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Cost assessment of hydrogen production from PV and electrolysis

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Executive summary

CSIRO has been leading the development of a roadmap for the Australian solar fuels industry. The roadmap aims to define the research, development and demonstration priorities to establish and foster an industry using solar thermal technologies. During the three-year project, the cost of photovoltaic (PV) technologies has significantly reduced, while interest has grown in the production of hydrogen from electrolysis. This report, commissioned by ARENA, assesses hydrogen production from PV and electrolysis. It is intended as both a standalone document and a useful reference point for comparison with solar thermal technologies. It considers the likely current cost as well as a 'realistic, optimistic' view of future possibilities, as presented in the solar thermal fuels roadmap.

Our evaluation of the current and future (2030) cost of hydrogen from PV and electrolysis shows that the potential cost using currently available technology is approximately \$18.70/kg H_2. The base case system consists of a PV module with power electronics connected to a proton exchange membrane electrolysis plant, which produces hydrogen only when the PV system is producing power. The assessment is based on an estimated system cost of \$2300/kW for a large scale, non-tracking PV system with a mid-range capacity factor of 20.5% and a weighted average cost of capital of 6.4%, as recently published by the CO2CRC (2015). It is assumed that the uninstalled cost of the electrolyser and associated components is \$2,285/kW, in line with recent estimates from the European Fuel Cell and Hydrogen Joint Undertaking (Bertuccioli et al., 2014). Significant cost reductions are predicted for both these technologies, cutting the estimated cost of hydrogen to \$9.10/kg by 2030.

The study also examined the potential of battery storage to reduce the cost of hydrogen production. In this scenario, the battery system was used to condition the power supply from the PV system, with sufficient storage capacity provided to enable continuous operation of the electrolyser. Lithium-ion battery technology was selected as the most appropriate. In both current and future scenarios, battery storage increased the cost of hydrogen relative to the base case, due to its relatively high cost compared with energy production from PV. Based on current and future battery costs of \$540 and \$200/kWh, the estimated cost of hydrogen was \$28.40 and \$11.30/kg in 2015 and 2030 respectively. While the current cost with battery storage is much higher than the case without storage, the gap is expected to be close if projected battery cost targets are met. It was also interesting to note that the addition of any amount of Li-ion battery storage to the system increased the hydrogen production cost relative to the base case.

The estimates of hydrogen production costs are significantly higher than the current cost of its production from steam methane reforming, which is typically in the range of \$1.50-2.50/kg H_2. Naturally, however, fossil fuels such as methane produce significant greenhouse gas emissions, while PV-electrolysis systems are instead based on renewable solar resources and produce zero-emission fuel.

1 Introduction

Solar energy can be converted directly to hydrogen by coupling a photovoltaic (PV) device with water-splitting technology, such as an electrolyser. This electrolysis pathway uses renewable resources, resulting in a zero-emission fuel.

Paets van Troostwijk and Deiman first demonstrated the use of electricity to split water in 1797, and by the early 1900s, industrial-scale hydrogen production using electrolysis was common (Ostwald, 1980). Because the energy needed to drive the water electrolysis reaction is derived from electricity, it can be obtained from a wide range of sources: from traditional fossil-fuelled generation to renewable supplies such as hydropower, wind and solar. Renewable electricity-based electrolysis emits virtually no greenhouse gases or other pollutants, and is therefore an attractive future option for production of hydrogen.

As renewable electricity generation technologies have been deployed at increasing rates throughout the world, the production price for electricity has significantly reduced. Many of these technologies are now cost competitive with existing generation methods. Coupling renewable technologies with electrolysis-based hydrogen production also enables the inherent variability of renewables to be managed, by allowing flexibility to shift production to best match resource availability with system operational needs and market factors. Additionally, in times of excess electricity production, instead of curtailing electricity production – as is often the case – the excess electricity can be used to produce hydrogen through electrolysis.

Several international programs are seeking to evaluate and demonstrate the large-scale production of hydrogen from electrolysis. The United States Department of Energy (DOE), through the Hydrogen and Fuel Cell program[1], allocates more than US$100 million annually to support the development of hydrogen production through fuel cell development, as well as addressing system and regulatory barriers through research and development. Focus areas include:

- innovative technologies to increase fuel cell durability
- reducing fuel cell costs
- reducing the costs of producing, delivering and storing hydrogen, particularly with respect to renewable hydrogen.

The DOE program also includes technology implementation activities to demonstrate hydrogen and fuel cell systems under real-world conditions to validate the technology status, as well as to gather and analyse performance data on existing systems to provide feedback for future research and development (R&D) efforts. A further goal is to address market barriers by developing information resources to address safety issues, providing critical information needed for the development of technically sound codes and standards, and providing financial and technical assistance to catalyse early market applications. This work is primarily motivated by transport

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[1] http://www.hydrogen.energy.gov

applications, with the electrolyser fed from the power grid and assumed to operate continuously, as shown in Figure 1.

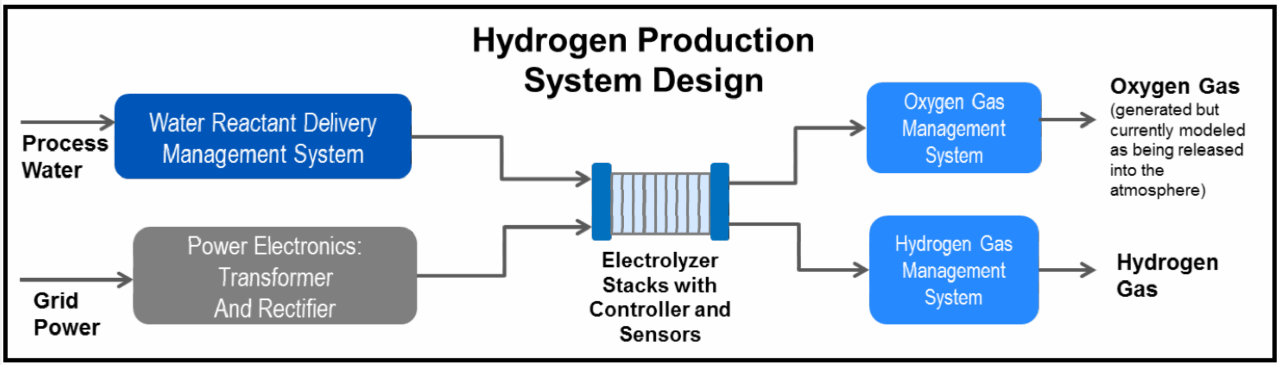

Figure 1: System configuration used in United States Department of Energy analysis.

Source: (Ainscough et al., 2014)

In Europe, improvement of hydrogen production technologies is promoted by the Fuel Cells and Hydrogen Joint Undertaking (FCHJU)[2]. This public private partnership supports research, technological development and demonstration activities in fuel cell and hydrogen energy technologies. The FCHJU aims to accelerate the market introduction of these technologies, realising their potential in a future carbon-lean energy system. The primary motivation of this activity is grid stabilisation and energy storage: assisting in the stabilisation of output from renewable sources (predominately wind) by providing load in the form of hydrogen generation where it would otherwise be curtailed. As does the DOE program, the FCHJU recognises that both automotive applications and hydrogen production for industry may play a significant role in the future.

More recently, Japan has made some positive announcements in energy policy that aim to support a transition towards a hydrogen-based energy supply chain (Government of Japan, 2014). To support this policy, the Japanese government has committed to collaborating with academia, government and industry in developing large-scale systems for using hydrogen. Their three-phase process is outlined as:

- Phase 1: Dramatic expansion of hydrogen use
- Phase 2: Full-fledged introduction of hydrogen power generation/establishment of a large-scale system for supplying hydrogen
- Phase 3: Establishment of a zero-carbon emission hydrogen supply system throughout the manufacturing process.

1.1 System overview

The basic components of a PV-based electrolysis system include:

- a PV array, made of several units
- a water purification and preparation system

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[2] http://www.fch.europa.eu

- power electronics, such as a DC–DC converter, used to operate the system at the maximum power of the PV system at all times and to supply the necessary DC current to the electrolyser
- an optional DC energy storage system (e.g. battery)
- an industrial electrolyser system, including the electrolyser and any gas conditioning components that are required to produce a pure hydrogen gas stream (e.g. gas dryer)
- a compression and storage system for hydrogen.

Each of these subsystems is approaching maturity on an individual basis. However, work is continuing on system integration and optimisation from both the technical and economic perspectives. These are being addressed separately from the component development areas of the European and DOE programs.

2 The Market for Hydrogen

2.1 Applications and potential market growth

Historically, hydrogen has been used for several industrial applications. The largest current consumers are ammonia production plants, oil refineries and methanol production plants. These applications require such large quantities of hydrogen that it is typically produced at the place of consumption, most commonly through the steam reforming of natural gas.

In Australia, about 1.3 million tonnes of ammonia is produced annually, partly for the export market. However, Australia imports a large portion of its nitrogen-based fertilisers, mainly as urea from the Middle East, and demand is expected to increase. ‘Green ammonia’, generated by electrolysis from renewable electricity, has the potential to support CO_2-free farming through both domestic and international fertiliser markets.

Hydrogen demand may also grow substantially as a source of clean energy and as a zero-emissions fuel for vehicles. In 2014, Toyota released the first commercial passenger fuel cell vehicle (FCV) driven by hydrogen, leading development towards a hydrogen economy in Japan. In 2015, Hyundai opened the first hydrogen refuelling station in Australia. Other international auto manufacturers, such as Honda, General Motors, Volkswagen, BMW and Nissan, have plans to follow.

While the fuel consumption of FCVs may provide an incremental increase to the existing hydrogen demand, the market could be drastically changed if hydrogen is substituted for natural gas at thermal power plants. For example, if natural gas was completely replaced by hydrogen at one 100-MW power plant, 31,150 tonnes hydrogen each year would be consumed: equivalent to the annual demand of 330,000 FCVs[3]. Such a plan is one element of the new energy strategy of the Japanese government (METI, 2014; Government of Japan, 2014), due for introduction in the 2020s – or even earlier, in time for the Tokyo Olympics and Paralympics in 2020.

If hydrogen thermal power plants are commercialised, hydrogen will become a tradable commodity as an energy carrier, with densely populated countries such as Japan likely to remain net importers of energy. At the same time, hydrogen production, which currently relies mostly on fossil fuels, should be switched to a cleaner energy source, such as electrolysis. Alternatively, hydrogen could be produced in conjunction with carbon capture and storage (CCS), and in the future with renewables.

Australia is blessed with one of the world’s best solar energy resources, vast resources of fossil fuels (including brown coal, black coal and natural gas) and areas that may be suitable for CCS. Together, these mean that the country is well placed to be a market leader in an international hydrogen trade.

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[3] Based on calculations using data in the following METI presentation: http://www.meti.go.jp/committee/kenkyukai/energy/suiso_nenryodenchi/suiso_nenryodenchi_wg/pdf/004_02_00.pdf

2.2 Hydrogen transport

One of the biggest challenges in the hydrogen supply chain is its transport. Hydrogen gas is the lightest molecule and has a very low volumetric density at ambient temperature, making its transport more expensive than other fuels.

For the transport of large quantities of hydrogen over long distances, pipelines are likely to be the most sensible solution on land. Efficient and economical systems of marine transport to overseas countries, such as Japan, will require an increase in energy density. From the point of handling and stability, storage in a liquid form is potentially more attractive than as gas under high pressure.

Having recognised this issue as a key barrier to transitioning to a hydrogen economy, Japan has invested significantly, both privately and publicly. Their Energy Carrier Project, supported by the Cross-Ministerial Strategic Innovation Promotion Program of the Cabinet Office, Government of Japan, coordinates and supports the necessary R&D for establishing a hydrogen economy. Its goal is to reduce the cost of hydrogen production and delivery within the supply chain, focusing on liquid hydrogen carriers, ammonia, methylcyclohexane (MCH), and liquefied hydrogen. The key parameters of these carriers, which are regarded as the most promising vectors to commercialise hydrogen import from overseas, are summarised in Table 1 and briefly described below.

Table 1: Hydrogen carriers for large quantity and long distance transport.

Carrier Parameter	Ammonia (liquid)	Methylcyclohexane/ toluene	Liquefied hydrogen
Data source	(Thomas and Parks, 2006)	(Okada and Shimura, 2013)	(NIST, 2011)
Chemical formula	NH_3	C_7H_{14}/C_7H_8	H_2
Hydrogen content	17.7 wt.%	6.2 wt.%	100 wt.%
H_2 volume density	121 kg-H_2/m^3	47.4 kg-H_2/m^3	70.8 kg-H_2/m^3
Boiling point	–33.3 °C	100.9 °C/110.6 °C	–253 °C
Melting point	–78 °C	–126.6 °C/–95.0 °C	–259 °C
Storage	Refrigerated tank	Conventional chemical tank (atmospheric pressure and room temperature)	Cryogenic tank <–253 °C

Ammonia contains 17.7 wt.% hydrogen in its molecular structure and has a volumetric density of 121 kg/m^3 (of hydrogen): the highest capacity of the three liquid carriers. While it has a boiling point of –33 °C at atmospheric pressure, it can be stored as a liquid at moderate pressure. However, decomposing ammonia to release the hydrogen for use downstream requires significant energy, which is a serious barrier to its use as a hydrogen carrier. The direct combustion of ammonia in thermal power plants is being evaluated within the Energy Carrier Project, potentially eliminating the need for decomposition and providing a more efficient pathway for transport and use of clean energy.

MCH is the reaction product of toluene and hydrogen. It contains 6.2 wt.% hydrogen, is stable at room temperature and atmospheric pressure, and can be stored and transported using conventional petrochemical equipment. At the consumption site, MCH is decomposed to hydrogen and toluene, which can be recycled. The heat consumption of the endothermic dehydrogenation reaction is much less than that of ammonia, but still needs to be considered. The Chiyoda Corporation has developed an innovative and durable catalyst for dehydrogenation and is working on a techno-economic evaluation of MCH as a hydrogen carrier, supported by Ministry of Economy, Trade and Industry of Japan (METI).

Liquefied hydrogen is recognised as an established commodity in industry. However, some technology development is still necessary to scale up production and handling materials, as well as large-volume vessels for marine transportation. Additionally, liquefaction is very energy intensive, and must be considered in the overall efficiency and operation cost. Kawasaki Heavy Industries, Ltd. (KHI), which is leading the concept of large-scale liquefied hydrogen transport, plans to use brown coal from the Latrobe Valley in Victoria as a hydrogen resource for their first supply chain. After gasification of the coal, hydrogen will be liquefied for transport, while the CO_2 produced will be separated and compressed for undersea storage with CCS technology. KHI estimates the cost, insurance and freight (CIF)[4] of hydrogen will be 29.8 JPY/Nm^3 ($3.73/kg) at commercialisation, which can generate electricity at 16 JPY/kWh (18 c/kWh), competitive with conventional gas-fired power plants in Japan (Yoshimura, 2012). A further feasibility study is ongoing, with the key technology in the supply chain – a cryogenic vessel for marine transport – being funded by METI and KHI and expected to be demonstrated by 2020.

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[4] CIF is a trade term requiring the seller to arrange for the carriage of goods by sea to a port of destination, and provide the buyer with the documents necessary to obtain the goods from the carrier.

3 System components

A conceptual view of a large-scale hydrogen production system using PV and electrolysis is shown in Figure 2. Our analysis excludes downstream components, such as storage and conversion to a transportable form, as described in the previous section. However, we include the PV system supplying the electricity, the electrolyser, and a high-level evaluation of the control and safety systems needed to operate such a plant. A key consideration here is power conditioning or battery storage to protect the electrolyser from spikes in voltage from the PV array, and to potentially extend the operating time of the electrolyser beyond daylight hours. Other necessary components include gas detection for hydrogen leaks, feed water treatment, and drying of the product hydrogen, but these are not described in detail in this report.

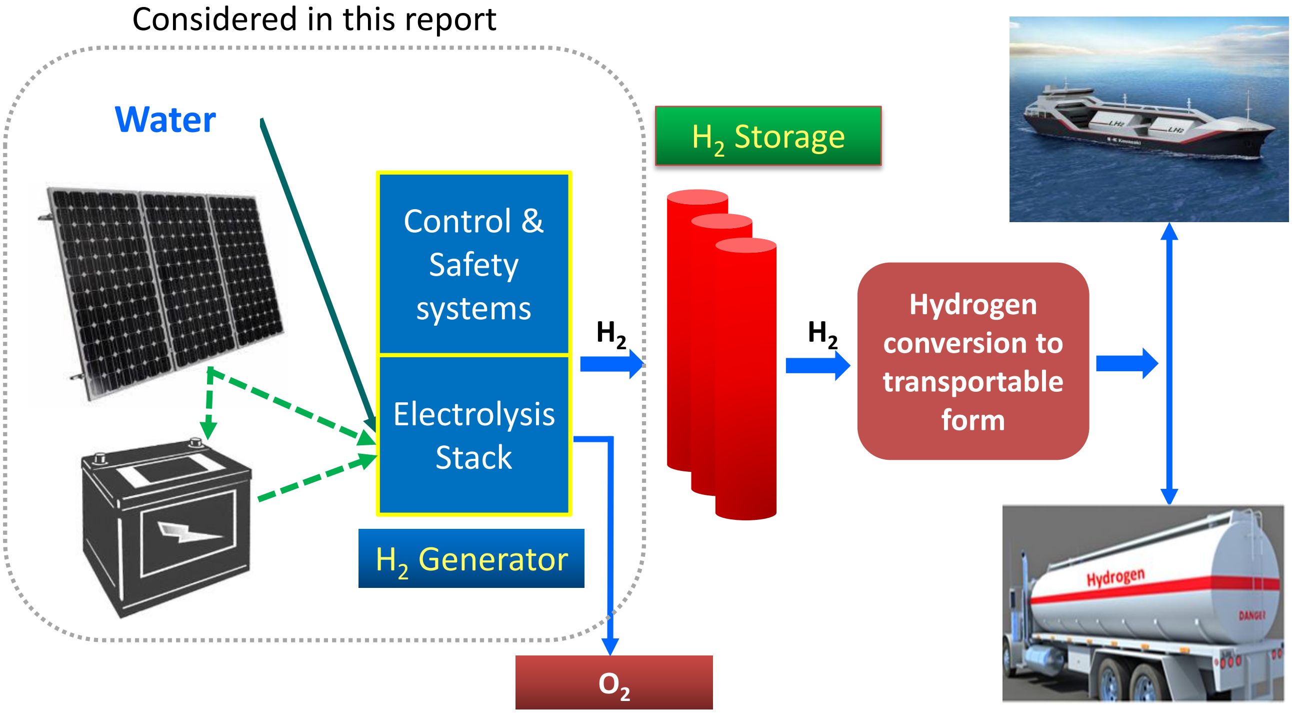

Figure 2: Concept diagram for large-scale production of hydrogen from photovoltaics and electrolysis.

Below, we discuss the three basic components that could be used to build a PV/electrolysis plant: PV, electrolysers and batteries.

3.1 Photovoltaics

Various types of PV technologies are available; however, most applications to date have used crystalline silicon, which includes single crystal and polycrystalline cells. These cell types are the dominant technology, representing 80% of PV cell manufacture in International Energy Agency-Photovoltaic Power Systems Programme (IEA-PVPS) countries (IEA 2015). The efficiency of silicon-based solar cells has improved over time, with best research-cell efficiencies of ~15% in the 1970s reaching ~26% today (Kurtz and Emery 2015). Commercial modules are typically around 17%, with the best products now more than 20% efficient (IEA, 2015b) with lifetimes of 25 years. At the same time, the cost of cell production has decreased by ~20% for every doubling in cumulative output (Gambhir, Gross et al. 2014), which equates to a decrease in cost from US$50/W in 1979 to <US$0.50/W today. The lowest cost available in Australia in 2014 was A$0.60/W (US$0.40/W) (Johnston et al., 2015). A large part of the recent (mid-2000s) cost reduction is due to economies of scale in manufacturing, which began in earnest with the introduction and increase in module manufacturing capacity in Asia. This can be seen in Figure 3, which shows the average module price along with the total global module production capacity and the growth in production capacity in non-IEA countries (including countries such as Taiwan and China). There is a clear correlation between growth in production capacity in non-IEA countries and reduction in module price.

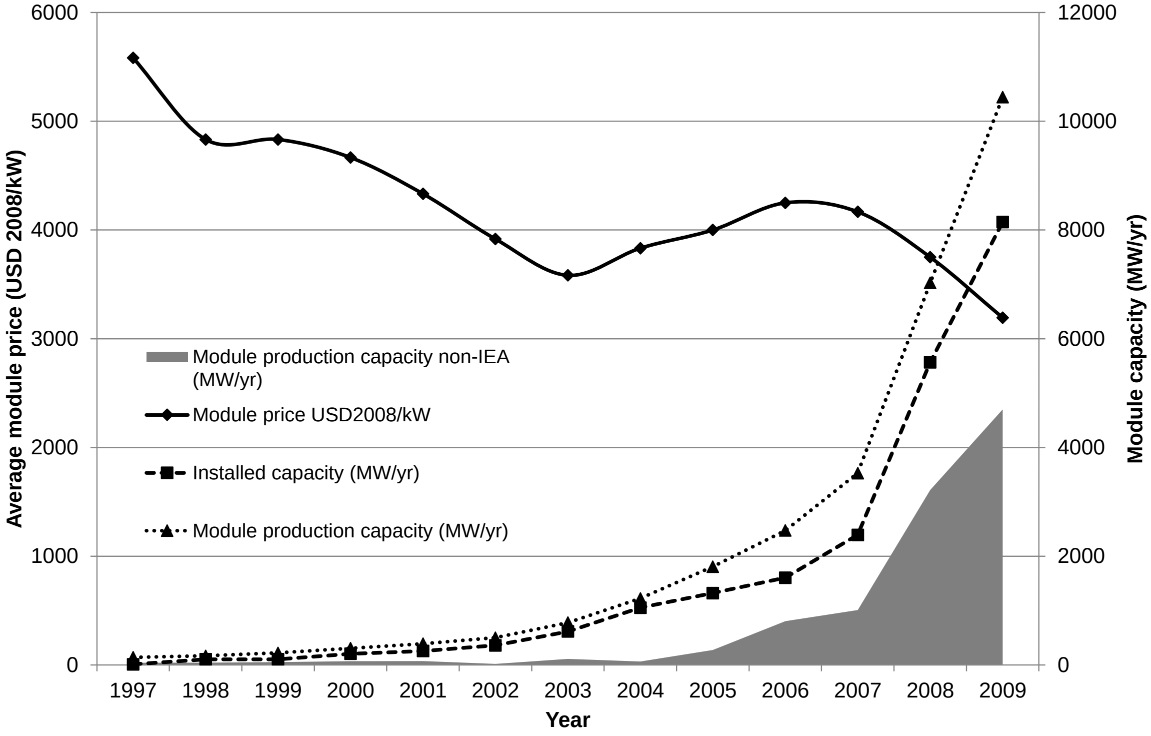

Figure 3: Average photovoltaic module price, and total and non-International Energy Agency (IEA) country module production capacity from 1997–2009.

Source: (Hayward and Graham, 2011)

From 2003 to 2007, there was strong demand for PV in Europe, and limitations in the supply of silicon. This increased the cost to above that expected from economies of scale and learning by doing. Once those limitations were removed, the price of modules dropped back to the long-term learning curve (Yu et al., 2011).

Of the thin-film PVs, cadmium telluride is the only one in large-scale production. It has lower production costs than crystalline PV, with comparable efficiency and lifetime (First Solar, 2015). Other promising thin films, such as copper indium gallium selenide, have cell efficiencies around ~21% (Razykov et al., 2011; Kurtz and Emery, 2015), but have not yet achieved stable commercial production. Organic and polymer cells are flexible and potentially low cost, but are limited by a relatively low efficiency of only 11.5%, low voltage and low stability (Kurtz and Emery, 2015). They are therefore not yet in large-scale commercial production. Dye-sensitised solar cells, perovskites and other emerging nanotechnology frameworks are under development, and are expected to be competitive in the future due to their promising efficiencies and low cost. Currently they are limited by poor stability, which could be solved with further R&D (Tyagi et al., 2013). Multi-junction cells have the highest recorded efficiencies of up to 46% for a four-junction concentrated PV system (Kurtz and Emery, 2015; Fraunhofer ISE, 2014). These cells are typically used for concentrating solar power systems, as they are too expensive for non-concentrating applications.

PV modules make up only a part of the system cost, and due to their falling prices, are typically no longer the most expensive component. The remaining system cost includes inverters, frames, wiring, installation, batteries and chargers (where required) and other soft costs. Figure 5 shows that PV modules only account for 35% of the overall system cost for a typical grid-connected residential system in Australia, based on Australian Photovoltaic Institute data (Johnston et al., 2015). Installation and balance-of-system costs vary between regions and scales of installation (e.g. rooftop to utility-scale). For example, the installation and balance-of-system costs for rooftop PV are much lower in Australia than in the United States. This difference was found to be due to greater regulatory requirements in the United States, and less efficient and thus longer installation times. Australia has rapid installation times due to effectively standardised system sizes and racks for installation. Typical Australian residential system sizes have increased from 1 kW to more than 4 kW over the past decade (APVI Solar Map, 2015)[5]. Competition in the sector, as well as early standardisation of utility connection agreements, led to these price reductions (Calhoun et al., 2014).

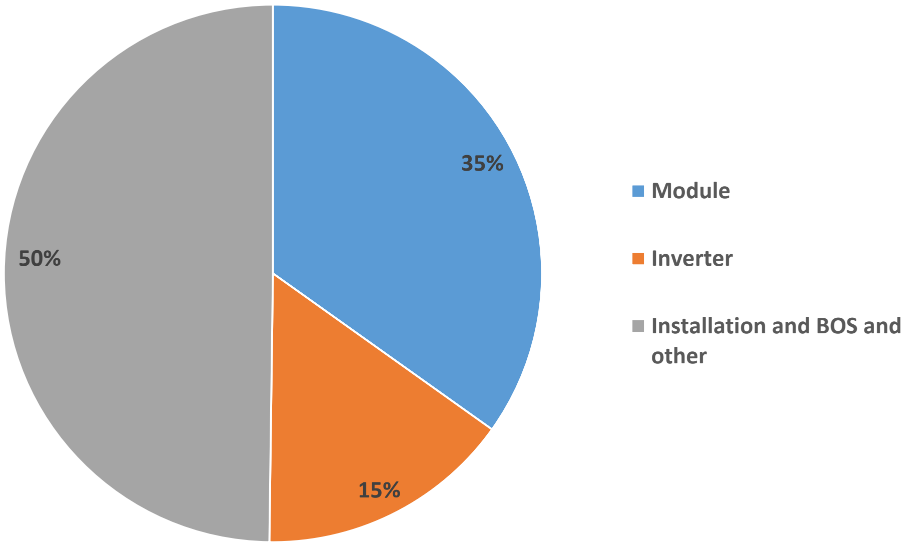

Figure 4: Contribution of each photovoltaic system component to the overall capital cost of grid-connected residential PV systems in Australia, 2014.

Note: BOS = balance of system

The 2014 standard PV module cost in Australia was $800/kW, and the best price was $620/kW (Johnston et al., 2015). As stated above, installation costs depend heavily on the application. For this paper, we assume that the PV will be installed on a large commercial scale (i.e. greater than 1 MW). The estimated current average residential and small-scale commercial scale system price is

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[5] http://pv-map.apvi.org.au/analyses

$1800/kW (Johnston et al., 2015). However, few large-scale systems have been installed in Australia to date, and prices are currently estimated to be $2,300/kW (CO2CRC, 2015). While somewhat counterintuitive and contradictory to economies of scale, this elevated price is attributed to additional ancillary costs of large-scale installations, such as land acquisition, civil footings and site preparation, and necessary support frames. Residential installations avoid most of these costs, with comparatively simple mounting to rooftops. The projected large-scale PV system cost in 2050 is around $650/kW, based on the assumptions used in the CO2CRC study, as shown in Figure 5. The 2015 cost of $2,300/kW is assumed to be composed of: bare module cost, $800; inverter, $500; installation and balance of plant, including contingency, $1,000.

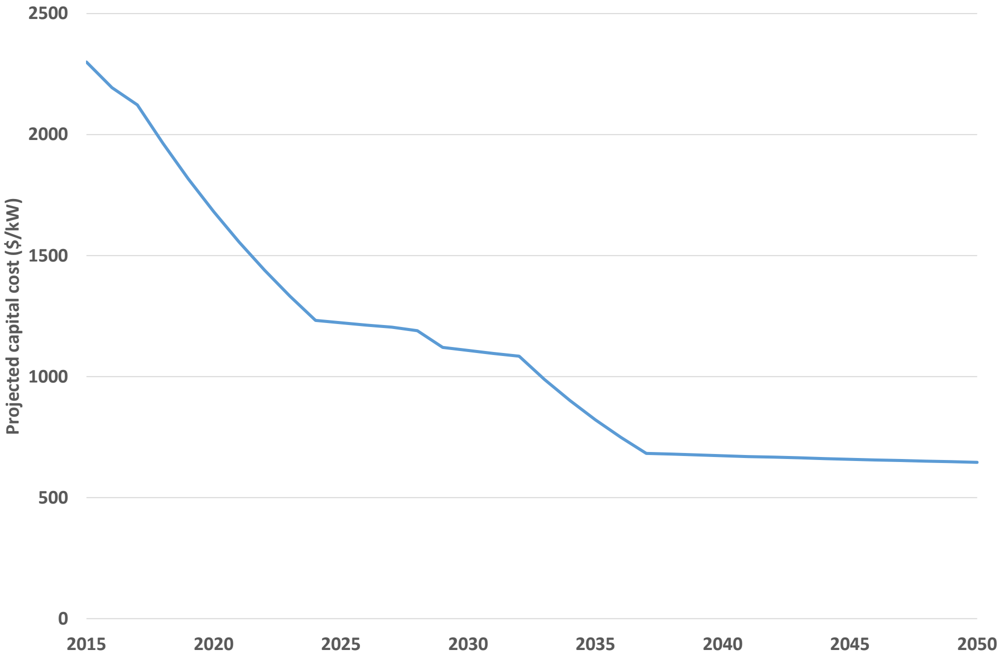

Figure 5: Projected large-scale photovoltaic system price in Australia.

Source: (CO2CRC, 2015)

The price is projected to reduce to $1,110/kW in 2030 and further to $650/kW by 2050, resulting in a cost reduction of ~72% over the next 35 years. Higher percentage cost reductions were observed in the past (as discussed earlier in this section). However, as the technology matures and there is a high level of cumulative capacity, time-based cost reductions are expected to decrease.

The 2030 cost consists of: module, $390 (49% of 2015 cost); converter/power electronics, $340/kW (68%); installation, $380/kW (38%). The different rates of cost reduction reflect the differences in learning rates among the different components, and the fact that global components learn on a global scale, whereas installation learns on a local scale (Hayward and Graham, 2013).

The operations and maintenance (O&M) costs of a large-scale PV system (100s of kW to MW) have been calculated at $25–30/kW-yr. for a fixed-plate system (CO2CRC, 2015). The mid-range capacity factor of a large-scale, non-tracking PV system is estimated at 20.5%, with high and low ranges of 19 and 22% (CO2CRC, 2015). The lifetime of the PV modules and associated infrastructure is 25 years, while the lifetime of the converter/power electronics is 12.5 years (Brinsmead et al., 2015).

3.2 Electrolysis – state of the art

Three main types of electrolysis technologies are recognised as current or potential products on the market, each named after the electrolyte type: alkaline electrolysis (AE) (liquid electrolyte), proton exchange membrane (PEM) electrolysis and solid oxide electrolysis cell (SOE). Each of these is described below.

AE is a well-established technology, with some relatively large historical installations for converting hydropower to hydrogen. The electrolyte is typically 30% KOH, which requires no noble metal catalysts. These units are typically configured with a diaphragm that separates the product gases, reducing downstream separation and removing safety concerns from mixing. The plants operate for decades, requiring maintenance only every 7–8 years.

Large AE plants of 95–160 MW have operated in several countries (e.g. India, Zimbabwe, Norway, Egypt) producing about 20,000–30,000 Nm^3/h of hydrogen, generally from hydropower (Smolinka et al., 2012). While some of these plants have been decommissioned and replaced by low-cost natural gas reforming, this form of electrolysis today accounts for 4% of global hydrogen production. The typical system is a few to tens of MW in size, installed in industries such as metallurgical processing and chemical manufacturing.

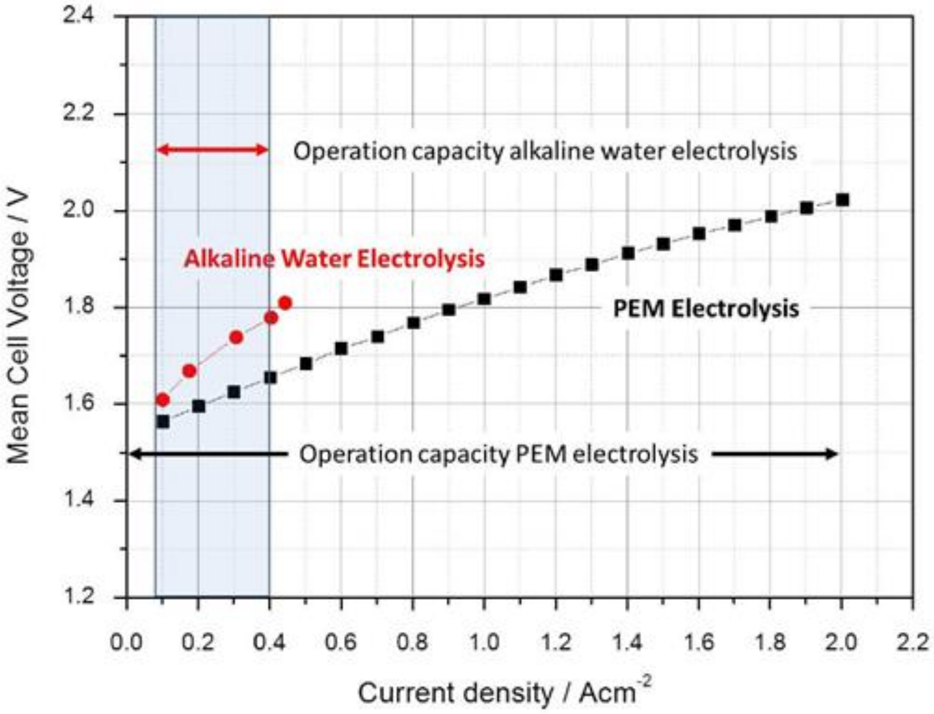

Figure 6: Typical current-voltage characteristics and operating ranges for alkaline electrolysis and proton exchange membrane (PEM) electrolysis.

Source: (Mergel et al., 2013)

PEM electrolysis technology is relatively new, but has developed rapidly over the last decade. As shown in Figure 6, PEM electrolysers can sustain at least twice the current density of AE, which can increase energy efficiency and decrease the total system footprint and capital cost. Note that increasing current density does increase the power consumption per unit of hydrogen, and operation above 1 A/cm^2 is likely to reduce electrode life.

The PEM system is also capable of self-pressurising. While AE generates hydrogen gas at ambient pressure or less than 30 bar, PEM electrolysis can achieve outlet pressures of up to 165 bar. Because hydrogen gas distribution by pipeline and much industrial hydrogen use occurs at lower pressures than this, high-pressure PEM electrolysis can eliminate the need for additional mechanical compression (see Figure 7). However, elevated pressures above 100 bar increase gas crossover past safe levels, requiring a thicker membrane that in turn, reduces efficiency (Millet et al., 2011). In the case of hydrogen for FCVs, which store hydrogen at 350 or 700 bar, high-pressure PEM may reduce the need for extra compression stages. Another advantage is that the purity of hydrogen gas from PEM electrolysis is high enough for direct use in FCVs without further purification by pressure swing absorption. The simpler system structure of PEM electrolysis therefore has the potential to significantly reduce the capital cost of hydrogen production.

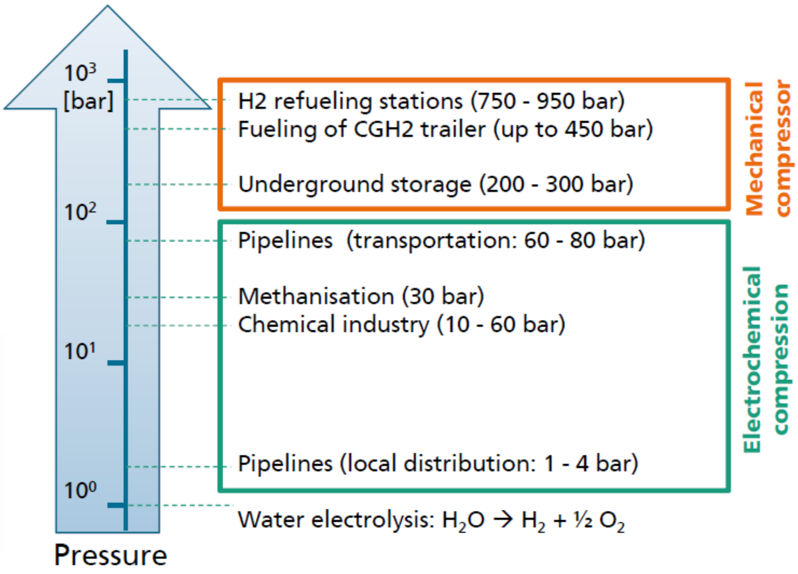

Figure 7: Pressure considerations of typical applications for hydrogen.

Source: modified from (Smolinka, 2014)

SOE technology is the most immature of the main electrolyser technologies, and is some years away from commercialisation. It has the potential of higher electrical efficiency than either alkaline or PEM electrolysis, because some of the energy required to split water is provided as thermal energy at temperatures of 700–1,000 °C (Edwards et al., 2002). Although an attractive technology, it will not be considered further here, due to its comparatively low technology readiness level and uncertainty of the associated cost of heat collection.

Table 2 compares the key features and present performance of the three electrolysis technologies discussed here.

Table 2: Comparison of key parameters for three prominent electrolysis technologies: alkaline, proton exchange membrane (PEM) and solid oxide electrolysis (SOE).

Parameter	Alkaline	PEM	SOE
Electrolyte	Liquid alkaline KOH	Proton exchange membrane	Ceramic metal compound
Electrode	Ni/Fe electrode	Noble metals (e.g. Pt, Ir)	Ni-doped ceramic
Temperature	50–80 °C	RT–90 °C	700–1,000 °C
Pressure	<30 bar	<165 bar	Atmosphere
Unit size (commercial)	3.2 MWe	1.5 MWe	kW range
Hydrogen production	760 Nm^3/h	285 Nm^3/h	~1 Nm^3/h
Size (current operation)	10s to 100s of MW	<10 MW	N/A
Current densities	0.2~0.6 A/cm2	1.0~2.0 A/cm2	N/A
Energy consumption	50–78 kWh/kg	50–83 kWh/kg	Energy 35.1 kWh/kg + Heat 11.5 kWh/kg
Lower partial load range	20–40%	0–20%	N/A
Gas purity	99.5–99.9998%	99.9–99.9999%	N/A
Lifetime of system	20 years or more	<20 years (?)	N/A
Lifetime stack	<90,000 hours	<80,000 hours	N/A
Capital investment cost	US$850–1,500 per kW	US$1,500–3,800 per kW	N/A

Compiled from: (Ainscough et al., 2014; Bertuccioli et al., 2014; IEA, 2015a)

3.2.1 Tolerance of variations in power input

Historically, industrial electrolysers have been designed and operated at constant load supplied by stable grid power. In contrast, coupling electrolysers to renewable power sources requires flexible and dynamic operation with fluctuating power input. This is not possible with older AE technology, as a result of cross-diffusion of product gases across the diaphragm under low system loads (Carmo et al., 2013). The response of an electrolyser stack to changes in power is defined by a function of both the electrochemistry of the stack and the power electronics. For example, state-of-the-art PEM electrolysis systems can start up within 1 min from stand-by mode, and follow a ramp-up or down of power within seconds. This quick response time is a result of tolerance for lower operational temperatures (20 °C) and the lack of delay from inertia within liquid electrolyte systems (Carmo et al., 2013).

The large load range of renewable power must also be considered. PEM systems tolerate a load as low as 10% or less of capacity, whereas conventional alkaline electrolysers require a consistent, substantial load. Figure 8 shows stack current and solar radiation data over a representative period of five days for a CSIRO 2-kW PEM electrolyser directly coupled to a 2.4-kW PV array at the Royal Melbourne Institute of Technology (RMIT University) (Clarke et al., 2009).

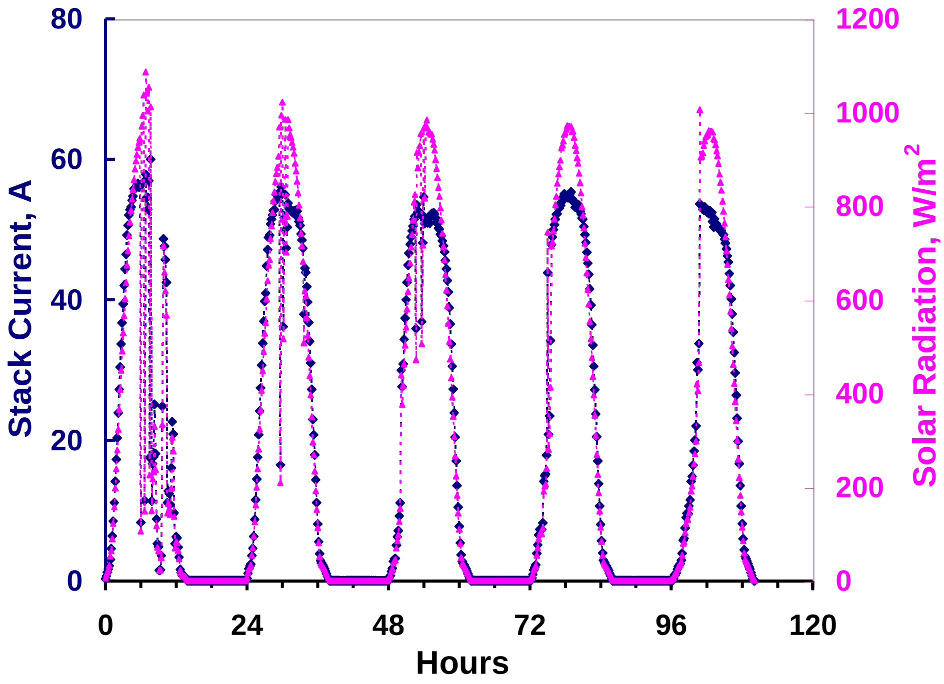

Figure 8: Stack current and solar radiation data for a proton exchange membrane electrolyser over a typical five-day period.

Although these load-following advantages have meant that PEM electrolysis is widely regarded as the most promising technology for use with renewables, there are still some aspects to be improved for commercial deployment. One such aspect is long-term stability. Alkaline electrolysers with stable grid power typically operate for more than 20 years in industry, including stack replacement after 7–10 years of operation. The lifetime of a PEM electrolyser plant may also be described as 20 years or more, but the durability of the PEM stack is currently less than 80,000 hours. Moreover, the fast ramping voltage and changing currents may degrade the stack and shorten the lifetime, although this has not been well quantified.

Scale-up for large production is another key issue. PEM electrolyser units have a smaller capacity than AE types, and replicating them to the required scale increases investment cost and complexity of control. Recently, several manufacturers have developed MW-scale modules of PEM electrolysers; future PEM plant scales are expected to reach several hundred MW with larger-scale modules. This is a current focus of development for manufacturers.

3.2.2 Cost and performance data for PEM electrolysers

Although several manufacturers already produce PEM electrolysers, the market is still developing and identifying realistic cost and performance parameters is difficult. Here, we review data from three recent key sources: the DOE, the IEA and a report prepared by E4tech for FCHJU. Note that the data from the DOE are projections from as-yet undemonstrated, large-scale plants using current technology. Current small-scale electrolyser units available in Australia cost from $20,000–50,000/kW (Badwal, S. P. S. 2015, pers. comm., 18 November).

On a large scale, the cost of PEM electrolysers is currently estimated to be approximately double that of AE, in the range of US$1,500–3,800/kW, according to the IEA Technology Roadmap for Hydrogen and Fuel Cells (IEA, 2015a). The DOE has also been very active in this area, aiming to understand the potential for hydrogen as a replacement for oil-derived fuels in transport. The cost target for production and delivery is US$4/gallon of gasoline equivalent (dispensed, untaxed) by 2020[6], while they estimate the uninstalled cost of large-scale (50,000 kg/day), state-of-the-art PEM electrolyser plants at US$900/kW (2012 prices) (Ainscough et al., 2014). The FCHJU report has higher capital costs, projected to decrease from the 2012) price of 1,860 to 2,320 €/kW to a range of 1,200 to 1,940 €/kW in 2015, including power supply, system control and gas drying (Bertuccioli et al., 2014).

Table 3 drills down more deeply into the key performance parameters from various reports to provide realistic values for use in our subsequent levelised cost calculations.

Table 3: Comparison of key parameters for proton exchange membrane electrolysis in recent publications.

Parameter	IEA Hydrogen and Fuel Cell Roadmap	DOE Hydrogen and Fuel Cell Program	FCHJU Electrolysis in the European Union (2015)	Selected value
Reference	(IEA, 2015a)	(Ainscough et al., 2014; James et al., 2013) [a]	(Bertuccioli et al., 2014)	
Capital cost/kW (current)	US$1,500–3,800 (2014)	US$900 (2012)	€1,200–1,940 (by 2015) Central: €1,570	€1,570 (A$2,285)
Capital cost / kW (2030)	US$800 (2014)	US$400 (2012)	€250–1,270 (2014) Central: €760	US$800 (A$1,100)
Energy consumption (stack and BOP) – current	51–61 kWh/kg H_2 (65–78% efficient, HHV)	54.3 kWh/kg H_2	47–73 kWh/kg H_2 Central: 52 kWh/kg H_2	54 kWh/kg H_2
Energy consumption (stack and BOP) – future (2030)	48 kWh/kg H_2 (82% efficient, HHV)	50.3 kWh/kg H_2	44–53 kWh/kg H_2 Central: 47 kWh/kg H_2	50 kWh/kg H_2
Stack lifetime – current	20,000–60,000 hrs Central: 40,000 hrs	53,000 hrs (7 years, 86% capacity factor)	20,000–90,000 hrs Central: 62,000 hrs	50,000 hrs
Stack lifetime – future	75,000 hrs	85,000 hrs (10 years, 97% capacity factor)	60,000–90,000 hrs Central: 78,000 hrs	80,000 hrs
Installation cost – current	Not mentioned	12% (current) 10% (future)	Specifically excluded	12% current 10% future
Fixed O&M cost	5%	5%	5% at 1 MW, 1.6% at 100 MW, 1.5% at 1 GW	5%
Stack replacement cost, % of total installed capital	Not mentioned	40% (see Section 3.2.3)	Not mentioned	40%

[a] Based on large-scale centralised production, using current technology but assuming large production volumes

BOP = balance of plant; DOE = United States Department of Energy; FCHJU = Fuel Cells and Hydrogen Joint Undertaking; HHV = higher heating value; IEA = International Energy Agency; O&M = operations and maintenance

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[6] One kg of H_2 is the equivalent of 1.019 gallons of gasoline according to the EPAct transportation Regulatory Activities fuel conversion factors, see http://www1.eere.energy.gov/vehiclesandfuels/epact/fuel_conversion_factors.html

3.2.3 Lifetime of electrolyser and stack replacement considerations

Due to the limited commercial development of PEM electrolysis, there is considerable uncertainty regarding the lifetime and replacement costs for the electrolyser stack. The stack cost is expected to account for 40–60% of the system cost, due to noble metals and cost-intensive components, such as the bipolar plates shown in Figure 9. With current technology, noble metals are required to withstand the corrosive environment (pH ≈ 2) and high overvoltage within PEM electrolysers (Carmo et al., 2013).

While the bulk of the electrolyser is anticipated to have a lifetime of more than 20 years, the stack requires periodic replacement. We have not been able to identify any studies that explicitly mention this cost. The DOE study indicates that the uninstalled stack cost is US$423, or 47% of the total electrolyser cost of US$900/kW. As the replacement will take place some years after the original installation, the stack replacement cost is assumed to be 40% of the original installed capital cost. This equates to a future uninstalled stack cost of US$360/kW: a reduction of 15%.

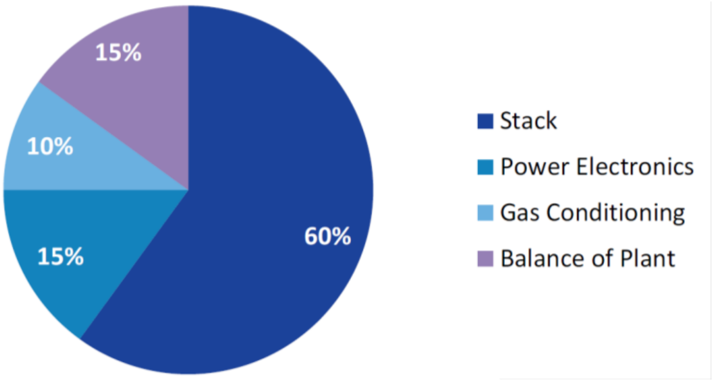
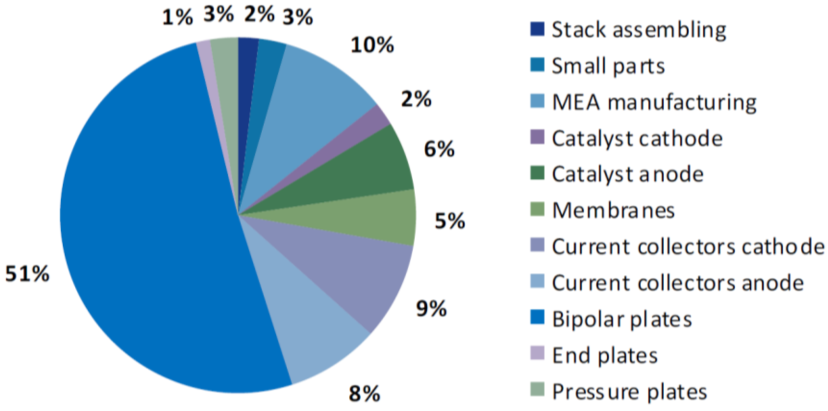
(a) Indicative system cost breakdowns for PEM electrolyser systems	
(b) Stack cost break down for PEM electrolysers	

Figure 9: Indicative system and stack cost breakdowns for proton exchange membrane (PEM) electrolysis (Fuel Cells and Hydrogen Joint Undertaking).

MEA is an acronym for the membrane electrode assembly, which both separates the anode and cathode compartments and contains the active electrodes where the electrochemical reactions take place.

3.3 Batteries

While many different types of energy storage technologies are available in a range of scales, batteries are a suitable storage type to couple with PV systems. They both use DC current, while batteries are modular and require little or no maintenance (apart from replacement).

Key performance parameters for batteries are the depth of discharge (DoD) which refers to the useable energy in a battery. A battery can be discharged beyond its DoD, but this will cause significant degradation and reduce cycle life. Cycle life is the number of cycles of complete discharge to the DoD a battery can undergo before replacement is needed. A battery can be used beyond its cycle life, but its performance will be severely compromised. The lifetime in years is another representation of cycle life, but in time rather than cycles. Most batteries come with a time-based warranty (10 years), during which they can be repaired or replaced if they fail. The round-trip efficiency is the percentage of energy a battery provides relative to the amount sent and stored in the battery. A range of values is typically associated with these performance metrics. However, because of the modelling required for this study, a single representative value of each performance parameter has been chosen.

Common battery classes include lead-acid, Li-ion, flow batteries and molten salt, each of which is described further below. Each class contains subclasses of different chemistries, which can affect the cost (depending on the materials used) and performance characteristics, and thus the commercial application.

- $LiFePO_4$ batteries (a subclass of Li-ion batteries) are commonly used in power tools, transport and consumer electronics. While the battery is mature in these applications, it has not been used to any great extent for residential or utility-scale energy storage, due to cost. A newer Li-ion subclass, nickel manganese cobalt oxide batteries, has better energy and power density than $LiFePO_4$. Energy storage systems such as those commercialised by Tesla and Panasonic use this battery chemistry. Li-ion batteries have the further advantage of a high cell voltage, which may make them more suitable for coupling with an electrolyser. Disadvantages of these batteries include safety risks and poor recycling options. The DoD is 90%, the round trip efficiency is 90% and the batteries last for 4000 cycles or 10 years (Brinsmead et al., 2015).
- Lead-acid batteries have been used in transport for many years. Various subclasses of lead-acid batteries, such as lead-acid gel, have been used in off-grid and remote power applications for telecommunications and household power. While these batteries are a mature technology and are low cost, they have shorter lifetimes than Li-ion batteries, and lower energy and power density. As with Li-ion batteries, disposal and recycling is complex, predominantly as a result of the lead plates. Advanced lead-acid batteries combine a supercapacitor with a lead-acid battery to improve performance. These batteries have been used in hybrid vehicles and for smoothing electrical output from variable renewable generation. However, they are a less mature technology than conventional lead-acid batteries and are currently higher in cost. The DoD is 40%, the round trip efficiency is 90% and the batteries last for 10 years or 4000 cycles (Brinsmead et al., 2015).
- Flow and molten salt batteries are even less technically mature than Li-ion or lead-acid batteries. They have been deployed in remote power applications, but not on a large scale. Molten salt batteries require a high temperature (~300 °C) to operate. As such, these will not

be considered for system analysis within this report. The DoD of flow batteries is 100%, the round trip efficiency is 75% and the lifetime is 10 years or 1500 cycles (Brinsmead et al., 2015).

The type of battery chemistry that is most suited to coupling with PV and an electrolyser is an energy battery, which could be any of the batteries described above. However, due to the higher parasitic loads of the flow battery, and the higher cost and the high temperature required for the molten salt battery, only advanced lead-acid and Li-ion batteries are considered to be suitable for this application.

Various studies are projecting that the cost of batteries will fall quite significantly in the future, due to learning-by-doing effects, including economies of scale in manufacturing (Brinsmead et al., 2015; Bronski et al., 2014). The cost reductions are expected to be similar to those seen for PV. Li-ion batteries are projected to be lower in cost than advanced lead-acid batteries, reaching A$180/kWh by 2035 (Brinsmead et al., 2015).

Discarded hybrid electric vehicle batteries can also be used for a PV/electrolysis application. The performance of these batteries is considered to be reasonable, and they are low in cost. Reusing something that would otherwise go to waste also makes sense from a sustainability perspective (James and Hayward, 2012). However, if the batteries' cycle life is extremely low, the labour costs of replacement may be too costly. This will depend on the location, since labour rates are higher in remote than in urban locations. The batteries may also be in more limited supply than newly manufactured batteries, which could be a potential problem if they are in high demand.

Energy storage systems also have O&M costs, which are 3.1 A$/MWh (variable) and 10 A$/kW-year (fixed) for Li-ion batteries and 0.5 A$/MWh (variable) and 5 A$/kW-year (fixed) for advanced lead acid batteries (Zakeri and Syri, 2015).

This study assumes that Li-ion batteries will be used, due to their lower capital cost and higher DoD than advanced lead-acid batteries.

3.4 Integration of PV and electrolysis

Section 3.2 indicates that PEM electrolysers are well suited for operation under a greater range of conditions than alkaline electrolysers. Nevertheless, it is inadvisable to directly connect the PV system and electrolyser, because the yield from a PV system has significant short-term variability and potentially high ramp rates in terms of the current and voltage that would be seen by the electrolyser. The typical daily output from a 135-kW PV plant is shown in Figure 10 (Sayeef et al., 2012). The variability would not be as high for a larger system, which would be more geographically dispersed. Nevertheless, such spikes can degrade the electrolyser – notably the catalyst-loaded electrodes – and reduce the lifetime of the electrolyser stack. Therefore, it is advisable to have some power conditioning between the two systems to manage these load variations. This could include a supercapacitor, a small battery system or a current-limiting device.

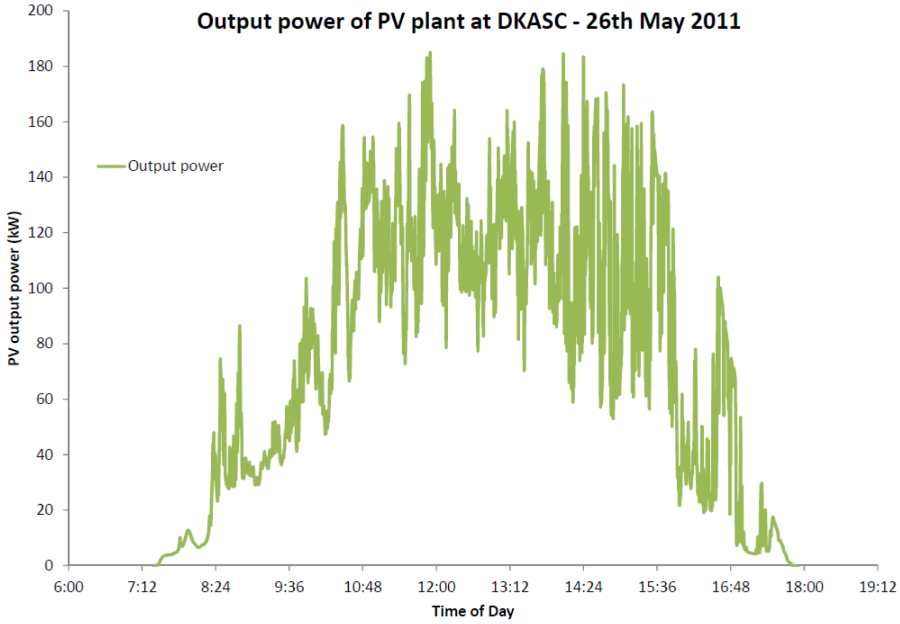


Figure 10: Power output from a photovoltaic (PV) plant at the Desert Knowledge Australia Solar Centre (DKASC) over one day.

Source: (Sayeef et al., 2012)Sayeef et al., 2012)

Direct coupling of PV and electrolysis has been examined experimentally, at least from the point of view of optimising the yield of hydrogen (Clarke et al., 2009). The authors concluded that it was possible to avoid the cost of a maximum power point tracker for a loss of only a few per cent in yield. However, they noted that: ‘Long-term performance degradation of PEM electrolyser, in a direct coupled solar-hydrogen system over an extended period of operation, is a concern, and requires further testing to determine the extent to which the degradation is directly attributable to the variability of the power input as opposed to usage over time at constant power’.

As well as providing some power conditioning, batteries have the potential to enable operation outside daylight hours. In the next section, we examine the impact of different levels of battery storage on the levelised cost of hydrogen ($LCOH_2$). We assume that the ‘power electronics’ included as part of the electrolyser system cost in Figure 9 will provide sufficient power conditioning, and that the inverter and power point tracking in a normal PV control system is not required.

4 Levelised cost of hydrogen model

This study employed a spreadsheet model in Microsoft Excel to evaluate the $LCOH_2$ under several different system configurations. The model can easily assess changes in any of the key input parameters, and thus explore future prospects for cost reduction.

4.1 Basic financial assumptions

The $LCOH_2$ is calculated in 2015 Australian dollars. It is a gate price that includes drying but not additional compression, and does not consider shipping costs. The model is based on a straightforward calculation in which the various system costs are evaluated and the sum divided by the amount of hydrogen produced. The initial installed capital cost is amortised over the assumed economic life of the system (25 years) to determine an annual repayment (using the 'PMT' function in Microsoft Excel). The PMT function uses a real weighted average cost of capital (WACC), assumed to be 6.4%. This value was used in a recent Australian power generation technology report and is the real WACC before tax (CO2CRC, 2015).

$$LCOH_2 = \frac{Annual\ capital\ repayment + O\&M\ Costs}{Annual\ production\ of\ H_2}$$

$$Annual\ capital\ repayment = -PMT(WACC, Economic\ life, Capex)$$

Where:

- $O\&M\ Costs$ = annual operating and maintenance costs
- $WACC$ = weighted average cost of capital (6.4%)
- $Economic\ life$ = 25 years
- $Capex$ = installed capital price, including contingencies

4.2 Data for levelised cost analysis

A summary of the costs and performance parameters used in the levelised cost analysis is shown in Table 4 and Table 5, based on data presented in the preceding sections. The installation costs have been converted into percentages of installed capital for ease of model population.

Table 4: Summary of cost data for the years 2015 and 2030 assumed in the levelised cost analysis.

Item	Units	2015	2030
PV module cost	$/kW	800	390
Converter/power electronics cost	$/kW	500	340
PV installation & indirect costs	$/kW	1,000	380
PV O&M cost	$/kW-yr.	28	28
PV O&M	% installed capital	1.22	2.52
PV/inverter lifetime	Years	25/12.5	25/12.5

Item	Units	2015	2030
Li-ion battery cost	$/kWh	540	200
Battery installation cost	% capital	12	10
Li-ion battery fixed O&M cost	$/kW/yr.	10	10
Li-ion battery variable O&M cost	$/MWh	3.1	3.1
Battery O&M	% installed capital	0.74	2.02
PEM electrolyser cost	$/kW	2,285	1,100
PEM electrolyser installation cost	% capital	12	10
PEM electrolyser O&M cost	% installed capital	5	5

O&M = operations and maintenance; PEM = proton exchange membrane; PV = photovoltaic

Table 5: Summary of key performance parameters assumed for the levelised cost analysis.

Parameter	Units	Value
Photovoltaic capacity factor	%	20.5
Voltage converter efficiency	%	95
Li-ion battery depth of discharge	%	90
Li-ion battery efficiency	%	90
Li-ion battery cycle life	No. of cycles	4,000
Li-ion battery lifetime	Years	10
Electrolyser efficiency	kWh/kg H_2	54 (2015) – 50 (2030)
Electrolyser cycle life	No. of hours	50,000 (2015) – 80,000 (2030)

4.3 Scenario analysis

Two basic scenarios have been considered: a direct use case where the PV system feeds an electrolyser which operates under highly variable loads; and a case where sufficient battery storage is provided to essentially operate the electrolyser continuously. Future costs are also explored, as well as a sensitivity analysis to examine the impact of key cost and performance parameters.

4.3.1 Scenario 1: no battery storage, current costs

The key information from the spreadsheet for the reference (current) scenario is shown in Table 6, and some of the key assumptions are explained in the text underneath. In this scenario, which has no storage, the electrolyser has been sized to match the PV system, allowing for a 5% decrease in power due to conversion losses. In normal operation, it is desirable to run the electrolyser at around 80% of design capacity. Due to daily and seasonal variations, the electrolyser will experience significant variations in voltage/current, but will generally operate below its maximum design capacity. The variable current efficiency is not considered in this analysis.

Table 6: Levelised cost of hydrogen calculations from Microsoft Excel spreadsheet – 2015, no battery storage.

Parameter	Units	PV	PV BOP	Electrolyser	Total	Cost
Capacity	kW	1,000	1,000	950		
Specific cost	$/kW	800	500	2,285		
Capital	$	800,000	500,000	2,170,750		
Capacity factor/utilisation	Annual, %	20.5	–	20.5		
Power demand	kWh/kg H_2			54		
Economic life	Years	25	12.5	25	25	
Converter efficiency	%	95				
Annual electricity	kWh	1,706,010			1,706,010	
Annual H_2 production	kg H_2			31,593	31,593	
Base capital (25 years)	$	800,000	1,000,000	2,170,750	3,970,750	
Installation, rate	% of capital	113	20	12		
Installation, cost	$	900,000	200,000	260,490	1,360,490	
Annual capital repayment	$/year	138,082	97,469	197,476	433,027	13.71
O&M	% of capex	1.22	1.22	5.00		
O&M, annual cost	$/year	20,740	14,640	121,562	156,942	4.97
Stack replacement	Annualised, $			0	–	–
$LCOH_2$	**$/kg**	**5.03**	**3.55**	**10.10**		**18.67**
$LCOH_2$	**$/GJ**					**155.62**

BOP = balance of plant; O&M = operations and maintenance; PV = photovoltaic

Notes and comments on the assessment:

- PV BOP refers to the cost of the 'balance of plant' components necessary for a PV system. Within the context of this report, these are considered to be explicit modules necessary for operation, such as inverters. Within this analysis, connection components such as wiring, footings and site preparation are considered as installation costs, rather than BOP.
- The PV system is assumed to have a capacity factor of 20.5% (annual yield/[rated capacity*hrs in year]).
- The stack in the electrolyser is assumed to have a lifetime of 50,000 hours, as for continuous operation. This is based on an assumption that the power conditioning in the system is sufficient to prevent significant spikes in current or voltage from the PV system passing to the electrolyser. At 20.5% utilisation, 50,000 hours equates to 27.8 years of operation. There is thus no need to replace the stack in the base case, so the stack replacement line entry shows as zero cost. In the sensitivity analysis, we consider the case where the stack lifetime is 20,000 hours: the low end of the range identified by the FCHJU (Bertuccioli et al., 2014).
- Installation costs for the PV system ($1,000) are split 90% for the PV modules and 10% for the BOP.
- Power conversion (voltage management) results in a 5% loss of available power from the PV system.
- The equivalent cost of electricity from the PV system was estimated to be 16c/kWh, indicating that the model is not grossly inaccurate.
- This scenario is predicated on the ability of the PEM electrolyser to readily adapt to fluctuations in current density. We recognise that PV systems without battery storage are currently rare, with the

exception of variable input applications such as water pumping, where a variable speed pump may be appropriate.

4.3.2 Scenario 2: battery storage, current costs

In this scenario, sufficient battery storage is nominally provided to run the electrolyser continuously. Again, the key details from the spreadsheet are shown in Table 7, while notes and comments on the assessment are shown underneath. The cost of hydrogen has significantly increased, from $18.67 to $28.43 per kg, with the battery system contributing $19.95. It should also be noted that this system is significantly more capital intensive, with an installed cost of $8.9 M compared to Scenario 1 at $5.3M. This is reflected in the higher contribution of the capital repayment compared to the ongoing O&M and stack replacement costs (85% compared to 73% in Scenario 1).

Table 7: Levelised cost of hydrogen calculations from Microsoft Excel spreadsheet – 2015, with battery storage.

Parameter	Units	PV	PV BOP	Battery	Electrolyser	Total	Cost
Capacity	kW	1,000	1,000	4,458	185		
Specific cost	$/kW(h)	800	–	540	2,285		
Capital	$	800,000	–	2,407,356	421,583		
Capacity factor/utilisation	Annual, %	20.5%			100%		
Power demand	kWh/kg H_2				54		
Economic life	Years	25	25	10	25	25	
Battery efficiency	%	90%					
Annual electricity	kWh	1,616,220				1,616,220	
Annual H_2 production	kg H_2				29,930	29,930	
Base capital (25 years)	$	800,000	–	6,018,390	421,583	7,239,973	
Installation, rate	% of capital	113%	77%	12%	12%		
Installation, cost	$	900,000	–	722,207	50,590	1,672,797	
Annual capital repayment	$	138,082	0	547,502	38,352	723,935	24.19
O&M	% of capex	1.22%	1.22%	0.74%	5.00%		
O&M, annual cost	$	20,740	0	49,591	23,609	93,940	3.14
Stack replacement	Annualised, $				33,090	33,090	1.11
LCOH₂	**$/kg**	**5.31**	–	**19.95**	**3.18**		**28.43**
LCOH₂	**$/GJ**						**236.93**

BOP = balance of plant; O&M = operations and maintenance; PV = photovoltaic

Notes and comments on the assessment:

- The sizing of the battery is based on the annual average yield, rather than the likely day-to-day variations, with higher yields in summer than winter. In practice, this would mean that some of the electricity generated could not be used, although this is not considered in our analysis. The PV system yields 4,920 kWh per day, but up to 910 kWh can be supplied directly to the electrolyser, meaning that a storage capacity of 4,010 kWh is required. The battery is assumed to have a DoD of 90%, leading to the sizing of 4,458 kWh.
- The PV BOP has been removed from this scenario, since an inverter is no longer required. We assume that sufficient current and voltage management is provided in the battery control system. Wiring and mounting is assumed to be allowed for within the installation cost. This may be an underestimate of the actual costs.
- The battery is assumed to have 90% round-trip efficiency, which is reflected in the reduced annual hydrogen production compared with Scenario 1.
- The other main difference between the two scenarios is in the stack lifetime, in terms of years of operation. The electrolyser in this scenario is considerably smaller, and operates continuously at constant load. We assume, as before, that the stack has a lifetime of 50,000 hours. However, as it operates continuously instead of only six hours a day, periodic stack replacement is required in this scenario. The bulk of the electrolyser system is assumed to last 25 years, with just some of the stack requiring replacement; this is assumed to be 40% of the installed cost of the electrolyser.

The model is capable of providing a continuous solution from 25 to 100% utilisation of the electrolyser. The cost of the battery is high enough that incorporating any storage in the system increases the $LCOH_2$, as shown in Figure 11. The chart shows the contribution of each system to the $LCOH_2$, and illustrates that the cost of providing electricity storage is greater than the savings from a smaller electrolyser system.

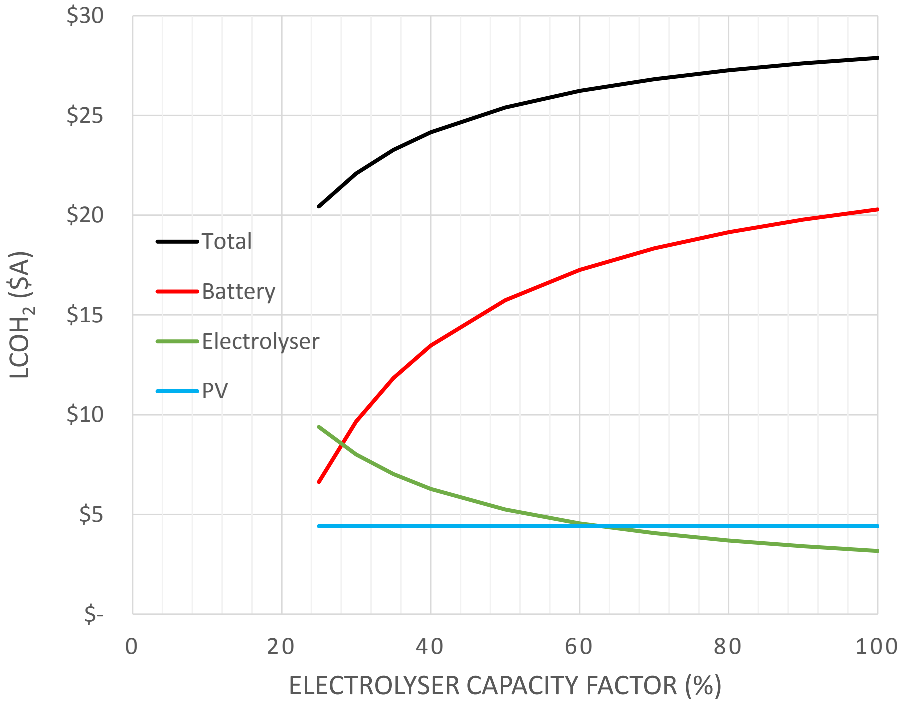


Figure 11: Impact of increasing battery storage on the levelised cost of hydrogen for a 1 MW PV system.

PV = photovoltaic

4.3.3 Future cost of hydrogen – no battery storage

The $LCOH_2$ in 2030 was estimated using the input parameters from Table 4 and Table 5 (Table 8). The estimated $LCOH_2$ is expected to decrease significantly from $18.67 today to $9.14 in 2030.

Table 8: Levelised cost of hydrogen calculations from Microsoft Excel spreadsheet – 2030 no storage.

Parameter	Units	PV	PV BOP	Electrolyser	Total	Cost
Capacity	kW	1,000	1,000	950		
Specific cost	$/kW	390	340	1,100		
Capital	$	390,000	340,000	1,045,000		
Capacity factor/utilisation	Annual, %	20.5		20.5		
Power demand	kWh/kg H_2			50		
Economic life	Years	25	12.5	25	25	
Converter efficiency	%	95				
Annual electricity	kWh	1,706,010			1,706,010	
Annual H_2 production	kg H_2			34,120	34,120	
Base capital (25 years)	$	390,000	680,000	1,045,000	2,115,000	
Installation, rate	% of capital	88	11	12		
Installation, cost	$	342,000	76,000	125,400	543,400	
Annual capital repayment	$	59,456	61,406	95,065	215,927	6.33
O&M	% of capex	2.52	2.52	5.00		
O&M, annual cost	$	18,446	19,051	58,520	96,018	2.81
Stack replacement	Annualised, $			0	–	–
$LCOH_2$	**$/kg**	**2.28**	**2.36**	**4.50**		**9.14**
$LCOH_2$	**$/GJ**					**76.19**

BOP = balance of plant; PV = photovoltaic

Notes: the electrolyser stack lifetime is assumed to be 80,000 hours.

As shown in Figure 12, the split between the PV system (module, BOP and installation) and electrolyser system costs remains around 50%, due to similar cost reductions for each. While the overall contribution of the PV system remains similar in percentage terms, the BOP costs are expected to contribute a greater share due to slower learning rates than anticipated for the modules.

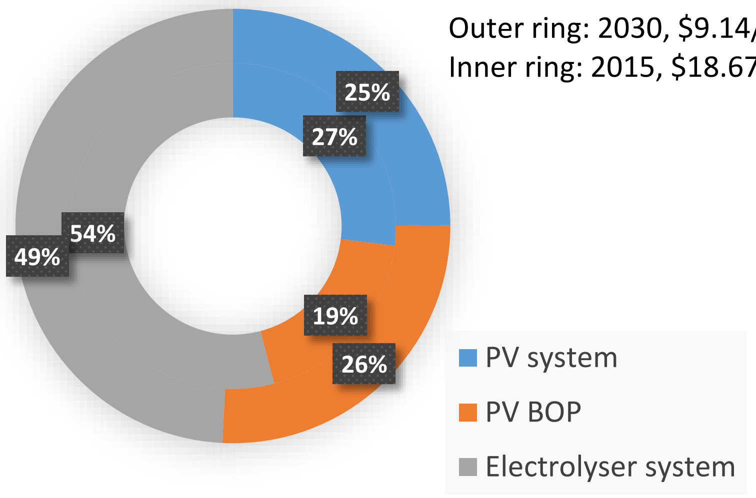


Figure 12: Contribution of subsystem costs to $LCOH_2$ (no battery storage) for 2015 and 2030.

4.3.4 Future cost of hydrogen – system with battery storage

The $LCOH_2$ for 2030 with Li-ion battery storage was also calculated. The key data from the spreadsheet calculation are presented in Table 9. It is apparent from this data that the forecast cost savings for the battery technology has closed the gap between systems with and without battery storage. The $LCOH_2$ for the system with battery storage is $11.31, only $2.17 (24%) more than the system without storage. This is a dramatic change from the situation in 2015, where the system with battery storage is more than twice as expensive in terms of $LCOH_2$. This is also reflected in a closing of the gap between respective installed capital costs, which is $3.4M for a system with battery storage compared to $2.7M without storage.

Table 9: Levelised cost of hydrogen calculations from Microsoft Excel spreadsheet – 2030 with battery storage.

Parameter	Units	PV	Battery	Electrolyser	Total	Cost/kg
Annual capital repayment	$/year	59,456	199,157	18,133	276,747	8.56
O&M	% of capex	2.52	2.02	5.00		
O&M, annual cost	$/year	18,446	49,591	11,162	79,200	2.45
Stack replacement	Annualised, $			9,778	9,778	0.30
$LCOH_2$	**$/kg**	**2.41**	**7.70**	**1.21**		**11.31**
	$/GJ					**94.28**

Notes: battery cost $200/kWh; stack life 80,000 hours.

Battery system costs remain the dominant contributor (around 70%) to the $LCOH_2$, as shown in Figure 13. The plot also shows that the battery and electrolyser systems are anticipated to show more significant cost reduction than the PV system, as the latter contributes a greater share of the future cost than is the case in 2015.

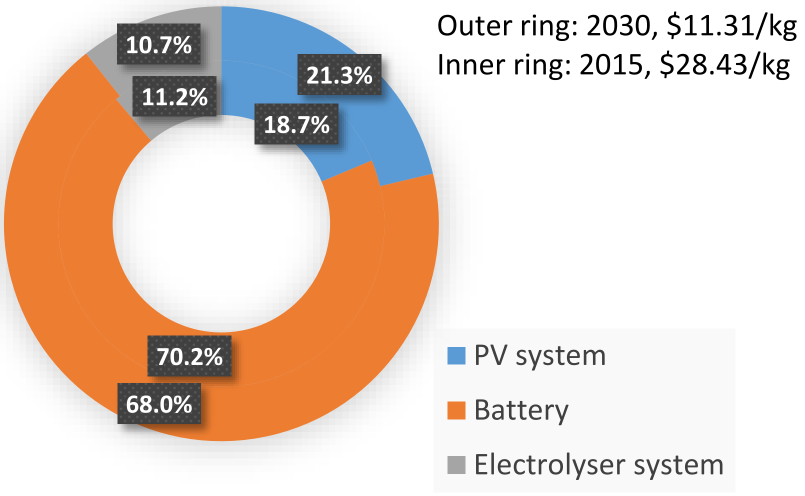


Figure 13: Contribution of subsystem costs on $LCOH_2$ with battery storage for 2015 and 2030.

4.3.5 Sensitivity analysis: parameters with greatest leverage – no storage

In order to investigate the influence of individual factors on the $LCOH_2$ assessments, a sensitivity analysis was undertaken on the 2015 scenarios. Selected parameters were varied by +/-30% around the assumed values used in the analysis, to identify the parameters with the greatest leverage. The calculated upper and lower values for the selected input parameters are shown in Table 10. In general the ranges are consistent with the upper and lower values identified in the literature, with the exception of capacity factor and stack lifetime. The expected range of capacity factor is narrower than shown in Table 10, while the current stack lifetime is thought to be across a slightly wider range.

Table 10: Upper and lower (+/-30%) values for scenario 1 – 2015, no battery storage.

Parameter	Lower	Base	Upper
PV Module Cost (A$)	560	800	1,040
Inverter/BOP (A$)	350	500	650
PV Installation Cost (A$)	630	900	1,170
Electrolyser Cost (A$)	1,600	2,285	2,970
Capacity Factor (%)	14.35	20.50	26.65
Weighted Average Cost of Capital (%)	4.48	6.40	8.32
Stack Lifetime (hrs)	35,000	50,000	65,000

Through the substitution of these values into the scenario calculations, ranges for the $LCOH_2$ were evaluated, as plotted in Figure 14.

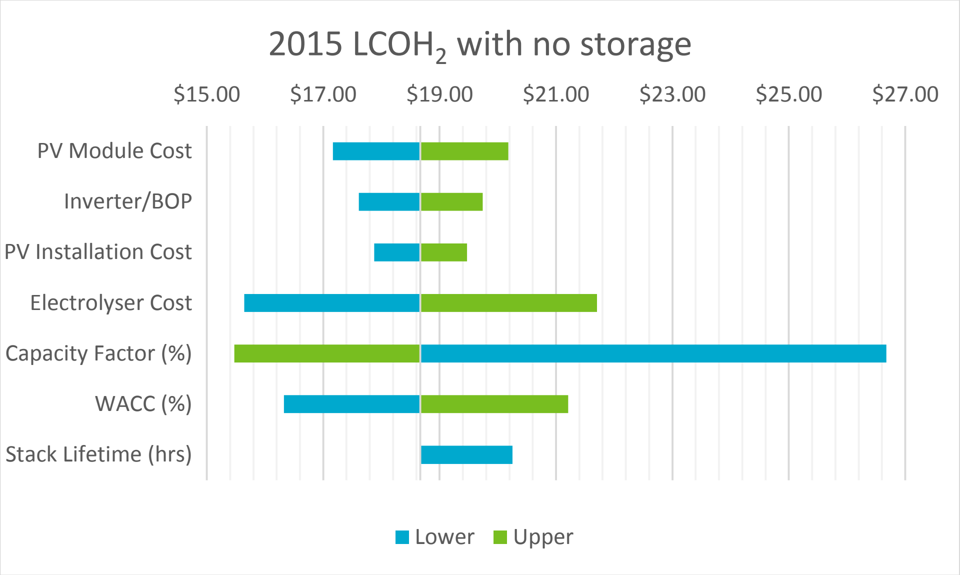


Figure 14: Tornado chart of LCOH$_2$ with no storage. The base LCOH$_2$ for this scenario is $18.67.

Figure 14 indicates that capacity factor has the greatest influence on the LCOH$_2$, reinforcing the importance of locating solar plants in areas with a very good solar resource. The electrolyser cost is the next most influential, which is unsurprising given it dominates both the capital and O&M costs (partly as consequence of its comparatively high O&M as a percentage of installed capital). The figure also highlights the importance – or perhaps irrelevance – of increasing stack lifetimes. Because of the intermittent operation, the stack is already expected to last for the economic life of the overall system, and future improvements in stack life do not have any impact on LCOH$_2$.

4.3.6 Sensitivity analysis: parameters with greatest leverage – battery storage

A sensitivity analysis was also conducted for scenario 2 (2015) with Li-ion battery storage. The calculated upper and lower values LCOH$_2$ are presented below in Table 11.

Table 11: Upper and lower (+/-30%) values for scenario 2 (2015) – incorporated battery storage.

Parameter	Lower	Base	Upper
PV Module Cost (A$)	560	800	1,040
PV Installation Cost (A$)	700	1,000	1,300
Battery Cost (A$)	380	540	700
Electrolyser Cost (A$)	1,600	2,285	2,970
Capacity Factor (%)	14.35	20.50	26.65
Weighted Average Cost of Capital (%)	4.48	6.40	8.32
Stack Lifetime (hrs)	35,000	50,000	65,000

Through the substitution of these bounds into the levelised costing model, new values of LCOH$_2$ were calculated, and are illustrated in Figure 15.

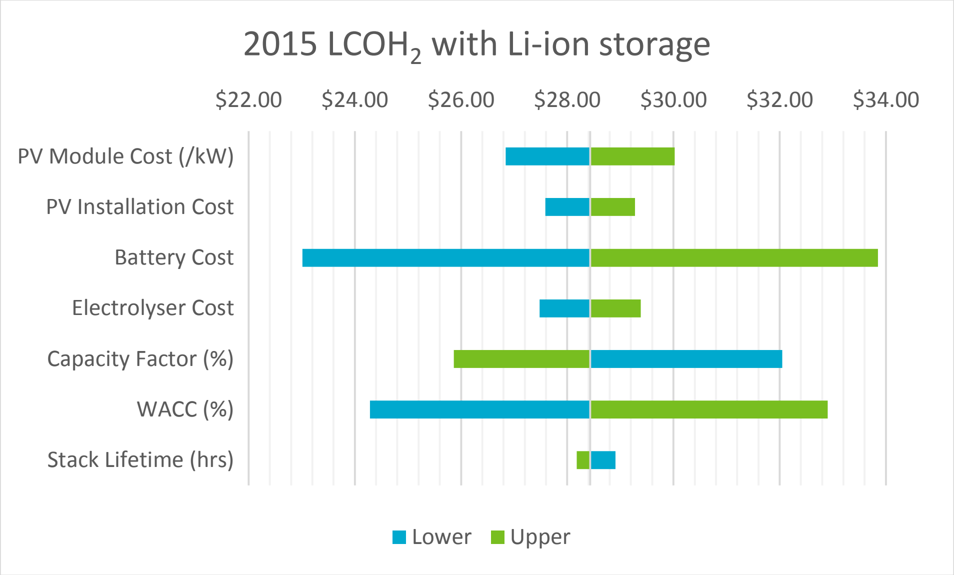


Figure 15: Tornado chart of $LCOH_2$ with incorporated battery storage. The base $LCOH_2$ for this scenario is $28.43.

In this scenario, battery cost and WACC have the greatest impact upon the $LCOH_2$. The battery system cost is highly influential as it dominates the capital investment, partly because of the need for periodic replacement. With a 10 year lifespan, the battery system needs to be replaced twice during the course of the 25 year assessment period. An increase in assumed battery lifespan to 15 years naturally has a significant impact on $LCOH_2$, decreasing it 21% to $22.33. Conversely, if the battery life were only 5 years, the $LCOH_2$ would be increased significantly to $46.72. This highlights importance of the lifespan of the battery system in establishing an economically viable system.

As in scenario 1, the WACC has a significant impact upon the calculated $LCOH_2$, due to the capital intensive nature of the overall concept. As this real (adjusted for inflation) WACC value is exposed to both cost of debt and equity, it is important to recognise that changes to the macroeconomic climate in Australia (e.g. interest rates, inflation) may significantly impact the projected $LCOH_2$ (as illustrated in Figure 15). The value of 6.4% was taken from a recent, relevant publication (CO2CRC, 2015), and therefore represents a realistic estimation of a discount rate for this system.

In contrast to scenario 1, an increase in stack lifetime was found to slightly impact $LCOH_2$. This is a consequence of the high utilisation of the electrolyser and the need for multiple stack replacements over the 25 years (a stack lifetime of 50,000 hours corresponds to an effective lifetime of 5.71 years).

5 Conclusions

Our evaluation of the current and future (2030) cost of hydrogen from PV and electrolysis shows that the potential cost using currently available technology is approximately \$18.70/kg H_2. The base case system consists of a PV module with power electronics connected to a proton exchange membrane electrolysis plant, which produces hydrogen only when the PV system is producing power. The assessment is based on an estimated system cost of \$2,300/kW for a large scale, non-tracking PV system with a mid-range capacity factor of 20.5%, as recently published by the CO2CRC (2015). It is assumed that the uninstalled cost of the electrolyser and associated components is \$2,285/kW, in line with recent estimates from the European Fuel Cell and Hydrogen Joint Undertaking (Bertuccioli et al., 2014). Significant cost reductions are predicted for both these technologies, cutting the estimated cost of hydrogen to \$9.10/kg by 2030.

The study also examined the potential of battery storage to reduce the cost of hydrogen production. In this scenario, the battery system was used to condition the power supply from the PV system, with sufficient storage capacity provided to enable continuous operation of the electrolyser. Lithium-ion battery technology was selected as the most appropriate. In both current and future scenarios, battery storage increased the cost of hydrogen relative to the base case, due to its relatively high cost compared with energy production from PV. Based on current and future battery costs of \$540 and \$200/kWh, the estimated cost of hydrogen was \$28.40 and \$11.30/kg, respectively. While the current cost with battery storage is much higher than the case without storage, the gap is expected to be closed if projected battery cost targets are met. It was also interesting to note that the addition of any amount of Li-ion battery storage to the system increased the hydrogen production cost relative to the base case.

The estimates of hydrogen production costs are significantly higher than the current cost of its production from steam methane reforming, which are around \$1.50-2.50/kg H_2. Naturally, however, fossil fuels such as methane produce significant greenhouse gas emissions, while PV-electrolysis systems are instead based on renewable solar resources and produce zero-emission fuel.

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