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The boy who cried hydrogen: Examining the cost impact of proactive vs reactive policy for electrolytic hydrogen

Duncan Mathews *, Paul Deane

MaREI Centre, Environmental Research Institute, University College Cork, Ireland

A R T I C L E I N F O

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A B S T R A C T

Hydrogen as an energy carrier has experienced repeated hype cycles with periodically surging enthusiasm subsequently followed by low levels of deployment and waning enthusiasm. Despite these anticlimactic false dawn events, research points towards important roles for hydrogen in a future decarbonized global economy. The repeated nature of these cycles opens the hydrogen sector to "the boy who cried wolf" effect which may see policymakers hesitate to subsidize and plan for the hydrogen sector considering multiple "false alarms". This work contextualizes potential cost penalties if a significant future demand for hydrogen arises in a policy environment defined by hesitation. Overall, we find that reactively rather than proactively integrating the electrolytic hydrogen sector with the power sector could be 8–15 % more expensive costing between 27 and 31 billion USD annually in 2050. We further find an isolated rather than integrated electrolytic hydrogen system could be 33–41 % more expensive, costing between 82 and 106 billion USD annually in 2050.

1. Introduction

1.1. Context & hype

From the late 20th century hydrogen as an energy vector has experienced cycles of interest and investment which have subsequently dissipated before the heralded "hydrogen economy" could materialize [1–3]. The pronounced and repetitive nature of this phenomenon is such that the hydrogen 'hype' has become a regular topic in studies examining technology hype cycle models [4–7]. In recent years, it appears that the peak of one such hydrogen hype cycle may again be giving way to headwinds with high numbers of hydrogen project cancellations reported [8]. Moreover, references to the "trough of disillusionment" are seen frequently across industry and social media [9–11]. The "trough of disillusionment" is a term associated with the Gartner Hype Cycle Model [7] in which the trough is followed by the "slope of enlightenment" and "plateau of productivity" as the technology matures and fulfills a realistic (rather than exaggerated) role.

Naturally, technological development and deployment pathways do not strictly adhere to any one model however useful they may be in examining technological progression or hype. Rather than strictly following the Gartner Cycle, hydrogen energy technologies have experienced several 'peaks of inflated expectation' and subsequent 'troughs of disillusionment.' However, these cycles have not yet resulted in the significant deployment levels that would indicate a true 'plateau of productivity' phase [2,4,8,12]. Notwithstanding the challenges the low carbon hydrogen sector is presently facing, recent literature points towards important roles for hydrogen in a decarbonized future global economy [1,3,8,13,14] and, consequently, an important role for subsidy [3,8].

This places policymakers in the unenviable position of determining appropriate subsidy levels and mechanisms to meet long-term decarbonization targets while navigating confounding cycles of exaggeration and disillusion in the clean hydrogen sector. Here, we suggest that the potentially important role of hydrogen in conjunction with its pronounced hype cycles open the door to a possible "boy who cried wolf" or "false alarm" effect. The erosion of trust due to repeated unfulfilled statements is a well-studied social phenomenon. This effect is often studied in relation to societal responses to severe weather warnings, for example, where hesitation to act on a potential false alarm has been observed to lead to sub-optimal responses [15,16].

In relation to hydrogen, this poses a risk that the repeated false starts of the hydrogen sector erode policymakers' trust in the underlying technologies leading to hesitancy and delays in infrastructure investment as policymakers become wary of committing resources to initiatives that may not materialize as promised. This is compounded by

* Corresponding author.
E-mail address: dmathews@ucc.ie (D. Mathews).

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concerns around the impact of electrolysis loads on power sector emissions in the short term while the power sector is still in the process of decarbonization. Such concerns have formed the rationale behind the European Union's strict requirements around emissions and renewable power generation additionality for electrolytic hydrogen under the Renewable Energy Directive (RED II) [17,18]. In Ref. [19] however, it is shown that allowing unrestricted use of grid electricity for hydrogen production, without applying constraints on the electricity's fuel mix, can lead to significantly lower production costs. Importantly, this does not necessarily result in higher emissions compared to the current use of unabated fossil hydrogen. Both [19,20] highlight increased costs of electrolytic hydrogen production under RED II. The authors of [20] find that with a sufficiently high carbon price, emissions benefits of electrolytic hydrogen can be maintained without the temporal congruency rule in RED II.

This work does not critique future competitiveness of hydrogen technologies or their short-term impact on emissions and instead we seek to understand the costs implications of uncertainty in policy planning for electrolytic hydrogen. Here we focus on electrolytic hydrogen specifically given the potential for close integration with the power sector. This coupling could lead to significant benefit through mechanisms like capacity sharing and flexibility provision, or indeed it could lead to increased stress on the power sector as RED II aims to avoid. Should a significant future role for hydrogen fail to materialize, policy hesitation on the matter would not be expected to pose significant consequences. However, if a significant future role for hydrogen does arise, hesitant or restrictive policy could lead to sub-optimal outcomes. This paper therefore puts some context on two particular research questions that arise as a result of these concerns. Specifically, what is the cost of global delay or hesitation in reactively planning for clean electrolytic hydrogen as opposed to proactively planning for an integrated coupled electricity and hydrogen system? Secondly, what is the cost of asserting strict isolation of the electrolytic hydrogen system from the power sector in a scenario where the coupling of the two sectors is discouraged by restrictive policy? Current literature points to cost penalties for restricted coupling of electricity and hydrogen at the hydrogen project level [19,20]. In this work, we will examine the global system-level impact of restricted coupling to capture knock-on effects in the power sector. In examining these questions under two scenarios in which significant demand for hydrogen emerge, this study aims to serve as a prompt upon which future work can build more exhaustively.

1.2. Hydrogen system modelling & Co-optimisation

A range of modelling approaches have been developed to analyse the role of hydrogen in energy systems, each varying in scope, complexity, and application. The full taxonomy of hydrogen system models across the literature and the benefits and trade-offs of each model archetype have been examined in Ref. [14]. These include integrated assessment models (IAMs), energy system models (ESMs), and power system models among other model archetypes. Regarding IAMs, the authors of [14] highlight their broad scope and ability to represent interactions between the energy system, the economy, and earth systems. However, such models exhibit low spatial and temporal resolutions considering the need to balance model complexity and tractability. ESMs and power system models both exhibit lower respective sectoral scopes than IAMs thereby affording greater flexibility for higher spatial and temporal resolution. However, these respective reductions in complexity require further exogenous inputs or assumptions at the boundaries with the other sectors outside of the models' scope. In model formulation terms, this reduction in scope or complexity (from IAM to power system model for example) amounts to a reduction in endogenous variables.

In [21], the framework for high resolution global coupled electricity and hydrogen models that will underpin the modelling in the current work was introduced. The issues of computational intensity, spatio-temporal resolution and sectoral scope or endogeneity are also prevalent in Ref. [21] wherein a power system model is soft-linked to an IAM to preserve the endogenously resolved hydrogen demand of the IAM within a higher resolution model. As these issues are a recurring theme across the energy system modelling discipline [13,14,21–24] we propose the definition of the "Energy Modelling Trilemma" (see Fig. 1) of computational tractability, spatio-temporal resolution and endogeneity (or scope) much like the "Energy Trilemma" of security, affordability and sustainability.

In physical terms, a reduction in endogeneity as model scope is reduced often manifests as a reduction in the degree to which the relevant sectors are co-optimized. It is established across industry and academic literature that co-optimisation has significant potential to deliver cost-savings, whether that encompass the co-optimisation of the planning and or operation of integrated sectors or intersectoral co-optimisation of energy and reserves in the power system for example [25–27]. Conversely, negating to co-optimise and integrate can lead to cost penalties. In this study, a system in which hydrogen is reactively planned is considered a system in which the electricity system is exogenous to the hydrogen sector model as it has already been planned and built around electricity demand only. In other words, the hydrogen demands are only known after the electricity system has been built. The proactive hydrogen system is that which is endogenously co-optimized alongside the electricity system with perfect foresight. In examining the relative cost penalty, it will contribute to the research gap identified in Ref. [14] in which it was noted that "Some studies have examined the consequences of having limited foresight, but not for hydrogen systems".

The same concepts extend to an isolated hydrogen system. From a modelling perspective, the electricity system is exogenous to the isolated hydrogen system, which does not interact with the power sector other than through competition for renewable power generation potential. Hydrogen is frequently modelled as an isolated system across the literature often to reduce the complexity of the model. For example, the large three-part study by the International Renewable Energy Agency [28–30] models a future global hydrogen system that is isolated and not co-optimized alongside an existing power sector while [31] optimises isolated country level hydrogen systems for least cost green hydrogen exports. In the current work, in examining the costs of a forcibly isolated electrolytic hydrogen system, we will also provide a sense of the potential system cost error impact of negating to explicitly model a coupled electricity sector when not specifically modelling off-grid hydrogen systems.

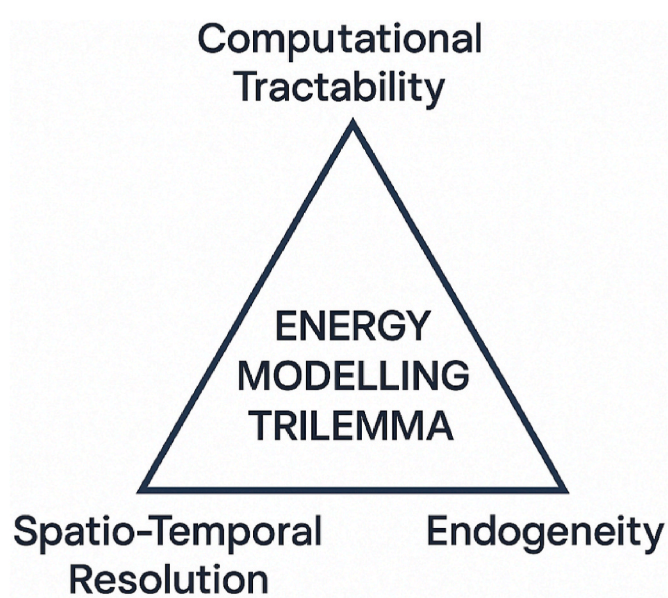

Fig. 1. The energy system modelling Trilemma.

2. Methodology

2.1. Existing modelling framework

The base model in this study is derived from the high spatial and temporal resolution global electricity & hydrogen framework presented in Ref. [21]. The modelling framework presented in Ref. [21] is centered around PLEXOS, a commercial modelling tool typically used to model power systems. The framework builds on the soft-linking methodology of [32] in which a power system model is soft-linked to an IAM scenario so as to downscale and assess the scenario at higher spatio-temporal resolution. In Ref. [21], this framework is extended to include the hydrogen sector and validated against an IAM scenario.

Fig. 2 presents a summary flow chart of the existing modelling framework. The annual regional electricity and hydrogen demands from the parent IAM scenario are spatially and temporally downscaled as outlined in Refs. [21,32] and passed exogenously to the core 256 region PLEXOS model. The core model is implemented in two phases, a capacity expansion phase and an operational economic dispatch phase. In both [21,32], the IAM regional power generation technology capacities are fixed in the capacity expansion phase via an equality constraint. Effectively, in Refs. [21,32], the capacity expansion model is simply determining the geographic distribution of the technology capacity and not the overall level. In the current work, the model is configured to perform a capacity expansion for each candidate technology without constraining the capacities to equal those from the parent IAM scenario. However, the hydrogen and electricity demand inputs are still derived from IAM scenarios in this study. This is to ground the energy commodity demands at a level that has been resolved endogenously in an energy system model with technological competition. As in Ref. [21], the capacity expansion models are run on a greenfield basis for a single target year - 2050. This simplification versus a multi-annual horizon is to maintain computational tractability at high temporal and spatial resolution. The temporal resolution of each model phase is flexibly configurable. In this study, we maintain an hourly resolution for the economic dispatch model phase and the two-hourly resolution for the capacity expansion model phase as in Ref. [21] but with a reduced sample of one representative day per month for computational efficiency. The objective function of both model phases is to minimize the total system costs subject to typical energy balance equations and technical capacity constraints. Full details on the mathematical formulation of the PLEXOS model are provided in the appendix of [21] and the data inputs needed to recreate these results in PLEXOS are provided in the data repository at https://doi.org/10.17632/pj7sxvmzy2.1 [33].

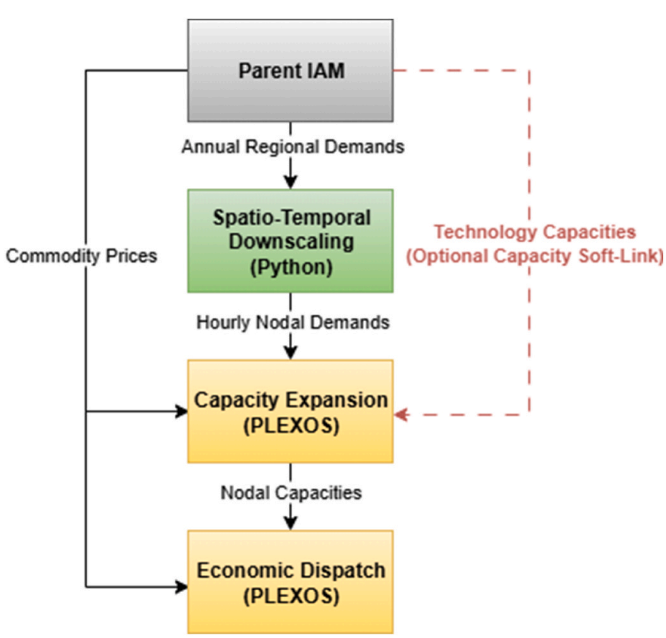

Fig. 2. Existing model framework.

2.2. Study conceptual design

The high-level design of the study is illustrated in Fig. 3 below with the core model run in three different configurations to simulate i) the proactively planned scenario, ii) the reactively planned scenario, and iii) the isolated systems scenario. Across the configurations, all demand and cost inputs remain the same, only the sequence of optimisation is varied. Note, when referring to cost in the study design, we are referring to total annualized system costs.

In configuration i), the proactively planned scenario, the model is configured to serve both the hydrogen and electricity system final demands via a co-optimized system with no limitations on sector coupling. From this configuration the costs of the proactively planned coupled system can be determined.

In configuration ii), the reactively planned scenario, the model is configured sequentially in two steps. In the first step, the electricity sector is optimized first with hydrogen demand switched off such that the model need only serve the final demand for electricity. Then, the resulting electricity-only solution is passed to the second step in a coupled electricity and hydrogen configuration. In this second step, minimum capacity constraints are asserted so that the electricity only capacities built in step one are fixed. In effect, the electricity system is optimized to meet electricity sector demand only and the hydrogen system is then optimized around it after the fact (with full sector-coupling permitted). From this configuration, the costs of the electricity system only can be calculated (from step one), as can the cost of the reactively planned coupled system.

In configuration iii), the isolated systems scenario is also run as a sequential two-step configuration. The first step is identical to that of configuration ii) in that the electricity sector is optimized in isolation. Then, in step two, the hydrogen system is also run in isolation with final demand for electricity switched off. In step two, we do not allow the capacity expansion model to build fossil or biomass candidates to serve the isolated hydrogen demand. This is to avoid the blurring of our demarcation between electrolytic hydrogen production and hydrogen produced from steam methane reforming or gasification of biomass which is outside the scope of this study. To ensure that the technical resource potentials for each resource-constrained technologies are not violated between the two steps, the upper bound on the maximum capacity constraints in the capacity expansion formulation are revised downwards by the amount 'absorbed' by the power sector in step 1. From this configuration, the costs of the isolated hydrogen system can be analyzed.

It should be highlighted that this approach assumes rather binary definitions of proactive versus reactive planning and coupled versus isolated systems. In reality, various degrees of proactivity and system coupling are possible between these boundary scenarios. The aim of the current work is simply to shed context on the relative costs at these boundaries.

2.3. IAM scenario demands

To provide context on the sensitivity of the relative costs to the overall electricity & hydrogen demand levels, the analysis is performed for two IAM scenarios. Namely, these are the SSP1_SPA1_26I_RE scenario derived from the IMAGE 3.2 integrated assessment model and the CEMICS_SSP1-1p5C-minCDR scenario derived from the REMIND-MAgPIE 2.1–4.2 integrated assessment model [34]. Fig. 4 below demonstrates the relative position of these two scenarios in respect of electricity and electrolytic hydrogen final consumption in 2050 compared to the other IAM scenarios in the AR6 Scenario Explorer and Database

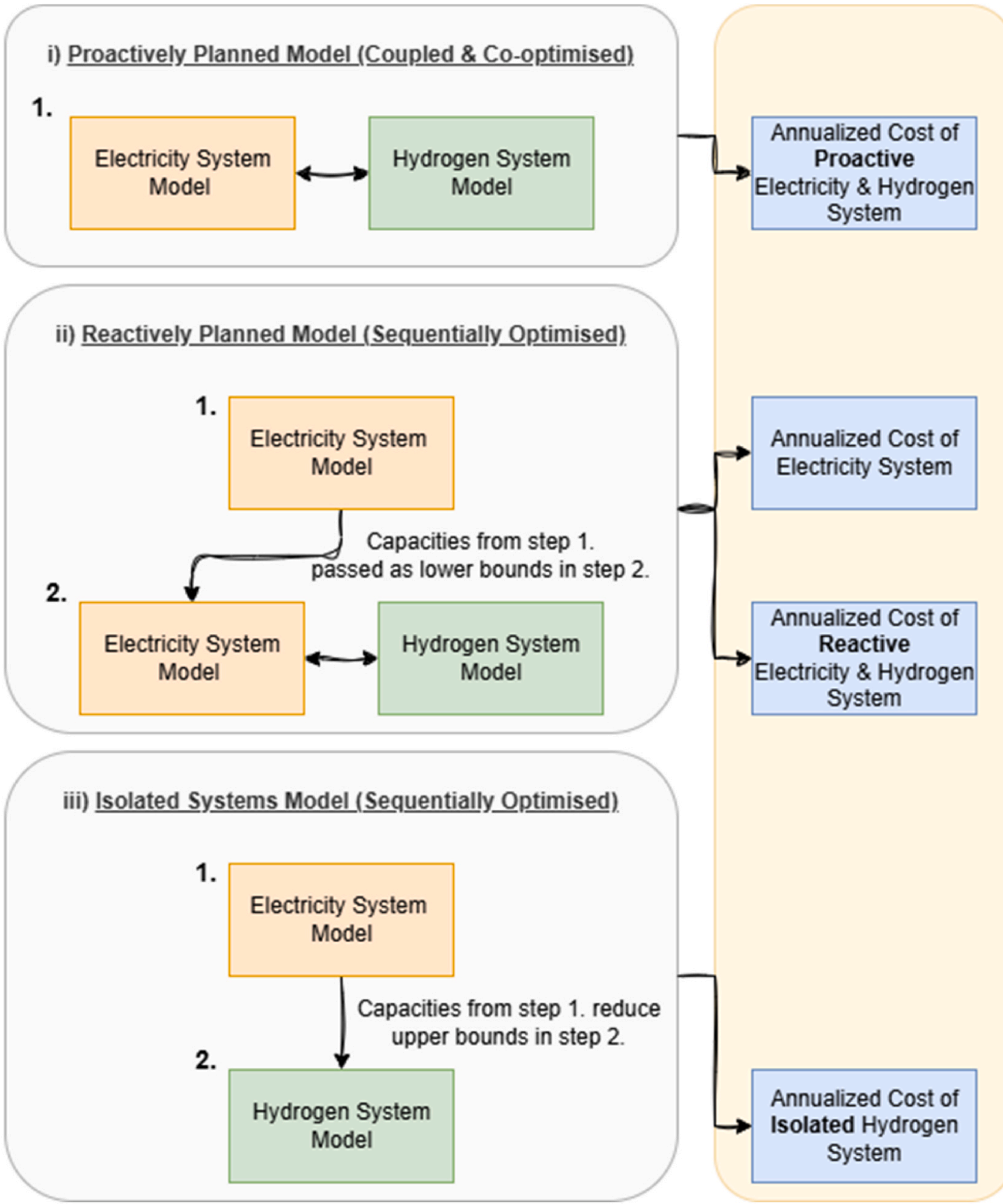

Fig. 3. High level design.

[35]. As in Ref. [21], the final consumption is de-rated by the fraction of hydrogen production that is from electrolysis. The resulting annual global demands are presented in Table 1. The SSP1_SPA1_26I_RE can be characterized by mid-high electricity consumption and a high penetration of electrolytic hydrogen in 2050 while the CEMICS_SSP1-1p5C-minCDR presents very high final consumption of electricity and lower (but still relatively high) demand for electrolytic hydrogen.

Both scenarios can be characterized as exhibiting significant outturning electrolytic hydrogen demand which forms the primary rationale behind their selection. Note that, when comparing the representativeness of hydrogen demand across all AR6 scenarios, it is necessary to consider differences between integrated assessment models and their treatment of hydrogen as explored in Refs. [13,21]. We do not examine a scenario in which electrolytic hydrogen plays a relatively small role as the overall costs of the sector would then be entirely dwarfed by the power sector and the consequences of reactive planning or forced de-coupling would be expected to be small in absolute terms.

2.4. *Key inputs & assumptions*

In general, the methodologies and modelling assumptions applied to the model framework in the current work are the same as those in Ref. [21] including but not limited to wind and solar load factor inputs, the temporal and spatial downscaling of the regional annual demands for electricity and hydrogen, and the technical resource potential of energy-limited technologies at each node.

In [21], it was not necessary to input realistic build costs and operational costs for many technologies given that most were constrained by the capacity soft-link with the parent IAM scenario. Given that this study is chiefly concerned with system costs and employs the framework of [21] with the capacity soft-link disabled, appropriate technology costs must be input to the modelling framework. For power generation technologies, total installation costs and operational costs are derived

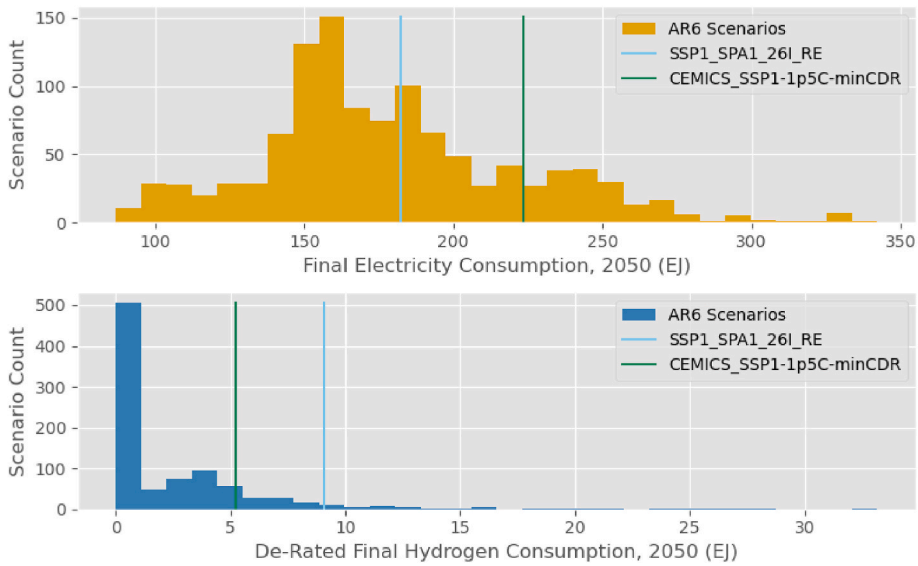

Fig. 4. AR6 scenario electricity & electrolytic hydrogen consumption.

Table 1
IAM scenario demands.

IAM Model	IAM Scenario	Electricity Demand, 2050	Hydrogen Demand, 2050	Electrolytic Fraction, 2050	De-Rated Hydrogen Demand, 2050
IMAGE 3.2	SSP1_SPA1_26I_RE	182.28 EJ/yr	26.95 EJ/yr	0.34	9.05 EJ/yr
REMIND-MAgPIE 2.1–4.2	CEMICS_SSP1-1p5C-minCDR	223.37 EJ/yr	6.05 EJ/yr	0.86	5.20 EJ/yr

from the International Agency's (IEA) World Energy Outlook 2023 (WEO 2023) [36], while those for Power-to-X technologies, such as electrolysers or ammonia synthesis plants are derived from the IEA's Global Hydrogen Review 2023 [37]. In all cases, where cost figures are presented regionally, the median regional value is taken to assume a uniform global value. This is to simplify the analysis and filter out geographic trends that are not driven by technical resource potential. All costs are referred to 2010 US dollars in keeping with the convention of the AR6 Scenario Database to facilitate comparison to the parent IAM scenario. The resulting technology cost figures and assumed economic lifetimes are published in the supplementary information accompanying this paper.

For energy commodity prices we assume those of the parent CEMICS_SSP1-1p5C-minCDR scenario as published in the AR6 Scenario Database [35]. This includes prices for biomass for power generation for which we also set a maximum consumption constraint equal to the consumption in the CEMICS_SSP1-1p5C-minCDR scenario to preserve the price-demand equilibrium of the biomass supply from the IAM scenario. As with the commodity costs, a carbon price (of a significant 765 $/t) in line with the CEMICS_SSP1-1p5C-minCDR IAM scenario is asserted. In addition, a constraint is added such that the system must exhibit net-zero emissions.

In [21] it was noted that the role of geothermal power generation in the soft-linked IAM parent scenario was limited and therefore the need for geospatial technical potential constraints for geothermal power was negligible. However, preliminary model runs with the IEA WEO 2023 cost inputs and arbitrarily high maximum resource constraints for geothermal units exhibited extremely high build-out of geothermal power capacity. As a result, technical potential constraints for geothermal power generation were asserted in the PLEXOS model based on the work of [38]. The authors of [38] leverage GIS to estimate the global technical potential of enhanced geothermal systems (EGS) at a $1^\circ \times 1^\circ$ spatial resolution. Aggregated EGS power generation capacity potentials are provided by country in levelized cost of energy (LCOE) increments of 5 €/MWh for 2050. We assert the total MW potential for each country summed across all LCOE increments except the last >100 €/MWh column as capacity upper bounds in the current model. This column is excluded as the capacity potential significantly balloons to incorporate the most technically challenging and expensive sites at which point our technology cost assumptions are likely to deviate significantly. For the countries in the current 256 region model that are broken down further into sub-national regions, the technical potentials are asserted on the national collection of sub-regional nodes.

Finally, while the model framework presented in Ref. [21] is an energy only model that does not include any operational constraints around reserve or inertia in the power sector, we consider that this is an aspect in which sector coupling may exhibit some efficiencies. To this end, we upscale the demand profiles of both electricity and hydrogen by 20 % for the capacity expansion model phase in all configurations so that the system is optimized to be resilient to 120 % of the demand of energy commodity. In effect, this is stipulating that a 20 % dynamic energy reserve be available in the power sector for example, although such a margin is not enforced at the unit commitment and economic dispatch model phase. This 20 % figure is consistent with recommended reserve margins by the International Energy Agency (IEA) and current practice by the North American Electric Reliability Corporation (NERC) [39,40].

2.5. *Calculation & framing of relative costs*

For clarity, most of the following analysis will be framed with respect to the additional cost of the hydrogen system in addition to the optimal electricity only system rather than the total combined electricity and hydrogen system cost. Notwithstanding the relatively high electrolytic hydrogen penetrations of the chosen scenarios, final demand for electricity significantly surpasses that of hydrogen in both scenarios. As a result, if the cost savings of proactivity vs reactivity regarding the integration of the hydrogen sector were presented as a percentage of the total coupled system cost, the magnitudes may appear misleadingly insignificant owing to the smaller role of hydrogen envisaged by the IAMs. From an optimisation perspective, for a high-resolution global model, it is possible that there are multiple optimal solutions and comparing individual technology capacities at each regional node from one scenario to another may not yield particularly useful insights. However, the globally aggregated costs can be more directly compared. Fig. 5 below extends Fig. 3 to clarify the derivation of key cost metrics in this study and how they are calculated from the model framework.

Step one of model configuration ii) (see Fig. 3) provides the cost of the electricity system only. We can then subtract the associated global total system cost of this system from that of the proactive coupled system costs from configuration i) and the reactive coupled system costs from step two in configuration ii). This yields our proactive and reactive hydrogen system costs or, more precisely, the additional system costs due to the hydrogen final demand. The isolated hydrogen system cost can be inferred more directly from step 2 of model configuration iii) in which the electricity final demand is not seen by the isolated hydrogen system model. At this point, the hydrogen system costs associated with each of the proactive, reactive and isolated scenarios have been calculated as shown in purple in Fig. 5.

Where capital expenditure (CAPEX) costs are annualized for ready comparison or summation with annual operation costs (OPEX), the following formula is applied as in equation (1) below:

$$Annualized\ CAPEX_f = CAPEX_f \times \frac{r}{1-(1+r)^{-n_f}} \tag{1}$$

Where the subscript “f” is the index denoting a specific facility such as a generator, storage facility or transmission line, r is the assumed interest rate of 10 % applied uniformly to all projects and n_f is the specific economic lifetime of the facility type in years. Here it is important to highlight that the actual cost of capital is not uniform globally. In this study, for the same reasons that we are not accounting for geopolitical factors such as trade restrictions between rival states, we are assuming a uniform global WACC. This is to maintain model dynamics and system costs driven by technical resource potentials and technology costs and not driven by perceived risk margins or regional politics that may change considerably between now and 2050. Notwithstanding this, the resulting impacts of a uniform cost of capital are explored in Refs. [41,42] and should be considered when interpreting this study. A global rate of 10 % has been chosen as the base case to align with ESMAP’s cost of capital assumptions for a nascent hydrogen sector [43] and to reflect the high cost of capital for the power sector in developing countries [41,44]. However, sensitivity of our results to the discount rate is examined in the following section.

3. Results & discussion

Table 2 presents the total annualized total system costs for each modelling configuration for both demand scenarios in trillion 2010 US Dollars. The base case data corresponding to a weighted average cost of capital of 10 % is highlighted in yellow for ease of reference and results for the 5 % and 15 % WACC sensitivities are also presented. Applying the calculation framework as shown in Fig. 5 yields the total annualized hydrogen system costs in the proactive, reactive and isolated hydrogen system planning scenarios as presented in billions of US Dollars in Table 3. As expected, the costs of each hydrogen system configuration increase steeply with the assumed WACC.

Table 2
Total annualized system costs by Configuration.

Scenario	Discount Rate	Reactive Elec & H2 (T $2010/yr)	Proactive Elec & H2 (T$2010/yr)	Elec Only (T $2010/yr)	Isolated H2 (T $2010/yr)
SSP1_SPA1_26I_RE	5 %	6.7	6.69	6.51	0.24
	10 %	8.44	8.41	8.21	0.29
	15 %	10.27	10.26	10	0.35
CEMICS_SSP1-1p5C-minCDR	5 %	5.58	5.57	5.3	0.34
	10 %	7.07	7.04	6.72	0.42
	15 %	8.62	8.59	8.2	0.53

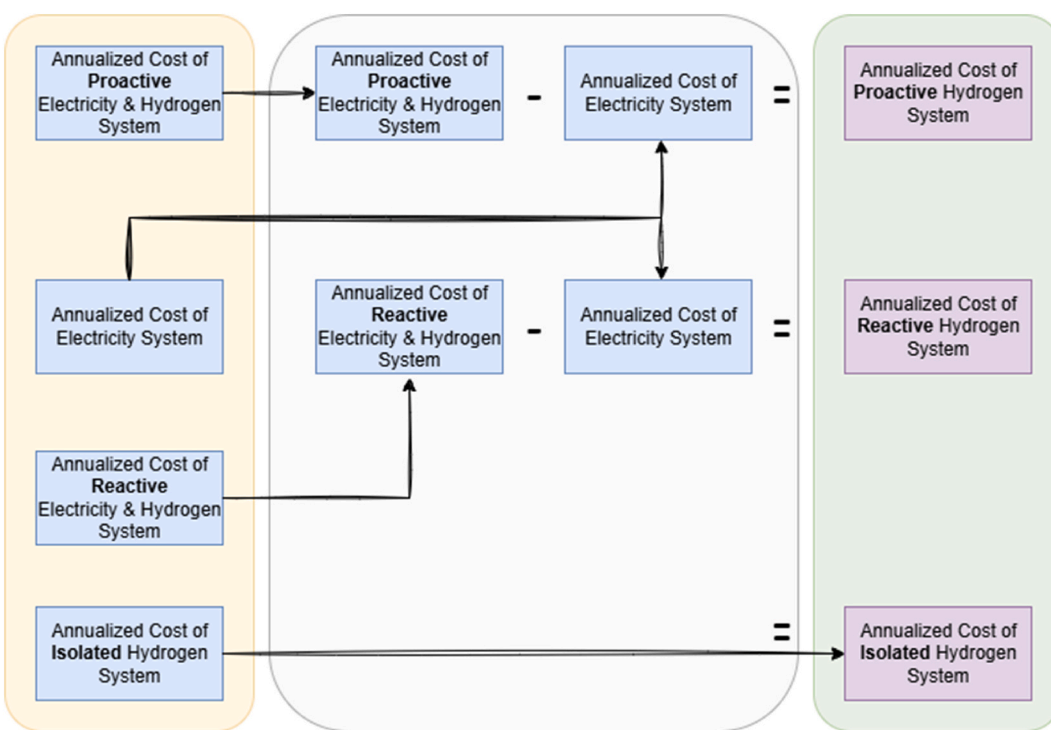

Fig. 5. Superposition of global system costs.

Table 3
Total annualized H2 system costs.

Scenario	Discount Rate	Reactive H2 (B$2010/yr)	Proactive H2 (B$2010/yr)	Isolated H2 (B$2010/yr)
SSP1_SPA1_26I_RE	5 %	187.82	179.4	239.88
	10 %	231.95	204.43	287.27
	15 %	276.65	261.83	347.63
CEMICS_SSP1-1p5C-minCDR	5 %	278.7	264.68	346.12
	10 %	349.51	318.95	424.72
	15 %	426.17	393.06	531.16

In examining the impacts of reactive planning and system isolation, the reactive and isolated planning penalties are calculated by subtracting the cost of the proactively integrated hydrogen system cost from the reactive and isolated hydrogen system costs respectively from Table 3. These figures are presented below in Table 4 both in absolute terms (in billions of US Dollars) and in relative terms as a percentage of the proactively integrated hydrogen system cost. A general trend of increasing absolute reactive planning and isolation penalties with increasing cost of capital is observed, with the exception of the 15 % WACC in the SSP1_SPA1_26I_RE demand scenario. No trend is apparent for the relative percentage penalties which vary between 5 % and 13 % of the proactively planned hydrogen system costs for reactive planning and 31 %–41 % of the proactive hydrogen system costs for isolation.

Fig. 6 below presents the base case (10 % WACC) relative cost penalty of the reactive planning and isolated hydrogen system configurations as a percentage of the annualized hydrogen system cost in the proactive planning configuration. From Fig. 6 we can see that the cost penalty of reactive planning is between 9 and 14 % of the annualized proactive hydrogen system costs for both of the IAM demand scenarios. However, the cost penalty of a reactive and isolated hydrogen system vs the proactive system is significant, between 33 and 41 % across both scenarios. This is an important finding given that, as noted in Ref. [21] and the introduction of the current work, many higher temporal and spatial resolution global hydrogen-focused studies model the future hydrogen system independently of the power system. For example, the large three-part study by the International Renewable Energy Agency (IRENA) [28–30] models an independent electrolytic hydrogen sector. Here, the implication is that such studies may yield a potential future system that is structurally different and more expensive than a sector-coupled system. Furthermore, there is potential for the same cost-impact dynamic to extend to other sectors or sub-sectors when they too are assumed away in a model. For example, in the manner that non-electrolytic hydrogen is not explicitly represented in the current work or in that of [21]. Moreover, the harsh cost penalty for isolating the hydrogen sector from the electricity sector suggests that policy and regulation regarding power generation capacity additionality and grid integration of electrolytic hydrogen production should be approached with care so as to not overly disincentivize efficient coupling dynamics.

Notably, the base case relative cost penalties are higher in the CEMICS_SSP1-1p5C-minCDR demand scenario in both the reactive and isolated model configurations despite the scenario exhibiting less electrolytic hydrogen demand than the SSP1_SPA1_26I_RE scenario. This is due to the larger overall combined electricity and hydrogen demand in the SSP1_SPA1_26I_RE scenario leading to tighter competition for the cheapest power generation resources. The methodology of the current work is limited in that the reactive policy scenario only allows the hydrogen sector to be optimized after the entire electricity sector has been optimized, it is also assumed that it is socially acceptable to build out the maximum technical potential of a given technology at a given system node. Public acceptance and community opposition to large-scale energy projects are well treated across the literature [45–47]. For example [47], examines public acceptance of renewable energy and grid expansion in Germany, finding that landscape modification is the most important factor influencing local acceptance. Large scale modification of the landscape at one node owing to significant resource potential at the node is unlikely to be wholly exploitable due to limitations around social acceptance. Regarding this study, this raises the implication that the technology specific nodal capacity constraints understate the degree to which the system is constrained and that the relative cost penalties of reactive planning may be even greater. To this end, the results of the current work should be considered with the understanding that the binary representation of reactive planning likely overstates the relative cost penalty of reactive planning, while the omission of social acceptance limitations on technology capacity limits would be expected to have the converse effect.

Fig. 7 breaks down the annualized hydrogen system costs (for the base case WACC) in all configurations by technology for both demand scenarios. While differing in magnitudes, the pattern of investment across each hydrogen system configuration is similar for both demand scenarios. Hydrogen system costs can be seen to be dominated by investment in solar PV, onshore wind and electrolyser facilities across the board. Immediately of note is the spike in battery storage costs in both demand scenarios for the isolated hydrogen system configuration. The additional cost attributable to solar PV and onshore wind in the isolated hydrogen system is also notable. In the reactive planning hydrogen configuration, while the differences are apparent, the drivers of cost differences with the proactively planned hydrogen system appear more nuanced.

Fig. 8 plots the *additional* total annualized cost of reactive rather than proactive hydrogen integration broken down by individual technologies so that the differences observed in Fig. 7 are clearer and more accentuated. The pattern is nearly identical across the two IAM demand scenarios with differing magnitudes. In both scenarios, the reactive planning configuration results in less expenditure on hydrogen pipelines, hydrogen storage, gas-fired power generation without carbon capture and storage, hydro power and onshore wind generation. On the other hand, the reactive configuration results in significantly more expenditure on solar PV, advanced geothermal power, electrolysis and electricity interconnection. The need for additional expenditure on electrolysis, battery storage and electricity interconnection in the reactive planning configuration suggests that sub-optimal locational infrastructure lock-in is a key driver of the reactive planning cost penalty. Fig. 8 also shows that both IAM demand scenarios incur higher costs related to ammonia technologies under reactive planning, including ammonia-to-power generation, ammonia synthesis and cracking plants, storage, and shipping. This further underlines the impact of spatial lock-in with the model deploying costly and inefficient ammonia transport while spending less on hydrogen pipeline infrastructure.

Table 4
Calculated absolute & relative reactive planning & isolation penalties.

Scenario	Discount Rate	Reactive Penalty (B$2010/yr)	Isolated Penalty (B$2010/yr)	Reactive Penalty (% of Proactive)	Isolated Penalty (% of Proactive)
CEMICS_SSP1-1p5C-minCDR	5 %	8.42	60.48	5 %	34 %
	10 %	27.52	82.84	13 %	41 %
	15 %	14.82	85.8	6 %	33 %
SSP1_SPA1_26I_RE	5 %	14.02	81.44	5 %	31 %
	10 %	30.56	105.77	10 %	33 %
	15 %	33.11	138.1	8 %	35 %

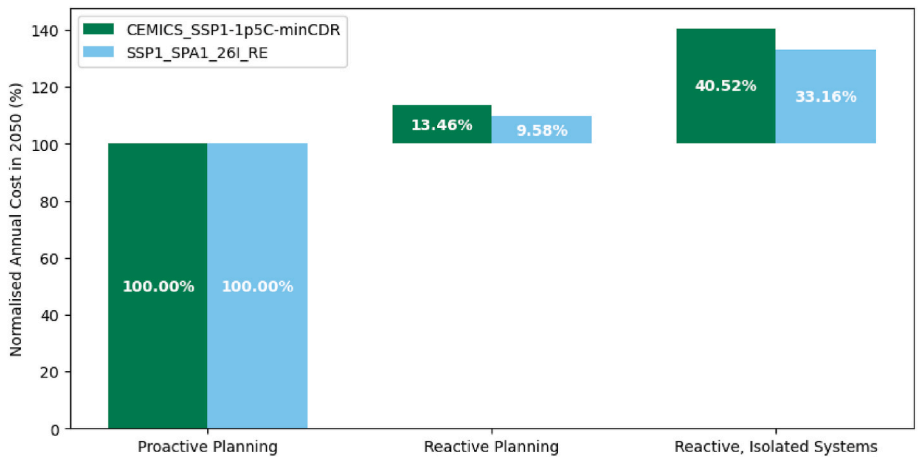

Fig. 6. Relative total system cost penalties.

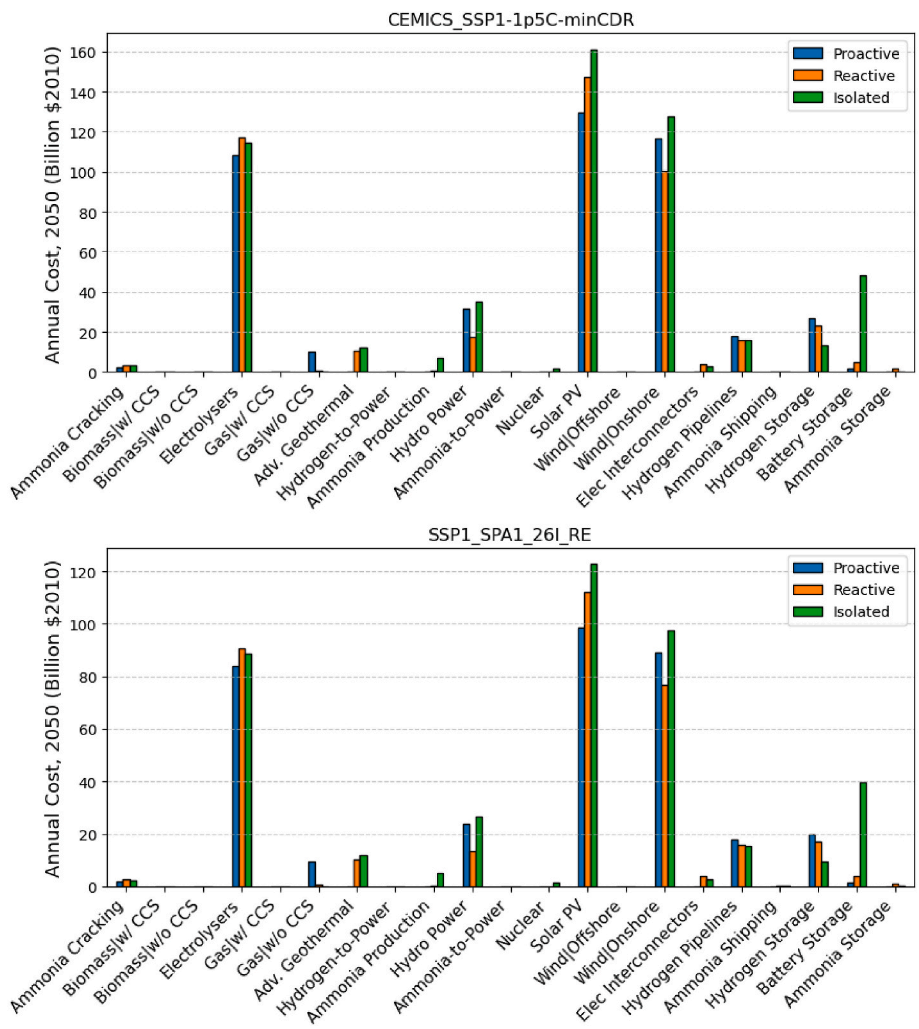

Fig. 7. Annual hydrogen system costs by technology (base case WACC).

Fig. 9 plots the additional total annualized cost of the isolated hydrogen system rather than the proactive sector-coupled hydrogen system configuration broken down by individual technologies. As in Fig. 8 the pattern is consistent across both IAM demand scenarios with differing overall magnitudes. The largest cost difference in both demand scenarios is driven by battery storage as is also clearly seen in Fig. 7. Additional costs are also associated with the need for additional power generation capacity compared to the coupled system including both variable renewable sources and clean firm power from advanced geothermal and nuclear power generation technologies. Overall, the effects of isolation are quite direct. In the absence of capacity sharing benefits through sector coupling, significant additional battery storage

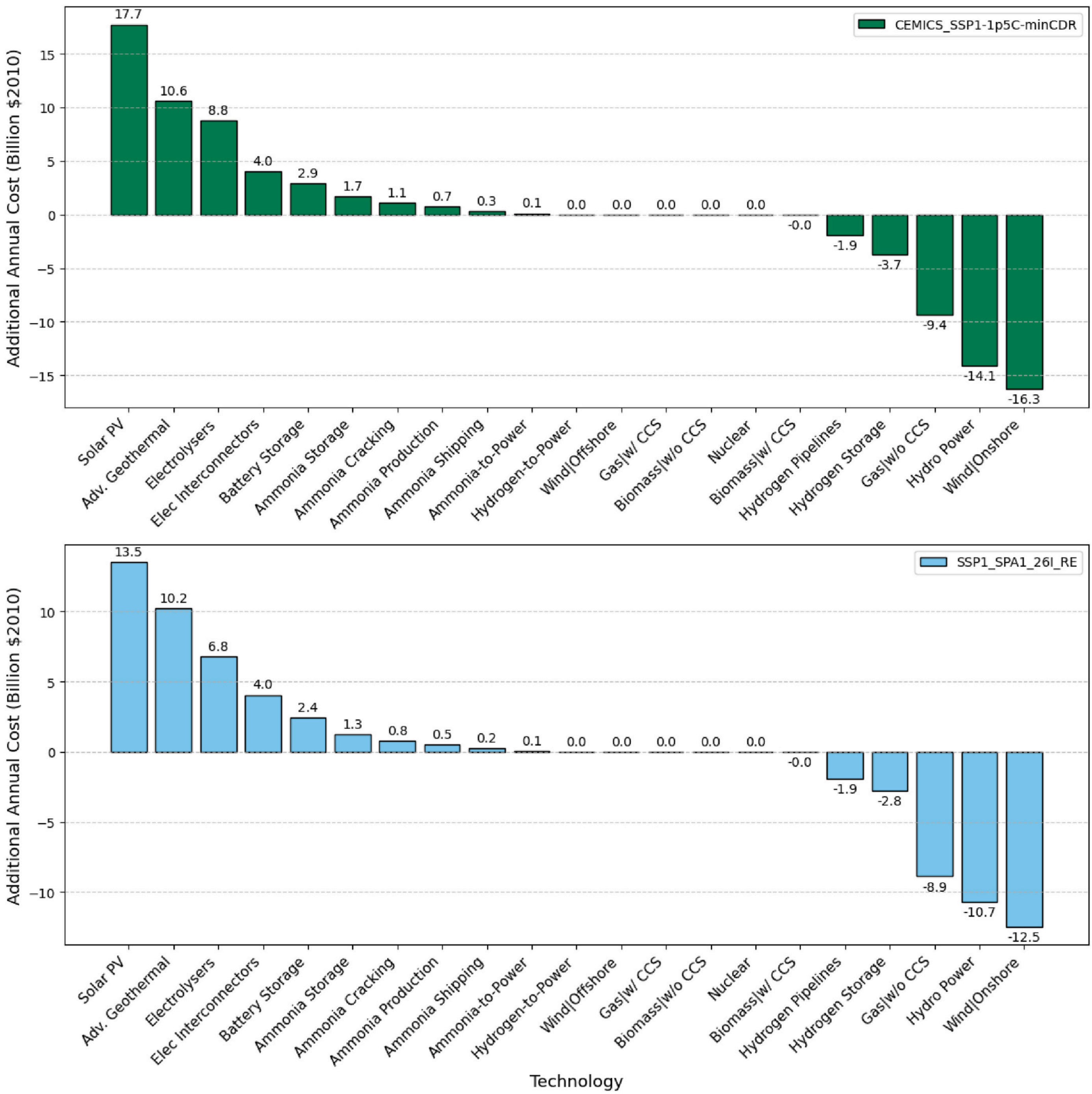

Fig. 8. Additional Costs of Reactive vs Proactive H2 Integration.

and power generation capacity is required in the hydrogen sector to facilitate high electrolysis load factors and avoid excessive curtailment of variable renewable power. This finding of significant additional costs when the electrolytic hydrogen sector is restricted to additional power generation capacity (that is inherently temporally congruent in this study) is consistent with the findings of [19,20].

Naturally, there are limitations to the work that warrant highlighting. Our results are sensitive to the cost assumptions that are input into the modelling framework. This is especially pertinent given that these costs are formulated at fixed values projected to 2050 rather than as a function of today's costs, a learning rate and level of deployment. Moreover, the greenfield approach overlooks the fact that some assets already in existence may still be in service in 2050 and doesn't account for the manner in which the inclusion of additional years across a longer time horizon can impact the optimal solution in the target year of study. It should also be noted that, at the intranodal level the model exhibits a copperplate assumption and therefore some of the capacity sharing efficiencies unlocked through sector coupling could actually warrant further cost due to the need for additional transmission capacity. This copperplate assumption could therefore overstate the cost savings associated with capacity sharing efficiencies. Lastly, we are assuming that the global electricity and hydrogen system would be planned with perfect foresight of demand in each modelling configuration, but in the reactive planning scenario the starting electricity system is fixed. This is an imperfect binary simulation of reactive planning but does provide insight into the dynamics of infrastructure lock-in. Notwithstanding

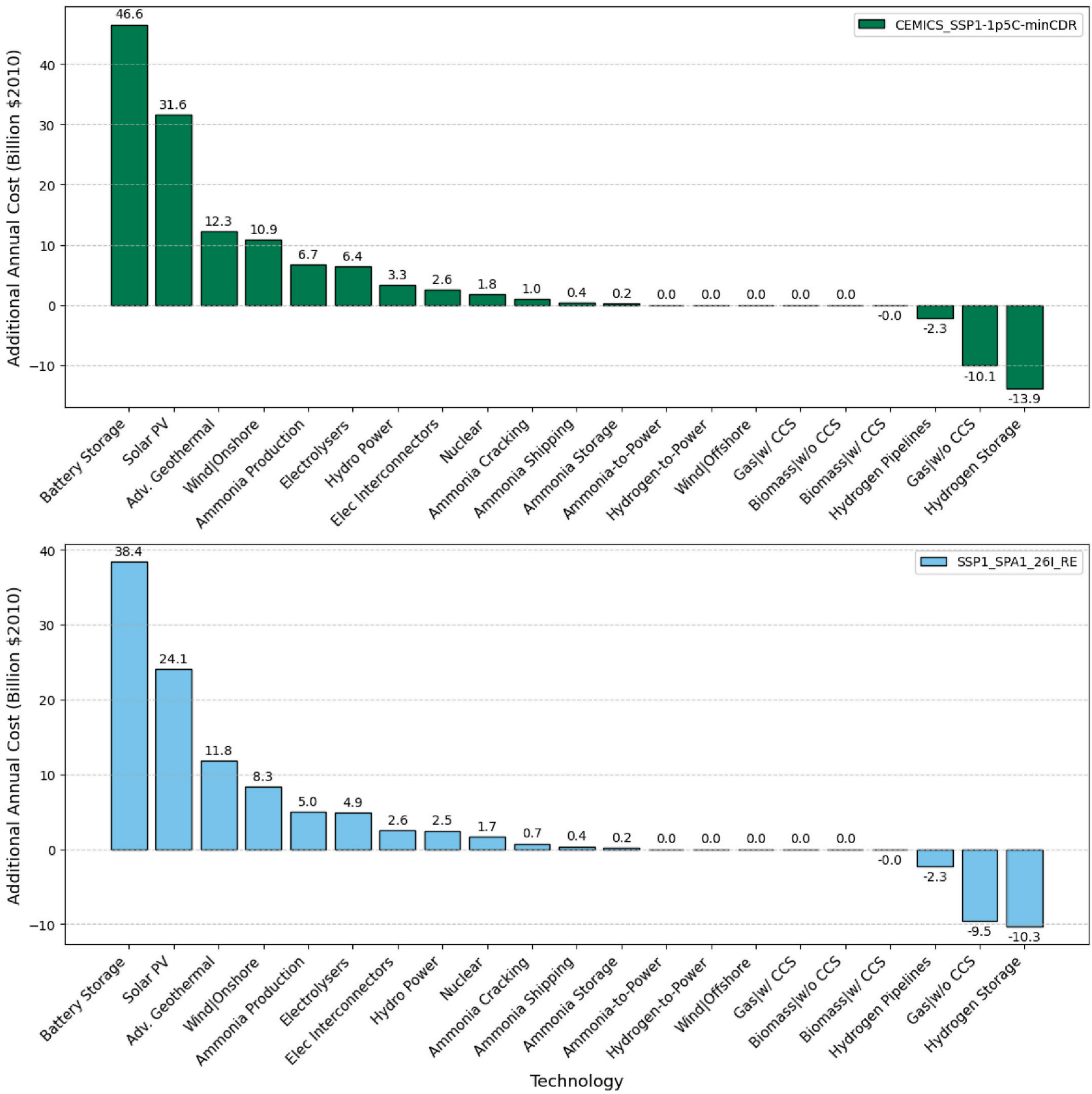

Fig. 9. Additional Costs of Isolated vs Coupled Proactive H2 Integration.

these limitations, the current approach does provide some needed context around the cost penalties of reactive planning and forced isolation of the electrolytic hydrogen system from the power sector.

4. Conclusion

We have estimated the cost penalty of reactively rather than proactively planning for the global integration of electrolytic hydrogen into the power sector given a significant demand for hydrogen in the future. We estimate this cost penalty to be of the order of an additional 8–15 % of the optimally integrated proactively planned hydrogen system cost depending on the overall combined global electricity and hydrogen demand. This corresponds to between 27 and 31 billion 2010 US dollars of additional costs annually in 2050. In general, this cost penalty can be expected to be greater when the cost of capital is higher and lesser when the cost of capital is lower. Whilst not catastrophic, the potential penalties due to sub-optimal infrastructure lock-in are not insignificant. These findings highlight the potential for further research aimed at evaluating realistic future roles for hydrogen building on work such as [3], and further modelling tailored to hydrogen (addressing the limitations highlighted in Ref. [14]) to exhibit notable positive impact. With the potential to avoid tens of billions of reactive planning penalties, this work suggests funding such research can achieve good value for consumers.

We also estimated the cost penalty of isolating a future electrolytic hydrogen sector from the electricity sector in a scenario wherein sector coupling is disincentivized. In this case, we estimate the cost penalty of isolation to be of the order of an additional 33–41 % of the cost of an optimally integrated and proactively planned hydrogen system. This corresponds to between 82 and 106 billion 2010 US dollars of additional costs annually in 2050. Under a lower cost of capital this range still comes in between 60 and 80 billion 2010 US dollars of additional costs annually in 2050. Consequently, policymakers should proceed cautiously in order to avoid policy measures that discourage optimal coupling of a future electrolytic hydrogen sector or face significant additional system costs in the event of significant future hydrogen demand arising. For example, concerns around the restrictiveness of RED II's requirements for grid-connected electrolysis should be evaluated seriously so as to minimize any isolating effects that aren't absolutely necessary to meet other objectives.

Our findings underscore the importance of "systems thinking" and forward planning. While we have focused particularly on electrolytic hydrogen and the power sector, it is likely that similar sub-optimal cost penalty dynamics extend into other coupled sectors in the energy system.

CRediT authorship contribution statement

Duncan Mathews: Conceptualization, Data curation, Formal analysis, Funding acquisition, Investigation, Methodology, Visualization, Writing – original draft. **Paul Deane:** Conceptualization, Funding acquisition, Methodology, Software, Supervision, Validation, Writing – review & editing.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.152350.

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