COMPARATIVE STUDY OF GROSS SPLIT AND COST RECOVERY PRODUCTION SHARING CONTRACTS IN INDONESIA

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering in Georesources and Petroleum Engineering
Department of Mining and Petroleum Engineering
FACULTY OF ENGINEERING
Chulalongkorn University
Academic Year 2020

การศึกษาเปรียบเทียบระบบสัญญาแบ่งปันผลผลิตระหว่างการหักต้นทุนก่อนการแบ่งปันกับภายหลังการแบ่งปันในประเทศอินโดนีเซีย

นายโมฮัมหมัด อูบายดิลลาห์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมทรัพยากรธรณีและปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2563

Thesis Title	COMPARATIVE STUDY OF GROSS SPLIT AND COST RECOVERY PRODUCTION SHARING CONTRACTS IN INDONESIA
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Field of Study	Georesources and Petroleum Engineering
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โมฮัมหมัด อูบายดิลลาห์ : การศึกษาเปรียบเทียบระบบสัญญาแบ่งปันผลผลิตระหว่างการหักต้นทุนก่อนการแบ่งปันกับภายหลังการแบ่งปันในประเทศอินโดนีเซีย. (COMPARATIVE STUDY OF GROSS SPLIT AND COST RECOVERY PRODUCTION SHARING CONTRACTS IN INDONESIA) อ.ที่ปรึกษาหลัก : ฐิติศักดิ์ บุญปราโมทย์

ประเทศอินโดนิเซียนำระบบสัมปทานปิโตรเลียม แบบ สัญญาแบ่งปันผลผลิต การชดเชยจ่ายคืนส่วนที่เป็นต้นทุน (PSC CR) มาใช้ ในปี ค.ศ. 1966 และยังคงใช้ ระบบดังกล่าวมาถึงปัจจุบัน ในปี คศ 2017 กระทรวงพลังงานและทรัพยากรธรณี นำระบบ ระบบใหม่ คือ สัญญาแบ่งปันผลผลิต แบบ แบ่งจากผลกำไร (PSC GS) กับ 3 กฎหมายฉบับแกไขเพิ่มเติม ใช้จนถึงปี ค.ศ. 2019 รัฐมณตรีเชื่อว่าระบบการคลังปิโตรเลียมใหม่นี้จะเป็นการดึงดูดนักลงทุนในอุสาหกรรมปิโตรเลียมและแก็สเข้ามาลงทุนในประเทศอินโดนิเซีย โดยมีนโยบาย 3 ประการ ได้แก่ ความแน่นอน ความมีประสิทธิภาพ และ ความเรียบง่าย การศึกษานี้เป็นการประเมินและเปรียบเทียบมุมมองทางการเงินของระบบการคลังปิโตรเลียมระหว่าง ระบบสัมปทานปิโตรเลียม แบบ สัญญาแบ่งปันผลผลิต การชดเชยจ่ายคืนส่วนที่เป็นต้นทุน (PSC CR) กับ สัญญาแบ่งปันผลผลิต แบบ แบ่งจากผลกำไร (PSC GS)

การวิจัยนี้เป็นการวิเคราะห์ทางการเงินซึ่งเปรียบเทียบระหว่างผลลัพธ์ของทั้งสองระบบโดยข้อมูลมาจาก 30 แหล่งตัวอย่างเป็นกรณีศึกษา โดยการศึกษานี้ได้นำตัวแปร เช่น มูลค่าปัจจุบันสุทธิ (NPV) และ อัตราผลตอบแทนภายใน (IRR) ซึ่งสามารถคำนวณได้จาก การนำตัวแปรนำเข้า (input) เช่น อัตราการผลิตน้ำมัน อัตราการลิตแก็สต้นทุนการผลิต ค่าใช้จ่ายในการลงทุน ค่าใช้จ่ายในการดำเนินงาน เป็นต้น ไปใช้ในสูตรสมการซึ่งได้มาจากโครงสร้างของระบบการคลังปิโตรเลียมในแต่ละแบบ ผลการศึกษาจาก ตัวอย่าง 30 แหล่ง พบว่า ระบบการคลังปิโตรเลียมแบบ การชดเชยจ่ายคืนส่วนที่เป็นต้นทุน (PSC CR) ให้ มูลค่าปัจจุบันสุทธิ (NPV) และ อัตราผลตอบแทนภายใน (IRR) ที่ดีกว่า สำหรับ สำหรับผู้ทำสัญญา และการศึกษาถัดมาคือ การวิเคราะห์ความเสถียรของผลการศึกษา

สาขาวิชา	วิศวกรรมทรัพยากรธรณีและปิโตรเลียม	ลายมือชื่อนิสิต ....
ปีการศึกษา	2563	ลายมือชื่อ อ.ที่ปรึกษาหลัก ....

6270805821 : MAJOR GEORESOURCES AND PETROLEUM ENGINEERING
KEYWORD: Indonesia, Petroleum Economic, Fiscal Regime
Mohammad Ubaidillah : COMPARATIVE STUDY OF GROSS SPLIT AND COST RECOVERY PRODUCTION SHARING CONTRACTS IN INDONESIA. Advisor: Asst. Prof. THITISAK BOONPRAMOTE, Ph.D.

In upstream oil and gas business, Indonesian has introduced Production Sharing Contract Cost Recovery (PSC CR) in 1966 and still implementing that fiscal system until nowadays. In January 2017, The Indonesian Minister of Energy and Mineral Resources (MEMR or ESDM) introduce new PSC system called Production Sharing Contract Gross Split (PSC GS) following with three amendments until 2019. Ministries believe this new Fiscal regime can attract more investor to invest Oil & Gas business in Indonesia by delivering three main values which are certainty, efficiency, and simplicity policies. This study evaluates and compares the financial aspect of new Indonesian fiscal regime called PSC GS with the former Indonesian fiscal regime PSC CR.

In this study, financial analysis was performed to compare the output of both fiscal terms on thirty fields samples as case studies. The comparation use some of key financial parameters, for instance Net Present Value (NPV) and Internal Rate of Return (IRR) which can be calculated from project input such as oil production, gas production, investment cost, operational cost etc. using the formula from the structure of each fiscal regimes. According to the result, it can be concluded that for majority of the 30 samples, PSC CR will generate a better NPV and IRR for the contractor. Next, sensitivity analysis is done by calculating Net Contractor Take percentage in several different hydrocarbon price scenario as representative of unpredicted future. According to the result, even though both regimes are showing regressive fiscal, but in overall PSC GR are tends to be resulting a lower NCT with sensitively changing in different price condition, meanwhile for PSC CR tends to be resulting a higher NCT with more stable NCT percentage in various condition of oil and gas prices. These results can be quideline that selecting the right fiscal regime can be affect the result of contractor financial project profit.

Field of Study:	Georesources and Petroleum Engineering	Student's Signature ....
Academic Year:	2020	Advisor's Signature ....

ACKNOWLEDGEMENTS

Assalamu'alaikum Warohmatulloh Wabarokatuh

First, I would like to give my biggest gratitude to God and prophet Muhammad which delivering Islam as my religion until death come.

I would like to thank you my parents, my family and my fiancée which always stay by my side in every situation.

I would also thank my thesis advisor Asst. Prof. Dr. Thitisak Boonpramote, Ph.D. of the Department of Mining and Petroleum Engineering at Chulalongkorn University. The author also wishes to thank all the professors and faculty members in the Department of Mining and Petroleum Engineering.

I appreciate to Scholarship Program from PTTEP Ltd and SKK Migas for the financial support.

Finally, I would also like to thank my friends from Petroleum Engineering for help and good friendship.

Mohammad Ubaidillah

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CHAPTER 1
INTRODUCTION

1.1. Petroleum Economics / Background

Analyzing and ensuring the value of investment feasibility of some business program, detail analysis of profitability value of the business program is compulsory needed. Petroleum economic is a common way to evaluate the financial degree of the business program. For instance, oil and gas project can be financially measured by knowing the rate of return. The well-known upstream oil and gas project characteristics are high risks project in every side, such as investment risk, health environment and safety risk, etc. It also needs a high cost investment value with longer time of income return compared to the other kind of business, which usually more than 10 years of pay out time (POT). Moreover, the uncertainty aspects of upstream business are commonly faced such as subsurface reserve uncertainty, field production problem, oil, and price fluctuation. All these aspects must be acknowledged and simulated in certain analysis model which in the end resulting a correct output which can judge whether the project is generating profit or cannot be executed.

Following project things can be found out the economic value by using analyze of petroleum economic:

- Discover a new oil and gas field or area.
- Receiving existing blocks from other company contract negotiations.
- Impact of the new or revised regulation the field economics.
- New project profitability level.
- New work area development program or existing work area optimization.
- Calculating the cash flow and related capital cost.
- Project performances evaluation.
- Method to help project decision making which needs to be prioritized with limited resources, whether a project needs to be revised, postponed, or even canceled if some changing in parameters.

At every stage in the development of oil and gas exploration and production project, petroleum economic involves the application of financial analysis techniques. Economic aspects of oil and gas projects are affected by several factors, in example:

- Conditions of the market,
- Effect of the applicable tax / royalty system,
- The uncertainty level of oil and gas fields owned data, and
- Field location, well completions and surface facilities configuration.

1.2. Fiscal Regime

In Oil & Gas industry, Fiscal regime is the set of instruments or tools (taxes, royalties, dividends, etc.) that determine how the revenues from oil projects are shared between the state and contractor. Fiscal regime is the only tools to secure the Government share from the sales of hydrocarbon product from the Contractor exploitation activity (Dharmadji & Parlindungan, 2002). Fiscal Regime also became the tool for the Contractor (Oil Company) to ensure the investation which placed in some working areas are securely recovered depended on the production hydrocarbon performance later. The main objective of oil and gas fiscal regime is ensuring that all resources are recovered to maximize economic value for country (Ravagnani, Lima, Barreto, Munerato, & Schiozer, 2012). Also, share of profit should be retained for the nation while ensuring return of investment needed to exploit resource recovery is sufficiently attractive.

There are two main types of hydrocarbon fiscal terms that applied in this world which are Royalty & Tax (R&T) and contractual systems. Furthermore, the contractual systems are subdivided into Production Sharing Contract (PSC) and Service Contract (Johnston, 2003). Indonesian has introduced PSC Cost Recovery in 1966 and still implementing that fiscal system until now.

In January 2017, The Minister of Energy and Mineral Resources (ESDM) introduce new Production Sharing Contract system called PSC Gross Split, which must be complied by the Oil & Gas Contractor within criteria mentioned. Ministries believe this new Fiscal regime can attract more investors to invest Oil & Gas business in Indonesia by delivering three main values which are certainty, efficiency, and simplicity policies.

1.3. Objectives and Scope of Study

This study aims to giving a clear explanation about Production Sharing Contract Cost Recovery in Indonesia that already applied for almost 57 years, giving explanation about PSC Gross Split and how to calculate a financial model using both fiscal. The explanation also includes the history, amendments and differences Indonesian PSC compared to the other country. Therefore, this study can be guideline for International Oil Company if attracted to investing in block in Indonesia.

This thesis addressed to give objective comparations of financial performance between new fiscal regime that introduced by the new Minister of Energy and Mineral Resources in year 2017 compared to the existing PSC Cost recovery that already applied for almost 57 years in Indonesia. By using field data from various types of working area in Indonesia, this study can show the majority calculation result that should be analyzed the Government and Contractor point of view.

By using sensitivity data, such as hydrocarbon price and hydrocarbon volume reserve, this research also can give a clear different sensitivity condition of both PSC Cost Recovery and PSC Gross Split, whether in categorized as regressive fiscal regimes (front end loaded) or progressive fiscal regime (back end loaded).

Fiscal regime is the most important aspect to take concern before IOC began to approach the government to propose the Field Development Scenario. In this study, numbered of Oil and Gas field in Indonesia are analyzed by calculate the financial investment of field development. The main objectives of this study are:

(1) To assess and evaluate the economic aspect using financial calculation model both new (PSC Gross Split) and existing (PSC Cost Recovery) petroleum fiscal systems in Indonesia
(2) To determine the parameters or conditions which might support the PSC Gross Split become a better fiscal regime to create attractiveness in petroleum upstream business

CHAPTER 2
THEORY AND LITERATURE REVIEW

2.1. Overview of Fiscal Regimes

In the business of oil and gas industry, two main families of fiscal regime exist. The first family includes ‘concessionary’ systems, so-called because the government grants the company the right to take control of the entire process – from exploration to marketing – within a fixed area for a specific amount of time. Since production and sale of the oil is then subject to royalties, taxes and other concessions, contracts in this family are commonly known as Royalty/Tax Systems (R/T systems). ‘Contractual-based’ systems comprise the second family. Agreements in this family belong to two predominant groups: production sharing contracts (PSC) and service agreements (SA).

In short, the distinguishing characteristic of each family of contract is where, when, and if ownership of the hydrocarbons transfers to the international oil company. While numerous variations and twists are found in both concessionary and contract-based systems,3 from a mechanical and financial point of view there are practically no differences between the various systems. As will be shown in the following sections, where the components of each system are discussed in detail, the key calculations in both families follow the same hierarchy. Any oil agreement takes into account, in the following order: (1) the generation of production and revenue; (2) the royalty or royalty equivalent elements for the government; (3) the cost recovery, tax deductions or reimbursement for the corporation; and (4) the way profits are divided (such as profit-oil sharing and/or taxes). While some interesting exceptions to this general rule exist, they are most likely to be found only among the SA of this world.

The belief that systems are somehow fundamentally different from a financial point of view has led to a number of common misconceptions. For instance, one common claim in discussions of the oil industry is that R/T systems and PSC systems each allocate different amounts of risk to either the NOC or IOC. Neither R/T systems nor PSC are inherently more likely to allocate greater risk either to the NOC or the IOC. Similarly, it is not the case that PSC allow the IOC to get their costs back faster, or even that they allow IOC to get them back at all. Nor is it necessarily true that PSC are more or less stable than R/T systems.

Prior to the late 1960s, R/T Systems—or ‘concessionary systems’—were for all practical purposes, the only arrangements available. R/T systems are characterized by several features:

- Oil companies are contracted for the right to explore for hydrocarbons.
- If a discovery is deemed commercially viable, the international oil company has the right to develop and produce the hydrocarbons.
- When hydrocarbons are produced, the international oil company will take title to its share at the wellhead (this “entitlement” equals gross production less royalty). If the royalty is 10% the international oil company can ‘lift’ (take physical and legal possession of its entitlement of crude oil) 90% of production. If the royalty is paid in cash from another source of funds, then the IOC can ‘lift’ 100% of production.
- Exploration and production equipment is owned by the IOC.
- The IOCs pay taxes on profits from the sale of the oil.

The concept of production sharing is ancient and widespread. Farmers in the USA have been familiar with the concept for decades. The concept of the PSC, as far as the oil and gas industry is concerned, was conceived in Venezuela in the mid-1960s. The first modern Production Sharing Contract was signed in 1966 between the Independent Indonesia American Petroleum Company (IIAPCO) and Permina, Indonesia’s National Oil Company at the time. The characteristic features of this pioneering agreement, which can still be found in most PSC arrangements worldwide, included:

- Title to the hydrocarbons remained with the state (Indonesia).
- Permina maintained management control (Indeed, putting management control in the hands of Permina is what really distinguished the PSC from the Indonesian predecessors).
- Contractor submitted work programs and budgets for government approval.
- Profit Oil (P/O) split—the amount of oil remaining after allocation of royalty oil and cost oil— was 65%/35% in favor of Permina.
- Contractor bore the risk.
- Cost Recovery Limit (the limit to the amount of deductions that can be taken for cost recovery purposes) was 40%.
- Taxes paid ‘in lieu’ (i.e. taxes paid for and on behalf of the IOC by Permina).
- Purchased equipment became property of Permina.

- Company entitlement equals cost oil (oil or revenue used to reimburse the contractor for exploration and development) plus profit oil.

Service contracts or service agreements (SA) generally use a simple formula: the contractor is paid a cash fee for performing the service of producing mineral resources. All production belongs to the state. The contractor is usually responsible for providing all capital associated with exploration and development (just like with R/T systems and PSC). In return, if exploration efforts are successful, the contractor recovers costs through the sale of oil or gas plus a fee. The fee is often taxable. These agreements can be quite similar to PSC or R/T systems except for the issue of entitlement (entitlements are not granted and fees are paid instead). Thus, for example, except on the issue of entitlement, the 1996 round of oil negotiations in Venezuela contain the features of an R/T system because it has royalties and taxes. The Philippine SA, however, uses the terminology and structure of a PSC with a cost recovery limit and profit oil split. (Onyeukwu, 2010)

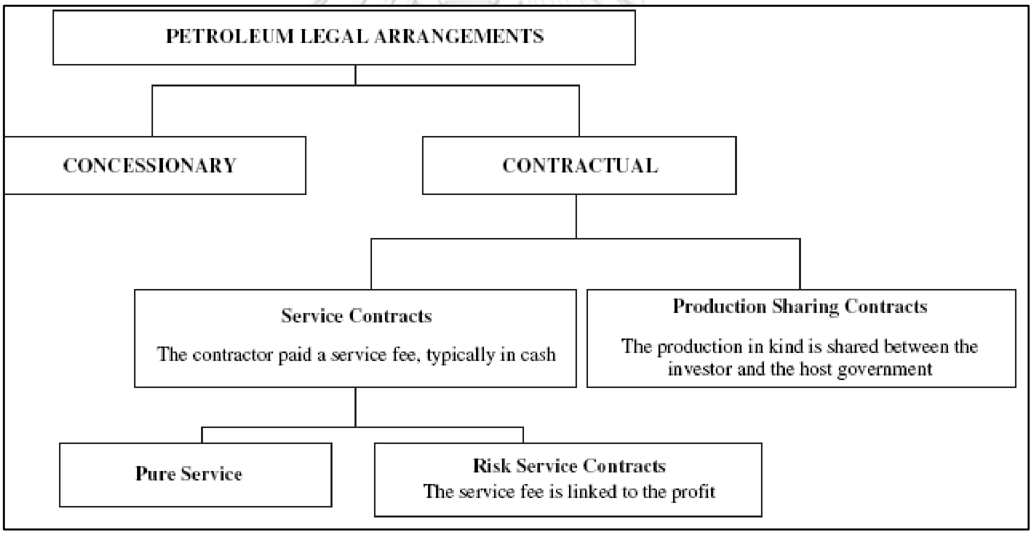

Figure 2.1.1 Fiscal Regime Classification by Johnston

2.2. Production Sharing Contract – Cost Recovery

Indonesia had created and introduced Production Sharing Contract or Production Sharing Agreement (PSC/PSA) at around 1966 (Ravagnani et al., 2012). This new contractual fiscal system had at least improved three times to fine tuning and improving to create a better regulation that can fit to various Indonesia Oil and Gas field condition. These are the three generations PSC in Indonesia (Lubiantara, 2012):

a. First Generation of PSC (years 1966 – 1975)

The principal regulations under First generation of PSC are:

i. Oil and Gas companies are stated as Contractor to Pertamina (Indonesia Oil & Gas company).
ii. All contractors managerial are hold by Pertamina.
iii. Cost recoveries are capped at 40% on each year.
iv. After deducting Gross revenue with Cost recovery on each year, this value will be divided 65% : 35% between Pertamina and Contractor consecutively. Pertamina share (also as representative of Government) will be increased to 67.5% for certain Oil rate production (depends on the contractual agreement rate production), generally if the productions above 50,000 BOPD).
v. Contractors have a responsibility to sell 25% of their production to Indonesia domestic market (knows as Domestic Market Obligation / DMO) using price 0.2$/barrel.

These First-generation rules are seeming simple and will create a certain minimum 39% of Government share (based on Gross Revenue) in each year.

When oil crisis happens on 1973 – 1974 due to Middle East war that resulting a spiking price of Oil price, Government of Indonesia (GOI) decided to re-evaluate the PSC with the Oil Company contractor.

b. Second Generation of PSC (years 1976 – 1988)

Other than the oil crisis that happened during those years, there is another aspect which is drive the Indonesian government to initiate the re-evaluation of PSC. On first generation of PSC, the taxes aspects are not clearly explained on the contract. 65% of Government share as listed on contract is acknowledged included with the contractor taxes already. At that moment, Internal Revenue Service in United Stated of America was rejected those acknowledgment as Contractor tax deductible, hence USA Oil Company are subjected to double charges tax.

This PSC regulation alteration to Second Generation is addressed to fix the taxes problem in origin country of the contractor which is not considered the taxes that paid in Indonesian's PSC contract already. The regulations listed on first generation are modified so the International Contractor will not suffer due to double charges tax issue. On the second generation, Government of Indonesia also adding concern with the Natural Gas production field which began to acknowledge as a valuable natural resource.

Amendment that listed on Second generation of PSC are:

i. Cost recovery will not be capped and must base to Generally Accepted Accounting Principle (GAAP)
ii. Remaining production amount between Gross revenue minus Cost recovery will be divided between Pertamina and Contractor as 65.91% : 34.09% for Oil and 31.82% : 68.18% for Gas (profit before tax).
iii. Contractor Share will be deducted by tax rates as much as 56% (consist of 45% of income tax and 20% of dividend tax). The final share between Government and Contractor will be as 85% : 15% for Oil and 70% : 30% for Gas (percentage after deducted by tax).
iv. Meanwhile, Indonesia had announced a new tax constitution in 1984. This tax regulation has lowered the tax rates from 56% to 48%, and to maintain the same final share percentage, then profit before tax are revised to 71.15% : 28.85% for Oil and 42.31% : 57.69% for Gas
v. For new field development, Contractor will received Investment Credit 20% from the Capital Investment for Producing Facilities.

Capital expenditure are depreciable within 5 years using Double Declining Balance (DDB)

The main aspect which attract more concern from International Contractor are the uncapped yearly cost recovery and the changing of profit sharing percentage from 65% : 35% to 85% : 15% for Contractor and Government of Indonesia, respectively.

In 1980s, world economic recession created less demand to the crude oil. Oil market was changing from "seller market" to become "buyer market" and shown by the sharp declining of oil price. To respond that, Oil company were slowing down and minimize the exploration activity to reduce cost, while the operating cost is normally increased due to inflation. These situations were getting worse and reach its worst condition when oil price was below 10$/barrel in 1986.

During those hard time, Government of Indonesia and Contractor were trying to figure out problems that faced, for instance:

i. New field commercial criteria that explained by Indonesian Government which stated that Government share must not less than 49% from Gross revenue (after included with contractor taxes). Those statement was creating issues for development of marginal field.

ii. High drop in oil price is creating problem to Indonesian Government due to a high portion of Government revenue is came from Oil and Gas business. Concerning to a low oil producing field, there will be a lower volumetric oil lifting that shared between Government and contractor. Conjunction with uncapped Cost recovery, there will be a chance that no more Oil production that can be shared. Which unlikely did not get along with the goal of Production sharing itself.

iii. Many PSC contracts will end in the next 10 years, existing international and local oil contractor are proposing a contract extension for another 20 years, to assure the return of investment and profit for their exploration and secondary recovery activity.

Those issues were considered by the government to revise the second generation PSC and announced the third generation.

c. Third Generation of PSC (years 1988 – until now)

As mentioned above, main issue for Indonesian government on the second-generation PSC is no certainty in each year will get production revenue due to uncapped cost recovery / no cost recovery ceiling. At low oil price condition, a big volume of oil production is needed to recover the operating and capital cost, because oil price and oil production are the parameters to resulting revenue which to paid the cost. At lower oil price condition, the higher demand volume of oil lifting is required. At worst condition, which certain low market oil price, all the hydrocarbon lifting can be only to recover the cost and causing no profit condition.

Indonesian Government needs adding a new feature in PSC to assure the government revenue each year. Then, First Tranche Petroleum (FTP) terms are introduced in third generation PSC. FTP calculated 20% from the gross revenue that shared between Government and Contractor. FTP is deducted at the beginning from the gross revenue (even before subtracted by cost recovery).

	1st Generation PSC (1965 - 1976)	2nd Generation PSC (1976 - 1988)	3rd Generation PSC (since 1988)
FTP	None	None	20%
Cost Recovery Ceiling	40%	100% (uncapped)	80% (due to FTP)
Investment Credit	None	20%	17% ~ 20%
DMO	DMO was defined as 25% of equity oil at 0.2$/barel	20% of equity oil, full price for the first 60 months and 0.2$/barel month after	25% of equity oil, full price for the first 60 months and 10% of export price month after
Equity to be Split Government : Contractor Oil Gas	 65% : 35% N/A	 85% : 15% 70% : 30% or 65% : 35%	 85% : 15% 70% : 30% or 65% : 35%

Table 2.2.1 Comparations Generation of Indonesian PSC

The diagram to explain Indonesian PSC – Cost Recovery scheme are shown below:

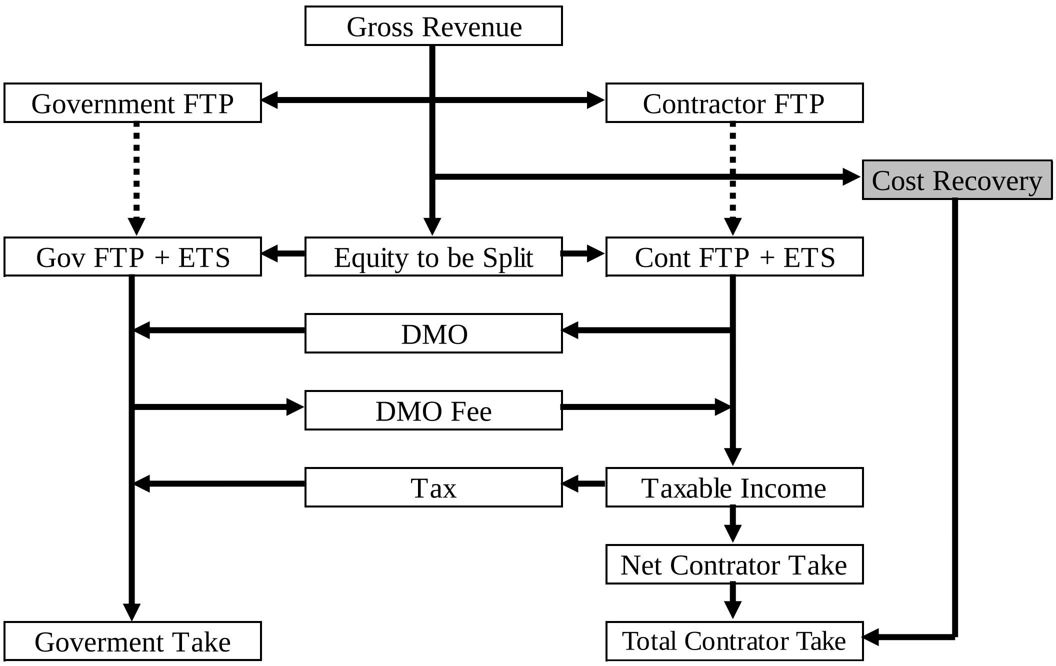

Figure 2.2.1 Indonesian PSC Cost Recovery Diagram

2.3. Production Sharing Contract – Gross Split

The main concept of contractual upstream oil and gas business under PSC – GS scheme is built upon gross production level of hydrocarbon and omits the operating cost reimburse mechanism. Indonesian Ministry of Energy and Mineral Resource (MEMR or ESDM) introduced PSC GS fiscal regime on 16 January 2017 and declared as replacement scheme to the PSC CR. Gross split fiscal is introduced in Ministerial Regulation (MR) Number 8-year 2017 (ESDM, 2017a). Later, that regulation is amended three times, which are the first amendment by MR Number 52 - year 2017 (ESDM, 2017b) on 29 August 2017 and second amendment by MR Number 20 year 2019 on 18 October 2019 (ESDM, 2019) to add or revised several clauses that missed in prior and intended to increase the attractiveness to the contractor by adding more contractor split. Meanwhile the third amendment by MR Number 12 – year 2020 is adding clauses about option for IOC to choose the desirable fiscal regime (PSC CR or PSCR GS) which is previously pre-determined by MEMR already.

MR number 8 - 2017 article 1 (which still valid and not amended), point out the PSC – Gross Split as one of production sharing contract in upstream oil and gas business that based on gross production of hydrocarbon which will be shared (split) between Government and Contractor and omits the operating cost recovery. By understanding that explanation, ESDM confirmed that PSC – Gross split was created using the same basic knowledge of PSC Cost Recovery. The main difference is that Gross split will settle the split in the gross level (available lifting volume of oil or gas production), meanwhile the Cost recovery system will calculate and pays all the operating cost first then the remaining profit will be shared afterward.

Stated in MR number 8 - 2017 article 2 (which still valid and not amended), ESDM explained the principal law and order of PSC Gross Split which the contractual system of upstream oil and gas business are cover minimum the following items:

d. All of natural resource (hydrocarbon) will still be owned by Indonesian government until to the point of delivery location.
e. SKK Migas will remain become the operational control institution as same as ongoing PSC Cost recovery.
f. Contractor will be borne all the capital and risk matters.

The diagram to explain Indonesian PSC Cost Recovery scheme are shown below:

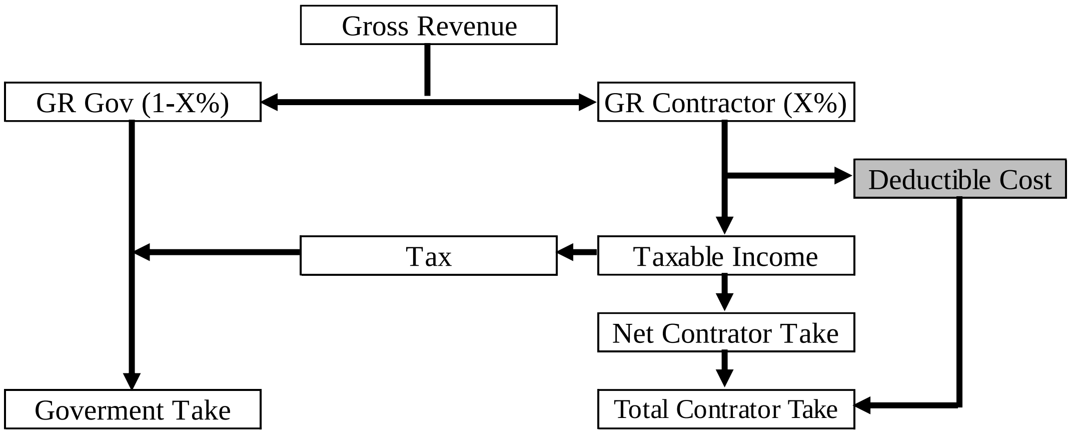

Figure 2.3.1. Indonesian PSC Gross Split Diagram

Details of the mechanism of gross production split are stated in MR number 8 - 2017 article 4 (which still valid and not amended in MR 52 – 2017 and MR 20 - 2019). Government categorized the type of split into three types, base split, variable split, and progressive split. All type of splits are calculated from gross revenue and before tax deduction (pretax), later common regulation of Indonesian tax will be calculated afterward to the Contractor split to deduct taxes. Each of split types are explained below:

a. Base Split

Base split is the initial shared value between Government and Contractor. The splits values are related with the hydrocarbon products which mean crude oil or natural gas production products from the same field will be calculated differently. Condensate product is categorized as Oil product. Meanwhile LNG and LPG are categorized as Gas product.

Hydrocarbon Type	Government	Contractor
Oil	57%	43%
Gas	52%	48%

Table 2.3.1. PSC Gross Split – Base Split

b. Variable split

Variable split is additional split to the Contractor base split and in other way will subtract to the Government split. In MR number 8 – 2017 explained there are 10 parameters of Variable split which all related to the specific hydrocarbon working area technical condition. Then, in MR number 52 – 2017, some parameters get revised which mean to increase attractiveness to the Oil Company. Variable split is determined fixed at the beginning of contract and remains constant until the end of contract.

The detail of Variable split showed in the table below:

No.	Parameter	Status	Contractor additional split	
			MR number 8-2017	MR number 20-2019
1	Block Status	POD 1 (Plan Of Development 1)	5.0%	5.0%
		POD 2 and next	0.0%	3.0%
		No POD	-5.0%	0.0%
2	Field Location	Onshore	0.0%	0.0%
		Offshore (0<h<=20m)	8.0%	8.0%
		Offshore (20<h<=50m)	10.0%	10.0%
		Offshore (50<h<=150m)	12.0%	12.0%
		Offshore (150<h<=1000m)	14.0%	14.0%
		Offshore (h>1000m)	16.0%	16.0%
3	Reservoir Depth	> 2500 m	1.0%	1.0%
		≤ 2500 m	0.0%	0.0%
4	Infrastructure	Well Developed	0.0%	0.0%
		New Frontier Offshore	2.0%	2.0%
		New Frontier Onshore	2.0%	4.0%
5	Reservoir Condition	Conventional	0.0%	0.0%
		Non Conventional	16.0%	16.0%
6	CO2 Content	X < 5%	0.0%	0.0%
		5% ≤ X < 10%	0.5%	0.5%
		10% ≤ X < 20%	1.0%	1.0%
		20% ≤ X < 40%	1.5%	1.5%
		40% ≤ X < 60%	2.0%	2.0%
		X >60%	4.0%	4.0%
7	H2S Content (ppm)	X < 100	0.0%	0.0%
		100 ≤ X < 1000	0.5 - 1 %	1.0%
		1000 ≤ X < 2000	N/A	2.0%
		2000 ≤ X < 3000	N/A	3.0%
		3000 ≤ X < 4000	N/A	4.0%
		X ≥ 4000	N/A	5.0%
8	Oil Specific Gravity (API)	X < 25	1.0%	1.0%
		X ≥ 25	0.0%	0.0%
9	Local Content	X < 30%	0.0%	0.0%
		30% ≤ X < 50%	2.0%	2.0%
		50% ≤ X < 70%	3.0%	3.0%
		70% ≤ X < 100%	4.0%	4.0%
10	Production Phase	Primary	0.0%	0.0%
		Secondary	3.0%	6.0%
		Tertiery	5.0%	10.0%

Table 2.3.2. PSC Gross Split – Variable Split

c. Progressive split

Meanwhile for Progressive split will add or subtract split from contractor related to oil price, gas price and cumulative production of the working area / field. As stated in MR 8 – 2017 article 9 (which strengthen in MR 52 – 2017 to add additional split for gas price), Progressive split will be calculated each month, helped by evaluation of SKK Migas.

No.	Parameter	Status	Contractor additional split	
			MR number 8-2017	MR number 20-2019
1	Indonesian Crude Price (ICP) (US$/Bbl)	X <40	7.5%	(85-ICP) x0.25%
		40 ≤ X < 55	5.0%	
		55 ≤ X < 70	2.5%	
		70 ≤ X < 85	0.0%	
		85 ≤ X < 100	-2.5%	
		100 ≤ X <115	-5.0%	
		X ≥ 115	-7.5%	
2	Gas Price (US$/MMBTU)	X <7	N/A	(7-Gas price)x2.5%
		7 ≤ X < 10		0.0%
		X ≥ 10		(10-Gas price)x2.5%
3	Cumulative Production of Oil and Gas aggregate (MMBOE)	X <30	3.0% - 5.0%	10.0%
		30 ≤ X < 60	1.0% - 2.0%	9.0%
		60 ≤ X < 90	1.0%	8.0%
		90 ≤ X < 125	1.0%	6.0%
		125 ≤ X < 175	0.0% - 1.0%	4.0%
		X ≥ 175	0.0%	0.0%

Table 2.3.3. PSC Gross Split – Progressive Split

2.4. Government Share different characteristics

For measuring the amount of money that received by the government from the revenue of Oil and Gas business activity are known as Government Share. Government Share are explained as all the income money that received from the first time of Oil or Gas field contract signed until the end of the contract life span. In other terms, Government Share can be described as percentage to the total profit, which known as Government Take or GT. Generally, hydrocarbon exporting country generates a fiscal regime and regulation which result a higher Government Share due to a better geological prospect. Meanwhile for countries whose have less proven hydrocarbon reserve and higher risk of geological aspect, will generate a smaller amount of Government Share. In conclusion, a higher risk of oil and gas project in a country will generate a smaller amount of Government Share, vice versa.

Some of government incomes are independent with the project profit, in example: bonus payment and royalty. Royalty will be paid to government at the beginning of production phase, does not matter whether the project has generated a profit to the company or not. In the other hand, another government income, such as profit share, can be generated after some of the investment cost has recovered. Meanwhile, for the tax's payment (income tax and another additional taxes), can be done after all the investment cost has been returned, or in other words after the project profit has been obtained.

Timing of the share payment to the government can be different on each fiscal system, depending on the regulation and contractual that have signed. Those aspect will matter to the economical aspect of the project, especially to the Oil company. Explained with the Figure 2.4.1 below.

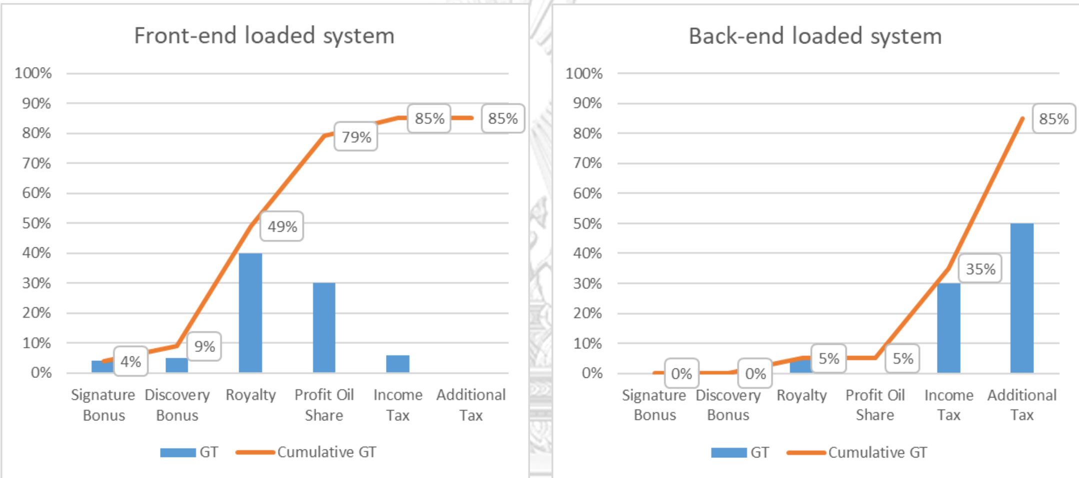

Figure 2.4.1. Front-end loaded system & Back-end loaded system

Figure 2.4.1 illustrated to us two different contrast system. The left graph assumed that a big portion of the government share payments are came from portion which is not related with the profit, such as signature bonus, discovery bonus, and royalty. For the right graph, the opposite condition is shown. The government portion are paid after profit received, which translated to taxes levies. The left system is known as "front-end loaded" and the right system is known as "back-end loaded".

Figure 2.4.1 also shown us as theory that Oil and Gas contractual system can generate same amount of GT (85% cumulative in that example) but with different detail breakdown source. But that graphic cannot represent the value of cash flow respect with time. Oil company as a contractor will prefer to back-end loaded system, in contrary Government will prefer to apply front-end loaded system to their country as the share can be received certainly without wait until the profit emerge. Front-end loaded system mostly applied in country with higher possibility of hydrocarbon can be found. Hence, GT cannot be the only parameter to assess government regulation whether the fiscal system is better enough to attract investor or attractive enough to catch investor eyesight whose looking on the international point of view.

2.5. Performance Financial Parameters

There are several economic criteria to determine whether the project is profitable or not. Same also with Oil and Gas project, as an upstream Oil and Gas business type, economic criteria need to be calculated and take a concern from the International Oil Company (IOC) before they start to sign contract with Government. From IOC point of view, they have to specifically analyze each of the block from countries around the world, with different level of geological risk, different level of investment cost and also different type of fiscal regime. At the end, IOC will be sorting all the projects and rank from most attractive to the less attractive. The most common and important economic indicators used by company to evaluate projects are Net Present Value (NPV) and Internal Rate of Return (IRR) (Gaspar Ravagnani, Costa Lima, Barreto, Munerato, & Schiozer, 2012). Both economic indicators will be explained below:

a. Net Present Value (NPV)

   NPV has explained by (Brigham, Ehrhardt, Koh, & Ang, 2014) is the result of current value of the project cash inflow / revenue deducted with the current value of the outflow / cost in a certain period of time frame. Meanwhile, (Johnston, 1994) describe NPV as a present value of net cash flow which can be calculated by present value of cash outflows deducted with present value of cash inflows, in period time step (daily, monthly and yearly). NPV is translated also as possible cash profit value which will be received in future time but must be converted to present value first, so bigger NPV value will be resulting a better opportunity of those project will be. NPV can be one of the primary indicators to evaluate project economic value.

   Both descriptions above have the same understanding to calculate first the cash inflow and cash outflow from certain time frame ahead to present time. Timing will be the important aspect of receiving or expending money / cost, in example if someone spend 1000 Baht money today, it will be different if that person spent 1000 Baht 10 years ago. Same as if someone received 1000 Baht money today compared to 10 years ahead. To accommodate those condition, discounting factor was introduced. Those discount factor / discount rate have a function to discount a future cash / money to present value. For instance, if some projects have calculated a revenue of 1100 Baht next year, then if applied 10% discount rate in a year, then present value of the revenue will be 1000 Baht. 100 Bath of discount or 10 % discount is to compensate the risk and uncertainty of the cash revenue within 1-year time frame. The discount rate will also reflect the value of alternative scheme of investment, regardless of the utilization. If someone saves his money in bank will be resulting a different value of interest compared to if he stores his money at home which can losses opportunity to receive interest. NPV is also known as discounted cash flow.

NPV can be calculated using certain value of discount rate which determined at the beginning of project. The most common value of discount rate used in oil and gas project is 10% also in this research the discount rate the used is about same level due to several reasons (Mashari & Sumandra, 2019). Using 10%, if the NPV still result positive cash flow, then all the investment that have spent will be paid back and generate a profit in the end. While a negative NPV will be translated as an uneconomic project, which means the investment did not generate a sufficient income to paid back the same amount of outflow cost. In other case, a zero NPV can be explained as the same amount of revenue compare with cost. The formula to calculate NPV is expressed below:

NPV = Present Value of expected cash flows – Present value of invested cash

= Present value of net cash flow

and by put in discount rate factor to the calculation in each year, the formula become:

$$NPV = \frac{C_0}{(1+r)^0} + \frac{C_1}{(1+r)^1} + \frac{C_2}{(1+r)^2} + \frac{C_3}{(1+r)^3} + \dots$$

Where:

Ct = net cash flow in one period of time t

r = discount rate or discount factor

t = time frame (can be, commonly in yearly period)

and in short, formula can be expressed as:

$$NPV = \sum_{t=0}^{n} \frac{C_t}{(1+r)^t}$$

In common project business, investment is spent in the beginning of year (t=0) without cash flow, thus will create a negative net cash flow in the first year (t=0), so NPV can be mathematically written as below:

$$NPV = -C_0 + \sum_{t=1}^{n} \frac{C_t}{(1+r)^t}$$

b. Internal Rate of Return (IRR)

After understanding that NPV equals to zero means the project will not receive any profit neither burden any cash loss at certain discount rate value (in example using 10% discount rate), Contractor point of view will prefer to have NPV = 0 compared to negative NPV but of course positive NPV will be the best scenario. In other way, that project need a 10% discount rate to get zero NPV, or the value of IRR of this project is 10%. (Brigham et al., 2014) explains that IRR is estimated discount rate value to force NPV to be zero. IRR also described as annual growth rate of an investment is expected to generate. Business company will use IRR as the parameter to determine whether the project is profitable or not. Project will be possible to start when the IRR is greater than minimum rate of return in another business type (deposited to bank which generates interest). Formula to calculate IRR will be based on NPV formula but replaced the NPV value with 0.

$$\sum_{t=0}^{n} \frac{C_t}{(1+IRR)^t} = 0$$

If the contractor are going to run several businesses and each of project will generates certain cash flow, then each business will be calculated certain amount of IRR. When calculate aggregate IRR of businesses, it cannot be sum directly, each proposed business needs to sum the forecasted cash flow analysis and combine it.

2.6. Taxation aspect in Indonesian PSC

The amount of income tax in Indonesia has been decline, begins with 45% in 1985 and year before then becomes 25% in 2010 until now. The most current tax constitution that applied is Constitution No. 36/2008 which applies 28% of income tax begins in January 2009, then reduced to 25% in January 2010 and still actively approved until current time. On top of income tax, Contractors are subject to taxes on interest, dividends, and royalties, which calculated as 20% x (1- Income tax). The detail of total contractor tax is tabulated below:

	Before 1985	1985 - 1994	1994 - 2009	2009-2010	2010 - Now
Income Tax	45%	35%	30%	28%	25%
Interest, Dividends, and Royalties Tax	11%	13%	14%	14%	15%
Total Contractor Tax	56%	48%	44%	42%	40%

Table 2.6.1 Income Tax, Interest, Dividends, and Royalties Tax.

Total contractor tax is applied in both oil and gas field, and both PSC CR and PSC GS will apply the same amount of contractor tax. The contractor tax always strict to the value which year of Plan of Development (POD) are approved by the government. For instance, in current 3rd generation of PSC CR, the common share between government and contractor are respectively 85% : 15% for oil field is the result after calculated by contractor tax (after tax), so if we use the latest Constitution Tax regulation, then the share between government and contractor which stated in POD agreement document will be 75% : 25% respectively (before tax). Those share proportions are calculated from the Equity to be Split (ETS/ETBS) amount which has recovered the total operational cost before. If the shares between government and contractor are included the cost recovery portion, then in general government final share will earn 45% to 60% of the gross production.

Meanwhile in PSC GS, all type of splits that mentioned in minister regulation are pretax split (before tax). After deducted by operational cost, then the same contractor tax percentage can be calculated and resulting the net contractor take which is explained in Figure 2.3.1.

CHAPTER 3
CALCULATIONS & ANALYSIS

3.1. Methodology

Evaluation in this study is done by calculating both Fiscal regime type (PSC Cost Recovery and PSC Gross Split). The input parameters are taken from 30 fields data in Indonesia, ranging from small hydrocarbon reserve field to big hydrocarbon reserve field with different locations and subsurface characteristics (quantitative analysis). Input date are consisting of oil production yearly basis, gas production yearly basis, sunk cost, drilling cost, facilities cost, operational expenditure, abandonment & site restoration costs (ASR) and other related cost or expenses. Also, the working field data that used are diverse from Oil Field, Gas Field, and mixed Oil-Gas field based to hydrocarbon sales product. The status of Oil field and Gas field are not representing 100% sales hydrocarbon product, but the oil/gas production are major compared to the other. In PSC Gross Split scheme, each of hydrocarbon product will be calculated using related Base split, Variable split, and Progressive split.

Another method to analysis fiscal regime can be done by qualitative methods, such as interviewing with expertise in Indonesia petroleum economics which have been done briefly by another researcher (Rulandari, Rusli, Mirna, Nurmantu, & Setiawan, 2018) and (Mashari & Sumandra, 2019). This method is not applicable in this research due to the condition and location constraint.

Calculations are modeled in Microsoft Excel by taking the source from the Law of Indonesian Ministry of Energy and Mineral Resource (ESDM) number 08 Year 2017 (ESDM, 2017a) about PSC Gross Split Fiscal Regime which published in January 2017 and some aspects amended by MR 52 – 2017 and MR 20 – 2019. Therefore, formula inside the Excel model (economic engine) use the latest revised regulation (MR 20 – 2019) to match the current condition. Meanwhile for the PSC Cross recovery fiscal are modeled from well-known 3rd Indonesian PSC which strengthened in Ministerial Regulation Number 22 - Years 2001.

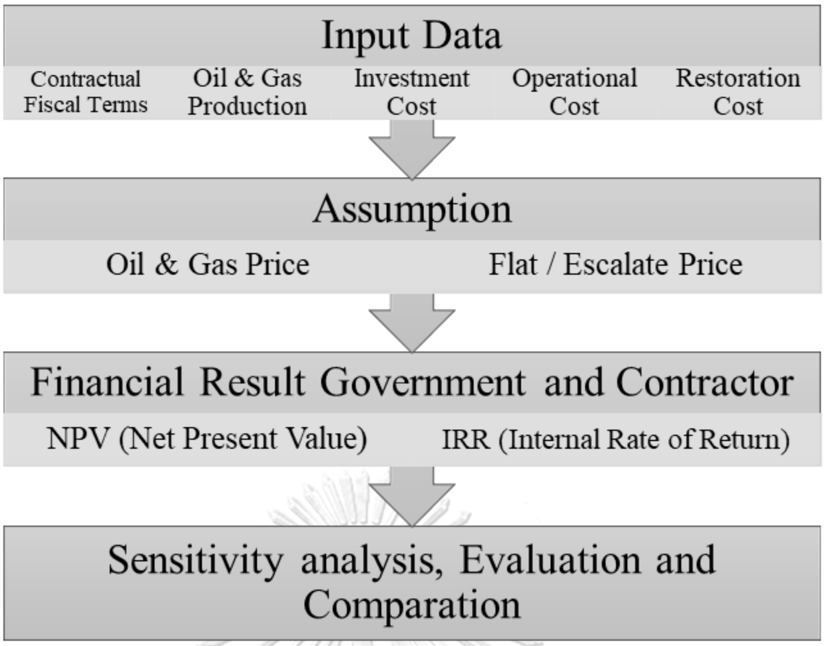

Figure 3.1.1 Framework in Evaluating the NPV / IRR of Contractors and Government by Using Cost Recovery PSC and Gross Split PSC.

3.2. Financial Calculation

Financial calculation can be done by inputting adequate data which related to the field development scenario. 30 fields data input are collected from historical and forecast Indonesian producing field from SKK Migas which masked the named as confidential aspect of each field. All input data for each Oil and Gas parameter are explained in Appendix A. Pointing out the Abandonment and Site Restoration (ASR) cost are expenses by IOC to ensure the re-vitalization asset or field after the development or production phase is ended. (Kurniawan & Jaenudin, 2017)

1. Depreciable Asset and Depreciation

   Depreciation is value reduction of asset (capital or tangible asset) due to the passage of time. Tangible asset cannot be charged 100% cost in the same year of investment, and depreciation is accounting process of allocating the cost of tangible asset to expense in systematic and rational manner to those periods expected to benefit from the use of asset, which is also translated as capital cost charge allocation on specific year future, allocation in yearly time frame usually used in financial calculations. There are some methods to calculate the depreciation of tangible asset, but in the PSC calculation model, contractor commonly used Double Declining Balance Method (DDB) with 25% depreciable rate in five years (Jaluakbar & Putra, 2017).

This mean, at the fifth year of investment, tangible asset cost has fully recovered. Table below shown the allocation factor for each year.

	DDB 5 yr, 25%
1st Year	25.00%
2nd Year	18.75%
3rd Year	14.06%
4th Year	10.55%
5th Year	31.64%

Table 3.2.1 Double Declining Balance of Depreciation

2. Domestic Market Obligation (DMO)

   DMO is an obligation for contractor to supply local (Indonesia) hydrocarbon need (especially oil product) by selling the hydrocarbon production in the certain amount of yearly volume with certain price regulated. DMO usually started at same time as the ETS have positive value. For new production field, which commencing 60 months from it commercial production, known as DMO Holiday (Abidin, 2015). Oil products will be sold to the local / domestic using discounted price (10% until 25% market price), and local / domestic will be paid as much as it (DMO Fee). Volume of DMO is regulated also, maximum 25% of total contractor hydrocarbon volume production each year. In the financial calculation, DMO means reduction in contractor revenue (DMO Net).

3. Government Take (GT)

   GT is all revenue that received by government. The most common GT value are around 40% to 85%, with world average around 64% (Gaspar Ravagnani et al., 2012).

In PSC GS, the split must be calculated in each year of production phase. Progressive split will have a different value in each year due to the changing of hydrocarbon price and production cumulative will keep increasing each year. The calculation parameters for PSC GS are explained also in Appendix A.

CHAPTER 4
RESULTS AND DISCUSSION

In this study, as the main objective is to simulate by calculate the financial parameter such as NPV, IRR, Government Take (GT) etc., the calculation model must be ensured to follow all the main Ministerial Regulation aspect (quantitative analysis). Also, the input data from 30 fields in Indonesia are double checked and filtered which can represent the whole various condition of Indonesian oil and gas field, which might be drastically different from West to East side of Indonesia country island.

4.1. Oil and Gas Field Data Analysis

30 fields data which are taken into financial model calculation are gathered from Indonesia active PSC contract. Majority of those fields are active field and facing the end of contract, so the contractors are intended to extend the field contract period further and asking the permission to the MEMR / ESDM. As the representative of Indonesian Government, SKK Migas are monitor and help contractor to calculate and compare using both PSC CR and PSC GS and giving the objective opinion about both fiscal regimes.

PSC GS has the uniqueness to determine the contractor gross share based on the technical criteria of the specific field which categorized in variable splits as mentioned in Table 2.2.2. Thirty fields technical criteria to determine the additional variable splits are shown at Table 4.1.1. Number or name at header the table is corresponding to the same order as ten technical aspects in Table 2.2.2 and the small box under is corresponding to each sub criteria of the technical aspect. In Table 4.1.1 each of technical aspect of corresponding field can be seen in detail and as the result of cumulative variable split are shown at the rightest column. Cumulative variable split for 30 fields is ranging from the smallest at only 2% for Field 09 until at 23% for Field 14. Bigger additional variable split is usually coming from location of the field that located in offshore and due to secondary recovery field status (waterflood field). This statement also giving a message to the international oil company that Indonesia is pursuing to explore and exploit more in the offshore and deeper area which 2/3 of Indonesia country are sea, also to encourage to do more secondary or tertiary recovery method such as waterflood, EOR etc. (Irham, Sibuea, & Danu, 2018)

Another big contribution to the cumulative additional split is coming from non-conventional field status such as shale oil, shale gas reservoir, coal bed methane (CBM) or methane hydrate but until this research is taking place, not a single field is economically operating in Indonesia

No	Mask Name	POD 1	POD 2 &	No POD	Onshore	Offshore	Offshore	Offshore	Offshore	Offshore	> 2500 m	≤ 2500 m	Well	New	New	Conventio	Non	X < 5%	5% ≤ X <	10% ≤ X <	20% ≤ X <	40% ≤ X <	X >60%	X < 100	100 ≤ X <	1000 ≤ X <	2000 ≤ X <	3000 ≤ X <	X ≥ 4000	X < 25	X ≥ 25	X < 30%	30% ≤ X <	50% ≤ X <	70% ≤ X <	Primary	Secondary	Tertiery	Sum Additional Split
1	Field 09			1	1							1	1			1		1						1							1		1			1			2.0%
2	Field 26			1	1							1	1			1		1						1							1			1		1			3.0%
3	Field 11			1	1							1	1			1		1							1						1		1			1			3.0%
4	Field 12			1	1							1	1			1			1					1							1			1		1			3.5%
5	Field 15			1	1							1	1			1		1						1							1				1	1			4.0%
6	Field 07			1	1							1	1			1		1						1							1				1	1			4.0%
7	Field 20			1	1							1	1			1					1				1						1		1			1			4.5%
8	Field 17			1	1							1	1			1		1						1						1					1	1			5.0%
9	Field 29			1	1						1		1			1		1						1							1				1	1			5.0%
10	Field 10		1		1							1	1			1		1						1							1		1			1			5.0%
11	Field 02			1	1							1	1			1					1				1						1			1		1			5.5%
12	Field 27			1	1						1		1			1			1					1							1				1	1			5.5%
13	Field 21			1	1							1	1			1		1						1							1				1		1		10.0%
14	Field 25			1	1							1	1			1		1							1						1			1			1		10.0%
15	Field 30			1	1							1	1			1			1										1	1					1	1			10.5%
16	Field 01		1		1							1	1			1		1						1							1		1				1		11.0%
17	Field 06	1			1							1		1		1		1						1							1		1			1			11.0%
18	Field 05	1			1							1		1		1		1						1							1		1			1			11.0%
19	Field 04		1		1							1	1			1					1								1		1		1			1			11.5%
20	Field 24		1		1							1	1			1		1						1						1			1				1		12.0%
21	Field 13		1		1							1	1			1		1						1							1			1			1		12.0%
22	Field 03		1		1							1	1			1		1						1						1				1			1		13.0%
23	Field 08			1			1				1		1			1				1				1						1				1		1			16.0%
24	Field 18		1		1							1		1		1		1						1							1			1			1		16.0%
25	Field 16	1				1						1			1	1		1						1							1		1			1			17.0%
26	Field 22		1		1							1	1			1					1			1							1				1			1	18.5%
27	Field 28	1					1				1				1	1		1						1							1		1			1			20.0%
28	Field 19	1					1					1		1		1		1						1							1		1			1			21.0%
29	Field 23	1						1				1			1	1		1						1						1			1			1			22.0%
30	Field 14	1							1			1			1	1		1						1							1		1			1			23.0%

Table 4.1.1. Contractor Additional Variable Split

Field data are ranging widely in terms of field reserves (Abidin, 2015). These reserves are translated to how much volume can be produced and later can be sold to become revenue. Both oil and gas reserves can be commercialized and will be produced until reach the economical rate (economical cut off) of each field assumption and can be different production rate across the fields sample. Cumulative production, as represent of the field reserve, are shown in Table 4.1.2, ranging from the smallest lifting of oil is Field 08 with 342 MSTB until the biggest lifting of oil is Field 06 with 500,000 MSTB. From the data sample, 500,000 MSTB lifting is the biggest number, it is quite different with the second biggest number which is only 67,000 MSTB. This condition may represent the Indonesian oil reserve condition which needs to be more exploration activity to find new oil reserve.

On the other side, for the gas lifting volume, Field 09 has the smallest with 1,622 MMSCF (around 2 BSCF) and the biggest gas lifting field is Field 04 with 1,245,960 MMSCF (around 1,246 BSCF). There are 4 fields with no oil lifting and 12 fields with no gas lifting. Fields with no gas lifting product usually still produce solution gas from the reservoir, but the company decided to use it as facility engine fuel rather than sell it to the market due to insufficient minimum buyer volume or inconsistent continuity of the gas production itself. This action is permitted by the government and the used gas is calculated as reduction to the operational expenditure (OPEX).

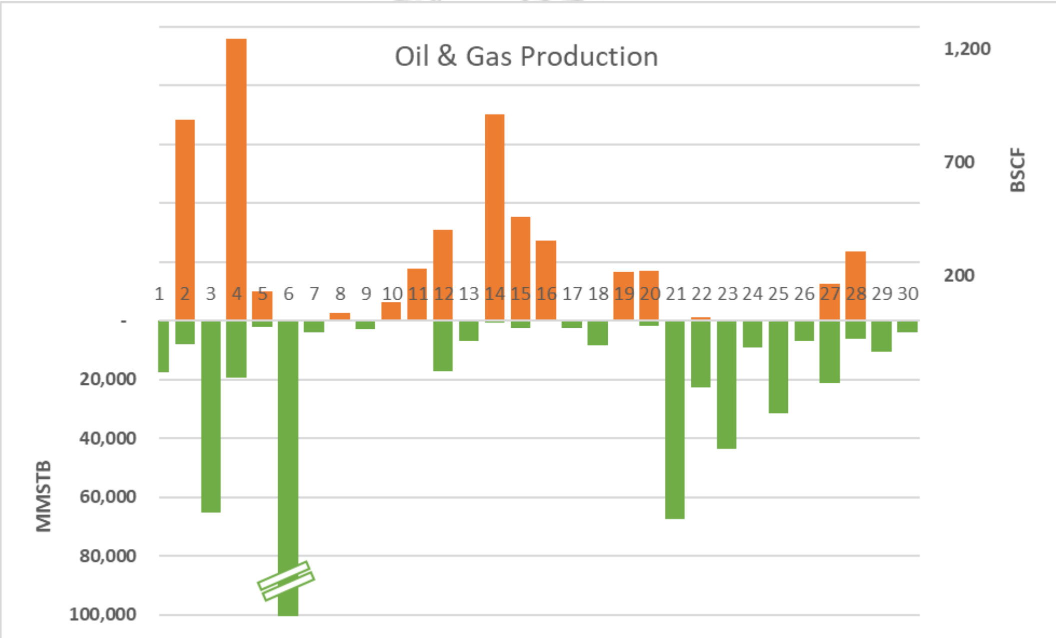

Figure 4.1.1 Oil and Gas lifting volume of 30 fields sample

No	Mask Name	Lifting Oil (MSTB)	Lifting Gas (BSCF)	Gross Revenue Oil (Dollar)	Gross Revenue Gas (Dollar)	Gross Revenue Total (Million Dollar)
1	Field 17	2,447	-	$ 162,149,147	$ -	$ 162
2	Field 09	2,736	2	$ 175,152,404	$ 9,274,603	$ 185
3	Field 30	3,827	-	$ 215,072,304	$ -	$ 215
4	Field 08	342	33	$ 20,536,084	$ 214,238,947	$ 235
5	Field 07	3,755	-	$ 244,104,423	$ -	$ 244
6	Field 10	-	82	$ -	$ 326,594	$ 327
7	Field 05	2,002	130	$ 92,076,360	$ 402,844,628	$ 495
8	Field 13	6,941	-	$ 527,494,851	$ -	$ 527
9	Field 18	8,456	-	$ 549,636,026	$ -	$ 550
10	Field 26	6,862	5	$ 576,395,289	$ 13,731,079	$ 590
11	Field 24	9,111	-	$ 604,765,433	$ -	$ 605
12	Field 29	10,660	-	$ 699,059,270	$ -	$ 699
13	Field 11	-	228	$ -	$ 1,007,733	$ 1,008
14	Field 19	-	214	$ -	$ 1,181,376	$ 1,181
15	Field 20	1,674	219	$ 100,460,923	$ 1,292,409,853	$ 1,393
16	Field 01	17,533	-	$ 1,420,144,253	$ -	$ 1,420
17	Field 22	22,608	17	$ 1,612,941,186	$ 34,756,276	$ 1,648
18	Field 03	65,101	-	$ 1,953,022,177	$ -	$ 1,953
19	Field 28	6,233	305	$ 373,985,780	$ 1,650,304,969	$ 2,024
20	Field 25	31,548	-	$ 2,050,608,868	$ -	$ 2,051
21	Field 27	21,128	162	$ 1,385,567,285	$ 706,623,224	$ 2,092
22	Field 16	-	355	$ -	$ 2,333,230,281	$ 2,333
23	Field 23	43,503	-	$ 2,610,174,000	$ -	$ 2,610
24	Field 15	2,459	459	$ 172,149,326	$ 2,861,652,272	$ 3,034
25	Field 12	17,136	402	$ 1,139,433,445	$ 3,689,059,628	$ 4,828
26	Field 21	67,538	-	$ 5,183,630,698	$ -	$ 5,184
27	Field 02	7,985	887	$ 584,962,729	$ 6,092,160,885	$ 6,677
28	Field 14	738	913	$ 51,668,330	$ 8,456,238,111	$ 8,508
29	Field 04	19,213	1,246	$ 1,498,065,888	$ 14,694,253,619	$ 16,192
30	Field 06	500,000	-	$ 29,148,713,475	$ -	$ 29,149

Table 4.1.2. Oil and Gas lifting volume, gross revenue of 30 fields sample

Meanwhile, for the gross revenue distribution data, the value is ranging from $162,149,147 (one hundred and sixty million dollar) which came from Field 17 until the biggest one $29,148,713,475 (twenty nine billion dollar) which came from Field 06 as the result of biggest oil lifting volume. As can be seen in Figure 4.1.2, the majority field sample revenue data has value less than ten million dollars, which might be categorized as small to medium revenue income. These small to medium revenues are dominating upstream oil and gas industry and still contribute to economic growth of local area across Indonesian archipelago.

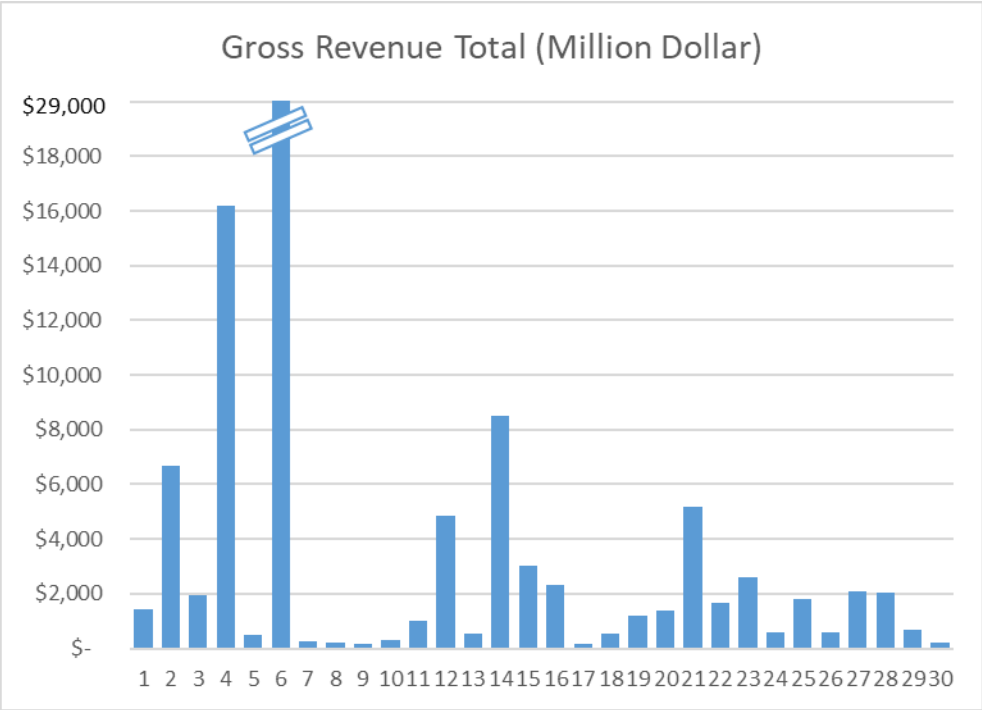

Figure 4.1.2 Gross Revenue Total of 30 Fields Sample

From the investment and cost perspective of 30 fields, it can be also ranked based on the value of it. Even though Field 2 has the smallest value of investment at seventy one million dollars but if the investment cost is compared with the revenue, then it can be seen that Field 01 has the lowest ratio of investment cost at 13% with one hundred and eighty million dollars investment. Even for the Field 30 which has as lower investment cost at one hundred and fifty million dollars, it became the highest ratio number at 72%. This small ratio number can be first sign that the project will generate an easier profit compared to higher percentage of investment cost. High cost to revenue ratio can be also sign for marginal field and need a further analysis about the technical development program. Using cost over revenue ratio, 30 samples can be categorized as the range of the distribution data which is shown also in Table 4.1.3. with summaries 1 data in 10% - 20%, 4 data in 20% - 30%, 6 data in 30% - 40%, 10 data in 40% - 50%, 4 data in 50% - 60%, 4 data in 60% - 70%, and 1 data in 70% - 80% ratio.

No	Mask Name	Gross Revenue Total (Million Dollar)	Deductible Cost / Cost Recoverable (Million Dollar)	Cost/Revenue Ratio	Range
1	Field 01	$ 1,420	$ 189	13%	10% - 20%
2	Field 02	$ 6,677	$ 1,425	21%	20% - 30%
3	Field 03	$ 1,953	$ 477	24%	20% - 30%
4	Field 04	$ 16,192	$ 4,207	26%	20% - 30%
5	Field 05	$ 495	$ 139	28%	20% - 30%
6	Field 06	$ 29,149	$ 8,627	30%	30% - 40%
7	Field 07	$ 244	$ 80	33%	30% - 40%
8	Field 08	$ 235	$ 81	34%	30% - 40%
9	Field 09	$ 185	$ 64	35%	30% - 40%
10	Field 10	$ 327	$ 115	35%	30% - 40%
11	Field 11	$ 1,008	$ 376	37%	30% - 40%
12	Field 12	$ 4,828	$ 1,944	40%	40% - 50%
13	Field 13	$ 527	$ 214	40%	40% - 50%
14	Field 14	$ 8,508	$ 3,509	41%	40% - 50%
15	Field 15	$ 3,034	$ 1,270	42%	40% - 50%
16	Field 16	$ 2,333	$ 1,004	43%	40% - 50%
17	Field 17	$ 162	$ 71	44%	40% - 50%
18	Field 18	$ 550	$ 246	45%	40% - 50%
19	Field 19	$ 1,181	$ 537	45%	40% - 50%
20	Field 20	$ 1,393	$ 636	46%	40% - 50%
21	Field 21	$ 5,184	$ 2,471	48%	40% - 50%
22	Field 22	$ 1,648	$ 872	53%	50% - 60%
23	Field 23	$ 2,610	$ 1,521	58%	50% - 60%
24	Field 24	$ 605	$ 352	58%	50% - 60%
25	Field 25	$ 1,803	$ 1,012	56%	50% - 60%
26	Field 26	$ 590	$ 372	63%	60% - 70%
27	Field 27	$ 2,092	$ 1,328	63%	60% - 70%
28	Field 28	$ 2,024	$ 1,322	65%	60% - 70%
29	Field 29	$ 699	$ 472	67%	60% - 70%
30	Field 30	$ 215	$ 154	72%	70% - 80%

Table 4.1.3. Gross Revenue, Cost Recoverable and Cost/Revenue Ratio of fields sample

After analyzing the input data from all companies, then PSC CR and PSC GS fiscal are modelled in excel and calculate on each year contractor net cash flow with the corresponding cash inflows and cash outflows based on historical and forecast event on the related company, then financial parameters results can be calculated as can be seen on Table 4.1.4. The results are calculated from Field 04 as the example input data. Meanwhile for Figure 4.1.3 and Figure 4.1.4 are explaining the simple calculation diagram of both regimes.

As shown at Table 4.1.4, some of financial parameters are different among regimes. For the input parameters, both regimes use the same parameters, but for the financial output will be resulting different detail parameter even though in the end there will be only contractor take (CT) and government take (GT) that will be concerned at most. In the PSC GS regime, the DMO policy is still applicable to the contractor financial, but different with the PSC CR that selling price only 25% of the market price, in the PSC GS the selling price will use 100% of the market price. This remission became sweetener for the contractor, especially the DMO will retained within the lifetime of the production field. The highlighted color in Table 4.1.4 is main parameter that will be analyzed next such as NPV, IRR, GT, and NCT.

		PSC Cost Recovery	PSC Gross Split
	Begin Year	2011	2011
Parameter	**Unit**	**Output Calculatio**	**Output Calculatio**
Lifting Oil	STB	19,213,100	19,213,100
Lifting Gas	MMSCF	1,245,960	1,245,960
Lifting LPG (Propane + Butane)	BBL	-	-
WAP - Oil/Condensate	US$/BBL	$ 78	$ 78
WAP - Gas Price	US$/MMBTU	$ 11	$ 11
WAP - LPG	US$/BBL	$ -	$ -
Gross Revenue	$	$ 16,192,319,507	$ 16,192,319,507
- Government FTP / Gross Revenue		$ 1,321,428,669	$ 6,406,661,518
- Contractor FTP / Gross Revenue		$ 1,917,035,232	$ 9,785,657,989
Sunk Cost	$	$ -	$ -
Total Investment	$	$ 2,098,000,000	$ 2,098,000,000
Tangible	$	$ 1,854,000,000	$ 1,854,000,000
Intangible	$	$ 244,000,000	$ 244,000,000
Operating Expenditure etc	$	$ 2,109,292,219	$ 2,109,292,219
- Operating Expenditure		$ 1,945,292,219	$ 1,945,292,219
- Asset Lease +ASR+LBT	$	$ 164,000,000	$ 164,000,000
Deductible Cost / Cost Recoverable	$	$ 4,207,292,219	$ 4,207,292,219
Unrecoverable Cost / Final Carry For	$	$ -	$ -
Contractor Profitability:			
Contr net Operating Profit	$	$ 3,941,448,794	$ 3,123,884,831
Contr net Cash Flow	$	$ 3,941,448,794	$ 3,123,884,831
NPV10 (fullcycle)	$	$ 281,561,187	$ 92,018,166
IRR (fullcycle)		13.8%	11.3%
(Net Cash Flow + Cost) to Gross Revenue		50%	45%
Net Cash Flow to Profit		33%	26%
PV Ratio		27.8%	9.1%
Goverment (Profitability) :		$ 8,043,578,493	$ 8,861,142,457
FTP / Gross Revenue	$	$ 1,321,428,669	$ 6,406,661,518
Equity Share		$ 3,566,050,901	
Net DMO	$	$ 59,246,299	$ -
Tax	$	$ 3,096,852,624	$ 2,454,480,939
GOI PV	$	$ 1,241,395,188	$ 1,430,938,209
Gov Share to Gross Revenue		50%	55%
Gov Share to Profit		67%	74%

Table 4.1.4 Detail financial parameter calculation resume for Field 04

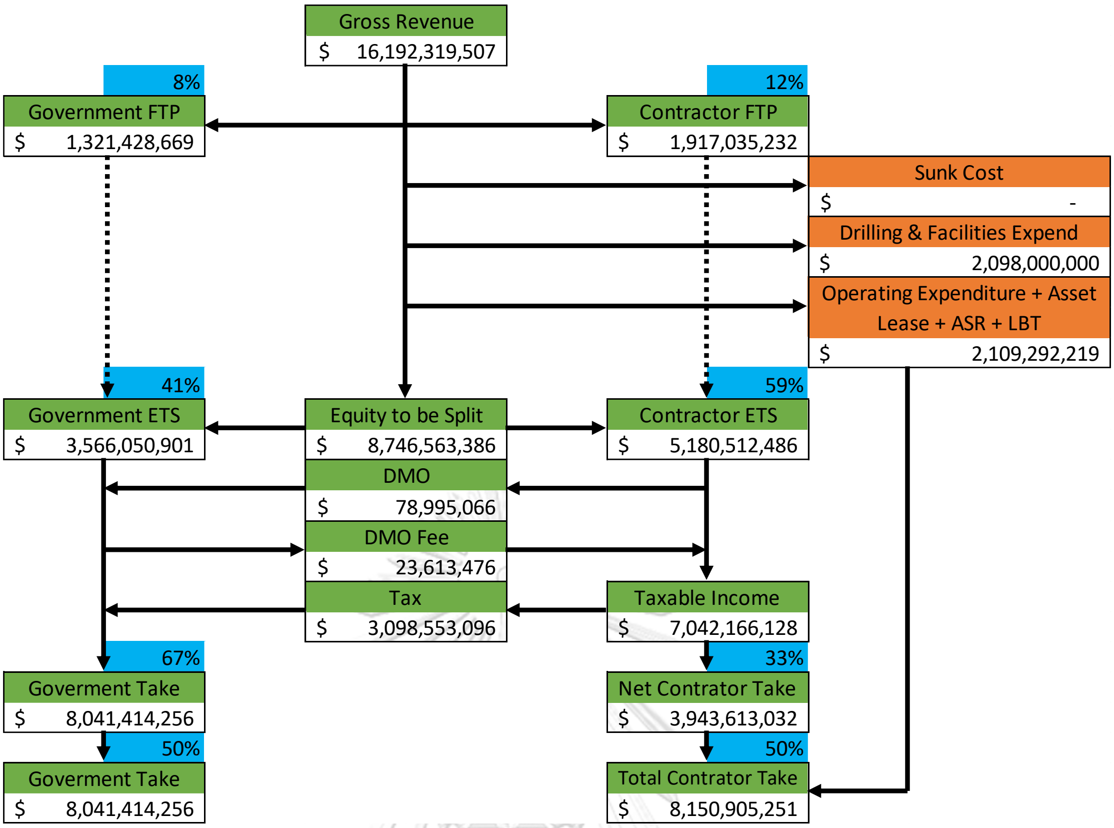

Figure 4.1.3 Flowchart diagram of PSC Cost Recovery calculation for Field 04

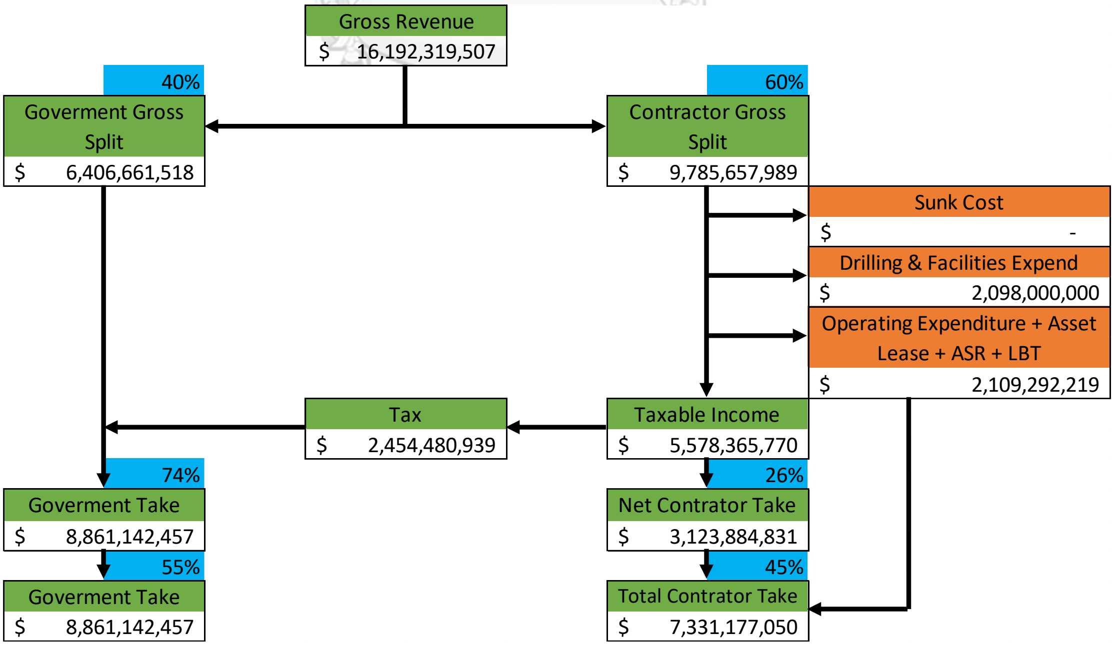

Figure 4.1.4 Flowchart diagram of PSC Gross Split calculation for Field 04

4.2. Net Present Value and Internal Rate of Return

Firstly, the Net Present Value (NPV) can be analyzed by comparing financial results between PSC CR and PSC GS. NPV result that shown in Table 4.2.1 are using discount rate value 10% with reasons (Mashari & Sumandra, 2019). Using PSC CR as the based value of NPV for the comparations, then from 30 fields samples that calculated, 20 fields gave a better NPV results if PSC CR are used as the fiscal contract.

N	Mask Name	Contractor NPV PSC CR	Contractor NPV PSC GS	Comparation	Variance ($)
1	Field 02	$ 1,227,671,207	$ 1,133,710,517	CR	$ -93,960,690
2	Field 04	$ 281,561,187	$ 92,018,166	CR	$ -189,543,021
3	Field 07	$ 45,234,984	$ 29,191,892	CR	$ -16,043,092
4	Field 08	$ 33,670,021	$ 27,308,821	CR	$ -6,361,200
5	Field 10	$ 20,532,718	$ 12,084,026	CR	$ -8,448,692
6	Field 11	$ 178,216,267	$ 135,873,274	CR	$ -42,342,994
7	Field 13	$ 69,046,725	$ 45,215,743	CR	$ -23,830,982
8	Field 14	$ 545,553,419	$ 414,114,259	CR	$ -131,439,160
9	Field 15	$ 67,462,884	$ (29,532,418)	CR	$ -96,995,302
10	Field 16	$ 77,761,358	$ 70,911,433	CR	$ -6,849,925
11	Field 17	$ 10,707,695	$ 9,433,655	CR	$ -1,274,040
12	Field 18	$ 38,219,936	$ 22,520,645	CR	$ -15,699,291
13	Field 20	$ 84,008,603	$ 20,856,318	CR	$ -63,152,285
14	Field 22	$ 118,137,257	$ 20,175,713	CR	$ -97,961,544
15	Field 24	$ 14,270,859	$ (22,809,530)	CR	$ -37,080,389
16	Field 26	$ 33,883,090	$ (18,698,898)	CR	$ -52,581,988
17	Field 27	$ 44,105,076	$ 6,916,634	CR	$ -37,188,442
18	Field 28	$ 159,627,333	$ 94,971,009	CR	$ -64,656,324
19	Field 29	$ 5,707,940	$ (19,237,942)	CR	$ -24,945,881
20	Field 30	$ 16,238,585	$ (5,228,495)	CR	$ -21,467,081
21	Field 01	$ 58,431,966	$ 225,272,601	GS	$ 166,840,636
22	Field 03	$ 95,364,678	$ 379,074,859	GS	$ 283,710,181
23	Field 05	$ 25,770,090	$ 34,327,475	GS	$ 8,557,385
24	Field 06	$ 571,801,512	$ 1,144,370,413	GS	$ 572,568,901
25	Field 09	$ 6,851,247	$ 16,553,521	GS	$ 9,702,274
26	Field 12	$ 303,627,592	$ 319,279,475	GS	$ 15,651,883
27	Field 19	$ 70,315,027	$ 77,994,645	GS	$ 7,679,618
28	Field 21	$ 170,309,858	$ 243,836,279	GS	$ 73,526,420
29	Field 23	$ 59,903,742	$ 148,110,658	GS	$ 88,206,917
30	Field 25	$ 27,961,639	$ 62,124,606	GS	$ 34,162,967

Table 4.2.1 Comparations of NPV from PSC CR and PSC GS

The higher NPV in PSC CR in 20 fields are ranging widely, depends on magnitude of the project revenue itself. Details of the comparison can be seen on Table 4.2.1. Higher NPV in PSC CR are ranging from $ 1,274,040 (Field 17) to $ 189,543,021 (Field 04), and if the variances calculated in percentage than the differences are ranging 8% to 437%. Moreover, in 5 fields (Field 15, Field 24, Field 26, Field 29, and Field 30), the financial result is showing a negative NPV if PSC GS is used. Negative NPV have a meaning that the project is not creating profit and cannot be executed or started, and thus became a great different in decision making of field development. Those 5 fields have a range of cost to revenue ratio 42% - 72%.

Meanwhile for the 10 fields (Field 01, Field 03, Field 05, Field 06, Field 09, Field 12, Field 19, Field 21, Field 23, Field 25) which are resulting a better PSC GS fiscal are mostly have a low-cost component compared to the revenue ratio, five fields (Field 01, Field 03, Field 05, Field 06, Field 09, Field 12) of which have cost to revenue ratio level under 35% (under 1/3 of the gross revenue) which highlighted in Table 4.1.3. The others five remaining fields, two of which have a high additional variable split portion, which 21% for Field 19 and 22% for Field 23. Additional variable split for both Field 19 and Field 23 are ranked as top 3 from 30 fields sample that calculated here which also highlighted in Table 4.1.1.

Additional aspect to support the NPV analysis is using the IRR value. IRR value cannot be analyzed if the condition of the net cash flow is following below circumstances,

a. When all cash flows are negative,
b. When all cash flows are positive,
c. Total undiscounted income is smaller than investment (for example, wells or marginal status fields are exhausted before reaching returns)
d. When the cumulative cash flow flows negatively more than once.

IRR result of both regimes for 30 fields are shown in Table 4.2.2. Some of the fields are resulting an error IRR value in both regimes due to all the net cash flow in every year are positive such as in Field 17, Field 02, Field 27, Field 08, Field 11, Field 07, Field 13, Field 21, Field 25, and Field 03. Meanwhile for Field 27, Field 26, Field 29, Field 12, and Field 09 the IRR values for PSC GS shown error result caused by has negative cumulative cash flow more than once. Therefore, for fields that mentioned above, the IRR value cannot be used for judging the financial status of the project and can be compared using NPV value.

No	Mask Name	Contractor NPV PSC CR	Contractor NPV PSC GS	Comparation	IRR - PSC CR	IRR - PSC GS
1	Field 02	$ 1,227,671,207	$ 1,133,710,517	CR	-	-
2	Field 04	$ 281,561,187	$ 92,018,166	CR	14%	11%
3	Field 07	$ 45,234,984	$ 29,191,892	CR	-	-
4	Field 08	$ 33,670,021	$ 27,308,821	CR	-	-
5	Field 10	$ 20,532,718	$ 12,084,026	CR	20%	16%
6	Field 11	$ 178,216,267	$ 135,873,274	CR	-	-
7	Field 13	$ 69,046,725	$ 45,215,743	CR	-	221%
8	Field 14	$ 545,553,419	$ 414,114,259	CR	20%	17%
9	Field 15	$ 67,462,884	$ (29,532,418)	CR	13%	9%
10	Field 16	$ 77,761,358	$ 70,911,433	CR	16%	15%
11	Field 17	$ 10,707,695	$ 9,433,655	CR	-	-
12	Field 18	$ 38,219,936	$ 22,520,645	CR	28%	19%
13	Field 20	$ 84,008,603	$ 20,856,318	CR	21%	13%
14	Field 22	$ 118,137,257	$ 20,175,713	CR	23%	12%
15	Field 24	$ 14,270,859	$ (22,809,530)	CR	14%	5%
16	Field 26	$ 33,883,090	$ (18,698,898)	CR	60%	-
17	Field 27	$ 44,105,076	$ 6,916,634	CR	-	-2%
18	Field 28	$ 159,627,333	$ 94,971,009	CR	20%	16%
19	Field 29	$ 5,707,940	$ (19,237,942)	CR	29%	-
20	Field 30	$ 16,238,585	$ (5,228,495)	CR	81%	-5%
21	Field 01	$ 58,431,966	$ 225,272,601	GS	102%	261%
22	Field 03	$ 95,364,678	$ 379,074,859	GS	-	-
23	Field 05	$ 25,770,090	$ 34,327,475	GS	21%	23%
24	Field 06	$ 571,801,512	$ 1,144,370,413	GS	22%	24%
25	Field 09	$ 6,851,247	$ 16,553,521	GS	-3%	-9%
26	Field 12	$ 303,627,592	$ 319,279,475	GS	-	-
27	Field 19	$ 70,315,027	$ 77,994,645	GS	17.9%	18.3%
28	Field 21	$ 170,309,858	$ 243,836,279	GS	-	-
29	Field 23	$ 59,903,742	$ 148,110,658	GS	23%	35%
30	Field 25	$ 66,994,412	$ 109,065,830	GS	-	-

Table 4.2.2 IRR value comparison

For the remaining fields, the IRR of both regimes can be analyzed by comparing it from the same field. First, analyzing the remaining 11 fields which is have a better NPV in PSC CR (Field 28, Field 20, Field 14, Field 04, Field 15, Field 30, Field 22, Field 16, Field 10, Field 24, Field 18), the IRR values of all those field have a same pattern which IRR of PSC CR is higher than IRR of PSC GS. Therefore, better NPV in PSC CR statement are strengthen with better IRR percentage in PSC CR. Besides that, in PSC GS in Field 15 and Field 24 have an IRR value less than 10%, which proven by negative value of NPV of it.

The remaining fields (Field 23, Field 01, Field 06, Field 05, and Field 19) which have a better NPV in PSC GS, also showing the same pattern in case of higher IRR value in PSC GS. In detail for Field 19, the IRR value is slightly difference, and this is also represented in NPV differences.

So, it can be concluded that both NPV and IRR parameters are showing a consistent result for analyzing fiscal regimes.

4.3. Sensitivity Analysis

Sensitivity Analysis is one of the methodologies to show the consistency of fiscal regimes if facing different scenario in the future. In this research, oil and gas prices are the item to be used as sensitivity analysis because historically oil and gas prices are commonly changing abruptly so it surely affects the performance of financial field status (Abidin, 2015). Moreover, Government of Indonesia took a concern more about fluctuation of hydrocarbon prices by creating a special additional or reductional contractor split that called progressive split which the formula is related with the hydrocarbon price. The detail sensitivity split for oil and gas price can be seen at Table 4.3.1

No.	Parameter	Status	Formula	Contractor Split
1	Indonesian Crude Price (ICP) (US$/Bbl)	X <40	(85-ICP) x0.25%	> 11%
		40 ≤ X < 55		8% - 11%
		55 ≤ X < 70		4% - 8%
		70 ≤ X < 85		0% - 4%
		85 ≤ X < 100		-4% - 0%
		100 ≤ X <115		-8% - 4%
		X ≥ 115		-8% <
2	Gas Price (US$/MMBTU)	X <7	(7-Gas price)x2.5%	0% - 15%
		7 ≤ X < 10	0.0%	0%
		X ≥ 10	(10-Gas price)x2.5%	-20% - 0%

Table 4.3.1 Maximum Range of Progressive Split

As stated in Table 4.3.1 progressive split for oil price is more agile compared to the gas price. The government of Indonesia might think that oil lifting is calculated using market price which might easily change following the market price trend. Also, oil lifting is easier to storage and delivered compared to gas lifting. Meanwhile for gas, the gas price usually agreed in the early of field development field contract with the gas buyer and might be changing but in slow tempo and more steadily. In this research, both sensitivity of oil and gas prices are covered with ranging from 80% to 120 % of original prices.

After knowing the sensitivity item that used as a main factor, then the financial indicator that used to comparing the sensitivity is net contractor take (NCT). In both regimes, PSC CR and PSC GR, after calculating financial model, in the end will have output of contractor take and government take. Both parameters are showing the real money that will be shared between government and contractor which considered as important commercial aspect for either side. In contractor terms, contractor take (CT) can be categorized as Total Contractor Take (TCT) and Net Contractor Take (NCT). The NCT is explained as profit that received by contractor after paid all the investment and operational cost. Meanwhile for the TCT is NCT plus all investment and operational cost. Why should be investment and operational cost are categorized as contractor benefit? Because in government point of view, all money or revenue that did not received by the government then it is categorized as contractor responsible. In this research, the financial model is calculating both TCT and NCT parameters, but to have clear image of sensitivity analysis then only NCT that will be compared, considering that the cost and investment are not changing. NCT can be also understood as net profit for the contractor. NCT and Government Take (GT) if summed up will become the total profit of the project itself, and by dividing the NCT to the total profit then the ratio of it will be the result to be analyzed. Finally, by doing sensitivity analysis, this research pursues to get the result of how much the changing in NCT compared to the changing of hydrocarbon price and resumed whether the fiscal regime is categorized as progressive or regressive fiscal. Table 4.3.2 showing the NCT ratio compared to the total profit of each field within price sensitivity mentioned at the table heading.

Contractor will be pleased if the NCT ratio as higher as possible, but in the other side, government will control the GT value high enough as become the source of government income source. GT value usually presented in percentage and can be calculated from the remaining amount of revenue after deducted by the cost and CT. GT can be calculated by divided with gross revenue or total profit, both values are valid. In this research, GT will be calculated by divided with the total profit because there is no sensitivity in investment cost, so it will be clearer to know the changing of GT in terms of fiscal progressivity

Table 4.3.3 shows the detail of GT ratio of both regimes and in different price scenarios, and the rightest column is the conclusion of which regime are better for the contractor. Higher percentage of GT will be also translated as a lower percentage of NCT which is unfavorable for contractor. In several fields, GT percentage that has higher than 100% means that NCT has a minus value and the project cannot be developed.

After comparing ratio, 20 fields are resulting a better NCT in PSC CR and the remaining 10 fields are resulting a better NCT ratio in PSC GS regime, in other words, GT in PSC CR for those 20 fields have a lower percentage compared with the GT in PSC GS as presented in Table 4.3.3. These results are getting along with the NPV comparations result and that statement is true. Majority of the data, the 20 fields that have a higher percentage in NCT (lower percentage in GT) is also have a better NPV in PSC CR, and vice versa for the remaining 10 fields. Except for Field 23 and Field 06 that the NCT has a slightly different ratio between both fiscal and creating a higher NCT ratio in PSC CR at lower price scenario and a higher NCT ratio in PSC GS for higher hydrocarbon price. In other words, for Field 16 and Field 12 have as higher GT value in PSC GS at lower price and lower GT percentage in PSC GS for higher price. The graphical explanation of all fields are presented in Figure 4.3.1 – Figure 4.3.3 to show better understanding of the changing of GT percentage. Explanation for the graphics, the blue line is representing GT percentage of PSC CR and orange line will represent GT percentage for PSC GS.

		Net Contractor Take - PSC CR					**Net Contractor Take - PSC GS**					
No	**Mask Name**	**80%**	**90%**	**100%**	**110%**	**120%**	**80%**	**90%**	**100%**	**110%**	**120%**	**Comparation**
1	Field 02	34%	34%	34%	34%	34%	31%	31%	30%	30%	31%	CR
2	Field 04	33%	33%	33%	33%	33%	26%	26%	26%	25%	24%	CR
3	Field 07	33%	35%	37%	38%	38%	15%	19%	21%	22%	22%	CR
4	Field 08	26%	27%	28%	28%	28%	19%	21%	21%	22%	24%	CR
5	Field 10	40%	40%	40%	40%	40%	29%	30%	31%	31%	31%	CR
6	Field 11	39%	40%	40%	40%	40%	24%	27%	28%	29%	30%	CR
7	Field 13	40%	40%	40%	40%	40%	25%	26%	27%	27%	27%	CR
8	Field 14	40%	40%	40%	40%	40%	30%	33%	35%	36%	36%	CR
9	Field 15	40%	40%	40%	40%	40%	25%	27%	28%	29%	29%	CR
10	Field 16	30%	30%	30%	30%	30%	27%	29%	30%	31%	31%	CR
11	Field 17	18%	21%	22%	23%	24%	10%	15%	18%	19%	20%	CR
12	Field 18	40%	40%	40%	40%	40%	29%	31%	31%	32%	32%	CR
13	Field 20	35%	36%	36%	37%	37%	15%	19%	21%	22%	24%	CR
14	Field 22	40%	40%	40%	40%	40%	22%	26%	28%	29%	29%	CR
15	Field 24	40%	40%	40%	40%	40%	-1%	11%	16%	18%	20%	CR
16	Field 26	30%	36%	38%	39%	40%	-97%	-43%	-21%	-9%	-4%	CR
17	Field 27	8%	13%	15%	16%	17%	-56%	-17%	1%	7%	10%	CR
18	Field 28	34%	39%	38%	38%	39%	-18%	16%	23%	26%	27%	CR
19	Field 29	-12%	4%	7%	7%	8%	-124%	-44%	-16%	-3%	3%	CR
20	Field 30	40%	40%	40%	40%	40%	-158%	-38%	-4%	7%	12%	CR
21	Field 01	8%	8%	8%	8%	9%	32%	31%	30%	30%	29%	GS
22	Field 03	10%	11%	11%	11%	11%	40%	41%	41%	40%	40%	GS
23	Field 05	30%	30%	30%	30%	30%	39%	39%	39%	39%	39%	GS
24	Field 06	11%	11%	11%	12%	12%	25%	25%	26%	25%	25%	GS
25	Field 09	-5%	0%	3%	5%	6%	4%	10%	13%	15%	16%	GS
26	Field 12	25%	26%	26%	26%	26%	16%	21%	25%	27%	27%	GS
27	Field 19	32%	33%	33%	34%	34%	35%	36%	37%	37%	37%	GS
28	Field 21	15%	15%	15%	15%	15%	12%	17%	19%	20%	20%	GS
29	Field 23	9%	12%	13%	13%	14%	21%	28%	30%	32%	32%	GS
30	Field 25	9%	15%	15%	15%	15%	-2%	13%	20%	23%	25%	GS

Table 4.3.2 Comparations of Net Contractor Take all fields in price 80% - 120%

Figure 4.3.1 Government Take of Field 01-10 in price 80% - 120%

Figure 4.3.2 Government Take of Field 11-20 in price 80% - 120%

Figure 4.3.3 Government Take of Field 21-30 in price 80% - 120%

N	Mask Name	Government Take - PSC CR					Government Take - PSC GS					Comparation
		80%	90%	100%	110%	120%	80%*	90%*	100%*	110%*	120%*	
1	Field 02	66%	66%	66%	66%	66%	69%	69%	70%	70%	69%	CR
2	Field 04	67%	67%	67%	67%	67%	74%	74%	74%	75%	76%	CR
3	Field 07	67%	65%	63%	62%	62%	85%	81%	79%	78%	78%	CR
4	Field 08	74%	73%	72%	72%	72%	81%	79%	79%	78%	76%	CR
5	Field 10	60%	60%	60%	60%	60%	71%	70%	69%	69%	69%	CR
6	Field 11	61%	60%	60%	60%	60%	76%	73%	72%	71%	70%	CR
7	Field 13	60%	60%	60%	60%	60%	75%	74%	73%	73%	73%	CR
8	Field 14	60%	60%	60%	60%	60%	70%	67%	65%	64%	64%	CR
9	Field 15	60%	60%	60%	60%	60%	75%	73%	72%	71%	71%	CR
10	Field 16	70%	70%	70%	70%	70%	73%	71%	70%	69%	69%	CR
11	Field 17	82%	79%	78%	77%	76%	90%	85%	82%	81%	80%	CR
12	Field 18	60%	60%	60%	60%	60%	71%	69%	69%	68%	68%	CR
13	Field 20	65%	64%	64%	63%	63%	85%	81%	79%	78%	76%	CR
14	Field 22	60%	60%	60%	60%	60%	78%	74%	72%	71%	71%	CR
15	Field 24	60%	60%	60%	60%	60%	101%	89%	84%	82%	80%	CR
16	Field 26	70%	64%	62%	61%	60%	197%	143%	121%	109%	104%	CR
17	Field 27	92%	87%	85%	84%	83%	156%	117%	99%	93%	90%	CR
18	Field 28	66%	61%	62%	62%	61%	118%	84%	77%	74%	73%	CR
19	Field 29	112%	96%	93%	93%	92%	224%	144%	116%	103%	97%	CR
20	Field 30	60%	60%	60%	60%	60%	258%	138%	104%	93%	88%	CR
21	Field 01	92%	92%	92%	92%	91%	68%	69%	70%	70%	71%	GS
22	Field 03	90%	89%	89%	89%	89%	60%	59%	59%	60%	60%	GS
23	Field 05	70%	70%	70%	70%	70%	61%	61%	61%	61%	61%	GS
24	Field 06	89%	89%	89%	88%	88%	75%	75%	74%	75%	75%	GS
25	Field 09	105%	100%	97%	95%	94%	96%	90%	87%	85%	84%	GS
26	Field 12	75%	74%	74%	74%	74%	84%	79%	75%	73%	73%	GS
27	Field 19	68%	67%	67%	66%	66%	65%	64%	63%	63%	63%	GS
28	Field 21	85%	85%	85%	85%	85%	88%	83%	81%	80%	80%	GS
29	Field 23	91%	88%	87%	87%	86%	79%	72%	70%	68%	68%	GS
30	Field 25	91%	85%	85%	85%	85%	102%	87%	80%	77%	75%	GS

Table 4.3.3 Comparations of Government Take all fields in price 80% - 120%

In progressive fiscal regime, GT should be increase in a better condition scenario, or in this context is higher hydrocarbon price condition. For PSC GS, as can be seen at Table 4.3.3 for 30 fields result, the GT percentage is decreasing with higher price condition, except in Field 08 which slightly increasing, and Field 02, Field 05, Field 03 which looks stagnant. Different with PSC CR, the GT ratio are mostly at stagnant value across price sensitivity, and the remaining was steadily decreasing GT for instance in Field 17, Field 27, Field 29, Field 09, and Field 23. In conclusion, from the 30 data sample, majority field will be giving same GT ratio across different condition, so PSC CR will be categorized as neutral fiscal regime, meanwhile for PSC GS will be categorized as regressive fiscal regime because majority of the field data show decreasing GT in a better financial condition (higher hydrocarbon price).

Contractors when faced with selection of which fiscal regime to be chosen, are preferring to choose more stable NCT percentage result from related fiscal condition, which mean a stable GT percentage also. Because in oil and gas industry, many parameters are contributing the uncertainty of financial result, such as subsurface uncertainty and surface facilities uncertainty. By eliminating one uncertainty parameter is preferable by the contractor to planning a better field development program. Also, a higher NCT ratio is certainly preferable by contractor.

CHAPTER 5
CONCLUSIONS AND RECOMMENDATION

This chapter presents the summaries of the research especially the fiscal regime of PSC CR and PSC GS comparations result. The results are resumed from the calculations of 30 field data samples and positively believe can represent the majority fields in Indonesia. This chapter also giving some aspects of recommendation for future research study which related to financial analysis to the related oil and gas projects.

5.1. Conclusion

From the result and discussion in Chapter 4, several summaries of the research can be resumed as below:

1. Result of financial analysis both PSC CR and PSC GS, especially from NPV and IRR Contractor parameters, it can be concluded that for majority of the 30 samples, PSC CR will generate a better NPV and IRR for the contractor. PSC GS will be generating a better NPV and IRR for the contractor which have low investment cost (lower cost to revenue ratio) and high contractor split.
2. Regarding the sensitivity analysis of hydrocarbon price result, to analyze the progressivity of fiscal regime. Even though both regimes are showing regressive fiscal, but in overall PSC GR are tends to be resulting a higher GT with sensitively changing in different price conditions, meanwhile for PSC CR tends to be resulting a lower GT with more stable NCT percentage in various condition of oil and gas prices. So, it can be concluded that PSC CR have neutral progressivity fiscal, and for PSC GS is categorized as regressive fiscal from 30 data samples in terms of GT value.
3. The most important aspect for contractor to take concern when choosing PSC GS as the scheme is the amount of contractor split. The specific variable split such as factor offshore location field, second & third recovery phase and non-conventional reservoir will grant a big portion of additional contractor split which favorable aspect for contractor in PSC GS contract. These are message from Indonesia government that for hydrocarbon exploration and exploitation activities, they will give a full support to create a better investment environment for the contractor to come and

implementing a breakthrough solution such ad a deeper reservoir, offshore location and secondary or tertiary recovery mechanism.

5.2. Recommendation

Recommendation explained below are related with the future research of fiscal regime or petroleum economics that related with project decision making analysis:

1. In this research, NPV and IRR are the only financial parameters that used to evaluate the fiscal regime. The results showing some errors in one of those parameters. It is suggested to use other financial indicators such as MIRR (Modified Internal Rate of Return) and DPIR (Discounted Profit to Investment Ratio) as a complement of the existing indicators, which hoped can minimize the errors result.
2. Hydrocarbon prices are used in this research as the main sensitivity factor to simulate the possibility future condition that may affected the financial condition. In real world cases, many conditions which can affect the financial performance of oil and gas business, such as the changing of hydrocarbon reserve, development program, and investment cost efficiency. Those conditions can be modelled as sensitivity factors also which can be used as more detailed research model later.

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APPENDIX A
CALCULATION METHODS

All input data for each Oil and Gas parameter are explained below.

1. Year of investment

   Year data is related with the first year of investment taken place by the contractor. If contractor paid the exploration cost at the beginning of field exploration, then the Year investment is inputted as it is.

2. Production data (Oil production rate, Condensate production rate, Gas production rate and LPG production rate)

   Production data are related with the historical and forecast field production. Inputted as daily rate data, in example Barrel per day (BPD) for Oil, Condensate, LPG and Million standard cubic feet (MMSCFD) for Gas.

3. Hydrocarbon Price (Oil Price, Condensate Price, Gas Price and LPG Price)

   Hydrocarbon prices are varying across contractors, it is related with the assumption of price forecast each company. Creating model for uncertainty of price forecast, in the calculation hydrocarbon price can be added in the sensitivity factor to create a sensitivities case. In this study, hydrocarbon price will be taken directly from company forecast which might not 100% related with global hydrocarbon price. The price unit is dollar per barrel ($/BBL) for oil, condensate and LPG, dollar per Million British Thermal Unit ($/MMBTU) for natural gas.

4. Gross Heating Value (GHV)

   GHV is the amount of heat produced by the complete combustion of a unit quantity of fuel, in this case is natural gas. The unit of GHV is well known aspect and approved across gas across the gas consumer company is Million British Unit (MMBTU) per MMSCF. The value of GHV is related with natural gas carbon number composition.

5. Sunk Cost ($)

Sunk cost is related with the predevelopment cost which invested in exploration phase, for example exploration drilling, exploration seismic acquisition and exploration seismic reprocessing. The name of "sunk" cost related with money that has spent already and cannot be recovered in future time. Sunk cost are excluded from future business decisions because the cost will remain the same regardless of the outcome of a decision.

6. Drilling Tangible and Intangible Cost (for each oil and gas)

   Drilling Costs are usually invested in the early of field development lifetime. Drilling costs are consisted of development well, exploration well in development phase, injection well etc. Each of which can be categorized as oil or gas well.

7. Facility Tangible and Intangible Cost (for each oil and gas)

   Likewise with Drilling Cost, facilities costs are usually invested in the early year of field development phase (1st to 2nd year of Development). These costs are consisted of many instruments such as pipeline, processing surface facilities, offshore platform, accommodation needs etc.

8. Survey GGR & Study Cost (for each oil and gas)

   This cost is translated as lab analyst cost, seismic re-processing cost, development geological and geophysical study etc.

9. Fixed Operating Cost (for each oil and gas)

   Fixed Operating Costs are related with the production volume of hydrocarbon to process until reach final hydrocarbon product to be sell. If the oil and gas productions are higher, then the total fixed operating cost will be higher too.

10. Variable Operating Cost

    Variable operating costs are still related with this fixed operating cost that depend on the hydrocarbon produce volume, but for the variable operating cost are more categorized as special cost which might not invested in every year.

11. Workover or Well services Costs (WO/WS Cost)

    These costs are related with Workover and Well Services activity which might be happened once in couple years.

12. Facilities Maintenance Cost

Facilities Maintenance Cost must be included in development program because the surface facilities have to be maintained to achieve the optimum production service in the field production lifetime.

13. EOR Operating Cost

    This cost related with all EOR activity, including lab analysis, pilot project, field trial etc.

14. Asset Lease

    Asset lease cost is expenses that incurred by the company to use some of operational business equipment such as office building and operational vehicle. This cost emerges due to the common regulation that company may not be permitted to have fixed asset in the host country. An asset lease enables you to have the use of your business equipment and the benefits of ownership, while the financier retains actual ownership of the equipment.

15. Land and Building Taxes (LBT)

    This tax is related with all the asset that used by the company. This expense is calculated using the Indonesian Ministerial Regulation of Tax and Finance.

The detail of calculation parameter in PSC CR are explained below

16. Year of investment

    Year data is related with the first year of investment taken place by the contractor. If contractor paid the exploration cost at the beginning of field exploration, then the Year investment is inputted as it is.

17. Production data (Oil production rate, Condensate production rate, Gas production rate and LPG production rate)

    Production data are related with the historical and forecast field production. Inputted as daily rate data, in example Barrel per day (BPD) for Oil, Condensate, LPG and Million standard cubic feet (MMSCFD) for Gas.

18. Hydrocarbon Price (Oil Price, Condensate Price, Gas Price and LPG Price)

    Hydrocarbon prices are varying across contractors, it is related with the assumption of price forecast each company. Creating model for uncertainty of price forecast, in the calculation hydrocarbon price can be added in the sensitivity factor to create a sensitivities case. In this study, hydrocarbon price will be taken directly from company forecast which might not 100% related with global hydrocarbon price. The price unit is dollar per barrel ($/BBL) for oil, condensate and LPG, dollar per Million British Thermal Unit ($/MMBTU) for natural gas.

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22. Facility Tangible and Intangible Cost (for each oil and gas)

    Likewise with Drilling Cost, facilities costs are usually invested in the early year of field development phase (1st to 2nd year of Development). These costs are consisted of many instruments such as pipeline, processing surface facilities, offshore platform, accommodation needs etc.

23. Survey GGR & Study Cost (for each oil and gas)

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24. Fixed Operating Cost (for each oil and gas)

Fixed Operating Costs are related with the production volume of hydrocarbon to process until reach final hydrocarbon product to be sell. If the oil and gas productions are higher, then the total fixed operating cost will be higher too.

25. Variable Operating Cost

    Variable operating costs are still related with this fixed operating cost that depend on the hydrocarbon produce volume, but for the variable operating cost are more categorized as special cost which might not invested in every year.

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28. EOR Operating Cost

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29. Asset Lease

    Asset lease cost is expenses that incurred by the company to use some of operational business equipment such as office building and operational vehicle. This cost emerges due to the common regulation that company may not be permitted to have fixed asset in the host country. An asset lease enables you to have the use of your business equipment and the benefits of ownership, while the financier retains actual ownership of the equipment.

30. Land and Building Taxes (LBT)

    This tax is related with all the asset that used by the company. This expense is calculated using the Indonesian Ministerial Regulation of Tax and Finance.

31. Abandonment and Site Restoration (ASR)

    ASR cost are expenses by IOC to ensure the re-vitalization asset or field after the development or production phase is ended. (Kurniawan & Jaenudin, 2017)

32. Revenue / Gross Revenue / Total Revenue

    Revenue is the total cash inflow as the result of hydrocarbon product sold to the buyer or market. Total Revenue is consisting of sales from Oil, Condensate, Natural Gas and LNG/LPG lifting.

    Oil / Condensate / LPG Revenue = Production * Days * price (after sensitivity)

    Gas Revenue = Production * Days * GHV * price (after sensitivity)

    Total Revenue = Oil Rev + Condensate Rev + LPG Rev + Gas Rev

33. First Tranche Petroleum (FTP)

    FTP can be calculated directly from Total Revenue. The fraction of FTP is agreed upon beginning of contract approval, ranging from 10% to 20% (usually 20%) and can be shared between government and the contractor.

    Oil FTP = 20% * (Oil Revenue + Condensate Revenue)

    Gas FTP = 20% * (Gas Revenue + LPG Revenue)

    Total FTP = Oil FTP + Gas FTP

    Oil FTP Contr = Oil Contr Share / (1-Tax) * Oil FTP

    Gas FTP Contr = Gas Contr Share / (1-Tax) * Gas FTP

    Total FTP Contr = Oil FTP Contr + Gas FTP Contr

    Oil FTP Gov = Oil FTP – Oil FTP Contr

    Gas FTP Gov = Gas FTP – Gas FTP Contr

    Total FTP Gov = Total FTP – Total FTP Contr

34. Revenue after FTP

    This function is just simply deducting the FTP from the Gross Revenue.

    Oil Revenue after FTP = Oil Rev + Condensate Rev – Oil FTP

    Gas Revenue after FTP = Gas Rev + LNG Rev – Gas FTP

    Total Revenue after FTP = Oil Rev after FTP + Gas Revenue after FTP

35. Cost Recovery Cap / Maximum limit (CR Cap)

    In several cases of field development in the early of PSC CR 1st and 2nd generation, there is a CR Cap as it is function to secure government revenue on each year of exploitation phase. In the 3rd Generation, the CR cap function has been replaced by the FTP. In the calculation, there is an option to still include CR Cap or not. Mostly current active field development does not use CR Cap anymore.

The formula to calculate CR Cap is

Oil CR Cap = Cap Percentage * (Oil Rev + Condensate Rev)

Gas CR Cap = Cap Percentage * (Gas Rev + LPG Rev)

Total CR Cap = Oil CR Cap + Gas CR Cap

Total Rev after FTP and CR Cap = Total Rev after FTP – Total CR Cap

36. Sunk Cost

    Sunk Cost in the financial calculation only shown for the contractor cash flow but did not included in NPV calculation.

37. Development Drilling Tangible & Intangible Cost with sensitivity

    Both costs are to calculate the Drilling cost but multiply with some percentage (80% until 120%) to create a sensitivity scenario which affected the cash analysis. Also adding the VAT portion for the Capital Expenditure cost are calculated here.

    Oil Drilling Tangible = Sensitivity Capex * Oil Drilling Tangible * (1+ Capex portion for tax * VAT)

    Oil Drilling Intangible = Sensitivity Capex * Oil Drilling Intangible * (1+ Capex portion for tax * VAT)

    Gas Drilling Tangible = Sensitivity Capex * Gas Drilling Tangible * (1+ Capex portion for tax * VAT)

    Oil Drilling Intangible = Sensitivity Capex * Gas Drilling Intangible * (1+ Capex portion for tax * VAT)

38. Facilities Tangible & Intangible Cost with sensitivity

    Same as Drilling cost, both costs are to calculate the facilities cost but multiply with some percentage (80% until 120%) to create a sensitivity scenario which affected the cash analysis. Also adding the VAT portion for the Capital Expenditure cost are calculated here.

    Oil Facilities Tangible = Sensitivity Capex * Oil Facilities Tangible * (1+ Capex portion for tax * VAT)

    Oil Facilities Intangible = Sensitivity Capex * Oil Facilities Intangible * (1+ Capex portion for tax * VAT)

Gas Facilities Tangible = Sensitivity Capex * Gas Facilities Tangible * (1+ Capex portion for tax * VAT)

Oil Facilities Intangible = Sensitivity Capex * Gas Facilities Intangible * (1+ Capex portion for tax * VAT)

39. Total Investment / Capital Expenditure (CAPEX)

CAPEX is the sum of drilling and facilities cost. The formula of Capex is

Oil Capex = Oil Drilling Tangible + Oil Drilling Intangible + Oil Facilities Tangible + Oil Facilities Intangible

Gas Capex = Gas Drilling Tangible + Gas Drilling Intangible + Gas Facilities Tangible + Gas Facilities Intangible

Total Capex = Oil Capex + Gas Capex

40. Depreciable Asset and Depreciation

Depreciation is value reduction of asset (capital or tangible asset) due to the passage of time. Tangible asset cannot be charged 100% cost in the same year of investment, and depreciation is accounting process of allocating the cost of tangible asset to expense in systematic and rational manner to those periods expected to benefit from the use of asset, which is also translated as capital cost charge allocation on specific year future, allocation in yearly time frame usually used in financial calculations. There are some methods to calculate the depreciation of tangible asset, but in the PSC calculation model, contractor commonly used Double Declining Balance Method (DDB) with 25% depreciable rate in five years (Jaluakbar & Putra, 2017). This mean, at the fifth year of investment, tangible asset cost has fully recovered. Table below shown the allocation factor for each year.

	DDB 5 yr, 25%
1st Year	25.00%
2nd Year	18.75%
3rd Year	14.06%
4th Year	10.55%
5th Year	31.64%

Double Declining Balance of Depreciation

Oil Depreciable = Oil Drilling Tangible + Oil Facilities Tangible

Gas Depreciable = Gas Drilling Tangible + Gas Facilities Tangible

Oil Depreciation = Allocation factor * Oil Depreciable

Gas Depreciation = Allocation factor * Gas Depreciable

Total Depreciation = Oil Depreciation + Gas Depreciation

41. Operational Expenditure (OPEX)

Opex is day to day cost or expenses which related with field development activity. Like Capex, Opex will multiply with some percentage (80% until 120%) to create a sensitivity scenario which affected the cash analysis.

The formula of Opex is,

Oil Opex = Fixed operating cost + Variable Operating Cost + WO/WS Cost + Facilities Maintenance + EOR Operating cost

Total Oil Opex = Sensitivity Opex * Oil Opex

Gas Opex = Fixed operating cost + Variable Operating Cost + WO/WS Cost + Facilities Maintenance + EOR Operating cost

Total Gas Opex = Sensitivity Opex * Gas Opex

Total Opex = Total Oil Opex + Total Gas Opex

42. Oil Cost and Gas Cost (to be Recovered)

Both Oil Cost and Gas Cost are the submission of related cost in the specific year, with formula below

Oil / Gas Cost = OPEX + Asset Lease + LBT + ASR + Depreciation + Drilling Intangible + Facilities Intangible + Sunk Cost

Total Cost = Oil Cost + Gas Cost

43. Recoverable Cost (Rec Cost)

Rec Cost is the amount of cost which can be recovered in each year (n = current year”).

Rec Cost can be calculated by,

Oil / Gas Rec Cost =

IF (Oil / Gas Cost “n” + Unrec Cost “n-1”) > Revenue after FTP “n”

THEN Revenue after FTP “n”

ELSE Oil Cost “n” + Final Unrec Cost “n-1”

44. Unrecoverable Cost (Unrec Cost)

Unrec Cost is the amount of money which cannot be recovered in current year, caused by smaller amount of Revenue

Oil Unrec Cost =

IF (Oil Cost "n" + Oil Unrec Cost Final "n-1") > Rec Cost "n"

THEN Oil Cost "n" + Oil Unrec Cost Final "n-1" - Rec Cost "n"

ELSE 0

45. Unrecoverable Oil Cost transfer to Gas Cost (Unrec Oil Cost transferred)

In the PSC terms, Oil Unrec Cost can be transferred to Gas Cost if any surplus in Gas recovery in the same year.

The formula to calculate is,

Unrec Oil Cost transferred =

IF (Gas Rev after FTP "n" – Gas Cost "n" – Final Mixed Gas & Oil Unrec "n") > Oil Unrec "n"

THEN Oil Unrec "n"

ELSE 0

46. Unrecoverable Oil Cost Final (Final Unrec Oil Cost)

Oil Unrec Cost Final will be same as Oil Unrec Cost if no Oil Unrec Cost transferred to Gas Cost.

Final Unrec Oil Cost = Oil Unrec Cost "n" – Oil Unrec Cost transfer to Gas Cost

47. Oil Revenue after deducted by Oil Recovered (Oil Rev after Oil Rec)

This parameter is about surplus revenue in particular year, on the other terms is profit.

Oil Rev After Oil Rec = Revenue after FTP – Oil Rec Cost

48. Mixed Gas & Oil Cost to be Recovered (Mixed Cost)

This parameter just sums up the Gas Cost with the Oil Unrec Cost transferred.

Mixed Cost "n" = Gas Cost "n" + Oil Unrec Cost transferred "n"

49. Mixed Gas & Oil Cost Recoverable (Rec Mixed Cost)

Rec Mixed Cost is the amount of mixed gas and oil cost which can be recovered in each year (n = current year").

Rec Mixed Cost can be calculated using following formula,

Rec Mixed Cost =

IF (Mixed Cost "n" + Final Unrec Mixed Cost "n-1") > Gas Revenue after FTP "n"

THEN Gas Revenue after FTP "n"

ELSE Mixed Cost "n" + Final Unrec Mixed Cost "n-1"

50. Mixed Gas & Oil Unrecoverable Cost (Unrec Mixed Cost)

This cost is the remaining Mixed Cost which cannot be deducted in the current year due to insufficient Gas Revenue.

Unrec Mixed Cost =

IF (Mixed Cost "n" + Final Unrec Mixed Cost "n-1") > Rec Mixed Cost "n"

THEN Mixed Cost "n" + Final Unrec Mixed Cost "n-1" - Rec Mixed Cost "n"

ELSE 0

51. Oil Revenue Transfer to Rec Mixed Gas & Oil Cost (Oil Rev Transferred)

Oil Rev Transferred is the maximum amount of cost that can be recovered the Unrec Mixed Cost. If the Unrec Mixed Cost is higher than Oil Rev Avail, then the remaining Unrec Mixed Cost will deliver to the following year.

Oil Rev Transferred =

IF Unrec Mixed Cost > Oil Rev Avail

THEN Oil Rev Avail

ELSE Unrec Mixed Cost

52. Final Mixed Gas & Oil Unrecoverable (Final Unrec Mixed Cost)

This parameter explains the amount of money or cost which cannot be deducted / recovered in the current year caused by insufficient Oil Revenue and Gas Revenue.

Final Unrec Mixed Cost =

Unrec Mixed Cost – Oil Rec Transferred

53. Total Cost Recoverable (Total Rec Cost)

Total Rec Cost is the total cost which can be recovered in each year. It is consisting of Oil Rec, Gas Rec and Oil Rev Transferred (Mixed Cost Rec)

Total Rec Cost = Oil Rec + Gas Rec + Oil Rev Transferred.

54. Total Cost Unrecoverable (Total Cost Unrec)

Total Cost Rec is the total cost which cannot be recovered in each year.

Total Unrec Cost = Final Unrec Oil Cost + Final Unrec Mixed Cost

55. Equity to be Split (ETS / ETBS)

ETS is the positive cash flow that received from the hydrocarbon sales after recovered all the cost explained above in each production year. ETS will be shared between government and contractor with certain percentage as explained in Table 2.1.1. The common percentage used in 3rd Generation PSC is 85% : 15% for oil product, and 70% : 30% for gas product, government : contractor respectively.

Oil ETS = Oil Rev Avail - Oil Rev Transferred

Oil ETS Contr = 15% / (1 – Tax) * Oil ETS

Oil ETS Gov = Oil ETS – Oil ETS Contr

Gas ETS = Gas Rev after FTP – Rec Mixed Cost

Gas ETS Contr = 30% / (1 – Tax) * Gas ETS

Gas ETS Gov = Gas ETS – Gas ETS Contr

56. Domestic Market Obligation (DMO)

DMO is an obligation for contractor to supply local (Indonesia) hydrocarbon need (especially oil product) by selling the hydrocarbon production in the certain amount of yearly volume with certain price regulated. DMO usually started at same time as the ETS have positive value. For new production field, which commencing 60 months from it commercial production, known as DMO Holiday (Abidin, 2015). Oil products will be sold to the local / domestic using discounted price (10% until 25% market price), and local / domestic will be paid as much as it (DMO Fee). Volume of DMO is regulated also, maximum 25% of total contractor hydrocarbon volume production each year. In the financial calculation, DMO means reduction in contractor revenue (DMO Net).

The formula to calculate DMO are written below,

DMO = DMO Portion * Oil Contr Share / (1-Tax) or

= Oil ETS Contr + Oil FTP Contr

Pick the lower amount.

DMO fee = DMO Price (percent) * DMO

DMO Net = DMO – DMO Fee

57. Income Tax

Tax Income Contr is the levies from government to any business which make profit in result. The tax portion are calculated from the income which called Taxable Income Contractor (Taxable Income). After cut by the Tax, then the company has the Contractor Net Share (Net Share Contr) or it also called Net Contractor Take (NCT)

Oil Taxable Income = Oil ETS Contr + Oil FTP Contr – DMO Net

Gas Taxable Income = Gas ETS Contr + Gas FTP Contr

Tax Contr = Tax * (Oil Taxable Income + Gas Taxable Income)

NCT = Oil Taxable Income + Gas Taxable Income – Tax Contr

58. Contractor Cash Flow / Net Cash Flow

Net Cash Flow is the final parameter to calculate whether contractor has resulting a positive or negative cash flow in each year. Net Cash Flow can be obtained by subtract cash inflow with all investment and operational expenses in each year (cash outflow). Even if the contractor received a positive NCT, the Net Cash Flow might be negative caused by a bigger cash outflow in particular year.

Net Cash Flow = (Total Cost Rec + Net Share Contr) – (Sunk Cost + Total investment + Opex Oil + Asset Lease + LBT + ASR)

59. Government Take (GT)

GT is all revenue that received by government. The most common GT value are around 40% to 85%, with world average around 64% (Gaspar Ravagnani et al., 2012).

From explanation above, government received revenue from different aspect such and explained by formula below,

GT = Oil FTP Gov + Gas FTP Gov + Oil ETS Gov + Gas ETS Gov + DMO Net + Tax Contr

The calculation parameters for PSC GS are explained below.

60. Base Split

Base Split has a fix value in all year. Contractor will be granted 43% for oil & condensate product and 48% for gas & LPG product.

61. Variable Split

    Variable Split also a fix additional value within production years. The value is determined at the PSC approval and related with the uniqueness of technical field characteristic.

62. Ministerial Discretion Split

    This split is special split that given to field that have a marginal status. In this study, none of the sample will have this split.

63. Progressive Split - Oil Price / Gas Price

    This Progressive Split is additional split for contractor related with oil price in each specific year.

64. Progressive - Cumulative Prod

    This Progressive Split is additional split for contractor related with cumulative volume of hydrocarbon in each specific year.

65. Total Split

    Total Split for contractor is the summary from all type of splits in each year. The value of total split will be different for oil and gas product due to the different percentage in base split.

    Total Split = Base Split + Variable Split + Progressive Split

66. Revenue / Gross Revenue / Total Revenue

    Formula to calculate Revenue Contractor and Revenue Government are,

    Rev Contr = (Oil Total Split * Oil Rev) + (Gas Total Split * Gas Rev)

    Rev Gov = Oil Rev + Gas Rev – Rev Contr

67. Development Drilling Tangible & Intangible Cost with sensitivity

    This parameter will be the same meaning and calculation formula as the PSC CR.

68. Facilities Tangible & Intangible Cost with sensitivity

    This parameter will be the same meaning and calculation formula as the PSC CR.

69. Total Investment / Capital Expenditure (CAPEX)

This parameter will be the same meaning and calculation formula as the PSC CR.

70. Depreciable Asset and Depreciation

This parameter will be the same meaning and calculation formula as the PSC CR.

71. Operational Expenditure (OPEX)

This parameter will be the same meaning and calculation formula as the PSC CR.

72. Oil Cost and Gas Cost

Oil Cost and Gas Cost have the same meaning and calculation formula as the PSC CR.

73. Gas Cost Deductible (Gas Cost Deduct)

Financial calculation for contractor PSC GS has different schematic compared to PSC CR. In PSC CR, oil cost will be calculated and recovered first, then if the oil cost not fully recover, then it can be transferred to gas cost to be recovered by gas revenue. In PSC GS, gas cost will be calculated to be deducted from gas revenue (in here the word “deducted” is used compared to “recovered”, because in PSC GS there is no cost recovery mechanism, but the cost will be deducted from contractor gross revenue).

Maximum value of gas cost that can be deducted (Gas Cost Deduct) in each year is same as gas revenue contractor, and the gas cost that cannot be deducted current year (gas revenue contractor did not enough to pay the gas cost) will be carried forward to the following year.

Gas Cost Deduct =

IF (Gas Cost “n” + Final Gas Cost CF “n-1”) > Gas Rev Contr “n”

THEN Gas Rev Contr “n”

ELSE Gas Cost “n” + Final Gas Cost CF “n-1”

74. Gas Cost Carry Forward (Gas Cost CF)

Gas Cost CF is the unpaid Gas Cost current year that carried forward to next year.

Gas CF =

IF Gas Cost “n” + Final Gas Cost CF “n-1”> Gas Cost Deduct “n”

THENGas Cost “n” + Final Gas Cost CF “n-1” - Gas Cost Deduct “n”

ELSE 0

75. Gas Cost Transfer to Oil Cost (Gas Cost Transferred)

The Gas Cost CF can be paid / transferred using Oil Rev Contr if the amount of Gas Cost CF is smaller than Oil Rev after paid the Oil Cost. The detail formula of this parameter is,

Gas Cost Transferred =

IF Gas Cost CF “n” < Oil Rev Contr “n” – Oil Cost “n” – Final Mixed Cost CF “n-1”

THEN Gas Cost CF “n”

ELSE 0

and Final Gas Cost CF “n” can be calculated using this formula,

Final Gas Cost CF “n” = Gas Cost CF “n” – Gas Cost Transferred “n”

76. Mixed Gas & Oil Cost (Mixed Cost)

The Gas Cost Transferred will add up with Oil Cost at the same year. This Mixed Cost will later be paid by Oil Rev Contr.

Mixed Cost “n” = Oil Cost “n” + Gas Cost Transferred “n”

77. Mixed Gas & Oil Cost Deductible (Mixed Cost Deduct)

Mixed Cost Deduct means the value of mixed gas & oil cost that can be deducted in each year from oil revenue contractor.

IF (Mixed Cost “n” + Final Mixed Cost CF “n-1”) > Oil Rev Contr “n”

THEN Oil Rev Contr “n”

ELSE Mixed Cost “n” + Final Mixed Cost CF “n-1”

78. Mixed Gas & Oil Cost Carry Forward (Mixed Cost CF)

The remaining mixed cost which cannot be deducted will be carried forward to next year.

Mixed Cost CF =

IF (Mixed Cost “n” + Final Mixed Cost CF “n-1”) > Mixed Cost Deduct “n”

THEN Mixed Cost “n” + Final Mixed Cost CF “n-1” - Mixed Cost Deduct “n”

ELSE 0

79. Mixed Gas & Oil Cost Transfer to Gas Cost (Mixed Cost Transferred)

The Mixed Cost CF can be deducted from gas revenue (transfer to gas cost) if available Gas Rev surplus after deducted by Gas Cost.

Mixed Cost Transferred =

IF Mixed Cost CF “n”>Gas Rev Contr “n” – Gas Cost Deduct “n”

THEN Gas Rev Contr “n” – Gas Cost Deduct “n”

ELSE Mixed Cost CF “n”

and Final Mixed Cost CF “n” can be calculated using this formula,

Final Mixed Gas & Oil Carry Forward (Final Mixed Cost CF)

Final Mixed Cost CF = Mixed Cost CF – Mixed Cost Transferred

80. Profit Contractor before DMO and Tax

The final revenue for the contractor after paid all the costs is called Profit. Formula to calculate it,

Oil Profit Contr = Oil Rev Contr – Mixed Cost Deduct

Gas Profit Contr = Gas Rec Contr – Gas Cost Deduct – Mixed Cost Transferred

81. Domestic Market Obligation (DMO)

DMO will be the same meaning as the PSC CR. The formulas are slightly different compared to PSC CR, to calculate DMO are written below,

DMO = DMO Portion * Oil Total Split * Oil Rev or

= Oil Profit Contr

Pick the lower amount.

DMO fee = DMO Price * DMO

DMO Net = DMO – DMO Fee

82. Income Tax

Income tax will be the same meaning as the PSC CR, but the formula is different.

Taxable Income Oil = Oil Profit Contr - DMO Net

Taxable Income Gas = Gas Profit Contr

Tax Contr = Tax * (Taxable Income Oil + Taxable Income Gas)

Net Profit Contr = Taxable Income Oil + Taxable Income Gas – Tax Contr

83. Government Take (GT)

Income tax will be the same meaning as the PSC CR, with a different formula.

GT = Rev Gov + Income Tax + Net DMO

The detail of each field characteristics are shown in table below. Majority of those fields are active field and facing the end of contract, so the contractors are intended to extend the field contract period further and asking the permission to the MEMR.

	Status			Field Location						Depth		Infrastructure			Reservoir Condi		CO2 Content						H2S Content						API Grav		Local Content				Prod Phase			
	5%	3%	0%	0%	8%	10%	12%	14%	16%	1%	0%	0%	4%	2%	0%	16%	0%	###	1%	###	2%	4%	0%	1%	2%	3%	4%	5%	1%	0%	0%	2%	3%	4%	0%	6%	10%	
Mask Name	**POD 1**	**POD 2 & next**	**No POD**	**Onshore**	**Offshore (0<h<=20m)**	**Offshore (20<h<=50m)**	**Offshore (50<h<=150m)**	**Offshore (150<h<=1000m**	**Offshore (h>1000m)**	**> 2500 m**	**≤ 2500 m**	**Well Develop**	**New Frontier Onshore**	**New Frontier Offshore**	**Conventional**	**Non Conventional**	**X < 5%**	**5% ≤ X < 10%**	**10% ≤ X < 20%**	**20% ≤ X < 40%**	**40% ≤ X < 60%**	**X >60%**	**X < 100**	**100 ≤ X < 1000**	**1000 ≤ X < 2000**	**2000 ≤ X < 3000**	**3000 ≤ X < 4000**	**X ≥ 4000**	**X < 25**	**X ≥ 25**	**X < 30%**	**30% ≤ X < 50%**	**50% ≤ X < 70%**	**70% ≤ X < 100%**	**Primary**	**Secondary**	**Tertiary**	**Sum Additional Split**
Field 09			1	1							1	1			1		1						1							1		1			1			2.0%
Field 26			1	1							1	1			1		1						1							1			1		1			3.0%
Field 11			1	1							1	1			1		1							1						1		1			1			3.0%
Field 12			1	1							1	1			1			1					1							1			1		1			3.5%
Field 15			1	1							1	1			1		1						1							1				1	1			4.0%
Field 07			1	1							1	1			1		1						1							1				1	1			4.0%
Field 20			1	1							1	1			1					1				1						1		1			1			4.5%
Field 17			1	1							1	1			1		1						1						1					1	1			5.0%
Field 29			1	1						1		1			1		1						1							1				1	1			5.0%
Field 10		1		1							1	1			1		1						1							1		1			1			5.0%
Field 02			1	1							1	1			1					1				1						1			1		1			5.5%
Field 27			1	1						1		1			1			1					1							1				1	1			5.5%
Field 21			1	1							1	1			1		1						1							1				1		1		10.0%
Field 25			1	1							1	1			1		1							1						1			1			1		10.0%
Field 30			1	1							1	1			1			1										1	1					1	1			10.5%
Field 01		1		1							1	1			1		1						1							1		1				1		11.0%
Field 06	1			1							1		1		1		1						1							1		1			1			11.0%
Field 05	1			1							1		1		1		1						1							1		1			1			11.0%
Field 04		1		1							1	1			1					1								1		1		1			1			11.5%
Field 24		1		1							1	1			1		1						1						1			1				1		12.0%
Field 13		1		1							1	1			1		1						1							1			1			1		12.0%
Field 03		1		1							1	1			1		1						1						1				1			1		13.0%
Field 08			1			1				1		1			1				1				1						1				1		1			16.0%
Field 18		1		1							1		1		1		1						1							1			1			1		16.0%
Field 16	1				1						1			1	1		1						1							1		1			1			17.0%
Field 22		1		1							1	1			1					1			1							1				1			1	18.5%
Field 28	1					1				1				1	1		1						1							1		1			1			20.0%
Field 19	1					1					1		1		1		1						1							1		1			1			21.0%
Field 23	1						1				1			1	1		1						1						1			1			1			22.0%
Field 14	1							1			1			1	1		1						1							1		1			1			23.0%

Example of input data Field 04,

Year	Oil Prod. (BOPD)	Condesate lifting (BCPD)	Oil Price ($/BBL)	Condensate Price ($/BBL)	Gas Lifting (MMSCFD)	Gross Heating Value (BTU/SCF)	Gas Price ($/MMBTU)	Sunk Cost ($)	Tangible Development Drilling ($)	Intangible Development Drilling ($)	Tangible Facility ($)	Intangible Facility ($)	GGR Study ($)	Fixed + Variable + WO/WS + Maintenance + EOR cost ($)	Asset Lease + LBT + ASR
						1,050									
2011						1,050			$ 1,000,000	$ 41,000,000	$ -			$ -	$ -
2012						1,050			$ -	$ -	$ -			$ -	$ -
2013						1,050			$ -	$ 3,000,000	$ 14,000,000			$ 6,000,000	$ -
2014						1,050			$ -	$ 7,000,000	$ 23,000,000			$ 10,000,000	$ -
2015						1,050			$ -	$ 11,000,000	$ 29,000,000			$ 15,000,000	$ -
2016						1,050			$ -	$ 11,000,000	$ 242,000,000			$ 23,000,000	$ -
2017						1,050			$ 31,000,000	$ 53,000,000	$ 351,000,000			$ 25,000,000	$ -
2018						1,050			$ 44,000,000	$ 110,000,000	$ 808,000,000			$ 28,000,000	$ -
2019	2,400		70		124.4	1,050	9.19		$ -	$ 8,000,000	$ 185,000,000			$ 98,000,000	$ 7,454,545
2020	3,200		78		172.0	1,050	9.37							$ 77,000,000	$ 7,454,545
2021	3,100		76		172.0	1,050	9.56							$ 79,000,000	$ 7,454,545
2022	3,000		74		172.0	1,050	9.75							$ 80,000,000	$ 7,454,545
2023	2,900		73		172.0	1,050	9.95							$ 82,000,000	$ 7,454,545
2024	2,900		70		172.0	1,050	10.15							$ 84,000,000	$ 7,454,545
2025	2,800		68		172.0	1,050	10.35							$ 86,000,000	$ 7,454,545
2026	2,700		68		172.0	1,050	10.56							$ 88,000,000	$ 7,454,545
2027	2,700		70		172.0	1,050	10.77							$ 90,000,000	$ 7,454,545
2028	2,600		71		172.0	1,050	10.98							$ 92,000,000	$ 7,454,545
2029	2,500		72		172.0	1,050	11.20				$ 34,000,000			$ 94,000,000	$ 7,454,545
2030	2,500		75		172.0	1,050	11.43				$ 51,000,000			$ 96,000,000	$ 7,454,545
2031	2,500		77		172.0	1,050	11.65				$ 41,000,000			$ 98,000,000	$ 7,454,545
2032	2,400		79		172.0	1,050	11.89							$ 100,000,000	$ 7,454,545
2033	2,400		83		172.0	1,050	12.13							$ 103,000,000	$ 7,454,545
2034	2,400		88		172.0	1,050	12.37							$ 105,000,000	$ 7,454,545
2035	2,300		92		164.5	1,050	12.62							$ 80,000,000	$ 7,454,545
2036	2,000		94		145.2	1,050	12.87							$ 82,291,416	$ 7,454,545
2037	1,700		95		125.9	1,050	13.12							$ 71,055,752	$ 7,454,545
2038	1,400		97		106.6	1,050	13.39							$ 60,044,928	$ 7,454,545
2039	1,200		99		88.9	1,050	13.66							$ 50,208,813	$ 7,454,545
2040	1,000		101		75.5	1,050	13.93							$ 42,691,310	$ 7,454,545

Calculation for Oil & Condensate

Tahun	Oil Prod. (BOPD)	Lifting Oil + Condensate (BBL)	ICP Index	Price Oil (US$/bbl)	Revenue Oil (US$)	FTP Oil	Rev Oil after FTP	CR Cap.	Rev Oil after FTP+CR Cap
				1.00					
2011	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2012	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2013	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2014	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2015	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2016	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2017	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2018	-	-	5	85	$ -	$ -	$ -	$ -	$ -
2019	2,400	876,000	3	70	$ 61,055,305	$ 12,211,061	$ 48,844,244	$ -	$ 48,844,244
2020	3,200	1,171,200	4	78	$ 90,999,706	$ 18,199,941	$ 72,799,765	$ -	$ 72,799,765
2021	3,100	1,131,500	4	76	$ 85,652,102	$ 17,130,420	$ 68,521,681	$ -	$ 68,521,681
2022	3,000	1,095,000	4	74	$ 80,699,131	$ 16,139,826	$ 64,559,305	$ -	$ 64,559,305
2023	2,900	1,058,500	4	73	$ 76,950,660	$ 15,390,132	$ 61,560,528	$ -	$ 61,560,528
2024	2,900	1,061,400	3	70	$ 73,977,283	$ 14,795,457	$ 59,181,827	$ -	$ 59,181,827
2025	2,800	1,022,000	3	68	$ 69,187,189	$ 13,837,438	$ 55,349,751	$ -	$ 55,349,751
2026	2,700	985,500	3	68	$ 66,716,218	$ 13,343,244	$ 53,372,974	$ -	$ 53,372,974
2027	2,700	985,500	3	70	$ 68,687,218	$ 13,737,444	$ 54,949,774	$ -	$ 54,949,774
2028	2,600	951,600	4	71	$ 67,276,061	$ 13,455,212	$ 53,820,849	$ -	$ 53,820,849
2029	2,500	912,500	4	72	$ 65,424,276	$ 13,084,855	$ 52,339,420	$ -	$ 52,339,420
2030	2,500	912,500	4	75	$ 68,161,776	$ 13,632,355	$ 54,529,420	$ -	$ 54,529,420
2031	2,500	912,500	4	77	$ 69,986,776	$ 13,997,355	$ 55,989,420	$ -	$ 55,989,420
2032	2,400	878,400	4	79	$ 69,128,179	$ 13,825,636	$ 55,302,543	$ -	$ 55,302,543
2033	2,400	876,000	4	83	$ 72,443,305	$ 14,488,661	$ 57,954,644	$ -	$ 57,954,644
2034	2,400	876,000	5	88	$ 76,823,305	$ 15,364,661	$ 61,458,644	$ -	$ 61,458,644
2035	2,300	839,500	5	92	$ 76,980,334	$ 15,396,067	$ 61,584,267	$ -	$ 61,584,267
2036	2,000	732,000	5	94	$ 68,465,272	$ 13,693,054	$ 54,772,218	$ -	$ 54,772,218
2037	1,700	620,500	5	95	$ 59,197,207	$ 11,839,441	$ 47,357,766	$ -	$ 47,357,766
2038	1,400	511,000	5	97	$ 49,725,654	$ 9,945,131	$ 39,780,523	$ -	$ 39,780,523
2039	1,200	438,000	5	99	$ 43,474,429	$ 8,694,886	$ 34,779,543	$ -	$ 34,779,543
2040	1,000	366,000	6	101	$ 37,054,506	$ 7,410,901	$ 29,643,605	$ -	$ 29,643,605
Sum		**19,213,100**		**78**	**$ 1,498,065,888**	**$ 299,613,178**	**$ 1,198,452,711**	**$ -**	**$ 1,198,452,711**

Tahun	Sunk Cost Oil rolled up to 1st year	Tangible Development Drilling - Sensitivity (M$)	Intangible Development Drilling - Sensitivity ($)	Facility Tangible - Sensitivity	Facility Intangible - Sensitivity	Total Invesment	Depreciable Oil	Opex Oil - sensitivity	Asset Lease + LBT +ASR + Import Duty	Depreciation + Amortization Oil
	100%									
		1.00						1.00		
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,000,000	$ -	$ -
2014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,000,000	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,000,000	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,000,000	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,000,000	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,000,000	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,985,326	$ 911,685	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,860,573	$ 954,625	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,451,455	$ 891,852	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,922,261	$ 831,392	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,612,100	$ 782,918	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,344,888	$ 740,564	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,918,547	$ 686,386	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,698,835	$ 652,174	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,940,975	$ 657,737	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802,651	$ 632,231	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,650,179	$ 606,687	$ -
2030	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,966,372	$ 618,601	$ -
2031	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,181,841	$ 622,366	$ -
2032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,085,753	$ 602,756	$ -
2033	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,559,115	$ 619,459	$ -
2034	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,041,620	$ 641,916	$ -
2035	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,060,179	$ 657,880	$ -
2036	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,165,573	$ 649,109	$ -
2037	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,075,944	$ 637,435	$ -
2038	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,005,800	$ 621,467	$ -
2039	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,288,974	$ 636,788	$ -
2040	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,584,946	$ 625,986	$ -
	$ -									
Sum	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**	**$ 278,203,906**	**$ 15,282,014**	**$ -**

Tahun	Intangible Oil	Oil Cost to be Recovered	IC Oil to be recovered	IC Rec by Oil Rev	IC Unrec by Oil	Rev after FTP+CR Cap+IC	Unrec. Cap Balance	IC (bef. Tax)		Oil Unrec transfer to Gas Cost
			0.00%							
2011	$ -	$ -	$ -	$ -	$ -	$ -				$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -				$ -
2013	$ -	$ 6,000,000	$ -	$ -	$ -	$ -				$ -
2014	$ -	$ 10,000,000	$ -	$ -	$ -	$ -				$ -
2015	$ -	$ 15,000,000	$ -	$ -	$ -	$ -				$ -
2016	$ -	$ 23,000,000	$ -	$ -	$ -	$ -				$ -
2017	$ -	$ 25,000,000	$ -	$ -	$ -	$ -				$ -
2018	$ -	$ 28,000,000	$ -	$ -	$ -	$ -				$ -
2019	$ -	$ 12,897,011	$ -	$ -	$ -	$ 48,844,244				$ -
2020	$ -	$ 10,815,198	$ -	$ -	$ -	$ 72,799,765				$ -
2021	$ -	$ 10,343,307	$ -	$ -	$ -	$ 68,521,681				$ -
2022	$ -	$ 9,753,653	$ -	$ -	$ -	$ 64,559,305				$ -
2023	$ -	$ 9,395,018	$ -	$ -	$ -	$ 61,560,528				$ -
2024	$ -	$ 9,085,452	$ -	$ -	$ -	$ 59,181,827				$ -
2025	$ -	$ 8,604,933	$ -	$ -	$ -	$ 55,349,751				$ -
2026	$ -	$ 8,351,009	$ -	$ -	$ -	$ 53,372,974				$ -
2027	$ -	$ 8,598,713	$ -	$ -	$ -	$ 54,949,774				$ -
2028	$ -	$ 8,434,881	$ -	$ -	$ -	$ 53,820,849				$ -
2029	$ -	$ 8,256,866	$ -	$ -	$ -	$ 52,339,420				$ -
2030	$ -	$ 8,584,972	$ -	$ -	$ -	$ 54,529,420				$ -
2031	$ -	$ 8,804,207	$ -	$ -	$ -	$ 55,989,420				$ -
2032	$ -	$ 8,688,509	$ -	$ -	$ -	$ 55,302,543				$ -
2033	$ -	$ 9,178,574	$ -	$ -	$ -	$ 57,954,644				$ -
2034	$ -	$ 9,683,536	$ -	$ -	$ -	$ 61,458,644				$ -
2035	$ -	$ 7,718,059	$ -	$ -	$ -	$ 61,584,267				$ -
2036	$ -	$ 7,814,682	$ -	$ -	$ -	$ 54,772,218				$ -
2037	$ -	$ 6,713,378	$ -	$ -	$ -	$ 47,357,766				$ -
2038	$ -	$ 5,627,268	$ -	$ -	$ -	$ 39,780,523				$ -
2039	$ -	$ 4,925,761	$ -	$ -	$ -	$ 34,779,543				$ -
2040	$ -	$ 4,210,931	$ -	$ -	$ -	$ 29,643,605				$ -
Sum	$ -	$ 293,485,919	$ -	$ -	$ -	$ 1,198,452,711	$ -	$ -	$ -	$ -

Tahun	Final Oil Unrec	Oil Rev post Oil Recovered	Mixed Gas+Oil Cost to be Recovered	ETS	ETS Oil Contractor	ETS Oil Government	FTP Oil Contractor	FTP Oil Government	DMO	DMO Fee
										0.25
2011	$ -	$ -	$ 41,250,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ 187,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ 6,000,000	$ -	$ 6,640,625	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 16,000,000	$ -	$ 15,480,469	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ 31,000,000	$ -	$ 24,847,656	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 54,000,000	$ -	$ 81,648,438	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 79,000,000	$ -	$ 204,808,594	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 107,000,000	$ -	$ 438,992,188	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 71,052,768	$ -	$ 394,975,503	$ -	$ -	$ -	$ 3,270,820	$ 8,940,241	$ -	$ -
2020	$ 9,068,201	$ -	$ 344,998,722	$ -	$ -	$ -	$ 4,874,984	$ 13,324,957	$ -	$ -
2021	$ -	$ 49,110,173	$ 312,853,426	$ -	$ -	$ -	$ 4,588,505	$ 12,541,915	$ -	$ -
2022	$ -	$ 54,805,652	$ 366,790,736	$ -	$ -	$ -	$ 4,323,168	$ 11,816,658	$ -	$ -
2023	$ -	$ 52,165,509	$ 138,594,683	$ 52,165,509	$ 13,972,904	$ 38,192,605	$ 4,122,357	$ 11,267,775	$ 5,152,946	$ 5,152,946
2024	$ -	$ 50,096,375	$ 82,369,093	$ 50,096,375	$ 13,418,672	$ 36,677,703	$ 3,963,069	$ 10,832,388	$ 4,953,836	$ 1,238,459
2025	$ -	$ 46,744,818	$ 84,849,613	$ 46,744,818	$ 12,520,933	$ 34,223,885	$ 3,706,457	$ 10,130,981	$ 4,633,071	$ 1,158,268
2026	$ -	$ 45,021,965	$ 87,103,536	$ 45,021,965	$ 12,059,455	$ 32,962,510	$ 3,574,083	$ 9,769,160	$ 4,467,604	$ 1,116,901
2027	$ -	$ 46,351,061	$ 88,855,833	$ 46,351,061	$ 12,415,463	$ 33,935,598	$ 3,679,672	$ 10,057,771	$ 4,599,590	$ 1,149,898
2028	$ -	$ 45,385,968	$ 91,019,664	$ 45,385,968	$ 12,156,956	$ 33,229,012	$ 3,604,075	$ 9,851,137	$ 4,505,093	$ 1,126,273
2029	$ -	$ 44,082,554	$ 101,697,679	$ 44,082,554	$ 11,807,827	$ 32,274,727	$ 3,504,872	$ 9,579,983	$ 4,381,090	$ 1,095,272
2030	$ -	$ 45,944,448	$ 113,994,573	$ 45,944,448	$ 12,306,549	$ 33,637,899	$ 3,651,524	$ 9,980,831	$ 4,564,405	$ 1,141,101
2031	$ -	$ 47,185,213	$ 121,244,088	$ 47,185,213	$ 12,638,896	$ 34,546,317	$ 3,749,292	$ 10,248,064	$ 4,686,614	$ 1,171,654
2032	$ -	$ 46,614,035	$ 117,211,349	$ 46,614,035	$ 12,485,902	$ 34,128,133	$ 3,703,295	$ 10,122,341	$ 4,629,119	$ 1,157,280
2033	$ -	$ 48,776,070	$ 123,178,315	$ 48,776,070	$ 13,065,019	$ 35,711,051	$ 3,880,891	$ 10,607,770	$ 4,851,114	$ 1,212,779
2034	$ -	$ 51,775,107	$ 123,231,947	$ 51,775,107	$ 13,868,332	$ 37,906,775	$ 4,115,534	$ 11,249,127	$ 5,144,418	$ 1,286,104
2035	$ -	$ 53,866,208	$ 92,709,143	$ 53,866,208	$ 14,428,449	$ 39,437,759	$ 4,123,946	$ 11,272,120	$ 5,154,933	$ 1,288,733
2036	$ -	$ 46,957,536	$ 81,931,280	$ 46,957,536	$ 12,577,912	$ 34,379,625	$ 3,667,782	$ 10,025,272	$ 4,584,728	$ 1,146,182
2037	$ -	$ 40,644,387	$ 71,796,919	$ 40,644,387	$ 10,886,889	$ 29,757,498	$ 3,171,279	$ 8,668,162	$ 3,964,099	$ 991,025
2038	$ -	$ 34,153,256	$ 61,872,206	$ 34,153,256	$ 9,148,193	$ 25,005,062	$ 2,663,874	$ 7,281,256	$ 3,329,843	$ 832,461
2039	$ -	$ 29,853,782	$ 52,737,597	$ 29,853,782	$ 7,996,549	$ 21,857,233	$ 2,328,987	$ 6,365,899	$ 2,911,234	$ 727,809
2040	$ -	$ 25,432,674	$ 45,934,924	$ 25,432,674	$ 6,812,323	$ 18,620,350	$ 1,985,063	$ 5,425,838	$ 2,481,329	$ 620,332
Sum	$ 373,120,969	$ 904,966,791	$ 3,913,806,300	$ 801,050,966	$ 214,567,223	$ 586,483,743	$ 80,253,530	$ 219,359,648	$ 78,995,066	$ 23,613,476

Tahun	Net DMO	Contractor Taxable Income	Contractor Tax	Contractor Net Share	Contractor Cash Flow	Cum. Contr. CF	Contr. POT	GOI Take
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ (6,000,000)	$ -6,000,000	$ -	$ -
2014	$ -	$ -	$ -	$ -	$ (10,000,000)	$ -16,000,000	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ (15,000,000)	$ -31,000,000	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ (23,000,000)	$ -54,000,000	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ (25,000,000)	$ -79,000,000	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ (28,000,000)	$ -107,000,000	$ -	$ -
2019	$ -	$ 3,270,820	$ 1,439,161	$ 1,831,659	$ 37,778,891	$ -69,221,109	$ -	$ 10,379,402
2020	$ -	$ 4,874,984	$ 2,144,993	$ 2,729,991	$ 64,714,558	$ -4,506,551	$ 8	$ 15,469,950
2021	$ -	$ 4,588,505	$ 2,018,942	$ 2,569,563	$ 60,747,937	$ 56,241,387	$ -	$ 14,560,857
2022	$ -	$ 4,323,168	$ 1,902,194	$ 2,420,974	$ 57,226,626	$ 113,468,012	$ -	$ 13,718,852
2023	$ -	$ 18,095,261	$ 7,961,915	$ 10,133,346	$ 10,133,346	$ 123,601,358	$ -	$ 57,422,295
2024	$ 3,715,377	$ 13,666,364	$ 6,013,200	$ 7,653,164	$ 7,653,164	$ 131,254,522	$ -	$ 57,238,668
2025	$ 3,474,803	$ 12,752,587	$ 5,611,138	$ 7,141,449	$ 7,141,449	$ 138,395,971	$ -	$ 53,440,807
2026	$ 3,350,703	$ 12,282,835	$ 5,404,447	$ 6,878,388	$ 6,878,388	$ 145,274,358	$ -	$ 51,486,821
2027	$ 3,449,693	$ 12,645,442	$ 5,563,995	$ 7,081,448	$ 7,081,448	$ 152,355,806	$ -	$ 53,007,057
2028	$ 3,378,820	$ 12,382,210	$ 5,448,173	$ 6,934,038	$ 6,934,038	$ 159,289,844	$ -	$ 51,907,142
2029	$ 3,285,817	$ 12,026,881	$ 5,291,828	$ 6,735,054	$ 6,735,054	$ 166,024,897	$ -	$ 50,432,356
2030	$ 3,423,303	$ 12,534,769	$ 5,515,298	$ 7,019,471	$ 7,019,471	$ 173,044,368	$ -	$ 52,557,333
2031	$ 3,514,961	$ 12,873,227	$ 5,664,220	$ 7,209,007	$ 7,209,007	$ 180,253,375	$ -	$ 53,973,561
2032	$ 3,471,839	$ 12,717,358	$ 5,595,638	$ 7,121,721	$ 7,121,721	$ 187,375,096	$ -	$ 53,317,950
2033	$ 3,638,336	$ 13,307,574	$ 5,855,333	$ 7,452,242	$ 7,452,242	$ 194,827,337	$ -	$ 55,812,489
2034	$ 3,858,313	$ 14,125,553	$ 6,215,243	$ 7,910,310	$ 7,910,310	$ 202,737,647	$ -	$ 59,229,459
2035	$ 3,866,200	$ 14,686,195	$ 6,461,926	$ 8,224,269	$ 8,224,269	$ 210,961,916	$ -	$ 61,038,005
2036	$ 3,438,546	$ 12,807,148	$ 5,635,145	$ 7,172,003	$ 7,172,003	$ 218,133,919	$ -	$ 53,478,588
2037	$ 2,973,074	$ 11,085,094	$ 4,877,442	$ 6,207,653	$ 6,207,653	$ 224,341,572	$ -	$ 46,276,176
2038	$ 2,497,382	$ 9,314,686	$ 4,098,462	$ 5,216,224	$ 5,216,224	$ 229,557,796	$ -	$ 38,882,162
2039	$ 2,183,426	$ 8,142,110	$ 3,582,529	$ 4,559,582	$ 4,559,582	$ 234,117,378	$ -	$ 33,989,086
2040	$ 1,860,996	$ 6,936,390	$ 3,052,012	$ 3,884,378	$ 3,884,378	$ 238,001,756	$ -	$ 28,959,197
Sum	**$ 55,381,590**	**$ 239,439,163**	**$ 105,353,232**	**$ 134,085,931**	**$ 238,001,756**		**$ 8**	**$ 966,578,213**

Next, Calculation for Gas and LPG product

Tahun	Gas Prod. (MMSCF)	GHV	Gas Price - Sensitivity ($/MMBBTU)	Gas Prod. (MMSCF) - 2	GHV 2	Gas Price - After Sensitivity ($/MMBBTU)	Gas Prod. (MMSCF) - Total	Revenue Gas + LPG (MMUS$)	FTP Gas	Rev Gas aft. FTP
2011	-	1050	-	-	1,050	-	-	$ -	-	-
2012	-	1050	-	-	1,050	-	-	$ -	-	-
2013	-	1050	-	-	1,050	-	-	$ -	-	-
2014	-	1050	-	-	1,050	-	-	$ -	-	-
2015	-	1050	-	-	1,050	-	-	$ -	-	-
2016	-	1050	-	-	1,050	-	-	$ -	-	-
2017	-	1050	-	-	1,050	-	-	$ -	-	-
2018	-	1050	-	-	1,050	-	-	$ -	-	-
2019	45,411	1050	9.19	-	1,050	-	45,411	$ 438,173,488	87,634,698	350,538,790
2020	62,956	1050	9.37	-	1,050	-	62,956	$ 619,605,753	123,921,151	495,684,602
2021	62,784	1050	9.56	-	1,050	5.60	62,784	$ 630,271,098	126,054,220	504,216,878
2022	62,784	1050	9.75	-	1,050	5.74	62,784	$ 642,876,520	128,575,304	514,301,216
2023	62,784	1050	9.95	-	1,050	5.88	62,784	$ 655,734,050	131,146,810	524,587,240
2024	62,956	1050	10.15	-	1,050	6.03	62,956	$ 670,681,193	134,136,239	536,544,955
2025	62,784	1050	10.35	-	1,050	6.18	62,784	$ 682,225,706	136,445,141	545,780,565
2026	62,784	1050	10.56	-	1,050	6.34	62,784	$ 695,870,220	139,174,044	556,696,176
2027	62,784	1050	10.77	-	1,050	6.49	62,784	$ 709,787,624	141,957,525	567,830,099
2028	62,956	1050	10.98	-	1,050	6.66	62,956	$ 725,966,893	145,193,379	580,773,514
2029	62,784	1050	11.20	-	1,050	6.82	62,784	$ 738,463,044	147,692,609	590,770,435
2030	62,784	1050	11.43	-	1,050	6.99	62,784	$ 753,232,305	150,646,461	602,585,844
2031	62,784	1050	11.65	-	1,050	7.17	62,784	$ 768,296,951	153,659,390	614,637,561
2032	62,956	1050	11.89	-	1,050	7.35	62,956	$ 785,809,912	157,161,982	628,647,930
2033	62,784	1050	12.13	-	1,050	-	62,784	$ 799,336,148	159,867,230	639,468,918
2034	62,784	1050	12.37	-	1,050	-	62,784	$ 815,322,871	163,064,574	652,258,297
2035	60,041	1050	12.62	-	1,050	-	60,041	$ 795,296,008	159,059,202	636,236,807
2036	53,128	1050	12.87	-	1,050	-	53,128	$ 717,808,820	143,561,764	574,247,056
2037	45,939	1050	13.12	-	1,050	-	45,939	$ 633,090,647	126,618,129	506,472,517
2038	38,895	1050	13.39	-	1,050	-	38,895	$ 546,737,082	109,347,416	437,389,666
2039	32,464	1050	13.66	-	1,050	-	32,464	$ 465,458,373	93,091,675	372,366,698
2040	27,639	1050	13.93	-	1,050	-	27,639	$ 404,208,911	80,841,782	323,367,129
Sum	**1,245,960**	**1,050**		**-**	**1,050**		**1,245,960**	**$ 14,694,253,619**	**$ 2,938,850,724**	**$ 11,755,402,895**

Tahun	Sunk Cost Gas rolled up to 1st year	Drilling Tangible Gas	Drilling Intangible Gas	Facility Tangible	Facility Intangible	Total Invesment	Depreciable Gas	Opex Gas - sensitivity	Asset Lease + LBT +ASR + Import Duty	Depreciation + Amortization Gas
								1.00		
2011	-	1,000,000	41,000,000	-	-	42,000,000	1,000,000	-	-	250,000
2012	-	-	-	-	-	-	-	-	-	187,500
2013	-	-	3,000,000	14,000,000	-	17,000,000	14,000,000	-	-	3,640,625
2014	-	-	7,000,000	23,000,000	-	30,000,000	23,000,000	-	-	8,480,469
2015	-	-	11,000,000	29,000,000	-	40,000,000	29,000,000	-	-	13,847,656
2016	-	-	11,000,000	242,000,000	-	253,000,000	242,000,000	-	-	70,648,438
2017	-	31,000,000	53,000,000	351,000,000	-	435,000,000	382,000,000	-	-	151,808,594
2018	-	44,000,000	110,000,000	808,000,000	-	962,000,000	852,000,000	-	-	328,992,188
2019	-	-	8,000,000	185,000,000	-	193,000,000	185,000,000	86,014,674	6,542,860	294,417,969
2020	-	-	-	-	-	-	-	67,139,427	6,499,921	271,359,375
2021	-	-	-	-	-	-	-	69,548,545	6,562,694	236,742,188
2022	-	-	-	-	-	-	-	71,077,739	6,623,153	289,089,844
2023	-	-	-	-	-	-	-	73,387,900	6,671,627	58,535,156
2024	-	-	-	-	-	-	-	75,655,112	6,713,982	-
2025	-	-	-	-	-	-	-	78,081,453	6,768,160	-
2026	-	-	-	-	-	-	-	80,301,165	6,802,371	-
2027	-	-	-	-	-	-	-	82,059,025	6,796,808	-
2028	-	-	-	-	-	-	-	84,197,349	6,822,315	-
2029	-	-	-	34,000,000	-	34,000,000	34,000,000	86,349,821	6,847,858	8,500,000
2030	-	-	-	51,000,000	-	51,000,000	51,000,000	88,033,628	6,835,945	19,125,000
2031	-	-	-	41,000,000	-	41,000,000	41,000,000	89,818,159	6,832,179	24,593,750
2032	-	-	-	-	-	-	-	91,914,247	6,851,789	18,445,313
2033	-	-	-	-	-	-	-	94,440,885	6,835,086	21,902,344
2034	-	-	-	-	-	-	-	95,958,380	6,812,630	20,460,938
2035	-	-	-	-	-	-	-	72,939,821	6,796,665	12,972,656
2036	-	-	-	-	-	-	-	75,125,844	6,805,437	-
2037	-	-	-	-	-	-	-	64,979,808	6,817,111	-
2038	-	-	-	-	-	-	-	55,039,128	6,833,078	-
2039	-	-	-	-	-	-	-	45,919,839	6,817,758	-
2040	-	-	-	-	-	-	-	39,106,364	6,828,560	-
Sum	**-**	**76,000,000**	**244,000,000**	**1,778,000,000**		**2,098,000,000**	**1,854,000,000**	**1,667,088,313**	**148,717,986**	**1,854,000,000**

Tahun	Intangible Gas	Gas Cost to be Recovered	IC Gas to be recovered	IC Paid	IC Unrec.	Rev after FTP+CR Cap+IC	Gas Rec Costs		Mixed Gas+Oil Cost Recoverable	Mixed Gas+Oil Unrec. Cost
2011	41,000,000	$ 41,250,000	$ -	$ -	$ -	$ -	$ -		$ -	$ 41,250,000
2012	-	$ 187,500	$ -	$ -	$ -	$ -	$ -		$ -	$ 41,437,500
2013	3,000,000	$ 6,640,625	$ -	$ -	$ -	$ -	$ -		$ -	$ 48,078,125
2014	7,000,000	$ 15,480,469	$ -	$ -	$ -	$ -	$ -		$ -	$ 63,558,594
2015	11,000,000	$ 24,847,656	$ -	$ -	$ -	$ -	$ -		$ -	$ 88,406,250
2016	11,000,000	$ 81,648,438	$ -	$ -	$ -	$ -	$ -		$ -	$ 170,054,688
2017	53,000,000	$ 204,808,594	$ -	$ -	$ -	$ -	$ -		$ -	$ 374,863,281
2018	110,000,000	$ 438,992,188	$ -	$ -	$ -	$ -	$ -		$ -	$ 813,855,469
2019	8,000,000	$ 394,975,503	$ -	$ -	$ -	$ 350,538,790	$ 350,538,790		$ 350,538,790	$ 858,292,181
2020	-	$ 344,998,722	$ -	$ -	$ -	$ 495,684,602	$ 344,998,722		$ 495,684,602	$ 707,606,301
2021	-	$ 312,853,426	$ -	$ -	$ -	$ 504,216,878	$ 312,853,426		$ 504,216,878	$ 516,242,849
2022	-	$ 366,790,736	$ -	$ -	$ -	$ 514,301,216	$ 366,790,736		$ 514,301,216	$ 319,622,196
2023	-	$ 138,594,683	$ -	$ -	$ -	$ 524,587,240	$ 138,594,683		$ 403,411,228	$ -
2024	-	$ 82,369,093	$ -	$ -	$ -	$ 536,544,955	$ 82,369,093		$ 82,369,093	$ -
2025	-	$ 84,849,613	$ -	$ -	$ -	$ 545,780,565	$ 84,849,613		$ 84,849,613	$ -
2026	-	$ 87,103,536	$ -	$ -	$ -	$ 556,696,176	$ 87,103,536		$ 87,103,536	$ -
2027	-	$ 88,855,833	$ -	$ -	$ -	$ 567,830,099	$ 88,855,833		$ 88,855,833	$ -
2028	-	$ 91,019,664	$ -	$ -	$ -	$ 580,773,514	$ 91,019,664		$ 91,019,664	$ -
2029	-	$ 101,697,679	$ -	$ -	$ -	$ 590,770,435	$ 101,697,679		$ 101,697,679	$ -
2030	-	$ 113,994,573	$ -	$ -	$ -	$ 602,585,844	$ 113,994,573		$ 113,994,573	$ -
2031	-	$ 121,244,088	$ -	$ -	$ -	$ 614,637,561	$ 121,244,088		$ 121,244,088	$ -
2032	-	$ 117,211,349	$ -	$ -	$ -	$ 628,647,930	$ 117,211,349		$ 117,211,349	$ -
2033	-	$ 123,178,315	$ -	$ -	$ -	$ 639,468,918	$ 123,178,315		$ 123,178,315	$ -
2034	-	$ 123,231,947	$ -	$ -	$ -	$ 652,258,297	$ 123,231,947		$ 123,231,947	$ -
2035	-	$ 92,709,143	$ -	$ -	$ -	$ 636,236,807	$ 92,709,143		$ 92,709,143	$ -
2036	-	$ 81,931,280	$ -	$ -	$ -	$ 574,247,056	$ 81,931,280		$ 81,931,280	$ -
2037	-	$ 71,796,919	$ -	$ -	$ -	$ 506,472,517	$ 71,796,919		$ 71,796,919	$ -
2038	-	$ 61,872,206	$ -	$ -	$ -	$ 437,389,666	$ 61,872,206		$ 61,872,206	$ -
2039	-	$ 52,737,597	$ -	$ -	$ -	$ 372,366,698	$ 52,737,597		$ 52,737,597	$ -
2040	-	$ 45,934,924	$ -	$ -	$ -	$ 323,367,129	$ 45,934,924		$ 45,934,924	$ -
Sum	244,000,000	3,913,806,300	-	-	-	11,755,402,895	$ 3,055,514,118	$ -	$ 3,809,890,475	$ 4,043,267,434

Tahun	Oil Rev available to Rec Mixed Gas+Oil Cost	Oil Rev Transfer to Rec Mixed Gas+Oil Cost	Final Mixed Gas+Oil Unrec	ETS	ETS Gas Contractor	ETS Gas Government	FTP Gas Contractor	FTP Gas Government	Contractor Taxable Income
2011	$ -	$ -	$ 41,250,000	-	-	-	$ -	$ -	-
2012	$ -	$ -	$ 41,437,500	-	-	-	$ -	$ -	-
2013	$ -	$ -	$ 48,078,125	-	-	-	$ -	$ -	-
2014	$ -	$ -	$ 63,558,594	-	-	-	$ -	$ -	-
2015	$ -	$ -	$ 88,406,250	-	-	-	$ -	$ -	-
2016	$ -	$ -	$ 170,054,688	-	-	-	$ -	$ -	-
2017	$ -	$ -	$ 374,863,281	-	-	-	$ -	$ -	-
2018	$ -	$ -	$ 813,855,469	-	-	-	$ -	$ -	-
2019	$ -	$ -	$ 858,292,181	-	-	-	$ 54,771,686	$ 32,863,012	54,771,686
2020	$ -	$ -	$ 707,606,301	-	-	-	$ 77,450,719	$ 46,470,431	77,450,719
2021	$ 49,110,173	$ 49,110,173	$ 467,132,676	-	-	-	$ 78,783,887	$ 47,270,332	78,783,887
2022	$ 54,805,652	$ 54,805,652	$ 264,816,545	-	-	-	$ 80,359,565	$ 48,215,739	80,359,565
2023	$ 52,165,509	$ -	$ -	121,176,012	75,735,008	45,441,005	$ 81,966,756	$ 49,180,054	157,701,764
2024	$ 50,096,375	$ -	$ -	454,175,861	283,859,913	170,315,948	$ 83,835,149	$ 50,301,090	367,695,062
2025	$ 46,744,818	$ -	$ -	460,930,952	288,081,845	172,849,107	$ 85,278,213	$ 51,166,928	373,360,058
2026	$ 45,021,965	$ -	$ -	469,592,639	293,495,400	176,097,240	$ 86,983,777	$ 52,190,266	380,479,177
2027	$ 46,351,061	$ -	$ -	478,974,267	299,358,917	179,615,350	$ 88,723,453	$ 53,234,072	388,082,370
2028	$ 45,385,968	$ -	$ -	489,753,850	306,096,156	183,657,694	$ 90,745,862	$ 54,447,517	396,842,018
2029	$ 44,082,554	$ -	$ -	489,072,756	305,670,473	183,402,284	$ 92,307,881	$ 55,384,728	397,978,353
2030	$ 45,944,448	$ -	$ -	488,591,271	305,369,544	183,221,727	$ 94,154,038	$ 56,492,423	399,523,583
2031	$ 47,185,213	$ -	$ -	493,393,473	308,370,920	185,022,552	$ 96,037,119	$ 57,622,271	404,408,039
2032	$ 46,614,035	$ -	$ -	511,436,580	319,647,863	191,788,718	$ 98,226,239	$ 58,935,743	417,874,102
2033	$ 48,776,070	$ -	$ -	516,290,603	322,681,627	193,608,976	$ 99,917,019	$ 59,950,211	422,598,646
2034	$ 51,775,107	$ -	$ -	529,026,350	330,641,469	198,384,881	$ 101,915,359	$ 61,149,215	432,556,828
2035	$ 53,866,208	$ -	$ -	543,527,664	339,704,790	203,822,874	$ 99,412,001	$ 59,647,201	439,116,791
2036	$ 46,957,536	$ -	$ -	492,315,776	307,697,360	184,618,416	$ 89,726,103	$ 53,835,662	397,423,462
2037	$ 40,644,387	$ -	$ -	434,675,598	271,672,249	163,003,349	$ 79,136,331	$ 47,481,799	350,808,580
2038	$ 34,153,256	$ -	$ -	375,517,460	234,698,413	140,819,048	$ 68,342,135	$ 41,005,281	303,040,548
2039	$ 29,853,782	$ -	$ -	319,629,102	199,768,189	119,860,913	$ 58,182,297	$ 34,909,378	257,950,485
2040	$ 25,432,674	$ -	$ -	277,432,205	173,395,128	104,037,077	$ 50,526,114	$ 30,315,668	223,921,242
Sum	**$ 904,966,791**	**$ 103,915,825**	**$ 3,939,351,609**	**$ 7,945,512,420**	**$ 4,965,945,263**	**$ 2,979,567,158**	**$ 1,836,781,702**	**$ 1,102,069,021**	**$ 6,802,726,965**

Tahun	Contractor Tax	Contractor Net Share	Contractor Cash Flow	Cum. Contr. CF	Contr. POT	GOI Take
2011	-	-	$ (42,000,000)	(42,000,000)	-	-
2012	-	-	$ -	(42,000,000)	-	-
2013	-	-	$ (17,000,000)	(59,000,000)	-	-
2014	-	-	$ (30,000,000)	(89,000,000)	-	-
2015	-	-	$ (40,000,000)	(129,000,000)	-	-
2016	-	-	$ (253,000,000)	(382,000,000)	-	-
2017	-	-	$ (435,000,000)	(817,000,000)	-	-
2018	-	-	$ (962,000,000)	(1,779,000,000)	-	-
2019	24,099,542	30,672,144	$ 95,653,400	(1,683,346,600)	-	56,962,553
2020	34,078,316	43,372,403	$ 465,417,658	(1,217,928,942)	-	80,548,748
2021	34,664,910	44,118,977	$ 472,224,617	(745,704,325)	-	81,935,243
2022	35,358,209	45,001,356	$ 481,601,680	(264,102,646)	11	83,573,948
2023	69,388,776	88,312,988	$ 411,664,689	147,562,043	-	164,009,834
2024	161,785,827	205,909,235	$ 205,909,235	353,471,278	-	382,402,865
2025	164,278,426	209,081,632	$ 209,081,632	562,552,911	-	388,294,460
2026	167,410,838	213,068,339	$ 213,068,339	775,621,250	-	395,698,344
2027	170,756,243	217,326,127	$ 217,326,127	992,947,377	-	403,605,665
2028	174,610,488	222,231,530	$ 222,231,530	1,215,178,907	-	412,715,699
2029	175,110,475	222,867,878	$ 197,367,878	1,412,546,785	-	413,897,487
2030	175,790,376	223,733,206	$ 191,858,206	1,604,404,991	-	415,504,526
2031	177,939,537	226,468,502	$ 210,062,252	1,814,467,243	-	420,584,361
2032	183,864,605	234,009,497	$ 252,454,809	2,066,922,052	-	434,589,066
2033	185,943,404	236,655,242	$ 258,557,585	2,325,479,638	-	439,502,591
2034	190,325,004	242,231,824	$ 262,692,761	2,588,172,399	-	449,859,101
2035	193,211,388	245,905,403	$ 258,878,059	2,847,050,458	-	456,681,463
2036	174,866,323	222,557,139	$ 222,557,139	3,069,607,597	-	413,320,401
2037	154,355,775	196,452,805	$ 196,452,805	3,266,060,401	-	364,840,923
2038	133,337,841	169,702,707	$ 169,702,707	3,435,763,108	-	315,162,170
2039	113,498,213	144,452,272	$ 144,452,272	3,580,215,380	-	268,268,505
2040	98,525,346	125,395,896	$ 125,395,896	3,705,611,276	-	232,878,092
Sum	**$ 2,993,199,865**	**$ 3,809,527,100**	**$ 3,705,611,276**		**$ 11**	**$ 7,074,836,043**

And the final calculation for both product (Oil, Condensate, Gas, and LPG) is submission from both tables above.

Tahun	Revenue (MMUS$)	FTP Oil + Gas	Rev aft. FTP	CR Cap.	Rev Oil aft. FTP+CR Cap	Sunk Cost	Drilling Tangible	Drilling Intangible	Facility Tangible	Facility Intangible
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000,000	$ 41,000,000	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,000,000	$ 14,000,000	$ -
2014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,000,000	$ 23,000,000	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,000,000	$ 29,000,000	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,000,000	$ 242,000,000	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,000,000	$ 53,000,000	$ 351,000,000	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,000,000	$ 110,000,000	$ 808,000,000	$ -
2019	$ 499,228,793	$ 99,845,759	$ 399,383,034	$ -	$ 399,383,034	$ -	$ -	$ 8,000,000	$ 185,000,000	$ -
2020	$ 710,605,459	$ 142,121,092	$ 568,484,367	$ -	$ 568,484,367	$ -	$ -	$ -	$ -	$ -
2021	$ 715,923,200	$ 143,184,640	$ 572,738,560	$ -	$ 572,738,560	$ -	$ -	$ -	$ -	$ -
2022	$ 723,575,650	$ 144,715,130	$ 578,860,520	$ -	$ 578,860,520	$ -	$ -	$ -	$ -	$ -
2023	$ 732,684,710	$ 146,536,942	$ 586,147,768	$ -	$ 586,147,768	$ -	$ -	$ -	$ -	$ -
2024	$ 744,658,477	$ 148,931,695	$ 595,726,781	$ -	$ 595,726,781	$ -	$ -	$ -	$ -	$ -
2025	$ 751,412,894	$ 150,282,579	$ 601,130,316	$ -	$ 601,130,316	$ -	$ -	$ -	$ -	$ -
2026	$ 762,586,437	$ 152,517,287	$ 610,069,150	$ -	$ 610,069,150	$ -	$ -	$ -	$ -	$ -
2027	$ 778,474,842	$ 155,694,968	$ 622,779,874	$ -	$ 622,779,874	$ -	$ -	$ -	$ -	$ -
2028	$ 793,242,954	$ 158,648,591	$ 634,594,363	$ -	$ 634,594,363	$ -	$ -	$ -	$ -	$ -
2029	$ 803,887,320	$ 160,777,464	$ 643,109,856	$ -	$ 643,109,856	$ -	$ -	$ -	$ 34,000,000	$ -
2030	$ 821,394,081	$ 164,278,816	$ 657,115,265	$ -	$ 657,115,265	$ -	$ -	$ -	$ 51,000,000	$ -
2031	$ 838,283,727	$ 167,656,745	$ 670,626,981	$ -	$ 670,626,981	$ -	$ -	$ -	$ 41,000,000	$ -
2032	$ 854,938,091	$ 170,987,618	$ 683,950,473	$ -	$ 683,950,473	$ -	$ -	$ -	$ -	$ -
2033	$ 871,779,453	$ 174,355,891	$ 697,423,562	$ -	$ 697,423,562	$ -	$ -	$ -	$ -	$ -
2034	$ 892,146,176	$ 178,429,235	$ 713,716,941	$ -	$ 713,716,941	$ -	$ -	$ -	$ -	$ -
2035	$ 872,276,342	$ 174,455,268	$ 697,821,073	$ -	$ 697,821,073	$ -	$ -	$ -	$ -	$ -
2036	$ 786,274,093	$ 157,254,819	$ 629,019,274	$ -	$ 629,019,274	$ -	$ -	$ -	$ -	$ -
2037	$ 692,287,854	$ 138,457,571	$ 553,830,283	$ -	$ 553,830,283	$ -	$ -	$ -	$ -	$ -
2038	$ 596,462,736	$ 119,292,547	$ 477,170,189	$ -	$ 477,170,189	$ -	$ -	$ -	$ -	$ -
2039	$ 508,932,802	$ 101,786,560	$ 407,146,241	$ -	$ 407,146,241	$ -	$ -	$ -	$ -	$ -
2040	$ 441,263,418	$ 88,252,684	$ 353,010,734	$ -	$ 353,010,734	$ -	$ -	$ -	$ -	$ -
Sum	$ 16,192,319,507	$ 3,238,463,901	$ 12,953,855,605	$ -	$ 12,953,855,605	$ -	$ 76,000,000	$ 244,000,000	$ 1,778,000,000	$ -

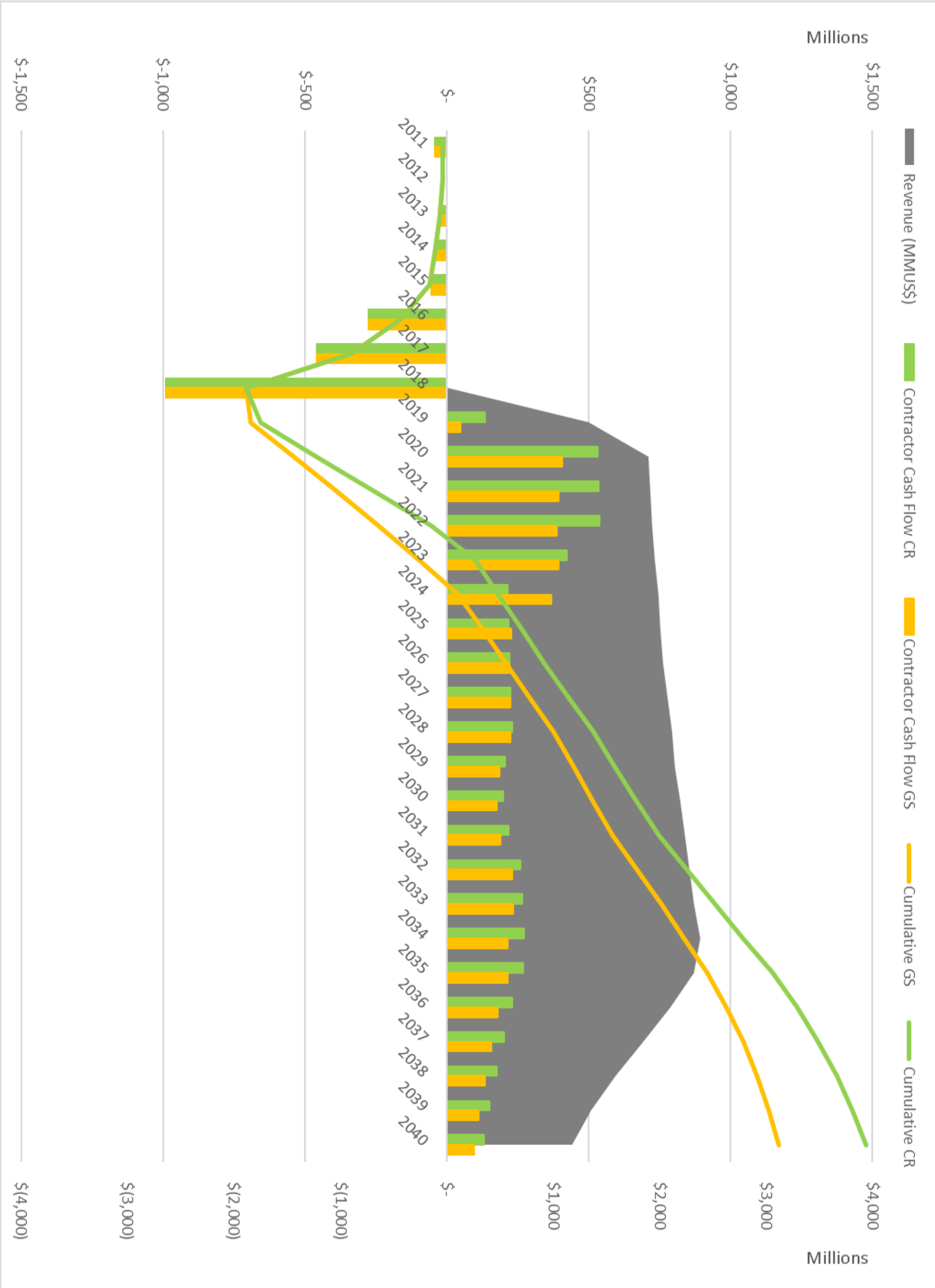
Tahun	Total Invesment	Depreciable	Opex	Asset Lease + LBT +ASR + Import Duty	Deprec.	Intangible	Cost Rec.	IC	IC Paid	IC Unrec.
2011	$ 42,000,000	$ 1,000,000	$ -	$ -	$ 250,000	$ 41,000,000	$ 41,250,000	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ 187,500	$ -	$ 187,500	$ -	$ -	$ -
2013	$ 17,000,000	$ 14,000,000	$ 6,000,000	$ -	$ 3,640,625	$ 3,000,000	$ 12,640,625	$ -	$ -	$ -
2014	$ 30,000,000	$ 23,000,000	$ 10,000,000	$ -	$ 8,480,469	$ 7,000,000	$ 25,480,469	$ -	$ -	$ -
2015	$ 40,000,000	$ 29,000,000	$ 15,000,000	$ -	$ 13,847,656	$ 11,000,000	$ 39,847,656	$ -	$ -	$ -
2016	$ 253,000,000	$ 242,000,000	$ 23,000,000	$ -	$ 70,648,438	$ 11,000,000	$ 104,648,438	$ -	$ -	$ -
2017	$ 435,000,000	$ 382,000,000	$ 25,000,000	$ -	$ 151,808,594	$ 53,000,000	$ 229,808,594	$ -	$ -	$ -
2018	$ 962,000,000	$ 852,000,000	$ 28,000,000	$ -	$ 328,992,188	$ 110,000,000	$ 466,992,188	$ -	$ -	$ -
2019	$ 193,000,000	$ 185,000,000	$ 98,000,000	$ 7,454,545	$ 294,417,969	$ 8,000,000	$ 407,872,514	$ -	$ -	$ -
2020	$ -	$ -	$ 77,000,000	$ 7,454,545	$ 271,359,375	$ -	$ 355,813,920	$ -	$ -	$ -
2021	$ -	$ -	$ 79,000,000	$ 7,454,545	$ 236,742,188	$ -	$ 323,196,733	$ -	$ -	$ -
2022	$ -	$ -	$ 80,000,000	$ 7,454,545	$ 289,089,844	$ -	$ 376,544,389	$ -	$ -	$ -
2023	$ -	$ -	$ 82,000,000	$ 7,454,545	$ 58,535,156	$ -	$ 147,989,702	$ -	$ -	$ -
2024	$ -	$ -	$ 84,000,000	$ 7,454,545	$ -	$ -	$ 91,454,545	$ -	$ -	$ -
2025	$ -	$ -	$ 86,000,000	$ 7,454,545	$ -	$ -	$ 93,454,545	$ -	$ -	$ -
2026	$ -	$ -	$ 88,000,000	$ 7,454,545	$ -	$ -	$ 95,454,545	$ -	$ -	$ -
2027	$ -	$ -	$ 90,000,000	$ 7,454,545	$ -	$ -	$ 97,454,545	$ -	$ -	$ -
2028	$ -	$ -	$ 92,000,000	$ 7,454,545	$ -	$ -	$ 99,454,545	$ -	$ -	$ -
2029	$ 34,000,000	$ 34,000,000	$ 94,000,000	$ 7,454,545	$ 8,500,000	$ -	$ 109,954,545	$ -	$ -	$ -
2030	$ 51,000,000	$ 51,000,000	$ 96,000,000	$ 7,454,545	$ 19,125,000	$ -	$ 122,579,545	$ -	$ -	$ -
2031	$ 41,000,000	$ 41,000,000	$ 98,000,000	$ 7,454,545	$ 24,593,750	$ -	$ 130,048,295	$ -	$ -	$ -
2032	$ -	$ -	$ 100,000,000	$ 7,454,545	$ 18,445,313	$ -	$ 125,899,858	$ -	$ -	$ -
2033	$ -	$ -	$ 103,000,000	$ 7,454,545	$ 21,902,344	$ -	$ 132,356,889	$ -	$ -	$ -
2034	$ -	$ -	$ 105,000,000	$ 7,454,545	$ 20,460,938	$ -	$ 132,915,483	$ -	$ -	$ -
2035	$ -	$ -	$ 80,000,000	$ 7,454,545	$ 12,972,656	$ -	$ 100,427,202	$ -	$ -	$ -
2036	$ -	$ -	$ 82,291,416	$ 7,454,545	$ -	$ -	$ 89,745,962	$ -	$ -	$ -
2037	$ -	$ -	$ 71,055,752	$ 7,454,545	$ -	$ -	$ 78,510,298	$ -	$ -	$ -
2038	$ -	$ -	$ 60,044,928	$ 7,454,545	$ -	$ -	$ 67,499,473	$ -	$ -	$ -
2039	$ -	$ -	$ 50,208,813	$ 7,454,545	$ -	$ -	$ 57,663,358	$ -	$ -	$ -
2040	$ -	$ -	$ 42,691,310	$ 7,454,545	$ -	$ -	$ 50,145,855	$ -	$ -	$ -
Sum	$ 2,098,000,000	$ 1,854,000,000	$ 1,945,292,219	$ 164,000,000	$1,854,000,000	$ 244,000,000	$4,207,292,219	$ -	$ -	$ -

Tahun	Rev after FTP+CR Cap+IC	Unrec. Cap Balance	IC (bef. Tax)	Witholding Tax	ICR	Rec. Gas	Total Oil Cost Recoverable	Total Gas Cost Recoverable	Total Cost Recoverable	Total Cost UnRecoverable
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,250,000
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,437,500
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,078,125
2014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,558,594
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 119,406,250
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 224,054,688
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 453,863,281
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 920,855,469
2019	$ 399,383,034	$ -	$ -	$ -	$ -	$ 399,383,034	$ 48,844,244	$ 350,538,790	$ 399,383,034	$ 929,344,949
2020	$ 568,484,367	$ -	$ -	$ -	$ -	$ 417,798,487	$ 72,799,765	$ 495,684,602	$ 568,484,367	$ 716,674,502
2021	$ 572,738,560	$ -	$ -	$ -	$ -	$ 332,264,934	$ 68,521,681	$ 504,216,878	$ 572,738,560	$ 467,132,676
2022	$ 578,860,520	$ -	$ -	$ -	$ -	$ 376,544,389	$ 64,559,305	$ 514,301,216	$ 578,860,520	$ 264,816,545
2023	$ 586,147,768	$ -	$ -	$ -	$ -	$ 147,989,702	$ 9,395,018	$ 403,411,228	$ 412,806,246	$ -
2024	$ 595,726,781	$ -	$ -	$ -	$ -	$ 91,454,545	$ 9,085,452	$ 82,369,093	$ 91,454,545	$ -
2025	$ 601,130,316	$ -	$ -	$ -	$ -	$ 93,454,545	$ 8,604,933	$ 84,849,613	$ 93,454,545	$ -
2026	$ 610,069,150	$ -	$ -	$ -	$ -	$ 95,454,545	$ 8,351,009	$ 87,103,536	$ 95,454,545	$ -
2027	$ 622,779,874	$ -	$ -	$ -	$ -	$ 97,454,545	$ 8,598,713	$ 88,855,833	$ 97,454,545	$ -
2028	$ 634,594,363	$ -	$ -	$ -	$ -	$ 99,454,545	$ 8,434,881	$ 91,019,664	$ 99,454,545	$ -
2029	$ 643,109,856	$ -	$ -	$ -	$ -	$ 109,954,545	$ 8,256,866	$ 101,697,679	$ 109,954,545	$ -
2030	$ 657,115,265	$ -	$ -	$ -	$ -	$ 122,579,545	$ 8,584,972	$ 113,994,573	$ 122,579,545	$ -
2031	$ 670,626,981	$ -	$ -	$ -	$ -	$ 130,048,295	$ 8,804,207	$ 121,244,088	$ 130,048,295	$ -
2032	$ 683,950,473	$ -	$ -	$ -	$ -	$ 125,899,858	$ 8,688,509	$ 117,211,349	$ 125,899,858	$ -
2033	$ 697,423,562	$ -	$ -	$ -	$ -	$ 132,356,889	$ 9,178,574	$ 123,178,315	$ 132,356,889	$ -
2034	$ 713,716,941	$ -	$ -	$ -	$ -	$ 132,915,483	$ 9,683,536	$ 123,231,947	$ 132,915,483	$ -
2035	$ 697,821,073	$ -	$ -	$ -	$ -	$ 100,427,202	$ 7,718,059	$ 92,709,143	$ 100,427,202	$ -
2036	$ 629,019,274	$ -	$ -	$ -	$ -	$ 89,745,962	$ 7,814,682	$ 81,931,280	$ 89,745,962	$ -
2037	$ 553,830,283	$ -	$ -	$ -	$ -	$ 78,510,298	$ 6,713,378	$ 71,796,919	$ 78,510,298	$ -
2038	$ 477,170,189	$ -	$ -	$ -	$ -	$ 67,499,473	$ 5,627,268	$ 61,872,206	$ 67,499,473	$ -
2039	$ 407,146,241	$ -	$ -	$ -	$ -	$ 57,663,358	$ 4,925,761	$ 52,737,597	$ 57,663,358	$ -
2040	$ 353,010,734	$ -	$ -	$ -	$ -	$ 50,145,855	$ 4,210,931	$ 45,934,924	$ 50,145,855	$ -
Sum	**$ 12,953,855,605**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,349,000,038**	**$ 397,401,744**	**$ 3,809,890,475**	**$ 4,207,292,219**	**$ 4,312,472,578**

Tahun	ETS	ETS Contr.	ETS Gov.	FTP Contr.	FTP Gov.	DMO	DMO Fee	Net DMO	Contr. Taxable Income
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ 58,042,506	$ 41,803,253	$ -	$ -	$ -	$ 58,042,506
2020	$ -	$ -	$ -	$ 82,325,703	$ 59,795,388	$ -	$ -	$ -	$ 82,325,703
2021	$ -	$ -	$ -	$ 83,372,393	$ 59,812,247	$ -	$ -	$ -	$ 83,372,393
2022	$ -	$ -	$ -	$ 84,682,733	$ 60,032,397	$ -	$ -	$ -	$ 84,682,733
2023	$ 173,341,522	$ 89,707,912	$ 83,633,610	$ 86,089,113	$ 60,447,829	$ 5,152,946	$ 5,152,946	$ -	$ 175,797,025
2024	$ 504,272,236	$ 297,278,585	$ 206,993,651	$ 87,798,218	$ 61,133,477	$ 4,953,836	$ 1,238,459	$ 3,715,377	$ 381,361,426
2025	$ 507,675,770	$ 300,602,778	$ 207,072,992	$ 88,984,670	$ 61,297,909	$ 4,633,071	$ 1,158,268	$ 3,474,803	$ 386,112,645
2026	$ 514,614,605	$ 305,554,855	$ 209,059,750	$ 90,557,861	$ 61,959,427	$ 4,467,604	$ 1,116,901	$ 3,350,703	$ 392,762,012
2027	$ 525,325,328	$ 311,774,380	$ 213,550,948	$ 92,403,125	$ 63,291,843	$ 4,599,590	$ 1,149,898	$ 3,449,693	$ 400,727,812
2028	$ 535,139,818	$ 318,253,112	$ 216,886,706	$ 94,349,936	$ 64,298,654	$ 4,505,093	$ 1,126,273	$ 3,378,820	$ 409,224,228
2029	$ 533,155,310	$ 317,478,300	$ 215,677,011	$ 95,812,752	$ 64,964,712	$ 4,381,090	$ 1,095,272	$ 3,285,817	$ 410,005,235
2030	$ 534,535,719	$ 317,676,093	$ 216,859,626	$ 97,805,562	$ 66,473,254	$ 4,564,405	$ 1,141,101	$ 3,423,303	$ 412,058,351
2031	$ 540,578,686	$ 321,009,817	$ 219,568,869	$ 99,786,410	$ 67,870,335	$ 4,686,614	$ 1,171,654	$ 3,514,961	$ 417,281,267
2032	$ 558,050,615	$ 332,133,765	$ 225,916,850	$ 101,929,534	$ 69,058,084	$ 4,629,119	$ 1,157,280	$ 3,471,839	$ 430,591,460
2033	$ 565,066,673	$ 335,746,646	$ 229,320,027	$ 103,797,910	$ 70,557,981	$ 4,851,114	$ 1,212,779	$ 3,638,336	$ 435,906,220
2034	$ 580,801,458	$ 344,509,801	$ 236,291,656	$ 106,030,893	$ 72,398,342	$ 5,144,418	$ 1,286,104	$ 3,858,313	$ 446,682,381
2035	$ 597,393,872	$ 354,133,238	$ 243,260,633	$ 103,535,947	$ 70,919,321	$ 5,154,933	$ 1,288,733	$ 3,866,200	$ 453,802,986
2036	$ 539,273,312	$ 320,275,271	$ 218,998,041	$ 93,393,885	$ 63,860,934	$ 4,584,728	$ 1,146,182	$ 3,438,546	$ 410,230,610
2037	$ 475,319,985	$ 282,559,138	$ 192,760,847	$ 82,307,610	$ 56,149,961	$ 3,964,099	$ 991,025	$ 2,973,074	$ 361,893,674
2038	$ 409,670,716	$ 243,846,606	$ 165,824,110	$ 71,006,010	$ 48,286,538	$ 3,329,843	$ 832,461	$ 2,497,382	$ 312,355,234
2039	$ 349,482,883	$ 207,764,737	$ 141,718,146	$ 60,511,284	$ 41,275,276	$ 2,911,234	$ 727,809	$ 2,183,426	$ 266,092,596
2040	$ 302,864,879	$ 180,207,451	$ 122,657,427	$ 52,511,177	$ 35,741,507	$ 2,481,329	$ 620,332	$ 1,860,996	$ 230,857,632
Sum	**$ 8,746,563,386**	**$ 5,180,512,486**	**$ 3,566,050,901**	**$ 1,917,035,232**	**$ 1,321,428,669**	**$ 78,995,066**	**$ 23,613,476**	**$ 55,381,590**	**$ 7,042,166,128**

Tahun	Contr. Tax	Contr. Net Share	Contractor Cash Flow CR	Cumulative CR	Contr. POT	GOI Take
2011	$ -	$ -	$ (42,000,000)	$ -42,000,000	-	$ -
2012	$ -	$ -	$ -	$ -42,000,000	-	$ -
2013	$ -	$ -	$ (23,000,000)	$ -65,000,000	-	$ -
2014	$ -	$ -	$ (40,000,000)	$ -105,000,000	-	$ -
2015	$ -	$ -	$ (55,000,000)	$ -160,000,000	-	$ -
2016	$ -	$ -	$ (276,000,000)	$ -436,000,000	-	$ -
2017	$ -	$ -	$ (460,000,000)	$ -896,000,000	-	$ -
2018	$ -	$ -	$ (990,000,000)	$ -1,886,000,000	-	$ -
2019	$ 25,538,703	$ 32,503,803	$ 133,432,292	$ -1,752,567,708	-	$ 67,341,955
2020	$ 36,223,309	$ 46,102,394	$ 530,132,215	$ -1,222,435,493	-	$ 96,018,698
2021	$ 36,683,853	$ 46,688,540	$ 532,972,554	$ -689,462,939	-	$ 96,496,100
2022	$ 37,260,402	$ 47,422,330	$ 538,828,305	$ -150,634,633	10.36	$ 97,292,800
2023	$ 77,350,691	$ 98,446,334	$ 421,798,035	$ 271,163,401	-	$ 221,432,130
2024	$ 167,799,027	$ 213,562,399	$ 213,562,399	$ 484,725,800	-	$ 439,641,533
2025	$ 169,889,564	$ 216,223,081	$ 216,223,081	$ 700,948,881	-	$ 441,735,268
2026	$ 172,815,285	$ 219,946,727	$ 219,946,727	$ 920,895,608	-	$ 447,185,165
2027	$ 176,320,237	$ 224,407,575	$ 224,407,575	$ 1,145,303,183	-	$ 456,612,722
2028	$ 180,058,660	$ 229,165,568	$ 229,165,568	$ 1,374,468,751	-	$ 464,622,841
2029	$ 180,402,303	$ 229,602,931	$ 204,102,931	$ 1,578,571,682	-	$ 464,329,843
2030	$ 181,305,675	$ 230,752,677	$ 198,877,677	$ 1,777,449,359	-	$ 468,061,859
2031	$ 183,603,757	$ 233,677,509	$ 217,271,259	$ 1,994,720,618	-	$ 474,557,922
2032	$ 189,460,242	$ 241,131,218	$ 259,576,530	$ 2,254,297,148	-	$ 487,907,016
2033	$ 191,798,737	$ 244,107,483	$ 266,009,827	$ 2,520,306,975	-	$ 495,315,080
2034	$ 196,540,248	$ 250,142,133	$ 270,603,071	$ 2,790,910,046	-	$ 509,088,559
2035	$ 199,673,314	$ 254,129,672	$ 267,102,328	$ 3,058,012,374	-	$ 517,719,468
2036	$ 180,501,469	$ 229,729,142	$ 229,729,142	$ 3,287,741,516	-	$ 466,798,989
2037	$ 159,233,217	$ 202,660,457	$ 202,660,457	$ 3,490,401,974	-	$ 411,117,099
2038	$ 137,436,303	$ 174,918,931	$ 174,918,931	$ 3,665,320,904	-	$ 354,044,332
2039	$ 117,080,742	$ 149,011,854	$ 149,011,854	$ 3,814,332,758	-	$ 302,257,590
2040	$ 101,577,358	$ 129,280,274	$ 129,280,274	$ 3,943,613,032	-	$ 261,837,289
Sum	**$ 3,098,553,096**	**$ 3,943,613,032**	**$ 3,943,613,032**	**$ 3,943,613,032**	**$ 10**	**$ 8,041,414,256**

Comparation of cash flow analysis of both regimes for Field 04 are presented in graphic below



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