

Hydrogen to Support Electricity Systems

Department of Environment, Land, Water and Planning

February 2020



Executive Summary

The Department of Environment, Land, Water and Planning (DELWP) engaged GHD Advisory and ACIL Allen to assess the roles, opportunities and challenges that hydrogen might play in the future to support Australia's power systems and to determine whether the relevant electricity system regulatory frameworks are compatible with both enabling an industrial-scale¹ hydrogen production capability and the use of hydrogen for power generation.

Technology to produce renewable hydrogen

The interaction of hydrogen with Australia's power systems stems from: the electricity required to produce hydrogen; and hydrogen-to-power applications, where hydrogen is used to produce electricity. In this paper, we concentrate on the use of electrolysis² for hydrogen production, as this has the largest effect on power systems and markets.

The commercial-scale production of hydrogen from electrolysis has the potential to have a significant impact on Australia's electricity systems. Electrolysis technologies vary in their respective stages of development with alkaline electrolyzers (AE), polymer electrolyte membrane (PEM) electrolyzers and solid oxide electrolysis cells (SOECs) representing the majority of current market offerings. Hydrogen-to-power fuel-cell technology and reverse SOEC operations (also known as solid oxide fuel cells (SOFC)) are fast-response systems in that the load they present to the network can be changed rapidly. They, therefore, have the potential to support the supply-demand balance of the power grid by matching the consumption of electricity with the produce from variable renewable energy generators such as wind and solar farms. They also offer the potential to provide frequency control services (load raise or lower).

The technology used to produce hydrogen using renewable energy at commercial scale is not yet competitive compared with the production of hydrogen from thermal methods using fossil fuels. However, as the cost of electrolysis is likely to be driven down by investment in research and development globally, coupled with increased, low marginal cost renewable energy, the viability of hydrogen developments in Australia will increase.

The carbon emissions intensity of hydrogen production using electrolysis will depend on the source of electricity used as an input. Using renewable energy will produce no carbon emissions³, while using grid-based electricity would produce 40.4 kg of CO₂-e per kilogram of hydrogen⁴.

¹ By industrial-scale, we are referring to plant is generally considered to have a capacity of 10 MW or above.

² Electrolysis is the chemical change produced by passing an electric current through a conducting solution or molten salt. Throughout this report we assume the conducting solution is water unless otherwise specified.

³ Based on scope 1 and 2 emissions as defined under the National Greenhouse and Energy Reporting Act 2007.

⁴ COAG Energy Council, 2019, Australia's National Hydrogen Strategy, based on electrolyser efficiency of 54 kWh per kg and an average emission intensive of 0.75 kg of CO₂ per kWh

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International review

There are only a few power to hydrogen projects operating around the world that may be classed as approaching commercial scale (i.e. of more than a few MW demand).

The overarching objective of these projects is to demonstrate the technical viability of commercial-scale green hydrogen production and use of green hydrogen for power generation. The aim is to encourage uptake of the technology, as critical mass for usage is essential for fostering economies of scale and decreasing average costs of using the technology.

Three projects that considered the interaction of hydrogen technologies to support electricity systems are:

- The INGRID project in Italy that demonstrated the technical feasibility of using a hydrolyser⁵ powered by renewable energy to provide frequency control services.
- The EnergiePark Mainz project in Mainz, Germany that demonstrated that PEM technology could respond quickly enough to enable the plant to provide ancillary services, and also served to illustrate some of the regulatory issues that have arisen for hydrogen projects in the country.
- The HyStock Green Hydrogen Park in Veendam, Netherlands that demonstrated the benefits of co-locating two renewable energy sources (solar and wind) with underground hydrogen storage that provides buffer capacity. The project delivered electricity to the high-voltage electricity grid and the Park's buffer capacity is also connected to the main gas network, demonstrating how existing power and gas systems can work to support these types of projects.

The resurgence in interest in hydrogen is a relatively recent phenomenon and the policy landscape is therefore still evolving. Most (if not all) countries are grappling with issues that are like those facing Australia. Similarly, most are still working on how to adapt their policies and regulatory frameworks to deal with the entry of hydrogen into the energy system.

Through our review of international efforts (and Australian⁶) to demonstrate the technical and commercial viability of large scale clean hydrogen production, we have identified several learnings that Australia could draw upon as it seeks to develop its own hydrogen sector. These include:

- That PEM electrolysis technology has proved itself technically capable of responding quickly enough to provide frequency control services and, from our assessment of Australia's electricity market rules, we consider that there are no impediments to the provision of such services.
- That hydrogen produced by a power-to-gas plant can have many uses. The key is to find an end-use that has the most value and hence can attract a price premium. This suggests that regulation should allow the maximum possible flexibility for projects to help them make a return on investment.

⁵ A hydrolyser is a form of electrolyser that uses water as the medium. Throughout this report references to electrolysers assume water as the medium.

⁶ See, for example, the H2U, Port Lincoln 15 MW electrolyser pilot plant, South Australia.

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Australia's power systems

Australia's power systems comprise electricity generation, transmission and distribution infrastructure used to produce, transmit and distribute electricity to end-use customers. The system includes several interconnected networks, as well as embedded and remote power systems.

The National Electricity Market (NEM) incorporates approximately 40,000 kilometres of transmission lines connecting five regional market jurisdictions in eastern Australia.

In Western Australia, there are several islanded electricity networks, the largest being the South West Interconnected System (SWIS), which services the majority of the State's customers.

The North West Interconnected System (NWIS) is a loosely integrated system located in the Pilbara region (in the north-west of the State) and provides power to several towns in the region, as well as mining communities. Horizon Power currently operates 37 isolated power systems in Western Australia that supply power to remote communities and towns.

In the Northern Territory, there are three regulated systems: the Darwin–Katherine interconnected system, Tennant Creek and Alice Springs. Minor centres, which are also regulated, are Yulara, Timber Creek, Borroloola, Nhulunbuy, and Ti Tree. In addition, there are 72 remote indigenous communities, as well as licensed self-generating commercial centres (mine sites, tourist resorts), and small unlicensed isolated power supplies (cattle stations, roadhouses, outstations).

Each network offers different challenges and opportunities for the connections and use of hydrogen production facilities.

The market structures that support investment in networks and trade in electricity between generators and retailers also differ across Australia. Those differences present both opportunities and challenges for the development of grid connected hydrogen production facilities.

The NEM and SWIS both offer significant levels of renewable generation which is already operating. That presents opportunities for large-scale green hydrogen production using electrolyzers in the short-term.

Hydrogen production sites that are located close to significant renewable generation facilities have the potential to extract value by avoiding network constraints, which might otherwise limit the generation of power from renewable sources. In addition they could vary their output to deliver wider system services such as generation following and frequency control.

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In all regions of Australia the increasing cost-competitiveness of variable renewable generation from wind and solar-based power, coupled with retirements of existing fossil fuel generation and trends towards decentralisation and democratisation⁷ of power system supply and use requires the development of cost effective approaches to managing the variability of supply and demand whilst maintaining power system security. This includes being able to:

- Match electricity consumption to renewable generation thereby removing the variability, and
- Store the energy produced from renewable generation to supply demand when there is little or no renewable generation.

The availability of electricity market mechanisms that allow participants to clearly identify both the current and future value of electricity will help investors in industrial-scale hydrogen facilities optimise the location, design and size of any investment.

Ancillary services (also referred to as essential system services) are required to securely operate power systems and hydrogen production facilities are able to provide a range of ancillary services. These may include providing stabilising load during system restart, load shedding services as part of frequency protection schemes, and controllable load to manage the effects of rooftop solar that may not be subject to Distributed Energy Resource standards for interoperability. The volume of ancillary services required is however small compared to the size of the wholesale electricity markets and this limits the value that hydrogen producers may be able to gain from providing ancillary services compared to the value they can extract from directly participating in the wholesale electricity markets and changing their electricity consumption to follow the generation available from renewable energy generators.

The NEM offers a well-developed ancillary service market and a very visible real-time energy price. However, there is a lack of visibility regarding future prices for energy and ancillary services. Similar concerns exist for other electricity markets and power systems within Australia. The interconnected nature of the NEM and the significant number of existing suppliers of frequency control services may mean that there is less value in those services than in other isolated systems.

In the SWIS, the Wholesale Electricity Market (WEM) reforms to connection arrangements and to the essential system services framework, both expected to be implemented in 2022, offer the potential to provide a simpler connection process and enhance the ability for hydrogen production facilities to extract value from the provision of essential system services.

The opportunities for industrial-scale hydrogen facilities in the NWIS system are most likely a result of co-located renewable energy and hydrogen developments.

⁷ Democratisation refers to the increasing choice and empowerment of energy users allowed by new technology and increasing power consumption awareness.

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Growing levels of solar generation connected to the power system in the Northern Territory may create opportunities for industrial-scale hydrogen production with production adjusting to follow renewable generation. The lack of renewable generation overnight may be a disincentive as it limits the potential for hydrogen production to daylight hours.

In the medium-term as technology costs continue to fall, isolated communities across Australia and the smaller isolated systems at Tennant Creek and Alice Springs may present opportunities for smaller-scale developments incorporating hydrogen production, storage and conversion of hydrogen back to power. This technology when coupled with renewable generation could enable remote communities and isolated power grids to reduce their dependence on liquid-fuelled generation.

However, the widespread uptake of such systems will depend on the commercial viability of the hydrogen facilities compared to alternatives such as battery energy storage for short-term (up to 8 hours) energy supply. Where longer-term energy storage is needed to provide back-up during extended renewable resource droughts and where road access for alternatives fuels is challenging or unavailable for parts of the year, hydrogen might provide a viable solution in the future.

Beyond 2030, the demand for hydrogen and therefore the requirements of Australia's electricity systems are less clear. Deloitte has forecast the additional hydrogen production from Australia (in excess of existing production) could be between 1 and 20 million tonnes (Mt) per annum by 2050 under their 'business as usual' and 'energy of the future' scenarios respectively⁸. Deloitte also forecast the electricity required to meet these production estimates could range from 5.5 terawatt hours (TWh) to 912 TWh per annum⁹.

In the NEM, there was a total generation capacity of 60,839 MW that produced around 205 TWh of electricity in 2018-19 including rooftop PV¹⁰. In the SWIS, installed generation capacity is around 5,768 MW, and around 18 TWh of electricity is supplied each year¹¹.

To meet 2050 hydrogen production estimates, the installed generation capacity in Australia will need to increase by around 3 per cent in total under a 'business-as-usual' scenario but will have to double or increase more than five-fold if a targeted hydrogen deployment or the most opportunistic hydrogen production scenarios eventuate¹².

The levels of electricity demand indicated by Deloitte's 2050 projections under the targeted hydrogen deployment and the most opportunistic scenarios are likely to be driven by significant hydrogen production developments that are off-grid and co-located with renewable power supplies. If the current electricity regulatory frameworks persist, the developments are likely to prefer the unregulated or lightly regulated economic environment that such off-grid developments afford.

⁸ Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, Table 1.2, p. 7.

⁹ Ibid, Table 6.1, p.104.

¹⁰ AER, State of the Energy Market Report 2019 Data Update, November 2019, refer to: 'State of the energy market – Data update – Chapter 2 National electricity – November 2019.xlsx'.

¹¹ AEMO, Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS, March 2019. Available at: <http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Integrating-utility-scale-renewables>

¹² Based on hydrogen production forecasts and electricity inputs requirements developed by Deloitte, assuming solar generation, and based on the current total installed capacity of 64,524 MW across the NEM and SWIS.

Source: Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, p. 95, 97, 104.

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While the frameworks do not prevent hydrogen connections of this size or their participation in electricity markets, the regulation does involve more extensive consultation and approval processes for large-scale projects. Investors in hydrogen projects considering development off-grid will need to weigh up the benefits of this reduced regulatory complexity with the higher risks of asset stranding and alternative electricity supply sources that grid connections afford.

Alternatively, if hydrogen production developments consist of a multitude of small, medium and large-sized plants (but not ‘super-sized’ projects¹³) dispersed throughout existing networks and the most opportunistic demand scenarios eventuate, expansion of networks to support the increased load (in the absence of co-location of production with renewables) will be substantial.

Generating multiple value streams with sector coupling

The scale-up of hydrogen production in Australia will introduce new cross-sector trade-offs and opportunities for investors that amplify the way our energy, transport and natural gas sectors interact.

Several characteristics of hydrogen, when combined, make it uniquely exchangeable between industries:

- Hydrogen can be stored for long periods of time without energy loss.
- Hydrogen is a versatile energy carrier and chemical feedstock. It can be used in a variety of markets for a variety of different purposes.
- Hydrogen can be readily transported in a truck and on transport vessels, so the geographical consumption points are less constrained than natural gas delivered through pipelines and electricity and more akin to liquid fuels.

The current markets for electricity, natural gas and other fuels such as diesel, petrol and oil are to varying degrees interlinked. Electricity is used in many of the production processes used to extract and process natural gas and other fuels. These fuels can, in turn, be used to produce electricity.

Hydrogen scale-up will amplify the connections between these markets, offering investors more flexibility as to which markets they participate in. For example, hydrogen producers may choose to sell into multiple domestic markets, store their product for later use or transport their product to export markets.

The extent to which markets become further aligned and integrated will, in part, depend on the transparency of future prices for hydrogen in each market. Transparency of future prices will allow investors to weigh the value in each market and choose the best use of any produced hydrogen. Producers will also weigh up the value of using the hydrogen today versus storing it for tomorrow. Where transparency and certainty of future hydrogen prices are better in one market compared to another, this will influence the direction in which hydrogen supply chains could develop. Importantly, if there is greater transparency and future prices are more certain in one market, investors are more likely to look to develop opportunities that service that market.

For hydrogen to be used as a fuel source for electricity, the electricity market needs to offer a reasonable trade-off compared to alternative markets. To do this, it must provide long-term future price transparency and certainty that values the energy storage potential of hydrogen.

¹³ ‘Super-sized’ refers to individual projects that require generation input capacity that is multiples of the existing generation capacity.

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While there are multiple tools available that enable an understanding of electricity market developments including information that can be used to forecast future electricity prices¹⁴, the certainty and transparency of 'bankable' future electricity prices that value dispatchable load and generation is limited. Hedge contracts offer a means of managing short to medium-term price volatility in spot markets like the NEM and can be a source of revenue for dispatchable load and generation. However, the liquidity of these markets can be limited particularly for hedging positions greater than a few years into the future.

Renewable generation projects often enter into longer-term power purchase agreements (PPA). These PPAs typically take the form of an offtake agreement where an agreed amount is paid for each unit of energy (MWh) produced. These arrangements do not give consideration to when the energy is produced and are purely volumetric in nature. Renewable generators financed through PPAs, rather than on the basis of secondary market contracts, can impact the number of hedging contracts traded, reduce the liquidity of the secondary contracts market¹⁵.

The availability of hedging contracts through a liquid long-term secondary contract market would assist hydrogen producers by signalling market expectations of future spot prices. These signals could help hydrogen producers to assess the value of the energy storage potential of hydrogen to the electricity market.

The lack of long-term price certainty in electricity markets is potentially unfavourable compared to the long-term price certainty that investors might be exposed to in other markets.

Uses of hydrogen to support the electricity system

The electricity market is transitioning. Historically, electricity generation has been controlled to follow electricity consumption in a way that maintains power system stability. This was achieved by dispatching electricity generators to deliver the level of power required to meet the expected demand from electricity consumers.

However, the growth of new technologies, including variable renewable generation, coupled with the retirement of existing fossil fuel generation and changing patterns of consumer demand is changing this dynamic. Renewable generation is becoming increasingly cost-competitive compared to new build of conventional generation. Renewable generation such as wind and solar is reliant on uncontrollable weather conditions, and is not able to follow consumption in the same way as traditional fossil fuel generation unless firmed.

The shift away from load-following generation is creating challenges for power system security. Maintaining a secure and reliable power system while achieving greater renewable energy penetration requires a shift towards a future where a large amount of demand is able to follow generation.

Electrolysers can ramp up and down very quickly, this allows them to match the electricity consumed to the available generation. Hydrogen is able to provide a valuable role in the transition of our power systems from a world where generation follows load, to a world where load adjusts to follow the availability of variable renewable generation.

¹⁴ Participants are able to retain specialist advice to run market simulations using information in publications such as AEMO's Electricity Statement of Opportunities in the NEM and WA, AEMO's Integrated System Plan (ISP) for the NEM, annual planning reports published by distribution and transmission networks to help understand potential future wholesale electricity prices.

¹⁵ AEMC, Annual Market Performance Review 2018.

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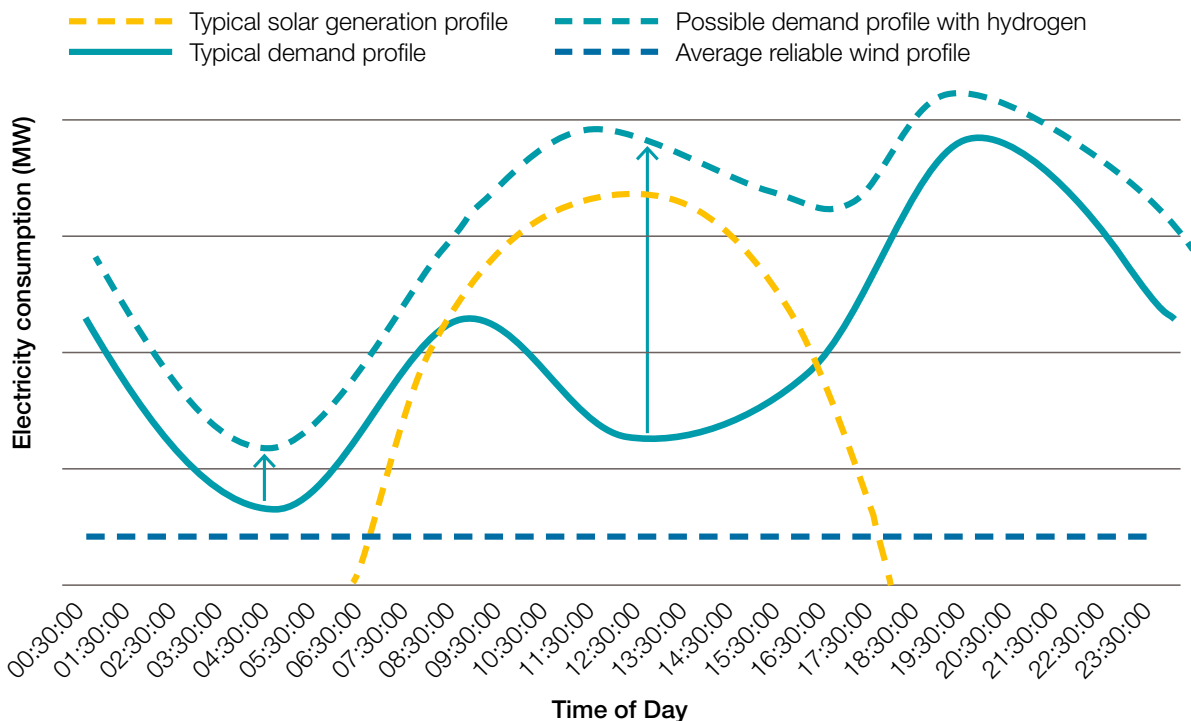
Generation-following load (where the load follows the output profile of generation) can be achieved by operating electrolyzers to increase hydrogen production when there is excess renewable electricity generated and reducing hydrogen production during periods when there would otherwise be a shortfall between supply and demand. Having significant amounts of load that follows generation will help facilitate higher utilisation of variable renewable generation and maintain electricity network frequency within prescribed limits.

With aligned incentives and ready access to networks, the new load resulting from a growing hydrogen economy has the ability to capitalise on excess renewable generation and smooth out demand. Figure 1 illustrates the concept. It shows a scenario where the rate of hydrogen production is modified across the day to follow the level of renewable generation available.

As the hydrogen production follows fluctuations of renewable wind and solar generation, the demand increases, on average, by the volume of reliable wind throughout the 24 hour period, and by the sum of the reliable wind and excess solar during daylight hours.

In the scenario, the peak demand on the grid does not increase substantially, and we maintain a load profile similar to the current load profile. However, with larger volumes of hydrogen production and other changes such as the growth of electric vehicles, this demand profile may change in the coming years. Demand throughout the 24 hour period may be multiples of the current demand, dwarfing current fluctuations across the day, if more opportunistic hydrogen production forecasts eventuate.

Figure 1 Simplified depiction of hydrogen load-following generation



Source: GHD, 2020

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Electricity networks and power systems can derive significant benefits by taking advantage of the controllable nature of hydrogen electrolyzers. However, the willingness of hydrogen proponents to provide these benefits depends on the incentives and potential revenue streams offered by energy markets and the associated costs to realise those streams.

We have reviewed the current market frameworks and reforms that are underway. Our research has found that there are no material barriers within electricity market frameworks and electricity rules that specifically support or detract from developing hydrogen production as a load or from the use of hydrogen as a fuel for power generation. There is, however, an opportunity for policymakers to consider making changes that will ensure hydrogen producers and hydrogen-based technologies interact positively with Australia's electricity systems as they evolve.

In the short-term, regulatory changes that will help ensure a supportive interaction between the hydrogen economy and the electricity network include:

- Changes that facilitate the registration of hydrogen facilities, including combined hydrogen production and electricity generation facilities, and
- Continuing to progress reforms that improve accessing transmission capacity and locational signals.

Once these opportunities are enabled, there are secondary benefits to the greater participation of electrolyzers and fuel cell technology in the electricity markets. These include changes to reform ancillary and essential services markets to better value the micro-interruptibility of hydrogen loads, enabling more variable renewable generation onto networks whilst enabling power system security¹⁶.

In the long-term, the effects of hydrogen production on the electricity systems are less clear. However the areas policymakers should be focused on are:

- Making changes to the regulatory approval process for network expenditure to ensure network developments are sufficiently responsive and keep pace with rapid changes to the market as hydrogen demand emerges supported by higher penetrations of variable renewables and to cater for the changing dynamic between supply and demand and the way networks will be used.
- Understanding and monitoring the interdependency of markets so that risks arising from the interdependency of markets can be managed appropriately. For example, as the electricity market becomes more reliant on gas-fired power generation, contingency events in the gas market become increasingly important for the electricity market to understand. Similarly, building awareness of cross-market solutions will increase the options available to solve emerging issues.
- Building national capabilities ahead of potentially significant market changes that will require a different mix of skills including new capabilities.
- Recognising and facilitating hydrogen pilot projects as short-term activities that enable longer-term insights and benefits for the electricity industry.
- Creating an environment that brings greater transparency and certainty over future electricity prices, to promote longer-term investment solutions. The transparency of future electricity prices is also particularly important for hydrogen facilities to enable the right investment decisions that leverage sector coupling opportunities.

¹⁶ Ancillary and essential service markets are significantly smaller than the electricity market. Information on the size of the frequency control ancillary services market in the NEM (the largest of Australia's markets for these services) is available on the AER website.

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Use-case scenarios

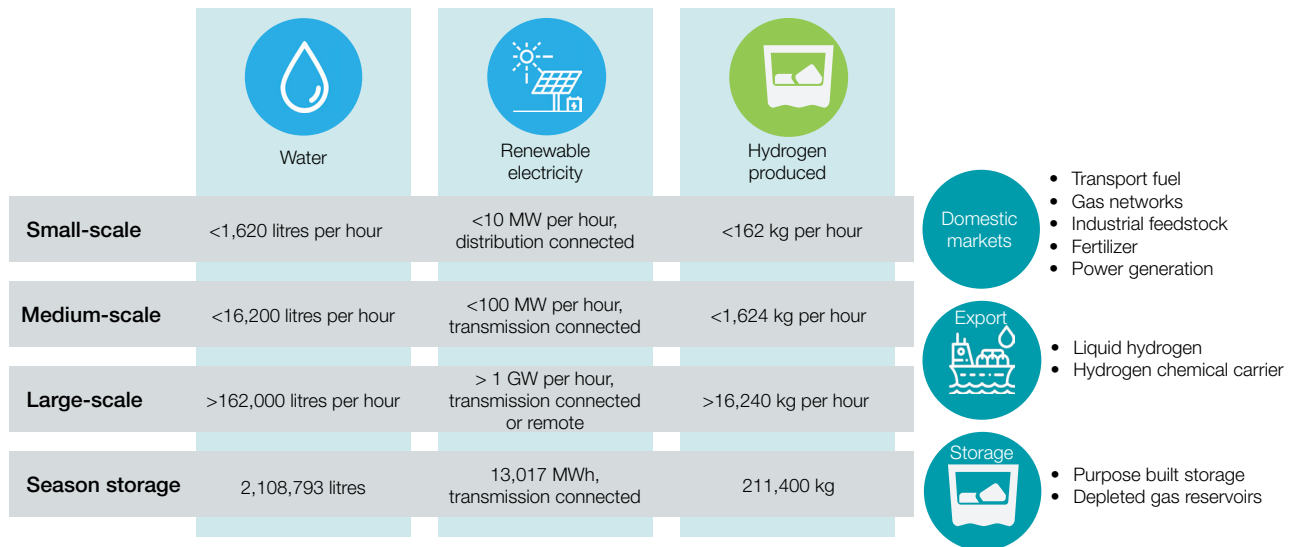
Four use-cases have been developed to illustrate the potential for opportunities for hydrogen facilities to deliver value through interaction with the power system.

The use-cases are differentiated by the size of the hydrogen plant and whether the plant connects to the transmission or distribution network. Each use-case has particular opportunities and challenges in addition to the common opportunities that have already been discussed.

While the use-case scenarios focus predominately on the interaction and considerations relating to electrical systems, in practice, producers of hydrogen will consider a range of factors when making investment decisions.

In particular, the siting of production facilities will be driven by type and location of demand, the transport options to deliver hydrogen to market, water required for production, and suitability of land for industrial production.

Figure 2 Summary of use-case scenarios



Note: Seasonal storage sufficient to store a day's output from all wind generation in South Australia¹⁷, assuming a 30% capacity factor.

Source: GHD, 2020

¹⁷ Existing, in-service wind generation in South Australia has a nameplate capacity of 1,807.95 MW. As per AEMO, 'Generation Information Page', accessed 5 February 2020, refer to 'Generation Information Page 20200131.xlsx'.

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Small-scale use-case scenario

Small-scale (<10 MW) hydrogen production facilities developed independently from renewable generation projects could be connected via a dedicated high voltage distribution feeder. The same connection option could support increased hydrogen production capacity (beyond 10 MW) if developed in combination with appropriately sized renewable generation.

A small-scale hydrogen production facility is relatively compact, which provides the opportunity for it to be located in light industrial areas. Land zoned for light industrial development within 10 km of an existing distribution substation could be ideal sites for small-scale hydrogen production.

Connecting small-scale hydrogen production facilities to substations with relatively high penetration of renewable generation could provide benefits to the electricity system by soaking up excess nearby rooftop PV, allowing the connection of additional renewable generation, minimising the need for export constraints on local renewable generators or network upgrades required to allow unconstrained operation of the local renewable generation.

Challenges for small-scale include the need to negotiate planning and development approvals with the relevant local authority, and the lack of transparency of locational and price signals at the distribution level for optimised hydrogen production profiles.

To realise these opportunities and overcome any potential barriers, recommended mitigations include:

- Knowledge sharing of network congestion locations at a distribution level: Increase the amount of information available on areas of network congestion and indicate where the additional controllable load would be beneficial in relieving congestion.
- Assessment of applications: Develop harmonised processes for the assessment of applications to develop small-scale hydrogen facilities.
- Incentivise controllable loads: Work with market participants to encourage the development of local markets providing price signals and mechanisms that incentivise the operation of controllable loads to help address local network issues.

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Medium-scale use-case scenario

The development of larger domestic markets, such as hydrogen as a transport fuel, will drive medium-scale hydrogen production that connects to existing transmission networks. By connecting to the transmission network, the quantities of power that medium-scale hydrogen production facilities can draw on are an order of magnitude greater than those afforded in the distribution network. In this use-case, we consider scenarios where the transmission connection will support electricity flows of 100s of MWs.

Transmission connected hydrogen producers may co-locate with renewable power generation, and opportunistically import or export power to the grid depending on relative energy prices, or may rely solely on the importation of power from the grid. Where the hydrogen producer imports power from the transmission network, the purchase will need to be supported by Power Purchase Agreements (PPA), new derivative instruments or alternative instruments that met the relevant certification schemes that enable the hydrogen to be classified as 'green'. While there are benefits that can be derived from co-locating hydrogen production and renewable generation, other factors such access to hydrogen transportation infrastructure, access to domestic demand or ports for exports and access to water for electrolysis are also important. These factors may favour locations near cities and ports or with relatively secure water access, such as those that are closer to the coast allowing seawater (combined with desalination or demineralisation) or locations allowing access to recycled water.

The unique opportunities for this scale of hydrogen production that also support the electricity system arise when the developments connect to shared electricity networks, rather than being developed in isolation of the existing shared networks. When this occurs, there is significant scope for generation following, ancillary and network support services to be provided in a way that is beneficial to the broader electricity market, while servicing hydrogen demand.

From a hydrogen production perspective, the connection to the network will enable production to be optimised over time with support from generators connected to the shared network (but who are remote from the production site). A connection to the network also allows for opportunistic take-up of alternative sources of revenue through ancillary service markets.

The unique factors for consideration to enable this use of hydrogen may include:

- Augmentations to the transmission network will be required to connect a hydrogen production facility consuming 100s of MW. Choosing the right location or coupling with new generation build should limit the extent of augmentation to either a new substation or expansion of an existing substation.
- To maximise the electricity market opportunities, facilities should be developed in areas with excess renewable generation capacity as this may also allow sharing of existing substations.
- Loads currently pay for the shared transmission network through the use of system charges. New loads may therefore only be asked to provide security over future transmission network charges (which will be recovered via network tariffs over the life of the project) rather than fund, upfront, the entire cost of the transmission network augmentation necessary to connect the load.

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Large-scale use-case scenario

To support the development of hydrogen exports, the future is likely to include large-scale hydrogen production where the capacity of electrolysis plants (and co-located generation) could exceed 1 GW.

The location of these large-scale developments will be driven by the availability of electricity input resources and the land requirements needed to support production, including renewable generation if co-located. Additionally, developers will be considering the availability of water sources, land use, surrounding community or social impacts, as well as the transport and logistics requirements (and costs) to deliver hydrogen to export markets.

The areas where these developments are most likely to arise will be away from developed metropolitan areas with access to sufficient water. A large-scale (1 GW) hydrogen production facility operating at full output will consume 3,888,000 litres of water per day (equivalent to the volume of water in 1.5 Olympic sized swimming pools). Accessing this volume of water may require development close to the coast to enable the use of seawater with desalination.

To meet the electricity requirements for large-scale hydrogen production, the developments could be co-located with significant quantities of renewable generation and operate in isolation from the electricity network. In this case, the systems will need to be electrically self-supporting. Alternatively, developments may be connected to the transmission network with the connection capacity sized to supply the entire electrolysis load from the grid. A third option that could be contemplated with hydrogen production facilities co-located with renewable generation, would see a grid connection with the capacity of the connection selected to optimise the value delivered by participating in the national electricity market and the cost of the connection.

The number of sites on existing electricity networks that can support large-scale production of hydrogen as a load drawing power in excess of 1 GW without significant augmentations is limited. Large-scale hydrogen producers relying solely on grid-supplied electricity may be able to 're-use' connections that previously supported closed power stations or aluminium smelters.

To realise these opportunities and overcome any potential barriers, recommended mitigations include:

- Identifying and aligning mutually beneficial interactions so that the developments do not emerge in isolation of the existing networks.
- Timely development of the transmission needed to support the connection to shared transmission networks represents a significant challenge within the current regulatory framework, particularly if it is to proceed as a regulated investment. While unregulated connection could be developed this will add significant costs to projects with investors needing to fund the capital cost of those connections.

Potential solutions to help facilitate connections to large-scale hydrogen production facilities include governments providing funding to support the development of the business case to justify any regulated network investment, this may include the cost of any works necessary to gain environmental and development approvals.

However, government support in these instances should focus on assisting developments that are likely to provide significant economic benefits and where generally changing regulatory arrangements are driving sub-optimal developments.

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Seasonal storage of renewable energy

Large-scale hydrogen storage could be used for storing seasonally variable renewable electricity. In this scenario, hydrogen will be produced during periods of excess electricity production and stored for conversion back to electricity or used for other means during periods of energy shortage or when price arbitrage opportunities exist.

Seasonal storage typically involves the storage of energy in one season and the release of the stored energy in a different season. In the UK and Norway, seasonal storage of this kind is attractive because there are significant differences in energy requirements between summer and winter months. However, seasonal storage can also refer to multi-annual storage and shorter-term storage of energy (such as several days).

In Australia, where the difference in energy requirements between seasons is less significant, storage that caters for shorter periods of energy deficit could be more appropriate. For example, storage facilities could be sized to cater for various electricity market contingencies, such as renewable resource droughts (several consecutive days with low wind and cloud cover) or failure of the largest generator.

Hydrogen storage has some advantages over both pumped hydro and large-scale batteries. Production of hydrogen (and conversion back to electricity) requires significantly less water than pumped hydro. The energy content of hydrogen is not lost when stored, so it has the potential to provide much longer-term energy storage solutions compared to batteries.

Hydrogen storage and conversion technology currently offers a significantly lower cycle efficiency than competing electricity storage technologies. Improving the cycle efficiency would enhance the commercial viability of this use-case.

The benefits to the electricity market from seasonal storage include reduced volatility of prices between seasons, increased energy security, and a significant opportunity to avoid waste of renewable power.

Seasonal storage will also make the electricity markets more resilient because hydrogen production can be ramped up or down, or converted back to electricity to meet peak electricity system needs and during periods when the grid is under pressure.

A storage facility need not only supply hydrogen for power generation. The same storage facility could provide hydrogen for transport, industrial and natural gas enhancement. As the different markets for hydrogen evolve and demand becomes clearer, the opportunity for owners of hydrogen storage facilities to arbitrage between markets will increase and is likely to positively influence the commercial feasibility of such investments.

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To realise these opportunities and overcome any potential barriers, recommended mitigations include:

- Investments in storage that support electricity grid resilience are likely to be significant. It is unlikely private industry will make these investments on their own. The government could help by:
 - Identification and feasibility of viable locations.
 - Demonstrating (quantifying) the benefits of increased energy security and electricity market resilience.
 - Quantifying the long-term energy storage required for various energy market contingencies and for emerging hydrogen markets (for example, transport, industrial), which will help appropriately sized storage facilities and allow investors to make better informed assessments.
- Develop long-term price signals from electricity markets that have not traditionally valued inter-seasonal saving of energy mainly because options to do this were not available.
- Continued research and development focused on improving the cycle efficiency of the technology used for the creation of hydrogen from electricity and the conversion of hydrogen to electricity.

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Conclusion

Electrolyser technologies used for the production of hydrogen have the capacity to deliver significant benefits because they are capable of adjusting the level of hydrogen production such that the electricity consumed matches the amount of renewable generation that is produced (i.e. load that follows generation).

Our review of international practice has identified several projects that demonstrate the ability for hydrogen production and storage facilities to provide generation following and frequency control services. Those capabilities could assist power systems across Australia to reach carbon emission reduction targets while maintaining system security and reliability.

The willingness of hydrogen proponents to provide generation following benefits to the electricity market depends on the incentives and potential revenue streams offered by these markets and the associated costs to realise those revenue streams.

Our research has found that there are no material barriers within energy markets and electricity rules that specifically support or detract from developing hydrogen production as a load or from the use of hydrogen as a fuel for power generation. Several market reforms are underway that offer the potential to enhance opportunities for hydrogen production facilities to derive value from participation in the electricity markets, including:

- In the NEM reforms being discussed as part of the coordination of generation and transmission investment (CoGaTi) review, offer the potential to provide better locational prices, which could enhance the ability for hydrogen production facilities to extract value from operating to relieve network congestion.
- Various reforms are proposed for the WEM including reforms to introduce an enhanced framework for the provision of essential system services. Those reforms could enhance the opportunity for hydrogen production facilities to derive value from providing essential system services such as frequency control services.

Once generation following opportunities are enabled, there are secondary benefits to the greater participation of electrolysers and fuel cell technology in the electricity markets. These include changes to reform ancillary and essential services markets to better value the micro-interruptibility of hydrogen loads, enabling more variable renewable generation onto networks whilst enabling power system security¹⁸.

The following actions are recommended to ensure that if and when ancillary service frameworks are established they provide opportunities for hydrogen projects:

- As reforms in the WEM to develop ancillary services markets (the Western Australian government refers to these as essential services markets¹⁹) are progressed, the market design and service specification should be technology neutral which will ensure revenue streams from the provision of these services are accessible to hydrogen proponents (if they can provide services competitively).
- If the introduction of ancillary services or essential services markets are considered for the Darwin–Katherine system, the framework should adequately cater for the characteristics of electrolysers as a micro-interruptible load to open up new revenue streams for market participants, including any future hydrogen proponents.

¹⁸ Ancillary and essential service markets are significantly smaller than the electricity market. Information on the size of the frequency control ancillary services market in the NEM (the largest of Australia's markets for these services) is available on the AER website here: https://www.aer.gov.au/wholesale-markets/wholesale-statistics?f%5B0%5D=field_accr_aer_stats_category%3A1076

¹⁹ Not to be confused with the Essential Services Commissions (technical regulators) in Victoria and South Australia.

Executive Summary

In the long-term, the effects of hydrogen production on the electricity systems are less clear, however **the areas policymakers should be focused on are:**

- Making changes to the regulatory approval process for network expenditure to ensure network developments are sufficiently responsive and keep pace with rapid changes to the market as hydrogen demand emerges supported by higher penetrations of variable renewables and to cater for the changing dynamic between supply and demand and the way networks will be used.
- Understanding and monitoring the interdependency of markets so that risks arising from the interdependency of markets can be managed appropriately. For example, as the electricity market becomes more reliant on gas-fired power generation, contingency events in the gas market become increasingly important for the electricity market to understand. Similarly, building awareness of cross-market solutions will increase the options available to solve emerging issues.
- Building national capabilities ahead of potentially significant market changes that will require a different mix of skills including new capabilities.
- Recognising and facilitating hydrogen pilot projects as short-term activities that enable longer-term insights and benefits for the electricity industry.
- Creating an environment that brings greater transparency and certainty over future electricity prices, to promote longer-term investment solutions. The transparency of future electricity prices is also particularly important for hydrogen facilities to enable the right investment decisions that leverage sector coupling opportunities.

Despite the increased attention on hydrogen, markets are still in their infancy, which means it is difficult to forecast or understand the full effect of future changes.

To understand the full requirements from the electrical systems to supply power for hydrogen production, we recommend analysis on the impact of hydrogen on electricity systems be revisited periodically as the market dynamics in the electricity market and energy markets continue to evolve.

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Disclaimer

This report has been prepared by GHD and ACIL Allen (working jointly) for the Department of Environment, Land, Water and Planning and may only be used and relied on by Department of Environment, Land, Water and Planning for the purpose of developing the 'hydrogen to support electricity systems' work stream that is informing the development of the Council of Australian Government's National Hydrogen Strategy.

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Chapter 1 | Introduction

1 | Introduction

As part of the preparation of a National Hydrogen Strategy, the Council of Australian Government (COAG) Energy Council established the Hydrogen Working Group and commissioned six work streams to inform aspects of the development of the Strategy.

GHD Advisory and ACIL Allen were commissioned to deliver the 'Hydrogen to support electricity systems' stream. This piece of work investigates, through a literature review the future role that hydrogen could play in supporting Australia's power systems, and seeks to:

- Better understand if the current electricity regulatory frameworks are supportive of the development of a green hydrogen industry, and
- Make suggestions that will enable positive interactions between a developing hydrogen industry and Australia's electricity systems.

In this report we focus on the opportunities and challenges for hydrogen producers and the electricity market from the development of hydrogen production facilities utilising electricity from renewable generators.

We focus on the production of hydrogen from renewable electricity generation using electrolyser technology.

The report considers the potential electricity input requirements needed from Australia's power systems to support a growing hydrogen economy and the opportunity for the integration of hydrogen facilities to provide power system benefits.

1.1 Background

In December 2018, the COAG Energy Council committed to a vision of making Australia a major player in the global hydrogen industry by 2030²⁰. COAG Energy Council approved a high-level work plan and established the Hydrogen Working Group to develop a national strategy to:

- Build a clean, innovative and competitive hydrogen industry, and
- Position Australia's hydrogen industry as a major global player by 2030²¹.

The Hydrogen Working Group consulted on topics raised in nine Issues Papers and subsequently released the National Hydrogen Strategy in November 2019²².

1.2 Purpose of report

The National Hydrogen Strategy identifies the important role hydrogen could play in supporting Australia's electricity systems and the opportunity to produce clean hydrogen from renewable power sources.

This purpose of this report is to investigate the potential of hydrogen to contribute to the resilience of electricity markets and power systems and assess required regulatory changes that will facilitate hydrogen's support of the electricity system and vice versa.

²⁰ COAG Energy Council, 'Establishment of the Hydrogen Working Group of the COAG Energy Council', updated 19 December 2018, accessed 5 August 2019, refer to: <http://www.coagenergycouncil.gov.au/publications/establishment-hydrogen-working-group-coag-energy-council>

²¹ Department of Industry, Innovation and Science, 'COAG Energy Council Hydrogen Working Group', accessed 3 August 2019, refer to: <https://www.industry.gov.au/about-us/what-we-do/coag-energy-council-hydrogen-working-group>

²² Available at: <https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy>

1 | Introduction


1.3 Structure of this report

The remainder of the report is structured as follows:

- Chapter 2 provides context for our review. We outline the ways hydrogen interacts with the electricity systems and provide an overview of available technology that forms the focus for the report.
- Chapter 3 presents the findings of our review of the international literature on the use of hydrogen to support electricity systems.
- Chapter 4 provides an overview of Australia's power systems and our assessment of the opportunities for hydrogen.
- Chapter 5 considers the role of hydrogen and its potential to extract value from sector coupling.
- Chapter 6 identifies the uses of hydrogen to support the electricity system.
- Chapter 7 outlines four use-case scenarios and draws out opportunities and challenges unique to each.
- Chapter 8 presents our key conclusions.

The report is supported by three appendices:

- Appendix A provides a list of the acronyms and abbreviations used in the report,
- Appendix B summarises the characteristics of electrolyser technologies currently available in the market, and
- Appendix C provides a list of the literature reviewed which informs this report.



Chapter 2 | Overview of technology

2 | Overview of technology

The interaction of hydrogen with Australia’s power systems primarily stems from the use of electricity to produce hydrogen by electrolysis, and from hydrogen to power applications where hydrogen is used to produce power or heat (fuel switching).

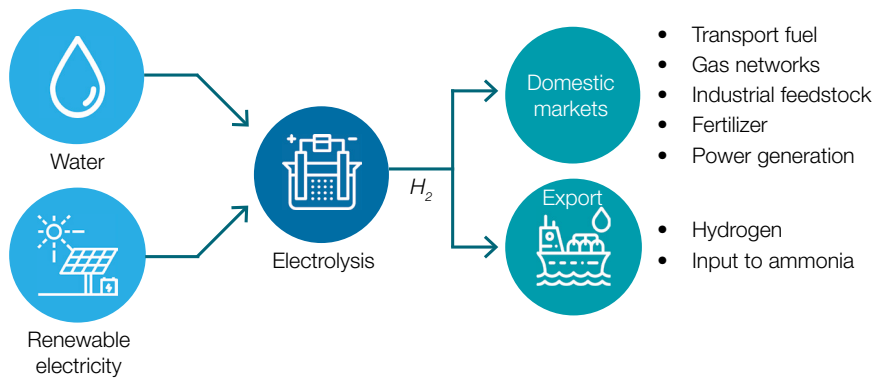
The figure below provides a simplified overview of the processes considered in this review.

In this paper, we concentrate on the use of electrolysis for hydrogen production, as this has the largest effect on power systems and markets.

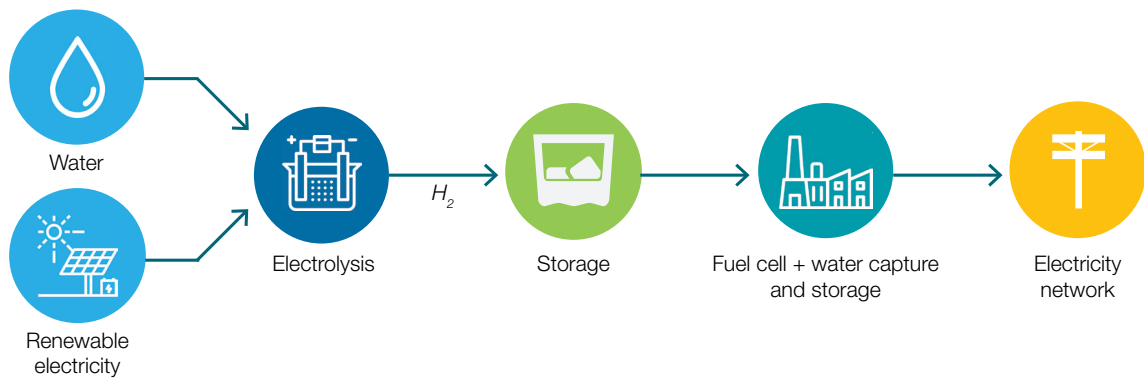
Noting that while there will be some electricity requirements associated with systems and services supporting fossil fuel-based hydrogen however these are not a direct input to production.

Figure 3 Overview of processes that form the focus of this report

Power + water → **electrolysis** → **store hydrogen** → **convert hydrogen back to electricity**



Power + water → **electrolysis** → **store hydrogen** → **convert hydrogen back to electricity**



Source: GHD, 2020

2.1 Technology that converts electricity to hydrogen

Three types of electrolyser technologies are commonly available: alkaline electrolysers (AE), polymer electrolyte membrane (PEM) electrolysers and solid oxide electrolysis cells (SOEC). AE and PEM are relatively mature technologies, while SOEC are yet to be commercialised²³. A summary of the characteristics of each of these technologies is provided in Appendix A.

²³ AE technology has been in commercial use since the 1920s, and PEM technology has been in use since the 1960s. SOECs, which promise higher electrical efficiencies than AE and PEM technologies, are beginning to enter the market. To date, electrolyser sizes for SOECs installed projects have been no higher than 10 MW (with modules of 2 to 4 MW), and generally much smaller.

Source: IEA, The Future of Hydrogen, June 2019, pp. 43-35.

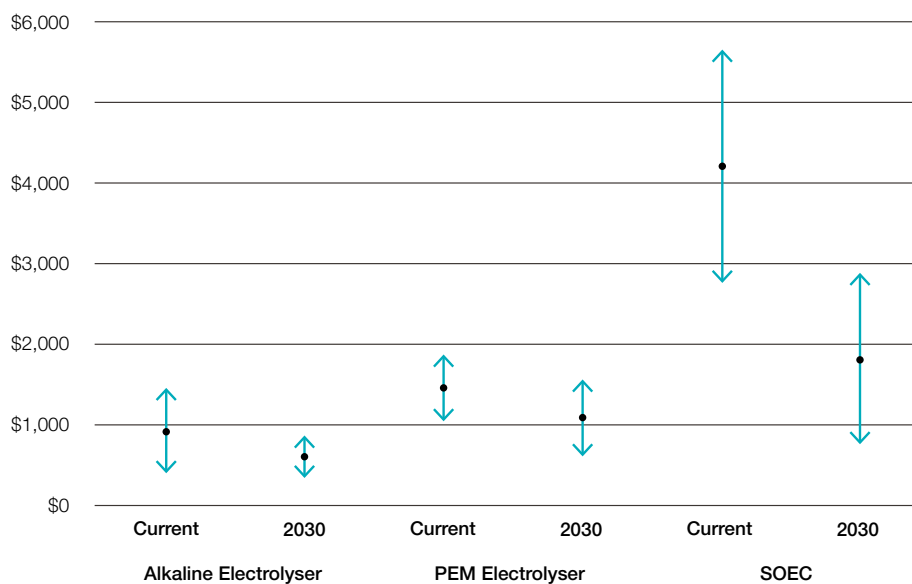
2 | Overview of technology

From an electricity systems perspective, the ability of a particular technology to provide a fast dynamic response to fluctuations in electricity inputs offers significant value. PEM technology offers faster dynamic response times and across a wider load ranges compared to AE technology²⁴.

Developments in SOEC technology is also important to the electricity industry. Unlike with AE and PEM technology, it is possible to operate a SOEC in reverse as a fuel cell, converting the hydrogen back into electricity. As such, this technology could provide balancing service to the grid in combination with hydrogen storage facilities²⁵.

While the technology used to produce hydrogen from renewable power is mature, it is not yet competitive compared to the production of hydrogen from thermal pathways using fossil fuels. However, there is increasing hydrogen-related investment by manufacturers of electrolyzers. As this occurs, we expect costs associated with this technology to fall and for the use of electrolyzers to produce hydrogen to become more competitive. Figure 4 shows the current and projected capital cost of electrolyser technology (US\$) for 2030.

Figure 4 Current and projected capital costs of electrolyser technology (US\$ per kWe)



Source: IEA, *The Future of Hydrogen*, June 2019, pp. 43-35.

The carbon emissions intensity of hydrogen production using electrolysis will depend on the source of electricity on which the electrolysis is based. For example, using renewable energy will produce no carbon emissions²⁶, while using grid-based electricity would produce 40.4 kg of CO₂-e per kilogram of hydrogen²⁷.

²⁴ CSIRO, National Hydrogen Roadmap – Pathways to an economically sustainable hydrogen industry in Australia, pp. 13.

²⁵ IEA, *The Future of Hydrogen*, June 2019, pp. 44.

²⁶ Based on scope 1 and 2 emissions as defined under the National Greenhouse and Energy Reporting Act 2007.

²⁷ COAG Energy Council, Australia's National Hydrogen Strategy, November 2019

2 | Overview of technology

2.2 Technology that converts hydrogen to electricity

Hydrogen can be used to create electricity using either fuel cells or gas turbine technology. We focus on hydrogen fuel cell technology that generates electricity by a chemical reaction.

Similar to electrolyzers, fuel cells are modular and have no moving parts so are more reliable than rotating plant generating technologies such as reciprocating engine generating sets and gas turbines. SOEC technology when applied to produce electricity is often referred to as hydrogen fuel cells (also known as solid oxide fuel cell (SOFC)). SOFC have two electrodes: the anode and the cathode respectively, an electrolyte which carries electrically charged particles from one electrode to the other and a catalyst to speed the reactions at the electrodes.

The inputs to the fuel cell are hydrogen and oxygen. The outputs from the fuel cell are electricity, water and heat. The fuel cell is more efficient (approximately 60 per cent efficiency) than the conventional thermal power generating units that utilise Rankine or Brayton thermodynamic energy conversion cycles. The efficiency of all cycles are improved if the heat generated is utilised, such as in co-generation facilities or for gas turbines, through the use of a heat recovery steam generator and steam turbine – closed cycle gas turbine plant.

For the industrial-scale²⁸ generation of electricity from hydrogen using fuel cells, there are some limitations that need to be observed, namely that they require very high purity of hydrogen, are currently relatively expensive, and have a relatively short lifetime (eight years for a stationary baseload operation).

2.3 Hydrogen storage for electricity

Unlike other forms of electrical energy storage, hydrogen can be stored for long periods without significant losses in energy content. It can also be discharged relatively quickly compared to other energy storage systems.

Table 1 (below) summarises the characteristics of electrical energy storage technologies that can currently provide large amounts of electrical power on demand (of at least 20 MW). Technologies differ significantly with respect to the amount of energy that can be stored and the discharge time, which is the time over which they can produce power before the energy storage is depleted. The lower efficiency ratings of hydrogen compared to with other, more mature technologies such as batteries and pumped hydro, is an impediment to it's use as an energy storage solution. The overall cycle efficiency for hydrogen is currently 20 to 30 per cent as compared with 80 per cent for pumped hydro or 90 per cent for batteries.

Table 1 Characteristics of selected energy storage systems

| | Power Rating (MW) | Discharge time | Max cycles or lifetime | Efficiency ²⁹ |
|-----------------------|-------------------|----------------|-------------------------|--------------------------|
| Pumped hydro | 3,000 | 4 h – 16 h | 30 – 60 years | 70 – 85% |
| Compressed air | 1,000 | 2 h – 30 h | 20 – 40 years | 40 – 70% |
| Molten salt (thermal) | 150 | hours | 30 years | 80 – 90% |
| Li-ion battery | 100 | 1 min – 8 h | 1,000 – 10,000 cycles | 85 – 95% |
| Lead-acid battery | 100 | 1 min – 8 h | 6 – 40 years | 80 – 90% |
| Flow battery | 100 | hours | 12,000 – 14,000 cycles | 60 – 85% |
| Hydrogen | 100 | mins – week | 5 – 30 years | 20 – 30% |
| Flywheel | 20 | secs - mins | 20,000 – 100,000 cycles | 70 – 95% |

Source: The World Energy Council, February 2019 as cited at: <https://www.eesi.org/papers/view/energy-storage-2019>; (a) Hydro Tasmania, Battery of the Nation – Pumped Hydro Energy Storage Projects - Prefeasibility Studies Summary Report, August 2019, p.20

²⁸ By industrial-scale, we are referring to plant is generally considered to have a capacity of 10 MW or above.

²⁹ Efficiency considers energy losses incurred during the conversion of electricity for storage and the conversion of stored energy into electricity.

2 | Overview of technology

Improvements in technology, including increased electricity and cycle efficiency, are expected as research continues. However, electrolyzers, cryogenic hydrogen storage, and to a lesser degree, hydrogen-powered generation, are mature technologies. The modular nature of electrolyser and fuel cell technologies also limits the ability for this technology to achieve economies of scale that might otherwise improve the efficiency rates.

The IEA expects efficiency rates for electrolyzers used to convert electricity to hydrogen to marginally improve between now and 2030 (Table 2). However, it is difficult to see the complete cycle efficiency for hydrogen production/storage/generation combinations to approach the 80 to 90 per cent seen by battery/inverter systems and pumped hydro energy storage systems in the near future.

Table 2 Electrical efficiency of electrolyser technologies

| | | Alkaline electrolyser | PEM electrolyser | SOECs |
|----------------------------------|------|-----------------------|------------------|--------|
| Electrical efficiency (%,LHV) | Now | 63-70% | 56-60% | 74-81% |
| | 2030 | 65-71% | 63-68% | 77-84% |

Notes: LHV = lower heating value. Source: IEA, *The Future of Hydrogen*, June 2019, pp. 43-35.

2.4 Scaling of modular technology

Electrolyser and fuel cell technologies are modular and readily scalable as capacity needs increase. While modular technology does not offer the same economies of scale advantages as non-modular technology, it has the advantage of de-risking investments because investors can progressively scale-up production as demand emerges, rather than making much larger upfront investments.

If electrolyser and fuel cell technologies are adopted as the hydrogen economy scales-up, interactions with the electricity market will be gradual and cumulative, accelerating as individual sites increase capacity to meet demand, rather than representing a step-change for the market (which may occur if the technology was not modular).



Chapter 3 | International experience

3 | International Experience

The primary driver for the renewed interest in hydrogen internationally is the potential role that it can play (in addition to solar and wind energy) in helping to decarbonise energy systems.

Currently, only a few electricity to hydrogen projects are operating around the world. These are mainly pilot or demonstration projects that seek to test the technical/commercial viability of the various technologies involved.

The overarching objective of these projects is to encourage uptake of the technology, as critical mass for usage is essential for fostering economies of scale and decreasing average costs of using the technology.

Below we examine three projects that support the utilisation of hydrogen in electricity systems:

- The INGRID project in Italy demonstrated the technical feasibility of using a hydrolyser³⁰ powered by renewable energy to provide frequency control services.
- The EnergiePark project in Mainz, Germany provided an illustration of some of the regulatory issues that have arisen for a hydrogen project in Germany. This project too demonstrated that PEM technology was able to respond quickly enough to enable the plant to provide ancillary services. While this project was developed for research, the partners in the project have announced that they plan to continue to operate it.
- The HyStock Green Hydrogen Park, in Veendam, Netherlands shows the benefits of co-locating two renewable energy sources (solar and wind) with underground hydrogen storage that provides a buffer capacity. The project delivered electricity to the high-voltage electricity grid and the Park's buffer capacity is also connected to the main gas network, demonstrating how existing power and gas systems can work to support these types of projects

These three projects were selected based on there being sufficient information on each such that they could inform thinking about what Australia might do to enable hydrogen to play a role in supporting off and on-grid electricity systems, however the availability of information differed for each project.

³⁰ A hydrolyser is a form of electrolyser that uses water as the medium. Throughout this report references to electrolysers assume water as the medium.

3 | International Experience

3.1 The INGRID project, Italy

The INGRID project³¹, located in Italy, is an EU demonstration pilot project established to examine the feasibility of using electricity produced from renewable energy (wind and solar) to produce hydrogen and use it for grid balancing.

The project consisted of a 1.2 MW electrolyser, a 60 kW hydrogen fuel cell, a one-tonne hydrogen storage system and instrumentations, control and telecommunication (ICT) control systems for real-time monitoring and control.

The project had eight partners from four countries: Engineering Ingegneria Informatica (coordinator), ARTI Puglia, e-distribuzione, RSE – Ricerca sul Sistema Energetico and Studio Tecnico BFP (Italy); McPhy Energy (France); Hydrogenics (Belgium) and TecNALIA (Spain).

The objectives of the project were:

- To investigate the feasibility of using hydrogen production to balance the grid³² and allow increasing amounts of variable generation from renewable energy.
- To improve the stability of the distribution system through active/reactive power control for voltage regulation and improving power quality

The hydrogen produced by the project was intended to be used in the transport sector, by industry, injection into the gas network and for grid balancing. The project began in 2013 and was completed in 2018.

The project participants have expressed satisfaction with the ability of the energy management system and the ICT control system to match the output from the demonstration plant to that specified in various scenarios.

3.1.1 Regulatory issues identified

None were identified. However, as a demonstration project designed primarily to test the technical feasibility of using hydrogen in the ways described above, there was no intention to operate the plant as a system connected to the grid.

3.1.2 Project cost and funding support provided

The project received funding under the EU's Seventh Framework Program (7FP). We were not able to find information on what proportion the funding was of the total cost of the project.

3.1.3 Learnings for Australia

- The technology proved to be technically capable of providing frequency control services.
- Multiple partners were involved in the project.

³¹ Refer to: http://www.ingridproject.eu/INDEX.PHP?OPTION=COM_CONTENT&VIEW=CATEGORY&LAYOUT=BLOG&ID=10&ITEMID=206

³² Maintaining the balance between electrical load and power generation is essential for secure power system operation.

3 | International Experience

3.2 The EnergiePark project, Mainz, Germany

The plant at EnergiePark³³ Mainz was built as a research facility and opened in September 2015. It was designed to provide ancillary services for a local power grid, to examine the possibilities associated with the use of large-scale PEM (Proton Exchange Membrane) electrolyzers.

The plant consists of a 6 MW electrolyser with an output of almost 90 kilograms of hydrogen an hour. The electrolyser is connected to an 8 MW wind farm. The hydrogen produced was pressurised to 8 MPa and stored in a one-tonne capacity tank.

The objectives of the project were to produce and store hydrogen using electricity from the variable wind farm. The hydrogen was pressurised and stored in tanks. The aim was to use the hydrogen to supply a nearby chemical industry or hydrogen refuelling stations via tanker delivery. A third potential use was to inject the hydrogen into the gas grid. The research project also was intended to test whether the hydrogen from the project could be used to fuel a nearby steam turbine power plant.

The partners in the project were:

- Hochschule Rheinmain (The RheinMain University of Applied Sciences).
- Siemens AG – The firm supplies hydrogen electrolysis systems based on PEM technology.
- The Linde Group – This firm is a multinational gases and engineering company.
- Mainzer Stadtwerke AG – The sole shareholder of this municipal utility is the German city of Mainz.

The project sourced electricity for its electrolyzers in three ways: from the European Power Exchange; surplus power from the connected wind farm; and by participating in the 'market for control reserve'. The latter approach proved to be the most economically viable. In March 2018 the partners announced that they would continue to operate the project in the long-term.

3.2.1 Regulatory issues identified

The regulatory framework was identified as a key issue. Various surcharges on electricity were also mentioned as barriers. The ability to capture a cost premium for the hydrogen produced was also mentioned. The transport sector was identified as an end-user where a cost premium could potentially be obtained.

When announcing the decision to continue to operate the project, the project partners called for governments to set appropriate frameworks for the systematic and market-oriented use of storage and 'power-to-X' technologies. Examples mentioned were eliminating market barriers such as end-user levies and allowing hydrogen used for transport to be credited against the greenhouse gas emissions.

³³ M. Kopp, Et Azl, 2017, EnergiePark Mainz: Technical and Economic Analysis of the Worldwide Largest Power-to-Gas Plant with PEM Electrolysis, International Journal of Hydrogen Energy, 42, 13311 – 13320; and <https://www.energiepark-mainz.de/EN/>

3 | International Experience

3.2.2 Project cost and funding support provided

The project cost around €17 million. About half the cost of the project was provided by Germany's Federal Ministry for Economic Affairs and Energy within the framework of its "Förderinitiative Energiespeicher" (Energy Storage Funding) initiative. The plant was also exempted from tax on electricity (for raising revenue to support renewable generation) and grid use fees.

3.2.3 Learnings for Australia

- Providing frequency control services may be an important means of generating revenue.
- PEM technology proved to be able to respond quickly enough to enable the plant to provide ancillary services.
- The partnership of government, industry and the research sector has been successful.

3.3 HyStock Green Hydrogen Park, Veendam, Netherlands

The HyStock³⁴ 1 MW power plant was officially opened on 26 June 2019. It is located near Groningen with an adjacent 1 MW solar field and nearby wind farms in the North Sea. The plant is the first step in creating a hydrogen supply chain.

This power-to-gas installation is an important step in scaling up power-to-gas technology. EnergyStock is a partner in the HyStock project. EnergyStock operates a nearby underground gas storage facility which will provide buffer capacity and connection with the main gas and electricity infrastructure.

The north Netherlands area is ideally suited to the production of hydrogen, with access to both wind and solar renewable energy, hydrogen storage capacity and grid connection extending from the Netherlands into Scandinavia and Germany.

Installation started at the end of 2018. The 1 MW solar field consisting of approximately 12,500 solar panels is located at EnergyStock's site, with approximately 4,500 panels dedicated to the HyStock project.

The other 8,000 panels will be used to improve the 'green credentials' of the energy consumption of the gas storage facility. EnergyStock can store large quantities of blue and green hydrogen in salt caverns.

³⁴ World Energy Council, Bringing the North Sea Energy Ashore Efficiently, 2017; and EnergyStock, 'The hydrogen project HyStock', 2019, accessed 30 July 2019, refer to: <https://www.energystock.com/about-energystock/the-hydrogen-project-hystock>

3 | International Experience

Most of the renewable energy (88 per cent) is delivered to the HyStock project via TenneT's high voltage electricity grid, enabling energy conversion between the high voltage electricity network and the gas transmission network. In addition, a compressor fills cylinders with hydrogen so that it can be transported to end users.

The partners in the project are:

- Gasunie – a company owned by the Netherlands Government
- EnergyStock – a subsidiary of Gasunie and operator of the gas storage facility
- TenneT – operates a high voltage grid that supplies 41 million people in northern Europe

3.3.1 *Regulatory issues identified*

Although no regulatory issues have been identified, it was reported in 2017 that there were no harmonised rules specifically relating to hydrogen and power-to-gas technology in the EU. Different laws apply in individual members' states.

The EU's Clean Energy Package does include initiatives towards a harmonised approach to power-to-gas technology. For example, a new definition of energy storage has been developed and a principle that, to avoid double pricing and taxation, a generator that integrates a storage facility at its location should not be discriminated against in the energy system, neither in terms of obligations nor in terms of eventual support that it receives in the energy system.

The revised Directive in the Clean Energy Package recognises a key role for demand-side and load management. Power-to-gas technology operators will be instructed by the grid operator to provide up or down responses for grid services, including frequency balancing services payments across the EU.

3.3.2 *Project cost and funding support provided*

The HyStock project was co-financed by the EU. It has not been possible to identify information on project costs, or the share of funding provided by the different partners in the project.

3.3.3 *Learnings for Australia*

This project shows the benefits of co-locating two renewable energy sources with underground hydrogen storage and good high voltage electricity network connections. Having two sources of renewable energy, grid connection and storage enables more continuous operation of the electrolyzers and should improve the economics of the project.

3 | International Experience

Conclusions

The literature review identified several international projects that demonstrate the potential for integration of hydrogen and power systems. Several countries have already completed pilot/demonstration projects (e.g. for transport), and there are a growing number of power-to-gas projects that are now 'quasi-commercial' (noting that they have been operating with government support or incentives).

Most power-to-gas systems currently described in the literature³⁵ are producing hydrogen to blend into natural gas networks or to generate methane³⁶, even though this provides generally only a modest return on investment.

The case studies have provided several learnings that Australia should draw upon as it seeks to develop its own hydrogen sector. These include:

- Most overseas projects have involved a partnership of government, industry and the research sector. Partners are often technology providers that can bring the required skills and experience to the project.
- The PEM power-to-gas technology has proved itself technically capable of responding quickly enough to provide generation following and frequency control services. However, this can occur only if the market structures and regulations allow power-to-gas plants to extract sufficient value from providing these services.
- The hydrogen produced by a power-to-gas plant can have many uses. The key is to find an end-use that has the most value and hence can attract a cost premium. This suggests that regulation should allow the maximum possible flexibility for projects to help them to make a return on investment.
- Certification schemes could help to establish a market for clean Australian hydrogen. Conversely, a failure to establish such a scheme could threaten Australia's ability to export hydrogen where customers require this hydrogen to be clean.
- The experience of other countries suggests that direct government investment may be required if it is in Australia's commercial and social interest to keep up with other advanced countries in adopting hydrogen as an energy carrier.

³⁵ See Wulf C, Linßen J and Zapp P 2018, Review of Power-to-Gas Projects in Europe, Energy Procedia 155, 367-378

³⁶ Quarton CJ and Samsatli S 2018, Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling, Renewable and Sustainable Energy Reviews, 98, 302-316

The image features a series of high-voltage power transmission towers, also known as pylons, silhouetted against a vibrant sunset sky. The sky transitions from a deep orange near the horizon to a pale purple at the top. The towers are constructed from a complex lattice of steel beams and are supported by multiple cross-arms. Numerous power lines stretch across the frame, connecting the towers. The foreground shows the dark silhouettes of trees and foliage, suggesting the towers are situated in a natural, possibly rural, environment. The overall composition is vertical, emphasizing the height and scale of the infrastructure.

Chapter 4 | Australia's power systems

4 | Australia's power systems

Australia's power systems comprise electricity generation, transmission and distribution infrastructure used to produce, transmit and distribute electricity to end-use customers. The system includes several interconnected networks, as well as embedded and remote power systems.

In this section, we provide an overview of the major power systems across Australia and the opportunities each presents for hydrogen production.

4.1 National Electricity Market

The National Electricity Market (NEM) incorporates approximately 40,000 kilometres of transmission lines connecting five regional market jurisdictions in eastern Australia.

The exchange of electricity between generators and retailers is facilitated by trading through the NEM's wholesale market mechanism. The wholesale market operates around a common pool, or spot market, for wholesale trading in physical electricity.

The National Electricity Rules (NER or Rules) govern the operation of the NEM. The Rules are made by the Australian Energy Market Commission (AEMC) under the National Electricity Law and have the force of law. The Australian Energy Market Operator (AEMO) and registered energy market participants are required to operate in accordance with the Rules. In making the Rules, the AEMC is required by law to ensure Rules meet the National Electricity Objective.

The National Electricity Objective as stated in the National Electricity Law is “to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- (a) Price, quality, safety, reliability and security of supply of electricity,
- (b) The reliability, safety and security of the national electricity system.”

4.1.1 NEM energy market

The NEM supplies around 10 million customers with about around 205 terawatt-hours (TWh) of electricity each year³⁷.

More than 250 large-scale power stations are connected to the NEM and sell electricity into the wholesale market. The total electricity generating capacity, including solar PV, for the NEM in 2018-19 was 60,839 MW in 2018-19³⁸. A further 7,052 MW of committed generation expected to come online shortly; however, 2,688 MW of capacity has been announced by its owners as withdrawing from the NEM by 2050 (the majority by 2023)³⁹.

While other generators are yet to announce committed retirement plans, AEMO has identify approximately 16 GW of capacity that could be expected to leave the NEM by 2050 assuming generation retires when it reaches 50 years of age⁴⁰.

³⁷ AER, State of the Energy Market Report 2019 Data Update, November 2019, refer to: 'State of the energy market – Data update – Chapter 2 National electricity – November 2019.xlsx'

³⁸ Ibid.

³⁹ AEMO, 'Generation Information page', accessed 20 July 2019, refer to: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>

⁴⁰ AEMO, "Observations: Operational and market challenges to reliability and security in the NEM", March 2018, refer to: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.

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The peak Operational Demand⁴¹ in the NEM for summer FY2018-19 was 37,997 megawatts (MW)⁴². The following table shows the maximum and average demand for jurisdictions in the NEM for 2018 and the installed, committed and generation to be withdrawn as of July 2019.

Table 3 Demand and generation capacity in the NEM, by jurisdiction

| Demand / Capacity | Region | | | | |
|---|--------|--------|-------|-------|--------|
| | NSW | QLD | SA | TAS | VIC |
| Maximum demand (MW) (Operational Demand) ¹ | 13,861 | 10,179 | 3,244 | 1,395 | 9,318 |
| Installed capacity (MW) ² | 17,479 | 14,585 | 5,858 | 2,988 | 12,078 |
| Committed generation (incl. upgrades) (MW) ² | 3,311 | 1,100 | 452 | 265 | 2,118 |
| Generation to be withdrawn (MW) ² | 2,000 | 0 | 480 | 208 | 0 |

Sources: 1) AEMO seasonal peak demand by region⁴³ 2) AEMO, 'Generation Information page', accessed 20 July 2019 does not include roof top PV.

Some key features of the NEM that distinguish it from other electricity markets around the world include:

- The NEM is a real-time market with the price of electricity set at the time of dispatch. An electricity price is determined every five minutes. The NEM does not include any market that is settled ahead of dispatch.
- The NEM is a gross pool meaning all energy is traded through the spot market
- The NEM is an energy-only design with the spot price allowed to vary widely between a floor price of -\$1,000 per MWh and a cap price of +\$14,200 per MWh. There is no capacity market.
- The frequency control ancillary service markets are co-optimised with the energy markets

The above factors contribute to wholesale electricity price volatility in the NEM being high compared to other markets.

⁴¹ Operational Demand in a region is demand that is met by local scheduled generating units, semi-scheduled generating units, and non-scheduled intermittent generating units of aggregate capacity ≥ 30 MW, and by generation imports to the region. It excludes the demand met by non-scheduled non-intermittent generating units, non-scheduled intermittent generating units of aggregate capacity <30 MW, exempt generation (e.g. rooftop solar, gas tri-generation, very small wind farms, etc.), and demand of local scheduled loads.

Source: AEMO, 'NEM Data Dashboard', accessed 20 August 2019, refer to: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard#operational-demand>.

⁴² AER, 'AER_Regional peak demand_1_2019070914230 AEMO.xlsx', 9 July 2019, accessed 20 August 2019.

⁴³ Ibid

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4.1.2 Opportunities for hydrogen

Most parts of the NEM, close to major urban load centres, are considered 'well-meshed' meaning there are multiple interconnected power network paths to a particular point such that if one path is affected by an outage or fails, there are alternative supply points. These areas offer potential hydrogen producers a high security of supply and can support 24/7 production.

Other areas of the NEM, including in northern Queensland and in parts of South Australia (e.g. the Eyre Peninsula), north-west Victoria and western New South Wales are more loosely connected and may consist of a single or twin radial line.

In these areas, power flow may be constrained or curtailed in instances of network faults and the security of power supply is lower. For hydrogen producers to connect to the transmission or distribution networks in these areas, upgrades to the network may be required or co-location of renewable generation may be desirable to reduce reliance on power from the network.

While the proportion of renewable generation in the NEM is increasing, power flowing through the network will not, when purchased from the market, meet standards for green hydrogen as long as there is a material fossil fuel element.

For the hydrogen to be considered 'green', producers will need to consider the following options:

- Power developments directly from renewable generation not connected to the grid.
- Enter into bi-lateral contracts with renewable generators, e.g. under contracts for the difference in the same way energy retailers and large energy users contract directly with both fossil fuel generators and renewable generators to hedge against wholesale price fluctuations.
- Enter into contracts for energy from renewable sources from energy retailers that contract for an equal amount MWh with renewable generators.

Reforms being considered under the coordination of generation and transmission investment (CoGaTi) review⁴⁴, being conducted by AEMC, aim to encourage the connection of new generation (including renewables) towards less congested parts of the network.

Similarly, AEMO has identified a series of renewable energy zones (REZs) in the NEM where the resources (wind, solar, hydro) for renewable generation (including wind and solar) are seen as favourable. However, the identification of a REZ by the AEMO does not necessarily mean that the existing grid in the area is supportive of further renewable developments. There are a number of identified REZs in north Queensland, north-western Victoria and western and south-west New South Wales where the network is already congested and cannot currently accommodate additional renewable generation without major network augmentation.

We recommend AEMO examine hydrogen production regions in a similar fashion to that adopted for REZs. There may also be value in providing similar information covering the Northern Territory and Western Australia.

⁴⁴ AEMC, 'Public forum on the CoGaTi review', 20 July 2019, refer to: <https://www.aemc.gov.au/news-centre/media-releases/public-forum-2019-cogati-review>

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These areas of congestion have been identified by AEMO in its Integrated System Plan (ISP)⁴⁵ and by the various Transmission Network Service Providers (TNSPs) in their Transmission Annual Planning Reports.

In some cases, there are already plans to address these constraints and a number are subject to Regulatory Investment Tests-Transmission (RIT-T). For example, the project energy connect is in advanced stages of development and will see a new high voltage interconnection established between Robertstown in South Australia and Wagga Wagga in New South Wales. Planning is also underway for strengthened interconnections between Victoria and New South Wales, Victoria and Tasmania and between Queensland and New South Wales.

Where renewable generation and hydrogen production is co-located, the electricity absorbed in the hydrogen production process acts to mitigate network congestion. As such, the scope and range of locations that may be available to co-locate renewable generation and hydrogen production operations may be wider than for standalone solar and wind operations. The identified renewable energy zones may, therefore, provide a useful guide of identifying potential sites for co-located developments.

4.2 Western Australia

There are several islanded electricity networks in Western Australia. The largest networks include the South West Interconnected System (SWIS), which is located in the south-west of the state and services the majority of Western Australia customers.

The North West Interconnected System (NWIS) is a loosely integrated system located in the Pilbara region (in the north-west of Western Australia) and provides electricity to several towns in the region, as well as mining and resources infrastructure and mining communities. Separate to the interconnected networks, Horizon Power currently operates 37 isolated power systems in Western Australia that supply power to remote communities and towns⁴⁶.

4.2.1 South West Interconnected System

The SWIS, through the Wholesale Electricity Market (WEM), provides approximately 18 TWh of electricity each year to more than 1.1 million households and businesses and incorporates 102,000 kilometres of transmission and distribution lines. It is geographically isolated, with no interconnections to other transmission systems⁴⁷. Approximately 52 per cent of Western Power's transmission and distribution assets serve only 3 per cent of its customer base⁴⁸.

The peak operational demand in FY2018-19 in the SWIS was 3,256 MW with an average demand of around 2,000 MW and a minimum operational demand of around 1,200 MW. The highest peak demand over the last 10 years was 4,004 MW which occurred on February 8 2016⁴⁹.

⁴⁵ AEMO, Integrated System Plan, June 2018

⁴⁶ Economics and Industry Standing Committee (WA Parliament), Report 5: Implications of distributed energy future, interim report, April 2019, pp. 19.

⁴⁷ AEMO, Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS, March 2019.

⁴⁸ Economics and Industry Standing Committee (WA Parliament), Report 5: Implications of distributed energy future, interim report, April 2019, pp. 30.

⁴⁹ Peak Demand and Energy Forecasts for the South West Interconnected System, Report to the Australian Energy Market Operator, ACIL Allen, 12 June 2019, pp. 13.

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As with the NEM, the peak demand has tended to occur later in the day, with the summer peak occurring at 3:00 pm in 2007-08, and at 5:30 pm in 2017-18 and 2018-19. This is largely due to the influence of increasing rooftop PV uptake, which generates more electricity during the early afternoon thus forcing the peak operational demand at the transmission level (as opposed to native demand at the household level) to shift to later in the day⁵⁰. There is around 5,768 MW of registered generation capacity in the SWIS, including more than 600 MW (nameplate capacity) of non scheduled (variable) generation.

Electricity is traded in two markets in the SWIS. The Short Term Energy Market (STEM) is a daily forward market that allows Market Participants to trade around their bilateral energy positions. The Balancing Market uses a 'pool' or spot market to determine the actual dispatch of electricity. Collectively, the STEM, Balancing Market and bilateral contracts between whole market suppliers and consumers are known as the WEM.

The current market arrangements (as amended from time to time) commenced operation in September 2006⁵¹. The STEM and Balancing Market operates with narrow price limits than the NEM (maximum STEM price is \$235 per MWh and the Alternative Maximum STEM Price is \$560 per MWh and the minimum STEM price is -\$1,000 per MWh⁵²). The volume of energy traded in the Balancing Market is small compared to the total energy traded through the WEM.

In the SWIS, generators can also access payments via a Reserve Capacity Mechanism, the intended purpose of which is to ensure that there is sufficient generation capacity to meet demand.

In the SWIS, five types of ancillary services are used by AEMO⁵³ in its System Management role:

- Load Following Ancillary Services (LFAS) are delivered by generators which adjust their output in response to electronic control signals issued System Management to correct imbalances between supply and demand,
- Spinning Reserve Ancillary Services (SRAS) are used to respond rapidly should contingencies result in a loss of power generation,
- Load Rejection Reserve Ancillary Services (LRRAS) are used to respond rapidly should contingencies result in a loss of load,
- Dispatch Support Services (DSS) are used to dispatch generators to maintain appropriate voltage control and meet security and reliability standards, and
- System Restart Services (SRS) are used to restart the power system in the event of a partial or system-wide blackout.

All generators connected to the SWIS are required to have control systems that act to arrest frequency disturbances, subject to energy source limitations. This mandatory requirement must be met, irrespective of whether the generator is contracted to provide ancillary services.

⁵⁰ Peak Demand and Energy Forecasts for the South West Interconnected System, Report to the Australian Energy Market Operator, ACIL Allen, 12 June 2019, pp. 13.

⁵¹ AEMO, 'Wholesale Electricity Market (WEM)', accessed 16 July 2019, refer to: <http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM>

⁵² STEM price caps limit the balancing market prices according to the definition in the WEM Rules as follows:

(a) a maximum price of:

- i. for a Balancing Facility to run on Non-Liquid Fuel, the Maximum STEM Price; or,
- ii. for a Balancing Facility to run on Liquid Fuel, the Alternative Maximum STEM Price; and

(b) a minimum price of the Minimum STEM Price.

AEMO, 'Price limits', accessed 6 December 2019, refer to: <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits>

⁵³ AEMO has, in the last two years, taken over operation of the Western Electricity Market (WEM) from the Independent Market Operator of Western Australia. However, AEMO operates the WEM under the market rules that were in place at the time of the Independent Market Operator.

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While Rule Participants that are certified by AEMO as being capable of providing LFAS can participate in the LFAS market, there is no open market for SRAS or LRRAS.

Under the WEM Rules, AEMO may contract with Rule Participants for SRAS if it believes that the ancillary service requirements cannot be met with Synergy's registered facilities (also referred to as the Balancing Portfolio) or if the contract provides a less expensive alternative to the services provided by Synergy's registered facilities⁵⁴.

Synergy is Western Australia's largest generator and retailer (following a merger between Verve Energy – the state-owned generation business and Synergy – the then state-owned retailer in January 2014).

Load rejection, system restart and dispatch support services are also provided via contract with the System Manager (i.e. AEMO) with the Economic Regulation Authority determining the administered prices for these services⁵⁵.

4.2.2 Opportunities for hydrogen

Similar to the NEM, the SWIS features some areas that are “well-meshed” and other sections that are less well connected, meaning there is only a single or twin radial line connecting that part of the network.

Renewable energy zones have been identified in the SWIS that include some locations where the availability of wind and solar resources is complementary such that the potential for 24-hour production of renewable generation is higher (wind can be used at night and solar during the day). These areas are likely to be of particular interest to clean hydrogen producers, depending on water availability.

The Western Australia Government is progressing a series of wholesale electricity market reforms⁵⁶. As a result, there is a level of uncertainty around connections to the SWIS and participation in the WEM. However, if the reforms commence by 2022, then the revised platform should be advantageous to all new market participants, including hydrogen proponents.

In an isolated power system such as the SWIS, the control of frequency is more challenging than in larger integrated power systems such as the NEM. The provision of generation following and frequency control services in the WEM may present opportunities for hydrogen production facilities ahead of similar opportunities arising in the NEM.

⁵⁴ AEMO, 'Ancillary Services', accessed 20 July 2019, refer to: <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services>

⁵⁵ ERA, 'Ancillary Services Parameter', accessed 20 July 2019, refer to: <https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters>

⁵⁶ Details regarding the WA Energy Transformation Strategy are available at: <https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy>

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With increasing levels of large and small scale renewable generation connecting to the SWIS, AEMO expects the LFAS capacity requirement to increase going forward⁵⁷. This represents an opportunity for hydrogen production facilities that can supply the rapid response required to deliver these services.

There are also significant reforms underway in the WEM that will change the way essential system services are defined and delivered. These are expected to increase the opportunities for some technology types, including electrolysers and fuel cells capable of relatively fast response times, to more easily participate in markets to provide these services⁵⁸.

4.2.3 North West Interconnected System

The North West Interconnected System (NWIS) comprises interconnected electricity generation, transmission and distribution assets in the Pilbara region of Western Australia, including the major towns of Port Hedland and Karratha. It provides electrical power to approximately 15,800 retail customers. Annual electricity consumption is approximately 468 GWh, with consumption dominated by larger customers⁵⁹.

Assets that make up the NWIS are privately and publicly owned. The NWIS transmission lines are linked to transmission lines owned by BHP and Alinta, but is otherwise geographically isolated.

While the system is interconnected, the interconnections are electrically weak, with a range of different voltages, multiple points of transformation and constrained capacity at points of the system.

There are currently four companies operating seven generation facilities within the NWIS. In addition, there are six large stand-alone generation facilities in the Pilbara that are proximate to the NWIS.

The NWIS is not centrally planned or operated. The system has developed in an uncoordinated manner over several decades, as resources and energy companies made individual investments in generation capacity and network infrastructure to meet their own needs, with government meeting the needs of other users in the major towns of Port Hedland and Karratha through Horizon Power.

Although the sector is open to retail contestability, all customers in the NWIS are supplied by Horizon Power. Horizon Power also supplies electricity to the small, isolated power systems for the towns of Onslow, Marble Bar and Nullagine in the Pilbara⁶⁰.

⁵⁷ AEMO, WEM Electricity Statement of Opportunities, June 2019, pp. 56. Available at: <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities>

⁵⁸ Details on the proposed reforms to the arrangements for essential system services are available at <https://www.wa.gov.au/government/document-collections/taskforce-publications>

⁵⁹ Department of Treasury WA, Improving access to, and operation of, the Pilbara electricity network – the North West Interconnected System, November 2017, p. 8

⁶⁰ Ibid, p. 8

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4.2.4 Opportunities for hydrogen

The NWIS system is only loosely interconnected which means that there is often little redundancy in the transmission network connecting loads and generators. The NWIS operates as an isolated system with no connection to any other power system.

This limits the ability to use the network to transport electricity from areas where renewable generation might locate to either demand centres or ports where hydrogen production facilities are likely to be located. As such, the hydrogen production facilities are most likely to consider developments that are co-located with renewable generation, and to make use of the network to 'top-up' electricity needs when renewable generation output is lower.

Reforms to introduce a light-handed regulatory regime to facilitate fair and reasonable access by third parties to networks in the Pilbara are underway⁶¹. These reforms are expected to commence in early 2020 and may establish clearer paths ways for connection to the network. As the area develops and more transmission lines are built to support mining operations, the pressure to formalise a market in this region and to strengthen weaker parts of the grid will increase. As such, the suitability of hydrogen production for export applications, in particular, may increase.

In remote locations within Western Australia, there may be opportunities to trial power to hydrogen to power applications as a replacement for trucking back-up diesel and or liquefied natural gas. However, where natural gas pipelines are close to remote towns or mine sites, it is unlikely that this application will be competitive in the near future.

⁶¹ Department of Treasury (WA), 'Pilbara Electricity Reforms', updated 15 March 2019, accessed 14 August 2019, refer to: <https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Pilbara-Electricity-Reforms/>

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4.3 Northern Territory

The Northern Territory energy system consists of a number of different networks and systems, influenced by geography, regulatory framework and size.

There are three regulated systems: the Darwin – Katherine interconnected system, Tennant Creek and Alice Springs. Minor centres, which are also regulated, are Yulara, Timber Creek, Borroloola, Nhulunbuy, and Ti Tree. In addition, there are 72 remote Indigenous communities⁶², as well as licensed self-generating commercial centres (mine sites, tourist resorts), and small unlicensed isolated power supplies (cattle stations, roadhouses, outstations)⁶³.

The Darwin Katherine Interconnected System is the largest of the three regulated systems. The system consists of 132 kV lines and 66 kV lines. Transmission lines (132 kV) are from Katherine to Channel Island and Channel Island to Hudson Creek.

A 132 kV double circuit overhead transmission line from Channel Island to Hudson Creek serves the Darwin area. The 300 km 132 kV single circuit Channel Island to Katherine line runs south from Darwin to Manton, Batchelor, Pine Creek and Katherine⁶⁴. The network in Darwin is relatively robust with the 66 kV network forming a series of loops. The 132 kV and 66 kV networks are strongly interconnected, albeit at a single point at Hudson Creek⁶⁵.

In 2017-18, approximately 1,620 GWh was consumed from the Darwin Katherine Interconnected System. The total generation capacity connected to the system is around 476 MW across five power stations. The fuel type of the generation units is made up of dual fuel (gas/diesel), gas only, heat recovery steam and landfill gas.

The Alice Springs power system is the second largest in the Territory. It supplies the township of Alice Springs and surrounding rural areas from the Ron Goodin (semi-retired), Owen Springs and Uterne (solar) power stations.

In 2017-18, 214 GWh was consumed from the Alice Springs grid. The highest voltage in the network is 66 kV. The total generation capacity in the system is around 124 MW across three power stations. Ron Goodin (42.6 MW) was planned to be decommissioned in 2019; however, we understand that it is being retained for spinning reserve purposes. Owen Springs power station comprises a mix of gas and diesel engines with a nameplate capacity of 36 MW, commissioned in 2014.

In 2017-18, the Owen Springs power station underwent a \$74.6 million upgrade to increase capacity to 77.1 MW, reduce emissions, and improve efficiency and reliability⁶⁶.

Tennant Creek power system supplies the township of Tenant Creek and surrounding rural areas. In FY2017 18, 9.3 GWh was consumed from the Tennant Creek grid (system demand). The installed generation capacity of around 24 MW in the Tennant Creek region is much greater than the maximum demand of 7.37 MW. Generation is provided by three units that will undergo a significant refurbishment process in 2019. The generators are diesel and gas⁶⁷.

⁶² NT Government, 'Services to remote communities and homelands', accessed 20 August 2019, refer to: <https://nt.gov.au/community/local-councils-remote-communities-and-homelands/services-to-remote-communities-and-homelands>.

⁶³ Northern Territory Government, Northern Territory Roadmap to Renewables, September 2017, Appendix 7, p. 72.

⁶⁴ Utilities Commission, Northern Territory Power System Performance Review 2017-18, p. 3.

⁶⁵ Ibid, p. 3.

⁶⁶ Territory Generation, 'Owen Springs Power Station', accessed 30 January 2020, refer to: <http://territorygeneration.com.au/home/our-power-stations/locations/owen-springs-power-station/>

⁶⁷ Utilities Commission, Northern Territory Power System Performance Review 2017-18, pp. 49 to 58.

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4.3.1 Opportunities for hydrogen

The relative size of the Darwin Katherine network may restrict the size of hydrogen production facilities or hydrogen-powered generation. However, there may be opportunities for co-located renewable and hydrogen production, particularly close to Darwin which are closer to potential end-use demand centres.

The Northern Territory Government has established a 50 per cent renewable energy target by 2030⁶⁸. The policy has the potential to influence the generation mix towards non-synchronous power sources and away from traditional forms of generation that are currently providing ancillary services to support power system security. The changes will make the intrinsic value of these services (which is currently not recognised in markets) increase.

Changes to the way these services are procured could be considered in the future, and if so, this would open up potential new revenue streams to hydrogen producers looking to locate in the region.

Solar power appears to be the most likely renewable generation option for the Northern Territory power systems. Increased levels of solar generation is likely to present challenges for managing the power system during the middle of the day as there will be less thermal generation dispatched reducing the ability to provide system services required to respond to generator contingencies or reduced solar generation during cloud cover events.

Hydrogen production facilities that are able to regulate their power consumption to provide system services could help support the Northern Territory power systems.

The remote location of the other interconnected systems in the Northern Territory makes the production of hydrogen other than for local use highly unlikely. In these locations, there may be opportunities to trial projects that use hydrogen to store renewable energy during the day and supply electricity outside of daylight hours and avoid the cost of generating from liquid fuels such as diesel. The exception may be where export markets develop to a point that the costs associated with the transport of significant quantities of hydrogen or power are outweighed by export revenue.

⁶⁸ Northern Territory Government, Roadmap to Renewables, September 2017, p. 4.

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4.4 Summary of hydrogen opportunities in Australia's power systems

Given the nature of the different systems in the eastern states compared to Western Australia and the Northern Territory, the opportunities for industrial-scale hydrogen differ.

The NEM and WEM both offer significant levels of renewable generation that is already operational which presents opportunities for large-scale green hydrogen production using electrolysers as hydrogen production initially ramps up. Hydrogen production sites that are located close to significant renewable generation facilities have the potential to extract value by avoiding network constraints that might otherwise limit the generation of power from renewable sources. In addition they could vary their output to deliver wider system services such as generation following or and frequency control.

The NEM reforms being developed through the CoGaTi review are likely to assist hydrogen production facilities to extract value from assisting to avoid network congestion.

In all regions of Australia the increasing cost-competitiveness of variable renewable generation from wind and solar-based power, coupled with retirements of existing fossil fuel generation and trends towards decentralisation and democratisation⁶⁹ of power system supply and use requires the development of cost effective approaches to managing the variability of supply and demand whilst maintaining power system security. This includes being able to:

- Match electricity consumption to renewable generation thereby removing the variability, and
- Store the energy produced from renewable generation to supply demand when there is little or no renewable generation.

The availability of electricity market mechanisms that allow participants to clearly identify both the current and future value of electricity will help investors in industrial-scale hydrogen facilities optimise the location, design and size of any investment.

Ancillary services are required to operate power systems securely and hydrogen production facilities can provide a range of ancillary services. These may include providing stabilising load during system restart, load shedding services as part of frequency protection schemes, and controllable load to manage the effects of rooftop solar that may not be subject to Distributed Energy Resource standards for interoperability. The volume of ancillary services required is however small⁷⁰ compared to the size of the wholesale electricity markets and this limits the value that hydrogen produces may be able to gain from providing ancillary services compared to the value they can extract from directly participating in the wholesale electricity markets and changing their electricity consumption to follow the generation available from renewable energy generators.

In the short-term, the NEM offers a well-developed ancillary service market and a very visible real-time energy price. There is however a lack of visible and bankable future prices for energy and ancillary services.

The interconnected nature of the NEM and the significant number of existing suppliers of frequency control services may mean that there is less value in those services than in other isolated systems. Similar concerns exist for other electricity markets and power systems within Australia.

⁶⁹ Democratisation refers to the increasing choice and empowerment of energy users allowed by new technology and increasing power consumption awareness.

⁷⁰ The size of the largest generator contingency in the NEM sets the requirement for contingency frequency control raise ancillary services. Currently the largest generator is 750 MW which is a small fraction of the 60,839 MW of generation capacity in 2018-19.

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The lack of future electricity prices is particularly important for hydrogen facilities. As discussed further in Chapter 5 the lack of a future electricity price does not assist hydrogen producers when attempting to value the benefit of using stored hydrogen for future power generation versus using it in other sectors. The sector coupling is a significant opportunity for hydrogen that is not present for other electricity generation technologies such as thermal generation from coal or generation from pumped hydro.

The WEM reforms to connection arrangements and to the essential services framework due for implementation in from 2022 offer the potential to provide a simpler connection process and enhance the ability for hydrogen production facilities to extract value from the provision of essential services.

The opportunities for industrial-scale hydrogen facilities in the NWIS system are most likely result from co-located renewable energy and hydrogen developments.

Growing levels of solar generation connected to the power system in the Northern Territory may create opportunities for industrial-scale hydrogen production with production adjusting to follow renewable generation. The lack of renewable generation overnight may be a disincentive as it limits the potential for hydrogen production to daylight hours.

In the medium-term as technology costs continue to fall, isolated communities in across Australia and the smaller isolated systems at Tennant Creek and Alice Springs may present opportunities for smaller-scale developments incorporating hydrogen production, storage and conversion of hydrogen back to power. This technology when coupled with renewable generation could enable remote communities and power grids to reduce their dependence on liquid-fuelled generation.

The widespread uptake of small-isolated systems will depend on the commercial viability of the hydrogen facilities compared to alternatives such as battery energy storage. In particular, as discussed in section 2.3, the cycle efficiency for hydrogen is lower than other technologies. For short-term electricity supply (up to 8 hours), batteries are likely to remain the most competitive alternative. An advantage of hydrogen that could be exploited in these small-isolated systems is when longer-term energy storage is required. Unlike batteries, hydrogen can be stored for long periods of time without energy loss. This might prove advantageous in remote areas where there are extended renewable resource droughts and road access is challenging or unavailable for parts of the year.

Beyond 2030, the demand for hydrogen and therefore the requirements of Australia's electricity systems are less clear. Deloitte has forecast the additional hydrogen production from Australia (in excess of existing production) could be between 1 and 20 Mt per annum by 2050⁷¹. Deloitte also forecast the electricity required to meet these production estimates could range from 5.5 TWh to 912 TWh per annum⁷².

⁷¹ Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, Table 1.2, p. 7.

⁷² Ibid, Table 6.1, p. 95.

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Table 4 summarises the current electricity demand and generation capacity in each of the NEM jurisdictions and in the Western Australian SWIS. In the NEM, there was a total generation capacity of 60,839 MW that produced around 205 TWh of electricity in 2018-19 including rooftop PV⁷³. In the SWIS there is installed generation capacity of 5,768 MW and around 18 TWh of electricity is supplied each year through the WEM⁷⁴.

Table 4 Demand and generation capacity in the NEM and SWIS

| Demand / Capacity | NEM | | | | | | SWIS | Total |
|---|--------|--------|-------|-------|--------|---------------|-------|---------------|
| | NSW | QLD | SA | TAS | VIC | Total | | |
| Maximum demand (MW) (Operational Demand) ^{1,2} | 13,861 | 10,179 | 3,244 | 1,395 | 9,318 | 41,253 | 3,256 | 44,509 |
| Installed capacity (MW) ^{3,2} | 17,479 | 14,585 | 5,858 | 2,988 | 12,078 | 58,756 | 5,768 | 64,524 |

Sources: 1) AEMO seasonal peak demand by region⁷⁵ 2) Peak Demand and Energy Forecasts for the South West Interconnected System, Report to the Australian Energy Market Operator, ACIL Allen, 12 June 2019, pp. 13, 3) AEMO, 'Generation Information page', accessed 20 July 2019.

To meet 2050 hydrogen production estimates developed by Deloitte, the installed generation capacity in Australia will need to increase by around 3 per cent in total under a 'business-as-usual' scenario but will have to double or increase more than five-fold if a targeted hydrogen deployment or the most opportunistic hydrogen production scenarios eventuate⁷⁶.

The levels of electricity demand indicated by Deloitte's 2050 projections under the targeted hydrogen deployment and the most opportunistic scenarios are likely to be driven by significant hydrogen production developments that are off-grid and co-located with renewable power supplies. If the current electricity regulatory frameworks persist, the developments are likely to prefer the unregulated or lightly regulated economic environment that such off-grid developments afford.

While the frameworks do not prevent hydrogen connections of this size or their participation in electricity markets, the regulation does involve more extensive consultation and approval processes for large-scale projects. Further, the significant amount of land required for the renewable generation that will support production will be substantial.

Deloitte estimates the total land area required under the most opportunistic scenario if only solar is used is 9,290 km² (equivalent to 75 per cent of the Sydney metro area) or 60,154 km² if only wind generation is used (equivalent to 4.86 times the size of the Sydney metro area) (Table 5).

Investors in hydrogen projects considering development off-grid will need to weigh up the benefits of this reduced regulatory complexity with the higher risks of asset stranding and alternative electricity supply sources that grid connections afford.

⁷³ AER, State of the Energy Market Report 2019 Data Update, November 2019, refer to: 'State of the energy market – Data update – Chapter 2 National electricity – November 2019.xlsx'.

⁷⁴ AEMO, Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS, March 2019.

⁷⁵ AER, 'AER_Regional peak demand_1_2019070914230 AEMO.xlsx', 9 July 2019, accessed 20 August 2019.

⁷⁶ Based on hydrogen production forecasts and electricity inputs requirements developed by Deloitte, assuming solar generation and based on the current total installed capacity of 64,524 MW across the NEM and SWIS.

Source: Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, p. 102.

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Alternatively, if hydrogen production developments consist of a multitude of small, medium and large-sized plants (but not 'super-sized' projects⁷⁷) dispersed throughout existing networks and the most opportunistic demand scenarios eventuate, expansion of networks to support the increased load (in the absence of co location of production with renewables) will be substantial.

Table 5 Generation capacity and land requirements if electrolyzers use renewable power

| Scenario | Total 2050 electrical load requirement (TWh) | Solar capacity required (GW) | Land area required for solar (km ²) | Wind capacity required (GW) | Land area required for wind (km ²) |
|--|--|------------------------------|---|-----------------------------|--|
| Scenario 1 Energy of the future | 912 | 372.59 | 9,290 | 247.72 | 60,154 |
| Scenario 2 Targeted deployment | 188 | 76.67 | 1,917 | 51.09 | 12,413 |
| Scenario 3 Business as usual | 5.5 | 2.24 | 56 | 1.48 | 362 |
| Scenario 4 Electric breakthrough | 65 | 26.68 | 666 | 17.81 | 4,313 |

Sources: Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, Table 6.1, p.102, and GHD analysis.

Note: Calculations assume the total electrical load is met by only solar or only wind. Realistically, the load will be met by a combination of these forms of renewable generation so the total generation capacity and land required will lie between the estimates provided in the table.

⁷⁷ Super-sized' refers to individual projects that require generation input capacity that is multiples of the existing generation capacity.



Chapter 5 | Generating multiple value streams with sector coupling

5 | **Generating** multiple value streams with sector coupling

The scale-up of hydrogen production in Australia will introduce new cross-sector trade-offs and opportunities for investors that amplify the way our energy, transport and natural gas sectors interact.

Several characteristics of hydrogen, when combined, make it uniquely exchangeable between industries:

- **Hydrogen can be stored.** Hydrogen can be stored for long periods, without loss of its energy content. This makes it unlike other types of electrical energy storage systems that tend to lose energy content over time. This characteristic gives producers (and users) of hydrogen the option of selling (or using) the hydrogen when it's produced or in the future.
- **Hydrogen is a versatile energy carrier and chemical feedstock.** It can be used in a variety of markets and for different purposes. After hydrogen is produced, it could be converted back into electricity, used as a transport fuel (replacing traditional fuels), sold to the industry as an input⁷⁸, used applications typically seen in the natural gas industry, or exported.
- **Hydrogen can be readily transported.** Hydrogen and liquid carriers of hydrogen⁷⁹ can be readily transported in a truck and on transport vessels. It is not reliant of an extensive system of poles and wires like those required for electricity, or pipeline networks like those used for natural gas. In this way, hydrogen is more similar to fuels such as diesel, petrol and other oil-based fuels. It is moveable, and it can be on-sold rather than used immediately, thus able to maximise it's value by choosing the geographic market and the time where the sale takes places.

The current markets for electricity, natural gas, and other fuels such as diesel, petrol and oil are to varying degrees interlinked. Electricity is used in many of the production processes used to extract and process natural gas and other fuels. These fuels can, in turn, be used to produce electricity.

Hydrogen scale-up will amplify the connections between these markets, offering investors more flexibility as to which markets they participate in. For example, hydrogen producers may choose to sell into multiple domestic markets, store their product for later use or transport their product to export markets.

The extent to which markets become further aligned and integrate will, in part, depend on the transparency of the future value of hydrogen in each market. Transparency of future prices will allow investors to weigh the value in each market and choose the best use of any produced hydrogen. Producers will also weigh up the value of using the hydrogen today versus storing it for tomorrow.

Where transparency and certainty of future hydrogen prices are better in one market compared to another, this will influence the direction in which hydrogen supply chains could develop. Importantly, if there is greater transparency and future prices are more certain in one market, investors are more likely to look to develop opportunities that service that market.

⁷⁸ While domestic industrial use of hydrogen is a potential future market for clean hydrogen, we do not consider the interaction of existing domestic hydrogen markets in depth (particularly industrial applications such as fertilizer, coolant, chemical input). These markets have estimated pricing for hydrogen and, in the absence of a carbon price, are unlikely to move to clean hydrogen unless it becomes competitive with their current (and future) arrangements.

⁷⁹ Liquid carriers may include ammonia, toluene, and metal hydrides.

5 | Generating multiple value streams with sector coupling

5.1 Transparency and certainty in longer-term electricity markets

For hydrogen to be used as a fuel source for electricity, the electricity market needs to offer a reasonable trade-off compared to alternative markets. To do this, it must provide long-term future price transparency and certainty that values the energy storage potential of hydrogen.

While there are multiple tools available that enable an understanding of electricity market developments including information that can be used to forecasts future electricity prices⁸⁰, the certainty and transparency of 'bankable' future electricity prices that value dispatchable load and generation is limited.

Hedge contracts offer a means of managing short to medium-term price volatility in spot markets like the NEM and can be a source of revenue for dispatchable load and generation. Futures and options markets trade hedge contracts on the ASX for NSW, VIC, QLD and SA⁸¹, however, these markets are typically thin more than three years out. However the liquidity of these markets can be limited particularly for hedging positions greater than a few years into the future.

Renewable generation projects often enter into longer-term power purchase agreements (PPA). These PPAs typically take the form of an offtake agreement where an agreed amount is paid for each unit of energy (MWh) produced. These arrangements do not give consideration to when the energy is produced and are purely volumetric in nature. Renewable generators financed through PPAs, rather than on the basis of secondary market contracts, can impact the number of hedging contracts traded, reduce the liquidity of the secondary contracts market⁸². The availability of hedging contracts through a liquid long-term secondary contract market would assist hydrogen producers by signalling of market expectations of future spot prices. These signals could help hydrogen producers to assess the value of the energy storage potential of hydrogen to the electricity market.

The lack of long-term price certainty in electricity markets is potentially unfavourable compared to the long-term price certainty that investors might be exposed to in other markets.

⁸⁰ Participants are able to retain specialist advisor to run market simulations using information in publications such as AEMO's Electricity Statement of Opportunities in the NEM and WA, AEMO's Integrated System Plan (ISP) for the NEM, annual planning reports published by distribution and transmission networks to help understand potential future wholesale electricity prices.

⁸¹ For more information refer to: <https://www.asx.com.au/products/energy-derivatives/australian-electricity.htm>

⁸² AEMC, Annual Market Performance Review 2018.

5.2 Regulated rewards versus market risks

Electricity, gas, and liquid fuel, by their nature are highly regulated. However, the regulatory frameworks across each sector differ. In particular, liquid fuels and transportable gases are predominately regulated from a safety perspective and not an access or economic (price) perspective, so investors are generally able to make commercial agreements unimpeded by economic regulations.

In contrast, the electricity and gas networks face additional regulations both from an access perspective and from an economic (price) perspective. These regulations recognise and address the natural monopoly characteristics of the electricity and gas networks.

In the electricity sector access and economic regulations impact network development which in turn can impact the ability to facilitate the unconstrained connection of new generation and load. The complex regulatory arrangements for electricity infrastructure often lead to delays in the planning and approval of transmission network augmentation with regulated network augmentations being delivered well after generation developments resulting in congestion risks. Network companies receive regulated low-risk returns that discourage pre-emptive network investments.

The regulated network investment framework can introduce a further layer of uncertainty regarding the future value that a hydrogen development could extract from participating in the electricity market. This uncertainty discourages grid-connected developments and encourages co-located hydrogen production and renewable generation developments less reliant on any grid connection.

Chapter 6 | Uses of hydrogen to support the electricity system



6 | Uses of hydrogen to support the electricity system

The electricity market is transitioning. Historically, electricity generation has been controlled to follow electricity consumption in a way that maintains power system stability. This was achieved by dispatching electricity generators to deliver the level of power required to meet the expected demand from electricity consumers.

However, the growth of new technologies, including variable renewable energy generation, coupled with retirements of existing generation and changing patterns of consumer demand is changing this dynamic. Renewable generation is becoming increasingly cost-competitive compared to new build of conventional generation. Renewable generation such as wind and solar is reliant on uncontrollable weather conditions, and are not able to follow consumption in the same way as traditional fossil fuel generation unless firmed.

The shift away from load-following generation is creating challenges for power system security. Maintaining a secure and reliable power system while achieving greater renewable energy penetrations requires a shift towards a future where a large amount of demand is able to follow generation.

6.1 Hydrogen load following opportunities

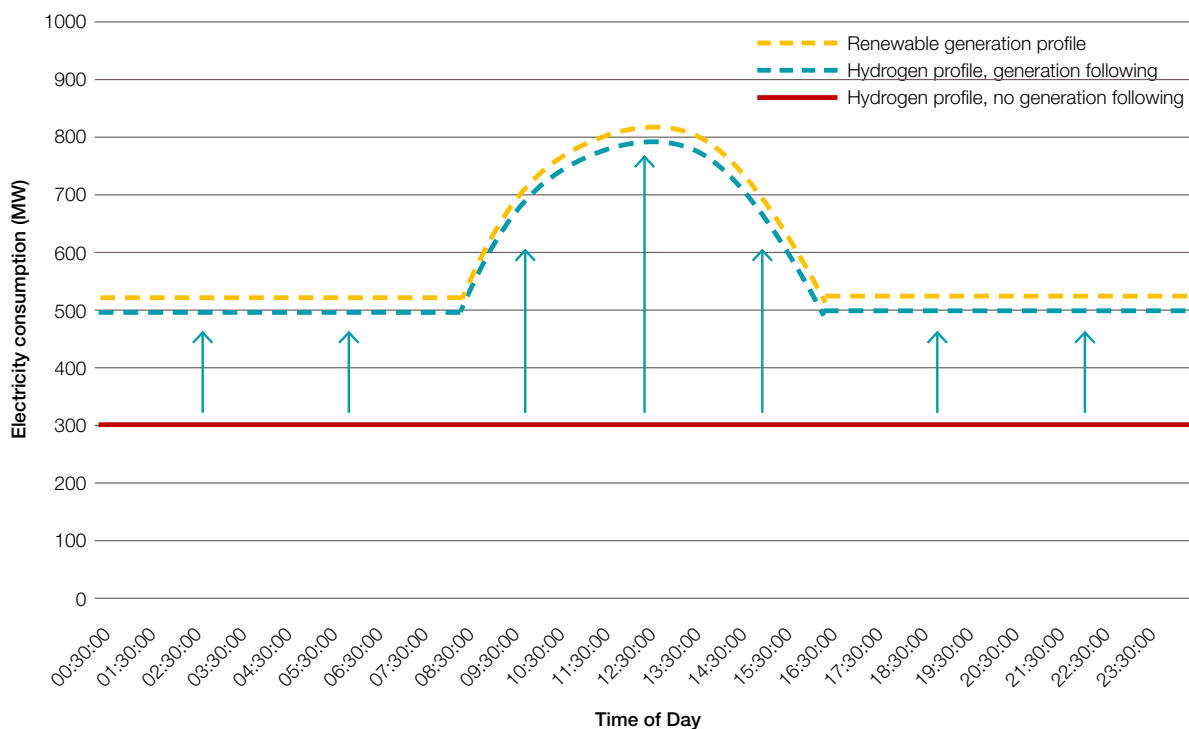
Electrolysers can ramp up and down very quickly, making them suitable to provide a load that follows generation. This can be achieved by diverting excess renewable electricity to increase hydrogen production during periods when electricity supply exceeds demand or reducing hydrogen production when there is a supply shortfall. Hydrogen storage coupled with facilities to generate electricity from hydrogen offers further potential to accommodate more variable renewable generation. The opportunity will be amplified as technology costs reduce as outlined in Section 2.1.

Figure 5 (below) shows two hypothetical hydrogen load profiles and a typical solar generation profile across a 24 hour period. Where hydrogen producers receive no time-of-use price signals from the electricity market and have no incentive to alter their consumption over time, their electricity consumption will be flat throughout the day.

Conversely, if hydrogen producers receive time-of-use price signals or are otherwise incentivised to consume electricity for hydrogen production in a way that aligns with renewable generation profiles, they will consume lower quantities of electricity at night and follow increases in solar generation during the day.

6 | Uses of hydrogen to support the electricity system

Figure 5 Hydrogen load profiles with and without aligned incentives (extreme example)



Source: GHD, 2020

Figure 5 shows a red line showing a 300 MW hydrogen production facility that has negotiated a firm supply contract for the supply of 300 MW of renewable generation from a renewable generation company with a diverse portfolio of wind and solar generation. It operates consuming a constant level of power, receiving no incentives or signals to change its consumption.

We have assumed that 300 MW is a conservative view of the renewable generation available taking into account wind variations and variations in solar with the time of day and cloud events. On any day, the actual renewable generation is likely to be considerably higher. The yellow dotted line shows a typical daily renewable generation curve on a clear day with no clouds. The renewable generation falls to a minimum of 500 MW overnight and peaks at just over 800 MW during the day. The green line shows the energy consumption for an 800 MW electrolyser that changes the hydrogen production and electricity used across the day to align with the actual renewable generation.

The green line represents the hydrogen plant sized and operated to follow renewable generation. This style of operation allows the hydrogen plant to account for variations in renewable generation avoiding any supply demand imbalance. The green arrows indicate the opportunity to produce more hydrogen if the production facility is willing to follow renewable generation.

For the electricity system to realise benefits from positive interactions of hydrogen production (and storage and generation), producers of hydrogen need to see value in turning off, ramping down or having their electricity services interrupted to match fluctuations in generation and other loads.

6 | Uses of hydrogen to support the electricity system

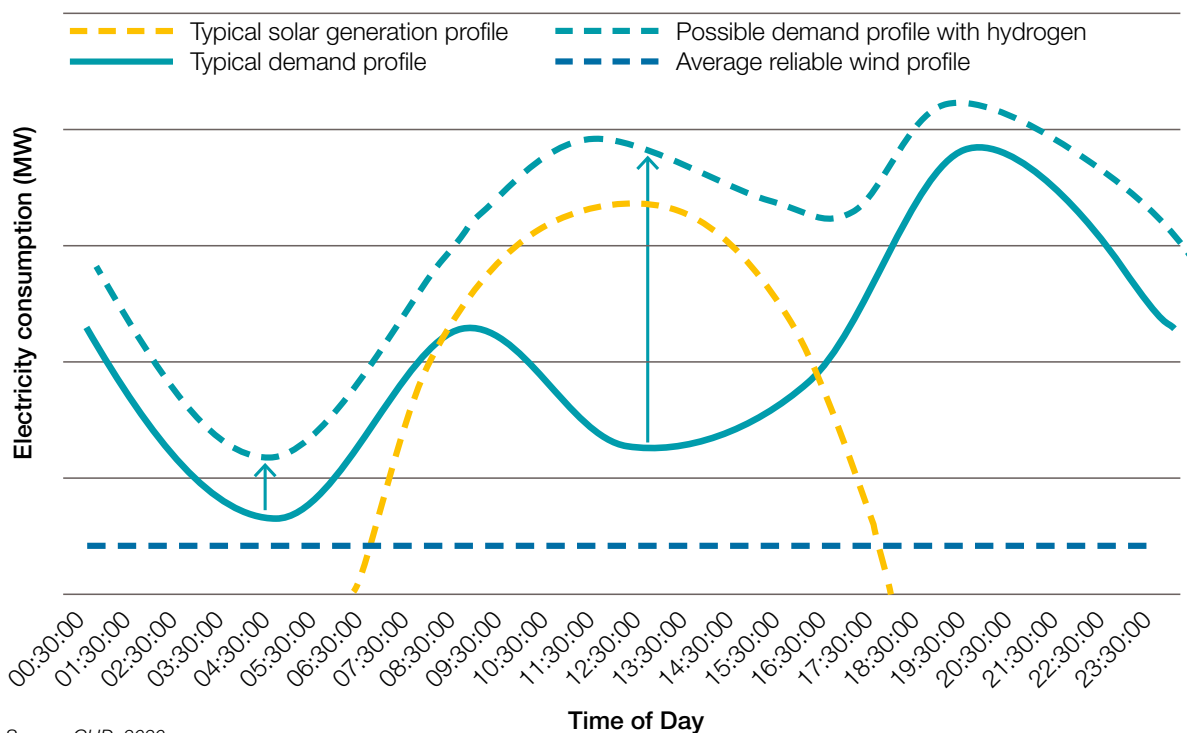
Figure 6 (below) provides a simplistic depiction of how hydrogen production may interact with the electricity market to alter the load profile seen by electricity networks. In the example, hydrogen producers opportunistically consume electricity for hydrogen production in a way that smooths demand and takes advantage of excess solar renewable generation during the day.

The solid green line represents the demand in the absence of a hydrogen production facility. The dashed green line shows the demand where hydrogen production follows renewable generation while not adding to the peak demand. The result is a much flatter demand curve.

The arrows show the amount of power consumed by the hydrogen production facility at different times of the day. As the hydrogen production follows fluctuations of renewable wind and solar generation, the demand increases, on average, by the volume of reliable wind throughout the 24 hour period, and by the sum of the reliable wind and excess solar during daylight hours.

In the scenario, the peak demand on the grid does not increase substantially and we maintain a load profile similar to the current load profile. However, with larger volumes of hydrogen production and other demand profile changes are driven, for example, by the growth of electric vehicles, this demand profile may change from that provided in Figure 6. In fact, demand throughout the 24 hour period may be multiples of the current demand, dwarfing current fluctuations across the day, if more opportunistic hydrogen production forecasts eventuate.

Figure 6 Simplified depiction of hydrogen load-following generation



Source: GHD, 2020

6 | Uses of hydrogen to support the electricity system

While PEM electrolyzers have the capability to adjust their demand in the manner shown on the diagram, the design and sizing of any facility would need to consider a range of factors including whether the value of hydrogen produced was sufficient to justify the investment required. Figure 5 illustrates a facility that, on the day shown, produced hydrogen at well below the rated capability of the electrolyser for much of the day. The commercial viability may be improved by reducing the maximum hydrogen capacity of the facility. That would result in some renewable generation that is not converted to hydrogen and instead used to supply other grid-connected load.

6.2 Capturing the hydrogen opportunity

Electricity networks and power systems can derive significant benefits by taking advantage of the controllable nature of hydrogen electrolyzers. However, the willingness of hydrogen proponents to offer these benefits depends on the incentives offered by energy-markets.

We have reviewed the current market frameworks and reforms that are underway. Our research has found that there are no material barriers within electricity market frameworks and electricity rules that specifically support or detract from developing hydrogen production as a load or from the use of hydrogen as a fuel for power generation. There is, however, an opportunity for policymakers to consider making changes that will incentivise hydrogen producers and hydrogen-based technologies to interact positively with Australia's electricity systems as they evolve.

The following subsections focus on regulatory changes in the electricity sector that will help the hydrogen economy contribute to electricity market objectives, by opening up market access or by better recognising the value that hydrogen-based technology can offer to the electricity market.

There are two areas of reform that are either currently being progressed, or should be progressed to ensure industrial-scale hydrogen developments interact positively with electricity markets:

- Registration of hydrogen facilities, and
- Accessing transmission capacity and locational signals.

These are described below.

6 | Uses of hydrogen to support the electricity system

6.2.1 Registration of hydrogen facilities

Registration of hydrogen to power and hydrogen-based energy storage systems represents a potential barrier, or complexity to be overcome.

In both the NEM and the WEM, registration categories are based on classes of facilities and do not cater well (or at all) to facilities that offer more than one type of services i.e. operating as both a generator and a load behind the same meter. There are specific rules in place for hydroelectricity pumped-storage and batteries which register as both a load and as a generator in the NEM and for which a separate marginal loss factor is calculated for the system operating as a load (pumping) compared to when it is generating.

Other than for the example of hydroelectric pump storage, neither market currently offers a registration category that adequately caters for services that incorporate storage of power. However, reforms are currently underway in both the NEM and the WEM to develop suitable registration categories.

Up until 1 July 2019, the WEM market rules featured a “dispatchable load” registration category. No facility had been registered under this category at the time the market rules were amended. In its final rule determination, the Rule Change Panel found the current design unworkable but considered developing a workable Facility Class for storage facilities lay within the scope of the WEM Reform Program⁸³.

In the NEM, the Australian Energy Market Commission (AEMC) is progressing a Rule Change that considers a new category of registered participant, a demand response service provider that would be able to bid demand response directly into the wholesale market as a substitute for generation⁸⁴.

Hydrogen-to-power applications that incorporate storage will benefit from the development of these current reforms. The new category in the NEM is also likely to facilitate aggregated demand-side response that could be offered by combined micro-embedded hydrogen production applications within the distribution network.

6.2.1.1 Recommendation

Progress reforms to the registration categories in the NEM and the WEM to facilitate the participation of storage systems in these markets, ensuring that hydrogen is not precluded.

⁸³ Rule Change Panel, RC_2014_06: Final Rule Change Report, 29 October 2018, p. 21.

⁸⁴ AEMC, ‘Wholesale Demand Response Mechanism’, accessed 20 July 2019, refer to: <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>

6 | Uses of hydrogen to support the electricity system

6.2.2 Accessing transmission capacity and locational signals

The transition to renewables underway across Australia's power systems has put pressure on network providers and regulators to approve expenditure to upgrade or build new networks to facilitate the transport of electricity from high-value locations (in terms of wind and solar resources) to demand.

Two processes are underway in the NEM that focus on helping create locational signals for new renewable generation. AEMO's Integrated System Plan for 2018 identified a series of high valued renewable energy zones⁸⁵ across Australia and a series of projects where investment in transmission is needed, in particular, to reduce congestion for existing and committed renewable energy developments. A number of RIT-T proposals are being progressed as a result of the work. The outcome of these processes on a growing hydrogen economy will be twofold:

- Firstly, the upgrade of network in some areas will facilitate the transfer of electricity from renewable energy zone to hydrogen production facilities, allowing more renewable resources to be used and providing for a 'cleaner' hydrogen to be produced.
- Co-location of hydrogen production within these renewable energy zones may be mutually beneficial where the networks remain constrained as electrolyzers can absorb any excess renewable power that is unable to be sent through the network. In this way, AEMO's ISP provides an input to starting discussions around the location of hydrogen production facilities (and co-location with renewable generation).

Secondly, AEMC's CoGaTi review proposes a series of reforms to market pricing that will prompt generators to locate in less congested areas of the network, and eventually allow generators to purchase firm transmission rights.

The AEMC reports every two years on drivers that could impact future transmission and generation investment. Since 1997, there have been fourteen major reports and reviews dealing with various aspects of congestion management and generation access, including nine projects undertaken by the AEMC in addition to the current CoGaTi review. The current review is the second CoGaTi review.

The current CoGaTi review proposes two significant changes to the market: 1) dynamic pricing, and 2) firm access for generation. The changes will be implemented over three phases:

- Dynamic regional pricing is expected to be implemented by July 2022. On implementation, generators will receive a dynamic regional price that reflects any congestion in the network, while retailers will continue to pay the reference price (as per current arrangements).
- Improved information produced from dynamic regional pricing is expected to be used to inform planning and investment decisions from July 2022.
- Generators will be able to fund transmission infrastructure from July 2023. Connecting parties (e.g. generators) can purchase firm transmission rights or firm access to the network, which are used to underwrite the network investment needed to physically provide access.

⁸⁵ AEMO, Integrated System Plan for the NEM, June 2018.

6 | Uses of hydrogen to support the electricity system

The AEMC is considering dynamic pricing for loads on a voluntary basis, meaning that hydrogen production facilities looking to connect to the grid could continue to pay the regional reference price, while any co-located generation facilities may receive a different price depending on the relative congestion the network. Regardless of whether hydrogen production facilities elect to receive the dynamic price, exposing generation to locational prices will encourage generators to contract with parties who can help address congestion such as appropriately located hydrogen production facilities.

Congestion can arise over time surprising load and generation investors. While the network may be uncongested when the load or generator first locates, conditions may deteriorate as new loads and generation are built. Developments in the third stage of the review, when connecting parties are able to purchase firm access to transmission networks, may help to mitigate these issues.

If the review is to be implemented, new generation in the NEM – including wind and solar used to support hydrogen production – will have better locational signals. This may drive production towards some areas within the NEM and away from other, more congested, network areas.

Regardless, where renewable power and hydrogen production is co-located, the electricity absorbed in the production process acts to mitigate network congestion. As such, the scope and range of locations that may be available to co-located renewable hydrogen production operations may be wider than for stand-alone solar and wind operations. The existing locational pricing signals of MLFs in the NEM and TLFs in the WEM, which encourage loads to be developed close to generators, and generators to be developed close to load centres will act to influence the location of electrolyser load, and hydrogen-fuelled generators to be located in areas of the network that minimise network losses.

6.2.2.1 Recommendation

- Consider the effectiveness of MLFs and TLFs as locational pricing signals in encouraging electrolyser loads and hydrogen-fuelled generation to be located so as to minimise losses in the network.

6 | Uses of hydrogen to support the electricity system

6.3 Secondary ancillary benefits

Hydrogen production facilities offer a potential new source of frequency control. The NEM, Western Australian, and Northern Territory electricity systems all follow the same general approach when it comes to frequency control. However, there are differences between the arrangements for procuring frequency control services in each jurisdiction. The more sophisticated and transparent frequency control markets that exist in the NEM would make it easier for hydrogen producers to access additional revenue streams for providing frequency services.

The frequency control markets in the NEM are open to all participants so long as they meet the necessary technical requirements⁸⁶. Participants are able to opt-in and out of the markets as desired. Once each market clears and an offer has been accepted, the load is effectively paid to be 'on-call' to provide the service for the specified period of time.

In contrast, opportunities to provide frequency services in the Western Australian SWIS are more limited, although market participation is possible through the WEM via the LFAS market. Reforms are currently underway to change the way ancillary services are defined and procured in the WEM. The "New Essential Services Framework" is expected to be implemented in the next two years, consistent with the Government's Energy Transformation Strategy⁸⁷. The new approach is expected to make it easier for Rule Participants, other than Synergy's facilities, to provide ancillary services.

In the Northern Territory, there is no market for frequency services. The services are currently provided by Territory Generation. While policymakers are looking to change this in the future, however, no definite timeline has been announced.

In the NEM, facilities must be able to respond to dispatch signals on a 5-minute basis. In Western Australia, the WEM operates on a half-hourly dispatch for these services, however the market is looking to move to five-minute dispatch⁸⁸ and so by the time large-scale hydrogen plants are built to commercial scale, it is likely there will likely be no difference between these two markets in terms of the dispatch timeframes needed to participate in the markets.

Electrolysers, as loads, and hydrogen-fuelled generation (particularly fuel cell-based) are highly suitable for participation in the six-second raise and lower frequency response and the 60-second frequency response markets. However, for an electrolyser load to participate in the frequency lower market, it would need to have a proportion of its electrolyser load in reserve in order to increase load.

Similarly, for a generator to participate in the frequency raise market, it would need to hold a certain amount of capacity in reserve in order to increase generation. The commercial merits of participating in such markets will depend on the relative income streams from FCAS as compared to either hydrogen production or hydrogen-fuelled generation. The income stream from the FCAS market is likely to be set by the costs (capital and operating) of alternative technologies of battery/inverter systems that are equally capable of achieving such fast response.

⁸⁶ The 'Managing power system frequency rules' commenced on 1 July 2018. Refer to: <https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque>

⁸⁷ Department of Treasury (WA), 'Delivering the Future Power System', accessed 20 July 2019, refer to: <https://www.treasury.wa.gov.au/Energy-Transformation/Delivering-the-Future-Power-System/>

⁸⁸ AEMO, Contingency Frequency Response in the SWIS (Draft), March 2019

6 | Uses of hydrogen to support the electricity system

On balance, the NEM currently provides the most favourable conditions for hydrogen production facilities to gain access to supplementary revenue streams from FCAS type services. However, the completion of the current reform of the WEM, will result in alignment between the NEM and WEM with respect to payment for FCAS provision through load management.

Similarly, hydrogen-fuelled generators, particularly fast response generators such as fuel cells and gas turbine plant will be able to take part in the frequency raise market by increasing generation under the instruction of the market operator. Again, there is a clearly defined mechanism in the NEM and WEM (less so in the NT) for payment of such services which will inherently be supportive to hydrogen fuel generation.

While the ancillary service markets are more advanced in the NEM, the isolated nature of the WEM, NWIS and NT power systems suggest that frequency control services in those markets could demand a higher value than in the NEM in the future, particularly with increased levels of renewable generation.

6.3.1 Recommendations

While the ability to provide ancillary services such as frequency control services provides an additional revenue opportunity for hydrogen facilities, the revenue derived is likely to be less important than the value created by being able to adjust the power consumption of those facilities to follow generation. Generation following load offers the potential to extract value by:

- Reducing the impact of network congestion on renewable generators
- Reducing the impact of declining marginal loss factors on renewable generators, and
- Electricity price arbitrage, although this may require hydrogen storage coupled with facilities to generate power from hydrogen.

The following actions are recommended to establish ancillary service frameworks that will maximise the value that can be captured by hydrogen projects:

- Progress reforms in the WEM to develop ancillary services markets (the Western Australian Government has tended to term these essential services markets⁸⁹), to ensure revenue streams from the provision of these services are accessible to hydrogen proponents (if they are able to provide services competitively).
- If the introduction of ancillary services or essential services markets are considered for the Darwin–Katherine system ensure the characteristics of electrolysers as micro-interruptible load are adequately catered for to open up new revenue streams for market participants, including any future hydrogen proponents.

⁸⁹ Not to be confused with the Essential Services Commissions (technical regulators) in Victoria and South Australia.

Chapter 7 | Use-case scenarios

7 | Use-case scenarios

In Chapter 6, we identified ways hydrogen could support the electricity system through higher utilisation of variable renewables, stabilisation of electricity networks, and by providing energy storage.

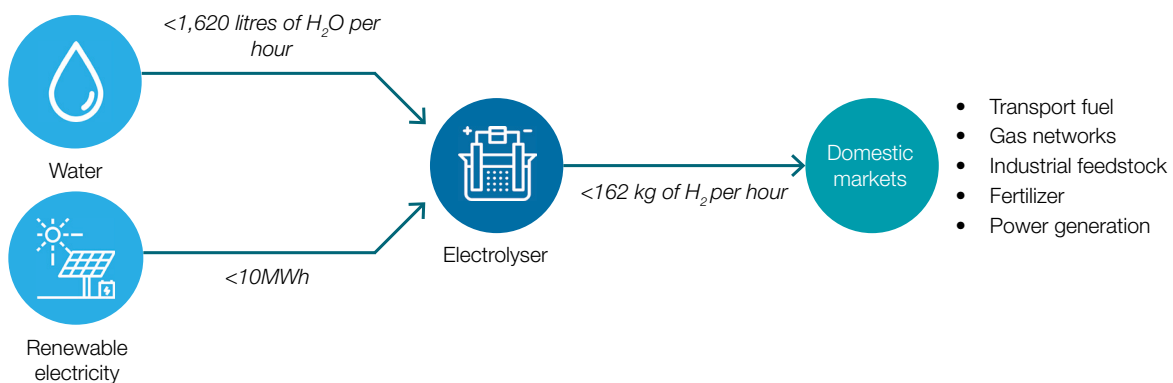
Some opportunities for the power system are common to all hydrogen use-cases, regardless of the size of the plant and the voltage at which plant is connected to electricity networks. For example, the presence of hydrogen production will increase the overall demand for electricity and prompt greater penetration of renewable generation on the network. However, some opportunities are dependent on the size of the hydrogen plant and the voltage levels at which plant is connected to electricity networks.

We have developed four use-case scenarios to illustrate the potential for opportunities for hydrogen facilities to deliver value through interaction with the power system. The use-cases are differentiated by the size of the hydrogen plant and whether the plant connects to the transmission or distribution network. Each use-case has particular opportunities and challenges in addition to the common opportunities that have already been discussed.

While the use-case scenarios focus predominately on the interaction and considerations relating to electrical systems, in practice, producers of hydrogen will consider a range of factors when making investment decisions. In particular, the siting of production facilities will be driven by type and location of demand, the transport options to deliver hydrogen to market, water required for production, and suitability of land for industrial production.

7.1 Small-scale use-case scenario

As domestic demand for green hydrogen emerges from a range of industries and across different geographies, small-scale hydrogen production facilities that take power from the electricity distribution network could emerge. These production facilities will be driven by opportunities to realise revenue from local hydrogen use, such as providing fuel for transport or for local industrial heating and feedstock, where lower transport, handling and supply chain costs offer compelling advantages. Connection to the electricity network is likely to be a secondary consideration at this small-scale.



Source: GHD, 2020

7 | Use-case scenarios

The electrical capacity of the electrolyzers at these facilities are likely to be sized to optimise the cost of connection and the amount of hydrogen produced. Typical distribution feeders can supply electrical loads in the order of 10 MW.

Hydrogen production facilities that consume this amount of power have the advantage of being able to be developed and easily connected to the power system. The connection costs would generally be limited to the construction of a dedicated high voltage feeder from an existing distribution substation.

Small-scale (<10 MW) hydrogen production facilities developed independently from renewable generation projects could be connected via a dedicated high voltage feeder. The same connection option could support increased hydrogen production capacity (beyond 10 MW) if developed in combination with appropriately sized renewable generation. In this variation, the operation of the renewable generation and hydrogen production facility would be coordinated to limit the net impact on the power system to no more than 10 MW at a connection point, avoiding the need for any additional high voltage feeders.

A small-scale hydrogen production facility is relatively compact, which provides the opportunity for it to be located in light industrial areas. Land zoned for light industrial development within 10 km of an existing distribution substation could be ideal sites for small-scale hydrogen production.

The land area needs to be sufficient for the hydrogen production plant, as well as any on-site processing and storage, and cater for any buffer zones required under MHF legislation and by local councils. The land is likely to be cheaper and the type of production more readily accepted in locations further away from residential areas.

7.1.1 *The benefits*

The unique opportunities for small-scale, distribution connected hydrogen production, to support the electricity system include the ability to locate these facilities in areas where they relieve congestion by better balancing load and generation.

Connecting small-scale hydrogen production facilities to substations with relatively high penetration of renewable generation could provide additional benefits by allowing the connection of additional renewable generation, minimising the need for export constraints on local renewable generators or network upgrades required to allow unconstrained operation of the local renewable generation.

Importantly, the hydrogen produced can be stored and later utilised to supply electricity during periods of diminished renewable generation or during upstream network outages that would otherwise restrict the ability to import power into that area of the distribution network, enhancing the reliability of supply to customers.

Better balancing load and generation at the local level also reduces network losses. Capturing this opportunity would require the use of technology such as SOEC that allows conversion of stored hydrogen to electricity. As noted in section 2.3, the lower cycle efficiency of hydrogen storage is a challenge for the deployment of this technology.

7 | Use-case scenarios

7.1.2 Factors to enable this scenario

The unique factors for consideration to enable this use of hydrogen may include:

- Each small-scale facility would need to negotiate planning and development approvals with the relevant local authority. Differences in the approach adopted by local authorities have the potential to add cost and discourage this sort of investment. Conversely, harmonising approval processes, for small-scale electrolysis, could reduce the development costs and encourage investment.
- Each small-scale facility will need to negotiate a connection with the local distribution network service provider. Currently, the connection standards and process differ between distribution network service providers. Harmonising the connection frameworks adopting a common best practice approach would help to simplify the connection of small scale facilities, reducing costs.
- The planning obligations on distribution network service providers continue to evolve with recent changes encouraging distribution businesses to provide geographic information identifying areas of emerging network constraint. The initial focus of this work has been to identify regions where growth in peak demand is likely to exceed network capability encouraging the development of demand-side solutions or the location of embedded generation in those areas. Extending the approach to also show areas of emerging constraints due to the level of renewable generation could assist developers of small scale hydrogen facilities to identify the best development sites.
- Energy market pricing signals currently reflect the state-wide balance between load and generation and those signals do not necessarily incentivise the operation of demand and generation facilities in a local area to best manage local network issues. Various reforms including those being considered through the CoGaTi review, have been proposed to enhance incentives for load and generation to be controlled locally to address local network issues. Developments of smarter distribution networks and allocating an entity with the responsibility for facilitating markets at a local level, for the exchange of power between loads and generations, could help amplify incentives for the development of small-scale hydrogen facilities.
- Capturing the maximum value from participation in the energy market may require small-scale facilities to participate in the electricity markets (the NEM and the WEM) as market loads. The price volatility in the NEM and the potential prudential requirements may present a disincentive for hydrogen producers to register as market participants. An alternative that may prove attractive could be for hydrogen production facilities to assign a third party to act as their financially responsible market participant (FRMP). Retailers or aggregators may be willing to act as the FRMP for hydrogen production facilities. This approach would reduce the risk for hydrogen producers but would result in a reduction of revenue due to the fees charged by the FRMP. In other electricity markets in Australia, price volatility is not as great as the NEM which means that direct participation in those markets may present an acceptable risk for hydrogen investors.

7 | Use-case scenarios

7.1.3 Recommendations

To realise these opportunities and overcome any potential barriers, recommended mitigations include:

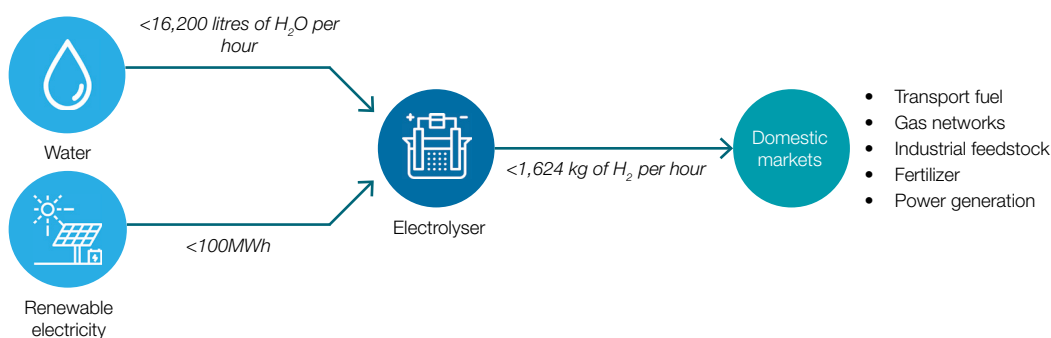
- Knowledge sharing of network congestion locations at a distribution level: Increase the amount of information available on areas of network congestion and indicate where the additional controllable load would be beneficial in relieving congestion.
- Assessment of applications: Develop harmonised processes for the assessment of applications to develop small-scale hydrogen facilities.
- Incentivise controllable loads: Work with market participants to encourage the development of local markets providing price signals and mechanisms that incentivise the operation of controllable loads to help address local network issues.

7.2 Medium-scale use-case scenario

As domestic and international markets for clean hydrogen emerge, medium-scale hydrogen production facilities that take power from the transmission network are likely to develop. The development of larger domestic markets, such as hydrogen as a transport fuel, will drive medium-scale hydrogen production that connects to existing transmission networks.

By connecting to the transmission network, the quantities of power that medium-scale hydrogen production facilities can draw on are an order of magnitude greater than those afforded in the distribution network. In this case use, we consider scenarios where the transmission connection will support electricity flows of 100s of MWs.

Transmission connected hydrogen producers may co-locate with renewable power generation, and opportunistically import or export power to the grid depending on relative energy prices, or may rely solely on the importation of power from the grid. Where the hydrogen producer imports power from the transmission network, the purchase will need to be supported by Power Purchase Agreements (PPA), new derivate instruments or alternative instruments that met the relevant certification schemes that enable the hydrogen to be classified as “green”. While there are benefits that can be derived from co-locating hydrogen production and renewable generation other factors such access to hydrogen transportation infrastructure, access to domestic demand or ports for exports and access to water for electrolysis are also important. These factors may favour locations near cities and ports or with relatively secure water access, such as those that are closer to the coast allowing seawater (combined with desalination or demineralisation) or locations allowing access to recycled water.



Source: GHD, 2020

7 | Use-case scenarios

7.2.1 The benefits

Currently, there are very few examples of facilities that consume more than 100 MW at a single site other than aluminium smelters. However, this level of power is typically supplied to distribution networks at bulk supply substations. Hydrogen production loads in the 100s of MW are therefore likely to require the establishment of a new bulk supply substation or expansion of an existing bulk supply substation.

The unique opportunities for this scale of hydrogen production that also support the electricity system arise when the developments connect to shared electricity networks, rather than being developed in isolation of the existing shared networks. When this occurs, there is significant scope for generation following, ancillary and network support services to be provided in a way that is beneficial to the broader electricity market, while servicing hydrogen demand.

From a hydrogen production perspective, the connection to the network will enable production to be optimised over time with support from generators connected to the shared network (but who are remote from the production site). A connection to the network also allows for opportunistic take-up of alternative sources of revenue through ancillary service markets.

Projects established in areas of the transmission grid that have significantly more renewable generation than demand will be able to capture a range of benefits including:

- Reducing the loss factor variability faced by renewable generators. By consuming locally produced generation, the losses on the transmission network are reduced, which improves the marginal loss factor seen from by local renewable generators. The hydrogen producer would be able to contract with local renewable generators to share in the value delivered. An illustration of the benefits of co-locating load and generation can be seen in the NEM by comparing the MLF for the Sun Metals Solar farm with other solar farms located in northern Queensland. The Sun Metals Solar farm and zinc smelter operate in combination to reduce losses achieving a generation loss factor close to 1.0.
- Avoiding transmission congestion. Renewable generators may face constraints when there is insufficient transmission capacity to convey the power produced to remote load centres. The development of a hydrogen production facility can reduce the risk of network congestion by aligning the production of hydrogen to the periods of peak generation from local renewable generators. Currently, the lack of appropriate sub-regional pricing signals when transmission constraints bind may impede the ability for hydrogen producers to capture these benefits.

Prudential requirements and the complexity of regulations can deter medium-scale producers from directly participating in the NEM. However, mechanisms exist for market participants to act as a market intermediary or the financially responsible market participant. This option may be an attractive way of capturing the benefits of NEM participation while reducing complexity for hydrogen producers.

The price volatility in the NEM is the key design element that drives the need for careful monitoring of the ability of market loads to meet their prudential requirements. The WEM employs a different market design which produces less price volatility. The WEM design encourages hydrogen producers to directly contract with generators. The contracts would identify the expected supply of electricity from generators to the hydrogen facility, with and changes due to unforeseen variations in renewable generation reflected via adjustments transacted in the balancing market.

7 | Use-case scenarios

The capacity market that is part of the WEM design may also provide a revenue opportunity for a medium-scale transmission connected hydrogen production facility. The capacity market allows interruptible loads to receive a capacity payment if they agree to reduce output under peak demand conditions or when there is a shortfall in electricity generation.

7.2.2 *Factors to enable this scenario*

The unique factors for consideration to enable this use of hydrogen may include:

- Augmentations to the transmission network will be required to connect a hydrogen production facility consuming 100s of MW. Choosing the right location should limit the extent of augmentation to either a new substation or expansion of an existing substation.
- To maximise the electricity market opportunities, facilities should be developed in areas with excess renewable generation capacity. This may also allow sharing of existing substations.
- Loads currently pay for the shared transmission network through the use of system charges. New loads may therefore only be asked to provide security over future transmission network charges (which will be recovered via network tariffs over the life of the project) rather than fund, upfront, the entire cost of the transmission network augmentation necessary to connect the load.

7.2.3 *Recommendations*

To realise the opportunities and overcome any potential barriers, recommended actions may also include:

- Knowledge sharing of network congestion location at a transmission level: Increase the amount of information available on areas of network congestion and indicate where the additional controllable load would be beneficial in relieving congestion.
- Measures that encourage these producers to participate in the wholesale electricity markets (rather than contract with retailers) to ensure price signals are observed.
- Resolving regional and sub-regional pricing issues so that hydrogen producers can realise the benefits of locating in congested parts of the transmission network and extract the full value from these locational decisions. The CoGaTi reforms currently being considered by the AEMC include mechanisms designed to address this issue.

7 | Use-case scenarios

7.3 Large-scale use-case scenario

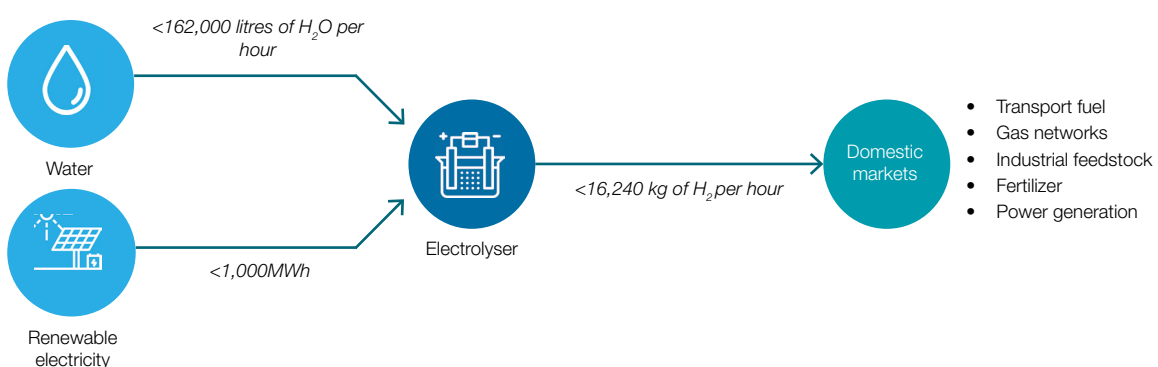
To support the development of hydrogen exports, the future is likely to include large-scale hydrogen production where the capacity of electrolysis plants (and co-located generation) could exceed 1 GW.

The location of these large-scale developments will be driven by the availability of electricity input resources, and the land requirements needed to support production, including renewable generation if co-located. Additionally, developers will be considering the availability of water sources, land use, surrounding community or social impacts, as well as the transport and logistics requirements (and costs) to deliver hydrogen to export markets.

The areas where these developments are most likely to arise will be away from developed metropolitan areas with suitable access to water. A large-scale (1 GW) hydrogen production facility operating at full output will consume 3,888,000 litres of water per day (equivalent to the volume of water in 1.5 Olympic sized swimming pools)⁹⁰. Accessing this volume of water may require development close to the coast to enable the use of seawater with desalination.

To meet the electricity requirements for large-scale hydrogen production, the developments could be co-located with significant quantities of renewable electricity generation and operate in isolation from the electricity network. In this case, the systems will need to be electrically self-supporting.

Alternatively, developments may be connected to the transmission network with the connection capacity sized to supply the entire electrolysis load from the grid. A third option that could be contemplated with hydrogen production facilities co-located with renewable generation, would see a grid connection with the capacity of the connection selected to optimise the value delivered by participating in the national electricity market and the cost of the connection.



Source: GHD, 2020

⁹⁰ Assuming 24 hours of hydrogen production 3,888,000 litres of water (24 x 162,000 litres per hour) is used. An Olympic sized swimming pool holds around 2,500,000 litres of water. GHD calculations assumes 1 litre of water is required to produce 0.10 kg of hydrogen, based on Siemens PEM technology.

7 | Use-case scenarios

The number of sites on existing electricity networks that can support large-scale production of hydrogen as a load drawing power in excess of 1 GW without significant augmentations are limited. Large-scale hydrogen producers relying solely on grid-supplied electricity may be able to re-use connections that previously supported closed power stations or aluminium smelters.

To reduce the augmentation costs and gain access to a wider range of locations, producers of large-scale hydrogen destined for export markets may choose to co-locate with renewable power.

Grid connections for sites with co-located generation can be sized to allow a level of participation in the electricity market that minimises costs of connection and any associated transmission augmentation. This may offer advantages over a facility supplied solely by remote generation via the transmission grid by reducing grid connection costs and providing greater flexibility regarding the selection of the site for the hydrogen production facility.

The development of large-scale facilities with a grid connection may be favoured by investors as it allows a level of independence between the hydrogen facility and the renewable generation. Without any grid connection, the viability of the large-scale hydrogen facility and the renewable generation is tightly coupled with each presenting a stranding risk for the other.

7.3.1 *The benefits*

The opportunities for this use of hydrogen that also support the electricity system arise when the developments connect to shared electricity networks, rather than being developed in isolation of the existing networks. The benefits are similar to those outlined in the medium-scale use-case scenario only magnified, i.e. significant scope for ancillary and network support services.

From a hydrogen production perspective, the connection to a network will enable production to be optimised over time with support from generators connected to the shared network (but who are remote from the production site), however this benefit is weaker compared to the medium-scale scenario as the generation capacity from existing networks may not be sufficient to fully supply the electrolyzers.

Where large-scale developments are co-located with renewables, connection to the transmission network offers an alternative revenue stream (besides hydrogen) and is likely to reduce the stranding risks for hydrogen producers.

7 | Use-case scenarios

7.3.2 Factors to enable this scenario

The unique factors to consider and address for this use of hydrogen, from an electricity system perspective, will be providing the large-scale production site owners with sufficient certainty over the benefits that can be derived from the grid connection to justify proceeding with the grid connection. The factors that enable the medium-scale facilities to maximise value from their participation in electricity markets will also apply to large scale grid-connected facilities.

There are a range of technical, financial and regulatory hurdles that, if not addressed, may incentivise these types of developments to arise in isolation of existing (and future shared) networks. Complex regulatory investment frameworks for transmission infrastructure can frustrate the development of large scale hydrogen production facilities reliant on new transmission lines to provide grid connections and may make investors less inclined to develop large scale grid-connected facilities.

The size of connections for a very large-scale development and the transmission infrastructure upgrades needed to support its connections will be substantial particularly if it is accessing renewable generation from distant areas of the power system. There is an opportunity to reduce the extent of transmission upgrades required if the facility operates to minimise any increased loading on the transmission system. This could be achieved by locating the hydrogen production facility in a region of the power systems with a substantial level of renewable generation. If the hydrogen production facility draws electricity only when it is produced by locally adjacent renewable generators this will minimise the impact on the transmission network.

Connecting a large-scale hydrogen production facility that requires significant upgrades to the transmission system will require the developer of the facility to work closely with the transmission network service provider.

A large-scale development of this type presents an opportunity to re-use a transmission connection established for a de-commissioned power station or a decommissioned large electricity-intensive industry such as an aluminium smelter. This approach would reduce the need for expensive and time-consuming upgrades to the transmission network associated with establishing new connections capable of supplying >1 GW of load at a single location.

7 | Use-case scenarios

7.3.3 Recommendations

To realise these opportunities and overcome any potential barriers, recommended mitigations include:

- Identifying and aligning mutually beneficial interactions so that the developments do not emerge in isolation of the existing networks.
- Timely development of the transmission needed to support the connection to shared transmission networks represents a significant challenge within the current regulatory framework, particularly if it is to proceed as a regulated transmission investment. While unregulated connection could be developed outside of the existing economic regulatory framework, this approach may add significant costs to the hydrogen production project as the investor is likely to be asked to fund the capital cost of the required transmission investment.

Potential solutions to help facilitate connections to large scale hydrogen production facilities include governments providing funding to support the development of the business case to justify any regulated network investment. This may include the cost of any works necessary to gain environmental and development approvals.

However, government support in these instances should focus on assisting developments that are likely to provide significant economic benefits and where generally changing regulatory arrangements are driving sub-optimal developments.

7 | Use-case scenarios

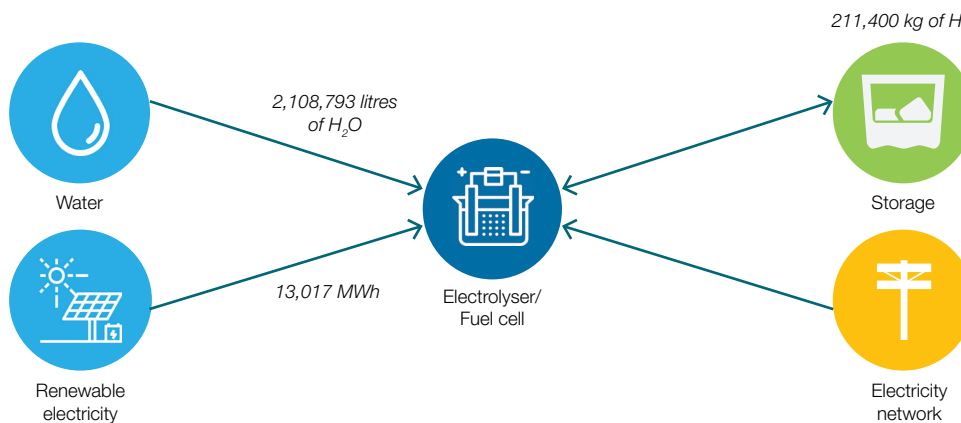
7.4 Seasonal storage of renewable energy use-case scenario

Large-scale hydrogen storage could be used for storing seasonally variable renewable electricity. In this scenario, hydrogen will be produced during periods of excess electricity production, for example from solar during the summer months, and stored for conversion back to electricity or used for other means during periods of energy shortage or when price arbitrage opportunities exist.

Seasonal storage typically involves the storage of energy in one season and the release of the stored energy in a different season. Storage of hydrogen (and natural gas) to help mitigate seasonal variation in energy production and consumption has been used in both the UK and Norway.

In the UK and Norway, seasonal storage of this kind is attractive because there are significant differences in energy requirements between summer and winter months. Here in Australia, large-scale hydrogen storage may be particularly important as an alternative to pumped hydro and large-scale batteries as the generation mix in Australia moves towards higher penetrations of renewable generation.

Seasonal storage can refer to multi-annual storage and shorter-term storage of energy (such as several days). In Australia, where the difference in energy requirements between seasons is less significant, storage that caters for shorter periods of energy deficit could be more appropriate. For example, storage facilities could be sized to cater to various electricity market contingencies, such as renewable resource droughts (several consecutive days with low wind and cloud cover) or failure of the largest generator.



Note: Seasonal storage sufficient to store a day's output from all wind generation in South Australia⁹⁰, assuming a 30% capacity factor.

Source: GHD, 2020

Hydrogen storage has some advantages over both pumped hydro and large-scale batteries. Production of hydrogen (and conversion back to electricity) requires significantly less water than pumped hydro; a benefit generally and in periods of drought. The energy content of hydrogen is not lost when stored, so it has the potential to provide much longer-term energy storage solutions compared to batteries. As noted in section 2.3, hydrogen storage and conversion technology currently offer a significantly lower cycle efficiency than competing electricity storage technologies. Improving the cycle efficiency would enhance the commercial viability of this use-case.

⁹¹ Existing, in-service wind generation in South Australia has a nameplate capacity of 1,807.95 MW. As per AEMO, 'Generation Information Page', accessed 5 February 2020, refer to 'Generation Information Page 20200131.xlsx'.

7 | Use-case scenarios

Physically, the storage must be significant for this use-case to provide meaningful smoothing of seasonal variations. Storage options may include depleted gas fields or gas reservoirs, aquifers or specifically designed large-scale storage facilities. The power required to connect electrolysis units that produce the hydrogen for storage is similarly likely to be large, potentially in the 100s of MWs.

A direct connection to the transmission level electricity network infrastructure would be required. The areas that will most efficiently support this application (without substantial upgrades to the transmission network capacity), from an electricity systems point of view, are locations that are already well supported by the transmission network. For example, sites of decommissioned power stations as these sites will support the bi-directional flow of electricity at the quantities needed. Where the hydrogen is planned for use in gas networks, locations close to existing pipelines may be also attractive.

7.4.1 *The benefits*

The benefits to the electricity market from seasonal storage include reduced volatility of prices between seasons, increased energy security, and a significant opportunity to avoid waste of renewable power.

Seasonal storage will also make the electricity markets more resilient because hydrogen production can be ramped up or down, or converted back to electricity to meet peak electricity system needs and during periods when the grid is under pressure.

Storage facilities need not only supply hydrogen for power generation. Facilities could also provide hydrogen for transport, industrial and natural gas enhancement. As the different markets for hydrogen evolve and demand becomes clearer, the opportunity for owners of hydrogen storage facilities to arbitrage between markets will increase and is likely to positively influence the commercial feasibility of such investments.

7 | Use-case scenarios

7.4.2 Factors to enable this scenario

The unique challenges for this use of hydrogen that relate to the current electricity market frameworks include:

- Price signalling of when to use hydrogen, particularly if storage solutions envision longer time frames, are currently weak in the electricity market. This current framework is a result of demand being inherently unpredictable so that retailers are reluctant to contract for longer periods of time, and there being few inter-seasonal and inter-year storage options – hydro being the only current source that does not contribute to carbon emissions.
- Identifying transmission connection opportunities that facilitate the efficient exploitation of opportunities for large-scale hydrogen storage. For example, areas of the transmission network that have high capacity availability in close proximity to aquifers capable of storing hydrogen would be advantageous.

7.4.3 Recommendations

To realise these opportunities and overcome any potential barriers, recommended mitigations include:

- Investments in storage that support electricity grid resilience are likely to be significant. It is unlikely private industry will make these investments on their own in the near term. The government could help by:
 - Identification and testing of the feasibility of viable locations, including investigations considering the engineering aspects of potential storage options and sites.
 - Demonstrating (quantifying) the benefits of increased energy security and electricity market resilience.
 - Quantifying the long-term energy storage required for various energy market contingencies and for emerging hydrogen markets (for example, transport, industrial), which will help appropriately size storage facilities and allow investors to make better-informed assessments.
- Develop long-term price signals from electricity markets that have not traditionally valued inter-seasonal saving of energy, mainly because options to do this were not available.



Chapter 8 | Conclusions

8 | Conclusions

Electrolyser technologies used for the production of hydrogen can deliver significant benefits to the electricity market because they are capable of adjusting the level of hydrogen production such that the electricity consumed matches the amount of renewable generation being produced (i.e. load that follows generation).

Our review of international practice has identified several projects that demonstrate the ability for hydrogen production and storage facilities to provide generation following and frequency control services. Those capabilities could assist power system across Australia to reach carbon emission reduction targets while maintaining system security and reliability.

The willingness of hydrogen proponents to provide generation following benefits to the electricity market depends on the incentives and potential revenue streams offered by these markets and the associated costs to realise those revenue streams.

Our research has found that there are no material barriers within energy markets and electricity rules that specifically support or detract from developing hydrogen production as a load or from the use of hydrogen as a fuel for power generation. However, in the short-term, regulatory changes that will help ensure a supportive interaction between the hydrogen economy and the electricity network include:

- Changes that facilitate the registration of hydrogen facilities, including combined hydrogen production and electricity generation facilities, and
- Continuing to progress reforms that improve accessing transmission capacity and locational signals.

Once generation-following opportunities are enabled, there are secondary benefits to the greater participation of electrolysers and fuel cell technology in the electricity markets. These include changes to reform ancillary and essential services markets to better value the micro-interruptibility of hydrogen loads, enabling more variable renewable generation onto networks whilst enabling power system security⁹².

In the long-term, the effects of hydrogen production on the electricity systems are less clear, however it is possible there will be a step-change in the volume of electricity required and the way in which networks are operated. To meet 2050 hydrogen production estimates, the installed generation capacity in Australia will need to increase by around three per cent in total under a 'business-as-usual' scenario but will have to double or increase by five-fold if a targeted hydrogen deployment or the most opportunistic hydrogen production scenarios eventuate⁹³.

⁹² Ancillary and essential service markets are significantly smaller than the electricity market. Information on the size of the frequency control ancillary services market in the NEM (the largest of Australia's markets for these services) is available on the AER website here: https://www.aer.gov.au/wholesale-markets/wholesale-statistics?f%5B0%5D=field_acc_aer_stats_category%3A1076

⁹³ Based on hydrogen production forecasts and electricity inputs requirements developed by Deloitte, assuming solar generation with a capacity factor of 30 per cent (rather than a capacity factor of 41 per cent as Deloitte assumes), and based on the current total installed capacity of 64,524 MW across the NEM and SWIS.

Source: Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the National Hydrogen Strategy Taskforce, November 2019, p. 102.

8 | Conclusions

The impacts of increases in hydrogen production under the most opportunistic scenario will depend on whether developments merge off-grid as ‘super-sized’ projects⁹⁴ or are dispersed throughout the existing networks as small, medium and large scale projects. Regardless, the areas policymakers should be focused on in the longer-term are:

- Making changes to the regulatory approval process for network expenditure to ensure network developments are sufficiently responsive and keep pace with rapid changes to the market as hydrogen demand emerges supported by higher penetrations of variable renewables and to cater for the changing dynamic between supply and demand and the way networks will be used.
- Understanding and monitoring the interdependency of markets so that risks arising from the interdependency of markets can be managed appropriately. For example, as the electricity market becomes more reliant on gas-fired power generation, contingency events in the gas market become increasingly important for the electricity market to understand. Similarly, building awareness of cross market solutions will increase the options available to solve emerging issues.
- Building national capabilities ahead of potentially significant market changes that will require a different mix of skills including new capabilities.
- Creating an environment that brings greater transparency and certainty over future electricity prices, to promote longer-term investment solutions. The transparency of future electricity prices is also particularly important for hydrogen facilities to enable the right investment decisions that leverage sector coupling opportunities.

Despite the increased attention on hydrogen, markets are still in their infancy, which means it is difficult to forecast or understand the full effect of future changes. To understand the full requirements from the electrical systems to supply power for hydrogen production, we recommend analysis on the impact of hydrogen on electricity systems be revisited periodically as the market dynamics in the electricity market and energy markets continue to evolve.

⁹⁴ Super-sized’ refers to individual projects that require generation input capacity that is multiples of the existing generation capacity



Appendix A | Acronyms, terms and
abbreviations

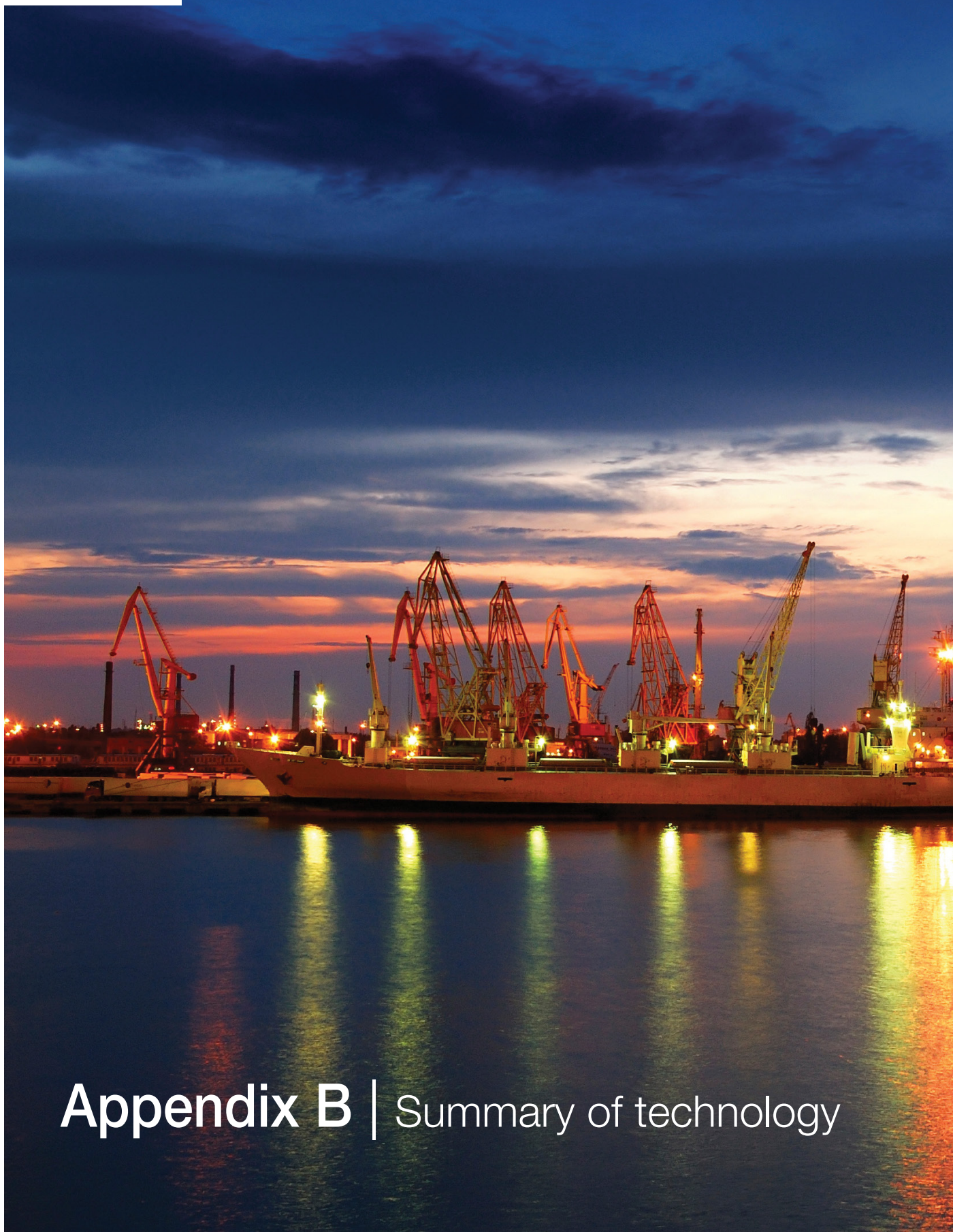
Acronyms, terms and abbreviations

The following acronyms, terms and abbreviations have been used in this report.

| Acronym / term / abbreviation | Meaning |
|-------------------------------|--|
| AE | Alkaline electrolyzers |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| ARENA | Australian Renewable Energy Agency |
| Capex | Capital expenditure |
| COAG | Council of Australian Governments |
| CoGaTil | Coordination of generation and transmission investment |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| DELWP | Department of Environment, Land, Water and Planning (Victoria) |
| DSS | Dispatch Support Service |
| EU | European Union |
| FCAS | Frequency Control Ancillary Service |
| FRMP | Financially responsible market participant |
| GW | Gigawatt |
| GWh | Gigawatt hour |
| H ₂ | Hydrogen |
| ICT | Instrumentation, control and telecommunications |
| IEA | International Energy Agency |
| ISP | AEMO Integrated System Plan, June 2018 |
| km | Kilometre |
| km ² | Square kilometre |
| kV | Kilovolt |
| LFAS | Load following ancillary service |
| LHV | Lower heating value |
| LRRAS | Load Rejection Reserve Ancillary Service |
| Market Participants | Registered participants of the National Electricity Market e.g. scheduled and semi-scheduled generators above 5 MW |
| MLF | Marginal loss factor |
| MPa | Mega Pascal |
| Mt | Million tonnes |
| MW | Megawatt |
| MWh | Megawatt hour |
| NEM | National Electricity Market |
| NEO | National electricity obligation |
| NER | National Electricity Rules |
| NLCAS | Network load control ancillary service |
| NSCAS | Network Support and Control Ancillary Service |
| NWIS | North West Interconnected System |
| Opex | Operating expenditure |
| PPA | Power purchase agreement |
| PEM | Polymer electrolyte membrane |
| PV | Photovoltaic |
| REZ | Renewable energy zone |

Acronyms, terms and abbreviations

| Acronym / term / abbreviation | Meaning |
|-------------------------------|--|
| RERT | Reliability and Emergency Reserve Trader |
| SOEC | Solid oxide electrolysis cell |
| SOFC | Solid oxide fuel cell |
| SRAS | System restart ancillary service (NEM), Spinning reserve ancillary service (WEM) |
| SRS | System Restart Service |
| STEM | Short term energy market |
| SWIS | South West Interconnected System |
| TLF | Transmission loss factor |
| TNSP | Transmission network service provider |
| TWh | Terawatt hour |
| UK | United Kingdom |
| US / USA | United States of America |
| USD | United States Dollars |
| VAR | Volts Amps reactive |
| WA | Western Australia |
| WEM | Wholesale Electricity Market (in Western Australia) |



Appendix B | Summary of technology

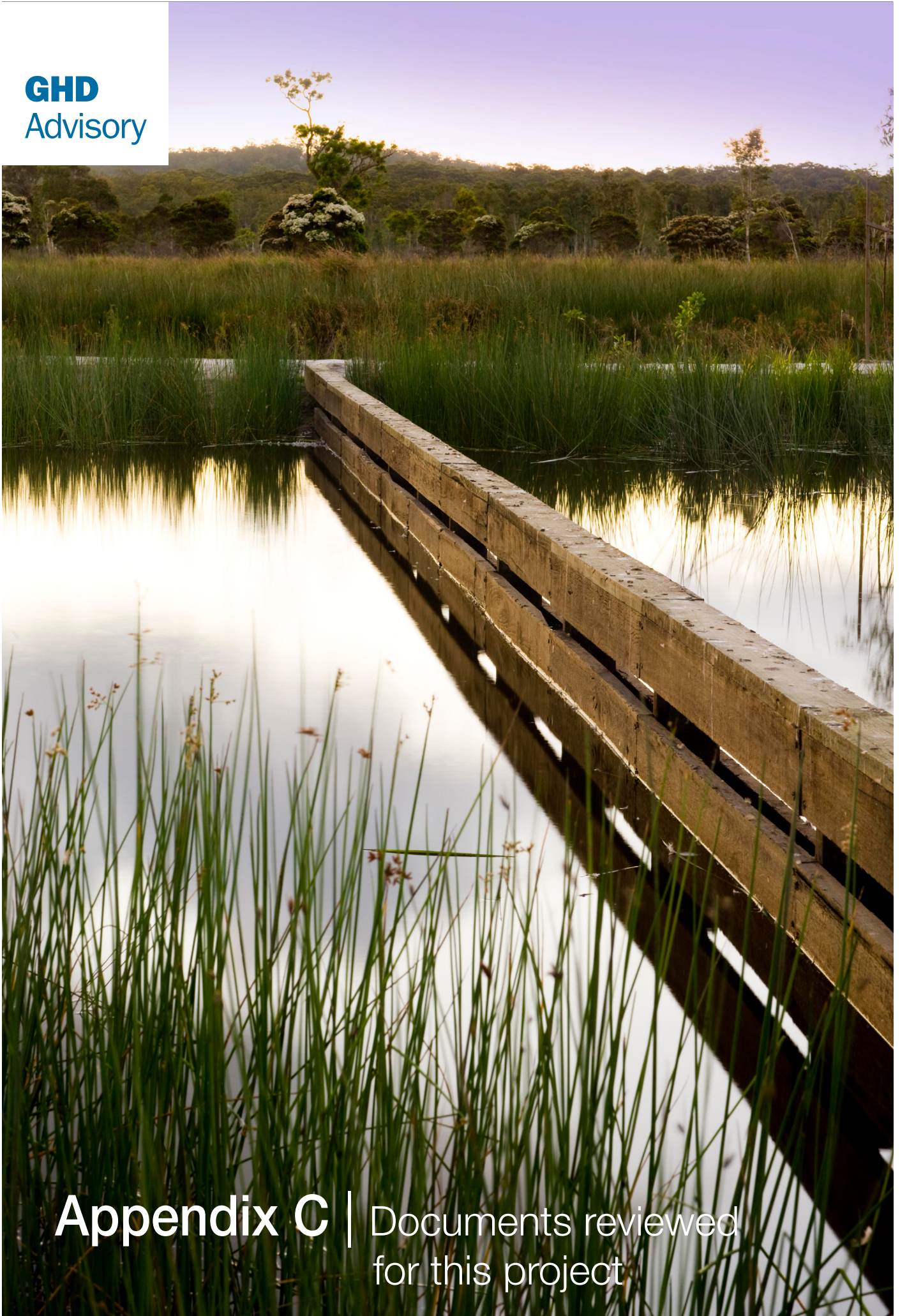
Summary of technology

Table 6 Summary of AE and PEM and SOEC electrolyser technologies

| | | Alkaline electrolyser | PEM electrolyser | SOECs |
|--|------|---|--|--|
| Description | | Electrochemical cell that uses a potassium hydroxide electrolyte to form hydrogen at the negative electrode and oxygen at the positive electrode. | Water is catalytically split into protons which permeate through a membrane from the anode to the cathode to bond with neutral hydrogen atoms and create hydrogen gas. | A solid oxide electrolysis cell (SOEC) is an electrochemical energy conversion cell that is capable of operating, in reverse mode, as a solid oxide fuel cell (SOFC). It uses ceramics as the electrolyte and is operated in very high temperatures. |
| Maturity of technology | | Mature and commercial, in use since 1920s. Well established supply paths. | Mature technology, in use since the 1960s. | Relatively immature technology. |
| Operating temperatures (°C) | | 60-80 | 0-160 | 650-1,000 |
| Plant footprint (m ² /kW _e) | | 0.095 | 0.048 | |
| Stack lifetime (operating hours) | Now | 60,000 to 90,000 | 30,000 to 90,000 | 10,000 to 30,000 |
| | 2030 | 90,000 to 100,000 | 60,000 to 90,000 | 40,000 to 60,000 |
| Electrical efficiency (% LHV) | Now | 63-70% | 56-60% | 74-81% |
| | 2030 | 65-71% | 63-68% | 77-84% |
| CAPEX (USD/kWe) | Now | 500 to 1,400 | 1,100 to 1,800 | 2,800 to 5,600 |
| | 2030 | 400 to 800 | 650 to 1,500 | 800 to 2,800 |

Notes: LHV = lower heating value; m²/kWe = square metre per kilowatt electrical.

Source: CSIRO, *National Hydrogen Roadmap – Pathways to an economically sustainable hydrogen industry in Australia*, p. 13; and IEA, *The Future of Hydrogen*, June 2019, pp. 43-35.



Appendix C | Documents reviewed
for this project

Documents reviewed for this project

Table 7 Documents reviewed for this project

| Document | Coverage |
|---|---|
| United Kingdom | |
| Fuelling the Future: Hydrogen's role in supporting the low-carbon economy, 2018 | Comprehensive report which examines production, transport and storage of hydrogen; decarbonising hard to reach sectors and integrating renewables. Observes that blending up to 20 per cent hydrogen with natural gas will deliver only small carbon savings but that this may be a useful first step. Considers that geological storage is feasible but not sufficiently available for large-scale storage of hydrogen. Power-to-gas using electrolyzers with fast response times could be useful to facilitate higher penetration of intermittent generation. Business models relying on curtailed renewables are not likely to be economic in the UK. Immediate steps include removing regulatory barriers, setting standards for green hydrogen, and continuing to exempt hydrogen from fuel duty. Well referenced. See https://policyexchange.org.uk/wp-content/uploads/2018/09/Fuelling-the-Future.pdf |
| The Clean Growth Strategy: Leading the way to a low carbon future, 2017 | Provides details of Government policies, programs and incentives relevant to hydrogen. See Updated in April 2018. See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf |
| Role of power-to-gas in an integrated gas and electricity system in Great Britain, 2015 | Discusses the role of power-to-gas in providing flexibility in the UK electricity and gas networks. Used a combined gas and electricity network optimisation model. Concluded that this approach would significantly reduce UK wind power curtailment and operating costs of the integrated system. See https://www.sciencedirect.com/science/article/pii/S0360319915005418 |
| The role of hydrogen and fuel cells in future energy systems, 2017 | Covers existing hydrogen "niche markets" and considers potential role of hydrogen and fuel cells in the UK with scenario modelling. Examines hydrogen and fuel cell systems for transport, heat and electricity generation. Explores how the transition to hydrogen and fuel cells might be achieved. See http://www.h2fcsupergen.com/wp-content/uploads/2015/08/J5212_H2FC_Super-gen_Energy_Systems_WEB.pdf |
| The role of hydrogen and fuel cells in delivering energy security for the UK, 2017 | Covers hydrogen production, fuel cell technology and their roles in providing energy security. Notes that adopting hydrogen as an end-use fuel would increase UK energy diversity/resilience and improve the UK's electricity system with its high penetration of renewables. See http://www.h2fcsupergen.com/wp-content/uploads/2015/08/J5214_H2FC_Super-gen_Economic_Impact_report_WEB.pdf |
| The economic impact of hydrogen and fuel cells in the UK, 2017 | A preliminary assessment based on analysis of the replacement of refined transport fuels and vehicles. Covers macroscale scenario switching (using an input-output model), supply chain, manufacturing base, employment, skills, export and intellectual property issues, with a short chapter on the international context. See http://www.h2fcsupergen.com/wp-content/uploads/2015/08/J5214_H2FC_Super-gen_Economic_Impact_report_WEB.pdf |
| Hydrogen and Fuel Cells: Opportunities for Growth-A Roadmap for the UK, 2016 | An earlier Government-commissioned roadmap. Considers what actions are needed to enable hydrogen and fuel cell benefits for the UK. Discusses priorities for policymakers, industry, hydrogen and fuel cell product developers, gas and electricity networks and regulators, regional organisations and researchers. See http://www.e4tech.com/wp-content/uploads/2016/11/UKHFC-Roadmap-Final-Main-Report-171116.pdf |
| HyLAW – Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications-UK National Policy Paper, 2018 | HyLAW stands for Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications. Comprehensive analysis of regulatory issues for hydrogen production, storage, transport and distribution, use as a fuel, vehicles, electricity and gas grid issues, and stationary power. Includes conclusions and recommendations. See https://www.hylaw.eu/sites/default/files/2019-01/HyLaw%20UK%20Policy%20Paper_Final_December%202018.pdf |
| Energy from gas: Taking a whole system approach, 2018 | Case studies. See https://www.imeche.org/docs/default-source/1-oscar/reports-policy-statements-and-documents/imeche-energy-from-gas-report-final-may-2018.pdf?sfvrsn=2 |
| Market and regulatory frameworks for a low carbon gas system, 2018 | This study first identifies what gas market models and regulatory frameworks may look like in a 2050 steady state under a range of scenarios for a low carbon gas system, and then looks at the risks, uncertainties and barriers there may be in the transition to a low carbon gas system. Options for how these may be managed or overcome are presented. See https://www.gov.uk/government/publications/market-and-regulatory-frameworks-for-a-low-carbon-gas-system |

Documents reviewed for this project

Germany

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| Analysis of the macro-economic and environmental benefits of power-to-gas, 2018 | Quantifies benefits from increasing integration of individual energy sectors and how this integration can reduce the need for power grid expansion. Study focused on an introductory phase of transition, to 2025 and a longer-term perspective to 2050. The analysis divided Germany into four regions with different energy profiles. Energy production, conversion, storage and use included in the modelling. Data rich. Literature cited mainly in German. See https://www.amprion.net/Dokumente/Dialog/Downloads/Studien/Studie-Sektorenkopplung/Study-Smart_Sector_Integration.pdf |
| National Organisation Hydrogen and Fuel Cell Technology (NOW) – Annual report 2017 and 2018 | Outlines activities including international cooperation, campaigns, publications (mostly in German), funding for hydrogen and fuel cells, charging infrastructure, local electric mobility and the German mobility and fuels strategy. See https://www.now-gmbh.de/en/news/press/now-annual-report-for-2017-published and https://www.now-gmbh.de/content/service/3-publikationen/7-now-jahresberichte/now_annual_report_2018.pdf |
| The importance of the gas infrastructure for Germany's energy transition: A model-based analysis, 2018 | Frontier Economics, IAEW, 4Management and Emcel report which analyses 2050 energy systems with and without the use of gas infrastructure under three scenarios: Electricity only, electricity and gas storage and electricity and green gas. See https://www.fnb-gas.de/files/fnb_gas_study_-_value_of_gas_infrastructure_-_english_translation_1.pdf |
| Energiepark Mainz: technical & economic analysis of the worldwide largest power-to-gas plant with PEM electrolysis, 2017 | Referenced in our report. See https://www.energiepark-mainz.de/EN/ |

France

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| Développons l'hydrogène pour l'économie française – étude prospective, 2018 | Presents potential uses and adoption to 2050. Transport and heating focus. Projected economic impact with emphasis on export of equipment. Exports and imports projected to 2030. See http://www.afhypac.org/documents/actualites/pdf/Afhypac_Etude%20H2%20Fce_VDEF.pdf |
| Plan de déploiement de l'hydrogène pour la transition énergétique, 2018 | Discusses the electricity system of the future, progress on hydrogen and plans for the deployment of hydrogen for the transition to a future energy system. See https://www.ecologique-solidaire.gouv.fr/sites/default/files/2018.06.01_dp_plan_deploiement_hydrogene_0.pdf |
| Plan hydrogène : un outil d'avenir pour la transition énergétique, | The Plan proposes 3 steps: Decarbonated hydrogen production for refineries and the chemical industry, commercialisation of hydrogen uses in mobility (complementary to batteries), and stabilising energy networks including reviewing regulations so that hydrogen can be injected into natural gas infrastructure by the end of 2018. See https://www.ecologique-solidaire.gouv.fr/plan-hydrogene-outil-davenir-transition-energetique |
| Stratégie française pour l'énergie et le climat, programmation pluriannuelle de l'énergie 2019-2023, 2024-2028, undated | Overview of France's energy system and what is expected/planned for the future. Includes various policy measures and some data. See https://www.ecologique-solidaire.gouv.fr/sites/default/files/2018.11.27_MTES_dp_PPE_SNBC_strategiefrancaiseenergieclimat.pdf |

Netherlands

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| Exploring the role of power-to-gas in the future Dutch energy system, 2014 | Conversion of renewable electricity to gas is an attractive option to accommodate intermittent electricity supply from wind and solar, and to decarbonise fossil-fuel-dependent end-use sectors such as transport and the built environment. Examines role of power-to-gas, drivers and bottlenecks. Presents modelling results and three regional case studies. See https://www.researchgate.net/publication/311087126_Exploring_the_role_for_power-to-gas_in_the_future_Dutch_energy_system |
| The effects of hydrogen injection in natural gas networks for the Dutch underground storages, 2017 | Analyses underground gas storage possibilities in the Netherlands in some detail, for different levels of hydrogen content. Includes material on hydrogen injection into natural gas networks in neighbouring countries and related safety regulations. See https://www.rvo.nl/sites/default/files/2017/07/The%20effects%20of%20hydrogen%20injection%20in%20natural%20gas%20networks%20for%20the%20Dutch%20underground%20storages.pdf |

Documents reviewed for this project

Netherlands

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| Energy transition: mission (im) possible for industry? A Dutch example for decarbonization | Decarbonizing the industrial sector is a challenge for the Netherlands. Making a change in one part of an industrial process (e.g. switching to electricity and hydrogen from electricity and natural gas) requires changes in other parts of the process. This McKinsey report concludes that a range of measures will be required and 60% decarbonisation by 2040 will cost €23 billion. Industry has long horizons, so comprehensive planning is needed. See https://energeia.nl/binaries/4000/04/14/het-rapport.pdf |
| Chemistry for climate: Roadmap for the Dutch Chemical Industry towards 2050, 2018 | Analyses pathways towards an 85-90% reduction in greenhouse gases over the next few decades and concludes that this is technically feasible while growing added value by 1% pa. Analyses investment needed and what the government needs to do to ensure to level the EU playing field and/or provide financial support. Calls for a joint industry-government approach to ensure that the energy system and associated infrastructure are developed in time for industry transition. Initial pathway to 2030 presented. See https://www.vnci.nl/Content/Files/file/Downloads/VNCI_Routekaart-2050.pdf |
| Outlines of a Hydrogen Roadmap, 2018 | Comprehensive analysis of energy transition scenarios to 2050 and the role of hydrogen in those scenarios. Covers policy, legislation and other non-technical issues. Again, hydrogen requires an integrated vision. Grey, blue or green hydrogen can be considered as long as the “final picture” is sustainable. See https://www.topsectorenergie.nl/sites/default/files/uploads/TKI%20Gas/publicaties/20180514%20Roadmap%20Hydrogen%20TKI%20Nieuw%20Gas%20May%202018.pdf |
| Feasibility study into blue hydrogen Technical, economic & sustainability analysis, 2018 | Covers production, carbon capture and storage, hydrogen transport, applications, etc. See https://www.cedelft.eu/en/publications/download/2585 |
| Topdutch hydrogen investment agenda, undated | Northern Netherlands. See https://www.topdutch.com/uploads/fckconnector/6671696a-e196-5521-a69d-d4d50c4d53d4/3113807077/hydrogen-investment-agenda.pdf |
| Bringing North Sea energy ashore efficiently, 2017 | PWC and others for the World Energy Council. See https://www.worldenergy.org/wp-content/uploads/2018/01/WEC-brochure_Online.pdf |

Canada

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| 2019 Hydrogen Pathways – Enabling a Clean Growth Future for Canadians, 2019 | Identifies twelve potential end use pathways where hydrogen and fuel cell technologies could be deployed. Available on request from NRCan.alternative_fuels-alternative_fuels.RNCan@canada.ca |
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United States of America

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| H2@Scale Analysis, 2018 | Identifies twelve potential end use pathways where hydrogen and fuel cell technologies could be deployed. Available on request from NRCan.alternative_fuels-alternative_fuels.RNCan@canada.ca |
| Regional Supply of Hydrogen, 2018 | Primary focus is hydrogen for transport. Some information on costs by production scenario over time. See https://www.hydrogen.energy.gov/pdfs/review18/sa063_penev_2018_p.pdf |
| Grid-Based Renewable Electricity and Hydrogen Integration | NREL presentation, looks at US “Goals for Electrolysis in Hydrogen Fuel Supply.” See https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/euiw_a12_elam.pdf |
| California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation, 2016 | NREL report. See https://www.nrel.gov/docs/fy17osti/67384.pdf |

Australia

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| National Hydrogen Roadmap | CSIRO report. See https://www.csiro.au/~media/Do-Business/Files/Futures/18-00314_EN_NationalHydrogenRoadmap_WEB_180823.pdf?la=en&hash=36839EEC2DE1BC38DC738F5AAE7B40895F3E15F4 |
| Regional Supply of Hydrogen, 2018 | This paper presents the discussion on significance of deploying hydrogen storage as a long-term large-scale application through a case study for South Australia. See https://www.mdpi.com/1996-1073/11/10/2825/pdf |
| Opportunities for Australia from hydrogen exports, 2018 | Report to ARENA referenced in this report. See https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf |

Documents reviewed for this project

Australia

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| Hydrogen as a Long-Term Large-Scale Energy Storage Solution to Support Renewables, 2018 | Two cases of battery energy storage and hybrid battery-hydrogen storage systems to support solar and wind energy inputs were compared. See https://www.mdpi.com/1996-1073/11/10/2825 |
| Submission to the National Hydrogen Strategy, 2019 | Useful details of current hydrogen projects in Australia. See https://www.energynetworks.com.au/sites/default/files/030419_hydrogen_strategy.pdf |
| Hydrogen Technologies Standards, 2018 | Standards Australia Discussion Paper. See https://www.standards.org.au/getmedia/2d89a05c-9dd0-4878-90f8-d1c228306d5b/D-1368-Hydrogen-discussion-paper.pdf.aspx |
| Hydrogen Standards Forum: Outcomes Report, 2018 | Reports outcomes from a workshop convened by Standards Australia in October 2018. Proposed seventeen international standards for potential adoption by Australia. See https://www.standards.org.au/getmedia/d51f264c-4744-45d7-a3eb-057c6fa19e0a/Hydrogen-Standards-Forum-Outcomes-Report.aspx |
| Advancing Hydrogen: Learning from 19 plans to advance hydrogen from across the globe, 2019 | Future Fuels CRC report. See https://www.adelaide.edu.au/global-food/system/files/media/documents/2019-07/RP1.1-03%20Hydrogen%20Strategies%20-%20Final%20Report%20EXTERNAL.pdf |

New Zealand

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| Hydrogen in New Zealand: Report 3 – Research, 2019 | A collation of material on hydrogen production, storage, distribution and use. Argues that large-scale production facilities are not suited to electrolysis because economies of scale are very limited. See http://www.concept.co.nz/uploads/2/5/5/4/25542442/h2_report_3_research_v4.pdf |
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Japan

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| Basic Hydrogen Strategy, 2017 | Discusses a range of hydrogen-related issues. A bit dated. See https://www.meti.go.jp/english/press/2017/pdf/1226_003b.pdf |
| METI Hydrogen Roadmap (updated) | Full documents not available in English, but for an English summary see https://www.meti.go.jp/english/press/2019/pdf/0312_002a.pdf |

Spain

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| HyLAW – National Policy Paper – Spain | One of a series of papers that review current legal frameworks applicable to hydrogen. This covers industrial applications, storage, transport and distribution, mobility and transport uses: electrolyser, electricity and gas network issues. See https://www.hylaw.eu/sites/default/files/2019-02/HyLAW_%20National%20policy%20Paper_ENG_Final.pdf |
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Italy

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| HyLAW – National Policy Paper – Italy, 2018? | One of a series of papers that review current legal frameworks applicable to hydrogen. This covers industrial applications, storage, transport and distribution, mobility and transport uses, electrolyser, electricity and gas network issues. See https://www.hylaw.eu/sites/default/files/2019-03/HyLAW_National%20policy%20Paper%20IT_eng.pdf |
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China

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| Overview of hydrogen and fuel cell developments in China, 2019 | Report by Holland Innovation Network China – China's initial interest in hydrogen has been in the automotive sector. The storage and delivery elements of China's hydrogen value chain are considered to be weak – no pipelines and liquid hydrogen transport is limited to military purposes. Regulations, codes and standards relating to hydrogen need to be updated. China has invested heavily in PEM fuel cells. High quality fuel cell power systems are being produced based on foreign fuel cell stacks. Six cities have large fleets of FECVs. Domestic PEM electrolysers are not sufficiently advanced for large-scale conversion of electricity to hydrogen. See https://www.nederlandwereldwijd.nl/binaries/nederlandwereldwijd/documenten/publicaties/2019/03/01/waterstof-in-china/Holland+Innovation+Network+in+China+-+Hydrogen+developments.+January+2019.pdf |
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Documents reviewed for this project

Chile

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| <p>Opportunities for the development of a solar hydrogen industry in the regions of Antofagasta and Atacama, 2018</p> | <p>Tractebel report which models the mix of electricity-producing and hydrogen-producing assets needed to achieve a 100% renewable target in 2035. These regions have both high PV and wind energy potential. See http://www.comitesolar.cl/wp-content/uploads/2018/10/Comite-Solar-2018-Opportunities-for-a-Hydrogen-Industry_Summary.pdf and related IRENA presentation https://innovation-week.irena.org/-/media/Files/IRENA/Innovation-Week/SessionalDocuments/IRENA-IW18-Hydrogen-03-Baeza-Development-in-Chile-06-Sept-18.pdf</p> |
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Multi country

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| <p>Power-to-gas-Short term and long-term opportunities to leverage synergies between the electricity and transport sectors through power-to-hydrogen, 2016</p> | <p>Examines 2 power-to-gas applications: green hydrogen for use in refineries and semi-centralised power-to-hydrogen system supporting local hydrogen mobility, covering reductions in greenhouse gas emissions, energy impacts, costs and investment requirements and regulatory issues. Focusses on EU, with more details on France and Germany. See http://www.lbst.de/download/2016/Hinico-LBST_2016_PtH2-study_Fondation-Tuck.pdf</p> |
| <p>Large-Scale Hydrogen Delivery Infrastructure, 2015</p> | <p>IEA report – Large-scale use of hydrogen as a fuel will materialize only if applications are supported by an appropriately large-scale infrastructure for producing and delivering hydrogen. Report provides an overview of current infrastructure. Hydrogen fuel cells in transport and interaction with renewable energy lead to infrastructure and supply chain requirements. Well-referenced for OECD and other countries. See http://ieahydrogen.org/Activities/Task-28/Task-28-report_final_v2_ECN_12_2_v3.aspx</p> |
| <p>Task 38 of the Hydrogen TCP: a Task dedicated to the study of P2X pathways, 2018</p> | <p>Presentation by Lucchese to a workshop in Gothenburg. 18 June 2018. See https://iea-etsap.org/workshop/gothenburgh_june2018/21-2018-06-18_IEA-HIA_Task38presentation.pdf</p> |
| <p>The future of hydrogen: Seizing today's opportunities, 2019</p> | <p>IEA report prepared for the G20 summit. Covers production of hydrogen and hydrogen-based products; storage, transmission and distribution; present and potential industrial uses; opportunities in transport, buildings and power (including hydrogen generation and storage); policies to boost momentum in key value chains and next steps. IEA notes that hydrogen can help tackle critical energy challenges, is versatile and can enable a greater contribution from renewables. Lack of hydrogen infrastructure and appropriate regulations are holding back widespread adoption. This reference provides access to a number of tables of information on national hydrogen projects, policies, R&D budgets, etc. ACIL Allen has reviewed all these to identify information relevant to this project. See https://www.iea.org/hydrogen2019/</p> |
| <p>Hydrogen from renewable power: Technology outlook for the energy transition, 2018</p> | <p>International Renewable Energy Agency (IRENA) report presenting current status of hydrogen technology status and development, with an analysis of applications and decarbonising end-use sectors. Compares different electrolyzers. Characterises four supply chain types. See https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power</p> |
| <p>Hydrogen roadmap Europe: A sustainable pathway for the European energy transition, 2019</p> | <p>Fuel cells and Hydrogen Joint Undertaking (FCH JU) report which covers renewables and power, transport, gas networks, buildings, industry heat and feedstock. Roadmap includes actionable steps and estimates of benefits. Report provides some high-level EU data. See https://www.fch.europa.eu/news/hydrogen-roadmap-europe-sustainable-pathway-european-energy-transition</p> |
| <p>FCH JU – Success stories, 2018</p> | <p>Useful examples, including one that describes using green hydrogen for energy storage and sector coupling. Four sections provide material on development and deployment, new generation products, opening markets and fuelling growth. See https://www.fch.europa.eu/success-stories</p> |
| <p>The prospects for hydrogen as an energy carrier: an overview of hydrogen energy and hydrogen energy systems, 2016</p> | <p>Discusses the role of hydrogen as an energy carrier and hydrogen energy systems' technologies. Some coverage of Canada, Germany, France and Japan. See https://www.researchgate.net/publication/294421947_The_prospects_for_hydrogen_as_an_energy_carrier_an_overview_of_hydrogen_energy_and_hydrogen_energy_systems</p> |
| <p>Hydrogen scaling up: A sustainable pathway for the global energy transition, 2017</p> | <p>Hydrogen Council vision and outline of what is needed to achieve that vision, with 2030 milestones and 2050 targets. See http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf</p> |

Documents reviewed for this project

Multi country

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| Clean energy and the hydrogen economy, 2017 | Analyses potential hydrogen energy consumption by sector, hydrogen pathways in renewable energy integrated systems (including storage), transport and distribution. Well referenced. See https://royalsocietypublishing.org/doi/full/10.1098/rsta.2016.0400 |
| Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling? 2018 | Reviews current power-to-gas (injection into the gas grid) projects and analyses economic assessments and systems modelling studies to compare them in scope, assumptions and outcomes. Provides a list of projects. See https://www.sciencedirect.com/science/article/pii/S1364032118306531 |
| Influence of added hydrogen on underground gas storage: a review of key issues, 2015 | Discusses underground storage of natural gas with hydrogen. Considers that there are limitations to using this storage in Germany. See https://link.springer.com/article/10.1007/s12665-015-4176-2 |
| Renewable smart hydrogen for a sustainable future, 2018 | Renewables face challenges including intermittence, over capacity, curtailment, constraints long transportation distance, varying CAPX, OPEX and changing market conditions. Hydrogen can mitigate these factors but needs to overcome its own challenges. Introduces concept of Smart Hydrogen which combines (1) a solution to the electrical grid network challenges faced by the mature renewable electricity technologies, (2) opportunities in hydrogen supply pathway, (3) prospects for new hydrogen applications and (4) creation of different and new trends in energy markets with "Power to X technologies". The aim of Smart Hydrogen is to create a hydrogen value chain that is optimal in technical performance and financial revenues. See http://www.nweurope.eu/media/3517/gencomm-smart-h2-position-paper-march-2018.pdf |
| Hydrogen in the electricity value chain, 2019 | This paper focuses on the position of hydrogen in the electricity value chain including: production during hours with surplus renewable electricity; - transportation & storage to balance production and demand, and – as a fuel for electricity generation during peak hours. A levelized cost approach to compare options for hydrogen use in the electricity value chain based on a representative electricity price duration curve for year 2050. The concept of a "surplus electricity merit order" is discussed because there are multiple options to cope with surplus electricity and each has its own value among others. The effect of large-scale hydrogen production on the electricity wholesale price is also discussed. See https://www.dnvgl.com/publications/hydrogen-in-the-electricity-value-chain-141099 |
| The role of hydrogen and fuel cells in the global energy system, 2019 | Up to date review. See https://pubs.rsc.org/en/content/articlepdf/2019/ee/c8ee01157e |
| Mission possible: Reaching net zero carbon emissions from harder to abate sectors by mid-century, 2018 | The message for these industries is that governments need to get started on this immediately. See http://www.energy-transitions.org/mission-possible |
| Hydrogen an enabler of the Grand Transition: Future Energy Leader position paper, 2018 | World Energy Council report assesses the potential of hydrogen as well as its current deployment status to enable the Grand Transition by addressing the entire energy system by: (1) enabling large-scale, efficient renewable energy integration; (2) distributing energy across sectors and regions; (3) acting as a buffer to increase system resilience; (4) decarbonizing transport; (5) decarbonizing industry energy use; (6) serving as feedstock using captured carbon; and (7) helping decarbonize building heating. See https://www.worldenergy.org/wp-content/uploads/2019/05/Hydrogen-an-enabler-of-the-Grand-Transition-FEL-WEC-2018-Final1.pdf |
| New hydrogen economy - hope or hype? 2019 | Another World Energy Council report which examines current state of play, success factors (recognising hydrogen as a whole system transition solution, unlocking sustainable production pathways, building an international hydrogen market, achieving cost effectiveness, developing Infrastructure) and future outlook for hydrogen. See https://www.worldenergy.org/publications/2019/world-energy-insights-brief-new-hydrogen-economy-hype-or-hope/ |

Documents reviewed for this project

Multi country

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| Modelling and evaluation of PEM hydrogen technologies for frequency ancillary services in future multi-energy sustainable power systems, 2019 | This paper examines the prospect of PEM electrolyzers and fuel cells to partake in European electrical ancillary services markets. First, the current framework of ancillary services is reviewed and discussed, emphasizing the ongoing European harmonization plans for future frequency balancing markets. Next, the technical characteristics of PEM hydrogen technologies and their potential uses within the electrical power system are discussed to evaluate their adequacy to the requirements of ancillary services markets. Last, a case study based on a realistic representation of the transmission grid in the north of the Netherlands for the year 2030 is presented. See https://www.sciencedirect.com/science/article/pii/S2405844018367471 |
| Potential of new business models for grid integrated water electrolysis, 2018 | Cross-commodity arbitrage trading for electrolyser is especially promising in power systems of high shares of wind power. Exemption from use of system charges and levies is crucial for profitability of grid integrated electrolyser operation. Economic efficiency of electrolyser operation is highly dependent on the end-user sector of hydrogen demand. Provision of grid services towards transmission grid operators can increase the profitability of electrolyser operation. The potential of grid service provision is highly dependent on the point of grid connection. See https://www.sciencedirect.com/science/article/pii/S0960148118302180 |
| Integration of power-to-hydrogen in day-ahead security-constrained unit commitment with high wind penetration, 2017 | The increasing integration of variable wind generation has aggravated the imbalance between electricity supply and demand. Power-to-hydrogen (P2H) is a promising solution to balance supply and demand in a variable power grid, in which excess wind power is converted into hydrogen via electrolysis and stored for later use. In this study, an energy hub (EH) with both a P2H facility (electrolyser) and a gas-to-power (G2P) facility (hydrogen gas turbine) is proposed to accommodate a high penetration of wind power. The EH is modelled. See https://link.springer.com/article/10.1007/s40565-017-0277-0 |
| EU Legislative framework for implementation of Hydrogen in different applications, 2018 (May) | A Hydrogen Europe presentation. See https://www.waterstofnet.eu/_asset/_public/powertogas/Conference/10-Nicolas-Brahy_Hydrogen-Europe-HyLaw-_Regulation-Overview.pdf |
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We acknowledge the key contribution from John Soderbaum, John Bell and Jeremy Tustin from ACIL Allen, as well as Stephen Hinchliffe, Hires Devaser and Brooke Maki from GHD Advisory.