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Advances in power-to-gas technologies: cost and conversion efficiency†

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Widespread adoption of hydrogen as an energy carrier is commonly believed to require continued advances in power-to-gas (PtG) technologies. Here we provide a comprehensive assessment of the dynamics of system prices and conversion efficiency for three currently prevalent PtG technologies: alkaline, polymer electrolyte membrane, and solid oxide cell electrolysis. We analyze global data points for system prices, energy consumption, and the cumulative installed capacity for each technology. Our regression results establish that over the past two decades every doubling of cumulative installed capacity resulted in system prices coming down by 14–17%, while the energy required for electrolysis was reduced by 2%. On the basis of multiple forecasts of future deployment growth, as well as policy and industry targets, our calculations project that all three technologies will become substantially cheaper and more energy-efficient in the coming decade. Specifically, the life-cycle cost of electrolytic hydrogen production is projected to fall in the range of \$1.6–1.9 per kg by 2030, thereby approaching but not reaching the \$1.0 per kg cost target set by the U.S. Department of Energy.

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Broader context

With the transition towards sustainable energy technologies gaining momentum, hydrogen is increasingly considered to be crucial for storing and flexibly delivering large amounts of clean energy. Widespread adoption of hydrogen, however, is expected to depend on substantial advances in power-to-gas (PtG) technologies that convert renewable electricity to hydrogen. To accelerate the speed of such improvements, governments worldwide have recently introduced sizable subsidy programs for the development, manufacturing, and deployment of hydrogen equipment. This paper provides a comprehensive assessment of the dynamics in system prices and energy efficiency for three prevalent PtG technologies: alkaline, polymer electrolyte membrane, and solid oxide cell electrolysis. By tracking global data points for system prices, energy consumption, and the cumulative installed capacity for each technology, our calculations yield significant and robust learning curves of 83–86% for system prices and 98% for energy consumption over the past two decades. Based on these estimates, we project that, over the coming decade, electrolytic hydrogen produced with any of the three technologies will become cost-competitive with traditional hydrogen supply derived from fossil fuels. Specifically, the life-cycle cost of electrolytic hydrogen production is projected to approach the \$1.0 per kg cost target set by the U.S. Department of Energy.

1 Introduction

In the intensifying debate about alternative pathways for rapid decarbonization, hydrogen is increasingly viewed as a critical building block for storing and flexibly dispatching large amounts of carbon-free energy.[1–4] Among alternative hydrogen production technologies, power-to-gas (PtG) in the form of electrolytic hydrogen has received particular attention.[5–7] Large-scale deployment of these technologies, however, is generally expected to hinge on substantial cost declines and energy conversion improvements. To accelerate the pace of these improvements, governments around the world have recently introduced significant regulatory initiatives and subsidy programs for the development, manufacturing, and deployment of hydrogen equipment.[8,9]

This paper projects cost and conversion efficiency improvements for three prevalent PtG technologies: alkaline, polymer electrolyte membrane (PEM), and solid oxide cell (SOC) electrolysis. Our analysis is grounded in a learning-by-doing model that postulates that system prices for electrolyzers and their conversion efficiency decline at a constant rate with every doubling of cumulative installments of the technology in question. Such learning models have proven highly descriptive in the context of solar photovoltaics,[10,11] onshore wind turbines,[12–14] or lithium-ion

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batteries.[15–17] Scarcity of data has so far limited the estimation of learning curves to alkaline electrolysis[17–20] or to a single equipment manufacturer,[21] resulting in learning estimates with low predictive power. Some earlier studies estimate the rate of past cost declines of PtG technologies against time[22–24] or rely on expert opinions about future cost developments.[25–27] Both approaches presume that technological progress is an exogenous function of time instead of an endogenous process driven by the rate of technology adoption.

Our analysis provides the first comprehensive assessment of the dynamics in system prices and energy efficiency for the three PtG technologies by tracking global observations on investment expenditures and energy consumption. This information is linked to capacity installations at facilities commissioned worldwide between 2000–2020. Our estimates return significant and robust learning curves for system prices in the range of 83–86%. Thus, system prices declined by 14–17% compared to the price levels prior to the doubling of cumulative installments. The relatively young SOC technology is projected to show the sharpest price decline at a 17% learning rate. PEM electrolyzers, in contrast, have experienced high capacity growth and a rapid price decline between 2003 and 2020. Here, our estimates yield a relatively slow learning rate of 14%. For conversion efficiency, we estimate that every doubling of cumulative installed capacity reduces the required kilowatt-hours (kWh) per kilogram (kg) of hydrogen produced by approximately 2% across all three technologies.

Our regression results can be extrapolated to yield forecasts for the system prices and conversion efficiencies of the three PtG technologies in question by the year 2030. For divergent growth forecasts issued by different industry and policy sources, the extrapolated values fall into ranges that are substantially narrower than most earlier estimates.[24,25,28–39] These calculations, in turn, lead us to conclude that electrolytic hydrogen production will become widely cost-competitive with traditional hydrogen supply based on fossil fuels. Furthermore, we find that the *Hydrogen Shot* target by the U.S. Department of Energy[9] of producing clean hydrogen at a cost of $1.0 per kg by 2030 is ambitious but not unrealistic. Because electricity prices will become the dominant component of the life-cycle cost of hydrogen by 2030, the attainment of the *Hydrogen Shot* target *via* electrolytic hydrogen ultimately hinges on the availability of inexpensive and clean electricity.

2 Learning curve estimates

Our analysis considers the three electrolyzer technologies alkaline, PEM, and SOC. For each of these technologies, modules combine electrolysis stacks with so-called balance-of-system components.[40] A stack broadly consists of multiple cells where electricity splits water molecules into hydrogen and oxygen. Power electronics, heat and fluid management, and hydrogen treatment comprise the balance of system.[41] Our analysis excludes the pressurization of hydrogen *via* compressors.

In addition to the acquisition price, the system price for a PtG system reflects project development and installation costs. Since PtG systems have been procured through customized manufacturing contracts in the past, some reductions in system prices have emerged from early efforts to standardize and automate production processes along with increased manufacturing capacity.[25,42,43] Technological improvements have further allowed manufacturers to build larger systems, cut production waste, and save on material costs. Examples of such innovations include better electrode design and bipolar plates, as well as replacing expensive, custom-made components with commercially available ones.[41,42,44,45]

The conversion efficiency of a PtG system is measured in the electricity in kWh required to produce one kg of hydrogen. This includes the energy required for the electrolytic production process but excludes the energy needed for heat management. Initial improvements in energy consumption have resulted from larger stacks with a better distribution of current density across the reactive surface area, lower system complexity, and improved system integration.[17,41] For PEM electrolyzers, new materials have enabled thinner membranes and more active catalysts at the cell level.[44]

Our global data collection effort tracks system prices, the energy consumption of the PtG systems, and capacity installations at the corresponding facilities for the years 2000–2020. As detailed in the ESI,† the information collected in our database stems from multiple sources, including manufacturers, industry databases, academic articles in peer-reviewed journals, and technical reports by agencies, consultancies, and industry analysts. In particular, information on system prices is based on two earlier reviews[24,39] and a replication of the analyses performed therein (details in Note S2, ESI†). Our search yielded 176 sources, primarily European and North American, containing 264 unique observations from industry or an original review of multiple sources. Of these observations, 105 pertain to alkaline electrolysis over the years 2003–2020, 81 to PEM system between 2003–2020, and 78 to SOC technology spanning the years 2011 to 2020. To focus on recent technological developments, we excluded sporadic estimates for alkaline systems that became available prior to the year 2000.[17–19]

Our data set of cumulative installed capacity is primarily based on the *Hydrogen Projects Database* by the International Energy Agency[46,47] (details in Note S3, ESI†). This database includes production facilities that have been commissioned worldwide since 2000 for the generation of clean hydrogen and hydrogen derivatives. In addition, we conducted our own review of hydrogen projects based on industry announcements and media coverage. Our final data set comprises 430 complete entries, of which 225 represent PtG facilities based on either alkaline, PEM, or SOC technology that were built worldwide between the years 2000–2020. Of these projects, 99 are alkaline electrolysis systems, 112 projects comprise PEM electrolyzers, and 14 facilities are based on SOC technology. The resulting total cumulative installed capacity across the three PtG technologies amounts to about 200 Megawatt (MW) in 2020, a figure that is consistent with recent industry estimates.[41,48] Information on specific energy consumption stems from the preceding two reviews (details in Note S4, ESI†). This information includes 130 data points for alkaline systems over the years

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2000–2020, 78 for PEM systems between 2005–2020, and 21 for SOC systems across 2011–2020.

For each PtG technology, the learning effects are assumed to conform to a constant elasticity learning model. Accordingly, both system prices and energy consumption are a function of the cumulative installed capacity of the particular technology.[49] Let ν_i denote the system prices per Watt (W) of peak power absorption of a technology in year i and Q_i the cumulative installed capacity of a technology in kilowatt (kW) in year i. In logarithmic form, we estimate the equation:

$$\ln(\nu_i) = \beta_0 + \beta_1 \ln(Q_i) + \mu_i, \qquad (1)$$

where β_1 denotes the learning elasticity parameter and μ_i is an idiosyncratic and unbiased error term. Eqn (1) predicts that with every doubling of installed cumulative electrolyzer capacity, the system price of a PtG technology declines to 2^{β_1} of its previous value. A parallel equation is used to estimate the learning factor of a technology's conversion efficiency.

Alkaline electrolyzers currently exhibit the highest cumulative installed capacity and the lowest average system prices at \$0.9 per W (Fig. 1a–c, details in Note S5, ESI†). The reduction in system prices across the years 2003–2020 corresponds to a learning factor of 2^{β_1} = 84.3% with a 95%-confidence interval of 2.7% ($p < 0.0001$, adj. $R^2 = 0.51$). This implies that system prices declined by 15.7% with every doubling of cumulative installed capacity. As of today, SOC electrolyzers, in contrast, have the lowest cumulative installed capacity and the highest system prices at \$2.3 per W in 2020. Yet, they also exhibit the fastest price decline, described by a learning factor of 83.3 ± 6.5% across the years 2011–2020 ($p < 0.0001$, adj. $R^2 = 0.24$). PEM electrolyzers experienced a sharp decline in system prices from \$8.3 per W in 2003 to \$1.1 per W in 2020 but also rapid growth in cumulative installed capacity from less than 0.1 to almost 100 MW. The resulting learning factor amounts to 86.2 ± 1.7% ($p < 0.0001$, adj. $R^2 = 0.74$).

In terms of energy consumption, alkaline systems have exhibited improvements from above 60 kWh per kg in the early 2000s to 52 kWh per kg in 2020 (Fig. 1d–f, details in Note S5, ESI†). Similarly, PEM electrolyzers have witnessed a decline from above 70 kWh per kg in the early 2000s to 57 kWh per kg in 2020, while the SOC technology improved from above 50 kWh per kg in 2011 to around 42 kWh per kg in 2020. Despite the differences in absolute values, our regression analysis yields very similar learning factors for the three PtG technologies. Specifically, the estimated learning factors are 98.3 ± 0.9% ($p < 0.001$, adj. $R^2 = 0.08$) for alkaline, 98.3± 0.9% ($p < 0.001$, adj. $R^2 = 0.15$) for PEM electrolyzers, and 98.4± 2.3% ($p < 0.2$, adj. $R^2 = 0.08$) for the SOC technology.

To examine the robustness of our learning curve estimates, we first examine the potential effect of changes in the size of PtG systems on the development of system prices. Earlier work suggests that the acquisition price of PtG systems declines at a diminishing rate as the capacity size of the system increases.[22,23,40] While information on system sizes available to us is largely disconnected from the data on system prices, we nevertheless examine multiple

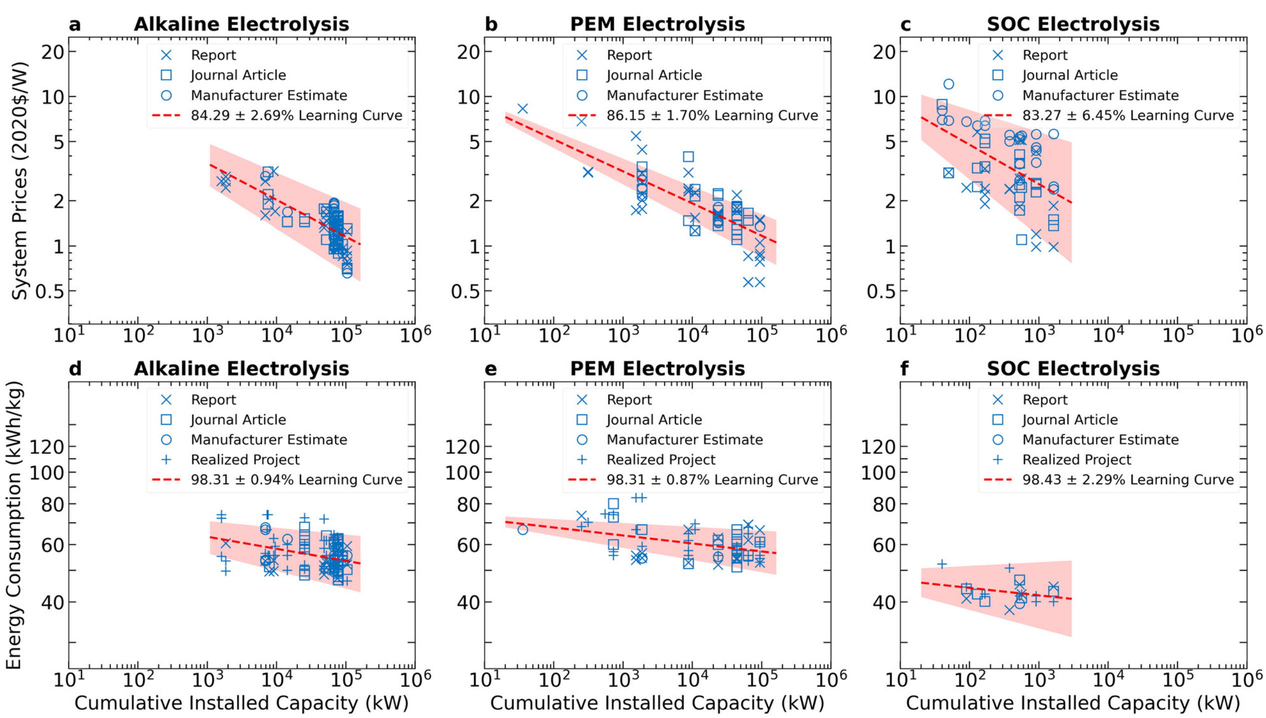

Fig. 1 Estimates of learning curves. This figure plots the global system prices in 2020 \$US against the global cumulative installed capacity together with our estimates of the corresponding learning curves for (a) alkaline, (b) PEM, and (c) SOC electrolyzers. The figure also plots the energy consumption against the global cumulative installed capacity together with our estimates of the corresponding learning curves for (d) alkaline, (e) PEM, and (f) SOC electrolyzers. Areas shaded in red represent 95%-confidence intervals. Detailed regression results are provided in Note S5 (ESI†).

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different specifications for estimating the potential effect of changes in the size of PtG systems on the trajectory of system prices (details in Note S6, ESI†). The results point towards significant and robust learning coefficients for cumulative installed capacity and a limited effect of capacity sizes. This finding is consistent with studies examining the cost dynamics of onshore wind turbines,[12–14] solar photovoltaic modules,[10,11] or lithium-ion batteries.[15–17] It is also consistent with the observation that scale economies of PtG plants appear to level off as system sizes exceed a particular threshold.[22,23,34]

Earlier studies have shown that learning curve estimates can be sensitive to the chosen time window.[10] We, therefore, repeat the estimation of learning curves for alkaline and PEM electrolyzers covering the years 2010–2020 to examine the most recent developments in system prices and conversion efficiencies. As detailed in Note S7 (ESI†), the learning curves for alkaline electrolyzers improve slightly in terms of both system prices and conversion efficiencies. For PEM electrolyzers, the learning curves for both system prices and energy consumption remain almost unchanged. For both technologies, the 95%-confidence intervals of both learning estimates increase due to smaller sample sizes.

Some components of PEM electrolyzers, such as the catalysts, porous transportation layers, and bipolar plates, currently comprise rare earths materials, primarily platinum and iridium. To estimate the potential effect of changes in the market prices of both metals, we calibrate an extension of eqn (1) for PEM systems that includes the annual average global market price for each metal as an additional regression coefficient. As detailed in Note S8 (ESI†), the regression result shows that the learning elasticity of cumulative installed capacity remains unaffected, while the estimated coefficients for both metals are economically and statistically insignificant. Yet, we note that industry observers have pointed out that a rapid increase in PEM electrolyzer production could lead to temporary shortages of these metals.

Earlier studies on the decline in the system prices of alkaline electrolyzers have estimated learning parameters between 82–84% with a 95%-confidence interval of ±6–13%.[17–19] While these values are similar in magnitude to our estimate for alkaline electrolyzers (Fig. 1a), the larger number of observations in our analysis yields a much tighter 95%-confidence interval at ±2.7%. Aside from sample size, the lower variance in our sample is also likely to reflect standardization in the product offering of electrolysis equipment manufacturers, particularly for alkaline and PEM systems.

An alternative approach to learning curves based on cumulative installed capacity is to estimate technological progress as a function of time. As detailed in Note S9 (ESI†), our regressions return annual declines in system prices of 6.0 ± 1.0% for alkaline over the years 2003–2020 ($p < 0.0001$, adj. $R^2 = 0.56$), 12.6 ± 1.4% for PEM between 2003–2020 ($p < 0.0001$, adj. $R^2 = 0.77$), and 10.6 ± 4.2% for SOC electrolyzers covering 2011–2020 ($p < 0.0001$, adj. $R^2 = 0.25$). Furthermore, we identify annual reductions in energy consumption of 0.8 ± 0.4% for alkaline across the years 2000–2020 ($p < 0.0001$, adj. $R^2 = 0.11$), 1.4 ± 0.7% for PEM electrolyzers across 2005–2020 ($p < 0.0001$, adj. $R^2 = 0.15$), and 1.0 ± 1.4% for the SOC technology between 2011–2020 ($p < 0.15$, adj. $R^2 = 0.07$).

Earlier studies[24,39] have estimated the annual decline in system prices at 3.0% for alkaline and 4.8% for PEM electrolysis covering the years 2003–2016, and at 9.0% for SOC electrolysis based on data for the years 2011–2019. We attribute the faster estimate regarding price declines emerging from our analysis to the impact of the most recent price observations. At the same time, we note that the estimate for PEM electrolyzers might be somewhat over-optimistic due to the relative richness of observations with lower system prices in recent years. We are not aware of previous studies examining changes in the conversion efficiency of PtG systems.

3 Extrapolating future performance

Based on the learning estimates in Fig. 1, we now project trajectories for future system prices and energy consumption for each PtG technology. Our projections consider three alternative scenarios to compare different growth scenarios for electrolyzer installations over the coming years.

The first scenario (called ''Past Growth'') examines the possibility that the cumulative installed capacity for each technology continues to grow at the same rate as observed on average in the past. To estimate this rate, we ran for each technology a univariate regression based on the constant elasticity functional form: $\ln(Q_i) = \lambda_0 + \lambda_1 \cdot i + \varepsilon_i$. The regressions yield an estimate for the annual growth of $e^{\lambda_1} - 1 = 42.8\%$ for alkaline electrolysis covering the years 2000–2020 ($p < 0.001$, adj. $R^2 = 0.83$), 76.0% for PEM systems between 2003–2020 ($p < 0.001$, adj. $R^2 = 0.98$), and 51.0% for SOC technology over 2011–2020 ($p < 0.001$, adj. $R^2 = 0.99$). The resulting estimates of cumulative installed capacity for each technology in 2030 are shown in Table 1 (details in Note S10, ESI†).

The second scenario (called ''Policy Target'') assumes that the cumulative installed capacity of the PtG technologies will grow such that their total in 2030 reaches the sum of individual policy targets for installed capacity. As detailed in Note S10 (ESI†), these targets stem from national hydrogen strategies articulated in recent years and, as of now, amount to about 115 Gigawatt (GW) in total. Since these targets are technology-agnostic and specified for installed capacity, we assume that each technology's share of the total cumulative installed capacity by 2030 is the same as in the Past-Growth scenario. Further, we interpolate the growth in cumulative installed capacity for each technology during the years 2020–2030. Alternative distributions for the technology-specific shares in 2030 have only a small effect on our subsequent findings, especially for alkaline

Table 1 Estimates of cumulative installed capacity by 2030

in MW	Alkaline	PEM	SOC	Total
Past Growth	3670	26 898	100	30 688
Policy Target	13 772	100 861	376	115 009
Industry Target	29 682	217 458	812	247 952

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and PEM electrolysis (see Note S10 for details, ESI†). In addition, we account for capacity depletion by adding in each year from 2021 onward the installed capacity expected to have gone offline until that year based on the installation year and a useful lifetime of 20 years.[24,39] Table 1 provides the resulting estimates, with implied annual growth rates for cumulative installed capacity of 63.4% for alkaline, 101.5% for PEM, and 72.8% for SOC electrolysis.

In direct analogy to the second scenario, our third scenario (called ''Industry Target'') assumes that the cumulative installed PtG capacity grows such that the sum across individual industry targets for installed capacity in 2030 is reached. These targets result from numerous announcements by project developers, hydrogen customers, and industry associations made in recent years and amount in total to about 248 GW. Table 1 shows the resulting estimates for cumulative installed capacity by 2030 for each technology. The implied (interpolated) annual growth rates for cumulative installed capacity amount to 75.9% for alkaline, 117.0% for PEM, and 86.0% for SOC systems.

The resulting trajectories shown in Fig. 2 suggest that the system prices of all three technologies are likely to fall substantially over the coming years. Specifically, our calculations project ranges for system prices by 2030 across the scenarios of \$285–475 per kW for alkaline, \$225–352 per kW for PEM, and \$441–767 per kW for SOC electrolysis. The higher values for SOC electrolysis reflect the relative novelty of the technology and its more complex heat management requirements. We also find that, despite the sizable variation in the growth of cumulative installed capacity across the scenarios, the trajectories of system prices for alkaline and PEM electrolysis stay relatively close to each other. For these two technologies, differences in the number of doublings in cumulative installed capacity across the scenarios are smaller than for SOC electrolysis.

Regarding the energy consumption of PtG systems, our projections for 2030 yield ranges across the scenarios of 47–49 kWh per kg for alkaline, 47–50 kWh per kg for PEM, and 36–38 kWh per kg for SOC technology. Thus, the energy consumption of alkaline and PEM systems is moving towards the target of 42 kWh per kg by 2050 set by the International Renewable Energy Association.[41] The projected reduction for alkaline systems is also consistent with recent advances in capillary-fed electrolysis cells that exhibit a 15% lower power consumption relative to commercially available systems.[50] SOC electrolyzers are likely to approach the theoretical optimum of 33 kWh per kg towards the end of this decade. Analogous to system prices, the trajectories for alkaline and PEM electrolysis stay relatively close to each other.

As a robustness check, we also extrapolate the future performance of PtG technologies based on time. As one would

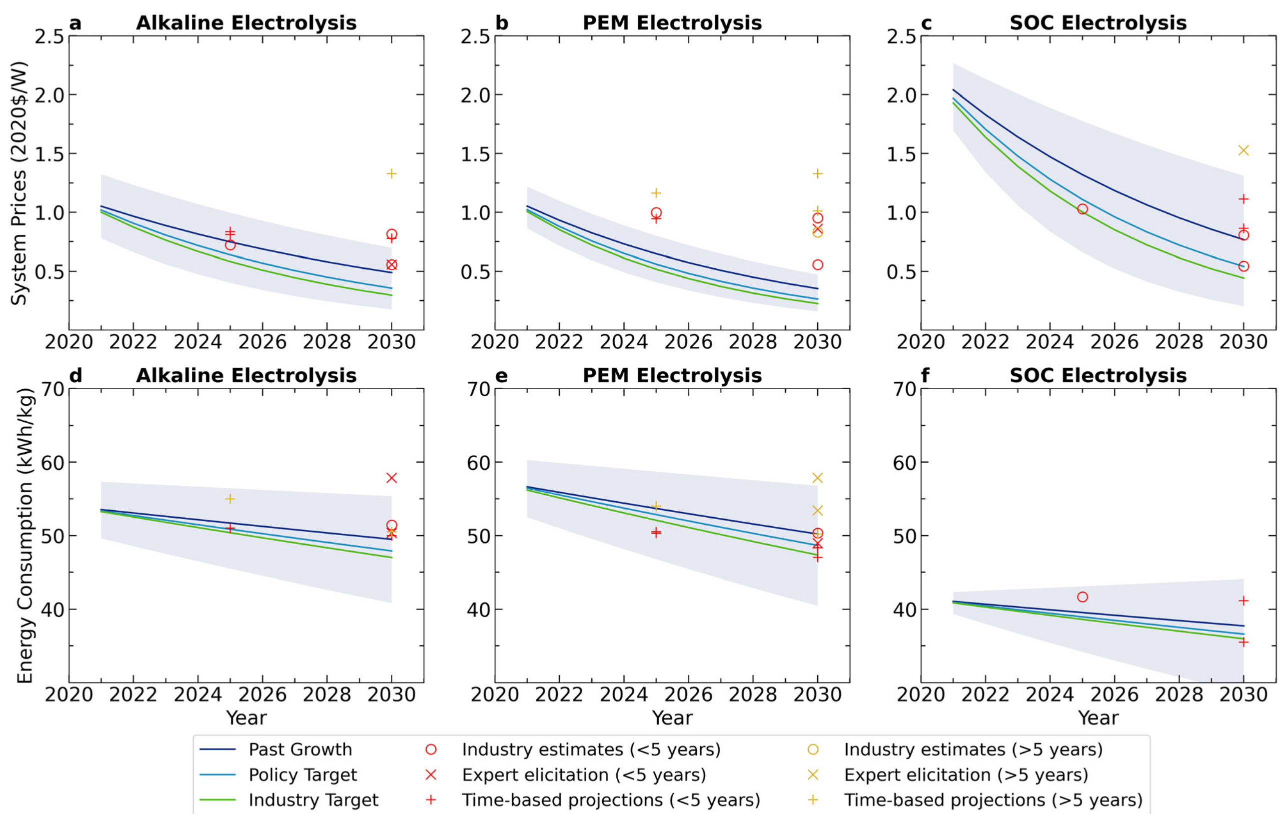

Fig. 2 Prospects for system prices and conversion efficiency. This figure shows our projections for the development of system prices in 2020 \$US for (a) alkaline, (b) PEM, and (c) SOC electrolyzers. It also shows our projections of the potential trajectory of energy consumption for (d) alkaline, (e) PEM, and (f) SOC electrolyzers. Shaded areas represent a joint 95%-confidence interval resulting from the learning curve estimates. Specifically, the upper bounds are derived from the upper bounds of the learning curve estimates in combination with the Past-Growth scenario, while the lower bounds are given by the lower bounds of the learning curve estimates combined with the Industry-Target scenario.

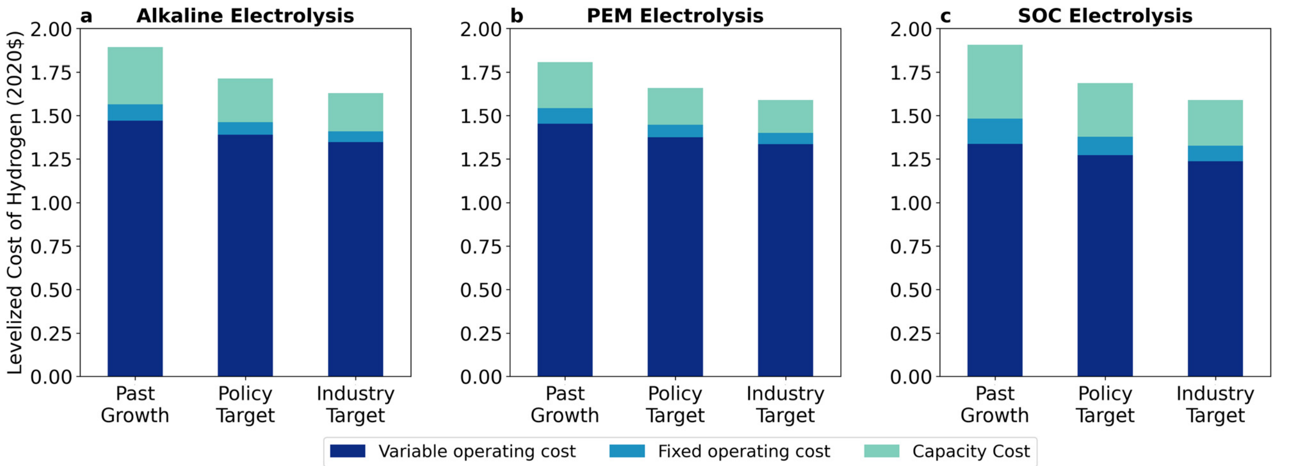

Fig. 3 Estimates of levelized cost of hydrogen by 2030. This figure shows our estimates of levelized cost of hydrogen by 2030 for (a) alkaline, (b) PEM, and (c) SOC electrolyzers for different growth scenarios.

expect, the resulting system prices and energy consumption values are close, if not identical, to the trajectories for the Past-Growth scenario reported in Fig. 2 (details in Note S11, ESI†). An exception to this observation is that the time-based projection for system prices of PEM electrolyzers is closer to the trajectory of the Industry-Target scenarios. We attribute this discrepancy to the large share of lower price observations in recent years. Furthermore, we examine a specification based on time and cumulative installed capacity. As detailed in Note S11 (ESI†), there is high multicollinearity between the two covariates, which weakens the resulting regression estimates. Nevertheless, the projected trajectories for system prices and energy consumption are again close to the Past-Growth scenario in Fig. 2.

Fig. 2 also shows point estimates for future system prices and energy consumption as articulated by industry experts,[28–30] technical reports[31–37] and academic studies.[24,25,38,39] In comparison, our projections for both system prices and energy consumption yield estimates that are consistently and substantially below most of the earlier estimates. We attribute this discrepancy to multiple factors. First, our projections model technological progress not as an exogenous function of time but as an endogenous process driven by deployment rates. In addition, the Policy and Industry Targets suggest a substantial acceleration in the deployment of PtG systems, the magnitude of which is consistent with the projected demand for clean hydrogen by 2030[51] and the ramp-up of manufacturing capacity for PtG systems.[52–54] Finally, our calculations are based on recent global information reflecting the rapid improvements in system prices and efficiencies as well as the observed recent growth in capacity deployments.

4 Levelized cost of hydrogen production

Recognizing the potential of hydrogen as a decarbonized energy source, the U.S. Department of Energy articulated the *Hydrogen Shot* initiative in 2021. According to this initiative, the cost of producing hydrogen is to come down to \$1.0 per kg by the year 2030.[9] The system prices and conversion efficiencies we forecast in Fig. 2 are useful in gauging whether the U.S. Department of Energy's goal appears to be a ''long shot''. To that end, we calculate a life-cycle cost measure termed the levelized cost of hydrogen (LCOH). Analogous to the levelized cost of electricity, the LCOH yields a break-even value for investing in a PtG system. If an investor were to receive the LCOH as the revenue per kg of hydrogen, the investor would exactly break even in terms of future discounted cash flows, including the initial capacity investment and all subsequent operating expenses (details in Economic methods).

Earlier studies have established that, in addition to system prices and conversion efficiency, electricity consumption is a major cost component of electrolytic hydrogen.[39,55,56] Our cost calculations are based on a scenario where the electrolyzer operates as a stand-alone PtG system. The operator can purchase power in the wholesale electricity market, subject to a markup for industrial customers. In optimizing the use of its PtG system, the operator has the option of idling the electrolyzer during those hours when the prevailing market price of electricity is high and, therefore, hydrogen conversion would have a negative contribution margin. Accordingly, we initially consider a simple price vector of 8760 hours, where each entry is calculated as the average across the day-ahead prices observed in the Texas market between the years 2016–2020. Our focus on Texas reflects that the state has deregulated its power market, deployed considerable amounts of renewable energy and hosts several large-scale hydrogen consumers.[57] The resulting annual average electricity purchasing price amounts to 3.6 cents per kWh. Fixed operating costs are estimated as a percentage of system prices and account for the replacement of electrolysis stacks during the life of the system. At the suggestion of manufacturers of SOC systems, our calculations increase the assumed energy consumption of such systems by 5 kWh per kg to account for more complex heat management.

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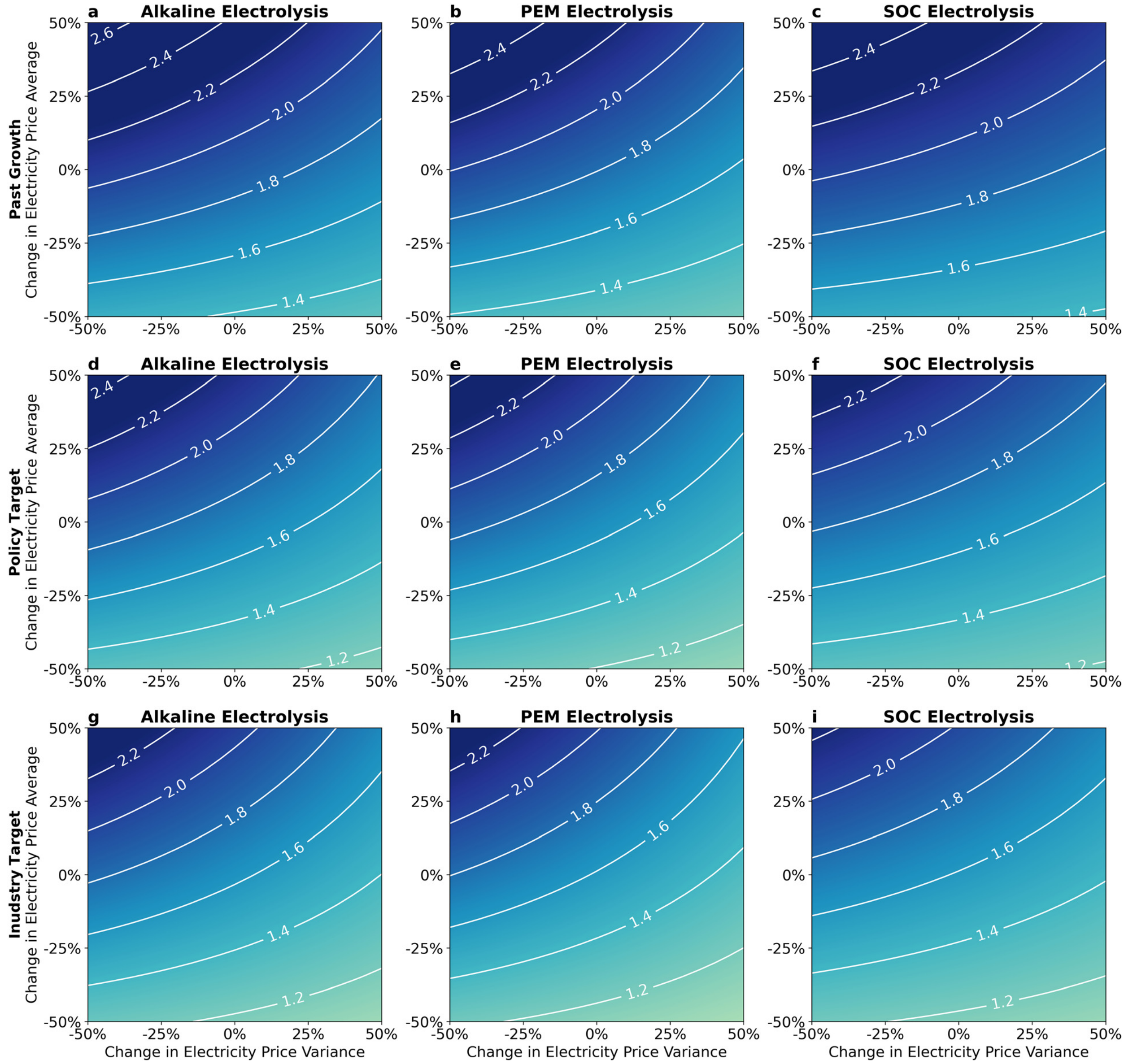

Fig. 4 Sensitivity of levelized cost of hydrogen estimates by 2030. This figure shows the sensitivity of our 2030 LCOH estimates to changes in the annual average and hourly variation of power prices for (a), (d) and (g) alkaline, (b), (e) and (h) PEM, and (c), (f) and (i) SOC electrolyzers for different growth scenarios.

The useful lifetime of a system is set to 20 years and the cost of capital to 5.0% for all technologies (details in Note S12, ESI†).

Depending on the growth scenario, our calculations yield LCOH estimates in the range of \$1.6–1.9 per kg for alkaline, \$1.6–1.8 per kg for PEM, and \$1.6–1.9 per kg for SOC electrolyzers (Fig. 3, details in Note S12, ESI†). The resulting LCOH ranges may appear surprisingly small, given the large variation in the assumed growth rates under the different scenarios. The main reason for the relatively limited LCOH range is that, depending on the electrolyzer technology, the variable cost of electricity accounts for about 70–90% of the total LCOH by the year 2030. Thus, even large differences in system prices and fixed operating costs as well as the assumed lifetime and the cost of capital have only a minor impact on the overall LCOH. In particular, SOC electrolysis is projected to entail similar LCOH values as the other technologies. The cost disadvantage of higher system prices in comparison to alkaline and PEM systems is compensated by the lower energy consumption of SOC electrolyzers.

To examine the sensitivity of our results in Fig. 3, we calculate LCOH values for simultaneous changes in the annual average and the hourly variation of power prices (details in Economic methods). These changes reflect electricity price distributions of economic market environments characterized by different costs and shares of competing power generation sources as well as the amounts and types of electricity demanded. Our calculations return the LCOH estimates shown in Fig. 4. Overall, if the annual average electricity price were to

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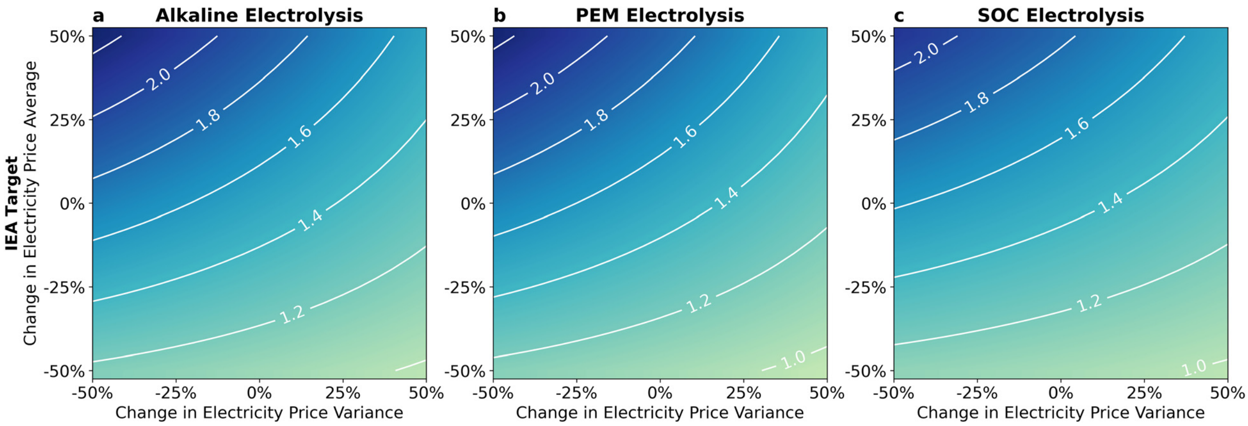

Fig. 5 Sensitivity of levelized cost of hydrogen estimates by 2030. This figure shows the sensitivity of our 2030 LCOH estimates to changes in the annual average and hourly variation of power prices for (a) alkaline, (b) PEM, and (c) SOC electrolyzers for the growth scenario postulated by the international energy agency (IEA).

decline by 50% and the hourly volatility to increase by 50%, the LCOH estimates for each technology and growth scenario would fall by about 30% relative to the values shown in Fig. 3. Conversely, if the electricity price average were to increase, yet hourly volatility were to decrease by 50%, the LCOH estimates would rise by about 40%. These muted range estimates reflect that it is advantageous to idle the electrolyzers only during hours when power prices are relatively high.

5 Policy implications

Our findings on the economics of electrolytic hydrogen speak directly to several recent policy initiatives. First, our estimates of the levelized cost of hydrogen indicate that the *Hydrogen Shot* cost target of \$1.0 per kg by 2030 appears difficult to achieve if electrolyzer deployments grow at the rates underlying our calculations. We note, however, that most data points underlying our Policy and Industry Targets were set prior to the recent hydrogen initiatives by the European Union[8] and the Inflation Reduction Act in the United States.[58] The production tax credit of up to \$3.0 per kg of clean hydrogen available under the Inflation Reduction Act is likely to advance the deployment growth of PtG systems significantly in the United States. This growth will be reinforced by the goal of the European Union that seeks to induce its member states to collectively source 20 million tons of green hydrogen annually by the year 2030.[8]

The level of subsidy support under the recent hydrogen initiatives by the European Union and the United States is tied in both jurisdictions to the carbon intensity of the hydrogen produced. In particular, the production tax credit of up to \$3.0 per kg available under the Inflation Reduction Act declines monotonically as the kg of carbon dioxide (CO_2) per kg of hydrogen produced increases beyond certain threshold levels. Our results in Fig. 3 and 4 allow us to estimate the maximum carbon intensity permissible for the LCOH minus the corresponding subsidy support to be equal to or less than \$1.0 per kg. Absent any changes in the annual average or hourly variation of power prices, we find that all three PtG technologies would need to receive a nominal production tax credit of about \$0.9 per kg in 2030, which allows a carbon intensity of at most 1.5 kg of CO_2 per kg of hydrogen. Yet, if the annual average electricity price were to decrease by about 25% while the hourly volatility increases by about 25%, then the lowest available nominal production tax credit of \$0.6 per kg would be sufficient for all three PtG technologies to achieve the \$1.0 per kg cost target. The corresponding maximal carbon intensity is then 4 kg of CO_2 per kg of hydrogen. These calculations, detailed in Economic methods, take into account that the production tax credit is only paid for the first ten years of operation and, therefore, the levelized tax credit is less than the nominal one.

We also note that even our most ambitious growth scenario for electrolyzer deployment, that is, the Industry Target, falls significantly short of the target for 2030 by the International Energy Agency (IEA). As part of its "Net-zero by 2050" scenario, the IEA postulates 850 GW of installed capacity by 2030 and 3000 GW by 2045.[59] To examine the implications of the IEA target, we first repeat our calculations in the preceding two sections, assuming that the total global installed capacity will reach 850 GW by 2030. The resulting LCOH ranges, reported in Fig. 5, show that the IEA target of 850 GW of installed capacity results in all three PtG technologies reaching LCOH values of \$1.0 per kg if the annual average electricity price were to decline by about 50% and the hourly volatility were to increase by about 50%. Achieving the \$1.0 per kg target with more moderate changes in electricity prices would require even faster growth in the cumulative installed capacity.

Ultimately, a key objective of governmental support programs for hydrogen is to make electrolytic hydrogen production cost-competitive with traditional hydrogen supply based on fossil fuels. Transaction prices for traditional hydrogen supply are segmented primarily by scale (volume) and purity: large-scale supply between \$1.0–2.5 per kg, medium-scale between \$2.5–4.0 per kg, and small-scale above \$4.0 per kg.[24,60,61] These values are applicable benchmarks for hydrogen whenever PtG facilities can be installed onsite or adjacent to a hydrogen buying site. Fig. 4 shows that all three PtG technologies are projected to become widely cost-competitive with industrial-

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scale hydrogen supply, even if cumulative installed capacity grows only at the rates observed on average in the past.

Finally, we emphasize that, regardless of the magnitude of the additional growth in deployments resulting from different policy initiatives, the availability of clean and inexpensive electricity will become increasingly important for electrolytic hydrogen, even if it is only available intermittently. It will, therefore, be essential for policymakers to take advantage of the inherent synergies between renewable power generation and electrolytic hydrogen.

6 Conclusion

Broad adoption of electrolytic hydrogen production will depend on improvements in system prices and conversion efficiency of power-to-gas technologies. This paper provides a comprehensive assessment of the dynamics in both parameters for alkaline, polymer electrolyte membrane, and solid oxide cell electrolyzer systems. Our calculations yield significant and robust learning curves of 83–86% for system prices and 98% for energy consumption over the past two decades. Based on these estimates, we project that all three technologies will become substantially cheaper and more energy-efficient. In particular, the life-cycle cost of electrolytic hydrogen production is projected to fall within \$1.6–1.9 per kg by 2030, approaching the *Hydrogen Shot* target of \$1.0 per kg set by the U.S. Department of Energy.

Future studies on electrolytic hydrogen production would benefit from more detailed information on the manufacturing cost and market prices of individual system parts (*i.e.*, electrolysis stacks and balance-of-system components) that is available for multiple years. They would also benefit from the research and development expenditures and the annual production capacity of equipment manufacturers. Such information could shed further light on the factors driving cost reductions.

It will also be instructive to broaden the line of inquiry in this paper to other technologies for clean hydrogen production, such as anion exchange membrane electrolysis, steam methane reforming with carbon capture and storage, or natural gas pyrolysis. The data available for these technologies has so far been too limited to allow for an analysis similar to the one in this paper. Naturally, such studies will need to reflect that the tax credits available for hydrogen production under the Inflation Reduction Act vary greatly with the assessed carbon intensity of the hydrogen produced.

Finally, future work could examine the cost dynamics of hydrogen compression, transmissions, and storage technologies. These components of the hydrogen supply chain can substantially affect the cost of hydrogen supply, especially when the production and consumption of hydrogen are geographically dispersed. However, the data available for these components have so far been rather limited and heterogeneous.

7 Economic methods

7.1 Levelized cost of hydrogen

In direct analogy to the commonly referenced levelized cost of electricity,[62] the LCOH identifies the constant price per kg of hydrogen that an investor would have to earn over the useful life of the PtG system in order to break even in terms of discounted after-tax cash flows. As such, the LCOH enables a cost comparison of alternative PtG technologies that differ in their cost structure and operational characteristics. The following derivation demonstrates that, for a given hydrogen price p, investment in a PtG system is profitable if and only if: $p \geq LCOH$.

The price per kWh at time t at which a PtG operator can purchase electricity from the market is denoted by $q(t)$. Here t is an integer where $1 \leq t \leq 8760$. Since all three of the PtG technologies considered here can be ramped up quickly to operating temperature and conversely can be ramped down rapidly,[39] the capacity utilization factor, denoted by $CF(t)$ can be chosen flexibly on the interval [0,1] for each hour of the year. Representing the conversion efficiency of a PtG system (in kg per kWh) by the parameter η, where $0 < \eta < 1$, the variable cost for producing 1 kg of hydrogen at time t is given by:

$$w(t) = q(t)\cdot\eta^{-1} + w_{\mathrm{h}}.$$

Here w_{h} reflects a cost increment incurred per kg of hydrogen produced for consumable inputs, such as water and reactants for deionizing the water. The optimized capacity factor, $CF^{*}(t)$, at time t will then be chosen to maximize $\eta\cdot[p - w(t)]\cdot CF(t)$. Thus, $CF^{*}(t) = 1$ if $p - w(t) > 0$, while $CF^{*}(t) = 0$ if $p - w(t) < 0$. This yields the optimized annual contribution margin:

$$CM^{*} \equiv \sum_{t=1}^{8760} \eta \cdot [p - w(t)] \cdot CF^{*}(t).$$

For the purpose of the economic model, we can normalize the capacity investment in the PtG system to 1 kW of peak electricity absorption without loss of generality. To be sure, our numerical analysis calibrates the costs and revenues of a PtG facility in accordance with the system sizes that have been built in recent years. We denote the fixed operating costs per kW of installed capacity by F_i in year i. In case the productive capacity of a PtG system degrades over time, we denote by x_i the share of the initial capacity that is still productive in year i. Given a price for hydrogen p, the overall pre-tax cash flows per kW of peak power absorption capacity of the PtG system in year i is then given by:

$$CFL_i^{\mathrm{o}} = x_i\cdot CM^{*} - F_i.$$

Let the system prices per kW of peak capacity be given by v. By definition, investment in the PtG system yields a non-negative net present value in terms of after-tax cash flows per kW of peak capacity over the useful life of T years if and only if:

$$\sum_{i=1}^{T} CFL_i \cdot \gamma^i - v \geq 0, \tag{2}$$

where $\gamma = (1 + r)^{-1}$ represents the discount factor when r is the applicable cost of capital, and CFL_i is the after-tax cash flow in year i. To account for the impact of corporate income taxes, we denote the firm's income tax rate by α with $0 < \alpha < 1$. Provided $d_i \geq 0$ is the percentage of the applicable tax depreciation

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charge in year i (where $\sum d_i = 1$), the firm's taxable income associated with the investment is $I_i = CFL_i^{o} - v \cdot d_i$. Thus, the after-tax cash flow in year i is:

$CFL_i = CFL_i^{o} - \alpha \cdot I_i$.

Direct substitution shows that the inequality in (2) holds if and only if:

$$(1-\alpha)\sum_{i=1}^{T}[x_i \cdot CM^* - F_i]\,\gamma^i \geq v \cdot [1 - \alpha \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i]. \quad (3)$$

Dividing by $(1-\alpha)$ the inequality in (3) reduces to:

$$\sum_{i=1}^{T}[x_i \cdot CM^* - F_i]\,\gamma^i \geq v \cdot \varDelta, \quad (4)$$

where the tax factor $\varDelta$, with $0 \leq \varDelta \leq 1$ is defined by:

$$\varDelta \equiv \frac{1 - \alpha \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i}{1-\alpha}.$$

It will be convenient to identify the life-cycle levelization factor as the anticipated number of kilograms of hydrogen that the PtG system will generate per kW of peak capacity over its useful life, given optimized capacity utilization:

$$L \equiv \sum_{i=1}^{T} x_i \cdot \gamma^i \cdot \left[\sum_{t=1}^{8760} \eta \cdot CF^*(t)\right].$$

Since the investment expenditure for capacity is shared by the entire quantity of hydrogen produced over the life-cycle of the facility, the levelized cost of capacity becomes:

$$c \equiv L^{-1} \cdot v.$$

Similarly, the levelized fixed operating cost per kg of hydrogen becomes:

$$f \equiv L^{-1} \cdot \sum_{i=1}^{T} F_i \cdot \gamma^i.$$

Finally, given optimized capacity utilization, the levelized variable cost per kg of hydrogen is given by:

$$w^* \equiv L^{-1} \cdot \left[\sum_{i=1}^{T} x_i \cdot \gamma^i \cdot \left[\sum_{t=1}^{8760} \eta \cdot w(t) \cdot CF^*(t)\right]\right].$$

The final step in the derivation is to verify that, for any given hydrogen price, inequality (4) is met if and only if:

$$p \geq LCOH \equiv w^* + f + c \cdot \varDelta.$$

If a PtG system is to receive a production tax credit under the Inflation Reduction Act per kg of hydrogen produced, the resulting profitability condition becomes:

$$p \geq LCOH - ptc,$$

where ptc denotes the levelized production tax credit. Let PTC denote the nominal production tax credit and T° the number of years for which the production tax credit is granted. The levelized production tax credit is then given by:

$$ptc \equiv \frac{PTC \cdot \sum_{i=1}^{T^{\circ}} x_i \cdot \gamma^i}{(1-\alpha) \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}.$$

7.2 Estimates of levelized cost of hydrogen

Our calculations are based on the system prices and energy consumption values reported in Fig. 2 for the year 2030. Based on discussions with manufacturers of SOC systems, we increase the energy consumption of such systems by 5 kWh per kg to account for heat management. Fixed operating costs are estimated as a percentage of system prices and account for the replacement of electrolysis stacks during the life of the system. Variable operating costs are mainly driven by electricity prices. Since our estimation requires hourly electricity prices, we initially assume a simple price vector where each hourly price is equal to the average across the day-ahead prices observed in Texas between the years 2016–2020 for the corresponding hour:

$$q(t) = \frac{1}{5}\sum_{i=2016}^{2020} q_i(t),$$

The resulting price vector reflects a deregulated electricity market with a substantial share of renewable power generation. All input parameters used in our calculations and all results are provided in Table S12 (ESI†).

Our analysis shows that the resulting LCOH values are mainly determined by electricity prices. To examine the sensitivity of the LCOH values on electricity prices, we consider simultaneous changes in the average of electricity prices as well as changes in the variance of the annual average. In particular, let $\mu(t)$ denote the multiplicative deviation factor given by:

$$q(t) \equiv \mu(t) \cdot \frac{1}{m}\sum_{t=1}^{m} q(t).$$

By construction,

$$\sum_{t=1}^{m} \mu(t) = 1.$$

Furthermore, let α denote the relative change in the annual average of electricity prices and β the relative change in the hourly variation of electricity prices during hours where prices are above average. In addition, we calculate the corresponding change in the hourly variation of electricity prices during hours where prices are below average, denoted by $\hat{\beta}$, such that the adjusted annual average remains unchanged. Thus, the adjusted electricity price in a particular hour is given by:

$$\hat{q}(t) = \begin{cases} \beta \cdot \mu(t) \cdot \alpha \cdot \frac{1}{m}\sum_{t=1}^{m} q(t) & \text{for } t, \text{where } \mu(t) \geq 1, \\ \hat{\beta} \cdot \mu(t) \cdot \alpha \cdot \frac{1}{m}\sum_{t=1}^{m} q(t) & \text{for } t, \text{where } \mu(t) < 1, \end{cases}$$

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where $\hat{\beta}$ is calculated such that

$$\frac{1}{m}\sum_{t=1}^{m}\hat{q}(t) = \alpha\cdot\frac{1}{m}\sum_{t=1}^{m}q(t).$$

Our sensitivity analysis does not seek a new model for future electricity prices. Instead, we examine the impact of different electricity price distributions on the life-cycle cost of electrolytic hydrogen production. Electricity price distributions are specific to the characteristics of the particular economic market. The rising deployment of intermittent renewable energy sources is expected to cause lower annual average electricity prices and higher hourly price volatility.[63–66] In contrast, the electrification of transportation services and industrial manufacturing, including hydrogen production, is expected to have a buffering effect on power prices. Naturally, the greenhouse gas emissions associated with electrolytic hydrogen production depend on the carbon intensity of the electricity consumed. Recent studies have examined the effect of different power sources and hydrogen production strategies on the carbon intensity of electrolytic hydrogen production.[67,68]

Data availability

The data used in this study are referenced in the main body of the paper and the ESI.† Data that generated the plots in the paper are provided in an Excel file available as part of the ESI.† Additional information is available upon request from the corresponding author.

Code availability

Computational code is available upon request to from the corresponding author.

Author contributions

G. G. developed the research question. G. G. and P. H. both collected the data, reviewed the literature, and conducted the analyses. All three authors contributed to the writing of the paper.

Conflicts of interest

The authors declare no competing financial or non-financial interests.

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