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# Grid-responsive hydrogen production: Capital utilization and current density vs. efficiency in variable electricity markets

Colby Smith [*], Joe Brauch, Meital Shviro, Bryan Pivovar, Alex Badgett [**]

*National Renewable Energy Laboratory, 5013 Denver W Pkwy, Golden, CO, 80401, USA*

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ABSTRACT

To achieve low-cost hydrogen production from water electrolyzers, grid tied electrolysis may need to operate dynamically to minimize the cost of supplying energy to the electrolyzer stack and produce hydrogen during low-cost hours and turn off/down during high-cost hours. Operating systems in this way can decrease capital utilization (capacity factor) and electricity costs. This strategy would shift the dominant cost drivers away from electricity (and thus efficiency) to the capital costs of the system, due to the underutilized capital when operating at low-capacity factors. Increasing the operational current density of the system could, in effect, reduce the capital cost of the system while producing hydrogen at a lower efficiency on a per unit energy basis. In the variable electricity cost profiles analyzed in this paper, increasing the current density for liquid alkaline from 0.5 A/cm2 to 1.5 Ac/m2 and proton exchange membrane electrolyzers from 2 A/cm2 to 4 A/cm2 resulted in substantial reductions in the levelized cost of hydrogen. Additionally, as capacity factors and electricity costs decrease, the optimal operating current density of the electrolyzer systems analyzed increases. These findings suggest R&D efforts should focus on increasing the operational current densities, reducing the turn down ratios, and understanding the durability implications of those strategies on low-temperature liquid alkaline and proton exchange membrane electrolyzers.

## 1. Introduction

Countries around the world have developed hydrogen roadmaps, many of which acknowledge the versatility of hydrogen as an energy carrier [1–5]. Globally, these roadmaps estimate potential for hydrogen demand to grow from 97 Mt (million metric tons) in 2023 to close to 150 Mt by 2030 and to 375 Mt by 2050 [6,7]. Hydrogen is seen as a critical component for energy security and resilience, job creation, and energy arbitrage, and its usage could span the transportation, power, industrial, and agriculture sectors [6,7]. Examples of use cases for hydrogen include, but are not limited to, fuel cells for medium-duty or heavy-duty vehicles, ammonia production, methanol production, steel production, and long-duration energy storage [6]. In support of domestic supply to meet these emerging demands, different sources of inexpensive hydrogen will continue to be developed [6,7].

Traditionally, hydrogen has been produced via steam methane reformation (SMR) of natural gas, coal gasification, or as a by-product of other processes [7]. There are several additional emerging hydrogen production technologies that are being deployed at industrial scales, such as methane pyrolysis and water electrolysis [8]. Depending on the location and availability of resources, these technologies may complement production from incumbent production technologies and be utilized to help meet growing global demands for hydrogen [6,8,9]. For example, worldwide announced electrolyzer projects amount to 100 times today's installed capacity [7].

This analysis focuses on the two most common types of low-temperature water electrolysis: proton exchange membrane (PEM) and liquid alkaline (LA) (for all nomenclature, see Table 1) [8]. Understanding cost drivers for electrolytic hydrogen production for these technologies is critical to deploying cost-effective electrolyzers and securing low-cost, reliable hydrogen. In addition to presenting and discussing the work conducted in this analysis, we overview major caveats, assumptions, and opportunities for future research in Section 4, such as the influence of the electric power sector, the role of life cycle analysis, and the relevance of our work across geographies and hydrogen market structures.

In most cases, the largest driver of levelized cost of hydrogen (LCOH) from water electrolysis is the cost of electricity [10]. Badgett et al. [11]

* Corresponding author.
** Corresponding author.
*E-mail address:* colby.smith@nrel.gov (C. Smith).

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**Table 1**
Nomenclature.

| Symbol | Meaning |
|---|---|
| PEM | Proton exchange membrane water electrolyzer |
| LA | Liquid Alkaline water electrolyzer |
| BOP | Balance of plant for the electrolyzer system |
| Capex | Capital expenditure of the system ($/kW) |
| Opex | The operational expenditure of the system |
| Q | Power provided to the electrolyzer system (kW) |
| SEC | The specific energy consumption of the electrolyzer (kWh/kg) |
| CFp | The production capacity factor of the electrolyzer system (–). |
| CFe | The electrical capacity factor of the electrolyzer system (–). |
| $\eta$ | The lower heating value |
| $C_e$ | The cost of electricity ($) |
| $c_e$ | The cost of electricity ($/MWh) |
| $C_{stack}$ | The capital cost of the stack ($/kW) |
| E | The energy consumed from the electrolyzer (kWh) |
| TDR | The turn down ratio of the electrolyzer system |
| I | The current density of the electrolyzer (A/cm$^2$) |
| V | The voltage of the electrolyzer (V) |
| $\delta$ | The voltage degradation rate of the electrolyzer (mV/1000h) |

identified several options for an electrolyzer to achieve low electricity costs, including direct connection to a low-cost electricity generation source or by interfacing with wholesale grid markets such that the electrolyzer only purchases electricity during the cheapest hours. This analysis is focused on dynamic integration with wholesale grid markets, which could result in electrolyzers that operate at low capacity factors to minimize electricity costs [11]. With electrolyzers operating at low capacity factors, the system capital costs become a larger cost driver, because of the amount of underutilized capital investment. As such, steps must be taken to reduce the capital costs of electrolyzer systems operating with this strategy.

Previous analysis work has considered strategies for reducing electrolyzer capital costs through alternative materials and/or reduced material usage [12–14]. To enable these cost reductions, experimental work has considered the performance and durability impacts of dynamic operating strategies and studied electrolyzers with lower usage of expensive materials and/or utilizing higher performing materials [15–20]. These two areas of work highlight a tradeoff between capital costs (in the form of more expensive materials) and performance and durability considerations (if those more expensive materials yield more efficient and stable electrolyzers). These tradeoffs and the relative impact on LCOH have not been adequately characterized and are an active area of experimental and analysis research.

In this study, we consider the economic impacts from increasing electrolyzer current density from a baseline 0.5 A/cm2 and 2 A/cm2 for LA and PEM electrolyzers, respectively. Our findings will inform the research community on tradeoffs between cost and performance under various operational scenarios for electrolyzers. For an electrolyzer with fixed components and materials costs, operating at a higher current density increases the amount of hydrogen generated per unit of catalytically active area, lowers the capital cost when expressed in $/kW, but lowers the efficiency of the electrolyzer. As such, economic advantages of higher current operation will depend on the costs and available electricity provided to the electrolyzer.

## 2. Methods and materials

### 2.1. Economic assumptions

All LCOH values presented in this analysis were calculated using the Production Financial Analysis Scenario Tool [21] (ProFAST). Assumptions for electrolyzer installation costs, indirect capital costs, and operating expenses are based on NREL's Hydrogen Analysis Production Models (H2A) [22]. We use parameters from the Current Central PEM Case since the plant scale is similar to the plant scale assumed in this analysis (56,500 kg/day in H2A vs 50,000 kg/day in this analysis) [22]. Most parameters scale with plant size (i.e., scale with capital cost) and are adjusted to match the plant sizes used in this analysis; however, land and labor costs are specified absolutely in H2A and are not adjusted for plant scale. For simplicity, we assume that LA electrolyzers have the same values for these parameters as PEM systems, since H2A does not have a LA case study. While LA and PEM electrolyzers would likely not have identical land, operating, and overhead costs, these costs as a fraction of capital expenses could be similar given the high-level similarity of LA and PEM electrolyzers as modular chemical plants. [22]. Relevant parameters are shown in Table 2.

We assume that all capital costs are depreciable over the 40-year plant life except for land costs. Unplanned replacements are distinct from specific stack replacements described in Section 2.5 and are intended to capture replacement of stacks and other components which fail before the end of their planned lifetime.

Within ProFAST, we use economic and financing parameters from Penev et al. (2024) [23], shown in Tables 2 and 3. We perform the analysis in real 2020 dollars, using appropriate real values (as opposed to nominal values) for relevant financial parameters with 0 % inflation and no cost escalation in future modeling years Note that while we report results in 2020 dollars, the financing parameters from Penev et al. represent industry values from 2023 to 2024, so this analysis represents installing and financing an electrolyzer plant in a financial environment in that time frame (reasonably close to present day).

### 2.2. Electrolyzer system

Uninstalled capital expenses (Capex) are the cost of materials, labor, etc. to manufacture the stack. This includes, but is not limited to, the membrane, electrodes, catalyst layers, flow fields, and balance of stack components and have been estimated through bottom-up cost modeling [13,14]. The baseline uninstalled costs of each stack represented in this analysis are 550 $/kW and 350 $/kW for PEM and LA electrolyzers, respectively, which are derived from the cost modeling from Badgett et al. and Strategic Analysis Inc., assuming cost reductions through manufacturing economies of scale [13,14]. Electrolyzers also have a supporting balance of plant (BOP) which can account for over half the total system capital costs [12,24,25]. There is on-going work about the differences between LA and PEM BOP, but for this analysis both uninstalled BOP Capex are assumed to be 250 $/kW, assuming aggressive R&D success [24,25]. This results in an uninstalled system cost of 600 $/kW and 800 $/kW for the LA and PEM systems respectively. For

**Table 2**
Capital and operating expense assumptions in this analysis.

| | Parameter | Value |
|---|---|---|
| Capital expenses | Purchase costs | $/kW cost for stack and balance of plant (BOP) described in Section 2.2 |
| | Installation costs | 12 % of purchase costs |
| | Engineering, construction, permitting, and contingency costs | 42 % of installed costs |
| | Land costs | $250,000 (5 acres at $50,000/acre)[a] |
| Operating expenses | Labor costs | $1,040,000 per year (10 workers at $50/hour)[a] |
| | General and administrative (G&A) costs | 20 % of labor costs |
| | Property tax and insurance | 2 % of total capital investment per year |
| | Maintenance costs | 3 % of installed cost per year |
| | Unplanned replacements | 0.5 % of depreciable capital investment per year |

[a] Costs from H2A are reported in 2016$ and are used as 2020$ in this analysis. Installation costs are based on the "Installation Cost Factor" assumed in the H2A Current Central PEM case; all other costs besides purchase costs are based on the corresponding input assumptions for the Current Central PEM case [22].

**Table 3**
Economic and financing parameters used in this analysis, sourced from Penev et al. [23].

| Parameter | Value |
|---|---|
| Dollar year | 2020$ |
| Inflation | 0 % (real dollars) |
| Debt interest rate | 4.4 % |
| Discount rate (return on equity) | 10.2 % |
| Debt type | Bond debt |
| Debt to equity ratio | 0.62 |
| Total tax rate | 25.7 % |
| Capital gains tax | 15 % |
| Depreciation schedule | 7-year Modified Accelerated Cost Recovery System (MACRS) |
| Cash-On-Hand reserve | 3 months of operating expenses |

reference, the current installed system of PEM electrolyzers is around 2000 $/kW [26], compared to an overnight cost of approximately $1272/kW for PEM systems in this analysis after applying assumed installation and overhead costs. Given that this assumption is lower than the current installed cost, the electrolyzer systems in this analysis could be thought of as representing potential near-term futures following capital cost reductions from R&D and manufacturing scale-up.

One way to reduce the system capital costs is by increasing the current density of the system. This reduces the stack Capex on a $/kW basis, as an increase in current density increases the power consumption and hydrogen production of a given stack. Since increasing the current density increases the current flow to the stack and production rate of hydrogen, it is assumed that the cost of the BOP will remain fixed and not decrease in the same way the stack costs decrease.

The penalty for increasing the current density is an increase in voltage or decrease in efficiency. Fig. 1 highlights the trends between the increase in voltage and the decrease in stack Capex. This work analyzes these tradeoffs and their impact on the LCOH of the hydrogen systems.

The electrolyzer system, operating at 100 % electrical capacity factor (CFe), was modeled as a plant producing 50,000 kg of hydrogen per day, shown in Equation (1).

$$CFe = \frac{\int_0^t Q_t dt}{\int_0^t Q_{rated} dt} \cong \frac{\sum_{t=1}^{8760} Q_t * (\Delta t)}{Q_{rated} * 8760} \tag{1}$$

Where $Q_t$ and $Q_{rated}$ are the instantaneous power at time $t$ and the rated power for the electrolyzer. This is roughly 125 MW and 104 MW for LA and PEM systems assuming a 5 kWh/kg BOP energy consumption, respectively. The *CFe* is utilized during the electricity cost linear optimization algorithm discussed in Section 2.3.

The production capacity factor (CFp), shown in Equation (2), is the amount of hydrogen that could be produced at rated power ($m_{H2,rated}$) vs the amount of hydrogen actually produced ($m_{H2,produced}$) where $SEC_t$ and $SEC_{rated}$ are the instantaneous (at time $t$) and rated energy consumption, in kWh/kg, of the electrolyzer system.

$$CFp = \frac{\int_0^t \frac{Q_t}{SEC_{inst}} dt}{\int_0^t \frac{Q_{rated}}{SEC_{rated}} dt} \cong \frac{\sum_{t=1}^{8760} \frac{Q_t}{SEC_t} * (\Delta t)}{\frac{Q_{rated}}{SEC_{rated}} * 8760} = \frac{m_{H2,produced}}{m_{H2,rated}} \tag{2}$$

The CFp is utilized during the non-linear operational cost optimization algorithm, discussed in Section 2.3 and is utilized as the capacity factor input into ProFAST to estimate how much hydrogen is being generated per day.

The specific energy consumption (kWh/kg), $SEC$, is calculated as shown in Equation (3). $\eta_{stack,LHV}$ is the lower heating value efficiency of the electrolyzer stack. In this analysis, the cell level polarization curves, shown in Fig. 1, are representative of the performance of the electrolyzer stack.

$$SEC = SEC_{BOP} + SEC_{stack} = SEC_{BOP} + \frac{33.6 \left[\frac{kWh}{kg}\right]}{\eta_{stack,LHV}} \tag{3}$$

The BOP efficiency curve was adopted from Wang et al. [27] and was used for both the LA and PEM stacks and changes as a function of operating power, shown in the SI.

### 2.3. Electricity costs

Hourly electricity cost distributions were accessed from NREL's Cambium dataset [28,29]. The Cambium data set contains hourly cost and other operational data for zones across the United States for NREL's standard electricity grid development scenarios [28,30]. It is important to note that the Cambium models electricity costs and not prices. These costs do not include any market predictions and may not fully reflect future electricity markets. We used three different locations, Casper, WY (P24), Amarillo, TX (P48), and Palo Verde, AZ (P28) at two different times, 2024 (Case 1) and 2035 (Case 2) for the 2022 Cambium "Mid-case 100 % Net Lifecycle CO2e Reduction by 2035" scenario to model

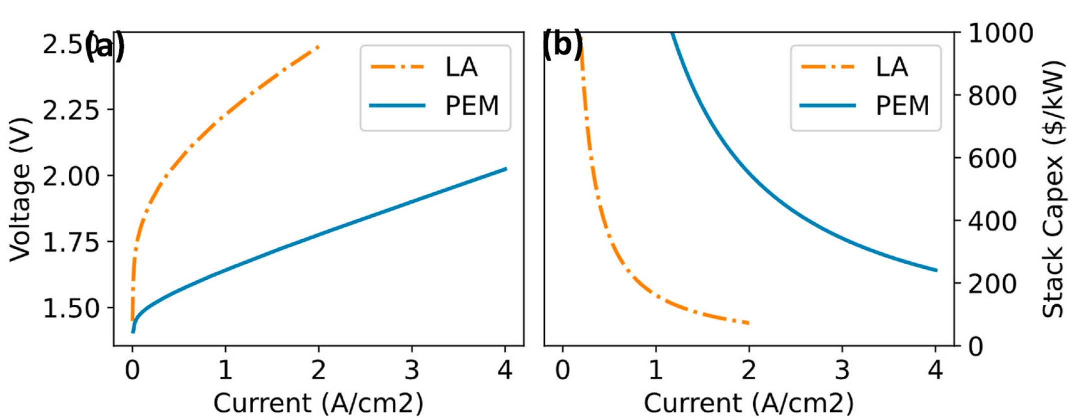


**Fig. 1.** State of the art (a) Polarization curves for liquid alkaline (LA, orange-dash) and proton exchange membrane (PEM, blue-solid) water electrolyzers obtained from the H2NEW consortium and (b) their associated stack capital costs (Capex) as a function of current density. The stack capital costs are baselined at $350/kW at 0.5 A/cm2 (2.05 V) and $540/kW at 2 A/cm2 (1.78 V) for LA and PEM electrolyzers, respectively. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

electricity costs utilized as the input electricity cost for the electrolyzer [28,30]. The locations are reflected by the modeled regions in NREL's Regional Energy Deployment System (ReEDS) model [31].

Using these scenarios as the input electricity cost, a linear optimization program, built in Python using the optimization package Pyomo [32,33], was developed to minimize the total electricity cost purchased through the whole year, while still meeting a minimum CFe. The effective average electricity cost ($c_{e,average}$) was then used in the levelized cost model (discussed in section 2.1). This program calculates the optimal drive cycle for a given input CFe. The electrolyzer operating ratio (0–1) at every hour of the year is treated as its own variable $x_t$ and there is an associated electricity cost for that hour ($c_{e,t}$). The objective function is shown in the numerator of Equation (4), where $c_{e,average}$ is the average cost of electricity for a given drive cycle ($/MWh). The constraints to the linear program are shown in Equations (5) and (6) where $x_t$ must be between 1 (operating at full capacity) and 0 (completely shut off) denoting the percent of rated capacity the plant is operating at, and the calculated capacity factor of the plant must be greater or equal to the user input capacity factor (CFe). Since the input electricity cost profile is an hourly profile for the year, n = 8760.

$$c_{e,average} = \frac{min\left(\sum_t^n c_{e,t} * x_t\right)}{\sum_t^n x_t} \quad (4)$$

$$1 \geq x_t \geq 0 \quad \forall x\, t = 1, 2, \ldots n \quad (5)$$

$$\sum_t^n \frac{x_t}{n} \geq CFe\ t = 1, 2, \ldots n \quad (6)$$

Turn down ratios (TDRs) change the optimization slightly. Instead of turning the electrolyzer fully off, TDRs are a number between 0 and 1 representing the lowest point the electrolyzer can operate at. TDRs are used in electrolyzers to avoid degradation and hydrogen crossover effects resulting from on/off cycling of the stack [15,16,34–36]. When using a TDR, the constraint of the electrolyzer operating setpoint must be changed as shown in Equation (7).

$$1 \geq x_t \geq TDR_p \quad \forall_x \quad t = 1, 2, \ldots n \quad (7)$$

Even though $x_t$ is unconstrained to operate at any point between the minimum and maximum operating points, the electricity optimization will favor always maximizing $x_t$ during low cost times, which leads to the electrolyzer either operating at full capacity or turning off/down during high costs. Introducing the efficiency profile into the optimization introduces non-linearities in the constraint of the program since efficiency is a non-linear curve, shown in Equation (8). The linear solver solves for the cheapest electricity cost ($/MWh) given an electricity profile, while the non-linear solver optimizes for the cheapest hydrogen production cost ($/kg) given an electricity cost profile and efficiency curve. We found that utilizing there was not a large difference between the two solvers. Solving the objective function (Equation (4)) with the new constraint will determine the best operating profile for the electrolyzer with the desired hydrogen production rate CFp.

$$\sum_t^n \frac{x_t}{SEC_t * n} \geq CFp \quad t = 1, 2, \ldots n \quad (8)$$

The linear program will produce an optimized drive cycle, which minimizes the electricity cost ($/MWh) while the non-linear program will optimize the hydrogen production cost across the year-long drive cycle ($/kg). Regardless of the optimization method chosen, the total cost of electricity purchased ($C_{total}$, $), total amount of energy consumed ($E_{total}$, kWh), and total hydrogen produced ($m_{total}$, kg) can be calculated with the drive cycle to obtain an effective cost of electricity ($c_{e,eff}$, $/MWh) and an effective specific energy consumption ($SEC_{eff}$) which can be used in the ProFAST discounted cash flow model, described in section 2.1.

$$c_{e,eff} = \frac{C_{total}}{E_{total} * \left(\frac{1}{1000}\right)} = \frac{Q_{rated} * \sum_t^n x_t * c_t}{Q_{rated} * \sum_t^n x_t} \quad (9)$$

$$SEC_{eff} = \frac{E_{total}}{m_{total}} = \frac{Q_{rated} * \sum_t^n x_t}{Q_{rated} * \sum_t^n \frac{x_t}{\eta_t}} \quad (10)$$

### 2.4. Turn down ratios

The minimum power an electrolyzer can operate at is referred to as the power turn down ratio ($TDR_p$). This can be limited by the power electronics, flow rates, or the gas crossover within the electrolyzer [34,36–39]. This analysis uses a minimum operational current of 0.05 A/cm2 and 0.2 A/cm2, which is 10 % of baseline rated current, or current turn down ratio ($TDR_c$), for LA and PEM electrolyzers, respectively. For the LA system this results in a $TDR_p$ of 8.5 % and 2.5 % for the baseline current density of 0.5 A/cm2 and the high current density of 1.5 A/cm2. For the PEM system, the $TDR_p$ is 8.5 % and 3.7 % for the 2 A/cm2 and 4 A/cm2 current densities, respectively. It is not a linear relationship because the current increasing also increases the voltage impacting the required power, shown in Equation (11) where $I_{TDR_c}$ and $V_{TDR_c}$ are the current density and voltage at $TDR_c$ and $I_{rated}$ and $V_{rated}$ are the operating current density and voltage.

$$TDR_p = \frac{I_{TDR_c} * V_{TDR_c}}{I_{rated} * V_{rated}} \quad (11)$$

### 2.5. Efficiency degradation and stack replacement

The baseline degradation rates ($\delta_{base}$) were assumed to be 3.2 mV/1,000hrs and 4.8 mV/1,000hrs for LA and PEM systems operating at baseline current density ($I_{base}$) of 0.5 A/cm2 and 2 A/cm2, respectively [24,25]. The degradation rates were assumed to be directly related to operational current density ($I_t$). For example, if the electrolyzers were operating at 1 A/cm2 and 4 A/cm for LA and PEM respectively, the degradation rates would be 6.4 mV/1000hrs and 9.6 mV/1000hrs. Degradation due to ramping, start-up and shut down, or cycling are not considered and are an active area of research [16,37]. This gives the degradation rate to be a function of $I$ shown in Equation (12).

$$\delta(I_t) = \delta_{base} * \frac{I_t}{I_{base}} \quad (12)$$

The annual degradation ($\delta_{annual}$) rate in mV/year was then calculated as a function of the drive cycle ($x_t$), shown in Equation (13). There are 8.76 1,000 hrs/yr which is used because degradation rate is expressed in mV/1,000hrs.

$$\delta_{annual} = \sum_t^n \frac{\delta(x_t)}{n} * 8.76 \quad (13)$$

In this analysis we assume that the electrolyzer plant is limited on the total amount of energy that it can buy for the year. This means that as the electrolyzer degrades, the production of hydrogen on a yearly basis, decreases, thus decreasing CFp.

Stack lifetimes are primarily determined by two metrics. The first is the optimal economic replacement period for the stack and the second is if there is a component failure and the stack can no longer be operated safely. In this analysis, we did not include the latter for determining the lifetime of the stack. As the stack degrades in efficiency, more electricity must be purchased to meet the same hydrogen output. Thus, the frequency of when to replace the stack is determined by factors such as the cost of electricity, cost of stack replacement, efficiency of the new stack, and degradation rate.

The stack life optimization reveals that at low degradation rates the optimum stack life occurs at over about 20 years of or 170,000h operational time, shown in Fig. SI3. For high degradation rates and high-capacity factors, the economic stack life is around 7 years. After this, the worse efficiency and electricity costs of \$0.03/kWh make the operating cost so high that buying a new stack (and operating at higher efficiency) is more economical. Since the stack lifetimes begin to plateau around 10 years (except the 9.6mV/1000hrs degradation rate in high CF high electricity cost scenario), it indicated that a 10-year stack life would be fair across scenarios.

The 10-year stack lifetime corresponds roughly to an 85,000 h stack life at 97 % CFe and a 44,000 h stack life at 50 % CFe. Although the low capacity factor scenarios have a much shorter operational stack life, additional years of stack lifetime would not have a major impact on the LCOH values presented, shown in Fig. SI3. The stack replacement cost, expressed as a fraction of installed capital cost, is shown in Equation (14), where $C_{stack}$, $C_{BOP}$, and $SV$ (salvage value) are the cost of the stack, the cost of the balance of plant, and the percentage value of the stack that can be recouped from recycling/salvaging. This cost (the fraction multiplied by the initial installed cost) is incurred in the discounted cash flow model whenever the stack is replaced.

$$C_{replacment} = \frac{C_{stack}*(1 - SV)}{C_{stack} + C_{BOP}} \qquad 14$$

Because PEM electrolyzers have more precious materials in the stack, it has been estimated that 85–90 % of the PGM material value can be recovered at the end of life of the stack [40]. These materials represent cost drivers for PEM stacks, so their high recovery rates suggest overall high salvage values for PEM stacks [13]. Accounting for potential overhead capital and operating costs with profit margin for a recycling facility, the salvage value for the PEM stacks are assumed to be 70 %, while the salvage value for the LA stacks are assumed to be 15 %.

## 3. Results and discussion

Grid mixes with a high percentage of renewable energy technologies are estimated to have a large distribution of hourly electricity costs [28,29], shown in the box-whisker plots in Fig. 2 a.) and b.) for the selected locations. The future scenarios are projected to have a higher frequency of high-cost hours, and those hours having a higher overall cost, although the average across all 8760 h in a year is lower than other scenarios. As such, grid connected electrolyzers might operate dynamically to take advantage of the low-cost electricity when available and consume less power during the times of high-cost electricity. This can be accomplished by minimizing the turn down ratio during the high-cost hours, explored by Badgett et al. [11] or by increasing the current density during the low-cost hours. This, in turn, decreases the Capex and the efficiency of the system, which drives up the hydrogen production cost, but lowers required initial investment. Because the effective electricity costs are low in these scenarios, the cost penalty from reduced efficiency is less significant than the cost benefit from reducing effective capital costs.

An increase of the current density from 0.5 A/cm2 to 1.5 A/cm2 for

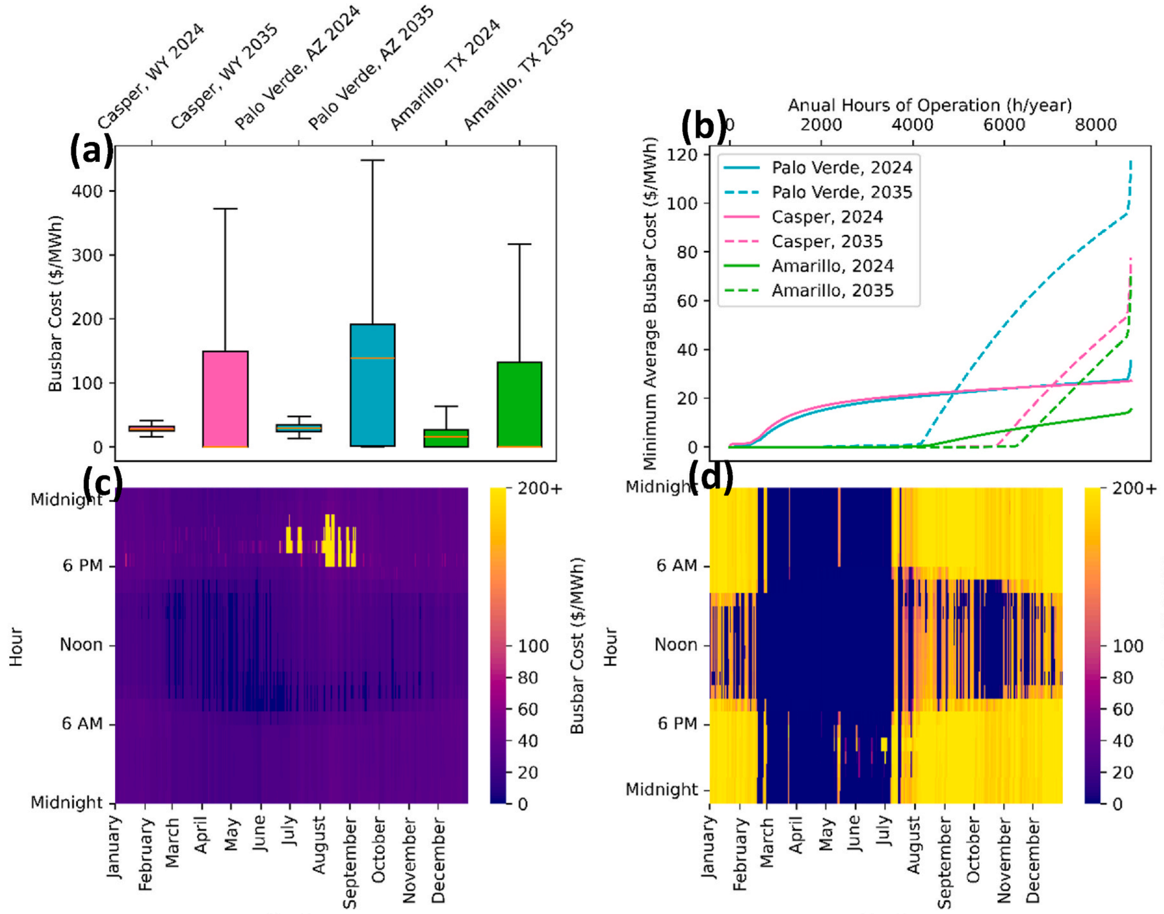


**Fig. 2.** Distributions of the National Renewable Energy Labs Cambium electricity cost scenarios at three locations: Casper, WY, Palo Verde, AZ, and Amarillo, TX for (a) Case 1 and 2 scenarios and (b) the minimum cost of electricity vs hour purchased. The heatmaps represent the spread of variability for Palo Verde, AZ for (c) Case 1 Cambium scenarios and (d) Case 2 Cambium scenarios [28,29] highlighting the temporal variability of electricity costs for both Cambium cases.

the LA system leads to a decrease in effective stack Capex from $350/kW to $101/kW while increasing the voltage from 2.06 V (55.31 kWh/kg) to 2.37 V (63.65 kWh/kg). Increasing the current density of the PEM system from 2 A/cm2 to 4 A/cm2 leads to a decrease in stack Capex of $550/kW to $241/kW while increasing the voltage from 1.78 V (47.75 kWh/kg) to 2.02 V (54.39 kWh/kg).

If the electrolyzer operates dispatchably to avoid the high-cost times of electricity, the average cost of electricity could significantly drop, especially during the higher variability 2035 scenarios. In 2024, reducing electrolyzer CFe in Palo Verde, AZ from 100 % to 50 % reduces electricity costs by 40 % (from $35.1/MWh to $21.22/MWh). In 2035, this same CFe reduction lowers costs by over 90 % to just $0.73/MWh (from $11.8/MWh). Taking advantage of this significant drop in electricity cost is integral to producing low-cost hydrogen from electrolysis when interfacing with the grid in this manner.

As capacity factors are reduced by targeting lower effective electricity costs, the dominant cost drivers of LCOH change, highlighted in Fig. 3. For the Palo Verde, AZ electricity cost profile, the capacity factor at the 'optimal' LCOH changes from about 98 % CFp for the 2024 to about 51 % CFp for the 2035 scenarios. As the capacity factor increases, the LCOH contribution attributed to capital costs decreases while the contribution from electricity costs increases. For the LA system modeled in this analysis, at the 'optimal' capacity factor (98 % CFp) for the 2024 scenario, electricity costs account for roughly 60 % of the total LCOH costs. In contrast, in the 2035 Palo Verde, AZ scenario, electricity accounts for only 30 % of the total LCOH costs, while capital costs account for over 40 % of the total LCOH when operating at the 'optimal' CFp (roughly 51 %). Lowering the turn down ratio can significantly decrease the costs of electricity incurred at the optimal CFp for the 2035 scenario because of the high-cost times of electricity. At a capacity factor of 51 %, the electricity costs start to increase rapidly, highlighted in Fig. 2b.

The PEM case exhibits a similar trend, but because of the higher capital costs and higher efficiency, the LCOH contributions from electricity cost are slightly less, shown in Fig. SI4. If the $TDR_p$ was zero, such that the electrolyzer would be able to shut off entirely to avoid the high-cost times, the electricity costs at the optimal operating point in the 2035 scenario would be near zero. These results indicate that the capital cost effects and efficiency changes from moving to higher current densities could yield a favorable reduction in LCOH during the 2035 scenario.

For the Palo Verde, AZ electricity cost profile, increasing the current density from 0.5 A/cm2 to 1.5 A/cm2 and 2 A/cm2 to 4 A/cm2 for LA and PEM respectively shows no LCOH improvement at the optimal operating point in the 2024 (Fig. 4(a) and (b)) scenario, but significant LCOH reductions in the 2035 scenario (Fig. 4(c) and (d)).

In the 2024 scenario, these trends are due to the moderate distribution in hourly electricity costs present in the 2024 Cambium scenario, highlighted in Fig. 2. The small increase in costs slowly counteracts the capital cost benefit gained from operating at higher current densities while also increasing an efficiency loss penalty. Additionally, as capacity factors rise, the capital investment becomes more utilized, further reducing the overall cost of capital on an LCOH basis.

In the 2035 scenario, the trends are similar to the 2024 electricity cost scenario until the inflection point of electricity costs, which is roughly correlated to the number of hours in a year where the cost of electricity is estimated to be near or equal to zero. For the 2035 Palo Verde, AZ scenario, the cost of electricity is almost $0/kWh until the 45–47 % capacity factor, shown in Fig. 2b. At this point, the cost of electricity rises drastically, which causes the efficiency penalty associated with higher operating current to increase. Eventually the capital reductions no longer provide enough savings to justify operating at elevated current densities (roughly 65 % and 70 % CFp for the LA and PEM systems, respectively). At this point, the electricity cost and capacity factor are high enough such that efficiency becomes more important to the system. Depending on the off-take of a plant, a larger plant operating at lower current densities may yield lower LCOH.

The PEM system ($3.02/kg) performs better than the LA system ($3.07/kg), on an LCOH basis, in the 2024 electricity cost scenario where the dominant cost driver is electricity as shown in Fig. 4a and c. This is due to the better efficiency from the PEM system than the LA system. On the other hand, if electrolyzers move towards low electricity cost and low-capacity factor systems, the capital costs become a larger cost driver and impact PEM systems ($2.78/kg) more than LA systems ($2.31/kg) due to the higher capital investment. Both systems see large improvement from increasing the current density during the 2035

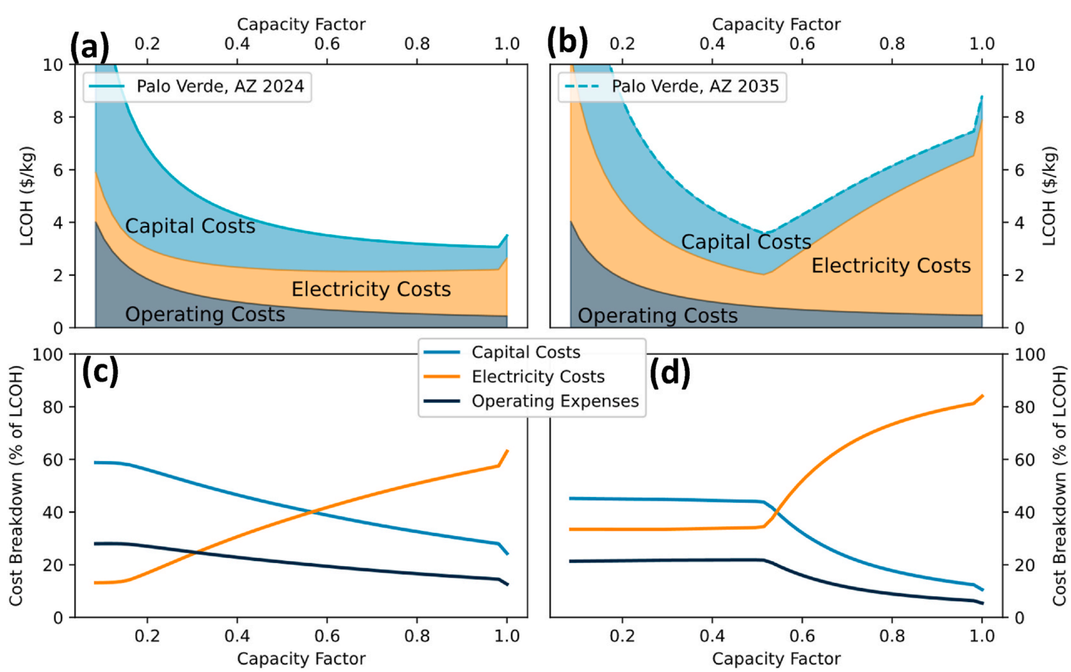


**Fig. 3.** The levelized cost of hydrogen (LCOH) for the liquid alkaline electrolyzer system using the National Renewable Energy Lab's Cambium scenario development for Palo Verde, AZ (a) Case 1 scenario and (b) Case 2 scenario as well as the LCOH breakdown as a function of capacity factor for the (c) Case 1 and (d) Case 2 scenarios [28,29].

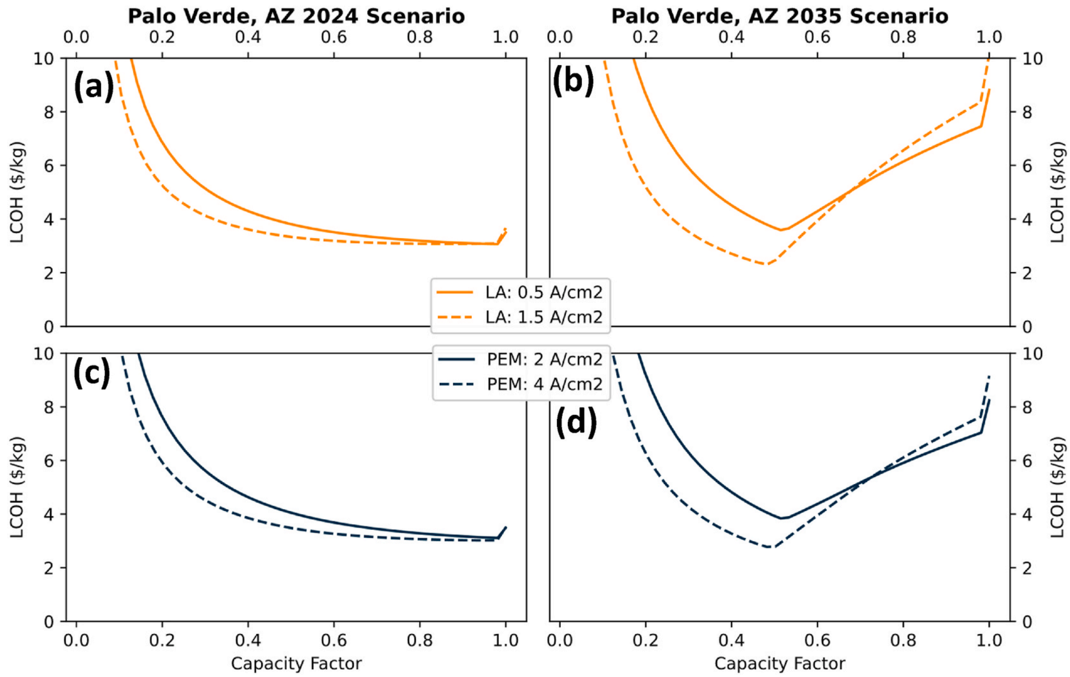


**Fig. 4.** The levelized cost of hydrogen (LCOH) vs capacity factor for Palo Verde, AZ a.) c.) Case 1 and b.) d.) Case 2 for the LA and PEM systems [28,29]. Does not include cost of potential bulk storage or other infrastructure.

scenario indicating that increasing current density for variability cost profiles can lead to a reduction in LCOH across both technologies.

Determining the optimal operational current density (on an LCOH basis) will depend on the chosen system, all the cost assumptions carried with it (CAPEX and OPEX), the capacity factor, and the electricity cost and availability. For both types of electrolyzers considered here, the optimal current density increases as a function of decreasing capacity factor and decreasing electricity cost, shown in Fig. 5. The impact of capacity factor, however, is less on the LA system due to the lower initial capital costs associated with that system (as of today). Additionally, since LA systems operate at lower efficiencies, and the ohmic region has a higher slope than that of PEM systems, only when both electricity costs and capacity factors are low is it the best option to run at the highest current densities. In contrast, the PEM system, which has a higher capital cost, prefers to run at higher current densities to produce hydrogen at higher rates for a given capital cost. This suggests that PEM systems would be well suited towards operating at much higher current densities than the status to fully capitalize on high variability electricity costs.

## 4. Analysis limitations and suggestions for future work

### 4.1. Cambium electricity costs

The Cambium electricity dataset does not attempt to predict wholesale costs of electricity such as location marginal prices (LMPs). Rather, it estimates the hourly marginal cost of energy at a given time and location. Cambium does not include sophisticated market structures

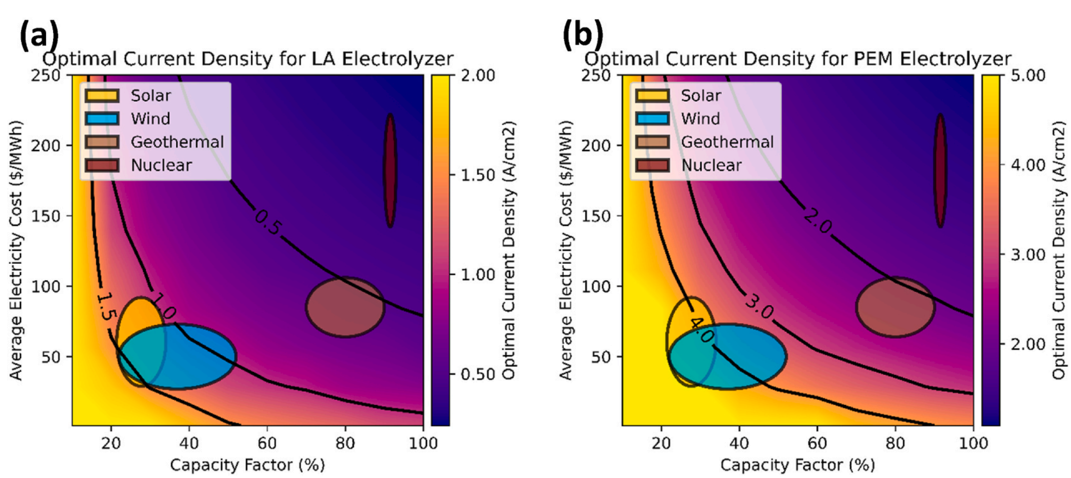


**Fig. 5.** The optimal current density as a function of capacity factors an electricity cost for (a) the liquid alkaline (LA) and (b) proton exchange membrane (PEM) electrolyzer systems described in this paper. The LA and PEM electrolyzers were constrained to operate between 0 and 2 A/cm2 and 0–5 A/cm2, respectively. Current levelized cost of energy and capacity factors for solar, wind, nuclear, and geothermal are overlayed illustrating what current densities electrolyzer systems that are connected to the generation technologies would operate at [41–45]. The widths of the ovals represent the range of capacity factors for the given electricity generation technology while the heights represent the range of levelized cost of energy, and the exact values can be found in the SI.

and other factors that influence the cost of operating the grid that are accounted for by Independent System Operators. As discussed, electricity costs are a key driver of LCOH. The actual variability of the electricity costs will change the LCOH, as well as the optimal operating current density for the electrolyzer system. These electricity cost dynamics change the available cost levers, discussed in the Conclusion and shown in Fig. 5. Future work focused on analyzing trends of existing LMPs could help validate this assumption. Lawrence Berkely National Lab has performed an analysis on the Cambium data-set validating the results and encouraged its use for electricity cost forecasting [46].

Additionally, this work did not consider marginal cost impacts associated with the additional load from electrolyzers. As more loads are added onto the grid, they will begin to impact the cost of energy at a given time. Future work would be well suited to analyze the implications of this trend using electrolyzers integrated into capacity expansion models and production cost modeling.

### 4.2. Turn down ratio

In this analysis the turn down ratio was limited at a fixed current minimum, instead of a percentage of operational current (0.05 A/cm2 and 0.2 A/cm2 for LA and PEM, respectively). Because of this, as the operational current density increases, the turn down ratio (on a percentage basis) decreases. If, instead, there was a turn down ratio as a function of operating current, the low power current density would increase as the operational current density increases. The power turn down ratio decreases drastically for the fixed current turn down, and only slightly (due to efficiency losses) from the percentage current turn down. This relationship can be seen in Fig. SI5. Determining how to decrease turn down ratios in the stack and the BOP is an important area of future analysis and experimental work. Determining the overall impact TDR has on LCOH is an area of on-going analysis.

### 4.3. Degradation

The degradation impact of cycling, start-up and shutdowns, and low power operation are an on-going area of study and were not accounted for in this analysis. Recent studies suggest that dynamic cycling may not change the degradation as a function of calendar time [47] in PEM systems. The steady state efficiency degradation used here was assumed to impact the overall hydrogen production of the stack over time, incrementally reducing the amount of hydrogen produced per unit of energy input (CFp). Continuing to study and understand the effects of degradation from cycling and low-power operation across PEM and LA electrolyzers is important to expand upon and inform future analyses.

### 4.4. Hydrogen off-take infrastructure

This analysis assumes that the hydrogen being produced can be consumed by the end-use at any rate without restriction. Effectively, this assumes a well-developed hydrogen transport network as an offtake, such as a pipeline or bulk storage. Included the costs of large scale storage could shift operating conditions and cost levers, potentially shifting towards higher capacity factor operation due to increased system capital costs. For a constant hydrogen offtake, on an hourly, daily, or weekly basis, the optimal operating strategy and largest cost levers could change and is an area of on-going analysis. Understanding how hydrogen off-take structures as well as the cost of storage impact the cost levers discussed in this analysis is an area of on-going analysis.

### 4.5. System design

The increase in hydrogen production rate (from operating at higher current density) was assumed to not have an impact on stack capex per area ($/m2), BOP Capex ($/kW), or BOP operating energy consumption (kWh/kg). The capital expenditures and parasitic losses of having systems designed for higher flow rates could potentially result in a slight change in impact of increasing current density, as discussed in the Conclusions. Studying how increased current densities impact balance of stack and balance of plant is an important step determining likely operational current densities for these electrolyzer systems.

### 4.6. Salvage value

The ability the re-coup value in the stacks from materials recovery and recycling at end of life is an on-going area of research. High salvage values effectively reduce the stack capital costs as more of the initial investment can be recovered when a new stack is purchased. High salvage values cause a decrease in economic stack life since the cost of purchasing a new stack is less, however, this generally has a smaller impact on LCOH than the other variables discussed.

### 4.7. Stack lifetime

The stack lifetime was assumed to be 10 years. As shown in Fig. SI3, the economic stack life may be shorter or longer depending on stack replacement costs, degradation rate, capacity factor, and electricity cost. Additional LCOH savings could be obtained by finding the optimum stack lifetime for a given system, although the scale of LCOH reductions is not a major cost driver for the low-cost electricity scenarios considered in this analysis.

### 4.8. Applicability of results across geographies and markets

The results presented and discussed in this work use electricity cost and availability data applicable to several regions across the United States. Readers should note that the applicability of our conclusions to different countries and markets, and even between areas within a single country are not likely to remain constant. For example, regulatory standards for how water electrolyzers integrate into grid electricity can dictate the value of operation at higher current density as analyzed here. For a utility rate structure that has a constant cost of electricity, an electrolyzer would be less incentivized to operate dynamically and may value operational efficiency more than peak current density. Local policy incentives, market structures, and other energy generation technologies and large-scale loads all can influence low-cost electrolytic hydrogen production strategies and should be considered in work that evaluates region-specific hydrogen production economics.

### 4.9. Morris elementary effect sensitivity study

To evaluate the impact some of the assumptions made here on LCOH estimates reported in this work, we developed a global Morris elementary effect sensitivity study, found in SI Fig. 5 and SI Table 2 [48]. The sensitivity study, performed under two electricity cost scenarios, agrees with the above analysis. As electricity costs and capacity factors are reduced, the capital costs associated with the electrolyzer become a larger cost driver. Additionally, with decreasing electricity costs and capacity factors, the impact from degradation rates decreases, which helps reduce uncertainties in the conclusions with the assumptions regarding degradation rates. The sensitivity study also helps highlight the importance of understanding system design consequences from operating at elevated current densities. Previous analysis has shown that under high manufacturing throughput, stack costs approach the cost of materials [13], which could indicate only small changes in cost per area ($/m2) for the stack. Understanding the cost changes in the balance of plant from elevated operating currents should be explored in future work.

### 4.10. Life cycle assessment

Life cycle assessment (LCA) is the most commonly used methodology for evaluating the environmental tradeoffs of hydrogen production pathways, including water electrolysis. For example, a cradle-to-grave LCA examines the environmental impacts from acquiring the source materials, building the electrolysis plant, plant operation (including electricity sourcing), and plant decommissioning. While conducting an LCA on the electrolyzer system modeled here is beyond the scope of this work, we acknowledge that conducting such an analysis is an opportunity for future work and summarize several related electrolysis LCAs in the literature in the following. Zaki et al. [49] performed an LCA on a liquid alkaline plant and determined that bulk carbon dioxide emissions come from the electricity sourced from the plant. Krishnan et al. [50] found that PEM and AEM electrolyzers have similar environmental impacts. Continuing to study the environmental impacts of different electrolysis technologies and stack designs will be integral to making informed choices on hydrogen production technology.

## 5. Conclusions

For grid-tied water electrolyzers with access to hourly electricity costs, being able to take advantage of low electricity cost hours is an opportunity to reduce overall LCOH. In this study we examined the implications of increased dynamics in hourly electricity costs as they apply to PEM and LA electrolyzer operation and performance R&D priorities. Generally, our results indicate that a decrease in capital costs enabled by operating an electrolyzer at a higher current density could outweigh the efficiency penalty from operating at higher current densities, resulting in a lower overall LCOH in the locations and future cost scenarios selected. More near-term hourly grid costs with less extreme counts of low- and high-cost hours may result in a smaller benefit to operating at higher current densities, a result of the less volatile and higher average costs of electricity increasing the influence of production efficiency on overall LCOH. Additionally, our findings suggest there are benefits of reducing the TDR increase with higher variability of electricity costs.

Trends between capital, efficiency, and current density tradeoffs are due to the linkage between capacity factor and electricity cost present in the electricity cost profile. More generally, as capacity factors are reduced, the capital costs become a larger cost driver. Additionally, as electricity costs are reduced, the efficiency penalty associated with elevated current density operation decreases. Conversely, should optimal capacity factors and electricity costs increase, the optimal current density decreases, favoring operating at the more efficient current densities.

These results also elucidate areas where future R&D and technoeconomic analysis could reduce costs and refine economic and performance assumptions. Firstly, long term experimental studies examining the assumption made here that a PEM or LA electrolyzer can operate at increased current densities without significant changes to the cost of materials or capital cost of a \$/m2 basis is critical. Additionally, experimental work to characterize tradeoffs between higher cost stack components and increased current density and changes to performance degradation over time can refine assumptions used in this work and inform optimal tradeoffs between component costs and performance. Secondly, an understanding of potential operating schemes and implications for cost drivers for total LCOH of electrolytic hydrogen production is important to further characterize. This work assumed that hydrogen could be produced dynamically anytime because it generally results in the lowest overall LCOH, although electrolyzers producing hydrogen at a steady state might have different performance metrics that drive cost. More steady-state hydrogen production might see costs drivers like efficiency as higher priority than current density, and more technoeconomic analysis to outline these variations can help inform tradeoffs. A comprehensive sensitivity analysis informed by specific scenarios for electricity costs and availability and future electrolyzer performance outcomes would help reduce uncertainties present in this work.

## CRediT authorship contribution statement

**Colby Smith:** Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Joe Brauch:** Writing – original draft, Software, Methodology. **Meital Shviro:** Writing – review & editing, Supervision, Project administration, Data curation. **Bryan Pivovar:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Alex Badgett:** Writing – review & editing, Visualization, Supervision, Software, Project administration, Methodology.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.152576.

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