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Techno-economic analysis of PV-based hydrogen production in Colombia: Policy perspectives on market competitiveness

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ABSTRACT

To support the development of Colombia's green hydrogen economy, this work analyzes the competitiveness of photovoltaic (PV)-electrolyzer systems. We contrast a direct-coupling system against a grid-connected configuration where PV energy is exported and hydrogen is produced via grid imports. We demonstrate that suboptimal sizing poses a critical risk to project viability, whereas proper system sizing—informed by stochastic modeling of solar and electricity prices—is essential to optimize operational efficiency and extract the maximum value from the investment. Case studies using data from Medellín reveal that green hydrogen requires a selling price of \$3.2/kg to create value; below this threshold, direct electricity sales offer superior returns. Furthermore, to align with the Colombia 2030 Hydrogen Roadmap—targeting 1–3 GW of capacity and 120 kt of demand—production costs must drop to \$1.7/kg. These findings provide a quantitative basis for policymakers to design effective incentives and for investors to strategize market entry.

1. Introduction

1.1. Background

A promising low-emission energy platform for decarbonizing a wide range of applications is green hydrogen (H_2) [1]. This has driven many nations to declare *green H_2 production* a key element of their long-term strategies [2].

The green premium of green hydrogen—defined as the extra cost relative to fossil-based hydrogen—is a key factor that must be minimized for this clean energy platform to become a reality. This cost gap depends not only on the level of carbon emission constraints, but also on the competitiveness and sustainability of low-carbon hydrogen business models.

The key drivers of these H_2-based business models (BM) are reduction in electrolyzer costs, improvements in their efficiency, and decline in electricity prices, as highlighted by Reichelstein [3]. A full description of the concept of business model (BM) was provided by Shafer et al. [4].

Another important logic for building H_2-based BMs is the synergies that emerge within a hybrid system. These synergies result from the strategic operation of the different technologies. As Glenk and Reichelstein [5] demonstrate, such synergies can yield total benefits that exceed the sum of the individual subsystems.

Synergies in hybrid systems are more common in multi-energy systems combining electricity, hydrogen, natural gas, and thermal needs. As illustrated by Kurtz et al. [6], Glenk and Reichelstein [7], El-Taweel et al. [8], and Abomazid et al. [9], more sustainable H_2-based BMs can obtain revenues not only from electricity but also from hydrogen sales.

Evaluating the attractiveness of an H_2-based BM for the private sector requires financial analysis. For simpler BMs, where cash flows are highly predictable, it is common to use a set of financial metrics. For more complex BMs, where many technologies integrate the energy system and various sources of uncertainty are present, it is essential to model short-term operational aspects in detail to robustly assess long-term economic viability.

Maximizing the value of H_2-based BMs primarily requires effective energy management. It addresses challenges such as sizing components, meeting electrical and hydrogen demands, capturing operational interconnections among components, and developing an optimal operational strategy [10]. The most appropriate strategy will upon depend on the components, energy resources and its availability, and the hydrogen

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Nomenclature

τ	Year index.
t	Time period expressed in 15-minute intervals.
α	Governmental tax rate (%).
β	Total investment tax allowance (%).
η_e	Efficiency of the electrolyzer system (kWh/kg).
η_h	Conversion rate of the electrolyzer (kg/kWh).
γ	Discount factor, defined as $\gamma = \frac{1}{1+r}$ (dimensionless).
$\mathbb{E}\,\tilde{C}_\tau(\phi)$	Expected annual operation and maintenance cost (MM$/yr).
$\mathbb{E}\,\tilde{P}_\tau$	Expected annual operating profits (MM$/yr).
$\mathbb{E}\,\tilde{q}_{t,\tau}$	Expected hydrogen production per period t in year τ (ton/15-minute period).
$\mathbb{E}\,\tilde{Z}_\tau$	Expected annual income tax cost (MM$/yr).
$\mathbb{E}\left[\tilde{T}^{\text{on}}_\tau(\phi)\right]$	Expected annual on-production time (hr/yr).
ϕ	Ratio of the electrolyzer capacity to the solar system capacity, defined as $\phi = k_h/k_{pv}$ (MW/MW).
π^h_τ	Fixed hydrogen price ($/kg).
ρ	Minimum operational fraction of the electrolyzer's nominal capacity required for hydrogen production (%).
ρ_0	Fraction of the electrolyzer's nominal capacity required to power the electrolyzer during the standby state (%).
$\text{Cov}(\tilde{\pi}^e_{t,\tau}, \tilde{v}^{pv}_t)$	Covariance term between the market price of electricity and normalized solar PV power ($/MWh).
PV^h_τ	Production value of hydrogen in year τ ($/MWh).
θ	Polynomial coefficients of the normalized solar power PDF.
$\tilde{v}^{pv}_t$	Normalized solar PV power at time t, calculated as $\tilde{p}^{pv}_t/k_{pv}$ (MW/MW).
$\tilde{\pi}^e_{t,\tau}$	Market price of electricity ($/MWh).
$\tilde{e}^{sal}_{t,\tau}$	Electricity sold to the grid during period t in year τ (MWh).
$\tilde{e}_{t,\tau}$	Electricity sold to the grid during period t in year τ (MWh).
$\tilde{e}^{SB}_{t,\tau}$	Stand-by electricity consumed by the electrolyzer during periods of low solar power production (MWh).
$\tilde{p}^{pv}_t$	Solar power output at time t (MW).
c^r_h	Hourly replacement cost of the electrolyzer, $c^r_h = I_h/h^{\text{life}}$ (MM$/MW-hr).
C^0_t	Fixed costs associated with the photovoltaic solar PV system and the electrolyzer system in period t (MM$/yr).
D_τ	Total deductions, defined as $D_\tau = I\left(d_\tau + i_\tau\right)$ (MM$/yr).
d_τ	Annual depreciation rate (%).
$f_v(v;\theta)$	Polynomial Probability Density Function (PDF) for solar power (dimensionless).
$F^e_v\left(v_i\right)$	Empirical cumulative distribution function (CDF) for the normalized solar power (dimensionless).
$f_{h,t}$	Fixed operation and maintenance cost of the electrolyzer system (MM$/MW-yr).
$f_{pv,t}$	Annual fixed costs of the photovoltaic system ($/kW-yr).
f_h	Annual fixed costs of the electrolyzer system ($/kW-yr).
h^{life}	Operational lifetime of the electrolyzers (hr).
I	Total investment cost (MM$).
I_{pv}	Investment cost of the solar photovoltaic system (MM$/MW).
i_τ	Annual portion of the total investment tax allowance (%).
k_h	Installed capacity of the electrolyzer (MW).
k_{pv}	Installed solar power capacity (MW).
w_h	Variable cost for purified water and chemical inputs for the electrolyzer system ($/ton).
x^h_τ	Degradation state of the electrolyzer (%).
x^{pv}_τ	Degradation state of the solar PV system (%).

demand to be met. The demand, which is seen as the amount of hydrogen mass to be delivered over a specified period of time, can significantly impact the economics of the BM.

Achieving Colombia's ambitious hydrogen targets—which aim to establish a sustainable low-carbon hydrogen economy by 2030, with 1 to 3 GW of electrolysis, 120 kt of low-carbon hydrogen demand, 1000 to 1500 heavy fuel-cell vehicles, 50 to 100 public hydrogen stations and a hydrogen production cost of $1.7/kg [11]—will require more than technological and economic progress; it will also depend on favorable financial and regulatory conditions such as the discount rate and government incentives. In this context, beyond quantitative analysis, our goal in proposing and evaluating solar-based H_2 production BMs is to identify the full range of factors that can ensure their long-term sustainability in Colombia.

1.2. Aim and literature review

There are multiple H_2-based BMs. The simplest involves a power-to-gas facility—where the investor owns only the electrolyzer system—powered by the electrical grid or a renewable energy plant exclusively dedicated to H_2 production [12–14]. When powered by the grid, the system will produce hydrogen if the revenue from selling hydrogen exceeds the cost of purchasing electricity from the grid [14]. In contrast, when powered by a renewable energy plant, H_2 production follows the renewable energy generation pattern.

Other approaches integrate renewable electricity not only for H_2 production but also for selling it to the electrical grid. One of the most remarkable works was Glenk and Reichelstein [7], which evaluated the economics of a green hydrogen system that includes a wind farm. They concluded that renewable hydrogen for industrial use is expected to be competitive in 2029 if current trends persist.

There are also other BMs that build on the previous approach by incorporating grid electricity for hydrogen production. This improves flexibility and viability at the cost of higher emissions. For example, Glenk and Reichelstein [5] demonstrated the existence of a synergistic investment value in a vertically integrated energy system that produces both electricity and hydrogen. Furthermore, Hurtubia and Sauma [15] showed that minimal use of grid electricity significantly increases the H_2 production load factor under low CO_2 tax penalties. In addition, Minutillo et al. [16] identified the optimal mix of grid and solar electricity to operate electrolysis units at hydrogen refueling stations.

The economic analysis of H_2-based BMs requires the use of key financial metrics. Among these is the Net Present Value (NPV), which discounts all project cash flows to their present value using a discount rate. Another important metric is the Levelized Cost of H_2 production (LCOH), which represents the minimum price an investor would require to sell a kilogram of H_2, ensuring that all costs are covered and a sufficient return is achieved.

The literature on the hydrogen economy has mainly evaluated simple BMs using the LCOH metric. Dozens of papers, including Sadeghi et al. [17], Benalcazar and Komorowska [18], Vartiainen et al. [19], and Burdack et al. [20], project that green H_2 production will reach competitive LCOH with fossil-based alternatives by 2050, especially in many regions and sectors around the world.

The LCOH falls short in assessing the economic viability of hybrid systems and more advanced BMs. This limitation arises from how the LCOH is calculated, equating the PV-electrolyzer system's NPV to zero rather than to the pre-established positive NPV of the solar PV project alone. As a result, it does not represent the minimum hydrogen price required to create value for the PV project. Furthermore, it is not robust, as it reflects only a single price scenario.

Since our goal in evaluating solar-based H_2 BMs is to identify the factors that ensure their long-term sustainability in Colombia, the mentioned LCOH limitations motivate the exploration of alternative economic metrics that are better suited for advanced BMs in conjunction with a stochastic sizing criterion. The assessment is conducted over two H_2-based BMs using hybrid solar PV-electrolyzer systems. In the first, the PV plant supplies electricity directly to the electrolyzer, while in the second, all the PV output is exported to the grid and H_2 is produced by importing power from it when electricity prices are relatively low.

To identify the required factors that ensure the long-term sustainability of these BMs, their corresponding probabilistic financial models were developed. They incorporate local uncertainties in solar PV generation and fluctuations in electricity prices to account for dynamic market conditions and ensure robust investment and operational decisions. Building on this framework, this work maximizes the expected NPV by properly sizing both the PV system and the electrolyzer. Ultimately, this comprehensive stochastic techno-economic analysis serves as a better-suited approach to assess the long-term sustainability of hydrogen BMs involving hybrid systems.

1.3. Contributions and paper organization

To the best of our knowledge, current economic literature largely overlooks the probabilistic nature of strategic solar-based hydrogen production under continuously changing conditions. This highlights the necessity to properly size the hybrid system according to the BM operations and rigorously model key uncertainties, such as solar PV availability and electricity prices, as they fundamentally dictate system economics. To address these gaps, this work provides the following contributions:

- Developing a robust stochastic framework that captures the high-resolution volatility of solar PV generation and electricity prices using highly granular real data.
- Formulating and comprehensively evaluating two hybrid solar-hydrogen BMs. Essentially, this evaluation relies on the sizing of the hybrid system—introducing a key degree of freedom to maximize the efficiency of initial investments and accurately determine the true economic value of the BMs under probabilistic conditions.
- Delineation of the technical, economic, and policy factors required to ensure the competitiveness and sustainability of low-carbon hydrogen BMs in Colombia.

This paper is organized as follows. Section 2 develops the cash-flow model for the proposed H_2-based BMs. Section 3 reports numerical results, and Section 4.1 compares the BMs. Section 4.2 presents a sensitivity analysis for electricity prices, and Section 4.3 reviews incentives that can be relevant to the proposed BMs. Section 4.4 explores the pathways to meet Colombia's 2030 hydrogen target, and Section 5.1 concludes.

2. Proposed H_2 -based business models (BMs)

This section illustrates the general approach focused on the economic analysis of two BMs affected by uncertainty. Fig. 1 shows the general architecture of both BMs. In both cases, project developers capture uncertain revenues from hydrogen and electricity sales. One of the BMs consists of a PV-electrolyzer system where solar energy directly powers the electrolyzer to produce hydrogen; excess PV generation is sold in the power market, and grid power is only required to maintain the electrolyzer in stand-by mode. In the second BM, all PV power is injected into the grid and hydrogen is strategically produced using imported electricity.

The differences between direct-coupling and grid-connected systems are governed by the technical constraints of electrolyzer operation. In the GIPES model, the direct-coupling architecture exposes the electrolyzer to high solar variability, where technical limits—such as the minimum load threshold—force the system into frequent transitions between different operational states. This intermittent operation exposes the electrolyzer, in turn, to unstable thermal conditions, significantly accelerating stack degradation.

In contrast, the GDPES model mitigates these technical limitations by using the grid as a supporting system. By protecting production from instantaneous solar fluctuations, this configuration avoids the minimum load threshold and maintains a more stable thermal state, resulting in lower stack degradation.

Other technical constraints of electrolyzer operation not considered in this work include non-linear efficiency behavior, ramp-rate restrictions, and cold and warm start-up times, as the focus is placed on capturing their long-term system-level implications rather than short-term operational detail.

2.1. Grid independent PV-electrolyzer system

In this BM, a photovoltaic (PV) solar system directly powers the electrolyzer as shown in 1. The H_2 production—via water electrolysis—is then sold in a H_2 market. Additionally, excess of solar PV power is sold in the power market at a random price. Grid power is only required to maintain the electrolyzer in stand-by mode. For simplicity, we refer to this business model as GIPES ("Grid-independent PV-electrolyzer system"), as it is designed to be as independent of the grid as possible.

2.1.1. Operational modeling

To incorporate the operational aspects of the H_2 production process, a three-state model of the electrolyzer, as outlined in Baumhof et al. [21], is adapted. This implies modeling three operational states for the electrolyzer: *on*, *off*, and *stand-by*.

In this model, the operational state of the electrolyzer is determined by the solar PV power production. This production is computed as $\tilde{p}^{\text{pv}}_{t,\tau} = \tilde{v}_t\, k_{\text{pv}}\, x^{\text{pv}}_{\tau}$, where $\tilde{v}_t$ denotes the normalized solar PV power, defined as the ratio of solar PV power to the capacity k_{pv}, and x^{pv}_{τ} represents the solar PV system's annual degradation state.

Fig. 2 shows a typical daily pattern of the solar PV power production. The green area represents the electricity transferred to the electrolyzer when it operates in the *on* state. This state is possible only

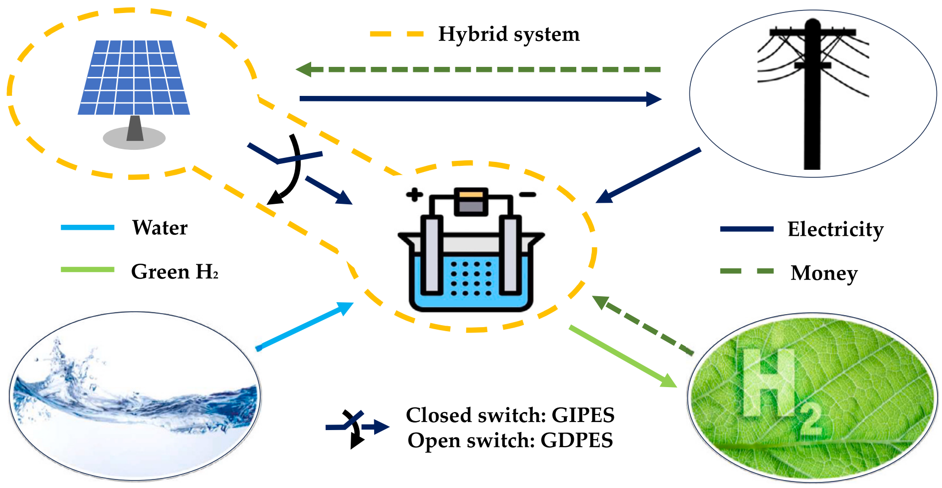


Fig. 1. Overview of our PV-based H_2 production BMs.

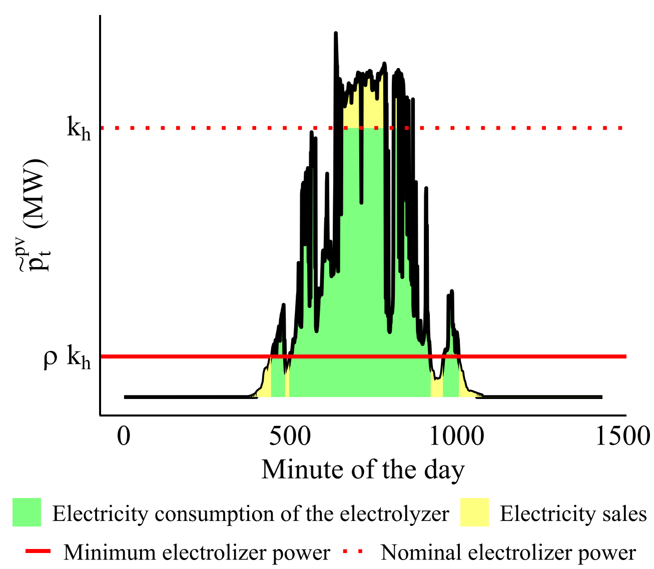


Fig. 2. Solar power management for H_2 production. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

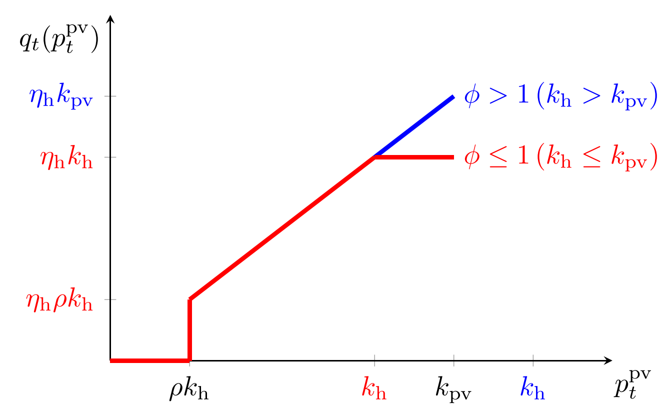


Fig. 3. H_2 production as a function of solar PV power.

when the solar PV power $\tilde{p}^{pv}_t$ exceeds a fraction $\rho \in [0.15, 0.20]$ of the electrolyzer's installed capacity k_h [22].

The yellow areas in Fig. 2 show the electricity exported to the grid. In cases where $\tilde{p}^{pv}_t < \rho k_h$, the electrolyzer does not produce hydrogen but absorbs a small fraction $\rho_0 \approx 0.04$ of its rated capacity to remain in the *stand-by* state [21]. During these periods, including those where $P^{pv}_t > k_h$, the solar PV power is sold to the market. Finally, in the *off* state, which occurs at night, no electricity is consumed.

2.1.2. Hydrogen production

The hydrogen production per period, denoted as $\tilde{q}_t(\phi)$, corresponds to the random amount (mass) of produced hydrogen. It is function of random solar PV power generation at time t, as illustrated in Fig. 3. When solar PV power allows the electrolyzer to be in the *on* state, hydrogen production increases linearly with the available solar PV power up to the electrolyzer's maximum capacity. Beyond this point, any surplus of solar PV power cannot be utilized by the electrolyzer. Since our purpose is to identify sound project sizing, we explicitly present this analysis in terms of $\phi = k_h/k_{pv}$. For each period (t,τ), hydrogen production is computed as:

$$\begin{aligned}\tilde{q}_{t,\tau}(\phi) &= \eta_h \min\left(\tilde{p}^{pv}_{t,\tau}, k_h\right) x^h_\tau \cdot \mathbf{1}_{\left\{\tilde{p}^{pv}_{t,\tau} \geq \rho\, k_h\right\}} \Delta t \\ &= \eta_h k_{pv} \min\left(\tilde{v}_t x^{pv}_\tau, \phi\right) x^h_\tau \cdot \mathbf{1}_{\left\{\tilde{v}_t \geq \rho\phi/x^{pv}_\tau\right\}} \Delta t. \end{aligned} \quad (1)$$

The green area shown in Fig. 2 represents the daily amount of H_2 production $\sum_{t\in D} \tilde{q}_{t,\tau}$.

2.1.3. Electricity sales

Available electricity to be sold, denoted as $\tilde{e}_{t,\tau}(\phi)$, corresponds to the electricity of period t in year τ. This energy is computed as the difference between solar PV production $\tilde{p}^{pv}_{t,\tau}\Delta t$ and electricity fed to the electrolyzer $\tilde{q}_{t,\tau}(\phi)\,\Delta t/\eta_h$ as indicated in Eq. (2):

$$\begin{aligned}\tilde{e}_{t,\tau}(\phi) &= \tilde{p}^{pv}_{t,\tau}\Delta t - \tilde{q}_{t,\tau}(\phi)\,\Delta t/\eta_h \\ &= k_{pv}\left(\tilde{v}_t x^{pv}_\tau - \min\left(\tilde{v}_t x^{pv}_\tau, \phi\right) x^h_\tau \cdot \mathbf{1}_{\left\{\tilde{v}_t \geq \rho\phi/x^{pv}_\tau\right\}}\right) \Delta t. \end{aligned} \quad (2)$$

The yellow area displayed in Fig. 2 represents the daily electricity sold $\sum_{t\in D} \tilde{e}_{t,\tau}$.

2.1.4. Stand-by electricity consumption

The SB electricity consumption of the electrolyzer during period t in year τ, denoted as $\tilde{e}^{SB}_{t,\tau}$, occurs during the *SB*-state. In this state, the electrolyzer needs a small power $\rho_0 k_h$ from the grid as represented in (3):

$$\tilde{e}^{SB}_{t,\tau}(\phi) = \rho_0\, \phi\, k_{pv} \cdot \mathbf{1}_{\left\{\tilde{v}^{pv}_t < \rho\phi/x^{pv}_\tau\right\}} \Delta t. \quad (3)$$

2.1.5. ON-state time

Time of use of the electrolyzer is important for analyzing the need for its replacement as it shall be presented in Section 2.1.8. Thus, we compute the number of hours per year in which the electrolyzer is actually producing hydrogen as in (4):

$$\begin{aligned}\mathbb{E}\left[\tilde{T}^{\text{on}}_{\tau}(\phi)\right] &= 365\sum_{t\in D}\mathbb{E}\cdot\mathbf{1}_{\left\{\tilde{p}^{\text{pv}}_{t,\tau}\geq\rho k_{\text{h}}\right\}}\Delta t,\ k_{\text{h}}>0\\ &= 365\sum_{t}\left(1-F_{v_t}\left(\rho\phi/x^{\text{pv}}_{\tau}\right)\right)\Delta t,\ \phi>0 \end{aligned}\tag{4}$$

where $F_{v_t}(\cdot)$ represents the CDF of the scaled solar PV production during period t. The expected time during ON-state $\mathbb{E}\left[T^{\text{on}}_{\tau}(\phi)\right]=0$ as long as $\phi=0$.

2.1.6. Expected revenues

Profits are the difference between total revenues and operation and maintenance costs according to the BM specifications. Let $\mathbb{E}\tilde{R}_{t,\tau}(\phi)=\mathbb{E}\left[\tilde{R}^{\text{h}}_{t,\tau}(\phi)+\tilde{R}^{\text{e}}_{t,\tau}(\phi)\right]$ be the expected revenues from hydrogen and electricity sales:

$$\begin{aligned}\mathbb{E}\tilde{R}_{t,\tau}(\phi) =&\mathbb{E}\left[\pi^{\text{h}}_{\tau}\,\tilde{q}_{t,\tau}(\phi)+\tilde{\pi}^{\text{e}}_{t,\tau}\,\tilde{e}_{t,\tau}(\phi)\right]\\ =&\pi^{\text{h}}_{\tau}\,\eta_{\text{h}}\,k_{\text{pv}}\,\mathbb{E}\left[\min\left(\tilde{v}_t x^{\text{pv}}_{\tau},\phi\right)\ x^{\text{h}}_{\tau}\cdot\mathbf{1}_{\left\{\tilde{v}_t\geq\rho\phi/x^{\text{pv}}_{\tau}\right\}}\right]\Delta t\\ &+k_{\text{pv}}\,\mathbb{E}\,\tilde{\pi}^{\text{e}}_{t,\tau}\left(\tilde{v}_t x^{\text{pv}}_{\tau}-\min\left(\tilde{v}_t x^{\text{pv}}_{\tau},\phi\right)\ x^{\text{h}}_{\tau}\right.\\ &\left.\cdot\mathbf{1}_{\left\{\tilde{v}_t\geq\rho\phi/x^{\text{pv}}_{\tau}\right\}}\right)\Delta t.\end{aligned}\tag{5}$$

The hydrogen revenue per period is computed as $\mathbb{E}\tilde{R}^{\text{h}}_{t,\tau}(\phi)=\pi^{\text{h}}_{\tau}\,\mathbb{E}\,\tilde{q}_{t,\tau}(\phi)$, where the expected H_2 production is computed as in (6):

$$\begin{aligned}\mathbb{E}\tilde{q}_{t,\tau}(\phi) &= \int_0^1 q_{t,\tau}f_{v_t}(v)\,dv\\ &= \eta_{\text{h}}k_{\text{pv}}x^{\text{h}}_{\tau}\Delta t\left[x^{\text{pv}}_{\tau}\int_{\rho\phi/x^{\text{pv}}_{\tau}}^{\min\left(\phi/x^{\text{pv}}_{\tau},1\right)} v\,f_{v_t}(v)\,dv\right.\\ &\left.+\int_{\min\left(\phi/x^{\text{pv}}_{\tau},1\right)}^{1}\phi\,f_{v_t}(v)\,dv\right]\end{aligned}\tag{6}$$

All the terms that require integrals and probabilities are computed through the estimated distributions of random solar PV power explained in Section 3.2.

On the other hand, the electricity revenue per period is $\mathbb{E}\left[\tilde{R}^{\text{e}}_{t,\tau}(\phi)\right]=\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\tilde{e}_{t,\tau}(\phi)\right]$, as presented in (7):

$$\begin{aligned}\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\tilde{e}_{t,\tau}(\phi)\right] =&k_{\text{pv}}\mathbb{E}\tilde{\pi}^{\text{e}}_{t,\tau}\left(\tilde{v}_t x^{\text{pv}}_{\tau}\right.\\ &\left.-\min\left(\tilde{v}_t x^{\text{pv}}_{\tau},\phi\right)\ x^{\text{h}}_{\tau}\cdot\mathbf{1}_{\left\{\tilde{v}_t\geq\rho\phi/x^{\text{pv}}_{\tau}\right\}}\right)\Delta t\\ =&k_{\text{pv}}\left(\tilde{\pi}^{\text{e}}_{t,\tau}\bar{v}_t+\operatorname{cov}\left(\tilde{\pi}^{\text{e}}_{t,\tau},\tilde{v}_t\right)\right.\\ &\left.-\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\min\left(\tilde{v}_t,\phi\right)\ x^{\text{h}}_{\tau}\cdot\mathbf{1}_{\left\{\tilde{v}_t\geq\rho\phi\right\}}\right]\right)\Delta t\end{aligned}\tag{7}$$

Since $\tilde{\pi}^{\text{e}}_{t,\tau}$ and $\tilde{e}_{t,\tau}$ are not necessarily independent random variables, we use the fact that $\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\ \tilde{v}_t\right]=\tilde{\pi}^{\text{e}}_{t,\tau}\bar{v}_t+\operatorname{cov}\left(\tilde{\pi}^{\text{e}}_{t,\tau},\tilde{v}_t\right)$. The terms $\operatorname{cov}\left(\tilde{\pi}^{\text{e}}_{t,\tau},\tilde{v}_t\right)$ and $\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\ \tilde{q}_{t,\tau}\right]$ are computed using extensive empirical available data as shown in Section 3.2.

In this way, the expected total annual revenue of the BM is represented as $R_{\tau}=365\sum_{t\in D_{\tau}}\mathbb{E}\tilde{R}_{t,\tau}$.

2.1.7. Investment costs

The initial investments in both the solar PV project and the hydrogen project should be considered as in (8):

$$I(\phi)=\left(I_{\text{h}}\,\phi+I_{\text{pv}}\right)k_{\text{pv}}.\tag{8}$$

2.1.8. Operational costs

Annual operational expenses include maintenance of the solar PV facility and the electrolyzer, purchases of stand-by electricity, and water and replacement costs. The total operational costs are presented in Eq. (9):

$$\begin{aligned}\mathbb{E}\tilde{C}_{\tau}(\phi) =&c^{\text{OM}}_{\text{pv}}k_{\text{pv}}+c^{\text{OM}}_{\text{h}}k_{\text{h}}+365\,\mathbb{E}\left[\sum_{t\in D}\tilde{\pi}^{\text{e}}_{t,\tau}\tilde{e}^{\text{SB}}_{t,\tau}\right]\\ &+365\,\mathbb{E}\sum_{t\in D}\pi^{\text{w}}_{\tau}\eta_{\text{w}}\tilde{q}_{t,\tau}(\phi)+\phi k_{\text{pv}}c^{\text{r}}_{\text{h}}\mathbb{E}\left[\tilde{T}^{\text{on}}_{\tau}(\phi)\right]\\ =&\left(c^{\text{OM}}_{\text{pv}}k_{\text{pv}}+c^{\text{OM}}_{\text{h}}\phi\right)k_{\text{pv}}\\ &+365\,\rho_0\phi k_{\text{pv}}\sum_{t\in D}\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\cdot\mathbf{1}_{\left(\tilde{v}_t<\rho\phi/x^{\text{pv}}_{\tau}\right)}\right]\Delta t\\ &+365\left(\pi^{\text{w}}_{t}\eta_{\text{w}}\sum_{t\in D}\mathbb{E}\tilde{q}_{t,\tau}+\right.\\ &\left.\phi k_{\text{pv}}c^{\text{r}}_{\text{h}}\sum_{t\in D}\left(1-F_{v_t}\left(\rho\phi/x^{\text{pv}}_{\tau}\right)\right)\Delta t\right)\end{aligned}\tag{9}$$

where $c^{\text{OM}}_{\text{pv}}$ and c^{OM}_{h} represent the annual fixed costs of the photovoltaic and electrolyzer systems. Stand-by electricity costs are computed as $\mathbb{E}\left[\tilde{\pi}^{\text{e}}_{t,\tau}\cdot\mathbf{1}_{\left(\tilde{v}_t<\rho\phi/x^{\text{pv}}_{\tau}\right)}\right]$ using empirical data. Water costs depend on π^{w}_{t} and water volume η_{w} to produce one unit of H_2 mass. The annual replacement cost equals the hourly cost, $c^{r}_{\text{h}}=I_{\text{h}}/h^{\text{life}}$, multiplied by the ON-state hours.

2.2. Grid dependent PV-electrolyzer system

In this BM, the solar PV system sells all of its electricity output to the grid, while the electrolyzer remains directly connected to the grid to ensure a steady electricity supply, as illustrated in Fig. 1. To make this BM attractive, hydrogen is produced when market conditions show selling H_2 is the profitable option for the hybrid project. From now on, we denote this business model as GDPES ("Grid-dependent PV-electrolyzer system"), as it is supported by the electrical grid.

2.2.1. Operational modeling

In the presence of an economic signal that justifies H_2 production in period t in year τ, the hydrogen generated is given by $\tilde{q}^{\text{h}}_{t,\tau}=\eta_{\text{h}}\,k_{\text{h}}\,\Delta t\,x^{\text{h}}_{\tau}$. Here, $k_{\text{h}}\Delta t$ denotes the electricity consumed by the electrolyzer from the grid, as it operates at full capacity when production is justified.

Whenever hydrogen is produced and sold, the corresponding revenue is calculated as $\pi^{\text{h}}_{\tau}\tilde{q}^{\text{h}}_{t,\tau}$, while the associated operational costs include electricity ($\tilde{\pi}^{\text{e}}_{t,\tau}k_{\text{h}}\Delta t$), water ($\pi^{\text{w}}_{\tau}\tilde{q}^{\text{w}}_{t,\tau}$), and electrolyzer replacement ($c^{\text{r}}_{\text{h}}k_{\text{h}}\Delta t$).

Specifically, the economic signal that justifies producing hydrogen depends on whether the revenue obtained from its sale is greater than or equal to the combined costs of electricity, water, and electrolyzer replacement, as reflected in Eq. (10):

$$\pi^{\text{h}}_{\tau}\tilde{q}^{\text{h}}_{t,\tau}-\tilde{\pi}^{\text{e}}_{t,\tau}\tilde{q}^{\text{h}}_{t,\tau}/\left(\eta_{\text{h}}\,x^{\text{h}}_{\tau}\right)-\pi^{\text{w}}_{\tau}\tilde{q}^{\text{h}}_{t}\eta_{\text{w}}-c^{\text{r}}_{\text{h}}\tilde{q}^{\text{h}}_{t,\tau}/\left(\eta_{\text{h}}\,x^{\text{h}}_{\tau}\right)\geq 0.\tag{10}$$

Since both the water cost and the replacement cost remain constant for each period t, the decision to produce hydrogen depends on whether the inequality (11) holds:

$$\text{PV}^{\text{h}}_{\tau}=\left(\pi^{\text{h}}_{\tau}-\pi^{\text{w}}_{\tau}\eta_{\text{w}}\right)\eta_{\text{h}}\,x^{\text{h}}_{\tau}-c^{\text{r}}_{\text{h}}\geq\tilde{\pi}^{\text{e}}_{t,\tau}.\tag{11}$$

The left-hand side of the inequality reflects the value of H_2 production in period t, denoted as $\text{PV}^{\text{h}}_{\tau}$ and expressed in \$/MWh. This value quantifies the gross profit from selling H_2 produced with 1 MWh of electricity, considering not only water costs but also electrolyzer replacement. In this way, the H_2 production policy is represented by Eq. (12):

$$\tilde{q}^{\mathrm{h}}_{t,\tau} = \eta_{\mathrm{h}}\, \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau} \cdot \mathbf{1}_{\left\{\mathrm{PV}^{\mathrm{h}}_{\tau} \geq \tilde{\pi}^{\mathrm{e}}_{t,\tau}\right\}}. \tag{12}$$

2.2.2. Expected revenues

At a given time t, the expected revenues come from electricity and hydrogen sales. Expected revenues from electricity, denoted by $\mathbb{E}\, R^{\tilde{\mathrm{e}}}_{t,\tau}$, are represented in Eq. (13):

$$\begin{aligned}\mathbb{E}\, \tilde{R}^{\mathrm{e}}_{t,\tau} &= \mathbb{E}\left[\tilde{\pi}^{\mathrm{e}}_{t,\tau}\, \tilde{\mathrm{e}}^{\mathrm{sal}}_{t,\tau}\right] = \mathbb{E}\left[\tilde{\pi}^{\mathrm{e}}_{t,\tau}\, \tilde{v}^{\mathrm{pv}}_{t}\, k_{\mathrm{pv}}\, x^{\mathrm{pv}}_{\tau}\, \Delta t\right] \\ &= k_{\mathrm{pv}}\, x^{\mathrm{pv}}_{\tau}\, \Delta t \left(\mathbb{E}\, \tilde{\pi}^{\mathrm{e}}_{t,\tau}\, \mathbb{E}\, \tilde{v}^{\mathrm{pv}}_{t} + \right. \\ &\qquad \left. \sigma_{\tilde{\pi}^{\mathrm{e}}_{t,\tau}}\, \sigma_{\tilde{v}^{\mathrm{pv}}_{t}}\, \mathrm{Corr}\left(\tilde{\pi}^{\mathrm{e}}_{t,\tau},\, \tilde{v}^{\mathrm{pv}}_{t}\right)\right).\end{aligned} \tag{13}$$

And expected revenues from hydrogen sales, denoted by $\mathbb{E}\, \tilde{R}^{\mathrm{h}}_{t,\tau}(\phi) = \mathbb{E}\left[\pi^{\mathrm{h}}_{\tau}\, \tilde{q}^{\mathrm{h}}_{t,\tau}\right]$, are presented in Eq. (14):

$$\mathbb{E}\, \tilde{R}^{\mathrm{h}}_{t,\tau}(\phi) = \eta_{\mathrm{h}}\, \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau}\, \mathbb{E}\left[\pi^{\mathrm{h}}_{t} \cdot \mathbf{1}_{\left\{\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \mathrm{PV}^{\mathrm{h}}_{\tau}\right\}}\right]. \tag{14}$$

2.2.3. Operational costs

The operational costs of this BM consist of the expected variable annual cost of the electrolyzer system in period t, $\mathbb{E}\left[\tilde{C}^{\mathrm{h}}_{t,\tau}(\phi)\right] = \mathbb{E}\left[\tilde{c}^{\mathrm{h}}_{t,\tau}\, \tilde{q}^{\mathrm{h}}_{t,\tau}\right]$, and the fixed annual cost of the entire hybrid system in the same period, denoted by $C^0_t(\phi)$. The former is computed as indicated in (15):

$$\begin{aligned}\mathbb{E}\, \tilde{C}^{\mathrm{h}}_{t,\tau}(\phi) &= \mathbb{E}\left[\left(\tilde{\pi}^{\mathrm{e}}_{t,\tau}/\eta_{\mathrm{h}} + \pi^{\mathrm{w}}_{t}\eta_{\mathrm{w}} + c^{\mathrm{r}}_{\mathrm{h}}/\eta_{\mathrm{h}}\right) \tilde{q}^{\mathrm{h}}_{t,\tau}\right] \\ &= \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau}\, \mathbb{E}\left[\left(\tilde{\pi}^{\mathrm{e}}_{t,\tau} + \eta_{\mathrm{h}}\left(\pi^{\mathrm{w}}_{t}\, \eta_{\mathrm{w}} + \right.\right.\right. \\ &\qquad \left.\left.\left. c^{\mathrm{r}}_{\mathrm{h}}/\eta_{\mathrm{h}}\right)\right) \cdot \mathbf{1}_{\left\{\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \mathrm{PV}^{\mathrm{h}}_{\tau}\right\}}\right] \\ &= \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau}\, \mathbb{E}\left[\tilde{\pi}^{\mathrm{e}}_{t,\tau} \cdot \mathbf{1}_{\left\{\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \mathrm{PV}^{\mathrm{h}}_{\tau}\right\}}\right] + \mathbb{E}\tilde{R}^{\mathrm{h}}_{t,\tau} \\ &\quad - \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau}\, \mathrm{PV}^{\mathrm{h}}_{\tau}\, \mathbb{P}\left(\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \max\left(\mathrm{PV}^{\mathrm{h}}_{\tau}, 0\right)\right).\end{aligned} \tag{15}$$

Meanwhile, $C^0_t(\phi)$ is computed as:

$$C^0_t(\phi) = \left(f_{\mathrm{pv},t} + f_{\mathrm{h},t}\, \phi\right) k_{\mathrm{pv}}. \tag{16}$$

2.2.4. Expected profits

The expected profits at time t in year τ, denoted by $\mathbb{E}\, \tilde{p}_{t,\tau}$, are calculated by subtracting the operational costs of the hybrid system from the total revenues obtained through electricity sales to the grid and hydrogen sales:

$$\begin{aligned}\mathbb{E}\, \tilde{p}_{t,\tau}(\phi) &= \mathbb{E}\, \tilde{R}^{\mathrm{e}}_{t,\tau} + \mathbb{E}\, \tilde{R}^{\mathrm{h}}_{t,\tau}(\phi) - \mathbb{E}\, \tilde{C}^{\mathrm{h}}_{t,\tau}(\phi) - C^0_t(\phi) \\ &= \phi\, k_{\mathrm{pv}}\, \Delta t\, x^{\mathrm{h}}_{\tau}\left(\mathrm{PV}^{\mathrm{h}}_{\tau}\, \mathbb{P}\left(\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \max\left(\mathrm{PV}^{\mathrm{h}}_{\tau}, 0\right)\right)\right. \\ &\quad \left. - \mathbb{E}\left[\tilde{\pi}^{\mathrm{e}}_{t,\tau} \cdot \mathbf{1}_{\left\{\tilde{\pi}^{\mathrm{e}}_{t,\tau} \leq \mathrm{PV}^{\mathrm{h}}_{\tau}\right\}}\right]\right) - C^0_t(\phi) + \mathbb{E}\, \tilde{R}^{\mathrm{e}}_{t,\tau}\end{aligned} \tag{17}$$

where $\mathbb{E}\, \tilde{P}_{\tau} = 365 \sum_{t \in D} \mathbb{E}\, \tilde{p}_{t,\tau}$. In this case, $\tilde{P}_{\tau}$ could substitute the difference between $\tilde{R}_{\tau}$ and $\tilde{C}_{\tau}$ within the NPV expression.

2.3. Financial valuation

NPV aggregates all discounted cash flows for investors and is widely recognized as a key tool for evaluating the financial performance of energy projects, including H_2 production. Typically, NPV incorporates annual revenues, initial investment costs, fixed and variable O&M expenses, and income taxes.

Income tax is particularly crucial, as it can determine whether a project is financially viable. In this work, it is calculated as the expected annual income tax, $\mathbb{E}[\tilde{Z}_{\tau}]$, defined as α times the difference between expected profits—expected revenues minus expected operating costs—and total tax deductions under the Colombian tax regime, including depreciation and the investment tax allowance (ITA).

For immature technologies, project viability often depends on tax incentives. In the United States, hydrogen with a carbon intensity below 0.45 kg CO_2e per kg H_2 may qualify for up to \$3/kg H_2 in tax credits [23]. In Colombia, green and blue hydrogen projects are eligible for a 50% investment tax deduction (ITA) [24].

The expected NPV, $\mathbb{E}\left[\mathrm{NPV}\left(\pi^{\mathrm{h}}, \phi\right)\right]$, for an investor operating a H_2-based BM can be calculated as presented in (18):

$$\begin{aligned}\mathbb{E}\left[\mathrm{NPV}\left(\pi^{\mathrm{h}}, \phi\right)\right] &= \mathbb{E}\left[-I + \sum_{\tau}\left(\tilde{P}_{\tau} - \tilde{Z}_{\tau}\right)\gamma^{\tau}\right] \\ &= -I + \sum_{\tau}\left(\mathbb{E}\, \tilde{P}_{\tau} - \alpha\left(\mathbb{E}\, \tilde{P}_{\tau} - D_{\tau}\right)\right)\gamma^{\tau} \\ &= -I + \sum_{\tau} D_{\tau}\, \gamma^{\tau} + \\ &\qquad (1-\alpha)\sum_{\tau}\left(\mathbb{E}\, \tilde{P}_{\tau} - D_{\tau}\right)\gamma^{\tau}.\end{aligned} \tag{18}$$

Once the expected NPV is expressed in Eq. (18), LCOH can be directly obtained by finding the hydrogen price π^{h}_{τ} that makes the NPV of the hybrid system zero, as indicated in Eq. (19):

$$\mathrm{LCOH}(\phi) = \left\{\pi^{\mathrm{h}} :\ \mathrm{NPV}\left(\pi^{\mathrm{h}}, \phi\right) = 0\right\} \tag{19}$$

Another important metric is the Break-Even Hydrogen Price (BEHP). According to Glenk and Reichelstein [7], it can be determined by equating the NPV of the hybrid system to the maximum of zero and the NPV of the solar PV project alone, as described in Eq. (20):

$$\mathrm{BEHP}(\phi) = \left\{\pi^{\mathrm{h}} :\ \mathrm{NPV}\left(\pi^{\mathrm{h}}, \phi\right) = \max\left(0, \mathrm{NPV}\left(\pi^{\mathrm{h}}, 0\right)\right)\right\}. \tag{20}$$

In practice, BEHP is the hydrogen price that preserves a pre-established positive NPV for the solar PV project alone. In other words, it is the price that neither increases nor reduces the original value of the solar PV project when integrated with hydrogen production. For this reason, it represents the minimum hydrogen price required to create value for the PV project.

3. Numerical results

3.1. Main inputs

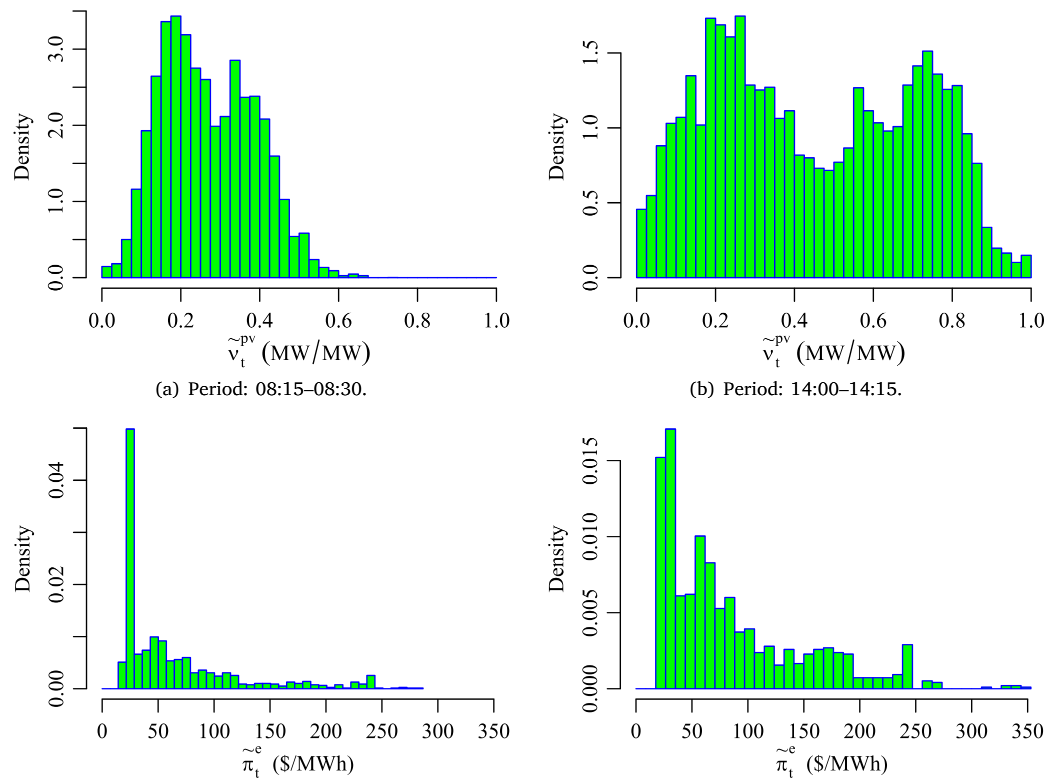
This section describes data sources and assumptions. The investment cost of the solar PV system, I_{pv}, was set at MM\$ 0.758/MW, based on data from [25]. Fixed O&M cost is \$10/kW-yr as suggested in [26], and a degradation rate of 0.05% as suggested by Jordan and Kurtz [27].

Electrolyzer parameters are presented in Table 1. Data for the ALK, PEM, and SOC electrolyzers were obtained from Glenk et al. [14], under the industry target scenario, while AEM-related information was taken from Enapter [28]. These values were adjusted to 2025 dollars using U.S. inflation rates from 2021–2024. Specifically, h^{life} values were taken from CAFT [29]. Tax parameters include a 33% tax rate α, a 50% ITA β claimed over the first five years in annual 10% portions i_{τ}, and a 33.33% depreciation rate d_{τ} over the first three years, as indicated in CRC [24]. The discount rate r is set at 10%, as specified in Glenk and Reichelstein [7], and the project horizon H is assumed to be 25 years.

3.2. Uncertain parameters

Both solar PV power and market electricity prices are analyzed as random variables whose distributions are estimated from historical real data.

For solar PV production, we use one-minute power measurements from a system at the University of Antioquia (2021 and 2023). A typical



(a) Period: 08:15–08:30.
(b) Period: 14:00–14:15.
(c) Period: 00:00–01:00.
(d) Period: 19:00–20:00.

Fig. 4. Two empirical PDFs for normalized solar PV power and two for electricity price.

Table 1
Parameters for each type of electrolyzer (in 2025 dollars).

Parameter	ALK	PEM	SOC	AEM	Units
I_{h}	705	712	1214	727	$/kW
f_{h}	7	9	12	9	$/kW-yr
w_{h}	5.0	5.0	112.0	19.3	$/ton
η_{e}	50.38	52.07	38.61	53.39	kWh/kg
h^{life}	80 000	70 000	40 000	40 000	hr

daily production profile was characterized using 15-minute periods. Since this work establishes a realistic baseline for the techno-economic evaluation, this techno-economic analysis reflects the hybrid system performance under historically price variability rather than predictive scenarios. Local hourly market prices were obtained from XM [30]. Data from 2021 to 2023 were indexed to December 2023 USD using the Producer Price Index (PPI).

Fig. 4 shows two empirical PDFs for normalized solar PV power $\tilde{v}_t^{\mathrm{pv}}$ for periods 08:15–08:30 and 14:00–14:15, and two for the price of electricity $\tilde{\pi}_{t,\tau}^{\mathrm{e}}$ for periods 00:00–01:00 and 19:00–20:00.

To clarify the system's operational design, the sizing of the PV-electrolyzer setup is explicitly evaluated due to its critical role in techno-economic performance. Instead of assuming deterministic inputs and an absolute capacity, our approach determines the optimal relative sizing parameter, ϕ. This method accounts for how stochastic variables—namely, solar availability and electricity prices—propagate through the hourly model. These uncertainties dynamically alter hydrogen production, shifting the thresholds for economic viability, LCOH and the break-even price. Consequently, this approach identify exactly which system configurations provide economic value, resulting in a robust design that achieves a positive expected NPV.

3.3. Results for the GIPES

NPV was calculated in R software for different combinations of ϕ, π_t^{h} and electrolyzer types (ALK, PEM, SOC, AEM). In these simulations, k_{pv} was fixed at 1 MW, k_{h} varied between 0 and 2 MW, and π_t^{h} was evaluated in the range $0–$14/kg for all $t = 1, \dots, H$.

At $\phi = 0.987$, H_2 production reaches its maximum regardless of the electrolyzer type. This configuration also maximizes the green operating region in Fig. 2. In particular, the ALK electrolyzer achieves the highest production as a result of its superior efficiency.

Maximizing H_2 production is equivalent to minimizing electricity sales. Higher hydrogen output demands greater electricity input for the electrolyzer, leading to a decrease in salable power, as explained by Eq. (2). As ϕ increases, the solar PV power supply is less likely to exceed the start-up threshold $\rho\, k_{\mathrm{h}}$. Thus, the electrolyzer tends to switch to stand-by mode more frequently and to increase stand-by energy consumption.

In contrast, the economically rational approach is to assess the NPV of the H_2-based BM, expressed in million dollars per MW of solar capacity. Fig. 5 shows that H_2 price defines a system size that maximizes NPV. As observed, if H_2 is to be sold at $4 per kg, the best decision is $\phi = 0$, i.e., only to construct a photovoltaic power plant. However, if it is sold at $10 per kg, the optimal size is $\phi = 0.61$, which indicates the H_2 production system adds value to the solar PV system.

The NPV was further analyzed in Fig. 6 as a function of hydrogen price and relative size. This analysis made it possible to identify the LCOH and the Break-Even Hydrogen Price (BEHP) of the hybrid system. As observed, three regions defined by LCOH and BEHP are identified: *(i)* yellow region, big electrolyzer sizes and relatively low hydrogen prices lead to negative hybrid system's NPV; *(ii)* orange region, although system's NPV is positive, hydrogen reduces the solar PV project's value given selling prices are not high enough; and *(iii)* green region, high prices guarantee hydrogen adds value to the system.

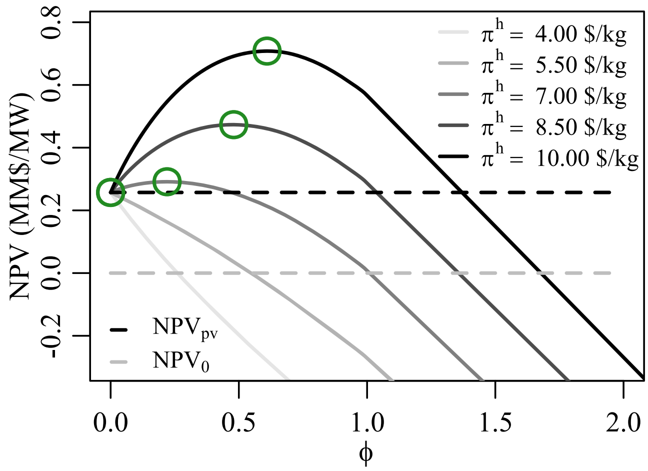


Fig. 5. NPV (expressed in MM$ per MW of solar capacity) as a function of ϕ for the GIPES with a PEM electrolyzer.

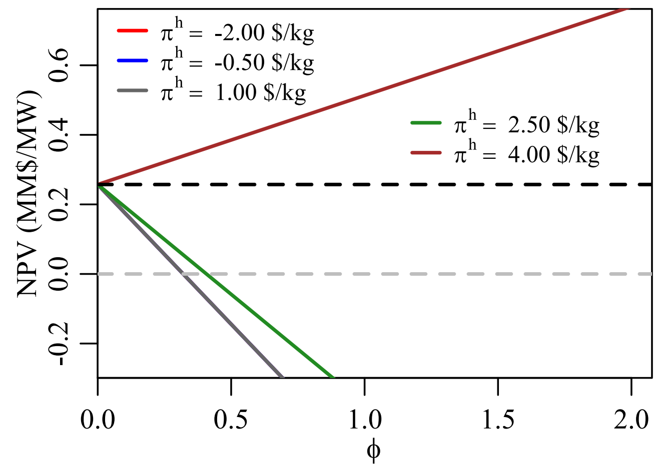


Fig. 7. NPV (expressed in MM$ per MW of solar capacity) as a function of ϕ for the GDPES with a SOC electrolyzer. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

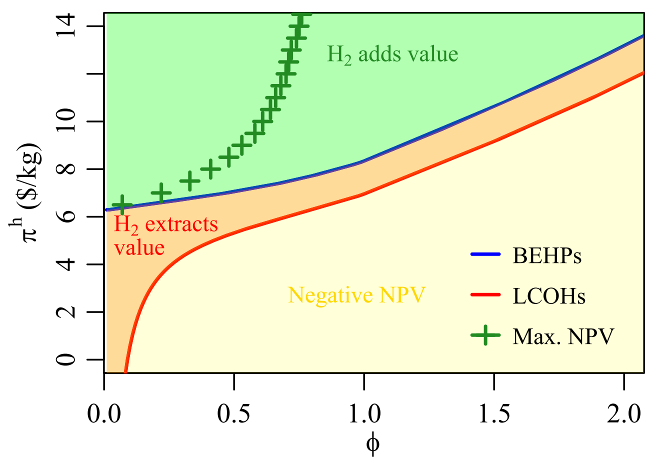


Fig. 6. Investment decision regions for the GIPES with a PEM electrolyzer. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

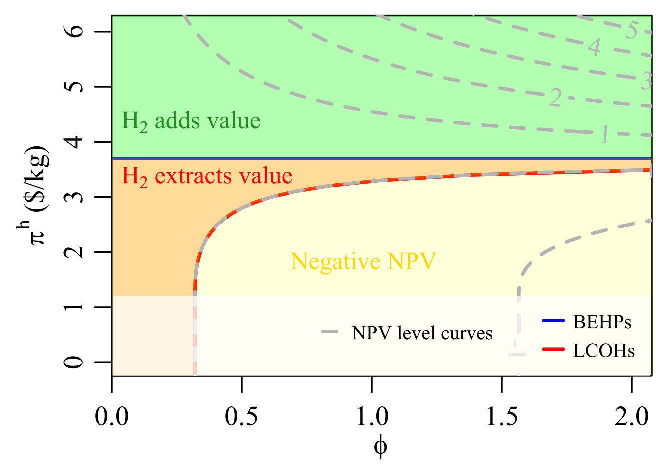


Fig. 8. Investment decision regions for GDPES with a SOC electrolyzer.

Green crosses, lying in the value-addition zone, highlight the optimal strategy path in terms of π^h_t and ϕ that maximizes NPV.

According to our results, LCOH can be even negative for extremely low-sized electrolyzers compared to the solar PV system, indicating the producer could even pay somebody for the consumption of H_2 production. However, it is worthwhile to consider the hydrogen system if it can be sold above the BEHP, which consistently remains above $6.29/kg. As electrolyzer size grows, both LCOH and BEHP must also rise due to a greater reliance on H_2 production for revenue.

3.4. Results for the GDPES

The expected NPV depends linearly on the capacity ratio, with a slope defined by the hydrogen price, as shown in Fig. 7. In that figure, the red, blue, and gray curves overlap. As the size ratio increases, the financial sustainability of this BM is highly dependent on hydrogen revenues. Thus, when prices are low, the NPV decreases with size and vice versa. In terms of optimal electrolyzer sizing, the strategy is to install the largest possible electrolyzer capacity if the price allows adding value to the hybrid system; otherwise, it is optimal to avoid H_2 production and only sell electricity.

Fig. 8 presents investment decision regions bounded by LCOH and BEHP. Sizes and prices lying in the green region indicate that hydrogen adds value to the system. Basically, this occurs if the price exceeds the BEHP, which is $3.7/kg. Low LCOH values can only be achieved when the electrolyzer capacity is relatively much smaller than that of the solar PV project. Gray-level curves represent NPV values in MM$/MW and shows high profitability as long as H_2 prices increase.

When H_2 price is less than $1.20/kg, the hydrogen production is zero, since there is no premium production to convert power to hydrogen. In this case $\mathbb{E}\left[\mathbf{1}_{\left\{\tilde{\pi}^e_{t,\tau} \leq PV^h_\tau\right\}}\right] = 0$. As a result, LCOH is not relevant in this situation.

For reference, BEHPs for ALK, PEM, and AEM are $3.0/kg, $3.2/kg, and $3.8/kg, respectively.

4. Discussion

Having presented the operational and financial base case results for both the GIPES and GDPES configurations, this section explores the broader implications of these results. The following discussion evaluates the comparative viability of the BMs, analyzes system sensitivity to fluctuating electricity prices, and identifies the specific policy incentives and 2030 target conditions required to foster a competitive low-carbon hydrogen market in Colombia.

4.1. Business model comparison

This comparison highlights how PV-electrolyzer systems sharing the same infrastructure, but governed by different business models, can lead to significantly different economic outcomes—even if the systems differ in sizing and technology selection and are therefore not directly comparable.

To support broader insights for policy makers in an evolving technological context, the business model comparison is first conducted under a technology-neutral framework with respect to electrolyzer selection and subsequently interpreted by considering electrolyzer–business model compatibility.

4.1.1. Technology-neutral business model comparison

After having taken into account technical aspects and rigorous market conditions, it has been observed that the GDPES configuration is the most financially efficient option. Its ability to operate even at night, due to electricity imports from the grid, when production value $PV_\tau > 0$ yields a higher expected H_2 production and NPV than the grid-independent BM. This applies for any combination of the electrolyzer size and H_2 price. For a hybrid system consisting of a 1 MW solar PV plant and a PEM electrolyzer sized at $\phi = 0.22$ (220 kW), selling hydrogen at $\pi^{\mathrm{h}}_\tau = \$7$/kg, the GIPES produces only 14.0 ton/yr, while the GDPES yields 31.5 ton/yr (i.e., 2.25× the PV-electrolyzer output). In terms of NPV, the GDPES reaches MM\$ 0.83 compared to MM\$0.29 for the GIPES (2.86×).

Although the LCOH in both BMs increases with electrolyzer size, the LCOH of the GDPES remains significantly lower. This suggests that, if environmental constraints are met, the competitiveness of the GDPES can be achieved more rapidly. From an economic perspective, the BEHP remains nearly constant with electrolyzer sizing in the GDPES, providing a clear and stable valuation of the business model. In contrast, in the GIPES, the BEHP varies with system configuration, requiring accurate estimates of all relevant parameters to determine whether the electrolyzer adds value to the PV system.

From a technical perspective, grid-connected PV-electrolyzer systems are more easily implementable. Unlike directly coupled systems, the case of our GIPES configuration, which are more suitable for remote areas, they do not require managing state transitions or using back-up power to maintain the intended operational policy. Another technical assumption for both models is that hydrogen demand is fixed; therefore, hydrogen is produced whenever technical conditions allow or market opportunities arise.

If all technologies are assumed to be compatible with the business model, the choice of electrolyzer mainly depends on business model performance. For the GIPES, although SOC investment cost is high, its higher efficiency makes it attractive for small electrolyzers; whereas ALK is appropriate for larger sizes because of its lower replacement cost (see Fig. 9). For the GDPES, ALK is preferred below \$5/kg, with SOC preferred otherwise (see Fig. 10). This is explained by the highest efficiency of SOC and the lowest replacement cost of ALK. In both figures, SOC is recommended in the gray regions and ALK in the red regions.

Another important aspect is that the GDPES may involve net emissions when electricity imports from the grid exceed PV exports. To address this, total expected net emissions over the analysis horizon $\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{net}}_{\mathrm{life}}$ are computed from the difference between hourly emissions resulting from grid electricity consumption $\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{imp}}_{hr,\tau}$ and those avoided through PV electricity exports $\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{avoid}}_{hr,\tau}$, based on the emission balance methodology proposed in Good et al. [31], as follows:

$$\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{net}}_{\mathrm{life}} \approx 365\,\mathcal{T} \sum_{hr\in D} \left(\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{imp}}_{hr,\tau} - \mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{avoid}}_{hr,\tau} \right)$$
$$\approx 365\,\mathcal{T} \sum_{hr\in D} \left(\mathbb{E}\left[\widetilde{FE}_{hr,\tau}\,\tilde{e}^{\mathrm{imp}}_{hr,\tau}\right] - \mathbb{E}\left[\widetilde{FE}_{hr,\tau}\,\tilde{e}^{\mathrm{sal}}_{hr,\tau}\right] \right) \tag{21}$$

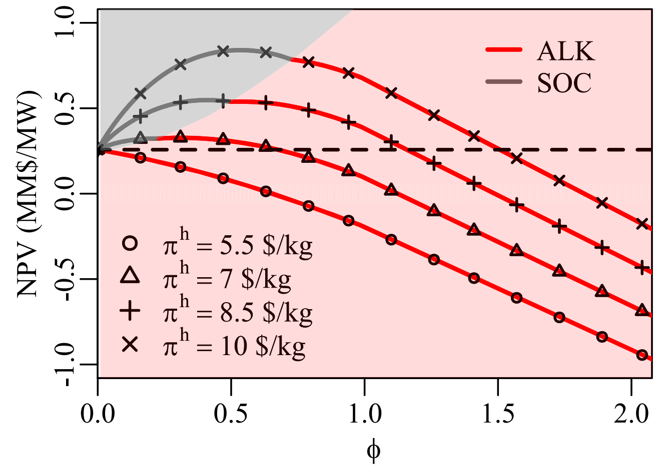


Fig. 9. Optimal electrolyzer technology regions for the GIPES (red: ALK, gray: SOC). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

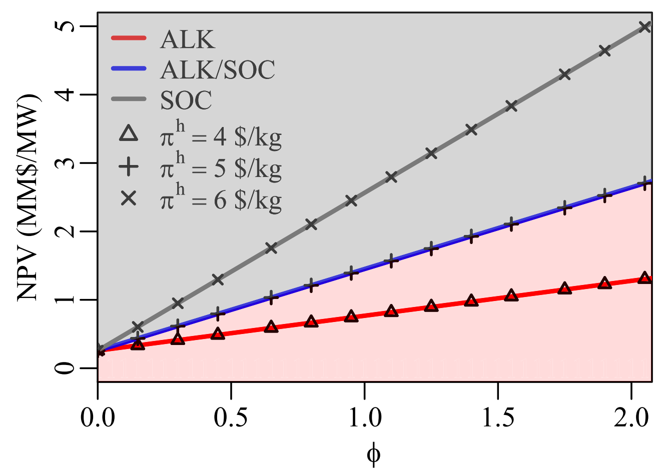


Fig. 10. Optimal electrolyzer technology regions for the GDPES (red: ALK, gray: SOC). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

By assuming weak correlation between the expected grid emission factor $\mathbb{E}\,\widetilde{FE}_{hr,\tau}$ (ton CO_2e/MWh)—obtained from the XM API [32] on an hourly basis for 2022–2023, and the expected electricity imports $\mathbb{E}\,\tilde{e}^{\mathrm{imp}}_{hr,\tau}$ and exports (sales) $\mathbb{E}\,\tilde{e}^{\mathrm{sal}}_{hr,\tau}$ (MWh), the expectation of the product is approximated as the product of expectations, as follows:

$$\mathbb{E}\,\tilde{\mathcal{E}}^{\mathrm{net}}_{\mathrm{life}} \approx 365\,\mathcal{T} \sum_{hr\in D} \left(\mathbb{E}\,\widetilde{FE}_{hr,\tau}\,\mathbb{E}\,\tilde{e}^{\mathrm{imp}}_{hr,\tau} - \mathbb{E}\,\widetilde{FE}_{hr,\tau}\,\mathbb{E}\,\tilde{e}^{\mathrm{sal}}_{hr,\tau} \right) \tag{22}$$

Fig. 11 shows the expected daily profiles of the grid emission factor, net emissions, and emissions avoided from PV exports. The integral of the net emissions curve represents the cumulative emissions over the day; this daily balance extrapolates over the analysis horizon, revealing $\phi = 0.9$ as the carbon neutrality threshold for the GDPES.

At this threshold, total expected grid emissions are exactly offset by total expected avoided emissions from PV exports. Thus, for $\phi > 0.9$, grid electricity consumption exceeds PV exports, resulting in net positive emissions. In contrast, for $\phi < 0.9$, PV exports exceed grid electricity consumption, leading to avoided emissions exceeding those produced.

4.1.2. Electrolyzer–business model compatibility

The choice of electrolyzer depends not only on business model performance but also on its compatibility with the system technologies.

Table 2
Compatibility matrix for electrolyzer technologies using a qualitative scale from very high to very low.

Compatibility with	ALK	PEM	SOC	AEM
intermittent renewables	Medium	Very high	Very low	High
continuous operation	Very high	High	Very high	High
industrial heat integration	Low	Low	Very high	Low
compact designs	Low	High	Medium	High
hydrogen purity	Medium	Very high	High	Very high
compression required	Low	Very high	Very low	High
specific applications	Industrial base-load	Renewable-flexible systems	External-heat integrated process	Decentralized modular systems

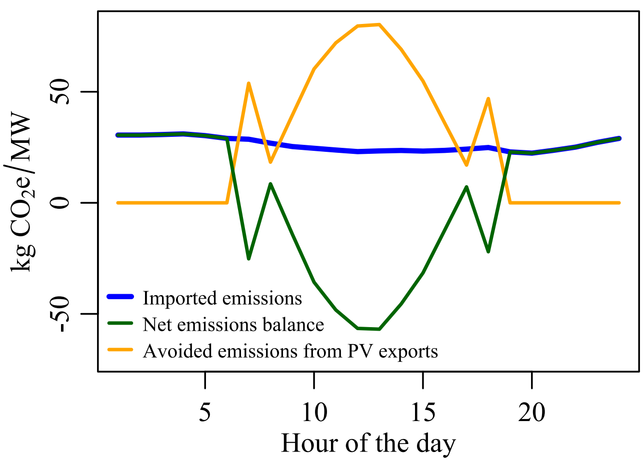


Fig. 11. Hourly profiles of imported, avoided, and net emissions for GDPES at $\phi = 0.9$.

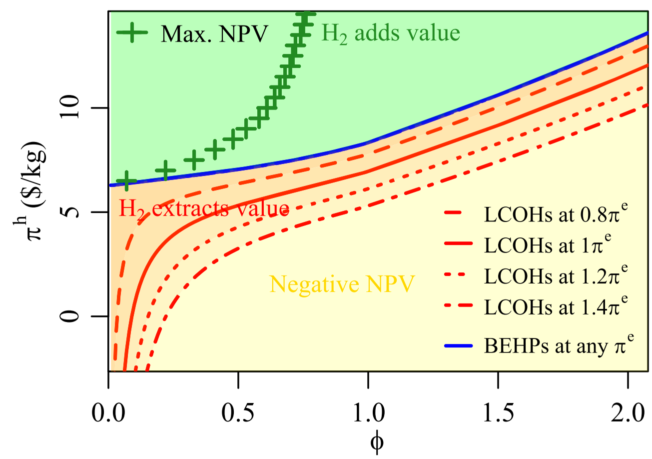


Fig. 12. Sensitivity analysis of electricity prices for the GIPES with a PEM electrolyzer.

Table 2 qualitatively summarizes the compatibility of the considered electrolyzer technologies with relevant system requirements. The data for this comparison were obtained from CAFT [29] and Power H2 [33].

The first three compatibility requirements in the table reflect how well each electrolyzer technology aligns with the GIPES and GDPES business models. Regarding compact design, compatibility depends on the available installation space, which is often limited in space-constrained sites, such as microgrids and behind-the-meter applications. Finally, hydrogen purity and compression requirements are of secondary importance, with their relevance depending on the specific application.

As observed in Table 2, the PEM electrolyzer is the only technology compatible with both business models, due to its high operational flexibility, fast response, and efficient performance under both intermittent renewable operation and price-driven (production value-based) strategies; similarly, the AEM electrolyzer shows promising PEM-like behavior, with strong potential for GIPES due to its high flexibility and modular integration with renewable energy systems, while its compatibility with GDPES remains conditional on improvements in durability and scalability.

In contrast, the ALK electrolyzer shows greater compatibility with GDPES than with GIPES due to its limited flexibility under intermittent renewable operation, but sufficient flexibility to respond to price-based (production value-driven) strategies; the SOC electrolyzer is even more restrictive, showing very low compatibility with GIPES and only conditional compatibility with GDPES, as it requires continuous operation under low electricity prices to sustain positive production value most of the time, as well as high-temperature conditions.

4.2. Sensitivity analysis for electricity prices

Expected electricity market prices have been adjusted by -20%, 20%, and 40% to analyze their impact on NPV. In the case of the GIPES, the BEHPs frontier remains unchanged, as shown in Fig. 12. Although electricity prices π^e do not affect H_2 production, they do influence the hybrid system's NPV. This is due to PV electricity exchanges with the local grid—exports when the electrolyzer cannot absorb the available electricity, and imports when the electrolyzer is in stand-by. To understand this effect, consider the NPV of the PV system (i.e., at $\phi = 0$). As π^e decreases, the NPV also decreases, reaching zero slightly below $0.8\,\pi^e$, as shown in Fig. 12. At this point, the BEHP and LCOH curves coincide. Note that the LCOH curve may exceed the BEHP curve if the NPV of the PV system becomes negative.

Regarding the GDPES, higher electricity prices drive the BEHPs frontier upward, as shown in Fig. 13. Higher electricity prices require higher hydrogen selling prices to sustain a positive H_2 premium. The investment decision region that extracts value from the solar PV project expands as electricity prices increase. This leads to an increase in the NPV of the solar PV project only, as higher electricity sales generate more revenue, helping mitigate potential losses on the hydrogen side when prices are not competitive. Consequently, the region of negative NPV becomes smaller.

4.3. Incentives for promoting low-carbon hydrogen

Law 2294 of 2023 establishes a framework aligned with the GIPES model by enabling public funding for energy infrastructure in prioritized energy communities [34]. Thus, if the total investment cost of

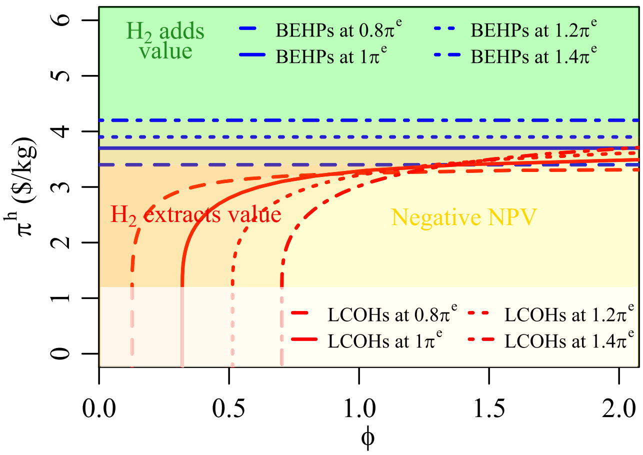


Fig. 13. Sensitivity analysis of electricity prices for the GDPES with a SOC electrolyzer.

the GIPES were fully subsidized, the BEHPs frontier for the hybrid system would decrease significantly at higher electrolyzer sizes. Without investment subsidies, BEHP values along ϕ (0.01–2.0) range from \$6.29 to \$13.17/kg, while full subsidization lowers them to \$4.90–6.34/kg.

In contrast, the GDPES is driven by a regulatory framework where tax incentives play a key role. Law 2099 of 2021 updated Law 1715 of 2014 to include low-carbon hydrogen as a non-conventional energy source eligible for tax incentives. The current ITA level of 50% may be insufficient, motivating a higher incentive level. Increasing the ITA from 50% to 100% reduces the BEHP frontiers, with estimated values of \$2.8/kg, \$3.0/kg, \$3.5/kg, and \$3.5/kg for ALK, PEM, SOC and AEM. These corresponds to reductions of 6.66%, 6.25%, 5.41%, and 7.89% compared to the base case scenario (presented in Fig. 8.)

Finally, it is important to highlight that the viability of green hydrogen depends not only on the competitiveness and sustainability of H_2-based BMs, but also on the carbon emission constraints imposed by regulators on polluting activities. Stronger constraints reduce the green premium of green hydrogen, promote the adoption of H_2-based BMs in industry, and, more generally, contribute to creating the business opportunities needed to promote a low-carbon economy.

4.4. Target conditions by 2030

This section identifies the market and regulatory conditions Colombia must meet to achieve its 2030 H_2 production targets, specifically developing 1 to 3 GW of electrolysis and achieving \$1.7/kg [11]. To do so, the financial feasibility of the proposed BMs was evaluated using idealized 2030 projections. The projected electrolyzer costs and electricity consumption for ALK, PEM and SOC were adapted from the industry target scenario presented in Glenk et al. [14]. This scenario was constructed based on the projected cumulative 2030 capacity targets ($\approx$ 248 GW) announced by H_2 industry associations. Data for AEM and stack lifetimes (all electrolyzers) were taken from CAFT [29].

For the GIPES, a tax rate of 0% was applied, excluding the depreciation and ITA provisions. In contrast, the GDPES applies the 100% ITA proposed in the incentive analysis. Other assumptions include modeling the electricity price using the expression $0.8\,\pi^e$ to reflect a hypothetical optimistic electricity price scenario; and setting the discount rate r at 8%, which represents a lower-bound value based on local WACC estimates for low-risk and debt-free projects [35]. The rest of the parameters are presented in Table 3.

For the GIPES, minimum BEHP values depend on ϕ and electrolyzer type. When $\phi = 0.39$, BEHPs reached \$3.33/kg (SOC), \$4.31/kg (ALK), \$4.36/kg (PEM), and \$4.54/kg (AEM). In contrast, the GDPES resulted in lower BEHPs of \$1.6/kg for ALK and PEM, \$1.7/kg for SOC, and

Table 3
Parameters for each type of electrolyzer (in 2030 dollars).

Parameter	ALK	PEM	SOC	AEM	Units
I_h	398	377	593	383	\$/kW
f_h	4	5	6	5	\$/kW-yr
w_h	5.0	5.0	112.0	19.3	\$/ton
η_e	47	47.34	35.96	49.36	kWh/kg
h^{life}	100 000	90 000	50 000	55 000	hr

\$1.8/kg for AEM, regardless of ϕ values. These values align with Colombia's 2030 H_2 production target of \$1.7/kg.

Exploring applications for H_2 under both BMs is essential. In the GIPES, a key use is cooking. In rural Caquetá, the average consumption of a 750 W stove is 242.6 kWh/month [36], equivalent to 12.13 kg of H_2. With a minimum BEHP of \$3.33/kg, H_2 cooking becomes competitive with electric stoves if electricity prices exceed \$0.165/kWh; this value was estimated using the effective energy formula from Schmidt Rivera et al. [37].

In the case of the GDPES, the potential applications of hydrogen are more diverse. Reference DOE [38] outlines that willingness to pay for green hydrogen in the U.S.—considering production, delivery, and on-site conditioning—ranges from as low as \$0.7/kg to as high as \$7.0/kg depending on the sector. Assuming that delivery and on-site conditioning costs are negligible compared to production, our most optimistic BEHP of \$1.6/kg could make H_2 economically viable in almost all sectors, except industrial heat, if these ranges also apply to Colombia.

5. Conclusions and future work

5.1. Conclusions and policy implications

This work supports the development of Colombia's green hydrogen economy by performing a techno-economic analysis of two photovoltaic-electrolyzer business models. The GIPES model produces hydrogen directly from solar PV electricity, making electrolyzer operation highly dynamic, whereas the GDPES alternative is based on a grid-supported PV-electrolyzer architecture, making hydrogen production more flexible.

These H_2-based hybrid systems were evaluated through a set of financial metrics—such as the expected NPV, LCOH, and BEHP—supported by operational indicators like electricity sales and hydrogen production. Together, they provide insights not only into the financial viability of the business models but also into the system's operational performance under solar resource and electricity price uncertainty.

The comprehensive evaluation reveals that optimal sizing strategies diverge significantly between the two models. In GIPES, profitability is maximized at a specific system size that balances electrolyzer's electricity consumption, surplus sales, and standby electricity requirements. In contrast, GDPES favors scalability, where the most effective decision is simply to install the largest possible electrolyzer capacity.

Electrolyzer technology selection is equally sensitive to the business model under study. In GIPES, SOC is the optimal choice for small electrolyzers, extending its optimal range to larger capacities as hydrogen prices rise. In the GDPES, the choice is governed by price rather than size, with ALK remaining superior below \$5/kg and SOC becoming the preferred option above this threshold. Within these local evaluations, PEM and AEM technologies failed to emerge as optimal choices based on the data used.

Beyond these technical results, a key finding is that the business model is the most significant factor influencing both the H_2-based hybrid system sizing and the electrolyzer technology selection. This element proved to be more decisive—in shaping these technical decisions—than other factors, such as electricity and hydrogen prices.

Another key finding is that policy makers and investors should evaluate hydrogen's value—in conventional renewable energy systems—using both LCOH and BEHP. In cases where PV projects already yield a positive NPV—as shown here, value creation requires hydrogen to be sold above the BEHP, rather than the LCOH. The inappropriate use of LCOH can mislead policy makers and investors, as its relevance declines as business models become more complex.

One policy implication is that BEHP offers valuable insights for designing incentive schemes. While investment incentives in the GIPES setting strongly promote the installation of larger electrolyzers, the GDPES configuration requires more attractive fiscal incentives to achieve significant impact. To illustrate, a stronger 100% ITA incentive would reduce the BEHP up to 7.89% compared to the current 50% ITA level, and up to 12.5% compared to the 0% ITA baseline. This has shown that this type of fiscal incentives needs to be redefined in order to achieve significant impacts on the hydrogen economy at the local level.

Another policy implication is that the government could assess the feasibility of allocating revenues from carbon emission charges to reduce electricity tariffs for GDPES. This could be implemented through a scheme in which subsidies to promote green hydrogen are directly linked to revenues from carbon taxes or environmental permits applied to polluting industries. For instance, a 20% reduction in electricity prices would lead to an 8.11% decrease in BEHP, reducing the green premium and accelerating industry development and business opportunities.

A further policy insight emerges from the analysis of electrolyzer–business model compatibility. In particular, ALK and SOC technologies show high compatibility with the GDPES model under low electricity prices that enable continuous operation. Such stable operating regimes could be supported through mechanisms such as Contracts for Difference (CfDs), which should be further explored from a policy perspective.

In the Colombian context under analysis, these policy considerations are particularly relevant for promoting GDPES, which emerges as the most financially efficient option given its ability to produce and sell hydrogen. Specifically, such a model achieves a BEHP of \$3.2/kg for the PEM electrolyzer. In contrast, the GIPES setting requires values above \$6.29/kg for the same electrolyzer technology. Furthermore, from a technical perspective, grid-connected PV-electrolyzer systems are readily implementable.

Our final finding highlights the optimistic conditions needed to meet Colombia's 2030 hydrogen roadmap targets between 1–3 GW of electrolyzer capacity and 120 kt of low-carbon hydrogen demand—which require a cost of \$1.7/kg. These conditions involve significant reductions in electrolyzer costs, improvements in electrolyzer efficiency, lower electricity prices, reasonable discount rates, feasible technical solutions, and, most importantly, high-value hydrogen business models driven by adequate and tailored incentives.

5.2. Future work

While the GDPES model provides a foundational analysis based on an energy-oriented autogeneration configuration, future research should explore additional BMs to capture the market potential of grid-connected PV–electrolysis systems. One particularly promising operational strategy deserves further detailed investigation: a baseload hydrogen demand model integrating storage should be analyzed to simulate industrial supply contracts. This configuration would allow hybrid systems to guarantee continuous hydrogen supply while strategically pausing production during peak electricity pricing hours to sell highly-valued solar power to the grid. Assessing these market-responsive dispatch strategies combined with storage will be crucial for understanding the long-term financial performance of low-carbon hydrogen projects.

Future research should integrate advanced electricity price forecasting models to better capture future real-world financial uncertainties and scenarios. Since the proposed hydrogen BMs rely heavily on dynamic price signals, predictive modeling can effectively complement the analysis and thus enhance the robustness of long-term techno-economic evaluations for grid-connected electrolysis systems.

Finally, future work should include a probabilistic analysis of NPV variance and distribution, as well as the incorporation of size-dependent cost functions for electrolyzer technologies to better represent economies of scale.

CRediT authorship contribution statement

Diego Mejía-Giraldo: Writing–review & editing, Validation, Methodology, Formal analysis, Conceptualization. **Alejandro Castillo-Ramírez:** Writing–review & editing, Writing–original draft, Validation, Software, Investigation, Data curation, Conceptualization. **Esteban Velilla-Hernández:** Supervision, Funding acquisition, Data curation.

Disclosure statement

During the preparation of this work the author Alejandro Castillo-Ramírez used Chat-GPT, Writefull, and Gemini in order to polish the text. After using these tools/services, the author reviewed and edited the content as needed and takes full responsibility for the content of the publication.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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