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Levelized cost of dynamic green hydrogen production: a case study for Australia's hydrogen hubs

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Abstract

This study evaluates the levelised cost of hydrogen (LCOH) dynamically produced using the two dominant electrolysis technologies, directly connected to wind turbines or photovoltaic (PV) panels in regions of Australia designated as hydrogen hubs. Hourly data are utilised to size the components required to meet the hydrogen demand. The dynamic efficiency of each electrolysis technology, as a function of input power, along with its operating characteristics and overload capacity are employed to estimate flexible hydrogen production. A sensitivity analysis is then conducted to capture the behaviour of the LCOH in response to inherent uncertainty in critical financial and technical factors. Additionally, the study investigates the trade-offs between carbon cost and lifecycle emissions of green hydrogen. This approach is applied to ascertain the impact of internalising environmental costs on the cost-competitiveness of green hydrogen compared to grey hydrogen. The economic modelling is developed based on the Association for the Advancement of Cost Engineering (AACE) guidelines. The findings indicate that scale-up is key to reducing the LCOH by a meaningful amount. However, scale-up alone is insufficient to reach the target value of AUD 3 (USD 2), except for PV-based plant in the Pilbara region. Lowered financial costs from scale-up can make the target value achievable for PV-based plants in Gladstone and Townsville, and for wind-based plants in the Eyre Peninsula and Pilbara regions. For other hubs, a lower electricity cost is required, as it accounts for the largest portion of the LCOH.

Keywords: Australian hydrogen hubs; Levelised cost of hydrogen (LCOH); Economic analysis; Dynamic efficiency; Overload capacity

Nomenclature Table

ALK	Alkaline electrolyser	MPP	Maximum power point
ARENA	Australian Renewable Energy Agency	MW	Megawatt
AUD	Australian dollar	n	Number of hour
BEC	Bare Erected Cost	N	Project lifetime
$CAPEX$	Capital expenditure	NEM	Australian National Energy Market
$CAPEX_{Base}$	Reference capital expenditure before scaling up	NREL	National Renewable Energy Laboratory
cc	Current cumulative production	$OMEX$	Operation and maintenance expenditure
cc_0	Initial cumulative production	OWC	Owner's other capital expenses
$CO_{2\text{-eq}}$	Carbon dioxide equivalent	PEM	Proton Exchange Membrane
CSIRO	Australia's Commonwealth Scientific and Industrial Research Organisation	PSC	Process contingency
CRF	Capital recovery factor	PTC	Project contingency
d	Discount rate	P_{in}^{t}	Input power at hour t
DC	Direct Current	PV	Photovoltaic
ESC	Engineering services fee	PWM	Present worth of money
FWM	Future worth of money	$REPEX$	Replacement expenditure
GW	Gigawatt	S	Size of the component after scaling up
H_2	Hydrogen	S_{Base}	Reference size of the component before scaling up
IEA	International Energy Agency	SEC^{t}	Specific energy consumption at hour t
IRENA	International Renewable Energy Agency	SF	Scaling factor
kg	Kilogram	TDR	Overall system degradation rate
kW	Kilowatt	TOC	Total Overnight Cost
LC	Cost of labour	TPC	Total Plant Cost
LCE	Life-cycle emissions	U	Utilisation rate of electrolyser capacity
LCOE	Levelised cost of renewable electricity	UC	Cost of uninstalled components
LCOH	Levelised cost of renewable hydrogen	USD	US dollar
LR	Learning rate	WACC	Weighted average cost of capital
m^3	Cubic metter	WT	Wind turbine
MC	Cost of materials	β	Power law index
m_{H2}^{t}	Hydrogen produced at hour t	η_{ALK}^{t}	ALK efficiency at hour t
M_{H_2}	Annual average hydrogen produced	η_{PEM}^{t}	PEM efficiency at hour t

1. Introduction

To meet the escalating demand for green hydrogen, the supply side will predominantly be shaped by countries possessing substantial potential in renewable energy resources. Consequently, this will lead to a competitive market, wherein various nations will strive to leverage their renewable energy capabilities to emerge as key suppliers of green hydrogen. For instance, as cited by International Renewable Energy Agency (IRENA), countries such as Australia, Chile, and Norway have focused on exporting green hydrogen to Japan and/or South Korea [1].

The conclusion of the latest United Nations Climate Change Conference (COP28) marked an agreement, the "beginning of the end" of the fossil fuel era, emphasising a much-needed transition to renewable hydrogen energy, requiring scaled-up finance [2]. In order to fulfil the commitments and obligations from previous COP conferences, Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) established a National Hydrogen Roadmap in 2018, aimed at transitioning towards a low-emission energy future [3]. Within this roadmap, the export of Australian green hydrogen stands out as a significant economic sector. Consequently, as noted by the Australian Renewable Energy Agency (ARENA), Australia has a unique opportunity to export green hydrogen, particularly to countries like Japan, South Korea, and Singapore [4]. However, as mentioned, there is a possibility of other potential suppliers also targeting Japan and South Korea as key markets for their green hydrogen. Therefore, Australia needs to compete with these other prospective hydrogen exporters.

According to ARENA, Australia holds a competitive advantage, primarily due to the abundance of essential natural resources, such as wind and solar energy (Fig. 1), and underutilised land. Additionally, the country possesses a well-established international reputation for being a reliable exporter of conventional energy resources [4]. This robust reputation as an energy exporter can mitigate future risks on the global stage and establish a potential market for the nation. From a domestic standpoint, public perception places significant emphasis on safety and climate-change mitigation when contemplating the transition to a large-scale hydrogen industry [5]. The assurance of safety can draw from the lessons learned from exporting liquefied natural gas, while the renewable hydrogen industry contributes to climate-change mitigation. As a result, there should be minimal concerns regarding the social aspects of renewable hydrogen projects.

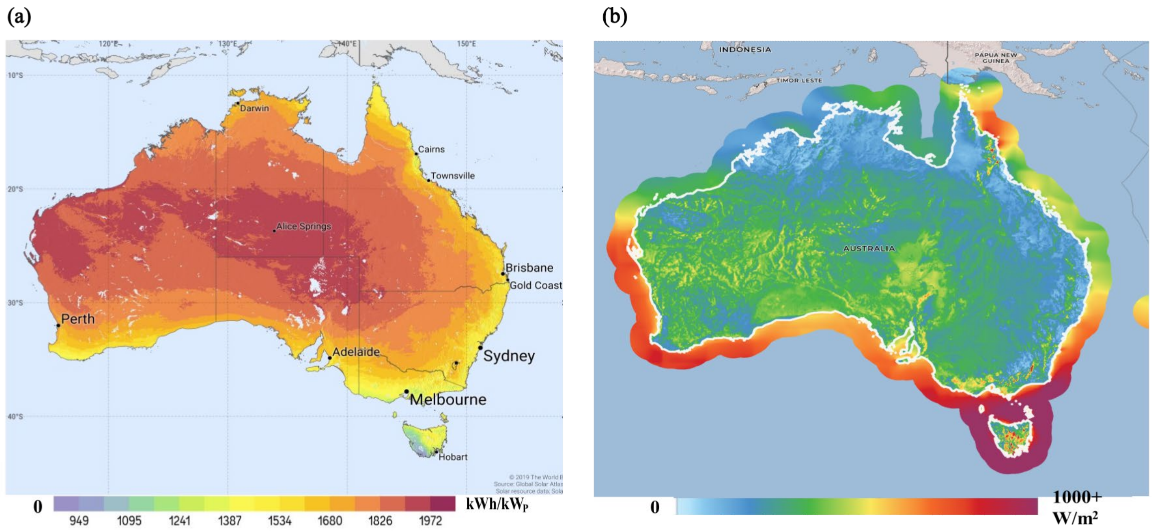

Fig. 1. (a) Long-term average of solar power potential [6] and (b) mean onshore/offshore wind power density at 100 m height adopted from [7]

However, several other non-social determining factors play a pivotal role in establishing long-term international trade between Australia and an importing nation. Among these factors, the hydrogen delivery/landed cost emerges as a critical consideration. In standard conditions, the majority of the hydrogen delivery cost stems from the cost of hydrogen production. This is primarily attributed to the investments made in renewable power generation systems and electrolysers. The remaining expenses encompass storage and transportation, which can fluctuate based on the chosen approach and the distance between the production facility and the importing country. Notably, using ammonia as a hydrogen carrier has been estimated to incur lower costs compared to alternative methods, and these costs exhibit a linear correlation with the transport distance [8]. Therefore, when assessing potential sites for establishing a green hydrogen plant, reliable evaluation of the cost of hydrogen production becomes indispensable.

According to the McKinsey model [9], certain hydrocarbon-rich countries, such as Saudi Arabia, the United Arab Emirates, and the United States, may have the potential to procure cost-competitive green hydrogen after 2030, as shown in Fig. 2. Thus, according to Australia's National Hydrogen Roadmap report, in order for the country to remain competitive in future markets, the farm-gate hydrogen cost should fall within the range of AUD2−3/kg.[1] The

[1] Farm gate cost refers to the cost of hydrogen production at the nominated facility without including the cost of storage and transport.

electrolyser capital expenditure (CAPEX)[2] and the levelised cost of electricity (LCOE) are the main cost drivers for hydrogen production. The LCOE is greatly influenced by location, varying with the renewable energy potential specific to each region. This implies that the LCOE will differ between the regions of Australia, which have widely differing climates, resulting in distinct levelised costs of hydrogen production. This underscores the paramount importance of estimating the LCOH for all potential locations, which constitutes the central focus of this study.

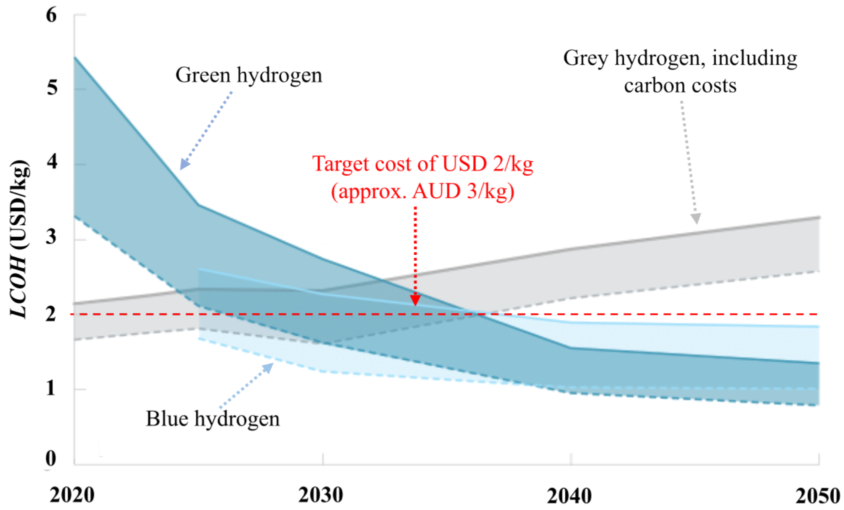

Fig. 2. Projected global cost of green hydrogen production [9].

To reliably estimate the LCOH, we take the following factors into account: I) electrolyser efficiency variation based on input power; II) occasional electrolyser operation under overload conditions; III) actual operating characteristics based on the electrolyser type; IV) the electrolyser system has a calendar life, while stacks have a usage life in operational hours; V) the learning rate concept to predict the routine end-of-life electrolyser stack replacement cost; VI) incorporation of economies of scale and VII) the cost of desalinated water and required land. The high importance of the first two points has been discussed in [10].

As environmental considerations gain prominence in society and future hydrogen markets, an additional assessment is needed to contrast the LCOH between the green and grey pathways, accounting for carbon costs. A review of the literature revealed that the carbon footprint of green hydrogen production varies based on geographical location and project-specific

[2] Normally, in the literature, there are two types of CAPEX. One refers to the uninstalled cost of equipment, also known as uninstalled CAPEX or direct CAPEX. The other type is the total CAPEX, which includes the cost of equipment when the system is installed and ready to operate. Throughout the entire text of the paper, unless stated otherwise, the term "CAPEX" refers to the total CAPEX.

attributes. For example, Zhang et al. [11] conducted an extensive life-cycle emissions (LCE) analysis of hydrogen production using wind and PV electricity in Switzerland. Their findings revealed a range of 0.6–3.6 $kgCO_{2\text{-eq}}/kgH_2$ for wind-PEM (Proton Exchange Membrane) hydrogen and 3–7.8 $kgCO_{2\text{-eq}}/kgH_2$ for PV-based hydrogen. In Germany, Bareiß et al. [12] estimated an LCE of 3.0 $kgCO_{2\text{-eq}}/kgH_2$ for a 1-MW PEM electrolyser powered by a combination of 65% wind and 35% PV electricity. The electricity component constituted 95% of the total LCE, with the PEM technology accounting for only 5% (1% from the stack and 4% from the balance of plant). An LCE of 0.8 $kgCO_{2\text{-eq}}/kgH_2$, with 95% contribution from wind electricity and 5% from the electrolyser, was reported in the National Renewable Energy Laboratory (NREL) report [13]. In the Netherlands, Delpierre et al. [14] calculated a range of 0.8–2.9 $kgCO_{2\text{-eq}}/kgH_2$ for wind-PEM hydrogen production. Mehmeti et al. [15] reported a midpoint LCE of 2.2 $kgCO_{2\text{-eq}}/kgH_2$ for wind-based PEM electrolysis. Parkinson et al. [16] estimated a range of 0.5–1.2 $kgCO_{2\text{-eq}}/kgH_2$ for wind electrolysis and 1.3–2.5 $kgCO_{2\text{-eq}}/kgH_2$ for solar electrolysis. From an in-depth LCE analysis of a large-scale PV-Alkaline hydrogen production plant in the Pilbara region of Western Australia, Palmer et al. [17] identified LCE values ranging from 0.8 to 7.8 $kgCO_{2\text{-eq}}/kgH_2$, contingent on the assessed conditions. In contrast, the LCE for grey hydrogen, which is produced mainly by steam reforming of natural gas, averages around 12 $kgCO_{2\text{-eq}}/kgH_2$ [18].

In addition to analysing the LCOH for green hydrogen, we investigate the trade-offs between lifecycle emissions and carbon cost. This analysis seeks to elucidate the strategies for achieving a competitive LCOH for green hydrogen comparison to grey hydrogen method when factoring-in environmental impacts. The comprehensive approach taken is summarised in Fig. 3.

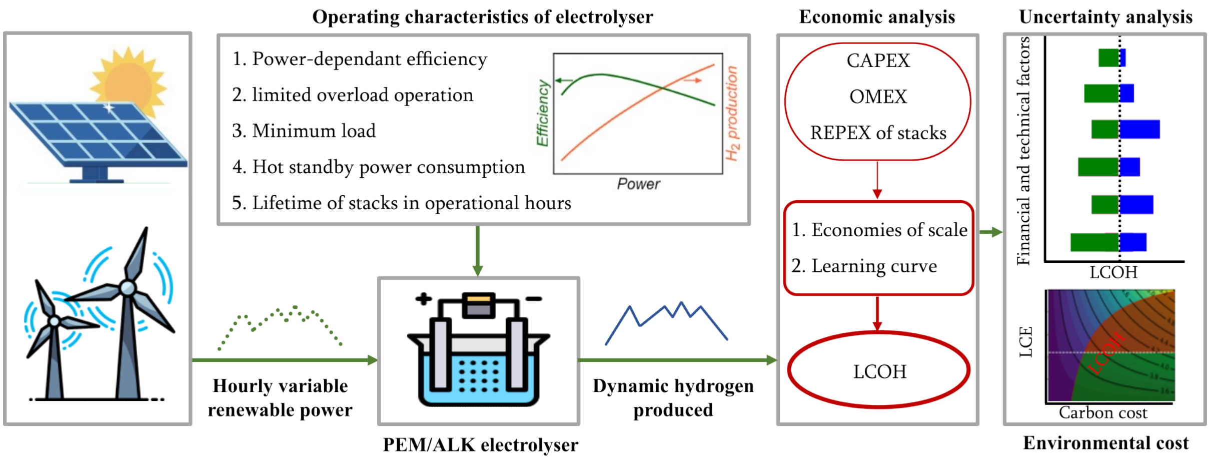

Fig. 3. Techno-economic modelling approach.

Table 1 summarises the main differences between our LCOH model and those in the existing literature.

Table 1. Contribution of our modelling compared to that of the existing literature.

Reference	Economies of scale	Learning curve	Electrolyser system efficiency	Overload	Environmental cost
[19-34]	–	–	Fixed	–	–
[35, 36]	–	–	Fixed	–	✓
[37-43]	✓	–	Fixed	–	–
[44, 45]	✓	–	Fixed	–	✓
[46]	–	✓	Fixed	–	–
[47]	–	✓	Fixed	–	✓
[48]	–	–	Fixed	✓	–
[49-52]	✓	✓	Fixed	–	–
[53, 54]	✓	✓	Fixed	–	✓
[55-59]	–	–	Stack dynamic	–	–
[60]	–	–	Stack dynamic	–	✓
[61]	✓	✓	Stack dynamic	–	–
Our model	✓	✓	Overall system dynamic	✓	✓

2. Methodology

2.1. Quantifying uncertainty in the projected LCOH

Due to the paucity of data available from actual large-scale green hydrogen projects and their associated components, such as electrolyser CAPEX, it is advisable to employ standardised guidelines and globally accepted frameworks to ensure comparable outcomes. The Association for the Advancement of Cost Engineering (AACE) proposes a categorisation of project cost estimates into five classes, determined by the level of project definition. This classification ranges from Class 5 (simplified design) with 0−2% of full definition to Class 1 (finalised design) with 50−100% of full definition [62]. Progressing from a cost estimate derived from a conceptual and preliminary design (simplified design) to a cost estimate resulting from a detailed design (finalised design) necessitates more time and investment. It is worth noting that this cost estimate classification is applicable to process industries, encompassing manufacturing and the production of chemicals, petrochemicals, and hydrocarbon processing.

As outlined by AACE, the uncertainty stemming from data limitations should be addressed through contingency costs, encompassing process contingency and project contingency. Process contingency pertains to the unpredictable additional cost of a process or component as it evolves into a fully developed commercial entity, while project contingency covers that of a project that would be realised in a more detailed design. These combined expenses are typically categorised as "miscellaneous capital costs". The former tends to diminish as a process or component advances from its conceptual stage to a mature commercial state, quantified based on its maturity level. The latter decreases as the project gains more precise details, applying to the entirety of the project rather than individual components. According to Rubin et al. [63], these contingency allocations effectively encompass project uncertainties. Drawing from a recent analysis of green hydrogen production costs in Germany [45] and a feasibility study for the Central Queensland Hydrogen Project (the CQ-H_2 Project) report [64], the appropriate cost estimate class is number 4, resulting in accuracy rate of approximately ±30%.

2.2. Nominated hydrogen hubs

In an effort to minimise infrastructure demands and associated expenses, several Australian regions have been identified as hydrogen hubs, intended to co-locate producers, users, and exporters [65]. Although the methodology developed here is applied specifically to these regions, it is equally applicable to any other region in the world. In the context of this study, therefore, we investigate Bell Bay in Tasmania, Eyre Peninsula in South Australia, Gladstone and Townsville in Queensland, Latrobe Valley in Victoria, Hunter Valley in New South Wales, and Pilbara in Southern Australia (as indicated in Fig. 4). The authors have chosen these regions based on data availability.

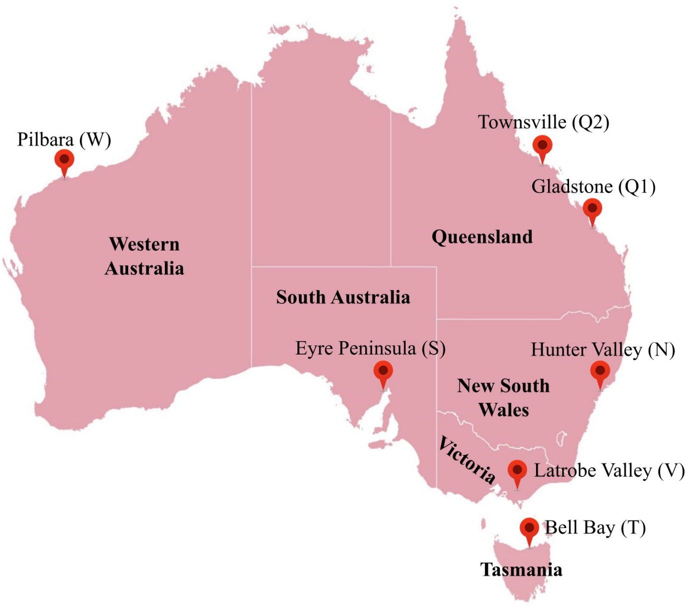

Fig. 4. Location of the nominated hydrogen hubs.

2.3. Techno-economic modelling

Our analysis is based on direct connection of PV power generation plant, and nearly direct connection of WT plant[3] and an electrolyser array. This approach reduces initial investment costs by eliminating (PV) or reducing (WT) the need for power converters, reducing system complexity, and minimising power losses [66]. In our study, we concentrate on two electrolysis options, chosen based on their technology readiness levels: Alkaline (ALK) and PEM technologies. From a technical perspective, PEM technology is expected to outperform ALK technology due to I) its greater "turndown" capability from maximum power, II) quicker response to input fluctuations and III) higher efficiency [67, 68]. From the economic viewpoint, however, ALK technology is cheaper [69]. As a result, we undertake a comparative analysis of the LCOH derived from both technologies.

To ascertain the sizes of components required to meet the yearly hydrogen demand, we employed hourly solar and wind power profiles specific to the hydrogen hubs. These profiles were estimated respectively based on methods from [70] and [71], and were imported to our model from [72]. Accordingly, the hourly hydrogen production can be calculated using the following equation:

$$m_{H2}^{t} = \frac{P_{in}^{t}}{SEC^{t}} \tag{1}$$

in which, m_{H2}^{t} represents the hydrogen produced at hour t, P_{in}^{t} signifies the input power at hour t, and SEC^{t} is the specific energy consumption of the electrolyser at hour t. In practice, SEC, which varies inversely with efficiency, is influenced by changes in input power. Thus, for more accurate outcomes, it's necessary to link SEC with the input power. To achieve this, we adopt the model proposed in a recent study by Hofrichter et al. [73]. This model correlates the efficiency of the electrolyser with the input power and was developed based on actual operating characteristics of a PEM electrolyser at the Mainz Energy Park in Germany [74]. According to the experimental data and observations, the electrolyser efficiency can be estimated as a function of the input power using Eq. (2):[4]

[3] Direct connection of PV to an electrolyser is feasible because the locus of the maximum power point (MPP) in voltage versus current with varying insolation closely resembles the polarisation curve of an electrolyser. In the WT case, the dissimilarity between the locus of the MPP with varying wind speed (expressed as voltage versus current) and the electrolyser polarisation curve leads us to conclude that absolutely direct connection with high efficiency is not feasible. The minimum requirement is therefore for a DC/DC converter to interface the WT to the electrolyser.

[4] It is important to note that this function may vary depending on the make and model of the electrolyser.

$$\eta_{PEM}^{t} = \begin{cases} if\ R < 15\% \rightarrow & (5.0e-05 \times U^5 - 6.1e-03 \times U^4 + 0.2372 \times U^3 \\ & -4.2014 \times U^2 + 36.675 \times U \\ & -62.87) \times 1.0025^{Basis\ year-2020} \\ if\ R > 15\% \rightarrow & (-0.149 \times U + 74.977) \times 1.0025^{Basis\ year-2020} \end{cases} \quad (2)$$

where η_{PEM}^{t} is the PEM efficiency at hour t, and R refers to the ratio of input power to the electrolyser's rated power. To account for anticipated advancements in electrolysis efficiency by the time the project commences, a rate of 0.25% per year was incorporated into the model, following the approach proposed by Hofrichter et al. [73], as adopted from [74, 75].

Regarding the ALK electrolyser, a polynomial fit was formulated in relation to the lower heating value, utilising experimental data from a test bench [76, 77]. This fit takes into account the same efficiency improvement rate as the PEM technology:

$$\eta_{Alk}^{t} = \begin{cases} if\ R < 50\% \rightarrow & (2.704e-07 \times U^5 - 5.636e-05 \times U^4 + \\ & 04.808e-03 \times U^3 - 0.2139 \times U^2 + \\ & 5.084 \times U + 5.546) \times 1.0025^{Basis\ year-2020} \\ if\ R > 50\% \rightarrow & (-0.037 \times U + 60.252) \times 1.0025^{Basis\ year-2020} \end{cases} \quad (3)$$

The valid economic metric that best serves the purpose of the study is the LCOH. The typical method for calculating $LCOH$ involves assessing all future costs in terms of base-year dollars, as shown in Eq. (4):

$$LCOH = \frac{CAPEX + \sum_{n=1}^{N}(\frac{OMEX_n + REPEX_n}{(1+d)^n})}{\sum_{n=1}^{N}\frac{(1 - n \times TDR) \times M_{H_2}}{(1+d)^n}} \quad (4)$$

where $CAPEX$ represents the capital expenditure valued in in base-year dollars. $OMEX$ refers to fixed operating and maintenance costs, which begin to incur annually from year 1. $REPEX$ is the replacement cost, also known as variable operating and maintenance cost. d is the discount rate, n is the number of years counted from the base year to the end of the project, denoted as, N. TDR is the rate at which the overall system efficiency decreases due to ageing. M_{H_2} represents the assumed value of annual hydrogen production, which is used to determine the sizes of the power generation plant and electrolyser array.

Based on Rubin et al. [63], in accordance with the AACE and the USDOE/NETL (US Department of Energy/National Energy Technology Laboratory) reports [62, 78], the core of a project cost estimate is the Bare Erected Cost (BEC). This includes the cost of components before installation, as well as the costs of materials and labor required for construction and installation. Other significant cost items are derived based on the BEC. To calculate the BEC, Eq. (5) is used:

$$BEC = UC + MC + LC \tag{5}$$

in which UC denotes the upfront uninstalled cost of components, also referred to as uninstalled/direct CAPEX. MC corresponds to the cost of all materials involved during the installation and construction phase, while LC refers to the expenses directly or indirectly tied to labour during this phase. Given that commercial-scale hydrogen production projects are in their nascent stages, and comprehensive labour and material data are currently unavailable, [79] suggests that a portion of UC should be allocated for MC and LC. As mentioned by [63], absence of detailed information places this estimation in cost estimate class 4.

To include the engineering service fee and accommodate costs associated with uncertainty, the Total Plant Cost (TPC) should be calculated as

$$TPC = BEC + ESC + PSC + PTC \tag{6}$$

where ESC stands for the engineering services fee, typically represented as a percentage of BEC. PSC is process contingency, which is introduced to account for uncertainties tied to the maturity of involved components or processes. This is expressed as a percentage of BEC, with higher values assigned to components in early developmental stages.[5] PTC is the project contingency, added to cover unforeseen expenses that may arise due to varying levels of project definition. This relates to the different classes of cost estimates, where lower values are attributed to projects with higher levels of definition. According to AACE and USDOE/NETL, contingency costs should be included in cost estimates because the experience gained from real projects shows that these costs are highly likely to occur, even if they are not evident or well-defined at the time of the initial cost estimate [78]. Subsequently, the Total Overnight Cost (TOC) or installed $CAPEX$ is estimated using Eq. (7). This final cost was assumed to include power management electronics and connections between components [45, 63].

[5] Since the power generation equipment and the electrolyser technologies are at different levels of maturity, PSC values should be calculated for them separately.

$$TOC = TPC + OWC \tag{7}$$

here OWC refers to owner's other capital expenses, encompassing additional costs not accounted for in the BEC. These costs include expenses such as the cost of purified water and the cost of acquiring the land needed for the power generation plant and hydrogen production facility [63].

An essential prerequisite for a sound financial analysis is a credible valuation of money across time, recognising its time-sensitive value. Therefore, it becomes imperative to establish a connection between the future worth of money (FWM) and the present worth of money (PWM) to convert all cost components spanning the project's lifetime into the base year. This conversion is carried out by

$$PWM = \frac{FWM}{(1+d)^n} \tag{8}$$

Usually, the weighted average cost of capital (WACC) is applied to discount the cash flow over time.

2.4. Learning rate and economies of scale

The trend of cost reduction through technological advancements was initially identified in the field of airplane construction [80]. This phenomenon was linked to the principle of learning-by-doing. This trend led to the development of a semi-empirical method known as the "learning curve" or "learning rate," which serves as a predictive tool for estimating future technology costs. Subsequently, this approach has found application in diverse energy technologies, e.g., steam turbines, as illustrated by Grübler et al. [81].

In our study, we utilise the learning rate model to predict $REPEX$, which represents the cost associated with the routine end-of-life replacement of the electrolyser stacks. According to the model, the cost reduction factor (CRF) of technological equipment can be projected as a function of production capacity growth by:

$$CRF = (cc/cc_0)^{-\beta} \tag{9}$$

$$\beta = -log_2(10) \times log_{10}(1 - LR) \tag{10}$$

where CRF is the rate at which the cost of electrolyser stacks tends to decrease in response to increasing production capacity, in line with the learning-by-doing principle. cc/cc_0 is the cumulative production growth, where cc is the current cumulative production and cc_0 is the initial cumulative production. β is the power-law index, and LR represents the learning rate value, which depends on the technology's current stage of development. For emerging technologies, a typical approximate LR value is 15−20%, which tends to decrease to 10% at an intermediate stage with at least a 5% market share. Eventually, it further declines to 0−5% as the technology matures [82]. As can be seen from the learning-rate model, the cost reduction trend is not directly tied to time. Therefore, the production capacity growth over time should be known for predicting $REPEX$ over the ensuing years. To this end, our learning-rate model is developed based on the predictions by the IEA [83], according to which total electrolyser capacity is almost doubling each year.

Beyond cost reduction due to technological learning, a similar trend driven by economies of scale has been noted and extensively discussed across various projects, including those in the realm of renewable energy [49, 84-87]. To accommodate the effects of scaling up, we apply an economies-of-scale model employing the following scaling function:

$$CAPEX = CAPEX_{Base} \times (\frac{S}{S_{Base}})^{SF} \tag{11}$$

$CAPEX$ is the unknown capital cost at the plant size S after scale-up. $CAPEX_{Base}$ is the known capital cost at size S_{Base}. SF is the scaling factor.

2.5. Scenarios and assumptions

We follow the methodology proposed by Rubin et al. [63], which is based on AACE [62]. This approach has been further developed by Gerloff [45], tailored specifically for the cost estimation of renewable hydrogen production. Assumptions specific to Australia are based on publications and reports conducted within the Australian context, including works such as the publication by Geoscience Australia [88] and [79].

The uninstalled $CAPEX$ values of the electrolysers are derived from the base values reported by CSIRO in the latest GenCost2022-23 report, presented in real 2022 AUD terms [82]. The fixed $OMEX$ value is also inflation-adjusted to the basis year, 2030. For the construction and installation timeframe, a 2-year duration is assumed, with 40% progress in the first year and 60% in the second year, following [45]. To estimate the prices of components at their routine end-of-life replacement round, the learning-curve model is applied. The model developed in our previous publication [89] is employed, and assumptions from the Hydrogen Council report [90] and the IEA report [83] are taken into account.[6] Under the current circumstances, learning rates of 13% for PEM stacks and 9% for ALK stacks have been reported in the Hydrogen Council report [90], with shares of 55% and 50% in uninstalled $CAPEX$ [91, 92]. These rates are likely to decrease as the technologies mature and reach mass-production scale. Initially, we apply these rates to predict $CAPEX$ in 2030, and subsequently reduce them to 10% and 5% for the 2030 basis year to predict $REPEX$ in the ensuing years. The learning rate for the rest of plant (including power electronics, gas conditioning, and balance of plant) is assumed to be the same for both technologies, with an average value of 10% based on [93].

According to [94], the land and water demands for producing green hydrogen via seawater desalination are considered viable to match the volume of Australia's liquid natural gas exports during 2018-2019, amounting to around 65 mega-tonnes of hydrogen per year. Consequently, for the purposes of this study, we assume that there will be no constraints on the availability of land and water in the investigated areas. The land costs are obtained from the latest report by the Australian Rural Bank [95],[7] and the land requirements are based on the Queensland solar farm guidelines report by Department of Natural Resources, Mines and Energy [96], as well as information from actual wind farms operating in Australia [97].

While direct usage of seawater for hydrogen production is a promising development [98], for the near term an additional cost for seawater desalination and polishing needs to be included. Levelised costs of water ranging from 1.8–2.2 AUD/m^3 have been reported for large-scale desalination plants in Australia. Here, we opt not to engage in intricate modelling for the water desalination plant, as the cost of purified water has been reported to account for less than 2% of $LCOH$ [3]. Instead, a fixed cost of AUD10/m^3 for feedwater into the electrolyser is assumed, representing the upper limit as suggested in [40], to account for the extra cost of obtaining water suitable for the PEM electrolyser and the potential inverse impact of economies of scale.

The critical financial values are based on the Merchant scenario, as outlined in a recent publication for the Australian National Electricity Market (NEM) [99], leading to a post-tax

[6] To create a detailed learning-rate model, precise knowledge of the future level of production capacity growth and the specific learning rate values for each technology is necessary. However, given that technologies comprise diverse components, each with varying levels of maturity and corresponding learning rates, a simplified model is employed to serve the intended purpose. In this approach, the electrolyser system is divided by the authors into stacks and the rest of the plant, with each following separate learning curves. The same principle is applied to the scaling factor.

[7] The cost of nearest land is taken into account if there are no data available for the exact location.

WACC of 8%.[8] Table 2 lists the additional fundamental assumptions for the base-case scenario.

Table 2. General assumptions for the base-case scenario.

Parameter	Assumed value
Project:	
Hydrogen production (to calculate M_{H_2})	10 tonnes/day
Project lifetime (N)	20 years
Plant degradation rate (TDR)*	0.5%/yr [100]
Project contingency rate	7% (based on the 2030 scenario in [88])
Components:	
Lifetime of stacks	PEM: 60,000 h and ALK: 90,000 h (based on the predictions for 2030 [68])
Uninstalled Electrolyser CAPEX in real 2022 AUD/kW	PEM: 1955; ALK: 1120 (based on the latest CSIRO GenCost2022-23 report [82])
Process contingency rate of power generation plant	5% (assumed based on AACE [62])
Process contingency rate of electrolyser	PEM and ALK: 10% (assuming that both technologies are widely available in 2030, following guidelines of [62])
PV scaling factor	0.90 (based on [52])
Wind turbine scaling factor	0.95 (based on [101])
Electrolyser scaling factor	PEM stack: 0.89; PEM rest of plant: 0.69; ALK stack: 0.88; ALK rest of plant: 0.67 (based on [92])

* To mitigate the risk of becoming an unreliable hydrogen exporter, an overcapacity is required to compensate for the system degradation rate, as noted by Nicita et al. [100].

In terms of process contingency, it should be noted that two different values are considered, one for the power generation plant, which is already in the phase of mass production and slated for further development by 2030, and another for water electrolysis technologies. Assuming no disruptions to the projected development plans by 2030, all involved technologies will fall under the "Commercially available" level, accounting for 0−10% of BEC in the final $CAPEX$ structure. We assume the mid-point value for the power generation plant and the upper bound for water electrolysis technologies.

Regarding the operational characteristics of ALK technology, it is assumed that the minimum acceptable input power is 20%[9] (80% turndown) based on [76, 77], the hot standby power

[8] This value is in line with the upper bound of the range used in the CSIRO GenCost report.
[9] To capture possible improvements by 2030, we assume the lower bound of the range 20-40% reported by CSIRO [102] and NREL [68].

consumption is 4% [103][10], and the start-up time from the cold state to the minimum load is 20 minutes[11] (under current circumstances, start-up time is 1 hour based on real experimental data from the Korea Institute of Energy Research [104] and the ARENA report [69]). The OMEX of ALK is assumed to be the same as for PEM, based on [103]. For PEM technology, the corresponding figures are respectively 5% [105], 2% [103], and 5 minutes [68]. Overload operation is also considered for both technologies, with a similar peak load of 150% of the rated input power. We assume the plant can sustain overload operation for a maximum of 1 hour, after which the load needs to be reduced for the subsequent 1 hour due to cooling requirements. To address the potential mismatch between the maximum power point of the renewable power generation plant's current-voltage curve and the electrolyser's polarisation curve, we have included an efficiency penalty of 5% for all scenarios, based on [106].

To evaluate the potential impact of greater energy yield from taller WT towers and PV installations with dual-axis trackers on $LCOH$, we incorporate an augmentation in uninstalled $CAPEX$ into the model to encompass their higher initial costs. The increment in uninstalled $CAPEX$ for dual-axis PV systems, relative to fixed PV installations, exhibits considerable variability. For example, there are reports of nearly 40% increase [107], 60% increase [108], a range of 30-75% increase [109], a 36% increase [110], and a 65% increase [111]. Considering the probable decline in the cost of dual-tracking technology due to learning-by-doing, we assume a 40% rise in uninstalled PV $CAPEX$. Regarding wind turbines with higher hubs, and noting that it has been predicted that by 2030 the contribution of the turbine tower to the uninstalled $CAPEX$ will be 20%, a 1.6%/meter rise in tower $CAPEX$ is assumed, based on the recent study by Satymov et al. [112].

3. Analysis and results

Taking into account all the assumptions, operational conditions, and efficiency curves of the two electrolysis technologies, we calculated the values of $LCOH$, with estimated accuracy ±30%, for the specified regions. As depicted in Fig. 5, at a production scale of 10 tonnes per

[10] This refers to the power consumption of the electrolyser when the input power is insufficient to operate the electrolyser, but enough to maintain it in standby mode. Consequently, the electrolyser is not completely shut down and the start-up time is short.
[11] This situation arises when the input power is insufficient to maintain the electrolyser even in the hot standby mode. To account for potential improvements by 2030, we assume the lower bound of the reported start-up time range of 20-60 minutes [68].

day, the target value is not attainable for any of the regions based on the base-case assumptions.

Despite ALK having a considerably lower $CAPEX$ (by 42.7%) compared to PEM, this reduction did not lead to a substantial decrease in $LCOH$. This is attributed to the relatively unfavourable operational characteristics of ALK technology. Its features, such as a high minimum load, long cold start-up time and lower efficiency, result in higher electricity costs. Consequently, the cost advantage in terms of $CAPEX$ for ALK could not adequately offset the elevated electricity expenses.

Depending on the location, investing in dual-tracking technology may result in lower $LCOH$ values, similar to the effect of increasing the hub height for wind turbines. As an example, Fig. 5 (a) indicates that PV-based $LCOH$ in the Latrobe Valley region (shown by V) decreases the most compared to other regions after applying dual-tracking technology, as intuitively expected from its relatively high latitude. Considering the contribution of three cost elements (1: electricity, 2: electrolyser, 3: water and land) to the overall $LCOH$, it is observed that using dual-tracking technology in the Latrobe Valley region decreases the share of the electrolyser in total $LCOH$, meaning better utilisation of the electrolyser. The almost equal contribution of electricity cost (for both non-tracking and dual-tracking technologies) means that the increased PV $CAPEX$ of dual-tracking PV is well offset by better energy yield. This increased energy yield leads to lower electrolyser capacity required, therefore to lower electrolyser $CAPEX$. Regarding wind-based $LCOH$ using PEM, Fig. 5 (a) indicates that both the Latrobe Valley and Hunter Valley regions can benefit significantly from taller hubs, resulting in lower electricity costs and effective utilisation of the electrolyser.

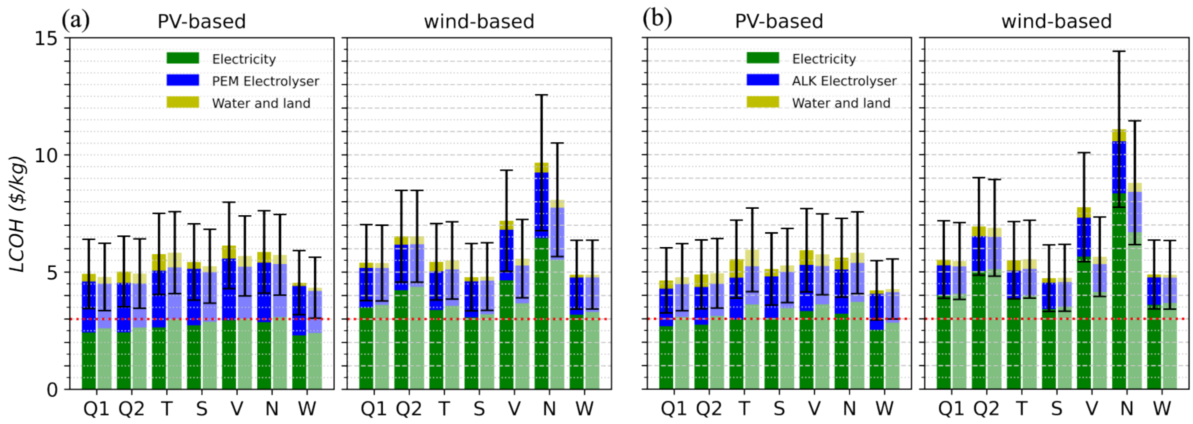

Fig. 5. $LCOH$ for (a) PEM technology and (b) ALK technology for Q1: Gladstone, Q2: Townsville, T: Bell Bay, S: Eyre Peninsula, V: Latrobe Valley, N: Hunter Valley, and W: Pilbara. The left bar for each area represents $LCOH$ for fixed PV and turbines with a 100-meter hub height, while the right bar for each area represents $LCOH$

for dual-axis PV and turbines with a 150-meter hub height. The red dotted line represents the target value.

Figure 6 illustrates the capacity factor[12] (or normalised full load hours) of the hydrogen production plant. Note that the capacity factor of the power plant and that of the hydrogen production plant differ. Generally, higher hubs and solar tracking technology are expected to enhance the capacity factor of the power plant, consequently leading to a higher capacity factor for the hydrogen production plant. However, the influence of these enhancements on $LCOH$ hinges on the consequent increase in $CAPEX$.

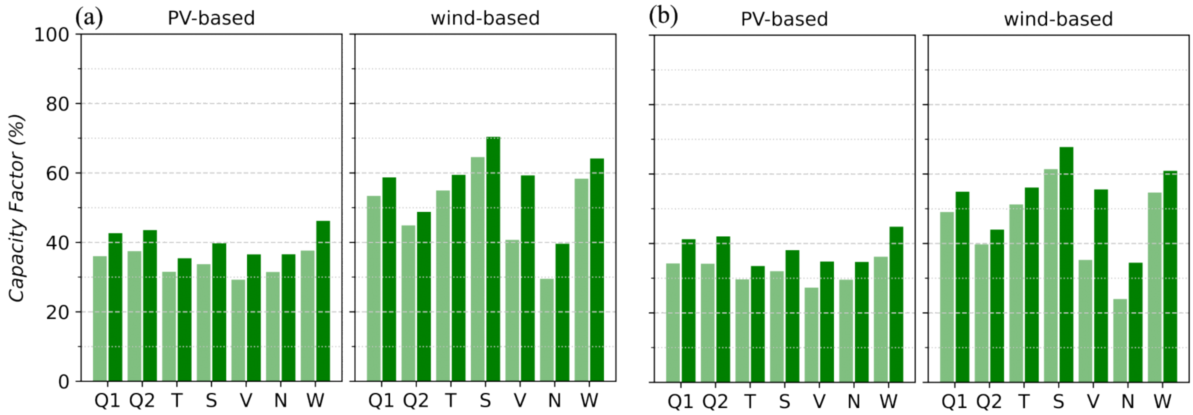

Fig. 6. Capacity factor or normalised full load hours of the hydrogen production plant for (a) PEM technology and (b) ALK technology. The left bar (light green) for each area represents capacity factor for fixed PV and turbines with a 100-meter hub height. The right bar (green) for each area represents capacity factor for dual-axis PV and turbines with 150-meter hub height.

Since there is no notable difference between $LCOH$ from ALK and that from PEM, we continue the study with PEM technology. This choice is based on the belief that by 2030, PEM technology will likely be the dominant electrolysis technology due to its better accommodation of the intermittency of renewable electricity [113].

According to the IRENA report [69], scale-up could drive down $LCOH$ from green electricity to achieve competitiveness. Accordingly, we explore the sensitivity of $LCOH$ to the scale of daily hydrogen production up to 500 tonne/day, subject to two values of $WACC$: an upper bound of 8% and a lower bound of 2%, based the CSIRO GenCost report [82].

With $WACC = 8\%$, the AUD3 target would only become achievable in the Pilbara region at the scale of ~350 tonne/day (~2.1 GW electrolyser). However, a small improvement in $WACC$

[12] Here, capacity factor means the ratio of the total hydrogen produced in a year to the total amount that could be produced at full load in a year.

would bring PV-based $LCOH$ down to the target value in Gladstone and Townsville (Fig. 7).

Regarding wind-based hydrogen production plants, the South Australian and the Western Australian hubs yielded the most favourable results (Fig. 8), albeit not enough to reach the target value.

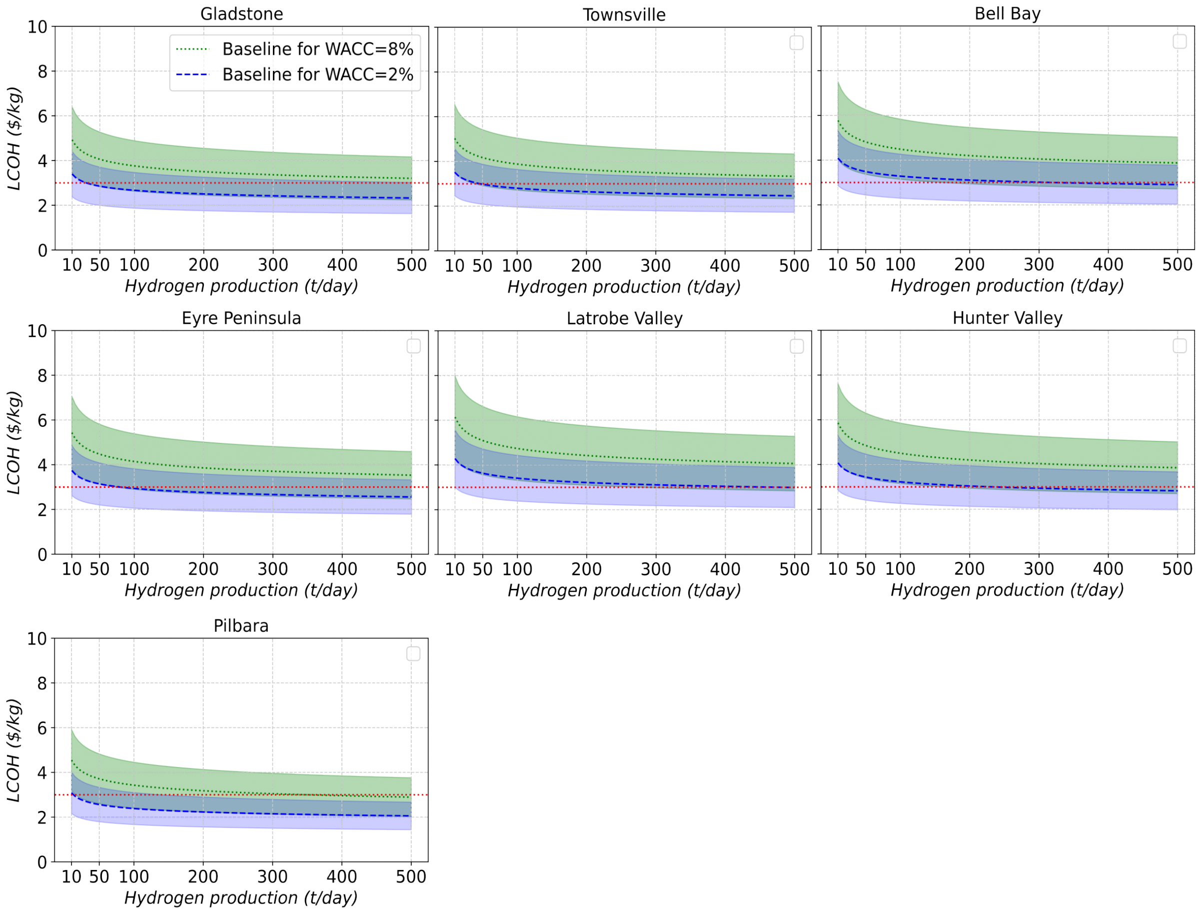

Fig. 7. Evolution of PV-based $LCOH$ as a function of daily hydrogen production. Shaded areas around the baselines correspond to ±30% uncertainty. The red dotted line represents the target value.

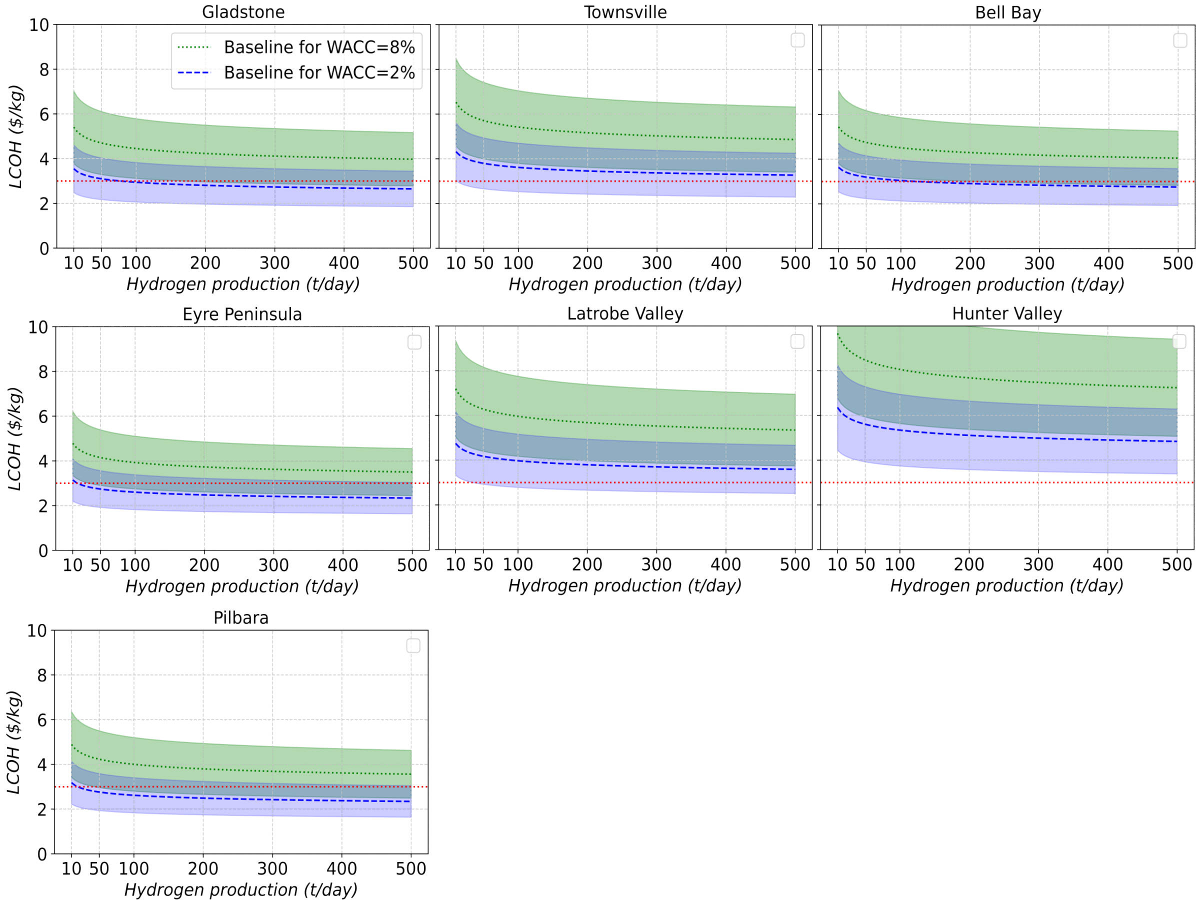

Fig. 8. Evolution of wind-based $LCOH$ as a function of daily hydrogen production. Shaded areas around the baselines correspond to ±30% uncertainty. The red dotted line represents the target value.

3.1. Sensitivity analysis

At the scale of 100 tonne/day, we studied the response of $LCOH$ to changes in $WACC$, $CAPEX$, efficiency improvement, overload utilisation, and the scaling factor to capture the inherent uncertainty in influential parameters (as shown in Fig. 9 and Fig. 10).

In general, $WACC$ has the greatest impact on $LCOH$, followed by the scaling factor. The extent of impact of the scaling factor depends on the corresponding $CAPEX$. The impact of overload, which is dependent on the hourly power profile, is meaningful, particularly for the PV-based plant. Excluding this factor leads to an overestimation of $LCOH$. Given our assumption regarding overload operating conditions, the PV-based LCOH is more sensitive to overload compared to the wind-based one. Also, the extent of reduction in $LCOH$ decreases as peak load increases. Therefore, overload operation is beneficial up to a certain level. The impacts of PV $CAPEX$ and PEM $CAPEX$ are comparable. However, $LCOH$ is more sensitive to $CAPEX$ of wind turbines because it is greater than $CAPEX$ of PV and PEM. A higher electrolysis efficiency can also drive down $LCOH$ by a meaningful amount. Therefore, a combination of favourable conditions can facilitate achieving the target value even at lower scales. Taking Gladstone as an example, PV-based $LCOH$ can reach the target value only when $WACC$ falls to 4%, which seems very low. More realistically, a combination of $WACC$ = 6% and a 5% improvement in economies of scale of both PEM and PV would suffice to reach the target. Alternatively, with $WACC$ = 6% and a 2% improvement in economies of scale of both PEM and PV (highly dependent on project owners), at least a 1%/yr increase in electrolysis efficiency (four times greater than the expected rate) would be required from its base-case value until 2030 to reach the target value. In the Pilbara region, the requirements can be satisfied much more easily for PV-based plant, analogous to the wind-based plant in the Eyre Peninsula region, compared to other regions.

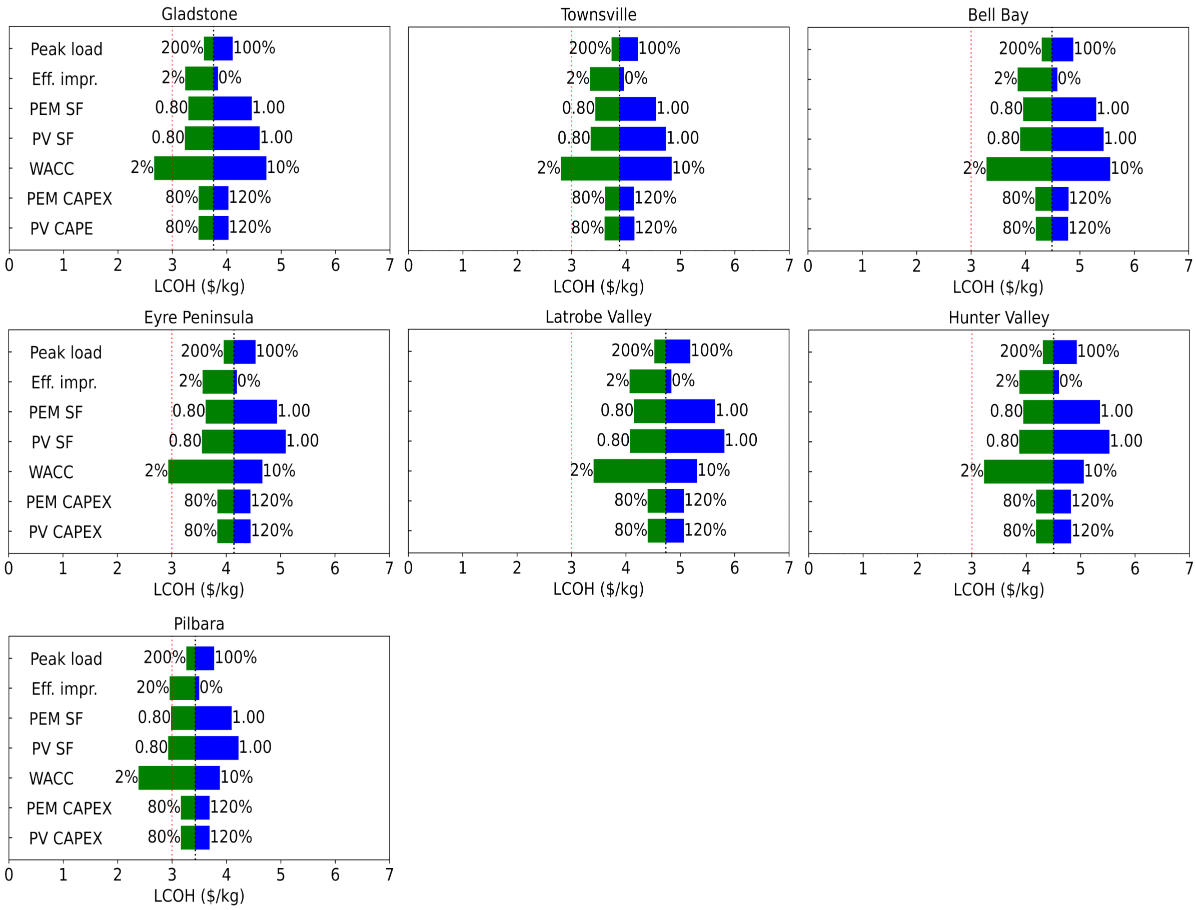

Fig. 9. Sensitivity analysis of PV-based $LCOH$ to uncertainty in financial and technical factors at 100 tonne/day capacity. Eff. impr. refers to yearly efficiency improvement. The red dotted line represents the target value.

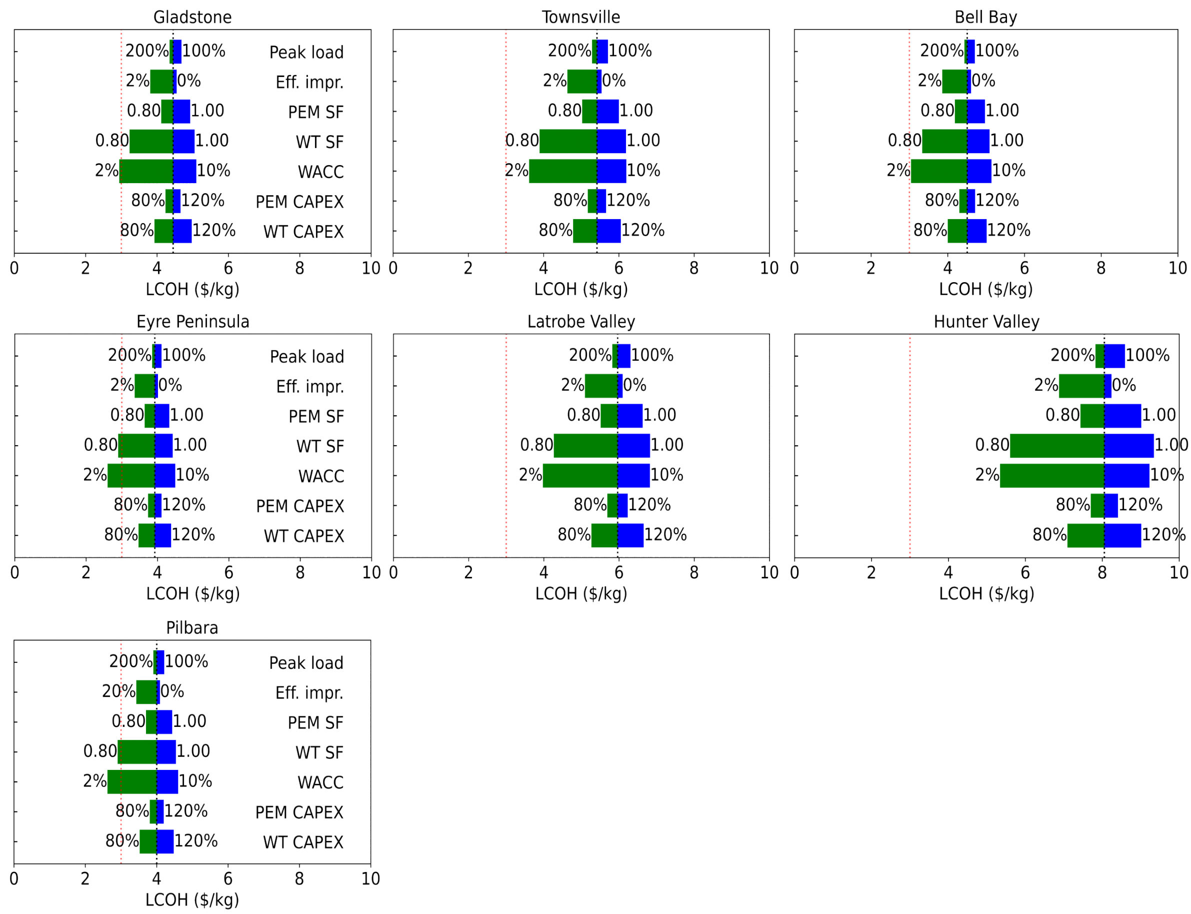

Fig. 10. Sensitivity analysis of wind-based $LCOH$ to uncertainty in financial and technical factors at 100 tonne/day capacity. Eff. impr. refers to yearly efficiency improvement. The red dotted line represents the target value.

3.2. Incorporation of environmental cost

Knowing that the exact value of LCE depends heavily on the project- and location-specific factors, e.g., origin of components, our approach is to estimate the trade-offs between the LCE and carbon cost, aiming to achieve $LCOH$ for green hydrogen below that of grey hydrogen. Different threshold values of carbon intensity, ranging from 0.45 to 4.4 $kgCO_{2\text{-}eq}/kgH_2$, have been suggested to consider a hydrogen production pathway low-carbon [114]. In this study, we estimate the trade-offs based on the CertifHy threshold for carbon intensity of hydrogen, which is set at 4.4 $kgCO_{2\text{-}eq}/kgH_2$ for the "Well-to-gate" pathway [115], following [116].

Assuming $LCOH$ = USD2/AUD3 per kg of grey hydrogen with $LCE = 12$ $kgCO_{2eq}/kgH_2$ [18], we explored the trade-offs that would make green hydrogen cheaper than grey hydrogen. The results are shown in Fig. 11 and Fig. 12.

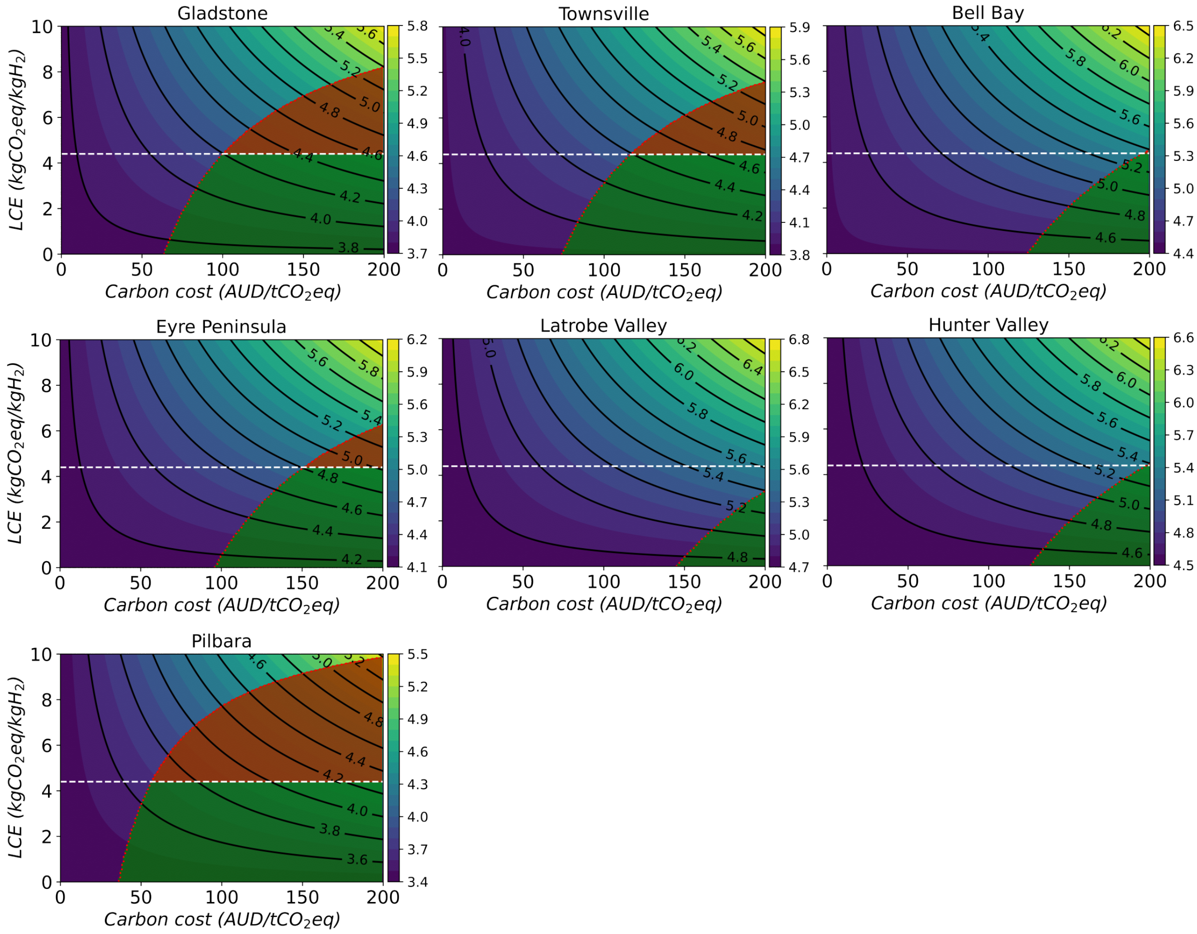

Fig. 11. Contour plots of constant PV-based $LCOH$ as a function of carbon cost and LCE. The horizontal white dashed line is the maximum acceptable LCE based on CertifHy. The red dotted line indicates the point where the $LCOH$ values of grey and green hydrogen become equivalent with the inclusion of environmental costs. The green shaded area indicates the trade-offs by which green hydrogen becomes cheaper than grey hydrogen. The brown shaded area also shows the region where green hydrogen is cheaper than grey hydrogen but LCE is not acceptable based on CertifHy.

Figure 11 indicates that with the introduction of environmental costs, PV-based green hydrogen produced in the Pilbara region, followed by Gladstone and Townsville, can reach cost competitiveness faster than other locations. For example, assuming LCE = 4 $kgCO_{2eq}/kgH_2$ for hydrogen produced in the Pilbara region, a carbon cost of approximately 55 AUD/tCO_{2eq} will drive the PV-based $LCOH$ below that of grey hydrogen. Assuming the same LCE for Gladstone and Townsville regions, carbon costs should increase up to 100 and 120 AUD/tCO_{2eq}, respectively. Figure 12 shows that higher carbon costs are required for projects using onshore wind energy to produce hydrogen, generally due to the higher cost of wind energy. The brown shaded areas in Fig. 11 and Fig. 12 represent trade-offs where PV- and wind-based hydrogen becomes cheaper than grey hydrogen but may not be considered green or low carbon based on the terms and conditions of certificates.

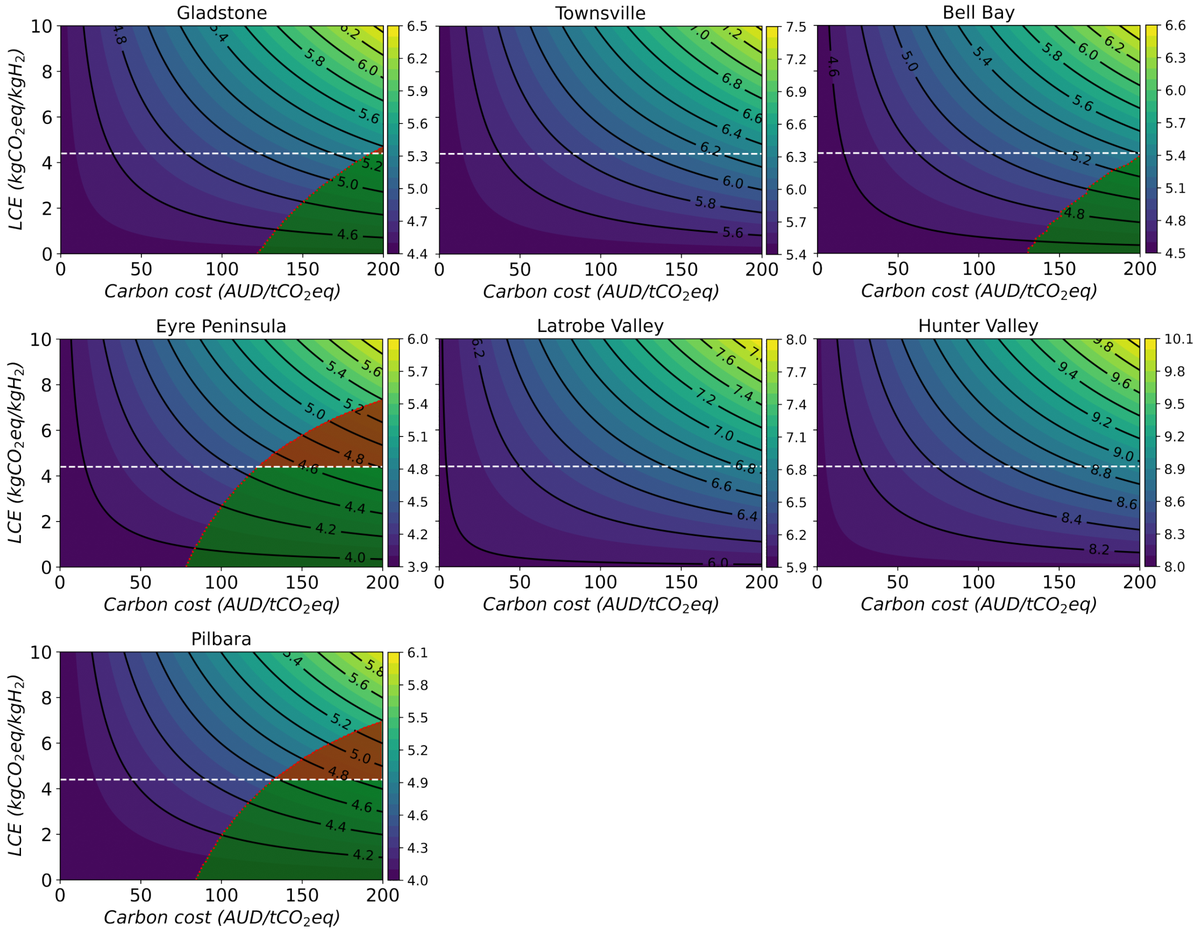

Fig. 12. Contour plots of constant wind-based $LCOH$ as a function of carbon cost and LCE. The horizontal white dashed line is the maximum acceptable LCE based on CertifHy. The red dotted line indicates the point where the $LCOH$ values of grey and green hydrogen become equivalent with the inclusion of environmental costs. The green shaded area indicates the trade-offs by which green hydrogen is cheaper than grey hydrogen. The red-brown shaded area also shows the region where green hydrogen is cheaper than grey hydrogen but LCE is not acceptable based on CertifHy.

4. Summary and conclusions

A transition from fossil fuels to renewables, including hydrogen, is inevitable. As a result, the likelihood of a global market for hydrogen emerging in the coming years is high. This presents a significant opportunity for countries with abundant renewable energy potential.

Being rich in solar and wind energy resources, Australia has placed its focus on renewable hydrogen, as outlined in its National Hydrogen Roadmap. To achieve this goal, it is crucial to thoroughly investigate and compare potential areas with high-quality renewable energy sources. Therefore, the study estimated wind and solar hydrogen production costs in various potential hydrogen hubs across the country. The developed methodology and some of the key findings are applicable in other countries. The key findings of the study are summarised as follows:

- Despite the significantly lower ALK $CAPEX$ compared to PEM $CAPEX$, there is no notable difference between the $LCOH$ values from both technologies. This is primarily due to the unfavourable operating conditions of the ALK electrolyser. The ALK technology has higher minimum load requirements, longer cold start-up times, and lower efficiency, which result in increased electricity costs. As a result, the lower $CAPEX$ of ALK cannot fully compensate for the higher electricity costs, leading to comparable $LCOH$ values between the two technologies.
- The response of $LCOH$ after deploying dual-tracking PV technology and taller WT towers is directly related to the additional initial costs and the improved capacity factor of the PV and wind turbine. The decision to adopt dual-tracking technology or taller towers depends on the extent to which the higher initial costs can be offset by the increased electricity generation capacity. For example, replacing fixed PV with dual tracking PV connected to PEM in the Latrobe Valley region increases the unit cost of installed PV by 40%, offset by decreases of about 22% and 20% respectively in the required PV and electrolyser capacities, resulting in $LCOH$ falling from 6.14 to 5.69 AUD/kg.
- Under the base-case scenario for the PV-based plant and the examined range for the scale, the target value could only be reached in the Pilbara region. The threshold scale for achieving the target value is 350 tonne/day, which would require a 2.1 GW PEM electrolyser.
- Under the base-case scenario for the wind-based plant, Eyre Peninsula and Pilbara show the highest potential. However, the target value remains unachievable at any hub, mainly due to worse economies-of-scale compared to the PV-based model. The position is expected to improve for offshore wind installations, where the capacity factor is significantly higher than on land.
- $WACC$, scaling factor, $CAPEX$, electrolysis efficiency and overload individually have a meaningful impact on $LCOH$. Therefore, careful consideration of these factors is essential. Additionally, overload is a critical factor that should not be overlooked, particularly for the PV-based plant, otherwise $LCOH$ is miscalculated.
- As an example of a combination of conditions which would result in $LCOH$ = 3 AUD/kg in the Gladstone region, $WACC$ = 6%, PV SF = 0.85 and PEM stack SF = 0.84 would suffice. Alternatively, if significant economies of scale cannot be captured, then $WACC$ =

6%, PV $SF = 0.88$, PEM stack $SF = 0.87$, along with a 1% per year increase in electrolysis efficiency would suffice.

- Introducing a carbon cost based on the carbon intensity of hydrogen production methods can significantly enhance the cost-competitiveness of green hydrogen at certain hubs.

5. Limitations and future research direction

A primary limitation in our analysis is the lack of publicly available data, particularly regarding large-scale wind and solar farms. Additionally, the absence of operational large-scale renewable-based hydrogen production projects at the time of writing further compounds this scarcity. These constraints restrict the depth and precision of our analysis in certain areas, leading us to rely on model-based estimations and broad assumptions rather than concrete empirical data. Consequently, our findings to some degree rely on approximation, due to the absence of direct, real-world data, such as learning rates and cumulative production capacity of PEM electrolysers. This limitation highlights the challenge of operating in a field where extensive operational data on renewable hydrogen production is not widely accessible. Despite these limitations, we have employed rigorous modelling techniques and integrated actual data from a PEM-technology project in Germany to establish the most reliable model for estimating $LCOH$.

Given the emerging nature of the industry, it is crucially important to conduct a techno-economic study to evaluate the entire supply chain of green hydrogen, whether for export or domestic use, including production, storage, delivery, and distribution, with a focus on storage and transportation.

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