

Article

Can Hydrogen Be Produced Cost-Effectively from Heavy Oil Reservoirs?

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Abstract

The potential for hydrogen production from heavy oil reservoirs has gained significant attention as a dual-benefit process for both enhanced oil recovery and low-carbon energy generation. This study investigates the technical and economic feasibility of producing hydrogen from heavy oil reservoirs using two primary in situ combustion gasification strategies: cyclic steam/air and CO₂ + O₂ injection. Through a comprehensive analysis of technical barriers, economic drivers, and market conditions, we assess the hydrogen production potential of each method. While both strategies show promise, they face considerable challenges: the high energy demands associated with steam generation in the steam/air strategy, and the complexities of CO₂ procurement, capture, and storage in the CO₂ + O₂ method. The novelty of this work lies in combining CMG-STARS reservoir simulations with GoldSim techno-economic modeling to quantify hydrogen yields, production costs, and oil-hydrogen revenue trade-offs under realistic field conditions. The analysis reveals that under current technological and market conditions, the cost of hydrogen production significantly exceeds the market price, rendering the process economically uncompetitive. Furthermore, the dominance of oil production as the primary revenue source in both methods limits the economic viability of hydrogen production. Unless substantial advancements are made in technology or a more cost-efficient production strategy is developed, hydrogen production from heavy oil reservoirs is unlikely to become commercially viable in the near term. This study provides crucial insights into the challenges that must be addressed for hydrogen production from heavy oil reservoirs to be considered a competitive energy source.

Keywords: hydrogen production; heavy oil reservoirs; economic feasibility; technical challenges; energy efficiency



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1. Introduction

Hydrogen is increasingly recognized as an important energy carrier in the transition to a low-carbon global economy, particularly due to its versatility in decarbonizing sectors such as transportation, power generation, and industrial processes [1–4]. As governments and industries strive to meet climate targets, hydrogen has emerged as a critical component of energy systems due to its potential for zero-emission fuel generation. Despite its promising attributes, hydrogen production faces significant challenges due to the high environmental footprint of traditional methods like steam methane reforming (SMR) and coal gasification, which emit approximately 9–12 kg and 19–22 kg of CO₂ per kilogram of hydrogen, respectively [5–7]. Currently, the dominant method of hydrogen production,

SMR, is heavily reliant on fossil fuels, emitting large amounts of CO₂ [8,9]. Consequently, there has been growing interest in exploring alternative, cleaner hydrogen production techniques, particularly those that utilize existing infrastructure in oilfields.

In situ hydrogen production from petroleum reservoirs presents a potentially transformative solution to this challenge [9–13]. By generating hydrogen directly within the reservoir through high-temperature reactions between hydrocarbons, rocks, and water, this method offers the possibility of harnessing the energy-rich hydrocarbons in place while simultaneously sequestering CO₂ and other byproducts in the reservoir. The key advantage of this process lies in its potential to leverage existing oilfield infrastructure, reducing the costs typically associated with building new facilities. Notably, the in situ combustion gasification method, which has gained significant interest in recent years, stands out as a promising technique for hydrogen production in heavy oil and bitumen reservoirs [14,15]. This method, particularly when combined with gas injection strategies such as steam/air or CO₂ + O₂ injection, has been shown to generate hydrogen while enhancing oil recovery, thus providing a dual benefit: the extraction of both oil and hydrogen from the same resource.

While in situ hydrogen production from petroleum reservoirs offers considerable promise, there are significant technical and economic challenges that must be addressed before this method can be scaled to meet global hydrogen demand. Several field studies have investigated hydrogen production from heavy oil and bitumen reservoirs, reporting varying results in terms of hydrogen yield (Table 1).

Table 1. Field projects with documented hydrogen production from heavy oil and Bitumen reservoirs.

Year	Project Title	Location	Porosity (%)	Permeability (mD)	Max. Yield (mol. %)	H ₂ Source
1977	Utah Tar Sand	United States	31	600–700	14	[16]
1979	Marguerite Lake	Canada	30	1000–3000	33	[17]
1985	Wolf Lake	Canada	32	1000–3000	25	[18]
2006	Whitesands	Canada	36	3000–12,000	10	[19]
2009	Kerrobert	Canada	32	2000–6000	7	[20]
2023	Whitesands	Canada	34	200–7000	15	[21]

Table 1 presents a summary of key field projects that have validated the feasibility of hydrogen production from heavy oil reservoirs. These projects, conducted in various locations, report significant variability in hydrogen yield, with maximum hydrogen concentrations ranging from 7 mol.% to 33 mol.% in the produced gas phase. Notably, these projects, while successful in producing hydrogen as a byproduct, were originally designed for enhanced oil recovery (EOR) processes. Thus, the variations in hydrogen yield across these projects point to several factors that influence the efficiency of the process, such as reservoir characteristics, injection methods, and operational conditions. Additionally, the fact that these projects prioritize oil recovery rather than hydrogen production suggests that, despite some success in hydrogen generation, there are still economic barriers that should be overcome for in situ hydrogen production to become commercially viable.

The current state of research highlights a critical gap in understanding the full technical and economic feasibility of hydrogen production from heavy oil reservoirs [22,23]. While there has been some investigation into the process, few studies have comprehensively addressed both the technical barriers and economic challenges of scaling up in situ hydrogen production. Most prior work has focused on isolated aspects, such as the technical processes involved in combustion gasification or the potential for EOR, without fully exploring the broader economic implications. This gap is significant, as the viability

of hydrogen production from heavy oil reservoirs relies not only on overcoming technical challenges but also on developing a cost-effective business model that can compete with other hydrogen production methods.

This study aims to address this gap by providing an in-depth analysis of the technical and economic analysis of hydrogen production from heavy oil reservoirs using two primary in situ combustion gasification strategies: steam/air and $\text{CO}_2 + \text{O}_2$ injection. By evaluating these methods in terms of hydrogen yield, energy consumption, economic drivers, and market conditions, we seek to provide a comprehensive assessment of whether hydrogen production from heavy oil reservoirs can be cost-effective and commercially viable. The insights gained from this analysis will be instrumental in determining whether hydrogen production from petroleum reservoirs can contribute to the global transition to a low-carbon hydrogen economy.

2. Methodology

2.1. Reservoir Modeling

The reservoir modeling investigates in situ hydrogen production through combustion gasification, utilizing detailed simulations within CMG-STARS 2024 version. Each component of the reservoir modeling process is defined, including the reservoir model specification, fluid composition, reaction kinetics, injection strategies, and grid size selection. The goal is to provide a comprehensive framework for predicting hydrogen yield from heavy oil reservoirs.

2.1.1. Reservoir Model

To evaluate in situ hydrogen generation from heavy oil formations, we adapted a full-field reservoir model based on [24] using data from the Marguerite Lake project (BP Resources, 1979). The 3-D grid model ($10 \times 10 \times 5$) with 500 active blocks (each $304.8 \text{ m} \times 304.8 \text{ m} \times 15.24 \text{ m}$) involves two injectors and one producer well (Figure 1). One injector handles steam, the other air or gas, and a production well operates under a minimum bottom hole pressure constraint of 137.9 kPa. The physical and chemical characteristics of the modeled reservoir, including porosity, permeability, depth, temperature, and heavy-oil composition, are identical to those described in [25].

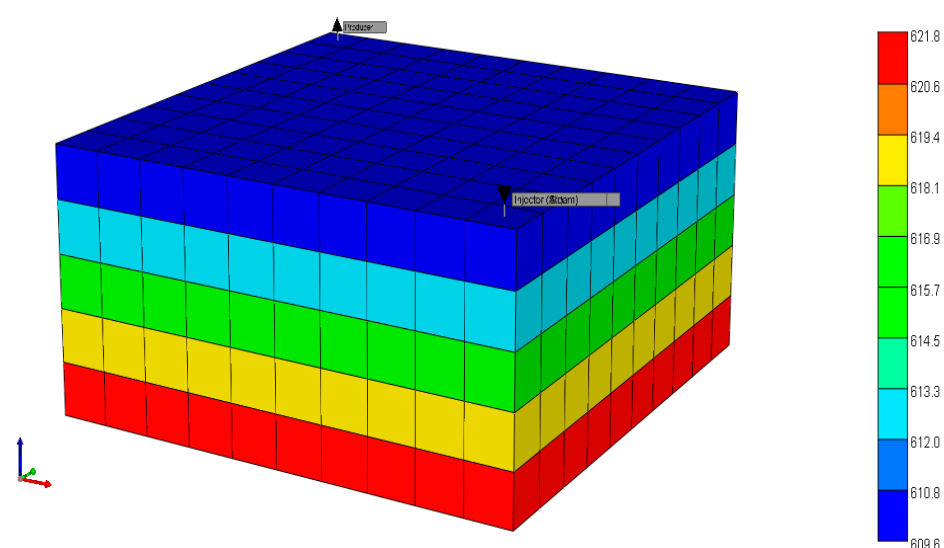


Figure 1. A 3-D representation of the reservoir simulation model (with both injectors located in the same position).

The reservoir model includes four phases: mobile gas, water, oil, and immobile solid (coke). Detailed reservoir and injection parameters are provided in Table S1.

2.1.2. Fluid Model

The fluid model comprises heavy oil divided into four pseudo-components: saturate, aromatic, resin, and asphaltene. Their properties are derived using the Peng-Robinson EOS in the CMG-WinProp package. Additionally, seven non-hydrocarbon components are included: Water, CO₂, N₂, O₂, H₂, CO, and Coke. Table S2 summarizes the properties of all eleven pseudo-components. The detailed SARA fractions and thermophysical properties are consistent with those reported in [25].

2.1.3. Reaction Kinetics Model

Hydrogen generation from heavy crude oil involves complex chemical reactions across various temperatures. For field feasibility and reproducibility, we balanced the number of reactions and components while maintaining energy and mass balance. The model, considering reservoir conditions, incorporated eleven SARA-based components and fourteen reactions, including cracking, combustion, gasification, and hydrogen-based reactions, with stoichiometric coefficients adjusted for mass balance in SARA fractions. Table S3 summarizes the reaction kinetics. The reaction network, kinetic parameters (activation energies and pre-exponential factors), and temperature-dependent formulations follow exactly the methodology of [25].

2.1.4. Injection Strategy

The injection strategy selected for this study includes two main approaches: CO₂ + O₂ and cyclic steam/air injection. These strategies are based on established methods in the literature for hydrogen production through in situ combustion gasification in heavy oil reservoirs [26–29]. The CO₂ + O₂ injection approach enhances gasification reactions by adding CO₂ as a reactive component, which can alter the composition and yield of produced gases. Cyclic steam/air injection supports sustained combustion and introduces steam, which promotes further gasification reactions. Each injection strategy is assessed within the model to evaluate its effect on hydrogen production.

In the model, each cycle follows a four-month injection period, adapted from the BP Resources Marguerite Lake EOR project that successfully demonstrated hydrogen generation. The injection stop time aligns with this four-month cycle, and thermodynamic equilibrium is achieved during ongoing cyclic operations without a dedicated resting phase, thereby ensuring sustained hydrogen production throughout the project timeline. Operational constraints were also specified: in the injector, a maximum surface water rate of 5 m³/day, a maximum bottomhole pressure of 20,000 kPa, and a maximum gas injection rate of 10,000 m³/day were imposed. At the producer, the model was constrained by a minimum bottomhole pressure of 137.9 kPa and a maximum liquid rate of 200 m³/day.

2.1.5. Grid Configuration Selection Justification

To ensure accurate modeling of in situ hydrogen generation from heavy oil reservoirs, a grid sensitivity analysis is conducted across various grid configurations to determine the most effective grid resolution that balances computational efficiency and model precision. The analysis examined five grid resolutions—5 × 5 × 3, 7 × 7 × 3, 10 × 10 × 5, 12 × 12 × 7, and 15 × 15 × 10—with each configuration evaluated over a five-year simulation using the cyclic steam/air injection strategy. The primary metrics evaluated include cumulative hydrogen and carbon dioxide production, along with temperature profiles near the combustion front.

The results in Table 2 indicate that the $10 \times 10 \times 5$ grid configuration produced cumulative hydrogen generation of 310,245 kg and cumulative CO₂ generation of 2482.56 m³. Notably, when transitioning to the $12 \times 12 \times 7$ and $15 \times 15 \times 10$ grid configurations, the cumulative hydrogen production increased marginally to 310,812 kg (a 0.18% increase) and 311,025 kg (a 0.07% increase), respectively. Similarly, cumulative CO₂ production showed slight increases to 2485.76 m³ and 2486.98 m³, reflecting percentage changes of only 0.13% and 0.05%.

Table 2. Summary of grid sensitivity results.

Grid Configuration	Number of Active Blocks	Cumulative H ₂ Produced (kg)	Cumulative CO ₂ Produced (m ³)	Average Temperature at Combustion Front (°C)
$5 \times 5 \times 3$	75	300,246	2421.85	705.4
$7 \times 7 \times 3$	147	305,142	2451.24	707.9
$10 \times 10 \times 5$	500	310,245	2482.56	710.2
$12 \times 12 \times 7$	1008	310,812	2485.76	711.1
$15 \times 15 \times 10$	2250	311,025	2486.98	712.3

Average temperatures at the combustion front were also consistent, stabilizing around 710.2 °C for the $10 \times 10 \times 5$ grid, with minimal variations noted in the finer grids (711.1 °C for $12 \times 12 \times 7$ and 712.3 °C for $15 \times 15 \times 10$), where each grid block in the $10 \times 10 \times 5$ configuration measures 304.8 m $\times$ 304.8 m $\times$ 15.24 m, for a total of 500 active blocks, indicating that the grid accurately captures essential thermal dynamics without further refinement.

Given these results, the $10 \times 10 \times 5$ grid configuration is selected to be the optimal choice for subsequent simulations. It provides reliable predictions of key parameters while ensuring efficient computational performance. The marginal gains observed in both hydrogen and CO₂ production at finer grids confirm that the $10 \times 10 \times 5$ grid is sufficiently accurate for modeling in situ hydrogen generation from heavy oil reservoirs, making it the preferred grid size for this study.

2.1.6. Reservoir Model Validation

The accuracy of the model's predictions has been validated in our previous publication [25]. In that work, we employed a different validation methodology by history matching the model's predictions with both published experimental results and independent modeling studies, thereby providing a comprehensive assessment of predictive accuracy.

However, to verify the accuracy of the reaction schemes, we performed an integrated validation using hydrogen yield data across a range of feedstocks documented in prior studies [30–38]. Specifically, we gathered data on hydrogen production from uncatalyzed gasification of various fossil fuels with differing hydrogen-to-carbon (H/C) ratios, incorporating insights from experimental, pilot, and commercial operations. These data points served as a benchmark for evaluating the validity of our model predictions against established hydrogen yields from similar feedstocks (Figure 2).

The validation approach involved interpolating the hydrogen yields reported in these studies and comparing them with the expected yield ranges for heavy oil, as shown in Figure 2. Light oils, with H/C ratios typically between 1.8 and 2.1 [40], generally produce hydrogen yields in the range of approximately 1.25 to 1.75 S m³/kg of fuel burned. In contrast, heavy oils, with H/C ratios between 1.3 and 1.7 [40], yield between 1.0 and 1.5 S m³/kg.

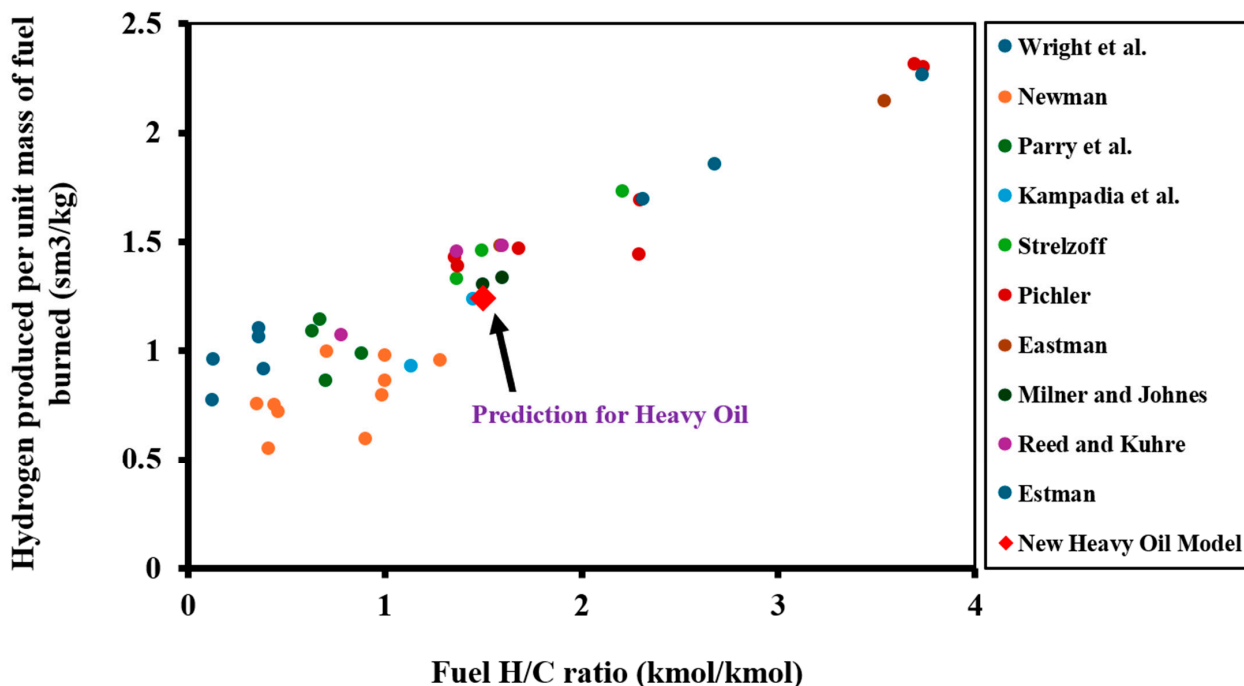


Figure 2. Hydrogen yield as a function of H/C ratio across various feedstocks, including predictions from the heavy model [30–39].

The new heavy oil model predicted a hydrogen yield of 1.241 S m³/kg of fuel burned. This falls well within the expected ranges derived from literature, indicating that the reaction schemes in our model effectively capture the essential mechanisms of hydrogen production during in situ combustion gasification of heavy oil reservoirs. It is important to note that this value is a direct output of the integrated reaction schemes in the CMG-STARS model. The predicted yield is not derived from a single analytical formula but is obtained through model simulations validated against experimental and literature benchmarks across a range of H/C ratios.

2.2. Economic Modeling

This study develops an economic model using GoldSim version 14.0 software, which has been effective in analyzing other oilfield projects [41,42]. The model is based on common hydrogen processes in the field. Figure 3, adapted from [43], illustrates the hydrogen production process flow. CO₂ is injected with oxygen into the reservoir via an injection well, yielding producer gas with over 16% hydrogen concentration via in situ combustion gasification of residual hydrocarbons [9]. Hydrogen is separated using a hydrogen-only membrane at the surface, and produced gas (including hydrogen, carbon dioxide and hydrocarbons) and water are extracted from a production well. The liquid phase undergoes water-oil separation, with oil conveyed for sale and water is reused. The gas phase is processed through a hydrogen-permeable membrane and a gas processing unit, separating hydrocarbons from CO₂ and hydrogen. The CO₂ is recycled, compressed, and reinjected with fresh CO₂ as needed.

The economic model is divided into three main components: injection, production, and CO₂ recycling (Table 3). The individual module includes submodules representing unique cost constraints.

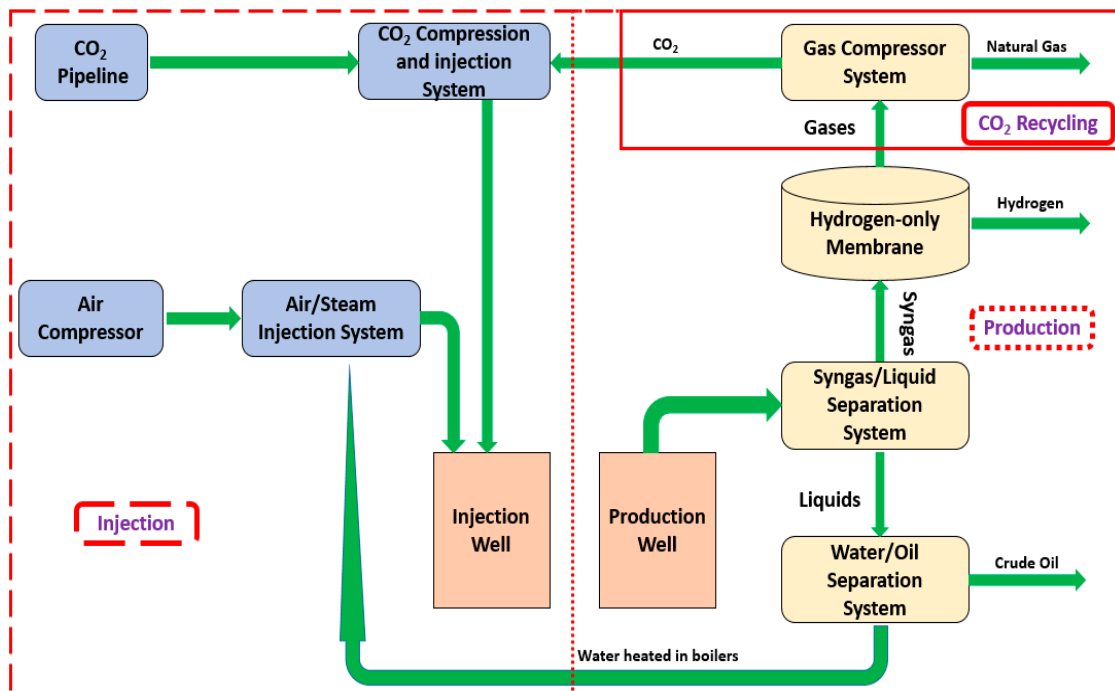


Figure 3. A typical process flow diagram of hydrogen production from petroleum reservoirs.

Table 3. Cost model structure.

Injection	Production	CO ₂ Recycling
Cost of equipment leased	Cost of production (equipment and Separation costs)	Cost of gas compression and processing (pumping, compression, and separation costs).
Annual operation-and-maintenance costs	Tax, royalty, social responsibilities, and revenue	
Cost of CO ₂ distribution within the system		
Steam cost		
Air source and cost		
CO ₂ source and cost		

2.2.1. Injection Cost Components

This component involves sub-components for calculating injection and injection well costs.

Lease Equipment Costs for Injection Well

The cost of injection equipment and injection wells impacts the overall running cost of the project. The U.S. Energy Information Administration provides a summary of additional costs associated with injection equipment and injection wells in West Texas for secondary oil recovery operations, covering 10 producing and 11 injection wells at various depths (Table S4). The data of the Consumer Price Index (CPI) used in this study is presented in Table S5. In this economic model, it is assumed that all investments are made prior to the commencement of the injection phase, with all associated investment costs allocated to the initial time step of the model. Additionally, the costs associated with exploration, drilling, and completion are not included as it is assumed that these infrastructures are available.

Annual Operating and Maintenance Costs

During the life of the project, periodic well workovers involving the replacement of tubing with new tubing designed to inhibit corrosion caused by CO₂ will be performed. The U.S. Energy Information Administration provides a summary of the direct annual operating costs for secondary oil recovery operations in West Texas, covering 10 producing and 11 injection wells at various depths (Table S8).

CO₂ Supply and Conveying Costs

In this model, we reference data from [42] and consider two main cost constraints for CO₂ distribution. The fixed cost is \$200,000, covering all manifolds and distribution lines on-site, which connect the production wells to the recycle plant and subsequently from the recycle plant to the injection wells. The variable cost is based on distance and flow rate, encompassing CO₂ supply systems from the pipeline.

Air Source and Cost

Air injection is essential for hydrogen production from petroleum reservoirs, involving the use of compressors to supply the necessary air for in situ combustion and gasification. The cost model includes both the cost of air and the required equipment, such as compressors and their accessories.

Industrial-grade air compressors, which draw ambient air and compress it to the required pressure, are suitable for large-scale reservoir operations. These compressors cost approximately \$50,000 per unit, with annual operating costs around \$5000 (Industrial Air Compressors). The compressors ensure the required injection pressure and flow rates, which are critical for effective hydrogen production. The air is drawn from the atmosphere, filtered to remove impurities, and then compressed to the desired pressure before being injected into the reservoir.

2.2.2. Carbon Dioxide (CO₂) Cost Components

This component involves sub-components that cover the costs related to CO₂ purchase and injection.

CO₂ Source and Cost

The economic feasibility of hydrogen production from petroleum reservoirs heavily depends on the procurement and transportation costs of CO₂, a critical component in the process. CO₂ can be sourced from natural reservoirs or industrial facilities, each option carrying distinct economic implications. Natural sources typically offer lower costs due to minimal processing requirements, whereas industrial sources, such as ammonia plants or catalytic cracking units, provide CO₂ with higher purity levels but may incur higher expenses due to regulatory compliance and processing.

Impurities commonly found in natural CO₂ sources, such as N₂, H₂S, or CH₄, can impact project costs by influencing minimum miscibility pressure requirements or necessitating specialized infrastructure. In contrast, industrial CO₂ sources may include contaminants like N₂ and CO, requiring additional processing to meet project specifications [40].

For this study, the cost of CO₂ procurement includes delivery to the project site, with transportation and pipeline costs excluded. CO₂ purchase prices typically correlate with oil prices, often approximating around 2.5% of the oil price based on previous studies [41,42].

The optimization of pipeline diameter based on CO₂ flow rates and distances plays a crucial role in minimizing capital and transportation costs. Reference [41] outlines a method for optimizing pipeline diameter, with the following tables (Tables S11 and S12)

detailing diameters for different CO₂ flow rates over 100 miles (160.9 km) and estimated pipeline capital costs:

Operating and maintenance costs for a 100-mile pipeline are estimated at approximately \$900,000 annually, unaffected by diameter [41]. Transportation costs are detailed in Table S13, showing that higher CO₂ flow rates reduce costs per metric tonne transported, influenced by pipeline diameter and length.

This cost-efficient transportation infrastructure is essential for maintaining project profitability over its estimated 20-year lifespan, accounting for a 6% discount rate. Therefore, the strategic sourcing and efficient transportation of CO₂ are critical for enhancing the economic feasibility of hydrogen production from petroleum reservoirs. This study's model will integrate these cost components with practical insights from industry methodologies, ensuring robust financial assessments and informed decision-making.

Calculation of Injection Pressure and CO₂ Pressurizing Expenses

To estimate the compression and pumping power required for CO₂ injection, wellhead pressures are calculated using an iterative method from [41], based on outputs from the CMG simulation. CO₂ properties such as viscosity, density, and compressibility factor, which are sensitive to temperature and pressure, are sourced from [44]. If the pressure at the wellhead is less than the CO₂ pressure in the outlet (1200 psi), additional pressurization for injection is unnecessary, and the injection pressure is set to the wellhead pressure.

2.2.3. Water Cost Components

This component involves sub-components that cover the costs related to water procurement and steam/air injection.

Water Procurement Cost

The cost of water procurement is a significant consideration. Based on available data, the volume of water consumed is estimated to be approximately 20–25% of the volume of hydrogen produced. Following the assumptions made by (AEA) we will adopt a water cost of \$0.14 per barrel. This cost reflects only the energy required to lift water from a well, assuming access to subsurface water resources. Consequently, this economic model will not include commodity cost for water procurement, as it assumes that subsurface water is readily accessible and that the primary expense is related to energy consumption for water extraction. This approach aligns with industry standard practices.

Steam/Air Injection Cost

For steam/air injection in in situ hydrogen production, wellhead pressure is determined by adding the wellbore pressure to the head pressure. The head pressure is calculated using Equation (S4). For steam at 150 °C and a depth of 1524 m, the head pressure is approximately 0.9 psi (0.006 MPa). For air, using a density of 1.225 kg/m³, the calculation follows similarly.

2.2.4. Production Cost Components

This component involves sub-components that cover the costs related to production equipment procurement, fluid lifting, syngas and water separations and the production revenues and taxes.

Cost of Production Equipment

The cost of the producing equipment and producing wells impacts the overall running cost of the project. The U.S. EIA provides a summary of additional equipment costs of

producing wells in West Texas for water flooding process, covering 10 producing wells at various depths (Table S14).

Cost of Fluid Lifting

In the context of in situ hydrogen production from petroleum reservoirs, an artificial lift system may be necessary to bring produced gas or syngas to the surface, particularly when reservoir pressure is inadequate. This requirement is like CO₂-EOR projects, where 80 percent of operations necessitate artificial lifting due to insufficient reservoir pressure (AEA). For hydrogen production, the same principle applies lifting is essential if reservoir pressure is lower than the hydrostatic pressure of the produced gas column.

Artificial lifting costs vary significantly depending on the depth of the well and the characteristics of the produced fluids. For instance, (AEA) indicated that artificial lifting requires 2–4 kWh/bbl for shallow wells and up to 25 kWh/bbl for deep wells. Reference [40] estimated a lifting cost of \$0.25/bbl for total fluid produced. For hydrogen production, lifting costs can be similarly estimated. Given the depth and pressure conditions typically encountered, a lifting cost of \$0.25/bbl is assumed for produced gases, aligning with the [40] assumption for fluid lifting in CO₂-EOR projects.

It is important to note that the separation cost for gas and liquid phases is considered negligible compared to the overall lifting costs. This assumption simplifies the economic model and focuses on the primary expenses associated with lifting in hydrogen production from petroleum reservoirs.

Cost of Syngas and Liquid Separation

The cost of syngas and liquid separation through membrane technology is critical for assessing the economic viability of hydrogen production from petroleum reservoirs. Membrane modules typically range from \$500 to \$1500 per square meter [45], with annual maintenance costs averaging 10% to 15% of the initial membrane investment [46]. Ancillary equipment can increase initial capital outlay by 50% to 100% [47], while membrane lifetimes range from 3 to 5 years, necessitating periodic replacements [48]. These factors, including procurement, maintenance, ancillary equipment, and replacement cycles, constitute the core financial considerations for membrane-based syngas and liquid separation. Ongoing advancements in membrane technology are expected to further optimize costs and enhance project economics.

Cost of Separating Oil and Water Mixture

The cost of separating the oil and water mixture is a critical component in the techno-economic analysis of hydrogen production from petroleum reservoirs. Schlumberger [49] provided cost projections for water control strategies for fluid production rates from twenty thousand to two hundred thousand barrels per day. The costs in 2000 dollars are shown in Table S17.

Production Revenue, Tax and Royalty Separation

Herein, it is assumed that hydrogen price is \$3/kg, aligning with current market trends [50,51]. We consider a royalty rate of 10%, reflecting typical agreements in the energy sector [52,53]. Additionally, a severance tax rate of 2% is applied, aligning with inducements often provided for innovative energy projects [54,55].

We utilize the residual income (R) as outlined in Equation (1).

$$R = (P_H \times Q_H) \times (1 - \tau_R - \tau_S) \quad (1)$$

In Equation (1), P_H is the hydrogen price (\$/kg), Q_H is the hydrogen production rate (kg/day), τ_R is the royalty rate, and τ_S is the severance tax rate.

2.2.5. Carbon Dioxide Recycling Cost Components

This component involves sub-components that cover the costs related to production equipment procurement, fluid lifting, syngas and water separations and the production revenues and taxes.

Gas Treatment: Gas Separation and Compression

Carbon dioxide recycling is a crucial aspect of hydrogen production from petroleum reservoirs, particularly for enhancing the efficiency and sustainability of the process. During hydrogen production, a portion of the injected CO_2 will be produced alongside hydrogen and other gases. This produced CO_2 must be separated and re-injected to maintain reservoir pressure and optimize hydrogen recovery. Typically, 15–50% of the injected CO_2 will be recycled in this manner [41].

The produced CO_2 , along with other gases, enters the gas processing unit. If the concentration of other gases (e.g., methane) in the produced fluid is significant, they can be separated and sold as valuable by-products. The concentration of these gases typically varies over time, being more in the initial stages of CO_2 injection [56]. Gas separation can be achieved through methods highlighted in Table S18. These processes primarily consume energy for refrigeration and compression.

We assume a refrigeration method in this model, as it is a common and cost-effective method for CO_2 separation [56–58]. Refrigeration has an estimated capital cost of \$500 per Mscf/day of produced gas [58], and it typically recovers 20–50% of hydrocarbons. Membrane separation, though effective, incurs higher costs due to the need for recompression of CO_2 . Ryan Holmes is another method but is very expensive. For simplicity, this cost model assumes a capital cost of \$500 per Mscf/day for CO_2 separation from hydrocarbon gas.

After separation, the CO_2 is compressed to critical pressure and then pressurized to 1200 psi (8.27 MPa) using a pumping system [58]. The compression and pumping costs are calculated separately by determining the required compression power, compressor capital, and operating and maintenance costs. This detailed approach aligns with the methodology suggested by [58], ensuring a comprehensive evaluation of the CO_2 recycling process's economic viability.

The costs of compression are significant. For the separated CO_2 , which is initially at atmospheric pressure (0.1 MPa), it needs to be pressurized to 1200 psi (8.27 MPa). This involves compressing it to its critical pressure (7.39 MPa) and then pumping it to the final pressure. Reference [59] suggested using five compressor stages to achieve this pressure. Equations (S6)–(S8) were used to calculate the compression power requirement at each stage.

After compression, the separated CO_2 needs to be pressurized to 1200 psi (8.27 MPa) using a pump. The pump capital cost is assumed to be 20% of the compressor capital cost, operating and maintenance costs. Capital costs for compression are typically estimated based on required compression power. (AEA) assumed \$2000 per horsepower (hp), while [60] mentioned costs ranging from \$1060 to \$3000 per hp. This research assumes \$2500 per hp for determining compressor capital costs based on the maximum required compression power. Operating and maintenance costs for compressors are mainly energy costs. The average retail price of electricity for the state of Texas of 13 cents per kilowatt-hour is applied to the cost model [61].

2.2.6. Parameters Utilized in the Economic Modeling

Table 4 outlines the inputs and constraints applied in the economic model, with all values adjusted to 2024 dollars where necessary.

Table 4. Overview of inputs and cost constraints adopted in the economic model.

Components	Computation Technique
Injection	
Equipment cost (\$)	60.682/ft + 85,997
Annual operating and maintenance costs	
➤ Normal daily (\$/year)	0.0027/ft ² –30.548/ft + 88,879
➤ Surface repair (\$/year)	0.0031/ft ² –34.465/ft + 106,019
➤ Subsurface repair (\$/year)	0.0053/ft ² –57.067/ft + 162,380
CO ₂ supply and distribution system costs	\$200,000
Air source and cost	\$50,000 with \$5000 per year operating cost
CO ₂ purchase cost (\$/Mscf)	2.5 percent of oil price
CO ₂ pressurizing cost	
Pump capital cost (\$)	$(1.944 \times 10^3 \times W_p) + 0.1224 \times 10^6$
➤ Pump operating and maintenance cost (\$/year)	13 Cents per kWh
➤ Water cost (\$)	\$0.14 per barrel
Steam/air pumping and injection cost	13 Cents per kWh
Production	
Cost of producing equipment	32.516/ft–21,146
Cost of fluid lifting	\$0.25 per barrel of produced fluids
Cost of syngas and liquid separation	\$1000 per square meter with 10% annual maintenance cost
Cost of water/oil separation	\$1.917 per barrel
Production revenue, tax and royalty	
➤ Severance tax	2% of the produced hydrogen value
➤ Royalty rate	10% of the produced hydrogen value
CO ₂ recycling	
Gas treatment: Gas separation and compression (\$)	\$500 of gas production rate
Compression costs	
➤ Compressor capital cost (\$)	\$2500 per horsepower
➤ Compressor operating and maintenance cost (\$/year)	13 Cents per kWh

2.2.7. Reservoir Classification Process

For the techno-economic simulations, the heavy oil reservoir is classified based on productivity, which is closely related to the ease of fluid flow. Porosity and permeability

are fundamental properties that influence how easily fluids can be stored and transmitted through the reservoir. The classification is based on these properties in Table 5.

Table 5. Reservoir classification.

Reservoir Property	Ultra-Low-Quality Reservoirs (ULQR)	Low-Quality Reservoirs (LQR)	Moderate-Quality Reservoirs (MQR)	High-Quality Reservoirs (HQR)
Permeability	<0.1	0.1–1 md	1–10 md	>10 md
Porosity	<5%	5–10%	10–20%	>20%

According to sources like [62–64], low permeability reservoirs often have permeability values below 1 md. Moderate permeability is typically in the range of 1 to 10 md, and high permeability exceeds 10 md. Additionally, according to [65], low porosity is generally less than 10%, moderate porosity ranges from 10% to 20%, and high porosity exceeds 20%.

3. Results and Discussion

3.1. Technical Aspects of Hydrogen Generation

The technical aspects involve key factors that influence hydrogen generation under in situ conditions. The analysis focuses on critical aspects such as hydrogen and other syngas yields for different injection strategies and initial reservoir temperatures, hydrogen diffusivity and combustion front mobility efficiency, and hydrogen generation mechanisms. Subsequent sections provide a more detailed exploration of these aspects.

3.1.1. Analysis of Hydrogen Yield and Gas Composition

This section focuses on cumulative hydrogen yield, gas composition, and impact of injection strategies, reservoir temperature, and the technical challenges posed by oil recovery and syngas generation. The analysis highlights the significant differences between the hydrogen generated within the reservoir and the hydrogen produced at the surface, which raises important questions about the long-term viability of hydrogen as a clean energy source from heavy oil reservoirs.

Impact of Injection Strategy on Hydrogen Generation

Herein, we used the parameters specified in Section 2.1 to study the impacts of the two injection strategies on hydrogen yield (Figure 4). The cyclic steam/air injection strategy yields the highest cumulative hydrogen. This finding is consistent with prior research, which indicates that cyclic steam/air injection strategies are more efficient in controlling oxygen supply, thus enhancing hydrogen production while reducing hydrogen-consuming reactions [27].

While cyclic steam/air generates the highest hydrogen, it also results in significant cumulative oil recovery and gas generation (Figure 4). This raises an important consideration: the high oil recovery observed suggests that the reservoir is not only a potential candidate for hydrogen generation but could also continue to serve as a significant source of crude oil for conventional fossil-based energy production. The simultaneous oil recovery presents a challenge for the sustainability of hydrogen production. Heavy oil reservoirs with high oil recovery rates face the issue of competing priorities: crude oil extraction for fossil-based energy versus hydrogen generation for clean energy. The oil produced could be used for traditional energy generation or refined into various fossil fuels, which complicates the feasibility of transforming such reservoirs into hydrogen-only generators for clean energy.

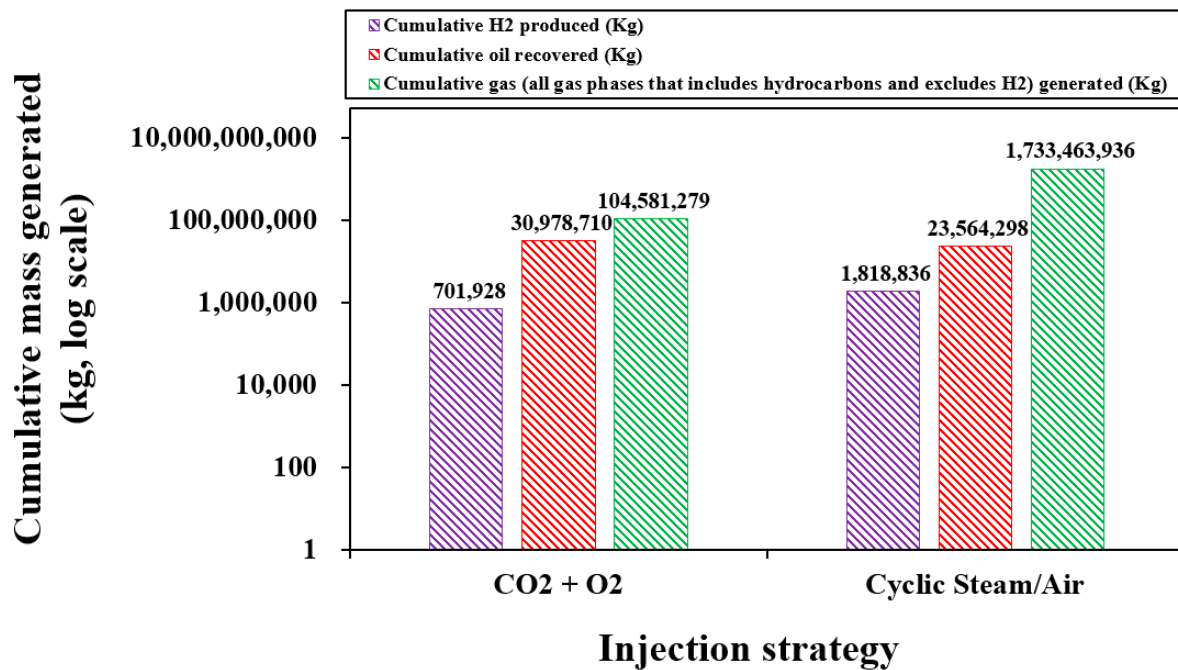


Figure 4. Cumulative mass of hydrogen, oil and other gas generated from heavy oil reservoir.

In contrast, the CO₂ + O₂ injection strategy generates lower hydrogen, and the lower oil recovery rates suggest that it might not be as efficient in both hydrogen generation and crude oil production. The higher hydrogen yields from cyclic steam/air do not entirely downplay the possibility of using these reservoirs for conventional energy extraction, but the efficiency of hydrogen generation is reduced compared to oil extraction.

Thus, the choice of injection strategy is not only important for hydrogen generation but also affects the overall energy output, potentially leading to a conflict between utilizing the reservoir for hydrogen production and extracting crude oil for traditional energy uses.

Temperature Dependence of Hydrogen Generation

Initial reservoir temperature plays an important role in determining feasibility of hydrogen generation from petroleum reservoirs. This is the minimum temperature the reservoir temperature should attain before hydrogen can be generated. This is achieved through heating the reservoir using either the injection of combustible gas or electromagnetic process [9,66]. Figure 5 shows the critical role of the initial reservoir temperature in determining the feasibility of hydrogen generation. The cumulative hydrogen yield for different injection strategies is strongly influenced by initial reservoir temperature, with a peak observed between 450 °C and 500 °C, particularly in the early time periods (10.4–100.3 days). Within this temperature range, reactions such as coke gasification and water-gas shift dominate, promoting the generation of hydrogen [67]. These reactions become increasingly favorable as the temperature rises, with thermal cracking and high-temperature coke oxidation playing a key role in enhancing hydrogen generation [17,25].

However, below 350 °C hydrogen generation becomes less feasible. At temperatures lower than 350 °C, hydrogen generation reactions slow down significantly because the thermal energy available is insufficient to overcome the activation energy for endothermic reactions, such as coke gasification, which are essential for sustained hydrogen generation. Although exothermic reactions like the water-gas shift can occur at lower temperatures, the overall rate of hydrogen-generating reactions decreases due to limited thermal activation [68]. For a short-term production plan, the temperature range between 450 °C and 500 °C represents the optimal condition for hydrogen generation (Figure 5a,b), where

hydrogen production reactions are maximized, and hydrogen-consuming reactions are minimized. This balance is critical to maintaining high hydrogen yields during the process.

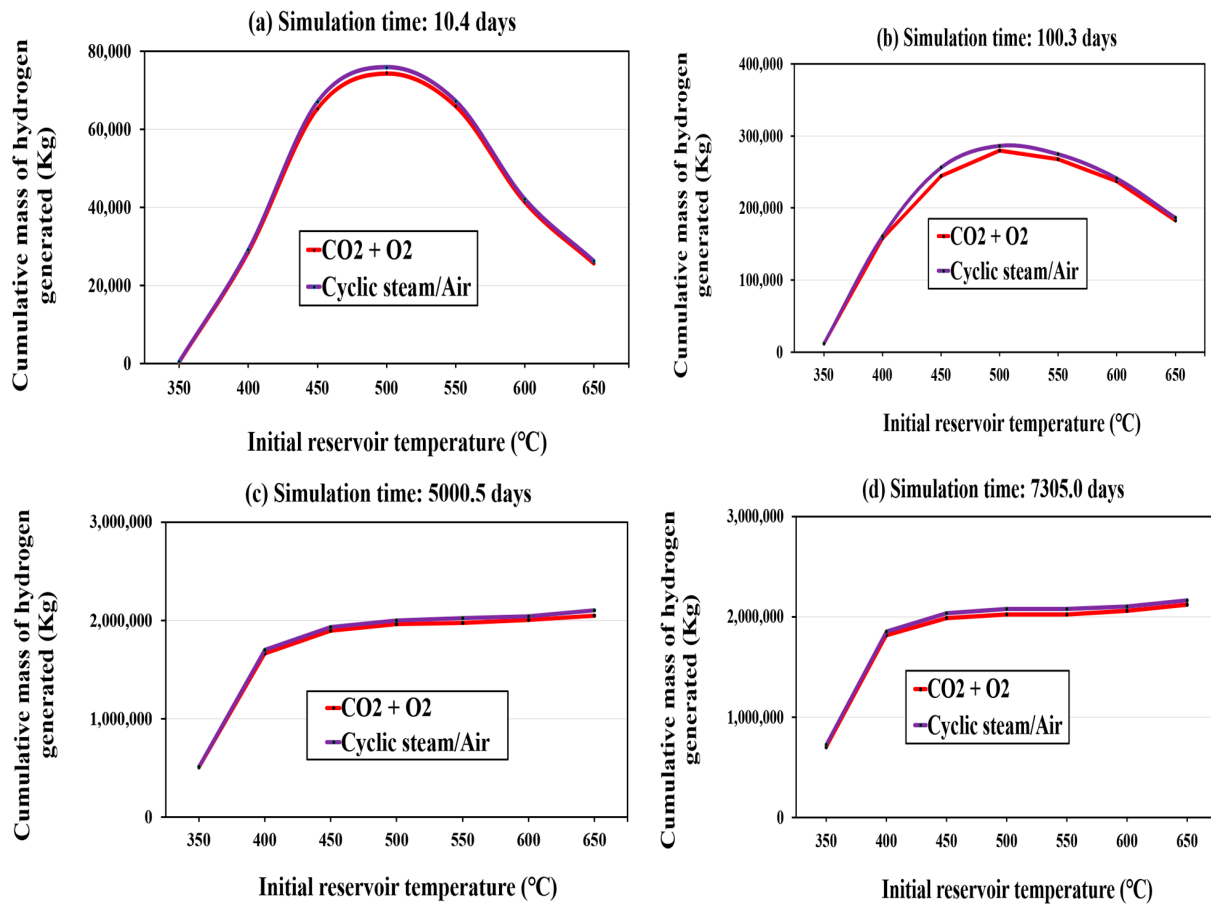


Figure 5. Cumulative hydrogen yield from heavy oil reservoirs at different initial reservoir temperatures over a period of 10.4, 100.3, 5000.5, and 7305.0 days.

At the late time periods (5000.5 to 7305.0 days), the interplay between combustion and gasification becomes more significant. Initially, the combustion processes, driven by the injection of air or oxygen, help ignite the reservoir and initiate the gasification of heavy oil. However, as time progresses, the contribution of gasification reactions increases, while combustion reactions continue to support the overall energy balance and hydrogen generation.

The cumulative hydrogen yield in the long term continues to increase, as seen in Figure 5c,d, particularly at higher initial reservoir temperatures, where cyclic steam/air injection shows the highest cumulative hydrogen generation. This can be attributed to the influence of spontaneous ignition within the reservoir, overcoming the initial delays between injection and ignition [12,69]. Over time, the hydrogen generation reactions, such as water-gas shift and coke gasification, prevail over the hydrogen-consuming reactions. This shift results in a more sustained and uniform hydrogen generation rate, contributing to the continuous rise in cumulative hydrogen yield [39].

The balance between combustion and gasification is crucial in ensuring sustained hydrogen generation. Combustion provides the necessary heat to maintain the required reservoir temperature, while gasification facilitates the conversion of heavy oil into hydrogen-rich gases. Achieving a balance between these two processes is essential for maximizing hydrogen generation.

3.1.2. Analysis of Combustion Front Propagation and Hydrogen Diffusion Impact of Combustion Front Propagation on Hydrogen Generation

This section investigates the propagation of the combustion front from the injection well to the production well and its impact on hydrogen generation and diffusion under different injection strategies. During combustion recovery processes, three key activities occur simultaneously: fluid displacement, heat transfer, and oxidation/gasification reactions. Air injection into the reservoir initiates combustion, either through spontaneous ignition when sufficient air permeability exists or by applying external heat using electromagnetic devices, gas burners, or reactive chemicals [70–73]. Once ignition is achieved, continuous air or steam injection drives the combustion front outward from the injection well toward the production well [72,74].

The combustion front transfers heat to the surrounding reservoir fluids and rock, promoting oxidation and gasification reactions at high temperatures near the front. These reactions generate hydrogen and syngas. Conversely, the cooler regions behind the combustion front promote condensation and hydrogen-consuming processes [9]. Sustained hydrogen generation in the reservoir requires the hydrogen generation process to progress faster than the advancing combustion front. A slow hydrogen generation rate or significant hydrogen loss during the in situ combustion gasification process may result in reduced hydrogen yields at the production well. Thus, optimizing combustion front mobility and hydrogen diffusion could maximize hydrogen recovery efficiency.

To investigate the impact of combustion front propagation from the injection well to the production well on hydrogen generation, we simulated the best-case injection strategy (i.e., cyclic steam/air) and initial reservoir temperature (350 °C) for long-term production (7305 days) from previous sections, and determine the propagation of the combustion front using oil saturation, water saturation, hydrogen concentration, and temperature distribution profiles along the injection well to the production well as shown in Figure 6.

As the combustion front advances through the reservoir, different thermal and compositional zones emerge, significantly influencing hydrogen generation and fluid saturations. The zone swept by the burning front is characterized by high temperatures, often exceeding 371 °C [75,76], leading to the evaporation of liquids, of which significant syngas, including hydrogen, gaseous hydrocarbons, and coke residues, could be present (Figure 6a). In this region, miscibility between the injected air and steam promotes oil displacement toward the production well (Figure 6b).

Immediately ahead of the burning front lies the “steam plateau,” a region with temperatures ranging from 93 °C to 204 °C [75]. Heat is transmitted forward by conduction through the reservoir rock and by convection due to the movement of vapors, gases, and steam from the combustion zone. This plateau region exhibits a steam-flooding effect, characterized by increased and stabilized water saturation and significant oil displacement. Hydrogen concentrations in this region gradually decline due to condensation and potential hydrogen-consuming reactions at low temperatures (Figure 6b).

Further ahead is the hot waterflood zone, where steam and oil condense, forming a lighter hydrocarbon bank [75]. Hydrogen generation in this region begins to decline significantly, as the lower temperatures reduce the rates of thermal cracking and gasification reactions that produce hydrogen. However, oil mobilization remains substantial, driven by the combined effects of heat transfer and steam-assisted displacement (Figure 6b). Beyond this zone lies the oil bank, composed of oil displaced from upstream zones and swept forward by the combustion front [75]. In this region, hydrogen concentrations are minimal, as thermal and hydrogen generation-reactions are not efficient. Finally, the unaffected reservoir oil is found ahead of the oil bank, remaining insulated from the thermal and chemical processes associated with the advancing combustion front.

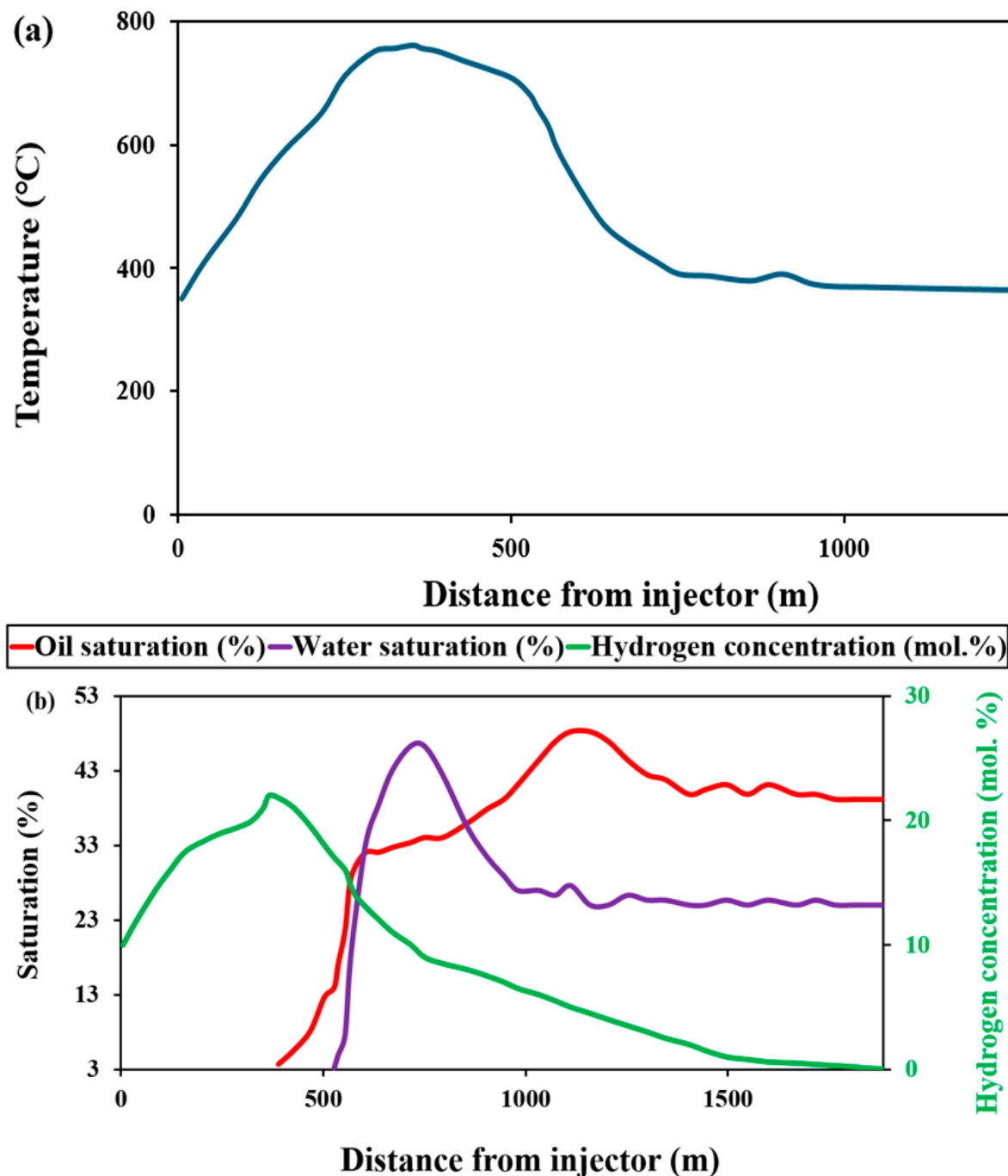


Figure 6. (a) Reservoir temperature distribution profile along the injection production wells. (b) Oil saturation, water saturation, and hydrogen concentration distribution profiles along the injection production wells.

This demonstrates that the propagation of the combustion front is a critical driver of hydrogen generation, with its thermal profile and mobility influencing reaction rates and hydrogen diffusivity across the reservoir. At the burning zone near the injector, high hydrogen generation is observed. However, as the combustion front propagates away from the injector, hydrogen generation progressively declines. This suggests a disparity between the hydrogen generated and the potential hydrogen that could be produced at the production well, likely due to technical challenges related to the propagation dynamics of the combustion front and possible hydrogen loss due to leakages and microbial activities.

Impact of Underground Hydrogen Migration and Diffusion on Hydrogen Generation

This section examines the migration and diffusion of hydrogen from the injection to production well over three annual production cycles, focusing on its influence on hydrogen generation and the role of oil saturation. The analysis was conducted using the injection strategy and parameters described in the previous section, with results presented in Figure 7.

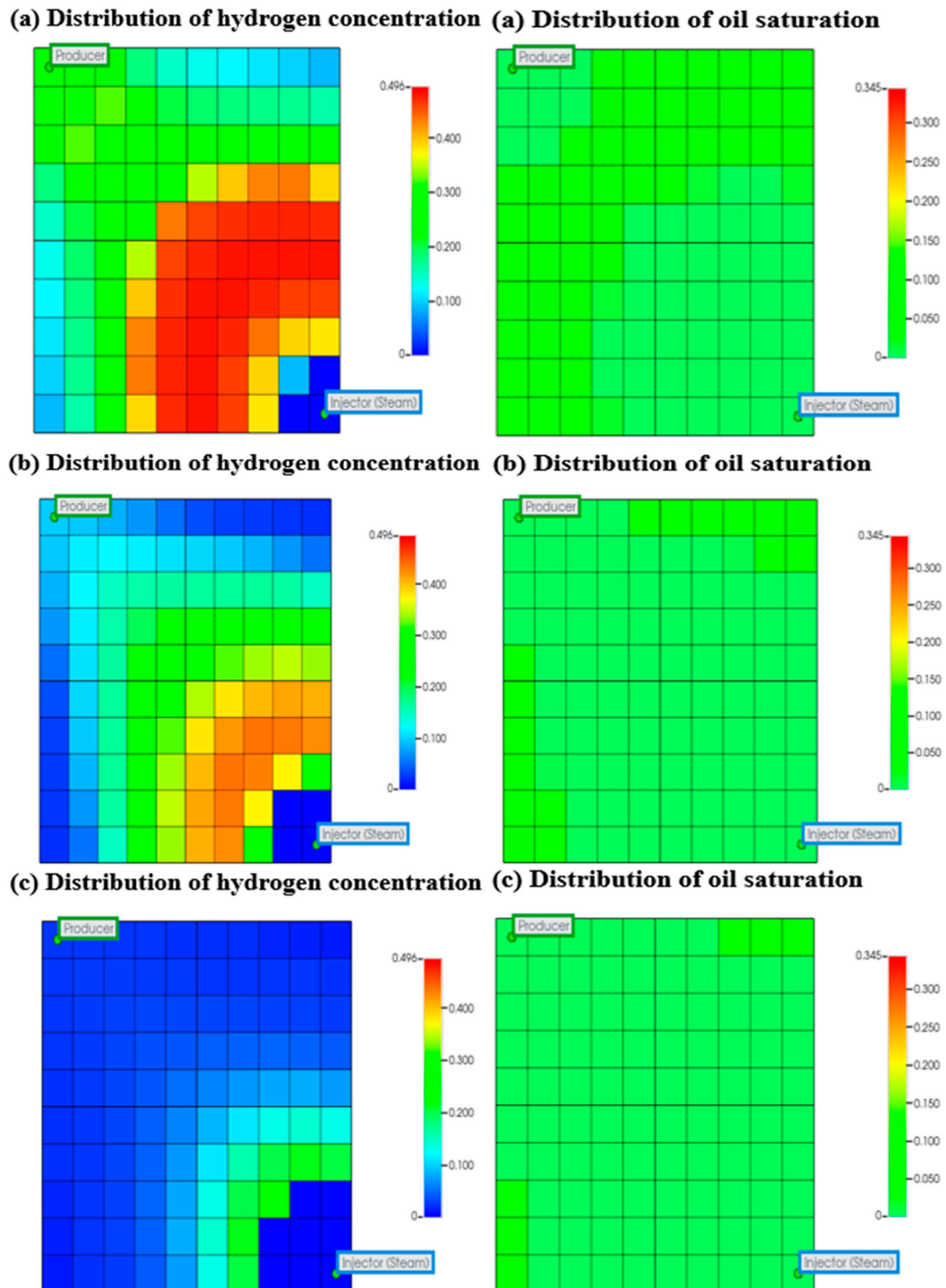


Figure 7. Distribution of hydrogen concentration and oil saturation between the injector and producer at: (a) First production cycle, (b) Second production cycle, (c) Third production cycle.

As shown in Figure 7, hydrogen concentration is highest near the injection well for all cycles, with the first cycle showing the peak levels. This corresponds to the high hydrogen generation near the burning front close to the injector (Figure 6). Conversely, higher oil saturation is observed near the production well, which could reduce pore space availability and effective permeability for hydrogen migration. This oil saturation could increase viscous drag and lower the relative permeability of hydrogen, significantly hindering its flow toward the production well.

As production progresses from the first to the third cycle, the likelihood of hydrogen breakthrough at the producer diminishes, while oil breakthrough becomes more prominent (Figure 7). High oil saturation near the producer reduces effective permeability to hydrogen by occupying larger pores and creating a capillary barrier, which could impede hydrogen migration [77–79]. Because hydrogen is less wetting than oil, it will be difficult to displace oil and migrate effectively [80]. Additionally, hydrogen may be lost through leakages, microbial or chemical reactions, or become trapped, delaying or preventing its breakthrough at the production well.

Further, hydrogen can dissolve into the oil phase depending on reservoir conditions such as temperature, pressure, and the solubility characteristics of hydrogen in the oil phase [81]. Dissolved hydrogen does not contribute to the free gas phase migrating toward the producer, further delaying its recovery. This reflects the challenges of achieving efficient hydrogen production due to the interplay of hydrogen diffusion, migration, and oil saturation.

3.1.3. Impact of Formation Damage on Hydrogen Generation

In this section, the relationship between pore volume, solid volume, and hydrogen generation was investigated under initial reservoir temperature conditions (650 °C) through simulation parameters for cyclic steam/air injection specified in previous section. The objective is to investigate the impact of formation damage on hydrogen generation due to solid deposition. Two key plots in Figure 8 were analyzed.

Figure 8 reveals an inverse correlation between solid volume and hydrogen generation, mediated by changes in pore volume. Regions of high solid volume correspond to significantly reduced pore volume and exhibit the lowest hydrogen generation rates. This behavior is consistent with the fundamental theory of formation damage, where the accumulation of solid-phase materials, such as coke and asphaltene plug pore spaces, leading to decreased permeability and limited transport of reactants (e.g., oxygen, water, and hydrocarbons) to reaction zones [82–89]. The restricted reactant flow inhibits key reactions, such as thermal cracking, gasification, and water-gas shift, which are necessary for hydrogen production.

As solid volume decreased, likely due to the progression of gasification reactions, pore volume increased, enhancing reactant transport and facilitating higher hydrogen generation rates. The observed stabilization of solid and pore volumes (Figure 8) corresponds to the establishment of a quasi-steady-state system, where the balance between solid formation (via incomplete combustion) and solid consumption (via gasification) maintains a stable pore network. Consequently, hydrogen production also stabilizes, reflecting equilibrium between reactant availability and reaction kinetics.

These findings are consistent with the principles of porous media flow and chemical reaction processes, wherein solid deposition acts as a primary factor influencing transport properties and reaction rates in thermal recovery processes [90]. Furthermore, the results represent the detrimental impact of formation damage on hydrogen recovery [14]. Regions with severe pore blockage are less effective in generating hydrogen, highlighting the importance of mitigating solid-phase accumulation during in situ gasification.

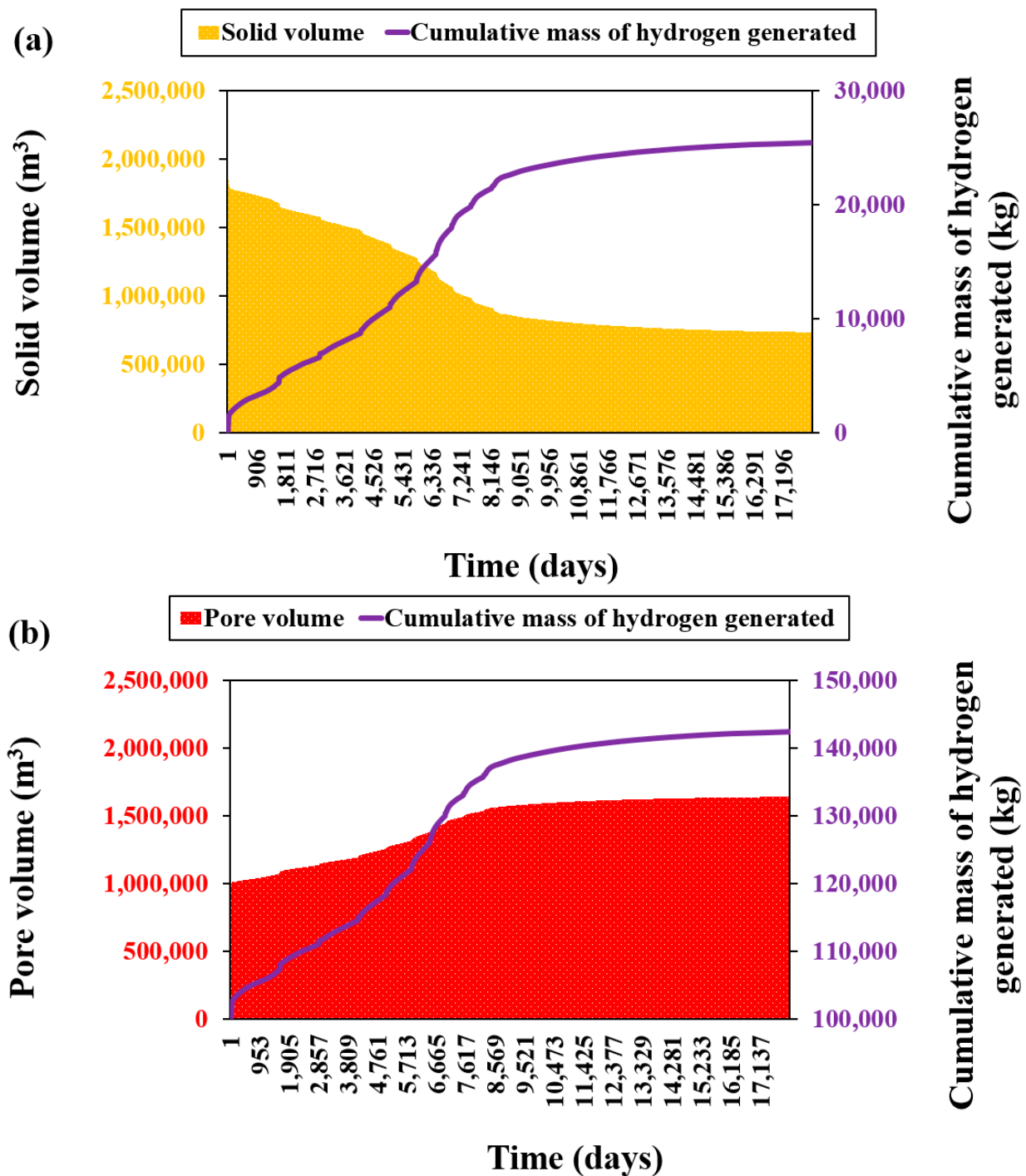


Figure 8. (a) Solid volume vs. Cumulative hydrogen generated, (b) Pore volume vs. Cumulative hydrogen generated.

The technical investigation revealed key challenges affecting hydrogen production from heavy oil reservoirs. Issues such as injection strategies, initial reservoir temperature, combustion front propagation, hydrogen migration, diffusion, and loss mechanisms contribute to discrepancies between in situ hydrogen generation and surface production, with the former being higher. These technical hurdles may explain why companies that observed hydrogen co-production during field projects (Table 1) opted to prioritize crude oil extraction over hydrogen production. Evaluating the cost-effectiveness of produced hydrogen is thus essential to inform investment decisions. The subsequent sections will present a detailed economic analysis to address these considerations.

3.2. Economic Aspects of Hydrogen Production

3.2.1. Cost and Profitability Analysis of Hydrogen Production

In this section, we evaluate the economic feasibility of hydrogen production from heavy oil reservoirs using in situ combustion gasification, based on the simulation results in Figure 4. The cumulative hydrogen yield from our simulation over a 20-year period was 1,818,836 kg for cyclic steam/air injection and 701,928 kg for CO₂ + O₂ injection.

Capital and Operating Costs

For the purpose of this analysis, capital and operating costs are based on the publicly available data from Proton Technologies' hydrogen production technology, as outlined in [91]. The capital and operating costs are as follows:

- Capital expenditures (CAPEX): Total initial capital expenditures for the infrastructure required for hydrogen production are estimated at US\$ 340 million. This covers:
 - US\$ 245 million for the construction of air separation units (ASUs);
 - US\$ 65 million for hydrogen purification systems;
 - US\$ 20 million for hydrogen pipeline infrastructure;
 - US\$ 10 million for production well development.
- Operating expenditures (OPEX): Annual operating costs, which include labor, maintenance, and administrative expenses, are estimated at US\$ 1.8 million per year, broken down as follows:
 - US\$ 1.37 million for labor and staffing;
 - US\$ 0.4 million for administrative and operational expenses;
 - US\$ 0.03 million for facility insurance.

Revenue from Hydrogen Production

Revenue from hydrogen production is another vital component in assessing the profitability of the project. The revenue from hydrogen production is calculated by multiplying the total hydrogen produced by the price per kilogram, assumed to be US\$ 3.00 per kg [92]. For the cyclic steam/air injection strategy, which produces 1,818,836 kg of hydrogen over the 20 years, the total revenue is approximately US\$ 5.46 million. In contrast, the CO₂ + O₂ injection strategy produces 701,928 kg of hydrogen, generating US\$ 2.10 million in revenue over the same period. This disparity in hydrogen yield results in significantly different costs per kilogram of hydrogen, which is a crucial factor in determining the overall economic viability of each strategy.

Cost per Kilogram of Hydrogen Produced

To evaluate the cost-effectiveness of hydrogen production, we calculate the cost per kilogram of hydrogen produced. This is derived by dividing the total capital and operating costs over the 20-year period by the cumulative hydrogen yield. The capital costs are annualized based on the initial US\$ 340 million capital expenditure, resulting in an annual capital cost of US\$ 17 million. Adding the annual operating costs of US\$ 1.8 million results in a total annualized cost of US\$ 18.8 million.

The cost per kilogram of hydrogen for each strategy is then calculated:

- Cyclic steam/air injection: With a total hydrogen production of 1,818,836 kg, the cost per kilogram of hydrogen is:

$$\text{Cost per kg} = \frac{18.8 \text{ million USD}}{1,818,836 \text{ kg}} \approx 10.3 \text{ USD/kg}$$

- CO₂ + O₂ injection: With a total hydrogen production of 701,928 kg, the cost per kilogram of hydrogen is:

$$\text{Cost per kg} = \frac{18.8 \text{ million USD}}{701,928 \text{ kg}} \approx 26.8 \text{ USD/kg}$$

The higher cost per kilogram of hydrogen produced using the CO₂ + O₂ injection method is primarily attributed to the lower hydrogen yield compared to cyclic steam/air injection. The cumulative yield from CO₂ + O₂ injection over 20 years is far lower than the cyclic steam/air injection. This disparity results in a higher allocation of capital and operating costs to each unit of hydrogen produced, thus increasing the cost per kilogram.

Additionally, the CO₂ + O₂ injection method may be less efficient in terms of combustion, which could lead to inefficient hydrogen generation. This inefficiency likely increases energy consumption and operational costs, further increasing the overall production cost. The need for specialized equipment and monitoring systems to handle the complexities of CO₂ and oxygen injection also contributes to the higher capital and operational costs.

Another factor is the carbon management costs associated with CO₂ injection. If the CO₂ is not efficiently captured or stored, additional infrastructure may be required, leading to higher costs. These added expenditures likely contribute to the higher per-kilogram cost of hydrogen from the CO₂ + O₂ injection method compared to the cyclic steam/air injection process.

Economic Comparison with Competing Methods

When comparing the costs of hydrogen production from heavy oil reservoirs to those of conventional methods such as water electrolysis and SMR, the production costs from in situ combustion gasification are higher. The current cost of hydrogen production through electrolysis ranges from US\$ 4 to US\$ 7 per kg [93], while SMR typically produces hydrogen at US\$ 1 to US\$ 3 per kg [94]. Thus, the costs from both cyclic steam/air injection and CO₂ + O₂ injection are higher than those of these traditional methods.

However, in situ combustion gasification may still be economically viable in regions where oil extraction infrastructure is already in place. In such scenarios, the upfront capital costs can be mitigated by leveraging existing oil wells, pipelines, and facilities, which reduces the need for new infrastructure. This could make hydrogen production from heavy oil reservoirs more attractive in specific contexts, particularly where other hydrogen production methods are less feasible due to logistical or geographical constraints.

The significantly higher cost associated with the CO₂ + O₂ injection method, however, suggests that it may only be economically viable under special circumstances. This could include access to carbon credits, government incentives, or the integration of the process with EOR techniques, which could help offset the higher production costs.

Opportunities for Cost Reduction

To improve the economic feasibility of hydrogen production from heavy oil reservoirs, several strategies could be deployed. Technological improvements in air separation units, hydrogen purification systems, and combustion efficiency could help reduce both capital and operating costs. Enhancing combustion efficiency and minimizing energy losses could lower operational expenses and improve overall cost-effectiveness.

Economies of scale can also play a role in reducing production costs. As the scale of hydrogen production increases, both capital costs and operating costs per unit of hydrogen are likely to decrease. Larger production facilities can help optimize resource utilization, thereby improving the cost structure.

Moreover, carbon management innovations, such as more cost-effective CO₂ capture and storage technologies, may reduce the additional costs associated with CO₂ injection. Furthermore, integrating renewable energy sources into the production process, such as using wind or solar energy to power the air separation units, could lower operational costs and improve the overall environmental profile of the hydrogen production process.

3.2.2. Breakeven Analysis

Breakeven analysis is critical in determining the economic viability of hydrogen production strategies, helping to identify the price and quantity of hydrogen required to cover total costs. In this section, we calculate both the breakeven price (P_b) and the breakeven quantity (Q_b), which are essential metrics for evaluating the profitability of each production strategy.

The breakeven price is the price per kilogram of hydrogen at which the total revenue from hydrogen production equals the total costs (capital and operating). It can be calculated by dividing the total annualized costs by the total hydrogen production over the project lifespan. The equation for breakeven price is given by:

$$P_b = \frac{C_{total}}{Q_{annual}} \quad (2)$$

where C_{total} is the total annualized cost (USD), and Q_{annual} is the annual hydrogen production (kg).

For the cyclic steam/air injection strategy, the breakeven price was found to be significantly higher than the assumed market price of hydrogen (US\$ 3.00 per kg), calculated at US\$ 206.5 per kg. For the CO₂ + O₂ injection strategy, the breakeven price was calculated to be US\$ 536.5 per kg, which is also well above the market price. This substantial difference indicates that both strategies would not achieve profitability at the current market price, emphasizing the need for cost reductions or efficiency improvements to make these methods commercially viable.

Additionally, the breakeven quantity represents the minimum amount of hydrogen that must be produced to cover the total costs at the market price of hydrogen. This is calculated by dividing the total annualized costs by the market price of hydrogen. The equation for breakeven quantity is expressed as:

$$Q_b = \frac{C_{total}}{P_{market}} \quad (3)$$

where P_{market} is the market price of hydrogen (US\$ per kg).

For both strategies, the breakeven quantity was found to be approximately 6.27 million kg per year. This represents the production levels needed to achieve profitability at the assumed market price of US\$ 3.00 per kilogram of hydrogen. This shortfall in hydrogen production relative to the breakeven quantity illustrates a considerable gap between the required and actual production levels, which would prevent either strategy from being profitable under current conditions.

These results highlight the challenges of achieving profitability in hydrogen production using the examined strategies. To move toward profitability, it is essential to explore opportunities for scaling up production, reducing costs, improving process efficiency, and potentially integrating additional revenue streams such as government subsidies or carbon credits. Enhancing the economic performance of these strategies could help bring the breakeven quantity within achievable production levels, thereby making them more commercially viable.

3.3. Comparative Techno-Economic Analysis of Hydrogen and Oil Recovery Strategies

A techno-economic model was developed within the GoldSim environment, organized according to the cost components outlined in Section 2.2 to facilitate the project's economic evaluation under specified scenarios. The model integrates a time series of outputs generated by CMG STARS as inputs for the economic evaluation.

The primary cost and economic drivers vary across injection strategies. For example, CO₂ + O₂ injection requires the inclusion of recycling facilities and CO₂ supply, whereas cyclic steam/air injection avoids these capital and input expenses. However, it typically incurs higher operational costs due to the energy required for steam generation. The techno-economic evaluation of the steam/air and CO₂ + O₂ injection strategies for hydrogen and oil recovery, highlighting critical differences in revenue generation, operational costs, and CO₂ management requirements, is shown in Table 6.

Table 6. Economic evaluation of injection strategies for hydrogen and oil production with CO₂ management.

Injection Strategy	Reservoir	Cum. Mass of H ₂ Prod. (kg)	Cum. Mass of Oil Prod. (kg)	Cum. Mass of CO ₂ Prod. (kg)	Cum. Mass of CO ₂ Inj. (kg)	Total Revenue from H ₂ (\$)	Total Revenue from Oil (\$)	Total Cost for New CO ₂ Procurement (\$)
Steam/air	ULQR	157.74	5146.17	55.60	0	473.22	2589.48	0
	LQR	195.48	7106.34	73.15	0	586.44	3575.52	0
	MQR	14,579.03	1,227,232.25	4541.80	0	43,737.09	617,390.93	0
	HQR	3,714,918	53,639,076	46,950,988	0	11,144,754	27,000,000	0
CO ₂ + O ₂	ULQR	19.58	1106.34	93.12	782.74	58.74	556.69	18.79
	LQR	46.48	3385.06	138.68	1472.04	139.44	1703.52	35.33
	MQR	13,575.51	1,127,300.13	19,542.98	24,643.49	40,726.53	567,764.45	591.44
	HQR	2,697,763.75	42,623,424	116,356,432	360,118,356	8,093,291.25	21,427,202.52	8,642,840.54

Table 6 reveals that while both strategies show potential for hydrogen and oil co-production, the economic viability of hydrogen production remains limited, particularly when compared to oil revenue. This disparity suggests that, for new fields, oil production offers a more economical investment, while hydrogen production may only become feasible under specific conditions or as part of broader clean energy initiatives.

For the steam/air injection strategy, cumulative hydrogen production and revenue are highest in HQR, generating \$11.14 million in revenue. In comparison, cumulative oil production in HQR generated \$27 million in revenue, more than double the hydrogen revenue. Similarly, in MQR, hydrogen production generates \$43,737, compared to \$617,391 from oil. This explains the dominant economic contribution of oil revenue under this strategy, despite the absence of CO₂ procurement costs and the relatively higher operational costs associated with steam generation.

The CO₂ + O₂ injection strategy shows a similar trend. For HQR, cumulative hydrogen production yields \$8.09 million, while cumulative oil production generates \$21.43 million in revenue. Fresh CO₂ purchase costs further reduce the net economic benefits, with expenses reaching \$8.64 million in HQR. This strategy's reliance on CO₂ procurement and recycling infrastructure also decreases its overall economic attractiveness, particularly in reservoirs of lower quality.

Reservoir quality significantly influences the economic potential of both strategies. LQR and ULQR exhibit limited production capacities and economic viability. For instance, hydrogen revenue from ULQR under the steam/air strategy is only \$473.22, with oil revenue at \$2589.48. In contrast, HQR under the same strategy generates over 23,000 times the revenue from hydrogen and over 10,000 times the revenue from oil. These findings suggest that LQR and ULQR offer limited potential for hydrogen, making them economically unattractive for investment.

Table 6 also reveals that the significantly higher revenue from oil production in all reservoir categories makes hydrogen production economically less favorable, particularly for new fields. Although hydrogen production aligns with clean energy goals, the current economic landscape indicates that it is not a competitive alternative to oil revenue. However, the co-production of hydrogen and oil in specific fields may require further investigation, particularly if technological advancements or policy incentives improve hydrogen's economic feasibility.

Factors contributing to the economic disparity between hydrogen and oil production include the relatively low hydrogen yield due to the technical issues mentioned in Section 3.1, higher operational and infrastructure costs associated with hydrogen production, the relatively low market value of hydrogen compared to oil, and the capital-intensive requirements for CO₂ management in the CO₂ + O₂ strategy. Additionally, field-specific factors such as reservoir quality, infrastructure availability, and market conditions play critical roles in determining the economic outcomes.

3.4. Discussion

The question of whether hydrogen can be produced cost-effectively from heavy oil reservoirs is central to the findings of this study. Despite the reported field projects by top energy companies that discovered hydrogen production potential from heavy oil reservoirs (Table 1), these projects have not continued with hydrogen production today. This could likely be attributed to the significant technical and economic challenges associated with the process. Our analysis indicates that, under current conditions, hydrogen production from heavy oil reservoirs is not cost-effective enough to justify its widespread adoption unless a revolutionary technology is developed to overcome the technical hurdles or a more efficient production strategy is implemented to address the economic barriers.

Technically, the major challenge lies in the efficiency of hydrogen generation. Both the steam/air and CO₂ + O₂ injection strategies demonstrate potential for hydrogen co-production; however, each strategy is faced with significant limitations. The steam/air injection method, while simpler and more cost-effective in terms of infrastructure requirements, leads to relatively low hydrogen yields and remains economically unattractive, especially when hydrogen production is secondary to oil recovery. The CO₂ + O₂ injection method, although capable of increasing hydrogen production, introduces additional complexities due to the need for CO₂ procurement, capture, and storage systems. These technical challenges hinder the scaling of hydrogen production from heavy oil reservoirs and contribute to the lack of commercial viability observed in the field projects discussed in Table 1.

Economically, the analysis reveals that the cost of hydrogen production far exceeds its potential market value under current conditions. With the hydrogen market price around US\$3.00 per kg, the breakeven price for both injection strategies is much higher, indicating that neither strategy can be considered economically viable at this time. In fact, the breakeven quantity of hydrogen required to cover production costs is approximately 6.27 million kg per year, which is far beyond the production levels achievable with the current technology. This suggests that, unless there is a substantial reduction in production costs or a dramatic increase in hydrogen yield, hydrogen production from heavy oil reservoirs will not be economically feasible.

Key cost drivers contributing to the high cost of hydrogen production include the energy-intensive nature of the steam generation process in the steam/air strategy and the substantial expenses related to CO₂ procurement, capture, and storage in the CO₂ + O₂ strategy. The costs associated with operating and maintaining the infrastructure for both methods, including the need for specialized equipment and personnel, further elevate

the overall cost structure. Additionally, the economic dominance of oil production in both strategies suggests that hydrogen production is a secondary consideration in terms of revenue generation, which makes it difficult to justify the investment in hydrogen production unless there are additional incentives or external revenue streams (e.g., carbon credits or government subsidies).

The comparative analysis also highlights the sensitivity of these strategies to reservoir quality. In higher-quality reservoirs, hydrogen production potential is greater, but even in these cases, oil production remains the dominant revenue source. In lower-quality reservoirs, hydrogen production is minimal and does not contribute significantly to the overall economic feasibility of the project [95]. This indicates that hydrogen production is unlikely to be the primary driver of economic returns in most heavy oil reservoirs, especially when considering the substantial upfront and operational costs required for hydrogen generation.

In conclusion, while hydrogen production from heavy oil reservoirs holds theoretical promise, the technical and economic challenges outlined in this study suggest that, under current conditions, it is unlikely to be cost-effective enough to compete with conventional oil production. Unless a breakthrough technology is introduced to overcome the technical barriers or a smarter, more cost-efficient production strategy is developed, hydrogen production from heavy oil reservoirs will remain an uncompetitive alternative to traditional oil recovery. Future research should focus on addressing these technical and economic challenges, exploring innovations in production processes, and identifying ways to improve hydrogen yield and reduce costs, potentially through integration with renewable energy sources or government support mechanisms.

4. Concluding Remarks

The production of hydrogen from heavy oil reservoirs holds significant theoretical promise, offering a potential pathway to both EOR and the generation of clean energy. However, as demonstrated in this study, there are substantial technical and economic challenges that currently prevent this process from being a commercially viable alternative to conventional oil recovery. Both steam/air and $\text{CO}_2 + \text{O}_2$ injection strategies, while showing potential for hydrogen co-production, are hindered by high production costs, limited hydrogen yields, and the complex infrastructure requirements associated with each method.

The simulations show that hydrogen yields from in situ combustion gasification of heavy oil remain below $1.5 \text{ Sm}^3/\text{kg}$ of fuel burned, with production costs more than double the current market price. The techno-economic analysis further highlights that oil revenues are consistently higher than hydrogen revenues across all scenarios, confirming oil as the primary economic driver. Even in higher-quality reservoirs, where hydrogen production potential is greater, oil recovery remains the primary focus.

Key achievements of this work include: (i) establishing validated simulation workflows that couple reservoir and techno-economic models, (ii) quantifying the economic thresholds at which hydrogen might become competitive, and (iii) identifying priority areas, such as cost reduction in steam generation and CO_2 capture, that require innovation before commercial deployment is feasible.

In conclusion, unless breakthrough technologies emerge to address the technical barriers or more efficient production strategies are developed, hydrogen production from heavy oil reservoirs will likely remain an uncompetitive option. Future research should focus on innovative solutions to enhance hydrogen yields, reduce operational costs, and explore the integration of renewable energy sources or government incentives to support the commercialization of this process.

Supplementary Materials: The following supporting information can be downloaded at: <https://www.mdpi.com/article/10.3390/en18205539/s1>. References [11,12,24,26,41,42,59–61,95] are cited in the Supplementary Materials.

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