Scientific Contributions Oil & Gas, Vol. 48. No. 3, October: 113 - 129

SCIENTIFIC CONTRIBUTIONS OIL AND GAS
Testing Center for Oil and Gas
LEMIGAS

Journal Homepage:http://www.journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

New Perspective of Unconventional Hydrocarbon Production with Emission Calculations

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Manuscript received: June 24th, 2025; Revised: July 25th, 2025
Approved: July 29th, 2025; Available online: October 14th, 2025; Published: October 14th, 2025.

ABSTRACT - The Paris Agreement aims to limit global temperature rise to below 2°C, with Indonesia committing to achieving net zero emissions by 2060. The oil and gas industry contributes around 15% of global emissions. On the other hand, as a developing country, we still depend on fossil fuels to meet our energy needs. Based on data from the IEA in 2015, Indonesia has 303 TCF of shale gas reserves that we use to meet future energy needs. This study conducts a case study on a shale gas field (MRCS Field) by calculating greenhouse gas emissions using engineering estimation methods. These calculations estimate methane and carbon dioxide emissions using activity data from each process and emission factors published in the 2021 American petroleum institute Compendium. Furthermore, this study analyzes emission control strategy scenarios so that MRCS Field produces fluids optimally with lower emissions. Based on the results of the MRCS field emission source study, emissions originate from two stages, namely pre-production, including normal operating processes such as mud degassing in drilling operations, flowback in hydraulic fracturing, and well test operations, followed by the production stage, including venting or gas release operations such as pneumatic controllers, casing gas vents, workover processes, and several gas processing tools such as glycol dehydration and glycol pumps. The total emissions generated during 12 years of production are estimated at 90.24 million tons of CO2e, with the largest emissions coming from hydraulic fracturing, well testing, and glycol pumps. The MRCS field development scenario is a combination of 20% production flow rate control and number of wells, resulting in an emission reduction ratio of 23% and a recovery factor of 28%. It can be concluded that the most effective field development strategy for the MRCS field is to increase the number of production wells to offset production decline, while regulating gas flow rates to reduce emissions. Controlling emissions during the field development planning stage is a crucial aspect in supporting the 2060 net-zero emissions target and the Paris Agreement commitments.

Keywords: shale gas; engineering estimations; carbon dioxide emissions; methane gas emissions.

How to cite this article:

Estherlita Elizabeth Syaranamual, Silvya Dewi Rahmawati, and Ardhi Hakim Lumban Gaol, 2025, New Perspective of Unconventional Hydrocarbon Production with Emission Calculations , Scientific Contributions Oil and Gas, 48 (3) pp. 113-129. DOI org/10.29017/scog.v48i3.1790.

INTRODUCTION

Greenhouse gases are gas molecules that absorb and emit solar radiation within the infrared spectrum, with the ability to reflect thermal (Idowu at al., 2013). When solar radiation of approximately 240 watts per square meter reaches and passes through the atmosphere, a small portion is absorbed by atmospheric components, while the rest reaches and warms the Earth's surface. Most of this radiation is absorbed by the surface, whereas the remaining portion is reflected back into the atmosphere. Of the reflected radiation, some escapes into space, some is absorbed and warms the atmosphere, and the rest is re-emitted toward the Earth's surface. This cycle continues until all the radiation is fully absorbed by either the surface or the atmosphere (Idowu et al., 2013)

If the average surface temperature of the Earth exceeds an increase of 2°C, it triggers uncontrollable climate change, potentially leading to widespread natural disasters (Buis 2019). Furthermore, if the concentration of greenhouse gases particularly CO_2 in the atmosphere continues to rise, it results in greater absorption and re-emission of heat radiation back to the Earth's surface, thereby causing the average global surface temperature to increase year by year.

The United Nations climate change conference in Paris (Paris Agreement to the United Nations Framework Convention on Climate Change) results in an agreement emphasizing the importance of efforts to limit the rise in the Earth's average surface temperature to below 2°C by maintaining a balance between CO_2 emissions and CO_2 absorption.

Oil and gas field operations contribute 15% of total emissions from the energy sector. (EIA 2024) or equivalent to 5.1 billion tons CO2eq in 2022. These emissions come from energy consumption at production facilities, natural venting of carbon dioxide contained in hydrocarbons, both oil and gas, flaring, and methane emissions from equipment leaks. Therefore, emissions from oil and gas operations need serious attention or, in other words, management.

Nowadays, various institutions project the replacement of fossil fuels with renewable energy, but based on projections from BP's 2024 energy outlook, there are two scenarios for global energy demand: current trajectory and net zero emissions. Based on these two scenarios, primary energy demand continues to increase until 2050, but with a different structure. The net zero emissions scenario shows that oil and natural gas are still needed, albeit in small amounts, namely 10% and 12% respectively (British Petroleum 2024). Therefore, special attention needs to be paid to the amount of emissions generated from oil and gas fields, which have a significant impact on the amount of greenhouse gas emissions. One of the proposals in this study is to calculate the amount of venting emissions from gas fields from pre-production to production.

One natural resource for future energy is shale gas. According to the U.S. Energy Information Administration (EIA) in 2013, the globally technically recoverable shale gas resources are approximately 7,299 trillion cubic feet (TCF). The International Energy Agency's (IEA) World Energy Outlook 2012 projects that shale gas reserves reach 200 TCF globally, accounting for nearly a quarter of the total estimated natural gas reserves. Shale gas extraction is around 145 billion cubic meters in 2010, with production increasing to 975 billion cubic meters by 2035 (IEA World Energy Outlook 2012). This growth causes the proportion of non-conventional gas production within total natural gas production to rise from 14% to 32%.

Indonesia is also a signatory to the Paris Agreement and actively participates in the implementation of the Net Zero Emission (NZE) initiative based on the agreed-upon terms. The Ministry of Energy and Mineral Resources' website details the government's principles and roadmap for achieving net zero emissions as outlined in document number 359.Pers/04/SJI/2021. This document affirms the government's commitment to realizing the NZE goal by 2060 or earlier.

The potential for shale gas in Indonesia is in several areas including two main formations, the Talang Akar and Dalaman Tungkal formations, both of which are in the Jambi sub-basin area of the South Sumatra Basin. The Talang Akar Formation has shale quality with high total organic carbon (TOC) content and maturity suitable for gas production (Julikah et al., 2020). Furthermore, the Deep Tungkal Formation has a sweet spot area of 8.9×10^8 ft² and has an initial gas in place (IGIP) of 2.12 TCF. The Lahat Formation is also one of the shale formations to develop because it has a hydrogen index > 100 mg/g, formation thickness > 40 m, TOC > 1, high maturity with Ro > 0.7, Tmax > 435°C, and at a depth of 1,800–3,050 m (Anand & Johri 2018). Based on the above, it is evident that unconventional gas is an energy source that contributes significantly to meeting future energy demands. In conventional gas production, wells typically produce gas freely once they reach a permeable reservoir. In contrast, extracting non-conventional gas requires more extensive efforts to flow the gas from the rock formations into the wells (Hamada G. M. 2016). Consequently, unconventional gas fields require more complex processes compared to conventional gas fields. This research emphasizes that calculating greenhouse gas emissions constitutes a critical new approach that we consider in the development of oil and gas fields to achieve net zero emissions in accordance with the Paris Agreement.

Emission calculations appear in several previous studies, such as the research by Xi Li et al. (2019), titled "Life Cycle Greenhouse Gas Emissions of China Shale Gas." This study focuses on calculating life-cycle emissions from pad preparation to well completion using a hybrid LCI (Life Cycle Inventory) model, which then converts into GWP (Global Warming Potential) units for methane (CH_4) and carbon dioxide (CO_2) emissions. The measured emissions come directly from field observations (Lia B. 2019)

The objective of this study is to analyze emission sources related to process and vented emissions, which specifically focus on those classified by the processes occurring at gas fields to facilitate the analysis of strategies for preventing excessive emissions, then to calculate CH_4 and CO_2 after sources are identified.

This study includes a case analysis of Marchelus Field, located in Northeastern Pennsylvania, characterized as a dry gas hydrocarbon reservoir.The dataset used in the analysis is derived from published sources, including the work of (Wigwe, Giussani, & Watson, 2021) and several additional referened papers that proved in activity factor data below. Emissions for wells are calculated using a simplified approach based on engineering estimations, which involves multiplying activity factors and emission factors. The average flow rate of the wells in the Marcellus field is 2,833.3 Mcf/day. The emission calculations primarily focus on unconventional fields.

The source of ventilation emissions at Field MRCS comes from normal operations. Starting from the drilling process, we estimate that gas releases from the mud carried to the surface. Emissions during hydraulic fracturing operations occur when the flowback reaches the surface and some of the gas releases, while emissions during well test operations occur when the hydrocarbons from the well test do not go to combustion (flare). Furthermore, during the pre-production stage, emissions originate from the workover process, whereby when subsurface equipment is lifted to the surface, some gas releases into the atmosphere. Emissions also originate from the normal process of liquid unloading. As gas production progresses, reservoir pressure decreases and the liquid layer below rises toward the well perforation, causing the liquid layer to mix with the produced gas. This progression ultimately slows the gas velocity to the point where it is unable to lift liquid droplets to the surface. Therefore, the approach to remove this liquid is liquid unloading, and this method of removing liquid causes methane emissions to release to the surface (Allen et al., 2015). Furthermore, casing gas venting is a common problem in shale gas fields due to hydraulic fracturing activities, which cause poor zonal isolation and form micro annuli between the casing and the formation. If the migrating gas does not release through the casing vent, pressure continues to accumulate in the annulus, potentially causing damage such as casing bursts, well integrity failure, and even blowouts, which are dangerous to safety and the environment. It is the release of this trapped gas that causes emissions to occur (Szatkowski et al., 2002).

METHODOLOGY

The calculation greenhouse gas emissions, there are several approaches that can be used. One method is to use emission factors published by the American Petroleum Institute (American petroleum institute), which are based on average emission characteristics of equipment from different fields. Another approach is the calculation of manufacturer emission factors, which determines emissions using factors derived from manufacturer data for specific equipment. In addition, engineering calculation methods use input data in the form of activity factors from the process being assessed. These activity factors include flow rate, number of wells, and process duration (American petroleum institute , 2021). Furthermore, the direct monitoring approach uses field equipment to take continuous or periodic measurements. In this study, emission calculations use the engineering estimation method with calculation guidance from the 2021 American petroleum institute Compendium.

The emission calculation methods according to the American petroleum institute GHG Compendium 2021 are a collection of methods used by the oil and gas industry to calculate greenhouse gas emissions. The methods in the American petroleum institute Compendium guide GHG emission estimates for individual projects, entire facilities, or a company's overall emissions inventory. The purpose of the GHG analysis, as well as data availability, generally determines the level of detail and estimation approach selected. The methodologies cover estimates for all six types of GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) from oil and gas industry operations (American petroleum institute 2021).

Emission source

There are several classifications of emission sources in oil and gas operations: combustion sources, waste gas disposal, process and vented emissions, equipment leaks, and indirect sources. Combustion source refer to emissions from the combustion of carbon-containing fuels in stationary equipment such as boilers, furnaces, gas turbines, heaters, or flare systems. The second emission source is waste gas disposal. Waste gas refers to emissions from equipment releasing gas outputs such as flares, incinerators, and vapor oxidizers, released during episodic venting, blowdowns, or maintenance activities like pipe cleaning (American Petroleum Institute 2021).

The third classification is process and vented emissions. Process and vented emissions occur during normal operations, maintenance, or certain emergencies. These are measurable and planned emissions. Examples include drilling, production, hydraulic fracturing, and maintenance activities such as workovers and liquids unloading (American Petroleum Institute 2021). Then, the fourth classification pertains to equipment leak sources, which are unintentional releases from piping, sealed surfaces, or underground pipelines. Sources include valves, connectors, pump seals, compressor seals, and other related equipment (American Petroleum Institute 2021).

The last, indirect sources are emissions from activities conducted by a company but not directly associated with facilities or assets owned or managed by the company (American petroleum institute , 2021). This study assumes emissions only come from normal processes and ventilation, meaning no emissions are included from equipment leaks or other indirect sources.Emissions from normal operations and ventilation in this study are calculated based on two stage classifications, namely pre-production and production. In the pre-production stage, emissions come from drilling, hydraulic fracturing, and well testing. Drilling emissions occur when gas separates from the circulating mud after drilling. In hydraulic fracturing, emissions come from flowback the return of injected fluids and gas to the surface (Tao, fu, xuemei, yang, & wanlu, 2018).In the production stage, emission sources include workovers, casing vents, pneumatic controllers, glycol dehydration, and glycol pumps. Workovers release gas when equipment such as casing, tubing, or pumps is retrieved (American petroleum institute 2021). Liquid unloading requires gas release to prevent fluid accumulation. Pneumatic controllers periodically vent gas to reduce internal pressure. In gas purification, glycol dehydration and glycol pumps may also release methane absorbed in the process (American petroleum institute 2021).

In gas fields, liquid unloading events occur, necessitating the release of gas to reduce pressure and prevent the accumulation of fluids that could lead to collapse. The gas released during this process represents a potential source of emissions. Furthermore, another emission source is the pneumatic controller, which is designed to periodically release gas to reduce the accumulated pressure within the controller. The gases released during these operations also represent a potential source of emissions (American petroleum institute 2021).

In gas purification equipment, such as glycol dehydration and glycol pumps, there is also potential for emissions. Glycol dehydration is used to remove water from the gas stream by contacting the gas with a glycol stream within the absorber. The glycol, which absorbs water from the gas stream, is then separated by heating the glycol in the reboiler. As a result, a small amount of methane gas absorbed by the glycol may be released, presenting a potential emission source.

Similarly, glycol pumps also have the potential to generate emissions. Glycol pumps are used to circulate glycol in the gas dehydration process. The glycol fluid being circulated may contain gas that was entrained from the absorber, thus posing a potential emission source, particularly methane (American petroleum institute 2021)

Emission calculation

Engineering estimations in emission calculations represent an approach that estimates GHG emissions based on operational activity data. This method applies technical parameters derived from emission-source analysis and emission factors. This research uses the Engineering Estimation Method with

Table 1. Several equations have been applied based compendium on American petroleum institute GHG 2021

Process	Equations
Well drilling	$E_X = days \times EF \times MW_X$
Hydraulic Fracturing	$E_{ch4,c02} = Q_G \times F_x \times MW_{ch4,c02}$
Well test	$E_x = Qg \times F_x \times \frac{MWx}{molar\ volume\ conversion}$
Workover	$E_{ch4,co2} = nw \times EF \times Fx_{ch4,co2}$
Liquid unloading	$E_{ch4,co2} = VR \times Fx_{ch4,co2} \times MW_{CH4,CO2}$
Casing gas vent	$E_{ch4,co2} number\ of\ well \times EF_{ch4} \times Tx \times Fx$
Pneumatic controller	$E_{ch4,co2} = Q_g \times Fx_{ch4,co2} \times MW_x \times T$
Glycol dehydration	$E_{CH4} = glycol\ treats \times T \times EF_{ch4} \times \frac{F_{CH4}}{methane\ content\ basis}$
Glycol pump	$E_{CH4} = glycol\ treats \times T \times EF_{ch4} \times \frac{F_{CH4}}{methane\ content\ basis}$

Table 2. Emission factor have been applied based compendium on American petroleum institute GHG 2021

Process	Emission factor
Well drilling	0.0458 $ton\ CH_4/day$
Hydraulic Fracturing	1.4 $ton\ CH_4/day$
Well test	0.728 $ton\ CH_4/well\ test$
Workover	3114 scf gas/workover
Liquid unloading	1.7 $ton\ CH_4/well-year$
Casing gas vent	0.00213$ton\ CH_4$/wellday
Pneumatic controller	2.1 scf $CH_4/controller-hour$
Glycol dehydration	0.0052859 ton $CH_4/10^6$ scf-day
Glycol pump	0.000244118 ton $CH_4/10^6$ scf-day

$$Emission\ Inventory = \sum_{i=1}^{\#sources} EF_i \times AF_i \tag{1}$$

Tier 1 accuracy, which calculates emissions using activity data and emission factors from the American petroleum institute GHG Compendium (American petroleum institute , 2021). The general equation is: where Emission inventory is the total emission of i source,EFi is the emission factor untuk source i, and AFi is the activity factor for source i. Table 1 presents several equations from the American petroleum institute Compendium 2021 applied to this study. Explanations of each variable in each equations are provided in the glossary of terms and symbols.

Emission factor

An emission factor is a representative value that quantifies the environmental impact of a process. It expresses the amount of greenhouse gas produced per unit of activity. Emission factors link activity data with emissions and facilitate the calculation of GHG inventories (American petroleum institute 2021).

Some processes such as hydraulic fracturing, well test, liquid unloading, and pneumatic controller do not use emission factors because they use other methods to represent the emission value of the process or use other approaches. in hydraulic fracturing it is recommended to use the Gilbert correlation to determine the flowback flow. The Gilbert correlation is an empirical approach in petroleum engineering used to estimate fluid flow under multiphase flow conditions. It employs parameters such as wellhead pressure, choke size, and fluid characteristics.A study conducted by Trimeric Noble and Trimeric show that multiphase flow correlations, such as the Gilbert-type method, estimate flow rates with only 0–3% deviation compared to EPA reference equations (Sexton et al., 2013).

$$Q_G = Q_L \times \left(\frac{P \times S^b}{c \times Q_L}\right)^{1/a} \tag{2}$$

Based on the above equation, it can be seen that Gilbert correlation has the same type as hydrocarbon flow in pipes or gas flow rate, Thus, this study uses gilbert correlation to represent flowback in hydraulic fracturing.

Activity factor

The activity factor is a quantitative measure of how much activity occurs in a process (e.g., fuel use, operating time, gas produced). It provides

Table 3. Activity data

Parameter	Define	Unit
Profile field (Wigwe, Giussani, & Watson, 2021)		
Number of well	• 2008: 29 • 2009: 265 • 2010: 899 • 2011: 2.032 • 2012: 3.563 • 2013: 5.161 • 2014: 6.582 • 2015: 7.656 • 2016: 8.378 • 2017: 9.265 • 2018:10.084 • 2019: 9.804	Wells
Type of hydrocarbon	Dry gas	
Gas in place	77.2	TCF
Well drilling (Ali, Jarni, & Aftab, 2020)		
Average days of drilling	98	days/well
Type of drilling	Horizontal drilling	
Type of drilling mud	Water based mud	
Well data (API, Characterizing pivotal sources of methana emissions from unconventional natural gas production, 2012)		
Choke size	1/64	Inch
Tubing ID	4.11	INCH
Depth	7888	Ft
Flowline pressure	98.75	Psig
Average flowline rate(SFR)	36458	Scf/hr
Unloading event data (API, Characterizing pivotal sources of methana emissions from unconventional natural gas production, 2012)		
Hours that well left open during unloading event (HR)	2.6	Hour
Hours for average well unloading(X)	0.5	Hour

operational data for calculating emissions (American petroleum institute 2021). The activity factor refers to operational data parameters used to represent the activities occurring within that process.

MRCS Field is assumed to operate under ideal conditions, so emissions only come from normal processes and ventilation. Table 3 shows the activity data of MRCS Field, which lies in the Marcellus Shale. The Marcellus is the largest shale formation in the U.S., stretching across the Appalachian Basin in

Table 4. Hydrocarbon composition hydrocarbon (Laughrey C. D., 2022)

Component	Average Mole(%)
O_2	0.076911765
CO_2	0.023117647
N_2	1.355588235
c_1	95.96941176
C_2	1.787529412
C_3	0.061044118
Ic_4	0.000985294

Pennsylvania with an area of 95,000 square miles, a depth of ~7,888 ft, and a reservoir thickness between 50 and 200 ft (Wigwe, Giussani, & Watson, 2021). The formation in MRCS Field is an organic shale of Middle Devonian age, with very low permeability (~120 nD) and average porosity of ~2%. MRCS Field is exploited using horizontal wells and hydraulic fracturing to enhance production. The hydrocarbon type is dry gas, with TOC ranging from 1–20% and vitrinite reflectance of 0.5–3.5 (Wigwe, Giussani, & Watson, 2021).

In the data above, the total emissions are calculated using the flow rate because, with this engineering estimation approach, the gas flow rate is used as an activity factor to represent the volume of gas that flows and is produced. This allows for the estimation of the amount of gas that can become emissions, such as methane and carbon dioxide. Furthermore, Table 4 presents the hydrocarbon composition data, which provides the percentages of methane, carbon dioxide, and other gases that may contribute to potential greenhouse gas emissions.

Table 4. Hydrocarbon composition hydrocarbon (Laughrey C. D., 2022) (Continued)

Component	Average Mole(%)
Nc_4	0.003114706
iC_5	0.000244118
nC_5	0.000126471
C_6	0.000923529
Total	**99.27899706**

Table 4 presents the results of gas composition analysis from the wells in MRCS Field, located in northeastern Pennsylvania. The data were collected from wellheads or separators and analyzed at Isotech Laboratories in Champaign, IL, USA (Laughrey, 2022). According to Table 4, methane (C_1) has the highest concentration among hydrocarbons, at 95.96%, followed by nitrogen gas (N_2). In comparison, carbon dioxide (CO_2) has a much lower concentration of only 0.023%.This study focuses on carbon dioxide and methane. Although CO_2 is a small fraction, it has a significant global impact due to its long atmospheric lifetime, while methane is more abundant and has a global warming potential 28 times higher than CO_2 over a 100-year horizon (American petroleum institute 2021).

RESULT AND DISCUSSION

The amount of greenhouse gas emissions at Field MRCS is calculated using engineering estimation based on the 2021 American petroleum institute Compendium method, classified into normal process and ventilation stages, with the assumption that the field is in ideal conditions, which means there are no emissions from other sources such as excess gas discharge, equipment leaks, or indirect emissions. Table 5 presents the GHG emission results for field MRCS per well.

Table 5. Result of GHG emission calculations in field MRCS per well

Sub Process	CH4 Emissions (ton CH_4 /year/well)	CO_2 Emissions (ton CO_2 /well/year)
well drlling	5.117	0.122
hydraulic frac	51.83	3.24
well test	37.73	0.02
workover	0.2278	1.3×10^{-4}
liquids unloading	7.099	0.004
casing gas vent	0.9108	5.2×10^{-6}
pneumatic controllers	18.916	0.01
glycol dehydration	6.63	-
glycol pump	23.875	0.013
Total	**152.34**	**3.410**

Table 5 presents the results of the calculation of greenhouse gas (GHG) emissions in each sub-process in MRCS Field per well, specifically for methane (CH_4) and carbon dioxide (CO_2). The total emissions from the entire process reach 152.34 tons of CH_4 and 3.410 tons of CO_2 per well per year. These data show that methane emissions are significantly higher than carbon dioxide emissions, indicating that managing methane emissions needs to be a major focus in the field's GHG mitigation strategy.

The process that contributes the most to methane emissions is hydraulic fracturing, with emissions totaling 51.83 tons CH_4, almost half of the total, followed by well test (37.73 tons CH_4) and pneumatic controllers (2.787 tons CH_4). Meanwhile, the workover process contributes very little to both types of emissions, with only 0.227 tons CH_4 and 1.3 ×

10^{-4} tons CO_2. On the CO_2 side, despite the relatively small amount, hydraulic fracturing is the largest contributor (3.24 tons CO_2), followed by well drilling (0.122 tons CO_2) and glycol pump (0.005 tons CO_2). Some sub-processes such as glycol dehydration do not produce measurable CO_2 emissions in this study.

This shows that while CO_2 is a common greenhouse gas of concern, CH_4 emissions have a much more dominant contribution in this operation. The aim of this study is to calculate the potential global warming impact caused by emissions from various processes occurring in MRCS Field. The total emissions are converted into Global Warming Potential (GWP) units using Equation 3:

$$CO_2e\ tonnes = \sum_{i=1}^{\#greenhouse\ gas\ species} (tonnes_i \times GWP_i) \quad (3)$$

Global warming potential provides a number that reflects how many times a particular gas is more effective at trapping heat compared to CO_2 over a given period (IPCC, 2014). In this calculation, a 100-year GWP is used to balance the short-term effects of high-impact gases such as methane and the long-term effects of more persistent gases like carbon dioxide. The 100-year GWP value for methane is 28, and for carbon dioxide is 1. Based on the emission calculations above, the contribution of emissions from Field MRCS to global warming is as follows:

Table 6. The total of emission green house gases in field MRCS

Year	Qgas (Mcf/ day)	Number of Well	Recovery factor (RF)	*Emission inventory (Billion Ton CO2e)*
2008	2.833,33	29	0%	0,12
2009	1.997,13	265	0%	0,60
2010	1.519,47	899	1%	3,06
2011	1.542,59	2032	2%	5,98
2012	1.286,35	3563	5%	8,24
2013	1.103,12	5161	7%	9,29
2014	1.412,37	6582	12%	11,26
2015	1.249,80	7656	16%	10,53
2016	1.120,79	8378	21%	9,35
2017	1.253,99	9265	26%	11,36
2018	1.122,48	10084	31%	11,08
2019	1.013,82	9804	36%	9,38
			Total	**90,24**

Emission distribution

Further analysis of the results shows that methane emissions dominate over carbon dioxide emissions. To carry out an emission-reduction strategy, an emission-distribution analysis identifies significant processes that produce emissions in order to select the right strategy.

The methane-emissions distribution diagram for Field MRCS shows that hydraulic fracturing accounts for 34% of total emissions. This indicates the importance of managing emissions carried by flowback. To anticipate emissions from this process, Reduced-Emission Completion (REC) or green completion is implemented, which is a practical procedure that reduces methane and volatile hydrocarbon emissions during the flowback stage by installing a closed separator so the separated gas is captured or routed to the sales line or flare. (Sullivan 2012; Umeozor et al., 2018).

Well testing contributes 25% of methane emissions if the hydrocarbons produced during well testing do not go to the sales pipeline but are flared. Pneumatic controllers contribute 12% due to periodic releases of methane. In Field MRCS, a high-bleed pneumatic controller is used. Emissions from this equipment are controlled by changing to low-bleed devices or switching from natural-gas-driven to water-based or electric devices (American petroleum institute 2021).

The drilling process contributes 3% of methane emissions from gas released during mud-gas separation. This is mitigated by using a closed mud-gas separator (American petroleum institute 2021). Gas-release processes such as casing gas vents and liquids unloading contribute 1% and 5% of methane emissions, respectively. Installing a plunger lift for liquids unloading is more effective than non-plunger methods because it lifts liquids without directly venting gas to the atmosphere. (EPA 2006). Emissions from casing gas vents are reduced by installing a Vapor Recovery Unit (VRU) on the vent outlet, preventing direct release by routing gas through closed piping to the VRU inlet (IEA, Methane tracker 2021; American petroleum institute 2021).

A VRU is a vapor capture and recovery system installed at the outlet of a tank or process system. It prevents direct atmospheric release by routing exhaust gas through a closed line to a separator that removes condensed liquids (returned to the production stream or storage). The recovered gas is then compressed to appropriate pressure and injected to the sales line or routed to the flare (EPA U. 2002). Figure 2 shows that CO_2 emissions per well in Field

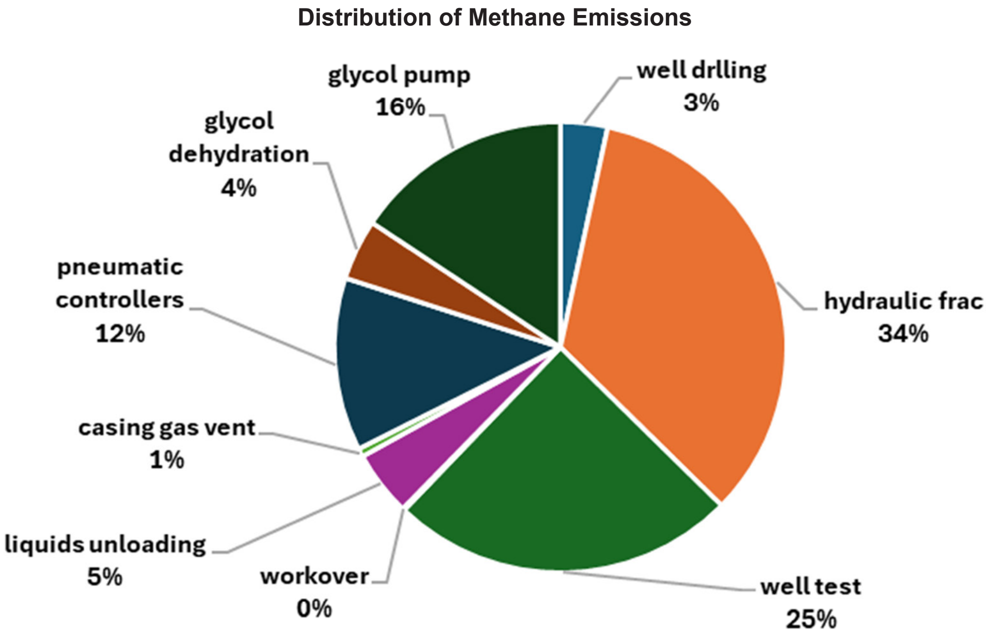

Figure 1. Distribution of methane emissions

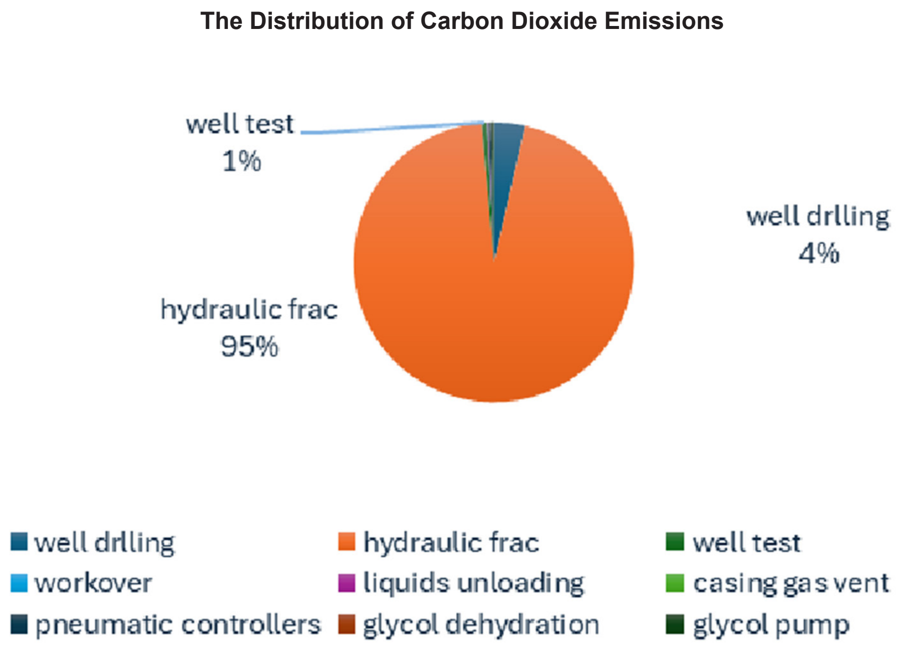

Figure 2. Distribution of methane emissions

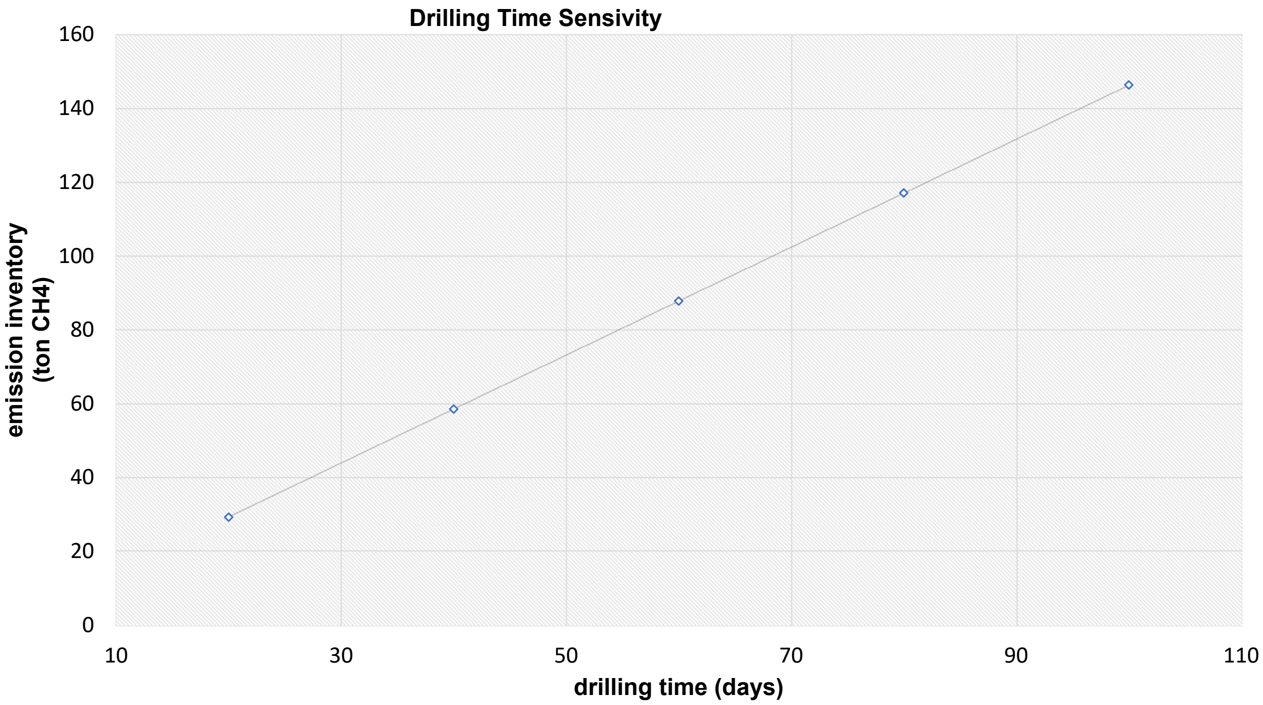

Figure 3. Drilling time sensivity

X concentrate in hydraulic fracturing (95%), well drilling (4%), and well test (1%). The dominance of CO_2 emissions in hydraulic fracturing implies that flowback rate is an important parameter to determine. REC/green completion therefore remains a key control (Sullivan, 2012) (umeozor, jordaan, & gates, 2018). The CO_2 share in drilling implies that the volume of drilling mud and drilling time affect the emissions produced.

Figure 3 shows the sensitivity of drilling time to total emissions. As drilling time increases, emissions increase. This is anticipated by minimizing non-productive time through strategies that include: designing mud formulations tailored to formation type, using real-time monitoring on motors and mud pumps and BHAs to prevent failures, and regulating wellbore pressure to prevent collapse or stuck pipe. (Compton et al. 2010).

New perspective of plan of development in oil and gas field

The results in this study align with IEA guidance that strict handling of methane emissions is a strategic step to reduce oil-and-gas operational emissions. Most emissions in such fields are methane. On a 100-year GWP scale, methane has a GWP 28 times greater than CO (American petroleum institute 2021). Therefore, minimizing methane emissions is important.

In addition to technical methods such as VRU and REC, calculating emissions using engineering estimation becomes an additional parameter for field-development considerations. Traditionally, field development focuses on recovery factor (RF), net present value (NPV), and internal rate of return (IRR). During the energy transition, it is imperative to add emissions as a design parameter.

Based on the calculation method used, activity-factor parameters are sensitized to obtain a Field MRCS production plan with low emissions. This study links the scenarios with recovery factor, which is the percentage of hydrocarbons produced from the total initially in place (Schlumberger 2024). Therefore, this study proposes three emission-reduction strategies: regulating the number of production wells, regulating the production flow rate, and a combination of both. The recovery factor uses:

$$RF = \frac{Np}{Gas\ In\ place} \times 100\% \qquad (4)$$

Table 7 shows the results for 12 years (2008–2019) in the base case. Based on this, sensitivity analysis is performed on the number of wells, flow rate, and a combination of both.

Number of well management strategy

Based on calculation parameters, the number of wells greatly affects the amount of emissions produced. Therefore, in this section, emission reduction sensitivity is calculated by changing the number of production wells. The number of wells in field MRCS is recalculated by applying reduction sensitivity to several scenarios from the base case conditions as follows:

Using the emission calculation method and linking it to the number of wells, the following results were obtained:

Figure 4 shows that emissions decrease significantly from the base case in the 20% and 30% scenarios. When correlated with recovery factor, the 20% well-setting scenario is superior to the 30% scenario (29% RF vs. 25% RF). If development prioritizes a balance of production and emission control, the 20%–30% scenarios are the best choices because RF decreases by 7–11% (to 25–29%), while emissions reduce by 22–31%. If the objective is to maximize emission control without production considerations, the 50% scenario is more ideal, though it may be disadvantageous economically.

Table 7. Base case Field MRCS (Wigwe et al., 2021)

Year	*Qg* *(Mcf/day)*	Number of well	*Recovery factor (RF)*	*Emission inventory (Billion Ton CO_2e)*
2008	2.833,33	29	0%	0,12
2009	1.997,13	265	0%	0,60
2010	1.519,47	899	1%	3,06
2011	1.542,59	2032	2%	5,98
2012	1.286,35	3563	5%	8,24
2013	1.103,12	5161	7%	9,29
2014	1.412,37	6582	12%	11,26
2015	1.249,80	7656	16%	10,53
2016	1.120,79	8378	21%	9,35
2017	1.253,99	9265	26%	11,36
2018	1.122,48	10084	31%	11,08
2019	1.013,82	9804	36%	9,38
Total				**90,24**

Table 8. Number of well scenario

Number of well from 2008-2019 scenario				
10%	**20%**	**30%**	**40%**	**50%**
29	29	29	29	29
239	212	186	159	133
809	719	629	539	450
1829	1626	1422	1219	1016
3207	2850	2494	2138	1782
4645	4129	3613	3097	2581
5924	5266	4607	3949	3291
6890	6125	5359	4594	3828
7540	6702	5865	5027	4189
8339	7412	6486	5559	4633
9076	8067	7059	6050	5042
8824	7843	6863	5882	4902

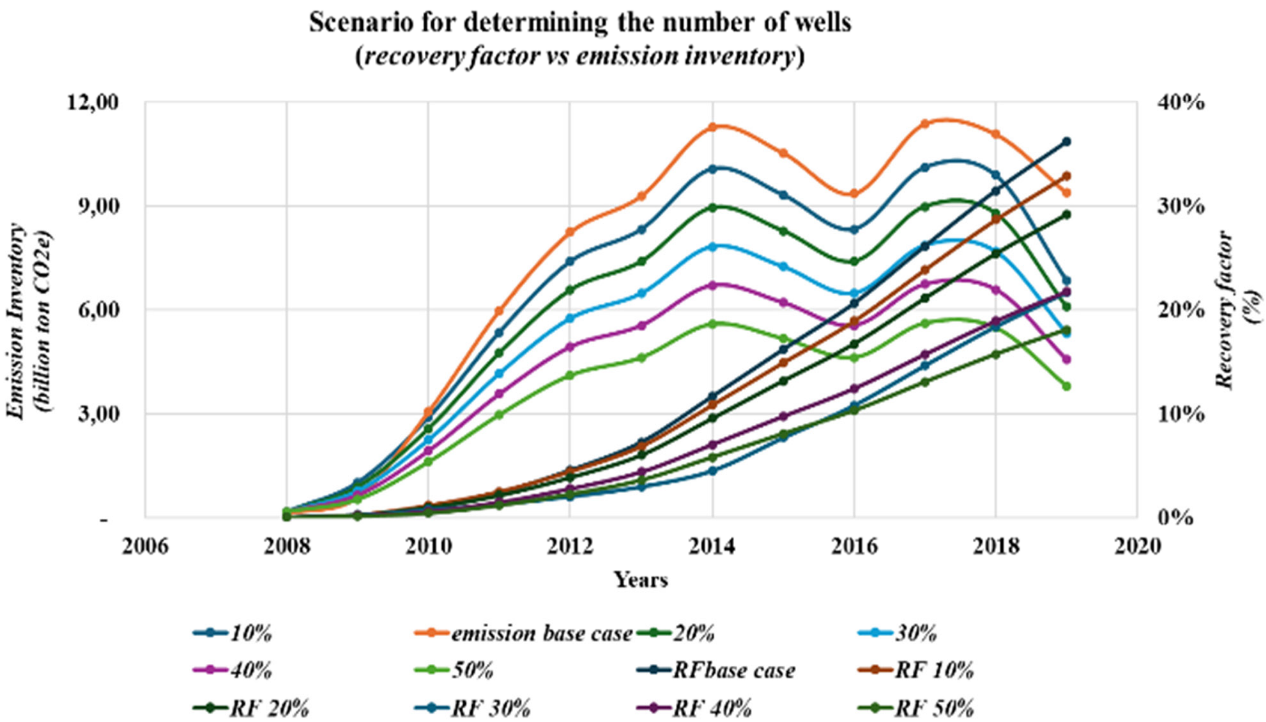

Figure 4. Scenario for determining the number of wells

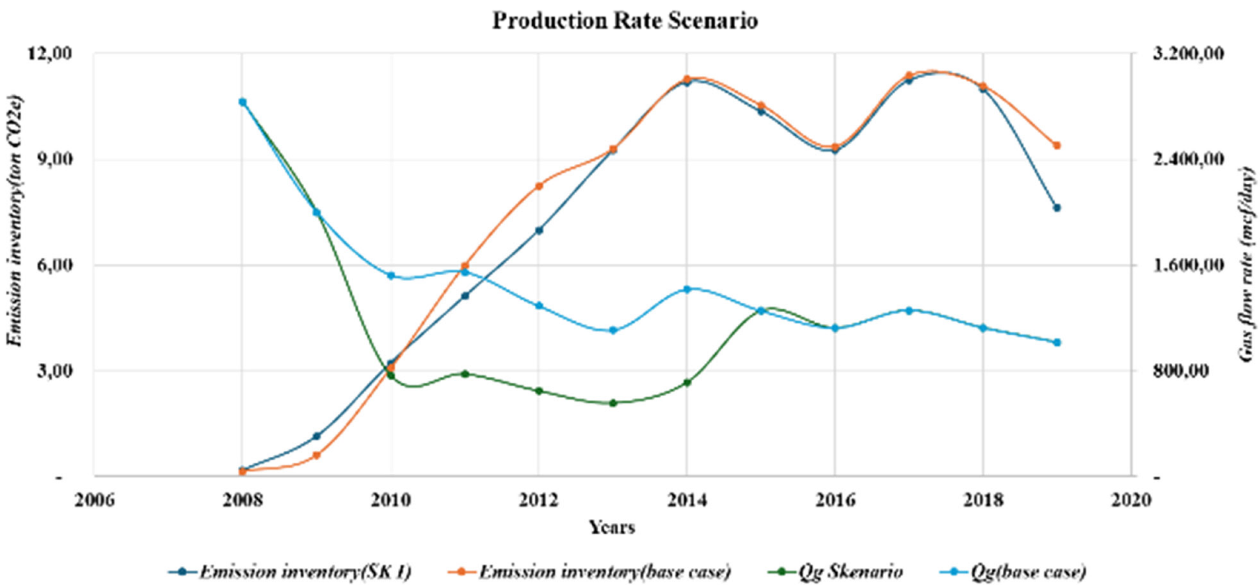

Figure 5. Production rate scenario

Production flowrate control strategy

Emissions in the production stage come from workovers and other gas-release activities, including pneumatic controllers, casing vents, liquids unloading, glycol dehydration, and glycol pumps. One parameter is the average gas flow rate per well. In the base case, Field X produces at full capacity. If production flow rate is controlled producing at half capacity during years when emissions surge and then returning to full capacity later total emissions decrease. From 2010 to 2014, base-case emissions increase significantly (Table 7), so the scenario reduces flow rate to half in those years.

Figure 5 shows that emissions decline gradually between 2010–2014. When production returns to full capacity in 2015, emissions increase. The emission ratio decreases by 4% compared to base, and RF decreases by 5%. This indicates the importance of regulating production flow rate to obtain an optimum rate consistent with reservoir conditions, economics, and environmental impact.

Combining emission control by regulating production flow rates and number of wells

To achieve maximum RF with low emissions, a combination of production-rate control and well-number control is implemented. The number of wells varies as in Table 8, and the production rate is half from 2010–2014 (as in the production-rate control scenario). The combination of well-number settings and production-rate control reduces emissions more than well-number control alone. As with other scenarios, emission settings affect RF. Emissions in this scenario decrease dramatically from base conditions.If the objective is to optimize gas production while minimizing emissions, the 20% combination scenario is preferred: it yields RF = 28% and a 23% emission reduction from base. It is more advantageous than the 30% combination because RF is 6% higher. Based on the strategies in Figure 7, Scenario 7 (the 20% combination) gives a good

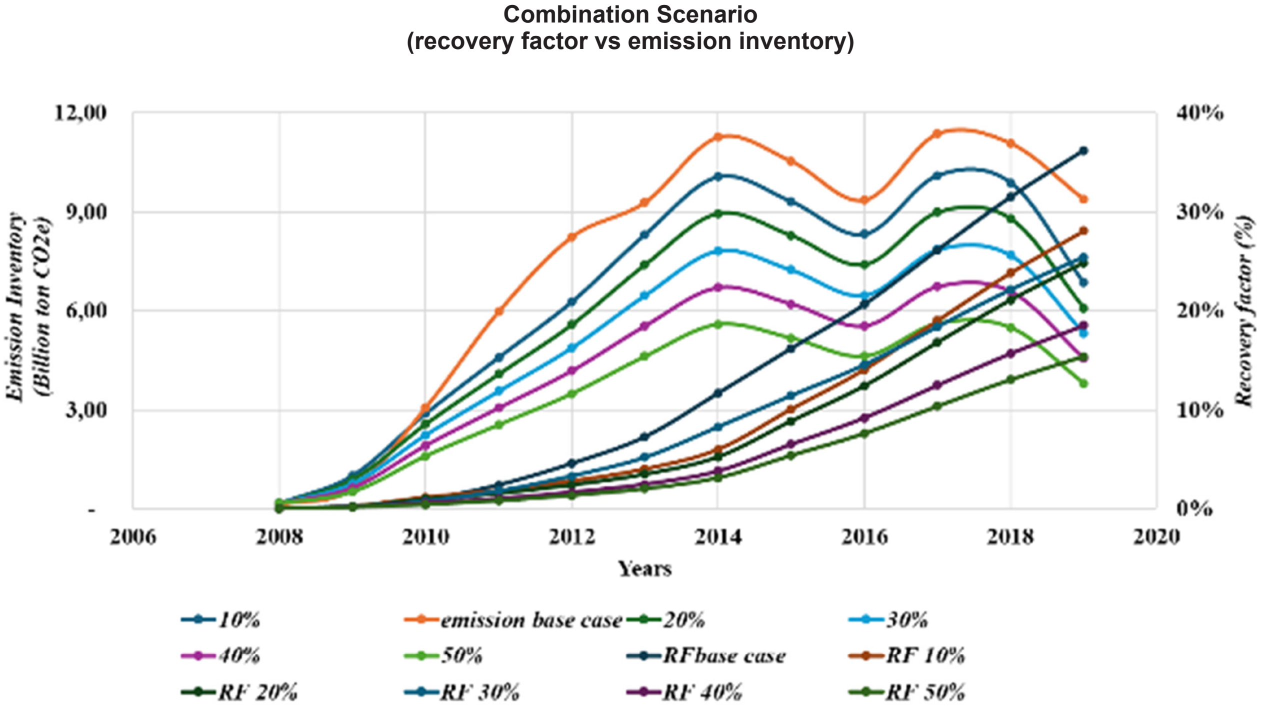

Figure 6. Combination scenario

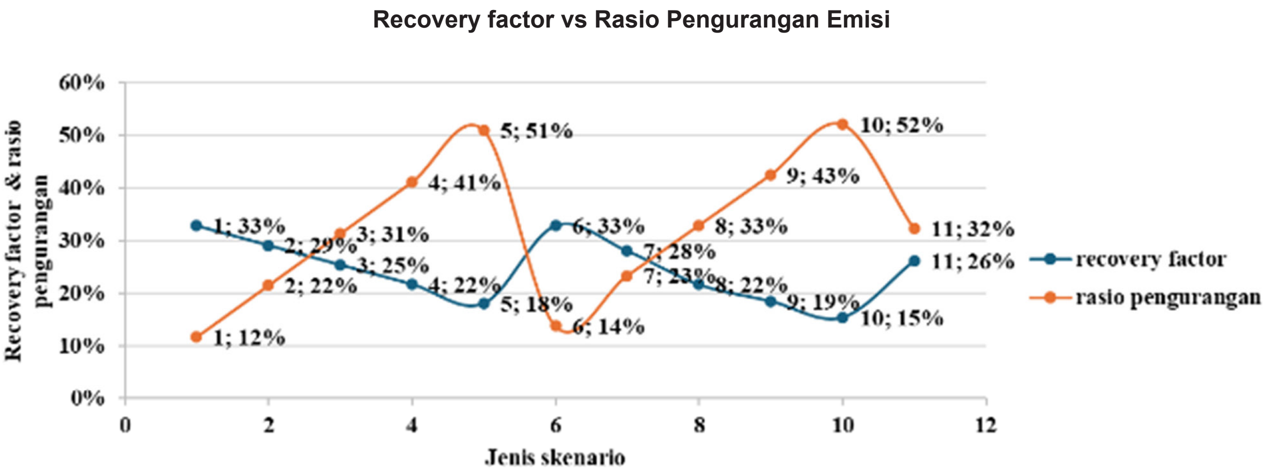

Figure 7. Plot of several scenario of development of field MRCS

 | DOI org/10.29017/scog.v48i3.1790

compromise: emissions reduce by 23% while RF decreases from 36% (base) to 28%.Thus, the field-development strategy for optimum production and minimal emissions is to add production wells to offset steep decline (notably in shale gas fields), while regulating gas production rate to reduce emissions. Once the number of production wells reaches an optimum point to support field production, the gas-production rate opens fully to maximize RF while minimizing the number of new wells drilled.

CONCLUSION

Based on this study we can conclude that: 1). Field MRCS produces methane emissions of 152.34 tons of CH_4/well and carbon dioxide emissions of 3,410 tons of CO_2/well. The total greenhouse gas emissions from Field MRCS during 12 years of production amount to 90.24 million tons of CO_2e; 2). Based on the distribution of emissions from Field MRCS, the hydraulic fracturing, well test, and glycol pump process produces the largest amount of greenhouse gas emissions, and methane gas contributes to emissions more than CO2. Therefore, Field MRCS requires control of methane emissions; 3). The number of wells is directly proportional to the reduction in emissions and recovery factor, so there are several emission-control scenarios that we implement, namely controlling the number of wells, controlling the production flow rate, or a combination of both; 4). The 20% combination scenario is the optimal scenario for Field MRCS production, yielding a recovery factor of 28% and an emission reduction ratio of 23% from the base-case conditions; 5). The field-development strategy for optimal production and minimal emissions is to massively add production wells to offset the steep decline in production, especially in shale gas fields, so that emissions reduce by regulating the gas production flow rate. Lastly, emission estimation in conventional and unconventional oil and gas field development planning is essential to support Indonesia's Net Zero Emission (NZE) target by 2060 and fulfill Paris Agreement commitments. This approach enables the design of more environmentally friendly operations without compromising production efficiency.

ACKNOWLEDGEMENT

I express my sincere gratitude to my supervisor for the continuous guidance and valuable insights provided throughout the research and preparation of this paper. I am also deeply thankful to LPDP for the support and opportunity given, which greatly contributes to the completion of this study.

GLOSSARY OF TERMS

Symbol	Defenitions	Unit
GHG	Green house gases	Tonnes CO_{2e}
TOC	Total organic carbon	g/t
IGIP	initial gas in place	TCF
Tmax	emperature at Maximum Hydrocarbon Generation	$°C$
Ro	Reflectance of Vitrinite	%
EF_i	Emission factor	Ton CH_4
AF_i	Activity Factor	
E_{CH4}	Emission inventory metana	Ton CH_4
E_{CO2}	Emission inventory	Ton CO_2
Qg	Gas flowrate	mcf
GWP	Global warming potential	-
CO_2	Carbon dioxide	lb mole gas
CH_4	Metana	lb mole gas
NZE	Net Zero Emission	-
VRU	Vapor Recovery Unit	-
REC	Reduced-emission complection	-
NPV	net present value	USD,IDR,EUR
RF	Recovery Factor	%
NP	N	
IRR	Internal rate of return	%

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