Scientific Contributions Oil & Gas, Vol. 49. No. 1, March: 489 - 504

SCIENTIFIC CONTRIBUTIONS OIL AND GAS

Testing Center for Oil and Gas
LEMIGAS

Journal Homepage:http://journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

A Decision-Oriented Techno-Economic Framework for Designing Fiscal Incentives in Horizontal Well Development of Marginal Oil Fields

Sudono[1], Aries Prasetyo[1], Najeela Faza Ramadhani[2]

[1]Institut Teknologi Sains Bandung
Deltamas City, Ganesha Boulevard Street No. 1, Bekasi Regency, West Java, Indonesia.

[2]Institut Teknologi Bandung
Ganesha Street No. 10 Bandung, West Java, Indonesia.

Corresponding Author : Sudono (sudono.data@gmail.com)

Manuscript received: January 20th, 2026; Revised: February 06th, 2026
Approved: March 09th, 2026; Available online: March 10th, 2025; Published: March 10th, 2026.

ABSTRACT - Horizontal wells are widely recognized for improving reservoir contact and recovery; however, their application in marginal oil fields remains economically challenging due to high capital intensity and fiscal exposure. This study develops a decision-oriented techno-economic framework to evaluate the feasibility of horizontal well development under Indonesia's Production Sharing Contract (PSC) regimes, namely PSC Cost Recovery and PSC Gross Split. Using a representative Indonesian marginal oil field, production forecasting, cost modeling, and cash-flow simulations are performed to assess project viability under Pessimistic, Moderate, and Optimistic Scenarios. Economic indicators, including Internal Rate of return (IRR), Net Present Value (NPV), Payout Time (POT), and Government Take, are evaluated, followed by sensitivity and optimization analyses. The analysis confirms that PSC Cost Recovery consistently yields superior economic performance compared to PSC Gross Split, particularly for capital-intensive developments. Optimization results indicate that Contractor Split adjustment and CAPEX Efficiency are the most influential fiscal levers, while Investment Credit and First Tranche Petroleum (FTP) adjustments have a limited impact. This study identifies the quantitative incentive thresholds required to achieve a contractor Minimum Attractive Rate of return (MARR) of 15%, offering practical guidance for policymakers and operators in structuring fiscal incentives for marginal field development. The findings provide a structured basis for aligning horizontal well deployment with fiscal policy to sustain upstream investment.

Keywords: Horizontal wells; marginal oil fields; PSC cost recovery; PSC gross split; fiscal incentives; techno-economic optimization.

How to cite this article:

Sudono, Aries Prasetyo, Najeela Faza Ramadhani 2026, A Decision-Oriented Techno-Economic Framework for Designing Fiscal Incentives in Horizontal Well Development of Marginal Oil Fields, Scientific Contributions Oil and Gas, 49 (1) pp. 489 - 504. DOI org/10.29017/scog.v49i1.2025

INTRODUCTION

Declining production from mature fields and limited large-scale discoveries have intensified the challenge of sustaining Indonesia's upstream oil and gas output. Under these conditions, marginal oil fields, characterized by limited reserves, elevated technical risks, and constrained economics, play an increasingly important role in maintaining national production levels. The development of such fields requires not only technical optimization but also fiscal structures that adequately balance investment risk and government revenue.

Horizontal well technology has been widely used to enhance reservoir contact and recovery efficiency, particularly in reservoirs with thin pay zones and high heterogeneity. Numerous studies have demonstrated the technical advantages of horizontal wells compared to vertical wells. However, their application in marginal fields is often constrained by substantially higher capital expenditures (CAPEX), which can undermine project feasibility when fiscal conditions are not sufficiently supportive.

In addition to capital intensity, marginal oil fields in Indonesia commonly exhibit relatively high operating expenditures (OPEX) compared to larger, more established producing assets. This condition is influenced by several structural factors, including a limited production scale, aging infrastructure, higher unit lifting costs, suboptimal reservoir performance, and, in some cases, remote or offshore operational settings.

As production rates decline while fixed operational commitments remain, the unit operating cost per barrel tends to increase, thereby compressing project margins. Consequently, the economic performance of marginal fields is often more sensitive to production efficiency and revenue allocation mechanisms than to capital-based incentives alone. This structural cost characteristic has important implications for fiscal design, particularly in evaluating which incentive instruments provide meaningful leverage in restoring project feasibility.

Within Indonesia's upstream regulatory framework, field development decisions must satisfy both technical and economic criteria, as stipulated in Law No. 22 of 2001 and further detailed in SKK Migas PTK-007 Rev-2. In practice, economic feasibility under the production sharing contract (PSC) system is highly sensitive to interactions among development cost, production performance, and fiscal parameters. Indonesia currently applies two principal PSC regimes, PSC Cost Recovery and PSC Gross Split, each offering distinct mechanisms for cost recovery, risk sharing, and revenue allocation.

Previous studies on petroleum fiscal systems and marginal field development have generally addressed fiscal incentives conceptually, examined single PSC regimes, or focused on technical productivity and cost estimation without integrating institutional fiscal structuring. While comparative discussions between PSC Cost Recovery and PSC Gross Split exist, most analyses remain descriptive and do not quantify the incentive thresholds required to restore project feasibility under capital-intensive development schemes.

In addition, existing techno-economic studies typically treat fiscal parameters as independent variables, without accounting for the hierarchical structure of regulatory authority within Indonesia's upstream governance system. In practice, certain fiscal adjustments may fall under operational flexibility and SKK Migas supervision, while others require higher-level regulatory intervention at the Ministerial level.

However, the literature does not provide a structured analytical framework that evaluates how incentive escalation across these authority levels affects contractor feasibility and Government Take under ring-fenced economic conditions. To address this gap, this study introduces a decision-oriented techno-economic framework that integrates dual PSC regime comparison (PSC Cost Recovery and PSC Gross Split), discounted cash-flow modeling, and design of experiment (DOE)-based optimization.

Unlike previous studies that discuss fiscal incentives in isolation, this research quantitatively determines fiscal incentive thresholds and evaluates them within a hierarchical regulatory structure. Therefore, the proposed framework transcends conceptual fiscal discussions and provides a structured policy simulation mechanism tailored to marginal oil field development in Indonesia. To clarify this contribution relative to the existing literature, a systematic comparison is presented in Table 1.

The uniqueness of this study lies in its integration of techno-economic simulations and hierarchical fiscal structuring within a dual PSC regime. By quantitatively determining the incentive thresholds required to achieve contractor MARR and evaluating the escalation of fiscal parameters across different levels of regulatory authority, this study goes beyond conceptual fiscal discussions toward a structured policy evaluation model applicable to the development of marginal horizontal oil fields in Indonesia.

METHODOLOGY

This study uses a techno-economic evaluation framework to assess the feasibility of horizontal well development in a representative Indonesian marginal oil field. The analysis integrates production forecasting, development cost estimation, fiscal modeling, and optimization techniques to evaluate project performance under different contractual regimes.

Production performance is estimated using the analytical horizontal well productivity formulation proposed by Joshi, with reservoir and fluid parameters adapted to marginal field conditions. Three development scenarios—Pessimistic, Moderate, and Optimistic—are constructed to reflect variations in reservoir permeability and resulting well deliverability. Future production profiles are generated by applying a deterministic decline rate consistent with mature field behavior.

Economic evaluation is conducted using discounted cash-flow analysis under two fiscal regimes: PSC Cost Recovery and PSC Gross Split. Key economic indicators include internal rate of return (IRR), net present value (NPV), payout time (POT), and Government Take. Fiscal assumptions are aligned with prevailing Indonesian regulations and contractual practices.

Sensitivity analysis was performed to evaluate the impact of key technical and economic

Table 1 Comparison of previous studies and this study.

Study	Primary focus	Methodology	Fiscal regime considered	Incentive treatment	Hierarchical fiscal structuring	Main limitation	Contribution relative to this study
Joshi (1991)	Horizontal well productivity	Analytical reservoir model	Not addressed	Not addressed	No	Purely technical; no fiscal dimension	This study extends technical productivity analysis into integrated fiscal feasibility under PSC regimes
Partowidagdo (2002)	Indonesian PSC economics	Contractual and economic evaluation	PSC Cost Recovery	General fiscal discussion	No	No field-level quantitative simulation	This study performs scenario-based DCF modeling at field scale
Lubiantara (2007)	Marginal field fiscal incentives	Conceptual fiscal evaluation	PSC Cost Recovery	Conceptual incentive discussion	No	No quantitative threshold calculation	This study quantifies incentive thresholds required to achieve contractor MARR
Aziz et al. (2023)	Techno-economic optimization (CCUS case)	Integrated techno-economic modeling	PSC Cost Recovery	Single-scenario simulation	No	No cross-regime comparison; no hierarchical authority analysis	This study integrates dual PSC comparison and authority-based incentive escalation
Montgomery (2017)	Design of Experiment methodology	Two-level factorial DOE	Not fiscal-specific	Not addressed	No	No fiscal application	This study applies DOE to fiscal parameter optimization
This Study	**Horizontal wells in marginal oil fields**	**Integrated techno-economic modeling and DOE-based optimization**	**PSC Cost Recovery and PSC Gross Split**	**Quantitative simulation of fiscal incentive thresholds**	**Yes – Structured hierarchical simulation (SKK Migas →**	Representative marginal field case	**Introduces a decision-oriented hierarchical fiscal intervention framework integrating dual PSC regimes and**

variables, including production rate, oil price, capital expenditure (CAPEX), and operating expenditure (OPEX), on project economics. To identify the most effective incentive mechanisms, an optimization analysis is conducted by varying fiscal parameters, such as Contractor Split, Investment Credit, first tranche petroleum (FTP), and CAPEX Efficiency.

A two-level factorial design of experiment (DOE) approach was employed to quantify the relative influence of each fiscal parameter on project IRR. This method enables the identification of dominant fiscal levers and interaction effects, providing a structured basis for determining the incentive combinations required to achieve the contractor's minimum attractive rate of return (MARR). The methodology is designed to support decision-making by highlighting the fiscal adjustments that materially improve project viability under marginal field conditions.

RESULT AND DISCUSSION

The economic evaluation was conducted based on production forecast data, development cost, oil prices, and PSC Cost Recovery and PSC Gross Split contract models. These data are inputs in the calculation and are explained below.

Estimated well production

The production rate was estimated using the Joshi horizontal well productivity model, as expressed in Equation (1).

$$q = \frac{\mathrm{kh}.(P_i - P_w)}{141.2\ \mu_o\ B_o.\ln(\frac{4L_e^2}{r_w h})} \quad (1)$$

Where:

- K is permeability, md
- h is thickness, ft
- Pi – Pw is drawdown pressure, psi
- μ_o is oil viscosity, cp
- Bo is oil formation volume factor, RB/STB
- L_e is effective length of horizontal well, ft
- r_w is wellbore radius, ft

The data obtained from a representative Indonesian marginal oil field (hereafter referred to as the study area) indicate an initial reservoir pressure (Pi) of 3,000 psia, a wellbore pressure (Pw) of 1,000 psia, fluid viscosity of 1.5 cp, an oil formation volume factor (Bo) of 1.2 RB/STB, reservoir thickness (h) of 50 ft, and a wellbore radius (rw) of 0.328 ft. The permeability in this reservoir is assumed to range from 15 to 30 millidarcies (md), depending on the evaluated scenario.

Based on these parameters, the calculated productivity index (PI) falls into the low-performance category, indicating suboptimal well deliverability. Consequently, from both operational and economic perspectives, hydraulic fracturing is recommended to enhance the well's productivity and improve early production rates.

The values of permeability (k) are scenario-dependent, with three cases considered: Pessimistic, Moderate, and Optimistic. The assumed permeability values for each scenario are summarized as follows:

- Pessimistic scenario: using a permeability value of 15 md, which reflects poor reservoir conditions for flowing oil, so that reservoir productivity is limited, and as a result, the production rate is low.
- Moderate scenario: using a permeability value of 21 md, which is the middle value of the permeability data distribution, reflecting moderate reservoir conditions in flowing oil, and indicating that the production rate is good for the study area.
- Optimistic scenario: assumes a permeability value of 27 md, indicating excellent reservoir conditions and allowing for higher production rates.

Based on the calculations using the aforementioned data, the estimated initial production rates under each scenario are as follows: The Pessimistic Scenario yields 482 STB/D, the Moderate Scenario yields 678 STB/D, and the Optimistic Scenario yields 860 STB/D.

The implementation of hydraulic fracturing significantly enhances production performance in all scenarios. Specifically, in the Pessimistic case, the productivity index improves from 0.24 to 0.60 STB/day/psi, resulting in an initial production rate of 1,206 STB/D. In the Moderate Scenario, the productivity index increases from 0.34 to 1.02 STB/day/psi, leading to an initial production rate of 2,032 STB/D. Meanwhile, the Optimistic Scenario sees an increase in the productivity index from 0.43 to 1.50 STB/day/psi, with an initial production rate reaching 3,009 STB/D. Future production performance is projected using an annual decline rate of 15% and summarized in Table 2 and Figure 1.

Table 2 Estimated well oil production for Pessimistic, Moderate, and Optimistic Scenarios.

Scenario	Initial rate	Cum. production	
		20 Years	Economic limit
	STB/D	MMSTB	MMSTB
Pessimistic	1,206	3.29	2.82
Moderate	2,033	5.52	4.73
Optimistic	3,010	8.17	7.01

Development plan

The development plan consists of exploration drilling, feasibility assessment, and staged field development aligned with technical, economic, and HSE requirements. The estimated oil production for the study area, based on well production and the development plan for each scenario, namely the Pessimistic Scenario, Moderate Scenario, and Optimistic Scenario, is presented in Table 3 and Figure 2 below.

Table 3. Estimated oil production for the study area under Pessimistic, Moderate, and Optimistic Scenarios.

Scenario	No. of well	Cum. production
	STB/D	MMSTB
Pessimistic	10	32.92
Moderate	10	55.5
Optimistic	10	82.18

Estimated field development cost

Based on the development plan outlined above, several price assumptions are used for the economic evaluation:

- Exploration well cost is assumed at US$ 47 million per well, based on SKK Migas standards for the 2019–2024 period for offshore exploration wells with a water depth below 200 meters. This cost is then escalated to reflect 2025 values.
- Development well cost is assumed at US$ 35

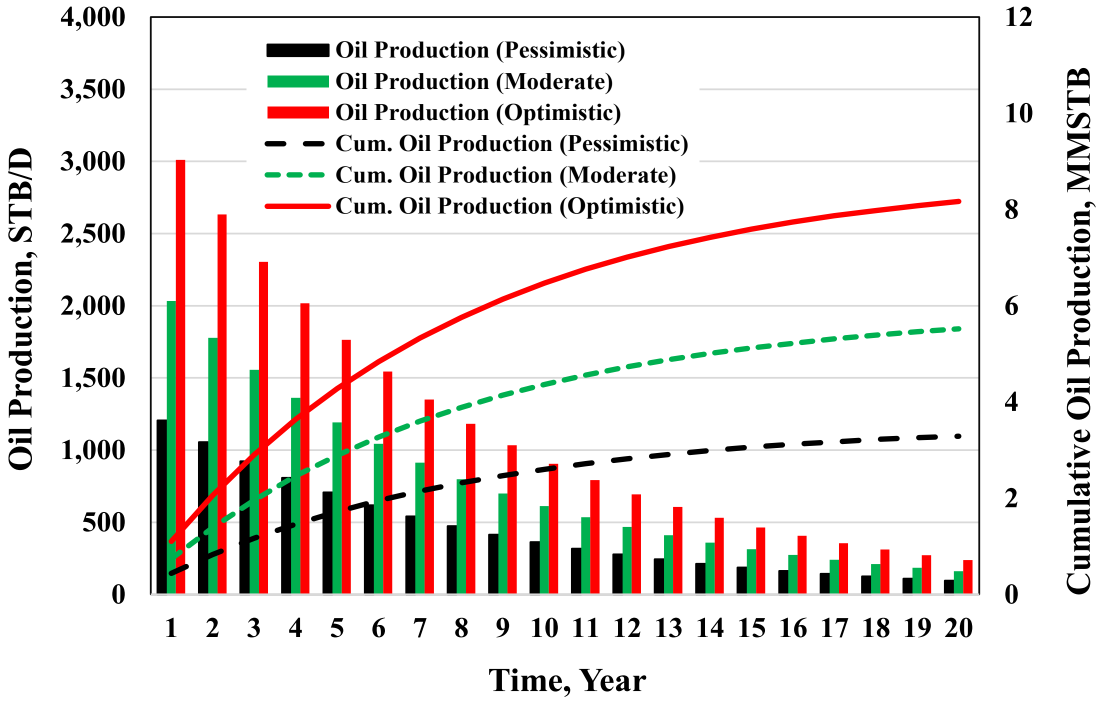

Figure 1. Well oil production estimates for Pessimistic, Moderate, and Optimistic Scenarios.

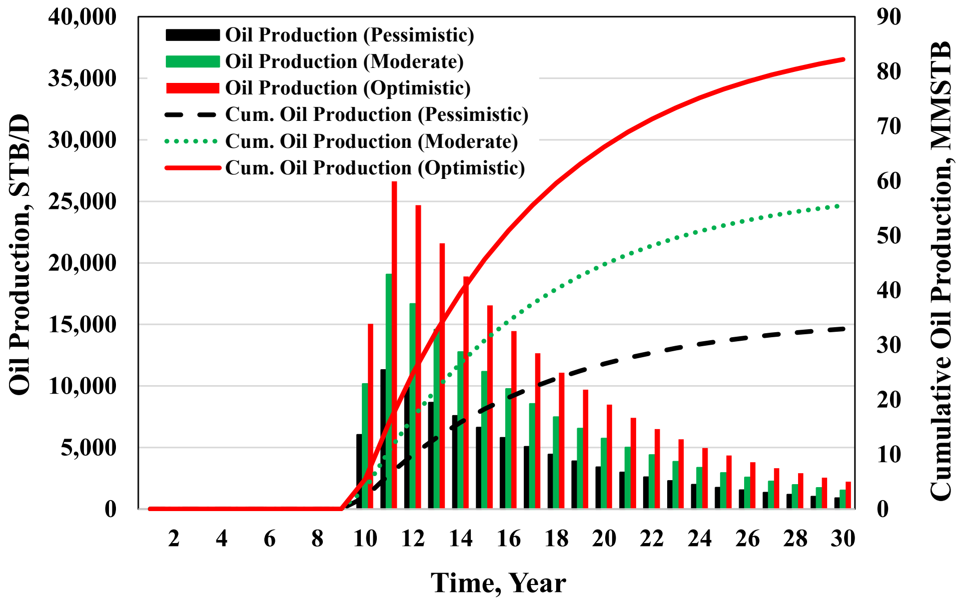

Figure 2. stimated oil production for the study area under Pessimistic, Moderate, and Optimistic Scenarios.

million per well. The development well cost of US$ 35 million per well includes horizontal drilling and hydraulic fracturing operations. Therefore, stimulation costs are fully incorporated in the capital expenditure assumption used in this study.

- Cost for studies and seismic surveys is estimated at US$ 5 million.
- Production facilities costs for the Pessimistic, Moderate, and Optimistic scenarios are US$ 141 million, US$ 438 million, and US$ 793 million, respectively.
- Variable oil operating cost is assumed at US$ 25 per barrel.

The estimated development costs for the Pessimistic, Moderate, and Optimistic Scenarios for the study area are presented in Table 4 below.

Table 4. Estimated development costs for the study area under Pessimistic, Moderate, and Optimistic Scenarios.

Scenario	Capital	Non capital	
	Capex tangible	Capex intangible	OPEX, ASR, etc.
	$MM	$MM	$MM
Pessimistic	204	338	839
Moderate	464	341	1,500
Optimistic	757	346	2,252

Contract fiscal terms

The economic evaluation was conducted using both the PSC Cost Recovery and PSC Gross Split contract models. The parameters and assumptions used are as follows:

PSC Cost Recovery model

- Contract life : 30 years
- FTP : 10% (shared)
- Contractor share : 45,00% (after tax)
- DMO : 25%
- DMOfee : 100%
- Effective tax rate : 37,6%
- Oil price : 70 US$/bbl
- Depreciation : Double Declining Balance, 25%, 5 years
- Discount factor : 10%

PSC Gross Split Model.

- Contract life : 30 Years
- Contractor Split follows Minister of Energy and Mineral Resources Regulation No. 8 of 2017 on Gross Split Production Sharing Contracts and its amendments.
- Contractor Split : 79,75%
- Effective tax rate : 37,60%
- Oil price : 70 US$/bbl
- Amortization : Unit of Production

Table 5. Economic evaluation results for the study area under Pessimistic, Moderate, and Optimistic Scenarios.

Scenario	Economic indicator	PSC cost recovery	PSC gross split
	IRR, %	12.56%	8.12%
Pessimistic	NPV@IO%, MMUS$	25.00	-18,772.00
	POT, Tahun	13.00	15.00
	IRR, %	13.56%	8.91%
Moderate	NPV@IO%, MMUS$	54	-17
	POT, Tahun	13.00	14.00
	IRR, %	14.54%	9.76%
Optimistic	NPV@IO%, MMUS$	1,099	-5
	POT, Tahun	13.00	14.00

- Depreciation : Double Declining Balance, 25%, 5 years
- Discount factor : 10%

Economic evaluation results

The economic calculations using the PSC Cost Recovery and PSC Gross Split contract models are presented in Tables 5 and 6 and in Figure 3 below.

Table 6. Comparative analysis of IRR, NPV, and Government Take percentage to gross revenue under PSC Cost Recovery and PSC Gross Split models for Moderate Scenario.

Parameters	Unit	PSC cost recovery	PSC gross split
IRR	%	13.56%	8.91%
NPV to Gross Revenue	%	1.39%	-0.44%
Gov. Take to Gross Revenue	%	22.37%	27.93%

The economic evaluation indicates that horizontal well development under the Moderate Scenario yields marginal economic performance under PSC Cost Recovery and is economically unviable under PSC Gross Split. This is reflected in the economic indicators, where the IRR and NPV under the PSC Cost Recovery model are more favorable compared to the PSC Gross Split model. Therefore, the PSC Cost Recovery model is considered more attractive for the development of the study area.

Based on the indicators of IRR, NPV, and Government Take, the following conclusions can be drawn:

- The PSC Cost Recovery model provides more favorable economic outcomes for both the contractor and the government.
- The PSC Gross Split model is economically unviable under the Moderate Scenario, primarily due to an IRR below 10% and a negative NPV.
- For field developments involving high risk and capital intensity, such as horizontal drilling and hydraulic fracturing, the PSC Cost Recovery model is more appropriate due to its superior risk-sharing characteristics.

Economic Sensitivity

Economic sensitivity analysis was conducted to evaluate the impact of changes in key input parameters such as production, oil price, capital expenditure (CAPEX), and operating expenditure (OPEX) on economic performance indicators, including internal rate of return (IRR), net present value (NPV), payout time (POT), and Government Take. The sensitivity analysis results based on the PSC Cost Recovery model are presented in the figures below.

The analysis indicates that the sensitivity of IRR, NPV, POT, and Government Take to variations in oil production, oil price, CAPEX, and OPEX follows consistent economic trends.

- The Oil Price and Production curves show the most significant relationship in terms of their influence on IRR, NPV, POT, and Government Take. When oil prices and production increase, IRR, NPV, POT, and Government Take also increase proportionally, and vice versa.

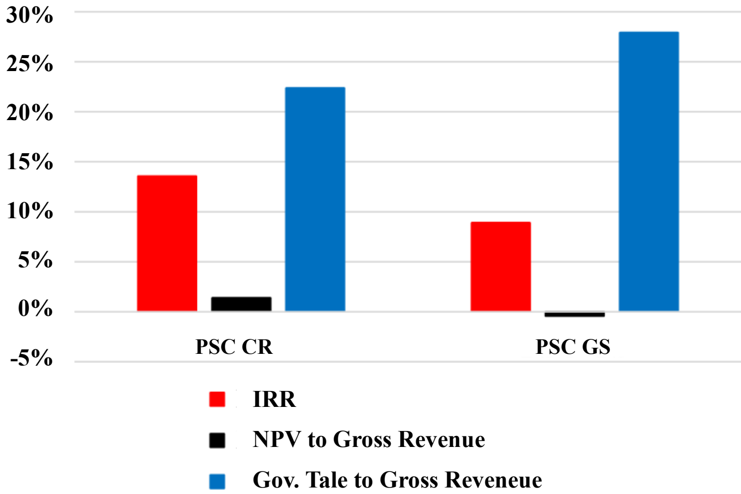

Figure 3. Comparative analysis of IRR, NPV, and Government Take percentage to gross revenue under PSC Cost Recovery and PSC Gross Split models for Moderate Scenario.

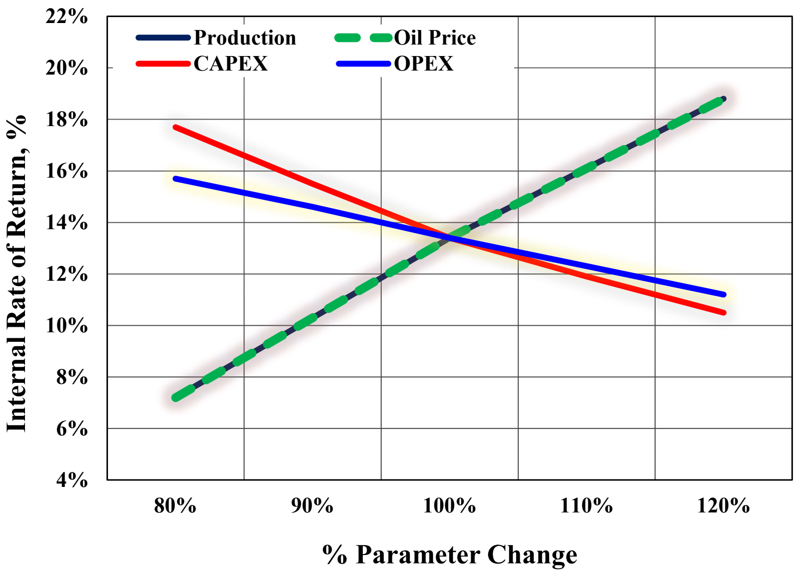

Figure 4. IRR as a function of oil production, oil price, CAPEX, and OPEX.

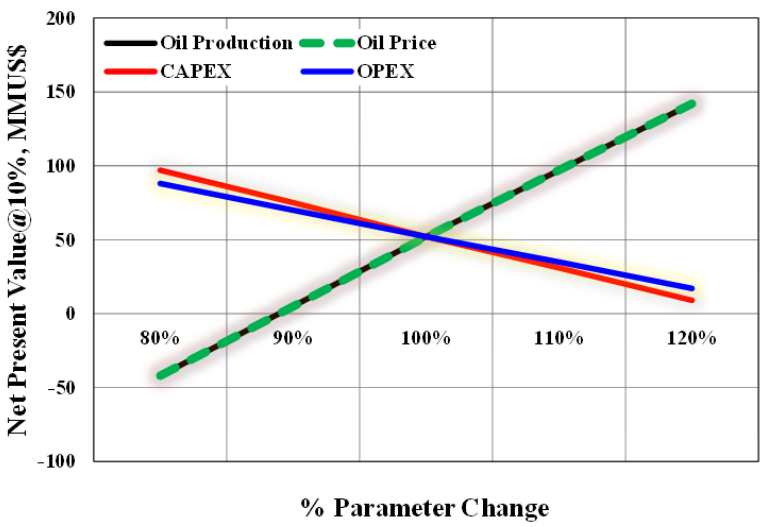

Figure 5. NPV as a function of oil production, oil price, CAPEX, and OPEX.

- Changes in CAPEX and OPEX have a relatively insignificant effect on IRR, NPV, POT, and Government Take. Increases in CAPEX and OPEX decrease IRR, and vice versa., NPV, POT, and Government Revenue compared to CAPEX. An increase in OPEX results in a sharper decline in IRR, NPV, POT, and Government Take compared to an equivalent increase in CAPEX.

Economic optimization

Optimization was performed to determine incentives for developing marginally performing horizontal wells to achieve the contractor's desired rate of return. The assumption in this case is that the contractor's minimum attractive rate of return (MARR) is 15%. This stage is carried out by implementing incentives contained in the PSC, such as investment credit (IC), CAPEX Efficiency through the use of shared facilities, changes to the first tranche petroleum (FTP), and changes to the contractor split (CS).

Economic optimization is performed by varying the following fiscal parameters:

1. Investment Credit (IC)
2. First Tranche Petroleum (FTP)
3. Contractor Split (CS), and
4. Capital expenditures (CAPEX) Efficiency.

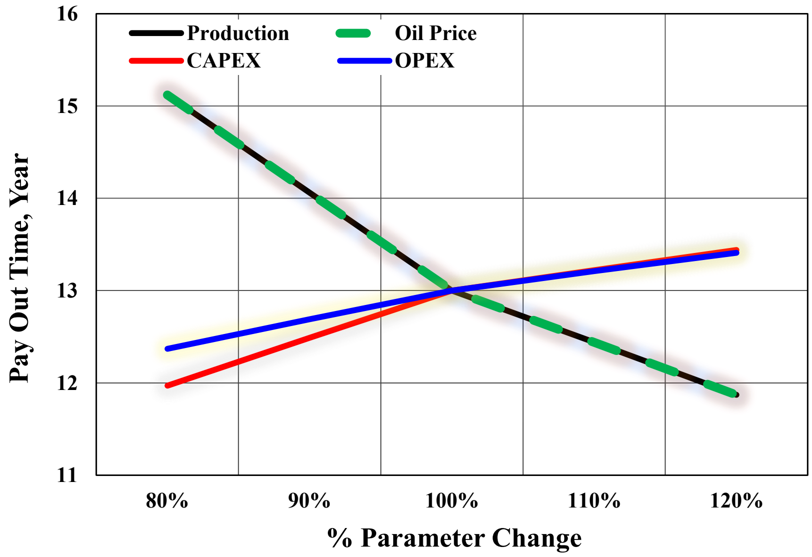

Figure 6. POT as a function of oil production, oil price, CAPEX, and OPEX.

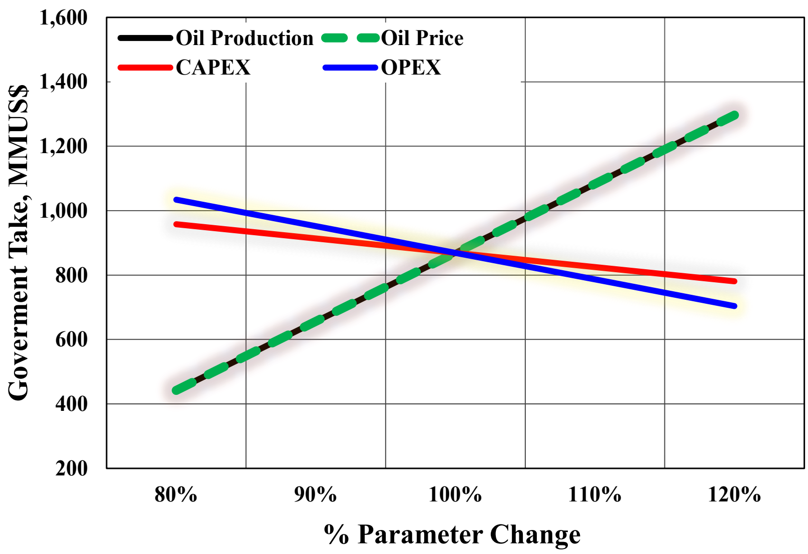

Figure 7. Government Take (GT) as a function of oil production, oil price, CAPEX, and OPEX.

The sensitivity of each optimization input to IRR is presented below.

Investment credit (IC)

The impact of Investment Credit (IC) incentives on the overall project economics is relatively limited. Applying a 17% Investment Credit yields a slight improvement, increasing the IRR by 0.24% in the Pessimistic case, 0.02% in the Moderate case, and 0.99% in the Optimistic case.

First tranche petroleum-shared (FTP-shared)

The first tranche petroleum (FTP) mechanism has limited influence on fiscal attractiveness, as a lower FTP rate results in only a modest enhancement of the project's economic indicators. When the FTP is reduced from 10% to 5%, the project's Internal rate of return (IRR) increases by only 0.14% for the Pessimistic case, 0.16% for the Moderate case, and 0.04% for the Optimistic case. Cash flow at the 10% FTP is more dominant in later years, as shown in columns 3 and 4, while cash flow at the 5% FTP is dominant in the early years. This significantly boosts the IRR, even though the total cash flow might be the same. These results suggest that FTP, despite being one of the earliest revenue streams for the government, does not decisively determine the viability of capital-intensive projects.

Contractor split

Contractor Split, which determines the portion of revenue allocated to contractors, plays a significant role in improving project feasibility. Several variations of Contractor Split have been implemented and are presented in Table 7 and Figure 8 below.

Table 7. Contractor Split after tax as a function of IRR.

Contractor Split (After Tax), %	IRR, %		
	Pessimistic	Moderate	Optimistic
45	12.56	13.40	14.54
50	13.00	14.00	15.00
55	14.10	15.02	16.33
60	14.80	15.76	17.16
62	15.07	16.04	17.48

The sensitivity analysis of the Contractor Split under the PSC Cost Recovery model indicates that an increase in the Contractor Split significantly enhances the internal rate of return (IRR). As illustrated in the table and figure above, increasing the Contractor Split by up to 15% results in a corresponding increase in IRR, ranging from 15.07% to 17.48%.

Capital expenditure efficiency (CAPEX)

The CAPEX Efficiency sensitivity analysis reveals a positive correlation between capital expenditure reductions and improvements in the contractor's internal rate of return (IRR). Accordingly, enhancing cost efficiency should be

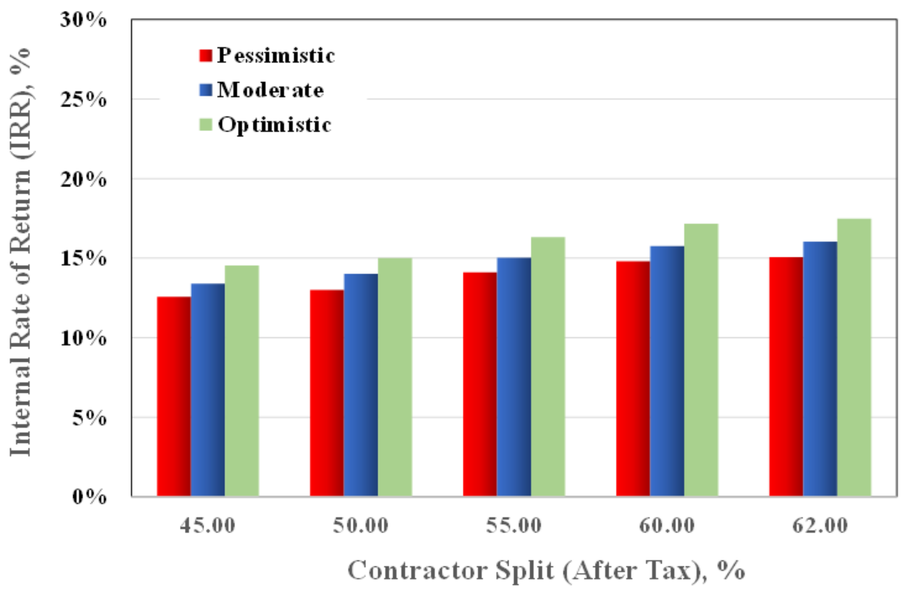

Figure 8. Contractor Split after tax as a function of IRR.

prioritized as a strategic objective in the development of horizontal wells and the implementation of hydraulic fracturing. The relationship between CAPEX Efficiency and IRR is illustrated in Table 8 and Figure 9 below.

Table 8. CAPEX Efficiency as a function of IRR.

CAPEX Efficiency, %	IRR, %		
	Pessimistic	Moderate	Optimistic
0	12.56	13.40	14.54
5	13.50	14.30	15.47
10	14.50	15.29	16.45
15	15.56	16.37	17.11

The sensitivity analysis of CAPEX Efficiency under the PSC Cost Recovery model indicates that improvements in CAPEX Efficiency lead to a significant increase in the internal rate of return (IRR). As shown in the figure above, enhancing CAPEX Efficiency by up to 15% results in an increase in IRR to the range of 15.56% to 17.11%. These findings underscore the critical role of investment cost management in development projects, as reducing CAPEX can substantially enhance a project's overall economic viability. The figure illustrates how effective cost management influences investment outcomes, thereby supporting strategic decision-making and the evaluation of long-term project sustainability.

The analysis of the input parameters for optimization was conducted using the Design of Experiment (DOE) method, a statistical approach for evaluating the effects of multiple input parameters on a given response (Montgomery, 2017). This approach enables the assessment of parameter interactions, the identification of dominant factors, and systematic optimization. A two-level factorial design was applied as an initial screening method, requiring only 2^k experiments, where k represents the number of parameters considered. In this study, four parameters were evaluated, yielding 2^4 or 16 experimental combinations. The relative influence of each parameter on the internal rate of return (IRR) is visualized using a Pareto chart, as illustrated in Figure 10.

The figure above shows that variations in Contractor Split parameters have the greatest impact on the internal rate of return (IRR), followed by CAPEX Efficiency. In contrast, the effects of First Tranche Petroleum (FTP) and Investment Credit are relatively minor.

Subsequently, the optimization process focuses on identifying the combination of parameters that yields the most favorable economic outcome, particularly the highest IRR value, using the Design of Experiment (DOE) method. The parameter boundaries used in the optimization are summarized in Table 9 below.

Table 9. Parameter two-level factorial design.

Parameters	Min.	Max.
Investment Credit (IC)	0%	17%
First Tranche Petroleum (FTP)	5%	10%
Contractor Split (CS)	45%	62%
CAPEX Efficiency	0%	10%

The statistical optimization results, based on the combination of the four parameters evaluated at two levels (minimum and maximum), are presented in Table 10 below. The analysis reveals that the combination of a high Contractor Split and increased CAPEX Efficiency consistently yields higher IRR values, regardless of the values assigned to FTP and Investment Credit.

This suggests that these two parameters, i.e., Contractor Split and CAPEX Efficiency, are the most influential in enhancing project economic performance. Based on the optimization sequence, to achieve a minimum internal rate of return (IRR) of 15%, a combination of incentive policies is required, as shown in the figures below.

The figures present several incentive scenarios as follows:

Case I: Providing an investment credit (IC) of 17%, a fixed first tranche petroleum (FTP) of 10%, and an increased Contractor Split. In this case:

- The Pessimistic Scenario requires an Investment Credit incentive of 17%, a fixed FTP of 10%, and a Contractor Split of 62% to generate an IRR of 15.03%.
- The Moderate Scenario requires an Investment Credit incentive of 17%, a fixed FTP of 10%, and a Contractor Split of 56% to generate an IRR of 15.02%.
- The Optimistic Scenario requires only an Investment Credit incentive of 17% to generate an IRR of 15.13%.

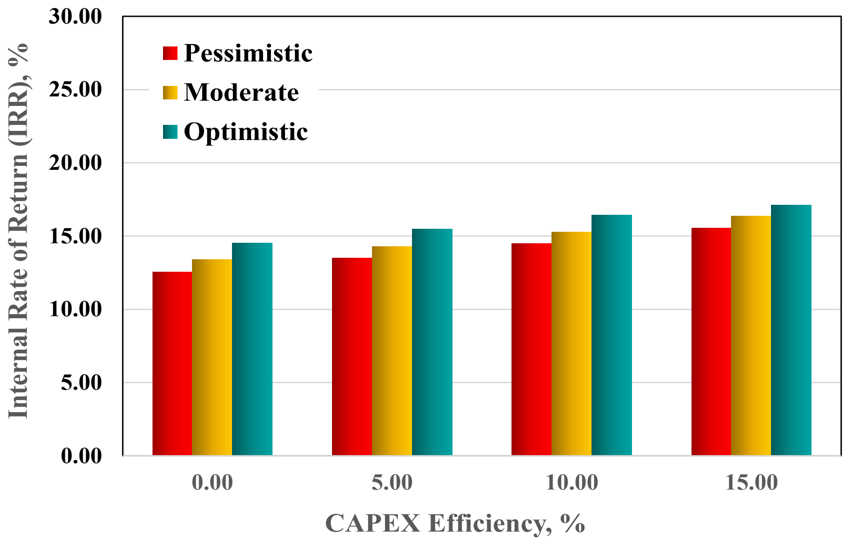

Figure 9. IRR as a function of CAPEX Efficiency.

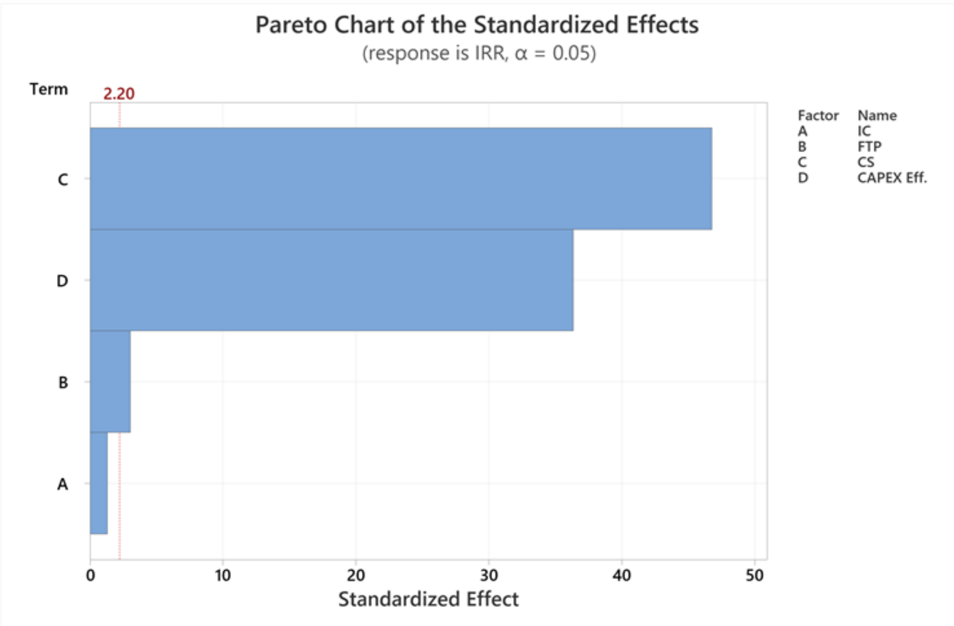

Figure 10. Results of incentive optimization using the Design of Experiment method.

Case II: Providing a 17% Investment Credit incentive, First Tranche Petroleum (FTP) reduction to 5%, increased Contractor Split, and CAPEX Efficiency. In this case:

- The Pessimistic Scenario requires a 17% Investment Credit incentive, 5% FTP, 55% Contractor Split, and 5% CAPEX Efficiency to achieve an IRR of 15.03%.
- The Moderate Scenario requires a 17% Investment Credit incentive, 5% FTP, and 55% Contractor Split, which already achieves an IRR of 15.07%.
- The Optimistic Scenario requires only a 17% Investment Credit incentive to achieve an IRR of 15.13%.

Case III: Providing an Investment Credit incentive at 17%, First Tranche Petroleum (FTP) remains at 10%, Contractor Split remains at 45%, and CAPEX Efficiency remains. In this case:

- The Pessimistic Scenario requires an Investment Credit incentive of 17%, FTP remains at 10%, Contractor Split remains at 45%, and CAPEX Efficiency remains at 12% to achieve an IRR of 15.07%.

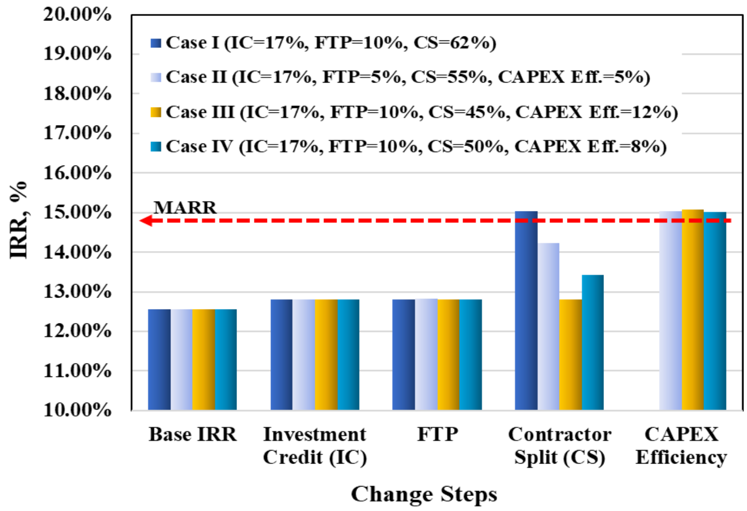

Figure 11. Optimization of incentive provision for Pessimistic Scenario.

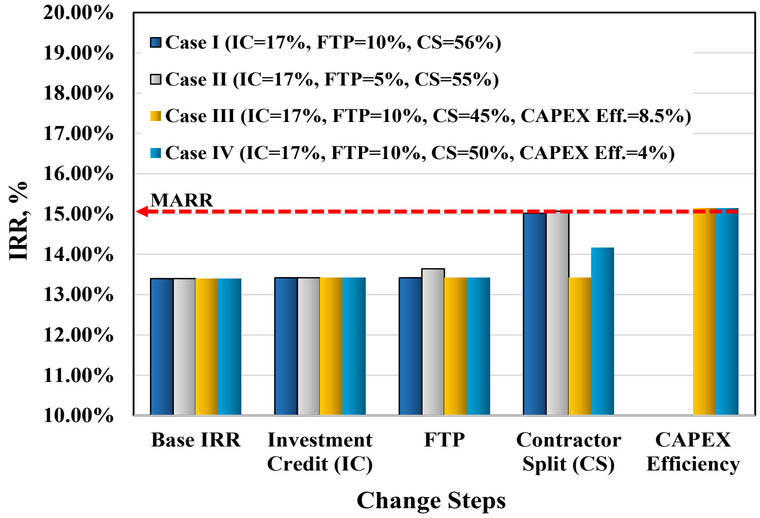

Figure 12. Optimization of incentive provision for Moderate Scenario.

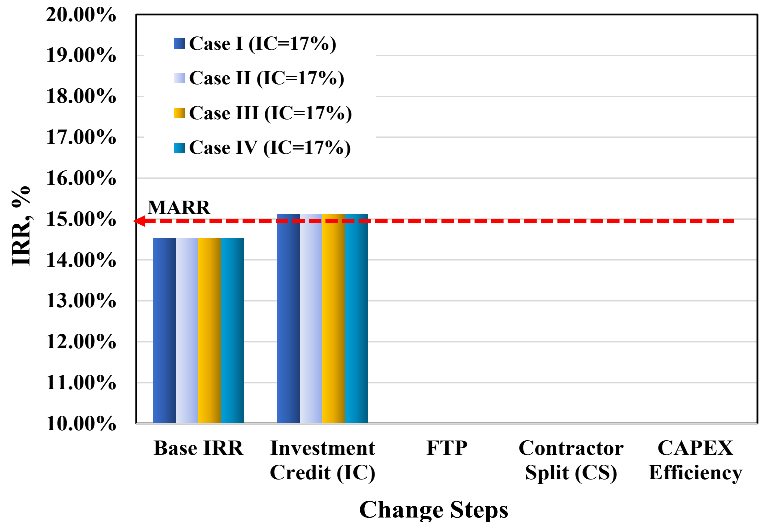

Figure 13. Optimization of incentive provision for Optimistic Scenario.

- The Moderate Scenario requires an Investment Credit incentive of 17%, FTP remains at 10%, Contractor Split remains at 45%, and CAPEX Efficiency remains at 8.5% to achieve an IRR of 15.14%.
- The Optimistic Scenario requires only an Investment Credit incentive of 17% to achieve an IRR of 15.13%.

Case IV: Providing a 17% Investment Credit incentive, fixed First Tranche Petroleum (FTP) at 10%, additional Contractor Split, and CAPEX Efficiency. In this case:

- The Pessimistic Scenario requires a 17% Investment Credit incentive, a fixed FTP at 10%, a 50% Contractor Split, and 8% CAPEX Efficiency to achieve an IRR of 15.03%.
- The Moderate Scenario requires a 17% Investment Credit incentive, a fixed FTP at 10%, a 50% Contractor Split, and 4% CAPEX Efficiency to achieve an IRR of 15.02%.
- The Optimistic Scenario requires only a 17% Investment Credit incentive to achieve an IRR of 15.13%.

CONCLUSION

- This study demonstrates that the economic feasibility of horizontal well development in marginal oil fields is highly dependent on the alignment between technical performance and fiscal structure. Although horizontal wells significantly enhance reservoir contact and production performance, their high capital intensity creates substantial economic challenges when applied to marginal fields under prevailing fiscal conditions.
- The comparative analysis between PSC Cost Recovery and PSC Gross Split indicates that the PSC Cost Recovery regime consistently provides more resilient economic outcomes for capital-intensive developments. Higher internal rate of return (IRR) and net present value (NPV) under PSC Cost Recovery reflect more effective risk-sharing mechanisms, particularly for projects involving horizontal drilling and hydraulic fracturing. In contrast, PSC Gross Split offers limited flexibility and results in economically unviable outcomes under Moderate and Pessimistic Scenarios.
- Optimization and sensitivity analyses reveal that not all fiscal incentives exert equal influence on project viability. Contractor Split adjustment and CAPEX Efficiency emerge as the most dominant fiscal levers for improving economic performance, while Investment Credit and First Tranche Petroleum (FTP) adjustments have a relatively marginal impact. These findings suggest that uniform fiscal relaxation may not represent the most efficient policy approach for marginal field development.
- By identifying the quantitative incentive thresholds required to achieve a contractor minimum attractive rate of return (MARR) of 15%, this study provides a decision-oriented basis for designing targeted fiscal incentives. The proposed framework enables policymakers and regulators to distinguish between incentives that materially enhance project viability and those with limited effectiveness, thereby supporting more efficient, evidence-based fiscal policy formulation for marginal oil field development.

Policy implication

The findings of this study suggest that fiscal incentive design for marginal oil field development should shift from uniform incentive relaxation toward evidence-based, targeted policy instruments. By demonstrating that Contractor Split adjustment and CAPEX Efficiency have a substantially greater influence on project viability than Investment Credit or FTP modification, this study provides a quantitative basis for prioritizing incentive mechanisms that deliver maximum economic leverage.

For regulators, the proposed framework can serve as a screening tool to evaluate incentive requests transparently and consistently, ensuring that fiscal flexibility is aligned with project risk, capital intensity, and production uncertainty. Such an approach may enhance upstream investment sustainability while preserving Government Take and fiscal discipline.

Recommendation

Based on the findings of this study, the following policy recommendations are proposed to support the sustainable development of marginal oil fields utilizing horizontal well technology:

- Adoption of Risk-Responsive Contract Selection. Regulators should provide flexibility in selecting PSC regimes based on project risk and capital intensity. For marginal fields requiring horizontal drilling and hydraulic fracturing, PSC Cost Recovery should be prioritized due to its superior risk-sharing characteristics and ability to sustain contractor investment under uncertain economic conditions.
- Implementation of Targeted Fiscal Incentives. Fiscal incentives should be designed selectively rather than uniformly. Increasing Contractor Split and improving CAPEX Efficiency deliver the most significant improvements in project viability. Therefore, incentive policies should prioritize these parameters rather than relying heavily on Investment Credit or FTP adjustments, which offer limited economic leverage.
- Tiered Incentive Structure Based on Field Risk. A tiered incentive framework is recommended, with Contractor Split adjustments and CAPEX Efficiency targets calibrated according to reservoir quality, production uncertainty, and capital exposure. For Pessimistic Scenarios, a higher Contractor Split (50–62%) and substantial CAPEX Efficiency improvements (8 –12%) are required, while Moderate Scenarios require more moderate adjustments.
- Regulators should facilitate CAPEX Efficiency through policies such as shared infrastructure utilization, accelerated depreciation for capital-intensive assets, and streamlined approval processes. These measures can materially improve project economics without significantly reducing Government Take.
- Integration of Techno-Economic Evaluation into Incentive Decision-Making. The decision-oriented techno-economic framework proposed in this study can be adopted as a screening tool for evaluating fiscal incentive requests. By quantifying the economic impact of each fiscal lever, regulators can ensure that incentive approvals are transparent, consistent, and aligned with national production sustainability objectives.

- The decision-oriented techno-economic framework proposed in this study can be adopted as a screening tool for evaluating fiscal incentive requests. By quantifying the economic impact of each fiscal lever, regulators can ensure that incentive approvals are transparent, consistent, and aligned with national production sustainability objectives.

ACKNOWLEDGEMENT

The author would like to express his gratitude to all teaching staff and colleagues of the Petroleum Engineering Study Program, Institut Teknologi Sains Bandung. He also extends his gratitude to Prof. Ir. Pudji Permadi, M.Sc., who provided valuable direction, support, and encouragement.

GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbols	Definition	Unit
BOPD	Barrels of Oil Per Day	Barrels/day
Bo	Oil Formation Volume Factor	RB/STB
CAPEX	Capital Expenditure	MMUS$
CS	Contractor Split	%
DMO	Domestic Market Obligation	%
DDB	Double Declining Balance	-
DOE	Design of Experiment	-
FEED	Front End Engineering Design	-
FTP	First Tranche Petroleum	%
GT	Government Take	MMUS$
HSE	Health, Safety, and Environment	-
IC	Investment Credit	%
IRR	Internal Rate of Return	%
k	Permeability	md
MARR	Minimum Attractive Rate of Return	%
MMSTB	Million Stock Tank Barrels	Barrels
NPV	Net Present Value	MMUS$
OPEX	Operating Expenditure	MMUS$
PI	Profitability Index	Fraction
POD	Plan of Development	-
POT	Payout Time	Year

PSC	Production Sharing Contract	-
PTK	Pedoman Tata Kerja	-
STB/D	Stock Tank Barrel per Day	Barrels/day

REFERENCES

Joshi, S.D., (1991), Horizontal Well technology. PennWell Books, Tulsa, Oklahoma.

Directorate General of Oil and Gas, (2024), Hydrocarbon Potential Study in Bunga Area, Jakarta.

Fajri, Muhammad., (2020), Legal Analysis of Gross Split Contract Scheme on Increasing Upstream Oil and Gas Investment, Journal of Law & Development, Volume 50, Airlangga University, Surabaya.

Johnston, Daniel., (1994), International Petroleum Fiscal Systems and Production Sharing Contract, PennWell Books, Oklahoma, USA.

Kurniawan, R. dan Amir, H., (2017), Fiscal Aspects of Upstream Oil and Gas Business, P.T. Nagakusuma, Jakarta.

Azis, P. A., Rachmat, M., Chandra, S., Daton, W. N., & Tony, B., (2023), Techno-economic solution for extending CCUS application in natural gas fields: A case study of B gas field in Indonesia. *Scientific Contributions Oil and Gas*, *46*(1),19–28.

Jumiati, W., & Sismartono, D., (2018), Tantangan keekonomian kontrak bagi hasil gross split dan cost recovery: Studi kasus lapangan gas offshore di Sumatera bagian utara. Lembaran Publikasi Minyak dan Gas Bumi, 52(2), 4–5. http://www.journal.lemigas.esdm.go.id

Lubiantara, B., (2012), Ekonomi Migas-Tinjauan Aspek Komersial Kontrak Migas, PT.Gramedia Widiasarana Indonesia, Jakarta.

Lubiantara, B., (2007), The Analysis of the Marginal Field Incentive - Indonesian Case. OGEL (Oil, Gas & Energy Law Intelligence), Vol 5.

Partowidagdo, W., (2001), Evaluasi kontrak perminyakan di Indonesia, Jurnal Teknologi Mineral (JTM), Institut Teknologi Bandung, Bandung.

Partowidagdo, W., (2002), Manajemen dan Ekonomi Minyak dan Gas Bumi, Institut Teknologi Bandung, Bandung.

Pujawan, I. N., (2019), Engineering Economics, Edisi 3, Lautan Pustaka, Yogyakarta

Ramadhani, N. F., Irawan, D., Sudono., & Aziz, P.A., (2025), A Techno-Economic Approach to Optimizing CCS Fiscal Parameters in Indonesia: A Case Study of Integrated Oil and Gas Development in CO2-Rich Areas. *Scientific Contributions Oil and Gas*, *48(3), 53–66*. http://www.journal.lemigas.esdm.go.id.

Regulation of the Minister of Energy and Mineral Resources of the Republic of Indonesia Number 08 of 2017 concerning Gross Split Production Sharing Contracts and its amendments, Jakarta.

Regulation of the Minister of Energy and Mineral Resources No. 1 of 2020 concerning Guidelines for the Preparation of Oil and Gas Field Development Plans.

Republic of Indonesia Law Number 22 of 2001 Concerning Oil and Natural Gas.

SKK Migas. (2018). PTK-007 Rev-2 Work Procedure Guidelines: Field Development Plan and Cost Management.

Sudono dan Prasetyo, A. (2017). Evaluation of Non -Conventional Oil and Gas Development Contracts in Indonesia, Journal of Oil and Gas Technology, Volume 14 No.2, Jakarta.

Sudono dan Prasetyo, A. (2017). Evaluation of Non -Conventional Oil and Gas Development Contracts in Indonesia, Journal of Oil and Gas Technology, Volume 14 No.2, Jakarta.