Economic Analysis Of Field Development Plan In Gelama Merah

Mohd.Razie Jaafar
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
mohd.razie_20000950@utp.edu.my

Myra Batrisyia Baha'Uddin
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
myra_19000410@utp.edu.my

Pg Mohd Ikhwan Haziq bin Agku Jali
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
pg_19000764@utp.edu.my

Muhammad Suhayl Aiman Bin Saiful Adzwar
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
suhayl_18001068@utp.edu.my

Faiq Hafiy Rozeman
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
faiq_19000904@utp.edu.my

Mohammad Aqasha Iman
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
mohammad_19000804@utp.edu.my

Juhairi Aris Bin Muhamad Shuhili
Department of Business and Management, Universiti Teknologi Mara Perak Branch Tapah Campus, 35400 Tapah Road, Perak
juhairiaris@gmail.com

Muhammad Adidinizar Bin Zia Ahmad Kusairee
Department of Business and Management, Universiti Teknologi Mara Perak Branch Tapah Campus, 35400 Tapah Road, Perak
adidi627@uitm.edu.my

Rosli Yakop
School of Engineering, Asia Pacific University of Technology & Innovation (APU), Kuala Lumpur, Malaysia
rosli.yusop@apu.edu.my

***Abstract* — The economic analysis of the Gelama Merah field involves a comprehensive examination of key factors, including the breakdown of costs, the intricacies of the Production Sharing Contract (PSC), the role of the National Oil Company (NOC), and the objectives of the host government. In dissecting the breakdown of costs, the analysis delves into the financial intricacies of exploration, development, and production, considering elements such as rig costs, well depth, and facilities. The PSC framework is scrutinized, emphasizing the cost and risk allocation to oil companies, profit-sharing mechanisms, and adherence to global standards. The NOC's objectives in maximizing wealth and maintaining control over resources guide its strategic decisions, while the host government focuses on encouraging exploration, providing a fair return, and reducing petroleum imports, emphasizing the transfer of technology for local industry development. This holistic economic analysis aims to unravel the nuanced dynamics shaping the Gelama Merah field's economic landscape, ensuring a thorough understanding of the stakeholders' roles, incentives, and implications for sustainable resource management and economic prosperity.**

Keywords—Breakdown of Costs, Production Sharing Contract (PSC), Host Government (HG), National Oil Company (NOCs.

I. Introduction

In the heart of Malaysia's offshore oil and gas industry lies the Gelama Merah field, a critical player in the nation's energy portfolio. As the demand for hydrocarbons continues to drive exploration and production activities, the economic intricacies of field development plan become paramount. This article embarks on a journey to unravel the economic landscape surrounding the Field Development Plan (FDP) in Gelama Merah, dissecting the various facets that contribute to its significance and impact.

The Gelama Merah field, situated off the shores of Malaysia, represents a pivotal asset in the energy sector, holding the promise of substantial reserves. A meticulous economic analysis of its FDP is essential not only to understand the potential returns for stakeholders but also to ensure sustainable and responsible resource management. This exploration will delve into the economic considerations, risk assessments, and strategic decision-making processes that underpin the development plan for this vital energy reservoir. As we navigate through the complex web of economic factors, this article aims to provide readers with insights into the financial dynamics governing Gelama Merah's FDP. From initial investment evaluations to revenue projections, we will scrutinize the cost-benefit analyses that guide industry players, investors, and policymakers in shaping the future trajectory of this significant energy project.

II. Literature Review

Economics drives the entire oil/gas producing industry. Almost every decision is made based on an economic evaluation. Economic evaluations are also performed to determine reserves and the "standardized measure of value" for reporting purposes for publicly held companies. In many cases, the goal of the company is to make decisions that have the best chance of maximizing the present-day profit. Having stated a company goal in terms of profit, it behooves us to examine the definition of profit. There are at least three ways to calculate profit, each with its own set of assumptions and rules and each leading to a different answer. The three models are the net cash flow model, the financial net income model, and the tax model.

When the purpose of an economic analysis is to help decide, there are several key managerial indicators or economic parameters that are considered. Although there are many parameters that can be considered the most common decision criteria are net present value, internal rate of return, and profit-to-investment ratio (both discounted and undiscounted)

Net present value is the sum of the individual monthly or yearly net cash flows after they have been discounted. The decision criterion using net present value is very simple. For project screening, all projects with a positive NPV at the company average investment opportunity rate are acceptable. If the projects with a positive NPV perform as projected, they will return more to the treasury than the average company project will return. In the case of mutually exclusive alternatives, where choosing one alternative precludes choosing another, the alternative with the highest NPV should be chosen. An example of mutually exclusive alternatives might be choosing between injecting CO2 or high- pressure air as a secondary recovery method, only one or the other may be chosen, not both (Larry W. Lake, 2017).

Meanwhile, internal rate of return (IRR) has been a popular managerial indicator since the 1950s, and it is still widely used today. IRR is defined as that interest rate which, when used in the calculation of NPV, causes the NPV to be zero. IRR can easily be used to screen projects. If the IRR is greater than the average investment opportunity rate, the project passes the screen. However, the unwary might be trapped in a situation where two mutually exclusive projects are being compared. Many evaluators tend to think that the project with the larger IRR is the better project. This is not necessarily so. If IRR is used to compare two mutually exclusive projects, it is necessary to calculate the IRR on the incremental capital used for the project with the larger investment. Although this can lead to the correct decision, the procedure is tedious enough that it is easier to just compare NPVs at the average investment opportunity rate. Choosing the project with the higher NPV, at the average investment opportunity rate, leads to the same decision as calculating incremental IRR ((Larry W. Lake, 2017).

III. Breakdown of Costs

Breakdown of costs in oil and gas industry are involving project evaluation. In the project evaluation, there are five main steps which are acquisition, exploration, development, production, and abandonment. All this step is critical step, but in this paper of Gelama Merah field where we develop the field development project, we only taking the consideration of acquisition till the production.

A. Exploration

Oil and gas exploration encompasses the processes and methods involved in locating potential sites for oil and gas drilling and extraction. Early oil and gas explorers relied upon surface signs like natural oil seeps, but developments in science and technology have made oil and gas exploration more efficient. Geological surveys are conducted using various means from testing subsoil for onshore exploration to using seismic imaging for offshore exploration. Energy companies compete for access to mineral rights granted by governments by either entering a concession agreement, meaning any discovered oil and gas are the property of the producers, or a production-sharing agreement, where the government retains ownership and participation rights. Exploration is high risk and expensive, involving primarily corporate funds. The cost of an unsuccessful exploration, such as one that consisted of seismic studies and drilling a dry well, can cost $5 million to $20 million per exploration site, and in some cases, much more. However, when an exploration site is successful and oil and gas extraction is productive, exploration costs are recovered and are significantly less in comparison to other production costs.

In the exploration, the cost also divided by several cost which are:

1. Rig Costs: Exploration typically involves the use of drilling rigs to extract core samples or drill wells to assess the presence of hydrocarbons (oil and gas). The cost of hiring or owning a drilling rig is a significant component of exploration expenses.

2. Time to Drill Wells: The duration it takes to drill a well is a crucial factor in exploration costs. Time-related expenses include rig rental costs, labour costs, and other operational expenditures. Delays in drilling can lead to increased costs due to extended rig rentals and ongoing operational expenses.

3. Well Depth: The depth of the exploration well directly impacts costs. Deeper wells require more time, resources, and specialized equipment, contributing to higher overall exploration expenses. Deep wells also tend to incur higher drilling and completion costs.

4. Number of Exploration Wells: The total number of wells drilled during the exploration phase is a fundamental determinant of exploration costs. Each well incurs its own set of expenses, including drilling, testing, and evaluation costs. Conducting multiple wells allows for a more comprehensive assessment of the potential hydrocarbon reservoir.

5. Seismic: Seismic exploration involves studying the subsurface geology by generating and analysing seismic waves. This geophysical method aids in identifying potential oil and gas reservoirs. The costs associated with seismic surveys, data acquisition, and interpretation contribute to the overall exploration expenses.

In essence, these factors collectively shape the financial aspects of the exploration phase in the oil and gas industry. Rig costs, time considerations, well depth, the number of exploration wells, and seismic activities are interrelated elements that impact the budgeting and financial planning of companies engaged in exploring new energy reserves. The efficiency and effectiveness of managing these factors play a pivotal role in the success and economic viability of an exploration project (Hisham Ben Mahmud, 2023).

B. Development

The chosen approach or concept for developing the oil and gas field significantly impacts costs. Different development concepts, such as fixed platforms, floating production systems, or subsea developments, have varying cost implications. The selected concept dictates the overall design and infrastructure requirements.

1. Field Size: The size of the oil and gas field being developed is a critical determinant of development costs. Larger fields may require more extensive infrastructure, facilities, and drilling activities, resulting in higher overall costs.
2. Water Depth (Offshore): For offshore developments, the water depth at the field location is a crucial factor. Deeper water depths often necessitate more complex and expensive infrastructure, such as floating platforms or subsea systems, contributing to increased development costs.
3. Facilities: The type and scale of facilities needed for processing, refining, and transporting extracted hydrocarbons influence development costs. Facilities can include

processing plants, storage tanks, compression units, and other infrastructure necessary for handling and transporting oil and gas.

4. Number of Wells: The number of wells required for extracting hydrocarbons from the field is a key factor in development costs. Each well incurs costs related to drilling, completion, and connection to the production infrastructure.

5. Wells Costs: The costs associated with drilling and completing individual wells play a significant role in overall development expenses. This includes expenses for well design, drilling equipment, casing, and other materials and services needed to bring wells into production.

6. Pipeline Costs: If pipelines are used to transport oil and gas from the field to processing facilities or distribution points, the length and complexity of the pipeline system impact costs. This includes expenses related to pipeline construction, installation, and maintenance.

Thus, development costs encompass a wide range of considerations, from the conceptualization of the development strategy to the physical infrastructure required for efficient extraction and processing (Hisham Ben Mahmud, 2023).

C. Production

Oil and gas production is one of the most capital-intensive industries: It requires expensive equipment and highly skilled labors. Once a company identifies where oil or gas is located, plans begin for drilling. Many oils and gas companies contract with specialized drilling firms and pay for the labor crew and rig day rates. Drilling depths, rock hardness, weather conditions and distance of the site can all affect the drilling duration. Tracking data using smart technologies can help with drilling efficiency and well performance by providing real-time information and trends. While every drilling rig has the same essential components, the drilling methods vary depending on the type of oil or gas and the geology of the location. Offshore drilling uses a single platform that is either fixed (bottom supported) or mobile (floating secured with anchors). Offshore drilling is more expensive than onshore drilling, and fixed rigs are more expensive than mobile rigs. Most production facilities are located on coastal shores near offshore rigs.

1. Type of Operations: The nature and complexity of the oil and gas operations significantly influence production costs. Different types of operations, such as conventional onshore drilling, offshore drilling, unconventional (e.g., shale) extraction, or enhanced oil recovery (EOR) techniques, come with distinct cost structures. For instance, offshore operations generally involve higher costs due to logistical challenges and the need for specialized equipment.

2. Maintenance: Regular maintenance activities are essential to ensure the ongoing functionality and efficiency of production facilities, wells, and associated infrastructure. Maintenance costs encompass routine inspections, repairs, equipment replacements, and other measures aimed at preventing downtime and optimizing production. The frequency and scope of maintenance activities impact overall production costs.

3. Workover: Workover operations involve interventions performed on wells to enhance or restore their production capabilities. This could include activities such as reperforating, cleaning out debris, or implementing stimulation techniques to improve well performance. Workover costs contribute to the overall expenses of maintaining and optimizing well productivity.

In summary, production costs are influenced by the operational context, the regular maintenance required to keep facilities operational, and specific interventions like workovers to enhance well performance. The efficient management of these factors is crucial for maintaining a consistent and cost-effective oil and gas production process. Optimizing production costs is vital for the economic viability of oil and gas operations, ensuring that the revenue generated from extracted hydrocarbons exceeds the operational expenditures associated with their production (Hisham Ben Mahmud, 2023).

IV. PRODUCTION SHARING CONTRACT (PSC)

A. Artificial Neural Network

In Production Sharing Contract, PSC, the host government assigns the right to the Oil Company to explore and develop surface defined area for petroleum resources in return for a share royalty, taxes and profit. The host government also owns the petroleum resources.

The Production Sharing Contract (PSC) outlined with its main features reflects a common arrangement in the oil and gas industry between the host government and the oil company. The key features:

Exclusive Rights to Petroleum Resources: Granting the host government exclusive rights to petroleum resources is a standard provision in PSCs. It ensures that the state retains control over its natural resources, allowing for sovereign management and regulation.

Cost and Risks Borne by Oil Company - Cost Oil Recovery: The allocation of the cost and risks of all operations to the oil company is a fundamental characteristic of PSCs. The recovery of these costs from a negotiated fraction of production, known as "Cost Oil Recovery," is a common mechanism. This structure incentivizes the oil company to operate efficiently and manage costs effectively.

Profit Split: The agreement to share or divide the remaining production according to an agreed formula, known as "Profit Split," is a crucial aspect of PSCs. This allows both parties to benefit from the commercial success of the project, providing a fair distribution of profits after cost recovery.

Income Taxes on Oil Company Profit: The imposition of income taxes on the profit generated by the oil company aligns with standard fiscal practices. This revenue stream for the host government ensures a share in the economic gains derived from the exploration and production activities.

Host Government Ownership of Equipment: The provision that the host government owns all equipment used in operations is a unique aspect. While it offers the government control over the assets, it may also raise considerations related to maintenance, replacement, and operational efficiency.

Table 1 : Distribution of World-Wide Petroleum Contract Arrangement

North America	Concession Agreements
Latin America	Mostly Concession Agreements with some countries using Production Sharing Contracts and Service Contracts
Europe	Mostly Concession Agreements with a few countries using Production Sharing Contracts
Africa	Mostly Concession Agreements and Production Sharing Contracts
Middle East	Mostly Service Contracts and Production Sharing Contracts
Far East/ Australasia	Mostly Concession Agreements and Production Sharing Contracts

Table 1 shows Malaysia is categorized as Far East, therefore we apply the PSC in our oil and gas industry including the Gelama Merah. The basic of PSC are work commitment, commerciality, cash payment to host government and NOC, cost recovery, production sharing, ring-fencing, government participation, domestic obligation. Figure 1 is one of the examples of PSC.

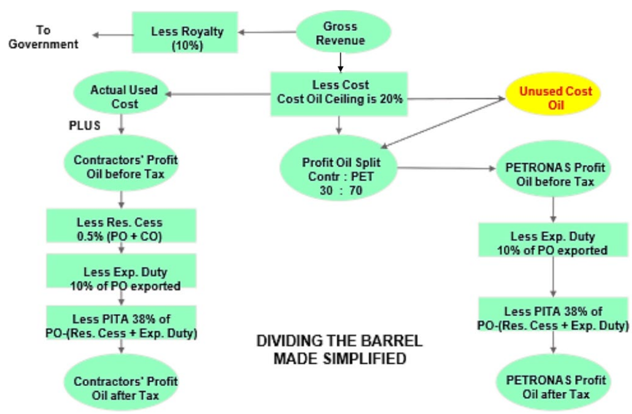

Figure 1 : Commercial Aspects of PSC

In summary, the outlined features of the PSC demonstrate a balanced and commonly accepted approach in the oil and gas industry. The arrangement ensures the host government's exclusive rights to petroleum resources, shares costs and risks with the oil company, establishes a profit-sharing mechanism, imposes income taxes on the oil company's profit, and grants ownership of equipment to the host government. This structure aims to create a mutually beneficial framework, aligning the interests of both parties and promoting responsible resource management. The success of such contracts often depends on the clarity of terms, fairness in profit-sharing formulas, and effective collaboration between the host government and the oil company (Hisham Ben Mahmud, 2023).

V. National Oil Company and Host Government

A. *National Oil Company Objectives*

National Oil Companies (NOCs) play a pivotal role in the global oil and gas industry, and their objectives often revolve around building equity and maximizing wealth for the benefit of the nation. The primary focus is on finding and producing oil and gas reserves at the lowest possible cost while ensuring the highest profit margins. This involves a strategic approach that encompasses exploration for large fields, balancing risks and rewards, and maximizing the economic return on investments.

Achieving a reasonable economic return is crucial, and NOCs strive to minimize the period during which invested capital is at risk. The repatriation of funds and the efficient export of crude oil entitlements are key considerations, ensuring a steady flow of revenue to the national economy. Retaining ownership of projects is a core objective, allowing the NOC to claim a share of the profits generated. Moreover, NOCs aim to avoid setting unfavorable precedents in contract terms that may hinder their interests in future agreements with other countries.

Maintaining global standards, efficiency, and a reputable standing in the industry is paramount for NOCs. This involves adhering to best practices, ensuring operational excellence, and upholding environmental and safety standards. Additionally, NOCs work towards balancing worldwide crude oil supplies and increasing oil reserves, contributing to global energy security.

In essence, the objectives of National Oil Companies are multifaceted, encompassing financial prudence, risk management, and strategic positioning in the global energy landscape. By pursuing these goals, NOCs aim to not only safeguard their nation's energy interests but also contribute positively to the stability and sustainability of the broader international oil and gas industry.

B. *Host Government Objectives*

The objectives of a host government in managing its natural resources, particularly in the context of the oil and gas industry, are driven by the need to maximize wealth and promote sustainable development. The primary goal is to encourage appropriate levels of exploration and development activities, and this is pursued through various strategic measures.

One key aspect of the host government's objectives is to ensure a fair return on the exploitation of its natural resources. This involves striking a balance between attracting foreign investment and safeguarding the nation's economic interests. Avoiding speculation and limiting administrative burdens are essential elements in creating a conducive environment for exploration and development, fostering flexibility and efficiency in the market.

Earning foreign exchange is a critical consideration for the host government, providing a steady influx of revenue and strengthening the country's economic position. Simultaneously, there is a focus on maximizing the economic return from resource extraction while also nurturing the growth of local industries. This dual objective aims to create a symbiotic relationship between foreign investors and the host country, fostering economic diversification and sustainability.

Maintaining and increasing control over the country's natural resources is a fundamental goal, ensuring that decisions regarding exploration, development, and extraction align with the nation's long-term interests. Reducing petroleum imports is another objective, promoting energy self-sufficiency and mitigating dependencies on external sources. Development of the local industry is a priority for the host government, encompassing not only the extraction of natural resources but also the transfer of technology. This technology transfer is essential for developing local technical expertise, fostering innovation, and building a skilled workforce. Ultimately, the host government seeks to harness the economic potential of its natural resources while simultaneously ensuring sustainable and responsible resource management for the benefit of present and future generations.

C. Gelama Merah NOC and HG

The Gelama Merah field in the Gelama Merah region, a significant asset, is owned by PETRONAS Carigali Sdn. Bhd., a major Malaysian National Oil Company (NOC) and a subsidiary of Petroliam Nasional Berhad (PETRONAS). As an NOC, PETRONAS Carigali plays a central role in the exploration and development of Malaysia's oil and gas resources, aligning with the country's broader energy objectives. In this case, PETRONAS Carigali engaged in a partnership by signing a contract with Japan Drilling Company for the deployment of the Hakuryu III, a semi-submersible drilling rig. This collaboration signifies international cooperation in the oil and gas sector, bringing together the expertise and resources of a prominent Malaysian NOC with the specialized drilling capabilities of a Japanese company. The use of the semi-submersible rig, known for its stability and versatility in offshore drilling, highlights the strategic and technologically advanced approach taken by PETRONAS Carigali in the exploration and extraction activities within the Gelama Merah field. This cooperative venture underscores the global nature of the oil and gas industry and reflects the efforts of both Malaysian and Japanese entities to optimize resource extraction in a mutually beneficial manner (PETRONAS Carigali Sdn. Bhd, 2003).

VI. RESULT AND DISCUSSION

After doing the different parameters in facilities using Questor and taking all aspects, we obtain all the results of the parameters. We have chosen Tie Back plus Pipeline for our oil and gas transportation. The table and figure below will show the result of CAPEX, Net Present Value, NPV, and Internal Rate of Return, IRR for 20 years.

A. Economics – Primary (Gas Lift)

Table 2:Results of Primary Gas Lift

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$116,530,000	$43,153,530.62	23%

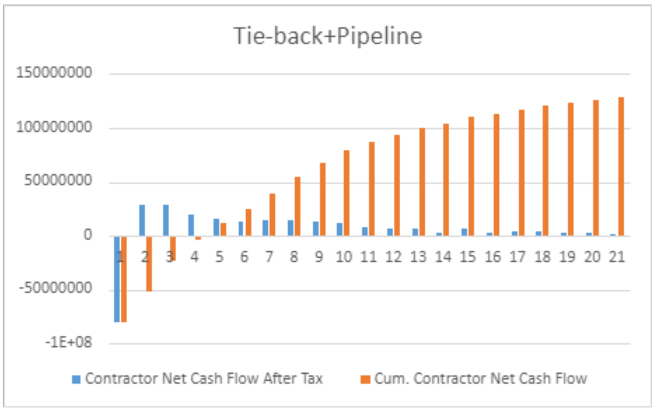

Figure 2:Primary Economic Indicator

B. Economics – Secondary 20000 bwpd

Table 3:Results of Water Injection 20000 bwpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$214,530,000	$18,639,822.00	12%

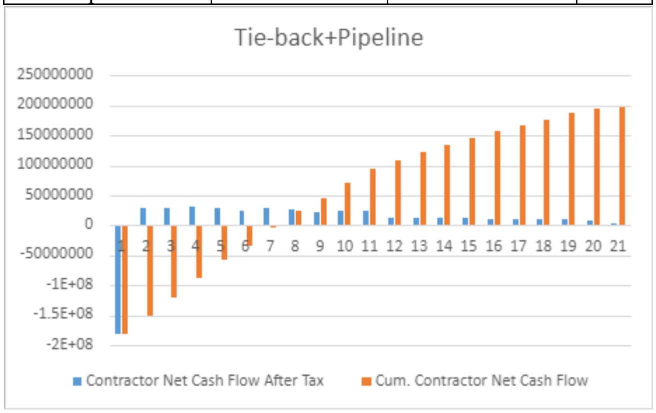

Figure 3: Secondary Water Injection 20000 bwpd Economic Indicator

C. Economics – Secondary 30000 bwpd

Table 4:Results of Water Injection 30000 bwpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$243,574,000	$7,463,787.89	11%

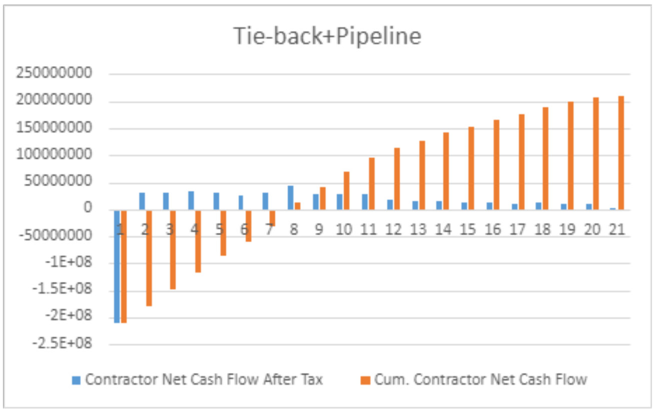

Figure 4: Secondary Water Injection 30000 bwpd Economic Indicator

D. Economics – Secondary 40000 bwpd

Table 5:Results of Water Injection 40000 bwpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$214,530,000	$31,202,304.46	13%

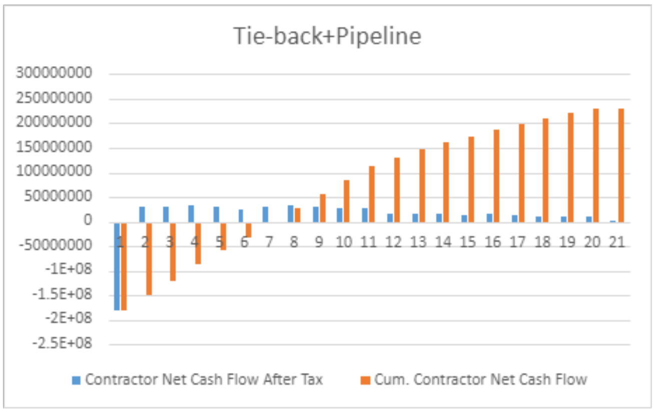

Figure 5: Secondary Water Injection 40000 bwpd Economic Indicator

E. Economics – Secondary 5000 bwpd

Table 6:Results of Water Injection 50000 bwpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$214,530,000	$34,822,106.41	13%

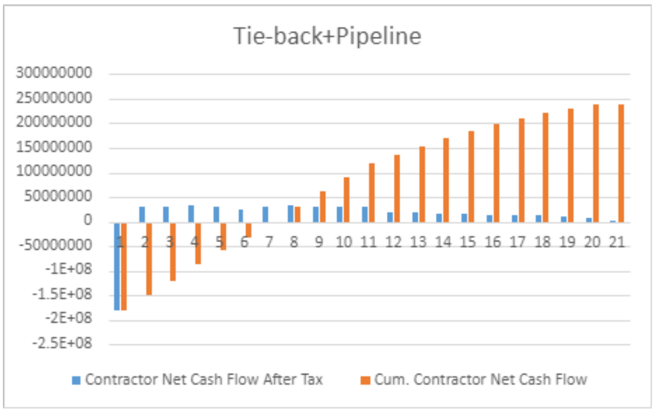

Figure 6: Secondary Water Injection 50000 bwpd Economic Indicator

F. Economics – Secondary 50 mmscfpd

Table 7:Results of Gas Injection 50 mmscfpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$214,530,000	$16,117,049.13	12%

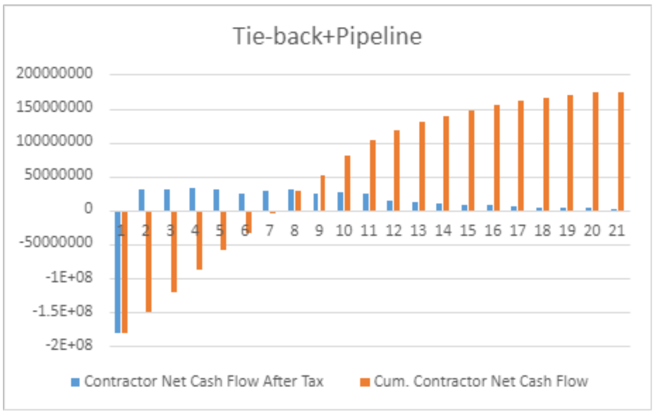

Figure 7: Secondary Gas Injection 50 mmscfpd Economic Indicator

G. Economics – Secondary 100 mmscfpd

Table 8:Results of Gas Injection 100 mmscfpd

Facilities Design	CAPEX	Cumulative NPV	IRR
Tie-back + Pipeline	$195,000,000	$47,398,025.40	15%

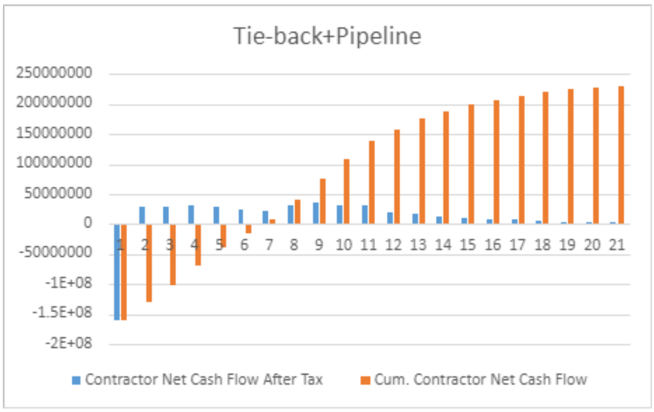

Figure 8:Secondary Gas Injection 100 mmscfpd Economic Indicator

VII. Conclusion

In summary, the breakdown of costs for the Gelama Merah project in the Gelama Merah field provides crucial insights for project evaluation. Following this analysis, the facilities team recommends well transportation and suggests proceeding with a Tie Back plus Pipeline approach. The primary production well for 20 years, with a CAPEX of $116,530,000, exhibits a promising NPV of $43,153,530.62 and an IRR of 23%. However, the addition of an injection well in the secondary production phase proves to be an optimization strategy. Water injection, initially explored, demonstrates optimal results at 30,000 barrels per day, with a CAPEX of $243,574,000 and respective NPV and IRR figures of $7,463,787.89 and 11%. Despite these favorable outcomes, the primary NPV remains unbeaten. Consequently, gas injection, implemented simultaneously with water injection due to favorable oil properties, emerges as the most lucrative option. With a gas injection rate of 100 million standard cubic feet per day, the result surpasses the primary NPV, reaching $47,398,025.40. This intricate analysis showcases the importance of considering various production techniques and injection methods for optimal economic returns in the Gelama Merah project.

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