Energy Thermofluids Eng. 3: 21-28 (2023)

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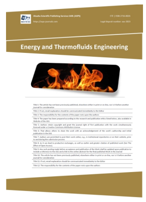

# Levelised hydrogen production costs for a standalone photovoltaic powered system in Australia

Sheikh Khaleduzzaman Shah ✉, Lu Aye

*Renewable Energy and Energy Efficiency Group, Department of Infrastructure Engineering, Faculty of Engineering and Information Technology (FEIT), The University of Melbourne, VIC 3010, Australia*

Received June 20, 2023

Revised July 12, 2023

Accepted July 13, 2023

Published online: July 20, 2023

*Keywords*

Hydrogen

Cost analysis

PV electrolysis

Energy system

Climate

**Abstract:** This article presents an analysis of levelised costs of producing hydrogen via the photovoltaic electrolysis in Australia. Eight locations (Darwin, Alice Springs, Brisbane, Perth, Sydney, Mildura, Melbourne, and Hobart) covering six climate zones in Australia are selected for the analysis. They receive varying solar radiation to produce electricity by using photovoltaic systems. In the present work, a standalone photovoltaic electrolysis and hydrogen engine system for 69 $kWh_e$ of daily electricity used is studied. Photovoltaic system is designed based on the minimum average monthly solar irradiation received for each selected location. The required photovoltaic array sizes are determined at the optimal slopes of the solar panels. By using the electricity generated from the photovoltaic, hydrogen is generated in electrolyser. The levelised cost of hydrogen was determined and found to be AU$ 6.79-10.62 $kg^{-1}$. The electrolyser cost was found to be 52-55% of the life cycle cost of the system. Therefore, the cost of an electrolyser is the determinant factor for the levelised hydrogen production cost.



## 1. Introduction

To meet climate change, decarbonisation strategies have become more attractive in many countries where hydrogen will have a critical role to play (IRENA 2020). Hydrogen can be produced from fossil fuels and electrolysis of water. The use of fossil fuels emits greenhouse gas (GHG). In contrary, hydrogen production by photovoltaic (PV) electrolysis is an alternative method without GHG emissions. However, a critical question is whether the PV electrolysis is financially viable or not (Longden et al. 2020). Hydrogen production based on renewable energy is better in the perspective of climate change and GHG emissions mitigation. Shakya et al. (2005) presented the technical feasibility and financial analysis of a standalone hybrid wind-PV system with hydrogen storage for Cooma (Australia). They found that levelised cost of electricity is lower with 100% PV share compare to the combined system of wind-PV together. A recent study shows that the estimated levelised cost of electricity (LCoE) is AU$ 0.025 $kWh^{-1}$ for both PV and onshore wind energy systems based on cost projection up to 2050. In contrast, the hydrogen production costs of AU$ 1.89-2.56 $kg^{-1}$ are based on solar PV electricity sources with a projection for 2030 (Longden et al. 2020).

In this article, the levelised cost of hydrogen (LCoH) was investigated for 30 years of project life in which hydrogen production via PV electrolyser was considered. Also, eight locations were selected considering six climate zones in Australia. The PV system was designed for each selected location. The standalone system using a modified spark ignition hydrogen engine considered is assumed to meet the same end-user (building) electricity consumption.

✉ Corresponding author. E-mail address: sheikhkhaled@unimelb.edu.au



ENERGY AND THERMOFLUIDS ENGINEERING | ETE | ISSN 2716-8026 (PRINT)

Available online at https://asps-journals.com/index.php/ete

https://doi.org/10.38208/ete.v3.753

## 2. Methods

This work considers a standalone hydrogen engine coupled with solar PV electrolyser as shown in Fig. 1. The major components of the system are PV modules, electrolyser, purifier, compressor, storage cylinder, hydrogen engine, and generator. The analysis was done based on an analytical model and computer simulations. The details of the steps are described in the following sections.

### 2.1. Weather data and load simulated

In this work, eight locations in Australia are representative of six climate zones in Australia (Naji et al. 2021): Hot Desert (Alice Springs), Savanna (Darwin), Cold Semi-arid (Mildura), Hot Summer Mediterranean (Perth), Humid Subtropical (Brisbane and Sydney) and Oceanic (Melbourne and Hobart). The selected locations on the Köppen-Geiger climate map of Australia (Peterson 2016) are shown in Fig. 2.

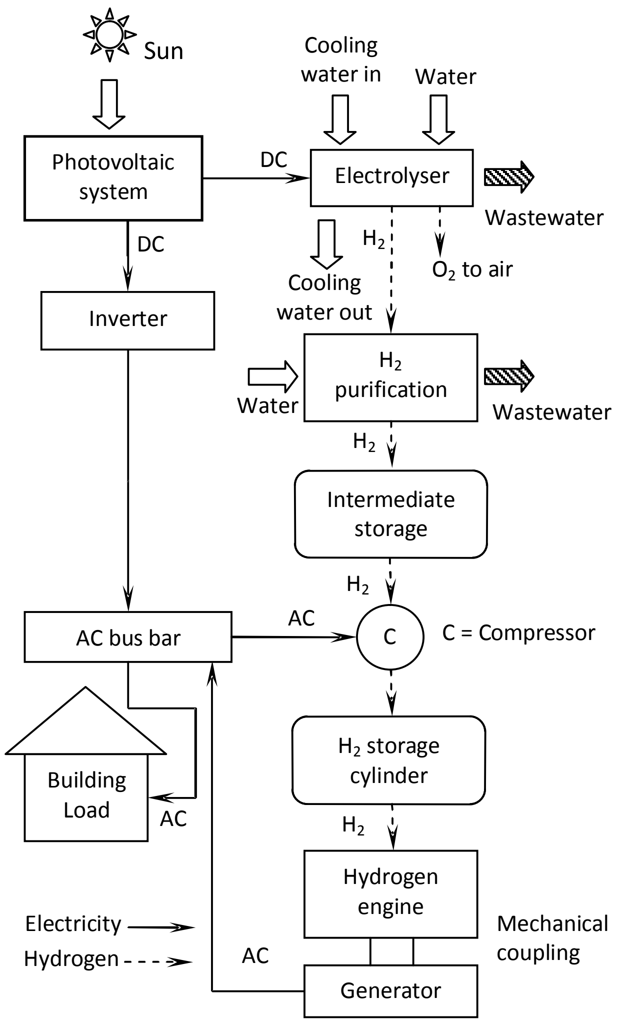


**Fig. 1** Schematic view of the standalone hydrogen production and electricity generation system.

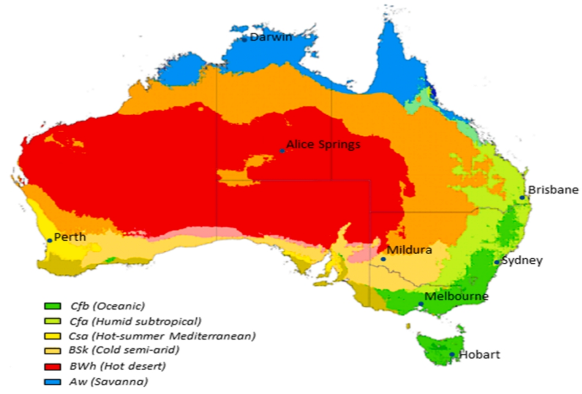


**Fig. 2** The selected locations (Naji et al. 2021) on the Köppen-Geiger climate map of Australia (Peterson 2016).

The Typical Meteorological Year (TMY) weather data file of each location was generated by using Meteonorm software (Remund et al. 2016). They are based on measured data for 1991-2010 solar radiations and 2000-2009 dry bulb and wet bulb temperatures. The details of the eight locations are presented in Table 1.

The end-user (building) daily electricity load was considered to be 69 $kWh_e$ for all selected locations. The end-user load profile was determined based on the building (the centre of Snowy Hydro Ltd.) electricity demand (Shakya et al. 2005). The building is located in Cooma (786 m above sea level, latitude 36.22°S, longitude 149.13°E), Australia. It was also assumed that the daily electricity load of the building remains the same throughout the year. The average daily electricity load for hydrogen compressor was estimated to be 5.04 $kWh_e$ based on the compressor electricity consumption 1.05 $kWh_e$ kg $H_2^{-1}$ (Satyapal 2009). The total electricity demand on PV modules was estimated by considering the inverter efficiency (95%) (Sandia 2021), the electrolyser factor (83%) (IRENA 2020), the factor of hydrogen purification (92%) (Shakya et al. 2005), the efficiency of the

**Table 1** Details of the locations selected.

| Parameter → Location ↓ | Climate code | Latitude (° S) | Longitude (° E) | *Irradiation ($MJh^{-1}m^{-2}$) | Lowest Month |
|---|---|---|---|---|---|
| Darwin | *Aw* | 12.4637 | 130.8444 | 0.750 | Feb |
| Alice Springs | *BWh* | 23.6980 | 133.8807 | 0.602 | Jun |
| Brisbane | *Cfa* | 27.4705 | 153.0260 | 0.467 | Jun |
| Perth | *Csa* | 31.9523 | 115.8613 | 0.407 | Jun |
| Sydney | *Cfa* | 33.8688 | 151.2093 | 0.360 | Jun |
| Mildura | *BSk* | 34.2080 | 142.1246 | 0.355 | Jun |
| Melbourne | *Cfb* | 37.8136 | 144.9631 | 0.270 | Jun |
| Hobart | *Cfb* | 42.8826 | 147.3257 | 0.216 | Jun |

*minimum average monthly irradiation

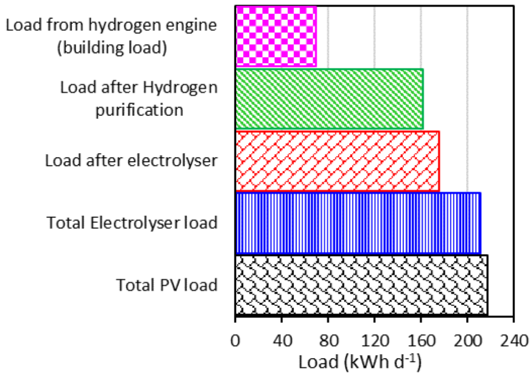


**Fig. 3** Daily loads for different components.

generator 95% (Times 2019), and the efficiency of hydrogen engine (45%) (Shakya et al. 2005). The estimated daily total electricity to be produced by the PV considering all energy conversion steps is shown in Fig. 3.

### 2.2. PV modules and electricity produced

Since the proposed PV powered system is standalone, there is no backup while meeting the annual demand of electricity. The average monthly irradiation was determined for each selected location and shown in Fig. 4. Since the electricity need is the same the month with the lowest irradiation was selected for the design according to AS/NZS4509.2 (2010) standard. The minimum monthly irradiation occurs in June for all locations excepts Darwin which is in February (Table 1).

For the PV array, JinkoSolar PV modules available in the Australian market were considered. Initial PV array areas were determined by using "an Ex*cel based simulation model*" in which hourly weather data of each location were used together with PV system parameters. The slope of the PV modules, $\beta$ (°) was the optimising variable to maximise the PV array output. The range of the optimum slope of the PV array is between 0 and 90°. The specifications of the PV module and the system parameters are provided in Table 2.

The annual electricity output per unit area of PV module, $E$ ($kWh_e$ $m^{-2}$) was estimated using hourly efficiency and hourly insolation as in Eq. (1) Shah et al. (2018).

$$E = \sum_{i=1}^{8760} \frac{\eta_i \, G_{T_i}}{1000} \Delta t \tag{1}$$

where $\eta_I$ is the PV system efficiency (-), $G_T$ is total irradiance (W $m^{-2}$), and the time step $\Delta t$ is one hour. The hourly system efficiency is estimated using Eq. (2) (Aye 2016).

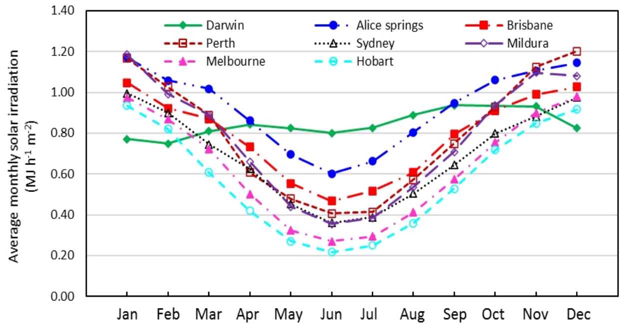


**Fig. 4** Average monthly solar irradiation.

**Table 2** Specifications of the PV module (JinkoSolar 2021) and system parameters.

| Parameter | Module |
|---|---|
| Brand name | JinkoSolar |
| Model | JKM340M-72 |
| STC power rating ($W_p$) | 340 |
| Module reference efficiency (%) | 17.52 |
| NOCT (°C) | 45 |
| Temperature coefficient ($K^{-1}$) | 0.0039 |
| Length (mm) | 1956 |
| Width (mm) | 992 |
| Efficiency of power tracking (%) | 90[a] |
| Transmittance absorptance product (-) | 0.9[a] |

[a] Duffie and Beckman (2013)

$$\eta = \eta_r [1 - \beta_t (t_c - t_r)] \eta_{pt} \tag{2}$$

where $\eta_r$ is the module reference efficiency (-), $\beta_t$ is the temperature coefficient of the efficiency (-), $t_c$ is the cell temperature (°C), $t_r$ is the reference temperature (°C), and $\eta_{pt}$ is the efficiency of the power tracking equipment. The detailed calculation steps to determine the hourly total irradiance are explained in Shah et al. (2016). The detailed steps for estimating hourly system efficiencies ($\eta$) and the equation applied are presented in Shah et al. (2018). The required total PV area, $A$, in $m^2$ can be estimated from the total annual electricity load, $L$ (kWh) of the PV for hydrogen production and the annual electricity output per unit area of the PV module, $E$ (kWh) by using Eq. (3).

$$A = L/E \tag{3}$$

### 2.3. Hydrogen production and storage

Hydrogen production involves the electrolysis and hydrogen purification processes. After hydrogen is produced, a compressor is used to increase the pressure for storage. The coupled spark ignition hydrogen engine and electric generator are utilised for standalone operation. To estimate the amount of hydrogen required, a heat energy density of 33.6 $kWh_h$ kg $H_2^{-1}$ (Molly 2019) is applied. The hydrogen produced is compressed and stored for later use to decouple the intermittent PV output and the continuous electricity demand. The number of storage cylinders ($NoSC$) can be calculated using Eq. (4).

$$NoSC = n \cdot m_{H_2} / C_{cy} \quad (4)$$

where $n$ is the days of autonomy (d), $m_{H_2}$ is the hydrogen required to meet the daily load (kg), and $C_{cy}$ refers to the capacity of the selected cylinder (kg). The days of autonomy with annual blackouts status (Stapleton 2019) were determined for selected locations based on the current AS/NZS4509.2 (2010) standard. The hydrogen storage cylinder capacity is assumed to be 2.52 kg based on availability in the market (Energy 2021) at 20 MPa pressure (Rödl et al. 2018).

### 2.4 Cost analysis

The initial costs of the entire system include the costs of these components: PV system, controller, electrolyser, purifier, compressor, storage cylinders, hydrogen engine, and generator. The levelised cost of electricity for the entire system can be estimated by using Eq. (5) (Branker et al. 2011, BREE 2012).

$$LCoE = \left( I_0 + \sum_{y=1}^{t} \frac{I_y + M_y + F_y}{(1+d)^y} \right) \Bigg/ \sum_{y=1}^{t} \frac{E_y}{(1+d)^y} \quad (5)$$

where $I_0$ means initial investment cost, $I_y$, $M_y$, and $F_y$ refers to capital investment cost, maintenance cost, and fuel cost at year $y$, respectively; $d$ is the real discount rate, and $t$ is the project life year; $E_y$ is the electricity generation by the system ($kWh_e$) in year $y$. It was assumed that the annual maintenance cost is 2% of the total initial investment cost. The amortisation period for the analysis was assumed to be 30 years project life. The lifespan of the electrolyser (IRENA 2020), compressor (Shakya et al. 2005), inverter (Choice 2021), controller (Shah et al. 2018), and hydrogen engine with generator (Shakya et al. 2005) were considered 10 years. However, the lifespan of hydrogen storage cylinder, and PV modules are considered 15 years (Shakya et al. 2005) and 30 years respectively. Besides, The LCoH can be estimated using Eq. (6). The reported hydrogen production cost considers the cost associated with the PV system, the electrolyser, and the hydrogen purification process (excluding the costs of storage cylinder, and hydrogen compressor which are under hydrogen distribution).

**Table 3** Assumed values of cost parameters.

| Parameter | 2021 AU$ | Reference |
|---|---|---|
| PV module ($kW_p^{-1}$) | 324.00 | (Solar 2021) |
| Electrolyser ($kW^{-1}$) | 1350.00 | (IRENA 2020) |
| Compressor ($kW^{-1}_{motor}$) | 1543.91 | (Bengbu 2021) |
| Storage cylinder ($unit^{-1}$) | 270.00 | (Energy 2021) |
| Hydrogen engine & Generator ($unit^{-1}$) | 4488.75 | (Wanda 2021) |
| Cables ($m^{-1}$) | 0.41 | (Holden 2021) |
| Inverter ($kW^{-1}$) | 160.00 | (Choice 2021) |
| Controller ($kW^{-1}$) | 16.20 | (Shah et al. 2018) |
| Structural mounting ($kW^{-1}$) | 80.00 | (ECG 2021) |
| Exchange rate (per US$) | 1.35 | (XE 2021) |

$$LCoH = C_0 + \sum_{y=1}^{t} \frac{C_y}{(1+d)^y} \Bigg/ \sum_{y=1}^{t} \frac{H_y}{(1+d)^y} \quad (6)$$

where $C_0$ means initial investment cost, $C_y$ is the total cost of components required to produce purified hydrogen ($), $H_y$ is the hydrogen production (kg) in year $y$. Assumptions made on cost parameters are presented in Table 3. The installation cost of PV, electrolyser and balance of system (BoS) were considered 113%, 12%, and 20% of component (capital) cost respectively (Hinkley et al. 2016). The BoS includes cables, inverter, controller, and structural mounting. Also, 10% real discount rate is used (BREE 2012).

## 3. Results and discussion

The monthly values of electricity to be produced by PV system are shown in Fig. 5. Since the end-user electricity demand is the same, the PV electricity is the same for all locations. Meanwhile the standalone PV system was design based on the lowest monthly irradiation, the PV system has more production than demand.

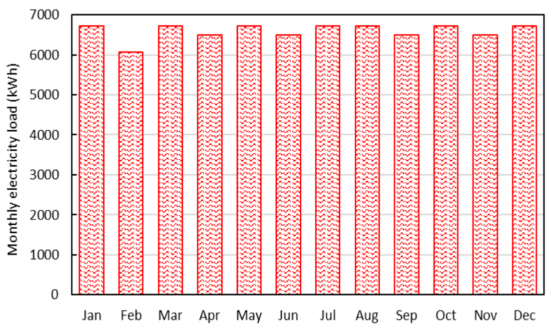


**Fig. 5** Monthly electricity load from PV modules.

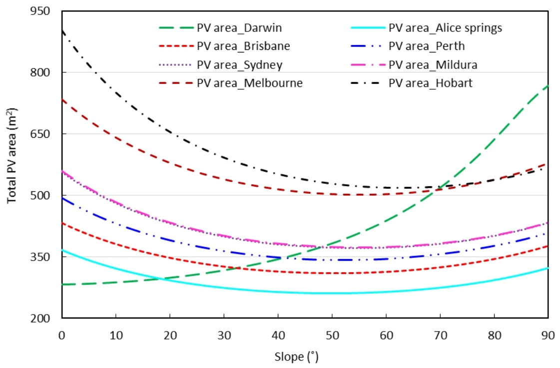


**Fig. 6** PV area versus slope of the PV panel.

The hydrogen production is assumed to be stop after fulfilling demand each day. Therefore, the potential 100% output of the PV system is not required. The fractions of the potential output used are 89%, 91%, 88%, 76%, 81%, 73%, 65%, and 68% for Darwin, Alice Springs, Brisbane, Perth, Sydney, Mildura, Melbourne, and Hobart respectively. The total PV areas required vs. the slope of the PV panel for all selected locations are shown in Fig. 6. It was found that the minimum PV area occurs with optimal slope at which maximum solar irradiance can be capture.

The optimise PV systems are able to produce sufficient electricity to produce hydrogen production via electrolyser. The Alice Springs and Hobart have minimum and maximum numbers of PV modules, respectively. The reason is that the annual solar irradiation is the highest at Alice Springs and the lowest at Hobart. The values of the optimal slope angle varied with the latitude of the location. However, the same optimal angle (± 1°) of slope was found for Sydney, Mildura and Melbourne since their latitudes are close to each other. The required PV area and number of modules with optimal slope values for each location is presented in Table 4 including cost of PV (both PV modules and installation cost).

**Table 4** PV array areas and number of modules with optimal slope (β).

| Parameter → Location ↓ | Optimal β ± 1° (°) | PV Area ($m^2$) | No. of modules (-) | Cost of PV (AU$) |
|---|---|---|---|---|
| Darwin | 0 | 282 | 146 | 34258 |
| Alice Springs | 50 | 261 | 135 | 31677 |
| Brisbane | 51 | 311 | 161 | 37777 |
| Perth | 49 | 343 | 177 | 41531 |
| Sydney | 55 | 372 | 192 | 45051 |
| Mildura | 55 | 373 | 193 | 45286 |
| Melbourne | 55 | 502 | 259 | 60772 |
| Hobart | 63 | 519 | 268 | 62884 |

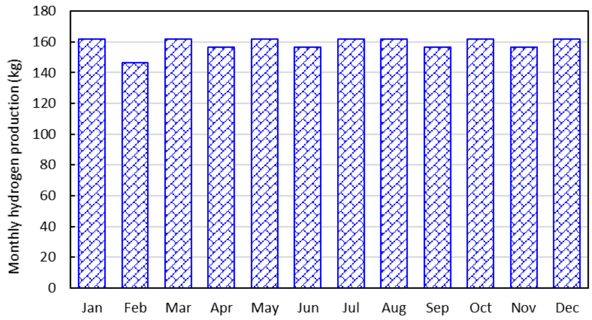


**Fig. 7** Monthly hydrogen production.

The monthly hydrogen production via electrolyser for all selected locations are shown in Fig. 7. To meet the constant daily load, same level of hydrogen produces via electrolyser for all locations for the design month. The annual hydrogen production is 1906 kg for each location. The trend of hydrogen production shows a good agreement with solar radiation and PV electricity production also has the same trend. The average daily raw hydrogen production is 5.22 kg where pure hydrogen production is 4.80 kg which is the daily hydrogen demand. This 4.80 kg hydrogen is able to supply sufficient electricity (daily demand 69 $kWh_e$) via the spark ignition hydrogen engine coupled with the generator.

The days of autonomy and their corresponding blackouts days estimated are presented in Table 5. The days of autonomy is required to prevent the power blackouts due to less/no electricity produce by PV under low/no sun operation. The days of autonomy required varies due to different weather conditions. Based on the analysis, the autonomy applied two days (in Brisbane), three days (in Perth and Sydney), four days (in Darwin, Mildura, and Hobart), and five days (in Alice Springs, and Melbourne) where the storage is able to provide sufficient hydrogen. It is noted that initially ten days autonomy is required for Alice Springs based on lowest month irradiation design. To compensate 10% oversize PV array area was selected for Alice Springs only.

**Table 5** Average blackouts days.

| Autonomy (d) → Location ↓ | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Darwin | 5.15 | 1.24 | 0.24 | 0.0 | 0.0 |
| Alice Springs | 4.18 | 2.11 | 1.11 | 0.11 | 0.0 |
| Brisbane | 4.02 | 0.0 | 0.0 | 0.0 | 0.0 |
| Perth | 5.05 | 1.05 | 0.0 | 0.0 | 0.0 |
| Sydney | 7.21 | 2.06 | 0.0 | 0.0 | 0.0 |
| Mildura | 4.86 | 1.96 | 0.78 | 0.0 | 0.0 |
| Melbourne | 9.97 | 5.32 | 2.07 | 0.49 | 0.0 |
| Hobart | 10.34 | 4.53 | 1.73 | 0.0 | 0.0 |

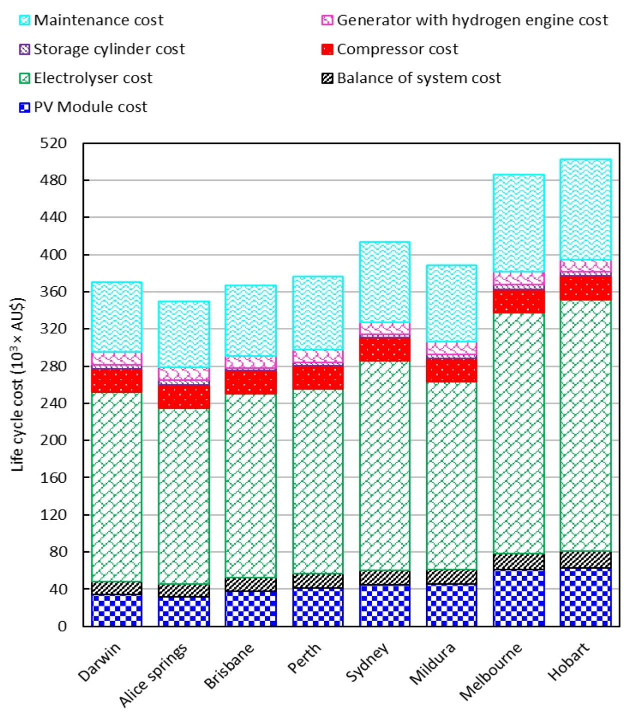


**Fig. 8** Life-cycle cost of components including cost of installation.

Fig. 8 shows the cost breakdown of the PV electrolysis system including hydrogen storage. The cost of the electrolyser was found to be the major cost component of the system. The electrolyser cost (including installation) was found 55.0%, 54.1%, 53.9%, 52.8%, 54.3%, 52.0%, 53.3%, and 53.9% of the system cost for Darwin, Alice Springs, Brisbane, Perth, Sydney, Mildura, Melbourne, and Hobart, respectively. For all locations, the total PV modules and installation cost ranges were found 9.1-12.5% where results were found 2.7-3.9% cost for generator with hydrogen engine. The hydrogen storage cylinder cost (0.6-1.5%) was found to be the lowest cost component of the system. However, hydrogen compressor cost was found 5.1-7.3%. In addition, the BoS cost was found 3.6-4.0% and maintenance cost was found 20.2-21.4%.

The initial investment cost ($C_0$) of the system, required NoSC, LCoH and LCoE for each location were calculated and presented in Table 6. The LCoH and LCoE were determined for 30 years project life. The highest $C_0$ was found for Hobart and the lowest for Alice Springs. A similar trend was found for LCoH and LCoE. Since $C_0$ is the highest for Hobart the LCoE is the maximum compare to that of other locations. The LCoH is highest for Hobart due to the highest cost of PV system which has the maximum number of PV modules. The NoSC was determined based on the days of autonomy and it varies between four and ten.

**Table 6** Initial investment cost ($C_0$), NoSC, LCoH, and LCoE.

| Parameter → Location ↓ | $C_0$ ($10^3$ × AU$) | NoSC (-) | LCoH (AU$ $kg^{-1}$) | LCoE (AU$ $kWh^{-1}$) |
|---|---|---|---|---|
| Darwin | 124.85 | 8 | 7.30 | 0.236 |
| Alice Springs | 117.68 | 10 | 6.79 | 0.222 |
| Brisbane | 125.76 | 4 | 7.35 | 0.236 |
| Perth | 130.89 | 6 | 7.60 | 0.244 |
| Sydney | 143.53 | 6 | 8.45 | 0.268 |
| Mildura | 136.79 | 8 | 7.90 | 0.253 |
| Melbourne | 173.60 | 10 | 10.20 | 0.319 |
| Hobart | 179.44 | 8 | 10.62 | 0.330 |

## 4. Conclusions

This article focuses on hydrogen production via PV electrolyser where the electricity comes from the PV system. For the analysis, eight locations were considered to cover all Australian climate zones. The investigation determined LCoH, LCoE, and PV modules required for the standalone system. It was found that the formulated PV electrolyser system is able to produce sufficient hydrogen to meet the annual electricity demand. The optimal slope of the PV modules for each location was identified and the required number of PV modules was estimated. The LCoH was found to be AU$ 6.79-10.62 $kg^{-1}$ of hydrogen. The electrolyser has the highest cost component (52-55%) of the entire system. Therefore, reduction of future LCoH would depend on the reduction of electrolyser cost. It should be noted that the findings are based on the assumptions made and the weather conditions in Australia, therefore, generalisations for other locations may not be appropriate.

## Disclosures

Free Access to this article is sponsored by SARL ALPHA CRISTO INDUSTRIAL.

## Acknowledgments

This research received no internal/external funding.

## Contributor Roles Taxonomy (CRediT) author statement

**Sheikh Khaleduzzaman Shah**: Conceptualisation, Software, Validation, Formal analysis, Investigation, Data Curation, Writing - original draft & editing, Visualisation, Project administration. **Lu Aye**: Conceptualisation, Methodology, Validation, Resources, Data Curation, Writing - review & editing, Supervision, Funding acquisition.

## Conflicts of Interest

The authors declare no conflict of interest.

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