Costs of hydrogen production with net-zero emissions: a case study in Kitchener

Laetitia Uwineza[1], Xiao Yu Wu[1*]
[1] Department of Mechanical and Mechatronics Engineering, University of Waterloo, 200
* Corresponding author: xiaoyu.wu@uwaterloo.ca

***Abstract*—This study estimates the cost of hydrogen production with net-zero emissions, focusing on life cycle greenhouse gas emissions (LCA) and including CO_2 removal costs. We design a PV-grid system for hydrogen production using HOMER's energy modelling software with simulations based on data from a site in the city of Kitchener. Additionally, we examine the relationship between the hydrogen production and its carbon intensity. The results illustrate that the levelized cost of hydrogen (LCOH), when including CO_2 removal costs, is 9.22% to 11.39% higher compared to the LCOH without carbon removal costs. These preliminary findings can serve as potential indicators for hydrogen pricing.**

Keywords-component; Renewable energy sources, green hydrogen, , and carbon capture costs.

I. INTRODUCTION

Greenhouse gas (GHG) emissions must be significantly reduced to mitigate the impact of global warming on both humans and the environment [1]. One approach to lowering GHG emissions in the transportation sector is to replace diesel-fueled trucks with fuel cell electric vehicles (FCEVs) powered by low-carbon hydrogen [2]. Recent research, particularly within progressive climate protection scenarios, highlights the positive impact of FCEVs on CO_2 reduction [3].

Several distinct pathways for hydrogen production with net-zero emissions have been analyzed using life cycle greenhouse emission assessment (LCA). For example, Garcia and Oliva [4] designed a techno-economic model to examine the costs and emissions associated with producing green hydrogen using hybrid energy systems in Chile. Their findings indicated that green hydrogen could be generated at competitive prices, ranging from $2.09 to $3.28 per kg, while maintaining low CO_2 emissions ranging from 1.06–1.57 kg CO_2/kg H_2.

In another study, Zhang et al. [5] conducted a comprehensive LCA analysis of hydrogen production using electricity from photovoltaic (PV) and wind energy in Switzerland. Their results showed a range of 3–7.8 kg CO_2/kg H_2 for PV-based hydrogen. In case study in the Netherlands, Delpierre et al. [6] found a range of 0.8–2.9 kg CO_2/kg H_2 from wind powered-proton exchange membrane (PEM) electrolysis.

Recently, Palmer et al. [7] investigated LCA of green hydrogen and found that hydrogen produced under their solar-battery scenario resulted in 2.3 -7.1kg CO_2/kg H_2. Al-Ghussain et al. [8] performed similar work. They developed a model to evaluate the costs and carbon footprint associated with producing green hydrogen using hybrid solar and wind energy systems in California, USA. They concluded that green hydrogen could be produced at competitive prices, ranging from $3.09 to $5.2per kg, and resulting in low CO_2 emissions (1.58–2.95 kg CO_2/kg H_2).

Despite numerous studies investigating the LCA and economic feasibility of green hydrogen, most have focused on the evaluating the carbon intensity of using renewable energy sources for hydrogen production. Without considering CO_2 removal, such as direct air capture (DAC), these systems are not net-zero. Therefore, understanding the costs for net-zero scenarios is crucial for optimizing production systems to minimize environmental impact and operational costs, informing policy decisions and advancing scientific knowledge in the field.

This study aims to determine the cost of hydrogen while incorporating CO_2 removal costs, ensuring that electricity-based hydrogen production pathways achieve net-zero lifecycle emissions. This approach allows us to compare hydrogen production methods with different carbon emission intensities while accounting for their associated emissions.

II. METHODOLOGY

In this study, the City of Kitchener in Ontario, Canada was selected as a case study for a potential site for the installation of hydrogen refueling stations powered by a PV-grid hybrid system. For each production pathway, we conducted a LCA and an economic evaluation. The production facility sizes were set at 100 kg, 300 kg, and 500 kg of hydrogen per day.

Meteorological data for the production site including solar irradiance and temperature along with hydrogen demand, the physical characteristics of the photovoltaic (PV) system, and grid electricity costs were input into HOMER. Since defining an hourly hydrogen demand profile is a complex task, HOMER was used to generate representative hydrogen demand data for the analysis [9]. Renewable energy data for the proposed hydrogen station location were obtained from the NASA Prediction of Worldwide Energy Resources database [10].

The simulation used 8,760-time steps, representing each hour of a specified year, to optimize the hybrid energy system and calculate the corresponding levelized cost of hydrogen (LCOH). Additionally, a LCA was performed for each production pathway. To achieve net-zero emissions, we considered CO_2 removal costs to compensate the required negative emissions technologies. This cost was included in the economic model as part of the overall hydrogen production cost. However, we did not consider life cycle emissions from electrolyser and hydrogen storage in this study. Figure 1 provides a schematic of the system configuration and emissions considerations.

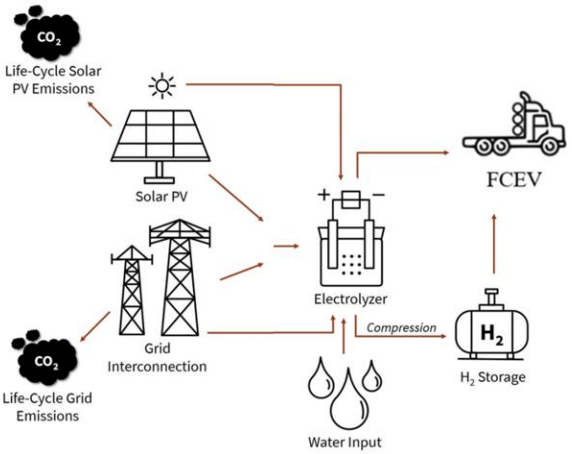


Fig.1. Hydrogen production system configuration and emissions consideration diagram.

In this work, hydrogen production is powered by two energy sources: solar energy and the grid. The mathematical modeling for each system is outlined below:

A. Solar PV model

The power output of PV panels is influenced by solar irradiance data and temperature of the PV panels. In this research, monocrystalline silicon is chosen based on its superior electrical properties, long lifespan, and high-power output per unit area [11]. The electricity generated by the PV system is calculated using the following formula [12]:

$$PV\ \ production = Y_{PV}\, f_{PV} \left(\frac{G_T}{G_{T,STC}}\right)\left[1 + K_P\left(T_c - T_{c,STC}\right)\right] \quad (1)$$

where Y_{PV} represents the rated capacity of the PV array at standard test conditions (kW) (depending on the specific PV system), f_{PV} is the derating factor (75%) G_T is the incident plane of array solar irradiance, $G_{T,STC}$ denotes the solar irradiance under standard test conditions (1.0 kW/m²), T_c is the PV cell temperature (°C) , $T_{c,STC}$ is the PV cell temperature at standard test conditions (25°C), and K_P is the power temperature coefficient (-0.46%/°C).

B. Electrolyser system

Electrolyser splits water into hydrogen and oxygen through the process of electrolysis, which is driven by electricity. In this study, electricity from the grid and PV is utilized to split water molecules and produce hydrogen using a PEM electrolyser. The PEM electrolyser is selected for its high efficiency and its capability to operate with fluctuating power inputs [13], making it ideal for this hybrid energy system. In this study, $\dot{m}$ (the hydrogen production rate kg/hr) is calculated based on η_{EL} electrolyser efficiency (%) and LHV_{H_2} (the lower heating value of hydrogen (kWh/kg) using the following equation.

$$\dot{m} = \frac{P_{EL}}{LHV_{H_2}} * \eta_{EL} \quad (2)$$

Although efficiency varies depending on the technology used, the base case in this study assumes a system efficiency of 72%, which corresponds to an energy consumption of 54.7 kWh per kilogram of hydrogen, based on the higher heating value (HHV) of hydrogen, taken as 39.4 kWh/kg [14].

C. Grid electricity

The power output from PV panels is highly variable due to the unpredictable nature of weather conditions [14]. To compensate for these fluctuations, integrating grid power provides a reliable solution for maintaining a stable electrolyser output. In this study, solar energy is integrated with the grid electricity to produce hydrogen, ensuring a continuous and stable hydrogen supply.

In order to assess the LCOH and the associated carbon emissions under different electricity mixes, Ontario's electricity price data was analyzed. Since most of Ontario's electricity is generated from nuclear and hydro sources, the grid provides a steady supply and stable rates. Additionally, Ontario's grid carbon emissions were considered as a representative example of modern low-carbon grids. Historical data on electricity prices and the generation mix of Ontario's grid were sourced from the Independent Electricity System Operator (IESO) [15].

D. Economic parameters

The CO_2 removal cost, i.e., CA$232 per metric ton of CO_2 for one year, was obtained from a previous study on direct air CO_2 capture [16] and included to calculate the LCOH achieving net-zero emissions in hydrogen production pathways. To ensure net-zero emissions for each pathway, we incorporate a CO_2 removal cost to account for the life cycle emissions of the PV and grid system, compensating the necessary negative emissions technologies. This cost is integrated into the economic model and considered part of the overall production cost. Additionally, key economic parameters, including the

LCOH and net present cost (NPC) for various optimized PV-grid system configurations, were calculated to assess hydrogen production expenses. These calculations are presented in Equations (3) and (4).

$$LCOH = \frac{Total\ NPC \times CRF}{\sum_{h=1}^{8760} m_{H_2}(kg)} \quad (3)$$

$$NPC = \frac{TAC + CM}{CRF(i,n)} \quad (4)$$

where $m_{H_2}(kg)$ is annual hydrogen production, while *CM* is CO_2 removal costs. The *NPC* (CA$) is determined by dividing the total annualized cost (*TAC*) comprising the capital expenditure (CAPEX), installation costs, operational expenses (OPEX), and replacement costs by the total capital recovery factor (CRF) [17]. The CRF is calculated as*:*

$$CRF(i,n) = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (5)$$

where $CRF(i,n)$ denotes the capacity recovery factor, n and i represents project lifetimes years and discount rate. $m_{H_2}(kg)$ is total hydrogen production.

Furthermore, the economic parameters data were sourced from published literature and are summarized in Table 1. A project lifetime of 25 years was assumed, with an inflation rate of 2% and annual real interest rate of 6% [18].

TABLE I. CAPITAL EXPENDITURE (CAPEX) AND OPERATING AND MAINTENANCE EXPENDITURE (OPEX) OF DIFFERENT COMPONENTS.

Components	CAPEX (CA$/kW)	OPEX (CA$/kW)	Source
PV (Monocrystalline)	1,000	10	[19]
Converter	300	10	[20]
Electrolyser (PEM)	1,200	17	[21]
Hydrogen tank	623	10	[22]

E. Environmental assessment

In this study, LCA analysis was used to estimate the emissions associated with hydrogen production in a PV-grid system. The assessment accounts for emissions generated during material extraction, manufacturing processes, and from the use of grid electricity in electricity-based production pathways. The carbon intensity of green hydrogen, expressed in kg CO_2 per kg of H_2, is calculated using Equation (8).

$$CO_2 = \frac{LCA_{PV} \times PV_Y + LCA_{Grid} \times Grid_Y}{mH_2} \quad (8)$$

where we used an average estimate of life cycle greenhouse gas emissions for PV (LCA_{PV}) of 13.6 g CO_2 /kWh times annual PV_Y (PV power production) [23], while $Grid_Y$ represents annual electricity from the grid, with an estimated LCA_{Grid} of 30 g CO_2/kWh in Ontario [15]. Then, the costs of direct air CO_2 capture were added as CO_2 removal costs to compensate for the carbon emissions from hydrogen production to achieve hydrogen production with net-zero emissions.

III. RESULTS AND DISCUSSIONS

A. Levelized cost of hydrogen

The results of the optimal sizing and techno-economic analysis of hydrogen production supported by renewable energy sources for the Kitchener site are presented in this section. The hydrogen refueling station is considered in three different configurations: the systems with designed hydrogen outputs of 100 kg per day, 300 kg per day and 500 kg per day are referred to as Scenarios 1, 2 and 3, respectively. The results are illustrated in Table 2. The optimal system for Scenario 1 consists of 755 kW of PV panels, a 459 kW electrolyser, and a 30 kg hydrogen tank. For Scenario 2, the optimal system includes a 2,536 kW solar panel, a 1,387 kW electrolyser, and a 30 kg hydrogen tank. The optimal system for Scenario 3 comprises a 4,355-kW solar panel, a 2,489 kW electrolyser, and a 30 kg hydrogen tank.

TABLE II. OPTIMAL RESULTS OF PV-GRID SYSTEM WITH A FIXED VALUE OF THE HYDROGEN STORAGE.

	Scenario1	Scenario 2	Scenario 3
PV (kW)	755	2,536	4,355
Electrolyser (kw)	459	1,387	2,489
Hydrogen tank (kg)	30	30	30
Electricity generated by PV system (kWh)	911,862	3,063,182	5,259,816
Electricity generated by grid (kWh)	907,851	3,044,138	5,252,149
Ratio of renewable (%)	50	50	50
Actual annual hydrogen production (kg)	36,451	109,379	183,318
CO_2 emissions (tonnes)	39.64	132.98	229.11
CO_2 removal costs (CA$)	222,988	771,301	1,328,780
NPC (CA$)	2,244,212	6,831,198	11,836,210
LCOH (CA$/kg)	4.67	4.74	4.99
LCOH(CA$/kg) with removal cost	5.15	5.28	5.45

As shown in Table 2, the net present cost (NPC) is calculated as CA$2,244,212 for Scenario 1, CA$6,831,198 for Scenario 2, and CA$11,836,210 for Scenario 3. The LCOH with CO_2 removal costs for the system in Scenario 1 is calculated as CA$5.15/kWh, CA$5.28/kWh for Scenario 2, and CA$5.45/kWh for Scenario 3, as illustrated in Figure 2. In Scenario 3, the largest contribution to the LCOH comes from the PV panels and electrolyser, which have the highest CAPEX and CO_2 removal costs. However, the LCOH values were calculated without considering the compressor, dispenser, and cooling unit. Table II also shows the electrical energy generated by the PV-grid system. All scenarios were designed to have 50% of the total electrical energy from PV and 50% from the grid. Furthermore, the actual hydrogen production for the optimal hybrid energy system supporting the on-site hydrogen station in Kitchener is 36,451 kg for Scenario 1, 109,379 kg for Scenario 2, and 183,318 kg for Scenario 3.

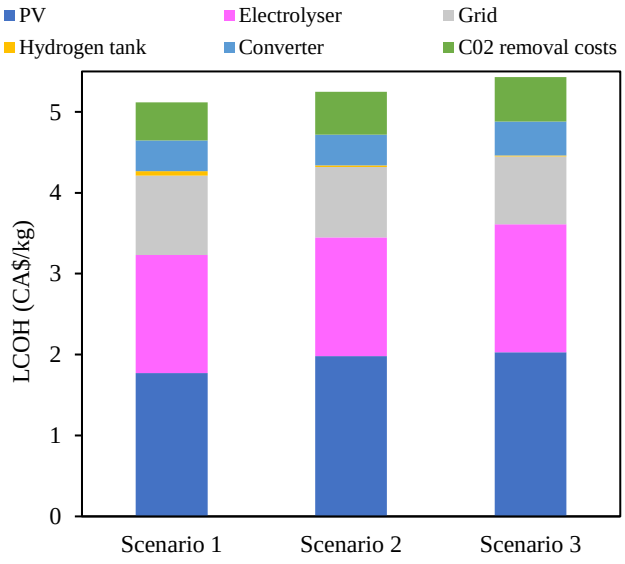


Fig. 2. LCOH with CO_2 removal costs for different scenarios.

The comparison between this study's findings and existing literature reveals both alignment and valuable insights regarding the estimation of the LCOH with carbon capture. For example, Bracci et al. [24] conducted a comprehensive analysis of net-zero hydrogen production across various electricity-based and fossil-based pathways. Their results indicate that the LCOH for the PV/Storage/Grid pathway is approximately $3.2/kg, whereas steam methane reforming with carbon capture (SMR + CCS) reaches around $5.2/kg demonstrating that fossil-based options with carbon capture tend to be significantly more expensive under net-zero, hourly-reliable conditions. These estimates fall within the range calculated in this study, providing general confirmation that our results are reasonable.

B. Estimation of CO_2 emissions from the generation of hydrogen

Figure 3 illustrates the CO_2 emissions per kilogram of hydrogen produced by the hybrid energy system. As shown, hydrogen generation using a combination of solar PV and grid electricity results in emissions ranging from 1.08 to 1.25 kg CO_2 per kg of H_2 in Kitchener, Ontario.

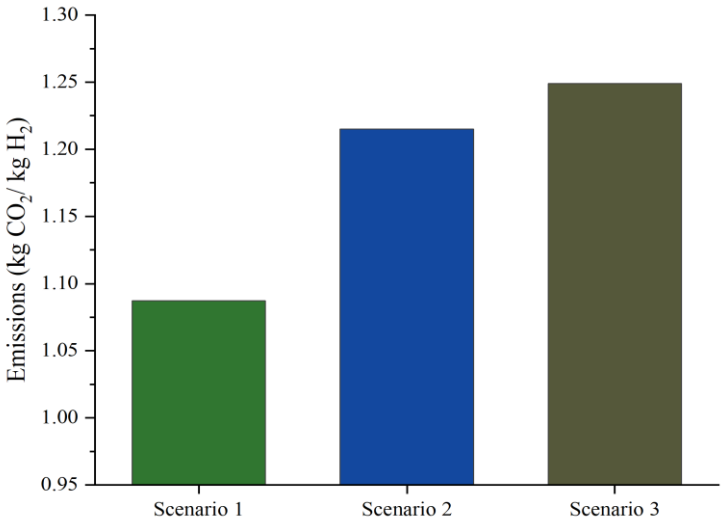


Fig. 3. Emissions generated by hydrogen production capacity.

IV. CONCLUSION

In this study, we examine the costs of a PV-grid system for hydrogen production with net-zero emissions across three hydrogen output scenarios: 100 kg, 300 kg, and 500 kg per day. The model uses local renewable energy sources to determine the optimal capacity of the on-site PV system, grid, and electrolyser. Additionally, our model evaluates the emissions associated with hydrogen production. The findings show that the optimal sizing and operational capacity of the hybrid energy system are significantly influenced by the production capacity. This study demonstrates that using 50% renewable energy for hydrogen production is viable, with low emissions generated per kilogram of hydrogen produced. The Kitchener site emerges as an ideal location for building a hydrogen refueling station.

Future work will focus on assessing the costs associated with hydrogen transportation. Additionally, the current model can be further developed to incorporate a more detailed analysis of relevant technical parameters. These extended studies would offer valuable insights into the critical factors required to produce hydrogen at a cost competitive with conventional fossil fuels, while also reducing environmental impacts.

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