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Multi-objective Optimization of CO_2 Recycling Operations for CCUS in Pre-Salt Carbonate Reservoirs

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Abstract

This study evaluates the potential of recycling carbon dioxide (CO_2) in the associated gas in ultra-deepwater pre-salt carbonate reservoirs for Carbon Capture Utilization and Storage (CCUS). We performed compositional subsurface modelling of a hypothetical field for multi-objective optimization, aiming at minimizing carbon emissions whilst maximizing the project's Net Present Value (NPV). Although no absolute reduction in total CO_2 emissions was met with economic improvement, all simulated CCUS scenarios yielded a lower carbon footprint oil, with 43.5% reduction in operational emissions and up to 25.5% increase in NPV. The best CCUS case presented break-even oil price of 39.5 USD/STB and operational CO_2 abatement cost of negative 94.8 USD/tCO_2 abated, also showing significant reduction in number of squeeze treatments and cost of calcite scale management.

Keywords: CO_2-EOR; CCUS; Optimization; Pre-Salt; WAG; calcite.

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1. Introduction

Scientific evidence indicates that anthropogenic greenhouse gases (GHG) emission is likely the leading cause of climate change [1]. A consensus hence emerged that the world's energy systems need a rapid unprecedented transition, and that the oil and gas (O&G) industry have a big role to play. First, because the sector ultimately accounts for 42% of global emissions, with two-thirds from upstream operations [2]. Second, because the O&G industry is best place to deploy one of the key technologies for reaching net-zero targets: carbon capture, utilization, and storage (CCUS) [3].

The main CCUS category is carbon dioxide (CO_2) injection in oilfield reservoirs for Enhanced Oil Recovery (EOR), a mature technology that has been successfully and commercially implemented in multiple countries over decades. The additional oil recovered by miscible and pressure maintenance effects brings extra income that finances the CO_2 capture and storage operations. In CO_2-EOR, a portion of the injected CO_2 remains underground and the CO_2 that returns to the surface is captured then reinjected in a closed loop for permanent storage.

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Following this rationale, CO_2 has been reinjected into deep-sea oil reservoirs in the Brazilian Pre-salt (BPS) region to improve oil productivity and safely dispose of a GHG that would otherwise be emitted. The Santos Basin project is pioneering commercial large-scale CCUS in deep-waters, with a current CO_2 capture capacity of 3 Mtpa (million metric tonnes per annum) [3]. The CO_2 comes from the associated gas, which can contain from 1% to 79% m/m of CO_2 in the Santos Basin, with a median concentration of approximately 15% [4].

CO_2-EOR is a promising recovery method for the supergiant BPS oilfields. Some key characteristics make these reservoirs apt for miscible displacement techniques: high initial reservoir pressure (depths from 5 to 6.5 km); moderate temperature (60 to 70 °C); light to moderate crude oil density (28 to 32 °API); preliminary studies showing high residual oil saturation after waterflooding; and high gas oil ratio (GOR), ranging from 200 to 400 sm^3/sm^3 [5]. Although geographical isolation - some 300 km from the shore - currently restrains anthropogenic CO_2 transportation to BPS fields, this demonstration project can act as a catalyst for commercial-scale CCUS, playing a strategic role in promoting a lower-carbon economy. Whilst avoiding gas flaring and venting, it can also create the infrastructure, prove the technology, and enable future CCS hubs.

The main BPS reservoirs are fractured carbonates with pronounced heterogeneity, which can cripple the efficiency of CO_2-EOR [6]. At high concentrations, CO_2 is highly mobile and flows preferentially through high permeability paths or top layers, resulting in poor oil sweep. To alleviate this problem, CO_2 can be intercalated with slugs of a lower mobility fluid such as water in a Water-Alternating-Gas (WAG) manner. WAG has been widely used in the oil and gas industry to tackle early breakthrough of low viscosity injected fluids such as CO_2 and improve sweep efficiency. However, the reactive nature of the BPS carbonate reservoirs poses a threat to flow assurance when CO_2-WAG is applied. As CO_2 is injected at high pressures, it speciates in the aqueous phase causing dissolution of calcium carbonate in the form of calcite, the most common mineral in these systems. The dissolution continues as fluids flow, until the brine becomes supersaturated. The lower pressures closer to production points will then result in precipitation, plugging the pores around production wells, tubing, and surface facilities.

In this context, it is desirable to delay CO_2 breakthrough and, ideally, ensure its permanent geological storage. This would in turn improve oil productivity, mitigate carbon emissions, and prevent flow assurance hazards [7]. It is, therefore, in the best interest of operators in the BPS to determine CCUS design parameters, specifically CO_2-WAG, that balance out the project's profitability, scaling risk and CO_2 emissions.

While there has been a number of investigations addressing these three issues separately [8-10], and some recent studies on the synergies and trade-offs between pairs of them [11-13], little research has been done on their integration. To the best of our knowledge, this is the first study assessing the economic, environmental, and operational viability (regarding mineral scale) of CCUS projects in the Pre-salt region, bridging the gaps amongst these three key aspects.

2. Objectives, Scope, and General Methods

Can CCUS operations be optimized to increase CO_2 storage underground and profitability, as well as to reduce carbonate scale hazards? This work addresses this question with a multi-objective optimization study of coupled CO_2-EOR and storage operations in a hypothetical BPS field. The goal was to find cost-effective ways to mitigate (ideally eliminate) gas flaring in the platform during the forecast period, by capturing the CO_2 from the produced gas and re-injecting it into the reservoir for EOR. Our objective functions were Net Present Value (NPV) and well-to-wheels (WTW) CO_2 emissions. We evaluated total emissions to capture the trade-offs between producing more oil and gas for revenue purposes and limiting it for environmental reasons. Considering direct operational emissions or CO_2 storage alone would be insufficient to represent this balance. We used Particle Swarm Optimization (PSO), a wellstablished population-based stochastic optimization technique implemented in CMG™ CMOST AI, to search for CO_2 re-injection strategies that yielded better economics and lower carbon footprint simultaneously.

We used reservoir modelling and simulation tools to investigate the operations of CCUS projects in a specific context: when the injection supply is restricted to the reservoir's native CO_2 and when there is considerable risk of carbonate scaling. We integrated reservoir engineering calculations with the following bespoke forecast models to support field operational decisions:

- cash flow projections that described the relationship between subsurface behavior, wells, and surface facilities with the economic response.
- carbon lifecycle analysis that quantified emissions for the hydrocarbons' entire value chain.
- scale prevention strategies for production wells. This was a post optimization step, where we designed the periodic injection of scale inhibitor in the rock formation through the production wells, a technique called squeeze treatment.

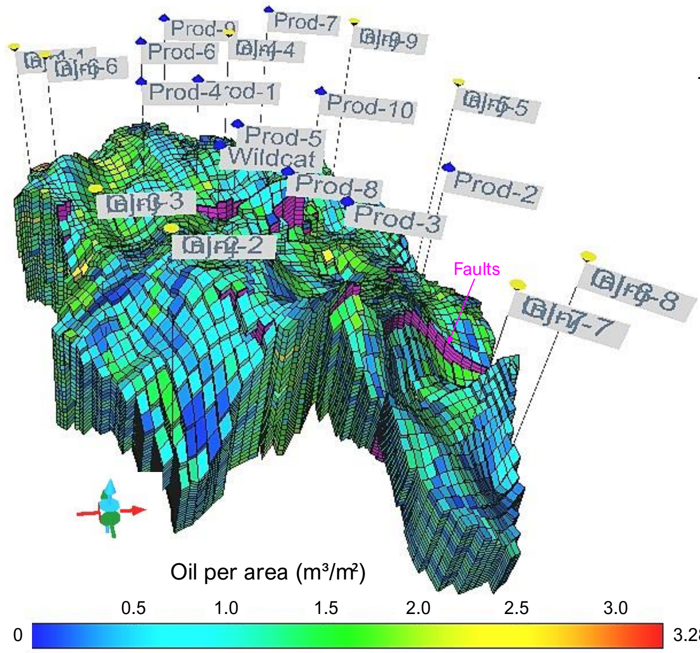
The proposed methodology provides insights into how to recycle CO_2 in an offshore oilfield for better economics and lower carbon footprint, considering calcite mineral deposition risk. Although tailored to the Brazilian Pre-salt characteristics, we believe the knowledge and methods presented here can be adapted to coupled CO_2-EOR and carbon storage projects where mineral scale poses a threat to flow assurance. Ultimately, the workflow integrates critical challenges that are interconnected yet often addressed independently and it can be applied to support the complex decision-making process of CCUS design operations in carbonate reservoirs.

3. CO_2-EOR and Storage Operational Optimization

This study modeled two field-wide objectives: net present value and well-to-wheels CO_2 emissions for a set of 481 operational designs. The baseline case - against which all subsequent simulations were compared - was a waterflood development with voidage replacement. Three EOR development strategies were considered: continuous gas injection (9 cases), uniform WAG (166 cases), and tapered WAG (306 cases). Within the EOR development strategies, the variables included were: injection well(s) (continuous gas injection), re-injection well pairs (uniform and tapered WAG), gas and water half-cycle durations (uniform and tapered WAG), gas and water half-cycle duration changes (tapered WAG), and the number of full WAG cycles per stage (tapered WAG). The outputs of the net present value and well-to-wheels CO_2 emissions for each simulation were then compared to identify optimal EOR development strategies and operating variables. More details on the methodology follows.

3.1. Field Description: Carbonate BPS Benchmark

The field-scale optimization study was performed using a synthetic, open-source, static model called UNISIM-II-D, combined with the production strategy (well placement and well opening schedule) of its derived model, UNISIM-II-H, which consists of nine horizontal injectors and 11 vertical producers [14]. The UNISIM-II benchmark is a dual-medium model of a fractured carbonate reservoir Type III, 3,658 m deep, with intermediate-wet relative permeability and geological features that mimics the BPS and Ghawar fields (Figure 1). We used a commercial simulator (CMG™ GEM) to run compositional calculations.



Property	Value
Average grid-cell size, m	100×100×8
Number of active blocks (corner -point)	65,000
Average kv/kh ratio	0.05
Rock mineralogy	80% calcite
Fractures, %PV	12%
Pore volume, rm^3	4.35×10^8
OOIP, sm^3	2.31×10^8
OGIP, sm^3	5.12×10^{10}
Initial pressure, MPa	44.13
Reservoir temperature, K	331.9
Bubble point pressure, MPa	38.29
Solution GOR (sm^3/sm^3)	221

Figure 1 UNISIM-II oil per unit area (m^3/m^2), well placement (left), and relevant model characteristics (right) [14].

Simulation timeline. From 30-Sep-2016, UNISIM-II-D has 516 days of 'historical' production data of one vertical producer – Wildcat – as part of an Extended Well Test (EWT), during which all produced gas is flared, since the gas export capabilities have not yet been installed. Field development – drilling, completion, well opening, facilities installations – lasted until 30-Sep-2021, when forecast commenced, until production ceased in 30-Sep-2045 (30 years of field life).

Wells and platform restrictions. The injection wells were set to not surpass a maximum surface rate of 6,000 sm^3/d and a maximum bottom-hole pressure (BHP) of 68.95 MPa, just below the fracture pressure. The BHPs of all producers were fixed at 31.03 MPa, the estimated minimal miscibility pressure of CO_2 in relation to the reservoir oil. The platform was limited by the operational restrictions of a standard BPS Floating Production Storage and Offloading (FPSO), according to Table 1 [15].

Table 1. Standard BPS FPSO operational constraints.

Platform restrictions	Oil (STB/day)	Gas (Sm^3/day)	Water (STB/day)
Production	150,000	6,000,000	120,000
Injection/compression	-	6,000,000	180,000
Export pipeline	-	6,000,000	-

Compositional model. The reservoir fluid used has similar characteristics of a typical BPS Santos basin oil: 29 °API, high methane content (51.3%) and moderate CO_2 contaminant (8.24%). We tuned experimental data (differential liberation, constant composition expansion and swelling test) from Moortgat et al. [16] and lumped the original components (pseudoization) to create a six pseudo-components Peng-Robinson Equation of State for the compositional subsurface modelling (more details in Rodrigues et al. [17]). A three-phase relative permeability hysteresis model was included to allow both water and gas relative permeability reductions due to repeated WAG injection cycles. We assumed a maximum trapped gas saturation of 0.4. The solubility of CO_2 into the aqueous phase was included using Henry's Law.

Injection assumptions. In this reservoir, as there is only around 10% m/m CO_2 concentration in the separator conditions, the CO_2-rich gas captured is only enough for one injector. As the FPSO is assumed to have no gas storage capacity and all the recycled gas must be re-injected, the WAG design includes two injectors to ensure no flaring during any water half-cycle. The pair has mirrored WAG ratios - when one well injects water, the other injects gas and vice-versa. Gas re-injection rates were constrained to a maximum of 2×10^6 sm^3/d per well, which was equivalent to the maximum injection water rates at reservoir conditions (gas is injected in a super-critical state). This WAG pairing approach was also adopted by Torrez Camacho [18], although the author tested pairs of injectors with a fixed WAG design (36 possibilities), subsequently optimizing the WAG variables.

3.2. Design Variables

We investigated three types of CO_2-EOR methods: (1) continuous CO_2-rich gas injection (CGI); (2) uniform WAG, where CO_2 and brine are injected in an alternating manner with the same design (water and gas half-cycle lengths) throughout the forecast period; and (3) tapered WAG, where the WAG design can change over time, responding to the reservoir performance. These are compared to a baseline waterflood model with voidage replacement to quantify the change in performance for each EOR design.

The optimization setup and variables for the three EOR methods differ in terms of their number and complexity. For the CGI study, the only optimization variable was which injection well should receive the recycled CO_2, therefore, only nine cases were simulated. For the WAG studies, the optimization variables were the re-injection well pair, and the gas and water half-cycle durations. Additionally, in the tapered WAG cases, we allowed the gas and water half-cycle durations to change on two points in time, meaning each simulation could have three WAG stages with distinctive designs in the same well pair. The number of full WAG cycles per stage was also a variable in the tapered WAG study. The resulting WAG ratio - defined as the volume of injected water per injected gas in each full cycle in reservoir conditions - was calculated afterwards, since the gas injection rates were dependent on the production rates, making the WAG ratio hard to fix. Table 2 shows the variables domains, defined based on literature review and field best practices [11, 19-22].

Table 2. Optimization design variables, their respective domains, and discrete increments.

WAG design parameter	Low	High	Increments
Gas or water half-slug (days)	90	360	30
Number of full cycles per stage	2	20	2
Injection WAG pair	Combination of any two wells from nine candidates		

Finally, for flow assurance purposes, we used the water production data forecasted in the reservoir simulations to estimate the number and cost of scale inhibitor squeeze treatments necessary to protect each production well from calcium carbonate scale damage. A detailed description of the calcite scale model assumptions can be found in Rodrigues et al. [23].

3.3. Economic Model

Net Present Value (NPV) analysis is widely applied to evaluate the economic feasibility of CO_2-EOR projects, calculated as a discounted cash flow that incorporates the income from oil and gas sales, various investment and operational costs, taxes, and CO_2 transfer costs. In the optimization study to follow, we used NPV10 (i.e., the NPV in money of the day assuming a 10% forward discount rate) calculations as one of the objective functions to drive the algorithm's search for operational strategies that yielded improved profitability.

The CO_2 utilized comes from the production wells within the platform and is continuously recycled in a closed-loop process. Based on common practices in the BPS fields, we assumed the CO_2 is captured by membrane permeation on the FPSO topside, designed to yield a purified natural gas with no more than 3% v/v of CO_2, which can be both commercialized and/or used in the platform's gas turbines to generate power. Our economic model assumes that the wet sales gas sent to the shore is further treated at a Natural Gas Processing Plant (NGPP) onshore, where the heavier ends (pseudo-components C_2-C_4 and C_{5+}) are recovered with a 95% efficiency (ε).

Average fuel gas consumption of a typical BPS FPSO is reported to be around 10 to 11% of the produced gas [24-26]. We increased the value to 14% v/v to include leaks and gas-lift usage. From the remaining gas, 80% is sent to sales through a subsea gas pipeline, the rest being re-injected in the reservoir for EOR. These assumptions for production gas destination are compatible with the gas breakdown of a typical BPS field with 10% CO_2 content in the associated gas [27].

The main sources of revenue and operational costs considered in this study are shown in Figure 2. Note that there are only two sources of revenue for the operator - oil sales and wet gas sales. Additionally, while the study incorporates WTW CO_2 emissions into the optimization, the CO_2 pricing (emission penalty cost) is kept constant and it is not included in the optimization (see the next section for details on the emissions accounting).

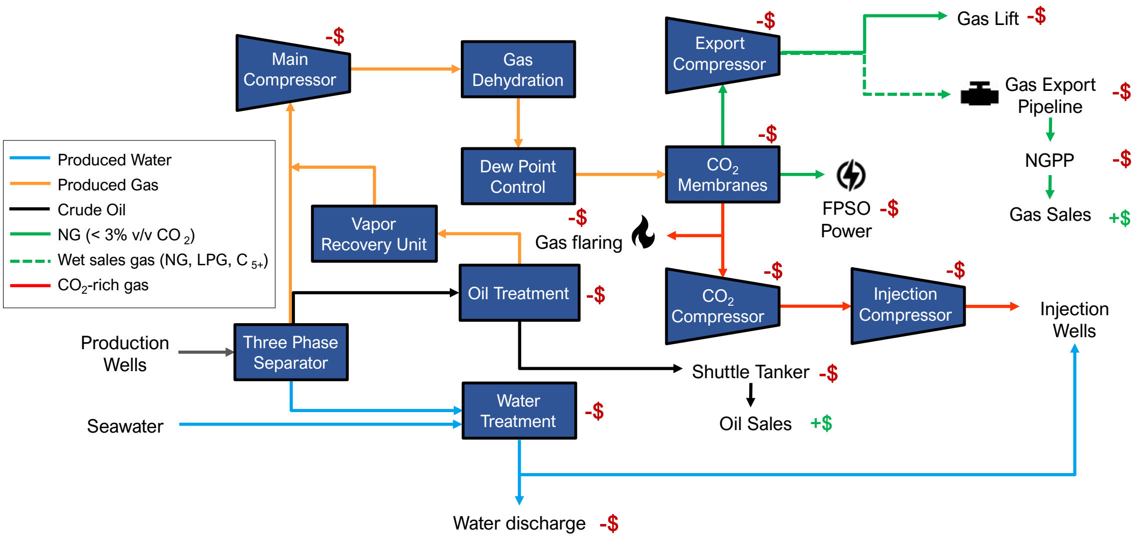


Figure 2 BPS FPSO topside operations and its main sources of income and costs. Adapted from de Andrade et al. [15].

Error! Not a valid bookmark self-reference. details the economic input parameters used in this study, including product prices, capital expenditure (CAPEX), and operational expenditures (OPEX). These were maintained fixed across time and scenarios. Any outdated cost was adjusted to the base-date using the Upstream Capital Costs Index [28]. The platform is assumed to operate 365 days per year. We assumed the injected water goes through a Sulfate Removal Unit (SRU) prior to injection to reduce sulfate scaling risk. A schematic view of the hypothetical system modelled is illustrated in Figure 3.

Table 3 Parameters used in the economic model.

Description	Oil	Gas	Unit
Oil price	50	-	USD/STB
NG (N_2-C_1) price [29]	-	13.20	USD/MMBtu
LPG (C_2-C_4) price [26]	-	0.40	USD/kg
C_{5+} price [26]	-	0.47	USD/kg
CAPEX exploration [30]	58.32	4.29	MMUSD
CAPEX D&C per well [30]	137.73	10.69	MMUSD
CAPEX submarine infrastructure [30]	1,025.82	81.24	MMUSD
CAPEX FPSO infrastructure [30]	974.16	78.99	MMUSD
CAPEX CO_2 membranes [30, 31]	-	232.71	MMUSD
CAPEX gas subsea pipeline[1] [30]	-	36.00	MMUSD
CAPEX compressors[2]	289.00	274.05	MMUSD
CAPEX SRU [33]	655.58	-	USD/(m^3/d)
CAPEX connection well-platform [14]	13.33	-	MMUSD
Depreciation rate [26]	4.00	4.00	% of CAPEX a.a.
Abandonment cost [30]	7.00	7.00	% of CAPEX a.a
OPEX oil transport (shuttle vessel)[3]	0.40	-	USD/sm^3
OPEX gas pipeline export [30, 35]	-	1.40	USD/MMBtu
OPEX oil processing at FPSO [14]	68.80	-	USD/sm^3
OPEX compressors[4] - CO_2 injection	1.78	-	USD/tCO_2
OPEX compressors - NG injection	2.99	-	USD/tonne NG
OPEX compressors - NG export	-	1.91	USD/tonne NG
OPEX water injection [14]	6.88	-	USD/m^3
OPEX water production [14]	6.88	-	USD/m^3
OPEX SRU [33]	0.55	-	USD/m^3

[1] Cost to build a 15 km pipeline with 18 in. diameter from the FPSO to the main pipeline of 300 km that links a few platforms to the NGPP onshore.

[2] Compressors for oil are 2×18 MW CO_2 injection compressors and 2×11 MW NG injection compressors. Compressors for gas are 3×11 MW main compressors and 2×11 MW export pipeline compressors [32]. We assumed unit CAPEX for compressors as 4.98 MMUSD/MW [26].

[3] Assuming round-trip in a Suezmax oil tanker with 160,000 sm^3 oil capacity, travelling at average velocity of 24 km/h, with connection/disconnection time of 20 hours and freight cost of 1,417 USD/h [34].

[4] The unitary compression cost was calculated assuming the OPEX is 4% a.a. of the compressors' CAPEX [36], compression capacity of 6×10^6 sm^3/d, and densities of CO_2, N_2-C_1 and export NG gas at standard conditions of 1.84, 0.67 and 1.05 kg/m^3, respectively.

OPEX NGPP gas processing [26, 30]	-	0.70	USD/MMBtu
CO_2 emission penalty [37]	-	40.00	USD/tCO_2
Royalties rate [14]	10.00	10.00	% of gross revenue
Social taxes rate [14]	9.25	9.25	% of gross revenue
Corporate tax rate [14]	34.00	34.00	% of net profit
Annual discount rate [30]	10.00	10.00	% a.a.

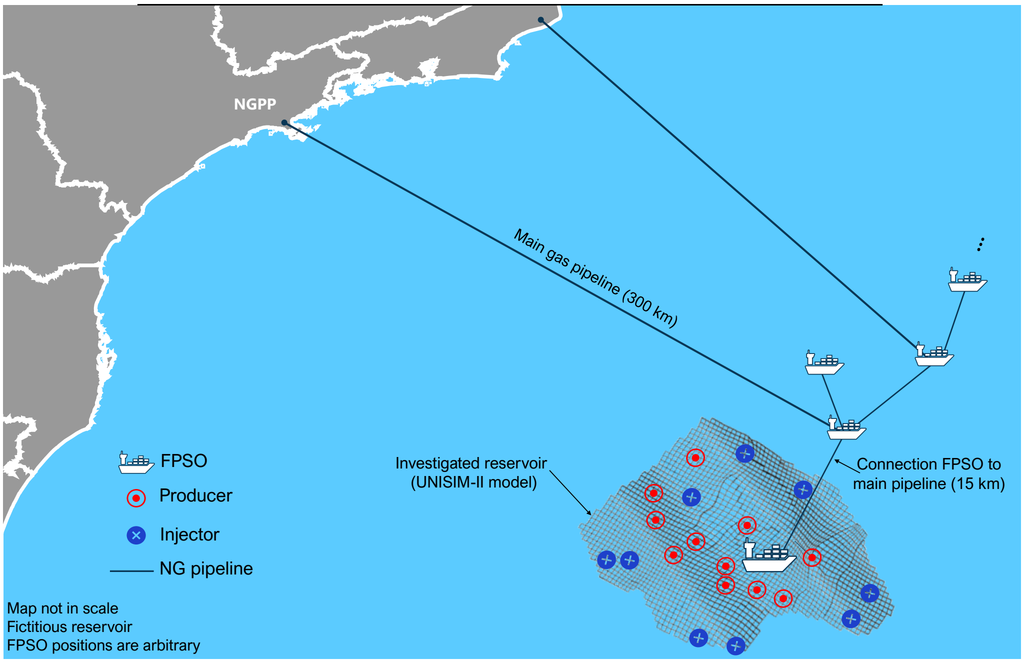


Figure 3. Hypothetical CCUS project modeled in this study based on the Brazilian Pre-salt fields.

For each simulation performed in CMG-GEM, monthly injection and production data were extracted to calculate revenues and costs for each timestep. Then, the 10% discount factor was applied and values were summed over the 30-year field life to obtain NPV10.

3.4. Well-to-Wheels CO_2 Emissions Quantification

We have created a simple model to estimate CO_2 emissions of commercializing the hydrocarbons produced in this oilfield. For each scenario simulated, the WTW emissions – from extraction to final consumer – were considered as the aggregate of the following sub-systems: (1) the exploration and production (E&P) offshore operations, which comprised power generation in the platform and gas flaring, (2) the hydrocarbons refining, (3) the combustion of the oil and gas fuel products and (4) the CO_2 stored in the reservoir, counted a negative emission input. Due to lack of suitable data, this analysis does not consider secondary emissions associated with the transport of the hydrocarbons, although we acknowledge their importance. In the Brazilian context, where road freight dominates long-distance transportation, the share of total emissions attributed to transport of the final products can be as high as 30% [40]. Finally, the carbon intensity (or carbon footprint) of a produced barrel was estimated as the total emissions divided by the total barrels of oil equivalent (BOE), which included both oil and gas produced.

Flaring was the key part of E&P emissions since it is the optimizable term. The following assumptions were made based on local flaring guidelines:

- During Extended Well Test (EWT) in the BPS, all produced gas is flared since the gas export capabilities have not yet been installed. Additionally, local regulations limit the flaring to a maximum of 500,000 sm^3/d, and the cumulative volume flared within the first 90 days of production cannot exceed 75×10^6 sm^3 [38].
- After the exploration period, the operator can flare up to 3% of the monthly produced gas volumes without legal implications, for security or planned well testing only [38].
- Flaring beyond the levels described is met with a penalty, which we are assuming is USD 40 per metric tonne of CO_2 emitted [37].

Considering each hydrocarbon component in the oil and gas phases as alkanes of the form C_nH_{2n+2}, we calculated CO_2 emissions from complete combustion of the gas in the FPSO for power and flaring (E&P emissions), as well as from combustion of the oil and gas for fuel by the end-consumer, according to the simplified equations:

$$\textit{Complete combustion:}\quad C_nH_{2n+2} + \left(\frac{3n+1}{2}\right)O_2 \rightarrow nCO_2 + (n+1)H_2O \tag{1}$$

$$CO_2\ emissions_j = \sum_n m_{n,j}^C . \bar{n} . \left(\frac{MM_{CO2}}{MM_n}\right) \tag{2}$$

$m_{n,j}^C$ is the mass of component n combusted during period j, where n can be CO_2 or a hydrocarbon component C_nH_{2n+2}; MM_n is the molecular weight of component n. We calculated $\bar{n}$ for each pseudo-component of the equation-of-state used in this work as the weighted average of the original components' fractions before pseudoization, as shown in Table 4. As CO_2 is not a combustible hydrocarbon, equation (2) considers the mass of CO_2 combusted as direct emissions ($\bar{n}$ = 1).

Table 4. Mole fractions and average coefficient $\bar{n}$ of the reservoir fluid's pseudo-components [16, 17].

Pseudo-component	Mole fraction (%)	$\bar{n}$
CO2	8.24	1
N_2-CH_4	51.56	1
C_2H_6-C_4H_{10}	14.63	2.7
iC_5H_{12}-$C_{10}H_{22}$	9.56	7.6
$C_{11}H_{24}$-$C_{14}H_{30}$	4.58	12.4
$C_{15}H_{32}$-$C_{20}H_{42}$	11.33	18.9

For end-use consumption emissions, we assumed that 80% of each oil barrel produced was is burnt for fuel [39], the rest being used as feedstock for petrochemicals, asphalt, and the like. Finally, to address the emissions from refining the oil, we used the average carbon intensity of refinery operations in Brazil in 2017 and 2018, which was approximately 35.9 $kgCO_2$ per barrel of oil equivalent processed [40].

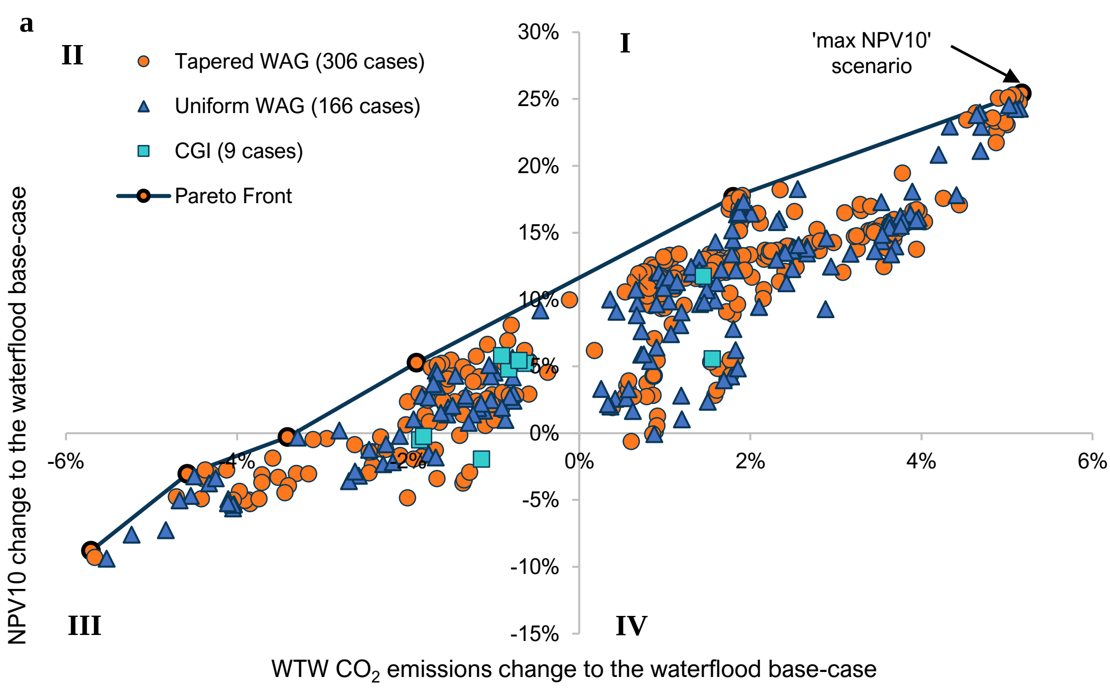
Although assuming perfect combustion, we acknowledge that flaring emissions depend not only on the volume of gas but also on the combustion efficiency of the flare. Inefficient flares generate more methane emissions, which has a global warming potential 28 to 36 times higher than of the CO_2 over 100 years [41]. According to the International Energy Agency [42], more than 99% of the natural gas can be fully combusted when flaring occurs in optimal conditions, but in reality these conditions are rare.

4. Results and Discussion

Beforehand, it is worth mentioning that the extreme case of complete flaring (not monetizing the gas and focusing on the oil production exclusively) would not financially make sense in this field. According to our calculations, flaring all the associated gas and selling only the oil would yield a negative NPV10, despite the investment cost savings (simpler platforms with no gas separation nor gas pipeline transport infrastructure). Additionally, the operational emissions of such scenario would be enormous: 6.8 times higher than the waterflood base-case with commercialization of the gas and flaring/venting of only the CO_2-rich gas.

The PSO algorithm implemented in CMG™ CMOST AI started by running a population of 20 random solutions. Navigation through the search space is guided by the best simulation outcomes, which usually results in a convergence towards better solutions, although optimality is not guaranteed. Following this procedure, a total of 481 designs (combinations of input variables) were simulated (9 cases of CGI, 166 cases of uniform WAG, and 306 cases of tapered WAG) until no significant improvement in the objective functions was observed with new experiments.

For each simulation case, the NPV10 and WTW CO_2 emissions were expressed as a percentage change from the baseline waterflood scenario, i.e., [(Case X - Baseline) / Baseline] x 100. Outcomes with higher NPV10 or higher WTW CO_2 emissions would therefore have positive values, while outcomes with lower NPV10 or lower WTW CO_2 emissions would have negative values. Figure 4 shows NPV10 on the y-axis and WTW CO_2 emissions on the x-axis. The design that yielded the highest NPV10 (called 'max NPV10') is identified in the figure and analyzed further.



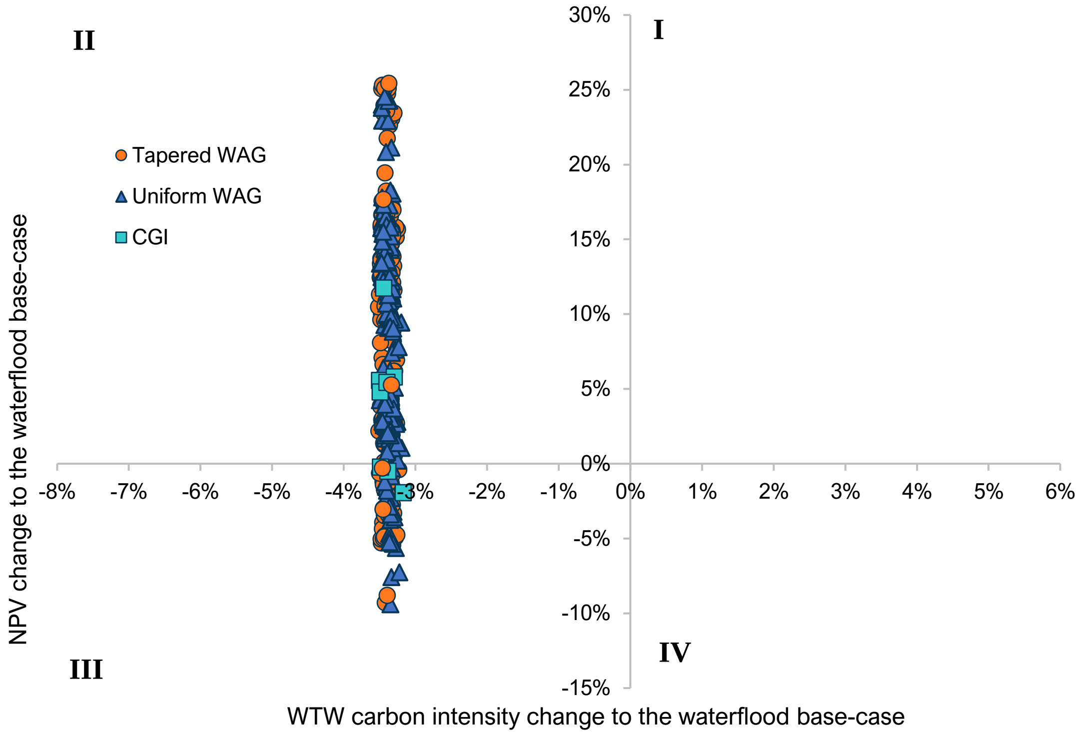


Figure 4. Percentage change in relation to the waterflood base-case of Net Present Value versus (a) well-to-wheels CO_2 emissions ($MMtCO_2$ emitted) and (b) well-to-wheels carbon intensity ($MMtCO_2$/BOE produced) for all CCUS operational strategies simulated in the optimization studies (481 experiments).

Ideally, the best results would be in quadrant II (improved NPV10 and reduced WTW emissions and intensity). However, the optimization results showed a direct correlation between the two objectives: the higher the efficiency of the EOR strategy was, the more hydrocarbons were produced, and the higher the revenues and total emissions were.

As this was a multi-objective optimization procedure, a Pareto frontier was identified, which consists of the best NPV10 and WTW CO_2 emissions simultaneously across the scenarios. This set of solutions represent a compromise between conflicting objectives, where no objective can be improved without harming the other(s). In this study, we assigned equal weighting to NPV10 and WTW CO_2 emissions. The Pareto frontier showed solely a trade-off between the objectives. This direct relationship reinforces the idea that additional emissions from the extra hydrocarbons produced due to EOR will overcast the emissions abatement from the flaring avoidance, in a scenario where the CO_2 injection supply is restricted to the reservoir's native CO_2. In fact, the WAG case with the highest NPV10 (called 'max NPV10') presented E&P emissions (gate-to-gate) 43.5% lower than the base-case, but the 9% increase in its end-use emissions was enough to increase total WTW emissions balance by 5% compared to the WF base-case (see Figure 5).

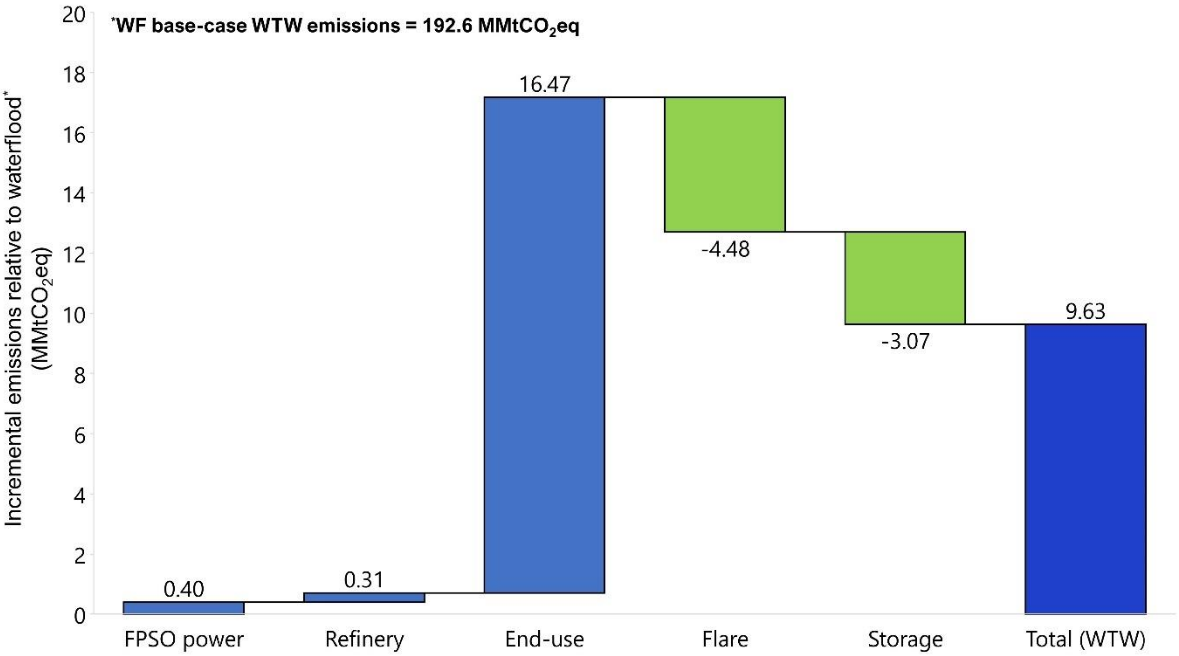


Figure 5. 'Max NPV10' tapered WAG incremental emissions ('max NPV10' emissions *minus* WF base-case emissions) by sector in relation to the waterflood base-case.

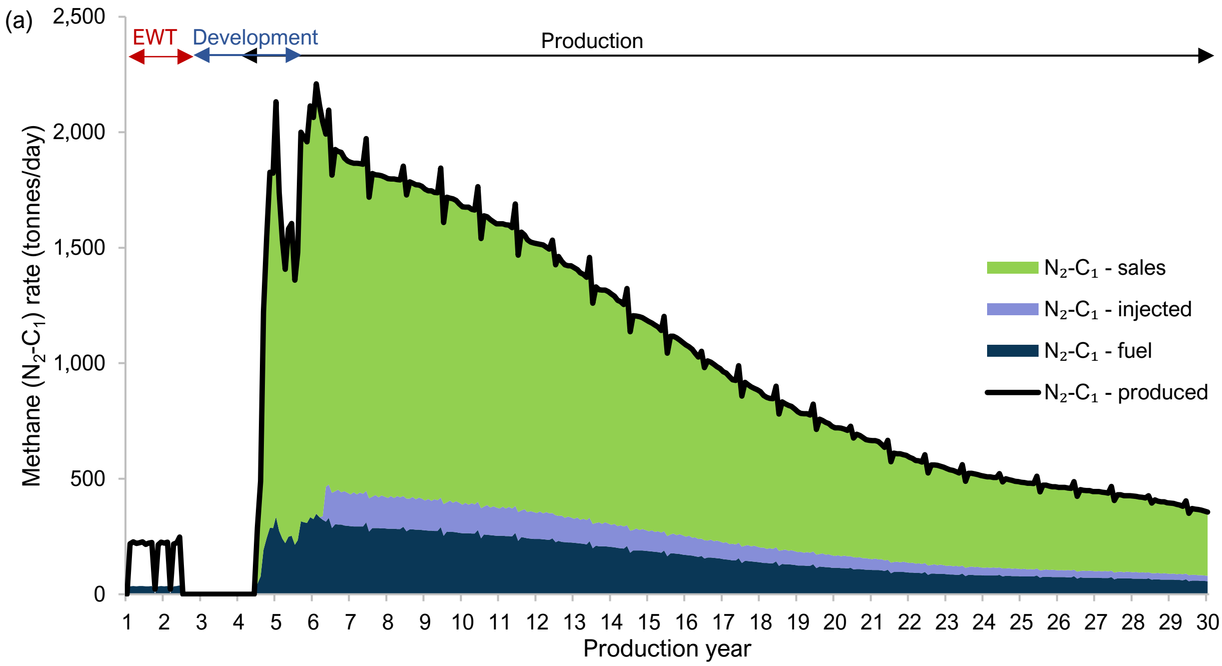
According to Figure 4b, all 'CO_2 recycle' CCUS scenarios, regardless of their absolute emissions (shown in Figure 4a), yielded a less carbon-intensive BOE compared to the WF base-case – a 3.4% average reduction. This is because the CO_2-EOR strategies were more efficient in producing oil compared to the WF baseline, therefore the ratio between CO_2 emissions and BOE produced was lower for every scenario, despite the larger absolute emissions in about half the simulations. This indicates that operational best practices in CO_2-EOR have the potential to produce a lower carbon footprint oil. And if this lower carbon footprint oil is simply meeting an existing demand – i.e., not increasing overall consumption - but rather displacing market share from a more carbon-intensive oil, emissions reduction could be promoted. As no process occurs in a vacuum, one should compare it to its most likely alternative when analyzing carbon mitigation scenarios, in this case, extracting the hydrocarbons through secondary recovery and flaring the CO_2-rich gas produced in the FPSO. If instead an effective CO_2 re-utilization design is applied, the financial and environmental objectives may align.

From Figure 4a is also clear that only a couple of CGI designs presented NPV10 improvements in relation to the WF reference case. Because of the sheer trade-off between the objectives and uniform carbon intensity amongst designs, it makes sense to differentiate them in economic terms. There were a few scenarios close to the maximum NPV10 of the search space but, for the sake of conciseness, we will take a closer look at the highest overall NPV10 ('max NPV10'). The max NPV10 scenario was a tapered WAG, and its design is summarized in Table 5. Figure 6 shows the breakdown of the methane and CO_2 destination if this operational design were applied. The resulting CO_2 injection concentration can be seen in Figure 7.

Table 5 'Max NPV10' tapered WAG design parameters generated by the PSO algorithm.

	Injector 1	Injector 6

WAG stage →	S1	S2	S3	S1	S2	S3
Water half-cycle (days)	90	90	240	90	90	90
Gas half-cycle (days)	90	90	90	90	90	240
Number of cycles	2	2	Rest of the time	2	2	Rest of the time
Average WAG ratio (rm^3 water/rm^3 gas)	3.72	2.75	4.10	3.94	4.07	2.51



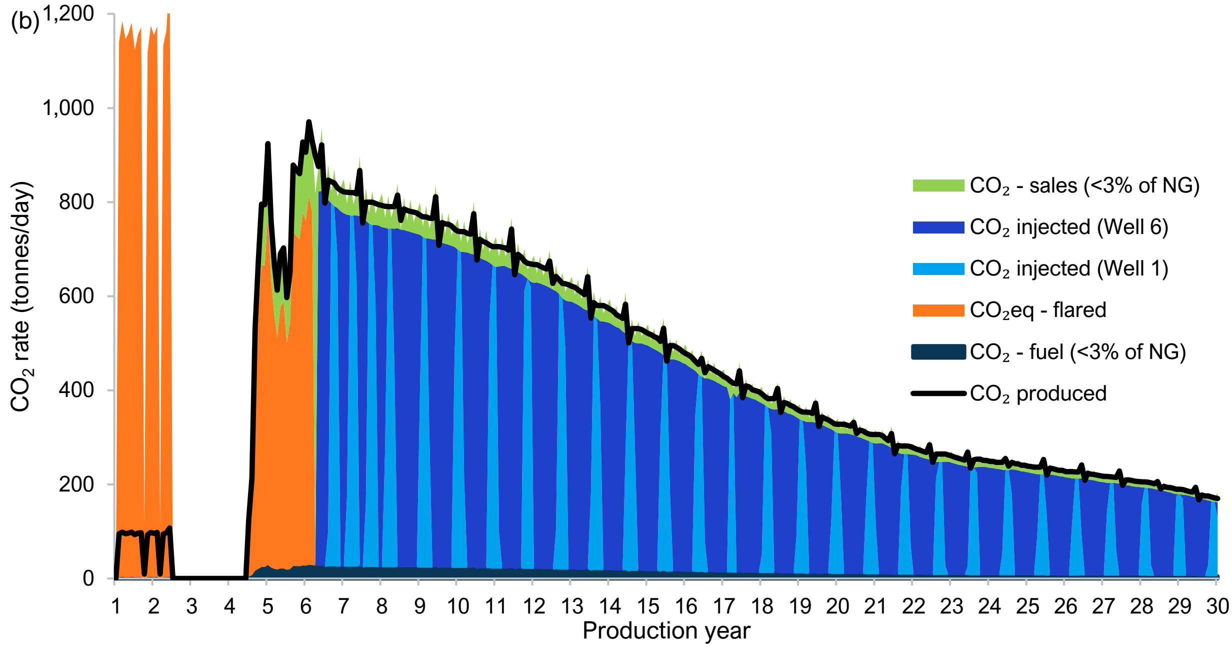


Figure 6. ‘Max NPV10’ tapered WAG gas production destination (monthly rates) for (a) N_2-C_1 component and (b) CO_2.

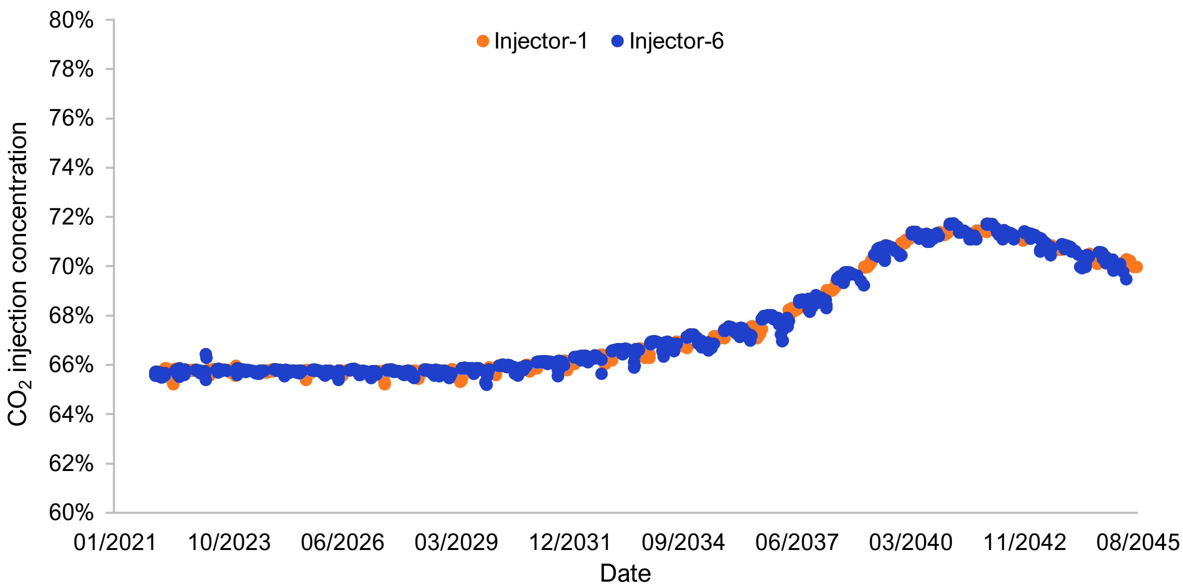


Figure 7 Recycled CO_2 injection concentration achieved during the ‘max NPV10’ tapered WAG.

According to Figure 6, the period with highest emissions was during the EWT, before the gas separation and export capabilities were installed, and before CO_2 re-injection commenced. During the forecasted period, however, most of the methane was sold or used for fuel and most of the CO_2 would be re-recycled for EOR. The 'max NPV10' tapered WAG design was able to reinject 90.7% w/w of all the CO_2 produced during the forecast period in a closed loop into injection wells '1' and '6' (total CO_2 injected was equivalent to 1.86% HCPV). The amount of CO_2 that the operator would avoid flaring (4.48 $MMtCO_2eq$) was roughly equivalent to removing 32,452 passenger cars from the roads [43].

Injector 1 lost injectivity during its WAG cycles, with water injection rates around 1,500 sm^3/d (rather than the 6,000 sm^3/d it was meant to inject), possibly due to relative permeability hysteresis effects. This explains the differences in average WAG ratio between the two injectors during stages S1 and S2, when the slug durations were the same. Injector 1 did not achieve maximum injectivity in the WF case, operating at rates of around 4,000 m^3/d, but it injected the same cumulative volume of water (equivalent to 59.4% PV or 73.2% HCPV) due to the voidage replacement assumption.

The savings in flaring penalties reached almost 91%, around 179 million USD reduction. We also estimated that the abatement cost of this CCUS strategy would be *negative* 94.8 USD/tCO_2 abated over the lifetime of the asset. Abatement cost is the incremental cost of a lower-emission technology (in this case, the 'CO_2 recycle' WAG) compared to the case without it (waterflooding), including the extra investment costs, operating costs, and possible revenues or savings generated by use of the lower-carbon alternative [44]. Thus, a negative abatement cost suggests financial benefit from the flaring avoidance and from the extra hydrocarbon recovery, even with the additional capital intensity of USD 45 per tonne of CO_2 avoided.

The injected CO_2 necessary to produce one incremental barrel of oil was 56 $kgCO_2$/incBOE (or 65.7 $kgCO_2$/inc. bbl) for the 'max NPV10' case, which is a relatively low CO_2 gross utilization ratio [45], but this is because the CO_2 supply was limited to the field itself. To put into perspective, each incremental barrel would emit 220 $kgCO_2$/incBOE (or 235 $kgCO_2$/inc. bbl) from 'wells to wheels' - still a long way to carbon neutrality. However, there is a vast potential to scale-up the CO_2 stored - e.g., in fields with higher initial CO_2 content or with CO_2 importation, either from neighbour platforms or from anthropogenic sources onshore, if a pipeline infrastructure is put in place.

Care should be taken on the CO_2 storage quantification. If we assume the CO_2 material balance in the reservoir is a simple account of what enters and leaves the system [46], disregarding the CO_2 initially in the reservoir, CO_2 storage would be *negative* since some of the CO_2 produced will end up in the oil and gas sold and there are no CO_2 external sources (e.g., purchase top-up). The "ideal" design in a strictly CO_2 recycling context would yield a zero CO_2 storage, meaning all the CO_2 produced was reinjected. Thus, the negative CO_2 storage of the 'CO_2 recycle' designs meant some of the CO_2 produced did not make its way back to the reservoir, ending up on a flare or combustion engine. These emissions are already included in our WTW emission calculations, so negative storage values were disregarded to avoid double counting.

The 'max NPV10' design was the best performing CCUS strategy in our calculations, but it appeared vulnerable to oil price fluctuations (see Figure 8). Additionally, the marginal cost of this design (or incremental cost to produce one extra barrel of oil equivalent) was 5.3 USD/BOE (or 5.65 $kgCO_2$/inc. bbl), yielding a return per BOE 0.8% lower than the WF reference case. Its break-even oil price - around 39.2 USD/STB - was still in alignment with deep-water projects.

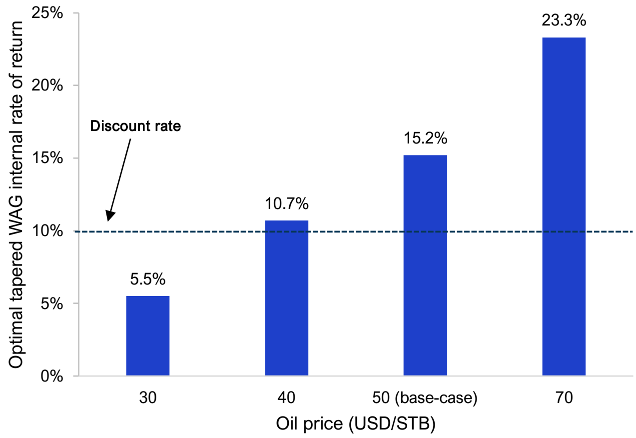


Figure 8. ‘Max NPV10’ tapered WAG internal rate of return per long-term oil price assumption.

Finally, in terms of calcite scale management, Figure 9 shows the incremental number of squeeze treatments that each producer would need under the ‘max NPV10’ WAG scheme as opposed to WF. A negative number represents a reduction in number of interventions. The plot also displays the NPV10 change that each well would experience (disregarding gas production, for simplicity) if the ‘max NPV10’ WAG design were applied. Note how most wells substantially improve their productivity, especially ‘Prod-6’, the closest to the WAG injection pair. Under WF, this well required numerous interventions - roughly every 3 months- but with the WAG scheme, oil production was favoured over water. Although some wells had their water production increased and needed more interventions, the total number of squeeze treatments was lower in the ‘max NPV10’ WAG design (182 against 187 interventions for the WF), with a drop of 13% in total squeeze costs and of 8% in the cost to protect a barrel of water produced.

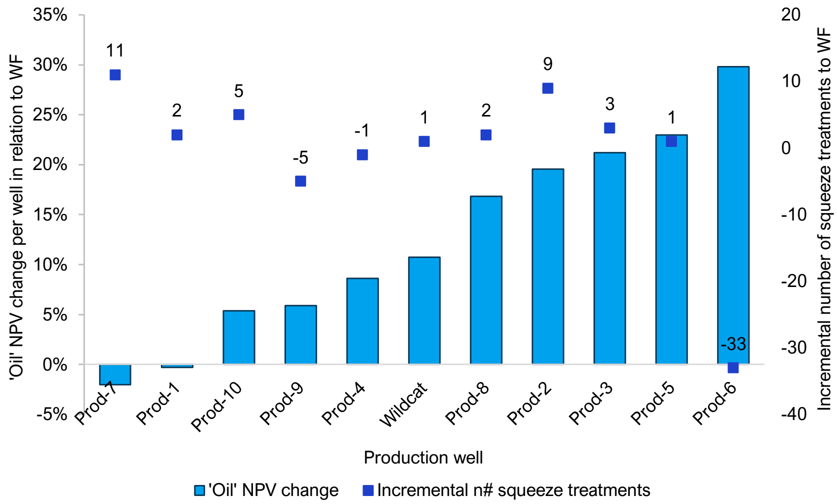


Figure 9. Net Present Value (considering oil only) change per production well and incremental number of squeeze treatments in relation to the waterflood base-case.

5. Conclusions

This work investigated the implications of recycling the natural CO_2 of an offshore carbonate reservoir for EOR and storage. We used reservoir modelling and simulation tools to investigate the operations of an offshore CCUS project in a carbonate reservoir with high natural CO_2 content. The objective was to achieve high economic returns, utilize the CO_2 produced sustainably (avoid flaring) and prevent calcite scale hazards.

The oil and gas produced in these remote fields can be especially energy-intense due to the non-conventional nature of its offshore operations, the application of EOR, and the need for artificial lift. Yet our results demonstrated that the total carbon intensity when CO_2-EOR is applied can be lower than the usual waterflood, due to the reduction in flaring emissions and increased efficiency of hydrocarbon recovery. Carbon intensity would reduce further by using more than the available recycled CO_2, sourced from neighbouring fields or from anthropogenic sources onshore via a pipeline. The repurposing of existing natural gas pipelines for the transport of captured CO_2 could prevent substantial decommissioning costs and would require only a fraction (1 to 10%) of the investment of building a new one [3]. Investigations of these next-generation alternatives would shed more light on the topic.

All simulated CCUS scenarios yielded a 3.4% lower carbon footprint oil, with 43.5% decrease in E&P emissions and, in the best scenarios, a 25% increase in NPV10, even if the WTW emissions did not reduce. Absolute WTW emissions varied slightly across WAG scenarios (±6% around the waterflood base-case), but carbon intensity was practically the same. This limitation on carbon intensity reduction was due to the restricted volumes of CO_2 available for reinjection.

Results on the internal rate of return for the ‘max NPV10’ WAG scenario suggested that large upfront capital investments and a prospect of low oil prices as climate change concerns grow may represent significant hurdles to offshore CCUS in the BPS. Finally, WAG schemes resulted in fewer squeeze interventions and a lower cost of calcite scale management, mainly due to reduction of water production due to the higher gas injection.

In summary, our study demonstrates how rearranging the WAG slugs in a tapered manner can significantly improve the economics, CO_2 storage and scale management of CCUS operations using recycled CO_2 from the associated gas. The proposed methodology also provides valuable insights into the simulation and co-optimization of these projects when multiple objectives are at stake.

Nomenclature

Bbl	barrel of oil
BHP	bottom-hole pressure
BOE	barrel of oil equivalent
BPS	Brazilian Pre-salt
CAPEX	Capital expenditure
CCUS	Carbon Capture Utilization and Storage
CGI	continuous gas injection
CO_2	carbon dioxide
EOR	Enhanced Oil Recovery

EWT	Extended Well Test
FPSO	Floating Production Storage and Offloading
LPG	Liquefied Petroleum Gas
MM	one million
NGPP	Natural Gas Processing Plant
NPV	Net Present Value
NPV10	Net Present Value with a 10% forward discount rate
OPEX	Operating expenditure
SRU	Sulfate Removal Unit
STB	standard barrel of oil
tCO_2	metric tonnes of carbon dioxide
USD	United States dollar
WAG	Water Alternating Gas
WF	Waterflood
WTW	well-to-wheels

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