

Optimally integrating hydrogen production, storage and local use in renewable energy communities

*Gabriele Volpato^a, Ronelly José De Souza^a, Davide Pivetta^a, Andrea Lazzaretto^b,
Mauro Reini^a and Rodolfo Taccani^a*

^a *Department of Engineering and Architecture, University of Trieste, Via Valerio 10, 34127, Trieste, Italy*

^b *Department of Industrial Engineering, University of Padova, Via Venezia 1, 35131, Padova, Italy
gabriele.volpato@unipd.it, ronellyjose.desouza@dia.units.it (CA), davide.pivetta@phd.units.it,
andrea.lazzaretto@unipd.it, reini@units.it, taccani@units.it*

Abstract:

Renewable Energy Communities (RECs) have emerged as key players in the transition towards low-carbon and decentralized energy systems, but their optimal design requires a careful assessment of various technologies and sector coupling strategies. In this context, hydrogen plays a vital role as a renewable energy carrier that could accelerate the decarbonization of final energy usage. The objective is to evaluate possible economic incentive scenarios for RECs in order to make renewable-driven H₂ production, storage and local use in an industrial area economically viable. The analyzed REC already incorporates a fixed-capacity solar photovoltaic (PV) plant, which enables energy sharing among the community members (residential, commercial, tertiary and public) and individual physical self-consumption by the public user. Any surplus PV power (not individually self-consumed, shared with other REC users, or injected into the grid) is delivered to an on-site industrial area, where H₂ is produced via electrolysis, compressed and stored. Optimal component sizing and hourly operational scheduling are determined by solving a Mixed-Integer Quadratic Constrained Programming (MIQCP) model. The optimization model minimizes the annualized investment, operational and replacement costs. It takes historical annual hourly time series of solar irradiance, energy demands and zonal grid electricity prices as input data.

This study explores what a realistic economic incentive would be for REC to deliver excess PV power to the industrial area for H₂ production. After identifying a realistic range of values for this incentive (i.e., 0.39-0.55 €/kWh), the study investigates the relationship between the economic revenues for the shared energy incentive and for H₂ production. The results show that these two types of incentive can coexist under specific operational constraints (i.e., around one sixth of the available PV power is used for producing H₂) and conditions related to hydrogen demand (i.e., low pressure hydrogen demand at 300 bar), leading to promising system economic performances (LCOH of around 3 €/kgH₂). These findings provide insights into the role of hydrogen production, storage, and consumption in guiding the design of sustainable integrated energy community systems.

Keywords:

Renewable Energy Community; Hydrogen-integrated Renewable Energy Community; Optimization; Levelized Cost of Hydrogen; Economic incentives.

1. Introduction

The recent backdrop of escalating geopolitical risks and the threat of climate change have prompted policymakers and scientists to seek more sustainable, resilient and fair energy solutions [1]. In the current energy transition, Energy Communities (ECs) have emerged as key players in enhancing local self-consumption of Renewable Energy Sources (RESs). Through the better match between local energy demand and production, ECs enable users to share energy [2], thus contributing to the achievement of the energy and environmental targets of the “Fit for 55” plan of the European Commission (e.g., reducing emissions of 55% within 2030 compared to the levels of 1990) [3]. In addition, European legislation [4] encourages Member States to support self-consumers and Renewable Energy Communities (RECs) by establishing appropriate technical, regulatory and legal frameworks, with the aim of shifting the energy paradigm towards a more decentralized and sustainable energy system. ECs are particularly important to raise environmental awareness and foster collective actions in rural areas, which are also the most exposed to the effects of the climate crisis [5]. Supported by aligned policies, technological progress and market strategies, ECs can help address energy poverty and improve energy security in developing countries [6].

1.1. Literature review

The Italian regulatory framework defined the RECs as local and autonomous aggregations of consumers, producers and prosumers sharing electricity through the public distribution grid under the same primary cabin (medium and high voltage substations) [7]. The REC receives a government incentive for shared energy that depends on the location and the size of the generation plant, as well as on the hourly zonal electricity prices [8]. Volpato et al. [9] showed that EC members characterized by complementary demand and generation profiles may achieve up to 15-20% economic cost savings compared to their independent operation. Another work of Volpato et al. [10] proposed a novel stochastic optimization procedure to evaluate the accuracy of stochastic forecasts of sizes and total costs for a REC under uncertainties in RES and user electricity demand. Belloni et al. [11] optimized the sizes of solar PV and electrical storage systems within a REC, varying the location (e.g., northern, central and southern Italy), market prices and the maximum size of PV plants. Carraro et al. [12] integrated Demand Response (DR) programs into the design optimization of an EC, analysing different hourly variations in users' electricity demand to better match it with local RES.

Few works have examined Multi-Energy System (MES) configurations encompassing ECs. De Souza et al. [13] optimized the design and operation of a district heating and cooling network integrated within an EC by minimizing both total annual costs and emissions. Dal Cin et al. [14] conducted a multi-objective optimization to find the optimal design and operation of different EC configurations, encompassing residential and commercial users with electricity and heating demands. The analysed configurations show an average economic cost saving of 14% and a reduction of emissions by 24% with respect to the case in which users are simple consumers. Ceglia et al. [15] analysed the MES of the municipality of Tirano (Italy), supplying a REC with electricity, heating and cooling demands.

RECs can provide an effective platform for sector coupling through electricity, heat, and emerging energy vectors [16]. Within this framework, renewable hydrogen represents not only a promising energy carrier but also an interesting option for long-term energy storage. It is expected to cover around 10% of EU's total energy needs by 2050, as set out in the European "Fit for 55" package [3] and in the REPowerEU plan [17]. The integration of renewable H₂ within RECs offers a favorable pathway to enhance renewable energy utilization and improve the flexibility of REC energy system.

However, the variability of RESs remains a key barrier to increasing self-consumption in RECs, which requires a critical assessment of energy storage for H₂ integration [18]. While batteries effectively address short-term storage, H₂ can provide a complementary long-term storage option, capable of allocating renewable energy surpluses across different sectors, such as electricity, heat, and mobility [19]. Dorahaki et al. [20] reviewed the technological, economic, environmental, regulatory and social opportunities of hydrogen-based energy communities with a view to achieving the concept of a hydrogen smart city, in which hydrogen is used across the industrial, building and transport sectors. Their analysis emphasized that enabling hydrogen use within local communities could promote the fair deployment of RESs. Candelaresi et al. [21] analyzed different passenger car fleets using renewable H₂ and natural gas or gasoline in Italy. They identified hydrogen blends as the most effective short-term strategy for promoting the use of H₂ in road transport, achieving a carbon footprint reduction of 7-35%. Other studies have considered the potential connection between RECs and H₂ production companies or H₂ Refuelling Stations (HRSs). Raimondi and Spazzafumo [22] proposed an Italian business model that addresses the instability caused by the excess electricity from RECs, while also providing grid balancing at the transmission level. The excess PV power from RECs is used to produce and store hydrogen, which is then supplied to a balancing service provider that manages an UVAM (Unità Virtuale Abilitata Mista, the Italian Virtual Power Plant) and participates in the ancillary service market. Salehizadeh et al. [23] presented a sequential decision-making procedure to optimally interconnect residential RECs and HRSs. RECs deliver the surplus of PV power to HRSs for H₂ production and storage, while HRSs with an electrical storage system support REC members during DR periods. This results in energy bill savings of up to 28.7%, reduced electrical shortfalls of up to 66.4%, and a contribution of 3-4.7% of RECs to H₂ production.

Few works modelled the uncertainty in input parameters in the context of hydrogen-based energy communities. Ferrara et al. [24] optimally sized an electrolyzer and electrical battery within a PV-based REC, accounting for uncertainties in PV generation, energy demand and prices through the Decision Theory approach. Dorahaki et al. [25] developed a robust operational optimization framework for energy communities integrating green hydrogen under solar PV uncertainty. They proposed an incentive-driven electricity tariff whereby higher hydrogen export volumes increase electricity discounts, thus decreasing prosumers' electricity bills by 5.27% and increasing community profits by 3.33%.

1.2. Goal and novelty

To the authors' knowledge, no work has optimized both the sizing (i.e., capacities) and operation of all technologies within a Hydrogen-integrated REC (HREC), while also evaluating the introduction of a new

economic incentive to foster H2 production from excess PV power. The objective is to identify a realistic interval of values for this incentive, within which H2 production, storage and consumption associated with the HREC configuration would be economically viable. As with the shared energy incentive, the proposed incentive for H2 production is assumed to be defined by the government. A case study focusing on an existing REC in the Italian province of Gorizia (northeastern Italy) is presented. A HREC configuration developed from the existing REC is proposed to exploit the excess PV power from the REC for H2 production, compression, storage and consumption. A Mixed-Integer Quadratic Constrained Programming (MIQCP) model, based on a previous model proposed by the first author of this paper [26], is used to optimize the design and operation of the HREC configuration. The optimization minimizes total annualized investment, operational and replacement costs of all technologies within HREC. The novelty of this work relies on analyzing the trade-off between the economic revenues due to the shared energy incentive for REC and those due to the new incentive for green H2 production.

2. Methods

Section 2.1 summarizes the MIQCP model of the REC proposed in [26] and introduces new equations and constraints for modelling and optimizing the proposed HREC configuration, which combines a REC with the energy system of an industrial area. Section 2.2 presents the input data.

2.1. Optimization model of the hydrogen-integrated renewable energy community

The Renewable Energy Community (REC) includes the residential (Res), tertiary (Ter) and commercial (Com) consumers, and the public (Pub) prosumer owning a solar Photovoltaic plant (PV) of 875 kW. It is assumed that these four members are representative of the 43 users within the existing REC "Comunità Energetica PartEnergy Soc. Coop. ARL" in San Pier D'Isonzo (Gorizia, Italy) [27]. According to the Italian legislation, users can share energy through the electrical grid under the primary substation. The REC manager supports the formation of the REC, bears the administrative costs and redistributes the economic revenues generated by the shared energy incentive among the participants according to an allocation criterion [28].

Figure 1 shows the HREC configuration that connects the REC to the industrial area. A Proton Exchange Membrane (PEM) electrolyzer, as well as low-pressure (LP) and high-pressure (HP) compressors, and LP and HP Hydrogen Storage (HS) can be installed in the industrial area. Moreover, Electrical Energy Storage (EES) can be installed in the REC. Excess power from the PV plant in the REC drives the PEM-based H2 production. Hydrogen produced at 30 bar is compressed up to 300 bar in the LP compressor and then delivered to the LP HS. Hydrogen discharged by the LP HS is compressed up to 820 bar in the HP compressor before finally entering the HP HS. The H2 storage units can satisfy LP and HP hydrogen demands.

The design (i.e., technology capacities) and operation of the system are optimized for different sets of representative days of PV capacity factor, zonal electricity prices and realistic user electricity demands, which are obtained by applying K-means clustering to an annual dataset (2023 for the PV capacity factor, 2025 for the other time series). The number of representative days varies from 4 to 25. The time horizon of the optimization is one year, assuming that the system operation is the same for each year of its life cycle (i.e., 25 years). Hence, the weight of each representative day is calculated as the ratio between the frequency of the associated cluster (i.e., the number of elements represented by this representative day) and the number of days in one year (i.e., 365). The decision variables and constraints refer to hour t of representative day d .

The design decision variables are the capacities of the PEM electrolyzer (cap^{ELECT}), LP and HP compressors ($cap^{COMP,LP}$ and $cap^{COMP,HP}$), LP and HP HS ($cap^{HS,LP}$ and $cap^{HS,HP}$) and EES (cap^{EES}). The capacity of PV (cap^{PV}) is known as it is already installed in the REC, which constitutes the starting point for optimizing the design of the HREC configuration. The operational decision variables are: the energy stored by EES ($E_{t,d}^{EES}$), its charging/discharging power ($P_{t,d}^{EES,+}/P_{t,d}^{EES,-}$) and the binary variable indicating its charging/discharging state ($\delta_{t,d}^{EES}$); the energy imported/exported from/to the electrical grid ($E_{t,d}^{imp}/E_{t,d}^{exp}$); the shifted electricity demands of users ($E_{t,d}^{el,shift}$); the on-off binary status of PEM ($\delta_{t,d}^{ELECT}$); the H2 stored in the LP ($H_{t,d}^{HS,LP}$) and HP ($H_{t,d}^{HS,HP}$) HS. The units of measurement for energy and power variables are kWh and kW , respectively, while those for H2 mass and mass flow rate are kg and kg/s , respectively.

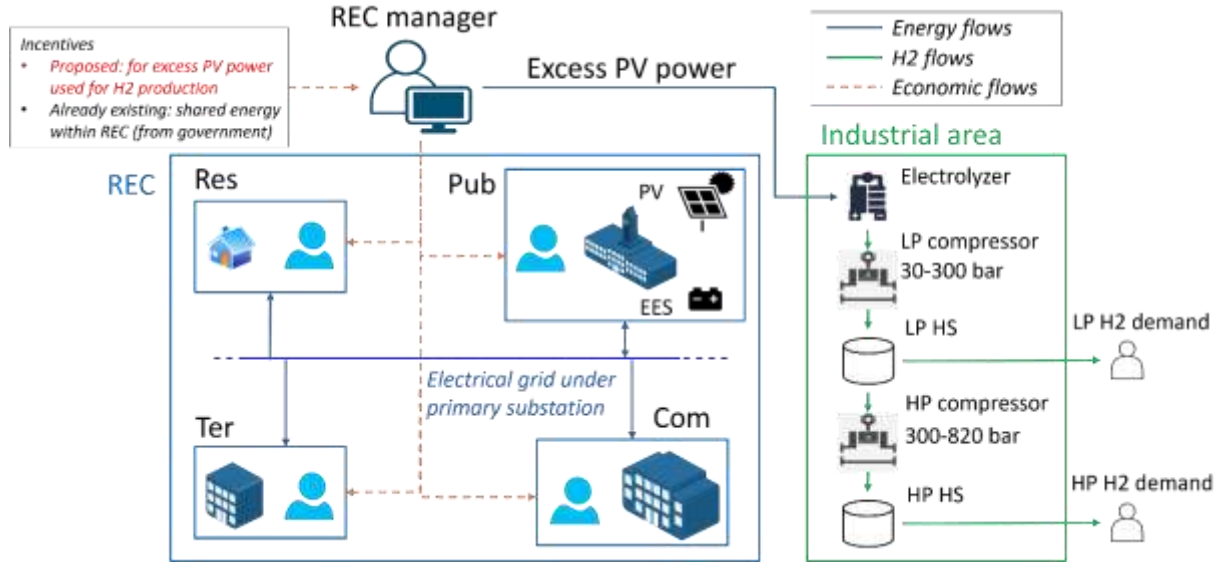


Figure 1. HREC configuration combining a REC and an industrial area.

The electricity balance of the prosumer *Pub* is:

$$E_{t,d}^{imp} - E_{t,d}^{exp} + (P_{t,d}^{PV} - P_{t,d}^{PV,excess} + P_{t,d}^{EES,-} - P_{t,d}^{EES,+}) \cdot \Delta t - E_{t,d}^{el,shift} = 0 \quad (1)$$

where $E_{t,d}^{imp}/E_{t,d}^{exp}$ is the energy imported/exported from/to the electrical grid, $P_{t,d}^{PV}$ is the electrical power generated by PV, $P_{t,d}^{PV,excess}$ is the excess PV power used to produce H2 (i.e., not sold to the grid, individually self-consumed or shared within the REC), $P_{t,d}^{EES,-}/P_{t,d}^{EES,+}$ is the power discharged/charged from/into EES, Δt is the step of one hour in the optimization and $E_{t,d}^{el,shift}$ is the shifted electricity demand.

The energy balance of EES is:

$$E_{t,d}^{EES} = E_{t-1,d}^{EES} \cdot (1 - SD) + (P_{t,d}^{EES,+} \cdot \eta^{EES,+} - P_{t,d}^{EES,-} / \eta^{EES,-}) \cdot \Delta t \quad (2)$$

where $E_{t,d}^{EES}$, SD , $P_{t,d}^{EES,+}/P_{t,d}^{EES,-}$ and $\eta^{EES,+}/\eta^{EES,-}$ are the state of charge [% of capacity], the self-discharge [% of the state of charge in each hour], the charging/discharging power and the charging/discharging efficiency [-] of EES, respectively. Other constraints of EES are:

$$E_{t,d}^{EES} \leq cap^{EES} \quad (3)$$

$$P_{t,d}^{EES,+} \leq \delta_{t,d}^{EES,+} \cdot C^{EES,+} \cdot cap^{EES} \quad (4)$$

$$P_{t,d}^{EES,-} \leq \delta_{t,d}^{EES,-} \cdot C^{EES,-} \cdot cap^{EES} \quad (5)$$

$$\delta_{t,d}^{EES,+} + \delta_{t,d}^{EES,-} \leq 1 \quad (6)$$

$$E_{t=1,d}^{EES} = E_{t=24,d}^{EES} \quad (7)$$

where $\delta_{t,d}^{EES}$ is the binary variable associated with the charging (+) or discharging (-) state of EES, $C^{EES,+}$ and $C^{EES,-}$ [kW/kWh] are the specific input and output capacity.

The electrical power generated by PV is:

$$P_{t,d}^{PV} = cap^{PV} \cdot I_{t,d} \quad (8)$$

where $P_{t,d}^{PV}$ is the power generated [kW] and $I_{t,d}$ [kW/kW] is the PV capacity factor on a tilted surface considering system losses of 14%.

The hourly electricity demand of each member *i* of the REC can be shifted as follows:

$$\sum_{t=1}^{24} E_{i,t,d}^{el} = \sum_{t=1}^{24} E_{i,t,d}^{el,shift} \quad (9)$$

$$E_{i,d}^{el,min} \leq E_{i,t,d}^{el,shift} \leq E_{i,d}^{el,max} \quad (10)$$

$$(1 - D^{var}) \cdot E_{i,t,d}^{el} \leq E_{i,t,d}^{el,shift} \leq (1 + D^{var}) \cdot E_{i,t,d}^{el} \quad (11)$$

where $E_{i,t,d}^{el}$, $E_{i,t,d}^{el,shift}$, $E_{i,d}^{el,min}$ and $E_{i,d}^{el,max}$, and D^{var} are, respectively, the input electricity demand, the shifted electricity demand in hour t of day d , the minimum and maximum of the input electricity demand in day d , and the hourly maximum fraction of the load that can be shifted (which is assumed to be 0.1).

The constraints associated with the electrolyzer are:

$$H_{t,d}^{COMP,LP} = (k_1^{ELECT} \cdot P_{t,d}^{ELECT} + k_2^{ELECT} \cdot cap^{ELECT}) \cdot \delta_{t,d}^{ELECT} \quad (12)$$

$$k_3^{ELECT} \cdot cap^{ELECT} \cdot \delta_{t,d}^{ELECT} \leq P_{t,d}^{ELECT} \leq k_4^{ELECT} \cdot cap^{ELECT} \cdot \delta_{t,d}^{ELECT} \quad (13)$$

where $H_{t,d}^{COMP,LP}$ is the H2 mass flow rate [kg/h] produced by the electrolyzer at the inlet of the LP compressor, $P_{t,d}^{ELECT}$ is the electrolyzer electrical consumption, k_1^{ELECT} and k_2^{ELECT} are proportionality coefficients associated with the PEM characteristic curve, and k_3^{ELECT} and k_4^{ELECT} define the lower and upper bounds of the electrical load.

The LP compressor is modeled as presented in [29] by assuming that its absorbed electrical power is proportional to the corresponding processed mass flow rate. The proportionality factor $k_1^{COMP,LP}$ is the ideal specific work of adiabatic isentropic compression, adjusted to account for mechanical, isentropic, and electrical efficiencies. Moreover, the compressor power is bounded between minimum and maximum fractions of its installed capacity, defined by k_2^{COMP} and k_3^{COMP} . The binary variable $\delta_{t,d}^{COMP,LP}$ represents the on-off status of the compressor. The same formulation is adopted for the HP compressor.

The LP hydrogen storage at 300 bar is described by the mass balance in Equation (14), where the stored hydrogen at time $t + 1$ is equal to the stored hydrogen at time t , plus the inflow from the LP compressor, minus the flow sent to the HP compressor, and minus the LP hydrogen demand. Likewise, the HP hydrogen storage at 820 bar is described by the mass balance in Equation (15), where the stored hydrogen at time $t + 1$ is equal to the stored hydrogen at time t , plus the inflow from the HP compressor, minus the HP hydrogen demand. In both the low- and high-pressure storage tanks, the hydrogen mass is bounded between fractions of the total tank capacity (k_1^{HS} and k_2^{HS}), and the amount of stored hydrogen at the beginning of the optimization horizon is imposed to be equal to that at the end, as described in [29].

$$H_{t+1,d}^{HS,LP} = H_{t,d}^{HS,LP} + H_{t,d}^{COMP,LP} - H_{t,d}^{COMP,HP} - H_{t,d}^{DEMAND,LP} \quad (14)$$

$$H_{t+1,d}^{HS,HP} = H_{t,d}^{HS,HP} + H_{t,d}^{COMP,HP} - H_{t,d}^{DEMAND,HP} \quad (15)$$

Note that the model calculates the H2 demands to assess whether the PEM-based H2 production, driven by the excess PV power, can satisfy H2 requirements from industrial users or vehicle fleets in realistic scenarios within the framework of the North Adriatic Hydrogen Valley (NAHV) [30]. This approach could be extended to analyze how emerging infrastructures can be effectively integrated into a cross-border H2 energy system encompassing Italy (Friuli Venezia Giulia region), Slovenia, and Croatia.

To guarantee that the excess PV power from the REC is conveniently exploited by the industrial area, the excess of PV is set equal to the power required by the electrolyzer. The objective function to be minimized is the life cycle cost of the system referring to one year:

$$C_{life\ cycle} = C_{design} + C_{operation} \quad (16)$$

where C_{design} and $C_{operation}$ are the investment and operational costs, with the investment cost actualized to one year of operation. The investment cost of the system is:

$$C_{design} = \sum_{u \in U} \left(\left(\frac{a \cdot (1+a)^n}{(1+a)^n - 1} + O\&M_{fix,u} + \frac{1}{(1+a)^{l_u}} \right) \cdot c_{inv,u} \cdot cap^u \right) \quad (17)$$

where u identifies a technology (U is the set of technologies), a [%] is the interest rate, n [years] and l_u [years] are the lifetime of the whole system and technology u , respectively, $O\&M_{fix,u}$ [% of the investment cost] is the fixed operation and maintenance cost of the technology u , $c_{inv,u}$ [€/kW or €/kWh or €/kgH2] is the investment cost, cap^u is the capacity [kW or kWh or kgH2] of the technology u . The first term within parenthesis represents the actualization factor for the investment cost, while the third term is associated with the replacement cost of technology u when its lifetime is shorter than that of the whole system. The annual operational cost based on a set of representative days is:

$$C_{operation} = \sum_{d=1}^K w_d \cdot \sum_{t=1}^{24} (E_{t,d}^{imp} \cdot c_{t,d}^{imp} - E_{t,d}^{exp} \cdot c_{t,d}^{exp} - E_{s,t,d} \cdot inc_{t,d} - P_{t,d}^{PV,excess} \cdot inc_{PV,excess}) \quad (18)$$

where K , w_d , $c_{t,d}^{imp}$ and $c_{t,d}^{exp}$ [€/kWh], $E_{s,t,d}$ [kWh] and $inc_{t,d}$ [€/kWh] are the number of representative days, the weight of representative day d , the grid purchase and sale prices, the shared energy and the associated incentive for the REC, respectively. $inc_{PV,excess}$ [€/kWh] is a new government incentive introduced to reward the REC for encouraging the use of surplus PV for H2 production. The aim of this incentive is to avoid renewable energy curtailment and promote the Power-to-H2 (P2H) concept. The first, second, third and fourth terms in Eq. (18) represent the cost of electricity imported from the grid, the revenue from electricity exported to the grid, the revenues associated with the shared energy within the REC and with exploiting PV excess for H2 production, respectively. The shared energy is calculated as the hourly minimum between the total net energy withdrawn from and injected to the grid by the REC according to the Italian legislation [7]. The incentive depends on the location, size of the generation plant and hourly zonal electricity prices [8]. Non-convex quadratic constraints are used to define the shared energy incentive (see previous work [26]), resulting in a Mixed-Integer Quadratic Constrained Programming (MIQCP) formulation for the developed model.

The Levelized Cost of Hydrogen (LCOH) is calculated as the annualized cost of producing hydrogen:

$$LCOH = \frac{(c_{design,H2} + c_{operation}) \cdot ratio_{H2}}{\sum_{d=1}^K w_d \cdot \sum_{t=1}^{24} (H_{t,d}^{COMP,LP})} \quad (19)$$

where $c_{design,H2}$ is the annualized investment cost of all technologies used to produce, store and deliver H2 to the final user (i.e., all technologies except the already installed PV), and $ratio_{H2}$ is the ratio between the electrical energy absorbed by the electrolyzer and the total energy generated and exchanged with the grid by REC.

2.2. Input data

Table 1 shows the values of the input techno-economic parameters. Data for PV and EES are retrieved from [12] and the PyPSA database [31], while those for PEM, HS and compressors are taken from [32]. The investment interest rate a is 5% and the life cycle n of the entire HREC configuration is 25 years. Other parameters associated with EES can be found in [10]. The time series of PV capacity factor refers to the location of Gorizia (Italy) and is taken from [33]. The time series of zonal electricity prices for northern Italy are taken from [34], where the grid sale price is assumed to equal the zonal price and the grid purchase price is calculated as the grid sale price plus 0.2 €/kWh. The time series of user electricity demands are adapted from [35]. The optimization model presented in section 2.1 is implemented in Python, using the commercial software Gurobi [36] as solver.

Table 1. Input techno-economic parameters of the optimization model.

Parameter	PV	EES	ELECT	HS	COMP
$c_{inv,u}$	800 €/kW	500 €/kWh	1000 €/kW	1500 €/kgH2	6000 (LP), 7000 (HP) €/kW
FOM_u [%/year]	1.57	1	4	2	8
Efficiency [-]	loss of 14%	0.91	-	1	mechanical (0.98), isentropic (0.8), electric (0.96)
lt_u [years]	20	10	15	25	15
Coefficients	-	-	$k_1^{ELECT}: 0.0074,$ $k_2^{ELECT}: 0.0063,$ $k_3^{ELECT}: 0.3,$ $k_4^{ELECT}: 1$	$k_1^{HS}: 0.2,$ $k_2^{HS}: 0.8$	$k_2^{COMP}: 0.2,$ $k_3^{COMP}: 1$

3. Results and discussion

The MIQCP model is solved for different sets of representative days, from 4 to 25, and for different values of the proposed H2 production incentive associated with excess PV power. The analysis confirms that the economic viability of the HREC strongly depends on this incentive, which directly affects optimal sizing, operation, and hydrogen production costs. In line with the scope of the model, the results are discussed in terms of optimal capacities, total annualized costs, incentive-related revenues, operating profiles, and LCOH. A feasible incentive range from 0.39 to 0.55 €/kWh is identified to guarantee hydrogen production. As can be observed in Figure 2a), at the lower bound of the incentive range, the electrolyzer is installed with the minimum

economically viable size around 50-100 kW, whereas increasing the incentive progressively drives up larger optimal capacities to 240-320 kW at the maximum feasible incentive (Figure 2b)). This confirms that the proposed policy instrument is not only an economic support mechanism, but also a direct driver of the HREC design.

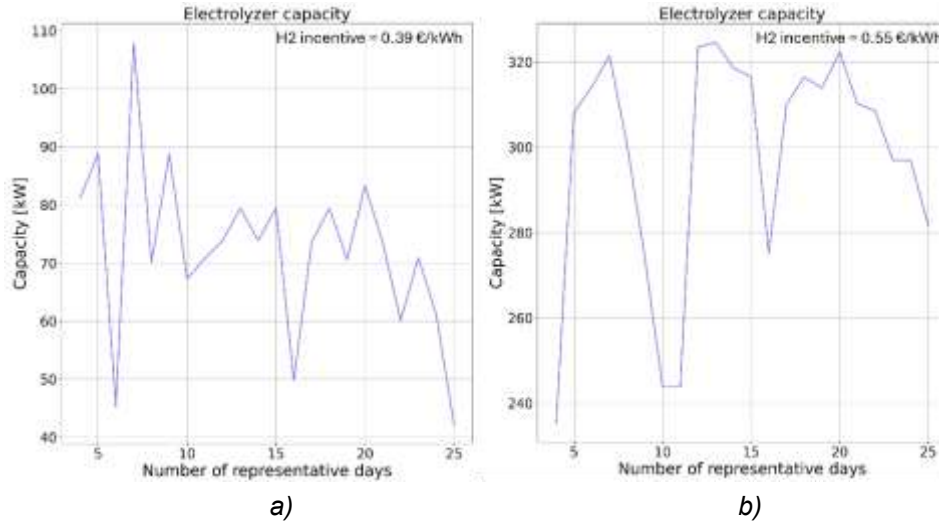


Figure 2. Variation of PEM electrolyser capacity as a function of the number of representative days and the H2 production incentive: a) 0.39 €/kWh and b) 0.55 €/kWh.

Figure 3a) shows that when the H2 production incentive is set to 0.45 €/kWh, which represents a balanced intermediate scenario, the total annualized costs remain within the range of approximately 340-360 k€ for 10-20 representative days. In the same interval of representative days, the share of revenues associated with the shared energy incentive is limited to about 4-5% of total costs, whereas the H2 production incentive covers about 50-75%, as observed also in Figure 3b). Therefore, while the two incentives coexist, they have clearly different economic weights. In this case, the H2-oriented incentive is the dominant revenue stream, consistently exceeding the economic relevance of the shared energy incentive defined by the Italian regulation, which has a maximum value of about 0.12 €/kWh for the analyzed 875 kW PV system in the REC configuration.

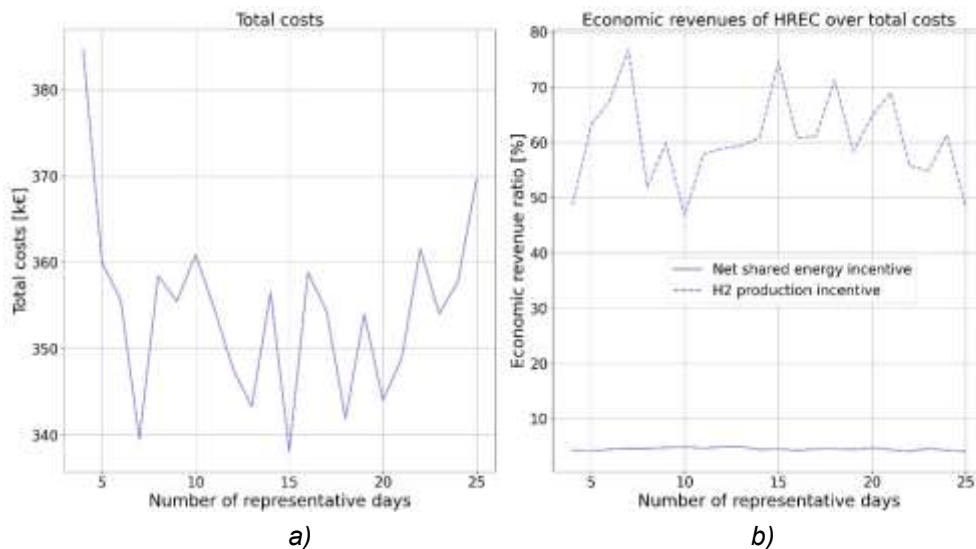


Figure 3. a) Total costs and b) economic revenues for the HREC with a H2 production incentive of 0.45 €/kWh.

The operational results for the 0.45 €/kWh case show a technically credible and non-extreme configuration. The optimal capacities are about 120-190 kW for the electrolyzer and 5-8 kW for the LP compressor. The excess PV power available for hydrogen production represents only around one sixth of the PV power generated (Figure 4a)), indicating that hydrogen production is limited by the residual renewable surplus after self-consumption and energy sharing within the REC. As a consequence, the mean hourly hydrogen production

over one year is approximately 0.8 kg (Figure 4b)), and the available excess PV power is sufficient to satisfy only the low-pressure H₂ demand. This outcome highlights that the main bottleneck does not lie in the hydrogen chain itself, but in the limited amount of PV surplus effectively available to the industrial area.

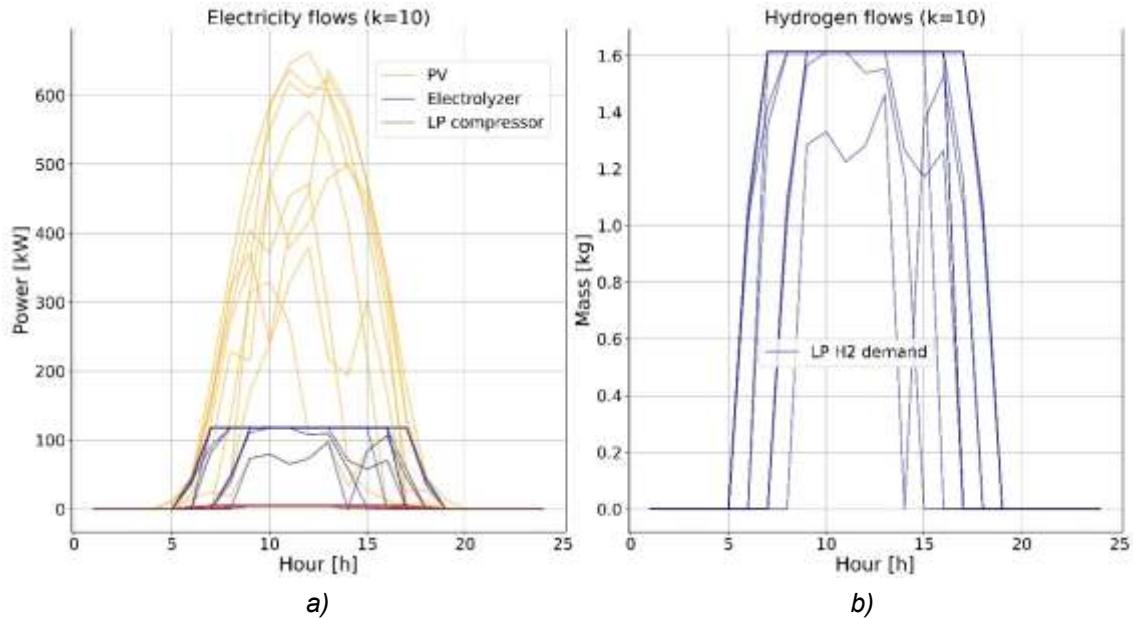


Figure 4. a) Electricity and b) hydrogen hourly flows for 10 representative days with a H₂ production incentive of 0.45 €/kWh.

The LCOH confirms the pivotal role of the proposed incentive. For the 0.45 €/kWh case, the LCOH decreases to about 1-3 €/kgH₂ when the H₂ production incentive is included, whereas it rises to about 12-14 €/kgH₂ when the incentive is neglected. Figure 5 presents the LCOH behavior for these two analyzed scenarios and for the different numbers of representative days. Hence, hydrogen production from REC excess PV cannot be considered economically viable without a dedicated support mechanism.

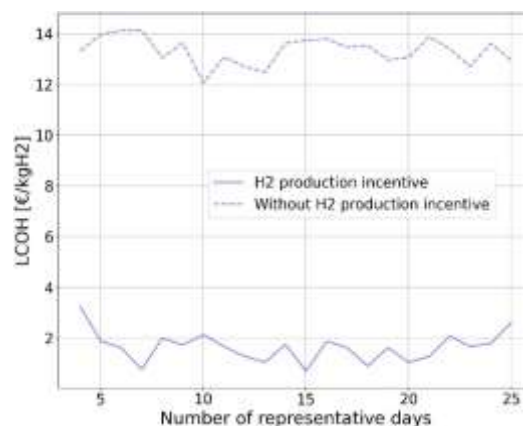


Figure 5. Levelized Cost of Hydrogen (LCOH), as a function of the number of representative days, with and without the H₂ production incentive of 0.45 €/kWh.

The comparison among the tested incentive levels further clarifies this trend. At 0.39 €/kWh, total annualized costs remain higher, approximately in the 370-390 k€ range, while the economic contribution of the H₂ production incentive is limited to about 16-38% of total costs. In this lower-incentive case, hydrogen production is still feasible, but the optimal hydrogen system remains closer to the minimum viable size, and the LCOH with incentive is still relatively high around 3-5 €/kgH₂. Without the incentive, the LCOH increases further to about 9-12 €/kgH₂, confirming the weak standalone competitiveness of H₂ production from REC excess PV.

By contrast, increasing the incentive to 0.50 €/kWh significantly improves the economic performance of the HREC. Total annualized costs decrease to about 310-335 k€ (Figure 6a)), while the H₂ production incentive

may account for around 80-135% of total costs, clearly surpassing the shared-energy contribution, which remains close to 4-5% (Figure 6b)). In parallel, both electrolyzer and LP compressor capacities increase, resulting in higher hydrogen production. The LCOH with incentive drops to around 0-1 €/kgH₂, and in some cases reaches slightly negative values, while the LCOH without incentive increases to about 14-16 €/kgH₂ (Figure 7). This shows that the greater the reliance of HREC on the proposed incentive, the more competitive hydrogen production becomes inside the optimized design. However, this also shifts more the economic logic of the system from electricity sharing to H₂ production.

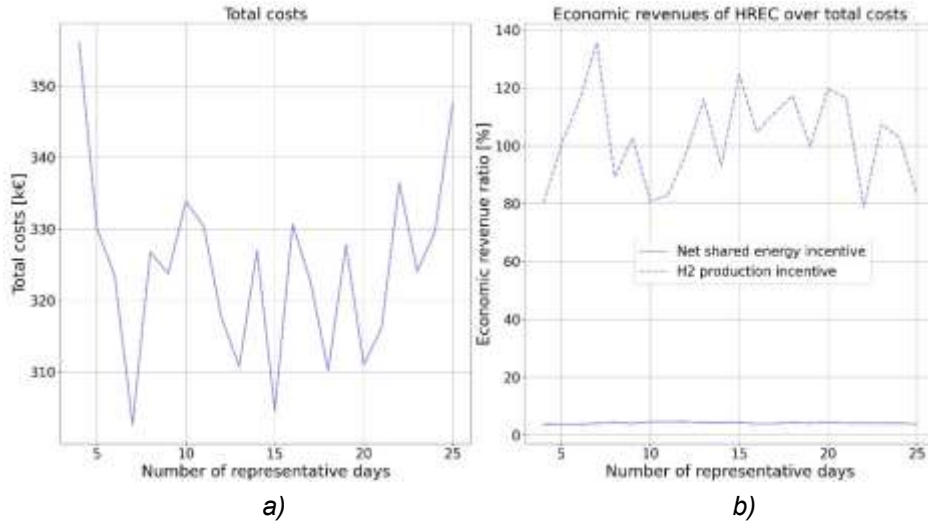


Figure 6. a) Total costs and b) economic revenues for the HREC with a H₂ production incentive of 0.5 €/kWh.

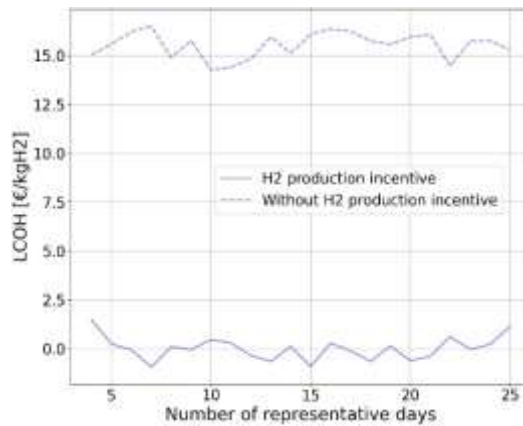


Figure 7. Levelized Cost of Hydrogen (LCOH), as a function of the number of representative days, with and without the H₂ production incentive of 0.5 €/kWh.

Overall, the results show a clear monotonic trend: the higher the H₂ production incentive, the lower the total annualized costs, the higher the optimal electrolyzer and LP compressor capacities, the larger the hydrogen production, and the lower the LCOH when the incentive is considered. However, the opposite trend is observed when the incentive is excluded from the LCOH calculation, meaning that hydrogen remains intrinsically expensive if a structured incentive framework is not introduced. From a system perspective, the proposed HREC configuration reduces renewable curtailment and provides an additional flexibility option that may also contribute to local grid stability by converting residual PV surplus into a storable energy carrier.

4. Conclusions

This work investigates the optimal integration of an existing Renewable Energy Community (REC) with green hydrogen production within an industrial area. The aim is to evaluate the economic feasibility of utilizing excess PV power from REC for H₂ production, compression, storage and local use in an industrial area by implementing an appropriate economic incentive. The developed MIQCP model jointly optimizes component sizing and hourly operation of the Hydrogen-integrated REC (HREC) components, with particular focus on the

trade-off between the shared energy incentive associated with the REC and a new incentive for hydrogen production from surplus PV electricity.

The results show that hydrogen production within the analyzed HREC is feasible only within a suitable incentive range, identified here as 0.39-0.55 €/kWh of excess PV power. Within this range, increasing the incentive systematically reduces total annualized costs, increases optimal hydrogen-related capacities, and improves hydrogen production performance. The proposed incentive has a much stronger economic impact than the shared energy incentive and becomes the main revenue driver for the HREC configuration.

Among the analyzed cases, the intermediate scenario with 0.45 €/kWh emerges as the most meaningful one, since it enables hydrogen production with moderate component sizes and competitive LCOH values around 3 €/kgH₂, while still preserving a residual role for shared-energy revenues. At the same time, the comparison with the 0.39 and 0.50 €/kWh cases shows that hydrogen production from REC excess PV is not economically affordable without a dedicated incentive mechanism. Therefore, the main conclusion of this work is that a structured green-hydrogen market and policy framework is necessary to make the use of additional renewable electricity from RECs attractive for hydrogen production.

Finally, the results suggest that the proposed HREC configuration can reduce renewable energy curtailment and improve the exploitation of local PV surplus. This supports more flexible and integrated community energy systems, and is in line with regional hydrogen production targets within the NAHV project. Further work should investigate the sensitivity of the results to user electricity demand and PV size, the relationship between LCOH and the Levelized Cost of Electricity (LCOE), the integration of hydrogen blending into the natural gas grid, and multi-objective economic-environmental optimization to assess the trade-off between cost reduction and emissions mitigation.

Acknowledgments

Authors acknowledge the financial support from the NAHV project. (North Adriatic Hydrogen Valley, HORIZON-JTI-CLEANH2-2022-2, Project ID: 101111927).

Nomenclature

Com	Commercial
HREC	Hydrogen-integrated Renewable Energy Community
HS	Hydrogen Storage
LCOH	Levelized Cost of Hydrogen
MIQCP	Mixed-Integer Quadratic Constrained Programming
PEM	Proton Exchange Membrane
Pub	Public
REC	Renewable Energy Community
RES	Renewable Energy Sources
Res	Residential
Ter	Tertiary

References

- [1] IEA, World Energy Outlook 2025, 2025. <https://www.iea.org/reports/world-energy-outlook-2025>.
- [2] EU, Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the Promotion of the Use of Energy from Renewable Sources (Recast), 2018. <https://eur-lex.europa.eu/eli/dir/2018/2001/oj>. (Accessed 11 May 2022).
- [3] EU, European Commission's Communication, 'Fit for 55': delivering the EU's 2030 Climate Target on the way to climate neutrality (COM(2021) 550 final), 2021. <https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX%3A52021DC0550>. (Accessed 11 May 2022).
- [4] EU, Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 on the promotion of energy from renewable sources, 2023. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L_202302413. (Accessed 3 February 2026).

- [5] M. Kowalska, E. Chomać-Pierzecka, M. Bogusz, A. Dąbrowski, I. Keşy, Individuals' Climate Change and Course of Energy Transition Process Efforts for Local Communities in Rural Poland, *Energies* 19(2) (2026) 534, doi:<https://doi.org/10.3390/en19020534>.
- [6] A.U. Rehman, D. Atzori, S. Corasaniti, P. Coppa, Smart Grids and Renewable Energy Communities in Pakistan and the Middle East: Present Situation, Perspectives, Future Developments, and Comparison with EU, *Energies* 19(2) (2026) 535, doi:<https://doi.org/10.3390/en19020535>.
- [7] ARERA, Testo integrato autoconsumo diffuso – TIAD, 2023. <https://www.arera.it/fileadmin/allegati/docs/22/727-22TIAD.pdf>. (Accessed 01 August 2023).
- [8] MASE, MASE Decree disposal, 2023. <https://www.mase.gov.it/sites/default/files/Decreto%20CER.pdf>.
- [9] G. Volpato, G. Carraro, M. Cont, P. Danieli, S. Rech, A. Lazzaretto, General guidelines for the optimal economic aggregation of prosumers in energy communities, *Energy* 258 (2022), doi:<https://doi.org/10.1016/j.energy.2022.124800>.
- [10] G. Volpato, G. Carraro, L. De Giovanni, E. Dal Cin, P. Danieli, E. Bregolin, A. Lazzaretto, A stochastic optimization procedure to design the fair aggregation of energy users in a Renewable Energy Community, *Renewable Energy* 237 (2024) 121580, doi:<https://doi.org/10.1016/j.renene.2024.121580>.
- [11] E. Belloni, D. Fioriti, D. Poli, Optimal design of renewable energy communities (RECs) in Italy: Influence of composition, market signals, buildings, location, and incentives, *Electric Power Systems Research* 235 (2024) 110895, doi:<https://doi.org/10.1016/j.eprsr.2024.110895>.
- [12] G. Carraro, E. Dal Cin, S. Rech, Integrating Energy Generation and Demand in the Design and Operation Optimization of Energy Communities, *Energies* 17(24) (2024) 6358, doi:<https://doi.org/10.3390/en17246358>.
- [13] R.J. De Souza, M. Reini, L.M. Serra, M.A. Lozano, E. Nadalon, M. Casisi, Multi-Objective Optimization of an Energy Community Powered by a Distributed Polygeneration System, *Energies* 17(13) (2024) 3085, doi:<https://doi.org/10.3390/en17133085>.
- [14] E. Dal Cin, G. Carraro, G. Volpato, A. Lazzaretto, P. Danieli, A multi-criteria approach to optimize the design-operation of Energy Communities considering economic-environmental objectives and demand side management, *Energy Conversion and Management* 263 (2022), doi:<https://doi.org/10.1016/j.enconman.2022.115677>.
- [15] F. Ceglia, E. Marrasso, C. Roselli, M. Sasso, Energy and environmental assessment of a biomass-based renewable energy community including photovoltaic and hydroelectric systems, *Energy* (2023) 128348, doi:<https://doi.org/10.1016/j.energy.2023.128348>.
- [16] L.M. Pastore, Sector Coupling and Flexibility Measures in Distributed Renewable Energy Systems: A Comprehensive Review, *Sustainability* 18(1) (2026) 437, doi:<https://doi.org/10.3390/su18010437>.
- [17] REPowerEU Plan, 2022. <https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52022DC0230>. (Accessed 20 June 2023).
- [18] M. Pasqui, L. Becchi, M. Bindi, M. Intravaia, F. Grasso, G. Fioriti, C. Carcasci, Community Battery for Collective Self-Consumption and Energy Arbitrage: Independence Growth vs. Investment Cost-Effectiveness, *Sustainability* 16(8) (2024) 3111, doi:<https://doi.org/10.3390/su16083111>.
- [19] R.M. Rengel Gálvez, J.J. Caparrós Mancera, E. López González, D. Tejada Guzmán, J.M. Sancho Peñate, Application of Electric Energy Storage Technologies for Small and Medium Prosumers in Smart Grids, *Processes* 13(9) (2025) 2756, doi:<https://doi.org/10.3390/pr13092756>.
- [20] S. Dorahaki, N. Amjady, S.M. Muyeen, The role of hydrogen-based local energy communities in the development of hydrogen cities: A systematic review, *International Journal of Hydrogen Energy* 192 (2025) 152386, doi:<https://doi.org/10.1016/j.ijhydene.2025.152386>.
- [21] D. Candelaresi, A. Valente, D. Iribarren, J. Dufour, G. Spazzafumo, Novel short-term national strategies to promote the use of renewable hydrogen in road transport: A life cycle assessment of passenger car fleets partially fuelled with hydrogen, *Science of The Total Environment* 859 (2023) 160325, doi:<https://doi.org/10.1016/j.scitotenv.2022.160325>.
- [22] G. Raimondi, G. Spazzafumo, Integrating renewable energy communities and Italian UVAM project through renewable hydrogen chain, e-Prime - Advances in Electrical Engineering, Electronics and Energy 10 (2024) 100819, doi:<https://doi.org/10.1016/j.prime.2024.100819>.
- [23] M.R. Salehizadeh, M.A. Beyazıt, A. Taşçıkaraoğlu, J. Liu, A sequential decision-making framework for integrating renewable energy communities and refueling stations in hydrogen production, *Applied Energy* 387 (2025) 125547, doi:<https://doi.org/10.1016/j.apenergy.2025.125547>.

- [24] M. Ferrara, F. Mottola, D. Proto, A. Ricca, M. Valenti, Integrating green hydrogen production and electrical energy storage in energy communities under uncertainty, *Applied Energy* 407 (2026) 127389, doi:<https://doi.org/10.1016/j.apenergy.2026.127389>.
- [25] S. Dorahaki, N. Al-Emadi, A. Iqbal, S.M. Muyeen, An integrated robust optimisation approach for energy communities utilising green hydrogen and renewable energy sources under dynamic, policy-driven tariff mechanisms for sustainable development, *International Journal of Hydrogen Energy* 198 (2026) 152756, doi:<https://doi.org/10.1016/j.ijhydene.2025.152756>.
- [26] G. Volpato, Impact of uncertainty on the fair allocation of economic benefits within an energy community, *Proceedings of ECOS 2025 - The 38th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems*, Paris, France, 2025.
- [27] GSE, Gestore Servizi Energetici, 2025. <https://www.gse.it/servizi-per-te/autoconsumo/mappa-interattiva-delle-cabine-primarie>. (Accessed 25 February 2026).
- [28] G. Volpato, G. Carraro, E. Dal Cin, S. Rech, On the Different Fair Allocations of Economic Benefits for Energy Communities, *Energies* 17(19) (2024) 4788, doi:<https://doi.org/10.3390/en17194788>.
- [29] D. Pivetta, C. Dall'Armi, R. Taccani, Multi-Objective Optimization of a Hydrogen Hub for the Decarbonization of a Port Industrial Area, *Journal of Marine Science and Engineering* 10(2) (2022) 231, doi:<https://doi.org/10.3390/jmse10020231>.
- [30] NAHV (North Adriatic Hydrogen Valley), 2025. <https://www.nahv.eu/>. (Accessed 17 April 2026).
- [31] PyPSA, PyPSA documentation, 2025. <https://docs.pypsa.org/latest/>. (Accessed 11 August 2025).
- [32] D. Pivetta, A. Tafone, S. Mazzoni, A. Romagnoli, R. Taccani, A multi-objective planning tool for the optimal supply of green hydrogen for an industrial port area decarbonization, *Renewable Energy* 232 (2024) 120979, doi:<https://doi.org/10.1016/j.renene.2024.120979>.
- [33] PVGIS, Photovoltaic Geographical Information System (PVGIS), 2024. <https://ec.europa.eu/jrc/en/pvgis>. (Accessed 25 March 2025).
- [34] GME, Gestore Mercati Energetici, 2025. <https://www.mercatoelettrico.org/en/default.aspx>. (Accessed 25 March 2025).
- [35] DOE, U.S. Department of Energy. Open EI., 2023. <https://openei.org/datasets/files/961/pub/>. (Accessed 14 March 2023).
- [36] Gurobi Optimization. <https://www.gurobi.com/>. (Accessed 11 May 2022).