Empresa de Pesquisa Energética

FINAL REPORT

DECARBONIZATION SCENARIOS FOR E&P

In compliance with CNPE Resolution No. 8/2024

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Public Value

EPE CONDUCTS STUDIES AND RESEARCH TO UNDERPIN THE FORMULATION, IMPLEMENTATION, AND EVALUATION OF BRAZILIAN ENERGY POLICY AND PLANNING. IN THIS CONTEXT, AND IN ACCORDANCE WITH RESOLUTION NO. 8/2024 OF THE NATIONAL ENERGY POLICY COUNCIL (CNPE), THE FINAL REPORT ON E&P DECARBONIZATION SCENARIOS ANALYZES THE OPPORTUNITIES AND CHALLENGES ASSOCIATED WITH DECARBONIZING OIL AND NATURAL GAS EXPLORATION AND PRODUCTION ACTIVITIES IN BRAZIL.

WITH THIS REPORT, EPE FOSTERS TRANSPARENCY AND REDUCES INFORMATION ASYMMETRY REGARDING ALTERNATIVES FOR EMISSION REDUCTIONS IN THE OIL AND GAS SECTOR. THE ANALYSIS TAKES INTO ACCOUNT ASPECTS SUCH AS GAS FLARING REDUCTION, THE USE OF RENEWABLE ENERGY SOURCES, THE OPTIMIZATION OF EXISTING INFRASTRUCTURE, AND THE IMPLEMENTATION OF CARBON CAPTURE TECHNOLOGIES. THE STUDY CONTRIBUTES TO PUBLIC POLICY FORMULATION THAT IS DATA-DRIVEN AND ALIGNED WITH BRAZIL'S NATIONAL COMMITMENTS TO ENERGY TRANSITION AND LONG-TERM SUSTAINABILITY.

IN ADDITION, THE REPORT SUPPORTS THE IDENTIFICATION OF EFFICIENT SHORT-, MEDIUM-, AND LONG-TERM STRATEGIES, ENSURING THAT DECISION-MAKING IS CONSISTENT WITH THE REGIONAL PARTICULARITIES OF EXPLORATION AND PRODUCTION ACTIVITIES. IN DOING SO, THE STUDY STRENGTHENS BRAZIL'S ABILITY TO MITIGATE EMISSIONS WHILE MAINTAINING ECONOMIC DEVELOPMENT AND REAFFIRMING ITS ROLE IN THE GLOBAL CLIMATE AGENDA.

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1. Background

This report was prepared in compliance with Resolution No. 8/2024, issued on August 26, by the National Council for Energy Policy (RCNPE 8/2024) , which establishes guidelines to promote the decarbonization of oil and natural gas exploration and production (E&P) activities in Brazil. The Energy Research Company (EPE), with support from the National Agency for Petroleum, Natural Gas and Biofuels (ANP) and Pré-Sal Petróleo S.A. (PPSA), was tasked with proposing measures to encourage decarbonization and with presenting decarbonization scenarios and their associated impacts to the CNPE within 180 (one hundred and eighty) days[1]. In addition to this document, the Fact Sheet *Emissions Reduction Technologies in Oil & Gas E&P* and the Slide Deck on *Proposals to Promote the Decarbonization of Oil and Gas E&P Activities* were also prepared and published, complementing the discussions and proposals presented herein.

The report is grounded in the recognition of the strategic importance of the oil and gas sector to the Brazilian economy, combined with the urgent need to reduce greenhouse gas (GHG) emissions amid the global climate emergency. The energy transition - aimed at gradually replacing fossil fuels with cleaner and more sustainable sources - must be pursued in a fair and inclusive manner, reconciling economic growth, job and income generation, social inclusion, and environmental stewardship.

Brazil already stands out for the composition of its energy matrix, with more than 49% of its energy supply derived from renewable sources and 89.2% of its electricity generated from renewables in 2023 (EPE, 2024e). Nonetheless, sectors such as industry and transportation, which are intensive in GHG emissions, continue to depend heavily on fossil fuels. Within this context, the oil and gas E&P sector plays a pivotal role in reducing emissions - particularly in a scenario of global energy transition. Brazil, with its highly renewable energy profile and a carbon footprint per barrel lower than the global average, is well positioned to act as a strategic player in the decarbonization of the energy sector, strengthening its competitiveness in the international market and contributing to a more equitable, efficient, and low-impact energy transition.

This study presents a range of scenarios and measures for decarbonizing oil and natural gas E&P activities, focusing on gas flaring reduction, the adoption of carbon capture technologies, the use of renewable sources, and the optimization of existing infrastructure. The objective is to provide a robust foundation for the development of public policies that promote emission reductions in the sector while supporting Brazil’s continued economic development and its contribution to global climate mitigation efforts.

Through this report, EPE seeks to offer a clear and comprehensive perspective on the opportunities and challenges of decarbonization in the E&P sector, contributing to the identification of effective short-, medium-, and long-term strategies. These strategies must be tailored to the specific conditions of E&P activities, reflecting their operational particularities - such as production environment, productivity, and asset maturity. In doing so, the study reinforces Brazil’s national commitment to the energy transition and to the achievement of long-term sustainability goals.

[1] We extend our gratitude to the National Agency for Petroleum, Natural Gas and Biofuels (ANP) and Pré-Sal Petróleo S.A. (PPSA), as well as the other directorates of EPE, for their participation and contributions to the discussions, which enabled us to achieve the results presented in this Report.

2. The E&P sector in Brazil

Brazil, the world's eighth-largest oil producer, recorded a production of approximately 3.402 million barrels of oil per day and 150 million cubic meters of natural gas per day in 2023, totaling an annual output of 1.585 billion barrels of oil equivalent. Repeating a trend observed over the past decade, most of the production was concentrated offshore, with pre-salt reservoirs accounting for 76.07% of national output and post-salt reservoirs ranking second, with a 19.03% share.

Onshore production represented less than 5% of the total volume produced in 2023 (ANP, 2024a). As of January 2024, Brazil had 268 producing oil and gas areas operated by 51 companies (ANP, 2024b). Although the Campos and Santos basins rank only third and fifth in terms of the number of producing fields, they are responsible for 18.84% and 75.62%, respectively, of total oil equivalent output.

Out of 34 sedimentary basins with minimum geological potential for oil and gas discoveries (EPE, 2023), only 15 currently host producing or developing fields. From a licensing perspective, by January 2025, 422 exploratory blocks were under contract with the National Agency for Petroleum, Natural Gas and Biofuels (ANP), over 66% of which were located onshore. The Potiguar, Recôncavo, and Alagoas basins alone accounted for nearly half of those blocks.

Present in all Brazilian macroeconomic regions and more than half of the states, oil and gas activities are vital to the national economy, with the sector representing nearly 10% of the country's industrial Gross Domestic Product (GDP) (IBP, 2024). The regional impact is particularly significant - ranging from direct and indirect job creation to royalty and tax collection, as well as investments in technology, innovation, and workforce training - especially associated with onshore production development. This relevance has been the focus of specific government initiatives, such as the Program for the Promotion and Revitalization of Oil and Natural Gas Exploration and Production Activities – Potencializa E&P (MME, 2024).

Beyond their economic importance, Brazilian oil and natural gas resources are also critical to national energy security. As continuous energy sources, they enable rapid flexibility in supply and demand to meet peak energy consumption. Additionally, the country's integrated transport, supply, and distribution infrastructure allows these resources to reach a large portion of the national territory, expanding access to affordable, reliable, and efficient energy. Knowing the expected growth in energy demand over the next decade (EPE, 2024a), the impact the oil and gas industry has on national socioeconomic well-being, and the necessity to solve the so-called energy trilemma, this sector needs to leverage its strengths to remain competitive in a net-zero emissions world.

Brazil benefits from a lower carbon intensity in its production (14.88 kg CO_2e per barrel of oil equivalent - boe) compared to the global average (20 kg CO_2e/boe) (IBP, 2024; ANP, 2025). This advantage is mainly due to the fact that most of this production originates from pre-salt reservoirs, which have a lighter composition and fewer impurities, facilitating the refining process. Additionally, the efficiency of techniques employed in drilling and fluid extraction stages in Brazilian Fields - through optimization and stage reduction - as well as the adoption of technologies mitigating emissions via CO_2 capture and storage systems or reduction of routine gas flaring (flare), contribute to this lower intensity (KENNETT et al., 2024; WORLD BANK - WGB, 2023).

It is important to note that, unlike the global average, Brazil's energy sector is not the main national greenhouse gas (GHG) emitter, having accounted for 18.30% of emissions in 2023, whereas the land-use change and agriculture sectors were responsible for 46.25% and 27.49%, respectively (Sistema de Estimativas de Emissões e Remoções de Gases de Efeito Estufa - SEEG, 2024). Within the energy sector, the transport category has remained the largest GHG emitter, emitting nearly 10% of total emissions in 2023, whereas oil and natural gas exploration, refining, and transport, related to fuel production, represented 1.06%, 1.15%, and 0.05%, respectively, of the nearly 2.30 Gt CO_2e emitted that year.

It is also noteworthy that, compared to the world's largest GHG emitters, the Brazilian energy sector emitted 27 times less than China's corresponding sector, 11 times less than the United States, 6 times less than India, 5 times less than Russia, and half as much as Indonesia - countries that, except Russia, have populations larger than Brazil (EMISSIONS DATABASE FOR GLOBAL ATMOSPHERIC RESEARCH - EDGAR, 2024). Specifically for the oil and gas (O&G) sector, production in the US alone (both onshore and offshore) emitted around 98 million tons of CO_2e in 2023; about 4.5 times the emissions registered for Brazil's production in the same year (Environmental Protection Agency - EPA, 2024).

Over the past years, various initiatives have been structured by the Brazilian government to enable compliance with the Paris Agreement targets. Updated in November 2024, Brazil's Nationally Determined Contribution (NDC) sets a goal to reduce the country's net GHG emissions between 59% and 67% by 2035, compared to 2005 levels (MDIC, 2024). To achieve these targets in the oil and gas sector, the Ministry of Mines and Energy (MME) has worked in close partnership with the regulatory agency (ANP), encouraging the adoption of sustainable practices and innovative technologies aimed at both improving process efficiency and reducing environmental impact.

Since 2021, Brazil has been part of the Global Methane Pledge, an effort created at COP26 by more than 100 countries committed to achieving a 30% reduction in methane emissions by 2030 compared to 2020 levels (EPE, 2024d). The country also participates in various international initiatives aimed at reducing emissions across multiple economic sectors.

In 2024, Brazil joined the World Bank initiative, Zero Routine Flaring, which aims to eliminate routine flaring of associated gas from oil production by 2030 (WGB, 2025). However, some oil companies operating in Brazil, such as Petrobras, BP, and Equinor, had already adhered to the initiative previously. That year was also particularly important for the enactment of significant legal milestones, such as Law No. 14,993 of October 8, 2024, which regulates carbon dioxide capture and geological storage.

Another significant advancement was the promulgation of Law No. 15,042 on December 11, 2024, which established the Brazilian Greenhouse Gas Emissions Trading System (SBCE), aligning with the Kyoto Protocol's guidance on implementing market-based emission compensation mechanisms (United Nations Framework Convention on Climate Change - UNFCCC, 1997).

Corporate initiatives also form part of the decarbonization strategies adopted by companies operating in Brazil. The Oil and Gas Decarbonization Charter, created in 2023, includes more than 50 companies committed to achieving net-zero Scope 1 and 2 GHG emissions by 2050; ending routine gas flaring by 2030; and reaching near-zero methane emissions in production by 2030 (EPE, 2024d).

Given the strategic role of the oil and gas sector in Brazil's economy and energy security, decarbonization challenges require coordinated efforts between government, companies, and investors. Growing social and regulatory pressure, coupled with international investors' demands for a smaller carbon footprint, have driven mitigation initiatives forward. The adoption of innovative technologies, the creation of market-based mechanisms, and adherence to global commitments are essential to ensure the sector's competitiveness during the energy transition. As the eighth-largest oil producer in the world, Brazil has the opportunity to lead the industry's decarbonization efforts, capitalizing on its comparatively lower emissions and developing sustainable solutions for a cleaner, more resilient energy future.

3. Emissions scenarios in the E&P sector in Brazil

In response to Article 3 of RCNPE 8/2024, EPE developed decarbonization scenarios with impact assessments of mitigation technologies, based on studies initiated in 2023. This Report presents scenarios with varying levels of complexity, drawing from the material published in April 2024 on the relevance of the oil and natural gas sector to the energy transition (EPE, 2024b).

3.1. Methodology

To prepare the decarbonization scenarios for E&P activities, EPE used the model developed in 2023 to estimate the potential for reducing greenhouse gas emissions in oil and natural gas E&P activities[2]. The model adopts a top-down approach, correlating sectoral energy demand and historical emissions with the production curve outlined in the Ten-Year Energy Expansion Plan (PDE in the Portuguese acronym) 2034, a product developed by EPE[3].

The model focuses on direct emissions, considers medium-term scenarios through 2037, and generates emissions reduction scenarios based on the application of different GHG mitigation measures. Emissions are categorized by activity - combustion, flaring, venting, and fugitive emissions - and by production stage, specifically: E&P, land transportation, maritime transportation, and abandoned wells.

This report analyzes only the emissions and mitigation opportunities related to the E&P and land transportation stages, as aligned with the focus of RCNPE 8/2024. The development of mitigation scenarios began with the mapping of technologies for reducing greenhouse gas emissions in the E&P segment, with an emphasis on the Brazilian context and the identification of emission sources and activities that are subject to mitigation.

Next, criteria were defined to assess the level of effort required to implement mitigation actions in Brazil's E&P segment. This enabled the classification of scenarios using a Mitigation x Effort matrix, which ranks actions according to their mitigation potential and the effort required for implementation.

The normalized effort index associated with each action is both qualitative and quantitative, based on two primary criteria: marginal abatement cost and technological implementation barriers. Three additional criteria - productivity loss (due to production interruptions), investment return, and operational cost - were introduced to support a qualitative assessment of the marginal abatement cost in cases where quantitative data is not available. Descriptions of the categories considered are presented in Table 1 and Table 2.

[2] Model developed by Green Domus - the consultancy hired by EPE in 2022, by electronic tender (CT-EPE-071/2022).

[3] Ad-hoc adjustments were made to correlate the variables, involving the empirical calibration of certain parameters to historical data in cases where it was not possible to obtain them using the VAR and ARIMA regression models applied.

Table 1: Criteria used to assess the implementation effort of mitigation measures

Criterion	Category	Effort	Index
1) Marginal abatement cost	0 US$/$tCO_2e$	Very low	1
	0 to 80 US$/$tCO_2e$	Low	2
	80 to 100 US$/$tCO_2e$	Medium	3
	100+ US$/$tCO_2e$	High	4
2) Technological barrier	Common practice with readily available operational technologies	Very low	1
	Common practice requiring adaptation of existing technologies	Low	2
	New practice with available technological solutions	Medium	3
	New practice with most technologies under development or unavailable	High	4

Table 2: Criteria used to estimate marginal abatement cost (C1) when quantitative data is unavailable.

Criterion	Category	Effort	Index
3) Productivity loss	No production interruption required	Very low	1
	Minimal production interruption	Low	2
	Temporary production shutdown	Medium	3
	Indefinite production shutdown	High	4
4) Investment return	Payback within 1 year	Very low	1
	Payback within 2 years	Low	2
	Long-term payback	Medium	3
	No return on investment	High	4

5) Operational cost	Requires temporary mobilization of in-house staff for implementation	Very low	1
	Requires temporary mobilization or hiring of staff for implementation and maintenance	Low	2
	Requires permanent mobilization of in-house staff for implementation and maintenance	Medium	3
	Requires permanent hiring of staff for implementation and maintenance	High	4

3.2. Mitigation measures

Mitigation measures in E&P are decarbonization actions adopted to eliminate or reduce GHG emissions in oil and natural gas exploration and production. The adoption of these measures is crucial in the context of the energy transition, with prospects of declining global demand and a shift toward prioritizing fields that are more competitive in terms of cost and emissions. The measures focus on aspects such as enhancing energy and process efficiency, promoting the use of alternative sources, and controlling emissions at the source - all aimed at reducing the GHGs emitted by E&P activities, mainly carbon dioxide (CO_2) and methane (CH_4).

Similar to emission sources, decarbonization measures can be divided into: (i) reducing the combustion of fossil fuels for energy generation; (ii) minimizing unnecessary flaring of produced natural gas; (iii) preventing the venting of produced natural gas; and (iv) controlling fugitive emissions. In this context, adopting more efficient operating practices and rigorously monitoring operations are essential for reducing emissions. From the four emission categories listed, nine groupings were established (Items 3.2.1 to 3.2.9), which include some related technologies - highlighted in bold and italics - and are detailed below.

3.2.1. Combined-Cycle Gas Turbines (CCGT)

Conventional (open-cycle) gas turbines used in oil extraction processes can be coupled with heat recovery systems. These systems use waste heat to produce steam, which powers an additional turbine (combined cycle), thereby increasing overall efficiency (SHIOZAKI et al., 2021; SILVEIRA, CARVALHO e VILELA, 2007).

Replacement of open-cycle gas turbines with combined-cycle turbines

The production of oil and natural gas requires substantial amounts of energy, typically generated locally on platforms by open-cycle gas turbines. Replacing them with combined cycle turbines could increase energy efficiency by approximately 30%, resulting in reduced natural gas consumption and associated emissions (AGÊNCIA PETROBRAS, 2024; VOLDSUND, 2023; IPIECA; IOGP, 2022).

On the national average, around 10% of the gas produced is consumed by operators, but this figure drops to just over 8% in the Santos Basin, which has more recent installations (ANP, 2024). As such, the measure can promote greater operational efficiency and lower environmental impact, making it a relevant strategy for optimizing the resource use and reducing emissions.

Given the scarcity of precise data available in the literature for the Brazilian scenario, a qualitative estimate was made of criterion 1 (marginal abatement cost) - based on the method presented in section 3.1 - and considering the range of 80 to 100 US$/t$CO_2$e, consistent with data obtained by Kittijungjit et al. (2025).

3.2.2. Electrification

One alternative for reducing fossil fuel consumption and fugitive emissions from leaks is to replace natural gas-powered equipment with electric motors. However, this measure may require structural and operational retrofitting of the production unit, leading to technical and economic challenges - particularly for assets already in operation. By contrast, electrification tends to be more viable and attractive for new projects, as they can be designed with this technology from the outset. Once the production unit is electrified, various alternatives can be adopted to meet electricity demand. Some of these also contribute to emission reductions and can be counted as additional mitigation measures.

The North Sea Transition Authority (NSTA), the UK's regulatory agency, has identified electrification as a key strategy for emissions reduction in the E&P sector. In some cases, its feasibility is even a determining factor for approving offshore Development Plans (NSTA, 2024). This reinforces the strategic importance of electrification among a broader range of mitigation strategies, including efforts to curb methane emissions, flaring, and venting.

In the British context, electrification of offshore operations is closely linked to the development of offshore wind power - including floating platforms - and the integration with CCS and hydrogen projects. This synergy underscores the role of renewable energy and infrastructure co-development in accelerating energy transition in the E&P sector.

Although the UK's offshore environment differs from Brazil's - particularly in terms of distance from shore - this strategy may still be relevant, especially if electrification feasibility becomes a criterion for approving Development Plans. This would support broader adoption of best available technologies in the Brazilian context.

Electrification of operations with centralized power generation (all-electric)

The full electrification of operations ("all electric") relies on centralized power generation from a natural gas-fired thermoelectric plant, supplying electricity to E&P production units. This setup improves energy efficiency and can reduce GHG emissions by up to 20% (IBP, 2021). Recent regulatory changes have also made electrification feasible for offshore platforms with energy demands above 100 MW (CONAMA 2006; CONAMA 2021). Although it requires investments in centralized generation, electrified equipment, and distribution infrastructure, the measure offers significant emissions reductions and enhanced production efficiency (AGÊNCIA PETROBRAS, 2024).

Electrification of operations with electricity sourced from the grid

Grid-powered electrification replaces on-site fossil fuel combustion with electricity supplied by the national power system, potentially reducing energy-related GHG emissions by up to 50%. However, implementation in offshore environments faces logistical and financial challenges - especially in Brazil, where many platforms are located over 60 km from the nearest grid connection (VOLDSUND, 2023). The marginal abatement cost ranges from US$30 to US$70 per tCO_2e for nearshore platforms and can exceed US$100 per tCO_2e for those located over 100 km offshore or in deep waters. While research on offshore electrification continues, high capital costs and the need for equipment retrofitting currently limit application primarily to onshore facilities, where grid access is more feasible.

Despite these challenges, the measure offers considerable potential. Electrification of Norway's Troll field, for instance, is expected to reduce CO_2 emissions by 200,000 tons per year and NO_x by 850 tons annually. Once fully operational, it will lower total O&G sector emissions in Norway by 4% and national emissions by 1%, while freeing up additional natural gas for European consumption (CAVCIC, 2024).

Electrification of operations with electricity sourced from a decentralized renewable energy generation system

This approach uses local renewable sources - such as solar or wind - to power E&P operations. Globally, about 75% of oil and gas production occurs in areas with favorable renewable potential. However, Brazil's offshore assets generally have moderate suitability, with a normalized score of 5 out of 10 - lower than countries like the U.S. and China (IEA, 2023a). In addition, the distance to shore increases infrastructure costs, with estimated abatement costs of about US$70 per tCO_2e. Despite technical and economic hurdles, decentralized renewable electrification represents a strategic innovation for offshore decarbonization and remains a key long-term alternative for lowering sectoral emissions.

3.2.3. Leak Detection and Repair (LDAR)

LDAR refers to the systematic process of identifying and fixing leaks that lead to fugitive emissions - particularly methane. It relies on various technologies and protocols to detect, quantify, and address leaks across oil and gas facilities. Implementing LDAR programs throughout the production chain is essential for reducing emissions, improving operational safety, and supporting decarbonization goals.

LDAR programs

Effective LDAR programs require investments in both detection technologies and workforce training. One of the most widely used tools is the infrared (IR) camera, particularly Optical Gas Imaging (OGI), which enables remote visualization of methane leaks. According to the IEA (2024b), theoretical methane abatement potentials vary from 40% with annual inspections to 90% with continuous monitoring, depending on the frequency and coverage across upstream and downstream operations. Petrobras, for instance, applied LDAR in its refining and power generation operations, achieving a 32% reduction in methane emissions between 2016 and 2021. In the E&P segment, LDAR deployment is being structured, starting with OGI technologies. Structured LDAR campaigns can cut up to 20% of fugitive methane emissions in Brazilian oil production. Additionally, around 90% of this volume can be mitigated at a negative marginal abatement cost, ranging from -6.2 to -3.3 USD/MBTU, depending on the applied technology and inspection frequency (IEA, 2024c).

Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves

Fugitive emissions from natural gas processing plants, pressurization units, compressor stations, and transmission components (e.g., seals, valves, and gate stations) account for up to 80% of methane losses in the natural gas supply chain. Direct inspection and maintenance programs involve using tools such as soap bubble tests, electronic leak detectors, infrared cameras, vapor analyzers, and gas samplers to pinpoint and quantify leaks. Repairs can include seal replacements, valve re-tightening, or equipment substitution. This measure has strong economic and environmental returns: it can reduce methane emissions by up to 96% (with an average around 77%), and the recovered gas typically pays back the investment in 1 to 3 years.

3.2.4. Pneumatic Device Replacement

Pneumatic devices are extensively used in exploration and production (E&P) operations to control valve actuation, regulate liquid levels, and manage pressure and temperature (EPA, 2024a; IEA, 2024b). Many of these systems are powered by natural gas, releasing methane through continuous bleed or leakage - often difficult to detect and repair. According to the EPA (2024b), pneumatic controllers are among the leading sources of methane emissions in the North American oil and gas value chain.

Replacement of natural gas-powered pneumatic devices with instrument air systems

One of the most effective technologies to reduce - or eliminate - fugitive methane emissions is substituting natural gas with compressed instrument air in pneumatic devices. These systems are typically powered by electricity, making power availability a key requirement. This switch could reduce upstream methane emissions by around 7%, with a negative abatement cost of -8.4 USD/MBTU, yielding a positive net present value (NPV) by monetizing the natural gas that would otherwise be vented (IEA, 2024c).

Replacement of natural gas-powered devices with electric equipment

In certain applications, gas-powered pneumatic devices can be replaced with electrically actuated systems, eliminating methane emissions from both combustion and leaks. This approach is particularly suitable for onshore operations and may contribute to a 2% reduction in methane emissions from Brazilian E&P activities. It also offers a negative abatement cost of up to -5.3 USD/MBTU, depending on local infrastructure and field characteristics (IEA, 2024c).

3.2.5. Gas Venting Management

Venting refers to the controlled and intentional release of unburned gas directly into the atmosphere, either for disposal or to ensure the facility's safe operation. It excludes fugitive emissions from piping and equipment leaks but includes gas purging (IOGP, 2024). Various operational measures and technologies can minimize venting, including Vapor Recovery Units (VRUs) and gas recovery during pipeline pigging. According to the IEA (2024c), VRUs are the most effective strategy for reducing methane emissions in Brazilian E&P.

In onshore operations, where vapor recovery may be technically or economically limited, the installation of flares may be considered a viable alternative to mitigate methane. Offshore units, however, are required to have flare systems in place from the design phase, making this option inapplicable in such contexts.

Installation of vapor recovery units (VRU)

VRUs are used to capture vented gas and reintegrate it into the system or use it as fuel. These systems help avoid methane emissions from gas volatilization - caused by pressure and temperature fluctuations in storage tanks, phase changes during fluid transfers, or circulation between tanks (IOGP, 2024).

By recovering gas that would otherwise be vented to prevent overpressurization or explosions, VRUs offer both environmental and economic benefits. The avoided losses from methane release often result in negative abatement costs, ranging from -10 to -8.4 USD/tCO_2e. VRUs can reduce 1.6% to 12.8% of methane emissions from E&P operations.

Key systems where VRU implementation should be considered include:

- *Glycol dehydration units*
- *Acid gas removal units*
- *Compressors*
- *Produced water treatment systems*
- *Gas-to-fuel systems*
- *Storage tanks (detailed in the next section)*

Installation of vapor recovery units in storage tanks

During oil and condensate storage, light hydrocarbons such as methane are lost due to volatilization and liquid-level fluctuations. Installing VRUs in storage tanks can recover up to 95% of these emissions, redirecting the captured gas back into the processing stream - often to be used as fuel. Although the initial investment is high, the payback period typically ranges from three months to three years, making the measure cost-effective and environmentally impactful.

Flare installation

Installing flares[4] enables the controlled combustion of methane that would otherwise be vented, converting it primarily to CO_2 (along with minor N_2O and residual CH_4 emissions). Due to methane's high global warming potential, flaring is preferable to direct venting when gas recovery is not feasible (IOGP, 2024). Flaring may reduce methane emissions by up to 33%, but it comes with trade-offs, including new CO_2 emissions and the economic cost of destroying a potentially valuable resource (IEA, 2023b).

Recovery of gas from pigging operations

In pressurized pipelines, the accumulation of hydrocarbon condensates can hinder gas flow. "Pigging" is the mechanical cleaning process used to remove these liquids. However, the process often results in methane venting from gas depressurization. Recovery systems - such as VRUs - can be deployed to capture methane emissions during pigging, preventing atmospheric release. This measure is economically attractive, with negative abatement costs and payback periods of 2 to 5 months.

Data show that methane losses from pigging range from 28 to 120 tCH_4 in production and processing and 27 to 46 tCH_4 in transportation. This highlights the substantial mitigation potential of gas recovery in pigging operations.

3.2.6. Routine Flaring Reduction/Elimination

During oil production, associated gas is released alongside crude oil from the reservoir. While part of this gas is consumed onsite or exported for commercial use, a portion is still flared due to technical or economic constraints (WGB, 2025). Reducing or eliminating routine flaring is both an environmental and economic priority, and multiple public and private initiatives seek to promote more efficient use of this resource.

In Brazil, ANP Resolution No. 806/2020 defines natural gas flaring as "the disposal of a volume of unused natural gas through flare systems" (ANP, 2020). The regulation allows flaring in situations involving operational safety, technical constraints, or emergencies. However, routine flaring - i.e., flaring due to design or operational choices - is restricted. For non-associated natural gas and oil, any routine flaring or loss is exceptionally prohibited. For associated gas, routine flaring is capped at 2% for offshore platforms and 3% for onshore units commissioned from 2025 onwards. Operators exceeding these limits must obtain prior regulatory approval.

Complying with these thresholds varies according to field conditions and infrastructure availability. The three main technical alternatives to flaring are: reinjection into reservoirs, onsite utilization, and export to markets. Areas with nearby consumers and infrastructure offer more attractive economics for monetizing associated gas. In the Santos Basin, for example, high reinjection rates, proximity to gas markets, and newer FPSOs with advanced control technologies help maintain flaring intensities below regulatory limits. In contrast, basins outside the pre-salt region - especially marginal fields or those operated by smaller companies - face greater challenges.

[4] In offshore facilities, flaring systems are a regulatory requirement and standard design feature, not a new mitigation strategy. Onshore, however, flare systems can still be expanded.

In such cases, gas exports are often not economically viable, and reinjection may require substantial investments in new wells.

Although flaring emits GHGs, it is a preferable alternative to venting, which has a far higher global warming potential. Despite being treated as a "loss" under Resolution 806, venting is not currently subject to detailed regulatory standards. Moreover, venting is only environmentally preferable if flare systems operate with high combustion efficiency.

Literature often cites flare efficiencies above 95%, actual performance may vary greatly depending on design and site-specific conditions (Miguel et al., 2021). In some cases, combustion efficiency may fall below 70%, particularly when suboptimal configurations or measurement methods are used (Burtt et al., 2022). A drop in flare performance can significantly increase methane emissions, underscoring the need for better monitoring.

In light of these challenges, a coordinated approach to flaring and venting is essential - especially in older or more remote installations. The following sections outline technological alternatives that can help reduce or eliminate routine flaring by enabling more productive uses of associated gas.

Routine flaring and/or venting of associated gas limited to 2%

ANP Resolution No. 806/2020 regulates the flaring and loss of oil and natural gas in Brazil. For associated gas, routine flaring must be limited to 2% (equivalent to a Gas Utilization Index, IUGA, of 98%) for offshore units starting operations after 2025, and to 3% (IUGA of 97%) for new onshore units.

Currently, Brazil's national average IUGA is 97%, already indicating low levels of flaring and venting. Petrobras - the country’s leading producer - reports a current IUGA of 97.2%, demonstrating the technical and economic feasibility of maintaining low flaring levels. The medium-term goal is to reach a national IUGA of 98%, supported by the start-up of new projects. In 2024, the index reached 97.5% (ANP, 2024a), reinforcing Brazil’s leadership among oil-producing countries in flaring control.

According to the World Bank’s Global Gas Flaring Tracker (2024), Brazil ranked 6th among the top 20 oil-producing countries[5] in terms of lowest flaring intensity in 2023, averaging 1 cubic meter of flared gas per barrel of oil produced[6].

Elimination of routine flaring through natural gas reinjection

One of the most common strategies for eliminating routine flaring is the reinjection of natural gas into geological formations. In Brazil, reinjection is already a widespread practice, with the reinjected share of associated gas increasing from 29% in 2016 to 50% in 2022. Although its contribution to overall emissions reduction may be limited - given the already low national flaring rates - reinjection has become essential for minimizing operational flaring and enabling production in areas without gas evacuation infrastructure.

This strategy is particularly relevant in offshore production units and electrified systems, where the demand for reinjection tends to increase due to reduced on-site gas consumption. In current projects, gas reinjection can help keep flaring rates below 1% of total production.

[5] According to the Statistical Review of World Energy (Energy Institute, 2024), the top 20 oil-producing countries are: United States, Saudi Arabia, Russia, Canada, Iran, Iraq, China, United Arab Emirates, Brazil, Kuwait, Mexico, Norway, Kazakhstan, Qatar, Nigeria, Algeria, Libya, Angola, Argentina, and Oman.

[6] The Global Gas Flaring Tracker Report defines flaring intensity as “the volume of gas flared, in cubic meters, per barrel of oil produced. It is usually calculated at the country level and, over time, serves as an indication of how well that country is doing in recovering and utilizing the associated gas” (WBG, 2024b).

Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: local use for electricity generation

Associated gas can also be captured and used locally for electricity generation. This is one of the most cost-effective uses of flare gas, especially when volumes are small and infrastructure constraints make export unfeasible. In such cases, modular generators and integrated systems may provide a viable alternative.

Petrobras, for instance, adopted Flare Gas Recovery Units (FGRUs) on three platforms to capture unburned gas and reintroduce it into processing. These systems have already avoided 80 ktCO_2e annually and are set to expand to eight additional platforms. Although flare-related emissions in Brazil are relatively low, on-site gas utilization remains an important complementary measure - especially when paired with electrification and thermal efficiency improvements.

Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: small-scale monetization using compressed natural gas

Another option for managing associated gas is small-scale monetization using compressed natural gas (CNG). By compressing gas to less than 1% of its original volume, CNG enables delivery to power plants, industries, and service stations not connected to pipelines.

CNG is typically transported by truck and stored in high-pressure cylinders. While it has a lower energy density than liquefied natural gas (LNG), it requires less upfront investment and is better suited for short distances and smaller volumes. When associated with flare gas mitigation, CNG has an estimated marginal abatement cost of -16 to -13 USD/tCO_2e, providing a cost-effective solution in many contexts.

Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: large-scale monetization

For larger volumes of gas, monetization can be achieved by processing and transporting gas to regional or national markets through pipelines. This strategy demands significant capital investment and depends on the quality of the gas, its proximity to processing facilities, and market demand.

While Brazil's potential for large-scale flare gas recovery is limited, this approach can still be viable in electrified systems or all-electric operations where gas is no longer consumed on site. In such cases, redirecting the surplus gas to consumers can yield both economic and environmental benefits, especially if supported by regulatory incentives or infrastructure sharing.

Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: small-scale monetization using liquefied natural gas

In areas without access to pipelines, small-scale gas monetization using liquefied natural gas (LNG) or gas-to-liquid (GTL) technologies may offer a feasible solution. LNG systems liquefy natural gas for transport and storage, while GTL technologies convert gas into synthetic fuels. These approaches allow gas to be safely stored and transported as a “virtual pipeline”, enabling delivery to users in remote or off-grid locations.

This strategy has an estimated marginal abatement cost between -2 and 4 USD/tCO_2e. While flare volumes in Brazil are relatively low, surplus gas from electrified operations - particularly where power is sourced from the grid or renewable sources - can be monetized and redirected to productive uses.

3.2.7. Carbon Capture Utilization and Storage (CCUS)

Carbon capture, utilization, and storage (CCUS) is a critical tool for reducing CO_2 emissions in the oil and gas industry, especially for aligning with net-zero commitments. It includes three primary forms of application: capturing CO_2 from fossil fuel combustion (post- or pre-combustion) or directly from the air (Direct Air Capture, DAC). Key opportunities include the capture of CO_2 from natural gas processing - where CO_2 concentrations are high - and its reinjection into geological reservoirs. The captured CO_2 is reinjected into geological reservoirs located at depths greater than 800 meters and sealed by layers of impermeable rock, ensuring gas storage for centuries or even millennia. It is worth noting that CCUS is also applicable in other segments of the oil and gas (O&G) production chain, such as refineries, and can benefit from shared infrastructure with other hard-to-abate sectors, including steel, iron, cement, chemicals, and fossil-fuel thermal power plants.

Estimates for typical projects indicate that the installation of a CCUS project in an onshore environment would require investments ranging from US$40 to US$150 million per $MtCO_2$ (million tons of CO_2 captured), while offshore projects could exceed US$240 million per $MtCO_2$ (SIEVERT; CAMERON; CARTER, 2023; FINDLAY, 2023). However, it is important to assess costs on a case-by-case basis, considering the scale of CO_2 capture and the available storage capacity. Initiatives such as the Northern Lights project-based on capturing CO_2 from onshore industrial sources and transporting it by ship and pipeline for storage in deep saline reservoirs in the North Sea - represent a collaborative effort between the Norwegian government and companies Equinor, Shell, and TotalEnergies. For its first phase alone, which aims to capture and store 1.5 $MtCO_2$ per year, the estimated CAPEX (capital expenditure) is around US$710 million (PALLANICH, 2024).

Reinjection of carbon dioxide from natural gas processing

CO_2 captured from gas processing - especially in high-CO_2 pre-salt fields - is compressed and reinjected into reservoirs (>800 m depth), secured by impermeable geological seals. Reinjection serves a dual purpose: permanent storage and enhanced oil recovery (EOR), improving reservoir output while preventing emissions. Though separation and drilling entail high costs - especially for deep offshore reservoirs - extended oil production and CO_2 mitigation often yield economic viability.

In Brazil, Petrobras has led global efforts - reinjecting 31 $MtCO_2$ between 2008 and 2021 and achieving its 2025 target of 40 $MtCO_2$ in 2022. Pre-salt operations benefit from significantly lower emissions thanks to widespread adoption of this technology.

3.3. Scenario analysis results

Among the mitigation technologies presented in section 3.2, 13 measures were selected to build 3 main emission scenarios, as well as 10 additional alternative scenarios. These scenarios aim to assess the reduction potential and the implementation effort required for the combined adoption of selected alternatives, chosen based on their relevance to the Brazilian context, mitigation potential, and/or technical and economic feasibility.

1. *Replacement of open-cycle gas turbines with combined-cycle turbines*
2. *Electrification of operations with centralized power generation (all-electric)*
3. *Electrification of operations with electricity sourced from the grid*
4. *Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves*
5. *Replacement of natural gas-powered pneumatic devices with instrument air systems*
6. *Installation of vapor recovery units*
7. *Replacement of natural gas-powered devices with electric equipment*
8. *Elimination of routine flaring through natural gas reinjection*

9. *Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: local use for electricity generation*
10. *Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: large-scale monetization*
11. *Flare installation*
12. *Reinjection of carbon dioxide from natural gas processing*
13. *Gas venting management: installation of vapor recovery units in storage tanks*

The thirteen measures were comparatively analyzed in terms of implementation effort (x-axis) and mitigation potential (y-axis), both normalized and plotted in the matrix below (Figure 1). Figure 2 illustrates the level of effort required - considering both costs and technological barriers - for the main technologies selected for analysis. It is worth noting that these assessments were made as an approximation for the entire Brazilian E&P sector. The specific characteristics of different production and operating profiles will be addressed in subsequent sections and chapters.

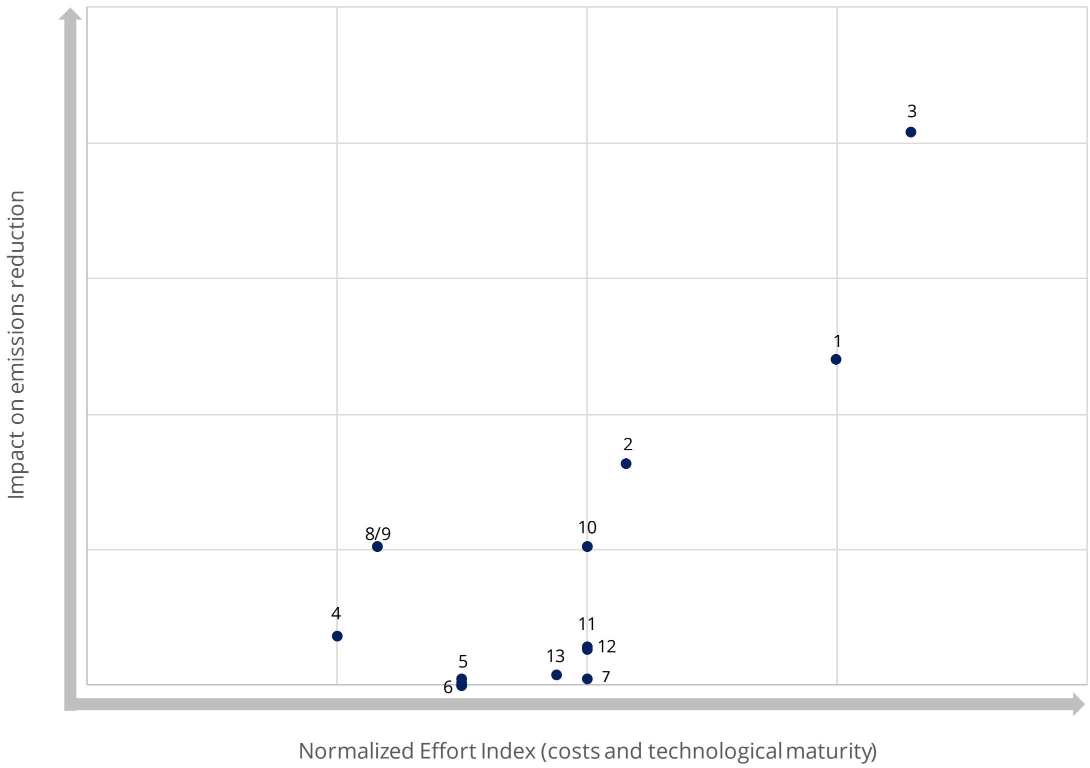

Figure 1. Effort x Mitigation matrix for the selected measures.

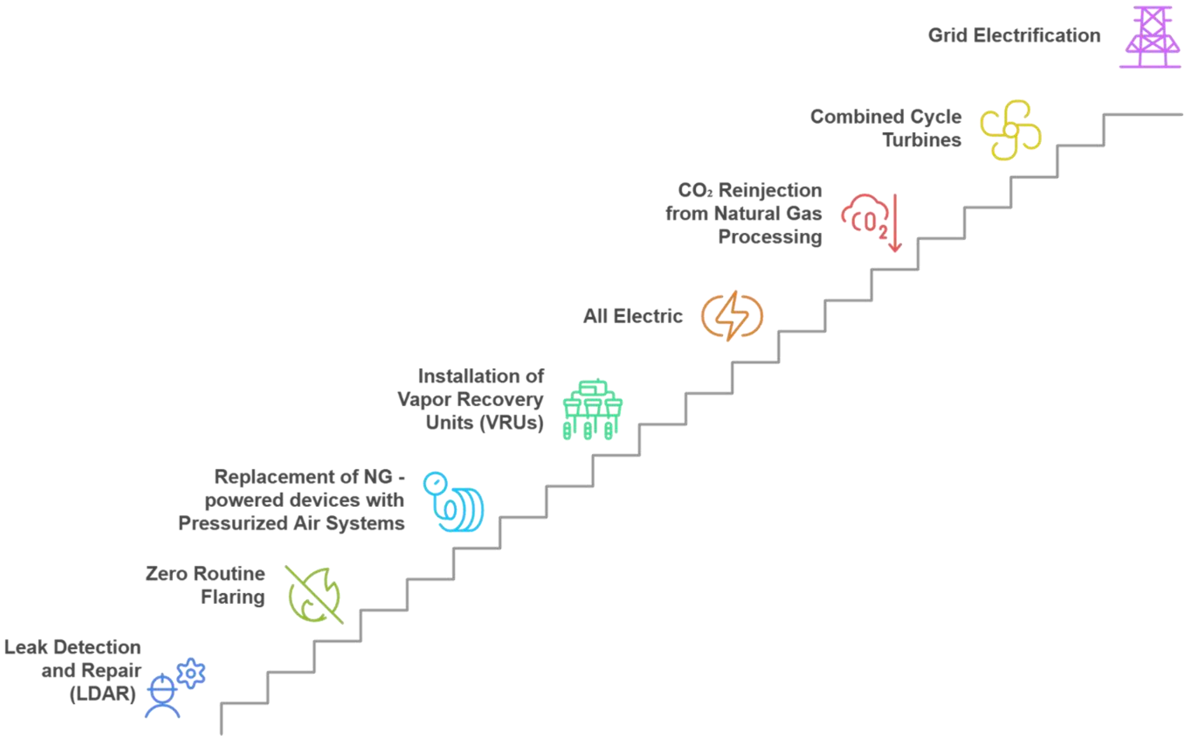

Figure 2. Technology ranking by effort level for some of the selected measures, based on the costs involved and current technological barriers.

The first of the three main scenarios was constructed using the measures positioned furthest to the left on the x-axis, representing the lowest relative effort among all the options presented in the matrix. In the other two scenarios, additional measures were included that may require greater effort but also offer higher potential for emission reductions. The three Main Scenarios and their respective selected measures are as follows:

- Main Scenario 1 (MS1)
    - 4) Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves
    - 5) Replacement of natural gas-powered pneumatic devices with instrument air systems
    - 6) Installation of vapor recovery units
    - 8) Elimination of routine flaring through natural gas reinjection
- Main Scenario 2 (MS2)
    - Measures 4, 5 and 6 from Main Scenario 1
    - 1) Replacement of open-cycle gas turbines with combined-cycle turbines
    - 10) Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: large-scale monetization
    - 12) Reinjection of carbon dioxide from natural gas processing
- Main Scenario 3 (MS3)
    - Measures 4, 5 and 6 from Main Scenario 1
    - Measures 10 and 12 from Main Scenario 2

- 3) Electrification of operations with electricity sourced from the grid
- 7) Replacement of natural gas-powered devices with electric equipment

After selecting the measures, the emissions projection and abatement potential tool presented in this chapter was applied. A baseline scenario was then built using the production curve from PDE 2034 (EPE, 2024c), considering cumulative emissions without any mitigation measures. Subsequently, cumulative reductions (2024 - 2037) were estimated for the three main scenarios, along with the effort index calculated based on the joint adoption of the selected measures. Figure 3 summarizes the results.

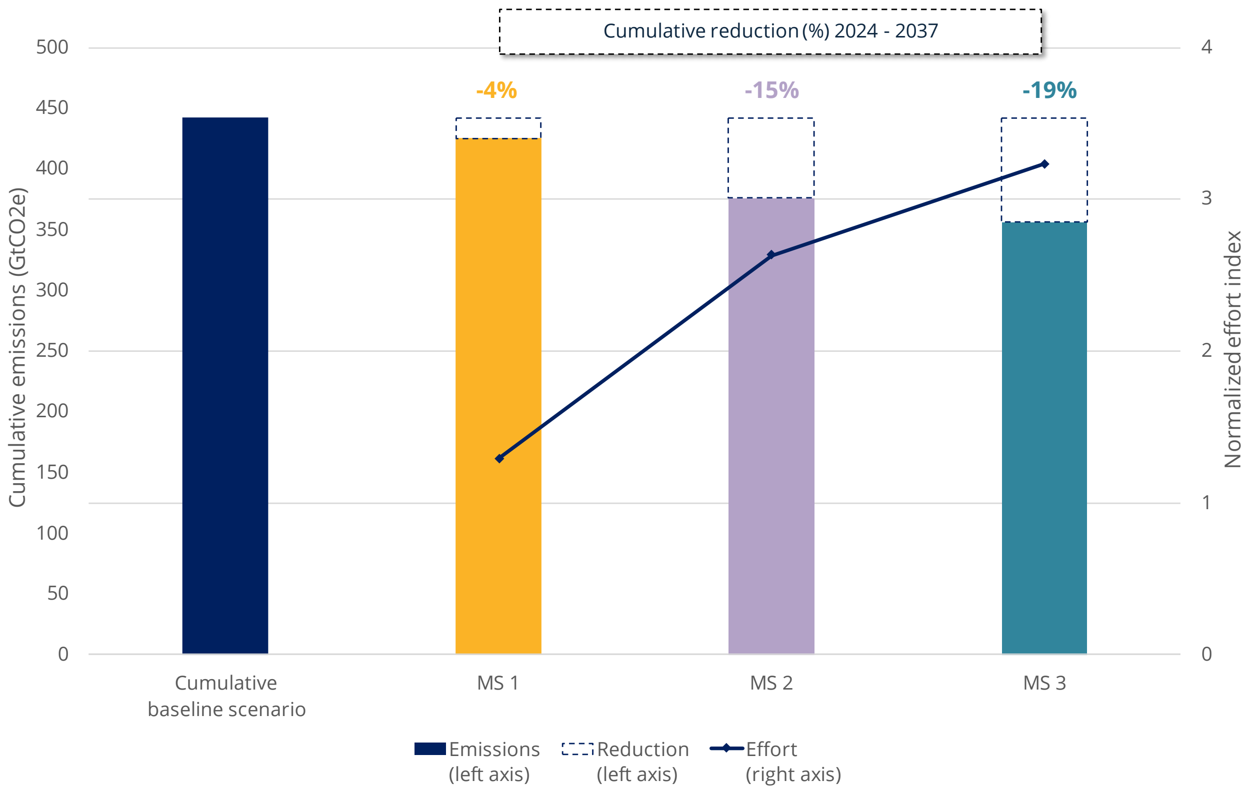

Figure 3. Reduction between Baseline Scenario and the three Main Scenarios in projected cumulative emissions from 2024 to 2037.

The purpose of developing scenarios and estimating mitigation outcomes - considering the implementation effort - is to contribute to the discussion on decarbonization pathways in the E&P sector. In this context, it is possible to identify priority actions that enable short-term emissions reductions through technologies that are already commercially available. Additionally, the scenarios provide a medium-term outlook for technologies with the potential to scale mitigation but that still require innovation, investment, and/or appropriate market incentives.

The first scenario (MS 1) shows that measures focused on flaring control, LDAR, vapor recovery, and device replacement can reduce emissions by nearly 5%. These are initiatives with a positive net present value (NPV) or short payback periods, and technologies that are available on a commercial scale. The integration of reinjection and combined-cycle turbines could enhance the reduction to 15% compared to the base scenario, although these still face scaling and adoption challenges across the Brazilian E&P sector. Finally, full electrification - including offshore operations - powered by grid electricity, still faces significant costs and technology barriers. These require further R&D investment to enable a decisive contribution to decarbonization and may not be feasible in all cases, depending on the location-specific characteristics of production. Nonetheless, emission reductions of approximately 20% are expected under this scenario, enabling a substantial improvement in emissions intensity indicators.

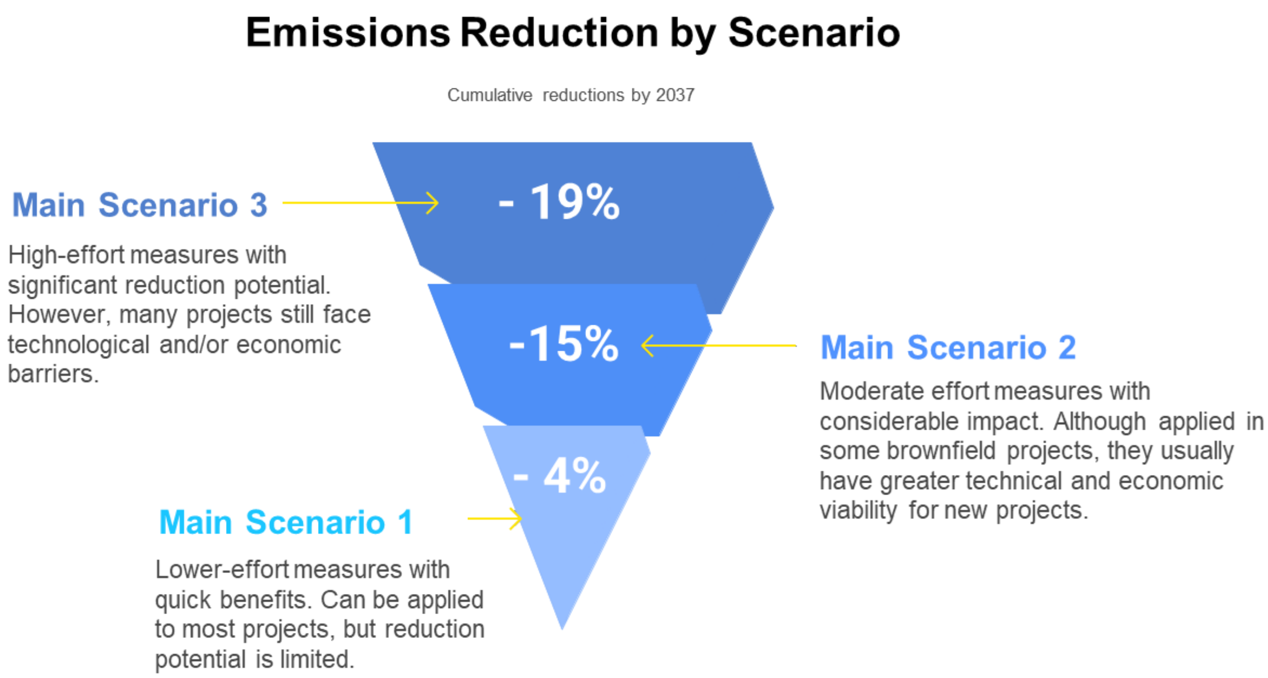

Figure 4. Cumulative reduction in emissions between 2024 and 2037.

In addition to the three Main Scenarios presented, alternative configurations involving fewer measures were developed in order to assess impact and effort in different contexts. These alternatives enhance the availability of information and complement the analysis. The ten alternative scenarios and their respective measures are as follows:

- Natural gas monetization (AS 1)
  - 10) Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: large-scale monetization
- LDAR and reinjection (AS 2)
  - 4) Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves
  - 8) Elimination of routine flaring through natural gas reinjection
- Combined-cycle gas turbines (AS 3)
  - 1) Replacement of open-cycle gas turbines with combined-cycle turbines
- LDAR and VRU (AS 4)
  - 4) Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves
  - 6) Installation of vapor recovery units
- Natural gas and CO_2 reinjection (AS 5)
  - 8) Elimination of routine flaring through natural gas reinjection
  - 12) Reinjection of carbon dioxide from natural gas processing
- LDAR, reinjection and venting (AS 6)
  - 4) Direct inspection and maintenance of gas processing plants, pressurization stations, compressor stations, gates, seals, and valves
  - 8) Elimination of routine flaring through natural gas reinjection

    - 13) Gas venting management: installation of vapor recovery units in storage tanks
- Electrification via grid (AS 7)
    - 3) Electrification of operations with electricity sourced from the grid
    - 7) Replacement of natural gas-powered devices with electric equipment
- All-electric with centralized power generation (AS 8)
    - 2) Electrification of operations with centralized power generation (all-electric)
    - 7) Replacement of natural gas-powered devices with electric equipment
    - 9) Elimination of routine flaring by capturing and utilizing natural gas for productive purposes: local use for electricity generation
- Electrification of facilities and equipment (AS 9)
    - 3) Electrification of operations with electricity sourced from the grid
    - 5) Replacement of natural gas-powered pneumatic devices with instrument air systems
    - 7) Replacement of natural gas-powered devices with electric equipment
- Facility interventions (AS 10)
    - 1) Replacement of open-cycle gas turbines with combined-cycle turbines
    - 6) Installation of vapor recovery units
    - 11) Flare installation
    - 12) Reinjection of carbon dioxide from natural gas processing

To support the comparative analysis of these alternatives, a second Mitigation x Effort matrix was constructed, featuring both the Main Scenarios (highlighted in yellow) and the Alternative Scenarios (in blue). Due to the normalization of the effort index, which accounts for all mapped measures, the effort value for each scenario corresponds to the sum of the individual effort scores of its respective measures.

As with the main scenarios, the mitigation potential calculation is based on the tool presented in Section 3.1. The reduction percentages reflect the volume of GHG (in CO_2 equivalent) mitigated cumulatively from 2024 to 2037 in comparison with the Baseline Scenario. The results for all scenarios are presented in Figure 5 and summarized in Figure 6 and Figure 7.

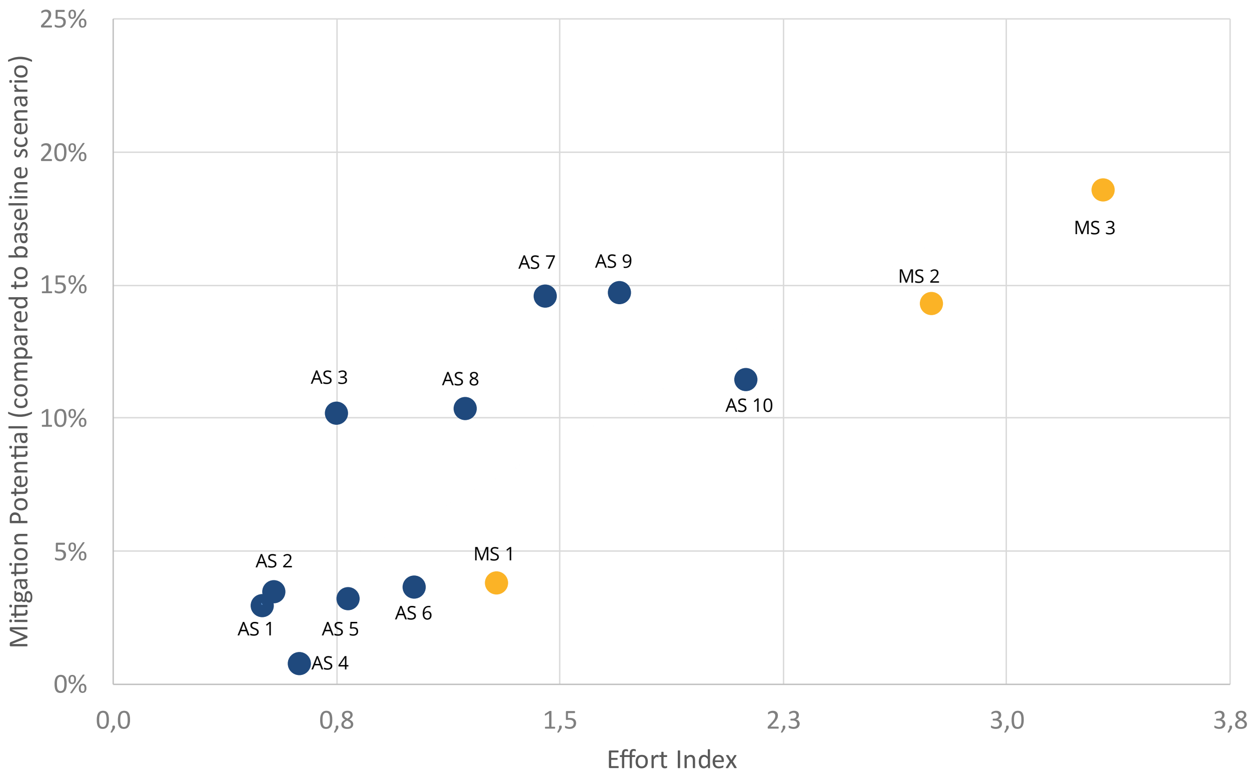

Figure 5. Effort x Mitigation Matrix for the Main Scenarios (MS) and Alternative Scenarios (AS) constructed.

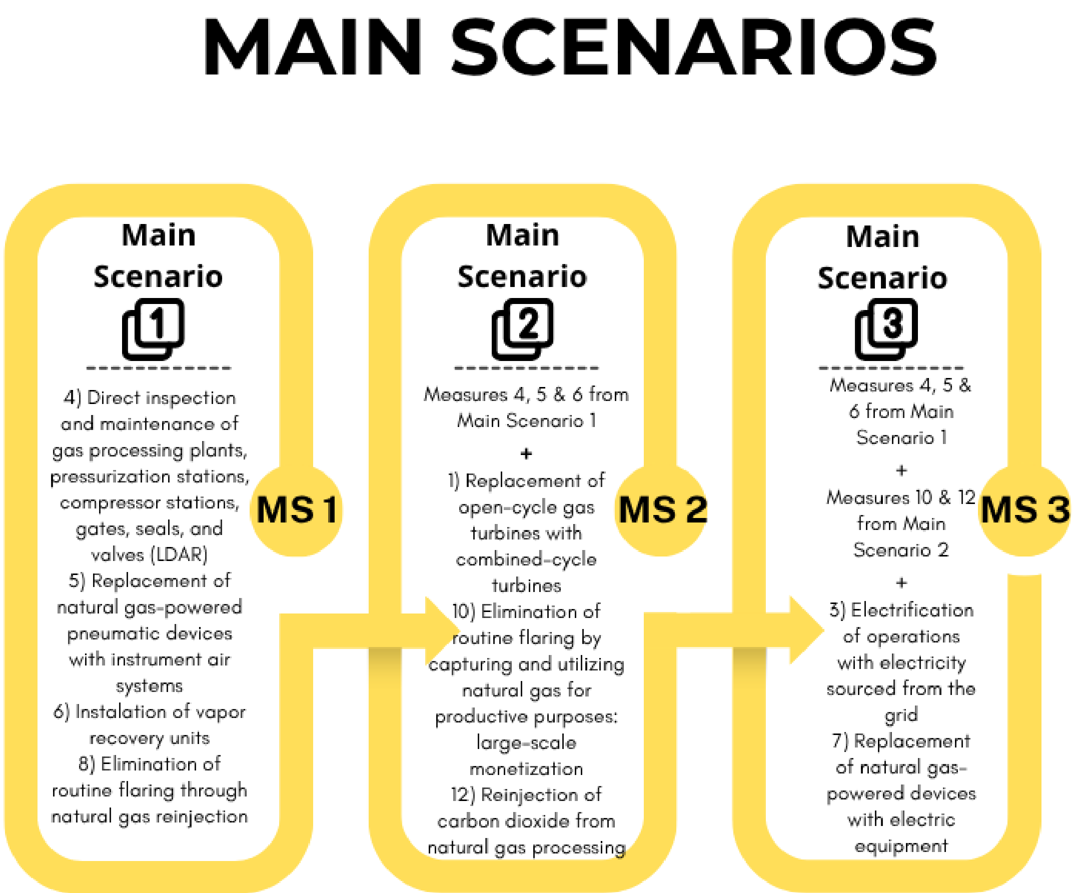

Figure 6. Summary of the measures that make up the main scenarios.

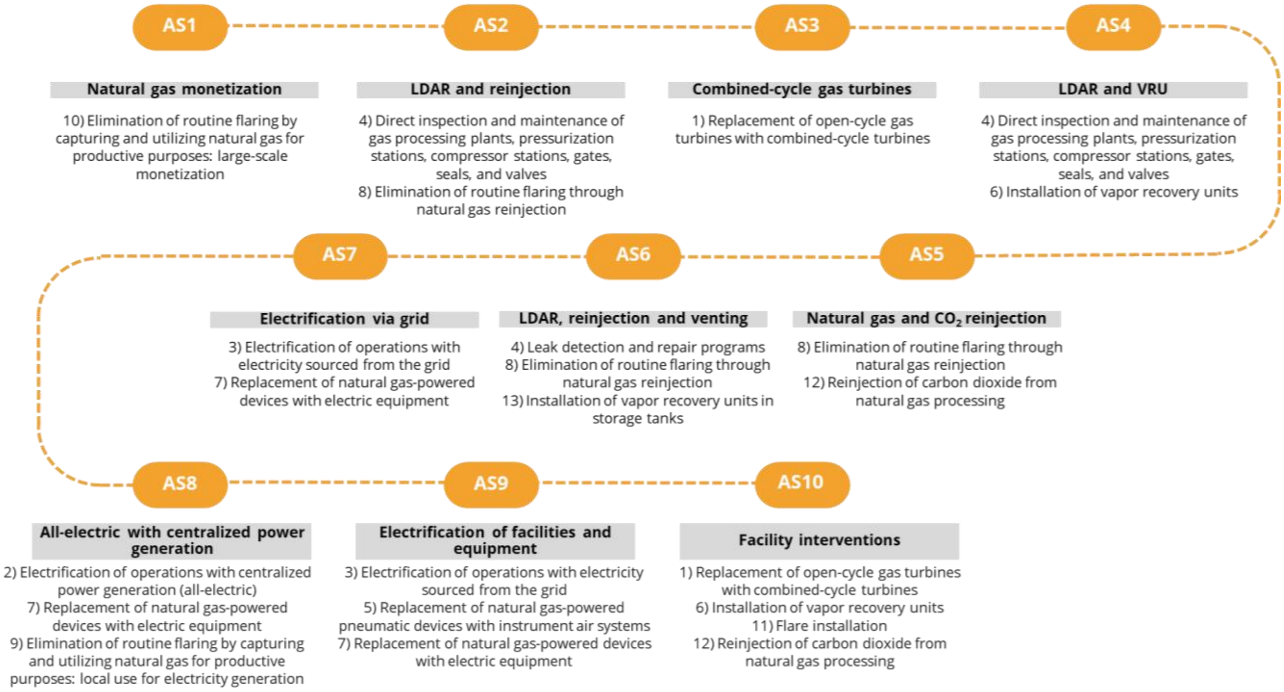

Figure 7. Summary of the measures that make up the alternative scenarios.

The alternative scenarios reinforce the potential of electrification measures, which are well-positioned to reduce emissions, but present higher levels of effort related to technological barriers, primarily offshore, and costs. Therefore, in addition to the importance of RD&I projects in this area, it will be necessary to increase fundraising to finance these technologies and achieve a greater impact in reducing emissions.

At the other end of the matrix, scenarios involving zero routine flaring and LDAR require less comparative effort and offer an opportunity to achieve quick results with available and cost-effective technologies. In this sense, it is essential to identify and prioritize the most emitting equipment, facilities, and activities, allowing for greater efficiency between the resources allocated and the results obtained. Given the specificities presented in this chapter, the following section details the particularities related to the different production profiles, as well as the associated challenges for mitigation.

3.4. Specificities and challenges associated with decarbonization scenarios

The top-down approach selected for this analysis involves the allocation of emissions and reduction potentials, requiring simplifications to address the complexity and variability of emission sources. As a result, the specificities of different technology profiles, assets, facilities, and equipment may be omitted, providing a general overview of trends. Nevertheless, further analysis is needed to examine the particularities of Brazilian E&P. This section discusses some of these specificities and qualitatively presents the challenges and potential solutions that may be most appropriate in different contexts.

3.4.1. Asset development stage (greenfield vs brownfield)

Reducing greenhouse gas (GHG) emissions is a goal shared by all projects in the oil and gas Exploration and Production (E&P) sector. However, selecting the most appropriate mitigation measures depends largely on the asset's development stage. Projects are generally classified into two categories: greenfield (projects still in the planning or early development phase) and brownfield (projects already in operation).

Greenfield projects offer greater flexibility in the design and integration of mitigation strategies, as decisions can be made during the early planning stages. This enables the adoption of cutting-edge technologies and more efficient, integrated solutions. However, this flexibility comes with significant challenges, including the need for higher upfront investments and longer payback periods, since the implementation of such measures often extends project timelines before production begins (CHATTERTON e DE VAUTIBAULT, 2021; CHIAVARI et al., 2020). Thus, while greenfield projects offer opportunities for structural and integrated emission reductions, their economic and operational implications must be carefully considered (HEIMERL et al., 2024).

It is also important to note that the pursuit of integrated, lower-emission solutions should be encouraged by regulatory agencies, which have the authority to require technical justification for not adopting more sustainable alternatives. This principle is reflected in Article 2 of RCNPE 8/2024.

Brownfield projects, on the other hand, involve a different set of challenges. Reusing existing infrastructure can offer cost and schedule advantages, such as lower implementation expenses and faster deployment. However, brownfields typically offer less flexibility for mitigation, since any measures must be compatible with the existing facilities (NGUYEN et al., 2016). Additionally, retrofitting these assets often requires partial or complete shutdowns.

Such operational halts can result in direct financial losses - such as production downtime - and face resistance from operators, who are generally inclined to minimize interruptions. This reluctance is especially pronounced in offshore assets, where the costs of shutdown and restart are significantly higher. As a result, interventions in brownfield operations must be carefully planned to balance short-term economic concerns with long-term environmental and operational benefits.

Although greenfields allow for more ambitious decarbonization strategies, focusing solely on new projects could undermine broader decarbonization goals in the oil and gas sector. This is because existing units - often associated with higher carbon intensities - will continue to contribute significantly to overall emissions. Therefore, decarbonizing brownfield assets is critical to reducing the sector’s carbon footprint and supporting a more balanced and effective energy transition.

To overcome the challenges of brownfield decarbonization, it is essential to adopt flexible and adaptable infrastructure, which can facilitate future upgrades with minimal operational disruption. Modular equipment and scalable technologies are especially promising for offshore projects, where logistical and financial constraints are greater.

Understanding the specificities and challenges of both greenfield and brownfield projects is essential to formulating effective GHG mitigation strategies in E&P. Such analysis not only supports decarbonization targets but also promotes more efficient and sustainable asset management throughout the lifecycle of oil and gas production facilities.

3.4.2. Project environment (onshore/offshore)

Although onshore basins accounted for only 4.2% of Brazil’s total oil and gas production in 2023, they were responsible for 9.7% of sectoral emissions that year, reflecting a significantly higher emissions intensity (34.3 $kgCO_2eq/boe$) than offshore basins (14.0 $kgCO_2eq/boe$) (ANP, 2025). This disparity is primarily due to the presence of large offshore reservoirs producing lighter, lower-impurity fluids - especially in the pre-salt layer - combined with the use of more efficient drilling and production techniques that enhance productivity. The growing adoption of technologies focused on reducing greenhouse gas (GHG) emissions has also contributed to the lower carbon intensity of offshore production.

In pre-salt fields specifically, Enhanced Oil Recovery (EOR) techniques - used to maximize hydrocarbon extraction after primary and secondary recovery (which relies on natural reservoir pressure or water injection) - have been widely deployed for over a decade. Broadly speaking, the adoption of EOR has expanded as the oil and gas (O&G) industry seeks to extend the productive life of mature fields. When properly applied, EOR can increase recovery rates from 30-40% (with conventional techniques) to 60-70% or more, depending on the selected method and reservoir characteristics (WERTHEIM; ABRANTES, 2019).

A notable example in Brazil is the Santos Basin, where more than 11 million metric tons of CO_2 were reinjected into producing reservoirs in 2022, significantly reducing the emissions intensity of offshore operations. Had this CO_2 been released into the atmosphere, the average carbon intensity of pre-salt production would have increased from 14 $kgCO_2eq/boe$ to 24 $kgCO_2eq/boe$, potentially undermining the environmental viability of the project. Additionally, due to infrastructure limitations for gas export and the need to meet commercial specifications, part of the produced natural gas was reinjected along with the CO_2 - improving both operational efficiency and emissions performance (SANTOS et al., 2024).

In contrast, many onshore assets lack the infrastructure required for the economic use of associated gas, which restricts monetization opportunities and increases methane emissions through venting and/or flaring. Nevertheless, onshore operations often provide significant economic and social benefits to underdeveloped regions, contributing to local revenue generation and fostering regional development.

Therefore, the selection and impact assessment of mitigation measures will depend heavily on the production environment in which they are implemented - whether onshore, offshore in shallow waters, or offshore in the pre-salt layer. While onshore assets may offer easier access to electricity and greater feasibility for satellite-based methane monitoring, high-productivity offshore fields typically provide shorter payback periods and greater potential for large-scale, cost-effective GHG reductions.

3.4.3. Electrification

Oil production is an energy-intensive activity, whether for powering the various pieces of equipment and facilities used to extract and process hydrocarbons from great depths or for ensuring the continuous operation and safety of production systems. Depending on the type of oil, depth of extraction, processing and export specifications, and facility operating conditions, electricity demand can reach several hundred megawatts (NGUYEN et al., 2014). This electricity may be supplied either by local utilities or the free market - common options for onshore operations - or via self-generation, which is typical of offshore units.

Self-generation is usually achieved through simple open-cycle gas turbines powered by natural gas or fuel oil produced onsite. A significant share of GHG emissions in Exploration and Production (E&P) activities comes from the combustion of these fuels - either directly in compressors, pumps, and heaters or indirectly through power generation turbines. For instance, a single FPSO (Floating Production, Storage, and Offloading unit) with a processing capacity of 150,000 barrels per day and powered by gas turbines can emit up to 328,000 tons of CO_2 annually (CRUZ et al., 2023). To put this into perspective, this is roughly equivalent to half of all emissions from the municipality of Vitória (ES) in 2023, according to the SEEG platform (2024).

Electric-powered systems can be significantly more efficient - surpassing 96% efficiency (IOGP, 2022) - compared to fossil-fueled processes. Therefore, a substantial portion of decarbonization efforts in the E&P sector hinges on the electrification of operations, particularly the replacement of mechanical drives with electric alternatives. In this context, promoting the use of clean and renewable energy sources to power these systems is critical to achieving meaningful GHG reductions.

Despite its high mitigation potential, electrification - especially from renewable sources - faces significant implementation challenges, which vary depending on whether the project is onshore or offshore, and whether it is a greenfield or brownfield development.

Onshore projects

Many onshore assets already rely on grid-supplied electricity, typically provided by local utilities. However, given the high energy intensity of E&P activities, long-term demand and supply reliability over the project's lifecycle - often exceeding 20 years - are critical considerations.

In terms of reliability, a recent survey by the National Confederation of Industry (CNI, 2024) showed that 70% of respondents experienced power outages in the previous 12 months, with 46% reporting significant production losses. The situation is even more critical in Brazil's North (52%) and Northeast (53%) regions - areas with a concentration of onshore oil production. In such sensitive operations, unscheduled shutdowns not only reduce output but may also compromise safety, such as preventing gas venting if compressors are not operating.

Although grid connection already results in significant emissions reductions - thanks to Brazil's clean power mix, with renewables accounting for over 89% of electricity generation in 2023 (EPE, 2024e) - onshore production sites also offer the opportunity to install dedicated renewable generation units, helping address reliability and availability issues. When field consumption does not justify dedicated generation, particularly in the Northeast, companies may still benefit from purchasing energy directly from nearby wind and solar farms.

Offshore projects

Offshore operations primarily rely on self-generated electricity from natural gas extracted onsite. Decarbonizing these systems involves either offshore renewable generation or connecting production units to the onshore power grid.

In terms of offshore generation, various global projects are exploring renewable options, especially offshore wind and, to a lesser extent, floating solar. However, these approaches present multiple challenges:

- High capital costs: the global average installation cost for offshore wind projects in 2023 was around USD 2,800/kW (IRENA, 2024). For floating solar, estimates range from USD 800–1,200/kW (WORLD BANK, 2018), while NREL indicates about USD 2,600/kW for installations on artificial water bodies - 25% higher than land-based systems (NREL, 2021). Marine installations - exposed to tides and waves - are expected to cost more than the reported averages.
- Logistics and infrastructure: port capacity to handle large turbines and offshore equipment remains a constraint, as does the feasibility of installing and maintaining solar arrays in open sea conditions (EPE, 2020).
- Legal and regulatory uncertainty: until recently, Brazil lacked a robust legal framework for offshore renewable energy. The enactment of Law No. 15,097/2025 now aims to address these gaps and foster investment.
- Environmental licensing: the licensing process for offshore renewable projects can be complex and time-consuming, with overlapping challenges from both the power and oil & gas sectors. Key issues include impacts on bird and marine life migration and the need for marine spatial planning.
- Socioeconomic conflicts: most offshore wind structures are installed in shallow waters, where conflicts with fishing or tourism activities may arise, especially if subject to the 500-meter navigation exclusion zone established by NORMAM-08/DPC.

- <u>Intermittency</u>: renewable sources are intermittent, while offshore operations require stable, continuous power. Therefore, robust storage solutions are essential to ensure uninterrupted supply.

Transmission over long distances is another critical factor - especially for grid-connected electrification. This is detailed below. When connecting platforms to the onshore grid, in addition to the general electrification challenges already discussed, distance becomes a major hurdle. According to the IEA (2023), Brazil is among the countries with the greatest distances - often over 60 km - between production sites and the grid. Subsea transmission cables require large upfront investment, have limited redundancy, and long maintenance lead times (IOGP, 2022). Water depth also affects cable design and feasibility. With most Brazilian offshore production located in deep and ultra-deep waters, the technical and economic complexity of subsea power transmission increases considerably.

Greenfield vs. Brownfield Projects

Electrification is more easily implemented in greenfield projects, where design flexibility allows for the early integration of electric systems. In contrast, retrofitting existing brownfield assets faces greater constraints - such as structural limitations (e.g., space and weight), the need for extensive modifications, and potential operational shutdowns. These constraints are particularly acute in offshore environments.

Therefore, it is recommended that operators integrate electrification provisions into the base design of new (greenfield) projects, even if the technology is not deployed immediately. This foresight can prevent future retrofit barriers and reduce costs. Following the example of the North Sea Transition Authority (NSTA, 2024), Brazilian regulatory bodies could also require the inclusion of electrification feasibility studies in the Development Plans submitted for approval - promoting best practices in E&P project planning and execution.

3.4.4. Future outlook for CCUS

In Brazil, interest in Carbon Capture, Utilization, and Storage (CCUS) has been increasing in recent years, in line with the broader global trend observed over the past decade (IEA, 2024a). Although current applications are mostly concentrated in the pre-salt production region of the Santos Basin - primarily for Enhanced Oil Recovery (EOR) - CCUS is expected to expand nationwide following the enactment of a legal framework (Law No. 14,993/2024, approved at the end of 2024) and the forthcoming regulations to be established by the ANP. The agency has recognized the value of pilot projects and transitional regulatory mechanisms as appropriate tools to guide early CCUS deployment while comprehensive legislation is still under development. In parallel, the recent establishment of a regulated carbon credit market under Law No. 15,042/2024 is further supporting the uptake of CCUS technologies by creating economic incentives for emission reductions.

Among the key barriers to scaling up CCUS are the high costs associated with carbon capture and, when applicable, transport. Capture costs are influenced by factors such as the level of CO_2 purity required, the concentration of CO_2 in the emission stream, and the type of capture technology employed (e.g., solvents, membranes, or sorbents) (GARCIA et al., 2022). Transportation costs, in turn, depend on variables including the distance between capture and storage sites, the physical state of the CO_2 (gas or supercritical fluid), the availability of existing pipelines or other infrastructure, the potential for shared use across sectors, and the complexity of environmental permitting (SMITH et al., 2021).

It is also important to emphasize that the role of carbon capture extends well beyond enhanced hydrocarbon recovery. CCUS can contribute substantially to the decarbonization of upstream production, midstream processing, and downstream thermal power generation.

Moreover, shared CCUS infrastructure has the potential to serve multiple hard-to-abate sectors - such as steel, cement, chemicals, and bioenergy - offering a more cost-effective and scalable pathway to reduce industrial emissions. Brazilian energy companies like Petrobras and Eneva are already exploring such integrated models to lower project costs and increase synergies (CHIAPPINI, 2022; ENEVA, 2024a; MACHADO, 2023). Coupling CCUS with hydrogen production also presents promising investment opportunities (ENEVA, 2024b).

As observed in other countries, the large-scale deployment of CCUS in Brazil will depend heavily on government support. Public policy instruments - such as financing mechanisms, carbon pricing frameworks, credit lines, and tax incentives - will play a key role. Equally important are transparency and public engagement strategies to communicate the long-term benefits of CCUS and foster societal acceptance. With these foundational elements in place, it is expected that CCUS will see broader adoption across multiple sedimentary basins in Brazil during the early 2030s, helping to advance national decarbonization targets and enabling a lower-carbon oil and gas industry.

4. Proposals for the decarbonization of the Brazilian upstream sector

Building on the context presented in Chapter 2 and the analysis of mitigation alternatives and emissions reduction scenarios discussed in Chapter 3, a set of proposals has been developed to support the formulation of a national decarbonization strategy for the Exploration and Production (E&P) segment.

Given the high complexity of decarbonizing an energy-intensive segment such as E&P, it is essential to implement actions that address the various dimensions of this activity. Accordingly, this strategic framework is structured around four main guiding axes, under which the proposed measures are categorized and organized. The detailed proposals and corresponding action axes are presented in the following sections.

While the impacts of these measures will vary depending on the specific characteristics of each facility, the proposed solutions, taken together, have the potential to broadly promote the decarbonization of Brazil's E&P segment.

4.1. Axis 1 - Dissemination of best practices and reduction of information asymmetry

The first proposed guiding axis focuses primarily on aligning technological knowledge and operational best practices within the context of a rapid transition toward a lower-emission energy sector. It begins by addressing measures for information dissemination and for encouraging the advancement of E&P operations to meet the highest global industry standards in the measurement, mitigation, and reduction of greenhouse gas (GHG) emissions.

One mechanism to reinforce best practices in emissions mitigation is the requirement - under ANP regulation - for operators to include decarbonization alternatives in their Development Plans, based on leading practices in the Brazilian industry and taking into account the specific characteristics of each facility.

I. *Expand knowledge on data and methodologies for GHG emissions accounting, enhancing the quality of public and sectoral inventories*

A. Identify major information gaps based on existing inventories and primary data collected and disclosed by operators and concessionaires.

B. Develop a sectoral guide for preparing GHG emissions and reduction inventories in E&P activities.

C. Promote sharing of best practices in emissions accounting across industry forums, tailored to the Brazilian context.

D. Encourage third-party verification of emissions data and reports disclosed by companies.

II. *Standardize industry knowledge on technical aspects of flaring and venting*

A. Disseminate technical content on critical analysis of flaring and venting criteria in E&P projects, detailing aspects such as emission factors and combustion efficiency, the impacts of released gases, and international best practices including standards and regulatory frameworks.

B. Assess the development of public policy or regulation to establish limits and guidelines for gas venting.

III. *Encourage adherence to public and corporate initiatives for emissions reduction*

A. Adopt globally recognized best practices for methane mitigation, such as the OGMP (Oil and Gas Methane Partnership) guidelines and the Methane Guiding Principles.

B. Promote company participation in sectoral commitments, such as the Zero Routine Flaring initiative and the Oil and Gas Climate Initiative (OGCI).

IV. *Propose actions to minimize the impact of fields, facilities, and activities with higher total emissions and emission intensity*

4.2. Axis 2 - Encouraging capacity building and innovation

Building on the previous proposals, the second suggested axis focuses on the technical aspects of Upstream activities. This aims to enable technological progress at the pace required to keep up with a rapidly evolving innovation landscape and growing emissions-related constraints. It seeks to technically strengthen not only the companies operating E&P contracts in Brazil but also the entire supply chain that supports oil and natural gas exploration and production.

V. *Strengthen the mechanisms of the R&D Clause, with a focus on decarbonization*

A. Set specific growth targets - either in absolute values or percentages - for resource allocation to areas and topics related to GHG emissions and environmental impacts.

B. Evaluate the creation of new subtopics focused on:

i. emissions measurement;

ii. advanced technologies for methane emissions detection and leak repair; and

iii. systems and equipment for electrifying operations.

C. Expand partnerships among government institutions, companies, and academia to accelerate the development and large-scale adoption of new technological solutions for decarbonizing E&P, as seen in programs like the Human Resources Training Program (PRH-ANP) and the ANP Entrepreneurship Program (NAVE).

VI. *Propose strategies and partnerships for training and capacity building within the supply chain, enhancing human capital qualification*

A. Promote recurring initiatives to ensure knowledge and technology transfer.

B. Structure projects or a Supplier Capacity Building Program, as established in ANP Resolution No. 918/2023, to train supply chain companies in adapting projects to GHG mitigation best practices, including new technologies and equipment.

VII. *Structure mentoring and training programs for projects focused on reducing carbon intensity*

4.3. Axis 3 – Incentives for enabling decarbonization projects

In addition to developing human capital, it is crucial that E&P projects in Brazil align with international best practices for lower carbon footprint production. In this regard, the oil and gas industry's experience in developing and operating complex, capital-intensive projects is highly valued. To enhance these capabilities and apply them to emissions-competitive projects, it will be necessary to provide an attractive market environment with investment opportunities and incentives for low-carbon sources.

VIII. *Facilitate access to international financing for emission reduction projects and expand national credit lines for decarbonization in E&P*

A. Foster market conditions that favor the attraction of funds from multilateral banks focused on the energy transition.

B. Structure new mechanisms or adapt existing credit lines with favorable conditions for producers that implement decarbonization measures, such as adopting renewable energy sources, improving energy efficiency, or implementing carbon capture.

C. Ensure access to financing for small producers, especially in assets with mapped mitigation opportunities and evidence of regional development potential.

IX. Identify opportunities to maximize low-carbon energy sources in E&P operations, including power supply

A. Identify asset types with the greatest potential for renewable energy supply, listing available sources, supply conditions, and potential barriers.

B. Establish renewable supply targets according to the different project profiles, respecting the characteristics and limitations identified in item A of this proposal.

X. Monitor the integration of sector companies into the carbon market

A. Support the incorporation of GHG emission costs into the viability assessments of E&P projects.

4.4. Axis 4 – Support for Regulatory and Oversight Activities

Considering that the previous proposals enable technical capacity building throughout the entire E&P value chain and the evolution of the business environment to facilitate the segment's transition toward a lower-emissions energy offering, this fourth and final axis focuses on ensuring the proper tools for regulating and overseeing these activities. It highlights the need for continuous improvement - the main objective of the proposals below - in a market expected to adopt new business models and attract diverse players in the coming years.

XI. Strengthen regulatory and oversight bodies responsible for GHG emissions in E&P

A. Ensure the necessary funding to adapt regulations to the challenges posed by new projects with differing characteristics.

XII. Support the regulator in structuring LDAR campaigns to identify super-emitters (equipment and assets)

A. Facilitate engagement with development institutions to support the acquisition of equipment and staff training.

B. Contribute to mapping unreported venting events.

XIII. Establish strategies for monitoring flare efficiency

A. Commission studies to adopt emission factors aligned with the Brazilian technological and operational context in flaring processes.

XIV. Encourage the development of an Emissions Reduction Action Plan by all companies operating in Brazilian E&P [7]

A. Establish specific content requirements, such as:

[7] The proposal aims to ensure that, after a defined period, all companies will have developed their Action Plans, without being required to create new strategies, provided that the basic requirements are met. Many companies in the sector already operate under the guidelines of previously established Emissions Reduction Plans, which would fulfill this requirement.

i. identification, monitoring, and mitigation opportunities applicable to assets;

ii. proposed initiatives for emission reduction and corresponding timelines;

iii. criteria for prioritizing mitigation measures; and

iv. defined reduction targets.

B. Adjust deadlines based on production levels, implementation capacity, and operational maturity of companies.

C. Require the inclusion of identified emissions reduction alternatives in the Development Plans submitted by operators.

Figure 8 visually summarizes the proposals presented in this chapter.

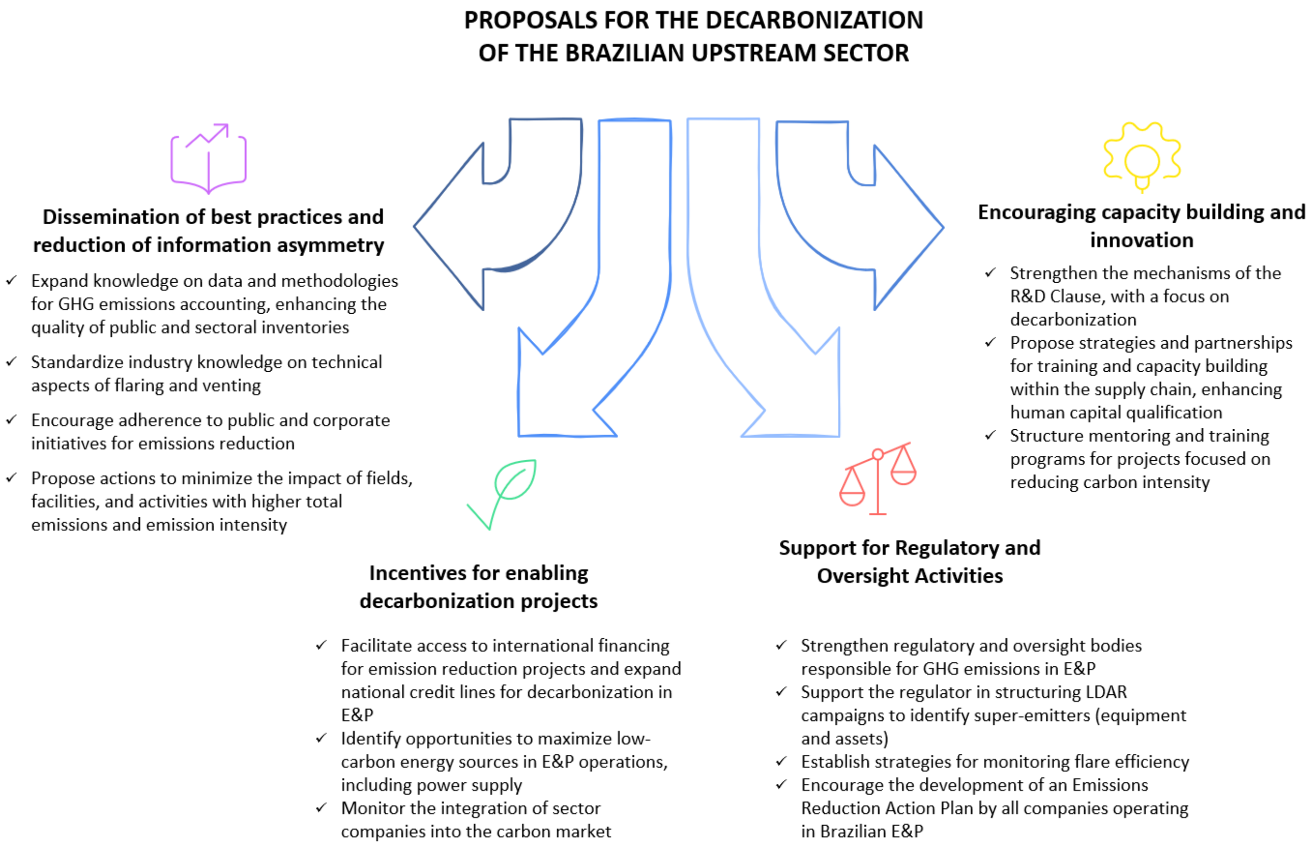

Figure 8. Proposals presented for the Brazilian E&P segment.

5. Conclusion

The decarbonization of oil and natural gas Exploration and Production (E&P) activities in Brazil constitutes a strategic and multidimensional challenge, requiring coordinated efforts from government, industry stakeholders, and investors. In alignment with the guidelines set forth in National Energy Policy Council (CNPE) Resolution No. 8/2024, this report presents a set of scenarios and measures aimed at reducing emissions within the E&P segment. It encompasses both readily available technological solutions and emerging alternatives, while also proposing strategic action areas to inform public policy for the sector's decarbonization.

Complementing this report are two supplementary documents: the *Fact Sheet on Technologies for Emissions Reduction in E&P* and the *E&P Decarbonization Scenarios – Methodological Slide Deck*. These materials elaborate on the response of EPE, ANP, and PPSA to Resolution No. 8/2024, presenting excerpts from the main report in a more visual and didactic format. They underscore EPE's role in reducing information asymmetry and in providing accessible, free content to a broad range of audiences.

The work carried out by the Energy Research Office (EPE), with the support of the National Agency for Oil, Natural Gas and Biofuels (ANP) and Pré-Sal Petróleo S.A. (PPSA), aims to provide a robust technical foundation for the formulation of public policies and the implementation of effective emissions mitigation strategies.

Given the central role of the oil and gas sector in Brazil's economy and energy security, the transition to a model with lower environmental impact must be conducted in a planned and structured manner. The growing global demand for cleaner energy, along with increasing pressure from investors and consumers for more sustainable practices, reinforces the need for a strong commitment to emissions reduction.

To this end, the study proposes four main guiding axes:

(i) the dissemination of best practices and reduction of information asymmetry, ensuring that companies of all sizes have access to knowledge and mitigation solutions.

(ii) the promotion of capacity building and innovation, enabling the development and adoption of new technologies for emissions reduction.

(iii) incentives to support the implementation of decarbonization projects, fostering a favorable economic environment for investment; and

(iv) support for regulatory and oversight activities, ensuring that environmental guidelines are enforced and continuously enhanced by strengthened institutions.

The analysis presented in this report highlights that decarbonization solutions in the E&P sector must be tailored to the specific characteristics of each operation, taking into account factors such as reservoir type, facility location, and available infrastructure. The objective of developing scenarios and mitigation estimates is to contribute to the ongoing discussion on decarbonization pathways in E&P, underscoring the importance of a structured approach.

As a first step, it is essential to prioritize short-term actions that enable immediate emissions reductions and are feasible with currently available technologies. At the same time, it is necessary to plan medium- and long-term strategies aimed at scaling up mitigation efforts, which will require innovation, investment, and appropriate incentives. This approach ensures that decarbonization efforts can be implemented in an efficient and sustainable manner.

Within the scope of short-term actions, particular emphasis should be placed on identifying and developing mitigation strategies targeting the largest emission sources. This involves implementing more rigorous detection and monitoring programs, covering both existing production facilities and new projects. The commissioning of targeted technical surveys and assessments for emissions quantification and mapping is essential to ensure more accurate and industry-aligned data. With a clearer understanding of the primary emission sources, the government will be better equipped to prioritize mitigation efforts, allocate resources more efficiently, and direct greenhouse gas reduction policies toward the most emission-intensive fields, installations, and operational activities.

In this context, it is vital to strengthen the role of the National Agency for Oil, Natural Gas and Biofuels (ANP) in the management of sectoral emissions. It is particularly important that the Development Plans required for each project include decarbonization scenarios and alternatives, thereby encouraging companies to commit to the adoption of low-carbon technologies and more efficient processes to reduce their greenhouse gas (GHG) emissions. These requirements may include the evaluation of electrification options for operations, the adoption of Carbon Capture, Utilization and Storage (CCUS), gas recovery systems, and the increased use of renewable energy in oil and gas fields, among other measures.

Brazil's oil and gas production already features a comparatively low carbon intensity, largely due to the characteristics of its pre-salt reservoirs and the efficiency of its operational processes. However, in order to consolidate this position and become a global benchmark in low-carbon production, it is essential to reinforce public policies that promote innovation and the widespread adoption of sustainable practices across the sector. Coordinated efforts among government bodies, regulatory agencies, operating companies, and research institutions will be crucial to ensuring that Brazil can balance economic growth and social development with the imperative of climate change mitigation.

Finally, this study underscores that the energy transition is not merely an environmental obligation, but also a strategic opportunity for Brazil to enhance its competitiveness in the global energy market. The implementation of the proposed measures - combined with the continued engagement of key stakeholders - can ensure that the country moves forward in a structured manner in decarbonizing the E&P segment, contributing to international emissions reduction commitments and solidifying its position as one of the world's leading producers of sustainable energy.

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