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e-ISSN: 2785-924X

Journal of Smart Science and Technology 5(2) 2025, 112-128

Journal of Smart Science and Technology

The Potential of Utilising Carbon Dioxide-Enhanced Oil Recovery Coupled with Carbon Capture and Sequestration in Trinidad and Tobago

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Citation:
Ramoutar, K., Alexander, D., Bahaw, E., Boodlal, D., Maharaj, R. (2025). The Potential of Utilizing Carbon Dioxide-Enhanced Oil Recovery Coupled with Carbon Capture and Sequestration in Trinidad and Tobago. *Journal of Smart Science and Technology*, *5*(2), 112-128.

ARTICLE INFO

Article history:
Received 27 September 2024
Revised 23 March 2025
Accepted 24 March 2025
Online first 16 July 2025
Published 30 September 2025

Keywords:
Enhanced oil recovery
global warming
reservoir
computer modelling group

DOI:
10.24191/jsst.v5i2.096

ABSTRACT

On a worldwide scale, Trinidad and Tobago (T&T) produces less than 1% of global greenhouse gas (GHG) emissions, with the largest emissions stemming from its power generation, transportation, and industrial sectors. The EOR 26 reservoir was modelled using the Computer Modelling Group (CMG) software. Comparing the original oil in place (OOIP) from the IMEX model (1.83 MMSTB) to the actual OOIP (1.87 MMSTB) gave only a 0.04 MMSTB difference, which was close enough to match the model, injection and production data. The CMOST program in CMG was used to identify the parameters that significantly affected the model (using the Sobol Analysis). Simulations were conducted for each scenario, and a comprehensive data analysis and economic evaluation were conducted. Scenario 4 was the most favourable since it runs for 69 years (as opposed to 100 years), sequesters the most volume of CO_2 (85.6 $MtCO_2$), produces the most oil volume (1.4 mmbbls) and gives a positive NCF for a range of oil price sensitivities. The NPV of this project at a 15% discount rate was calculated to be 0.23 MMUSD and the payback period was less than 2 years. The economic evaluations can be improved by aligning costs and revenue closer to the T&T framework.

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https://doi.org/10.24191/jsst.v5i2.096

1 INTRODUCTION

According to the World Bank, the economy of T&T is largely based on oil and gas, with the petroleum and petrochemical industries accounting for about 37 percent of GDP[1]. On a worldwide scale, T&T produces less than 1% of global greenhouse gas (GHG) emissions with the largest emissions stemming from its power generation, transportation, and industrial sectors. As signatories to the Paris Agreement, T&T is committed to reducing its carbon footprint to 103 million tonnes by 2030[2]. This can be accomplished by two main options: the adoption of renewable energy (RE) resources to reduce the volumes of CO_2 being emitted and, by capturing and sequestering the existing CO_2. This second option falls within the process of CO_2-enhanced oil recovery (CO_2-EOR) and carbon capture and sequestration (CCS). CO_2-EOR can help with enhancing oil production in existing mature oil fields as well as sequestering large volumes of CO_2 gas emissions.

According to Taber et al.[3], the following are screening criteria used for selection of EOR methods: Oil properties (API gravity, viscosity, composition) and, reservoir characteristics (oil saturation, formation type, net thickness, average permeability, depth, temperature). If only depth and oil gravity are considered, it appears that about 80% of the world's reservoirs could qualify for some type of CO_2 injection and about 67 billion tonnes of CO_2 would be required to produce 206 billion bbl of additional oil[3].

A screening study was found to be the best approach to reducing the risk of project failure by short-listing and prioritising candidate reservoirs for further detailed studies prior to field trials. Rivas et al.[4] performed simulations to evaluate the most effective reservoir conditions for CO_2 injection with results as follows: oil gravity (API gravity) of 36°API, temperature (T) of 150 F°, permeability (k) of 300 mD, oil saturation at the start of the injection (Soi) of 60%, reservoir pressure at the time of injection (Pi) of around 200 psi over minimum miscibility pressure, porosity (ø) of 20%, net oil sand thickness (NOS) of 40 ft reservoir dip of 20°.

Of the above parameters, those whose changes around the optimum influence the most process performance are API gravity, oil saturation and reservoir pressure. Therefore, the reservoirs with these three parameters closer to the optimum values are the best candidates for CO_2 injection. Other operational factors should be considered, such as depth as reservoirs that are too deep (>6,000') would require additional compressor demands, and too shallow (<1,500') could pose a risk of surface breakouts. Because of its chemical properties, CO_2 improves oil recovery by lowering interfacial tension, swelling the oil, reducing viscosity, and mobilising the lighter components of the oil[5]. CO_2 flooding can be of two varieties, miscible or immiscible. This is governed by CO_2 injection pressures. According to Morgan[6], if the pressure of the injected CO_2 is above its minimum miscibility pressure, the flood would be a miscible flood, and the gas would act as a solvent. In miscible flooding the gas is injected into the reservoir by means of injection wells; the gas mobilises lighter hydrocarbon components, swelling the total volume of the oil and reducing the oil's viscosity so that it flows more freely. The amount of oil flowing to the production well is increased.

Since the price of oil decides the economic viability of the EOR project, the researcher agrees with Li et al.[7] who state gas injection is most preferable when the oil prices are low. Various methods of flooding the reservoir with CO_2 have been implemented practically to increase oil volumes recovered[8]. From the literature, injection of CO_2 is the most traditional technique adopted to improve the recovery of oil in the conventional reservoirs. The water alternating gas (WAG) method gives higher recoveries than other methods, with laboratory tests showing recoveries of 50% and 76% for 16° API and 29° API crudes respectively, whereas continuous CO_2 injection on the same crudes gave recoveries of 37% and 42%, respectively[9].

However, since gas can move through a reservoir more easily than oil, there is always a danger that the CO_2 will break through, leaving oil behind. To prevent this, water flooding is often alternated with CO_2 flooding in a WAG scheme. Water moves through the reservoir more slowly than either oil or CO_2, so it

https://doi.org/10.24191/jsst.v5i2.096

creates a cheap and effective barrier to gas breakthrough and helps maintain a stable front for the CO_2 flood. CO_2 flooding can also be immiscible if the injected gas pressure is lower than the minimum miscibility pressure. While some of the gas is absorbed into the oil, the remainder contributes to the free gas behaviour in the reservoir. The free gas sweeps the hydrocarbon towards the production well and thereby improves the oil recovery. CO_2-EOR is a proven process, and more than 166 CO_2-EOR projects are currently active around the world producing more than 450,000 bbl of oil per day[10]. These numbers are expected to increase to more than 1.2 million bbl and 1.64 million bbl of oil per day in 2030 and 2040, respectively[11].

It is important to have a clear understanding of the processes underlying CO_2-EOR for successful field application. In addition to maintaining or increasing the reservoir pressure, which provides the "artificial drive" for oil production, CO_2 injection is responsible for other effects, which enhance oil recovery. According to Rojas and Ali[12] and Tunio et al.[13], there are four major processes which are responsible for CO_2-EOR: oil viscosity reduction, oil swelling, oil and water density reduction and vaporisation and extraction of portions of oil. To evaluate and optimise reservoir performance for CO_2-EOR coupled with CCS: Utilise CMG modelling to analyse the performance and effectiveness of CO_2 injection in the EOR 26 reservoir in Forest Reserve Field; Optimisation of reservoir performance and CO_2 injection; Analysis of various scenarios to determine volumes of CO_2 injected, produced, sequestered and corresponding oil produced.

The reservoir or field of interest to evaluate is the EOR 26 Upper Forest sands. The technical and economic feasibility of restarting this CO_2-EOR project will be evaluated with the main objective of maximising oil production while maximising CO_2 sequestered. This reservoir was selected since there is a significant opportunity for recoverable reserves as its primary recovery was only 4.9% and only 7.5% incremental recovery during its tertiary lifecycle. During the CO_2-EOR process, injection was intermittent with many years of no injection.

2 METHODOLOGY

The flowchart depicted in Fig. 1 outlines the methodological workflow adopted in this study. It begins with the geological assessment of the study area, followed by a map and reservoir development. An existing reservoir model was further refined using CMG software to simulate various enhanced oil recovery (EOR) scenarios. Sensitivity analyses were conducted on injection rates and well spacing to optimise recovery, culminating in a feasibility assessment incorporating oil price variations.

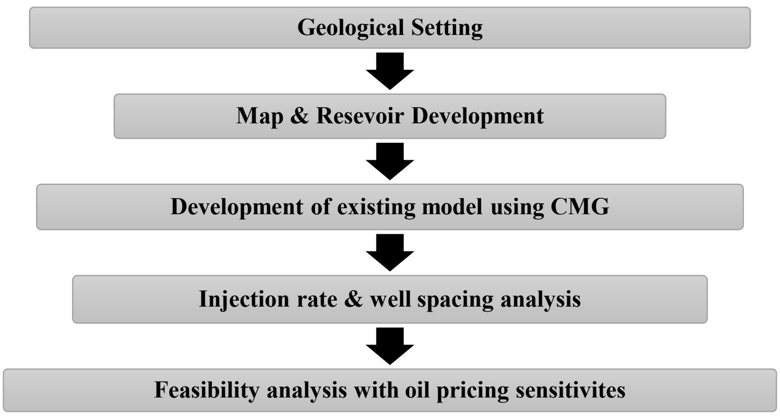

Fig. 1. Methodology flowchart.

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2.1 Geologic setting

Through qualitative and quantitative methods, most of the data collected were obtained from secondary sources. The EOR 26 reservoir input data were obtained from the SPE published work of Mohammed-Singh and Singhal[14].

EOR 26 - Geology

According to the study by Mohammed-Singh and Singhal[14] as illustrated in Fig. 2, the EOR 26 reservoir was located in the Forest Reserve field on the southern flank of the east-northeast trending Fyzabad Anticline. This flank dips steeply towards the south, where bottom water exists in most pay intervals. Reservoirs were deposited under deltaic conditions as distributary channels fill the lower delta plain environment and is highly heterogeneous and complex. They were characterised by the occurrence of levees, crevasse splays, over-bank mud, etc. They contained numerous shale lenses due to several changes in the paths of fluvial channels during the Pliocene period.

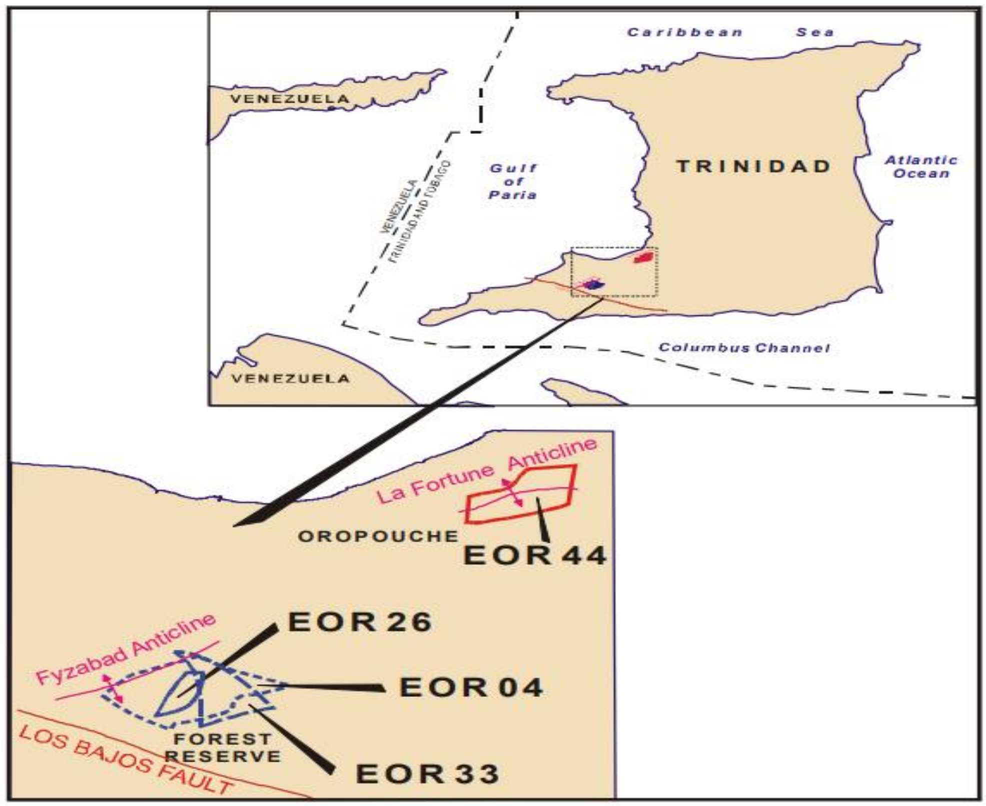

Fig. 2. Location of Trinidad's CO_2 Projects[14].

EOR 26 – Reservoir properties

Mohammed-Singh and Singhal[14] also detailed the EOR 26 reservoir as dipping toward the south with an average dip of 30°. Reservoir depth ranges from 2,600 ft to 4,200 ft with a net thickness of 60 ft to 200 ft. Permeabilities and porosities averaged 150 md and 30%, respectively. Oil gravity ranges from 17–25° API with oil viscosities in the range of 13–32 cp at reservoir conditions (120 F° and 600 psi). Reservoir rock and fluid properties are listed in Tables 1 and 2, respectively.

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Table 1. EOR 26 Rock Properties

ROCK PROPERTIES	
AREA (acres)	21
Pay Zone	Upper Forest
Depth (ft)	2600
Thickness (ft)	58
Porosity (ø)	30
Permeability (mD)	150
Oil Saturation (%)	70
Temperature (F°)	120
Transmissibility (md-ft/cp)	189

Table 2. EOR 26 Fluid Properties

FLUID PROPERTIES			
Initial Conditions		*At CO_2 Flood Start*	
Reservoir Pressure (psi)	1300	Reservoir Pressure (psi)	600
Solution Gas Oil Ratio (scf/bbl)	150	Solution Gas Oil Ratio (scf/bbl)	80
Oil Formation Volume Factor	1.07	Oil Formation Volume Factor	1.04
Oil Viscosity (cp)	32	Oil Viscosity (cp)	46
Oil Gravity (deg API)	17		

2.2 Map and reservoir development

Didger and the CMG software were utilised to develop and digitise the structure map and reservoir model respectively. The contours for the structure map and the net oil sand isopach maps, which were retrieved from the study by Mohammed-Singh and Singhal[14], were digitised for the reservoir development (see Figs 3 & 4). This allows for a more accurate assessment of the volume of the reservoir.

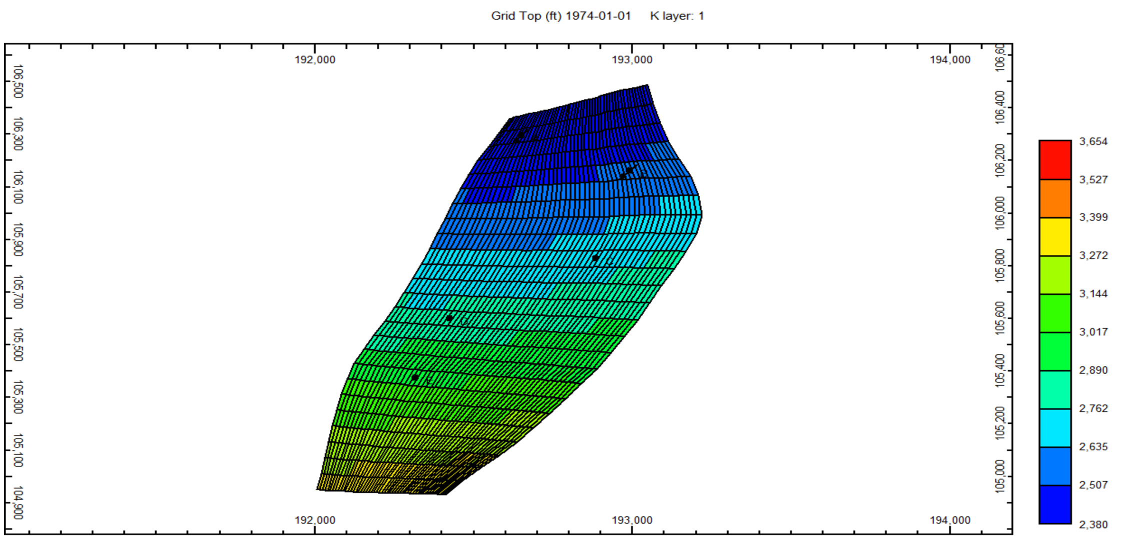

Fig. 3. Digitized Map - EOR 26.

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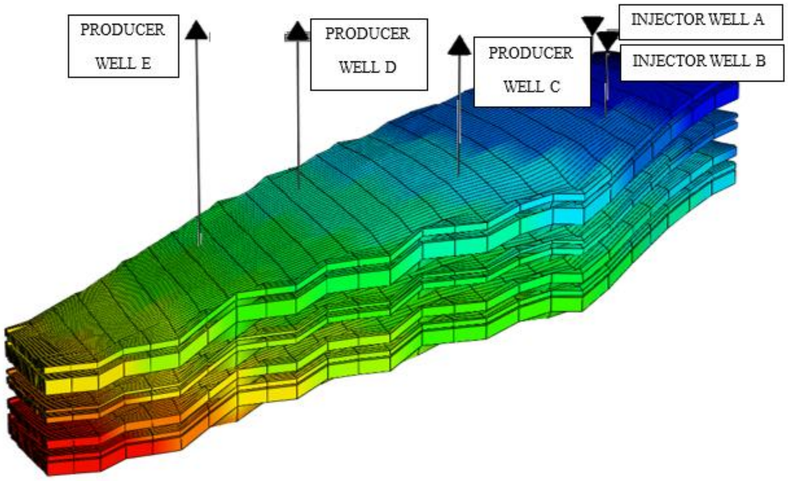

Fig. 4. A 3-D Map - EOR 26 (Injection & Producing Wells).

As shown in Fig. 5, the well log presents 13 distinct layers, comprising sand and interbedded shale, which aided in the development of the reservoir model. This information allowed for thicknesses of sand and shale units to be measured and input into CMG software for model development. Faults within the reservoir were assumed to be sealing again based on the study by Mohammed-Singh and Singhal[14].

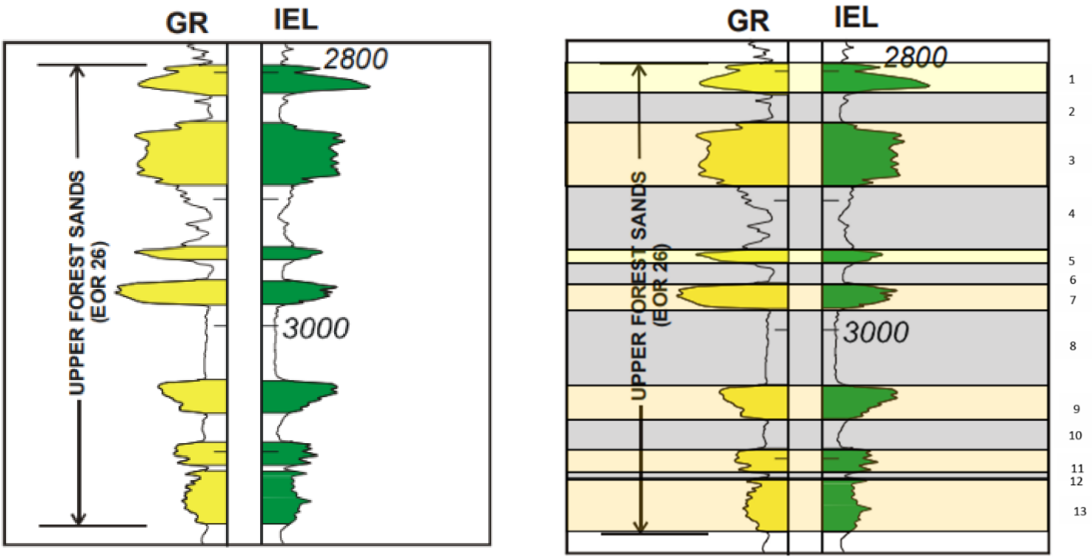

Fig. 5. Type Log-EOR. Left: before numbered layers; Right: after numbered layers.

2.3 Develop existing model using CMG

Using the Builder option in CMG and the above-mentioned data set, the initial reservoir model was created. The model was first validated with IMEX by running to view initialisation (run one-time step). Once the model OOIP matched the actual reservoir OOIP in Table 3, the simulation was run for the following periods in Table 4 with constraints assumed from Mohammed-Singh and Singhal[14].

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Table 3. Recovery, forest reserve EOR 26

Project	EOR 26 - Upper Forest Sands
Original Oil in Place (OOIP), MBO (Thousands of Barrels of Oil)	1,874
CO_2 Injection Start	Jan-74
Primary, WF, GI Recovery, % OOIP	4.9
CO_2 Recovery @ Sept 2003, MBO (%OOIP)	142 (7.6)
Cumulative CO_2 Utilization, MCF/BBL (Thousand Cubic Feet of CO_2 per Barrel of Oil)	11.4
Production Sept 2003, BOPD (Barrels of Oil per Day)	0
Injectors / Producers	0
Remaining Recoverable Reserves (REM. REC. RES), MBO	0
Ultimate CO_2 REC., % OOIP	7.6

Table 4. Simulation run data

Date	Status	Constraints	
		Injection pressure /psi	Injection volume / Million Standard Cubic Feet per Day (MMSCFD)
Jan 1974 – Jan 1979	Open	1500	0.5
Jan 1979 – Jan 1989	Shut-in	-	-
Jan 1989 – Jan 1992	Open	1500	0.5
Jan 1992 – Jan 1996	Open	1500	1
Jan 1996 – Jan 2025	Shut-in	-	-
Jan 2025 – Jan 2060	Open	1500	1

2.4 Sensitivity analysis

Studies by Arnaut et al.[15] identified the long run-time of a typical compositional reservoir model as the main reason why no guidelines for the analysis or selection of multi-case simulations are more frequent. The researcher was meticulous in choosing the sensitivities in which to vary.

The CMOST program was used to perform a sensitivity analysis, and Table 5 highlights the selected parameters. After CMOST's sensitivity was run, the following scenarios were compared using the CMOST best case for an injection period of 100 years:

BASE CASE - CO_2 continuously injected at initial (CMOST Optimised) conditions (injection rate = 0.5 mmscf/d/well)

Scenario 1 – The effect of continuous CO_2 injection at maximum injection rate as selected by CMG.

Scenario 2 – The Cyclic CO_2 injection at maximum injection rate (20 years on, 20 years off).

Scenario 3 – Addition of 2 injector wells in 2025 with continuous CO_2 injection at maximum injection rate as selected by CMG.

Scenario 4 – Addition of 2 injector wells in 2025 at different locations with continuous CO_2 injection at maximum injection rate as selected by CMG.

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Table 5. Parameters selected for CMOST sensitivity analysis

Parameters	Lower Limit	Initial Values	Upper Limit
KRG	0.225	0.3	0.375
KRO	0.6	0.8	1
NG	1.5	2	2.5
NOG	1.5	2	2.5
Perm 1	112.5	150	187.5
Perm 2	112.5	150	187.5
Perm 3	112.5	150	187.5
Perm 4	112.5	150	187.5
Perm 5	112.5	150	187.5
Perm 6	112.5	150	187.5
Perm 7	112.5	150	187.5
Por 1	0.225	0.3	0.375
Por 2	0.225	0.3	0.375
Por 3	0.225	0.3	0.375
Por 4	0.225	0.3	0.375
Por 5	0.225	0.3	0.375
Por 6	0.225	0.3	0.375
Por 7	0.225	0.3	0.375
Residual Gas Saturation	0.15	0.2	0.25
Residual Oil Saturation	0.3	0.4	0.5
Residual Water Saturation	0.3	0.4	0.5
SO 1	0.525	0.7	0.875
SO 2	0.525	0.7	0.875
SO 3	0.525	0.7	0.875
SO 4	0.525	0.7	0.875
SO 5	0.525	0.7	0.875
SO 6	0.525	0.7	0.875
SO 7	0.525	0.7	0.875
SW 1	0.225	0.3	0.375
SW 2	0.225	0.3	0.375
SW 3	0.225	0.3	0.375
SW 4	0.225	0.3	0.375
SW 5	0.225	0.3	0.375
SW 6	0.225	0.3	0.375
SW 7	0.225	0.3	0.375

3 RESULTS AND DISCUSSION

Comparing the OOIP from the IMEX model (1.83 MMSTB) to the actual OOIP (1.87 MMSTB) gave only a 0.04 MMSTB difference, which was close enough to match the model, injection and production data. The minimal OOIP difference implies that the reservoir model is well-calibrated, technically robust and suitable for planning, which is foundational to both the technical justification and economic confidence in proceeding with CO_2-EOR and CCS development in the EOR 26 reservoir.

From the CMOST sensitivity analysis the parameters (Table 6) were most influential on affecting the cumulative injection and production rates as identified for each well (using a 3% cut-off point). These values were obtained using the Sobol analysis, which determines how much of the variability in model output is dependent upon each of the input parameters, either upon a single parameter or upon an interaction between different parameters[16].

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Table 6. Parameters that affected injection (ft^3) and production (bbls) volumes

Well/ parameter	Cumulative CO_2 injection Well A	Cumulative CO_2 injection Well B	Cumulative oil production Well C	Cumulative oil production Well D	Cumulative oil production Well E
KRG	5.61%	6.42%	-	-	5.74%
KRO	3.48%	3.01%	-	-	9.33%
PERM 2	27.7%	27.1%	-	-	32.3%
PERM 4	3.38%	-	-	-	-
PERM 5	16.4%	17.2%	-	-	12.5%
PERM 7	10.8%	9.69%	-	-	8.75%
POR 1	4.34%	5.4%	7.4%	8.54%	7.16%
POR 2	-	-	40.1%	33.8%	-
POR 4	-	-	5.08%	4.48%	-
POR 5	-	-	12.3%	14.7%	4.28%
POR 6	-	-	4.35%		-
POR 7	-	-	29.1%	28.7%	7.16%
SO 1	3.02	-	-	-	4.07%
SW 7	3.81 %	3.43 %	-	-	-
Maximum	1.37×10^{11} (ft^3)	1.89×10^{11} (ft3)	4.95×10^5 (bbls)	3.77×10^5 (bbls)	4.84×10^5 (bbls)
Minimum	7.55×10^{10} (ft^3)	1.06×10^{11} (ft3)	3.67×10^5 (bbls)	2.80×10^5 (bbls)	3.25×10^5 (bbls)

For the Operational and Economic Evaluations, phases relevant to the CO_2-EOR process were identified, as illustrated in Fig.6. The key phases include CO_2 capture, transportation, injection/reinjection, sequestration/production, wellhead capture and monitoring and operating. These phases represent the sequential and interdependent steps necessary for implementing and sustaining a CO_2-EOR project. Each stage carries specific technical requirements and cost implications, which are critical for accurate economic forecasting and operational planning.

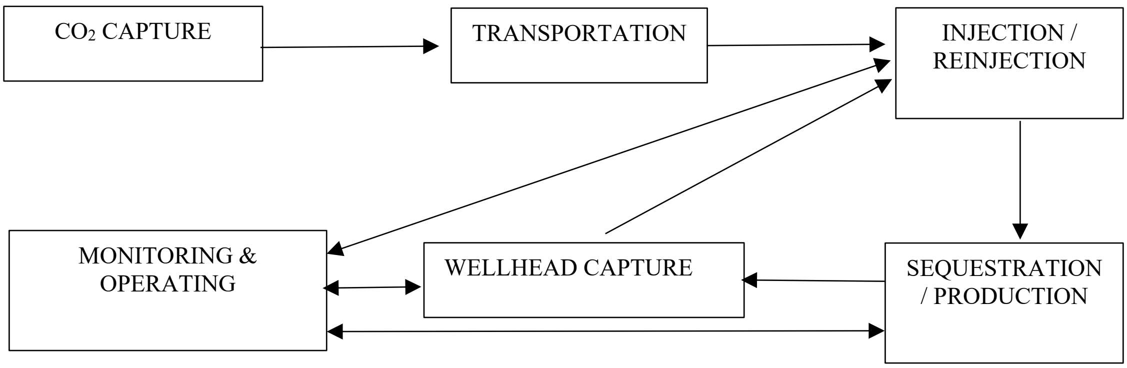

Fig.6. CO_2-EOR Project Lifecycle.

Using these optimised values from CMOST as the base case, the model was updated, and simulations were conducted for several different scenarios detailed in Table 7 below. Scenario 4 gives the most CO_2 sequestered at 645 mmscf while increasing oil production by an additional 1.4 mmbbls. This scenario includes drilling of 2 additional wells, bringing the total injectors to 4. A full economic analysis will be performed to determine the economic limitations. Evaluating the tabulated data, the maximum CO_2 volumes required as recommended by CMG is 30 mmscf/d for Scenario 1 & 2. These scenarios do not include drilling additional wells. For scenarios 3 & 4, both of which involve drilling two additional wells, the required CO_2 volumes increase to 60 & 65 mmscf/d respectively.

https://doi.org/10.24191/jsst.v5i2.096

Table 7. Scenarios run in CMG (CO_2 injected, produced & sequestered & oil produced)

Scenario	Description	Average daily solvent injected (mmscf/d)	Cumulative solvent injected (scf)	Cumulative solvent produced (scf)	Cumulative solvent sequestered (scf)	Cumulative oil produced (bbls)
Pre-2025			2,918,154,240	2,912,403,456	5,750,784	277,796
Base Case	CO_2 continuously injected at initial conditions (injection rate = 0.5 mmscf/d/well) 2 injector wells	1	39,442,153,472	39,412,277,248	29,876,224	868,670
	LESS VALUES PRE 2025		36,523,999,232	36,499,873,792	24,125,440	590,874
1	Continuous CO2 injection at maximum injection rate as selected by CMG 2 injector wells	30	1,060,993,040,400	1,060,555,522,000	437,518,400	1,466,676
	LESS VALUES PRE 2025		1,058,074,886,160	1,057,643,118,544	431,767,616	1,188,880
2	Cyclic CO_2 injection at maximum injection rate (10 years on, 10 years off) 2 injector wells	30	665,538,854,910	665,128,140,800	410,714,110	1,341,189
	LESS VALUES PRE 2025		662,620,700,670	662,215,737,344	404,963,326	1,063,393
3	Adding 2 injector wells in 2025 with continuous CO_2 injection at maximum injection rate as selected by CMG 4 injector wells	60	2,228,369,227,800	2,227,762,888,700	606,339,100	1,592,781
	LESS VALUES PRE 2025		2,225,451,073,560	2,224,850,485,244	600,588,316	1,314,985
4	Adding 2 injector wells in 2025 at different locations with continuous CO_2 injection at maximum injection rate as selected by CMG 4 injector wells	65	2,312,381,399,000	2,311,729,709,100	651,689,900	1,719,421
	LESS VALUES PRE 2025		2,309,463,244,760	2,308,817,305,644	645,939,116	1,441,625

Assessing specifically the plots of average pressure POVO SCTR and cumulative injected solvent CO_2 vs time, the point of intersection for each plot identifies the period when (at the specified injection rate and pressure) the solvent's sweep efficiency decreases to a point where no matter how much more solvent is injected, there will be little to no further effect on reservoir pressure and hence oil recovery rates will be reduced to a minimum. The CO_2-EOR will become less effective at that point, possibly indicating the end of the CO_2-EOR at the specified injection rate and pressure (Table 8), reaching its operational limit. The relationship seems to be directly proportional (see Fig. 7) since as the volumes of CO_2 injected increase, so does the operational limit.

https://doi.org/10.24191/jsst.v5i2.096

Table 8. Operational limit for each scenario

Scenario	Date of intersection	Operational limit (resuming from 2025)	Average pressure POVO (psi)	Cumulative solvent injection (mmscd)
Base Case	2032	7	290	5.64
1	2074	49	738	567,000
2	2076	51	714	370,000
3	2091	66	935	1,500,000
4	2094	69	980	1,650,000

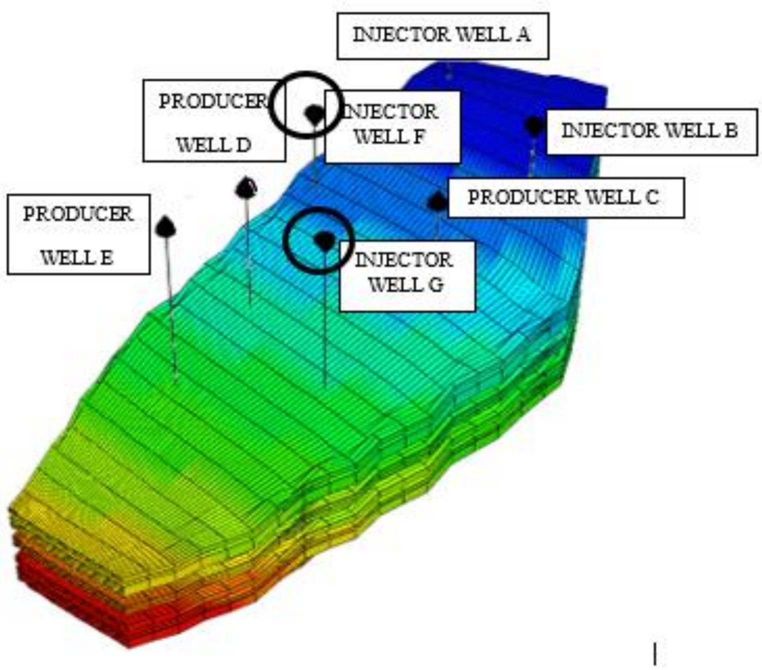

Fig. 7. 3-D Map - EOR 26 (Scenario 3 - Additional Injector Wells).

3.1 Economic evaluations

According to Ren et al.[17], in traditional CO_2-EOR operations, the capital expenditure (CAPEX) cost will include infill drilling; installation of a CO_2 compression system and pipeline networks for water and CO_2; well workovers; and other surface installation expenses. Operating expenditure (OPEX) includes: the costs of CO_2 purchase and electricity for running compressors to recycle CO_2 and pumps to produce fluids and to reinject water. Project revenues come from sales of crude oil, as well as tax credits and carbon sequestration payments from the incidental storage of CO_2. In this analysis, a percentage of the costs identified in Table 9 was used where the actual costs cannot be obtained.

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Table 9. CAPEX & OPEX Costs (North Sea Operations)

CAPEX cost component		€ mn
1)	Survey costs to examine the reservoir characteristics with respect to CO_2-EOR	1.50
2)	Platform construction/restructuring costs to adapt to CO_2-EOR requirements, including a) surface facilities costs to pretreat the CO_2 before injection b) recycle installments to separate, compress and re-inject CO_2	
3)	Well drilling costs for new injection wells	17.5
4)	Monitoring and verification facility	7.1
		52.5
		3% of CAPEX

OPEX cost component		€mn/MtCO_2
1)	Facility operation	5% of CAPEX
2)	Oil production	12.1
3)	CO_2 recycling	5.2
4)	CO_2 compression and injection	8.7
5)	Monitoring and verification	0.4

CAPEX

According to the Ministry of Energy and Energy Industries[18] "the volume of CO_2 emitted and a suitable method of economic transmission from the sources to the destination were determined. The Carbon Reduction Strategy Task Force found that the sources of concentrated CO_2 that can be easily accessed are the ammonia manufacturing plants at the Point Lisas Industrial Estate (PLIE) (4-9 mmMT per year) and the CO_2 removal system of the Atlantic LNG facility 9 of (96,000–135,000 MT per year). For the transportation aspect of the CO_2, an onshore pipeline network was identified for use to transport an estimated 6 mmMT per year of CO_2 from sources in Pt Lisas to onshore oilfields in the southwestern Trinidad would cost two to four million USD in capital expenditure and installation costs. The possible routes would lie generally along the path of the previous CO_2 pipeline from Pt Lisas to Fyzabad and Oropouche, where possible and feasible, considering line encroachments." – 4 MMUSD.

It was assumed that the EOR 26 project was not in operation for approximately 28 years, all equipment including compressors, valves, well components monitoring systems etc., will need to be serviced or replaced. The system will be a closed system which means that the production wells will be tied into a gathering facility with 3-phase separators that will collect the produced gas (that includes CO_2), treat it, and reinject the CO_2. Surface facilities to pretreat, recycle, compress and re-inject CO_2 – 10 MMUSD.

Well Construction Costs - 2 additional injector wells (Scenario 3 & 4)

For Scenarios 3 & 4, two additional wells are required to be drilled and completed which costs approximately 2 MMUSD per well = 4 MMUSD. These are two string casing wells drilled to +/-3,500' in the Fyzabad area. The drilling and completion of each well should take approximately two months and should be ready for a 2025 start-up date.

Total CAPEX – Base Case, Scenario 1 & 2 = 14 MMUSD

Total CAPEX – Scenario 3 & 4 = 18 MMUSD

OPEX

Facility operation – 1.0 MMUSD

Oil production per workovers – 10 MMUSD

CO_2 recycling – 1.2 MMUSD

CO_2 compression and injection – 2.6 MMUSD

Monitoring and verification – 1.2 MMUSD

Total OPEX = 16.0 MMUSD per MtCO_2

https://doi.org/10.24191/jsst.v5i2.096

The NPV was calculated using a 15% discount rate based on projected cash flows from both oil revenues and carbon credits (Table 10). The cash inflows considered both oil sales at various price sensitivities and carbon credits at $60 per tonne CO_2 sequestered. The payback period was determined as the time taken for cumulative cash flows to offset initial CAPEX, resulting in a period of less than two years at conservative estimates.

Table 10. Economic evaluation summary for Scenario 4, including NPV and payback period calculations at a 15% discount rate

Parameter	
Discount rate	15%
Project lifetime (Scenario 4)	69 years
Initial CAPEX	USD 18 million
OPEX per year (average)	USD 1.6 million
Total revenue (Oil + CO_2 credits)	USD 40.2 million
Carbon credits (CO_2 stored)	USD 38.75 million (645,939 tCO_2 @ $60/$tCO_2$)
Total oil revenue (1.4 MMbbls @ $30/bbl)	USD 42 million (sensitivity from $30 to $90 used)
Net cash flow (revenue - OPEX - CAPEX)	USD 0.23 million (at $30 oil price)
NPV (15% Discount Rate)	USD 0.23 million
Payback period	< 2 years

3.2 REVENUE

Oil revenue

The price of oil was very difficult to predict as it was based on several factors including news cycles, policy changes, supply, consumer demand, politics[19] and even fell to - USD 37 per bbl in 2020. Due to this volatility, the price of oil was estimated at USD 30, 60 and 90 per bbl for sensitivity analysis.

Carbon credits

Ning and Tura[20] state that capturing CO_2 and storing via EOR yields a profit of USD 60 per metric ton CO_2. In this study, it was assumed that whenever CO_2 credits became available within the T&T framework, it was retroactive from the restart of injection operations (2025).

Tax incentives

Tax Incentives as outlined by Price Waterhouse Coopers in the perspective of Carbon capture, storage, and enhanced oil recovery allowance states that an allowance that is equal to 30% of the actual expenditure incurred investing in carbon capture, storage and enhanced oil recovery is available, up to a maximum of TTD 500,000 (Trinidad and Tobago - Corporate - Tax Credits and Incentives[21]= USD 73,474).

3.3 OPERATIONAL LIMIT REVENUE

Based on the economics for 100 years, the base case yields a positive net cash flow (NCF) of USD 90 per bbl. All other scenarios yield a negative cash flow. The economics was run using the Operational Limit as the end of the CO_2-EOR, with the resulting full economic analysis presented in Fig. 8.

https://doi.org/10.24191/jsst.v5i2.096

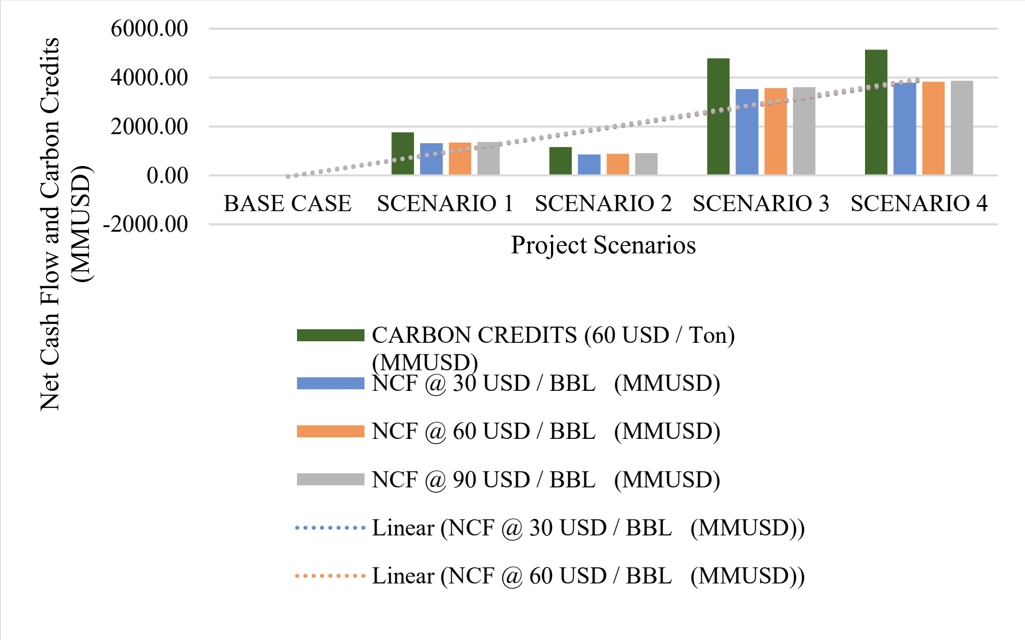

Fig. 8. Net Cash Flow for each scenario (Operational limit).

It can be seen that using the Operational Limit years as the end of the EOR is economically feasible as all the scenarios (Fig.9) return positive NCF's.

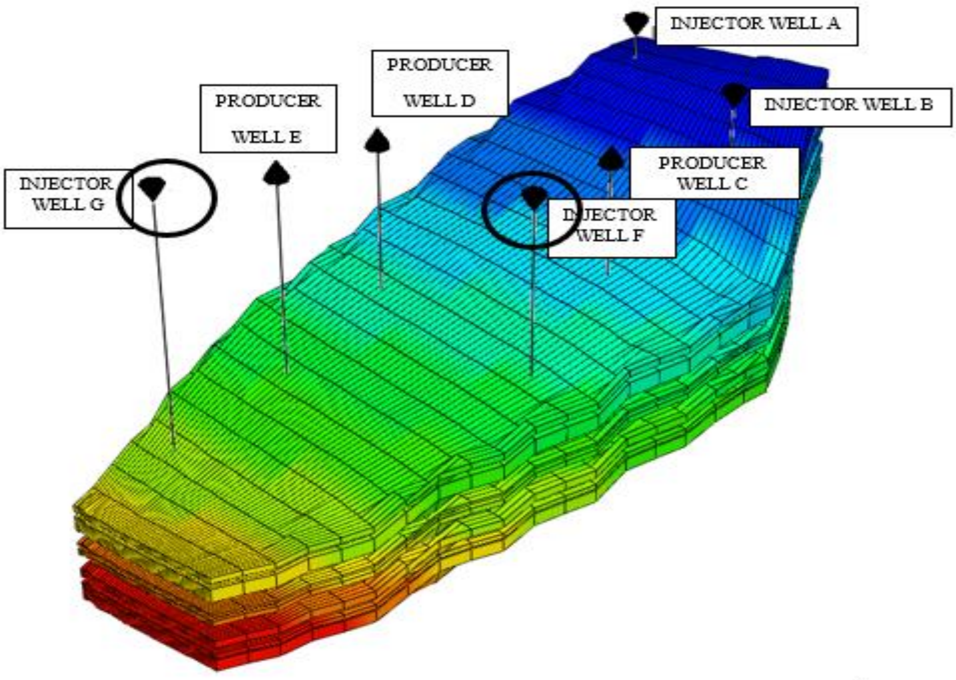

Fig. 9. Scenario 4 – Most operationally & economically viable option.

https://doi.org/10.24191/jsst.v5i2.096

This is attributed mainly to the fact that most of the revenue comes from the CO_2 stored via the EOR process and not necessarily from the changes in oil prices. The data also show that as the CO_2-EOR goes past its operational limit, the operating costs for treating CO_2 for reinjection become relatively high, as well as producing CO_2 (and not trapping it) becomes more evident.

These results suggest that the integration of CO_2-EOR with CCS in TT has both technical and economic feasibility, with Scenario 4 emerging as the most advantageous option. It not only maximises CO_2 sequestration but also significantly enhances oil production, which aligns well with national energy and environmental goals. The ability to achieve positive NCF under varying oil price scenarios highlights the project's resilience against market volatility. However, further work could optimise operational strategies to balance CO_2 utilisation with oil recovery efficiency.

4 CONCLUSION

Scenario 4 offers the most viable path forward for CO_2-EOR coupled with CCS in TT. The project has demonstrated the ability to sequester approximately 85.6 $MtCO_2$ while producing 1.4 million barrels of additional oil over a 69-year period. The economic analysis confirms that the project delivers a positive NPV of 0.23 MMUSD at a 15% discount rate, with a payback period of less than 2 years. These findings suggest that CO_2-EOR integrated with CCS could play a significant role in supporting TT's emission reduction commitments while boosting domestic oil production.

ACKNOWLEDGEMENTS/ FUNDING

We would like to express special thanks to Ms. Amy Clark for the support and assistance in the preparation of this research paper.

CONFLICT OF INTEREST

The authors declare that there was no conflict of interest.

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