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Evaluation of Offshore Project Development under Two Fiscal Regime in Indonesia

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ABSTRACT

The general characteristics of deep water offshore field development are the uncertainty of geological conditions, high technology requirements and development costs, and volatility of oil and gas prices. Despite these challenges, the development of a deep water offshore field remains a strategic project for sustainable economic growth. This study will evaluate the impact of current fiscal of the three offshore field development and estimates the limits of oil and gas price, reserves, and expenses. The intention is to obtain the optimal conditions to encourage the development of new offshore fields. The approached will used a discounted cash flow modelling, followed by evaluate the profitability risk using deterministic and stochastic sensitivity analysis. Monte Carlo simulation used to take into account the uncertainty of several variables, such as oil and gas prices, operating costs, development costs, and reserves. The result shows that investment decisions for the development of new and/or extensions fields in offshore areas remain quite challenging economically, considering to the high development and operating costs, as well as fluctuating of oil and gas prices. The opportunity to obtain a positive net present value on new deep water offshore development fields is <41%, thus indicates that further initiative of cost efficiency and fiscal incentive is required in preparing investment planning of new deep water offshore field to compensate the high development and operational cost

Keywords: Monte Carlo Simulation, Offshore Development, Petroleum Economic, Production Sharing Contract, Stochastic Sensitivity
JEL Classifications: K120, Q40, Q48

1. INTRODUCTION

In some countries, including Indonesia, the mineral resources in those countries are owned by the State. However, most governments indicated that they did not have sufficient financial or technical capacity to develop these resources. As a result, the government relies on investors, including foreign investors, to develop nation's mineral resources using fiscal schemes with aims to share the loss or gain fairly between the government and investors. Several changes and flexibility of fiscal schemes are also offered by resource countries to increase investment attractiveness.

As in Indonesia, the increasing number of approved plan of development (POD) shows that upstream oil and gas investment in Indonesia is still very attractive despite of hydrocarbon price volatility (Azizurrofi et al., 2019). The flexibility of the current production sharing contract (PSC) scheme allows this to happen. With the target to reach production up to one million barrels per day and twelve billion cubic feet per day in 2030, it is expected to be able to improve the national economy including creating employment opportunities, despite facing some challenges in finance, technology, geology complexity, development costs and government policy.

In order to achieve those target, there is still 60% potential of new offshore oil and gas fields which opens up opportunities for investors to develop and produce hydrocarbons and earn profits. A fast and appropriate strategy are needed to maintain the sustainability of the offshore field development, considering that exploration activities in eastern Indonesia are decreasing, while the area has the highest number of oil and gas reserves per project (Azizurrofi and Firdaus, 2019). However, the high development cost of new offshore fields is a challenge in investing and generating profits (Akinlawon, 2017; Mardiana and Saputra, 2023), that requires cost efficiency innovation and fiscal adjustments to increase the economic value.

To minimize development and operating cost of a new offshore development field, sharing facility concept by subsea tieback to existing infrastructure facilities for new development project also used in one of the offshore field developments in Indonesia. This concept commonly used in UKSC (Abdul-Salam et al., 2021; Acheampong, 2020) and discussion related the fiscal regime impact on the long-term project economic of the assets has been conducted (Acheampong et al., 2015; Willigers and Hausken, 2013; Rush, 2012; Willigers et al., 2010a, 2010b).

This study will analyze the economics of three offshore project development in Indonesia that has various terms and conditions. Block A is a mature field that applies a new gross split PSC scheme at the time of obtaining its contract extension. Block B also uses gross split PSC scheme and developed with the concept of sharing facilities or third party access by subsea tieback to existing facilities in Block C. Moreover, Block B has a different fiscal scheme with the infrastructure assets owner. These different development concept and fiscal term is expected to provide different economic outcomes and incentives.

The study will also estimates the limit of oil and gas price, reserves, and expenses, to obtain an optimal condition that will encourage the upcoming new offshore field development. Deterministic discounted cash flow modeling will used to evaluate the economic project, includes the sensitivity of net present value (NPV) with the change of oil and gas price, finding and development cost, and production success ratio. Stochastic analysis will also use to quantify risk and uncertainties of finding and development cost, operating cost, oil and gas price, and reserves that will affect to the NPV.

2. LITERATURE REVIEW

2.1. Petroleum Fiscal Regime

Exploration and production of hydrocarbon is known as a high-risk investment and requires decision making under uncertainty. The uncertainties comes from geological complexity that combined with all economic and engineering input to obtain models to make a decision process (Johnston, 2008). Thus, the host government's concern on issuing petroleum fiscal regimes is how the profits are shared fairly. In order to ensure that the fiscal systems are fair for all stakeholders, there are some instruments that open for negotiate (Johnston, 2003).

Production sharing contract (PSC) scheme are used in Indonesia's petroleum upstream contract, with two types of PSC, called cost recovery PSC and gross split PSC. With the concept that the state owns the mineral resource, contractor is required to submit and obtained an approval of annual work program and budget. The host government does not have to bear the investment risk directly, thus contractor shall provide financial and technology required for development and bear all the risks. All those cost will be recover from the revenue after the field commercially produced, and the remaining profit will be share between government and contractor. Meanwhile, different concept was applied on gross split scheme, whereas the profit is divided from the production without cost recovery mechanism. The split determination will based on three component; base split, variable split, and progressive split. Oil or gas field type is specified in the base split, then adjusted with variable split according to the field condition and progressive split for the uncontrollable conditions, such as crude price and production. Figure 1 shows the summary of cost recovery and gross split fiscal terms.

Some previous research to compare and analysis the strength and weaknesses of those two PSC scheme have been widely discussed. Comparing those two PSC's on three offshore field, Mardiana et al. (2019) suggests that gross split PSC will be more favorable to the contractor by improving the cost efficiency. It was align with previous research stated that higher contractor's share is required to attract the investor to further improve the operations efficiency and to maintain the profit on lower project's profitability (MacKenzie, 2017; Masons, 2017; Giranza and Bergmann, 2018; Anjani and Baihaqi, 2018). As also pointed out by Sabaris et al. (2020), since that contractors gets a bigger split in gross split PSC to cover all cost incurred, makes the gross split PSC provides better economic results compared to cost recovery scheme.

2.2. Infrastructure Sharing Development

Standalone deep-offshore field development are often uneconomical due to extremely high development cost and lower production volumes negating any economies of scale (Abdul-Salam et al., 2021; Kemp and Phimister, 2010). Clustering development or third party access of the fields into unit developments by shared common infrastructure (such as processing facilities, pipelines, subsea manifold) has been recommended as a solutions of reducing development and operating expenditures to improve the economic viability (Kemp and Stephen, 2019).

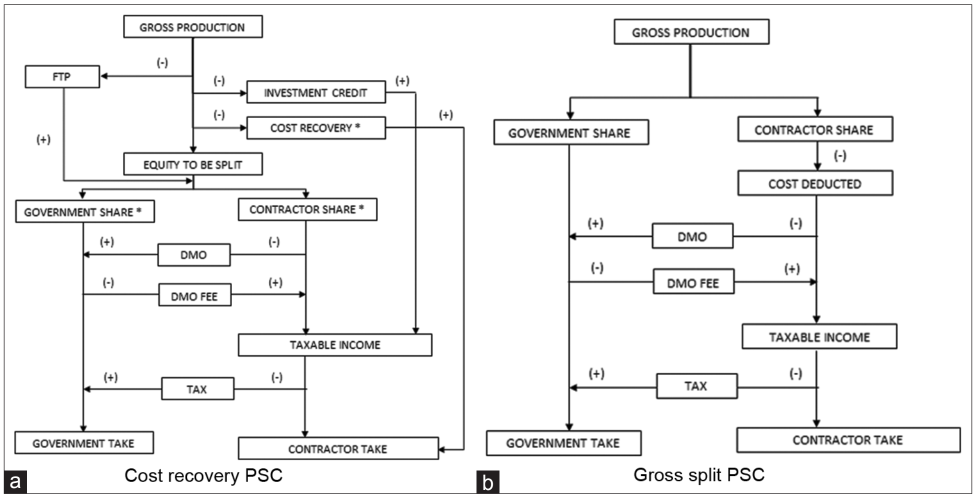
There are many literature mentions the significant potential benefits of cluster schemes development, such as reducing unit operating costs and improve field profitability (Willigers et al., 2010; Santoro et al., 2017), maximizing national economic recovery by deferring assets abandonment (Santoro et al., 2017; Pedroso et al., 2012), unlocking marginal fields development and increase national oil production (Abdul-Salam et al., 2021). However, the development of this cluster scheme have not been widely carried out in recent decades even though technological advances in this area are also increase extensively.

In this paper, the cost-sharing model in the sharing facilities scheme will include the capital costs that are calculate proportionated into the remaining reserves, while operating costs are calculate based on production.

2.3. Economic Indicators and Sensitivity Analysis

Economic models are vital in analyzing project viability. A deterministic cash flow model is carried out using a discounted cash flow model that incorporates time value of money into a cash flow. While cash flow models subtracts all disbursement

Figure 1: (a and b) PSC fiscal scheme in Indonesia (from Lubiantara, 2012)



(cash out) from receipts (cash in). To determine the investment profitability, some indicator such as net present value and internal rate of return are used.

Sensitivity analysis used to identifies how changes in input variable impact to the expected outcome. Unpredictable input like price, reserves size, capital and operating expenditure are most sensitive factors in project economics (Johnston, 2003; Seba, 2016). The analysis can be done deterministically and stochastically.

Stochastic sensitivity analysis using Monte Carlo simulation was used on the economic model in this study to account the risk and uncertainty of some input parameter such as price, expenditure, and reserves size simultaneously affected to the expected outcome of NPV. This analysis is needed as part of strategic planning as well as decision-making, considering to the complexity and complicated relationship between variables and economic indicators. Ojaraida et al. (2018) used stochastic analysis to determine the probability level of economic outcomes from two different PSC type. While Adeogun and Ildare (2018) used the result of stochastic analysis for the profitability level of several marginal field, identify the criticality field based on the probability result and suggest some incentive as a recommendation.

3. METHODS

The methodology to evaluate the profitability of offshore fields was conduct in two parts; deterministic model analysis and stochastic modelling technique. The deterministic models assumes the output are obtained with certainty, while the stochastic models take into accounts the risk and uncertainty of input parameter, such as oil and gas price, production rate, and finding and development (F&D) cost. The profitability indicator used in this assessment is net present value, internal rate of return, and government take.

Using secondary data from each working area and some assumption used to determine the deterministic and stochastic model, the stages of research carried out in four stages as follows:

a. Data collection from three oil and gas offshore fields. It includes fiscal term, production profile and cost required for the offshore field development in the full life cycle contract. Table 1 shows field condition and assumption for each field, with the assumption of 40% direct income tax, using declining balance depreciation for 5 years, and 10% discounted rate.
b. Running economic calculation for each field based on the respective PSC scheme as shown Figure 1 and equation for the contractor and government take will refer to Mardiana et al. (2019). The economic indicators use discounted cash flow model to evaluate the NPV, IRR, POT, and government take. The NPV must be equal to or greater than zero, if it result less than zero then project will not be attractive. While for the IRR, at least greater than the discounted rate are acceptable.
c. Conduct deterministic sensitivity analysis with the changes of oil and gas prices, F&D cost to the value of NPV on three scenarios reserves size for each block.
d. Conduct stochastic sensitivity analysis with Monte Carlo simulation to determine the NPV distribution on the distribution of oil and gas prices, F&D cost, operating cost, and the amount of reserves, as shown in Table 2. Simulations of 3000 iterations will carried out to ensure the accuracy of stochastic results.

4. RESULTS AND DISCUSSION

The study results covering three offshore field economic evaluations using both fiscal schemes and sensitivity analysis are discussed as follows:

4.1. Economic Indicator Analysis

The economic results of three offshore working area in Table 3 indicates that investment decisions for the development of new offshore fields remain challenging economically, considering to the high development costs and operating costs. The high investment of finding and development (F&D) cost on new development of offshore fields in block C that was not compensate by an increase of revenue provides a negative NPV result that will burden the overall project economy. This also shown on investment price ratio as an indication of cost development to revenue of block C has reach 58%, and cost to profit ratio has reach 69%.

Table 1: Field condition and assumption

Parameter	Description		
	Block A	**Block B**	**Block C**
CAPEX	Extension field	New development field tied to existing facilities owned by other PSC	New development field
	Total CAPEX: $2.1 Bn	Total CAPEX: $1.7 Bn	Total CAPEX: $4.6 Bn
OPEX	24 $/bbl (include indirect tax and others cost)	1.6 $/mmscf (include indirect tax and others cost)	2.7$/boe
Reserves	260 MMBO	0.8 TCF	1.25 TCF
Price	Oil: 60 $/bbl	LNG : 7.3 $/mmbtu	LNG: 7.3 $/mmbtu
	Gas: 6.5 $/mmscf	Pipe gas : 5.3 $/mmbtu	Condensate: 55 $/bbl
F&D cost	8.4 $/boe	13.6 $/boe	21.9 $/boe
Fiscal Term	PSC Gross split Contractor split for oil: 65.5% and 70.5% for gas (exclude progressive split)	PSC Gross split Contractor split: 85.1% for gas (include progressive split and discretion)	PSC Cost Recovery Profit share for contractor: 28.5714% (before tax) FTP: 15% shareable

Table 2: Input parameter distribution

Variable	Minimum	Most likely	Maximum
Oil price ($/bbl)	40	60	80
LNG price ($/mmbtu)	5.5	7.3	8
F&D at block A, % of baseline	80	100	120
OPEX at block A, % of baseline	80	100	120
F&D at block B, % of baseline	70	100	160
OPEX at block B, % of baseline	70	100	130
F&D at block C, % of baseline	70	100	130
OPEX at block C, % of baseline	70	100	120
Reserves, % of baseline	80	100	120

Table 3: Economic evaluation result

Parameter	Block A	Block B	Block C
Cum. Prod	260 MBO	805 BCF	1.25 TCF
Total Investment, MM$	1,954	1,716	4,607
Total Expenditure, MM$	8,409	2,882	5,485
Gross Revenue, MM$	13,598	5,051	7,896
Contractor take, MM$	691	787	370*
Contractor NPV@10%, MM$	102	136	(1,184)
Internal Rate of Return (IRR)	21%	13%	1%
Pay Out Time, year	2.2	4.7	~
Government take, MM$	4,585	1,381	1,214
%GT to GR	34%	27%	15%
Cost to profit ratio	62%	57%	69%

Figure 2: Relation of NPV and F&D cost on each block

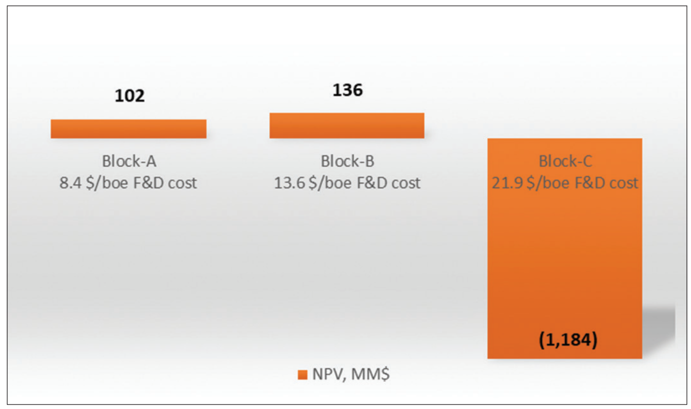
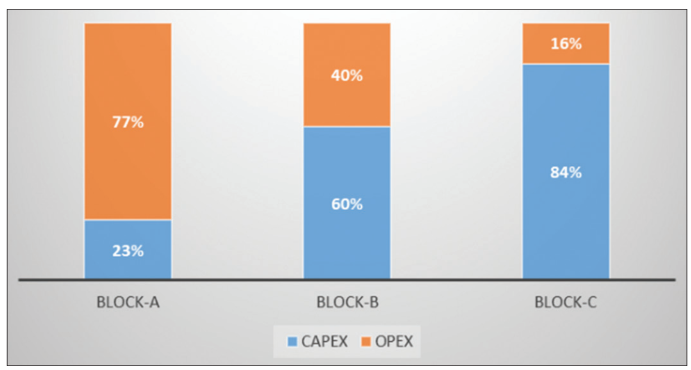


Figure 3: Capex and Opex ratio on each block



Finding and development cost is determined as ratio cost of exploration, development and ASR to the reserves. F&D cost is one of the important parameters that must be consider in the development of new offshore fields, especially deep-sea offshore fields. Block B and C are located in the deep water with a depth of 1000 meters and 500 meters, respectively, and required F&D cost of $13.6/boe to $21.9/boe to develop these fields. While F&D cost of block A is only $ 8.4/bbls that located less than 100 meters depth of sea level. From the result, it deduced that investment risks tends to increase along with the water depth, as well as study from Echendu (2011) in Gulf of Guinea. This result confirm that the high F&D cost at 21.9 $/boe could not provide an attractive economic results for offshore field development with reserves of 1.2 TCF, as shown on Figure 2.

Block B had benefits from the concept of sharing production facilities in the form of lower F&D costs, even though the field has a deeper water depth than block C. Thus, it suggest that the clustering development strategy by utilizing shared facilities has proven to be able significantly reduce the F&D costs (13.6 $/boe) and provide better economic results (NPV at 136 MM$), rather than have to build new production facilities like in block-C. Figure 3 shows the effect of facility sharing development concept on development and operating cost between block B and block C. There is reduction on development cost in block B (as third party assets) and operating expenditure reduction in block C (as assets operator).

In addition, in order to maintain the economic value of mature field, as in block-A case, improvement on cost efficiency also need to carry out. Figure 3 presents that 77% of the total costs incurred in block-A is for an operating cost, indicates that mature and declining field requires more operational costs.

4.2. Fiscal Scheme Analysis

Field with gross split PSC scheme on block A and block B indicates that the higher costs incurred will directly reduce the contractor's take, likewise, the government's take will also decreases as contractor's income tax decreases. However, at the highest expense required for the field development, the government still gets the certainty of a minimum take equal to the government split (before tax). While on cost recovery PSC scheme, the government's minimum take certainty is as much as FTP.

The cost to revenue ratio in block B at 57% is still within a reasonable amount, considering to the contractor's split at 85.1%, that will provide contractor's take to gross revenue ratio at 16% (after tax) or 788 MM$ of total revenue of 5,051 MM$. Simulation on the increase of expenses on block B at 13%, on Table 4, affected to the increase of cost to revenue ratio of 7%, will directly reduce contractor's take to gross revenue ratio of 6%, and furthermore reduce the government's take of 2% as the effect of contractor's income tax reduction.

From the host government point of view, gross split scheme ensures the host government take, excluding taxes, in accordance with the government split, in this case 34% from block A and 27% from block B. Meanwhile, any cost efficiency by contractor will also improve government take through saving index mechanism (Mardiana et al., 2019; Johnston, 2017), that also confirm by the result on this study, as shown on Table 4. Along with the decrease of cost to revenue, in this case through F&D cost reduction, the government and contractor takes will increase, vice versa. However, at the cost to revenue ratio is higher than its recoverable cost, in case of block C with cost recovery PSC is more than 69%, the government and contractor's take will maintain as much as it's FTP portion. Moreover, there will unrecovered cost at the end of contract and affects to contractor's cash flow.

4.3. Development Scenario and Sensitivity Analysis

The results of deterministic sensitivity analysis of three working areas that modelled on three cases based on the reserves size shown in Table 5. The table presents how NPV varies with the variation of hydrocarbon price, and F&D cost at each reserves size. It is suggests that the decrease of oil or gas prices, as well as the increase of F&D costs will have a significant effect on the economic value of the field, especially in the new development offshore field like block B and block C.

Based on sensitivity analysis results on Table 5 and calculation, block A was still able to produce positive NPV at the lowest oil price of 42$/bbl on the field with a reserve more than 260 MMBO, and survive at oil price 40.5$/bbl by optimizing the F&D costs. While in block B presents that the field with reserves of 0.6 TCF will economically attractive with the LNG price at the highest of 8 $/mmbtu. The lowest LNG price that can provide positive NPV value in block B is 6.3 $/mmbtu for the field with reserves more than 0.8 TCF. Combined with optimization on F&D costs by 5% are able to provide better economic results when LNG price reduce at 6 $/mmbtu. This result suggests that fields with smaller reserves size are not profitable in a period of low hydrocarbon price.

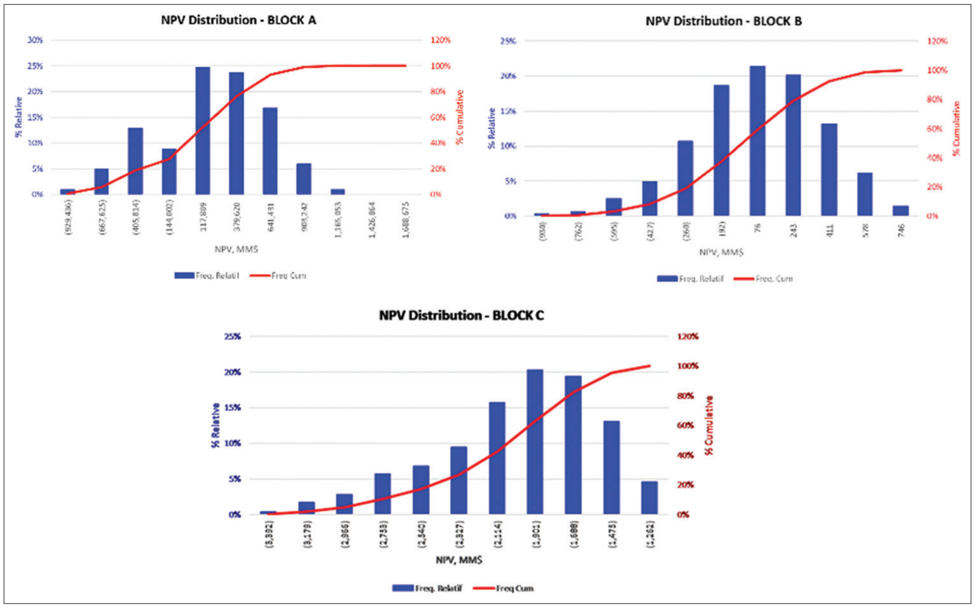
Table 4: Simulation of expense changes to contractor and government take to revenue ratio

Scenario	Block A			Block B			Block C		
	Cont. take to revenue	Gov. take to revenue	Cost to Revenue	Cont. take to revenue	Gov. take to revenue	Cost to Revenue	Cont. take to revenue	Gov. take to revenue	Cost to Revenue
low F&D	6%	35%	59%	20%	29%	51%	5%	27%	55%
base F&D	5%	34%	61%	16%	27%	57%	3%	15%	69%
high F&D	4%	33%	63%	10%	25%	64%	3%	15%	87%

Table 5: Deterministic sensitivity of the three offshore field, NPV

Block A	208 MMBO			260 MMBO			311 MMBO		
	40 $/bbl	60 $/bbl	80 $/bbl	40 $/bbl	60 $/bbl	80 $/bbl	40 $/bbl	60 $/bbl	80 $/bbl
$7.5/boe F&D Cost	(1.261)	(438)	231	(658)	221	894	(116)	753	1.539
$8.4/boe F&D Cost	(1.367)	(538)	150	(761)	140	824	(212)	683	1.470
$9.5/boe F&D Cost	(1.496)	(660)	46	(885)	34	739	(333)	594	1.385
Block B	**0.64 TCF**			**0.8 TCF**			**1 TCF**		
	4.5 $/mmbtu	**5.3 $/mmbtu**	**6 $/mmbtu**	**4.5 $/mmbtu**	**5.3 $/mmbtu**	**6 $/mmbtu**	**4.5 $/mmbtu**	**5.3 $/mmbtu**	**6 $/mmbtu**
$2/mmscf F&D Cost	(554)	(331)	(154)	(247)	17	213	(116)	753	1.539
$2.4/mmscf F&D Cost	(815)	(592)	(400)	(503)	(239)	(34)	(212)	683	1.470
$4/mmscf F&D Cost	(1.810)	(1.556)	(1.346)	(1.455)	(1.174)	(935)	(333)	594	1.385
Block C	**1 TCF**			**1.2 TCF**			**1.5 TCF**		
	5 $/mmbtu	**6 $/mmbtu**	**7 $/mmbtu**	**5 $/mmbtu**	**6 $/mmbtu**	**7 $/mmbtu**	**5 $/mmbtu**	**6 $/mmbtu**	**7 $/mmbtu**
$3/mmscf F&D Cost	(1.419)	(1.217)	(1.016)	(977)	(787)	(693)	(705)	(595)	(505)
$4/mmscf F&D Cost	(2.408)	(2.207)	(2.005)	(1.711)	(1.460)	(1.225)	(1.309)	(1.080)	(946)
$5/mmscf F&D Cost	(3.579)	(3.377)	(3.176)	(2.882)	(2.630)	(2.378)	(2.185)	(1.883)	(1.597)

Figure 4: NPV distribution with stochastic sensitivity



To analyze the effect of F&D cost, in any case of the increase F&D cost until 24 $/boe in block B, the sensitivity presents that only field with a reserves higher than 1 TCF still able to provide good economic results at a LNG price of 7.3 $/mmbtu. This result also suggests that fields with reserves size <0.8 TCF could be challenging to obtain an attractive economic value with F&D cost at 12 $/boe.

In block C, the results of deterministic sensitivity show that the three variables of gas price, F&D costs, and production have a significant effect on NPV, however still unable to improve the NPV to positive value in the specified input parameter range. Thus suggesting to improve operating cost efficiency and increase production rate until end of contract, considering that all those development cost have been incurred. The efficiency could be by enhanced clustering development with other operators, considering to the success of the cluster scheme with block B.

The stochastic results present P10, P50 and P90 values of contractor's NPV distribution are shown on Figure 4. It is shows that the NPV still have a negative value for all scenarios in P10 and P50 for all block. However, there is 48% and 41% probability to produce a positive NPV on block A and block B, respectively, as shown in Table 6. The mean NPV of block A is 380 MM$, but there is still a 52% possibility of experiencing a decrease in NPV due to variations in oil price declines, increases in F&D and operating cost, as well as a decrease in oil production. While in block B, the mean NPV is quite lower at 4 MM$, however there is 41% probability to obtain a positive NPV including when LNG price is low at 6 $/mmbtu, and F&D cost at 12 $/boe.

The low probability of obtaining a positive NPV value in block B shows that the investment risk in developing new fields using sharing facilities is remain high. Although there are reductions on F&D costs for production facilities development, efforts to reduce development costs from drilling wells must still be pursued. Sharing facilities utilization with other new PCS's around the area is expected to be able to reduce operating costs in the upcoming years. In addition, suggestion from Mardiana et al. (2020) related with the changing production strategy by increasing production rate in the beginning year that will affect to the contractor's cash flow through progressive split from cumulative production, can be used as an initiative in terms of production optimization strategy. As also mentioned by Mudford and Stehemeier (2003) and Marques et al. (2014).

Table 6: Monte carlo simulation result

Item	Block A	Block B	Block C
Model NPV (MM$)	641	76	(1,688)
Mean NPV (MM$)	380	4	(2,114)
Probability of positive NPV	48%	41%	0%

The results in block C shows that the investment risk for the new development offshore fields is very high, that require more efforts and initiatives to increase the economic value of the field. Such as, providing fiscal incentives (Esrar, 2021), preparing the F&D and operating costs be more efficient by collaboration with other operator on cluster development strategy (Akinlawon, 2017).

5. CONCLUSIONS

This study was addressed the economic analysis of three offshore fields that has different characteristic and fiscal terms. The results show that the economic outcome is more vulnerable in deep-offshore fields that require high finding and development costs. Cluster development strategy through the utilization-shared facilities owned by other operators has proven to be able to reduce investment costs and provide better economic results, including expectation to drive operating cost down in the following years. Deterministic and stochastic sensitivities indicates that to improve the economic outcomes of new deep-offshore field development, further initiative of cost efficiency and fiscal incentive are required.

Meanwhile, in the mature offshore fields, optimization of operating cost efficiency are also needs to be improved, considering that there is still a 51% chance of experiencing a decrease in NPV due to variations of low oil price, high F&D and operating costs, and production decline.

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