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Monetization of Natural Gas from the Búzios Field through an ssm-FLNG Platform: Economic and Financial Assessment

Lauron Arend[1*], Daniel Prata Vieira[2], Fernando Cörner da Costa[1], Edmilson Moutinho dos Santos[1], Xuefeng Hu[3], Junkai Feng[3]

[1]Institute of Energy and Environment, University of São Paulo, São Paulo, Brazil
[2]Department of Naval Architecture & Ocean Engineering, Polytechnic School, University of São Paulo, São Paulo, Brazil
[3]CNOOC Petroleum Brasil Ltda., Beijing, China
Email: *lauron@usp.br, daniel.prata@usp.br, fcorner@uol.com.br, edsantos@iee.usp.br, huxf@cnoocbrasil.com, fengjk@cnoocbrasil.com

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Abstract

The monetization of natural gas resources associated with oil production in Brazil's pre-salt layer represents a strategic pillar for the country's energy and industrial development. This can be achieved through an increased supply of natural gas or, potentially, by becoming an exporter of natural gas or liquefied natural gas (LNG), as production occurs offshore near the oil and gas fields. This paper proposes the concept of using a small-scale mobile floating LNG platform (ssm-FLNG) offshore to collect natural gas produced by Floating Production, Storage, and Offloading units (FPSOs) operating in the Búzios Field, located in the Santos Basin off the Brazilian coast. After initial processing by the FPSOs, which separate oil, gas, and water fractions, the treated raw gas is sent to the ssm-FLNG for final treatment and cryogenic liquefaction, turning it into LNG for transportation and marketing via LNG carriers. This study developed an economic and financial model of the liquefaction platform to verify the financial feasibility of the concept and the potential revenue it could generate. Brazil holds abundant gas reserves in the pre-salt layer, but their economic utilization is often replaced by reinjection, driven by technical needs for enhanced oil recovery, high CO_2 content, and limitations in transportation and processing infrastructure. The FLNG connected to an FPSO is proposed as a solution to reduce reinjection, increasing gas availability for the market. The required infrastructure investment is substantial, with estimates from EPE for pipeline networks reaching billions of Brazilian Reais. The use of floating liquefied natural gas (FLNG) is seen as a potential substitute for traditional pipeline networks, which are costly, environmentally impactful, and rigid in terms of capacity. FLNG allows for gas supply to the domestic market via Floating Storage and Regasification Units (FSRUs) located along the Brazilian coast, adding value to the national industry, or for sale on the global market. This study suggests that the FLNG should be situated offshore and directly connected to an FPSO, rather than a pipeline network, to supply the consumer market with liquefied gas. No similar projects have been identified worldwide, making this a novel and unique proposal. The primary objective is to develop a model that serves as a tool for stakeholders interested in incorporating the ssm-FLNG structure into their investment decisions. Due to various assumptions in this study, sensitivity analysis around these assumptions may produce different results from those shown here. Finally, the simulated results are presented, demonstrating the viability of the proposed solution.

Keywords

LNG, ssm-FNLG Offshore, Búzios Basin, Brazilian Pre-Salt

1. Introduction

Brazil is positioning itself as a significant producer in the global oil market, primarily driven by discoveries in the pre-salt layer. This region, where the first discoveries were made in 2006, has become the country's primary source of oil. In 2024, for example, Petrobras' pre-salt production reached new annual records, accounting for 81% of the company's total output [1] [2]. In January 2025, total pre-salt production reached 3.471 million barrels of oil equivalent per day (boe/d or bbl/d), representing 77.9% of Brazil's total production. Petrobras' 2024-2028 Strategic Plan reinforces this trend, projecting that the pre-salt will account for 79% of total output by 2028/2029 [3] [4].

According to [5], global demand for natural gas is expected to continue growing, surpassing 5300 billion cubic meters, despite the expansion of renewable energy sources. In contrast, demand for coal and oil is projected to decline. Therefore, demand for natural gas is expected to remain strong.

Regarding natural gas, a striking feature of Brazilian production is its strong association with oil. More than 80% of the gas produced in the country is associated gas, coming predominantly from offshore fields. In January 2021 alone, pre-salt fields accounted for 65% of the total natural gas produced [6]. Despite these significant production volumes, Brazil faces a major challenge: a substantial portion of the natural gas produced is reinjected into reservoirs and not utilized commercially. In September 2024, the reinjected volume reached a record high of 93.5 million m^3/day, accounting for the country's total production [7]. This high reinjection rate is identified as the main factor limiting the availability of gas for commercialization in the domestic market [8].

This situation highlights a critical disconnect between Brazil's vast natural gas resources and its actual ability to deliver them to the market. Reinjection—despite the high levels of pre-salt production—points to a fundamental bottleneck in infrastructure and economic monetization, rather than a shortage of supply. Reinjection that exceeds technically necessary volumes does not contribute economically [7] and represents an economic inefficiency driven by inadequate processing and transportation infrastructure.

Given this scenario, studies have been proposed to optimize the use of natural gas with the goals of increasing domestic supply, boosting industrial sectors, enhancing energy security by supplying thermal power plants, enabling commercialization in the international market, and integrating natural gas into low-carbon energy transition strategies [8]. The approval of a government decree authorizing the National Agency of Petroleum, Natural Gas, and Biofuels (ANP) to mandate the reduction of gas reinjection [9] signals a strong and targeted political initiative to address the issue of gas monetization, in addition to increasing its availability.

Evaluating oil and gas production projects is a complex task, especially when determining the ideal reinjection strategy. This crucial decision depends on the specific geological characteristics of each field and on technical and economic assumptions that may change over time. Despite this complexity and the variables involved, decisions made during the project approval phase are nearly irreversible. The reinjection strategy is defined during the development plan stage. Companies analyze several reinjection options to determine which one maximizes the field's value. However, once this strategy is established and platform construction begins, changing it becomes extremely difficult [10].

As a solution for utilizing pre-salt natural gas in Brazil, particularly in the Búzios field, this study proposes the use of a floating liquefied natural gas (FLNG) unit adjacent to and connected with the FPSO. The FPSO would be responsible for separating and treating the gas, removing impurities such as CO_2 and other contaminants, as well as natural gas liquids (NGLs), and delivering the treated gas to the FLNG unit, which would then liquefy the natural gas into LNG offshore. Once liquefied, the LNG would be stored onboard the FLNG unit and later offloaded onto specialized LNG carriers for commercialization in both domestic and international markets. In Brazil, the LNG could supply regasification terminals along the coast, such as the Port of Sergipe (SE), operated by Eneva; the Port of Açu (RJ), operated by GNA (Gás Natural Açu); the Terminal Gás Sul (SC) and the Barcarena Terminal (PA), both operated by New Fortress Energy; and the TRSP terminal in São Paulo, operated by Compass.

As an application of LNG in the domestic market—beyond the traditional Gas-to-Wire model that supplies thermal power plants—four major private players have emerged with distinct strategies to compete in Brazil's new LNG market. GNA (Gás Natural Açu) is developing a gas hub project at the Port of Açu (RJ), leveraging economies of scale.

Compass, part of the Cosan Group, aims to expand its gas distribution inland through small-scale LNG logistics, utilizing its terminal in São Paulo. Eneva, in turn, has developed an integrated model using road transport to deliver LNG to large clients in northern Brazil, effectively creating virtual pipelines [11].

FLNG technology consists of an offshore platform positioned after the extraction and processing phases—responsible for separating and purifying the gas—delivering natural gas that is free from CO_2 and other contaminants, ready to be liquefied, stored, and offloaded [12] [13]. This approach eliminates the need for extensive subsea pipelines to the coast, offering potential advantages in terms of reduced environmental impact, faster project deployment, and economically viable monetization of remote gas fields [13].

FLNG facilities contribute to economic expansion and diversification of the global LNG market. By enabling the development of previously untapped reserves, FLNG supports market growth and ensures a more diversified and resilient LNG supply. This economic diversification increases the industry's ability to respond to demand fluctuations and geopolitical factors.

The deployment of FLNG facilities also has the potential to stimulate regional economic development. The strategic placement of these units near offshore gas fields creates job opportunities, infrastructure development, and economic growth in the regions hosting FLNG projects. Local communities may benefit from increased economic activity associated with FLNG operations [14].

One of the main advantages of FLNG technology is its ability to access remote and stranded gas reserves. Traditional onshore facilities are often limited by geographic constraints, making the development of certain gas fields economically unfeasible. FLNG units, being mobile, can be strategically positioned near offshore reserves, overcoming the geographic limitations associated with conventional LNG infrastructure. FLNG facilities play a crucial role in unlocking previously economically unviable stranded gas reserves. These reserves, often located in challenging offshore environments, can now be utilized for LNG production. This not only expands the global gas supply but also harnesses valuable energy resources that would otherwise remain untapped [15] [16].

Floating facilities have evolved from conceptual designs into operational structures, driven by technological advances that have made them economically viable and accessible to remote gas reserves, significantly motivating their global adoption [17] [18]. They also represent a paradigm shift in the economic considerations within the LNG industry [19]. FLNG encapsulates the ingenuity of marine engineering and liquefaction technologies [20], enabling the development of offshore gas fields that were previously considered economically unfeasible or technically challenging.

As global demand for LNG continues to grow, FLNG is emerging as a strategic asset, providing a flexible and agile means to unlock new energy resources and contribute to the growth and sustainability of the LNG market [21]. The need for extensive pipeline infrastructure to transport gas from remote offshore reserves to onshore facilities is eliminated. This reduction in infrastructure requirements significantly contributes to cost savings, making FLNG a financially attractive option for the development of offshore gas fields [22].

Widely used for receiving LNG deliveries and regasifying the gas to be injected into a country's pipeline network or to supply a thermal power plant or industrial facility, Floating Storage and Regasification Units (FSRUs) are a fundamental solution for providing new and flexible LNG import capacity, especially amid changing energy security needs and evolving market conditions. By the end of 2024, global offshore floating regasification capacity had reached 207.3 million tons per year through 52 operational terminals [23].

The proposal of this study focuses on an offshore platform whose role is to liquefy natural gas (NG) into LNG and then load it onto LNG carriers for transportation to either domestic or international commercial destinations.

This work presents the economic modeling of these solutions to demonstrate the economic behavior of an FLNG platform receiving natural gas from FPSOs operating in the Búzios Fields. The FPSO would handle processing the natural gas, including the separation of CO_2 and other contaminants. Therefore, this pre-treatment stage is not modeled within the FLNG. The FPSO would supply the gas in a suitable condition for liquefaction to a small-scale FLNG unit. This model utilizes data from various sources, which will be explained throughout the article, to produce financial output data that enables a profitability analysis of the proposed solution.

This study becomes more specific by proposing that the FLNG structure be located offshore and connected directly to an FPSO, rather than to a pipeline network, for the delivery of natural gas. No similar project of this type has been found worldwide.

The main objective of this study is to develop a model that serves as a tool to support stakeholders interested in adopting ssm-FLNG structures in their investment decision-making processes. Given the various assumptions established in this study, sensitivity analysis across the range of those assumptions may lead to results that differ from those presented here.

To achieve the objectives of this article, it is divided into seven sections. The first is this introduction, followed by Section 2, which describes the Brazilian scenario for natural gas production from the potential so-called Brazilian pre-salt layer. Section 2 details the need for reinjection of the raw gas produced and the regulatory and economic motivations for utilizing this gas for commercialization, which is the main theme of the study proposed in this article. Section 3 then explores the concept of small-scale modular floating platforms for LNG production and the strategic application of this type of structure. This technological solution is proposed in this work as a replacement for the fixed pipeline structures that transport gas produced in the Brazilian pre-salt fields to the national coast for commercialization. This process and the proposed replacement are explained in Section 4. Section 5 is considered the main part of this work, as it details and demonstrates all the economic and financial modeling and simulations performed to validate the thesis proposed in this paper. This section describes all the modeling performed, the data sources, the assumptions considered, and the case study. The Búzios Field in the Santos Basin was chosen because it is one of the largest oil and gas fields in Brazil. Moving toward the final part of this work, the sixth section describes the results obtained in the simulation rounds and the financial indicators analyzed. Finally, the conclusion of the entire work demonstrates that the proposal is a viable solution for monetizing the NG that has previously been reinjected into the Búzios Field, which is part of all Brazilian oil and gas exploration.

2. Production, Reinjection, and Availability of Natural Gas in Brazil's Pre-Salt Layer

The pre-salt layer remains the primary source of oil production in Brazil. In 2024, Petrobras set new annual production records in the pre-salt, reaching 2.2 million boe/d. This volume represented 81% of the company's total production. In January 2025, the total pre-salt production reached 3.471 million boe/d, corresponding to 77.9% of Brazilian production [3] [4].

The National Energy Balance (BEN) of 2024 indicated Brazilian natural gas production of 153 million m^3/day for the year 2024 [24]. This document does not provide a breakdown by pre-salt field contribution; however, EPE's projections, according to the Ten-Year Energy Expansion Plan (PDE) 2034, indicated that pre-salt gross natural gas production would be approximately 126 million m^3/day in 2024, with significant growth to 252 million m^3/day by 2034. This growth trajectory indicates that pre-salt gas will account for approximately 80% of the national gross gas production by the end of the decade. In terms of pre-salt net natural gas production, the forecast is 37 million m^3/day in 2024, with a forecast of 81 million m^3/day by 2034, which would correspond to about 60% of the national net production [25].

2.1. Reinjection of Natural Gas

A considerable portion of the natural gas produced in Brazil is reinjected into the reservoirs. This volume reached a record 93.5 million m^3/day in September 2024 [7]. This high reinjection rate is identified as the main factor limiting gas availability for the domestic market [25]. Fields with high and low CO_2 concentrations determine total or partial natural gas injection [10].

Gas reinjection presents both economic and technical challenges. It is not merely a waste but a complex interaction of technical needs, economic optimization, and a lack of flow infrastructure to the national coast. A detailed analysis of reinjected gas (with an average of 29% CO_2, 24% entrained CH_4, and 47% due to economic reasons/lack of infrastructure) illustrates that a significant part of the reinjection is not purely technical [8]. The economic logic of prioritizing oil revenue and the explicit mention of infrastructure limitations demonstrate that the current system is driven by a complex cost-benefit analysis at the individual asset level [10].

The reasons for reinjection are diverse: Technical and Economic Drivers for Enhanced Oil Recovery (EOR): Reinjection is a crucial technique for EOR, as it helps maintain reservoir pressure and improve the oil recovery factor [26]. Petrobras and its partners have successfully developed and implemented the Alternating Water and Gas Injection (WAG) strategy specifically for pre-salt fields, aiming to optimize oil recovery [27]. High carbon dioxide (CO_2)Content and Separation Challenges: Pre-salt natural gas often contains high levels of CO_2, with concentrations ranging from less than 5% to as high as 45% in some fields [28]. The process of separating CO_2 from natural gas is inherently costly. Furthermore, membrane separation technologies typically employed on pre-salt platforms have low selectivity, meaning that some of the valuable natural gas (methane) is inadvertently entrained and reinjected with the CO_2 flow [28]. To address this, Petrobras has patented and is developing the HISEP (High Pressure Separation) technology, which separates CO_2-rich gas at the seabed and reinjects it directly into the reservoirs. This innovation not only reduces greenhouse gas emissions by up to 30% but also frees up valuable capacity in the upper reaches of FPSOs for increased oil processing [29]. The FPSO Marechal Duque de Caxias is scheduled to pioneer the commercial application of HISEP technology starting in 2028 [29]. Infrastructure Limitations: A significant factor in reinjection is the current inadequacy of gas flow and treatment infrastructure, in addition to the reduction/elimination of flaring to avoid releasing greenhouse gases (GHG). Delays in important gas pipelines like Route 3 [30] and the technical limitations of existing processing units, such as the Natural Gas Processing Units (UPGN) on Route 1 (which cannot process pre-salt gas without blending it with lighter gas from the declining Mexilhão field), have directly restricted the ability to bring more gas to market. The current maximum flow and treatment capacity is limited to 44 million m^3/day, considering all planned routes [27]. Economic Prioritization of Oil: In some cases, operators make the strategic economic decision to reinject all produced gas to maximize oil production [27]. There is an opportunity to evaluate ways to convert the field to produce more gas through Water Alternating Gas (WAG) technology, which was developed by Petrobras and partners for pre-salt fields. This technology involves reinjecting water into an injection well until the water content in adjacent producing wells begins to increase. Gas is then injected, blocking water circulation, until the gas-to-oil ratio increases, at which point water reinjection resumes [27].

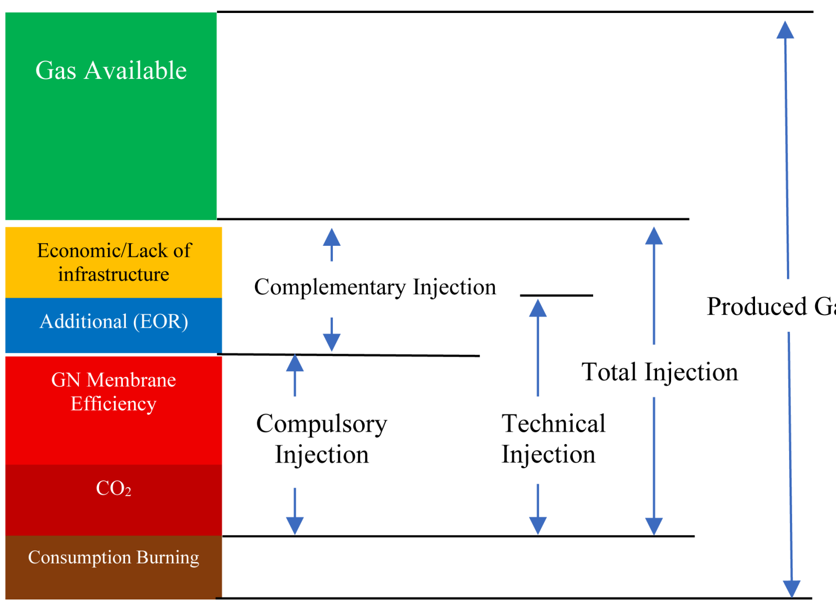
Reinjection is a crucial EOR technique as it helps maintain reservoir pressure and improve the oil recovery factor [26]. Petrobras and its partners have successfully developed and implemented the Water Alternating Gas (WAG) injection strategy specifically for pre-salt fields, aiming to optimize oil recovery [10].

Natural gas from pre-salt often contains high levels of CO_2, with concentrations ranging from less than 5% to up to 45% in some fields. The process of separating CO_2 from natural gas is inherently costly. Furthermore, the membrane separation technologies typically employed on pre-salt platforms exhibit low selectivity, meaning that a portion of valuable natural gas (methane) is inadvertently entrained and reinjected with the CO_2 stream [28]. To address this, Petrobras patented and is developing HISEP (High-Pressure Separation) technology, which separates CO_2-rich gas at the seabed and reinjects it directly into the reservoirs. This innovation not only reduces greenhouse gas emissions by up to 30% but also frees up valuable topside capacity on FPSOs, allowing for increased oil processing. The FPSO Marechal Duque de Caxias is scheduled to pioneer the commercial application of HISEP technology starting in 2028 [29].

A significant factor for reinjection is the current inadequacy of gas flow and treatment infrastructure, in addition to the reduction or elimination of flaring to avoid releasing Greenhouse Gases (GHG). Delays in important pipelines like Rota 3 [31] and the technical limitations of existing processing units, such as the Rota 1 UPGN (which cannot process pre-salt gas without mixing it with lighter gas from the declining Mexilhão field), have directly restricted the ability to bring more gas to market. The current maximum flow and treatment capacity are limited to 44 million m^3/day, considering all planned routes [10].

In some cases, operators make a strategic economic decision to reinject all produced gas to maximize oil production. There is an opportunity to evaluate methods for increasing gas production in the field through the Water Alternating Gas (WAG) technology, developed by Petrobras and its partners for pre-salt fields. This involves injecting water into an injection well until the point where the water fraction in adjacent production wells begins to increase. Then, gas is injected to block water circulation until an increase in the gas-oil ratio occurs, at which point water reinjection is resumed [10].

Figure 1 represents the destination of raw gas production in the Brazilian pre-salt Campos Basin. It was developed from a hypothetical profile, based on fields



Source: [8].

Figure 1. Proposed nomenclature for categories of produced gas parcels.

that comprise the pre-salt production of the Santos Basin, with the following premises: CO_2 content of 10%; Drag (CH_4/CO_2) = 2, implying Compulsory Injection (CO_2 + Drag) = 30%; Consumption = 9%; Flaring = 3%; Market Availability = 35%; and Complementary Injection = 23% [8].

Focusing solely on the production from the Búzios Field, a production forecast is available, including both the Búzios ECO12 and Tambuatá units, due to data availability from the ANP. In the early years, all produced gas was injected. Starting from the first year of production, in 2021, gas availability has been increasing, with a forecast to reach 30% of available gas by 2027. Total injection accounts for 68% of the total produced. Considering that the Búzios field has CO_2 contents of 23%, which contributes to a Compulsory Injection of 29%. Complementary Injection is projected to reach 29% by 2027 [8].

2.2. Regulatory Motivation for Reducing Reinjection

The Brazilian government, through the "Gas for Employment" program, has been seeking to reduce unnecessary gas reinjection since 2023. This is being done through regulatory measures (Decree 12.153/2024 [32]) that authorize the ANP to review and potentially determine changes to field development plans, provided the economic viability of the assets is maintained [9]. However, the intense political pressure to reduce reinjection clashes with inherent operational inertia and the economic reality of irreversible investment decisions already made for existing platforms.

The ANP is actively evaluating regulatory provisions to establish natural gas availability as the standard baseline scenario for field development, requiring explicit justification for reinjection [8] [33]. The governmental decree mentioned in the previous paragraph further empowers the ANP to determine reductions in gas reinjection where technically and economically feasible. Although the new Gas Law and ANP guidelines represent a strong political signal to increase gas availability and promote shared infrastructure, the actual market response will be shaped by the economic viability of these capital-intensive projects. The high costs of ultra-deepwater infrastructure and the complexities of handling CO_2-rich gas [26] [34] mean that market participants will continue to prioritize profitability.

3. The Concept of a Small-Scale FLNG

The ssm-FLNG units offer several attractive economic advantages, including accelerated time-to-market, inherent scalability for phased expansion, and reduced reliance on fixed infrastructure. Additionally, the ability to relocate FLNG units to new gas fields increases asset utilization and value. However, challenges persist, notably the substantial upfront capital investment required, the inherent complexity of offshore projects, and the intricate offloading operations in challenging environments, such as the open sea.

3.1. Modular Small-Scale LNG

The FLNG market has shown a clear trend toward small and medium-scale projects, referred to in English as "small scale" (or ss-FLNG), which offer significant advantages in terms of lower capital costs, faster development, and greater flexibility to monetize diverse gas resources [17] [35].

The International Gas Union (IGU) provides a more specific definition based on capacity, classifying small-scale liquefaction plants as those with capacities ranging from 0.05 MTPA (million tons per year)[1] to 1 MTPA [36] [37]. Additionally, any liquefaction project with a capacity below 0.5 MTPA is also generally categorized as small-scale [38]. A defining characteristic of these plants, particularly FLNGs, is their modular design. This involves assembling large sections (modules) of the LNG plant at off-site fabrication yards, which are then transported to the project site (or vessel) for integration and final assembly. This modular approach is fundamental to all modern FLNG designs [39].

The lack of a single, clear definition for "small-scale LNG" based solely on capacity is notable. Instead, descriptions from technology providers and industry groups often link "small scale" with "standard" designs and "medium scale" with "modular" designs. This suggests that the main characteristic is not just a numerical limit, but also the design and construction approach (standardized or modular), as well as the strategic use (niche markets, remote fields, virtual pipelines, and gas monetization). This flexible definition indicates that market players should focus less on strict capacity limits and more on the functional benefits and project execution methods that small-scale and modular solutions provide. It shows that the value of ss-FLNG is in its flexibility, quick deployment, and ability to make otherwise uneconomical gas reserves viable, rather than just its size. Therefore, cost comparisons should consider the underlying design philosophy (standard versus customized, modular versus stick-built) and not rely solely on production rate.

The modular and compact nature of FLNG facilities allows for faster development schedules compared to traditional LNG projects. These floating units can be built in shipyards, enabling parallel construction activities while the project site is being prepared. This accelerated pace of development minimizes financing costs and increases the overall economic viability of FLNG projects.

This project also explores the mobility aspect of small-scale FLNG. These structures offer greater operational flexibility due to their size, allowing them to be relocated to different gas fields as needed. This adaptability enhances the economic efficiency of FLNG (ensuring payback) by enabling operators to respond dynamically to changing market conditions and the discovery of new reserves. The ability to avoid the sunk costs associated with fixed onshore infrastructure further contributes to the economic appeal of FLNG (Fortini, 2019). This characteristic gives FLNG the name "mobile," and with that, we add the letter "m" to the name, arriving at ssm-FLNG.

[1]MTPA—The acronym for Million Tons per Year, which is one of the units of measurement for LNG used worldwide.

3.2. Applications of Small-Scale Modular FLNG

FLNG facilities are autonomous floating units that integrate crude gas processing, liquefaction, and storage capabilities. These units can be purpose-built platforms or, more commonly, converted ships or barges repurposed from decommissioned projects, where the vessel has been retired from its previous use. Their design eliminates the need for extensive onshore infrastructure, such as subsea pipelines to the coast, large onshore processing plants, and dedicated jetties [40]. A modular FLNG unit of 0.5 MTPA or 1370 TPD is often considered an "unconventional" configuration, typically designed as a barge-type facility with minimal onboard LNG storage, often relying on a nearby FSU for larger storage requirements [41].

Strategically, these units are ideal for monetizing associated gas from existing oil fields, developing remote or isolated gas fields that would otherwise be uneconomical, and supplying niche markets or regions with underdeveloped gas infrastructure [41] [42]. The modular approach, utilizing multiple trains, particularly for capacities such as 0.5 MTPA (where several grouped 0.5 MTPA modules can form a larger facility), offers significant operational advantages. These include the ability for incremental capacity build-up, phased development that can be aligned with upstream gas supply, enhanced turndown capabilities, easier startup procedures, and improved operational flexibility. For example, shutting down one modular train for maintenance does not require a complete production shutdown [1] [43].

Looking at FLNG projects globally, whether in operation or planned, we can categorize them by size, the technology used, and the scope of the NG treatment they handle, as presented in **Table 1**.

Table 1. Description of the scales of worldwide FLNG projects.

Scale	Description	Source
Small-Scale (up to 1 MTPA)	Projects like Tango FLNG (0.6 MTPA) and Pilot LNG (0.5 MTPA) demonstrate the viability of smaller units, often for specific applications such as LNG bunkering (supplying ships with LNG for fuel) or niche markets.	[44]
Medium-Scale (1 - 3 MTPA)	This segment includes several operational units. Petronas' PFLNG Satu (1.2 MTPA, operational since 2017) and PFLNG Dua (1.5 MTPA, operational since 2021) are pioneering examples from Malaysia. Golar LNG's Hilli Episeyo (2.4 - 2.5 MTPA, operational since 2018) and Gimi FLNG (2.5 - 2.7 MTPA, operational from 2025) demonstrate the successful conversion of LNG carrier vessels.	[42] [45]
Large-Scale (above 3 MTPA)	Shell's Prelude FLNG (3.6 MTPA, operational since 2018) is the world's largest FLNG facility, measuring 488 meters long and 74 meters wide, with an estimated cost of US$10 - 13 billion.	[46]

The focus on cost reduction, primarily through modularization and the conversion of existing vessels, indicates a shift in the industry toward optimizing both capital expenditure (CAPEX) and operating expenditure (OPEX) for FLNG projects. While earlier large-scale FLNG projects like Prelude involved substantial costs, newer projects and designs specifically emphasize lower CAPEX and the advantages of modularization [47]. The development of standardized, repeatable modules and the conversion of existing LNG carriers directly address the need for more financially attractive projects. This trend makes FLNG a more viable option for Petrobras, potentially lowering the investment threshold and speeding up the time-to-market.

Modularization is an essential trend that enables off-site fabrication and quicker integration. New Fortress Energy's Fast LNG uses modular units on repurposed jack-up platforms. Compact liquefaction modules, ranging from 0.8 to 2 MTPA, can be added gradually to increase production capacity [48]. Many successful FLNGs are conversions of existing LNG carriers (e.g., Hilli Episeyo, Gimi, Golar MK II), providing cost and time savings. Newbuilds (e.g., Prelude, Coral Sul) are specifically built for field conditions [49]. The key technologies to consider in the liquefaction process include Air Products' AP-DMR (Coral Sul) [49], Black & Veatch's PRICO (Hilli Episeyo, Gimi, Golar MK II) [50], and Chart Industries' IPSMR (Rovuma LNG, Fast LNG, Tango FLNG) [51].

For an FLNG unit to be solely responsible for processing already well-treated NG, it is crucial that, before receiving the NG, the FPSO unit performs specific impurity removal steps. This includes reducing CO_2 to less than 50 ppmv (parts per million by volume), hydrogen sulfide (H_2S) to less than 4 ppmv, total sulfur to below 30 ppmv, water (H_2O) to less than 0.1 ppmv, and mercury (Hg) to 0.01 μg/Nm^3 (standard cubic meter). Additionally, heavier hydrocarbons (C5+) must be removed to a concentration of less than 0.1 mol%, and benzene to a concentration of less than 1 ppmv. Depending on the quality of the inlet gas, the feed to the LNG liquefaction plant may primarily consist of methane and nitrogen, with nitrogen being separated within the liquefaction facility. Therefore, the FPSO provides high-quality feed gas to the FLNG, essentially free of impurities that could cause freezing or corrosion during the cryogenic liquefaction process [35] [52].

The rise of FLNG models that focus solely on liquefaction marks a key shift in the FLNG market. This strategy enables developers to separate liquefaction from the geological and operational risks associated with upstream exploration and production. By utilizing existing pipeline infrastructure, these projects can reach the market faster, have lower initial investment costs, and tap into various gas sources, including shale gas. This helps reduce upstream project risks and provides more commercial flexibility. In the past, FLNGs were built to operate in an integrated way, handling both extraction and liquefaction directly at the offshore field.

Despite the above description of FLNG projects with the exclusive function of liquefying natural gas, this study becomes more specific by proposing that this structure be located offshore, connected to an FPSO unit rather than a pipeline network for its gas supply. No examples of this specific type of project have been found worldwide, even though authors have mentioned the subject [53]-[59], thus making this project an innovative and unique idea.

The closest project to the proposal of this work would be the FLNG Gimi, within the Greater Tortue Ahmeyim (GTA) project, with a capacity to produce up to 2.7 MTPA [60]. However, this platform, despite being referred to as "offshore," is situated 10 kilometers from the coast on the maritime border between Mauritania and Senegal in Africa. The project's FPSO, which pre-processes the gas before sending it to the FLNG, is approximately 40 kilometers offshore, supplying the FLNG via a subsea pipeline on the ocean floor. Specialized LNG carriers transport LNG to eliminate the need for long pipelines to the coast [61].

Speaking more about this project, as it represents the closest configuration to the proposal in this work, this vessel was converted from an LNG carrier built in 1976, with the conversion to FLNG occurring in 2023. The first LNG production was achieved in 2025. In terms of costs, the Golar Gimi has an annual EBITDA potential of approximately US$215 million, a Moss-type carrier with a 4-module plant externally aggregated [62]. There is no explicit CAPEX for the initial Gimi conversion. However, the cost of an evolved design (MK II FLNG), which is an evolution of the Gimi, is approximately US$600 per ton of liquefaction capacity, with a total budget of US$2.2 billion for the conversion [35] [52] [63].

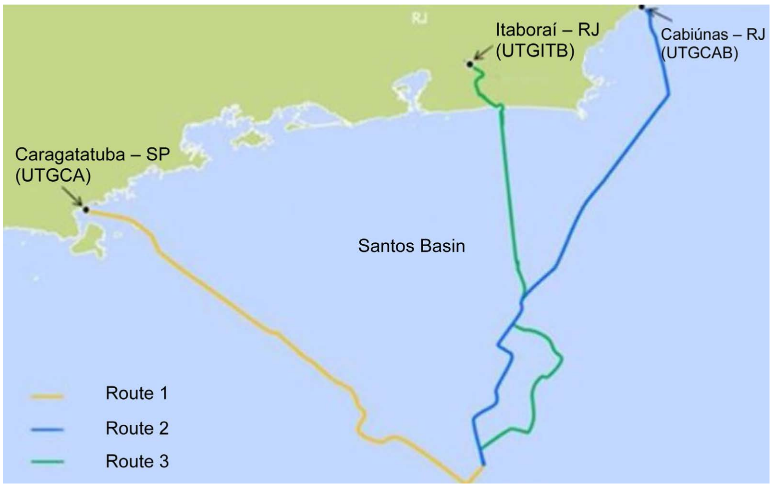
4. FLNG as a Replacement for Brazilian Gas Pipelines

There are several options for gas transportation, including pipelines and the LNG method, which are primarily used for exporting natural gas. Recently, the use of small LNG units with production capacities of up to 1 MTPA has become more common in the LNG industry, often deployed offshore on floating platforms [55] [57] [58].

In the Brazilian pre-salt FPSO projects, it was planned that the off-take pipelines would transport the produced natural gas to the Brazilian coast. These pipelines were envisioned to play a key role in transporting pre-salt gas, with Rota 3 being the most important pre-salt gas offtake pipeline in Brazil. It has a capacity of 18 million cubic meters per day and is scheduled to begin operations in 2025. Rota 3 was designed to connect the Tupi, Búzios, and Tambuatá fields directly to the GasLub processing unit in Itaboraí, Rio de Janeiro. Despite its importance, the project experienced notable delays. It was originally expected to be completed in 2019, but it did not enter operation until the first half of 2025 [31].

Brazil's NG production from the pre-salt in an offshore environment, up to 500 km from the mainland and at a depth of approximately 5 km, is primarily based in the Campos and Santos Basins. Until then, all this production was brought for domestic consumption and monetized through pipelines that transport the hydrocarbon to the UPGNs on the Brazilian coast. Investment in these pipelines presented significant construction challenges and environmental concerns, as they operate at great depths and encounter substantial variations in underwater terrain.

As shown in **Figure 2**, two routes are currently in operation for utilizing pre-salt gas. Route 1 has been operating since 2011 with a capacity of 10 million m^3/day, with a delivery point at the UPGN in Caraguatatuba, São Paulo, and Route 2 has been operating since 2016, with a capacity to transport up to 16 million m^3/day, with a delivery point in Cabiúna, Rio de Janeiro. Route 2 has already been approved for expansion by the ANP, and once implemented, it will have an additional capacity of 20 million m^3 per day. In addition to these routes, a new route, designated as Route 3, with a capacity of 18 million m^3/day, is currently under construction. It will have its delivery point in Maricá, Rio de Janeiro, and will be connected via a land pipeline in Itaboraí.



Source: Extracted from [64].

Figure 2. Brazil's pre-salt pipelines.

There are studies for a fourth route to serve the Santos Basin up to the city of Cubatão in São Paulo, thus supplying the large consumer center of the state of São Paulo. The company Cosan is studying this project.

The existing pipeline infrastructure can function and operate, transporting NG volumes from different agents until it reaches its installed capacity. It is estimated that the limit for transporting NG from the Pre-Salt, considering only the existing and under-construction infrastructure, will be reached in 2026, based on the reference scenario of the PDE 2029 [65].

According to [66], additional volumes to the existing and upcoming capacity will depend on investment decisions by the agents that can be monetized. Several monetization options have been examined, with transportation pipelines being just one option. Other options include transporting compressed natural gas (CNG), LNG, or liquid fuels. However, it is essential to note that these alternatives necessitate technical, economic, and socio-environmental analyses for each specific case. Not all of them may be suitable for every project.

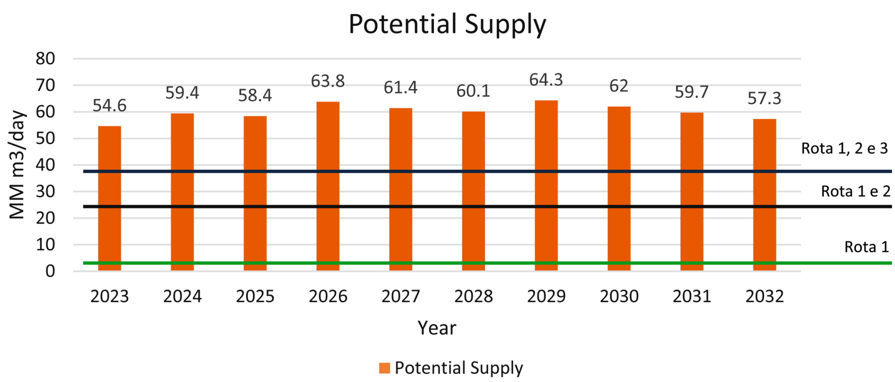
The pre-salt polygon is a vast area of approximately 150,000 km^2, encompassing the Santos and Campos basins. Fields in this region are characterized by deep waters, which necessitate the construction of very long and technically complex offshore pipelines. Studies by EPE frequently analyze the economic viability of gas monetization based on distance from the coast, highlighting the significant cost implications of long-distance ultra-deepwater connections [28]. Furthermore, exclusive pipeline sections for each platform begin to be underutilized as wells naturally deplete.

Historical delays, such as those experienced by Rota 3, have directly impacted the availability of gas. The fact that the Rota 1 UPGN cannot adequately process pre-salt gas without blending it [10]—to achieve a phase blend that meets the initial project requirements of this UPGN—highlights that onshore processing capabilities and gas specifications are as crucial as offshore collection. This demonstrates that the system is a tightly coupled network, where a weakness in one part can propagate and compromise the efficiency and profitability of the entire gas monetization effort, emphasizing the need for integrated planning and execution.

An eventual reduction in gas reinjection levels in the pre-salt polygon automatically necessitates gas flow to the continent. This can occur either via the existing offtake routes, which are limited to a maximum capacity of 44 million m^3/day (assuming all connected fields feed them), or through an alternative mode such as LNG liquefaction and transport via LNG carriers. The latter offers flexible sizing to meet the needs of gas transportation.

In various projected scenarios, gas production surpasses natural gas offloading capacity, as shown in **Figure 3**. Thus, the current offloading capacity is insufficient to handle the full technical production potential of pre-salt gas.

The logistics process involving LNG must be adapted to the market demand in which it will operate, with the goal of continuous optimization at all levels while maintaining operational reliability and safety. In the case of Brazil, when discussing scale, one must consider the market potential for adding new volumes to the national NG matrix. This, in turn, depends on industrial growth and electricity production, as both uses are the main drivers of Brazil's NG demand.



Source: [10].

Figure 3. Maximum potential supply after technical reinjection into platforms that can separate and export gas in the Pre-salt.

Brazilian Floating Storage Regasification Units

To expand the production of NG from the pre-salt and thus increase the viability of offshore platforms through the monetization of discoveries not covered by Routes 1, 2, and 3, the option of transforming NG into LNG on offshore platforms and transporting it to regasification terminals on the coast is shown on the map in **Figure 4**.

Source: Prepared by authors (2025).

Figure 4. Most prominent Brazilian LNG terminals in operation and planned.

This LNG can also be exported to any LNG (or NG) consuming country by being equipped with a liquefaction terminal. In this way, the opportunities and possibilities increase, bringing the commercial value of LNG to the global market as a reference for the feasibility study of these projects.

The FSRU was first developed in 2005, as pointed out by [67] and [68]. It is originally a reused LNG tanker ship, modified into a floating dock terminal with some process equipment modifications. The FSRU is responsible for receiving and unloading LNG while ensuring safe mooring and operational delivery. Currently, FSRU storage capacities range from 30,000 m^3 up to 200,000 m^3 as described in [69].

According to [70], by the end of 2021, the global fleet consisted of approximately 700 LNG tankers, with 48 of these operating FSRUs worldwide, representing an 11% increase compared to the previous year. Meanwhile, the LNG market grew by 4.3% [71]. An FSRU vessel can be built from an existing LNG tanker through a transformation process that includes the addition of transshipment, regasification equipment, and mooring systems.

The financial viability and resulting profitability are the most important decision factors when choosing the appropriate type to be used, as shown in **Table 2**, which summarizes a comparative study between the CAPEX required for classic onshore terminals and FSRUs with a capacity of 3 MTPA. The comparison shows a cost difference of 35% in favor of the FSRU. Regarding operational costs, they range between $20,000 and $45,000 per day for FSRUs, compared to a range of

$20,000 to $40,000 per day for onshore terminals [72].

Table 2. Required CAPEX comparison between an LNG terminal and FSRU (3 MTPA).

Component	LNG Terminal	FSRU
Dock including piping	USD 60 million	USD 60 million
Unloading lines	USD 100 million	Not applicable
Tanks 1 × 180,000 m^3	USD 85 million	On FSRU
FSRU vessel	Not applicable	USD 250 million
Process equipment	USD 130 million	Na FSRU
Utilities	USD 60 million	Not applicable
Onshore infrastructure	Not applicable	USD 30 million
Land fees and other charges	USD 125 million	USD 20 million
Total	USD 560 million	USD 360 million

Source: [72].

Modularity is another key benefit of the FSRU, making it particularly vital for small or developing markets, such as the Brazilian market. According to [73], when evaluating the needs of an onshore terminal, selecting a suitable port with stable mooring conditions and favorable weather is necessary. Conversely, the FSRU requires minimal land space and provides flexibility for potential relocation. Regarding the construction and delivery timeline, an FSRU can be delivered more quickly than an onshore terminal, which involves a longer civil works schedule in a coastal area, resulting in higher costs and increased construction risks [74], noted that the FSRU can be considered safer because it is built in a controlled shipyard, rather than constructed temporarily in a remote location.

[68] also mentioned that FSRU ship buyers can choose from various leasing options to initiate operations for a specified period. Depending on the business model, leasing is typically more cost-effective than purchasing. This provides quicker access to LNG for emerging countries entering the LNG market.

Another option that should not be forgotten, in a country like Brazil, where natural gas has not yet advanced much inland, would be the construction of onshore cryogenic storage tanks from which, in addition to gasification to pipelines, trucks and isotanks could be supplied, enabling the advance into the interior and forming a consumption matrix that would make future gas pipelines viable.

5. Economic and Financial Modeling and Analysis of the Use of an ssm-FLNG—Case Study: Búzios Field of the Brazil-Ian Pre-Salt

The Búzios field in the Brazilian pre-salt is the largest oil and gas field in Brazil, with production projections of up to 2 million barrels per day (bpd) and colossal volumes of associated natural gas [75]. The efficient monetization of this gas is a strategic imperative, especially given the potential saturation of existing and planned pipeline infrastructure.

This study presents an economic-financial model, developed in spreadsheets, to assess the viability of an offshore ssm-FLNG unit, focusing on monetizing the gas.

This tool enables the economic and financial evaluation of the proposed ssm-FLNG, a small-scale, modular floating platform for natural gas processing and LNG generation. The modeling assumes that this FLNG will receive natural gas with a purity level suitable for liquefaction, with all pre-processing performed by an adjacent FPSO. The oil and gas production data for the Búzios FPSOs used in this modeling are obtained from the Environmental Impact Study/Environmental Impact Report (EIA/RIMA) prepared by Petrobras for [76]-[80], ensuring a robust and regulatorily validated database, as well as from actual production data available on the ANP's production dashboard [81].

This study aims to develop a modeling tool that allows scenario simulations by changing input data and adjusting assumptions. The main challenge lies in collecting data, such as the commercial value of gas at an offshore FPSO wellhead, as well as CAPEX and OPEX figures from both domestic and international market players. This challenge led to the use of assumptions based on literature references, which may not fully reflect market reality. It is important to recognize that this information is often not disclosed by companies due to its sensitive nature, including commercial strategies and trade secrets. Given this limitation, this work focuses on developing a modeling framework to simulate potential value ranges.

In a discounted cash flow analysis, the starting point of the methodology usually involves gathering operational assumptions, revenues, costs, investments, and taxes. Using these elements, at various levels of detail, financial statements are estimated until the end of the project's useful life. This approach produces summarized results in concepts widely recognized in finance, such as Net Present Value (NPV), revenue, among others.

5.1. Modeling and Simulation Assumptions

To perform the simulations via modeling, we used oil and gas production data from IBAMA/Petrobras [76]-[80] along with actual production data from the Búzios fields available on the ANP dashboards [81]. Additionally, a series of assumptions was adopted, as shown in **Table 3**.

Table 4 details the assumptions that remained constant and were adopted as fixed across all simulated scenarios, as well as those that were not considered in the simulations.

The limitations of this work include the exclusion of simulations and analyses of the scope and costs of chartering LNG vessels, the need for any type of insurance, and the costs of regasification fees at the destination FSRU, both in Brazil and elsewhere. Therefore, the analysis is limited to the delivery of LNG in international waters. Future work suggests analyzing and simulating the delivery of this LNG to consumer markets.

Given the complexity of Brazilian tax regimes and the possibility of tax regimes that could be applied, this work focused on similarities and the operational results of the proposed solution, with the limitation being the economic results before tax costs and royalty payments. This limitation was established due to the complexity of Brazilian tax issues, which could detract from the main focus of this work. Including a tax analysis of the results of this work could be a suggestion for future work.

Table 3. Assumptions adopted for modeling and simulation at each stage.

Stage	Stage 1 100% Gas and CO_2 Reinjection (No Gas Production)	Stage 2 20% Reinjection (80% Production) of NG	Stage 3 20% Reinjection (80% Production) with FLNG	Stage 4 20% Reinjection (80% Production) with s-FLN
Reinjection	100% (does not produce NG)		80% of production, as proposed by [82]	
Natural gas and oil production data (Annual data)	Ibama/ Original Petrobras (all reinjected natural gas) From 2016 to 2041 (26 years) Average Oil: 0.052 million bbl/day Average gas: 86 million scf/day		Eighty percent of raw gas Discounted CO_2 according to the percentage of each well Discounted natural gas used for internal fuel in the FPSO (33%) [76]-[81]	
CAPEX	CAPEX for natural gas treatment on the FPSO of USD 4 billion/million bbl. Considered only for 6 of the 12 platforms, as 6 already have this infrastructure in place. (Authors' estimate)	To process the NG and deliver purified fuel (+10% of FPSO CAPEX) (authors' estimate)	FLNG 600 million USD/TON (Gimi FLNG) [35]	SSFLNG: (+5% over LNG) (authors' estimate)
ABEX (abandonment costs)	ABEX for NG treatment on the FPSO of 7% of the total CAPEX divided by the last 10 years of operations (authors' estimate)		There is no abandonment cost, as it is mobile and can be used in another project	
LNG Module Size	No processing due to not having received GN	Modular plans of 0.5 MTPA [37]		Used s-LNG
S-LNG Module Size	No processing due to not having received GN	Used LNG and not S-LNG		Modular plans of 0.07 MTPA [37]
NG value	GN was not delivered	3.31 USD/million MBTU Natural Gas (NYM) 23/05/25 Adjusted annually for US inflation at 2% per year		No natural gas was delivered, only LNG
LNG world market value—US LNG Export—Mar/25—source EIA	It was not produced		8.88 USD/million MBTU—March/25 [83] Maximum: 16.72 (Sep/22) in the last 5 years Minimum: 4.74 (Apr/22) in the last 5 years	

Source: Author (2025).

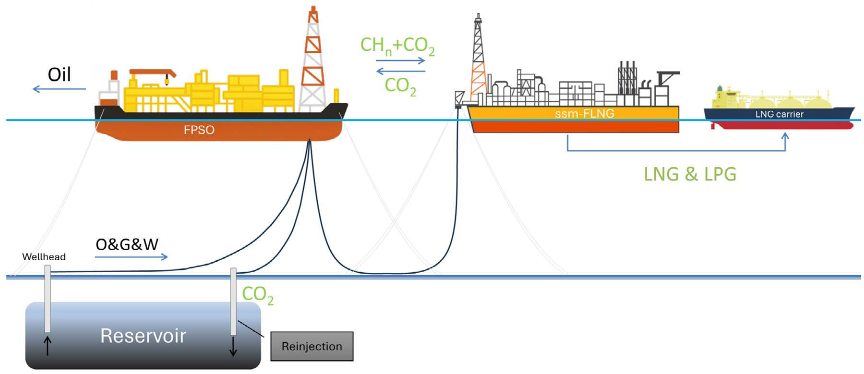
Table 4. Fixed assumptions adopted for the modeling and simulation of scenarios.

Assumption	Considerations in the modeling of this work
Oil value	Oil production was not considered in the calculations of these simulations
Value of raw gas at the wellhead	Adopted USD 2 / million MBTU [84] Below USD 2,86 / million MBTU [8]
OPEX	OPEX for natural gas treatment on the FPSO is 3% of the total CAPEX, divided over the first 10 years of operation. (authors' estimate)
Losses in the NG treatment process	5% (authors' estimate)
FLNG treatment process losses	5% (authors' estimate)
SS-FLNG treatment process losses	5% (authors' estimate)
CO_2 (not varied among scenarios)	Discounted CO_2 according to the percentage of each well
GOR (not varied among scenarios)	Values resulting from oil and gas production predicted in the Petrobras/Ibama EIA/RIMA [76]-[80]
EOR (not varied among scenarios)	Not considered in the study
WAG (not varied among scenarios)	Not considered in the study
NG consumption as internal fuel in the FPSO (%) (Not varied among scenarios)	33% (authors' estimate)
Consumption of NG as internal fuel in FLNG (%)	15% (authors' estimate)
Calorific value of LNG	2.0 million MBTU/m^3 (authors' estimate)
Calorific value of natural gas/Gross Calorific Value (GCV)	9400 kcal/m^3 (authors' estimate)
Utilization factor of LNG and SS-LNG modules	maximum of 87% and a minimum of 33.33% (authors' estimate)
Gas liquids (volume)	Analysis was not considered, as it is known in the literature that production is low and complexity is high compared to the required CAPEX
Social Contribution	Not considered in the study
Income tax	Not considered in the study
Royalties	Not considered in the study
R&D Assignment	Not considered in the study
Interest	12% (authors' estimate)
Financial variables such as depreciation and amortization	Not considered in the study
American Inflation	2% (authors' estimate)
Other NG logistics costs, in addition to those discussed here	Not considered in the study

Source: Author, 2025.

5.2. Method and Stages of Simulation Performed

The method used for modeling and consequently the calculations used in the simulation translate the process of natural gas delivered from the FPSO to the ssm-FLNG as demonstrated in the drawing of the ships side by side, as shown in **Figure 5** and represented by the diagram in **Figure 6**.

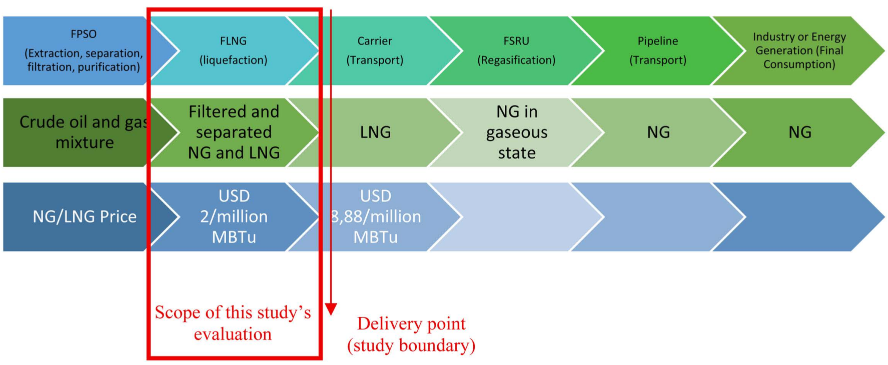


Source: Author (2025).

Figure 5. The export process of the rich hydrocarbon line to ssm-FLNG, and then the liquefied gas export operation using LNG carriers.

The stages of this process include the delivery of gas volumes that were not reinjected by the FPSO, discounting losses in the CO_2 separation process and natural gas filtration, making it suitable and ready for liquefaction. After this, the natural gas was considered delivered to ssm-FLNG through specific hoses. The ssm-FLNG was designed with several small-scale modules to process the natural gas and liquefy it into LNG, as well as separate the LPG so that both can be delivered to tankers and sold, as a traditional process.

Figure 6 shows the flow where the FPSO unit directly supplies NG to the FLNG unit. The diagram displays, in the first section, the process flow from the well to the final consumer. Below that, in the second row, the products being processed at each stage are listed. In the last row, the values considered for these products are presented.



Source: Author (2025).

Figure 6. Natural gas flowchart from its extraction by the FPSO to consumption by the end customer.

Some key observations differentiate the two processes described above. When the FPSO supplies NG to the FLNG, it is assumed that all necessary processing of the raw gas into primarily methane (CH_4), free of impurities and other components such as gas liquids, has already been completed by the FPSO. Currently, only some FPSOs in the Búzios field have these characteristics, known as Theoretical Type 1 FPSOs [85]. For the P-80, P-82, P-83, and the future Búzios 12 FPSOs, the Theoretical Type 1 FPSO configuration will be used to enable gas export and provide access to the natural gas consumer market, as they are expected to connect to the existing gas pipeline network.

5.3. CAPEX, Abandonment, and Decommissioning (ABEX) for Small-Scale Modular FLNG

Liquefaction costs vary among projects, but on average, they have increased significantly over the last decade. Several projects have seen cost increases of 30% to 50% compared to initial estimates. Construction delays have also impacted these costs.

Factors determining liquefaction costs include location, capacity, the liquefaction process itself, and the choice of technologies such as the compressor engine, storage, availability of skilled labor, and regulatory and licensing requirements. Bulk materials, including steel, are major cost components across projects, while gas processing needs vary depending on the upstream resource. Depending on different locations, the gas produced can exhibit different exploration characteristics, just as the resulting NG specifications can also vary from market to market. For example, the dry gas that most U.S. projects will obtain will limit the need for gas treatment infrastructure, which typically includes acid gas, NGL, and mercury removal, in addition to dehydration. In Brazil, on the other hand, pre-salt gas production requires cumbersome treatment for CO_2 separation and NG purification, as these reserves exhibit characteristics of a strong CO_2 presence.

The International Gas Union notes that average unit liquefaction costs rose from US$404/ton between 2000 and 2008 to US$1,005/ton between 2009 and 2017. Projects in the Atlantic Basin showed a smaller increase in liquefaction costs, averaging US$1,011/ton between 2009 and 2017, versus US$480/ton between 2000 and 2008 [86].

Vessel conversions typically present lower costs compared to purpose-built FLNG proposals [86]. The example already cited in this work, the FLNG Gimi, which had a CAPEX of around US$600 per ton of liquefaction capacity, with a total budget of US$2.2 billion for the conversion, shows conversion values that are lower than those for new platforms. It is also important to consider that Gimi is not equipped with a raw NG treatment system, which is similar to the proposal of this study.

The FLNG CAPEX is a substantial initial investment, but it often proves to be competitive or even lower than that of large onshore LNG plants. Values can vary significantly depending on the unit's capacity, the complexity of the project (including the site's meteorological and oceanographic conditions), the type of design (new build or conversion), and the construction location. Generally, FLNGs have the following characteristics:

- FLNG projects require an initial investment of several billion dollars.
- In terms of cost per ton of annual capacity, industry reports (Wood Mackenzie, 2021) indicate that the average cost for FLNG and LNG projects has been around US$1400 per ton.
- For conversion designs (such as those for the Golar Gimi FLNG), costs can be as low as US$550 per ton to US$600 per ton.
- Newbuilds, such as those from Samsung Heavy Industries (SHI) and WOM, have been around US$750 per ton.

Some factors influence CAPEX, such as size and capacity (larger FLNGs with greater liquefaction capacity will have higher CAPEX), gas processing complexity (if the natural gas requires extensive treatment before liquefaction, e.g., removal of impurities, natural gas liquids, this will add costs), site conditions (adverse meteorological and oceanic conditions, such as high waves and strong currents, require more robust designs and complex mooring systems, increasing costs), construction type (converting an existing vessel, such as an LNG carrier, into an FLNG generally has lower CAPEX and a faster construction schedule than a new vessel), standardization (adopting standardized designs for the hull and processing units has the potential to significantly reduce CAPEX and the engineering, procurement, construction, installation, and commissioning schedule), and labor (the cost of labor in construction is also a relevant factor). Several factors affect CAPEX; for instance, larger FLNGs with greater liquefaction capacities usually have higher capital expenditures. Additionally, the complexity of gas processing significantly impacts costs; extensive treatment of natural gas before liquefaction, such as impurity removal and extraction of natural gas liquids, adds to the overall expenses. Site conditions are also important, as challenging meteorological and oceanographic factors, such as high waves and strong currents, require more robust designs and complex mooring systems, further increasing costs.

Furthermore, the choice of construction type influences costs. Converting an existing vessel, such as an LNG carrier, into an FLNG generally results in lower CAPEX and shorter construction timelines compared to building a new vessel from scratch. Standardizing designs for hulls and processing units can help cut both CAPEX and the EPCIC schedule. Lastly, labor costs during construction are a key factor that can greatly affect the overall budget.

For the simulations in this study, a CAPEX reference of US$600 per ton of LNG processed was adopted, aligning with the project proximity of the Gimi FLNG, as previously presented.

Additionally, ABEX for the FPSO platform accounted for 7% of the total CAPEX, with the allocation divided equally over the last 10 years of operation. However, ABEX costs were not included for the simulations of the FLNG and ssm-FLNG structures. This is because these platforms are considered generic and can be utilized in other projects worldwide.

5.4. OPEX of an FLNG Structure

The OPEX of an FLNG unit encompasses daily operational costs, maintenance, personnel, fuel, insurance, and other expenses necessary to keep the facility running. While the initial CAPEX might be lower than that of an onshore plant, the OPEX of an FLNG can be higher due to its offshore nature and the complexity of operations. The typical operating cost for FLNGs, as well as FPSOs, is approximately 3% to 5%. In this study, a premise of 3% per year on the total CAPEX of the structure considered in the simulation was adopted.

Several factors influence OPEX, including availability and reliability, which are vital for operational efficiency. Onshore LNG plants usually reach about 98% uptime, while FLNG facilities often operate at roughly 90%. This lower uptime can result in decreased production and increased costs per unit of LNG. Maintaining offshore equipment is inherently complex and costly, especially considering the remote and harsh environments where these facilities are located. Insurance costs for offshore assets are also high and tend to rise over time. Additionally, running an FLNG requires a highly skilled team, with significant expenses for salaries, accommodations, and offshore logistics. Energy use during the liquefaction process accounts for a substantial part of operational expenses. Furthermore, severe weather can greatly affect operations, leading to higher safety and logistics costs. Overall, these interconnected factors greatly influence the operational costs and efficiency of FLNG plant operations.

Operational costs for offshore platforms are naturally higher than for onshore facilities. This is because of the complexities of maritime operations, specialized logistics (such as personnel and supply transportation by helicopter), and the need for highly skilled labor, which commands higher wages [87].

For technologies developed explicitly for CO_2 removal, such as membrane separation, the operational cost is estimated at 5% annually of the associated CAPEX. This cost is directly allocated to natural gas. In broader EPE studies, OPEX and ABEX are generally estimated at 6% (half fixed and half variable) and 7% of the total CAPEX, respectively. The transparency of these operational costs is considered vital for establishing a fair and reasonable remuneration model for infrastructure, thereby fostering a more competitive market [8].

5.5. Indicators Resulting from Simulations

The main economic-financial metrics evaluated include:

- Revenue: Represents the total value of sales resulting from the GN or LNG.
- Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA): Measures a company's operational cash generation capability prior to interest, taxes, depreciation, and amortization.
- Net Present Value (NPV): Measures the value added by the project by discounting all future cash flows to the present.

6. Results

This chapter presents and analyzes the results of the economic evaluation of the ssm-FLNG configuration, obtained through a simulation model. The analysis highlights the positive results in terms of revenue, NPV, and EBITDA, and examines the impact of the input assumptions. Given the empirical nature of the research, presenting the data and elucidating the connections between them is crucial to offer a concise overview of the findings.

The economic evaluation was conducted for a specific scenario, whose input data and assumptions were thoroughly described in previous sections of the report. This contextualization is crucial for interpreting the results, as the viability of natural gas projects in remote areas or those lacking adequate onshore infrastructure poses a significant challenge, which this study aims to address.

The simulation results demonstrate that the ssm-FLNG configuration added positive economic value, as evidenced by the economic viability indicators. The NPV and EBITDA were favorable, indicating the project's attractiveness under the adopted assumptions.

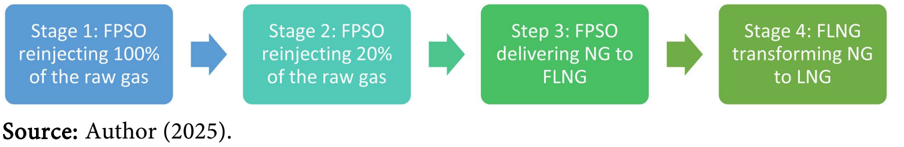
The in-depth analysis of the financial indicators provides a robust understanding of the ssm-FLNG configuration's economic performance.

Given the scale of the Búzios field and the global demand for LNG, the modeling demonstrated a positive NPV for the FLNG unit. The FLNG's specialization in liquefaction, receiving already cleaned gas from the FPSO, optimizes the CAPEX and OPEX of the FLNG unit, contributing to greater economic attractiveness. The ability to monetize Búzios' associated gas, which might otherwise be flared or reinjected, confers additional strategic value to the project, aligning it with Brazil's energy security and resource optimization goals.

Annual production figures were simulated without considering daily or monthly variations or any monthly seasonality.

The graphs presented in the report, which illustrate each indicator's contribution to the outcome, highlight the key factors driving the economic viability of the ssm-FLNG project. Analyzing these graphs identified how various components, such as CAPEX, OPEX, and revenues from gas and condensate, affect the positive NPV and EBITDA results.

To understand the results, it is essential to comprehend the impact of the assumptions at each stage, as detailed below. The flow at each stage is described, with the contribution of Figure 7.



Source: Author (2025).

Figure 7. The process is divided into stages, from raw gas processing to LNG transformation.

This stage implies no natural gas production and only oil production.

Therefore, this stage was not considered or modeled within this study. It is important to understand that these costs and results are already part of the FPSO's oil exploration process, without contributing to the monetization of natural gas, which is the objective of this work.

1st Stage: FPSO Processing Crude Oil and Gas, Reinjecting 100% of the Gas

This stage involves only oil production, with no NG production. Therefore, it was neither considered nor modeled in this study. It is included here to clarify that these costs and results are part of the FPSO's oil exploration process and do not contribute to NG monetization, which is the goal of this work.

In this stage, the assumptions and estimates were treated as follows:

- It processes only oil, reinjecting all crude gas produced without gas treatment. Consequently, the gas result is zero (no revenue and no EBITDA generated).
- The CAPEX refers only to the traditional platform for oil processing (USD 4000 million/million bbl or USD 4000/bbl—estimate), totaling USD 50 billion for the 12 Búzios FPSOs.
- CAPEX is considered to be divided over the first 10 years.
- ABEX is considered to be 22% of the total CAPEX, divided over the last 10 years.
- OPEX is considered to be 3% - 5% per year of the total CAPEX.

2nd Stage: FPSO Processing Crude Oil and Gas, Reinjecting 20%

In this stage, we considered the sale of processed NG from the FPSO, though not as LNG, and without accounting for transport costs to the mainland. Crude gas would be reinjected at a 20% ratio before any separation, still containing CO_2 and all other contaminants present during extraction.

In this stage, the assumptions were treated as:

- Eighty percent of crude gas processing is assumed, with deductions for CO_2 (specific to each FPSO) and internal consumption for fuel production (33%).
- The FPSO will process crude gas to achieve a purity suitable for liquefaction in the FLNG.
- Process losses on NG were estimated at 5%.
- Dedicated CAPEX for NG processing is set at 10% of the FPSO's CAPEX (estimate). This totals the six Búzios FPSOs. This investment applies only to the six platforms that are not of the "Theoretical Type 1" FPSO, as previously explained, since the six Theoretical Type 1 FPSOs in the Búzios field are already equipped with the necessary structure to process NG.
- Only revenue generated by the aggregated NG is considered (at global market prices of USD 3.31/million MBTU, NYMEX May/25, adjusted annually by U.S. inflation of 2% per year).
- The value paid for NG at the wellhead (at the FPSO) is deducted (at USD 2/million MBTU [84], adjusted annually by U.S. inflation of 2% per year).

3rd Stage: FPSO Processing Crude Oil and Gas, Reinjecting 20%, and Delivering the Resulting NG to the FLNG

In this stage, we deducted the values for reinjection, fuel, and CO_2. The presence of NGL was not considered, as it typically accounts for less than 1% to 3%, nor were other impurities accounted for. The gas delivered to the FLNG is considered ready for liquefaction and priced at the wellhead gas value as per the established assumptions table (having already been processed in the previous stage, with all its associated costs, including the wellhead gas cost).

The large-scale FLNG is considered to have 0.2 MTPA modules (author's estimate), with a minimum utilization factor of 33.33% and a maximum of 87% (author's estimate). As such, the 12 FPSOs reached a maximum utilization of 20 modules in the years 2029 and 2030 (14th and 15th years). This translates to a maximum of 4 MTPA on a single platform.

Additionally, 32% of the gas was considered for liquefaction fuel use, with an estimated 15% loss in the liquefaction process (authors' estimates).

In this stage, the assumptions were treated as follows:

- Losses in the liquefaction process were 5% (estimated).
- CAPEX, which is dedicated to processing NGL, was set at US$900/ton of LNG, following the Gimi project (Black & Veatch, 2025). This totals US$7.2 billion for all 12 Búzios FPSOs.
- Revenue generated from LNG (at global market prices of US$8.88/million MBTU, adjusted annually by U.S. inflation of 2% per year) without considering transport costs to the final destination.

4th Stage: Transforming FLNG into ssm-FLNG

The ssm-FLNG considers 0.07 MTPA modules (authors' estimate), with a minimum utilization factor of 33.33% and a maximum of 87% (authors' estimate).

Consequently, the 12 FPSOs will reach a maximum utilization of 64 modules in the years 2029 and 2030 (14th and 15th years). This means a maximum of 5.18 MTPA. This represents an increase in processing from 4 MTPA to 4.48 MTPA (a 12% increase).

Additionally, 32% of the gas was considered for liquefaction fuel use, with an estimated 15% loss in the liquefaction process (authors' estimates).

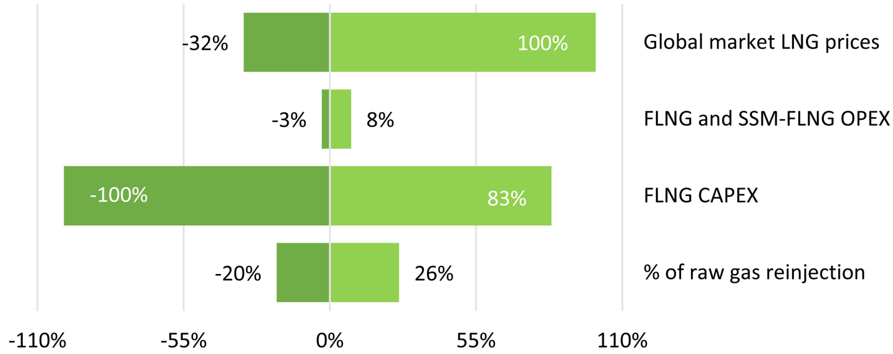
In this stage, the assumptions were treated as:

- Losses in the liquefaction process were estimated at 95%.
- CAPEX, which is dedicated to processing NGL, is set at US$900/ton of LNG, following the Gimi project (Black & Veatch, 2025). This totals US$22 billion for all 12 Búzios FPSOs.
- Revenue generated from LNG sales (at global market prices of US$8.88/million MBTU, adjusted annually by U.S. inflation of 2% per year) without considering transport costs to the destination.

6.1. Simulation of Extreme Scenarios through the Limits of the Main Variables

To evaluate attractive ranges that yield positive results, this study simulated the extreme limits of certain variables while maintaining the evaluated indicators at a level attractive enough to justify the use of ssm-FLNG platforms.

The assumptions from Figure 8 were chosen for scenario simulations, yielding the results shown in the table. It is essential to note that these limits maintain attractive and positive results, with each assumption being varied one at a time.



Source: Author (2025).

Figure 8. Sensitivity analysis of the main variables.

This figure uses the variables FLNG CAPEX, percentage of reinjection of raw gas, OPEX (considering the percentage of total CAPEX applied per year) or price of LNG in the global market that have a representative influence on the indicators analyzed in this work, in order to take these variables to the extreme limits, both lower and upper, without making the work indicators unviable, whether jointly or individually. The variables for the percentage of CAPEX adopted as annual OPEX cost and the reinjection percentage are measured in this work as percentages, so in this graph, they present the lower limit as the limit where they would result in a zero absolute value. The other two variables, such as the overall LNG value and FLNG CAPEX, are already in absolute financial values, meaning that their upper and lower limits reach the total percentage, depending on the case.

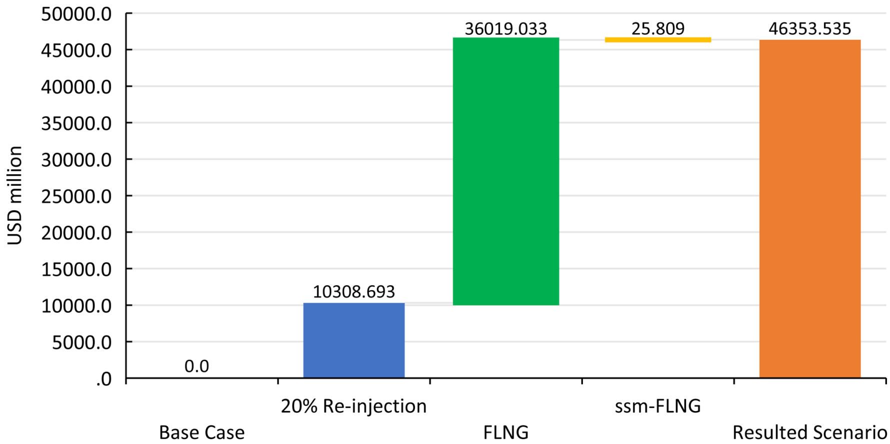
Analyzing Figure 8 above helps to overcome the difficulty of this work in obtaining real OPEX and CAPEX values for the analyzed structures. In other words, even without such values, this graph allows us to understand that within the FLNG structure's CAPEX range, extrapolating up to 83% of the value considered in this work, the proposed work is still viable. This also applies to the reinjection of raw gas from −20% to 26% beyond the values considered here, as well as to the other variables, each with its own outcome.

The resulting graphs below illustrate the contribution of each analyzed component to the overall revenue, NPV, and EBITDA, providing an aggregated view of their effect. This is presented as an additional contribution to the habitual oil production of the Búzios Field platforms during the production years from 2016 to 2055, covering 40 years of field production. Taxes and royalties on the calculated EBITDA were not considered.

The explanations, calculated results, and respective graphs are detailed in Sections 6.2, 6.3, and 6.4.

6.2. Revenue Added by LNG

Figure 9 illustrates the revenue contribution when considering platforms producing 80% of raw gas as NG, after CO_2 has been accounted for. This NG is then sold at the wellhead, where it is delivered to a hypothetical export pipeline or another transportation solution to a point where it can be commercialized. At this point, the solution proposed in this article would be applied via unification through an NG hub, connecting to an ssm-FLNG unit to be transformed into LNG and then commercialized by LNG carriers, both for the Brazilian market and the global LNG market, at global prices.



Source: Author (2025).

Figure 9. Analysis of revenue increase considering all Búzios fields over 40 years of operation.

Analyzing graph 9, first, the NG production process with 80% non-reinjection generates a total revenue (across the 12 Búzios FPSOs) of US$10.3 billion (over 40 years of operation).

Next, with the use of the FLNG platform to liquefy NG and sell it as LNG at global market prices, it generates a total revenue (across the 12 Búzios FPSOs) of US$46.3 billion (over 40 years of operation). Subtracting the result from the previous stage yields US$36 billion.

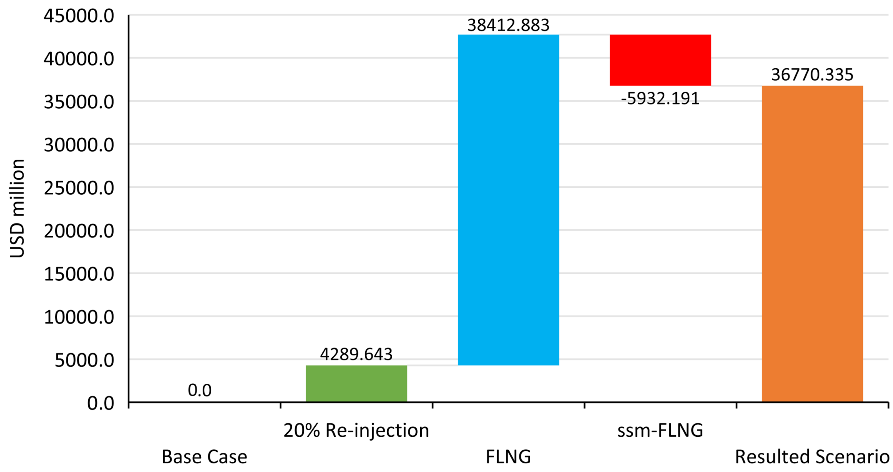
Finally, using the small-scale model, a total revenue (across the 12 Búzios FPSOs) of US$46.3 billion is generated (over 40 years of operation). Subtracting the previous stage yields US$0.026 billion (or US$26 million).

6.3. EBITDA

The EBITDA evaluation for the ssm-FLNG configuration yielded a positive value, as illustrated in **Figure 10**. EBITDA is an operational profitability metric that reflects a project's ability to generate cash from its core activities before considering interest, taxes, depreciation, and amortization. A positive EBITDA indicates the project's operational efficiency and its ability to generate gross profits from its operations.

While a positive EBITDA is a strong indicator that ssm-FLNG operations are profitable, it is important to understand its role in the broader financial context. It demonstrates the operation's gross cash generation capacity, which is essential for covering operational costs and, eventually, debt service. However, it is crucial to note that EBITDA does not incorporate the impact of taxes, financing interest, or asset depreciation, which are real expenses affecting net profit and final cash flow. Therefore, for a complete and accurate financial analysis, EBITDA should be evaluated in conjunction with NPV (Net Present Value).

Evaluating Figure 10, the production process on the FLNG generated an EBITDA of US$38 billion. With the use of small-scale units, there is a reduction of US$5.9 billion, resulting in a final aggregated result of US$32.1 billion.

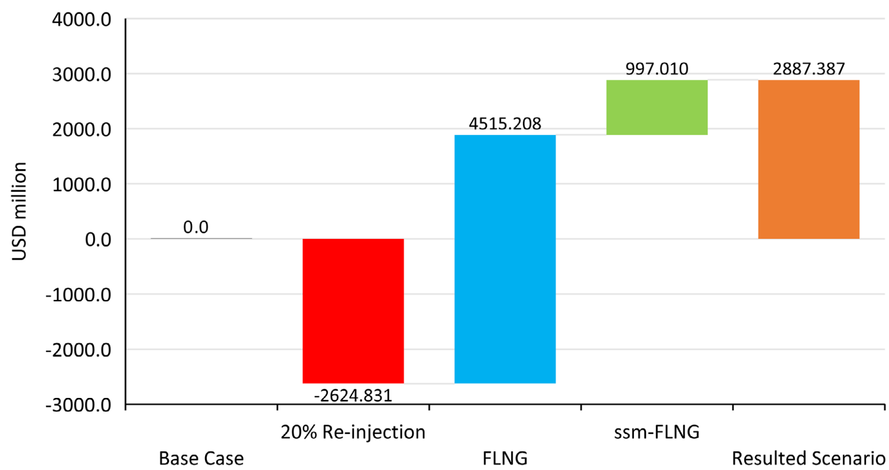


Source: Author (2025).

Figure 10. EBITDA analysis considering all Búzios Fields.

6.4. Net Present Value (NPV)

The calculated NPV for the ssm-FLNG configuration yielded a positive value, as shown in Figure 11. This outcome is a fundamental indicator of the project's economic attractiveness, as it means the present value of expected benefits exceeds the present value of total costs, generating a surplus that adds wealth to investors. Quantifying this added value is crucial for informed investment decision-making,



Source: Author (2025).

Figure 11. NPV analysis considering all Búzios fields.

especially in capital-intensive sectors like oil and gas. A positive NPV for the ssm-FLNG demonstrates that, under the study's assumptions, the project not only covers its costs and required rate of return but also creates excess value, which is a clear sign that the investment is financially advantageous.

Evaluating **Figure 11**, we first observe the behavior of the NG production process on the FPSO itself, which generated a negative cash flow (not yet discounted) of US$ −0.6 billion. When discounted at a 12% annual rate, it also yields a negative result of US$ −2.6 billion.

With the utilization of the FLNG, there is a discounted cash flow (at a 12% annual rate) of US$4.5 billion.

Finally, with the use of the ssm-FLNG, the discounted cash flow (at a 12% annual rate) results in a final value of US$2.8 billion.

7. Conclusions

Projections indicate continuing growth in the natural gas market for at least the next 25 years, ensuring global demand for this transitional energy source. The exploration and production of Brazil's natural gas reserves, whether in existing basins or the equatorial margin, will undoubtedly enable the monetization of this energy resource.

A distinct aspect of this work is the development of an economic modeling tool that transcends the evaluation of a specific case. This tool was designed to flexibly and adaptively assess the viability of ssm-FLNG structures. The tool represents a significant methodological contribution, offering a new means or an adaptation of existing techniques to conduct research and feasibility analyses of small-scale offshore FLNG structures. Its design allows it to be applied in diverse scenarios, with different data and assumptions, facilitating future and flexible evaluations of FLNG/FPSO projects.

The economic simulation conducted demonstrated that the ssm-FLNG configuration, under the assumptions of the evaluated scenario, presents positive and robust economic results, as evidenced by the NPV, IRR, and EBITDA indicators. These findings confirm that ssm-FLNG can be a cost-effective solution for offshore natural gas monetization.

The positive results of the ssm-FLNG economic evaluation have important practical implications for the oil and gas industry. The demonstrated viability indicates a promising path for developing associated gas fields in deep waters and remote areas, where building export infrastructure is either unfeasible or too expensive. ssm-FLNG's economic viability could directly influence investment choices and strategic planning for energy companies. If the solution proves reliable, it could serve as a competitive alternative to traditional methods, potentially accelerating the development of new projects and the monetization of gas assets that might previously have been considered marginal. This impacts capital allocation and encourages technological innovation in the sector.

In the theoretical realm, the study's conclusions align with existing knowledge on the economic evaluation of offshore energy projects. The results can support or expand theoretical models for cost optimization and value maximization in complex environments, providing empirical data to refine analytical frameworks. It is essential to acknowledge that the presented results are inherently dependent on the input data and assumptions employed in the simulated scenario.

Additionally, this work served as a case study for a specific situation. The generalization of results to other gas fields or operational conditions should be approached with caution, considering the market and regulatory differences of each new context. The cost-benefit relationship with FLNG facilities can help make LNG prices more competitive. By reducing infrastructure and transportation costs, FLNG projects can deliver LNG at a more competitive price in the global market. This economic benefit increases the overall competitiveness of LNG from FLNG compared to traditional onshore sources.

In conclusion, the economic considerations and accessibility of FLNG facilities contribute to the changing dynamics of LNG production occurring worldwide. From economic development and access to remote reserves to broader economic impacts on the global LNG market, FLNG emerges as a catalyst for innovation and economic efficiency in the energy sector. The economic benefits of FLNG extend beyond individual projects, contributing to the resilience, diversity, and accessibility of the global LNG market.

The primary difficulty lies in obtaining the value of gas at the wellhead of an FPSO, as well as CAPEX and OPEX values from both national and international market companies. Similarly, preparing a basic or indicative project to enable an equipment manufacturer to fully quote a desired structure also becomes costly.

It is also worth noting that this information is typically not disclosed by companies, as it encompasses commercial strategy and business secrets.

As suggestions for future work, some developments of this study could involve using the developed model for new simulations with stress scenarios to test assumptions. For example, simultaneously setting minimum global market FLNG prices while varying other representative variables with high sensitivity to the results, such as the CAPEX of FLNG structures, and potentially generating graphs showing the variation of more than one assumption. Another possibility and scenarios of simulations with analyses of the scope and costs of chartering LNG vessels, the need for any type of insurance, and the costs of regasification fees at the destination FSRU, both in Brazil and elsewhere, and scenarios including a tax analysis of the results of this work.

And finally, a suggestion would be to develop a strategy for utilizing only one, two, or three ssm-FLNG platforms to serve all 12 FPSOs in the Búzios field, according to each FPSO's production curve. Finally, as already discussed by market players and the Brazilian government, the use of a natural gas (NG) hub platform responsible for collecting all NG produced by various FPSOs, treating and processing it to achieve liquefaction-quality NG, and from that point, delivering it to the ssm-FLNG platform proposed in this work.

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Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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