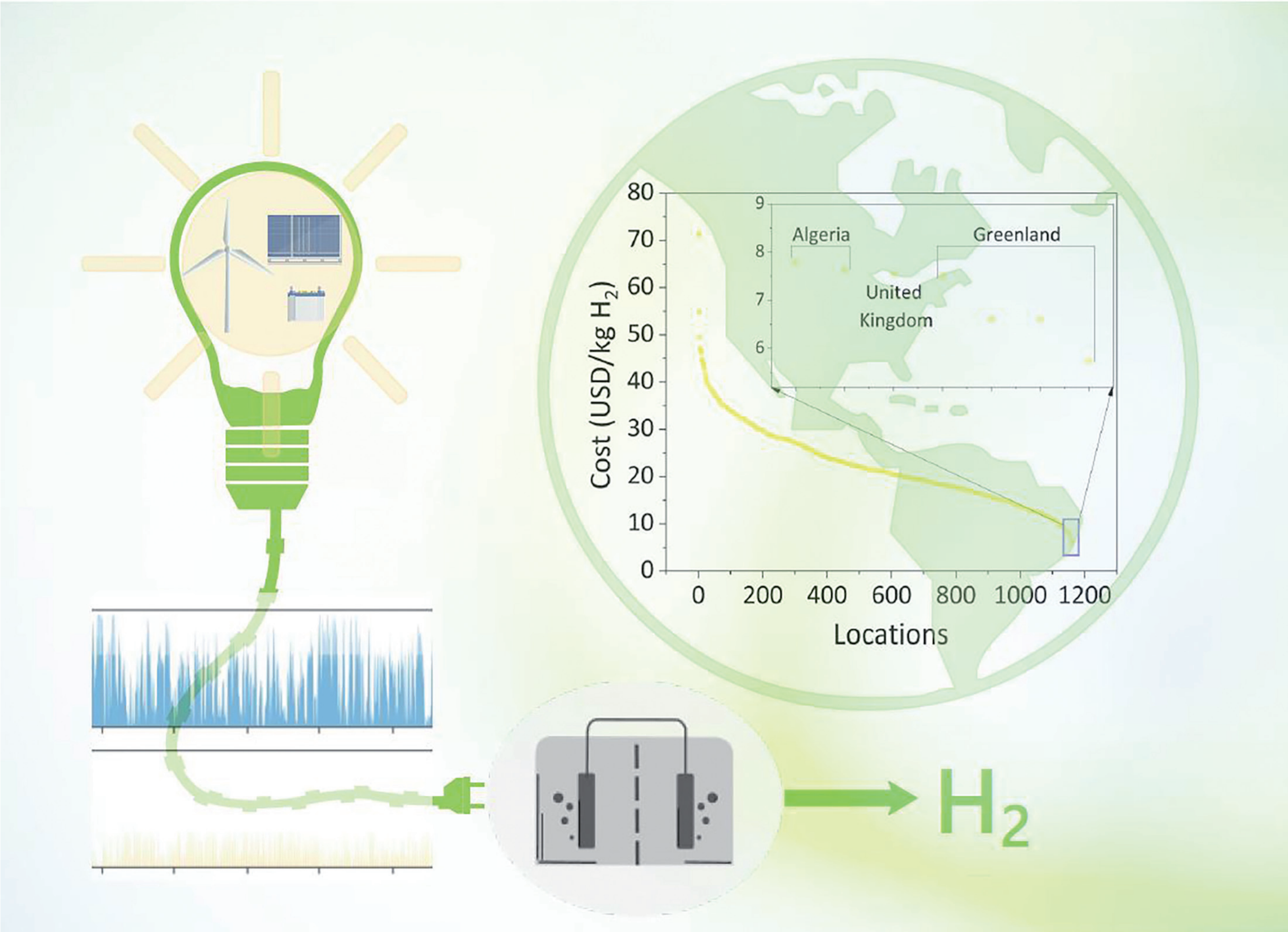

Showcasing research from Professor Niall Mac Dowell's group, Centre for Environmental Policy, Imperial College London, UK.

Quantifying global costs of reliable green hydrogen

This study assesses the present and future costs of reliable green hydrogen, considering inter- and intra-annual variability of renewables, based on 20 years of hourly-resolved wind and solar data from 1,140 locations around the world. Current costs range from \$18 to \$22 per kg of H_2, with a minimum of \$5 per kg. Future projections foresee costs decreasing to \$8–\$10 per kg, with a minimum of \$3 per kg. Success hinges on minimising energy asset oversizing, cutting renewable energy and capital investment costs, and capitalising on surplus energy sales.

As featured in:

See N. Mac Dowell *et al.*, *Energy Adv.*, 2023, **2**, 2042.

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Quantifying global costs of reliable green hydrogen†

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The current energy crisis has resulted in natural gas prices at an unprecedented level in many parts of the world, with significant consequences for the price of food and fertiliser. In this context, and with the projected reduction in the costs of renewables and electrolysers, green hydrogen is becoming an increasingly attractive option. In this study, we evaluate the current and future costs of green hydrogen, produced on a reliable schedule, so as to be coherent with industrial demand. Here, we take full account of both inter- and intra-annual variability of renewable energy, using 20 years of hourly resolution wind and solar data from 1140 grid points around the world. We observe that simply using average annual capacity factors will result in a significantly under-sized system that will frequently be unable to meet demand. In order to ensure production targets are met, over-capacity of power generation assets and energy storage assets are required to compensate for inter-annual and intra-annual variations in the availability of wind and solar resources, especially in the time periods known as "dunkelflauten". Whilst costs vary substantially around the world, contemporary costs of reliable green hydrogen are estimated to be, on average, 18–22 USD per kg_{H_2} with a minimum of 5 USD per kg_{H_2}, depending on the ability to monetise "surplus" or "excess" renewable energy. The primary cost driver is renewable energy capacity, with electrolysers and energy storage costs exerting a second-order effect. With cost reduction, future costs are anticipated to be, on average, 8–10 USD per kg_{H_2} with a minimum of 3 USD per kg_{H_2}, again as a function of the ability to monetise otherwise curtailed power. Another key factor in future costs is found to be hurdle rates for capital investments. Finally, we observe that continued cost reduction of renewable power is key to reducing overall system costs of green hydrogen production.

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1. Introduction

Recent geopolitical events have led to a renewed focus on energy security. In some regions, this fact has led to increased attention to the value of modern renewable energy in general, and that of green, or electrolytic, H_2 in particular.

As has been discussed elsewhere,[1–6] for electrolytic H_2 to be considered truly low-carbon, the power supply must be abundant, cheap, and deeply decarbonised, with a carbon intensity in the range of 30–70 kg_{CO_2} MWh^{-1}. At the time of writing, this is not available in most regions *via* a grid connection, and thus, in order to meet ambitious targets for production,[7–12] new power generation assets will be required.

Recently, some very ambitious targets for the low cost production of green hydrogen ($H_{2,g}$), *i.e.*, hydrogen produced exclusively *via* renewable power, have been articulated, with stated goals of achieving prices of 1 USD per $kg_{H_{2},g}$.[13,14] Whilst wind and solar power are becoming increasingly cheap, their intermittency will inevitably present cost challenges in the form of decreased capital asset utilisation. This is due to the over-sizing of the production and storage units required to balance the effect of the inter-daily, inter-seasonal and inter-annual variability that characterise wind and solar energy resources. Thus, a production facility will need access to sufficient power generation and energy storage capacity – either electrons or protons so as to reliably produce green H_2. Moreover, H_2 orders will need to be filled on time, and, increasingly, to a defined carbon intensity – simply relying on the grid as a backup may not be an option. As a given production facility will be expected to operate for 15–25 years, all these factors must be taken into

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account in its design and in assessing the costs of producing reliable green H_2.

Importantly, such an energy supply from renewable sources would have the virtue of being entirely insulated from the volatility of the fossil energy markets. The question is, at what cost can a reliable supply of green H_2 be obtained, and under what circumstances, if any, can the goal of 1 USD per $H_{2,g}$ be reached?

A brief history of hydrogen

In the context of green H_2, it is important to recognise that its production has a long history, with the first laboratory demonstration taking place in 1789[15] by the Dutch merchants Jan Rudolph Deiman and Adriaan Paets van Troostwijk. It took about a century for this concept to be demonstrated in an industrial context; in 1888, the Russian engineer Dmitry Lachinov[16] demonstrated the industrial production of hydrogen and oxygen, and by 1902, more than 400 alkaline water electrolysis (AE) units were in operation,[22] and this technology persists until this day. By the 1920's, the technology had been brought to the 100 MW scale, primarily for the production of ammonia fertiliser in Canada and Norway using low-cost hydroelectricity.[23] Technology innovation has continued, and Thomas Grubb and Leonard Niedrach developed the polymer electrolyte membrane (PEM) electrolysis technology at General Electric Co. in the early 1960s.[24–26] This technology has significant advantages compared to alkaline electrolysis, namely higher energy efficiency and product purity, lower maintenance costs and a wider operating range in terms of current density and pressure, which allows a quick reaction to fluctuations typical of renewable energy generation.[24,27–29]

Over the past 60 years, technology for producing green H_2 has continued to improve. In 1972, the development of water electrolysis with solid oxides began, while advanced alkaline systems started to be developed from 1978 onwards.[22] By 1985 in Germany, Dönitz and Erdle published the first results for solid oxide electrolyser cells (SOEC) based on electrolyte-supported tubular cells as part of the HotElly project.[30] In spite of the progress in PEM and SOEC electrolysis, they were not commercialised on a large scale at that time, mainly because of

Table 1 Literature review of the current and future production cost of green H_2

Source	Reported cost	Assumptions
Bertuccioli *et al.* (2014)[17]	5.9–8.7 USD per $kg_{H_2,g}$ in 2012 and 4.2–6.7 USD per $kg_{H_2,g}$ in 2030	– Trend lines constructed through stakeholder consultation – PEMEL costs between 2690–3355 USD per kW in 2012 and 361–1836 USD per kW by 2030 (figures account for capital costs of key components of the electrolysis technology but exclude installation expenses, *e.g.*, civil works, land use and additional project costs). – Electricity price: 72 and 115 USD per kW per h for the low and high values, respectively. – Full-load operation
Felgenhauer and Hamacher (2015)[18]	5.5–9.8 USD per $kg_{H_2,g}$	– PEM electrolysis process driven by low-cost electricity (78–81 USD per MW per h) – Full-load operation.
IEA (2019)[12]	Long-term global costs ranging from less than 1.6 to more than 4.0 USD per $kg_{H_2,g}$.	– Green H_2 produced from hybrid solar PV and onshore wind systems – Fixed discount rate: 8% – CAPEX: – Electrolyser: 450 USD kW_e^{-1} (efficiency$_{LHV}$: 74%) – Solar PV system: 400–1000 USD per kW – Onshore wind system: 900–2500 USD per kW
Hydrogen council (2020)[19]	6.0 USD per $kg_{H_2,g}$ for 2020, falling to 2.6 USD per $kg_{H_2,g}$ by 2030.	– PEMEL operating at a capacity factor (CF) of 0.5 with an electricity supply from both solar and wind power. – Constant learning rates of 13% for the PEMEL – Installed capacity of electrolysers in 2030:90 GW – Electricity costs: down from 57 to 33 USD per MW per h.
Mallapragada *et al.* (2020)[20]	2.5 USD per $kg_{H_2,g}$ or less by 2030, depending on the system's configuration and location.	– Levelised cost for a continuous supply of green H_2 from PV-electrolysis by 2030 based on the least-cost modelling of design and operations. – Cost projections rely on a sharp reduction in the cost of PV systems (42%), PEMELs (62%) and H_2 storage vessels (33%), as well as an increase in electrolyser efficiency (+12% on a lower heating value (LHV) basis) compared to current values (2020).
IRENA (2020)[21]	Current production cost: 2.7–6.0 USD per $kg_{H_2,g}$	Present: – Electricity cost: 53 USD per MW per h – Electrolyser efficiency$_{LHV}$: 65% – Lifetime of electrolyser: 10 years – Full load hours: 3200 (onshore wind) – Weighted average cost of capital (WACC): 10%
	Future cost projections: 0.8–1.2 USD per $kg_{H_2,g}$	Future: – 80% reduction in electrolyser costs – Electricity cost: 20 USD per MW per h – Electrolyser efficiency$_{LHV}$: 76% – Lifetime of electrolyser: 20 years – Full load hours: 4200 (onshore wind) – Weighted average cost of capital (WACC): 6%

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their high cost. It is since the 1990s, and especially in the last ten years, that water electrolysis has gained significant interest worldwide, as green H_2 has become valued as a carrier of renewable energy, and for powering fuel cells.[31]

At present, the commercial maturity of these electrolysis technologies varies, with alkaline electrolysers (AELs) being the most mature technology, followed by proton exchange membrane electrolysers (PEMELs) and solid oxide electrolyser cells (SOECs), the latter being still in the demonstration phase.[32]

Despite the long history of technical innovation on the supply side, growth on the H_2 demand side has been historically sclerotic for a variety of technical, economic, and policy reasons. In 2020, global hydrogen demand was approximately 90 Mt. This has grown from 35.3 Mt in 1990 – a rate of about 1.8% per year.[33,34]

The role of hydrogen in net zero targets

As nations come forward with net-zero strategies to align with their international climate targets, hydrogen has once again risen up the agenda from Australia and the UK through to Germany and Japan.[35] Its use is now being seriously considered by different sectors, *e.g.*, heat, power, mobility, and industry.[36] As a full-scale H_2 economy develops, the global demand for H_2 is expected to increase from $\approx$95 Mt per year today to $\approx$650 Mt per year by 2050.[37] In the case of green H_2, the European Union has announced its ambitions to produce 1 Mt for the 2020–2024 period with the aim to reach 10 Mt per year for the period between 2025 and 2030.[38]

In the wake of renewed interest in green H_2, driven by the current global situation where access to low-cost money, global supply chains, and cheap energy is becoming increasingly difficult, several studies have reported various cost figures, both current and future, as shown in Table 1. As can be observed, reported costs for green H_2 are in the range of 1.6–9.8 USD per $kg_{H_2,g}$. In most cases, the low-cost estimates rest upon optimistic techno-economic assumptions, *e.g.*, low-interest rates or rapid technological improvements of electrolytic processes. In other cases, studies have envisaged excess renewable energy being abundantly available at zero cost, for H_2O electrolysis. In addition, some of the figures reported have been calculated on the basis of fixed interest rates, regardless of the production location, which does not reflect the investment risk associated with the different regions of the world, and could introduce substantial bias to the results.[39,40] Furthermore, most of these studies do not clearly explain how the intermittency of renewables is accounted for in the calculation of the reported costs, which is a crucial factor given the need to ensure continuous production of green H_2.

2. γ-AW:E model for green hydrogen

Most studies assessing the production of platform chemicals and fuels from renewable energies assume that renewable electricity is available at a fixed cost, often based on an average of different studies.[41] However, in reality, the cost of electricity will be a location-dependant function of the inter- and intra-annual variability of renewable energy at that specific point in the globe. It will further be key to "right-size" the installed capacity of both power generation and energy storage assets so as to overcome inter- and intra-annual variability in availability. It will further be important to account for the regional variation in the hurdle rate, *i.e.*, return on equity (ROE), associated with a given capital project and account for how this impacts project costs.[42,43]

Thus, this study employs a modified version of the γ-AW:E model[43] to assess the continuous production of green H_2 from a hybrid solar and wind energy system at any particular location. This model quantifies the capacities of the processes (solar PV, wind, PEMEL) and energy storage (H_2 or electricity) units, including the additional capacity needed to balance the inter- and intra-annual intermittency of renewables. It is therefore possible to estimate the amount of surplus electricity, *i.e.*, the excess electricity generated as a result of oversizing the process units, which can be sold, thus contributing to lowering the cost of green H_2 production. The model is illustrated in Fig. 1.

In essence, the model follows the principles of reaction network flux analysis.[44] The inputs are the chemical compounds involved, reaction pathways available, storage options, mass and energy balances (including heat integration), CAPEX of the equipment units and the location-specific availability of renewable energy. From this information, the model determines the cost-optimal production route, including the plant's optimal design and operation required to meet the production target. Further details on this model initially designed to evaluate optimal production routes of solar ammonia and methanol, including all equations and assumptions, are available in the original publication.[43]

3. Study framework and scenario description

In this contribution, we quantified the net production cost (NPC) of green H_2 for a plant with a production target of 1 GW_{LHV}, *i.e.*, 30 t h^{-1} $H_{2,g}$. Based on this target, $\approx$ 335 and 2500 of these production plants would be needed to meet the current and future global demand for H_2, respectively.[45–47] This NPC was calculated for 1140 locations, derived from the Universal Transverse Mercator (UTM) coordinate system and grouped in nine global regions based on the capital cost values of wind and solar energy provided by the IEA's World Energy Outlook[48] and IRENA.[49] The worldwide production cost of green H_2 was assessed for 2019 (today) and 2050 (future). Fig. 2 shows the system's framework adopted in this study.

To capture the risk associated with hydrogen investments in different regions of the world, we adopted a region-specific ROE (see ESI,† Appendix B), *i.e.*, the profit margin required for an investment or project to proceed.[50] For offshore projects, located within one grid cell from land, we took the onshore ROE + 1.5% for 2019. As cheaper and less risky offshore projects

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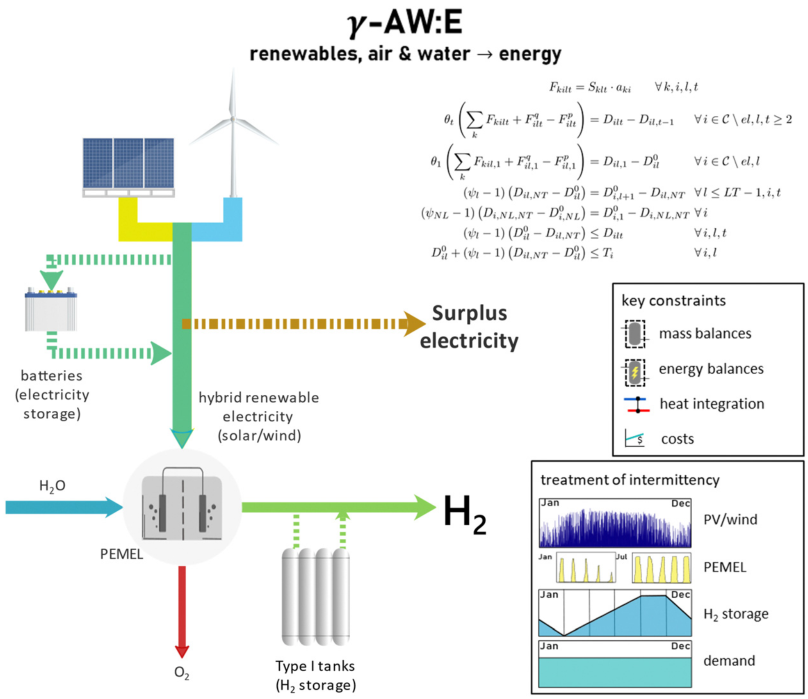

Fig. 1 Overview of the γ-AW:E model for green H_2. Here, green H_2 is produced from fluctuating renewable electricity from solar and wind energy. To balance the intermittency of renewables, energy storage systems are included. The production plant modelled consists, therefore, of solar PV and wind systems, a PEMEL system (including the BOP), and storage options, *i.e.*, batteries and H_2 storage. The products of the system are a continuous flow of hydrogen and, occasionally, the surplus electricity generated in the process.

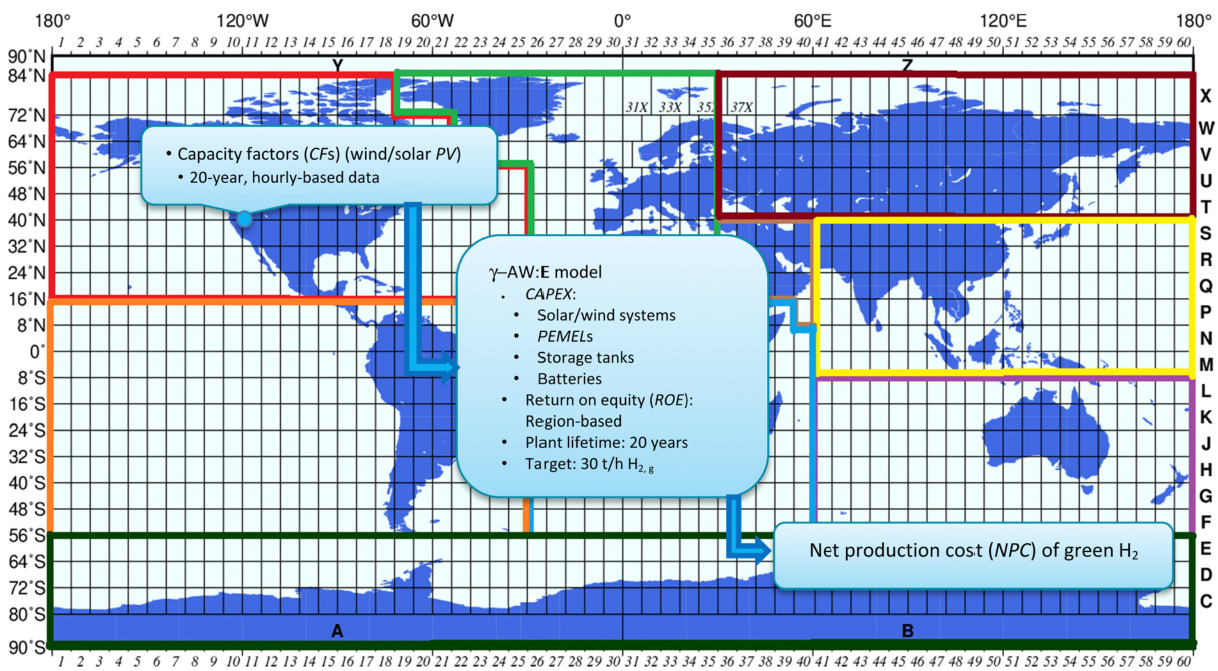

Fig. 2 Methodology overview. The net production cost (NPC) of green H_2 was estimated according to the optimal schedule determined by the γ-AW:E model. The model was run for each location based on the CAPEX of the equipment units, the CFs, and the ROEs. For each location, 20 years, hourly-based CFs for wind and solar PV systems were retrieved from renewable.ninja. Target production of 30 t h^{-1} of green H_2 was fixed, and a plant lifetime of 20 years was assumed for each run.

are expected in the future, it was assumed that the onshore and offshore ROE will be the same in 2050. We considered for deep offshore locations, *i.e.*, those beyond one grid cell from land, the offshore ROE + 3%, both for 2019 and 2050.[51,52] In addition,

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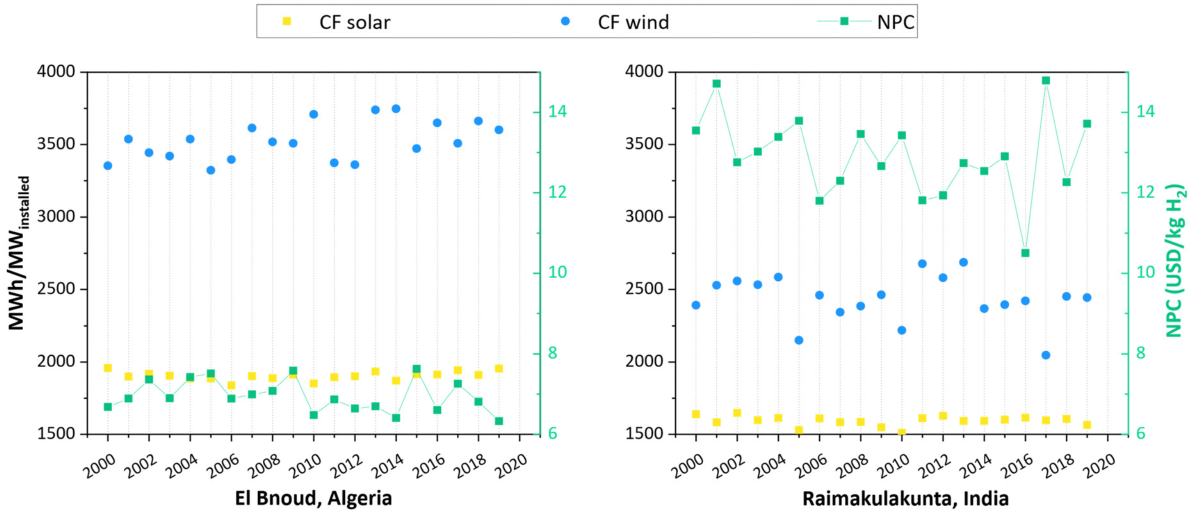

Fig. 3 Net production cost *vs.* annual availability of renewable energy. For this 20 years analysis, the annual NPC of green H_2 ranges from 6.3 to 7.6 USD per $kg_{H_2,g}$ (21% variation) in El Bnoud (Algeria) and from 10.5 to 14.8 USD per $kg_{H_2,g}$ (41% variation) in Raimakulakunta (India), respectively.

to accurately account for the seasonal and daily intermittency of wind and solar power, we worked with 20 years hourly CFs (from 2000 to 2019) for each location.[53,54] To identify realistic cost projections of PEMELs, we followed a bottom-up approach and decomposed their manufacturing into a range of sub-processes, from which the potential cost reduction was quantified by applying learning rates (see ESI,† Appendix A.1.). The present and future NPC of green H_2 at each location and for each of the 20 years was then calculated according to the procedure detailed in Appendix A.2. from the ESI,† provided in Appendix B.

Since a surplus of electricity can be generated due to the production of a fixed flow of green H_2, the cost of production at each location was further assessed on the basis of two scenarios, namely, (i) when revenues from the sale of the surplus electricity are excluded from the maximum NPC obtained from the 20 years analysis (Scenario 1), and, (ii) when these revenues are included in the minimum NPC obtained from the 20 years analysis (Scenario 2). It was assumed that the surplus electricity could be sold at the levelised cost of production (see ESI,† Appendix A.2.). In this way, the value of connecting the system to the grid was evaluated based on site-specific factors.

4. The impact of intra-annual variability of renewable energy

A critical yet often overlooked aspect associated with the production of H_2 is the intermittent nature of renewable energy sources (RES),[42,43] whose availability depends on local conditions at any given time.[55,56] To balance interannual, seasonal, and daily fluctuations in renewable energy and enable the reliable production of green H_2, it is essential to have both sufficient capacity of both energy storage and power generation, as well as capacity of electrolysis units. Neglecting to do this will result in an under-sized system which will be frequently unable to meet demand over its economic lifetime.

Therefore, an accurate assessment of the cost of green H_2 requires assessing the seasonal and daily fluctuation of renewable energy with sufficient spatial and temporal resolution. In this area, a conventional approach in energy system modelling is to represent each year by sequences of days (representative days) instead of using full hourly data by following different approaches such as heuristics, clustering, random selection, optimisation models, and structured algorithms, depending on the application.[57–61] However, it has been shown that the solution to this type of problem can be more reliable and accurate when a full hourly resolution is used, as seasonal changes in the availability of renewables are represented in greater detail.[62] Thus, as long as model solution times are within an acceptable range, a more detailed representation of time should be used to ensure more robust results.

The results presented in Fig. 3 illustrate this point. As can be observed, owing to the interannual variation in the availability of renewable energy (represented by the CFs of wind and solar power) – primarily wind power, the NPC of green H_2 varies by between 21–41% over the 20 years analysis.

The remainder of this paper is set out as follows; we first present the results of the current and future production cost of green H_2 in maps, along with a statistical analysis of their cost distribution, including and excluding the potential sale of surplus electricity. Next, the results of a detailed analysis of the cost of intermittency are presented and discussed. Finally, the results of sensitivity and risk analyses of future green H_2 production costs are reported, in which the impact of variations in the projected capital cost and system components are assessed.

5. Hydrogen net production costs (NPC): present and future

The maximum NPCs resulting from the 20 years analysis at each location are plotted in the maps in Fig. 4 and 6 for ''today'' and the ''future'', respectively. Furthermore, the

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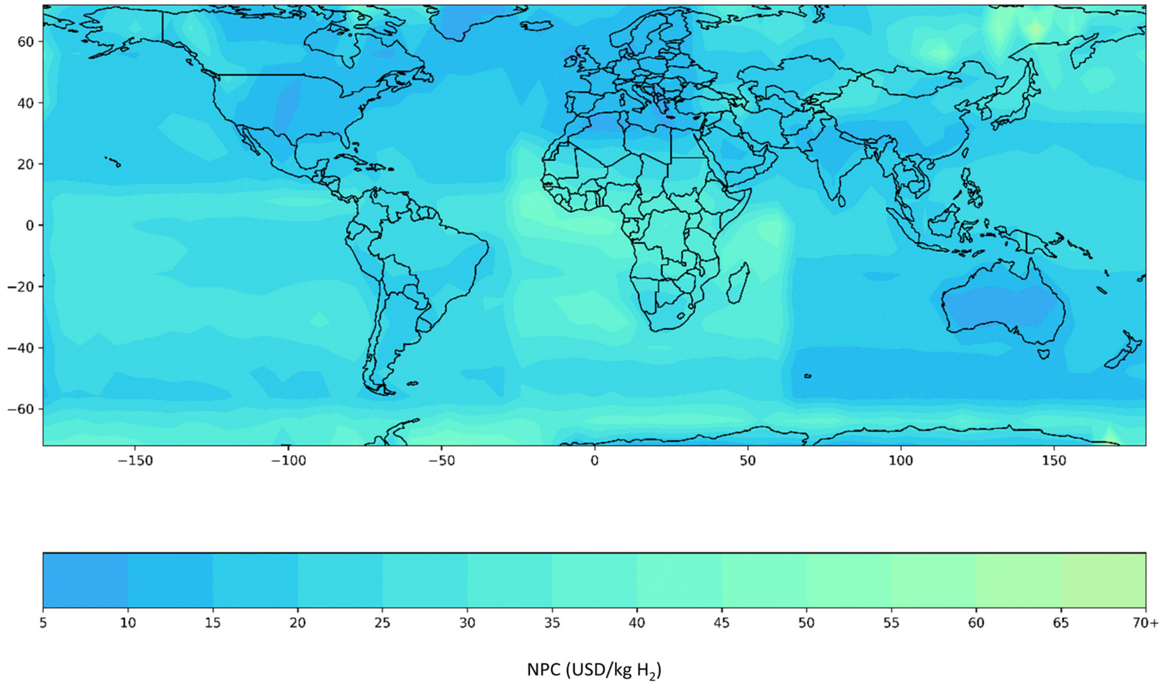

Fig. 4 NPC of green H_2 "today". The map illustrates the variation of the maximum global NPC of green H_2 with existing technologies.

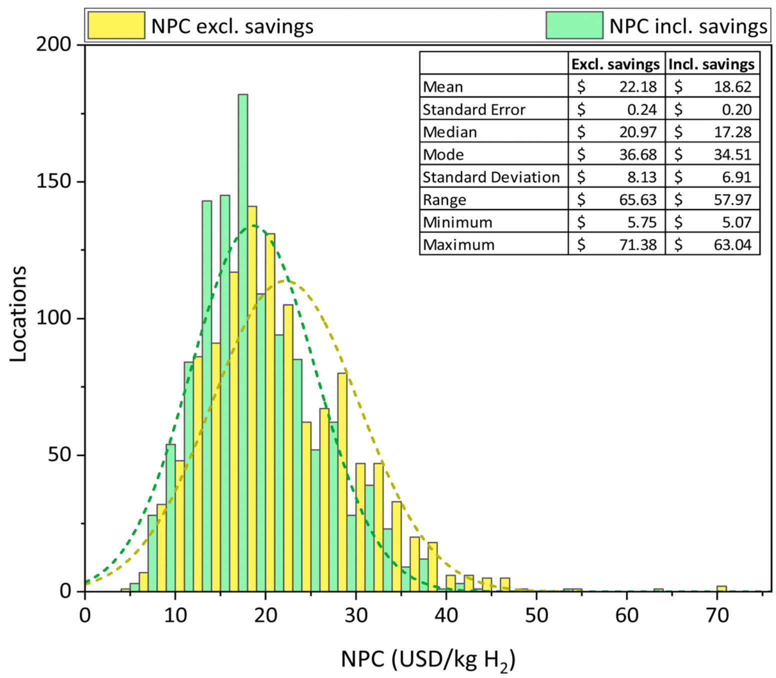

Fig. 5 Histograms of the NPC of $H_{2,g}$ "today", excluding (yellow) and including (green) the potential savings from the sale of surplus electricity. The sale of this electricity would result in an average saving of 11% on the NPC of green H_2.

distribution of costs and results of the statistical analyses are presented in Fig. 5 and 7, for "today" and the "future", respectively. The present production cost of green H_2 ranges from 5–72 USD per $kg_{H_2,g}$, with an average of 22 USD per $kg_{H_2,g}$ and a median of 21 USD per $kg_{H_2,g}$. This can be reduced to 5–63 USD per $kg_{H_2,g}$, with an average of 18 USD per $kg_{H_2,g}$ and a median of 17 USD per $kg_{H_2,g}$, when revenues from the sale of surplus electricity are considered.

As shown in Fig. 7, the average cost of green H_2 in the future is anticipated to be approximately 56–57% lower than the current cost, primarily owing to the projected cost reduction of renewable energy (see Fig. C-3 in the ESI†). Cost reductions

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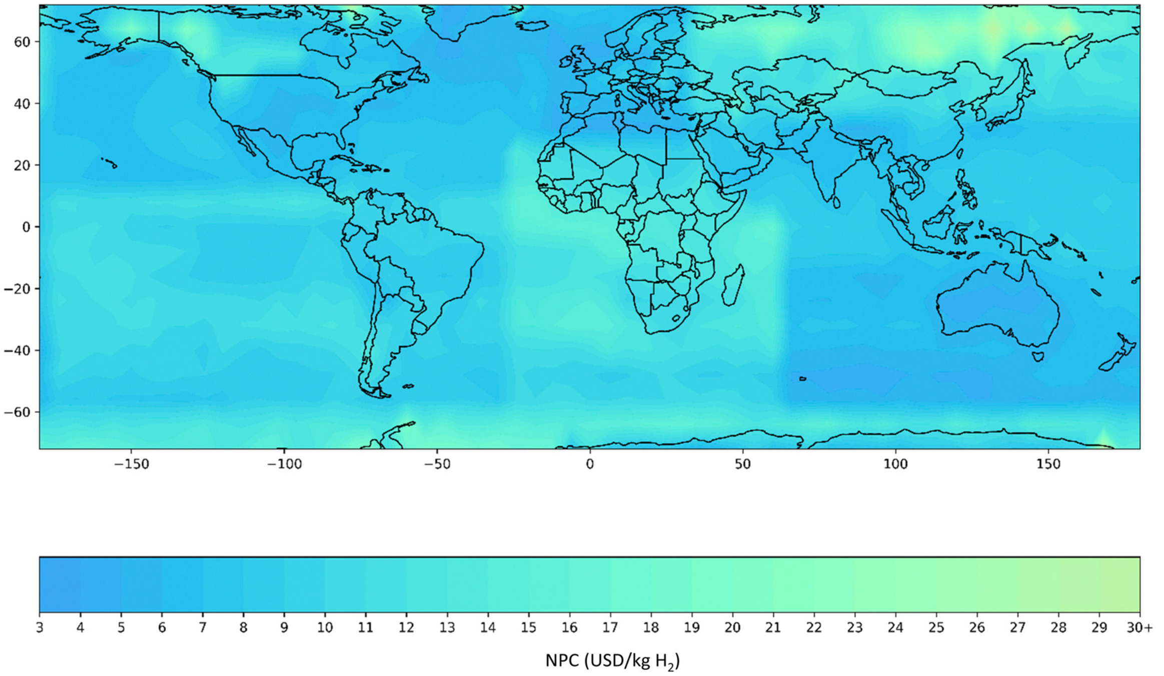

Fig. 6 NPC of green H_2 "in the future". The map depicts the future worldwide NPC of green H_2.

and efficiency improvements in energy storage technologies and PEMELs[21,63] lead to further cost reductions. As a result, costs in the range of 3–36 USD per $kg_{H_2,g}$ and 3–44 USD per $kg_{H_2,g}$, with an average of 8–10 USD per $kg_{H_2,g}$, are obtained for the scenarios including and excluding the potential savings of selling excess power, respectively.

As can be observed, there is a considerable decrease in average overall costs due to the sale of surplus power to the electricity system. This has implications as to the kinds of contracts that may be entered into between the electrolysis facility and the renewable power producers, *e.g.*, a power purchase agreement with the provision to sell surplus power to the grid. This highlights the importance of ensuring that grid infrastructure has the facility to incorporate renewable power that would otherwise be curtailed. In this context, the installation of regional grids could contribute not only to alleviating this additional burden on national power systems by absorbing part of it but also to reducing the cost associated with increasing their capacity.[64]

From a geographic standpoint (see Appendix C in the ESI†), the cheapest green H_2 would be produced in Greenland at present (from electrolysis powered by approximately 50% solar electricity and 50% wind electricity) and in the future (from electrolysis powered almost exclusively by wind electricity). Overall, when we compare the best possible locations in the future with respect to the present in terms of the cheapest NPC of green H_2, we see a shift from onshore to offshore locations, owing to higher CFs in power generation and a greater rate of reduction in the cost of offshore wind relative to other options.

As can be observed from Fig. 4 and 6, the anticipated "current" and "future" cost of hydrogen production varies substantially around the world. Costs are observed to be driven by myriad factors, including availability of land and water, distance from market, and the cost and reliability of the energy supply. A detailed analysis of these cost breakdowns is presented in Appendix C.

The breakdown of current and future green H_2 NPC for the best production locations (see Fig. C-3 in the ESI†) reveals that renewable energy systems account for approximately 50% of the cost. PEM electrolysis and energy storage systems each account for approximately 25% of the cost. Conversely, for the locations with the greatest level of inter- and intrannual intermittency, 50% of the cost is associated with energy storage systems. This is discussed in more detail in the next section as "the cost of intermittency".

Through a variety of policy mechanisms, *e.g.*, contracts for difference, strike prices, production mandates/obligations, tax credits, *etc.*, it is possible to significantly reduce the capital risk associated with the deployment of new technologies. Thus, a sensitivity analysis is performed on the required ROE, or hurdle rate, to analyse its influence on the future NPC of green H_2. For this purpose, we vary the ROE according to three scenarios, namely, (i) ROE − 8%, (ii) ROE − 4%, (iii) ROE + 4%.

As shown in Fig. 7, reducing the ROE by 4% would represent a decrease of approximately 20% relative to the reference case, with an equivalent increase in ROE having an equivalent, opposite effect. It was observed that only if the ROE was reduced by 8% compared to the reference value, would the NPC be decreased such that green H_2 could be produced for less than 2 USD per $kg_{H_2,g}$ (1.6 USD per $kg_{H_2,g}$, to be precise). Such a decrease in ROE would represent a fairly low cost of capital, as in the case of Europe, where the ROE for onshore wind would be 1.6%. Given the current outlook for central bank interest rates,[65] this seems to be a very ambitious assumption.

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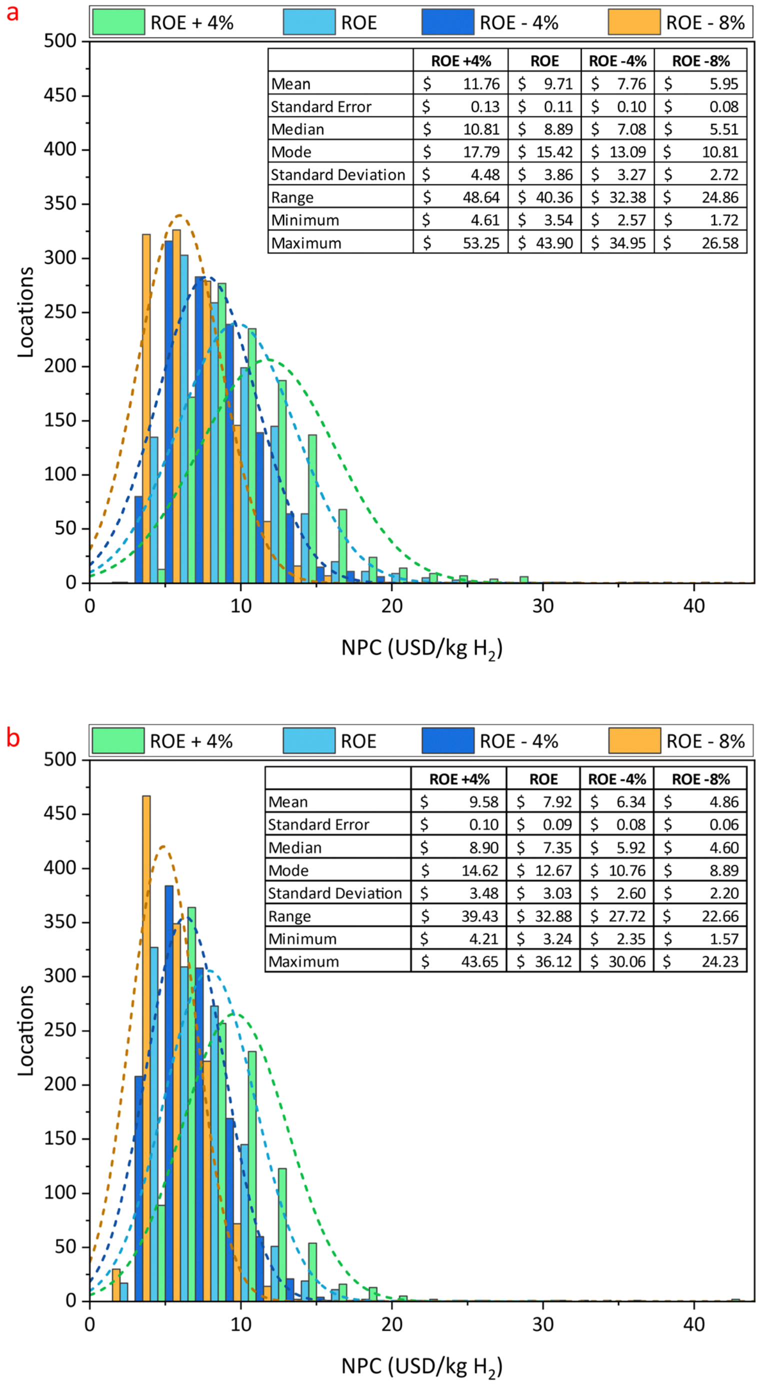

Fig. 7 Histograms of the NPC of green H_2 "in the future". Subplots a and b show the histograms of the NPC for the base case scenario ("ROE") and the scenarios evaluated in the sensitivity analysis, *i.e.*, (i) ROE − 8%, (ii) ROE − 4% and (iii) ROE + 4%, when revenues from the potential sale of surplus electricity are excluded (a) and included (b) in the NPC of H_2. For the base case scenario ("ROE"), the sale of this electricity would result in an average saving of 13% on the NPC of H_2.

6. Green hydrogen: the cost of intermittency

Subsequent analysis was performed to quantify the impact of intermittency on the cost of hydrogen. For this purpose, the Isle of Jura in the UK was chosen as a reference for this analysis due to the high inter- and intra-annual intermittency of the wind energy available there (represented by the wind CFs in Fig. 8 and 9(a)). Fig. 8 also illustrates the annual NPC of green H_2 from 2000 to 2019. As can be observed, owing to the inter- and intra-annual variation of the wind, there is a 35% variation in the NPC over this 20 years period.

The cost of intermittency is defined as the difference in system cost between the optimal system with the actual

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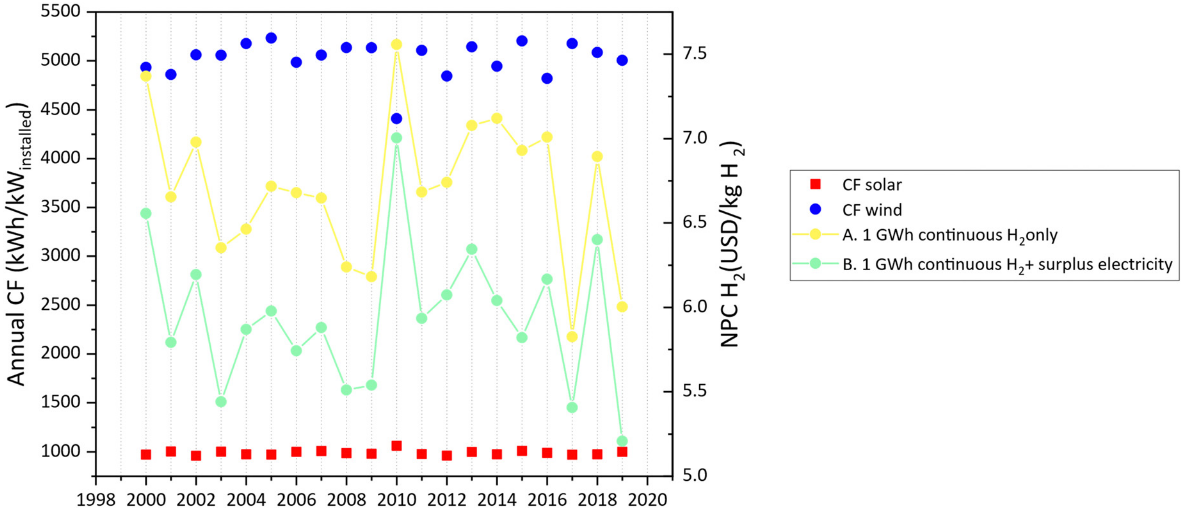

Fig. 8 Cost of intermittency. The annual NPC of green H_2, excluding (yellow) and including (green) the potential savings from the sale of surplus electricity, together with wind and solar energy CFs over the last 20 years (2000–2019), are displayed for the Isle of Jura in the UK (Lat: 56, Lon: −6).

wind/solar profiles and a hypothetical baseline system, *i.e.*, a steady-state plant operating at constant availability (equivalent to the 20 years average CF) that produces a constant supply of green H_2[43] In our case, the baseline cost was calculated assuming all wind CF in the reference year was used to produce H_2. Further details on the calculation procedure, including the equations used, can be found in Appendix A.3.

Fig. 9(a) contrasts the CFs, system design and operation of the years with the highest (2010) and lowest (2017) NPC. Owing to both inter- and intra-annual variations in CFs, it is necessary to install H_2 storage capacity and oversize production units to satisfy demand during periods of low availability of renewables. As illustrated, the electrolyser is oversized and operated at full capacity when renewable energy is available, feeding green H_2 to storage. In turn, stored H_2 is used to meet demand during periods of low availability of renewable energy. This variable optimal operation of the electrolyser emphasises the value of electrolysers being able to operate flexibly.

The time periods shown in Fig. 9(a) represent potential bottleneck periods for the system, *i.e.*, multiday periods when CFs are low (also known as "dunkelflaute" or "dark doldrums"), which could determine the system design. It is evident that the potential bottleneck period in 2010 exhibits more extended periods of lower CFs than in 2017, leading to the difference in system design and the corresponding cost.

As illustrated in Fig. 9(b), the cost of intermittency accounts for approximately 49% and 41% of the total NPC of green H_2 in 2010 and 2017, respectively. As can be seen, more generation and storage capacity is needed in 2010 to compensate for the periods of low CF.

7. Future costs of green hydrogen: sensitivity and risk analysis

Here, Monte Carlo simulations are carried out to study the impact that the variation in the cost of each component of the $H_{2,g}$ system would have on its future NPC. To this aim, 1000 independent samples from the minimum, median and maximum NPC values were evaluated. We assumed a normal distribution with an SD of 20% relative to the base values[66] as an indication of the uncertainty of the future cost of the variables affecting the cost of green H_2, *i.e.*, the cost of wind and solar systems, electrolysers, energy storage systems and the sale of surplus electricity.

The results of the Monte Carlo analysis are presented in Fig. 10. For the minimum and maximum NPC of green H_2 obtained from the "future" cost distribution curve (Fig. 7, "ROE" scenario), the cost of the wind system constitutes the most important variable influencing the NPC of green H_2. However, for the median NPC, the cost of the solar system represents the primary variable. Finally, even when considering a significant variation in the cost of the components (SD = ±20% with respect to the reference values), the minimum NPC of green H_2 that could be achieved is 2.7 USD per $kg_{H_2,g}$. It must also be recognised that this is the cost of electrolytically produced H_2 and does not consider any subsequent transport or storage costs that will ultimately be reflected in a "price" to a consumer.

8. Conclusions

This study introduces a critical assessment focused on the global, large-scale, reliable production of green H_2 *via* PEM electrolysis. Realistic estimates of the current and future cost of green H_2 were calculated using a framework that explicitly considers the inter- and intra-annual intermittency of solar and wind. We take a strict definition of green H_2, *i.e.*, exclusively produced *via* wind and/or solar power with storage *via* batteries or H_2 storage permitted.

Current production costs are found to be in the range of 5–72 USD per $kg_{H_2,g}$, with an average of approximately 22 USD per $kg_{H_2,g}$. Future costs are projected to decrease to

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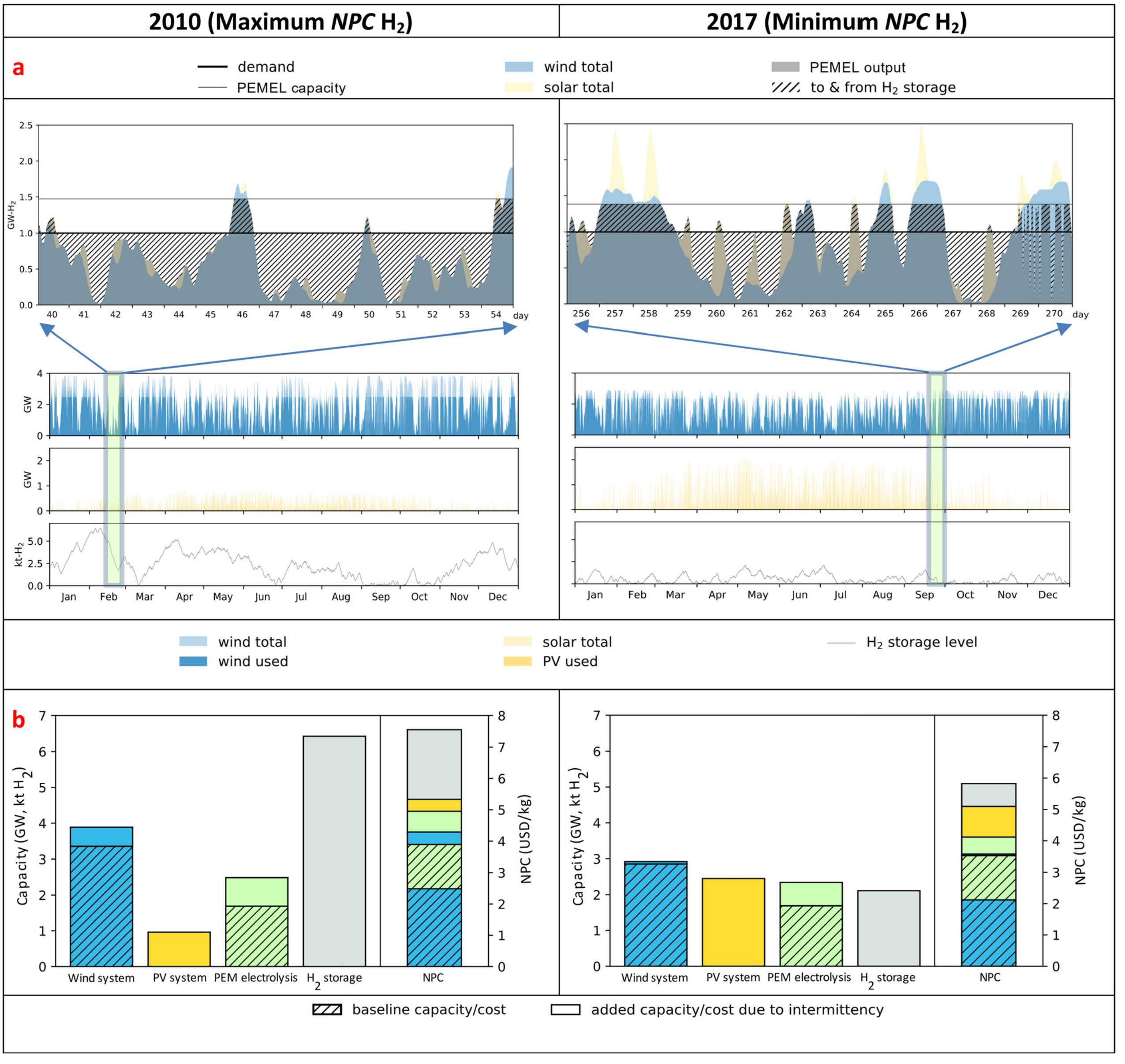

Fig. 9 Energy profiles and cost of the system, including the "cost of intermittency" for the year with maximum (2010) and minimum (2017) NPC of green H_2 for the Isle of Jura in the UK. The solar and wind profiles of the total available energy and energy used are shown in subplot a, along with the H_2 storage levels for the system producing a continuous flow of H_2 (1 GW) without considering the sale of surplus electricity. The capacity of the system components and their NPC, including the cost due to intermittency, are shown in subplot b. The cost of intermittency represents *ca.* 49% and 41% of the total production cost of green H_2 for 2010 and 2017, respectively.

3–44 USD per $kg_{H_2,g}$, showing an average of approximately 10 USD per $kg_{H_2,g}$. This cost reduction is primarily driven *via* lower-cost renewable power, chiefly offshore wind.

Overall, we find our estimated average costs to be higher than the cost figures reported in previous studies (see Table 1) for the following reasons:

(a) In all cases, we have designed the system on the basis of a reliable H_2 supply, *i.e.*, that demand is consistently met. It is assumed that this investment will need to be robust to both inter- and intra-annual variability in the availability of renewable power.

(b) We have assigned a hurdle rate that reflects perceived investment risk as a function of region.[50] The consequence of this is that, even for regions that are well-endowed with renewable energy, this risk increases the cost of H_2. As was noted, there are existing mechanisms to reduce this hurdle rate, *e.g.*, the World Bank loan guarantee program, and if these are deployed, they can significantly reduce the cost of H_2 – up to 1.6 USD per $kg_{H_2,g}$, when the ROE is reduced by 8% from the reference value, as shown in Fig. 7. However, it is also true that there is a limit to the extent to which these mechanisms can be deployed, after which normal commercial terms will apply.

(c) We observe that whilst the cost of PEMEL is important, it is second order to the projected reduction in renewable energy costs – principally wind power.

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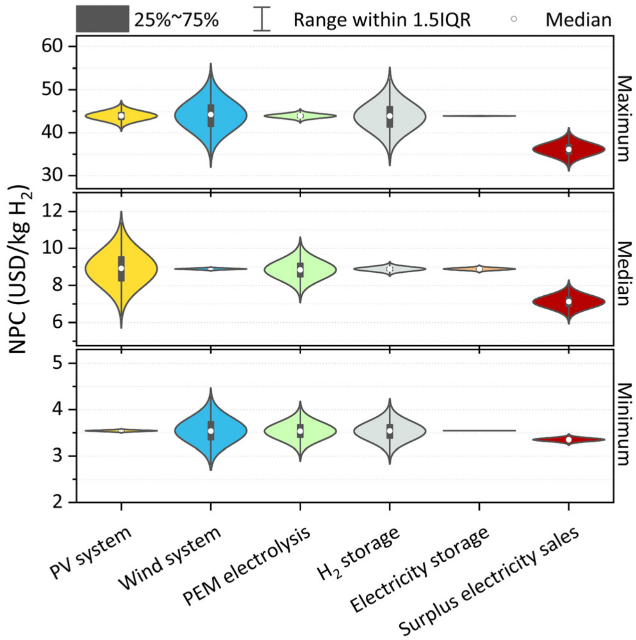

Fig. 10 Monte Carlo analysis. 1000 independent samples of the minimum, median and maximum "future" NPC of green H_2 were considered to generate the violin graphs for each component of the system, assuming a normal distribution with an SD of ±20% with respect to the reference values of the "ROE" scenario. In the figure, the higher the height of the violin, the greater the influence of the cost of the system component on the NPC of H_2. Therefore, for the minimum and the maximum NPC cases, which are wind-dominated systems, the variation of the wind system cost has the greatest influence on the NPC of H_2. Conversely, for the median NPC case, the variation of the solar PV system cost has the greatest influence on the NPC of H_2. From this analysis, a minimum and a maximum NPC of 2.7 USD per $kg_{H_2,g}$ and 56.4 USD per $kg_{H_2,g}$ are obtained, respectively.

Given that the reliable production of green H_2 requires the overcapacity of installed power generation, this implies that, in some years, substantial amounts of surplus renewable energy will be available. If it is possible to sell this power to the electricity grid at the levelised cost of electricity, this will reduce the production cost of H_2 by approximately 16–18%. This estimation assumes that the grid will be able to absorb this additional renewable energy and does not account for any potential system integration costs associated with doing so.

As noted above, the production cost of green H_2 will vary substantially around the world. In the best areas, *i.e.*, those with the most reliable supplies of renewable energy, hydrogen and electricity storage account for about a quarter of the total production cost. However, for the worst locations, the cost of energy storage cost could constitute around half of the total costs.

We note that the cost of producing green hydrogen will also have been further impacted by recent inflation and supply chain pressures, observed to have added ∼20–30% to 2020 costs.

Moreover, we emphasise that we have considered here the cost of reliable production of green hydrogen, not the cost of delivered hydrogen, which would add a further layer of cost and complexity.

Finally, as with all modelling studies, these results are subject to substantial uncertainty in, *e.g.*, technology costs and financing assumptions. To address this, we have chosen to adopt data sets from independent third parties, *e.g.*, IRENA, and have presented a comprehensive sensitivity and risk analysis to explore edge cases and identify which technology components are most important from the perspective of future cost reduction.

Author contributions

Diego Freire Ordóñez: conceptualisation, methodology, validation, formal analysis, investigation, data curation, writing – original draft, writing – review & editing, visualisation. Caroline Ganzer: methodology, formal analysis, writing – review & editing, visualisation. Thorsteinn Halfdanarson: methodology, validation, formal analysis, data curation, visualisation. Andrés González Garay: methodology, validation, formal analysis, visualisation. Piera Patrizio: writing – review & editing. André Bardow: writing – review & editing. Gonzalo Guillén-Gosálbez: writing – review & editing. Nilay Shah: writing – review & editing. Niall Mac Dowell: conceptualisation, methodology, writing – review & editing, supervision.

Conflicts of interest

Niall Mac Dowell is a member of Joule's Advisory Board. All authors consult widely for a range of international public and private organisations involved in carbon management and energy services.

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