	2.37	2.22	2.56	2.33	2.65	2.22	2.57
2020	2.02	1.91	1.79	1.74	1.75	1.63	1.77	2.3	1.92	2.39	2.61	2.59	2.04
2021	2.71	5.35	2.62	2.66	2.91	3.26	3.84	4.07	5.161	5.51	5.05	3.76	3.90
2022	4.38	4.69	4.9	6.6	8.14	7.7	7.28	8.81	7.88	5.66	5.45	5.53	6.42
								Average 10 years (US$/MMBTU)				=	3.43

APPENDIX C

Well Cost Calculation

Table C1 Well cost/ meter of Northeast Thailand.

Well Name	Year	Depth (m)	Well cost/meter (us/m)
PHUHORM-4	2004	2621	2428
PHUHORM-5	2004	2951	2408
PHUHORM-7ST	2006	3837	3826
PHUHORM-6	2007	3542	3291
PHUHORM-10ST	2007	3307	3076
DONGMUN-3	2007	3127	3733
SOUTH PHUHORM-1	2008	3229	3885
PHUKHENG-1	2009	2405	3355
Si-That-3st	2009	3150	2972
TEW-B(ST1)	2010	3308	2956
TEW-E	2010	4580	2719
Doa Ruang-2	2011	2781	5009
Doa Ruang-3ST	2011	2390	5442
TEW-EST	2011	3395	1959
Dong Mun-3ST	2012	3010	2246
Rattana-1ST	2012	3728	1823
Average well cost/meter			3195.5

Well cost calculation

Based on seismic profile line 92NR180, the two-way travel time of the Pha Nok Khao Formation is 1.3 milliseconds. According to Satarugsa (2007), the seismic velocity of the Khorat Group is 2400 meters per second. The average well cost in northeastern Thailand is 3.195 million US dollars per kilometer, as indicated in Table C1.

Depth (m) of the reservoir = (TWT/2 (s) * Velocity (m/s)

= 1.3/2 * 2400

= 1560 m.

The well cost (MMUS$/well) = Depth (km.) * Well cost (MMUS$/km.)

= 1.560 * 3.195

= 4.985 MMUS$/well

APPENDIX D

Sensitivity Analysis of Gas Price

Table D1 Cash flow summary for the Thailand III fiscal regime at -50% of the base price (1.718 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 1.718 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	1.718	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	1.718	5.992	0.30						1.395	1.395
2025	9.556	3487.940	1.718	5.992	0.30						1.395	1.395
2026	9.556	3487.940	1.718	5.992	0.30						1.395	1.395
2027	9.556	3487.940	1.718	5.992	0.30						1.395	1.395
2028	9.556	3487.940	1.718	5.992	0.30					1.20	1.395	2.595
TOTAL		17439.70		29.961	1.50	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	3.54	0.54
		2.45					2.45	2.45	3.54	1.77
			2.45				2.45	2.45	3.54	1.77
				2.45			2.45	2.45	3.54	1.77
					0.00		0.00	1.20	4.79	2.40
							12.26	13.46	16.50	8.25

Table D1 Cash flow summary for the Thailand III fiscal regime at -50% of the base price (1.718 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	5.99	0.00	1.40	0.30	0.54	3.75	3.51	0.9342	1.0200
2025	5.99	0.00	1.40	0.30	1.77	2.53	2.21	0.8728	1.0404
2026	5.99	0.00	1.40	0.30	1.77	2.53	2.06	0.8154	1.0612
2027	5.99	0.00	1.40	0.30	1.77	2.53	1.93	0.7618	1.0824
2028	5.99	1.32	1.40	0.30	2.40	0.58	0.41	0.7117	1.1041
TOTAL	29.96	16.58	6.98	1.50	8.25	-3.34	-5.14		

PIR = -0.2

IRR = -9.26%

Table D2 Payback period for Thailand III fiscal regime at -50% of the base price (1.718 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		3.75	3.75
3		2.53	6.28
4		2.53	8.81
5		2.53	11.34
6		0.70	12.04
Payback period			N/A

Table D3 Cash flow summary for the Thailand III fiscal regime at -33.55% of the base price (2.282 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 2.282 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	2.282	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	2.282	7.959	0.40						1.395	1.395
2025	9.556	3487.940	2.282	7.959	0.40						1.395	1.395
2026	9.556	3487.940	2.282	7.959	0.40						1.395	1.395
2027	9.556	3487.940	2.282	7.959	0.40						1.395	1.395
2028	9.556	3487.940	2.282	7.959	0.40					1.20	1.395	2.595
TOTAL		17439.70		39.797	1.99	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	5.51	1.53
		2.45					2.45	2.45	5.51	2.75
			2.45				2.45	2.45	5.51	2.75
				2.45			2.45	2.45	5.51	2.75
					0.00		0.00	1.20	6.76	3.38
							12.26	13.46	26.33	13.17

Table D3 Cash flow summary for the Thailand III fiscal regime at -33.55% of the base price (2.282 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	7.96	0.00	1.40	0.40	1.53	4.64	4.33	0.9342	1.0200
2025	7.96	0.00	1.40	0.40	2.75	3.41	2.98	0.8728	1.0404
2026	7.96	0.00	1.40	0.40	2.75	3.41	2.78	0.8154	1.0612
2027	7.96	0.00	1.40	0.40	2.75	3.41	2.60	0.7618	1.0824
2028	7.96	1.32	1.40	0.40	3.38	1.46	1.04	0.7117	1.1041
TOTAL	39.80	16.58	6.98	1.99	13.17	1.09	-1.52		

PIR = 0.07

IRR = 2.69%

Table D4 Payback period for Thailand III fiscal regime at -33.55% of the base price (2.282 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		4.64	4.64
3		3.41	8.05
4		3.41	11.47
5		3.41	14.88
6		1.59	16.46
Payback period			6.00

Table D5 Cash flow summary for the Thailand III fiscal regime at -25% of the base price (2.576 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 2.576 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	2.576	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	2.576	8.985	0.45						1.395	1.395
2025	9.556	3487.940	2.576	8.985	0.45						1.395	1.395
2026	9.556	3487.940	2.576	8.985	0.45						1.395	1.395
2027	9.556	3487.940	2.576	8.985	0.45						1.395	1.395
2028	9.556	3487.940	2.576	8.985	0.45					1.20	1.395	2.595
TOTAL		17439.70		44.925	2.25	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	6.53	2.04
		2.45					2.45	2.45	6.53	3.27
			2.45				2.45	2.45	6.53	3.27
				2.45			2.45	2.45	6.53	3.27
					0.00		0.00	1.20	7.78	3.89
							12.26	13.46	31.46	15.73

Table D5 Cash flow summary for the Thailand III fiscal regime at -25% of the base price (2.576 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW	DISCOUNT	ESCAL.
				ROYALTY	INCOME TAX		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	8.98	0.00	1.40	0.45	2.04	5.10	4.77	0.9342	1.0200
2025	8.98	0.00	1.40	0.45	3.27	3.87	3.38	0.8728	1.0404
2026	8.98	0.00	1.40	0.45	3.27	3.87	3.16	0.8154	1.0612
2027	8.98	0.00	1.40	0.45	3.27	3.87	2.95	0.7618	1.0824
2028	8.98	1.32	1.40	0.45	3.89	1.92	1.37	0.7117	1.1041
TOTAL	44.92	16.58	6.98	2.25	15.73	3.39	0.37		

PIR = 0.2

IRR = 8.06%

Table D6 Payback period for Thailand III fiscal regime at -25% of the base price (2.576 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		5.10	5.10
3		3.87	8.98
4		3.87	12.85
5		3.87	16.72
6		2.05	18.77
Payback period			4.93

Table D7 Cash flow summary for the Thailand III fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 2.9857 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	2.9857	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	2.9857	10.414	0.52						1.395	1.395
2025	9.556	3487.940	2.9857	10.414	0.52						1.395	1.395
2026	9.556	3487.940	2.9857	10.414	0.52						1.395	1.395
2027	9.556	3487.940	2.9857	10.414	0.52						1.395	1.395
2028	9.556	3487.940	2.9857	10.414	0.52					1.20	1.395	2.595
TOTAL		17439.70		52.070	2.60	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	7.96	2.75
		2.45					2.45	2.45	7.96	3.98
			2.45				2.45	2.45	7.96	3.98
				2.45			2.45	2.45	7.96	3.98
					0.00		0.00	1.20	9.21	4.61
							12.26	13.46	38.61	19.30

Table D7 Cash flow summary for the Thailand III fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	10.41	0.00	1.40	0.52	2.75	5.74	5.37	0.9342	1.0200
2025	10.41	0.00	1.40	0.52	3.98	4.52	3.94	0.8728	1.0404
2026	10.41	0.00	1.40	0.52	3.98	4.52	3.68	0.8154	1.0612
2027	10.41	0.00	1.40	0.52	3.98	4.52	3.44	0.7618	1.0824
2028	10.41	1.32	1.40	0.52	4.61	2.57	1.83	0.7117	1.1041
TOTAL	52.07	16.58	6.98	2.60	19.30	6.61	3.00		

PIR = 0.40

IRR = 14.95%

Table D8 Payback period for Thailand III fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		5.74	5.74
3		4.52	10.26
4		4.52	14.78
5		4.52	19.30
6		2.69	21.99
Payback period			4.37

Table D9 Cash flow summary for the Thailand III fiscal regime at base price (3.435 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	9.53	3.54
		2.45					2.45	2.45	9.53	4.76
			2.45				2.45	2.45	9.53	4.76
				2.45			2.45	2.45	9.53	4.76
					0.00		0.00	1.20	10.78	5.39
							12.26	13.46	46.44	23.22

Table D9 Cash flow summary for the Thailand III fiscal regime at base price (3.435 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	3.54	6.45	6.02	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	4.76	5.22	4.56	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	4.76	5.22	4.26	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	4.76	5.22	3.98	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	16.58	6.98	3.00	23.22	10.13	5.89		

PIR = 0.61

IRR = 21.95%

Table D10 Payback period for Thailand III fiscal regime at base price (3.435 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		6.45	6.45
3		5.22	11.67
4		5.22	16.89
5		5.22	22.12
6		3.40	25.51
Payback period			3.92

Table D11 Cash flow summary for the Thailand III fiscal regime at +25% of the base price (4.294 US$/MMBTU).

	Gas Production and Selling Plan : 2nd Year Production Plan					CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
	Gas Reserve Size 17.4 BCF @ 4.294 US$/MMBTU					2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	4.294	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	4.294	14.977	0.75						1.395	1.395
2025	9.556	3487.940	4.294	14.977	0.75						1.395	1.395
2026	9.556	3487.940	4.294	14.977	0.75						1.395	1.395
2027	9.556	3487.940	4.294	14.977	0.75						1.395	1.395
2028	9.556	3487.940	4.294	14.977	0.75					1.20	1.395	2.595
TOTAL		17439.70		74.886	3.74	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
1	2	3	4	5	6	7	TOTAL			
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	12.52	5.04
		2.45					2.45	2.45	12.52	6.26
			2.45				2.45	2.45	12.52	6.26
				2.45			2.45	2.45	12.52	6.26
					0.00		0.00	1.20	13.78	6.89
							12.26	13.46	61.42	30.71

Table D11 Cash flow summary for the Thailand III fiscal regime at +25% of the base price (4.294 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	14.98	0.00	1.40	0.75	5.04	7.80	7.28	0.9342	1.0200
2025	14.98	0.00	1.40	0.75	6.26	6.57	5.74	0.8728	1.0404
2026	14.98	0.00	1.40	0.75	6.26	6.57	5.36	0.8154	1.0612
2027	14.98	0.00	1.40	0.75	6.26	6.57	5.01	0.7618	1.0824
2028	14.98	1.32	1.40	0.75	6.89	4.62	3.29	0.7117	1.1041
TOTAL	74.89	16.58	6.98	3.74	30.71	16.87	11.42		

PIR = 1.02

IRR = 34.24%

Table D12 Payback period for Thailand III fiscal regime at +25% of the base price (4.294 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		7.80	7.80
3		6.57	14.37
4		6.57	20.94
5		6.57	27.51
6		4.74	32.25
Payback period			3.32

Table D13 Cash flow summary for the Thailand III fiscal regime at +50% of the base price (5.153 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 5.153 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	5.153	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	5.153	17.973	0.90						1.395	1.395
2025	9.556	3487.940	5.153	17.973	0.90						1.395	1.395
2026	9.556	3487.940	5.153	17.973	0.90						1.395	1.395
2027	9.556	3487.940	5.153	17.973	0.90						1.395	1.395
2028	9.556	3487.940	5.153	17.973	0.90					1.20	1.395	2.595
TOTAL		17439.70		89.867	4.49	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	15.52	6.53
		2.45					2.45	2.45	15.52	7.76
			2.45				2.45	2.45	15.52	7.76
				2.45			2.45	2.45	15.52	7.76
					0.00		0.00	1.20	16.77	8.39
							12.26	13.46	76.40	38.20

Table D13 Cash flow summary for the Thailand III fiscal regime at +50% of the base price (5.153 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INCOME TAX		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	17.97	0.00	1.40	0.90	6.53	9.15	8.54	0.9342	1.0200
2025	17.97	0.00	1.40	0.90	7.76	7.92	6.91	0.8728	1.0404
2026	17.97	0.00	1.40	0.90	7.76	7.92	6.46	0.8154	1.0612
2027	17.97	0.00	1.40	0.90	7.76	7.92	6.03	0.7618	1.0824
2028	17.97	1.32	1.40	0.90	8.39	5.97	4.25	0.7117	1.1041
TOTAL	89.87	16.58	6.98	4.49	38.20	23.62	16.94		

PIR = 1.42

IRR = 45.61%

Table D14 Payback period for Thailand III fiscal regime at +50% of the base price (5.153 US$/MMBTU)

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		9.15	9.15
3		7.92	17.06
4		7.92	24.98
5		7.92	32.90
6		6.09	39.00
Payback period			2.92

Table D15 Cash flow summary for the Thailand III fiscal regime at +75% of the base price (6.011 US$/MMBTU).

	Gas Production and Selling Plan : 2nd Year Production Plan					CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
	Gas Reserve Size 17.4 BCF @ 6.011 US$/MMBTU					2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	6.011	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	6.011	20.966	1.05						1.395	1.395
2025	9.556	3487.940	6.011	20.966	1.05						1.395	1.395
2026	9.556	3487.940	6.011	20.966	1.05						1.395	1.395
2027	9.556	3487.940	6.011	20.966	1.05						1.395	1.395
2028	9.556	3487.940	6.011	20.966	1.05					1.20	1.395	2.595
TOTAL		17439.70		104.830	5.24	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	18.51	8.03
		2.45					2.45	2.45	18.51	9.26
			2.45				2.45	2.45	18.51	9.26
				2.45			2.45	2.45	18.51	9.26
					0.00		0.00	1.20	19.77	9.88
							12.26	13.46	91.37	45.68

Table D15 Cash flow summary for the Thailand III fiscal regime at +75% of the base price (6.011 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INCOME TAX		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	20.97	0.00	1.40	1.05	8.03	10.49	9.80	0.9342	1.0200
2025	20.97	0.00	1.40	1.05	9.26	9.27	8.09	0.8728	1.0404
2026	20.97	0.00	1.40	1.05	9.26	9.27	7.56	0.8154	1.0612
2027	20.97	0.00	1.40	1.05	9.26	9.27	7.06	0.7618	1.0824
2028	20.97	1.32	1.40	1.05	9.88	7.31	5.21	0.7117	1.1041
TOTAL	104.83	16.58	6.98	5.24	45.68	30.35	22.45		

PIR = 1.83

IRR = 56.37%

Table D16 Payback period for Thailand III fiscal regime at +75% of the base price (6.011 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		10.49	10.49
3		9.27	19.76
4		9.27	29.02
5		9.27	38.29
6		7.44	45.73
Payback period			2.64

Table D17 Cash flow summary for the Thailand III fiscal regime at +100% of the base price (6.870 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 6.870 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	6.870	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	6.870	23.962	1.20						1.395	1.395
2025	9.556	3487.940	6.870	23.962	1.20						1.395	1.395
2026	9.556	3487.940	6.870	23.962	1.20						1.395	1.395
2027	9.556	3487.940	6.870	23.962	1.20						1.395	1.395
2028	9.556	3487.940	6.870	23.962	1.20					1.20	1.395	2.595
TOTAL		17439.70		119.811	5.99	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	21.51	9.53
		2.45					2.45	2.45	21.51	10.75
			2.45				2.45	2.45	21.51	10.75
				2.45			2.45	2.45	21.51	10.75
					0.00		0.00	1.20	22.76	11.38
							12.26	13.46	106.35	53.17

Table D17 Cash flow summary for the Thailand III fiscal regime at +100% of the base price (6.870 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW	DISCOUNT	ESCAL.
				ROYALTY	INCOME TAX		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	23.96	0.00	1.40	1.20	9.53	11.84	11.06	0.9342	1.0200
2025	23.96	0.00	1.40	1.20	10.75	10.61	9.26	0.8728	1.0404
2026	23.96	0.00	1.40	1.20	10.75	10.61	8.65	0.8154	1.0612
2027	23.96	0.00	1.40	1.20	10.75	10.61	8.09	0.7618	1.0824
2028	23.96	1.32	1.40	1.20	11.38	8.66	6.16	0.7117	1.1041
TOTAL	119.81	16.58	6.98	5.99	53.17	37.09	27.98		

PIR = 2.24

IRR = 66.73%

Table D18 Payback period for Thailand III fiscal regime at +100% of the base price (6.870 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		11.84	11.84
3		10.61	22.45
4		10.61	33.07
5		10.61	43.68
6		8.79	52.47
Payback period			2.44

Table D19 Cash flow summary for the Thailand III fiscal regime at +106.8% of the base price (7.100 US$/MMBTU).

YEAR	Gas Production and Selling Plan : 2nd Year Production Plan / Gas Reserve Size 17.4 BCF @ 7.100 US$/MMBTU / Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)	CAPTAL EXPENSE (CAPEX) 2-D SEISMIC	3-D SEISMIC	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST	OPERATING EXPENSES (OPEX)	TOTAL COST
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	7.100	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	7.100	24.764	1.24						1.395	1.395
2025	9.556	3487.940	7.100	24.764	1.24						1.395	1.395
2026	9.556	3487.940	7.100	24.764	1.24						1.395	1.395
2027	9.556	3487.940	7.100	24.764	1.24						1.395	1.395
2028	9.556	3487.940	7.100	24.764	1.24					1.20	1.395	2.595
TOTAL		17439.70		123.822	6.19	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%) TANGIBLE EXPENSES 1	2	3	4	5	6	7	TOTAL	WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	22.31	9.93
		2.45					2.45	2.45	22.31	11.16
			2.45				2.45	2.45	22.31	11.16
				2.45			2.45	2.45	22.31	11.16
					0.00		0.00	1.20	23.56	11.78

Table D19 Cash flow summary for the Thailand III fiscal regime at +106.8% of the base price (7.100 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	24.76	0.00	1.40	1.24	9.93	12.20	11.40	0.9342	1.0200
2025	24.76	0.00	1.40	1.24	11.16	10.98	9.58	0.8728	1.0404
2026	24.76	0.00	1.40	1.24	11.16	10.98	8.95	0.8154	1.0612
2027	24.76	0.00	1.40	1.24	11.16	10.98	8.36	0.7618	1.0824
2028	24.76	1.32	1.40	1.24	11.78	9.02	6.42	0.7117	1.1041
TOTAL	123.82	16.58	6.98	6.19	55.18	38.90	29.45		

PIR = 2.35

IRR = 69.46%

Table D20 Payback period for Thailand III fiscal regime at +106.8% of the base price (7.100 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		12.20	12.20
3		10.98	23.18
4		10.98	34.15
5		10.98	45.13
6		9.15	54.28
Payback period			2.39

Table D21 Cash flow summary for the Thailand III fiscal regime at +125% of the base price (7.729US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan Gas Reserve Size 17.4 BCF @ 7.729 US$/MMBTU						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	7.729	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	7.729	26.958	1.35						1.395	1.395
2025	9.556	3487.940	7.729	26.958	1.35						1.395	1.395
2026	9.556	3487.940	7.729	26.958	1.35						1.395	1.395
2027	9.556	3487.940	7.729	26.958	1.35						1.395	1.395
2028	9.556	3487.940	7.729	26.958	1.35					1.20	1.395	2.595
TOTAL		17439.70		134.791	6.74	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
1	2	3	4	5	6	7	TOTAL			
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	24.51	11.03
		2.45					2.45	2.45	24.51	12.25
			2.45				2.45	2.45	24.51	12.25
				2.45			2.45	2.45	24.51	12.25
					0.00		0.00	1.20	25.76	12.88
							12.26	13.46	121.33	60.66

Table D21 Cash flow summary for the Thailand III fiscal regime at +125% of the base price (7.729US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	26.96	0.00	1.40	1.35	11.03	13.19	12.32	0.9342	1.0200
2025	26.96	0.00	1.40	1.35	12.25	11.96	10.44	0.8728	1.0404
2026	26.96	0.00	1.40	1.35	12.25	11.96	9.75	0.8154	1.0612
2027	26.96	0.00	1.40	1.35	12.25	11.96	9.11	0.7618	1.0824
2028	26.96	1.32	1.40	1.35	12.88	10.01	7.12	0.7117	1.1041
TOTAL	134.79	16.58	6.98	6.74	60.66	43.83	33.50		

PIR = 2.64

IRR = 76.80%

Table D22 Payback period for Thailand III fiscal regime at +125% of the base price (7.729US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		13.19	13.19
3		11.96	25.15
4		11.96	37.11
5		11.96	49.08
6		10.14	59.21
Payback period			2.27

Table D23 Cash flow summary for the Thailand III fiscal regime at +150% of the base price (8.588 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 8.588 US$/MMBTU						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	8.588	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	8.588	29.954	1.50						1.395	1.395
2025	9.556	3487.940	8.588	29.954	1.50						1.395	1.395
2026	9.556	3487.940	8.588	29.954	1.50						1.395	1.395
2027	9.556	3487.940	8.588	29.954	1.50						1.395	1.395
2028	9.556	3487.940	8.588	29.954	1.50					1.20	1.395	2.595
TOTAL		17439.70		149.772	7.49	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	27.50	12.52
		2.45					2.45	2.45	27.50	13.75
			2.45				2.45	2.45	27.50	13.75
				2.45			2.45	2.45	27.50	13.75
					0.00		0.00	1.20	28.75	14.38
							12.26	13.46	136.31	68.15

Table D23 Cash flow summary for the Thailand III fiscal regime at +150% of the base price (8.588 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	29.95	0.00	1.40	1.50	12.52	14.54	13.58	0.9342	1.0200
2025	29.95	0.00	1.40	1.50	13.75	13.31	11.62	0.8728	1.0404
2026	29.95	0.00	1.40	1.50	13.75	13.31	10.85	0.8154	1.0612
2027	29.95	0.00	1.40	1.50	13.75	13.31	10.14	0.7618	1.0824
2028	29.95	1.32	1.40	1.50	14.38	11.36	8.08	0.7117	1.1041
TOTAL	149.77	16.58	6.98	7.49	68.15	50.57	39.02		

PIR = 3.05

IRR = 86.65%

Table D24 Payback period for Thailand III fiscal regime at +150% of the base price (8.588 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		14.54	14.54
3		13.31	27.85
4		13.31	41.16
5		13.31	54.47
6		11.48	65.95
Payback period			2.14

Table D25 Cash flow summary for the Thailand III fiscal regime at +175% of the base price (9.446 US$/MMBTU).

YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)	2-D SEISMIC	3-D SEISMIC	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST	OPERATING EXPENSES (OPEX)	TOTAL COST
Gas Production and Selling Plan : 2nd Year Production Plan; Gas Reserve Size 17.4 BCF @ 9.446 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	9.446	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	9.446	32.947	1.65						1.395	1.395
2025	9.556	3487.940	9.446	32.947	1.65						1.395	1.395
2026	9.556	3487.940	9.446	32.947	1.65						1.395	1.395
2027	9.556	3487.940	9.446	32.947	1.65						1.395	1.395
2028	9.556	3487.940	9.446	32.947	1.65					1.20	1.395	2.595
TOTAL		17439.70		164.735	8.24	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%) TANGIBLE EXPENSES 1	2	3	4	5	6	7	TOTAL	WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	30.49	14.02
		2.45					2.45	2.45	30.49	15.25
			2.45				2.45	2.45	30.49	15.25
				2.45			2.45	2.45	30.49	15.25
					0.00		0.00	1.20	31.75	15.87
							12.26	13.46	151.27	75.64

Table D25 Cash flow summary for the Thailand III fiscal regime at +175% of the base price (9.446 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	32.95	0.00	1.40	1.65	14.02	15.88	14.84	0.9342	1.0200
2025	32.95	0.00	1.40	1.65	15.25	14.66	12.79	0.8728	1.0404
2026	32.95	0.00	1.40	1.65	15.25	14.66	11.95	0.8154	1.0612
2027	32.95	0.00	1.40	1.65	15.25	14.66	11.17	0.7618	1.0824
2028	32.95	1.32	1.40	1.65	15.87	12.71	9.04	0.7117	1.1041
TOTAL	164.74	16.58	6.98	8.24	75.64	57.31	44.54		

PIR = 3.46

IRR = 96.31%

Table D26 Payback period for Thailand III fiscal regime at +175% of the base price (9.446 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		15.88	15.88
3		14.66	30.54
4		14.66	45.20
5		14.66	59.86
6		12.83	72.69
Payback period			2.04

Table D27 Cash flow summary for the Thailand III fiscal regime at +200% of the base price (10.305 US$/MMBTU).

YEAR	Gas Production and Selling Plan : 2nd Year Production Plan / Gas Reserve Size 17.4 BCF @ 10.305 US$/MMBTU					CAPTAL EXPENSE (CAPEX)					OPERATING EXPENSES (OPEX)	TOTAL COST
	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)	2-D SEISMIC	3-D SEISMIC	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST		
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	10.305	0.000	0.00	0.30		2.991	11.964		0.000	15.255
2024	9.556	3487.940	10.305	35.943	1.80						1.395	1.395
2025	9.556	3487.940	10.305	35.943	1.80						1.395	1.395
2026	9.556	3487.940	10.305	35.943	1.80						1.395	1.395
2027	9.556	3487.940	10.305	35.943	1.80						1.395	1.395
2028	9.556	3487.940	10.305	35.943	1.80					1.20	1.395	2.595
TOTAL		17439.70		179.716	8.99	0.3	0.00	2.99	11.96	1.20	6.976	23.431

AMORTIZATION (20%) TANGIBLE EXPENSES								WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
1	2	3	4	5	6	7	TOTAL			
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.45							2.45	2.45	-2.45	0.00
	2.45						2.45	2.45	33.49	15.52
		2.45					2.45	2.45	33.49	16.75
			2.45				2.45	2.45	33.49	16.75
				2.45			2.45	2.45	33.49	16.75
					0.00		0.00	1.20	34.74	17.37
							12.26	13.46	166.25	83.13

Table D27 Cash flow summary for the Thailand III fiscal regime at +200% of the base price (10.305 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	35.94	0.00	1.40	1.80	15.52	17.23	16.10	0.9342	1.0200
2025	35.94	0.00	1.40	1.80	16.75	16.01	13.97	0.8728	1.0404
2026	35.94	0.00	1.40	1.80	16.75	16.01	13.05	0.8154	1.0612
2027	35.94	0.00	1.40	1.80	16.75	16.01	12.19	0.7618	1.0824
2028	35.94	1.32	1.40	1.80	17.37	14.05	10.00	0.7117	1.1041
TOTAL	179.72	16.58	6.98	8.99	83.13	64.05	50.06		

PIR = 3.86

IRR = 105.85%

Table D28 Payback period for Thailand III fiscal regime at +200% of the base price (10.305 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		17.23	17.23
3		16.01	33.24
4		16.01	49.24
5		16.01	65.25
6		14.18	79.43
Payback period			1.96

Table D29 Cash flow summary for the PSC fiscal regime at -50% of the base price (1.718 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 1.718 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	1.718	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	1.718	5.99	0.60							1.40	1.40
2025	9.56	3487.94	1.718	5.99	0.60							1.40	1.40
2026	9.56	3487.94	1.718	5.99	0.60							1.40	1.40
2027	9.56	3487.94	1.718	5.99	0.60							1.40	1.40
2028	9.56	3487.94	1.718	5.99	0.60						1.20	1.40	2.60
TOTAL		17439.70		29.961	3.00	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	2.70	2.70	13.95	2.70	1.35	1.35	4.00	4.04	0.81	3.24	1.95
18.05	2.70	5.39	12.65	2.70	1.35	1.35	4.00	4.04	0.81	3.24	1.95
19.44	2.70	8.09	11.35	2.70	1.35	1.35	4.00	4.04	0.81	3.24	1.95
20.84	2.70	10.79	10.05	2.70	1.35	1.35	4.00	4.04	0.81	3.24	1.95
23.43	2.70	13.48	9.95	2.70	1.35	1.35	2.80	4.04	0.81	3.24	1.95
	13.483			13.483	6.741	6.741	3.534	20.224	4.045	0.924	9.737

Table D29 Cash flow summary for the PSC fiscal regime at -50% of the base price (1.718 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	5.99	0.00	1.40	0.60	0.81	1.35	3.24	3.02	0.9342	1.0200
2025	5.99	0.00	1.40	0.60	0.81	1.35	3.24	2.82	0.8728	1.0404
2026	5.99	0.00	1.40	0.60	0.81	1.35	3.24	2.64	0.8154	1.0612
2027	5.99	0.00	1.40	0.60	0.81	1.35	3.24	2.46	0.7618	1.0824
2028	5.99	1.32	1.40	0.60	0.81	1.35	3.24	2.30	0.7117	1.1041
TOTAL	29.961	16.580	6.976	2.996	4.045	6.741	0.924	-2.00		
									PIR =	0.056
									IRR =	1.99%

Table D30 Payback period for the PSC fiscal regime at -50% of the base price (1.718 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		3.24	3.24
3		3.24	6.47
4		3.24	9.71
5		3.24	12.94
6		3.24	16.18
payback period (year)			N/A

Table D31 Cash flow summary for the PSC fiscal regime at -49.1% of the base price (1.748 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 1.748 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)	2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST		
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	1.748	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	1.748	6.10	0.61							1.40	1.40
2025	9.56	3487.94	1.748	6.10	0.61							1.40	1.40
2026	9.56	3487.94	1.748	6.10	0.61							1.40	1.40
2027	9.56	3487.94	1.748	6.10	0.61							1.40	1.40
2028	9.56	3487.94	1.748	6.10	0.61						1.20	1.40	2.60
TOTAL		17439.70		30.485	3.05	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	2.74	2.74	13.91	2.74	1.37	1.37	4.09	4.12	0.82	3.29	1.98
18.05	2.74	5.49	12.56	2.74	1.37	1.37	4.09	4.12	0.82	3.29	1.98
19.44	2.74	8.23	11.21	2.74	1.37	1.37	4.09	4.12	0.82	3.29	1.98
20.84	2.74	10.97	9.86	2.74	1.37	1.37	4.09	4.12	0.82	3.29	1.98
23.43	2.74	13.72	9.71	2.74	1.37	1.37	2.89	4.12	0.82	3.29	1.98
	13.718			13.718	6.859	6.859	4.005	20.577	4.115	1.207	9.907

Table D31 Cash flow summary for the PSC fiscal regime at -49.1% of the base price (1.748 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	6.10	0.00	1.40	0.61	0.82	1.37	3.29	3.08	0.9342	1.0200
2025	6.10	0.00	1.40	0.61	0.82	1.37	3.29	2.87	0.8728	1.0404
2026	6.10	0.00	1.40	0.61	0.82	1.37	3.29	2.68	0.8154	1.0612
2027	6.10	0.00	1.40	0.61	0.82	1.37	3.29	2.51	0.7618	1.0824
2028	6.10	1.32	1.40	0.61	0.82	1.37	3.29	2.34	0.7117	1.1041
TOTAL	30.485	16.580	6.976	3.048	4.115	6.859	1.207	-1.77		

PIR = 0.073
IRR = 2.59%

Table D32 Payback period for the PSC fiscal regime at -49.1% of the base price (1.748 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		3.29	3.29
3		3.29	6.58
4		3.29	9.88
5		3.29	13.17
6		3.29	16.46
payback period (year)			6.00

Table D33 Cash flow summary for the PSC fiscal regime at -25% of the base price (2.576 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 2.576 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	2.576	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	2.576	8.98	0.90							1.40	1.40
2025	9.56	3487.94	2.576	8.98	0.90							1.40	1.40
2026	9.56	3487.94	2.576	8.98	0.90							1.40	1.40
2027	9.56	3487.94	2.576	8.98	0.90							1.40	1.40
2028	9.56	3487.94	2.576	8.98	0.90						1.20	1.40	2.60
TOTAL		17439.70		44.925	4.49	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	4.04	4.04	12.61	4.04	2.02	2.02	6.69	6.06	1.21	4.85	2.92
18.05	4.04	8.09	9.96	4.04	2.02	2.02	6.69	6.06	1.21	4.85	2.92
19.44	4.04	12.13	7.31	4.04	2.02	2.02	6.69	6.06	1.21	4.85	2.92
20.84	4.04	16.17	4.66	4.04	2.02	2.02	6.69	6.06	1.21	4.85	2.92
23.43	4.04	20.22	3.21	4.04	2.02	2.02	5.49	6.06	1.21	4.85	2.92
	20.216			20.216	10.108	10.108	17.001	30.324	6.065	9.004	14.601

Table D33 Cash flow summary for the PSC fiscal regime at -25% of the base price (2.576 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	8.98	0.00	1.40	0.90	1.21	2.02	4.85	4.53	0.9342	1.0200
2025	8.98	0.00	1.40	0.90	1.21	2.02	4.85	4.23	0.8728	1.0404
2026	8.98	0.00	1.40	0.90	1.21	2.02	4.85	3.96	0.8154	1.0612
2027	8.98	0.00	1.40	0.90	1.21	2.02	4.85	3.70	0.7618	1.0824
2028	8.98	1.32	1.40	0.90	1.21	2.02	4.85	3.45	0.7117	1.1041
TOTAL	44.925	16.580	6.976	4.492	6.065	10.108	9.004	4.62		

PIR = 0.543

IRR = 17.76%

Table D34 Payback period for the PSC fiscal regime at -25% of the base price (2.576 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		4.85	4.85
3		4.85	9.70
4		4.85	14.56
5		4.85	19.41
6		4.85	24.26
payback period (year)			4.39

Table D35 Cash flow summary for the PSC fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 2.9857 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	2.9857	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	2.9857	10.41	1.04							1.40	1.40
2025	9.56	3487.94	2.9857	10.41	1.04							1.40	1.40
2026	9.56	3487.94	2.9857	10.41	1.04							1.40	1.40
2027	9.56	3487.94	2.9857	10.41	1.04							1.40	1.40
2028	9.56	3487.94	2.9857	10.41	1.04						1.20	1.40	2.60
TOTAL		17439.70		52.070	5.21	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	4.69	4.69	11.96	4.69	2.34	2.34	7.98	7.03	1.41	5.62	3.38
18.05	4.69	9.37	8.67	4.69	2.34	2.34	7.98	7.03	1.41	5.62	3.38
19.44	4.69	14.06	5.38	4.69	2.34	2.34	7.98	7.03	1.41	5.62	3.38
20.84	4.69	18.75	2.09	4.69	2.34	2.34	7.98	7.03	1.41	5.62	3.38
23.43	4.69	23.43	0.00	4.69	2.34	2.34	6.78	7.03	1.41	5.62	3.38
	23.431			23.432	11.716	11.716	23.432	35.147	7.029	12.862	16.923

Table D35 Cash flow summary for the PSC fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	10.41	0.00	1.40	1.04	1.41	2.34	5.62	5.25	0.9342	1.0200
2025	10.41	0.00	1.40	1.04	1.41	2.34	5.62	4.91	0.8728	1.0404
2026	10.41	0.00	1.40	1.04	1.41	2.34	5.62	4.59	0.8154	1.0612
2027	10.41	0.00	1.40	1.04	1.41	2.34	5.62	4.28	0.7618	1.0824
2028	10.41	1.32	1.40	1.04	1.41	2.34	5.62	4.00	0.7117	1.1041
TOTAL	52.070	16.580	6.976	5.207	7.029	11.716	12.862	7.78		

PIR = 0.776

IRR = 24.58%

Table D36 Payback period for the PSC fiscal regime at -13.08% of the base price (2.9857 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		5.62	5.62
3		5.62	11.25
4		5.62	16.87
5		5.62	22.49
6		5.62	28.12
payback period (year)			3.93

Table D37 Cash flow summary for the PSC fiscal regime at base price (3.435 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	5.39	5.39	11.26	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
18.05	5.39	10.78	7.26	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
19.44	5.39	16.17	3.27	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
20.84	4.66	20.84	0.00	6.12	3.06	3.06	9.39	7.72	1.54	6.18	4.26
23.43	2.60	23.43	0.00	8.19	4.09	4.09	8.19	6.69	1.34	5.35	5.29
	23.431			30.484	15.242	15.242	30.484	38.673	7.735	15.683	21.233

Table D37 Cash flow summary for the PSC fiscal regime at base price (3.435 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.54	3.06	6.18	4.71	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	7.735	15.242	15.683	10.23		

PIR = 0.946

IRR = 30.35%

Table D38 Payback period for the PSC fiscal regime at base price (3.435 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		6.18	25.59
6		5.35	30.94
payback period (year)			3.54

Table D39 Cash flow summary for the PSC fiscal regime at +25% of the base price (4.294 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 4.294 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	4.294	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	4.294	14.98	1.50							1.40	1.40
2025	9.56	3487.94	4.294	14.98	1.50							1.40	1.40
2026	9.56	3487.94	4.294	14.98	1.50							1.40	1.40
2027	9.56	3487.94	4.294	14.98	1.50							1.40	1.40
2028	9.56	3487.94	4.294	14.98	1.50						1.20	1.40	2.60
TOTAL		17439.70		74.886	7.49	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	6.74	6.74	9.91	6.74	3.37	3.37	12.08	10.11	2.02	8.09	4.87
18.05	6.74	13.48	4.57	6.74	3.37	3.37	12.08	10.11	2.02	8.09	4.87
19.44	5.96	19.44	0.00	7.52	3.76	3.76	12.08	9.72	1.94	7.78	5.26
20.84	1.40	20.84	0.00	12.08	6.04	6.04	12.08	7.44	1.49	5.95	7.54
23.43	2.60	23.43	0.00	10.88	5.44	5.44	10.88	8.04	1.61	6.43	6.94
				43.967	21.983	21.983	43.967	45.414	9.083	21.076	29.472

Table D39 Cash flow summary for the PSC fiscal regime at +25% of the base price (4.294 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	14.98	0.00	1.40	1.50	2.02	3.37	8.09	7.56	0.9342	1.0200
2025	14.98	0.00	1.40	1.50	2.02	3.37	8.09	7.06	0.8728	1.0404
2026	14.98	0.00	1.40	1.50	1.94	3.76	7.78	6.34	0.8154	1.0612
2027	14.98	0.00	1.40	1.50	1.49	6.04	5.95	4.53	0.7618	1.0824
2028	14.98	1.32	1.40	1.50	1.61	5.44	6.43	4.58	0.7117	1.1041
TOTAL	74.886	16.580	6.976	7.489	9.083	21.983	21.076	14.81		

PIR = 1.271
IRR = 40.93%

Table D40 Payback period for the PSC fiscal regime at +25% of the base price (4.294 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		8.09	8.09
3		8.09	16.18
4		7.78	23.95
5		5.95	29.90
6		6.43	36.33
payback period (year)			3.04

Table D41 Cash flow summary for the PSC fiscal regime at +50% of the base price (5.153 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 5.153 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	5.153	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	5.153	17.97	1.80							1.40	1.40
2025	9.56	3487.94	5.153	17.97	1.80							1.40	1.40
2026	9.56	3487.94	5.153	17.97	1.80							1.40	1.40
2027	9.56	3487.94	5.153	17.97	1.80							1.40	1.40
2028	9.56	3487.94	5.153	17.97	1.80						1.20	1.40	2.60
TOTAL		17439.70		89.867	8.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	8.09	8.09	8.56	8.09	4.04	4.04	14.78	12.13	2.43	9.71	5.84
18.05	8.09	16.18	1.87	8.09	4.04	4.04	14.78	12.13	2.43	9.71	5.84
19.44	3.26	19.44	0.00	12.91	6.46	6.46	14.78	9.72	1.94	7.78	8.25
20.84	1.40	20.84	0.00	14.78	7.39	7.39	14.78	8.79	1.76	7.03	9.19
23.43	2.60	23.43	0.00	13.58	6.79	6.79	13.58	9.39	1.88	7.51	8.59
	23.431			57.449	28.725	28.725	57.449	52.155	10.431	26.469	37.711

Table D41 Cash flow summary for the PSC fiscal regime at +50% of the base price (5.153 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	17.97	0.00	1.40	1.80	2.43	4.04	9.71	9.07	0.9342	1.0200
2025	17.97	0.00	1.40	1.80	2.43	4.04	9.71	8.47	0.8728	1.0404
2026	17.97	0.00	1.40	1.80	1.94	6.46	7.78	6.34	0.8154	1.0612
2027	17.97	0.00	1.40	1.80	1.76	7.39	7.03	5.35	0.7618	1.0824
2028	17.97	1.32	1.40	1.80	1.88	6.79	7.51	5.34	0.7117	1.1041
TOTAL	89.867	16.580	6.976	8.987	10.431	28.725	26.469	19.32		

PIR = 1.596

IRR = 50.98%

Table D42 Payback period for the PSC fiscal regime at +50% of the base price (5.153 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		9.71	9.71
3		9.71	19.41
4		7.78	27.19
5		7.03	34.22
6		7.51	41.72
payback period (year)			2.70

Table D43 Cash flow summary for the PSC fiscal regime at +75% of the base price (6.011 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 6.011 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	6.011	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	6.011	20.97	2.10							1.40	1.40
2025	9.56	3487.94	6.011	20.97	2.10							1.40	1.40
2026	9.56	3487.94	6.011	20.97	2.10							1.40	1.40
2027	9.56	3487.94	6.011	20.97	2.10							1.40	1.40
2028	9.56	3487.94	6.011	20.97	2.10						1.20	1.40	2.60
TOTAL		17439.70		104.830	10.48	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	9.43	9.43	7.22	9.43	4.72	4.72	17.47	14.15	2.83	11.32	6.81
18.05	8.61	18.05	0.00	10.26	5.13	5.13	17.47	13.74	2.75	10.99	7.23
19.44	1.40	19.44	0.00	17.47	8.74	8.74	17.47	10.13	2.03	8.11	10.83
20.84	1.40	20.84	0.00	17.47	8.74	8.74	17.47	10.13	2.03	8.11	10.83
23.43	2.60	23.43	0.00	16.27	8.14	8.14	16.27	10.73	2.15	8.59	10.23
	23.431			70.916	35.458	35.458	70.916	58.889	11.778	31.856	45.941

Table D43 Cash flow summary for the PSC fiscal regime at +75% of the base price (6.011 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE				CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	20.97	0.00	1.40	2.10	2.83	4.72	11.32	10.58	0.9342	1.0200
2025	20.97	0.00	1.40	2.10	2.75	5.13	10.99	9.59	0.8728	1.0404
2026	20.97	0.00	1.40	2.10	2.03	8.74	8.11	6.61	0.8154	1.0612
2027	20.97	0.00	1.40	2.10	2.03	8.74	8.11	6.17	0.7618	1.0824
2028	20.97	1.32	1.40	2.10	2.15	8.14	8.59	6.11	0.7117	1.1041
TOTAL	104.830	16.580	6.976	10.483	11.778	35.458	31.856	23.81		

PIR = 1.921

IRR = 60.79%

Table D44 Payback period for the PSC fiscal regime at +75% of the base price (6.011 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		11.32	11.32
3		10.99	22.31
4		8.11	30.42
5		8.11	38.53
6		8.59	47.11
payback period (year)			2.47

Table D45 Cash flow summary for the PSC fiscal regime at +100% of the base price (6.870 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 6.870 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	6.870	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	6.870	23.96	2.40							1.40	1.40
2025	9.56	3487.94	6.870	23.96	2.40							1.40	1.40
2026	9.56	3487.94	6.870	23.96	2.40							1.40	1.40
2027	9.56	3487.94	6.870	23.96	2.40							1.40	1.40
2028	9.56	3487.94	6.870	23.96	2.40						1.20	1.40	2.60
TOTAL		17439.70		119.811	11.98	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	10.78	10.78	5.87	10.78	5.39	5.39	20.17	16.17	3.23	12.94	7.79
18.05	7.26	18.05	0.00	14.30	7.15	7.15	20.17	14.41	2.88	11.53	9.55
19.44	1.40	19.44	0.00	20.17	10.09	10.09	20.17	11.48	2.30	9.18	12.48
20.84	1.40	20.84	0.00	20.17	10.09	10.09	20.17	11.48	2.30	9.18	12.48
23.43	2.60	23.43	0.00	18.97	9.49	9.49	18.97	12.08	2.42	9.66	11.88
				84.399	42.199	42.199	84.399	65.630	13.126	37.249	54.180

Table D45 Cash flow summary for the PSC fiscal regime at +100% of the base price (6.870 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE ROYALTY	INC. TAX	SHARE	CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	23.96	0.00	1.40	2.40	3.23	5.39	12.94	12.09	0.9342	1.0200
2025	23.96	0.00	1.40	2.40	2.88	7.15	11.53	10.06	0.8728	1.0404
2026	23.96	0.00	1.40	2.40	2.30	10.09	9.18	7.49	0.8154	1.0612
2027	23.96	0.00	1.40	2.40	2.30	10.09	9.18	7.00	0.7618	1.0824
2028	23.96	1.32	1.40	2.40	2.42	9.49	9.66	6.88	0.7117	1.1041
TOTAL	119.811	16.580	6.976	11.981	13.126	42.199	37.249	28.26		

PIR = 2.247

IRR = 69.98%

Table D46 Payback period for the PSC fiscal regime at +100% of the base price (6.870 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		12.94	12.94
3		11.53	24.47
4		9.18	33.66
5		9.18	42.84
6		9.66	52.50
payback period (year)			2.31

Table D47 Cash flow summary for the PSC fiscal regime at +106.8% of the base price (7.100 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 7.100 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	7.100	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	7.100	24.76	2.48							1.40	1.40
2025	9.56	3487.94	7.100	24.76	2.48							1.40	1.40
2026	9.56	3487.94	7.100	24.76	2.48							1.40	1.40
2027	9.56	3487.94	7.100	24.76	2.48							1.40	1.40
2028	9.56	3487.94	7.100	24.76	2.48						1.20	1.40	2.60
TOTAL		17439.70		123.822	12.38	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	11.14	11.14	5.51	11.14	5.57	5.57	20.89	16.72	3.34	13.37	8.05
18.05	6.90	18.05	0.00	15.39	7.69	7.69	20.89	14.59	2.92	11.68	10.17
19.44	1.40	19.44	0.00	20.89	10.45	10.45	20.89	11.84	2.37	9.47	12.92
20.84	1.40	20.84	0.00	20.89	10.45	10.45	20.89	11.84	2.37	9.47	12.92
23.43	2.60	23.43	0.00	19.69	9.85	9.85	19.69	12.44	2.49	9.95	12.32
				88.009	44.004	44.004	88.009	67.435	13.487	38.693	56.387

Table D47 Cash flow summary for the PSC fiscal regime at +106.8% of the base price (7.100 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	24.76	0.00	1.40	2.48	3.34	5.57	13.37	12.49	0.9342	1.0200
2025	24.76	0.00	1.40	2.48	2.92	7.69	11.68	10.19	0.8728	1.0404
2026	24.76	0.00	1.40	2.48	2.37	10.45	9.47	7.72	0.8154	1.0612
2027	24.76	0.00	1.40	2.48	2.37	10.45	9.47	7.22	0.7618	1.0824
2028	24.76	1.32	1.40	2.48	2.49	9.85	9.95	7.08	0.7117	1.1041
TOTAL	123.822	16.580	6.976	12.382	13.487	44.004	38.693	29.45		

PIR = 2.334

IRR = 72.43%

Table D48 Payback period for the PSC fiscal regime at +106.8% of the base price (7.100 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		13.37	13.37
3		11.68	25.05
4		9.47	34.52
5		9.47	43.99
6		9.95	53.95
payback period (year)			2.26

Table D49 Cash flow summary for the PSC fiscal regime at +125% of the base price (7.729US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 7.729 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
				GROSS	ROYALTY	2-D SEISMIC	3-D SEIMIC	SIGNATURE	DRILLING		ABANDONMENT		
YEAR	Gas PRODUCTION		GAS PRICE	REVENUE	(10%)			BONUS	INTANG.	TANG.	COST		
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	7.729	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	7.729	26.96	2.70							1.40	1.40
2025	9.56	3487.94	7.729	26.96	2.70							1.40	1.40
2026	9.56	3487.94	7.729	26.96	2.70							1.40	1.40
2027	9.56	3487.94	7.729	26.96	2.70							1.40	1.40
2028	9.56	3487.94	7.729	26.96	2.70						1.20	1.40	2.60
TOTAL		17439.70		134.791	13.48	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	12.13	12.13	4.52	12.13	6.07	6.07	22.87	18.20	3.64	14.56	8.76
18.05	5.91	18.05	0.00	18.35	9.17	9.17	22.87	15.09	3.02	12.07	11.87
19.44	1.40	19.44	0.00	22.87	11.43	11.43	22.87	12.83	2.57	10.26	14.13
20.84	1.40	20.84	0.00	22.87	11.43	11.43	22.87	12.83	2.57	10.26	14.13
23.43	2.60	23.43	0.00	21.67	10.83	10.83	21.67	13.43	2.69	10.74	13.53
				97.881	48.941	48.941	97.881	72.372	14.474	42.642	62.420

Table D49 Cash flow summary for the PSC fiscal regime at +125% of the base price (7.729US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	26.96	0.00	1.40	2.70	3.64	6.07	14.56	13.60	0.9342	1.0200
2025	26.96	0.00	1.40	2.70	3.02	9.17	12.07	10.54	0.8728	1.0404
2026	26.96	0.00	1.40	2.70	2.57	11.43	10.26	8.37	0.8154	1.0612
2027	26.96	0.00	1.40	2.70	2.57	11.43	10.26	7.82	0.7618	1.0824
2028	26.96	1.32	1.40	2.70	2.69	10.83	10.74	7.65	0.7117	1.1041
TOTAL	134.791	16.580	6.976	13.479	14.474	48.941	42.642	32.71		

PIR = 2.572

IRR = 79.12%

Table D50 Payback period for the PSC fiscal regime at +125% of the base price (7.729US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		14.56	14.56
3		12.07	26.63
4		10.26	36.89
5		10.26	47.15
6		10.74	57.90
payback period (year)			2.16

Table D51 Cash flow summary for the PSC fiscal regime at +150% of the base price (8.588 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 8.588 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	8.588	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	8.588	29.95	3.00							1.40	1.40
2025	9.56	3487.94	8.588	29.95	3.00							1.40	1.40
2026	9.56	3487.94	8.588	29.95	3.00							1.40	1.40
2027	9.56	3487.94	8.588	29.95	3.00							1.40	1.40
2028	9.56	3487.94	8.588	29.95	3.00						1.20	1.40	2.60
TOTAL		17439.70		149.772	14.98	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	13.48	13.48	3.17	13.48	6.74	6.74	25.56	20.22	4.04	16.18	9.74
18.05	4.57	18.05	0.00	22.39	11.20	11.20	25.56	15.76	3.15	12.61	14.19
19.44	1.40	19.44	0.00	25.56	12.78	12.78	25.56	14.18	2.84	11.34	15.78
20.84	1.40	20.84	0.00	25.56	12.78	12.78	25.56	14.18	2.84	11.34	15.78
23.43	2.60	23.43	0.00	24.36	12.18	12.18	24.36	14.78	2.96	11.82	15.18
				111.364	55.682	55.682	111.364	79.113	15.823	48.035	70.659

Table D51 Cash flow summary for the PSC fiscal regime at +150% of the base price (8.588 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	29.95	0.00	1.40	3.00	4.04	6.74	16.18	15.11	0.9342	1.0200
2025	29.95	0.00	1.40	3.00	3.15	11.20	12.61	11.01	0.8728	1.0404
2026	29.95	0.00	1.40	3.00	2.84	12.78	11.34	9.25	0.8154	1.0612
2027	29.95	0.00	1.40	3.00	2.84	12.78	11.34	8.64	0.7618	1.0824
2028	29.95	1.32	1.40	3.00	2.96	12.18	11.82	8.41	0.7117	1.1041
TOTAL	149.772	16.580	6.976	14.977	15.823	55.682	48.035	37.16		

PIR = 2.897

IRR = 88.24%

Table D52 Payback period for the PSC fiscal regime at +150% of the base price (8.588 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		16.18	16.18
3		12.61	28.79
4		11.34	40.13
5		11.34	51.47
6		11.82	63.29
payback period (year)			2.02

Table D53 Cash flow summary for the PSC fiscal regime at +175% of the base price (9.446US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 9.446 US$/MMBTU						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	9.446	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	9.446	32.95	3.29							1.40	1.40
2025	9.56	3487.94	9.446	32.95	3.29							1.40	1.40
2026	9.56	3487.94	9.446	32.95	3.29							1.40	1.40
2027	9.56	3487.94	9.446	32.95	3.29							1.40	1.40
2028	9.56	3487.94	9.446	32.95	3.29						1.20	1.40	2.60
TOTAL		17439.70		164.735	16.47	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	14.83	14.83	1.82	14.83	7.41	7.41	28.26	22.24	4.45	17.79	10.71
18.05	3.22	18.05	0.00	26.43	13.22	13.22	28.26	16.44	3.29	13.15	16.51
19.44	1.40	19.44	0.00	28.26	14.13	14.13	28.26	15.52	3.10	12.42	17.42
20.84	1.40	20.84	0.00	28.26	14.13	14.13	28.26	15.52	3.10	12.42	17.42
23.43	2.60	23.43	0.00	27.06	13.53	13.53	27.06	16.12	3.22	12.90	16.82
				124.831	62.415	62.415	124.831	85.846	17.169	53.422	78.889

Table D53 Cash flow summary for the PSC fiscal regime at +175% of the base price (9.446US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE				CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	32.95	0.00	1.40	3.29	4.45	7.41	17.79	16.62	0.9342	1.0200
2025	32.95	0.00	1.40	3.29	3.29	13.22	13.15	11.48	0.8728	1.0404
2026	32.95	0.00	1.40	3.29	3.10	14.13	12.42	10.13	0.8154	1.0612
2027	32.95	0.00	1.40	3.29	3.10	14.13	12.42	9.46	0.7618	1.0824
2028	32.95	1.32	1.40	3.29	3.22	13.53	12.90	9.18	0.7117	1.1041
TOTAL	164.735	16.580	6.976	16.474	17.169	62.415	53.422	41.61		

PIR = 3.222

IRR = 97.36%

Table D54 Payback period for the PSC fiscal regime at +175% of the base price (9.446US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		17.79	17.79
3		13.15	30.94
4		12.42	43.36
5		12.42	55.78
6		12.90	68.68
payback period (year)			1.93

Table D55 Cash flow summary for the PSC fiscal regime at +200% of the base price (10.305 US$/MMBTU).

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 10.305 US$/MMBTU						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)	2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST		
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	10.305	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	10.305	35.94	3.59							1.40	1.40
2025	9.56	3487.94	10.305	35.94	3.59							1.40	1.40
2026	9.56	3487.94	10.305	35.94	3.59							1.40	1.40
2027	9.56	3487.94	10.305	35.94	3.59							1.40	1.40
2028	9.56	3487.94	10.305	35.94	3.59						1.20	1.40	2.60
TOTAL		17439.70		179.716	17.97	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	16.17	16.17	0.48	16.17	8.09	8.09	30.95	24.26	4.85	19.41	11.68
18.05	1.87	18.05	0.00	30.48	15.24	15.24	30.95	17.11	3.42	13.69	18.83
19.44	1.40	19.44	0.00	30.95	15.48	15.48	30.95	16.87	3.37	13.50	19.07
20.84	1.40	20.84	0.00	30.95	15.48	15.48	30.95	16.87	3.37	13.50	19.07
23.43	2.60	23.43	0.00	29.75	14.88	14.88	29.75	17.47	3.49	13.98	18.47
				138.314	69.157	69.157	138.314	92.588	18.518	58.815	87.128

Table D55 Cash flow summary for the PSC fiscal regime at +200% of the base price (10.305 US$/MMBTU). (Continued)

YEAR	CASH FLOW SUMMARRY							DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE			CONTRACTOR TAKE	CASH FLOW	DISCOUNT	ESCAL.
				ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	35.94	0.00	1.40	3.59	4.85	8.09	19.41	18.13	0.9342	1.0200
2025	35.94	0.00	1.40	3.59	3.42	15.24	13.69	11.95	0.8728	1.0404
2026	35.94	0.00	1.40	3.59	3.37	15.48	13.50	11.01	0.8154	1.0612
2027	35.94	0.00	1.40	3.59	3.37	15.48	13.50	10.28	0.7618	1.0824
2028	35.94	1.32	1.40	3.59	3.49	14.88	13.98	9.95	0.7117	1.1041
TOTAL	179.716	16.580	6.976	17.972	18.518	69.157	58.815	46.06		

PIR = 3.222

IRR = 97.36%

Table D56 Payback period for the PSC fiscal regime at +200% of the base price (10.305 US$/MMBTU).

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.46	0	0
2		19.41	19.41
3		13.69	33.10
4		13.50	46.59
5		13.50	60.09
6		13.98	74.07
payback period (year)			1.85

APPENDIX E

Sensitivity Analysis of Well Cost

Table E1 Cash flow summary for the Thailand III fiscal regime, well cost at 3 MMUS$.

YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)	2-D SEISMIC	3-D SEISMIC	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST	OPERATING EXPENSES (OPEX)	TOTAL COST
	Gas Production and Selling Plan : 2nd Year Production Plan; Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)					CAPTAL EXPENSE (CAPEX)						
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		1.800	7.200		0.000	9.300
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	1.80	7.20	1.20	6.976	17.476

AMORTIZATION (20%) TANGIBLE EXPENSES 1	2	3	4	5	6	7	TOTAL	WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1.50							1.50	1.50	-1.50	0.00
	1.50						1.50	1.50	10.48	4.49
		1.50					1.50	1.50	10.48	5.24
			1.50				1.50	1.50	10.48	5.24
				1.50			1.50	1.50	10.48	5.24
					0.00		0.00	1.20	10.78	5.39
							7.50	8.70	51.21	25.60

Table E1 Cash flow summary for the Thailand III fiscal regime, well cost at 3 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	9.30	0.00	0.00	0.00	-9.30	-9.30	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	4.49	5.50	5.13	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	5.24	4.75	4.14	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	5.24	4.75	3.87	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	5.24	4.75	3.62	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	10.62	6.98	3.00	25.60	13.71	9.79		

PIR = 1.29

IRR = 44.2%

Table E2 Payback period for Thailand III fiscal regime, well cost at 3 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	10.50	0	0
2		5.50	5.50
3		4.75	10.24
4		4.75	14.99
5		4.75	19.74
6		3.40	23.13
payback period (year)			3.05

Table E3 Cash flow summary for the Thailand III fiscal regime, well cost at 4 MMUS$.

	Gas Production and Selling Plan : 2nd Year Production Plan Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)					CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		2.400	9.600		0.000	12.300
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	2.40	9.60	1.20	6.976	20.476

AMORTIZATION (20%) TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
1.98							1.98	1.98	-1.98	0.00
	1.98						1.98	1.98	10.00	4.01
		1.98					1.98	1.98	10.00	5.00
			1.98				1.98	1.98	10.00	5.00
				1.98			1.98	1.98	10.00	5.00
					0.00		0.00	1.20	10.78	5.39
							9.90	11.10	48.81	24.40

Table E3 Cash flow summary for the Thailand III fiscal regime, well cost at 4 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	12.30	0.00	0.00	0.00	-12.30	-12.30	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	4.01	5.98	5.58	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	5.00	4.99	4.35	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	5.00	4.99	4.07	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	5.00	4.99	3.80	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	13.62	6.98	3.00	24.40	11.91	7.83		

PIR = 0.87

IRR = 30.7%

Table E4 Payback period for Thailand III fiscal regime, well cost at 4 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	13.50	0	0
2		5.98	5.98
3		4.99	10.96
4		4.99	15.95
5		4.99	20.94
6		3.40	24.33
payback period (year)			3.51

Table E5 Cash flow summary for the Thailand III fiscal regime, well cost at 5 MMUS$.

Gas Production and Selling Plan : 2nd Year Production Plan						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		3.000	12.000		0.000	15.300
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	3.00	12.00	1.20	6.976	23.476

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.46							2.46	2.46	-2.46	0.00
	2.46						2.46	2.46	9.52	3.53
		2.46					2.46	2.46	9.52	4.76
			2.46				2.46	2.46	9.52	4.76
				2.46			2.46	2.46	9.52	4.76
					0.00		0.00	1.20	10.78	5.39
							12.30	13.50	46.41	23.20

Table E5 Cash flow summary for the Thailand III fiscal regime, well cost at 5 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.30	0.00	0.00	0.00	-15.30	-15.30	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	3.53	6.46	6.03	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	4.76	5.23	4.56	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	4.76	5.23	4.26	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	4.76	5.23	3.98	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	16.62	6.98	3.00	23.20	10.11	5.86		

PIR = 0.61

IRR = 21.8%

Table E6 Payback period for Thailand III fiscal regime, well cost at 5 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.50	0	0
2		6.46	6.46
3		5.23	11.68
4		5.23	16.91
5		5.23	22.14
6		3.40	25.53
payback period (year)			3.92

Table E7 Cash flow summary for the Thailand III fiscal regime, well cost at 6 MMUS$.

YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)	2-D SEISMIC	3-D SEISMIC	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST	OPERATING EXPENSES (OPEX)	TOTAL COST
	Gas Production and Selling Plan : 2nd Year Production Plan; Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)					CAPTAL EXPENSE (CAPEX)						
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		3.600	14.400		0.000	18.300
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	3.60	14.40	1.20	6.976	26.476

AMORTIZATION (20%) TANGIBLE EXPENSES 1	2	3	4	5	6	7	TOTAL	WRITE OFF	TAXABLE INCOME	INCOME TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2.94							2.94	2.94	-2.94	0.00
	2.94						2.94	2.94	9.04	3.05
		2.94					2.94	2.94	9.04	4.52
			2.94				2.94	2.94	9.04	4.52
				2.94			2.94	2.94	9.04	4.52
					0.00		0.00	1.20	10.78	5.39
							14.70	15.90	44.01	22.00

Table E7 Cash flow summary for the Thailand III fiscal regime, well cost at 6 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INCOME TAX		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	18.30	0.00	0.00	0.00	-18.30	-18.30	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	3.05	6.94	6.48	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	4.52	5.47	4.77	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	4.52	5.47	4.46	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	4.52	5.47	4.16	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	19.62	6.98	3.00	22.00	8.31	3.90		

PIR = 0.42

IRR = 15.5%

Table E8 Payback period for Thailand III fiscal regime, well cost at 6 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	19.50	0	0
2		6.94	6.94
3		5.47	12.40
4		5.47	17.87
5		5.47	23.34
6		3.40	26.73
payback period (year)			4.30

Table E9 Cash flow summary for the Thailand III fiscal regime, well cost at 7 MMUS$.

Gas Production and Selling Plan : 2nd Year Production Plan; Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						CAPTAL EXPENSE (CAPEX)					OPERATING	TOTAL
						2-D SEISMIC	3-D SEISMIC	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REV. SALE INCOME	ROYALTY SLIDING SCALE (5%)			INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.000	0.000	3.435	0.000	0.00	0.30		4.200	16.800		0.000	21.300
2024	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2025	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2026	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2027	9.556	3487.940	3.435	11.981	0.60						1.395	1.395
2028	9.556	3487.940	3.435	11.981	0.60					1.20	1.395	2.595
TOTAL		17439.70		59.905	3.00	0.3	0.00	4.20	16.80	1.20	6.976	29.476

AMORTIZATION (20%)										
TANGIBLE EXPENSES								WRITE	TAXABLE	INCOME
1	2	3	4	5	6	7	TOTAL	OFF	INCOME	TAX(50%)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
3.42							3.42	3.42	-3.42	0.00
	3.42						3.42	3.42	8.56	2.57
		3.42					3.42	3.42	8.56	4.28
			3.42				3.42	3.42	8.56	4.28
				3.42			3.42	3.42	8.56	4.28
					0.00		0.00	1.20	10.78	5.39
							17.10	18.30	41.61	20.80

Table E9 Cash flow summary for the Thailand III fiscal regime, well cost at 7 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY					ANNUAL	DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		CASH FLOW	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INCOME TAX				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	21.30	0.00	0.00	0.00	-21.30	-21.30	1.0000	1.0000
2024	11.98	0.00	1.40	0.60	2.57	7.42	6.93	0.9342	1.0200
2025	11.98	0.00	1.40	0.60	4.28	5.71	4.98	0.8728	1.0404
2026	11.98	0.00	1.40	0.60	4.28	5.71	4.65	0.8154	1.0612
2027	11.98	0.00	1.40	0.60	4.28	5.71	4.35	0.7618	1.0824
2028	11.98	1.32	1.40	0.60	5.39	3.27	2.33	0.7117	1.1041
TOTAL	59.91	22.62	6.98	3.00	20.80	6.51	1.94		

PIR = 0.29

IRR = 10.8%

Table E10 Payback period for Thailand III fiscal regime, well cost at 7 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	22.50	0	0
2		7.42	7.42
3		5.71	13.12
4		5.71	18.83
5		5.71	24.54
6		3.40	27.93
payback period (year)			4.64

Table E11 Cash flow summary for the PSC fiscal regime, well cost at 3 MMUS$.

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 Years average)						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			1.80	7.20		0.00	9.30
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	1.80	7.20	1.20	6.976	17.476

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
9.30	0.00	0.00	9.30	0.00	0.00	0.00	-9.30	0.00	0.00	-9.30	0.00
10.70	5.39	5.39	5.30	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
12.09	5.39	10.78	1.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
13.49	2.70	13.49	0.00	8.08	4.04	4.04	9.39	6.74	1.35	5.39	5.24
14.88	1.40	14.88	0.00	9.39	4.69	4.69	9.39	6.09	1.22	4.87	5.89
17.48	2.60	17.48	0.00	8.19	4.09	4.09	8.19	6.69	1.34	5.35	5.29
	17.476			36.439	18.219	18.219	36.439	35.695	7.139	19.256	24.210

Table E11 Cash flow summary for the PSC fiscal regime, well cost at 3 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	9.30	0.00	0.00	0.00	0.00	-9.30	-9.30	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.35	4.04	5.39	4.40	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.22	4.69	4.87	3.71	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81	0.7117	1.1041
TOTAL	59.905	10.625	6.976	5.991	7.139	18.219	19.256	14.31		

PIR = 1.812

IRR = 58.66%

Table E12 Payback period for the PSC fiscal regime, well cost at 3 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	10.50	0	0
2		6.47	6.47
3		6.47	12.94
4		5.39	18.33
5		4.87	23.21
6		5.35	28.56
payback period (year)			2.62

Table E13 Cash flow summary for the PSC fiscal regime, well cost at 4 MMUS$.

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 Years average)						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.40	9.60		0.00	12.30
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.40	9.60	1.20	6.976	20.476

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
12.30	0.00	0.00	12.30	0.00	0.00	0.00	-12.30	0.00	0.00	-12.30	0.00
13.70	5.39	5.39	8.30	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
15.09	5.39	10.78	4.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
16.49	5.39	16.17	0.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
17.88	1.71	17.88	0.00	9.08	4.54	4.54	9.39	6.24	1.25	5.00	5.74
20.48	2.60	20.48	0.00	8.19	4.09	4.09	8.19	6.69	1.34	5.35	5.29
	20.476			33.439	16.719	16.719	33.439	37.195	7.439	17.456	22.710

Table E13 Cash flow summary for the PSC fiscal regime, well cost at 4 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	12.30	0.00	0.00	0.00	0.00	-12.30	-12.30	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.25	4.54	5.00	3.81	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81	0.7117	1.1041
TOTAL	59.905	13.625	6.976	5.991	7.439	16.719	17.456	12.28		

PIR = 1.281

IRR = 41.38%

Table E14 Payback period for the PSC fiscal regime, well cost at 4 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	13.50	0	0
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		5.00	24.41
6		5.35	29.76
payback period (year)			3.09

Table E15 Cash flow summary for the PSC fiscal regime, well cost at 5 MMUS$.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 Years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			3.00	12.00		0.00	15.30
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	3.00	12.00	1.20	6.976	23.476

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.30	0.00	0.00	15.30	0.00	0.00	0.00	-15.30	0.00	0.00	-15.30	0.00
16.70	5.39	5.39	11.30	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
18.09	5.39	10.78	7.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
19.49	5.39	16.17	3.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
20.88	4.71	20.88	0.00	6.08	3.04	3.04	9.39	7.74	1.55	6.20	4.24
23.48	2.60	23.48	0.00	8.19	4.09	4.09	8.19	6.69	1.34	5.35	5.29
	23.476			30.439	15.219	15.219	30.439	38.695	7.739	15.656	21.210

Table E15 Cash flow summary for the PSC fiscal regime, well cost at 5 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.30	0.00	0.00	0.00	0.00	-15.30	-15.30	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.55	3.04	6.20	4.72	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81	0.7117	1.1041
TOTAL	59.905	16.625	6.976	5.991	7.739	15.219	15.656	10.19		

PIR = 0.942

IRR = 30.21%

Table E16 Payback period for the PSC fiscal regime, well cost at 5 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	16.50	0	0
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		6.20	25.61
6		5.35	30.96
payback period (year)			3.55

Table E17 Cash flow summary for the PSC fiscal regime, well cost at 6 MMUS$.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 Years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			3.60	14.40		0.00	18.30
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	3.60	14.40	1.20	6.976	26.476

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
18.30	0.00	0.00	18.30	0.00	0.00	0.00	-18.30	0.00	0.00	-18.30	0.00
19.70	5.39	5.39	14.30	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
21.09	5.39	10.78	10.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
22.49	5.39	16.17	6.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
23.88	5.39	21.57	2.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
26.48	4.91	26.48	0.00	5.87	2.94	2.94	8.19	7.85	1.57	6.28	4.13
	26.476			27.439	13.719	13.719	27.439	40.195	8.039	13.856	19.710

Table E17 Cash flow summary for the PSC fiscal regime, well cost at 6 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	18.30	0.00	0.00	0.00	0.00	-18.30	-18.30	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.62	2.70	6.47	4.93	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.57	2.94	6.28	4.47	0.7117	1.1041
TOTAL	59.905	19.625	6.976	5.991	8.039	13.719	13.856	8.06		

PIR = 0.706

IRR = 22.40%

Table E18 Payback period for the PSC fiscal regime, well cost at 6 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	19.50	0	0
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		6.47	25.88
6		6.28	32.16
payback period (year)			4.01

Table E19 Cash flow summary for the PSC fiscal regime, well cost at 7 MMUS$.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 Years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			4.20	16.80		0.00	21.30
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	4.20	16.80	1.20	6.976	29.476

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
21.30	0.00	0.00	21.30	0.00	0.00	0.00	-21.30	0.00	0.00	-21.30	0.00
22.70	5.39	5.39	17.30	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
24.09	5.39	10.78	13.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
25.49	5.39	16.17	9.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
26.88	5.39	21.57	5.31	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
29.48	5.39	26.96	2.52	5.39	2.70	2.70	8.19	8.09	1.62	6.47	3.89
	26.957			26.957	13.479	13.479	24.439	40.436	8.087	11.049	19.469

Table E19 Cash flow summary for the PSC fiscal regime, well cost at 7 MMUS$. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	21.30	0.00	0.00	0.00	0.00	-21.30	-21.30	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.62	2.70	6.47	4.93	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.62	2.70	6.47	4.60	0.7117	1.1041
TOTAL	59.905	22.625	6.976	5.991	8.087	13.479	11.049	5.20		

PIR = 0.488

IRR = 15.77%

Table E20 Payback period for the PSC fiscal regime, well cost at 7 MMUS$.

Year	CAPEX	Annual Cash Flow	Cumulative annual cash flow
1	22.50	0	0
2		6.47	6.47
3		6.47	12.94
4		6.47	19.41
5		6.47	25.88
6		6.47	32.35
payback period (year)			4.48

APPENDIX F

Cost Recovery Analysis

Table F1 Cash flow summary for the PSC fiscal regime, cost recovery at 0%.

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY 0%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	0.00	0.00	16.65	10.78	5.39	5.39	9.39	5.39	1.08	4.31	6.59
18.05	0.00	0.00	18.05	10.78	5.39	5.39	9.39	5.39	1.08	4.31	6.59
19.44	0.00	0.00	19.44	10.78	5.39	5.39	9.39	5.39	1.08	4.31	6.59
20.84	0.00	0.00	20.84	10.78	5.39	5.39	9.39	5.39	1.08	4.31	6.59
23.43	0.00	0.00	23.43	10.78	5.39	5.39	8.19	5.39	1.08	4.31	6.59
	0.000			53.915	26.957	26.957	30.484	26.957	5.391	6.311	32.948

Table F1 Cash flow summary for the PSC fiscal regime, cost recovery at 0%. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.08	5.39	4.31	4.03	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.08	5.39	4.31	3.76	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.08	5.39	4.31	3.52	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.08	5.39	4.31	3.29	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.08	5.39	4.31	3.07	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	5.391	26.957	6.311	2.41		

PIR = 0.381

IRR = 12.77%

Table F2 Cash flow summary for the PSC fiscal regime, cost recovery at 10%.

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)	2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING INTANG.	DRILLING TANG.	ABANDONMENT COST		
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY 10%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	1.08	1.08	15.57	9.70	4.85	4.85	9.39	5.93	1.19	4.74	6.05
18.05	1.08	2.16	15.89	9.70	4.85	4.85	9.39	5.93	1.19	4.74	6.05
19.44	1.08	3.23	16.21	9.70	4.85	4.85	9.39	5.93	1.19	4.74	6.05
20.84	1.08	4.31	16.52	9.70	4.85	4.85	9.39	5.93	1.19	4.74	6.05
23.43	1.08	5.39	18.04	9.70	4.85	4.85	8.19	5.93	1.19	4.74	6.05
	5.391			48.523	24.262	24.262	30.484	29.653	5.931	8.468	30.252

Table F2 Cash flow summary for the PSC fiscal regime, cost recovery at 10%. (Continued)

YEAR	CASH FLOW SUMMARRY							DISCOUNTED	7.040%	2%
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE			CONTRACTOR TAKE	CASH FLOW (NPV@7.04%)	DISCOUNT FACTOR	ESCAL. FACTOR
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.19	4.85	4.74	4.43	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.19	4.85	4.74	4.14	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.19	4.85	4.74	3.87	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.19	4.85	4.74	3.61	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.19	4.85	4.74	3.38	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	5.931	24.262	8.468	4.18		

PIR = 0.511

IRR = 16.78%

Table F3 Cash flow summary for the PSC fiscal regime, cost recovery at 19.7%.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

COST	COST RECOVERY 19.712%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	2.13	2.13	14.52	8.66	4.33	4.33	9.39	6.45	1.29	5.16	5.53
18.05	2.13	4.25	13.79	8.66	4.33	4.33	9.39	6.45	1.29	5.16	5.53
19.44	2.13	6.38	13.06	8.66	4.33	4.33	9.39	6.45	1.29	5.16	5.53
20.84	2.13	8.50	12.33	8.66	4.33	4.33	9.39	6.45	1.29	5.16	5.53
23.43	2.13	10.63	12.80	8.66	4.33	4.33	8.19	6.45	1.29	5.16	5.53
	10.628			43.287	21.644	21.644	30.484	32.271	6.454	10.562	27.634

Table F3 Cash flow summary for the PSC fiscal regime, cost recovery at 19.7%. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.29	4.33	5.16	4.82	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.29	4.33	5.16	4.51	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.29	4.33	5.16	4.21	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.29	4.33	5.16	3.93	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.29	4.33	5.16	3.67	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	6.454	21.644	10.562	5.89		

PIR = 0.637

IRR = 20.56%

Table F4 Cash flow summary for the PSC fiscal regime, cost recovery at 20%.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY 20%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	2.16	2.16	14.49	8.63	4.31	4.31	9.39	6.47	1.29	5.18	5.51
18.05	2.16	4.31	13.73	8.63	4.31	4.31	9.39	6.47	1.29	5.18	5.51
19.44	2.16	6.47	12.97	8.63	4.31	4.31	9.39	6.47	1.29	5.18	5.51
20.84	2.16	8.63	12.21	8.63	4.31	4.31	9.39	6.47	1.29	5.18	5.51
23.43	2.16	10.78	12.65	8.63	4.31	4.31	8.19	6.47	1.29	5.18	5.51
	10.783			43.132	21.566	21.566	30.484	32.349	6.470	10.624	27.556

Table F4 Cash flow summary for the PSC fiscal regime, cost recovery at 20%. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED CASH FLOW (NPV@7.04%)	7.040% DISCOUNT FACTOR	2% ESCAL. FACTOR
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE						
				ROYALTY	INC. TAX	SHARE				
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.29	4.31	5.18	4.84	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.29	4.31	5.18	4.52	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.29	4.31	5.18	4.22	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.29	4.31	5.18	3.94	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.29	4.31	5.18	3.68	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	6.470	21.566	10.624	5.94		

PIR = 0.641

IRR = 20.67%

Table F5 Cash flow summary for the PSC fiscal regime, cost recovery at 30%.

Gas Production and Selling Plan : 2nd Year Production Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						CAPTAL EXPENSE (CAPEX)						OPERATING EXPENSES (OPEX)	TOTAL COST
						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST		
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY 30%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	3.23	3.23	13.42	7.55	3.77	3.77	9.39	7.01	1.40	5.61	4.97
18.05	3.23	6.47	11.58	7.55	3.77	3.77	9.39	7.01	1.40	5.61	4.97
19.44	3.23	9.70	9.74	7.55	3.77	3.77	9.39	7.01	1.40	5.61	4.97
20.84	3.23	12.94	7.90	7.55	3.77	3.77	9.39	7.01	1.40	5.61	4.97
23.43	3.23	16.17	7.26	7.55	3.77	3.77	8.19	7.01	1.40	5.61	4.97
	16.174			37.740	18.870	18.870	30.484	35.045	7.009	12.781	24.861

Table F5 Cash flow summary for the PSC fiscal regime, cost recovery at 30%. (Continued)

YEAR	CASH FLOW SUMMARRY						CONTRACTOR TAKE	DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE				CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.40	3.77	5.61	5.24	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.40	3.77	5.61	4.89	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.40	3.77	5.61	4.57	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.40	3.77	5.61	4.27	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.40	3.77	5.61	3.99	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	7.009	18.870	12.781	7.71		

PIR = 0.771

IRR = 24.44%

Table F6 Cash flow summary for the PSC fiscal regime, cost recovery at 40%.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY 40%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	4.31	4.31	12.34	6.47	3.23	3.23	9.39	7.55	1.51	6.04	4.43
18.05	4.31	8.63	9.42	6.47	3.23	3.23	9.39	7.55	1.51	6.04	4.43
19.44	4.31	12.94	6.50	6.47	3.23	3.23	9.39	7.55	1.51	6.04	4.43
20.84	4.31	17.25	3.58	6.47	3.23	3.23	9.39	7.55	1.51	6.04	4.43
23.43	4.31	21.57	1.86	6.47	3.23	3.23	8.19	7.55	1.51	6.04	4.43
	21.566			32.349	16.174	16.174	30.484	37.740	7.548	14.937	22.165

Table F6 Cash flow summary for the PSC fiscal regime, cost recovery at 40%. (Continued)

YEAR	CASH FLOW SUMMARRY							DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE			CONTRACTOR TAKE	CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.51	3.23	6.04	5.64	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.51	3.23	6.04	5.27	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.51	3.23	6.04	4.92	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.51	3.23	6.04	4.60	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.51	3.23	6.04	4.30	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	7.548	16.174	14.937	9.48		

PIR = 0.901

IRR = 28.11%

Table F7 Cash flow summary for the PSC fiscal regime, cost recovery at 50%.

Gas Production and Selling Plan : 2nd Year Production						CAPTAL EXPENSE (CAPEX)						OPERATING	TOTAL
Gas Reserve Size 17.4 BCF @ 3.435 US$/MMBTU (10 years average)						2-D SEISMIC	3-D SEIMIC	SIGNATURE BONUS	DRILLING		ABANDONMENT COST	EXPENSES (OPEX)	COST
YEAR	Gas PRODUCTION		GAS PRICE	GROSS REVENUE	ROYALTY (10%)				INTANG.	TANG.			
	MMSCF/D	MMSCF/Y	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2023	0.00	0.00	3.435	0.00	0.00	0.30			2.99	11.96		0.00	15.26
2024	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2025	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2026	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2027	9.56	3487.94	3.435	11.98	1.20							1.40	1.40
2028	9.56	3487.94	3.435	11.98	1.20						1.20	1.40	2.60
TOTAL		17439.70		59.905	5.99	0.3	0.00	0.00	2.99	11.96	1.20	6.976	23.431

CUMULATIVE COST	COST RECOVERY MAX50%	CUMULATIVE COST RECOVERY	COST BANK	PRODUCTION SHARING	CONTRACTOR SHARE	GOVERNMENT SHARE	PROJECT ANNUAL CASH FLOW	TAXABLE INCOME	INCOME TAX(20%)	CONTRACTOR TAKE	GOVERNMENT TAKE (NON TAX)
MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	MMUS$	MMUS$
15.26	0.00	0.00	15.26	0.00	0.00	0.00	-15.26	0.00	0.00	-15.26	0.00
16.65	5.39	5.39	11.26	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
18.05	5.39	10.78	7.26	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
19.44	5.39	16.17	3.27	5.39	2.70	2.70	9.39	8.09	1.62	6.47	3.89
20.84	4.66	20.84	0.00	6.12	3.06	3.06	9.39	7.72	1.54	6.18	4.26
23.43	2.60	23.43	0.00	8.19	4.09	4.09	8.19	6.69	1.34	5.35	5.29
	23.431			30.484	15.242	15.242	30.484	38.673	7.735	15.683	21.233

Table F7 Cash flow summary for the PSC fiscal regime, cost recovery at 50%. (Continued)

YEAR	CASH FLOW SUMMARRY							DISCOUNTED	7.040%	2%
	GROSS	CAPEX	OPEX	GOVERNMENT TAKE			CONTRACTOR TAKE	CASH FLOW	DISCOUNT	ESCAL.
	REVENUE			ROYALTY	INC. TAX	SHARE		(NPV@7.04%)	FACTOR	FACTOR
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$		
2023	0.00	15.26	0.00	0.00	0.00	0.00	-15.26	-15.26	1.0000	1.0000
2024	11.98	0.00	1.40	1.20	1.62	2.70	6.47	6.04	0.9342	1.0200
2025	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.65	0.8728	1.0404
2026	11.98	0.00	1.40	1.20	1.62	2.70	6.47	5.28	0.8154	1.0612
2027	11.98	0.00	1.40	1.20	1.54	3.06	6.18	4.71	0.7618	1.0824
2028	11.98	1.32	1.40	1.20	1.34	4.09	5.35	3.81	0.7117	1.1041
TOTAL	59.905	16.580	6.976	5.991	7.735	15.242	15.683	10.23		

PIR = 0.946

IRR = 30.35%

APPENDIX G

Publication

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ORIGINAL PAPER

Undiscovered hydrocarbon resource assessment of Si Kew prospect, Thailand

Pornchaya Phumiphan[1] · Akkhapun Wannakomol[1] · Kriangkrai Trisarn[1]

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Abstract

Permian carbonate rocks are northeast Thailand's main hydrocarbon source and reservoir rocks. The Si Kew prospect is one of the untested petroleum prospects, according to the study of Chantong (2007), which has high potential as a Permian carbonate source and reservoir prospects in this region. It is located at the edge of the southwestern Khorat Plateau in the vicinity of Si Kew district, Nakhon Ratchasima province. To date, this prospect has not been drilled, studied, or assessed with regard to its potential as a hydrocarbon resource. Therefore, the main objective of this study is to assess the undiscovered hydrocarbon resource of the Permian carbonate rocks of the Si Kew prospect. In this study, the assessment of undiscovered hydrocarbon resources of the Permian carbonate rocks of the Si Kew prospect was analyzed using the Fast Appraisal System for Petroleum Universal (FASPU) program, play analysis, and probability theory approach since these methods are suitable and most widely used to assess the undiscovered hydrocarbon of the limited geologic data and untested/undrilled prospect. Data required in the assessment were derived and collected from relevant data provided by the Department of Mineral Fuels (DMF), Thailand. The necessary input data are geological and engineering parameters, including the probability of favorable hydrocarbon source, timing, potential reservoir facies, hydrocarbon migration, effective porosity, trapping mechanism, number of hydrocarbon accumulation, reservoir lithology, hydrocarbon types, closure area, the thickness of the reservoir, hydrocarbon trap fill percent, depth of the reservoir, hydrocarbon saturation percent, gas formation volume factor, recovery factor of hydrocarbon, and the number of drillable prospects. Based on available required data and the FASPU program calculation, the estimated undiscovered hydrocarbon from the Si Kew prospect Permian carbonate rocks is present in the form of complementary cumulative probability distribution with the arithmetic mean estimate of 23.641 billion ft^3 of non-associated gas.

Keywords Hydrocarbon volume assessment · Permian carbonate rocks · Northeast Thailand · Si Kew prospect

Introduction

Present-day Thailand consumes approximately 1.5 million barrels of crude oil equivalence per day, and about 60% of this demand is imported from the Middle East (Department of Mineral Fuels 2023). The Department of Mineral Fuels (DMF), Thailand, indicates that Thailand's petroleum proven reserves were estimated at 2300 million barrel oil equivalence, and about 80% of these reserves are natural gas. However, the predicted gas demand is possibly over 7000 million ft^3 per day, and approximately 4000 million ft^3 per day is expected as the energy supply from the domestic source. Though Thailand's discovered oil and gas fields have been continually developed during the past decade, this discovered petroleum is in the depletion phase and insufficient to respond to this rising demand. Therefore, promoting domestic petroleum exploration and production investment is critical, especially for the new, undiscovered/untested oil and gas fields.

Hydrocarbons in Thailand have been discovered and produced from Tertiary and Pre-Tertiary Basins. Tertiary Basins are widely distributed in various parts of the country, onshore (north, central, and south) and offshore (Gulf of Thailand and Andaman Sea). Pre-Tertiary Basins are mainly

Responsible Editor: Santanu Banerjee

✉ Pornchaya Phumiphan
pornchaya.phumiphan@gmail.com

[1] School of Geotechnology, Institute of Engineering, Suranaree University of Technology, Nakhon Ratchasima 30000, Thailand

in northeastern Thailand and comprise Triassic and Permian Basins.

The Khorat Plateau is one of the important petroleum provinces of Thailand. It is located in northeast Thailand. It is a circular basin with a rim that rises like a saucepan. The basin extends into Laos, and the structure can be subdivided into five subbasins: Ubon Subbasin, Khon Kaen Subbasin, Vientiane Subbasin, Sakon Nakhon Subbasin, and Savannakhet Subbasin (Piyasin 1995). The stratigraphic sequences of the Khorat Plateau region range in age from the Early Paleozoic to the Neogene. Most of the area of the Khorat Plateau consists of Khorat Group rocks. Based on drilled well data, the Khorat Group rocks are the Late Triassic to Early Cretaceous sediments. The overlying Late Tertiary Tha Chang, the Late Cretaceous–Middle Eocene Mahasarakham and Phu Tok formations, and the underlying Late Triassic Huai Hin Lat Formation (Kuchinarai Group) are excluded from the Khorat Group rocks (GMT 1999; Sattayarak 2005; Atop 2006; Chantong 2007; Glumglomjit 2010; Minezaki 2019). The litho-stratigraphy, depositional environment, and hydrocarbon system of northeastern Thailand are depicted in Fig. 1.

Petroleum exploration in northeast Thailand was executed by drilling more than 30 wells. Natural gas was discovered only in Nam Phong, Dong Mun, and Sin Phu Horm, and gas has been recently produced in only Nam Phong and Sin Phu Horm fields (Department of Mineral Fuels 2019). However, there are many opportunities for petroleum exploration and development in the northeastern provinces (GMT 1999; Atop 2006). Based on surface and subsurface geology,

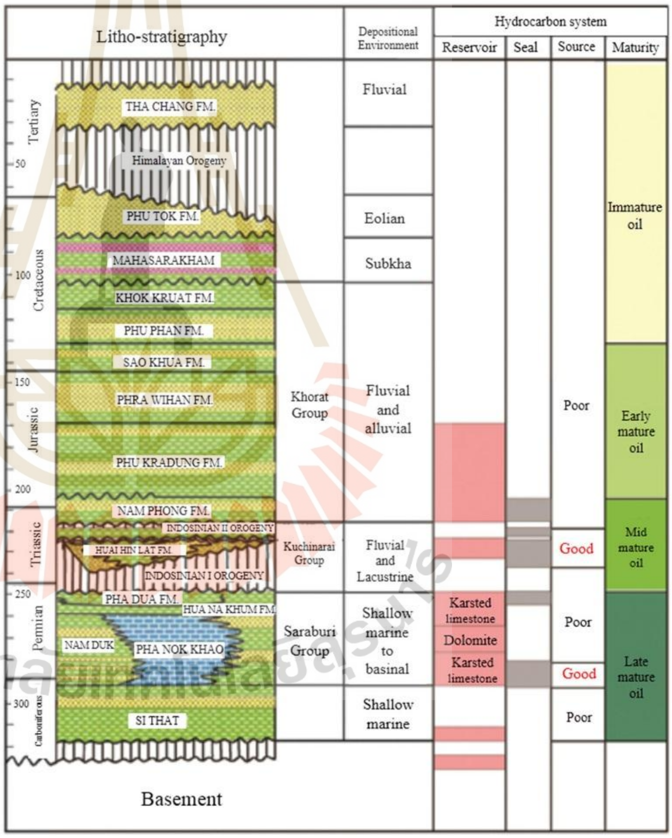

Fig. 1 Litho-stratigraphy, depositional environment, and hydrocarbon system of northeastern Thailand (modified after Chantong 2007)

seismic, and drilled well data, 59 petroleum prospects in the northeastern region of Thailand could be identified (GMT 1999; Chantong 2007). These identified petroleum prospects are categorized into three main groups: (1) successful potential (or gas shows) prospects (6 prospects), (2) unproved potential (or minor gas shows) prospects (11 prospects), and (3) untested petroleum (or undrilled) prospects (42 prospects). The location of the 59 petroleum prospects and 2D seismic survey lines of northeastern Thailand is depicted in Fig. 2. Most of the source and reservoir rocks in the northeast are carbonate rocks of the Permian era. A study of geochemical data suggested that the Late Triassic Huai Hin Lat Formation, the Permian Hua Na Kham and the Pha Nok Khao Formations of the Saraburi Group, and the Late Carboniferous Wang Saphung Group contain good to fair source richness. Surface, subsurface, and bottom hole temperatures

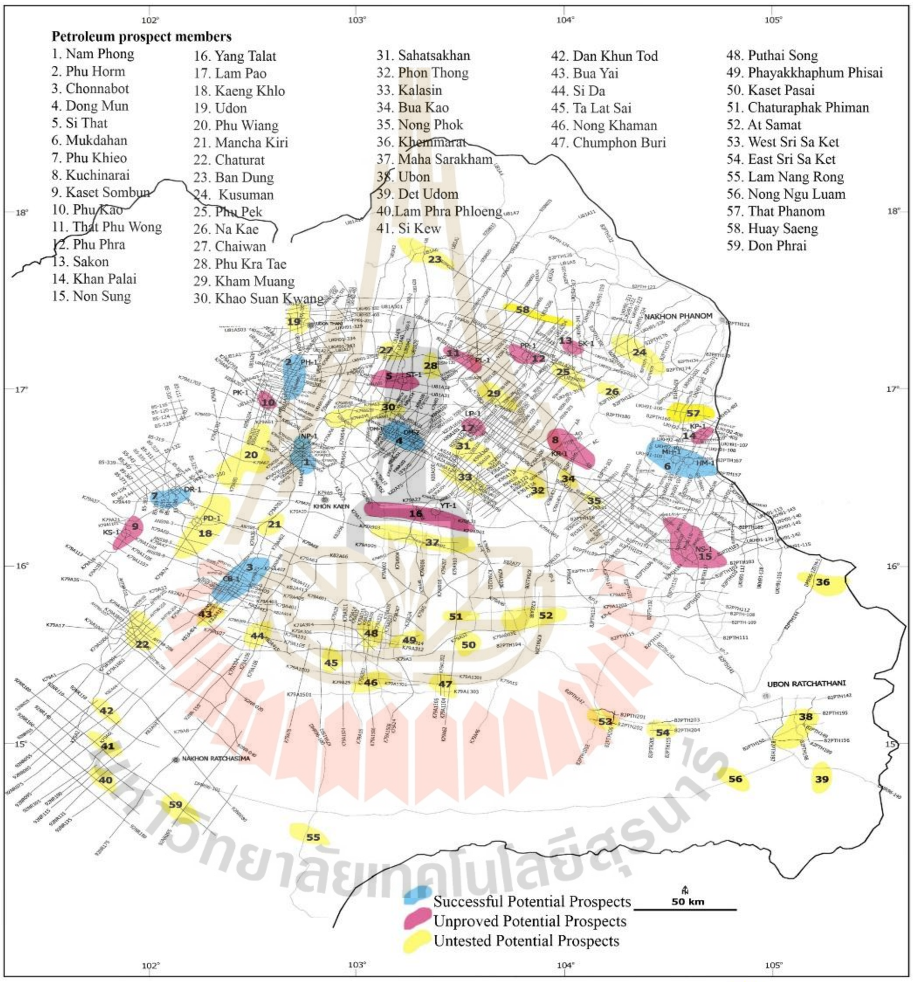

Fig. 2 The petroleum prospect map and 2D seismic survey lines of northeastern Thailand (modified after Chantong 2007)

indicated that the Khorat Plateau has a present-day geothermal gradient of 1.20 °F/100 ft (Sattayarak et al. 1989). The available exploration data suggest that the Permian carbonates are significant reservoirs and are usually the primary targets. The Sap Phlu Basin, located in Nakhon Ratchasima province, is an interesting area with high petroleum potential (Chantong 2007). The seismic profile, outcrop, and subsurface data indicate that the petroleum system of this basin is appropriate, the subsurface structure can be a good petroleum trap, and there is a possibility for petroleum exploration and production. However, this basin has not been drilled. Therefore, this study aims to assess the potential of the undiscovered hydrocarbon resource of the Permian carbonate rocks of the Si Kew prospect (one of the untested petroleum prospects according to the study of Chantong (2007)) in this basin. The results of this study may enhance the domestic natural gas supply to ensure the sustainability of Thailand's energy supply security.

The Si Kew prospect is located in the vicinity of Si Kew district, Nakhon Ratchasima province, in the southwestern part of the Khorat Plateau between latitudes 14° 55′ 0″ and 15° 05′ 0″ north and longitudes 101° 45′ 0″ and 102° 00′ 0″ east (Fig. 3), and the Si Kew prospect on a seismic profile is depicted in Fig. 4.

This study applied to play analysis and the Fast Appraisal System for Petroleum Universal (FASPU) program to assess the undiscovered hydrocarbon resource potential at a play scale within the Si Kew prospect (Permian Carbonate Play).

Materials and methods

Materials

In this study, the FASPU program employed petroleum geology and petroleum reservoir engineering parameters for the undiscovered hydrocarbon resource assessment.

The probability for discovery in the plays assessed by the FASPU program is related to three petroleum geology parameters: play, prospect, and hydrocarbon (accumulation) volume attributes. All prospects share a common geological mechanism for petroleum occurrences within a geological play. A play should represent a group of prospects within geographic and stratigraphic limits with geologically similar sources, reservoirs, and traps. The play attributes probability expresses the favorability of the hydrocarbon source, the timing for migration from the source rock to the reservoir, the effectiveness of the migration path, and the potential reservoir facies. The prospect attributes express the favorability of the trapping mechanism, effective porosity (> 3%), and accumulation of hydrocarbon. The hydrocarbon volume attributes comprise the closure area (thousand acres), trap fill (percent), effective porosity (percent), depth of the

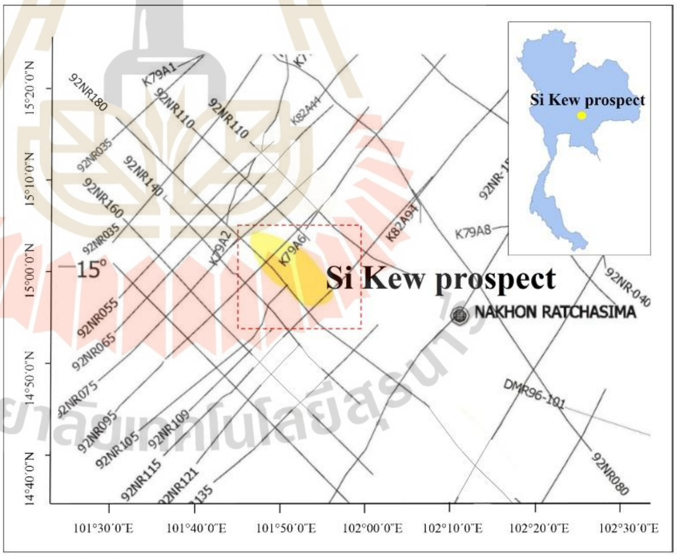

Fig. 3 Si Kew prospect location and nearby 2D seismic lines (modified after Chantong 2007)

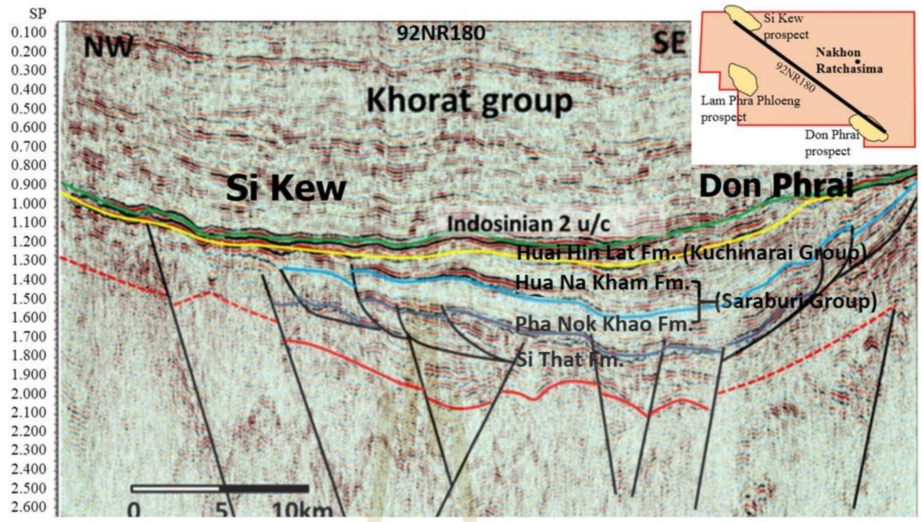

Fig. 4 Seismic lithostratigraphic of Si Kew prospect on the seismic profile along the 92NR180 seismic survey line (modified after Department of Mineral Fuels 2019)

reservoir (thousand feet), thickness of the reservoir (feet), saturation of hydrocarbon (percent), and number of drillable prospects.

Petroleum reservoir engineering parameters comprise the required parameters for the hydrocarbon volume calculation, including oil and gas recovery factor (percent), original reservoir pressure (psi), oil floor depth (feet), gas compressibility factor, temperature of the reservoir (°R), oil formation volume factor, and gas-oil ratio (Mcf/bbl.).

Required petroleum geology and engineering parameters were collected from the well summary report of drilled wells in the Khorat Plateau: Chonnabot-1, Dao Ruang-1, Nam Phong-1, and Phu Wiang-1. The Department of Mineral Fuels (DMF), Thailand, provided and supported these required data.

Methods

In this study, the petroleum system of the Permian carbonate rocks, including potential source rocks, hydrocarbon geochemistry, trap and seal mechanism, and potential reservoir rocks, were studied and identified.

The study of undiscovered hydrocarbon resource assessment of Permian carbonate rocks was conducted using the Fast Appraisal System for Petroleum Universal (FASPU) program, play analysis, and analytic method.

Play analysis is a general term for various geologic models and probabilistic methods of analyzing a geologic play for hydrocarbon potential assessment. Most of the input parameters used in the geologic model are expressed in a probability form (Crovelli and Balay 1986). As a result, the uncertainty about the input parameters and the resulting resource estimates can be quantitatively expressed as probability distributions.

In the play analysis, the presence of the four play attributes is due to the play being favorable for containing petroleum. If the lack of one or more of these attributes is not favorable, the play will not have any petroleum accumulations. The judgments for the probability of the presence of each play attribute will be done by the assessor with subjective assessments under supporting geologic data. The product of the probability of these four attributes is equal to the probability that the play would have petroleum accumulation (marginal play probability). In case the play attributes are favorable, and there is the presence of the three prospect attributes, it is enough to indicate that there is petroleum accumulation in that prospect. The assessor will expect the probability of each prospect attributes with subjective judgment as in the play attributes. The product of these three prospect attributes will equal the prospect's probability of containing hydrocarbon (conditional deposit probability). In this study, the probability of favorable of the four play attributes and the three prospect attributes were estimated and given based on the available required data and the guidance for the probability of hydrocarbon discovery for various depositional environment reservoirs and petroleum systems of the Coordinating Committee for Coastal and offshore Geosciences Programmes in East and Southeast Asia (CCOP) (1990).

The accumulation (hydrocarbon) volumes are analytically calculated from the thickness of the reservoir (feet), reservoir depth (feet), closure area (thousand acres), trap fill (percent), effective porosity (percent), and hydrocarbon saturation (percent). The engineering parameters such as oil formation volume factor, oil recovery factor (percent), original reservoir pressure (psi), gas recovery factor (percent), gas-oil ratio (Mcf/bbl.), gas compressibility factor, reservoir temperature (°R), and oil floor depth (feet) are also used in this calculation (Crovelli and Balay 1994).

In this study, only the Permian carbonate rocks of the Saraburi Group have been assessed regarding their undiscovered hydrocarbon resources since they have a high probability of having high petroleum potential, according to many previous studies (GMT 1999; Sattayarak 2005; Atop 2006; Chantong 2007; Glumglomjit 2010; Chantong et al. 2013; Minezaki 2019). The overall workflow of the analytic method of the play analysis to assess the undiscovered hydrocarbon resources is depicted in Fig. 5.

The FASPU program employed the volumetric method to calculate the volume of oil in place using Eq. (1) and the volume of non-associated gas in place by Eq. (2).

$$\textit{Oil in place}(MMbbl) = 7758 \times 1000 \times A \times F \times H \times P \times (S_h/B_o) \tag{1}$$

$$\begin{aligned}\textit{Non-associated gas in place } (Bcf) = 1537.7 \times 1000 \times A \times F \\ \times H \times P \times S_h \times (P_e/T) \\ \times (1/Z)\end{aligned} \tag{2}$$

where

A closure area (thousand acres)

F trap fill (decimal fraction)

H thickness of reservoir (feet)

P effective porosity (decimal fraction)

S_h hydrocarbon saturation (decimal fraction)

B_o oil formation volume factor (no unit)

P_e original reservoir pressure (psi)

T reservoir temperature (degree Rankine)

Z gas compressibility factor (no unit)

For the FASPU program, zoned linear, exponential, power, and logarithmic mathematical functions are used to generalize the geologic model for modeling the five reservoir engineering variables as a function of depth. Each mathematical function has A and B parameters, except zoned linear, which has a set of A and B coefficients for each zone. These mathematical functions can be obtained from:

(1) Zoned linear function: $(A \times \text{depth}) + B$ Maximum of 4 zones with three transition depths (feet)
(2) Exponential function: $A \times [\exp (B \times \text{depth})]$
(3) Power function: $A \times (\text{depth} \times B)$
(4) Logarithmic function: $A \times [\text{Ln} (B \times \text{depth})]$

Results and discussion

Petroleum system

Source rocks and source rock maturity

Several Permian rock samples from the surface and exploration wells show TOC of 0.29–1.59% (Thongboonruang 2008). The potential source is restricted chiefly to Permian shales intercalated within the Pha Nok Khao Formation (Piyasin 1995). The lower part of the Pha Nok Khao Formations in Dao Ruang-1 contains fair source richness (TOC 0.5–1%) in limestones. It contains kerogen type III and is gas prone (Chinoroje and Cole 1995). Geochemical analysis of these sediments shows that they are very mature to overmature. Maturation modeling using the present-day geothermal gradient of 1.20 °F/100 ft (Sattayarak et al. 1989) suggested that oil could probably be generated in the Jurassic after the deposition of the lower part of the Khorat Group.

Reservoir rocks

The available exploration data indicated that Permian carbonates are significant reservoirs and are usually the primary targets within the Khorat Plateau (GMT 1999; Atop 2006; Chantong 2007; Chantong et al. 2013; Minezaki 2019). Based on the available data, the properties and characteristics of the Permian carbonate reservoirs in the Khorat Plateau are summarized below.

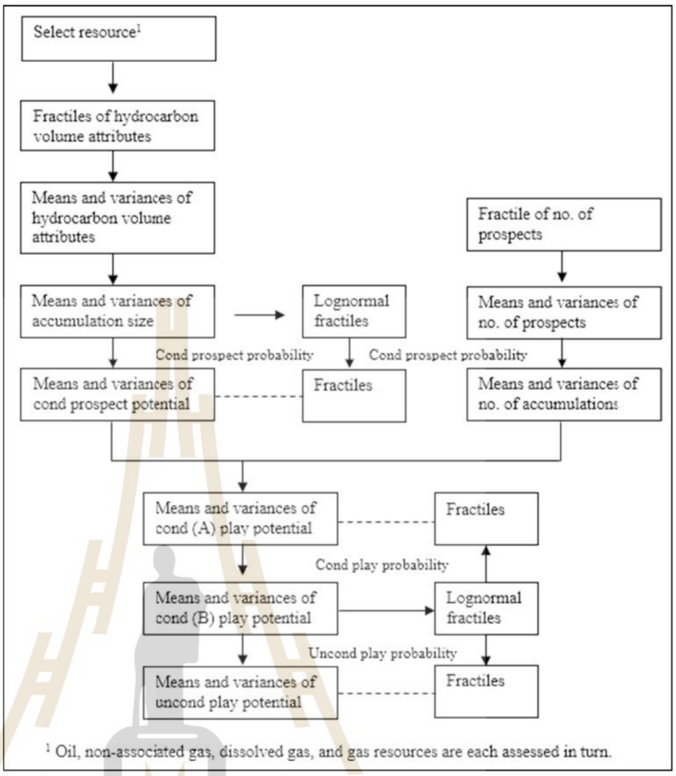

Fig. 5 The analytic method of the play analysis flow chart to assess the undiscovered hydrocarbon resource (Crovelli and Balay 1994)

- The carbonates were deposited on the isolated platforms. As observed in cores, lithofacies of the carbonates are predominantly fossiliferous packstone and grainstone, while wackestone and mudstone are less common.
- Low porosity and low permeability are the norms for these carbonates. Generally, porosity ranges from 0 to 18% (average 4.0%).
- They were subjected to deep burial, multiphase karstification, and deep erosion.
- The porosity values observed in the mud-rich lithofacies (mudstone and wackestone) are higher than those in the grain-rich lithofacies (packstone, grainstone, and boundstone). By lithology, the dolomite appears to have higher porosity than limestone (Kozar et al. 1992).
- Permeability of the carbonates appears to rely mainly on the presence of microfractures. A good gas flow rate of the Nam Phong Structure within the Khorat Plateau is likely due to these open microfractures.

Trap and seal

The geologic structures suitable for petroleum traps in northeastern Thailand are (1) the angular unconformity between the Saraburi and the Huai Hin Lat Formation and (2) the anticlinal structures developed in the Tertiary.

Geologic attributes

Play attributes

The probability for each play attribute can be defined and analyzed from petroleum geology, geochemical, geophysical, and petroleum reservoir engineering data of the available drilled well data.

According to the study of Chantong (2007), the Si Kew prospect is defined as Permian Carbonate Play. For this play type, the Khorat Group will be the main seal, and Permian Saraburi Group will be the main reservoir. Sources may come from the Permian Group itself or the Triassic Group. These Permian carbonate rocks contain a fair to excellent organic richness. The thermal maturity of these carbonate source rocks indicated a late-to-overmature oil stage (Sattayarak et al. 1989; Chinoroje and Cole 1995; Piyasin 1995; Thongboonruang 2008). Therefore, the probability of a hydrocarbon source's existence is 1.00. The probability of favorable timing for hydrocarbon migration from the source to the reservoir is also 1.00 since they are local sources. However, the probability of the potential migration path is 0.90 because the reservoir rock is expected to be the fractured carbonate reservoir (GMT 1999; Atop 2006; Minezaki 2019). Since the fractures and microfractures in these carbonate reservoirs were partly filled with calcite influenced by numerous tectonics, the probability of favorable potential reservoir facies is 0.90. Consequently, the marginal play probability of the Si Kew prospect is equal to 0.81 ($1\times1\times0.9\times0.9$).

Prospect attributes

In the Si Kew prospect, the seismic profile clearly shows an unconformity between the Permian Saraburi Group and the Triassic Huai Hin Lat Formation (CCOP 1990; Atop 2006). Therefore, the probability of the existence of a trapping mechanism is given at 1.0. Data from previously drilled wells in the Permian carbonate rocks in the Khorat Plateau indicate that these carbonate rocks have high average porosity (Esso Exploration and Production Korat Inc. 1982). Therefore, the probability of effective porosity is given 0.80. Since reservoir and source rocks in the Si Kew prospect are the same Permian carbonate rocks, the probability of petroleum accumulation is 1.00. Consequently, the conditional deposit probability of the Si Kew prospect is equal to 0.80 ($1\times0.8\times1$). The probability of favorable of each play and prospect attribute is summarized and shown in Table 1.

Available petroleum geology and engineering parameters were collected from available drilled well data and estimated by the authors. These data are presented in Table 2. The complementary cumulative plots of these available data were used for generating the probability distribution for each hydrocarbon volume attribute. As a result, the favorable value at the fractiles of 100th, 95th, 75th, 25th, 5th, and 0th of all six hydrocarbon volume attributes, equal to or greater than at seven fractiles, can be estimated (Table 3).

Reservoir engineering parameters

For this assessment, the required reservoir engineering parameters were plotted with depth. The relationship between these essential reservoir engineering parameters and depth is made based on the four types of mathematic functions of the FASPU program. These relationships are summarized and shown in Table 4.

Estimating the undiscovered hydrocarbon resource quantities of the Si Kew prospect (Permian Carbonate Play) by the FASPU program is a complementary cumulative probability. These distributions summarize the estimates range as a single probability curve in an "equal to or greater than" format. Consequently, the estimated undiscovered resources are reported at the arithmetic mean and the five confidence levels, as shown in Table 5.

However, results of the geochemical study of the Permian carbonate source rocks in the Khorat Plateau of Chantong (2007) and Thongboonruang (2008) suggest that there is no chance of discovering oil resources within the Permian carbonate play of the Si Kew prospect and the possible generated natural gas could be only non-associated gas.

Conclusions

Based on the available data, including relevant surface/subsurface geology, seismic, drilled well data provided by the DMF, and the published literature, the untested

Table 1 Probability of favorable for each input play and prospect attribute of the Si Kew prospect (Permian Carbonate Play)

Input	Attribute	Probability of favorable
Play attributes	1. Hydrocarbon source	1
	2. Timing	1
	3. Migration	0.9
	4. Potential reservoir facies	0.9
	Marginal play probabilities = 0.81 ($1\times2\times3\times4$)	
Prospect attributes	5. Trapping mechanism	1
	6. Effective porosity (> 3%)	0.8
	7. Hydrocarbon accumulation	1
	Conditional deposit probabilities = 0.80 ($5\times6\times7$)	

Table 2 Raw data of required hydrocarbon volume parameters

Hydrocarbon volume parameters	Wells/source of data	Range of data
1. Area of closure (1000 acres)	Structural contour map of Si Kew prospect (Chantong, 2007)	0.119–0.302
2. Reservoir thickness (ft)	Chonnabot-1, Phu Wiang-1	103–322
3. Effective porosity (%)	Chonnabot-1, Phu Wiang-1	0.00–0.17
4. Trap fill (%)	Determined by the assessors	30–80
5. Reservoir depth (1000 ft)	Chonnabot-1, Phu Wiang-1	11.4–16.4
6. Hydrocarbon saturation (%)	Nam Phong-1, Chonnabot-1, Phu Wiang-1	3.0–90.0
7. No. of drillable prospects	Structural contour map of Si Kew prospect (Chantong, 2007)	3–5

Table 3 Hydrocarbon volume parameters of the Si Kew prospect (Permian Carbonate Play)

Hydrocarbon volume parameters	Reservoir lithology		Carbonate				
	Hydrocarbon type		Gas			98	
	Prob. %		Oil			2	
Attribute	Probability (equal to or greater than)						
	100	95	75	50	25	5	0
Closure area (1000 acres)	0.120	0.125	0.151	0.235	0.345	0.432	0.451
Reservoir thickness (ft)	100.0	120.0	205.0	234.0	256.0	323.0	340.0
Effective porosity (%)	3.00	3.14	3.71	4.61	7.00	13.10	18.00
Trap fill (%)	30.00	35.00	40.00	45.00	50.00	70.00	80.00
Depth of reservoir (1000 ft)	11.40	11.65	12.65	13.90	15.15	16.15	16.40
HC Saturation (%)	60.00	64.00	72.00	82.00	86.00	89.00	90.00
No. of drillable prospects	3	3	3	4	4	5	5

Table 4 Engineering parameters input data for hydrocarbon resource assessment of the Si Kew prospect (Permian Carbonate Play)

Original reservoir pressure (psi)	=	(0.7166 × depth) + 14.5038
Reservoir temperature (°R)	=	(0.0267 × depth) + 538.00 (from 0 to 2300 ft)
	=	(0.0068 × depth) + 579.00 (from 2300 to 5500 ft)
	=	(0.0115 × depth) + 537.00 (below 5500 ft)
Gas-oil ratio (Mcf/bbl)	=	0.0056146
Oil formation volume factor	=	1.00
Gas compressibility factor	=	(0.00001 × depth) + 1.02384
Oil floor depth	14,870 ft	
Oil recovery factor (%)	=5	
Gas recovery factor (%)	=90	

(undrilled) Si Kew prospect is defined as Permian Carbonate Play. The main seals of this prospect are the Khorat Group rocks, and the main reservoir is the Permian Saraburi Group. Hydrocarbon sources come from the Permian Group itself. These Permian carbonate rocks contain a fair to excellent organic richness, and the thermal maturity of these carbonate source rocks indicated a late to overmature oil stage. Therefore, this suitable petroleum geology system led the untested Si Kew structure to be a high petroleum potential prospect.

According to the available input geological and engineering parameter data, the estimated undiscovered hydrocarbon of the Si Kew prospect is only the non-associated gas resources varying from 4.84 Bcf (very high confidence, F95), 10.31 Bcf (high confidence, F75), 17.45 Bcf (medium confidence, F50), 29.52 Bcf (low confidence, F25), 62.90 Bcf (very low confidence, F05), and 23.64 Bcf at the arithmetic mean respectively.

However, the reliability of the estimates of undiscovered hydrocarbon assessment depends not only on the accuracy and the amount of the input parameters, the geological model, and the proposed play type but also on the geological uncertainty. The geological uncertainty

Table 5 Results of a hydrocarbon resource assessment of the Si Kew prospect (Permian Carbonate Play)

Result	Mean	F95	F75	F50	F25	F05
Oil resource						
Number of accumulations	0.039	0	0	0	0	0
Accumulation size (MMbbl)	0.540	0.11	0.24	0.40	0.67	1.43
Unconditional play potential	0.017	0	0	0	0	0
Non-associated gas resource						
Number of accumulations	2.800	1	2	3	3	4
Accumulation size (Bcf)	23.641	4.84	10.31	17.45	29.52	62.90
Unconditional play potential	53.628	0	23.98	47.24	75.01	136.97

F fractile, *Mean* arithmetic mean

consists of two elements, the uncertainty involved in interpreting the geological play and the uncertainty involved in the areal extent of the different play attributes.

Moreover, the carbonate reservoir heterogeneity distribution is one of the most critical parameters that affect and play an essential role in the exploration risk and the success ratio of this play type in northeastern Thailand.

The estimates of undiscovered hydrocarbon resources of the untested Si Kew prospect from this study are novel since this prospect have never been assessed. Thailand must promote investment in domestic petroleum exploration and production, especially from the new and undiscovered/untested oil and gas field, to respond to its high domestic energy demand. Therefore, the results of this study can enhance the domestic natural gas supply to ensure the sustainability of the energy supply security of Thailand in the near future.

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Data availability Most of petroleum geology and petroleum engineering data used in this study are highly confident and are under the permission of the Department of Mineral Fuel, Thailand, and do not reveal.

Declarations

Conflict of interest The authors declare that they have no competing interests.

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BIOGRAPHY

Miss Pornchaya Phumiphan was born on July 5, 1990 in Nakhon Ratchasima Province. In 2008, she earned her high school diploma from Suranaree Wittaya School, specializing in science and mathematics. Subsequently, she achieved a bachelor's degree in Earth Science with first-class honors from Kasetsart University in Thailand in 2012. Following her undergraduate studies, she pursued her doctoral degree in the Petroleum Engineering Program at the School of Geotechnology, Institute of Engineering, Suranaree University of Technology.