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CO_2 emission reduction through fuel switching from liquid to gaseous fuels in an Indonesian oil refinery toward a sustainable energy transition case study in Sumatra refinery

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Abstract: Fossil fuels are expected to remain the primary contributors to Indonesia's greenhouse gas (GHG) emissions by 2030, accounting for an estimated 57% of the total national emissions. A significant portion of these emissions originates from oil refinery operations, particularly due to the persistent use of high-carbon residual liquid fuels. In light of Indonesia's commitment to achieving net-zero emissions by 2060, this study investigates the effectiveness of partial fuel substitution as a mitigation strategy. Using the American Petroleum Institute [1] activity-based emissions estimation methodology with specific emission factors, the study quantifies CO_2 emissions from a selected refinery unit in Sumatra, Indonesia. A simulation scenario involving the replacement of up to 56% of liquid fuels with gaseous fuels was conducted. The results indicate a potential CO_2 emission reduction of approximately 38%, demonstrating the significant environmental benefits of this transition. The findings highlight the technical feasibility of fuel switching within refinery operations and its alignment with Indonesia's Nationally Determined Contribution (NDC) targets. These insights may inform future policy development and support strategic initiatives toward a low-carbon transition in the energy and industrial sectors.

Keywords: *CO_2, Emissions, greenhouse gases, Carbon, Energy, Fuel.*

1. Background

Indonesia has aligned itself with the United Nations in pursuing the Sustainable Development Goals (SDGs), with Climate Action identified as a key priority. Climate change is increasingly recognized as a major global challenge that poses serious risks to human life and ecosystems. The primary driver of this issue is human activity, particularly the release of greenhouse gases (GHGs) into the atmosphere through the combustion of fossil fuels. These anthropogenic emissions have greatly intensified global warming, with the average global surface temperature rising by approximately 1.1°C above pre-industrial levels between 1850–1900 and the 2011–2020 period [2]. In this context, transitioning to a more sustainable energy system is regarded as a crucial measure to address the negative impacts of climate change.

Indonesia's industrial sector, notably the oil refining industry, continues to serve as a key pillar in fulfilling national and global energy demands. Despite its strategic importance, refinery operations are associated with substantial environmental impacts, particularly due to their reliance on carbon-intensive fuels such as residual oil. These fuels are commonly utilized to supply thermal energy for core processes including distillation, catalytic treatment, and storage. The combustion of liquid fuels results in significant greenhouse gas (GHG) emissions—primarily carbon dioxide (CO_2), methane (CH_4), and nitrogen oxides (NO_x)—which are recognized as major contributors to global climate change [3].

By 2030, fossil fuel consumption is projected to account for 57% of Indonesia's total GHG emissions, with liquid fossil fuels contributing approximately 36% of total CO_2 emissions [4]. As part of

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its commitment under the Nationally Determined Contribution (NDC), Indonesia has set an emission reduction target of 29% by 2030, equivalent to around 834 million tons of CO_2 equivalent (CO_2e). Of this figure, the energy sector is expected to contribute a reduction of 314 million tons of CO_2 [5].

A key component of Indonesia's shift toward sustainable energy involves replacing fossil fuel-based energy sources—including solid, liquid, and gaseous fuels—with alternatives that are cleaner, more efficient, and emit lower levels of carbon. To achieve net zero emissions by 2060, mitigation strategies targeting refinery operations must be prioritized. As suggested by Zhao, et al. [6] transitioning from liquid to gaseous fuels in refinery boilers and heaters offers a viable path to reducing refinery-based CO_2 emissions. Nevertheless, the financial feasibility of this fuel-switching process remains a key concern and must be assessed through comprehensive economic evaluation. Moreover, increasing regulatory pressure and the potential for sanctions further necessitate immediate industry compliance and proactive emission management.

This study investigates a case of fuel substitution at Refinery X, located in Sumatra, by replacing residual oil with refinery gas and natural gas in its combustion systems. Emissions are estimated using internationally recognized methodologies, namely the American Petroleum Institute [1]. The goal is to quantify emissions reductions and assess the contribution of this initiative toward achieving the refinery's internal emission reduction target of 30% by 2030 [7].

2. Regulation

Indonesia's industrial sector holds a central position in the nation's strategy to curb greenhouse gas (GHG) emissions, supported by a robust legal and regulatory framework that reflects both domestic priorities and international obligations. In line with the principles of the Paris Agreement, Indonesia has introduced several key regulatory instruments aimed at facilitating emissions mitigation, particularly in high-emission sectors such as oil and gas. The following subsections outline the primary legal instruments that serve as the foundation for Indonesia's GHG reduction policies.

2.1. Law No. 16 of 2016 (Ratification of the Paris Agreement)

Law No. 16 of 2016 marks Indonesia's formal ratification of the Paris Agreement, reflecting its engagement in global climate change mitigation efforts. Under this legal mandate, the country commits to reducing its GHG emissions by 29% through domestic action by 2030, with the potential to achieve a 41% reduction if supported by international cooperation. The law obliges national authorities to implement policy instruments, regulatory frameworks, and institutional mechanisms consistent with the targets outlined in Indonesia's Nationally Determined Contributions (NDCs) [8].

2.2. Presidential Regulation No. 98 of 2021 (Carbon Economic Value Implementation)

Presidential Regulation No. 98 of 2021 provides a regulatory basis for integrating carbon economic value (CEV) into national development agendas. The regulation establishes a market-based mechanism to encourage emissions reductions through instruments such as carbon trading schemes, carbon taxes, and result-based payments. It enables sectoral emissions balancing via Emission Trading Schemes (ETS) and carbon offset mechanisms, permitting the allocation, trade, and reconciliation of emissions allowances. The regulation applies to strategic sectors—including energy, industry, waste, agriculture, and forestry—and mandates the formation of a governing body responsible for administering the carbon market, overseeing implementation, and evaluating progress [9].

2.3. Ministerial Regulation No. 21 of 2022 (Ministry of Environment and Forestry)

Ministerial Regulation No. 21 of 2022, which was officially enacted on October 20, 2022, provides the technical foundation for executing Indonesia's Carbon Economic Value (CEV) framework. The regulation is designed to support the realization of Indonesia's emission reduction commitments under its Nationally Determined Contribution (NDC), which targets a 29% decrease in greenhouse gas (GHG) emissions through national measures and up to 41% with international collaboration by 2030. This policy instrument specifies a comprehensive set of guidelines covering the processes of measurement, reporting, and verification (MRV), certification of emission reductions, financial management procedures, and continuous evaluation mechanisms to monitor the performance and effectiveness of CEV implementation across sectors [10].

2.4. Ministerial Regulation No. 13 of 2009 (On Stationary Source Emission Standards)

To control air pollutants from stationary sources in the oil and gas sector, Ministerial Regulation No. 13 of 2009 establishes specific maximum emission limits for several major pollutants, including Total Particulate Matter, Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Carbon Monoxide (CO), and Opacity levels. These emission thresholds apply uniformly across all upstream and downstream oil and gas operations. Adherence to the standards is legally required, and any violations may result in administrative penalties, including the potential suspension or revocation of operational permits. The regulation officially came into force one year after its promulgation date, on April 24, 2010 [11].

2.5. Ministerial Regulation No. 12 of 2012 (On Emission Load Calculation in the Oil and Gas Industry)

Ministerial Regulation No. 12 of 2012 provides a unified framework for estimating emission loads arising from activities within the oil and gas industry. Designed to strengthen greenhouse gas (GHG) inventory systems and air pollution mitigation strategies, this regulation offers detailed methodological guidelines for quantifying emissions from various operational sources. These include combustion engines, gas flaring, fugitive emissions, storage facilities, and material transfer processes such as loading and unloading. Furthermore, it introduces standardized emission factor approaches applicable to key GHGs—namely carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)—to ensure consistency and accuracy in emissions reporting across the sector [12].

3. Refinery Emission

Oil refineries play an essential role in the petroleum value chain, serving as the core facilities responsible for processing crude oil into refined products such as transportation fuels, feedstocks for industrial applications, and materials for various manufacturing sectors. Despite their strategic importance in ensuring global energy availability, refinery operations contribute significantly to greenhouse gas (GHG) emissions. The two main GHGs emitted from these operations are carbon dioxide (CO_2) and methane (CH_4). CO_2 emissions predominantly originate from the combustion of fuels—including liquid fuels like residual oil and gaseous fuels such as natural or refinery gas—used to generate heat for key processing stages, including distillation, catalytic reactions, and storage systems. In contrast, CH_4 emissions primarily stem from flaring and venting activities, particularly the unintentional release of hydrocarbon gases during processing or from storage units.

To address emission quantification in this context, the API Compendium provides a sector-specific framework tailored to the operational profile of the oil and gas industry. Developed by the American Petroleum Institute, this methodology is widely utilized both for regulatory compliance and as a reference for emissions mitigation strategies initiated by industry stakeholders [1].

The API methodology follows a structured approach consisting of the following steps that shown at Figure 1 below:

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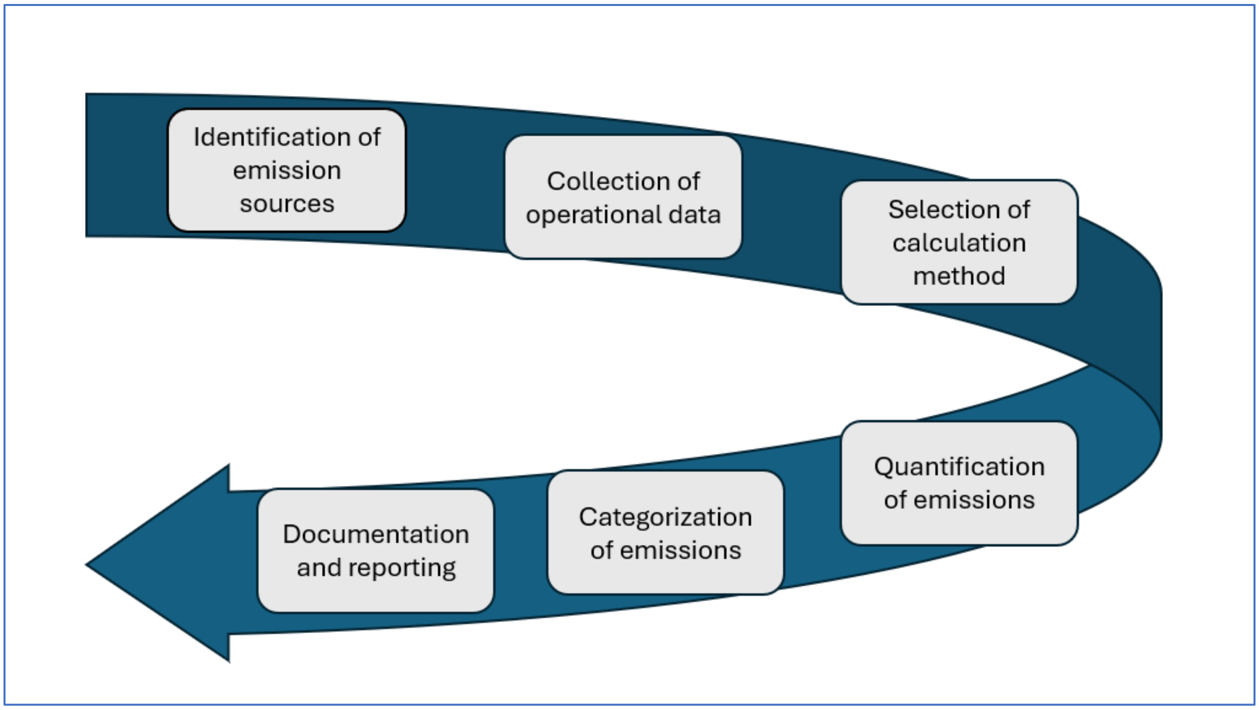

Figure 1.
Step of the API methodology.

The API methodology adopts a systematic framework to estimate greenhouse gas emissions in refinery operations. It begins with the identification of emission sources across various processing units. This is followed by the collection of operational data, which encompasses equipment specifications, fuel types, and other relevant process parameters. Based on the quality and availability of this data, an appropriate calculation approach is selected to balance accuracy and feasibility. Emissions are then quantified using standardized equations or measurement-based tools. Subsequently, the emissions are classified according to their origin, such as combustion processes, fugitive releases, or flaring activities. The final step involves thorough documentation and reporting, ensuring transparency, traceability, and compliance with regulatory standards.

The strength of the API Compendium lies in its flexibility and compatibility with international standards. It allows for adaptive use based on the availability and granularity of operational data, enabling more accurate emissions reporting and mitigation planning in oil and gas facilities.

4. Greenhouse Gas Emission Estimation Methods

In general, emissions resulting from fuel combustion can be estimated by multiplying the quantity of fuel used with a corresponding emission factor, as expressed in Equation (1) [13]:

$$E,i \quad = FC\ x\ EF \tag{1}$$

where

E,i = Emission of pollutant i (in tons)
FC = Fuel consumption (in standard cubic feet or liters)
EF = Emission factor specific to pollutant i

When direct measurements of fuel consumption at the facility or equipment level are unavailable, a Tier 1 estimation method may be adopted. This approach utilizes default values and operational assumptions to approximate emissions. Fuel consumption is determined based on equipment specifications and assumed thermal performance using Equation (2) [1]:

$$FC = ER\ x\ LF\ x\ OT\ x\ ETT\ x\ \frac{1}{HV} \quad (2)$$

where
FC = Annual fuel consumption (volume / year)
ER = Equipment rating (horsepower, kilowatts, or joules)
LF = Load factor (as a decimal)
OT = Operating time per year (hours/year)
ETT = Thermal efficiency of the equipment (e.g., $Btu_{input}/hp\text{-}hr_{output}$)
HV = Heating value of the fuel (energy per volume)

The default carbon dioxide (CO_2) emission factor, expressed in kilograms per terajoule (kg/TJ), was obtained from the API Compendium, specifically from Table 4.3. These values, as summarized in Table 1 , represent standard emission coefficients for various fuel types and are used in Tier 1 calculations when site-specific data are unavailable.

Table 1.
Default emission factor CO_2 (modified from American Petroleum Institute [1]).

Fuel	**EF_{LHV} (kg CO_2/ TJ)**	**EF_{HHV} (kg CO_2/ TJ)**
Residual Fuel Oil / fuel oil	74.900	71.100
Refinery Gas / fuel gas	57.600	51.800
Natural Gas / fuel gas	55.700	50.100

The CO_2 emissions produced from gaseous fuel, assuming 100% oxidation, can be calculated using Equation (3) as follows:

$$\boldsymbol{E_{CO_2} = FCx\frac{1}{molar\ volume\ conversion}xMW_{Mixture}xWt\%C_{Mixture}x\frac{44}{12}} \quad (3)$$

where
E_{CO_2} = CO_2 emission mass (lb, kg)
FC = fuel consumption (scf, m^3)
Molar volume conversion = 379,3 scf/lbmole or 23,685 m^3/kgmole (conversion factor)
MWmixture = molar mass of the gas mixture
44/12 = Stoichiometric conversion from carbon (C) to carbon dioxide (CO_2)

Meanwhile, for liquid fuels, the CO_2 emissions are calculated using Equation (4) as follows:

$$\boldsymbol{E_{CO_2} = FCxDxWt\%C_{Mixture}x\frac{44}{12}} \quad (4)$$

where
FC = fuel consumption (gallons or cubic meters)
D = fuel density (lb/gal or kg/m^3)
C% = mass fraction of carbon in liquid fuel
44/12 = conversion factor from carbon to carbon dioxide

These equations follow standard methodologies used in GHG estimation, particularly in oil and gas sector emissions modelling, such as those described in the API Compendium [1].

5. Result and Discussion

The American Petroleum Institute (API) has developed a comprehensive methodology—outlined in the API Compendium—for estimating greenhouse gas (GHG) emissions in the oil and gas sector. This framework adopts an activity-based approach tailored to the distinct operational characteristics of petroleum facilities. It incorporates standardized unit conversions and organizes emission sources based on key operational phases, such as upstream exploration, production, and downstream marketing. Designed to support both site-level project evaluations and organization-wide emissions inventories, the method primarily targets major GHGs, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). In addition, the API Compendium distinguishes between direct emissions, which originate from main operational processes, and indirect emissions, which result from ancillary activities that support, but are not directly involved in, hydrocarbon production [1].

The estimation of emission factors within the API Compendium is based on actual operational data obtained from field activities, complemented by direct measurements and monitoring practices. Given that the Compendium is tailored to the oil and gas sector, utilizing industry-specific operational inputs improves both the precision and contextual relevance of the estimates. Developed to promote consistency in greenhouse gas (GHG) accounting, the framework is widely adopted by oil and gas companies for reporting emissions to a range of stakeholders, including regulators, investors, and environmental organizations [14]. Its methodological robustness and granular emission categorizations contribute to enhanced transparency and accountability in corporate environmental disclosures.

The CO_2 emission value is expressed in units of CO_2 mass per unit of fuel calorific value. Referring to Equations (3) and (4), where emissions are initially calculated in units of CO_2 mass, the following calculation steps are taken to convert the results into CO_2 mass per unit of calorific input:

5.1. Determination of Lower Heating Value (LHV) and Higher Heating Value (HHV) for Each Fuel Type

For gaseous fuels, the calculation of Lower Heating Value (LHV) and Higher Heating Value (HHV) is conducted by assessing the contribution of each component in the gas mixture. The overall heating value of the fuel is derived from the weighted average of the heating values of its individual constituents, based on their respective molar or volumetric fractions within the mixture. Component of natural gas and refinery gas is detailed in Table 3 and heating value of each fuel gas component is detailed in Table 2. Data is modified from Gas Processors Suppliers Association [15].

Table 2.
Heating value of fuel gas component (Modified from Gas Processors Suppliers Association [15]).

Component LHV	**LHV (MJ/m³)**
CH_4	33.88
C_2H_6	60.28
C_3H_8	86.25
i-C_4H_{10}	111.79
n-C_4H_{10}	112.18
i-C_5H_{12}	137.82
n-C_5H_{12}	138.12
C_6H_{14} +	189.05
N_2	0
CO_2	0

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Table 3.
Components of natural gas dan refinery gas*.

Component	Natural Gas (%mole)	Refinery Gas 1 (%mole)	Refinery Gas 2 (%mole)	Refinery Gas 3 (%mole)
CH_4	98.74	27.16	42.20	14.76
C_2H_6	0.19	12.58	18.90	5.02
C_3H_8	0.05	7.86	10.50	6.60
i-C_4H_{10}	0.01	3.16		2.30
n-C_4H_{10}	0.01	3.14	2.00	1.63
i-C_5H_{12}	0.00			
n-C_5H_{12}	0.00	2.67	2.11	2.76
C_6H_{14} +	0.00			
C_2H_4		1.77	3.70	0.55
C_3H_6		2.82	6.70	
H_2		38.74	13.80	66.32
N_2	0.74			
CO_2	0.26	0.09	0.09	0.06

Note: *data directly from actual operational records of a refinery unit located in Sumatra Indonesia.

To calculate the LHV of fuel gas based on the components listed in Table 3, Equation (5) was applied, and the results are presented in Table 4.

$$HV = \sum(y_i \; x \; HV_i) \quad (5)$$

where
HV = Heating Value of gases (MJ/m³, BTU/scf)
y_i = mole fraction of component *i* in the gas mixture
HV_i = Heating Value of component i (MJ/m³, BTU/scf)

Table 4.
Heating values from various fuel gases*.

Fuel gases	LHV (MJ/Nm³)
Natural gas	33.63
Ref Gas 1	42.86
Ref Gas 2	50.55
Ref Gas 3	29.94

Note: *calculated from Equation (5) and Table 3.

For liquid fuels, the LHV values can be obtained from actual measured data. Table 5 lists the LHV values of the respective liquid fuels.

Table 5.
LHV of liquid fuel*.

SG	LHV (Kcal/kg)	LHV (MJ/kg)
0,883	10.074	42.15
0,89	10.054	42.06
0,894	10.043	42.02
0,892	10.046	42.03
0,89	10.052	42.06

Note: *data directly from actual operational records of a refinery unit located in Sumatra Indonesia.

5.2. Calculating the Emission Factor

An emission factor is a value used to estimate the quantity of pollutants released into the atmosphere from a combustion process or specific activity, based on units of activity, fuel consumption, or energy content. The basic emission factor for carbon dioxide (CO_2), grounded in combustion stoichiometry, the emission can be calculated using Equation (6) as follows:

$$EF = \frac{Cf}{HV} x \frac{44}{12} \tag{6}$$

where
Ef = Emission factor of fuels (kg CO_2/TJ)
Cf = Carbon content of fuel (% wt)
HV = Heating value (TJ/kg)

According to the American Petroleum Institute [1] emission factor can also be adjusted depending on whether the energy basis is expressed in terms of Lower Heating Value (LHV) or Higher Heating Value (HHV) can be calculated using the following formulas, Equation (7) for gaseous fuels and Equation (8) for liquid or solid fuels.

$$EF_{HHV} = EF_{LHV}\ x\ \left(\frac{1-0.1}{1}\right) \tag{7}$$

$$EF_{HHV} = EF_{LHV}\ x\ \left(\frac{1-0.05}{1}\right) \tag{8}$$

Table 6 and Table 7 summarizes of the calculation for emission factors for all fuel types presents the following data:

Table 6.
The emission factor of fuel gases*.

Fuel gas	**EF_{LHV} (kgCO$_2$/TJ)**	**EF_{HHV} (kgCO$_2$/TJ)**
Bentu	45.030.56	40.527.50
Ref. Gas 1	56.283.45	50.655.10
Ref. Gas 2	70.421.67	63.379.50
Ref. Gas 3	29.814.83	26.833.35
Average Refinery Gases	52.173.32	46.955.98

Note: *calculated from Equation (6), (7) and Table 30.

Table 7.
The emission factor of liquid fuel*.

Liquid fuel	**EF_{LHV} (kgCO$_2$/TJ)**	**EF_{HHV} (kgCO$_2$/TJ)**
A	76.552.69	72.725.06
B	76.704.98	72.869.73
C	76.788.99	72.949.54
D	76.766.06	72.927.76
E	76.720.24	72.884.23
Average	76.706.59	72.871.26

Note: *calculated from Equation (6), (8) and Table 5.

5.3. Calculating the Emission Reduction

To reduce emissions at Refinery X, high-emission liquid fuels are replaced with gaseous fuels. Table 8 provides a consolidated summary of emission factors derived from Table 6 and Table 7, which serve as the basis for the emission calculations.

Table 8.
Emission factor for calculations*.

Fuel	**EF_{LHV} (kgCO$_2$/TJ)**	**EF_{HHV} (kgCO$_2$/TJ)**
Residual Fuel Oil	76.706.59	72.871.26
Refinery Gas	52.173.32	46.955.98
Natural Gas	45.030.56	40.527.50

Note: *calculated from Table 6 and Table 7.

The fuel consumption data used in this study were obtained from operational records using flowmeters. Figure 2 presents the average daily fuel consumption in volumetric units at refinery X. The area marked with a red box represents the period before the implementation of fuel switching. During this period, liquid fuel consumption was approximately 80 m³/day, while refinery gas consumption was around 15,000 Nm³/h. Following the transition from liquid fuel to gaseous fuel, liquid fuel consumption decreased to approximately 30 m³/h, with refinery gas usage at 10,000 Nm³/h and natural gas consumption increasing to 33,000 Nm³/h.

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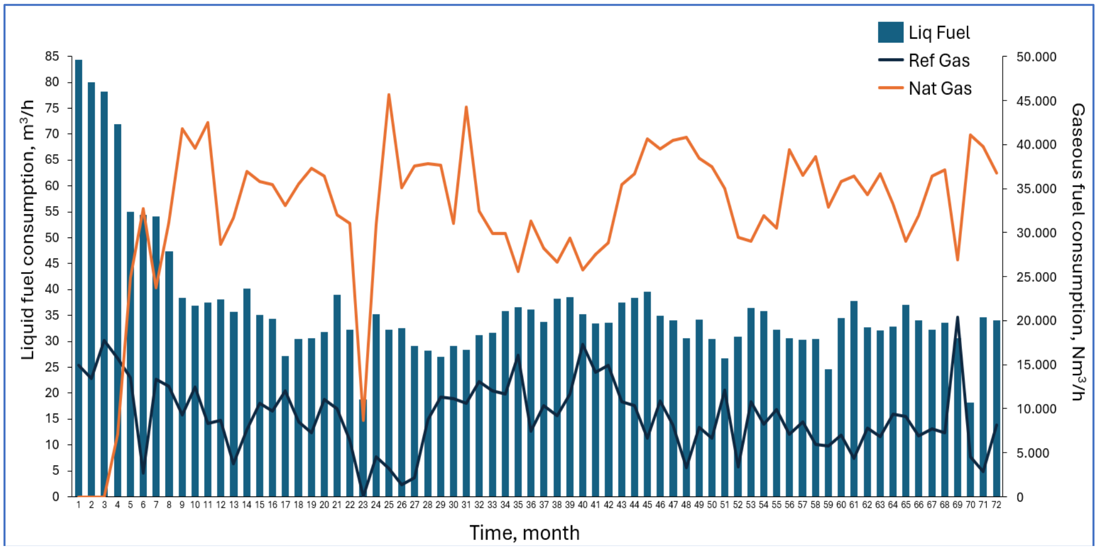

Figure 2.
Average daily fuel consumption (in volumetric units) at Refinery X in Sumatera Indonesia (2019-2024).

The fuel switching did not reduce the total fuel consumption when expressed in terms of energy units. As shown in Figure 3, the average energy consumption at Refinery X remained unchanged despite the shift in fuel type.

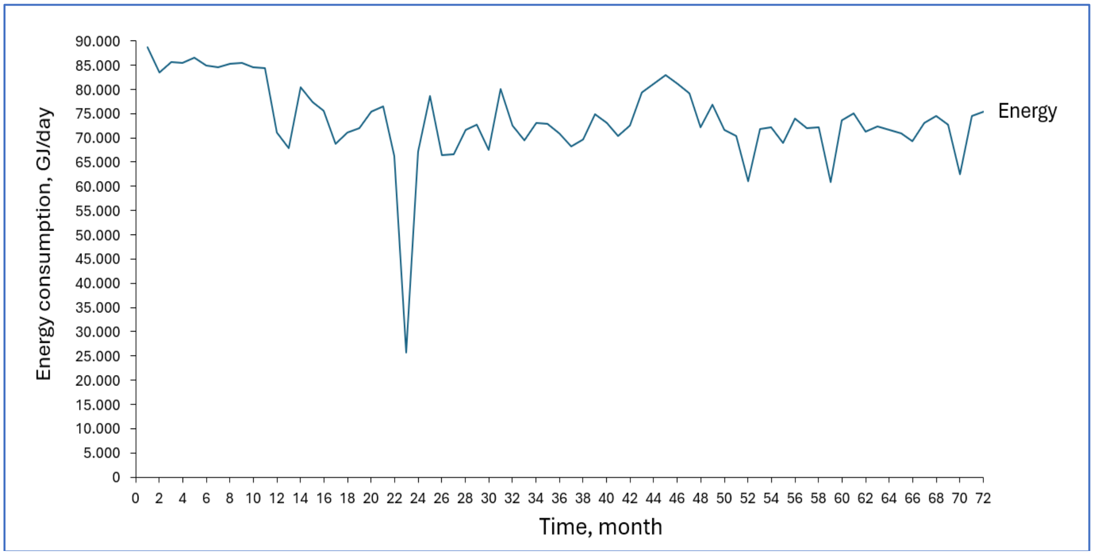

Figure 3.
Average daily fuel consumption at Refinery X in units of energy.

The estimation of CO_2 emissions was conducted based on Equation (1), using detailed fuel consumption data as illustrated in Figure 2. Emission values were derived by multiplying the emission factors of individual fuel components by their respective flow rates. These component-specific emission factors are provided in Table 8. Figure 2 also highlights, in the red box, the period in which liquid fuels remained the dominant energy source in the refinery. This baseline phase is contrasted with the subsequent operational period, where fuel switching to natural gas was implemented. The comparative analysis between these two periods indicates a significant shift in emission profiles.

As demonstrated in Figure 4, total CO_2 emissions decreased following the transition from liquid to gaseous fuels. This reduction correlates with the declining share of liquid fuel consumption and the increased contribution of natural gas, which inherently emits less carbon due to its higher hydrogen-to-carbon (H/C) ratio. These findings affirm the effectiveness of fuel switching in mitigating direct emissions from combustion processes. Compared to liquid fuels, natural gas combustion yields a lower volume of CO_2 per unit of energy produced, reinforcing its role as a cleaner energy source in carbon-sensitive applications. Furthermore, Table 9 summarizes the emissions before and after the fuel substitution, quantifying the reduction achieved and validating the simulation outcomes. These findings align with previous studies Zhang, et al. [16] and Sadeghzadeh, et al. [17] reinforcing the view that partial or full replacement of liquid fuels with natural gas is a viable decarbonization strategy in the refining sector.

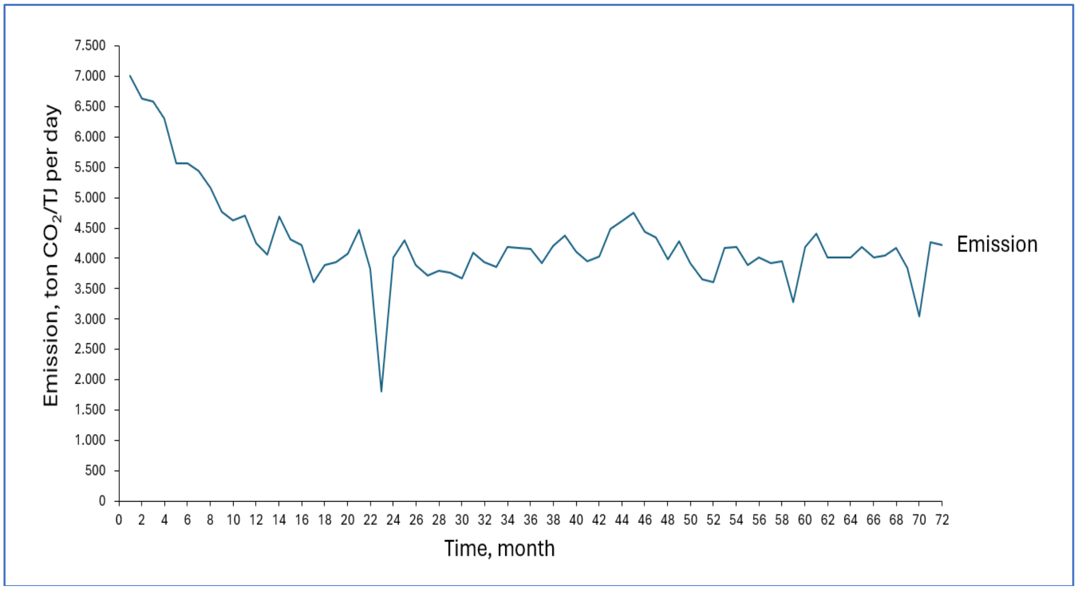

Figure 4.
Total emissions.

Table 9.
Quantified reduction in emissions due to fuel type substitution.

Emission	Result
Before fuel switching (tonCO_2/day)	6.741
After fuel switching (tonCO_2/day)	4.163
Reduction (% mass)	38

As the consumption of liquid fuel decreases, the total CO_2 emissions generated by Refinery X also decline. The data indicate that the reduction in total CO_2 emissions reaches 38%, primarily due to the lower carbon-to-hydrogen (C/H) ratio in natural gas compared to liquid fuels [18]. In the context of emission calculations, this refers to the amount of carbon present in the fuel, which determines the number of moles of CO_2 produced under ideal combustion conditions. Consequently, the total CO_2 emissions are directly proportional to both the carbon concentration in the fuel and the volume of fuel consumed. As illustrated in Equation (6), a higher carbon content results in a greater emission factor. This is evident in Table 8, where liquid fuels exhibit higher emission factors than natural gas.

This result is consistent with previous scientific studies. For instance, Zhao, et al. [19] through a Life Cycle Assessment (LCA) study conducted on a refinery in China, found that switching from heavy oil to natural gas could reduce CO_2 emissions by 25–30%, with combustion and reforming units being the most significantly affected components. Similarly, a study by Kong, et al. [20] using a dynamic system modeling approach based on LCA demonstrated that replacing liquid fuels with natural gas could lower total CO_2-equivalent emissions by 28–35%, depending on combustion efficiency.

The 38% emission reduction achieved at Refinery X exceeds the upper range reported in international literature. This higher reduction is attributed to the particularly low emission factor of Bentu Gas, which contains over 98% methane (C_1), significantly higher than typical natural gas compositions, which range between 80–96% [21]. Furthermore, Table 10 presents simulation results of CO_2 emission reductions based on varying natural gas compositions. The findings reveal that the reduction in emissions ranges between 25% and 33%, which is consistent with values documented in international studies and aligns with global benchmarks reported in the literature.

Table 10.
Simulation of CO_2 emission reductions using alternative natural gas compositions.

Natural Gas	C_1 Composition* (% mole)	LHV ($kgCO_2$/TJ)	CO_2 Emission Reductions (% mass)
Arun	74.9	71.209	25.9
Martin	80.2	63.814	29.6
Barrcouta	85.4	55.131	32.7
Bentu	98.7	45.030	38

***Source:** Seddon [22].

Furthermore, a non-ideal scenario simulation was performed to assess the impact of partial fuel substitution on CO_2 emissions. The simulation considered natural gas replacement levels of 19%, 30%, 40%, 47% and 56% relative to the total liquid fuel consumption. The outcomes, as illustrated in Figure 5 and summarized in Table 11, reveal the emission reduction trends associated with varying degrees of fuel switching. These results demonstrate a proportional relationship between the extent of fuel replacement and the corresponding reduction in CO_2 emissions, highlighting the potential of even partial transitions toward cleaner fuels in refinery operations.

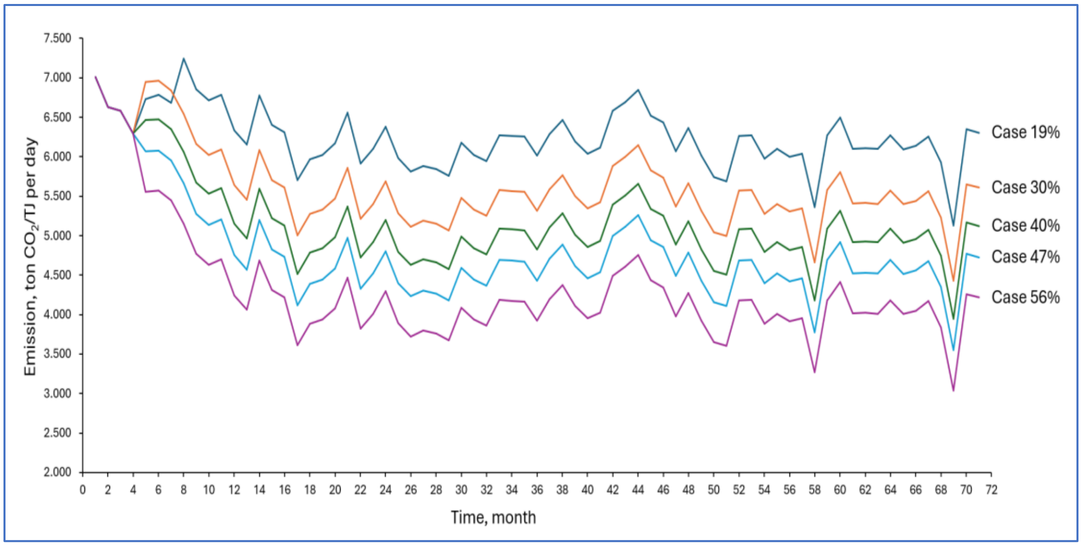

Figure 5.
Simulation of CO_2 Emission Reductions under Varying Percentage Changes in Gas Composition.

Table 1.
Simulation of CO_2 Emission Reductions under Varying Percentage Changes in Gas Composition.

Case	**Emission before**	**Emission After**	**Reduction**	
	tonCO_2/day	**tonCO_2/day**	**tonCO_2/day**	**% mass**
19%	6.629.70	6.180.75	448.95	6.77
30%	6.629.70	5.523.50	1.106.20	16.69
40%	6.629.70	5.036.21	1.593.49	24.04
47%	6.629.70	4.639.41	1.990.29	30
56%	6.629.70	4.131.23	2.498.47	37.69

Based on the simulation results, substituting liquid fuels with natural gas at Refinery X demonstrated a potential CO_2 emission reduction ranging from 6.77% to 37.69%, depending on the level of fuel replacement implemented (19% to 56%). This effectiveness is primarily attributed to the chemical characteristics of natural gas, particularly its higher hydrogen-to-carbon (H/C) ratio compared to liquid fuels. A higher H/C ratio allows for greater energy release per unit of carbon combusted, thereby improving thermal efficiency and reducing the carbon emission intensity per gigajoule of energy produced [16].

Moreover, as reported by Sadeghzadeh, et al. [17] the use of natural gas significantly reduces residue formation in combustion equipment, which extends the operational lifespan of processing units and lowers maintenance costs. The minimal residue formation also reflects a cleaner combustion process, further reinforcing the observed reduction in CO_2 emissions. These findings affirm that replacing liquid fuels with natural gas represents a technically viable and effective mitigation strategy for decarbonizing the oil refining sector. In addition to reducing greenhouse gas (GHG) emissions, this approach also offers operational benefits through improved efficiency and reduced maintenance demands.

6. Conclusion

Based on the analysis and calculations conducted on fuel switching from liquid fuel to gaseous fuel at Refinery X, it can be concluded that the use of gaseous fuel significantly reduces CO_2 emissions compared to the use of liquid fuel. This reduction can be primarily attributed to the lower carbon content of gaseous fuels and their cleaner combustion characteristics. The fuel switching did not lead to an increase in the total energy consumption, indicating that the refinery's thermal efficiency remained stable despite the change in fuel type.

The emission estimation method based on the API Compendium yielded consistent results, demonstrating a clear emission reduction trend following the fuel transition. The potential reduction in CO_2 emissions reached over 30% compared with initial operating conditions, which is consistent with the internal emission reduction targets of Refinery X and supports Indonesia's broader commitment to its Nationally Determined Contribution (NDC). These outcomes demonstrate that fuel switching is both a technically sound and operationally viable approach, offering significant environmental benefits. Furthermore, this strategy contributes meaningfully to the national agenda for achieving Net Zero Emissions (NZE) by 2060, in line with international climate mitigation frameworks.

Transparency:

The authors confirm that the manuscript is an honest, accurate, and transparent account of the study; that no vital features of the study have been omitted; and that any discrepancies from the study as planned have been explained. This study followed all ethical practices during writing.

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