

Unlocking Australia's hydrogen opportunity

Australian Hydrogen Council
September 2021

e: info@H2council.com.au | w: H2council.com.au

Contents

Acronyms and abbreviations	4
The Australian Hydrogen Council.....	5
Executive summary	6
1 The energy transition and the role for hydrogen	9
1.1 Global commitment to decarbonisation is accelerating.....	11
1.1.1 Our fossil fuel trading partners are likely to withdraw over time	11
1.1.2 Market experts say Australia will go first	13
1.2 Hydrogen has a vital role in future energy systems	14
1.3 Structure of this paper	15
References	16
2 How we get to scale	17
2.1 Recognise the task is large and complex.....	19
2.2 Support co-location of facilities and infrastructure	24
2.3 Provide adequate public funding support to start the markets.....	27
2.4 Recommendations.....	30
2.4.1 Set up planning and ownership of the task	30
2.4.2 Fund projects and infrastructure	32
2.4.3 Focus on no regrets demand stimulation.....	33
References	36
3 Accelerate market growth through repurposing natural gas assets where economic.....	38
3.1 Recommendations.....	41
3.1.1 Co-optimize assets with end user prices in mind.....	41
3.1.2 Blend hydrogen into the natural gas networks.....	42
References	43
4 Advance heavy road transport applications.....	44
4.1 Hydrogen fuel cell vehicles play a vital role	45
4.2 Diesel replacement is the first step.....	46
4.3 Barriers to hydrogen in transport.....	47
4.4 Recommendations.....	48
4.4.1 Fund key transport projects in the national interest	48
4.4.2 Incentivise FCEV uptake through policy settings	52
References	55
5 Support local manufacturing.....	56
5.1 Very high temperature processes are the first step	58
5.2 Priority sectors.....	59
5.2.1 Iron and steel	59
5.2.2 Ammonia	62

5.2.3 Methanol.....	63
5.2.4 Aluminium and alumina.....	63
5.3 Barriers to hydrogen uptake.....	64
5.4 Recommendation.....	65
References.....	66
Appendix A: Different hub concepts.....	67
Hydrogen valleys.....	68
Hydrogen clusters.....	69

Tables

Table 1: Domestic hub assessment framework, adapted from ARUP (2019) page 77.....	24
Table 2: AHC internal costing for different potential project mixes to align with Deloitte scenarios.....	27
Table 3: Diesel road vehicles in Australia in 2020, with source data from ABS (2020).....	46
Table 4: Indicative total costs of ownership for near term FCEV fleets.....	49
Table 5: Trial FCEV truck projects.....	51
Table 6: BITRE freight corridor recommendations, with key facts.....	51
Table 7: Sectors using >800°C.....	58
Table 8: Major iron and steel companies in Australia.....	60
Table 9: Grattan Institute future steel industry scenario: Central Queensland and Hunter Valley.....	61
Table 10: Major ammonia-based fertiliser and explosives plants in Australia.....	62

Figures

Figure 1: Deep storage balances energy loads throughout the year.....	14
Figure 2: Different perspectives on the size of the global hydrogen industry in 2050.....	19
Figure 3: Analysis of lowest costs for hydrogen transport.....	21
Figure 4: AHC member responses to question about end use markets for their business's interests in hydrogen, May 2021.....	26
Figure 5: Multiple potential uses of hydrogen in a low carbon economy, some of which can provide early 'off take' for clean hydrogen.....	33
Figure 6: Economic gap (2020) by industry (\$/kg).....	34
Figure 7: Hydrogen Valley archetypes.....	68
Figure 8: Energy Transitions Commission perspective on hydrogen hubs.....	69

Acronyms and abbreviations

Acronym/abbreviation	Definition
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
BEV	Battery electric vehicle
BNEF	Bloomberg New Energy Finance
CEFC	Clean Energy Finance Corporation
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CCS	Carbon Capture and Storage
FCEV	Fuel cell electric vehicle
GW	Gigawatt
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ktpa	kilotonnes per annum
LNG	Liquefied Natural Gas
MJ	Megajoule (10^6 Joules, or 1,000,000 Joules)
Mt	Millions of tonnes
MW	Megawatt
PJ	Petajoule (10^{15} Joules, or 1,000,000,000,000,000)
TUOS	Transmission Use of System charges
ZEV	Zero emissions vehicle

The Australian Hydrogen Council

The Australian Hydrogen Council, or AHC, is the peak body for the emerging hydrogen industry.

We represent the emerging hydrogen industry and connect it with its stakeholders to collectively create a clean and resilient energy future that has hydrogen as a key part of the energy mix.

Our members are companies from the energy, transport, technology, consulting and financial sectors.



Executive summary

We have an enormous opportunity in this country to create a vibrant hydrogen industry, both for domestic and export use.

Australia has the renewable energy resources, the technical skills, and the track record with international partners to become a global hydrogen leader.

Meeting Australia's stated hydrogen objectives requires strong national leadership to plan, collaborate and communicate with partners and stakeholders. Government must drive and lead the creation of the clean hydrogen industry. With the world moving to net zero there is no real alternative.

Planning is vital

An Australian hydrogen industry will require large-scale electrolysers, renewable electricity, hydrogen storage, water and water pipelines, electricity infrastructure, CCS as appropriate, and hydrogen pipelines (which may be repurposed from existing pipelines). Industrial and port facilities will need to be developed to process and export hydrogen and its derivatives, including ammonia. Mineral and chemical companies will invest in new production processes, and transport and logistics companies will procure new vehicle technologies. Refuelling stations will be required to supply hydrogen for vehicles. Households and businesses can convert from gas and oil-based fuels to hydrogen or electricity for heating and mobility.

Each of these elements will have its own costs, dependencies, and engineering reality, which in turn affects the business case for different means of producing, storing, transporting and using hydrogen. Several elements will also have long timeframes for project design, feasibility and planning.

Impacts on local economies will also need to be understood and planned for, as will important community (and societal) questions about competing uses for land and water, and priorities for infrastructure for different purposes. The emerging industry will require a fit-for-purpose regulatory approach with the flexibility to work across sectors and jurisdictions.

The task ahead will thus need whole-of-economy planning that addresses multiple hydrogen production, delivery and use pathways, and lays the foundation for regulatory developments and community engagement.

Comprehensive and published planning information – defined here as projections and assessments of future energy supply and demand pathways to net zero – would assist governments, the private sector and the public to make informed decisions about their options and actions.

Funding key applications will develop the market

The hydrogen industry is not yet commercial and considerable investment is required. It is likely that capital investments to produce hydrogen alone could run to tens of billions of dollars.

Until the industry has reached commercial scale, grant funding is essential. Public investment will unlock several times its value from the private sector.

In the short to medium term, it is worth prioritising funding for applications that are more dependent on clean hydrogen for decarbonisation and have a medium economic gap to commerciality. If we can close the economic gap (and technology and knowledge gaps in some cases) for applications like ammonia production and heavy transport, we start to see the new hydrogen domestic industry take shape. Further, if we can drive large sources of new demand, which could be production of steel, ammonia and other chemicals for local and particularly export markets, as well as blending into natural gas networks, we will start to see scale and reduced costs.

Focussing on building scale and capability in the sectors and applications that will be hard to abate without hydrogen is the best 'no regrets' approach that can be taken in an uncertain environment. This approach should also actively build room for other applications that might value hydrogen at lower prices and with an established (and shared) infrastructure.

Recommendation 1: Plan in the national interest

We recommend that the Australian Government establishes a body to develop an evidence-based approach to planning and coordinating the transition to net zero – including the development of hydrogen infrastructure – and reporting progress. An initial annual budget of approximately A\$10 million would be required.

Recommendation 2: Establish a Net Zero Fund

We recommend that the Australian Government establishes a Net Zero Fund, with an initial allocation of A\$10 billion and a top up of A\$1 billion each year to 2030. Drawdowns should be decided in response to planning and market soundings.

Recommendation 3: Prioritise hard to abate and scalable demand sources

We recommend that the Australian Government prioritises project funding to grow demand for hydrogen in the applications that are more likely to require clean hydrogen to decarbonise, and more likely to achieve large scale. Ideally these should demonstrate an ability to open the market to other applications, through knowledge/technology sharing, geographic proximity, and/or cost reduction. Recommendations 6 and 8 provide further information on these priorities.

Recommendation 4: Build sector coupling into planning

We recommend that the Australian Government explicitly tasks the planning body under Recommendation 1 to address how the gas and electricity infrastructure can be co-optimised for delivering lowest cost hydrogen to end consumers.

Recommendation 5: Blend hydrogen into natural gas to create demand

We recommend that the Australian Government sets a target of 10 per cent hydrogen by volume in the natural gas networks, by 2030.

Recommendation 6: Trial heavy transport

We recommend that the Australian Government funds:

- At least two heavy vehicle trials of large fleets, at a minimum amount of A\$200 million each, focussed on heavily-trafficked truck routes (e.g. Sydney-Melbourne).
- At least three larger trials for lighter trucks for logistics near hydrogen centres, at A\$25 million each.
- At least two larger trials for bus routes near hydrogen centres, at A\$45 million each for 40 buses (or a combination of smaller and larger, at A\$12 million per small trial for 10 buses).

Funding would be drawn from the Net Zero Fund and should be aligned with funding from state/territory governments. Some of this work might be funded by the Future Fuels Fund, which we note has just under A\$50 million available after the first BEV round.

Processes to commence these projects should start as soon as possible given that they will take time to implement; beyond the contracting process (which may take a year) there will be time required to procure the vehicles in sufficient numbers.

Use of funding to replace diesel should also extend to other means of transport – such as trains and ferries – as the business cases and demand for these evolve.

Recommendation 7: Incentivise markets in FCEVs

We recommend that the Australian Government:

- Sets carbon emissions standards for all vehicle types.
- Provides tax offsets for vehicle purchases and removes taxes that inhibit purchasing.
- Sets a 50 per cent ZEV target for fleets of cars, buses and ancillary vehicles for 2030. This would include privately operated public transport fleets and government owned logistics providers.
- Supports ZEV fleet procurement across state/territory and the federal government, with information sharing and guidance on relevant matters, such as available operators, manufacturers and optimal contractual measures for the evolving markets.

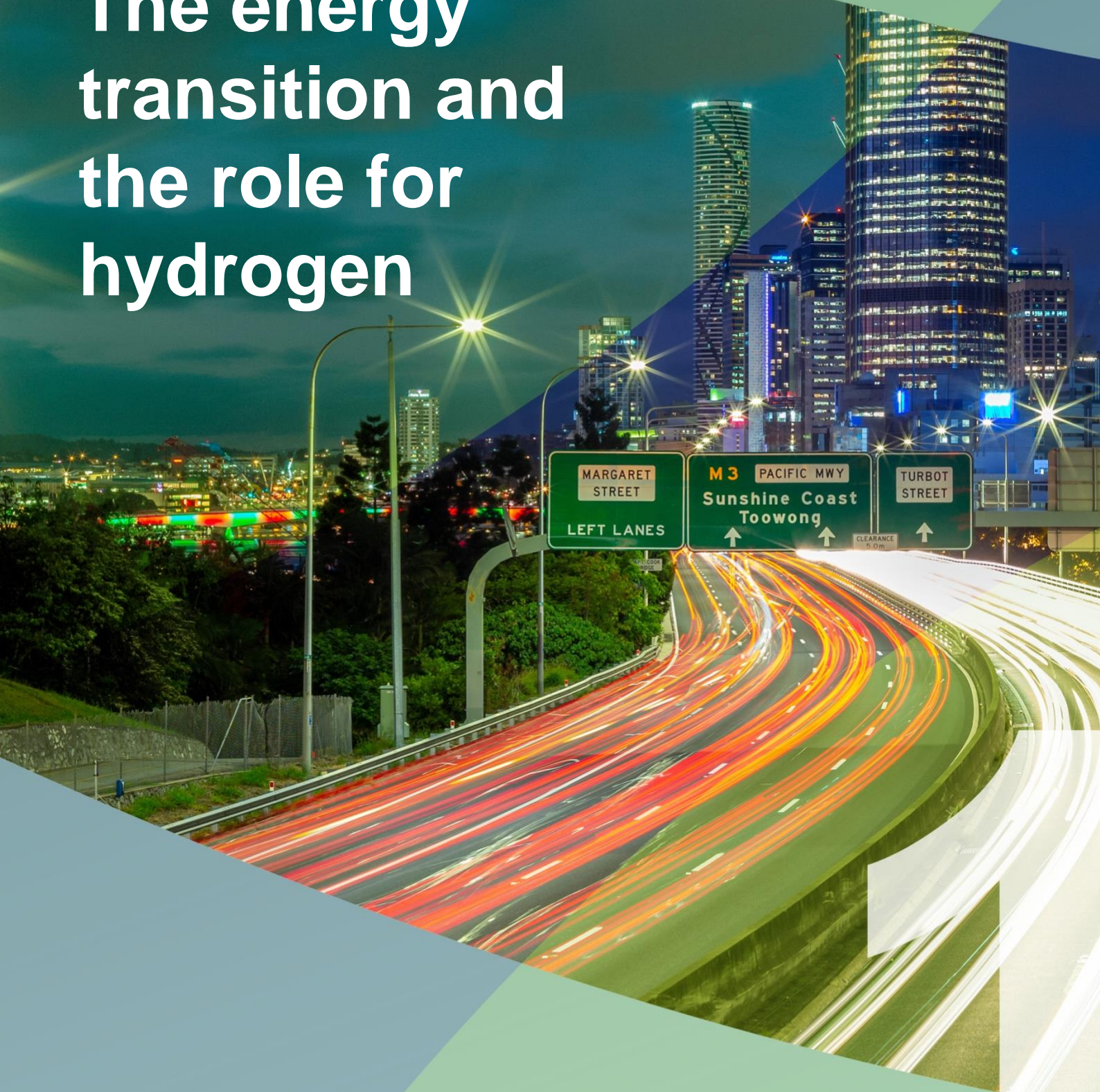
Recommendation 8: Support hydrogen for hard-to-abate industries

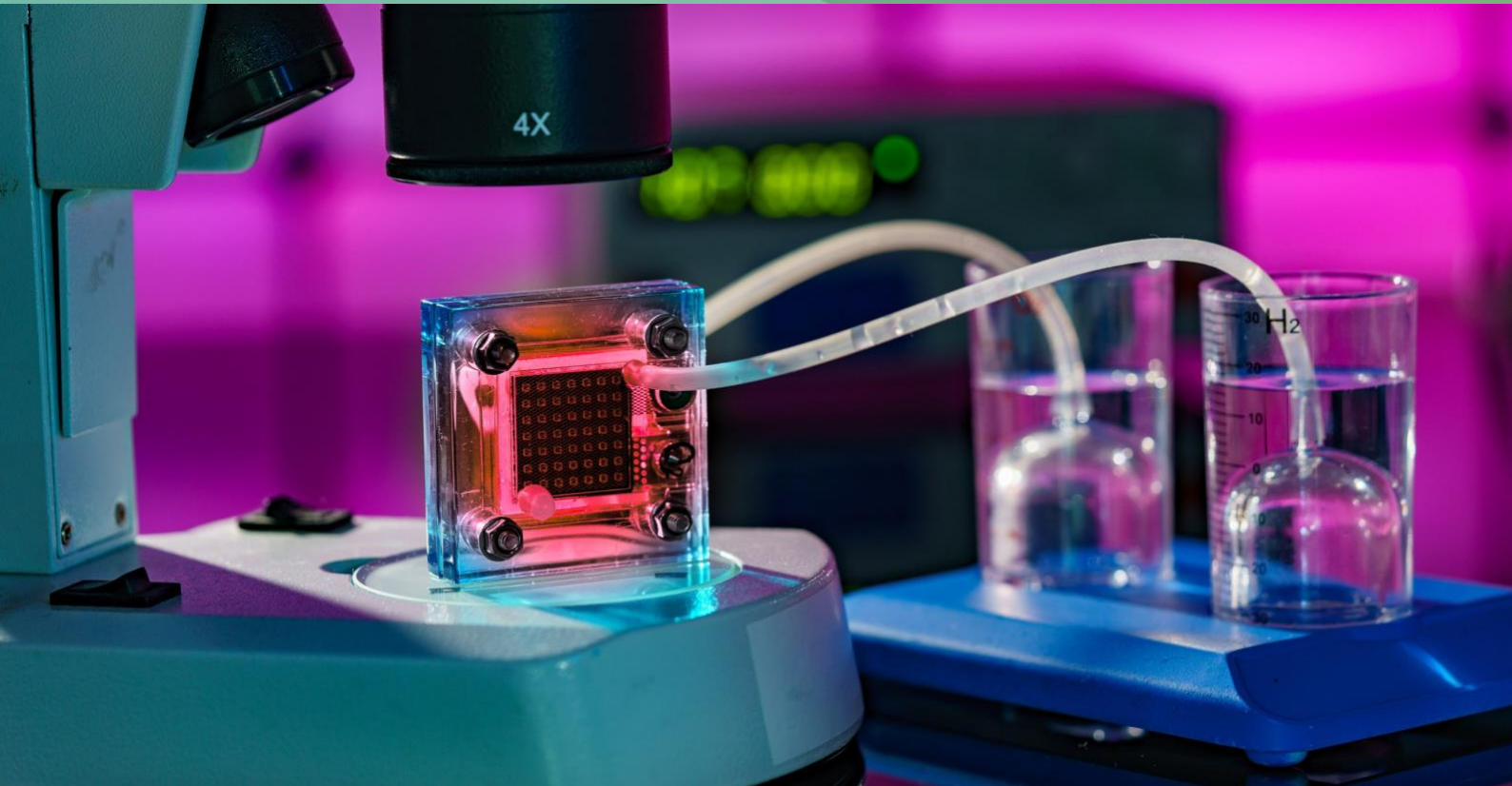
We recommend that the Australian Government funds a hydrogen readiness programme of at least A\$1 billion for industrial processes that cannot readily be electrified, including (and not exclusively) for the production of iron/steel, ammonia, methanol, and alumina/aluminium.

Funding would be drawn from the Net Zero Fund and should be aligned with funding from state/territory governments.

Funding should be prioritised for projects that protect or create local jobs and have a detailed plan for skilling and re-skilling. Applicants should be required to share information to support industry knowledge development – this could be assisted by engaging with industry associations to support delivery.

The energy transition and the role for hydrogen





We have an enormous opportunity in this country to create a vibrant hydrogen industry, both for domestic use and for export. Australia has the renewable energy resources, the technical skills, and the track record with international partners to become a global hydrogen leader.

We are already seeing significant investment from local and international businesses, and the National Hydrogen Strategy¹ and jurisdictional announcements have signalled the value that the Australian Government and states and territories see in the developing industry. Work for the National Hydrogen Strategy estimated potential benefits to Australia could be as high as A\$26 billion a year in additional GDP and 16,900 new jobs by 2050.²

The objectives of the National Hydrogen Strategy – and in 2020, the ‘H₂ under \$2’ target set in the Government’s Low Emissions Technology Statement³ – are considerable. They require a further significant demonstration of government commitment to implementation and market development.

Meeting Australia’s stated hydrogen objectives requires strong national leadership to plan, collaborate and communicate with partners and stakeholders. Government must drive and lead the creation of the clean hydrogen industry. With the world moving to net zero, there is no real alternative.

1 COAG Energy Council (2019).

2 Deloitte (2019), page 1.

3 Australian Government Department of Industry, Science, Energy and Resources (2020).

1.1 Global commitment to decarbonisation is accelerating

The need to decarbonise the global economy is becoming widely accepted, and pledges to achieve net zero emissions by 2050 or soon thereafter are growing in number. Communities, companies and countries are announcing their support to eliminate carbon emissions and limit climate change. Predictions of global warming are being increasingly validated by measurable changes in the world's climate. Scepticism about complex climate models has become muted and marginal. The evidence is validating the science.

Further, investors are increasingly recognising that they have both an ethical and fiduciary duty to play an active role in transitioning to a decarbonised economy. The global financial system is already valuing the risk. There may be different views on when and how fossil fuels will demonstrably decline; however, markets are responding *now*.

Energy transition risk is often viewed as a long-term risk, the impacts of which will not be felt for decades to come. However, this view is an imprecise presentation of reality. This is because although completion of transition might take decades, the increased uncertainty around the transition impacts the energy markets on a much shorter time scale than the transition itself.⁴

With a quarter of equity markets and half of corporate bond markets said to be 'carbon entangled', the global financial system is vulnerable to the energy transition.⁵ This has also been noted by the Reserve Bank of Australia, which stated in October 2020 that climate change exposes the financial system "to risks that will rise over time and, if not addressed, could become considerable".⁶ These risks explicitly include transition risks.

Based on a survey of institutional investors, researchers from the Oxford Institute for Energy Studies found that uncertainty about the energy transition had, in fact, already started to alter the risk preferences of investors in fossil fuels, with these investors "demanding higher hurdle rates in order to invest in coal and long cycle oil projects", which:

extends the payback period of discounted investment costs into a more uncertain future part of the energy transition period and thus disincentivises investment in long cycle projects. It also concentrates upstream investment around short-term projects with shorter payback periods.⁷

1.1.1 Our fossil fuel trading partners are likely to withdraw over time

As countries look to deliver on the emissions reduction targets of the Paris Agreement by incorporating cleaner fuels into their energy mix, the decline in demand for fossil fuels such as coal and natural gas threatens the Australian resources sector. There will also be increasing pressure for metals to be mined and extracted in a way that minimises carbon emissions.

While the short to medium-term outlook for Australian coal and natural gas exports remains optimistic, the long-term threat posed by decarbonisation commitments across the world must not be ignored if Australia is to ensure its continued economic success.

And the 'long term' may be closer than once thought. Carbon Tracker argues "It is in the interest of fossil fuel importers to move to a Paris compliant world as quickly as they can",⁸ meaning that Europe, China and India will tend to progress to renewables faster.

4 Fattouh, Poudineh and West (2019), page 1.

5 Bond, Vaughan and Benham (2020), page 4.

6 Reserve Bank of Australia (2020), page 43.

7 Fattouh et al. (2019), page 1.

8 Bond et al. (2020), page 42.



A recent Reserve Bank of Australia paper states:

To date, the decline in renewable energy costs has been faster than expected. Should this trend continue, the substitution away from thermal coal and towards renewable energy sources would also be faster. In addition, if countries increase their commitments to reducing emissions, there would be an even faster transition. In the IEA's 'Sustainable Development' scenario (in which countries implement policies that the IEA suggests are comparatively more aligned with the Paris Agreement), coal's share in the electricity generation mix would decline from around 40 per cent currently to around 5 per cent in 2040.⁹

The export of hydrogen and its derivatives provides Australia not only with an economic growth opportunity, but a way to evolve the resources and mining sectors and provide economic resilience in a decarbonising world. Hydrogen also provides tangible opportunities for Australia to decarbonise its domestic energy system, including power generation, manufacturing and transport.

Australia is particularly well-positioned to play a key role in the hydrogen export market with its abundant renewable resources, existing bilateral trade relationships with Japan, Korea and China and low sovereign risk.

9 Cunningham, Van Uffelen, and Chambers (2019).



However, the window of opportunity will not exist forever. Competing hydrogen producers across the globe seek a share of the international market and are scaling up hydrogen production in their respective countries to supply the Japan, Korea and China markets as soon as 2025.¹⁰ These competitors include Brunei, Qatar, UAE and Norway, and in the longer-term, market entrants such as the United States, Brazil, Chile and New Zealand.

Many of these countries have similar strengths to Australia, including abundant renewable resources, access to low cost gas for blue hydrogen production, carbon capture and storage capabilities, large areas of land for solar installations, and proximity to key hydrogen export markets.

1.1.2 Market experts say Australia will go first

Australia is not only affected in its export markets – the transition is well-progressed domestically, at least for electricity. In its Integrated System Plan for 2020, the Australian Energy Market Operator (AEMO) stated that Australia is experiencing “what is acknowledged to be the world’s fastest energy transition”.¹¹

The pace of transition is also affecting AEMO’s own projections: last year AEMO was noting that by 2035 there might be periods where renewables would meet nearly 90 per cent of demand,¹² but by August 2021 this view changed to 100 per cent of customer demand that could be met by renewables by 2025.¹³

This would seem to indicate that there is a need to engage in longer-term planning from a policy perspective, so that Australia can exit from fossil fuels in an orderly way; that is, to avoid a loss of supply security and to maintain affordability for electricity consumers.

AEMO notes that, depending on the scenario, the National Electricity Market will also “need 6-19 GW of new flexible, utility-scale dispatchable resources to firm up the inherently variable resources”.¹⁴ This includes ‘deep’ storage¹⁵ for ‘droughts’ of variable renewable energy and seasonal smoothing. Figure 1 shows how inter-seasonal smoothing would work.

What this means is that there is both a need and an opportunity for new energy storage to match the domestic electricity transition.

10 ACIL Allen consulting (for ARENA) (2018), Opportunities for Australia from Hydrogen Exports, page 15.

11 AEMO (2020), page 8. See also Farmer (2020).

12 AEMO (2020), page 18, see also Tilly (2021).

13 AEMO (2021).

14 AEMO (2020), page 50.

15 AEMO defines three broad types of storage in this context:

- shallow storage: for capacity ramping and to provide FCAS services that make the system more stable (e.g., VPP batteries and 2-hour grid connected batteries);
- medium storage: for intra-day shifting (e.g., 4-hour batteries, 6 - 12 hour pumped hydro); and
- deep storage: for VRE ‘droughts’ and seasonal smoothing.

1.2 Hydrogen has a vital role in future energy systems

Hydrogen provides the versatility required by future energy systems in a carbon constrained world. With its long-term energy storage potential, and the potential for electrolyzers to become large dispatchable loads which can be turned on or off as required, hydrogen is the perfect complement for variable renewable electricity and batteries. Hydrogen also has the unique potential to be shipped and traded globally as a zero-carbon fuel, in both liquefied form and in chemical variants (such as ammonia).

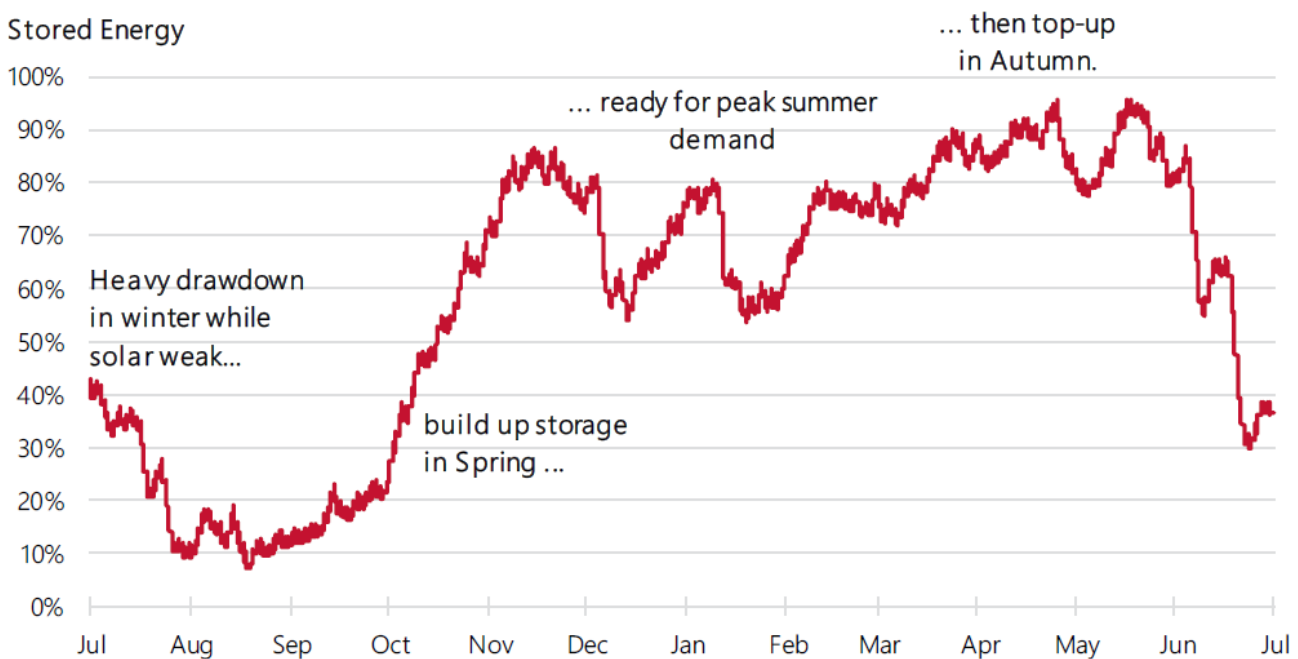


Figure 1: Deep storage balances energy loads throughout the year, 2034-35, SOURCE: AEMO, 2020, p. 52.

The 2015 Paris Agreement was the first global compact to seek national commitments to carbon neutrality, to avoid dangerous climate change. The effect is to require targets for electricity decarbonisation to shift from partial to total, and for decarbonisation efforts to extend to sectors in which abatement is more difficult than in electricity, such as land, sea and air transport, mineral processing, chemical manufacturing and agriculture.

The Paris Agreement has effectively made hydrogen an essential element of decarbonisation plans. Prior to Paris, national policies appeared to assume that partial decarbonisation targets would be achieved with greater energy self-sufficiency, particularly

in renewables. However, the Paris goal of full decarbonisation puts self-sufficiency out of reach for countries with limited clean energy resources and large populations.

There will also be geopolitical consequences from the energy transition that will need to be accommodated. The International Renewable Energy Agency (IRENA)¹⁶ refers to this as a ‘democratising effect’ – driven by the fundamental physical differences between fossil fuels and renewable technologies in how they are produced and at what scale.¹⁷ This will fundamentally change the long-term value of global energy markets as different countries explore their alternatives and opportunities for self-sufficiency.

¹⁶ IRENA (2019), page 23.

¹⁷ For example, renewables are not as geographically concentrated as fossil fuels, reducing the importance of current energy ‘choke points’. Renewables are also largely inexhaustible and harder to disrupt than fossil fuels. Renewables are also deployable at ‘almost any scale’ and are compatible with decentralised energy production and use.

1.3 Structure of this paper

This paper sets out some recommendations for next steps in policy to support a ‘no regrets’ net zero and hydrogen policy.

Chapter 2 describes the scale of assets and infrastructure required to meet Australia’s hydrogen objectives, finding that the task ahead will need whole-of-economy planning that addresses multiple hydrogen production, delivery and use pathways, and encourages co-location of projects. In this chapter we argue that policy and funding should prioritise the demand side, and demand for harder to abate applications with opportunities to build scale should take precedence.

Chapter 3 explores the need to consider how we can reuse existing gas infrastructure to get to scale, noting that we need to be careful to plan for the economic lives of assets already in the ground to support energy affordability for consumers. Hydrogen also creates ‘sector coupling’ opportunities, where planners and project proponents can choose between electricity and gas infrastructure for different purposes. With the scale required to ‘move molecules’ or ‘move electrons’ in producing hydrogen, both gas and electricity infrastructure will need to be in play.

We also address the relatively easy way that demand can be stimulated by implementing a 10 per cent target for hydrogen to be blended into the natural gas system.

Chapter 4 is about a key demand to be served, and one that we suggest is no regrets: heavy road transport. Diesel is already close to price parity with hydrogen, and heavy transport is also hard to abate with electricity and batteries. The problem with this market is that the refuelling infrastructure isn’t in place and the vehicles are not yet in the country. In this chapter we recommend a programme of heavy and lighter truck (and bus) trials that will start the necessary refuelling backbone. The trials will also provide data to build transport operator confidence in the costs per kilometre for truck and bus purchases.

Chapter 5 is about the second key set of markets for demand: manufacturing products that already use hydrogen as a feedstock or fuel, and the use of hydrogen in new markets that can grow Australia’s manufacturing capabilities. The markets identified here are iron and steel, ammonia, methanol, and alumina and aluminium. Steel is an ambitious future use for hydrogen but has promise that needs to be explored fully. Ammonia and methanol are already produced from hydrogen, with each also presenting great promise for larger scale production and export as low-carbon fuels, particularly for shipping.

References

AEMO (2020) *2020 Integrated System Plan for the National Electricity Market*, July, <https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en>.

AEMO (2021) 'Reliability outlook positive as energy transition accelerates', media release, 31 August, <https://aemo.com.au/newsroom/media-release/2021-esoo>.

Australian Government Department of Industry, Science, Energy and Resources (2019) 'The Australian resources sector - significance and opportunities', in *Australia's National Resources Statement*, February, <https://www.industry.gov.au/data-and-publications/australias-national-resources-statement/the-australian-resources-sector-significance-and-opportunities>

Australian Government Department of Industry, Science, Energy and Resources (2020) *Technology Investment Roadmap: First Low Emissions Technology Statement 2020*, 22 September, <https://www.industry.gov.au/data-and-publications/technology-investment-roadmap-first-low-emissions-technology-statement-2020>.

ACIL Allen consulting (for ARENA) (2018) *Opportunities for Australia from Hydrogen Exports*, <https://arena.gov.au/knowledge-bank/opportunities-for-australia-from-hydrogen-exports/>.

Bond, K., Vaughan, E. and H. Benham (2020) *Decline and Fall: The size and vulnerability of the fossil fuel system*, Carbon Tracker, 4 June, <https://carbontracker.org/reports/decline-and-fall/>

Burchardt, J., Herhold, P., Päivärinta, J. and S. Schönberger (2020) 'Have We Passed Peak Demand for Fossil Fuels?', BCG, <https://www.bcg.com/en-au/publications/2020/have-we-passed-peak-demand-for-fossil-fuels>.

COAG Energy Council (2019) *Australia's national hydrogen strategy*, November, <https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf>.

Cunningham, M., Van Uffelen, L., and M. Chambers (2019) 'The Changing Global Market for Australian Coal', *RBA Bulletin*, September, Reserve Bank of Australia, <https://www.rba.gov.au/publications/bulletin/2019/sep/the-changing-global-market-for-australian-coal.html>.

Deloitte (2019) *Australian and global hydrogen demand growth scenario analysis*; COAG Energy Council – National Hydrogen Strategy Taskforce, November, https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-and-global-hydrogen-demand-growth-scenario-analysis-report-2019_1.pdf.

Farmer, M. (2020) "Fastest energy transition" for Australia after renewables ramp-up', *PowerTechnology*, 25 August, <https://www.power-technology.com/features/australia-energy-transition-analysis-coal-decline-solar-wind-project-pipeline-energy-markets-aemo-globaldata/>.

Fattouh, B., Poudineh, R. and R. West (2019) *Energy Transition, Uncertainty, and the Implications of Change in the Risk Preferences of Fossil Fuels Investors*, Oxford Energy Insight: 45, The Oxford Institute for Energy Studies, University of Oxford, January, <https://www.oxfordenergy.org/publications/energy-transition-uncertainty-implications-change-risk-preferences-fossil-fuels-investors/>

IRENA (2019) *A New World: The Geopolitics of the Energy Transformation*, the Global Commission on the Geopolitics of Energy Transformation, <https://irena.org/publications/2019/Jan/A-New-World-The-Geopolitics-of-the-Energy-Transformation>

Office of the Chief Economist (2020) *Resources and Energy Quarterly*, Department of Industry, Science, Energy and Resources, September, <https://www.industry.gov.au/data-and-publications/resources-and-energy-quarterly-september-2020>

Reserve Bank of Australia (2020) *Financial Stability Review*, 8 October 2020, <https://www.rba.gov.au/publications/fsr/2020/oct/pdf/financial-stability-review-2020-10.pdf>.

Tilly, M. (2021) 'AEMO says renewables growth "well ahead" of greenest forecast', *Energy News Bulletin*, 10 May.

How we get to scale





The clean hydrogen industry is still emerging, with most aspects of the value chain still pre-commercial. The costs of producing hydrogen need to fall significantly, and we do not yet have (pure) hydrogen-ready infrastructure, equipment or vehicles/vessels at any meaningful scale.

As of August 2021, the largest Australian electrolyser – the machine to make green hydrogen (see below) – is 1.25MW.¹⁸ Three 10MW electrolyser projects are scheduled to come on-line in 2023, where the project proponents were the recipients of A\$103.3 million from the Australian Renewable Energy Agency (ARENA).¹⁹

These are the green shoots we need to see. However, the task to get to scale is still significant. For example, Deloitte²⁰ provided demand scenarios for the National Hydrogen Strategy where the two most ambitious scenarios had Australian production for 2030 at 724 kilotonnes (kt) per year and 1,777 kt per year. To produce this much hydrogen by 2030 Australian projects will likely need to have deployed multiple electrolysers closer to the 1GW scale – 100 times the size scheduled to come online in 2023.

There will be different mixes of project sizes in the coming years, but for the sake of simplicity, if we only produced hydrogen with 1GW sized electrolysers we would need seven and 18 of these to get to the production figures in the respective Deloitte scenarios.

Figure 2 shows a comparison of several estimates of global hydrogen demand by 2050. We can see there is some difference in perspective, and this is largely due to the scenario and assumptions employed. The more ambitious demand figures are around 800 million tonnes (Mt) per year, which we see from BNEF and the Energy Transitions Commission. Importantly, most scenarios see industry demand as a major proportion of total demand, closely followed by transport applications.

The International Energy Agency's recent analysis about how to reach net zero by 2050 sees global hydrogen consumption reaching 530Mt per year,²¹ with the main categories of demand being transport (road transport, shipping and aviation, and as ammonia and synfuels as well as hydrogen), chemicals, and iron and steel. Hydrogen and hydrogen-based fuels make up 13 per cent of total energy demand in 2050.

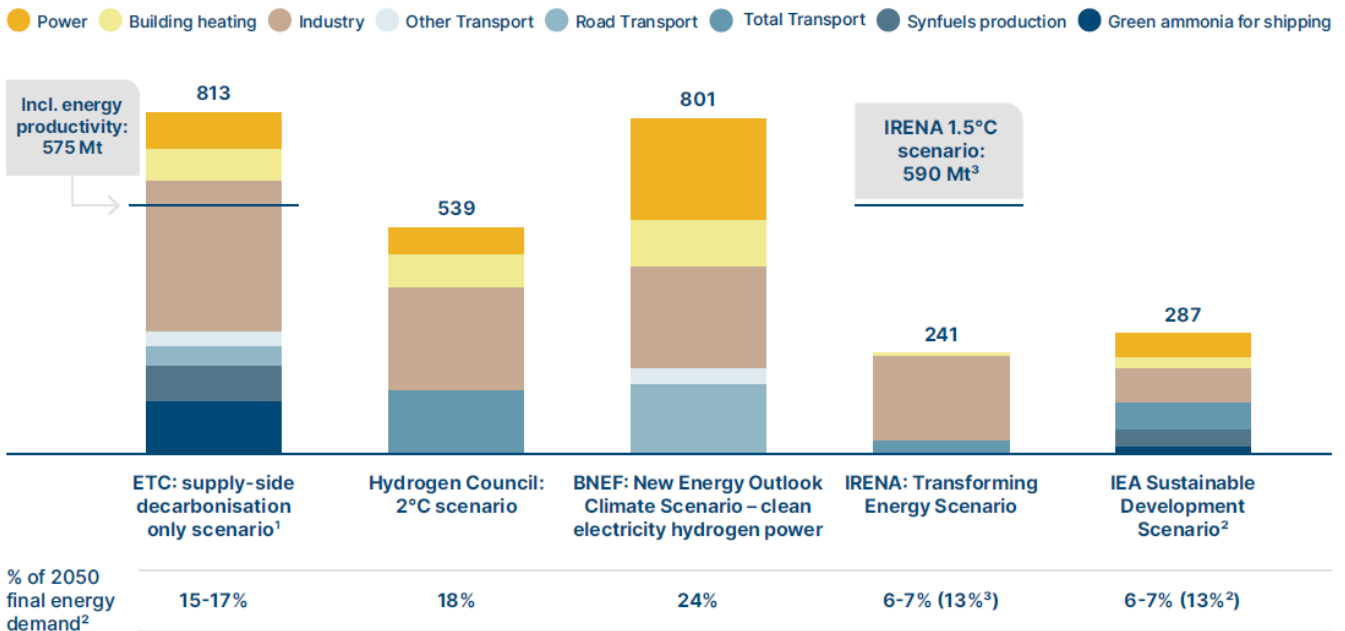
18 This is Hydrogen Park SA, see HyResource (2021).

19 ARENA (2021).

20 Deloitte (2019).

21 International Energy Agency (2021), pages 75, 109.

2050 hydrogen demand
Mt hydrogen / year



NOTES: ¹ Illustrative scenario considering 2050 final energy demand without application of energy productivity levels which would reduce energy needs in a net-zero scenario, ² Hydrogen reaches 13% of final energy demand by 2070 in IEA SDS, with hydrogen volumes of 520 Mt/year, ³ IRENA 1.5C scenario does not include split in uses, but represents 13% final energy demand.

SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); Hydrogen Council (2017), *Hydrogen scaling up – A sustainable pathway for the global energy transition*; BloombergNEF (2020), *New Energy Outlook*; IRENA (2021), *World Energy Transitions Outlook – 1.5C Pathway*; IRENA (2020), *Global Renewables Outlook*, IEA (2019), *The future of hydrogen*

Figure 2: Different perspectives on the size of the global hydrogen industry in 2050, with sector breakdown. SOURCE: Energy Transitions Commission (2021), page 23.

2.1 Recognise the task is large and complex

The hydrogen supply chain has many moving parts, with economic and engineering decisions to be made about large scale investments at multiple points, such as for:

- Making hydrogen:** Unlike traditional energy sources such as timber, coal, and petroleum products, hydrogen doesn't exist in specific locations in concentrated forms. However, it can be produced via several processes from a wide variety of resources that contain hydrogen. The process most often associated with current discussions about clean hydrogen is to use an electrolyser to make 'green' hydrogen, which requires renewable electricity and water as inputs. However, there is also the opportunity to

make 'blue' hydrogen, which is produced via the traditional means of steam methane reforming or coal gasification but capturing and storing the carbon emitted.

Assuming long-term clean hydrogen is green, significant electricity generation capacity will be required. This is on top of the renewable electricity required to replace coal from domestic electricity generation and to electrify light transport. The requirements for new generation capacity grow further if Australia is to meet its hydrogen export objectives. Dr Alan Finkel says that if we were to export as much hydrogen by energy value as the LNG we exported in the year to June 2020 (33 million tonnes) we would need about eight times

the total electricity that was generated in Australia in 2019²² (2200TWh, and Australia generated 265TWh in 2019).²³ He says that if we used solar for that energy, we would need around 75 times Australia's installed solar capacity in 2019 (1000GW capacity, more than the installed solar capacity worldwide).

Adding other export capabilities, such as a new green steel industry, will increase our renewable electricity requirements by further orders of magnitude. For example, BlueScope has calculated that:

To replace just 20 per cent of the pulverised coal injection (PCI which is <30% of the fuel/reductant in our Blast Furnace) at Port Kembla Steelworks, for example, with 'green hydrogen' would require 29 x 10MW electrolysers, with each electrolyser having a footprint of 1000m². They would consume 290MW of electricity (the Steelworks currently consumes an average of about 100MW).²⁴

If we use this example to calculate what 100 per cent of all fuel/reductant at that one site might consume, this comes to 4.8GW.²⁵ If the electrolysers are (hypothetically) running at near 100 per cent capacity factor, that gets to 10-20GW of renewable capacity, depending on source (offshore wind, onshore wind, solar). To provide context, under its electricity roadmap NSW plans to instal 12GW for the whole state by 2030.²⁶

- **Transporting hydrogen:** Once hydrogen is made, decisions need to be taken about the means for its transportation. This is about both the form of the hydrogen to be transported and the form of hydrogen transport. Hydrogen to be used domestically (and as pure hydrogen) will most likely be in its gas or liquid form, with gas likely to be the better option, at least in current estimates. Liquefying hydrogen requires additional facilities,

and transportation at the low temperature required to maintain a liquid form (-253°C) is expensive. Figure 3 shows the view of the Energy Transitions Commission about the better means of transporting hydrogen for different circumstances. The method of transportation for domestic use is most likely to be via pipeline or tube trailer, or potentially between coastal sites via ship.

Hydrogen for export from Australia will need to be by ship, and this natural constraint on available volume and weight means that a range of options are being considered for the most efficient form for the hydrogen. Current discussions focus most on hydrogen being shipped in a liquid form or via a chemical carrier such as ammonia. However, there are also innovations to ship hydrogen as a compressed gas or as a metal hydride.²⁷

- **Using hydrogen:** Hydrogen use can cover many sectors, from applications in industrial processes (such as making ammonia or steel), to replacing liquid fuels for transport uses (the whole spectrum from forklifts to container ships), to replacing natural gas for domestic and commercial heating and cooking. It can also be used in power stations to generate electricity when required.



22 Finkel (2021), pages 66-67.

23 Australian Government Department of Industry, Science, Energy and Resources (n.d).

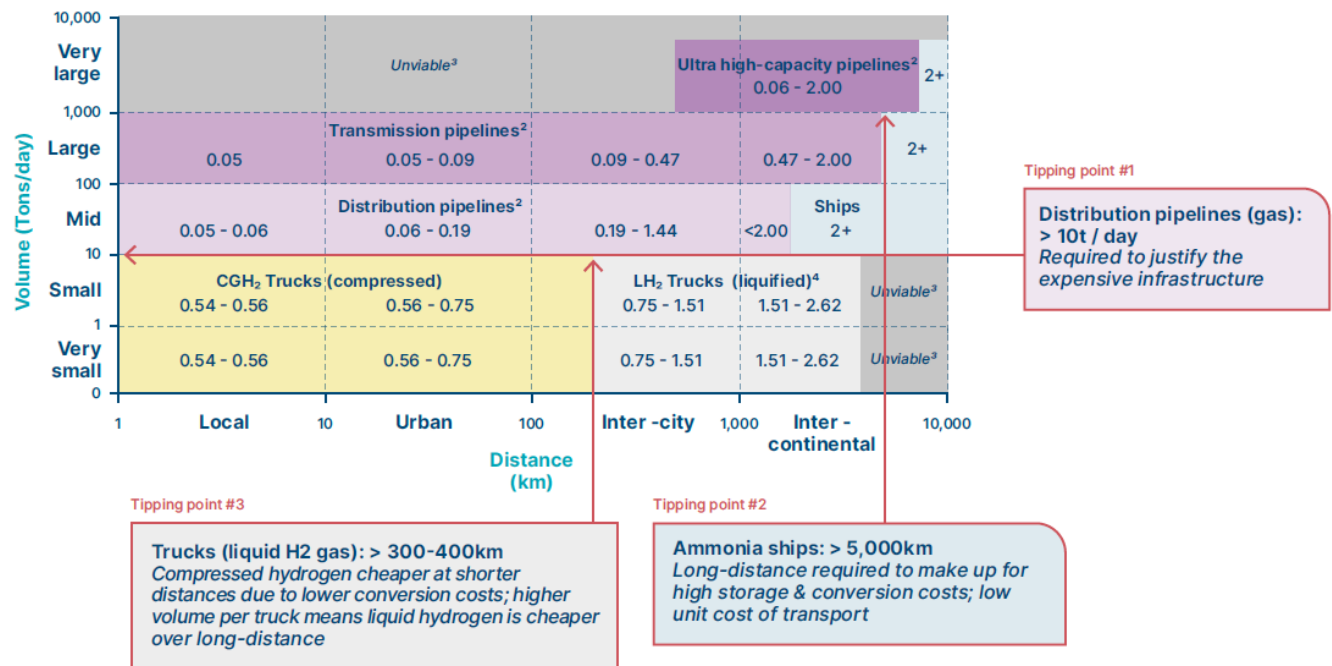
24 BlueScope Steel (2021), page 12.

25 Where 5x3.3=16.5 times 290MW comes to 4.8GW.

26 NSW Department of Planning, Industry and Environment (2020), page 30.

27 See for example, Hydrogen Energy Research Centre (n.d).

Lowest cost form of hydrogen transportation¹ based on volume and distance
\$/kg H₂



NOTE: ¹ Including conversion and storage; ² Assumes salt cavern storage for pipelines; ³ Ammonia assumed unsuitable at small scale due to its toxicity; ⁴ While LOHC (liquid organic hydrogen carrier) is cheaper than liquid hydrogen for long distance trucking, it is unlikely to be used as it is not commercially developed.

SOURCE: Adapted from BloombergNEF (2019), *Hydrogen: The Economics of Transport & Delivery*, Guidehouse (2020), *European Hydrogen backbone*

Figure 3: Analysis of lowest costs for hydrogen transport. SOURCE: Energy Transitions Commission (2021), page 38.

We can see that the versatility of hydrogen also brings complexity. Hydrogen allows planners to choose between gas and electricity infrastructure to some degree – it allows ‘sector coupling’, which is a linking of different sectors of the economy, especially different energy sectors, to co-optimize networks and markets. Hydrogen has the potential to become a key technology in this context, bringing the opportunity to create Australian strategic value chains.

An Australian hydrogen industry will require large-scale electrolyzers, renewable electricity, hydrogen storage, water and water pipelines, electricity infrastructure, CCS as appropriate, and hydrogen pipelines (which may be repurposed from existing

pipelines). Industrial and port facilities will need to be developed to process and export hydrogen and its derivatives, including ammonia. Mineral and chemical companies will invest in new production processes, and transport and logistics companies will procure new vehicle technologies. Refuelling stations will be required to supply hydrogen for vehicles. Households and businesses can convert from gas and oil-based fuels to hydrogen or electricity for heating and mobility.

Each of these elements will have their own costs and dependencies, engineering reality and level of social acceptance, which in turn affects the business case for different means of producing, storing, transporting and using hydrogen.

This also means a variety of timeframes, such as the timing for:

- Building the necessary electricity, gas and refuelling infrastructure.
- Vehicle and vessel design, testing, production and deployment, which can take over seven years.
- Major industrial process changes, such as key sectors planning for and purchasing new equipment that is expected to operate for decades. This can also take several years.
- Very large or ‘mega’ projects, such as in traditional oil and gas, where the process to go from initial investigation to a final investment decision can be as much as eight years.

It appears that we need to have locked down a great deal within the next year or so if we are to achieve objectives such as the National Hydrogen Strategy’s ‘Australia as a top three exporter to Asian markets by 2030’ or getting hydrogen to less than A\$2/kg by then.²⁸

Further, the various windows of opportunity need to be aligned as far as possible if we are to get to scale and do so competitively. This means planning and co-optimising different assets, and timing needs to address a range of different markets.

For example, at a high level there are two hydrogen supply pathways:

- **Moving the electrons**, which means limiting the need to transport hydrogen by making it near the end use, and instead taking the renewable electricity (and raw water) to the hydrogen production site.
- **Moving the molecules**, which co-locates the source of renewable electricity (and raw water) with the hydrogen production, and then transporting the hydrogen to its end use.

In each case there will be different economics depending on the proposed project’s size, the terrain and available sun and wind, whether the electricity is sourced from the grid or not, and whether the project needs to have port access or not.

Several experts have advocated for common user infrastructure, such as pipelines and ports, as a way of managing some of the complexity and creating efficiencies. This provides an opportunity to share risk among multiple producers and capture efficiencies and allow “users to participate in the hydrogen economy without first mover disadvantage/cost burden”.²⁹

This is also a key lesson learned from Australia’s LNG experience, where a Deloitte³⁰ survey of LNG leaders found that a lack of forecasting and collaboration between industry players meant that they worked on independent projects in parallel: “In terms of post Final Investment Decision (FID) construction, collaboration among companies was virtually non-existent and this led to a dramatic overbuilding of infrastructure. For example, the three large LNG projects in Queensland don’t even share a road”. LNG developers were said to race against one other “to build infrastructure at almost any cost”.³¹



28 While the ‘H2 under \$2’ target does not officially have a date associated with it, AHC believes that it should be 2030. This is because of the messages being sent from our key trading partners Japan and South Korea – meeting their pricing needs would require hydrogen at around \$2 at the point of production.

29 Advisian (2021), page 16.

30 Reid and Cann (2016), page 8.

31 Ibid., page 11.

Researchers from the Grattan Institute explain the need for coordination if we are to compete effectively, using the example of low carbon steel:

producing net-zero steel, for example, requires not just a zero-emissions steel smelter, but also a supply of zero-emissions hydrogen for the smelter, which in turn requires zero-emissions electricity. It requires land for hydrogen production and storage. And renewable energy production requires transmission lines from these renewable energy facilities to hydrogen production sites, and so on.

When this needs to be repeated for half-a-dozen facilities in the same geographical area, the benefits of coordination become obvious. Achieving scale will be essential for successful transformation. Other countries will be seeking to transform their industrial sectors at the sametime as Australia, and where we are a small producer (for example, of steel, aluminium, or ammonia), individual Australian firms will be well down the queue for equipment suppliers.³²

And it's not only about land and infrastructure; vast amounts of construction activity will require workforce planning. Again, there are lessons to be learned from Australia's LNG experience:

There is a high probability that undertaking several major capital projects within the same geographic area will create resource scarcities, which in turn will drive up costs to unsustainable levels. Yet, in Australia, this likelihood was largely ignored. As a smaller nation, Australia had inherent resource scarcities, particularly in terms of labour. Additionally, LNG companies did not give a great deal of forethought to how stiff competition among multiple operators would affect local wage rates. This resulted in an 'arms race' of sorts in assuring access to scarce resources, with wage rates soaring to astronomical levels. How high is astronomical? As described by one survey participant, a journeyman carpenter, whose task was to build forms for pouring concrete, commanded AU\$250,000 per year at the height of the building activity.³³

Impacts on local economies will need to be understood and planned for, to avoid the worst from Australia's previous boom-bust cycles and surges of economic activity. The sheer scale of construction and development will also raise important community (and societal) questions about competing uses for land and water, and priorities for infrastructure for different purposes. There will be a diverse group of stakeholders and connections to be built.

On a related matter, clearly the emerging hydrogen industry will affect several different markets in different timeframes, from now to beyond 2050. This will require a fit-for-purpose regulatory approach with the flexibility to work across sectors and jurisdictions. This means that project planning must also consider and shape regulatory developments.

³² Wood, Reeve, and Ha (2021b), page 43.

³³ Reid and Cann (2016), page 10.

2.2 Support co-location of facilities and infrastructure

Australia's National Hydrogen Strategy states the importance of hydrogen 'hubs', which are clusters of demand that share risks and costs:

Hubs aggregate various users of hydrogen into one area. Doing so minimises the cost of providing infrastructure – such as powerlines, pipelines, storage tanks, refuelling stations, ports, roads or railway lines – and supports economies of scale in producing and delivering hydrogen to end users. Hubs also help focus efforts for innovation and building a 'hydrogen-ready' workforce.³⁴

Besides co-locating hydrogen users, factors influencing hub site choices include access to hydrogen production (and the necessary land, low-priced electricity, electricity infrastructure, water and relevant storage capacity), access to suitable ports, road and rail infrastructure, and access to gas transmission pipeline easements. Stakeholder and community interest and acceptance is also vital.³⁵ In work undertaken for the National Hydrogen Strategy, consultant ARUP developed hub criteria as shown in Table 1.

Criteria – level 1	Criteria – level 2
Production (Green)	Renewable source Weather data Backup energy supply
Essential considerations	Transport access Transmission lines Water access Health and safety provisions Environmental considerations Economic and social considerations Land availability
Demand	Population size and density Colocation with industrial ammonia production Colocation with future industrial opportunities Proximity to export hubs
Supply chain to domestic demand	Existing gas networks Gaseous hydrogen storage Refuelling stations

Table 1: Domestic hub assessment framework, adapted from ARUP (2019) page 77.

34 COAG (2019), page 34.

35 Ibid., page 34.

In September 2021, the Australian Government announced that it would support seven hydrogen hubs, with a funding amount of \$464 million.³⁶ Seven locations have been suggested, with a final decision to be made in 2022. Applicants for funding are expected to be consortia of Australian and international industry players, potentially with state and international government backing. Favourable locations will be those with large scale industrial energy demand, a skilled workforce, existing infrastructure that can be utilised, and proximity to energy resources.

Globally, hubs are considered vital to establish scale in clean hydrogen.

The 'hydrogen valley' concept (used in Europe) is similar, where they bring parties together around a common hydrogen supply infrastructure to create a local ecosystem. Hydrogen valleys tend to:

- **Be large in scale**, with project scoping that includes several sub-projects and goes beyond "mere demonstration activities and entails at least a two-digit multi-million EUR investment".
- **Have a clearly defined geographic scope**, with a footprint that "can range from a local or regional focus (e.g. a major port and its hinterland) to a specific national or international region (e.g. a transport corridor along a major European waterway)."
- **Cover the hydrogen value chain**, from hydrogen production to storage and distribution, through to end users.
- **Supply to users from a range of end sectors**, such as hydrogen for industrial use, for transport and for energy supply.³⁷

A report for the European Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) advises that the hydrogen valleys across the world have flourished, with estimated investment volume at €250 million in 2017, and growing to more than €18,000 million in 2019.³⁸ Interest and investment is also shifting from the public and research sector to the private sector, which is said to be a sign of "a maturing market with more and more profitable investment cases".³⁹ The global hydrogen valleys are also said to be on track to grow in size, number and complexity.

Hydrogen valleys are also apparently aligning with three "archetypical value chain setups", as follows:

- **Archetype 1: Transport focussed smaller-scale producers and consumers of hydrogen** that come together to aggregate consumption volumes from different mobility users and share the means of refuelling vehicles, including hydrogen supply and refuelling stations.
- **Archetype 2: Industrial medium-scale producers and users of hydrogen as a feedstock**, where the demand (off-take) is "on one or more larger off-takers as 'anchor loads', typically from the industry or energy sector (e.g. refineries)" who create a critical mass for initial demand.
- **Archetype 3: Export-focussed large-scale hydrogen producers** "aiming for international, long-distance transport to off-takers abroad". The domestic focus is on off-take from the industry and energy sector "to commercially de-risk the necessary upstream and midstream investments".⁴⁰

See Appendix A for these archetypes and the 'cluster' equivalent from the Energy Transitions Commission.

36 Australian Government (2021).

37 Weichenhain, Kaufmann, Benz, and Matute Gomez (2021), page 13.

38 Ibid., page 22.

39 Ibid., page 26.

40 Ibid.

In the AHC’s assessment of our members’ plans, we found most have identified multiple key markets for their own involvement in hydrogen.

In May 2021 we asked our members from a range of sectors (consulting, energy, finance, industrial gases, science, technology and transport) which end uses they saw as relevant to their hydrogen ambitions. Figure 4 shows the responses, where we can see road transport and blending into natural gas networks were the most popular. In these responses we can also see industry players shifting into surprising sectors, such as gas networks valuing transport, and transport businesses considering electricity grid stabilisation.

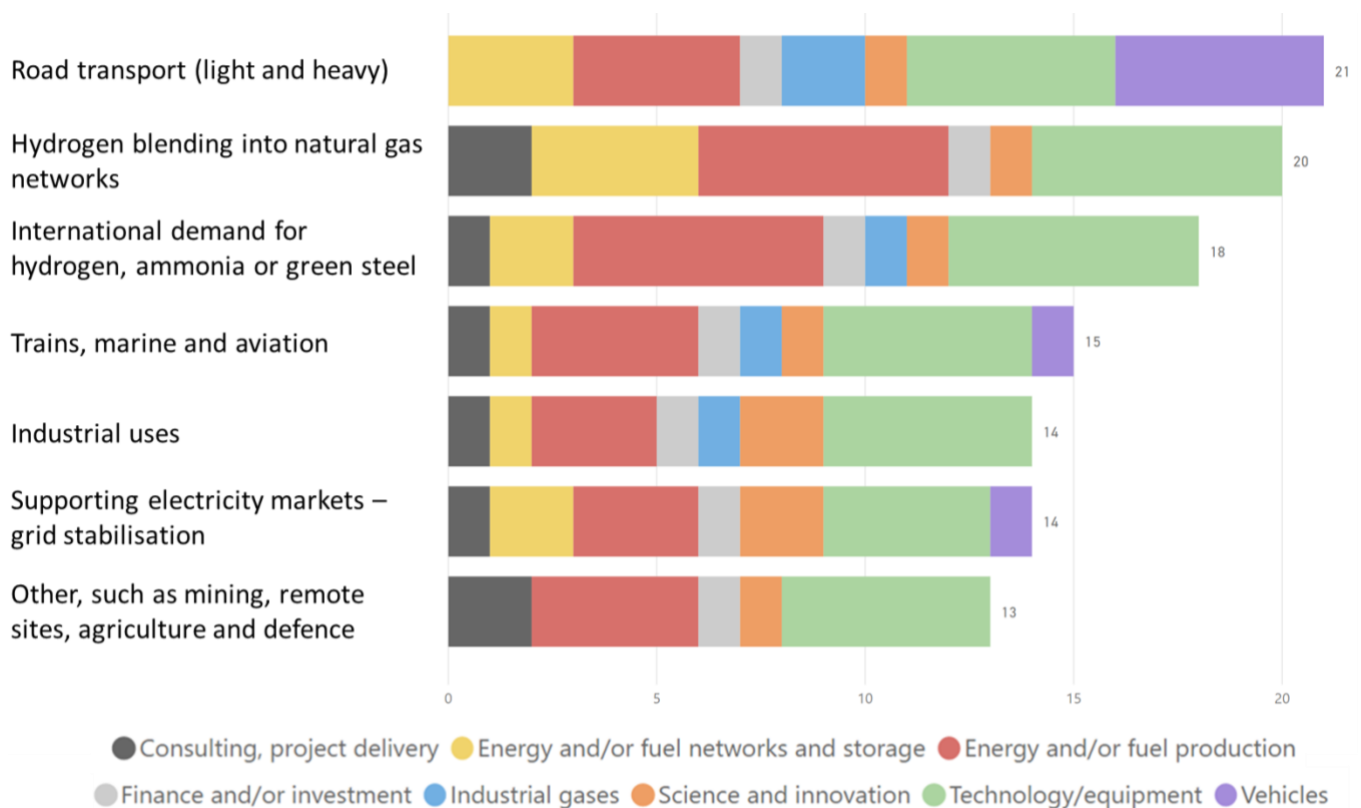


Figure 4: AHC member responses to question about end use markets for their business’s interests in hydrogen, May 2021, n=30, AHC internal analysis.

2.3 Provide adequate public funding support to start the markets

Until the industry has reached commercial scale, grant funding is essential. We noted at the start of this chapter that the scale of the electrolyzers required to reach scale will be 1GW, and we will need several of these.

It is difficult to estimate the total cost of the various large scale projects that could develop: there are too many unknowns, many variables, and we know the costs of electrolyzers and renewable electricity will come down. However, it is likely that the capital investments for production of hydrogen alone could run to the tens of billions of dollars.

For example, using Deloitte's⁴¹ two most ambitious 2030 demand scenarios for the National Hydrogen Strategy (724 kt per year and 1,777 kt per year), we estimate potential hydrogen production costs based on sample project mixes, as shown in Table 2.

We also show how the investment gap (the difference to create a commercial enterprise) might be considered, based on an assumption of 75 per cent government funding required for the near term. Of course, in practice there will be a sliding scale of costs per project per timeframe, with the investment gap varying as well. We might expect that a total of A\$21 billion (for example, from column 1) would be spread over several years, and while the government funding to start with would be closer to the 75 per cent, this would reduce to zero over time.

Each scenario has two different mixes of project sizes to illustrate different costs. Columns 1 and 3 reflect relatively more efficient choices than columns 2 and 4 – these have larger projects and show some economies of scale.

H2 production	Electrolyser equivalent	1. Energy of the future Total: 1,777ktpa	2. Energy of the future Total: 1,777ktpa	3. Targeted deployment Total: 724 ktpa	4. Targeted deployment Total: 724 ktpa
1ktpa	10MW	20	700	20	524
10ktpa	100MW	15	60	15	20
50ktpa	500MW	12	10	5	
100ktpa	1GW	10		3	
Total H2 volume (ktpa)		1,770	1,800	720	724
Projects		57	770	43	544
Cost (m)		A\$21,550	A\$42,000	A\$10,350	A\$20,720
Gap - 2021 75%		A\$16,163	A\$31,500	A\$7,763	A\$15,540

Table 2: AHC internal costing for different potential project mixes to align with Deloitte scenarios

We can see from Table 2 that the costs of hydrogen production alone (not including costs of the electricity and water inputs) could be in the range of around A\$10 billion (column 3: smaller ambition, more efficient project mix) to A\$42 billion (column 2: larger ambition, less efficient project mix).

If all projects received public funding at 75 per cent, funding for production would be at least around \$7.7 billion (column 3) and might be expected to be closer to A\$15-\$20 billion for strong growth and reasonable efficiency. As noted above, the expenditure will of course be over time, and as scale and industry confidence build, we would see a corresponding reduction in public funding over the period.

41 Deloitte (2019).

We have addressed the costs of electrolyser projects and now need to add the costs of electrolyser inputs, upgrades to infrastructure, the costs of new assets and equipment, and other usage costs. These costs can also be expected to come to tens of billions of dollars.

Indicative total costs include:

- New wind and solar at large scale could be A\$1 million a megawatt,⁴² resulting in 10GW installed capacity costing A\$10 billion.
- The cost to convert one blast furnace to make green steel has been priced at A\$2.8 billion.⁴³ The capital cost for a new 4Mt/year integrated steelmaking facility is said to be around US\$4 billion depending on the jurisdiction.⁴⁴
- Electricity and gas infrastructure costs will also be in the billions: for example, the Dampier to Bunbury pipeline is valued at around A\$3 billion,⁴⁵ which covers 1,539 kilometres of high pressure pipeline.
- Around A\$0.5 million to A\$1 million per tonne of hydrogen for storage at scale⁴⁶ (more than 20 tonnes).
- One ammonia plant could be over A\$700 million,⁴⁷ and likely closer to A\$1 billion for a 800 ktpa plant, depending on the existing infrastructure and availability of utilities.
- Port upgrades could be hundreds of millions of dollars per port; for example, Townsville's current channel upgrade is reported as costing A\$232 million.⁴⁸

Bringing some of these costs together, engineering consultant Hatch has recently developed a case study⁴⁹ based on WA iron ore to demonstrate the scale that supply chains will need to reach to displace diesel for transportation in mining. Hatch found that the cost to replace 3,000 ML per year of diesel would be A\$28 billion.⁵⁰ This is a total cost, not a government funding amount, but we can see that even a small level of government support for a project like this (say 10 per cent) is A\$2.8 billion.

Globally, the international Hydrogen Council's 2020 *Path to hydrogen competitiveness* report (supported by McKinsey analysis) estimates that US\$70 billion (A\$100 billion) of investment in hydrogen is required across the globe by 2030 to meaningfully activate the global hydrogen economy:

Reaching the scale required will call for funding an economic gap until a break-even point is reached – an investment to offset the initially higher costs of hydrogen as a fuel and of hydrogen equipment compared to alternatives. Instead of being perceived as costs, this should be seen as an investment to shift the energy system and industry to low-carbon technology.⁵¹

BNEF analysis goes further, estimating that US\$150 billion (A\$214 billion) will be needed globally until 2030 to bridge the cost gap between hydrogen and the cheapest fossil fuels, not just the cheapest low-carbon alternative.⁵²

42 Solgen (n.d).

43 BlueScope Steel (2021), page 10.

44 BHP (2020).

45 AGIG (2020), page 99.

46 Ardent Underground Hydrogen Storage (n.d).

47 Milne (2021).

48 Hartmann (2021).

49 Hatch (2021), page 4.

50 This analysis assumed the total cost of renewable energy generation installed capacity would be A\$18 billion for 14GW of solar or A\$14 billion for 9GW of wind. The electrolysers for 5.6GW were estimated to be A\$10 billion, and there was a need for storage cost of A\$2.4 billion for 37 kt of hydrogen.

51 Hydrogen Council (2020), page 66.

52 BNEF (2020), pages 4-5.

Recent announcements from overseas provide a further sense of the commitments required. For example:

- The US has allocated US\$9.5 billion (~A\$13 billion) directly to hydrogen,⁵³ with further potential multi-billion impacts from other infrastructure coverage. There aren't announced figures for the US hydrogen production targets, but estimates are that the opportunity (not necessarily by 2030) could be to produce up to 40Mt of hydrogen per annum.⁵⁴
- The UK has committed £240 million (~A\$452 million) directly, with a further ~£1.3 billion (~A\$2.5 billion) for net zero with hydrogen as a priority.⁵⁵ This builds on the Prime Minister's 'Ten Point Plan for a Green Industrial Revolution', which aims for 5GW of low carbon hydrogen production capacity by 2030 for use across the economy.
- The European Union has an 'Innovation Fund',⁵⁶ expected to provide around €20 billion (~A\$32.3 billion) of support over 2020-2030, for the commercial demonstration of innovative low-carbon technologies. For hydrogen, the EU has developed an ambitious plan to reach 2x40 GW of electrolyzers by 2030, with 40GW in Europe and 40GW in Europe's neighbourhood with export to the EU.⁵⁷ Writing in 2020, the European Commission said:

From now to 2030, investments in electrolyzers could range between €24 and €42 billion. In addition, over the same period, €220-340 billion would be required to scale up and directly connect 80-120 GW of solar and wind energy

production capacity to the electrolyzers to provide the necessary electricity. Investments in retrofitting half of the existing plants with carbon capture and storage are estimated at around €11 billion. In addition, investments of €65 billion will be needed for hydrogen transport, distribution and storage, and hydrogen. From now to 2050, investments in production capacities would amount to €180-470 billion in the EU.⁵⁸

To compare, at this stage with over A\$1 billion announced for hydrogen,⁵⁹ the Australian Government's financial commitment to hydrogen is significant, but comparatively speaking, it is not where it needs to be if we are to achieve our national objectives. For example, the UK ambition is to produce 5GW of clean hydrogen by 2030, which is around 500kt per annum. The Deloitte scenarios for the Australian National Hydrogen Strategy (refer to Table 2), are more than this for 2030, with our ambitious hydrogen production figure at three and a half times more than the UK target.

While the figures in this section are approximate, they make clear that meeting our Paris Agreement pledge, and becoming a clean energy exporter to help other countries reach theirs, is a far larger task than we have previously taken on. Playing our part in full decarbonisation is a major increase in ambition. This ambition may be realised over decades, but as noted by the European Commission: "As investment cycles in the clean energy sector run for about 25 years, the time to act is now".⁶⁰

53 The whole package is for US\$944 billion in total spending over five years, with US\$550 billion in new spending. Passed by the US Senate in August 2021, the Infrastructure Investment and Jobs Act: Supports four regional hydrogen hubs, with US\$8 billion over 4 years; provides US\$500 million over 4 years for hydrogen research, development, and demonstration projects; and provides US\$1 billion to fund a grant program to support electrolysis, ideally to reduce the cost of hydrogen produced via electrolysis to less than US\$2 per kilogram of hydrogen by 2026. The bill now moves for consideration in the U.S. House of Representatives.

54 Smith (2021), also Ivanenko (2021).

55 In August 2021, the UK government launched its hydrogen strategy. The UK policy includes £240 million for government co-investment in production capacity through a Net Zero Hydrogen Fund. It also designates hydrogen as a key priority area a £1 billion fund called the Net Zero Innovation Portfolio, to accelerate commercialisation of low-carbon technologies and systems for net zero. There is a further £315 million Industrial Energy Transformation Fund and £20 million Industrial Fuel Switching Competition.

56 European Commission (2019).

57 European Commission (2020), pages 5-6. The strategic objective of the first phase (2020 to 2024) is to install at least 6 GW of electrolyzers in the EU and the production of up to 1 million tonnes of renewable hydrogen. The objective of the second phase (2025 to 2030) to install at least 40 GW of renewable hydrogen electrolyzers by 2030 and the production of up to 10 million tonnes of renewable hydrogen in the EU.

58 European Commission (2020), pages 7-8.

59 As of August 2021, this was at least A\$920 million (announced), and some proportion of over A\$1.62 billion that will be available for ARENA over the next ten years. See Grubnic (2021), page 7. Australian Government funding was then increased in September 2021 by a further \$150 million for hubs, bringing total spend to at least \$1.1 billion (see Australian Government, 2021).

60 European Commission (2020), page 3.

2.4 Recommendations

The transition to net zero energy emissions will require unprecedented rates and complexity of investment in new energy sources, infrastructure and energy use equipment, which will need to be synchronised with an equally unprecedented exit, stranding or repurposing of existing capital stock (e.g. coal-fired power stations, gas networks, oil import supply chains, coal export supply chains).

Those investments will arise from the interplay of policies and programs of federal and state governments, regulatory bodies, a large number of companies in the private sector, energy users from households to major industrial consumers, and governments and companies of our major trading partners.

The scale of the task requires planning, funding, and targeted demand stimulation.

2.4.1 Set up planning and ownership of the task

Comprehensive and published planning information – defined here as projections and assessments of future energy supply and demand pathways – would assist governments, the private sector and the public to make informed decisions about their options and actions. We are suggesting broader net zero planning here rather than for hydrogen alone.

No such planning and reporting information is currently being produced. AEMO's Integrated System Plan (ISP) is the nearest example but it does not cover oil, energy exports, the consumption of electricity and gas off main grids, the full period to 2050, or the achievement of policy and programme goals. So, while the ISP would be important input to a national energy planning document, it serves a different, more specific, and limited purpose.

Our proposal is planning information only in the sense that it is intended to inform the planning of many stakeholders. It would not be a central plan that is intended to be implemented by governments. A close analogy is the International Energy Agency's outlook reports. Indeed, the IEA's reports would be a source of input to a more detailed view of Australia, which would in turn inform the IEA.

The proposed planning information would need to be updated regularly to update supply, demand, technology costs and other parameters that underlie projections. Scenarios would be employed, and subjected to sensitivity analysis, to inform policy, commercial and community decisions rather than advocate preferred directions. Actual results for the relevant parameters would also be reported (e.g. emissions, renewable energy share, vehicle fleet emissions, energy consumption and technology costs) and compared to earlier forecasts and federal and state targets. The impact of policies would be assessed where feasible.

Exports of energy (coal, LNG, hydrogen) and commodities that could be processed with clean energy (e.g. iron ore, steel) would be in scope of forecasting and reporting.

Non-energy indicators of related economic and social impacts (e.g. employment in relevant sectors and regions, energy costs, productivity impacts, land use change due to energy production, air quality and associated health outcomes) would be forecast and reported.

The volume, type and price of offsets could be included in the projections and reporting, as could non-energy emissions.



The development and publication of this planning information:

- Could be undertaken by a body established under statute, with information gathering powers and consultation obligations (with governments, agencies, business and public). It could operate under a Commonwealth-State agreement and legislation adopted nationally. It would need a secure line of funding from general taxation or by a levy on energy production.
- Would be overseen by a Board that is not subject to ministerial direction as to the use of its information powers or its findings. The research would be subject to expert peer review.
- Would cover all sources and uses of energy, and consideration could be given to including non-energy emissions from the outset, or at a later date.

Some transfer of expertise from governments, agencies and academia would be important to provide the required rigour to be achieved as quickly as possible.

A staged approach to expanding the scope (e.g. to non-energy emissions) may be required to make the establishment of the body and its outputs manageable.

Recommendation 1: Plan in the national interest

We recommend that the Australian Government establishes a body to develop an evidence-based approach to planning and coordinating the transition to net zero – including the development of hydrogen infrastructure – and reporting progress. An initial annual budget of approximately A\$10 million would be required.

2.4.2 Fund projects and infrastructure

Given the sheer scale of required funding support, and the extended timeline, there should be a specific fund developed to support the emerging hydrogen industry, and early adopters, in managing technology risk. As noted by Wood et al., technology risk is “particularly acute” for Australia’s industrial sector because there tend to be only a few facilities per business, amplifying the cost of failed technology.⁶¹ Further:

When technology is new, potential users and investors (in this case, large industrial corporations and their shareholders and financiers) will have less confidence about feasibility, viability, and risks, all of which adds to the cost of capital. If this fear persists, it can create a ‘risk trap’, where the risk remains poorly understood and poorly priced because of lack of experience with the technology, and experience does not develop because of lack of investment.⁶²

We note that hydrogen has a role within a broader net zero policy, and decisions about funding require a national perspective that covers the range of ways to get to net zero. We know that hydrogen has a fundamentally important role and so feel confident that objective and evidence-based decision-making will see and value what this new industry can provide.

Therefore, the AHC recommends that the Australian Government establishes a Net Zero Fund, with an initial allocation of A\$10 billion into the fund, with drawdowns to be decided in response to planning and market soundings.

We can expect this kind of public investment will unlock several times its value from the private sector. Assuming all else is equal, figures from ARENA and CEFC suggest that government funding in hydrogen might be expected to unlock at least three times as much private investment.⁶³

We recommend that there is a Net Zero Authority created to administer the money allocated from the Net Zero Fund, with power to cover the full spectra from research to commercialisation, and from grants to finance. It will be important to consider ARENA and CEFC in the design, with a view to coordinating or integrating their operations.

We note that the Grattan Institute has recommended the same amount be used for an Industrial Transformation Future Fund, topped up with A\$1 billion each year to 2030. Grattan’s recommendation fulfils a different role to ARENA and the CEFC, with a “focus on transformation rather than demonstration (unlike ARENA); and...a strong risk appetite without the obligation to pursue returns (unlike CEFC)”.⁶⁴

While we are not against this idea, it is not clear how a third body with this remit would work relative to the other agencies. We believe that the funding needs are broader than the coverage suggested by Grattan. For example, while the industry is keen to move ahead, the need for practical demonstration and trial projects remains strong. As discussed in subsequent chapters of this report, there are many uncertainties confronting owners of significant assets, and the industry still needs to develop and share knowledge to grow investor confidence.

We do support the funding amount, although we note this may still not be the funding level required for a country seeking to become a market leader, and the A\$10 billion is also not hydrogen specific. The billions of dollars of future GDP envisioned in the National Hydrogen Strategy will only be realised with a significant down payment.

61 Wood et al. (2021b) page 39.

62 Ibid.

63 De Atholia, Flannigan, Lai (2020). Further, if we take advice from the Hydrogen Council (2020, 2017) across two recent reports, a similar expectation of the ratio of public to private funds emerges: the 2020 report says around US\$70 billion is required from government, and in a 2017 report the Council states that ‘building the hydrogen economy would require annual investments of [US]\$20 to 25 billion for a total of about [US]\$280 billion until 2030’ (page 66).

64 Wood et al. (2021b), page 42.

Recommendation 2: Establish a Net Zero Fund

We recommend that the Australian Government establishes a Net Zero Fund, with an initial allocation of A\$10 billion and a top up of A\$1 billion each year to 2030. Drawdowns should be decided in response to planning and market soundings.

2.4.3 Focus on no regrets demand stimulation

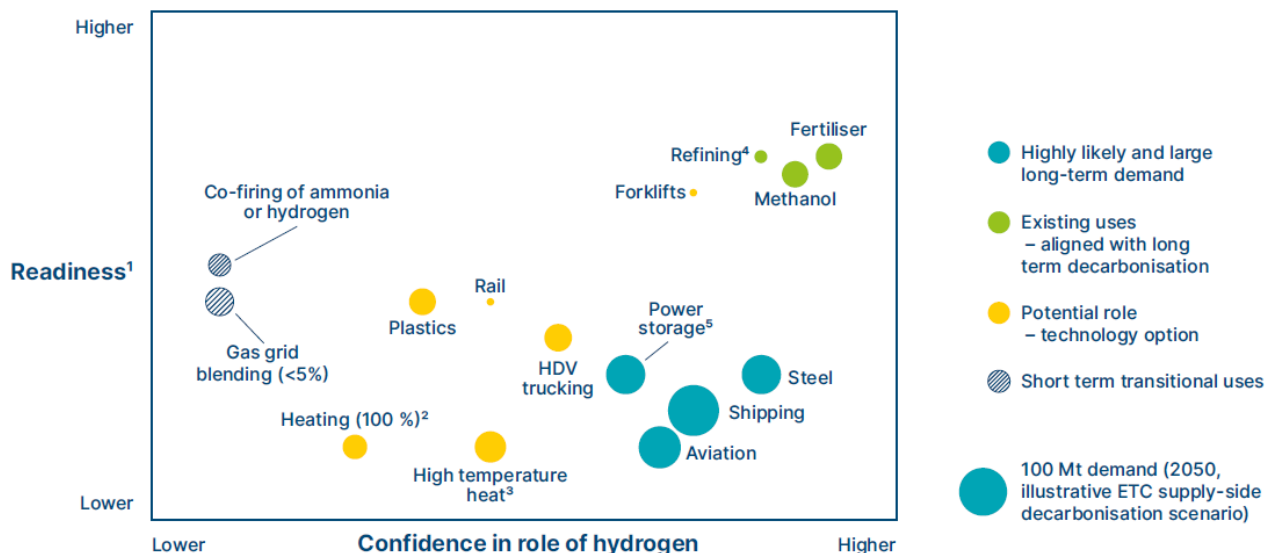
Given the options, the interlinkages, and the need for scale across different markets, the issue for the industry and policymakers is picking where to start when considering potential markets. The AHC encourages prioritising sources of demand – and growing these – to draw through supply.

Figure 5 shows analysis from the Energy Transitions Commission,⁶⁵ which plots various end uses for hydrogen by confidence in hydrogen as having a role, and the readiness to use it. This is global analysis and so is not expected to precisely reflect the Australian environment.

We can see from Figure 5 see that the hydrogen uses toward the right along the x-axis reflect stronger

confidence, with uses higher up the y-axis reflecting greater readiness. Uses that rate well on both axes relate to where hydrogen already plays a role, such as in the production of fertiliser. Very heavy transport and steel are less ready, but also represent sectors where hydrogen will need to play a role. These are the ‘hard to abate’ sectors for which direct use of renewable electricity, or use of batteries, is unlikely to be economically or technically feasible.

In work undertaken for the Clean Energy Finance Corporation, consultant Advisian⁶⁶ estimated the economic gap between likely delivery price and capacity to pay across 20 industry end use applications in 25 end use sectors. The analysis was for 2020, 2030 and 2050.



NOTES: ¹ Readiness refers to a combined metric of technical readiness for clean hydrogen use, economic competitiveness and ease of sector to use clean hydrogen. ² Heating (100%) refers to building heating with hydrogen boilers via hydrogen distribution grid. ³ High temperature heat refers to industrial heat processes above ca. 800°C. ⁴ Current hydrogen use in refining industry is higher due to greater oil consumption. ⁵ Long-term energy storage for the power system.

Figure 5: Multiple potential uses of hydrogen in a low carbon economy, some of which can provide early ‘off take’ for clean hydrogen. SOURCE: Energy Transitions Commission (2021), page 17.

65 Energy Transitions Commission (2021), page 17.

66 Advisian (2021).

Figure 6 shows the Advisian analysis for 2020, where a more positive figure suggests a higher economic competitiveness for a hydrogen-based technology compared with the incumbent technology. A sizeable negative gap (such as for marine shipping) reflects a hydrogen application that is some way away from being able to effectively compete.

The analysis also shows the extent to which hydrogen applications are likely to be dependent on hydrogen to decarbonise. This shows as a colour scale, where darker green identifies applications that are likely to have a high dependence on hydrogen to decarbonise.

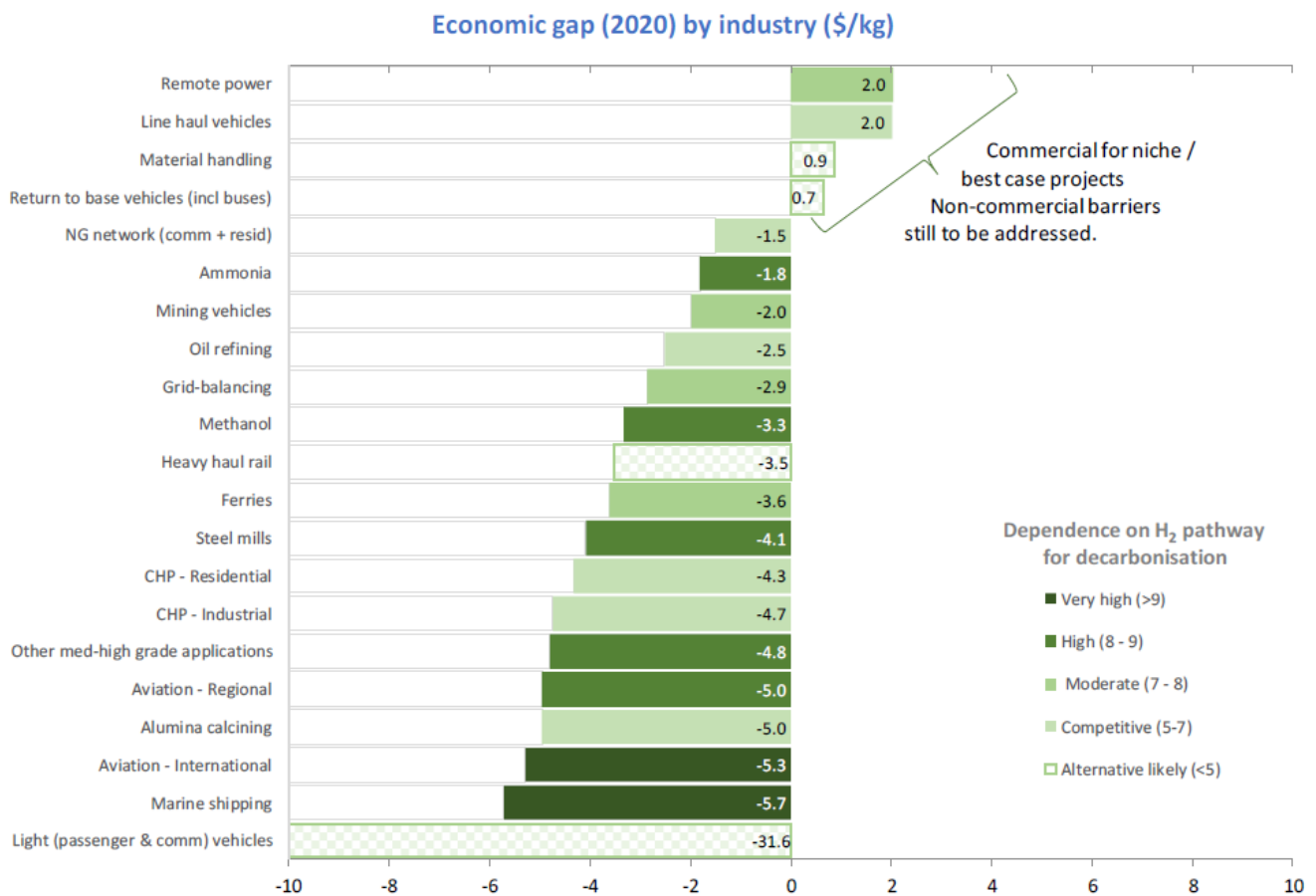


Figure 6: Economic gap (2020) by industry (\$/kg), SOURCE: Advisian (2021), page 12.

While the analytical approaches of Advisian (in Figure 6) and the Energy Transitions Commission (in Figure 5) are different, we can see the conclusions are not. The darker green applications from Advisian's analysis are the same sectors as the 'higher confidence' applications from the Energy Transitions Commission. The readiness assessments of the applications are also well aligned.

The AHC is of the view that in the short to medium term it is worth prioritising funding for applications that are more dependent on hydrogen for decarbonisation and have a medium economic gap. If we can close the economic gap (and technology and knowledge gaps in some cases) for applications like ammonia production and heavy transport, we start to see the new hydrogen domestic industry take shape. Further, if we can drive large sources of demand, which again could be ammonia, as well as steel and blending into natural gas networks, we start to see scale and reduced costs.

As noted by the Grattan Institute:

risk will be lower where another competitive advantage can be identified (for example Australia's proximity to iron ore, abundant cheap renewable electricity, and proximity to growing Asian markets create a competitive advantage for steel). This is why government assistance to bridge the risk gap should focus on industries where Australia has an advantage – it lessens the call on government funds and develops industries that contribute to ongoing growth.⁶⁷

Consistent with this, we do need to start thinking about and planning for applications like shipping and aviation that have a high dependence on hydrogen, but these are also applications that are likely to be progressed by other countries, such as for ship building. As a start for Australia, driving scale in fuels that might be used for shipping and aviation (such as ammonia, methanol and synfuels) will have a positive impact. This is all the more important because the world will be looking for the hydrogen, ammonia and methanol to meet international climate goals.⁶⁸

Focussing on building scale and capability on the sectors and applications that will be hard to abate without hydrogen is the best 'no regrets' approach that can be taken in an uncertain environment. This approach should also actively build room for other applications that might value hydrogen at lower prices and with an established (and shared) infrastructure. This is where hubs (and clusters, to use the Australian version, which is about communities of practice) also have an important role to drive collaboration and shared benefit.

The remaining sections of this paper identify the following applications as requiring immediate support:

- hydrogen blending into natural gas networks;
- heavy road transport; and
- manufacturing iron/steel, ammonia, methanol and aluminium/alumina.

Recommendation 3: Prioritise hard to abate and scalable demand sources

We recommend that the Australian Government prioritises project funding to grow demand for hydrogen in the applications that are more likely to require clean hydrogen to decarbonise, and more likely to achieve large scale. Ideally these should demonstrate an ability to open the market to other applications, through knowledge/technology sharing, geographic proximity, and/or cost reduction. Recommendations 6 and 8 provide further information on these priorities.

⁶⁷ Wood et al. (2021b), page 39.

⁶⁸ Energy Transitions Commission (2020), page 11.

References

- Advisian (2021) *Australian hydrogen market study: Sector analysis summary*, 24 May, for the Clean Energy Finance Corporation, <https://www.cefc.com.au/media/nhnhwixu/australian-hydrogen-market-study.pdf>.
- AGIG (2020) Five year plan for the Dampier to Bunbury Natural Gas Pipeline, January, <https://www.agig.com.au/-/media/files/agig/stakeholder-engagement/agig-dbnqp-final-plan-2021-2025.pdf>
- Ardent Underground Hydrogen Storage (n.d.) website accessed 9 September 2021, <https://ardentunderground.com/>.
- ARENA (2021) 'Over \$100 million to build Australia's first large-scale hydrogen plants', media release, 5 May, <https://arena.gov.au/news/over-100-million-to-build-australias-first-large-scale-hydrogen-plants/>.
- ARUP (2019) *Australian Hydrogen Hubs Study: Technical study*, Issue 2, prepared for the COAG Energy Council Hydrogen Working Group, November, <https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy>.
- Australian Government Department of Industry, Science, Energy and Resources (n.d.) 'Electricity generation', website accessed 12 September 2021, <https://www.energy.gov.au/data/electricity-generation#:~:text=Total%20electricity%20generation%20in%20Australia%20in%202019%20was,including%20coal%20%2856%25%29%2C%20gas%20%2821%25%29%20and%20oil%20%282%25%29>.
- Australian Government (2021) 'Future hydrogen industry to create jobs, lower emissions and boost regional Australia', joint media release from The Hon. Scott Morrison MP, Prime Minister and The Hon. Angus Taylor MP, Minister for Energy and Emissions Reduction, 20 September, <https://www.minister.industry.gov.au/ministers/taylor/media-releases/future-hydrogen-industry-create-jobs-lower-emissions-and-boost-regional-australia>.
- BlueScope Steel (2021) *BlueScope submission to the Standing Committee on State Development's Inquiry into the development of a hydrogen industry in NSW*, 26 February, <https://www.parliament.nsw.gov.au/committees/inquiries/Pages/inquiry-details.aspx?pk=2643#tab-submissions>.
- BNEF (2020) *Hydrogen Economy Outlook: key messages*, March 30, <https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf>
- Coady, D., Parry, I., Le, N-P., and B. Shang (2019) *Global Fossil Fuel Subsidies Remain Large: An Update Based on Country-Level Estimates*, IMF Working Paper, Fiscal Affairs Department, WP/19/89, May, <https://www.imf.org/en/Publications/WP/Issues/2019/05/02/Global-Fossil-Fuel-Subsidies-Remain-Large-An-Update-Based-on-Country-Level-Estimates-46509>.
- COAG (2019) *Australia's National Hydrogen Strategy*, November, <https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf>.
- De Atholia, T., Flannigan, G. and S. Lai (2020) 'Renewable energy investment in Australia', Reserve Bank of Australia <https://www.rba.gov.au/publications/bulletin/2020/mar/pdf/renewable-energy-investment-in-australia.pdf>.
- Energy Transitions Commission (2020) *The First Wave: A blueprint for commercial-scale zero-emission shipping pilots*, prepared for the Getting to Zero Coalition, version 1, 11 November, <https://www.globalmaritimeforum.org/content/2020/11/The-First-Wave-%E2%80%93-A-blueprint-for-commercial-scale-zero-emission-shipping-pilots.pdf>.
- Energy Transitions Commission (2021) *Making the Hydrogen Economy Possible – Accelerating Clean Hydrogen in an Electrified Economy*, the Making Mission Possible Series, April, version 1.1, <https://www.energy-transitions.org/publications/making-clean-hydrogen-possible/>.
- European Commission (2020) *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: A hydrogen strategy for a climate-neutral Europe*, Brussels, 8 July, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.
- European Commission (n.d.) 'Innovation Fund', website accessed August 2021, https://ec.europa.eu/clima/policies/innovation-fund_en.
- Finkel, A. (2021) 'Getting to Net Zero: Australia's energy transition', *Quarterly Essay*, QE81, March, Black Inc: Melbourne.
- Grubnic, P. (2021) *A Short Report on Hydrogen Industry Policy Initiatives and the Status of Hydrogen Projects in Australia*, May, <https://research.csiro.au/hyresource/wp-content/uploads/sites/378/2021/05/Short-Report-on-Hydrogen-Policy-and-Projects-Status-in-Australia-May-2021-v0.pdf>.
- Hartmann, I. (2021) Untitled, *Infrastructure Magazine*, <https://infrastructuremagazine.com.au/2021/08/04/townsville-ports-channel-upgrade-project-milestone/>.

Hatch (2021) *Case study for decarbonising Western Australia's iron ore sector using hydrogen*, prepared for the Green Hydrogen Consortium, August.

Hydrogen Council (2017) *Hydrogen Scaling Up: A Sustainable Pathway for the Global Energy Transition*, November, <https://hydrogencouncil.com/en/study-hydrogen-scaling-up/>.

Hydrogen Council (2020) *Path to hydrogen competitiveness: a cost perspective*, <https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective> .

Hydrogen Energy Research Centre (n.d.) UNSW Sydney website accessed 29 Aug 2021, <https://www.herc.unsw.edu.au/programs/about-hydrogen>.

HyResource (n.d.) CSIRO website, accessed 29 August 2021, <https://research.csiro.au/hyresource/hydrogen-park-south-australia/>.

International Energy Agency (2021) *Net Zero by 2050: A Roadmap for the Global Energy Sector*, May, <https://www.iea.org/data-and-statistics/data-product/net-zero-by-2050-scenario>.

Ivenenko, I. (2021) 'What Is The Role Of Hydrogen In Biden's Infrastructure Plan?', *Forbes*, 5 August, <https://www.forbes.com/sites/forbestechcouncil/2021/08/05/what-is-the-role-of-hydrogen-in-bidens-infrastructure-plan/?sh=381dad372bd3>.

Milne (2021) 'Yara plans massive Pilbara green ammonia plant by 2030', 30 June, *Boiling Cold*, <https://www.boilingcold.com.au/yara-plans-massive-pilbara-green-ammonia-plant-by-2030/>.

NSW Department of Planning, Industry and Environment (2020) *NSW Electricity Infrastructure Roadmap: Building an Energy Superpower*, Overview, November, https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20Overview_1.pdf.

Reid, S. and Cann, G. (2016) *The good, the bad and the ugly: The changing face of Australia's LNG production*, Deloitte, <https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/gx-australian-Ing-production.html>.

Smith, A. (2021) 'Biden administration and industry alike see hydrogen as "Swiss Army knife" for eliminating emissions', *Washington Examiner*, 15 April, <https://www.washingtonexaminer.com/policy/energy/biden-administration-and-industry-alike-see-hydrogen-as-swiss-army-knife-for-eliminating-emissions>.

Solgen (n.d) Solgen Energy Group website, accessed 29 August 2021, <https://solgen.com.au/solar-power-plant-cost/>.

Weichenhain, U., Kaufmann, M., Benz, A., and G. Matute Gomez (2021) *Hydrogen Valleys: Insights into the emerging hydrogen economies around the world*, prepared by Roland Berger and Inycom for the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU), July, https://www.fch.europa.eu/sites/default/files/documents/20210527_Hydrogen_Valleys_final_ONLINE.pdf.

Wood, T., Reeve, A., and Ha, J. (2021b). *Towards net zero: Practical policies to reduce industrial emissions*, Grattan Institute, Report No. 2021-10, August, <https://grattan.edu.au/report/towards-net-zero-practical-policies-to-reduce-industrial-emissions/>.



**Accelerate
market growth
through
repurposing
natural gas
assets where
economic**

3

Natural gas emits less carbon than coal when combusted, and it is used in significant quantities across the country for a range of applications.

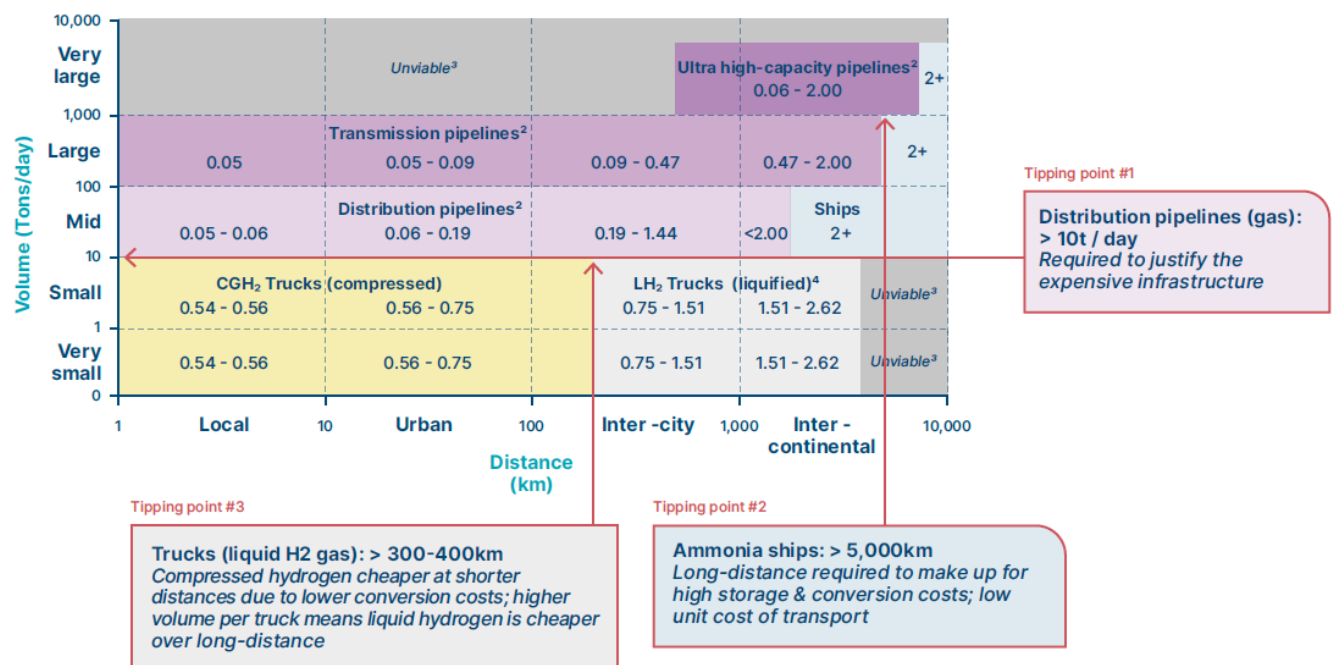
However, political decisions are starting to be made on the future of natural gas in a decarbonised world. These decisions may unintentionally stifle or delay the benefits from both the hydrogen industry and from more coordinated planning across gas and electricity.

Hydrogen (and biogas) can be used in gas transmission and distribution pipelines, initially to decarbonise natural gas use, and in the longer term to replace natural gas entirely. The future for hydrogen (as another gas) may also be reliant on hydrogen pipelines for transportation. Hydrogen allows 'sector coupling', which allows planners to choose between electricity and gas infrastructure for different needs,

across greenfield and existing assets. The economic efficiency that this brings will improve cost (and consumer price) outcomes. It will also reduce the risk of stranded assets in the gas infrastructure and promote energy resilience through diversity.

Figure 3 from the previous chapter showed lowest cost transportation options from a recent Energy Transitions Commission report. We have repeated the figure below to reiterate how important gas distribution and transmission pipelines will be for moving hydrogen in larger volumes (shown here as more than 10 tonnes a day). This provides a clear illustration of how different transport options suit different needs.

Lowest cost form of hydrogen transportation¹ based on volume and distance
\$/kg H₂



NOTE: ¹ Including conversion and storage; ² Assumes salt cavern storage for pipelines; ³ Ammonia assumed unsuitable at small scale due to its toxicity; ⁴ While LOHC (liquid organic hydrogen carrier) is cheaper than liquid hydrogen for long distance trucking, it is unlikely to be used as it is not commercially developed.

SOURCE: Adapted from BloombergNEF (2019), *Hydrogen: The Economics of Transport & Delivery*, Guidehouse (2020), *European Hydrogen backbone*

Figure 3: Analysis of lowest costs for hydrogen transport. SOURCE: Energy Transitions Commission (2021), page 38.



The tipping points noted here may not always be a precise reflection of Australia's circumstances, but we note there is some consistency in the pipeline transportation tipping point. In its work for the Clean Energy Finance Corporation, Advisian⁶⁹ found that transporting hydrogen via pipelines would result in a lower final cost for delivered hydrogen where a hydrogen electrolyser project is around 20MW capacity. Using our internal calculations, this is roughly equivalent to the 10 tonne/day tipping point in Figure 3.⁷⁰

Advisian also notes that other factors should be considered when comparing the 'moving the electrons' and 'moving the molecules' options⁷¹ in producing and delivering hydrogen, such as interfaces with the National Electricity Market and uncertainties regarding transmission use-of-system (TUoS) fees. Further, while the move molecules

approach "generally incurs higher initial capital costs, the resulting pipeline infrastructure can provide storage functions through linepack and it may be possible to realise additional revenue from third party agreements to move hydrogen".⁷²

Building on the concept of pipelines providing value through linepack storage, the Energy Transitions Commission analysis shows that moving molecules is preferred to moving electrons where there is no storage close to the end use location. If there is low-cost hydrogen storage close to the end use location the choice between moving electrons and moving molecules is less definitive for greenfield transmission pipelines (depending on the cost of the electricity transmission lines), but overall "retrofitted natural gas transmission pipelines will offer the lowest transportation costs".⁷³

69 Advisian (2021), page 16.

70 Hydrogen production is around 3,369 tonnes a year, which, if we assume a theoretical 100 per cent capacity for a 20MW electrolyser, is close to the 3650 tonnes a year from the Energy Transitions Commission.

71 See page 22 for our discussion of this.

72 Advisian (2021), page 10.

73 Energy Transitions Commission (2021), page 40.

3.1 Recommendations

Decisions on future hydrogen infrastructure and project locations should consider the existing natural gas infrastructure and the degree to which it might be repurposed for hydrogen.

It is vital to avoid making decisions that unnecessarily lock out hydrogen applications or have the effect of unnecessarily delaying the scale required for Australia to compete for hydrogen exports (or reach net zero). However, this should not be at any cost: the effects on customer prices must also be understood and built into planning.

3.1.1 Co-optimize assets with end user prices in mind

Gas pipelines are long-lived (can be 80 years old), are already in the ground, and their costs are shared between current and future gas users. Assets are depreciated over their useful (that is, economic) lives, with the depreciation cost apportioned over time.

As pointed out by the Australian Energy Regulator (AER):

The longer an asset stays in use, the lower the depreciation cost born by customers each year. Uncertain future utilisation of the pipelines may put pressure on prices by shortening the economic lives of network investments.⁷⁴

The AER discusses a case study that it is worth reproducing here in full, as follows.

Case study: Evoenergy

In response to the ACT Government's policy decision to phase out gas connections in the ACT and promote electric alternatives to gas, we accepted Evoenergy's proposal to shorten the asset lives for its new pipeline assets in its 2021-26 access arrangement. As noted earlier, shortening asset lives has the effect of increasing the depreciation cost in any given year, which, other things being equal, will increase the pipeline's efficient cost and access prices. This decision was taken to reduce the risk that these new assets may become stranded (that is, they are no longer capable of making an economic return, despite not being fully depreciated) and to protect customers from significant price increases resulting from a declining customer base in the future. In particular, we were concerned about intergenerational equity for gas consumers, as well as the lesser ability of vulnerable consumers to switch away from gas.

Falling gas demand and our decision to allow accelerated depreciation of gas assets has put pressure on gas prices in the ACT. In Evoenergy's case, operational costs and asset maintenance costs will not fall in line with demand, leaving fewer customers to share the costs. While there are some offsets from lower investment requirements, the overall impact of our Evoenergy decision is estimated to increase residential and small business consumer bills by 3.2 per cent and 3.5 per cent respectively over five years.

As customers switch from gas to electricity, significant new investment in Evoenergy's electricity network is required. The extent of these investments, and the extent of offsetting downward pressure on prices from increased electricity demand is not yet clear. Overall though there is a risk that the switch from gas to electricity will put pressure on both gas and electricity prices. Further, the pace of the transfer of gas demand to electricity creates reliability risk for the electricity network if not carefully managed.⁷⁵

This case neatly demonstrates some unintended consequences of the energy transition and the need for careful planning across both the gas and electricity sectors to support energy affordability for consumers.

⁷⁴ Australian Energy Regulator (2021), page 2.

⁷⁵ Ibid.

Recommendation 4: Build sector coupling into planning

We recommend the Australian Government explicitly tasks the planning body under Recommendation 1 to address how the gas and electricity infrastructure can be co-optimised for delivering lowest cost hydrogen to end consumers.

3.1.2 Blend hydrogen into the natural gas networks

Regardless of any future ambitions to repurpose the gas distribution and transmission networks to transport and store hydrogen, the gas networks can provide important offtake support to the emerging hydrogen industry. This can also occur without significant additional investment in infrastructure: experts agree⁷⁶ that despite the difference between the physical properties of natural gas and hydrogen, hydrogen can be blended into the natural gas system up to a 10 per cent volume without any impact on the pipeline materials, gas safety or end uses.

The hydrogen required for a 10 per cent blend for NSW, Queensland, South Australia and Victoria has been estimated as 71,500 tonnes,⁷⁷ which (even with only some jurisdictions included) is already 10 per cent of Deloitte's 2030 'targeted deployment' scenario for the National Hydrogen Strategy.⁷⁸

A project to blend hydrogen into the natural gas distribution networks has already commenced,⁷⁹ with 15 further projects in various stages of development.⁸⁰ There is also a research and testing programme

across the country⁸¹ to establish the science on higher percentages of hydrogen and address potential consumer experiences.

However, explicit government policy support is required, as the gas networks cannot effectively make rate cases to the economic regulator without policy endorsement for expenditure. The most valuable support at this stage is for the Australian Government to address targets for hydrogen blending within a broader planning framework under Recommendation 1.

In addition to the offtake value, we consider that the adoption of an initial 10 per cent target for blending hydrogen into the natural gas networks could also have the benefit of lowering the carbon intensity of homes and business connected to the network while allowing these entities to defer potentially significant investment decisions until connected appliances reach the end of their useful life. Hydrogen blending can also enable additional planning to be undertaken to further determine the economic and social ramifications of electrification or transition to higher concentrations of hydrogen (e.g., the ability of low income households to transition to new energy sources).

Recommendation 5: Blend hydrogen into natural gas to create demand

We recommend the Australian Government sets a target of 10 per cent hydrogen by volume in the natural gas networks, by 2030.

76 For example, GPA Engineering (2019), page 2. See also COAG Energy Council (2019), page 42.

77 Australian Gas Infrastructure Group (AGIG), Jemena Gas Networks (JGN), AusNet Services (AusNet), and EvoEnergy (2020).

78 See Table 2 in chapter 2 of this report.

79 In May 2021, AGIG has started delivering a 5 per cent blend to 700 customers in Mitchell Park, a suburb in South Australia.

80 Number from a search of HyResource (n.d.) for gas network projects.

81 See for example, the work of the Future Fuels Cooperative Research Centre (n.d.), which partners with industry and researchers to undertake research to enable the decarbonisation of Australia's energy networks.

References

Advisian (2021) *Australian hydrogen market study: Sector analysis summary*, 24 May, for the Clean Energy Finance Corporation, <https://www.cefc.com.au/media/nhnhwixu/australian-hydrogen-market-study.pdf>.

Australian Gas Infrastructure Group (AGIG), Jemena Gas Networks (JGN), AusNet Services (AusNet), and EvoEnergy (2020) *Expression of Interest – Achieving 10% Renewable Hydrogen in Australian Gas Networks*, <https://www.agig.com.au/media/files/agig/expression-of-interest--achieving-10-renewable-hydrogen-in-australian-gas-networks.pdf>.

Australian Energy Regulator (2021) *AER Submission: Victoria's Gas Substitution Roadmap Consultation Paper*, AER212808, 2 August, <https://www.aer.gov.au/publications/submissions/victorias-gas-substitution-roadmap-consultation-paper>.

COAG Energy Council (2019) *Australia's national hydrogen strategy*, November, <https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf>

Energy Transitions Commission (2021) *Making the Hydrogen Economy Possible – Accelerating Clean Hydrogen in an Electrified Economy*, the Making Mission Possible Series, April, version 1.1, <https://www.energy-transitions.org/publications/making-clean-hydrogen-possible/>.

Future Futures CRC (n.d.) website accessed 29 August 2021, <https://www.futurefuelscrc.com/about/>.

GPA Engineering (2019) *Hydrogen in the Gas Distribution Networks*, Kickstart Project, prepared for South Australian Department for Energy and Mining (SA) and Future Fuels Cooperative Research Centre, GPA Document No: 19184-REP-001, <https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy>.

HyResource (n.d.) website accessed 26 August 2021, see <https://research.csiro.au/hyresource/projects/facilities/>.

Advance heavy road transport applications



Decarbonisation of Australia's transport sector is becoming increasingly urgent. Transport is Australia's second largest emitter, making up 19 per cent of current greenhouse emissions.

Of transport emissions in 2019, light vehicles were responsible for 62 per cent, and rigid and articulated trucks were responsible for 20 per cent emissions.⁸²

Clean hydrogen can usefully decarbonise transport and can already compete as a fuel with existing liquid fuels. In work for the Clean Energy Finance Corporation, Advisian notes “the comparatively high cost of liquid fuels supporting the transportation

sectors, yields a high relative competitiveness”.⁸³ This is also consistent with CSIRO's National Hydrogen Roadmap.⁸⁴

Transport applications also provide significant hydrogen offtake potential, which can help grow the hydrogen industry and have the advantages of having a public profile.

4.1 Hydrogen fuel cell vehicles play a vital role

Experts acknowledge that fuel cell electric vehicles (FCEVs) will work alongside battery electric vehicles (BEVs). As noted in the National Hydrogen Strategy, hydrogen fuel carries significantly more energy than the equivalent weight of batteries. This is particularly useful for buses and trucks that must travel long distances, or where battery weight compromises effective payload. It is also suitable for commercial use, where effective range and recharging/refuelling times affect the bottom line.⁸⁵

FCEVs have advantages over BEVs for heavy (line haul) transport and can be expected to comprise the bulk of future trucks for road freight. This has been confirmed by Advisian for the Clean Energy Finance Corporation,⁸⁶ where the line haul vehicle sector is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 6 out of 10.

For smaller truck sizes and buses, the duty cycle/route associated with vehicle use will likely dictate which technology reflects a better investment. Advisian found that the return to base (often rigid truck) vehicle sector has a low dependence on hydrogen for

decarbonisation (rating 4 out of 10), with BEVs likely to be “more important” and to potentially have a cost advantage for shorter routes.⁸⁷

As an example, analysis for a US transit company on the most cost-effective approach for a particular bus route found that the 12-year lifecycle cost favoured FCEVs over BEVs.⁸⁸ The main reason for this was that the route in question was long enough to require coverage by 1.5 BEV buses but only 1 FCEV bus. The route required a fleet of 34 BEV buses (at US\$60.5 million total cost of ownership)⁸⁹ compared with 20 FCEV buses to cover the same passenger outcomes (at a total cost of US\$47.5 million).

Hydrogen provides benefit for lighter vehicles as well; these are in fact on our roads right now. An FCEV can be filled from a relatively familiar looking bowser in just a few minutes. This will allow users to operate FCEVs in a similar manner to how they currently operate an internal combustion engine vehicle. This is of benefit to those who prefer the current mode of refuelling, including people without off-street parking that allows for overnight recharging.

82 Wood et al. (2021a), page 29.

83 Advisian (2021), page 43.

84 Bruce, Temminghoff, Hayward, Schmidt, Munnings, Palfreyman and Hartley (2018).

85 See California Fuel Cell Partnership (2021), page 9.

86 Advisian (2021), page 43. See also Shell (2021), page 10.

87 Ibid., page 55.

88 Foothill Transit (2020).

89 Covering capital costs of buses and refuelling infrastructure, 12 years of fuel and mid-life maintenance.

4.2 Diesel replacement is the first step

CSIRO⁹⁰ and other observers have noted that hydrogen has reached price parity with diesel, and so diesel presents a clear near-term opportunity for hydrogen sector development. Replacing diesel is also desirable from a public health perspective. This applies to all uses of diesel, including remote area power systems and trains.

Looking at road transport opportunities in diesel replacement, ABS data⁹¹ in Table 3 shows that trucks and buses are predominantly fuelled by diesel. In 2020 there were over 600,000 diesel trucks (rigid and prime movers/articulated) in circulation.

Vehicle type	Total fleet	Number of vehicles that use diesel	% of total that use diesel
Passenger vehicles	14,679,246	1,948,299	13%
Light commercial	3,407,014	2,340,494	69%
Rigid trucks (inner city deliveries, small volume freight)	535,513	515,871	96%
Articulated trucks (long haul, high volume freight)	105,139	104,009	99%
Buses	100,470	80,821	80%

Table 3: Diesel road vehicles in Australia in 2020, with source data from ABS (2020)

The need for road transport will only increase in future years – in fact we have estimated that future requirements in each category (across all current fuel types, based on past growth rates) might be close to double by 2050.

Looking at trucks only, this could mean 200,000 articulated trucks on the roads. Given the articulated truck category is considered to have a moderate dependence on hydrogen for decarbonisation, we can see this as possible minimum case for hydrogen planning in road transport.

For the rigid truck category, even if BEVs will be better for most duty cycles/routes, a smaller share of one million future rigid trucks as FCEVs is still a significant volume.



90 Bruce et al. (2018).

91 Australian Bureau of Statistics (2020).

4.3 Barriers to hydrogen in transport

In general, transport operators and vehicle manufacturers see the carbon reduction potential in using hydrogen, but many cannot yet see the business case. This is for a combination of reasons, including:

- **No refuelling infrastructure:** the demand for FCEVs will not grow until an adequate refuelling network exists; however, investment in refuelling infrastructure is difficult to justify for the private sector in the absence of a significant vehicle fleet to use it. Development of refuelling infrastructure and vehicle supply thus need to largely occur in tandem, with flexibility built into planning.
- **Insufficient market demand to draw through vehicle supply:** vehicle manufacturers report that they are waiting for more certainty of demand to produce vehicles at scale.⁹² The lack of demand certainty is largely a result of a lack of clear policy around emissions or fuel efficiency standards, with some automakers reported as saying that this is why they do not send their lowest emission vehicles to Australia.⁹³ The fact that we are a right-hand drive market is unrelated, but this further amplifies the problem of low supply; we rely on technology designed for the UK and Japan to develop first.
- **No market data about the full lifecycle cost of a hydrogen vehicle:** it is difficult for procurement agencies and fleet operators to know how to consider total costs of ownership (or return on investment) given the industry is still in development and that vehicles have long lives. Adoption may be slow (under 5 per cent in 2030) until early commercial pilots provide commercial operators with strong validation of a fully commercial product and business model.
- **No second-hand market:** first owners want to be able to resell vehicles at good prices.⁹⁴ This is an issue even today with diesel vehicles as there is no ready local disposal route for right-hand drive vehicles in the region.

- **Costly inconsistency with overseas vehicle standards:** Australia imports over 90 per cent of its medium trucks from Japan, and around two thirds of heavy trucks from Japan or Europe. However, Australian design standards are different from all overseas markets: Australian trucks cannot be wider than 2.5m, which is misaligned with Europe (2.55m) and North America (2.6m). Vehicles based on EU or US market designs are around 60 per cent of new heavy trucks, and the cost to redesign for our market is estimated at A\$15-\$30 million a year.⁹⁵ Future BEV and FCEV trucks will be even more costly/difficult to redesign. We note that the Australian Government is currently addressing this issue.⁹⁶

BEVs face some of the same challenges, but the need for public refuelling infrastructure for FCEVs is greater than recharging for BEVs, and BEVs have had a head start on vehicle supply.

A further challenge is how vehicle availability and lifecycles align (or misalign) with procurement processes. While fleet procurement allows purchase in bulk – thus enhancing the business case for vehicle purchasers – this is also a challenge.

For example, buses are a promising segment for strong adoption, with centralised fleets owned by public agencies. However, procurement occurs only periodically, near the end of the operational lifetime of an existing fleet, which is typically 15-20 years. Contracts for these extended timeframes still tend to value lowest cost, which advantages existing diesel vehicles and locks them in for years. There are also sometimes many contracts, which adds unwanted complexity; for example, Queensland has 18 contracts for regional buses only, and NSW has 15 contracts for its bus network.

These issues do not encourage private sector operators to take on the risk of new technologies.

⁹² This is regularly reported to AHC, see also Shell (2021), page 7.

⁹³ Wood et al. (2021a), page 17.

⁹⁴ Shell (2021), page 7.

⁹⁵ Department of Infrastructure, Transport, Regional Development and Communications (2021), page 5.

⁹⁶ Ibid.

4.4 Recommendations

There is a need for clear public policy support for FCEVs.

First, the transport sector is complex, with:

- many vehicle types used over different uses, duty cycles and routes;
- many different owners, stakeholders and contractual parties,⁹⁷ each with their own purchasing criteria and timeframes; and
- long lived equipment (including vehicles); and
- significant infrastructure requirements.

When we combine these characteristics with the fact that vehicle design and production is an expensive and multi-year process (usually more than seven years for a commercial vehicle), we can see that transitioning transport to BEVs and FCEVs will require coordination and planning if we are to get to scale.

Amplifying this need is the cost of not acting. The Grattan Institute has shown that slow uptake of zero emissions trucks could mean most of the fleet still uses diesel in 2050.⁹⁸ Further, the Truck Industry Council notes that almost 42 per cent of the nation's truck fleet above 4.5t gross vehicle mass (GVM)⁹⁹ was manufactured before 2003 when basic, or no, exhaust emission regulation existed.¹⁰⁰

This is clearly problematic given that trucks represent around 4 per cent of total Australian carbon emissions (based on 2019/2020 data).

4.4.1 Fund key transport projects in the national interest

Given the urgent need to tackle decarbonising transport, and the important role of hydrogen within this task, it is vital that the Australian Government helps to close the investment gap for hydrogen in transport applications.

There are also knowledge gaps which affect the investment gap. As noted by Advisian,¹⁰¹ manufacturers need to provide supply to create fleet sizes that justify the (unclear) potential infrastructure spend, and purchasers need proof of fuel consumption and operational cost benefits over the life of a vehicle (also currently unclear).

Further, it is important to obtain data about vehicle performance and other issues in Australian conditions:

The heavy vehicle sector in Australia is subject to subtly different influences compared to other countries around the world. The key differences that might influence our selection and rate of uptake of low emission vehicles are:

- *relatively long vehicle life;*
- *less rail competition;*
- *exposure to hot, low humidity environments for sustained periods;*
- *minimal exposure to freezing / salt laden conditions; and*
- *long stringy power grid with limited capacity to accommodate heavy electrical demand variation.*¹⁰²

97 Shell (2021, page 18) notes that globally there are around three million companies in road freight. "Many of them are small or very small businesses, making the sector highly fragmented and competitive with low profit margins. These companies are responsible for transporting almost 22 trillion tonne-kilometres of cargo each year. In other words, it is roughly equivalent to a large truck with 20 tonnes of cargo travelling around the equator 30 million times".

98 This is based on trucks being retired due to age only. Wood et al. (2021a, page 31) provide an example where sales of zero-emissions trucks reach 1 cent by 2030, 50 per cent by 2040 and 100 per cent by 2050, without any policy to cause diesel trucks to retire early.

99 These are heavy trucks, which around 30 per cent of all rigid and articulated trucks (calculated from Bureau of Infrastructure, Transport and Regional Economics, 2019, page 18).

100 Truck Industry Council (2019), page 11.

101 Advisian (2021), page 52.

102 Ibid., page 50.

This means that there needs to be a range of vehicle trials in Australia to both help close the investment gap by getting projects established, and to provide the necessary data for subsequent investment. This would appear to be best achieved with a few significant projects that:

- provide for heavy transport (line haul) in the first instance, with room to scale up;
- also facilitate lighter transport, with room to scale up; and
- are sited in major freight corridors and connected to ports via hubs.

In its work for the National Hydrogen Strategy in 2019, Aurecon¹⁰³ recommended that trials should be more than A\$5 million, and that investment within the A\$20-\$100 million range would allow for a 'substantial-enough' size of fleet.

Aurecon provided analysis of a range of different trial options, including cars, buses, materials handling

and different sized trucks. Of the 13 options, Aurecon positively ranked the following:

- a trial of around 9 buses (said to be a medium sized fleet) for metropolitan routes (3.8/5);
- an integrated pilot of a larger 35 vehicle bus fleet for 'park and ride' use across three commuter suburbs, with three refuelling stations (3.5/5);
- an integrated pilot for road freight, trialling around 90 vehicles (3.2/5).¹⁰⁴

Using a combination of Aurecon's suggested fleet sizes for bus and truck trials, industry estimates, and assuming costs based on total cost of ownership estimates from Advisian, we suggest some preliminary costings in Table 4 below. The costs are total cost of ownership across 12 years and include access to refuelling infrastructure, and operations and maintenance.¹⁰⁵ We have rounded up some of the Aurecon fleet numbers to the nearest 20, to match the Advisian figure of 20 vehicles per refuelling station.

Vehicle	Approximate fleet size	Indicative cost (2021)
Light truck (50,000 km/yr) ¹⁰⁶	Medium – 10	A\$6.3 million
	Large – 40	A\$25.2 million
Bus (100,000 km/yr) ¹⁰⁷	Medium – 10	A\$12 million
	Large – 40	A\$44 million
Heavy truck (200,000 km/yr) ¹⁰⁸	Medium – 20	A\$38.4 million
	Large – 100	A\$192 million

Table 4: Indicative total costs of ownership for near term FCEV fleets

103 Aurecon (2019), page 10.

104 These hypothetical projects were considered to highly satisfy most or all of the criteria Aurecon set out for success, as did a mining truck trial and a large passenger fleet trial.

105 A refuelling station costs around US\$1.9 million (Department of Energy, 2020, page 2).

106 Using Advisian's assumptions for light trucks, which result in a total cost of ownership of A\$1.08 for a vehicle travelling 50,000 km/year.

107 We note an Australian bus would usually travel 80,000 to 100,000 km a year, for a bus that is out all day. A whole of fleet average is closer to 55,000 km/yr. Bus costs are also higher than for trucks, given extra requirements for passenger fit outs; for example, the hydrogen city bus which sold to Auckland transport in 2021 was NZ\$1,175,000.

108 Using Advisian's assumptions for heavy trucks, which result in a total cost of ownership of A\$0.8 for a vehicle travelling 200,000 km/year.

The figures in Table 4 are dependent on a range of assumptions, but they provide a useful indication of the quantum of investment required. For example, we can see that a heavy truck trial for a medium sized fleet could be around A\$40 million, and a much larger fleet may be closer to A\$200 million.

Looking at a selection of global truck trials, we can see these figures are not unreasonable. Table 5 shows four examples, with a range of sizes and announced costs. While it is not possible at this stage to realistically compare costs (we don't know the basis for the overseas costings) we can see that the indicative costs above fall within the parameters of what has already been announced to date.

Project	Description	Proponents	Announced cost
Shore-to-Store (S2S) project ¹⁰⁹ USA	<p>Announced June 2021, a 12-month demonstration of 10 FCEV heavy duty (Class 8) trucks and two refuelling stations, also including two battery-electric yard tractors, and two battery-electric forklifts.</p> <p>Designed to assess the operational and technical feasibility of the vehicles in a heavy-duty setting, as well as to expand infrastructure to support hydrogen throughout California.</p> <p>Vehicles' duty cycles will consist of local pickup and delivery and drayage near the Port of Los Angeles and short regional haul applications.</p>	Port of Los Angeles with more than a dozen public and private sector partners	<p>US\$82.5 million (A\$112 million)</p> <p>The California Air Resources Board (CARB) grant of US\$41.1 million.</p> <p>Project partners are contributing the remaining US\$41.4 million in financial and in-kind support.</p>
HECTOR (Hydrogen Waste Collection Vehicles in North West Europe) ¹¹⁰	<p>EU-funded project that deploys and tests seven fuel cell garbage trucks in seven cities across North West Europe. Range from container trucks to front arm loading trucks, both left- and right-hand drive.</p> <p>Approved in January 2019 and will run for 4 years. Pilot sites will cover a wide range of operational contexts but normal operating conditions. Some trucks are in city centres, others in rural areas. Some collect municipal waste on a fixed schedule, others collect industrial waste on a flexible schedule.</p> <p>Using existing hydrogen refuelling infrastructure and ideally green hydrogen.</p>	Coordinated by the European association HyER (Hydrogen Fuel Cells and Electro-Mobility in European Regions) Aberdeen City Council Municipality of Groningen SUEZ recycling and recovery Netherlands	<p>€9.28 million (A\$14.9 million)</p> <p>The EU is funding €5.57 million of this.</p>
Fast-Track Fuel Cell Truck project ¹¹¹ USA	<p>Deploy five plug-in hybrid fuel cell-electric heavy duty (Class 8) trucks in Southern California, from 2018 to 2020.</p> <p>Designed to validate the commercial viability of heavy duty zero-emissions fuel cell-electric hybrid trucks operating in demanding, real-world applications.</p> <p>Trucks supported by charging and mobile hydrogen fuelling infrastructure at the Port of Los Angeles and in the San Diego region. The vehicles will be fuelled onsite from mobile tube-trailer and at public hydrogen stations.</p>	TransPower, TTSI, Frontier Energy, Center for Sustainable Energy, Cummins (Hydrogenics), Loop Energy, Peterbilt Motors and OneH2.	<p>US\$6.2 million (A\$8.5 million)</p> <p>California Air Resources Board (CARB): US\$5,081,478 Matching funds: UD\$1,139,950</p>

109 Port of Los Angeles (2021).

110 Interreg North-West Europe (n.d.).

111 California Air Resources Board (2020).

Project	Description	Proponents	Announced cost
H2Haul ¹¹² Europe	<p>Develop and deploy 16 zero-emission long-haul heavy-duty fuel cell trucks at four sites (Belgium, France, Germany and Switzerland).</p> <p>Began in 2019 and will run for five years.</p> <p>Intent is to drive the fuel cell trucks for more than one million kilometres during normal commercial operations, also to develop the business case for the further deployment of heavy-duty fuel cell trucks.</p> <p>Also new high-capacity hydrogen refuelling stations.</p>	15 industry partners	€12 million from FCH JU¹¹³ (A\$19.2 million)

Table 5: Trial FCEV truck projects

There is also the question of location, and whether there are better refuelling station options for various transportation corridors. In work for the National Hydrogen Strategy, the Bureau of Infrastructure, Transport and Regional Economics (BITRE)¹¹⁴ recommends locations for consideration for initial hydrogen refuelling station deployment to service the Sydney, Melbourne and Brisbane inter-capital freight corridors (both directions). Table 6 provides some detail about these routes and freight volumes.

Recommended freight corridor	Distance	Tonnes in 2013-14	Trips per day (2013-14)
Sydney–Melbourne	850 km	8.7 million tonnes	1200
Sydney–Brisbane	917 km	4.1 million tonnes	556
Melbourne–Brisbane	1776 km	1.6 million tonnes	220

Table 6: BITRE freight corridor recommendations, with key facts

BITRE notes that the overlap in the key urban freight centres involved in inter-capital freight will allow refuelling infrastructure to be used for multiple routes, including refuelling for port-based hydrogen-fuelled freight vehicle operations (potentially a back to base application).

112 H2Haul (n.d.)

113 It is not clear if this is total or only the FCH JU contribution. See Ruf, Baum, Zorn, Menzel and Rehberger (2020), page 32.

114 Bureau of Infrastructure, Transport and Regional Economics (2019), pages 4-5.

Recommendation 6: Trial heavy transport

We recommend that the Australian Government funds:

- At least two heavy vehicle trials of large fleets, at a minimum amount of A\$200 million each, focussed on heavily-trafficked truck routes (e.g. Sydney-Melbourne).
- At least three larger trials for lighter trucks for logistics near hydrogen centres, at A\$25 million each.
- At least two larger trials for bus routes near hydrogen centres, at A\$45 million each for 40 buses (or a combination of smaller and larger, at A\$12 million per small trial for 10 buses).

Funding would be drawn from the Net Zero Fund and should be aligned with funding from state/territory governments. Some of this work might be funded by the Future Fuels Fund, which we note has just under A\$50 million available after the first BEV round.¹¹⁵

Processes to commence these projects should start as soon as possible given that they will take time to implement; beyond the contracting process (which may take a year) there will be time required to procure the vehicles in sufficient numbers.

Use of funding to replace diesel should also extend to other means of transport – such as trains and ferries – as the business cases and demand for these evolve.

We note that in its work for the National Hydrogen Strategy, Aurecon¹¹⁶ also suggested that there was merit in an integrated pilot ‘Hydrogen Demonstration Zone’ of 3km with 375 passenger fleet vehicles and eight refuelling stations (3.5/5). This concept could have a place within a hydrogen hub, as discussed in Chapter 2.

4.4.2 Incentivise FCEV uptake through policy settings

Governments can provide the right signals by setting targets and reducing barriers to vehicle purchasing. They can help create the demand that will draw through private investment in vehicles and infrastructure. This will give certainty to manufacturers and investors in the early stages.

Policy settings that will create demand for FCEVs will need to value the public benefit of clean hydrogen relative to incumbent fuels. This needs to be undertaken as part of a well-considered and articulated economy-wide approach.

Set vehicle emissions standards

Carbon emissions standards for all vehicle types should be a priority to encourage the market.

Enforceable standards will send the right economic messages to vehicle manufacturers about the value of lower emissions vehicles in Australia and improve their internal business cases for sending vehicles here. The standards to be employed will need to be consistent with low-emission vehicles that are being mass-produced for larger markets.

It is also worth investigating a low carbon fuel standard that sets carbon intensity benchmarks for fuels, taking into account the emissions for lifecycle of the fuel.

Address tax settings

Tax settings can be amended to improve the business case for vehicle owners and operators. Examples include:

- Tax breaks or instant asset write-off on the purchase of hydrogen powered trucks, buses and

¹¹⁵ Taylor (2021).

¹¹⁶ Aurecon (2019), page 50.

trains.¹¹⁷ For example, the California Hybrid and Zero Emission Truck and Bus Voucher Incentive Project (HVIP) is a point-of-sale price reduction in the purchase cost of clean medium and heavy duty trucks. This is as much as US\$120,000 for electric prime movers.¹¹⁸

- Scrapping import duties on zero emissions vehicles (ZEVs), potentially saving consumers about 5 per cent of the upfront vehicle cost. These duties were originally created to protect Australian auto manufacturing and are no longer needed.¹¹⁹
- Exemption from luxury car tax, and for the states, removing the motor vehicle stamp duty for all zero-emissions vehicles, which would reduce the cost of new EVs in several states by 4-6.5 per cent, and help to stimulate the second-hand market for zero-emissions vehicles.¹²⁰

Set vehicle targets

Governments can also set vehicle targets. There is some precedent for this: both NSW and Victoria have announced targets for 50 per cent ZEVs by 2030, but they have not yet established a means of enforcement. AHC supports a 50 per cent zero emissions vehicle target for fleets of cars, buses and ancillary vehicles for 2030. This would include privately operated public transport fleets and government owned logistics providers.

The Grattan Institute¹²¹ suggests that ZEV sales targets are an alternative to the (more effective) policy of vehicle emissions standards. Grattan notes that this approach would need to be combined with a form of tradeable credit scheme (similar to the Large-scale

Renewable Energy Target), to provide for vehicle manufacturers who cannot meet the target to be able to purchase credits from those who exceed it.

Support coordinated procurement processes

Commercial and government fleets provide opportunities for FCEVs to establish a foothold. Many fleets operate on a 'back to base' basis and will require a single point refuelling station to be developed rather than rely on having access to refuelling infrastructure at several locations. Further, the purchasing power of fleet operators who buy multiple vehicles in a single transaction will help grow the penetration of FCEVs faster than individual purchasers.

It is therefore important that procurement processes provide for ZEVs, and also that they allow for changes during the contract for innovations and cost recovery for operators.

Ideally, procurement processes would also be consistent across contracts in providing for zero emissions vehicle outcomes. At the least there could be a role for the Australian Government to provide information to the market about the various contract durations and renewal periods.

It is also important to value the multiple lives for FCEVs. Several AHC members have imported right hand drive FCEVs into Australia or are in a position to immediately manufacture them to client specification if required. However, potential operators have expressed a reluctance to adopt FCEVs due to the risk of them not being able to sell into a second hand market.

117 The Truck Industry Council (2019, page 4) suggests the following:

(1) A 30% depreciation allowance that offsets the costs associated with the purchase of a new Australian Design Rules (ADR) 80/03 diesel only truck and a 50% depreciation allowance that offsets the costs associated with the purchase of a new alternatively fuelled and powered truck for pre-ADR 70/00 (i.e. pre-1996) operators; or

(2) A 15% depreciation allowance that offsets the costs associated with the purchase of a new ADR 80/03 diesel only truck and a 25% depreciation allowance that offsets the costs associated with the purchase of a new alternatively fuelled and powered truck for ADR 70/00 and later (post-1996) operators.

(3) Acknowledging that some operators will not be in a position to purchase new vehicles, the government could consider providing a 15% depreciation allowance towards the purchase of used ADR 80/02 and ADR 80/03 emissions controlled trucks.

118 California HVIP (n.d.).

119 Wood et al. (2021a, page 19) notes "Import duties were intended to protect Australian auto manufacturing. With the decline of that industry, they are no longer fit-for-purpose, and are increasingly being removed via free trade agreements. Vehicles from countries including Japan, Korea, and the US already attract zero import duty due to free trade agreements".

120 Ibid.

121 Ibid., page 24.

We suggest that fleet operators be incentivised to make their refuelling infrastructure available to secondary users of FCEVs (in a way which does not impede their commercial operations) as a means of ensuring that a market for old fleet stock can develop.

Recommendation 7: Incentivise markets in FCEVs

We recommend that the Australian Government:

- Sets carbon emissions standards for all vehicle types.
- Provides tax offsets for vehicle purchases and removes taxes that inhibit purchasing.
- Sets a 50 per cent ZEV target for fleets of cars, buses and ancillary vehicles for 2030. This would include privately operated public transport fleets and government owned logistics providers.
- Supports ZEV fleet procurement across state/territory and the federal government, with information sharing and guidance on relevant matters, such as available operators, manufacturers and optimal contractual measures for the evolving markets.

References

- Advisian (2021) *Australian hydrogen market study: Sector analysis summary*, 24 May, for the Clean Energy Finance Corporation, <https://www.cefc.com.au/media/nhnhwixu/australian-hydrogen-market-study.pdf>.
- Australian Bureau of Statistics (2020) *Motor vehicle census*, Australia, 29 May, <https://www.abs.gov.au/statistics/industry/tourism-and-transport/motor-vehicle-census-australia/31-jan-2020>
- Australian Government (2021a) 'Funding boost for infrastructure to drive uptake of future fuel technologies', media release, the Hon Angus Taylor MP, Minister for Energy and Emission Reductions, 30 July, <https://www.minister.industry.gov.au/ministers/taylor/media-releases/funding-boost-infrastructure-drive-uptake-future-fuel-technologies>.
- Aurecon (2019) *Hydrogen for transport: Prospective use cases*, October, <https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy>.
- Bruce, S., Temminghoff, M., Hayward, J., Schmidt, E., Munnings, C., Palfreyman, D. and P. Hartley (2018) *National Hydrogen Roadmap*, CSIRO, Australia, <https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap>.
- Bureau of Infrastructure, Transport and Regional Economics (BITRE) (2019) *Hydrogen as a Transport Fuel: Location options for a freight-based limited initial deployment of hydrogen refuelling stations*, analysis prepared for the National Hydrogen Strategy, October, <https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy>.
- California Air Resources Board (2020) 'Fast-Track Fuel Cell Truck', March, <https://ww3.arb.ca.gov/msprog/lct/pdfs/fasttrack.pdf>.
- California Fuel Cell Partnership (2021) *Fuel cell electric trucks: A vision for freight movement in California – and beyond*, July, <https://app.greenrope.com/content/Fuel-Cell-Electric-Trucks-Vision-CaFCP.pdf>.
- California HVIP (n.d.) website accessed 29 August 2021, <https://californiahvip.org/>.
- Department of Energy (2020) *Hydrogen fueling stations cost*, US Government, DOE Hydrogen Program Record, 21001, 11 February, <https://www.hydrogen.energy.gov/pdfs/21002-hydrogen-fueling-station-cost.pdf>.
- Department of Infrastructure, Transport, Regional Development and Communications (2021) *Discussion Paper: Safer freight vehicles*, Australian Government, <https://www.infrastructure.gov.au/vehicles/design/files/discussion-paper-safer-freight-vehicles.pdf>.
- Foothill Transit (2020) *Cost comparison and fuel technology direction – battery electric bus vs. fuel cell bus*, memo for the Executive Board, 24 July, see <https://www.fuelcellpartnership.net/sites/default/files/07-24-2020-Foothill-ZEB-Update-to-Board.pdf>.
- H2Haul (n.d.) website accessed 29 August 2021, <https://www.h2haul.eu/>.
- Interreg North-West Europe (n.d.) 'HECTOR – project summary', website accessed 29 August 2021, <https://www.nweurope.eu/projects/project-search/hector-hydrogen-waste-collection-vehicles-in-north-west-europe/>.
- Port of Los Angeles (2021) 'Port of Los Angeles rolls out hydrogen fuel cell electric freight dimension', media release, 7 June, https://www.portoflosangeles.org/references/2021-news-releases/news_060721_zanzeff.
- Ruf, Y., Baum, R., Zorn, T., Menzel, A. and J. Rehberger (2020) *Fuel cell hydrogen trucks: Heavy duty's high performance green solution, Study report for Fuel Cells and Hydrogen Joint Undertaking (FCH 2 JU) by Roland Berger*, December, <https://www.fch.europa.eu/sites/default/files/FCH%20Docs/201211%20FCH%20HDT%20-%20Study%20Report%20final%20vs.pdf>.
- Shell (2021) *Decarbonising Road Freight: Getting into Gear, Industry Perspectives*, in collaboration with Deloitte, 21 January, <https://www.shell.com/energy-and-innovation/the-energy-future/decarbonising-road-freight.html>.
- Truck Industry Council (2019) *National Truck Plan: Modernising the Australian Truck Fleet*, June, <https://www.truck-industry-council.org/downloads>.
- Wood, T., Reeve, A., and J. Ha (2021a) *Towards Net Zero: Practical policies to reduce transport emissions*, Grattan Institute, <https://grattan.edu.au/report/towards-net-zero-practical-policies-to-reduce-transport-emissions/>.

Support local manufacturing



5



Australian manufacturers are feeling pressure to reduce emissions. End use customers are seeking low carbon products and services and this need is percolating through supply chains.

Hydrogen can support decarbonisation of manufacturing in two ways:

- **As a fuel:** Hydrogen can produce heat through combustion or chemical processes. Manufacturing sectors that use industrial heat include steel, non-ferrous metals, chemicals, food processing, ceramics and cement. Around 23 per cent of Australia's energy is used for process heat, with an indicative value of A\$8 billion per year.¹²² Carbon emissions from combustion in manufacturing were 30 million tonnes in 2019.¹²³
- **As a feedstock:** Hydrogen is already used as a feedstock¹²⁴ for several industrial processes, including the manufacture of ammonia, chemicals and synthetic fuels. Existing fossil fuel-derived hydrogen (generally steam methane reforming of natural gas) can be replaced with clean hydrogen

to decarbonise these processes. Carbon emissions from chemical processes were five million tonnes in 2019, with the ammonia-making process releasing two million tonnes.¹²⁵

Using clean hydrogen also creates new opportunities, such as growing Australia's domestic production of value-added commodities like steel. Further, with the hydrogen of the future not being exposed to fluctuating global prices for commodities such as oil and gas, it presents the possibility of offering more stable energy costs for industrial users.¹²⁶

However, early adopters of hydrogen technology in manufacturing still face significant financial risk. There is public benefit in supporting Australia's manufacturing sector, and there could also be major avenues for job creation to add value to our hydrogen for export.

122 ITP (2019), page xvii.

123 Wood, Reeve, and Ha (2021b), page 19.

124 This means it is not combusted for its energy value but used for its chemical value.

125 Wood et.al (2021b), page 19.

126 COAG Energy Council (2019), page 5.

5.1 Very high temperature processes are the first step

Process heat is said to be medium temperature when between 250°-800°C, and high temperature when over 800°C. Taken together, processes in these ranges represent around 10 per cent of total Australian energy consumption.¹²⁷

Experts consider that electrification will be more cost effective than hydrogen and other alternatives for many heating applications. However, technological constraints make electrification challenging for processes requiring more than 800°C. Advisian¹²⁸ has rated high temperature heating as 8 out of 10 for dependence on hydrogen for decarbonisation.

Sector	PJ/year >800°C
Iron and steel	93.9
Alumina and other non-ferrous metals	85.5
Ammonia and other chemicals	38
Cement, lime products	28.5
Bricks and ceramics	14.9
Glass and glass products	6.6
Petroleum refining	6.5
Other mining	5.3
Other ¹²⁹	4.4

Table 7: Sectors using >800°C, extract from ITP (2019: 29).

Table 7 shows the sectors of the economy that use high temperature heat, with the energy per sector.

To calculate how much hydrogen demand this translates to, we multiply the energy by the heating value of hydrogen.

Taking the higher heating value of hydrogen at 142MJ/kg¹³⁰ then this gives a hydrogen demand of:

- Around 900 ktpa, as a lower estimate, which assumes use only for alumina and non-ferrous metals, and ammonia and chemicals.
- Around 2,400 ktpa as an upper estimate, which covers all high temperature heating.

As a point of reference, Deloitte¹³¹ ran scenarios for the National Hydrogen Strategy that showed hydrogen production figures, where the most ambitious scenario had Australian total hydrogen production (for domestic use and export) at 1,777 kt per annum by 2030, and the second most ambitious scenario at 724 kt per annum. We can see that the lower estimate of demand for hydrogen to replace all high temperature process heating is more than the second Deloitte scenario's entire hydrogen production figure, and the upper estimate is 135 per cent higher than the first Deloitte scenario's entire hydrogen production figure.

The production of hydrogen to support high temperature processes can also support domestic manufacturing in new ways. As discussed by the Grattan Institute, new clean energy industries can "plausibly create new jobs at a scale comparable to existing carbon-intensive industries".¹³² The scenarios addressed by Grattan suggest between 40,000 and 55,000 ongoing jobs across green steel, green ammonia, and biofuels for aviation, which is similar to today's 55,000 geographically-concentrated carbon workers. Further: "Manufacturing activities are typically more labour-intensive than renewable energy operation and are likely to have conditions and pay more like today's jobs in smelting and coal power stations".¹³³

Many of these new and replacement jobs are likely to be located in carbon-intensive locations, because these locations have key infrastructure such as ports and electricity transmission, as well as access to natural gas networks. Such jobs are also likely to be created in other regional areas where renewable energy resources are most favourable.

127 ITP (2019).

128 Advisian (2021) page 76.

129 Includes 1.5PJ/yr for 'Other hydrocarbon products', 1.3PJ/yr for 'Other non-metallic mineral', 1.1PJ/yr for 'Solvents, lubricants, greases and bitumen', 0.4PJ/yr for fabricated metal products and 0.1PJ/yr for water and sewerage.

130 Note the lower heating value of hydrogen is 120MJ/kg and using the lower value would increase this estimate by around 17 per cent.

131 Deloitte (2019).

132 Wood, Dundas and Ha (2020), page 26.

133 Ibid., page 15.

5.2 Priority sectors

The processes that appear to hold the greatest benefits for more immediate ‘no regrets’ planning and investment include iron/steel, ammonia, methanol and aluminium/alumina.

This is because each of these sectors is more dependent on hydrogen for decarbonisation and can also drive large sources of demand. These are scalable markets and support both direct and indirect growth in jobs.

Achieving scale in hydrogen production for these sectors can then pave the way for other industries that use high temperature heating at relatively smaller scale, such as food and meat processing.¹³⁴

5.2.1 Iron and steel

Steel is the world’s second largest commodity value chain after crude oil.¹³⁵ Steel is used for building materials, including new clean energy infrastructure such as wind towers, hydropower, solar farms, electricity transmission infrastructure, and transport systems.¹³⁶ Producing more than 1.8 billion tonnes of steel per annum, the global steel industry is responsible for around 8 per cent of global direct emissions.

Table 8 shows the major iron and steel companies in Australia, and key facts about each. To provide an example of the scale of Australia’s current largest steelworks at Port Kembla, the steelworks provides 11 per cent of Gross Regional Product (at A\$1.6 billion) for NSW and 24 per cent of the region’s total output (at A\$6.5 billion).¹³⁷

There are two common ways to make steel. Most steel starts as iron ore, which is reduced to iron in a blast furnace. The iron is then processed in a basic oxygen furnace to produce steel. The second common way to make steel is to melt scrap steel with other elements in an electric arc furnace.

A newer approach is to make steel from direct reduced iron (DRI) sent to an electric arc furnace.

The direct reduced iron is produced from iron ore and reductant gases, where natural gas is primarily used now. Green hydrogen can be used instead of natural gas to produce the iron. When combined with renewable electricity for the electric arc furnace, the resulting steel will be below to zero emissions, and ideally ‘green’.

Advisian¹³⁸ rates steel as 8.5 out of 10 for reliance on hydrogen to decarbonise,¹³⁹ noting that while the economic gap will reduce over time, hydrogen use is not expected to reach parity with the incumbent process before 2050.



¹³⁴ While there are many more food processing plants than refineries, the scale is much smaller. For example, a large alumina refinery uses around 30,000 to 40,000TJ/year, and a modest sized factory in the food sector might use 20TJ/year. See ITP (2019), page xiv.

¹³⁵ BHP (2020).

¹³⁶ BlueScope (2021), page 3.

¹³⁷ Ibid., page 3.

¹³⁸ Advisian (2021), page 75.

¹³⁹ Ibid., page 52.

Company	Suburb	State	Main activities	Production technology	Production capacity per year, in million tons	Energy use per year in PJ
Bluescope Steel (AIS) Pty Ltd, Port Kembla steel works	Port Kemba	NSW	Primary iron and steel manufacture	BF, BOS	2.6	52
Bluescope Steel Limited, - Springhill	Port Kemba	NSW	Integrated steel works, flat products	BF, BOS	-	-
Commonwealth Steel Company Ltd, MolyCop Waratah	Waratah	NSW	Secondary steel manufacture	EAF	1.7	-
OneSteel Manufacturing Pty Limited, Whyalla Steelworks (Arrium)	Whyalla	SA	Integrated steelworks, long products	BF, BOS	1.28	34
OneSteel	Rooty Hill	NSW	Secondary steel manufacture	EAF	0.625	-
OneSteel	Waratah	NSW	Secondary steel manufacture	EAF	0.33	-
OneSteel	Laverton	VIC	Secondary steel manufacture	EAF	0.74	-
Tasmanian Electro Metallurgical Co Pty Ltd, TEMCO	Bell Bay	TAS	Manganese ferroalloy smelter	EAF	-	-

Table 8: Major iron and steel companies in Australia (BF: Blast Furnace; BOS: Basic Oxygen Steelmaking; EAF: electric arc furnace). SOURCE: ITP, 2019: 121. Note: errors in table in original ITP report corrected in communication with author on 20 September 2021.

Green steel is a manufacturing opportunity that could potentially provide tens of thousands of new jobs. The Grattan Institute notes that today Australia produces 38 per cent of the world's iron ore and 18 per cent of the world's metallurgical coal, but only produces 0.3 per cent of the world's steel.¹⁴⁰

Australia does not make significant amounts of steel because the economics currently favour sending the raw materials to major manufacturing and steel-consuming countries, such as China, Japan, Korea, and India. The cost of shipping is not high enough to offset the costs of producing steel onshore (mainly related to domestic wages). However, using hydrogen for direct reduced iron “turn the economics of steel-making on its head”:

The cost of shipping hydrogen strongly favours making green steel – or at least the hydrogen-intensive direct reduction process – where the hydrogen is made. This is likely to be in renewable-rich Australia, rather than in countries that have lower-quality renewable energy resources and limited land, such as Japan, Korea, Indonesia, Vietnam, and Thailand.¹⁴¹

Grattan states that it makes sense for Australia to export steel to countries with relatively high wages, such as Japan or Korea, and to export direct reduced iron to countries with lower wages, such as Indonesia.

140 Wood et al. (2020), page 22.

141 Ibid.

The Energy Transition Hub¹⁴² has modelled a scenario where the future Australian steel industry converts 18 per cent of iron ore output (where 18 per cent is 160Mt) into 100 million tonnes of crude steel per year, similar in size to Japan’s current steel industry. This is produced by 40 plants. This scenario has the steel industry adding A\$65 billion to its base revenue from the iron ore (A\$19 billion), to make a total of A\$84billion. This scenario as modelled provides 50,000 on-going jobs in the steel industry, plus the workforce for the new 160GW of solar and wind energy that will need to be constructed.

The Grattan Institute has also modelled a future green steel industry based in central Queensland and the Hunter Valley (see Table 9).¹⁴³ This industry scenario has 40 million tonnes of steel exported per year to our regional trading partners, to a total value of A\$65 billion, and capital investment of A\$195 billion. Conservatively, this would mean 25,000 ongoing plant jobs in the region (just for steel manufacturing), to supply 6.5 per cent per cent of the world’s steel.

	Central Queensland	Hunter Valley	Combined
Ongoing plant jobs in region	15,000	10,000	25,000
Direct reduced iron (DRI) output (Mt per year)	60	35	95
DRI exported (Mt per year)	30	17.5	47.5
Steel exported (Mt per year)	25	15	40
Output as share of 2020 global steel market (including steel produced from exported DRI)	4%	2.5%	6.5%
Output as share of today’s integrated steel production by prospecting trade partners	30%	20%	50%
Annual value (\$b)	40	25	65
Capital investment (\$b)	115	80	195
Renewable generation capacity required (GW)	75	60	135
Renewable outgoing jobs (mostly outside region)	2,000	1,500	3,500
Water input (GL per year)	200	150	350
Land required (share of state area)	0.45%	0.65%	0.5%
<i>Notes: Assumes half of Australia’s DRI production is exported, and half is used to produce steel in Australia. All jobs are ongoing full-time equivalent jobs, and exclude construction jobs. Plant jobs include operation and maintenance of both steel plant and electrolyzers for hydrogen supply. Prospective trading partners are Japan, Korea, Indonesia, Malaysia, Taiwan and Vietnam.</i>			

Table 9: Grattan Institute future steel industry scenario: Central Queensland and Hunter Valley. SOURCE: Wood et al. (2020), page 30.

It is difficult to do a direct comparison of these studies given the different coverage and assumptions, but there is a key message nonetheless, in that each study shows a potential green steel industry that is worth over A\$65 billion, with at least 25,000 new jobs. This is for a level of global market penetration for Australian green steel that does not appear infeasible in principle.

These potential benefits need to be better understood, particularly against the cost of shipping for iron and steel (shipping steel will be much more expensive than iron), exposure to international markets in each, and how local and overseas delivery needs can be met (industry experts advise that steel users tend to require delivery of steel products quickly).

142 Lord, Burdon, Marshman, Pye, Talberg, Venkatamaran (2019), page 22.

143 Wood et al. (2020), page 30.

5.2.2 Ammonia

Ammonia is the second most commonly produced chemical in the world, with most ammonia used as the basis for the fertilisers that support food production. Ammonia is also used to manufacture a range of other products, such as explosives and plastics.

Australia currently uses hydrogen from steam methane reforming as a feedstock to make ammonia, which means there is an opportunity to decarbonise this industry. Production of ammonia is by far the largest user of gas in the whole chemicals sector.

There are currently seven major ammonia plants in Australia. Table 10 shows the major ammonia plants and their production capacity as of 2019.

Company	Suburb	State	Main activities	Production capacity ton per year
Yara	Burrup	WA	Ammonia	85,000
Orica	Kooragang	NSW	Ammonia + AN + nitric acid	360,000
Incitec	Gibson island	QLD	Fertilisers	Ammonia: 360,000, Urea: 280,000, AS: 200,000
Incitec	Phosphate Hill	QLD	Ammonia for DAP production at Mt Isa	>950,000
Incitec	Moranbah	QLD	AN	330,000
CSBP, Incitec	Moura	QLD	AN	210,000
CSBP	Kwinana	WA		260,000

Table 10: Major ammonia-based fertiliser and explosives plants in Australia (AN: Ammonium nitrate, DAP: diammonium phosphate, AS: ammonium sulphate). SOURCE: ITP, 2019: 109.

The ammonia market is also likely to grow significantly, as ammonia also becomes an energy carrier or clean fuel. Japan anticipates using clean ammonia in power stations and is currently undertaking a large-scale demonstration of ammonia co-firing at the 4.1GW Hekinan Thermal Power Station.¹⁴⁴ Ammonia energy is also considered a logical replacement for the bunker fuel used for shipping.¹⁴⁵ Unlike hydrogen, ammonia has been traded globally for decades and has well developed technologies for large scale storage and transport.

Regarding the potential use of ammonia for shipping, Australia can engage with first movers across energy and maritime to collaborate on commercial-scale demonstration projects. The Energy Transitions Committee¹⁴⁶ sees this as vital, with a high priority for the shipping industry to:

choose pilot locations that offer privileged access to low-cost renewable electricity and hydrogen, opting for regions with large renewable energy potential, preferential prices and tax exemptions for major industrial electricity consumers, and industrial clusters where several transport and industry sectors will share energy infrastructure costs.

Researchers from the Grattan Institute¹⁴⁷ state that if Australia was to produce 6.5 per cent of the world's ammonia with green hydrogen by 2050, there would be a further 5,000 ongoing jobs. This number rises by a further 15,000 jobs if global shipping moved exclusively to ammonia and Australia maintained 6.5 per cent market share.

Advisian rates ammonia as 8 out of 10 for reliance on hydrogen to decarbonise, noting that ammonia production using green hydrogen is unlikely to be competitive against natural gas until around 2050.¹⁴⁸ However, niche applications may become commercially attractive before then, and large-scale

144 JERA (2021).

145 The American Bureau of Shipping (2019, page 46) notes a US company announcement for production of 275,000 tons of ammonia for a marine fuel by using methane pyrolysis powered by green renewable energy. Companies Ørsted and Yara have also announced plans to produce 75,000 tons of green ammonia per year using offshore renewable energy.

146 Energy Transitions Committee (2020), page 19.

147 Wood et al. (2020), page 36.

148 Advisian (2021), page 78.

deployment of green ammonia production is expected to drive down costs rapidly.

While clean ammonia is not economically competitive in the short term, it “represents the easiest major strategic industrial transformation and is linked to the idea of future renewable energy exports”.¹⁴⁹

5.2.3 Methanol

Hydrogen is used for both fuel and feedstock to make methanol, and clean hydrogen is a good prospect to decarbonise the sector’s high temperature processes.

There is an established global market, with extensive experience in handling. The global methanol market is growing, with China in particular said to be consuming over 50 per cent of the world’s production:

*Much of the recent growth can be attributed to China substituting methanol for petroleum derivatives as feedstock for the production of ethylene and propylene, the precursors for most types of synthetic polymers and plastics. However, a variety of fuel applications for methanol are also emerging. Methanol has been blended with petrol (similar to ethanol blending) in China and other countries for a number of years as a way of reducing air pollution. More recently, ships are being modified to run on methanol as well as diesel oil in order to comply with stricter air quality standards in many ports around the world.*¹⁵⁰

Australia imports over 100,000 tonnes of methanol each year, mainly to produce formaldehyde for particle board and other manufacturing processes. Australia used to produce methanol at a site in Victoria, but the plant was “placed in care and maintenance mode” in March 2016 because of an inability to secure competitively priced natural gas.¹⁵¹

Like ammonia, methanol is considered a possible replacement for bunker fuels in shipping – it is already in operation for international shipping, albeit at a small scale.¹⁵²

If the economics can be made to work, the production of methanol is another growth opportunity for Australia. Advisian¹⁵³ states that the methanol sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8 out of 10.

5.2.4 Aluminium and alumina

As shown in Table 7, the aluminium industry is another strong prospect for using hydrogen to decarbonise the sector’s high temperature processes, particularly in the production of alumina.

Primary aluminium is made from bauxite, which is refined to make alumina before being smelted to make aluminium. Refining bauxite to produce alumina has four stages: digestion, clarification, precipitation, and calcination. Digestion takes place at 150-270°C and calcination at temperatures above 1000°C.

Australia is the second largest producer of alumina in the world, and the largest exporter. In 2020, Australian total alumina production was 21.2 Mt, and export was worth A\$6.8 billion.¹⁵⁴ Six Australian alumina refineries supply alumina to the four Australian aluminium smelters and the export market.

Advisian rates the alumina sector as 6 out of 10 for dependence on hydrogen, noting that it could be the key decarbonisation technology if the costs of production can reach parity with natural gas.¹⁵⁵ Further, there is a benefit for hydrogen if alumina calcination switched to hydrogen because the sector’s significant energy consumption could “provide demand for demonstration and larger scale domestic hydrogen consumption”.¹⁵⁶

149 ITP (2019), page xvi.

150 ADME Fuels (2019), page 2.

151 Coogee (n.d.).

152 Hand (2021), see also Maersk (2021).

153 Advisian (2021), page 79.

154 Australian Aluminium Council (n.d.).

155 Advisian (2021), page 75.

156 Ibid., page 74.

5.3 Barriers to hydrogen uptake

The barriers faced by parties seeking to integrate hydrogen into their heating and chemical processes are largely the same as for transport and any other use; that is, the significant cost required to convert assets, and the uncertainty about the total asset life costs of doing so given lack of current experience. For industrial processes there is also the complication of hydrogen being more expensive than the natural gas it is (often) replacing.

Starting with the costs of conversion, the investment needed to transform Australia’s industrial asset base will be significant, with Grattan¹⁵⁷ noting that while there is no current estimate for Australia, an estimate for the European Union suggests required expenditure between 76 per cent and 107 per cent beyond that required for current technologies.¹⁵⁸

If we look at steel for example, a modern blast furnace can have a lifecycle of 50 years or more, with major overhauls or ‘relines’ every 15-20 years to stay operational. The capital cost for a 4.0 Mt/year integrated steelmaking facility is around US\$4 billion, compared with relining a blast furnace at between US\$50 million and US\$200 million, depending on the jurisdiction.¹⁵⁹

In a submission to the 2021 NSW Parliamentary Inquiry into Hydrogen, BlueScope Steel¹⁶⁰ advises that its operational blast furnace at the Port Kembla Steelworks comes to the end of its current operating campaign around 2026 to 2030. It is still working but given the importance of the furnace working at full capacity (Port Kembla is a one blast furnace operation), BlueScope has commenced a pre-feasibility study on relining another blast furnace that was mothballed in 2011, to have this available from around 2026. BlueScope advises that a reline is the

better option given the prospective hydrogen iron making technologies are promising but are in the early stage of technology development.¹⁶¹

Relining the mothballed blast furnace is said to cost around A\$700-800 million, likely to be spent over FY2023 to FY2025.¹⁶² To compare this with the alternative to use hydrogen, BlueScope advises:

- The capital cost of conversion¹⁶³ would be “prohibitive”; at more than A\$2.8 billion it is more than four times more expensive than relining a blast furnace.¹⁶⁴
- The high cost of natural gas and electricity in eastern Australia compared to other jurisdictions would result in output that was not globally competitive, with BlueScope’s analysis indicating “even halving of...current gas prices would not allow such a plant to be competitive when compared to the existing BF-BOF plant”.¹⁶⁵
- Using green hydrogen would require an electrolyser of around 1.4GW, requiring 3GW of installed renewable electricity generation capability coupled with storage to ensure continuous supply.¹⁶⁶

The BlueScope experience shows how long-lived industrial assets like blast furnaces need long term planning for major renewals. This planning needs to occur in the environment of changing social acceptance and uncertain technological choices, where the asset owner needs to maintain production while not locking in choices that in the future might be found to be poor. And the risk is particularly high with companies (and sectors) with few facilities, such as steel and ammonia.

157 Wood et al. (2021b), page 39.

158 Material Economics (2019).

159 BHP (2020).

160 BlueScope Steel (2021).

161 Ibid., page 7.

162 Strategic Research Institute (2021).

163 Converting from BF-BOF (Blast Furnace – Basic Oxygen Furnace) to DRI-EAF (Direct Reduced Iron – Electric Arc furnace) using hydrogen as the reductant.

164 BlueScope Steel (2021), page 10.

165 Ibid., page 12.

166 BlueScope compares this to the total increase in Australia’s installed capacity of large-scale renewable energy (mostly solar) in 2019 being 2.2GW across 34 projects.

While BlueScope chose to reline a mothballed blast furnace rather than take the chance on early technology, other companies or sectors may not have this flexibility and need to replace rather than refurbish 40-year-old assets if they are to stay operational.¹⁶⁷ This could mean closures (with associated job

losses), or it could mean “a like-for-like replacement of an old facility, or shift to a proven but still relatively emissions-intensive process, locking in emissions for another 30 years or more”.¹⁶⁸ This is all the more likely while producers cannot recover the additional costs of greener technology via green premium prices.



5.4 Recommendation

Recommendation 8: Support hydrogen for hard-to-abate industries

We recommend that the Australian Government funds a hydrogen readiness programme of at least A\$1 billion for industrial processes that cannot readily be electrified, including (and not exclusively) for the production of iron/steel, ammonia, methanol, and alumina/aluminium.

Funding would be drawn from the Net Zero Fund and should be aligned with funding from state/territory governments.¹⁶⁹

Funding should be prioritised for projects that protect or create local jobs and have a detailed plan for skilling and re-skilling. Applicants should be required to share information to support industry knowledge development – this could be assisted by engaging with industry associations to support delivery.

¹⁶⁷ Regarding ammonia, Advisian (2021 page 77) advises: “A large portion of Australia’s ammonia manufacturing capacity is beyond the initial design life of the facility and survives through judicious asset management and favourable domestic gas pricing”.

¹⁶⁸ Wood et al. (2021b), page 37.

¹⁶⁹ Such as the NSW NZIIP fund for High Emitting Industries (\$380 million), which “seeks to align with business investment cycles while achieving the lowest cost emissions reduction through a staged process, where potential funding is identified early and reserved (subject to future negotiation) to provide a level of certainty for long term investment decision making”. See Department of Planning, Industry and Environment (2021).

References

- ADME Fuels (2019) *Response by ADME Fuels to a Request for Information on a Discussion Paper (March 2019) on Australia's National Hydrogen Strategy prepared for the COAG Energy Council*, 28 March, https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-request-for-input/consultation/view_respondent?show_all_questions=0&sort=submitted&order=ascending&q_text=adme&uuld=270528247
- Advisian (2021) *Australian hydrogen market study: Sector analysis summary*, 24 May, for the Clean Energy Finance Corporation, <https://www.cefc.com.au/media/nhnhwlu/australian-hydrogen-market-study.pdf>.
- Australian Aluminium Council (n.d.) website, accessed 1 September 2021, <https://aluminium.org.au/australian-bauxite/>.
- American Bureau of Shipping (2019) *Setting the course to low carbon shipping: view of the value chain*, 4 June, <https://ww2.eagle.org/en/Products-and-Services/Sustainability.html>.
- BHP (2020) 'Pathways to decarbonisation episode two: steelmaking technology', 5 November 2020, <https://www.bhp.com/media-and-insights/prospects/2020/11/pathways-to-decarbonisation-episode-two-steelmaking-technology/>
- BlueScope Steel (2021) *BlueScope submission to the Standing Committee on State Development's Inquiry into the development of a hydrogen industry in NSW*, 26 February, <https://www.parliament.nsw.gov.au/committees/inquiries/Pages/inquiry-details.aspx?pk=2643#tab-submissions>.
- COAG Energy Council (2019) *Hydrogen for industrial users*, National Hydrogen Strategy, Issues paper 9, https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-issues-papers/supporting_documents/NationalHydrogenStrategy_Issue9HydrogenforIndustrialUsers.pdf.
- Coogee (n.d.) 'Methanol plant in North Laverton, Melbourne', business website accessed August 2021, <https://www.coogee.com.au/Our-Businesses/Chemicals-Manufacturing/Manufacturing-Facilities/Methanol-plant-in-North-Laverton,-VIC>,
- Deloitte (2019) *Australian and global hydrogen demand growth scenario analysis*; COAG Energy Council – National Hydrogen Strategy Taskforce, November, https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-and-global-hydrogen-demand-growth-scenario-analysis-report-2019_1.pdf.
- Department of Planning, Industry and Environment (2021) *Net Zero Industry and Innovation Program" Driving a clean industrial revolution*, March, https://www.energysaver.nsw.gov.au/sites/default/files/2021-03/NetZero-Industry-Innovation-Program_FINAL_24-March-21_webaccessible.pdf
- Energy Transitions Commission (2020) *The First Wave: A blueprint for commercial-scale zero-emission shipping pilots*, prepared for the Getting to Zero Coalition, version 1, 11 November, <https://www.globalmaritimeforum.org/content/2020/11/The-First-Wave-%E2%80%93-A-blueprint-for-commercial-scale-zero-emission-shiping-pilots.pdf>.
- Hand, M. (2021) 'EPS set for methanol/ammonia powered ship under MAN and OCI partnership', *Seatrade Maritime News*, 5 March, <https://www.seatrade-maritime.com/environmental/eps-set-methanolammonia-powered-ships-under-man-and-oci-partnership>.
- ITP Thermal (2019) *Renewable Energy Options for Industrial Process Heat*, prepared for Australian Renewable Energy Agency, August, <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf>.
- JERA (2021) 'JERA and IHI to Start a Demonstration Project Related to Ammonia Co-firing at a Large-Scale Commercial Coal-Fired Power Plant', press release, 24 May, https://www.jera.co.jp/english/information/20210524_677.
- Lord, M., Burdon, R., Marshman, N., Pye, J., Talberg, A., and M. Venkatamaran (2019) *From mining to making: Australia's future in zero-emissions metal*, Energy Transition Hub, 8 November, https://www.energy-transition-hub.org/files/resource/attachment/zero_emissions_metals.pdf
- Material Economics (2019) *Industrial Transformation 2050: Pathways to Net-Zero Emissions from EU Heavy Industry*, University of Cambridge Institute for Sustainability Leadership, <https://www.climate-kic.org/wp-content/uploads/2019/04/Material-Economics-Industrial-Transformation-2050.pdf>.
- Maersk (2021) 'A.P. Moller - Maersk accelerates fleet decarbonisation with 8 large ocean-going vessels to operate on carbon neutral methanol', press release, 24 August, <https://www.maersk.com/news/articles/2021/08/24/maersk-accelerates-fleet-decarbonisation>.
- Strategic Research Institute (2021) 'BlueScope May Reline Blast Furnace 6 at Port Kembla Steelworks', *SteelGuru Business News*, <https://www.steelguru.com/steel/bluescope-may-reline-blast-furnace-6-at-port-kembla-steelworks>.
- Wood, T., Dundas, G., and J. Ha (2020) *Start with steel*, Grattan Institute, Report No. 2021-07, July, <https://grattan.edu.au/report/start-with-steel/>.
- Wood, T., Reeve, A., and J. Ha (2021b) *Towards net zero: Practical policies to reduce industrial emissions*, Grattan Institute, Report No. 2021-10, August, <https://grattan.edu.au/report/towards-net-zero-practical-policies-to-reduce-industrial-emissions/>.

Appendix A: Different hub concepts



Hydrogen valleys

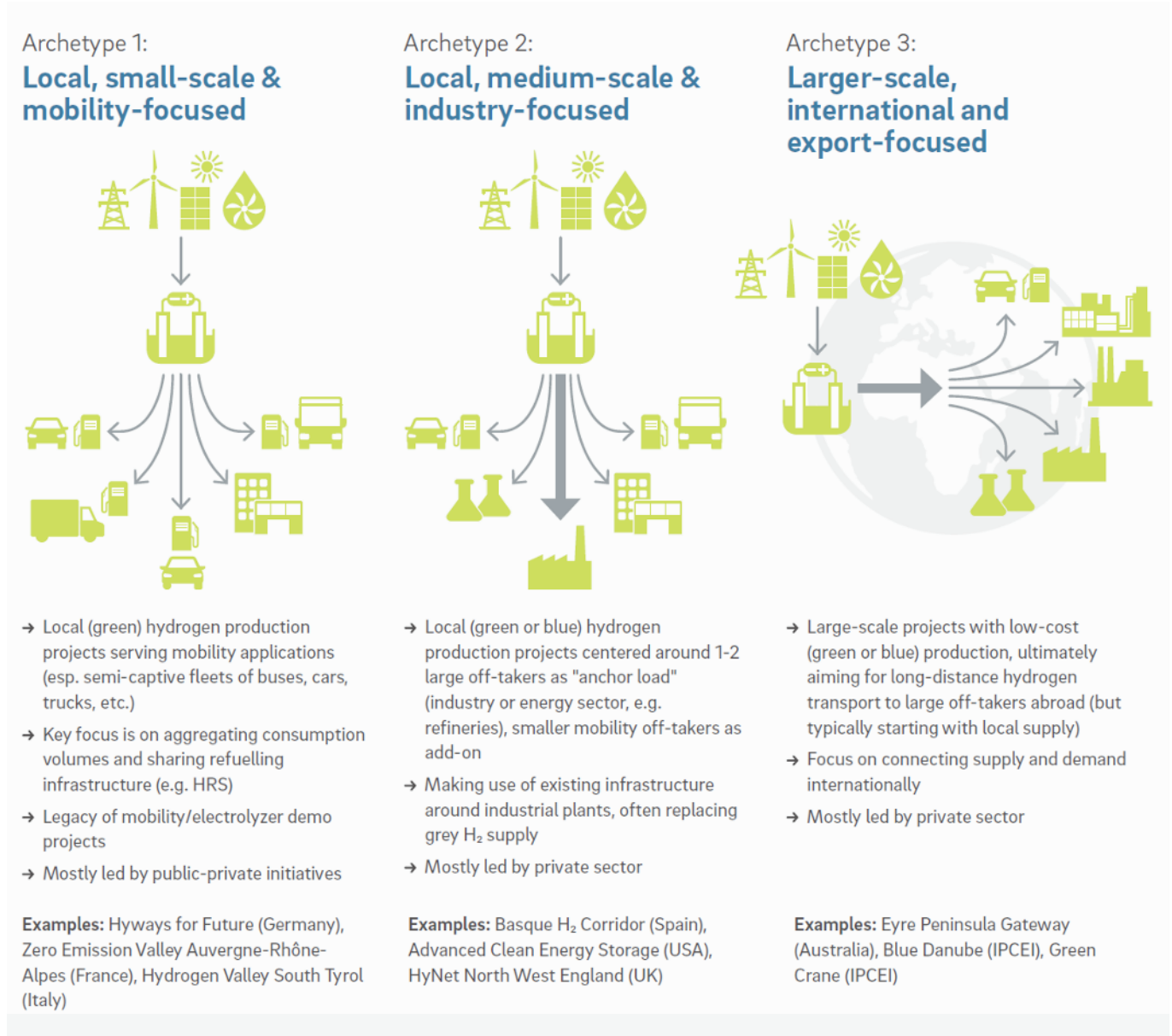


Figure 7: Hydrogen Valley archetypes, SOURCE: Weichenhain et. al (2021, page 28)

Hydrogen clusters

Four archetypes for hydrogen clusters based on “early demand” use cases

1 Port	2 City	3 Refining & Fertiliser	4 Steel
<p>Ports¹ as infrastructure hubs for import/export of feedstocks and goods.</p> <p>Core off-taker:</p> <ul style="list-style-type: none"> Shipping (Ammonia) <p>Often co-located with:</p> <ul style="list-style-type: none"> Refining & Fertiliser Import/export of LNG for these industries Steel Import/export of feedstocks and products Road Transport Container transport Aviation Coastal transport hub Forklifts & Ground Operations Container/goods handling Option for blending dependant on trade-offs (see Box B) Coincide with LNG storage 	<p>Continental cities serve as non-coastal hub for transport and are often well connected to gas grid infrastructure.</p> <p>Core off-takers:</p> <ul style="list-style-type: none"> Aviation Long-haul trucking & buses Option for low % H₂ blending into natural gas grid dependant on trade-offs (see Box B) <p>Often co-located with:</p> <ul style="list-style-type: none"> Refining & Ammonia As large natural gas demand sites commonly close to gas storage/import sites Forklifts & Ground Operations Heavy transport in mines 	<p>Refineries and fertiliser production are frequently co-located and require large amounts of hydrogen.</p> <p>Core off-taker:</p> <ul style="list-style-type: none"> Refining & Fertiliser <p>Often co-located with:</p> <ul style="list-style-type: none"> Ports Gas storage facilities – option for low % H₂ blending into natural gas grid dependant on trade-offs (see Box B) 	<p>Hydrogen-DRI steel production as major hydrogen off-taker (medium sized steel site requires approximately ~120 kt H₂/year).</p> <p>Core off-taker:</p> <ul style="list-style-type: none"> Hydrogen-DRI steel production <p>Often co-located with:</p> <ul style="list-style-type: none"> Ports
<p>Refining, Fertiliser and Steel offer sufficient off-take to operate on stand-alone basis, but co-location enables shared off-take</p>			
<p>Road Transport Dependant on long-term role of hydrogen in road transport & hydrogen refuelling infrastructure network requirements</p>			

Illustrative cluster size

Large to very large (~100- >1000 t/day)	Small to very large (~1 - >1000 t/day)	Medium to Large (~50-400 t/day)	Large (100-300 t/day)
-----------------------------------------	----------------------------------------	---------------------------------	-----------------------

Existing pipeline of projects exemplifies these archetypes:

<p>Port of Amsterdam:</p> <ul style="list-style-type: none"> Partners: Nouryon, Tata Steel 100 MW electrolysis Oxygen bi-product from electrolysis will be used in steel production <p>Port of Rotterdam:</p> <ul style="list-style-type: none"> 1.2 Mt clean hydrogen production via green and blue route by 2030 Wide variety of end-uses targeted in several consortia and pilots including shipping, trucking and aviation <p>North Sea Port²:</p> <ul style="list-style-type: none"> Partners: 500 MW electrolysis End-users include refinery, ammonia and steel plant in proximity to port 	<p>Aberdeen Hydrogen Hub, Scotland:</p> <ul style="list-style-type: none"> Hydrogen refuelling stations and deployment of hydrogen powered L/M/HDV Feasibility study to expand to building heating and industry <p>Hydrogen Cities, South Korea:</p> <ul style="list-style-type: none"> 4 cities as candidate cities for the hydrogen economy Road transport refuelling infrastructure Hydrogen grid for building heating/cooling <p>Liverpool & Manchester, UK:</p> <ul style="list-style-type: none"> Partners: Consortium lead by Cadent and Progressive Energy Blue hydrogen for gas grid blending combined with local industry and transport 	<p>Puertollano, Spain³:</p> <ul style="list-style-type: none"> Partners: Iberdrola and Fertiberia 20 MW electrolysis (2021) Green hydrogen used to co-feed (10%) into existing ammonia plant <p>Lingen, Germany³:</p> <ul style="list-style-type: none"> Partners: BP and Oersted 50 MW electrolysis Green hydrogen to replace 20% of grey hydrogen in refinery <p>Antofagasta, Chile³:</p> <ul style="list-style-type: none"> Partners: Engie and Enaex 1600 MW electrolysis For local ammonium nitrate plant and export market <p>Large projects such as Australian Renewable Energy Hub⁴ and NEOM⁵ are in early planning stages</p>	<p>Lulea, Sweden:</p> <ul style="list-style-type: none"> Partners SSAB, Vattenfall, LKAB Pioneering hydrogen-direct reduction (DRI) technology Commencing early commercial production in 2026 <p>Duisburg, Germany:</p> <ul style="list-style-type: none"> Partners: Thyssenkrupp, RWE 100 MW electrolysis Co-feed of hydrogen into coal-powered blast-furnace as first step prior to conversion to DRI plants <p>Dunkirk, France:</p> <ul style="list-style-type: none"> Partners: AcelorMittal, Air Liquide Development of hydrogen-DRI and hybrid BF/DRI technology
-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------	-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------	-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------	---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

NOTES: ¹ Particular focus on coastal ports due to much bigger size compared to inland ports; ² Partners: Dow, Yara, Zeeland Refinery, ArcelorMittal, Ørsted and North Sea Port; ³ Early projects only have one-off-taker, but are in principle located in close proximity to additional refinery or fertiliser production facilities; ⁴ Partners: InterContinental Energy, CWP Energy Asia, Vestas, Pathway Investments. Up to 23 GW electrolysis for ammonia production in early planning stages. ⁵ Partner: Air Products, ACWA Power, Thyssenkrupp, Haldor Topsoe. Target: 650 t/day H₂ production to produce 1.2 Mt ammonia / year

SOURCES: Port of Amsterdam, "Nouryon, Tata Steel, and Port of Amsterdam partner to develop the largest green hydrogen cluster in Europe", October 18th 2018; Port of Rotterdam, "Port of Rotterdam becomes international hydrogen hub", May 7th 2020; North Sea Port, "Ørsted North Sea Port to develop one of the world's largest sustainable hydrogen plants for Dutch and Belgian industry", April 1st 2021; Aberdeen City Council, "H, Aberdeen", retrieved April 2021; FuelCellsWorks, "Korean Government announces its selection of World's first hydrogen cities", January 6th 2020; HyNet North West (2020), "Unlocking net zero for the UK"; Iberdrola, "Iberdrola and Fertiberia launch the largest plant producing green hydrogen for industrial use in Europe", July 24th 2020; Reuters, "BP, Ørsted launch green hydrogen project at German oil refinery", November 10th 2020; Power Engineering International, "First green hydrogen projects emerge in Chile", October 5th 2020; The Chemical Engineer, "Australian Government backs renewable energy hub", October 23rd 2020; AirProducts, "Air Products, ACWA Power and NEOM Sign Agreement for \$5 Billion Production Facility in NEOM Powered by Renewable Energy for Production and Export of Green Hydrogen to Global Markets", July 7th 2020; Hybrit, "SSAB, LKAB and Vattenfall to begin industrialization of future fossil-free steelmaking by establishing the world's first production plant for fossil-free sponge iron in Gällivare", March 24th 2021; Thyssenkrupp, "Green hydrogen for steel production: RWE and thyssenkrupp plan partnership", June 10th 2020; AcelorMittal, "ArcelorMittal Europe to produce 'green steel' starting in 2020", October 13th 2020.

Figure 8: Energy Transitions Commission perspective on hydrogen hubs. SOURCE: Energy Transitions Commission (2021), page 68.