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Harmonizing the assessment of (green) hydrogen supply chain: a modular and parametrized life cycle assessment framework

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Despite a growing number of life cycle assessment (LCA) studies on green hydrogen technologies, a lack of harmonization in how to scope the LCA modeling framework and transparently disseminate results prevents the field from fully capitalizing on this expanding body of knowledge. This paper presents a harmonized LCA framework to support a consistent assessment of green hydrogen supply chains and comparison with functionally equivalent alternatives. The framework guides the practitioners to define the functional unit, tailored to six identified end-use applications of hydrogen. The process tree is developed as a unified and agile modular structure applicable to describe the value chain of any green hydrogen technology, each module representing a standalone building block that can be modified or replaced within the product system. It provides a parametrized inventory model linking the flows of the product systems to key parameters characterizing their design or performance. The framework has been implemented in a dedicated LCA tool (the HTWOL), supported by a library of modules representing pre-set configurations of elementary processes (*e.g.*, electrolyser technologies), enhancing accessibility for users with varying levels of expertise. The framework has been successively applied to representative use cases. Results show the importance of ensuring low-impact energy supply and always striving to maximize the overall energy-efficiency in delivering the functional units. Environmentally relevant deployment of green hydrogen technologies would target end-use applications with no viable fossil substitutions (*e.g.*, production of ammonia) and long-term renewable electricity storage. Efforts toward direct electrification and demand reduction must continue in parallel.

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Broader context

Green hydrogen is widely regarded as a key energy vector for the energy transition, calling for a rapid development and deployment of green hydrogen technologies. The literature has been offering a growing number of life cycle assessment (LCA) studies assessing their environmental performance. However, these LCAs are based on heterogeneous methodological choices that often make their findings not directly comparable, and prevent the field from fully capitalizing on this expanding body of work. This lack of consistency ultimately complicates decision-making related to investments, infrastructure development, and policy design. This paper proposes (i) a harmonized methodological framework for the LCA of the green hydrogen supply chain applicable to any technological contexts and applications, and (ii) its operationalization into an open-source software tool (HTWOL) for stakeholders with different levels of expertise: from technology developers aiming to improve the eco-design of electrolysers and fuel cells to energy planners and decision-makers that aims to improve their understanding on the environmental relevancy of hydrogen technologies. The results demonstrate that hydrogen appears most relevant for hard-to-electrify sectors (chemical feedstock production or long-distance shipping). It is generally not environmentally competitive in applications where direct electrification is feasible (automobile transportation or heat generation).

1 Introduction

1.1 Motivations

Although interest in hydrogen dates to the oil crisis of the 1970s,[1] the molecule is re-emerging as a potential solution for decarbonization efforts.[2–4] In particular, water electrolysis has gained renewed attention as a promising pathway for

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producing hydrogen using electricity.[5–9] Fuel cells and electrolyser (FC&EL) technologies form the backbone of this hydrogen economy, enabling the reversible conversion between electricity and hydrogen. Electrolyser technologies use electricity to split water into hydrogen and oxygen, proposing an electrified alternative to fossil-based hydrogen typically obtained by steam methane reforming (SMR). Fuel cell technologies perform the reverse electrolysis process, converting hydrogen back into electricity. Several literature reviews described a list of existing and potential applications of FC&EL technologies.[10–13] The so-called green hydrogen produced by electrolysers supplied with renewable electricity can serve as a cleaner industrial chemical platform for traditional applications (*e.g.*, reducing agent in metal transformation or reagent for chemical synthesis). Beyond its use as an industrial chemical platform, the development of green hydrogen paves the road for emerging hydrogen applications. By coupling electrolysers and fuel cell systems, green hydrogen can serve as an energy carrier to facilitate the integration of renewable sources in the energy mix by offering a flexible solution for energy storage and grid balancing. The mobility sector is also seeking to replace conventional fuels with green hydrogen by developing hydrogen-based fuel[14] and by developing vehicles equipped with fuel cell powertrains.[15,16]

FC&EL technologies can be broadly categorized into two main families based on their operating temperature.[9,17–19] Low-temperature systems operate with liquid water at temperatures typically ranging from 60 to 80 °C and include alkaline electrolysis (AEL) and proton exchange membrane (PEM) technologies, both of which are commercially mature. Alkaline electrolysers are cheaper and more robust, while PEM offers highly flexible operation. An emerging variant within this category is the anion exchange membrane (AEM) technology, which is still at a low technology readiness level (TRL 6/7). In contrast, high-temperature systems operate with steam at temperatures between 600 and 1000 °C. These systems offer higher electrical efficiency due to favorable thermodynamics and kinetics at elevated temperatures, but require significantly more heat input, and their operation offers low flexibility due to the high temperature of operation. Solid oxide (SO) technologies are the most developed among high-temperature systems, but they remain at the pilot or demonstration stage (TRL 8). Solid oxide system can be reversible – working both in electrolyser and fuel cell mode (r-SOC).[20] To supply hydrogen to its various end-use applications, these FC&EL technologies must be integrated into complete supply chains.[9,11,13,21] These include electricity generation, hydrogen conversion *via* electrolysis, gas preparation and purification, storage and distribution infrastructures, and potential reconversion of hydrogen into electricity using fuel cells. Each stage of this chain involves material and energy inputs that contribute to the overall environmental profile of the green hydrogen value chain.

As green hydrogen gains attention, several life cycle assessment (LCA) have been performed to assess their environmental performance. LCA offers a standardized framework for quantifying the environmental impacts of a product or system across its entire supply chain.[22,23] Understanding the environmental impacts of FC&EL systems is essential for at least three reasons. First, hydrogen is often portrayed as a ''flagship'' or ''the most promising technology'' for the ecological transition,[3,5,24] but without a critical and systemic evaluation, its true potential and limitations remain unclear. It is therefore crucial to assess the potential environmental impacts of FC&EL technologies over the entire supply chain, and to compare them with existing technological systems fulfilling the same function. Second, the material composition and the efficiencies differ between the families of technology (SO, AEM, PEM, Alkaline).[9] A comparison of the environmental performances of the different FC&EL technologies specific to each application (*i.e.*, function and technical requirements) would enable a tailored development of the most promising technologies. Third, as FC&EL are still emerging technologies, they present a unique opportunity to integrate eco-design strategies at the early stage of their development[25,26] through the identification of their environmental hotspots and the most sensitive parameters affecting their environmental performances and by identifying the risk of burden shift of proposed innovations. These three questions correspond to the intended objectives that an LCA of FC&EL technologies can pursue.

According to ISO 14044 standards,[22,23] LCA must be tailored to the goal of the study, including the specific type(s) of technology being developed, the end-use application(s) of the hydrogen produced, the regional and temporal context, and the intended objectives of the study. Yet, to date, there is no comprehensive LCA framework capable of consistently assessing any FC&EL system—regardless of family, application, or study objective. As a result, a wide variety of LCA models have emerged, each using different assumptions and terminology adapted to their particular technologies and applications. The consequence is that existing case studies are often neither comparable nor generalizable across different applications and technologies. From a systemic perspective, this fragmentation hinders a coherent understanding of green hydrogen potential across its diverse technologies and applications. Notably, no study has yet succeeded in providing a comprehensive overview of these technologies, indicating that the field is not yet fully capitalizing on the extensive knowledge and datasets generated so far by the rapidly growing body of LCA research.

1.2 Critical analyses of green hydrogen LCA frameworks and case studies

A structured literature review of existing LCA studies on green hydrogen is conducted to identify methodological gaps hindering harmonization. Nine green hydrogen LCA reviews,[21,27–34] complemented by two additional methodological contributions,[2,35] thirty-six practical LCA use cases,[17,36–72] and five techno-economic analyses[73–77] have been reviewed (see SI-1). This review highlights the following methodological inconsistencies and limitations. (i) Two types of functional unit (FU) are flexibly used to quantify the system's primary function and serve as the basis for comparison: those based on intermediate

hydrogen products (*e.g.*, kg or kWh of H_2 produced) and those reflecting the final service delivered by the hydrogen (*e.g.*, km driven, MJ supplied). (ii) Key processes of the supply chain delivering the final service are often omitted without justification: for instance, storage, distribution, hydrogen leakage, end-of-life, or core stack components such as end-plates or current collectors (iii) Life cycle inventories (LCI), which quantify physical input and output flows of the product systems, are mainly based on static datasets (*i.e.*, fixed or aggregated values) rather than parametrized relationships expressed as a function of key parameters of the system. (iv) Datasets from different LCA studies can barely be compared due to misaligned metrics (*e.g.*, stack manufacturing processes reported per kW, per m^2, or per stack unit) or misaligned definitions (*e.g.*, multiple conventions coexist for quantifying system efficiency: stack-limited or system efficiencies; lower heating value-based, higher heating value-based, or thermoneutral-based efficiencies; beginning of life or average efficiencies). (v) The maturity and size of the evaluated systems are not always described, and technologies are often compared on the basis of different maturity levels (defined as the technology's development stage, from current performance to anticipated 2050 targets) and size (defined as the system production capacity, from lab-scale to industrial-scale deployments).

1.3 Contribution of the paper

In response to these limitations, several solutions have been identified. First, the definition of end-use oriented functional units, adapted to both traditional and emerging applications of hydrogen technologies, to ensure consistent assessment and comparison across hydrogen applications. Second, the organization of unit processes within the system boundaries according to a harmonized modular structure aligned with the FU and adapted to the different hydrogen product systems. A modular structure decomposes a supply chain into exchangeable units (modules) that represent specific life-cycle stages or components.[70] Modularization has been beneficial in other industries for simplifying the assessment of value chains composed of several possible routes.[78–81] Third, the development of parametrized LCI (also called parametric LCI) linking the inventory flows of each unit process through explicit equations as a function of independent parameters characterizing technological properties, rather than relying on aggregated or computed numbers.[82] Parametrization successfully enhances the transparency and adaptability of LCA in different fields.[83–88]

The paper is organized into three main contributions.

(1) It develops a harmonized and flexible LCA framework that integrates the novel methodological solutions identified above: end-use functional units, a modular structure, and a parametrized inventory.

(2) It operationalizes the framework into a parametrized tool that automates the impact assessment of the green hydrogen product system, and increases the tool's usability by computing pre-set configurations, which are aggregated datasets that characterize performance, material composition, or impact scores of reference FC&EL technologies, storage and distribution processes, and energy mixes.

(3) It demonstrates the application of the framework and the tool through a series of illustrative case studies.

2 Methodology

This section describes the novel approach developed for the LCA of FC&EL technologies. The methodology is divided into three parts, each addressing a research objective. The first part develops the harmonized LCA framework for the green hydrogen supply chain. The second part explains how this LCA framework is operationalized in an online tool called HTWOL. The third part illustrates the use of the framework and the HTWOL tool for two applications of hydrogen.

2.1 Development of a harmonized LCA framework for green hydrogen supply chain

2.1.1 Selection of the functional units and system boundaries for each application. The LCA framework presented in this paper anchors the hydrogen supply chain to the main applications of hydrogen technologies, as represented in Fig. 1. The hydrogen value chain is structured in six main life cycle processes: the production of electricity, the conversion of this electricity into hydrogen using an electrolyser, the post processing of the hydrogen to reach technical requirements (such as pressure and purity required by the hydrogen application), the distribution of the hydrogen from production site to application site, the storage of the hydrogen, and the reconversion of hydrogen into electricity using a fuel cell (which co-produces heat).[9,11,13,21,89,90] The color code used in Fig. 1 to represent these processes is used consistently throughout the paper. The value chain processes included within the system boundary depend on the end-use application of the hydrogen produced. Six main hydrogen applications have been identified.[10–15,43] Hydrogen can be used as a chemical platform, serving as a molecular building block or reducing agent in processes such as ammonia or methanol production, metal reduction and refining; as industrial heat, where it is burnt in a burner to supply high-temperature needs in sectors like steel, cement, or glass; as domestic energy source, with co-generation of power and household heating; for transportation, either in combustion engine vehicles (e-fuel) or in fuel cell electric vehicles; and as renewable electricity storage, where electricity is chemically stored in hydrogen molecules for later use.

The functional units are derived from the end-use services of hydrogen for each application, ensuring that they specifically reflect the technical performances of the delivered service. End-use processes (*e.g.*, fuel cell vehicle, burner) may be needed to link the hydrogen produced or the electricity reconverted by the system to its final service, extending the system boundaries from an intermediate flow to the end-use functional unit.

Additionally, a flowchart has been developed as a guideline for practitioners to ensure the construction of consistent system boundaries for each application, aligned with the goal of the study and the recommended end-use functional unit (Fig. 2). Through a series of guiding questions, the flowchart

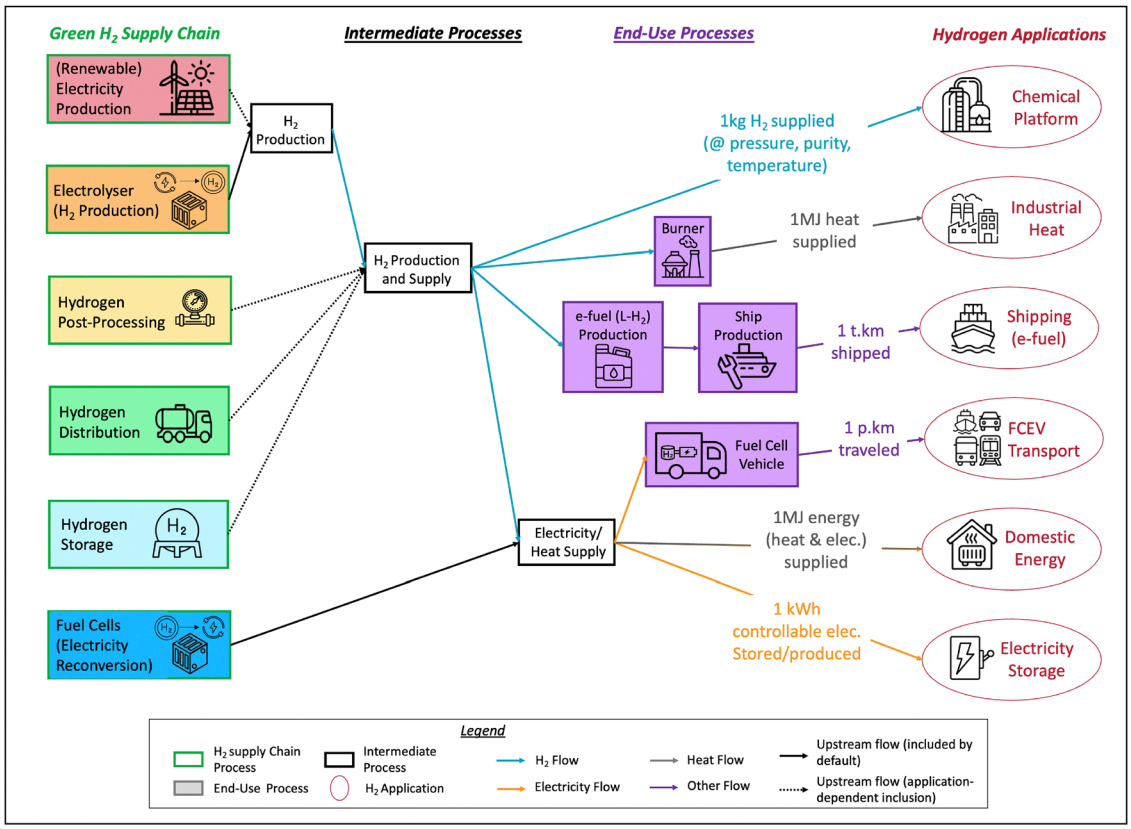

Fig. 1 Graphical representation of the green hydrogen product system with explicit links to hydrogen applications. Boxes with green contours and rainbow fills represent the main life-cycle processes, with the same color code used consistently throughout the paper. Red circles describe current and prospective applications of hydrogen. An explicit functional unit is associated with each application. Intermediate processes (black boxes) combine different supply-chain processes to create intermediate products, which may require additional end-use processes (grey boxes) to provide the intended end-use service/product.

clarifies which processes of the supply chain or end-use processes should be included or not in the system boundaries: each colored zone indicates whether the same-colored supply-chain process (from Fig. 1) is included within the system boundary. It also specifies how the heat co-produced by fuel cells is accounted within these system boundaries. To exemplify the use of the flowchart, it is applied to the main applications identified above. For each case, the recommended end-use functional unit is recalled, a set of functionally equivalent technologies enabling meaningful comparisons is identified, and the corresponding pathway through the flowchart is partially traced and represented by a colored line.

For chemical platform applications, the functional unit is defined as supplying 1 kg of H_2 at a specific pressure, purity, and temperature. The system boundaries include electricity generation and hydrogen production. Inclusion of hydrogen post-processing, storage, and distribution depends on the application. These choices are consistent with the existing LCA of H_2 produced through steam methane reforming from fossil resources,[91] enabling a comparison with this technology.

For industrial high-temperature heat production, the functional unit is defined as 1 MJ of heat. The system boundaries include electricity generation, hydrogen production, and combustion in an adapted industrial burner. Depending on the application scale and requirements, daily storage and distribution processes can be included.[92] Industrial heat systems can be compared to alternative fuels currently used in industry (natural gas, fuel, and electric heaters).

For domestic energy applications, a fuel cell system that combines the production of low-temperature heat and electric power is considered. A functional unit of 1 MJ of energy supplied is chosen, implying that electricity and heat are equivalent, because both forms of energy provide a useful domestic service in this application. Therefore, an energy allocation is applied to account for the heat co-produced by the fuel cells.[35] The system boundaries include electricity production, electrolyser, hydrogen storage, and electricity reconversion processes.[49,58] Distribution and post-processing can be included depending on the application. The alternative includes energy systems combining a heat source (heat pump, electrical boilers, gas or fuel boiler) and an electrical power source (the same as the one used for producing the hydrogen). These alternative systems are sized to provide 20% of electricity and 80% of heat, which is representative of the energy consumed yearly in a household[49] (in Milan).

Transportation is modeled through two distinct hydrogen-based applications. First, the transportation using fuel cell vehicles is assessed using an end-use functional unit of

1 vehicle km (v km), which can be adapted to different vehicle types. The system boundaries encompass the entire hydrogen supply chain, including hydrogen production, conditioning, distribution, and on-site storage at refueling stations, as well as the production and operation of the fuel cell vehicle and its powertrain.[16,48] Heat co-produced by the fuel cells is considered a waste.[83] This scope enables a functionally consistent comparison with alternative propulsion technologies, such as gasoline vehicles (GV) and battery electric vehicles (BEV).

Second, hydrogen use for maritime freight transport is assessed through its conversion into e-fuels, specifically liquid hydrogen. In this case, the functional unit is 1 ton km (t km) transported. The system boundaries include hydrogen production, storage, and refueling infrastructure, conversion to liquid hydrogen, as well as the production and operation of the vessel.[93] This system can be compared to traditional maritime freight operated with heavy fuel oil. At present, this application is restricted to shipping, since direct hydrogen combustion in jet turbines is still at an early stage of development (TRL 3–4).[94]

For renewable electricity storage, two functional units are defined. The first focuses on the electricity storage function alone in a chemical form (hydrogen). Defining the functional unit as 1 kWh of electricity stored during a defined duration allows isolating the impacts of the electricity storage processes from those of electricity generation. These system boundaries only include the conversion from electricity to hydrogen, hydrogen storage, and reconversion to electricity, enabling a fair comparison with alternative storage technologies (battery, hydro pump & storage). Heat recovery depends on the system configuration, and when applicable, is accounted for using exergy allocation (as heat provides a secondary function in that context).[58,95] The second functional unit addresses the production of 1 kWh of controllable electricity, integrating the electricity generation process with the electricity storage system defined before. This broader goal and scope allows for comparison between the green hydrogen power-to-X-to-power system and other controllable electricity sources, such as nuclear or fossil-based power plants.

These example system configurations can be used both by LCA practitioners operating within specific hydrogen applications and by researchers and engineers focusing on stack development. For the latter, we recommend evaluating emerging technologies across several pathways to test the sensitivity of environmental results to the end-use context. Alternatively, the framework allows the assessment of FC&EL technologies outside a specific application context—although this option is not recommended and is therefore not represented in the flowchart. In such cases, storage, distribution, and end-use processes are assumed to be unnecessary, while standardized hydrogen conditioning requirements (1 bar, 98% purity, 25 °C) are applied.

2.1.2 A common modular structure for the green hydrogen value chain. The simplified representation of the green hydrogen supply chains (Fig. 1) is refined for LCA modelling (Fig. 3). The main life-cycle stages (electricity supply, electricity-to-hydrogen conversion, post-processing, distribution, storage, reconversion of hydrogen to electricity, and any additional end-use processes) are detailed and organized into a modular structure. A module is defined as a group of one or more elementary processes that delivers a specific intermediary flow through the hydrogen life cycle. It serves as a standardized building block for constructing the foreground system. Modules can be included or excluded depending on the study goal (see Fig. 2), enabling an adaptable but consistent modelling approach across all the functional units defined. Modules are interchangeable: because they are consistently organized and named, different technologies or suppliers can be substituted within the same structure. This ensures comparability across stack families or across storage and distribution options.

The elementary processes in all the modules are classified into four categories: the operation consumables (in pink), the stack manufacturing (in grey), the equipment manufacturing (in brown), and the end-of-life of the system (in khaki). Operation consumables include the processes that feed the electrolyser stack (electricity, heat, ultrapure water, KOH), the equipment (electricity), and the fuel-cell stack (hydrogen, KOH). The elementary flows (direct emissions) released during operation (hydrogen leakage) are also represented in pink. The equipment manufacturing covers the complete life cycle for the balance-of-plant of the FC&EL systems, for the storage and distribution of hydrogen, and for the end-use processes. The stack manufacturing comprises all processes for producing the FC&EL stacks. Each stack consists of multiple identical cells (the core electrochemical components) arranged with a frame, end plates, and seals. The cells contain functional layers described in the electrolyser and fuel cell modules. Finally, the end-of-life includes all processes for managing the waste of the system (stack and equipment).

In reality, the electrolyser system draws a single electricity inflow. In the model, this flow is disaggregated into three processes: electricity consumed by the stack, electricity consumed by the BoP (both shown as pink processes in the electrolyser module), and the chemical energy stored as hydrogen (corresponding to the main life-cycle module in red in Fig. 3). This disaggregation enables transparent identification of key contributors to environmental impacts at each stage and highlights eco-design levers for improvement.

Modules are supplied by the background system, which consists of processes for which primary data on materials, energy, and services are generally unavailable; generic datasets are therefore used to estimate cradle-to-gate life cycle inventories of the respective supply chains.

2.1.3 Parametrized life cycle inventory modeling. This section presents the main assumptions and the key parameters (*i.e.*, parameters characterizing a process or a technology) that support the parametrized modeling of the LCI of the fuel cell and electrolyser modules. Fig. 4 illustrates the structure of the parametrized LCI model, linking input key parameters (*i.e.*, parameters configurable by the modeler or through a pre-set configuration), calculated key parameters (*i.e.*, intermediate, commonly used metrics that clarify system performance and design, which are calculated by the model), and the resulting

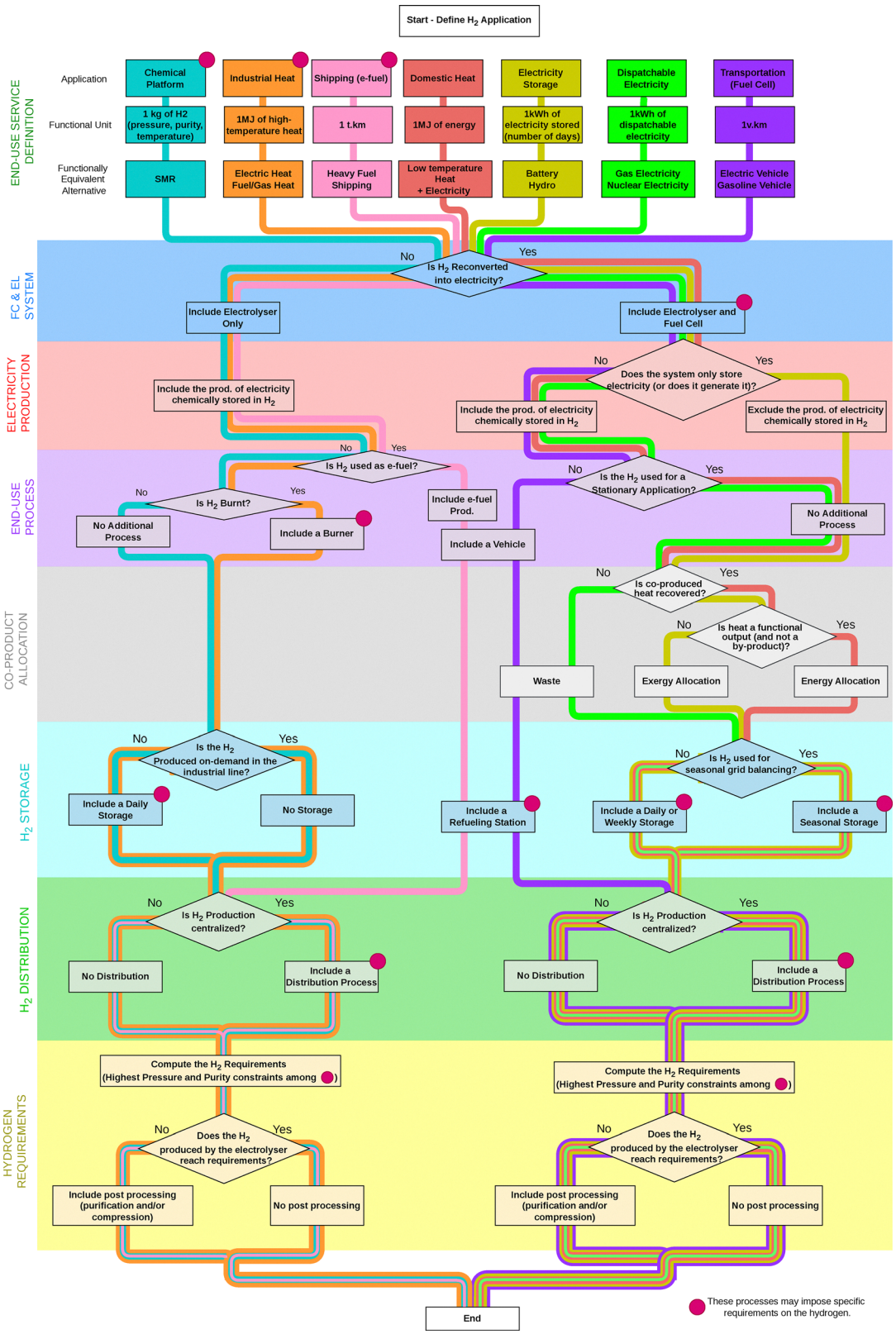

Fig. 2 Flowchart for defining harmonized LCA scope of green hydrogen supply chains depending on the application and the goal of the study. Each colored zone guides the inclusion of a supply-chain process in the system boundary. The method is demonstrated for six main applications, with colored routes answering the decision nodes; two paths are shown where alternatives remain.

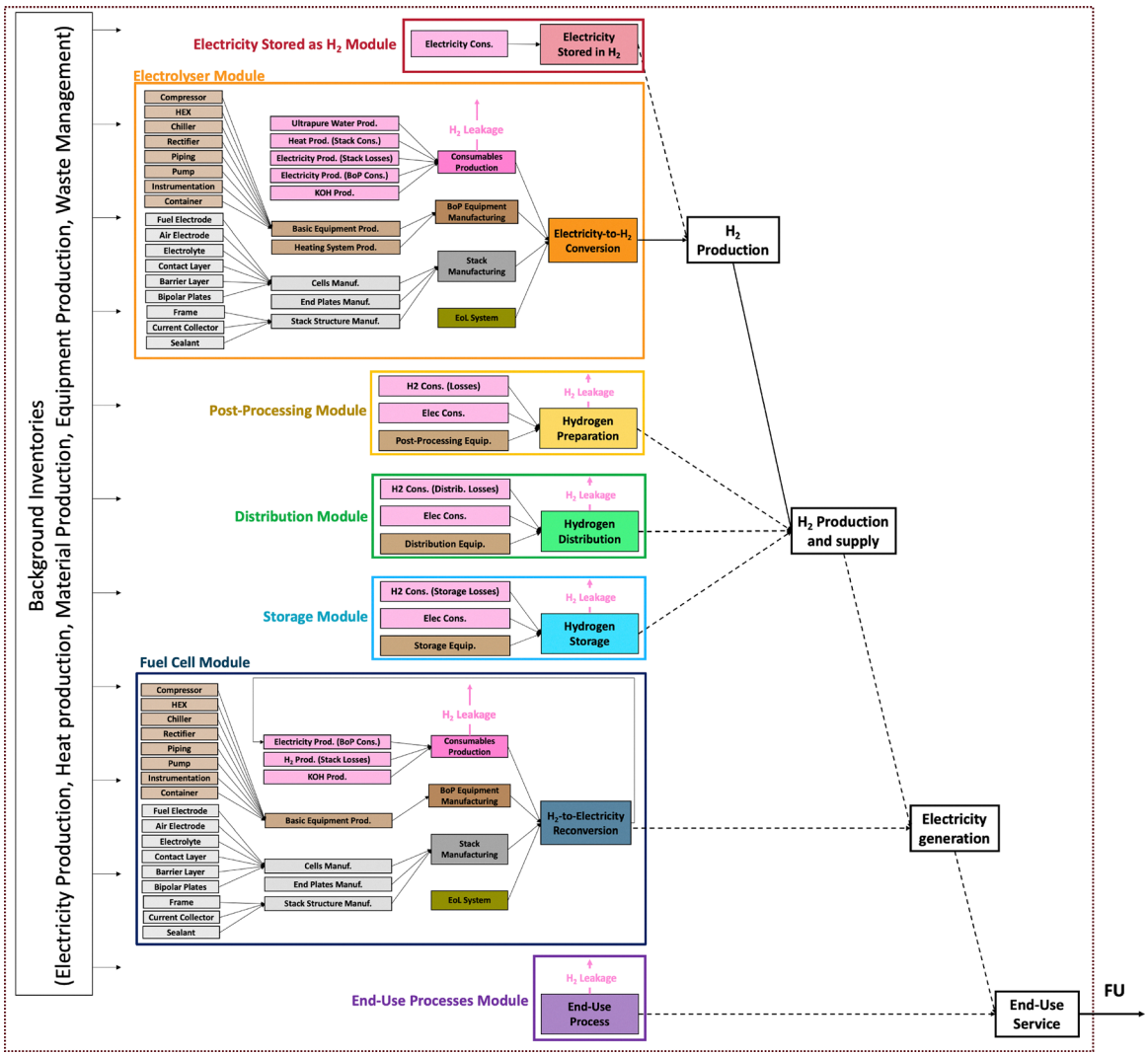

Fig. 3 Modular structure of the green hydrogen product system. The system is organized into modules—coherent groups of one or more elementary processes that deliver a specific intermediary flow throughout the hydrogen life cycle.

parametrized flows. The detailed equations used to calculate the flows are provided in SI-3.

2.1.3.1 Stack and BoP modules.

Electrochemical cell. Each electrochemical cell has the same active surface area. The physical structure of the cell is described by a series of functional layers composing the electrochemical core, each characterized by its material, thickness, surface ratio (relative to the active area), and, when applicable, coatings or additives.

Stack. Identical cells are assembled into stacks, with the maximum number of cells per stack defined as a key parameter. The stack structure includes additional non-electrochemical components (frame, current collector, sealant), characterized by their material composition and expressed as mass per active surface, except for the endplates, which are modeled using the same parameters as the functional layers.

Balance of Plant (BoP). The BoP encompasses all peripheral equipment required for system operation. Each component is defined by its own capacity, expressed per unit of hydrogen flowrate (*e.g.*, kW per kgH_2 per h for a compressor or m^2 per kgH_2 per h for a heat exchanger (HEX)), depending on the nature of the equipment. This parametrization reflects the core functionality of each device, which is scalable according to the hydrogen flowrate it handles throughout the process.

System. The complete system (*i.e.*, stack and BoP) is dimensioned to meet the required capacity: a hydrogen flowrate (kgH_2 per h) in electrolysis mode or an electrical power output (kW) in fuel cell mode. The operating current density is a key parameter that governs stack operational performance. Given this current density and the required service, the total active surface area (the sum of the active areas of all electrochemical cells in the system) is determined. From this, the number of cells and the number of stacks (based on a maximum number of cells per stack) are derived. All components are then scaled to the functional unit by calculating the total quantity of product delivered over the system's lifetime (*i.e.*, lifetime × capacity). As the BoP is parametrized per unit of flowrate, the capacity of

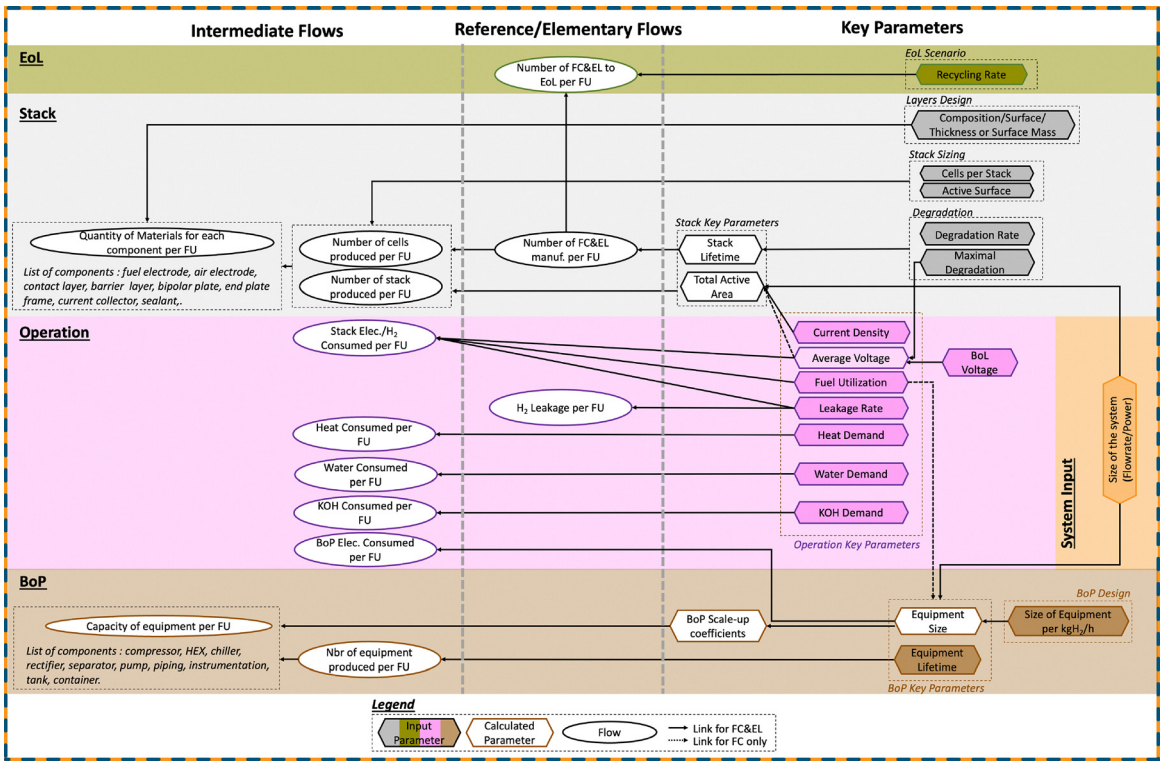

Fig. 4 Mapping the main key parameters determining intermediary and elementary flows in the FC&EL system modules. Colored hexagons denote input key parameters for the stack (grey), balance of plant (brown), operational conditions (pink), and end-of-life (khaki). Arrows indicate how these input parameters feed into the calculation of calculated key parameters (white hexagons) and ultimately determine the flows of the module (white ellipses).

each equipment is divided by its lifetime to match the functional unit.

End-of-life. For stacks, potential recycling of metallic parts is considered; a recycling rate is defined as an input key parameter, and the unrecycled remainder is considered disposed of. The end-of-life of equipment is already included in the cradle-to-gate datasets representing those components and is not modelled again here. A cut-off approach is used to model the end-of-life in this work, meaning that the product system includes the burdens of primary and recycled material production (which includes waste treatment and recycling processes), while no credits are assigned for material substitution in subsequent life cycles.[2]

2.1.3.2 Operation consumables

Electrical conversion. Electricity consumed (electrolyser) or generated (fuel cell) is determined by the average cell voltage, which reflects both the useful energy and faradaic losses (ohmic resistance).[96,97] For electrolysers, higher voltages increase losses; for fuel cells, lower voltages indicate reduced electrical efficiency. The operating voltage evolves over time due to degradation. For simplicity, a linear voltage drift is assumed over the system's life.[67,76] Additionally, in fuel cells, hydrogen is supplied in excess to protect the stack. Despite recirculation, part of the hydrogen is inevitably lost, reducing the conversion efficiency.[98,99]

BoP electrical consumption. Electricity is used to operate equipment such as the compressor, the rectifier, the pump, the chiller, and instrumentation. Depending on the components, the electricity consumed per FU is based on the input power of the equipment (compressor, pump, chiller, instrumentation) or operational inefficiencies of the equipment (rectifier).[68,100]

Thermal management. Electrolysers may require external heat input due to their endothermic reaction and/or their operating temperature. Heat demand depends on operating conditions and heat integration of the system; this demand is modeled as an aggregated parameter. For fuel cells, the exothermic reaction generates recoverable heat. The amount of heat recovered per FU is also considered as an aggregated parameter. This heat can be valued as a co-product or treated as waste, with system boundaries adjusted accordingly (see Fig. 2).

Energy mixes. The model allows users to define the energy supply configuration through the parametrization of the electricity mix and the heat mix. It is considered that systems are supplied with medium voltage electricity, which can be sourced from wind, hydro, PV, nuclear, or fossil-based generation sources. Heat can come from natural gas or electricity. An additional option includes fatal heat, referring to waste heat recovered and valorized from unrelated industrial processes, which is assumed to be impact-free.[89] These mixes determine the upstream environmental impacts of the energy used.

Other consumables. Water and KOH are modeled as direct input parameters expressed per functional unit.

H_2 leakage. Hydrogen leakage is quantified by the leakage rate specified for the electrolyser and the fuel cell. This results

in both elementary emissions of hydrogen to the atmosphere and additional hydrogen production or consumption to compensate for the loss.

2.1.3.3 Complementary modules along the supply chain

Electricity stored in H_2. Hydrogen is assumed to contain 33.3 kWh per kgH_2 of chemical energy that is provided by electricity during the water electrolysis process, which corresponds to the lower heating value (LHV) of hydrogen.

Post-processing, storage, and distribution. These modules share a common structure, each comprising three processes: equipment manufacturing, electricity consumption (cradle-to-gate processes), and H_2 consumption (provided by the upstream processes of the supply chain). The following key parameters are associated with these elementary processes: the equipment size, the electricity consumed to provide the service, and the hydrogen leakage rate during equipment operation.

For the storage and the distribution, H_2 pressure and purity required are included as additional input key parameters, to comply with specific hydrogen specifications for these modules.

For post-processing, the type of equipment, the size of the equipment, and the electricity consumed depend on the hydrogen requirements:

– A compressor is operated when the pressure of the hydrogen produced by the electrolyser is lower than the pressure required. The model of Escamilla *et al.* (2022) is used to size the compressor[96] depending on the hydrogen pressure before and after compression.

– A pressure swing adsorption (PSA) unit is used as a proxy to represent hydrogen purification processes. The PSA is operated when the hydrogen purity supplied by the electrolysis does not reach the required purity.[37,101] The size of the PSA depends on the difference between the required purity and the purity of hydrogen supplied by the FC&EL system.[98,102]

End-use process module. End-use processes constitute the final step to reach the end-use functional unit and may form a separate sub-system, treated as a cradle-to-gate process. This module is parametrized by two elements: the hydrogen leakage rate, to quantify the elementary hydrogen emission; and the quantity of intermediate product required per FU, either hydrogen (kgH_2 per FU) or electricity (kWh per FU), which specifies and links the upstream supply needed to deliver the final service.

2.1.3.4 Influence of the size and the maturity. The critical review identified up-sizing (predicting impacts of larger systems delivering more H_2 or power) and up-scaling (predicting impacts of more mature systems, *i.e.*, systems at higher TRL and/or further advanced through learning-curve effects and prospective improvements) as distinct challenges for prospective LCA. The parametrized framework offers a novel approach to model the influences of size and maturity on the environmental impacts of the supply chain.

Size. Current literature provides no consistent evidence that size systematically alters stack operation parameters (cell voltage, current density), or equipment operation parameters (efficiencies or hydrogen leakage rates). For stack design, as literature reports diverge on how cells per stack scale with size,[67,68] it is considered that system up-sizing affects only the number of stacks deployed and the cell active area. These parameters do not influence the life cycle inventory (see SI-3). Stacks are assumed without explicit manufacturing gains at scale (neither in material production nor in stack assembly).[68] By contrast, BoP components exhibit economies of scale.[103] To represent this, BoP components follow a power-law scaling[40,48] using empirically derived factors from ecoinvent,[103] adjusted to reflect environmental rather than economic scaling; the approach is detailed in SI-4.

Maturity. As the values of the input key parameters evolve with learning and development of the technologies, the level of maturity is modeled through differentiated scenarios in the data collection (3.2.1).

2.2 LCA framework and inventory data management

The following sections describe the sources and methods used for data collection and quantification, including (i) the development of pre-set configurations characterizing the unit processes in the foreground system (*i.e.* the gate-to-gate processes identified in the modular structure); (ii) the creation of LCI datasets for representing the background system (*i.e.* the cradle-to-gate processes that complete the life cycle of processes in the modular structure); and (iii) the selection of the life cycle impact assessment (LCIA) method and indicators for feeding the characterization matrix.

2.2.1 Generating pre-set configurations of unit processes of the modular structure. Pre-set configurations of elementary processes have been developed to provide greater granularity and flexibility in modeling the LCA results. These ready-to-use configurations set default values to key input parameters and assign default materials and energy providers to model cradle-to-gate processes. Together, the different pre-set configurations enable a comprehensive definition of all input parameters, ensuring usability for practitioners with varying levels of expertise. At the same time, each parameter can be modified manually, allowing advanced users to refine assumptions and achieve a higher level of detail when needed. Table 1 provides illustrative default values for a subset of the pre-set configurations, while a comprehensive list of default inputs across all configurations is available in SI-2. Pre-set configurations are defined for: electrolyser and fuel cell systems, storage and distribution systems, and energy mixes. For electrolyser and fuel cell systems, a pre-set configuration is defined by the combination of technology and maturity. Four technology types are modeled (solid oxide, proton exchange membrane, anion exchange membrane and alkaline), plus one specific scenario of PEMFC adapted to vehicles. Three scenarios of maturity have been modeled: (1) one characterizing the current performances of the technologies (2025); (2) one characterizing the target or prospective performances for 2030; and (3) one quantifying the target or prospective performances for 2050. To develop these configurations, a systematic review of existing FC&EL was conducted, with the studies being

Table 1 Representative default values of key parameters across the pre-set configurations representing the elementary processes. Technical systems are classified by life cycle stages (*e.g.*, electrolyser (EL), fuel cell (FC)), by type (*e.g.*, alkaline (A), proton-exchange membrane (PEM), anion-exchange membrane (AEM), and solid oxide (SO)), and maturity level ('2025' current performances and '2050' prospective targets)

Electrolyser

Description	AEL		PEMEL		AEMEL		SOEL	
Maturity	2025	2050	2025	2050	2025	2050	2025	2050
Current density [A cm^{-2}]	0.3	2.0	1.4	4.0	0.2	1.8	0.3	2.0
Beginning of life cell voltage [V]	1.96	1.70	2.03	1.68	2.05	1.70	1.32	1.28
Degradation rate [% kh^{-1}]	0.2	0.1	0.2	0.1	1	0.5	1.9	0.1
Stack lifetime [kh]	70	100	50	110	10	30	20	80
Stack elec. demand [kWh per kgH_2]	59.3	52.0	61.0	51.3	60.3	52.7	50.5	38.0
BoP lifetime [kh]	100	250	100	175	100	175	100	175
Water demand [L per kgH_2]	15	15	13	13	13	13	13	13
Heat demand [kWh per kgH_2]	—	—	—	—	—	—	10	7
BoP elec. demand [kWh per kgH_2]	6	6	5.8	5.8	5.6	5.6	5.5	5.5
Hydrogen leakage [%]	1.23	0.15	1.23	0.15	1.23	0.15	1.23	0.15

Fuel cells

Description	AFC		PEMFC		AEMFC		SOFC		FCEV (PEM)	
Maturity	2025	2050	2025	2050	2025	2050	2025	2050	2025	2050
Current density [A cm^{-2}]	0.2	4.0	0.6	2.2	0.8	1.3	0.3	1.0	0.9	1.3
Cell voltage [V]	0.64	0.85	0.65	0.89	0.60	0.76	0.65	0.81	0.70	0.77
Fuel utilization [−]	0.9	0.98	0.9	0.98	0.9	0.98	0.9	0.98	0.9	0.98
Degradation rate [% kh^{-1}]	3.1	0.5	1.4	0.4	5.6	1.0	1.7	0.2	4.2	3.5
Stack lifetime [kh]	5	10	15	80	10	10	20	80	4	8
Stack elec. reconverted [kWh per kgH_2]	13.4	21.4	12.4	19.8	6.5	18.1	10.7	18.1	14.3	15
BoP lifetime [h]	50	100	50	100	50	100	50	100	50	100
Heat available [kWh per kgH_2]	13	8	17	12	17	12	15	12	—	—
BoP consumption [kWh per kgH_2]	6.5	6.5	6.3	6.3	6.3	6.3	4.8	4.8	7.6	7.6
Hydrogen leakage [%]	2.31	0.85	2.31	0.85	2.31	0.85	2.31	0.85	2.31	0.85

Storage

Description	Buffer tank (Day)		Buffer tank (Week)		Salt cavern (Season)		Refueling station (FCEV)	
Maturity	2025	2050	2025	2050	2025	2050	2025	2050
Hydrogen leakage [%]	0.32	0.07	2.14	0.36	1.53	0.68	1.95	0.25
Pressure required [bar]	50	50	100	100	100	100	700	700

Distribution

Description	Pipeline (250 km)		Pipeline (2500 km)		Shipping (2500 km)	
Maturity	2025	2050	2025	2050	2025	2025
Hydrogen leakage [%]	0.82	0.15	0.82	0.15	1.53	0.29
Pressure required [bar]	100	100	100	100	100	100

Electricity mix

Description	100% Renewable mix	Grid-based mix	Nuclear power only
Wind power	75%	0%	0%

Table 1 (*continued*)

Electricity mix			
Description	100% Renewable mix	Grid-based mix	Nuclear power only
Hydro power	18%	0%	0%
Solar power	7%	0%	0%
Nuclear power	0%	0%	100%
European grid	0%	100%	0%
Carbon intensity [gCO_2eq. per kWh]	34.5	320	8.7

Heat mix			
Description	Industrial coupling	Electric heater	Fossil burner
Fatal heat	64%	0%	0%
Electric heat	36%	100%	0%
Natural gas heat	0%	0%	100%
Carbon intensity [gCO_2eq. per kWh]	12.4	34.5	280

classified according to their technology type and maturity level.[9,17,19,30,38,40,42,46,49,61,64,65,67,72,83,100,104–161] The key parameters for the parametrized inventory modeling (Fig. 4) were extracted for each study. The pre-set configurations were constructed by assigning average parameter values and selecting representative materials for each technology and maturity level. Similarly, pre-set configurations for hydrogen storage (buffer tank, salt cavern, refueling station) and distribution (pipeline, shipping) were defined for the three maturity levels (2025, target 2030, target 2050).[89,162–174] For energy inputs, different pre-set electricity and heat mixes are implemented. For electricity, three configurations were considered: a 100% renewable mix,[175] the current average European grid mix, and a 100% nuclear mix. For thermal energy, three supply scenarios were modeled: 100% natural gas, using a conventional boiler integrated into the BoP; 100% electricity, *via* an electric heater; and a "fatal heat" scenario assuming freely available industrial heat, representing potential synergies between electrolysers and nearby high-temperature industrial processes. The complete list of parameters and process selection, including all assumptions, organized references, and pre-set configurations preparation, is provided in the SI (SI-2).

Default configurations have also been defined for the end-use processes. A 90% LHV-based efficiency is considered for the burner,[176,177] including 0.5% of hydrogen leakage. This increases the quantity of hydrogen (LHV of 120 MJ per kgH_2) produced per MJ of industrial heat to 9.3 g H_2 per MJ heat. For the FCEV, an average European fuel cell automobile is modeled. The characteristics of the car are taken from Carculator.[83] The parametrized tool PETRAUL[86] was used to estimate the energy demand to be supplied by the fuel cell system, set at 0.20 kWh km^{-1}. For the hydrogen-fueled shipping application, 0.85 g H_2 per t km (with a Grade D purity[162]) are required to propel the ship;[93] the hydrogen liquefaction (including 2% hydrogen leakage and 11 kWh per kgH_2 electricity consumed) and the cargo manufacturing are modeled from literature.[93]

2.2.2 Modeling cradle-to-gate life cycle inventories for green hydrogen product system. Cradle-to-gate LCI datasets were developed for elementary processes supplying the main materials, equipment, and energy sources required by the elementary processes of the modular structure. They are based on models from the literature[17,38,39,49,64,67,101,149,168,178,179] and *ecoinvent* database v3.10.[103] All these assumptions and models are available in SI-2.

2.2.3 Modeling alternative technologies. The alternative technologies used for comparison with FC&EL systems (Fig. 2) were modeled using *ecoinvent* and complemented with data from recent studies, reflecting the current performance of batteries[180] and the characteristics of an average-size European vehicle (gasoline and battery electric).[83,86] For all electricity-powered systems, three electricity mix scenarios (100% renewable, European average, and 100% Nuclear) were applied, consistent with those used for FC&EL technologies.

2.2.4 Life cycle impact assessment method. The potential environmental impacts have been assessed using three versions of the Impact World + v2.0 method,[181] enabling users to select

the LCIA version most suited to their expertise and the LCA goal. The first version is a climate change–only method, applied to assess greenhouse gas emissions (GWP100, in $kgCO_2eq.$). The second possibility is the Expert version of IW+, which aggregates damage results into two areas of protection: human health (expressed in DALY) and ecosystem quality (expressed in PDF m^2 year), with midpoint indicators feeding into these endpoints. The third possibility is the footprint version of IW+ that assesses five categories of impacts: the carbon footprint (GWP100, in $kgCO_2eq.$), the water scarcity footprint (in m^3 world-eq), the fossil and nuclear energy use (in MJ deprived), the remaining human health (in DALY) and the remaining ecosystem quality (in PDF m^2 year). The category indicators rest of human health and rest of ecosystem quality are presented excluding the contributions of climate change indicators and water availability indicators. The climate change impact of hydrogen emissions in the air is currently not addressed in LCIA methodologies. A characterization factor of 10.8 $kgCO_2eq.$ per kgH_2 derived from Warwick *et al.* (2022) was applied to assess climate change impacts of hydrogen emissions (GWP100).[182] Effect factors for Expert Version categories have been calculated in SI (SI2 – Consumables background).

2.2.5 The HTWOL. The LCA framework for the hydrogen product system is operationalized on a web-based tool. The so-called HTWOL tool combines the algorithms and matrices defined by the framework, enabling automated calculations of environmental impacts according to the parametrized matrix formulation. Results automatically generated include contribution analyses of the reference scenario; comparison of different configurations of green hydrogen supply chain; and comparison with alternative technologies offering equivalent functions. Two versions of the tool have been created. An open-access demo version† is based on a limited life cycle inventory database generated from publicly available data from literature. The full version of the tool, based on the ecoinvent database, is available on request through a valid ecoinvent license. The user guide and the architecture of the HTWOL tool to organize these datasets and run the calculations are further discussed in the GitHub repository of the tool.[183]

3 Results

The results are structured in three sections, each answering one of the LCA intended objectives addressed by our framework: identification of the hotspots along the respective hydrogen product systems; comparison between different FC&EL technologies; comparison of hydrogen technologies with alternative functionally equivalent technologies. Detailed results are available in SI-5.

3.1 Identification of the hotspots for a solid oxide system

In this section, contribution and scenario analyses are performed for a green hydrogen supply chain delivering 1 kWh of controllable electricity. The reference scenario uses a commercial SOEL (current performance) producing 10 kgH_2 per h, pipeline distribution (250 km), seasonal storage, and reconversion *via* a commercial 100 kW SOFC (current performance); renewable electricity and electric heat are assumed for energy inputs, and no heat recovery is included.

The modular structure facilitates the interpretation of LCA results by organizing the contribution analysis by life cycle stages or elementary processes. In Fig. 5a, the results highlight the hydrogen-to-electricity reconversion (dark blue) as the most impactful life cycle stage (68–70%). The electricity (from renewable sources) converted and stored as chemical energy in hydrogen (33 kWh) represents 11–15% of the overall impact score (red). The other contributors in decreasing order of importance are the electrolysis (orange, 12–13%), post-processing compression (yellow, 3–4%), distribution (green, 1–2%), and storage (skyblue, 1–2%). The contribution analysis by elementary processes (Fig. 5b) is dominated by the surproduction of hydrogen to compensate for H_2 losses (62–67%). Electricity consumed (including both the 33 kWh electricity stored into hydrogen, but also electricity losses along the supply chain) contributes to 20–26% of the impact scores. Smaller contributors to the overall impact scores are stack manufacturing (2–9%), equipment manufacturing (1–4%), heat consumed (supplied by electrical heaters, 3–4%), water consumption during operation (0–1%), or hydrogen leakage (0–6%). A cross-analysis of the two charts shows that fuel cell losses (*i.e.*, surplus hydrogen production) are the main hotspot of the study. Electricity is the second largest contributor, but about half of it is actually stored as chemical energy. Only the remaining half reflects electricity consumed or lost, which can be reduced with more efficient systems. The stack and BoP manufacturing impacts are comparatively modest within the modules, suggesting eco-design efforts should focus on improving stack efficiency rather than reducing manufacturing impacts.

A sensitivity analysis is performed using a one-at-a-time approach. Each assumption in the reference solid oxide scenario is varied while all others are held constant: electricity (nuclear and grid mixes) and heat (fatal heat and natural gas mixes) supplied; heat recovery allocation (no recovery, exergy allocation, energy allocation); hydrogen pressure (from 100 bar to 1000 bar) and purity (from 98% to 99.999%) requirements; electrolyser technology (SO, PEM, AEM, Alkaline), maturity (current performance, Target 2030, Target 2050), and size (from 0.1 to 100 kgH_2 per h); storage technology (buffer tank and geological storage); distribution pathway (pipeline from 250 km to 2500 km); fuel cell technology, technological maturity, and size (from 1 kW to 1 MW). The results for the climate change indicator are reported in Fig. 6. Results for the other indicators are provided in SI-5.

This sensitivity analysis reveals a strong sensitivity to the energy mix. Climate change impacts increase sevenfold when the system operates on the European grid electricity instead of renewable power, and by 1.7 times when switching from electric to natural gas heat. The use of renewable energy sources is therefore key to achieving low-carbon intensity hydrogen production. Heat recovery is also recommended as

† https://htwol-co2.streamlit.app/

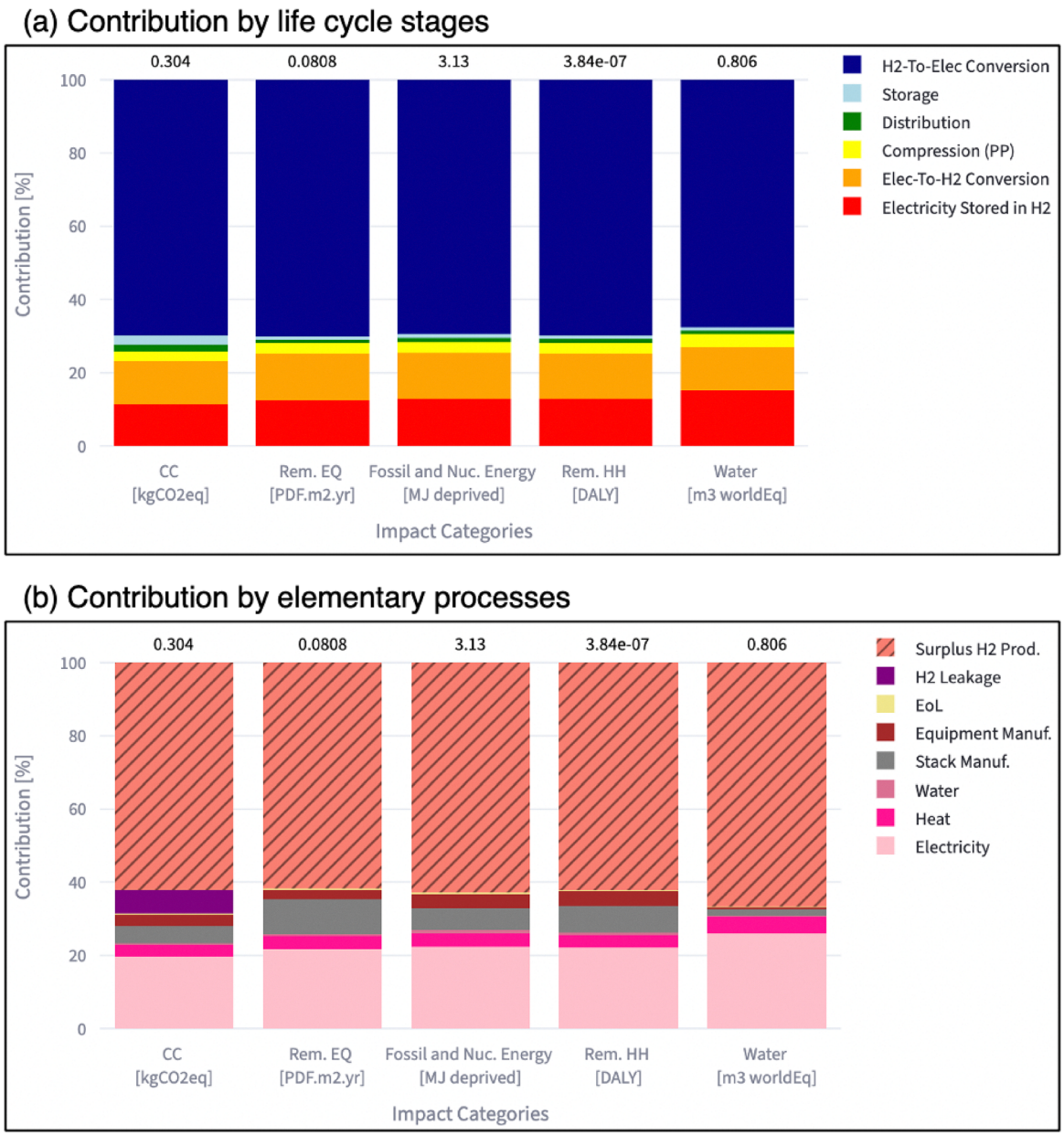

Fig. 5 Contribution analysis of the LCA results for the solid oxide product systems, delivering 1 kWh of controllable electricity (with seasonal storage and pipeline transportation). Contributions are broken down by (a) life-cycle stages and (b) elementary flows.

it reduces the potential impacts by 33–50%, depending on the allocation method selected. The electrolyser and fuel cell configurations also have a significant influence on results. The type of technology can lead to variations of up to 65%, with alkaline electrolyser and solid oxide fuel cells performing better in this specific application and maturity. Technological maturity further affects impacts, with projected reductions of up to 35% between current systems and 2050 targets, highlighting the potential of eco-design improvements. In contrast, system size has only a marginal influence (~0–6% variation). Finally, hydrogen specifications (pressure and purity, up to 33% variation), distribution mode (up to 50%), and storage type (up to 15%) also show a significant influence on the variability of LCA results, reflecting the importance of constructing system boundaries consistent with the goal of the study (Fig. 2).

3.2 Comparison between solid oxide and proton-exchange membrane technologies

In this section, solid oxide (SO) and proton-exchange membrane (PEM) technologies are compared for four hydrogen applications, described in Table 2. For each application, two technology-driven scenarios are defined, building on specific pre-set configurations representing the solid oxide and the PEM product systems. Both scenarios fulfill the exact same functional unit. The environmental impact scores for these eight configurations have been computed with the HTWOL.

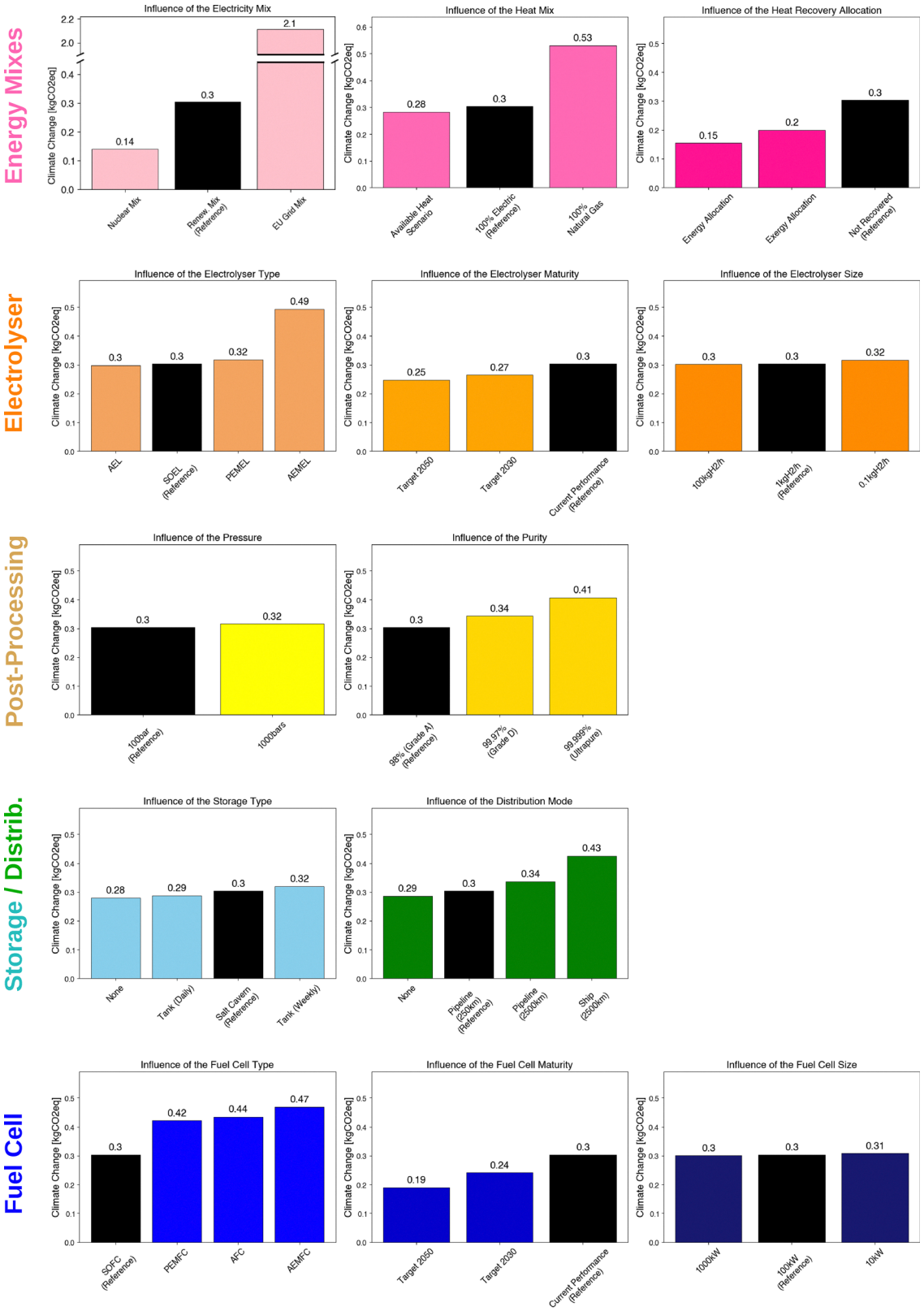

Fig. 6 Results of the sensitivity analyses on climate change impact score of the reference green hydrogen product system, delivering 1 kWh of controllable electricity. 29 one-at-a-time scenarios have been generated by modifying a single assumption from the reference scenario. Scenarios are grouped and colored by the main life cycle stages (*e.g.*, energy mixes/recovery, pressure/purity, electrolyser type/maturity/size, storage and distribution, fuel cell type/maturity/size), with several configurations tested within each group.

Table 2 Description of the four applications and the derived functional units and technological scenarios using solid oxide technologies (SO) and proton-exchange membrane (PEM) technologies

Application information		Functional unit			Technological scenario							
Description	Scenario	Service/ product	Pressure required	Purity required	Electricity mix	Heat mix	Electrolyser (type, maturity, size)	Storage (type, duration, maturity)	Distribution (type, distance, maturity)	Fuel cell (type, maturity, size)	Heat co-produced (yes/no, allocation)	End-use processes
Application A: a german ammonia producer consumes green hydrogen @1 bar and 98% purity. The hydrogen is produced in spain (100 kgH_2 per h) and imported by pipeline, and stored in buffer tanks before being used in the industrial chain. Fatal heat from other processes on-site is available.	SO	1 kgH_2 produced	100 bar (storage)	98%	Renewable electricity	Available heat	SOEL (current Perf., 100 kgH_2 per h)	Buffer tank (weekly, current Perf.)	Pipeline (2500 km, current Perf.)	—	—	—
	PEM						PEMEL (current Perf., 100 kgH_2 per h)			—	—	
Application B: a german glass producer consumes green hydrogen @1 bar and 99.999% purity. The hydrogen is produced on-site (1 kgH_2 per h) and directly injected in the industrial line (no storage and no distribution). Renewable electricity is used to supply electrical heater when heat is needed.	SO	1 kgH_2 produced	1 bar	99.999%	Renewable electricity	Electrical heat	SOEL (current Perf., 1 kgH_2 per h)	None	None	—	—	—
	PEM						PEMEL (current Perf., 1 kgH_2 per h)			—	—	
Application C: an electricity producer generates renewable electricity in summer, for being injected in winter (1 MW) after seasonal storage (a pipeline distribution is required between the electricity production and the salt cavern). The same renewable electricity is used to supply electrical heater when heat is needed.	SO	1 kWh of controllable elec.	100 bar (storage)	98% (SOFC)	Renewable electricity	Electrical heat	SOEL (current Perf., 30 kgH_2 per h)	Geological storage (season, current Perf.)	Pipeline (250 km, current Perf.)	SOFC (current Perf., 1 MW)	Yes (exergy allocation)	—
	PEM			99.97% (PEMFC)			PEMEL (Current Perf., 30 kgH_2 per h)			PEMFC (current Perf., 1 MW)	Yes (exergy allocation)	
Application D: a building is powered by a fuel cell system (co-generation of 50 kW). The hydrogen production is centralized in the region (50 kgH_2 per h delivered in pipeline) and stored on-site in buffer tanks. Natural gas heat is used when needed.	SO	1 MJ of domestical energy	100 bar (storage)	98% (SOFC)	Renewable electricity	Natural gas heat	SOEL (current Perf., 50 kgH_2 per h)	Buffer tank (weekly, current Perf.)	Pipeline (250 km, current Perf.)	SOFC (current Perf., 50 kW)	Yes (energy allocation)	—
	PEM			99.97% (PEMFC)			PEMEL (current Perf., 50 kgH_2 per h)			PEMFC (current Perf., 50 kW)	Yes (energy allocation)	

The climate change score is plotted in Fig. 7, while other indicators are displayed in SI-5.

The LCA results illustrate that the environmental performances of green hydrogen technologies vary depending on the application, as they require specific technology-dependent scenarios to fulfill the functional unit. The PEM scenario performs worse than the solid oxide scenario in application A (+10%) and C (+45%) for the following reasons. First, the high operating temperature of SOEL reduces the environmental impact of the stack, as less catalytically active material is required and lower-impact materials can be used. Second, equivalent energy consumption is achieved by SOEL systems (55 kWh of electricity and 10 kWh of heat per kgH_2 produced, including BoP electricity consumption) and by PEMEL systems (64 kWh of electricity), but the share of heat in the energy demand is advantageous when heat is supplied by fatal heat (application A). These benefits are evidenced in the conversion of electricity-to-hydrogen life cycle stage (in orange). Third, although SOFC and PEMFC achieve similar energy efficiencies (around 20 kWh of energy reconverted per kgH_2, including electricity and heat recovered, but also fuel utilization and BoP electricity consumption losses), SOFC co-produces high-temperature heat (high exergy), whereas PEMFC co-produces low-temperature heat (low exergy). Consequently, in the application C, where heat is recovered and exergy-allocation is applied, the ratio of impacts allocated to the electricity generated is much lower for the SOFC, reducing the impact scores of this system. The PEM scenario performs better than the solid oxide scenario in application B (−30%) and D (−50%) for the following reasons. First, a portion of SOEL energy demand is heat; when the heat mix is natural gas (application D), the SOEL system's impacts rise substantially (in orange), which also affects the surplus production of hydrogen due to hydrogen losses in the fuel cell (in dark blue). Second, an additional purification step for reaching the 99.999% purity required (application B) is necessary for SOEL but not for PEMEL, which already produces ultrapure hydrogen. This purification step represents an addition of 30% of the impact scores (in the post-processing stage, in yellow).

3.3 Comparison of the solid oxide baseline with alternative technologies

To demonstrate the environmental relevance of green hydrogen technologies against alternative functionally equivalent technologies, solid oxide product systems (Table 3) are compared with alternative technologies supplying the exact same functional unit for the six hydrogen applications depicted by the framework (Fig. 2). Fig. 8 compares the solid oxide system (in purple) with fossil-based alternative technologies (in brown); and with the electrified technologies (in green) which are supplied with the same renewable electricity mix than the SOEL. The climate change indicator is the only impact score represented in this figure; the other indicators are displayed in SI-5.

The climate change results highlight that the green hydrogen product system performs better than the fossil-based alternatives for all applications: for hydrogen production (3.5 times better than SMR), industrial heat production (5 times better than fuel), domestical energy co-generation (2 times better than a combination of fuel (for heat) and renewable electricity), shipping (2 times better than traditional fuel shipping), automobile transportation (more than 2 times better than GV), and for controllable electricity production (more than

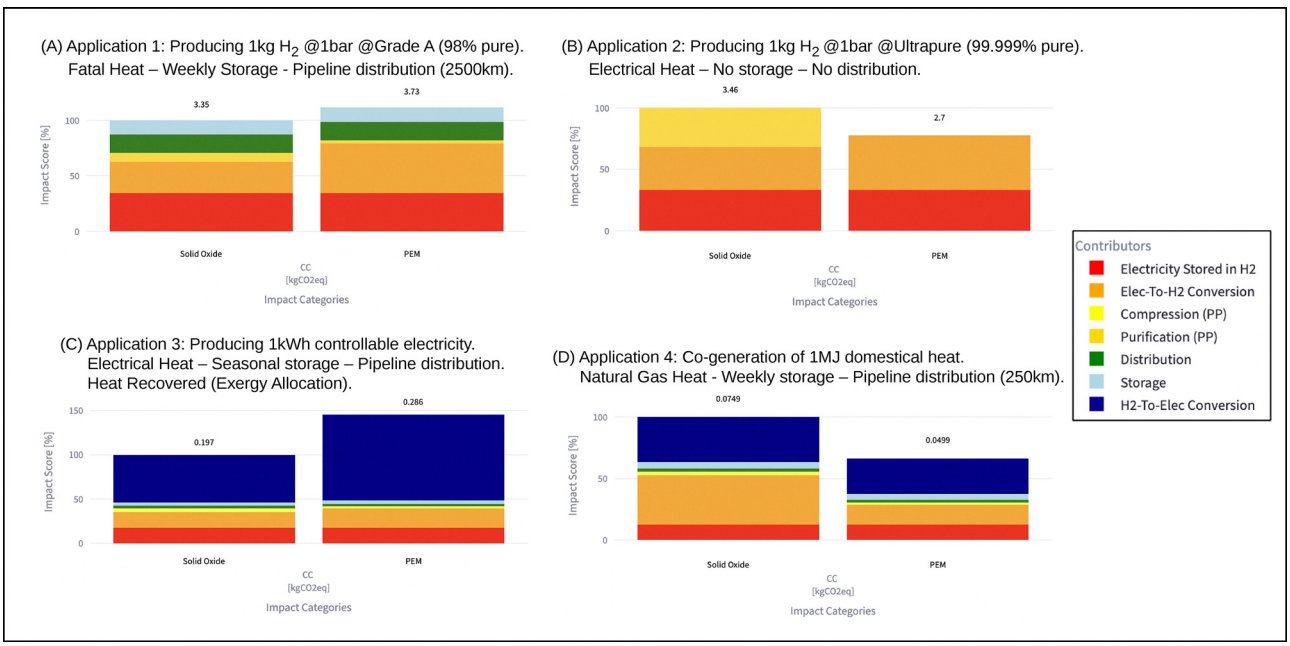

Fig. 7 Comparative LCA of solid oxide and proton exchange membrane systems for various scenarios. Impact scores (IW+ expert version) are computed with the HTWOL and are normalized to the solid oxide system results. The contribution of each life cycle stage is represented, using the same colors as the framework representation.

Table 3 Description of the seven applications and the derived functional units and technological scenarios using solid oxide technologies (SO)

Application information	Functional unit			Technological scenario							
Description	Service/product	Pressure required	Purity required	Electricity mix	Heat mix	Electrolyser (type, maturity, size)	Storage (type, duration, maturity)	Distribution (type, distance, maturity)	Fuel cell (type, maturity, size)	Heat co-produced (yes/no, allocation)	End-use processes
1-Chemical platform	1 kgH_2 produced	1 bar	99.97%	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Buffer tank (daily, current Perf.)	Pipeline (250 km, current Perf.)	—	—	—
2-Industrial heat	1 MJ of heat	1 bar	98%	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	None	None	—	—	Burner
3-Domestic energy (co-generation)	1 MJ of domestical energy	100 bar (storage)	98% (SOFC)	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Buffer tank (daily, current Perf.)	Pipeline (250 km, current Perf.)	SOFC (current Perf., 50 kW)	Yes (energy allocation)	—
4-Shipping freight	1 t km shipped	100 bar (storage)	99.97%	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Refueling station (daily, current Perf.)	Pipeline (250 km, current Perf.)	—	—	e-Fuel prod. cargo prod.
5-Automobile transportation	1 v km of automobile transport	100 bar (storage)	99.997% (PEMFC)	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Refueling station (daily, current Perf.)	Pipeline (250 km, current Perf.)	PEMFC (for FCEV) (current Perf., 100 kW)	—	FCEV
6-Renewable electricity storage	1 kWh of electricity stored (season)	100 bar (storage)	98% (SOFC)	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Geological storage (season, current Perf.)	Pipeline (250 km, current Perf.)	SOFC (current Perf., 1 MW)	Yes (exergy allocation)	—
7-Controllable electricity production	1 kWh of controllable energy	100 bar (storage)	98% (SOFC)	Renewable electricity	Electrical heat	SOEL (current Perf., 50 kgH_2 per h)	Geological storage (season, current Perf.)	Pipeline (250 km, current Perf.)	SOFC (current Perf., 1 MW)	Yes (exergy allocation)	—

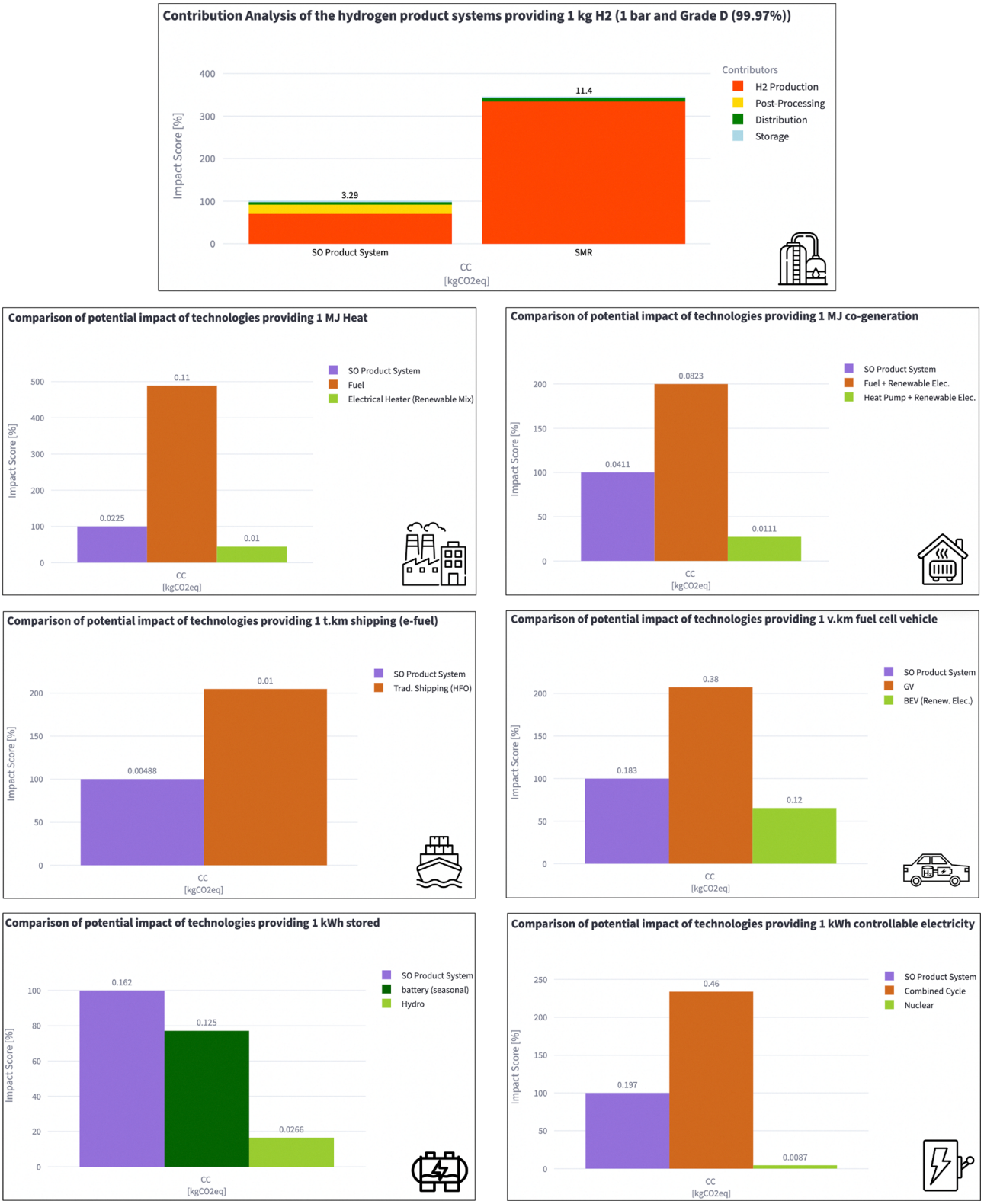

Fig. 8 Comparative LCA of the solid oxide baseline with alternative technologies providing the same function for each of the seven hydrogen end-use applications. Each panel compares the baseline with the corresponding alternative technologies. Climate change scores are normalized to the solid oxide system. For hydrogen production, the contribution of the supply chain processes is plotted to compare solid oxide with steam methane reforming supply chains. For other applications, the solid oxide system is represented in purple, fossil-based options are shown in brown, and electricity-based options in green.

2.2 times better than combined cycle). These benefits are induced by the use of renewable energies instead of fossil energies. However, the green hydrogen product system performs worse than many electric-based alternative solutions: direct electrical industrial heat (−60%), domestic energy from heat pump and renewable electricity (−75%), battery electric vehicles (−35%), pumped hydro storage (−85%), or nuclear power generation (−95%). These results are explained by the high conversion losses in the hydrogen supply chain, which makes green hydrogen technologies less energy-efficient solutions than the other electrical alternatives, and leads to higher impact scores. For long-term storage, the battery performs better than the solid oxide product system (−20%), but results are close for all impact categories. Therefore, green hydrogen might offer a relevant option for renewable electricity seasonal storage in locations where further development of hydropower is limited.

4 Discussion and limitations

4.1 Current literature underestimates the environmental impacts of the hydrogen supply chain

The environmental impacts of hydrogen production estimated in this study were compared with values reported in the current literature. Here, hydrogen production supplied by renewable electricity ranges from 2.9 to 3.7 $kgCO_2eq.$ per kgH_2, compared with roughly 1.4–3.0 $kgCO_2eq.$ per kgH_2 in previous studies.[17,36,40,43,46,65,67,72,89,90,184,185] This corresponds to an average increase of around 40%. As detailed in this section, three main factors explain this difference: (i) higher energy requirements estimated for the electrolyser system, (ii) the inclusion of additional processes along the supply chain beyond the sole hydrogen production to fulfill the end-use function, and (iii) the explicit accounting of hydrogen leakage.

Fig. 9 presents a Sankey diagram decomposing energy demand associated with hydrogen production and supply for a PEM electrolyser delivering hydrogen to the end user (Application A, Table 3). In this example, 63.9 kWh of electricity are required for hydrogen production alone. Of this, 33.3 kWh are stored in the hydrogen (LHV), 21.7 kWh are lost due to faradaic losses associated with operation at 2.03 V (beginning-of-life), 3.1 kWh result from increasing faradaic losses due to degradation, and 5.8 kWh correspond to BoP consumption. By contrast, many literature estimates fall within 45–60 kWh per kgH_2,[17,36,40,46,65,67,72,89,184] as they often neglect BoP or degradation effects, and may assume prospective voltages. This already represents an average difference of about 20%.

Beyond production, additional processes are required to supply hydrogen to the end user, which further increase total energy demand. These include compression (2.8 kWh) and distribution (7.5 kWh in the long-distance delivery scenario considered), bringing total electricity demand across the supply chain to around 74.2 kWh, raising total energy demand by up to 15% (Fig. 9). They also generate additional impacts through infrastructure and equipment manufacturing, accounting for

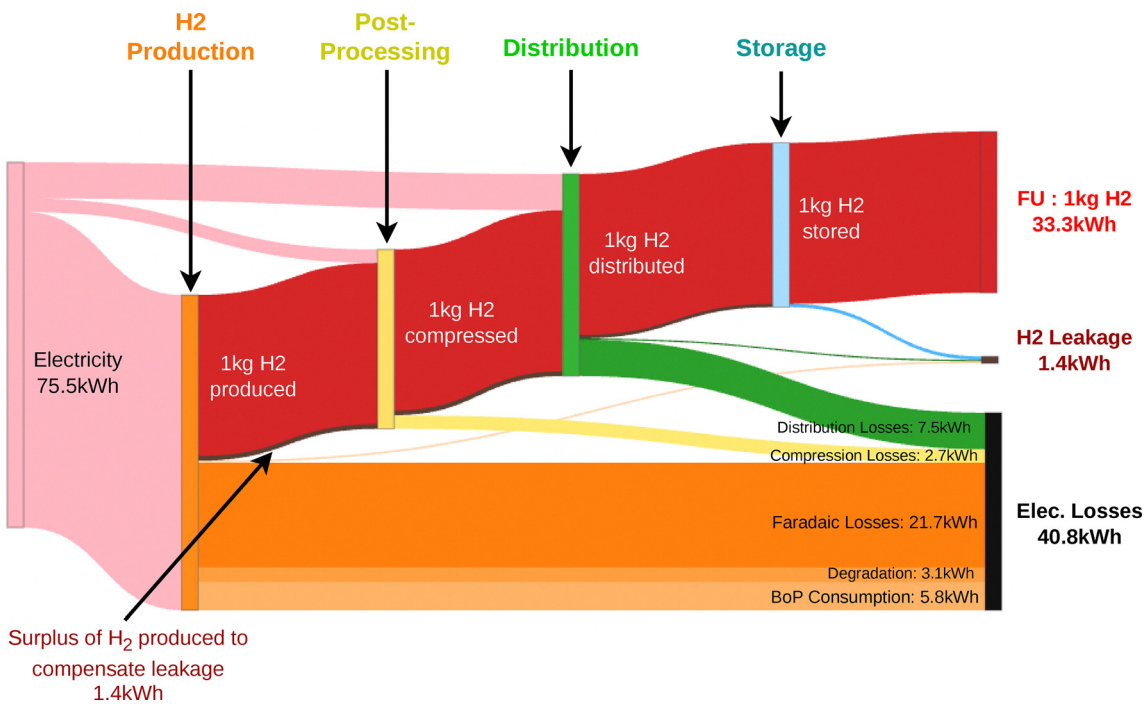

Fig. 9 Sankey diagram of energy flows associated with the production and supply of hydrogen *via* a PEMEL system. The scenario includes hydrogen production (orange), compression to 100 bar (yellow), distribution *via* a 2500 km pipeline (green), and storage in a buffer tank (blue). The diagram distinguishes electricity inputs (pink), hydrogen flows along the supply chain (red corresponding to the hydrogen fulfilling the functional unit and brown representing surplus hydrogen required to offset H_2 leakages), and electricity losses at each stage (colored according to their process of origin).

10–40% of total environmental impacts in the applications presented in Fig. 7.

This study also provides an operationalized assessment of hydrogen leakage by combining a synthesis of leakage rates along the supply chain with an appropriate characterization factor. As anticipated in recent literature,[185,186] these emissions are not negligible: they contribute up to 15% of the climate change impacts of hydrogen supply chains in our results. Moreover, leakage induces surplus hydrogen production to compensate for losses, thereby generating further upstream impacts, including approximately 1.4 kWh of additional electricity consumption.

Collectively, the more comprehensive energy accounting, the expanded system boundaries including supply-chain processes, and the explicit integration of hydrogen leakage explain why the energy demand (75.5 kWh per kgH_2) and overall environmental impacts estimated here exceed values commonly reported in the literature.

4.2 Consequences and takeaways for the hydrogen industry

This section examines the most promising application pathways for hydrogen deployment, building on and updating insights from previous studies in light of the higher impact estimates obtained in this study. It also identifies the main industrial levers for reducing environmental impacts. Key insights are summarized in Fig. 10.

Our results demonstrate that hydrogen produced from renewable electricity proves most relevant for end-use applications where no viable electrified alternatives exist and current solutions remain fossil-based. This includes its role as an industrial chemical platform (*e.g.*, ammonia production, refining, chemicals, and use as a reducing agent in the metal industry) and its use as a feedstock for e-fuels replacing heavy fuel oil (HFO) in the shipping sector. These findings are consistent with previous literature supporting hydrogen deployment in these sectors.[14,36,40,43,72]

Conversely, where direct electrification options are available, hydrogen product systems are generally less environmentally favorable. Their relevance largely depends on the technical and systemic limitations of electric solutions in each sector. In automobile transport, the results clearly support BEV over FCEV, reinforcing the growing consensus in favor of BEVs[83,187–189] despite some remaining debate and mixed conclusions in the

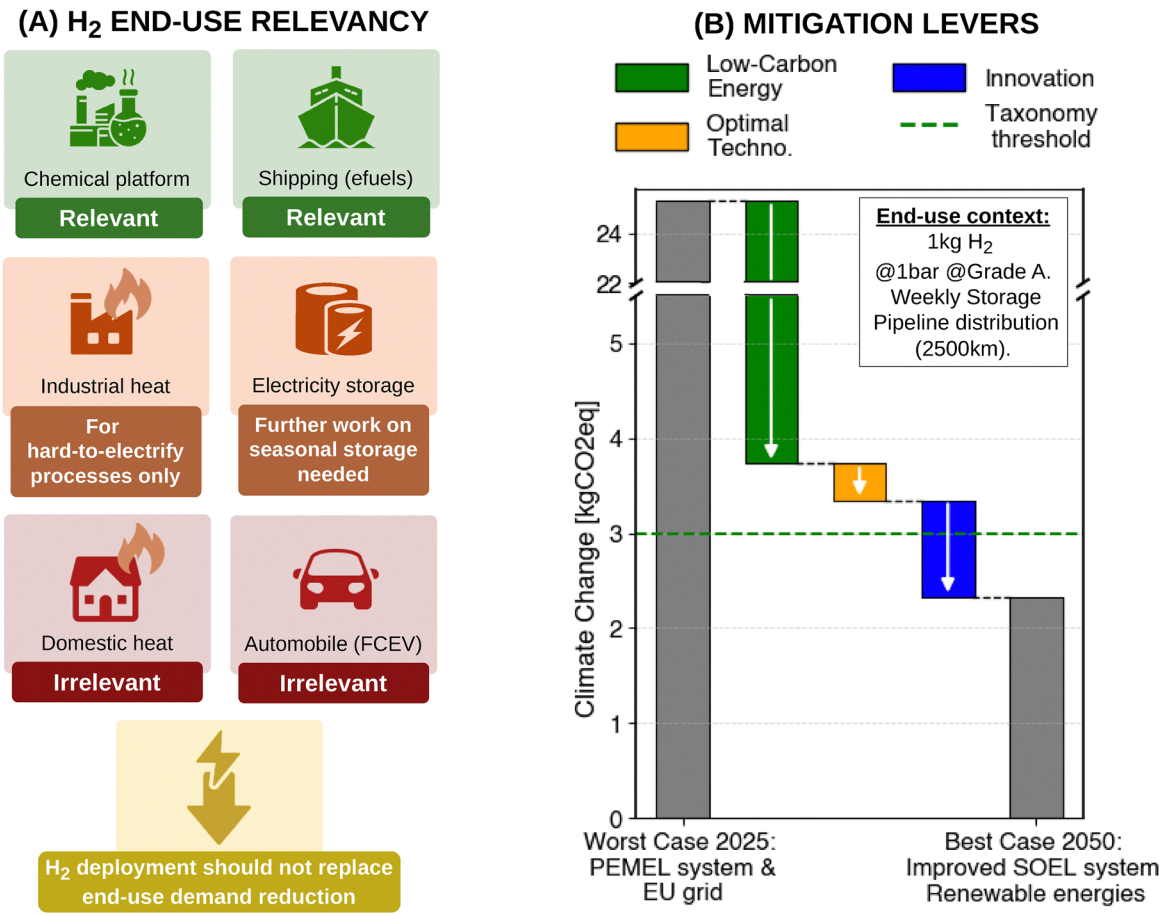

Fig. 10 Takeaways of the study for the hydrogen industry. (A) Hydrogen end-use applications are classified according to their environmental relevance based on the present results: green indicates relevant applications, orange indicates conditional relevance, and red indicates low environmental relevance. (B) Mitigation levers and their potential to reduce climate change impacts for a specific end-use context are illustrated, showing the range between a worst-case configuration in 2025 and a best-case configuration in 2050. The European taxonomy threshold is shown as a reference (green dashed lines).

literature.[190,191] In domestic heating, the findings further strengthen the case for heat pumps, which have already been identified as the most environmentally efficient option.[187,192,193] In both sectors, these technologies are already mature and widely deployable, making the acceleration and prioritization of direct electrification more relevant than developing hydrogen-specific infrastructure. For high-temperature industrial heat, the literature indicates that electrical solutions are environmentally preferable but face technical (*e.g.*, low energy density) and economic constraints.[187,194–197] Similarly, hydrogen-based seasonal electricity storage remains more impactful than pumped hydropower and slightly more than batteries.[198–201] However, hydropower is geographically constrained, and batteries still face technical and economic limitations related to scale, materials, and long-duration storage.[200–202] In these contexts, direct electrified alternatives should be prioritized where feasible, but hydrogen remains a relevant complementary option that warrants continued research and development.

Finally, demand-side mitigations must continue in parallel, as keeping or increasing world energy end-use demand is not compatible with ecological transition.[1,203,204]

Regardless of the applications in which hydrogen proves environmentally relevant, reducing the impacts of hydrogen systems remains essential to preserve its relevance. This is particularly critical given that the inclusion of full supply-chain processes shows hydrogen production impacts exceeding 3 $kgCO_2$eq. per kgH_2 in most cases, which corresponds to the life-cycle greenhouse-gas intensity threshold defined in the EU Taxonomy framework to qualify hydrogen as ''green''.[205] This indicates that current production conditions – even when supplied with renewable electricity – do not yet consistently meet the criteria for ''green'' hydrogen and highlight the need for targeted mitigation strategies. Reducing the environmental impacts of hydrogen supply chains relies on three main levers: low-carbon energy supply, appropriate technology selection, and technological innovation (Fig. 10b).

First, environmental performance is primarily driven by energy consumption. Using the current European electricity mix is environmentally counterproductive; hydrogen product systems are environmentally relevant only when powered by renewable or nuclear energy sources. Second, selecting fuel-cell and electrolyser technologies suited to their end-use application and energy system integration[206] reduce the impacts by 10%. High-temperature systems such as SOEL can offer superior electrical efficiency when operated with available industrial fatal heat, while SOFC systems can provide useful heat to industrial processes. Differences in hydrogen purity requirements across applications also matter: PEM and AEM electrolysers should be prioritized when high-purity hydrogen is required, as they do not necessitate purification post-processing. Therefore, continued development of both low- and high-temperature technologies remains essential. Third, the ambitious innovation objectives of the field constitute a major mitigation lever. Ongoing efforts to reduce energy losses and minimize hydrogen leakage across the supply chain could decrease environmental impacts by 30% by 2050. However, it is important to recognize that the potential for further improvements is bounded. Efficiency improvements are constrained by the intrinsic 33.3 kWh per kgH_2 contained in hydrogen;[207] reducing hydrogen leakage is technically possible but often comes at high cost;[208] and lowering material demand may introduce trade-offs with energy efficiency.[209,210] By combining these levers, the sector can realistically achieve the targeted performance for 'green' hydrogen in the future; however, its impacts are likely to remain above 2–2.5 $kgCO_2$eq. per kgH_2.

4.3 Limitations and future works

Despite the strengths of this approach, several limitations should be acknowledged.

First, several physical relationships remain to be defined. Operational parameters such as voltage, heat demand, or water demand could be further detailed to capture strategies like load flexibility or variations in operating temperature or in steam conversion.[211,212] Additionally, the influence of stack design on durability is not yet modeled. These relationships can significantly affect the sensitivity of key parameters on the overall environmental impact scores, and highlight the need to incorporate them in future LCA developments to support the integration of a global sensitivity in the model framework.

Second, the developed pre-set configurations of elementary processes are to be considered with care due to the several uncertainty sources regarding: (i) transparent datasets are still lacking in the literature. (ii) System configurations, material intensities, and performance parameters are likely to evolve rapidly due to the fast-moving development of FC&EL technologies. (iii) Some technologies and product system configurations are still under development, such as emerging electrolyser designs (*e.g.*, PCC) or alternative hydrogen carriers for storage. (iv) Quantification of hydrogen leakage across the supply chain is particularly uncertain, and the resulting climate impacts are highly sensitive to the time horizon considered (*e.g.*, GWP20 *vs.* GWP100), which can lead to markedly different estimates of hydrogen's indirect contribution to global warming.[185] Consequently, regular updates of inventory data and assumptions are required to preserve the robustness of LCA results.

Third, while environmental performance is the key focus of this paper, it must be balanced within a broader multi-dimensional framework guiding technology choices. The current assessment does not include the assessment of critical raw material, which can be particularly relevant for emerging technologies that rely on rare or geopolitically sensitive supply chains (*e.g.*, platinum-group metals, rare earth elements).[213] As hydrogen technologies continue to evolve, integrating resource criticality and circularity metrics will be important to complement the environmental profile. Economic viability, but also factors like rapid response capabilities, ease of deployment, or compatibility with existing infrastructure, can support the adoption of hydrogen and specific FC&EL technologies. Future research should extend this flexible framework to multi-criteria analyses that combine environmental, economic, and operational metrics, to provide a more comprehensive evaluation of hydrogen's role across sectors.

Finally, beyond the hydrogen sector, the modular and parametrized structure developed in this work is inherently transferable to other technological domains. Modular structures are relevant both for representing and readily modifying supply chain processes, making them suitable for nearly any industrial technology. Similarly, parametrized LCI have already been applied across a wide range of sectors, demonstrating their relevance beyond the single hydrogen field. While the initial effort required may be substantial (in terms of data structuring, methodological alignment, and tool implementation), the resulting gains in adaptability, transparency, reproducibility, and collaborative use make this investment worthwhile. We therefore support a broader transition of the LCA field toward modular and parametrized approaches.

5 Conclusions

A harmonized LCA framework for fuel cell and electrolyser technologies was developed. The framework relies on:

– The definition of explicit end-use functional units, which ensures functional equivalence across applications delivering the exact same service and therefore enabling a fair and transparent evaluation between competing technologies for a wide range of end-use applications.

– The development of an agile modular framework that enables a consistent description of the value chain of any green hydrogen technology, thereby facilitating comparability across studies and the progressive construction of a coherent literature corpus.

– a parametrized inventory for each module that ensures adaptability to different technological contexts while remaining physically grounded; in particular, it allows the explicit representation of phenomena such as component degradation and balance-of-plant energy consumption, which are often simplified or neglected in the literature and can lead to underestimated energy demands.

– This framework has been operationalized through an online LCA tool called the HTWOL. This latter provides a library of pre-set configurations and automates LCA calculations, ensuring the usability of the framework for practitioners with varying levels of expertise.

The HTWOL was applied to the four main electrolyser technologies (AEL, PEMEL, SOEL, and AEMEL) for 6 representative hydrogen end-use applications: chemical platform, industrial heating, freight shipping, automobile transportation, renewable electricity storage, and domestic co-generation of heat & power. It demonstrated its ability to support the three main intended goals of LCA: comparison with alternative technologies, comparison between families of hydrogen technologies, and eco-design support. The results show that:

– Green hydrogen is most environmentally relevant for end-use applications where viable fossil or electrified alternatives are limited, such as chemical feedstocks (*e.g.*, ammonia synthesis, metal reduction) or long-distance shipping. In contrast, for applications where direct electrification options exist, such as passenger transport or low-temperature heat, green hydrogen product systems are not capable of outperforming electricity-based solutions (*e.g.*, battery electric vehicles or heat pumps).

– Technology choice depends on the application and the context: solid oxide electrolysis generally performs better when low-carbon or fatal heat is available, whereas PEM electrolysis is more favorable for applications requiring high-purity hydrogen, as it delivers such quality without additional processing.

– Across all configurations, energy supply remains the dominant contributor to the overall environmental impacts. Supplying electrolysers with low-carbon electricity is therefore a strict prerequisite for hydrogen to outperform steam methane reforming. Eco-design strategies should therefore focus on maximizing energy efficiency across the entire hydrogen supply chain, including the stack and balance of plant manufacturing, post-processing, storage, and distribution.

Overall, this work provides both a methodological and operational contribution to the harmonization of hydrogen LCAs. By combining a consistent conceptual framework with an accessible and flexible tool, it supports more robust, transparent, and forward-looking assessments of hydrogen technologies, and enables a more rational and targeted integration of green hydrogen into future energy systems.

Author contributions

Gabriel Magnaval: conceptualization, methodology, software, investigation, data curation, validation, visualization, writing – original draft. Maël Mouhoub: software, investigation, data curation, writing – review & editing. Anne-Marie Boulay: supervision, methodology, writing – review & editing, funding acquisition. Manuele Margni: supervision, conceptualization, methodology, writing – review & editing, funding acquisition, resources.

Conflicts of interest

Authors have no conflicts to declare.

List of abbreviations

AEL	Alkaline electrolyser
AFC	Alkaline fuel cells
AEMEL	Anion-exchange membrane electrolyser
AEMFC	Anion-exchange membrane fuel cells
BEV	Battery electric vehicle
BoP	Balance-of-plant
CC	Climate change
EoL	End-of-life
EQ	Ecosystem quality
FC&EL	Fuel cells and electrolyser
FCEV	Fuel cell vehicle
FU	Functional unit
GV	Gasoline vehicle
HH	Human health
HHV	Higher heating value

IW +	Impact world+
KOH	Potassium hydroxide
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
LHV	Lower heating value
PEMEL	Proton-exchange membrane electrolyser
PEMFC	Proton-exchange membrane fuel cells
PSA	Pressure swing adsorption
SMR	Steam methane reforming
SOEL	Solid oxide electrolyser
SOFC	Solid oxide fuel cells
TRL	Technology readiness level

Data availability

Supplementary information (SI) are accessible at https://doi.org/10.5281/zenodo.17428316.[183] It is distributed under the Creative Commons Attribution 4.0 International (CC BY 4.0) license. The code and datasets used for computing the HTWOL-Demonstrator are available at: https://github.com/CIRAIGx HEVS/HTWOL_DEMONSTRATOR. Ref. 214–220 are cited in the supplementary information. Supplementary information: SI1_literature: detailed literature review. This includes the complete review analysis (SI1a) and a complementary excel table summarizing, for each LCA methodological step, the main methodological choices and results reported for the analyzed use cases (SI1b). SI2_data&processes: data used for pre-set configurations and background processes. SI3_LCI_equations: detailed equations and calculations of the model. SI4_BoP_sizing: data for balance-of-plant up-sizing. SI5_results: detailed results. SI6_HTWOL: code and datasets for the HTWOL demonstrator. See DOI: https://doi.org/10.1039/d5ee07747h.

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