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Corresponding author:
Qi Adlan
qi.adlan@brin.go.id

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Petroleum system risk quantification for PSC investment in Indonesia's LNG sector

Qi Adlan[1], Eric Aldo Tanuwijaya[2*]

[1]Research Centre for Geological Resources, National Research and Innovation Agency (BRIN), Indonesia
[2]Faculty of Geological Engineering, Universitas Padjadjaran, Indonesia
*Present address: FERG Geosains Indonesia, Indonesia

Abstract

Investment decisions in upstream oil and gas sector of Indonesia often involve acquiring stakes in existing Production Sharing Contract (PSC) areas. Such decisions require careful assessment of geological uncertainty, economic viability, and regulatory constraints. For investors evaluating PSC blocks, a robust understanding of regional geological risk within the petroleum system is critical. This study introduces a practical and scalable geological risk quantification framework to support upstream investment decisions in the LNG sector in Indonesia. The framework is designed for application under the current fiscal regime and can be effectively implemented even when data availability is limited, such as when relying on information from the Migas Data Repository (MDR). Recognizing that early-stage opportunities often involve significant geological uncertainty, we developed a tailored petroleum system risk metric comprising five parameters: source rock, trap, dynamic factors, reservoir conditions, and subsurface issues. The framework was applied to five PSC blocks using Multi-Attribute Utility Theory (MAUT), integrating operator-specific economic indicators (Net Present Value, Internal Rate of Return, Payout Time, and Profitability Index) alongside CO_2 emission intensity. Monte Carlo simulations were conducted to evaluate investment rankings under uncertainty. A key finding is that the proposed risk quantification approach is simple enough to be implemented with limited MDR data, yet robust enough to support investment strategy. Furthermore, the framework builds upon and complements existing standardization efforts by the regulator, SKK Migas, offering a practical tool for upstream investors in an evolving regulatory landscape.

1. Introduction

In recent years, investment in Indonesia's oil and gas sector has been disrupted by changes to the Production Sharing Contract (PSC) framework. The government shift from a Cost Recovery model to a Gross Split scheme, formalized under Ministry of Energy and Mineral Resources Regulation No. 8 of 2017, marked a significant fiscal reform (Yuniza et al., 2020).

These fiscal terms define the regulatory, legal, and taxation conditions for the oil and gas exploration, production, and distribution framework (Yun et al., 2020; Mardiana et al., 2024; Firera et al., 2024). According to Article 5 (Yuniza et al., 2020) of the fiscal regulation, the base revenue split allocates 57 percent to the state and 43 percent to the contractor for petroleum (MEMR, 2017). For natural gas, the split is slightly more favorable to contractors, with 52 percent allocated to the state and 48 percent to the contractor (MEMR, 2017). Regardless of the global price gap between gas and oil, this regulation reflects the distinct policy treatment of oil and gas. With liquefied natural gas (LNG) emerging as a key transitional energy source, Indonesia fiscal framework and existing infrastructure create favorable conditions for continued LNG investment. This policy direction aligns with national energy strategies and global decarbonization goals, positioning natural gas as a strategic bridge fuel. As a result, Indonesia gas sector represents a promising avenue for sustainable and competitive energy development.

While the Gross Split model aims to streamline administrative processes and increase transparency, it transfers full financial and operational responsibility to the contractor. As a result, investors must now manage greater exploration and development risk independently, including technical uncertainties and cost exposure (Yuniza et al., 2020; Giranza and Bergmann, 2018). On the other hand, for existing Production Sharing Contracts (PSCs) areas, selling stake or transferring Participating Interests (PI) or ownership in Indonesia requires a formal process regulated by the Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas), as outlined in MoEMR Regulation No. 48 of 2017 and No. 57 of 2018. As part of this process (Firera et al., 2024; MEMR, 2017), SKK Migas assesses the investors technical and financial capacity to maintain or enhance production levels. Consequently, upstream studies are essential to guiding investment strategies.

A key component of upstream evaluations is petroleum system risk assessment (Otis and Schneidermann, 1997), which helps companies determine hydrocarbon type, quantify exploration risks, and address geological uncertainties. For investors entering or expanding within existing PSC areas in Indonesia, a clear understanding of these risks is critical. The Migas Data Repository (MDR), managed by SKK Migas, the Indonesian oil and gas regulatory body, is a membership-based system that provides PSC Contractors with streamlined and cost-effective access to vital exploration data. However, data access can be delayed due to the membership process, and non-members face limited accessibility.

This study aims to improve existing standardization efforts by SKK Migas (Pardede et al., 2010) and demonstrate investment decision-making in upstream oil and gas sector by developing a risk quantification approach that accounts for geological uncertainties related to hydrocarbon type (oil or gas), particularly within the context of LNG investment and the Gross Split fiscal framework. The analysis is conducted using publicly accessible (non-member) MDR data. This risk assessment is followed by a simulation using synthetic data from five operational PSCs in Indonesia, incorporating factors such as economic feasibility and environmental considerations. The final decision-making framework incorporates a modified geological chance factor within an acquisition-oriented simulation using Multi Criteria Decision Making (MCDM) method, specifically the Multi-Attribute Utility Theory (MAUT) approach (Siskos et al., 1984).

The integrated model enables a holistic evaluation by incorporating geological risk, economic feasibility, and environmental impact. It equips upstream companies with a structured approach to prioritize petroleum system elements, target high-potential areas, and align LNG investment strategies with both emissions goals and commercial objectives. By bridging geological analysis with fiscal strategy, this study supports investment and acquisition decisions that advance both profitability and long-term sustainability.

2. Background

Investment in Indonesia (Oil and Gas Industry)

Indonesia has a long history of oil and gas production, dating back to 1885 (Tejo and Putra, 2018). Since the 1960s, the sector has been governed by the Production Sharing Contract (PSC) system (Paramita, 2022), which divides production between the government and contractors according to a predetermined percentage. Efforts to boost oil and gas recovery continue to shape Indonesia fossil fuel industry (Mwakipunda et al., 2023), alongside volatile oil prices (Choi and Kim, 2018; Ansari and Kaufmann, 2019), and aging production infrastructure (Paramita, 2022). Together, these factors have intensified the financial strain on the PSC system. Until 2017, this system operated under a cost recovery model, wherein contractors were reimbursed for exploration and development costs. However, frequent audit reports flagged inflated claims, raising concerns about state losses (Yuniza et al., 2020; Firera et al., 2024; Tejo and Putra, 2018). To address this, the government introduced a gross split PSC in 2017 (MEMR, 2017). The revised model eliminates cost recovery and instead provides additional production splits based on specific factors such as low oil prices, high domestic content, and project economics. Despite these adjustments, industry stakeholders have expressed concern over the lack of regulatory clarity (Wood Mackenzie, 2017), while contractors continue to face challenges related to fiscal rigidity (Acquah-Andoh et al., 2019) and rising capital and operational expenditures (Attia et al., 2019), which have negatively impacted the economic viability of petroleum projects (Firera et al., 2024). The gross split formula, as defined by the Ministry of Energy and Mineral Resources (MEMR,2017), is calculated before tax and follows this structure:

Gross Split = Base Split (A) + Progressive Split (B) + Variable Split (C)

For contractors, the base split (A) is determined by the hydrocarbon type, with 43 percent applied to oil and 48 percent to gas. The progressive split (B) is based on fluctuations in oil and gas prices as well as cumulative production volumes. The variable split (C) is particularly significant, as it reflects several geological factors and technical conditions outlined in the 2017 Gross Split framework, including field status, field location, the presence of existing infrastructure, the level of local content, production phase, reservoir depth, reservoir conditions, as well as the concentrations of carbon dioxide (CO_2), hydrogen sulfide (H_2S), and the oil's specific gravity.

The updated 2024 Gross Split regulation continues to reflect geological dependencies (MEMR, 2024). In the updated version, the base split for contractors has been increased to 47 percent for oil and 49 percent for gas. A flexibility clause has now been added, allowing the Minister to award an additional split during stages such as planning (POD I or II) or contract extension (MEMR, 2024). Additionally, the regulation related to unconventional hydrocarbon resources has now been clarified (MEMR, 2024). Although changes have been made to the variable split (C) component, the base split (A) remains influenced by geological characteristics, particularly the hydrocarbon type. Therefore, effective application still requires detailed petroleum system analysis, highlighting the essential role of geoscience in supporting investment decisions.

Evaluation of Geological Risk Factors

Effectively quantifying and managing geological risk is essential for the upstream oil and gas sector (Nosjean et al., 2021; Smalley et al., 2008; Citron et al., 2018), particularly in the context of investments targeting LNG. A critical foundation for addressing this challenge lies in the concept of the petroleum system, introduced by Magoon (Magoon, 1988), which describes the geological components that control hydrocarbon generation, migration, and accumulation. Assessing geological uncertainty through a scientifically grounded probability of success for these elements is essential to enhancing project value, optimizing exploration portfolios, and enabling more informed investment decisions (Nosjean et al., 2021). Managing these uncertainties requires a multi-scale analytical approach, ranging from regional basin to detailed prospect-level evaluations (Figure 1).

In this study, the geological risk factor is treated as equivalent to the probability of geological success (Pg), as defined by Rose (Rose, 2017; Rose and Citron, 2000). Pg represents the likelihood of discovering new hydrocarbon resources within a reservoir capable of sustaining commercial flow. Here, it is adapted and modified to reflect the potential upside value of a Production Sharing Contract (PSC) area, especially when existing infrastructure is already compatible with the type of hydrocarbon produced. This alignment significantly enhances the area's investment appeal. Expressed as a percentage, Pg is commonly used to rank segments and prospects by risked resource estimates (White, 1993). In this context, it serves as the first step in a broader investment decision-making process.

In Indonesia, the national upstream regulator SKK Migas has taken steps toward standardizing Pg evaluations. Pardede (Pardede et al., 2010) incorporates methodologies adapted from a variety of international sources (Otis and Schneidermann, 1997; Mackay, 1996; Harper, 2000; Ward and Whitaker, 2016; Milkov, 2021; Milkov, 2017; Bagley and Bond, 2018; Søiland, 2019; Bond et al., 2022), and is tailored to suit Indonesia's regulatory context.

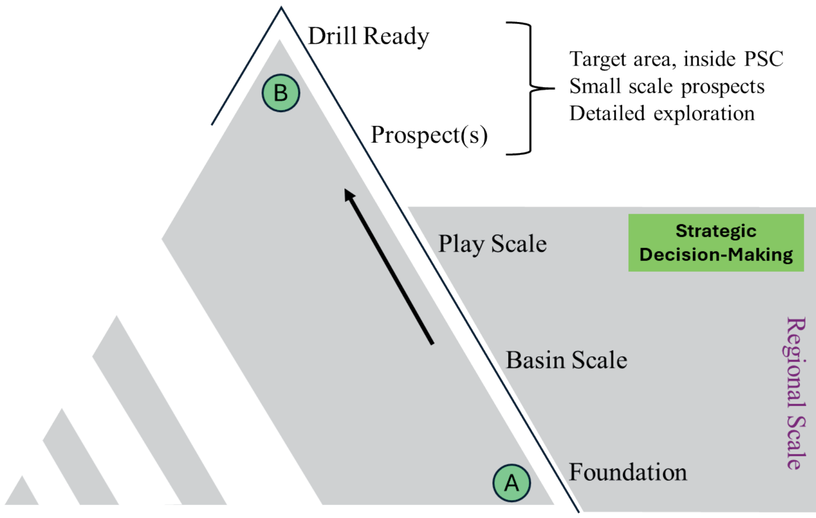

Figure 1. The Exploration Triangle, modified from Nosjean et al., 2021. From the regional scale (A) to the field play level (B).

3. Methods

Geological Risk Factor Adapted for PSC Evaluation

In the upstream oil and gas sector, the probability of geological success (Pg) is commonly calculated by multiplying a set of independent chance factors, each representing the likelihood of key petroleum system elements being present (Rose, 2017; Milkov, 2015; Gotautas, 1963). The number and definitions of these factors vary among companies, ranging from as few as four (Duff and Hall, 1996; Snow et al., 1996; Johns et al., 1998) to more than a dozen (Nosjean et al., 2021; Watson, 1998). Despite this variability, these elements are typically grouped into five principal categories: reservoir quality, source rock presence and maturity, hydrocarbon migration and timing, structural configuration, and sealing or preservation capacity. Previous standardization efforts by SKK Migas (Pardede et al., 2010) are not always suitable for investment scale evaluations, as many criteria require direct access to area-specific data, complicating early-stage screening. To address this, our study evaluates the extent of publicly accessible data available through Migas Data Repository (MDR), focusing on non-subscription data to simulate the perspective of investor. The SKK Migas risk standardization framework was then modified by integrating the petroleum system concept to quantify geological risk factors, emphasizing their role in investment decisions. Using the same abbreviations adopted by Duff and Hall (1996) and Pardede et al. (2010), the assessments are defined as Source Rock Assessment (PSr), Trap Assessment (PT), Dynamic Assessment (PD), Reservoir Variability and Quality (PRr), and Subsurface Issue (Ssi). The detailed justification is presented as follows:

Source Rock Assessment

Source rock quality is a fundamental control on hydrocarbon phase (Tissot and Welte, 1984; Curiale, 2008). It determines whether a PSC area is more likely to yield oil, gas, or a mix of both. Source rocks are commonly classified into three types: Type I (oil-prone), Type II (mixed oil and gas), and Type III (gas-prone) based on kerogen composition (Peters and Cassa, 1994). In Indonesia, many Cenozoic basins contain multiple source intervals (Barber et al., 2005; Hall and Smyth, 2008; Adlan et al., 2016a; Adlan et al., 2016b), which enhances the gas potential of a block, especially for LNG-focused investment. This study uses the number of source rock intervals, kerogen type, and maturity (Ro%) as key indicators of gas-prone systems, adapted from SKK Migas criteria (Pardede et al., 2010).

Trap Assessment

Effective trap analysis is central to evaluating hydrocarbon retention risk (Rose and Citron, 2010; Milkov, 2015). However, many of the criteria used by SKK Migas (Pardede et al., 2010), such as seismic reprocessing age and qualitative seismic interpretations, are often inaccessible or impractical during early-stage investment screening. This study uses a simplified, scalable approach based on publicly available geological and seismic metadata, suited for regional LNG exploration in gas-prone plays. Trap assessment integrates four key proxies:

- Tectonic History: Timing and deformation style influencing trap formation (Abdalla et al., 2024; Faturrakhman et al., 2025; Doust and Sumner, 2007).
- Seismic Coverage: The number of 2D seismic lines from the MDR serves as a proxy for structural definition and data density (Pardede et al., 2010).
- Exploration Maturity: The presence of wells within or near the block indicates prior interest and subsurface calibration (White, 1993; Pardede et al., 2010).
- 3D Seismic Availability: Even without full access, known 3D seismic coverage signals advanced structural mapping and reduced uncertainty (Wadas et al., 2023).

Dynamic Assessment

The dynamic assessment used in this study is streamlined for investment-scale evaluation and differs from the more detailed approach proposed by SKK Migas (Pardede et al., 2010), which relies on extensive basin and petroleum system modeling. While such analyses are useful for exploration and resource classification (Magoon, 1988), early-stage investment decisions require a more practical method. Key dynamic factors, including hydrocarbon migration and charge, remain essential as they influence geological success (White, 1993; Milkov, 2015). In this study, we use two proxies: (1) the geometry and likelihood of effective migration pathways, and (2) the structural position of the prospect relative to the fetch area. These are evaluated based on regional stratigraphy and structure, using established literature from Southeast Asian basins (Hall and Smyth, 2008; Doust and Sumner, 2007; Allen and Allen, 2013; Wisesa et al., 2017; Shaylendra et al., 2017; Adlan et al., 2025b). This method enables credible yet accessible risk evaluation aligned with investment requirements.

Reservoir Variability and Quality

Reservoir risk is evaluated using five criteria, tailored for investment-scale screening:

- Reservoir lithology: Limestone reservoirs carry higher uncertainty due to complex diagenesis (Adlan et al., 2020; Adlan and John, 2023; Adlan et al., 2023).
- Number of reservoir formations: Hydrocarbon accumulations are often preserved across multiple formations (Doust and Sumner, 2007; Rizal et al., 2018; Syafriyono et al., 2018; ;Anhaer et al., 2024; Ehrenberg et al., 2024).
- Reservoir depth: Depth is a key factor affecting development cost (Pardede et al., 2010).
- Presence of fractured or basement reservoirs: These reservoirs have shown high permeability in Southeast Asia, can enhance early production (Parsons, 1966).
- Potential for carbon capture and storage (CCS): CO_2 storage feasibility supports long-term environmental and commercial goals (Irzon, 2024).

Subsurface Issue

Subsurface issues are critical under the Gross Split fiscal regime, which takes into account geological risks such as CO_2 and H_2S content. In this study, we assess three key factors: overpressure, CO_2 levels, and H_2S presence. These risks are typically linked to geological conditions. For instance, elevated CO_2 is often associated with deeply buried carbonate formations (Adlan et al., 2023; Adlan et al., 2025a). High concentrations of H_2S and the presence of overpressure zones increase operational complexity (Ramdhan et al., 2021) and cost, directly affecting investment feasibility.

Case Simulation Test

To evaluate the practical applicability of the investment-scale petroleum risk assessment developed in this study, we conducted a simulation involving five PSC blocks located in various sedimentary basins across Indonesia (Table 1). These blocks were selected to reflect a range of geological settings, allowing us to test the robustness of the proposed geological and economic decision framework under diverse conditions.

While the geological characteristics of these PSC blocks are based on actual data obtained from the MDR, the investment environment was simulated to replicate early-stage screening from perspective of the investor. Each block was assigned to a hypothetical operating company to simulate investor behavior and decision-making without introducing bias related to existing operators. For each PSC, we generated synthetic economic parameters, including projected Net Present Value (NPV), Internal Rate of Return (IRR), Pay-Out Time (POT), and Profitability Index (PI). Additionally, an emission intensity indicator was incorporated into each scenario to account for environmental sustainability considerations, as reflected by the volume of CO_2 produced and the CO_2 emission rate. These indicators serve as proxies for carbon intensity and regulatory compliance risk, highlighting the growing importance of environmental, social, and governance (ESG) factors in upstream investment decisions.

Table 1. Synthetic PSC scenarios for investment simulation.

PSC / Operator	Sedimentary Basin (Petroleum System)	Economics		Emission Intensity	
				CO_2 Prod.	CO_2 rate
Sunda Betung Block Op: Faza Oil Ltd	South Sumatra Basin	NPV IRR POT PI	3278800000 28.96% 6.75 29.32%	21917700	0.29
North Kambuna Block Op: Nakula Oil Ltd	North Sumatra Basin	NPV IRR POT PI	3322000000 29.13% 9.37 57.83%	19573100	0.12
Arafura Banli Block Op: Fahrul Oil Ltd	Arafura Basin	NPV IRR POT PI	3345000000 27.30% 10.68 29.70%	57183700	0.11
Brantas Salatiga Block Op: Indah Oil Ltd	Onshore East Java Basin	NPV IRR POT PI	260000000 25.14% 13.67 76.22%	4907300	0.32
East Mentawai Block Op: Sahid Oil Ltd	Ombilin Basin	NPV IRR POT PI	215000000 19.40% 9.55 48.85%	20573000	0.27

Multi Criteria Decision Method

Since the 1970s, Multi-Criteria Decision-Making (MCDM) methods have been widely developed and applied across various disciplines (Mulyadi and Nur, 2018; Sitorus and Brito-Parada, 2022; Al Ghiffari and Widodo, 2022; Permanajati et al., 2023). MCDM provides a systematic and transparent framework for evaluating multiple conflicting factors, supporting objective decision-making in complex investment and environmental assessments (Sitorus and Brito-Parada, 2022). In the context of upstream oil and gas investment, MCDM allows decision-makers to integrate geological risk, economic indicators, and environmental factors into a unified framework for informed project evaluation. Here, MCDM approach was applied to identify the most suitable PSC block for investment by integrating geological risk, economic performance, and environmental considerations into a unified analytical framework. Specifically, the Multi-Attribute Utility Theory (MAUT) method was employed, as it effectively combines both qualitative and quantitative inputs while accounting for uncertainty in various attributes (Siskos et al., 1984). This analysis was conducted on five selected PSC blocks across Indonesia (see Section 3.2), using four key criteria outlined previously (Section 3.1). The relative weightings of these criteria were established through expert elicitation via questionnaires distributed to two senior specialists from a private oil company's new ventures division in Indonesia, each with over 20 years of relevant experience.

The collected data were processed using the open-source decision support tool ENTSCHEIDUNGSNAVI (von Nitzsch et al., 2020), following the established protocol by Peters (Peters et al., 2024). The use of an MAUT-based approach is particularly relevant given that economic estimations are influenced by uncertain global price fluctuations. Then, the outcomes of the MAUT analysis were tested using a Monte Carlo simulation (Kalos and Whitlock, 2009; Mujahid et al., 2025), allowing for probabilistic ranking of PSC investment alternatives under a wide range of simulated scenarios.

To incorporate uncertainty into the investment simulation, key assumptions were made regarding gas prices and emissions intensity. Historical gas price data from 2024 were used, with a median value of 3.9 USD per MMBtu. A pessimistic scenario (P10) assumed a price of 2.2 USD per MMBtu, representing 43.5 percent below the median, while an optimistic case (P90) used 4.5 USD per MMBtu, or 15.3 percent above the median. These variations directly influence economic indicators such as Net Present Value (NPV) and Internal Rate of Return (IRR). In addition, a carbon dioxide intensity rate, used as a proxy for environmental sustainability and regulatory risk, was calculated based on average emissions from existing fields in each PSC. To simulate potential variability in emissions under different development scenarios, a 20 percent deviation from the median value was applied to represent P10 and P90 conditions.

4. Results

Proposed Risk Assessment Framework

This study adopts five key geological risk criteria: Source Rock (Tissot and Welte, 1984; Peters and Cassa, 1994; Barber et al., 2005), Trap (Doust and Sumner, 2007; Wadas et al., 2023), Dynamic Factors (Allen and Allen, 2013; White, 1993), Reservoir (Adlan and John, 2023; Ehrenberg et al., 2024), and Subsurface Issues (Adlan et al., 2023; Irzon, 2024). As each criterion is grounded in well-established geological principles and supported by industry references, this study combines it with simplified SKK Migas geological risk standardization (Pardede et al., 2010). The resulting framework is detailed as follows (Table 2).

Table 2. Petroleum risk framework adaptation suitable for investment decision support.

Petsys Element	Criteria	Category	Score
Source Rock Assessment (PSr)	How Many Source Rocks	1	0.8
		2	0.9
		3	0.99
	Type Of Kerogen	Type I	0.8
		Type II	0.9
		Type III	1
		Type IV	0.0625
	Source Rock Maturity in Fetch Area TOC	0 – 0.5	0.0625
		0.5 – 1	0.25
		1 – 2	0.5
		2 – 4	0.75
		>4	1
	Source Rock Maturity (%Ro)	Immature (0-0,6)	0.0625
		Early Mature (0,6-0,65)	0.5
		Peak Mature (0,65-0,9)	1
		Late Mature (0,9-1,35)	1
		Over Mature (>1,35)	0.125
Trap Assessment (PT)	Tectonic Event (Trap Forming)	1 event	1
		2 or more	0.5
	Amount of Existing Seismic Lines	>20	1
		Equal to or less than 20	0.5
	Amount of Existing Wells	>20	1
		Equal to or less than 20	0.5
	3D Seismic Availability	Exist	1
		Not Exist	0.5

Petsys Element	Criteria	Category	Score
Dynamic Assessment (PDa)	Dynamic Migration Pathway	Vertical	0.8
		Vertical - Lateral	0.9
		Vertical-Lateral - Bsm chrg	0.99
	Dynamics Migration Pathways Position of Trap With Respect to Kitchen/Fetch Area	Very Near (0 – 2 KM)	0.99
		Near (2 – 5 KM)	0.9
		Middle (5 – 10 KM)	0.8
		Long (10 – 20 KM)	0.6
		Very Long (>20KM)	0.4
Reservoir, Variability, & Quality (PRr)	Reservoir Lithology	Sandstones Homogenous	0.9
		Carbonates	0.9
		Sandstones Heterogenous	0.8
		Clastic Carbonates	0.5
		Vulcanoclastics	0.5
		Conglomerate	0.5
		Fractured Meta Sediment	0.4
		Fractured Metamorf	0.4
		Fractured Igneous Rocks	0.4
		Coal	0.2
		Others	0.2
	Reservoir Count (Proven)	1	0.8
		2	0.9
		>2	1
	Estimate Depth of Reservoir	1-3 KM	0.9
		3-4 KM	0.8
		>4 KM	0.7
	Basement Reservoir/ Fracture Play	Yes	1
		No	0.9
	Existing Study on CCS Potential	Exist	1
		Not Exist	0.9
Subsurface Issue (Ssi)	Overpressure	No	0.99
		Yes	0.7
	CO_2 Content	0-3% (Low CO_2)	0.99
		>3-10% (Moderate CO_2)	0.9
		>10-25% (High CO_2)	0.8
		>25-50% (Very High CO_2)	0.7
		>50% (Ultra High CO_2)	0.5
	H_2S Content	<4 ppm (Very Low H_2S)	0.99
		4-100 ppm (Low H_2S)	0.9
		>100-1.000 ppm (Moderate H_2S)	0.8
		>1.000-5.000 ppm (High H_2S)	0.7
		>5.000 ppm (Very High H_2S)	0.5

Geological Risk Factor for gas resources (LNG)

Using 18 geological and subsurface criteria (Table 3), including source rock quality, seismic and well data availability, reservoir characteristics, and environmental constraints, a normalized geological risk score was calculated for each simulation block. The results reflect the relative geological favorability and investment potential of each block based on literature review and data availability via MDR. North Kambuna scored highest at 0.81, indicating the most favorable geological conditions. Sunda Betung followed with 0.78, while Arafura Banli, Brantas Salatiga, and East Mentawai recorded lower scores of 0.73, 0.70, and 0.68, respectively.

These differences are primarily attributed to variations in source rock maturity, data coverage, migration pathway clarity, and reservoir quality. This structured risk quantification offers a clear basis for further economic and environmental evaluation, ensuring that geological uncertainties are fully considered in early-stage PSC investment decisions for LNG development.

Table 3. Geological risk quantification scores for five selected PSC blocks based on 18 petroleum system criteria relevant to LNG investment.

Petsys Element	Risk Quantification	Sunda Betung	North Kambuna	Arafura Banli	Brantas Salatiga	East Mentawai
Source Rock Assessment	Source Rock count	2	2	1	2	1
	Type Of Kerogen	II & III	II & III	II & III	II & III	I
	Source Rock TOC	1.5 - 2	2 - 5	2 - 5	0.79 - 4	1.5 - 2
	Source Rock Maturity	Early to good Mature	Mature - Overmature	Late Mature	Mature - Overmature	Early to good Mature
Trap Assessment	Tectonic Episodes	3 Phase	3 Phase	4 Phase	3 Phase	2 Phase
	2D Seismic Line	>20	>20	>20	>20	>20
	Well Data	>20	3	7	>20	>20
	3D Seismic	Exist	Exist	Exist	Exist	Not Exist
Dynamic Assessment	Pathway	Vertical-Lateral	Vertical-Lateral	Vertical-Lateral	Vertical-Lateral	Vertical-Lateral
	Migration Pathway	5-30 Km	5- 30km	10-30km	<10 km	5-30 Km
Reservoir, Variability, & Quality	Res.Lithology	SS and LST	SS	SS	SS and LST	SS and LST
	Res. Fm. Count	2	3	1	2	2
	Res. Depth	1.6 - 1.8 Km	4.2 - 4.3 km	3.9 – 4.2km	2.5-3.5 km	1.6 - 1.8 Km
	Basement Play	Yes	Yes	Yes	Yes	Yes
	Study on CCS	Exist	Not Exist	Not Exist	Exist	Not Exist
Subsurface Issue	Overpressure	Yes	Yes	Yes	Yes	Yes
	CO_2 Content	30%	13.76%	10%	25%-35%	30%
	H_2S Content	10 ppm	50-100 ppm	10 ppm	10000 ppm	10 ppm

Simulation Result and Investment Rank

A hierarchical structure was first developed to evaluate three key criteria: geological risk, economic performance, and environmental impact. Weighting was determined through a survey of senior specialists from the new ventures division of a private oil company. The results assigned weights of 0.70 to economic performance, 0.25 to geological risk (petroleum system factor), and 0.05 to emission intensity. It is important to note that these weightings are not fixed and can be customized to align with specific strategic priorities or risk acceptance of each company. These criteria were organized into an objective hierarchy (Figure 2), and their respective weights were incorporated into the utility functions to reflect investor preferences. To account for uncertainty, worst-case and best-case values were applied to selected attributes, namely net present value (NPV), internal rate of return (IRR), and carbon dioxide emission rate (Table 4). These inputs were then evaluated using a Multi-Attribute Utility Theory (MAUT) approach using the ENTSCHEIDUNGSNAVI platform.

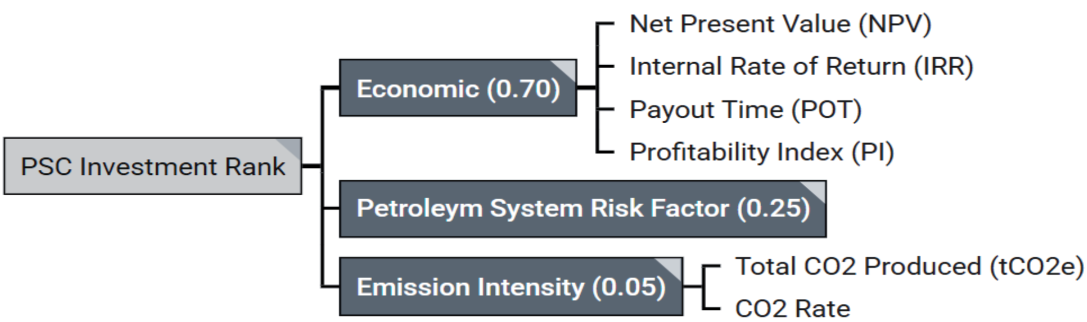

Figure 2. Hierarchical structure of the three evaluation criteria: geological risk, economic performance, and environmental impact, along with their respective weights.

Simulation results indicate a consistent preference for the North Kambuna Block in the North Sumatra Basin, which ranked first in 69% of Monte Carlo iterations and second in 25%. This top ranking is driven by its superior Profitability Index and the most favorable petroleum system risk score compared to the other blocks. The Sunda Betung Block in the South Sumatra Basin ranked second in 54% of iterations, while placing first and third in 29% and 18%, respectively. Its strong performance is largely attributed to having the fastest Pay-Out Time among all candidates. The Arafura Banli Block in Offshore Papua consistently ranked third in 72% of iterations, followed by the remaining blocks, which occupied the bottom two ranks in 73% and 76% of the runs as their overall criteria scores were lower than the North Kambuna and Sunda Betung blocks. These results highlight a strong investment preference for the North Kambuna and Sunda Betung blocks, demonstrating the robustness of the MAUT framework in integrating geological, economic, and emission factors into a coherent investment decision model (Table 5).

Table 4. Combined input variables used in the MAUT analysis.

PSC	Influence Factor	Net Present Value (NPV)	Rate of Return (IRR)	Payout Time (POT)	Profitability Index (PI)	Petsys risk	Total CO2 Produced	CO_2 Rate
Sunda Betung Block	Worst (p.10)	1852522000	16.36					0.33
	Median (p.50)	3278800000	28.96	6.75	29.32	0.78	21917700	0.29
	Best (p.90)	3780456400	33.39					0.16
North Kambuna Block	Worst (p.10)	1876930000	16.46					0.14
	Median (p.50)	3322000000	29.13	9.37	57.83	0.81	19573100	0.12
	Best (p.90)	3830266000	33.59					0.07
Arafura Banli Block	Worst (p.10)	1889925000	15.42					0.12
	Median (p.50)	3345000000	27.30	10.68	29.70	0.73	57183700	0.11
	Best (p.90)	3856785000	31.48					0.06
Brantas Salatiga Block	Worst (p.10)	146900000	14.20					0.37
	Median (p.50)	260000000	25.14	13.67	76.22	0.70	4907300	0.32
	Best (p.90)	299780000	28.99					0.18
East Mentawai Block	Worst (p.10)	121475000	10.96					0.31
	Median (p.50)	215000000	19.40	9.55	48.85	0.68	20573000	0.27
	Best (p.90)	247895000	22.37					0.15

Table 5. Final investment ranking of PSC blocks based on Monte Carlo simulation integrating geological risk, economic performance, and environmental impact.

			Frequency of rank				
		ø Rank	1	2	3	4	5
1.	North Kambuna Block	1.37	69%	25%	6%	0%	0%
2.	Sunda Betung Block	1.89	29%	54%	18%	0.05%	0%
3.	Arafura Banli Block	2.79	2%	21%	72%	4%	1%
4.	Brantas Salatiga Block	4.19	0%	>0%	4%	73%	23%
5.	East Mentawai Block	4.76	0%	0%	0.43%	23%	76%

5. Discussion and Implications

The simulation results of this study underscore a strong investor preference for the North Kambuna Block in North Sumatra Basin, which consistently ranked among the top investment options across most Monte Carlo iterations. Coincidentally, North Sumatra strategic role in natural gas sector of Indonesia provides an important contextual anchor for interpreting the simulation results in this study. As one of the earliest and most prolific gas-producing regions (particularly through the legacy of the Arun LNG plant), the North Sumatra Basin offers well-established infrastructure, proven petroleum systems, and favorable geological settings, all of which contribute to lower exploration and development risks. he consistently high investment preference for blocks like North Kambuna in this basin, as indicated by the MAUT simulation, aligns with the region track record in supporting LNG operations and underscores the relevance of integrating geological risk assessment into early-stage investment screening. Furthermore, North Sumatra proximity to international LNG markets and its growing role in domestic gas supply reinforce its importance under Indonesia evolving fiscal and energy transition frameworks.

These findings demonstrate the practicality of an integrated evaluation approach that incorporates geological, economic, and environmental factors for the decision-making process (Figure 3). Other than the economics aspect, blocks with favorable petroleum system indicators, such as higher source rock maturity, shallower reservoir depths, and well-defined migration pathways are consistently achieve higher scores, confirming the critical role of subsurface risk quantification in upstream decision-making. This decision-making framework also aligns with regulatory context. Despite revisions introduced in the 2024 Gross Split fiscal regime, geological parameters remain central. Both the base split and several components of the variable split still rely on petroleum system characteristics. As fiscal terms continue to evolve, a clear distinction emerges between the incentive structures of cost recovery and gross split schemes. Under cost recovery, exploration incentives are designed to mitigate risk and encourage reserve growth by allowing the government to recoup significant expenditures through future production revenues. In contrast, the gross split model prioritizes cost efficiency and reduces direct government oversight, creating a more challenging environment for early-stage exploration. Without guaranteed cost recovery, contractors face greater financial exposure, reducing their willingness to invest in frontier or high-risk prospects. Although the framework proposed in this study was developed within the context Gross Split regime, its methodology is robust enough to be applied across other fiscal regimes. The fundamental difference between the Cost Recovery and Gross Split schemes lies in their incentives and risk handling. Under Cost Recovery, the government shares exploration risk by allowing for the reimbursement of costs, thereby encouraging investment in blocks with higher geological uncertainty. Conversely, the Gross Split model places the entire risk on the contractor, leading investors to prioritize blocks with more adequate data and measurable risks. The geological risk assessment methodology we propose remains relevant in both schemes because early-stage risk quantification is a universal foundation for decision-making. However, the weighting assigned to each criterion, particularly between geological and economic factors, would likely be adjusted. For example, under a Cost Recovery regime, an investor might be more tolerant of geological risk if the potential for a large reserve discovery could justify the reimbursable exploration costs. The integrated framework proposed in this study addresses these challenges by supporting investor decision-making in data-limited settings.

Indonesia confronts two critical challenges: sustaining its role as a primary pillar of national energy security and adapting to the accelerating global energy transition. The latter continues to divert investment toward renewable energy, exerting pressure on capital allocation for upstream oil and gas activities. According to the 2025 State Budget Financial Note (IPA, 2024), the government has set oil and gas production targets at 600,000 barrels of oil per day and 1.005 million barrels of oil equivalent per day for natural gas (IPA, 2024). However, SKK Migas data indicate that oil lifting in 2024 reached only 576,000 barrels per day, with projections suggesting a modest year-end increase to 595,000 barrels per day, falling short of the stated target (IPA, 2024). In light of these conditions, strategic recommendations have emphasized the need for comprehensive studies to identify and assess underexplored regions with significant hydrocarbon potential. To support this, investment strategies must increasingly incorporate rigorous subsurface evaluation, particularly as fiscal frameworks shift toward performance-based mechanisms. This study provides a methodological approach to inform exploration decisions and mitigate geological uncertainty, thereby enhancing investment justification in high-risk blocks.

Moreover, the simulation results reflect a growing emphasis on ESG (Environmental, Social, and Governance) metrics in upstream investment. Blocks with lower emission intensity will likely become increasingly attractive as carbon regulations tighten and investor pressure mounts for low-carbon portfolios (Friede et al., 2015). This trend reinforces the need to embed sustainability considerations into early-stage screening tools like the one presented here. On a global scale, the implications are even more significant. According to the GECF Global Gas Outlook (GECF, 2025), natural gas demand will require cumulative investments of approximately USD 9 trillion by 2050, with upstream alone accounting for USD 8.2 trillion. Most of this will be directed toward conventional resources. Importantly, much of this investment will be needed not only to meet rising demand but also to counteract natural declines in existing fields. As the supply curve trends toward higher-cost, long-cycle projects, comprehensive pre-investment risk assessments will be essential for capital efficiency. Future gas production is expected to originate increasingly from higher-cost and technically complex fields. This makes the accurate evaluation of geological risk, economic return, and environmental impact more important than ever.

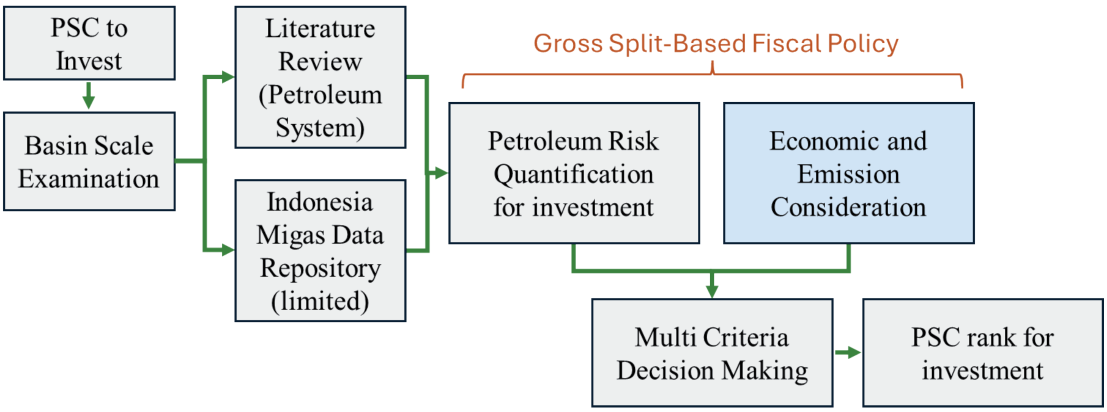

Figure 3. Petroleum system risk assessment scheme tailored to PSC investment stages under the Gross Split fiscal regime, with emphasis on early-stage screening.

6. Conclusions

This study presents a scalable and practical framework tailored to the upstream oil and gas sector in Indonesia, particularly under the evolving Gross Split fiscal regime. By quantifying geological uncertainty and integrating economic and environmental parameters, the model enables informed early-phase screening of petroleum blocks, even when data availability is limited. A key finding is that the proposed risk quantification approach is simple enough to be applied using limited Migas Data Repository (MDR) datasets, yet robust enough to support strategic investment decisions. Furthermore, the framework builds upon and complements existing standardization efforts by the regulator, SKK Migas, providing a transparent and practical tool for upstream investors in the changing regulatory environment in Indonesia.

As global exploration increasingly focuses on new and underexplored gas-prone basins, Indonesia resource potential can be more effectively realized through systematic and standardized risk evaluation. However, challenges such as rising production costs, fiscal uncertainty, and environmental, social, and governance (ESG) pressures continue to elevate investment risks. The integrated decision-support model proposed in this study can help both investors and policymakers balance profitability with long-term resource security and sustainability objectives, strengthening Indonesia role in the global energy transition.

Data Availability

The dataset examples used in this study, including input parameters for the MAUT-based simulation of the five PSC blocks, are provided in the Supplementary Material.

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