

Improving Greenhouse Gas Emission Calculation Accuracy in the Oil and Gas Industry in the context of Indonesia

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Case Report

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Abstract

International climate policy increasingly pressures companies to demonstrate credible greenhouse gas (GHG) emission accounting. While various frameworks exist, firms struggle with system boundaries in complex industrial operations. This study addresses this challenge by developing an emissions calculation grounded in real field conditions and offering strategic insights for Indonesia's oil and gas sector using Pertamina as a case study particularly regarding future carbon-tax exposure. The research introduces a high-resolution accounting approach for the CPP Gundih gas processing facility in Central Java, correcting a long-standing source of uncertainty where Pertamina assumed the entire 13 MMSCFD of Acid Gas Removal Unit off gas was combusted, inflating annual emissions to 250 ktCO₂. Field inspections revealed that 10–13 MMSCFD is diverted to a Biological Sulfur Recovery Unit. Using an IPCC Tier 3 carbon-content method anchored to real routing data, this study establishes a corrected baseline of 38 ktCO₂ per year. Under Indonesia's carbon levy of IDR 30,000/ton, this revision reduces annual tax liability from IDR 7.5 billion to IDR 1.15 billion, preventing a four-to-sixfold overpayment. The economic analysis further examines how this compliance costs interact with two upstream fiscal regimes: PSC Cost Recovery and PSC Gross Split. The Gross Split model consistently delivers contractor margins roughly four times higher than Cost Recovery and shows stronger resilience to carbon-policy fluctuations. Integrating Tier 3 accounting with the Gross Split structure outlines a practical pathway to reduce long-term climate liabilities while keeping assets aligned with Indonesia's Net Zero 2060 ambitions.

1. Introduction

The growing global push to confront climate change has brought greenhouse gas (GHG) emissions to the forefront of international policy discussions and company efforts (OECD, 2025). According to the Intergovernmental Panel on Climate Change (IPCC), energy-related to carbon dioxide (CO₂) makes up around 73% of all anthropogenic GHG emissions, with the oil and gas industry standing among the largest contributors (IPCC, 2023). As countries intensify their efforts to meet the temperature goals set under the Paris Agreement, the need for precise and trustworthy GHG measurement systems has become increasingly fundamental (UN Environment Programme, 2023). Without credible measurement, both national strategies and international accountability frameworks lose their effectiveness (UNFCCC, 2026).

The oil and gas sector continues to grapple with deep rooted and technically complex obstacles in producing emissions data, despite the critical role that measurement plays in global climate action (Halttunen et al., 2022). Unlike fixed combustion sources, operations in this industry generate emissions through multiple and highly variable pathways, from fugitive methane leaks to routine and emergency flaring, vented process gases, and a wide range of indirect emissions across upstream, midstream, and downstream activities (Olczak et al., 2023). Each pathway introduces its own layer of uncertainty, making precise quantification difficult (Alvarez et al., 2018). The challenge become even more pronounced when considering the wide variation in operating environments, the age and conditions of assets, reservoir characteristics, and the uneven quality of monitoring systems accross companies and regions (Ding et al., 2025). These differences create a measurement landscape where reported figures can diverge sharply from the actual emissions released into the atmosphere, ultimately weakening the credibility of corporate climate pledges and the reability of national GHG inventories (Papadopoulos, 2022).

Accurate assessment of emissions in oil and gas operations is crucial for regulatory, environmental, and financial reasons, particularly as emission levies and carbon credits grow increasingly prevalent This research is based on a case study of Pertamina EP Cepu (Indonesia's national company in the oil and gas sector) regarding their emission estimation, especially the lack of sophistication in calculating emissions in each of their gas production processes

before reaching the buyer. The errors and inaccuracies in calculating and reporting emissions in the gas field they estimate in the amount of emissions produced can make them pay more carbon tax or miscalculation. It is hoped that by raising this topic, it can become a continuous improvement project and formula recommendation for Pertamina EP Cepu in determining their emissions precisely, monitored and validated.

Carbon emission estimation method in the energy sector is increasingly applied, and oil and gas companies particularly those producing natural gas are paying closer attention to the emissions generated during their operations (Liggio et al., 2019). A recent study show that assuming all gases from oil and gas wells are released and combusted through flaring is misleading, as not all produced gases are flared or emitted directly (Abidin, 2022). This can introduce significant errors in emission estimates and underscores the need for more accurate, site-specific measurement and reporting approaches. In practice, treatment at Pertamina EP Cepu, the Central Processing Plant (CPP) Gundih is a gas-processing facility that produces acid gas after purification, primarily composed of H_2S and CO_2 (Abidin, 2022). Existing literature on emission estimation in industrial settings including ports and oil and gas facilities highlights recurring issues such as underestimation due to missing sources and the absence of broadly applicable methodologies (Wang & Li, 2023). However, in the case of Pertamina EP Cepu, however, the challenge involves both overestimation and underestimation arising from generic calculation techniques that fail to reflect actual process flow (Abidin, 2022).

The structure of the article is arranged as follows. Section 2 reviews the existing literature and theoretical foundation for emission calculation in the oil and gas sector. Section 3 emphasize the method and the data used to estimate total carbon emission. Section 4 applies this framework to a case study, examining the potential scenario for the company. The final section reflects on the broader policy implications that emerge from the analysis.

2. Literature review and theoretical foundation

Extant literature on GHG accounting within the oil and gas industry highlights a continuous friction between idealized global measurement standards and the nuanced operational realities of industrial activities, particularly in emerging markets. The theoretical underpinning of emission carbon accounting hinges on five core tenets: relevance, completeness, consistency, transparency, and precision with precision serving as the bedrock for trustworthy climate policy (Crocker, 2024). However, exactness is not merely an isolated technical parameter; rather, it is continually mediated by the convergence of quantification methodologies, data integrity, and local institutional landscapes. This variance introduces systemic bottlenecks when frameworks tailored for International Oil Companies (IOCs) operating in mature regulatory regimes are transplanted onto National Oil Companies (NOCs) in nations like Indonesia. Recent scholarship in climate policy and industrial emissions accounting highlights persistent inaccuracies in conventional estimation methods, particularly in sectors with complex process flows such as oil and gas (Kim et al., 2024). The PEGANG application at CPP Gundih addresses these highlighted gaps in the literature by offering a bespoke solution for Pertamina EP Cepu's particular operating setting. Recent work at PT Pertamina EP Cepu, notably at the CPP Gundih plant, developed the PEGANG application, which used a Non-Clause Method to segregate emissions computations for gas vented to the Thermal Oxidiser (TOX) and gas transformed to sulphur in the Biological Sulphur Recovery Unit (Abidin, 2022). This methodology produces more precise, and often lower, emission estimates than standard approaches that assume all acid gas is vented. This is a major methodological advancement in emissions accounting for oil and gas activities.

A recent study by Lu et al. (2025) examines the development of the China Carbon Standard System, which adapts international standards to the country's domestic context (Tan & Iyer, 2025). On the 2022, PEGANG (CPP Gundih) (Abidin, 2022) provided a novel application-based Non-Clause technique for more accurate emission calculations.

While promising, this technique needs through data and has yet to be established as an industry standard. In the CO₂-EOR (JTB Field, Cepu) research (Panggabean et al., 2022), value engineering was combined with enhanced oil recovery (EOR) technology to maximise carbon utilisation. However, its high implementation costs and early stage status require further evaluation. A review of the extant literature reveals significant shortcomings in the current state of the art from IPCC guideline (Amon et al., 2021; IPCC, 2019), particularly with regard to the calculation of carbon emissions for each process of each device, extending beyond the scope of gas flaring or burning phase. A previous study by Abidin (2022) has questioned that carbon capture efficiency reaches 100%, so it is certain that some emissions are released into the atmosphere. With the performance of emission capture equipment declining for example, some equipment in the Bio Sulfure Recovery Unit (BSRU) is currently experiencing a decrease in performance some of the H₂S produced is burned in the TOx system.

Although several studies have been conducted at the Gundih gas processing field, from The Economic Research Institute for ASEAN and East Asia (ERIA) Feasibility Study and Asian Development Bank (ADB) team (Kelly et al., 2019) identifies Indonesia as a priority location for ASEAN's first carbon capture and storage (CCUS) pilot project after 2025 and highlights the country's substantial deep-saline storage potential. CPP Gundih is uniquely advantaged for early CCUS deployment because its AGRU off-gas stream is already a high-purity CO₂ stream, requiring minimal pre-treatment and significantly lowering capture costs. The other one in which a research team from Gadjah Mada University calculated exhaust emissions such as SO_x using Clause method. However, the formula used does not reflect the conditions at the Gundih field because it assumes that all acid gas produced is classified as exhaust emissions. This is because the calculations do not consider the role of bacteria in reducing emissions, and the calculated SO₂ emissions are too high and fail to reflect real-world conditions. This lack of accuracy may negatively affect future emission reporting and carbon tax assessments.

Furthermore, the Pertamina EP Cepu team developed the PEGANG application to calculate the emissions of individual pieces of equipment using Non-Clause method (Abidin, 2022). However, the scope of this application is restricted to SO_x compounds only instead of CO₂e. Therefore, it is not possible to estimate the future carbon tax payable in accordance with national and international standards. Furthermore, the calculations need to be conducted with IPCC guidelines. The IPCC categorizes methodologies for calculating greenhouse gases into three distinct tiers, striking a compromise between analytical exactness and administrative ease (Eggleston, 2006; IPCC, 2023). The foundational approach, Tier 1, utilizes standardized global emission parameters and macro-level activity statistics; while straightforward, it introduces considerable margin for error in the Indonesian context, where regional operational realities deviate significantly from Western-derived baseline data. Progressing to Tier 2 enhances granularity by integrating localized or asset-specific indicators, though widespread deployment is stymied by a scarcity of verified, country-specific baselines for critical emission sectors. Ultimately, Tier 3 offers the apex of granularity via continuous physical tracking and deterministic process modeling, yet this standard demands rigorous technical proficiency and extensive analytical infrastructure.

Consequently, for state-owned energy entities like Pertamina, the strategic dilemma centers on engineering a methodology to elevate tracking protocols from not even implemented yet the assessments toward high fidelity frameworks without compromising operational viability. In-depth research is therefore needed on carbon emission and carbon tax calculations that prioritise feasibility and viability for companies to consider when performing sustainable business operations.

3. Methodology

3.1 Method

To support the findings of this research, a dual approach was employed, incorporating both qualitative and quantitative methodologies. The qualitative approach was carried out in the form of site visits, observations, and discussions with field workers at Pertamina EP Cepu. This allowed for an understanding of the flow of the gas production process in the field and an investigation of the points of carbon emissions that are released in each process section. These stages encompassed various levels of analysis, including national, regional, and global perspectives. The focal point of these reviews was on oil and gas companies, with a view to elucidating the current state of carbon emission reduction strategies within this sector. The initial step in this process was to read field documents related to the company's history and to understand the various projects that have been carried out to reduce carbon emissions.

After the above data was obtained through laboratory tests, several collaborative methods were used to obtain significant results from this research. First, a third party conducted a compositional gas analysis at the Gundih CPP gas metering plant. A baseline calculation was performed to determine the carbon emissions produced without gas processing, which are considered greenhouse gas (GHG) emissions. Next, a scenario calculation was performed after gas processing. Regarding CO₂ emissions and CO₂e tax, this study applies IPCC Tier 3 method to estimate CO₂ emissions from the TOX and flare systems at the Gundih CPP (Intergovernmental Panel on Climate Change, 2019; Yona et al., 2022). This method was applied because the data were recorded in real time at the gas production facility through both sampling and online monitoring conducted by the production operation control room. The emissions calculation begins at the wellhead and continues along the entire process until the point of gas delivery to the buyer. Furthermore, a formulation was derived to represent the calculated outputs for the Pertamina EP Cepu field. This formula is derived from the IPCC guidelines. To ensure credibility and global comparability, it is essential to employ the most recent IPCC recommendations and ISO 14040/14044 for life cycle inventory (LCI) and emissions reporting (Eggleston, 2006; IPCC, 2023). A thorough examination of data sets pertaining to daily emissions and gas production was undertaken. Furthermore, a dashboard was developed that can be seamlessly integrated with the user interface. In addition, the utilization of visualization in real time is imperative. The study applies a facility-level carbon mass approach to quantify CO₂ flows in a natural gas processing system operated by Pertamina EP Cepu at the Central Processing Plant (CPP) Gundih. The methodology is aligned with the IPCC 2006 guidelines (Tier 3 approach) (Eggleston, 2006), the GHG Protocol Corporate Standard of scope 1 emission (Ranganathan et al., 2004), and the US EPA greenhouse gas reporting framework (Subpart W – Petroleum and Natural Gas Systems) .

The previous studies exhibited several notable limitations in both methodology and practical application. They have not yet incorporated the updated IPCC calculation standards. Key impurity components remain unaccounted for, and the assumption of zero emissions from the BSRU is technically unrealistic given that real systems inevitably leave a 1–2% residual due to efficiency constraints. The analyses also concentrate narrowly on SO₂ derived from H₂S while overlooking Thermal Oxidizer (TOX)-related emissions, even though carbon-pricing regulations require full CO₂e accounting from fuel and residual-gas combustion. Moreover, the PEGANG application's "Non-Claus" approach by (Abidin, 2022) is validated only against older formulas rather than against actual stack measurements such as Continuous Emission Monitoring System (CEMS) or laboratory spot checks, leaving its real-world accuracy unverified. The studies further fail to explain how the method responds to operational disturbances such as Biological Sulfur Recovery Unit (BSRU) performance drops that divert gas to Tox despite the need for contingency calculations and TOx efficiency corrections (DRE). Due to performance degradation, the assumption that equipment efficiency is below 100% should be applied specifically to the BSRU and Tox systems. Other than that, without integrating mass balance, comprehensive CO₂ estimation, real-time monitoring data, and uncertainty analysis, the current methodology remains insufficient for regulatory compliance, international verification, or carbon-credit claims.

The Formula of IPCC for the flare gas must be performed to address the previous research limitation as follows:

$$E_{CO_2} = \sum_{p=1}^N \left(V_p \times CC_p \times M_p \times \frac{44}{12} \right)$$

1

Where:

E_{CO_2} = Total carbon dioxide emissions (mass of CO_2 in tonne)

V_p = Volume of flare gas during period p (scf)

CC_p = Carbon content of gas during period p (mole fraction)

M_p = Molar density of gas during period p (mass per unit volume)

44/12 = Molecular weight ratio of CO_2 to Carbon (g/mole)

N = Total number of measurement period

P = Observation or calculation period index

The study applies a facility-level carbon mass approach to quantify CO_2 flows in a natural gas processing system operated by Pertamina EP Cepu at the Central Processing Plant (CPP) Gundih. The methodology is aligned with the IPCC 2006 guidelines (Tier 3 approach) (Eggleston, 2006) and the GHG Protocol Corporate Standard of scope 1 emission. Besides a research interview about the business process and recent company's strategy to address their emissions would be conducted to get more holistically knowledgeable about the company internal regulation and plan.

In addition, to determine what percentage of the emission payment expenses to be borne by Pertamina EP CEPU will be covered by its net gas sales scheme, it is important to note that in Indonesia, two types of contracts are commonly used in the oil and gas sector: the Cost Recovery Production Sharing Contract (PSC) and the Gross Split contract (AHP, 2017). Indonesia's upstream oil and gas regulatory framework has undergone substantial changes, shifting from the long-standing Cost Recovery Production Sharing Contract (PSC) to the Gross Split PSC in 2017, and later returning to a flexible system in 2020 (Jone day, 2017). These contractual models determine how revenue, operational responsibilities, and financial risks are allocated between the state and contractors. Under the traditional Cost Recovery PSC which governed the sector for more than five decades contractors finance exploration and production activities upfront but may recover all government-approved expenditures from a portion of production known as Cost Oil or Cost Gas once a commercial discovery is made. The government secures early revenue through First Tranche Petroleum (FTP), typically around 10% of gross production, and maintains strict oversight through SKK Migas, which must approve annual budgets, procurement, and Authorizations for Expenditure (AFE). This structure provides significant financial protection for contractors, making it suitable for high-risk or capital-intensive projects.

Source: (Anjani, B. R., & Baihaqi, 2018)

In contrast, the Gross Split PSC introduced by Ministry of Energy and Mineral Resources eliminates the cost-recovery mechanism entirely. Production is divided upfront based on a base split of 57% (government) : 43% (contractor) for oil and 52% : 48% for gas, which is then adjusted through variable components such as deep-water operations (+ 16%), unconventional reservoirs (+ 16%), high CO_2 or H_2S content (+ 1–2%), and domestic content incentives and progressive components linked to Indonesian Crude Price (ICP) and cumulative production levels MEMR, 2017).

Under this model, contractors bear 100% of financial risk but gain greater operational autonomy, as SKK Migas no longer approves detailed budgets or procurement decisions. Operating costs are treated as tax-deductible expenses rather than reimbursable items.

Concerns that the Gross Split system did not sufficiently attract new investment led to MEMR Regulation No. 12/2020, which restored flexibility by allowing each new or extended work area to adopt either the Gross Split or Cost Recovery model based on project characteristics (Rodyanto, 2020). This policy adjustment aims to counter declining trends in production, reserves, and contract signings. A notable recent development is the Abadi LNG Project, which incorporated Carbon Capture and Storage (CCS) into its revised plan of development expected to become Indonesia's first CCS project implemented under a cost-recovery framework.

3.2 Data collection

Profile of company

Pertamina EP Cepu is a subholding of the Indonesian national oil and gas company called Pertamina. The company operates and produces gas from the Gundih Field and processes the raw natural gas at the Central Processing Plant (CPP) Gundih. The production capacity of CPP Gundih is 70 MMSCF per day, with a total gas supply to customers of 50 MMSCF per day.

The gas produced at Gundih Field is characterized as acid gas. To handle this, the Acid Gas Removal Unit (AGRU) technology is used to convert acid gas into sweet gas. The main components of the acid gas, which are categorized as GHG emissions, are Carbon Dioxide (CO_2) and Methane (CH_4). The total amount of these emissions is approximately 13 MMSCF per day. Based on laboratory test data of gas samples from the Gundih CPP, the gas composition has been identified in both upstream and downstream areas. Upstream, laboratory tests showed CO_2 content of 19.22%, N_2 content of 0.44% and CH_4 content of 69.57%. The H_2S content was 4.641 ppmv and the water content was 165 lb/mmscf. Looking at the results of the downstream gas laboratory analysis, the gas composition was identified in the gas sales section where it entered the buyer's sales pipeline. The results showed that the gas composition was 93.72% CH_4 , 0.0008% CO_2 , 0.46% N_2 and 0.0005% H_2S .

4. Results and Discussion

Before calculating emissions and potential taxes, understanding the gas processing flow is essential for recommending the company's next emission reduction strategy. The diagram below illustrates the gas processing flow, from the raw sour gas at the well to the sweet gas that is ready for sale to the buyer. As shown in the flow diagram above, the natural gas purification process begins with the extraction of raw, acidic gas containing H_2S and CO_2 from the wellhead, which is then immediately routed to a separator to be separated into two fluid phases: liquid and gas. Next, the separated acid gas is directed to the Acid Gas Removal Unit (AGRU) to capture the acid gases, specifically H_2S and CO_2 , resulting in sweet gas, which is then sent to the dehydration unit before being delivered to the gas sales metering station. Regarding H_2S and CO_2 along with other impurity fractions, they are routed to the BSRU and TOx; specifically, H_2S is sent to the BSRU and converted into solid sulfur in pellet form, while CO_2 is directly burned in the TOx unit. In the final stage, CO_2 is burned in a process known as "stationary combustion" in the IPCC 2006/2019 reports.

Source: Company and Authors' Modification.

4.1 Carbon emission assessment and evaluation

The AGRU unit at the Gundih Power Plant produces approximately 13 MMSCFD of sour gas, which is predominantly CO₂ with a small amount of H₂S. Unlike the assumptions of the old emissions calculation template, which assumed that all sour gas was burned in a Claus-type Thermal Oxidizer (TOx) system, actual operational data shows that the majority of the gas stream (approximately 10–13 MMSCFD) is diverted to the BSRU for the biological conversion of H₂S into elemental sulfur (Abidin, 2022). Consequently, the previous template produced overestimates of flue gas emissions. Therefore, this study separates the emissions inventory by counting only the gas flow entering the TOx combustion process as direct flue gas emissions, while the flow directed to the non-Claus BSRU unit is evaluated separately.

The CO₂ emission results obtained in this study were calculated using the Tier 3 carbon-content method, which relies on actual gas composition, measured gas volumes, and stoichiometric carbon conversion. The formula applied using Eq. 1.

Because the AGRU off-gas at CPP Gundih is composed almost entirely of CO₂ (with only trace H₂S), the carbon fraction in the gas is fixed at $CC_{CO_2} = 12/44$. Substituting this value into the Tier 3 equation simplifies the expression to:

$$E_{CO_2} = V_{CO_2} \times \rho_{CO_2}$$

2

This simplification does not introduce a Tier-1-type emission factor; instead, it is the direct mathematical consequence of the Tier 3 carbon-content formula when applied to a nearly pure CO₂ stream. In practical terms, the mass of CO₂ emitted is simply the product of the actual CO₂ volume entering the Thermal Oxidizer (TOx) and the density of CO₂ at standard conditions. The resulting conversion (≈ 52.6 ton CO₂ per MMSCF CO₂) is therefore not a default emission factor but the numerical outcome of the Tier 3 mass-balance relationship.

Using this Tier 3 approach, several routing scenarios were evaluated to reflect the actual operating configuration of CPP Gundih. The legacy calculation template—currently used in internal reporting assumes that the entire 13 MMSCFD of acid gas is combusted in the TOx. Under this assumption, the calculated CO₂ emission reaches approximately 684 ton/day, or 250 kt/year, which explains why the existing emission report appears disproportionately high.

However, operational evidence indicates that most of the acid gas is routed to the Biological Sulfur Recovery Unit (BSRU), and only a smaller fraction enters the TOx. When a more realistic baseline scenario is applied where 11 MMSCFD is routed to the BSRU and 2 MMSCFD enters the TOx the resulting CO₂ emission decreases dramatically to approximately 105 ton/day (≈ 38 kt/year). A high-emission sensitivity case, assuming 3 MMSCFD to the TOx, yields 158 ton/day (≈ 58 kt/year), while a low-emission bound of 0 MMSCFD to the TOx results in zero combustion-based CO₂ emissions.

Table 1
Comparative CO₂ Emission Outcomes Under Different TOx Feed Rates.

Scenario	Description	TOx feed (mmscfd)	CO ₂ emission (ton/day)	CO ₂ emission (ton/year)
Scenario (legacy template)	All 13 MMSCFD assumed to enter TOx (full Claus assumption)	13	684	≈ 250,000
Baseline scenario	11 MMSCFD to BSRU, 2 MMSCFD to TOx (realistic operation)	2	105.2	≈ 38,400
High-emission sensitivity	10 MMSCFD to BSRU, 3 MMSCFD to TOx (upper realistic bound)	3	157.8	≈ 57,600
Low-emission sensitivity	All acid gas routed to BSRU, none to TOx	0	0	0
Source: Authors' Analysis				

These findings demonstrate that the legacy “all to TOx” assumption significantly overestimates actual CO₂ emissions because it does not account for the operational split between the TOx and the BSRU. The Tier 3 calculation, which incorporates real gas routing and the true composition of the acid gas stream, produces a more accurate and substantially lower emission range. This has direct implications for regulatory reporting and potential carbon-tax exposure under Law No. 7/2021, as the taxable emission base is considerably smaller when the actual process configuration is properly represented (Climate Change Laws, 2021).

4.2 Indonesia's carbon market mechanism

Prior to evaluating the carbon tax liability for CPP Gundih's emissions, it is imperative to thoroughly understand Indonesia's carbon market framework. The implementation of a carbon tax mechanism in Indonesia, officially known as the Carbon Levy, is one of the key instruments within the Economic Value of Carbon (EVC) framework as stipulated in Presidential Regulation No. 110 of 2025 (Trucarbon, 2025). This policy is not designed as a standalone levy but is integrated into a cap-and-tax-and-trade system that links the tax mechanism with the Emissions Trading System (ETS). Under this scheme, the government establishes the Technical Agreement on Upper Emission Limits for Business Entities (PTBAE-PU) as the maximum emission limit for each business entity. If the emissions generated exceed the established quota, companies are required to purchase additional quotas from other entities or utilize Greenhouse Gas Emission Reduction Certificates (SPE-GRK) traded through the carbon exchange. A carbon tax is then imposed on the remaining greenhouse gas emissions that still exceed the limit after accounting for the results of such emissions trading.

Source: Authors' Analysis

The government plans to implement the carbon tax starting in 2025 with an initial rate of Rp30,000 per ton of carbon dioxide equivalent (CO₂e) (Jonathan, 2025). The initial phase of implementation will focus on the energy sector, particularly coal-fired power plants (PLTU), before gradually expanding to high-emission industrial sectors, such as the cement, steel, and paper industries. Setting a relatively low rate in the initial phase is intended to give the industrial sector an opportunity to adjust and transition toward more environmentally friendly technologies without causing significant economic disruption.

To ensure transparency and prevent double accounting, this mechanism is supported by a Dual Registry system. All mitigation actions and emission reductions are recorded in the National Registry System for Climate Change Control

(SRN PPI) under the coordination of the Ministry of Environment, while carbon units traded or used to fulfill tax obligations are recorded in the Carbon Unit Registry System (SRUK) supervised by the Financial Services Authority (Trucarbon, 2025). The integration of fiscal instruments, such as a carbon tax, with market-based instruments through emissions trading is expected to create strong economic incentives for companies to reduce their carbon emission intensity, thereby supporting the achievement of Indonesia’s Net Zero Emission target by 2060 or even sooner.

4.3 Carbon Tax Calculation

Under Indonesia’s statutory carbon tax of IDR 30,000 per ton CO₂ (roughly €1.46 at current exchange rates) (Raynaldi & Harangozo, 2025), relying on the outdated "all to TOx" template slaps the asset with an annual tax bill of IDR 7.5 billion (~€366,000). Transitioning to a realistic Tier 3 framework, where only 2 MMSCFD is routed to the TOx, dramatically shrinks this exposure to just IDR 1.15 billion (~€56,000). The sensitivity analysis shows a strict operational swing between IDR 0 and IDR 1.73 billion (~€84,000). Ultimately, shifting to actual gas-routing logic prevents the field from paying 4 to 6 times more than its actual compliance obligation.

Table 2
Carbon Emission and Carbon Tax Calculation of CPP Gundih Plant

Scenario	CO ₂ emission (ton/year)	Tax (idr/ton)	Annual tax (idr)	Annual tax (eur)
Scenario (legacy template)	250,000	30,000	7,500,000,000	365,000
Baseline scenario	38,400	30,000	1,152,000,000	56,064
High-emission sensitivity	57,600	30,000	1,728,000,000	84,096
Low-emission sensitivity	0	30,000	0	€0
Source: Authors Analysis				

Given the volume of emissions generated, a comparative analysis of global carbon pricing and its mechanisms is crucial. This is especially true when considering a scenario in which Pertamina expands into these regions as part of its international business strategy. The breakdown is as follows:

Table 3
Global Emission Benchmark Comparison Carbon Price (per ton of CO₂e)

Country	Mechanism	Carbon price (per ton of CO ₂ e)
Indonesia	Carbon tax	Rp 30.000 (≈ EUR 1.46) (Trucarbon, 2025)
EU (EU ETS)	Cap-and-trade	≈ EUR 74 – 75 (TRADING ECONOMICS, 2026)
UK ETS	Cap-and-trade	≈ GBP 40–60 (Department for Energy Security and Net Zero, 2025)
California	Cap-and-trade	≈ USD 35–44 (≈ EUR 30–38) (Statista, 2025)
Korea ETS	Cap-and-trade	≈ USD 6–10 (≈ EUR 5–6) (L. Bo-yu, 2025)
China ETS	Cap-and-trade	≈ USD 9–14 (≈ EUR 7–12) (Tan & Iyer, 2025)

Source: Authors’ Analysis

Important Note

All figures listed are based on spot market prices, which are subject to fluctuation. As an exception, the indicator for Indonesia refers to the statutory minimum tariff, not the actual price on the carbon market. On the other hand, cost projections for China and South Korea reflect secondary market prices, which are highly volatile. When compared with actual data trends, the calculations in the initial table are generally aligned, except for the South Korean market, which is currently recorded lower in the range of USD 6–10, and the Chinese market, which has seen a slight increase to the range of USD 9–14.

At IDR 30,000 per ton CO₂ ($\approx$ €1.46), Indonesia’s carbon tax is among the lowest in the world. When benchmarked against established carbon markets, the gap becomes substantial: the EU ETS price is 50–70 times higher, the UK ETS is 30–45 times higher, and California’s system is 20–25 times higher. Even regional peers such as Korea (EUR 5–9) and China (EUR 7–12) maintain significantly stronger price signals. This extremely low carbon price explains why high-cost mitigation technologies like CCUS remain economically unviable without complementary instruments such as CCFDs or more ambitious carbon-pricing reforms. The comparison highlights a pronounced carbon-price disparity that shapes investment behavior, industrial competitiveness, and Indonesia’s broader decarbonization trajectory. When comparing the carbon tax revenues for each region, as shown in the table below:

Table 4
Global Benchmark Comparison of Annual CO₂ Emission Prices

Scenario	Emissions (tco ₂ /year)	Indonesia (€1.46)	EU ETS (€74–75)	UK ETS (€47–70)	California (€30–38)	Korea ETS (€5–9)	China ETS (€7–12)
Scenario (legacy)	250,000	€365,000	18,500,000–18,750,000	11,750,000–17,500,000	7,500,000–9,500,000	1,250,000–2,250,000	1,750,000–3,000,000
Baseline	38,400	€56,064	2,841,600–2,880,000	1,804,800–2,688,000	1,152,000–1,459,200	192,000–345,600	268,800–460,800
High	57,600	€84,096	4,262,400–4,320,000	2,707,200–4,032,000	1,728,000–2,188,800	288,000–518,400	403,200–691,200
Low	0	€0	€0	€0	€0	€0	€0
Source: Authors’ Analysis							

Based on Table 5, maintaining identical emission baselines across all configurations highlights massive regional differences in compliance costs. While the annual liability stays relatively minor under Indonesia's framework (amounting to EUR 56,064 in the baseline scenario), it climbs sharply to EUR 2.8–2.9 million within the EU ETS, EUR 1.8–2.7 million under the UK ETS, and EUR 1.15–1.46 million in California's market. This discrepancy grows severe under the outdated Scenario legacy; here, a flawed emissions baseline inflates projected costs to a staggering EUR 18–19 million annually in the EU ETS. Ultimately, these projections prove that a facility's true financial risk such as that of CPP Gundih are dictated by both the chosen calculation method (Tier 3 versus the legacy template) and the local carbon pricing structure.

4.4 Comprehensive Sensitivity Analysis of Carbon Costs Across Gas Pricing Tiers

As the payment of carbon emissions cost is categorized as part of company’s operational cost (Hao et al., 2024), in order to cover the cost of the carbon tax, Pertamina EP Cepu will certainly use the net profit from gas sales, which in this case, the gas are purchased by the State Electricity Company (PLN) and the State Gas Company (PGN), both of which are located in Semarang City and Blora Regency, Central Java (Abidin, 2022). If we look at the gas balance data

which covers production from upstream to downstream you can see the table below, which is based directly on the data (Abidin, 2022):

Table 5
Natural Gas Distribution Flow of CPP Gundih Gas Processing Plant

Stream	Flowrate (MMSCFD)	Description
Raw gas production (inlet)	70	Total gas entering CPP Gundih from the reservoir
Acid gas removed in AGRU	13	CO ₂ + H ₂ S separated using aMDEA
Sweet gas after AGRU	≈ 57	Treated gas (mainly CH ₄) available for use/sales
Sales gas to buyers (pln & pgn)	50	Gas delivered to external consumers
Internal use / losses	≈ 7	Fuel gas, utilities, operational consumption, losses
Source: Authors' Analysis		

Natural gas from the Gundih CPP, amounting to 50 MMSCFD measured under standard conditions of 60°F and 14.73 psia is distributed to PLN and PGN, then converted from volume units to energy units (MMBTU/day) because the price of gas is determined based on its energy content. This conversion process multiplies the gas volume by the Higher Heating Value (HHV), which represents the total energy per unit volume. For the Central/East Java region, the HHV of the gas ranges from 950 to 1,050 BTU/SCF; however, calculations generally use the SKK Migas standard reference value of 1,000 BTU/SCF (Ubaidillah, 2020). Based on this calculation, the volume of 50 MMSCFD equivalent to 50,000,000 SCF/day is multiplied by the reference value of 1,000 BTU/SCF to yield a total energy of 50,000,000,000 BTU/day, or the equivalent of 50,000 MMBTU/day. This analysis assesses the financial impact of carbon costs relative to the annual Net Contractor Take across five gas pricing tiers. The percentages below represent the exact proportion of Net Contractor Take consumed by annual carbon costs at each price level.

The following part presents the results of a financial analysis and a comprehensive sensitivity matrix that simultaneously integrates five gas price scenarios, four carbon emission scenarios, and two contract schemes (Cost Recovery and Gross Split). The five gas-price scenarios differ primarily due to the degree of government regulatory intervention and the complexity of their respective logistical chains. The first three Gov. JTB (USD 6.10), HGBT feedstock (USD 6.50), and HGBT Fuel (USD 7.00) are administratively regulated and partially subsidized prices designed to support strategic sectors such as PLN and priority national industries including cement, fertilizer, and steel. In contrast, the Commercial price (USD 9.16) reflects a fully market-based rate determined through business-to-business negotiations with general private-sector consumers (Adhinegara et al., 2025). The LNG Regasification price (USD 16.77) is the highest because it incorporates extensive downstream logistics: natural gas must be liquefied into LNG, transported by specialized vessels, and then regasified at receiving terminals before delivery (Petromindo, 2025). These five gas price scenarios are categorized based on government regulatory intervention and their respective logistical frameworks. The Gov. JTB, HGBT feedstock, and HGBT Fuel scenarios are fully regulated by the government (subsidized rates) specifically to ensure the economic viability of the strategic upstream sector, raw materials for national priority industries, and fuel for PT PLN power plants. Conversely, the Commercial scenario represents a purely free-market price based on business-to-business (B2B) negotiations without subsidies for the general industrial sector. Finally, the LNG Regasification scenario is categorized as a premium price because it includes the accumulated costs of a complex downstream supply chain, ranging from the gas liquefaction process, shipping, to regasification at the receiving terminal (Isaac, 2025). This mapping is crucial because the lower the price scenario, the tighter Pertamina's profit margins become, making the Tier 3 emissions accounting I propose a vital financial lifeline.

Understanding these distinctions is crucial, as lower regulated price scenarios significantly compress Pertamina's net margins. This makes the adoption of the Tier 3 methodology particularly important, as it provides a more accurate and defensible emissions calculation framework that helps safeguard the company's financial performance under subsidized gas-pricing scheme.

Scheme A: PSC Cost Recovery Framework (Net Take After Carbon Tax Deductions)

This matrix reflects the final take-home revenue for the contractor after subtracting the respective annual carbon compliance costs from the base Net Contractor Take.

Table 6
Net Contractor Take Sensitivity Matrix Under PSC Cost Recovery

Gas pricing scenario	Base price (eur/mmbtu)	Base net contractor takes (eur)	Scenario (legacy) 250,000 tCO ₂ /yr tax: €365,000	Baseline scenario 38,400 tCO ₂ /yr tax: €56,064	High sensitivity 57,600 tCO ₂ /yr tax: €84,096	Low sensitivity 0 tCO ₂ /yr tax: €0
GOV. JTB	€5.25	€7,397,879	€7,032,879 (4.98% deduction)	€7,341,815 (0.76% deduction)	€7,313,783 (1.15% deduction)	€7,397,879 (0.00% deduction)
HGBT Feedstock	€5.59	€7,882,954	€7,517,954 (4.67% deduction)	€7,826,890 (0.72% deduction)	€7,798,858 (1.08% deduction)	€7,882,954 (0.00% deduction)
HGBT fuel	€6.02	€8,489,297	€8,124,297 (4.34% deduction)	€8,433,233 (0.67% deduction)	€8,405,201 (1.00% deduction)	€8,489,297 (0.00% deduction)
Commercial	€7.88	€11,108,599	€10,743,599 (3.31% deduction)	€11,052,535 (0.51% deduction)	€11,024,503 (0.76% deduction)	€11,108,599 (0.00% deduction)
LNG regasification	€14.42	€20,337,785	€19,972,785 (1.81% deduction)	€20,281,721 (0.28% deduction)	€20,253,689 (0.42% deduction)	€20,337,785 (0.00% deduction)

Source: Authors' Analysis

Scheme B: PSC Gross Split Regime (Net Take After Carbon Tax Deductions)

This matrix isolates the contract resilience under a fixed-split distribution, showing final take-home values and the minor revenue percentage eaten by compliance.

Table 7
Net Contractor Take Sensitivity Matrix Under PSC Gross Split

Gas pricing scenario	Base price (eur/mmbtu)	Base net contractor takes (eur)	Scenario (legacy) 250,000 tCO2/yr tax: €365,000	Baseline scenario 38,400 tCO2/yr tax: €56,064	High sensitivity 57,600 tCO2/yr tax: €84,096	Low sensitivity 0 tCO2/yr tax: €0
Gov. JTB	€5.25	€30,440,851	€30,075,851 (1.21% deduction)	€30,384,787 (0.19% deduction)	€30,356,755 (0.28% deduction)	€30,440,851 (0.00% deduction)
HGBT feedstock	€5.59	€32,437,050	€32,072,050 (1.14% deduction)	€32,380,986 (0.17% deduction)	€32,352,954 (0.26% deduction)	€32,437,050 (0.00% deduction)
HGBT fuel	€6.02	€34,932,124	€34,567,124 (1.05% deduction)	€34,876,060 (0.16% deduction)	€34,848,028 (0.24% deduction)	€34,932,124 (0.00% deduction)
Commercial	€7.88	€45,711,179	€45,346,179 (0.81% deduction)	€45,655,115 (0.12% deduction)	€45,627,083 (0.19% deduction)	€45,711,179 (0.00% deduction)
LNG regasification	€14.42	€83,687,387	€83,322,387 (0.44% deduction)	€83,631,323 (0.07% deduction)	€83,603,291 (0.10% deduction)	€83,687,387 (0.00% deduction)
Source: Authors' Analysis						

The integrated sensitivity analysis highlights that the asset's exposure to carbon taxation is jointly determined by both the applied accounting methodology and prevailing gas price conditions. Under Scheme A (Cost Recovery), the most pronounced financial impact occurs at the lowest gas price tier (€5.25/MMBTU) when combined with the unrevised (legacy) emission profile. In this configuration, the fixed carbon liability of €365,000 translates into a 4.98% reduction in Net Contractor Take, lowering net earnings to €7,032,879. However, when the validated Tier 3 baseline emission approach is applied at the same price level, the carbon liability declines substantially to €56,064, limiting the profit erosion to only 0.76% and preserving net revenue at €7,341,815. This contrast underscores the role of the Tier 3 methodology as an effective financial stabilizer that mitigates margin compression under low-price market conditions.

In contrast, the Scheme B (Gross Split) structure exhibits a significantly stronger inherent buffer against carbon cost volatility. Due to its higher contractor share of gross production (approximately 53% effective split), baseline net revenues are substantially higher across all price scenarios, ranging from €30.44 million to €83.68 million. Even under the most unfavorable legacy emission assumptions, the resulting profit reduction remains limited to a maximum of 1.21%, while the implementation of the Tier 3 baseline further reduces the impact to a marginal range between 0.19% and 0.07%. This indicates that Gross Split assets maintain a high degree of structural insulation from carbon price fluctuations, thereby offering greater fiscal predictability for upstream investment planning.

Additionally, the high-emission sensitivity boundary (57,600 tCO₂/year) provides evidence of operational robustness under disruption scenarios, such as BSRU maintenance or temporary acid gas rerouting to the Thermal Oxidizer. Even under worst-case conditions combining low gas prices (€5.25/MMBTU) and maximum emissions intensity, the Cost Recovery framework caps total financial exposure at 1.15%, corresponding to a net income of €7,313,783. This demonstrates that the system can absorb short-term operational variability without generating systemic cash flow instability in upstream field operations.

In summary, the analysis clearly indicates that Scheme B, the PSC Gross Split framework, offers the most advantageous fiscal structure for the CPP Gundih asset. From a commercial perspective, the Gross Split regime delivers a take-home profit that is nearly four times higher than the traditional Cost Recovery scheme when operating under regulated gas-price scenarios, thereby providing substantially greater revenue certainty for the contractor. More importantly, this larger net-revenue base acts as a robust fiscal buffer against environmental compliance obligations. Under the proposed Tier 3 Baseline methodology, the carbon-tax burden represents only 0.19% of net returns in the Gross Split model, compared with 0.76% under Cost Recovery. Even under stress-test conditions such as inflated emissions from legacy templates or high-emission operational disturbances the Gross Split structure continues to protect asset profitability, keeping net-margin distortions below 1.3%. Accordingly, integrating advanced Tier 3 carbon-accounting practices with a Gross Split contractual design is strongly recommended to safeguard Pertamina's upstream portfolio against increasingly stringent climate-policy requirements.

4.4 Limitations of the research

While this study provides a comprehensive analytical framework for corporate GHG accounting, several limitations of our research should be acknowledged. This study is limited to a single facility (CPP Gundih), therefore findings may not be directly generalizable to other upstream assets due to the differences in operational conditions. Besides, the evaluation of PSC Cost Recovery versus Gross Split frameworks reflects current legislative parameters. Given that Indonesian upstream energy policies have undergone frequent changes over the past decade, future regulatory adjustments to the base split or variable components could alter the relative commercial advantage of either contract structure. Future projections of carbon prices, carbon taxes, natural gas prices, and net revenue from natural gas sales should be simulated to evaluate how companies can adapt their business operations sustainably in terms of financial aspect.

5. Conclusions and policy implications

Indonesia's upstream oil and gas sector is entering a pivotal transition as the national carbon pricing framework gradually expands toward full coverage of high emitting industries. Although upstream operations are not yet directly taxed under the Presidential Regulation on the Economic Value of Carbon, this regulatory gap provides a crucial preparatory window for operators to strengthen their emissions accounting systems and align with emerging national and international standards. This study responds to that need by developing a rigorous Tier 3 carbon accounting methodology for CPP Gundih, replacing the outdated legacy template that assumed all 13 MMSCFD of AGRU off-gas was combusted in the Thermal Oxidizer (TOx). Operational evidence shows that 10–13 MMSCFD is actually routed to the Biological Sulfur Recovery Unit (BSRU), with only a small fraction entering the TOx. As the document states, as the previous template produced overestimates of flue gas emissions because it did not account for the operational split between the TOx and the BSRU. By applying the Tier 3 carbon content formula to real routing data, this study establishes a corrected emissions baseline of 105 ton/day ($\approx$ 38 kt/year), with sensitivity bounds ranging from 0 to 158 ton/day. This correction is not merely technical; it prevents Pertamina from overpaying 4–6 times of its true carbon-tax liability under Indonesia's statutory rate of IDR 30,000 ($\approx$ 1.46 EUR) per ton CO₂.

The results of this study have implications that reach well beyond the operational boundaries of CPP Gundih and contribute to wider debates in energy economics and environmental accounting. Methodologically, the analysis shows that selecting an emissions estimation tier is not a routine compliance choice; it is a decision with direct financial consequences that can materially influence contractual performance indicators. When Tier 3 activity based calculations are applied rather than legacy default assumptions the resulting carbon tax liabilities shift substantially. Under the older “all to TOx” template, carbon-tax deductions under a Cost Recovery PSC at low gas-price levels (USD 6.10–7.00) amount to roughly 4.34–4.98% of the Net Contractor Take. Under the Tier 3 baseline, however, the burden falls to just 0.67–0.76%. This study therefore adds to the methodological literature by showing that reliance on simplified, default based estimation can skew significantly financial outcomes in upstream oil and gas operations an issue that remains underexamined in existing research.

At the theoretical level, this study advances the intersection of fiscal regime theory and carbon cost exposure analysis. The comparative performance of Cost Recovery PSC and Gross Split PSC under rising carbon price trajectories offers new evidence that contractual architecture functions as a structural moderator of environmental compliance risk. The Gross Split regime's carbon-tax burden remaining between 0.07% and 0.19% across all gas-price tiers and its net-margin distortions staying below 1.3% suggests that fiscal regime design embeds an implicit carbon resilience premium that is insufficiently captured in conventional upstream project appraisal frameworks. This has theoretical implications for how production sharing contract literature models risk allocation: environmental compliance volatility should be treated as an endogenous fiscal variable rather than an external shock.

The study further contributes to the emerging literature on carbon price convergence and its effects on developing economy energy sectors. The disparity between Indonesia's current effective carbon price (approximately EUR 1.46) and prevailing benchmarks in the EU ETS (EUR 74–75), UK ETS (EUR 40–60), and California cap-and-trade (EUR 30–38) represents not merely a policy gap but a structural underpricing of long-run operational risk. As regulatory harmonization progresses, upstream project economics in jurisdictions currently insulated from global carbon pricing will face a discrete repricing event, the magnitude of which existing valuation models do not adequately anticipate. This study's scenario analysis provides a methodological template for embedding forward looking carbon price trajectories into Net Present Value and contractor take models, which can be generalised beyond the Indonesian context.

In terms of policy implications, the evidence supports institutionalizing Tier 3 emissions accounting as the regulatory standard for upstream reporting, integrating real-time monitoring outputs into both internal financial workflows and SRN-PPI compliance obligations, and retiring legacy estimation templates that systematically overstate taxable emissions. Beyond accounting reform, the structural carbon resilience advantage demonstrated by the Gross Split regime suggests that policymakers designing future production sharing frameworks should explicitly incorporate emissions cost sensitivity analysis as a standard contractual evaluation criterion. Finally, the case for early CCUS investment at facilities such as CPP Gundih is best understood not as a firm-level operational choice but as a theoretically grounded response to the anticipated convergence of domestic and international carbon pricing one that reduces taxable emissions before full enforcement while simultaneously generating option value in Indonesia's nascent CCUS value chain and reinforcing alignment with the Net Zero 2060 commitment.

More importantly, several directions for future research follow from the limitations and findings of this study. First, although this analysis quantifies the financial effects of tier selection at a single facility, further work should test whether the Tier 3 margin observed here also appears in other upstream gas plants in Southeast Asia with similar geological and fiscal settings. Comparative studies across facilities or countries would help establish the broader applicability of these findings. Second, the fiscal regime comparison in this study is static, relying on a single carbon

price assumption. Future research could build a dynamic stochastic model that incorporates carbon-price volatility into contractor take simulations, enabling probabilistic evaluations of fiscal performance as Indonesia's emissions trading system evolves. Third, while CCUS is discussed here as a strategic option, subsequent studies should develop a full ex-ante NPV model for CCUS deployment at gas processing facilities, integrating storage geology, transport logistics, and projected carbon price pathways to support investment decisions. Fourth, the link identified between fiscal design and environmental compliance costs raises a broader question for contract theory: whether production sharing agreements should include carbon contingent revenue sharing mechanisms, and how such clauses would shift risk between governments and contractors. Formal modelling of this issue would add meaningfully to the upstream fiscal economics literature. Finally, as Indonesia's carbon-market regulations mature, longitudinal research tracking real financial outcomes under Gross Split and Cost Recovery PSCs especially as domestic carbon prices rise would provide the empirical evidence that this study's scenario analysis anticipates but cannot yet observe.

Declarations

Ethics approval and consent to participate

Not Applicable. Consent to participate Not Applicable.

Consent to publication

Not Applicable.

Competing interest

The authors declare no competing interests.

Clinical trial number

Not applicable.

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Author Contribution

Muhammad Raynaldi: Contributed to the conceptualization, Data Analysis, and Writing of the original draft. A. Zainal Abidin: Conducted the survey and data observation. Gabor Harangozo: Conceptualization, Writing and Supervision.

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Data Availability

The datasets generated during and/or analysed during the current study are available from the corresponding author on reasonable request.

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Figures

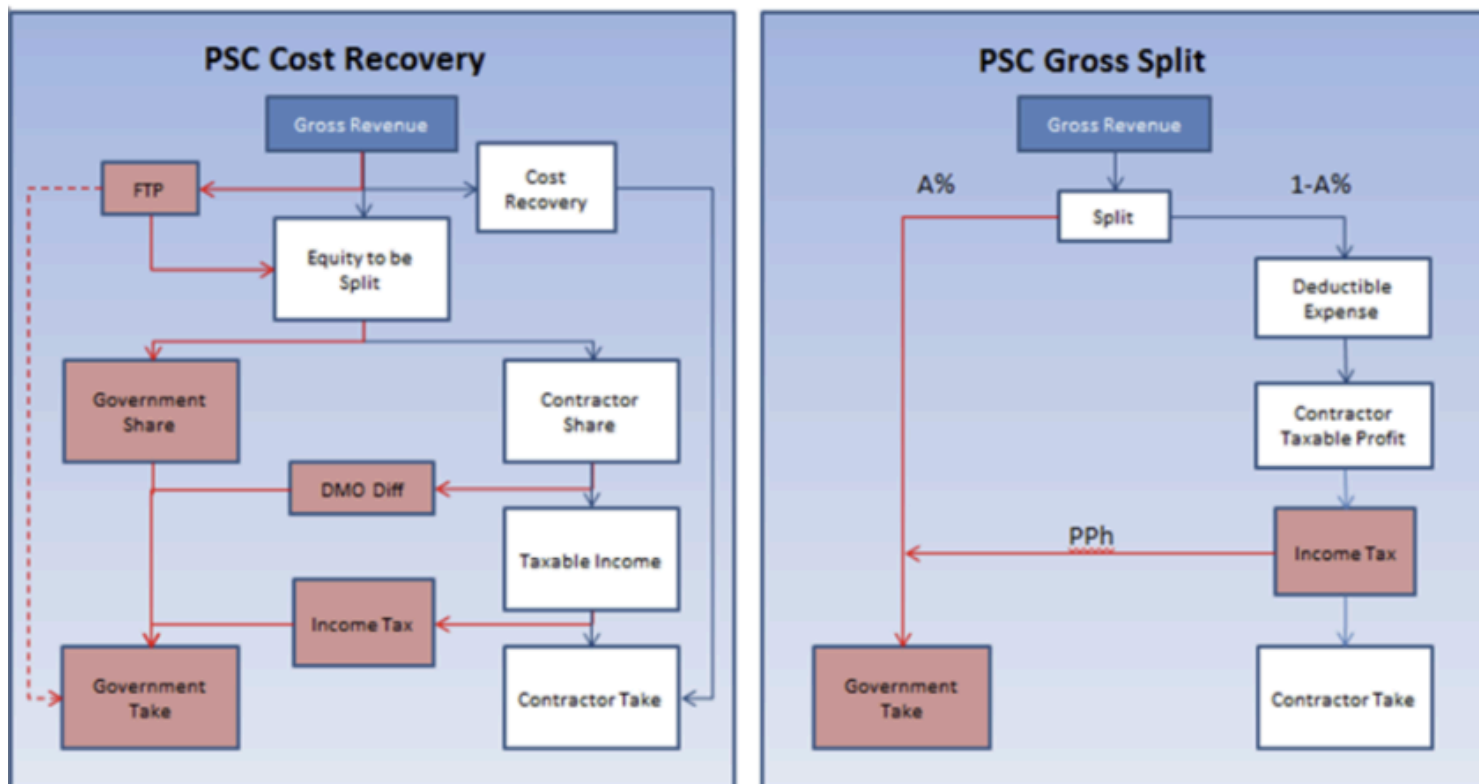


Figure 1

Comparison Between PSC Cost Recovery and PSC Gross Split

Source: (Anjani, B. R., & Baihaqi, 2018)

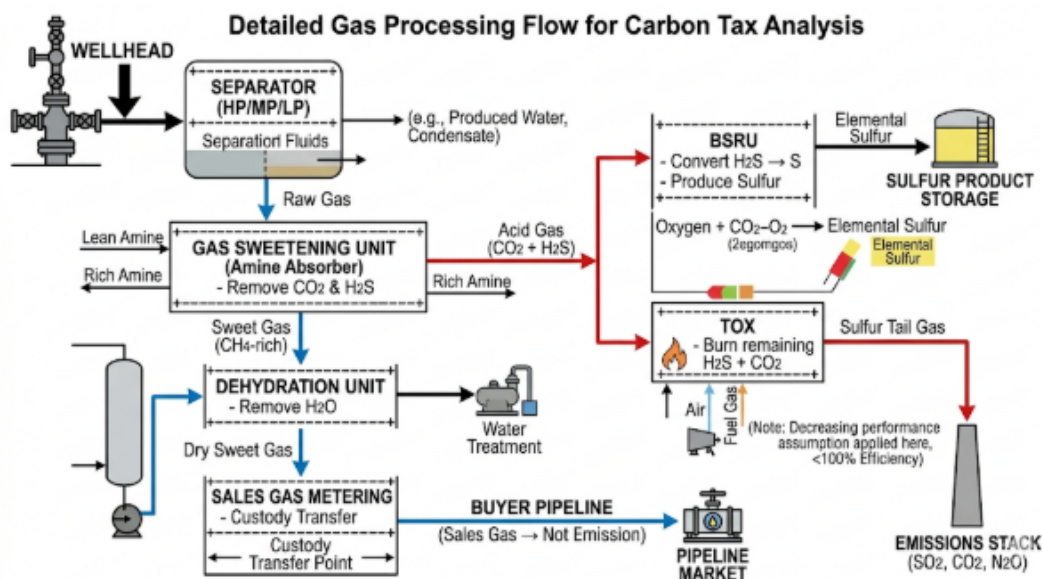


Figure 2

Diagram Flow of CPP Gundih Gas Processing Plant

Source: Company and Authors' Modification.

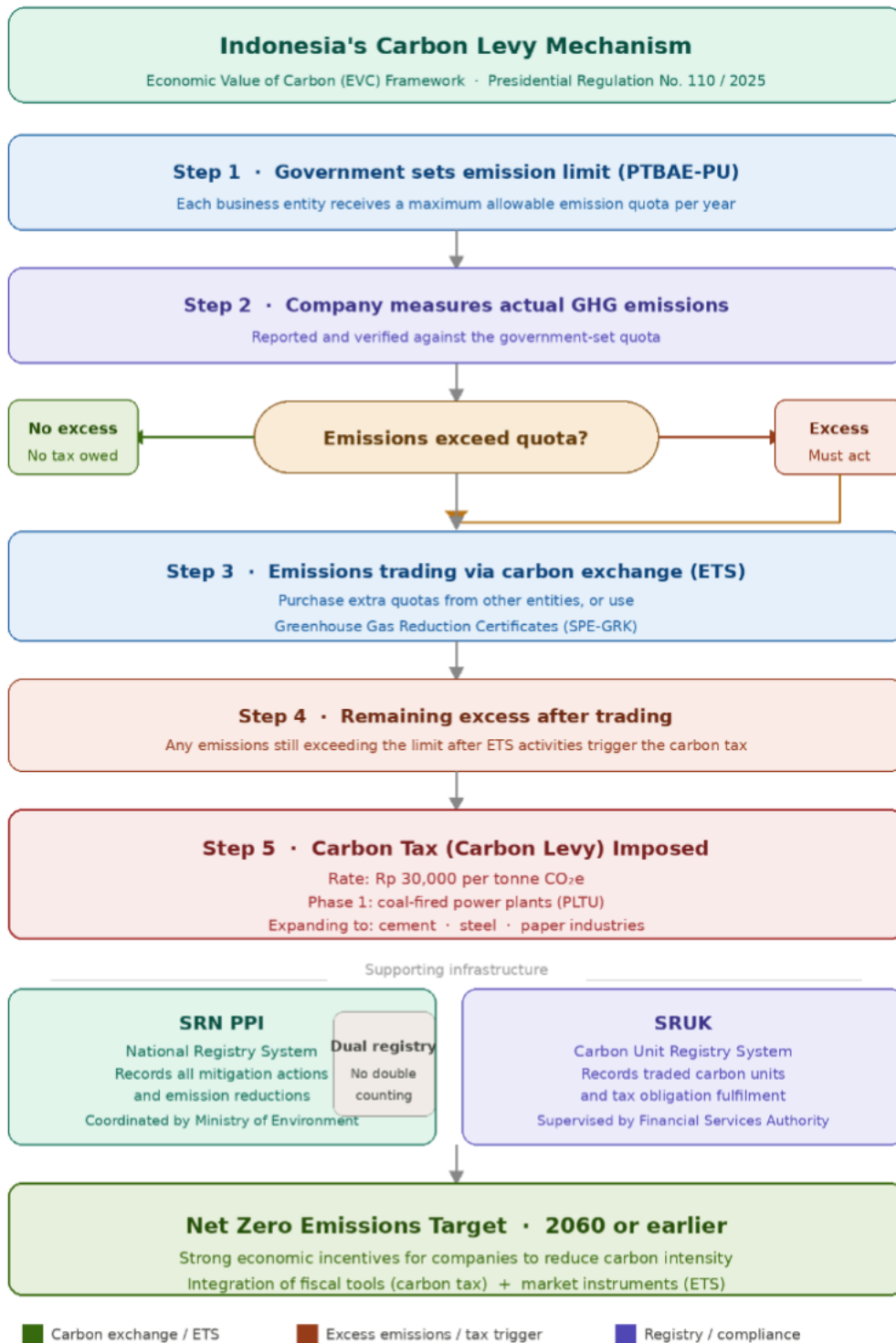


Figure 3

Indonesia's carbon market framework

Source: Authors' Analysis