European Journal of Energy Research
Vol 4 | Issue 2 | June 2024
ISSN 2736-5506

RESEARCH ARTICLE

Optimizing Wind-to-Hydrogen Production in Newfoundland for Export: A Techno-Economic Perspective

Dipak Timalsina[1,*] and Davoud Ghahremanlou[2]

ABSTRACT

This study explores the feasibility of generating green hydrogen using wind energy in Newfoundland and Labrador (NL) for potential export to Germany, aiming to reduce their heavy reliance on grey hydrogen. NL features abundant wind resources, deep-water export harbours, and proximity to Europe, making it an ideal location to contribute to Europe's energy security. Utilizing the Hybrid Optimization of Multiple Energy Resources (HOMER Pro) microgrid software, we conducted a techno-economic analysis of a wind-to-hydrogen case study at the Port au Port location aimed at offsetting 1% of Germany's grey hydrogen consumption. The optimal system comprises 49 wind turbines, each with 4.2 MW capacity, a 130 MW PEM electrolyzer, a liquid hydrogen storage facility, and a grid as a backup. We evaluated various financial metrics, including Net Present Cost (NPC), Levelized Cost of Energy (LCoE), and Levelized Cost of Hydrogen (LCoH) for short-term, mid-term, and long-term storage scenarios. The financial metrics were compared with similar case studies around the globe to highlight the economic competitiveness of clean hydrogen production in Newfoundland and Labrador.

Keywords: HOMER pro, Levelized cost of energy, Levelized cost of hydrogen, Net present cost.

Submitted: March 26, 2024
Published: June 18, 2024

10.24018/ejenergy.2024.4.2.139

[1] *Faculty of Engineering and Applied Science, Memorial University of Newfoundland, Canada.*
[2] *Faculty of Business Administration, Memorial University of Newfoundland, Canada.*

****Corresponding Author:***
e-mail: dtimalsina@mun.ca

1. Introduction

Hydrogen, a versatile chemical element, is poised to play a pivotal role in the global economy's decarbonization efforts. Various colour codes, such as grey, blue, and green, are used to differentiate between production methods based on carbon intensity. Germany, a leader in hydrogen production and consumption, currently relies heavily on grey hydrogen, with an estimated annual consumption of 1.7 million tons, corresponding to 55 terawatt-hours (TWh) [1]. Grey hydrogen, produced through steam methane reforming (SMR) with natural gas, emits approximately 11.57 kg CO_2-eq/kg of H_2 [2]. With projections indicating a twofold increase in hydrogen consumption by 2030, there is a pressing need to explore alternatives due to the limitations of fossil fuel feedstock and the associated high carbon intensity [3]. Blue hydrogen, employing the same production method as grey hydrogen but with carbon capture utilization and storage (CCUS), offers a partial solution to mitigate emissions. However, the practicality of CCUS remains uncertain [4]. In contrast, green hydrogen, produced via water electrolysis powered by renewable energy sources, presents a sustainable and environmentally friendly alternative with zero carbon emissions [5]. Its adoption holds promise in reducing Germany's reliance on grey hydrogen, aligning with the goals outlined in the German National Hydrogen Strategy 2023. Newfoundland and Labrador have emerged as appealing collaborator due to its rich wind resources, proximity to water reservoirs, and strategic positioning for shipping logistics. Recognizing the urgency of reducing emissions and achieving carbon neutrality, European unions and the Canadian government are uniting to tackle these issues. Additionally, Germany has established a partnership with Canada, with a specific emphasis on importing renewable hydrogen [6]. Despite challenges in the wind turbine supply chain and regulatory processes, Canada has made significant strides in wind energy capacity addition, which can be seen in Fig. 1, with cumulative capacity reaching 15.29 GW by 2022, and the growth is expected to continue as the cost of wind and solar for

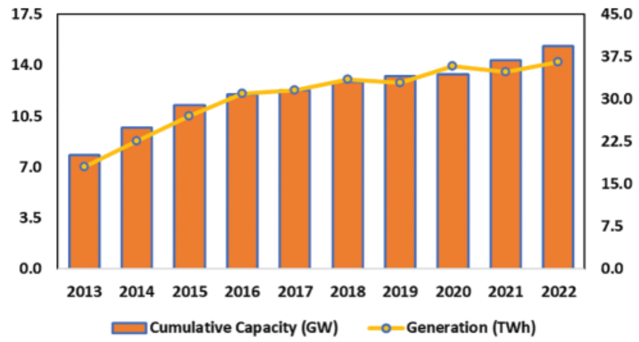

Fig. 1. Wind energy capacity addition and generation in Canada from 2013 to 2022.

large-scale power generation decreases [7], [8]. In addition to implementation efforts, research to power remote indigenous communities has also expanded, reaching as far as Nain in NL [9]. Although large-scale renewable power is favourable for green hydrogen production, commercialization still has a barrier due to its production costs, which are 3 to 6 times higher than those of grey and brown hydrogen, and as a result, green hydrogen currently only constitutes 5% of total hydrogen production [10]. The high prices of green hydrogen stem from three main factors: the high cost of renewable energy, challenges in high-volume hydrogen storage, and the expensive nature of system components such as wind turbines and electrolyzers. Although NL holds competitive edges in certain areas, it is essential to prioritize the reduction of wind energy generation costs, optimization of system components, storage capacity, and duration to attract stakeholders and achieve commercial viability. This study identifies major technologies that significantly impact the LCoE and LCoH in wind to hydrogen production in NL. A techno-economic case study is presented to illustrate the potential for cost-effective production of green hydrogen in Port au Port, which lies in the western region of NL. The case study utilizes HOMER Pro software to identify the optimal system components and configurations to produce green hydrogen at the lowest NPC. It meticulously examines key cost-influencing parameters, including wind turbine and electrolyzer capacity, as well as storage volume. The optimized configuration is tested against multiple storage scenarios to analyze its effect on financial metrics. This study consists of a brief literature review, followed by a detailed case study and subsequent discussion of results, concluding with a comprehensive summary of key findings.

2. Literature Review

Multiple academic studies have examined the wind-to-hydrogen production process. These investigations primarily concentrate on the techno-economic analysis of harnessing renewable resources to power water electrolysis to produce environmentally friendly hydrogen gas. In 2023, Messaoudi and colleagues conducted a study employing a GIS-based approach to assess the potential for wind-to-hydrogen production in Algeria. Their research revealed that utilizing a 730,719 km^2 area for wind farms could yield an annual production of 1.066 Gt of green hydrogen. The study found that the LCoH in Algeria ranged from 1.51 to 15.37 US $/kg, depending on the chosen wind turbine and location [11]. Another research explored 84 locations in southern Argentina to isolate optimal LCoH from wind farms. They developed a model to optimize the wind farm design, electrolyzer plant, compressor station, and storage capacity with multiple dispatch constraints. The primary aim of model optimization was to minimize the LCoH. Results showed that imposing dispatch constraints led to an increase in LCoH from 25% to 40%, accompanied by a reduction in hydrogen production from 5% to 30% [12]. Likewise, Karayel and Dincer conducted a study to assess the potential for hydrogen generation from onshore wind farms in Canada. They employed a combination of V90-Vestas (V90) wind turbines and PEM electrolyzers to estimate the total production capacity of each province and the country. Their findings indicated that Canada has the capacity to produce 402.63 Mt of green hydrogen annually, with Newfoundland and Labrador contributing 19.87 Mt annually [13].

3. Methodology

The methodology for this study encompasses several key steps aimed at data collection, system sizing, simulating, and analyzing a wind-to-hydrogen system tailored to the context of Port au Port, NL. Information regarding the study location is obtained from Google Maps, while HOMER Pro is utilized for configuring the system optimally and performing techno-economic analysis. Simulation outcomes are exported and further analyzed using Microsoft Excel and the Python programming language. Additionally, financial metrics derived from the analysis are compared with those from similar studies in the literature to provide a comprehensive assessment of the proposed system's viability (Fig. 2).

3.1. *Demand Estimation*

The system's load includes two primary categories for simulation in HOMER Pro: the electrical load and the hydrogen load. The electrical load is fundamental to this study for several reasons. Firstly, within the wind farm infrastructure, electricity is consumed for lighting as well as heating and cooling systems, ensuring operational functionality. Additionally, the system requires electricity for the critical processes of hydrogen liquefaction and compression for storage. Specifically, a power demand of 1100 kW is allocated for the liquefaction of hydrogen, while an additional 400 kW is separated for ancillary appliances. This allocation ensures the efficient operation of the system and supports various auxiliary functions essential for optimal performance. Similarly, the hydrogen load is designated for export to Germany, aimed at minimizing the country's heavy reliance on grey hydrogen. To determine the hydrogen load, one percentage share of Germany's grey hydrogen consumption in 2022 has been selected as a benchmark, which is 44.24 kilotons per day, as referenced in the introduction section. By aligning with Germany's hydrogen consumption patterns, the system aims to contribute to the transition towards cleaner hydrogen sources,

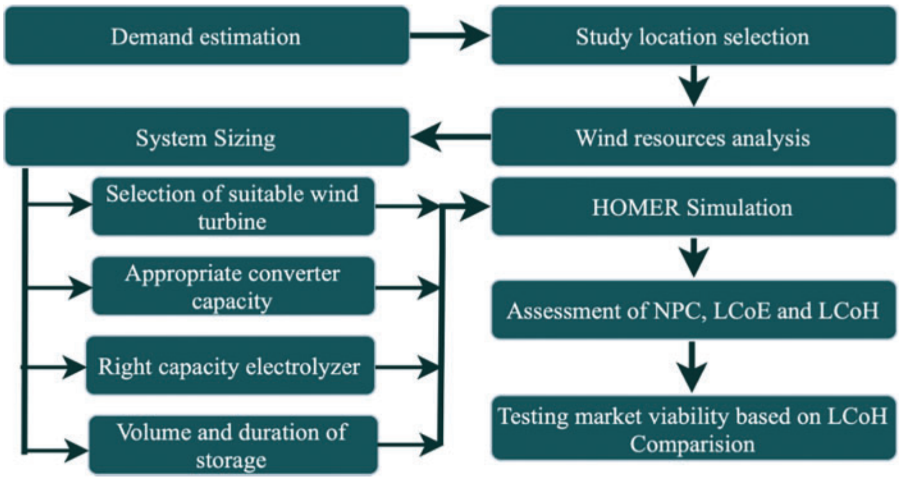

Fig. 2. Methodology of the study.

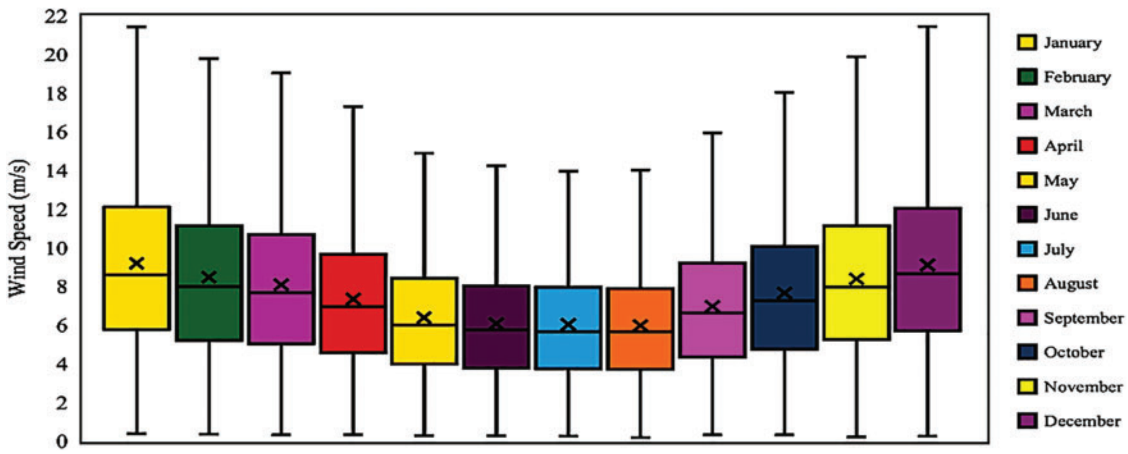

Fig. 3. Box plot representation of wind data.

thereby fostering sustainability and reducing carbon emissions on a broader scale.

3.2. *Study Location*

We choose Port au Port in Newfoundland and Labrador province for our case study. The site is located at an altitude of approximately 10 m to 32 m above sea level, 48.65° N latitude and 58.96° W longitude. This region is chosen for our wind-energy-to-hydrogen-production project considering its quality of wind resources, its closeness to water resources, and the port of Stephenville for ease of export.

3.3. *Wind Resource*

The weather data are different at different geographical locations due to atmosphere conditions such as air pressure, temperature, humidity, wind speed, direction, and so on. HOMER Pro features a comprehensive library for weather data based on the longitude and latitude of a specific location. The software allows users to download and import these data from the NASA Atmospheric Science Data Centre for simulation purposes. The average wind speed in Port Au Port is 8.06 m/s, while the maximum wind speed recorded is 21.36 m/s, making it an ideal site for wind power generation. Fig. 3 utilizes a box plot to display the wind speed distribution used in our case study simulation.

3.4. *System Sizing*

Estimating the component size of a renewable hybrid energy system poses a considerable challenge when compared to single-source energy systems. This complexity arises from the characteristics of renewable energy resources, unpredictable weather, and the multitude of variables and parameters involved in the system design. An optimal sizing methodology becomes essential to address these complexities and optimize investment while maximizing the utilization of system components. Various sizing methods are employed to achieve optimal system reliability and cost-effectiveness, including graphical construction, probabilistic approaches, iterative processes, and artificial intelligence techniques. We have adopted the iterative process to reach the optimal system size to meet our research objective.

The initial approximation of the system size can be done based on the scale of the annual load and can be iteratively refined based on simulation results.

3.4.1. *Wind Turbine*

HOMER Pro offers various sizes of wind turbines starting from kW to MW capacity in its library. It is important to understand the cut-in, rated, and cut-out wind speeds and analyze the power curve to select the right capacity wind turbine. We choose the Enercon E-126 wind turbine

TABLE I: Wind Turbine Characteristics

Characteristics	Value
Manufacturer	Enercon
Rated power (kW)	4200
Hub height (m)	129
Rotor diameter (m)	141
Swept area (m^2)	15,614.5
Cut-in speed (m/s)	3
Rated wind speed (m/s)	12
Cut-out wind speed (m/s)	25
Net capacity factor	58

with a 4.2 MW capacity. Specifications of the wind turbine are presented in Table I [14].

3.4.2. *Electrolyzer*

Electrolysis, at its core, involves the splitting of water molecules (H_2O) into hydrogen (H_2) and oxygen (O_2) gases using an electric current. This process facilitates the production of high-purity hydrogen without carbon emissions, harnessing renewable energy sources for eco-friendly hydrogen generation. Its versatility allows for both onsite and distributed production, with scalability as a prominent feature. This technology is experiencing rapid growth in operational capacity and efficiency. Among the three primary water electrolysis methods-Alkaline, Proton Exchange Membrane (PEM), and Solid Oxide Electrolyzer Cell (SOEC)-the former two are commercially available, with the low-temperature PEM system dominating the market. We have used a PEM electrolyzer for the case study because of its various advantages over an alkaline electrolyzer, such as rapid system response and high purity of hydrogen production. The total electrolyzer system capacity is taken as 130 MW and has an efficiency of a minimum of 55%.

3.4.3. *Hydrogen Storage*

Hydrogen can be stored in various forms, and among these options, liquid hydrogen storage has been selected due to its competitive advantage over gaseous and underground storage alternatives. The storage component significantly influences the overall financial performance of the system. Therefore, the system is subjected to simulation under three distinct hydrogen storage scenarios. Initially, the system is simulated with hydrogen storage capacity tailored to sustain storage for one week before exportation, representing short-term storage. Subsequently, the investigation extends to storage durations of two weeks, denoting mid-term storage and, finally, one month before exportation, representing long-term storage. Through these simulated scenarios, the impact of storage volume and duration on key financial metrics such as NPC, LCoH, and LCoE can be comprehensively assessed, providing valuable insights into the economic feasibility of different storage configurations.

3.5. *System Design and Simulation*

HOMER Pro software has been used to simulate the optimal system design to satisfy the electricity and hydrogen load of the case study. The software is especially known for its ability to produce system sizing to meet the user-defined constraints at the lowest net present cost. It achieves this by employing various mathematical equations outlined in the following section, which are derived from the HOMER Pro software. A techno-economic analysis is carried out with a discount rate of 8% and the inflation rate of 2%. The project lifetime is considered as 25 years for the simulation.

The net present cost, also known as the life-cycle cost, represents the present value of all expenses associated with the installation and operation of a component throughout the project's lifespan, subtracting the present value of generated revenues over the same duration. HOMER Pro computes the NPC for individual components within the system, as well as for the system. To conduct this analysis, HOMER generates a comprehensive cash flow table, capturing all relevant financial inflows and outflows, except for any salvage value, which usually occurs in the 25th year. The mathematical equation to calculate NPC of a component is presented in (1).

$$NPC = \sum_{n=1}^{t} i_d (C_{Cap} + C_{Rep} + C_{O\&M} + C_{Fuel} - P_{Sal}) \quad (1)$$

where n is project lifetime in years, i_d is the discount rate, which can be further calculated based on (2), C_{Cap} is the capital cost of the component, C_{Rep} is the replacement cost, $C_{O\&M}$ is the operation and maintenance cost, C_{Fuel} is the fuel cost and P_{Sal} is the salvage price.

$$i_d = \frac{1}{(1+i)^n} \quad (2)$$

where i is the annual real interest rate, which can be calculated based on another equation presented in (3).

$$i = \frac{i' - f}{1 + f} \quad (3)$$

where i' is the nominal interest rate, and f is the annual inflation rate.

Annualized cost is another important financial metric in techno-economic analysis, which is achieved by first calculating the net present cost, then multiplying it by the capital recovery factor, as shown in the following equation:

$$C_{Ann} = CRF\left(i, R_{Proj}\right) \times C_{NPC} \quad (4)$$

where C_{Ann} is the annualized cost, CRF is a function returning the capital recovery factor, i is the annual real discount rate, R_{Proj} is the project lifetime, and C_{NPC} is the component's net present cost.

HOMER defines the levelized cost of energy (COE) as the average cost per kWh of useful electrical energy produced by the system. To calculate the LCoE, HOMER divides the annualized cost of producing electricity by the total electric load served using the following equation:

$$LCoE = \frac{C_{Ann,tot}}{E_{Served}} \quad (5)$$

where, $LCoE$ is the levelized cost of energy, $C_{Ann,tot}$ is the annualized cost of the system.

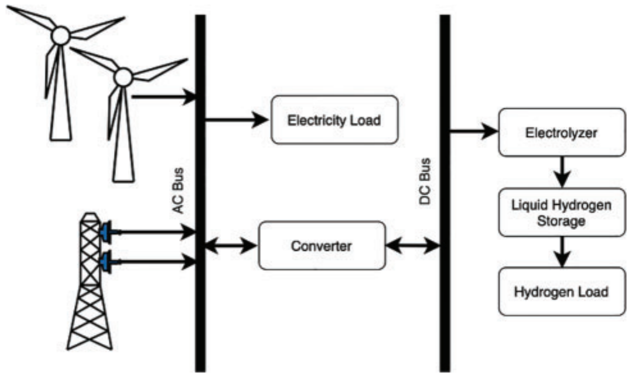

Fig. 4. HOMER Pro system architecture.

Similarly, HOMER uses the following equation to calculate the levelized cost of hydrogen production:

$$LCoH = \frac{C_{Ann,tot} - \nu_{Elec}(E_{prim,AC} + E_{prim,DC} + E_{def} + E_{grid,sales})}{M_{Hydrogen}} \quad (6)$$

where, $C_{Ann,tot}$ is the total annualized cost, ν_{Elec} is the value of electricity, $E_{prim,AC}$ and $E_{prim,DC}$ are the primary electrical load in AC and DC respectively, E_{def} is the deferrable load, $E_{grid,sales}$ is the total energy sold to the grid, and $M_{Hydrogen}$ is the total hydrogen production.

Fig. 4 illustrates the architectural layout of the energy system within the HOMER Pro software framework. Primary energy sources, including wind turbines and the grid, are connected to the AC bus bar. A segment of the AC electricity generated is allocated to meet the AC load demand. The remaining major portion of the electricity is regulated using a voltage converter and converted to DC using a rectifier before being supplied to the electrolyzer. The conversion to DC power is imperative as the electrolyzer exclusively operates with DC input, which is directed to the electrolysis chamber at the anode. Water is also passed through the electrolyzer facilitating the electrolysis process to produce hydrogen and oxygen. Produced hydrogen and oxygen are conveyed to the gas separator unit to obtain high-purity hydrogen. Following this separation, the hydrogen undergoes a liquefication process within a dedicated section and is pumped, compressed, and stored in tanks for dispatch.

Once the components are selected in the software, it further requires the capital cost, replacement cost, operation and maintenance cost, project lifetime and efficiency parameters. Similarly, interest rate and inflation rate also need to be configured to conduct the financial analysis. We have allocated 50% and 2% of the total cost as the replacement and O&M cost for all components except the storage tank. Based on references from multiple literature, we calculated an average cost of the component as an input to the system [15]–[17]. The capital, replacement, and O&M cost of the wind turbine is set to $1501/kW, $750.5/kW, and $30.02/kW/year; the component lifetime is selected as 25 years. The electricity price from the grid is finalized at $0.0928/kW. The capital, replacement, and O&M cost of the converter is fixed at $300/kW, $150/kW, and $6/kW/year, respectively, with a lifetime of 25 years.

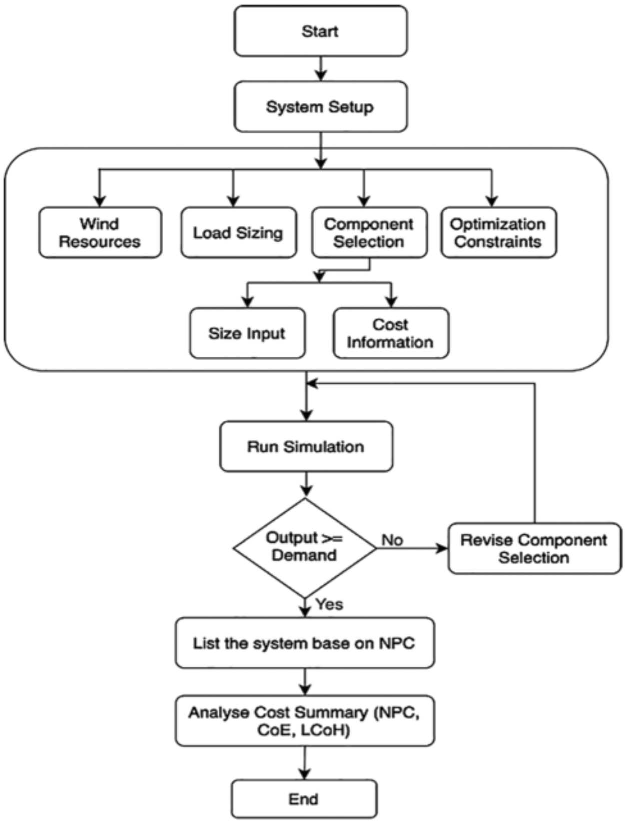

Fig. 5. Homer Pro optimization algorithm.

Another major component is the electrolyzer, whose capital, replacement, and O&M costs are set at $2000/kW, $1000/kW, and $36/kW/year, respectively. The minimum efficiency of the electrolyzer is configured at 55%. Lastly, the capital, replacement, and O&M cost of the liquid hydrogen tank is set at $500/kg, $500/kg, and $10/kg per year, respectively, with a component lifetime of 25 years.

4. Results and Discussion

We followed the iterative simulation and optimization process as presented in the form of a flowchart in Fig. 5. The system was set up with all HOMER-required technical and economical specifications for optimization. Once the inputs were validated, simulation was initiated, and the results were tested iteratively until convergence was achieved at the lowest NPC. Notably, the system exhibited a convergence pattern from an initially over-dimensioned state to a precisely calibrated capacity sizing tailored to meet demand requirements optimally. This optimization approach was uniformly applied for all short-term, mid-term, and long-term hydrogen storage scenarios. Each scenario went through techno-economic analysis, with results systematically arranged in ascending order of NPC. Furthermore, the outcomes were segmented into the same three scenarios. The power generation, converter output, and electrolyzer output remained consistent, while storage capacity varied for all scenarios. It's worth noting that while storage capacity did not directly influence system sizing and other component cost in HOMER Pro, it did impact metrics such as NPC, LCoE, LCoH. Our optimization revealed that 49 wind turbines totaling

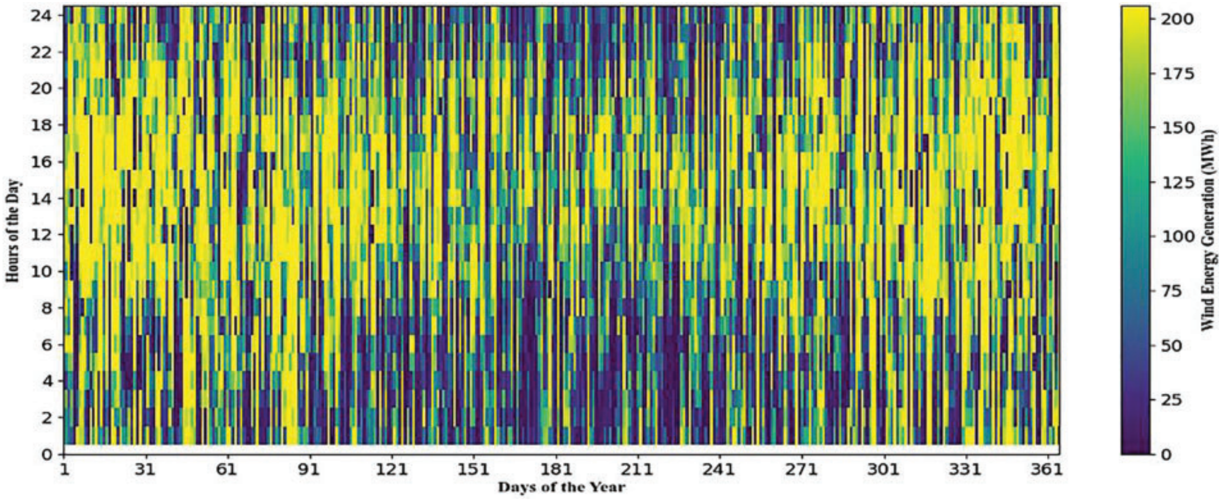

Fig. 6. Electricity generated from wind turbine.

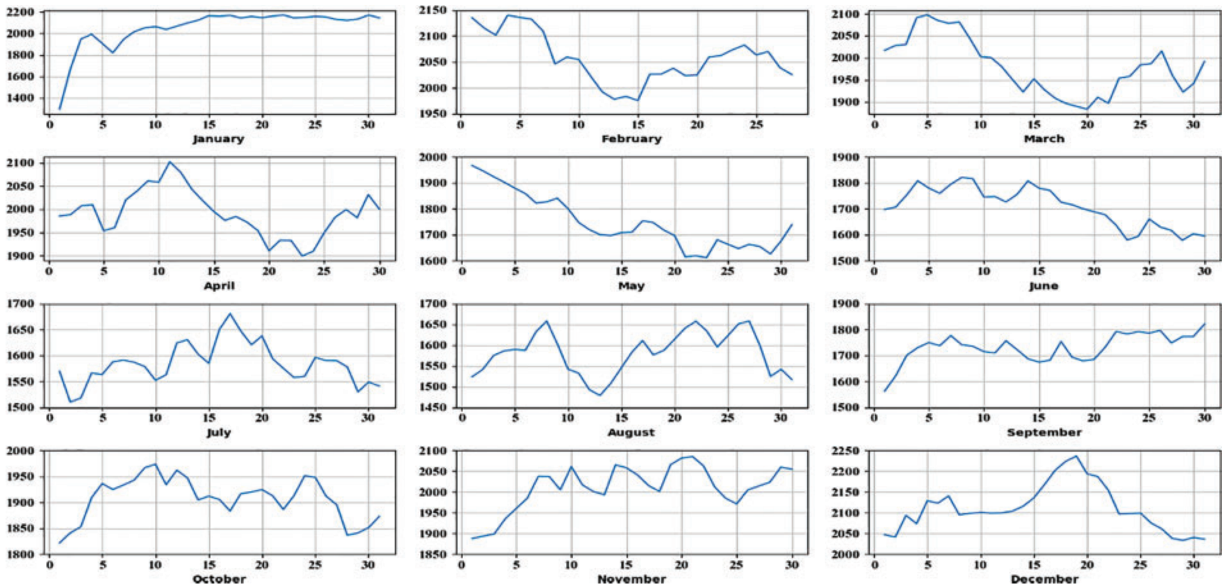

Fig. 7. Monthly green hydrogen production.

205.8 MW capacity adequately satisfy the defined electrical and hydrogen load constraints. The wind turbine has a capacity factor 58.9 and produces 1.048 TWh of electricity annually. The detailed renewable electricity generation is presented in Fig. 6 in the form of a heat map.

The electrical energy flows through the AC bus bar and reaches the converter, where an average energy of 0.801 TWh is supplied. With an efficiency rating of up to 95%, the converter yields approximately 0.768 TWh of usable energy. This energy output is then directed to the electrolyzer, with a capacity of 130 MW and operating at a capacity factor of 66.9%. The electrolyzer consumes 46.8 kWh/kg of energy and delivers a mean output of 1874 kg of green hydrogen per hour. The total annual production of the PEM electrolyzer is 16.417 kilotons, and the detailed breakdown of monthly hydrogen production is presented in Fig. 7. The graph illustrates a clear correlation between hydrogen production and wind patterns. Specifically, from September to April, there is a notable increase in average wind speed, leading to higher electricity generation and, consequently, greater hydrogen production. Conversely, during the remaining months, wind speeds are slightly lower, resulting in a reduction in hydrogen output.

The simulation for short-term hydrogen storage, HOMER Pro reveals a net present cost of $1.143 billion. The wind turbine accounts for 42% of the total NPC, followed by the electrolyzer at 37%, and the hydrogen tank at 29.9%. Transitioning to the mid-term storage scenario, the total NPC escalates to $1.417 billion, with the hydrogen tank contributing 48%, the wind turbine 34%, and the electrolyzer 30%. Lastly, the long-term storage scenario carries the highest NPC, amounting to $1.96 billion, with 70% attributed to the hydrogen tank, 25% to the wind turbine, and 22% to the electrolyzer. A granular breakdown of NPC and the respective contribution from each component is depicted in stacked clustered column bars within Fig. 8. The weekly dispatch strategy reduces the need for high-volume tanks and long storage duration, yielding a low levelized cost for both energy and hydrogen. In the context of short-term hydrogen storage, the LCoE is recorded at $0.3580/kWh, accompanied by a corresponding LCoH of $3.34/kg. Transitioning to the

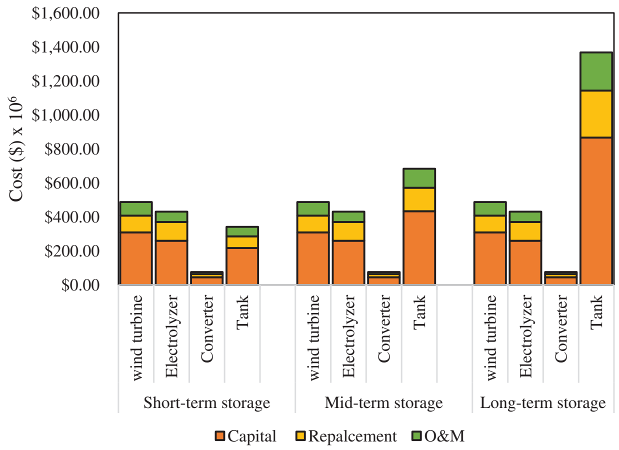

Fig. 8. Break down of NPC for all 3 scenarios.

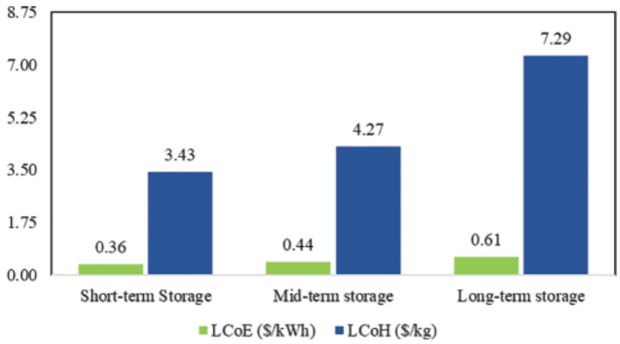

Fig. 9. LCoE and LCoH comparison under 3 scenarios.

mid-term storage scenario, a notable impact on the total NPC is observed, resulting in a slightly elevated LCoE of 0.4434/kWh and an LCoH of $4.72/kg. The need for long-term hydrogen storage requires a high-volume hydrogen tank contributing significantly to a total NPC of $1.96 billion. Notably, nearly a third of the total NPC is allocated to the hydrogen tank, resulting in a significantly high LCoE of $0.614/kWh and an LCoH of $7.29/kg. A detailed comparison of LCoE and LCoH across all three storage scenarios is delineated in the clustered column bar chart depicted in Fig. 9.

Furthermore, to assess market competitiveness, the LCoH derived from our study's scenarios is compared with data from various regions worldwide. Table II presents a comparative analysis of LCoH values obtained implementing either solar PV, wind, or a combination of both, sourced from different literature, and arranged in descending order [18]–[21]. Korea has the highest recorded green hydrogen price range of $13.81/kg to $14.58/kg, while Iraq offers a considerably lower price range of $8.7/kg to $9/kg. Morocco has a slightly lower price, in the range of $5.57/kg to $13.8/kg. Egypt showcases the most economically favourable range, presenting green hydrogen within a price bracket of $3.73/kg to $4.79/kg. Remarkably, our study underscores the feasibility and economic viability of green hydrogen, with a price range spanning from $3.43/kg to $7.29/kg, positioning it among one of the most competitive options globally.

TABLE II: LCoH Variation Across Different Countries

Country	LCoH (US$/kg)
Korea	13.81–14.58
Iraq	8.7–9
Morocco	5.57–13.8
Egypt	3.73–4.79
Our study-Canada (NL)	3.43–7.29

5. Conclusion

In this study, we conducted a brief review of wind-to-hydrogen production technology. Our investigation centred on a techno-economic analysis of a wind-to-hydrogen case study located in Port au Port, Newfoundland, with the objective of supplying green hydrogen to Germany, thereby mitigating its heavy reliance on grey hydrogen. Leveraging HOMER Pro software, we simulated various configurations to determine the optimal system setup, resulting in the deployment of 49 wind turbines, each having a capacity of 4.2 MW, along with a 140 MW AC to DC converter and a 130 MW PEM electrolyzer, all integrated with adequate storage capabilities. The optimal system was tested against short, mid, and long-term storage options to examine their impact on NPC, LCoE, LCoH. The short-term storage system exhibited a $1.143 billion NPC, accompanied by an LCoE of $0.3580/kWh and an LCoH of $3.43/kg. Transitioning to mid-term storage, the NPC slightly increased to $1.417 billion, with corresponding LCoE and LCoH values of $0.4434/kWh and $4.72/kg, respectively. The long-term storage scenario incurred the highest NPC at $1.96 billion, along with elevated LCoE and LCoH values of $0.6140/kWh and $7.29/kg, respectively. Our findings underscored a clear correlation between storage volume and duration with LCoE and LCoH, highlighting the importance of strategic planning in system design and operation. Furthermore, upon comparing LCoH with international benchmarks, Newfoundland and Labrador emerged as a compelling market player due to its exceptionally low-cost green hydrogen, affirming its competitive advantage in the global arena.

Conflict of Interest

The authors declare that they do not have any conflict of interest.

References

[1] Fuhrmann M. *Germany's National Hydrogen Strategy-Serious Efforts to Realize a Decarbonized Society; Development of Green Hydrogen Supply Infrastructure is the Challenge*. Mitsui & Co. Global Strategic Studies Institute; 2021.

[2] Hermesmann M, Green TE. *Green, Turquoise, Blue, or Grey? Environmentally Friendly Hydrogen Production in Transforming Energy Systems*, vol. 90. Progress in Energy and Combustion Science. Elsevier Ltd; 2022.

[3] BMWK. National hydrogen strategy update. federal ministry of economic affair and climate action. 2023. Available from: www.bmwk.de.

[4] Bauer C, Treyer K, Antonini C, Bergerson J, Gazzani M, Gencer E, *et al.* On the climate impacts of blue hydrogen production. *Sustain Energy Fuels*. 2022 Jan 7;6(1):66–75.

[5] Panchenko VA, Daus YV, Kovalev AA, Yudaev IV, Litti YV. Prospects for the production of green hydrogen: review of countries with high potential. *Int J Hydrogen Energy*. 2023 Feb 8;48(12):4551–71.
[6] Sakthi P, Ghahremanlou D, Qavi Lardi ABA. Sustainable hydrogen production, storage, and distribution–A systematic review for newfoundland and labrador. *J Sustain Dev*. 2023 Nov 18;17(1):1.
[7] Renewable Energy Agency I. *Renewable Energy Statistics*. About IRENA; 2023. Available from: www.irena.org.
[8] Squadrito G, Maggio G, Nicita A. The green hydrogen revolution. *Renewable Energy*. 2023 Nov 1;216.
[9] Kotian S, Ghahremanlou D. Design for hybrid power system in newfoundland and labrador: a case study for nain. *Eur J Electr Eng Comput Sci*. 2024 Feb 8;8(1):1–5.
[10] Friedmann SJ, Fan Z, Tang KE. Low-carbon heat solutions for heavy industry: sources, options, and costs today [Internet]. [cited 2024 Mar 2]. Available from: www.sipa.columbia.edu. 2019.
[11] Messaoudi D, Settou N, Allouhi A. Geographical, technical, economic, and environmental potential for wind to hydrogen production in Algeria: GIS-based approach. *Int J Hydrogen Energy*. 2024 Jan 2;50:142–60.
[12] Schmidhalter I, Mussati MC, Mussati SF, Oliva DG, Fuentes M, Aguirre PA. Green hydrogen levelized cost assessment from wind energy in Argentina with dispatch constraints. *Int J Hydrogen Energy*. 2024 Jan 31;53:1083–96.
[13] Karayel GK, Dincer I. A study on green hydrogen production potential of Canada with onshore and offshore wind power. *J Clean Prod*. 2024 Jan;437:140660. Available from: https://linkinghub.elsevier.com/retrieve/pii/S0959652624001070.
[14] Enercon. Enercon-wind turbine manufacturer. En.wind-Turbine-Models.com [Internet]. 2013. [cited 2024 Mar 2]. Available from: https://en.wind-turbine-models.com/manufacturers/22-enercon.
[15] Amos WA. Costs of storing and transporting hydrogen [Internet]. 1998. Available from: http://www.doe.gov/bridge/home.html.
[16] International Energy Agency I. Global hydrogen review 2023 [Internet]. 2023. Available from: www.iea.org.
[17] Authors L, Schwabe P. Work package 1 final report IEA wind task 26 multi-national case study of the financial cost of wind energy. 2010. Available from: http://www.osti.gov/bridge.
[18] Al-Orabi AM, Osman MG, Sedhom BE. Evaluation of green hydrogen production using solar, wind, and hybrid technologies under various technical and financial scenarios for multi-sites in Egypt. *Int J Hydrogen Energy*. 2023 Dec 19;48(98):38535–56.
[19] Hasan MM, Genç G. Techno-economic analysis of solar/wind power based hydrogen production. *Fuel*. 2022 Sep 15;324.
[20] Jang D, Kim K, Kim KH, Kang S. Techno-economic analysis and Monte Carlo simulation for green hydrogen production using offshore wind power plant. *Energy Convers Manag*. 2022 Jul 1;263.
[21] Touili S, Alami Merrouni A, El Hassouani Y, illah AA, Rachidi S. Analysis of the yield and production cost of large-scale electrolytic hydrogen from different solar technologies and under several Moroccan climate zones. *Int J Hydrogen Energy*. 2020 Oct 16;45(51):26785–99.