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Advances in Power-to-Gas Technologies: Cost and Conversion Efficiency

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Abstract

Widespread adoption of hydrogen as an energy carrier is widely 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%. Incorporating multiple forecasts of future deployment growth, our calculations project that, in the coming decade, all three technologies will become substantially cheaper and more energy-efficient. Specifically, the life-cycle cost of electrolytic hydrogen production is projected to fall in the range of $1.6–1.9/kg by 2030, thereby approaching but not reaching the $1.0/kg cost target set by the U.S. Department of Energy.

Keywords: learning-by-doing, hydrogen, electrolysis, power-to-gas, energy storage

JEL Codes: M1, O33, Q41, Q42, Q48, Q54, Q55

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[1–3]. Among alternative hydrogen production technologies, Power-to-Gas (PtG) in the form of electrolytic hydrogen has received particular attention[4–6]. 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 sizeable regulatory initiatives and subsidy programs for the development, deployment, and manufacturing of hydrogen equipment[7;8].

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[9;10], onshore wind turbines[11–13], or lithium-ion batteries[14–16]. Scarcity of data has so far limited the estimation of learning curves to alkaline electrolysis[16–19] or to a single equipment manufacturer[20]. Some earlier studies estimate the rate of past cost declines of PtG technologies against time[21–23] or rely on expert opinions about future cost developments[24–26].

Our analysis provides a 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. Even for divergent growth forecasts issued by different industry and policy sources, the extrapolated values fall into a relatively narrow range. These calculations, in turn, lead us to conclude that the *Hydrogen Shot* target by the U.S. Department of Energy[8] of producing clean hydrogen at a cost of $1.0/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 Results and Discussion

2.1 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[27]. 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[28]. 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[24;29;30]. 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[28;29;31;32].

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[16;28]. For PEM electrolyzers, new materials have enabled thinner membranes and more active catalysts at the cell level[31].

For the years 2000–2020, our global data collection effort tracks system prices, the energy consumption of the PtG systems, and capacity installations at the corresponding facilities. As detailed in *Methods*, 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. Overall, the resulting data provide a sizeable sample for alkaline and PEM systems beginning in the early 2000s. To focus on recent technological developments, our analysis excludes sporadic estimates for alkaline systems that became available prior to the year 2000[16–18]. For the more recent technology of SOC electrolyzers, our data begin in 2011. 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[28;33].

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[34]. Let v_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:

$$\ln(v_i) = \beta_0 + \beta_1 \cdot \ln(Q_i) + \mu_i, \tag{1}$$

where β_1 denotes the learning elasticity parameter and μ_i is an idiosyncratic and unbiased error term. Equation 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/W (Figure 1a–c, details in Supplementary Note 1). The reduction in system prices across the years 2003–2020 corresponds to a learning factor of $2^{\beta_1} = 84.3\%$ 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/W in 2020. Yet, they also exhibit the fastest price decline, described by a learning factor of $83.3 \pm 6.5\%$ 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/W in 2003 to \$1.1/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 $86.2 \pm 1.7\%$ ($p < 0.0001$, adj. $R^2 = 0.74$).

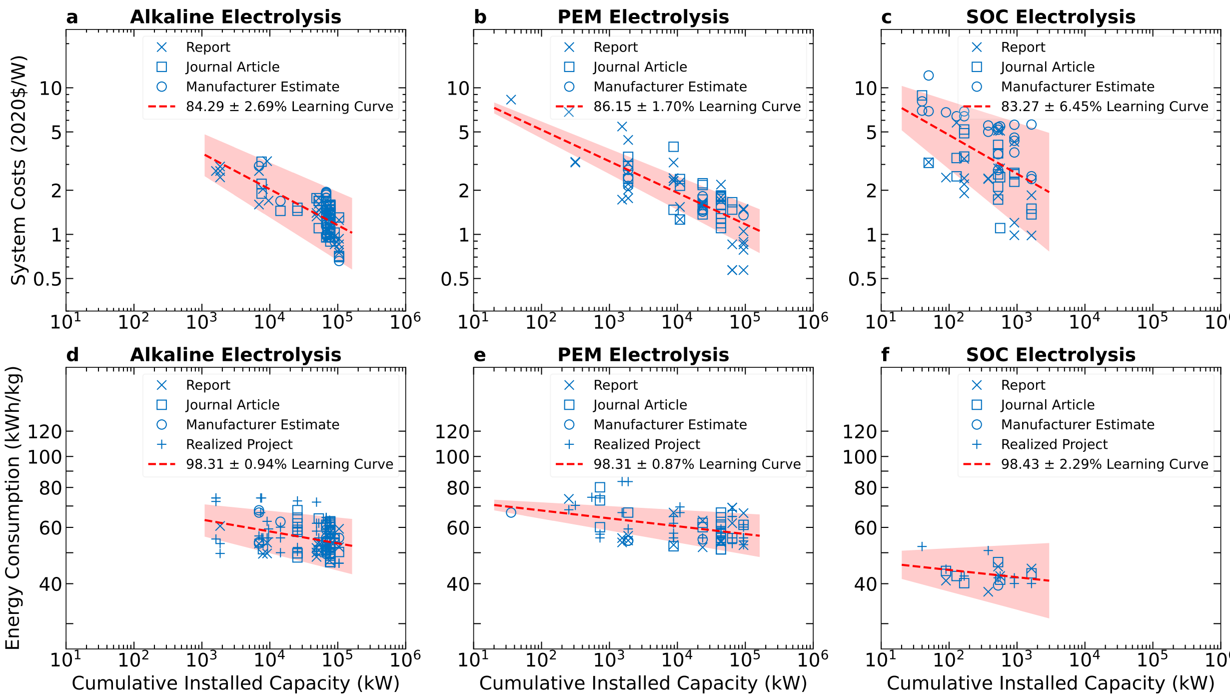

Figure 1. Estimates of learning curves. This figure plots the global system prices in 2020 \$US against the global cumulative installed capacity together with our estimates of the corresponding learning curves for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers. The figure also plots the 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 Supplementary Note 1.

In terms of energy consumption, alkaline systems have exhibited improvements from above 60 kWh/kg in the early 2000s to 52 kWh/kg in 2020 (Figure 1d–f, details in Supplementary Note 1). Similarly, PEM electrolyzers have witnessed a decline from above 70 kWh/kg in the early 2000s to 57 kWh/kg in 2020, while the SOC technology improved from above 50 kWh/kg in 2011 to around 42 kWh/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 $98.3 \pm 0.9\%$ ($p < 0.001$, adj. $R^2 = 0.08$) for alkaline, $98.3 \pm 0.9\%$ ($p < 0.001$, adj. $R^2 = 0.15$) for PEM electrolyzers, and $98.4 \pm 2.3\%$ ($p < 0.2$, adj. $R^2 = 0.08$) for the SOC technology.

To examine the robustness of our learning curve estimates, we first implement different specifications for estimating the potential effect of changes in the size of PtG systems on the development of system prices. As detailed in *Methods*, our regression results indicate significant and robust learning coefficients for cumulative installed capacity and a limited effect of capacity sizes. In addition, we repeat the regressions for alkaline and PEM electrolyzers covering the years 2010–2020 to examine the most recent developments for system prices and conversion efficiencies. The learning curve estimates for alkaline systems become slightly more favorable for both parameters, while those for PEM systems remain almost unchanged. Furthermore, we estimate the potential effect of changes in the market prices for platinum and iridium, which are currently included in components of PEM electrolyzers. This analysis shows that the learning factor of cumulative installed capacity remains unchanged, while the estimated coefficients for both metals are economically and statistically insignificant.

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% [16–18]. While these values are similar in magnitude to our estimate for alkaline electrolyzers (Figure 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.

A common alternative to learning curves based on cumulative installed capacity is the estimation of technological progress as a function of time. As detailed in *Methods*, we find significant and robust annual improvements in system prices and energy consumption for all three PtG technologies. The annual decline rates for system prices lie substantially below those identified in previous studies [21–23], which reflects the rapid development captured by the global information in our database. We are not aware of previous studies examining changes in the conversion efficiency of PtG systems.

2.2 Extrapolating Future Performance

Based on the learning estimates in Figure 1, we now project trajectories of 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: $\ln(Q_i) = \lambda_0 + \lambda_1 \cdot i + \epsilon_i$. 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 Supplementary Note 2).

Table 1. Estimates of cumulative installed capacity by 2030.

in MW	**Alkaline**	**PEM**	**SOC**	**Total**
Past Growth	3,670	26,898	100	30,688
Policy Target	13,772	100,861	376	115,009
Industry Target	29,682	217,458	812	247,952

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 Supplementary Note 2, 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 and PEM electrolysis (see Supplementary Note 2 for details). 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[23;35]. 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.

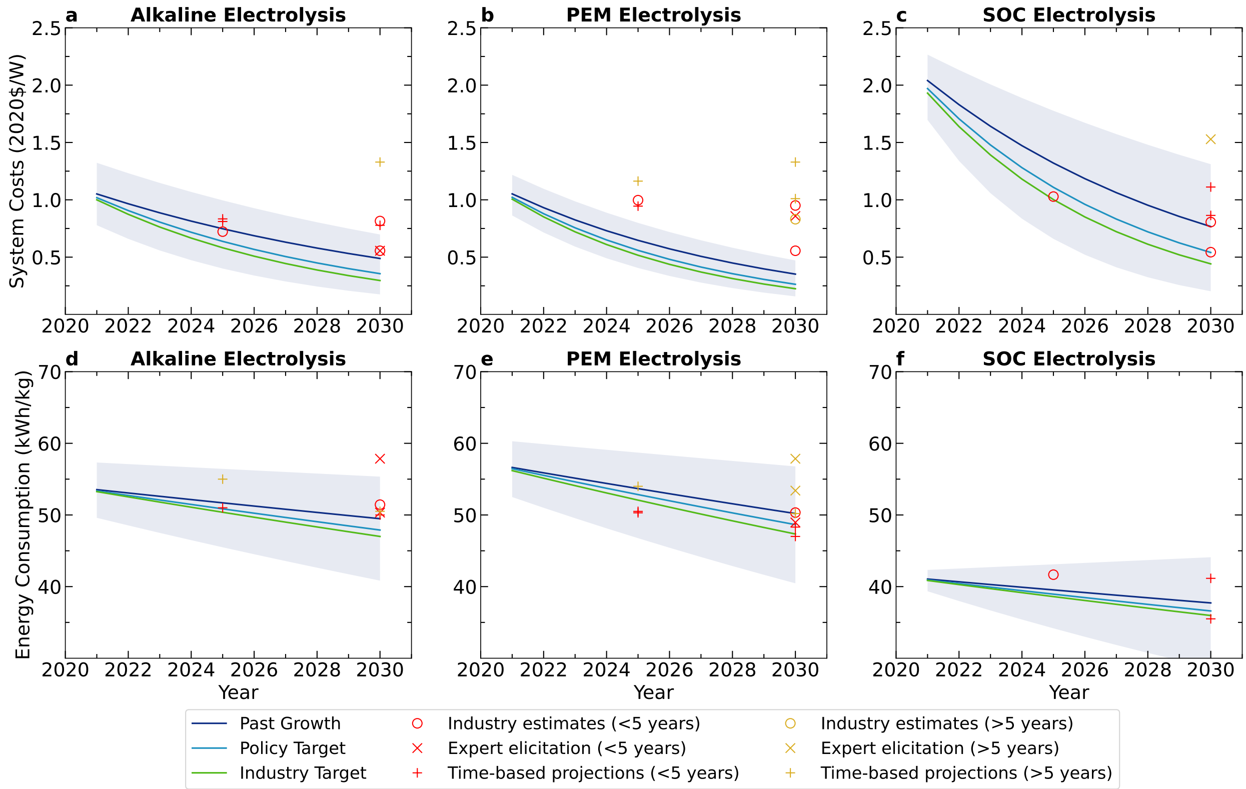

Figure 2. Prospects for system prices and conversion efficiency. This figure shows our projections of the potential development of system prices in 2020 $US for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers. It also shows our projections of the potential trajectory of energy consumption 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.

The resulting trajectories shown in Figure 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/kW for alkaline, $225–352/kW for PEM, and $441–767/kW for SOC electrolysis. 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/kg for alkaline, 47-50 kWh/kg for PEM, and 36–38 kWh/kg for SOC technology. Thus, the energy consumption of alkaline and PEM systems is moving towards the target of 42 kWh/kg by 2050 set by the International Renewable Energy Association[28]. 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[36]. SOC electrolyzers are likely to approach the theoretical optimum of 33 kWh/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 expect, the resulting system prices and energy consumption values are close, if not identical, to the trajectories for the Past-Growth scenario reported in Figure 2. Furthermore, we examine a specification based on time and cumulative installed capacity. As detailed in *Methods*, there is high multicollinearity between the two covariates. Nevertheless, the projected trajectories for system prices and energy consumption are again close to the Past-Growth scenario.

Figure 2 also shows point estimates for future system prices and energy consumption as articulated by industry experts[37–39], technical reports[40–45] and academic studies[23;24;35;46]. 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[47] and the ramp-up of manufacturing capacity for PtG systems[48–50]. Finally, our calculations are based on recent global information reflecting the rapidly improving system prices and efficiencies as well as the observed recent growth in capacity deployments.

2.3 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/kg by the year 2030[8]. The system prices and conversion efficiencies we forecast in Figure 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 (see *Methods* for details).

Earlier studies have established that, in addition to system prices and conversion efficiency, electricity consumption is a major cost component of electrolytic hydrogen[35;51;52]. 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 8,760 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[53]. The resulting annual average electricity purchasing price amounts to ¢3.6/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. The useful lifetime of a system is set to 20 years and the cost of capital to 5.0% for all technologies (details in *Methods* and Supplementary Note 7).

Depending on the growth scenario, our calculations yield LCOH estimates in the range of \$1.6–1.9/kg for alkaline, \$1.6–1.8/kg for PEM, and \$1.6–1.9/kg for SOC electrolyzers (Figure 3, details in Supplementary Note 7). 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

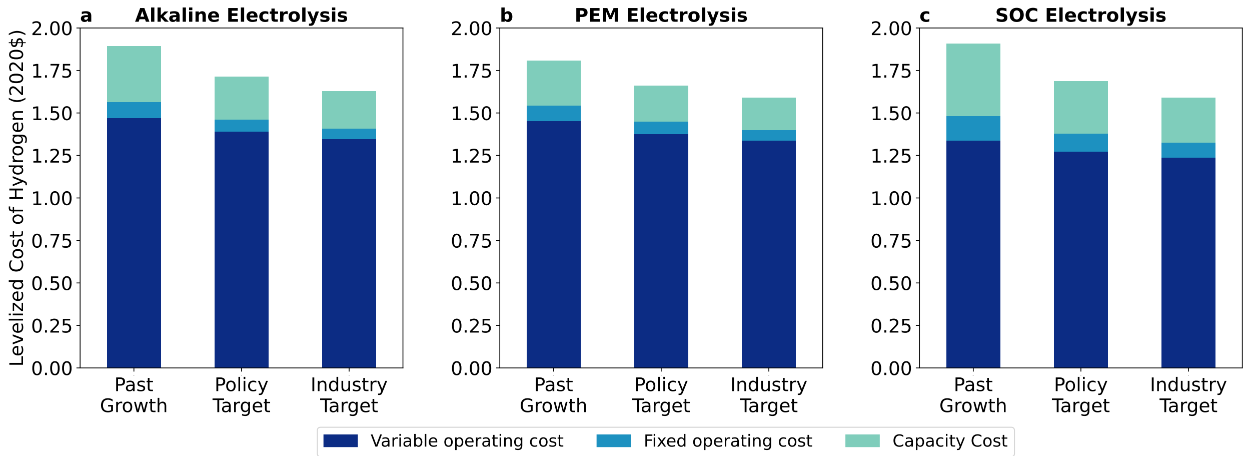

Figure 3. Estimates of levelized cost of hydrogen by 2030. This figure shows our estimates of levelized cost of hydrogen by 2030 for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers for different growth scenarios.

technology, the variable cost of electricity accounts for about 70–90% of the total LCOH by the year 2030. Thus, system prices, fixed operating costs, 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 Figure 3, we calculate LCOH values for simultaneous changes in the annual average and the hourly variation of power prices (see *Methods* for details). 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 Figure 4. Overall, if the annual average electricity price were to 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 Figure 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 with relatively high prices.

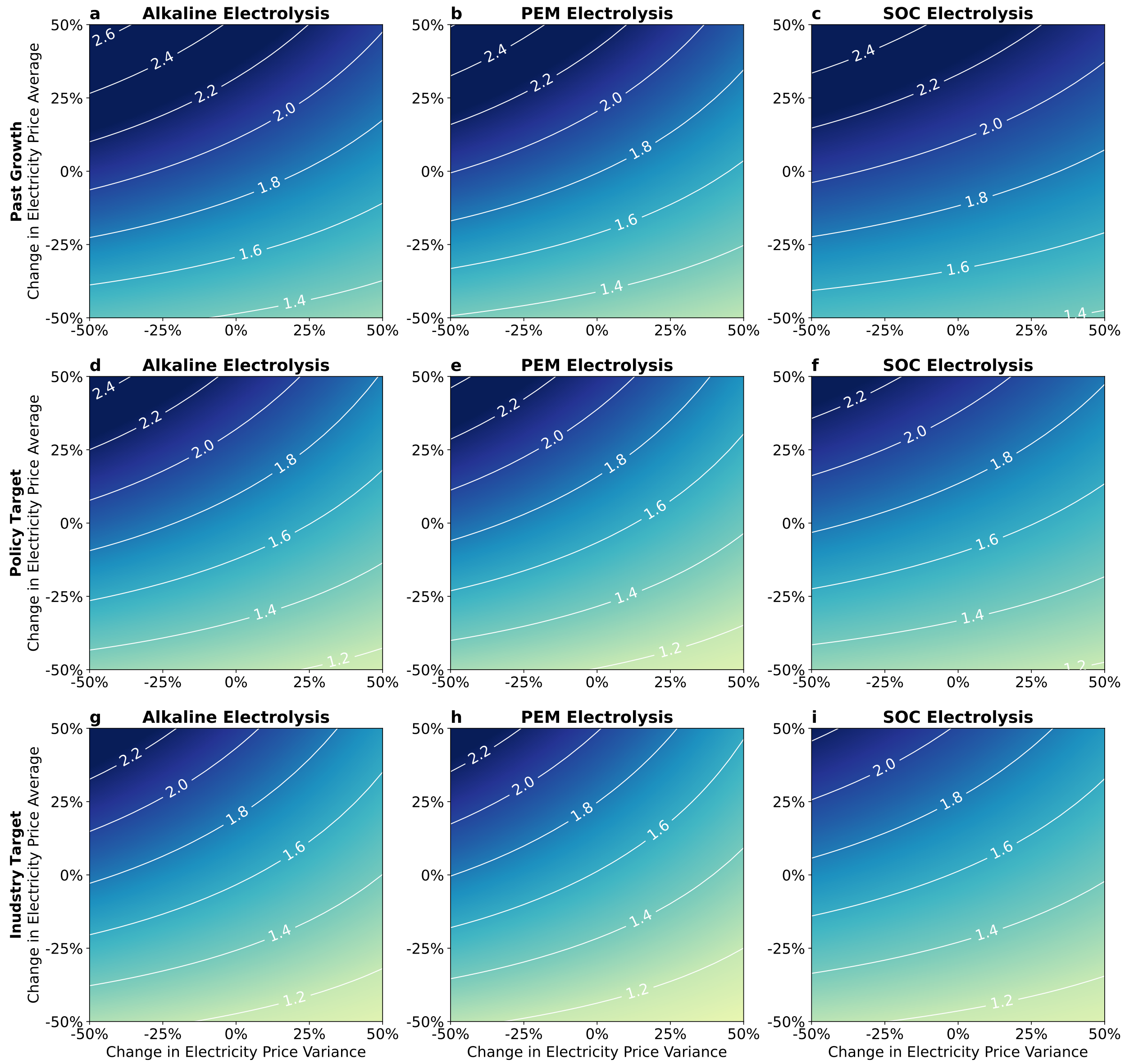

Figure 4. Sensitivity Analysis: LCOH. This figure shows the sensitivity of our levelized cost of hydrogen estimates by 2030 for changes in the annual average and hourly variation of power prices for (**a**, **d**, **g**) alkaline, (**b**, **e**, **h**) PEM, and (**c**, **f**, **i**) SOC electrolyzers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

2.4 Policy Implications

Our findings on the economics of electrolytic hydrogen speak directly to several recent policy initiatives. We first 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 3,000 GW by 2045 [54].

Our findings on the levelized cost of hydrogen indicate that the *Hydrogen Shot* cost target of \$1.0/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 [7] and the Inflation Reduction Act in the United States [55]. The production tax credit of up to \$3.0/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 produce 20 million tons of green hydrogen annually by the year 2030 [7]. Regardless of the magnitude of the additional growth in deployments obtained from these 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.

3 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/kg by 2030, approaching the *Hydrogen Shot* target of \$1.0/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 alkaline exchange membrane electrolysis, steam methane reforming with carbon capture and storage, or natural gas pyrolysis. Naturally, such studies will need to reflect that the tax credits available for hydrogen production under the U.S. Inflation Reduction Act vary greatly with the assessed carbon intensity of the hydrogen produced.

Methods

Review of System Prices

Information on system prices is based on two earlier reviews[23;35] and a replication of the analyses performed therein. Specifically, we gathered price estimates from various sources, including manufacturers, academic articles in peer-reviewed journals, and technical reports by agencies, consultancies, and industry analysts. Academic articles were found by searching databases like Web of Science, Scopus, Google Scholar, and Sciencedirect. Keywords used in the search include 'electrolyzer system prices', 'power-to-gas system prices', and 'electrolyzers for hydrogen production + system prices'. Industry publications and technical reports were retrieved with a Google search based on the same keywords, where we reviewed the top 100 search results.

Our review procedures retrieved 396 unique sources, which we filtered by multiple criteria to maintain quality and timeliness. We first excluded sources without clear information on system prices (60). We also excluded sources referencing other articles as original sources (66) but then traced the references back to the original sources and added those sources to the pool if they included original data. We further excluded sources without explicit references or methods for obtaining the cost estimate (94). We excluded five articles that were published before the year 2000. Finally, we excluded estimates for alkaline systems manufactured in China[29], primarily because of differences in technology and manufacturing standards[56]. To focus on recent technological advances, we also excluded sporadic estimates for alkaline systems from before the year 2000[16–18]. Most of these earlier data points are primarily based on estimates for individual large-scale capacity installations instead of observations for installations of different sizes.

Our procedure yielded 176, primarily European and North-American, sources containing 264 unique observations from industry or an original review of multiple sources. Of these observations, 105 belong 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. Since SOC electrolyzers are reversible, we include estimates for fuel cells in our sample.

For all sources, we converted any range estimates to the midpoint in the reported range. Estimates given in currencies other than $US were converted based on the annual average exchange rate of the respective year. We further adjusted historical price information for inflation using the yearly inflation adjustment factor for qualified energy resources as provided by the US Internal Revenue Service.

Finally, all observations of one technology were winsorized at the 5.0% level in combination with a moving time window of 3 years ranging from 1 year before to 1 year after the year in which price estimates are adjusted. Winsorization has only a minor effect on our findings for all technologies.

Review of Cumulative Installed Capacity

Our data set of cumulative installed capacity is primarily based on the *Hydrogen Projects Database* by the International Energy Agency[57]. The original database includes production facilities that have been commissioned worldwide since 2000 for the generation of clean hydrogen and hydrogen derivatives. Production technologies listed in the database comprise alkaline, PEM, and SOC electrolysis, coal gasification and natural gas steam reforming both with carbon capture and storage technology, and other production pathways such as biogas pyrolysis, biogas steam reforming, or biogas membrane separation. In addition, the database also includes facilities where the type of electrolysis is undisclosed.

The original database lists 445 separate hydrogen production facilities. Since many of these entries miss information on the commissioning date and the installed capacity size, we manually reviewed each entry. We thereby relied on the source provided in the database and on publicly available information from news coverage, industry reports, project websites, and press releases of investors, project developers, and manufacturers. In the course of our review, we could verify information for 186 projects from the original database and could amend or adjust entries for 111 projects. We could not verify or complete information for 111 projects due to a lack of publicly accessible information. Furthermore, we excluded 37 projects based on production technologies other than water electrolysis.

In addition, we conducted our own review of hydrogen projects based on industry announcements and media coverage. This review identified 133 additional projects that we added to the data set. 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. If projects had a construction period of more than one year, we use the starting year, that is, the commission date in our calculations. The resulting total cumulative installed capacity across the three PtG technologies amounts to about 200 Megawatt (MW) in 2020, which is consistent with recent estimates by industry analysts[28;33].

The IEA recently published an update of the *Hydrogen Projects Database*[58]. This update includes some changes to the list of capacity installations in the previous version from which our review departed. However, the total cumulative installed capacity across the three PtG technologies in 2020 resulting from the update is slightly less than the 200 MW resulting from our database. We attribute this difference to the additional review of capacity installations we conducted.

Review of Conversion Efficiency

Information on specific energy consumption stems from the preceding two reviews. In total, we retrieved 229 data points: 130 for alkaline systems over the years 2000–2020, 78 for PEM systems between 2005–2020, and 21 for SOC systems across 2011–2020. We interpret these values as those obtained at full capacity utilization. Alkaline and PEM electrolyzers attain a near-constant energy consumption beyond a small threshold utilization level[27]. For SOC systems, existing literature provides little evidence for the change in energy consumption as a function of capacity utilization. For all technologies, the energy consumption values incorporate conversion losses incurred for the heat management of a PtG system.

Analog to system prices, we converged range estimates (if given) to the arithmetic mean of the lowest and highest points in the range. Furthermore, estimates given in units other than kWh/kg were converted based on the lower heating value of hydrogen (120 MJ/kg) and a density of hydrogen of 0.090 kg/Nm^3. All observations of a technology were winsorized at the 5.0% level in combination with a moving time window of 3 years ranging from 1 year before to 1 year after the year in which the estimates are adjusted. Analog to system prices, this winsorization has a small effect on our findings for all technologies.

Discussion of Learning Estimates and Projections

Our analysis has relied on the common concept of univariate constant elasticity learning curves based on cumulative installed capacity. Yet, earlier work suggests that the system prices of a PtG facility decline at a diminishing rate as the capacity size of the system increases[21;22;27]. Information on system sizes available to us is largely disconnected from the data on system prices. Nevertheless, we examine multiple different specifications for estimating the potential effect of changes in the size of PtG systems on the trajectory of system prices (details in Supplementary Note 3). The results point towards significant and robust learning coefficients for cumulative installed capacity and a limited effect of capacity sizes. This is consistent with studies examining the cost dynamics of onshore wind turbines[11–13], solar photovoltaic modules[9;10], or lithium-ion batteries[14–16]. It is also consistent with the observation that scale economies of PtG plants appear to level off as system sizes exceed a particular threshold[21;22;43].

Earlier studies have shown that learning curve estimates can be sensitive to the time period over which they are calculated[9]. 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 Supplementary Note 5, the learning curves for alkaline electrolyzers improve slightly for both system prices and conversion efficiencies. This suggests that most development has resulted from the past years. 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, primarily platinum and iridium. To estimate the potential effect of changes in the market prices for both metals, we calibrate an extension of equation (1) for PEM systems that includes the annual average global market price for each metal as additional regression coefficient. As detailed in Supplementary Note 4, 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, industry observers have pointed out that a rapid increase in PEM electrolyzer production could lead to temporary shortages of these metals.

An alternative approach to learning curves based on cumulative installed capacity is to estimate technological progress as a function of time. As detailed in Supplementary Note 6, our regressions return annual declines in system prices of $6.0 \pm 1.0\%$ for alkaline over the years 2003–2020 ($p < 0.0001$, adj. $R^2 = 0.56$), $12.6 \pm 1.4\%$ for PEM between 2003–2020 ($p < 0.0001$, adj. $R^2 = 0.77$), and $10.6 \pm 4.2\%$ for SOC electrolyzers covering 2011–2020 ($p < 0.0001$, adj. $R^2 = 0.25$). Furthermore, we identify annual reductions in energy consumption of $0.8 \pm 0.4\%$ for alkaline across the years 2000–2020 ($p < 0.0001$, adj. $R^2 = 0.11$), $1.4 \pm 0.7\%$ for PEM electrolyzers across 2005–2020 ($p < 0.0001$, adj. $R^2 = 0.15$), and $1.0 \pm 1.4\%$ for the SOC technology between 2011–2020 ($p < 0.15$, adj. $R^2 = 0.07$).

Earlier studies[23;35] 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 price declines identified in our analysis to the additional price observations reflecting the recent dynamics in productive and innovative activity by electrolyzer manufacturers. At the same time, we note that the estimate for PEM electrolyzers might be somewhat over-optimistic due to many observations of lower system prices in recent years.

We then use our estimates of the annual decline rates to project potential future system prices and energy consumption. The resulting trajectories for system prices and energy consumption are close, if not identical, to the trajectories for the Past-Growth scenario reported in Figure 2. As an exception to this, 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.

We also analyze a specification based on both time and cumulative installed capacity. As detailed in Supplementary Note 6, this specification exhibits considerable multicollinearity between the two covariates, which leaves the resulting regression estimates unreliable. Despite this, the projected trajectories for system prices and energy consumption are again close to the Past-Growth scenario in Figure 2. In summary, we conclude that all scenarios and specifications in our calculations deliver a consistent assessment regarding the magnitudes of and trends in cost and efficiency improvements.

Levelized Cost of Hydrogen

In direct analogy to the commonly referenced levelized cost of electricity[59], 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 $1 \leq t \leq 8,760$. Since all three of PtG technologies considered here can both be ramped up quickly to operating temperature and conversely can be ramped down rapidly[35], 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/kWh) by the parameter η, where $0 < \eta < 1$, the variable cost for producing 1 kg of hydrogen at time t is given by:

$$w(t) = \frac{q(t)}{\eta} + w_h.$$

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:

$$CM^* \equiv \sum_{t=1}^{8,760} \eta \cdot \big[p - w(t)\big] \cdot CF^*(t).$$

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:

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

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 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:

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

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

$$\sum_{i=1}^{T}\Big[x_i \cdot CM^* - F_i\Big]\gamma^i \geq v \cdot \Delta, \tag{4}$$

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

$$\Delta \equiv \frac{1 - \alpha \cdot \sum\limits_{i=0}^{T} d_i \cdot \gamma^i}{1-\alpha}. \tag{5}$$

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:

$$L \equiv \sum_{i=1}^{T} x_i \cdot \gamma^i \cdot \left[\sum_{t=1}^{8,760} \eta \cdot CF^*(t)\right].$$

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:

$$w^* \equiv L^{-1} \cdot \left[\sum_{i=1}^{T} x_i \cdot \gamma^i \cdot \left[\sum_{t=1}^{8,760} \eta \cdot w(t) \cdot CF^*(t) \right] \right].$$

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

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

Estimates of Levelized Cost of Hydrogen

Our calculations are based on the system prices and energy consumption values reported in Figure 2 for the year 2030. Based on discussions with a manufacturer of SOC systems, we increase their energy consumption by 5 kWh/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:

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

with i reflects the years from 2016–2020. 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 Supplementary Note 7.

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:

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

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[60–63]. 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[64;65]. Regulators in Europe and the United

States are currently developing guidelines for determining the carbon intensity of electrolytic hydrogen production[66;67].

Data availability

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

Code availability

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

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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.

Declaration of Interests

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

Supplementary Information:

Advances in Power-to-Gas Technologies: Cost and Conversion Efficiency

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Supplementary Note 1. Learning Estimates by Cumulative Capacity

Supplementary Table 1 provides detailed results for our regression estimations of the constant elasticity learning curve in equation (1) in the main body of the paper. Learning estimates for the energy consumption of SOC electrolysis are not statistically significant due to the limited sample size. Yet, the results are consistent with industry estimates and anecdotal evidence from manufacturers.

Supplementary Table 1. Regression results for equation (1)**.**

	System prices			Energy Consumption		
	Alkaline	PEM	SOC	Alkaline	PEM	SOC
β_0	8.1870***	7.9849***	7.8592***	1.6876***	1.7502***	1.3262***
	(0.0952)	(0.0488)	(0.0865)	(0.0267)	(0.0202)	(0.0233)
β_1	−0.2466***	−0.1910***	−0.2641***	−0.0232**	−0.0246***	−0.0228
	(0.0236)	(0.0151)	(0.0582)	(0.0070)	(0.0064)	(0.0162)
2^{β_1}	0.8429	0.8760	0.8327	0.9841	0.9831	0.9843
Adj. R^2	0.5069	0.6719	0.2432	0.0718	0.1507	0.0471
N	106	79	62	132	78	21

System prices are in 2020 $US/kW and cumulative installed capacity is in MW. All values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** ≤ 0.001, ** ≤ 0.01, * ≤ 0.05.

Supplementary Note 2. Future Cumulative Installed Capacity

Our projections consider three alternative scenarios for the growth of cumulative installed electrolysis capacity over the coming decade. The first scenario (called "Past Growth") assumes that the cumulative capacity of each considered technology continues to grow over the coming decade at the same average rate as in the past. As described in the main body of the paper, we estimate the past average growth rate of cumulative capacity for each technology based on a univariate regression for a constant elasticity model of the form:

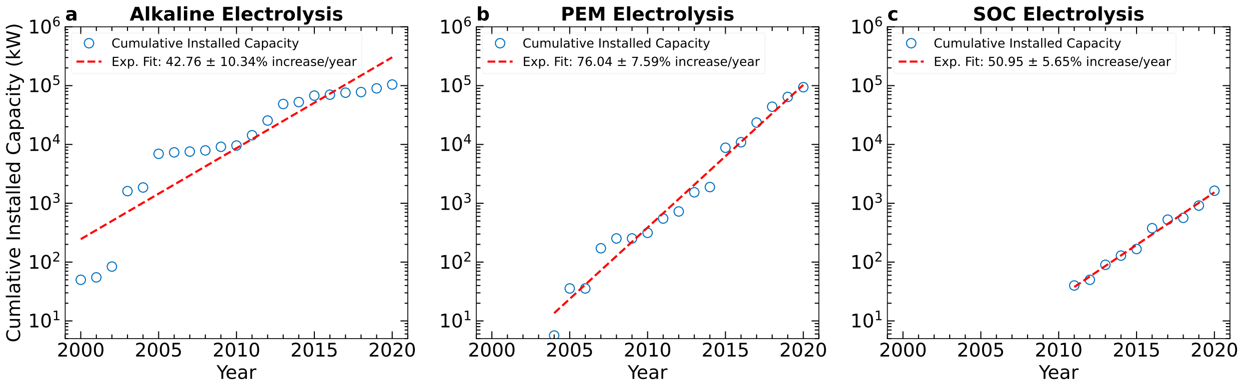
$$\ln(Q_i) = \lambda_0 + \lambda_1 \cdot i + \epsilon_i, \tag{A6}$$

where ϵ_i denotes the idiosyncratic error term with $E[\epsilon_i] = 0 \; \forall i$. Accordingly, the cumulative installed capacity of a PtG technology is predicted to increase every year to e^{λ_1} of its value in the preceding year. The detailed regression results are provided in Supplementary Table 2, while an illustration is provided in Supplementary Figure 1.

Supplementary Table 2. Regression results for equation (A6).

	Alkaline	**PEM**	**SOC**
λ_0	-713.3481^{***}	-1137.7098^{***}	-831.4175^{***}
	(72.1765)	(41.8446)	(33.3476)
λ_1	0.3560^{***}	0.5655^{***}	0.4118^{***}
	(0.0359)	(0.0208)	(0.0165)
$e^{\lambda_1} - 1$	0.4276	0.7604	0.5095
Adj. R^2	0.8295	0.9775	0.9857
N	21	18	10

Cumulative installed capacity is in MW. Entries in parentheses are standard errors. Key to statistical significance: $^{***} \leq 0.001$, $^{**} \leq 0.01$, $^{*} \leq 0.05$.



Supplementary Figure 1. Past development of cumulative installed capacity. a, b, c This figure shows the growth in cumulative installed capacity for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers. It also shows our estimates of the corresponding annual growth rates.

The second scenario (called "Policy Target") assumes that cumulative installed electrolysis capacity will grow such that global installed capacity in the year 2030 meets an aggregate of policy targets. At the point of our analysis, the aggregate target amounts to about 115 GW and stems from the following national and supranational hydrogen strategies: Chile 25 GW[68] and the European Union with 40 GW in Europe and 40 GW in its neighborhood, in particular North Africa[69], where 36 GW are currently targeted to be built in France (6.5 GW), Germany (5.0 GW), Italy (5.0 GW), Scotland (5.0 GW), Spain (4.0 GW), the Netherlands (3.5 GW), Portugal (2.25 GW), Poland (2 GW), Austria (1.5 GW), and Denmark (1.3 GW)[70–80].

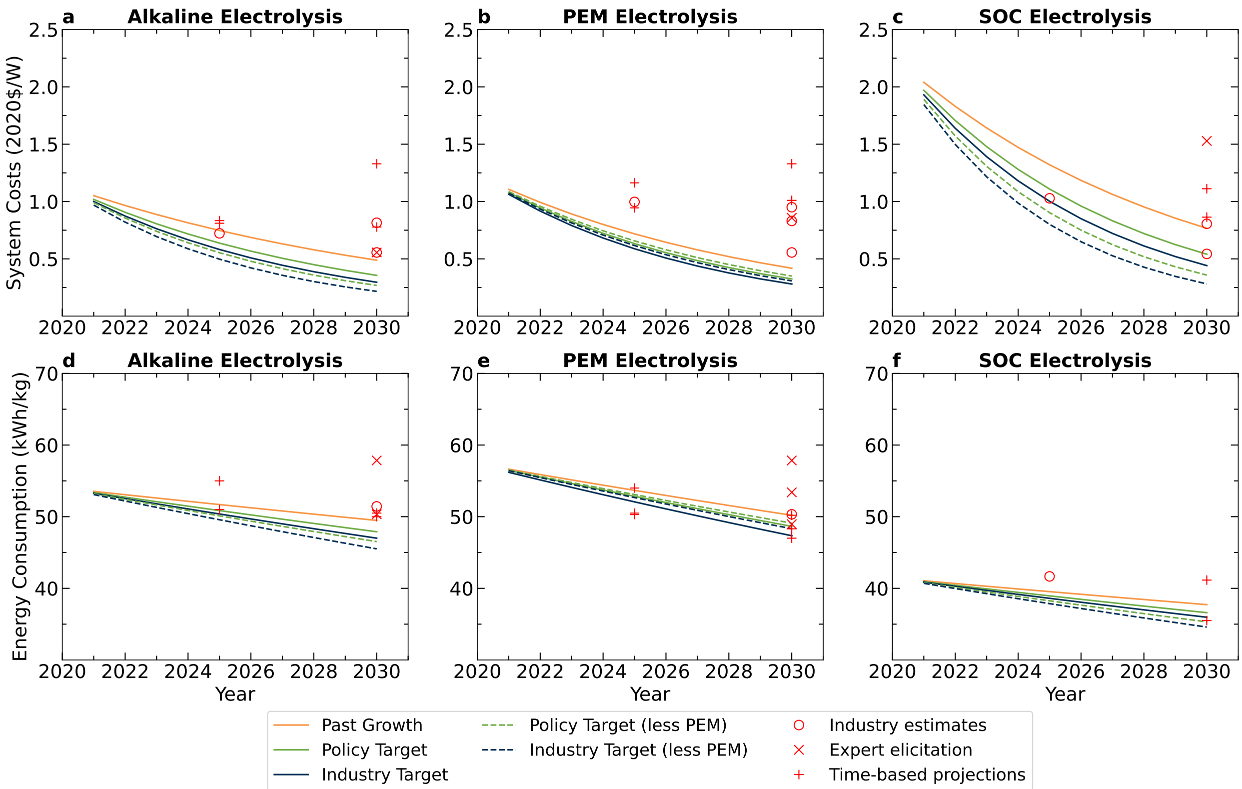
Since the policy targets are technology-agnostic and specified for installed rather than cumulative installed capacity, we implement two adjustments. First, we assume that a technology's share of the total cumulative installed capacity in 2030 is equal to the share the technology obtains in the Past-Growth scenario for 2030. Given the observed cumulative capacity for each electrolysis technology in 2020 and our estimate of installed capacity in 2030, we then interpolate the exponential growth in capacity installation required for the years 2021–2029. In addition, we account for potential capacity depletion by adding for each year from 2021–2030 the amount of installed capacity that is expected to have gone offline until that year based on the installation year and the useful lifetime assumed in our calculations. Yet, these additions are small relative to the growth required to reach the overall target in 2030.

Supplementary Table 3. Estimates of cumulative installed capacity by 2030.

in %	**Alkaline**	**PEM**	**SOC**	**Total**
Past Growth	3,670	26,898	100	30,688
Policy Target	13,772	100,861	376	115,009
Policy Target (less PEM)	45,002	68,221	1,787	115,009
Industry Target	29,682	217,458	812	247,952
Industry Target (less PEM)	110,143	133,362	4,446	247,952

Our third scenario (called "Industry Target") is directly analogous to the second scenario with the exception that the aggregate target in 2030 stems from announcements by project developers, hydrogen customers, and hydrogen industry associations. The aggregate target currently amounts to about 248 GW of capacity that is planned to be installed by 2030 in the following countries: China 100 GW, Spain 72 GW, Australia 27 GW, the Netherlands 8 GW, Oman 6.7 GW, Germany 6.5 GW, Greece 5.0 GW, Denmark 3.6 GW, Brazil 3.4 GW, Chile 3.0 GW, the United Kingdom 2.1 GW, Ireland, 1.6 GW, Romania 1.6 GW, Sweden 1.5 GW, Belgium 1.2 GW, France 1.2 GW, Portugal 1.1 GW, Norway 1.0 GW, Italy 0.8 GW, Poland 0.3 GW, Bulgaria 0.2 GW, and other countries in the European Union 0.4 GW[81–84]. In case targets for installed capacity in 2030 were given in a range, we converted these to the arithmetic mean of the lowest and highest targets in the range. All included announcements for installed capacity have a scheduled completion date before 2030.

Some industry observers argue that the growth in PEM installations over the coming years might be slower than in the past because of shortages of rare earth materials and bans on fluoric coatings, which are expected in some jurisdictions, including the European Union. To examine this possibility, we analyze variants of the Policy and Industry Target scenarios. Here, we assume that each technology will obtain the same cumulative installed capacity in 2030 as in the Past-Growth scenario. The remaining growth in capacity required to reach the policy (or industry) target is then equally distributed between alkaline and PEM electrolysis, where each one obtains a share of 49%. SOC technology is assumed to obtain the remaining share of 2%, representing the relative youth of the technology. The resulting estimates for the alternative scenarios in cumulative installed capacity are provided in Supplementary Table 3. The corresponding projections for the trajectories of system prices and conversion efficiency are provided in Supplementary Figure 2.



Supplementary Figure 2. Prospects for system prices and efficiency (all scenarios). a, b, c, d, e, f This figure shows our projections of the potential 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.

Supplementary Note 3. The Effect of System Sizes

Earlier work suggests that the system prices of a PtG facility decline at a diminishing rate as the capacity size of the system increases[21;22;27]. To examine the potential effect of changes in the size of PtG systems on the trajectory of system prices in our data set, let S_i denote the system size in kW of peak power absorption for a particular technology in year i. The functional specification of the extended constant elasticity learning curve in logarithmic form is then given by:

$$\ln(v_i) = \beta_0 + \beta_1 \cdot \ln(Q_i) + \beta_2 \cdot \ln(S_i) + \mu_i, \tag{A7}$$

where β_2 denotes the size elasticity and μ_i the idiosyncratic error term with $E[\mu_i|Q_i, S_i] = 0$ $\forall i$. As such, the system prices of a PtG technology is estimated to decline with every doubling of system sizes to 2^{β_2}% of its previous value.

Our data set on S_i results from our reviews on system prices, energy efficiency, and installed capacity. In total, we gather 125 observations for alkaline system sizes, 114 for PEM, and 18 for SOC[27;57;85]. However, most of these observations are disconnected from our data on system prices. Specifically, only 13 size observations for alkaline and 8 size observations for PEM electrolyzers are connected to information on system prices.

Supplementary Table 4. Regression results for equation (A7) (specification 1)

	System Prices		
	Alkaline	PEM	SOC
β_0	8.0645***	8.0690***	7.5712***
	(0.1274)	(0.2636)	(0.5067)
β_1	−0.2821***	−0.2141***	−0.3072***
	(0.0341)	(0.0256)	(0.0948)
β_2	0.0383	−0.0021	0.0571
	(0.0267)	(0.0460)	(0.0990)
2^{β_1}	0.8224	0.8621	0.8082
2^{β_2}	1.0269	0.9986	1.0404
Adj. R^2	0.5120	0.7363	0.2347
N	106	79	62

System prices are in 2020 $US/kW, cumulative installed capacity is in MW, system sizes are in MW. All values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** ≤ 0.001, ** ≤ 0.01, * ≤ 0.05.

Given the data limitations, we implement three different specifications to investigate the potential impact of changes in system sizes on system prices. First, we estimate equation (A7) for each technology with S_i given as the annual average system size of the technology. The resulting regression estimates are shown in Supplementary Table 4. Differences between our learning estimates, β_1, in Supplementary Tables 1 and 4 are small. In addition, the estimated coefficients for size, β_2, are close to zero and statistically insignificant. For alkaline and SOC, they are even positive. We attribute the results to the set of system prices available to us, which includes in all sample years ranges of price estimates that are likely to originate to some extent from different capacity sizes.

Some of our data sources[27;85] provide ranges for system sizes with corresponding ranges for system prices. In the second specification, we first assume that the largest (smallest) system size in the size range of a data source corresponds to the lowest (highest) system price per kW in the cost range. We then interpolate the two ranges following the notion that larger systems entail lower system prices per kW. This procedure yields 18 additional pairs of system prices and sizes for alkaline and 11 additional pairs for PEM electrolyzers. We replace the average annual system size with the interpolated values for these pairs and add them to our initial pairs of system prices and sizes. We then estimate (A7) again for all technologies.

Supplementary Table 5. Regression results for equation (A7) **(specification 2)**

	System Prices		
	Alkaline	PEM	SOC
β_0	8.2610***	8.3115***	7.6049***
	(0.1159)	(0.1508)	(0.4153)
β_1	−0.2254***	−0.1977***	−0.3018***
	(0.0303)	(0.0173)	(0.0839)
β_2	−0.0233	−0.0461	0.0510
	(0.0209)	(0.0260)	(0.0814)
2^{β_1}	0.8554	0.8720	0.8113
2^{β_2}	0.9840	0.9685	1.0360
Adj. R^2	0.5081	0.7467	0.2355
N	106	79	62

System prices are in 2020 \$US/kW, cumulative installed capacity is in MW, system sizes are in MW. All values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** ≤ 0.001, ** ≤ 0.01, * ≤ 0.05.

Supplementary Table 5 provides the regression results for the second specification. Again, we find no statistically or economically significant parameter estimates for the size coefficient. Meanwhile, the learning estimates for each technology are close to those reported in Figure 1. This finding is consistent with analog studies examining the cost dynamics of other clean energy technologies.

Finally, we compare a specification in which we use only the direct matches and interpolated data, which is intended to produce significant size estimators. Consequently, we exclude all data points with matched yearly average system sizes and remain with our original and interpolated pairs only. We employ this specification to assess the impact of a theoretically significant size estimator on our learning parameters. Due to no available data for SOC, we can only carry out this analysis for alkaline and PEM. We find that alkaline electrolyzers exhibit a $2^{\beta_1} = 84.5\%$ learning curve from cumulative installed capacity and a reduction of $1 - 2^{\beta_2} = 5.5\%$ with every doubling of system sizes (Supplementary Table 6). PEM electrolyzers, in contrast, show an 83.2% learning curve from cumulative installed capacity and a reduction of 7.4% from system sizes. The learning curves for both alkaline and PEM technology are close to those reported in Figure 1, even though the regressions are based on a much smaller data set.

Supplementary Table 6. Regression results for equation (A7) **(specification 3)**

	System Prices		
	Alkaline	PEM	SOC
β_0	8.8281***	8.8914***	-
	(0.2369)	(0.2499)	-
β_1	−0.2451***	−0.2644***	-
	(0.0544)	(0.0398)	-
β_2	−0.0809**	−0.1106*	-
	(0.0247)	(0.0336)	-
2^{β_1}	0.8438	0.8325	-
2^{β_2}	0.9455	0.9262	-
Adj. R^2	0.5760	0.7207	-
N	32	19	-

System prices are in 2020 $US/kW, cumulative installed capacity is in MW, system sizes are in MW. All values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** $\leq$ 0.001, ** $\leq$ 0.01, * $\leq$ 0.05.

Supplementary Note 4. The Effect of Precious Metal Prices

Some components of PEM electrolyzer systems, such as the electrodes, bipolar plates, and porous transportation layers, so far require the precious metals platinum and iridium[28;86]. To examine the potential effect of a change in the market prices of either metal, let $Platinum_i$ and $Iridium_i$ denote the respective global annual average market prices in year i and β_3 and β_4 the corresponding regression coefficients. The logarithmic form of the extended learning curve is then given by:

$$\ln(v_i) = \beta_0 + \beta_1 \cdot \ln(Q_i) + \beta_3 \cdot Platinum_i + \beta_4 \cdot Iridium_i + \mu_i, \tag{A8}$$

where μ_i is again assumed to have a zero mean and to be uncorrelated with the independent variables.

Market prices for both metals are taken from `www.platinum.matthey.com`. Supplementary Table 7 provides detailed regression results. Similar to before, we find that the differences between our learning estimates, β_1, in Supplementary Tables 1 and 7 are relatively small. At the same time, the estimated coefficients for both metals are economically insignificant.

Supplementary Table 7. Regression results for equation (A8)**.**

	System prices
β_0	8.2219***
	(0.2333)
β_1	−0.1957***
	(0.0210)
β_3	0.0000
	(0.0002)
β_4	-0.0002
	(0.0001)
2^{β_1}	0.8731
Adj. R^2	0.7390
N	79

System prices are in 2020 $US/kW, cumulative installed capacity is in MW, platinum and iridium prices are in 2020 $US/ounce. Entries in parentheses are standard errors. Key to statistical significance: *** $\leq$ 0.001, ** $\leq$ 0.01, * $\leq$ 0.05.

Supplementary Note 5. Learning Curve Estimates for the Years 2010–2020

Here we repeat the learning curve estimations for alkaline and PEM electrolyzers covering only the years 2010–2020 to examine the most recent development. The reduction in system prices for alkaline electrolyzers corresponds to a learning curve of $2^{\beta_1} = 82.30\%$ with a 95%-confidence interval of 6.7% ($p < 0.0001$, adj. $R^2 = 0.17$). Accordingly, system prices declined by 17.7% with every doubling of cumulative installed capacity, which is about 2.0% higher than the estimate reported in Figure 1 in the main body. Regarding the conversion efficiency of alkaline systems, the shorter period results in a learning curve of $96.9 \pm 2.33\%$ ($p < 0.05$, adj. $R^2 = 0.05$), which is also lower than in our main specification. Thus, alkaline system improvements appear to originate mainly from the past ten years.

For PEM electrolyzers, the learning curve estimates for system prices and conversion efficiency over the years 2010–2020 are almost identical to those reported in Figure 1 in the main body. In particular, our calculations return a learning curve of $86.3 \pm 2.91\%$ ($p < 0.0001$, adj. $R^2 = 0.50$) for system prices and a learning curve of $98.4 \pm 1.0\%$ ($p < 0.01$, adj. $R^2 = 0.11$) for conversion efficiency. For all specifications, especially for alkaline, the adj. R^2 values are now lower, while the 95%-confidence intervals are higher because of the decreased sample sizes.

Supplementary Table 8. Regression results for last 10 years.

	System prices		**Energy Consumption**	
	Alkaline	PEM	Alkaline	PEM
β_0	8.3304***	8.0475**	1.7747***	1.7452***
	(0.2631)	(0.0769)	(0.0723)	(0.0236)
β_1	−0.2810***	−0.2133**	0.0177*	0.0074**
	(0.0621)	(0.0248)	(0.0177)	(0.0074)
2^{β_1}	0.8230	0.8626	0.9693	0.9841
Adj. R^2	0.1732	0.5029	0.0493	0.1054
N	94	73	106	75

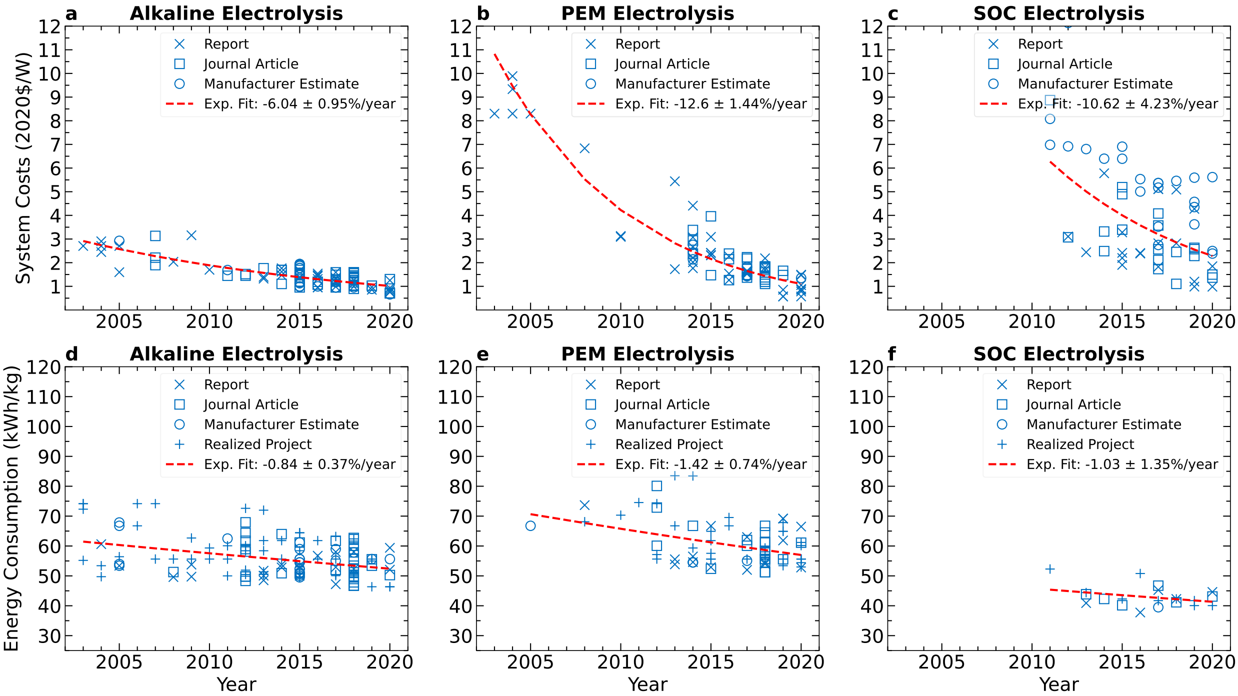
System prices are in 2020 \$US/kW, cumulative installed capacity is in MW. Entries in parentheses are standard errors. Key to statistical significance: *** $\leq$ 0.001, ** $\leq$ 0.01, * $\leq$ 0.05.

Supplementary Note 6. Learning Estimates and Projections by Time

A common alternative to learning curves based on cumulative installed capacity is the estimation of technological progress as a function of time. To that end, we now estimate the development of system prices by means of a univariate regression for a constant elasticity model of the form:

$$\ln(v_i) = \lambda_0 + \lambda_1 \cdot i + \epsilon_i, \tag{A9}$$

where ϵ_i denotes the idiosyncratic error term with $E[\epsilon_i] = 0 \ \forall i$. Accordingly, the system prices of a PtG technology are predicted to fall every year to e^{λ_1} of its value in the preceding year. Our estimation of the changes in a technology's energy consumption is again symmetric.



Supplementary Figure 3. Dynamics of system prices and efficiency over time. a, b, c, d, e, f This figure shows the trajectory of system prices in 2020 \$US and our estimates of the corresponding annual price decline for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers. It also shows the development of the energy consumption and our estimate of the corresponding annual improvement for (**d**) alkaline, (**e**) PEM, and (**f**) SOC electrolyzers.

Supplementary Figure 3a–c shows the system prices of the three electrolysis technologies and our estimates of the corresponding annual price decline. For alkaline electrolyzers, the reduction in system prices across the years 2003–2020 corresponds to an annual decline of $1 - e^{\lambda_1} = 6.0\%$ with a 95%-confidence interval of 1.0% ($p < 0.0001$, adj. $R^2 = 0.56$). In contrast, SOC electrolyzers exhibit a price decline between 2011–2020 described by an annual reduction of $10.6 \pm 4.2\%$ ($p < 0.0001$, adj. $R^2 = 0.25$). PEM electrolyzers show a similarly rapid decline in system prices across 2003–2020 of $12.6 \pm 1.4\%$ ($p < 0.0001$, adj. $R^2 = 0.77$). See Supplementary Table 9 for details.

Supplementary Figure 3d–f shows the changes in energy consumption and our estimates of the annual improvement. We find that the improvement in energy consumption of alkaline systems across the years 2000–2020 corresponds to an annual increase of $0.8 \pm 0.4\%$ ($p < 0.0001$, adj. $R^2 = 0.11$). In contrast, SOC electrolyzers show an annual improvement between 2011–2020 of $1.0 \pm 1.4\%$ ($p < 0.15$, adj. $R^2 = 0.07$). PEM electrolyzers display an annual increase across 2005–2020 of $1.4 \pm 0.7\%$ ($p < 0.0001$, adj. $R^2 = 0.15$).

Supplementary Table 9. Regression results for equation (A9)**.**

	System Prices			**Energy Consumption**		
	Alkaline	PEM	SOC	Alkaline	PEM	SOC
λ_0	132.7101***	279.1588***	234.6324***	17.9059***	30.5509***	22.2568***
	(10.3038)	(16.8381)	(48.9072)	(3.9154)	(7.6656)	(13.1918)
λ_1	−0.0623***	−0.1347***	−0.1123***	−0.0081***	−0.0143***	−0.0104***
	(0.0051)	(0.0084)	(0.0243)	(0.0019)	(0.0038)	(0.0065)
e^{λ_1}	0.9396	0.8740	0.8740	0.9916	0.9858	0.9897
Adj. R^2	0.5839	0.7686	0.2511	0.1139	0.1461	0.0703
N	106	79	62	132	78	21

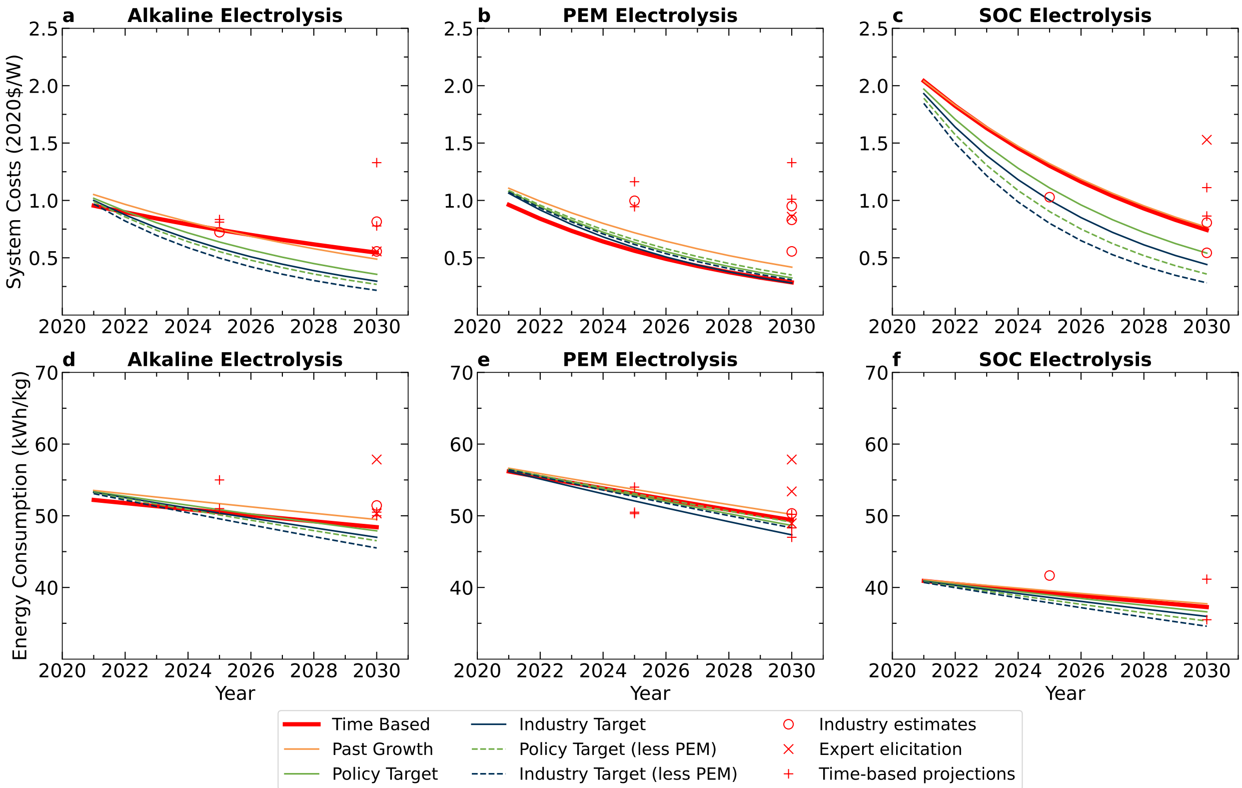
System prices are in 2020 \$US/kW and time is given in years. Price values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** ≤ 0.001, ** ≤ 0.01, * ≤ 0.05.

We now use our estimates in Supplementary Figure 3 to project an alternative trajectory of future system prices and energy consumption for each PtG technology. As one would expect, the resulting trajectories for system prices and energy consumption shown in Supplementary Figure 4 are close, if not identical, to the previous trajectories corresponding to the Past-Growth scenario. As an exception to this, 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 a large share of lower price observations in recent years.

As a final robustness check, we examine a specification based on time and cumulative installed capacity. The bivariate constant elasticity functional form is given by:

$$\ln(v_i) = \beta_0 + \beta_1 \cdot \ln(Q_i) + \beta_2 \cdot i + \epsilon_i, \tag{A10}$$

where ϵ_i denotes the idiosyncratic error term with $E[\epsilon_i|Q_i] = 0 \; \forall i$. The estimation of the changes in a technology's energy consumption is again symmetric.



Supplementary Figure 4. Prospects for system prices and efficiency based on time. a, b, c, d, e, f This figure shows our time-based projections of the potential development of system prices in 2020 $US for (**a**) alkaline, (**b**) PEM, and (**c**) SOC electrolyzers. It also shows our time-based projections of the potential trajectory of energy consumption for (**d**) alkaline, (**e**) PEM, and (**f**) SOC electrolyzers.

Supplementary Table 10. Regression results for equation (A10)

	System Prices			Energy Consumption		
	Alkaline	PEM	SOC	Alkaline	PEM	SOC
β_0	153.6344***	405.2188**	313.6040	29.9637***	2.7511	128.1963
	(32.8751)	(121.1544)	(376.1014)	(10.1289)	(44.1837)	(98.7539)
β_1	0.0468	−0.1974	0.0942	0.0219	−0.0238	0.1295
	(0.0698)	(0.0602)	(0.4445)	(0.0180)	(0.0372)	(0.1196)
β_2	−0.0727***	0.1029**	−0.1514	−0.0141**	−0.0005	−0.0628
	(0.0164)	(0.0979)	(0.1863)	(0.0051)	(0.0220)	(0.0489)
2^{β_1}	1.0330	0.8721	1.0674	1.0153	0.9837	1.0939
e^{β_2}	0.9298	1.0739	0.8595	0.9860	0.9995	0.9391
Adj. R^2	0.5817	0.7689	0.2389	0.1275	0.1394	0.0786
N	106	79	62	132	78	21

System prices are in 2020 $US/kW, cumulative installed capacity is in MW, average system sizes are in MW. All values are logarithmized using the natural logarithm (ln). Entries in parentheses are standard errors. Key to statistical significance: *** ≤ 0.001, ** ≤ 0.01, * ≤ 0.05.

Supplementary Table 10 provides detailed regression results. For both system prices and energy consumption, the regression coefficients for cumulative installed capacity are now positive and statistically insignificant, while the coefficients for time are close to those reported in Supplementary Table 9. These results can be attributed to severe multicollinearity between the two independent variables. Specifically, alkaline electrolyzers exhibit a Pearson correlation coefficient of 0.95 and a variance inflation factor of 10.3. PEM systems show a Pearson correlation coefficient of 0.99 and a variance inflation factor of 52.0. Finally, SOC technology shows a Pearson correlation coefficient of 0.99 and a variance inflation factor of 58.1. Nevertheless, projected trajectories for system prices and energy consumption based on the regression estimates are close to the time-based projections reported in Supplementary Figure 4. As such, all scenarios and specifications in our calculations yield a consistent assessment of the magnitudes and trends in price and efficiency improvements.

Supplementary Note 7. Levelized Cost of Hydrogen

Supplementary Table 11 provides detailed inputs and outputs for our LCOH calculations.

Supplementary Table 11. Estimates of levelized cost of hydrogen by 2030.

in 2020 $US	**Source**	**Alkaline**	**PEM**	**SOC**
General parameters				
Economic lifetime, T (years)	[1]	20	20	20
Cost of capital, r (%)	[2]	5.00	5.00	5.00
Number of hours per year, m (h)		8,760	8,760	8,760
Corporate income tax rate, α (%)	[3]	21.00	21.00	21.00
Depreciation method (–)*	[4]	3	3	3
Degradation rate, x (%)	[7]	1.00	1.00	1.60
Electricity buying price, $q_i(t)$ ($/kWh)	[5]	0.0359	0.0359	0.0359
Past Growth				
System price, v ($/kW)	[6]	475	352	767
Fixed operating cost, F_i ($/kW)	[6]	9	9	15
Hydrogen conversion rate, η^{-1} (kWh/kg)	[6]	49.48	49.84	42.72
Average optimized capacity factor, CF^* (%)		0.73	0.66	0.85
Levelized cost of hydrogen, $LCOH$ ($/kg)		1.89	1.81	1.91
Policy Target				
System price, v ($/kW)	[6]	340	263	536
Fixed operating cost, F_i ($/kW)	[6]	7	7	11
Hydrogen conversion rate, η^{-1} (kWh/kg)	[6]	47.86	48.21	41.58
Average optimized capacity factor, CF^* (%)		0.60	0.53	0.74
Levelized cost of hydrogen, $LCOH$ ($/kg)		1.71	1.66	1.69
Industry Target				
System price, v ($/kW)	[6]	284	225	441
Fixed operating cost, F_i ($/kW)	[6]	6	6	9
Hydrogen conversion rate, η^{-1} (kWh/kg)	[6]	46.51	48.72	40.96
Average optimized capacity factor, CF^* (%)		0.52	0.46	0.68
Levelized cost of hydrogen, $LCOH$ ($/kg)		1.63	1.59	1.59

*3: 20-year 150%-declining balance; Sources: [1],[87] [2],[88;89] [3],[90] [4],[91] [5], `www.ercot.com`,[92] [6], own analysis [7],[27;29;93].

Contact.

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