Quantifying the Flexibility of Hydrogen Production Systems to Support Large-Scale Renewable Energy Integration

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Abstract

Hydrogen is a flexible energy carrier that can be produced in various ways and support a variety of applications including industrial processes, energy storage and electricity production, and can serve as an alternative transportation fuel. Hydrogen can be integrated in multiple energy sectors and has the potential to increase overall energy system flexibility, improve energy security, and reduce environmental impact. In this paper, the interactions between fuel cell electric vehicles (FCEVs), hydrogen production facilities, and the electric power grid are explored. The flexibility of hydrogen production systems can create synergistic opportunities to better integrate renewable sources into the electricity system. To quantify this potential, we project the hourly system-wide balancing challenges in California out to 2025 as more renewables are deployed and electricity demand continues to grow. Passenger FCEV adoption and refueling behavior are modeled in detail to spatially and temporally resolve the hydrogen demand. We then quantify the system-wide balancing benefits of controlling hydrogen production from water electrolysis to mitigate renewable intermittency, without compromising the mobility needs of FCEV drivers. Finally, a control algorithm that can achieve different objectives, including peak shaving, valley filling, and ramping mitigation is proposed. Our results show that oversizing electrolyzers can provide considerable benefits to mitigate renewable intermittency, while also supporting the deployment of hydrogen vehicles to help decarbonize the transportation sector.

Keywords: grid integration; hydrogen; fuel cell electric vehicle; renewable energy; electric power system; duck curve.

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Nomenclature	
FCEV	fuel cell electric vehicle
H1G	uni-directional energy flow to electrolyzer
H2G	bi-directional reversible electrolyzer which can feed power back to grid
t	time index, $t = 1, \ldots, T$
$N(t)$	system electric net load at time t, net load = total load – renewable generation.
PEV	plug-in electric vehicle
$Pmax$	maximum net load power
$Pmin$	minimum net load power
$P(t)$	total electrolyzer load at time t
$\underline{P}(t)$	lower electrolyzer load boundary at time t
$\overline{P}(t)$	upper electrolyzer load boundary at time t
$\mathrm{Ramp}_{\max}$	maximum ramping rate of net load
$\mathrm{Ramp}_{\min}$	minimum ramping rate of net load
E^{total}	total daily hydrogen consumption.
η	conversion efficiency of the electrolyzer, in kWh/kg-H_2 produced.

1. Introduction

Increased adoption of renewable energy sources is a key strategy to mitigate climate change, improve local air quality, increase energy security, and provide other benefits. California is taking aggressive steps to reduce greenhouse gas (GHG) emissions following Assembly Bill 32 (AB32) and Senate Bill 32 (SB32) [1], decarbonize the electricity sector through a renewable portfolio standard (RPS) policy that requires 33% of electricity to come from renewable sources by 2020, and 50% by 2030 (SB350) [2], and encourage the adoption of zero-emission vehicles [3]. Given the intermittent nature of wind and solar resources, however, unique challenges in terms of electric grid balancing (the matching of supply and demand) arise from increasing renewable generation. At low renewable penetrations, this variability has been managed by a number of techniques including regional

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cooperation and regulating the power output (ramping) of existing power plants in order to balance electricity supply and demand [4]. However, as the portion of electricity coming from renewable sources grows, grid balancing will become increasingly more difficult to maintain. Periods of over-generation will increase renewable curtailment, while periods of low renewable generation will require large amount of dispatchable generation (*i.e.,* fossil fuel power plants) that will be characterized by low overall utilization, or discharge of energy storage systems [5]. These effects led in California, which is characterized by significant usage of solar, to what is often referred to as the "Duck Curve", named for the shape of the net electricity demand published by the California Independent System Operator (CAISO) in 2013 [6]. To ensure continued grid reliability, California has a procurement target for the deployment of 1.325 GW of stationary energy storage by the end of 2024 [7]. However, the large capital investment of stationary storage makes this an expensive solution for supporting the integration of renewable energy sources. An alternative solution to reduce requirements on the generation system, and allow for easier integration of intermittent resources, is to increase the flexibility of demand side resources [8].

Along with promoting energy efficiency and greater adoption of renewable electricity, transportation electrification is another ongoing activity that can help achieve greenhouse gas reduction and local air quality goals. The California zero-emissions vehicle (ZEV) mandate requires the deployment of 1.5 million ZEVs by 2025, including plug-in electric vehicles (PEV) and fuel-cell electric vehicles (FCEV) [9]. Many researchers have articulated that PEVs can provide the dual benefit of decarbonizing transportation while lowering the capital costs for large-scale energy storage [10][11][12][13]. However, use of PEVs as energy storage is still controversial, due to warranty issues, limited availability, coordination challenges, and required consumer engagement. Moreover,

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these benefits are all based upon the assumption that the system operator or aggregator can properly communicate and coordinate charging activities with a large population of PEVs, which requires complex communication/control systems and market mechanisms.

Compared to electricity, hydrogen for FCEVs is easier to store, and hydrogen production from fewer plants is more flexible and easier to be controlled without impacting drivers. Hydrogen production/storage facilities (i.e., electrolyzers with storage) could thus simultaneously support both zero-emission vehicle efforts and provide demand flexibility to support the electric system [14][15]. In practice, electrolytic hydrogen production could provide a buffer for the electric grid and enable energy shifting and potentially greater uptake of otherwise-curtailed renewable generation, along with provision of other grid services. Given their scale, and the storage opportunities for hydrogen, electrolyzers acting as flexible loads have clear advantages over the coordination and communication requirements of a large population of privately-owned PEVs, which may or may not be available at the desired time. In comparison to PEVs, production of hydrogen via electrolysis is a larger flexible grid resource (i.e., systems are at the MW-scale) that does not involve a multitude of single-agent (often irrational) decision makers, capable of rapidly ramping, and more easily provide grid services [15]. Gonzalez et al. [16] studied viability of hydrogen production via electrolysis using wind power in Ireland. Their results show that the economic viability of hydrogen systems to enable larger penetrations of wind energy are dependent upon low wind electricity costs and high hydrogen market prices. Hou et al. [17] articulated that in Denmark combining hydrogen systems with wind farms can improve their business case. Hydrogen could also be used as a way to store electricity by using low-cost or excess electric power to produce hydrogen that is then reconverted into electricity when needed [18]. Independent of the final end use (industrial feedstock, transportation fuel or as energy storage)

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tighter integration of hydrogen systems with the electric grid can improve the value proposition for those systems [19][20]. While all of the above studies explore the possible benefits related to the use of hydrogen systems to contribute to grid stability and support the integration of renewables, none directly addresses the role that FCEVs and hydrogen systems could play in mitigating future challenges associated with large-scale renewable integration, like the "Duck Curve".

In this paper, a bottom-up framework is developed to quantify the potential of centralized electrolytic hydrogen production to support renewable adoption and provide system flexibility, using California as a case study. First, the challenges related to high renewable penetration are quantified by projecting the net electric load in California up to 2025. Hydrogen consumption is then estimated based on detailed FCEV adoption and refueling models based on real-world travel itineraries. Two controllers are designed to estimate the capability of centralized electrolysis to provide 1) peak shaving/valley filling, and 2) ramping mitigation. These two controllers are tested under different configurations to simulate the potential contributions to mitigate the "2025 Duck Curve". To our knowledge, this is the first paper that quantifies the potential grid support that can be provided by hydrogen generation using controllable electrolysis to support a large fleet of FCEVs. Case study results are estimated for the California net load curve in 2025, but the approach and methodology can be applied to other geographies with different FCEV adoption and/or different electricity generation mixes. This paper, thus, highlights a potential additional source of value for FCEVs that has not been quantified before and sets the stage for further economic quantification of these benefits and further comparisons with other competing technologies to support grid operations.

Comparing this work to other vehicle-to-grid modelling studies, Tarroja *et al.* [10] studied the performance of PEVs versus stationary energy storage systems to enhance renewable power

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penetration and showed that PEVs can facilitate higher renewable penetration because the round-trip efficiency penalty of stationary storage systems is lessened. The modelling framework in this paper is similar to what proposed by Coignard *et al.* [13] but here the time-resolved hydrogen fuel demand for a large fleet of FCEVs is considered instead of the charging profile for a fleet of PEVs. Wang et al. [11] proposed a decentralized way to schedule PEV charging activities, while the model in this paper is a centralized optimization method to evaluate the aggregate flexibility from hydrogen production load.

The remainder of the paper is organized as follows: The challenges of high renewable penetration are presented in Section 2. The proposed methodology is explained in Section 3, and simulation results are shown in Section 4. Conclusions and future work are highlighted in Section 5.

2. Quantifying the Challenges of High Renewable Penetration in California

To illustrate the challenges that an electricity system will face as substantial renewable generation (especially solar) is deployed, the California Independent System Operator (CAISO) released their 2014 historical and 2021 forecast daily net load (often referred to as the "Duck Curve"), illustrated in Figure 1 [6]. CAISO, which serves approximately 80% of California's population, defines net load as the demand on the grid minus the generation from intermittent renewables (i.e., solar and wind). Each line in Figure 1 represents a historical or forecast net load profile for a single day (March 31) in different years. The Duck Curve highlights four important issues as more intermittent renewables are deployed:

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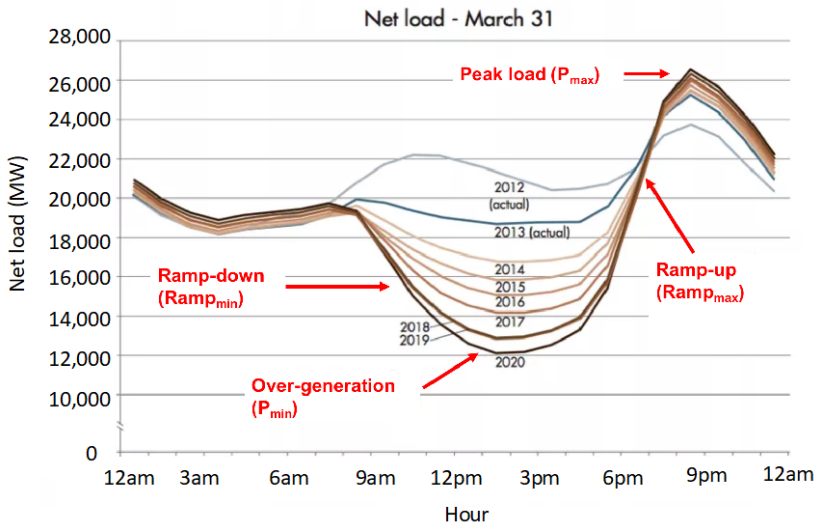

Figure 1. California "Duck Curve" [22]

1) Low daytime net load or over-generation (P_{min}). Demand is low and solar generation is at a maximum, leading to substantial problems with over-generation as more solar capacity is deployed. This will require either daily reductions in the output from large base-load generating stations, which are typically non-flexible, or curtailment of renewable generation, which is highly undesirable.

2) High evening net load (P_{max}). Peak daily load when output from solar generation is low, leading to significant requirement for alternative generation (or storage discharge).

3) Sharp mid-morning down-ramps ($Ramp_{min}$) due to rapidly increasing generation from solar resources.

4) Substantial evening up-ramps ($Ramp_{max}$). Load increases while solar generation decreases. This will require rapidly bringing additional generation resources online and rapidly ramping up online resources (a technically difficult and potentially expensive challenge to be faced daily [21]).

Over-generation, and sharp evening up-ramps are commonly considered the most severe of these challenges [22].

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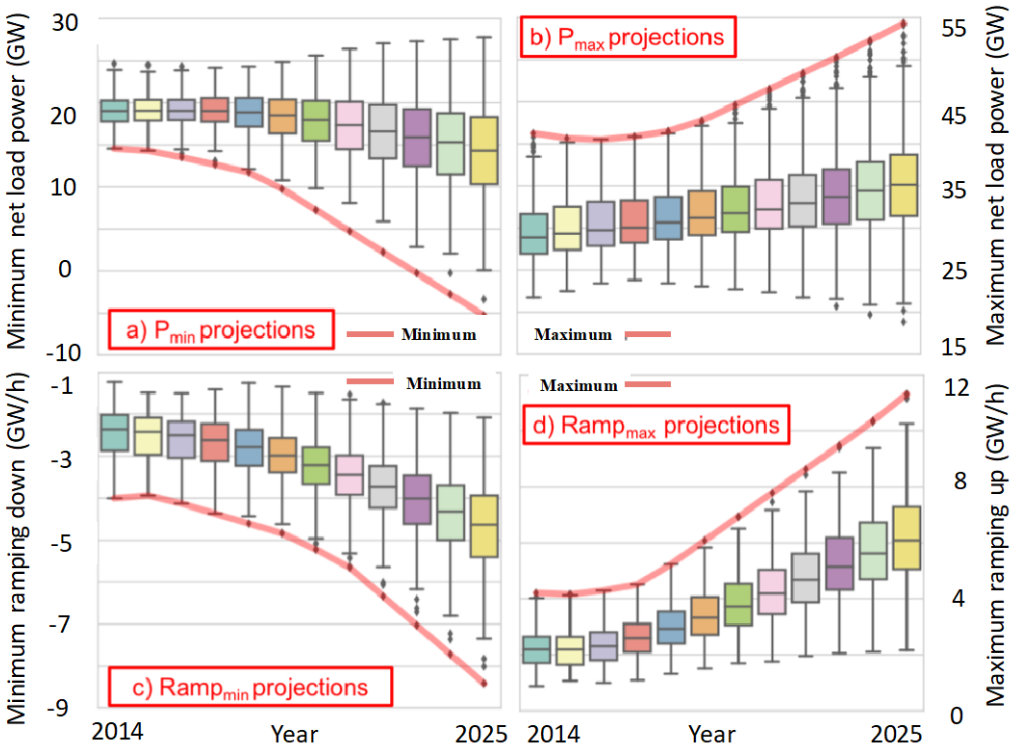

Figure 2. In the absence of interventions, the large-scale deployment of intermittent renewables targeted in California will lead to significant challenges for the grid. These challenges are summarized by projections of four key metrics defining the Duck Curve, (a) P_{min}, (b) P_{max}, (c) $Ramp_{min}$, (d) $Ramp_{max}$ through 2025.

The Duck Curve presented in Figure 1 provides a snapshot for a single day of each year. Hourly net loads are projected for each day of the year out to 2025 by scaling historical net load data from 2014 based on net load projections for 2021 from CAISO [23], and linearly extrapolating until 2025. The projected net load for 2025 includes increases in renewable energy capacity for both solar and wind generation (4.9% and 5.6% of overall generation, respectively in 2014 to 17.5% and 7.3% respectively, in 2025). For each day in each future year we calculate P_{min} (the lowest power demand during the day), P_{max} (the highest power demand during the day), $Ramp_{min}$ (the highest hourly power reduction during the day), and $Ramp_{max}$ (the highest hourly power increase during the day). These metrics are summarized in Figure 2 (a)-(d).

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The red line in each plot shows the worst day of the year for the different metrics for each year, while the boxplots show the distributions for each day of the year (boxes represent the central 50% distribution of days, and whiskers indicate the 95% interval). Figure 2 (a)-(d) show that each metric is expected to evolve so as to create more challenges as more renewables are deployed. We find that: 1) daytime over-generation, shown in Figure 2 (a), become highly problematic with system-wide net load falling to levels potentially requiring substantial renewables curtailment on a regular basis; 2) evening peak net loads continue to increase, as shown in Figure 2 (b), even though more renewables generation is being installed each year; 3) daily down-ramping rates shown in Figure 2 (c), and daily up-ramping rates shown in Figure 2 (d), continue to increase in magnitude, necessitating changes to the electric system and potentially more expensive grid resources to mitigate these effects. From these results, it is clear that new mitigations strategies are needed to ensure grid reliability and manageable costs as more renewables are deployed in California.

The California system is currently estimated to have 13-15 GW of non-flexible generation resources, which is difficult or highly undesirable to ramp down [24]. In other words, today's California grid system is problematic to manage when net load falls below 15 GW. In 2014, the net load fell below 15 GW for only 0.03% of the time [23]. By 2025, however, net load is projected to fall below 15 GW for 14.2% of the time. Similarly, by 2025, ramp down and ramp up rates will be twice as large as they were in 2014, reaching -8 GW/h and +11 GW/h, respectively.

3. Methods

3.1. Modeling Framework

In this section, we propose a framework to quantify the interactions between FCEVs, centralized electrolytic hydrogen production, and electricity power systems, as shown in Figure 3.

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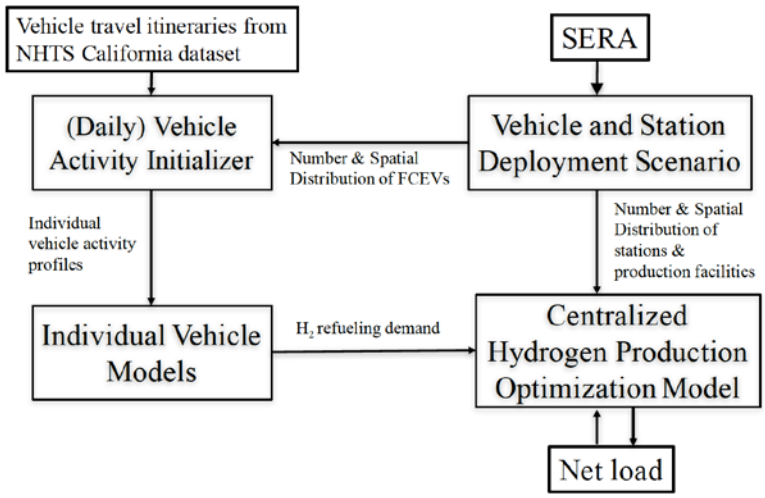

Figure 3. Modeling framework to explore the interactions between FCEVs, hydrogen production facilities, and electricity power systems.

Scenarios of FCEV adoption and hydrogen refueling station deployment are generated using the Scenario Evaluation and Regionalization Analysis (SERA) model [25], developed and maintained by the National Renewable Energy Laboratory (NREL). SERA provides information on FCEV adoption and hydrogen demand scenarios relevant to early market transition, considering geospatially and temporally resolved vehicle adoption in each urban area in California based on demographics and early adopter metrics, annual vehicle mileage based on empirical evidence, FCEV fuel economy improvement over time, and vehicle stock turnover. Individual vehicles energy consumption and refueling behavior are explicitly modeled in this paper to capture real-world use. In particular, real-world vehicle travel data or fleet usage statistics are used in a vehicle activity initializer to generate individual vehicle activity profiles with minute-scale resolution. These individual vehicle activity profiles are used in a backward dynamic vehicle model, described below, to estimate energy consumption of FCEV operation and fueling behavior (timing and magnitude of FCEV refueling events).

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Based on the detailed information on vehicle use (and thus hydrogen refueling demand) and station deployment, a high fraction of hydrogen production using electrolysis (50% of total hydrogen demand) is assumed to explore the potential interactions with the electric power system. We assume large centralized hydrogen production facilities (e.g., 750,000 kg/day) that take advantage of economies of scale are used to meet the large hydrogen demand [26], and that hydrogen is then delivered to individual refueling stations (e.g., via trucks or pipelines).

3.2. Hydrogen Demand Estimation

In the scenarios discussed in this paper, hydrogen only serves as a fuel for passenger FCEVs. Estimating hydrogen demand from FCEVs is the first step to assess the influence of hydrogen production systems on the power grids. As shown in Figure 3, we project FCEV adoption and simulate the energy consumption of each individual FCEV and aggregate them to estimate the total hydrogen demand. Each vehicle is modeled as a sequence of driving and parking events within a given day. Travel itineraries for California drivers from the National Household Travel Survey [27] are utilized, which includes the travel records of ~17,000 vehicles, to obtain unique schedules of events for a representative collection of drivers. Table 1 shows an example of the travel itinerary information.

A detailed backward powertrain simulation model, similar to the Autonomie powertrain model [28], is developed to predict the energy consumption of any vehicle make/model on any specific driving cycle (including grade considerations), including ancillary power loads (e.g., from a vehicle AC system). We assume that all FCEV on the road have characteristics in line with those of the commercially available Toyota Mirai [29].

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Table 1. An example of travel itinerary information provided to simulation

Start time	End time	Distance	Location
0:00	8:30	N/A	Home
8:30	9:30	38.7	N/A
9:30	16:30	N/A	Work
16:45	17:15	5.0	N/A
17:15	17:45	N/A	Restaurant
17:45	18:45	38.7	N/A
18:45	0:00	N/A	Home

Input to the vehicle model is a second-by-second driving cycle velocity profile, including road grade, that is used to estimate the second-by-second energy consumption. For the results presented in this paper, the trip-specific driving cycles are derived from the Environmental Protection Agency (EPA) standard driving cycles for city (UDDS), highway (HWFET), and high acceleration aggressive driving (US06) [30], as shown in Figure 4 (a)-(c). The corresponding cumulative consumption of hydrogen is simulated by the detailed powertrain model, shown in Figure 4 (d)-(f).

The refueling behavior is modeled as a linear function of the vehicle state of energy (SOE), which is the hydrogen storage level. We assume that a FCEV driver first considers stopping at a hydrogen refueling station when the SOE reaches 50%. As the SOE decreases, the probability of the driver stopping to refuel increases linearly, with the probability of a driver stopping to refuel approaching 1 as the SOE approaches 0%. FCEV are assumed to get fully refueled when stopping at a hydrogen refueling station. All simulations are performed for 30 days assuming that the vehicles' tanks are initially full (100% SOE) but only the last day is considered in the results, so as to remove the dependence on the initial condition.

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It should be noted that we choose to focus on passenger fuel cell vehicles in this paper, following the state Zero Emission Vehicle goal of 1.5 million passenger vehicles on the road by 2025 [3]. There is a lot of interest in zero emission commercial vehicles such as buses and medium-duty and heavy-duty vehicles, but the state has not yet established goals for these vehicle classes.

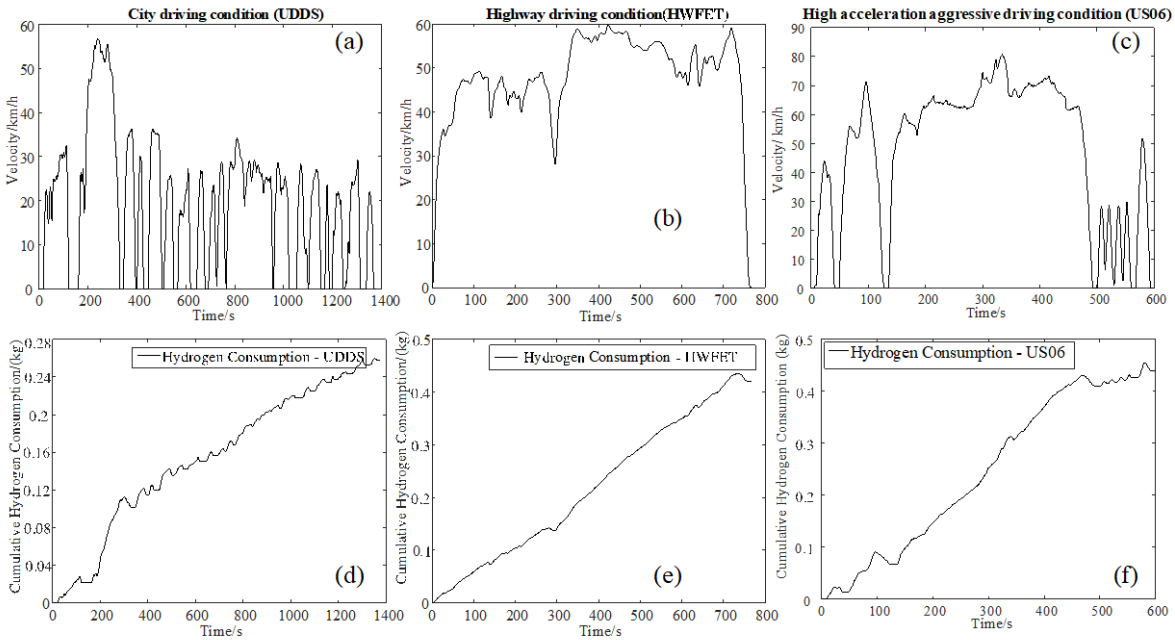

Figure 4. Environmental Protection Agency (EPA) standard driving cycles (a. UDDS, b. HWFET, c. US06) and their corresponding hydrogen consumption profiles simulated by the detailed powertrain model.

3.3. Optimization on the Centralized Hydrogen Production

Based on the total projected hydrogen demand, we compare three strategies to exploit the flexibility of the hydrogen production facility and interaction with the electric power grid:

1) Uncontrolled hydrogen production: The electrolyzer is sized to perfectly match the FCEVs' demand for hydrogen and it operates continuously at nominal capacity. In this case, there is no added grid flexibility.

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2) Uni-directional controlled hydrogen production (H1G): The electrolyzer is oversized (capacity>100%), so that it can provide a buffer for the electric grid and shift the electricity load (we assume that enough hydrogen storage is available to shift hydrogen production during the day). For instance, the electrolyzer may reduce its production during evening peaks and increase production during daytime electricity over-generation periods. The controllable electrolyzer power is assumed to range from 100% to 10% of its rated power below which the electrolyzer must shut off.

3) Bi-directional controlled hydrogen production (H2G): Besides the flexibility deriving from load shifting (the electrolyzer is again over-sized), we assume that the hydrogen production facility is equipped with a reversible electrolyzer or an on-site fuel cell that can generate electricity from hydrogen and feed it back to the grid at any time. Again, the power for the reversible electrolyzer is assumed to range from 100% to 10% in either direction below which the devices must shut off.

The finite controllable resource from the hydrogen production systems can be applied in two different ways to mitigate the challenges connected to the Duck Curve:

1) Peak shaving and valley filling – The electrolyzer can maximize its power consumption during the daytime over-generation period (i.e., 9 am to 2:30 pm) and limit hydrogen production or even feed energy back to the grid (H2G) during the evening peak (i.e., around 5 pm) with the objective of limiting renewable curtailment and mitigating the peak load.

2) Ramp rate mitigation – Hydrogen production load can be adjusted to minimize the ramping rates of the net load profile. For sharp ramp-down periods (i.e., 7 am to 9 am), this typically results in hydrogen production facilities transitioning from generating electricity to using energy during the hours adjacent to the sharp ramp-down. For sharp ramp-up periods (i.e., 2 pm to 5 pm), hydrogen systems transition from consuming energy (to produce hydrogen) to generating electricity during the

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hours adjacent to the sharp up-ramp. With this control objective, ramp-down and ramp-up rates are mitigated to the greatest extent, and there is also some benefit for the daytime over-generation and evening peak periods. Ramp rate mitigation can be achieved in either H1G or H2G case.

The objective function for the peak shaving and valley filling control is given in (1), while the objective function for the ramp rate mitigation is given in (2):

Peak-valley control:

$$min \sum_{t=0}^{T} (N(t) + P(t))^2 \tag{1}$$

Ramp control:

$$\min \sum_{t=1}^{T} (N(t) + P(t) - N(t-1) - P(t-1))^2 \tag{2}$$

The constraints for both objective functions are:

$$\underline{P}(t) \leq P(t) \leq \overline{P}(t) \tag{3}$$

$$\sum_{t=0}^{T} P(t)/\eta = E^{\text{total}} \tag{4}$$

where t is the time index, $t = 0, 1, \ldots, T$. $N(t)$ is the net load at time t. The decision variable $P(t)$ is the power consumption for hydrogen production at time t. $\underline{P}(t)$ and $\overline{P}(t)$ are the lower and upper power boundaries of electrolyzer at time t. We assume that the electrolyzer power is continuously adjustable between 10% to 100%. E^{total} is the total hydrogen consumption of the entire day, as predicted by the vehicle model based on the adoption scenarios generated in SERA. η is the conversion efficiency of the electrolyzer in kWh/kg-H_2 produced. Equation (3) is the electrolyzer power constraint. Equation (4) requires that the total hydrogen production must equal the consumption at the end of scheduling horizon. It should be noted that storage tank limitations are not included in this formulation. However, ex-post calculations are performed to explore the storage

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requirements in Section 4.

4. Results

We explore the potential of hydrogen production systems to mitigate the issues related to the California "Duck Curve" in 2025 based on different FCEV adoption scenarios.

The daily FCEV demand for hydrogen (E^{total}) determines the overall electricity requirements for the electrolysis process, and we implement the controllers presented in Section 3.3 to quantify the potential of hydrogen production systems to alleviate the problems caused by high intermittent renewable penetration, specifically P_{min}, P_{max}, $Ramp_{min}$ and $Ramp_{max}$. Sensitivity analyses, summarized in Table 2, are performed to understand the implications of different FCEV adoption levels, different electrolyzer sizes, and different control strategies (H1G/H2G). In particular, three FCEV adoption scenarios are simulated (Low: 0.2 million; Medium: 0.8 million; and High: 1.5 million FCEVs on the road in 2025). The fuel economy of FCEV is assumed to be 67 MPG-equivalent [29] and the electrolyzer conversion efficiency is assumed to be 67.3 kWh/kg-H2 [31]. The annual hydrogen demand for each FCEV is computed based on the average annual vehicle miles traveled (VMT) in California [25]. We assume that in 2025 half of the total hydrogen production will be achieved by water electrolysis and the other half from other sources. Three electrolyzer sizing cases are considered: a reference case in which the electrolyzers are sized just to meet the hydrogen demand (100% capacity, meaning that the electrolyzers operate continuously at nominal capacity to meet the hydrogen demand from FCEVs and provide no flexibility) and two scenarios in which the electrolyzers are oversized by 25% and 50% to provide flexibility to the grid. For H2G cases, electricity-to-hydrogen efficiency of 70% is assumed and hydrogen-to-electricity (electricity generation) efficiency is 50%, which makes the round-trip efficiency around 35% [32].

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Table 2. Scenario summary.

FCEV Adoption Scenario	Number of FCEVs in 2025	H_2 Production (ton/yr)	Electrolyzers Capacity (MW)		
			100%	125%	150%
1	200,000	40,150	152	190	228
2	800,000	160,600	608	760	917
3	1,500,000	301,125	1140	1,424	1,709

Note: We assume that in 2025 half of the H_2 production will be achieved by water electrolysis and the other half from other sources.

Net load for a typical summer day (07/08/2025) is considered to illustrate how hydrogen production systems can help the effective integration of renewable sources and alleviate the "Duck Curve" issues. The results of performing peak shaving and valley filling (control scheme 1) are shown in Figure 5 (a)-(f). If the electrolyzer is used only to match the hydrogen demand (capacity 100%), the net load profiles in the three scenarios are increased by 152MW, 608MW, and 1,140MW, respectively. If the electrolyzer is oversized by 25%, it will run at its nominal power rating during 8:00- 14:00 to fill the valley, and also avoid increasing the peak at 19:00 (the peak of new load profiles assuming H1G and 125% electrolyzer capacity overlaps with the original net load since there is no way for the system to reduce the load not related to hydrogen production).

Assuming H2G capabilities as shown in Figure 5 (d)-(f), however, the system can feed electricity back to the grid during peak times and the peak load is reduced by 0.09 ~ 0.85 GW, depending on the scenario. The introduction of H2G cannot further enhance the valley filling capabilities, because in both H1G and H2G cases the electrolyzer produces hydrogen with maximum rate during the valley time and thus the minimum loads for H1G and H2G are the same in each FCEV adoption scenario). Further oversizing the electrolyzer (150% capacity) leads to higher benefits in terms of valley filling and peak shaving (for the H2G cases only, since the electrolyzer with 25% oversizing already reduces the peak to the original load with no hydrogen production).

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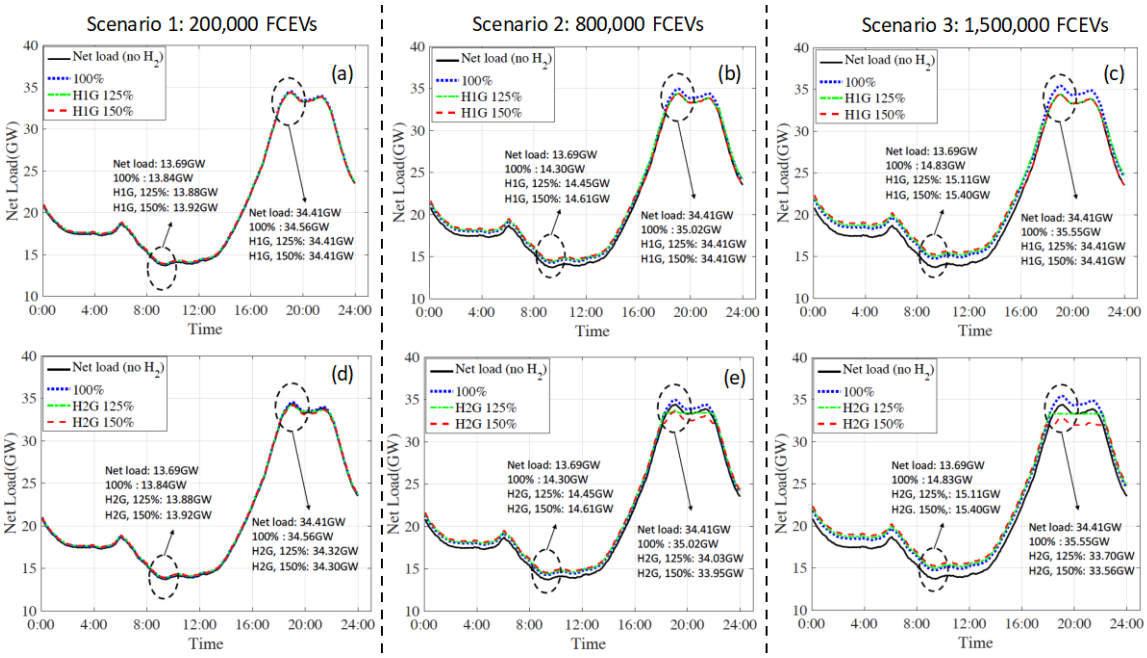

Figure 5. Peak shaving and valley filling opportunities for hydrogen production systems during a typical summer day assuming different FCEV adoption scenarios.

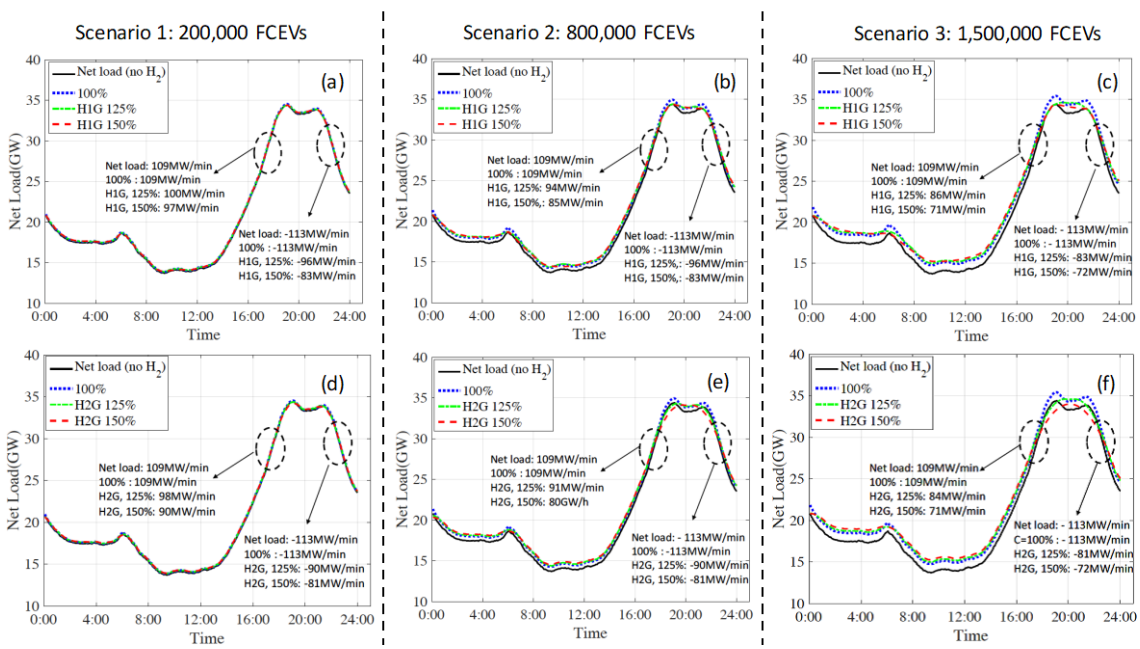

Figure 6. Ramp mitigation opportunities for hydrogen production systems during a typical summer day assuming different FCEV adoption scenarios.

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The results of performing ramp mitigation (control scheme 2) are shown in Figure 6 (a)-(f). The most aggressive ramp-up happens around 17:30 and the most aggressive ramp-down happens around 23:30. Again, if the electrolyzer is used only to match the hydrogen demand (capacity 100%), the additional electrolysis load (a constant load) is just added to the original net load, and the ramping of the total load will not change in the three scenarios. If the electrolyzer is oversized by 25%, assuming H1G capabilities the maximum ramp-up will be reduced by up to 23 MW/min for the most aggressive FCEV adoption scenario and the ramp-down will be reduced by up to 30 MW/min, a significant mitigation of the sharp ramping caused by large-scale intermittent renewable deployment. Further oversizing the electrolyzer (150% capacity) leads to additional reductions in maximum ramping, up to an additional 15 MW/min and 11 MW/min for ramp-up and ramp-down, respectively. Figure 6 (d)-(f) show that H2G capabilities do not significantly enhance the ramping mitigation capability in these scenarios.

Table 3. Ex-post calculations on storage sizes.

Number of FCEVs	Required Storage in H1G (hr)			Required Storage in H2G (hr)		
	100%	125%	150%	100%	125%	150%
200,000	6.49	6.61	6.27	6.49	7.27	7.72
800,000	6.49	6.60	6.25	6.49	7.13	7.66
1,500,000	6.49	6.59	6.22	6.49	7.00	7.60

As mentioned in Section 3, we perform ex-post evaluations on the storage requirement for different scenarios, shown in Table 3. These values are calculated by determining the maximum difference in hydrogen between when hydrogen is produced and when it is consumed. That value is converted to hours at rated electrolyzer capacity. Results indicate that none of the scenarios considered require more than 8-hour storage.

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Figure. 5 and 6 are based on a typical summer day net load (07/08/2025). In order to explore the extent to which controlled hydrogen production can alleviate the "Duck Curve" issues, we also study the four worst days of the year with respect to P_{min}, P_{max}, $Ramp_{min}$, and $Ramp_{max}$ (P_{max}: 08/06/2025, P_{min}: 03/24/2025, $Ramp_{max}$: 12/01/2025, $Ramp_{min}$: 03/15/2025), as shown in Table 4. In terms of peak shaving and valley filling, H1G can shift 1 GW from load peak to valley when the electrolyzer capacity is 125%. H2G can further shave the peak by feeding electricity back to the grid during the peak load time. The values of P_{min} in H1G and H2G cases are the same, because during the valley, the electrolyzer will work at its maximum power rate. For an electrolyzer that is 25% oversized, both ramp-up and ramp-down are reduced by more than 40MW/min. The effects are even larger assuming a larger electrolyzer (i.e., 150% capacity). H2G can only slightly increase the capability of ramping mitigation. It should be noted that in both 125% and 150% capacity cases (H1G), the peaks are the same as no H2 case, since the plants are turned off during the peak load time.

Table 4. Impact of hydrogen production to alleviate Duck Curve issues during the four worst-case days assuming 1,500,000 FCEV on the road in 2025.

	Electrolyzer Capacity = 125%				Electrolyzer Capacity = 150%			
	Peak shaving and valley filling		Ramp mitigation		Peak shaving and valley filling		Ramp mitigation	
	Pmax (GW)	Pmin (GW)	Ramp-up (MW/min)	Ramp-down (MW/min)	Pmax (GW)	Pmin (GW)	Ramp-up (MW/min)	Ramp-down (MW/min)
Netload (no H_2)	54.32	-6.32	223	180	54.32	-6.32	223	180
Uncontrolled net load	55.46	-5.18	223	180	55.46	-5.18	223	180
H1G	54.32	-4.90	183	133	54.32	-4.61	173	121
H2G	53.61	-4.90	182	122	53.47	-4.61	161	109

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5. Conclusions and Future Work

In this paper, a framework is proposed to evaluate the potential interactions between FCEVs, hydrogen production facilities and the power grid to mitigate the issues associated with increasing levels of intermittent renewable electricity. First, we quantify the significant grid challenges that arise as more renewables are deployed, specifically the increasing daytime over-generation, increasing evening peaks, and increasing demand ramping (both up and down). Then, opportunities related to controlling hydrogen production systems (i.e., electrolyzers) are explored that enable clean transportation solutions to also support the large-scale deployment of renewables. In order to estimate the total FCEV hydrogen demand, we use a detailed vehicle deployment model, real-world travel itineraries, and a powertrain model to calculate the second-by-second energy consumption on real-world trips. Two controllers are designed to quantify the potential of hydrogen production systems to mitigate the main issues related to the "Duck Curve": peak shaving/valley filling and ramp rate mitigation.

Results show that controlled electrolytic hydrogen production can greatly help peak shaving/valley filling and ramping mitigation. Assuming 1.5 million FCEVs on the road in California in 2025 (half of which receive fuel from water electrolysis), a 25% oversized electrolyzer can provide 1.4GW net load valley-to-peak shifting and around 50MW/min ramp mitigation. If the electrolyzer is further oversized, more benefits can be obtained. Our results also show that, even though use of hydrogen to produce electricity to be fed back to the grid (H2G) can improve the peak shaving capability, it has only minor contributions to ramp mitigation. We also explore the hydrogen storage requirements to support controlled electrolytic hydrogen production in these scenarios (acknowledging that storing

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hydrogen is easier and cheaper than storing electricity) and conclude that 8 hours of storage are sufficient to optimally operate the system.

We conclude that substantial benefits to facilitate widespread intermittent renewable deployment in California can be achieved through the use of controllable hydrogen production systems, which also produce a clean fuel for transportation applications. In other words, significant synergies can exist between the transportation and electric sector. Oversizing electrolyzers to enable controllable hydrogen production can also help accomplish the objectives of California's aggressive storage procurement target.

In the future, we will continue to quantify the opportunities related to the flexibility of hydrogen systems, including the benefits and costs for hydrogen systems to provide other grid benefits such as greater utilization of generation assets and grid services like frequency regulation, spinning reserve, etc.

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