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Conditions for low cost green hydrogen production: mapping cost competitiveness with reduced-form marginal effect relationships

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Abstract

Green hydrogen holds promise as a zero-carbon energy carrier if production costs fall low enough to achieve cost-competitiveness with alternatives. We specify reduced-form marginal effect relationships that capture the underlying dynamics of existing structural models of hydrogen production via electrolysis. These specifications provide the marginal effect of electricity costs, electrolyser capital costs and capacity utilisation factors on the cost of producing hydrogen. And we use them to identify the potential combinations of cost components that meet threshold production costs under which green hydrogen will be cost-competitive. In the near-term, there is particular promise for low cost green hydrogen production where electrolysers are co-located with renewable energy parks to use electricity that would otherwise be curtailed. Or when they operate during periods of low or negative prices in electricity grids. Green hydrogen stand-alone operations could be commercially viable with continued reductions in renewable energy generation and electrolysers.

Keywords:
Hydrogen; electrolysis; renewable energy; energy economics

JEL Classification:
Q41, Q42, Q47

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Green hydrogen holds promise as a zero-carbon energy carrier if production costs fall low enough to achieve cost-competitiveness with alternatives. We specify reduced-form marginal effect relationships that capture the underlying dynamics of existing structural models of hydrogen production via electrolysis. These specifications provide the marginal effect of electricity costs, electrolyser capital costs and capacity utilisation factors on the cost of producing hydrogen. And we use them to identify the potential combinations of cost components that meet threshold production costs under which green hydrogen will be cost-competitive. In the near-term, there is particular promise for low cost green hydrogen production where electrolysers are co-located with renewable energy parks to use electricity that would otherwise be curtailed. Or when they operate during periods of low or negative prices in electricity grids. Green hydrogen stand-alone operations could be commercially viable with continued reductions in renewable energy generation and electrolysers.

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The authors declare no conflict of interest.

The code and data used to produce the estimates and graphics in this paper are available at: https://github.com/tlongden620/H2cost

1 Introduction

Green hydrogen holds promise as a zero-emissions energy carrier for heavy transport, industrial applications, as a feedstock to produce ammonia or steel, and in some instances power generation. Projections of potential global demand for hydrogen in 2050 range widely, examples include 8 EJ/year (IRENA, 2018), 78 EJ/year (Hydrogen Council, 2017), and 99-195 EJ/year (BloombergNEF, 2020). The Sustainable Development Scenario produced by the IEA projects 3 EJ/year in 2030, which grows to 11 EJ/year in 2040 and 43 EJ/year in 2070 (IEA, 2020a, IEA, 2020b). Global current primary energy demand is around 600 EJ/year (IEA, 2020b). Making hydrogen from renewable energy using electrolysis has clear advantages over the currently dominant fossil fuel based processes as there are no carbon dioxide emissions and no need for carbon capture and storage systems (which cannot capture 100% of carbon dioxide created in the conversion process). However, green hydrogen has been costlier to produce and fossil-fuel based production dominates (IEA, 2019). Recent reductions in the cost of renewable electricity mean that the production of green hydrogen has become more economical and can be cost-competitive in certain cases, and the cost of electrolysers is also falling with learning rates for electrolysers estimated at 9% and 13% (Guerra et al., 2019, Saba et al., 2018, IEA, 2019, Glenk and Reichelstein, 2019, Schmidt et al., 2017, Hydrogen Council, 2020).

The largest factor determining the cost of producing hydrogen using electrolysis is the cost of electricity, followed by the capital cost of the electrolyser system in combination with the operating capacity factor of the electrolysers (Felgenhauer and Hamacher, 2015, Levene et al., 2007). The share by factor depends on the assumptions used. For example, with a cost of electricity at approximately $65/MWh, the cost of electricity expenditure has been estimated to be 65-80% of total production costs (Strategic Analysis, 2014, NREL, 2018b). The cost of electricity for the production of green hydrogen will be determined by the average cost of newly installed renewable power generation and/or the opportunity to draw on electricity at prices below average cost. Such opportunities can arise when excess renewable energy is curtailed and in particular where electrolysers are co-located with renewable energy parks, or when grid power prices are very low or negative during periods of time of oversupply of renewable energy (Troncoso and Newborough, 2011, Jørgensen and Ropenus, 2008, Guerra et al., 2019, Zhang and Wan, 2014, Beccali et al., 2013).

Our analysis shows the trade-off between ranges of values for the three major determinants of hydrogen production costs, and explores the impact of very low cost electricity on hydrogen costs using defined periods of curtailment. Some green hydrogen studies did not explicitly assess the impact of running electrolysers during times of low (or negative) electricity prices (Yates et al., 2020, Gallardo et al., 2020, Grube et al., 2020).

This paper uses regression analysis to develop reduced-form marginal effect relationships that capture the underlying dynamics of existing structural models of hydrogen production via electrolysis. Reducing structural models to a reduced-form specification is a common practice in econometrics and is similar to structural decomposition analysis. We condense the structural models into calibrated equations using a few key parameters/variables so that they can be adapted for a range of modelling exercises and practical applications. Using a structural techno-economic model (NREL, 2019a), we specify reduced-form relationships of the production cost of hydrogen for a Proton Exchange Membrane (PEM) electrolyser. Using a bottom-up model of electrolysis, which was developed using Monte-Carlo analysis (Yates et al., 2020), we also provide a reduced-form method for converting PEM costs into production costs for an Alkaline (AE) electrolyser, or vice versa.

These are novel and widely applicable reduced form specifications of hydrogen production costs. These specifications simultaneously account for capital costs, the cost of electricity, curtailment, and the operating capacity factor. We apply them to analyse the case of electrolysers co-located with solar/wind power generation where it is possible to capitalise on low-cost or zero-cost electricity when curtailment is needed. Other applications are possible and we provide all of the details needed for these equations to be applied by modellers, researchers and government or industry decision-makers.

Section 2 provides background on existing estimates for hydrogen production costs and cost components, illustrating the fact that there is a profusion of widely differing point estimates. Section 3 describes our method of estimating calibrated equations for hydrogen production costs from a techno-economic model of a PEM electrolyser. Section 4 contains the regression results and applies these estimated functional relationships to different contexts, including co-located electrolyser/solar/wind installations. Section 5 discusses the computation of threshold costs to ascertain the cost competitiveness of hydrogen in different end uses and the conditions that allow these production costs to be achieved. Section 6 concludes. A supplementary section provides detail for converting PEM costs to AE electrolyser costs.

2 Background on existing cost estimates

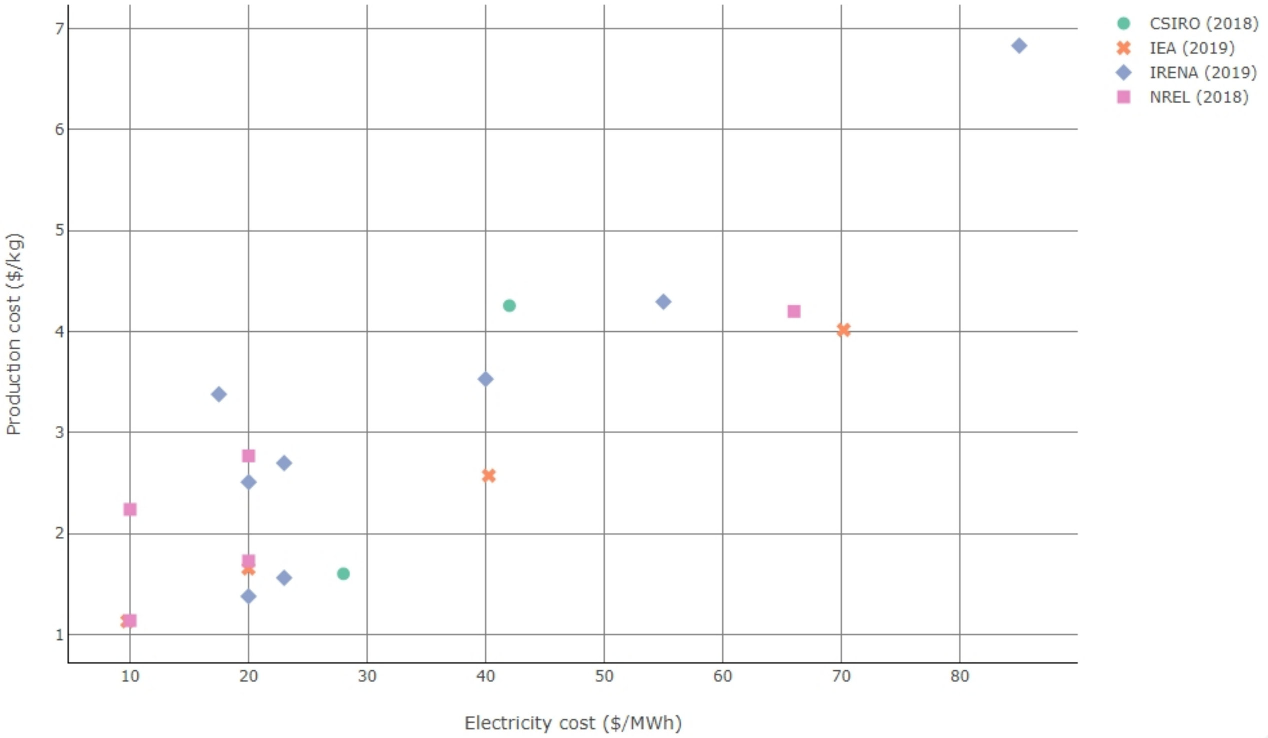
Recent ambitions to develop a hydrogen industry are reflected in the national hydrogen strategies and roadmaps of numerous countries. These include Australia, Germany, Japan, South Korea, Canada and Norway (Commonwealth of Australia, 2019, NRCan, 2019, German Fed Government, 2020, METI, 2019, RVO, 2019, MPE, 2020). Some of these set expectations or targets for hydrogen costs, such as the Japanese hydrogen roadmap target of $2 per kg and the Australian government's target of around $1.40 per kg of hydrogen (equivalent to AUD2, or "H2 under 2")[1]. Reports prepared by intergovernmental organisations (IEA, 2019, IRENA, 2019) also provide cost estimates and projections. The assumed cost of electricity, and of electrolyser costs, differs substantially across these reports and the studies associated with the national strategies/roadmaps (Figure 1). This in turn has a notable impact on the assumed future production cost of hydrogen from electrolysis in these studies.

Over the last few years, major reports have estimated production costs between $1/kg and $7/kg depending on the electricity cost assumed (Figure 1a). Most studies used estimates of electricity costs above $50/MWh, despite recent reductions in the cost of solar and wind. For example, the LCOE for 2019 provided by IRENA (2020) was $52/MWh and $38/MWh for utility-scale solar PV plants and onshore wind. Further reductions in LCOEs are reflected in auction prices of $30/MWh and $27/MWh for solar PV and onshore wind in 2021 (IRENA, 2020). For 2019, Lazard reported the LCOE of solar PV and onshore wind at costs as low as $36/MWh and $28/MWh (Lazard, 2019). Recent projections have the LCOE for solar PV at $23/MWh in 2030 and $18/MWh in 2040. The equivalent numbers for wind are $32/MWh and $30/MWh. When low electricity costs are applied, eg below $30/MWh, hydrogen costs from electrolysis tend to be below $3/kg (Figure 1a).

Capital costs of electrolysers are another crucial component and there are a wide range of costs used in recent studies or mentioned in industry reports. Present day capital costs have been reported at levels above $1000/kW and as low as $200/kW (Figure 1b).

[1] All monetary values are in US dollars. Where currency conversions were done, the average exchange rate for October 2020 was used.

a



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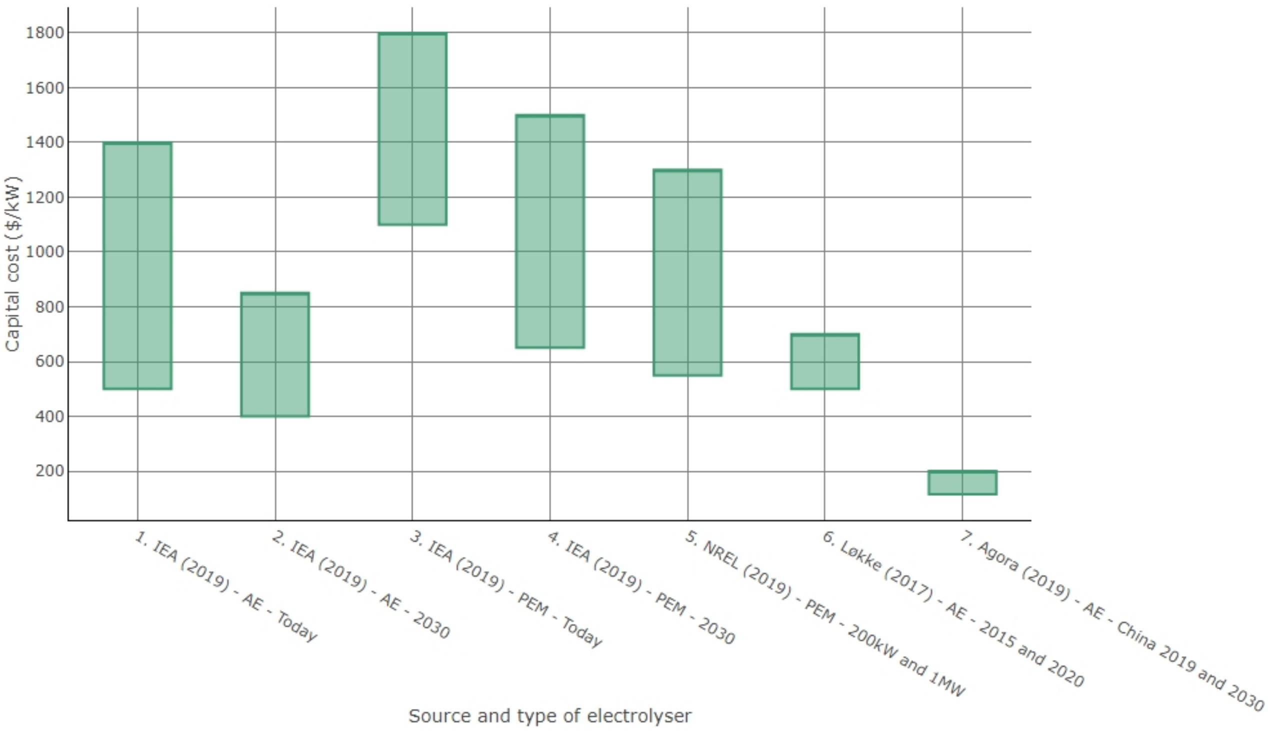


Figure 1 | Example estimates of the cost of hydrogen production and capital costs.
a Production cost of hydrogen ($/kg) as a function of electricity cost ($/MWh) – examples from CSIRO (2018), NREL (2018a), IEA (2019), IRENA (2019).
b Capital costs for Alkaline (AE) and Proton Exchange Membrane (PEM) electrolysers ($/kW) – examples from IEA (2019), NREL (2019b), Løkke (2017), Agora (2019).

3 Material and methods

This section discusses the methodology used to transform large structural techno-economic models into marginal effect reduced-form specifications that can be used in a range of applications. Section 3.1 describes the structural techno-economic model of a PEM electrolyser that we condense into reduced-form relationships in section 3.2. The parameters estimated/calibrated using regression analysis are presented in section 4. Section 8 contains reduced-form method for converting PEM costs into AE costs, which is the compression of a bottom-up model of electrolysis that was developed using Monte-Carlo analysis.

3.1 National Renewable Energy Laboratory (NREL) model of hydrogen production using PEM electrolysis

The data source for our calibration is the National Renewable Energy Laboratory (NREL) model of hydrogen production using PEM electrolysis. This is a detailed structural techno-economic model of a standalone grid powered PEM electrolyser system with a total hydrogen production capacity of almost 50,000 kg/day (NREL, 2019a). Different attributes were developed for a current and future version of the model and in this paper we focus on the current version (Table 1). The model is a generic electrolysis system designed by NREL staff with inputs from industry collaborators who have commercial experience in PEM electrolysis systems. The model can be downloaded from the NREL website (https://www.nrel.gov/hydrogen/h2a-production-case-studies.html). We used version 3 from September 2019. This model has baseline values as follows: a capital cost of \$460/kW, feedstock electricity cost at \$70/MWh and an operating capacity factor of 97%, which results in a production cost of \$4.83/kg (Table 1).

3.1.1 Calculation of capital costs

An electrolyser is made up of three main components (Figure 2). These are the electrolyser stack, the mechanical component, and the electrical system. The cost of capital for the entire system is the summation of these three parts shown in Equation 1. Equation 2 shows the calculation of the system cost of the electrolyser stack ($\mathrm{Stack_{SC}}$), which is a function of voltage (V), current density (CD) and the stack cost per cm² (γ). Equation 3 shows the calculation of the mechanical balance of plant (BoP) cost, which is a function of the system peak production ($\mathrm{P_{peak}}$), the stack input power peak ($\mathrm{SIP_{peak}}$) and the mechanical system cost per daily production (∂). The electrical balance of plant cost ($\mathrm{Elec_{BoP}}$) accounts for the cost of an AC transformer and an AC to DC rectifier, which is specified in \$/kW. Parameter values are shown in Table 1.

$$\mathrm{Total_{SC}} = \mathrm{Stack_{SC}} + \mathrm{Mech_{BoP}} + \mathrm{Elec_{BoP}} \tag{1}$$

$$\mathrm{Stack_{SC}} = \gamma/(\mathrm{CD} * \mathrm{V}) * 1000 \tag{2}$$

$$\mathrm{Mech_{BoP}} = \left(\partial * \mathrm{P_{peak}}\right)/\mathrm{SIP_{peak}}/1000 \tag{3}$$

Table 1: Baseline attributes of the NREL PEM model

Attribute	**Current model parameters**
Assumed start-up year	2015
Total system capital cost ($)	$54,579,000
Total system capital cost ($/kW)	$460/kW
Plant design capacity or peak production ($\boldsymbol{P_{peak}}$)	56,500 kg/day
Operating capacity factor	97%
Actual plant output	54,805 kg/day
Current density (CD)	2 A/cm²
Voltage (V)	1.9 V/cell
Stack input power peak ($\boldsymbol{SIP_{peak}}$)	119 MW
Total system input power peak	131 MW
Stack electrical usage	50.4 kWh/kg
Balance of plant electrical usage	5.1 kWh/kg
Total system electrical usage	50.5 kWh/kg
Cost of feedstock electricity	$70/MWh
Stack Life	7 years
Hours per stack life	59,480 hrs/life
Stack degradation Rate	89 V/life
Stack oversize due to degradation	13.00%
Production cost of hydrogen	**$4.83/kg**

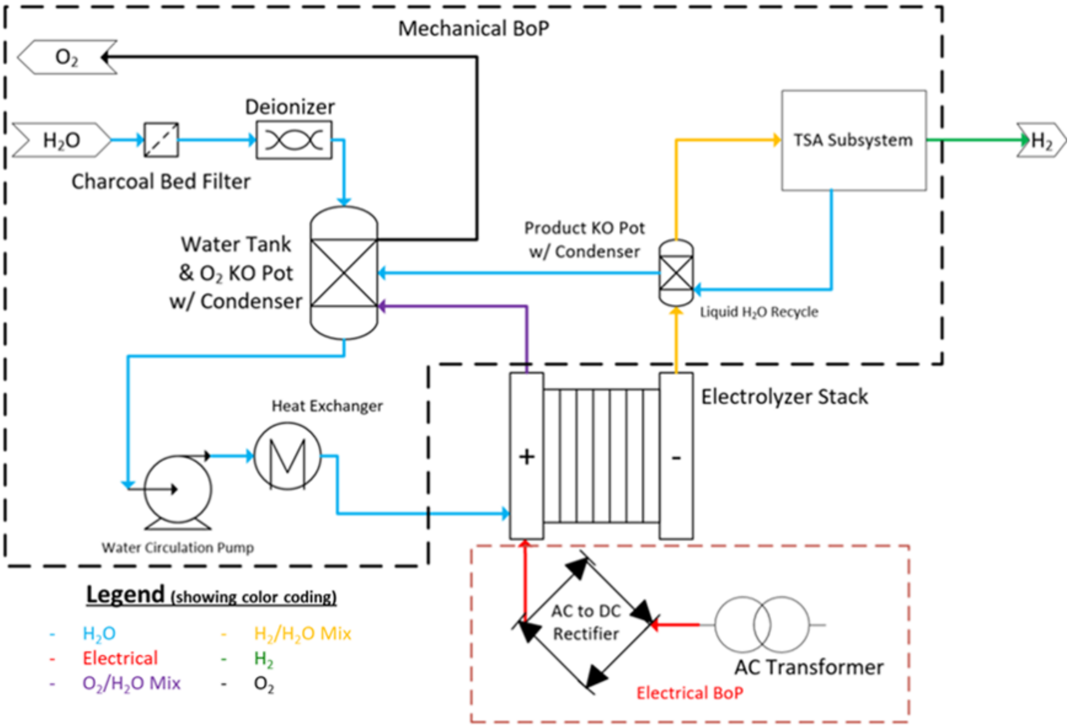
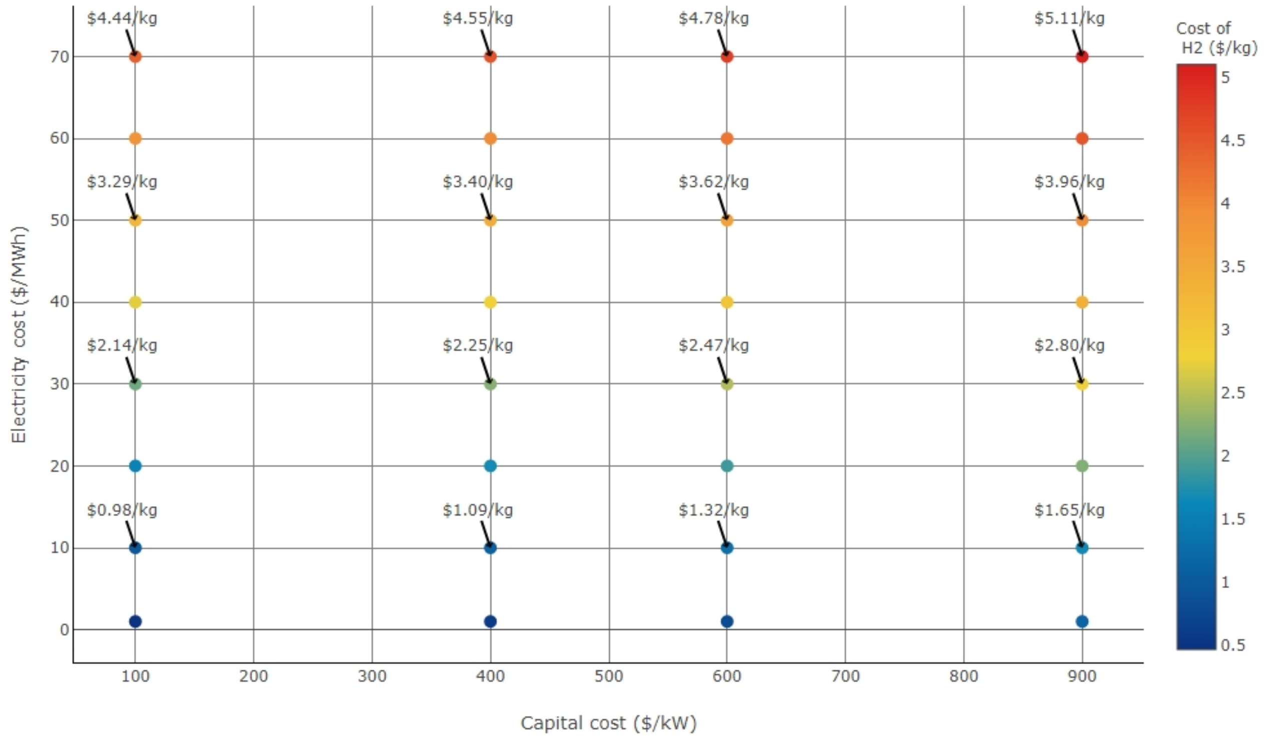


Figure 2 | Process flow diagram of the NREL PEM model.
Sourced from NREL (2019) and is part of the model documentation.

3.1.2 Data from the NREL model

To develop the reduced form specifications of the production cost of hydrogen we iteratively entered different combinations of input parameters into the NREL model. We created two data sets of PEM hydrogen production costs for various levels of the major determinants of cost (Figure 3). These data were used to explore the relationships between key factors and then estimate regressions for the production cost of hydrogen. Based on previous studies, we focused on different combinations of electricity cost, capital cost, and the operating capacity factor (Felgenhauer and Hamacher, 2015, Levene et al., 2007). Other cost factors such as maintenance, operation, land, water and labour are relatively minor and are not specified in the model. However, they are accounted for in the $/kg data sourced from the NREL model. The linear regression is estimated for different combinations of electricity cost and capital cost (Figure 3a). The non-linear regressions are different combinations of electricity cost, capital cost, and the operating capacity factor (Figure 3b). The code and data used to produce the estimates and graphics in this paper are available at: https://github.com/tlongden620/H2cost a



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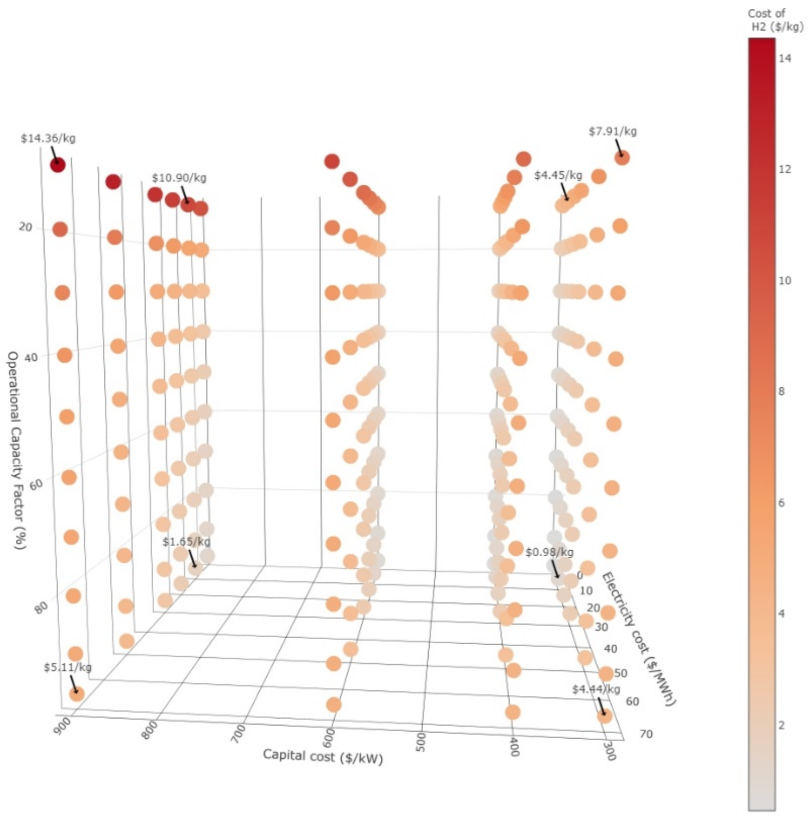

Figure 3 | Raw data from the NREL PEM model.
a Data for the estimation of a production cost model (relevant for equation 4 in section 3.2).
b Data for the estimation of non-linear production cost models (relevant for equations 5 and 6 in section 3.2).

3.2 Specifying reduced-form equations of the production cost of hydrogen

Analysis of these data sets led to the model specifications below, where HC is the cost of producing hydrogen ($/kg), FOC is the fixed operating cost ($/kg), EC is the feedstock electricity cost ($/MWh), CC is the capital cost ($/kW) and OCF is the operating capacity factor (%).

Equation 4 defines hydrogen production costs as a function of electricity cost and capital cost only. The parameters in equation 4 ($\beta_0, \beta_{1,}\beta_2$) are an intercept, the marginal effect of a change in electricity cost, and the marginal effect of changing the level of capital cost, respectively. This specification has a fixed operating capacity factor and, accordingly, was specified using the smaller data set.

$$HC = \beta_0 + \beta_1 EC + \beta_2 CC \tag{4}$$

Being able to modify the operating capacity factor is important for an analysis of the production of hydrogen using renewables due to the intermittence of solar and wind. The reduced form equations below include a variable operating capacity factor and were specified using the larger data set. Equation 5 defines hydrogen production costs as a function of the capital cost (CC) divided by the operating capacity factor (OCF). The marginal effect of a change in the ratio of CC and OCF is captured by ϑ.

$$HC = \beta_1 EC + \vartheta \frac{CC}{OCF} \tag{5}$$

Equation 6 defines the hydrogen production cost using a specification where both capital cost and the operating capacity factor are variables with separate coefficients. This equation is useful for cases where the operational capacity factor needs to be varied.[2] This specification will be useful for modelling exercises where both variables are used in other equations, such as a model where a learning curve sets capital costs and the capacity factor is varied for different combinations of solar/wind/grid electricity. The marginal effect of a change in the level of capital cost (CC) is captured in equation 6 as α. The marginal effect of the operating capacity factor (OCF) is a function of two parameters, τ and θ, that combine to specify that an increase in hydrogen costs occurs when the electrolyser is not used at maximum capacity, i.e. below 97%.

[2] The OCF scales the capital cost multiplicatively, for example an OCF of 0.5 means that twice as much capital equipment is needed to achieve the same ouput as with an OCF of 1.

$$HC = \beta_1 EC + (\alpha CC + \delta)(\tau OCF^{-\theta}) \quad (6)$$

Equation 7 extends equation 6 to allow for electricity costs that differ during the time of day, which will be the case during periods of curtailment. We include a factor that captures different proportions of time (q) where the electricity cost is at a very low level due to curtailment or excessive supply relative to demand on the grid (EC_c). The cost of electricity is set at a different cost (EC_a) at other times. The share of high/normal cost during other time periods is captured by $(1 - q)$.

$$HC = (\beta_1 EC_a)(1 - q) + (\beta_1 EC_c)(q) + (\alpha CC + \delta)(\tau OCF^{-\theta}) \quad (7)$$

We use q as a curtailment ratio for solar and wind electricity generators. Alternatively, it can be used to capture the share of near-zero costs in grids due to oversupply of renewable power relative to demand. It is the share of time during which electrolysers can be operated at zero or very low electricity cost. We set values for q based on the estimated marginal loss factors for solar and wind electricity generators in the three largest regions of east Australia (AEMO, 2020d). Marginal loss factors are an estimate of the network loss that would occur if more generation was dispatched at that point of the grid, and thereby can serve as proxy for curtailment rates where a new solar/wind generator is built near existing facilities.

An alternative way to set q is based on the share of time during which wholesale electricity prices are near or below zero in renewables-rich grids. As an illustration, in the State of South Australia grid prices were below \$1/MWh for 9% of the time between 1 January and 2 November 2020. They were below \$1/MWh for 5% of the 2019 calendar year (AEMO, 2020e).

4 Results

4.1 Econometric model estimations

As previously mentioned, we created two data sets of PEM hydrogen production costs for various levels of the major determinants of cost. These values ranged from \$70/MWh to \$1/MWh (EC), \$900/kW to \$100/kW (CC), and 97% to 10% (OCF). We used different values of γ, ∂ and $\mathrm{Elec}_{\mathrm{BoP}}$ to specify the capital cost levels. The first data set does not include variations of the operating capacity factor and has 32 observations rather than the 240 observations in the second data set. The regressions of equations 4 to 6 accurately estimate the hydrogen production cost point estimates from the NREL PEM model, which is shown in Table 2 as the R-squared indicator is close to or equal to one.

Across all of the equations estimated, the coefficient for electricity cost is approximately 0.06, which means that for every \$10/MWh decrease in the cost of electricity there is a \$0.60/kg decrease in the production cost of hydrogen (Table 2). The dynamics of these relationships are further discussed in Section 4.2, which contains contour plots using these estimates. At this point, the key detail is that the reduced form equations are well calibrated and capture the underlying relationship of the structural PEM model.

4.2 Contour plots of hydrogen production costs

Having specified and calibrated the equations, we now display the relevant relationships that underpin the production costs of hydrogen from electrolysis. We start with the relationship between electricity costs and capital costs (with a fixed capacity factor). The estimate for β_1 is the same across all of the statistical regressions, which means that for every \$10/MWh decrease in the cost of electricity there is a \$0.58/kg decrease in the cost of hydrogen (Figure 4a). This holds across multiple specifications of the equations and is also consistent with the relationship shown in IEA (2019). Meanwhile, using equation 4, a \$100/kW decrease in capital cost leads to a decrease in the cost of hydrogen of \$0.11/kg when the operating capacity factor is set to 97% (also Figure 4a).

The dramatic effect of electricity costs is most evident in Figure 4a. For a capital cost of \$900/kW, the hydrogen production cost decreases from \$3.95/kg to \$2.22/kg and \$1.13/kg as electricity costs decrease from \$50/MWh to \$20/MWh and \$/1MWh (points a, b and c in Fig. 4a). These electricity price points can be seen as proxies for a) current day wholesale grid prices in relatively high cost locations, b) average costs of renewable energy generation in low cost applications in the near future, and c) as an illustrative price point for electricity that would otherwise need to be curtailed. Points d, e and f replicate this example for a capital cost of $450/kW and production costs are $3.45/kg, $1.72/kg and $0.63/kg, respectively.

The operating capacity factor is also important, especially for applications with standalone intermittent renewables where capacity factors could be low, or where a share of operation takes place at very low electricity costs. A reduction in the operating capacity factor impacts the number of hours an electrolyser runs. This impacts the cost of hydrogen production (per kilogram) by reducing output relative to the fixed operating costs, which includes paying off capital costs. As most other components of fixed operating costs are minor, this relationship can be captured by dividing capital costs with the operating capacity factor, as specified in equation 5. This provides a linear relationship where halving the capacity factor is effectively the same as doubling capital costs (Figure 4c). For example, both point a and b in Figure 4c produce hydrogen at $2.31/kg. Points c and d replicate this example for lower capacity factors with a production cost of $3.63/kg.

Electrolysers are a modular technology. In practice, it will be possible to upscale/downscale the size of an electrolyser system to achieve a target production cost or daily production level based on the operating capacity factor. This can be calculated using equation 5 when applying a fixed capital cost for the chosen application. This means that a change in the ratio ($\frac{CC}{OCF}$) captures the upscaling/downsizing of an electrolyser system. A target production price will be achieved for lower capacity factors with a higher initial outlay on capital. This can be adapted to determine an optimal size of an electrolyser.

For a given electricity cost, a decrease in the operating capacity factor results in a non-linear increase in the cost of producing hydrogen (shown in Figure 4e). This is due to the relative increase in fixed operational cost compared to the expenditure on electricity. From $3.45/kg (point a in Fig. 4e), the production cost increases to $4.11/kg and $4.72/kg when the capacity factor is decreased from 97% to 45% and 30% (point b and c in Fig. 4e). Note that we use 45% and 30% as they are capacity factors consistent with high grade onshore wind and solar PV in eastern Australia (AEMO, 2020a). Similar comparisons for lower cost electricity a production cost of \$1.72/kg increasing to \$2.38/kg and \$2.99/kg (for points d, e and f in Fig. 4e) and \$0.63/kg increasing to \$1.28/kg and \$1.89/kg (for points g, h and i in Fig. 4e).

Table 2: Regression results – equations 4 to 6

	Explanatory variables	**Total cost of H2 production (\$/kg)**
Equation 4	Constant (β_0)	0.2603***
		(0.03)
	Electricity cost (β_1) [\$/MWh]	0.0577***
		(0.00)
	Capital cost (β_2) [\$/kW]	0.0008***
		(0.00)
	Observations	32
	R-squared	0.998
Equation 5	**Explanatory variables**	**Total cost of H2 production (\$/kg)**
	Electricity cost (β_1) [\$/MWh]	0.0586***
		(0.00)
	Capital cost divided by Operational Capacity Factor (ϑ) [ratio]	0.1168***
		(0.00)
	Observations	240
	R-squared	0.9985
Equation 6	**Explanatory variables**	**Total cost of H2 production (\$/kg)**
	Electricity cost (β_1) [\$/MWh]	0.0577***
		(0.00)
	Capital cost (α) [\$/kW]	0.0017***
		(0.00)
	δ	0.1000
	Operational Capacity Factor (τ) [%]	64.0900***
		(0.14)
	θ	0.9972***
		(0.00)
	Observations	240
	R-squared	1.000

Standard errors in parentheses, *** p<0.01, ** p<0.05, * p<0.1

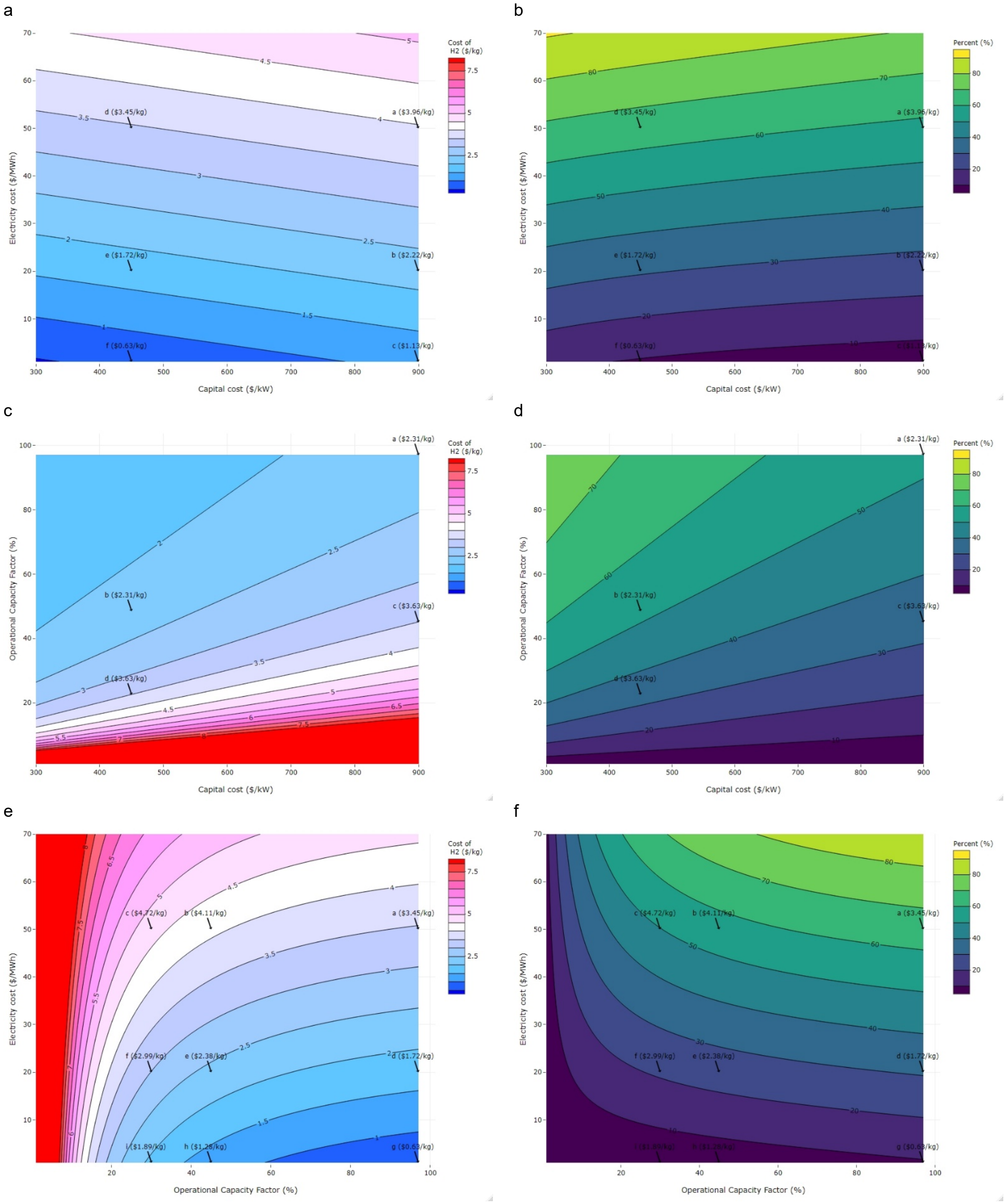

Figure 4 | Cost of hydrogen production.
a,b Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) as a function of electricity cost and capital cost (with operating capacity factor at 97%).
c,d Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) as a function of operational capacity factor and capital cost (with electricity cost at $20/MWh).
e,f Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) as a function of electricity cost and operational capacity factor (with capital cost at $450/kW).

4.3 Achieving low cost hydrogen production with curtailed electricity

Lower cost hydrogen will be produced at co-located solar/wind/electrolyser installations that can capitalise on low cost electricity when curtailment is needed. To compare production costs, we provide reference cases for wind and solar PV, which differ in the operational capacity factor and the curtailment ratio. Again, we assume operational capacity factors of 30% and 45% for solar and wind (AEMO, 2020a). We now combine these with high/moderate levels of curtailment, which are based on example marginal loss factors in eastern Australia (AEMO, 2020d). For a high capital cost, these reference cases coincide with hydrogen production costs of \$4.75-4.92/kg for solar and \$3.77-3.98/kg for wind (Figure 5a). These estimates are for an average cost of electricity of \$30/MWh, curtailment providing electricity at a low-cost of \$1/MWh, and a capital cost of \$900/kW. If we assume that further technological progress is made, as reflected by a reduction in the average electricity cost (\$20/MWh) and capital cost (450/kW and \$250/kW), then the production costs of hydrogen fall to \$2.70-2.82/kg and \$1.99-2.11/kg for solar. For wind the equivalent values are \$2.21-2.35/kg and \$1.74-1.88/kg. This is shown in Figure 5b and Figure 5c.

Assuming the same cost of electricity (i.e. \$30-20/MWh), an improvement in capacity factors by combining wind and solar at high quality sites will result in lower costs. For example, the combined scenarios (with a capacity factor of 55%) have costs falling to \$3.33-3.46/kg (Fig. 5a), \$1.97-2.06/kg (Fig. 5c), and \$1.59-1.68/kg (Fig. 5e). These are presented as best case production costs for co-located solar/wind/electrolyser installations without grid connected electricity.

The achieved operational capacity factors will be site specific and differ based on the size of the electrolyser system compared with the installed solar and wind generation. The capacity of the grid connection will also matter. In practice, the decision of how to co-locate these technologies will need to account for all of these factors simultaneously. The numbers used in this analysis closely match the Central-West Orana Renewable Energy Zone pilot in Australia (NSW Govt, 2020, AEMO, 2020b, AEMO, 2020c), however, a site specific analysis would be needed to specify the optimal size of an electrolyser for this co-located solar and wind site.

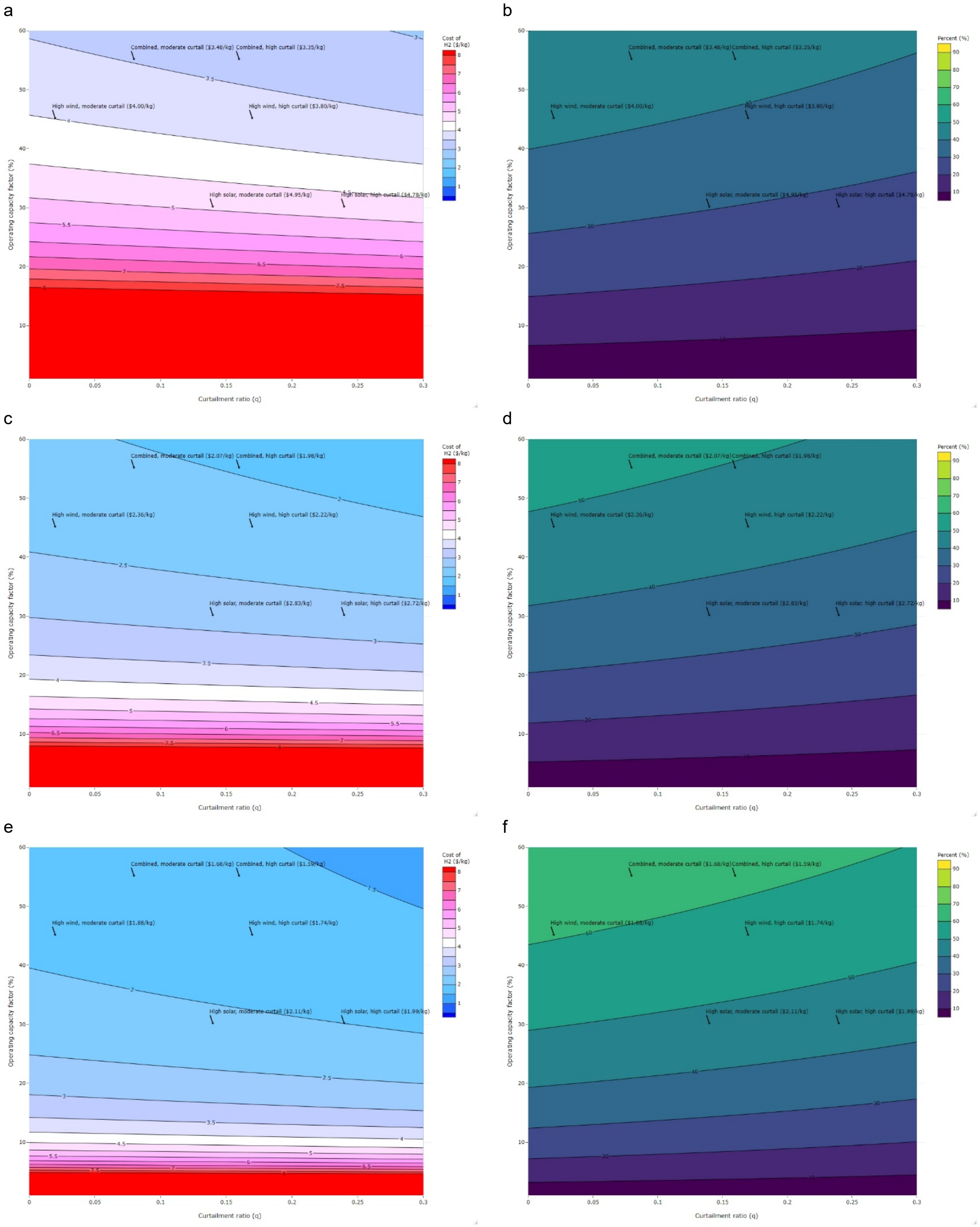

Figure 5 | Production of hydrogen with low cost electricity during curtailment.
a, b Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) with average cost of electricity at $30/MWh, curtailed electricity at $1/MWh and capital costs at $900/kW.
c, d Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) with average cost of electricity at $20/MWh, curtailed electricity at $1/MWh and capital costs at $450/kW.
e, f Production cost of hydrogen ($/kg) and percent of production cost due to expenditure on electricity (%) with average cost of electricity at $20/MWh, curtailed electricity at $1/MWh and capital costs at $250/kW.

5 Discussion - conditions needed to achieve cost competitiveness

5.1 Reference prices of hydrogen needed to achieve cost competitiveness

Assessing hydrogen production cost levels requires a notion of price levels at which hydrogen would be cost competitive with other fuels in relevant end use applications. Here we compare the cost of producing hydrogen to comparison fuels based on the equivalent energy embodied in each fuel. Reference prices of cost competitiveness correspond to specific end-uses (as shown in Table 3). The reference fuel prices do not include any taxes, which explains the low value of the reference price for diesel fuel. These end-uses are liquefied hydrogen for heavy fuel-cell vehicles ($4.50/kg), blending hydrogen in natural gas pipelines for residential use ($2.50/kg), ammonia used in co-fired power generation ($1.80/kg), and ammonia in industrial uses, including fertilisers ($1.50/kg).

Note that IEA (2019) found similar reference prices when converting current fuel prices into hydrogen-equivalent prices on the basis of energy and efficiency. Based on energy content, the reference prices for gasoline used in cars, diesel used in trucks and natural gas used in homes were $5.00/kg, $3.47/kg, and $2.53/kg, respectively. Using relative efficiency, these reference prices were $9.71/kg, $6.84/kg, and $2.48/kg (IEA, 2019). For the case of diesel, we have also calculated a conversion using the improved efficiency of a fuel cell vehicle, which results in a reference price of hydrogen over $8/kg. However, we use the $4.50/kg reference price as the use of hydrogen in the transport sector will have additional costs associated with new refuelling infrastructure.

We do not account for the impact of competing technologies or the cost of conversion and storage, so the cost of hydrogen production needs to be lower than these reference prices by a notable margin. Indicative USD values from the Australian Hydrogen Roadmap are $0.21-0.38/kg for compression, $1.83-2.24/kg for liquefaction, and $0.99-1.20/kg for Haber Bosch conversion of hydrogen to ammonia. This estimate for conversion to ammonia does not account for an energy penalty of about 8 kWh/kg H_2. Transport costs for movement by truck range from $0.24/tkm NH_3 (for ammonia), $0.66/tkm H_2 (for liquefaction) to $1.66/tkm H_2 (for compression). For movement by rail these costs are $0.03/tkm NH_3, $0.20/tkm H_2, $0.39/tkm H_2, respectively. For more detail on these costs, refer to the Australian

Hydrogen Roadmap (CSIRO, 2018). The Hydrogen Council also provided estimates for shipping liquid hydrogen between countries, which include the cost of liquefaction, terminals and shipping. For liquid hydrogen this was $60/MWh compared to $12/MWh for LNG (Hydrogen Council, 2020).

As the addition of carbon prices will assist the cost-competitiveness of green hydrogen, we have also provided the additional cost that would be incurred if a carbon price of $10t/CO2 were applied to the traditional reference fuel. Note that there can be notable emissions at the conversion stage when fossil-fuel based energy is used to liquefy or compress hydrogen or as part of the Haber Bosch process. Our analysis does not account for these types of emissions as our focus is on the use of renewables and production of hydrogen from electrolysis. At the moment, low-carbon hydrogen certification schemes account for emissions from the feedstock and the production of hydrogen, but most do not account for the emissions associated with conversion and reconversion (White et al., 2021).

Table 3: Comparison costs of fuels and computation of end-use reference prices

Traditional fuel type and comparison price	Example fuel prices	Energy conversion to hydrogen equivalent	Reference end-use	Reference price of hydrogen (without carbon price) ($/kg)	Impact of a carbon price of $10/tCO2 on reference price ($/kg)	Emission intensity of reference fuel (kg CO2/ kg H2)
Diesel at $0.60/l	**United States:** Min. $0.30/l, Median $0.60/l, Max. $0.89/l August 2010 to August 2020 (EIA, 2020a) **Eurozone:** Min. $0.40/l, Median $0.68/l, Max. $0.93/l August 2010 to November 2020 (EC, 2020) **Australia:** Min. $0.27/l, Median $0.60/l, Max. $0.77/l August 2010 to November 2020 (AIP, 2020)	7.47 litres of diesel per kg H2 (Commonwealth of Australia, 2019)	Liquefied hydrogen for heavy fuel-cell vehicles	4.48	0.08	8.39 (DEE, 2019)
Natural gas at $21.29/GJ	**United States:** Min. $8.74/GJ, Median $12.32/GJ, Max. $19.58/GJ August 2010 to August 2020 (EIA, 2020b) **European Union:** Min. $18.42/GJ, Median $21.29/GJ, Max. $22.67/GJ 2011 to Q2 2020 (EuroStat, 2020) **Australia:** Min. $15.35/GJ, Median $22.52/GJ, Max. $24.92/GJ 2011 to 2020 (IPART, 2020)	0.12 GJ of natural gas per kg H2 (Commonwealth of Australia, 2019)	Blending hydrogen in natural gas pipelines for residential use	2.55	0.06	6.17 (DEE, 2019)
Liquid Natural Gas (LNG) at $5.85/MMBtu	**United States:** Min. $2.95/MMBtu, Median $4.32/MMBtu, Max. $9.07/MMBtu February 2016 to June 2019 (OFE, 2020) **Japan:** Min. $2.60/MMBtu, Median $7.50/MMBtu, Max. $18.30/MMBtu March 2014 to September 2020 (METI, 2020) **LNG Japan/Korea Marker Futures:** Min. $2.00/MMBtu, Median $5.85/MMBtu, Max. $13.15/MMBtu November 2018 to December 2022 (ACCC, 2020)	0.30 MMBtu of LNG per kg H2 (Australian Hydrogen Strategy Group, 2018)	Ammonia used in co-fired power generation	1.78	0.11	10.99 (Robert, 2020)
Ammonia at $250/tNH3	**United States:** Tampa contract price $250.00/tMH3 early 2020 (ICIS, 2020)	5.79 kg NH3 of ammonia per kg H2 (CSIRO, 2018)	Ammonia in industrial uses, incl. fertilisers	1.45	0.10	9.69 (Smith et al., 2020)

5.2 Conditions that achieve cost competitiveness

As previously noted, the cost effectiveness reference prices are for liquefied hydrogen for heavy fuel-cell vehicles ($4.50/kg), blending hydrogen in natural gas pipelines for residential use ($2.50/kg), ammonia used in co-fired power generation ($1.80/kg), and ammonia in industrial uses, including fertilisers ($1.50/kg). As a comparison, the Japanese Hydrogen Roadmap has target prices for a landed cost of hydrogen of $3/kg for 2030 and $2/kg for post-2030 (METI, 2019). The second of these was based on LNG, which is used for power generation. $2/kg is also a target for cost competitiveness set by the US Department of Energy for the levelised cost of hydrogen at the plant gate (US Department of Energy, 2015). All of the hydrogen production cost figures in this paper can be compared to these reference prices of hydrogen. But as our central focus is on producing green hydrogen, we focus on the results for the case of a co-located solar/wind and electrolyser installation (Figure 6).

Our focus is also on the production costs of hydrogen from a PEM electrolyser. This means that we do not account for the cost of conversion, storage or transport. The cost of hydrogen production needs to be lower than these reference prices by a notable margin. Reducing conversion, storage and transport costs will be needed to ensure cost competitiveness, especially for cases with long-term storage and when transport distances are large. This is especially the case for the export of hydrogen, which is discussed in numerous national roadmaps and strategies. In many cases, additional infrastructure will be needed at the point of end-use, such as refuelling stations for transport applications.

Cost competitive production of green hydrogen is viable in the near-term future when considering applications in the transport sector. Co-located sites with high solar and wind potential can produce hydrogen below $4.50/kg as long as electricity costs are below $45/MWh (Figure 6). While we do not account for the relative cost of fuel-cell vehicles (compared to diesel vehicles), adding a cost of carbon will improve cost competitiveness as there would be an additional cost of carbon of $0.08/kg with a carbon price of $10/tCO2 applied to diesel fuel.

For other applications to be cost competitive there will need to be further cost reductions in both the capital cost of electrolysers and average electricity costs. Cost-competitiveness with respect to the use of natural gas in households occurs with low electricity costs and improves with decreases in capital costs (Figure 6).

However, cost-competitiveness with ammonia and LNG will need a sizable carbon price applied (Figure 6). The reference prices for these fuels is low (<$1.80/kg). And while low electricity and capital costs could achieve hydrogen costs below $1.80/kg, these production costs do not account for the Haber-Bosch conversion process, which will add an additional cost of $1/kg or more based on the Australian Hydrogen Roadmap (CSIRO, 2018). For these two ammonia based reference end uses, we calculated an additional cost of carbon of $0.10-0.11/kg using a carbon price of $10/tCO2. This means that a carbon price of greater than $90/tCO2 would be needed to offset the cost of the Haber-Bosch conversion process and achieve cost-competitive green hydrogen production with respect to ammonia and LNG. Note that the Japanese Hydrogen Roadmap target price of $2/kg was set using a cost of LNG at $10/MMBtu, which is higher than our fuel price (Table 3), and a carbon price of $44/tCO2 (METI, 2019).

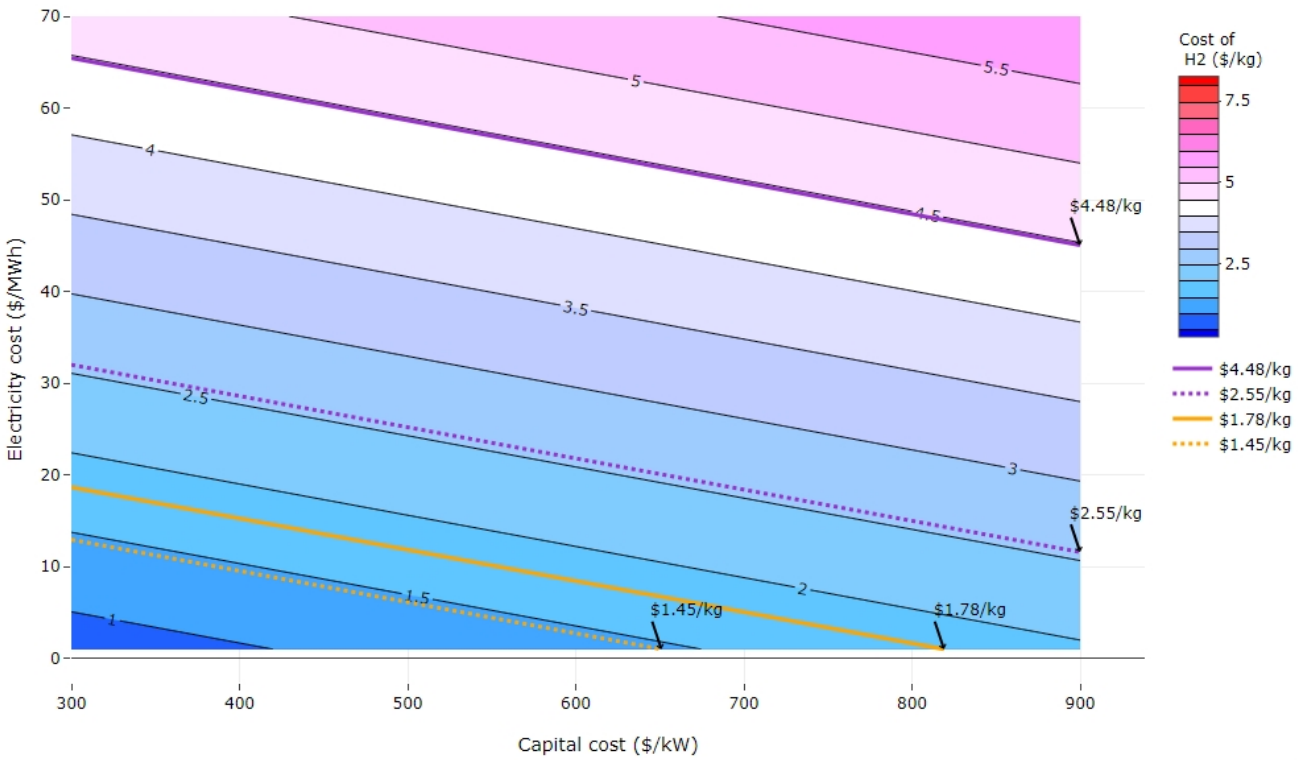

Figure 6 | Combinations that achieve cost competitiveness using end-use reference prices.
Liquefied hydrogen for heavy fuel-cell vehicles – end-use reference price of $4.48/kg
Blending hydrogen in natural gas pipelines for residential use – end-use reference price of $2.55/kg
Ammonia used in co-fired power generation – end-use reference price of $1.78/kg
Ammonia in industrial uses, incl. fertilisers – end-use reference price of $1.45/kg

6 Conclusion

In this paper we have developed reduced form equations that capture the underlying dynamics of existing structural models of hydrogen production via electrolysis. We presented a range of specifications that can be used to specify hydrogen production costs for both Proton Exchange Membrane (PEM) and Alkaline (AE) electrolysers. These equations are highly adaptable and could be applied in a range of modelling or evaluation exercises. They simultaneously account for capital costs, the cost of electricity, curtailment, and the operating capacity factor. All of the details needed to apply the calibrated equations are provided. We use them to identify the conditions needed to establish cost-competitive green hydrogen production. And we analyse the case of electrolysers co-located with solar/wind power generation where it is possible to capitalise on low-cost or zero-cost electricity when curtailment is needed.

Low cost electricity and continued capital cost declines are needed to make the production of green hydrogen commercially competitive. We assessed cost competitiveness by comparing fuel costs adjusted for energy intensity. These fuel costs are the incumbent energy carriers that will compete with the application of hydrogen in transport, power and industrial sectors. We find that applications of hydrogen in transportation are much closer to cost competitiveness than power generation. Whether this happens will depend upon the cost and demand for fuel cell vehicles. This in turn will be impacted by the diffusion of battery electric vehicles and the availability and cost of fuel cell vehicles and related infrastructure. Accordingly, we expect that the most viable early applications of green hydrogen will be in freight (or heavy) transport when refuelling infrastructure can be centralised or in remote applications where fuel costs are high.

Whether substantial capital cost reductions will occur by 2030 or afterwards will depend on the diffusion of electrolysers and the realised experience rate on the cost of capital. Until this happens, an initial step for countries with abundant solar and wind resources, such as Australia, will be pairing solar/wind installations with electrolysers to capitalise on low cost electricity when curtailment is needed. The hydrogen produced would reduce the need for fossil fuel based hydrogen in the lead up to large scale hydrogen production. There are many viable solar and wind sites across Australia with opportunities for capacity factors above 30%. And as the renewable share of an electricity grid increases, accounting for curtailment is increasingly important as reflected by the recent marginal loss factors in Australia.

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8 Supplementary material

8.1 Conversion from PEM costs to AE costs

Other than the materials used, the key differences between a PEM and AE electrolyser are the level of capital costs, the electricity usage per kg H2 produced, the load flexibility, and durability. The current capital cost of an AE electrolyser is lower than that for PEM. However, there are some expectations that this gap will decrease and with research/time this could lead to lower costs for PEM electrolysers (CSIRO, 2018, IRENA, 2019). PEM electrolysers are typically more efficient. PEM electrolysers are also have better load flexibility, so they are more suited to applications with variable renewable energy supply or where electrolysers are switched on and off for other reasons (IRENA, 2019, Yates et al., 2020, IEA, 2019, Parra and Patel, 2016, Schiebahn et al., 2015). There is evidence that degradation of the electrolyser stack differs over time for PEM and AE electrolysers. Usually the stack degradation is higher for PEM, which results in greater voltage requirements for the same level of hydrogen production each year. Degradation increases until the stack is replaced. The difference in degradation between PEM and AE has been found to be lower for larger installations (Parra and Patel, 2016). Overall, the key differences affecting hydrogen production costs are efficiency and capital costs (Yates et al., 2020).

We now provide a method for converting our PEM estimates into AE estimates based on the difference in efficiency (kWh/kg) and capital costs ($/kW). Equation S1 defines the difference in hydrogen production costs for PEM and AE electrolysers. The variables included in the specification are the difference in feedstock electricity per kilogram of hydrogen (EPK), the difference in capital cost (DC), and a constant (γ_0).

$$HC_{PEM} - HC_{AE} = \gamma_0 + \gamma_1 EPK + \gamma_2 DC \tag{S1}$$

We developed this equation based on data in Yates et al. (2020), which was developed using a Monte-Carlo analysis of key parameters for AE and PEM electrolysers. It was calibrated using regressions of example point estimates from Yates et al. (2020).

Table S1: Regression results – equation S1

	Explanatory variables	Difference in the cost of H2 production PEM compared to AE ($/kg)
Equation 11	Constant (γ_0)	0.1062***
		(0.00)
	Difference in capital cost (γ_1) [$/kW]	0.0016***
		(0.00)
	Difference in electricity per kilogram of hydrogen (γ_2) [kWh/kg]	0.0725***
		(0.00)
	Observations	81
	R-squared	0.999

Standard errors in parentheses, *** $p<0.01$, ** $p<0.05$, * $p<0.1$

For every $100/kW difference in capital costs there is a $0.16/kg impact on the difference in the production cost of hydrogen for PEM and AE electrolysers (Table S1 and Figure S1). And better efficiency, as reflected by a negative difference in feedstock electricity per kilogram of hydrogen, leads to a reduction in costs of $0.07/kg for every 1 kWh/kg not used. This captures the average cost of electricity used in the Monte-Carlo analysis as the rate of operating expenditure per year for both PEM and AE electrolysis was held constant. This means that γ_2 is a parameter that should be changed when applying this reduced form relationship to an application where the cost of electricity changes. The constant shows that setting the two variables (EPK and DC) equal to zero would penalise PEM production costs by $0.11/kg (compared to AE). This coefficient captures the impact of greater degradation of the stack, which increases the voltage needed over time for PEM electrolysers. Degradation was the only other factor that varied in the Monte-Carlo analysis conducted in Yates et al. (2020) and hence the reduced form estimation captures this in the constant (γ_0).

It has been noted that PEM has better efficiency of up to 3-4 kWh/kg (CSIRO, 2018, Yates et al., 2020), but PEM capital costs are likely to remain at least $110/kW higher than AE based on an expert elicitation (Schmidt et al., 2017). If realised, these values mean that there would be a small difference in hydrogen production costs between PEM and AE electrolysers (point a in Fig. S1). This assumes that capital costs for PEM have caught up with AE. Lower capital costs for PEM would mean that PEM has a cost advantage over AE (eg point b in Fig. S1). But, at the moment, PEM electrolysers are costlier than AE. Based on the mid-points of the PEM and AE capital costs in IEA (2019), the current differential in capital costs is $500/kW. This means that there is a $0.63/kg additional production cost for PEM electrolysis (point c in Fig. S1). This should be kept in mind when reading the results section as the costs presented are for PEM electrolysers. Note that the estimate for γ_2 can also be used to conduct experiments on improvements in the efficiency of PEM and AE electrolysers.

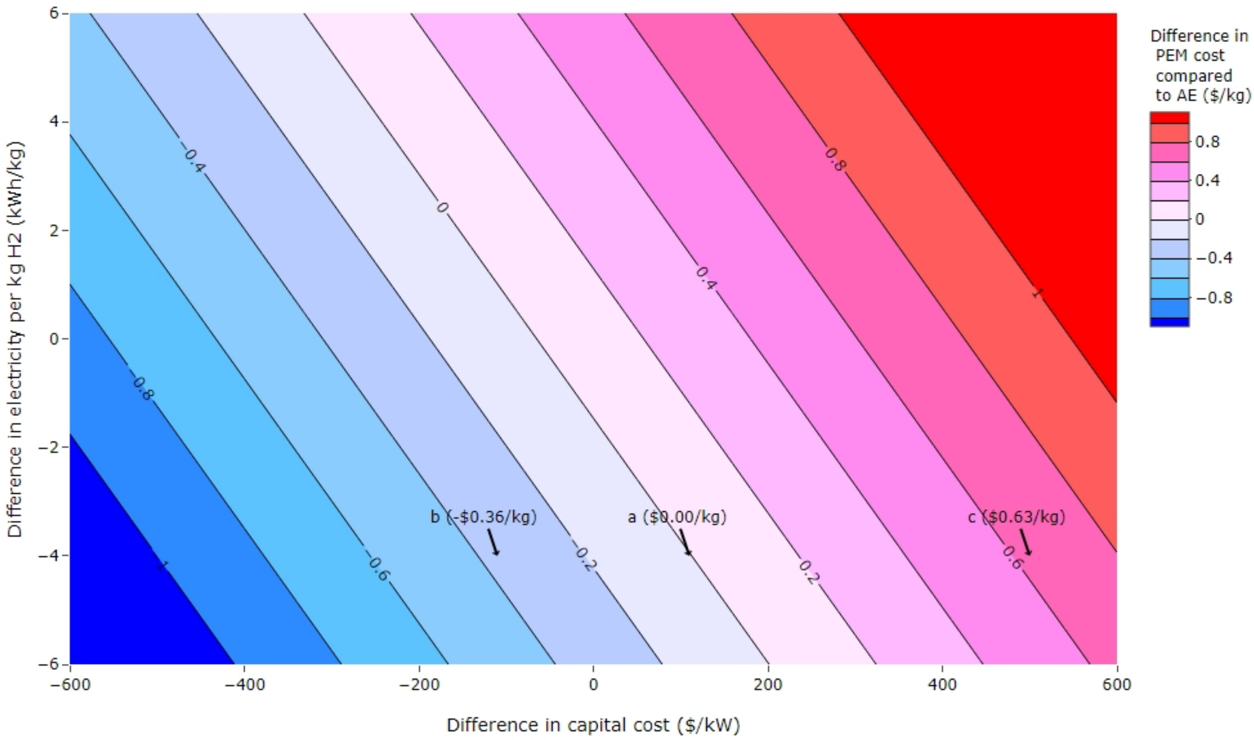

Figure S1 | Difference in hydrogen production costs between a Proton Exchange Membrane (PEM) electrolyser and an Alkaline (AE) electrolyser.
Estimated using data from Yates et al. (2020) and equation S1.