Flexible grid-based electrolysis hydrogen production for fuel cell vehicles reduces costs and greenhouse gas emissions

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Abstract

Hydrogen fuel cell electric vehicles (FCEVs) have been proposed as an option for lowering carbon dioxide (CO_2) and pollutants emissions from the transportation sector, when implemented in combination with green hydrogen production methods such as water electrolysis powered by renewable electricity. FCEVs also have the added advantages of high specific energy density and

rapid refueling, two important challenges that battery electric vehicles have not yet fully overcome. Moreover, flexible operation of electrolysis could support the grid and lower electricity costs. In this paper, we simulate time-varying FCEV hydrogen refueling demand for light, medium- and heavy-duty vehicles met using electrolysis systems distributed throughout the Western U.S. power system. We find that by oversizing electrolyzers the resulting load flexibility results in different hydrogen generation temporal profiles, average electricity costs, renewable curtailment levels, and CO_2 emissions. Our results indicate that increasing hydrogen production flexibility lowers hydrogen and electricity generation cost and CO_2 emissions, but there is a tradeoff between lowering operational cost and increasing electrolyzer capital cost, yielding a minimum total system cost at a size corresponding to between 80% and 90% annual capacity factor assuming a future electrolyzer cost of $300/kW.

1. Introduction

Transportation is a major global consumer of energy (28% of total energy demand) and source of CO_2 emissions (24% of energy-related emissions), growing to as much as 10.3 $GtCO_2$/yr globally in 2040 assuming minimal shifting away from petroleum-based fuels [1]. There were approximately 1.2 billion vehicles on the world's roads in 2014, with 95% of those being light-duty passenger vehicles; by 2035, this number may increase to 2 billion, and reach 2.5 billion by 2050 [2]. Therefore, transportation systems emitting less CO_2 and pollutants will rapidly be needed as the total number of vehicles continues to grow.

According to previous literature [3][4][5][6], the transportation sector will be among the most difficult to decarbonize, due to a combination of urban infrastructure built around vehicle dependency, rapid adoption of vehicles in the developing world, mature and inexpensive combustion-based engine technologies, low petroleum costs, and limited alternatives to petroleum-derived fuels for many non-highway modes like aviation and marine transport. One way to decarbonize the sector is through electric vehicles (EVs), whose sales have grown rapidly since 2010, stimulated in part by falling battery costs and strong government policies in several countries. EVs recently surpassed 5 million cumulative sales at the end of 2018, up 62% from the previous year [7]. Most projections of future transportation vehicles assume accelerating growth of battery and plug-in hybrid EVs, with optimistic forecasts indicating >250 million EVs by 2030 and >550 million by 2040 [8].

However, hydrogen can also play an important role in our future transportation system [9][10]. Currently, three light-duty hydrogen fuel cell electric vehicles (FCEVs) are commercially available in some parts of the U.S. [11]: the Toyota Mirai [12], Hyundai Nexo [13] and Honda Clarity [14]. Outside the U.S., China is starting to embrace a hydrogen future, with a vision of 1 million FCEVs on the road by 2029 [15]. The country is home to many established companies as well as new startups pursuing hydrogen, and its government is investing tens of millions of U.S. dollars in R&D and purchase subsidies [16]. Smaller FCEVs, such as motorcycles and scooters, are also being developed for global markets by companies such as Intelligent Energy [17], Suzuki [18], Honda in collaboration with Nissan and Toyota, as well as Volkswagen, Hyundai and General Motors [19].

Meanwhile, heavy-duty FCEVs are being developed around the world. FCEV buses are being evaluated in many locations in the U.S. [20]; the California Fuel Cell Partnership maintains a growing map of FCEV bus activities globally [21]. Hyundai, Kenworth, Nikola, Toyota, TransPower, UPS and US Hybrid are also developing FCEV trucks [22-27]. In 2017, China Railway Rolling Corporation Tangshan Co. began demonstrating the world's first FCEV tramcar in Tangshan, China; the company also plans to introduce the technology in Quanzhou, Taizhou and Tianjin, China, as well as Toronto [27]. In Germany, Alstom has introduced the Coradia iLint, a first-of-its-kind FCEV train that was placed into service in 2018 and has since expanded to six German states. Starting in 2021, the Landesnahverkehrsgesellschaft Niedersachsen (LNVG) will begin transporting regular passengers on 14 such trains in Saxony, Germany [28]. In the U.K., the HydroFLEX train began tests in June 2019 [29]. There is also interest in hydrogen-powered ships [30] and airplanes [31].

The production of hydrogen without substantial CO_2 emissions will be key to lowering emissions from the transportation sector. Pavlos and Andreas provide a comprehensive review of typical hydrogen production processes [32]. Hydrogen can be generated from many energy sources, but most hydrogen produced today is made from steam reforming of methane from natural gas, which is inexpensive and 85% efficient, but emits significant amounts of CO_2 (and can leak methane, a potent greenhouse gas). While hydrogen could be made from biomass [33], fossil fuels with CO_2 capture and sequestration [34], or even fossil resources that remain in the ground along with produced CO_2 [35], water electrolysis provides a scalable, flexible and distributed approach to hydrogen production. The level of CO_2 emissions associated with water electrolysis depends on the electricity generation mix. Electricity with a high fraction of low-carbon sources can lower CO_2 emissions relative to conventional vehicles, while reliance on electricity generated from fossil fuels can raise CO_2 emissions.

About 4% of global hydrogen is produced by electrolysis today [36]. Previous literature has examined the cost of various electrolysis technologies, including proton exchange membrane, alkaline, and solid oxide [37][38][39][40]. Ursua et al. projects that water electrolysis will be deployed in the future because both hydrogen and electricity can be produced flexibly and transported over long distances [41]. Also, hydrogen production can be integrated with the electricity grid to support electricity generation, and at high penetrations of renewable generation, the CO_2 emissions associated with hydrogen production can become quite low. Moreover, the ability to generate hydrogen flexibly using water electrolysis can support grid operations by helping to maintain grid stability and reducing operational costs. While dispensed hydrogen costs between $12 and $16 per kg today [42], many expect that hydrogen retail prices could drop significantly in the future [43]. In the current study, the average hydrogen production cost from electrolysis is assumed to be reduced to ~$4/kg (excluding distribution and dispensing costs), consistent with U.S. Department of Energy (DOE) targets [44]. However, the average electrolytic hydrogen production cost is affected by both capital and operating costs, and thus is expected to vary with electrolyzer size and utilization.

Renewable electricity installed capacity continues to increase rapidly in many parts of the world, with about 100 GW of solar PV, 50 GW of wind, and 30 GW of other renewable generation (excluding large hydropower) installed in 2018, bringing the total global renewable electricity capacity to 2,400 GW [45]. As renewables become a greater contributor to electricity generation they will create operational challenges, such as balancing instantaneous power demand with fluctuating and intermittent power output from an increasing share of generators [46]. While flexible grid resources that address these issues exist today, they are mostly fossil-based, such as ramping natural gas or coal power plants. To minimize electricity-sector CO_2 emissions, a combination of more widespread load flexibility, dedicated energy storage, and flexible low-carbon generation technologies (including hydro, biomass-fired plants, geothermal and concentrating solar power) must be developed. Grid-connected EVs have been identified as a growing flexible load resource that could play an increasingly important role in renewables integration [47], but hydrogen generation via electrolysis can also act as a buffer to help match electricity supply to demand [48].

In this study, we simulate hydrogen production via electrolysis in the U.S. Western Interconnection (WI) power system. While this region encompasses the entire U.S. (and parts of Canada and Mexico) west of approximately 105°W, the 5.3 million FCEVs we simulate are assigned to California, with no FCEVs outside the state. These forecasts, while aggressive for 2030, are consistent with some long-term forecasts of 20% FCEV penetrations for cars and trucks [49]. For example, the IEA has developed FCEV scenarios assuming that 12-25% of passenger light duty vehicle stock and 5-10% of freight vehicle stock (light commercial, medium-duty and heavy-duty trucks) are hydrogen-powered by 2050 [50]. Our purpose is to investigate the time-dependent influence (and cost in particular) of hydrogen refueling on grid operations under different assumptions of electrolysis sizing and flexibility, using a large-scale power system model implemented in PLEXOS. The methods of this study, while limited to one specific year and region, can be readily generalized to other electricity grids and FCEV penetration levels, providing potentially useful results applicable to other cases.

2. Methodology

The model methodology can be divided into three steps. The first step estimates time-resolved energy consumption of FCEVs by class (light-duty, medium-duty, etc.). For different kinds of vehicles, a detailed vehicle model is used to calculate the energy consumption, which is converted to hydrogen dispensing profiles according to refueling behavior assumptions specific to each vehicle class. Second, hydrogen refueling demand is aggregated geographically, and converted to an electricity demand for the electrolyzer that represents the minimum amount of consumption to meet hydrogen demand to support fuel cell vehicles. Third, the electrolysis load for hydrogen production is added to overall electricity demand in the system, and we simulate electricity grid operation by generator (including renewables curtailment) to obtain production costs for power system operation. We also include estimates of hydrogen electrolysis capital and storage costs to arrive at an overall cost of producing hydrogen via grid electrolysis under various flexibility assumptions. By integrating these components, we are able to explore the relative cost and benefits for integrating electrolytic hydrogen production with the grid, while satisfying the refueling demands of FCEVs. This approach is presented graphically in Figure 1.

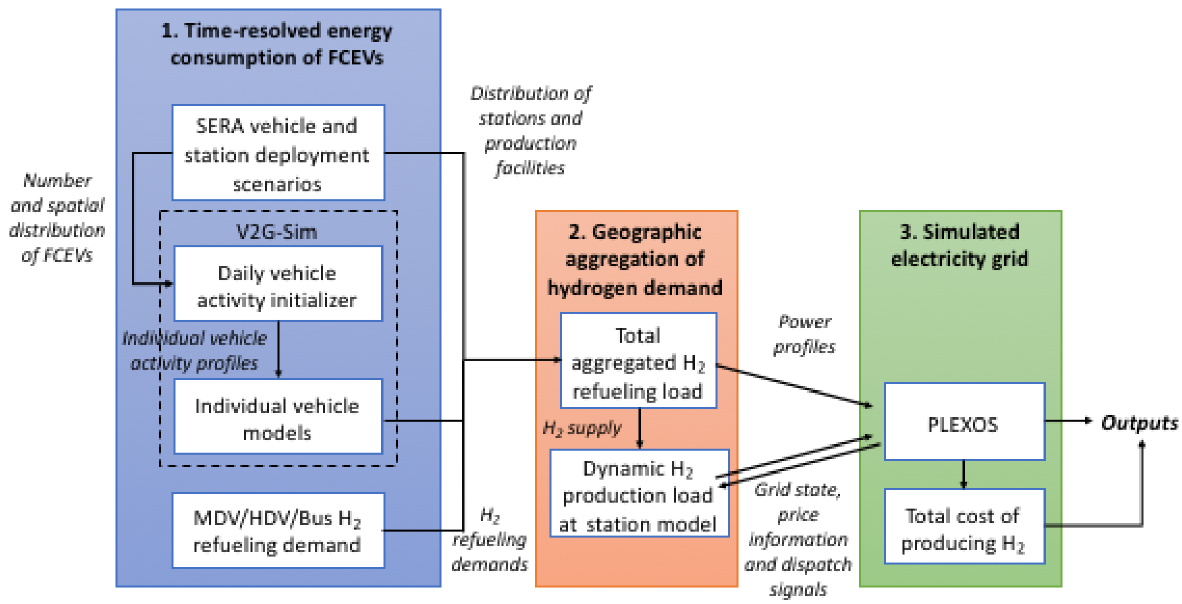


Figure 1. The overall methodology structure for this work

We chose the PLEXOS production cost model to simulate power system operation to meet this total load [68]. The total electricity generation cost and CO_2 emissions were calculated, placing the flexible hydrogen production process into an integrated power system context. Specifically, we used the 2030 Low Carbon Grid Study (LCGS) target scenario, which was developed by the National Renewable Energy Laboratory (NREL), to represent the WI power system [69]. The 2030 target scenario considers a 50% carbon reduction stemming from increased energy efficiency and renewable energy. The resulting renewable penetration level in California (which is a subset of the WI) is 56% including rooftop solar and transmission losses. In comparison, the state of California has a target of 60% renewable retail sales by 2030. While not modeled for this activity it is worth noting that California also has a 100% zero-carbon electricity target by 2045.

2.1 Modeled vehicles

The goal of this research is to investigate the influence of hydrogen production on the electricity grid with significant numbers (~millions) of FCEVs. As a reference scenario, the 2030 LCGS model is selected as a base case without FCEVs [51]. We then consider different FCEV adoption scenarios and associated hydrogen generation when calculating the hydrogen consumption and implementing the production cost simulations. As shown in Table 1, the vehicle classes cover a large range of gross vehicle weights, ranging from light-duty vehicles (≤3,853 kg) to Class 8 heavy-duty trucks and buses (>11,786 kg).

Table 1. Vehicle class definitions and projected number of FCEVs in 2030 for California

Vehicle class	**Abbre-viation**	**Definition**	**Gross vehicle weight (GVW) [52]**	**Projected number of FCEVs (see text)**
Light-duty vehicle	LDV	Passenger cars and light trucks (class 2a)	≤3,853 kg (≤8,500 lbs.)	5.0 million (18%)*
Medium-duty vehicles	MDV	All class 2b-6 vehicles	3,854-11,786 kg (8,501-26,000 lbs.)	274,000 (23%)*
Heavy-duty vehicles	HDV	All class 7 and 8 vehicles except buses	>11,786 kg (>26,000 lbs.)	33,500 (9%)*
Buses	BUS	Urban, school and other buses		19,400 (26%)*

* The fraction of vehicle stock in 2030 for California

We chose four vehicle types to represent the hydrogen demand of the 2030 transportation system in California: light-duty vehicles (LDVs), medium-duty vehicles (MDVs), heavy-duty vehicles

(HDVs), and buses (BUS, which are separated from other HDVs). We define each vehicle type using definitions provided by the U.S. Environmental Protection Agency [52]. The total number of FCEVs of each vehicle type is shown in the rightmost column of Table 1. Numbers are synthesized from a variety of 2030 projections [53] (C. Busch, Energy Innovation, pers. commun., 2018; M. Miller, University of California, Davis, pers. commun., 2018) that include both FCEVs and EVs (collectively, zero-emission vehicles or ZEVs). Given the uncertainty in the future choice of low-carbon vehicle technologies, an assumption based on total ZEVs seemed appropriate when constructing an optimistic future scenario for FCEVs. Projections are consistent with the industry's long-term forecasts of 20% hydrogen vehicle penetrations for cars and trucks [54][55].

2.2 Estimating hydrogen refilling demand

2.2.1 Light-duty vehicles

For LDVs, the Toyota Mirai is taken as a representative vehicle, as it currently has the largest stock share of FCEVs in the world [56]. The Mirai, which has a 5-kg hydrogen tank, has a range of 502 km (~312 miles) [12]. We use a detailed vehicle physics model called V2G-Sim to simulate the energy consumption of each vehicle [57], based on a set of empirical parameters calibrated specifically to the Mirai, along with instantaneous speed to estimate second-by-second energy consumption. Trip data are provided from the National Household Travel Survey (NHTS) for California [58]. Based on the average speed of each trip (see Figure S1 in the Supplementary Materials), one of three reference driving cycles developed by the U.S. Environmental Protection Agency (UDDS, US06, HWFET) [59] is chosen to represent the selected trip, and this cycle is applied repeatedly as needed to generate a vehicle speed vs. time profile throughout each trip. As a result, a time-dependent hydrogen consumption array is estimated for each vehicle.

We use a probabilistic approach to determine when hydrogen refilling takes place. Based on real-world data of FCEV refilling behavior [60], a continuous refilling profile is calculated (see Figure S2 in the Supplementary Materials). There is a probability that refueling will occur when the tank level is lower than 100% and that probability grows as the hydrogen remaining in the tank (known as the state of energy or SOE) decreases. We assume that an FCEV is fully refueled when stopping at a hydrogen refueling station. The hydrogen refilling demand (shown in Figures S3 and S4 in the Supplementary Materials) is obtained by launching V2G-Sim and merging the refilling profiles generated through the above approach.

2.2.2 Medium- and heavy-duty vehicles

For other vehicle classes, we used data from the California EMissions FACtor (EMFAC) model to obtain gasoline or diesel energy consumption per hour for one representative subclass each of MDV, HDV and BUS [61]. We then applied a conversion factor based on the difference in efficiency between hydrogen fuel cells and diesel engines to estimate the expected energy consumption per kg of hydrogen [62][63]. The EMFAC tool can simulate the fuel consumption for all vehicle classes [64]. All medium- and heavy-duty vehicles shown in Table 1 are chosen to calculate the hourly fuel consumption rate across the entire state. The fuel consumption was converted to the equivalent hydrogen consumption using the energy content of each fuel and an efficiency ratio of ~1.5 between hydrogen fuel cells and diesel engines [65].

To generate temporal fuel consumption profiles of individual vehicles, we opted for a stochastic sampling of the hourly aggregate fuel consumption data provided by EMFAC, following a probability curve for refueling similar to that of LDVs (see Figure S5 in the Supplementary Materials).

2.3 Geographic distribution of vehicles and filling stations

The Scenario Evaluation and Regionalization Analysis (SERA) model [66][67] outputs the FCEV numbers and locations of hydrogen filling stations. Based on the EMFAC result, the actual hydrogen refuel profile for the California region is scaled accordingly, combining the hydrogen refueling profiles for each FCEV class, to obtain an aggregated hydrogen refuel profile. This profile forms the input to the production cost modeling tool PLEXOS [68], which was used to evaluate the impacts of the hydrogen filling stations on the operation of the WI power system. PLEXOS optimizes power system operations in the day-ahead electricity market. Power system operations are optimized by minimizing the total production cost, e.g., variable operations and maintenance (VO&M) costs, fuel costs, and start up and shutdown costs, related to the unit commitment and economic dispatch decisions. PLEXOS solves the unit commitment and economic dispatch of the direct current optimal power flow (DC-OPF) problem using a mixed integer linear programming (MILP) formulation. The day-ahead market is simulated using a one-day optimization time frame with hourly resolution, plus a one-day look-ahead horizon using a four-hour resolution.

2.4 Importing hydrogen refueling profiles into PLEXOS

In order to simulate the hydrogen electrolyzer operation in PLEXOS, we chose the pumped-storage hydroelectric (PSH) power station object to model hydrogen production and storage devices, which satisfied the following two requirements (with stored “water” representing hydrogen): 1) It allowed for flexible production of hydrogen (as long as the station had enough hydrogen to supply FCEV demand, the electrolysis load could be shifted in time), and 2) it allows the enforcement of hydrogen storage limitations. After adding hydrogen production and storage units using PSH objects in the Low Carbon Grid Study (LCGS) PLEXOS model, the system is able to simulate and optimize when to produce hydrogen. Regarding the LCGS PLEXOS model, the associated techno-economic assumptions, e.g., fossil fuel prices, electricity demand growth, and power generation and transmission fleet, are provided in the LCGS report [69][51].

The following scenarios were defined in order to investigate the influence of the flexible load on the grid operations:

- Business-as-usual (BAU). A reference scenario representing the Western Interconnection (WI) area electricity grid without any FCEVs included.
- Inflexible scenario. This scenario represents the integrated grid after adding the FCEV load to the BAU scenario. In this scenario, the hydrogen generating rate is fixed, e.g., the capacity factor (CF) = 100%, and the electrolyzer is constantly operated at the maximum rated power to meet the FCEV hydrogen demand throughout the year. This is an idealized case, as it offers no flexibility in electrolyzer

operation, and there is no extra capacity to generate more hydrogen if demand increases. While an unlimited amount of hydrogen storage is initially assumed in the model, this is subsequently reduced to the maximum level needed annually for cost estimation purposes (see section 3.3).

- Flexible scenarios. As in the Inflexible scenario, the Flexible scenarios represent an integrated grid after adding FCEV load to the BAU scenario, but the hydrogen generation rate is variable. In other words, the electrolyzer is oversized for the hydrogen demand, allowing for variable operation. Hence, the electrolyzer can work across a wider range of hydrogen generation output rates than in the Inflexible scenario. This is more realistic because the electrolyzer should be configured to have extra capacity to generate hydrogen at times when it is favorable for the system to produce more hydrogen, or to meet increases in future demand. We explore a range of flexible scenarios in 10% decrements from CF = 90% to 50%.

Based on estimates from the literature [70], 1 kg of hydrogen requires between 48 and 67.5 kWh of electricity to produce it via electrolysis. We assumed a value of 54.3 kWh/kg in our model. With an annual hydrogen demand of 917 million kg for all vehicles, the electricity demand to generate the hydrogen was 49.8 TWh, for an average power level of 5.6 GW, which represents the minimum power size of the electrolyzer (P_{min}).

P_{flex} represent the maximum power capacity of the electrolyzer. In the Inflexible scenario, CF = 100%, which means $P_{flex}$is equal to P_{min}. In the CF = 50% scenario, $P_{flex}$is twice as large as P_{min}; thus ${P_{flex}}_{50}$ = 11.2 GW. The electrolyzer in this scenario has much more flexible capacity with which to generate the hydrogen. For example, the electrolyzer can generate more hydrogen when the overall net electricity load or the average electricity cost per unit is low, and reduce its hydrogen output during high net load or high price periods. In general, the larger the electrolyzer is sized, the more flexibility is enabled in hydrogen generation to reduce the system cost, but at a certain point, the cost savings is not enough to cover the cost of the larger electrolyzer. Thus, there is an optimum point of flexibility that minimizes total system cost. In the following section, the key output parameters will be shown to analyze the economic opportunities across different scenarios.

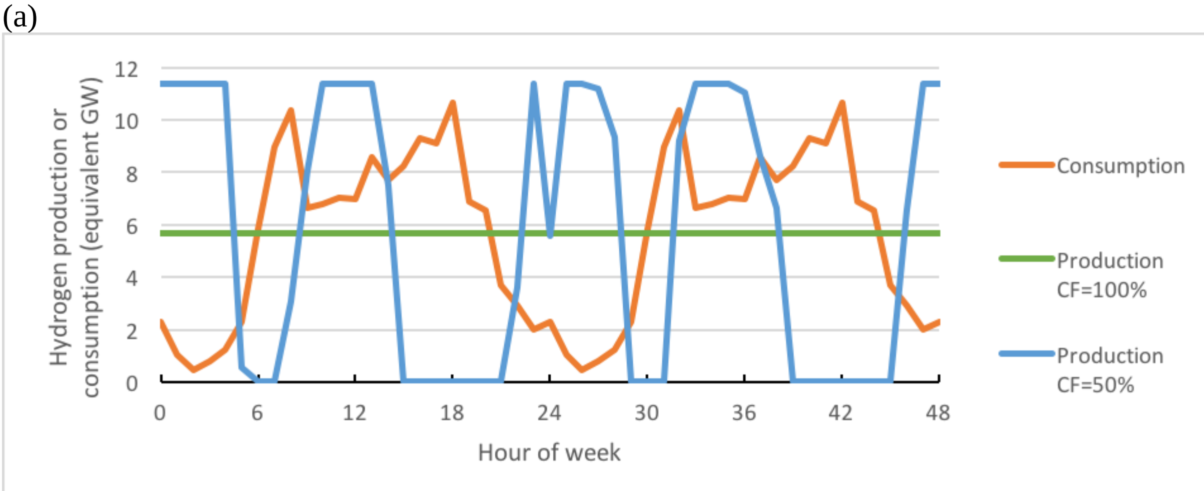
2.5 Electrolyzer and hydrogen storage cost estimation

The output of the PLEXOS simulations provides the operation cost of hydrogen production. However, to estimate the total hydrogen production cost, the capital costs of electrolyzers, compressor and hydrogen storage tanks were included (hydrogen distribution and dispensing costs are not considered). According to [71], the capital cost of a medium pressure hydrogen tank is $822/kg. The compressor cost is interpolated from [71] considering compressors with a maximum flow rate of 83 kg/hr. resulting in a cost of $9,627/kg-hr. The 2020 target electrolyzer capital cost is around $300/kW [44]. We assume the lifetime of these components are 20 years, and a yearly discount rate of 10%, in order to convert these capital costs into annualized costs.

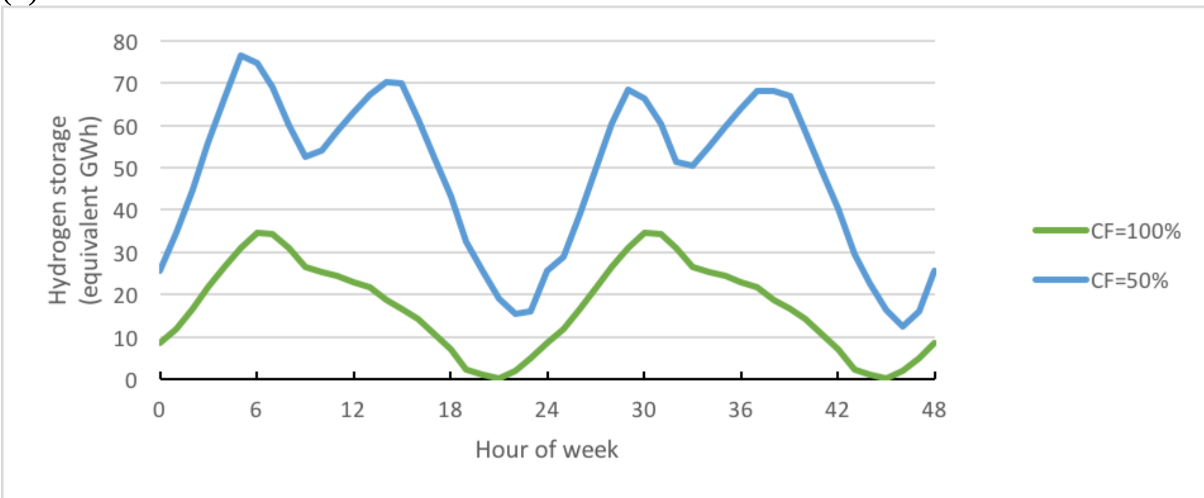
3. Results

Figure 2 shows a two-day representative snapshot in January of hourly hydrogen consumption, production, and storage for two electrolyzer capacity factor cases (CF = 50% and 100%), as well as the total electricity production cost. The hydrogen consumption (withdrawal) rate is the same for both cases. Hydrogen is expressed in terms of equivalent GW (production and consumption) or GWh (storage). We see in the CF = 100% case that hydrogen production is by definition constant, whereas for the CF = 50% case hydrogen production is flexible and varies over time, swinging between zero and maximum output at least twice per day. With hydrogen demand highest during daytime hours, and lowest after midnight, in both cases there is a depletion of hydrogen storage through the evening hours, reaching a minimum at 9-10 pm. Hydrogen storage is then filled up again in early morning hours. However, in the CF = 100% case, constant production leads to a single peak storage level each day (around 6 am), whereas in the CF = 50% case, variable production leads to two daily storage peaks (at around 5 am and 2 pm) and an overall larger daily range in storage level. Unlike in the inflexible case (CF = 100%), an oversized electrolyzer (e.g., CF = 50%) can act as a flexible load. The timing of the flexible load is driven by hourly electricity cost: when costs spikes, hydrogen production is stopped. As a result of this flexible load, total electricity production costs are lower in the flexible case compared with the inflexible case since generation from cheaper sources is maximized.

(a)



(b)



(c)

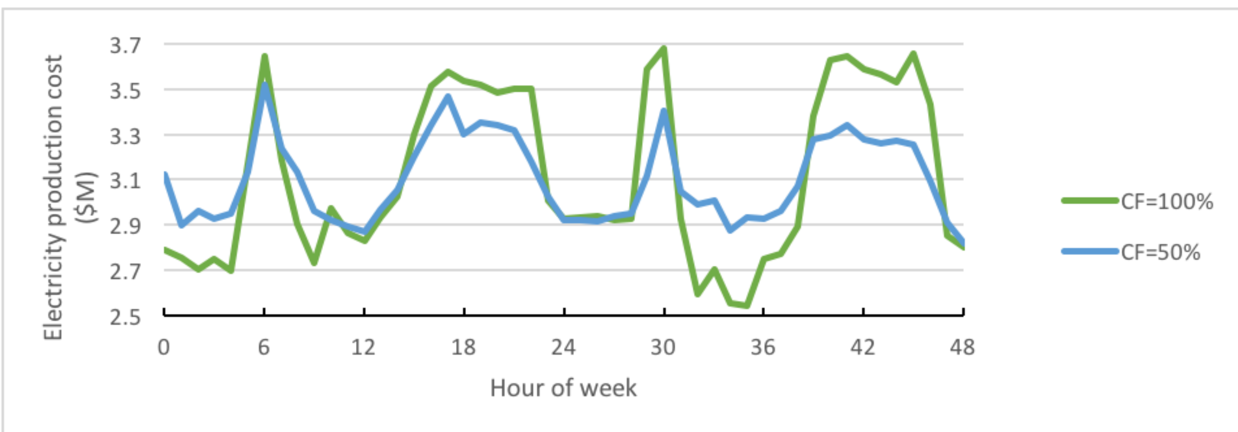


Figure 2. (a) Hydrogen consumption and production, (b) hydrogen storage, and (c) total electricity production cost, for two cases: CF = 50% and CF = 100% (inflexible). Note that hydrogen consumption is the same for both cases.

3.1 Average and marginal electricity unit costs

Figure 3, panel (a) shows the average cost per unit output ($/MWh) in all scenarios. The average electricity cost per unit output for the WI power system is defined as follows:

$$UC_{ave} = \frac{C_{all}}{L_{all}} \tag{1}$$

Here UC_{ave} is the average electricity unit cost (\$/MWh); C_{all} is the total system cost (\$) in a scenario that includes the cost of fuel, operations and maintenance, and generator startup and shutdown (see Figure S6 in Supplementary Materials); and L_{all} is the total system load (MWh) including hydrogen production, if applicable.

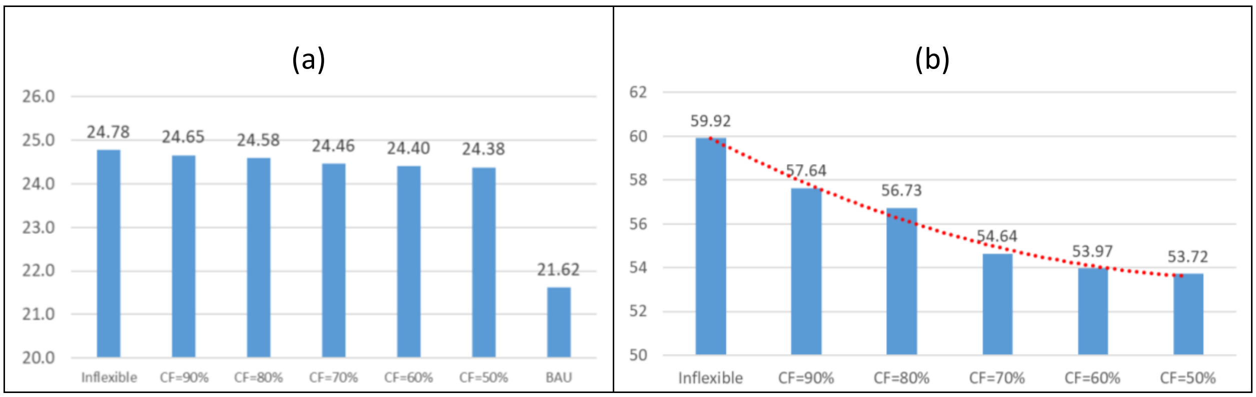


Figure 3. (a) Average electricity cost per unit output for BAU and various hydrogen scenarios across the WI (unit \$/MWh). (b) Marginal electricity cost (defined in the text) per unit output for hydrogen scenarios (unit \$/MWh).

The average costs in the hydrogen scenarios are all significantly higher than the BAU scenario, because the newly added hydrogen load must be supplied by more expensive generators, in contrast to the existing load that is, by definition, served using the lowest-cost generators. (Note that these scenarios do not include capacity expansion options.)

The marginal cost per unit output measures the cost of the newly added load. We define marginal cost according to the following equation:

$$UC_{marg} = \frac{C_{all} - C_{BAU}}{L_{all} - L_{BAU}} \tag{2}$$

where UC_{marg} is the marginal electricity cost per unit output ($/MWh), C_{BAU} is the total system cost ($) in the BAU scenario, and L_{BAU} is the system load (MWh) without any hydrogen production.

Figure 3, panel (b) shows the marginal cost per unit output for the hydrogen cases, which highlights the increased cost: the marginal cost is more than twice as high as the average cost (as expected). The marginal cost also decreases with decreasing CF, reflecting the value of flexible operations. However, the red dotted line (quadratic best-fit curve) shows that as the electrolyzer CF decreases, the electricity cost decreases more slowly, so the additional value of flexible operation diminishes.

Both the average and marginal electricity cost metrics presented above only include operating costs and do not include the capital investment for generators or the transmission and distribution network (which are fixed across scenarios). Adding a new large load could potentially require transmission and/or distribution upgrades, or even expansion of power generation capacity; however, in the context of this paper, electrolyzers are considered to be distributed across the region. As a result, all of the additional load for electrolyzers is served using the existing network without dropping any load. This should not be taken to imply that the lowest cost implementation for electrolyzers never involves installing additional equipment, but rather that the system considered is able to support the levels of additional load explored here. Moreover, if new capacity is built to meet additional loads, the lowest-cost resources (aside from policy or other considerations) will tend to be selected, which in many parts of the world including the U.S. are now wind and solar generation [72].

3.2 Generation mixes of added load

The marginal operating cost for renewable energy generation is assumed to be zero in PLEXOS. In contrast, the traditional generators consume fossil fuels and have higher operational costs. For example, the average combined cycle natural gas generator cost is \$56.6/MWh. Thus, using the natural gas generator will lead to a higher system operating cost. As shown in Figure 4, panel (a), the blue bar is the generation output for each kind of the generator type in the BAU scenario, while the orange bar represents the CF = 50% scenario. The majority of these two datasets are overlapped.

(a) (b)

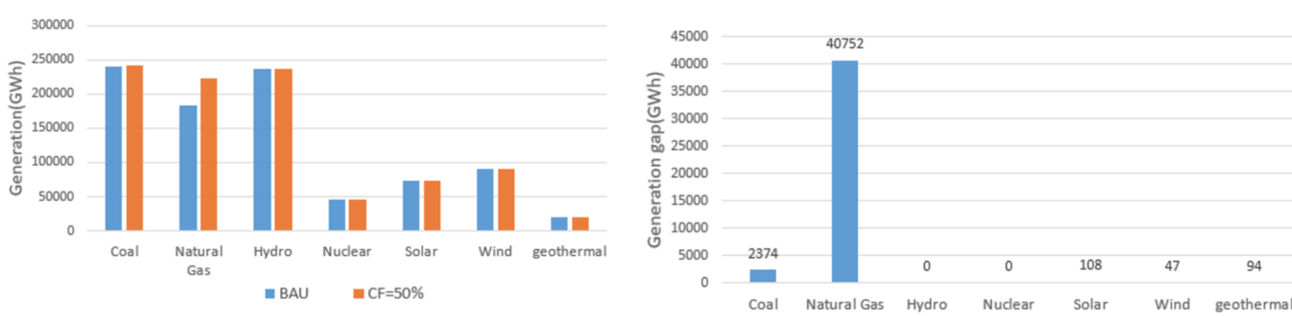


Figure 4. Annual generation output (in GWh) for each generator type: (a) Comparison of generation mix between BAU and CF=50% scenarios; (b) Net generation increase from flexible hydrogen load (difference between CF = 50% and BAU scenarios).

To make the comparison clear, the difference in generation between the two scenarios is shown in Figure 4, panel (b). Compared to the BAU scenario, the hydrogen demand requires 43.4 TWh/yr of electricity in the CF = 50% scenario. About 94% (40.8 TWh/yr.) of that electricity is supplied by natural gas generators. This result is based on the PLEXOS production cost modeling with fixed generation capacity, where the newly added demand is met by the spare marginal capacity of generator plants available. If we consider the supply curve, it is reasonable that the newly added load leads to a higher average cost per unit for the electricity consumption, because PLEXOS does not build new generation capacity to respond to increases in demand. Also, PLEXOS has already optimized the BAU case to achieve the lowest operation cost, which means that any additional electricity consumption will use the next lowest cost generator, which always leads to higher average generation cost. Note, however, that a small amount of zero-cost renewable generation (solar, wind and geothermal) is also utilized, but these resources are quickly saturated. Figure 4 should not be interpreted to indicate that the best approach to generate hydrogen is by burning natural gas to generate electricity to make hydrogen; indeed, the literature has many examples illustrating that production of hydrogen via natural-gas produced electricity is often considered[73][74][75][76]. Rather, based on these results and the assumptions presented in section 2.4, a key takeaway from our paper is quantification of the impacts of electrolyzer oversizing to enable flexible operation compared to an inflexible electrolysis operation case.

3.3 Benefit versus cost comparison

To determine the optimal amount of electrolyzer flexibility, we have included estimates of the capital cost of electrolyzers and associated hydrogen storage and compression infrastructure, and subtracted the BAU costs, to arrive at the total marginal cost to install and operate the electrolyzers for each scenario (Table 2 and Figure 5). We see that the total cost has a minimum point of $3.94 billion/yr with a capacity factor between 80% and 90%, indicating an intersection between decreasing operational costs and increasing capital costs. However, the results are sensitive to the equipment cost. While we assumed a target electrolyzer cost of $300/kW, the current cost is much higher (>$1,000/kW), which would result in the lowest-cost scenario being the inflexible case, with no advantage to oversizing.

Table 2. Storage size, electrolyzer size, and annualized capital and operations costs for hydrogen production.

Scenarios	Electrolyzer Size (GW)	Storage Size (GWh)	Annualized Storage + Compressor Cost ($B/yr)	Annualized Electrolyzer Cost ($B/yr)	Annual Operation Cost ($B/yr)	Total cost ($B/yr)	Nominal Hydrogen Cost ($/kg)
Inflexible (CF = 100%)	5.6	52	$0.27	$0.39	$2.98	$3.64	$3.97
CF = 90%	6.3	62	$0.31	$0.43	$2.87	$3.61	$3.94
CF = 80%	7.1	72	$0.36	$0.48	$2.77	$3.61	$3.94
CF = 70%	8.1	82	$0.41	$0.55	$2.72	$3.68	$4.01
CF = 60%	9.5	92	$0.46	$0.65	$2.69	$3.80	$4.14
CF = 50%	11.2	100	$0.53	$0.77	$2.67	$3.97	$4.33

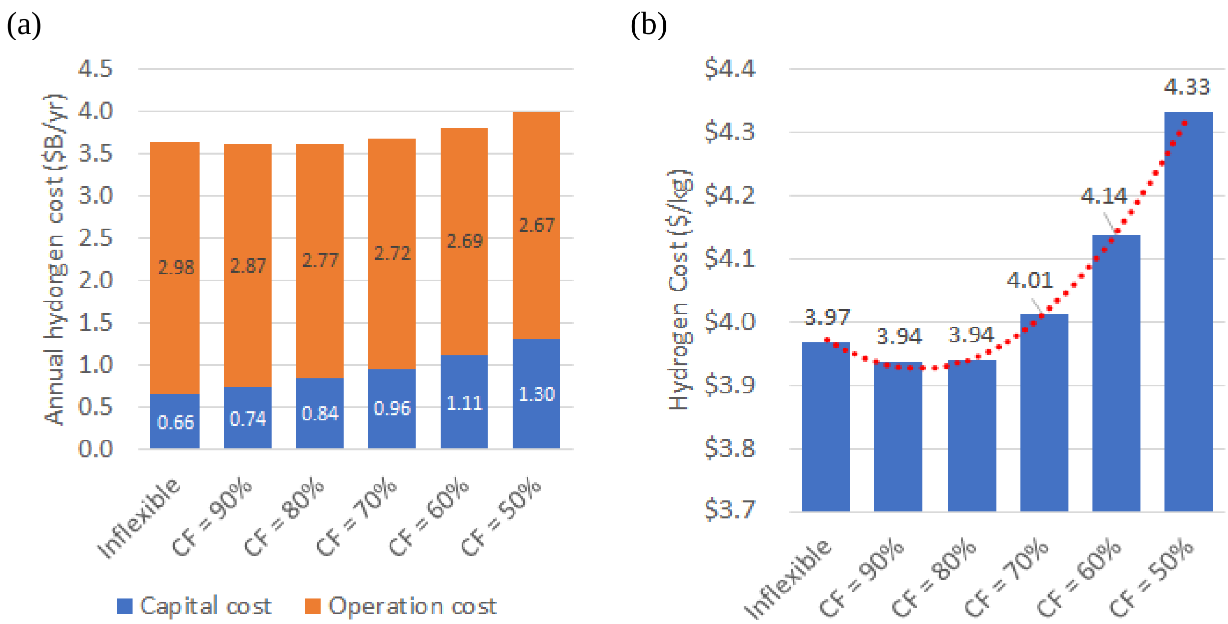


Figure 5. (a) Total system cost (including the capital cost and operating expenses); (b) Complete cost for hydrogen production, compression and storage ($/kg)

In this representation, the electrolyzer receives 100% of the benefits for its flexible operation (e.g., if the electrolyzer prevents a shutdown and startup event for a combustion turbine that occurred in the BAU case, the electrolyzer receives the entire value of that as an operating cost reduction). This represents the maximum benefit achievable for the electrolyzer. In contrast, if the electrolyzer was able to receive wholesale prices and bid into markets the system is not able to capture all of the benefits that it provides (e.g., most wholesale markets do not internalize the startup and shutdown cost in the wholesale energy prices) [77]. Similarly, flexible loads may not even have wholesale market access and may have to take service under retail utility rates. While retail rates use detailed cost allocation methods to ensure that fixed and variable costs are covered, the incentive structure for a flexible load to respond to retail rates is different than wholesale rates, which results in operation that is different than the system optimal and thus reduces the actual benefit provided by the flexible operation of the electrolyzer [78].

3.4 Renewables curtailment

A natural follow-on question to ask, after considering the marginal cost of generators in the presence of hydrogen electrolyzer loads, is how load flexibility affects renewables curtailment, or the amount of renewables generation (primarily from intermittent wind and solar PV generators) that is not utilized by the grid and thus "curtailed." While the total amount of renewables curtailment, shown in Table 3, is small compared with overall generation in all cases, it does change measurably, though there are no meaningful differences among hydrogen scenarios. For the entire WI, curtailment drops from 4.06% in the BAU case to 3.02% in the hydrogen case, whereas for California, curtailment drops from 4.88% in the BAU case to 3.01% in the hydrogen case—a nearly 40% relative reduction. The total renewable energy generation is the same in all cases (see Table 3). The reduction in curtailment, 2.47 TWh/yr. across the WI, is a small fraction of total hydrogen electrolysis demand of 43 TWh/yr., but is worth $62 million/yr. at an average electricity price of $25/MWh. Therefore, while hydrogen production does decrease renewables curtailment, it is due primarily to additional load, and is not altered by increased load flexibility. By comparison, a study in the E.U. indicated that flexibility measures could reduce curtailment on that grid of wind and solar PV from 7.0% to 1.6%, or 67 TWh/yr in 2040 [79].

Table 3. Renewables curtailment fraction (defined as 1 – ratio of renewable electricity used to available renewable electricity)

Region	BAU	Hydrogen	Renewable generation (TWh/yr.)
Western Interconnection	4.06%	3.02%	236.2
California	4.88%	3.01%	122.9

3.5 Greenhouse gas emissions

Figure 6 presents total annual carbon dioxide (CO_2) emissions from the WI electricity grid in the FCEV cases, plus transportation-sector emissions from an identical number of conventional vehicles in the BAU case (see Table S1 in Supplementary Materials). For the same reason that we see higher average electricity costs when additional load is added to the system, the hydrogen scenarios where additional load is added increase emissions compared to BAU. This is because the additional generation to meet the new electricity load comes largely from natural gas generators, which results in higher overall CO_2 emissions. That may change if the installed generation mixture is allowed to change based on the additional electrolyzer load – a point that is described in more detail in section 3.6. However, compared to the additional CO_2 emissions from conventional vehicles in the BAU scenario, this increase is only slightly higher: 3.2-3.8 million metric tons CO_2 ($MMtCO_2$)/yr. depending on the scenario, or ~1% of total emissions. (By comparison, if electrolysis electricity demand were satisfied entirely by renewable generation, emissions would be 18.0 $MMtCO_2$/yr. (~5%) lower than in the BAU scenario.) Comparing only the hydrogen scenarios in panel (b), greater flexibility results in lower emissions by up to 0.6 $MMtCO_2$ /yr.—not enough to reduce the total below the BAU scenario, but about a 16%

decrease. Since CO_2 emissions were not the objective of the optimization, this result is not causal, but happens nonetheless due to reductions in natural gas generation with additional flexibility from the electrolyzers. Beyond 2030 the renewable generation fraction will continue to increase, as evidenced by California's commitment to 100% zero-carbon electricity by 2045. As this renewable generation fraction increases, or if dedicated renewable resources are built to provide electricity for hydrogen production, the resulting CO_2 emissions in the hydrogen scenarios would be significantly lower than in the BAU scenario.

(a) (b)

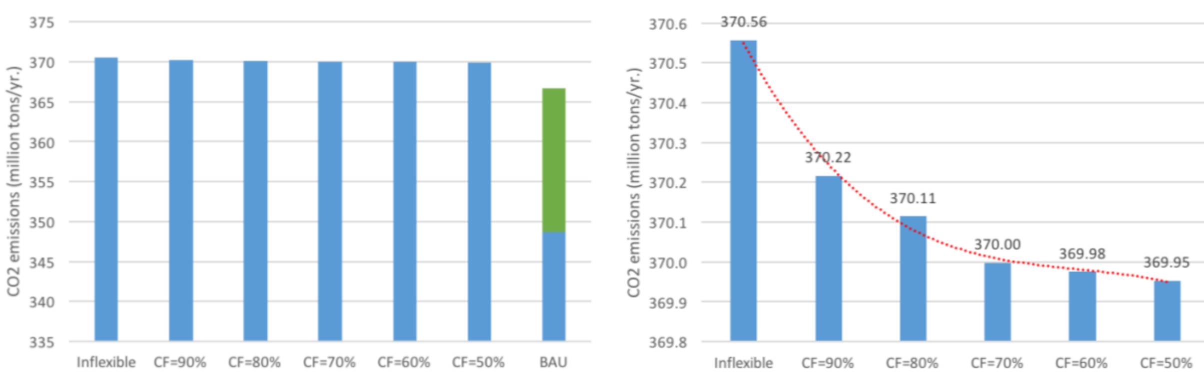


Figure 6. Annual greenhouse gas emissions (a) total for all scenarios and (b) total for hydrogen scenarios. Blue = electricity sector CO_2 emissions; green = vehicle sector marginal CO_2 emissions.

3.6 Study limitations

In our scenario, LDVs represent ~90% of the total hydrogen demand. Therefore, even though non-LDV hydrogen refueling demand has a somewhat different diurnal profile from LDVs, it has little influence on the overall demand and almost no impact on the results. While out of scope for this project, future work could explore scenarios with different compositions of LDV and non-LDV hydrogen vehicles, such as a case where there are many more non-LDVs, to identify the role that vehicle fleet composition has on the results. To make this a meaningful comparison, however, better estimates of non-LDV hydrogen demand temporal profiles will be required.

Our simulations also did not take into account the possibility of EVs providing additional flexible loads to the grid along with hydrogen electrolysis. Future work could include realistic market shares of both FCEVs and EVs, and in particular explore whether the different temporal load shapes associated with these vehicle types could provide opportunities for synergistic load-shifting (via controlled charging of EVs, and spare hydrogen production capacity for FCEVs), further reducing grid costs.

The PLEXOS model employed in our study was not run in a capacity-expansion mode so the generation portfolio (and the transmission system) was fixed, and generators were selected only to minimize total cost of meeting load, which varied across the scenarios. While keeping generation capacity fixed might not be an ideal assumption, it is a fairly common one to answer a certain set of questions like the ones we tackle, and one that is widely used in the literature[80][81][82]. As a result, dispatchable generators with higher marginal cost, such as natural gas, were overwhelmingly selected over renewable generators that had zero marginal cost, because the output of these latter generators could not be increased (however, curtailment was reduced slightly in the hydrogen scenarios relative to the BAU). Moreover, CO_2 emissions associated with hydrogen generation (computed based on marginal electricity generation) were much higher than might be expected if that electricity was produced primarily from renewable sources; total CO_2 emissions were even slightly higher than the BAU scenario with conventional petroleum-based vehicles. However, in a future electricity grid built to maximize the use of renewable generation for new loads such as from hydrogen electrolysis, marginal CO_2 emissions are expected to be much lower, leading to significant reductions relative to the BAU scenario. An interesting area of future work could be including hydrogen production from electrolysis in a capacity expansion tool such that the optimal resource mix and transmission network can be deployed to meet the additional load.

4. Conclusion

Hydrogen production via electrolysis can be regarded as a flexible load added to the electricity grid. This flexible load can provide support to the grid in a variety of ways including shifting load demand profiles and mitigating generator startups and shutdowns. In the scenarios explored in the paper, hydrogen electrolysis loads constituted ~3% of overall grid load. Compared to inflexible (100% CF) electrolyzer operation, greater flexibility can reduce these grid operational costs by more than \$6/MWh, or nearly 30% of the average BAU cost. In addition to reducing generation costs, adding hydrogen production can also reduce renewables curtailment by ~40%, and load flexibility can decrease CO_2 emissions by up to 16% or 0.6 $MMtCO_2$/yr for the 2030 system. However, the operational cost savings from increased load flexibility must be balanced with the additional capital costs associated with larger electrolyzer capacity that is underutilized. Combining the levelized cost calculation approach with an avoided cost for grid impacts, this analysis calculates the benefits and costs for flexible hydrogen production. Under future electrolyzer, compression and storage cost assumptions, an optimal least-cost point occurs at a flexibility level corresponding to a capacity factor of between 80% and 90%, corresponding to an oversizing of the electrolysis capacity of between 11 and 25%. However, while these results are sensitive to a number of assumptions including the power system that is modeled, hydrogen demand temporal profiles, and future technology costs, the results are potentially applicable to other regions with similar future grid configurations and FCEV penetration levels and use. Finally, while the method for calculating grid benefits using a production cost model is unique, it is also resource intensive, which limits the number of sensitivities that can be performed. Future work will build on these findings and explore a greater number of sensitive parameters to better characterize the role that flexible hydrogen generation can play in lowering the costs of hydrogen electrolysis and improving grid operations.

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