ECOS 2026: The role of hydrogen in temporary remote deployable energy systems

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Abstract:

Europe has led global decarbonisation efforts through its climate neutrality target for 2050, supported by policy frameworks such as the European Green Deal. Integrating renewable energy systems is a critical step in this transition, yet the intermittency of renewable sources poses challenges for reliable energy supply, particularly in remote locations where grid access and fuel availability are limited. The European Commission's hydrogen strategy identifies low-carbon hydrogen as a key enabler for deep decarbonisation, offering long-term energy storage, sector coupling, and a pathway for defossilising energy-intensive applications. However, hydrogen production and storage are associated with significant capital costs, technical complexity, and spatial requirements, raising questions about when and where its deployment is justified, particularly in temporary remote deployable systems with limited land availability and logistical constraints.

This study investigates the role of hydrogen in the energy system design and operation of temporary remote deployable energy systems. A techno-economic mixed-integer linear programming (MILP) optimisation framework is applied to assess the influence of hydrogen supply strategy, grid electricity access and land availability on the optimal system configuration. Seven scenarios are evaluated for a hypothetical defence camp of 2,000 residents located in a temperate oceanic climate.

Simulation results demonstrate that hydrogen's role as an energy vector depends highly on the imposed simulation constraints. In unconstrained islanded operation, locally produced hydrogen reduces total system costs by providing seasonal storage that eliminates renewable overcapacity. When land constraints are imposed for islanded operation, hydrogen becomes a structural necessity, as batteries and renewables alone cannot cover seasonal demand within spatial limits. Import of hydrogen can additionally reduce costs of the energy system without grid access. This is done by eliminating both renewable oversizing and electrolyser investment, though at the expense of supply chain dependency. These findings provide guidance for designing low-carbon energy systems for temporary off-grid applications.

Keywords:
Hydrogen; Deployable energy systems; Techno-economic optimisation; Islanded operation; Mixed-integer linear programming

1. Introduction

The European Union's commitment to climate neutrality by 2050 requires the large-scale deployment of renewable energy, deep electrification of end uses, and the integration of low-carbon flexible energy carriers such as hydrogen [1]. The EU hydrogen strategy explicitly targets rapid deployment of electrolyser capacity and associated infrastructure as a central lever to realise these ambitions [2]. Hydrogen's system value is particularly pronounced in energy systems with high shares of variable renewables and pronounced seasonal mismatches between supply and demand. In such contexts, battery storage is generally superior for short-term balancing, whereas hydrogen becomes increasingly attractive for multi-day to seasonal storage and cross-sector flexibility, despite its lower round-trip efficiency [3]. Techno-economic studies confirm that combining batteries with hydrogen storage can enhance reliability and reduce lifecycle costs compared to battery-only designs when resource variability is high or fossil fuel use is constrained [4]. However, hydrogen infrastructure is capital-intensive and operationally complex, so its deployment must be evaluated against alternative flexibility options on a case-by-case basis rather than assumed universally optimal [5].

Remote and off-grid energy systems including islanded microgrids used in mining operations, research stations and defence camps represent a demanding class of applications where the trade-offs between hydrogen and alternative storage options are especially acute. Such systems face limited access to liquid fuels, challenging logistics, high reliability requirements, and growing decarbonisation targets that discourage continued reliance on diesel generation [6]. Techno-economic studies show that adding hydrogen production and storage to solar and wind resources can improve supply security and reduce net present costs relative to diesel-based or battery-only solutions, particularly at larger scales and under strong seasonal variability [7]. Within this category, temporary deployable defence camps represent an especially challenging case as they must be rapidly deployable and dismantlable, operate with a high degree of autonomy, and increasingly align with national and alliance-level climate objectives [8]. Their heavy reliance on fossil fuels creates substantial logistical and operational vulnerabilities, motivating interest in more efficient, low-carbon energy solutions [9]. Existing studies, however, mostly focus either on large-scale national or regional systems [10], on permanent energy hubs in urban or campus contexts [11], or on generic off-grid microgrids without constraints on land use or deployment duration [12]. By contrast, deployable defence camps and similar temporary installations combine three features that are rarely analysed together:

- land availability for energy infrastructure is limited by operational layouts, camouflage, and security requirements;
- deployment duration is finite and often short, affecting the amortisation of capital-intensive assets such as electrolysers and hydrogen tanks;
- access to external energy vectors can range from non-existent to relatively abundant, at prices several times higher than in conventional supply routes.

These dimensions critically influence whether hydrogen should be produced locally, imported, or excluded from the optimal design, yet there is little quantitative guidance on their combined effect for temporary net-zero systems.

Mixed-integer linear programming (MILP) has proven effective for co-optimising technology sizing and operational dispatch in hybrid microgrids and energy hubs under detailed techno-economic and environmental constraints [13]. Recent works show that hydrogen is typically selected in MILP-optimised systems when long-duration storage is required, fuel logistics are costly or uncertain, or stringent emissions constraints are imposed [14]. Nonetheless, most of these studies do not simultaneously incorporate land-use constraints, explicit limits on deployment duration, and the option to import hydrogen or electricity, which are central elements of deployable defence camps and analogous temporary sites [15].

This paper addresses this gap by developing and applying a MILP-based techno-economic optimisation framework to quantify the role of hydrogen in a representative temporary deployable defence camp. The framework includes seven scenarios spanning three dimensions: hydrogen strategy (no hydrogen; local electrolyser/storage loop; imports), electricity access (islanded vs. grid-connected), and land availability (unlimited vs. constrained). By comparing costs, land footprint, storage requirements, and energy flows across these scenarios, the study derives boundary conditions under which hydrogen becomes an economically and operationally justified energy vector in temporary remote systems. The results provide actionable guidance for planners of future deployable energy systems and help translate high-level European hydrogen and climate strategies into concrete infrastructure choices for highly constrained environments.

2. Methodology

The techno-economic assessment presented in this study is based on a scenario-based optimisation framework designed to identify the conditions under which hydrogen emerges as a justified energy vector in temporary, net-zero deployable energy systems. Rather than prescribing hydrogen's role in advance, the framework resolves technology selection and sizing through cost-minimising optimisation, allowing the comparative economics of hydrogen, battery storage, and renewable generation to drive system design under each set of operational constraints.

2.1. Case study description

The hypothetical temporary defence camp analysed in this study is located near Ede, in the Netherlands, representing a temperate oceanic climate zone. The camp is assumed to house 2,000 residents across 50 buildings, with a fleet of 80 vehicles that the optimiser can assign to either hydrogen fuel cell or battery electric powertrains depending on system economics. Renewable resource availability is characterised by an average solar irradiance of 285 W/m² and an average wind power density of 200 W/m², derived from Global Solar Atlas and Global Wind Atlas data for the selected location, as shown in Figure 1. The one-year deployment horizon was chosen as the primary case to reflect the short-term operational cycles typical of deployable defence camps, while simultaneously representing the most demanding amortisation condition for capital-intensive hydrogen infrastructure.

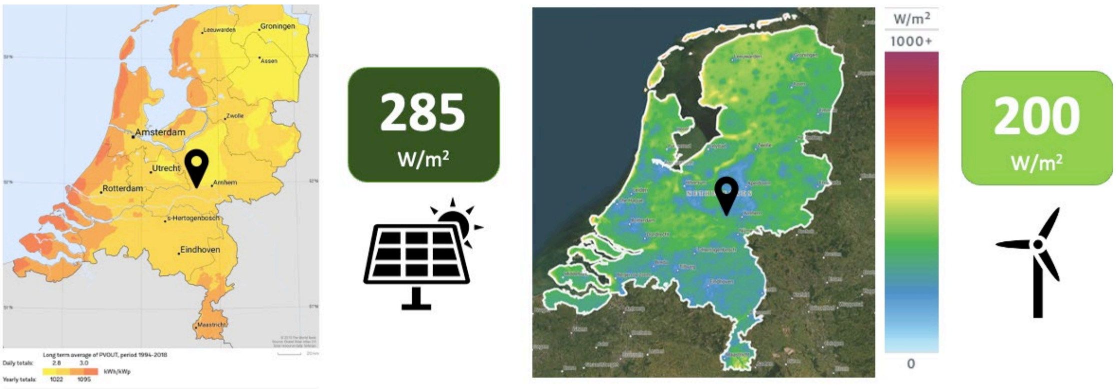

Figure. 1. *Solar and Wind power density resource maps from Global Atlas [16], [17]*

2.2. Scenario definition

To explore the sensitivity of optimal system design to three operationally motivated dimensions (hydrogen supply strategy, access to grid electricity, and available land for energy infrastructure) seven scenarios were constructed, as summarised in Table 1. The hydrogen supply dimension distinguishes between configurations in which no hydrogen pathway is permitted (No H2), those in which local production via electrolysis is enabled (Islanded and Grid connected scenarios), and those in which hydrogen can either be produced locally or imported from an external supply chain (H2 supplied). Although hydrogen was enabled as an option in all analysed scenarios except 05-No H2, its actual utilization depended entirely on the economic outcome of the optimisation. The grid connected scenarios contrast islanded operation since electricity can be drawn from the national network at variable or fixed import prices. The land availability dimension reflects the spatial constraints and is represented by unlimited-area and constrained-area scenarios.

Table 1. *Scenario matrix for techno-economic evaluation of hydrogen as an energy vector*

Scenario title	Abbreviation	Electricity grid connection	Hydrogen enabled as an energy vector	Hydrogen supply from external sources	Available area for camp deployment
01 - Islanded	Islanded	NO	YES	NO	UNLIMITED
02 - Islanded limited	Islanded limited	NO	YES	NO	LIMITED
03 - H2 supplied	H2	NO	YES	YES	UNLIMITED
04 - H2 supplied limited	H2 limited	NO	YES	YES	LIMITED
05- Islanded – No H2	No H2	NO	NO	NO	UNLIMITED
06 - Grid connected*	Grid	YES	YES	NO	UNLIMITED
07 - Grid connected limited**	Grid limited	YES	YES	NO	LIMITED

* In scenario 06-Grid connected, price of electricity was varied between low electricity price (Sweden case) and 10,000 €/MWh. ** In scenario 07-Grid connected limited, price of electricity was varied between 200 €/MWh and 50,000 €/MWh.

2.3. MILP optimisation model

Energy system topology optimisations were performed with the CAIRN planning tool [18], which employs MILP for deterministic optimisation over a one-year operational horizon. The energy system topology available to the optimiser is illustrated in Figure. 2. As candidate technologies it includes photovoltaics, wind turbines, battery storage, electrolysers, hydrogen tanks, fuel cells, heat pumps, and thermal storage, with optional hydrogen and electricity import pathways depending on the scenario.

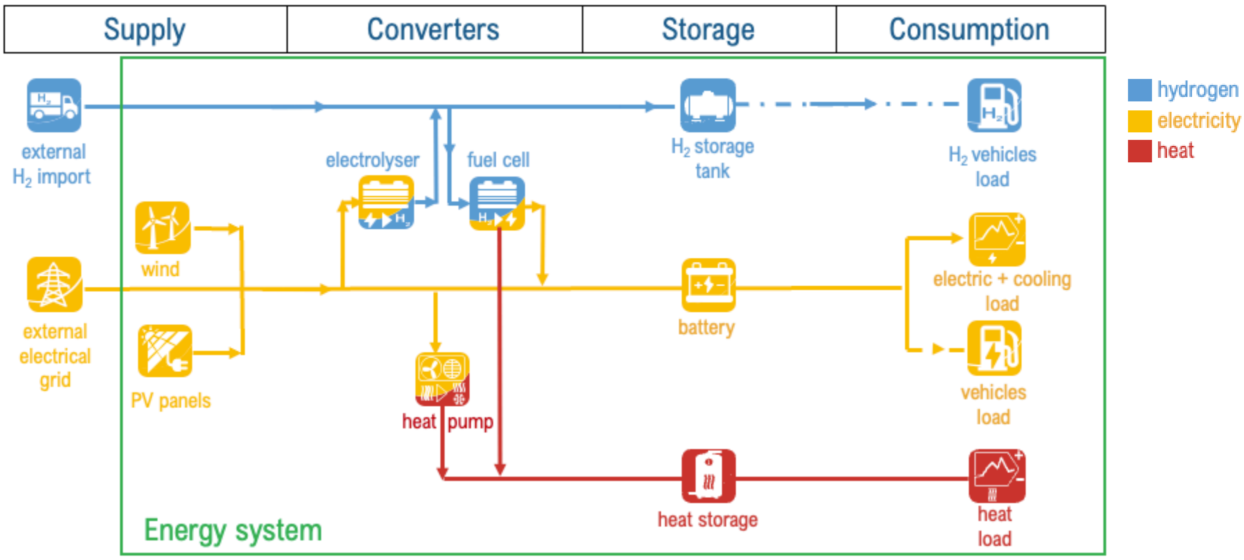

Figure. 2. *Candidate technologies and energy carrier interconnections available to the CAIRN planning tool*

The model minimises the total system cost, combining capital expenditure (CAPEX) and operational expenditure (OPEX) across all installed components c and all hourly time steps t, where $t = \{1,2,\ldots,8760\}$ represents the 8,760 hours of the one-year simulation horizon, as expressed in (1):

$$min \sum\nolimits_c (CAPEX_c \cdot x_c + OPEX_c \cdot x_c) + \sum\nolimits_t (p_{grid,t} \cdot E_{grid,t} + p_{H_2} \cdot m_{H_2,t}), \tag{1}$$

where x_c is the installed capacity of component c, $p_{grid,t}$ is the electricity grid price at time t, $E_{grid,t}$, is the electricity imported from the grid, p_{H_2} is the hydrogen import price, and $m_{H_2,t}$ is the hydrogen mass imported at time t. Costs are expressed in €/kW for CAPEX and OPEX, while energy import prices are expressed in €/kWh for electricity and €/kg for hydrogen.

The optimisation is subjected to energy balance constraints enforced at each time step t. The electrical energy balance is expressed in (2):

$$\sum\nolimits_c E_{c,out,t} - \sum\nolimits_c E_{c,in,t} + E_{grid,t} = D_{elec,t} + \Delta SOC_{bat,t} \tag{2}$$

where $E_{c,out,t}$ and $E_{c,in,t}$ are electrical energy output and input of component c at time t, $D_{elec,t}$ is the electrical demand at time t, and $\Delta SOC_{bat,t}$ is the change in battery state of charge at time t. All equation terms are expressed in kWh. The thermal energy balance is expressed in (3):

$$\sum\nolimits_c Q_{c,out,t} - \sum\nolimits_c Q_{c,in,t} = D_{heat,t} + \Delta SOC_{tes,t}, \tag{3}$$

where $Q_{c,out,t}$ and $Q_{c,in,t}$ are the heat output and input of component c at time t, $D_{heat,t}$ is the thermal demand at time t, and $\Delta SOC_{tes,t}$ is the change in thermal storage state of charge at time t. All equation terms are expressed in kWh. The hydrogen mass balance is expressed in (4):

$$\sum\nolimits_c m_{H_2,prod,c,t} - \sum\nolimits_c m_{H2,cons,c,t} + m_{H_2,imp,t} = D_{H_2,trans,t} + \Delta SOC_{H_2,t} \tag{4}$$

where $m_{H_2,prod,c,t}$ and $m_{H2,cons,c,t}$ are the hydrogen mass production and consumption of component c at time t, $\dot{m}_{H_2,imp,t}$ is the hydrogen import mass at time t, $\Delta SOC_{H_2,t}$ is the change in hydrogen storage state of charge at time t, and $D_{H_2,trans,t}$ is the hydrogen demand for transport at time t. All equation terms are expressed in kg. Component capacities, conversion efficiencies, storage limits, and import pathway availability are enforced as additional linear constraints.

2.4. Input data

The simulation input data were derived from two primary sources: a systematic review of literature and internally maintained databases, with the goal of simulating utilisation of current state-of-the-art equipment. Static parameters define the techno-economic characteristics of each candidate technology component, while dynamic parameters describe time-varying inputs such as load profiles and resource availability. All values reflect current state-of-the-art equipment and are summarised in the following subchapters.

2.4.1. Static parameters — techno-economic characteristics

The techno-economic characteristics of all candidate energy system components used as inputs to the MILP optimisation are summarised in Table 2. For each component, the table lists the specific CAPEX, annual OPEX, and conversion efficiency or relevant technical parameter used by the CAIRN planning tool. Given the one-year deployment horizon of the camp, CAPEX is applied directly as a one-time investment cost without annualisation, representing the most demanding economic condition for capital-intensive hydrogen infrastructure. In the spatially limited scenarios, area was limited to 1 km^2.

Table 2. *Main static techno-economic parameters for energy system components.*

Component	CAPEX (€/kW or €/kWh) and import price	OPEX (% of CAPEX/yr)	Additional data
Photovoltaic (PV) panels	54 €/m^2	0.28 %	—
Wind turbines	219,000 €/unit	0.002 %	Limited to 50 units
Battery storage	273.9 €/kWh	2 %	Round-trip efficiency: 98 %
Electrolyser (PEM)	1000 €/kW	2 %	Efficiency: 68 %
Hydrogen tank	0.567 €/kWh	0.005 %	Storage pressure: 350 bar
Fuel cell (PEM)	900 €/kW	2 %	Efficiency: 40 %
Heat pump	500 €/kW	3 %	—
Thermal storage	8 €/kWh	3 %	Heat loss rate: 5 %
H_2 import	15 €/kg	—	—
Grid electricity import	Variable (see Figure 4) or constant 200–10,000 €/MWh	—	—

2.4.2. Dynamic parameters — time series inputs

Dynamic inputs consist of hourly time series over the one-year simulation horizon, covering energy demand profiles, renewable resource availability, and electricity import prices. When considering only hours with non-zero demand, the average hourly loads are approximately 1,700 kW for electricity, 1,300 kW for heating, and 360 kW for cooling, as shown in Figure. 3.

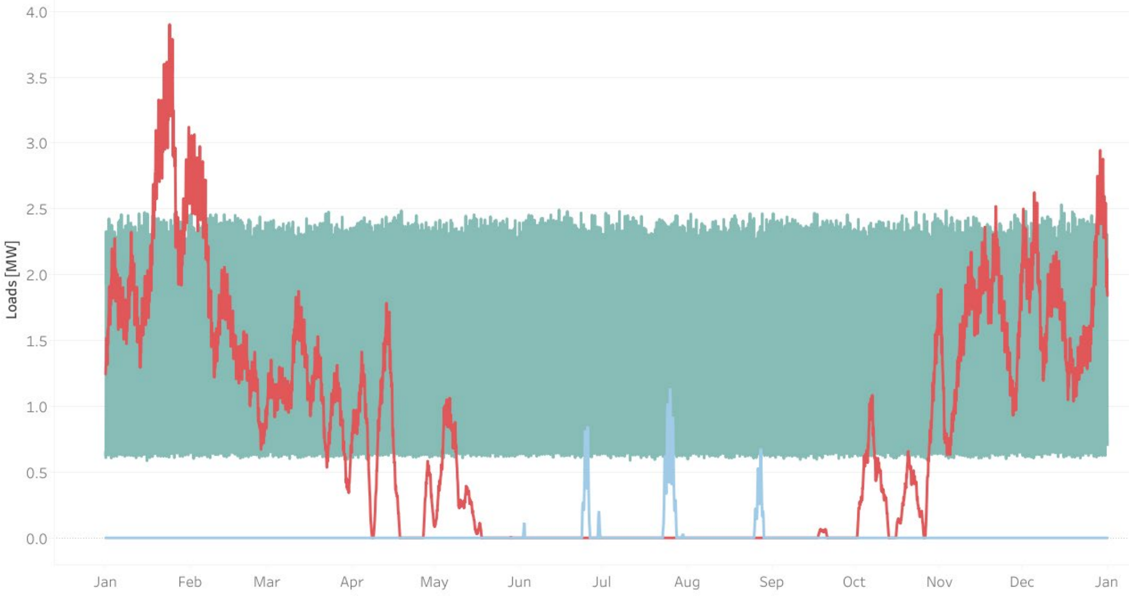

Figure. 3. *Hourly load profiles for electrical, heating and cooling of the temporary defence camp*

Electricity import prices for the grid-connected scenarios were drawn from 2025 historical market data for two contrasting European price regions: North-Central Sweden (low-price reference) and Central-Northern Italy (high-price reference), as shown in Figure. 4.

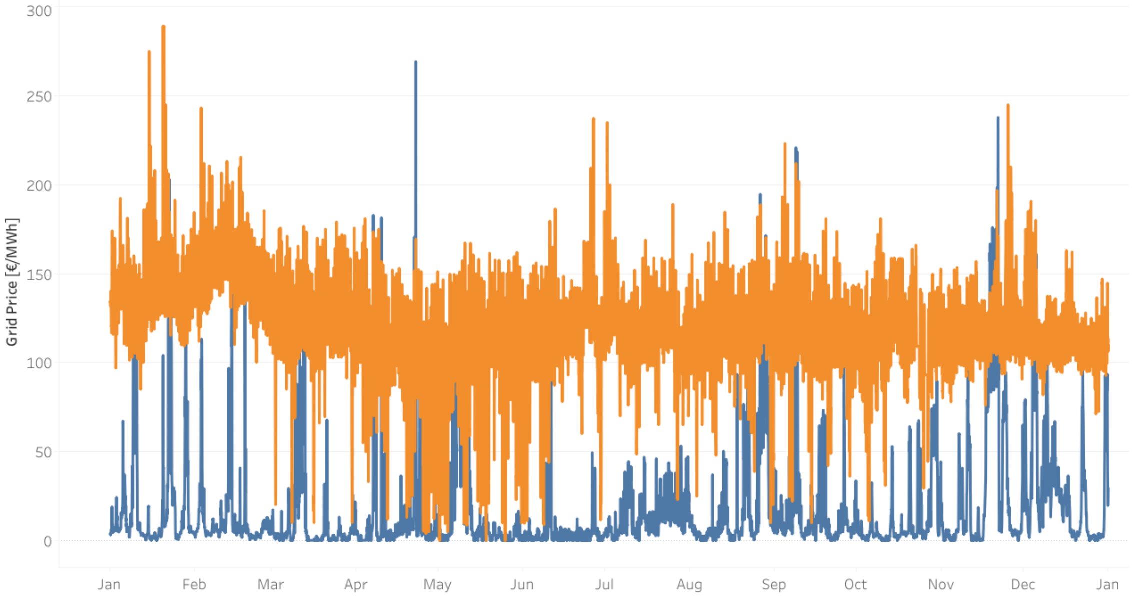

Figure. 4. *Variable Grid Prices for Central-Northern Italy (High Grid Price - orange) and North-Central Sweeden (Low Grid Price - blue)*

In addition, to map the full transition from grid-dependent to islanded hydrogen-integrated configurations, a systematic sweep of constant grid prices was performed: 200–10,000 €/MWh for the Grid scenario and 200–50,000 €/MWh for the Grid Limited scenario.

Results

The optimisation results across all seven scenarios reveal that the CAIRN planning tool selects hydrogen only under specific combinations of conditions, and never simply because it is enabled as an option. For a one-year deployment horizon, the short amortisation window acts as a powerful economic filter against capital-intensive hydrogen infrastructure. However, whether hydrogen is deployed in the optimal solution depends on the available electricity supply, the hydrogen strategy, and the land constraints imposed on the system. The following subsections examine how these factors influence system design, annual energy flows, and total costs, before synthesising the boundary conditions that govern hydrogen adoption across the analysed scenarios.

3.1 Influence of hydrogen on system design

The physical infrastructure selected by the optimiser varies substantially across scenarios, with the most pronounced differences occurring in generation capacity and storage sizing.

Figure. 5 shows that PV and wind turbines form the core of electricity generation across all scenarios. The only exceptions are the two variable-price grid cases (Low grid price Sweden and high grid price Italy), where grid imports fully displace local generation investment. Among the islanded configurations, the hydrogen-free scenario (05-No H2) requires the largest renewable capacity. Without seasonal storage, the optimiser must size PV and wind to guarantee supply through the worst winter weeks, resulting in significant overcapacity for the remainder of the year. Introducing hydrogen in the unconstrained islanded case (01-Islanded) removes this requirement, allowing renewables to be scaled to average rather than peak seasonal demand and significantly reducing installed generation capacity. When land is restricted (02-Islanded Limited), hydrogen takes on a dual role. It continues to provide seasonal storage while simultaneously compensating for the generation capacity reduction as a result of spatial constraints, which is why electrolyser and fuel cell generation capacities increase relative to the unconstrained case. The H2-import scenarios (03-H2 and 04-H2 Limited) carry this logic further. Since hydrogen arrives from an external supply chain, no electrolyser is needed, and the optimiser scales renewables only to cover average daily electrical and heat pump loads rather than seasonal extremes.

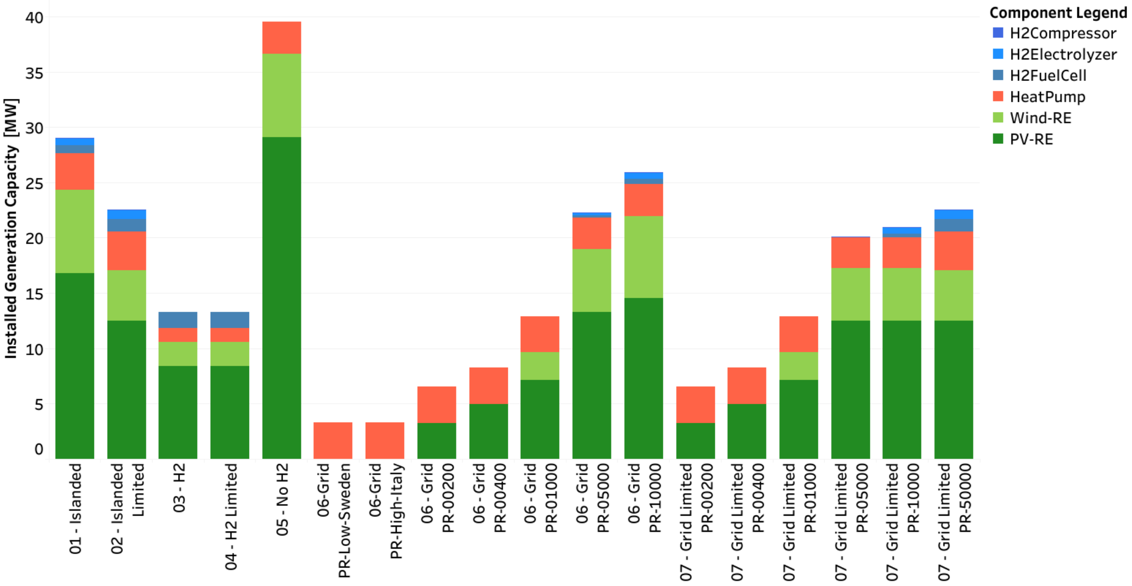

Figure. 5. ~~-~~*Installed generation capacity*

The storage subsystems, presented in Figure. 6, provide quantitative evidence of the design logic through the storage dimension. Batteries appear in every scenario, providing intra-day balancing regardless of hydrogen strategy. Hydrogen storage appears selectively, only where fuel cells are deployed and seasonal bridging is required. The most telling comparison is between scenarios 01-Islanded and 02-Islanded Limited, where hydrogen storage increases nearly tenfold under land constraints. This confirms that hydrogen absorbs the burden of both seasonal storage and generation capacity replacement when spatial limitations apply, at the cost of ~~a~~ additional capital investment. Thermal storage is present across all scenarios but is generally larger in islanded configurations, where the heat pump cannot rely on a continuous electricity supply from the grid, PV or wind turbines. In the hydrogen-free scenario (05-No H2) in particular, thermal storage takes on an additional role as an indirect electricity buffer, shifting heat pump operation away from periods of unfavourable renewable output and thereby reducing peak electricity consumption.

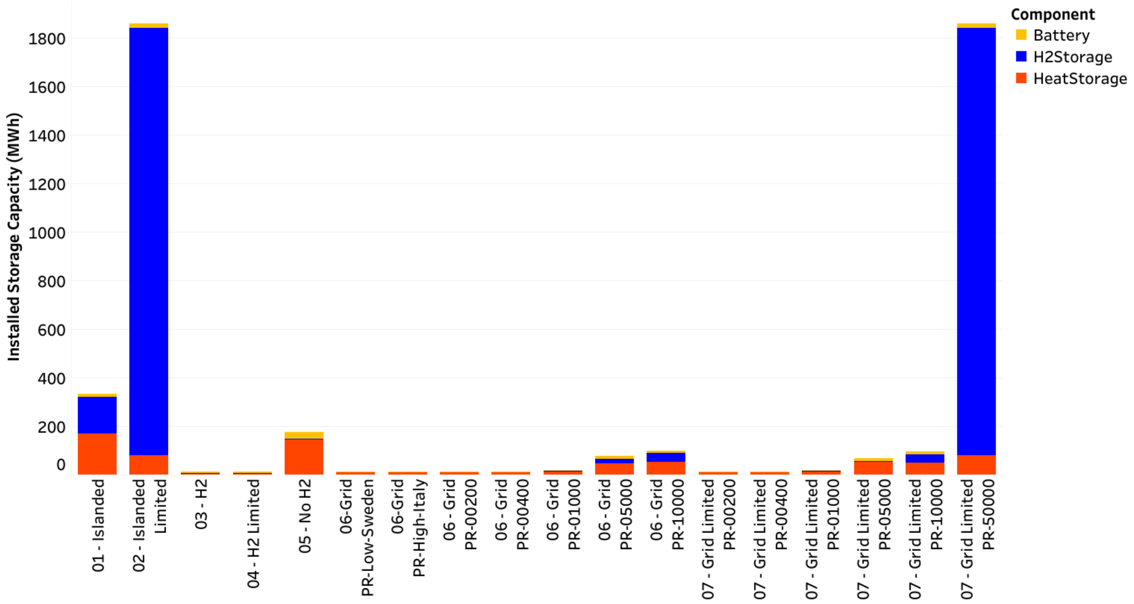

Figure. 6. *Installed storage capacity*

3.2 Influence of hydrogen on system operation

Figure. 7 illustrates the annual electricity flows across all scenarios and reveals how hydrogen reshapes the balance between local generation, storage cycling, and imports at the operational level.

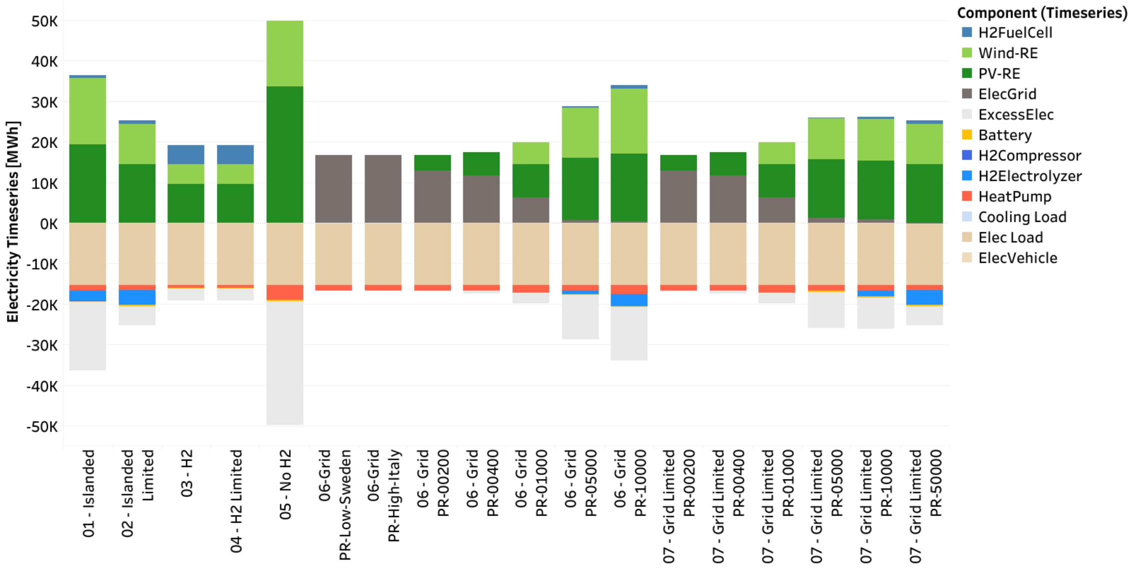

Figure. 7. *Total energy generation and consumption per year*

As depicted, the hydrogen-free scenario (05-No H2) produces the most operationally inefficient outcome. Because renewables must be heavily oversized to guarantee winter supply, large amounts of excess electricity arise during summer and high-wind periods once battery storage is full. This curtailment is an inherent consequence of the design logic described in section 3.1, and it is reduced progressively as hydrogen is introduced. In hydrogen-enabled islanded scenarios, excess electricity is converted to hydrogen via electrolysis and recovered through fuel cells when generation falls short, allowing the optimizer to right-size renewables to average demand rather than worst-case weeks. This optimization of the generation-consumption balance is the primary operational benefit of hydrogen in islanded configurations.

A further operational consequence of hydrogen is that it extends the feasible design space. Restricting the deployment area in the hydrogen-free case renders the optimisation problem unsolvable, as no combination of renewables and batteries can cover winter demand within the spatial limits. Introducing hydrogen as an option, as demonstrated by scenario 02-Islanded Limited, resolves this by absorbing the mismatch that constrained generation capacity cannot cover, making year-round self-sufficient operation achievable where it would otherwise be infeasible.

In the grid-connected scenarios, system operation is governed by electricity import prices. At low prices, as in the Sweden and Italy variable-price cases, the grid acts as an infinite source and local generation closely matches consumption with no curtailment. As import prices increase towards extreme values of 10,000 €/MWh or 50,000 €/MWh in the area-limited case, the optimiser progressively reduces grid imports in favour of local renewable generation, and at sufficiently high prices hydrogen is also introduced into the optimal configuration, converging towards operational behaviour that resembles the islanded cases.

3.3 Influence of hydrogen on system cost

Figure. 8 presents total annual costs including CAPEX and OPEX across all scenarios. Since the combined cost is the objective function minimised by the MILP optimiser, it represents the most direct metric for assessing hydrogen's techno-economic viability across the analysed scenarios.

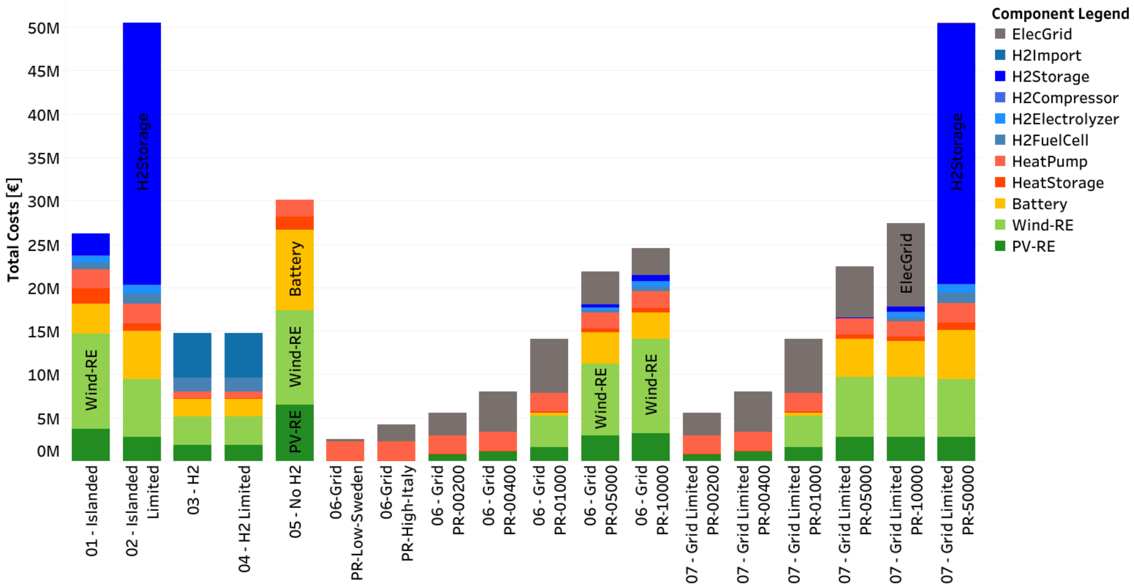

Figure. 8. *Total costs per year including CAPEX, OPEX and fuel costs*

Within the islanded configurations, the progression from 05-No H2 to 01-Islanded to 02-Islanded Limited reveals two distinct economic effects of hydrogen. Comparing 05-No H2 with 01-Islanded shows that locally produced hydrogen reduces overall costs despite adding electrolyser and storage infrastructure, because it eliminates the far more expensive combination of renewable oversizing and large battery banks required to survive winter without hydrogen seasonal storage. However, when land constraints are imposed in 02-Islanded Limited scenario, this economic benefit reverses sharply. Hydrogen storage grows to absorb the missing generation capacity, representing nearly half of total system costs and pushing total costs from approximately 27 million to more than 50 million euros. This confirms that hydrogen's cost benefit in islanded operation is conditional on sufficient land being available for renewable generation.

The H2-import scenarios (03-H2 and 04-H2 Limited) achieve substantially lower total costs than any islanded configuration, as imported hydrogen eliminates both renewable oversizing and large storage investments. The cost structure shifts from production-cost-dominated to import-cost-dominated, which is better suited to short-term deployments, although at the expense of increased supply chain dependency.

Figure. 9 reinforces these findings through normalised cost shares. Across most scenarios, the dominant cost categories are either energy imports or storage components, with hydrogen tanks and battery systems accounting for the largest shares in islanded configurations. Wind power plants consistently carry higher costs than PV installations, since their more stable year-round generation profile reduces the need for costly storage and justifies the premium. Grid-connected scenarios at low electricity prices achieve the lowest overall costs of all configurations, but costs escalate steeply with import price, with the area-limited grid scenario at extreme prices approaching the cost levels of the islanded cases.

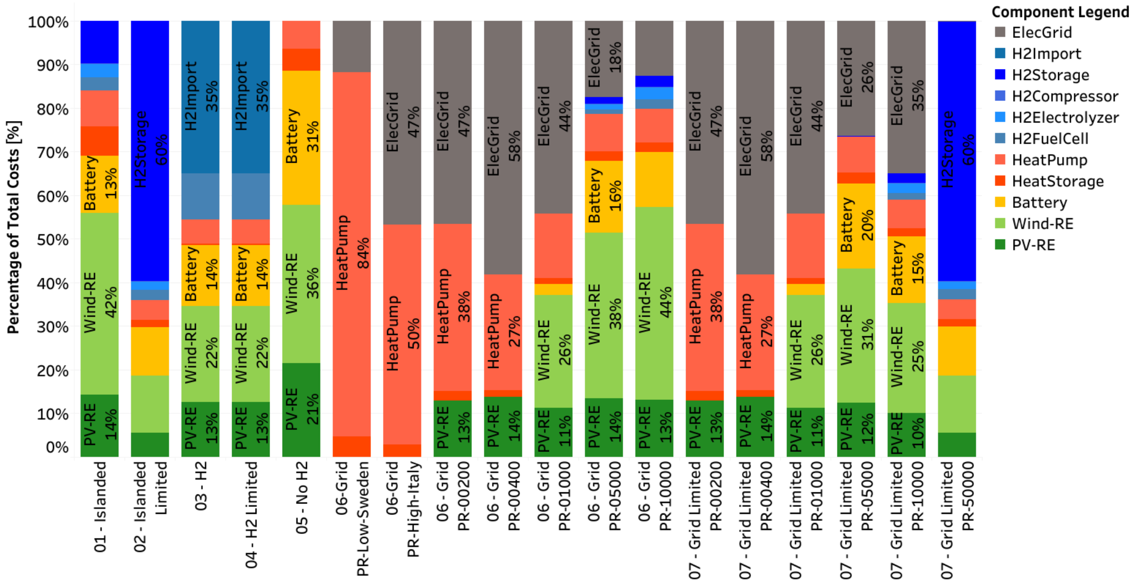

Figure. 9. *Share of total costs*

3.4 Conditions under which hydrogen becomes justified

The preceding subsections 3.1-3.3 examined how hydrogen shapes system design, operation, and costs individually. This subsection synthesises those findings into a concise set of boundary conditions that determine when and why hydrogen adoption is justified across the analysed scenarios for one-year deployment horizon.

In islanded operation with unconstrained land, hydrogen is economically justified as a seasonal storage medium. It reduces renewable overcapacity and total system costs relative to a battery-only design, even under the demanding one-year amortisation window. This justification, however, depends on sufficient land being available for renewable generation. When spatial constraints are imposed simultaneously with islanded operation, hydrogen transitions from an economically advantageous option to a structural necessity. Under this combination of constraints, no feasible net-zero configuration exists without hydrogen, establishing it as a required condition rather than a preferred one.

Imported hydrogen represents the most economically attractive pathway of all islanded configurations. By decoupling renewable sizing from seasonal demand peaks and eliminating the electrolyser investment, it achieves the lowest costs of any configuration that does not rely on electrical grid access. The trade-off is a shift from capital expenditure to import cost dependency, which means that the price of imported hydrogen has significant implications for the overall economic attractiveness of this pathway. In this study, the import price was fixed at 15 EUR/kg, reflecting a conservative estimate for green hydrogen supply in the near-term context. At higher import prices, the cost advantage of hydrogen import over local production would narrow, potentially shifting the economic optimum back towards islanded configurations with on-site electrolysis.

In grid-connected operation, hydrogen adoption is governed by the electricity import price. Below a certain price threshold, grid supply dominates and hydrogen is not selected. As import prices rise, the optimiser progressively replaces grid electricity with local renewable generation, and at sufficiently high prices hydrogen enters the optimal configuration as the enabling technology that makes the transition towards fully autonomous islanded operation economically viable.

4. Conclusions

This paper presented a MILP-based techno-economic optimisation framework to quantify the role of hydrogen as an energy vector in a temporary deployable defence camp. By systematically varying hydrogen strategy, land availability, grid access, and external energy import options across seven scenarios, the study derived quantitative boundary conditions under which hydrogen is economically and operationally justified in temporary deployments.

The results demonstrate that hydrogen's role is not fixed but shifts fundamentally depending on the constraints imposed. In unconstrained islanded configurations it acts as a cost-reducing seasonal buffer. Under land restrictions it becomes a structural enabler without which net-zero operation is not feasible. As an imported carrier, hydrogen achieves the best economics of any configuration that operates without grid access, by eliminating both renewable oversizing and the electrolyser investment, though it introduces supply chain dependency and remains more costly than grid electricity where the latter is available at competitive prices. For system planners, this means that the appropriate hydrogen strategy is site-specific and must be determined considering the spatial, logistical, and grid access conditions of each deployment.

A key finding is that hydrogen remains viable even under the economically restrictive one-year amortisation horizon. The short deployment window narrows the conditions under which hydrogen is selected, yet three distinct adoption pathways remain viable. This suggests that the results are particularly relevant for temporary deployable systems in which capital-intensive infrastructure must demonstrate clear economic justification within a constrained timeframe. For longer deployment horizons, the role of hydrogen would be expected to broaden further. As capital costs are distributed over extended operational periods, the relative weight of fuel and operational expenditure increases, strengthening the economic case for local hydrogen production and expanding the range of conditions under which on-site electrolysis enters the optimal configuration.

Acknowledgments

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