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Designing Oil and Gas Exploration Strategy For The Future National Energy Sustainability Based on Statistical Analysis of Commercial Reserves and Production Cost in Indonesia

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Abstract. Indonesia's declining oil production and rising domestic oil consumption have been a big issue for the last few decades which has turned Indonesia into a net oil importer from 2004 onward. The lack of exploration activities and other investments in oil and gas sector have resulted in the decline of Indonesia's oil production. This condition is a result of the plunge of global oil price which has fallen to its lowest level, i.e., US$43.14/Bbl (average oil price in 2016) over the last 12 years. The purpose of this paper is to analyze the distribution of oil and gas production in Indonesia along with the production cost. This analysis will allow investors to find and map working areas in Indonesia with potential commercial reserves while maintaining the lowest possible production costs. The approach of this empirical study is to divide Indonesia into 6 (six) geographical areas, namely Sumatera, Natuna Sea, Java, Kalimantan, Sulawesi and Papua. We have collected relevant data about commercial reserves and production cost from existing working areas. Our preliminary results depict that Kalimantan has the highest commercial reserves (i.e., 18.60 MMBOE per contract area) and Papua has the lowest production cost (i.e., US$3.24/BOE). Sulawesi, meanwhile, has the lowest commercial reserves (i.e., 5.39 MMBOE/Contract Area) and Natuna has the highest production cost (i.e., US$16.46/BOE). In summary, this study has shown that Eastern area of Indonesia might hold more oil and gas reserves which can be further managed by Contractor for the benefit of the Country. This study also recommends the Government of Indonesia to be aware of the condition of each working areas to maintain a sustainable oil and gas production on a National level and create attractiveness for investors in the future.

Keywords: Commercial reserves, cost per barrel, energy, investment, production cost, working areas.

1. Background of Oil and Gas Industry in Indonesia

1.1 Introduction on SKK Migas

Based on Law of the Republic of Indonesia Number 22 of 2001 and Presidential Regulation Number 9 of 2013, the Government of the Republic of Indonesia formed an institution called Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas). The Institution is assigned to manage the upstream oil and gas business activities under a Cooperation Contract. One of SKK Migas's functions is to approve Plan of Development (POD) documents or proposal based on the technical and economical evaluation.

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1.2 Production Sharing Contract

Since 1966, the Production Sharing Contract (PSC) concept has been the basic form of cooperation with foreign oil companies working in petroleum exploration and production in Indonesia. Under the PSC regime, the period of contract shall not exceed 30 years. The exploration period is six years and is included in the 30-year period. The exploration period can be extended once but cannot exceed four years, which will further proceed to the production phase, if there is sufficient hydrocarbon. If the contractor fails to produce hydrocarbon commercially within ten years, the working area shall be returned to the Government of Indonesia.

Here is the general flow diagram of PSC in Indonesia:

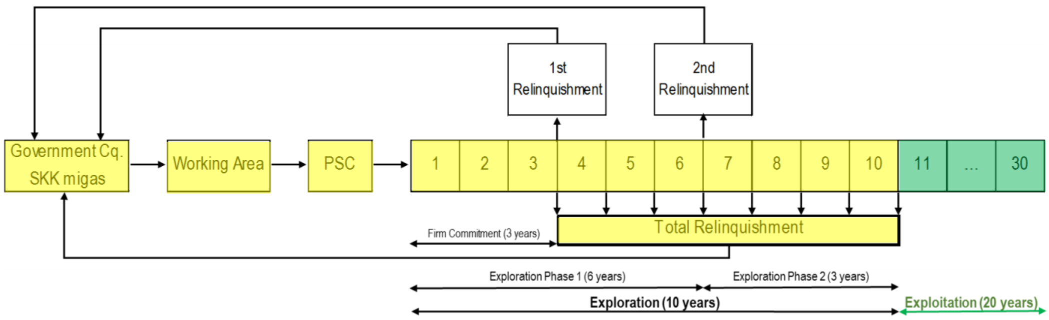

Figure 1. Production Sharing Contract Flow Diagram (Rukmana, 2011)

The duration of the PSC is 30 years from the date of the contract signed and may be extended for 20 years. Contract extensions can be proposed to the Minister of Energy and Mineral Resources through SKK Migas within two to ten years before the original contract expiry date. SKK Migas will further evaluate the proposal and provide recommendations for the ministry's approval.

The following table shows oil and gas exploration and exploitation activities within 30 years under PSC:

Table 1. Activities During Exploration and Exploitation Phases of a PSC

Exploration Phase (10 Years)	Exploitation Phase (20 Years)	
	Development	Production
▪ Geological & Geophysical ▪ Seismic & Survey ▪ Exploratory Drilling ▪ Other Facilities ▪ Etc.	▪ Development Drilling ▪ Reservoir Studies ▪ Completion ▪ Drilling Operation ▪ Well Equipment ▪ Etc.	▪ Production Operations ▪ Production Facilities ▪ Technical Services ▪ General & Administration ▪ Transportations ▪ Etc.

Notes:
A. Exploration
1. 6 (six) years with a 4 (four) years extension upon Contractor's request after the fulfillment of the minimum requirements.
2. Should the Contractor find no commercial discovery during the ten-year exploration period, the PSC shall be terminated.
3. During the first three years of the exploration period, Contractor shall perform committed work programs at the estimated amount as set out in the contract. In the event Contractor terminates it before completing the work programs, the outstanding commitments shall be payable to the Government through SKK Migas.

B. Exploitation
Upon approval of the first Plan of Development (POD), the Contractor shall commence the development of the field no later than five years following the end of the exploration phase (Yuwono, 2008).

Under PSC fiscal regime, in order to enable the project to be economically accepted, the Contractors may alternate the terms and conditions of the PSC, *i.e.*, change in the percentage of First Tranche Petroleum (FTP) shares and split ratio (between Contractor and Government), request for incentives (Investment Credit and Interest Cost Recovery), Domestic Market Obligation holiday and depreciation acceleration.

The following diagram illustrates the flow of a PSC:

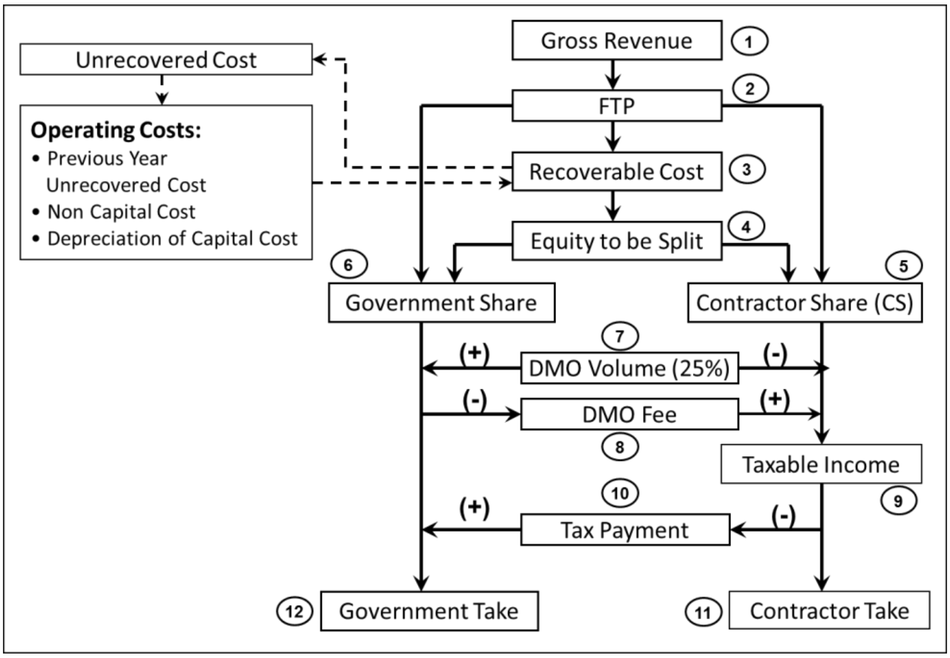

Figure 2. Production Sharing Contract (PSC) Diagram (Lubiantara, 2013)

In general, oil and gas price highly depends on the world market. As the market price is very volatile, the Contractors (both oil and gas) must properly manage their costs, risks, and technology. Based on that, in August 2016, Minister of Energy and Mineral Resources attempted to create a new paradigm of upstream oil and gas management with the Government Regulation Number 52 of 2017 on Gross Split Production Sharing Contracts. This regulation set out a new fiscal and economic structure for PSCs based on dividing gross production between the state and Contractors, without a mechanism for the PSC Contractor to recover operating costs.

The purpose of the establishment of a Gross Split PSC include (Tahar, 2017):

a. Encourage robust and expeditious exploration and exploitation efforts.
b. Encourage oil and gas contractors to be more efficient and perceptive to the price volatility.
c. Encourage the Contractors to be more accountable in managing and controlling their expenditures.

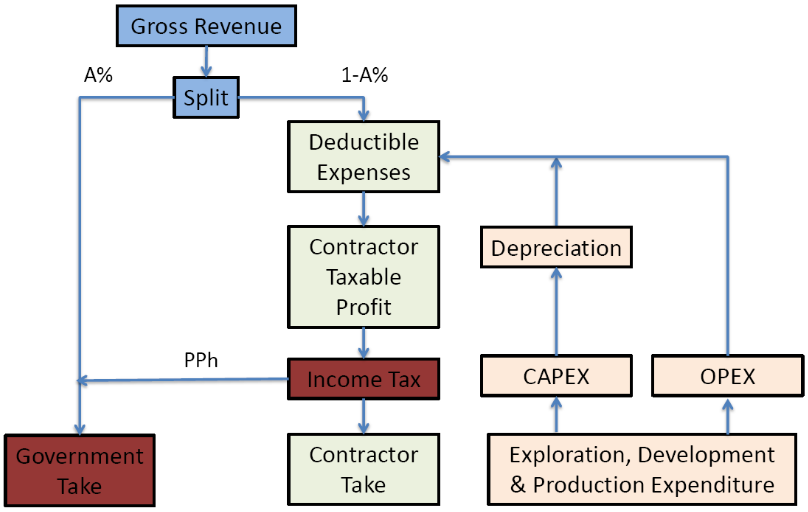

Figure 3. Gross Split PSC Diagram (Tahar, 2017)

As for the benefits that are expected with the implementation of Gross Split PSC, they include: (Tahar, 2017):

a. the concept of "Share Pain - Share Gain"
b. business risks mitigated through incentive split
c. shorter business processes: it is expected the Contractor will save around two to three years on the procurement process and achieve early production
d. decrease cycle time and cost of first gas and oil
e. enhanced involvement of local contents to achieve a greater split.

Here are the general terms and conditions in Gross Split PSC based on *regulation* of the *Minister* of energy and Mineral resources Number 52 of 2017:

Table 2. Base Split on Gross Split PSC (MEMR Regulation No. 52 of 2017)

Hydrocarbon	Government	Contractor
Oil	57	43
Gas	52	48

Table 3. Type of Incentives (MEMR Regulation No. 52 of 2017)

No.	Characteristic	Parameter	Additional Contractor Split
1	Field Status	POD I	5,0%
		POD II etc.	3,0%
		no POD	0,0%
2	Field Location	Onshore	0,0%
		Offshore (0<h≤20m)	8,0%
		Offshore (20<h≤50m)	10,0%
		Offshore (50<h≤150m)	12,0%
		Offshore (150<h≤1000m)	14,0%
		Offshore (h>1000m)	16,0%
3	Reservoir Depth	≤2500m	0,0%
		>2500m	1,0%
4	Supported Infrastructure	Well Develop	0,0%
		New Frontier Offshore	2,0%
		New Frontier Onshore	4,0%
5	Reservoir Condition	Conventional	0,0%
		Non-Conventional	16,0%
6	CO2(%)	<5%	0,0%
		5%≤x<10%	0,5%
		10%≤x<20%	1,0%
		20%≤x<40%	1,5%
		40%≤x<60%	2,0%
		x≥60%	4,0%
7	H2S (ppm)	<100	0,0%
		100≤x<1000	1,0%
		1000≤x<2000	2,0%
		2000≤x<3000	3,0%
		3000≤x<4000	4,0%
		x≥4000	5,0%
8	Oil Specific Gravity (API)	API<25	1,0%
		API≥25	0,0%
9	Local Content	<30	0,0%
		30≤x<50	2,0%
		50≤x<70	3,0%
		70≤x<100	4,0%
10	Production Phase	Primary	0,0%
		Secondary	6,0%
		Tertiary	10,0%
11	Cumulative Production (mmboe)	<30	10,0%
		30≤x<60	9,0%
		60≤x<90	8,0%
		90≤x<125	6,0%
		125≤x<175	4,0%
		x≥175	0,0%
12	Oil Price	(85-ICP) x 0.25	5,0%
13	Gas Price	<7	(7 - Gas Price) x 2.5
		7 - 10	0%
		>10	(10 - Gas Price) x 2.5

1.3 Plan of Development

In Indonesia, the term Field Development Plan (FDP) is usually known as Plan of Development (POD). A POD is a plan to develop one or more oil and gas field in an integrated way to produce hydrocarbon reserves optimally by considering the technical, economic and other aspects.

There are several types of POD as follows:

1. POD I
   POD I is the first plan to develop oil and gas field once a PSC is signed. This POD is subject to Ministry of Energy and Mineral Resources ("MEMR")'s approval. In general, the first POD must be proposed and approved before the end of a ten-year exploration period. Should there be no approval given by MEMR within the stated exploration period, the working area must be returned to the Government, and all exploration costs shall be borne by contractors. The first approval of POD signifies the end of exploration period and the contractor shall proceed to development and production phase in the next 20 years.

2. POD 2 *etc.*
   A plan to develop oil and gas field in another structure different from POD I, but in the same working area. POD 2 *etc*. shall be approved by SKK Migas.

3. POFD
   A plan to develop oil and gas to produce the incremental of hydrocarbon from existing POD whenever estimated reserves are higher than what was predicted and established in a POD. The processing facilities in POFD will use the existing facilities in the previously approved POD. POFD is subject to SKK Migas's approval.

4. POP
   A plan to produce one or two exploration wells that had been drilled to collect and analyze the subsurface data to find more commercial reserves (if any) that can be continued to field POD. Similar to POFD, the processing facilities in POP will use the existing facilities in the previously approved POD. POP is subject to SKK Migas's approval.

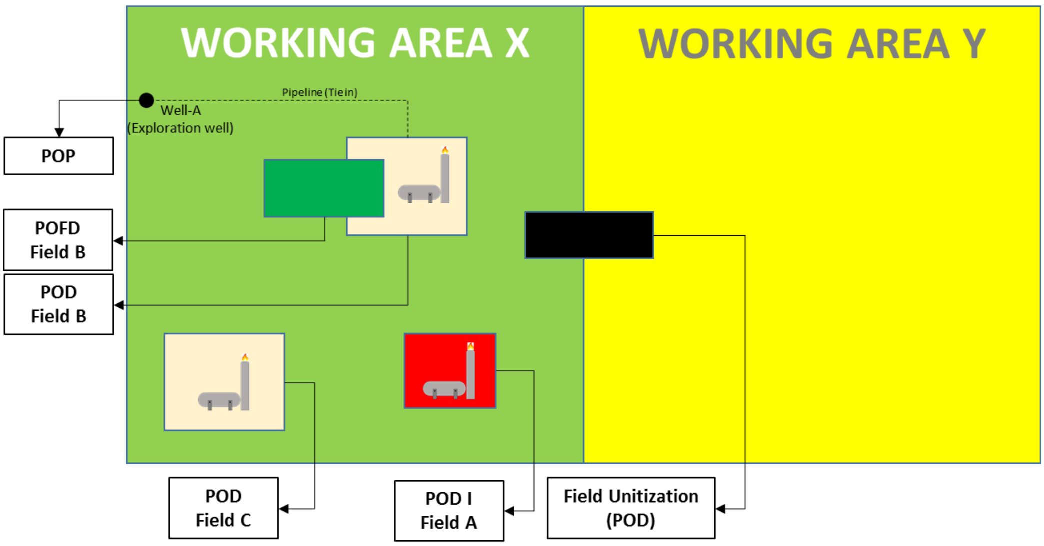

Figure 4. Types of Plan of Development (Azizurrofi, 2017)

Based on the prevailing SKK Migas internal guidelines (Pedoman Tata Kerja or PTK) for POD year 2010, the approved POD can be revised whenever there are significant changes in the following aspects:

a. Oil and gas reserves;
b. The development scenarios, including:
   - Number of wells;
   - Production facilities; and
   - Economics.

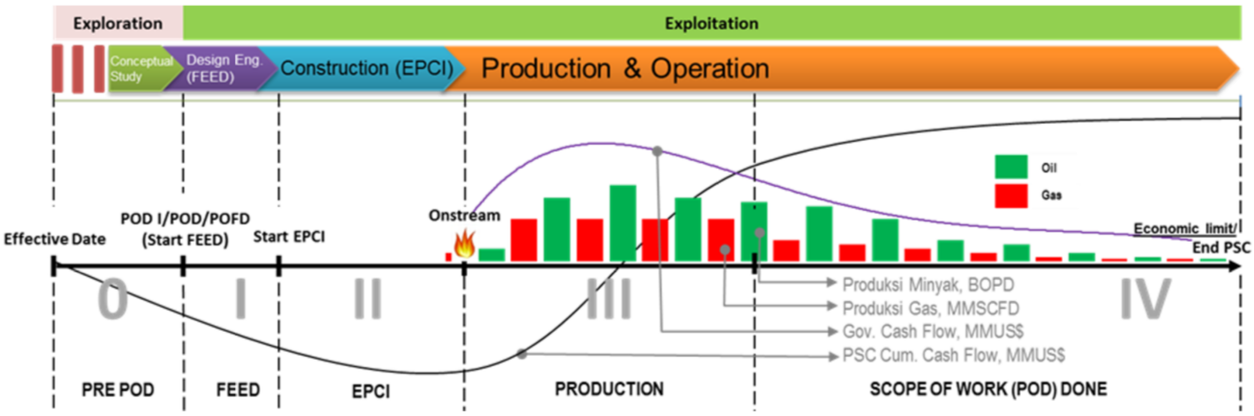

Figure 5. Project Cash Flow and Stages of Exploitation Activities (SKK Migas Report, 2016)

The exploitation activities in field development consist of 4 (four) stages:

1. Phase I: Phase after POD approval in the form of FEED implementation or preparation for engineering, procurement, construction and installation (EPCI), drilling and at this stage, there is no hydrocarbon production (on-stream).
2. Phase II: Implementation phase of EPCI and at this stage, there is no hydrocarbon production (On-stream).
3. Phase III: The stage when there is hydrocarbon production in the field, and there are still unfinished POD work programs.
4. Phase IV: The stage when there is hydrocarbon production in the field, and the implementation of the POD work program has been completed.

Since the establishment of SKK Migas, a total of 424 PODs have already been approved (as of December 2016). In 2015, there were 57 approved PODs, the highest number of PODs since 2002, while the oil price was at its lowest point since 2005. The increasing number of POD approvals indicates that investing in Indonesia's oil and gas industry is still considered very attractive and this might have been caused by the flexibility of terms and conditions of the PSC regime in Indonesia that helped the projects become economically acceptable.

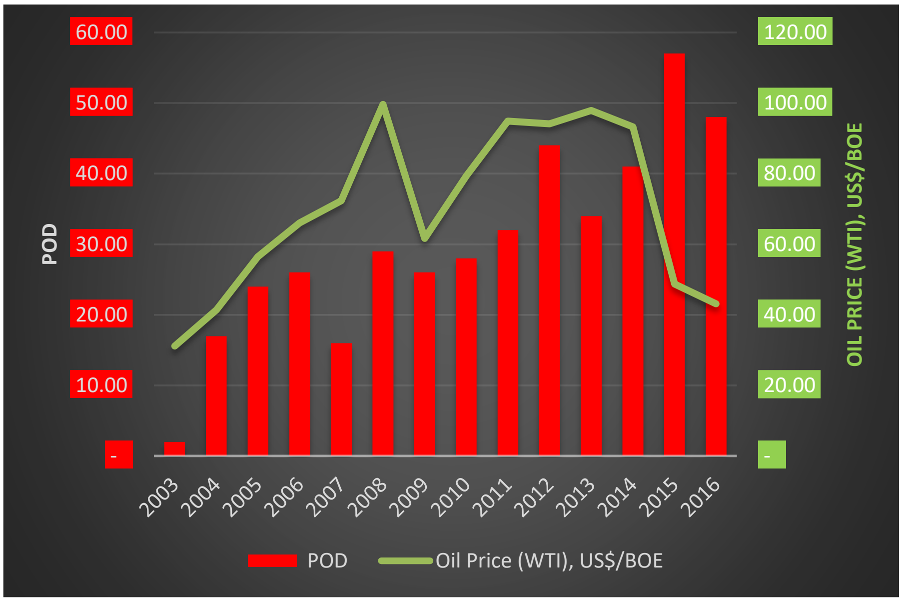

Figure 6. Plan of Development (POD) Approvals vs. Oil Prices for Period of 2003 – 2016 (SKK Migas, 2016)

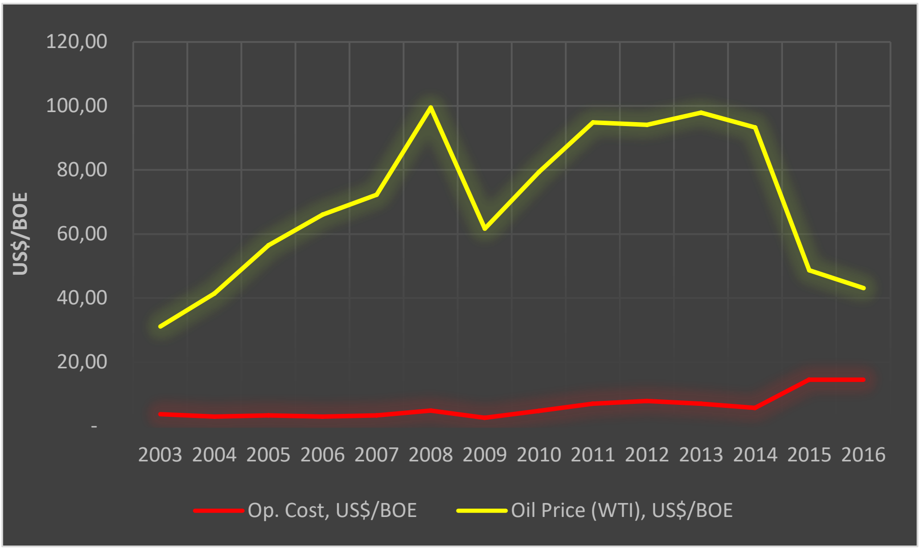

Figure 7. Oil Prices vs. Operating Cost of POD in Indonesia for Period of 2003 – 2016 (SKK Migas, 2016)

Based on statistical analysis, the operating costs of the POD are far below the oil prices (Figure 7), although in 2016 has reached the highest since 2003 and was close to the oil prices.

The distribution of types of the POD in Indonesia (as of December 2016) can be seen as follows:

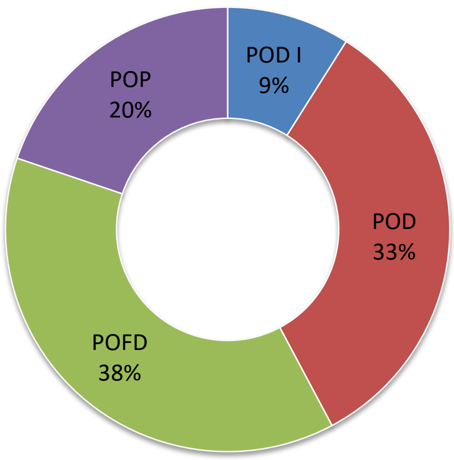

Figure 8. Distribution types of the POD

Based on Figure 8, we may infer that the PODs were dominated by POFD (38%) followed by POD (33%). The high percentage of POFDs shows that the number of proven reserves was higher than previously valuated by the earlier approved PODs.

1.4 Work Program and Budget

Work Program and Budget ("WP&B") is a proposed breakdown of Contractors' annual operating and expenditure plans that analyzes the conditions, commitments, effectiveness, and efficiency of operations. It describes long-term plans for the activities such as exploration commitments, PODs, other approved long-term programs as well as those proposed in a Contract Area to meet the SKK Migas's approval.

The WP&B cycle in one year is illustrated in the following graph:

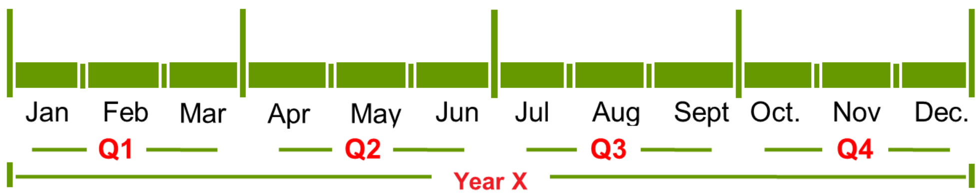

Figure 9. Work Program and Budget Cycles (Lubiantara, 2013)

The documents of WP&B contain the following information (Lubiantara, 2013):

a. Exploration Activities (Seismic & Geological Survey, Drilling, and G & G Studies), Lead & Prospect, Exploration Commitment.
b. Production activities and the efforts to maintain the production
    - Infill Drilling
    - Plan of Development
    - Production and Work Over
    - Maintain Production
    - EOR Project (Secure Recovery & Tertiary Recovery)
c. Cost of the following work programs:
    - Exploration Activities
    - Development Drilling & Production Facilities
    - Production & Operations
    - General Administration, Exploration Administration & Overhead Costs

In the event of changes in approved WP&B such as General Objective and Expenditures, Contractors may propose these changes in WP&B Revision mechanism. The following items explain the criteria for revision of WP&B (Lubiantara, 2013):

a. Changing the general goals (General Objective)
   i. Exploration Phase:
      - Changes of approved Firm Commitment.
      - Delays/acceleration/alteration of study activities, seismic/survey, exploration wells.
   ii. Exploitation Phase:
      - Changes in the production target (increase or decrease production).
      - Changes in the drilling of development wells.
      - Changes in the competition of constructions of the production facility.

b. Increase in Expenditures
   In case of any expenditure which may increase the approved budget of Work Program and Budget.

2. Problem Statements

The downfall of global oil prices and production have significantly affected exploration and exploitation activities. These activities became less attractive for the Contractors despite high demand in Indonesia.

Therefore, by using WP&B 2017 data, the paper aims:

- to evaluate the distribution of oil and gas production in Indonesia along with the production costs which will allow investors to find and map working areas in Indonesia that have potential commercial reserves while maintaining the lowest possible production costs;

- to provide a big picture of the current distribution of oil and gas production in Indonesia and to attract investors;

- to provide information for the Government that can be utilized as a reference to improve the current regulations and to implement policies that would further support the oil and gas industry.

3. Methodology and Results

Two types of analysis were performed in this paper; quantitative analysis mapping of commercial reserves and production costs among existing Contractors, and qualitative analysis of the final results and possible Government's further action to attract investments. The sources of data used in this study include empirical data from WP&B SKK Migas and IHS Markit.

3.1 Quantitative Analysis: Mapping Petroleum Commercial Reserves and Production Cost

For this paper, we mapped the existing Contractors' Working Areas and clustered them into 6 (six) geographical areas, namely Sumatera, Natuna Sea, Java, Kalimantan, Sulawesi and Papua. Furthermore, the data for commercial reserves and production costs from 67 Working Areas in 2017 have been collected, and the reserves and production costs calculated and distributed between these areas.

The following diagram summarizes the mapping process for this research:

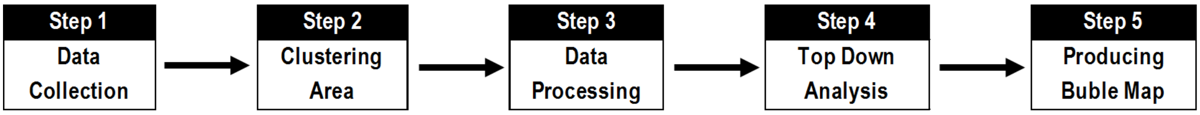

Figure 10. Methodology of Analysis and Mapping of Petroleum Commercial Reserves and Production Cost

Here is the explanation of the methodology:

a. Data Collection
As of 2017, there were 87 Working Areas (at an exploitation phase) dan 67 of them has submitted their proposal for WP&B 2017 (excluding PT. Pertamina EP's working areas as it consists of several projects that are scattered all over Indonesia). We utilized and processed the data gathered from *Work Program & Budget* in 2017, particularly those related to commercial reserves and its expenditures.

b. Clustering Area
Indonesia has been divided into 6 (six) geographical areas, namely, Sumatera, Natuna Sea, Java, Kalimantan, Sulawesi and Papua. We consider the classification of 6 (six) geographical areas to be reliable as we view that the existence of projects are pretty big in those areas. The oil and gas production and its operating costs were generated and processed from WP&B 2017 data.

c. Calculation Process
Calculate the commercial reserves and production cost by using the formula below.

$$\boldsymbol{Prod.Cost\ Area\ X} = \frac{\boldsymbol{Total\ Cost\ of\ Production\ Area\ X}}{\boldsymbol{Total\ Commercial\ Reserves\ Area\ X}}$$

$$\boldsymbol{Commercial\ Reserves} = \frac{\boldsymbol{Total\ Commercial\ Reserves\ Area\ X}}{\boldsymbol{Total\ Working\ Area\ in\ Area\ X})}$$

The rationale for using this is to obtain the value of production costs and commercial reserves as these variables can show the potential areas as well as investment costs required to develop those areas.

Table 4. Operating Costs and Commercial Reserves

No	Area	Number of Contract Area (Production Phase)	Oil, MBO	Gas, MMBOE	Oil + Gas, MMBOE	Opex, MUS$	Prod. Cost, US$/BOE	Commercial Res., MMBOE/ Contract Area
1	Natuna	3	8.268,35	28,99	37,26	613.381,37	16,46	12,42
2	Sumatera	33	117.076,47	101,18	218,26	3.159.489,09	14,48	6,61
3	Java	12	97.652,78	52,78	150,43	1.158.244,19	7,70	12,54
4	Kalimantan	8	30.683,04	118,12	148,80	1.152.199,84	7,74	18,60
5	Sulawesi	6	5.877,06	26,45	32,33	184.196,04	5,70	5,39
6	Papua	5	4.567,67	78,97	83,53	270.845,36	3,24	16,71

Attractive Area

d. Analysis
Perform Top-down Analysis of the commercial reserves and production cost from 6 (six) areas. This analysis was conducted to assess which areas have the highest and the lowest commercial reserves and production costs.

e. Bubble Map
Produce bubble map of the commercial reserves and production cost in 6 (six) clustered areas as to provide the big picture of the geographical areas in Indonesia that will help Contractors to identify the most attractive ones.

The results of the bubble map of Commercial Reserves and Production Cost are as follows:

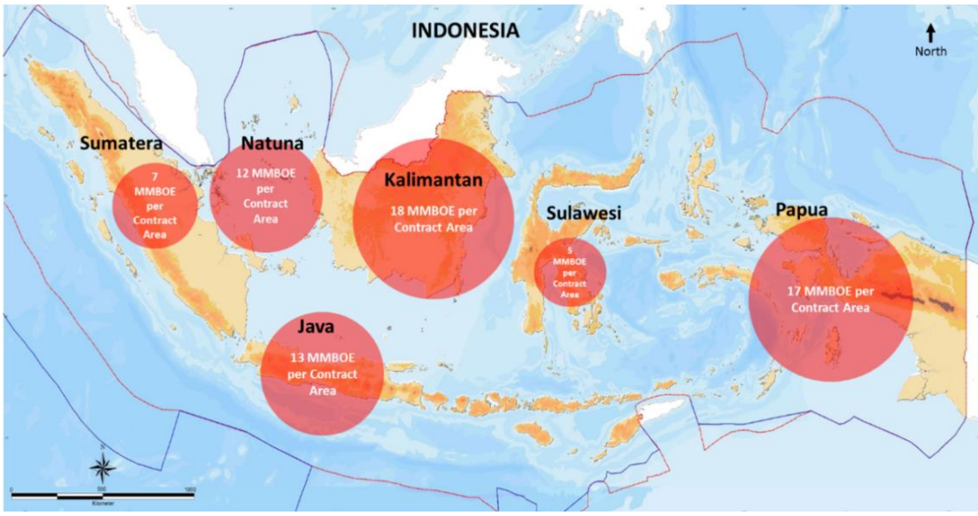

Figure 11. Bubble Map of Commercial Reserves Year 2017

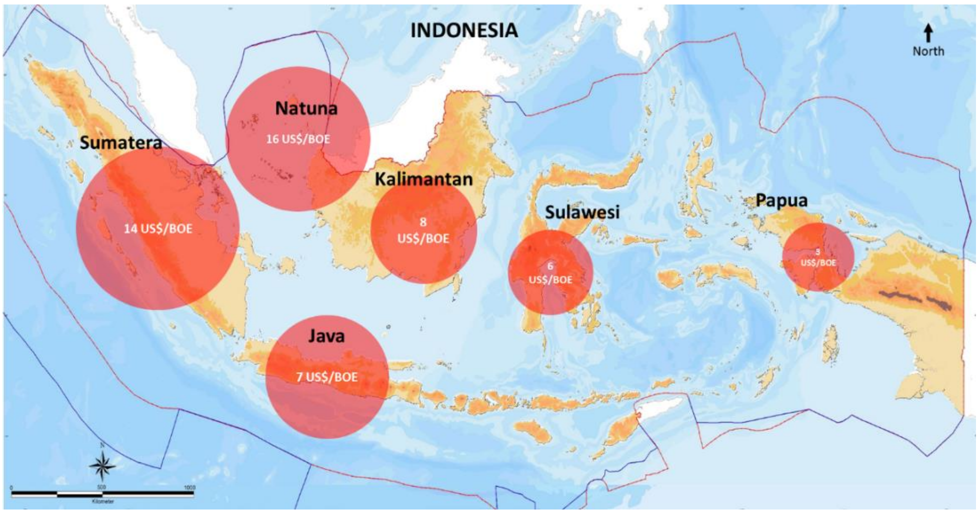

Figure 12. Bubble Map of Production Cost Year 2017

As seen in Figure 11 and Figure 12, Kalimantan has the highest commercial reserves of more less 18 MMBOE per Contract Area. Meanwhile, Sulawesi has the lowest reserves of ~5 MMBOE/Contract Area. As for the cost of production, Natuna has the highest (US$16/BOE), while Papua has the lowest (US$3/BOE).

The following graph shows the additional information on the distribution of oil and gas production in Indonesia based on data from WP&B 2017:

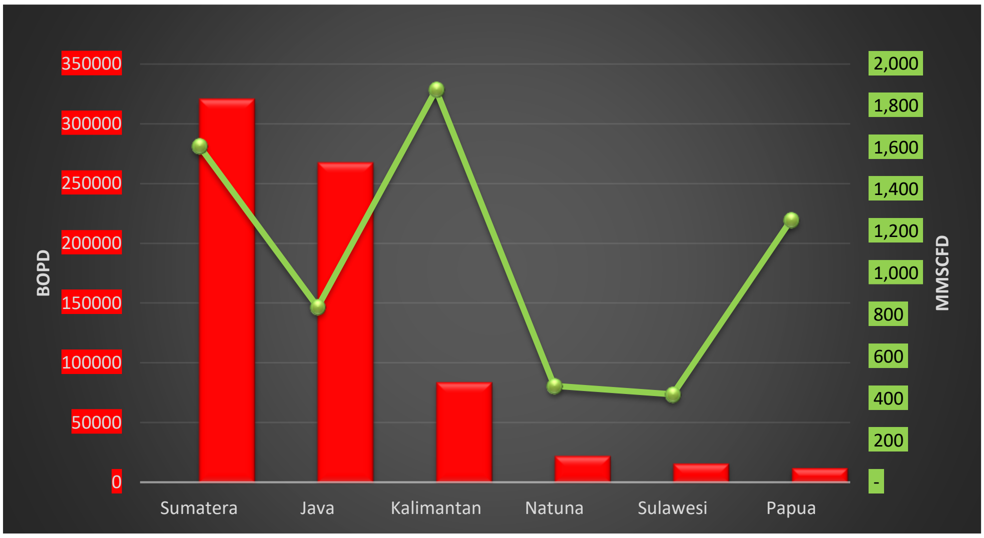

Figure 13. Distribution of Oil and Gas Production from 67 Working Area

Based on Figure 13, the following additional information can be obtained from the WP&B 2017 of the oil and gas production in Indonesia:

- Oil Production
  Sumatera, which has 33 producing working areas, still dominates the oil production at around 320 kbd, or 10 kbd per working area. Meanwhile, Papua with 5 (five) producing working areas has the lowest oil (condensate) production around 11 kbd or 2 kbd per working area.
- Gas Production
  Kalimantan, which has 8 (eight) producing working areas, dominates the gas production at 1.877,00 MMSCFD or 235,00 MMSCFD per working area. Meanwhile, Sulawesi with 6 producing working areas has the lowest gas production of 420,00 MMSCFD or 70 MMSCFD per working area.

The results of WP&B 2017 analysis support and strengthen our analysis of the Contract Areas and PODs. The combined results are shown in the following table:

Table 5. Operating Costs and Commercial Reserves analysis based on Contract Area, POD and WP&B 2017

No	Area	by Contract Area		by POD		by WP&B 2017	
		MMBOE/CAs	Dev. Cost, US$/BOE	MMBOE/POD	Op. Cost, US$/BOE	MMBOE/CAs	Op. Cost, US$/BOE
1	Sumatera	46,94	16,06	7,26	8,10	6,61	14,48
2	Natuna	215,25	12,10	153,88	5,40	12,42	16,46
3	Java	132,83	16,05	20,61	7,01	12,54	7,70
4	Kalimantan	243,89	13,24	49,48	3,25	18,60	7,74
5	Sulawesi	236,65	11,61	98,60	5,40	5,39	5,70
6	Papua	626,49	9,47	129,94	3,59	16,71	3,24

: Attractive area

In conclusion, based on our analysis of Contract Area, POD and WP&B 2017, it is evident that the eastern area of Indonesia tends to have a low cost of production and high commercial reserves compared to other areas. Hence, it is advisable for the investors to do massive exploration and exploitation activities in the Eastern area.

3.2 Qualitative Analysis

Whilst it is believed that most of the discoverable hydrocarbon deposits lie in eastern regions (Kalimantan and Papua as less-explored areas), the paper also analyzes the relevance of Government's support in creating a more conducive regulatory environment and fiscal terms to attract investors as finding and exploiting those areas will require big investment and deep-sea drilling activities due to challenges in infrastructure and geological aspects. Regulatory environment and fiscal terms govern the relationship between governments and private companies, and determine the allocation of financial risks and benefits in a particular project.

The following figure shows that Indonesia is currently at a mature level. Therefore, investors require more favorable terms for investment compared to countries which are considered frontier or mature.

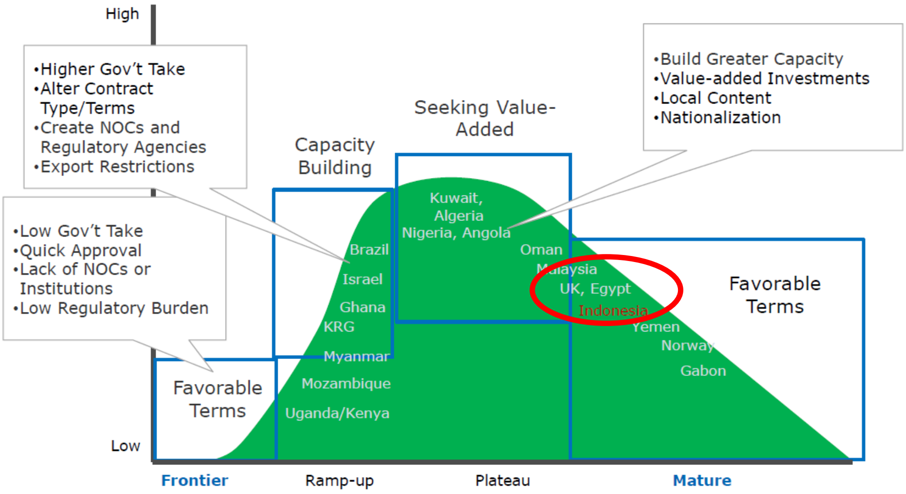

Figure 14. Production Cycle (IHS Markit, 2017)

In oil and gas industry, regulatory and fiscal terms have to be structured by taking into account the following industry characteristics:

1. Petroleum and mineral resources are not infinite. Therefore, Governments must generate returns that are sufficient to compensate the country for the value of the asset being depleted.
2. Oil and gas projects require a massive amount of advance investments before the Contractors could generate revenues.
3. Managing project risks which include geological risks, technical uncertainties, price risk, market risks, political risks, etc.
4. Extractive revenues have the potential to represent a dominant share of a country's public revenues.

In general, a government must set up a sharing profits system (in the form of a fiscal regime or fiscal mechanism) whenever it deals and negotiates with the investors (or IOCs) to allow it to maximize the benefit for its citizens. A fiscal stimulus will make the country an attractive place for the contractors to invest. The choice of a fiscal regime depends on the necessity of the government to generate revenues as well as its ability to born associated risks and attract investors. The factors above will affect the ultimate government take and contractor take – their respective shares of the net profit.

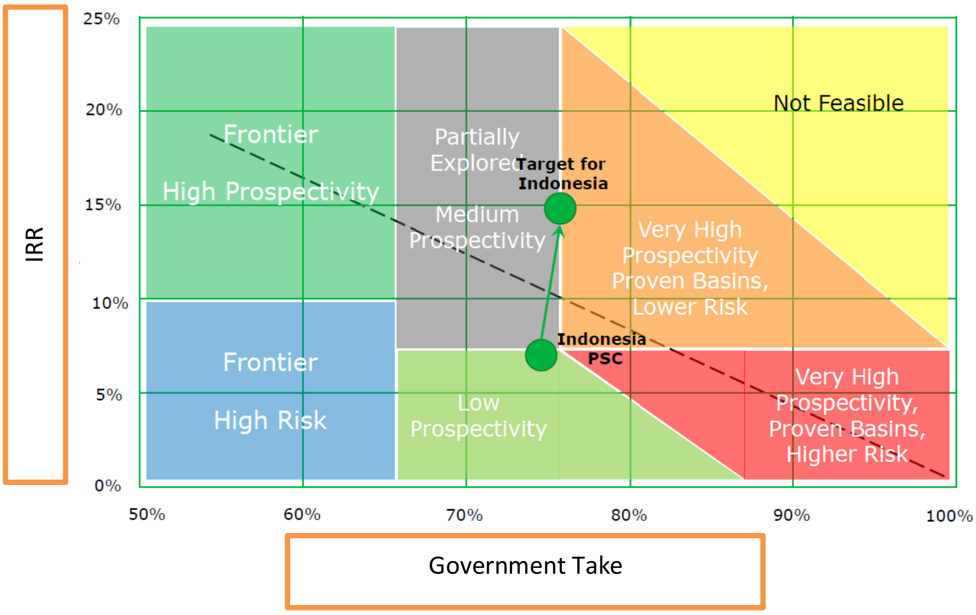

Figure 15. A correlation between IRR and Government Take (IHS Markit, 2017)

The above figure shows that the frontier areas are typically having low Internal Rate of Return ("IRR"). IRR can be treated as the rate of growth a project is expected to generate. It is a decision criterion in capital budgeting. In order to calculate an IRR, the project manager will utilize a project's estimated cash flow based on capital and non-capital expenditure, revenues, and the timing of their occurrence.

As for now, there are many Indonesian basins that are yet to be explored for oil and gas deposits extensively, making for potential additional reserves. If we compare Western areas of Indonesia basin to the Eastern part, the latter is considered to be underexplored due to poor infrastructure, deep water condition, remote on-shore location, and a poor understanding of the geology. Due to the potential reserves that lie in the Eastern part of Indonesia, the Government may want to shift its priority in order to develop the eastern regions and provide better incentives or fiscal terms for the investors to enable them in achieving their expected IRR.

Concerning the application of Gross Split PSC, at this stage, it may be difficult to determine whether the Gross Split scheme can promote better future investment compared to the current PSC Cost Recovery mechanism. The PSC Cost Recovery mechanism provides more attractive returns in early years of production to recover exploration and development costs to the investor. Based on this fact, the Government may carefully monitor the application of Gross Split PSC *vis-à-vis* the old PSC Cost Recovery mechanism to analyze which investment booster is more suitable for specific contract areas.

4. Conclusion

Based on the analysis of WP&B data of 2017, Papua has the lowest cost of production (US$3,24/BOE) compared to other areas of Indonesia, while Natuna has the highest (US$16,46/BOE). In addition, Kalimantan has the highest commercial reserves per contract area (18,60 MMBOE/Contract Area), while Sulawesi has the lowest ones (5,39 MMBOE/Contract Area).

Thus, it can be concluded that oil and gas projects in Indonesia are economically acceptable because the cost of production is still under the current oil price (US$60,46/BBL, WTI per December 2017), and these analyses show that Eastern Indonesia has the lowest development cost and big enough commercial reserves, meaning that the petroleum exploration activity is highly recommended to be conducted in Eastern Indonesia.

Despite the current adverse conditions, this paper provides insights for the investors and helps them create and revisit their strategy and portfolio to invest in Indonesia's oil and gas industry.

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