# Hydrogen vehicle refuelling infrastructure

Priorities and opportunities for Australia

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## Acknowledgments

CSIRO is Australia's National Science Agency. CSIRO works with industry, government and the research community to turn science into solutions to address Australia's greatest challenges, including food security and quality; clean energy and resources; health and wellbeing; resilient and valuable environments; innovative industries; and a secure Australia and region.

CSIRO would like to acknowledge the assistance and input of the parties set out in Appendix A.5. The positivity and enthusiasm of industry participants is a strong signal of future success. The comments and suggestions have been wide-ranging and always valuable, and in a number of cases provide strong direction for further targeted investigations beyond this report.

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# Foreword

Australia is a big country and Australians don't hesitate to drive long distances. Every day our cars and trucks clock up millions of kilometres, contributing to the estimated 156 Megalitres of petroleum fuels burned through each and every day in this country.

If Australia is to meet its Net Zero commitments, we need to urgently decarbonise our transport sector which currently accounts for 18.6% of our greenhouse gas emissions. The use of hydrogen as a transport fuel can be a critical part of that.

Australia's National Hydrogen Strategy sets out how hydrogen will transform our world, integrating more renewable energy into our electricity network, reducing dependence on imported fuels, reducing carbon emissions and making Australia an energy superpower.

But while we know hydrogen will play a critical role we also know that much of the key infrastructure for storing, moving and distributing hydrogen for use as a transport fuel – including pipelines, storage tanks and refuelling stations – is yet to be built.

That's why this report is so important.

It sets out the considerations for governments and industry to build out hydrogen refuelling infrastructure in Australia and decarbonise road transport in this country, including long-haul travel and freight. It compares the different hydrogen storage and dispensing options available, and evaluates refuelling infrastructure options based on fuel demand and distance from the hydrogen source.

As well as spelling out the opportunities, the report also points to how far we have got to go. Australia currently has only five refuelling stations in operation, with another 20 under construction or planned. That's an encouraging start but a drop in the ocean compared to what is required to sustain our long-haul transport fleet. We need to see significant further investment in refuelling stations, and we need to see it urgently.

This report builds on best practice globally, drawing on international connections built by lead authors GHD Advisory and CSIRO through our Hydrogen Industry Mission The mission is supporting the establishment of a commercially viable Australian hydrogen industry, comprising both domestic and export value chains by 2030, to contribute to global decarbonisation.

We are doing that by collaborating with Australian and international governments and research organisations, partnering to build demonstration projects, and delivering the enabling science to remove barriers to the hydrogen industry. The Hydrogen Refuelling Infrastructure Report is an output of the mission, providing practical guidance to industry, government and regulators working to build hydrogen infrastructure in Australia.

CSIRO also has skin in the game, with our own hydrogen refuelling station in Victoria set to open in the next few months. Through building this station we have confirmed many of the findings included the report and the station will help us demonstrate the safety and environmental aspects of hydrogen storage and distribution. It is a great addition to our Hydrogen Technology Demonstration Facility, which enables researchers and entrepreneurs to test their hydrogen technologies.

There is no opting out of Net Zero; it is wicked problem we must solve to avoid the catastrophic consequences of runaway climate change. This report sets out how we can meet and beat that challenge by refuelling Australia's transport sector on renewable hydrogen and setting Australia on the path to becoming the energy superpower we deserve to be.

**Bronwyn Fox**
CSIRO Chief Scientist

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# Glossary

| | |
|---|---|
| °C | Degrees Celsius |
| ABS | Australian Bureau of Statistics |
| ACT | Australian Capital Territory |
| AE | Alkaline Electrolysis |
| AEM | Anionic Exchange Membrane |
| AEMO | Australian Energy Market Operator |
| amb | ambient |
| Ancillary services | Services used by electricity grid operators to manage power systems safely, securely, and reliability |
| ARENA | Australian Renewable Energy Agency |
| ASX | Australian Stock Exchange |
| ATEX | The hazard of explosive atmospheres occurring in the workplace due to the presence of flammable gasses or combustible dust mixed in air |
| ATEX Directives | EU regulations for products used in explosive environments (Atmospheres Explosibles) |
| atm | An atmosphere, being the average air pressure at sea level at a temperature of $15^0$C, equal to 101.3 kPa |
| B-double | A prime mover towing two semitrailers utilising "B" type couplings |
| bar | Measure of pressure, being 100 kPa |
| behind-the-meter | Electricity generated and used on the same site, that is, not delivered via an external power grid, thus avoiding metered system transmission and distribution charges |
| BEV | Battery electric vehicle, fully electric vehicle with rechargeable batteries |
| bn | billion |
| BOG | Boil-Off Gas |
| Boil-off | As liquid hydrogen is stored as a cryogenic liquid that is at its boiling point, any heat transfer to the liquid causes some hydrogen evaporation, known as boil-off and thus hydrogen leakage |
| BoP | balance of plant |
| C | Celsius |
| capex | capital expenditure |
| Carbon Capture and Storage | The process of capturing and permanently storing carbon emissions |
| Carbon emissions | Carbon dioxide released to the atmosphere from burning fossil fuels, manufacturing, mining, land use and / or other activities |
| CarbonNet | A Victorian Government project aimed at establishing a commercial-scale CCS network to transport by pipeline and inject CO2 into underground offshore storage sites in Bass Strait |
| CcH2 | Cryo-compressed Hydrogen |
| CCS | Carbon Capture and Storage |
| CEFC | Clean Energy Finance Corporation |
| CEM | Clean Energy Ministerial |
| Center for Hydrogen Safety | A not-for-profit organisation, established by the American Institute of Chemical Engineers, aimed at promoting the safe operation, handling and use of hydrogen |
| CF | capacity factor |
| CGH2 | Compressed hydrogen gas |
| CH4 | Methane, a hydrocarbon that is a primary component of natural gas. Also is a greenhouse gas. |

| | |
|---|---|
| Clean Energy Ministerial | A global forum held to promote policies and to share best practices with the aim of accelerating a transition to clean energy. The forum includes partnerships and collaboration between the private sector, public sector, non-governmental organisations, and others |
| Clean hydrogen | Hydrogen produced using renewable energy, or fossil fuels with substantial carbon capture and storage |
| CMSM | Carbon molecular sieve membranes |
| CNG | Compressed natural gas |
| CO | Carbon monoxide |
| CO2 | Carbon dioxide $CO_2$ |
| CO2e | Carbon dioxide equivalent, a metric used to standardise the emissions from various greenhouse gases to determine their individual and total contributions to global warming |
| CO2CRC | CO2 Cooperative Research Centre |
| cryo | cryogenic |
| cryotanks | cryogenic tanks |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation – Australia's national science agency |
| CT | Carbon Tax |
| deg | degrees |
| Demand response | A change in the electricity consumption of a user to assist in matching demand and supply |
| DOE | US Federal Agency, Department of Energy |
| ECHC | Electrochemical Hydrogen Compressor |
| EHS | Electrochemical Hydrogen Separation |
| Electrolysis | The process of using electricity to split water into hydrogen and oxygen |
| EN | European Standards – abbreviated from "European Norm" |
| Energy market bodies | Bodies which have a role regulating and operating Australian energy systems and markets |
| Energy markets | Commodity markets that deal specifically with the trade and supply of energy, generally electricity, gas, and liquid fuels |
| Energy systems | Energy markets and energy supply networks |
| ETS | Emissions Trading Scheme |
| EU | European Union |
| EUR | Euro, being the official currency of 19 of the 27 member states of the European Union |
| EV | Electric vehicle |
| Excise | A tax on manufactured goods that is levied at the point of manufacture, rather than at scale |
| FCEV | Fuel cell electric vehicle |
| fuel cell electric vehicle | An electric vehicle that uses electricity generated by a fuel cell powered by hydrogen, rather than electricity from onboard batteries |
| G20 or Group of Twenty | An international forum for the governments and central banks of 19 countries and the European Union (EU) |
| gallon | 4.546 litres |
| Gasification | A process that converts fossil fuel-based materials into gases |
| GDP | Gross Domestic Product |
| GH2 | Gaseous hydrogen |
| GJ | Gigajoule, a unit of electrical energy equal to 1,000,000 kilojoules |

| | |
|---|---|
| GHG | Greenhouse gas, a group of gases including carbon dioxide, methane, nitrous oxides, and water vapor that absorb and emit radiant energy, thus contributing to climate change |
| GTL | Gloyer-Taylor Laboratories |
| GVA | Gross Value Add |
| GWh | Gigawatt Hour, the amount of electrical energy provided by one gigawatt of power for one hour, equal to 1,000 MWh |
| $H_2$ | Hydrogen |
| H2FA | Hydrogen Fuels Australia |
| H2ICE | Hydrogen-fuelled internal combustion engine |
| H35 | Hydrogen compressed to 350 bar pressure |
| H70 | Hydrogen compressed to 700 bar pressure |
| HDV | Heavy Duty Vehicle |
| HEM | Hydrogen Energy Ministerial |
| HESC | Hydrogen Energy Supply Chain Project, a pilot project to produce and transport clean hydrogen from Victoria's Latrobe Valley to Japan |
| HFCV | Heavy fuel cell vehicle |
| HGV | Heavy goods vehicle |
| HMCA | Hyundai Motor Company Australia |
| HMI | Human-Machine Interface |
| HP | High pressure |
| HRS | Hydrogen refuelling station |
| HSM | Hydrogen storage materials |
| Hydrogen | A colourless, odourless, tasteless, flammable substance that is the simplest chemical element in the periodic table |
| Hydrogen Energy Ministerial Meeting | An annual Ministerial forum initiated by Japan in 2018 |
| Hydrogen hub | Aggregation of producers and users of hydrogen in a geographic area, whether a port, suburb or remote |
| HyNet | Hydrogen Energy Network Co, Ltd, a joint venture of 13 Korean companies, with Hyundai Motor Company, Korea Gas and Air Liquide Korea as major shareholders |
| HyP SA | Hydrogen Park South Australia, an electrolyser delivering renewable hydrogen |
| HyResource | A hydrogen collaboration and knowledge sharing resource of CSIRO |
| ICE | Internal combustion engine, typically fuelled by petrol or diesel |
| IEA | International Energy Agency |
| IECEx | International Electrotechnical Commission |
| Integrated System Plan | A whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond |
| Intergovernmental Agreement | An agreement made between two or more Commonwealth, state or territory governments that details commitments to cooperate on a specific matter of mutual interest |
| IPHE | International Partnership for Hydrogen and Fuel Cells in the Economy |
| IRENA | International Renewable Energy Agency |
| $IrO_2$ | Iridium (IV) oxide |
| ISO | International Organization for Standardization |

| | |
|---|---|
| JAEPA | Japan Australia Economic Partnership Agreement |
| JHyM | Japan H2 Mobility LLC, a venture of eleven companies to accelerate deployment of hydrogen stations in Japan |
| K | Kelvin, SI unit of temperature |
| kg | kilogram being 1,000 grams |
| KOH | Potassium hydroxide |
| kPa | Kilopascal being 1,000 Pascals, being a measure of pressure |
| kW | Kilowatt - a measure of one thousand watts of electrical power |
| kWe | Kilowatts of energy, equal to 1,000 watts |
| kWh | Kilowatt hour - the amount of electrical energy provided by one Kilowatt of power for one hour |
| L | Litre |
| LCOH | Levelised cost of hydrogen - the average net present cost of a unit of hydrogen (per kilogram in this report) over the project lifetime. In this report, LCOH as annotated with a subscript, is alternatively used as a measure of the cost of hydrogen production, measure of the cost of dispensed hydrogen and the contributory cost of component processes (transportation/distribution, compression, storage and filling). |
| $LCOH_C$ | Levelised cost of hydrogen compression |
| $LCOH_D$ | Levelised cost of dispensed hydrogen |
| $LCOH_F$ | Levelised cost of vehicle filling equipment and process |
| $LCOH_P$ | Levelised cost of hydrogen production |
| $LCOH_S$ | Levelised cost of hydrogen storage |
| $LCOH_T$ | Levelised cost of hydrogen transportation (distribution) |
| LDV | Light Duty Vehicle |
| Leadership Group for Industry Transition | An international public private collaboration to drive decarbonisation in carbon and energy-intensive sectors of the economy, launched under the Industry Transition Track of the UN Secretary-General's Climate Summit |
| $LH_2$ | Liquid hydrogen |
| LNG | Liquefied natural gas, the form in which natural gas is transported over long distances |
| LP | low pressure |
| LPG | liquefied petroleum gas |
| m | Metre |
| MCH | methylcyclohexane |
| MCP | Manifold Cylinder Packs |
| MDP | maximum design pressure |
| MEGC | multi element gas container |
| MDV | Medium Duty Vehicle |
| METI | Japanese Ministry of Economy, Trade and Industry |
| MHC | Metal Hydride Compressor |
| min | Minute/s |
| Mission Innovation | A global initiative of 24 countries and the European Commission to accelerate clean energy innovation |
| MJ | Megajoule or 1,000,000 Joules |
| MoU | Memorandum of Understanding |

| | |
|---|---|
| MWh | Megawatt hour - the amount of electrical energy provided by one megawatt of power for one hour, equal to 1,000 kWh |
| n/a | not applicable |
| NA | Not available |
| NAIF | Northern Australia Infrastructure Facility |
| National Energy Security Assessments | Reviews conducted by the Australian Government of the country's energy needs, and assessments of risks to energy supply and costs |
| NEM | National Electricity Market – the wholesale electricity market that interconnects Queensland, New South Wales, Victoria, South Australia, Australian Capital Territory, and Tasmania |
| Ni | nickel |
| no. | number |
| NREL | National Renewable Energy Laboratory |
| NSW | New South Wales |
| OEM | Original Equipment Manufacturer |
| opex | operating expenditure |
| Pa | Pascal, a measure of pressure |
| PAN | polyacrylonitrile |
| PBI | polybenzimidazole |
| Pd | palladium |
| PDBT | perhydro dibenzyl toluene |
| PEM | proton exchange membrane (also known as polymer electrolyte membrane) |
| PFSA | polyfluoroalkyl substances |
| PJ | Petajoule, a unit of electrical energy equal to 1,000,000 gigajoules |
| PSA | Pressure swing adsorption |
| Pt | platinum |
| Public Private Partnership | A long-term contract between a private entity and a government, typically used by governments to pay for the delivery of public infrastructure, assets, or services |
| PV | Photovoltaic |
| R&D | Research and development |
| RD&D | Research, development, and demonstration |
| Renewable energy | Energy that is collected from renewable resources, which are naturally replenished on a human timescale, such as sunlight, wind, rain, tides, waves, and geothermal heat. |
| Revenue arrangements | Contributions to government revenues, which can be levied by governments on sources including income, business profits, or added to the cost of certain goods, services, and transactions. Taxes, excises, fees, and levies are examples of revenue arrangements |
| REZ | Renewable energy zone |
| RuO2 | ruthenium (IV) oxide |
| SAE | SAE International, a global association of engineers and related technical experts in the aerospace, automotive and commercial-vehicle industries |
| Scope 1 emissions | Carbon emissions released into the atmosphere as a direct result of an activity, or series of activities at a facility |

| | |
|---|---|
| Scope 2 emissions | Indirect carbon emissions from consumption of purchased electricity, heat, or steam. Most Scope 2 emissions represent electricity consumption but can include other forms of energy transferred across facility boundaries. |
| Sector coupling | The increased linking of sectors through technology or product changes. Where this linking is well managed it creates opportunities for new or additional benefits and services. Hydrogen technologies can create novel opportunities for sector coupling across electricity, transport, heating, and industry, allowing energy to be used in new ways to benefit users and the environment |
| SI | Standards International |
| $sLH_2$ | supercooled liquid hydrogen (also known as slush hydrogen) |
| SMR | Steam Methane Reforming |
| SOEC | Solid oxide electrolyser cell |
| Stack | In the context of electrolysers, the cells that are typically assembled in series in a “cell stack” that produces more hydrogen and oxygen as the number of cells increases |
| Standards Australia | Australia’s peak standards development body that facilitates technical committees made up of stakeholders from government, business, industry, community, academia, and consumers to develop standards and technical specifications |
| Steam methane reforming | A method to extract hydrogen from natural gas involving catalytically reacting natural gas with steam to produce hydrogen and carbon monoxide (a mixture known as syngas). A subsequent reaction involving more steam produces further hydrogen while also converting carbon monoxide CO to CO2 |
| Supply chain | Activities involved to make, move, store, and use a product |
| SUV | Sports Utility Vehicle |
| tpd | tonnes per day |
| Trailer-swap | A means of delivering hydrogen to the HRS where a fully loaded tube trailer is delivered to site and acts as the onsite storage tank and an empty tube trailer removed |
| TRL | Technology Readiness Level |
| TSA | Temperature Swing Adsorption |
| Tube trailer | A road transport trailer fitted steel tubes for transporting gaseous hydrogen |
| TWh | Terawatt hour, the amount of electrical energy provided by one terawatt of power for one hour, equal to 1,000 GWh |
| UK | United Kingdom |
| US | United States of America |
| USA | United States of America |
| USD | Dollars of the United States of America |
| VRE | Variable Renewable Energy – energy generation that fluctuates depending on the renewable resource availability, such as wind, solar, wave and tidal power |
| WA | Western Australia |
| Well-to-wheel | Well-to-wheel emissions include all emissions related to fuel production, processing, distribution, and use |
| wt | weight |
| ZEV | Zero Emission Vehicle |

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# Executive summary

## Introduction

This report is aimed at providing information around the opportunities and challenges for the deployment of refuelling stations for hydrogen-powered road vehicles in Australia, with particular regard to fuel cell electric vehicles (FCEVs). This report identifies priorities for action, including areas that would benefit from targeted research and innovation. Whilst battery electric vehicles (BEVs) are currently the leading means of decarbonising road transport, FCEVs are expected to play a significant role with heavy duty (HD) and linehaul freight transport, due to their ability to enable:

- much shorter refuelling times, being especially important where time-cost is of key importance
- payload maximisation, through avoiding a substantial negative impact of carrying large, heavy batteries
- greater range between refuelling stops.

## Global context

There are five key overseas jurisdictions, each being major centres of automobile manufacturing, which have made, and are continuing to make, substantial progress in rolling-out hydrogen refuelling stations (HRSs). Germany, Japan, California, South Korea and China between them have around 600 HRSs, being over 80% of the world's total, that service close to 50,000 FCEVs. The progress in these jurisdictions has resulted largely from strategic partnerships and financial incentives from government, supported by the establishment of necessary regulations and standards to provide clarity for project developers.

The overseas experience has highlighted that how hydrogen is produced and distributed to HRSs has important implications for station location, design, scale, and cost and for the environmental benefits of hydrogen use in transportation. Geography, resources, local demand as well as government and industry objectives can be seen to be shaping station configurations. A variety of designs have been developed overseas, with no single preferred configuration emerging as yet. Onsite and offsite production, standalone facilities and additions to existing refuelling locations all continue to be developed.

## Hydrogen refuelling station configurations and sizes

This report considers the Australian context and the merits of a range of HRS configurations across four sizes of stations defined by Maximum Daily Throughput of hydrogen:

- Small: 200 kilograms or 3.3 Heavy Duty FCEV fills
- Medium: 500 kg, 8.3 fills
- Large: 1,000 kg, 16.7 fills
- Extra-Large: 4,500 kg, 66.7 fills.

The HRS configurations are summarised below.

**Table 1. Key configurations considered**

| Config' | Description | Production | Form | Distribution | Storage | Dispensing |
|---|---|---|---|---|---|---|
| 1 | Onsite production, electrolysis using grid electricity | Electrolysis using grid electricity | Gas | n/a | Gaseous storage | Gas compressor and dispenser |
| 2 | Onsite production, electrolysis using onsite renewables augmented by grid electricity | Electrolysis using behind-the-meter renewables | | n/a | | |
| 3 | Offsite production, road transport of gas | Through any of:<br>- electrolysis<br>- reforming<br>- gasification or<br>- by-product | | $CGH_2$ tube trailer | Trailer-swap or bulk delivery | |
| 4 | Offsite production, road transport of liquid | | Liquid | $LH_2$ trailer | Cryogenic tanks | Cryogenic pump and dispenser |
| 5 | Offsite production, pipeline transport of gas | | Gas | pipeline | n/a | Gas compressor and dispenser |

Legend: $CGH_2$ – compressed gaseous hydrogen, $LH_2$ – liquid hydrogen, n/a – not applicable

In relation to the configurations, key conclusions are:

**Configuration 1**, involving the production of hydrogen from an onsite (on HRS) electrolyser is the preferred configuration for pilot or ‘proof of concept’ projects, due to being self-contained (not reliant on an external supply chain for transport and production) and not requiring significant scale to service a modest number of FCEVs. It is also a solution where HRSs are very long distances from offsite production sources.

**Configuration 2**, being the same as Configuration 1, other than there being a source of behind-the-meter renewable electricity in addition to grid electricity to power the onsite electrolyser, is likely only attractive where there is significant space nearby for solar or wind generation and the installed renewable electricity is of a scale beyond that required for the HRS (e.g., for the purposes of export to the grid).

**Configuration 3**, which involves procuring gaseous hydrogen from an external production source and having it transported to the station in bulk compressed form, is likely the most effective configuration (in the midterm) as the scale of HRSs and supporting hydrogen production centres and transportation infrastructure is developed.

**Configuration 4**, which involves procuring liquid hydrogen from an offsite producer and having it transported to site for storage in cryogenic tanks has the potential to be an effective longer-term configuration as liquid hydrogen processes mature, due to liquid hydrogen being a much more concentrated source of energy than gaseous hydrogen, resulting in larger delivery payloads and hence reduced delivery costs.

**Configuration 5**, being a variant of Configuration 3 in that it uses a pipeline rather than road transport to deliver gaseous hydrogen to the HRS site, is likely only suitable for situations where otherwise un-utilised pipelines are available for use or where the HRS is situated in an industrial precinct that includes hydrogen production. Installing a purpose-built dedicated hydrogen distribution pipeline from a remote production source will likely involve a much greater cost than using road transport.

## Cost implications

Significant investments in project development, scale, research and innovation are required to achieve commercially-viable prices at the dispenser that will be competitive with fossil fuels. Cost modelling presented in this report does not attempt to mirror any particular project that may currently be in development in Australia. Rather, it takes a forward-looking approach and assumes that the required investment in supporting infrastructure (e.g. compressing/filling equipment at offsite hydrogen producers) and assets such as Type III and Type IV tube trailers or Multi Element Gas Containers (MEGCs) has been made by industry participants, with those costs then recovered through charges to the HRS operators. The costs and cost components are presented in terms of Levelised Cost of Hydrogen (LCOH), being the average net present cost per kilogram of hydrogen over the project lifetime, calculated using a real discount rate of 7% (which may be lower than investment hurdle rates of some developers). In this report, as annotated by subscript, LCOH is alternatively used as a measure of the cost of hydrogen production ($LCOH_P$), cost of dispensed hydrogen ($LCOH_D$) and the contributory cost of component processes (transportation/distribution, compression, storage and filling (dispensing) – $LCOH_T$, $LCOH_C$, $LCOH_S$ and $LCOH_F$ respectively) at different pressures.

Our cost analysis does not include:

- the cost of the HRS site (too variable an input to meaningfully average)
- any necessary civil works, such as hardstand, drainage or installation of utilities
- any necessary upgrades to grid power supply and connections.
- commercial profit margins
- corporate overheads.

The LCOH figures presented are to provide a comparative analysis of the alternative business models and allow focus on those costs components which are most material to the development of HRSs. Our analysis does not quantify the alternative risk profiles that may be applicable to each project configuration. In addition, it is noted that the most significant contribution to $LCOH_D$ across all considered configurations is the cost of electricity (whether the hydrogen is produced onsite or transported from an offsite production site). For some scenarios (of configuration and scale) electricity comprises close to 50% of the overall $LCOH_D$. This report does not attempt to contemplate the wide range of electricity price scenarios that may eventuate in the future as Australia's energy market transitions towards net zero emission targets, rather it assumes a central AEMO price path. The $LCOH_D$ of all modelled scenarios will rise or fall in line with future electricity price outcomes.

For **Configuration 1**, the modelled dispensed cost of hydrogen on a levelised cost basis ($LCOH_D$) is in the range of \$11.60 (Small HRS) to \$8.59 (Extra-Large HRS) per kilogram, with the cost of producing the hydrogen ranging from 51% to 43% of the $LCOH_D$. In turn, the electricity to power the onsite electrolysers comprises around half of the hydrogen production cost.

Thus, for onsite production, whilst there should be focus on reducing the costs of procuring and installing electrolysers, there should be equal or greater focus on improving electrolyser power efficiency in response to escalating electricity prices. Focussed consideration should be given to optimising the flexibility of the electrolyser plant, and time-of-day load management to reduce input electricity costs.

Second to the cost of hydrogen production, is the cost of onsite hydrogen compression with, similar to the electrolysis, around 50% of $LCOH_C$ being the cost of grid electricity input. Compressor costs benefit greatly from economies of scale with $LCOH_C$ reducing from \$2.32 per kilogram for a Small HRS to \$0.58 per kilogram for an Extra-Large HRS.

Modelling of **Configuration 2** provides similar, but higher cost outcomes, as Model 1 due to the cost of establishing onsite renewable electricity (assumed to be solar photovoltaic). Whilst on a marginal cost basis, solar electricity is much lower cost than grid electricity, this is outweighed by the capital cost of installing the solar array. The use of onsite (or otherwise behind-the-meter) electricity is likely best suited where there is a wider proximate electricity need (e.g. where the HRS might be part of an energy hub or where it is intended to export power to the grid).

**Configuration 3**, based on the modelling, is the best solution for most scenarios where round-trip delivery distance is less than approximately 600km. It is premised on the availability of compressed hydrogen transport vehicles and hydrogen producers that have the capacity, infrastructure and willingness to sell to HRS operators. Whilst there are Type I tube trailers (230 bar pressure) currently available in Australia, tube trailers with higher pressures and higher capacities (Types III and IV) can play a substantial role in improving the economics of the offsite production model.

**Configuration 4** (transporting liquid hydrogen from remote production facilities) is expected by many industry stakeholders to be an attractive future option for HRSs with high throughput, due to the potential to transport and store larger volumes of hydrogen at a lower cost. This is borne out by our financial modelling, with a $LCOH_D$ of dispensed hydrogen as low as \$6.65 per kilogram for an Extra-Large HRS. Thus, liquefaction, and transporting, storage and dispensing of liquid hydrogen present as areas of great interest for commercial and industrial research and innovation.

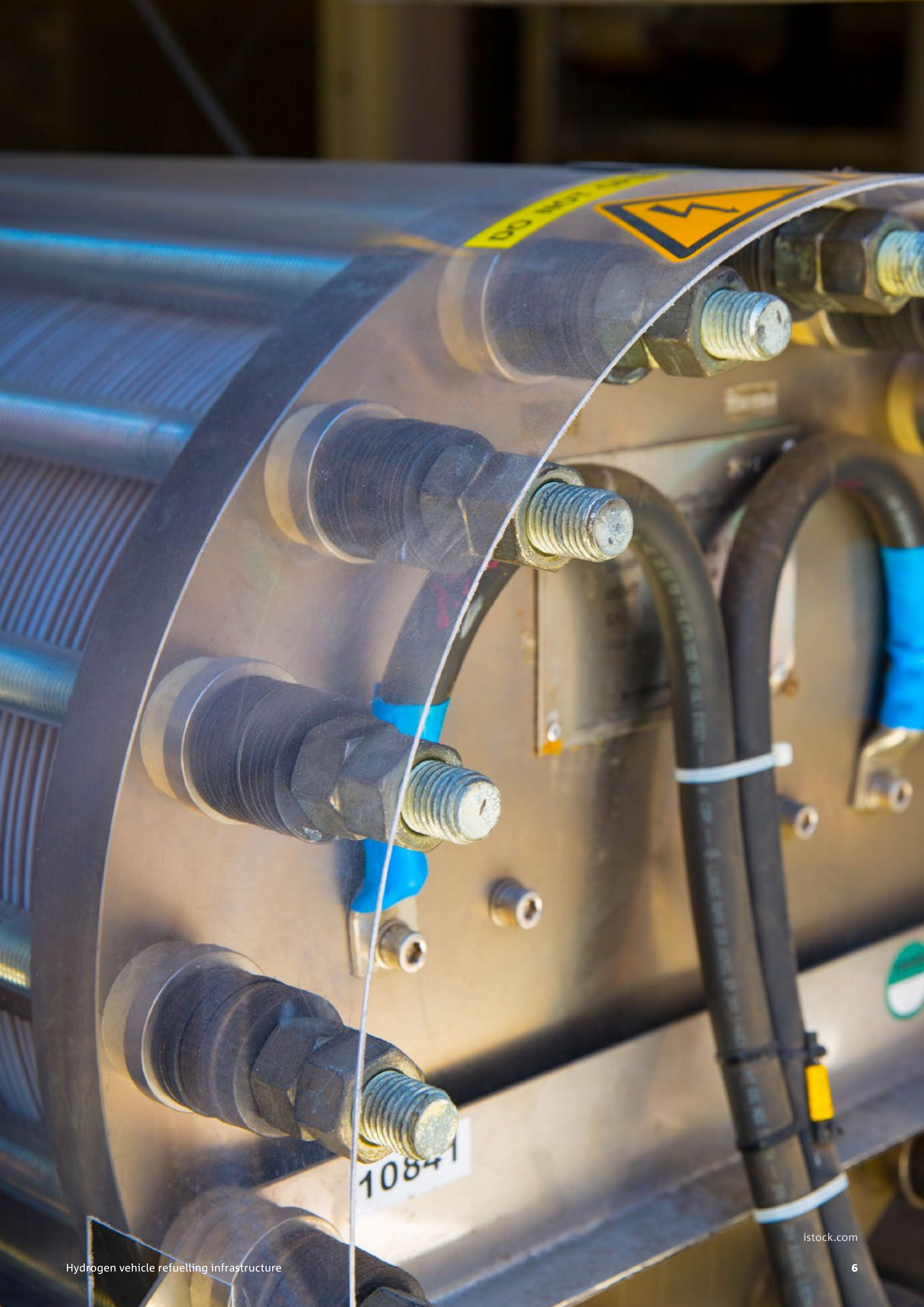
## Other findings

The table below sets out some of the key observations and findings in this report, along with the associated opportunities.

**Table 2. Summary of other observations and findings**

| Key observations / findings | Opportunities | Report reference |
|---|---|---|
| **Industry initiatives and business models** | | |
| 1. Those overseas jurisdictions that are much more developed than Australia with their roll-out of HRSs have utilised major public sector – private sector partnerships and consortia to provide a collective approach to stimulating demand, promoting research and development, sharing risks and achieving initial scale to allow supply chain cost reductions. | Incorporate learnings from overseas to expedite infrastructure development in Australia.<br>Incentivise international technology partnerships.<br>Further develop Australia's Hydrogen Hubs' strategy to incorporate a wider scope of stakeholders in mobility projects, especially from fuel retailing and vehicle manufacturing.<br>Governments to investigate the potential to found / support the creation of sector partnerships/consortia in the Australian market. | 3.1. 3.2 |
| **Offsite versus onsite hydrogen production** | | |
| 2. Centralised offsite production and distribution of hydrogen to HRSs is likely to be the dominant future model due to cost efficiencies with scale and the avoidance of needing to accommodate onsite production when selecting sites. | Governments and developers should focus on the enablers of larger scale HRSs utilising hydrogen supplied by centralised offsite production facilities. | 8.2.1, 8.2.3 |
| 3. To date, onsite production of hydrogen is currently the supply model of the existing early HRSs and those currently being planned/developed in Australia, due to it being self-contained and not dependent on transporters and external producers of hydrogen. | Continue to develop onsite production as an early-stage approach, and as a prototype for remote locations that may be long distances from offsite production sites, and that may have less neighbourhood constraints to accommodating larger scale onsite production. | 2.5 |
| 4. Modelling shows that incorporating the use of purpose-built behind-the-meter renewable electricity, scaled to the size of the HRS, adds to the cost of onsite hydrogen production versus fully relying on grid-supplied electricity. | Consider co-locating HRSs with existing large-scale renewable electricity sources where possible (having regard to established freight routes) and /or if new renewable electricity was to be utilised, it being of a scale beyond that needed for servicing the HRS. | 8.2.2 |
| **Pressure and form of hydrogen** | | |
| 5. Currently most Heavy Duty and Medium Duty FCEVs (overseas) use hydrogen at 350 bar pressure. However, a number of vehicle manufacturers are now flagging a transition to 700 bar, especially for long haul transport – initially aiming at 1,000km range. | The cost of onsite storage at 700 bar is significantly higher than that of storage at 350 bar, thus this is an area that would benefit from focussed research and innovation, including continued research into the optimisation of cascade storage. | A1.1, 5.4.2 |
| 6. Liquefaction, and transport and storage of liquid hydrogen, to be dispensed as a gas presents as an opportunity to greatly improve distribution and storage capacities. However, transport and storage of liquid hydrogen at low volumes is currently very expensive compared to compressed hydrogen. | Promote focussed research and innovation to enhance the technology and processes for liquefaction, and transport and storage of liquid hydrogen. | 5.2.2 |
| 7. Long-haul vehicle manufacturers are flagging future use of onboard liquid hydrogen as fuel, which will greatly increase the hydrogen energy that can be carried in vehicle tanks, thus increasing range and limiting the impost of the tank volume. | Dispensing technology is developed, but field experience is limited. Demonstration trials are necessary. | 5.5.4, 5.5.5 |

| Key observations / findings | Opportunities | Report reference |
|---|---|---|
| **Distribution of hydrogen to HRSs** | | |
| 8. Road distribution of hydrogen utilising existing steel tube trailer technology is limited by capacity constraints. There is an overseas trend towards transporting in higher pressure Type III and Type IV carbon fibre cylinders that can transport hydrogen much higher volumes, with lower weight. | Explore Australia's access to Type III and Type IV tube trailers and consider a potential collective approach to acquisition of trailers for shared use of fuel companies / hydrogen distributors. | 5.2.1 |
| 9. For the foreseeable future, transport of hydrogen directly to HRSs by dedicated pipeline will likely be difficult to justify in most cases, due to high capital intensity and relatively low demand of individual HRSs. However, there could be refuelling locations in industrial or port areas (e.g. hubs) that are suitable for direct pipelines, due to proximity to the supply source and/or having pre-existing pipelines that can be repurposed, although additional onsite compression will be required due to lower delivery pressures. | Explore use of new or repurposed pipelines for distributing pure hydrogen from production facilities to high demand facilities and/or delivery hubs (from which road transport could complete the deliveries).<br><br>Undertake further research and technology development for the extraction of hydrogen from natural gas network blends. | 5.2.3 |
| **Policies, standards and regulation** | | |
| 10. Government policy can be a leading driver of the adoption of alternative fuels for road transport. | Consider targeting GHG abatement in transport as a priority within broader decarbonisation policies. Options include, enaction of emission standards (e.g. carbon intensity) for road vehicles, or incentive measures such as tax exemptions. | 3.2, 3.3, 3.4 |
| 11. Australia currently lacks nationwide standards, regulations and planning processes for transport of hydrogen, HRS equipment and configuration, contributing to uncertainty, cost and investment uncertainty. | Align requirements of road regulators, work safety agencies, environment protection agencies and energy departments. Introduce a comprehensive set of standards/certifications for harmonised application across states and territories and a simplified, nationally consistent approach for certifying equipment manufactured overseas for use in Australia. | 3.3 |
| 12. Regardless of the scale, onsite versus offsite production, and preferred location, developers and investors are seeking clarity of planning processes. | Develop clear, predictable and well-documented planning and environmental processes for siting of HRSs. Develop clear standard approach to assessing and mitigating risk – consider standard planning templates and distances per AS1940 and NFPA2, in particular for $LH_2$. Consider adopting international standards for equipment to simplify HRS development. | 3.3, 6.1, 6.2, 6.3 |
| **Costs** | | |
| 13. Compression, and associated cooling, is expensive in terms of both capital and operating costs. | Continue research into technology improvement and associated cost reductions.<br><br>Focus on achieving sufficient scale to reduce unit costs. | 5.3 |



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# 1 Introduction

This report is aimed at providing information around the opportunities and challenges for the deployment of hydrogen refuelling stations (HRSs) for road vehicles in Australia.

In particular, this report provides focus on and analysis of five different HRS combinations of production, distribution, storage and dispensing of hydrogen, as shown below in Table 3.

**Table 3. Key HRS configurations**

| Option | Description | Production location | Production | Form | Distribution | Storage | Dispensing |
|---|---|---|---|---|---|---|---|
| **1** | Onsite production, electrolysis using grid electricity | Onsite | Electrolysis using grid electricity | Gas | n/a | Gaseous storage | Gas compressor and dispenser |
| **2** | Onsite production, electrolysis using onsite renewables augmented by grid electricity | | Electrolysis using behind-the-meter renewables | | n/a | | |
| **3** | Offsite production, road transport of gas | Offsite | Through any of<br>- electrolysis,<br>- reforming,<br>- gasification, or<br>- by-product | | $CGH_2$ tube trailer | Trailer-swap or bulk delivery | |
| **4** | Offsite production, road transport of liquid | | | Liquid | $LH_2$ trailer | Cryogenic tanks | Cryogenic pump, vaporiser and dispenser |
| **5** | Offsite production, pipeline transport of gas | | | Gas | pipeline | n/a | Gas compressor and dispenser |

This report is set out in the following parts:

**Part A: Context** sets out relevant Australian and International context for consideration of HRSs, and the key development and business considerations.

**Part B: Hydrogen supply technologies** provides information in relation to the key supply chain components relevant to dispensing hydrogen to road vehicles.

**Part C: Hydrogen refuelling configurations** provides explanation of five key options for making available hydrogen for road transport refuelling.

**Part D: Cost analysis** provides comparative financial analysis of the HRS configurations.

**Part E: Key priorities, challenges and opportunities** sets out priorities for government and industry action, including areas that would benefit from targeted research and innovation.

Appendices include background overview information in relation to **FCEVs (Appendix A.1)**, and components and layouts of **HRSs (Appendix A.2)**.

# Part A – Context


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# 2 Australia's opportunity for hydrogen-powered road transport

## 2.1 Australia's emissions reduction challenge

The world is on a journey to reduce carbon emissions. Globally, transport makes up nearly a quarter of total emissions of which road transport contributes around 75%.

In Australia, road transport currently produces 34 million tonnes per annum[1] of carbon emissions, with this amount continuing to grow each year. Globally, many major vehicle manufacturers have committed to cease production of fossil fuel internal combustion engine (ICE) vehicles in the next decade and consequently, fuel suppliers are developing business strategies to align with the plans of the vehicle manufacturers. To align with domestic and international decarbonisation agendas, such as Australia's newly adopted climate change legislation (43% emissions reduction by 2030 relative to 2005 levels, and net zero by 2050), Australia's road transport emissions need to be reduced in an effective manner.

Road networks make up an integral part of Australia's multi-modal transport network, providing an estimated 4.5% of total Gross Value Add (GVA) or $236bn in added economic value[2]. Around 13 percent of all freight in Australia is moved by road vehicles, with freight movement in urban centres expected to increase by 60 percent from current levels by 2040[3]. The importance of movement of goods by road in Australia flows from the large size of the country, its low population density, and limitations with rail connections (albeit that rail is expected to play an increasing important role in Australia's decarbonisation). There are many smaller centres scattered across the Australia that are accessible by road only.


**Figure 1. Australia's key road freight routes[4]**

1 DCCEEW 2022, National inventory by economic sector: annual emissions, accessed August 2022 from https://www.dcceew.gov.au/climate-change/publications/national-greenhouse-accounts-2019/national-inventory-by-economic-sector-annual-emissions

2 Roads Australia 2021, The value that roads deliver to the Australian community, access July 2022 from https://roads.org.au/wp-content/uploads/FINAL_2021_RA_BISOE_ImpactReport.pdf

3 National Freight and Supply Chain Strategy 2016, What is Strategy?, accessed July 2022 from https://www.freightaustralia.gov.au/what-is-the-strategy#:~:text=The%20nature%20of%20the%20freight%20challenge%20is%20also,60%20per%20cent%20over%2020%20years%20to%202040.

4 National Key Freight Routes Web App (infrastructure.gov.au)

## 2.2 Why hydrogen for road transport?

For road transport, the key options for replacing the carbon-emitting fossil fuels of petrol, diesel and liquefied petroleum gas (LPG) are:

- battery electric vehicles (BEVs)
- hydrogen-fuelled vehicles, both fuel cell electric vehicles (FCEVs) and hydrogen internal combustion engine ($H_2$ICEs) vehicles.

For the purposes of this report, our primary vehicle reference will be to FCEVs rather than H2ICEs, due to FCEVs currently being more prevalent and proven than $H_2$ICEs vehicles for road transport.

Biofuels and e-fuels are also anticipated to make a contribution towards decarbonisation of road transport, however of a more peripheral nature than BEVs and FCEVs, due to scale limitations.

Whilst there is a view that BEVs may have better 'well-to-wheel' energy efficiencies than FCEVs, and are seen to be increasingly-proven for light vehicles, there is a view that FCEVs may be a better solution for heavy duty (HD) and linehaul vehicles due to:

- having much shorter refuelling times, which can be especially important for freight and linehaul transport, where time-cost is a key factor
- avoiding the substantial negative impact on payload capacity that can result from carrying large, heavy, batteries of the size required to power freight vehicles
- providing greater range between refuelling stops.

It is considered that FCEVs are gradually becoming more competitive with existing diesel HD vehicles in terms of refuelling times and range. With continued reductions in hydrogen supply costs and added technological advances (for example, improved fuel cell efficiency), FCEVs are anticipated to emerge in the future as being cost competitive with petrol and diesel HD vehicles, and play a significant role in linehaul road transport in Australia. For these reasons, in consultations, a number of linehaul vehicle manufacturers and trucking operators have indicated a preference for hydrogen fuel cells over their counterpart electric battery-powered vehicles.

Appendix A.1 sets out a background overview of FCEVs.

## 2.3 Global leaders with FCEVs and HRSs

There are five key jurisdictions overseas, being major centres of automobile manufacturing, which have made, and are continuing to make, substantial progress in rolling-out hydrogen refuelling stations (HRSs). Germany, Japan, California, South Korea and China between them have around 600 HRSs, being over 80% of the world's total, that service close to 50,000 FCEVs. The progress in these jurisdictions has resulted largely from strategic partnerships and financial incentives underpinned by government strategies, supported by the establishment of necessary regulations and standards to provide clarity for project developers.

Appendix A.2 sets out a background overview of HRSs.

## 2.4 Why now?

Globally and in Australia, the threat of climate change is accelerating the drive to decarbonise human activity. This drive is presenting through increasing regulatory, market and social pressures. These pressures carry an urgent need to progress the likely highly disruptive (divergent from traditional approaches and behaviours), decarbonisation of road transport. These pressures directly drive the imperative for zero emissions vehicles (including FCEVs) and refuelling infrastructure deployment.

Moreover, the critical elements in evaluating emissions reduction strategies are the amount and timing of the reduction. The time value of carbon is critical as the impacts of emissions are cumulative and there is a limited amount of time to reduce these consequences.

## Regulatory pressures

In Australia, regulatory pressures arise from the need to meet legislated decarbonisation targets, with a requirement for all state and territory governments to achieve net-zero carbon emissions by 2050 or earlier following ratification of the Paris Climate Agreement in 2016. This in turn is resulting in state-based emissions mandates and Zero Emission Vehicle (ZEV) targets[5], thus driving transport operators to consider how they will switch to alternative fuels and modes. The rate at which this is occurring, and the subsequent proliferation of FCEV deployment, will require significant investment in refuelling infrastructure and strategic deployment of HRSs at existing service stations.

Globally, regulatory pressures are significantly influencing product developments in Australia's vehicle and refuelling technology supply markets, hence our regulations and infrastructure must move to support and accommodate the new and emerging vehicles coming from those markets.

## Market pressures

Market pressures stem from transport organisations needing to maintain competitiveness in both domestic and international markets. As international automotive manufacturers transition to decarbonised solutions in the form of increased BEV and FCEV production, and the development of hydrogen-fuelled internal combustion engines ($H_2$ICEs), Australia will require infrastructure suitable to support their deployment.

Manufacture of refuelling equipment is currently undertaken overseas and imported, indicating that the procurement of any refuelling networks in Australia will be intrinsically linked to the international market.

Many major overseas jurisdictions have aggressive targets and mandates for the adoption of 100% zero emission vehicle sales and / or banning of internal combustions engines (that use fossil fuels), from as early as 2025 through to 2040. These mandates, alongside initiatives such as the UN Global Technical Regulations (GTR13) for hydrogen fuelled vehicles and ISO/TC22 Road Vehicles, will drive the balance of global production toward electric and hydrogen vehicles with Australia currently beholden to its supplier markets.

## Want for enhanced security of fuel supply

Over past decades Australia has become increasingly reliant on foreign supply for its transport fuels (over 90% imported according to recent research by The Australia Institute). This along with the recent decline in local refining capacity translates into an increased security of fuel supply risk, accentuated by recent experience of post-COVID supply chain uncertainties in many sectors, and geopolitical instability in Europe. At a domestic level, the development of hydrogen refuelling networks, as a source of demand, will make some contribution to the stimulation of local production of hydrogen (as an alternative to fossil fuels). Arguably development of hydrogen refuelling networks will also propagate growth of local and distributed level ecosystems, protecting against the risk to security of fuel supply. Australia's hydrogen export aspirations should also support investment in the development of large-scale hydrogen production infrastructure.

## Social pressures

In Australia and around the world, there is increasingly a social expectation to move towards decarbonisation of human activity. Mounting transparency and customer service requirements have led consumers, investors, and employees to have a voice on tackling carbon emissions across transport supply chains. The stakeholder base for consumer goods freight and large passenger carrying vehicles is so significant, and 'consumer perception' such an important factor, that the level of scrutiny is only expected to increase. Ultimately, the development of hydrogen refuelling networks, in conjunction with anticipated BEV networks, is expected to be one of the most effective means for transport organisations to both decarbonise their fleets, and brand and promote their efforts to satisfy social expectations.

5 I can be assumed that a proportion of these will be FCEV based.

## 2.5 Current status in Australia

There are less than one-hundred FCEVs in Australia, with nearly all being light passenger vehicles - Toyota Mirai sedans and Hyundai NEXO SUVs. The FCEVs are aligned with one of the five existing operational refuelling stations, shown in the table below.

There are currently up to 20 further stations under development or planned around Australia (see Appendix A.3). Both public and private hydrogen refuelling infrastructure is currently expected to grow significantly over the next five to ten years. Hydrogen as a transport fuel will contribute to the decarbonisation of the road transport sector, it may provide strategic security of fuel supply and reduce energy dependency on other countries and provide some relief to the extent of electricity distribution and fast charging otherwise required.

**Table 4. Existing Operational Australian Hydrogen Refuelling Stations**

| Project Name | Location | Daily capacity | Vehicles serviced |
|---|---|---|---|
| Toyota Hydrogen Centre | Altona, Melbourne, Vic | 80 kg | 20 Toyota Mirai sedans leased to government. The Victorian Government is supporting the future launch of two FCEV buses |
| ActewAGL Hydrogen Refuelling Station | Fyshwick, Canberra, ACT | 22 kg | 20 Hyundai NEXO SUVs leased to ACT Government |
| BOC Hydrogen Production and Refuelling Project | Brisbane, Qld | 80 kg | Fleet vehicles with further vehicles and 350-bar trucks and buses to be added in a second phase |
| Hyundai Hydrogen Refueller | Macquarie Park, Sydney, NSW | 20 kg | Hyundai NEXO SUVs |
| ATCO / Fortescue Hydrogen Refueller Station Project | Jandakot, Perth, WA | 63 kg | Toyota Mirai sedans used by ATCO, Fortescue and approved third parties |

# 3 The lessons of international experience

## 3.1 State of play overseas

On a global basis, existing HRSs are heavily concentrated in a limited number of regions, with over 80% located in California, China, Germany, Japan and South Korea, with most of the balance of the world's refuelling stations in northern Europe (outside of those in Germany)[6] and the UK. The FCEV market is also concentrated primarily in these jurisdictions, with only 6 per cent of FCEVs outside the five biggest markets, see Table 5. Appendix A.1 to this report sets our explanatory background in relation to the workings and features of FCEVs.

## 3.2 What is different overseas?

Despite Australia's ambitious objectives around hydrogen, targeted policies and funding, the country is a long way behind the leading jurisdictions with the rollout of hydrogen refuelling networks. To understand this phenomenon, stakeholders engaged for this report, from across the value chain, were asked: *What is driving overseas development? What can Australia do to become more competitive?* The responses universally touched on one or all the following points:

- clear government policy on emissions reductions will render fossil fuels unviable, driving a pivot to alternative fuels for vehicle Original Equipment Manufacturers (OEMs) and fuel retailers
- establishing clear strategic objectives, supported by government, joint ventures and partnerships along the hydrogen refuelling value chain
- establishing Australian standards and regulations on station configuration, material handling and equipment
- providing adequate financial and regulatory support for industry first movers.

### Government Policy

Government policy has been a primary reason for development of hydrogen infrastructure overseas. Put simply, many businesses in the automotive supply chain believe that government regulations will make fossil fuels unviable in many overseas jurisdictions within the next 20 to 30 years, if not sooner. Regulations are encouraging and incentivising alternative fuel vehicles. In February 2022 the European Parliament voted to approve a new law banning the sale of new petrol and diesel cars from 2035. Table 6 below shows legislated end dates for sales of petrol vehicles for the jurisdictions with the most HRSs.

**Table 6. Final year of petrol vehicle sales by country[8]**

| Country | Final year of new petrol car sales |
|---|---|
| Germany | 2035 |
| China | 2040 |
| Japan | 2035 |
| California, USA | 2035 |
| South Korea | 2030 |

**Table 5. Global numbers of HRSs and FCEVs[7]**

| | California | China | Germany | Japan | South Korea | Rest of the world | Total |
|---|---|---|---|---|---|---|---|
| HRSs | 67 | 147 | 91 | 169 | 114 | 141 | **729** |
| Percentage of total | 9% | 20% | 12% | 23% | 16% | 19% | **100%** |
| FCEVs | 12,358 | 8,474 | 1,549 | 6,741 | 19,404 | 2,911 | **51,437** |
| Percentage of global FCEVs | 24% | 16% | 3% | 13% | 38% | 6% | **100%** |
| FCEVs per HRS | 184 | 58 | 17 | 40 | 170 | 21 | **71** |

6 International refers to the previously mentioned jurisdiction, based on their status as the most developed in this sector.

7 Perna A, Minutillo M, Di Micco S, Jannelli E.2022, Design and Costs Analysis of Hydrogen Refuelling Stations Based on Different Hydrogen Sources and Plant Configurations. Energies, 15(2)

8 WorldAtlas 2021, Countries that will ban gasoline cars, accessed July 2022 from https://www.worldatlas.com/articles/countries-that-will-ban-gasoline-cars.html

A price on carbon is a common factor in the most progressed hydrogen transport jurisdictions. Stakeholders also pointed to this as a reason for more development overseas. In particular, motor vehicle manufacturers in carbon pricing jurisdictions have a financial imperative to focus on ZEVs, given that they pay higher taxes for producing high emission models. Table 7 outlines the carbon taxes or trading systems found throughout these markets.

## Strategies and objectives

The governments of the cited countries/states have strategies which are highly focused on developing hydrogen refuelling station networks. From this, clearly defined objectives on development of HRSs and FCEV ownership levels have been developed. This focus is coupled with well-funded and capable joint ventures and partnerships, with the objective of creating refuelling networks. Table 8 shows the target numbers of HRS and FCEV uptake of the most mature jurisdictions.

## Joint ventures and partnerships

Collaborative joint ventures and partnerships are a key enabler of refuelling infrastructure development in the most mature networks. There is a focus on combining businesses and government organisations where multiple entities from across the value chain pool resources, knowledge, and influence to share costs, expertise and risk. Significant HRS consortia are shown in the table below.

**Table 7. International Carbon Mechanisms[9]**

| Country | Primary mechanism ETS or CT | Carbon Price (USD/t$CO_2$e) | Share of emissions covered | Revenue raised (USD m) |
|---|---|---|---|---|
| **California** | ETS | 17.9 | 80% (Incl. transport) | 1,698 |
| **China** | ETS & CT | <10 (regional variance) | 20-40% (not incl. transport) | Variable but <20 |
| **Germany** | ETS | 29.4 | 40% (incl. transport) | N/A |
| **Japan** | CT (ETS in Tokyo & Saitama) | 2.6 | 70% (incl. transport) (20% Tokyo & Saitama) | 2,365 |
| **South Korea** | ETS | 15.9 | 74% (incl. transport) | 219 |

ETS: Emissions Trading Scheme, CT: Carbon Tax

**Table 8. 2030 targets of key markets for numbers of HRSs and FCEVs**

| 2030 target numbers | California | China | Germany | Japan | South Korea |
|---|---|---|---|---|---|
| HRSs | 1,000 | >1,000 | 300 | 900 | 660 |
| FCEVs | 1,000,000 | >1,000,000 | No target | 800,000 | 850,000 |

9 The World Bank 2021, State and Trends of Carbon Pricing, accessed July 2022 from https://www.worldbank.org/en/news/press-release/2022/05/24/global-carbon-pricing-generates-record-84-billion-in-revenue#:~:text=WASHINGTON%2C%20May%2024%2C%202022%20%E2%80%94%20Global%20carbon%20pricing,and%20Trends%20of%20Carbon%20Pricing%E2%80%9D%20report%20released%20today.

Table 9. Major Hydrogen Refuelling Station consortia[10][11]

| Partnership/JV | Market | Partners | Activities | Industry Participants |
|---|---|---|---|---|
| Japan H2 Mobility (JHyM) | Japan | Toyota, Honda, Iwatani, Air Liquide, Development Bank of Japan, Tokyo Gas | Building and operating hydrogen refuelling stations throughout Japan. As of early 2022, 63 of Japan's 166 locations were constructed by JHyM | Car Manufacturers, Chemical Process |
| True Zero | California | Iwatani, Toyota, Honda, Mitsui, Air Liquide, California Energy Commission | Dedicated hydrogen refuelling company serving the Californian market. Currently hold the most locations in that network | Car Manufacturers, Chemical Process, Government |
| H2 Mobility | Germany | Air Liquide, Daimler, Hyundai, Linde, OMV, Total Energies, BMW, Honda, Toyota, Volkswagen, Tank & Rast | Developing HRSs across Germany, with a goal for 100 stations to service 6 million people without needing to make detours of more than 5km | Car Manufacturers, Chemical Process, Fuel Retailers |
| Hydrogen Energy Network (HyNet) | South Korea | Hyundai, Korea Gas Corporation, Air Liquide Korea, Korean Ministry of Environment | Aiming to build and operate 100 HRSs throughout South Korea by 2022 | Car Manufacturers, Chemical Process, Government |
| Jet H2 Energy | Germany, Austria, Denmark | Phillips 66, H2 Energy Europe (Swiss H2 station operator) | Aiming to develop approximately 250 HRSs by 2026 | Fuel Retailers, Government |

These partnerships are supported by focussed government funding that has been made available for infrastructure and in the form of incentives, particularly for the uptake of FCEVs. This dual pronged approach of stimulating both supply and demand has been crucial in the development of overseas networks. It is noted that despite significant government support, some industry participants indicated that investment in hydrogen refuelling in these jurisdictions currently remains a 'loss leader' activity with a focus on future road transport markets (and decarbonisation targets).

Table 10. HRS and FCEV strategies and funding in the most developed jurisdictions[12]

| | China | Japan | South Korea | Germany | California |
|---|---|---|---|---|---|
| National/regional strategies for HRSs | ✓✓ | ✓✓ | ✓✓ | | |
| Funding commitments for HRSs | $300m+ | $640m | $199m | $188m | $279m |
| Subsidies for FCEV uptake | ✓✓ | ✓✓ | ✓✓ | ✓✓ | ✓✓ |
| Refuelling stations being developed by a consortium | | ✓✓ | ✓✓ | ✓✓ | ✓✓ |

10 H2 Bulletin 2021, Japan JHyM to add four new hydrogen stations, access July 2022 from https://www.h2bulletin.com/japan-jhym-to-add-four-new-hydrogen-stations/

11 Fuel Cells Bulletin 20219, Korean joint venture HyNet aims to set up 100 stations by 2022, media release, accessed July 2022 from https://www.sciencedirect.com/science/article/abs/pii/S1464285919301518

12 CMS 2021, Hydrogen Law, Regulations & Strategy in South Korea, accessed July 2022 from https://cms. law/en/int/expert-guides/cms-expert-guide-to-hydrogen/south-korea

### Regulations, codes and standards

To support the above targets, hydrogen refuelling standards and regulations have been developed. For example:

- California's Government has released a '*Hydrogen Station Permitting Guidebook'*[13]
- South Korea has updated its transportation laws to establish standards on safety and handling for hydrogen refuelling stations and FCEVs more generally[14]
- Germany has adopted EU standards and regulation around hydrogen refuelling with regards to safety, station configuration and material handling[15]
- Japan has amended its existing regulations for gases and refuelling stations to include sections on requirements for HRS[16]. This clarity has played a significant role in facilitating the infrastructure rollout, according to stakeholders engaged for this report.

Appendix A.4 sets out further background information in relation to the international experience to date.

## 3.3 Australia's experience – how to remain competitive?

Targeted policy drivers, financial support, and regulation similar to those in the indicated overseas jurisdictions may enhance Australia's progress with the roll-out of HRSs. In addition, Australia could benefit from greater co-operation between private sector parties through purpose-driven industry associations and large-scale consortia.

Industry stakeholders interviewed for this report cite the following as key barriers to Australia's progress:

- lack of regulatory pressure around transport emissions is a key contributor to relative inertia of progress
- high-cost and complexity associated with planning, permitting and station configuration has led to slower uptake in HRS development
- a lack of national standards for refuelling equipment contributes to a more difficult vendor (supplier) selection process
- the need to reconfigure equipment to meet disparate regulatory requirements adds significant cost and complexity
- there is a low level of renewable hydrogen supply in Australia.

### High costs

Prohibitive costs of establishing a station and ensuring supply are another prominent issue affecting the pace of Australia's HRS rollout. Equipment such as storage, compression and electrolysers were noted as the primary focus. Stakeholders advised that incentives and grants were generally necessary to purchase these items, especially given the uncertainty of demand for hydrogen refuelling. Additional assistance for capital expenditure and focussed research and development investment on hydrogen production, storage and compressions equipment was also flagged as a possible solution.

## 3.4 Lessons for Australia

Given the overseas experience, Australia can evaluate the possibility of:

- embedding a transition to alternative zero emissions fuels in broader climate change and decarbonisation regulation and legislation
- establishing public and private partnership for financial support
- creating tax incentives to stimulate the pivot away from fossil fuels
- ensuring the development of hydrogen production capacity, especially from renewables, to support a growing HRS network
- promotion of public-private sector partnerships to develop and share research, innovation and funding.

13 California Governor's Office 2020, Hydrogen Station Permitting Guidebook

14 CMS 2021, Hydrogen Law, Regulations & Strategy in South Korea, accessed July 2022 from https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/south-korea

15 Wurster, R, Hof, E. 2021, The German hydrogen regulation, codes and standards roadmap.Int J Energy Res.45, pages 4835– 4840.

16 CMS 2021, Hydrogen Law, Regulations & Strategy in Japan, accessed July 2022 from https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/japan

# 4 Development and business considerations

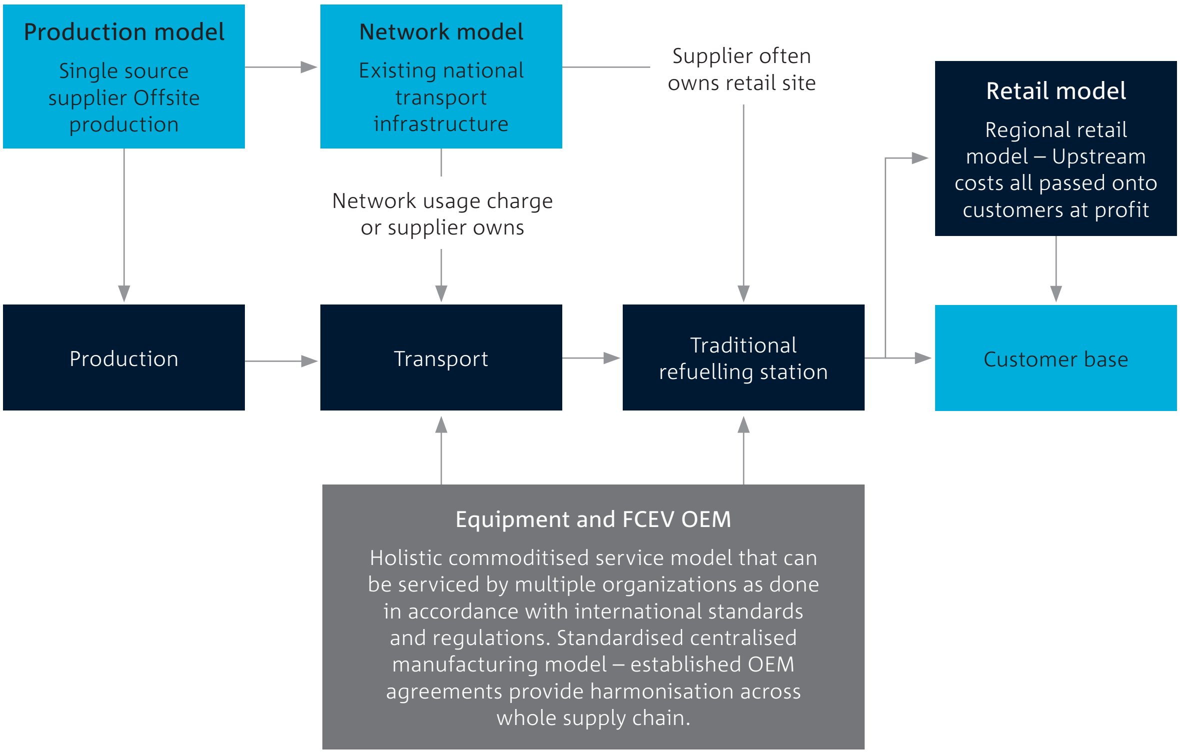
## Background

There are notable differences in the design, deployment, operation, and customer bases for HRSs to those of traditional petrol and diesel refuelling stations. Traditional refuelling deployment and operations are static and predictable, determined by mature fuel production and distribution supply chains, vertically integrated oligopolistic market structures and isotropic consumer base (high traffic density centres, connecting corridors and predictable demand). In contrast, the hydrogen refuelling sector depends on an unproven demonstration scale supply chain, a diverse, innovative, and disruptive first mover market and a customer base that does not yet exist in any material sense, and that is heavily dependent on the development of supply. The implication of this context has led to a 'gold rush' of business models and approaches looking to capitalise the opportunities in this sector.

To understand the implications and reasoning behind the approaches that are being taken, it is useful to draw comparisons with the existing traditional refuelling station business model, which has been developed to be an efficient, cost-effective, integrated, standardised, highly-regulated, low-risk operational and business environment. This then illustrates where the disparities in context arise and how they are being addressed.


CSIRO

**Traditional Refuelling Station Model – Simple: Established stakeholders, predictable dynamic and standardise processes**




## Infrastructure model

In the traditional refuelling model, as a result of developing from the establishment of the LNG and petroleum industry, infrastructure is linear and well established. Large scale centralised production centres are connected to demand hubs through nationally spanning transport and distribution networks (pipeline, road transport and storage). The operation and management of infrastructure is governed by internationally recognised and legally binding standards and regulations. This last point provides an industry wide standardisation that means infrastructure interfaces can be designed to optimise the movement of commodities through the value chain and allows all stakeholders; customers, automakers, fuel providers, etc. to operate in the market effectively.

## Ownership model and entity engagement

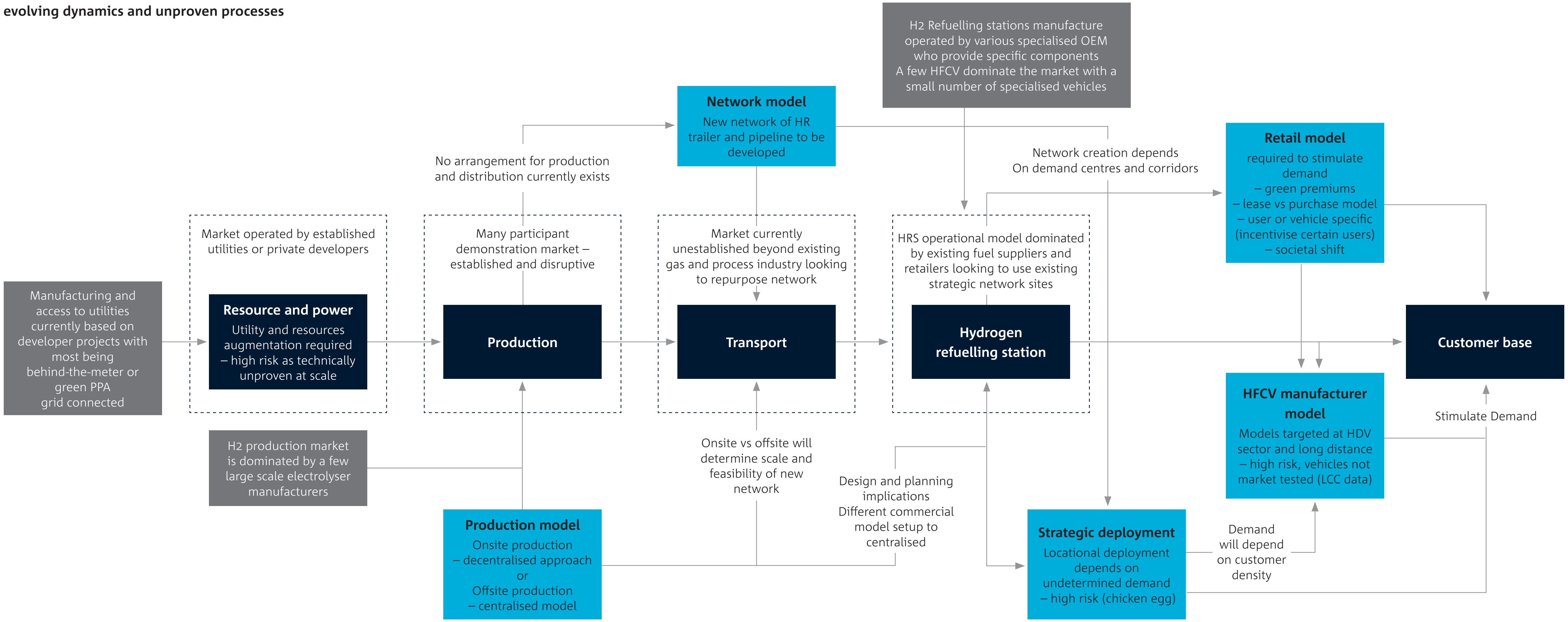
From an ownership and operational perspective, the model is characterised by a vertically integrated structure with two entities owning all production and 6-10 primary retailers. Given the predictable nature of supply and production and the foreign imports that that keep domestic participants globally competitive, established contracts exist between upstream and downstream entities and competitive dynamics are well understood and regulated.

## Manufacturing and procurement

Just as fuel has been commoditised so too has the equipment and manufacturing of the supply chain. Due to the effect of market pressures, engineering design, assets, process and behaviours behind the production, distribution and supply of fossil fuels have been refined to the point where practices are highly prescriptive creating a low-risk environment.

**Figure 2. Traditional refuelling station business model**

**Present Hydrogen Refuelling Station Model – Complex/Disruptive: multiple competing stakeholders, evolving dynamics and unproven processes**




## Infrastructure model

In comparison, the present hydrogen refuelling infrastructure model consists of multiple Green/brownfield assets that act independently of one another in isolation, but which have design and operational impacts on each other. The principle of systems engineering is only recently being applied, due to the cost prohibitive nature of equipment, and so infrastructure interfaces are not well understood. Most infrastructure is at demonstration level and economies of scale, whilst predicted, have not yet been leveraged. The development of infrastructure is further hindered by the ongoing development of standards and market mechanisms to managed hydrogen as a commodity.

## Ownership model and entity engagement

Ownership of supply chain elements is disconnected, with MOU and strategic partnerships only coming to fruition in last 5 years. The novel nature of the sector has also created high levels of competition, a lack of industry coordination and direction and a generally volatile and high-risk ecosystem.

Sector is currently occupied by various large oil/gas and utilities as well as disruptive renewable developers. Many of the former are looking to repurpose assets, whilst the latter are introducing innovative alternative solutions.

There is still a broad range of across the industry price points and levlelied costs (result of different methods of production and fuel displacement opportunities). This creates added complications as there are little Cost and price transparency or forecast capability.

Resultantly, organisations have been seeking to partner over neighbouring stages of the supply chain to ensure risk free fuel movements and fair pricing.

## Manufacturing and procurement

Manufacturing and procurement in hydrogen refuelling sector is still very embryonic, with majority of production occurring in only a few regions (Europe, Asia, USA). This has resulted in two challenges: gaps in regulation across sectors domestically and very low levels of regulatory harmonisation at an international scale. Standardisation and harmonisation are an essential tool to demonstrate compliance with a regulatory framework, which provides confidence from investors and organisations, leading to higher investment in production and greater willingness to pay premiums for buyers. Ultimately this has slowed development of the supply chain sector, however it is characterised but a decentralised dynamic market of innovative and disruptive organisations, driving prices down at a rapid rate. Very similar to wind and solar market of early 2000's.

Figure 3. Hydrogen refuelling station business model

## 4.1 Current HRS configurations and approaches

As a means of navigating the uncertainty inherent in this early-stage of developing HRSs, current models and approaches are predicated on the ability to mitigate and transfer risk. This is being implemented in several ways:

- strategic partnerships to diffuse commercial and technical risk between organisations
- development of innovative financial frameworks to transfer or defer costs
- agreements to guarantee supply and offtake of fuel and resources
- partnerships to ensure co-operation across procurement.

These principles have led to a variety of unique models (variation of ownership, partnerships, and commercial models).

## 4.2 Cross value chain consortia

The most common currently emerging business model is the strategic partnership or consortium model, where multiple entities from across the value chain pool resources, knowledge, and influence. The purpose is generally to share risk in technology scaleup, thereby accelerating deployment of infrastructure or products, though each model may have differing areas of focus:

- **Downstream Focus:** Viva Energy's New Energies Service Station in Geelong, Victoria, is aimed at driving hydrogen demand in parallel with infrastructure development through a cross-section of FCEV adoption activities. The consortium includes local water utilities, equipment manufacturers and transport operators and centres around an onsite centralised production facility. One of the key challenges to the deployment of hydrogen refuelling infrastructure and FCEV is the lack of operational data. This model coalesces downstream retail and FCEV users, providing an efficient, shared-risk approach to, reducing market barrier entry by collecting operational data. It paves the way to grow from singular back-to-base facility into a strategic network connecting Melbourne, Sydney and Brisbane on Australia's east coast.
- **Upstream Focus:** The BP/BOC Bulwer Island refuelling station partnership centres around the utilisation of existing upstream assets, in addition to well-established refuelling and process knowledge and resources. The project involves an offtake for the Bulwer Island production facility, a supply source for the BP Lytton refuelling station, and again de-risks initial operations. This model is also an example of government's role in the sector, as it is intended that a government fleet of Hyundai NEXO passenger cars will utilise the HRS. This latter element supports the project by providing demand and transferring offtake risk from industry to government.
- **Hubs Focus:** Some organisations are pursuing the aspirational target of a hubs model through the forging of partnerships that span the entire value chain and involve different hydrogen end-users. As well as manufacturing FCEVs and developing their own hydrogen refuelling stations, US company Nikola Motor is currently in partnership with several fuel providers and pipeline owners, hydrogen production facilities, a power utility authority, and several major chemical and process organisations. By creating a collaborative ecosystem spanning the whole value chain, they have diffused the risk inherent in the operation and interaction of each individual stage. The establishment of memoranda of understanding and contractual arrangements make the dynamics of the value chain more manageable and more closely aligned to the traditional refuelling model. In addition to this, Nikola have also taken steps to maximising capture of market incentives. At novel stages in the value chain, specifically production and fuel dispensing, they have created Special Purpose Vehicles (SPVs) that are partially owned by partners and in which Nikola has an equity stake. Whilst they remain separate entities to Nikola, production and dispensing SPVs allow Nikola to capture these sections of the value chain and not only reduce supply chain costs but also qualify for financial incentives such as Production and Low Carbon Fuel Standard Credits. The resulting model is very similar to the vertical integration of the traditional model and demonstrates its utility as a risk-sharing mechanism.

### 4.2.1 Other notable partnerships

Other notable partnerships include:

- **Han-Ho Hydrogen Consortium (QLD)** consists of Australian-based Ark Energy and its parent company Korea Zinc, as well as Korean conglomerates Hanwha Impact and SK Gas. The consortium's plans centre around the development of Ark Energy's Collinsville Green Energy Hub which will have potential generation capacity of up to 3,000 MW. The involvement of Hanwha Impact and SK Gas enhance the integrity of Ark Energy's plans by firming up the technology development and offtake credentials of the supply chain operations.
- **Total Energies and Daimler Truck AG (EU)** are collaborating in the development of ecosystems for heavy-duty trucks running on hydrogen, including hydrogen sourcing and logistics, dispensing of hydrogen in service stations, development of hydrogen-based trucks and establishment of a customer base.
- **Toyota, Air Liquide and CaetanoBus (EU)** have formed a partnership to develop an integrated hydrogen ecosystem that will accelerate infrastructure development and vehicle fleets expansion, using the complementary expertise of the partners to address the entire value chain of hydrogen mobility, ranging from production, distribution, and refuelling infrastructure to the deployment in different vehicle segments, as well as integrated vehicles offers (leasing and service) to customers such as taxi companies, fleet operators, local authorities, and others.
- **BP and Daimler (UK)** have signed a memorandum of understanding to assess the feasibility of designing, constructing, operating and supplying a network of up to 25 hydrogen refuelling stations across the UK by 2030.
- **Shell and Shenergy (China)** have signed an agreement to form a joint venture, to build a network of hydrogen refuelling stations in Shanghai. The joint venture will see development of 10 hydrogen refuelling stations over next the five years.
- **Government Supported Partnerships (Global):** Significant volumes of FCEVs have been directly underpinned by government-supported initiatives, including the Fuel Cell and Hydrogen Joint Undertaking in Europe and the National Fuel Cell Bus Program in the United States.

### 4.2.2 Australian implications: upstream partnerships and international dependence

Downstream-focussed partnerships have been popular in prominent auto manufacturing jurisdictions, where large and often multiple organisations can pool resources, capabilities and ranging market access to their advantage. Japan, South Korea and Germany all demonstrate this occurrence, with Toyota, Hyundai and Daimler being industry first-movers in this space. Australia does not have a comparable auto manufacturing industry and so it is unlikely to see many partnerships of this sort beyond the government fleet and international investment currently trying to stimulate demand (small scale). In contrast, the upstream partnership approach has demonstrated growing momentum with an 'Industry Consortia' approach being adopted at a national scale. Several large-scale utilities and gas network operators are undertaking initiative to produce and distribute hydrogen to potential transport hubs. Origin Energy, AGL, Santos, Ampol and Stanwell Corporation are just a few of the entities that have partnered with transport and mobility providers to develop hydrogen refuelling networks. As owners of gas network infrastructure, they have a vested interest for repurposing to avoid stranding their assets.

A heavy dependence on international manufacturing and procurement and the lack of established standards and regulation puts Australia in a precarious position, as this creates international reliance and compliance barriers. There have been many challenges regarding equipment compliance for imports and Australian standards are currently adapting to international examples to bridge this gap. Adoption of international standards in Australia is seen as a resolution to this as it is unlikely there will be harmonisation, at least to same level as traditional fuel standards, given the intrinsic link to a country's own renewable aspirations and their natural advantages to produce, import, export hydrogen. From a business model perspective, international collaboration would be advised, particularly with government bodies or organisations where reciprocal agreements can be leveraged.
The Korea-Australia business partnership agreement that promotes hydrogen automotive products for exported green hydrogen is an example[17].

17 Australia-South Korea Business Council 2021, Mapping the Australia-Korea Hydrogen Intersections Report

### 4.2.3 Disruptive ownership models

As a means of overcoming market entry barriers, through incentivisation to consumers, organisations are deploying innovative and unconventional commercial and ownership models.

- Total Cost Ownership Models: Capitalising on the breadth of resource and capabilities that comes from such a wide partnership, Nikola Motors offer a full-service leasing model for FCEV customers. Nikola Motors recognised that with every FCEV it sells (USD400,000), it also opened up the opportunity for USD500,000 of hydrogen fuel revenue over the lifetime of the vehicle. Anticipating the ability to sell hydrogen that is cost competitive with diesel they offered a bundled lease including capital and service costs and requirement to by fuel from Nikola refuelling stations. In return, customers will receive a 40% reduction in capital investment, 50% reduction in fuel over the lease lifetime (expected to be around seven years or 70,000 miles) and a 10% reduction in servicing costs[18]. The model is beneficial as it reduces the barrier to market entry for consumers, stimulates initial demand provided by affordable FCEV and refuelling options and drives cost reductions through volume increase, material cost reductions and supply chain localisation.
- Riversimple, a UK-based manufacturer of FCEVs, is also adopting a similar 'Sale of Service' model using a pricing structure that enables customers to pay a single monthly fee that covers everything – the car, the maintenance, the insurance, the fuel, etc. The model is a much smaller scale and benefits from a distributed manufacturing model (consequence of the simple modular FCEV design) that allows easy setup around identified demand hubs. This model benefits from flexibility and adaptability to meet demand, which may be useful in the early stages of the transition (high risk and uncertainty).
- Subsidies and fuel cards are a popular add-on to traditional commercial models. In California, the Clean Vehicle Rebate Project offers rebates from $1,000 to $7,000 for the purchase or lease of new, eligible zero-emission vehicles. Most FCEV OEM provide fuel cards to incentivise, as a buffer to the current fuel prices, as well as additional government perks such as high occupancy lane driving and discounted parking.

### 4.2.4 What will business models look like in future?

As the hydrogen refuelling sector continues to coalesce into a stable model, through the pressures and influences mentioned, there are a variety of final state future that the Australian market could tend toward. A potential future is outlined below:

- Production is dominated by the large resource and renewable developer organisations who, over the next 5 to 10 years, establish centralised large scale production hubs. Strong partnerships are created between these production organisations, power utilities and international investors organisations due to the hydrogen price shadowing the power price.
- Transport is dominated by road and rail freight/HGV early on. This is supported by easing regulation and financial incentives for producers and retailers to accelerate growth, whilst pipeline transport is developed. As production increases, transport of hydrogen transitions to use of existing gas transmission networks in and around the centralised production hubs. These are owned and operated by the same large resource organisations looking to repurpose potentially stranded assets or build greenfield in existing corridors and built-up areas. Road and rail transport remain to service outer and rural areas.
- Downstream at the HRS and retailing stages, the market is initially comprised of 15-20[19] competing consortia, comprised of refuelling station owners, FCEV operator and OEMs. Repurposing brownfield sites and having an existing presence across high traffic corridors and urban centres provide advantage to established infrastructure owners and gradually whittles down the number of market players.

18 Nikola Motors slides

19 The HHH funding round has identified 15-20 applicants with this indicative consortium structure. Reasonable to assume this will continue.

# Part B –
# Technologies

# 5 Hydrogen technology

This section sets out explanatory commentary and recommendations in relation to key technical components required to enable hydrogen refuelling, viz:

- production
- distribution (to the HRS when the hydrogen is produced offsite)
- compression
- storage
- dispensing.

## 5.1 Production

Hydrogen, for use as a vehicle fuel, must meet ISO 14687:2019 Hydrogen fuel quality – Production specification. It can distributed from offsite production plants to HRSs using tube trailers for gaseous hydrogen, or cryogenic tankers for liquid hydrogen. Alternatively, hydrogen can be produced onsite. These options are represented in Figure 4 below.

The amount of hydrogen required for road transport in Australia is likely to be a small portion of the country's future hydrogen production output. There is a growing number of planned large-scale hydrogen production facilities that will produce hydrogen primarily for industry, power and export. This will likely align well with hydrogen demand for transport fuel and offer cost benefits from scale (where the HRS utilises hydrogen produced offsite in relative proximity to the HRS).

The optimal offsite versus onsite production pathway is determined by many factors, not least of which is transport distance, and is explored later in this report. The choice between onsite production and delivery of hydrogen from an offsite source has a significant impact on the required land footprint, capital investment and risk profile of the refuelling facility.

### 5.1.1 Electrolysis

Electrolysis is an electrochemical process that uses electric current to split water molecules into hydrogen and oxygen, with there being no resultant carbon (or greenhouse gas) emissions. There are two commercially dominant technologies for producing hydrogen through electrolysis, Alkaline Electrolysis (AE) and Polymer Electrolyte Membrane (PEM) electrolysis. The 'colour' or carbon intensity of the resulting hydrogen reflects how the input electricity was produced. Hydrogen is considered 'brown' if the electricity is generated from coal, oil or gas power, or 'green' if the electricity is from a renewable source, such as wind or solar. It should be noted that the attributed colour of the hydrogen, is not always a clear reflection of its carbon intensity.

#### Alkaline electrolysers (AE)

Alkaline type electrolysis is the more mature and lower-cost electrolyser technology, with the chemical reaction occurring between two electrodes in a solution of liquid potassium hydroxide electrolyte. At the cathode, hydroxide and hydrogen ions are produced from water. The hydroxide ions travel through the electrolyte to the anode, where they release an electron and combine to produce water molecules and oxygen gas. AE require lower cost materials and catalysts (compared to the PEM alternative discussed below), and their component parts are produced at scale. As a better-known and more widely deployed process they offer lower technology and cost risk. However, alkaline electrolysers require onsite storage of hazardous potassium hydroxide which must meet regulatory requirements. They also have a lower turndown capacity, reduced ramp rates, and an increased risk of impurities in the produced hydrogen gas. There are two types of alkaline electrolysers: unipolar cells using tanks in series and bipolar type like filter press.

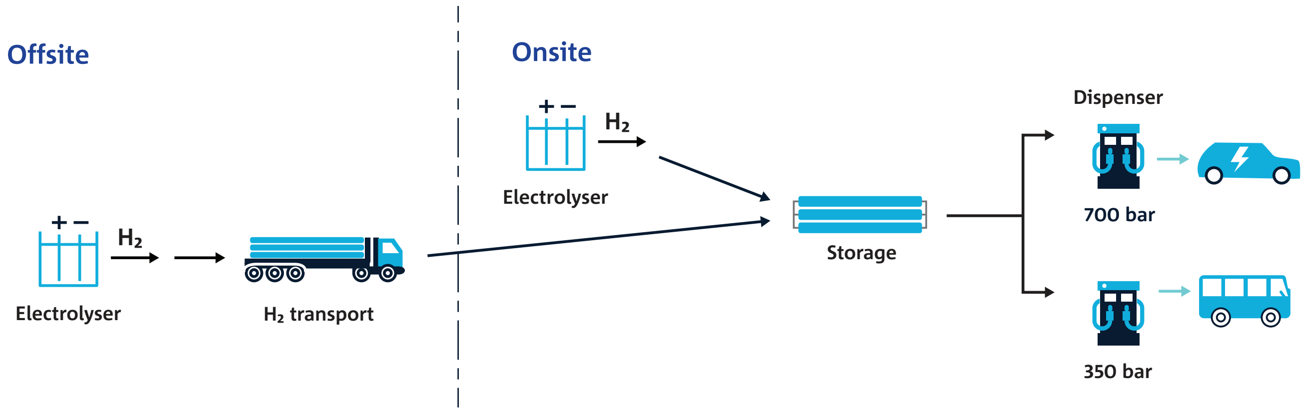



Figure 4. Depiction of hydrogen supply chain

Unipolar type generates H2 at lower pressure than PEM but bipolar type can discharge at 20bar which is close to PEM, which claims discharge at 30bar but is often lower. Discharges at lower pressures require additional compression of the gas to storage at refuelling pressures, which incurs additional cost.

### Polymer Electrolyte Membrane (PEM)

In a PEM electrolyser, water reacts at the anode to produce oxygen, hydrogen ions, and free electrons. The electrons travel along the external electrical circuit to the cathode. The hydrogen ions travel across the solid polymer electrolyte to the negatively charged cathode. At the cathode, the hydrogen ions combine with the electrons from the external circuit to produce hydrogen gas.

PEM units can operate at high pressure and offer greater flexibility in operation, being able to respond more quickly than alkaline units to load changes and provide a greater turndown range. However, PEM electrolysers require high-cost platinum group catalysts and membranes. PEM electrolysers are less tolerant to water impurities than alkaline units but produce higher purity hydrogen gas, an impact that can be addressed by downstream purification. Membranes in the electrolyser are prone to the effect of poison, particularly from H2S, CO and NH3. Poisoning can happen in a few months resulting in efficiency drops. Replacing membranes are costly and time-consuming, with consequential impact on lifecycle costs.

Significant investment in research and development of PEM technology is being actively undertaken by several manufacturers, which is leading to significant improvements in performance and efficiency of PEM electrolysers.

PEM technology offers the following features:

- efficient production at lower outputs and suited for both smaller and large operations
- greater turndown and ramp rates, important in single-train installations and better suited to variable renewable energy sources
- higher hydrogen output purity, critical for later use in fuel cells
- produces hydrogen at pressure, reducing compression needs.

### Comparative features of PEM and AE

The features of alkaline and PEM electrolyser stacks are shown in Table 11. The data shown is obtained from publicly available sources and generally aligns with budget pricing and design information from OEMs.

The data shown in Table 11 excludes balance of plant (BOP), the design of which depends on:

- water quality and availability
- ambient conditions
- utility system designs (particularly the cooling system)
- quality specifications of the hydrogen and oxygen products
- storage and transfer pressures of the hydrogen and oxygen products
- hydrogen storage volume.

## 5.1.2 AE or PEM

In addition to the features listed in Table 11. Typical specifications for AE and PEM electrolysers, the correct selection of electrolyser stack technology should be informed by project and/or site-specific parameters such as capital expenditure, operating expenditure, site risk factors, town planning, state regulations, footprint, and schedule.

The dynamic response of the electrolyser to fluctuating renewable power supply and/or hydrogen demand is an important consideration for hydrogen production facilities. Alkaline electrolyser stacks are less responsive to fluctuations in power supply than PEM electrolysers. This can be a significant disadvantage in the context of industrial-scale facilities that are powered by intermittent renewable energy but less so for small scale predictable refuelling station applications. Moreover, alkaline electrolysers are comparatively less costly, have a lower specific power load (MWh per kg of hydrogen produced) and have a longer operating life than PEM electrolyser stacks.

PEM electrolyser stacks have a fast response to fluctuations in electricity supply, have a large operating load range due to their high current intensities and because there is no co-mingling of the oxygen and hydrogen gases, the hydrogen product is always high purity. Although costs and specific power load are higher with PEM, some vendors now offer stacks that have comparable power demand to alkaline electrolyser stacks.

**Table 11. Typical specifications for AE and PEM electrolysers**

| Feature | Parameter | Units | Alkaline | PEM |
|---|---|---|---|---|
| Design | Electrolyte | - | KOH aqueous solution | PFSA membrane |
| | Stack Only Power Consumption | kWh / kg $H_2$ (vendor dependent) | 45 – 60 | 50 – 65 |
| Materials of Construction | Cathode | - | Ni or Ni-Mo alloys | Pt or Pt-Pd |
| | Anode | - | Ni or Ni-Mo alloys | $RuO_2$ or $IrO_2$ |
| | Demineralised Feed Water Consumption | L / kg $H_2$ | 10 | 10 |
| Cells | Current Intensity | Amp / cm$^2$ | 0.2 – 0.4 | 0.6 – 2.0 |
| | Voltage | V | 1.8 – 2.4 | 1.8 – 2.2 |
| | Voltage Efficiency | % HHV | 62 – 82 | 67 – 82 |
| | Cell Area | m$^2$ | < 4 | < 3 |
| | Degradation (Specific Energy Increase) | % / year | < 1% | < 1% |
| Stacks | Maximum Size | MW | 20 | 20 |
| | Lifetime | h | 80,000 – 90,000 | 40,000 – 50,000 |
| | Replacement Cost | % of capital expenditure | Approx. 20-30% | Approx. 20-30% |
| Operating Conditions | Cathode Pressure ($H_2$) | bar | < 0.1 | 30 |
| | Anode Pressure ($O_2$) | bar | 0 | 0 |
| | Temperature | °C | 30 – 80 | 80 – 90 |
| Operational Flexibility (Dynamic Response) | Minimum Load | % Nominal Load | 15 – 40 | 3 – 10 |
| | Operating Load Range | % Nominal Load | 15 – 100 | 3 – 200 (theoretical) |
| | Load Ramp-up / Ramp Down | % Nominal Load/s | 0.2 – 20 | 100 |
| | Normal Start-up Time (Warm) | min | 1 – 10 | 0.02 – 5 |
| | Cold Start Time to Minimum Load | min | 20 – 60 | 5 – 20 |
| | Shutdown | min | < 10 | < 1 |
| Technology Maturity | Commercial Availability | Approx. years | 70 | 20 |

The cost of the balance of plant (BOP) is another important consideration. Hydrogen is released at near atmospheric pressure from alkaline electrolysers and typically at 30 bar from PEM electrolysers. Compression is required for storage and end-use, resulting in several stages to compress hydrogen from atmospheric pressure to 30 bar. Depending on the scale of the hydrogen production facility, the additional compression costs associated with an alkaline electrolyser system can quickly off-set the initially anticipated savings.

## Continuous Power Supply Considerations

For facilities that utilise a continuous or uninterrupted power supply (grid connected or high-capacity factor (CF) variable renewable energy (VRE) that is sustained at full load for much of the time, the economics tend to favour alkaline electrolyser stacks due to the capital expenditure savings, despite the additional and operational cost of compression.

## Fluctuating Power Supply Considerations

For refuelling sites with intermittent or variable power supplies, the electrolyser stack will cycle through the various operational stages (start-up/ramp-up/ramp down/shutdown) in accordance with the provided power load. Since PEM electrolysers have fast response times, they are preferable for larger-scale hydrogen production facilities with fluctuating renewable power supply.

An electrolyser cannot start producing hydrogen until the minimum load is provided. The minimum required load is generally 40% of the nominal load for alkaline electrolysers and around 10% for PEM electrolysers. For an alkaline electrolyser it may take up to an hour before the minimum load is reached for a cold start-up and up to 10 minutes for a normal (warm) start-up. During this time, the facility is 'losing money' because electricity is being consumed but no hydrogen is being produced. For a PEM electrolyser stack, it may take up to 20 minutes before the minimum load is reached for a cold start-up and typically only a few seconds for a normal start-up.

Figure 5 conceptually depicts the positive effect of the faster start-up time, faster response time and increased operating load range of a PEM electrolyser stack on hydrogen production over a day for a hypothetical hydrogen production facility powered by solar energy. The blue shading shows the additional hydrogen output from a PEM electrolyser compared to an alkaline electrolyser for the cold start-up in the morning, then for a temporary loss of renewable power in the late morning due to sudden cloud cover.

PEM electrolysers are better suited to frequent fluctuations throughout the day. However, if the fluctuation in power supply load is no more than a few times a day, then alkaline electrolyser stacks may be suitable, especially if used in conjunction with a Battery Energy Storage System (BESS) and/or if the system is configured as multiple smaller-sized stacks to improve turndown. In this case, consideration should be given to comparing the $LCOH_P$ for both alkaline and PEM based facilities. The $LCOH_P$ determinations should consider the effect of fluctuating power generation on hydrogen production.

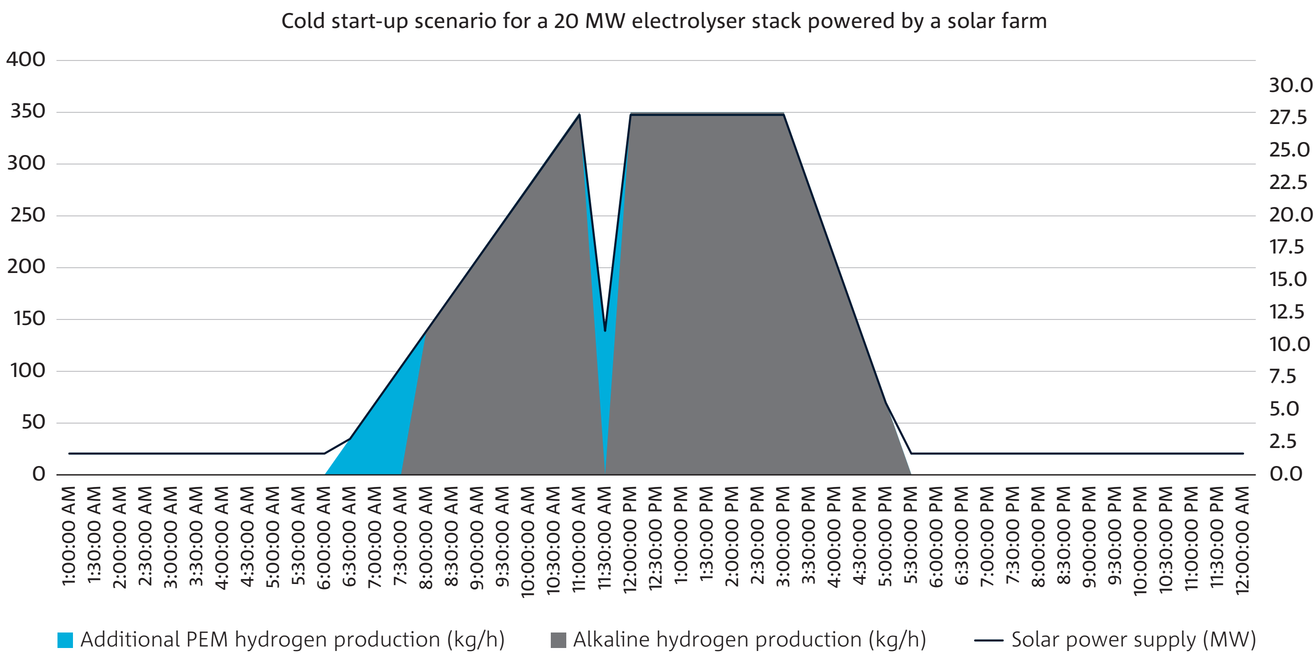



**Figure 5. Example of hydrogen production from 20 MW AE and PEM electrolyser stacks[20]**

20 Developed by GHD based on electrolyser vendor turndown information and solar capacity factors in WA

### Overall comparison of Alkaline and PEM hydrogen production facilities

Key impacts of electrolyser technology on hydrogen production are shown in the Table 12 below. Overall facility footprint, capital expenditure and operating expenditure are excluded as they are highly specific to vendor electrolyser package design, cooling system design, hydrogen storage requirements and hydrogen end-use.

Commercial-scale electrolyser technology continues to advance over time and in the next five to 10 years improvements such as pressurised alkaline electrolysers, improved electrolyser efficiencies and lower costs are anticipated.

## 5.1.3 Research and innovation opportunities

The main means for lowering hydrogen production costs are through achieving economies of scale (larger units), optimisation (higher efficiency) and innovation (new technologies).

### PEM technology improvements

Alkaline electrolysers are considered the most commercially mature method for hydrogen production, with components and operation very similar to those used in the chlor-alkali industry to produce chlorine and hydrogen[21]. However, PEM electrolysers offer greater flexibility in operation and can respond to load changes more quickly than alkaline units. In addition, their turndown range is improved compared to alkaline units. The responsiveness of the unit compared to alkaline electrolysers is a result of the proton transport across the membrane, which responds quickly to the power input and is not delayed by inertia in the system (a system barrier for liquid electrolytes[22]).

Current development efforts for PEM technology are targeted at reducing system complexity to enable system scale-up and reducing capital cost through less expensive materials of construction and more sophisticated stack manufacturing processes. PEM water electrolysers are 50%-60% more expensive than alkaline, representing an additional barrier to market penetration[23]. In addition, there is ongoing development to improve the stack efficiency of PEM units, as at present they are still less efficient than alkaline units.

**Table 12. Key investment and operational considerations for AE and PEM technology**

| Parameter | Alkaline Stacks | PEM Stacks |
|---|---|---|
| Stack dynamic response time | Slow. Unsuitable for highly variable power supply | Fast. Suitable for variable power supply |
| Stack operating range | Turndown is limited | Wide operating range |
| Stack overhaul | After eight to ten years | After five to six years |
| Electrolyser package footprint | Stacks are less compact, and package contains a lye circuit | Stacks are more compact and do not require an electrolyte circuit |
| Impact on overall facility footprint | Slightly larger due to an additional compression train | Slightly smaller as no precompression is required |
| Electrolyser package operating expenditure | 2% of initial capital expenditure | 2% of initial capital expenditure |

21 International Energy Agency 2019, The Future of Hydrogen - Seizing today's opportunities, Prepared for the G20, Japan.

22 Power2Hydrogen 2018, Potential of Hydrogen in Energy Systems. Accessed July 2022 from http://hybalance. eu/wp-content/uploads/2017/01/Power2Hydrogen-WP1-report-Potential-of-hydrogen-in-energy-systems. pdf

23 IRENA 2020, Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal

## High-efficiency electrolyser

The development of a high-efficiency electrolyser (circa 95% efficiency[24]) is a focus for electrolyser technology developers. Increased efficiency should provide two major benefits, through reduced:

- power load requirements per unit hydrogen produce, which significantly reduces the $LCOH_P$ (power costs are usually the single largest contributor to $LCOH_P$)
- cooling water requirements and system losses. Typically, the elimination or mitigation of the direct and indirect energy losses arising from bubble formation in the electrolyser leads to the energy savings[25].

## Advanced Alkaline Exchange Membrane

Creating an electrolyser membrane with increased efficiency and improved operational lifetime has been a significant challenge for the commercial application of advanced alkaline water electrolysis. The Dalian Institute of Chemical Physics is developing an Advanced Alkaline Exchange Membrane unit aimed at improving ion conductivity and enhancing stability and resistance to degradation. Ultimately this will reduce costs due to cheaper materials being utilised for stacks, improve stack efficiency and potentially extended stack lifetimes.

There are also emerging technologies that are currently in their infancy but show promise to reduce the cost of green hydrogen production, such as seawater electrolysis, which represents a potential solution to hydrogen production without reliance on freshwater[26] and a development to generate hydrogen through electrolysis utilising porous silicon as a solid-state hydrogen generating material[27].

## Electrolyser improvements

Capital expenditure requirements are currently in the range of $700–2,000 per kWe and $1,700–2,200 per kWe for Alkaline and PEM electrolysers respectively. The electrolyser stack is responsible for 50% and 60% of these costs, with power electronics, gas-conditioning and plant components accounting for much of the rest[28].

Electrolyser costs are the dominant portion of hydrogen production capital costs, and therefore small improvements in electrolyser capital cost due to, for example, being able to select cheaper materials of construction or grouping balance of plant equipment in the electrolyser package, together can have a significant influence on $LCOH_P$. According to the International Energy Agency (IEA), switching to larger multi-stack systems (that is, combining several electrolyser stacks to increase the overall capacity of the electrolyser system) could reduce capital cost by up to 20% for Alkaline electrolysers and up to 40% for PEM units[28.]

The electrolysers are also the largest power consumer in the hydrogen production facility. Improving electrolyser performance would reduce power consumption (as well as cooling requirements). For example, alkaline electrolysis stack efficiency is predicted to improve from 65% to 80% by 2040, saving almost 10 kWe per kg of hydrogen produced, or $1per kg of hydrogen at a $100 per MWh electricity price. Similarly, improving PEM electrolyser efficiency from the current 55% to the predicted 74% could reduce the production cost of hydrogen by $1.5 per kg.

High efficiency electrolysers promise even further improvement, and at 95%, could reduce the cost of hydrogen production by $1.6 per kg from current alkaline electrolyser production costs. Two examples of developments in electrolyser technology include:

- Capillary-fed electrolysers by Australian company Hysata, which forecasts 95% system efficiency equating to 41.5 kWh/kg of hydrogen produced, compared with the industry benchmark of 52.5 kWh/kg or 75% system efficiency. Hysata is looking to scale up to gigawatt-scale production capacity by 2025.
- Korean Institute Science & Technology is undertaking research to lower electrolyser capital costs by using anionic exchange membranes (AEM), which do not require expensive platinum group metal catalysts.

24 Hysata 2021, Technology, accessed July 2022 from https://hysata.com/technology/

25 Swiegers, G.F.et.Al. The prospects of developing a highly energy-efficient water electrolyser by eliminating or mitigating bubble effects. Sustainable energy & Fuels, Issue 5, 2021.

26 Sun.F., Quin, J., Wang, Z. et.al. 2021. Energy-saving hydrogen production by chlorine-free hybrid seawater splitting coupling hydrazine degradation. Nat. Commun 12, 4182

27 H-2 Tech 2022, EPRO Advance Technology develops porous silicon material to generate ultra-pure H2 from a water source, accessed August 2022 from https://h2-tech.com/news/2022/07-2022/epro-advance-technology-develops-porous-silicon-material-to-generate-ultra-pure-h-sub-2-sub-from-a-water-source/

28 IEA.(2019). The Future of Hydrogen. Prepared by the IEA for the G20, Japan.

## 5.2 Distribution

### 5.2.1 Road distribution of compressed hydrogen

In Australia, hydrogen is typically distributed as a compressed gas by tube trailers containing series of high pressure manifolded tubes or cylinders. The most common tube trailers are configured with an arrangement of manifolded steel tubes to US DOT standards and categorised as Type I cylinders (ISO 11515*ISO 11515:2013 Gas cylinders — Refillable composite reinforced tubes of water capacity between 450 L and 3000 L — Design, construction, and testing)* as shown in Figure 6. Type I tubes, or cylinders, are pressured to around 200 bar, resulting in a payload of about 255 to 300 kg for a trailer. Trailers with Type I tubes are heavy, with much of the transport energy used to carry the tubes themselves. The weight of H2 being transported in Type I cylinders is around 1% of the combined gross weight of the prime mover, trailer and cylinders. They may be considered for short distribution routes but, based on the low payload, distribution costs for distances beyond 100 km (at which levelised costs may be $1 to 2/kg) may be cost prohibitive.

**Figure 6. A hydrogen transport tube trailer**[29]

Some manufacturers are now developing systems for distributing hydrogen in Type IV cylinders constructed from carbon fibre composites. They are lighter than Type I cylinders, operate at a higher pressure and hold more hydrogen. The cylinders are stored vertically in ISO container type structures, known as Manifold Cylinder Packs (MCP), that are three to 12 metres in length, Figure 7. The hydrogen is stored at 300 or 500 bar. Larger modules can transport up to 1,000 kg at 500 bar, although the transport of large amounts of hydrogen at high pressure may generate community concern and require regulatory authorities to review governance. The maximum pressure for transporting compressed hydrogen is 500 bar in Europe, and 200 bar in USA, although exemptions for transport at 500 bar are common. Australian authorities do not currently specify a maximum pressure for the road transport of compressed hydrogen, but in practice this is limited by vessels available on the market, all of which are manufactured in Europe or the USA.

**Figure 7. Example configuration of vertically stacked carbon fibre composite cylinders**[30]

The tubes or MCPs may be permanently fitted to a trailer and driven to site, at which point gas is either decanted into onsite storage using a combination of pressure differential and a compressor, or the full trailer is left on site and the empty trailer carried away. Where trailer-swaps are used, the site may have two trailers to ensure full use of the contents of a trailer and to maintain supply continuity during an exchange.

The tubes or MCPs may also be fitted into structures independent of the trailer and loaded onto a flatbed trailer for distribution and lifted into position at the destination. This arrangement is more commonly used where temporary storage is required.

The logistical challenges of transporting hydrogen become evident when comparing the weight and energy content with conventional fuels. Even in liquid form, hydrogen takes up significant space, although with little weight.

29 City Machine & Welding, Inc. Amarillo, TX, accessed August 2023 from https://cmwelding.com/configuration/hydrogen-h2-tube-trailer-9-tubes-dot-3aax-2400psi-40-ft

30 Hexagon Purus, Hydrogen distribution systems, accessed August 2022 from https://hexagonpurus.com/our-solutions/hydrogen-systems/hydrogen-distribution-systems

The difference for a notional B-double road-tanker can be seen in Table 13 below, noting that hydrogen is not transported in a B-double tanker like diesel (more often single tanker for liquid or tube trailer for gas). Vehicle range is useful to compare performance of different fuels.

**Table 13. Comparison of diesel and hydrogen energy and weight for a notional road tanker**

| | $GH_2$ (350 bar) | $LH_2$ | Diesel |
|---|---|---|---|
| **Volume (l)** | 56,000 (350 bar) | 56,000 (-253°C) | 56,000 |
| **Weight of fuel (kg)** | 1,344 | 3,976 | 46,500 |
| **Energy content (GJ)** | 162 | 476 | 2,128 |

## 5.2.2 Road distribution of liquid hydrogen

Transportation of hydrogen as cryogenic liquid by tanker truck is undertaken overseas, mainly in the USA, but not currently in Australia. Chart Industries, a key supplier of cryogenic tankers advise that close to 340 cryogenic trailers are actively transporting an estimated 400 tonnes of $LH_2$ in the USA, a figure that is increasing year on year. Chart notes a growing number of tandem or 'B-double' style trailers on order. Similarly, Plug Power, a major US based hydrogen equipment manufacturer, states its strategy in their report, Why Turn to Hydrogen Liquefiers? (plugpower.com): *"Plug is building a network of liquid hydrogen plants to provide 500 tons per day (TPD) of green liquid hydrogen by 2025 to alleviate near-term hydrogen supply constraints and accelerate the adoption of hydrogen technology in North America."*

Liquid hydrogen ($LH_2$) has a density of 71 kg/m$^3$, compared to 24 kg/m$^3$ for GH2 at 350 bar and 38 kg/m$^3$ at 700 bar and 20°C. Consequently, distribution of hydrogen as a liquid may reduce the delivered cost by moving more hydrogen in a single trip (Table 14). A semi-trailer tanker can carry around 3.6 tonnes of $LH_2$, while a B-double tanker, where permitted, can carry closer to 5 tonnes. Tankers delivering $LH_2$ can offload using pumped transfer at a rate of up to 80kg/min, equating to an offload time of 45 minutes for a semi-trailer carrying 3,600kg.

**Table 14. Example carrying capacities**

| Vehicle | Storage configuration | Capacity (kg) |
|---|---|---|
| Tube trailer | T1 steel tubes at 160 bar | 200 |
| MCP trailer | T4 composite cylinders at 500 bar | 1,000 |
| $LH_2$ Tanker | Insulated steel vessel -253°C and 10 bar | 3,600 |

Pressure to improve hydrogen transport efficiency and onsite storage capacity combined with plans by OEMs such as Hyzon, Nikola, and Daimler to introduce medium and heavy-duty vehicles equipped with LH2 tanks, will see demand for $LH_2$ increase. Distributing hydrogen as a liquid requires construction of liquification plants, which are more complex and capital intensive than compressors for $GH^2$ and require a large scale to justify. Consequently, sufficient demand must be developed for liquid hydrogen to become an attractive investment. At the time of writing Australia's production of $LH_2$ is minor with the single production plant, the HESC project in Hastings Victoria, operated by Coregas. Some projects are in the feasibility and design stages, details of which are available on the CSIRO HyResource site https://research.csiro.au/hyresource/.

Unlike $GH_2$, $LH_2$ suffers losses during storage and handling. Loss of $LH_2$ occurs when it is transferred from one vessel to another, say from liquefaction plant to road tanker, road tanker to station storage, station storage to pump or compressor and during dispensing[31]. $LH_2$ is also lost during storage in tanks, either on site, or while in a road tanker, where it warms due to heat transfer from the environment.

Hydrogen must maintain a temperature below its boiling point of -253°C, to remain a liquid. The ullage or vapour space in $LH_2$ tanks is generally maintained below 20 bar, a value that varies with tank type and application. Heat will eventually transfer into the tank from the atmosphere where the vapor temperature will increase faster than that of the liquid due to its higher thermal diffusivity. Heat will transfer across the vapor–liquid interface and cause a temperature gradient in the top layer of the liquid with the interface at a higher temperature than the bulk liquid.

31 Guillaume Petitpas, Int J Hydrogen Energy, Simulation of boil-off losses during transfer at a LH2 based hydrogen refueling station, 2018, 43, 21451-21463

This results in evaporation in the tank which will increase the pressure in a process known as self-pressurisation. The tank will vent when the pressure exceeds the relief set point resulting in a loss of inventory. This is known as 'boil-off' and the vented gas called Boil-Off Gas (BOG)[32]. The boil-off rate is influenced by tank shape, materials, insulation effectiveness, ambient temperature, quantity of liquid hydrogen inventory in the destination vessel and residence time in tank storage.

Actual boil-off rates vary in the field, typically reducing as the tank size increases. For a 50 $m^3$ tank, the boil-off rate can be 0.4% per day, whilst for a 20,000 $m^3$ tank the boil-off rate may be 0.06% per day[32]. Modelling with field validation, undertaken by the Lawrence Livermore Laboratory[33] showed losses of 7 kg or 1% per day in a 12.5 $m^3$ tank, filled to 10,220 L (725kg $LH_2$), Figure 8. The loss rates approximately accord with those indicated in OEM literature, with higher losses observed for smaller tanks.

Modelling of the transfer of $LH_2$ from road tanker to site storage indicates losses of 25kg from the site storage vessel and 100kg from the tanker for a transfer of 724kg (10,200 litres) equating to approximately 1.2%. There are two modes of losses during transfer – venting of gas displaced by the rising liquid and boil-off. Modelling, validated by field observations, showed that transfer losses can be minimised by 'spraying' $LH_2$ into the ullage at the top of the container, which promotes ullage vapour condensation[30].

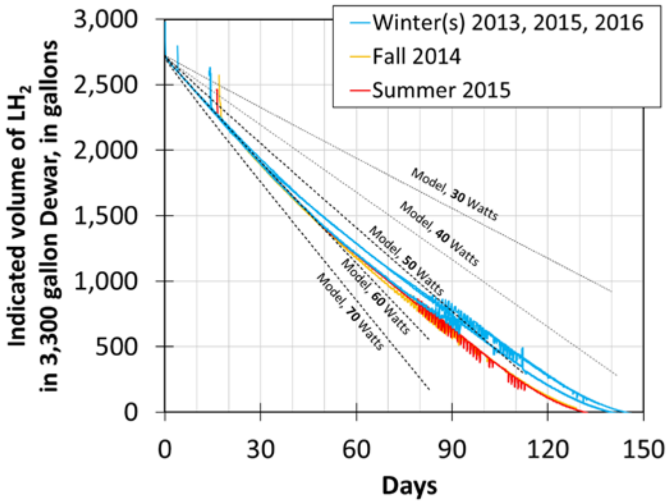



**Figure 8. Variation in $LH_2$ volume over time[34] in a 12.5kl, 3 bar vented, tank, filled to 10.2kl[33]**

### 5.2.3 Pipeline distribution

Distribution of gaseous hydrogen by pipeline is undertaken internationally, but not currently in Australia. However, due to the high cost, this would only likely be viable under favourable conditions, such as a very high throughput HRS located close to the hydrogen production or distribution facility. The cost could be reduced by re-purposing an existing pipeline, which avoids much of the initial capital investment, but costs for replacing incompatible fittings must be considered. Other issues such as hydrogen loss through the pipeline could be mitigated with an impermeable liner sleeved inside, or by reducing hydrogen pressure below previous operating conditions.

Injecting hydrogen into an existing natural gas pipeline or reticulation network, then recovering it at the point of use may also be viable. In 2021 Linde plc and Evonik Industries AG constructed a demonstration plant in Dormagen, Germany[35] to assess the process under differing conditions. A polymer gas separation membrane was used to produce a stream containing up to 90% hydrogen and when combined with pressure swing adsorption (PSA) increased the hydrogen purity to above 99.999%[36]. The remaining natural gas was returned to the reticulated network.

32 Saif Z.S. Al Ghafri; Adam Swanger; Vincent Jusko; Arman Siahvashi; Fernando Perez; Michael L. Johns and Eric F. May, Modelling of Liquid Hydrogen Boil-Off, Energies 2022,15, 1149

33 G.Petitas, Boil-off losses along the LH2 pathway, Lawrence Livermore National Laboratory, LLNL-TR-750685, 2018

34 Data based on field observations and modelled results.

35 Linde 2022, Linde Engineering Starts up World's First Plant for Extracting Hydrogen from Natural Gas Pipelines Using Membrane Technology, media release, accessed July 2022 from https://www.linde-engineering. com/en/news_and_media/press_releases/news20220120.html#:~:text=The%20full-scale%20plant%20at%20Linde%20production%20site%20in,way%20for%20transporting%20hydrogen%20in%20natural%20gas%20pipelines.

36 National Grid UK, Hydrogen deblending in the GB network – Feasibility study, NIA NGGT0156, 2021

The PSA process functions by adsorbing impurities at elevated pressures and releasing them at lower pressures. In hydrogen service, a PSA is typically comprised of four or more pressure vessels filled with various adsorbents, where each vessel periodically cycles from high to low pressure. In the four-bed configuration, at any stage there is one bed online producing pure hydrogen, one at low pressure being purged of impurities, one bed increasing in pressure in preparation to come online, and one bed reducing in pressure preparing for the purge step.

Extraction of the hydrogen is also possible using cryogenic distillation (i.e. separation of hydrogen from the components of the natural gas by means of differing boiling points). This is a relatively capital-intensive process and requires the removal of a range of impurities including $CO_2$, moisture, heavy hydrocarbons, and mercury, as it could lead to embrittlement of aluminium heat exchangers, before reaching cryogenic temperatures. This process may be viable if there are opportunities to use spare cold energy during hydrogen liquefaction[37].

Another approach is to use membranes that are permeable to protons (hydrogen ions). Hydrogen molecules are split into protons, selectively passed through the membrane and recombined as hydrogen molecules on the other side. This technology is still in development and yet to be commercialised.

Beyond the above technologies, palladium membranes represent another pathway. They work by allowing the diffusion of hydrogen through the metal lattice (by virtue of their small size) while trapping larger molecules. Very high purity can be achieved. However, the capital cost is high relative to the polymer membranes considered above, and the process needs to run at temperatures greater than 300°C, adding to both capital and operating costs. CSIRO has also developed a metal membrane reactor system based on vanadium alloys as a more cost-effective alternative to palladium for separating hydrogen from decomposed ammonia streams. Once the separation technology has been developed and commercialised, hydrogen generated at a location remote to the market could be distributed within a natural gas transmission pipeline to a centralised extraction facility, from where it may be distributed to refuelling stations or other users by road. Ensuring the separated $H_2$ meets the fuel quality standards expressed in AS ISO 14687-2020 Hydrogen fuel quality – Product specification, and verifying compliance will be a key enabling technology for the implementation of this supply chain to a HRS. Hydrogen that is transported with another gas will need to be re-tested after separation, imposing additional cost.

If capital and operating costs for separation technology are reduced to a commercially viable level, it may be possible to justify extraction of hydrogen from natural gas at a refuelling station which is otherwise serviced by reticulated natural gas.

Use of existing natural gas networks for distribution of hydrogen and its impact on downstream users equipped for natural gas is an area that would benefit from further research, particularly in the Australian context. Some pilot projects in the UK and Europe are dosing hydrogen into natural gas networks at rates in the range of 4% to 20%. No modifications to end-user appliances are required at lower dosing rates, but minor modifications are needed as dosing rates are increased. There are three hydrogen blending projects in Australia. The Hydrogen Park South Australia (HyP SA) is a project run by AGIG, that is currently blending 5% hydrogen into a local natural gas network that services around 700 homes, with plans for expansion[38] (10% blending is likely to be the point where compressor operation should be evaluated[39]). This will provide a base for considering extraction technology, however, the announcement by the Victorian Government that installation of reticulated natural gas in new housing developments will be prohibited may be an early signal that this form of distribution may not have a long-term future.

For pipeline distribution, hydrogen would have to be compressed to the operating pressure of the network, usually less than 100 bar, and additional compressor stations at intervals may be required along the line to ensure the pressure is maintained despite loss of flow in the pipeline. When hydrogen is injected into an existing natural gas network as a blend, compressors in the network would have to be evaluated to determine at what concentration additional compression capacity may be required. To enable optimal utilisation with high distribution energy density in hydrogen operation, approximately three times the drive power and therefore a correspondingly higher number of turbines and compressors are required than in natural gas operation. Blending rates up to 20% may not require restaging, although this would need to be confirmed through test cases. Compressors that are currently installed along natural gas pipelines were not selected for high

37 National Grid UK, Hydrogen deblending in the GB network – Feasibility study, NIA NGGT0156, 2021

38 HyResource 2022, Hydrogen Park South Australia, accessed August 2022 from https://research.csiro.au/hyresource/hydrogen-park-south-australia/

39 Hydrogen in the Gas Distribution Networks, COAG, pg. 30

hydrogen concentrations; components such as seals, bearings and other high friction areas need to be assessed for the potential impact of hydrogen at various blend levels.

Where hydrogen is delivered to an HRS by pipeline, whatever the length of pipeline or origin, additional compression and purification will be required at site. Delivery of gaseous hydrogen in cylinders will be at pressures between 180 and 500 bar, i.e. between two and five times the pressure of gaseous hydrogen delivered by pipe, which imposes additional compression demand with implications for space, capital cost for plant and power consumption.

### 5.2.4 Research and innovation opportunities

#### Road distribution

Distribution efficiency and cost effectiveness may be increased by reducing the cost of cylinders and tubes and by increasing the relatively low payloads. Steel cylinders (Type I cylinders) are relatively low cost, however at a pressure of 160 to 200 bar, the cargos of 250 to 300 kg per delivery limits the cost-effective distribution range.

Use of Type II, Type III or Type IV cylinders allows pressures of 300 and 500 bar and provides options for carrying up to 1,000 kg per delivery, but the higher capital cost of these cylinders reduces that benefit for shorter distances. Higher costs arise from the cylinders being constructed from wrapped carbon composite with lightweight aluminium liner (Type III) or carbon composites with a polymer liner (Type IV). The key benefit of Type IV cylinders is their low weight; however, they are less robust and resistant to damage than steel cylinders. The polymer lining also does not provide a completely impermeable barrier, so that they are prone to leakage[40] over time. Furthermore, the polymer liners in Type IV cylinders are subject to heat damage associated with the rapid filling of 700 bar vehicle fuel tanks. Type III and Type IV cylinders are designed to limited design life, whereas Type I and Type II cylinders may be requalified with periodic inspection.

Tank fabricators such as Hanwha Cimarron are developing a Type V hydrogen cylinder, made from carbon fibre composite material without an inside liner that is more than 10% lighter than a Type IV cylinder[41.] These tanks are currently being considered for vehicle tank storage but may also be suited for transport or onsite storage. The cylinders would be able to store hydrogen up to 900 bar, however road regulations may limit the maximum transport pressures, refer Section 5.2.1. To date, such cylinders have only been utilised for specialist applications and not for hydrogen.

Distribution of hydrogen at 200 bar using Type I cylinders, assuming a maximum load of 300 kg and 100 km, results in a distribution cost of ~$2/kg $H_2$ at a diesel price of $2/L. Increasing the truck pay load to 1,000 kg at 500 bar with Type IV cylinders, delivers a distribution cost of ~$1/kg $H_2$. Some emerging technologies aimed at improving distribution efficiency include:

- improved downstream separation technologies, where pipelines are utilised, to leverage use of existing natural gas networks for hydrogen distribution
- Type V cylinders fabricated from carbon fibre that are lower weight and capable of higher pressures
- novel solutions for chemical storage and distribution.

#### Chemical storage and distribution of hydrogen

Chemical storage of hydrogen involves chemical conversion of hydrogen to produce a carrier molecule. Examples include ammonia (able to carry 18 weight % hydrogen), methanol (12.5 %) and liquid organic carriers such as methyl cyclohexane (14.3 %) and perhydro dibenzyl toluene (DBT) (13.2%), however not all of the hydrogen contained within these more complex chemicals can be recovered. Chemical carriers typically have high energy densities and offer potential ease of use, particularly if systems involve liquid at ambient or close to ambient conditions. In many cases, existing bulk liquids infrastructure may be utilised for distribution and storing of hydrogen in these forms.

Hydrogen binds strongly with other molecules and requires an energy input for release. The choice of chemical storage is informed by the hydrogen content (weight percentage hydrogen in the carrier) and the round-trip energy efficiency. Typically, the compounds must be produced in a centralised high-volume plant and the reaction products recycled. These carriers are more economically viable at bulk volumes and for export distances rather than domestic distribution.

40 ams composite cylinders, Choosing the Right Gas Cylinder, accessed August 2022 from https://ams-composites.com/choosing-the-right-gas-cylinder-type-1-type-2-type-3-or-type-4/

41 Hoon, Y. T 2021, Hanwha Solutions developing Type 5 hydrogen tank, accessed August 2022 from https://www.thelec.net/news/articleView.html?idxno=3450

The key requirement is to provide the 'loading' systems at the production site, with sufficient storage capacity to suit the anticipated logistics and delivery models, as determined in conjunction with off takers. Typically, depending on the organic fluid, 57 kg or more of hydrogen could be stored per 1,000 litres of carrier fluid, so that a B-double truck carrying approximately 50,000 litres of carrier fluid would have an equivalent hydrogen payload of 2.85 tonnes of hydrogen.

All forms of hydrogen carriers require additional processing at the production site, and potential reprocessing or direct use at the hydrogen offtake point. Appropriate technology must be deployed at the destination to separate hydrogen from the carrier fluid, the cost of which would likely be prohibitive for deployment at a refuelling station but may be justifiable at centralised distribution terminals. The technology for conversion and recovery exists, but further development is required for commercial viability and deployment at scale.

Research is ongoing into organic carriers with lower energy inputs and higher conversion and reconversion efficiencies. In addition, smaller scale containerised systems are under development so that organic carriers may be used for smaller scale distribution. An example of this is Hydrogenious[42], a manufacturer that offers containerised conversion equipment. Their containerised solutions start at 5 tpd of hydrogen processing, and hydrogen release equipment starts at 1.5 tpd, which may be suitable for hydrogen refuelling station use. The units have a small footprint and could be semi-mobile due to their containerised design (containable within a 20 or 40 ft shipping type container).

Direct conversion of hydrogen to carriers without producing hydrogen in a separate step is also gaining research attention. This allows the hydrogen to be extracted from the carrier at the off-taker site. ENEOS is developing technology to produce methylcyclohexane in a single step from water, toluene and renewable energy. Water is oxidised on the anode catalyst to produce oxygen, protons and electrons. The resulting protons flow to the cathode through an ion exchange membrane, where they react with toluene and electrons from the external circuit on the cathode catalyst to produce methylcyclohexane. This technology is being demonstrated in Australia[43].

## Pipelines

In circumstances where the challenge of initial capital intensity can be overcome, the use of pipeline transmission could reduce the delivered cost of hydrogen by up to $1.00–1.50/kg. However, higher efficiency and lower cost separation technologies to extract hydrogen from the blend is required before the use of existing pipelines for hydrogen distribution through blending hydrogen with natural gas is economically viable.

There are commercially available technologies to separate hydrogen from carbon dioxide, for example, especially utilising membranes, but separating low hydrogen blends from a methane-concentrated stream is a very different process. There is a need to increase the $H_2/CH_4$ membrane selectivity to limit permeate $CH_4$ losses and decrease separation unit costs by reducing required membrane surfaces as well as recompression costs.

Pressure swing adsorption (PSA) and temperature swing adsorption (TSA) technologies are industrially mature and make it possible to obtain hydrogen of ultra-high purity. PSA units operating on low hydrogen concentrations, such as 20% mixtures, are feasible. However, these units are sized to remove gas impurities such as carbon dioxide and are not directly relevant for purification of a low hydrogen content flux. PSA and TSA units are relatively simple to operate and do not have high investment costs. However, a proportion of hydrogen will not be recoverable from the blend as the typical hydrogen recovery rate is 85-96%, and this is from a 'typical' hydrogen/$CO_2$/$CH_4$ blend gas produced from, for example, natural gas reforming and shift. The recovery rates may be lower for a hydrogen gas blend with a high methane concentration. In addition, PSA units produce hydrogen and rejected gas streams at relatively low pressures, so that the separated methane stream would have to be recompressed to be injected back to the pipeline.

Other technologies being investigated for the separation of hydrogen from a natural gas blend use membranes include polymer or carbon molecular sieve membranes (CMSM) and electrochemical hydrogen separation (EHS), also known as hydrogen pumping.

42 Hydrogenius, The StorageSYSTEMS, accessed August 2022 from https://www.hydrogenious.net/index.php/en/products-2/thestoragesystems/

43 ENEOS, Direct MCH – one-step chemical hydride production using renewable energy, accessed August 2022 from https://www.eneos.co.jp/english/company/rd/intro/low_carbon/dmch.html

Polymeric membranes appear promising due to ease of use and competitive costs. Typically, these membranes would be utilised as a pre-concentration module for hydrogen recovery. There are some membrane coatings that are being developed that show a good resistance to plasticisation[44]. For example, ring opening metathesis polymerisation membrane coating shows a good resistance to plasticisation coupled with a good selectivity towards hydrogen. CMSMs are also promising and are particularly selective towards hydrogen, leading to high hydrogen recovery at high purity. These membranes offer high permeability in their operating range. The biggest disadvantage to these membranes is that their operating range is at 500-900°C, so that they require a significant heat input to achieve separation.

Electrochemical separation is a more elaborate method for bulk hydrogen recovery. Two technologies are currently used, these being Nafion-based membrane systems and polybenzimidazole (PBI) systems. Nafion-based pumps are considered more technologically mature, but PBI technology has lower compression requirements. These systems require humidification which may result in a requirement for downstream moisture removal from the extracted hydrogen to make it suitable for refuelling purposes.

## Liquid Hydrogen

Minimising BOG during transfer, storage and distribution will enhance safety and reduce cost by increasing loads and minimising wastage. In the past much effort was invested in increasing insulation effectiveness, with many gains in past years. More recently however work is being undertaken to understand and model phase transition, transfer losses and boil-off at different points in the supply chain, and within storage tanks, and to understand specific chemical and thermodynamic mechanisms and how these may be controlled.

Hydrogen undergoes several changes during the liquefaction and transfer process including 2 phase transition, sub-cooled liquid phase, super-heated warming, and non-uniform temperature distributions across the saturation film[45.] These can be accurately modelled to quantify boil-off and transfer losses under different conditions and the outcomes used to inform future designs of storage and handling equipment.

In their work modelling BOG[46], Al Ghafri et al note the influence of conversion between the two hydrogen spin isomers, orthohydrogen and parahydrogen to correctly forecast boil-off rates. Under ambient conditions hydrogen comprises 75% ortho-and 25% para-hydrogen molecules, however at -253$^{0}$C, as hydrogen the para-hydrogen content is 99.8% [31]. Conversion of ortho-$H_2$ to para-$H_2$ is an exothermic reaction with a slow kinetic and represents approximately 10% of the energy to liquefy. If the hydrogen has not been correctly converted to para, then the boil-off will occur as the ortho converts to para, which gives off energy, creating further boil-off. Liquefaction processes use heterogeneous catalysts to ensure this ratio is attained to prevent the exothermic ortho- to para-hydrogen conversion from occurring during storage. Work being undertaken by the CSIRO and the University of Western Australia is seeking to control boil-off by increasing the proportion of parahydrogen during cooling prior liquefaction using a ferric oxide catalyst[47].

Some degree of BOG is inevitable, but there are opportunities to enhance the design of storage and handling equipment to capture and use BOG. For example, some liquid to gas refuelling station equipment captures BOG by routing vented hydrogen to a compressor then on to storage.

While extensive work has been undertaken to model $LH_2$ transfer losses and boil-off using various models, the outcomes are not readily accessible for use by designers and facility owners or operators to develop case specific techno economic models to inform investment decisions.

44 Plasticisation involves swelling of the membrane structure due to the sorption of a penetrant within the polymer matrix which leads to decreased performance over time.

45 Saif Z.S. Al Ghafri; Adam Swanger; Vincent Jusko; Arman Siahvashi; Fernando Perez; Michael L. Johns and Eric F. May, Modelling of Liquid Hydrogen Boil-Off, Energies 2022,15, 1149

46 Guillaume Petitpas, Int J Hydrogen Energy, Simulation of boil-off losses during transfer at a LH2 based hydrogen refueling station, 2018, 43, 21451-21463

47 CSIRO HyResource website, https://research.csiro.au/hyresource/

## 5.3 Compression

### 5.3.1 Compression technology

Hydrogen delivered to the HRS by road is transferred to onsite storage under pressure differential until the pressures of the source and destination tanks approach equalisation, after which a compressor is required to complete the transfer. Hydrogen produced onsite is discharged from an electrolyser at pressures of between 20 and 30 bar (if PEM type) and transferred to storage using a compressor. An alkaline electrolyser may operate at close to atmospheric pressure, requiring additional compression.

Most HRS compressors are positive displacement, either reciprocating or rotary, although some manufacturers offer hydraulic compressors, which are a subset of reciprocating positive displacement. Reciprocating compressors use a moving piston or a diaphragm to compress the gas and are suited for applications that require a high compression ratio, where effective heat transfer can be incorporated. The diaphragm style compressor has no dynamic leak path and is designed so the gas does not contact anything other than the diaphragm. This is attractive for use in refuelling stations due to its ability to maintain 99.999% purity, compress to 1000 bar and provide effective monitoring in the event of diaphragm failure. Reciprocating compressors with piston rings will have a small leakage by design, which needs to be managed. Rotary compressors require tighter tolerances to prevent leakage and are used less frequently[48].

Rotary screw compressors are used to handle larger volume of atmospheric pressure hydrogen in a single stage, for example with large (>25 MW) alkaline electrolysers producing around 800kg/hr $H_2$, the use of a rotary screw compressor is usually recommended.

Ionic compressors, another subset of reciprocating compressors, use ionic liquids in addition to the piston to avoid piston rings. They do not require conventional bearings and seals, two of the common sources of failure in reciprocating compressors, and include filtration to ensure no carry-over of liquid. Reciprocating and hydraulic compressors are mature technology and have a lower capital cost, but higher operational and maintenance cost. Ionic compressors are being incorporated into some OEM electrolyser packages and show increased efficiencies, but with a higher capital cost[49], Table 15.

**Table 15. Relative performance of compressors**

| Compressor | Inlet pressure (bar) | Outlet pressure (bar) | Power consumption (kWh/kg) | Typical Capacity (kg/hr) |
|---|---|---|---|---|
| Reciprocating | 20 | 440 | 2.23 | 41 |
| Ionic[50] | 6-200 | 500 | 1.0-3.3 | 28 |
| Hydraulic | 30 | 450 | 4.7 | 4 |
| Reciprocating | 20 | 880 | 3.0 | 41 |
| Ionic[51] | 6-200 | 900 | 1.0-2.8 | 37 |
| Hydraulic Boost | 450 | 1000 | 0.6 | 54 |

Starting pressure ambient (20°C) at 1 atm

48 US DoE, Gaseous Hydrogen Compression, accessed August 2022 from https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression

49 NREL 2014, Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs

50 Linde Engineering, Hydrogen value chain, accessed August 2022 from https://www.linde-engineering.com/ ,Power includes thermal management

51 Idro meccanica, Compressors, accessed August 2022 from http://www.idromeccanica.it, accessed from Energy for hydraulic compression for 30 to 450 bar must be added to the energy boost to 1000

## 5.3.2 Research and innovation opportunities

For HRSs where the hydrogen is produced offsite, compressors are the largest onsite capital cost, accounting for 54% of capital and 28% of energy consumption and representing a significant potential opportunity for reducing the dispensed levelised cost of hydrogen ($LCOH_D$)[52].

To compress hydrogen utilising a typical mechanical (reciprocating) compressor from 30 bar (typical electrolyser production pressure) to 300 bar (a typical road transport pressure) requires 2.24 kWh/kg $H_2$, and to then compress it from 300 bar to 700 bar (light vehicle delivery pressure) requires an additional 0.86 kWh/kg $H_2$. If compressed from 300 to 1,000 bar, an additional 1.28 kWh/kg $H_2$ is required. All of these figures assume a compressor efficiency of 45%. A typical package cost for reciprocating compressors is $10,000/kg $H_2$/h. Work is ongoing to lower capital and maintenance costs and to increase efficiency.

Non-mechanical compressors using metal hydrides and electrochemical reactions are showing promise. They have several advantages over mechanical compressors, including: (i) no moving components; (ii) quiet operation; (iii) high reliability and safety; (iv) structural simplicity and (v) greater compactness[53].

Electrochemical Hydrogen Compressors (ECHC) use proton exchange membranes flanked by electrodes to purify and compress hydrogen in a single process. They use an external power source to separate hydrogen at the anode and combine it at the cathode at a higher pressure. The compression mechanism is purely electrochemical, so that no moving unit is needed to drive it. This translates into a very high efficiency, up to 60%. In addition, ECHC provides isothermal compression of hydrogen, which requires a lower energy demand compared to a polytropic or adiabatic process, and very high discharge pressures can be reached, even up to 100 MPa. Despite these advantages, the efficiency of an ECHC decreases considerably as the discharge pressure increases.

Metal Hydride Compressors (MHCs) use metals that form hydrides via exothermic reactions and then release hydrogen at high pressures when heat is applied. They are an efficient method for converting energy from heat into a compressed hydrogen gas. High desorption temperatures must be used to achieve high discharge pressures. To date, the average desorption temperature in metal hydride compressors is typically about 573 K, which significantly reduces efficiency by up to 10%. Current research into improving performance of MHCs is examining cycling stability and lifetime and materials development, as well as selecting materials requiring lower desorption temperatures.

Adsorption-desorption compressors are thermally driven, similarly to metal hydride compressors. Compression comes from thermal cycles consisting of progressive cooling and heating stages. Hydrogen adsorption is initially carried out at cryogenic temperatures, and compression comes from the desorption of the pre-adsorbed amount of hydrogen as the hydrogen passes from the denser adsorbed phase to the bulk phase in a confined tank volume when the temperature rises. This type of technology is still developing, and it is therefore difficult to present performance and costs. However, given the absence of moving parts, it should have significantly lower installation and maintenance costs compared to mechanical compressors.

In Table 16, energy consumption and capital costs for other compressors such as ionic compressors are compared against mechanical compressors. It should be noted that although the selection of compressor type can have a significant influence on the compressor cost and power consumption, these should be put into perspective with electrolyser costs. For example, the power consumed by compressors (compressing from 30 to 1,000 bar) is less than 10% of the power consumed by the electrolyser stack per kilogram of hydrogen produced.

52 NREL 2014, Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs

53 Sdanghi, G. et.al. (2020). Towards Non-Mechanical Hybrid Hydrogen Compression for Decentralized Hydrogen Facilities. Energies (2020), 13, 3145

**Table 16. Potential emerging compressor technologies performance**

| Compressor type | Compressor energy required (kWh/kg $H_2$) | Capital cost ($/kg $H_2$/h) |
|---|---|---|
| Mechanical | 3.52 | 10,000 |
| Ionic | 2.26 | No current information |
| Electrochemical | 2.64 | 10% of mechanical compressor equivalent projected[54] |
| Hydride | 10 (heat energy) | 85-90% of mechanical compressor equivalent projected[55] |
| Adsorption-desorption | Unknown | Unknown |

Note: assumes compression from 30 to 1,000 bar

Assuming an electricity cost of $100/MWh, selecting an ionic compressor over a mechanical compressor could result in a cost saving of $0.125/kg $H_2$, only considering power savings. Additional savings may result from lower capital and maintenance costs.

## 5.4 Storage

Storage of hydrogen is a key component in hydrogen supply and can be expensive due to its low volumetric density, especially in gaseous form. Selection of the most appropriate hydrogen storage technology must consider the quantity of hydrogen storage required, fill and dispensing methods, physical footprint and energy usage.

### 5.4.1 Gaseous storage

Hydrogen at most refuelling stations globally is stored as a gas, rather than liquid, however the quantity of hydrogen stored, tank configuration, and storage pressures vary considerably from site to site. Hydrogen transfer from a storage tank to a vehicle tank is driven by the pressure difference between the two tanks. The transfer, or refuelling rate decreases as the difference in pressures decreases.

Dispensing into a vehicle with a 700 bar tank requires the source or buffer tank to be at least 900 bar, while a 350 bar tank requires a source tank at around 500 bar to undertake a complete fill. Relatively large volumes of stored gas are required to achieve refuelling using only pressure differential throughout the fill. Correctly sizing the buffer storage is critical for the ability to fill vehicles back-to-back.

If buffer storage is undersized then there will be a wait time in between vehicles while the onsite compressor refills the buffer tanks, a key issue observed in the US. The size of the buffer storage may be reduced by manifolding several smaller high-pressure tanks or using a compressor to complete the fill.

Bulk and high-pressure or buffer storage may be divided into multiple banks, of either the same or different pressures, which are then used sequentially to fill a vehicle, a process known as 'cascade filling'. For example, one configuration may have hydrogen stored in banks at low (200 to 300 bar), medium (450 to 500 bar) and high (900 to 1,000 bar) pressures. Where this is the case, vehicles are filled initially from the low-pressure bank, then the medium pressure bank, then topped off using the high-pressure or buffer bank. In configurations that do not include a high pressure (900-1,000 bar) buffer or where multiple vehicle fills are required in succession, a compressor may be placed after the buffer tank to complete the fill.

Cascade storage configurations and top up using a compressor are also employed to minimise the energy of compression by utilising lower pressures at each stage of the filling process. Cascade storage refuelling significantly reduces cooling energy consumption, while not exceeding the expected light duty vehicle refuelling time of three to five minutes. Reducing the cooling energy consumption is also important, as this could exceed 10 kWh per kg of hydrogen[56], representing approximately 80% of the total energy consumption for an HRS (excluding hydrogen production onsite). The high-pressure cascade storage tank places greater demand on HRS cooling energy consumption than the other lower pressure units.

54 Sdanghi, G. et.al. (2020). Towards Non-Mechanical Hybrid Hydrogen Compression for Decentralized Hydrogen Facilities. Energies (2020), 13, 3145

55 Sdanghi, G. et.al. (2020). Towards Non-Mechanical Hybrid Hydrogen Compression for Decentralized Hydrogen Facilities. Energies (2020), 13, 3145, a

56 Luo et al. (2022). Multi-objective optimization of cascade storage system in hydrogen refuelling station for minimum cooling energy and maximum state of charge. International Journal of Hydrogen Energy 47 10963-10975.

Storage and compression capacity is configured to meet daily turnover and the usage profile comprising the total daily demand, fill size, and number of back-to-back fills. Increased usage across one or more of these parameters will increase quantity of hydrogen held at higher pressures and increase compression and chilling duty. All of these have associated impacts on footprint, electrical infrastructure, capital investment and operating costs.

There are several approaches to onsite storage, the more common are described below, each of which has variations to further align to usage profile.

## Permanent onsite storage installation

Permanent or fixed installations come in a variety of arrangements but have in common tanks that are fixed in place. They are replenished by transfer from a delivery vehicle (see Figure 9) or from an onsite electrolyser.

Hydrogen is transferred from the tube trailer delivery vehicle to the fixed storage initially by pressure differential. When the pressure difference between the delivery and site tanks falls below a trigger value, an onsite compressor is used to complete the transfer.

## Tube trailer-swap

Tube trailers holding from 200 to 1,000 kg of hydrogen, either at a single pressure or in a cascade format, integrate racks of hydrogen tubes mounted on a trailer hitched to a prime mover for transport. They may be fitted with either horizontal 'Type I' tubes at 200 bar, or with 'Type IV' cylinders at either 300 or 500 bar.

Tube trailers are driven to site, unhitched from the prime mover, and connected to the site refuelling system, as shown in Figure 9. The prime mover will then typically take away the depleted tube trailer that had been supplying previously. This arrangement works best if the site has two tube trailers. A single tube trailer may work if the site is fitted with large, medium pressure, fixed storage to provide continuity of supply during trailer changeover. Site footprint and accessibility will be important factors when considering tube trailer-swapping.

Tube trailers store hydrogen at pressures between 180 and 500 bar and need to be supplemented by a compressor that can transfer hydrogen to a buffer tank or fill vehicles directly.

## ISO Storage Modules

ISO storage modules comprise racks of tubes or cylinders fitted into a skid mounted frame based on ISO shipping containers or Manifold Cylinder Packs (MCP). They are transported to site on a flatbed trailer and lifted into position with a crane. MCPs are used for temporary or backup storage (or for the permanent installation above) and as an alternative to tube trailers where modules are replaced when empty. MCPs can be configured in a cascade arrangement or more commonly all cylinders are stored at the same pressure with a site-based compressor and buffer tank.

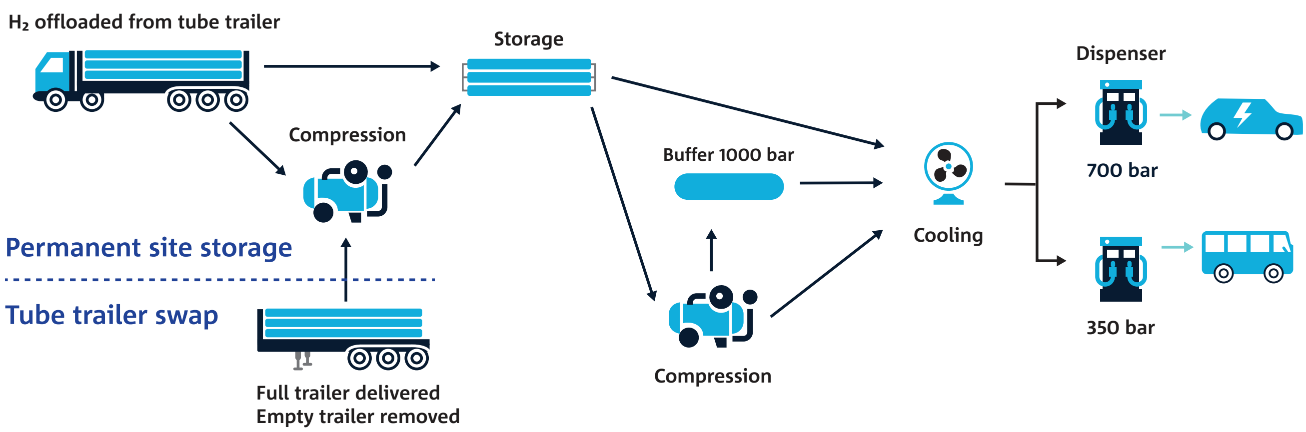



Figure 9. Example delivery and storage configurations

### 5.4.2 Liquid storage

Storing hydrogen as a liquid provides the substantial benefit, versus comparable quantities of gaseous hydrogen (as shown in Figure 10. Hydrogen density response to pressure and temperature), of increased energy density and, thus, reduced required storage space. Liquid storage at the refuelling station may also reduce capital and operating costs since it is possible to eliminate the need for buffer storage, a chiller and one stage of compression for dispensing into vehicles, although a cryogenic pump and insulated pipes and fittings are needed. $LH_2$ is transferred from the delivery tanker to the vacuum insulated double walled steel site storage tank using a cryogenic pump. Storage tanks for LH2 are available in sizes ranging from around 800 kg up to 4,800 kg.

Loss of $LH_2$ occurs during transfer and storage due to boil-off, as described in Section 5.2.2. Vented $GH_2$ may be captured and redirected to station storage, where it is compressed and held at medium or high pressure and available for dispensing to customers.

One of the drawbacks of $LH_2$ is the cost to liquefy. The cost for liquefaction decreases with increasing volume, but volumes used at refuelling stations are below that required to make on site liquefaction viable. Centralised liquefaction can be preferential, with current large scale facilities limiting price increase to $1.40 to $2.00/kg to the production price. This price is expected to reduce with increased production levels.

### 5.4.3 Cryo-compressed storage

$LH_2$ is stored at a cryogenic temperature (minus 253$^0$C) at essentially atmospheric pressure, while $CH_2$ is stored at ambient temperature, but at pressures up to 1,000 bar. Cryo-compressed hydrogen ($CcH_2$) combines both storage approaches and offers the benefits of each, such as the high energy density of $LH_2$ and mass retention of $CH_2$. It also addresses the disadvantages of each such as $LH_2$ boil-off and the low energy density of $CH_2$, as shown in Figure 10 below.

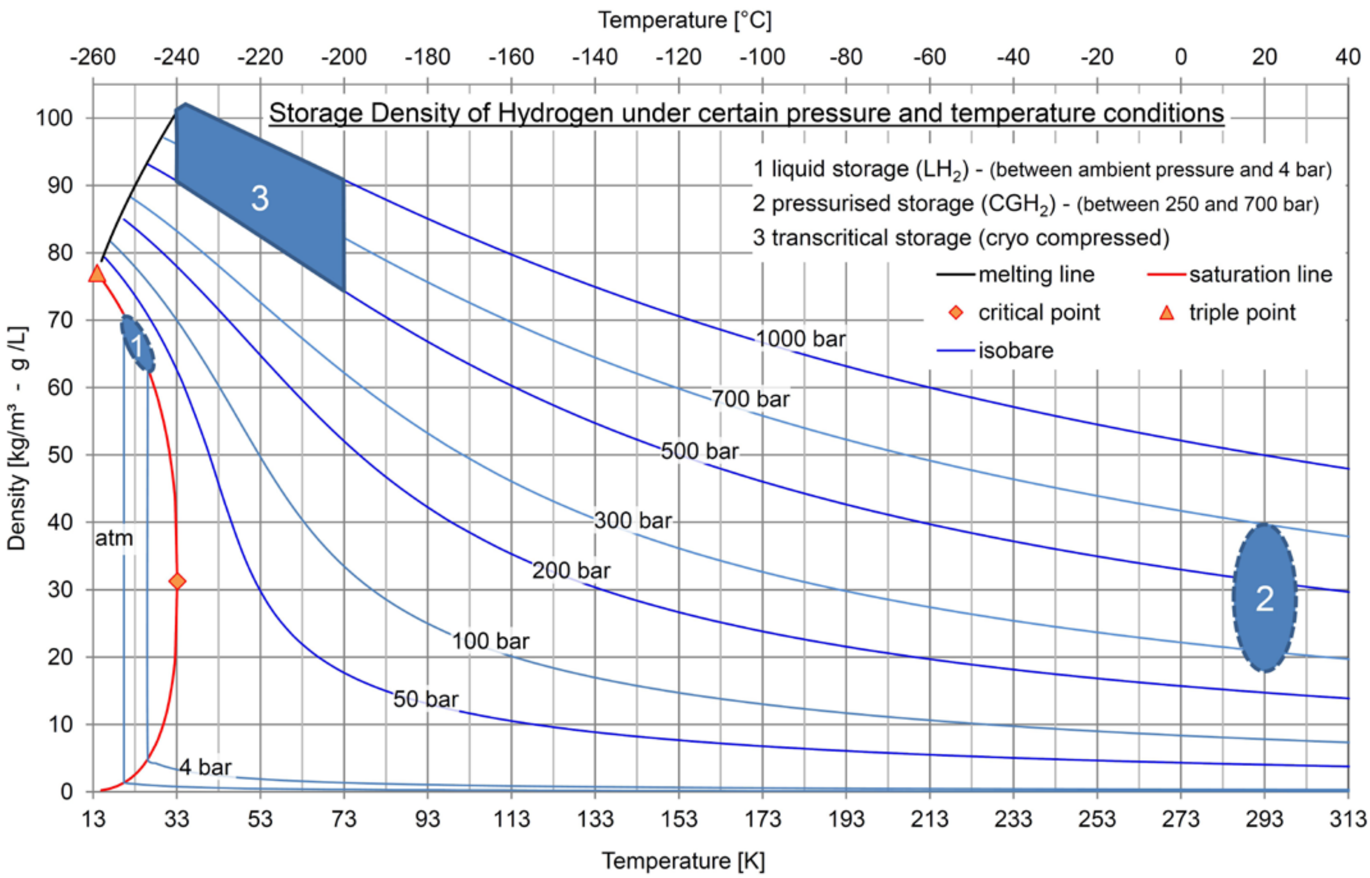



**Figure 10. Hydrogen density response to pressure and temperature**[57]

57 ILK Dresden, Home page, accessed August 2022 from https://www.ilkdresden.de/leistungen/forschung-und-entwicklung/projekt/wasserstoff-und-methan-versuchsfeld-am-ilk (Report: High energy density storage of gaseous marine fuels: An innovative concept and its application to a hydrogen powered ferry, pg)

Compressing liquefied hydrogen at a temperature of minus 253°C increases volumetric storage density from 70 g/l at 1 bar to 87 g/L at 240 bar. The benefits of $CcH_2$ can be achieved using pressures as high as 300 bar which may reduce the requirement for more costly carbon-fibre composites, however the technology for handling $CcH_2$ on site and onboard vehicle storage is still under development, with the development of materials emerging as a key opportunity. Some development has focused on applications using Type III vessels, but issues remain with $LH_2$ pump performance, vacuum stability, and manufacturability[58].

### 5.4.4 Research and innovation opportunities

Development of hydrogen storage technology represents a key opportunity to reduce capital and operating costs with benefits flowing to both the transport and refuelling links of the supply chain.

Hydrogen storage can be grouped into various categories as shown in Figure 11.

Current research activities are focussed on:

- Increasing hydrogen storage density through increasing storage pressures for $GH_2$.
- Decreasing compressor costs and power demands to store $GH_2$ at a higher pressure.
- Vessel type and materials of construction, potentially resulting in lower $GH_2$ storage costs.
- Reducing electricity demand to liquefy the hydrogen.
- Tank design to reduce boil-off.
- Metal hydride storage to improve volumetric and gravimetric capacities, hydrogen adsorption/desorption kinetics, cycle life, and reaction thermodynamics of potential material candidates. In addition, there are numerous hydrides commonly available for hydrogen storage, but they typically have a high capital cost, due to the use of platinum group metals[60]. There is also difficulty in manufacturing at large scale. In all cases, heat (energy) is required to release hydrogen from the hydride; in many cases, the amount of heat required make this type of storage is uneconomical. Research is ongoing into other hydrides such as aluminium, lithium, magnesium, and boron to reduce the cost of hydrogen hydride storage and reduce the energy requirements to release hydrogen. One example of a commercialised metal hydride storage solution is offered by LAVO[61].

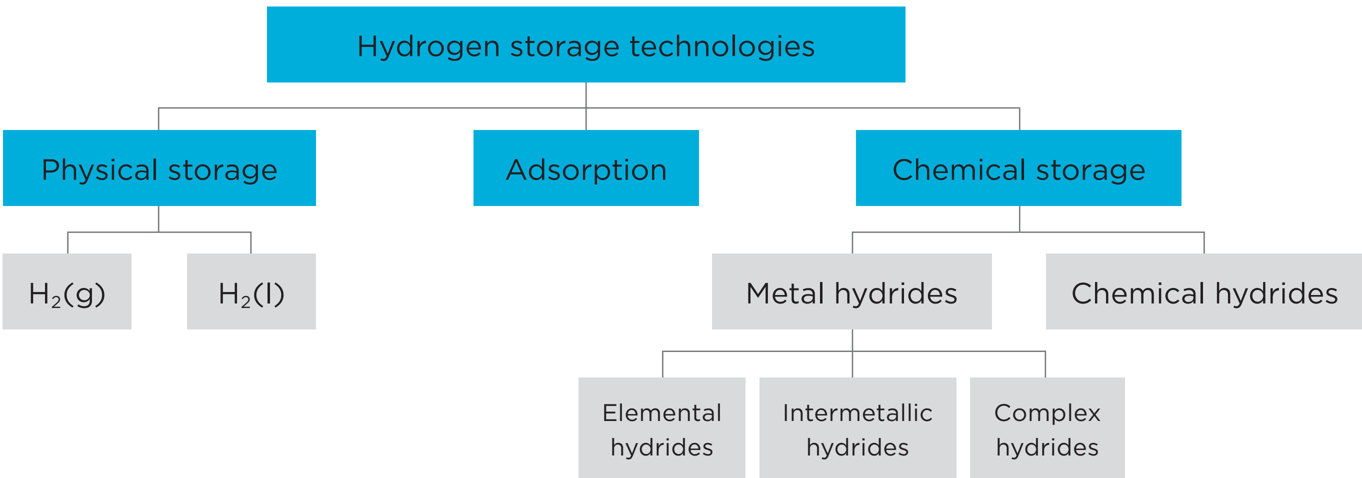



**Figure 11. Hydrogen storage categories (currently available and emerging technologies)[59]**

58 ILK Dresden, Home page, accessed August 2022 from https://www.ilkdresden.de/leistungen/forschung-und-entwicklung/projekt/wasserstoff-und-methan-versuchsfeld-am-ilk

59 Andersson, J. & Gronkvist, S. 2019. Large-scale storage of hydrogen. International Journal of Hydrogen Energy 44, pages 11901-11910

60 Smith, C. and Lloyd, A. 2019. Hydrogen as a component of city development – The business case for city hydrogen deployment with Tyseley Energy Park an exemplar case study.

61 https://www.lavo.com.au

- Materials for reversible hydrogen storage such as high surface area adsorbents and metal organic frameworks for increasing storage capacities by optimizing pore size and volume.  Adsorbent materials research is focused on increasing effective adsorption temperatures and improving storage capacities. Metal-organic frameworks can generate extremely high, regular surface areas that increase carrying capacity[62]. There are also opportunities with flexible metal organic frameworks where a pressure induced phase change from a low surface area to high surface area structure may lead to high degrees of isothermal reversibility over a narrow pressure range, see Figure 12.

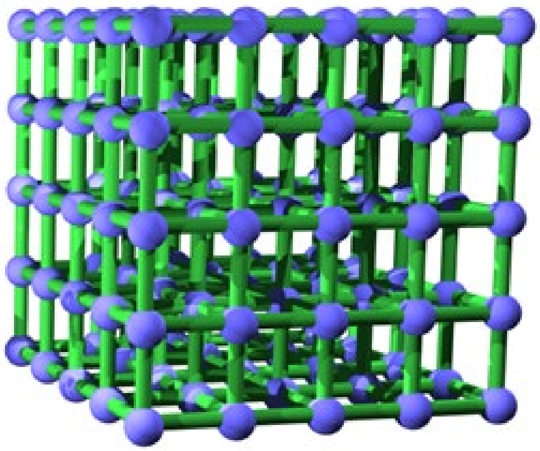


**Figure 12. Metal Organic Frameworks (MOF) materials are under research for hydrogen storage**

- Cryo-compressed and cold gas storage. Advances in storage materials to determine lower cost and more durable materials for wider use.
- The use of aluminium. While aluminium is not strictly a hydrogen storage method, it can be reacted with water to release hydrogen and form aluminium hydroxide. It can then be reconverted to aluminium. This has a favourable round-trip efficiency, but a low carrying capacity of 3.7 wt% hydrogen.
- Chemical hydride storage, which works by converting an aromatic group in an organic chemical compound to a saturated cyclic compound through hydrogenation. A typical example of this is toluene to methylcyclohexane. The methylcyclohexane can be stored at room temperature and atmospheric pressure. These liquids can generally store high values of hydrogen weight per volume (13 to 14%%). The main challenges for this type of hydrogen storage are considerable energy consumption to dehydrogenate the liquid to release the hydrogen again when required, the capital required to construct hydrogenation and dehydrogenation units and side reactions leading to hydrogen losses and useless co-products during dehydrogenation. Research is ongoing to identify organic liquid/hydrogenated liquid pairs where these disadvantages could be minimised. Various proponents are working on containerised hydrogenation/dehydrogenation equipment for smaller installations.

## 5.5 Dispensing

### 5.5.1 Dispensers

Like petrol and diesel refuelling stations, HRSs are typically being designed to be ‘self-serve’, where drivers fill their vehicle tanks without supervision. Dispensers are designed to create a user-experience like refuelling a petrol or diesel-fuelled vehicle, although refuelling with hydrogen more closely resembles refuelling with LPG. Filling instructions are usually provided on or near the dispenser, as for LPG.

The hydrogen dispenser includes a user interface, payment system, metering, and safety features such as breakaway joints, reverse flow prevention, excess flow prevention, sensors for temperature and pressure, remote stop, hydrogen gas detection and alarm, infrared flame detectors, fuel tank overpressure protection and purge-system monitoring. To protect the onboard vehicle tanks and to assist refuelling speeds, a pre-cooler, or cooling block that uses a refrigerant system, is employed; this can be supplied separately or incorporated into the dispenser casing, depending on the design conditions.

A hydrogen-only nozzle from the dispenser is connected to the vehicle refuelling point using a snap-lock style fitting to ensure a firm gastight connection. Figure 13 illustrates a dispenser, showing key features, including the fuelling block.

62 Materials-Based Hydrogen Storage | Department of Energy

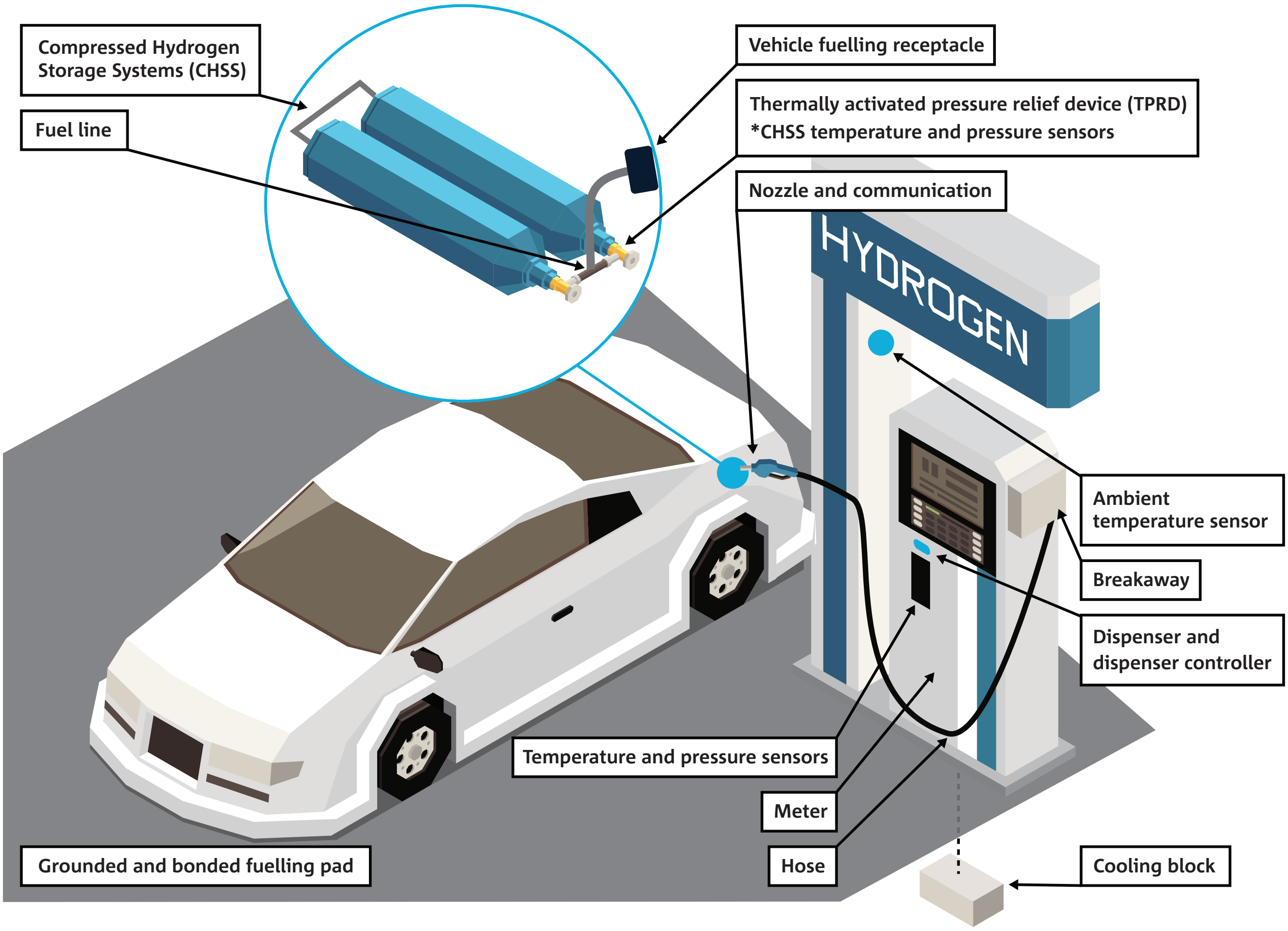



**Figure 13. Key components of a hydrogen dispensing system**[63]

Experience in Europe and USA shows that dispenser improvements are still needed, with a common issue being attaching and detaching the nozzle to the vehicle fill valve. The refuelling protocols defined in SAE J2601 provide a degree of protection by preventing the refuelling process to commence until a proper connection is achieved. At the end of the refuelling process some nozzles are 'frozen' in place with external or internal ice accumulation. The impact of this may be alleviated by human-factors engineering, like providing a towel for wiping down the nozzle before/after refuelling, signs alerting drivers to the issue and detailing actions, or programming the Human-Machine Interface (HMI) screen that instruct drivers to wait before attempting to disconnect if the nozzle sticks to the vehicle refuelling connection.

Dispensers for LDVs fill a 5-6 kg tank at 700 bar at a rate of approximately 1 kg/min, resulting in a refuelling time of around five minutes. Dispensers for HDV or MDV with 350 bar tanks, transfer at a rate of 2.5-3.6kg/min, but with cooling can go as high as 7kg/min, resulting in a refuelling time of around 10 to 15 minutes for a 30-40 kg tank and 20 minutes for an 80 kg tank. A traditional long-haul truck with a 1,000 litre tank using a high-flow diesel dispenser with a flow rate of 80 litre/min takes around 12 minutes to refuel. In contrast, a BEV truck[64] will achieve the same range (assumed > 2,000km on a single 1,000 litre tank) after at least eight stops to charge, with each charge taking 90mins[65].

63 ISO 19880.1 Gaseous Hydrogen-Fuelling stations – Part 1: General requirements

64 Scania BEV Rigid Truck, 468kWh battery capacity can achieve range of 350km at 60% of its design load. https://www.scania.com/group/en/home/products-and-services/trucks/battery-electric-truck.html

65 Assuming a 375kW charger – high voltage and designed for prime mover/ HGV

### 5.5.2 Refuelling protocols

SAE International's *Fueling Protocols for Light Duty Gaseous Hydrogen Surface Vehicles* standard, J2601, defines dispenser fuelling protocols for LDVs. This standard is referenced in ISO 19880-1 *Gaseous hydrogen — Fuelling stations — Part 1: General requirements*. *SAE J2601-2 Fuelling Protocol for Gaseous Hydrogen Powered Heavy Duty Vehicles* defines similar protocols for HDVs.

ISO/TC 197 is developing standards for fuelling protocols, but no release date has been advised:

- SO/DIS 19885-1 Gaseous hydrogen — Fuelling protocols for hydrogen-fuelled vehicles — Part 1: Design and development process for fuelling protocols
- ISO/AWI 19885-2 Gaseous hydrogen — Fuelling protocols for hydrogen-fuelled vehicles — Part 2: Definition of communications between the vehicle and dispenser control systems
- ISO/AWI 19885-3 Gaseous hydrogen — Fuelling protocols for hydrogen-fuelled vehicles — Part 3: High flow hydrogen fuelling protocols for heavy duty road vehicles

The refuelling protocols define the conditions for safe vehicle fuelling and specify the monitoring of process limits such as the fuel delivery temperature, fuel flow rates, the rate of pressure increase and end pressure. Some features of the refuelling protocols are:

- connection pulse - to equalise the storage pressure with the vehicle fuel tank
- initial leak check – checks system integrity
- fuelling leak check – mid fuelling check to test for system leaks.

There are two types of refuelling protocols defined in SAE J2601: those based on look-up tables that use fixed pressure ramp-up rates and formulas for temperature control, while the other uses a dynamic pressure ramp rate that is monitored and adjusted throughout the fill process to maintain thermal integrity. Both protocols may be remotely monitored via a communications process defined in SAE J2799 *Hydrogen Surface Vehicle to Station Communications Hardware and Software*. The emerging trend in Australia is for dispensers to adopt the dynamic protocol with station to dispenser communications.

### 5.5.3 Temperature and chilling

Hydrogen heats when compressed into a vehicle fuel tank (due to its negative Joule-Thompson Coefficient). In recognition of this heating effect and its potential to damage the internal lining of the Type IV cylinders used for vehicle fuel tanks, SAE J2601 section 6.3.2 and ISO 19880 C5.1 require the internal surface of the fuel tank to be kept below 85°C. The refuelling protocol will stop the dispensing operation if 85°C is reached, which will result in a partial fill. Temperature increases can be controlled by reducing the fill rate or chilling the hydrogen. Dispensing rates of around 1kg per minute equates approximately to the filling rate of petrol into a passenger vehicle. To achieve a dispensing rate of 1 to 1.5 kg per minute into a fuel tank with 700 bar compression, the hydrogen must be chilled to minus 40°C. If slightly slower fill rates are acceptable operators may consider chilling to only minus 20°C and reduce the capital and operating expense associated with chilling down to minus 40°C. From a process flow perspective, the chilling unit is placed between the source tank (or compressor discharge) and dispenser. Hydrogen flows from the tank or compressor and passes through the chiller or heat exchanger, not contacting the refrigerant in order to avoid contamination. Once cooled to the required temperature, -40°C for H70 dispensing, the hydrogen flows to the dispenser. Configurations and chilling processes vary by manufacturer, but the chilling unit must be located within reasonable proximity to the dispenser.

At lower ambient temperatures, refuelling heavy vehicle 350 bar tanks is not as temperature sensitive but fill rates of 2.5 to 3.6kg/min are best achieved with chilling, which is typically to -20°C. Fuel transfer temperature checks are included within the protocols defined in SAE J2601 and equipment that use the protocols will shut down the refuelling operation if the system detects the temperature limits have been exceeded. Temperature limitations during refuelling operations protect the tank and allows a fill rate that meets customers' expectations and the operational requirements of commercial vehicles. The ability to chill the fuel is a critical component to replicate the traditional refuelling experience with hydrogen, and if the cooling system fails, the refuelling station will either need to temporarily close, or remain open on the H35 dispenser-only.

### 5.5.4 Liquid hydrogen

Currently all commercially-available FCEVs operate on gaseous hydrogen. Therefore, hydrogen stored onsite as a liquid must be vapourised to gas before dispensing into vehicles. Prototype dispensers for liquid hydrogen have been developed, but are still undergoing testing and refining. Components such as break-away couplings, hoses and dispensing nozzles are still being refined and tested for operability and safe use by untrained vehicle drivers.

Separately, of particular note, some manufacturers are in the process of developing FCEVs that will carry on-board liquid hydrogen. For example, Daimler expects to commence road trials of a truck that will utilise liquid hydrogen in 2023.

### 5.5.5 Research and innovation opportunities

Development of hydrogen dispensing technology represents a key opportunity to improve the user experience, reduce capital and operating costs and enhance safe operations.

The requirement to chill gaseous hydrogen to achieve a 'fast fill' for 700 bar vehicle tanks imposes both a capital and operating cost. Refuelling at higher rates will reduce refuelling times, particularly for heavy duty vehicles that are carrying increasingly greater quantities of gaseous hydrogen, now over 80 kg, and many looking to store this at 700 bar. One way to address this problem is to increase the heat resistance of the liners in Type IV tanks. Adapting the Type V tank that does not require internal permeation barriers, to automotive applications may also increase heat tolerance, while also reducing the weight of the vessel.

Pumping liquid hydrogen directly from storage to an evaporator, and then to the dispenser, bypassing the chilling unit offers promise. In addition to negating the need for a chiller at all, it essentially allows continuous back-to-back fills.

shutterstock.com (Ned Snowman)

# 6 Standards, planning and regulations

## 6.1 Standards

Standards Australia's ME093 Hydrogen Technologies Committee and its Mobility Applications Working Group leads the development of standards across the hydrogen mobility value chain. These standards must link to and align with the Australian Design Rules, being the national standards for motor vehicles, as applicable.

In 2018 Standards Australia hosted the Hydrogen Standards Forum aimed at identifying opportunities for addressing the future standards needs of the hydrogen sector. In 2019 the Committee released the *ME-093 Hydrogen Technologies Strategic Work Plan* that describes a roadmap for standards development and identified focus areas for 2020-23. Since then, Standards Australia has made some progress as noted below.

### 6.1.1 Adopted Standards

To date, Standards Australia has adopted several International Organization for Standardization (ISO) standards for Gaseous Hydrogen – Fuelling Stations, as indicated in Table 17 below.

**Table 17. AS ISO 19880 "Gaseous Hydrogen – Fuelling Stations" standards adopted by Standards Australia**

| Standards Australia Designation | Part | Scope |
|---|---|---|
| AS 19880.3 | 3: Valves | Outlines requirements and test methods for safety performance of high-pressure gas valves that are used in hydrogen stations providing up to H70 |
| AS ISO 19880.5:2021 | 5: Dispenser hoses and hose assemblies | Outlines requirements for dispenser hoses and hose assemblies for dispensing up to H70 $GH_2$ |
| AS ISO 19880.8: 2021 | 8: Fuel quality control | Fuel quality control for $GH_2$ for PEM fuel cells in FCEVs. |
| AS ISO 19880.8/AMD 1:2021 | 8: Fuel quality control | Fuel quality control – Amendment 1: Alignment with Grade D of ISO 14687 |

In addition to standards in the ISO 19880 series, the following standards for hydrogen refuelling have also been adopted by Standards Australia, as shown in Table 18 below.

**Table 18. Other ISO Standards as adopted by Standards Australia**

| Standards Australia Designation | Title | Scope |
|---|---|---|
| AS 22734:2020 | Hydrogen generators using water electrolysis – Industrial, commercial, and residential applications | Defines the construction, safety and performance requirements of electrolysers |
| AS 16110.1:2020 | Hydrogen generators using fuel processing technologies, Part 1: Safety | Specifies requirements of hydrogen production equipment with a capacity of less than 400 m3/h at 0 °C and 101,325 kPa, that use fuel to produce hydrogen |
| AS ISO 16110.2:2020 | Hydrogen generators using fuel processing technologies, Part 2: Test methods for performance | Provides test procedures for determining the performance of hydrogen generators (with a capacity less than 400 m3/h at 0 °C and 101325 kPa) that use fuel processing technologies |
| SA TS 19883:2020 | Safety of pressure swing adsorption systems for hydrogen separation and purification | Identifies safety measures and applicable design features that are used in the design, commissioning, and operation of pressure swing adsorption systems for hydrogen separation and purification |
| AS ISO 16111:2020 | Transportable gas storage devices – Hydrogen absorbed in reversible metal hydride | Defines the requirements applicable to the material, design, construction, and testing of transportable hydrogen gas storage, not exceeding 150 l internal volume and having a maximum developed pressure (MDP) not exceeding 25 MPa. Applicable to refillable hydrogen storage |
| AS ISO 19881:2020 | Gaseous hydrogen – Land vehicle fuel containers | Outlines requirements storage container for compressed $GH_2$ to be used as fuel.<br>These containers a) are permanently attached to the vehicle, b) have a capacity of up to 1 ,000 L water capacity, and c) have a nominal working pressure that does not exceed 70 MPa |
| AS 26142:2020 | Hydrogen detection apparatus – Stationary applications | Defines the performance requirements and test methods of hydrogen detection systems, designed to measure and monitor hydrogen concentrations in stationary applications |
| AS ISO 14687:2020 | Hydrogen fuel quality – Product specification | Specifies the minimum quality characteristics of hydrogen fuel |
| SA TR 15916:2021 | Basic considerations for the safety of hydrogen systems | Provides guidelines for the use of hydrogen in gaseous and liquid forms as well as its storage in either form. Outlines the basic safety concerns, hazards and risks, and describes the properties of hydrogen that are relevant to safety |
| AS/NZS IEC 60079.10.1, Sup 1, Appendix E1.5 | Explosive atmospheres – Classification of areas | Provides examples of hazardous zones for hydrogen installations. Direction provided in the Energy Institute "*Guidance on Hydrogen delivery Systems for refuelling of motor vehicles co-located with petrol filling stations*", Supplement to the Blue Book, March 2017, which provides additional examples of hazardous area classification for refuelling station equipment |

### 6.1.2 Developments in standards

Table 19 below shows the standards ISO is currently developing within its ISO 19880 series, with Standards Australia likely to adopt these once completed.

**Table 19. ISO 19880 "Gaseous hydrogen – Fuelling Stations" standards under review by Standards Australia**

| Standard Designation | Part | Scope |
|---|---|---|
| ISO 19880.1:2020 | Part 1: General requirements | General requirements for hydrogen refuelling stations |
| ISO/CD 19880.6 | Part 6: Fittings | Defines safety requirements for fittings |
| ISO/WD 19880.7 | Part 7: O-rings | Outlines the requirements for O-rings |
| ISO/CD 19880.9 | Part 9: Sampling for fuel quality analysis | Sampling for fuel quality analysis |

ISO 19880.1 is currently being adopted by modification to AS 19880.1. The Standards Australia process has completed the public comments process and is expected to be published mid-2023.

To date, few manufacturers claim conformance with either ISO 19880.3 or, by adoption, AS 19880.3 for valves. However, ISO 19880.1 (expected to become AS 19880.1) has a clause which allows the use of ISO 15649 for piping and pipe fittings including valves in place of ISO 19880.3/AS 19880.3. ISO 15649 effectively points to ASME B31.3. Generally, most valve manufacturers, especially those used in hydrogen service, conform with ASME B31.3.

ASME have also published a standard specially for hydrogen service ASME B31.12.

In addition to the 19880 series, Standards Australia's ME-093 Mobility Applications Working Group is also engaged with the following developments:

- new Australian Technical Specification SA TS 5359:2022 The: Storage and Handling of Hydrogen, Published in December 2022
- participating in ISO/TC 197 projects related to: refuelling protocols (especially for fast fuelling of heavy vehicles) and refuelling station equipment design and performance
- assessing the need for Australia to establish National Mirror Committees to ISO/TC 22 – Road Vehicles and ISO/TC 110 – Industrial Trucks
- reviewing published international standards related to hydrogen refuelling for both gaseous and liquid hydrogen, particularly around impact of hazardous areas.

### 6.1.3 Compliance considerations

Some providers of original equipment have experiencing issues relating to equipment compliance, particularly around AS/NZS 3000 compliance and ATEX versus IECEx compliance. Compliance issues can create additional costs in verifying that internationally certified equipment affords an equivalent level of safety to that required by Australian Standards.

For example, Australia adopted *ISO 22734 Hydrogen generators using water electrolysis – Industrial, commercial, and residential applications* (AS 22734:2020) with minimal changes and references. One equipment manufacturer produces an electrolyser that meets ISO 22734 (thus AS 22734), but it fails to meet hazardous certification of the International Electrotechnical Commission (IECEx) certification since the European Union (EU), where the equipment is manufactured and certified, only requires that the equipment follows the regulations of the EU's ATEX Directives.

Unlike Australia, New Zealand does permit equipment certified by a third party to ATEX requirements to be used in hazardous areas. ATEX Category 3 equipment (i.e. deemed suitable under a Manufacturer's Declaration of Conformity) is however not permitted.

Some manufacturers indicated there may be less risk with accepting equipment compliance with international standards such as ISO or European Standards (EN - European Norm), whilst acknowledging the need for AS/NZS 3000 compliance for external connections and power supplies. It should be noted however that while deviation from Part 2 of AS/NZS 3000 may be acceptable where an equivalent level of safety can be demonstrated, compliance with all aspects of Part 1 is mandatory.

Currently, HRS designers must undertake detailed fire studies, radiant heat and over-pressure modelling and quantitative risk assessments to establish separation distances and other layout parameters. These can be costly and time consuming, particularly if undertaking high-level feasibility studies. Standards that document generic approaches to assessing risk and include reference tables for separation distances and mitigations based on first principles modelling of typical scenarios would be of benefit to developers and planners alike.

## 6.2 Planning and approvals

Planning and approval frameworks for HRSs exist in all Australian jurisdictions, but the pathway varies across states and is not as clearly defined as the process for traditional service stations. The usual pathways across jurisdictions require station developers to interact with, and seek approvals from:

1. emergency services
2. work safety agencies
3. energy regulators in some states
4. environmental regulators
5. local councils and advocacy groups.

Planning and approvals legislation and regulations are currently subject to the National Hydrogen Regulatory review, (refer Section 6.3 below) which is intended to identify gaps in existing regulations and approvals processes as well as barriers to development of the hydrogen industry, then to develop options for legislative reform. Currently however, a lack of experience approving hydrogen refuelling stations can result in delays in zoning and planning approvals, which represents a risk for developers. Explaining the risks and technology to relevant authorities will likely be crucial in securing approval until a clear pathway supported by an appropriate framework is developed.

This risk has already materialised. Stakeholders commented on the time taken to secure approvals for hydrogen refuelling. There is uncertainty around the role of each authority in approving planning submissions. It is possible that different state-based planning pathways and differing requirements from each of the regulatory bodies may hinder efficient deployment once refuelling station roll out gathers pace. Businesses exploring multi-state network options report that documentation requirements for each state can vary widely, which adds to cost and complexity.

Recent announcements to establish and develop HRSs are expected to trigger a streamlined approach to planning approvals to fast track hydrogen refuelling infrastructure. Overseas jurisdictions, such as California have developed detailed planning 'guidebooks' for hydrogen refuelling stations, providing developers with a certain amount of clarity[66]. Similar guides, at the state level would benefit this planning to develop hydrogen refuelling stations.

State planning authorities suggested guidance on framing a planning and approvals process would help improve both state and local planning and approvals processes and provide consistency across jurisdictions. A consistent approach, based on robust risk modelling and understanding of technology would address problems such as imposing conservative risk management overlays based on a misunderstanding of the risks and mitigations for hydrogen.

## 6.3 Legislation and regulation

States and territories are responsible for most of the regulations, planning and environment approvals associated with the construction and operation of hydrogen refuelling stations, dangerous goods transport, Major Hazard Facilities thresholds and appliance approvals, while the Commonwealth Government develops legislation that covers fuel quality, vehicle standards, trade measurement, emissions accounting and excise.

The existing Commonwealth and state regulatory frameworks were developed before hydrogen emerged as an energy storage medium, a mobility fuel and a potential export commodity, and before the scale of production required to meet anticipated demand had been recognised. Consequently, the existing framework at both state and Commonwealth levels of government is not tuned to *optimise industry development, while keeping Australians safe and protecting the environment*[67].

66 California Governor's Office 2020, Hydrogen Station Permitting Guidebook

67 COAG Energy Council Hydrogen Working Group, 2019, Commonwealth of Australia's National Hydrogen Strategy

The Commonwealth Department of Climate Change, Energy, Environment and Water (DCCEEW) is driving the National Hydrogen Regulatory Review in line with the National Hydrogen Strategy (NHS) published by the then Commonwealth Department of Industry, Innovation and Science in 2019.

Action items 4.1 – 4.4 of the NHS call for all jurisdictions to:

- review the regulatory framework
- coordinate review outcomes nationally
- amend or draft new legislation where necessary
- seek national regulatory consistency.

A Legal Frameworks Review Working Group was established, with representatives from the Commonwealth and each state and territory, and the review commenced in mid-2021. The working group mapped hydrogen industry activities to existing legislative frameworks that regulate or could regulate hydrogen for those activities. The intended outcome is to achieve legislative reform that will:

- improve hydrogen safety and consistency of safety requirements
- improve efficiency and transparency of regulatory approvals
- ensure international competitiveness.
- be adaptive to rapid technological change and innovation.[68]

The Working Group concluded that while hydrogen is captured in the existing regulatory frameworks its broad range of applications as a fuel or energy source may require more complex regulation than traditional fuels. It also identified areas where there is no regulation or a lack appropriate standards, and where the application of existing legislation is unclear creating approval, compliance, and enforcement delays. Regarding hydrogen refuelling stations, the review found the following[69]:

- Each state and territory take a different approach to the regulation of service stations.
- There is no regulatory tool for available for HRS approvals as they fall below the Major Hazard Facility threshold.
- Due to unique properties of hydrogen, namely high storage pressures requirements, approaches typically used for regulating safety at petrol stations area not appropriate for HRSs. Applying safety regulations used for major hazard facilities would impose a greater burden than necessary.
- The risks and standards for hydrogen dispensing are substantially different to petrol, assessment will be made on novel tracks resulting in compliance uncertainty, approval delays and increased costs.

Once the Legal Frameworks Review Working Group has identified legislative and regulatory gaps or barriers it will identify priority areas for industry and develop solutions or options for reform. These will be presented to energy ministers for review, particularly those that can deliver national consistency. It is intended that when reform options are agreed by energy ministers, the working group will consult with industry on the details and how the reform can be implemented.

At the time of writing this the regulatory review was undertaking industry consultation for proposed areas of reform, priority and preferences for specific regulation and national consistency.

68 Commonwealth Department of Climate Change, Energy, the Environment and Water, Nov 2022, National Hydrogen Regulatory review, Industry consultation presentation.

69 Commonwealth Department of Climate Change, Energy, the Environment and Water, 2022, Review of Hydrogen Regulation Industry Consultation: Information for seminar and survey participants

# Part C –

# Hydrogen refuelling configurations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# 7 HRS configurations analysed

This chapter describes five different configurations – in terms of production, distribution, storage and dispensing – for HRSs as summarised in Table 20 below.

**Table 20. Key configurations investigated**

| Config' | Description | Production | Form | Distribution | Storage | Dispensing |
|---|---|---|---|---|---|---|
| 1 | Onsite production, electrolysis using grid electricity | Electrolysis using grid electricity | Gas | n/a | Gaseous storage | Gas compressor and dispenser |
| 2 | Onsite production, electrolysis using onsite renewables augmented by grid electricity | Electrolysis using behind-the-meter renewables | | n/a | | |
| 3 | Offsite production, road transport of gas | Through any of:<br>- electrolysis<br>- reforming<br>- gasification or<br>- by-product | | $CGH_2$ tube trailer | Trailer-swap or bulk delivery | |
| 4 | Offsite production, road transport of liquid | | Liquid | $LH_2$ trailer | Cryogenic tanks | Cryogenic pump and dispenser |
| 5 | Offsite production, pipeline transport of gas | | Gas | pipeline | n/a | Gas compressor and dispenser |

The configurations are largely based on existing and proven technologies. Set out in the following sections are further descriptions of the configurations, their advantages and disadvantages, and the commercial contexts in which they may operate going forward.

## 7.1 Configuration 1: Onsite electrolysis production, using grid electricity

This configuration involves production of hydrogen by an onsite electrolyser powered by grid electricity. It favours small-scale HRSs, due to the size and capital cost requirements for electrolysers to produce hydrogen. Furthermore, smaller production units (with smaller footprints) mean existing refuelling sites can be utilised.

Many pilot, demonstration and commercial refuelling stations use this model employing onsite production with small-scale electrolysers.

**Table 21. Features of Configuration 1 – Onsite production, grid electricity**

| Production | Description | Constraints | Opportunities |
|---|---|---|---|
| Onsite using electrolysis powered by grid electricity | Hydrogen produced onsite using a PEM electrolyser, powered by grid electricity.<br><br>The hydrogen produced is compressed for cascade gaseous storage. The $GH_2$ is then pre-cooled for dispensing at either 350 or 700 bar.<br><br>This model favours a relatively small-scale HRS, servicing light vehicles. Due to space and electricity requirements for the electrolyser. | Demands on grid electricity likely mean that only small-scale electrolysers, and therefore small-scale hydrogen production is possible using this model.<br><br>Producing 1 kg of hydrogen requires around 54 kWh of electricity (electrolyser consumption only) with additional electricity needed for compression and cooling. | Small scale electrolysers can be installed in existing refuelling stations.<br><br>Small-scale production units require less capital and operating expenditures, making the model attractive as trial/demonstration investments.<br><br>Emergence of modular offerings that include all the equipment needed to allow for lower installation and operations costs. |

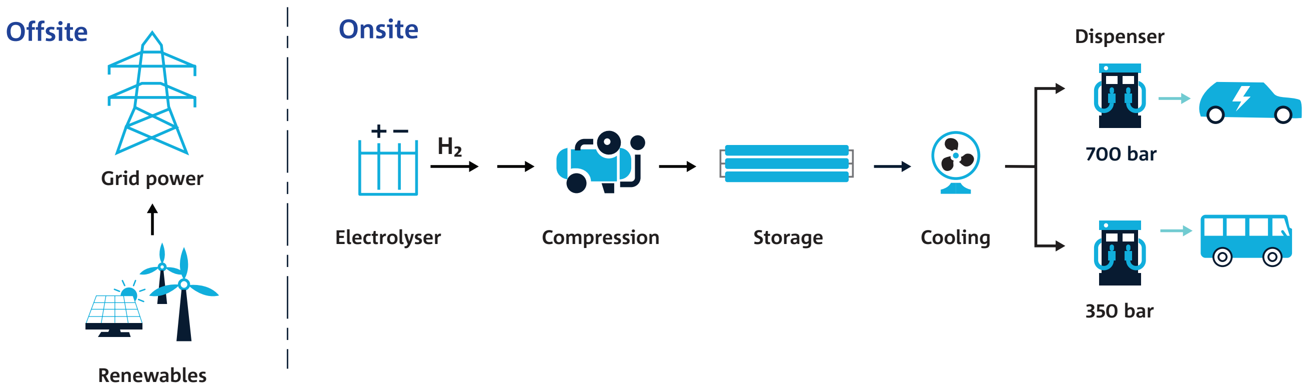


**Figure 14. Configuration 1 – Onsite hydrogen production using grid electricity**

## 7.2 Configuration 2: Onsite electrolysis production, using onsite renewables

Configuration 2, in contrast to Configuration 1, involves using onsite (behind-the-meter) renewable electricity supply, such as from wind and solar photovoltaic (PV), to augment grid electricity to power the electrolyser. For analysis purposes, the behind-the-meter supply is sized to provide the maximum electrolyser load. When there is no behind-the-meter electricity supply (due to a lack of wind and /or sun) the required electrolyser energy input would be sourced from the grid. The benefit of using a co-located renewable energy is direct input of (zero-emission) renewable electricity and reduced reliance on grid electricity.

This supply model is currently being developed in Australia. Viva Energy's New Energies Service Station project in Geelong, which is currently under development, is planned to use a co-located solar electricity generation facility to power an onsite electrolyser. Additionally, Ark Energy's facility in Queensland uses a co-located solar farm to power its electrolyser, producing hydrogen for refuelling logistics trucks.

It should be noted that significant land is required to generate enough electricity to fully power an electrolyser. Assuming the behind-the-meter supply was solar PV around 71m$^2$ of land is required to power the production of one kilogram of hydrogen per day. This makes it challenging in metropolitan locations due to space limitations.

**Table 22. Features of Configuration 2 – Onsite production, onsite renewables**

| Production | Description | Constraints | Opportunities |
|---|---|---|---|
| Onsite using electrolysis powered by onsite renewables | Hydrogen produced onsite using an electrolyser, powered by renewable electricity, either solar or wind. A PEM electrolyser is assumed. The hydrogen produced is compressed for cascade gaseous storage. The $GH_2$ then pre-cooled for dispensing at either 350 or 700 bar.<br><br>This model favours a large-scale HRS, with scope for servicing all vehicle types. Due to space requirements for renewable energy generation, this model would suit locations with large areas of land available.<br><br>Given that in the Australian context, land is most likely available in rural areas, this type of model may suit refuelling locations along key freight routes, that travel through non-urban areas with predictability. | Land requirements for renewable energy production equipment can be significant.<br><br>Added capex and operating expense of renewable energy production equipment. | Can be co-located with existing and planned hydrogen hubs around Australia as well as in REZs.<br><br>Without the constraints of grid electricity, there is also scope for larger hydrogen production than Model 1.<br><br>Possibility of selling surplus energy produced via renewables back into the grid.<br><br>Possibility of selling surplus hydrogen to other industries and/or refuelling locations. |

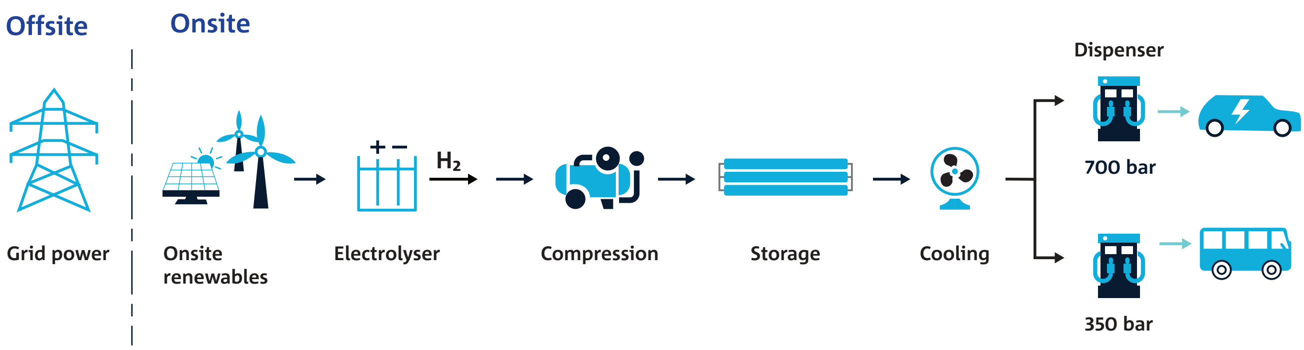


**Figure 15. Configuration 2 – Onsite electrolysis production using renewable electricity**

## 7.3 Configuration 3: Offsite production, road transport of gas

Configuration 3 involves utilisation of hydrogen produced offsite which is then distributed by road transport in gaseous form to the HRS. It has some similarity to the existing petrol and diesel fuel supply chain. The centralised production of hydrogen will likely result in some cost efficiencies due to economies of scale. This configuration has been deployed in commercial settings abroad, especially in California, South Korea and Japan.

**Table 23. Features of Configuration 3 – Offsite production, road transport of gas**

| Production | Description | Constraints | Opportunities |
|---|---|---|---|
| Offsite production, with road transport of gas | Hydrogen produced offsite is then compressed for transport in pressurised Type I tubes (<200 bar) or Type IV tubes (300 or 500 bar) for transportation to a HRS.<br><br>At the HRS, the hydrogen is either transferred to site storage or a trailer-swap occurs (i.e, the trailer acts as the onsite storage). In both configurations the hydrogen may be compressed into a high-pressure buffer or pumped directly to the dispenser. Trailer-swap and direct transfer to dispenser was modelled herein. | Requires a reliable source of hydrogen. Currently this is not well established in Australia, especially for hydrogen made with renewables.<br><br>Possible issues for first movers of securing hydrogen (especially made from renewables) reliably and cost-effectively.<br><br>Capex, logistical and safety requirements for hydrogen transport vehicles. | Offsite production removes capex for electrolyser and operating costs associated with running the production unit.<br><br>Mass production of hydrogen likely to result in cost savings due to economies of scale.<br><br>Allows for more freedom in site selection compared to onsite production models that have significant constraints due to production equipment. |

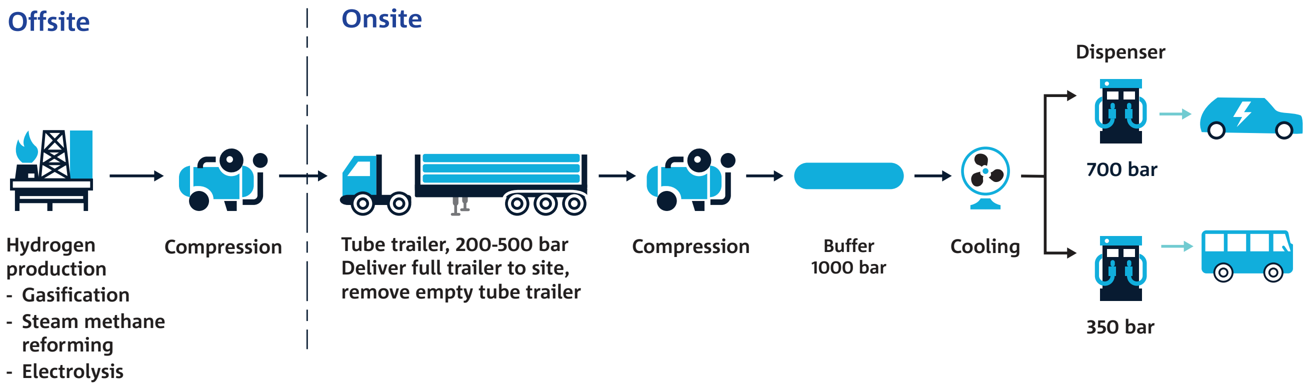


**Figure 16. Configuration 3 – Offsite production, road transport of gas**

## 7.4 Configuration 4: Offsite production, road transport of liquid

Configuration 4 involves liquefaction of offsite produced hydrogen for transportation to the HRS, to then be dispensed as a gas.

Many stakeholders across the value chain expressed a view that liquid hydrogen will ultimately dominate the hydrogen refuelling industry, as trucking and storing liquid hydrogen will eventually become more economical than gaseous hydrogen. In addition, storing liquid hydrogen and regasifying on demand could remove the requirement for compressors or chillers, but introduces the need for other equipment such as a cryogenic pump and fittings and insulated pipes.

The Californian market currently has the most widespread use of liquid hydrogen, but uptake is still in an early stage[70].

**Table 24. Features of Configuration 4 – Offsite production, road transport of liquid**

| Production | Description | Constraints | Opportunities |
|---|---|---|---|
| Offsite production, with road transport of liquid | Hydrogen is produced offsite, then liquified, and stored in thermally insulated vessels. The $LH_2$ is transported by road tanker to the refuelling station and pumped into cryogenic liquid tanks.<br><br>$LH_2$ is vapourised and the gas either compressed into high pressure buffer storage, after which it is chilled and dispensed. Alternatively, the gas may be pumped directly to the dispenser, without the need for chilling. The latter process was modelled herein. | Requires a reliable source of liquid hydrogen to function.<br><br>Possible issues for first movers of securing hydrogen made from renewables reliably and cost-effectively.<br><br>$LH_2$ is an emerging technology, so there are still several issues associated with the technology including:<br>• reduced lifetime of components exposed to cryogenic temperatures;<br>• flow metering to charge customers<br>• restriction on the length of vacuum insulated piping to lower the risk of boil-off<br>• currently no high-performance refuelling protocols for heavy duty tank sizes (up to 100kg).<br><br>Limited understanding of transporting liquid hydrogen compared to gaseous, although in California the practice is well established. | Offsite production avoids the need for capital expenditure on an electrolyser and operating costs associated with running the production unit.<br><br>Stakeholders from across the value chain view liquid as the future of hydrogen refuelling, due to greater energy performance of liquid hydrogen compared to gaseous and superior ability to transport more fuel using liquid.<br><br>Up to 6 tonnes can be delivered to locations up to 700km from the production site. This allows for a supply chain closely resembling the structure of the existing liquid fuel (petrol and diesel) retail industry. |

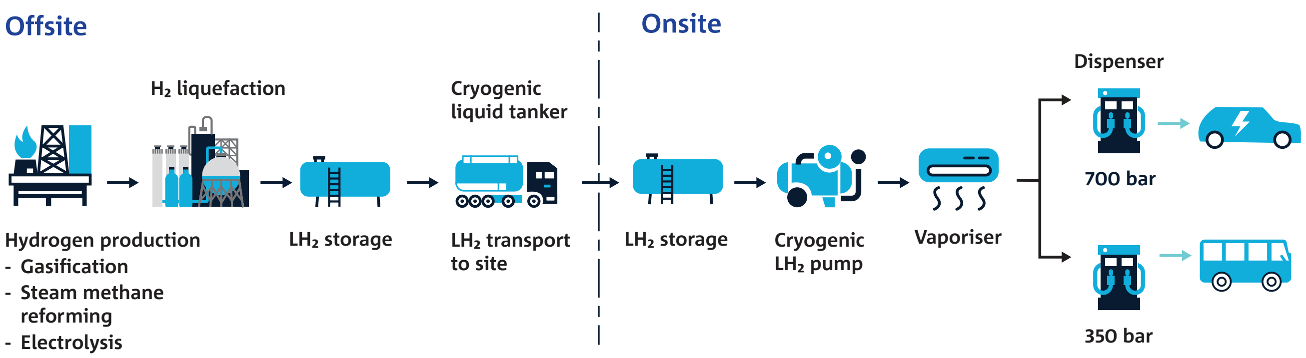


**Figure 17. Configuration 4 – Offsite production and transport of liquid hydrogen**

70 California Fuel Cell Partnership, CAFCP Station Map, accessed August 2022 from https://cafcp.org/stationmap

## 7.5 Configuration 5: Offsite production, pipeline transport of gas

Configuration 5 considers offsite production of gaseous hydrogen, with transmission to the refuelling station by pipeline. Hydrogen could be transferred through existing pipelines, although this is highly dependent on age, condition and materials of construction. When extracted at the refuelling site, the hydrogen must be separated from natural gas prior to use.

There is no existing example of this configuration utilised in a commercial setting. Technology that can support this configuration is developing.

**Table 25. Features of Configuration 5 – Offsite production, pipeline transport**

| Production | Description | Constraints | Opportunities |
|---|---|---|---|
| Offsite production, with pipeline transport of gas | Hydrogen is produced and placed in storage, before being compressed and dosed into the natural gas network.<br><br>A hydrogen separator located close to a distribution or refuelling station is used to separate the hydrogen from the natural gas. The $GH_2$ is then transported to site, unless separation occurs on site. | Limited proof-of-concept at scale.<br><br>Only a limited amount (maximum of 20vol%) of hydrogen can be blended into natural gas pipelines. Furthermore, the extraction process onsite typically results in loss of hydrogen. | Utilises existing natural gas network infrastructure, reducing transport costs.<br><br>Able to service a variety of station scopes and sizes, given that theoretically any location connected to the gas network can receive hydrogen. |

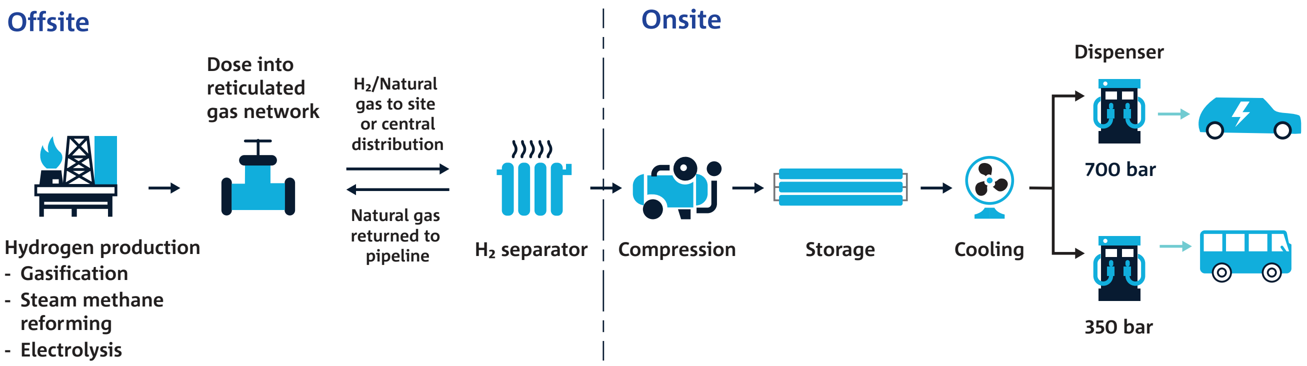


**Figure 18. Configuration 5 – Offsite production, pipeline transport of gas**

# Part D –

# Cost analysis

# 8 Cost analysis

## 8.1 Financial model

### 8.1.1 Introduction

Financial modelling of HRS configurations was undertaken to provide an understanding of the key cost characteristics of alternative hydrogen refuelling configurations – to assist in informing allied industry and government activities, and in guiding development initiatives. The modelling outputs provide comparative analysis of the implications of configuration and HRS size choices. It should be noted that the cost modelling does not attempt to mirror any particular project that may currently be in development in Australia. Rather, it takes a forward-looking approach and assumes that the required investment in supporting infrastructure (e.g. compressing/filling equipment at offsite hydrogen producers) and assets (e.g. Type III tube trailers) has been made by industry participants, with those costs then recovered through charges to the HRS operators.

The outputs bring focus to those cost elements that have the greatest bearing on the commerciality of hydrogen as a road transport fuel. In particular, the financial modelling:

- ascertains and compares the estimated dispensed Levelised Cost of Hydrogen ($LCOH_D$) for HRS configurations at different supply capacities and distances from offsite hydrogen supply sources
- determines the absolute and relative composition of the calculated cost of each scenario (electricity supply, production, distribution, compression, storage, dispensing)
- identifies the supply/cost chain elements with greatest impact on the commercial viability of refuelling stations, such as power unit cost
- identifies those parts of the cost chain that could be influenced through investment or research and innovation to reduce the cost of hydrogen refuelling.

Configurations 1 to 4, outlined in Section 7 and set out below in Table 26 were modelled.

Configuration 5, which involves offsite production and transport of gaseous hydrogen by pipeline, has been excluded from the financial analysis for the following reasons:

- the difficulty in ascribing a useful benchmark scenario
- HRSs expected to be geographically dispersed and individually being relatively small demand centres
- there not being any prospect in the foreseeable future of dedicated purpose-built hydrogen distribution pipelines being cost competitive with distribution by road.

Nevertheless, Configuration 5 has been introduced in this report as there may be opportunities to repurpose existing natural gas (or other) pipelines, and even blend hydrogen into natural gas pipelines for extraction and separation at the refuelling site, but these could only be reasonably assessed on a case-by-case basis. Where there are opportunities to utilise existing infrastructure and pipelines in industrial precincts, where hydrogen production, users and refuelling infrastructure are close to each other, such opportunities would need specific assessment in the light of the location and available assets. Separately, blending hydrogen into natural gas pipelines for extraction at HRSs is not yet at a commercial technology readiness level (TRL) and hence a lack of use-cases means it is not possible to provide a meaningful financial model. There could also be future opportunities to transport hydrogen by road from remote offsite production sites to a central location for short haul pipeline reticulation, but the number of potential variables to consider make this scenario difficult to analyse without a 'real world' potential case.

**Table 26. HRS configurations modelled**

| Configuration | Production | Distribution | Storage |
|---|---|---|---|
| 1 | Onsite using grid electricity | n/a | Cascade |
| 2 | Onsite using renewable energy and grid electricity | n/a | Cascade |
| 3 | Offsite | Gaseous by road | Onsite tube trailers |
| 4 | Offsite | Liquid by road | Cryogenic liquid storage |

For Configurations 1 to 4, the cost implications of HRS scale have been modelled. The intent here is to identify cost efficiencies achieved through larger scale, and how each of the configurations are impacted by hydrogen throughput. The HRS sizes and respective throughputs modelled are outlined in Table 27 below.

Table 27. Different HRS sizes modelled

| Sizes | Maximum Daily Throughput | | Average Daily Throughput |
|---|---|---|---|
| **HRS** | **kg** | **Heavy Duty FCEV fills*** | **kg** |
| Small | 200 | 3.3 | 150 |
| Medium | 500 | 8.3 | 375 |
| Large | 1,000 | 16.7 | 750 |
| Extra-Large | 4,500 | 75.0 | 3,375 |

*Based on onboard tank capacity of 60kg

The costs and cost components are presented in terms of Levelised Cost of Hydrogen (LCOH), being the average net present cost per kilogram of hydrogen over the project lifetime, calculated using a real discount rate of 7% (which may be lower than investment hurdle rates of some developers). LCOH enables ease of comparison between projects of different scale and where there are different trade-offs between capital and operating costs. It also takes account of the assumed volume of hydrogen output. In this report, as annotated by subscript, LCOH is alternatively used as a measure of the cost of the hydrogen production ($LCOH_P$), cost of dispensed hydrogen ($LCOH_D$) and the contributory cost of component processes (transportation/distribution, compression and storage – $LCOH_T$, $LCOH_C$ and $LCOH_S$ respectively) at different pressures.

Our cost analysis does not include:

- the cost of the HRS site (too variable an input to meaningfully average)
- any necessary civil works, such as hardstand, drainage or installation of utilities
- any necessary upgrades to grid power supply and connections
- commercial profit margins
- corporate overheads.

The LCOH figures presented are to provide a comparative analysis of the alternative business models and allow focus on those costs components which are most material to the development of HRSs. Our analysis does not quantify the alternative risk profiles that may be applicable to each project configuration. In addition, it is noted that the most significant contribution to $LCOH_D$ across all considered configurations is the cost of electricity (whether the hydrogen is produced onsite or transported from an offsite production site). For some scenarios (of configuration and scale) electricity comprises close to 50% of the overall $LCOH_D$. This report does not attempt to contemplate the wide range of electricity price scenarios that may eventuate in the future as Australia's energy market transitions towards net zero emission targets, rather it assumes a central AEMO price path. The $LCOH_D$ of all modelled scenarios will rise or fall in line with future electricity price outcomes.

### 8.1.2 Key model inputs

The assumptions set out below have been used for all configurations and HRS sizes modelled.

Table 28. Key model inputs

| Parameter | Unit | Value |
|---|---|---|
| Discount rate (real) | % | 7 |
| Years of production | Years | 20 |
| Hours in year | Hours | 8,760 |
| Electricity | $/kWh | 0.1205[71] |
| Water | $/L | 0.0030[72] |

71 Electricity modelled using Victoria Power Price, AEMO 2022

72 Commercial Water Pricing, SAWater 2022

## 8.2 Model outputs

### 8.2.1 Overall cost of supply to vehicles

The $LCOH_D$, based on different configurations of HRSs, range widely from $6.78 to $15.60 per kilogram, as shown in Figure 19 below. The largest cost element in terms of supply chain process across all configurations and for all HRS sizes is the production of hydrogen. For onsite production, this cost can be almost double that of offsite production. This is largely due to the economies of scale efficiencies achieved by large offsite production facilities.

The second largest supply chain cost impost for onsite production (Configurations 1 and 2) is compression of the hydrogen. Other costs are relatively immaterial. For offsite production (Configurations 3 and 4), the cost of distribution to the HRS (assumed to be by road tube trailer and cryogenic tanker respectively) is the second most significant cost factor.

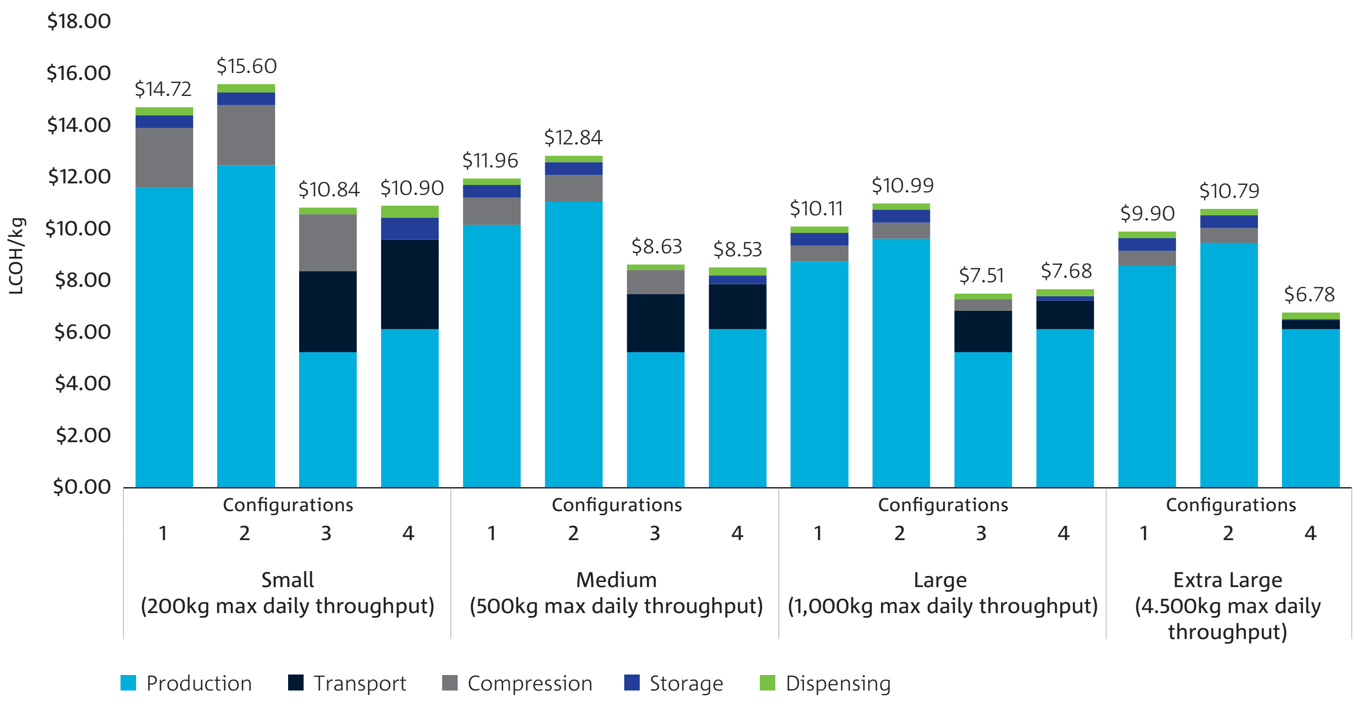


**Figure 19. $LCOH_D$ and its breakdown per configuration and HRS size**

### 8.2.2 Onsite production (Configurations 1 and 2)

As shown above, across all configurations and scales, the largest supply chain contributor to the dispensed cost of hydrogen ($LCOH_D$) is the cost of the hydrogen production. Our analysis of the breakdown of the production cost is confined to that of onsite electrolysis with the focus of this report not being on analysis of the cost structure of large-scale offsite production. The breakdown between capital and operating costs for hydrogen production using grid electricity (Configuration 1) or, alternatively, an amount of behind-the-meter renewable electricity in combination with grid electricity (Configuration 2) is shown in Figure 20 below.

The main contributors to the capital expenditure component of $LCOH_P$ are the cost of the PEM electrolyser and its installation, as well as the cost of overhauls. The main components of the contribution of operational expenditure to $LCOH_P$ are electricity, water and maintenance costs.

The cost stacks show the benefits of scale - the greater the production capacity, the lower the levelised cost of a kilogram of hydrogen. Increasing the scale of HRSs from Small (200 kg) to Large (1,000 kg) reduces unit cost by 25%. The incremental benefits of increased scale decrease beyond Large through to Extra-Large (4,500 kg).

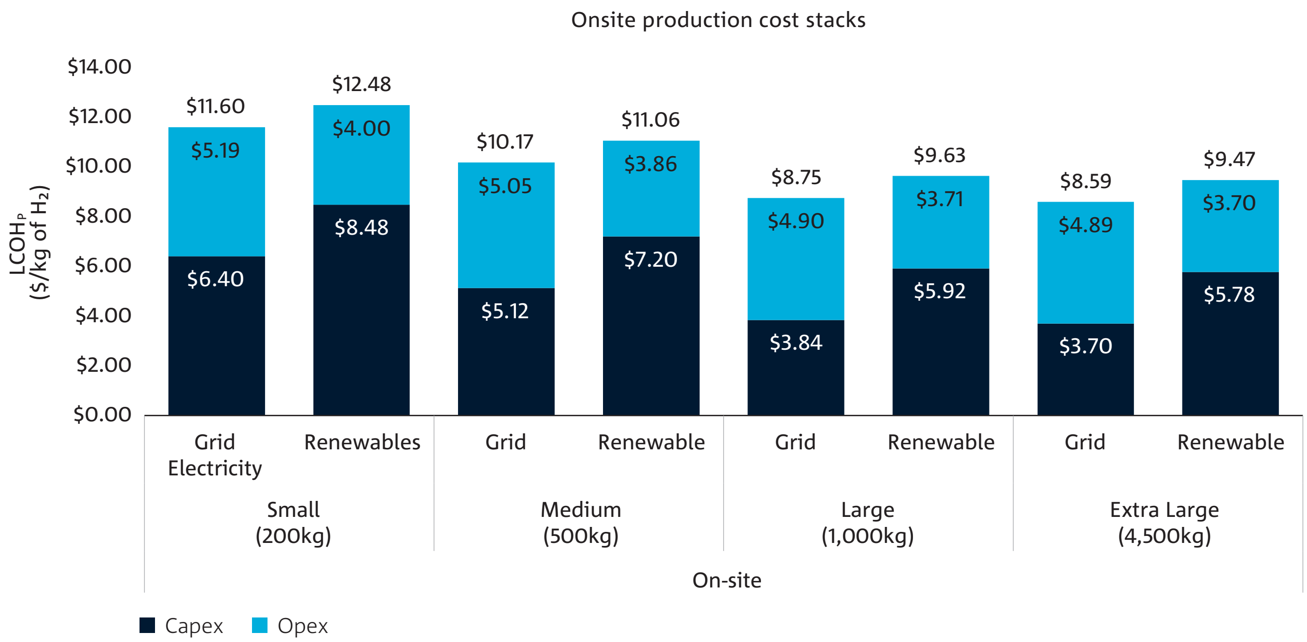


**Figure 20. Configuration 1 and 2 – Split of $LCOH_P$ between capital and operating costs for onsite production**

For any size HRS, the above cost stacks also show that the use of an amount of purpose-built onsite (or otherwise behind-the-meter) renewable electricity to power the electrolyser alongside grid electricity, results in a higher $LCOH_P$.

For Configuration 1 it can also be seen that as the scale of HRS increases, that capital costs become a smaller portion, and operating costs become a larger portion, of the total $LCOH_P$. This is due to:

- the reducing relationship between the electrolyser package capital cost per kilowatt and the electrolyser module size, as illustrated in Figure 21 below. This is in part due to economies of scale with gas conditioning and other balance of plant equipment, although the electrolyser stacks themselves are likely to remain relatively small, with several stacks being grouped together to form the core of an electrolyser package (at present, most stacks are designed at 0.5, 1, 2 or 5 MW; with the largest stacks currently understood to be 10 MW)
- the electricity input requirement remaining relatively constant.

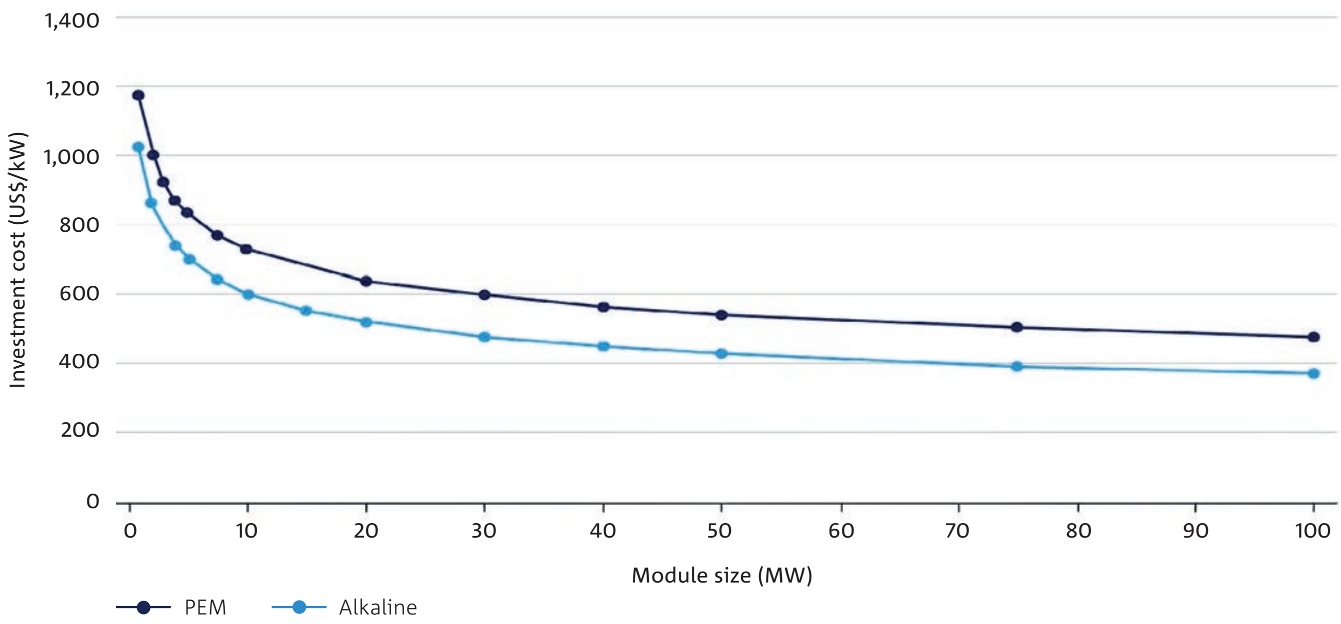


**Figure 21. PEM module size to capital cost**[73]

73 Figure adapted from: Department of Planning, Industry and Environments 2021, NSW Hydrogen Strategy, https://www.energy.nsw.gov.au/nsw-plans-and-progress/government-strategies-and-frameworks/nsw-hydrogen-strategy

The pie charts set out below in Figure 22 provide breakdowns of the levelised cost of hydrogen production ($LCOH_P$) in terms of the contributions of each of the key capital and operating costs. The cost of the electrolyser and its installation, and electricity costs dominate. The cost contribution of water is relatively immaterial.

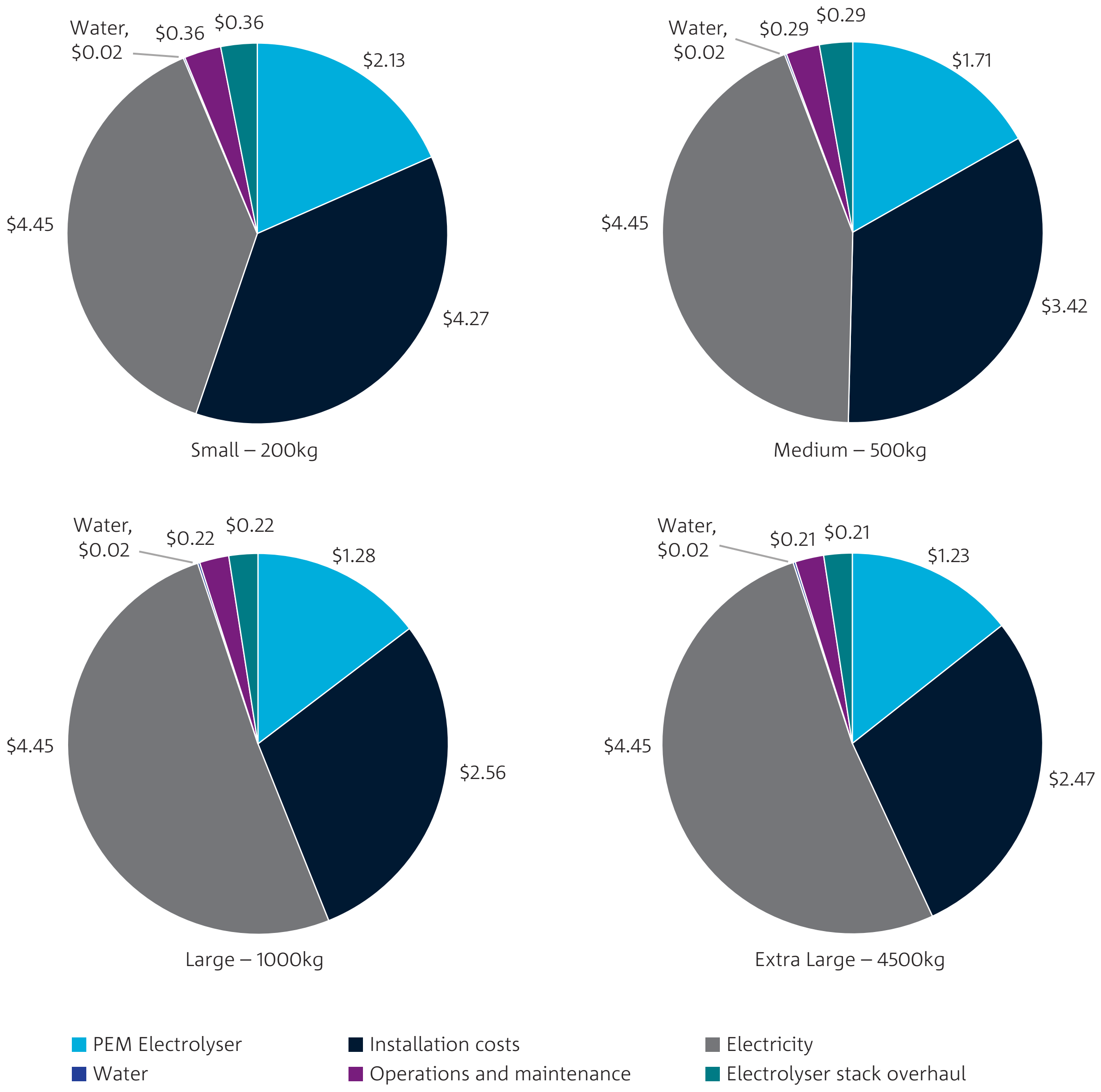


**Figure 22. Configuration 1 – Onsite hydrogen production using grid electricity, composition of LCOHP**

Configuration 2 uses behind-the-meter renewable electricity (for modelling purposes, assumed to be photovoltaic (PV)). The PV array is sized to provide 100% of the maximum electricity input of the electrolyser, with an assumed capacity factor of 32%. The balance of the required electricity input, when the “sun isn’t shining” is supplied from the grid.

The capital costs of Configuration 2 are significantly higher than for Configuration 1 due to the cost of the PV installation, as shown in Figure 23 below.

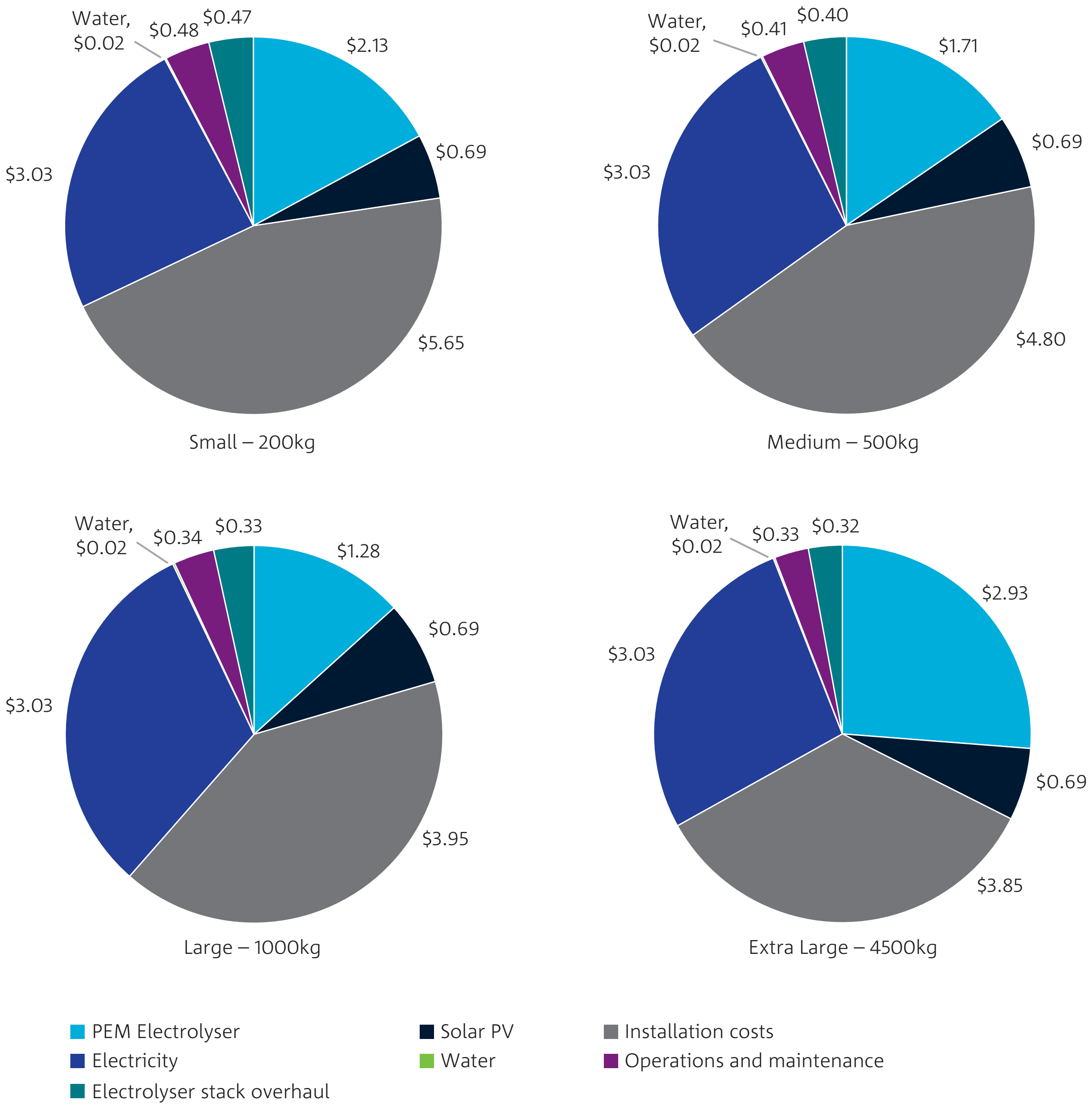


**Figure 23. Configuration 2 – Onsite production using renewables and grid electricity, composition of $LCOH_P$**

#### 8.2.2.1 Compression (Configurations 1 and 2)

Compression is the second largest cost element for onsite production across both Configuration 1 and Configuration 2. The largest contributor to this cost is the capital cost of the compressor, contributing between $0.58 to $2.32 towards $LCOH_P$, depending on production scale. The composition of the compression cost for onsite production is shown in Figure 24 below.

These capital costs benefit from economies of scale. As the scale of hydrogen production increases, the contribution of the cost of the compressor to $LCOH_P$ decreases.

In terms of operating costs, electricity is the major driver, at $0.20 per kilogram across all scales of HRS. Most electricity is consumed during the initial compression phase with compression to 200 bar accounting for $0.12 of $LCOH_C$, while further compression stages (200 to 1,000 bar), only accounting for $0.07. This is shown in Figure 25.

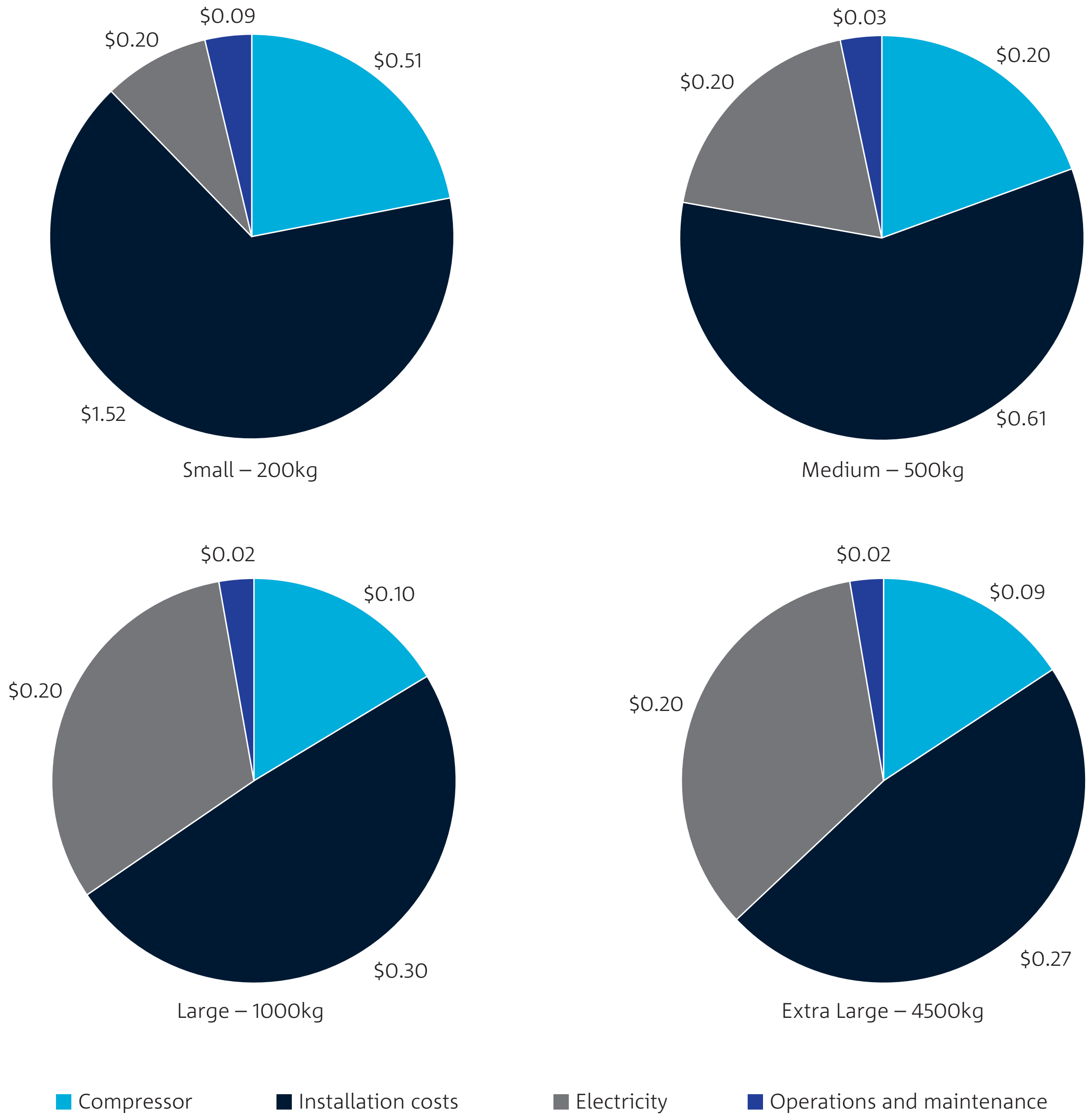


**Figure 24. Configuration 1 and 2 – Onsite compression costs, contributions to $LCOH_P$**

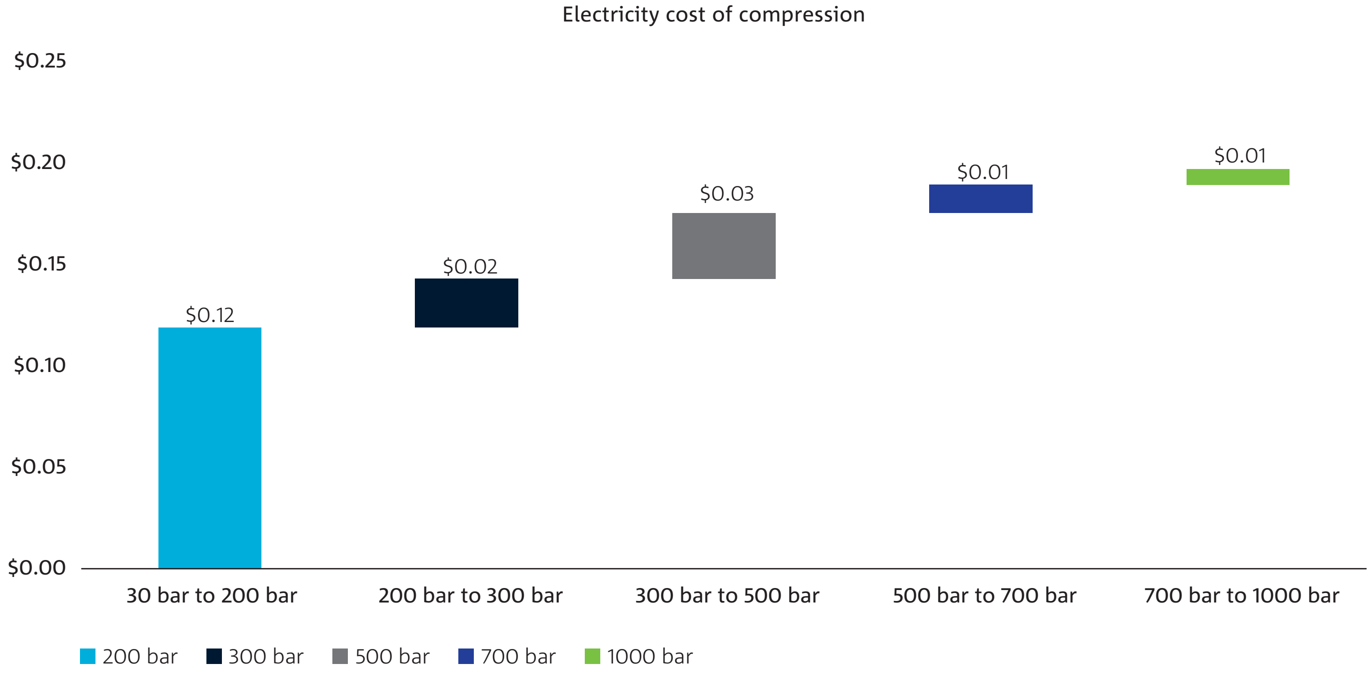


**Figure 25. Configurations 1 and 2 – Contribution of electricity to cost of compression (LCOH$_C$)**

### 8.2.2.2 Gaseous storage (Configurations 1 and 2)

For Configurations 1 and 2, it has been assumed that the amount of onsite cascade storage is equal to 150% of the daily maximum throughput of each HRS size. A typical pressure split between cascade storage tanks is shown in Table 29.

**Table 29. Cascade storage split**

| Pressure (bar) | Percentage storage |
|---|---|
| 500 | 40% |
| 700 | 30% |
| 1,000 | 30% |

Due to the variability in different sizes of cascade storage systems, the model assumes a fixed storage cost of $1,400 per kg, with the cost breakdown shown in Figure 26 being the same across all sizes of HRS.

Storage is a relatively minor cost driver, with a LCOH$_S$ of around $0.49 per kg across Configurations 1 and 2 for all HRS sizes.

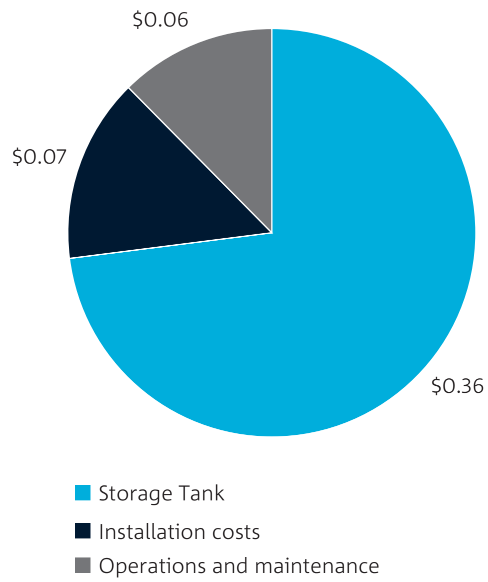


**Figure 26. Configurations 1 and 2 – Gaseous storage costs for all HRS sizes**

## 8.2.3 Offsite production (Configuration 3 and 4)

### 8.2.3.1 Production (Configurations 3 and 4)

For Configurations 3 and 4, hydrogen is produced offsite and transported by road to the HRS with the price of hydrogen production (offsite $LCOH_P$) a fixed model input of $9.90 per kg. Configuration 4 includes the additional cost of liquefaction at a fixed wholesale price of liquid hydrogen at $11.58 per kg.

### 8.2.3.2 Transport (Configurations 3 and 4)

#### 8.2.3.2.1 Transport methods

In Configuration 3, gaseous hydrogen requires compression to 200 bar, 300 bar or 500 bar for transportation in tube trailers. Each trailer has varying capacities dependent on the types and number of tubes on the tube trailer, as set out in Table 30. Costs of tube trailers increase significantly with the increased pressures.

Once the hydrogen is delivered it can either be used to fill onsite storage (decanted), or the tube trailer can be unloaded and connected to the refuelling system (this approach is sometimes known as 'swap and go', but for the purpose of this report we use the term 'trailer-swap'). With trailer-swap, a set of tube trailers with identical specifications are rotated, with one being onsite, while the other is being filled. It has been determined that it is generally more cost-efficient to use the decanting method for the transport of gaseous hydrogen with a trailer-swap approach being up to $0.77 per kilogram more expensive depending on the scenario. The value changes with the number of tubes per trailer, maximum delivery pressure and the scale of the HRS.

The preferred delivery methodology, as gauged through stakeholder engagement, appears to be trailer-swap due to its simplicity to execute compared to fixed storage on site with decanting. Configuration 3 assumes the use of trailer-swap transport and storage.

Using trailer-swap has the advantage of removing fixed buffer storage on site leading to reduced total capital cost on site as well as potentially reducing cost for compression between the tube trailer and dispensing (depending on the delivery pressure).

**Table 30. Configuration 3 – Gaseous hydrogen transport pressures and mass**

| Pressure (bar) | No. of tubes per trailer | Hydrogen per trailer (kg) | Cost ($m) |
|---|---|---|---|
| **200** | 16 | 290 | $0.615 |
| **300** | 8 | 336 | $1.360 |
| | 10 | 418 | $1.480 |
| | 12 | 502 | $1.610 |
| | 14 | 586 | $1.730 |
| | 16 | 670 | $1.850 |
| **500** | 8 | 500 | $1.680 |
| | 10 | 626 | $1.860 |
| | 12 | 750 | $2.040 |
| | 14 | 876 | $2.220 |
| | 16 | 1,000 | $2.410 |

In Configuration 4, the hydrogen is liquefied and transported in cryogenic tankers to the refuelling site where it is decanted into onsite storage. The configuration uses two cryogenic tankers that are currently available on the market, a single semi-tanker which can transport 3,500 kg of liquid hydrogen, and a B-double tanker capable of transporting 5,000 kg of liquid hydrogen. Utilisation of a semi-tanker was consistently more cost-efficient across all configurations and all scales of HRS due to the benefit of reduced operating expenditure with a B-double (from less trips) not outweighing the increased capital costs of the larger truck. A limitation of the model is that it assumes that the tanker is delivering solely to one refuelling station. It is possible that when it is assumed that the truck is making multiple stops to refuel multiple stations, it may result in the larger B-double tanker being more cost efficient.

The model assumes a maximum of three deliveries to the site per day. Any more than this could be an unwanted impediment to access for refuelling. The maximum amount of $GH_2$ that can be delivered by tube trailer is 1,000 kg and the average daily throughput of the Extra-Large HRS is 3,375 kg per day. Consequently, Configuration 3 does not include the Extra-Large HRS size.

#### 8.2.3.2.2 Distance travelled

The distance between the offsite production source and the HRS directly impacts the $LCOH_T$ and the optimisation of the transportation method, which also impacts subsequent compression and storage costs.

Table 31 below compares transportation method, in terms of tube trailer pressure and capacity, to the return trip delivery, and the resulting implications of the combined production, transport, compression costs on the $LCOH_D$. The matrix also demonstrates the distances at which onsite production, compression and storage (for both Configuration 1 and Configuration 2) are at cost parity with the cost of offsite production and delivery by road transport, as indicated by the blue and green shading (refer table legend).


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Table 31. Return transport distances at which onsite production is more cost-effective than offsite production (blue and green cells)

| | | Roundtrip Distance | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Form | Transport | 100 km | 200 km | 300 km | 400 km | 500 km | 600 km | 700 km | 800 km | 900 km | 1000 km |
| | | Hydrogen Delivered Cost ($/kg) | | | | *Note: includes Production + Transport + Compression + Storage Costs | | | | | |
| **Small** | | | | | | | | | | | |
| 200 bar | 16 tubes | $9.74 | $10.57 | $11.40 | $12.23 | $13.06 | $13.89 | $14.73 | $15.56 | $16.39 | $17.22 |
| 300 bar | 8 tubes | $11.37 | $12.09 | $12.81 | $13.53 | $14.24 | $14.96 | $15.68 | $16.40 | $17.11 | $17.83 |
| | 10 tubes | $11.52 | $12.10 | $12.67 | $13.25 | $13.82 | $14.40 | $14.98 | $15.55 | $16.13 | $16.71 |
| | 12 tubes | $11.74 | $12.22 | $12.70 | $13.19 | $13.67 | $14.16 | $14.64 | $15.13 | $15.61 | $16.09 |
| | 14 tubes | $11.95 | $12.37 | $12.78 | $13.19 | $13.61 | $14.02 | $14.43 | $14.85 | $15.26 | $15.68 |
| | 16 tubes | $12.19 | $12.55 | $12.91 | $13.27 | $13.63 | $13.99 | $14.35 | $14.71 | $15.07 | $15.43 |
| 500 bar | 8 tubes | $11.87 | $12.35 | $12.84 | $13.32 | $13.81 | $14.29 | $14.78 | $15.26 | $15.74 | $16.23 |
| | 10 tubes | $12.20 | $12.59 | $12.98 | $13.36 | $13.75 | $14.14 | $14.53 | $14.91 | $15.30 | $15.69 |
| | 12 tubes | $12.57 | $12.89 | $13.21 | $13.53 | $13.85 | $14.17 | $14.49 | $14.82 | $15.14 | $15.46 |
| | 14 tubes | $12.95 | $13.23 | $13.51 | $13.78 | $14.06 | $14.34 | $14.62 | $14.89 | $15.17 | $15.45 |
| | 16 tubes | $13.37 | $13.61 | $13.85 | $14.10 | $14.34 | $14.58 | $14.82 | $15.06 | $15.31 | $15.55 |
| $LH_2$ | Semi-trailer | $10.02 | $10.32 | $10.62 | $10.93 | $11.23 | $11.53 | $11.83 | $12.13 | $12.43 | $12.73 |
| | B-double | $12.79 | $13.09 | $13.39 | $13.69 | $13.99 | $14.29 | $14.59 | $14.90 | $15.20 | $15.50 |
| **Medium** | | | | | | | | | | | |
| 200 bar | 16 tubes | $7.58 | $8.41 | $9.25 | $10.08 | $10.91 | $11.74 | $12.57 | $13.40 | $14.23 | $15.06 |
| 300 bar | 8 tubes | $8.16 | $8.88 | $9.59 | $10.31 | $11.03 | $11.75 | $12.47 | $13.19 | $13.90 | $14.62 |
| | 10 tubes | $8.13 | $8.71 | $9.29 | $9.86 | $10.44 | $11.02 | $11.60 | $12.17 | $12.75 | $13.33 |
| | 12 tubes | $8.16 | $8.64 | $9.12 | $9.60 | $10.08 | $10.56 | $11.04 | $11.52 | $12.00 | $12.48 |
| | 14 tubes | $8.20 | $8.62 | $9.03 | $9.44 | $9.85 | $10.26 | $10.68 | $11.09 | $11.50 | $11.91 |
| | 16 tubes | $8.27 | $8.63 | $8.99 | $9.35 | $9.71 | $10.07 | $10.43 | $10.79 | $11.15 | $11.52 |
| 500 bar | 8 tubes | $8.19 | $8.68 | $9.16 | $9.64 | $10.12 | $10.61 | $11.09 | $11.57 | $12.05 | $12.54 |
| | 10 tubes | $8.27 | $8.65 | $9.04 | $9.43 | $9.81 | $10.20 | $10.58 | $10.97 | $11.35 | $11.74 |
| | 12 tubes | $8.38 | $8.70 | $9.02 | $9.34 | $9.67 | $9.99 | $10.31 | $10.63 | $10.95 | $11.28 |
| | 14 tubes | $8.50 | $8.78 | $9.06 | $9.33 | $9.61 | $9.88 | $10.16 | $10.44 | $10.71 | $10.99 |
| | 16 tubes | $8.65 | $8.89 | $9.13 | $9.37 | $9.61 | $9.85 | $10.10 | $10.34 | $10.58 | $10.82 |
| $LH_2$ | Semi-trailer | $7.87 | $8.17 | $8.48 | $8.78 | $9.08 | $9.38 | $9.68 | $9.98 | $10.28 | $10.58 |
| | B-double | $8.98 | $9.28 | $9.58 | $9.88 | $10.18 | $10.49 | $10.79 | $11.09 | $11.39 | $11.69 |

**Transport distance at which onsite production has cost parity with offsite production:**

Grid electricity (Configuration 1)

Grid electricity and renewable electricity (Configuration 2)

| | | Roundtrip Distance | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Form | Transport | 100 km | 200 km | 300 km | 400 km | 500 km | 600 km | 700 km | 800 km | 900 km | 1000 km |
| | | Hydrogen Delivered Cost ($/kg) | | | | *Note: includes Production + Transport + Compression + Storage Costs | | | | | |
| **Large** | | | | | | | | | | | |
| 200 bar | 16 tubes | $6.87 | $7.70 | $8.53 | $9.36 | $10.19 | $11.02 | $11.85 | $12.68 | $13.51 | $14.34 |
| 300 bar | 8 tubes | $7.08 | $7.80 | $8.52 | $9.24 | $9.95 | $10.67 | $11.39 | $12.11 | $12.82 | $13.54 |
| | 10 tubes | $7.00 | $7.58 | $8.15 | $8.73 | $9.31 | $9.88 | $10.46 | $11.04 | $11.61 | $12.19 |
| | 12 tubes | $6.97 | $7.45 | $7.93 | $8.41 | $8.89 | $9.37 | $9.85 | $10.33 | $10.81 | $11.29 |
| | 14 tubes | $6.95 | $7.37 | $7.78 | $8.19 | $8.60 | $9.01 | $9.43 | $9.84 | $10.25 | $10.66 |
| | 16 tubes | $6.96 | $7.32 | $7.68 | $8.04 | $8.40 | $8.76 | $9.12 | $9.48 | $9.84 | $10.20 |
| 500 bar | 8 tubes | $6.97 | $7.45 | $7.93 | $8.42 | $8.90 | $9.38 | $9.86 | $10.35 | $10.83 | $11.31 |
| | 10 tubes | $6.96 | $7.34 | $7.73 | $8.11 | $8.50 | $8.89 | $9.27 | $9.66 | $10.04 | $10.43 |
| | 12 tubes | $6.98 | $7.30 | $7.62 | $7.94 | $8.26 | $8.59 | $8.91 | $9.23 | $9.55 | $9.87 |
| | 14 tubes | $7.02 | $7.30 | $7.57 | $7.85 | $8.12 | $8.40 | $8.67 | $8.95 | $9.22 | $9.50 |
| | 16 tubes | $7.08 | $7.32 | $7.56 | $7.80 | $8.04 | $8.28 | $8.52 | $8.76 | $9.01 | $9.25 |
| $LH_2$ | Semi-trailer | $7.12 | $7.39 | $7.65 | $7.92 | $8.18 | $8.44 | $8.71 | $8.97 | $9.24 | $9.50 |
| | B-double | $7.67 | $7.94 | $8.20 | $8.47 | $8.73 | $9.00 | $9.26 | $9.53 | $9.79 | $10.06 |
| **Extra-Large** | | | | | | | | | | | |
| $LH_2$ | Semi-trailer | $6.75 | $7.20 | $7.65 | $8.11 | $8.56 | $9.01 | $9.46 | $9.91 | $10.37 | $10.82 |
| | B-double | $6.65 | $6.87 | $7.10 | $7.33 | $7.55 | $7.78 | $8.00 | $8.23 | $8.46 | $8.68 |

**Transport distance at which onsite production has cost parity with offsite production:**

Grid electricity (Configuration 1)

Grid electricity and renewable electricity (Configuration 2)

As an example, the table shows that the minimum distance where onsite production for a Small HRS would be at cost parity with transporting hydrogen from an offsite source is a roundtrip of 500km or greater. The larger the size of the HRS, the greater the commercially feasible transport distance versus production onsite. For example, for a Large HRS it is more cost effective to transport gaseous hydrogen at 500 bar in a 14 tube trailer over a roundtrip of 1,000 km (at $9.50) than onsite production.

#### 8.2.3.2.3 Transport optimisation

To perform a comparative analysis between the configurations, one configuration was decided upon for each HRS size for Configuration 3 and Configuration 4. To determine which configuration should be used for each HRS size, production, transport, compression, and storage costs were combined for each tube trailer variation. A fixed distance of 200 km was used to compare these costs. Table 32 shows the results of the optimisation process.

As shown, the optimal distribution mode to small and medium sized HRSs is a 200 bar Type I tube trailer for transport, while the optimal configuration for the large HRS is the Type IV 500 bar, 14 tube, trailer. This is driven by the lower capital cost of the Type I tube trailer having a positive effect on $LCOH_T$ as the volume of hydrogen to be moved around is not large. For larger HRSs, the higher cost for tube trailers with Type IV tubes can be justified by the larger volume of hydrogen that can be moved by these trailers.

A similar process was conducted for Configuration 4, as shown in Table 33.

The semi-trailer liquid hydrogen tanker is the optimal configuration across all sizes of HRSs considered. This is primarily due to the reduced operating costs associated with an increased volume of transport, not being able to accommodate the larger capital costs of the B-double cryogenic tanker, and associated storage costs.

Table 32. Configuration 3 – Transport optimisation summary

| | | Production + Distribution + Compression + Storage Cost | | | |
|---|---|---|---|---|---|
| **Pressure (bar)** | **Tubes** | **Small** | **Medium** | **Large** | **Extra-Large** |
| 200 | 16 | $10.57 | $8.41 | $7.70 | |
| 300 | 8 | $12.60 | $8.88 | $7.80 | |
| | 10 | $12.25 | $8.71 | $7.58 | |
| | 12 | $12.10 | $8.64 | $7.45 | |
| | 14 | $12.02 | $8.62 | $7.37 | |
| | 16 | $12.02 | $8.63 | $7.32 | |
| 500 | 8 | $12.19 | $8.68 | $7.45 | |
| | 10 | $12.11 | $8.65 | $7.34 | |
| | 12 | $12.15 | $8.70 | $7.30 | |
| | 14 | $12.28 | $8.78 | $7.30 | |
| | 16 | $14.10 | $8.89 | $7.32 | |

Table 33. Configuration 4 – Transport optimisation summary

| | | Production + Transport + Storage Cost | | | |
|---|---|---|---|---|---|
| **Form** | **Tubes** | **Small** | **Medium** | **Large** | **Extra-Large** |
| $LH_2$ | Semi-trailer | $10.32 | $8.70 | $7.38 | $7.27 |
| $LH_2$ | B-double | $13.09 | $9.28 | $7.93 | $7.83 |

#### 8.2.3.2.4 Transport costs

Using the optimised configuration, Figure 27 illustrates the cost component breakdown of transportation, and the relative cost of transport across the different configurations. The model makes the assumption that tube trailers including the hydrogen storage tubes, associated maintenance costs are a separate cost to the cost of the prime mover which includes an amortised cost of capital, as well as labour, fuel, operations and maintenance.

As can be seen by the pie charts, the prime mover is the most substantial cost for Small and Medium HRSs. As those configurations use 200 bar pressure, more frequent deliveries are required, as shown in Table 34.

Table 34. Configuration 3 – Number of roundtrips

| HRS Size | Heavy Duty FCEV fills* | Transport | Annual no. of roundtrips |
|---|---|---|---|
| **Small** | 3.3 | 200 bar – 16 tube trailer | 189 |
| **Medium** | 8.3 | 200 bar – 16 tube trailer | 472 |
| **Large** | 16.7 | 500 bar – 14 tube trailer | 313 |

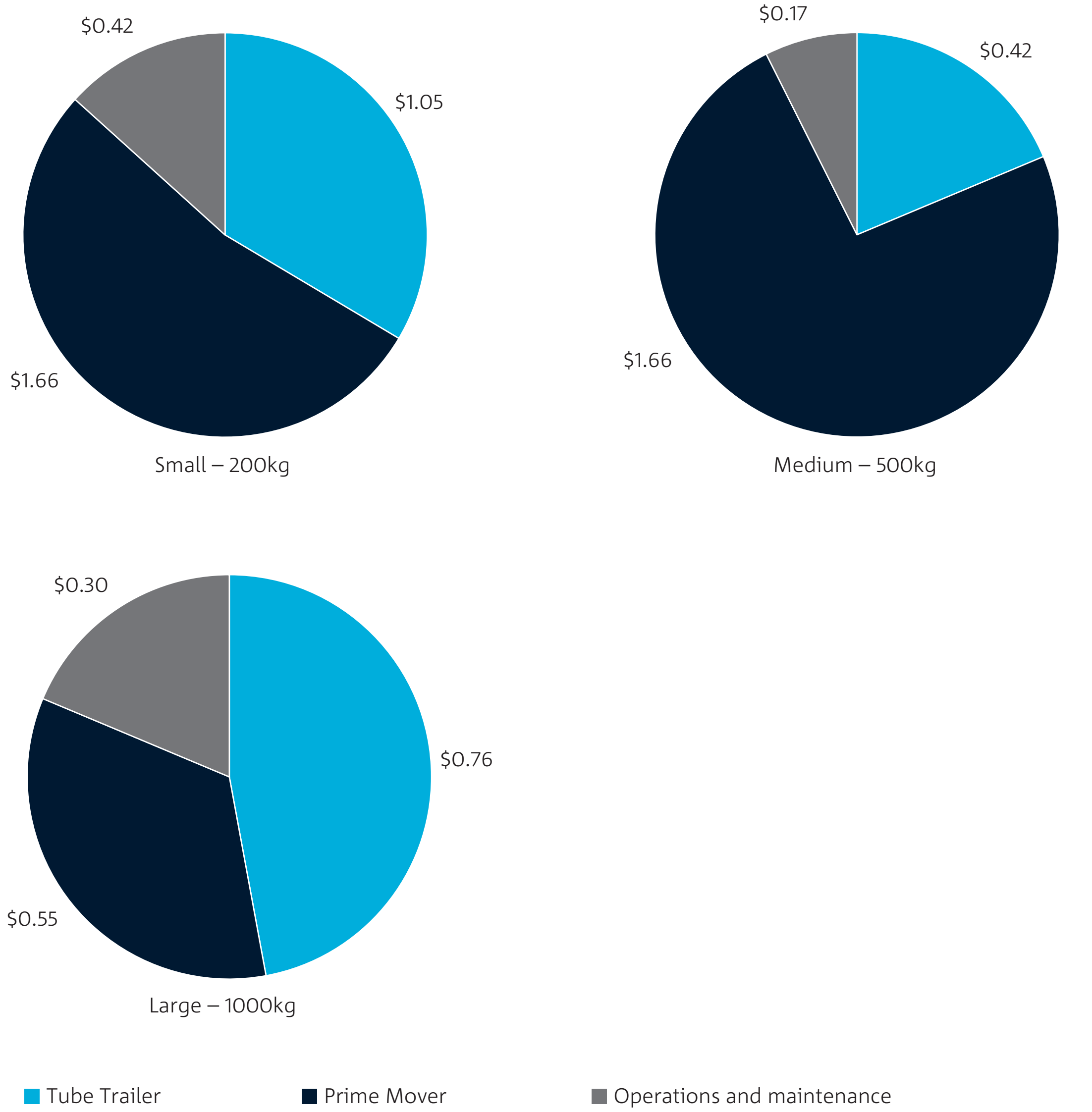



Figure 27. Configuration 3 – Gaseous hydrogen transport costs, breakdown of $LCOH_T$

The large refuelling station uses 500 bar pressure for transport, requiring fewer trips and reducing the prime mover costs. However, the initial capital costs for the Type IV, 500 bar tube trailers are higher, at an estimated $2.2 million compared to a Type I tube trailer at $615,000. Despite these factors, the $LCOH_T$ across these models decreases as the HRS scale increases, demonstrating the economy of scale achieved when larger volumes of gaseous hydrogen are transported.

Comparatively, in Configuration 4, optimised transport is consistent across all HRS sizes, making it easier to compare the impact of scale on the relative costs of components, as shown in Figure 28.

For Small and Medium sized HRS, the cryogenic tanker is the largest driver of transport cost, due to the limited number of trips (see Table 35), and the high capital cost for the cryogenic tanker per kilogram of hydrogen.

**Table 35. Configuration 4 – Number of delivery roundtrips of cryogenic semi-trailer tanker**

| HRS Size | Annual no. of roundtrips |
| --- | --- |
| Small | 68 |
| Medium | 171 |
| Large | 171 |
| Extra Large | 513 |

For the Large and Extra-Large scale of HRSs the prime mover has a more significant cost compared the other scales, because the cost capital equipment is averaged over a larger volume of hydrogen.

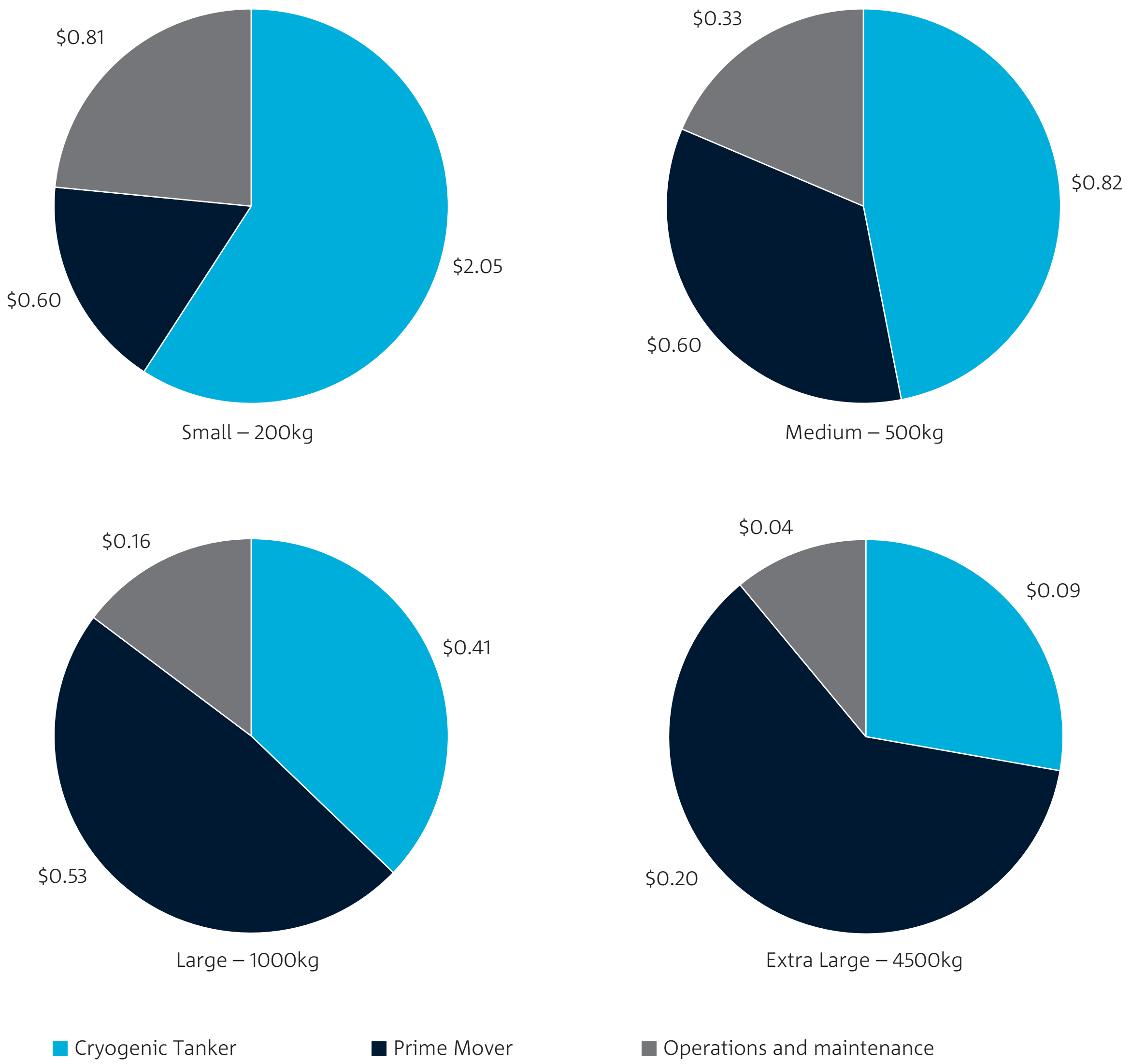



**Figure 28. Configuration 4 – Liquid hydrogen transport costs, composition of $LCOH_T$**

### 8.2.3.3 Compression (Configuration 3)

As previously outlined, using the optimised trailer-swap method in Configuration 3 allows for compression directly from the tube trailer to the dispenser without requiring additional buffer storage. Figure 29 outlines the cost breakdown of compression for Configuration 3.

Similar to Configuration 1 and 2, capital expenditure is the largest contributor to $LCOH_C$ across all HRS sizes. As all the transport configurations in Configuration 3 use pressure greater than 200 bar, the cost of power for compression is significantly lower than Configuration 1 and 2 ($0.08 compared to $0.20) due to the initial pressure of the tanks. Overall, compression is cheaper for Configuration 3 compared to Configurations 1 and 2, primarily due to the difference in the cost of electricity, however this is a relatively minor cost difference.

For Configuration 4, compression is not included as the liquid hydrogen is vaporised directly into the dispenser, which is accounted for in Section 8.2.4.

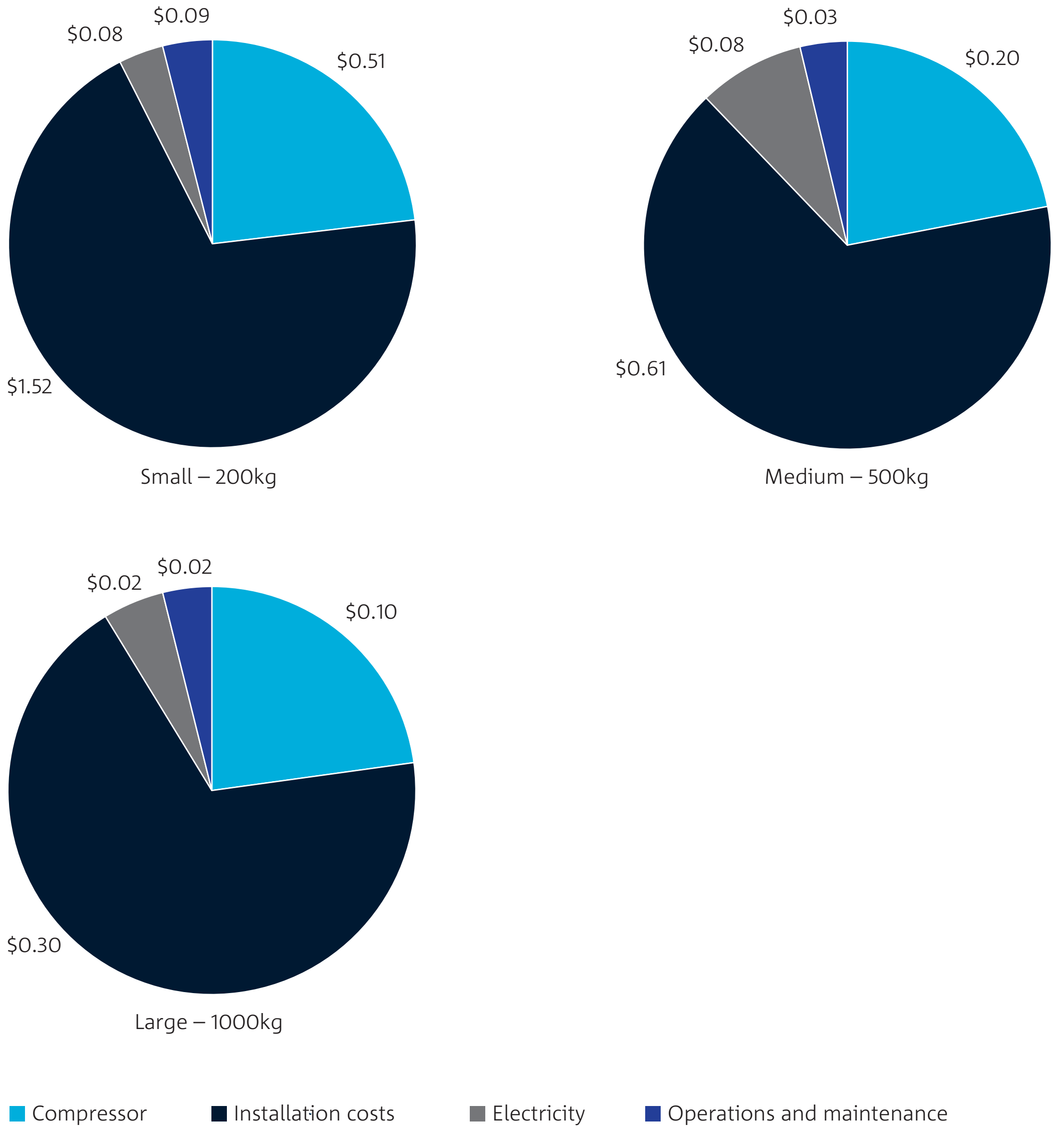



**Figure 29. Configuration 3 – Compression costs, breakdown of $LCOH_C$**

### 8.2.3.4 Liquid storage (Configuration 4)

There are limited liquid hydrogen storage options currently commercially available. The assumed storage capacities for each HRS throughput size are based on feedback from stakeholders and shown in the table below.

**Table 36. Configuration 4 – Storage based on daily throughput**

| HRS Size | Maximum throughput (kg/day) | Storage option (kg) |
|---|---|---|
| Small | 200 | 800 |
| Medium | 500 | 800 |
| Large | 1,000 | 1,600 |
| Extra-Large | 4,500 | 4,800 |

The breakdowns of the key cost components of liquid hydrogen storage are shown in Figure 30 below.

The capital cost of the storage tank is the main driver of the cost of storage across all sizes of HRS, however, storage is not a large driver of the overall dispensed cost of hydrogen ($LCOH_D$) for Configuration 4.

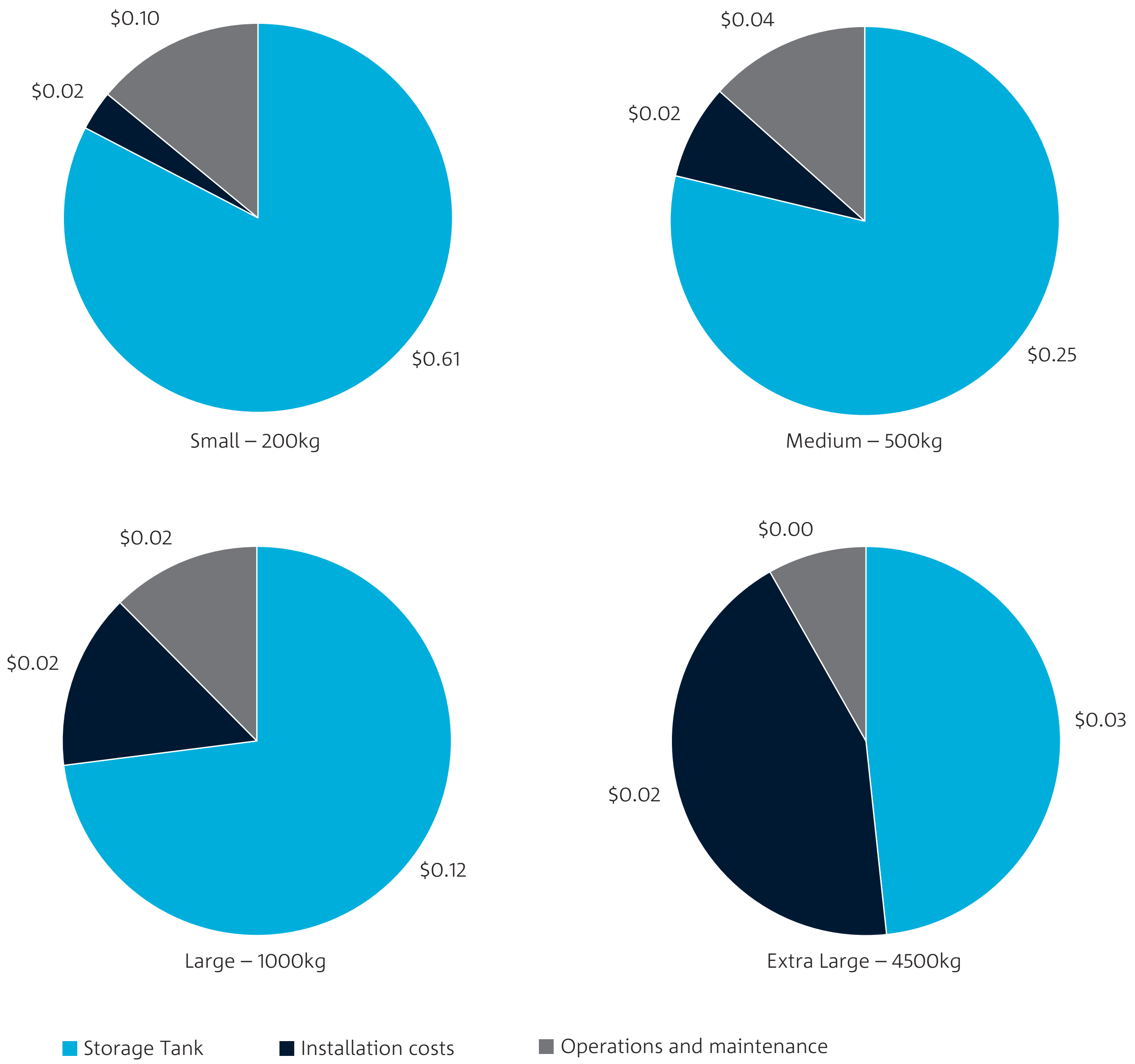



**Figure 30. Liquid storage costs, breakdown of $LCOH_S$**

### 8.2.4 Filling (dispensing) (All configurations)

Configurations 1, 2 and 3 dispense hydrogen into vehicles at either 350 or 700 bar, depending on the vehicle requirements. The cost breakdown of filling/dispensing is shown in Figure 31 below.

A typical dispenser design allows for a maximum of 250 kg per day to be dispensed, which for our analysis has been assumed in all cases. In the case of the Small HRS, the dispenser is therefore oversized, resulting in a slightly higher capital and maintenance cost relative to the average throughput of the HRS. The Medium, Large and Extra-Large HRSs use multiple 250 kg dispensers resulting in the same overall cost stack composition. The refuelling mechanism and process is not a large driver of the total $LCOH_D$ across these configurations.

Configuration 4 filling requires vaporisation of liquid hydrogen to gaseous form and use of a cryogenic piston pump which takes liquid hydrogen at low pressure and low temperature and delivers it as a cryogenic compressed gas at the determined pressure. The breakdown of cost components for Configuration 4 is shown in Figure 32.

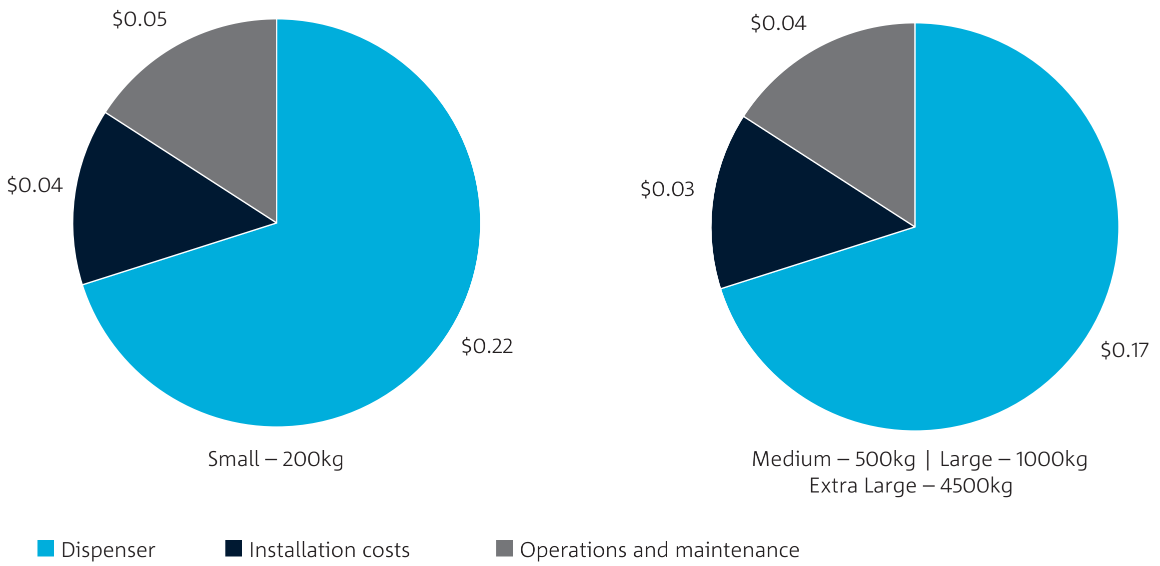



**Figure 31. Configuration 1, 2 and 3 – Filling (dispensing) costs, breakdown of $LCOH_F$**

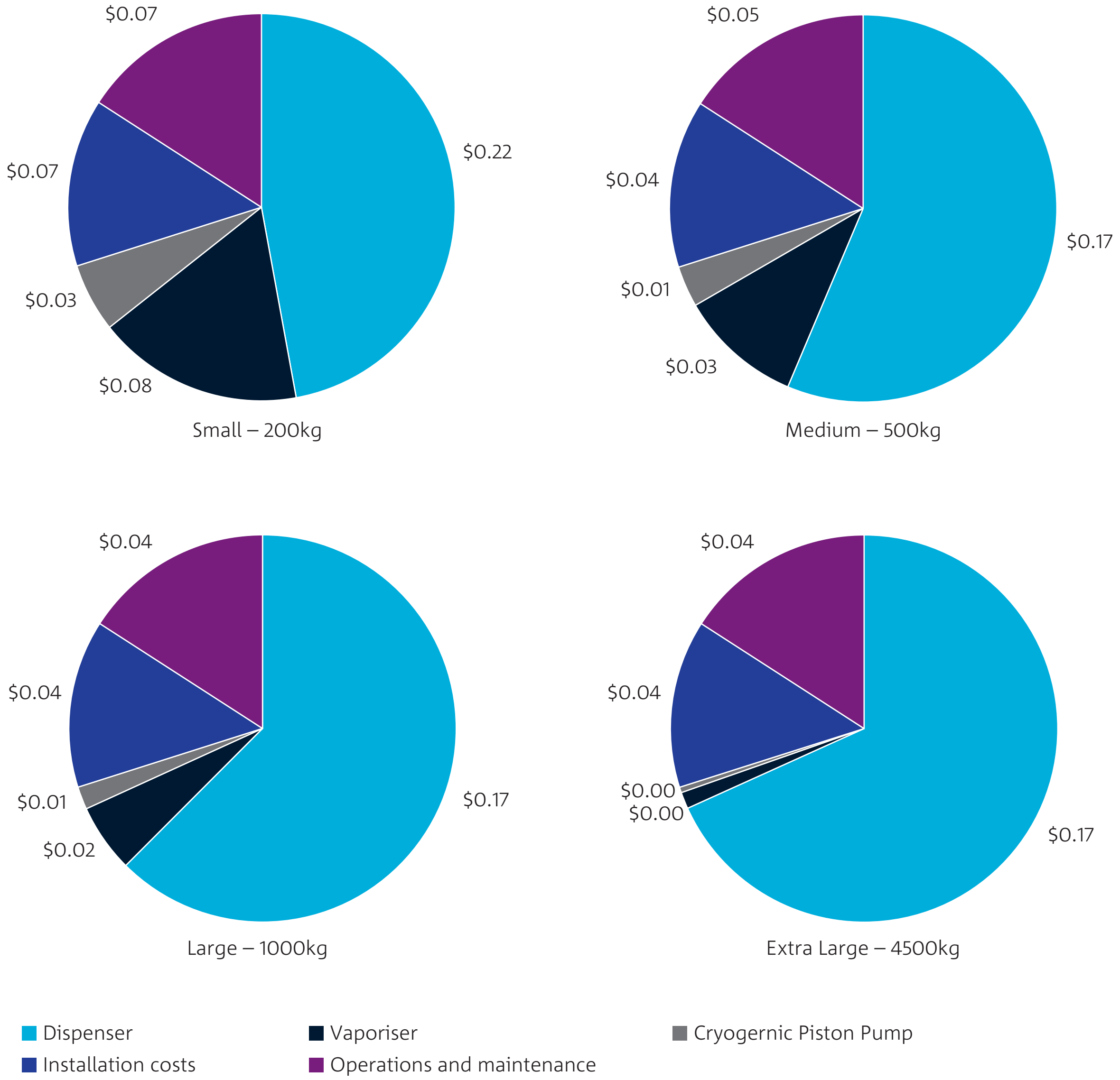



**Figure 32. Configuration 4 – Filling costs, contributions to LCOH**

Similar to the other configurations, the dispenser used in the configuration dispenses a maximum of 250 kg per day. Configuration 4 benefits most from economies of scale, with the Small HRS dispensing equipment having an $LCOH_R$ of $0.46 per kg, and the Extra-Large HRS dispensing equipment contributing and $LCOH_R$ of $0.25 per kg.

The overall contribution to $LCOH_D$ of the cost of liquid hydrogen dispensing/refuelling is relatively low, though higher than the contribution of dispensing gaseous hydrogen, because of the need for the cryogenic pump.

## 8.3 Key conclusions

Key conclusions from the financial modelling and analysis are:

- By far the largest contributor to the cost of dispensing hydrogen for road transport ($LCOH_D$) is the cost of hydrogen production. The next largest contributors are transport and compression costs. It was found that the lowest refuelling supply chain $LCOH_D$ was for hydrogen to be produced and liquified offsite and transported to the HRS via single tankers. The calculated $LCOH_D$ is $6.78 per kg, configured to serve large scale demand of 4,500 kg per day. In contrast, the same scenario with onsite production resulted in a $LCOH_D$ of $9.90 per kg.
- Onsite production of hydrogen from renewable resources, at any scale, only becomes financially favourable compared to offsite generation where transport distances exceed 400 to 600 km. Offsite production, with a range of off-takers, is expected to benefit from considerable economies of scale versus dedicated onsite production. However, onsite production could be much more convenient for proponents as the complicated logistics to transport hydrogen to site is removed from the model.
- A reduction in hydrogen production costs (mainly driven by electrolyser capital cost and electricity consumption) could lead to a large reduction in $LCOH_D$. There are many predictions regarding future electrolyser costs – as more units become available, the technology advances and mass production is implemented. In addition, electrolyser efficiencies are likely to improve. These advances will have a large reduction in supply chain $LCOH_D$.
- For offsite production of gaseous hydrogen, transport to the HRS contributes 5-35% of $LCOH_D$ and compression contributes 5-20%, thus potential improvements in these two areas will have a significant reduction impact.
- For liquid hydrogen, it was determined that this could be favoured over gaseous hydrogen for large scale HRSs. It is predicted that liquid hydrogen could become the preferred carrier as it allows delivery of large quantities of hydrogen across multiple sites avoiding multiple round trips, and potentially avoids compression at the HRS site.
- Storage and dispensing are relatively minor cost drivers for the $LCOH_D$. Storage contributed 2-7% whilst dispensing contributed between 2-5%. While there are some improvements to be made in these areas, they are unlikely to have a large influence on the $LCOH_D$ supply chain. Instead, these improvements are likely to impact process risk, rather than costs.

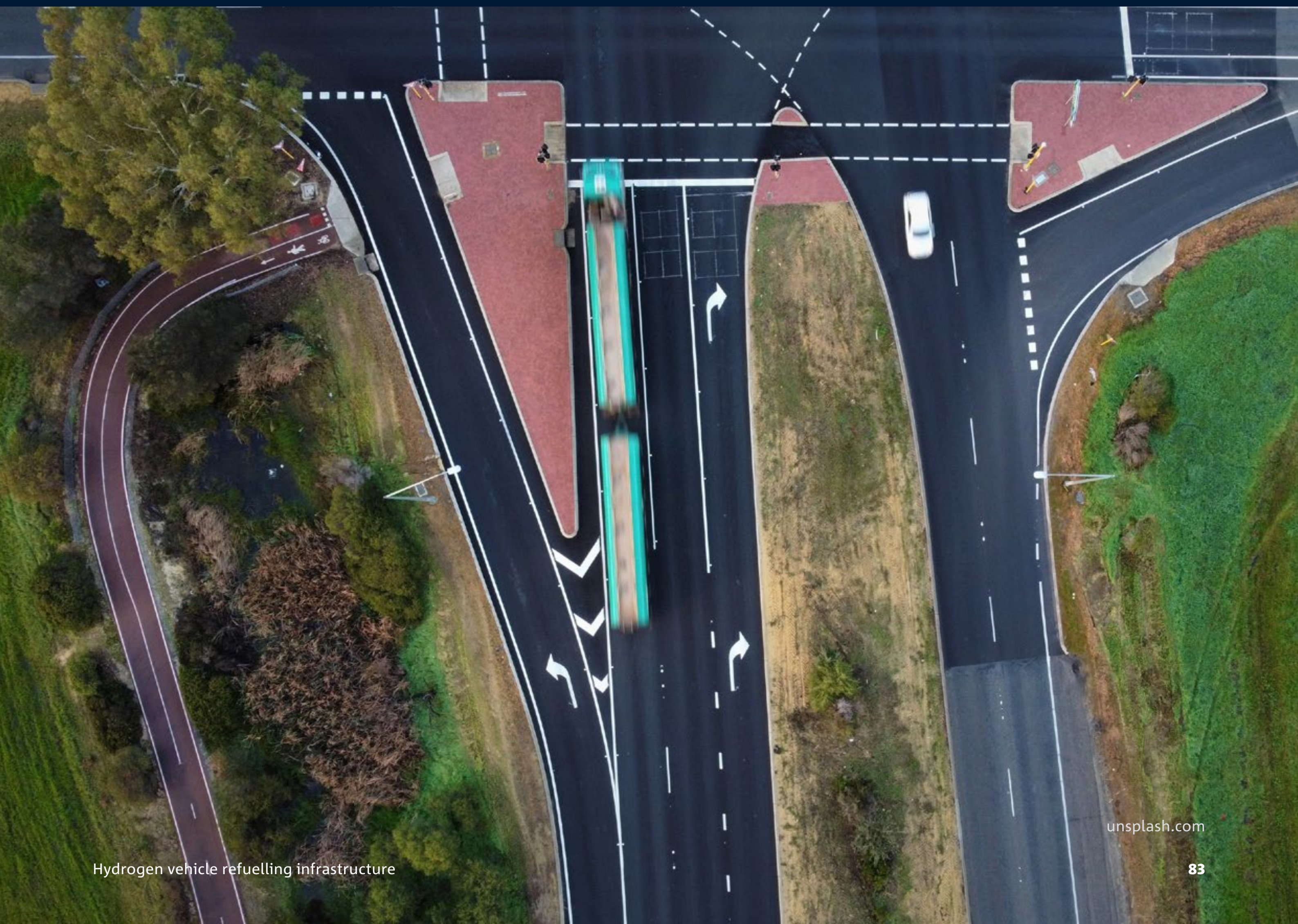
The key findings for each of the configurations modelled are shown in Table 37.

Table 37. Key findings from financial modelling

| | Configuration 1 | Configuration 2 | Configuration 3 | Configuration 4 |
|---|---|---|---|---|
| Summary description | Onsite production of hydrogen with grid power | Onsite production of hydrogen using renewable, behind-the meter, power along with grid power | Offsite production of hydrogen with road transport to site | Offsite production of liquid hydrogen with road transport to site |
| Key findings | • Production of hydrogen is the largest cost driver, followed by compression, which makes up a relatively small proportion of the $LCOH_D$, more so as the refueller size increases.<br>• With a high $LCOH_D$, it is unlikely that HRS at this scale would be feasible for a mass rollout in typical metro service station locations.<br>• Could be appropriate where there is access to grid power, and when there is a great distance between a hydrogen producer and the HRS for example in a remote setting. | • Production of hydrogen is the largest cost driver in this configuration, followed by compression, however overall, compression makes up a small proportion (5-14%) of the $LCOH_D$.<br>• The overall $LCOH_P$, and the space requirements to accommodate the solar photovoltaic equipment would make this configuration unfeasible in typical metro service station locations. | • Offsite production is the largest cost driver in this configuration. However, the combined transport and compression elements are also significant cost drivers and could be areas worth researching to reduce the total LCOH at the pump.<br>• This configuration provides one of the lowest $LCOH_D$ and operates similar to the existing petrol and diesel service stations.<br>• Typical equipment design is well established and available to the Australian market, and as such is likely to be the preferred HRS configuration in the short term. | • Liquid hydrogen production is the largest cost driver in this configuration, particularly with the additional cost of liquefaction. However, the transport is also a significant cost driver due to the high capital costs, particularly at the small scale.<br>• This configuration uses emerging technology. As the market becomes more established, it is likely to become cheaper overall, reducing the $LCOH_P$. Very little liquid hydrogen supply is currently available in Australia.<br>• This configuration allows for future flexibility should liquid hydrogen vehicles become the dominant technology. This configuration allows for a transition from gaseous fuel to liquid fuel by changing the dispensing configuration. While gaseous vehicles are currently the predominant hydrogen vehicle type, liquid hydrogen vehicles could become the dominant technology in the future. |

# Part E –

# Key priorities, challenges and opportunities



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# 9 Key priorities, challenges and opportunities

Key findings of this report, including opportunities for action, are set out below.

**Table 38. Key priorities and opportunities**

| Key observations / findings | Opportunities | Report reference |
|---|---|---|
| **Industry initiatives and business models** | | |
| 1. Those overseas jurisdictions that are much more developed than Australia with their roll-out of HRSs have utilised major public sector – private sector partnerships and consortia to provide a collective approach to stimulating demand, promoting research and development, sharing risks and achieving initial scale to allow supply chain cost reductions. | Incorporate learnings from overseas to expedite infrastructure development in Australia.<br>Incentivise international technology partnerships.<br>Further develop Australia's Hydrogen Hubs' strategy to incorporate a wider scope of stakeholders in mobility projects, especially from fuel retailing and vehicle manufacturing.<br>Governments to investigate the potential to found / support the creation of sector partnerships/consortia in the Australian market. | 3.1. 3.2 |
| **Offsite versus onsite hydrogen production** | | |
| 2. Centralised offsite production and distribution of hydrogen to HRSs is likely to be the dominant future model due to cost efficiencies with scale and the avoidance of needing to accommodate onsite production when selecting sites. | Governments and developers should focus on the enablers of larger scale HRSs utilising hydrogen supplied by centralised offsite production facilities. | 8.2.1, 8.2.3 |
| 3. To date, onsite production of hydrogen is currently the supply model of the existing early HRSs and those currently being planned/ developed in Australia, due to it being self-contained and not dependent on transporters and external producers of hydrogen. | Continue to develop onsite production as an early-stage approach, and as a prototype for remote locations that may be long distances from offsite production sites, and that may have less neighbourhood constraints to accommodating larger scale onsite production. | 2.5 |
| 4. Modelling shows that incorporating the use of purpose-built behind-the-meter renewable electricity, scaled to the size of the HRS, adds to the cost of onsite hydrogen production versus fully relying on grid-supplied electricity. | Consider co-locating HRSs with existing large-scale renewable electricity sources where possible (having regard to established freight routes) and /or if new renewable electricity was to be utilised, it being of a scale beyond that needed for servicing the HRS. | 8.2.2 |
| **Pressure and form of hydrogen** | | |
| 5. Currently most Heavy Duty and Medium Duty FCEVs (overseas) use hydrogen at 350 bar pressure. However, a number of vehicle manufacturers are now flagging a transition to 700 bar, especially for long haul transport – initially aiming at 1,000km range. | The cost of onsite storage at 700 bar is significantly higher than that of storage at 350 bar, thus this is an area that would benefit from focussed research and innovation, including continued research into the optimisation of cascade storage. | A1.1, 5.4.2 |
| 6. Liquefaction, and transport and storage of liquid hydrogen, to be dispensed as a gas presents as an opportunity to greatly improve distribution and storage capacities. However, transport and storage of liquid hydrogen at low volumes is currently very expensive compared to compressed hydrogen. | Promote focussed research and innovation to enhance the technology and processes for liquefaction, and transport and storage of liquid hydrogen. | 5.2.2 |
| 7. Long-haul vehicle manufacturers are flagging future use of onboard liquid hydrogen as fuel, which will greatly increase the hydrogen energy that can be carried in vehicle tanks, thus increasing range and limiting the impost of the tank volume. | Dispensing technology is developed, but field experience is limited. Demonstration trials are necessary. | 5.5.4, 5.5.5 |

| Key observations / findings | Opportunities | Report reference |
|---|---|---|
| **Distribution of hydrogen to HRSs** | | |
| 8. Road distribution of hydrogen utilising existing steel tube trailer technology is limited by capacity constraints. There is an overseas trend towards transporting in higher pressure Type III and Type IV carbon fibre cylinders that can transport hydrogen much higher volumes, with lower weight. | Explore Australia's access to Type III and Type IV tube trailers and consider a potential collective approach to acquisition of trailers for shared use of fuel companies / hydrogen distributors. | 5.2.1 |
| 9. For the foreseeable future, transport of hydrogen directly to HRSs by dedicated pipeline will likely be difficult to justify in most cases, due to high capital intensity and relatively low demand of individual HRSs. However, there could be refuelling locations in industrial or port areas (e.g. hubs) that are suitable for direct pipelines, due to proximity to the supply source and/or having pre-existing pipelines that can be repurposed, although additional onsite compression will be required due to lower delivery pressures. | Explore use of new or repurposed pipelines for distributing pure hydrogen from production facilities to high demand facilities and/or delivery hubs (from which road transport could complete the deliveries).<br><br>Undertake further research and technology development for the extraction of hydrogen from natural gas network blends. | 5.2.3 |
| **Policies, standards and regulation** | | |
| 10. Government policy can be a leading driver of the adoption of alternative fuels for road transport. | Consider targeting GHG abatement in transport as a priority within broader decarbonisation policies. Options include, enaction of emission standards (e.g. carbon intensity) for road vehicles, or incentive measures such as tax exemptions. | 3.2, 3.3, 3.4 |
| 11. Australia currently lacks nationwide standards, regulations and planning processes for transport of hydrogen, HRS equipment and configuration, contributing to uncertainty, cost and investment uncertainty. | Align requirements of road regulators, work safety agencies, environment protection agencies and energy departments. Introduce a comprehensive set of standards/certifications for harmonised application across states and territories and a simplified, nationally consistent approach for certifying equipment manufactured overseas for use in Australia. | 3.3 |
| 12. Regardless of the scale, onsite versus offsite production, and preferred location, developers and investors are seeking clarity of planning processes. | Develop clear, predictable and well-documented planning and environmental processes for siting of HRSs. Develop clear standard approach to assessing and mitigating risk – consider standard planning templates and distances per AS1940 and NFPA2, in particular for $LH_2$. Consider adopting international standards for equipment to simplify HRS development. | 3.3, 6.1, 6.2, 6.3 |
| **Costs** | | |
| 13. Compression, and associated cooling, is expensive in terms of both capital and operating costs. | Continue research into technology improvement and associated cost reductions.<br><br>Focus on achieving sufficient scale to reduce unit costs. | 5.3 |

# Appendices


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# A.1 Fuel cell electric vehicles (FCEVs)

## A1.1 Introduction

This appendix sets out explanatory information in relation to hydrogen powered vehicles – both FCEVs and vehicles with internal combustion engines (ICEs) that utilise hydrogen.

Both Battery Electric Vehicles (BEVs) and Fuel Cell Electric Vehicles (FCEVs) are propelled by electric powertrains. BEVs use electricity drawn from onboard batteries, which need to be recharged periodically from an external electricity source. FCEVs convert gaseous hydrogen (and in future could use liquid hydrogen) from an onboard tank that needs to be refilled periodically, to produce electricity using a Proton Exchange Membrane fuel cell.

FCEVs can have more than one hydrogen storage tank, in which case, the tanks are connected to a common manifold on both the inlet and outlet, with the inlet manifold terminating at the refuelling connection point on the vehicle exterior. The size, configuration and location of tanks differ depending on vehicle architecture and quantity of hydrogen that is sought to be stored. A typical configuration of a passenger FCEV with two onboard storage tanks is shown in Figure 33 below.

Under steady driving conditions, electric output from the fuel cell is fed directly to the motor while excess power generated by the fuel cell is diverted to a battery. Power from the battery is used to supplement fuel cell power output when required, for example when the vehicle is accelerating or travelling uphill. The battery acts as a capacitor, modulating the electrical inputs and outputs of the fuel cell, and is an essential component to the powertrain. FCEVs do not produce any greenhouse gases and emit only water vapor and heat.

FCEVs are grouped into the three categories shown in Table 39.

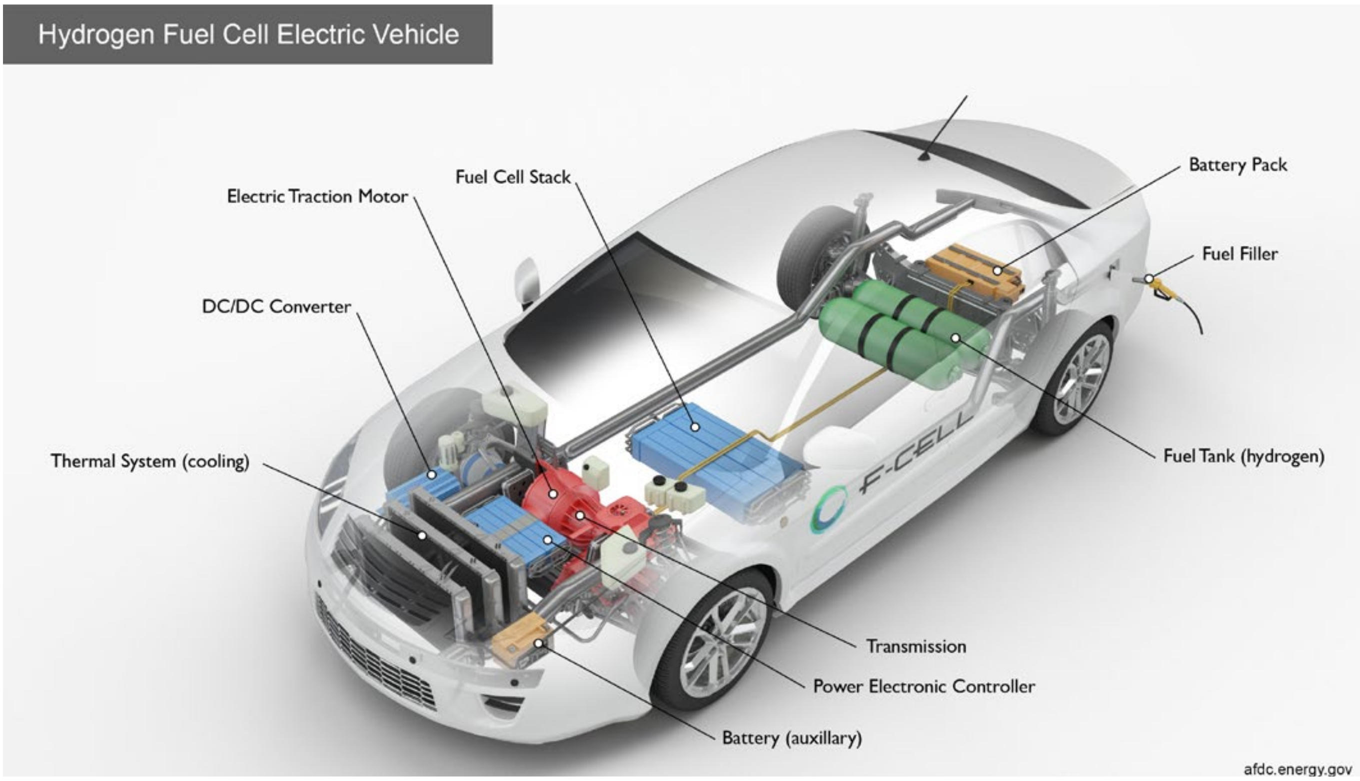


**Figure 33. Key components of passenger fuel cell electric vehicles[74]**

74 US DoE, Energy Efficiency & Renewable Energy, Vehicle Technologies Office, AFDC 2022, https://afdc.energy.gov/vehicles/how-do-fuel-cell-electric-cars-work

**Table 39. FCEV categories**

| Vehicle category | Description | Fuel tank capacity (kg) | Pressure (bar) |
|---|---|---|---|
| Light Duty (LD or LDV) | Passenger vehicles | 5 to 7 | 700 |
| Medium Duty (MD or MDV) | Light commercial vehicles, buses, vans, smaller trucks | up to 90 | 350 |
| Heavy Duty (HD or HDV) | Long-haul transport | up to 90 | 350 |

Some manufacturers of MDVs and HDVs are planning to introduce 700 bar or liquid hydrogen to increase range.
Since MDVs and HDVs store $GH_2$ at 350 bar, they are sometimes grouped into a single category, HDV.

## A1.2 FCEVs currently in Australia

Two brands of passenger (Light Duty) FCEVs are currently available in Australia (and are the dominant passenger FCEVs worldwide), with summary specifications shown in Table 40 below.

**Table 40. Currently available passenger FCEVs**

| Vehicle (2022 model) | Tank pressure (bar) | Storage of $H_2$ (kg) | Range (km) | Refuelling time (minutes) |
|---|---|---|---|---|
| Toyota Mirai[75] | 700 | 5.6 | 560 to 640 | 5 |
| Hyundai NEXO[76] | 700 | 6.3 | 570 to 610 | 5 |

Medium (MD) and Heavy Duty (HD) FCEVs are yet to be deployed in Australia, although plans are in progress associated with some of the existing and planned HRSs. Specifications for MD and HD FCEVs that have recently been released or due for release overseas are shown in Table 41 below.

**Table 41. Specifications of MD and HD FCEVs available overseas**

| Make / model | Style | Load (tonne) | Tank pressure (bar) | Tank capacity (kg) | Range (km) |
|---|---|---|---|---|---|
| Hyzon HyMax[77] | Prime mover and trailer | 24 | 350 | 30 | 400 |
| | | 46 | 350 | 70 | 680 |
| | | 70 | 700 | 95 | 600 |
| | | NA | $LH_2$[7] | NA | >1500 |
| Hyundai Xcient FC[78] | Rigid | 36 | 350 | 34 | 400 |
| Daimler[79] | Prime mover and trailer | 40 | $LH_2$[7] | 80 | 1000 |
| Nikola TRE[80] | Prime mover and trailer | NA | 700 | NA | >560 |
| | | NA | $LH_2$ | NA | |

75 Toyota 2022, Mirai Fuel Cell Vehicle, accessed July 2022 from https://www.toyota.com/mirai/
76 Hyundai 2022, NEXO Fuel Cell, accessed July 2022 from https://www.hyundaiusa.com/us/en/vehicles/nexo/compare-specs
77 Hyzon 2022, HYMAX Series, accessed July 2022 from https://www.hyzonmotors.com/vehicles/hyzon-hymax-series
78 Hyundai 2022, Hydrogen Mobility, accessed July 2022 from https://trucknbus.hyundai.com/global/en/eco/hyundai-hydrogen-mobility
79 Nikola 2022, TRE BEV, accessed July 2022 from https://nikolamotor.com/tre-bev
80 Under development, limited information available

## A1.3 Vehicle fuel storage

Evolution of technology for onboard storage of hydrogen will be a key enabler of mass deployment of FCEVs. Whilst hydrogen has the highest energy per mass of any fuel, its low density requires use of either high pressures or cryogenic temperatures to store enough fuel onboard to allow travel distances comparable to those petrol or diesel vehicles[81].

In existing commercially available road transport vehicles, hydrogen is stored as a compressed gas. Original Equipment Manufacturers (OEMs) and government agencies are undertaking research into increasing the carrying capacity of vehicle hydrogen tanks by improving the energy density of onboard storage through deployment of liquid hydrogen cryo-compressed storage and the use of hydrogen storage materials (HSMs), where hydrogen is stored on the surfaces of solids by adsorption or within solids by absorption. The US Department of Energy is supporting this research, with a system target of 1.8 kWh/kg (4.5 wt.% hydrogen)[82] by 2025.

## A1.4 Gaseous storage

Onboard vehicle fuel tanks used for gaseous hydrogen are similar to Type IV cylinders as categorised in ISO 11515:*2022 Gas cylinders — Refillable composite reinforced tubes of water capacity between 450 L and 3000 L — Design, construction, and testing.* They are constructed from a carbon fibre load-bearing shell fitted with an internal polymer liner that serves as a hydrogen gas permeation barrier. A fibreglass composite outer shell is fitted for impact and mechanical protection as shown in Figure 34.

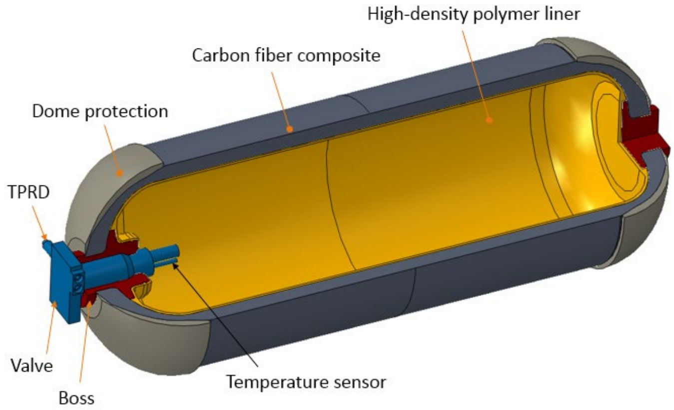


**Figure 34. Composite overwrapped pressure vessel, suitable for use in 700 bar FCEV[83]**
**Credit: Process Modeling Group, Nuclear Engineering Division, Argonne National Laboratory (ANL)**

## A1.5 Liquid hydrogen storage

Liquid hydrogen is stored at cryogenic temperatures, below its boiling point of minus 253°C. Typically made from stainless steel, tanks currently in use hold between 40 and 65 kg. Onboard tanks for liquid hydrogen vehicles are not actively cooled or refrigerated, they rely on heavy insulation and thermal mass to reduce losses through boil-off. Despite that, boil-off is a concern may limit the use of $LH_2$ to vehicles with predictable use and low 'down times', such as freight vehicles, buses, couriers, and garbage trucks. Consequently, passenger vehicles that more frequently travel short distances and have regular non-operational periods are unlikely to benefit from LH2 until there are effective ways to reduce boil-off or to utilise the boiled-off gas onboard.

Some vehicle manufacturers are trialling the use of $LH_2$ tanks for medium duty vehicles such as buses and smaller trucks. Others, such as Daimler, Hyzon and Nikola, are trialling $LH_2$ for long haul trucks fitted with more than one tank to extend range, with commercial sales likely in the second half of this decade.

81 US DoE 2022, DOE Technical Targets for Onboard Hydrogen Storage for Light-Duty Vehicles, accessed August 2022 from https://www.energy.gov/eere/fuelcells/doe-technical-targets-onboard-hydrogen-storage-light-duty-vehicles

82 US DoE 2022, DOE Technical Targets for Onboard Hydrogen Storage for Light-Duty Vehicles, accessed August 2022 from https://www.energy.gov/eere/fuelcells/doe-technical-targets-onboard-hydrogen-storage-light-duty-vehicles

83 Process Modelling Group, Nuclear Engineering Division, Argonne National Lab, Sourced from Hydrogen Storage, Fuel Cell Technologies Office, DOE/EE-1552, US DoE March 2017: Hydrogen Storage (energy.gov)

## A1.6 Hydrogen storage and range

Vehicles powered by hydrogen require fuel tanks that are physically much larger than those for petrol or diesel because hydrogen has a volumetric energy density less than one third of that of petrol and diesel. Conversely hydrogen has a gravimetric energy density approximately three times that of petrol or diesel as indicated in Table 42 below.

Considering that FCEVs are around twice as efficient at converting fuel energy into forward motion than internal combustion engines, storage tanks for FCEV need to be approximately two to 10 times as large, depending on vehicle type, duty and hydrogen storage configuration. Table 43 below shows onboard fuel storage and distances travelled for different vehicle types and fuels. The data reflects manufacturers' indicative values and is shown for comparison.

**Table 42. Relative energy density for hydrogen and other fuels**

| | Storage Pressure (bar) | Storage temp[84] °C | Density (kg/L) | Energy density volumetric[85] (MJ/L) | Energy density (LHV) (MJ/kg) |
|---|---|---|---|---|---|
| $LH_2$ | 1 | -253 | 0.07 | 8.5 | 120 |
| $GH_2$ | 350 | amb | 0.02 | 2.9 | 120 |
| $GH_2$ | 700 | amb | 0.04 | 5.8 | 120 |
| Diesel | 0 | amb | 0.83[86] | 38.0 | 45.3 |
| Petrol | 0 | amb | 0.73[87] | 33.0 | 45.8 |

**Table 43. Comparison of key metrics for conventionally fuelled and hydrogen vehicles[88]**

| Vehicle | Fuel | Weight kg | Volume L | Energy MJ | Nominal Efficiency MJ/100km | Distance travelled (km) |
|---|---|---|---|---|---|---|
| LDV | Petrol | 43.8 | 60 | 2,006 | 214 | 882 |
| LDV | $GH2_{70}$ | 5.5 | 110 | 660 | 142 | 550 |
| LDV | 72.6 kWh BEV | 250-400 | NA | 261 | 61 | 450 |
| MDV | $GH2_{35}$ | 30 | 1,500 | 3,600 | | 400 |
| MDV | Diesel | 83 | 100 | 3,760 | 1,086 | 350 |
| MDV | 336 kWh BEV | >750 | NA | 1,210 | 403 | 300 |
| HDV | $LH_2$ | 80 | 1,143 | 9,144 | 60-80 | 1,500 |
| HDV | $GH2_{70}$ | 95 | 1,900 | 11,400 | 70-100 | 600 |
| HDV | Diesel | 706 | 850 | 31,770 | 2,097 | 1,540 |

84 The Geography of Transport Systems, Energy Density of some Combustibles (in MJ/kg), accessed July 2022 from transportgeography.org

85 The Geography of Transport Systems, Energy Density of some Combustibles (in MJ/kg), accessed July 2022 from transportgeography.org

86 Bp, Data Sheets – Diesel Petrol, accessed July 2022 from https://www.bp.com/en_au/australia/home/products-services/data-sheets.html

87 Bp, Data Sheets – Unleaded 91 Petrol, accessed July 2022 from https://www.bp.com/en_au/australia/home/products-services/data-sheets.html

88 LDV (petrol) based on Toyota Camry, specifications accessed July 2022 from https://www.toyota.com.au/-/media/toyota/main-site/vehicle-hubs/camry/files/20220711_camry_spec-sheet.pdf
LDV (GH2) based on Toyota Mirai: specifications accessed July 2022 from https://www.toyota.com/mirai/
LDV BEV based on Hyundai IONIQ 5, specifications accessed July 2022 from https://www.hyundai.com/au/en/cars/eco/ioniq5
MDV BEV based on Mercedes Benz eActros 300 6X2 27T, specifications accessed July 2022 from https://www.mercedes-benz-trucks.com/de_DE/emobility/world/our-offer/eactros-and-services.html#root/content/headline_489846305
MDV (Diesel) based on Hyundai Pantec EX6, specifications accessed July 2022 from https://hyundaitrucks.com. au/our-range/pantech
MDV & HDV (GH2) based on Hyzon Hymax 24T & 70T respectively, specifications accessed July 2022 from https://www.hyzonmotors.com/vehicles/hyzon-hymax-series
HDV (Diesel) based on Hyundai Excient 6 X 4, specifications accessed July 2022 from https://hyundaitrucks.com.au/images/content/brochure/xcient-brochure.pdf
HDV (LH2) based on Hyzon SuperMAX, accessed July 2022 from https://www.hyzonmotors.com/vehicles/hyzon-hymax-series
HDV and MDV diesel efficiencies: ABS 2019
G. Parks, R. B.2014. Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs . Golden Colerado, USA: National Renewable Energy Laboratory.
US DoE 2022. Hydrogen Storage. Retrieved from Office of Energy Efficiency & Renewable Energy: https://www.energy.gov/eere/fuelcells/hydrogen-storage

## A1.7 Research and innovation opportunities

The relatively high costs of hydrogen fuel tanks and fuel cells compared with existing internal combustion engine technology imposes a cost premium for hydrogen-fuelled vehicles over diesel and petrol vehicles, even in the most optimistic scenarios of volume and technology improvements. At present, the fuel cell system makes up approximately 73% of energy module cost and 13% of total fuel cell vehicle cost[89]. Other than the fuel cell system itself, hydrogen tanks contribute towards 15% of the energy module costs.

Reducing the cost of vehicle hydrogen tanks could therefore lead to significant cost savings for FCEVs[90]. This could be achieved through several means including higher volume lighter tanks or storing liquid hydrogen instead of compressed gas. The US Department of Energy (DOE) uses gravimetric and volumetric density to measure storage system performance. Table 44 shows current and projected values[91].

**Table 44. Current and projected 700 bar compressed hydrogen storage costs[91]**

Projected performance and cost of compressed automotive hydrogen storage systems
Compared to 2020 and ultimate DOE targets[a]

| Storage system targets | Gravimetric density kWh/kg system (kg $H_2$/kg system) | Volumetric density kWh/L system (kg $H_2$/L system) | Cost $/kWh ($/kg $H_2$) |
|---|---|---|---|
| 2020 | 1.5 (0.045) | 1.0 (0.030) | US$10 (US$333) |
| Ultimate | 2.2 (0.065) | 1.7 (0.050) | US$8 (US$266) |
| **Current status (from Argonne National Laboratory)** | **Gravimetric density kWh/kg system (kg $H_2$/kg system)** | **Volumetric density kWh/L system (kg $H_2$/L system)** | **Cost[b] $/kWh ($/kg $H_2$)** |
| 700 bar compressed (Type IV, single tank) | 1.4 (0.042) | 0.8 (0.024) | US$15[c] (US$500) |

a. Assumes a storage capacity of 5.6 kg of usable hydrogen
b. Cost projections are estimated at 500,000 units per year and are reported in 2007$
c. Cost projection from Strategic Analysis (November 2015)

The DOE proposes several actions that could lead to significantly lower costs of hydrogen storage tanks in vehicles including:

- reductions in costs of carbon fibre composites
- developing lower cost alternative fibre reinforced composites
- reduction in the amount of fibre reinforcement required in the tank through increased utilisation
- higher efficiency tankage systems manufacturing
- tank liner and supporting components cost reduction.

The cost breakdown of gaseous hydrogen Type IV storage tanks is shown in Figure 35. Cost breakdown of hydrogen storage tanks.

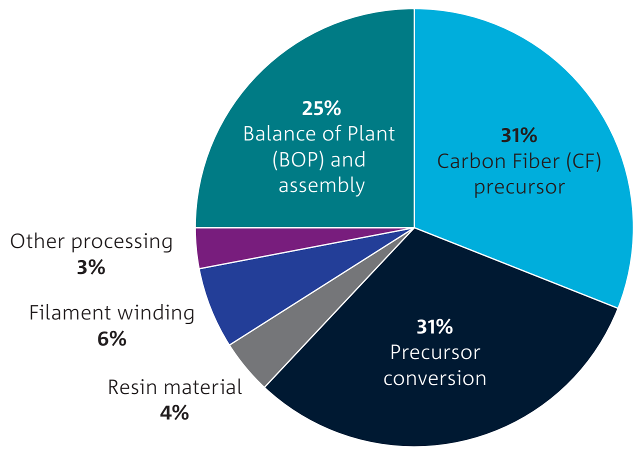


**Figure 35. Cost breakdown of hydrogen storage tanks[92]**

89 Deloitte China, Fuelling the Future of Mobility, accessed October 2022 from deloitte-cn-fueling-the-future-of-mobility-en-200101.pdf

90 H2Accelerate, Whitepaper: Analysis of cost of ownership and the policy support required to enable industrialisation of fuel cell trucks, accessed October 2022 from https://h2accelerate.eu/wp-content/uploads/2022/09/H2A-Truck-TCO-and-Policy-Support-Analysis-VFinal.pdf

91 Office of Energy Efficiency & Renewable Energy, USA Federal Energy Department, Physical Hydrogen Storage, accessed October 2022 from https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage

92 US DoE March 2017, Process Modelling Group, Nuclear Engineering Division, Argonne National Lab, Sourced from Hydrogen Storage, Fuel Cell Technologies Office, DOE/EE-1552, https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage

Carbon fibre, which accounts for 30% of the cost of Type IV tanks, has become less expensive due to advances in the production of raw materials, alternate sources of materials, manufacturing technologies and assembly techniques. At present, most carbon fibre is based on polyacrylonitrile (PAN), with an average cost of around $20 to $25 per kg, and a conversion efficiency of 50%[93]. Development of low cost and high yield precursors for the manufacture of commercial carbon fibre will significantly reduce the cost of carbon fibre. In Australia, there are several research groups focusing on producing carbon fibre from low-cost sources such as coal. There are also various advanced carbon fibre production technologies that are being developed, such as fast cycle manufacturing techniques, lay-up automation and automation of labour-intensive activities[93].

Although not currently recognised in ISO 11515:2022, manufacturers such as Hanwha Cimarron in the USA are developing a Type V cylinder for use in commercial aviation, aerospace and shipping. They are constructed from carbon fibre composite, without an internal liner and are claimed to be 10% lighter than Type IV cylinders.

Longer term onboard tankage solutions rely on having access to liquid hydrogen storage tanks on board vehicles, allowing for increased hydrogen density storage[94]. For a typical compressed gas hydrogen tank, the typical mass fraction of fuel to tank is only 10 to 11%, which means that for every kilogram of hydrogen, approximately nine kilograms of tank is required[95]. A USA-based company Gloyer Taylor Laboratories (GTL) has been developing ultra-lightweight cryogenic tanks (also known as cryotanks) made from graphite fibre composites, among other materials. GTL claims to have built and tested cryotanks demonstrating a 75% mass reduction as compared with current state of the art cryotanks. It is claimed that the tanks are at a Technology Readiness Level (TRL) of 6+ at present. While these tanks have been developed for aerospace applications, similar technology could be applied for FCEVs. Such tanks would result in higher quantities of onboard hydrogen storage, while significantly reducing tank weight.

## A1.8 Hydrogen internal combustion engines

Hydrogen may be used in internal combustion engines ($H_2$ICE) and offers an alternative to fuel cell technology. $H_2$ICEs work in much the same way as traditional internal combustion engines (ICE) using hydrocarbon fuels and mechanical drivetrain for forward motion.

Hydrocarbon-fuelled ICEs are a long-established mature technology, having been deployed as a source of power in a wide variety of applications for over a century and integration of ICEs within existing vehicle architecture such as chassis, transmissions and drive trains is well understood by manufacturers and fleet operators. By contrast, FCEVs are still in the early phase of deployment, with successive models incorporating updates derived from current and recent user experiences and technology developments.

Whilst the use of hydrogen in ICEs is less energy efficient than its use in fuel cells, the more familiar and highly developed ICE system is cheaper to produce, at least at this early stage of hydrogen vehicle deployment. Furthermore, the economic impact of lower efficiency may be offset by the less demanding hydrogen purity requirements of a $H_2$ICE. To achieve optimal life, fuel cells demand 99.999% hydrogen purity, (Type 1 Grade D in AS ISO 14687:2019) which itself requires 55 kWh energy input to produce. $H_2$ICEs do not need the same high level of hydrogen purity, and thus need less energy for hydrogen production. This has implications for stationery plant, power generation or sites deploying only $H_2$ICE vehicles such as mines.

93 Shama Rao N. et al, Whitepaper: Carbon composites are becoming competitive and cost effective, Infosys 2018, accessed October 2022 from https://www.infosys.com/engineering-services/white-papers/documents/carbon-composites-cost-effective.pdf

94 Cryospain 2022, Hydrogen fuel tanks for long-distance heavy distance, accessed October 2022 from https://cryospain.com/hydrogen-fuel-tanks-for-long-distance-heavy-vehicles

95 New Atlas 2022, Ultra-light liquid hydrogen tanks promise to make jet fuel obsolete, accessed October 2022 from https://newatlas.com/aircraft/hypoint-gtl-lightweight-liquid-hydrogen-tank/

Manufacturers of ICEs for heavy and medium duty vehicles, such as Cummins, are developing hydrogen ICEs based on the four-stroke spark ignition engine. They are less like the traditional compression ignition diesel engine and more like engines that run on petrol or LPG. They use the same main components as a traditional petrol engine: engine block, crank, cylinder heads, ignition system, installation parts, etcetera, however due to hydrogen's physical properties there are some differences. For example, hydrogen's wide ignition range means it is subject to pre-ignition, however this may be overcome by using direct injection of hydrogen into the cylinders. In 2022, Cummins announced a 15 litre and 7.6 litre $H_2$ICE using direct injection that it indicates will be in production by 2027[96].

Work is also being undertaken to run compression engines on hydrogen, but this is still in early stages of development. Researchers at the University of NSW have converted a diesel engine to run as a hybrid diesel-hydrogen engine that uses a fuel blend of 90% hydrogen and 10% diesel. Gaseous hydrogen and diesel are directly injected into the cylinder through separate fuel injectors. An 85% reduction in $CO_2$ is reported.[97]

Hydrogenus Energy (Hydrogenus), a company based in Melbourne, Australia, has indicated success with a naturally aspirated spark ignition engine fuelled by hydrogen at relatively low pressure. The engine is being developed as a cost-effective alternate to diesel for power generation in remote areas. Its potential competitiveness arises from a lower level of compression and lesser purity requirement of the hydrogen.

Toyota modified its turbo-charged inline three-cylinder 1.6 litre Yaris GR spark ignition engine to run on hydrogen and is trialling it in its Rookie Racing Corolla Sport[98]. The engine operates on the four-stroke cycle (intake / compression / power / exhaust) and uses direct injection for the hydrogen fuel. Larger engines are also undergoing review for use of hydrogen fuel. Yamaha teamed up with Toyota and redesigned the 5.0 litre naturally aspirated V8 engine from the Lexus RC F to use hydrogen and claiming to produce 335 kW and 540 Nm at 3,600 rpm[99].

Some engine manufacturers claim that $H_2$ICEs offer superior power performance to fuel cells or batteries under heavy loads, for example for long-haul trucks and mining plant, and also in applications where transient response and operation is a requirement such as with garbage trucks (as well as stationery plant and machinery). However, $H_2$ICEs are less efficient than fuel cells at converting the energy in hydrogen into forward motion[100,101] and operate at considerably higher temperatures than fuel cells and can emit NOx, although less than for ICEs using hydrocarbon fuels[26].

Hydrogen ICE vehicles have several benefits for both the user and wider hydrogen industry:

- The engines can be manufactured on existing production lines and placed into existing vehicle models with relatively minor modifications to vehicle architecture, which reduces the cost and time to take the vehicle to market, which may tip the business case for operators wanting to adopt zero emissions technology but need it to be commercially viable.
- They operate like conventionally fuel vehicles, so there is little mental shift for fleet operators and drivers, which may eliminate a barrier to uptake. Installation, maintenance, and servicing can usually be undertaken by existing personnel with minor upskilling.
- Deployment of hydrogen ICE vehicles will increase demand for hydrogen and support increased hydrogen production and the roll out of a refuelling network.

96 Cummins 2022, Cummins Newsroom accessed Nov 2022 from https://www.cummins.com/news/releases/2022/05/09/cummins-inc-debuts-15-liter-hydrogen-engine-act-expo

97 Xinyu Liu; Gabrielle Seberry; Sanghoon Kook; Qing Nian Chan; Evatt R. Hawkes Direct injection of hydrogen main fuel and diesel pilot fuel in a retrofitted single-cylinder compression ignition engine Int Journal Hydrogen Energy 2022, 47, 35864-35876

98 Toyota 2022. Toyota Newsroom accessed Nov 2022 from https://pressroom.toyota.com/the-familiarity-of-sound-sensation-without-all-of-the-carbon-toyota-refines-its-hydrogen-engine-corolla-concept/

99 Yamaha 2022 accessed Nov 2022 from https://www.yamaha-motor.com.au/discover/news-and-events/news/corporate/2022/february/tapping-the-potential-within-hydrogen-powered-engines

100 USDoE Fuel Cell Technology Office 2015, Fuel Cells, https://www.energy.gov/sites/prod/files/2015/11/f27/fcto_fuel_cells_fact_sheet.pdf

101 Lúcia Bollini Braga, Jose Luz Silveira, Marcio Evaristo da Silva, Einara Blanco Machin, Daniel Travieso Pedroso, Celso Eduardo Tuna, Comparative analysis between a PEM fuel cell and an internal combustion engine driving an electricity generator: Technical, economical and ecological aspects Applied Thermal Engineering, 63, 2014, pp 354-361

# A.2 Hydrogen refuelling stations (HRSs)

## A2.1 Components

Currently, all HRSs require essentially the same components, regardless of their location or capacity[102,103]. The key differences between stations are the source of hydrogen, and storage, both of which inform the type of equipment used and how it is configured.

Hydrogen is either produced by onsite electrolysis or delivered to sites as compressed gas or less frequently delivered by pipeline. However, equipment manufacturers indicate an increasing role for the delivery of offsite-produced hydrogen as a liquid.

### A2.1.1 Gaseous hydrogen storage and dispensing

Figure 36. Key components for a compressed hydrogen refuelling station below, shows the key components of a gaseous hydrogen (GH2) refuelling station. It depicts three alternatives for the supply of hydrogen:

- tube trailer
- pipeline
- onsite electrolysis.

It also shows two options for storage:

- High pressure cascade storage, using three tiers of compression, the highest at 950 bar. Dispensing into vehicle tanks commences from the lowest pressure tank, then after equalisation, gas is dispensed from the medium pressure tank, after equalisation, filling is completed using the higher-pressure tank.
- Medium pressure storage, with an optional buffer or accumulator tank, held at 900 bar. In this arrangement, the accumulator or buffer tank may be used for the entire fill and a second compressor used to recharge the accumulator after each fill is complete.

The key components of gaseous HRSs are:

- electrolyser (for onsite production only, includes water treatment)
- pipeline delivery (occasionally used in USA, not used in Australia)
- tube trailer or ISO module supply and optional storage
- compressor
- storage vessels and accumulator or buffer, sized to suit demand and offtake profile
- chiller with heat exchanger
- dispenser, 700 bar and/or 350 bar.

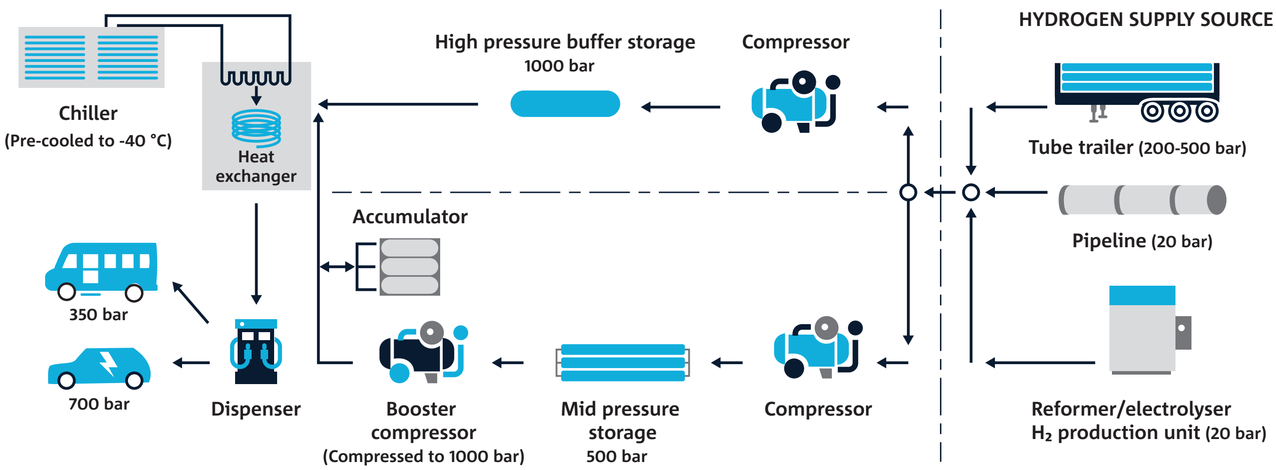


Figure 36. Key components for a compressed hydrogen refuelling station[104]

102 California Governor's Office 2020, Hydrogen Station Permitting Guidebook

103 NREL & Sandia Laboratories 2015, H2FIRST Reference Station Design Task/

104 Argone National Laboratory, Hydrogen Refuelling Station Analysis Model, accessed August 2022 from https://hdsam.es.anl.gov/index.php?content=hrsam

### A2.1.2 Liquid hydrogen storage with gaseous dispensing

At higher turnover sites, storing hydrogen as a liquid may be viable, with it being pumped into cryogenic storage from a delivery tanker. Thereafter it can be pumped to an evaporator and onto compressed storage, as shown in Figure 37. Some manufacturers offer configurations that pump hydrogen directly from the evaporator to the dispenser ('Direct' path in Figure 37), eliminating the chiller and second heat exchanger resulting in lower capital and operating costs. In such configurations the number of back-to-back fills is only limited by the quantity of $L_{H2}$ on hand.

Cryogenic storage tanks are available in a variety of configurations and sizes, and unlike for GH2, cryogenic tanks may be buried, reducing footprint and increasing site layout flexibility. Refuelling stations that convert onsite stored liquid hydrogen to gaseous for vehicles usually do not vaporise the hydrogen until the refuelling process begins.

The key components for HRSs that receive and store liquid hydrogen, and then dispense gaseous hydrogen are:

- cryogenic liquid hydrogen storage, up to 4.8 tonne
- cryogenic pump
- storage vessels (cryogenic/insulated)
- vaporiser / heat exchanger
- dispenser, 700 bar shown and/or 350 bar.

### A2.1.3 Liquid hydrogen storage and liquid dispensing

Currently there are no commercially-available FCEVs that use liquid hydrogen (though some are in development), thus there are no refuelling stations that dispense liquid hydrogen. The set-up is expected to be relatively straight forward, comprising a cryogenic tank, pump and lines, no requirement for chilling, compression or buffer storage, as shown in Figure 37.

Hydrogen equipment OEMs are working alongside vehicle OEMs to develop $LH_2$ dispensing technology and are refining elements such as limiting boil-off, nozzle connections, hoses and break away couplings.

Current vehicle OEM development is focussing on deployment in heavy and medium duty vehicles, with none indicating use within light duty or passenger vehicles.

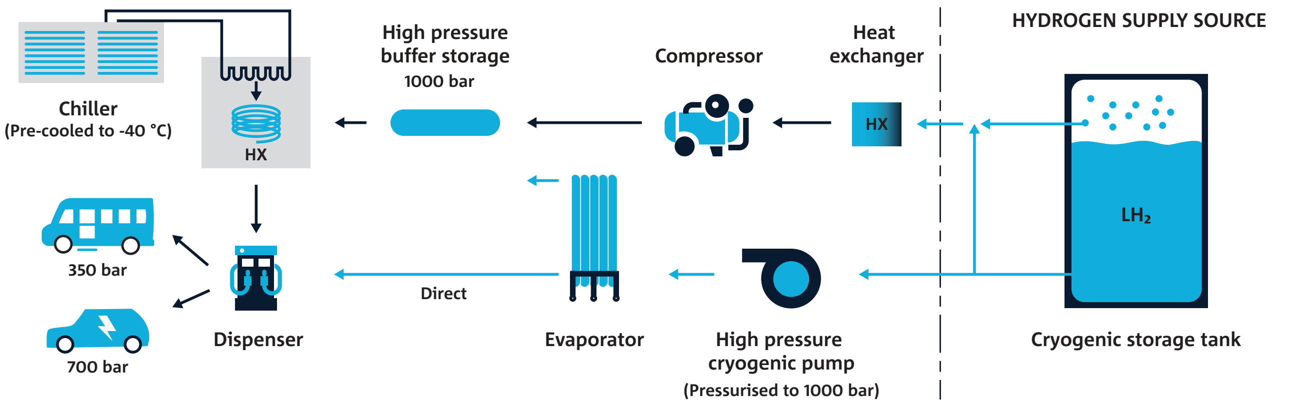


**Figure 37. Key components for a liquid hydrogen refuelling station**[105]

105 Argone National Laboratory, Hydrogen Refuelling Station Analysis Model, accessed August 2022 from https://hdsam.es.anl.gov/index.php?content=hrsam

## A2.1.4 Dispensers

Gaseous hydrogen dispensers typically resemble traditional fuel (petrol, diesel and CNG) dispensers in both appearance and operation. Current designs include similar features such as valving, high pressure break-aways, hoses, nozzles, flow metering, control electronics, a customer interface (point of sale system), and are equipped to dispense at either 350 or 700 bar.

Some dispensers are offered as stand-alone units and can be installed on dispensing islands along with traditional fuels or at a dedicated hydrogen fill stand. Some OEMs incorporate dispensers into modularised refuelling packages.

Dispensers for refuelling light vehicles to 700 bar, fill at a rate of around 1 kg per minute, but only if the gaseous hydrogen is cooled to minus 40°C in accordance with J2601, called 'fast fill'. Dispensing into a 350 bar HD FCEV tank, requires less cooling, at around -20°C, but can fill at higher rates, up to 2.5 to 7 kg/min due to the lower tank pressure and larger volumes.

HRSs installed globally are typically capable of dispensing 100 to 2,500 kg per day. Facilities usually have one nozzle operational for smaller sites and up to four nozzles for larger ones (large facilities are based on 5 kg fills for LDVs, 30 kg fills for MDVs, and 60 kg fills for HDVs[106]).

Fill time is an important operational metric in determining the value proposition of HRSs and FCEVs. Refuelling station utilisation is defined as the ratio of hydrogen dispensed to the station nameplate capacity (daily). Actual daily usage may exceed a station's nameplate capacity, as that capacity is not necessarily a physical limit and is not defined uniformly across all stations. High station utilisation is also an important indicator of the economic viability of the hydrogen station (demonstration of meeting demand), whilst lower utilisation indicates the capacity to serve more vehicles.

## A2.1.5 Modular systems

Many hydrogen equipment manufacturers offer solutions that aggregate individual components of a refuelling station into a single structure, often based on a 20 ft or 40 ft ISO shipping container-style structure, Figure 38.

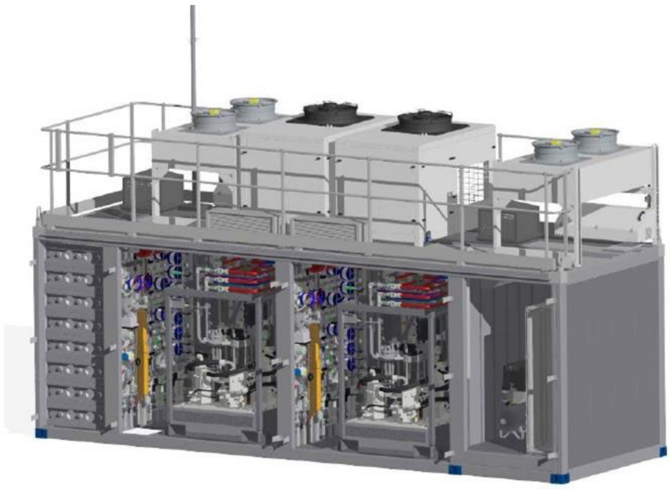

**Figure 38. Modularised hydrogen system (reproduced with permission from Linde)**

Compliance with ISO dimensions facilitates transport and deployment. Such packages are useful in applications with limited space as they reduce the footprint and can be scaled up if required. Off-the-shelf packages range in refuelling capacity from as low as 2 to 3 LDV per day up to >75 LDV per day at 700 bar. Modularised packages may include a combination of:

- electrolyser (including water conditioner)
- compressor
- cooling block
- chiller
- storage
- control electronics
- dispenser.

106 H2Mobility, 08/2021, Overview Hydrogen Refuelling For Heavy Duty Vehicles

In some cases, a dispenser is included in the container, but more frequently it is installed as a free-standing unit remote from the container.

Aggregating components into modular packages reduces the cost of installation and is an effective way for the OEM to manage quality. Additionally, such packages may be shipped & constructed at lower cost when produced in high volume using standardised components. Research undertaken by NREL show that the primary savings associated with modularised hydrogen refuelling systems are in the installation costs[107].

## A2.2 Site layout considerations

### A2.2.1 General considerations

The layout of a hydrogen refuelling station is similar in most respects to that of a traditional petrol/diesel service station, as shown in Figure 39. Stations must be safe for customers to access, intuitive to operate, have good visibility, optimise vehicle movements, and accommodate site layout constraints such as separation distances. It is expected that the future commercial model for HRSs will need to, by necessity, also incorporate BEV charging points.

Whilst components are relatively standard, configuration and layout will vary, so development of Standard Layouts will have limited value. Some hydrogen refuelling stations are dedicated facilities, while others are co-located with either a traditional service station or an industrial plant. Either way, the configuration and layout are subject to the following considerations:

- for onsite hydrogen production space and suitable electricity supply are required for an electrolyser
- for offsite hydrogen production, the site needs to allow for delivery tankers to manoeuvre on site
- demand or offtake profile (number and size of fills within a nominated period), which impacts:
  - storage capacity and configuration
  - compressor size
  - chilling capacity
  - power demand
  - space requirement
  - number of dispensers
- hazardous areas
- proximity to BEV recharging points
- emergency responder access
- maintenance requirements, especially access
- the facility location – in a densely populated urban or industrial environment, or a rural area. This is a key consideration during early design and will heavily influence the outcomes of fire studies or the requirement for mitigation measures such as fire or blast walls, particularly in urban areas.

Other broader considerations include:

- existing site layout and proximity of storage tanks, chiller and compressors to property boundaries, existing onsite buildings, and operations
- traffic and pedestrian movements
- equipment footprint and space for hydrogen deliveries
- setbacks from property boundaries
- separation distances between items of hydrogen equipment and to other equipment, activities or structures, both on and off site
- separation distance to other fuel (petrol, diesel and LPG) assets such as vents, fill points, tanks and dispensers
- travel paths for customers and delivery vehicles
- use of modular self-contained kits
- storage configuration – cascade, bulk and buffer, tube trailer – static, or trailer-swap.

107 Hecht, E.S. and J.Pratt 2017, Comparison of conventional vs. modular hydrogen refuelling stations, and onsite production vs. delivery. Sandia National Laboratories Report SAND2017-2832

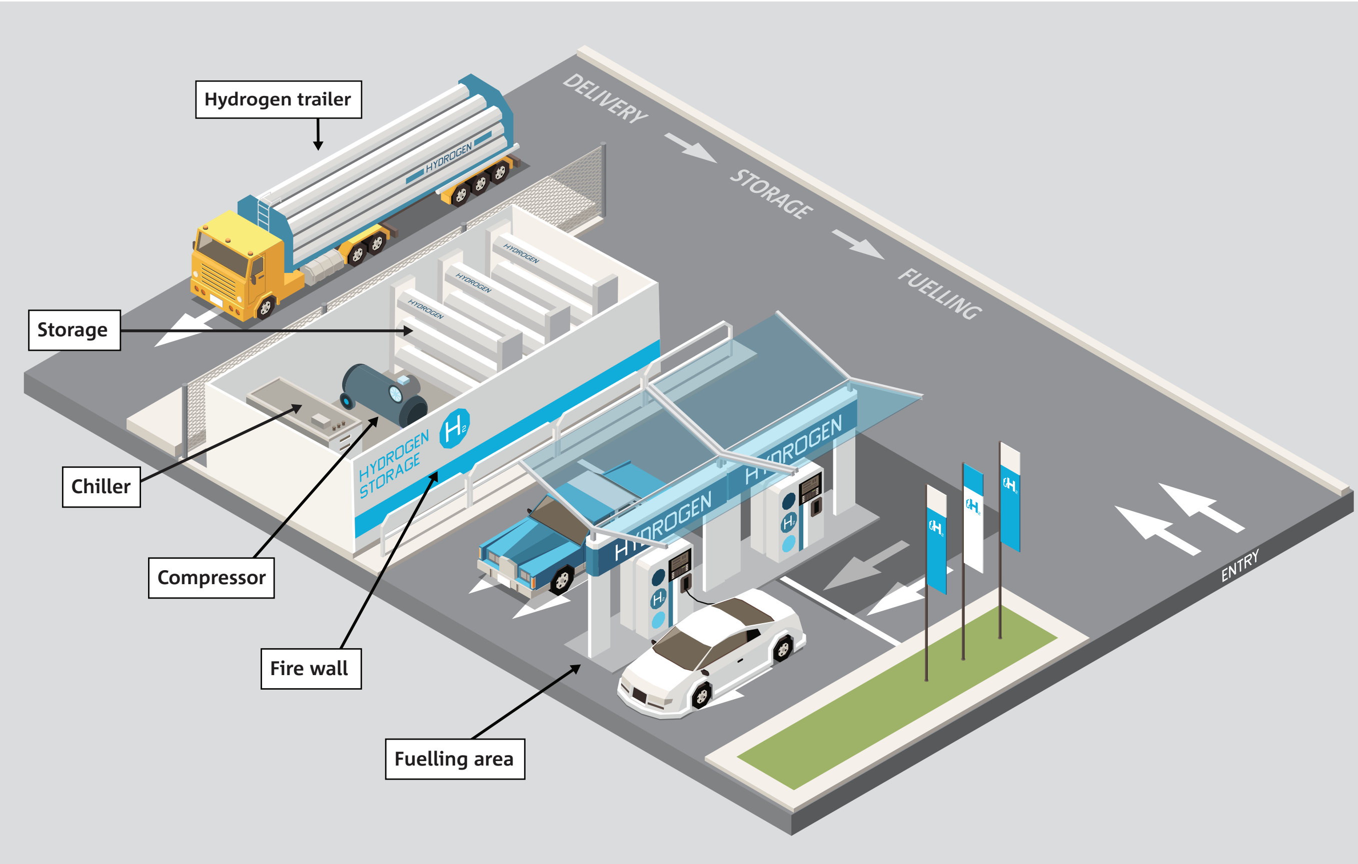


**Figure 39. Hydrogen refuelling co-located with traditional service station**[108]

## A2.2.2 Hazardous areas

Hydrogen storage and handling equipment generate hazardous areas, zones that surround potential release points or sources of hydrogen gas that may cause an explosive atmosphere. They are classified by likelihood of occurrence and inform selection of electrical equipment, refer AS/NZS IEC 60079.10.1:2022 *Classification of areas – Explosive gas atmospheres* and *Supplement 1* to AS/NZS IEC 60079.10.1:2022. All electrical devices within the hazardous area of the hydrogen refuelling equipment, or of equipment associated with other fuels or chemicals on site such as petrol or LPG, must be rated for use within the hazardous area in accordance with the AS/NZS IEC 60079 series of standards.

Supplement 1 to AS/NZS IEC 60079.10.1:2022 includes specific examples of hazardous areas associated with hydrogen storage and handling equipment, but there are gaps in areas like dispensing. The UK Energy Institute document *Guidance on hydrogen delivery systems for refuelling of motor vehicles, co-located with petrol fuelling stations*, *Supplement to the Blue Book*, March 2017 includes some guidance on hazardous area zone classification that may inform designers, Figure 40. This document is not referenced in Australian Standards or legislation, however the AS/NZS IEC 60079 services provides a framework for calculating hazardous areas from first principles.

108 ISO 19880.1 Gaseous Hydrogen-Fuelling stations – Part 1: General requirements

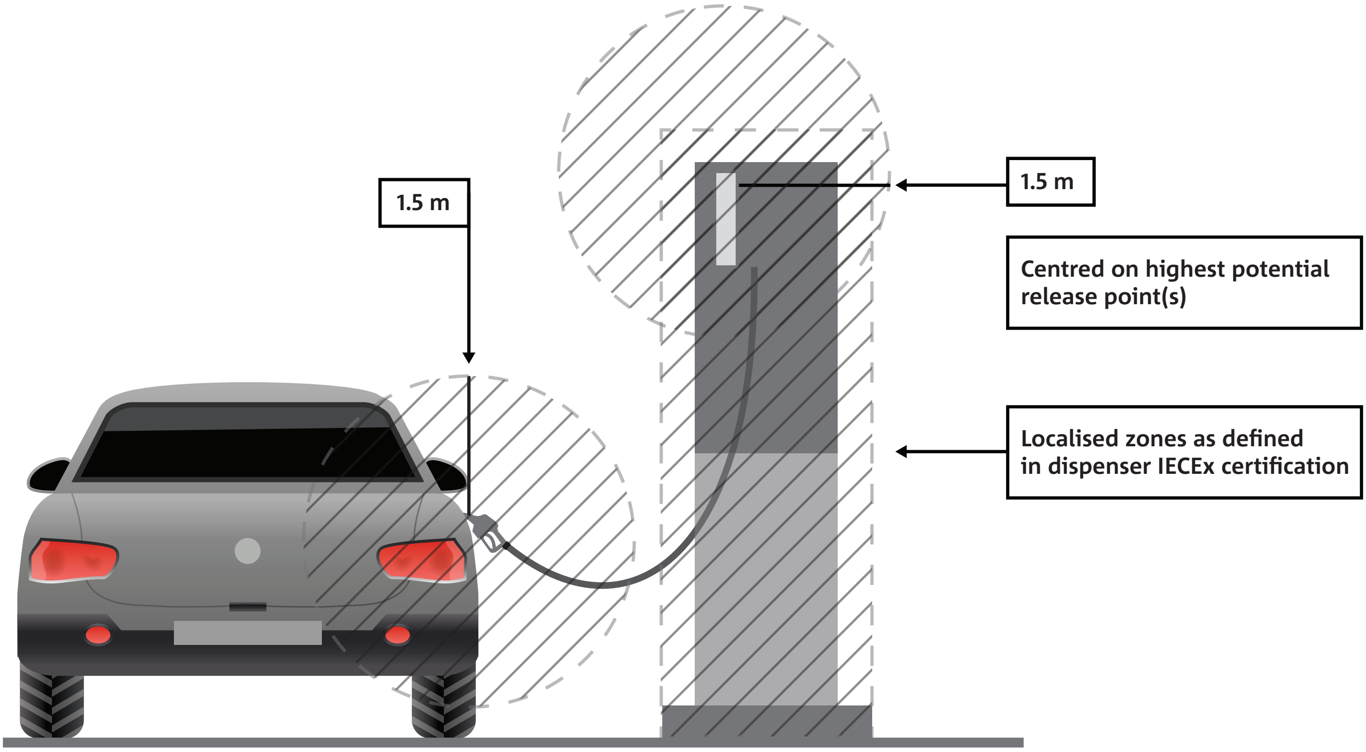


Figure 40. Hazardous Area zone classification for a hydrogen dispenser when refuelling[109]

### A2.2.3 Separation distances

A key refuelling station design objective is to minimise the impact of a fire from one piece of equipment on another, be that hydrogen related or not. Separation distances specify the minimum distance between nominated hydrogen equipment and people, structures or other fuel equipment that may be impacted. They are specified to protect equipment that handles or stores hydrogen from fires elsewhere, on or off the site, and to protect people, other fuels and buildings from hydrogen equipment fires.

Separation distances for petrol, diesel, LPG and CNG refuelling are documented in relevant Australian Standards, but not yet for hydrogen refuelling, although they are expected in 2023. ISO 19880-1:2020 Gaseous hydrogen — Fuelling stations —Part 1: General requirements provides guidance on calculating separation distances and is expected to be adopted as an Australian Standard with minor changes in 2023.

More precise guidance is provided in the new Standards Australia Technical Specification 5359:2022The Storage and Handling of Hydrogen, released in 2022. It includes examples of separation distances based on radiant heat modelling and dispersion analysis. Ultimately however, such guidance is just that, and selecting and arranging equipment needs to be supported by a fire study and quantitative risk assessment to identify and mitigate risk using a variety of measures including distance.

109 Guidance on hydrogen delivery systems for refuelling of motor vehicles, co-located with petrol fuelling stations, Supplement to the Blue Book, Energy Institute, London, March 2017

# A.3 Australian experience to date

This appendix sets out:

- some of the funds and initiatives of Australian governments aimed assisting the development of HRSs (Table 45)
- hydrogen refuelling stations currently operational in Australia (Table 46)
- hydrogen refuelling stations under development and planned for Australia (Table 47).

**Table 45. Hydrogen Refuelling Funds and Initiatives**

| Initiative | Sponsors | Funding | Key objectives / description |
|---|---|---|---|
| Future Fuels Fund | State and Federal governments | $250 million | To establish a series of demonstration hydrogen refuelling and production facilities across Australia, consistent with the approach for hydrogen in transport agreed to in the National Hydrogen Strategy. Supporting the demonstration of refuelling infrastructure is aimed at lowering the risk for private investors seeking to invest in FCEVs as they become more widely available. |
| Hume Hydrogen Highway | NSW and VIC governments | $20 million | Aimed at supporting the design and delivery of at least four HRSs along the Hume Highway, between Melbourne and Sydney, along with around 25 hydrogen-powered long-haul freight vehicles. |
| Queensland Hydrogen Super Highway | QLD Government (Department of Energy and Public Works) | Up to $35 million | Aimed at driving an expansion of the use of hydrogen in the road transport sector with the establishment of an initial six refuelling stations along the State's heavy haulage transport routes.<br>Aimed at decarbonising the state's main heavy haulage routes |
| East Coast Renewable Hydrogen Refuelling Network | VIC (DELWP), NSW and QLD governments | NA | Supported by tri-state Memorandums of Understanding (MoU) this initiative aims to support the development of a hydrogen refuelling network for heavy transport and logistics along Australia's eastern seaboard, starting with the Hume Highway, the Pacific Highway and the Newell Highway. |

Table 46. Hydrogen Refuelling Stations currently operational in Australia

| Project Name and Developer | Commissioned | Capital expenditure | Capacity per day | Vehicles serviced | Funding support | Partners / contractors / production / equipment | Other |
|---|---|---|---|---|---|---|---|
| **Toyota Hydrogen Centre** Altona, Melbourne, Vic<br>**Toyota Australia** | March 2021 | $7.4m | 80 kg | 20 leased Toyota Mirai sedans, onsite forklifts | ARENA $3.07m | Onsite 200 kW electrolyser powered by 86 kW of solar panels<br>100 kW of battery storage and grid electricity<br>Hydrogen stored in a bank of storage tubes at low and high pressure | 30 kW fuel cell also being installed to convert hydrogen back into electricity to power the site if needed |
| **ActewAGL Hydrogen Refuelling Station** Fyshwick, Canberra, ACT<br>**ActewAGL** | March 2021 | NA | 22 kg | 20 Hyundai NEXOs leased to the ACT Government<br>Limited public access | ACT Government | ActewAGL, ACT Government, Hyundai, SG Fleet ENGV<br>Nel 0.075 MW PEM electrolyser<br>PDC Machines and Ivys compression and refuelling solution | Onsite electrolysis using grid electricity<br>Three storage tanks can hold 44 kg of hydrogen |
| **BOC Renewable Hydrogen Production and Refuelling Project** BP Truck Stop at Port of Brisbane | Early 2023 | $5.5m | 80 kg | Queensland Government is trialling five Hyundai NEXOs<br>Private, light, BOC's industrial customers | ARENA $1.11m<br>BOC $3.20m<br>Other sources $0.23m | 220 kW PEM electrolyser at BOC's Bulwer Island facility, supplied by UK-based company ITM Power powered by a 100 kW solar PV array | The HRS will be upgraded to support heavy transport trucks as part of the East Coast hydrogen highway |
| **Hyundai Hydrogen Refueller** Macquarie Park, Sydney, NSW<br>**Hyundai** | 2023 | $1.7m | 20 kg | Private, light and forklifts, Hyundai NEXOs | NA | US-based PDC Machines and IVYS Energy Solutions to supply the hydrogen refuelling station, known as SimpleFuelFast, with ENGV responsible for local integration, installation and ongoing operational services<br>Onsite electrolyser | Located at Hyundai's corporate headquarters<br>Will replace Hyundai's existing HRS |
| **Hydrogen Refueller Station Project** Perth, WA<br>**ATCO Gas Australia and Fortescue Metals Group** | Dec 2022 | NA | 63 kg (based on electrolyser capacity) | Fleet of Toyota Mirai sedans made available to ATCO and Fortescue | $1m WA Government Renewable Hydrogen Fund | ATCO will use its existing 260 kW PEM electrolyser | Located at ATCO's Clean Energy Innovation Hub at its Jandakot Operations Centre in Perth |

Table 47. Hydrogen Refuelling Stations under development and/or planned for Australia

| Project Name and Developer | Planned opening | Capital expenditure | Capacity per day | Vehicles serviced | Funding support | Partners / contractors / production / equipment | Other |
|---|---|---|---|---|---|---|---|
| **Tarcutta Hume Highway Refuelling**<br>Tarcutta, NSW<br>**Hydrogen Fuels Australia CLARA Energy** | 2025 | $500m | 25,000 kg (Stage 1), 100,000 kg after two further stages | Capacity to service 200 HD trucks per day, and 800 from further stages | Unknown | MoU between H2FA and CLARA to develop five HRSs between Melbourne and Sydney<br>Behind-the-meter PV solar array<br>CLARA Energy to develop hydrogen production capacity<br>H2FA to act as distributor and HRS operator | Further plans for HRSs in Epping and Seymour in VIC and Southern Highlands and Sydney in NSW |
| **New Energies Service Station**<br>Geelong, VIC**,**<br>**Viva Energy Australia** | Early 2024 | $43.4m | Up to 850 kg | Toll Group, ComfortDelGro Corporation Australia, Cleanaway and Barwon Water to procure 15 FCEV prime movers, buses, and wastewater and waste collection vehicles from Hyzon and ARCC | $22.8m grant from ARENA's Advancing Renewables Program<br>$1m from Vic Government's Renewable Hydrogen Commercialisation Pathways Fund | Onsite 2 MW electrolyser using recycled water from nearby water plant<br>Station to include 150 kW BEV recharging and traditional diesel refuelling infrastructure | To be located at Viva's Geelong petroleum refinery<br>Will use recycled water from Barwon Water's Northern Water Plant<br>To be begin as a back-to-base operation, but planned to be part of a Viva network of HRSs on Australia's east coast |
| **Green Hydrogen for City of Cockburn**<br>Perth, WA<br>**City of Cockburn** | TBC | $24.0m | 440 kg | Waste collection and light vehicle fleets | Feasibility study, $325,000, funded by:<br>WA Government Renewable Hydrogen Fund, $149,000<br>City of Cockburn, $176,000 | Stage 1: Onsite 1.25 MW electrolyser powered by a 1.2 MW solar array | Feasibility study only |
| **SunHQ Hydrogen Hub**<br>Townsville, QLD<br>**Ark Energy** | Late 2022 | $13.1m for Phase 1 (electrolyser, storage, compression) | 433 kg | Five 140 tonne Hyzon HD FCEVs for Townsville Logistics to operate between Sun Metals Zinc Refinery and the Port of Townsville, a 30km round trip | ARENA $3.02m<br>CEFC $12.50m<br>QLD Government $5.00m | Plug Power supplying 1 MW PEM electrolyser with behind-the-meter connection to co-located 124 MW solar array<br>GPA Engineering as Owner's Engineer | |

| Project Name and Developer | Planned opening | Capital expenditure | Capacity per day | Vehicles serviced | Funding support | Partners / contractors / production / equipment | Other |
|---|---|---|---|---|---|---|---|
| **Hydrogen Refueller Station Project**<br>Perth, WA | Second half 2024 | $2m | 235 kg with potential to scale up to 800 kg | Private heavy and light | Western Australian Government Hydrogen Fuelled Transport Program, $10m<br>Matched funding from Woodside Energy | Hydrogen Refueller $H_2$ Perth<br>2 MW electrolyser powered by renewable electricity from South West Interconnected Systems (SWIS) | |
| **Christmas Creek Renewable Hydrogen Mobility Project**<br>Christmas Creek, WA<br>**Fortescue Metals Group** | Late 2022 | $32.0m | 180 kg | 10 full-sized HYZON coaches to replace the existing fleet of diesel coaches | Western Australian Government Renewable Hydrogen Fund (capital works project) $2m | BOC to supply two 700 kW ITM electrolysers<br>Electricity from nearby 50 MW Chichester Solar Gas Hybrid Project<br>ITM Power | |
| **Renewable Hydrogen Production and Refuelling Project**<br>Brisbane, QLD | Late 2022 | $5.54m | 80 kg | Private and public, heavy and light | $1.1m ARENA<br>$3.2 million BOC<br>$0.2m Other sources | 220 kW PEM electrolyser powered by 100 kW solar array<br>ITM Power | |
| **Hydrogen Fuels Australia Truganina HRS**<br>Truganina, VIC<br>**Hydrogen Fuels Australia (HF2A)** | 2023 | | 60-90 kg<br>Ultimately 6,500 kg | Public light | | Green Hydrogen Systems A/S to provide onsite 432 kW Alkaline electrolyser supported by a 640 kW solar array<br>Hydrogen storage tanks (300 kg capacity onsite, and 900 kg transported in)<br>Skai Energies and Nilsson for energy control system | |
| **Hyundai Refuelling Centre**<br>Sydney, NSW<br>**Hyundai** | Late 2022 | | 20 kg | Private light vehicles and company fleet | | Onsite electrolyser<br>PDC Machines and IVYS Energy Solutions for equipment<br>ENGV for integration, installation and ongoing service | |
| **CSIRO Hydrogen Refuelling Station**<br>Clayton, VIC<br>**CSIRO** | Mid 2023 | $2.3m | 20 kg | Leased Toyota Mirai | $11m Swinburne University Victorian Hydrogen Hub ($VH_2$), $1.3m CSIRO | Onsite electrolyser powered by onsite solar panels<br>ENGV is supply the station using kit from its US partners, PDC Machines and IVYS Energy Solutions | Demonstration project |

| Project Name and Developer | Planned opening | Capital expenditure | Capacity per day | Vehicles serviced | Funding support | Partners / contractors / production / equipment | Other |
|---|---|---|---|---|---|---|---|
| **Frontier Energy Hydrogen Refuelling Station**<br>Perth, WA<br>**Frontier Energy Ltd** | 2023 | unknown | 20 kg<br>at 700 bar | Public light | unknown | ENGV for integration, installation and ongoing service<br>Onsite PEM electrolyser using renewable electricity<br>PDC Machines and IVYS Energy Solutions for equipment | Frontier aims to eventually roll-out a hydrogen highway across WA, backed by a government focus on renewable hydrogen as an alternative to diesel. |
| **Hyzon Motors Green Hydrogen Refuelling Depot**<br>Noble Park, VIC<br>**Hyzon Motors Australia** | Late 2023 | unknown | Unknown | Hyzon towing vehicles for RACV subsidiary, Nationwide Group | unknown | In part from onsite solar generation and grid electricity powered electrolyser<br>RACV<br>ENGV | Frontier aims to eventually roll-out a hydrogen highway across the state, backed by a government focus on renewable hydrogen as an alternative to diesel. |
| **Port Kembla Hydrogen Refuelling Facility**<br>Port Kembla, NSW<br>**Coregas (part of Wesfarmers)** | Early 20230 | | NA | Two Hyzon Hymax-450 FCEV prime movers | $0.5m Port Kembla Investment Fund | Using existing hydrogen production facility within neighbouring BlueScope steel works<br>Equipment provider - Haskel Hydrogen Systems Group | Coregas is developing the HRS adjacent to its Port Kembla hydrogen production plant |
| **Warrnambool Hydrogen Mobility Project**<br>Hycel Technology Hub<br>Warrnambool, VIC<br>**Warrnambool Bus Lines** | Late 2023 | The Hycel Technology Hub is part of Deakin's $23m hydrogen research and innovation program | NA | 12 buses servicing the Warrnambool, Port Fairy and Allansford area in South West Victoria | $9m from Victorian Government | Deakin University<br>Air Liquide Australia's role includes hydrogen production, compression and the provision of storage and hydrogen refuelling equipment<br>Hyzon - air filtration<br>PACCAR - fuel cell trucks | The project will be based at a dedicated site co-located with the Hycel Technology Hub at Deakin University's Warrnambool campus, directly adjacent to the Princes Highway road and rail freight corridor |
| **Total capacity** | | | 27,401 – 136,807+ kg | | | | |

# A.4 International experience with HRSs

## A.4.1 Overview

Globally, 80% of HRSs are located in five jurisdictions, being California, China, Germany, Japan and South Korea. These states and countries are major automobile manufacturers.

Key themes and issues for consideration in an Australian context, include:

- regulatory and legislative support
- financial support
- station configuration
- equipment
- supply and demand of hydrogen.

Given the realities of developing large-scale infrastructure of this type and from consultation with local stakeholders, it is clear that the above issues will feature prominently in Australia's continued activities in the rollout of HRSs. Understanding how foreign counterparts have interacted with these issues is important.

In summary, key takeaways for Australia are:

- establishment of regulations and standards is vital in creating supply chains and reliability of equipment for retailers and consumers
- financial support from a range of organisations along the supply chain is vital for early development
- offsite production configurations are likely to dominate in future
- domestic knowledge of equipment is vital to decrease 'nozzle downtime'
- coordination is required with producers to match supply and demand.

## A.4.2 Regulatory and legislative support

Recurring regulatory and legislative support measures feature in the most developed hydrogen refuelling networks. These being:

- overarching national legislation/strategy for hydrogen use as a transport fuel
- vehicular emissions reduction requirements.

Internationally, the most impactful driver of hydrogen refuelling development is ambitious carbon reduction policies. The perspectives of stakeholders engaged to inform this report, from both fuel retail and automotive industries, agreed that regulatory requirements to reduce emissions and eventual phase out ICE vehicles are the catalyst for the transition to alternative fuels such as hydrogen.

Since road transport has been identified as a relatively 'easy-to-abate' sector, governments around the world have focussed significant carbon reduction efforts on road transport. According to transport sector stakeholders, fossil-fuel vehicles and related infrastructure are anticipated to be unviable within 20 years overseas, due to aggressive decarbonisation targets, and this will have significant consequences for both low-emissions vehicle uptake and the establishment of refuelling networks.

### Lessons for Australia

At the higher level, effective policy positions have resulted in successful regulatory and legislative introductions being embedded in jurisdiction climate and decarbonisation strategies, providing a line of sight to the operational elements (common across all jurisdictions). At the operational level, the use of regulation and legislation in developing FCEVs and refuelling infrastructure, in the most progressive jurisdictions, has been primarily centred around removing barriers for car manufacturing and boosting the uptake of vehicles. This can also be heavily attributed to California, China, Germany, Japan and South Korea all having significant automotive industries. This approach may not be entirely transferable to the Australian context[110].

110 Cars are the most imported product in Australia, coming from Japan, South Korea, Germany, Thailand, and the USA.https://oec.world/en/profile/bilateral-product/cars/reporter/aus

However, the considerations given to developing refuelling stations such as BEV percentage share requirements, accessible and relevant reporting requirements, and the definition of distinct hydrogen transport fuel standards[111] should definitely be adopted.

## A.4.3 Financial support

The most common and pertinent barrier to development of the hydrogen transport sector is cost, particularly where only renewable hydrogen is being considered. As a new fuel source, the development of a hydrogen market requires significant financial support to reduce the economic differential with existing options. However, being a complex area, the structuring of financial support with regard to the context (who provides, who receives, how it is implemented, where, when, etc) is critical to its effectiveness or lack thereof.

Across the jurisdictions with the most advanced networks, a recurring feature is meaningful financial support in the form of:

- **public and private funding mechanisms:** large public and private funding underpins the majority push for financial support across most jurisdictions, with allocated funds deriving from implementation of regional Hydrogen Strategies; and/or
- **tax incentives for consumers and business to adopt hydrogen fuel:** tax policy can be an effective instrument to incentivise switching from fossil fuels to new energy carriers. Instead of providing positive incentives via financial support ('carrot'), it can sometimes be more effective to implement the proverbial ('stick') through taxation. This can be deployed through three mechanisms: carbon tax, emissions trading scheme (ETS) and increased fossil fuel taxation.

The tables below outline the financial and tax support mechanisms in the mentioned jurisdictions.

### Lessons for Australia

Learning from overseas experience, Australia can evaluate the possibility of:

- establishing public and private partnerships for financial support
- creating tax incentives to stimulate the pivot away from fossil fuels.

**Table 48. Financial Support Mechanisms for HFCV and HRS**

| Country | Financial support | Total funding for HRSs | $m / HRS |
|---|---|---|---|
| California | State dependent subsidies and tax rebates (ZEV program) | | |
| China | Subsidies for purchase of FCEV | | |
| | Subsidies for installation of new refuelling stations | +$300m for 146 | $ 2.05 |
| Germany | Subsidy for purchase of FCEVs | | |
| | Direct capital expenditure/operating expenditure funding for HP onsite, subsidy for operation of HP delivered and 50% capital expenditure tax right-off for LP onsite | $118m for 107 | $ 1.10 |
| Japan | Subsidy for purchase for HFCV fleets including construction of refuelling infrastructure | | |
| | Subsidy for capital expenditure/operating expenditure for HP (national and regional government), subsidy for operation of HP delivered and 50% capital expenditure tax right-off for LP onsite | $640m for 166 | $ 3.86 |
| | $2.5 bn ZEV fund to build charging infrastructure | $279m for 179 | $ 1.56 |
| South Korea | Subsidies for purchase | | |
| | Direct capital expenditure/operating expenditure | $199m for 87 | $ 2.29 |

111 A particular focus should be on fuel standards given the current distinct lack of relevant standards in Australia

**Table 49. International Carbon Mechanisms**[112]

| Country | Primary mechanism | Carbon price (US$/$tCO_2e$) | Share of emissions covered (incl transport) | Revenue raised (USD m) |
|---|---|---|---|---|
| California | ETS | 17.9 | 80% | 1,698 |
| China | ETS & CT | <10 (regional variance) | 20-40% (not incl. transport) | Variable but <20 |
| Germany | ETS | 29.4 | 40% | N/A |
| Japan | CT (ETS in Tokyo & Saitama) | 2.6 | 70% (20% Tokyo & Saitama) | 2,365 |
| South Korea | ETS | 15.9 | 74% | 219 |

## A.4.4 Station configurations

How hydrogen is produced and distributed to refuelling stations has important implications for station design, scale, and cost and for the environmental benefits of hydrogen use in transportation. Geography, resources, government and industry objectives are shaping station configuration. A variety of designs have been developed overseas, with no style coming to dominate yet. Onsite and offsite production, standalone facilities and additions to existing refuelling locations all continue to be developed.

Core considerations for the development of stations include:

- onsite versus offsite production
- station location
- planning and regulatory issues around equipment and space.

### Lessons for Australia

From overseas experience of HRS configurations, the following lessons have emerged:

- offsite production is likely to be the dominate future supply chain configuration
- standards will mandate distance requirements which add cost and restrict flexibility in site selection.

## A.4.5 Supply and demand – need for a supply-driven approach

With overseas HRSs and networks, reliable availability and supply for users has been challenging due to:

- the mismatch of supply and demand due to low hydrogen production capacity for transport fuel – especially from renewable feedstocks
- the lack of operational HRS sites exacerbating shortages.

The experience in California highlights the problem of having a supply and demand mismatch, with 'nozzle downtime' – where customers are unable to fill vehicles. Initial investment saw a surplus of stations that were under-utilised. As vehicle ownership rapidly grew, stations became often unable to meet demand. Nozzle downtime could last many hours, with onsite production or a resupply from an offsite source required before service could resume.

More than half of California's stations were unavailable at times during 2020, with 10 or more of northern California's 19 stations unavailable at times in December 2020[113]. It is understood that the German and Japanese networks have experienced similar issues. For the German network there are websites that show the operational status of stations[114].

112 The World Bank 2021, State and Trends of Carbon Pricing 2021

There can be dozens of stations down (non-operational) at any given time whilst hydrogen is being produced to refill storage tanks. Given that hydrogen will compete with other fuels that have characteristics that mean 'nozzle downtime' is minimised, Australia must prepare a reliable supply network to allow the industry to thrive.

Whilst refuelling delays are frustrating for customers, the demand that is not being met on a timely basis has spurred development of increased production capacity for refuelling in California, South Korea, Germany and Japan. Stakeholders have expressed the belief that in future, hydrogen for refuelling will be a substantial market segment for production. Already, this trend is being seen to emerge. In addition to increasing reliability, the added production capacity will likely make hydrogen cheaper for end-users, given improved economies of scale.

In California, the Clean Transportation Program, a government body, is actively funding hydrogen supply projects to meet the demand. In late 2021, it funded two projects with combined capacity of 3,000 kilograms per day to service demand for transport refuelling. These are expected to be operational by 2023[115].

Additionally, the private sector is developing significant supply capacity. First Element Fuel, the main supplier of True Zero, the retailer with the most locations in the state, has recently entered into a 2,400 kg per day supply agreement with Linde's Ontario hydrogen production plant. It has also commenced building a 2,000 kg per day supply facility with Air Liquide. This supply will be used by True Zero's liquid hydrogen refuelling stations[116].

The German Government has committed 8 bn Euros to large-scale hydrogen projects[117]. This public funding came with goals of a further 33 bn Euros of private investment into the hydrogen supply chain[118]. Establishing refuelling networks and technology is a significant focus of this funding[119]. For the use of vehicles, a facility is in development that will produce over 1,350 tonnes of renewable hydrogen each year, with much of it to supply the refuelling network[120].

South Korea is undertaking several production projects aimed at supplying the refuelling network, although its hydrogen strategy does stress the importance of imports. The flagship project is a 13,000 mt/year liquid hydrogen plant in Ulsan on the country's east-coast, with much of it destined for FCEV refuelling stations[121]. Hyosung and Linde will build the plant in a partnership.

Japan has constructed one of the world's largest green hydrogen production facilities in Fukushima with capacity to produce enough hydrogen to refuel over 550 FCEVs per day. It serves as a key supplier for the refuelling stations in Japan[122].

Hydrogen supply and demand lessons for Australia include:

- hydrogen production capacity, especially from renewables, is crucial to establish before growing the network. PPP investment has been crucial in developing the added production capacity overseas
- offsite production simplifies network development.

113 Joint Agency Staff Report on AB 8: 2021 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in Californiaz

114 H2.LIVE: Hydrogen Stations in Germany & Europe

115 Joint Agency Staff Report on AB 8: 2021 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California

116 Joint Agency Staff Report on AB 8: 2021 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California

117 https://www.nasdaq.com/articles/germany-to-invest-around-%2410-bln-in-hydrogen-projects-2021-05-28#:~:text=Germany%20will%20invest%20more%20than%208%20billion%20euros,alternative%20to%20fossil%20fuels%20to%20meet%20climate%20targets.

118 Germany's Hydrogen Industrial Strategy | Center for Strategic and International Studies (csis.org)

119 Germany's Hydrogen Industrial Strategy | Center for Strategic and International Studies (csis.org)

120 One of Germany's Largest Hydrogen Generation Plants Breaks Ground (process-worldwide.com)

121 South Korea pushes energy transition dream with liquid hydrogen plant plan | S&P Global Commodity Insights (spglobal.com)

122 Fukushima powers up one of world's biggest hydrogen plants - Nikkei Asia

### A.4.6 Equipment

The equipment required to operate hydrogen refuelling stations presents potential challenges as much of the technology is relatively novel for existing fuel retailers and consumers in Australia. From stakeholder engaged for this report articulated that a lack of:

- experience in equipment manufacture means quality and reliability is low relative to existing refuelling equipment
- standards and regulations mean refuelling station developers have added uncertainty around quality and safety
- domestic service and maintenance knowhow has led to equipment being out of service for long periods.

Whilst Original Equipment Manufacturers (OEMs) have been producing hydrogen refuelling equipment for a number of years, use of that equipment by retailers is comparatively early stage. Issues with the use of equipment such as defective software in dispensing units, compressor problems, purging and venting issues, tubing/fitting/hose failure and delivery methods are examples[123] of how equipment is not yet mature and causing negative consumer experience.

For most retailers, the equipment is also imported from overseas, which means there is often inadequate domestic knowledge for repairs and servicing. According to a stakeholder, hydrogen dispensing units in Japan have been unusable for months as a qualified repairperson had to be flown in from Europe to fix what should have been a relatively trivial issue. Stakeholders have also advised in California, especially during the early rollout, equipment would frequently malfunction. Often, it would be a relatively simply item such as a nozzle or hose. Consumers react very negatively towards interruptions given the availability and reliability they have come to expect when refuelling with hydrocarbon fuels.

#### Lessons For Australia

From experience of equipment overseas, rollout of HRSs in Australia would be assisted by:

- establishing or adopting overseas standards for equipment and maintenance
- exploring opportunities for domestic manufacture of refuelling equipment (potentially for both local and export markets).

123 Hydrogen Incident Examples, Select Summaries of Hydrogen Incidents from the H2tools.org Lessons Learned Database

# A.5 Stakeholder consultations

| | |
|---|---|
| ACT Government's Treasury and Economic Development Directorate | A department of the Government of Australian Capital Territory |
| ActewAGL | Joint venture of Australian Gas Light Company (AGL) and Icon Water Ltd (formerly ACTEW Corporation), an ACT Government-owned corporation. |
| Aerzen | A German founded manufacturer of blowers and screw compressors |
| Air Liquide S.A. | French multinational industrial gas, chemical and electronics manufacturer |
| Ampol Ltd | Australian gas and petroleum retailer, primarily through a chain of service stations |
| ARENA | Australian Renewable Energy Agency, part of the Australian Federal Government |
| ARK Energy Group | Australian based energy retailer and supplier |
| BOC Ltd | Multinational British-based industrial gas company, now part of Linde plc |
| BP plc | British oil and gas company |
| Chart Industries | A global manufacturer of highly engineered cryogenic equipment servicing multiple application in the clean energy and industrial gas markets |
| Coregas | An Australian manufacturer and distributor of industrial gases |
| Daimler | Daimler Truck, a subsidiary of Daimler AG, based in Germany |
| DELWP | Victorian Government's Department of Environment, Land, Water and Planning (now Department of Energy, Environment and Climate Action) |
| DISER | Australian Department of Industry, Science, Energy and Resources (now Department of Climate Change, Energy, the Environment and Water) |
| Engie | French-based multinational company, operating in the fields of energy transition, electricity generation and distribution, natural gas, renewable energy and petroleum |
| Hyundai | Hyundai Motor Company Australia |
| Linde plc | UK-based chemical company |
| PACCAR Inc | US-based public company that manufacturers medium and heavy-duty trucks |
| Toyota Motor Corporation | Japanese multinational automotive manufacturer |
| Standards Australia | Primary non-government standards developer in Australia |
| Viva Energy Australia | Exclusive Australian licensee of Shell plc |

# A.6 Directory of parties referenced

| | |
|---|---|
| ActewAGL | A joint venture of Australian Gas Light Company (AGL) and Icon Water Ltd (formerly ACTEW Corporation), an ACT Government-owned corporation. |
| Air Liquide S.A. | A French multinational industrial gas, chemical and electronics manufacturer |
| AGL Energy Ltd | Australian listed public company involved in the generation and retailing of electricity and gas for residential and commercial use |
| ARCC | Australian-based manufacturer, Aluminium Revolutionary Chassis Company |
| ARK Energy Group | Australian based energy retailer and supplier |
| Barwon Water Corporation | Victorian Government-owned corporation that operates the water supply system in the region in and around Geelong, Victoria |
| BOC Ltd | Multinational British-based industrial gas company now part of Linde plc. |
| BP plc | British oil and gas company |
| CaetanoBus | Portuguese manufacturer of electric and hydrogen buses |
| Chevron Corporation | An American multinational corporation, working primarily in oil and gas |
| Cleanaway | Australian based industrial and residential waste disposal and handling company |
| CO2 Cooperative Research Centre | Industry-led research organisation, supported by Australian Government's Cooperative Research Centres Program, to research and demonstrate CCS technology |
| ComfortDelGro | Multinational land transport company listed on the Singapore Stock Exchange |
| Daimler Truck | Subsidiary of Daimler AG of Germany, one of the world's largest manufacturers of commercial vehicles - light, medium and heavy-duty trucks, city and intercity buses, coaches and bus chassis |
| Dalian Institute | Dalian Institute of Chemical Physics, Chinese Academy of Sciences located in Dalian, China |
| ENGV | Australian full-service provider in all areas of gas storage, vehicles and transport |
| Foton Mobility | Distributor of Foton New Energy vehicles, a subsidiary of BAIC Foton Motor Co. Ltd of Beijing, China |
| Frontier Energy | An energy consulting and research company |
| Future Fuels Cooperative Research Centre | Industry-led research organisation supporting Australian energy sector transition to low carbon fuels |
| Gloyer-Taylor Laboratories | US-based technology company (GTL) |
| H2USA | Public-private partnership promoting the introduction and widespread adoption of FCEVs across America |
| Hanwha Cimarron | South Korean manufacturer of large-scale hydrogen tube trailers, based in the USA |
| Hydrogenious | Manufacturer of containerised conversion equipment to liquid organic carrier |
| Honda Motor Co Ltd | Japanese automotive manufacturer |
| Hyundai | Hyundai Motor Company Australia |
| Hyzon Motors Inc | US-based hydrogen commercial vehicle manufacturer |
| IVYS Energy Solutions | US-headquartered clean fuels infrastructure provider for fleet applications |
| Linde plc | UK-based chemical company |

| | |
|---|---|
| NERA | National Energy Resources Australia |
| Nikola | Public company based in USA manufacturing zero emissions vehicles |
| Origin Energy | ASX-listed public company, a major integrated electricity generator, and electricity and natural gas retailer |
| PDC Machines | Designer and manufacturer of high-pressure diaphragm compression systems |
| Riversimple Movement Ltd | UK-based manufacturer of FCEVs |
| Santos Ltd | Australian oil and gas exploration and production company, based in Adelaide, South Australia. |
| Shell plc | British multinational oil and gas company |
| Shenergy Group Company Limited | Chinese state-owned enterprise, principally in electricity, petroleum and natural gas investments in Shanghai and Eastern China regions |
| Standards Australia | Primary non-government standards developer in Australia |
| Stanwell Corporation | Queensland Government-owned corporation, the state's largest electricity generator and Australia's third-largest greenhouse gas emitter |
| Toll Group | Australian-based subsidiary of Japan Post Holdings, providing logistics |
| Toyota Motor Corporation | Japanese multinational automotive manufacturer |
| UK Energy Institute | Professional organisation of engineers in energy-related fields |
| Viva Energy Australia | Exclusive Australian licensee of Shell |

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