MONETIZATION STRATEGY FOR MARGINAL GAS PROJECT: CASE STUDY OF NORTH KAL PRODUCTION SHARING CONTRACT (PSC) INDONESIA

Andini Wuriastuti Mulyandari
Widhyawan Prawiraatmadja
Wiwiek Mardawiyah Daryanto

ABSTRACT

North Kal is one of exploratory oil and gas fields in Indonesia. The exploration activities to find hydrocarbon accumulation in North Kal block has started since 2004 until some proven resources were found on BDK field on 2013, and followed by discovery of PRG field on 2017. The next challenge for the PSC operator is then to formulate a robust monetization strategy to develop the block, considering the location in captive market area with minimum infrastructure and undeveloped industries. Some development scenarios have been assessed based on techno-economic standpoint to find the most optimum development strategy that gives acceptable return for the contractor. Significant high capital expenditures are required to develop these two fields, exacerbated by the burden of past exploration costs, and have resulted in the delay of project for a few years, mostly due to finding potential gas buyer that can generate sufficient returns to the contractor. All of these factors define the marginality nature of the project. The main purpose of this study is to assess economic evaluation of North Kal gas development project in order to find the most suitable scenario under PSC scheme. The project investment decision comprises of strategic viewpoint were done based on technical approach and economic evaluation with capital budgeting model indicators, such as Net Present Value (NPV) and Internal Rate of Return (IRR). The finding shows that a flexibility in PSC terms are need to be made to improve the attractiveness of marginal project as well as to create an acceptable return for the contractor and fair revenue for Government of Indonesia (GoI). The study also shows that delay in project execution due to complex regulation could have significant impact to project's revenue loss.

Keywords: PSC, marginal field, gas field development, capital budgeting model

INTRODUCTION

North Kal PSC was signed between the Executive Agency for Upstream Oil and Gas (SKK Migas) and the designated contractor on 2004 and included in the rules of block base PSC. The working area is located in the Tarakan Basin, offshore North Kalimantan province, with sea water depths ranging from 30 m to 400 m. The hydrocarbon accumulation in this block was proved by gas exploration discovery of BDK structure on 2013, and followed by another discovery of PRG structure on 2017.

The North Kal PSC is located in remote area that has limited available buyers. The project will be done on an offshore open area, with no existing production facility, thus making the project classified as Greenfield Project that require higher capital expenditure (CAPEX) and longer time to build compared to tie-back development fields. The project also has been delayed for a few years mostly due to finding potential gas buyer.

Monetization strategy in oil and gas industry comprises technical and non-technical plans to bring out the hydrocarbon production from below the ground and give optimum profit return for the operator. Considering the significant capital to carry out an upstream project along with the complex regulation and administration, a thorough plan is needed before project execution to have a cost efficient project development from techno-economic standpoint.

Several scenarios that are technically feasible were assessed to carry out the project. The scenarios proposed are (1) Do-nothing scenario; (2) Standalone Scenario; and (3) Integrated Development Scenario. The "Do-nothing Scenario" covers the regulation of contractor's liability to deliver first production at maximum five years after first Plan of Development (POD) approval. SKK Migas regulates that any contractor fails to deliver its first production after the five-year time limit since POD I approval shall return the operated block to Government of Indonesia. On this scenario, the PSC operator will have to borne all the exploration cost as sunk cost that cannot be cost-recovered. The "Standalone Scenario" will satisfy the needs of refinery project that requires 90 MMSCFD gas for short period, volume that fit the production capacity of BDK field alone, but will requires 60 km of new pipeline, while the "Integrated Development Scenario" is aiming for gas supply to petrochemical plant that will be built nearby with the needs of 90 MMSCFD gas for minimum 20 years.

Challenge remains for the project is the low gas price offered by potential buyer. On the contrary, past exploration cost and offshore development for North Kal block requires high capital, thus higher gas price is needed to meet the minimum requirement of economic value for the project

From the decision analysis, the Integrated Development Scenario was considered as the most attractive one with some room for improvement to increase the economic value. Sensitivity analysis was then carried out to determine how different values of independent variables impacting the economic value of the project. Project delay has the highest impact of revenue loss in the North Kal gas development project, followed by CAPEX and gas prices.

Another exercise was also carried out in respond to the latest update of gas price regulation of Indonesian Ministry of Energy and Mineral Resources (MoEMR) decree no 89, 2020. GoI have decided to reduce the natural gas price to an average US$ 6 per MMBTU in consumer plant gate, and adjustment on upstream and transportation side need to be made accordingly. This decree also guarantees that the decline in gas price will not reduce the revenue of contractor. The exercise showed that to reduce gas price from US$ 5 to US$ 4 per MMBTU and maintaining contractor profit share at the same time, Government take should be lowered from 37.38% 28.34% of GoI take.

LITERATURE REVIEW

Historically, Indonesia's oil and gas sector began after the first discovery of oil field in North Sumatra on 1885 and Indonesia has remained a major player in the sector since then, especially in South East Asia. Indonesia was a longtime member of OPEC, suspended its membership in 2008 after years of oil production decline, but returned to OPEC in 2015 demonstrating serious commitment in the industry.

Indonesia's oil production started to decline due to limited number of significant new development projects that makes long-term supply outlook depends heavily on existing mature fields. On 2007 Indonesia's production rate fell below 1 million barrel per day, and continues to fall to just 696 thousand barrels per day at the end of 2019. Despite of its oil production decline, Indonesia still manage to have a steady gas output of more than 6 billion standard cubic feet per day (BSCFD) for the last two decades, maintaining Indonesia's position as the largest gas producer in South East Asia.

In term of energy resources, Indonesia has proven reserves of more than 2 billion barrels of oil and about 41 trillion cubic feet of gas. The country also has unconventional resources of 450 trillion cubic feet of coal bed methane (CBM) and about 75 trillion cubic feet of shale gas. Yet as of today, Indonesia required oil imports to cover more than 50% of its domestic consumption (1). There are several reasons for the shortfall, with the most significant is natural decline of Indonesia's existing oil and gas fields. Indonesia needs acceleration of new FID projects to be on-stream and more exploration activities seeking for new oil and gas discoveries.

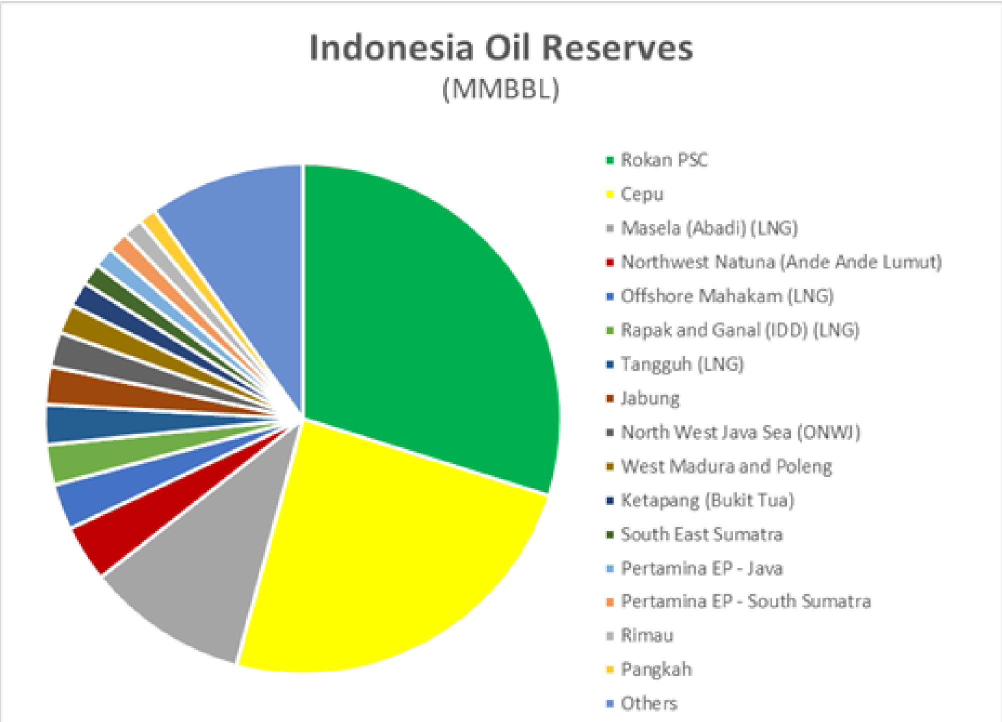
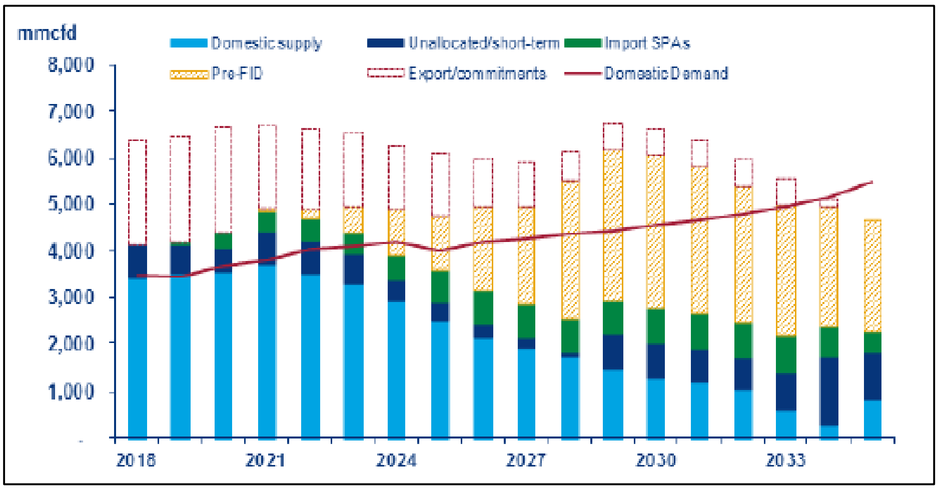


Fig.1: Indonesia Oil and Gas Commercial Reserves

Indonesia's rapid economy growth is driving higher demands of energy, and as of 2018 Indonesia is the second largest gas market by demand after Thailand. Gas demand is expected to grow further from about 3,500 million standard cubic feet (MMSCFD) of gas in 2018 to above 4,000 MMSCFD in 2025 (2). New demand will be coming from various potential users, including small scale LNG and refinery projects. Looking at graph presented on Fig.2, Indonesia will remain as net gas exporter until 2035, but this figures heavily depend on realization of pre-FID projects. However, progress on several key pre-FID projects has been limited and existing production has suffered from a combination of natural decline, decreasing in investment and regulatory uncertainty.



Source: Wood Mackenzie, 2018

Fig.2: Indonesia's Gas Balance Forecast

Without the development of new sources of gas supply, Indonesia's switch from gas net exporter to gas net importer may have taken place as early as 2026. The timely implementation of those pre-FID projects will ensure that Indonesia remains a net gas exporter until at least 2035. In order to maintain future production of gas, Indonesia needs to ensure that approvals such as license extensions and the Development Plan (POD) are released in a timely manner, and allow some flexibility in fiscal terms to ease project economics (2).

Indonesia PSC Scheme

The main concept of PSC scheme is that the contractor should cover all exploration risks and costs at the beginning of contract period. If exploration succeed and the amount of production can proceed, these costs can be recoverable and the contractors may claim a share of the production in order to recover costs, an investment credit, if granted, and an after-tax interest in the remaining production. If the production does not proceed the exploration and operation costs, these costs are non-recoverable (3).

In the oil and gas upstream industry, Indonesia is the pioneer of PSC system, with the first contracts signed in the early and mid-1960s. All oil and gas resources within Indonesia 's statutory mining territory are considered as national wealth controlled by the state that represented by SKK Migas. The PSC operator shall possess financial capabilities, technical competencies, experiences and professional skills necessary to carry out the petroleum operations.

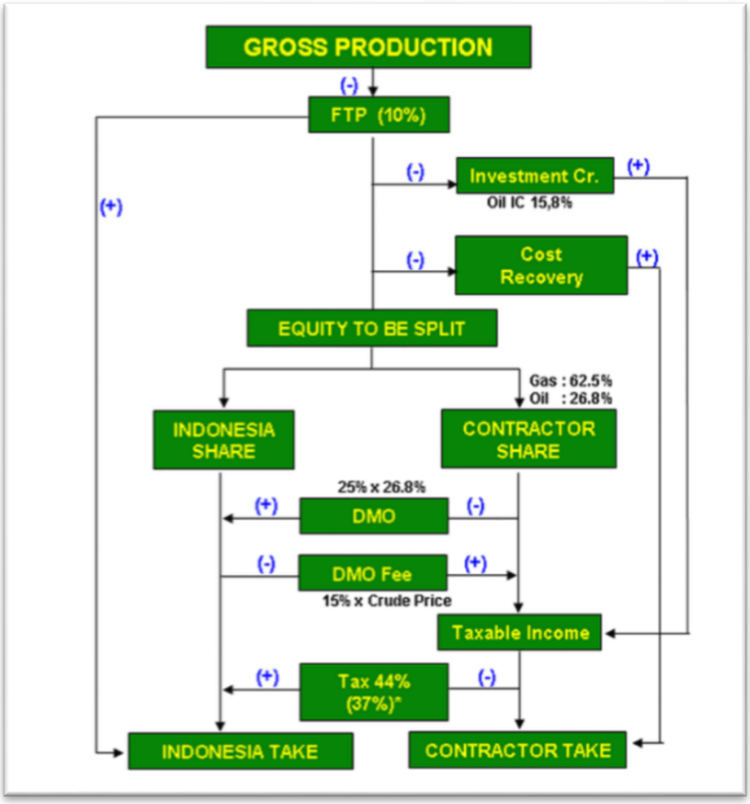


Fig.3: Indonesian PSC terms

Economic Variables

a. Net Present Value (NPV)
NPV is the sum value of all future cash flow, both positive and negative, for the life of and investment that discounted to the present value. NPV analysis is one of parameters that is used to determine the value of investment or capital project. The formula of NPV is as follows:

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

where,

CF = Net cash inflow during the period
i = Discount Rate
t = time period

b. Internal Rate of Return (IRR)
IRR represents the discount factor that makes NPV equal to zero. The IRR formula is as follows:

$$\mathbf{IRR} = \sum_{t=1}^{n} \frac{CF_t}{(1+IRR)^t} - CF_0$$

IRR commonly used as the decision criteria of a project.

METHODOLOGY

To accomplish this study, the steps are: (1) Gathering technical data (production profile forecast, CAPEX, and OPEX) for each scenario; (2) Estimating the basic assumptions to run economic calculation; (3) Calculating the capital budgeting based on PSC scheme for each scenarios of the project; (4) Selecting the most optimum scenario that gives acceptable returns for the PSC operator based on economic parameters, such as NPV and IRR; (5) Performing optimization on selected development scenario; (6) Carrying out sensitivity analysis to determine how different values of independent variables impacting the economic value of the project.

Data used in this study are primary data. Estimated production profile data are simulated based on reservoir engineering practice, with available geologist and geophysical data to predict the hydrocarbon resources. Production facility cost and engineering design are referred to the latest Front End Engineering Design (FEED) and market study.

RESULT AND DISCUSSION

The assumptions used for the North Kal block are based on PSC scheme, they are: (1) First Tranche Petroleum (FTP) = 10% - non-shareable;

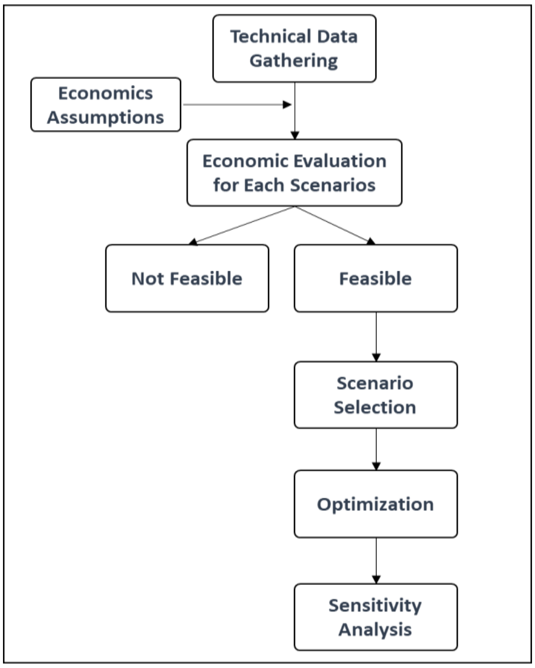


Fig. 4: Research Model

(2) No investment credit applied; (3) Contractor oil split before tax = 62.50 %; (4) GoI oil split before tax = 37.50%; (5) Contractor gas split before tax = 71.43%; (6) GoI gas split before tax = 28.57%; (7) Tax rate = 44%; (8) Domestic Market Obligation (DMO) = 25%; (9) DMO fee = 10%; (10) Depreciation type: Double Declining Balance; (11) Depreciation period = 5 years. Additional assumptions made for the gas development project are:

- Production start 2025
- Basic gas price: US$ 5 / MMBTU
- Oil price assumption: EIA forecast, 2019
- Discount rate: 10%
- Past exploration cost: US$ 372 Million
- Economic limit: PSC life (2034)

As discussed earlier, a good monetization strategy consists of a cost efficient project scenario that can give an optimum return for the operator. Two economic parameters that could be used to define the profitability of a project in capital budgeting method are NPV and IRR. In this study, a unique capital budgeting method are used based on Indonesia PSC terms. The PSC term regulates that all the past cost from exploration activities can be reimbursable to Government once the field produce oil and gas through cost recovery mechanisms. The economic evaluation for the three scenarios being proposed are addressing its own complexity and will be evaluated based on IRR and NPV as economic parameters. Table 1 shows the summary of economic calculation for the all the three scenarios proposed.

Based on economic evaluation it could be seen that abandoning the project on the “Do Nothing Scenario” will cause the contractor to loose US$ 372 Million from past exploration cost, while developing the BDK field only in “Standalone Scenario” yields NPV of US$ 46 Million and IRR 13.10%, the number that did not pass the minimum internal requirement of greenfield development, and the project is considered as unattractive. The “Integrated Scenario” has NPV of US$ 81 Million, it means that developing BDK and PRG field as integrated project is more beneficial. The NPV number also implies that even with additional CAPEX required to develop PRG field, the project can finance itself.

Table.1. Summary of Economic Evaluation

PARAMETER	UNIT	DO NOTHING	STANDALONE	INTEGRATED
PRODUCTION				
Oil +Condensate	MBO	-	4,625	19,544
Gas	MBTU	-	225,399	350,680
INVESTMENT		-	-	-
CAPEX	MMUS$	-	557.27	807.63
OPEX	MMUS$	-	335.73	674.80
Sunk Cost	MMUS$	372.13	372.13	421.63
Gross Revenue	MMUS$	-	1,445.77	2,984.70
CONTRACTOR		-	-	-
NPV	MMUS$	(372.17)	46.27	81.17
IRR	%	0.00%	13.10%	15.98%
MIRR	%	0.00%	10.90%	13.15%
% Contracor Take	%	0.00%	0.91%	8.05%
Contractor Take	MMUS$	-	13.144	240.232
% Cost Recovery	%	0.00%	87.40%	62.97%
Cost Recovery	MMUS$	-	1,263.565	1,879.577
Unrecovered Cost	MMUS$	372.13	1.56	24.49
GOVERNMENT OF INDONESIA		-	-	-
% GoI Take	%	0.00%	11.69%	28.98%
GoI Take	MMUS$	-	169.06	864.89

For project ranking, commonly IRR is used as one of important parameters for decision making. The highest the IRR number, the more profitable the project is. From those three scenarios being evaluated, the Integrated Development Scenario gives the highest IRR number, 15.98 %. This number also pass the minimum hurdle rate of company to proceed an exploration project.

Once scenario has been carefully selected, the next phase is to seek for optimization that is technically possible to boost up attractiveness of the project. For the "Integrated Development Scenario", parameters than can be further optimized is to ask for guarantee of PSC extension to Government of Indonesia (GoI).

Table 2: PSC Life vs. Gas Contract Period Economic Summary

PARAMETER	UNIT	PSC LIFE	GAS CONTRACT PERIOD
PRODUCTION			
Oil +Condensate	MBO	19,544	31,804
Gas	MBTU	350,680	685,239
INVESTMENT			
CAPEX	MMUS$	807.63	933.02
OPEX	MMUS$	674.80	1,321.76
Sunk Cost	MMUS$	421.63	421.63
Gross Revenue	MMUS$	2,984.70	5,429.86
CONTRACTOR			
NPV	MMUS$	81.17	141.08
IRR	%	15.98%	17.72%
MIRR	%	13.15%	12.26%
% Contracor Take	%	8.05%	13.32%
Contractor Take	MMUS$	240.232	723.508
% Cost Recovery	%	62.97%	49.29%
Cost Recovery	MMUS$	1,879.577	2,676.401
Unrecovered Cost	MMUS$	24.49	0.00
GOVERNMENT OF INDONESIA			
% GoI Take	%	28.98%	37.38%
GoI Take	MMUS$	864.89	2,029.95

In the upstream industry, especially for a greenfield exploration project where it took so long to confirm the hydrocarbon accumulation and PSC time is limited, it is common to ask to Government for a PSC extension guarantee to secure the investment. On this study, PSC extension up to gas contract limit on 2045 could increase economic value to NPV US$ 141 Million and project IRR to 17.7 % (compared to NPV US$ 81 Million and IRR 15.9% for project until PSC limit) as summarized on Table 2.

The PSC extension guarantee is considered as a win-win solution for both the operator and government, since the development of this project will not only add government revenue from oil and gas production and tax, but also will bring multiplier effects to national and local economic growth, especially if the project located in undeveloped areas.

Sensitivity analysis is used to illustrate and assess the level of confidence that may be associated with the conclusion of an economic evaluation. It is performed by varying key assumptions made in the evaluation (individually or severally) and recording the impact on the result of the evaluation. In model-based economic evaluations this includes varying the values of key input parameters, as well as structural assumptions concerning how the parameters are combined in the model (4). Sensitivity analysis in this study will cover some key economic parameters that are considered as volatile or have tendency to out of prediction, they are: (1) Gas price; (2) Oil price; (3) CAPEX; (4) OPEX; (5) Production; and (6) Project delay.

The result and summary of sensitivity analysis could be seen on Figure 5.

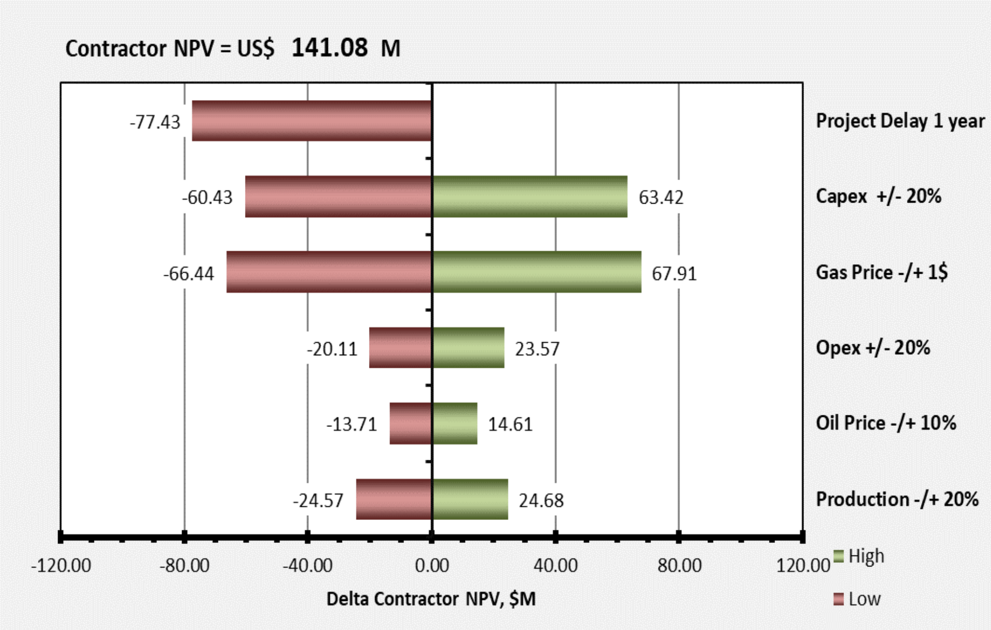


Fig.5: Sensitivity Analysis – NPV Contractor

Based on sensitivity analysis, parameters that has the most significant impact is timing of the project. Delaying project by only one year could potentially reduce the NPV of US$ 77 Million. This fact is in-line with recent findings in internal study regarding advance project scheduling for better economic result. Considering the scale of this project, the second significant parameter is CAPEX, reducing CAPEX spending by means of optimization of production facility or drilling technology has the potential to increase NPV project by US$ 63 Million. Successful negotiation to have $1 increase of gas price per MMBTU could also boost up the NPV by US$ 67. However, given the recent condition of domestic gas price regulation, the contractor should be prepared of having a decrease in gas price. Oil price doesn't have that much impact on this project because majority of production as revenue generator in this project is gas.

Responding to the latest update of gas price regulation by the issuance of MoEMR decree no. 89, 2020 that GoI have decided to reduce the price of natural gas to an average of US$ 6 per MMBTU at consumer plant gate starting April 1, 2020. It follows the implementation of President's decree no. 40 of 2016 to reduce the gas price at consumer plant gate, so that adjustment will have to be made on upstream and transportation side. The upstream gas prices must be reduced between US$ 4 – 4.5 per MMBTU, and transportation and distribution costs can be reduced between US$ 1.5 – 2 per MMBTU. However, the decree further guarantees that the decline in gas prices will not reduce the amount of oil and gas contractor revenues. Sensitivity study is made to address the possibility of reducing gas price below US$ 5 per MMBTU as per North Kal PSC gas sales agreement, with summary as seen on Table 3.

Table 3. Economic Evaluation of Reducing Gas Price Sensitivity

PARAMETER	UNIT	GAS CONTRACT PERIOD	SENSITIVITY GAS PRICE
PRODUCTION			
Oil +Condensate	MBO	31,804	31,804
Gas	MBTU	685,239	685,239
INVESTMENT			
CAPEX	MMUS$	933.02	933.02
OPEX	MMUS$	1,321.76	1,321.76
Sunk Cost	MMUS$	421.63	421.63
Gross Revenue	MMUS$	5,429.86	4,744.62
CONTRACTOR			
NPV	MMUS$	141.08	141.08
IRR	%	17.72%	17.72%
MIRR	%	12.26%	12.26%
% Contracor Take	%	13.32%	15.25%
Contractor Take	MMUS$	723.508	723.51
% Cost Recovery	%	49.29%	56.41%
Cost Recovery	MMUS$	2,676.401	2,676.401
Unrecovered Cost	MMUS$	0.00	0.00
GOVERNMENT OF INDONESIA			
% GoI Take	%	37.38%	28.34%
GoI Take	MMUS$	2,029.95	1,344.71

This regulation has been applied immediately after its issuance on April 2020 on several gas fields in Indonesia. The incentives given to operator in term of GoI take reduction following the new gas price regulation has been approved by MoEMR by signing Side Letter of PSC between PSC contractor and SKK Migas at the end of July 2020. The PSC Side Letter has limited purpose only, without changing the contents of PSC as a whole, but has the same legal force as the PSC, so that it can provide legal certainty as a guarantee for the investment that has been made and will be made by PSC operators. The implementation of MoEMR decree regarding gas price regulation is a commitment of the Government's partisanship to support industrial competitiveness and added value in gas user industry, and also evidence of the support from upstream industry toward strengthening the capacity of downstream industries.

However, considering the time frame between issuance of the decree and finalization of this study, further response and discussion by other related ministries in Government are still inconclusive.

LIMITATION

This study has evaluated the economic parameters for several scenarios in upstream marginal project. The economic calculation done in this study were using primary data and some benchmarking for derived the assumptions to represent the actual condition in the industry. In the future, it is suggested to perform research with wider scope on various type of marginal field to get more generalized result. In addition, the study was carried out based only on techno-economic standpoint to see the project's feasibility, excluding any other aspects in oil and gas upstream industry.

CONCLUSION AND RECOMMENDATION

The purpose of this study is to assess the economic evaluation of several scenarios available for North Kal PSC gas development project. Two major challenges for the contractor in this greenfield gas development project are the high sunk cost from previous exploration activities and limited potential buyer in captive market area.

Several scenarios were made to assess technical feasibility and economic valuation of the project. The “Do-Nothing Scenario” was carried out to taken into account the loss that the contractor will have to burden for abandoning the project, or if by regulation, the block has to fully relinquished back to the Government. Economic evaluation of this scenario resulting in NPV of US$ - 372 million, the number equal to all of past expenses for exploration activities, reflecting the loss opportunity for the expenses to be cost-recovered by Government. The “Standalone Scenario” consisted development for BDK field only for short period of production time. Economic evaluation for this scenario yields in NPV US$ 46.27 million and IRR 13.10%, the number that did not pass the minimum requirement of greenfield project, and considered as unattractive.

From the decision analysis, the “Integrated Development Scenario” was considered as the most attractive one with some room for improvement to increase the economic value. From technical standpoint, integrated development gives more flexibility for CAPEX optimization and bigger volume helps in reducing the OPEX as benefit of economies-of-scale. The “Integrated Development Scenario” has the potential to give NPV of US$ 81.17 million and IRR 15.98% for the contractor if the project carried out only until the end of PSC in 2034. Higher economic value could be achieved if the contractor can convince Government to extend PSC as of gas sales contract in 2045, corresponds to NPV of US$ 141.08 million and IRR 17.72%.

Sensitivity analysis was done to determine how different values of independent variables impacting the economic value of the project. It can be seen from the sensitivity analysis that time is the most sensitive variable in the project. Delaying the project by 1 year could potentially reduce NPV by US$ 77.43 million. The next sensitive variables are CAPEX and gas price, where increasing 20% of CAPEX could reduce the NPV by US$ 60.43 million, while optimization 20% CAPEX could increase NPV project by US$ 63.42 million. Gas price sensitivity of US$ 1 increase per MMBTU could increase NPV by US$ 66.44 million, and each US$ 1 decrease per MMBTU could also impact in NPV decreasing of US$ 67.91 million.

Another exercise was also carried out in respond to the latest update of gas price regulation of MoEMR decree no 89, 2020. GoI have decided to reduce the natural gas price to an average US$ 6 per MMBTU in consumer plant gate, and adjustment on upstream and transportation side need to be made accordingly. This decree also guarantees that the decline in gas price will not reduce the revenue of contractor. The exercise showed that to reduce gas price from US$ 5 to US$ 4 per MMBTU and maintaining contractor profit share at the same time, Government take should be lowered from US$ 2,029 million (37.38% GoI take) to US$ 1,344 million (28.34% GoI take). This decree aims to give positive catalyst for downstream investment in Indonesia, and reviving domestic gas demand at the same time.

Some recommendations that could be drawn from the study of North Kal PSC and future similar marginal projects are:

1. Implement project scheduling and road map at the beginning of each project.
It could be clearly seen from this study that time has significant impact on economic evaluation. Delaying project for one year could decrease the economic value of more than US$ 70 million. Should the contractor implement a robust road map and project scheduling since the very beginning of the project, the NPV project might be improved. Government should also facilitate any PSC contractor in speeding up project execution by shortening administration and permit approval.

2. Perform decision analysis in exploration project to avoid ballooning sunk cost.
A thorough decision analysis standard need to be made to minimize risk exposure in exploration projects. Complete guidance with expert team are needed to reduce technical risk, as well as tight monitoring on budget allocation and portfolio project prioritization.

3. Field development in several phase could result in better economic value by spreading capital expenditure.
Capital budgeting model use a discounted value calculation that is sensitive to time. Develop field in phasing scheme and spreading capital expenditure on several periods if possible, rather than spending it all at once, could improve economic value of the project. Cautions need to be made in spending CAPEX within 5 to 8 years before PSC expires (depend on depreciation time) to avoid unrecovered cost.

4. Contractor should ask for Government assurance of PSC extension to secure investment.
Sensitivity analysis on this case study has shown that extending time limit to gas sales contract period could almost double the NPV from US$ 81 million to US$ 141 million. It is a common practice in the upstream industry to ask Government for PSC extension assurance before final investment decision are made.

5. Government to facilitate more integrated development or facility sharing within nearby fields across different PSC.
Integrated development for several fields nearby and having a facility sharing agreement could help reduce CAPEX that will be increase project revenue for both contractor and Government. This will help so much especially for frontier exploration blocks, new developments, and marginal fields.

6. Close monitoring for on-going projects is recommended to secure optimum profitability.

Subsurface data are very volatile and can change from time to time as more wells are drilled and more data are acquired. Resources and reserves calculation are subject to change in term of new data addition. It is very recommended to have a close monitoring on these data, since resources and reserves are revenue generator in upstream business.

REFERENCES

1. Dolya, A., Sastry, A., Tamboto, A., and Rahman, F. (2017). Indonesia's $120 billion oil and gas opportunity. BCG Publications.
2. WoodMackenzie. (2018). Tipping the balance – can Indonesia maintain gas exports. WoodMacKenzie.
3. PricewaterhouseCoopers. (2019). Oil and gas in Indonesia – investment and taxation guide. PwC Publications.
4. Lubiantara B. (2000). Ekonomi Migas: tinjauan aspek komersial kontrak migas. Gramedia Widiasarana Indonesia.
5. Anthony RN, Hawkins DF, Merchant KA. (2011). Accounting: text and cases. McGraw-Hill.
6. Begg, S., Bratvold, R., & Campbell. J. (2003). Decision making under uncertainty. MIT Press.
7. WoodMackenzie. (2018). Better project delivery: upstream' s value opportunity. WoodMackenzie.
8. Rothaermel, F. T. (2019). Strategic management (4th ed.). McGraw-Hill Education.
9. SocietyofPetroleumEngineers. (2018). Petroleum resources management system. SPE.
10. Tarek, Ahmad. (2000). Reservoir engineering handbook (2nd ed.). Gulf Publishing.

Andini Wuriastuti Mulyandari
Sekolah Bisnis dan Manajemen, Institut Teknologi Bandung
Email: andini_mulyandari@sbm-itb.ac.id

Widhyawan Prawiraatmadja
Sekolah Bisnis dan Manajemen, Institut Teknologi Bandung
Email: widhyawan@sbm-itb.ac.id

Wiwiek Mardawiyah Daryanto
Sekolah Tinggi Manajemen IPMI
Email: wiwiek.daryanto@ipmi.ac.id