Investor Group on Climate Change

Unlocking investment in the Australian hydrogen industry

About the Investor Group on Climate Change

The Investor Group on Climate Change (IGCC) is a collaboration of Australian and New Zealand institutional investors focused on the impact of climate change on investments. IGCC represents investors with total funds under management of over $3 trillion in Australia and New Zealand and $30 trillion around the world. IGCC members cover over 7.5 million people in Australia and Aotearoa New Zealand.

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About Baringa

Tackling climate change and creating a sustainable future for our planet and society represent the greatest challenges and opportunities facing humanity. System-wide change and collaboration are needed to bring shared values between stakeholders. Businesses must make decisions based on environmental and social factors that truly matter to achieve a pathway of sustainable growth and facilitate a transition. As a global leader in the energy transition, we help organisations navigate the complex world of climate change and sustainability to deliver net zero ambitions and drive positive impacts.

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1 EXECUTIVE SUMMARY

1.1 Background

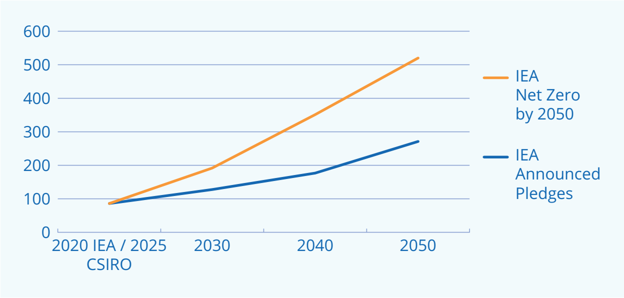
This report defines low-carbon hydrogen as hydrogen with lifecycle emissions lower than 3 tonnes (t) of carbon dioxide equivalent (CO2e) per t of hydrogen. There is substantial interest from the government, industry, investors and other stakeholders in establishing a low-carbon hydrogen industry in Australia. The shift to a net zero global economy is a key driver. However, there are considerable risks of making major investments in the hydrogen industry given the complexities of the evolving energy landscape – this report aims to highlight the barriers, risks and enablers for investors, as well as the opportunity for investors to play a leading role in developing a high-integrity hydrogen industry that capitalises on the opportunities for low-carbon fuels.

1.2 Modelled hydrogen market expects significant growth to 2050

The hydrogen market is expected to grow rapidly by 2050 in the global transition away from fossil fuels (**Figure 1**), and there are strong demand signals from Asia. The major export opportunities for Australian hydrogen are economies that reside within the Asia-Pacific (APAC) region, specifically Japan, South Korea, Singapore and China in the long-term, and are likely to be characterised by the following:

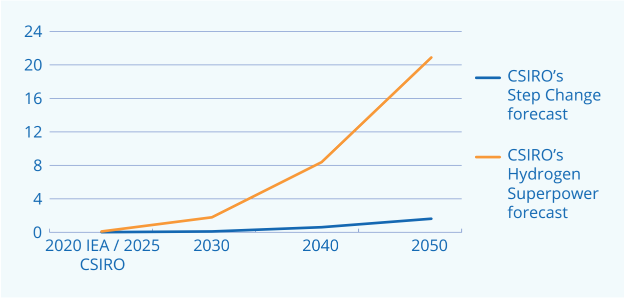
- Great demands for energy in hard-to-abate sectors (such as manufacturing and heavy industries) and existing energy supply relationships with Australia.
- Relatively poor access to renewable energy sources due to climatic conditions and/or land constraints.
- Increasingly binding emission-reduction agendas that are incentivising the use of hydrogen.

Figure 1: Projected global hydrogen production (Mt)



Source: IEA

Figure 2: Projected Australian (NEM-domiciled[1]) hydrogen production (Mt)



Source: CSIRO

1. NEM-domiciled indicates hydrogen production within the NEM's geographic area, and does not distinguish between types of hydrogen production, nor differences between grid-connected and off-grid. It also excludes regions such as Western Australia and the Northern Territory.

Within Australia, the key sectors expected to transition to hydrogen are different due to differences in energy use patterns and the cost and availability of energy. The two Australian CSIRO forecasts in **Figure 2** show two key findings:

1. In the near-term (i.e., over the 2020s), hydrogen demand comes from domestic sources, including chemical production, industrial processes, flexible power generation, hydrogen fuel-cell vehicles and displacing some natural gas in existing gas pipelines and existing gas appliances by blending hydrogen.
2. Demand for Australian hydrogen production is expected to be predominantly driven by global demand in the medium and long-term, with export demand increasingly dwarfing domestic demand and relying on technology improvements and economies of scale in Australia.

In the near to medium-term, domestic demand for low-carbon hydrogen provides valuable use cases and learning opportunities. Near-term demand also provides an opportunity to revitalise Australia's manufacturing sector and produce low-carbon goods that take advantage of Australia's abundant renewable resources. For example, BlueScope is exploring options for using hydrogen from renewable energy (green hydrogen) to produce low-carbon steel [1]. For hydrogen to be competitive, particularly in international markets, hydrogen producers will need to provide transparency over lifecycle emissions as discerning buyers begin to price embodied carbon emissions.

1.3 The oil and gas sector may have a role to play

In 2020, approximately 80% of global hydrogen production was produced from mostly unabated fossil fuels, and oil refining was the largest consumer of hydrogen, accounting for nearly 50% of total demand [2]. Australia's oil and gas sector has expressed interest and announced plans to produce hydrogen from gas, with carbon capture and storage (CCS) (blue hydrogen) as part of a decarbonisation pathway. However, few firm or near-term commitments have been backed by sufficient capital. A low level of commitment to blue hydrogen is likely to continue with high gas prices and the reduction of blue hydrogen economics. The sector is divided over what form of hydrogen will be the solution; for example, Shell and Equinor explore green hydrogen via the NorthH2 consortium [3], whereas Santos states an intention to explore blue hydrogen [4]. Additionally, while the industry has an opportunity to leverage some existing infrastructure, such as ammonia exporting infrastructure, there are technological challenges in leveraging the existing gas infrastructure to transport hydrogen.

1.4 The current political context signals growing support for hydrogen

The Australian federal government has submitted a new Nationally Determined Contribution that includes a 43% emissions reduction target by 2030 alongside a commitment to achieve net zero by 2050. Australia requires significant public and private investment across all sectors to achieve these goals. The Australian state and federal governments have consistently articulated that hydrogen is expected to play a key role in achieving emissions-reduction targets. It is critical that Australia maintains alignment with its own decarbonisation ambitions by setting strong national targets and directing public funds to produce hydrogen that meets sufficiently low-carbon and emissions intensity thresholds. There is a significant risk of hydrogen-importing countries decreasing their emissions, only for Australia's emissions to increase by exporting high carbon forms of hydrogen.

While the political context shows support for hydrogen, there are conflicting signals due to patchwork climate policies, such as the lack of a carbon price and several fossil fuel subsidies. Policy settings should aim to mitigate the key risks outlined below. The government could unlock institutional capital by building strong global multilateral agreements with target markets and incentivising investment in the hydrogen industry, for example, by replicating the Renewable Energy Target and creating a market for low-carbon hydrogen. Collaboration between government and industry and robust regulation are required to decrease production costs and limit lifecycle emissions of hydrogen.

The key investment risks and barriers for the hydrogen industry include the following:

- **Pre-commercial technology and small-scale project risks** – new technologies are often risky and lack sufficient data and a proven track record. This risk increases the costs and the need for detailed due diligence in every transaction. While risks also exist for large projects, they are exacerbated by the proliferation of small projects in the market (e.g., less than $50–$100 million in scale), which incur much higher transaction costs.
- **Regulatory risk, lack of carbon price and the presence of harmful fossil fuel subsidies** – a carbon price reflects the risk of carbon in market prices and incentivises decarbonisation. Any subsidies to produce high-carbon hydrogen that does not meet appropriate low-carbon thresholds may lead to perverse outcomes, rendering new and emerging technologies uncompetitive, locking in carbon, risking stranding assets and hindering decarbonisation efforts. Support for end uses of hydrogen should also be directed at specific key end uses (refer to the section '**4. Likely uses of hydrogen are limited to a few key sectors**') where it makes economic sense.
- **Hydrogen investments have long return horizons but high-risk profiles** – the hydrogen industry has high levels of risk and does not yet provide secure long-term revenue streams that investors need to unlock private capital in a highly capital-intensive industry. Some of the key risks that limit investment include the quality and reliability of cash flow projections, short-term performance pressures, low demand, social licenses to operate risks and financial market regulations.

The key technical and financial barriers to the commercialisation of hydrogen include the following:

- Difficulties in storing and transporting hydrogen, including challenges in using existing domestic gas pipelines to transport hydrogen.
- Costly end-user plant upgrades and retrofits.
- Insufficient transmission infrastructure.
- Slow regulatory and approval processes.

1.5 Hydrogen's role in a net zero future

Increasing global ambition to limit global warming to 1.5 °C[2] has meant that the role of hydrogen as a fuel that does not produce carbon emissions at the point of combustion[3] has gained widespread interest. Further, the falling costs of renewable energy are rapidly improving the economic and financial outlooks for hydrogen. This report focuses on the most common and likely mature forms of low-carbon hydrogen production methods in Australia: green and blue hydrogen.

The exponential growth projected for the hydrogen sector reflects the global action on decarbonisation and the expected decline in grey hydrogen as a share of total hydrogen demand. As the IPCC Working Group III notes, net zero energy systems will be characterised by widespread electrification and the use of hydrogen in harder-to-abate sectors less amenable to electrification [5]. An open question is how much each type of low-carbon hydrogen will grow, as there is a reason for caution over the emissions abatement potential of blue hydrogen.

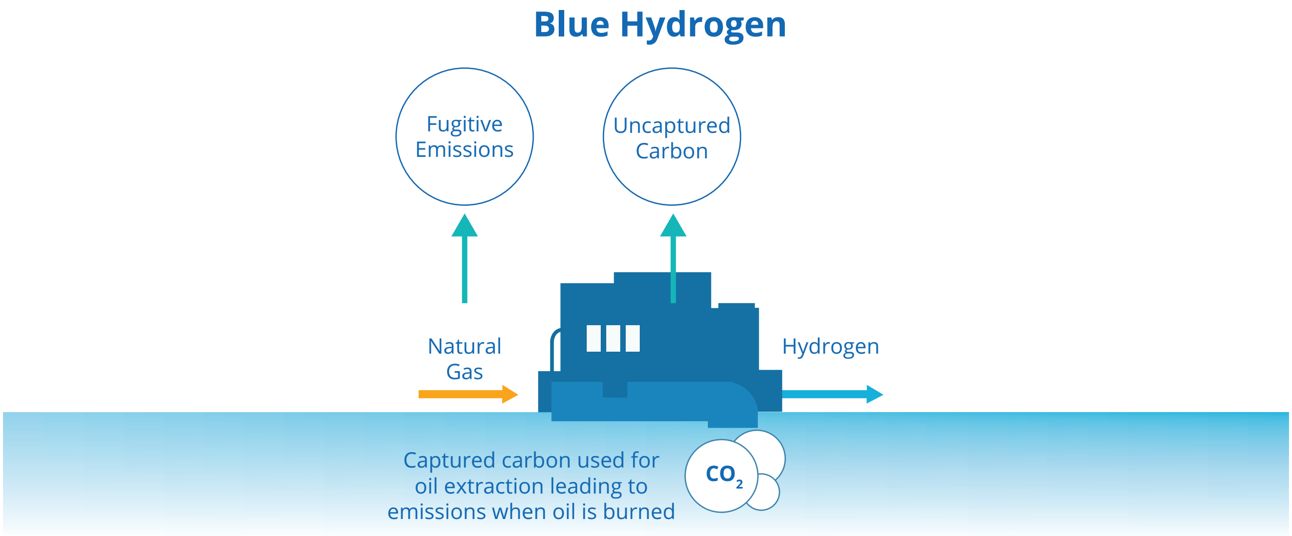
2. It is generally considered that avoiding 'dangerous' global warming means limiting global average temperature rises to no more than 2 °C by year 2100, relative to year 1900.
3. Although hydrogen does not produce carbon dioxide when combusted, carbon dioxide may be emitted during the process of producing hydrogen.

1.6 Blue hydrogen may not be low-carbon[4] and carries higher risk

Blue hydrogen climate credentials are a significant concern. As per **Figure 3**, the production of blue hydrogen may generate substantial lifecycle emissions from:

- Fugitives lost during the extraction.
- Uncaptured carbon during the CCS process.
- The risk of using offsets to claim clean credentials.
- Captured carbon being used for oil extraction.

Figure 3: Sources of emissions from the production of blue hydrogen



There are also concerns that blue hydrogen may not have substantially lower emissions than grey hydrogen; for example, a report found total emissions of blue hydrogen (produced internationally) was only 9–12% less than grey hydrogen [6]. The measurement, reporting and verification of emissions from gas extraction and steam methane reforming (SMR) processes need to be improved significantly. For example, a recent report found that methane emissions from oil and gas extraction in Australia could potentially be underreported by approximately 33% [7]. The costs of abating all lifecycle emissions from blue hydrogen production need to be considered when compared to green hydrogen; otherwise, the two fuels are categorically different in terms of abatement potential. Transparency over lifecycle emissions is essential, as buyers will price carbon accordingly.

Robust emissions intensity thresholds are necessary to ensure the full abatement potential of hydrogen as a low-carbon fuel. Not all blue hydrogen is low-carbon, and only production methods with the strictest emissions abatement methods (e.g., gas with 90%+ capture rates) meet the emissions intensity thresholds put forward by the EU taxonomy[5] and CertifHy [8],[6] while other certification schemes such as the Smart Energy Council's do not allow for blue hydrogen at all [9]. Blue hydrogen carries the risk of prolonging fossil fuel demand, may lead to stranded asset risks [10], and focusing on blue hydrogen may direct investment away from low-carbon fuels with more abatement potential.

In contrast, green hydrogen has a small emissions footprint; however, new renewable energy must be developed to alleviate the increasing demand for renewable energy. Given this emissions profile, there is an increasing interest in green hydrogen as an important opportunity for the emerging hydrogen industry.

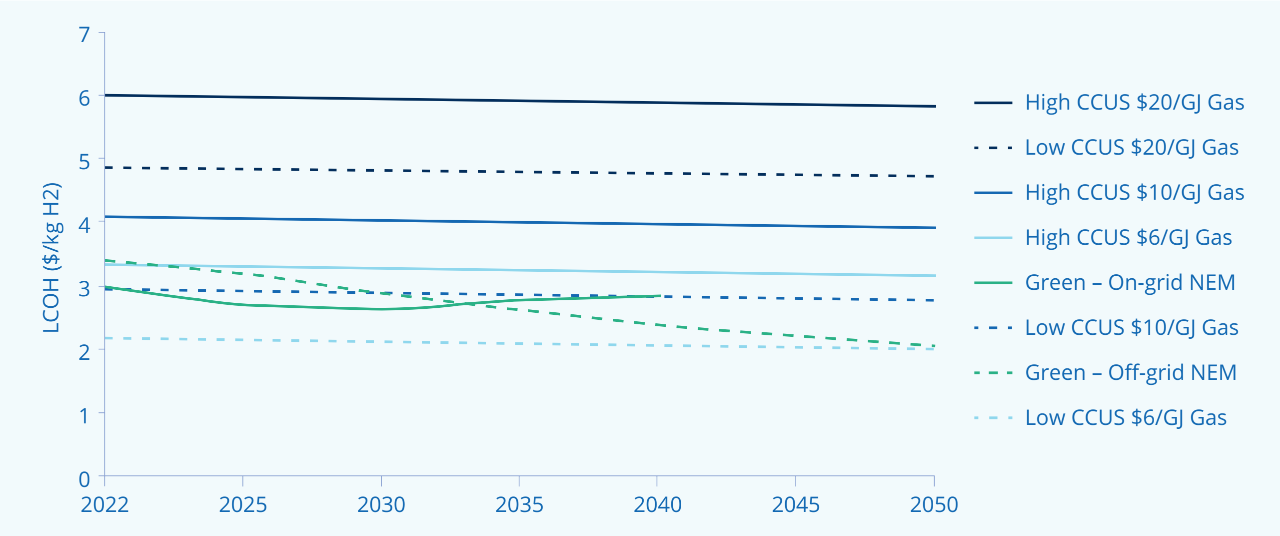
4. 'Low-carbon emissions hydrogen' is aligned with the EU taxonomy and defined as hydrogen produced with a maximum of $3tCO_2e/tH_2$.
5. The EU taxonomy is a classification system, establishing a list of environmentally sustainable economic activities.
6. CertifHy is the first EU-wide Guarantee of Origin scheme for Green and Low Carbon Hydrogen. https://www.certifhy.eu/

1.7 There is no winning colour on costs

The costs of producing green and blue hydrogen vary significantly and depend on the number of inputs. There was some optimism that blue hydrogen would have been the comparatively cheaper form of hydrogen production; however, this is unlikely to be the case going forward. Blue hydrogen is highly sensitive to high gas prices, and with LNG netback prices[7] expected to remain above $20 per GJ through to 2024 [11], the economic viability of blue hydrogen is challenging and currently more expensive than green hydrogen. Additionally, production costs increase with high capture rates (refer to **Figure 4**), which means that producing blue hydrogen cheaply is unlikely to be low-carbon. The attractiveness of green hydrogen in comparison is underscored by rapid reductions in the cost of renewable energy, especially wind and solar photovoltaics (PVs) in Australia and projected further declines in these costs, along with projected declines in the costs of electrolysers.[8]

Australia's levelised cost of hydrogen (LCOH) relative to other international competitors is critical to remain competitive with the production of other countries. **Figure 4** shows the projected LCOH for domestic blue and green hydrogen production by 2050 based on current key inputs and assumptions that may change, given the emerging nature of the industry.

Figure 4: Projected LCOH of selected green and blue production[9]



Source: Baringa Partners LLP

7. In the context of Australian LNG, the netback price is the international price of Australian LNG 'netted back' to Australia by subtracting off the liquification and transport costs from the international price. This then represents a hypothetical domestic price for Australian natural gas.

8. Green hydrogen is an example of producing hydrogen from renewables via the use of electrolysis.

9. Figure 2 notes and assumptions: LCOH is the all-in cost to produce hydrogen, expressed as a $ per kg of hydrogen. Capture rates reflect 90% CO_2 capture from the SMR and includes transport and storage costs of the CO_2. Costs of any offsets procured to cover fugitive emissions from gas extraction, or revenue from stored carbon are not included. Transport or conversion costs of hydrogen have not been included. As electricity price projections are only out to year 2055, LCOH for a 15-year plant-life can only be determined out to 2040 for on-grid production. 'On-grid' NEM is green power is procured via PPA with renewables volume matched. Off-grid combined green hydrogen has not been included due to insufficient data as there is a lack of large-scale, mature projects that disclose adequate information. 'High CCUS' = $20.02 per tCO_2, 'Low CCUS' = $3.5 per tCO_2. Wholesale electricity price increases are expected through the 2030s as significant capacity (coal generation) exits the market then moderates with new capacity. Electrolysers are expected to have some flexibility to ramp down in response to high prices. Carbon prices have not been included. $ = AUD.

1.8 Investors have a role to play in accelerating a hydrogen industry

There are a range of opportunities for investors to support the development of the Australian hydrogen industry.

These include:

- Engagement with portfolio companies (hydrogen producers and users) to ensure that the industry has a low-carbon profile.
- Advocacy for robust policy settings and regulations with transparent emissions lifecycle analysis.
- Industry association engagement.
- Capital allocation to new industrial entrants.

Within these areas of engagement, the analysis in this report suggests that investors should focus on the following priorities:

- Supporting and investing in the production of genuinely low-carbon hydrogen. Blue hydrogen should not be prioritised given producing low-carbon (i.e., 90%+ capture rates) blue hydrogen at high gas prices does not appear economically favourable. While several historic hydrogen pathways incorporate blue hydrogen growth at scale, updated models will likely have a reduced role for blue hydrogen given its relatively weaker economics.
- Supporting and investing in developments that enable a green hydrogen industry (e.g., expansion of renewable energy to meet increased demand for hydrogen production and avoiding cannibalisation of renewable energy in the grid, research and development of electrolysers, large-scale hydrogen hubs and carbon pricing mechanisms). Australia has sufficient renewable resources to develop hydrogen export opportunities [12]; however, existing barriers, such as scaling up transmission infrastructure and land access, need to be addressed.
- Supporting and investing in hydrogen for its key end uses set out in this report, for domestic use and export. This includes support for large-scale hydrogen hubs producing hydrogen in various carrier forms (dependent on its key customers and intended end use) for export and smaller-scale hydrogen projects for domestic use to overcome technological learning curves and provide valuable use cases.
- Advocating for regulations and standards that incorporate lifecycle emissions accounting and reporting. Further, encouraging portfolio companies that are users of hydrogen to set standards for lifecycle emissions over the hydrogen they purchase, and to enter into offtake agreements with producers of low-carbon hydrogen.

2 INTRODUCTION

2.1 Purpose

Understanding the long-term pathways and potential of the industry is critical for investors considering the future of hydrogen. Currently, key questions about the enduring viability and pathway for hydrogen in Australia remain unanswered, including the policies required to enable Australia to emerge as a low-cost producer of hydrogen, the role of existing Australian companies as potential producers and users of hydrogen, and the relative role of green and blue hydrogen in scaling up of Australia's hydrogen industry.

Investors seek to resolve some of these key questions so that there can be informed consideration of the future of hydrogen when engaging with corporates, fulfilling stewardship duties, advocating for specific policies and making investment decisions. Investors are interested in the future commercial pathway, including opportunities, barriers and drivers.

The purpose of this report is to achieve the following outcomes:

1. Developing an independent view of the pathway for the Australian hydrogen industry – the current state of play, what a viable pathway looks like, the roles of blue and green hydrogen, the key drivers of demand domestically and internationally.
2. Identifying insights on what a commercial and strategic transition to hydrogen in this viable pathway looks like, the key risks, the barriers, levers and policy settings that enable this transition – what we expect companies to be doing already, and which technologies/characteristics should they be investing in to be competitive under this pathway.
3. Identifying the investor role in accelerating the Australian hydrogen industry, including supporting engagement by investors with companies in their portfolios that are developing new projects (hydrogen producers) or planning to use hydrogen (hydrogen users).

2.2 Methodology

IGCC engaged Baringa Partners to investigate a viable net zero hydrogen pathway for Australia, to provide investors with insights on the risks and opportunities associated with hydrogen and help to identify the investor role in developing the industry. Baringa conducted an extensive review of existing literature, including roadmaps and energy models, and held targeted workshops with several stakeholders involved in the industry, including government funding agencies, research institutions, green and blue hydrogen producers, and industrial hydrogen users.

This report focuses on the risks and opportunities, drivers and enablers of Australian low-carbon hydrogen production and consumption. It includes a discussion of trends in international hydrogen production, consumption and markets, especially related to opportunities for Australian hydrogen exports, emissions profiles of blue and green hydrogen, as well as discussing projected cost trends related to hydrogen production and transport.

It is not within the scope of this report to undertake a detailed assessment of each of these elements of the hydrogen industry and its viability in the future or to consider or assess the financial or economic prospects of individual hydrogen projects. This report focuses primarily on low-carbon hydrogen, considering the potential role of blue and green hydrogen in Australia.

3 THE HYDROGEN MARKET IS EXPECTED TO GROW SIGNIFICANTLY TO 2050

3.1 Global and Australian hydrogen production grows rapidly in net zero scenarios

Hydrogen is a key component of net zero pathways. A recent report found that hydrogen has an abatement potential of 7 gigatonnes (Gt) of carbon dioxide (CO_2) per year and could contribute 20% of the total abatement required by 2050 [13]. Key buying markets for Australian hydrogen are likely to be characterised by:

- Great demands for energy in hard-to-abate sectors (such as manufacturing and heavy industry) and with existing energy supply relationships with Australia.
- Relatively poor access to renewable energy sources due to climatic conditions and/or land constraints.
- Increasingly binding emission-reduction agendas that are incentivising the acceleration of hydrogen.

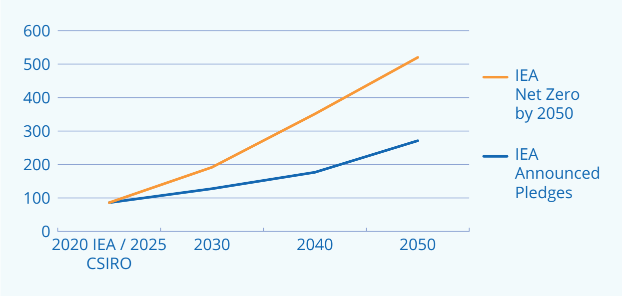
Many of these economies are within the APAC region, specifically Japan, South Korea, Singapore, and China in the longer term, representing major export opportunities for Australia.

Figure 1 and **Figure 2** show the projected hydrogen demand in megatonnes (Mt) using four scenarios that represent credible and relevant pathways. These scenarios include both green and blue hydrogen. However, green hydrogen comprises the bulk of projected hydrogen demand, noting CSIRO's hydrogen projections relate to hydrogen facilities located within Australia's National Electricity Market (NEM). For comparison, global production was 90Mt in 2020 [14]. All scenarios considered in this study are listed in '**13.1 Appendix A**'.

A summary of the four key scenarios is as follows:

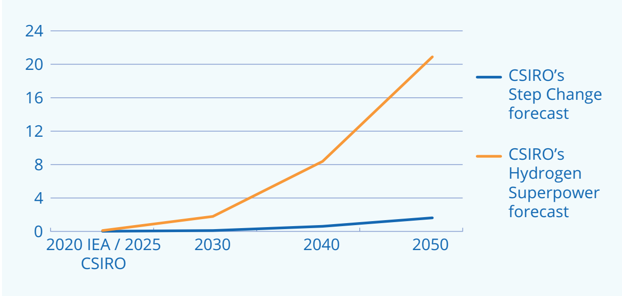
- *IEA Announced Pledges:* This scenario includes both stated government policies and many net zero emissions pledges by governments around the world and is aligned with limiting warming to 2.1 °C in 2100.
- *IEA Net Zero by 2050:* This scenario models the global energy mix required to achieve net zero emissions in a manner consistent with limiting warming to 1.5 °C in 2100.
- *CSIRO Step Change:* This scenario assumes that Australia achieves net zero emissions by 2050 and is aligned with limiting warming to 1.8 °C and with the NEM-domiciled (excludes Western Australia and the Northern Territory) hydrogen industry realising relatively modest growth.
- *CSIRO Hydrogen Superpower:* This scenario assumes a more aggressive carbon constraint than the CSIRO Step Change scenario and also assumes steeper declines in hydrogen production costs such that a hydrogen export industry develops to serve global hydrogen demand.

Figure 1: Projected global hydrogen production (Mt)



Source: IEA

Figure 2: Projected Australian (NEM-domiciled[10]) hydrogen production (Mt)



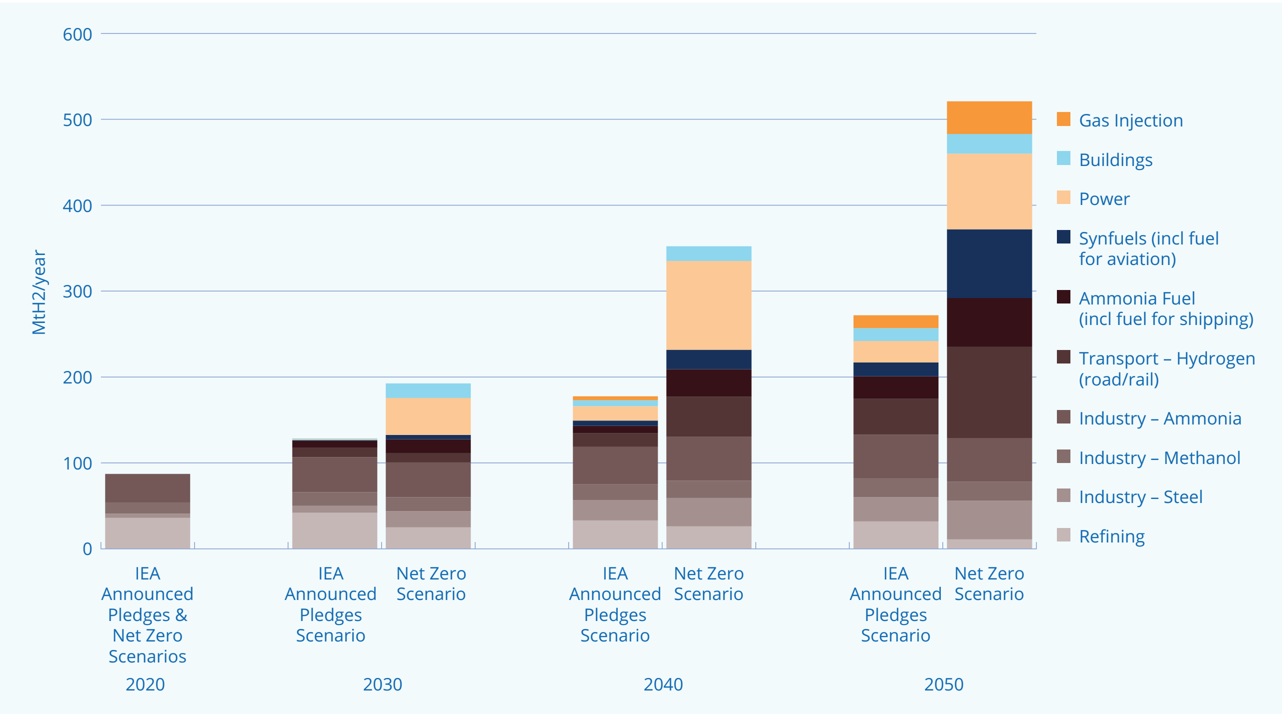
Source: CSIRO

3.2 The next decade will see hydrogen supporting fossil fuel substitution

In the next decade, rapid global growth is expected with hydrogen substituting traditional fossil fuels in the power and gas sector, where the infrastructure and technology to blend a small proportion of hydrogen with gas already exist. The recent energy security crisis has pushed up gas prices, a key input to blue hydrogen, and is galvanising a global shift away from fossil fuels and boosted support for renewable hydrogen, as noted by the European Commission's REPowerEU Plan [15].

From 2030 to 2050, the IEA projects that hydrogen consumption will continue to grow in the power sector, and new growth areas are expected in the transport and steel sectors (**Figure 5**). Notably, the power sector is the main driver of hydrogen demand divergence between the two IEA scenarios over the next decade. The Net Zero scenario identifies a much larger potential than the Announced Pledges scenario. The key uses of hydrogen are discussed in later sections.

Figure 5: Projected global hydrogen demand by end use – IEA Announced Pledges and Net Zero scenarios



Source: IEA

10. NEM-domiciled indicates hydrogen production within the NEM's geographic area, and does not distinguish between types of hydrogen production, nor differences between grid-connected and off-grid. It also excludes regions such as Western Australia and the Northern Territory.

3.3 Strong hydrogen demand signals are coming from Asia

A report from the Economic Research Institute for ASEAN and East Asia forecasted that Australia is well positioned to supply 42% (13.6Mt) of the projected 32.4Mt demand in East Asia by 2040 [17]. These countries have not yet publicly stated a preference for green or blue hydrogen and instead focus on the most cost-effective form of hydrogen, irrespective of lifecycle emissions. It should be noted that without a preference for low-carbon hydrogen, switching to using hydrogen in countries such as Japan could increase Australia's emissions, resulting in little net global emissions reduction. For example, a recent study published by ANU in 2021 showed that Japan could reduce emissions by 40Mt per annum by switching to ammonia (a hydrogen derivative), and if Australia were to be the sole supplier to Japan, Australia's direct emissions could rise by 35–45 Mt per annum [18]. Given this challenge, buyers will likely become more sensitive to lifecycle emissions and price.

- **Japan**

  The Japanese Government sees hydrogen as a key component in achieving emissions reductions of 46% (from 2013 levels) by 2030 [19]. Japan also intends to reduce the share of natural gas in the energy mix, down to 41% by 2030 [20] and seeks to drive down the cost of hydrogen to about one-third of the current level by 2030. Japan has also released its Basic Hydrogen Strategy with ambitious sector-specific targets for hydrogen use by 2030.

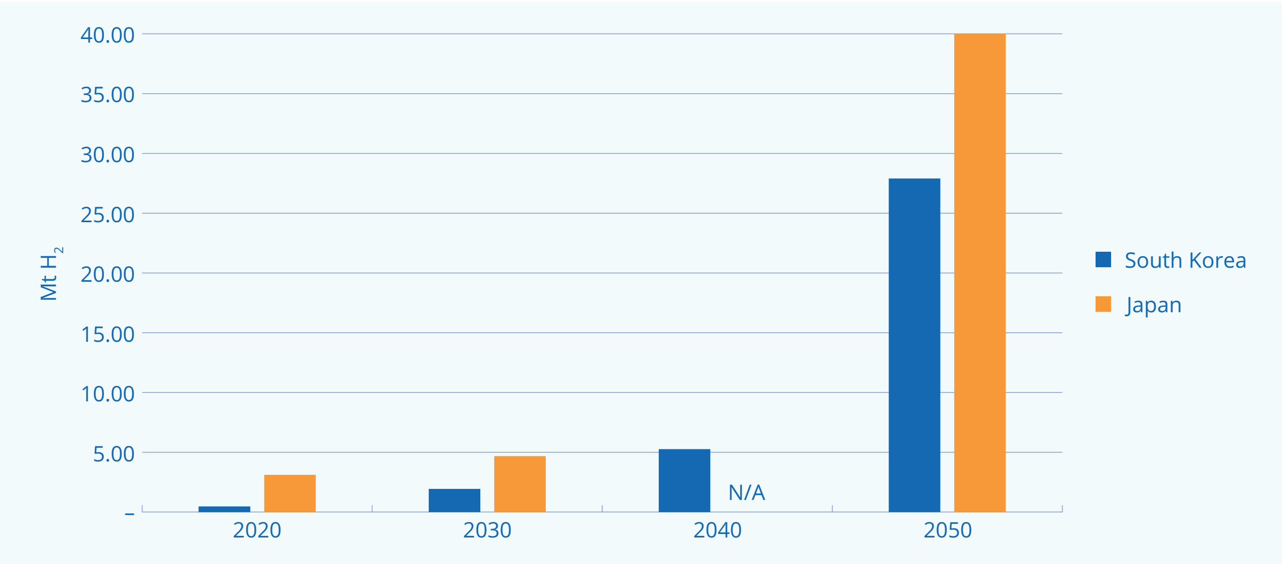
- **South Korea**

  The South Korean Government's hydrogen roadmap targets an expansion of its hydrogen consumption from 130 Kt per annum in 2020 to 5.26Mt per annum by 2040 [21], with consumption projected to be 28 Mt per annum in 2050 (**Figure 6**). South Korea's New Deal, announced in 2020, made hydrogen one of its central pillars to help the country achieve its emissions reduction target of 40% (relative to 2018 levels) by 2030. It has set a series of targets that largely focus on transport-sector emissions. The revised draft of K-taxonomy [22][11] includes green hydrogen as an eligible 'green activity' defined as a truly green economic activity essential for carbon neutrality. However, K-taxonomy also includes the production of blue hydrogen as a 'transition activity', which is a temporary intermediary step and may not be part of K-taxonomy over the longer term. Blue hydrogen eligible for inclusion must reduce emissions by over 60% compared to LNG-based reformed hydrogen.

  Figure 6 describes the South Korean and Japanese demand for hydrogen by 2050, which ticks up slowly in the short term and eventually rises to 28–40Mt in 2050.

11. The K-Taxonomy guideline is the Korean classification of green economic activities contributing to six environmental goals. It is not legally binding. http://www.me.go.kr/home/web/policy_data/read.do?menuId=10260&seq=7853

Figure 6: Projected South Korean and Japanese demand for hydrogen[12]



Source: DLA Piper (2021), South Korean Ministry of Trade, Industry and Energy (2021)

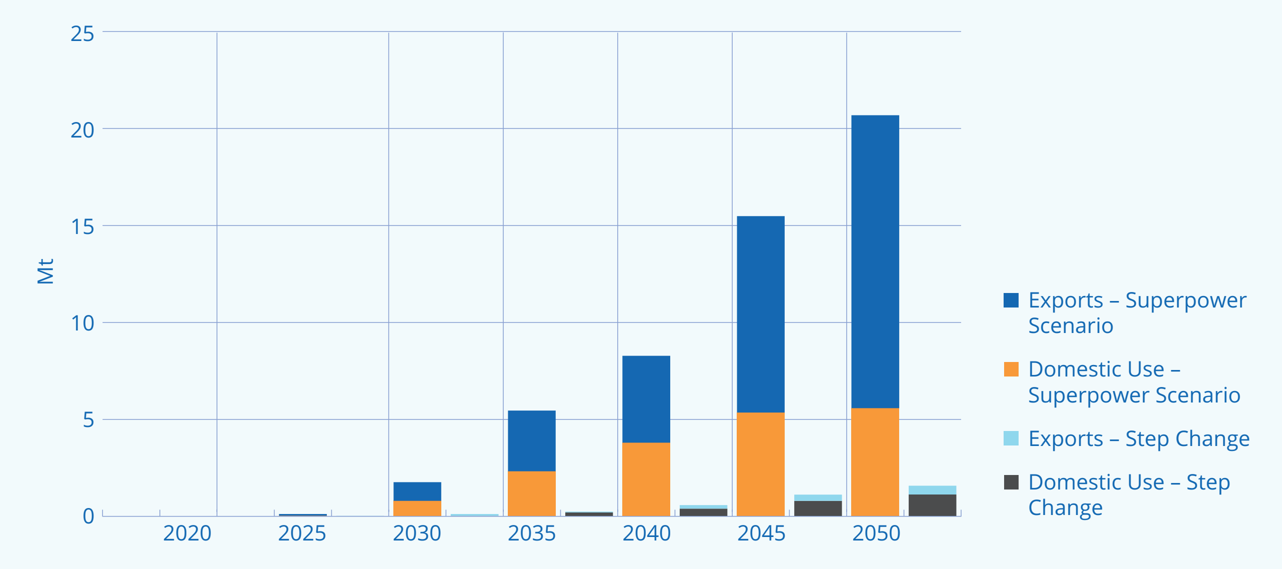
- **Singapore**
  Singapore's demand for Australian hydrogen is driven by its potential to act as an intermediary for other Asian hydrogen consumers. As such, the government has flagged its support for Australia's hydrogen industry.

3.4 A domestic hydrogen market is required to incubate an eventual export industry

Figure 7 shows the NEM-domiciled domestic demand for hydrogen. Near-term domestic demand enables domestic producers to launch pilot projects, overcome technological learning curves, and provide use cases, in turn generating investor confidence in larger supply projects. This domestic demand is eventually dwarfed by hydrogen export in the medium to long term [23]. It is critical that hydrogen is adopted for its key uses first (as set out later in this report), as upgrading existing plants and infrastructure will be costly and difficult to execute. Domestic demand can also help revitalise Australia's manufacturing sector to produce low-emissions goods that leverage its abundant renewable resources. For example, Fortescue Future Industries is investigating building green ammonia supply chains between Australia and Japan [24].

12. Singapore has not released any projections for anticipated hydrogen demand. While projected demand for Japan for the year 2040 is not available, total projected East Asian hydrogen demand is likely to exceed 32.4Mt per annum in 2040 (the amount projected by Economic Research Institute for ASEAN and East Asia), given Chinese hydrogen demand for itself is projected to be 36Mt per annum by 2030.

Figure 7: Projected NEM-domiciled hydrogen production: export vs domestic

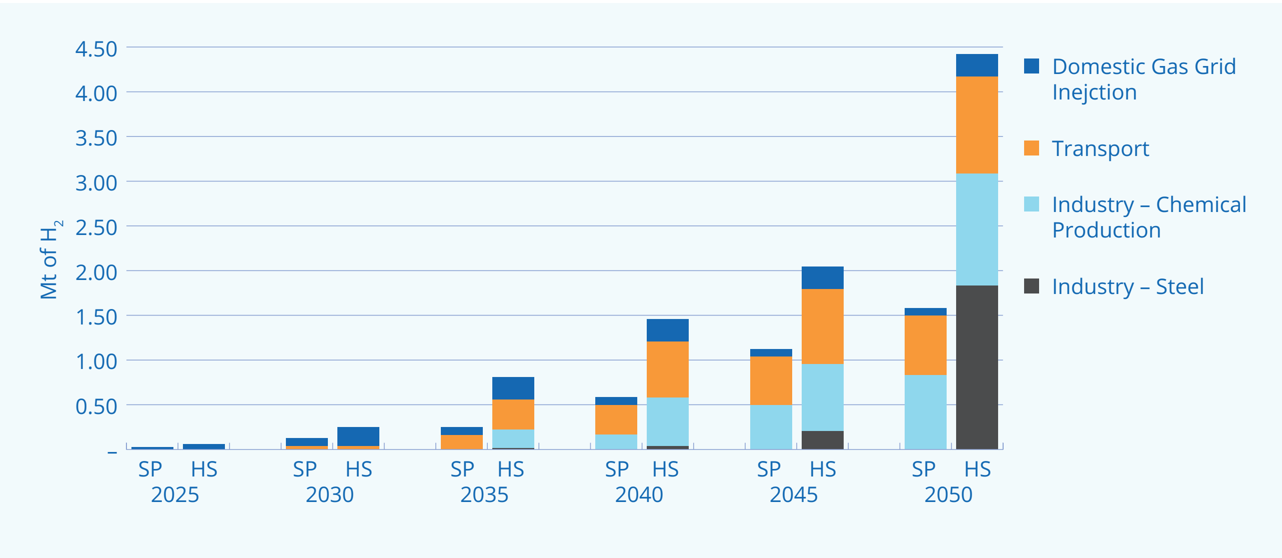


Source: CSIRO

The key sectors in Australia that are expected to transition to hydrogen differ from international sectors because of differences in energy use patterns and the cost and availability of energy. The two CSIRO Australian forecasts in **Figure 8** show two key findings related to hydrogen:

1. In the near-term (i.e., over the 2020s), falling renewable energy costs drive hydrogen demand in specific industrial processes, power generation (to support increased renewable energy penetration), heavy hydrogen fuel-cell vehicles and displaces some natural gas in existing gas pipelines and existing gas appliances by blending hydrogen.
2. Demand for Australian hydrogen production is expected to be predominantly driven by global demand in the medium and long-term, with export demand increasingly dwarfing domestic demand and relying on technology improvements and economies of scale in Australia.

Figure 8: Projected domestic hydrogen consumption – CSIRO Step Change (SP) vs Hydrogen Superpower (HS) scenarios



Source: CSIRO

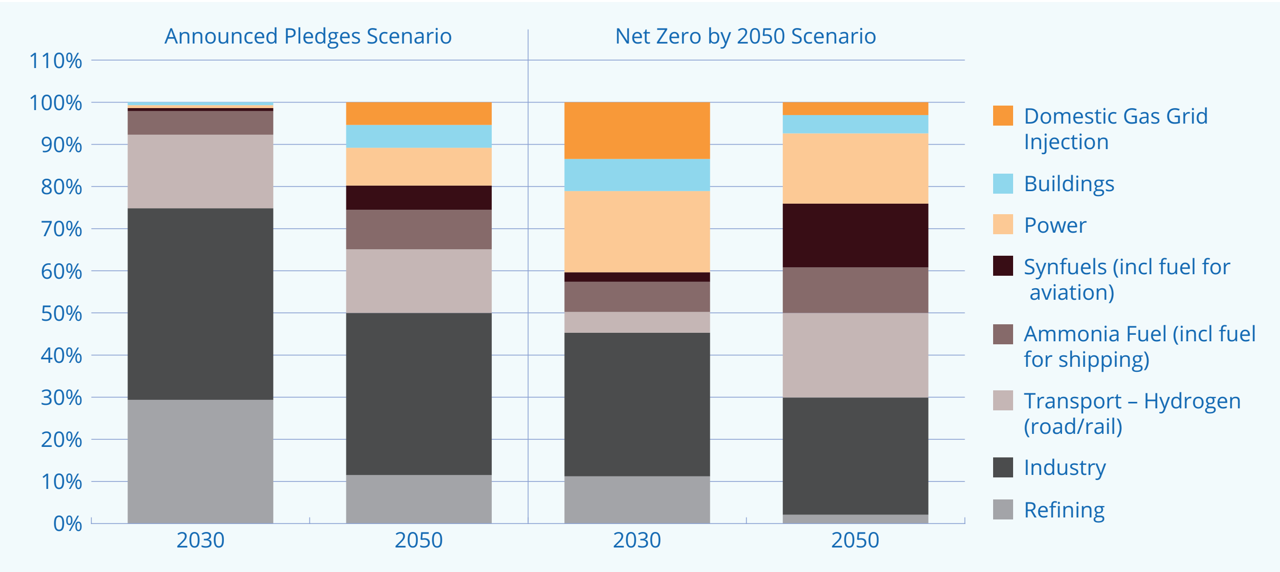
4

LIKELY USES OF HYDROGEN ARE LIMITED TO A FEW KEY SECTORS

4.1 The key uses of hydrogen eventually overtake demand for hydrogen in oil refining

Oil refining was the largest hydrogen consumer in 2020, making up nearly 50% of total demand [2]. In a net zero pathway, demand for hydrogen for refining eventually decreases and the key projected sectors globally for hydrogen demand are refining, chemicals, iron and steel, freight and long-distance transport, buildings, and power generation and storage [25]. The proportional demand by sector modelled by the IEA is presented in **Figure 9**.

Figure 9: IEA-projected global hydrogen consumption: by source of demand and by scenario



Source: IEA

4.2 There are a range of barriers and enablers for each type of hydrogen end use

The uses, barriers, and enablers for the key end uses of hydrogen in Australia in a net zero pathway have been set out in the following table, considering blue and green hydrogen equally only if both forms of hydrogen are sufficiently low-carbon.

Table 1: Key end uses of hydrogen

	Use Case	Barriers	Enablers
Chemical production	Production of: • Ammonia (for fertilisers explosives). • Liquid fuels • Oil refining.	• Cost competitiveness against high-carbon incumbents. • Regulation challenges for emissions from aviation and shipping due to the global nature of the industry.	• Adoption of clean synthetic fuels for shipping and aviation. • Consumer commitments to purchase low-carbon hydrogen (in various carrier forms). • Scale-up of low-carbon chemicals production capacity within Australia.
Fuel-cell vehicles	Hydrogen may be used where alternatives (e.g., electric vehicles) are less viable or appropriate, for example, in heavy vehicles.	• Competition from electric vehicle alternatives and cost competitiveness against high-carbon incumbents. • Supply constraints of hydrogen vehicles and lack of availability.	• High taxes on diesel and petrol heavy vehicles will drive demand for hydrogen (and electric) vehicles. • On-site production of hydrogen at locations hydrogen vehicles will be used. • Development of refuelling infrastructure where hydrogen vehicle traffic is reliable and consistent (e.g., freight routes).
Industrial feedstock	Industrial processes, for example, steel production, green alumina and building materials.	• Technical challenges and high costs to upgrade and retrofit facilities to use hydrogen. • Cost-competitiveness with high-carbon incumbents.	• Development of a domestic and international market for low-carbon products, such as green steel or building materials. • Declining costs of green hydrogen production and improvements in low-carbon product technology, such as Direct-Reduced Iron (DRI). • Hydrogen production hubs near industrial steel producers, and ammonia to minimise conversion and transport costs.
Flexible power	A complement to increasing renewable energy penetration that supports other forms of renewable energy storage.	• Highly dependent on government support due to current technology and cost limitations. • Alternative, cheaper forms of low-carbon energy storage, such as pumped storage hydro and high-carbon incumbents.	• Appropriate value assigned to hydrogen as a form of low-carbon grid support and energy storage compared to traditional, higher emissions options.
Blended gas pipeline	Hydrogen can be blended into pipeline gas as a substitute for a portion of the natural gas to reduce the carbon emissions of end-use applications.	• Limitations of existing gas infrastructure limit hydrogen blends to a maximum of 10%. • Long-term demand for pipeline gas is expected to decline in most markets partly due to changes in consumer preferences. • High gas prices in Australia limit the willingness to increase the cost of supplied gas further.	• Mandates for hydrogen blending.

5 THE AUSTRALIAN CONTEXT IS SUPPORTIVE OF A HYDROGEN INDUSTRY BUT NEEDS GREATER INVESTMENT AND ROBUST POLICIES TO GROW

5.1 Corporate commitments in Australia are mostly directed towards green hydrogen

Only a few Australian hydrogen projects have reached operational or even construction stages. For illustrative purposes, **Table 2** sets out Australian hydrogen projects, and although anticipated costs of announced projects exceed AUD$124b, nearly all of this investment is contingent upon successful pilot projects or feasibility studies [26].[13] The largest announced projects (in terms of dollar value) mainly target exports rather than domestic demand (some are shown in **Figure 10**). The table shows that, of the new hydrogen projects, at least 65 are green hydrogen projects in Australia, compared to just three trying to create hydrogen from fossil fuels and CCS. Limited gas availability and high gas prices increase the opportunity cost of blue hydrogen which may further restrain the growth of blue hydrogen projects.

Table 2: Published projects and estimated costs[14]

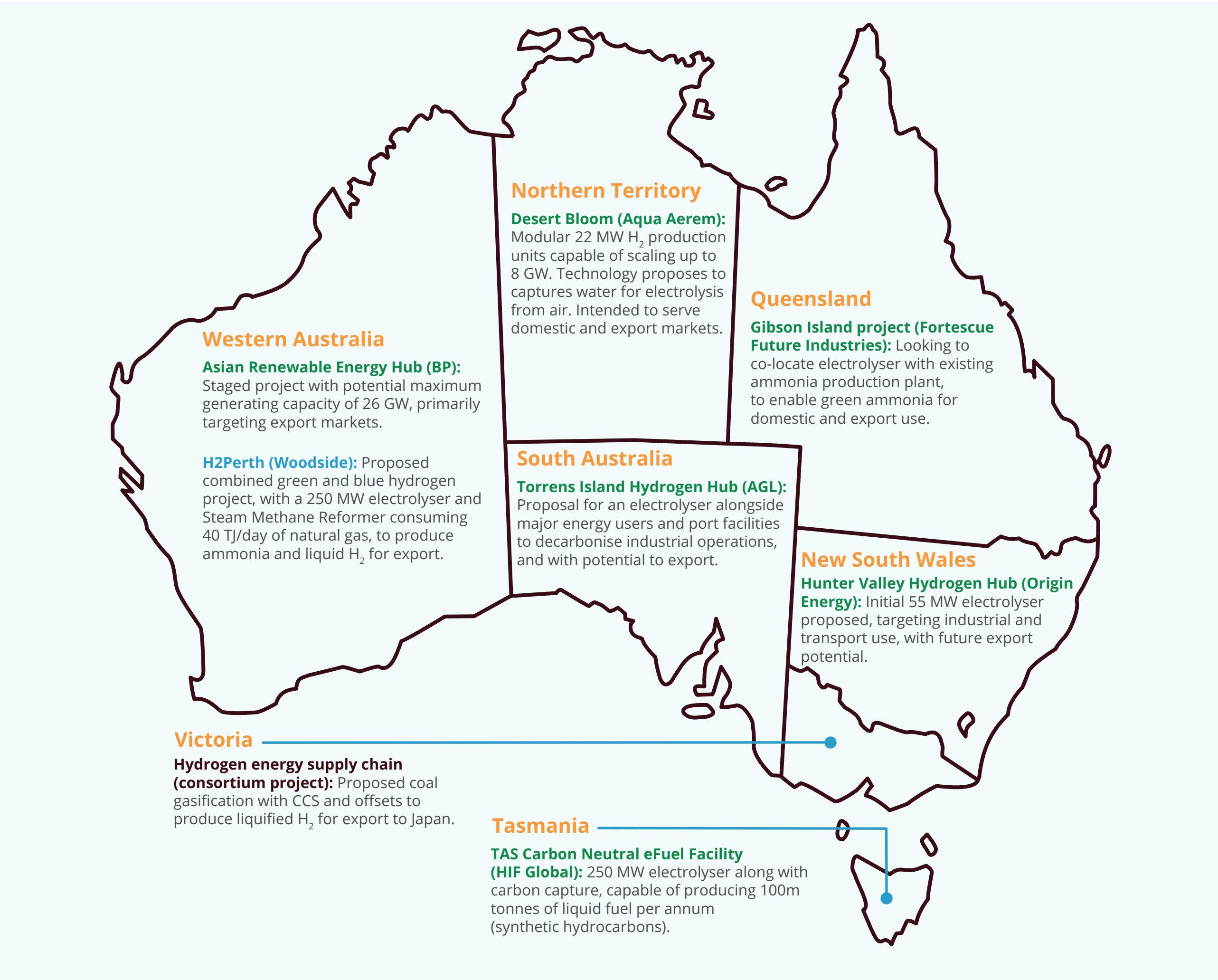
Region	Total Projects	Projects with Estimated Costs	Total Estimated Cost ($m)[15]
Western Australia	24	16	111,190
New South Wales	7	4	108
Queensland	26	12	639
Australian Capital Territory	3	2	465
Victoria	8	5	652
Tasmania	6	1	3
South Australia	5	4	1,009
Northern Territory	1	1	10,750

13. Project data taken from CSIRO 'HyResource' Project List [25] as at 1 February 2021.

14. Project data taken from CSIRO 'HyResource' Project List [25] as at 1 February 2021. $ = AUD.

15. Estimated cost refers to the total costs assuming successful feasibility studies and pilot phases.

Figure 10: A selection of some of the largest proposed hydrogen projects in each state



5.2 There are supportive policy signals from the Australian Government

The Australian federal government released a long-term emissions reduction plan (October 2021) that outlined the high-level steps required to achieve the 2050 goal of net zero emissions. With the change in government at the time of this report, many aspects of an updated plan have not yet been developed. Following the change in government, a new Nationally Determined Contribution of 43% by 2030 was lodged with the United Nations Framework Convention on Climate Change. Other relevant policy commitments from the new government include a commitment to rachet emissions limits over time for facilities covered by the government's safeguard mechanism, a $15b National Reconstruction Fund to rebuild Australia's industrial base, and investment of $20b to rebuild and modernise the grid [27]. Australian state and federal mid-term targets and the National Hydrogen Strategy are referenced in '**13.4 Appendix D**'.

5.3 But there are a number of regulatory challenges and barriers that need to be overcome

Current policy settings do not provide sufficient support for the long-term institutional investment required to build a globally competitive hydrogen industry in Australia. The key significant perceived risks by investors include pre-commercial technology and small-scale project risks, the lack of a carbon price and high fossil fuel subsidies, and high risks associated with a long-term return profile, as described in the '**1. Executive Summary**'.

A summary of policy expectations investors can advocate for to support the hydrogen industry can be found in the section '**9. Investor role in accelerating a sustainable hydrogen industry**'. '**13.4 Appendix D**' summarises current national and state hydrogen-related strategies and investments.

Stakeholders participating in the development of this report also noted several regulatory and approval challenges affecting the development of the hydrogen industry. These include:

- The Australian planning and environmental approval processes are relatively slow.
- Securing property rights and access may be difficult.
- Connection agreements for high voltage transmission, and approvals for any new connection assets are required.
- Safety compliance issues.

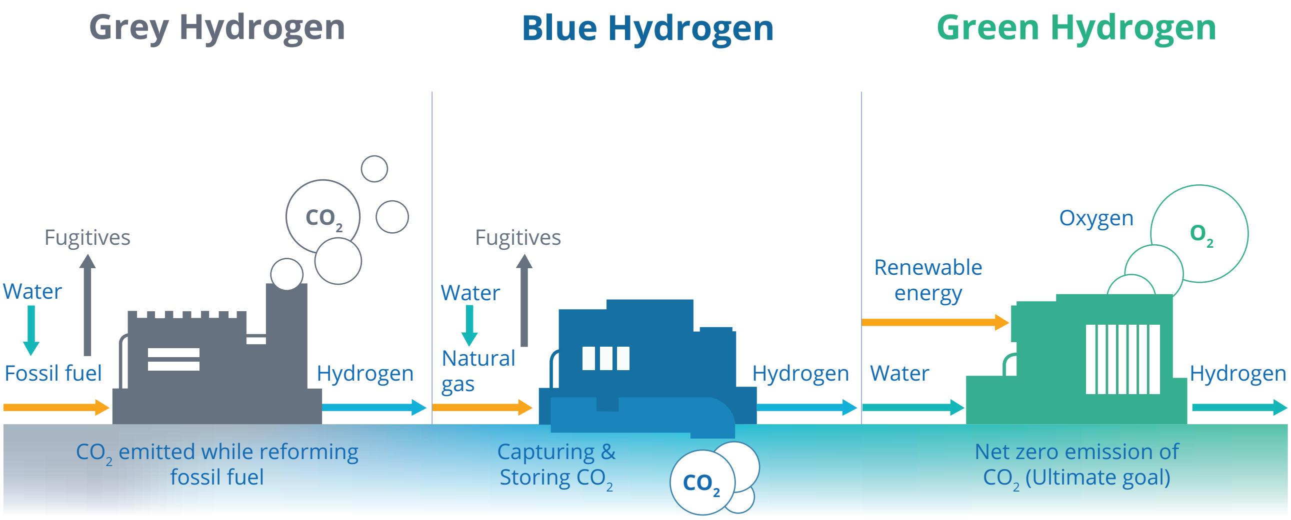
6 HYDROGEN EMISSIONS AND ENVIRONMENTAL PROFILE

6.1 The most promising types of low-carbon hydrogen production in Australia are blue and green

In 2020, approximately 80% of global hydrogen production was produced from fossil fuels, mostly unabated [2]. While hydrogen production is a highly emissions-intensive process, interest in its use as a low-carbon fuel is increasing as hydrogen combustion does not produce any carbon by-products.[16]

There are numerous methods to produce hydrogen. The most commonly cited and promising low-carbon production methods in Australia are green and blue hydrogen, which are the focus of this report. However, because blue hydrogen is often associated with higher emissions, it is less likely to be classified as low-carbon hydrogen. The end uses and costs associated with green and blue hydrogen are discussed in later sections of this report. The exponential growth projected for the hydrogen sector reflects action on decarbonisation commitments, especially in hard-to-abate sectors and includes expected declines for grey hydrogen as a share of total hydrogen demand.

Figure 11: Types of hydrogen production

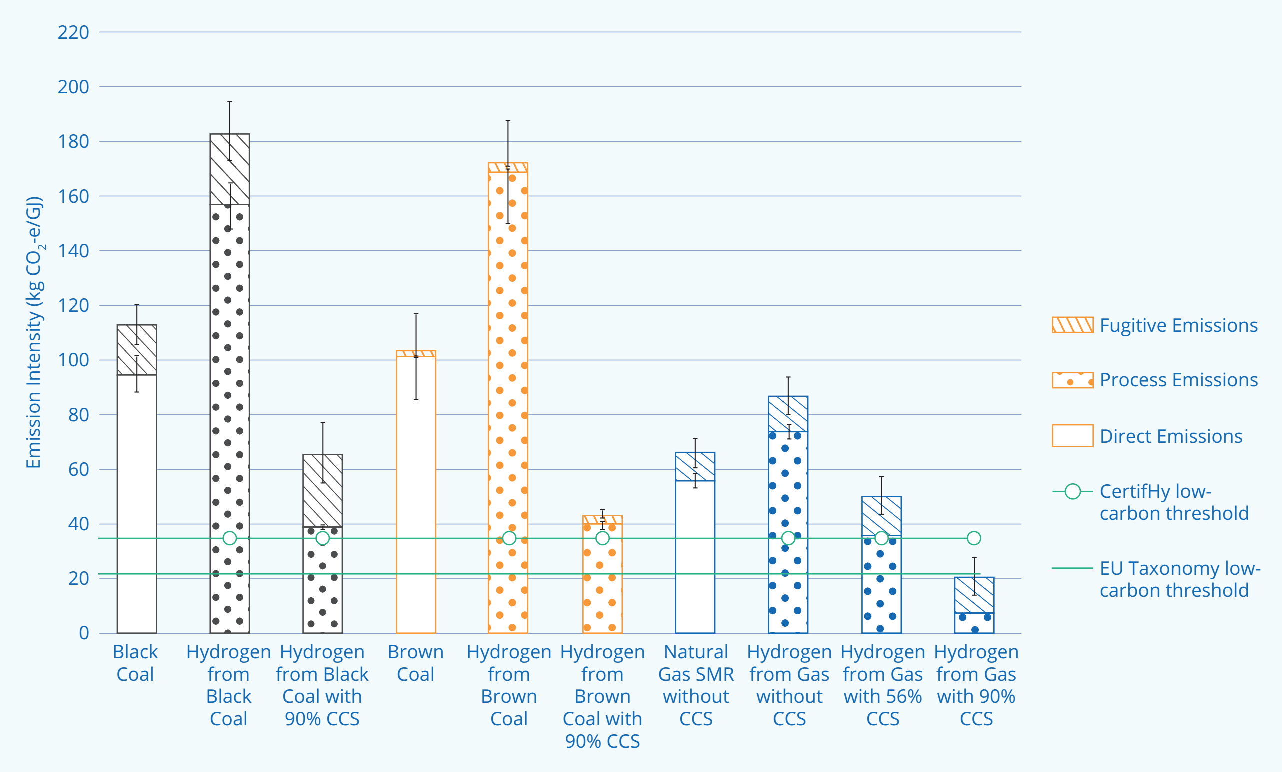


16. Note, while some hydrogen end uses, such as fuel cell vehicles, produce only water vapor as a waste product, this is not uniformly the case.

6.2 Hydrogen production may be emissions intensive depending on its production method

This section provides an overview of the emissions profiles of both blue and green hydrogen and the key issues that need to be addressed for hydrogen to be a genuinely low-carbon option in the transition to a net zero economy. The EU taxonomy for sustainable activities[17] has deemed the production of hydrogen as sustainably aligned; however, it places strict requirements on the inclusion and specifies hydrogen must be around 25g of CO_2e per MJ[18] or lower. CertifHy places the carbon intensity limit of low emissions hydrogen at 36g of CO_2e per MJ or lower.[19] The chart below depicts the emissions intensity of a range of fossil hydrogen production methods and shows only blue hydrogen from gas with 90% capture rates when accounting for fugitive emissions is below the EU Taxonomy and CertifHy emissions intensity thresholds. Given that blue hydrogen will be more emissions intensive, it faces greater regulatory risks from regulations targeting emissions reduction and may not benefit from policy measures that support lower carbon substitutes. The economic assessment of blue and green hydrogen is discussed in later sections.

Figure 12: Hydrogen emissions intensity thresholds of the EU Taxonomy and CertifHy



Source: ANU [30]

Other aspects that must be considered regarding emissions are hydrogen leakage[20] and transportation emissions, which can be mitigated by project-specific due diligence. Transportation costs have been discussed in later sections.

17. The EU taxonomy is a classification system, establishing a list of environmentally sustainable economic activities.

18. Around 25g of CO2e per MJ has been calculated based on the EU Taxonomy's lifecycle emissions savings requirement of 73.4% relative to a fossil fuel comparator of 94g of CO_2e per MJ, or 3t of CO_2e per t of hydrogen or lower. https://ec.europa.eu/sustainable-finance-taxonomy/activities/activity_en.htm?reference=3.10

19. CertifHy's lifecycle emissions savings requirement is defined as resulting in lifecycle emissions savings of 60% relative to SMR of 91g of CO_2e per MJ. 'Low-carbon hydrogen' is defined by CertifHy as originating from non-renewable origin using CCS/CCUS. CertifHy thresholds includes all upstream emissions up to the point of hydrogen production. https://www.certifhy.eu/go-labels/

20. Hydrogen burns with a high temperature flame, and hydrogen combustion can cause reactions in the surrounding air that create nitrogen products (NOx). This is something typically addressed in traditional natural gas consumption processes, and it is yet to be demonstrated that a similar emissions mitigation process can be implemented in hydrogen combustion facilities.

6.3 Blue hydrogen is unlikely to be a low-carbon fuel

There are significant concerns regarding the potential climate credentials for blue hydrogen. Producing blue hydrogen may create substantial lifecycle emissions from fugitives lost during gas extraction, uncaptured carbon during the CCS process, the risk of using offsets to claim clean credentials, and captured carbon being used for oil extraction. The measurement and reporting of emissions from the gas extraction and SMR processes need to be substantially improved. A recent report found that methane emissions from oil and gas extraction in Australia could be underreported by approximately 33% [7]. Additionally, a report found total emissions of blue hydrogen (produced internationally) was only 9–12% less than grey hydrogen [6] and questioned the abatement potential of blue hydrogen. The associated costs with reducing these lifecycle emissions are often not accounted for when comparing the costs of blue and green hydrogen, thus lifecycle emissions reporting and robust emissions intensity standards are required for transparency, as buyers will accordingly price emissions. Not all blue hydrogen is low-carbon, and only production methods with the strictest emissions abatement methods (e.g., gas with 90%+ capture rates) meet the emissions intensity thresholds put forward by the EU taxonomy[21] and CertifHy [8], while other certification schemes such as the Smart Energy Council's do not allow for blue hydrogen at all [9]. Blue hydrogen carries the risk of prolonging fossil fuel demand, may lead to stranded asset risks [10], and focusing on blue hydrogen may direct investment away from genuinely low-carbon fuels.

Blue hydrogen is reliant on CCS

Hydrogen produced from gas via SMR processes creates direct CO_2 emissions of 9kg of CO_2 per kg of hydrogen that must be captured, while upstream methane emissions from natural gas production and transport can add another 1.9–5.2kg of CO_2e per kg of hydrogen (global average of 2.7kg of CO_2e per kg of hydrogen) [2]. While there are reportedly seven operational blue hydrogen facilities globally [28], it is unlikely these facilities capture enough carbon to be claimed as blue hydrogen. For example, one of the seven facilities listed is Shell's Quest project, which Shell has stated should not be considered a blue hydrogen facility [29]. CCS capture rates during SMR processes are rarely reported, and although high capture rates of approximately 90% are often quoted and are technically possible, they are rare in practice – this is a key risk for blue hydrogen producers making low-carbon hydrogen claims [30]. An opportunity to further capture up to 98% of emissions produced at point of production includes using autothermal reforming (ATR) [31] and powering the process with renewable energy. Investment should be directed towards technologies that capture larger amounts of carbon.

IPCC WG3 highlights the need to develop CCS to decrease costs and improve capture rates while also noting that renewable technologies are improving and becoming more economically competitive at a far faster rate [5].

Other emissions challenges for blue hydrogen

Carbon that is captured is often used in enhanced oil recovery due to the financial benefit from either selling carbon for use in enhanced oil recovery [32], or from the sale of the oil itself, which leads to significant re-emission of carbon when the oil is combusted. For blue hydrogen to be comparable to green hydrogen as a low-carbon fuel, the captured carbon should be stored and not re-emitted via enhanced oil recovery.

As blue hydrogen is reliant on gas, the rate of methane leakage related to the extraction of gas is key and will require measurement and transparent reporting and will come with a cost to minimise methane leakage. Research suggests methane leakage is likely systematically underestimated [33]. Based on satellite data, the IEA estimates that the global oil and gas sector emitted approximately 70Mt of methane in 2020, equivalent to 2.1Gt of CO_2e [35], around 10% of lifecycle emissions associated with the oil and gas sector [43]. Additionally, a recent report suggested methane emissions from oil and gas extraction in Australia may be potentially underreported by approximately 33% [7]. When producing blue hydrogen, methane emissions upstream from natural gas production and transport could add another 1.9–5.2kg of CO_2e per kg of hydrogen [2]. Further, fugitive emissions may be even greater for blue hydrogen than for gas, if gas is used to power the SMR and CCS processes [6].

21. The EU taxonomy is a classification system, establishing a list of environmentally sustainable economic activities.

Offsets

Some blue hydrogen producers may consider pursuing strategies with low capture rates and purchasing offsets. In the context of this report, the significant use of offsets beyond offsetting residual emissions that the current technology cannot capture is not considered blue hydrogen. It is a controversial strategy given the accepted practice of using a mitigation hierarchy that prioritises abatement over-reliance on offsets due to the risk offsets may delay efforts to abate emissions [36]. Additionally, the credibility of the offsets themselves can be contentious [37], with the government planning an integrity review of ACCUs [38]. There are signals that the Australian Government's Guarantee of Origin scheme (Hydrogen GO) will prevent the use of offsets to reduce hydrogen lifecycle emissions. Purchasing offsets carries risks and may not be economically viable, this has been discussed further in the section '**7.3 Blue hydrogen production has greater cost variability**'.

6.4 Green hydrogen has a strong case as a low-carbon emissions fuel

Green hydrogen from 100% renewable energy sources has a small emissions footprint. Renewable energy may be sourced off-grid or from the grid via renewable power purchase agreements (PPAs). Green hydrogen's role in the future hydrogen supply mix has gained substantial interest given rapid reductions in the cost of renewable energy, especially wind and solar PV in Australia, and projected further declines in these costs, along with projected declines in the costs of electrolysers.[22]

Increasing the production of green hydrogen will subsequently increase the demand for renewable energy, and demand may outstrip supply. This will risk prolonging the fossil fuel energy supply in the NEM. It is critical to ensure a sufficient supply of renewable energy at the scale of the hydrogen industry.

6.5 Water availability is a key consideration for both blue and green hydrogen

Considering Australia's drought conditions, green hydrogen requires access to relatively large volumes of purified water as an input. Electrolysis to produce green hydrogen requires 9 kg of water to produce 1 kg of hydrogen compared to blue hydrogen, which requires 13–18 kg of water to produce 1 kg of hydrogen [2].[23] Stakeholders identified that, in practice, 12–14 kg of water was used per kilogram of green hydrogen, with the excess water being recycled. At the industrial scale, water availability may become scarce. Depending on its location, green hydrogen production may require desalination or wastewater treatment plant to secure a supply of freshwater, which will add additional capital costs, although many of the proposed hubs and projects to date have been selected based on water availability. In contrast, while blue hydrogen has higher lifecycle water requirements (due to the water required during gas extraction), if gas is imported instead of being domestically extracted, the water required within Australia's borders will decrease. When looking only at the point of production, blue hydrogen requires less water than green hydrogen.

22. Green hydrogen is an example of the broader process of producing hydrogen from renewables via the use of electrolysis.

23. Figures refer to lifecycle water demand and includes water from precipitation and abstraction but excludes water that may have been contaminated (e.g., oil spills). https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf

6.6 Carbon emissions certification is crucial to avoid emissions creep

As discussed in the previous sections, hydrogen can have high lifecycle emissions. It is critical to ensure that a hydrogen industry in Australia does not drive up national emissions.

Currently, there are no international standards for emissions levels or methodologies to define blue hydrogen, and there is no regulated certification scheme for hydrogen to measure and report embodied carbon content, although several international country-specific schemes are being developed, including CertifHy in Europe. The COAG Energy Council's *National Hydrogen Strategy* identified establishing the Hydrogen GO scheme as a priority action [39] that will help hydrogen users manage their purchased emissions. The overarching goal should be comparable, reliable and assurable hydrogen standards that promote a globally consistent investment approach to hydrogen investments that give purchasers transparency over hydrogen's carbon profile. As the expected domestic demand is relatively small compared to potential exports, a certification scheme is necessary to ensure that Australian hydrogen is internationally cost competitive.

In 2021, the Australian Government published a paper on the Hydrogen GO scheme, which applies a lifecycle approach to ensure blue hydrogen emissions from gas extraction to the point of production are accounted for but would exclude product transport and storage of hydrogen [40], and there are signals this scheme will also prevent the use of offsets to reduce lifecycle emissions.

Blue hydrogen is likely at a higher risk when certification is phased in, given the need to account for transportation leakage, fugitives and other lifecycle emissions, whereas green hydrogen produced from renewable energy does not emit carbon.

7 NEITHER GREEN OR BLUE HYDROGEN IS CHEAPER IN ALL SCENARIOS

The costs of producing green and blue hydrogen have significant variability; however, the analysis for this report suggests the following interdependencies:

- If blue hydrogen has low capture rates, low gas prices and no price for residual or fugitive emissions, blue hydrogen would be cheaper than green hydrogen.
- If blue hydrogen has high capture rates, high gas prices and a price for residual or fugitive emissions, green hydrogen is cheaper than blue hydrogen.

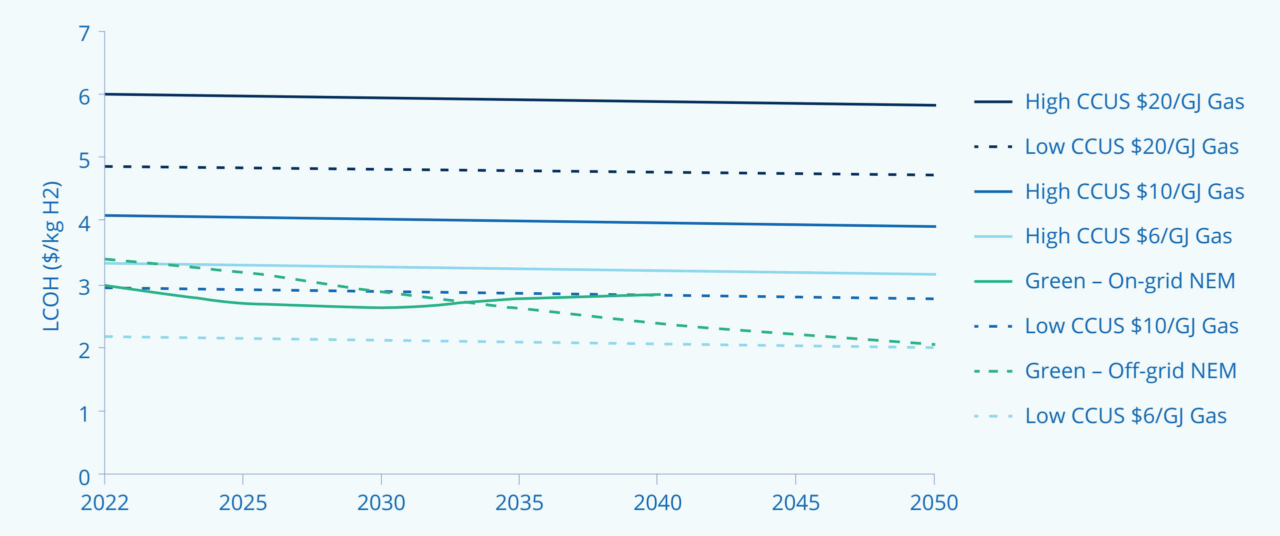
There was some optimism that blue hydrogen would have been the comparatively cheaper form of hydrogen production in projected forecasts; however, it is highly sensitive to high gas prices, and production costs increase with high capture rates (refer to **Figure 4**), which means producing blue hydrogen cheaply is unlikely to be low-carbon. LNG netback prices are expected to remain above $20 per GJ through to 2024 [11]; at these levels, the economic viability of blue hydrogen is extremely challenging and more expensive than green hydrogen. The attractiveness of green hydrogen in comparison is underscored by rapid reductions in the cost of renewable energy, especially wind and solar PV, in Australia and projected further declines in these costs, along with projected declines in the costs of electrolysers.[24]

If gas prices return to $20 per GJ, green hydrogen at current technology costs will reach cost parity with gas at a $190 per t carbon price, and learning rates (decreases in costs of technology) for shipping, electrolysers and electricity prices will further decrease the carbon price required for hydrogen to reach cost parity with gas and enable its substitution with gas.

Australia's LCOH relative to other international competitors will be critical to remain competitive with other countries' production. **Figure 4** shows the projected LCOH for domestic blue and green production by 2050. The analysis was based on key inputs and assumptions that are current but may change given the emerging nature of the industry and the expected technology gains, increasing demand and government support, among other factors that will help create a market for low-carbon hydrogen and reduce projected costs, at potentially rapid rates.

24. Green hydrogen is an example of producing hydrogen from renewables via the use of electrolysis.

Figure 4: Projected LCOH of green and blue hydrogen, selected production[25]



Source: Baringa Partners LLP

7.1 High carbon prices support the economic feasibility of hydrogen

The price gap between low-carbon hydrogen and its high-carbon alternatives can be closed with a carbon price that appropriately prices carbon risk. Carbon prices for Australia's key export partners in the APAC region are currently lagging behind Europe's (EU) effective price, although convergence is expected within the next decade, following diplomatic and political pressure, which includes the EU's planned Carbon Border Adjustment Mechanism. For reference, Germany's current carbon price is around $124.9 per Mt of CO_2 and is expected to rise further due to net zero commitments.

Australian ACCUs are indicative of a carbon price in Australia, and despite the 180% surge in ACCU spot prices over the past year to the current spot price of $47 per tonne, stakeholders suggested it was more economical for consumers to purchase offsets instead of low-carbon hydrogen (although purchasing offsets instead of abatement is not defined as low-carbon hydrogen in the context of this report). However, the government has committed to rachet emissions limits for facilities under the safeguard mechanism and has appointed an independent panel to review the integrity of ACCUs, which will likely drive up the prices of ACCUs.

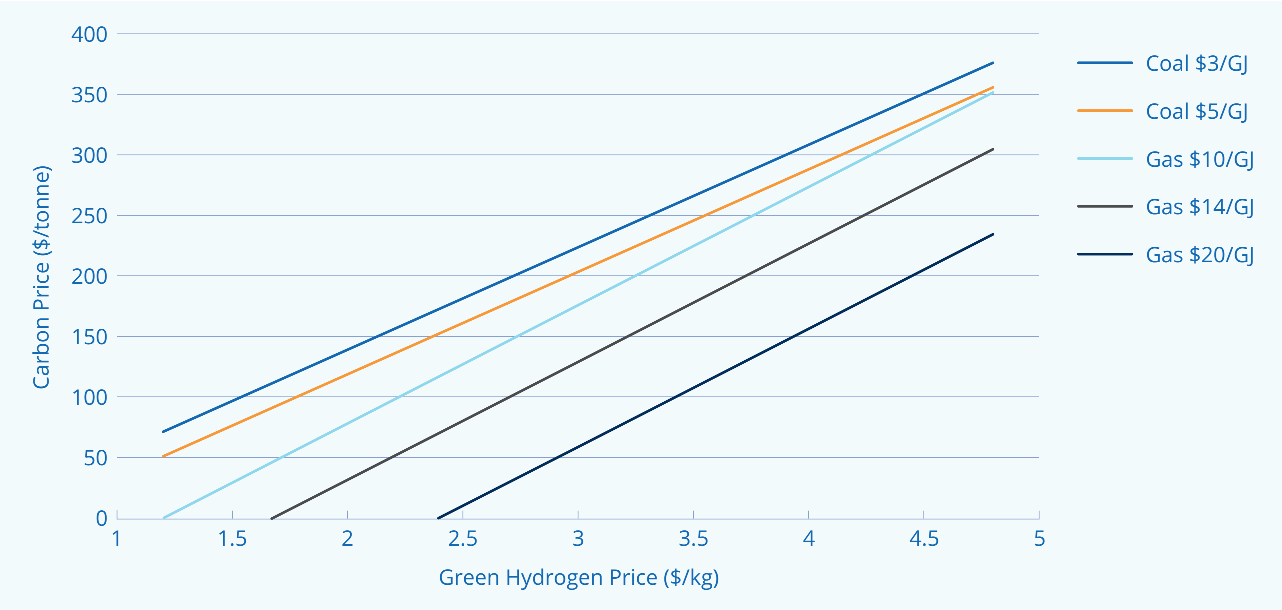
Hydrogen (both blue and green) at $4.5 per kg reaches cost parity with gas at $20 per GJ, with $190 per t carbon price

Hydrogen is often considered a substitute for gas (however, it is important to note that hydrogen displaces other fuels). Based on current technology and assumptions, the analysis undertaken as part of this report found that a $190 per t carbon price would make hydrogen cost competitive with gas. The Australian ACCUs are currently well below this level (approximately $50 per t). Potential learning rates for transportation and shipping costs, faster reductions in electrolyser costs and/or renewable electricity prices will further decrease the carbon price required for green hydrogen to reach cost parity with gas. Similarly, blue hydrogen may reap the benefits of a high carbon price if it can first abate sufficient amounts of emissions to be considered low-carbon.

25. Figure 2 notes and assumptions: LCOH is the all-in cost to produce hydrogen, expressed as a $ per kg of hydrogen. Capture rates reflect 90% CO_2 capture from the SMR and includes transport and storage costs of the CO_2. Costs of any offsets procured to cover fugitive emissions from gas extraction, or revenue from stored carbon are not included. Transport or conversion costs of hydrogen have not been included. As electricity price projections are only out to year 2055, LCOH for a 15-year plant-life can only be determined out to 2040 for on-grid production. 'On-grid' NEM is green power is procured via PPA with renewables volume matched. Off-grid combined green hydrogen has not been included due to insufficient data as there is a lack of large-scale, mature projects that disclose adequate information. 'High CCUS' = $20.02 per t of CO_2, 'Low CCUS' = $3.5 per t of CO_2. Wholesale electricity price increases are expected through the 2030s as significant capacity (coal generation) exits the market then moderates with new capacity. Electrolysers are expected to have some flexibility to ramp down in response to high prices. Carbon prices have not been included.

Figure 13 shows the carbon price (left vertical axis) required at hypothetical levels of green hydrogen prices (bottom horizontal axis) for green hydrogen to reach cost parity with natural gas and coal. For example, green hydrogen at $3 per kg and gas prices at $20 per GJ would imply a carbon price of approximately $55 per t for green hydrogen production to achieve cost parity with natural gas production.

Figure 13: Implied carbon price for cost parity of green hydrogen with fossil fuels



Source: Baringa Partners LLP

Although hydrogen has a range of end uses and may displace other fuels, this report has not analysed the cost parity of hydrogen against other fossil fuels, as the comparison is highly nuanced and difficult to measure.

7.2 Green hydrogen production has higher upfront capital costs

Green hydrogen production costs have comparatively higher upfront capital costs than blue hydrogen and are most sensitive to electrolyser capital costs and electricity prices. The costs covered in this section relate only to costs specific to green hydrogen and do not include additional costs such as transport or conversion to different hydrogen carriers, which will be covered in later sections. The revenue from government funding in any form (e.g., ERF, ARENA) has not been included, as it has not been included in the costing of blue hydrogen in later sections of this report. '**13.2 Appendix B**' presents an illustrative example of the sensitivity of green hydrogen to various input costs.

Capital costs specific to green hydrogen:

- Electrolyser costs.
- Balance of plant (which includes the AC-DC power conversion, water purification (if required), compression, hydrogen processing and other components).
- Desalination or wastewater treatment plants to secure a supply of freshwater.[26]

Other cost elements:

- Cost of renewable electricity.
- Capacity factors – higher capacity factors lead to improved hydrogen production efficiency (e.g., grid-connected, combined renewable resources off-grid).
- Refurbishment costs (expected to be approximately 3% of the total cost of the electrolyser [41]).

26. Although many of the proposed hubs and projects to date have been selected based on water availability. Blue hydrogen will also require significant amounts of lifecycle water due to the water required for the extraction of gas.

For green hydrogen to be viable, capital costs must decrease by improving electrolyser technologies

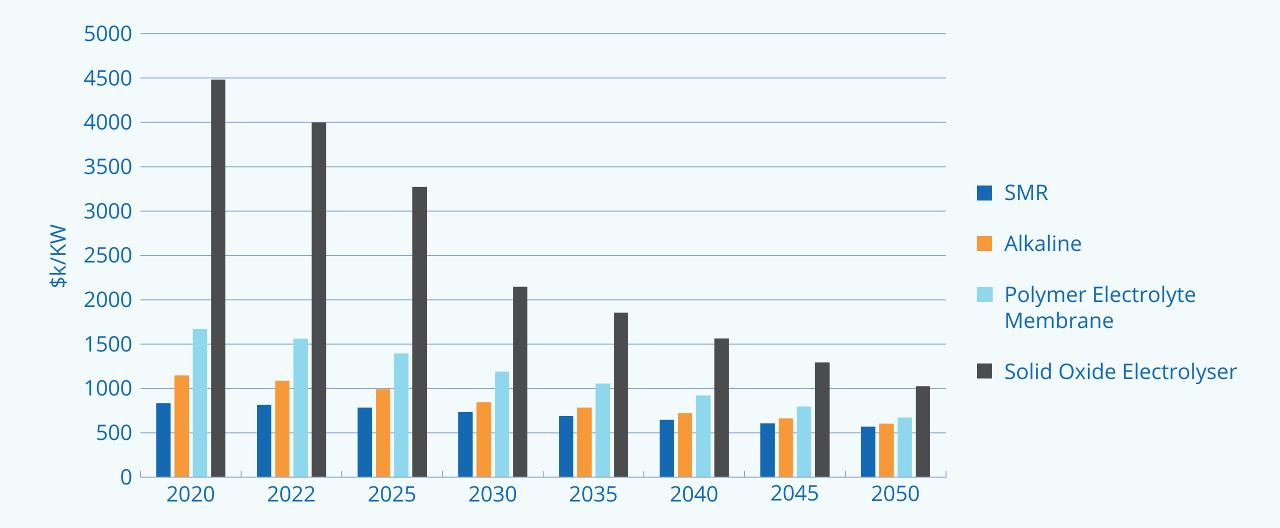
A key component of capital costs is electrolyser costs, and investment is needed to improve electrolyser technologies (a summary of various electrolyser technologies can be found in **Table 3**). A recent study by IRENA indicates electrolyser costs are already declining due to greater electrolyser efficiency and utilisation, a benefit of ongoing technological advancements and particularly noted for scale projects (more than 500MW) [42]. All three electrolyser types are projected to decline even further; for example, CSIRO estimates polymer electrolyte membrane (PEM) electrolyser capital costs to decline by 86% by 2050 (from $3,510 per kW to $500 per kW) [43]. Additionally, this study demonstrates that cost reductions have come from using less critical materials and economies of scale from mass manufacturing, standardisation and replication (i.e., learning-by-doing). As the industry scales, cost reductions will eventuate, such that larger-scale projects will become viable, benefiting from economies of scale.

Table 3: Summary of various electrolyser technologies

	Alkaline Electrolysers	Polymer Electrolyte Membrane	Solid Oxide Electrolysers
Costs	Lowest	Moderate	Highest
Maturity	Most mature and used commercially	New technology used commercially	Used in small projects and the pilot stage
Advantages	Lowest cost	Can operate more flexibly (can capitalise on low electricity prices at certain times of the day)	Higher efficiencies and can operate flexibly
Disadvantages	Least flexible and is not equipped to handle intermittent energy supply	Require precious metals and is more expensive than alkaline electrolysers	Highly expensive and not yet commercial
Cost projection declines	Lowest declines	Steep decline	Steepest decline

Figure 14 shows the capital costs of developing large-scale green hydrogen projects are currently very high compared to those of blue hydrogen. In the stakeholder workshops Baringa facilitated, multiple stakeholders indicated that, at the present time, the most viable projects in Australia are at the less than 10MW demonstration scale due to dependence on government support (through grants and subsidies). A significant scale-up in size reduces the balance of plant costs, achieves economies of scale and should be the end goal for investment in the hydrogen industry.

Figure 14: Capital costs for various electrolyser technologies and SMR[27]



Source: Baringa Partners LLP

For green hydrogen to be viable, renewable electricity costs must decrease

Renewable energy is the highest single cost of green hydrogen production [42] and can make up 50–90% of total production expenses [2]. To reduce the cost of green hydrogen, the cost of renewable energy must be decreased. Currently, the electrolysis process requires 45–83kWh per kg of hydrogen, dependent on the technology.[28] However, energy-efficient technologies are expected to decrease the energy required to produce green hydrogen by 2050. Securing renewable energy costs of less than $30 per MWh was viewed by stakeholders as the key to commercialising green hydrogen. Similarly, the Global Hydrogen Review found electricity prices should be below US$20 per MWh to enable a hydrogen market [2].

Unlike on-grid production, off-grid green hydrogen production operational costs are not tied to wholesale electricity prices, which makes energy costs more predictable. Electricity losses are also lower, and some hardware costs can be avoided, although off-grid systems may require more flexible electrolyser options to manage electricity intermittency. The benefits of off-grid production are not projected to offset its higher capital costs until the early 2030s, after which off-grid green hydrogen is projected to have a lower LCOH than on-grid green hydrogen (**Figure 15**).

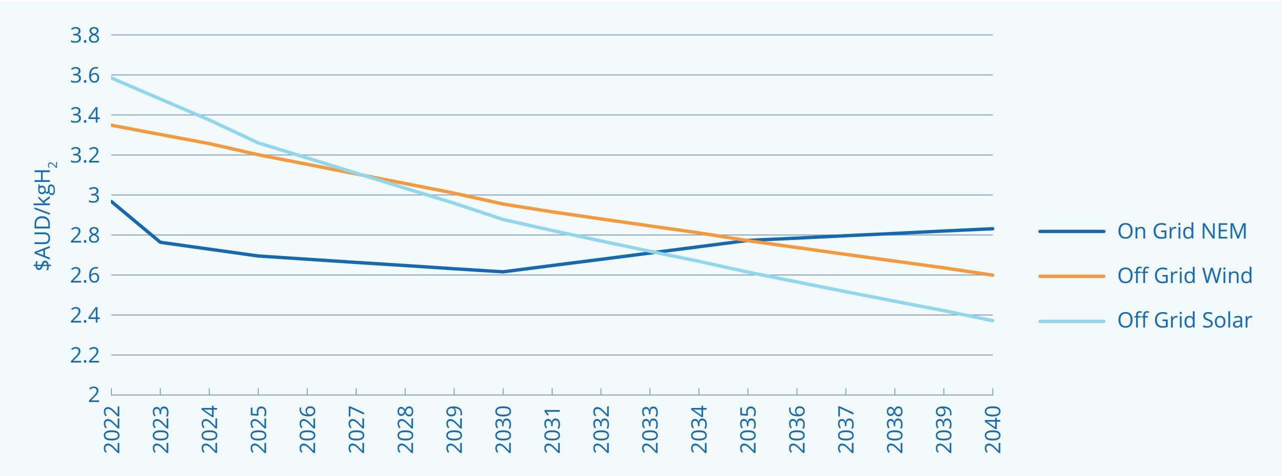
In comparison, on-grid green hydrogen production has lower capital costs and the ability to operate continuously (i.e., operate at higher capacity factors), and can take advantage of low-cost periods in the electricity market. The levelised cost of electricity (LCOE) is declining due to the ongoing technological advancements in wind and solar PV generators. For example, between 2010 and 2019, global LCOE of onshore wind generation fell by 38%, and the global LCOE of large-scale solar PV fell by 82% [44]. Electricity price reductions have been even larger for hydrogen producers exposed to spot prices, with the increased frequency and severity of zero and negative spot prices in Australia's NEM and Western Electricity Market (WEM), especially in the middle of the day, which flexible (i.e., PEM) electrolysers can capitalise on.

Producers require cheap renewable energy, which may increase demand for renewable electricity, placing an upward pressure on prices. Additionally, if the demand for renewable energy outstrips supply, it risks prolonging the fossil fuel energy supply in the NEM. It is critical to ensure a sufficient supply of renewable energy as the green hydrogen industry grows. Large-scale green hydrogen projects intended for export will likely not be grid-connected, and will have sufficient access to renewable resources.

27. kW was chosen to represent hydrogen production capacity of the facility to understand how fast can the facility produce hydrogen (maximum capacity). Capture efficiency was assumed to be 90%. The costs shown in Figure 14 are aligned with the IEA's *Announced Pledges*, around 2.1 °C global warming, scenario, rather than the IEA's more-decarbonised *Net Zero by 2050* scenario (1.5 °C aligned). The SMR Capital Costs shown in Figure 14 are for a 1,000MW plant and includes capex for CCS capabilities. Alkaline electrolysers = highly alkaline potassium or sodium hydroxide electrolyte solution. PEM = Polymer Electrolyte Membrane is a solid plastic material as the electrolyte and separate hydrogen upon application of electric current. SOEC = Solid Oxide Electrolysers are under development and is a high-temperature electrolyser.

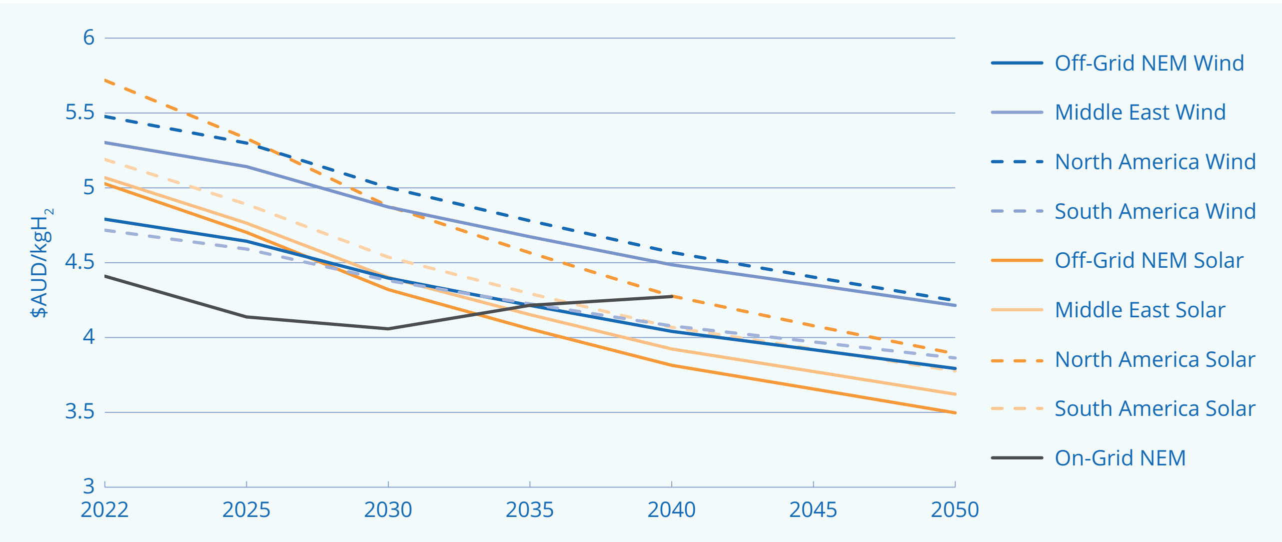
28. Figures drawn from IRENA and other sources.

Figure 15: Projected LCOH of green hydrogen[29]



Source: Baringa Partners LLP

Figure 16: Delivered cost of green hydrogen for different regions and different technologies[30]



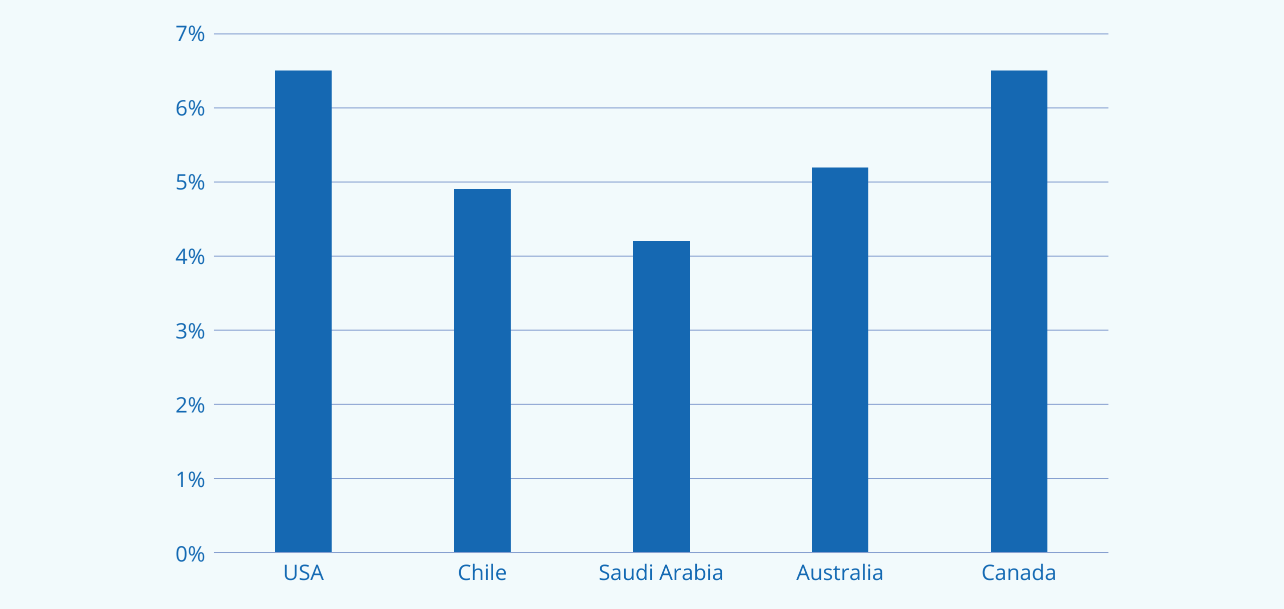
Source: Baringa Partners LLP

Figure 16 shows the production of Australian off-grid and on-grid green hydrogen compared to several other key hydrogen-producing markets and shows that Australia can produce green hydrogen competitively. A comparison of Australia's renewable energy weighted average cost of capital (WACC) versus these markets shows it is relatively cheap to pursue renewable energy projects, although there is competition from some countries that can lower costs due to super-scale state-owned monopolies (**Figure 17**).

29. LCOH is the all-in cost to produce hydrogen, expressed as a $ per kg of hydrogen. Transport or conversion costs of hydrogen have not been included. As electricity price projections are only out to year 2055, LCOH for a 15-year plant-life can only be determined out to 2040 for on-grid production. 'On-grid' NEM is green power is procured via PPA with renewables volume matched. Off-grid combined green hydrogen has not been included due to insufficient data as there is a lack of large-scale, mature projects that disclose adequate information. Wholesale electricity price increases are expected through the 2030s as significant capacity (coal generation) exits the market then moderates with new capacity. Electrolysers are expected to have some flexibility to ramp down in response to high prices. Carbon prices have not been included.

30. This analysis does not factor in a price on carbon (or, relatedly, costs associated with purchasing CO_2 offsets to abate any emissions associated with output from fossil-fuel generators to supply on-grid green hydrogen). On-grid NEM includes renewables + firming and assumes offsets are purchased for residual emissions based on comparing hydrogen electrolyser intraday load profile with intraday emissions intensity of the NEM.

Figure 17: WACC for renewable energy projects by region [45]



Source: Baringa Partners LLP

7.3 Blue hydrogen production has greater cost variability

Blue hydrogen projects have lower upfront capital costs but face greater cost variability because of their dependence on gas prices. There are also fewer favourable locations that are close to carbon storage sites with existing carbon transport and infrastructure.

Capital costs specific to blue hydrogen:

- Steam methane reformers.
- CCS.

Other cost elements:

- Gas prices.
- Operational costs of CCS.
- Capture of fugitive emissions from upstream gas production, uncaptured emissions (around 5–10%).
- Costs of offsets for residual emissions.

For blue hydrogen to be economically viable, gas prices must be low and existing infrastructure used

The cost of gas is a key factor in determining whether blue hydrogen is economically feasible.

Natural gas prices (used as a proxy of the opportunity cost of supplying that natural gas directly to domestic and international markets) along Australia's east coast have been volatile and increasing over the last decade, as indicated by ACCC LNG netback prices. In particular, the past year has been particularly volatile due initially to European supply chain issues (in late 2021/early 2022) and then the crisis in Ukraine. LNG spot netback prices rose 14-fold between September 2020 and April 2022, from $3.14 per GJ to $44.5 per GJ, with prices expected to remain above $20 per GJ until February 2024 (**Figure 18**). Gas prices at these levels make potential blue hydrogen projects financially unviable.

Note: The costs covered in this section relate only to costs specific to blue hydrogen and do not include additional costs, such as transport and conversion to different hydrogen carriers.

Figure 18: Historical and projected LNG netback prices

Source: ACCC [11]

Lifecycle emissions must be managed for blue hydrogen

Carbon capture and storage

Another major cost consideration for blue hydrogen is operational costs for ongoing carbon capture and storage (CCS). There are costs associated with operating CCS, as well as costs to transport and store carbon, which increase as the distance to storage sites increases. There are highly uncertain forecasts that suggest a range between $3.5 per t of CO_2 ('Low CCUS in **Figure 4**') and $20.02 per t of CO_2 ('High CCUS in **Figure 4**') [46][31] and incorporate the costs to transport, store and monitor captured CO_2 (excluding additional costs embedded in SMR processes, which have been captured in capital expenditure instead), which equates to additional costs between $0.26–$1.4 per kg of hydrogen. 'High CCUS' costs relate to the CO_2 captured from the SMR process, which results in emissions reductions of around 90% [2]. A report published by ANU researchers found it becomes significantly more expensive to capture around 90% or more of emissions [30], potentially disincentivising producers to capture sufficient amounts of carbon to achieve a low-carbon status. Without high capture rates, blue hydrogen cannot be comparable to green hydrogen from an emissions standpoint.

While CCS could be retrofitted to existing grey hydrogen facilities, additional complexity, integration and cost barriers arise from retrofitting plants to capture carbon, transport and store it. While possible, it may be expensive and not economical to do so.

The recent reports by the IPCC highlight the need for CCS in several hard-to-abate applications, and the IEA report supports the need to scale-up deployment and investment in CCS [47]. Given the need for CCS, CCS technology must develop and become an economically viable emissions abatement solution; however, its use with all but the most hard-to-abate sources of emissions is controversial.

Offsets

Some concerns around using offsets include prolonging investment in assets that may eventually become stranded, over investment in actual emissions reduction or capture technologies with longer-term value. Additionally, as demand for offsets increases, the availability of credible offsets decreases, while the costs to purchase offsets increase, making purchasing offsets an expensive long-term strategy. Additionally, the credibility of the offsets themselves can be contentious [37], and the review of ACCU integrity may limit the number of available ACCUs, again driving up prices. This analysis did not include revenue generated from government support via carbon credits, government funding for renewable energy and green hydrogen, and revenue from the sale of carbon credits in the voluntary market. In the context of this report, hydrogen combined with offsets instead of abatement is not considered low-carbon.

31. Note: cost is for transporting, storing and monitoring the captured carbon. Additional costs in the SMR units themselves are included in the capex to capture the CO_2 from SMR processes.

Fugitives

For blue hydrogen to be comparable to green hydrogen as a low-carbon fuel, the fugitive emissions incurred in the gas extraction process must also be abated, resulting in associated costs. Based on satellite data the IEA estimates that the global oil and gas sector emitted around 70Mt of methane in 2020, equivalent to 2.1Gt of CO_2e [34], and contributed around 10% of lifecycle emissions associated with the oil and gas sector [35]. While that is a global figure, methane emissions in Australia from oil and gas extraction have also recently been found to be potentially underreported by 33% [7]. Additionally, fugitive emissions will be even higher if gas is used to power the SMR and CCS process, as additional energy will be required to power these processes [6]. This report mentions that fugitive emission measurement and reporting need to be improved.

The United Nations Environment Program estimated that 60–80% of methane emissions in the oil and gas sector could be abated at low or negative cost [48], while McKinsey estimates that reducing fugitive emissions and flaring could abate 1.5Gt of CO_2e per annum by 2050, at the cost of less than $15 per t of CO_2e [49].

7.4 Transportation costs of hydrogen may be high, and cost reductions will benefit the economics of blue and green hydrogen

The types of hydrogen carriers include:

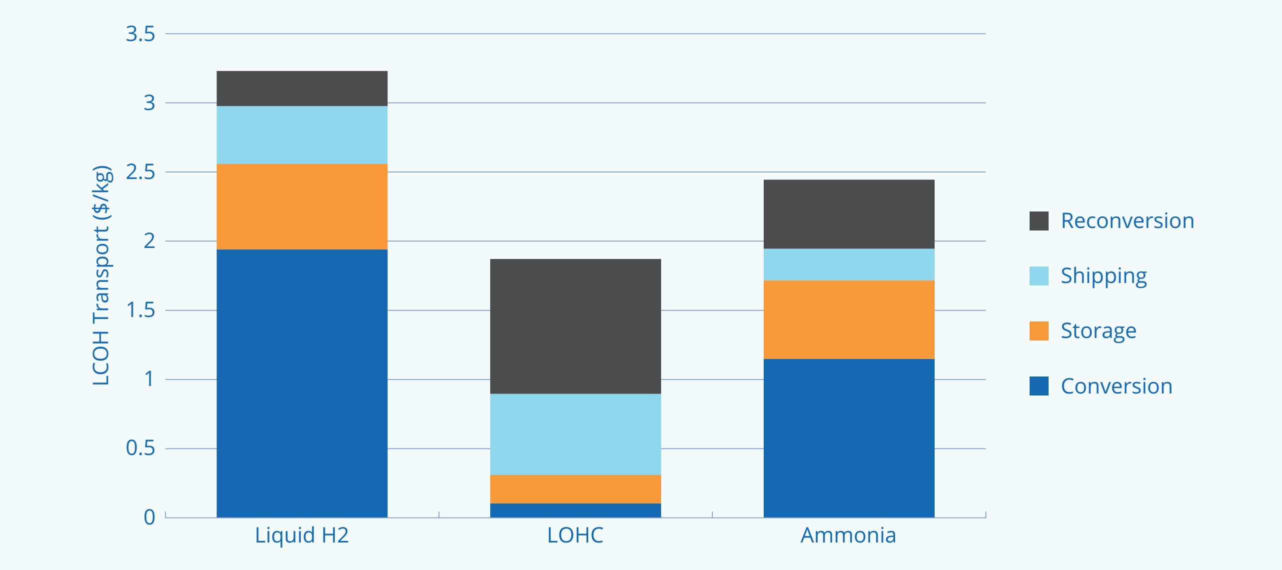
- Liquefied hydrogen.
- Liquid organic hydrogen carrier.[32]
- Ammonia.
- Methane and methanol (produced from hydrogen).

The storage and transport of hydrogen can be technically and financially challenging because existing natural gas pipelines are not suitable for safe and efficient hydrogen transport. Domestic gas pipelines are only technically ready to facilitate hydrogen blends; blends higher than 10% would require significant modifications to avoid pipeline cracking. While hydrogen transport in gas form may make sense in fit-for-purpose pipelines, it is unable to fully utilise most existing gas pipelines, and the transport and storage of hydrogen to end users will require other forms to be considered, such as liquified hydrogen, ammonia and liquid organic hydrogen carriers. To achieve economies of scale, projects are likely to require the development of hydrogen hubs, co-location with key hydrogen infrastructure (e.g., ammonia conversion infrastructure) and dedicated pipeline infrastructure to reach key demand centres. Hydrogen for export, both blue and green, is likely to be converted into ammonia and is located close to ports to minimise transportation costs. An open question is the potential for hydrogen-importing countries to import gas and convert it to hydrogen within its own borders, to resolve the difficulties transporting hydrogen. There are a range of factors to consider related to this strategy, including mitigating fugitive emissions from importing gas, the energy availability of the destination country (i.e., if a country is already short on energy, it will require even more to convert gas to hydrogen, and potentially convert it again to another carrier form such as ammonia), and the other costs discussed in the prior section.

Figure 19 compares the costs associated with transporting hydrogen (in its three leading hydrogen carriers) and shows the highest costs are conversion from hydrogen to its carrier form or reconversion. The transportation, conversion, and reconversion of hydrogen can add significant costs, and technological developments are needed to increase the economic viability of hydrogen.

32. A hydrocarbon compound formed by adding hydrogen with another molecule at high temperatures. It generally cannot be burned directly as a fuel.

Figure 19: End-to-end transportation costs for the three leading hydrogen carriers[33]



Source: Baringa Partners LLP

33. LOHC = Liquid Organic Hydrogen Carrier. Assuming an electricity price of $60/kWh in both delivery and recipient nations, and across different hydrogen carrier forms, and that transportation occurs via shipping hydrogen over a distance of 10,000 km over water.

8 SUCCESSFUL CHARACTERISTICS OF BLUE AND GREEN HYDROGEN PRODUCERS

The following table summarises the findings from prior sections and describes the key barriers and enablers for both blue and green hydrogen production. This table shows the different characteristics required for successful blue and green hydrogen production.

Table 4: Key barriers and enablers for blue and green hydrogen production

	Blue	Green
Capital costs	Lower capital costs.	Higher capital costs (primarily electrolyser technologies).
R&D gains	Less opportunity for technology gains.	Greater opportunity for technology gains.
Energy costs	Low gas prices are critical.	Low renewable electricity prices and sufficient supply is critical. Dependent on increasing transmission infrastructure. Off-grid electricity costs are variable and dependent on location.
Cost variability	Higher cost variability due to gas price dependence on commodity markets.	Lower cost variability.
Emissions profile	Higher emissions profile and lifecycle emissions. Risk of locking in carbon leading to stranded asset risks.	Lower emissions profile.
Emissions boundaries	Must have capture rates of more than 90%. ATR + renewables is preferable to SMR (due to higher capture rate potential and use of renewable energy). Supply chain fugitives must be measured directly. Carbon should not be sold for enhanced oil recovery or other purposes that re-emit carbon.	Energy supplied must be 100% renewable; for example, obtained via PPAs, directly connected to renewable sources of energy, etc.
Geography	Located close to carbon storage sites, conversion and storage facilities.	Off-grid production sites must be close to renewable generation and conversion facilities. Grid connection offers greater flexibility but must be fully secured by renewable PPAs.

<table>
<tr><th></th><th>Blue</th><th>Green</th></tr>
<tr><td>Carbon border adjustments mechanisms</td><td>Greater risk if emissions profile is not certified and sufficiently low-carbon.</td><td>Beneficial for green hydrogen.</td></tr>
<tr><td>Social license</td><td>Lower social license and more difficult to obtain government funding and approvals.</td><td>Higher social license and easier to obtain government funding and approvals.</td></tr>
<tr><td>Transportation costs</td><td>Proving more challenging than production costs. Combined efforts are required to bring down transportation, conversion and reconversion costs.

An open question is the potential for international customers is to import LNG and produce blue hydrogen in destination country (noting this will add energy conversion loads).</td><td>Proving more challenging than production costs. Combined efforts are required to bring down transportation, conversion and reconversion costs.</td></tr>
<tr><td>Size</td><td colspan="2">While risks exist for large projects, risks are exacerbated for small project sizes (e.g., less than $50–100 million in scale), which incur much higher transaction costs than large conventional investments and cannot benefit from economies of scale. Small-scale projects are more suitable for domestic demand and where it is co-located with their end use and does not require conversion/reconversion to other carrier forms for transportation.</td></tr>
<tr><td>Shared asset arrangements</td><td colspan="2">Beneficial for both blue and green hydrogen producers, enabling cost sharing and increased utilisation and readiness for export. Existing gas pipelines cannot be used for hydrogen transport unless significantly upgraded.</td></tr>
<tr><td>Offtakers</td><td colspan="2">Secure long-term offtake agreements (10–15 years) and/or underwritten by the government are ideal. Strong bilateral relationships should be developed with target markets and leverage Australia’s strong existing customer relationships.</td></tr>
<tr><td>Carbon prices</td><td colspan="2">High-carbon prices are beneficial for hydrogen as it reaches cost parity with gas at a $190 per t carbon price, assuming gas prices of $20 per GJ. No or low-carbon prices act as a barrier to the uptake of hydrogen compared with using gas as purchasing offsets is comparatively cheaper note that in the context of this report, hydrogen using offsets instead of abatement is not considered low-carbon).</td></tr>
</table>

9 INVESTOR ROLE IN ACCELERATING A SUSTAINABLE HYDROGEN INDUSTRY

There is a range of opportunities for investors to support the development of a high-integrity, low-carbon hydrogen industry that is economically viable and will meet the energy demands of a net zero future.

The following section of the report looks at the role of investors in supporting the growth of the Australian hydrogen industry and ensuring that hydrogen is a low-emission fuel in the future:

1. Engage with companies that produce hydrogen and encourage low lifecycle emissions.
2. Engage with hydrogen-user companies and support the demand for low-carbon hydrogen.
3. Directly support broader market enablers of a hydrogen industry.
4. Advocate for robust policy settings and regulations that would ensure a high-integrity, long-term, competitive industry is developed in Australia for domestic and export use.

9.1 Engage with companies that produce hydrogen and ensure low lifecycle emissions

This report outlines the risks, costs, barriers and enablers associated with blue and green hydrogen production. Questions that investors should ask companies producing blue and green hydrogen are compiled below.

Questions for blue hydrogen producers

1. Which customers do the company engage with? Are they engaging with new and existing customers? (i.e., beyond LNG customers to chemical, transport, industrial, flexible power and gas pipeline users)
2. What is the planned capture rate from hydrogen production? (note: capture rates below a minimum of 90% should not be considered low-carbon)
    a. How is energy sourced to power SMR and CCS processes? Has a switch to ATR and renewable energy been considered?
3. Where and how is emitted carbon stored? How close are the hydrogen facilities located to carbon storage sites? Will captured carbon be used for enhanced oil recovery?
4. If offsets are used, what is the price profile assumed? At what price does blue hydrogen production become uneconomical with grey or green hydrogen? What proportion of emissions reduction does the company attribute to offsets? How does the company guarantee the credibility of offsets (noting that offsets should be used as a last resort to manage residual emissions only)?
5. Are plants designed for CCS retrofits (if not, capture rates may be lower than expected)? What capture rate is the company expected after upgrading its CCS?
6. What are the upstream fugitive emissions from gas (per cent)? How does the company guarantee the accuracy of accounting for fugitive emissions? How does the company intend to address these emissions in its blue hydrogen plans?
7. Does the company intend to have its hydrogen emissions profile certified under a guarantee of origin or CertifHy-type scheme?
8. How can gas price volatility be managed? What gas supply contracts are in place and what is the timeframe?
9. What are the financial liabilities of the project if CO_2 is not sequestered?

10. What existing infrastructure (e.g., pipelines, carbon storage) can the company expect to be utilised by hydrogen? What adjustments should be made?
11. What revenue does the company expect to generate from carbon credits? How does the company ensure that double counting does not occur? Is CCS feasible only with ACCUs, and if so, at what price?
12. What proportion of hydrogen production has been secured through offtake agreements? What are the timeframes for these agreements (ideally 15–20 years for international, 5–15 years for domestic agreements)?
13. A high-carbon price supports the growth of a hydrogen market: What are the public policy positions on the carbon pricing of the company and its industry associations?
14. How can transportation (including conversion, reconversion, and storage) constraints be addressed?

Questions for green hydrogen producers

1. If grid-connected, have PPAs been procured and covered 100% of the supplied energy? Has the company underwritten new electricity generation to avoid cannibalisation of renewable energy in the grid?
2. How does the company ensure a sustainable water source? Has the impact of future drought conditions been considered?
3. What proportion of hydrogen production has been secured through offtake agreements? What are the timeframes for these agreements (ideally 15–20 years for international, 5–15 years for domestic agreements)?
4. How will a company secure a green premium for low-carbon hydrogen?
5. A high-carbon price supports the growth of the hydrogen market. How does the company consider a carbon price, and what advocacy is being done?
6. What existing infrastructure (e.g., pipelines, carbon storage) can the company expect to be utilised by hydrogen? What adjustments should be made?
7. How can transportation (including conversion, reconversion, and storage) constraints be addressed?

9.2 Engage with companies that use hydrogen and support the demand for low-carbon hydrogen

This report has outlined the barriers and enablers of hydrogen consumption domestically and globally. Questions investors should ask companies that are or are projected to become hydrogen users have been compiled below.

Questions for hydrogen users

1. What are the emission intensity limits of low-carbon hydrogen procured by the buying company? How does a company define, assess and verify these emissions?
2. Will the company seek to purchase low-carbon hydrogen certified by external certifiers, such as through a guarantee of origin scheme or CertifHy?
3. When do procurement contracts end? (Shorter contracts allow for flexibility to move to purchasing lower carbon hydrogen or lower cost hydrogen more quickly.)
4. How does the company see hydrogen fitting in its long-term emission reduction pathway? How is the company creating a market for low-carbon hydrogen? Examples include the disclosure of partnerships and consortium models.
5. Has the company invested in products/equipment that can be switched to using hydrogen? If the company already uses hydrogen, how does the company ensure that hydrogen is low-carbon? Does the company consider the full lifecycle emissions from the production of blue hydrogen?

9.3 Directly support broader market enablers of a hydrogen industry

Investors can support the domestic hydrogen industry outside of engaging with companies and policymakers in several ways.

1. The direct private investment in hydrogen production meets the standards of integrity and low emission requirements set out in this report.
2. Direct investment in renewable energy, storage and transmission infrastructure to increase the availability of green electricity in the grid and reduce electricity prices, as well as investment in off-grid renewable energy to support off-grid green hydrogen hubs.
3. Invest in technology that supports the production of low-carbon hydrogen and the use of hydrogen, including hydrogen carriers, storage and hydrogen carrier conversions, electrolysers, ATR and high capture technology.

9.4 Advocate for robust policy settings and regulations to ensure a high-integrity, long-term, future-proof industry is developed in Australia for domestic and export use

Additional government policies are required to enable rapid industry scaling to ensure that domestic production is internationally competitive. In addition to economy-wide policy interventions, investors should advocate for policies that address existing constraints on low-carbon hydrogen and avoid the risk of stranded assets or investment in technologies with high costs and emissions. In particular, the Australian federal government should:

1. Use and build bilateral economic and geopolitical relationships with target markets to build global demand and establish global standards for Paris-aligned hydrogen technologies. This may include:
    a. Seeking green hydrogen targets backed by national policies from all partners to create visibility of future hydrogen demand.
    b. Establishing commitments from partners to align hydrogen investment strategies with 1.5 °C pathways.
    c. Establishing national and globally consistent standards for robust hydrogen certification.
2. As part of the COAG's national energy transition plan, it engages with investors and coordinates state government efforts. Core objectives should be: to incentivise investment in the industry and create a market for hydrogen through mechanisms similar to the Renewable Energy Target; and avoid crowding out, or conflict with, private investment or enterprise contract negotiations.
3. Coordinate policy to maximise the efficiency of enabling infrastructure assets, planning coordination and asset sharing arrangements (e.g., ports, conversion facilities and pipelines, and have robust environmental regulations. A proliferation of small-scale projects is less efficient and project grants, which are immaterial relative to project capital costs, is less productive than enabling large-scale projects.
4. Commission an independent agency to develop a due diligence framework that investors can use to address core questions (e.g., cost of technology, demand projections, etc.).
5. Undertake early work to build the social licence to develop national hydrogen infrastructure (e.g., communicate fuel safety, water access licensing, community and worker benefits, etc.). Communities that are currently heavily dependent on fossil fuel employment should be prioritised, when possible, when considering the placement of hydrogen development and infrastructure.
6. Implement a targeted skills program to develop a workforce with appropriate specialist skills (e.g., building and maintaining electrolysers and conversion facilities, electricity networks and renewable energy projects). A likely challenge for policymakers is to match the location of workforce training facilities with regions that can support commercially viable hydrogen projects.

7. Within the new COAG energy strategy, implement targeted domestic strategies and subsidies to build the domestic demand and consumption of low-carbon hydrogen products, including developing sector goals, road taxes and investment subsidies.
8. Government programs should focus on green hydrogen given the emissions, price, lock-in carbon and stranded asset risks associated with blue hydrogen. Governments should not take on these risks as they are better managed by the private sector. Government investment in green hydrogen carries lower risks to public expenditure and is better aligned with the government's objective of an orderly transition to net zero emissions.
    a. Support adequate scaling of the upstream electricity network, both from a network capacity and power generation capacity perspective, and overcome planning and approval hurdles for large-scale renewables projects.
    b. Investing in renewable energy, which may include more offshore wind development to reduce land and amenity pressures in the community.
    c. Investing in transmission infrastructure and incentivising landholders to support transmission infrastructure so that it is more attractive than other uses (e.g., currently, landowners will be compensated around 10x more to host wind farms in comparison to hosting transmission).

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11 LIST OF ABBREVIATIONS

Abbreviation	Explanation
$	Australian Dollars, unless otherwise stated in another currency
ACCC	Australian Competition & Consumer Commission
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
APAC	Asia-Pacific
ARENA	Australian Renewable Energy Agency
ATR	Autothermal Reforming
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COAG	Council of Australian Governments
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DRI	Direct-reduced iron
ERF	Emissions Reduction Fund
EU	European Union
GJ	Gigajoule
GW	Gigawatt
H_2	Hydrogen
IEA	International Energy Agency
IGCC	Investor Group on Climate Change
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
kWh	Kilowatt-hour
LCOE	Levelised cost of energy
LCOH	Levelised cost of hydrogen
LNG	Liquified natural gas
LOHC	Liquid organic hydrogen carrier
Mt	Megatonne

Abbreviation	Explanation
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
PEM	Polymer electrolyte membrane
PPA	Power Purchase Agreement
R&D	Research and development
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cells
Solar PV	Solar photovoltaics
WACC	Weighted average cost of capital

12 DEFINITIONS

Terminology	Explanation
Abatement	Reduction of emissions (does not include netting off emissions via any form of carbon credit).
Alkaline electrolyser	Highly alkaline potassium or sodium hydroxide electrolyser.
Ammonia	Form of hydrogen carrier to transport hydrogen, and has common industrial applications as a fertiliser, used in explosives and as a feedstock for other chemicals.
Autothermal reforming	Directly combusts oxygen and is a process that can produce hydrogen.
Blue hydrogen	Hydrogen produced from natural gas where CO_2 emissions are captured and stored (use of offsets to net off emissions is not sufficient).
Capacity factor	Capacity factors (per cent) measure average output over the maximum output over a specific timeframe. It is a metric to assess how efficiently a plant is operating, for example, capacity factors of 100% indicate a plant is producing 100% of the time.
CertifHy	The first EU-wide Guarantee of Origin scheme for green and low-carbon hydrogen.
Direct-Reduced Iron	Steelmaking technology to turn iron ore into iron and can use green hydrogen (instead of gas) at relatively high percentages to reduce the emissions intensity of steelmaking.
Electrolyser efficiency	The efficiency that an electrolyser converts electricity into hydrogen.
Emissions Reduction Fund (ERF)	Administered by the Clean Energy Regulator and is a voluntary scheme to incentivises emissions reductions by providing monetary value on abated carbon.
Enhanced oil recovery	The extraction of crude oil from an oil field that cannot be extracted otherwise.
EU Taxonomy	A classification system that establishes a list of environmentally sustainable economic activities.
Fugitive emissions	Emissions of gases or vapours from pressurised equipment due to venting and flaring, leaks and other irregular releases of gases.
Green hydrogen	Hydrogen produced from renewable energy via electrolysis.
Grey hydrogen	Hydrogen produced from fossil fuels through a steam reforming process.
Hard-to-abate	Relates to emissions or sectors that cannot be easily abated through currently existing technology.
Hydrogen	In the context of this report, is a fuel that shows potential to displace incumbent fossil fuels as it does not emit carbon when combusted.
Hydrogen GO	The Australian Government is developing a certification scheme to measure and track emissions from hydrogen production.
K-taxonomy	The Korean classification of green economic activities contributing to six environmental goals. It is not legally binding.
Learning rates	Expected decreases in costs of technology due to technological advancements as the technology matures.
Levelised cost of electricity	Measurement of the cost of electricity generation over a plant's lifetime used to compare different methods of electricity generation consistently.

Terminology	Explanation
Levelised cost of hydrogen	Measurement of the cost of hydrogen generation over a plant's lifetime used to compare different methods of hydrogen production consistently.
Lifecycle emissions accounting	Emissions are reported under a 'well-to-gate' boundary that incorporates all emissions to the point of hydrogen production.
Liquid organic hydrogen carrier	Type of hydrogen carrier to transport hydrogen that can be dehydrogenated via heat or catalysis to return to a form that can be used or combusted.
Liquified hydrogen	Type of hydrogen carrier that is more energy dense than its gaseous form to transport hydrogen.
LNG netback price	The international price of Australian LNG 'netted back' to Australia by subtracting the liquefaction and transport costs from the international price. This represents a hypothetical domestic price for Australian natural gas.
Low-carbon hydrogen	This report defines low-carbon hydrogen as hydrogen produced with a maximum of $3tCO_2e/tH_2$. This definition is aligned with the EU taxonomy.
Methane	Type of greenhouse gas commonly emitted as a fugitive during a fossil fuel supply chain. Or made synthetically using hydrogen as an input as a low-carbon form that may be used as an energy source.
Nationally Determined Contribution	Non-binding national plan highlighting climate change mitigation, including climate-related targets for greenhouse gas emission reductions.
Near- medium- and long-term	Near term refers to the period between the present and 2025. Medium term refers to the period between 2026 and 2035. Long term refers to the period between 2036 and 2050.
NEM-domiciled	NEM-domiciled indicates hydrogen production within the National Electricity Market's geographic area and does not distinguish between types of hydrogen production nor differences between grid-connected and off-grid. It excludes Western Australia and the Northern Territory.
Net zero emissions	The state where greenhouse gas emissions have been reduced to as close to zero as possible and any residual emissions have been effectively offset through lasting carbon sequestration methods.
Off-grid	Used in the context of this report to represent green hydrogen production plants that are not connected to an electricity grid.
Offtaker/offtake agreement	An offtaker is a buyer of hydrogen. An offtake agreement is between a buyer and seller of hydrogen produced by a particular project.
Offsets	A reduction or removal of carbon equivalent (CO_2e) emissions outside the reporting entity's value chain.
On-grid	Used in the context of this report to represent green hydrogen production plants that are connected to an electricity grid.
Polymer Electrolyte Membrane	Type of electrolyser composed of solid plastic material as the electrolyte and separates hydrogen using electricity.
Renewable Energy Target	An Australian Government scheme designed to reduce emissions of greenhouse gases in the electricity sector and encourage the additional generation of electricity from sustainable and renewable sources.
Safeguard mechanism	Administered through the National Greenhouse and Energy Reporting scheme and sets emissions thresholds upon facilities designed to prevent emissions from rising.
Solid Oxide electrolyser	Is under development and is a high-temperature electrolyser.
Spot price	The current price in the market that an asset (e.g., ACCUs, gas, hydrogen) can be bought or sold for immediate delivery.
Steam Methane Reforming	Uses natural gas as an input and is a process that can produce hydrogen.

13 APPENDIX

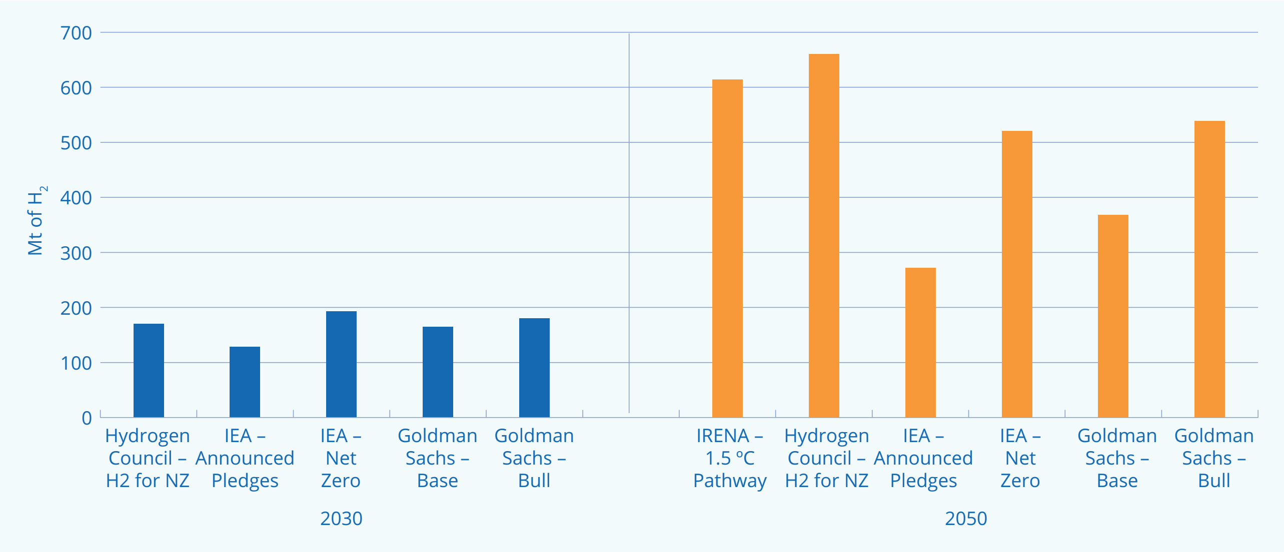
13.1 Appendix A

Hydrogen production scenarios

This analysis draws on the most credible forecasts from the IEA, given the sophistication of its whole-of-energy-system whole-of-world modelling framework relative to the other forecasters shown in **Figure a1**. The two main IEA scenarios are as follows:

- *Announced Pledges:* this scenario includes both stated government policies and many net zero emissions pledges by governments around the world (the latter being excluded from the IEA's more conservative scenario, *Stated Policies*, which only includes stated policies backed by robust legislation and regulatory measures), even where such pledges lack detailed policies and plans.
- *Net zero by 2050:* This scenario models the global energy mix required to achieve net zero CO_2 emissions, consistently limiting global warming to 1.5 °C in the year 2100. This scenario envisages deeper decarbonisation than Announced Pledges, with the latter aligned with around 2.1 °C of global warming by the year 2100.

Figure a1: Projected global hydrogen production in 2030 and 2050, by forecaster and by scenario

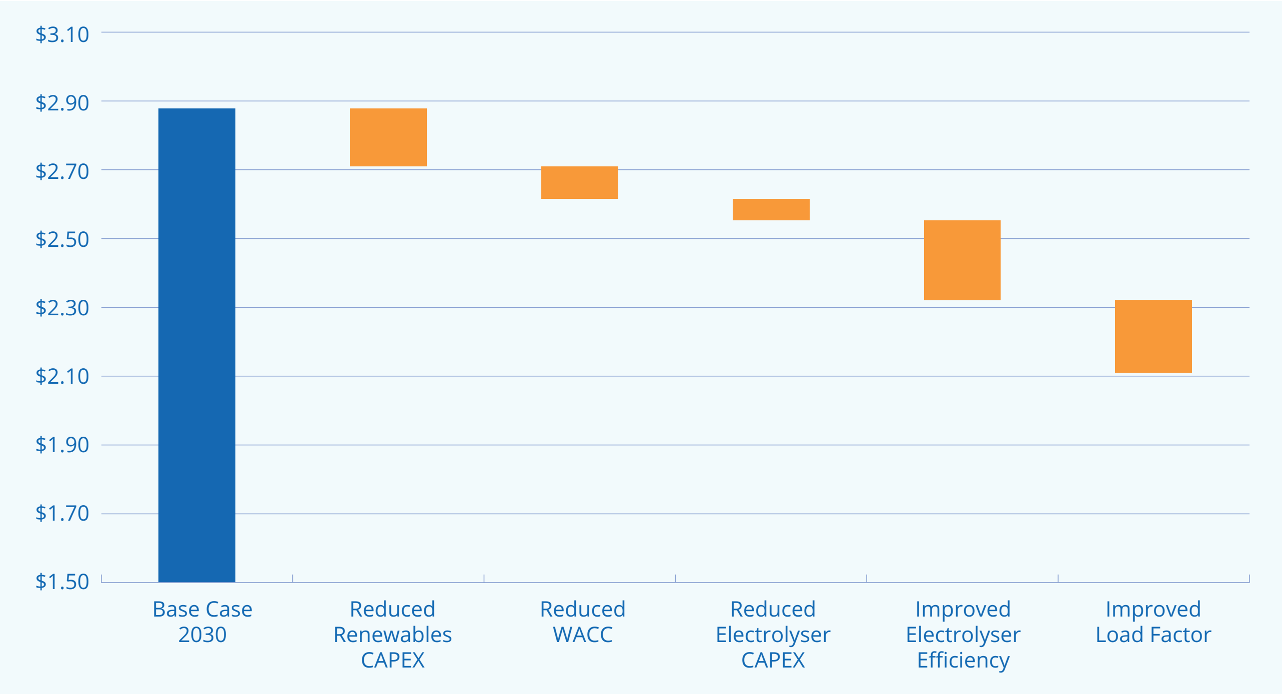


Sources: Baringa Partners LLP; Goldman Sachs (2022) [50]; IEA (2021) [16], Hydrogen Council (2021) [51], IRENA (2021) [52]

13.2 Appendix B

For illustrative purposes, the below chart shows the input costs for green hydrogen in 2030 and has hypothetically applied a 10% improvement to each of the inputs collectively to show a substantial drop in costs from $2.90 per kg to $2.10 per kg (**Figure a2**). The chart shows the sensitivity of LCOH to 10% changes in each of its inputs, noting the largest impacts are derived from decreases in cost of renewable energy, electrolyser efficiencies and load factors (utilisation of the electrolyser facility).

Figure a2: Sensitivity of Green LCOH to 10% change in selected inputs[34]



Source: Baringa Partners LLP

13.3 Appendix C

Roadmap for an Australian hydrogen industry

Table a1 presents a roadmap for the Australian hydrogen industry – outlining the key risks and dependencies at different points up to 2050 – to realise the possible domestic- and export-driven demand discussed in the above sections. The inputs for this roadmap are discussed throughout this report and have been based on the four key scenarios listed in the section '**3 The hydrogen market is expected to grow significantly to 2050**', stakeholder interviews and desktop research.

34. Base case 2030 prices are based on off-grid Solar from Figure 17.

Table a1: Summary assessment of the Australian hydrogen sector over time

	2025	2030	2040–2050
Global hydrogen production	More than 87 Mt	193Mt	521Mt
Australian hydrogen production (CSIRO forecast demand)	0.13Mt	1.76Mt	21Mt
Australian hydrogen production – export vs domestic use	International MOUs to support import-export hydrogen strategies and trade	In low-carbon emissions hydrogen-based chemical production and export, hydrogen is blended into production	
Global demand and uses	Larger source of demand compared to domestic Heavy vehicles (although likely to be constrained by availability) Trials to co-fire or use hydrogen-based fuels for electricity generation R&D to replace fossil-based industrial processes, transport and chemicals and fertilisers	Larger source of demand compared to domestic Heavy vehicles (although likely to be constrained by availability) Trialling and development of hydrogen for use in shipping/ aviation fuels Minor industry process modification for hydrogen as feedstock International pipelines being built to support hydrogen	Larger source of demand compared to domestic Heavy vehicles (although likely to be constrained by availability) Hydrogen for use in shipping/ aviation fuels Hydrogen for use as feedstock in industry Pipelines support distribution of hydrogen
Domestic demand and uses	Beginning to see domestic demand Blended hydrogen gas pipeline Heavy vehicles, mining and agriculture machinery to replace diesel alternatives (although likely to be constrained by availability) R&D to replace fossil-based chemical production and other industrial applications, including steel and fertilisers, with hydrogen Hydrogen being trialled by miners to support off-grid electricity generation to replace diesel Refuelling co-investment	Rising domestic demand but still on a small scale Deploy refuelling stations on major freight routes/industry hubs Hydrogen to replace fossil fuels in chemical production and fertilisers Growth of DRI steel production and continued R&D Hydrogen supporting off-grid electricity generation and replacing diesel	Significant domestic demand in industry and transport Widespread deployment of refuelling stations Hydrogen use in chemical production represents 1.25Mt per annum and over 25% of domestic hydrogen demand Established Aus hydrogen DRI steel production as the dominant production method Off-grid electricity generation via renewables and supported by hydrogen
Price	Highly efficient projects hydrogen (less than \$5 per kg hydrogen) to reach breakeven delivered costs (less than \$10 per kg delivered costs) with less onerous carbon requirements	Highly efficient projects/ cargoes (production within \$3–\$4 range) with more onerous carbon requirements	Highly efficient carbon-free projects/cargoes (less than \$2 hydrogen range) delivered cost)

	2025	2030	2040–2050
Cost	Goal: less than $2 kg		
Commercial characteristics	Large-scale projects (potentially tranched) Underwritten by long-term 100% offtake (i.e., no spot exposure) De-risked upstream electricity supply For 'green projects' located on-grid near ports For 'blue projects' located near CCS, stable storage facility and port Low cost of capital Sophisticated supply chains and trading functions Projects range from 100–500MW	Large-scale projects (incl. second tranches), and smaller projects for domestic demand More flexible plant operations Underwritten by long-term contracts, potential for spot market exposure Upstream electricity may include off-grid solutions Low cost of capital Electrolysis support network services Most projects produce 500MW	Portfolio-based projects and acceptance of higher risk Sophisticated supply chains, including storage, trading functions, shipping competitiveness Off-grid co-location with scaled demand (near ports, at mining or industry facilities) 500–1,000MW
Supply chain infrastructure	Shared asset access arrangements between hydrogen, conversion and storage facilities, close to ports. Lower transport costs through economies of scale and scope	Establish commercial infrastructure sharing arrangements between producers for infrastructure owners Investment in supply chain infrastructure R&D for hydrogen-capable pipelines to transport fuels	Deploy hydrogen pipelines
Offtake agreements	New hydrogen projects partially underwritten by long-term offtake contracts with investment-grade counterparties.	New hydrogen projects fully secured by long-term offtake agreements with investment-grade counterparties.	New hydrogen projects fully secured by long-term offtake agreements with investment-grade counterparties.
Hydrogen spot market	Illiquid market	Establish global traded liquid market for hydrogen	Mature global traded liquid market for hydrogen
Green hydrogen	Primarily on-grid, renewable sourced Investment required to improve technology gains and drive down capital costs of electrolysers. Electrolysers primarily lower cost and inflexible	More projects developed at a large scale. Continued investment in electrolysers drive down capital costs Emerging industrial-use larger capacity, more flexible electrolysers. High capacity factors nearing 70%	Primarily large-scale projects located near ports and demand centres. Electrolysers are efficient, and costs are sufficiently low and comparable to grey hydrogen production High capacity factors >70%

	2025	2030	2040–2050
Domestic renewable generation and grid support	Scale-up investment in renewable energy Scale-up investment in the transmission network Supply contracts with on-grid renewable energy Trials using grid-connected electrolysis for load balancing and grid firming	Continued investment in renewable energy Continued growth in renewable energy and transmission infrastructure Hydrogen acting to support renewable grid variability via electrolysis	Off-grid electricity supply co-located to demand centres
Blue hydrogen	CCS investment, testing and scoping, CCS only deployed with capture rates of more than 90% Renewable energy procured to power SMR processes Direct measurement of fugitive emissions installed by oil and gas companies and around 35% of fugitive emissions captured	Large-scale blue hydrogen projects with CCS capture rates of more than 90% Renewable energy powers SMR processes Scaled blue supply located near ports 70% of fugitives captured	Blue supply located lowest-cost CCS around 75+% of fugitive emissions captured
Oil and gas prices	High price volatility	High price volatility and decreasing demand	Limited demand for oil and gas
Hydrogen certification	Transparency over embodied carbon via hydrogen certification schemes. Trial for hydrogen emission tracking pilot.	Well-regulated market for carbon accounting. Emissions targets for embodied carbon emissions will decrease.	Mature market for carbon accounting and limited appetite globally for embodied emissions.
Regulation	Establishment of credible local institutional arrangements governing the sector Perception of Australia as a more stable and credible producer (e.g., supportive energy infrastructure investments, better accounting over embodied carbon)	Government grants not as heavily dependent on bridge economics	Government grants no longer necessary to bridge economics
Carbon prices	Carbon prices rises from around \$50 to \$100 per tCO_2 Rise to support hydrogen industry	Carbon prices of more than \$100 per tCO_2	Carbon prices near \$190 per tCO_2
Fuel conversion and transportation	R&D into conversion and reconversion of liquid hydrogen, ammonia and LOHC	Pilot and deploy Ammonia and LOHC as main export carriers; costs significantly decrease	Ammonia and LCOH as an export carrier

Source: Baringa Partners LLP

13.4 Appendix D

The Australian state and federal governments mid-term targets have been captured below.

Table a2: Australian governments' emissions reduction targets

Australian government	2030 emissions reduction target (relative to 2005, unless stated otherwise)
Federal	43%
New South Wales	50%
Victoria	45–50%
South Australia	>50%
Queensland	30%
Western Australia	To be developed in 2022
Tasmania	Plans to legislate net zero emissions by 2030
Northern Territory	No interim target but plans to achieve 50% renewable energy by 2030
Australian Capital Territory	65–75% from 1990 levels

National Hydrogen Strategy

In 2019, the Australian Government published a National Hydrogen Strategy, which primarily sought to support technology development, identify and remove policy barriers, and set up processes and partnerships to facilitate industry growth (from improved planning approvals to international export partnerships).

Technology Investment Roadmap

Following the publication of the National Hydrogen Strategy document, the Australian Government released the Technology Investment Roadmap in 2020, which identified priority technologies and 'stretch goals' for each, many of which are relevant to the hydrogen industry:

- 'Clean' Hydrogen: goal of under $2 per kg.
- Low-carbon materials: goal of low emissions steel production under $900 per t and low emissions aluminium under $2,700 per t.
- CCS – CO_2 compression, hub transport and storage: goal of under $20 per t of CO_2.

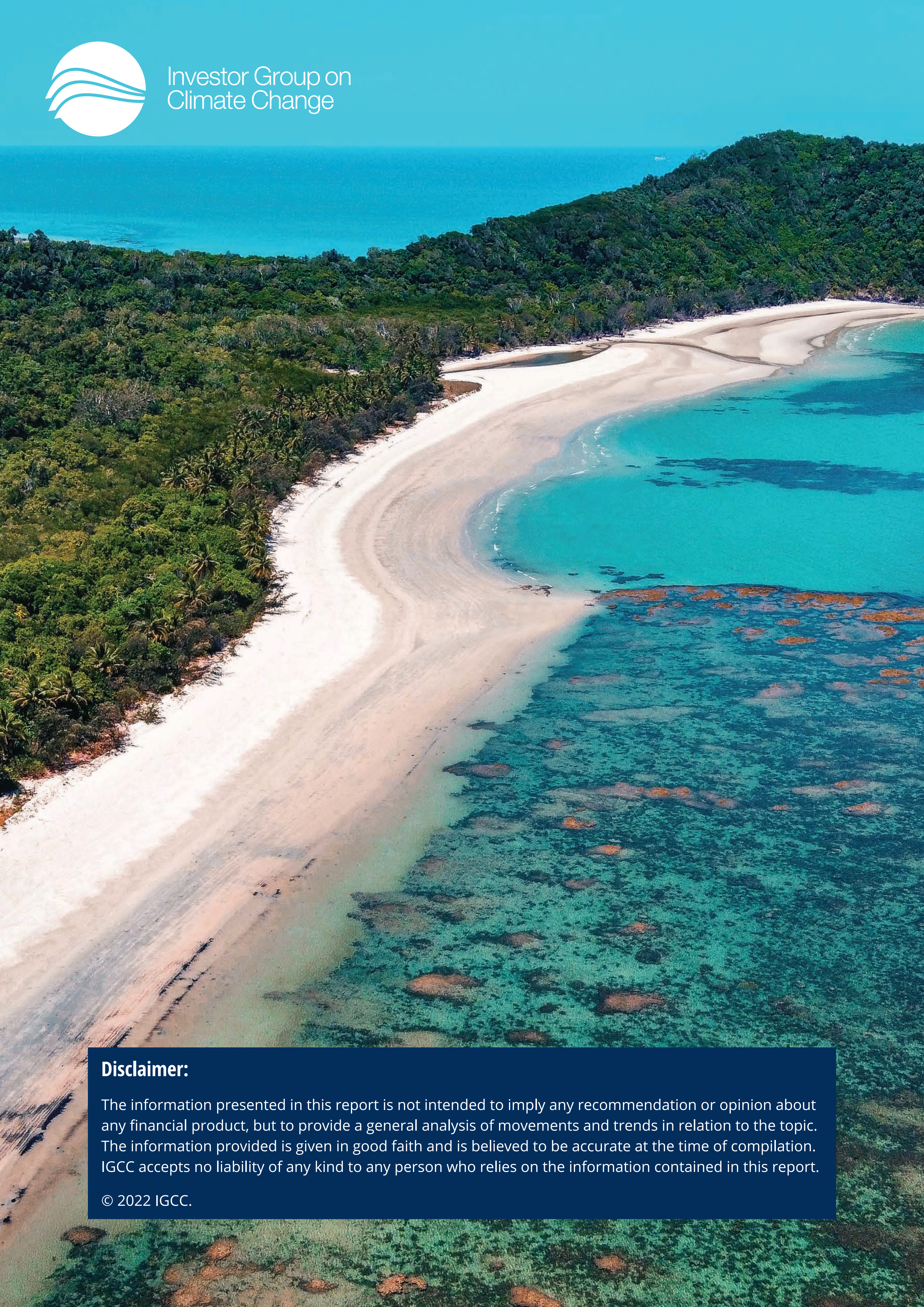
State and territory hydrogen strategies

Australia's state and territory governments have published their documents outlining their intentions for jurisdictional hydrogen industries. Announced spending has been captured in the table below.

Table a3: Announced hydrogen spending by federal, state and territory governments

Jurisdiction	Announced Spending
Australian federal government	$1.2 billion via ARENA and the CEFC
NSW Government	Up to $3 billion in incentives, including investing $70 million to establish hydrogen hubs, starting with the Hunter and Illawarra, which have both traditionally been central to coal export.
Victorian Government	Invested $10 million in an Accelerating Victoria's Hydrogen Industry program. This included $6.2 million to establish two grants programs to support hydrogen projects in the state.
SA Government	$1.25 million commitment to complete a hydrogen export pre-feasibility study and produce an online modelling tool.
Queensland Government	The first round of funding, allocated in 2019, supported four projects, including hydrogen supply and use. A second round with $10 million of funding was run in 2021, with recipients yet to be announced.
WA Government	$15 million available through two rounds of funding, awarding grants to capital works and feasibility studies.
Tasmanian Government	$50 million package over 10 years. Includes a $20 million Tasmanian Renewable Hydrogen Fund and $20 million in concessional loans.
Territory Government	Dollar value not disclosed.

Investor Group on Climate Change



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