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A Techno-Economic Study on The Impact of Carbon Tax on Production Rate and Production Duration in An Oil Field

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ABSTRACT - This study investigates the economic implications of carbon taxation on upstream oil and gas operations by integrating emission quantification with techno-economic evaluation in a mature offshore oil field. Greenhouse gas emissions were calculated from major upstream sources, including fuel combustion, flaring, venting, and fugitive emissions, using activity-based approaches aligned with IPCC methodologies. Emissions were monetized using Norwegian carbon tax rates, reaching approximately USD 87 per ton CO_2 by 2025, and integrated into project cash flow analysis. The quantified carbon costs were incorporated as additional operating expenditures to evaluate their impact on Net Present Value (NPV) and Internal Rate of Return (IRR). The quantified emissions were monetized using the Norwegian carbon tax framework and incorporated into project cash flow analysis as additional operating costs. Government allowance and subsidy mechanisms were also considered to partially offset the carbon burden. Net Present Value (NPV) and Internal Rate of Return (IRR) were evaluated for baseline conditions and nine production optimization scenarios combining production rate reductions of 10%, 20%, and 30% with production duration extensions of one to three years. The baseline case shows a reduction in NPV of approximately 19% after incorporating carbon costs. Fugitive emissions represent more than 60% of cumulative upstream emissions and dominate total carbon expenditures. Scenario analysis indicates that higher production rate reductions progressively reduce economic losses caused by carbon taxation, although at the expense of lower revenue generation. The results demonstrate that operational optimization can partially mitigate carbon tax impacts in mature oil fields but must be complemented by targeted emission mitigation strategies for long-term sustainability.

Keywords: carbon tax, production optimization, upstream emissions, techno-economic analysis, mature oil field.

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INTRODUCTION

The oil and gas industry remains a vital contributor to global energy supply and economic development; however, its operations are also associated with significant greenhouse gas emissions. In response to climate change mitigation efforts, carbon pricing mechanisms, particularly carbon taxes, have been increasingly adopted to internalize environmental externalities by assigning monetary value to carbon dioxide equivalent (CO_2e) emissions. These policies directly affect operational expenditures and long-term investment decisions within energy-intensive sectors (IEA 2021).

The economic implications of carbon taxation are especially pronounced in mature oil fields, where declining reservoir performance and rising unit production costs reduce operational margins. In such fields, declining reservoir pressure and increasing operational complexity often necessitate production optimization or artificial lift reconfiguration to sustain economic viability, as demonstrated by techno-economic evaluations of ESP implementation in high gas–liquid ratio mature wells (Pamungkas et al., 2025).

Previous studies indicate that climate policies can accelerate asset retirement, alter production strategies, and discourage reinvestment in late-life fields, despite the presence of transitional mechanisms such as emission allowances or fiscal incentives (Jiang et al., 2019; UNFCCC 2020).

Operational activities such as fuel consumption for surface facilities, gas flaring and venting, and unintended hydrocarbon leakage constitute the primary sources of upstream emissions. These emission components vary with production rate, facility efficiency, and field maturity, directly influencing carbon tax liabilities. Therefore, integrating emission quantification with reservoir performance forecasting and economic evaluation is essential to develop effective mitigation strategies. A techno-economic framework that couples production optimization with emission cost modeling enables the identification of operational scenarios that balance revenue generation and carbon cost exposure, thereby supporting sustainable field management under carbon pricing regimes (OGCI 2022).

METHODOLOGY

Integrated techno-economic framework

An integrated techno-economic framework was developed to explicitly connect upstream emission generation with project economic performance. The framework converts operational activity levels into quantified greenhouse gas emissions, monetizes emissions using carbon pricing policies, incorporates net carbon costs into discounted cash flow analysis, and evaluates the economic implications of alternative production strategies.

Case study: volve field

The proposed framework is applied to the Volve Field, a mature offshore oil field located in Production License 046 on the Norwegian Continental Shelf. Volve Field is selected as a representative mature offshore oil field due to its well-documented production history and availability of operational data. The dataset used in this study is derived from publicly available Plan for Development and Operation (PDO) reports and related publications, and is therefore classified as secondary data. The field provides a suitable basis for evaluating the techno-economic impact of carbon taxation under realistic operational conditions. This field is situated approximately 200 km west of Stavanger in water depths of around 90 m and was developed using a jack-up production platform supported by a floating storage unit, see Figure 1. The Volve Field represents a typical mature offshore asset characterized by declining production rates, increasing operational complexity, and heightened sensitivity to additional fiscal burdens such as carbon taxation.

The dataset used in this study is derived from publicly available Plan for Development and Operation (PDO) reports and related technical publications for the selected field. Therefore, the data used in this study are classified as secondary data. Additional assumptions and data processing steps were applied to reconstruct production profiles and emission inventories under consistent modeling conditions.

Reservoir production data, facility capacity constraints, and historical operating conditions are obtained from publicly available PDO documentation. These data provide the basis for constructing realistic production forecasts and emission inventories. The selection of the Volve Field as a case study is motivated by the availability of detailed operational data and the relevance of Norway’s long-standing carbon tax regime, which makes the field a representative example for assessing carbon pricing impacts on mature offshore developments.

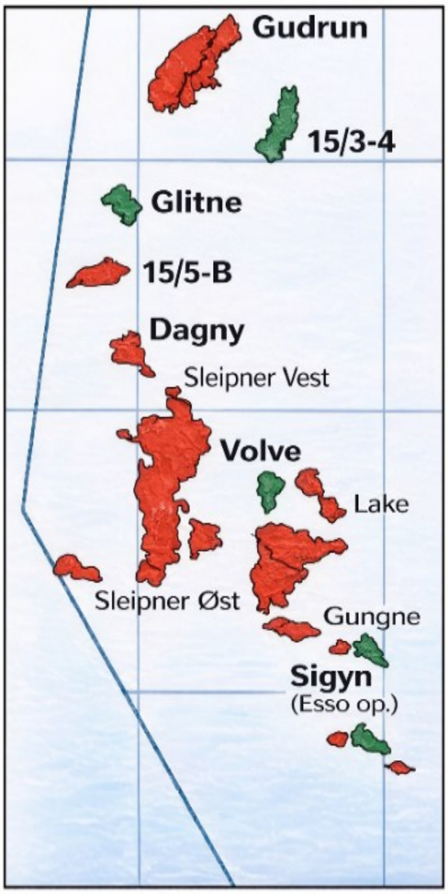

Figure 1. Location of the volve field on the Norwegian Continental Shelf. Source: adapted from PDO report

Emission estimation and carbon monetization

Emissions were calculated from four principal upstream sources: fuel combustion, flaring, venting, and fugitive releases. Activity-based estimation methods were employed using methodologies from the intergovernmental panel on climate change (IPCC), which provides standardized guidelines for greenhouse gas emission estimation. Activity-based estimation methods were employed to quantify annual emissions, which were subsequently converted into carbon dioxide equivalents.

Fuel combustion emissions arise from energy consumption for power generation, pumping, and compression activities and are calculated based on recorded fuel usage and stoichiometric conversion factors. Flaring emissions include both carbon dioxide from combustion and methane slip associated with incomplete combustion, with combustion efficiency values adopted from standard industry practices and IPCC guidelines. Venting emissions are quantified as direct releases of uncombusted gas during operational events such as maintenance and pressure control. Fugitive emissions represent unintentional methane leaks from equipment and piping systems and are estimated using activity-based factors calibrated to field operating conditions. All methane emissions are converted to CO_2-equivalent using appropriate global warming potential values to ensure consistency in carbon cost calculations.

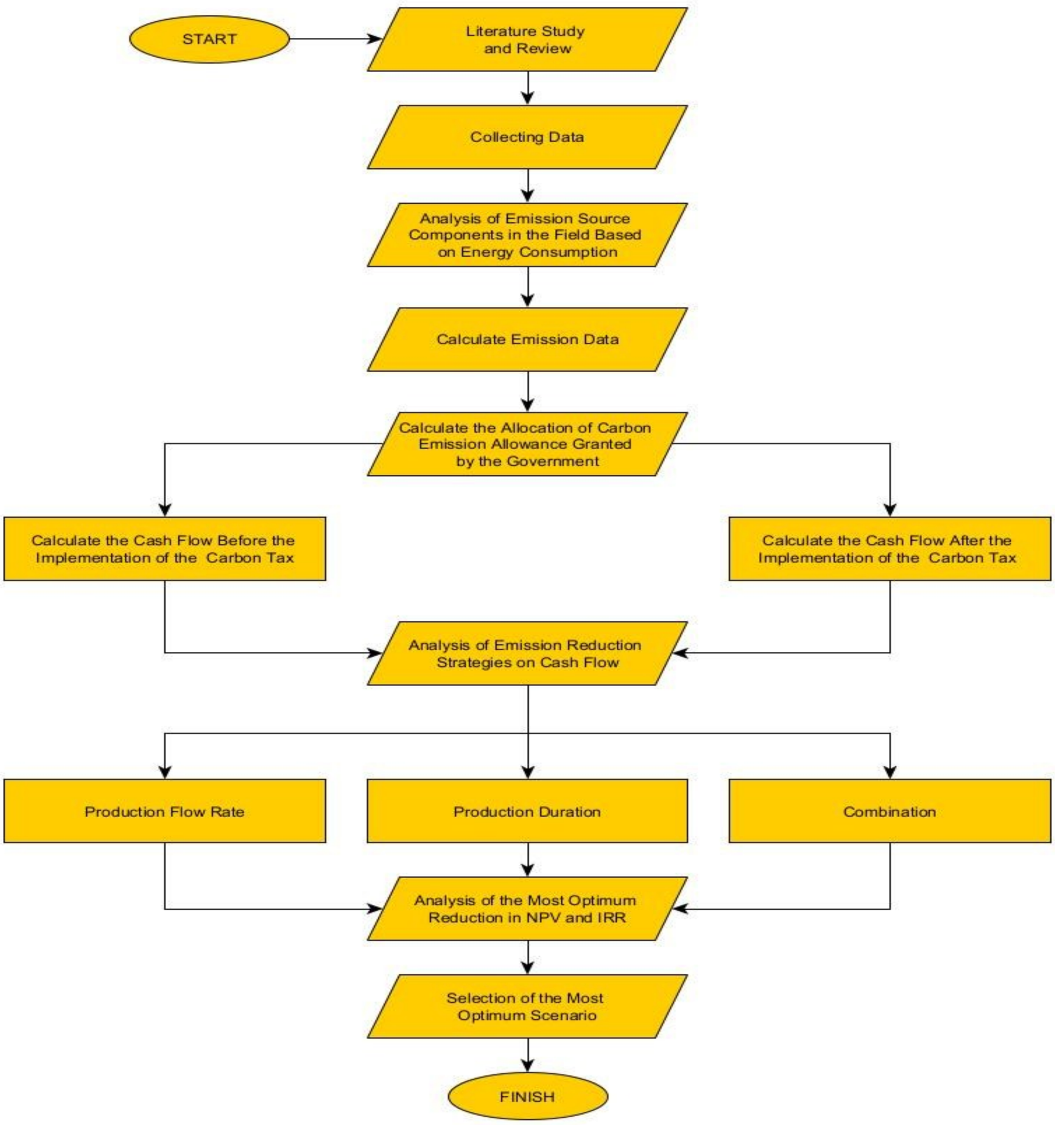

Figure 2. Integrated techno-economic framework linking production forecasting, emission quantification, and economic evaluation under carbon tax. Source: author's illustration

The total carbon footprint was multiplied by prevailing carbon tax rates to determine gross carbon payments. Allowance allocation and subsidy mechanisms were incorporated to reflect net financial exposure. Fuel combustion emissions:

$$E_{comb} = V_{fuel}\ x\ \rho_{CH_4}\ x \frac{12}{16} x \frac{44}{12}\ x\ ox \quad (1)$$

where E_{comb} represents combustion emissions (tCO_2e), V_{fuel} is the volume of fuel consumed (Sm^3), and OX is the oxidation factor representing the fraction of carbon oxidized during combustion (dimensionless). Flaring emissions:

$$E_{flare} = V_{flare} x\ \rho_{CH_4}\ x\ \frac{12}{16} x\ ECx \frac{44}{12} \quad (2)$$

$$E_{slip} = V_{flare}\ x\ \rho_{CH_4}\ x(1 - EC)\ x\ f_{CH4}\ x\ GWP \quad (3)$$

where E_{flare} represents CO_2 emissions from flaring (tCO_2e), E_{slip} represents methane slip emissions due to incomplete combustion (tCO_2e), E_{flare} is the flared gas volume (Sm^3), EC is the combustion efficiency (dimensionless), and f_{CH_4} is the methane fraction in the gas stream (dimensionless). Venting emissions:

$$E_{vent} = V_{vent}\ x\ \rho_{CH_4}\ x\ f_{CH4}\ x\ GWP \quad (4)$$

where E_{vent} represents venting emissions (tCO_2e), V_{vent} is the volume of vented gas (Sm^3). Fugitive emissions:

$$E_{fug} = V_{fug}\ x\ \rho_{CH_4}\ x\ f_{CH4}\ x\ GWP \quad (5)$$

where E_{fug} represents fugitive emissions (tCO_2e), V_{fug} is the estimated leakage volume (Sm^3). Total annual emissions are calculated as:

$$E_{total} = E_{comb} + E_{flare} + E_{slip} + E_{vent} + E_{fug} \quad (6)$$

where E_{total} represents total annual greenhouse gas emissions (tCO_2e).

Carbon cost calculation and allowance mechanism

Total upstream greenhouse gas emissions were monetized using the prevailing carbon tax rate applicable to the oil and gas sector. Annual gross carbon costs were calculated by multiplying total emissions by the carbon price for each production year. To reflect regulatory mitigation mechanisms, free allowance allocation and subsidy schemes were incorporated following benchmark-based allocation rules established by the government. The allocated allowances represent the portion of emissions exempted from direct carbon payments.

The net carbon burden introduced into project cash flows was therefore determined as the difference between gross carbon costs and allocated allowances. This net value represents the effective carbon-related operating expense borne by the project and was integrated into the discounted cash flow model alongside conventional operating costs.

$$C_{carbon,t} = E_{total,t}\ x\ P_{carbon,t} \quad (7)$$

where C_{carbon} is the gross carbon cost (USD), E_{total} is total emissions (tCO_2e), and P_{carbon} is the carbon price (USD/tCO_2e).

If free allocation or compensation mechanisms apply, the net carbon cost is calculated as:

$$C_{net,t} = C_{carbon,t} - A_t \quad (8)$$

$$A_t = V_{fuel} x\ LHV\ x\ 10^{-6} x\ Benchmark\ Energy \quad (9)$$

where C_{net} represents the net carbon cost (USD) and A is the allocated allowance or subsidy (USD).

The allowance allocation was estimated following harmonized benchmark-based methodologies adopted in emission trading schemes, where free allowances are calculated from fuel consumption, lower heating value, and sectoral energy benchmarks.

Allowance values were derived from publicly available benchmark-based allocation rules and do not represent project-specific preferential treatment.

Economic modeling

Carbon costs were treated as incremental operating expenditures within the project cash flow structure. Annual revenues were computed from hydrocarbon production volumes, while total costs included operating expenditures, carbon payments, and fiscal charges.

Project profitability was assessed using Net Present Value (NPV) and Internal Rate of Return (IRR).

$$NPV = \sum_{t=0}^{n} \frac{R_t - O_t - C_{net,t} - T_t}{(1+r)^t} - CAPEX \quad (10)$$

$$0 = \sum_{t=0}^{n} \frac{R_t - O_t - C_{net,t} - T_t}{(1+IRR)^t} \quad (11)$$

Where NPV is net present value (USD), R_t is revenue at year t (USD), O_t is operating expenditure (USD), C_t is net carbon cost (USD), T_t is tax (USD), r is the discount rate, and t is the project year, while internal rate of return (IRR) is the discount rate that makes NPV = 0.

Cumulative and annual ratios for inflation adjustment

The cumulative escalation ratio represents the total price growth over the analysis period and is used to quantify long-term inflation effects on economic variables. The corresponding annual escalation ratio converts this cumulative growth into an equivalent yearly factor, enabling consistent application of inflation and price escalation within time-dependent cash flow calculations. The cumulative escalation ratio is defined as the ratio between final and initial price levels Equation 12, where I_n represents the final price index, I_0 the initial price index, and n the number of years. The annual escalation factor is then derived from this cumulative ratio, as expressed in Equation 13.

$$ER_{cum} = \frac{I_n}{I_0} \quad (12)$$

$$ER_{ann} = (\frac{I_n}{I_0})^{\frac{1}{n}} \quad (13)$$

where ER_{cum} is the cumulative escalation ratio, I_n is the final price index, I_0 is the initial price index, and ER_{ann} is the annual escalation ratio andis the number of years.

Production optimization strategy design

Operational scenarios were structured to systematically explore the techno-economic impacts of production adjustment. Production rate reductions of 10%, 20%, and 30% were combined with production duration extensions of one to three years, forming nine optimization scenarios.

Table 1. Operational scenarios analyzed

Production rate reduction	Production duration extension
10%	1 Year
	2 Year
	3 Year
20%	1 Year
	2 Year
	3 Year
30%	1 Year
	2 Year
	3 Year

RESULT AND DISCUSSION

Production profiles

Baseline production profiles of the studied field exhibit a characteristic decline pattern typical of mature offshore reservoirs. Figure 3 shows the oil production profile under baseline conditions, where production decreases progressively over time due to reservoir depletion and declining reservoir pressure. This behavior reflects the late-life stage of the field, where sustaining production becomes increasingly challenging.

Figure 4 presents the corresponding gas production profile, which follows a similar declining trend. The reduction in gas production is primarily associated with decreasing reservoir energy and changes in fluid flow dynamics as the reservoir matures.

These declining production trends have direct implications for both revenue generation and emission distribution throughout the project life. As production decreases, operational efficiency and unit production costs become increasingly sensitive to additional financial burdens such as carbon taxation. Therefore, the baseline production profiles serve as a critical reference for evaluating the techno-economic performance of alternative production scenarios under carbon pricing conditions.

Carbon emission structure breakdown

The cumulative upstream emission inventory indicates that fugitive emissions dominate total greenhouse gas emissions, accounting for approximately 60.43% of total CO_2-equivalent output. Fuel combustion contributes 25.88%, followed by venting emissions at 11.11% and flaring emissions at 2.58%. The emission inventory indicates that methane-related fugitive emissions dominate the upstream carbon footprint, contributing more than 60% of cumulative emissions. Fuel combustion represents the second largest contributor, followed by venting and flaring.

The dominance of fugitive emissions (>60% of total CO_2e) is primarily associated with methane leakage from surface facility components such as valves, flanges, connectors, and seals. In mature offshore installations, aging infrastructure, pressure cycling, and limited accessibility for frequent inspections exacerbate leakage rates. Previous measurement-based studies and IPCC Tier-2/3 frameworks indicate that a small number of high-emitting components ("super-emitters") can disproportionately contribute to total fugitive emissions, explaining the observed emission structure in the studied field.

Figure 5 presents the breakdown of cumulative upstream emissions by source. The results clearly show that fugitive emissions dominate the total emission profile, contributing more than 60% of total CO_2-equivalent emissions. This dominance indicates that methane leakage is the primary contributor to carbon cost exposure in the studied field.

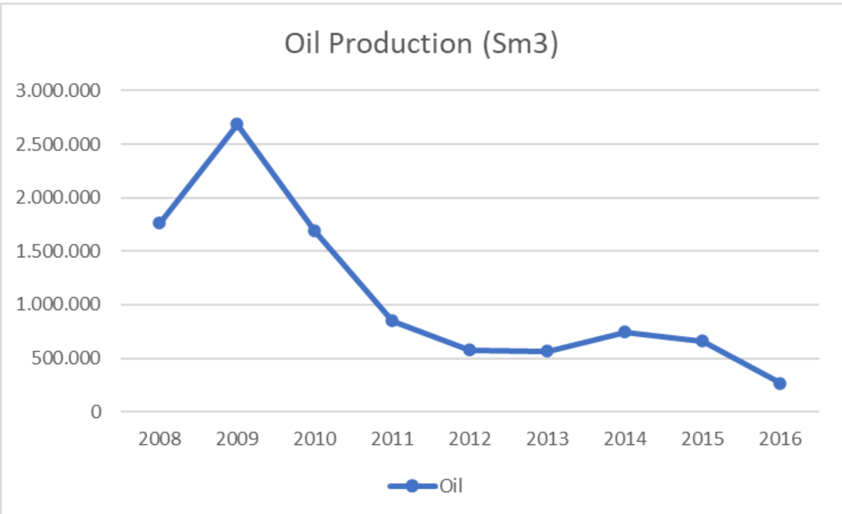

Figure 3. Gas production profiles of the Volve Field under baseline conditions. Source: author's calculation based on PDO data

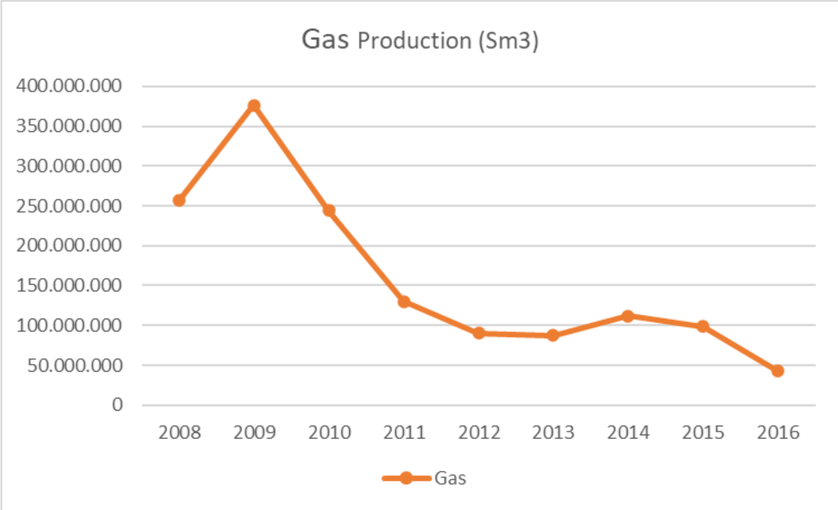

Figure 4. Gas production profiles of the Volve Field under baseline conditions. Source: author's calculation based on PDO data

Table 2. Cumulative upstream emissions by source

Emission source	Total emission (tCO_2)	Share of total emission (%)
Fuel Combustion	561.201	25.88%
Flaring	25.972	2.58%
Venting	259.729	11.11%
Fugitive	1.298.648	60.43%

Economic impact of carbon tax integration

The economic performance of the project was evaluated using Net Present Value (NPV) and Internal Rate of Return (IRR) as primary financial indicators. NPV represents the present value of cumulative project cash flows discounted over the project lifetime, as defined in Equation (10), and reflects the overall economic attractiveness of the investment. IRR, defined in Equation (11), corresponds to the discount rate at which the NPV equals zero and indicates the profitability threshold of the project.

By incorporating monetized carbon emissions into the project cash flow model, carbon taxation introduces an additional operating expense that directly reduces net revenues. The economic consequences of this integration are summarized in Table 3, which compares project performance before and after the application of carbon tax.

The results demonstrate a substantial deterioration in economic indicators following carbon tax implementation. The baseline NPV decreases from USD 339.8 million to USD 273.7 million, corresponding to an approximate reduction of 19%. Similarly, IRR declines from 47.68% to 41.21%, indicating a notable decrease in investment attractiveness. These reductions confirm that carbon-related costs constitute a material financial burden rather than a marginal regulatory expense.

Figure 6 compares project NPV before and after carbon tax implementation. The results show a significant reduction in NPV after incorporating carbon costs. This confirms that carbon taxation introduces a substantial economic burden on project profitability.

Overall, the integration of carbon costs into project cash flows significantly alters project viability and highlights the necessity of explicitly accounting for emission-related expenses in techno-economic evaluations of upstream oil and gas developments.

Carbon cost structure under baseline operations

The monetization of upstream greenhouse gas emissions generates substantial gross carbon costs throughout the project life, as calculated by multiplying total annual emissions by the prevailing carbon price. To account for regulatory mitigation mechanisms, a compensation scheme based on allowance allocation was incorporated following Equation 8, while the quantity of allowances granted to the project was determined using the allocation methodology defined in Equation 9.

Table 3. Economic indicators before and after carbon tax

Indicator	Before carbon tax	After carbon tax
NPV (USD Million)	339,8	273,7
IRR (%)	47,68%	41,21%

The resulting gross carbon costs, allowance coverage, and net carbon costs under baseline operations are summarized in Table 4. During the early production years, higher production levels correspond to larger allowance allocations, which significantly offset the gross carbon burden. Consequently, net carbon payments remain lower relative to gross carbon costs despite high emission volumes. As production declines over time, allowance coverage gradually decreases, leading to a relatively higher proportion of gross carbon costs being borne by the project.

Although regulatory compensation mechanisms partially mitigate early-stage carbon expenditures, net carbon costs remain economically material throughout the production period. The persistence of these costs confirms that allowance systems do not eliminate financial exposure to carbon pricing but rather redistribute it over time. When integrated into the project cash flow model, these net carbon expenses contribute directly to the observed deterioration in economic performance indicators.

Figure 7 illustrates the impact of carbon cost integration on project economics over time. The figure indicates that carbon-related expenditures persist throughout the project life and significantly influence discounted cash flow outcomes.

Overall, the results highlight the critical role of allowance allocation in moderating carbon cost impacts during peak production phases while demonstrating that carbon taxation remains a dominant economic factor under baseline operating conditions.

Scenario comparison

Table 5 summarizes the techno-economic outcomes of all production optimization scenarios under carbon taxation. Although cumulative emissions remain constant across scenarios, redistributing production and associated carbon costs over longer operational periods significantly alters project cash flows and discounted economic indicators. The results indicate a systematic

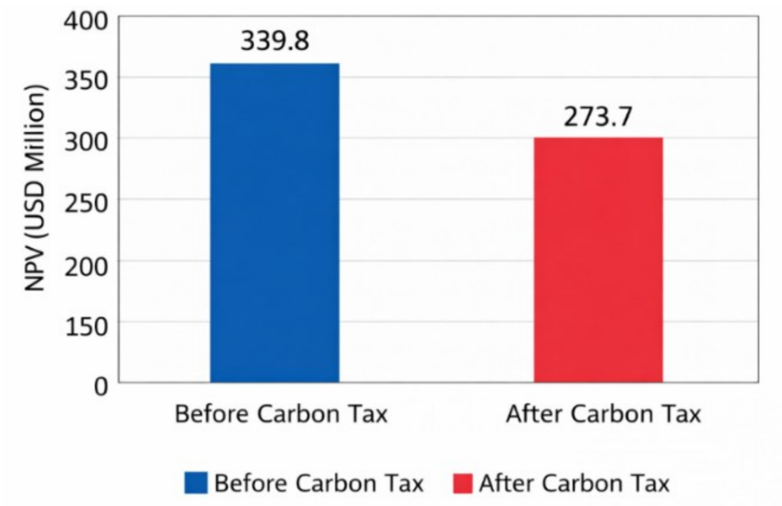

Figure 6. Comparison of project NPV before and after carbon tax implementation. Source: author's calculation based on techno-economic model

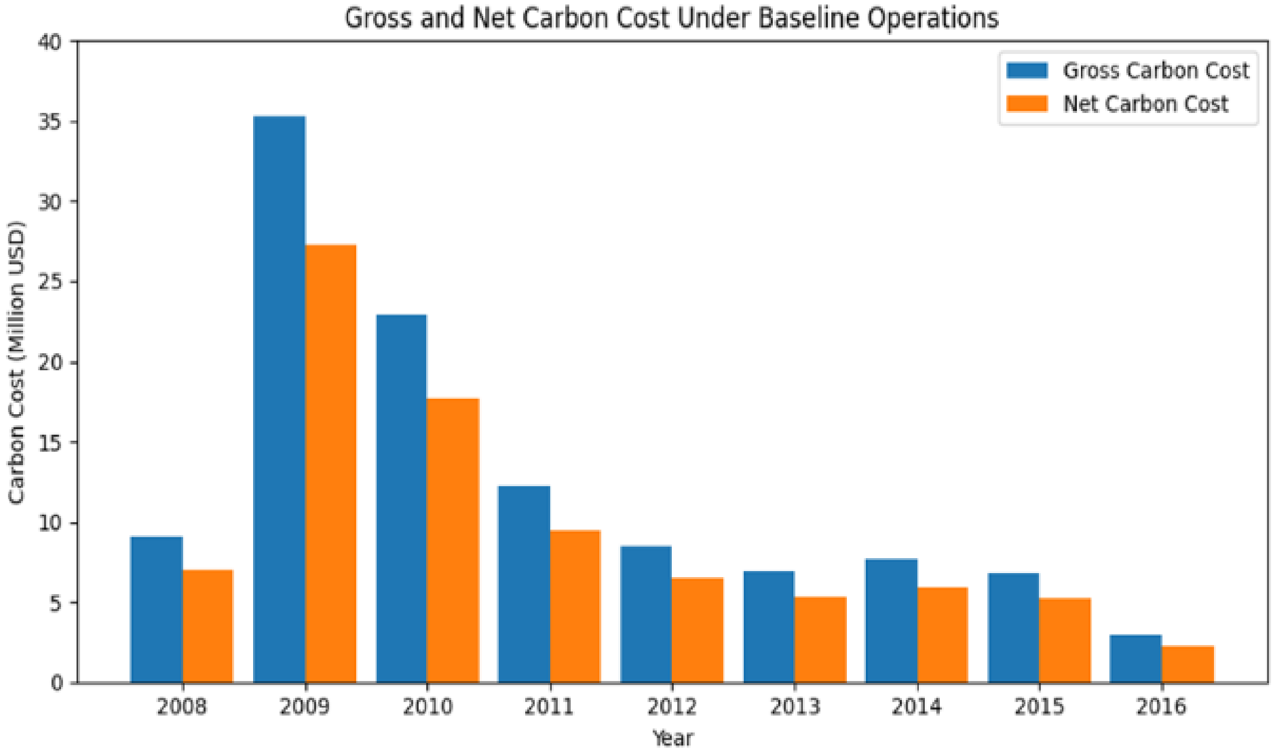

Figure 7. Comparison of project NPV before and after carbon tax implementation. Source: author's calculation based on carbon cost modeling

decrease in ΔNPV and ΔIRR as production rate reductions increase, demonstrating the economic effect of operational adjustments on carbon cost exposure.

Table 6 presents the economic performance of all optimization scenarios (A1–C3) under carbon tax conditions. The scenarios combine production rate reductions of 10%, 20%, and 30% with production duration extensions of one to three years. The results reveal a systematic trend across all scenario groups.

For group A (10% production rate reduction), ΔNPV ranges from USD 62.77 million (A3) to USD 63.03 million (A1). These values indicate that limited production rate reduction provides only marginal mitigation against carbon tax impacts compared to the baseline case. The corresponding ΔIRR values remain relatively high, ranging between 5.97% and 6.15%, suggesting that the investment attractiveness is still significantly affected by carbon taxation.

In group B (20% production rate reduction), ΔNPV decreases to a range of USD 59.46–59.97 million. This represents an improvement of approximately 5–6% compared to group A. Similarly, ΔIRR declines to 5.25–5.49%, indicating enhanced economic resilience under carbon pricing. These results demonstrate that moderate production rate reduction offers a better balance between revenue retention and emission mitigation.

Group C (30% production rate reduction) exhibits the lowest economic losses. ΔNPV further decreases to USD 56.14–56.91 million, corresponding to an improvement of approximately 11% compared to group A. ΔIRR also reaches the lowest range (4.37–4.61%), confirming that aggressive production optimization effectively dampens the adverse impact of carbon taxation.

Figure 7 illustrates these trends clearly, showing a monotonic decrease in both ΔNPV and ΔIRR as production rate reduction increases from group A to group C. This pattern confirms that higher production rate reductions systematically reduce exposure to carbon costs.

Figure 8 presents the economic performance of different production scenarios under carbon tax conditions. The results indicate that higher production rate reductions lead to lower economic losses. This suggests that production optimization can partially mitigate carbon cost exposure.

However, extending production duration from one to three years within each group slightly increases cumulative carbon tax exposure. This effect is reflected in the gradual increase of ΔNPV within each group (e.g., A1 to A3 and B1 to B3), indicating that longer production periods lead to higher cumulative carbon payments despite lower annual production rates.

Overall, the results highlight a clear trade-off between economic performance and operational mitigation. While aggressive production rate reduction minimizes carbon tax impacts, it also reduces total revenue potential. Therefore, the optimal strategy should be selected based on field maturity, oil price outlook, and corporate economic objectives.

Sensitivity of economic performance to price escalation assumptions

To evaluate the robustness of production optimization strategies under evolving market and policy conditions, a sensitivity analysis was conducted by incorporating differential escalation rates for oil price, general economic inflation, and carbon price. Oil price and operating cost components were assumed to increase at an annual rate of 2.5%, reflecting long-term inflation-adjusted energy market trends. In contrast, carbon prices were escalated at a higher annual rate of 8.9%, representing increasingly stringent climate policy trajectories.

The baseline carbon price of USD 16 per ton CO_2 in 2005 was adopted based on historical carbon market assessments reported by the European Environment Agency (EEA) shown in figure 9, while the rapid increase in carbon price projections was aligned with observed market developments reported by the Intercontinental Exchange (ICE) shown in figure 10, where carbon prices approached approximately USD 87 per ton CO_2 by 2025. These reference points were used to construct long-term escalation pathways capturing the asymmetric growth between hydrocarbon revenues and carbon-related costs.

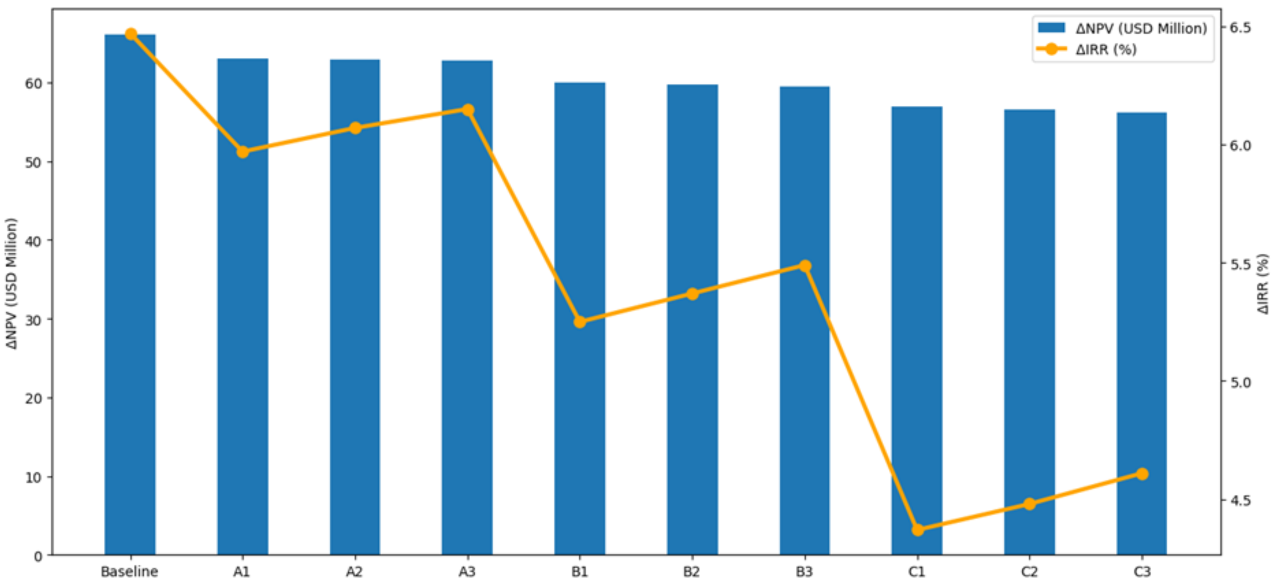

Figure 8 Economic performance of production rate and production duration scenarios under carbon tax. Source: author's calculation based on production optimization scenarios

Figure 9 illustrates the historical evolution of carbon prices in early market phases, showing initial volatility followed by an upward trend, and Figure 10 shows recent carbon price trajectories, indicating a rapid increase driven by tightening climate policies.

To quantify cumulative price growth over the analysis period, the escalation ratio was defined as the ratio between final and initial price levels, as expressed in Equation 12. The corresponding annual escalation factor was then derived as the nth root of the cumulative ratio, as shown in Equation 13, enabling consistent integration of inflation and price escalation effects into time-dependent economic calculations.

Using this formulation, general economic inflation of 2.5% resulted in a cumulative escalation ratio of 1.64 over 20 years, while carbon price escalation of 8.9% produced a cumulative ratio of 5.50 over the same period, highlighting the substantially faster growth of carbon-related costs relative to conventional economic variables.

The resulting oil price and carbon price projections under differential growth assumptions are presented in Table 7. The table clearly demonstrates the exponential divergence between carbon price and oil price trajectories over the project life. While oil prices increase moderately due to inflationary effects, carbon prices escalate aggressively under climate policy-driven market dynamics, progressively becoming the dominant economic burden in later production years.

Figure 11 further illustrates the contrasting growth patterns of oil and carbon prices, highlighting the rapidly expanding gap between revenue growth and carbon cost escalation. This divergence indicates that carbon-related expenditures increasingly outweigh revenue gains in long-term project economics, fundamentally altering the profitability landscape of upstream developments. The sensitivity results confirm that carbon costs increase at a substantially faster rate than hydrocarbon revenues, disproportionately penalizing early-period emissions while amplifying the economic

Figure 9. Historical evolution of European Union Allowance (EUA) carbon prices during early EU ETS phases, illustrating market volatility and long-term upward policy-driven trends. Source: European Environment Agency (EEA)

advantage of production strategies that defer carbon exposure. Consequently, extended production configurations consistently outperform higher-rate short-term production cases under escalating carbon pricing environments. Among the evaluated scenarios, C1 remains the economically optimal configuration, offering the most balanced trade-off between deferred carbon payments and retained revenue streams. While further extensions of production duration continue to reduce early carbon exposure, the associated dilution of revenues outweighs marginal economic benefits.

Table 7. Escalated oil price and carbon price projections under differential growth assumptions

Year	Oil price (USD/bbl)	Carbon price (USD/ton CO_2)
2005	18.70	16.00
2010	21.16	24.51
2015	23.94	37.53
2020	27.08	57.48
2025	30.64	88.04
2030	34.67	134.84
2035	39.22	206.64
2040	44.36	316.70
2045	50.19	485.61

Overall, these findings demonstrate that moderate production rate reductions combined with limited production extensions provide the most resilient techno-economic response to long-term carbon price escalation.

While the baseline case indicates an NPV reduction of approximately 19% under prevailing carbon tax conditions, the sensitivity analysis highlights that economic viability is strongly dependent on long-term carbon price escalation. Under moderate carbon price trajectories, operational optimization remains effective. However, under aggressive escalation scenarios, carbon costs increasingly dominate project cash flows, eventually driving NPV toward breakeven and negative values. This demonstrates that economic risk arises not only from the carbon tax level itself, but from long-term carbon price volatility and uncertainty.

Robustness check using shifted baseline production timing

To assess the temporal robustness of the production optimization strategy under escalating market and policy conditions, the

Figure 10 Recent carbon market price trajectory showing EUA futures approaching USD 87 per ton CO_2, reflecting accelerated carbon price escalation under tightening climate policy frameworks.
Source: Intercontinental Exchange (ICE)

baseline production profile was re-evaluated by shifting its start year to later periods while maintaining identical production volumes and emission characteristics. Two representative cases were examined, in which the baseline production scheme was assumed to commence in 2025 and 2045, respectively. The corresponding economic outcomes are summarized in Table 8 and Table 9.

Oil prices and general economic variables were escalated at an annual rate of 2.5%, whereas carbon prices were escalated at a substantially higher annual rate of 8.9%, reflecting long-term climate policy tightening. This asymmetric escalation introduces increasing economic pressure on upstream operations as carbon-related expenditures grow faster than hydrocarbon revenues.

The 2025 start-year case demonstrates that production optimization through scenario C1 remains economically viable and continues to outperform the baseline strategy. As shown in Table 8, moderate production rate reduction combined with limited production extension successfully mitigates early carbon cost exposure while preserving sufficient revenue streams, resulting in superior NPV and IRR performance relative to the unadjusted baseline profile.

However, when the production profile is shifted to 2045, the economic balance fundamentally changes. The dramatic escalation of carbon prices dominates project cash flows, overwhelming the moderate increases in oil prices and general inflation. Under this extreme carbon cost environment, operational optimization alone becomes insufficient to sustain economic feasibility. As indicated in Table 9, scenario C1 no longer provides an economic advantage and fails to offset the rapidly increasing carbon burden.

These results reveal the existence of a temporal threshold beyond which production optimization strategies lose effectiveness under aggressive carbon price escalation. While operational adjustments offer a robust medium-term mitigation pathway, long-term project sustainability will require complementary technological emission reduction measures or policy interventions beyond production rescheduling.

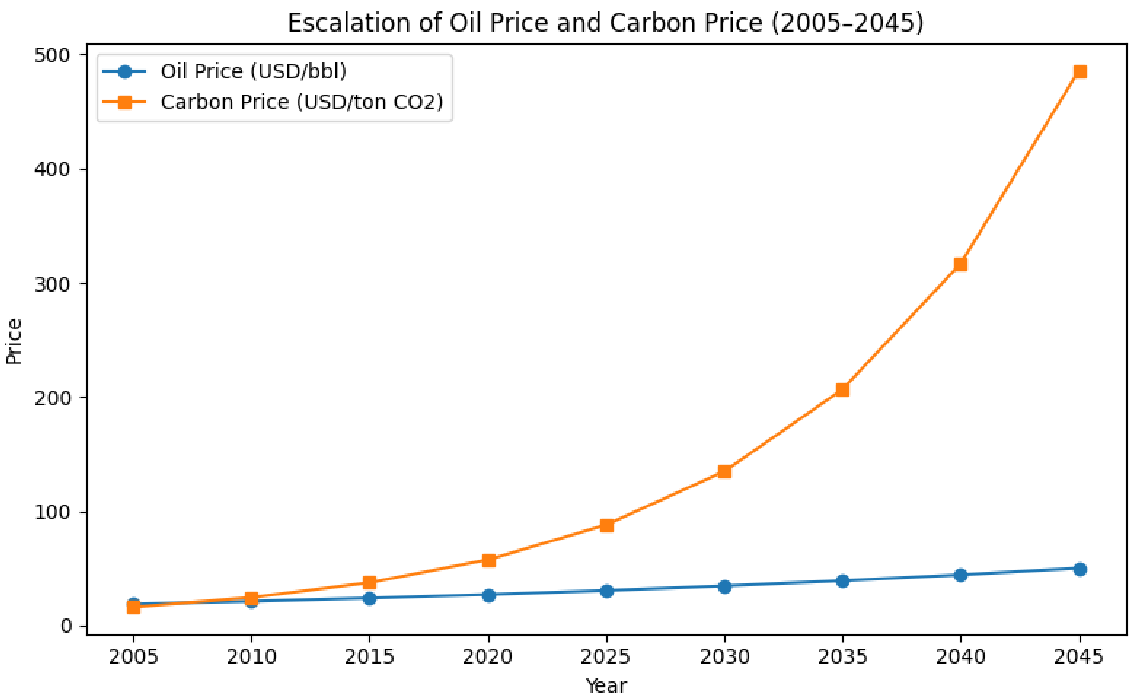

Figure 11. Escalation trajectories of oil price and carbon price under differential annual growth assumptions (2005–2045). Source: author's calculation based on oil and carbon price projections

Discussion

The integration of emission-derived carbon costs into the techno-economic framework demonstrates that carbon taxation constitutes a material and increasingly dominant driver of upstream project profitability. Even after accounting for allowance allocation mechanisms, net carbon costs significantly deteriorate economic indicators under baseline operating conditions. This confirms that carbon pricing cannot be treated as a marginal regulatory expense but must be explicitly incorporated into project-level cash flow models.

The scenario analysis reveals that redistributing production and associated emissions over longer operational periods can partially mitigate the economic burden imposed by carbon taxation. Although total cumulative emissions remain unchanged across scenarios, shifting carbon cost exposure to later years reduces their present value due to discounting effects. This temporal reallocation explains the systematic reduction in ΔNPV and ΔIRR observed as production rate reductions increase. The findings highlight the importance of emission timing, rather than emission volume alone, in determining economic vulnerability under carbon pricing regimes.

The allowance mechanism plays a critical role in moderating early-stage carbon burdens, particularly during high-production years. However, its mitigating effect diminishes over time as escalating carbon prices progressively dominate cost structures. Consequently, while regulatory subsidies alleviate short-term financial pressure, they do not eliminate long-term exposure to carbon cost escalation.

The sensitivity analysis further demonstrates that asymmetric price growth between hydrocarbons and carbon fundamentally reshapes optimal operational strategies. Under moderate future conditions represented by the 2025 start-year case, production optimization through scenario C1 remains economically viable and continues to outperform the baseline strategy. This indicates that operational adjustments provide a robust medium-term response to rising carbon costs.

It should be noted that extending field life through production rate reduction may increase unit lifting costs during the late production phase. Declining reservoir pressure, increasing water cut, and higher energy requirements for artificial lift can accelerate OPEX per barrel toward the economic limit. In this study, OPEX structures are held constant to isolate the effect of carbon taxation. Incorporating dynamic OPEX escalation represents an important extension for future work.

In contrast, the 2045 start-year assessment reveals a critical economic tipping point. The rapid escalation of carbon prices overwhelms the relatively modest growth in oil prices and general inflation, rendering operational optimization alone insufficient to preserve project value. Under such extreme policy-driven cost environments, even the most favorable production rescheduling strategy fails to sustain economic feasibility.

These results suggest that while production optimization offers an effective short- to medium-term mitigation pathway, it cannot serve as a standalone long-term solution under aggressive carbon pricing trajectories.

Previous feasibility studies have shown that Carbon Capture, Utilization, and Storage (CCUS), particularly CO_2 injection in mature oil fields, can simultaneously enhance oil recovery and reduce net greenhouse gas emissions, although economic viability remains highly sensitive to oil price and carbon cost assumptions (Saputra et al., 2018).

CONCLUSION

This study presents an integrated techno-economic framework that explicitly incorporates upstream greenhouse gas emissions, carbon taxation, and regulatory allowance mechanisms into project-level economic evaluation. The results demonstrate that carbon pricing substantially reduces project profitability, even when subsidy schemes are applied.

Operational production optimization can partially mitigate these impacts by redistributing emission-related costs over time. Among the evaluated strategies, moderate production rate reduction combined with limited production extension (scenario C1) consistently provides the most economically resilient configuration under current and near-term carbon price conditions.

However, sensitivity analysis under long-term carbon price escalation reveals a threshold beyond which operational adjustments lose effectiveness. While scenario C1 remains optimal when production is initiated in 2025, it becomes economically unviable under the extreme carbon cost environment projected for 2045. This indicates that future carbon policies may ultimately exceed the mitigation capacity of operational strategies alone.

The findings highlight the critical role of emission timing in determining economic exposure to carbon pricing and underscore the necessity of integrating carbon costs directly into techno-economic decision-making processes. In the medium term, operational optimization offers a practical and low-capital mitigation approach. In the long term, however, maintaining economic viability will require complementary technological emission reduction measures and supportive policy mechanisms.

Overall, this study provides a quantitative basis for evaluating carbon management strategies in mature oil field developments and contributes to informed operational planning under increasingly stringent climate policy regimes.

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DECLARATIONS

Author contribution

Adithya Aladar: Conceptualization, methodology, data analysis, and writing – original draft. Silvya Dewi Rahmawati: Supervision and validation. Ardhi Hakim Lumban Gaol: Data validation and technical review. All authors have read and approved the final manuscript.

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None

The use of AI or AI-assisted technologies

None

GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbols	Definition	Unit
CO_2e	Carbon dioxide equivalent	
CH_4	Methane	
CO_2	Carbon dioxide	
E_{comb}	Combustion emissions	CO_2e
V_{fuel}	Fuel volume fraction	Sm^3
ρ_{CH_4}	Methane density	
OX	Oxidation factor	
$E_{CO_2,flare}$	Flare emissions	CO_2e
V_{flare}	Flare volume fraction	Sm^3
EC	Combustion efficiency	
$E_{Slip}^{CO_2e}$	Flare slip emissions	CO_2e

f_{CH4}	Methane volume	
$E_{Vent}^{CO_2e}$	Venting emissions	CO_2e
V_{vent}	Venting volume fraction	Sm^3
$E_{fug}^{CO_2e}$	Fugitive emissions	CO_2e
V_{fug}	Fugitive volume fraction	Sm^3
CF_t	Cash flow	USD
r	Discount rate	%
t	Period year	
R_t	Revenue	USD
O_t	Opex	USD
T_t	Tax	USD
CT_t	Carbon tax	USD
$E_{m\,total}$	Total emission	CO_2e
ΔNPV	Delta npv	USD
I_n	Final price index	USD
I_o	Initial price index	USD
n	Number of years	

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