Electrolytic Renewable Fuel Production Optimal Operation Investigation - H2@Scale

Cooperative Research and Development Final Report

CRADA Number: CRD-19-00818

NREL Technical Contact: Omar José Guerra Fernández

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP- 6A40-82908
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Cooperative Research and Development Final Report

Report Date: April 20, 2022

In accordance with requirements set forth in the terms of the CRADA agreement, this document is the CRADA final report, including a list of subject inventions, to be forwarded to the DOE Office of Scientific and Technical Information as part of the commitment to the public to demonstrate results of federally funded research.

Parties to the Agreement:

University of California Irvine (UCI) (Advanced Power and Energy Program – APEP)

CRADA Number: CRD-19-00818

CRADA Title:

Electrolytic Renewable Fuel Production Optimal Operation Investigation - H2@Scale

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Sponsoring DOE Program Office(s):

Office of Energy Efficiency and Renewable Energy (EERE), Hydrogen and Fuel Cell Technologies (HFCT)

Joint Work Statement Funding Table showing DOE commitment:

Estimated Costs	NREL Shared Resources a/k/a Government In-Kind
Year 1 Year 2	\$25,000.00 \$25,000.00
TOTALS	\$50,000.00

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<u>Executive Summary of CRADA Work</u>:

This work explored the optimal design and operation of electrolytic hydrogen production from renewable power. While there are many financial incentives for renewable hydrogen, this work investigated the effects of Low Carbon Fuel Standards ((LCFS) on the hydrogen breakeven cost. To this end, this project developed optimized operational strategies for electrolytic hydrogen facilities in the California. Four specific model projects were used as the basis for the analysis. Three model projects will be located in California and one in Texas or the Midwest to be determined during the project. All projects include interconnection to the natural gas grid as a method of transport for the product fuel and the hydrogen cases will also consider alternative modes of transport. The operational optimization will maximize project return through fuel production and grid services based on future scenarios for the value of each. The effort will rely on modeling tools developed by NREL and the UCI for grid modeling as well as the integrated resource planning tool (IRP), RESOLVE, which is the official IRP tool used by the California Public Utility Commission (CPUC). The development of this project can help to inform future hydrogen deployment, policy and regulation makers, research and development decisions, and private and public investment.

<u>Summary of Research Results</u>:

1 Project Summary

Develop Detailed Project Descriptions:

This work explored the optimized production of electrolytic hydrogen under different configurations of renewable power facilities and electrolyzer sizes. There are many renewable power sources that can be used to produce electrolytic hydrogen, but we considered solar photovoltaic (PV) and wind as renewable energy sources for this study. These solar PV and wind facilities are on-site or off-site connected through existing power networks. There are several financial incentives being developed for generating clean fuel, and such incentives play an important role in the cost-competitiveness of new renewable technologies. LCFS is one of such incentives that was considered in this study. LCFS credit represents credits earned for one metric ton of carbon dioxide reduced. Four electrolytic hydrogen facilities located in California are considered in this study.

All projects included interconnection to the natural gas grid as a method of transportation for the product fuel. The operational optimization maximizes project return through fuel production and grid services based on future scenarios for the value of each.

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2 Modeling Methodology

Define Modeling Approach and Input Requirements:

NREL's modeling activities were used to better understand the optimal operation of hydrogen electrolysis equipment in the future and to provide input to the air quality modeling being carried out by UCI.

NREL used the Revenue, Operation, and Device Optimization (RODeO) model to solve the hydrogen operations optimization problem. RODeO explores optimal system design and operation considering different levels of grid integration, equipment cost, operating limitations, financing, and credits and incentives. It is an open-source price-taker model formulated as a mixed-integer linear programming (MILP) model in the General Algebraic Modeling System (GAMS) modeling platform. The objective is to maximize the net revenue for a collection of equipment at a given site. The equipment includes generators (e.g., gas turbine, steam turbine, solar, wind, hydro, fuel cells, etc.), storage systems (batteries, pumped hydro, gas-fired compressed air energy storage, long-duration systems, hydrogen), and flexible loads (e.g., electric vehicles, electrolyzers, flexible building loads). The input data required by RODeO can be classified into three bins as shown in Figure 1.

1. Utility service data refers to retail utility rate information (meter cost, energy and demand charges).
2. Electricity market data, which includes energy and reserve prices.
3. Other inputs refer to additional electrical demand, product output demand, technological assumptions, financial properties, and operational parameters.

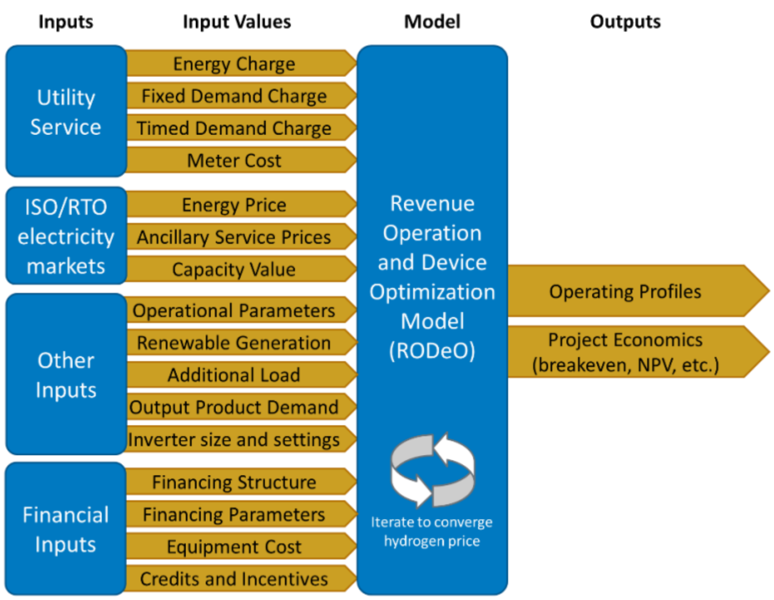

Figure 1. RODeO system diagram

Subsequent sections describe the data sources that are used to input into the RODeO model. Also, a list of scenarios to be performed for this analysis is outlined.

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3 Data Sources

Develop Electric Rate, Ancillary Services and Fuel Market Assumptions:

The RODeO model can accept a variety of inputs. Some, including the electricity price, equipment sizing and device efficiency, are required, while others including cost data, additional load, and on-site renewables, are optional.

For this analysis we focus on wholesale market integration, leveraging historical price signals from the California Independent System Operator (CAISO) and future price signals for Southern California from the Low Carbon Gid Study (LCGS) (https://www.nrel.gov/docs/fy16osti/64884.pdf). We are using the regional locational aggregated price for Southern California Edison in 2019.

The LCGS project envisioned a California grid with 50% emissions reductions in the power sector by 2030. We use the "Target" scenario from LCGS which includes a higher level of energy efficiency and a diverse mix of renewable resources with a renewable penetration of 56%, not including hydro (for an annual load of 320 TWh). From the LCGS we use the equivalent Southern California Edison regional price (labeled CISC). Average hourly base price signals are shown in Figure 2.

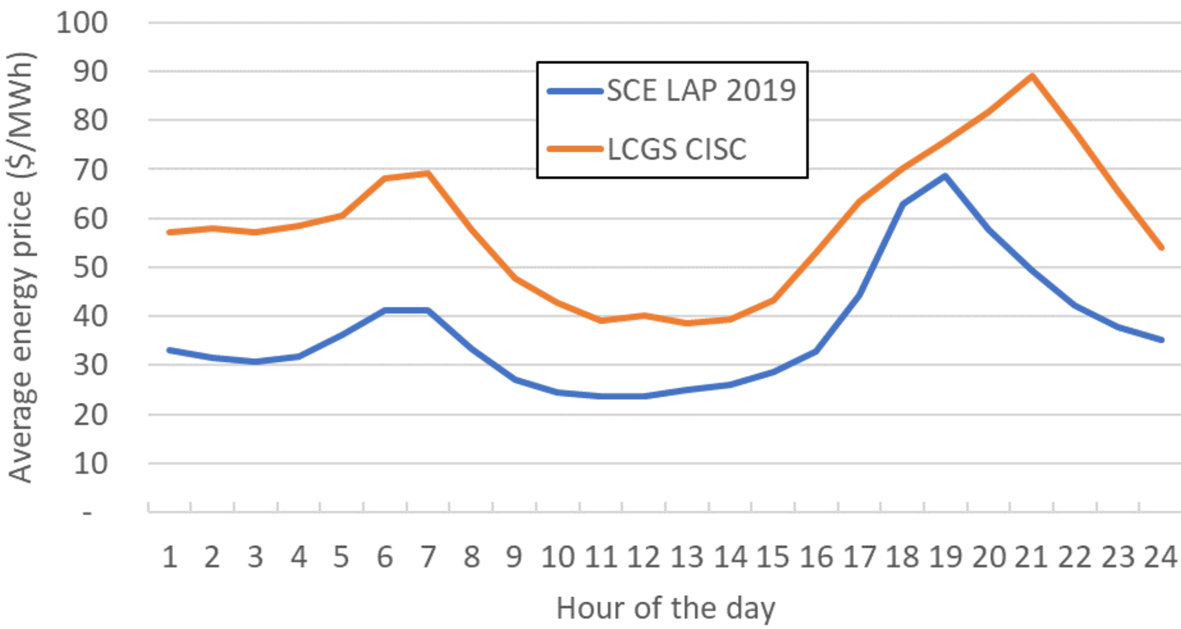

Figure 2. Average hourly price for historical and LCGS price signals

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For this project we used an average hourly price of $15/MWh. To this end, we adjusted the electricity price time series for CISC, as detailed in equation 1.

$$\overline{P_h} = \left(\frac{1}{24}\sum_{h}^{h+24} P_h - P_h\right) \cdot S \quad \text{where} \quad \overline{P_h} \leq 2{,}000 \quad \text{and} \quad \overline{P_h} \geq 0 \qquad \text{Eqn. 1}$$

Where P_h is the price signal at each hour (h)

$\overline{P_h}$ is the adjusted price signal at each hour

S is the standard deviation adjustment value (e.g., 0.2, 0.4, 0.8)

This process is demonstrated for several average adjustment values and standard deviation adjustment values in Figure 3. The red dot without an adjustment to standard deviation or the average is the base CISC profile. This process allows us to extrapolate a variety of potential future price signals by varying the statistical parameters of the original price signal.

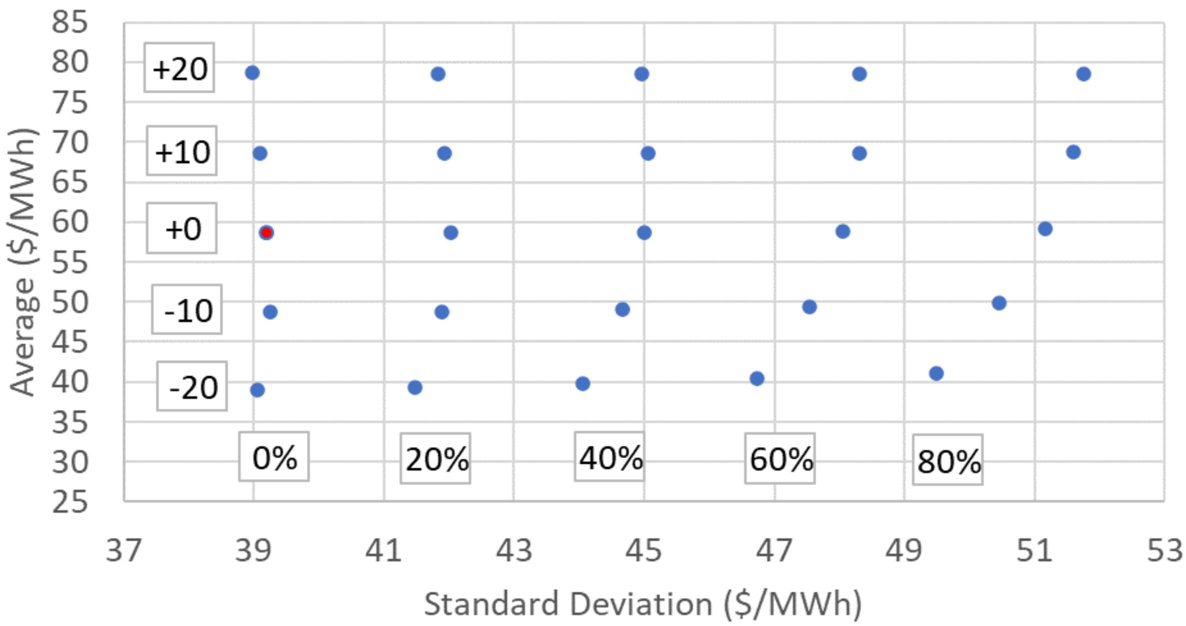

Figure 3. Example adjustments to average and standard deviation for the LCGS CISC price signal

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4 Scenarios

Develop Modeling and Analysis Case Matrix:

Preliminary scenario information is detailed in Table 1 and Table 2. This includes sizing and cost values for each technology considered and each location. Electrolyzer capital and operation and maintenance costs are pulled from the DOE's H2A model for the future PEM electrolyzer case adjusted to 2019. Renewable pricing is pulled from NREL's Annual Technology Baseline.

Table 1. Device sizing and cost parameters

Category	Property	Moreno Valley		Downtown LA (DTLA)	Five Points (5PT)
		MV-1	MV-2		
Hydrogen	Electrolyzer size (MW)	15	50	2	30
	Electrolyzer capital cost ($/kW)	400-800	400-800	400-800	400-800
	Electrolyzer fixed operation and maintenance cost ($/kW-yr)	53	53	53	53
	Hydrogen storage cost ($/kg)	822 [1]	822 [1]	822 [1]	822 [1]
	Hydrogen compressor cost ($/kg)	See footnote [1]	See footnote [1]	See footnote [1]	See footnote [1]
Renewable	Onsite Solar PV size (MW)	5	50	0	30
	2020 Annual Technology Baseline Price info	2030 - Solar - moderate	2030 - Solar - moderate	NA	2030 - Solar - moderate
	Renewable capital cost ($/kW)	687.8	687.8	NA	687.8
	Renewable fixed operation and maintenance cost ($/kW-yr)	8.055	8.055	NA	8.055

To improve the economics of the hydrogen production systems, an off-site wind facility was included for each system configuration presented in Table 1. The capex for the off-site wind facilities was $1,227.00/kW. Additionally, we performed a sensitivity around the capacity for the off-site wind facilities, as follows: facility DTLA→ wind capacity from 1.5 MW to 3 MW, facility 5PT→ wind capacity from 5 MW to 35 MW, facility MV1→wind capacity from 10 MW to 17.5 MW, and facility MV2→wind capacity from 15 MW to 45 MW.

[1] Values pulled from compressor cost curve in Pratt, J., Terlip, D., Ainscough, C., Kurtz, J. & Elgowainy, A. H2First Reference Station Design Task. Project Deliverable 2-2. https://www.nrel.gov/docs/fy15osti/64107.pdf (2015).

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Table 2. Assumptions for Financial Properties

Property	Values
Federal tax rate	21.0% (2019)
State tax rate	8.84% (California 2019)
Depreciation	5-year MACRS depreciation and first year bonus depreciation of 50%
Weighted Average Cost of Capital (WACC)	7%[2]
Other properties	Rate of return: 4.89% Return on equity: 10.25% Debt interest rate: 4.81% Debt period: 20 years Debt fraction: 58% (calculated from above properties) Equity fraction: 42% (calculated from above properties) U.S. Inflation: 1.9%
Low Carbon Fuel Standard Price ($/credit)	20, 60, and 100

The result from these scenarios will be used to improve the understanding of how to operate electrolyzers in future power systems. In addition, the operational results will be provided to the air quality assessment team to improve their representation of electrolyzers in the air quality assessment.

[2] WACC = Debt fraction * (1 – Debt interest rate) * Rate of return + Equity fraction * Rate of equity

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5 Results

Total hydrogen breakeven costs

Summarize Findings and Recommendations:

In this section we summarize the results from the RODeO model (described in Section 2), using the data and scenarios described in sections 3 and 4 of this report. First, the total hydrogen breakeven cost for each system is presented in Figure 4, including the corresponding sensitivities around off-site wind capacity, electrolyzer capex, and Low Carbon Fuel Standard (LCFS) credit. As expected, hydrogen production costs vary widely from $0.6/kg to $6.75/kg based on system configuration and assumptions. In general, hydrogen production costs are higher for DTLA facility in comparison with the other three locations, which indicates that co-location with solar PV helps to reduce hydrogen production costs. Moreover, the results presented in Figure 4 indicate that there is a tradeoff between the utilization of the electrolyzer and the deployment of off-site wind capacity. For example, increasing off-site wind capacity helps to increase the utilization of the electrolyzer, which reduces hydrogen production cost. However, there is an inflection point from which the wind capacity is overbuilt and therefore hydrogen production cost increases. Additionally, it is observed that there is a $0.3-$0.6 per kg decrease in hydrogen breakeven cost with every $200/kW decrease in electrolyzer CAPEX. Similarly, there is a ~$1.3/kg decrease in hydrogen breakeven cost for every $40 increase in LCFS credit, which indicates that LCFS credit is an effective mechanism towards the cost-competitiveness of electrolytic hydrogen production in California.

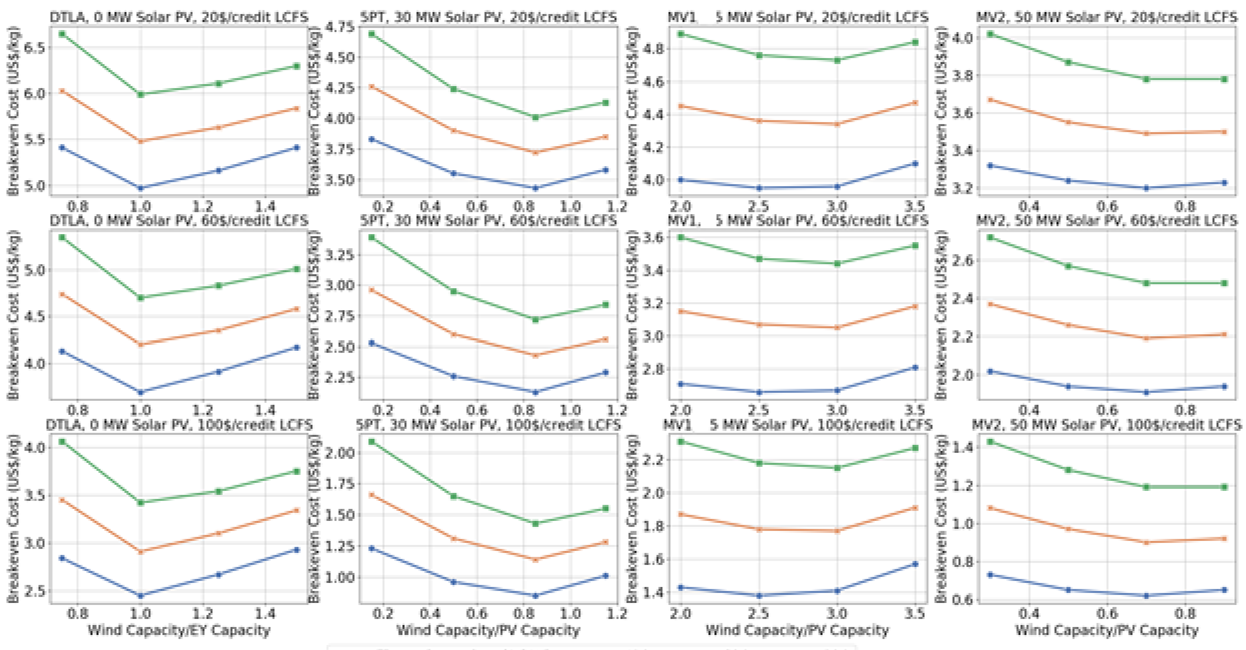

Figure 4. Hydrogen breakeven cost for each location, including sensitivity around wind capacity, electrolyzer capex, and LCFS credit.

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Cost breakdown and electrolyzer operation for each facility and $100/LCFS credit

Results regarding the hydrogen cost breakdown for each location and $100/LCFS credit are summarized in Figure 5, Figure 6, Figure 7, and Figure 8 for LA1, 5PT, MV1, and MV2, respectively. It is observed that renewable capital expenditure (CAPEX) is a key contributor to hydrogen breakeven cost. Moreover, the optimal capacity factor for the electrolyzer varies as a function of the off-site wind capacity, e.g., VRE capacity/electrolyzer capacity (VRE/EY metric). Note that the solar PV capacity is fixed based on information from Table 1, thus different values of the VRE/EY metric are associated with different values for the off-site wind capacity. Indeed, the optimal VRE/EY capacity ratio varies as function of the location and seems to be less sensitive to the electrolyzer CAPEX. Additionally, DTLA has the lowest optimal electrolyzer capacity factors, e.g., between 25% and 28%, and the highest hydrogen production costs. On the other hand, MV2 has the highest optimal electrolyzer capacity factors, e.g., between 41% and 47%, and the lowest hydrogen production costs. Thus, the selection of the location as well as the co-location with solar PV are key aspects for the economics of electrolytic hydrogen production facilities. The corresponding results for $20/LCFS credit and $60/LCFS credit are presented in the Appendix section.

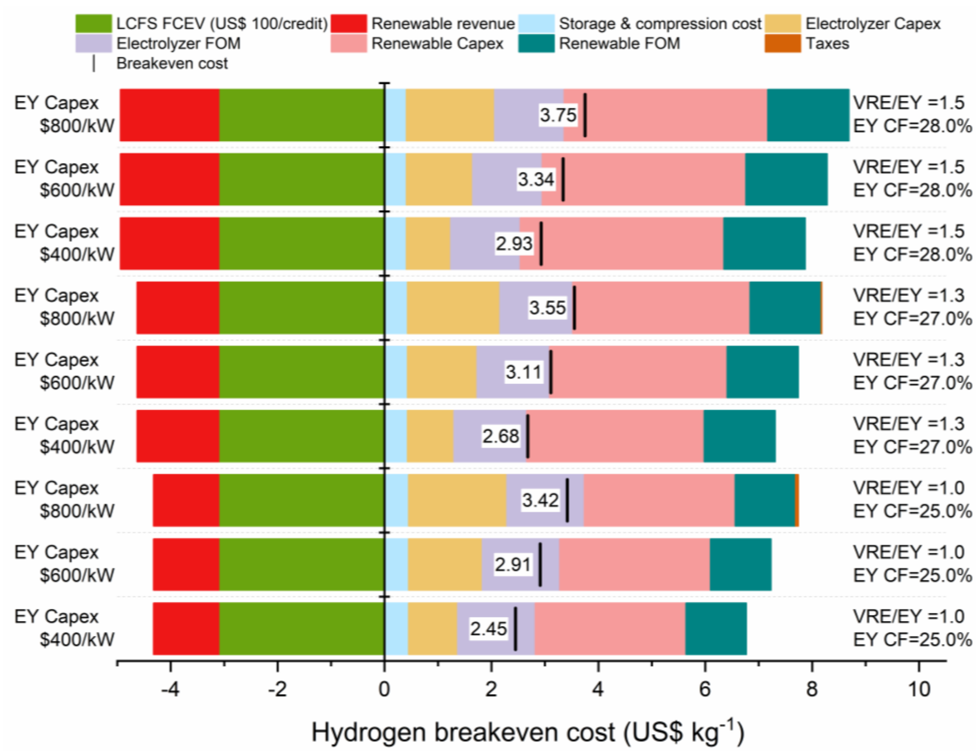

Figure 5. Hydrogen cost breakdown for facility DTLA and $100/LCFS credit.

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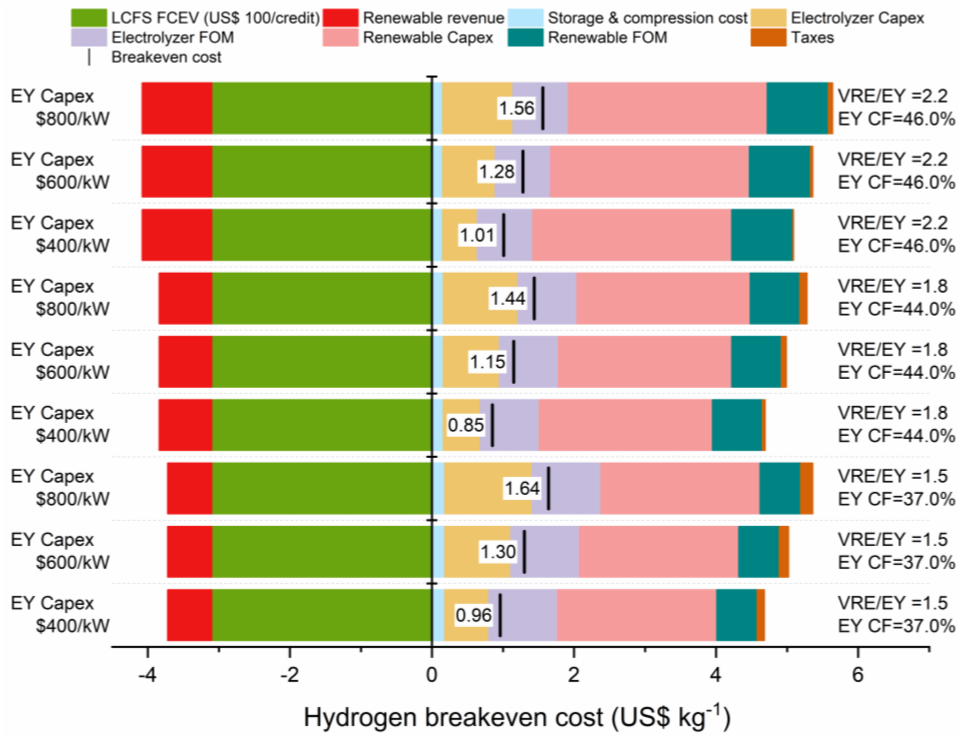

Figure 6. Hydrogen cost breakdown for facility 5PT and $100/LCFS credit.

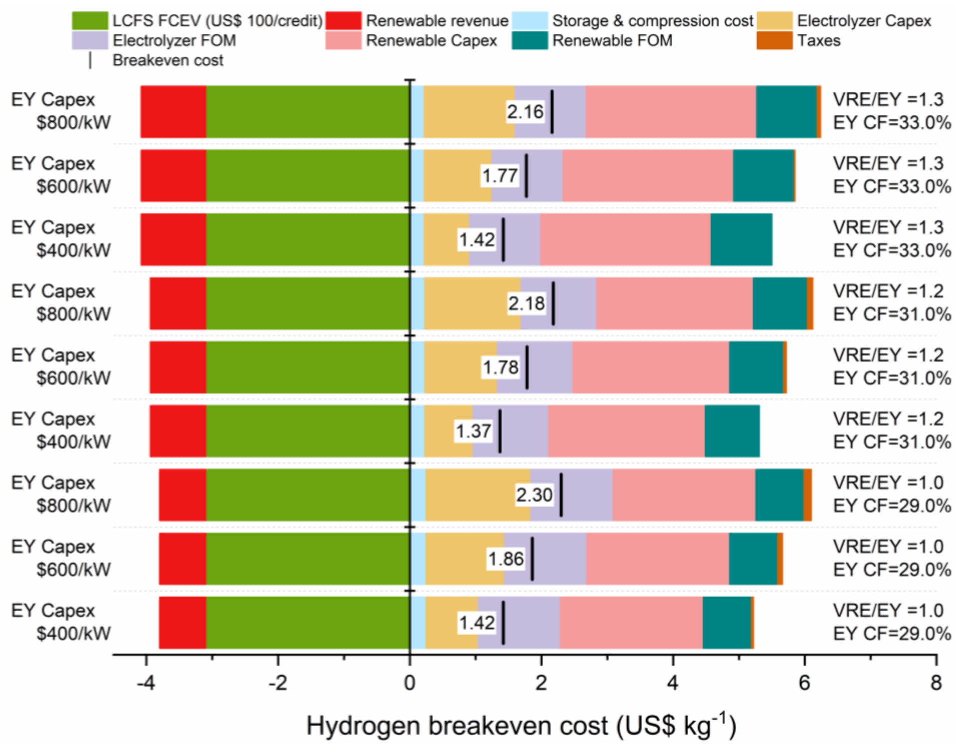

Figure 7. Hydrogen cost breakdown for facility MV1 and $100/LCFS credit.

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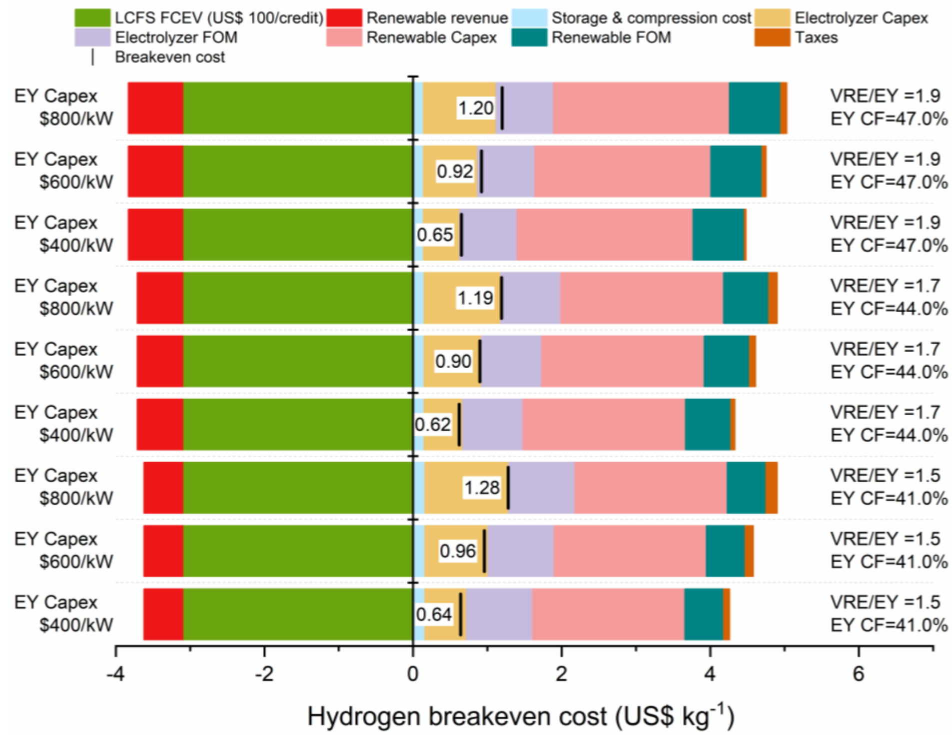

Figure 8. Hydrogen cost breakdown for facility MV2 and $100/LCFS credit.

Figure 9, Figure 10, Figure 11, and Figure 12 summarize the cumulative hourly operation of the hydrogen facility broken down based on the input energy source as well as the renewable energy sales for DTLA, 5PT, MV1, and MV2, respectively. The energy is aggregated hourly over one year of operation and is represented in the plots as bars (blue corresponding to wind, orange corresponding to solar PV and gray corresponds to the energy sale). The magenta-colored curve corresponding to the right axis represents the hourly average energy sale price determined over one year's data.

All the hydrogen facilities show a strong correlation between the total renewable energy sales and the energy sale prices, e.g., relatively low energy sales during low energy prices and relatively high energy sales during hours with high energy prices. Moreover, if co-located with solar PV, the electrolyzer uses most of the solar PV generation, since low energy prices are correlated with higher availability of solar PV generation. These results illustrate how the optimal operation of the electrolyzer varies as function of the specific system configuration, e.g., off-site wind facility versus co-location with solar PV plus off-site wind.

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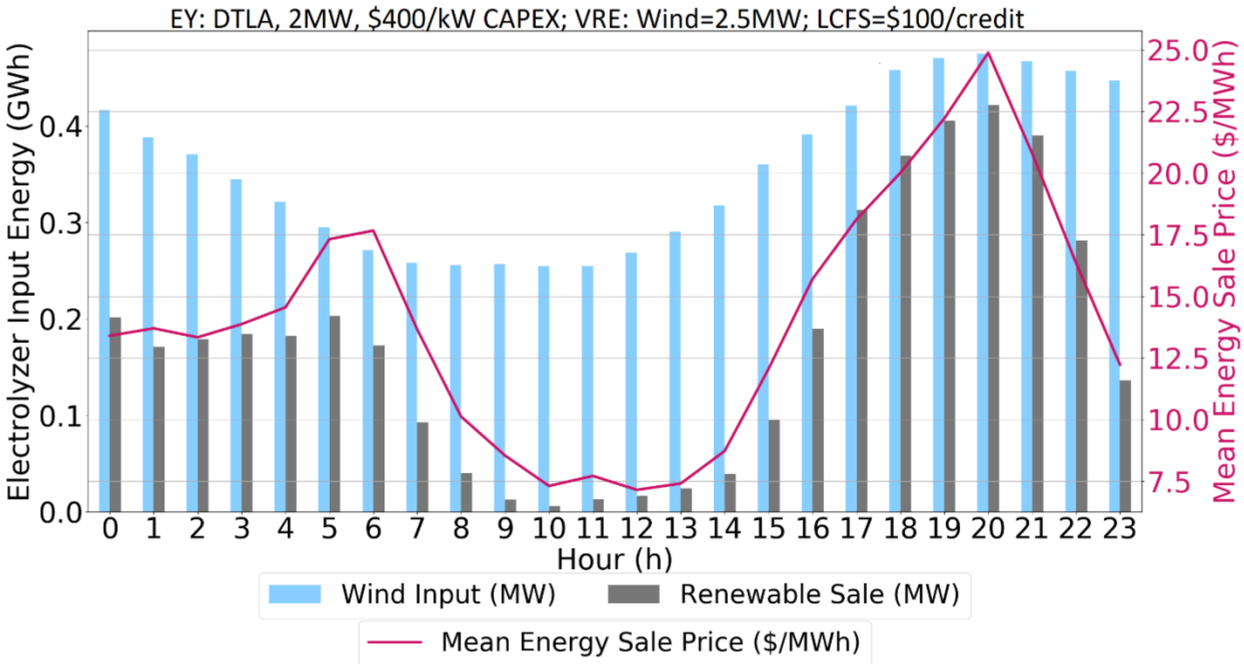

Figure 9. Electrolyzer operation for DTLA facility and $100/LCFS credit. The bars represent the hourly aggregated energy for one-year operation, and the magenta curve represents the hourly average energy sale price for the same period and corresponds to the right axis.

It must be noted from the Figure. 9 that the DTLA has no on-site solar PV and the entire energy for the electrolyzer is derived from the off-site wind. The off-site wind has a stronger correlation to the energy sale price than the other facilities that have both on-site solar and off-site wind because of the higher investment costs related to the wind units. The price curve correlates to the California energy demand “duck-back” curve that has the characteristic low price during the middle of the day reflecting high solar energy, and a steep ramp in energy prices from hour 17. This price dynamics makes the electrolyzer utilize more renewable energy produced during hour 8 through 14 with negligible energy sold. The Figure 10 through 12 represents the energy breakdown for the hydrogen facilities with onsite solar PV and an offsite wind facility. A similar trend of energy sale and energy price correlation can be observed. Noted that even though the energy sales appear to be decreasing between hour 17 and 21, the energy sold as a percentage of available renewable energy is still rising. The hours 6 through 17 have significant solar PV energy produced on-site and used by the electrolyzer.

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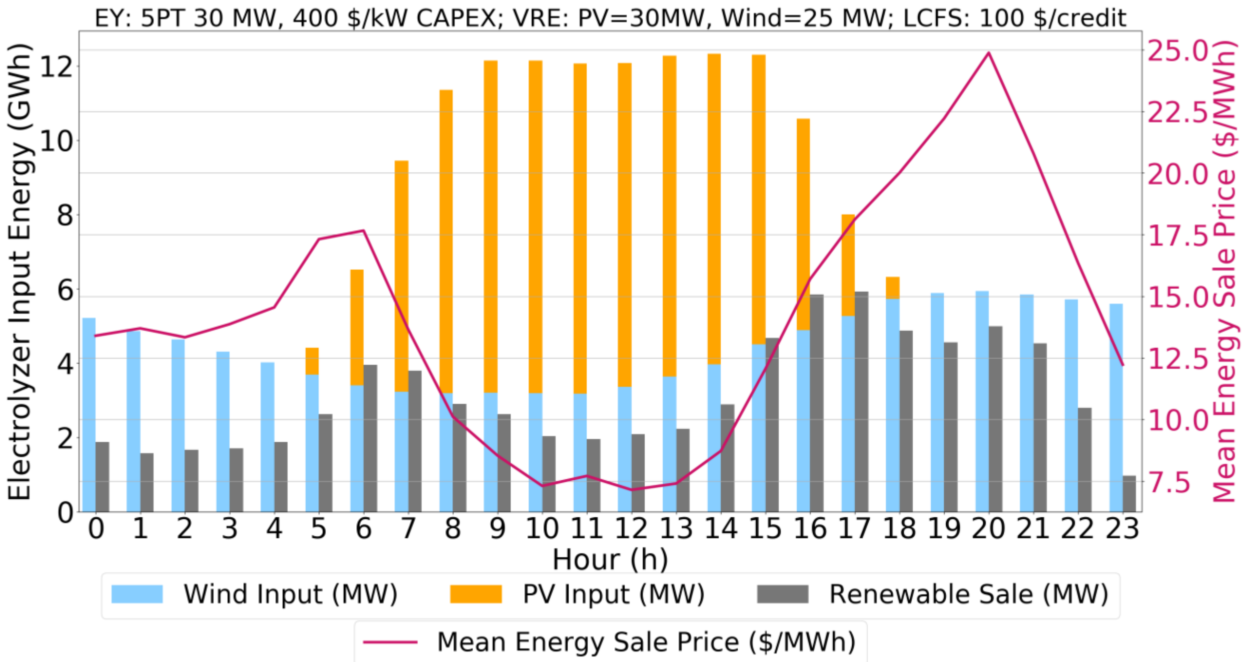

Figure 10. Electrolyzer operation for 5PT facility and $100/LCFS credit. The bars represent the hourly aggregated energy for one-year operation, and the magenta curve represents the hourly average energy sale price for the same period and corresponds to the right axis.

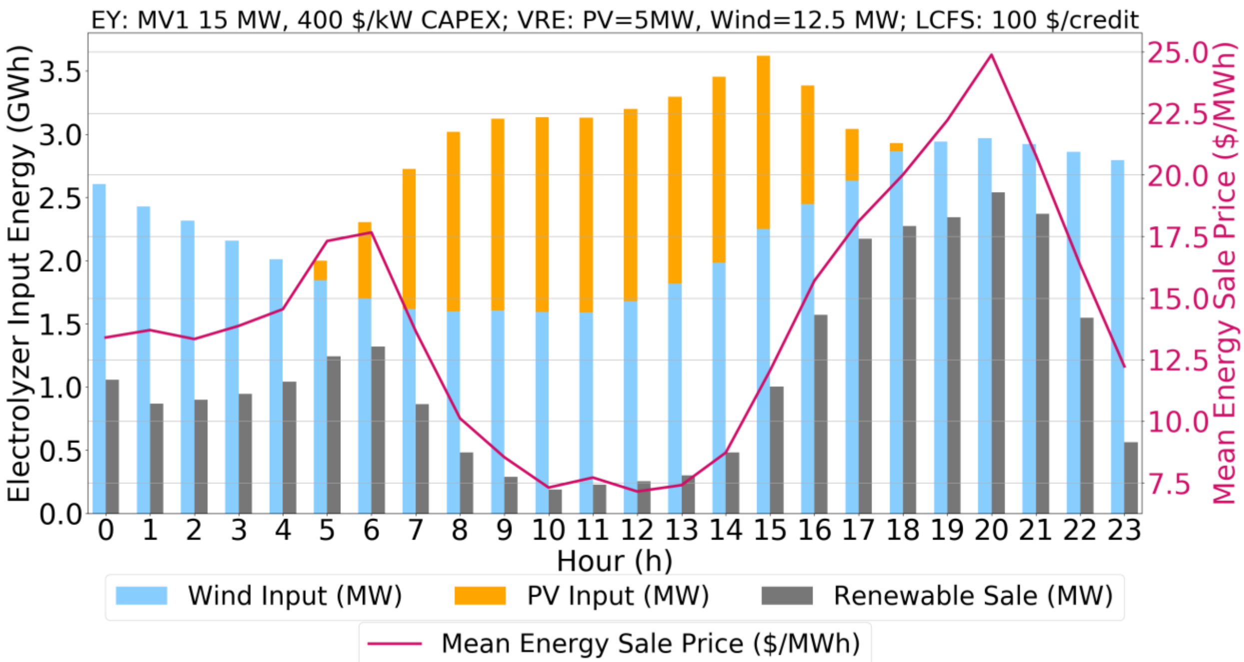

Figure 11. Electrolyzer operation for MV1 facility and $100/LCFS credit. The bars represent the hourly aggregated energy for one-year operation, and the magenta curve represents the hourly average energy sale price for the same period and corresponds to the right axis.

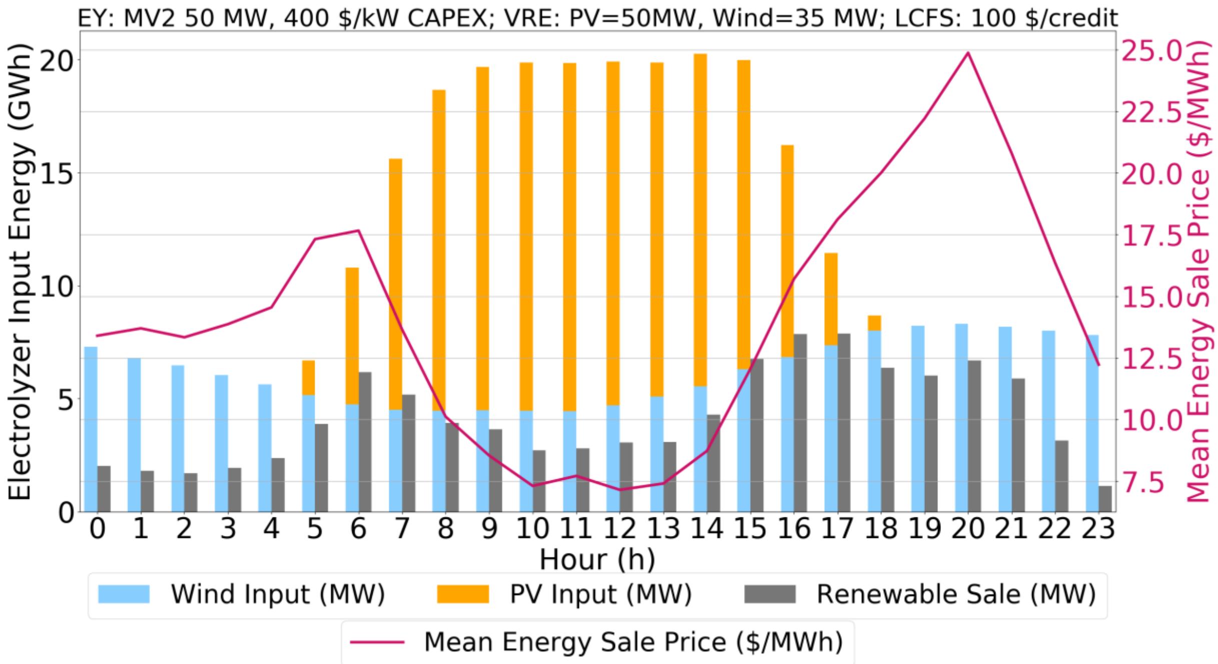

Figure 12. Electrolyzer operation for MV2 facility and $100/LCFS credit. The bars represent the hourly aggregated energy for one-year operation, and the magenta curve represents the hourly average energy sale price for the same period and corresponds to the right axis.

6 Conclusions

In this study we evaluated the design renewable hydrogen production facilities for transportation applications (2030 timeframe). To this end, we estimated the breakeven cost of hydrogen production under different system configurations. Additionally, the effects of different techno-economic assumptions on the hydrogen breakeven cost were also evaluated, e.g., via sensitivity analysis. The main takeaways from this study are as follows:

- Economy of scale could be key to achieve low hydrogen production costs (higher electrolyzer capacity →lower hydrogen production cost).
- Location MV2 (the largest electrolyzer used this study, e.g., 50 MW) has the least hydrogen breakeven cost (0.62 $/kg).
- Policy driven mechanisms such as LCFS and other credits can significantly reduce hydrogen breakeven cost (decrease of ~$1.3 per kg for an increase of $40 per LCFS credit for MV2).
- Co-location with solar PV facilities helps to reduce hydrogen breakeven cost by increasing the utilization of the electrolyzer.

<u>Subject Inventions Listing</u>:

None

<u>ROI #</u>:

None

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Appendix

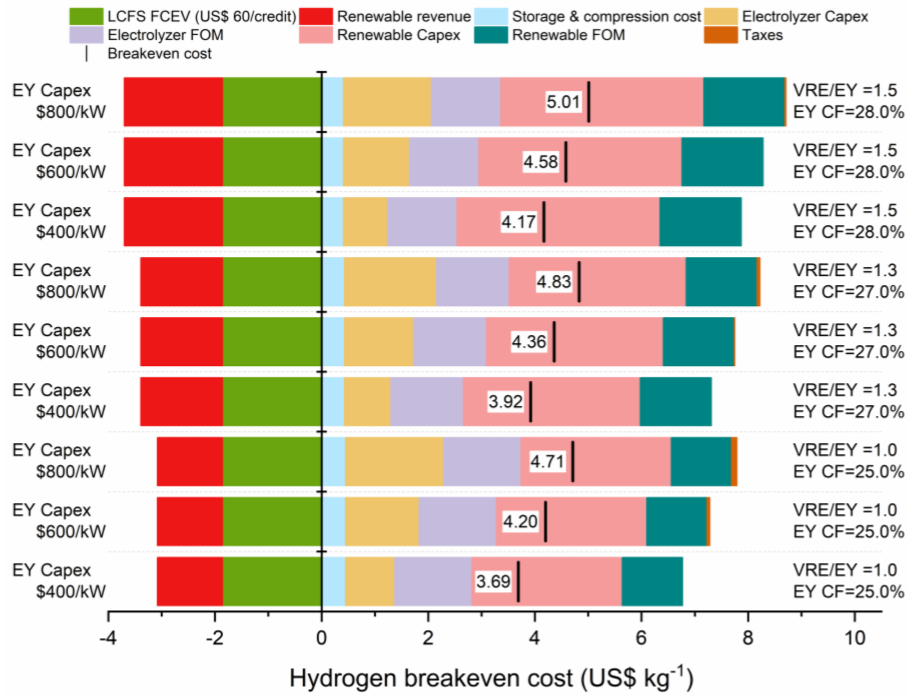

Figure 13. Hydrogen cost breakdown for facility DTLA and $60/LCFS credit.

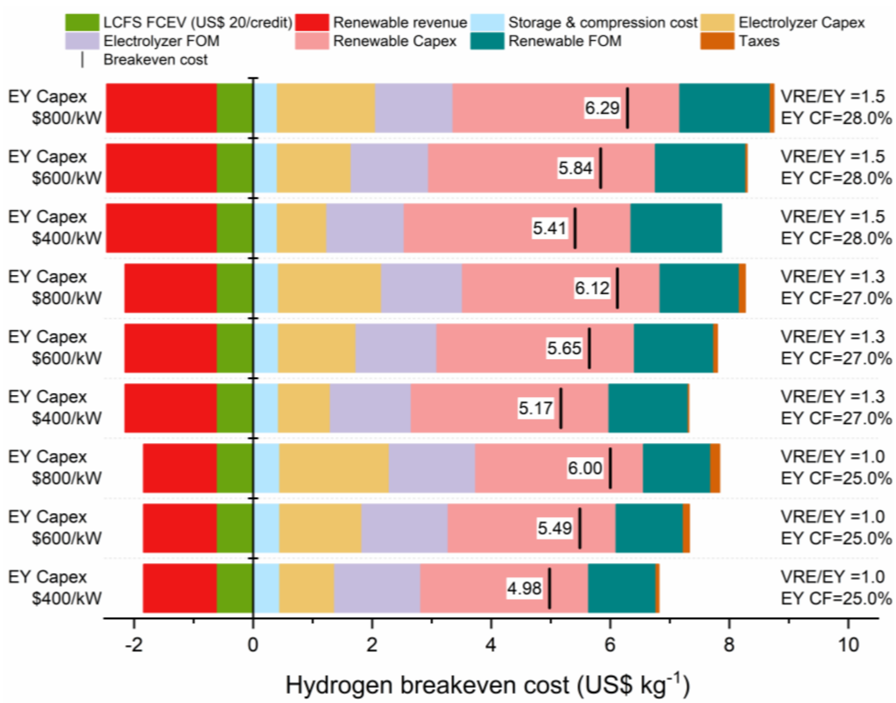

Figure 14. Hydrogen cost breakdown for facility DTLA and $20/LCFS credit.

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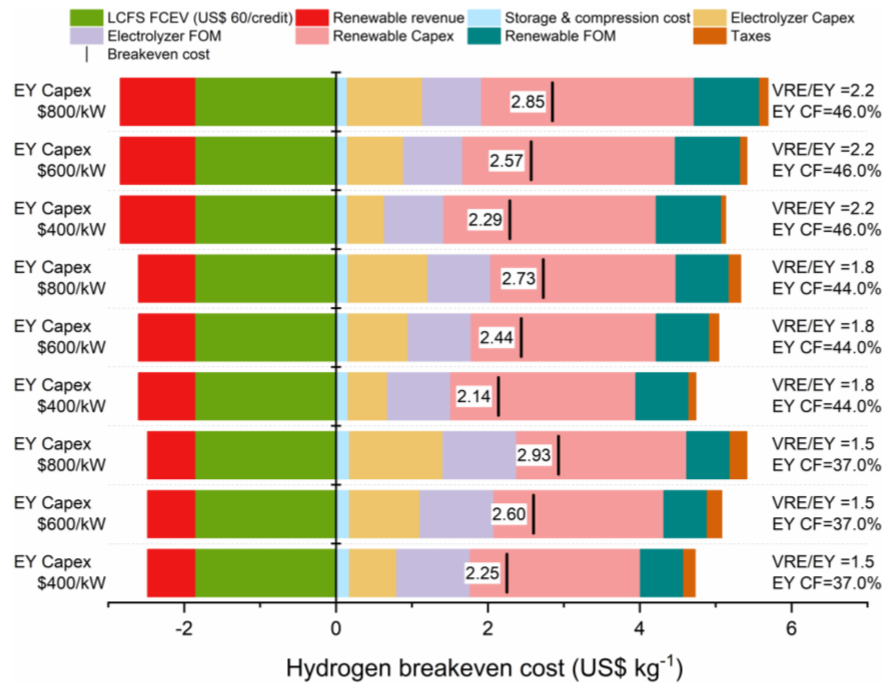

Figure 15. Hydrogen cost breakdown for facility 5PT and $60/LCFS credit.

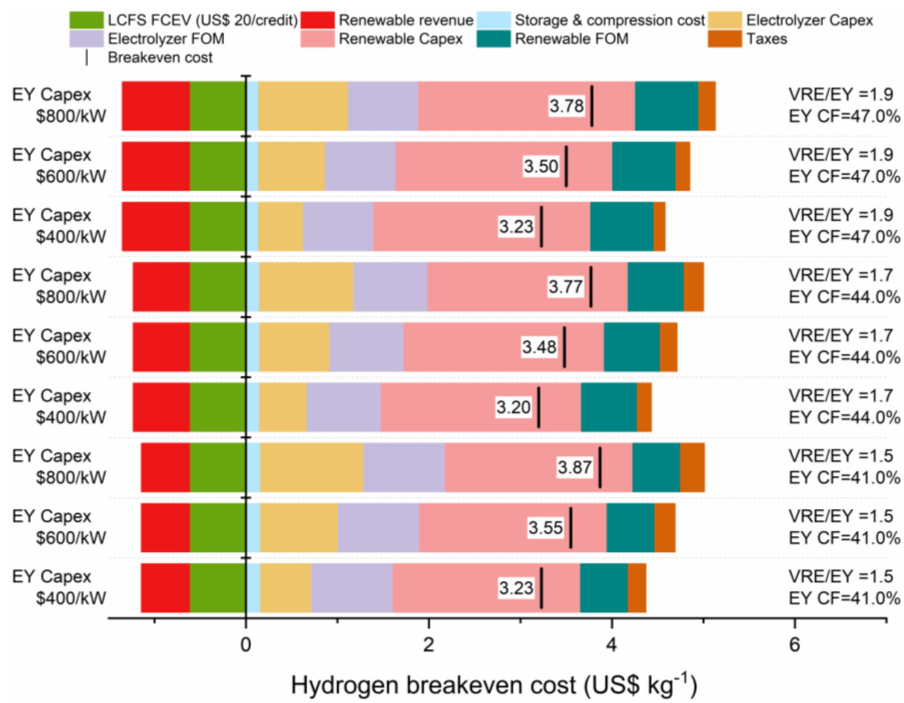

Figure 16. Hydrogen cost breakdown for facility 5PT and $20/LCFS credit.

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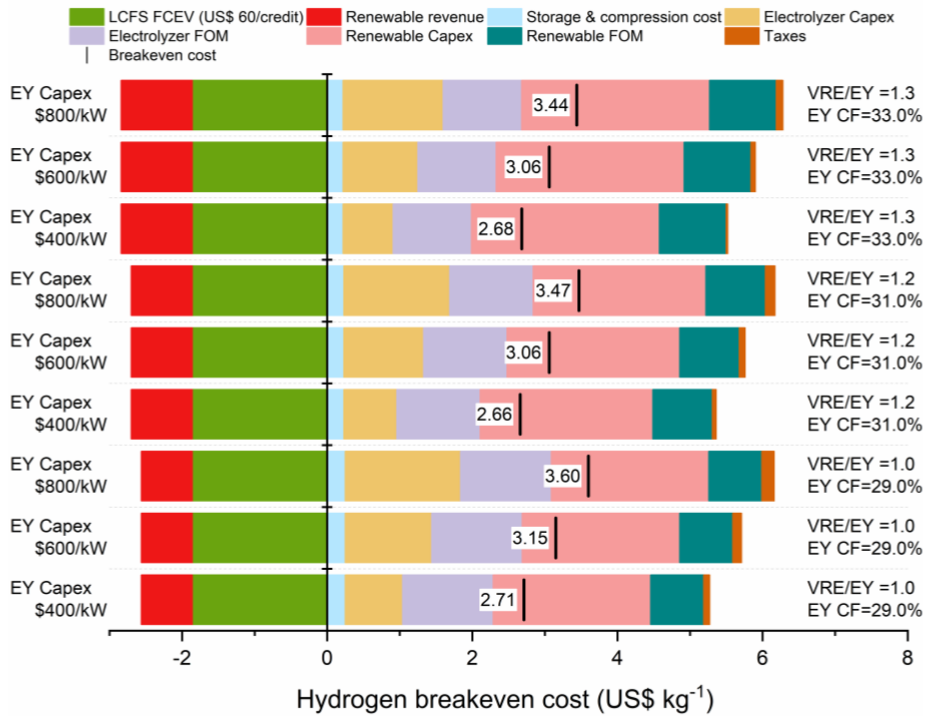

Figure 17. Hydrogen cost breakdown for facility MV1 and $60/LCFS credit.

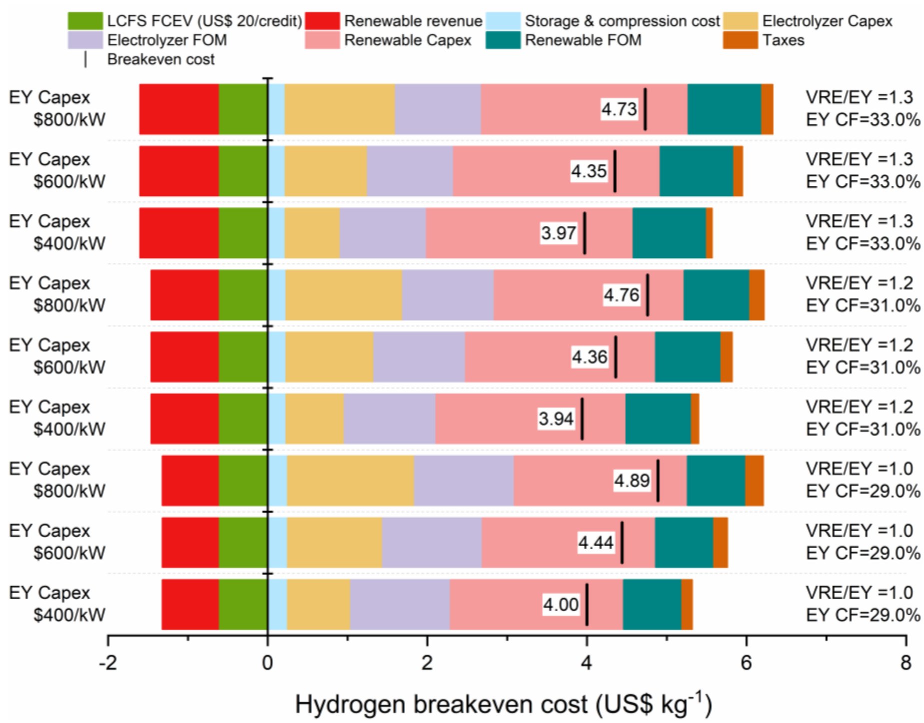

Figure 18. Hydrogen cost breakdown for facility MV2 and $20/LCFS credit.

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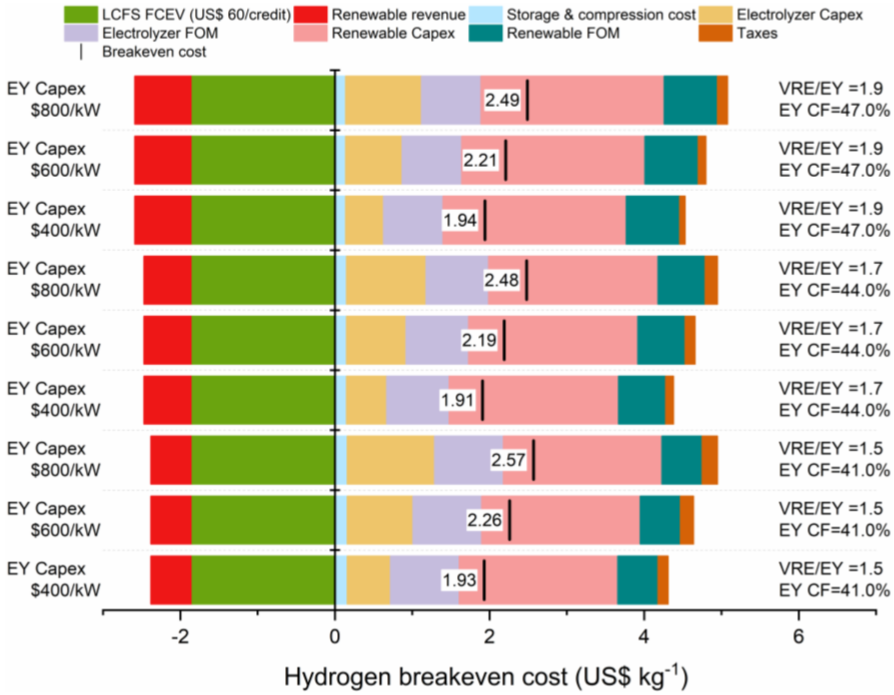

Figure 19. Hydrogen cost breakdown for facility MV2 and $60/LCFS credit.

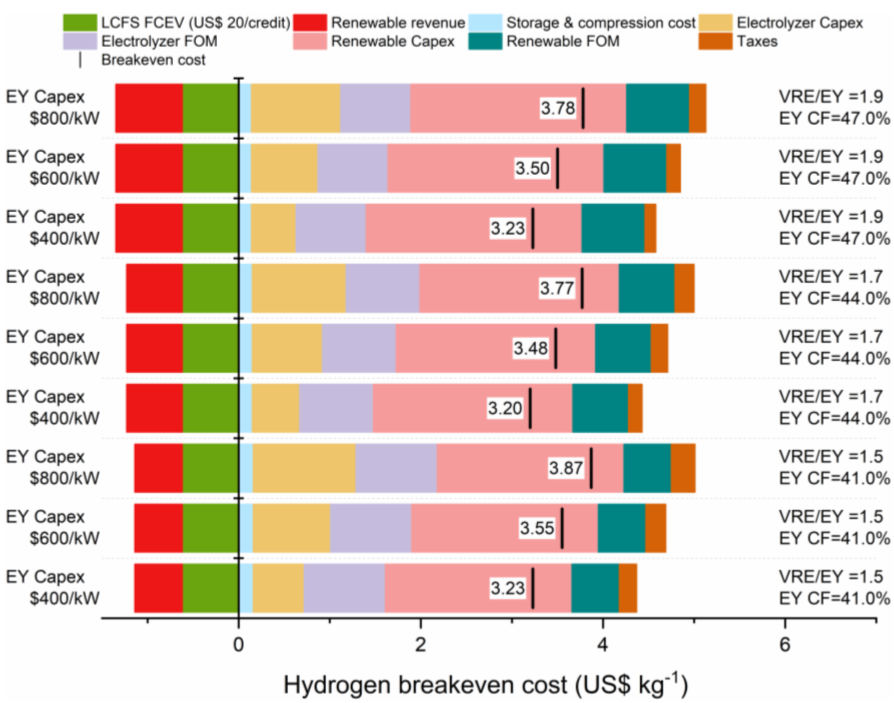

Figure 20. Hydrogen cost breakdown for facility MV2 and $20/LCFS credit.

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