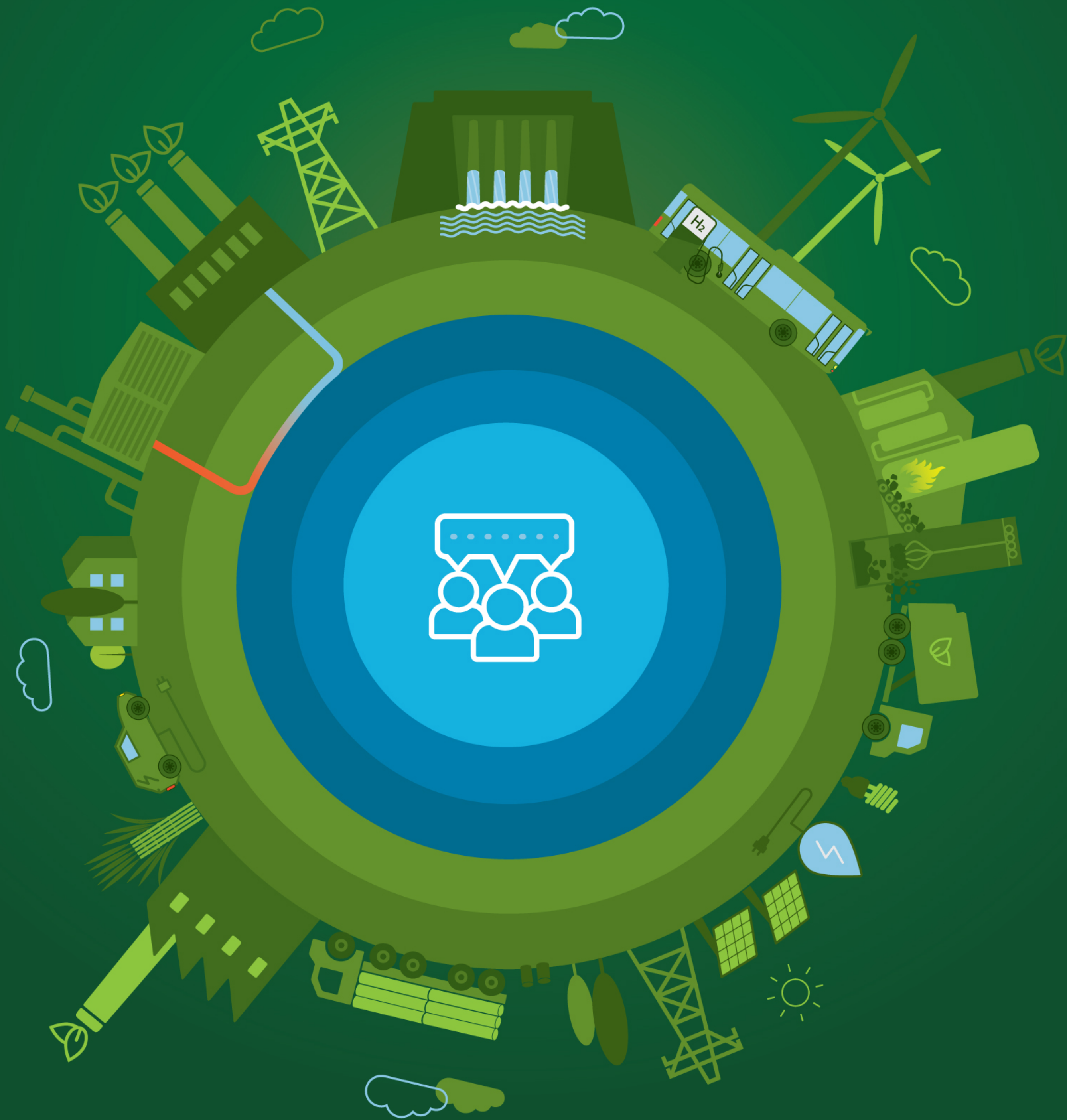
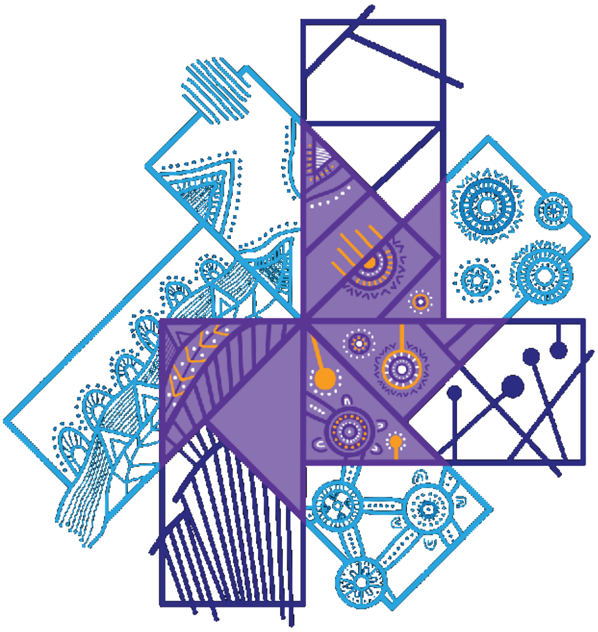
ARUP

National Hydrogen Infrastructure Assessment: Final Report



This report was prepared for the Department of Climate Change, Energy, the Environment and Water



Acknowledgement of Country

We acknowledge the Traditional Custodians of the lands where we work and live. We celebrate the diversity of Aboriginal and Torres Strait Islander peoples and their ongoing cultures and connections to the lands and waters of this country.

We pay our respects to Elders past, present and emerging and acknowledge the Aboriginal and Torres Strait Islander people present today.

’Shift to shape an even better world’ by Gilimbaa artist Tarni O’Shea.

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Foreword

The demand for clean hydrogen is expected to grow substantially decade upon decade across Australia reflecting a strong growth in both domestic and export demand.[1] Australia's National Hydrogen Strategy (NHS) 'sets a vision for a clean, innovative, safe and competitive hydrogen industry that benefits all Australians. The NHS has outlined an adaptive pathway focussed on development of a globally competitive industry underpinned by safe and secure supply of lowest cost hydrogen.

This inaugural National Hydrogen Infrastructure Assessment provides Australia's first nation-wide infrastructure assessment focussed on development of the Australian clean hydrogen industry[2]. Strategic and timely investment in Australia's hydrogen supply chain infrastructure will underpin the rapid scale up of a competitive hydrogen industry needed over the next decade to decarbonise our economy and secure our position as a major global hydrogen player and future energy supplier.

Arup and Frontier Economics have been appointed by the Department of Climate Change, Energy, the Environment and Water (DCCEEW) to lead the assessment on behalf of the Commonwealth, State and Territory Governments. Stakeholder engagement and consultation has been undertaken throughout the NHIA with a wide range of government, industry, research, advocacy and community stakeholders.

[1] Globally, clean hydrogen supply could grow from 3.3 Mt H_2 to 142 Mt in 2030 and 500 Mt in 2050, according to the 'Net Zero Emissions by 2050 Scenario' in the IEA World Energy Outlook 2021.

[2] For the purpose of the NHIA, clean hydrogen can either be green hydrogen (produced from water electrolysis powered by renewable energy) or blue hydrogen (produced from coal gasification or natural gas steam methane reformation coupled with carbon capture and storage).

Australia's National Hydrogen Strategy sets a path for building Australia's hydrogen industry. One of the early-stage actions of the Strategy is to complete an initial National Hydrogen Infrastructure Assessment (NHIA).

Update

The hydrogen industry is fast evolving. Whilst every attempt has been made to incorporate relevant aspects of the existing hydrogen landscape in Australia there has naturally been progression of the industry during the period of this assessment (2021-22) and more specifically since finalisation of our modelling inputs.

The following announcements are notable:

- *Government funding announcements (Federal and State Govt) – Hydrogen Hubs & Projects*
- *Private development announcements (refer Geoscience Australia and HyResource[13])*
- *Global geopolitical events bringing issues of global energy security and action on climate change to the fore in relationships with our trading partners, and causing global energy security concerns and impacting global energy market sentiment*
- *Climate policy - Australia's announcement of climate targets*
- *Trading partner announcements e.g. Germany looking to Australia as a trusted energy trading partner*

Water Usage for Hydrogen

Research on water consumption for hydrogen production undertaken during this study highlighted a general lack in literature of detailed analysis of water requirements and identified the need for further investigation.

A separate study, 'Water for Hydrogen'[3], undertaken by Arup for DCCEEW and the Australian Hydrogen Council (AHC) during the final stages of this assessment analysed in detail the water consumption of hydrogen processes. While the results of the study were available only after the techno-economic model assessment, it can be confirmed that the water requirements assumed in the assessment for the NHIA are consistent with the conclusions of the 'Water for Hydrogen' Study (Arup,2022).

AEMO ISP 2022

The approach to our modelling has optimised the supply chain for hydrogen production to meet demand based on the lowest Levelised Cost of Hydrogen (LCOH). The demand scenarios were developed in 2021 in consultation with AEMO and other government bodies. In the ISP 2020, AEMO's predictions for hydrogen as a possible scenario were limited to identifying sector coupling. Specific mention that the ISP 2020 does not include any quantitative analysis is made, as the industry remains in early stages of development (PAGE 22 ISP 2020, BOX 1). Contrasting this in AEMO's ISP 2022, where the market operator has conducted quantitative analysis of a potential scenario "Hydrogen Superpower". The 2022 ISP was released at the time of concluding this report. Due to development timelines, variances in methodologies and approaches to these demand scenarios exist. Nevertheless, the hydrogen demand sensitivity analysis included in this study (with low, medium and high demand scenarios) encompasses the demand levels in the AEMO ISP 2022 "Hydrogen Superpower" scenario, providing an understanding of the infrastructure needs for the AEMO hydrogen demand.

DISER, State of Hydrogen Report, December 2021

The State of Hydrogen Report was published by DISER (former Department of Industry, Science, Energy and Resources) as part of delivering Australia's National Hydrogen Strategy. The data for the snapshot of hydrogen development in Australia used for the NHIA is sourced from the Geoscience Australia database which is consistent with that used for the State of Hydrogen Report.

[3] ARUP Australia 2022, '*Technical Paper - Water for Hydrogen*', DCCEEW, Australian Hydrogen Council.

Executive Summary

Executive summary

Introduction

As the global hydrogen economy moves from demonstration to deployment, supply chain infrastructure is now a critical element in unlocking the full potential of domestic and international markets.

Strategic and timely investment in Australia's supply chain infrastructure will underpin the rapid scale up of a competitive hydrogen industry required over the next decade to secure our position as a major global hydrogen player.

> Australia's National Hydrogen Strategy 'sets a vision for a clean, innovative, safe and competitive hydrogen industry that benefits all Australians. It aims to position our industry as a major global player by 2030'.

The NHIA provides a review of existing infrastructure and a robust and transparent prioritisation of supply chain opportunities for lowest cost of hydrogen, under several agreed scenarios. A clear roadmap for investment in infrastructure is required to meet future hydrogen demand.

The National Hydrogen Strategy (NHS) identified that a national review of hydrogen infrastructure requirements would be valuable in informing infrastructure investment prioritisation, for governments and the private sector. The Strategy recognises the need for regular updates to the NHIA to respond to the rapid expansion of the global hydrogen economy, which will continue to be shaped by energy security, energy equity and environmental sustainability.

Arup and Frontier Economics have been appointed by the Department of Climate Change, Energy, the Environment and Water (DCCEEW), formerly Department of Industry, Science, Energy and Resources (DISER), to lead the assessment on behalf of the Commonwealth, State and Territory Governments. Stakeholder engagement and consultation has been undertaken throughout the NHIA with a wide range of government, industry, research, advocacy and community stakeholders.

Australia's Competitive Edge

Australia has high calibre renewable resources, established energy and transport infrastructure, world-class research and technological development, workforce capability, stable economy and trading relationships, supply chains and proximity to major potential markets.

Based on natural resources and the existing bi-lateral trade relationships and existing trading partners with Asia and Europe in particular, Australia has already been identified as having a competitive advantage in the race to develop a hydrogen economy due to access to low-cost gas for blue hydrogen productions, depleted oil fields for carbon capture and storage (CCS) and being already a leader in the production of green hydrogen. Each element can play its part in supporting hydrogen industry growth.

> The National Hydrogen Infrastructure Assessment (NHIA) is a key next step in implementation of Australia's National Hydrogen Strategy.

The Need for Smart Investment

The main challenge to realising Australia's full hydrogen potential is achieving the scale necessary for it to provide a cost-competitive alternative to the existing emissions intensive energy and fuel sources, in a globally competitive environment. To stay competitive, Australia must be smart with how it invests.

The vast array of viable options across the hydrogen supply chain poses a considerable hurdle for domestic use and export. Production, storage and transport methods are interdependent and require different infrastructure to allow safe and efficient use of hydrogen in our future economy.

Securing Australia's hydrogen future requires the right supply chain investment in the right place at the right time.

The NHS envisages a domestic hydrogen economy developing in parallel to an export industry to act as a buttress of economic development. Hydrogen hubs are defined as areas where users of hydrogen are co-located to maximise the investment in common user infrastructure. Utilising this shared infrastructure around Australia is the springboard to achieve accelerated industry growth. Development of demonstration hubs around Australia to seed the industry development is being supported by the Australian Government as well as all State and Territory Governments.

By identifying and prioritising supply chains and coordinating jurisdictional and industry enablers to collaborate, the full potential of these hubs can be realised. However, navigating the myriad of complex factors and competing priorities to identify and assess these supply chains requires an innovative and resourceful approach.

Stakeholder Engagement

Stakeholder engagement and consultation has been undertaken throughout the NHIA with a wide range of government, industry, research, advocacy and community stakeholders. Engagement activities included a series of over 20 virtual workshops focussed around primary impacted sectors (~300 participants); and one on one stakeholder interviews and discussions. Together with broader engagement to raise awareness, the wider stakeholder community was engaged for the gathering of data and inputs to the assessment. State and Territories were consulted on both assessment inputs and results.

The NHIA will support governments and investors in their decision making on hydrogen industry infrastructure investment and development.

Assessment Approach

The development of the hydrogen economy in Australia can be viewed as an ecosystem of infrastructure hubs and interconnected links supported by technology and supply chain clusters.

This complex ecosystem can be tangibly represented through the development of a 'Node and Link' flow model. The method is commonly used in energy, transport and network engineering, making it most suitable for the strategic representation and assessment of the emerging multi sectorial hydrogen economy.

The assessment framework shown below outlines the methodology for delivery of the NHIA in stages. The NHIA was undertaken in five stages to deliver the project outcome, which is to 'highlight priorities for future infrastructure for competitive hydrogen supply chains'.

The project is underpinned by stakeholder data inputs and endorsement of methodology and outputs across all stages. Each stage within the assessment framework is described in the following sections and summarised below.

Industry needs analysis: A desktop assessment of current infrastructure and hydrogen industry development to inform focus of the NHIA on hydrogen supply chain needs.

Stakeholder engagement: Consultation with Government, industry, research, and community stakeholders during the NHIA. Input and endorsement of the assessment by state and territory governments together with broader engagement to raise awareness, gather data and inputs to the assessment from the wider stakeholder community.

Demand scenarios modelling: Scenarios for hydrogen demand across the next 30 years based on potential future fuel switching away from coal, gas and liquid fuels to hydrogen; future new markets in hydrogen commodity export; and new industrial uses such as low emissions steel. Hydrogen demand locations were identified in collaboration with Commonwealth, State, and Territory Governments, and their priorities at the time of developing the baseline model.

Techno-economic supply chain modelling: A quantitative assessment of modelled supply chain options identified to support hydrogen demand nodes. The techno-economic assessment used input data and assumptions to identify optimal hydrogen supply chains, by balancing the production, storage, and transportation requirements to meet each demand scenario and achieve the lowest overall cost configurations.

Techno-economic assessment: A qualitative assessment of modelled supply chain outputs to identify priority infrastructure investment to support development of the hydrogen industry in Australia. Discussion of other factors to be considered for infrastructure investment and development including water, land use and environmental planning and shared infrastructure opportunities are included.

Summary of NHIA Outputs and Insights

The assessment of infrastructure needed to support the growth of the hydrogen industry in Australia has been undertaken by identifying infrastructure needs for lowest cost supply chains.

- The assessment considers an agreed set of supply and demand locations. Energy supply locations include renewable energy zones (or equivalent defined by States and Territories), coal/gas production locations). Hydrogen demand locations were determined based on potential switching of domestic fossil fuel use and export ports.
- Distribution of hydrogen from the demand locations to the distributed final point of hydrogen use is beyond the scope of the assessment (e.g. hydrogen refuelling station, chemical plant, steel manufacturer, offshore export customer). Similarly, complementary enabling infrastructure such as water supply infrastructure will be needed. The water requirements for each hydrogen demand scenario have been estimated however the water infrastructure supply chain is beyond the scope of this assessment.
- Only low-emission hydrogen production was assumed in the supply chain modelling. For the purpose of this analysis, hydrogen can either be produced from water electrolysis powered by renewable energy (green hydrogen) or produced from coal gasification or natural gas steam methane reformation coupled with carbon capture and storage (blue hydrogen).
- The techno-economic modelling uses a number of input assumptions which were tested with stakeholders during the project. A range of sensitivity tests were also undertaken in the techno-economic modelling to understand the sensitivity of the outputs to input criteria such as capital cost of electrolysers, cost of grid electricity, hydrogen demand and geographical distribution of export demand

The future role of hydrogen in our energy systems is not yet known. Hydrogen demand scenarios from 2025 to 2050 have been applied to enable the assessment of infrastructure needs across a range of possible hydrogen demand futures.

- The demand for hydrogen was modelled to grow substantially decade upon decade across Australia to reflect the potential strong growth in both domestic and export demand linked to the switching to low carbon fuel alternatives.
- Export demand has the potential to approximately match the demand for domestic uses based on fuel-switching assumptions, accounting for slightly less than half of the total across all timeframes in the central demand scenario.
- Export demand in the central scenario is based on the assumption that by 2050 Australia will capture a share of global hydrogen demand similar to the share of global natural gas demand it currently supplies. Domestic demand in the model is driven by low carbon fuel-switching and new uses in industrial feedstock and production (e.g. green steel, chemicals) and marine shipping. Low, high and central hydrogen demand scenarios were considered.

The outcomes of the techno-economic assessment provide the following insights:

- The techno-economic model, built to select the low-emission hydrogen production method based on lowest cost supply chains, has identified electrolysis powered by behind-the-meter wind and solar PV as the preferred hydrogen production technology across most locations and timeframes (moving molecules is generally preferred to moving electrons).
- In the base case scenario, hydrogen produced from natural gas is selected in particularly favourable locations in Queensland and Northern Territory. However, this only occurs in 2030 and by 2040 no blue hydrogen production is preferred Australia-wide. The sensitivity analysis of high electrolyser capex costing made blue hydrogen competitive at these locations out to 2040.
- The total power generation required for green hydrogen production in 2050 based on the central demand scenario is estimated to be nearly 20 times the current renewable power generation. After 2040, the capacity of the modelled renewable energy zones become saturated for the production of hydrogen in the areas around Sydney, Melbourne and Perth. Additional capacity can be captured by expansion of REZs and/or addition of offshore and onshore new REZ. Additionally planning of the REZ may consider opportunities where pipelines can provide LCOH and avoid grid connection costs and constraints.
- The hydrogen industry is currently at a nascent stage. The relative number, type and maturity of existing hydrogen supply chains is reflective of this early industry stage. Production and supply of hydrogen to meet demand will require the rapid development and scaling up of these supply chains at unprecedented rates, in parallel to uptake of new technology, and wider environmental, economic and societal considerations. The speed at which these supply chains can be established will be fundamental to the timely supply of hydrogen to meet demand. Supply chain infrastructure planning therefore needs to be integrated with hydrogen demand timing.
- Early in the hydrogen industry development, green hydrogen and some blue hydrogen supply chains are selected by the model as lowest cost hydrogen options. Blue hydrogen options are usually identified where existing natural gas production for SMR exists in proximity to corresponding potential carbon capture and storage sites. It is notable that blue hydrogen from coal gasification with carbon capture and storage is not preferred due to the high CAPEX cost of the supply chain. Over time however the predicted reduction in renewable technology costs (primarily electrolyser costs) are expected to make green hydrogen the lowest cost production method. A sensitivity analysis was undertaken to explore the impact of higher electrolyser costs on selection of blue or green supply chains and found that this resulted in some blue hydrogen supply chains remaining lowest cost out to approximately 2040.

- Shared infrastructure opportunities for lowest cost of hydrogen supply chains have been investigated by the model using the common 'compressed hydrogen' carrier in pipelines. This has also enabled exploration of common user storage, for example salt caverns.
- In 2025 and 2030 the relatively limited hydrogen transport between supply and demand locations for lowest cost of hydrogen is serviced by compressed gas trucks. The only exceptions to this are the two hydrogen pipelines used to connect behind-the-meter hydrogen generation at the local renewable energy zones to Gladstone and also to Townsville in Queensland, reflecting strong export demand at these ports. This result remains valid even when noting that the modelled domestic demand in Townsville includes the regional demand for Queensland and is therefore an overestimation of the local demand. Nevertheless, over 70% of the hydrogen piped to Townsville is dedicated to export, and this hydrogen flow is sufficient to justify the development of the pipeline according to the cost inputs used in the model. In 2040 and 2050 most hydrogen transport is carried out via dedicated gas pipelines, to connect production areas, demand locations and large-scale hydrogen sites. When allowed by the model, rail infrastructure is used consistently until 2040.
- Two salt cavern locations (Adavale Basin in Queensland and Canning Basin in Western Australia) are consistently selected in 2040 and 2050 by the model for large-scale hydrogen storage, when the scale of hydrogen production and demand justifies the cost of their development and connection to hydrogen networks.
- The techno-economic model assumes the demand of hydrogen to be always in the form of hydrogen gas, to better highlight the opportunities for shared infrastructure. Under this assumption, the model selects methylcyclohexane (MCH) as the preferred medium for short- and medium-term hydrogen storage due to the low cost of MCH storage tanks and MCH transport via truck, however it is expected that Ammonia could equally be considered. The requirement for a different final hydrogen product would likely impact the choice of hydrogen storage carrier. As an example, if the final use of hydrogen was to be in the form of ammonia (e.g. for export), the related hydrogen storage infrastructure would likely be in the form of ammonia tanks (which provide comparable levelised cost of hydrogen storage to that of MCH tanks) to avoid unnecessary conversion and reconversion steps. The development of the domestic and international hydrogen markets will lead to the establishment of preferred hydrogen carrier technologies, which will drive the shape of the storage and transport infrastructure.

Overall, the water consumption for the future hydrogen economy is considerable but not prohibitive. The water demand for hydrogen production in the base case scenario in 2050 is expected to be comparable to the current water use in the mining sector (2020 data). The water infrastructure required for water extraction, treatment and supply will vary for each location on the basis of available water resource and supply chain requirements with social, environmental, regulatory, and economic factors weighing strongly into decision making.

Social and environmental impacts are considerations in all infrastructure development that can impact the project costs and timelines to avoid or mitigate impacts and achieve regulatory planning approval. Using protected areas mapping as a proxy for sensitive land use constraints and approvals complexity, an industry of this scale will face challenges which can be somewhat mitigated by planning and co-ordination to avoid and minimise impacts on LCOH. Shared infrastructure is one way of minimising industry impact on social and environmental values.

Priority Infrastructure Requirements

The techno-economic assessment undertaken for the NHIA has identified priority infrastructure requirements for lowest cost of hydrogen supply chains. Relative timing of the infrastructure need is also outlined below based on the modelled timeframes.

Infrastructure investment opportunities

All

2025	2030	2040	2050
REZ planning and prioritisation Infrastructure corridor planning – electricity, pipelines Storage investigations – hydrogen and CCS Planning and installation of hydrogen refuelling stations on main transport corridors Port upgrade requirements investigation and planning Water supply planning	REZ planning and prioritisation, including the selection of additional areas for renewable energy production to satisfy future demand Infrastructure corridor planning and implementation for transmission lines and pipelines Establish hydrogen refuelling station network Large-scale hydrogen storage pilot and demonstration projects Port upgrade planning and implementation Water supply planning and implementation, case-by-case assessment of infrastructure requirements	REZ planning and prioritisation, increase of REZ and renewable power generation portfolio. Potential for green hydrogen production for export in remote coastal areas Continue developing pipeline infrastructure tio connect hydrogen generation and demand, and large-scale storage facilities Establish infrastructure to supply hydrogen to industrial hubs Large-scale hydrogen storage implementation Continue port upgrades, where required Water supply planning and implementation, case-by-case assessment of infrastructure requirements	Continue expansion of renewable power generation, potential for development of remote inland hydrogen production locations to supply domestic demand via pipelines Continue developing pipeline infrastructure to connect hydrogen generation and demand Water supply planning and implementation, case-by-case assessment of infrastructure requirements

Queensland

2025	2030	2040	2050
Power generation, hydrogen production and water supply infrastructure for REZs in Northern Queensland and Fitzroy Co-located hydrogen production and power transmission upgrades to Brisbane Dedicated pipelines between Northern Queensland – Townsville, Fitzroy – Gladstone	Co-located hydrogen production and power transmission upgrades to Brisbane, Darling Downs, Townsville, Gladstone Upgrade of the ports in Townsville and Gladstone	Additional power generation, hydrogen production and water supply for REZs in Far North Queensland and Darling Downs Co-located hydrogen production and power transmission upgrades to Townsville, Gladstone Salt cavern development in Adavale basin Additional dedicated pipelines between Far North Queensland – Townsville, Adavale basin – Brisbane, Daring Downs – New England (NSW)	Additional power generation, hydrogen production and water supply for REZs in North Queensland Clean Energy Hub, Barcaldine, Isaac, Wide Bay Dedicated pipelines between all REZs and local demand centres

New South Wales and Australian Capital Territory

2025	2030	2040	2050
Co-located hydrogen production infrastructure in Sydney, Wollongong, Newcastle, ACT and Regional NSW Power transmission upgrades to Sydney	Additional co-located hydrogen production and infrastructure and power transmission upgrades in Sydney, Wollongong, Newcastle, ACT and Regional NSW Upgrade of the ports in Newcastle and Wollongong	Power generation, hydrogen production and water supply infrastructure for REZs in North West NSW, New England, Central-West Orana Dedicated hydrogen pipelines between Central-West Orana – Sydney, New England – Newcastle, North West NSW – Sydney, ACT – Sydney, ACT – Victoria Additional co-located hydrogen production and infrastructure and power transmission upgrades in Wollongong	Additional power generation, hydrogen production and water supply infrastructure for REZs in Wagga Wagga, South West NSW, Broken Hill Additional dedicated pipelines between Wagga Wagga – ACT, South-West NSW – Victoria, Broken Hill, South Australia Additional co-located hydrogen production and infrastructure and power transmission upgrades in Wollongong

Victoria

2025	2030	2040	2050
Co-located hydrogen production and water infrastructure in Melbourne, Geelong, Regional VIC Power transmission upgrades to Melbourne	Additional co-located hydrogen production and water infrastructure in Melbourne, Geelong, Regional VIC and Portland Additional power transmission upgrades to Melbourne, Geelong, Regional VIC and Portland Upgrade of the ports in Geelong and Portland	Power generation, hydrogen production and water supply infrastructure for REZs in Murray River, Western VIC Dedicated hydrogen pipelines between Murray River – Melbourne, Western VIC – Geelong, Melbourne – Canberra (ACT) Additional power transmission upgrades to Melbourne, Geelong, Regional VIC and Portland	Additional power generation, hydrogen production and water supply infrastructure for REZs in South Western VIC, Central North VIC Additional hydrogen pipelines between South Western VIV – Geelong, Central North VIC – Melbourne, Murray River – NSW Additional power transmission upgrades to Melbourne, Geelong, Regional VIC

Tasmania

2025	2030	2040	2050
Power generation, hydrogen production and water supply infrastructure for REZ in Tasmania Midlands	Co-located hydrogen production and water infrastructure in Hobart Power transmission upgrades to Hobart Dedicated pipeline between Tasmania Midlands – Bell Bay Upgrade of the port in Bell Bay	Additional power generation, hydrogen production and water supply infrastructure for REZ in North East Tasmania Additional co-located hydrogen production and water infrastructure in Hobart Additional power transmission upgrades to Hobart Dedicated pipeline between North East Tasmania – Bell Bay	Additional power generation, hydrogen production and water supply infrastructure for REZ in North West Tasmania Additional co-located hydrogen production and water infrastructure in Hobart Additional power transmission upgrades to Hobart, Bell Bay Dedicated pipeline between North West Tasmania – Bell Bay

South Australia

2025	2030	2040	2050
Co-located hydrogen production and water infrastructure in Adelaide, Regional SA Power transmission upgrades to Adelaide	Additional co-located hydrogen production and water infrastructure in Adelaide, Port Bonython, Regional SA Additional power transmission upgrades to Adelaide, Port Bonython Upgrade of the port in Port Bonython	Power generation, hydrogen production and water supply infrastructure for REZ in Leigh Creek, Mid-North SA Additional power transmission upgrades to Adelaide, Regional SA Dedicated hydrogen pipelines between Leigh Creek – Port Bonython, Mid-North SA - Adelaide	Additional power generation, hydrogen production and water supply infrastructure for REZ in Roxby Downs, Northern SA, Riverland, Yorke Peninsula, South East SA Additional power transmission upgrades to Regional SA Additional dedicated hydrogen pipelines between Roxby Downs – Port Bonython, Northern SA – Port Bonython, Riverland – Adelaide, Yorke Peninsula – Adelaide, Adelaide – NSW, Adelaide – VIC, Adelaide – South

Western Australia

2025	2030	2040	2050
Power generation, hydrogen production and water supply infrastructure for REZ in Mid-West WA Co-located hydrogen production and water infrastructure in Perth, Regional WA, Goldfields, Pilbara	Power transmission upgrades to Perth, Regional WA, Goldfields, Port Hedland, Pilbara Upgrade of the ports in Port Hedland, Geraldton, and Perth (Kwinana)	Additional power generation, hydrogen production and water supply infrastructure for REZs in Mid-East WA, South West WA, Pilbara Inland Additional power transmission upgrades to Goldfields Salt cavern development in Canning basin Dedicated hydrogen pipelines between Mid-East WA – Perth, South West WA – Perth, Mid West WA – Perth, Pilbara Inland – Pilbara, Canning basin – Pilbara	Additional power generation, hydrogen production and water supply infrastructure for REZs in Pilbara, South East WA Additional power transmission upgrades to Perth, Regional WA, Goldfields, Pilbara Additional dedicated hydrogen pipelines between South East WA – Perth, Pilbara (REZ) – Pilbara, Pilbara (REZ)

Northern Territory

2025	2030	2040	2050
Co-located hydrogen production and water infrastructure in Darwin	Additional co-located hydrogen production and water infrastructure in Darwin Power transmission upgrades to Darwin Upgrade of the port in Darwin	Additional co-located hydrogen production and water infrastructure in Darwin Additional power transmission upgrades to Darwin Power generation, hydrogen production and water supply infrastructure for REZ in Tennant Creek Dedicated hydrogen pipeline between Darwin – Tennant Creek	Additional power generation, hydrogen production and water supply infrastructure for REZ in Tennant Creek

Next Steps

The context of hydrogen industry development exists within the broader energy transformation responding to geopolitical and climate agendas shaping our communities and economies around the world. As the hydrogen industry moves from demonstration to commercialisation, the planning and investment of infrastructure will need to be responsive to the scale and timing of the evolving industry needs.

Further integration of the prospective role of hydrogen in our energy system and infrastructure planning is required. The National Hydrogen Strategy envisaged an update to the NHIA at least every 5 years. Given the current fast pace of hydrogen industry development and uncertain wider energy landscape, it may be advantageous to update this assessment more regularly and in line with other energy planning and infrastructure implementation planning such as the AEMO ISP (Australian Energy Market Operator Integrated System Plan) and broader Federal and State energy planning and infrastructure planning pipelines (e.g. Infrastructure Australia priority infrastructure list).

1 Introduction

1 Introduction

1.1 Purpose

As the global hydrogen economy moves from demonstration to large scale market activation, supply chain infrastructure is now a critical element in unlocking the full potential of domestic and international markets.

Strategic and timely investment in Australia's supply chain infrastructure will underpin the rapid scale up of a competitive hydrogen industry needed over the next decade. This will secure our position as a major global hydrogen player and future energy supplier.

The hydrogen infrastructure assessment provides a review of existing infrastructure and a robust and transparent prioritisation of supply chain opportunities for lowest cost of hydrogen under various agreed scenarios.

Australia's National Hydrogen Strategy (NHS)[4] 'sets a vision for a clean, innovative, safe and competitive hydrogen industry that benefits all Australians. It aims to position our industry as a major global player by 2030'.

The National Hydrogen Strategy recognises that the growth of the hydrogen industry will increase the use of local infrastructure, such as for water, electricity, gas and transport. Managing these new demands and expanding infrastructure capacity will require strategic planning and coordination at all levels of government.

This inaugural National Hydrogen Infrastructure Assessment (NHIA) is one of the scale up activities identified in the NHS to assess supply chain infrastructure needs. The NHS identified that a national review of hydrogen infrastructure requirements would be valuable in informing infrastructure investment prioritisation, for governments and the private sector. The Strategy recognises the need for regular updates to the NHIA as part of the adaptive pathway approach to development of Australia's hydrogen industry.

The NHIA provides a robust and transparent prioritisation of supply chain opportunities under various agreed scenarios to supply the lowest cost of low emission hydrogen to meet the scenarios of hydrogen demand.

The assessment supports targeted and coordinated infrastructure investment through identifying infrastructure needs for lowest cost hydrogen supply chains.

1.2 Supply Chain Needs

Hydrogen production

Australia has an abundance of resources to support the production of hydrogen from both renewable and fossil fuel sources. The challenge faced by the market is continuously applying downward pressure on the cost of production components of the supply chain. This will continue to promote future competitive pricing across electrolysis equipment, electricity, water, fossil fuel prices, and carbon capture and storage. Only hydrogen produced from water electrolysis powered by renewable energy (green hydrogen) or produced from coal gasification or natural gas steam methane reformation coupled with carbon capture and storage (blue hydrogen) was included in the analysis.

[4] COAG Energy Council Hydrogen Working Group, 2019, '*Australia's National Hydrogen Strategy*', https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf

Supply and distribution

In Australia there is often considerable distance between optimal production resources (e.g. renewable energy zones and gas fields) and hydrogen demand centres. In addition, end uses are geographically distributed, which results in variability of hydrogen carrier requirements.

At the broadest scale, costs for transport and storage are often overlooked in initial project assessments and there is currently a lack of clarity over optimal configuration for location of electrolysis production to be close to electricity generation or end-use (i.e. transporting electrons vs molecules).

End use

Securing end-use off take is currently a significant barrier to project definition and hydrogen investment.[5] Prospective domestic uses include transport re-fuelling, residential, commercial, and industrial gas blending and replacement, remote area and grid service power systems and industrial feedstocks use. Export use infrastructure focuses on port facilities for shipping carriers of hydrogen (LH_2, NH_3, MCH etc.) and new 'green' goods including locally manufactured supply chain components and products such as low emissions explosives, fertilisers, aluminium and steel.

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

1.3 Existing Infrastructure

Australia has an extensive infrastructure network supporting our cities and regional centres. This existing infrastructure will be able to support the development of the hydrogen industry owned by governments or the private sector. It has been estimated that the total infrastructure investment required to achieve Australia's aspirations as the dominant East Asian hydrogen exporter could be up to $80 billion by 2030.[6] Utilising existing infrastructure could help to minimise these costs.

Integrated approach

The NHIA is primarily aimed at informing infrastructure investment decisions based on several scenarios characterising industry growth. The assessment also acknowledges opportunities to integrate with related analyses and measures including the Regional Hydrogen Hubs program outcomes, AEMO (Australian Energy Market Operator) 2021 GSOO (Gas Statement of Opportunities), WAGSOO (Western Australian Gas Statement of Opportunities), AEMO 2020 ISP and others. Input from AEMO team developing the ISP (Integrated System Plan) and the DCCEEW team developing the National Gas Infrastructure Plan has been sought as part of the project methodology.

Existing production

Australia's current hydrogen production is around 650 ktpa and is made using Natural Gas Steam Methane Reforming (SMR) and consumed by the associated ammonia synthesis (65%) and crude oil refining (35%) plant. Based on their age it is unlikely that these assets (ammonia plants, oil refineries and other processing facilities) could be re-purposed for merchant hydrogen production.[7] There are currently no commercial scale renewable hydrogen production facilities in Australia, however extensive commitments from both governments and the private sector have been made.

Electricity supply

Australia's power generation and electricity network covers and interconnects the major

[5] Results from stakeholder consultation continuously raised off-taker agreements as a key barrier to project developments

[6] Hydrogen Council, Hydrogen Scaling Up, 2017 p. 66

[7] CEFC, Australian Hydrogen Market Study 2021, p. 21

population and regional industrial centres. AEMO operates two electricity markets and power systems in Australia. On the east coast, the National Energy Market (NEM) network is some 5,000 km long and services Queensland, New South Wales, the Australian Capital Territory, South Australia, Victoria and Tasmania. In Western Australia, the Wholesale Electricity Market (WEM) supplies electricity to the south-west of the state via the South West Interconnected System (SWIS). Western Australia hosts an additional integrated network in the Pilbara region, the North West Integrated System (NWIS). The Northern Territory has three independent systems for Darwin, Katherine, Tennant Creek and Alice Spring regions.

AEMO[8] has functions which seek to promote the efficient investment in, and efficient operation and use of, gas and electricity for the long-term interests of Australian consumers in relation to price, quality, safety, reliability and security. This translates to the following areas of responsibility:

- Maintain secure electricity and gas systems.
- Manage electricity and gas markets.
- Lead the design of Australia's future energy system.

A secure, reliable and affordable supply of electricity is fundamental for renewable hydrogen development. While Australia has abundant renewable energy resources to meet this demand, it is important to ensure that this can be supplied when and where it is needed.

This is why governments are identifying strategic renewable energy zones and are supporting priority transmission projects. These include Project Energy Connect, Marinus Link, Victoria to New South Wales Interconnector West (VNI West) and HumeLink, which will reduce constraints and enable the connection of new energy projects. There are also new dispatchable generation projects, to complement and firm increasing levels of variable renewable energy and ensure the security, reliability and affordability of supply.

The approach to our modelling has optimised the supply chain for hydrogen production to meet demand based on the lowest Levelised Cost of Hydrogen (LCOH). The demand scenarios were developed in 2020 in consultation with AEMO and other government bodies. In the ISP 2020[9], AEMO's predictions for hydrogen as a possible scenario were limited to identifying sector coupling. Specific mention that the ISP 2020 does not include any quantitative analysis is made, as the industry remains in early stages of development (PAGE 22 ISP 2020, BOX 1). Contrasting this in AEMO's ISP 2022[10], where the market operator has conducted quantitative analysis of a potential scenario called "Hydrogen Superpower". The 2022 ISP was released at the time of concluding this report. Due to the different timelines for the development of these reports, variances in methodologies and approaches to these demand scenarios exist.

The NHIA outputs have optimised heavily to hydrogen produced as close to the energy generation source, which reduces increased investment in electricity transmission infrastructure, soon to come under significant pressure as the country moves to greater electrification. This is highlighted as one of the primary actions in the ISP 2022; to invest heavily in electricity transmission infrastructure.

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[8] https://www.aemo.com.au/about/what-we-do

[9] AEMO ISP 2020, https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

[10] AEMO ISP 2022, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

Gas network

There are over 100 natural gas transmission pipelines across Australia[11] connecting gas production centres to the gas distribution networks in the major demand centres. There is significant research and demonstration project activity underway, globally and in Australia, to assess the gas infrastructure compatibility and augmentation requirements for hydrogen blending and 100% conversion of both the transmission and distribution networks. It is expected that up to 10% hydrogen can be achieved in the distribution networks without significant infrastructure investment.[12] The National Gas Infrastructure Plan provides a forecast of gas infrastructure investment for the next 20 years. The accelerated work on the National Gas Law review through the Energy Ministers is being undertaken in parallel to ensure hydrogen (and other renewable gases) are recognised in the legal and regulatory frameworks.

Land transportation

Australia has an extensive shipping, road and rail network for the domestic transport of goods including existing supply chains for hazardous chemicals and liquid natural gas. It is expected that the existing network will cater for hydrogen projects with potential for some augmentation of existing facilities required to cater for specific projects, and/or to meet safety regulation requirements. For further information please refer to the Commonwealth Government's identified prospective locations discussed on page 16 and Geoscience Australia report 'Prospective hydrogen production regions of Australia'[13].

Hydrogen storage facilities

Short to medium term storage of hydrogen is expected to be in tanks with design dependent on the carrier form (liquified, compressed, ammonia, MCH). Line packing in pipelines is also being explored. Technological knowledge is readily applicable from existing chemical and gas industry applications. Long-term cost-effective storage for hydrogen is being explored by using salt caverns and depleted gas fields.

Current storage for natural gas includes seven locations on the east coast and two in Western Australia.

Carbon capture and storage

Thermochemical hydrogen production can be coupled with carbon capture and storage (CCS) to reduce the carbon footprint of the product. Several CCS research and pilot programs have been run in Australia, with one large-scale project currently in operation in Western Australia.[14] Infrastructure is required for the CO_2 capture, transport (typically via pipelines), and storage in underground formations. Project Gorgon in Western Australia and the Carbon Net Project in Victoria are the most prominent CCS initiatives, and the Australian Government has committed half a billion dollars to further CCS hubs in the future. Santos has recently announced final investment decision on their Moomba CCS project in South Australia.

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[11] https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

[12] Green Hydrogen for a European Green Deal; A 2x40 GW Initiative p.13

[13] *'Prospective hydrogen production regions of Australia'*, GA 2019, https://d28rz98at9flks.cloudfront.net/130930/Rec2019_015.pdf

[14] https://australia.chevron.com/our-businesses/gorgon-project/carbon-capture-and-storage

Port infrastructure

There are numerous ports in Australia currently shipping ammonia, which has a mature commodity market. The National Hydrogen Strategy[1] identified 30 potential ports, including these, for development of hydrogen export hubs based on several factors including existing and potential infrastructure capacity. The primary hub infrastructure required to be located at the port includes shipping berth capability and capacity, enabling infrastructure for electricity, water, gas pipelines and storage. For liquid hydrogen – liquefaction plant and loading facilities will need to be co-located with the wharf to minimise boil off losses. The conversion of hydrogen into other hydrogen carriers, if undertaken at the port locations, will require additional power infrastructure to be installed at these locations to supply electricity to drive the conversion processes.

Water supply

Securing sustainable water supplies in many areas will require new and augmented water infrastructure such as desalination and water purification plants, dams and pipelines, particularly where there is competing local demand for water resources. Reliability of supply, community support and development approval are important considerations. The cost component of water in hydrogen production, approximately 2%, is not a significant barrier to growth from this perspective.

1.4 Hydrogen Industry Snapshot

Australia is a global energy and resources export powerhouse and has enjoyed strong domestic energy security with oil production and refining capability, coal and gas resources, power generation and more recently increasing renewables mix. With the release of the National Hydrogen Strategy and Technology Investment Roadmap, Australia signalled its intention to use its natural resources to be a major global player in the hydrogen market by 2030.

There is a growing recognition that the development of an Australia's hydrogen industry that benefits all Australians should consider opportunities beyond hydrogen production to include value added low carbon goods (e.g. low emissions ammonia and steel), and also research, manufacturing and skilled labour for supply chain equipment component manufacture and maintenance. All of Australia's major trading partners have low emission and/or hydrogen strategies.

The Australian Government has committed over half a billion dollars to establish low emissions technology partnerships. Australia currently has agreements with countries such as Japan, South Korea, Germany, Singapore, UK (United Kingdom) and India.

Balance of trade with our major trading partners is also expected to include imports of technology and equipment. Similarly to Liquefied Natural Gas (LNG), it is expected that other resource rich countries and regions such as the USA (United States of America), Canada, China, the Middle East and South America will likely join the hydrogen global commodity market with some jurisdictions already progressing hydrogen strategy implementation. It is expected that hydrogen import into Europe will be driven by decarbonisation targets and trade relationships providing an opportunity for low emission hydrogen from Australia.

Initial investment has been in hydrogen production for transport and mobility and gas pipeline blending. A reform of the national gas regulatory framework to allow hydrogen blends and renewable gases in the gas network is currently under way.[15] Some projects are also aimed at low emissions industrial applications and export scale up. Most export focussed projects have a mix of local and international partners.

[15] https://www.energy.gov.au/government-priorities/energy-ministers/priorities/gas/gas-regulatory-framework-hydrogen-renewable-gases

To support this growth, one key aspect of the NHS's approach is the creation of hydrogen hubs. As defined in the State of Hydrogen 2021 report, 'hydrogen hubs are regions where multiple hydrogen producers, user and potential exporters are co-located.' 16 The aim of these hubs is to develop end-to-end supply chains, develop hydrogen demand, and reduce hydrogen costs by co-locating hydrogen users, producers and exporters. Securing off take agreements for hydrogen production is commonly cited in the stakeholder engagement as an impediment to project financial investment. This is expected considering the early state of the industry and the higher cost of using low emission hydrogen compared to existing chemical and energy alternatives.

The Strategy set a path for the development of the hydrogen industry initially centred around hubs of co-located hydrogen demand, focused on increasing uptake through cost competitiveness

The NHS initially identified 30 potential export hubs and envisaged that sector coupling will be enabled for domestic and export demand at many of these initial hubs. The development of a national hydrogen technology cluster was also identified in the NHS as an important component to scale up Australia's domestic industry to become a global hydrogen competitor. The National Energy Resources Australia (NERA) have provided funding to support 15 emerging hydrogen technology clusters across Australia.

The Australian Government has also committed $464 million to develop up to seven Regional Hydrogen Hubs across Australia. The locations that were awarded hubs implementation grants in 2022 prior to publication of this report are Bell Bay (TAS), Eyre Peninsula (SA), Gladstone (QLD), Hunter Valley and Newcastle (NSW), Kwinana (WA) and Pilbara (WA).[17]

The position of the aforementioned locations, together with the initial NHIA focus areas, is presented in Figure 1.4.1.

[16] Australian Government - Department of Industry, Science, Energy and Resources, 2021, State of Hydrogen https://www.industry.gov.au/sites/default/files/December%202021/document/state-of-hydrogen-2021.pdf

[17] https://www.minister.industry.gov.au/ministers/taylor/media-releases/future-hydrogen-industry-create-jobs-lower-emissions-and-boost-regional-australia

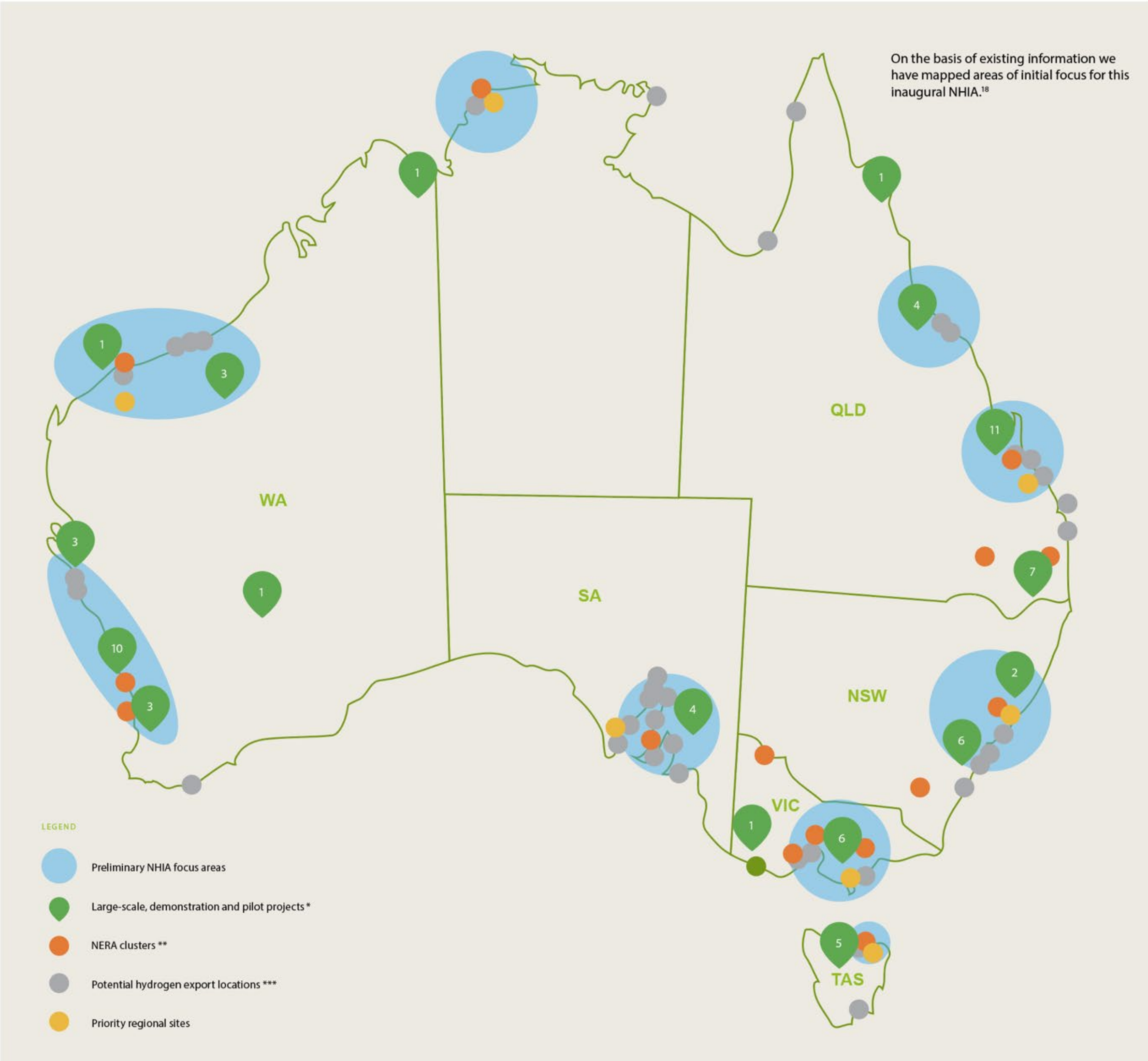

Figure 1.4.1 Areas of initial focus for the low emission hydrogen industry.

Commercial in confidence considerations and lack of broader industry transparency make infrastructure planning and collaboration in the industry difficult. Hydrogen industry announcements suggest that the industry is moving from the current focus of delivering industry led demonstration projects that de-risk hydrogen technology deployments in Australia to large scale commercial projects. Most commercial scale projects are not yet through the feasibility and final investment phases and therefore are likely several years from operation depending on scale and end use application.

2 Approach & Methodology

2 Approach and Methodology

2.1 Overview

The assessment framework shown below outlines the main stages in the methodology for delivery of the NHIA. The NHIA was undertaken in five stages to deliver the main project outcome, which is to 'highlight priorities for future infrastructure for competitive hydrogen supply chains'.

Focus of NHIA is on the hydrogen supply chain from hydrogen production to hydrogen demand points to supply the hydrogen demand. The techno-economic model outputs also provide information on anticipated requirements for upstream resources required for hydrogen production (e.g. fossil fuels, renewable energy, water) to inform infrastructure planning of these aspects. Consideration of end user application needs is addressed in terms of infrastructure for hydrogen carrier conversion and storage. Distributed infrastructure for end-user application (e.g., port infrastructure, re-fuelling stations etc) will be discussed qualitatively.

The successful outcome of the project is underpinned by stakeholder data inputs and the endorsement of methodology and outputs across all stages. Each stage within the assessment framework is described in the following sections and summarised below.

Industry needs and analysis

A desktop assessment of currently known and planned infrastructure initiatives and proposed hydrogen developments to establish a baseline of current infrastructure planning and hydrogen industry development needs.

Stakeholder engagement

Consultation with Government, industry, research, and community stakeholders during the NHIA. Input and endorsement of the assessment by state and territory governments together with broader engagement to raise awareness, gather data and inputs to the assessment from the wider stakeholder community.

Demand scenarios modelling

Scenarios for hydrogen demand across the next 30 years based on potential future fuel switching away from coal, gas and liquid fuels to hydrogen; future new markets in hydrogen commodity export; and new industrial uses such as low emissions steel.

Techno-economic supply chain modelling

The techno-economic model provides an analysis of the lowest cost hydrogen supply chains based on modelled parameters. A quantitative assessment of modelled supply chain options were identified to support hydrogen demand locations. The techno-economic assessment used input data and assumptions to identify optimal supply chains, by balancing the production, storage, and transportation requirements to meet each demand scenario and achieve the lowest overall cost configurations for modelled parameters.

Techno-economic assessment

A qualitative assessment of the wider techno-economic considerations for development of hydrogen supply chains. These include environmental and social considerations of resource and land use planning for the modelled hydrogen supply chain infrastructure of hydrogen production, transport and storage as well as for the upstream electricity, water supply and downstream end user facilities including port facilities. Opportunities for shared investment opportunity are explored for lowest cost supply chains.

2.2 Stakeholder engagement

Consultation with Government, industry, research, and community stakeholders was undertaken during the NHIA. The input and endorsement of the assessment by all Governments was progressed primarily through the inter-governmental Hydrogen Project Team set up by the Energy Ministers to deliver upon the actions of the National Hydrogen Strategy.

Broader engagement to raise awareness, gather data and inputs to the assessment from the wider stakeholder community has been undertaken through a series of focus group workshop sessions and one-on-one targeted consultations. The complete list of stakeholders is included in Appendix D.

2.3 Demand scenarios

Demand scenarios modelling was undertaken to ascertain the potential growth of hydrogen, both domestically and as an export, in order to inform the demand that the infrastructure would be required to supply. This section summarises the approach taken to develop the hydrogen demand scenarios that underpin the NHIA, further detail is in Appendix C.

As hydrogen is an emerging sector with limited historical data from which to base future trends, a bottom-up analysis was undertaken to define expected demand for hydrogen (and its derivatives) into the future. Demand profiles were based on expected end use consumption of hydrogen, which were determined by volume of switching rates. The demand modelling also assumes an ongoing cost reduction due to domestic and international investment in technology innovation. Figure 2.3.1 outlines the sources for future demand, which are aggregated into three components:

- Demand for hydrogen due to switching from an existing fuel source to hydrogen
- Demand for hydrogen that represents new energy demand in Australia
- Demand for hydrogen for export.

As well as estimating annual demand for hydrogen, an estimate of daily demand for hydrogen is also created. Daily demand for hydrogen, or at least peak daily demand for hydrogen, is important for determining the required investment in hydrogen production, storage and transportation capacity. Details can be found in Appendix C.

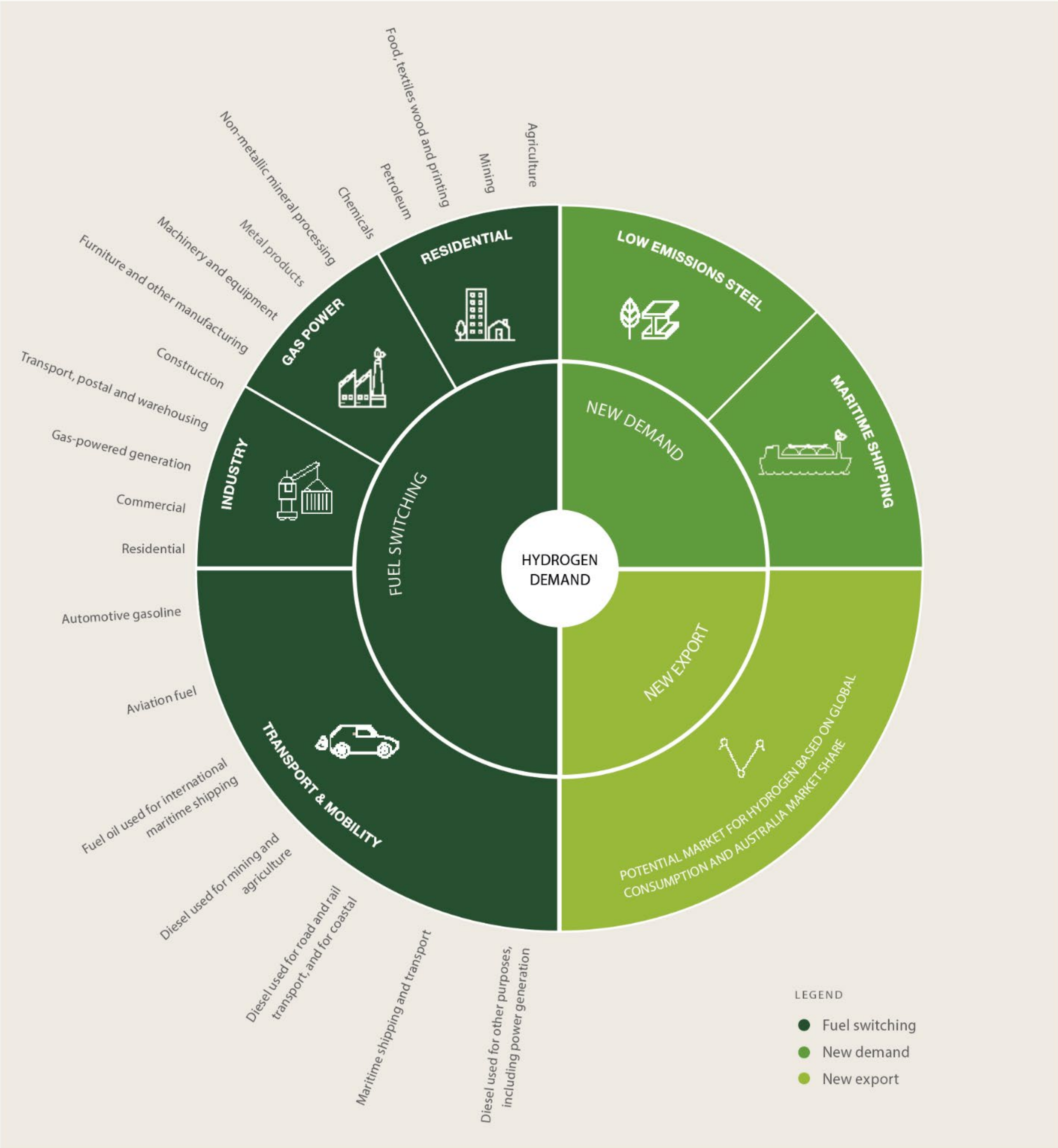

Figure 2.3.1 Diagram of disaggregated hydrogen demand sectors.

2.3.1 Demand for hydrogen due to switching from an existing fuel source to hydrogen

The potential for hydrogen to displace three existing fuel types - natural gas, liquid fuel and coal – was considered. Switching assumptions are informed by research on the technical capability for switching to hydrogen and the potential economics underpinning this switch. For many sectors, technology is still developing and there is considerable scope to reduce costs, which means that there is substantial uncertainty about these assumptions. This was reflected by varying the assumptions on the rate and timing of switching between the high, medium and low demand scenarios, as per Section 2.3.4.

Pricing and the influence this will also have on demand was considered in addition to technical developments. Without regulatory and pricing shifts driven by the decarbonisation agenda, hydrogen uptake will not occur if cheaper alternatives exist, and will be driven by competitive pricing against sources such as natural gas and liquid fuel, industrial processing feedstocks and international markets. This was factored into the assumptions involving timing and switching rates, with early switching rates driven by scenarios in technological advancement and hydrogen price competitiveness.

Switching from use of natural gas to use of hydrogen

Natural gas is used by industrial customers both as feedstock and for raising heat, by gas-powered generators to generate electricity and by commercial and residential customers for space heating, water heating and cooking. Each of these uses of natural gas has the potential to switch to hydrogen (or its derivatives), although other options to meet these energy demands are also available.

A main source for rate and pace of switching is the IEA's (International Energy Agency) Energy Technology Perspectives 2020 Report[18]. The report considers where clean energy technologies (such as hydrogen) stand today, the readiness of the technology for adoption, barriers to adoption, and the relative costs of competing clean energy technologies outlines estimates of when and the rate at which these technologies will be adopted.

Scenarios reflect AEMO's views on the key drivers of future demand by each customer group.[19] For example, residential and commercial consumption account for drivers of gas consumption such as population growth, retail gasprices and energy efficiency measures, while consumption by gas-powered generation accounts for the evolution of the generation technology mix in the NEM, particularly developments of renewable generation and retirement of coal-fired generation.

The hydrogen for the residential and commercial sectors is assumed to be delivered via the existing natural gas distribution network, initially by blending with natural gas (e.g. 10% hydrogen blend by volume) and, as hydrogen demand increases, by converting a growing number of network sections to 100% hydrogen.

Switching from use of liquid fuel to use of hydrogen

Liquid fuel is largely used for road, rail, aviation and maritime transport, but some is also used for other purposes such as mining and agriculture and for electricity generation. Each of these uses of liquid fuel has the potential to switch to hydrogen (or its derivatives), although other options to meet these energy demands are also available.

[18] '*Energy Technology Perspectives 2020'*, IEA, https://iea.blob.core.windows.net/assets/7f8aed40-89af-4348-be19-c8a67df0b9ea/Energy_Technology_Perspectives_2020_PDF.pdf

[19] As reported in *AEMO, Gas Statement of Opportunities, For eastern and south-eastern Australia, 2020* and *AEMO, 2020 Western Australia Gas Statement of Opportunities, 2020*

For many sectors, technology is still developing, which means that there is substantial uncertainty about these assumptions. This uncertainty is reflected by varying the assumptions on the rate and timing of switching between the high, medium and low scenarios (described in more detail in Section 2.3.4).

Switching from use of coal to use of hydrogen

Most coal used in Australia is used for electricity generation. Electricity from coal-fired generation can by replaced by electricity from other sources. The potential for hydrogen to be used in electricity generation is based on AEMO's scenarios of natural gas used for electricity generation. A smaller, and declining, amount of coal is also used for manufacturing, mostly iron and steel manufacturing. The use of hydrogen in steel manufacturing is accounted for in the assessment of the potential for a green steel industry in Australia.

2.3.2 Demand for hydrogen that represents new energy demand in Australia.

New energy demand for hydrogen may occur because the development of a hydrogen supply chain in Australia makes certain activities economic in Australia that would not otherwise be economic. The two new sources of energy demand driven by hydrogen supply chains that are quantified in this assessment are green steel production and hydrogen for use in international cargo shipping for Australia's imports and exports.

Low emissions steel

With substantial ore reserves, fossil fuel/CCS, solar and wind resources and potential for low emissions hydrogen production, Australia has the natural resources to produce and export low emissions steel. Estimates for the potential hydrogen demand for low emissions steel are based on; assumptions about the share of scenarios exports of iron ore that will be used domestically to produce low emissions steel, the amount of low emissions steel produced annually and hydrogen requirements for low emissions steel production.

Maritime shipping fuel

Abundant natural resources and opportunities for low emissions hydrogen production suggest that Australia may be a much more competitive source of fuel for international maritime shipping that makes use of hydrogen rather than liquid fuel. In a future where ships are powered by hydrogen (or ammonia), bunkering may increase in Australia to take advantage of low-cost supplies of hydrogen (or ammonia). Estimates for the potential hydrogen (or ammonia) demand for international maritime shipping are based on potential size of market for hydrogen bunkering-based estimates of global fuel use for international maritime shipping and estimates of the share of this that is powered by hydrogen (or ammonia), and Australia's share of the global market for hydrogen (or ammonia) bunkering based on Australia's share of seaborne international trade.

In a similar way to ammonia, methanol could also become a prominent hydrogen carrier to be used as a fuel for decarbonising shipping. While methanol was not included in this assessment due to its smaller role in hydrogen projects under development in Australia at the time of writing, we highlight that it could represent an additional investment opportunity in the future energy systems.

Currently, Australia's supply of fuel oil for international maritime shipping is much smaller than Australia's share of seaborne international cargo (by weight). This reflects the practice of bunkering at ports with lower cost supplies of fuel oil. In a future in which ships are powered by hydrogen (or ammonia), this practice may change with bunkering occurring in Australia to take advantage of low-cost supplies of hydrogen (or ammonia).

2.3.3 Demand for hydrogen for export

Export of hydrogen could occur where Australia has a competitive advantage in producing green hydrogen from its abundant renewable wind and solar resources. To estimate Australia's exports of hydrogen, estimates of global consumption of hydrogen (or its derivatives) are combined with the share of those imports Australia might capture. The assumption for the central demand scenario is that Australia will capture the same share of global hydrogen demand as it does currently with LNG (around 3%) by 2050.

Data for internationally traded fuels markets is used as a proxy to estimate the share of global hydrogen production that will be traded. Given the similar relative economics of international shipping of LNG and hydrogen, particular attention is paid to the patterns of global trade in LNG.

2.3.4 Demand locations

The National Hydrogen Strategy 2019[1] Hydrogen Hubs Report[20] initially identified criteria for domestic and export hub potential. Thirty potential export hubs were initially identified, and it was envisaged that sector coupling will be enabled for domestic and export demand at many of these initial hubs. As outlined in Section 1.4, initial hydrogen industry development activity in Australia has focussed on several hubs.

Hydrogen demand scenarios modelling for fuel switching use has aligned hydrogen demand locations with their current fossil fuel users. New hydrogen demand associated with export commodities is centred around port locations. Further discussion on selection of demand locations for techno-economic modelling is included in Section 3.1 and are summarised in Table 2.1 below.

State/Territory	Domestic Demand Node	Export Demand Node (Port)
Tasmania	Hobart	Bell Bay
Victoria	Melbourne, Geelong, Regional Vic (Bendigo)	Portland, Geelong
New South Wales	Sydney, Newcastle, Wollongong, Regional NSW (Tamworth, Hunter)	Newcastle, Port Kembla/Wollongong
Australian Capital Territory	Canberra	
Queensland	Brisbane, Gladstone, Darling Downs, Mt Isa, Regional Qld (Townsville)	Gladstone, Townsville
Northern Territory	Darwin	Darwin
Western Australia	Perth, Goldfields, Pilbara, Regional WA (Geraldton)	Fremantle and Kwinana/Perth, Oakajee/Geraldton, Port Hedland/Pilbara
South Australia	Adelaide, Regional SA (Port Augusta, Eyre Peninsula)	Port Bonython /Eyre Peninsula

Table 2.1 Domestic and export demand locations included in the model.

[20] https://www.nera.org.au/regional-hydrogen-technology-clusters

The development of a national hydrogen technology cluster was also identified in the Strategy as an important component to scale up Australia's domestic industry to become a global hydrogen competitor. The National Energy Resources Australia (NERA) have provided funding support for 18 emerging hydrogen technology clusters across Australia[21]. At the time of model development there were 69 hydrogen projects with government support[22]. It is noted during the development of the NHIA there has been further announcements on government supported hub and projects, including those supported by the Australian Government Regional Hydrogen Hubs program[23] (refer to Section 1.4).

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[21] NERA, https://www.nera.org.au/NERA-projects/H2TCA

[22] Geosciences Australia 2020, https://www.ga.gov.au/news-events/news/latest-news/mapping-australias-hydrogen-future

[23] https://www.industry.gov.au/news/funding-available-for-clean-hydrogen-industrial-hubs

2.3.5 Demand scenarios

Low, central and high demand scenarios were developed by combining assumptions of rates of fuel switching and hydrogen uptake. In combination, these scenarios provide a broad spectrum of potential eventualities against which infrastructure requirements can be assessed. These scenarios will progressively be refined in subsequent analyses, with the expectation that the NHIA be revised at least every five years.

SCENARIOS	LOW	CENTRAL	HIGH
GAS-POWERED GENERATION*	AEMO slow switching scenario.	AEMO central scenario.	AEMO fast switching scenario.
RESIDENTIAL AND COMMERCIAL GAS SWITCHING	Most appliances switch from natural gas to electric, ultimately no delivery of hydrogen through distribution network.	Initially, 10% blending of hydrogen with biogas in the distribution network, ultimately network switches to hydrogen and most existing gas customers remain connected.	Initially, 10% blending of hydrogen with biogas in the distribution network, ultimately network switches to 100% hydrogen and all existing gas customers remain connected.
INDUSTRIAL	High electrification, hydrogen used only for high heat processes and feedstock.	Medium electrification, hydrogen used for some medium heat processes and all high heat processes and feedstock.	Low electrification, hydrogen used for most medium heat processes and all high heat processes and feedstock.
AUTOMOTIVE GASOLINE AND DIESEL	Uptake of HFCV is slower with switching starting at 2030 and limited to 10% market share.	EV captures most of automotive market, HFCV limited to fleet vehicles due to range and charging. Switching occurs in 2025 and captures 20% market share.	HFCV uptake is fast and not limited to fleet vehicles. Automotive gasoline vehicles replaced at same rate as central scenario, 2025 switching starts with 20% market share cap.
REMOTE DIESEL USE	Remote diesel generators mostly replaced with renewables with batteries.	Remote diesel generators replaced with split of renewables with batteries and hydrogen generators or fuel cells.	Remote diesel generators mostly replaced with hydrogen generators or fuel cells.
AVIATION	Switching to start in 2040, with a share for hydrogen of 10% in over 30 next years.	Switching to start in 2030, with a share for hydrogen of 15% over next 30 years.	Switching to start in 2030, with a share for hydrogen of 40% over next 30 years.
SHIPPING	Low switch to hydrogen (or ammonia) powered shipping, Australia's share of bunkering does not increase.	Medium switch to hydrogen (or ammonia) powered shipping, Australia's share of bunkering increases.	High switch to hydrogen (or ammonia) powered shipping, Australia's share of bunkering increases.
EXPORT	Slower growth of international market for hydrogen. Lower share captured by Australia.	Medium growth of international market for hydrogen, aligned with AEMO. Medium share captured by Australia.	High growth of international market for hydrogen. Higher share captured by Australia.

* Natural gas forecasts – industrial (heat and feedstock), commercial, residential and gas-powered generation

Figure 2.3.2. Hydrogen demand growth scenarios divided by sector.

The significant uncertainty around the evolution of hydrogen demand in Australia has led to this study's sensitivity analysis with low, central and high demand scenarios covering a wide range of demand projections. Figure 2.3.3 presents the scenarios for hydrogen demand in Australia for the three NHIA demand scenarios, compared to what was presented in recent reports. The range of hydrogen demand considered in the NHIA encompasses the demand in the other studies, with the exception of the very low hydrogen demand in the Deloitte 'Electric breakthrough' scenario, which was developed in 2019 to analyse a future where technological improvements in hydrogen technologies are slow and where electricity-based options outcompete the hydrogen-based ones.[24]

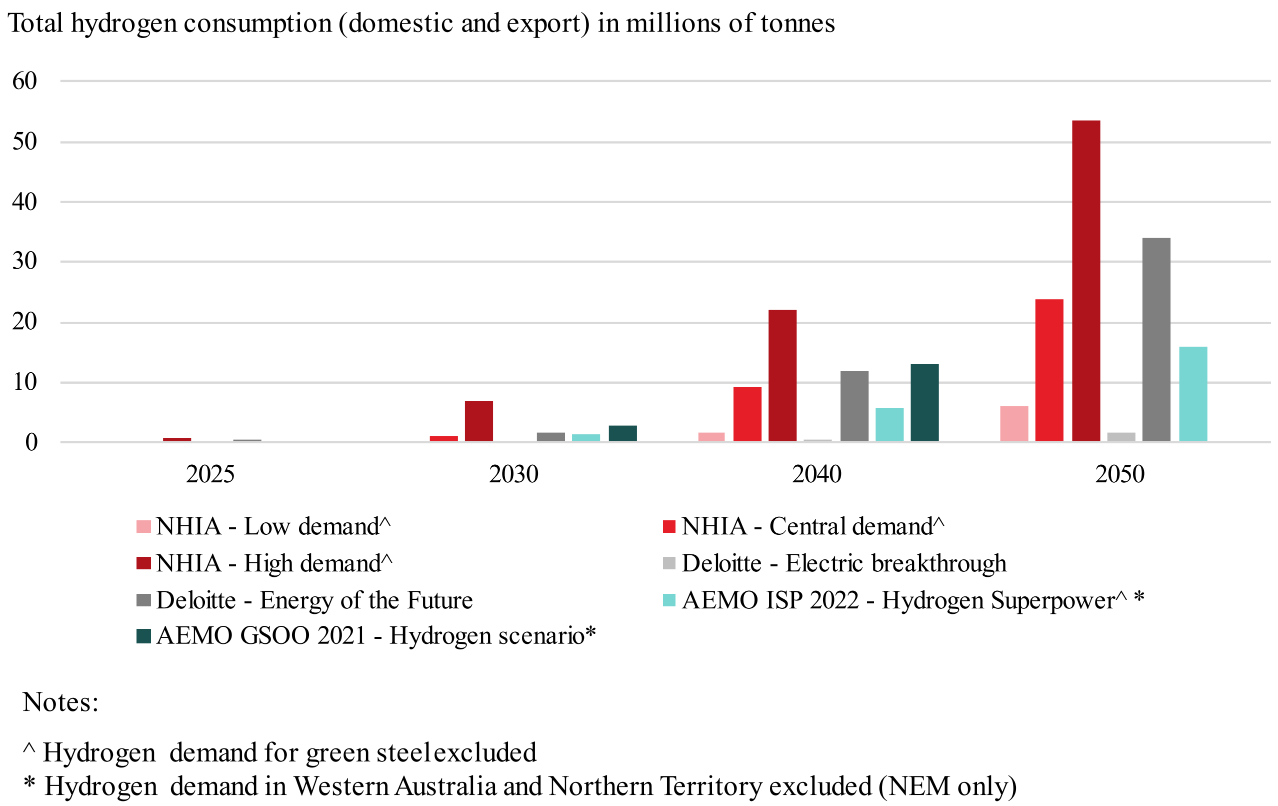

Figure 2.3.3 Comparison of hydrogen demand projections between NHIA base scenarios and other studies.[25]

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[24] Deloitte, 2019, Australian and Global Hydrogen Demand Growth Scenario Analysis

[25] External sources: Deloitte, 2020, ERRATUM: Australian and Global Hydrogen Demand Growth Scenario Analysis, pages 2-5. AEMO, 2021, Gas Statement of Opportunities 2021, page 66. AEMO, 2022, Integrated System Plan 2022, Inputs assumptions and scenarios workbook

2.4 Techno-economic modelling

2.4.1 Introduction and rationale

The purpose of the techno-economic assessment is to understand at a macro level the lowest cost supply chain configurations to meet each demand scenario, based on the input data and assumptions for hydrogen production, storage and transport. The model accomplishes this goal this by using a linear optimisation algorithm to find the configuration which best balances the costs of hydrogen production, storage, and transport to identify the configuration that leads to the lowest Levelised Cost of Hydrogen (LCOH) nation-wide.

By modelling the supply chain as a network of locations and links, the model can be flexible to identify a range of potential solutions, some of which may not be immediately obvious and may not match areas currently being focused on for investment and development. Many of the private project developments currently underway are focused on projects which are implementable, deliverable, and can access public funding or subsidies to improve viability. These private drivers, when pursued in parallel, may not necessarily result in optimal outcomes for the economy as a whole, unless independent system planning informs and incentivises outcomes that are in the public interest. This model allows for the informed, independent system planning required, while also allowing for interrogation of the impacts of other potential outcomes.

Arup deployed a Python-based network flow linear optimisation modelling package, Calliope[26], which was created specifically for the energy sector to address questions around the transition to renewable energy. It is used by leading energy specialists in industry and academia to develop solutions for complex, multi-technology energy supply problems at scales ranging from urban districts to entire continents.

The model takes a range of inputs and assumptions relating to locations and costs of hydrogen production and storage, locations and quantities of hydrogen demand, and methods for transporting hydrogen between production, storage and demand. The benefits of this type of model are its robustness and flexibility. It can be coded to model a wide variety of scenarios and constraints so that many questions can be interrogated.

2.4.2 Model structure

The underlying structure of the supply chain optimisation model can be separated into three main components:

- Technologies considered: the different technologies which have been included in the model with costs and technical constraints defined. These are the fundamental technologies which could be pivotal to forming a hydrogen supply chain across Australia
- Locations: the locations across Australia which could be utilised for the production of hydrogen, locations with potential hydrogen demand, and potential locations for large-scale geological storage of hydrogen
- Links: the allowable transmission links that hydrogen carriers can utilise to be transported across Australia to reach from the point of production to demand location.

Overall, the model produces the combination of selected technologies, production locations and links with the lowest LCOH to meet the hydrogen demand at each demand location and for each demand scenario.

[26] https://calliope.readthedocs.io/

NHIA Technology Considerations

The technologies and supply chains included in the model are presented in Figure 2.4.1.

The hydrogen production technologies assessed include Polymer Electrolyte Membrane (PEM) Electrolysis utilising renewable electricity for green hydrogen and either steam methane reforming or coal in combination with carbon capture and storage (CCS) technologies for blue hydrogen. PEM electrolysis was chosen as the modelled green hydrogen production technology due its higher flexibility of operation (faster ramp-up and ramp-down, and wider load range) compared to alkaline electrolysers. This was an important modelling consideration due to the intermittent nature of wind and solar PV generation.

Each of these hydrogen production technologies is \ assumed to produce low pressure hydrogen gas which needs to be converted into a higher density hydrogen carrier for long-distance transport. The hydrogen carriers considered in the model include compressed hydrogen gas (at a pressure of either 10 MPa or 35 MPa), liquefied hydrogen, ammonia, and a Liquid Organic Hydrogen Carrier (LOHC) – in this case Methylcyclohexane (MCH).

Each hydrogen carrier has an associated conversion technology to capture the cost of converting the hydrogen gas into the carrier required, i.e., a Haber-Bosch plant converts hydrogen gas into ammonia. Each carrier has multiple transport options available including rail, trucks and pipelines. The costs of transportation of each carrier varies for each technology dependent on factors such as the carrier's density. The assumption in this first iteration of the NHIA is that the existing natural gas transmission infrastructure cannot be converted to the use with hydrogen above a 10% hydrogen content by volume. It is noted that this assumption may not represent the future use of existing gas pipelines. In fact, there could be the possibility of converting at least a portion of transmission pipelines to 100% hydrogen and research is underway to confirm this. The use of existing natural gas pipelines to move blended hydrogen or 100% hydrogen may offer cheaper options for moving hydrogen rather than building new pipelines. This potential hydrogen transport pathway should be considered for the next assessment.

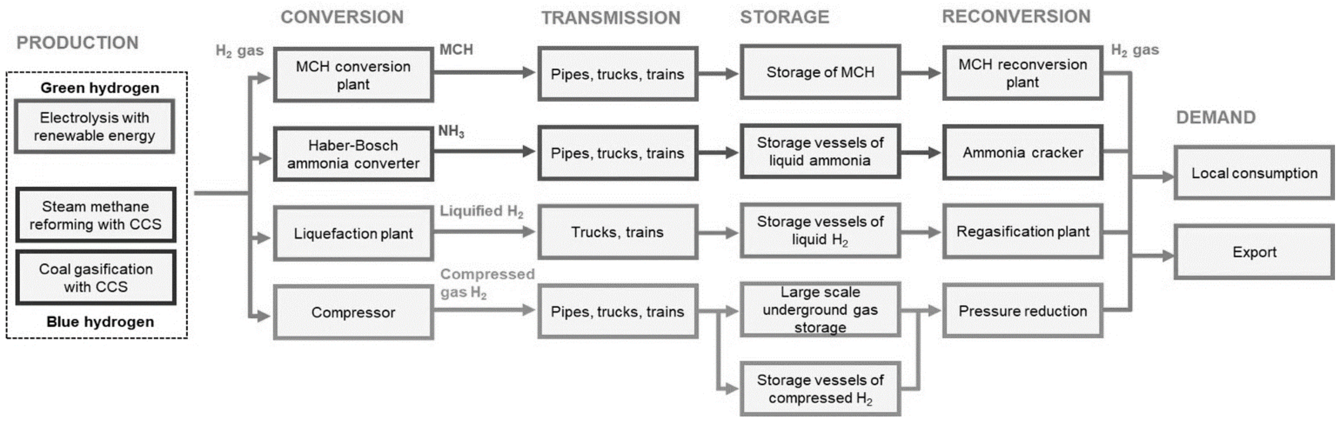

Figure 2.4.1 Hydrogen supply chains included in the techno-economic model.

Storage technologies are also included in the model and can be co-located at either the production or demand of the hydrogen.

Large-scale geological storage of hydrogen is also available to the compressed hydrogen gas carrier, utilising either salt caverns or depleted gas fields for storage which can scale up to an inter-seasonal capacity.

The hydrogen demand has been modelled as low-pressure hydrogen gas consistently across each demand location. Therefore, each hydrogen carrier must be reconverted at the demand locations. For example, liquid hydrogen must undergo regasification before the model is satisfied the hydrogen demand has been appropriately met. For export locations, the port is the demand point. As international buyer preferences are not yet defined, the assumption of all hydrogen demand in the form of gaseous hydrogen allows to optimise the supply chain for the lowest cost of hydrogen within Australia. In order to optimise the cost of the supply chain when considering the demand in an export appropriate hydrogen carrier (i.e., ammonia, liquefied hydrogen and MCH) a consideration would need to be made into off-taker preference, shipping distances and the costs at the receiving port which is outside of the model's scope.

Additionally, the modelling of a consistent form of hydrogen demand enables the model to identify the potential for common infrastructure when determining the lowest cost supply chains. Additional costs will be incurred in supply chains not making use of these opportunities to meet demand. If other demand carriers were to be considered this would add additional conversion costs from hydrogen gas to the respective demand carriers. These additional costs are discussed in Appendix B.1.3. The consideration of alternate hydrogen demand carriers could also mean less integrated networks with common infrastructure are outputted by the model, due to the segregation of hydrogen demand carriers potentially having upstream impacts on the hydrogen carriers selected in the optimised supply chain.

The key technical constraints and costs attributed to each technology have been summarised in Section 2.4.3 and Appendix B respectively.

Locations utilised in the model

The model requires specific production, demand, and allowable geological storage locations as inputs. In total, 66 unique production locations spanning across each state and territory were considered (excluding co-locating electrolysers at demand locations which is covered in further detail in Appendix A); 45 renewable energy locations which could house dedicated renewable energy generation to power electrolysers, 15natural gas locations and six potential coal gasification locations. These selected production locations were formed in consultation with state governments and referencing AEMO ISP and WAWOSP[27] (Whole of System Plan), utilising previously identified renewable energy zones as the starting point for green hydrogen production.

Commonwealth, State, and Territory Governments were consulted on the final proposed demand location, and they were modelled by Frontier Economics in their hydrogen demand scenarios. It should be noted that in some cases a region's demand had to be attributed to a singular location for the model, this location specification was conducted by Arup – further reasoning behind the specificity requirement for demand locations is covered in Appendix A.

The locations suitable for geological storage were compiled after consulting Geoscience Australia – with salt caverns and depleted gas fields being included in the model.

The graphic below provides an overview of all locations, and existing infrastructure transmission links, considered in the model optimisation. Depleted gas fields are represented in the map by the natural gas locations (FFG) since the assumption is that they are always available and co-located with natural gas extraction locations.

[27] Energy Transformation Taskforce WA *'Whole of System Plan'*, 2020, https://www.wa.gov.au/system/files/2020-11/Whole%20of%20System%20Plan_Report.pdf

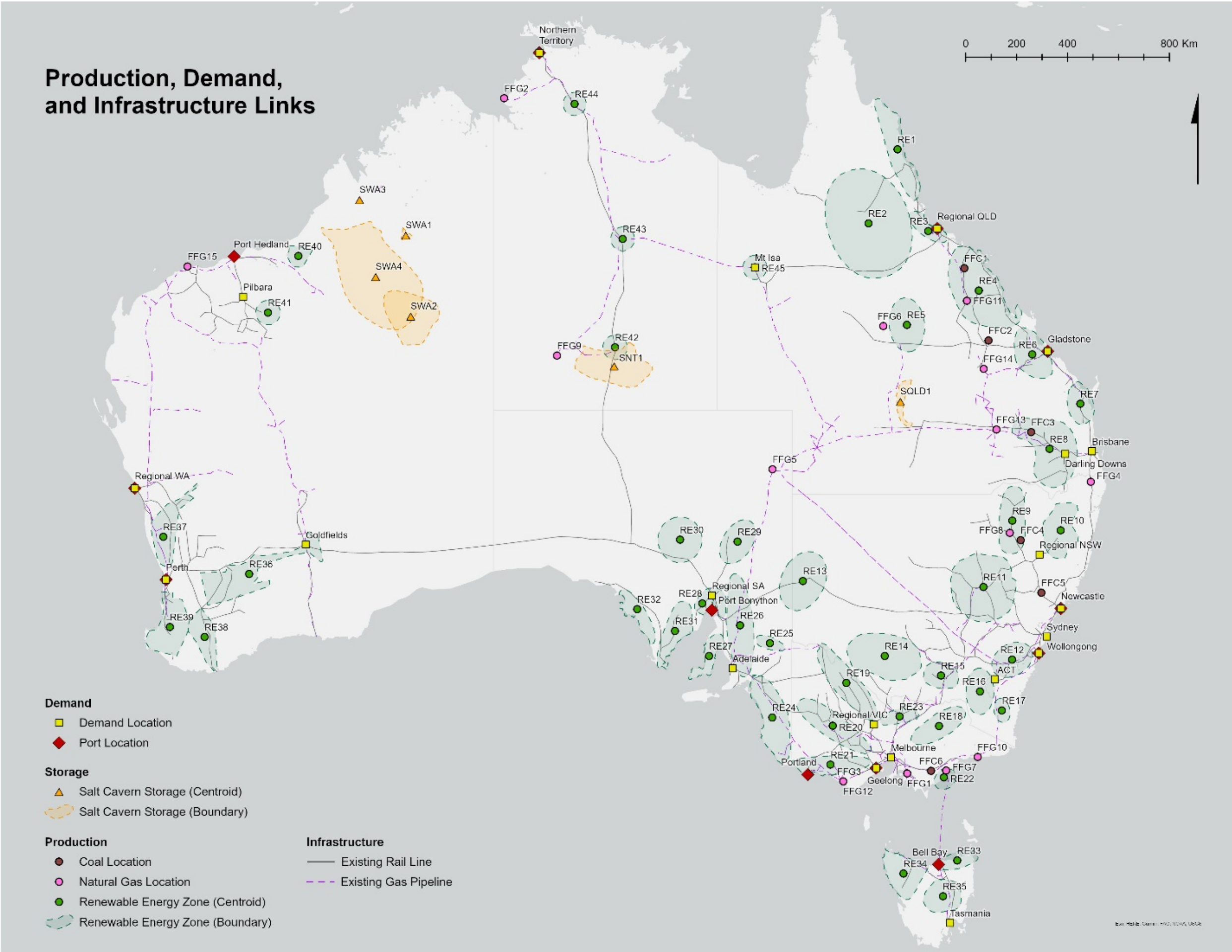

Figure 2.4.2 Hydrogen production, demand and storage locations and existing gas and rail infrastructure.

Links in Model

The 'Node and Link' model allows the transportation of the hydrogen carriers to be considered by multiple mediums. Two of the transportation options (building dedicated hydrogen pipelines and utilising dedicated trucks) were assessed independently of existing infrastructure across Australia. The other two transportation options (freight railways and blending with existing natural gas pipelines) are more limited based on the current infrastructure in Australia.

The list of allowable transmission links between locations in the model was created by analysing datasets covering the existing natural gas pipeline and railway networks. Figure 2.4.3 shows the hydrogen transport links that are allowed and optimised by the model. The links shown graphically are straight line distances between the nodes and do not represent exact routes. Green lines indicate links which allow for new truck routes or new pipelines, whereas brown lines indicate the possibility of transportation by railway or existing natural gas lines in addition to new truck routes or new pipelines, whereas blue lines indicate the use of underwater existing natural gas pipelines.

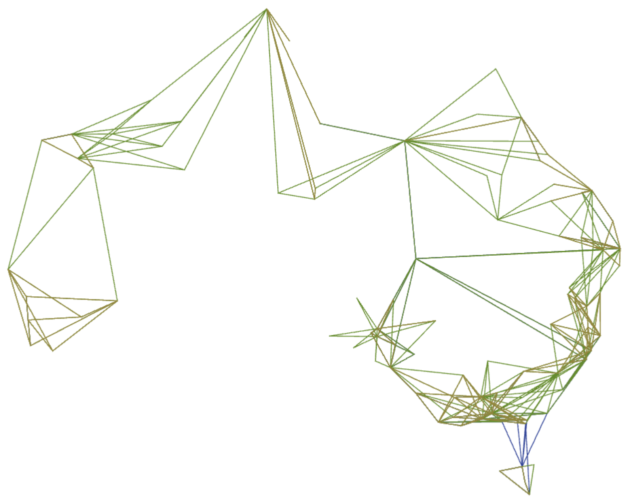

Figure 2.4.3 Hydrogen transport links allowed in the optimisation model.

Optimisation Stages

Due to the complexity of the energy system model, the optimisation process is broken down into three sequential stages to ensure a solution could be reached without restricting the number of technologies, locations and links to be considered. The outputs from each optimisation stage are used as an input for the following stage. The three sequential optimisation stages are shown in Figure 2.4.4.

Stage 1: Renewable energy mixture optimisation
Utilising an annual model with hourly granularity to determine the optimum ratio of solar PV, wind and electrolyser sizing to achieve lowest LCOH at each production location and timestep .

Optimum ratio of solar PV, wind and electrolysers for renewable energy production locations used as input in next stage.

↓

Stage 2: 'Unrestricted' model run:
Completely 'unrestricted' model run with no limitations on number of links or locations processed. Utilising an annual model at monthly granularity to ensure seasonal variation of hydrogen demand is still considered.

Links and locations outputted by the 'unrestricted' model are used as the only available links and locations for the final stage.

↓

Stage 3: 'Refined' model run:
Cost-capacity curve applied to transmission links identified in previous optimisation stage, this allows for assessment of shared infrastructure opportunities. Utilising an annual model at monthly granularity.

Figure 2.4.4 Optimisation stages of the techno-economic model.

2.4.3 Inputs and assumptions

A combination of discussions with collaborators, stakeholder engagement and publicly available references were utilised to determine the inputs and assumptions forming the basis of the model. Consultations were conducted with members of AEMO, CSIRO (The Commonwealth Scientific and Industrial Research Organisation) and Geoscience Australia to discuss the approaches taken for the model and the appropriateness of assumptions made.

Table 2.2 Summary of the references for the main techno-economic model inputs

Input for model	Main Reference(s) / Stakeholders Engaged
Electrolyser – technical performance and capex	CSIRO National Hydrogen Roadmap[28], IRENA (International Renewable Energy Agency) Green Hydrogen Cost Reduction 2020[29], IEA Future of Hydrogen[30], CEFC (Clean Energy Finance Corporation) Australian Hydrogen Market Study[31]
Blue hydrogen – steam methane reforming & coal gasification with CCS	IEA Future of Hydrogen, COAG (Council of Australian Governments) Energy Council Australia's National Hydrogen Strategy[4]
Hydrogen carriers – technical parameters, transport & storage costs (excluding geological storage costs)	IEA Future of Hydrogen, CSIRO National Hydrogen Roadmap
Renewable energy zones – location, costs, solar PV and wind generation profiles, build limits	AEMO Integrated System Plan (ISP) 2020[6], WA Whole of System Plan (WOSP)[27], CSIRO GenCosts[32], HySupply State of Play[33], RenewablesNinja[34]. *Stakeholder input:* The majority of the renewable energy production locations from the model were taken from the AEMO ISP, with members of the WA and NT government were consulted with for the selection of the renewable energy production locations in their respective states equivalent to the locations within the NEM.
Gas & Coal Production – locations & costs	AEMO ISP 2020, WA WOSP
Demand – locations and quantity	Developed by Frontier Economics for 2025 to 2050 (Appendix C) *Stakeholder input:* Engagement with the Bureau Of Steel Manufacturers Of Australia (BOSMA) resulted in changes to how hydrogen demand for green steel manufacture were distributed within the model.
Transmission infrastructure	Geoscience Australia Portal[35], AEMO ISP 2020
Geological hydrogen storage	Geoscience Australia Portal, BloombergNEF[36], Northern Gas Networks[37]

The table below provides an overview of some major inputs utilised in the development of the techno-economic model and their references.

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28 Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National Hydrogen Roadmap. CSIRO, Australia.

29 IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi

30 IEA (2019), The Future of Hydrogen, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen

31 '*Australian hydrogen market study*', CEFC 2021, https://www.cefc.com.au/media/nkmljvkc/australian-hydrogen-market-study.pdf

32 Graham, P., Hayward, J., Foster J. and Havas, L. 2021, GenCost 2020-21: Final report, Australia, accessed: https://data.csiro.au/collection/csiro:44228

33 R. Daiyan, I. MacGill, R. Amal, S. Kara, K.F. Aguey-Zinsou, M.H. Khan, K. Polepalle, W. Rayward-Smith. (2021). The Case for an Australian Hydrogen Export Market to Germany: State of Play Version 1.0. UNSW Sydney, Australia.

34 https://www.renewables.ninja/

35 Geoscience Australia, Geoscience Australia Portal, 2021, accessed: https://portal.ga.gov.au/

36 BloombergNEF, Hydrogen: The Economics of Storage, 2019

37 Northern Gas Networks, H21 Leeds City Gate Report, 2016, accessed: https://h21.green/app/uploads/2022/05/H21-Leeds-City-Gate-Report.pdf

Table 2.3 Summary of the techno-economic model inputs and assumptions

Financial

Input	Reference
Real pre-tax WACC	AEMO ISP 2020[38] – Central Scenario
Payback period for capital investments	Assumption – some exceptions are evident

Utilities

Input	Reference
Wholesale Electricity Cost	Calculated – average NEM wholesale electricity price for 2020 at 85% utilisation
Transmission Costs - % of wholesale cost	Assumption[39]
Total Electricity Cost: including transmission and LGCs (Large-scale Generation Certificate)	CER (Clean Energy Regulator), LGCs ceased for 2050 costing
Water	Assumption (taken from range of $1 - $4 for seawater desalination[40])
Natural Gas	AEMO ISP 2020, WA WOSP27, CORE Energy Gas Price Outlook[41]
Black Coal	AEMO ISP 20206
Brown Coal	AEMO ISP 2020

Hydrogen Production – 2025 value (2050 value)

Input	Reference
Electrolyser	IRENA: Green Hydrogen Cost Reduction[42]
Steam Methane Reformer with CCS	IEA Future of Hydrogen Assumptions[43]
Coal Gasification with CCS (black)	IEA Future of Hydrogen Assumptions
Coal Gasification with CCS (brown)	IEA, CSIRO
Carbon Capture and Storage (CCS)	Assumption within range of IEA p. 2, CSIRO National Hydrogen Roadmap p. 8128, CarbonNet project estimate, Global CCS Institute p. 38[44]

Notes:

* Tested as sensitivity to model

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[38] AEMO, ISP Inputs and Assumptions Workbook, 2019, Australia, accessed: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions

[39] Assumed flat-rate transmission cost of 7% utilised due to modelling existing network being outisde boundaries of techno-economic modelling – validity of assumption discussed with AEMO. Transmission cost does not include network or environmental charges

[40] Desalination Fact Sheet, Australian Water Association Australia, accessed: https://www.awa.asn.au/resources/fact-sheets

[41] CORE Energy & Resources, Delivered Wholesale Gas Price Outlook 2020-2050, 2019, Australia, accessed: https://aemo.com.au/-/media/files/electricity/nem/planning_and_scenariosing/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_report.pdf?la=en&hash=4D53CA4DD239E0A075336D0B572462C7

[42] IRENA, Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, 2020, Abu Dhabi, accessed: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

[43] IEA, Future of Hydrogen: Assumptions Annex, 2019, accessed: https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions

[44] Global CCS Institute, March 2021, Technology Readiness and Costs of CCS, p38, accessed: https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCS-Tech-and-Costs.pdf

Values vary across locations in Australia

+ Values vary across years considered in model (2025, 2030, 2040 and 2050)

Additionally, the tables in Appendix B covers the conversion, transmission and storage assumptions unique to each hydrogen individual hydrogen carrier considered in the model: compressed hydrogen gas, liquefied hydrogen, ammonia, Liquid Organic Hydrogen Carrier (LOHC) – in this case methylcyclohexane (MCH).

Green hydrogen

Green hydrogen is defined as hydrogen that is produced from renewable energy. For the purpose of this analysis, green hydrogen production is based on water electrolysis powered by solar PV and wind, in line with the most developed renewable resources in Australia. Polymer Electrolyte Membrane (PEM) electrolysers were selected as the preferred green hydrogen production technology on the base of their high stack life, efficiency and load flexibility compared to other technologies such as alkaline electrolysers.

Renewable electricity

In the techno-economic model, green hydrogen production facilities can either be co-located with the renewable power generation system or can be positioned directly at the hydrogen demand location. The quality of renewable resources, the distance between renewable generation areas and hydrogen demand locations, and the cost of transporting hydrogen versus transmitting power all play a role in deciding where hydrogen production plants should be located.

At each dedicated renewable energy production location, a combination of behind-the-meter solar PV and wind generation is available to power the electrolyser. The full list of renewable energy locations is provided in Appendix A. The solar PV and wind ratio that achieves the best combination of electricity cost and capacity factor leading to the lowest cost of hydrogen was optimised for each timeframe and renewable energy zone by simulating the performance of a solar PV/wind/electrolyser system over a whole year by using the solar PV and wind renewable hourly generation profiles.

These profiles were obtained from AEMO, HySupply and RenewablesNinja. The results of this analysis, which include the ratio of solar PV and wind, the renewable power capacity factor and the levelised cost of renewable electricity, were used as inputs in the model.

To produce green hydrogen directly at the demand locations the electricity used must be zero-emissions. For electrolysers connected to the power grid, unless the grid is fed by 100% renewable sources as it is assumed to be the case in 2040 and 2050, renewable power can be purchased via renewable Power Purchase Agreements (PPAs). For the 2025 and 2030 timesteps, this has been costed on the wholesale cost of electricity with an additional transmission cost and the need to purchase an equivalent number of Large-scale Generation Certificates (LGCs). The Large-Scale Renewable Energy Target scheme that governs the generation of LGCs ends in 2030, so a cost was included post-2030.

The production limit for each renewable energy zone on the NEM was based on the build limits set out in the AEMO ISP 2020[6], however for each zone a combination of wind and solar PV was allowed to be used to meet the overall maximum production limit. The production limit for renewable energy production locations in Northern Territory and Western Australia were selected to align with the scale of production limit seen in the NEM locations, allowing greater amount of behind-the-meter renewable energy to be installed in more regional locations. For example, most green hydrogen production locations in Western Australia and in the Northern Territory a build limit of 10 GW was assumed, however for the remote green hydrogen production locations in the Pilbara (Western Australia) and Mt Isa (Queensland), a larger build limit of 23 GW was assumed.

The AEMO ISP 2020[9] provides data on the potential to build new solar and wind energy capacity in each REZ along the NEM. The combined solar and wind limit as presented by AEMO was used in the model assumptions to set limits to the available renewable capacity in the production locations. Based on the information provided in the AEMO '2019 Input and Assumptions workbook'[45], it is our understanding these capacity limits were determined from a combination of transmission restrictions and land availability considerations.

Costing

The cost of producing green hydrogen is influenced by several factors:

- Cost and capacity factor of renewable electricity (behind-the-meter or grid + LGC)
- Hydrogen production facility technical and economic parameters, including efficiency, utilisation rate, and capital and operational costs.

The cost and capacity factor of the electricity supply is the main parameter that influences the cost of hydrogen production. For behind-the-meter hydrogen production the electrolyser is assumed to follow the hourly profile of the renewable power resources (no battery or other buffer energy system between power resources and electrolysis plant is assumed in the model). Renewable resources that achieve a high capacity factor while maintaining low production cost lead to the lowest cost of hydrogen.

In the model, for each renewable location and each timeframe, the solar PV/wind capacity ratio was optimised to achieve the lowest cost of hydrogen in each timeframe. The best configuration varies between timeframes due to the changes in the cost of renewable power technologies, as well as in the capital cost and efficiency of the electrolysis systems.

In the case of grid-connected electrolysers, the utilisation rate was assumed constant for all locations and equal to 85% to account for planned and unplanned maintenance. The additional cost due to the transmission of power from the generation location to the hydrogen production site was assumed to be 7% of the cost of electricity.

Electrolyser technologies are expected to continue to develop in the near future. Data from the International Renewable Energy Agency (IRENA) was used in the model to estimate the future improvements in cost and efficiency of the technology.

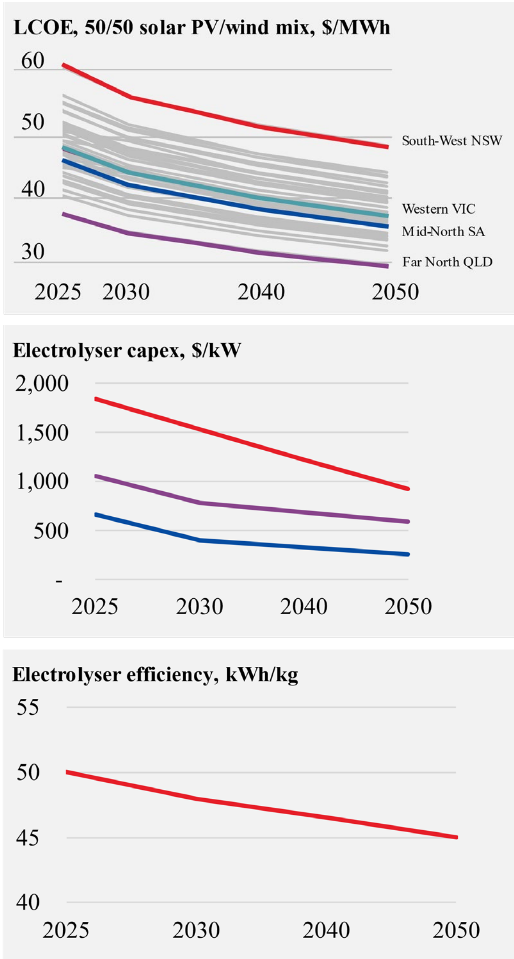

Figure 2.4.5 Estimated evolution of main economic parameters for green hydrogen production

Blue hydrogen

Blue hydrogen technologies of steam methane reforming of natural gas and gasification of coal,

[45] https://aemo.com.au/-/media/files/electricity/nem/planning_and_scenariosing/inputs-assumptions-methodologies/2020/2019-input-and-assumptions-workbook-v1-5-jul-20.xlsx?la=en

both with CCS have been modelled together with green hydrogen production in the 'low emissions' scenario. The model selects the preferred hydrogen production technology for each location based purely on what technology can provide the lowest cost of hydrogen.

The model includes 15 natural gas locations and 6 six coal gasification locations. These selected production locations were identified in consultation with state governments and referencing AEMO ISP[6] and WA WOSP[27], and are based on the availability of the local resource as well as on the assumption that carbon dioxide can be stored nearby (see below section).

Costing

The economic base for the techno-economic model selects the required hydrogen infrastructure by optimising for the lowest whole system cost to develop supply chains that meet demand at the demand locations.

For blue hydrogen technologies, the LCOH is determined by including the following parameters:

- Cost of fuel (natural gas or coal)
- Production technology technical and economical parameters
- Cost of carbon dioxide separation, compression, transport, and storage.

The cost of fossil fuel input is a crucial component of the LCOH, particularly for hydrogen production from SMR. The future price of natural gas at each production location and for each modelled timeframe is estimated from AEMO GSOO and CORE Energy Gas Price Outlooks[46].

The forecast gas price presents little variation between the 2025 and 2050 timeframes, with the average price increasing only slightly from \$7.7/GJ to \$8.7/GJ.

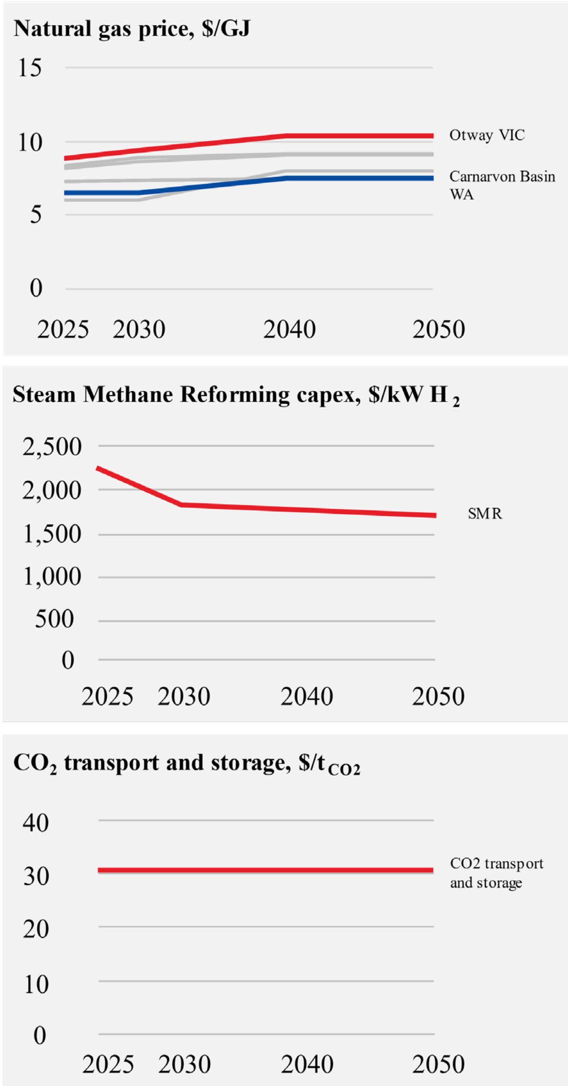

Figure 2.4.6 Estimate of the evolution of main economic parameters for hydrogen production from SMR + CCS

[46] *'Delivered Wholesale Gas Price Outlook 2020-2050'*, CORE Energy & Resources December 2019, https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_scenariosing/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_report.pdf?la=en&hash=4D53CA4DD239E0A075336D0B572462C7

For coal gasification, the largest component of the LCOH is the large initial upfront CAPEX of setting up the plant, ranging from \$3,650 / kW H_2 to \$4,315 / kW H_2 for black and brown coal respectively and inclusive of carbon capture. The data for the technologies technical and economical parameters (CAPEX, OPEX (Operating Expenses), efficiency and capacity factor) were retrieved from the IEA 'The Future of Hydrogen' report[22] and relative appendix[47]. The coal price is assumed to remain constant from 2040 to 2050.

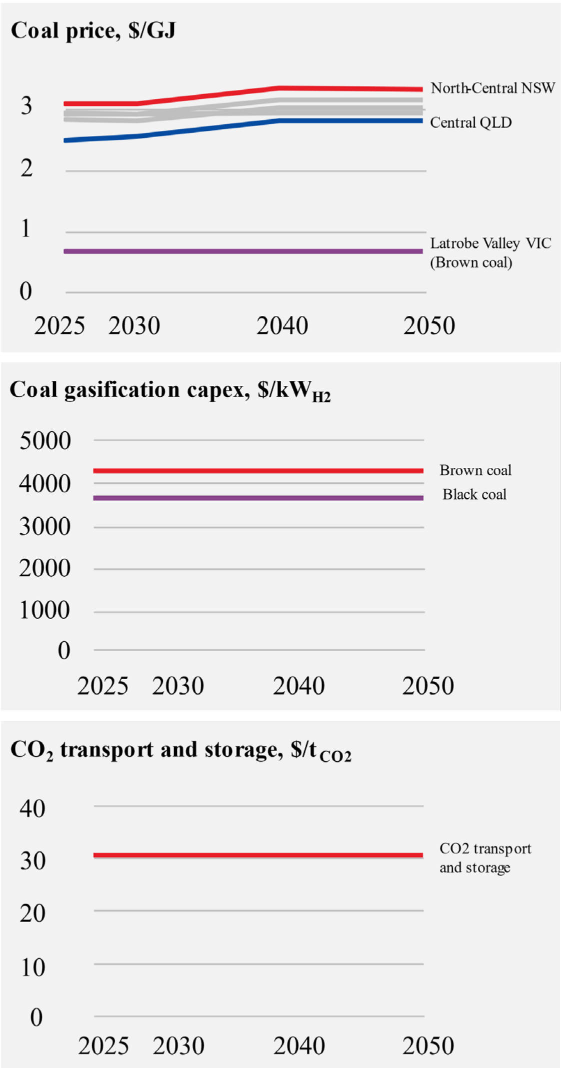

Figure 2.4.7 Estimate of the evolution of main economic parameters for hydrogen production from coal gasification + CCS

[47] International Energy Agency, December 2020, The Future of Hydrogen – Assumptions annex, Revised version, https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf

Cost of carbon dioxide capture and compression

The cost of carbon dioxide capture and compression was based on the information available from two detailed reports on hydrogen production from coal and natural gas released by the IEAGHG in 2014[48] and 2017[49]. The capture and compression of CO_2 increases the complexity of the hydrogen production plant, raising its capital and operational costs as well as reducing its overall efficiency. This impact was included in the CAPEX and OPEX of the blue hydrogen production technologies.

Cost of carbon dioxide transport and storage

The cost of CO_2 transport and storage was added separately. Publicly available data on the specific CAPEX and OPEX costs for these components of the CCS technology is very limited. Therefore, this cost was added as a 'service cost' and estimated on a dollar per tonne of stored CO_2 basis.

The selected value for the implementation in the model is \$30/tCO_2 (tonnes of CO_2). This is based on the literature review on CCS and on conversations with the CarbonNet Project representatives. A summary of the cost of transport and storage costs for CO_2 is presented in the table below.

Table 2.4 Review of costs for carbon dioxide transport and storage

Data source	Inclusions in cost of CCS	Cost (currency)	Cost (2021 A$)
IEA, 2019, The Future of Hydrogen[22]	CO_2 transport and storage	20 \$/tCO_2 (2019 US\$)	26.2 A\$/tCO_2
Communications with CarbonNet	CO_2 compression, transport and storage	30 – 50 \$/tCO_2 (2021 A\$)	30 – 50 A\$/tCO_2
CSIRO, 2018, National Hydrogen Roadmap[16]	CO_2 transport and storage	10 – 40 \$/tCO_2 (2018 A\$)	10 – 40 A\$/tCO_2
Global CCS Institute, 2021, Technology readiness and costs of CCS[50]	CO_2 transport, storage and monitoring	\$5.5 – 48 \$/tCO_2 (2020 US\$)	7 – 63 A\$/tCO_2

The table above shows the variability (and uncertainty) in the estimated cost of CO_2 transport and storage. In addition, this cost will vary on a site-by-site basis, depending on the CO_2 flowrate, distance between production and storage injection well, onshore or offshore location of the storage site and project life.

Based on the \$30/tCO_2 assumption, carbon transport and storage adds approximately 0.27 \$/kgH_2 (kilograms of H_2) and 0.57 \$/kgH_2 to the LCOH for SMR and coal gasification produced hydrogen respectively. This corresponds to between 10% and 20% of the total LCOH for Blue Hydrogen.

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[48] IEAGHG, May 2014, CO_2 Capture at Coal Based Power and Hydrogen Plants, https://ieaghg.org/docs/General_Docs/Reports/2014-03.pdf

[49] IEAGHG, February 2017, Techno – Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS, http://documents.ieaghg.org/index.php/s/HKtMncwfw2vaBxl

[50] Global CCS Institute, March 2021, Technology readiness and costs of CCS, https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCS-Tech-and-Costs.pdf

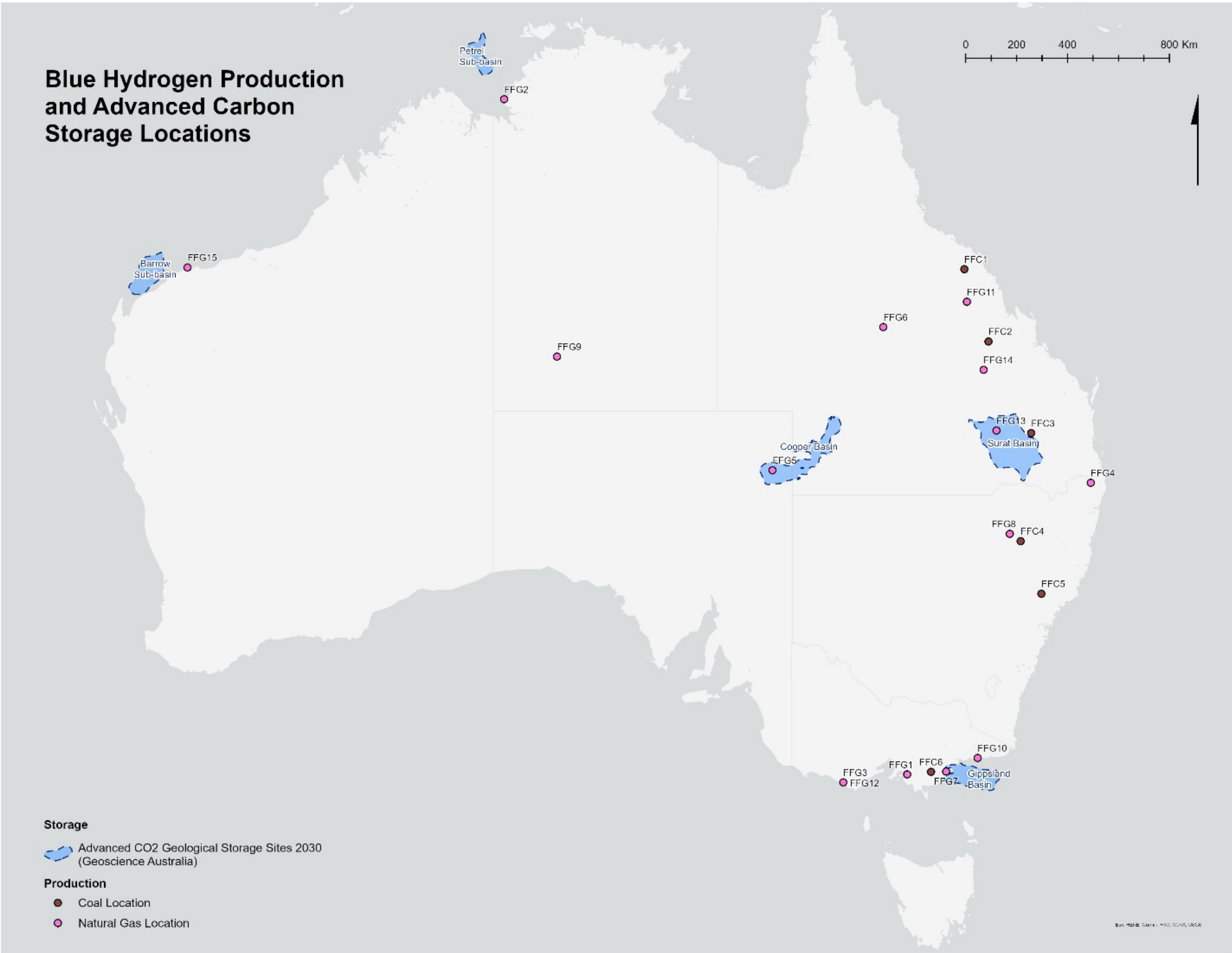

Figure 2.4.8 Blue hydrogen production locations and advanced CO_2 geological storage sites [51]

Assumptions and limitations to blue hydrogen

The following assumptions and limitations to the implementation of blue hydrogen were included in the model to take into account the scalability of the technology and the technology readiness level. These include:

- Minimum size limit applied due to the economy of scale of CCS, assumed to be not feasible at the small scale due to large, fixed costs for geological exploration, wells testing, and wells drilling
- Maximum size of blue hydrogen installations limit applied due to limits to CO_2 injection flowrates. The limit included in the model is 5.0 $MtCO_2$ (Megatonnes of CO_2) per year, based on the planned injection rate of the CarbonNet project in the Bass Strait. For reference, the Gorgon carbon dioxide injection project in Western Australia has a planned injection rate between 3.3 and 4.0 Mt/year[52]. At this site, 2.2 $MtCO_2$ were injected in the 2020-2021 financial year due to issues with the pressure management system. [53]

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[52] Western Australia – Department of Mines, Industry Regulation and Safety, Gorgon carbon dioxide injection project, https://www.dmp.wa.gov.au/Petroleum/Gorgon-CO2-injection-project-1600.aspx

[53] Chevron, 17 November 2021, Gorgon Gas Development and Jansz Feed Gas Pipeline - Environmental Performance Report 2021 p.44, https://australia.chevron.com/-/media/australia/our-businesses/documents/gorgon-gas-development-and-jansz-feed-gas-pipeline-environmental-performance-report-2021.pdf

Availability of CCS for blue hydrogen from 2025. It has been assumed that options for CCS would not be available for blue hydrogen until after 2025 due to the short timeframe available for development and the small scale of hydrogen production (CCS is assumed not to be feasible at the small scale as noted above). While it is acknowledged that there is potential for specific trials and demonstration-scale projects to reach completion by 2025 (e.g., Moomba CCS project), the model assumption indicates that such developments should not be expected to be available in every natural gas and coal locations.

Additional considerations on blue hydrogen

Assuming a 90% CO_2 capture rate, the direct emissions for the production of blue hydrogen are not 'zero' and are estimated at:

- 1.0 $kgCO_2/kgH_2$ for SMR with 90% capture rate
- 2.1 $kgCO_2/kgH_2$ for coal gasification with 90% capture rate

Direct emissions do not include fugitive emissions generated from the mining and extraction of coal and natural gas. These emissions, which are dependent on the specific fossil fuel extraction site, were not estimated for this assessment. However, it should be noted that they can be significant, and considerably higher than direct emissions.

Consideration may need to be made into the additional tariff costs and restrictions on exporting blue hydrogen, such as the impact of initiatives such as the EU Carbon Adjustment Border Mechanism (CBAM)[54]

The vast majority of hydrogen projects under development in Australia are based on electrolysis powered by green electricity, reflecting a climate currently more favourable to zero emissions options.

Limited detailed understanding of the potential of Australian basins to accommodate CO2 storage, further investigations are required. The water required for the gasification of brown coal could be provided by the moisture content of the lignite, potentially removing the need for water supply infrastructure and related costs.

2.4.4 Scenarios and sensitivities

The model was run annually to meet the hydrogen demand scenarios for four unique timesteps: 2025, 2030, 2040, and 2050.

Both the magnitude of hydrogen demand and the cost of essential components may differ depending on the year modelled i.e., renewable electricity generation and electrolysers are expected to reduce in cost. This allows the analysis of how the preferred hydrogen supply chain may evolve over the next 30 years, while considering the effect of future technology costs. Furthermore, the low, central, and high demand scenarios are tested across each year, providing guidance on the scale of infrastructure and lowest supply chain cost configuration for an indicative lower and upper bound of infrastructure required to meet the hydrogen demand in those scenarios.

The scenarios and sensitivities tested by the model were designed to provide an understanding into how uncertainties in the cost and technical performance of developing technologies may affect the configuration of the preferred hydrogen supply chain. Whether key infrastructure is susceptible to changes in different scenarios is one way of tracking the security of a major infrastructure investment. The scenario and rationale table below provides context around the insight that is to be gained from each scenario tested.

[53] Chevron, 17 November 2021, Gorgon Gas Development and Jansz Feed Gas Pipeline - Environmental Performance Report 2021 p.44, https://australia.chevron.com/-/media/australia/our-businesses/documents/gorgon-gas-development-and-jansz-feed-gas-pipeline-environmental-performance-report-2021.pdf

[54] Council of the EU, 15 March 22, Council agrees on the Carbon Border Adjustment Mechanism (CBAM), accessed: https://www.consilium.europa.eu/en/press/press-releases/2022/03/15/carbon-border-adjustment-mechanism-cbam-council-agrees-its-negotiating-mandate/

Table 2.5 Summary of scenarios tested in the techno-economic model

Scenario	Description	Rationale
Base case	Utilises main set of inputs and assumptions to provide 'base' case supply chain. Tested for low, central and high hydrogen demand scenarios.	Provides base model results for which the effect of sensitivities (both technical and economical) can be tested. Provides comparison of infrastructure required for varying hydrogen demand.
Electrolyser – capex sensitivities	Using low, medium, and high cost estimates for electrolysers capex	Uncertainty of future capex of electrolyser technologies is great, it will be important to assess how significant the uncertainty of electrolyser capex changes the resulting supply chain configuration.
Geological storage excluded	Large-scale geological hydrogen storage opportunities excluded	Large-scale geological storage opportunities typically have significant uncertainty in their availability and viability.
Existing infrastructure included	Allowing for the usage of existing railway and natural gas pipeline infrastructure to transport hydrogen carriers	Due to uncertainties unique to each portion of existing infrastructure (i.e. current usage of each railway portion, whether they will be available for future use, current available operating capacity), use of existing infrastructure was excluded from the base case. This scenario allows for the assessment of the existing infrastructure, noting that further feasibility work would be needed to determine if any particular piece of infrastructure identified via the model is suitable to be utilised for hydrogen transport.
Low emissions technology included	Allowing for hydrogen production from both electrolysis and from fossil fuel derived production with CCS allowed	Major uncertainties surround the usage of blue hydrogen production, including the technical and economic feasibility of large-scale carbon capture, transportation and storage and hence it has been excluded from the base case. This scenario allows for the economic assessment of the potential utilisation of blue hydrogen.
Grid electricity high	Utilising average wholesale electricity price from 2017-18 in NEM (i.e. $90/MWh)	Using alternate price of purchasing renewable energy through the grid to see effect on utilisation of renewable energy production locations vs co-located electrolysers at demand nodes, as well as overall impact on LCOH
Incumbent green steel	Scenario whereby green steel is made by existing industry	Analyses the hydrogen infrastructure required if steel production locations stay the same geographically as current steel production.
Green steel iron-ore	Green steel production at location of major iron ore deposits in the Pilbara	Analyses the hydrogen infrastructure required to support a green steel industry sized to process the current iron ore production and co-located with operating iron ore extraction locations within Australia.
Northern export demand	Base scenario splits demand between nominated ports equally. This scenario allocates all export demand to three Northern geographical ports: Pilbara (Port Hedland), Northern Territory (Darwin), Queensland (Gladstone). Low emissions technology has also been included.	Analyses the impact on the overall supply chain and infrastructure requirements if only a select few major ports are to be utilised for hydrogen export.

2.4.5 Outputs

The model outputs the lowest cost supply chain it has determined to meet the demand quantities inputted into the model. The solved supply chain indicates the capital costs, operating costs, carrier consumption / production (i.e., quantity of each energy vector consumed by each piece of infrastructure), as well as the capacities of the infrastructure required. From these outputs the LCOH of the overall supply chain and infrastructure components was determined, as well as an analysis of trends of locations utilised in model and preferred hydrogen production pathways. Guidance on the graphical results produced for each supply chain is provided in Section 3.1.

2.5 Wider considerations for techno-economic assessment

The techno-economic model provides an analysis of the lowest cost hydrogen supply chains based on modelled parameters. There are many wider aspects to consider when optimising the development of lowest cost hydrogen supply chains. Of particular note are the following:

- Water availability and supply infrastructure
- Land use availability, environment and planning considerations
- Shared infrastructure opportunities associated with hydrogen hubs

These are at discretion of individual planning authorities, investment and private developer decision making, and are being undertaken in real time with project proponents and governments seeking best way forward and not within the scope of this assessment. The following assessment however provides a proxy for these considerations to inform the NHIA at this point in time as outlined below.

- Water stress
- Land use mapping – protected areas, environmental value and other planning constraints
- Hydrogen industry snapshot - locations of hydrogen industry development activity from public and private sector (refer to Section 2.3.4)

These aspects are regionally relevant and are further discussed in the State and Territory insights in Section 4.

2.5.1 Water supply requirements

Water is required as an input to all hydrogen production and its availability and supply is a crucial consideration in location of hydrogen developments. The water requirements vary considerably depending on the hydrogen production technology, the specific design of the production plant and the quality of the water source.

Hydrogen production requires water for the following purposes:

- Water is a fundamental feedstock for the chemical reactions in both blue and green hydrogen production processes considered in this analysis, noting requirements are much larger for green
- Water is often consumed in the cooling systems required by hydrogen production processes.

The water consumption values used in this assessment were assumed to be the same for each hydrogen production location and are as follows:

- 30.3 litres of water per kg of hydrogen from electrolysis (14.5 L/kg – 152 L/kg according to ‘Water Usage in Hydrogen’ study)
- 13.6 litres of water per kg of hydrogen from SMR + CCS (8.4 L/kg – 61 L/kg according to ‘Water Usage in Hydrogen’ study)
- 31.5 litres of water per kg of hydrogen from black coal gasification + CCS (not included in ‘Water Usage in Hydrogen’ study).

The water requirements at production nodes associated with the hydrogen supply chains for the NHIA assessment were based on estimates by the U.S. Department of Energy’s Argonne National Laboratory[55]. These values, which include both water consumption for feedstock and system

[55] Argonne National Laboratory, 2015, Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels

cooling, were also subsequently compared and found to be within the water consumption ranges identified in the ‘Technical paper – Water for Hydrogen’ study (Arup, 2022).

For each hydrogen production location in the model, the total annual water consumption was estimated by multiplying the amount of hydrogen produced in one year in that location by the water consumption coefficient for the specific production technology.

The extent of water use for hydrogen at each location was then used to understand potential water supply chain risks and compared to the local future water stress level as identified by the World Resources Institute (WRI). Locations of high water stress are expected to have higher competition for water resources and can in this way be used as a proxy for potential higher cost of water supply and infrastructure requirements (water treatment, desalination, water pipelines).

Since the high-level analysis of this assessment did not detail the specific water infrastructure required by each hydrogen production location, a flat rate cost of water supply was used to estimate the impact of the cost of water to the overall hydrogen production cost.

2.5.2 Environment and land use planning

Development of the hydrogen supply chains will need to consider avoiding and mitigating potential engineering risks (e.g. geotechnical, safety, hazards etc) as well as impacts to environment and the community. Developments require regulatory planning approvals which take into consideration the relative compatibility of land use of the proposed development and potential social and environmental impacts. Locations of high environmental value and protected land use which have Australia-wide databases have been used to inform this high-level desktop assessment.

Whilst the regulatory environment of each jurisdiction varies, the extent of land use constraints for hydrogen development can be used to understand potential regulatory approval risks which can in this way be used as a proxy for higher supply chain development costs to avoid or mitigate impacts.

3 Modelling Results & Insights

3 Modelling Results and insights

The following provides a summary of the results and insights of the techno-economic model. Unless predicated otherwise this discussion relates to supply chains requirements to meet the central hydrogen demand scenario. The Australian hydrogen economy is expected to develop quickly and will require the rapid scale up of several technologies and supply chain elements. These will include renewable energy systems, large-scale electrolysers, water pipelines and desalination plants, hydrogen pipelines and geological hydrogen storage.

Small- and medium-scale storage in the form of a hydrogen carrier, including the related conversion and reconversion facilities will also form part of the landscape, however the decision on the hydrogen carrier (liquid hydrogen, ammonia or a liquid organic hydrogen carrier) will depend on the specifics of each project and on the final use of hydrogen.

Based on the hydrogen demand in the modelled scenarios and REZ locations and capacities, it is expected that renewable generation capacity in some REZs will become constrained by 2040 due to hydrogen demand alone, not accounting for other renewable energy requirements of the economy (see Section 3.4.1). The renewable power generation required by hydrogen production alone is expected to climb to 1,090 TWh by 2050, requiring 26 times the generation from wind and solar PV than in 2019-20.[56]

The AEMO ISP is regularly updated to consider the system planning requirements of the grid. In addition, statutory planning of the REZs is underway in several jurisdictions, including consideration of dedicated offshore REZs, which will help to alleviate onshore pressures. Potential expansion of REZ's, particularly those located in regional / remote areas may also be possible. Early market trends are showing that the very large (GW) export scale projects are investigating behind-the-meter renewable energy from regional areas, both within and beyond REZs where land is available. The transport of molecules generally provides a more cost-effective option particularly over longer distances, compared to the transport of electrons.

In 2025 and 2030 most hydrogen is generated directly at the demand locations, produced in electrolysers powered by the grid. This additional electricity demand for hydrogen production, similar to what is included in the AEMO ISP 2022[7] 'Hydrogen Superpower' scenario estimates, will require targeted investment in power transmission infrastructure. In later timeframes, the bulk of the required electricity will be used directly in behind-the-meter hydrogen production plants located at the REZs, without need to access the power transmission infrastructure.

[56] Australian Energy Statistics, Australian Energy Update 2021, September 2021 https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202021%20Energy%20Update%20Report.pdf

The assessment identifies a preference for hydrogen transport via trucks in 2025, and rail also under consideration where transport corridor exist, however in later timeframes the bulk of domestic transport of hydrogen is carried out along new dedicated pipeline corridors, modelled in the form of compressed gas. Existing natural gas transmission pipelines could also be converted to transport hydrogen, where feasible.

The water demand associated with the production of hydrogen is estimated to reach 740 GL by 2050. For reference, this is equivalent to 60% of the water consumption of the mining industry today (see Section 3.7). To secure sufficient water supply and to manage social and environmental impact concerns strategic planning will be required, assessed locally and concerted at a national level.

Hydrogen export will shape the future development of ports, in a similar way to other fossil fuel commodity exports, such as liquefied natural gas (LNG). Development on port lands could include the supply chain from hydrogen production to export, however with constraints on land use it is expected that land closest to berthing infrastructure will be prioritised for compression and liquification facilities and relevant balancing storage and bunkering infrastructure. End use infrastructure will also be required, starting from hydrogen refuelling infrastructure in major cities and along strategic heavy transport routes. The preference for hydrogen transport via tube trailers in 2025 is well compatible with the distribution of hydrogen to refuelling stations. Natural gas networks could also see the adoption of hydrogen blending stations, potentially co-located with the city gates and supplied by trucks.

3.1 Demand modelling output and insights

The following summarises the modelling outputs and insights from the central hydrogen demand scenario out to 2050. The hydrogen demand scenarios were developed by considering the demand generated by the switching from an existing fuel source to hydrogen, the demand from new energy uses and the demand for hydrogen export, as explained in Section 2.3. This central scenario has demand approximately split 50/50 between domestic uses and export.

The bottom-up evaluation considered the distribution of demand across States and Territories, and timeframes. The results of the analysis are summarised in Table 3.1.

Table 3.1 Annual hydrogen demand split by State/Territory and timeframe, Central demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	17	164	1,175	2,556
	Export	0	66	714	1,859
	Total	**17**	**230**	**1,889**	**4,416**
NSW, ACT	Domestic	20	169	1,085	2,536
	Export	0	66	714	1,859
	Total	**20**	**235**	**1,800**	**4,396**
VIC	Domestic	15	153	1,121	2,441
	Export	0	66	714	1,859
	Total	**15**	**219**	**1,836**	**4,301**
TAS	Domestic	0	4	49	138
	Export	0	33	357	930
	Total	**0**	**37**	**406**	**1,067**
SA	Domestic	5	38	235	542
	Export	0	33	357	930
	Total	**5**	**71**	**592**	**1,471**
WA	Domestic	11	120	1,129	3,879
	Export	0	99	1,071	2,789
	Total	**11**	**219**	**2,201**	**6,668**
NT	Domestic	1	13	265	642
	Export	0	33	357	930
	Total	**1**	**46**	**622**	**1,572**

3.1.1 Local Demand

The transport sector is the primary contributor to the domestic demand for hydrogen, particularly in the first and second timeframes. This demand is disaggregated across a large area rather than concentrated in single locations like with export. To support this demand, the use of local refuelling networks and infrastructure will be required. Key policy initiatives such as the Hydrogen Hume Highways[57] are already beginning to address these. However, whilst the assumption behind the analysis is that demand transport will be significant, it is predicated on vehicle manufacturers being able to supply hydrogen vehicles by 2025. This will require the establishment of hydrogen refuelling infrastructure in major cities and along major freight routes.

The use of hydrogen in the mining sector is also expected to contribute to hydrogen demand in the near term. Hydrogen could play an important role in the decarbonisation of mining operations, particularly if in off-grid or fringe-of-the-grid locations.

Overall, the domestic hydrogen demand in the modelled scenarios is significant, reaching 12.6

[57] Hydrogen Hume Highway initiative, https://business.gov.au/grants-and-programs/hume-hydrogen-highway-initiative

million tonnes of hydrogen by 2050 and equivalent to 14% of the current global demand (90 million tonnes).[58]

3.1.2 Export Demand – DCCEEW

The export demand in the central demand scenario (11.2 million tonnes) accounts for almost half of the total hydrogen demand in 2050. Consequently, the assumed distribution of this demand across the port options has a significant impact on the assessment outcome. Identifying which ports will be best placed to deliver this export is a complex issue tying technical, economic and political considerations. Selecting ports which are likely to be hydrogen ready, ports that achieve the optimal supply of hydrogen or choosing ports that provide equitable opportunity for all states and territories.

AEMO and DCCEEW have had direct input in the selection of the most appropriate ports, primarily based (in this initial stage) on ports identified in the AEMO ISP 2020[6] forecast (for the jurisdictions within the NEM) and in the Australian Hydrogen Hubs Study[59]. For Western Australia, which is outside the AEMO ISP scope, the selection of modelled ports was based on state-based funding and feasibility studies as well as on input from the Western Australia government. Up to three ports were selected for each state and territory (excluding the land-locked ACT).

In the base case, the export demand is distributed equally across each identified port. Conversely, in the 'Northern export demand' scenario the export demand is distributed amongst only ports in the north of Australia, testing the potential effect of redistributing export demand on the resulting supply chain configuration.

[58] IEA, 2021, Global Hydrogen Review 2021 https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf

[59] ARUP Australia November 2019, '*Technical Study – Australian Hydrogen Hubs Study*', Issue 2, COAG Energy Council Hydrogen Working Group, https://www.industry.gov.au/sites/default/files/2021-09/nhs-australian-hydrogen-hubs-study-report-2019.pdf

3.1.3 Green Steel – Incumbent

The future low emissions steel industry demand assumes that a proportion of future iron ore export (used to make steel offshore) would now be used to make steel domestically. Historically, iron ore exports have only been located in Western Australia, which skews the location of all future low emissions steel hydrogen demand scenarios.

Following a combination of interactive workshops and subsequent targeted interviews, the Bureau of Steel Manufacturers of Australia (BOSMA) provided guidance on what a more reflective future scenario would entail.

Recommendations were made for the development of hydrogen hubs and green steel production on the East Coast (Hunter Valley, Illawarra) and South Australia (Whyalla). Incumbent steel manufacturers at these locations provided ‘commercial in confidence’ input on forecast hydrogen demand for manufacture of ‘green steel’ as part of their future planning. Since this time announcements have been made by both Bluescope Port Kembla and Liberty Steel Whyalla steelworks on their plans to commercialise breakthrough technologies for decarbonising steel production using hydrogen.

The selected locations also provide several advantages including: water availability, proximity to domestic demand (industrial and household), co-located with steel production assets and markets, proximity to skilled labour supply, ease of export including value added materials and leverage of existing brownfield investment.

To accommodate the collective recommendations of BOSMA a modelling sensitivity was formulated to model a future in which the growth of a low emissions steel industry was more closely tied to the aforementioned considerations. For the purposes of the model’s detail, this demand was encompassed in the regional South Australia node (Port Augusta) and the Wollongong and regional New South Wales (Tamworth) nodes.

3.1.4 Regional Demand Locations – DCCEEW

A substantial proportion of demand is attributed to what is referred to as regional demand and accounts for the amalgamation of all demand not located at primary demand centres. Whilst there is current demand for hydrogen in regional areas, the focus for the inaugural NHIA remains on primary demand centres, as these are presumed to be where the greatest gains can be made for now (future iterations of the NHIA will consider more particular regional supply chains, such as Daintree renewable hydrogen or Christmas Creek projects), and significant enabling infrastructure needed to unlock.

It is foreseeable that before the next iteration of the NHIA demand will grow in a select few additional locations within each state. These locations were informed through feedback and discussions during the stakeholder engagement phase and have been identified as the following:

Townsville, Qld

Based on the planned national and international investment and backing by Queensland government, Townsville was suggested as a potential hub during both the State and Territory government and industry organisation workshops. The existing port facilities, industrial capability and proximity to REZ and neighbouring region of Gladstone also contributed to its selection. The selection of this site selection was reinforced by subsequent Federal Government announcements regarding the provision of funds to establish one of the hydrogen hubs in Townsville.

Tamworth, NSW

The Hunter region was consistently mentioned as a key hydrogen and industrial hub during both S&T government and industry organisation workshops. Tamworth was selected to capture the demand in this region.

Bendigo, Vic

During the stakeholder consultation phase there was no major preference given to a particular centre or region beyond those already identified. Bendigo was selected as the most suitable location given its central location within the expected regional demand area, nexus of transport and transmission infrastructure, and existing demand centres.

Port Augusta, SA

During the stakeholder consultation phase SA was consistently identified as having significant renewable resource and access to suitable ports. Port Augusta was selected due to proximity to REZ, access to port facilities and additionally, prospective hub links with Whyalla and neighbouring Port and industrial areas.

Geraldton, WA

Geraldton and the surrounding region is currently the site of significant hydrogen project development (advanced) and was recommended as a suitable area to house the regional demand.

To mitigate against the uncertainty of modelling regional demand as singular locations, a proportion of the regional demand was further equally redistributed to the primary demand nodes, taking the weight of this node and including in nodes that were certain.

3.2 Infrastructure map interpretation

For each scenario and timeframe analysed, alongside the quantitative assessment of the LCOH and the capacity of the infrastructure of the optimised supply chain, a graphical output is produced to help visually identify the main trends. An example of these outputs, which are produced in the form of Australia-wide maps, is presented below together with the interpretation guideline

3.2.1 Example map output

The graphic below is an example of the graphical representation of the model outputs, with the following Section 3.2.2 containing a guide on how to interpret the map outputs.

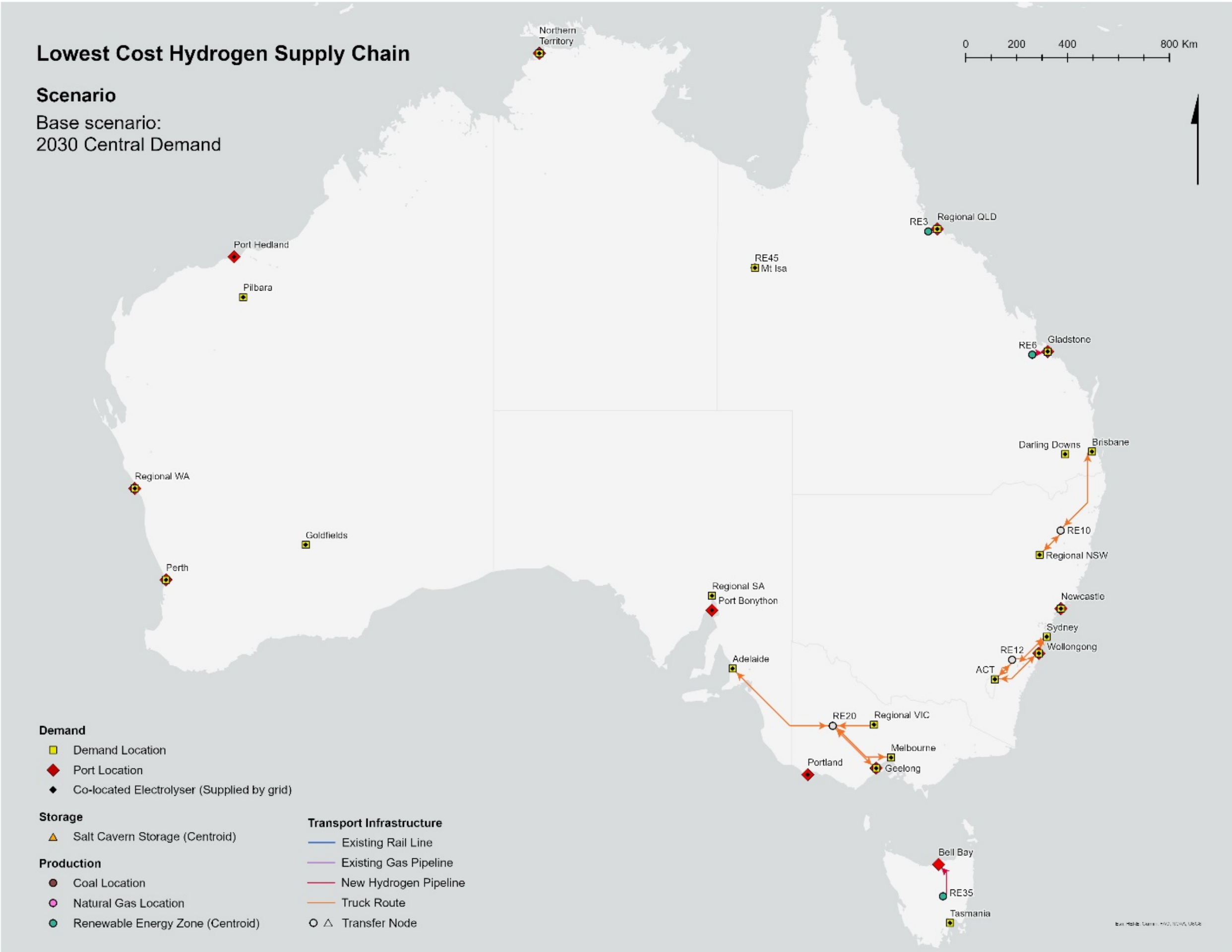


Figure 3.2.1 Example of techno-economic model output map

3.2.2 Map interpretation guidelines

The below map interpretation guideline explains the purpose of each node represented in the optimised supply chain. It should be noted that locations which do not feature in the optimised supply chain are not shown on the map outputs.

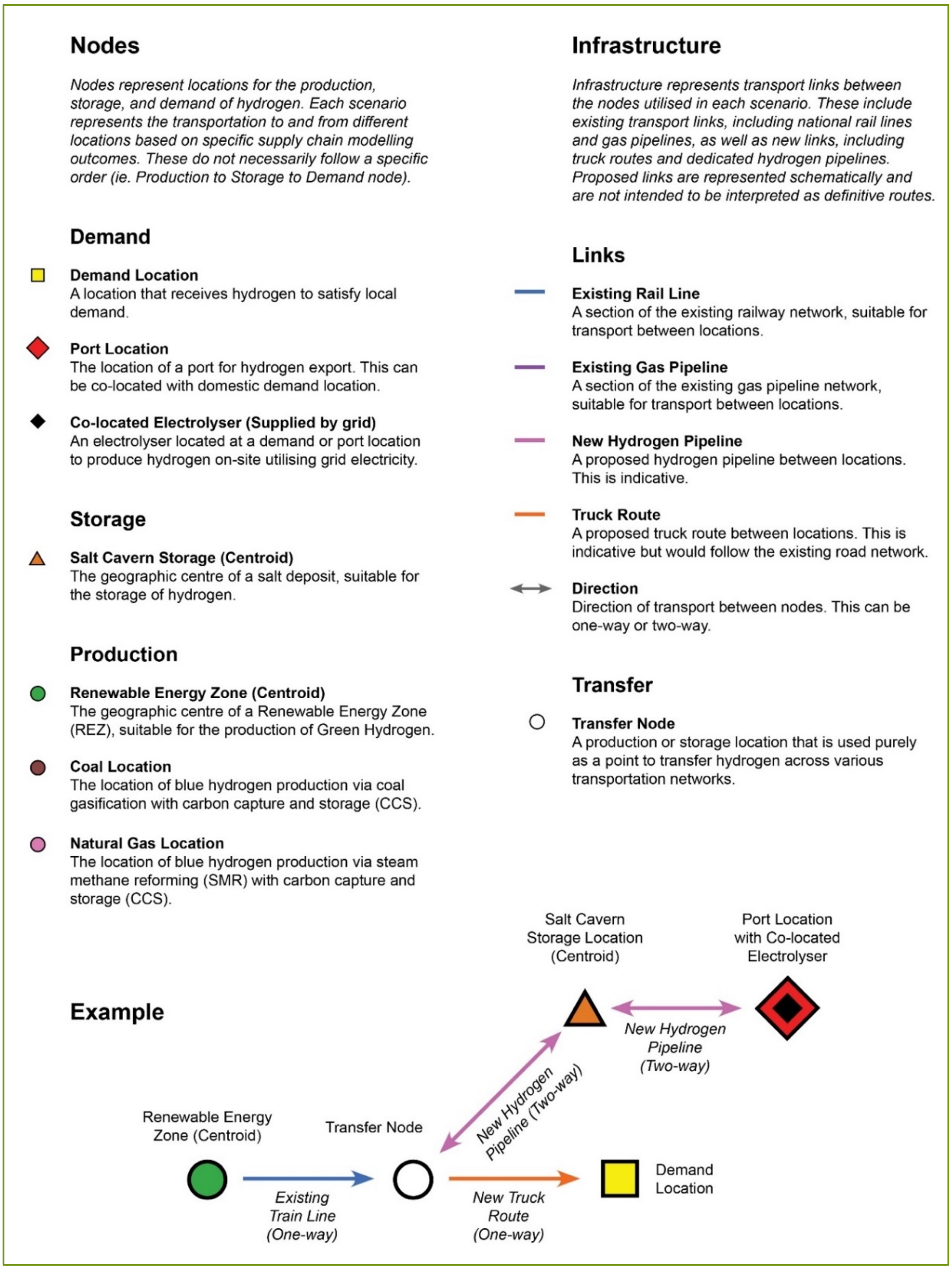


Figure 3.2.2 Techno-economic model map interpretation guidelines

3.3 Base case model results

The main scenario of the techno-economic analysis is the ‘base case’ scenario, which is based on the main set of inputs and assumptions. This scenario provides a base for the additional analysis and testing of sensitivities. Main characteristics of the base case inputs are:

- Inclusion of only renewable energy powered hydrogen production
- ‘Central’ hydrogen demand
- ‘Medium’ capex of electrolysers
- Hydrogen export demand distributed evenly across ports
- Use of existing infrastructure not included
- Use of salt cavern and depleted oil field large-scale geological hydrogen storage included.

3.3.1 2025

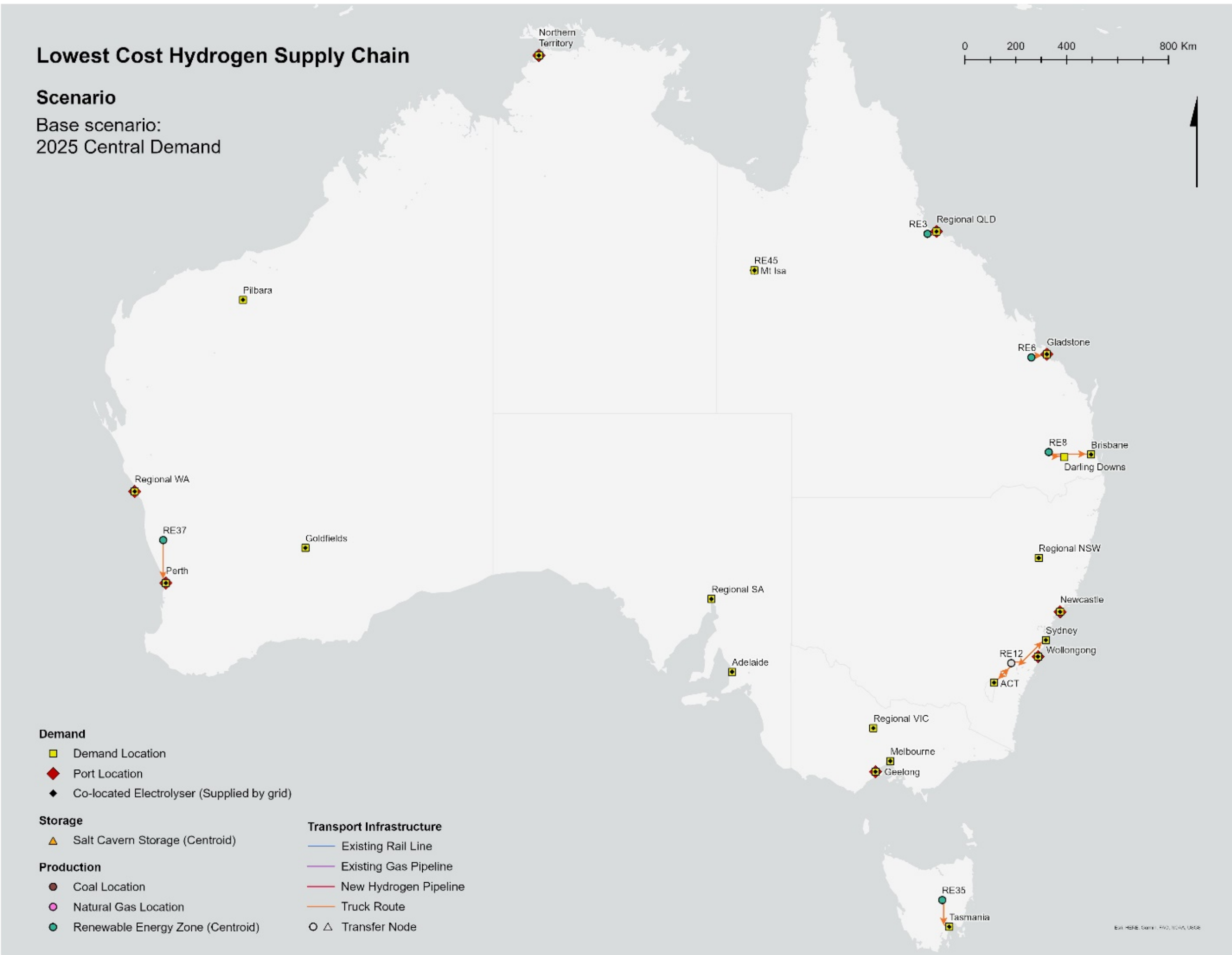


Figure 3.3.1 Techno-economic model result map for the 2025 timeframe, Base case

Summary of scenario

In the 2025 base case scenario, the hydrogen demand is evenly satisfied by electrolysers located at the demand nodes powered by grid electricity (with LGCs), and by hydrogen produced and transported from closely located renewable energy zones. The choice, based on the lowest cost of hydrogen, is determined by the cost of renewable energy and transport distance.

The limited hydrogen storage is provided by MCH (methylcyclohexane) tanks and conversion/reconversion facilities.

In this scenario, the scale of hydrogen transport is limited and entirely carried out by road trucks. Most of the hydrogen is transported in the form of compressed hydrogen gas, with some MCH between nodes located farther apart.

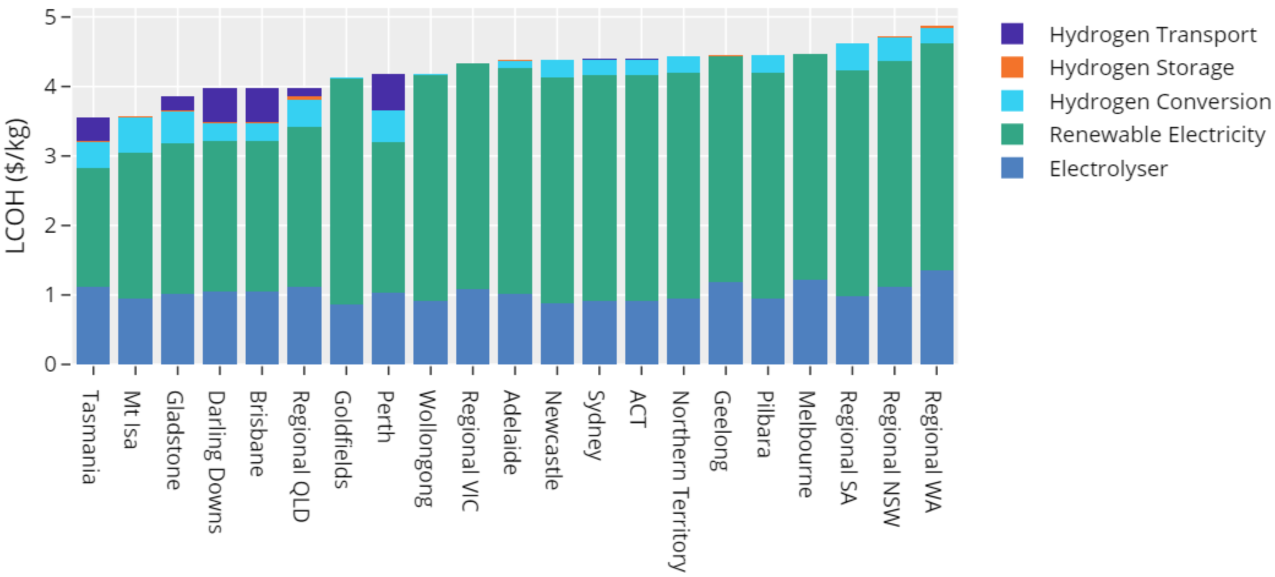


Figure 3.3.2 LCOH at the demand nodes according to the techno-economic model for the 2025 timeframe, Base case

3.3.2 2030

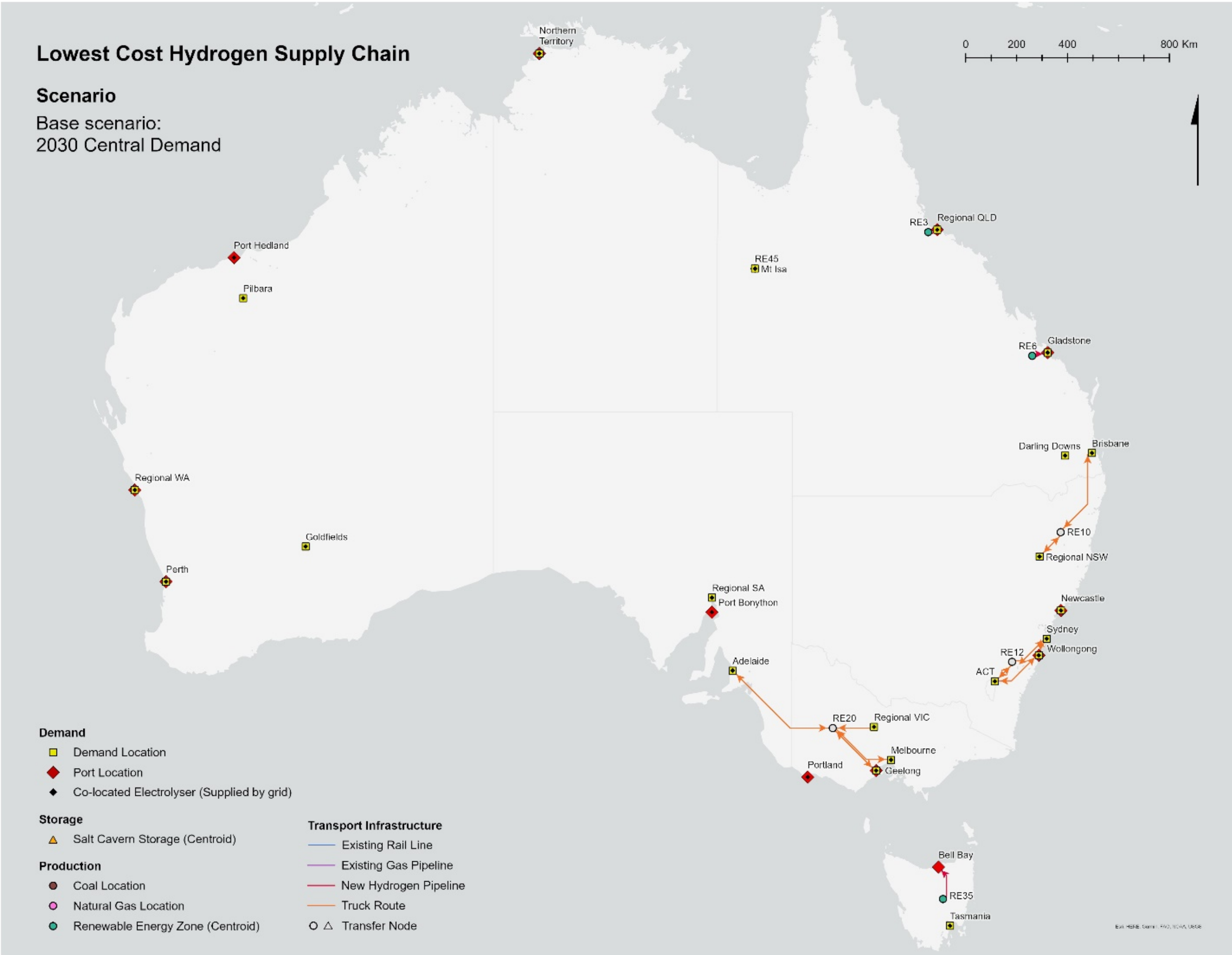


Figure 3.3.3 Techno-economic model result map for the 2030 timeframe, Base case

Summary of scenario

Several demand nodes are still serviced by co-located electrolysers powered by grid electricity. This is mostly due to the lower input cost of grid electricity compared to 2025, because of the forecast end of the LGCs program.

Compared to 2025, several additional road transport routes develop, with the scope of sharing hydrogen storage infrastructure and reduce the overall cost of delivered hydrogen. Transport of compressed hydrogen via truck develops particularly in areas most densely populated by demand locations.

Across Australia, hydrogen is stored in the form of MCH.

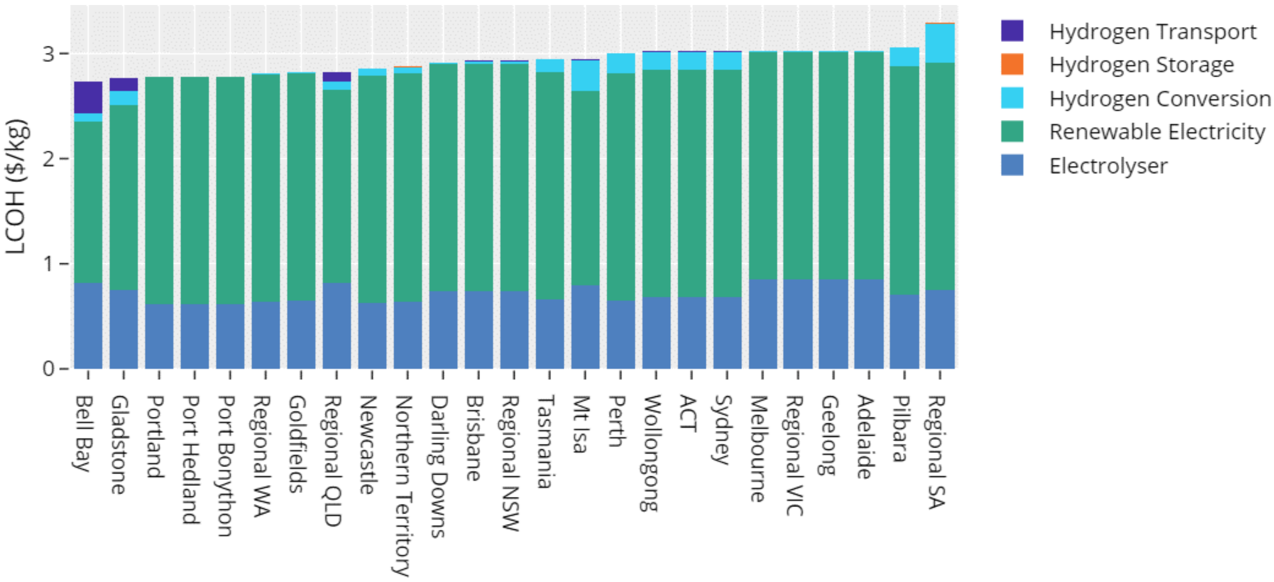


Figure 3.3.4 LCOH at the demand nodes according to the techno-economic model for the 2030 timeframe, Base case

3.3.3 2040

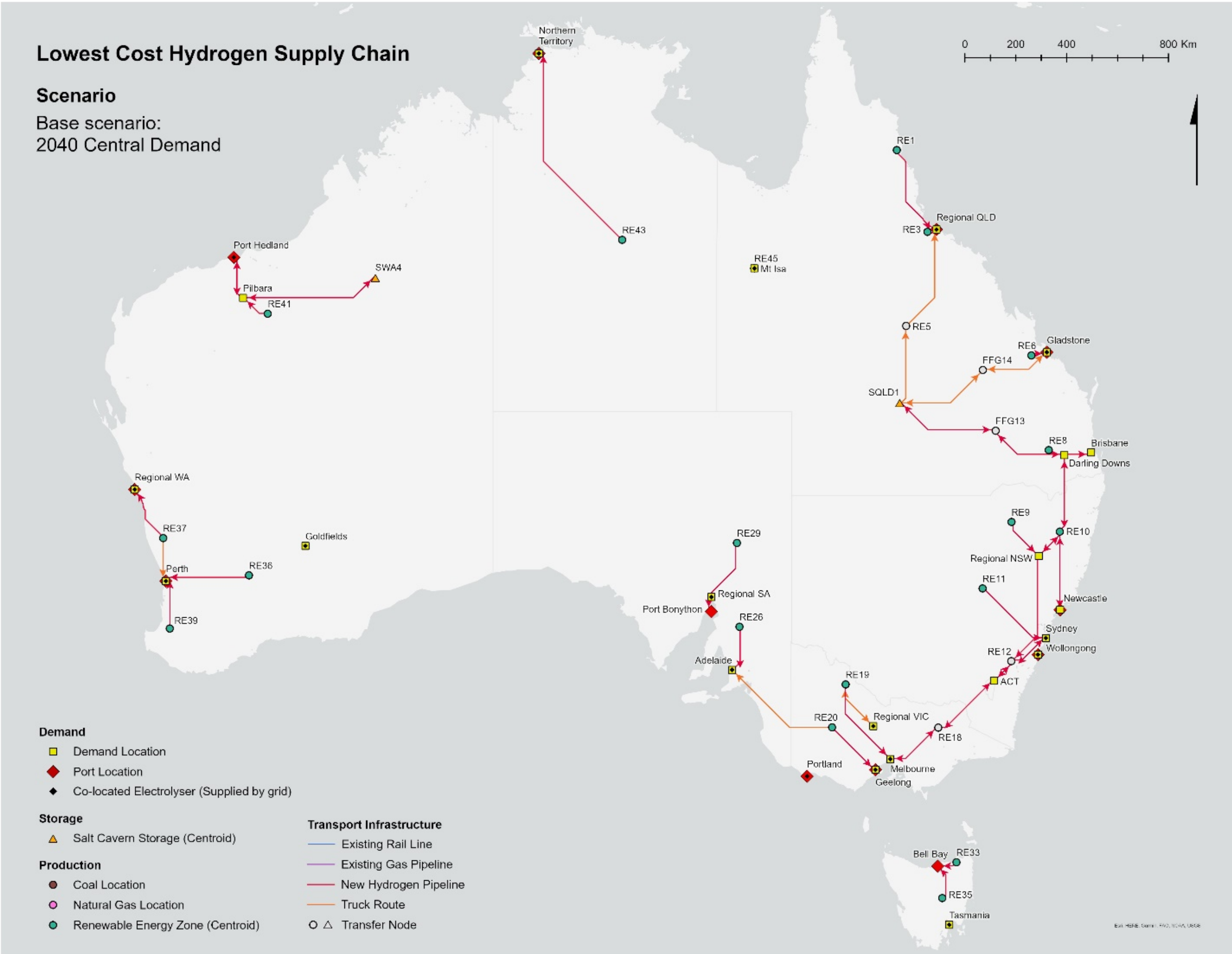


Figure 3.3.5 Techno-economic model result map for the 2040 timeframe, Base case

Summary of scenario

The increasing hydrogen demand (9.3 million tonnes across Australia) justifies the installation of several dedicated gas pipelines to serve the majority of nodes. In particular, an interconnected network linking Melbourne to the ACT, Sydney, Newcastle and Brisbane is developed. Transport via truck is still in use for low-capacity links, exclusively in the form of compressed gas.

The production of hydrogen is concentrated in the REZs (78% of the total), with still some significant production co-located with most demand nodes.

Two salt cavern storage locations are utilised in Queensland and Western Australia, while depleted gas fields are not used in this scenario.

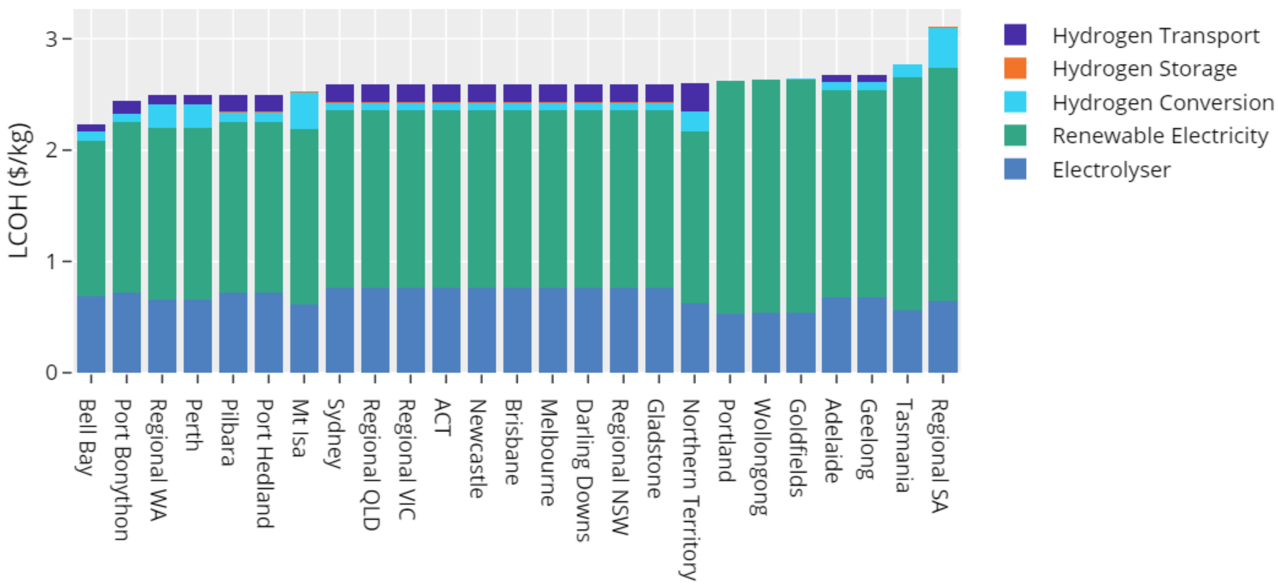


Figure 3.3.6 LCOH at the demand nodes according to the techno-economic model for the 2040 timeframe, Base case

3.3.4 2050

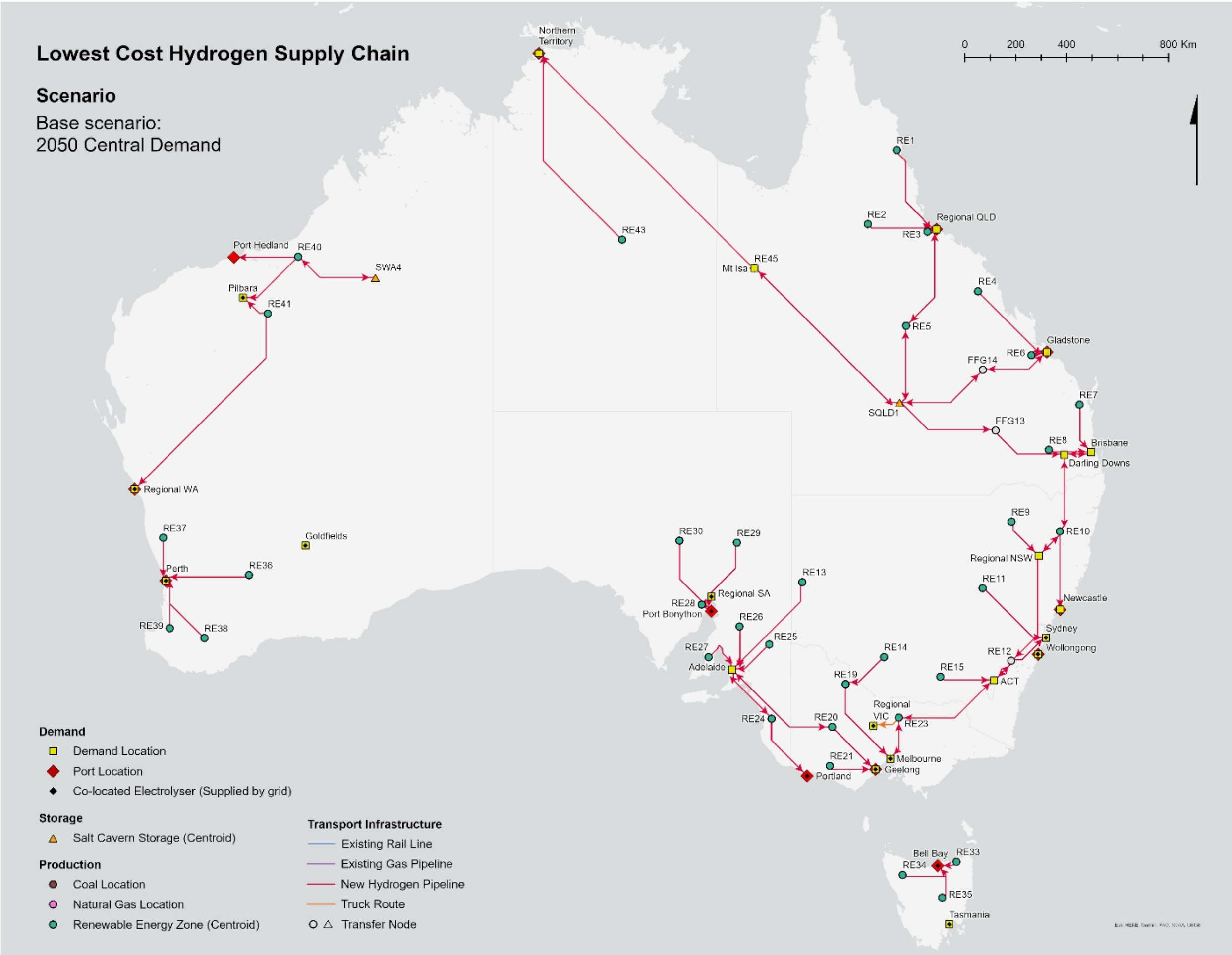


Figure 3.3.7 Techno-economic model result map for the 2050 timeframe, Base case

Summary of scenario

The network of dedicated hydrogen pipelines increases in complexity, to the point of connecting the East coast network with the Northern Territory. Transport via truck is almost completely replaced.

The share of hydrogen produced at the REZs (78%) remains constant compared to the 2040 and remains the dominant source of hydrogen. However some significant co-located hydrogen production remains in locations like Perth, Melbourne and Wollongong due to the saturation of renewable resources in the nearby areas.

The same hydrogen large-scale storage locations are selected as for 2040, with two salt cavern storage systems in Queensland and Western Australia.

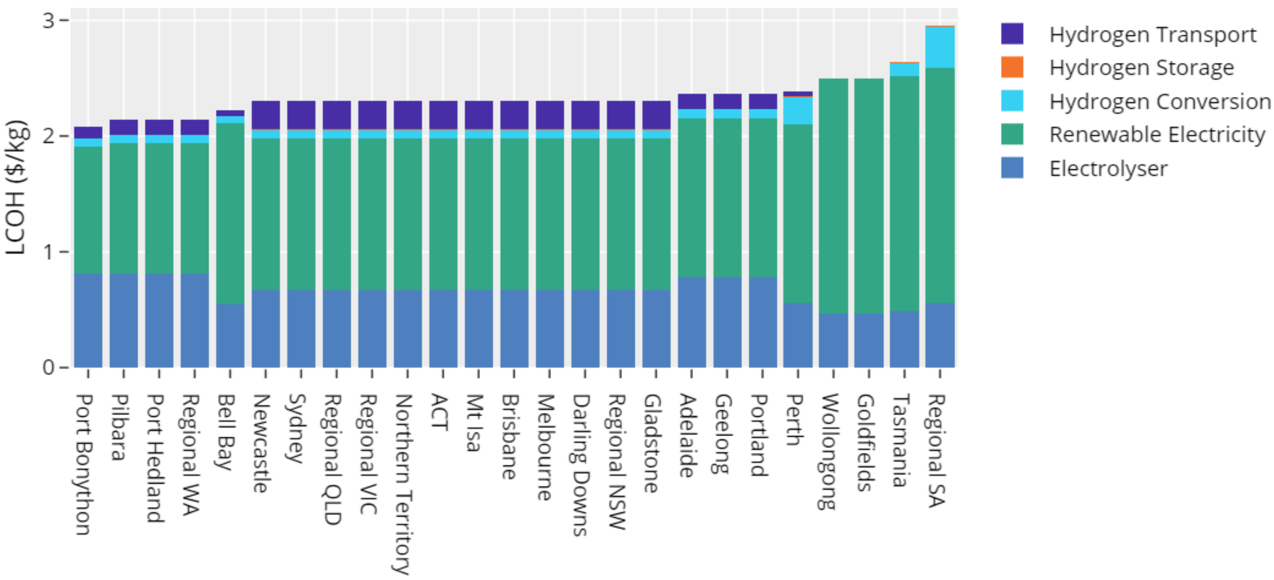


Figure 3.3.8 LCOH at the demand nodes according to the techno-economic model for the 2050 timeframe, Base case

3.4 Hydrogen Production

For each demand location, the techno-economic model identifies the lowest cost hydrogen supply chain. Based on the hydrogen production and transport cost data presented in Section 2.4.3, the model selects the locations where to produce hydrogen, the production technology, and the best form of transport.

While the scenarios that test the sensitivity of the economics of hydrogen production do provide different results from the base case ones, there is an overall trend that sees green hydrogen playing the largest role in the production of hydrogen. The table below shows how the base case (including low-emission technologies) compares to the cases that test the sensitivity to electrolyser capital cost and to hydrogen demand level.

Table 3.2 Evolution of hydrogen production split between blue and green hydrogen technologies for different scenarios.

Sensitivity		Timeframe			
Hydrogen demand	**Electrolyser capex**	**2025[60]**	**2030**	**2040**	**2050**
Central	Central	100% green 0% blue	85% green 15% blue	100% green 0% blue	100% green 0% blue
Central	Low	100% green 0% blue	100% green 0% blue	100% green 0% blue	100% green 0% blue
Central	High	100% green 0% blue	27% green 73% blue	70% green 30% blue	100% green 0% blue
High	Central	100% green 0% blue	75% green 25% blue	100% green 0% blue	100% green 0% blue

It is noted that the results for hydrogen production are to some extent affected by limitations in the techno-economic model, particularly for what regards the spatial allocation of hydrogen demand. The concentration of demand in a limited number of locations is a simplification required by the model to allow the optimisation of the supply chain infrastructure and does not fully represent the disaggregated demand distribution that can be expected in reality. One consequence is reflected in the cost of hydrogen for transport, as well as the additional infrastructure required. While the model assumes the final use of hydrogen to happen at the demand locations, hydrogen refuelling stations will be in part situated along major transport routes and highways. The model therefore fails to consider the need for hydrogen trucking from production sites to the refuelling stations, which will increase the delivered cost of hydrogen and will also require additional hydrogen transport via road compared to what is presented in the results.

The inclusion of regional hydrogen demand as a single point for every state and territory has similar consequences on the results, particularly in terms of hydrogen distribution requirements via road.

While the results are generally valid, and the impact of regional and transport demand are limited particularly in the latest timeframes, it is acknowledged that the results of the analysis must be analysed considering the inevitable limitations of the model.

3.4.1 Hydrogen from electrolysis

Electrolysis is the preferred hydrogen production technology

The results of the model, based on techno-economic considerations, highlight that, overall, renewables-powered electrolysis is expected to be the lowest cost technology for hydrogen production in Australia, after 2040 in particular.

[60] The lack of blue hydrogen production in the 2025 timeframes is due to the model assumption that the required infrastructure would not be available within that timeframe.

The expected improvements in green hydrogen production, which include a decrease in cost for renewable power systems and electrolysis technologies, as well as an increase in the power-to-hydrogen conversion efficiencies, make green hydrogen increasingly competitive. By the 2050 timeframe, electrolysis is the only hydrogen production technology in all the tested scenarios and sensitivities. This highlights the risk of stranded blue hydrogen assets, in particular for long-life installations like the carbon dioxide transport and storage infrastructure.

Most hydrogen is produced within the REZs

Over the time period considered in this assessment, most of the hydrogen production happens at the renewable energy production zones. Hydrogen is then transported to the demand locations as a gas or via other chemical carriers.

In 2025 and 2030 demand locations are still mostly supplied with hydrogen produced by co-located electrolysers powered by the grid. This is due to the higher utilisation factor for electrolysers powered by the grid rather than directly connected to variable renewable energy sources, leading to a lower cost of hydrogen. As the cost of electrolysers reduces, and the efficiency of this technology increases, the renewable energy zones take the largest share of the hydrogen production. By 2050, 78% of the hydrogen is produced remotely.

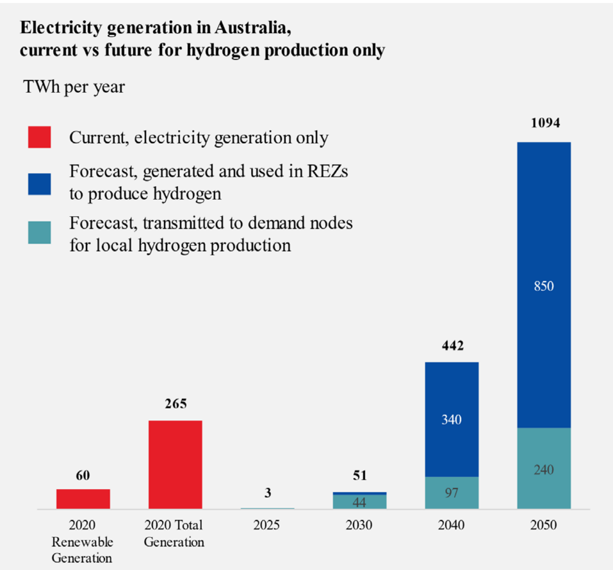


Figure 3.4.1 Comparison of current electricity production in Australia and modelled electricity requirement for hydrogen production (base case scenario).

The additional power consumption for hydrogen generation at the demand locations is still considerable, growing from 3 TWh in 2025 to 240 TWh in 2050 (roughly doubling the current electricity supply to the demand centres). This will require case-by-case assessments of the power generation and transmission infrastructure in these locations.

As the hydrogen demand increases and behind-the-meter hydrogen production projects reach very large scale (e.g. GW scale), specific infrastructure will be required within the project boundaries. In particular, the transmission of power from the vast renewable energy production area and the hydrogen production site (or sites) will require extensive power systems that will include transmission lines, substations and the road infrastructure to provide access for construction and maintenance. Some economies of scale can be expected as hydrogen projects increase in size, however if the capital and operational costs of the internal power transmission infrastructure were such that very large scale systems would become less feasible, the modular nature of hydrogen production technologies could lead to multiple smaller-scale projects within the same REZ and development area.

Optimum mixture of solar PV, wind and electrolyser capacity

The optimum mixture of wind and solar PV generation for each production location was determined in line with respect to the generation technologies costs and constraints and associated capacity factors. The cost of the electrolysers also influenced the optimal amount of wind and solar PV respectively. While electrolysers are more expensive a high proportion of both wind and solar PV is installed to ensure the electrolyser utilisation factor remains as high as possible. In future when both electrolysers and solar PV are expected to undergo notable price decreases, the model generally opted to focus only on installing solar PV couple with a cheap electrolyser operating at a lower utilisation factor. As can be seen in the graphic below the proportion of solar PV across Australia increases from 2030 to 2050.

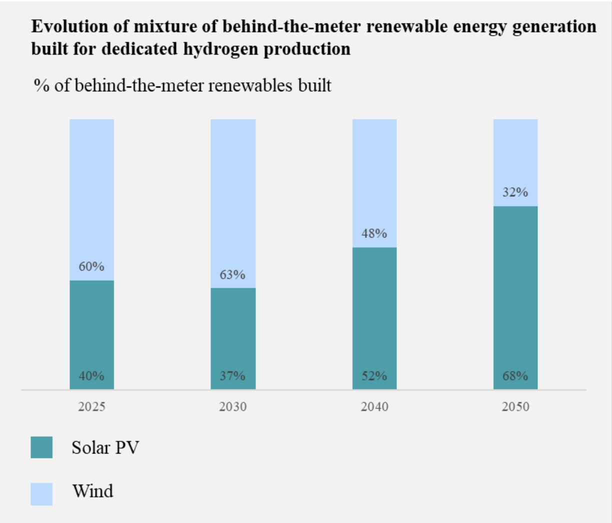


Figure 3.4.2 Trend of solar PV and wind generation installed in supply chain as fraction of overall behind-the-meter renewable electricity installed from 2025 to 2050.

As electrolyser capital costs decrease over the years, the utilisation factor of the electrolyser becomes less of a priority in minimising the levelised cost of green hydrogen. Instead, the cost of the electricity in input becomes the dominant parameter in defining the cost of hydrogen. Solar PV provides a lower cost electricity compared to wind energy, and for this reason the solar PV share of power generation increases as the cost of electrolysers decreases, even though it leads to a lower utilisation factor for the electrolyser.

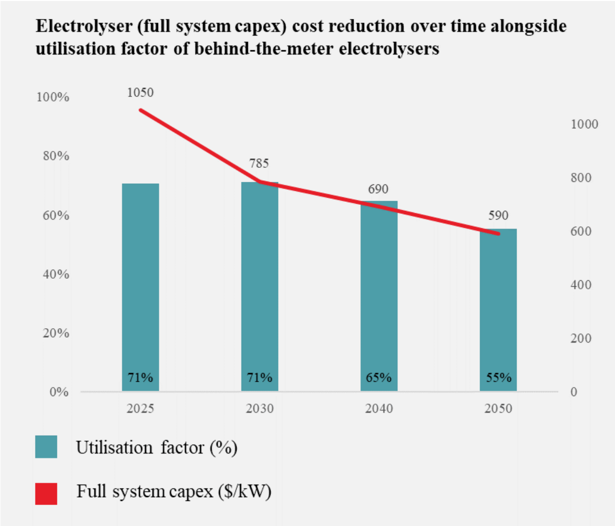


Figure 3.4.3 Trend of electrolyser utilisation factor and capex of electrolyser system from 2025 to 2050.

A more noticeable reduction in the electrolyser utilisation factor occurs in the electrolyser low-capex sensitivity, with solar PV becoming the dominant renewable installed. Conversely, in the electrolyser high-capex scenario shows a more balanced share of solar PV and wind to keep the electrolyser utilisation factor high and limit the capital outlay required to install the relatively more expensive electrolysers.

Electricity demand for electrolysis saturates REZs

A clear challenge of the hydrogen transition is the supply of sufficient electricity to feed the electrolysers. The unprecedented scale of power generation required just for hydrogen generation could lead to the saturation of the renewable energy production capacity of several REZs. This is likely to trigger a competition between the supply of electricity for hydrogen production and for the supply of power for increasingly electrified cities.

Just taking into account the electricity required for hydrogen production, after 2040 several REZs reach the production limit imposed in the model, with the production limit for each renewable energy zone primarily being based on the build limits presented by the AEMO ISP[6]. Where a REZ reaches maximum capacity, the model selects the next available option in order of hydrogen delivered cost, which is often a REZ located farther from the demand location and/or with inferior renewable resources. Therefore, as the demand for electricity increases, the levelised cost of hydrogen also tends to increase.

The hydrogen demand for export represents about half of the total demand. Noting that the base case scenario assumes that the hydrogen export demand is evenly split between port locations in Australia, there is potential for reducing the strain on renewable energy resources in critical areas by redistributing the hydrogen demand. This was tested in the 'Northern export demand' scenario, where all the export demand is concentrated in three ports in the northern part of Australia. As expected, the results of this sensitivity show less constrained supply chains in the south of Australia. However, in Victoria, the high domestic demand and smaller local REZs continue to lead to the saturation of renewable sources, although the start of the saturation issues shift from 2040 to 2050.

Overall, the satisfaction of most export demand with very large-scale hydrogen export projects, located in remote areas, could contribute to at least partially release renewable generation in more densely populated and critical areas.

3.4.2 Hydrogen from fossil fuels

Hydrogen from natural gas limited to few locations and timeframes

In the 2030 and 2040 timeframes, hydrogen production from natural gas with carbon capture and storage (SMR + CCS) is selected by the model in particularly favourable locations across Australia.

The three gas basin locations where blue hydrogen appears most consistently are the onshore Clarence Moreton basin in Queensland/NSW, the Carnarvon basin in Western Australia, and the offshore Bonaparte basin in the Northern Territory. Common characteristics of these locations are the lower input cost of natural gas and being within relatively close proximity to a demand location.

All blue hydrogen production is limited to the 2030 and 2040 timeframes. In 2025, due to the assumption that the short timeframe will not allow the development of the infrastructure required for blue hydrogen (carbon dioxide storage in particular), the model does not allow the production of hydrogen from natural gas. In 2050, the modelled low cost of renewable power and of electrolysers make green hydrogen too competitive to allow a role for blue hydrogen. In this timeframe (2050) this is true also in scenarios that use input data particularly favourable to blue hydrogen, as the 'high electrolyser capex' scenario and the 'high demand' scenario.

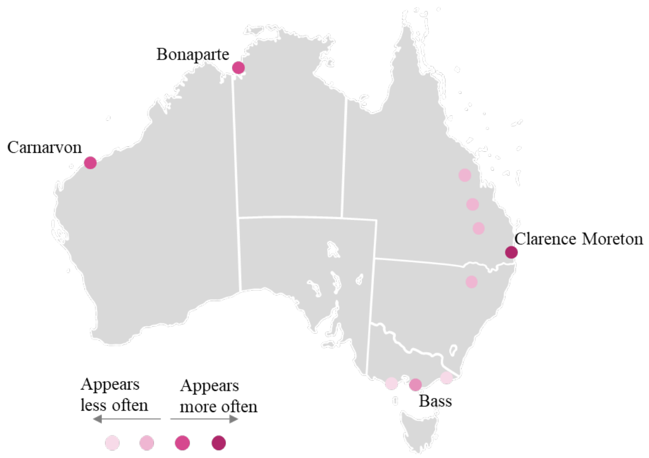


Figure 3.4.4 Preferred blue hydrogen (SMR + CCS) locations according to the techno-economic model.

No coal gasification selected by the model

Based on the cost assumptions for coal gasification and CCS, the levelized cost of blue hydrogen from coal is not competitive with green hydrogen and blue hydrogen from natural gas. This is also true for hydrogen produced from brown coal, which despite being significantly cheaper than black coal it also presents a lower calorific value, increasing the specific size and therefore the cost of the gasification plant.

Potential effect of natural gas price

No sensitivity on the gas price was run in the techno-economic modelling price, but given the relatively minor amount of SMR featured in the optimum supply chains it is expected that a further increase in the natural gas price may make the option economically infeasible in all scenarios.

3.5 Hydrogen storage

Hydrogen storage infrastructure is a significant piece of the puzzle to enable the development of the hydrogen economy. Storage removes the time dependency between hydrogen production and use and provides a buffer to secure reliability of supply. Hydrogen storage is particularly important when hydrogen is produced from variable renewable resources, as the daily and seasonal variability in energy output must be smoothed and adapted to the demand.

MCH preferred for small-medium scale storage

Based on the cost inputs implemented in the techno-economic model, the preferred storage technology for small to medium storage sizes is methylcyclohexane (MCH). The cost of storage includes the cost of the storage tanks as well as the cost of the infrastructure and energy to convert hydrogen into the hydrogen carrier and back to hydrogen. Overall, hydrogen storage in the form of MCH resulted to be the most competitive option.

It is to be noted, however, that the choice of type of storage technology is very sensitive to the cost data used as input. A relatively small increase in the conversion and storage cost of MCH may favour storage in the form of ammonia or liquefied hydrogen instead. It is therefore suggested that at any location where the usage of MCH has appeared, that with further detailed analysis it is not unreasonable to expect that ammonia or liquefied hydrogen may be the more practical or cost-effective option. The selection of MCH as a storage carrier is suggested to be best interpreted as highlighting the opportunity for storage in a hydrogen carrier (MCH, ammonia, liquefied H_2) other than compressed hydrogen, rather than a definitive selection of the preferred future technology.

In addition, the techno-economic model does not include a limitation based on the available land and the footprint of storage infrastructure. If available, underground storage options (including storage in depleted gas fields) or above ground storage technologies with higher density could be favoured in land-constrained locations.

Salt caverns preferred for large scale storage

Hydrogen storage in salt caverns is commonly regarded as the established hydrogen storage technology with the lowest cost of hydrogen storage for large-scale applications.[61]

The model includes four salt cavern locations, positioned in remote areas of Western Australia, Northern Territory and Queensland. Despite the large distance between these locations and the main hydrogen production and demand areas, the low hydrogen storage cost justifies the use of these locations when the hydrogen demand is sufficiently high to justify their development.

Large-scale hydrogen storage in depleted gas fields is also allowed by the model. However, this technology never appears in the results due to the higher levelised cost of hydrogen storage compared to salt caverns due to the higher specific capital cost and particularly to the lower allowed cycles per year (the cost model for large-scale hydrogen storage assumes six charge/discharge cycles per year for salt caverns and one cycle per year for depleted gas fields).

The identification of suitable underground storage location is in its infancy, and the future focus should be on the assessment of the viability of each site.

Salt caverns for the storage of hydrogen are currently in operation in the United States of America and in the United Kingdom.[62] While salt deposits have been identified in Australia, more research is required to verify whether these sites are suitable for the storage of hydrogen. In addition, the remote inland locations of these deposits raise the issue of supplying the freshwater required for the excavation of these caverns. Due to these uncertainties, this assessment includes a scenario that analyses the hydrogen infrastructure in Australia in case underground storage of hydrogen was found not to be feasible. In this case, due to the higher cost of the storage alternatives available, hydrogen storage volumes are greatly reduced and are only deployed in the form of MCH tanks.

3.5.1 Hydrogen transport

Hydrogen is an energy vector. Therefore, a crucial consideration for the development of the hydrogen economy is how to connect production locations and demand sites.

Most domestic transport is in the form of compressed hydrogen

The results from the model highlight a preference of hydrogen transport in the form of compressed gas rather than other chemical carriers, as for example MCH. This result is based on the input data utilised for the costing of the transport options, with the economies of compressed hydrogen transport overall more convenient compared to the alternatives. Depending on the scale of hydrogen transport links, compressed hydrogen is either transported via truck or in dedicated pipelines.

[61] Lord A., Kobos P., Borns D., 2014, Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands

[62] Future Fuels CRC, 2021, Underground storage of hydrogen: Mapping out the options for Australia

Transport via truck gives the way to new pipelines

In 2025, the relatively low demand for hydrogen and the consequent low hydrogen transport needs mean that all transport can be carried out with compressed hydrogen trucks. Limited truck routes are established between hydrogen production areas and nearby demand locations.

In 2030 most locations are still linked by compressed hydrogen trucks. However, the first hydrogen gas pipelines constructed by this timeframe are responsible for most hydrogen flow capacity due to their favourable economics at large-scale compared to road transport.

The hydrogen pipelines that first appear in 2030 are also present in the following timeframes and most sensitivity cases, highlighting their potential for investment. These main pipelines are:

- 90 km between RE6 and Gladstone in Queensland
- 40 km between RE3 and Regional Queensland
- 150 km between RE35 and Bell Bay in Tasmania.

All three of the above pipeline options link a short distance directly from nearby dedicated renewable energy production locations to export demand locations. Their implementation is therefore tightly linked to the development of these locations into export hubs.

In the 2040 and 2050 timeframes, the transport of hydrogen via trucks is almost entirely replaced by transmission along pipelines. However, while this is expected to be true for major hydrogen transport links (e.g. moving hydrogen from production to demand locations), the lack of road transport in these timeframes is primarily a result of the limitations of the model in terms of the concentration of hydrogen demand in single-point locations. The distribution of hydrogen between regional towns and within major centres will still likely require some transport via road, with transported volumes approximately proportional to the overall demand.

The same applies to the distribution of hydrogen to hydrogen refuelling stations, which can be expected to be concentrated in populated areas and along major heavy vehicle transport routes (e.g. Hume highway between Sydney and Melbourne).

The growing network of pipelines are required to move hydrogen from production to demand locations, and to link the geological storage areas with the other nodes.

While there might be the potential to convert part of the current natural gas transmission network to transport hydrogen, the assumption behind the model is that existing pipelines are not available for the transport of pure hydrogen. This assumption is based on the current lack of clarity as to whether such conversion would be feasible, and on the consideration that there could be natural gas users that might require the supply of pure natural gas during the transition period to hydrogen. In addition, existing natural gas pipelines are designed to connect demand locations with gas extraction fields, following paths that do not necessarily intersect REZs, where, according to the model, most of the hydrogen production occurs. Finally, it can be expected that some gas users will continue to require natural gas well into the future, because of restrictions linked to their process (e.g. the use of natural gas as feedstock). This would require maintaining the current transmission pipelines to continue to deliver natural gas.

On the other hand, the model does allow the transport of hydrogen via the blending of small volumes of hydrogen (10% by volume) in the natural gas transmission network. The cost model for this option includes the cost of hydrogen deblending at the end-use location, since the underlying assumption of the model is that the demand is always in the form of pure hydrogen gas. However, the capital and operational cost of the deblending infrastructure makes this option more expensive compared to other transport technologies, and the model never selects it.

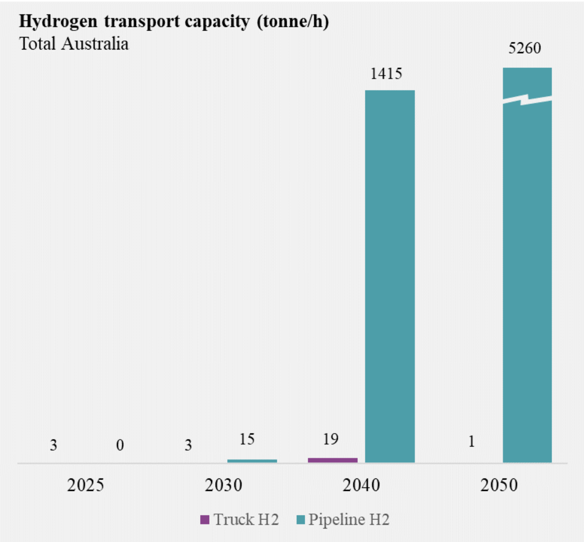


Figure 3.5.1 Evolution of hydrogen transport requirements in Australia, divided between transport on trucks and via pipeline (base case scenario).

Existing rail network could play a role

When allowed by the model, and where geographically available, the use of Australia's extensive rail network is favoured over the use of road transport. The low cost of rail transport as input in the model increases the hydrogen exchanges between locations, with the consequent reduction in the need for storage and a more economic distribution of hydrogen. As a result, the overall cost of hydrogen across Australia decreases.

As an example, in Victoria in the 2040 timeframe hydrogen transport via pipeline is heavily supported by transport on the existing rail infrastructure. The few connections that in the 2040 base case are operated via truck, are instead carried out via the train in the 'existing infrastructure' scenario (see comparison in Figure 3.5.2).

Further feasibility assessments would be required to understand the full practical and cost requirements of integrating hydrogen transport within existing railway network. Each component of railway infrastructure is likely to face unique challenges. It is also noted that the assumption behind the model relies on the hydrogen being directly moved from the production facilities onto the trains, without including the additional infrastructure (and the related costs) required to move the hydrogen to the rail lines. While the results indicate that hydrogen transport via rail could play a role in the future of hydrogen supply chains, this will require a case-by-case assessment. For these reasons, the use of the existing rail infrastructure for hydrogen transport is not included in the base scenario.

Figure 3.5.2 Comparison of hydrogen transport infrastructure between base case (left) and 'existing infrastructure' scenario (right) in Victoria, 2040 timeframe.

Hydrogen carrier for export will influence domestic hydrogen carriers

One limitation of the techno-economic model, as explained in Appendix B Section B.3, is that hydrogen demand is always assumed to be in the form of gaseous hydrogen. This simplification could have a large impact on the preferred transport and storage hydrogen carrier. As an example, if ammonia were to become the preferred hydrogen carrier for export, there could be a business case for storing and transporting hydrogen in the form of ammonia also domestically, avoiding additional hydrogen conversion steps.

As the demand distribution for hydrogen becomes more defined, both domestically and for export, a review of the future hydrogen storage and transport infrastructure will be required.

3.6 Green steel

Incumbent green steel

When comparing the base case scenario (no hydrogen demand for green steel production) and the 'Incumbent green steel' scenario, it is evident that, while the hydrogen demand increases at the identified green steel locations (Port Bonython, Wollongong and Regional NSW), no significant variation appears in the supply chain infrastructure. The reason for this is the close proximity of the new green steel hydrogen demand to very large-scale hydrogen export locations. For example, in 2050 the yearly green steel demand at Whyalla (SA) was identified as 0.07 Mt H_2, whereas the export demand assigned to the neighbouring Port Bonython is an order of magnitude larger at 0.93 Mt H_2. Figure 3.6.1 compares the techno-economic model output map for the base case and the 'Green Steel – BOSMA' scenario. No significant difference in infrastructure is visible.

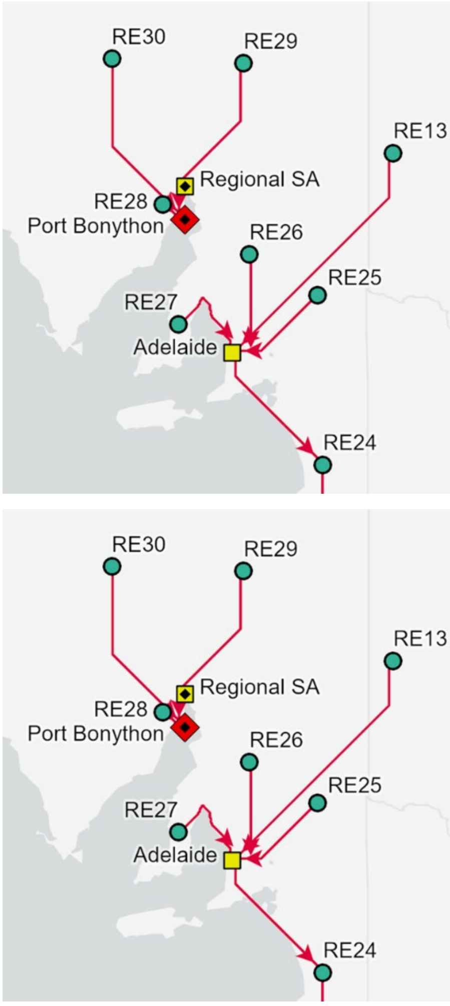


Figure 3.6.1 South Australia hydrogen supply chain, 2050. Left: Base case scenario, Right: Incumbent green steel scenario

New green steel

The amount of hydrogen required to process current iron ore production in the Pilbara to produce green steel is extremely high. From a modelling perspective, the main effect is the rapid saturation of the two REZs available in the Pilbara, which total a generation capacity of 46 GW. Another outcome is the grid-powered production of hydrogen in Port Hedland, due to the fact that the RE40 that supplies it in the base case scenario has no available capacity in the 'New green steel' sensitivity. Another consequence of the increased demand in the Pilbara is the absence of the pipeline linking this region to Geraldton (Regional WA).

In the Pilbara, the model satisfies most of the demand with grid powered electrolysers, since the electricity available in the grid is not limited by the model. In reality, the additional electricity requirement would need to be provided by additional renewable capacity. The results of the model ultimately highlight the insufficiency of the capacity of the two REZs provided.

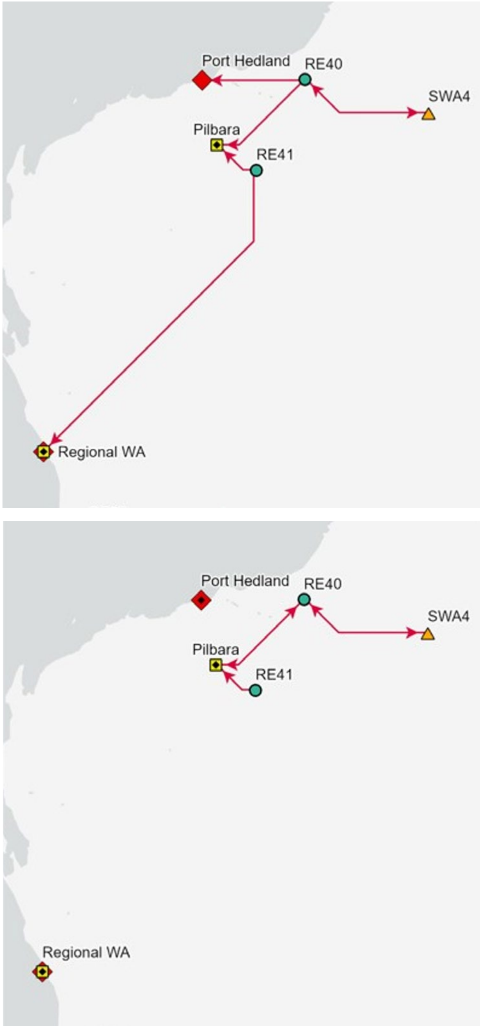


Figure 3.6.2 Western Australia hydrogen supply chain, 2050. Left: Base case scenario, Right: New green steel scenario

3.7 Water requirements

Water is a fundamental feedstock for all three hydrogen production technologies considered in this analysis. In addition, water is also required for the cooling of hydrogen production equipment, increasing the overall demand.

The techno-economic model is built on the assumption that sufficient water is available at every production location. However, it is evident water availability is not equally distributed across regions, and that competition for water in certain high water stress areas could influence hydrogen development locations due to insufficient water availability or additional treatment and infrastructure requirement needs, impacting project viability and cost.

Various water sources will be available at different locations, and include:

- Surface water
  (e.g., lakes, dams, rivers and creeks)
- Groundwater
  (e.g., well water, aquifers and bore water)
- Recycled water
  (e.g., treated wastewater effluent)
- Brackish water sources
  (e.g., saline surface water and groundwater)
- High salinity water sources
  (e.g., seawater, estuary water).

Each type will have different water quality parameters and will require specific infrastructure to extract it, handle it and prepare it for use by hydrogen plants. The source water available for use in hydrogen projects will ultimately vary for each location on the base of resource, social, environmental, regulatory, and economic factors, and with that the required infrastructure.

Hydrogen production could be favoured in coastal and low water stress areas

The World Resources Institute (WRI) has modelled current and future scenarios for water stress across the globe, including Australia. The water stress is a measure of what share of the available water (renewable surface water only) is withdrawn for use, and it gives an indication of the potential for limited water availability for additional uses (e.g. hydrogen production). It is noted that the WRI water stress information is an extract from a global model and the modelling methodology was not developed specifically for and with a deep understanding of Australia.

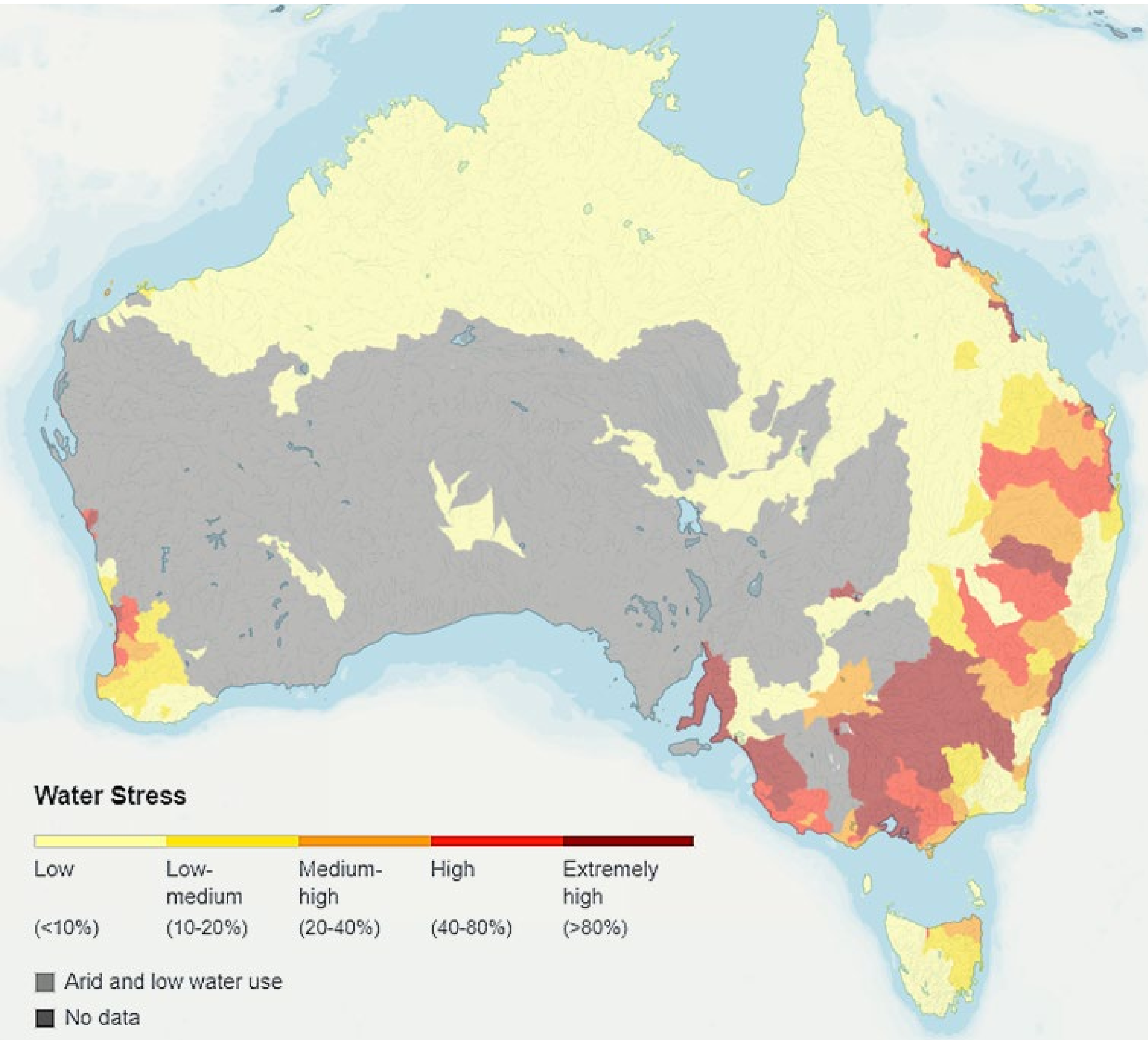


Figure 3.7.1 Water stress map of Australia, sourced from the World Resources Institute, 2040 timeframe, 'Business as usual' scenario[63].

As shown in Figure 3.7.1, the areas in Australia that are expected to be at higher risk of water stress are those around large cities and inland areas in Victoria, New South Wales and South Queensland.

63 World Resources Institute, Aqueduct Water Risk Atlas, https://www.wri.org/aqueduct

Several hydrogen production locations in the model sit within those high water stress areas and will require particular attention in the assessment of water availability for hydrogen production, particularly considering the need for draughtproof water. On the other hand, hydrogen production locations along the coastline could have access to water from purpose-built desalination plants, with this potential water source excluded from the WRI model. The development of such facilities, while it could slightly increase the cost of hydrogen, could represent an opportunity for shared infrastructure with the local communities and provide an additional source of potable water to supplement local supply. However, the environmental impact of such plants should also be carefully evaluated, as the high salinity brine released in the water purification process can impact delicate ecosystems such as the Great Barrier Reef in Queensland.

Water demand will be high but manageable

Overall, the water consumption for the future hydrogen economy is considerable but not prohibitive. As presented in Figure 3.7.2, by 2050 the water demand for hydrogen production in the central demand scenario is expected to be ~60% of water use currently used in mining and under a high demand scenario of the same order of magnitude to the current water use in the mining sector. In addition, design options are available to reduce the water demand from hydrogen production facilities.

While the feedstock water demand is unavoidable for the production technologies considered in this analysis, the cooling water consumption can be reduced by increasing the process efficiency or eliminated by the implementation of dry cooling, although in this case an increase in the plant CAPEX can be expected. This consideration is also important for hydrogen conversion processes (e.g. conversion to ammonia, liquefaction, etc), where process cooling requirements could be satisfied with dry cooling in case of limited availability of water.

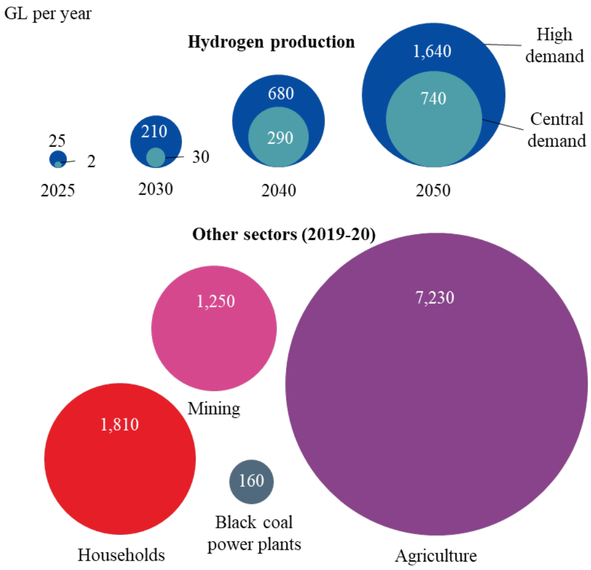


Figure 3.7.2 Modelled water consumption for hydrogen production, compared to current consumption in other Australian sectors. [64]

[64] Data for household, mining and agriculture water consumption from *Australian Bureau of Statistics, Water Account 2019-20 – Table 2.1 Physical Water Supply and Use*. Data for water consumption of black coal power plants in New South Wales and Victoria from *Overton IC (2020) Water for coal: Coal mining and coal-fired power generation impacts on water availability and quality in New South Wales and Queensland.*

3.8 Land use, Environment and planning

Infrastructure planning and development in Australia is significantly influenced by Government land use planning and regulatory approval processes. These include Commonwealth, State and/or Local Government approval processes. The renewable energy and hydrogen industries are in their infancy however current indications are that they will use existing development approval pathways.

Whilst each infrastructure development is required to progress development approvals separately, there are land uses which can be considered broadly as to indicate more constraints to development which can be considered to be a proxy for more complexity, additional time and cost to develop.

A desktop review of available GIS (Geographic Information System) mapping layers for constrained land has been undertaken as part of the jurisdictional assessments in Section 4. By overlapping the hydrogen supply chain links with the protected area dataset (sourced from Geoscience Australia[65] and the Department of Agriculture, Water and the Environment[66]), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, agriculture/ forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

Figure 3.8.1 shows the distribution of protected, prohibited and forestry areas across Australia (dark grey areas), together with the hydrogen infrastructure identified for the base case scenario in 2050. The land constraint layer is a composition of several levels:

- Collaborative Australian Protected Areas Database (CAPAD), including information about government, Indigenous and privately protected areas in Australia that meet the International Union for Conservation of Nature's definition of 'protected area'
- Prohibited areas, primarily including Defence training areas. These are defined as areas into which entry is restricted or prohibited without permission from the controlling authority
- Forestry reserves, which refers to public land reserved for forestry purposes.

65 https://services.ga.gov.au/gis/rest/services/NM_Reserves/MapServer

66 https://www.environment.gov.au/fed/catalog/search/resource/details.page?uuid=%7B4448CACD-9DA8-43D1-A48F-48149FD5FCFD%7D

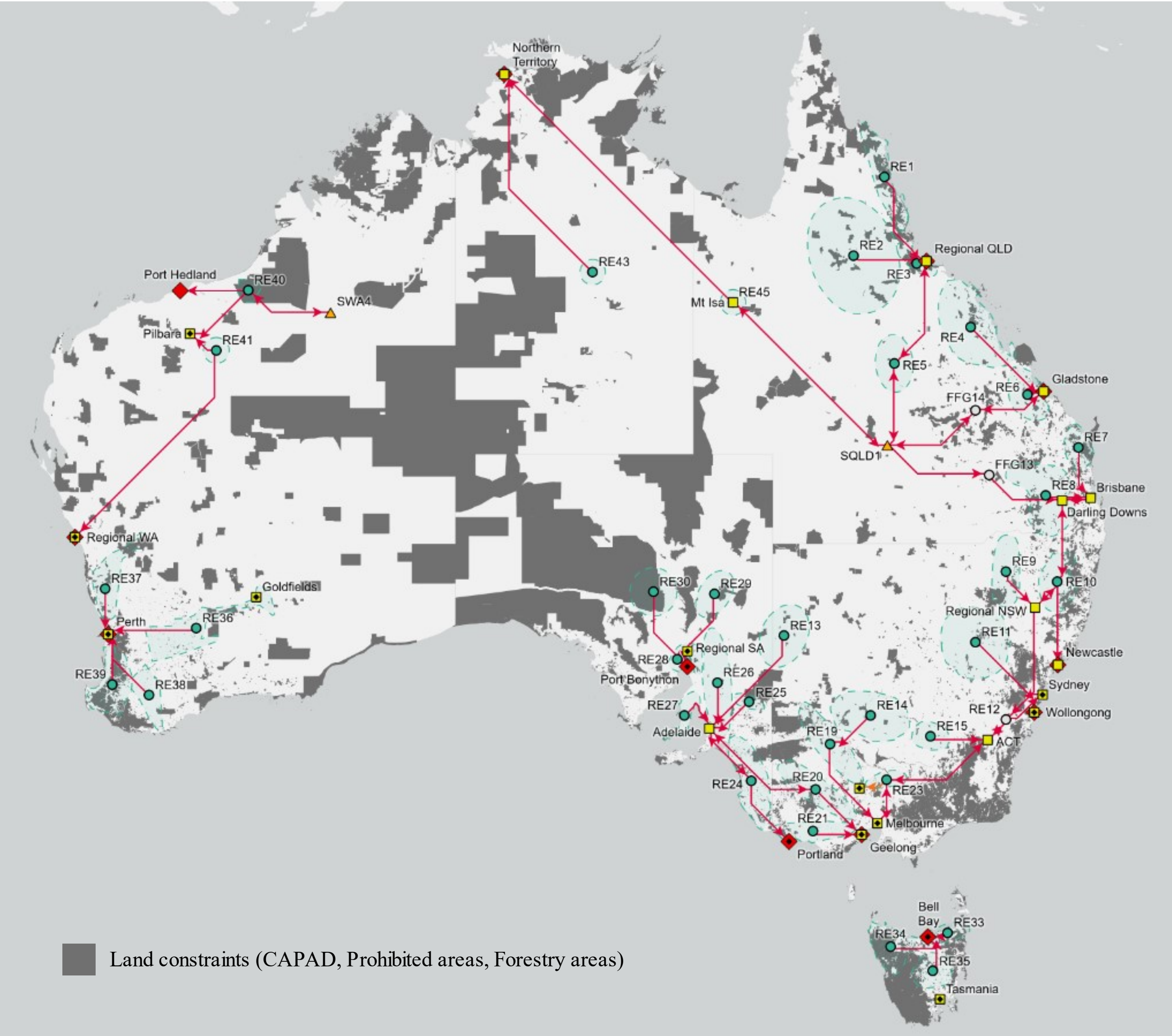


Figure 3.8.1 Constrained land in Australia overlayed with the 2050 base case scenario results

Demand locations are generally within the urban footprint of capital cities and regional centres and at Ports which generally have highly planned and competitive land use requirements, with multi-stakeholder and community interest. Blue hydrogen production is generally co-located with fossil fuel development and likely to be within a brownfield environment with complementary land use.

Green hydrogen however may be located within the REZs or at demand locations. Planning of the REZs has broadly been considered from an energy requirements perspective by AEMO and State and Territory Governments however land use planning is only just commencing in most jurisdictions. The REZs will need to consider renewable energy production – wind and solar as well as storage from batteries and pumped hydroelectric, and potential for hydrogen development. Some jurisdictions are already progressing infrastructure corridors (for electricity and/or pipelines) from REZs to demand centres. Linear infrastructure corridors must navigate multiple land parcels and landowners increasing the risk of incompatible land use and/or impacted stakeholders.

4 State & Territory Level Findings

4 State- and Territory-level findings

This section of the report presents an overview of the main results of the infrastructure assessment for state and territory jurisdictions recognising the role of State/Territory Government in infrastructure planning and delivery. The approach of this section is to provide a State/Territory-level perspective to the results for the base case scenario (central demand), presented in Section 3.3. Insights from other scenarios and sensitivities, where relevant, are added as an additional layer of information. It is noted that Australian Capital Territory is considered together with New South Wales as no supply chain falls fully within the ACT jurisdiction alone.

4.1 Queensland

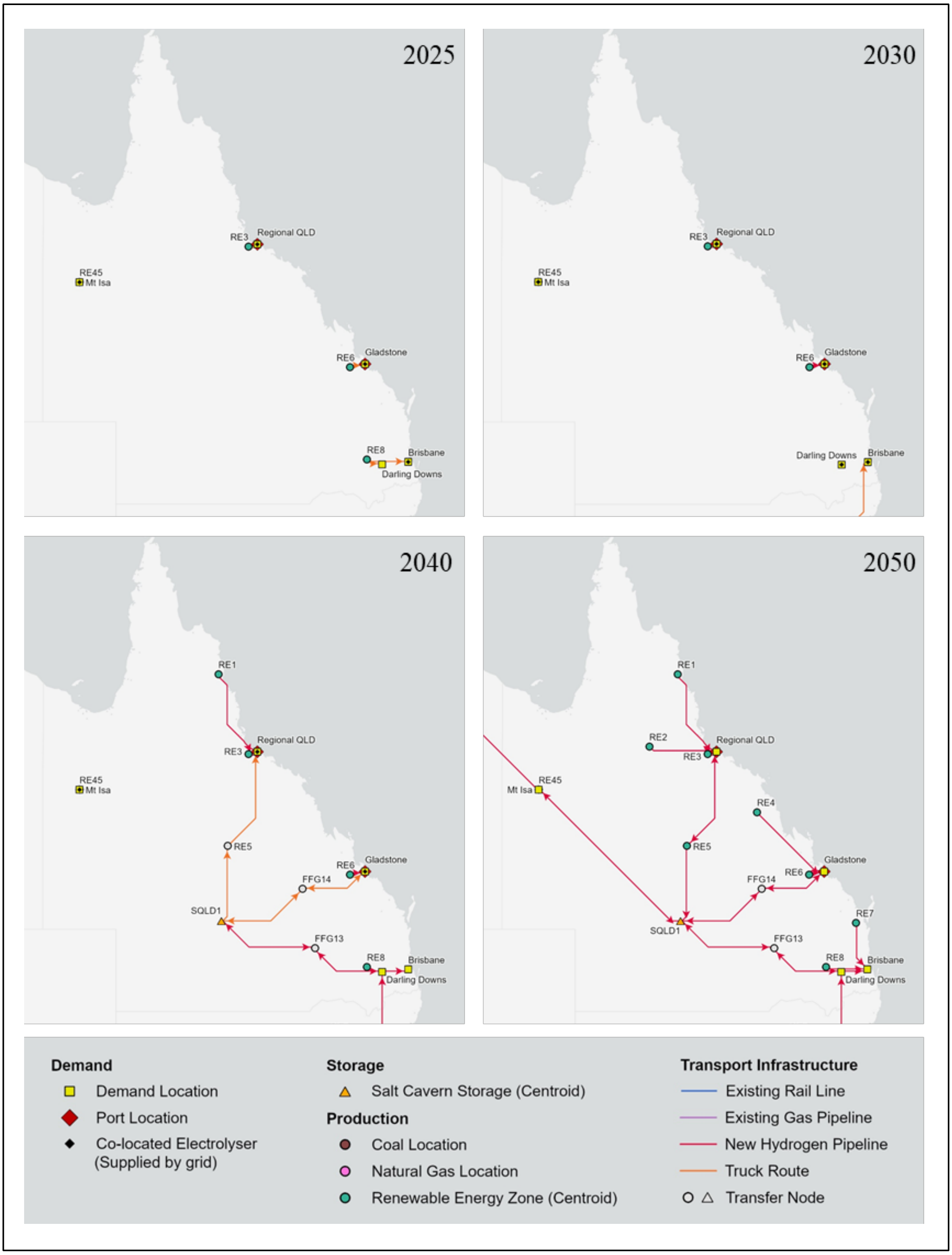


Figure 4.1.1: Queensland: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case.

4.1.1 Overview

Queensland hydrogen demand is estimated to grow substantially decade upon decade reflecting both a growing demand for transport and mining as well as for export as show in Section 4.1.3. Main demand centres (model locations) are identified at Brisbane, Gladstone, Mt Isa and Regional Qld (Townsville).

Queensland has resources for both blue and green hydrogen production available due to extensive fossil fuel resources, potential carbon storage and renewable energy resources. Renewable energy zones identified by AEMO and more recently under consultation by the Queensland Government are proposed to house the renewable energy required for green hydrogen. While the REZs in Queensland have sufficient capacity to satisfy the energy production required for the production of hydrogen in the central demand scenario, several REZs would reach saturation once the additional power capacity for the decarbonisation of the power grid is considered. Fossil fuel resources and locations were also selected based on the projects and their respective basins resources presented in the AEMO ISP 2020[6].

The model results for Queensland from 2025 to 2050 show a hydrogen supply chain based on green hydrogen from electrolysis powered by behind-the-meter renewable energy primarily from the Northern Queensland (RE3), Fitzroy (RE6) and Darling Downs (RE8) renewable energy zones. The production of hydrogen at the REZs and its transport in the form of compressed gas is generally preferred to the transmission of electricity to power electrolysers located at demand locations.

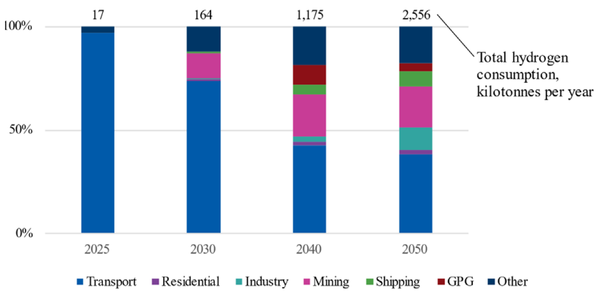
Hydrogen produced in the REZs is expected to be transported through dedicated hydrogen pipelines to supply Townsville and Gladstone as early as 2025, notably earlier than most other locations in Australia, reflecting size of demand and relatively close proximity and good renewable resources of the REZs. In other locations such as South-East Queensland, transport via road is assumed until demand volumes reach adequate capacity to justify pipeline construction by 2040. The development and connection to the salt cavern storage in the Adavale Basins is selected from 2040 onwards, reflecting demand volumes to justify pipelines and storage requirements. This salt cavern location also provides storage for the New South Wales hydrogen network. Depleted gas fields could be an alternative large-scale storage option to salt caverns, however they are not selected by the model due to their higher levelised cost of storage compared to salt caverns.

Blue hydrogen production from natural gas (coal seam gas) is favoured in South-East Queensland in 2030 but with the predicted falling cost of renewables and electrolysers is expected to be replaced by green hydrogen production afterwards. Blue hydrogen production from natural gas appears in the 2040 results in Queensland only in the ‘high electrolyser CAPEX’ scenario, however even in this sensitivity no blue hydrogen is produced in the 2050 timeframe. A suitable CCS location is assumed to be available in depleted gas fields located in the vicinity of the blue hydrogen production location. The Surat basin, considered to be a CCS location at an advanced stage of development according to Geoscience Australia, is also located relatively close, 300 km west of the hydrogen production location.

4.1.2 Hydrogen demand

The source of hydrogen demand for the 2025 (base case scenario) is primarily related to the use as fuel in low-emissions transport vehicles. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in populated areas and along major heavy haulage transport routes. In this regard, the Queensland Government is establishing the Queensland Hydrogen Super Highway[67] to support the introduction of hydrogen trucks and the implementation of a hydrogen refuelling station network. As hydrogen technologies develop, more opportunities of decarbonisation are made available. The total domestic demand in Queensland increases almost ten-fold in 2030 to164 kilotonnes, three quarters of which is dedicated to transport and about 10% for use in mining. In 2040 and 2050 the applications for hydrogen are more diversified. Transport and mining generate about two thirds of the demand, while industry, gas-fired power generation (GPG), and shipping fuel are responsible for about a fifth of the total demand. Total domestic demand in 2050 is 2,556 kilotonnes, equivalent to 85 TWh ofenergy or 30 GW of electrolyser capacity.

Figure 4.1.2 Modelled domestic hydrogen demand for Queensland – Base case.



Hydrogen demand for export is highly dependent on what share of Australian export is taken by each port location. The base case scenario assumes an even distribution of export across all Australian port locations, which includes the two modelled ports in Queensland, Townsville (Regional Queensland) and Gladstone. Both ports have masterplans in place that reserve sites for future expansion. Gladstone in particular has an area that is designated for future energy exports, already reclaimed, and has lots of space dedicated to coal and gas export and would benefit from transition opportunities. The port in Townsville is more space constrained and proximate to the town and other industries (navy, cruise ship terminal, containers) that would make more difficult to maintain buffer zones. No export demand is included in the 2025 timeframe. For the other timeframes, the increase in the total hydrogen demand averages around 40%, to reach an overall demand of 230 kt in 2030, 1,889 kt in 2040 and 4,416 kt in 2050.

4.1.3 Hydrogen production

Renewable hydrogen

Hydrogen production in the RE3 (Northern Queensland) and RE6 (Fitzroy) are a feature common to all scenarios due to their proximity tothe main demand nodes. The high hydrogen flows from these production points justifies the construction of dedicated hydrogen pipelines todemand locations at Gladstone and Regional Queensland (represented by Townsville). RE8 (Darling Downs) is also heavily utilised.

Additional renewable energy zones are engaged asthe demand for hydrogen increases.

The ratio of solar PV and wind energy production dedicated to hydrogen is relatively balanced throughout the scenarios (approximately 50% solar PV and 50% wind), with a slight preference for wind in 2025, shifting to a preference for solar PV towards 2050 due to the expected reduction in the costs of this technology.

[67] Queensland Hydrogen Super Highway initiative, https://www.epw.qld.gov.au/about/initiatives/hydrogen/hydrogen-super-highway

Power transmission

From an infrastructure point of view, one of the main aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. While hydrogen production at the renewable energy zones is assumed to be powered by behind-the-meter renewable energy systems, with no requirement for access to the existing power transmission infrastructure, electrolysers situated in demand locations are assumed to be supplied by electricity transported via the power transmission infrastructure.

In the timeframes from 2025 to 2040, as outlined below, the hydrogen economy will increase the load on the power transmission infrastructure as a share of hydrogen is produced at the demand nodes using electrolysers powered by grid electricity.

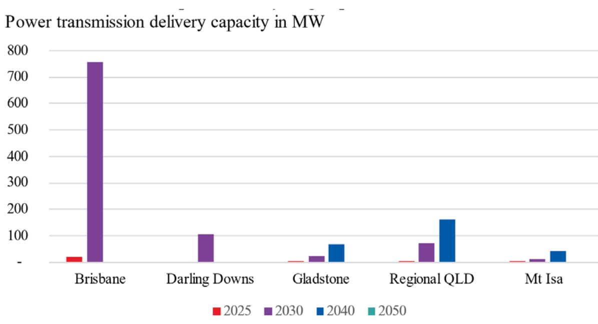
As presented in Figure 4.1.3, the electricity required to power the electrolysers at the demand locations in 2025 is limited, with 20 MW of power transmission required to supply Brisbane and 5 MW or less for the other locations. The existing power infrastructure will likely be able to support this additional demand.

In 2030, the power transmission requirements increase significantly, with 750 MW of additional transmission to Brisbane and up to 100 MW for the other locations, to service co-located hydrogen production at demand locations. Augmentation of critical power lines between renewable energy production areas and demand locations is likely to be required and could be carried out together with the augmentation for the electrification of other energy sectors.

From 2040, hydrogen production at the demand locations reduces overall because of the reduced cost of behind-the-meter renewable electricity, with no co-located hydrogen production in Brisbane and up to 160 MW of electrolyser capacity in other demand locations. This corresponds to the development of a hydrogen transmission pipeline in the same timeframe. While in reality electrolysis systems installed at demand locations in 2030 would still be in operation in 2040, the shift in preference towards behind-the-meter hydrogen production is an important indication of where the market might be moving in the future, and it provides valuable insights for decision making in the hydrogen space.. No co-located hydrogen production appears in the results for 2050.

While co-located electrolysers will add to the electricity demand of the demand centres, with consequent possible strain on the power transmission infrastructure, the overall trend is a strong preference for hydrogen production in the REZs.

Figure 4.1.3 Power transmission capacity required for hydrogen production in Queensland – Base case.



Low-emissions hydrogen

In the scenario that includes blue hydrogen technologies, coal seam gas from the Clarence Moreton basin (FFG4), south of Brisbane, is identified for the production of hydrogen in 2030.

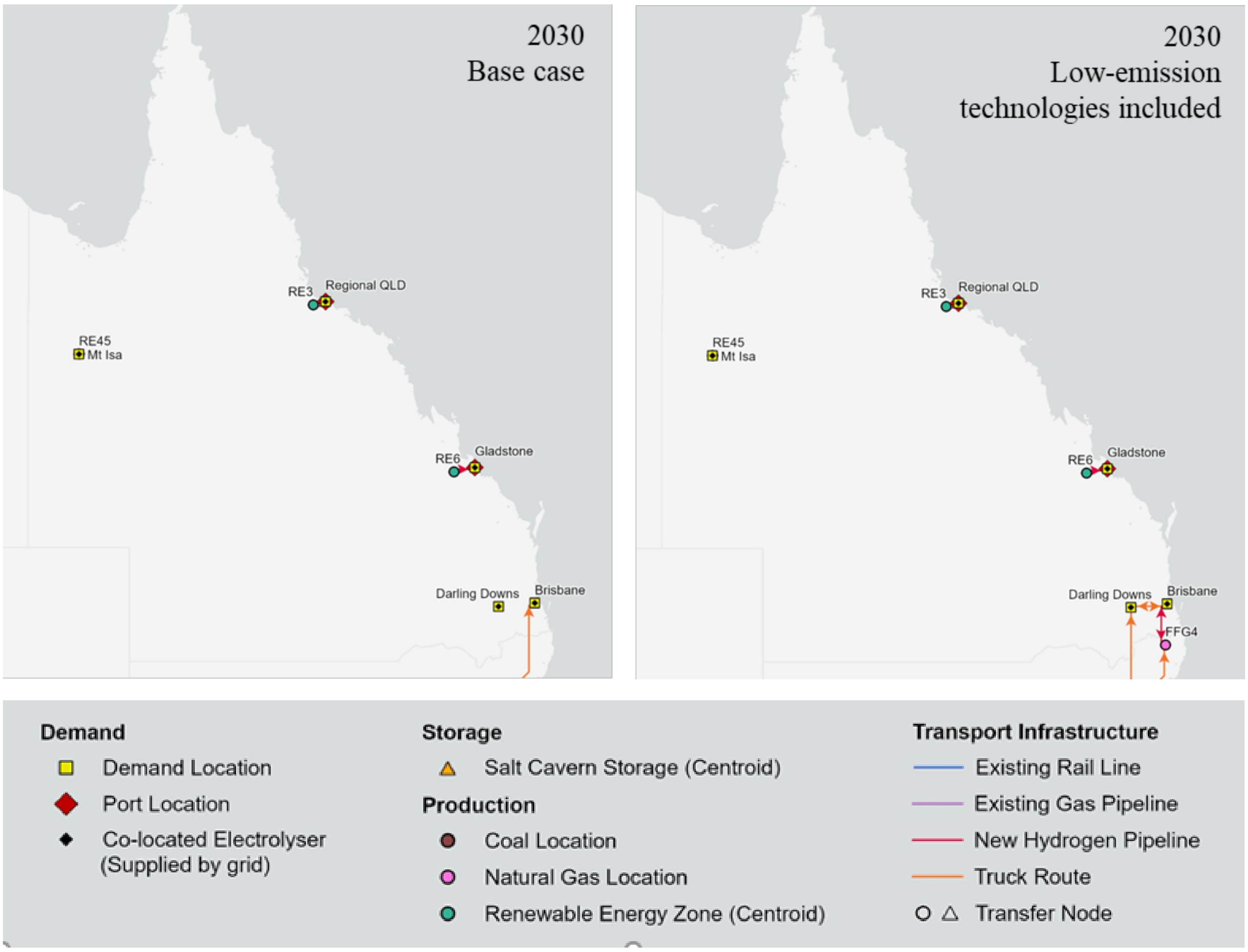


Figure 4.1.4 Queensland, 2030: Comparison of the model results for the base case and for the scenario with low-emissions technologies included.

While this gas basin was included in the techno-economic model, in line with the assumptions of the AEMO ISP 2020[6], it is noted that it is only a prospective gas production location and that it is not currently operational. The model does not distinguish between developed and prospective gas locations, as long as they are included as potential production areas, and therefore does not consider higher cost of natural gas supply for locations not yet developed. If blue hydrogen production levels will not justify the development of new gas extraction from the Clarence Moreton basin, other existing natural gas locations are available in the Surat basin east of Brisbane and could be utilised instead. While the larger distance between these locations and the hydrogen demand areas would lead to a slight increase in the hydrogen transport cost, the difference is expected to be minor and unlikely to change the results and lead to a preference for other hydrogen supply options.

A suitable CCS location is assumed to be available in depleted gas fields located in the vicinity of the blue hydrogen production location, although it is noted that further investigation will be required to assess the suitability of these underground formations for the long-term storage of carbon dioxide. If only CCS locations at an advanced stage of development (according to Geoscience Australia[68]) were to be considered, the Surat basin is the closest CCS location, 300 km west of the blue hydrogen production location.

By 2040 the cost of renewable energy and electrolysers in the base case scenario has reduced to the extent that no blue hydrogen production is selected by the model. Blue hydrogen production from natural gas appears in the 2040 results in Queensland only in the ‘high electrolyser CAPEX’ scenario, however even in this sensitivity no blue hydrogen is produced in the 2050 timeframe. This result discourages the development of blue hydrogen production plants as their cost of hydrogen production could be higher than other alternatives before the end of the plant’s life.

4.1.4 Hydrogen storage

Similarly to the results for the whole of Australia, the two types of hydrogen storage technologies selected by the model are MCH tanks and salt caverns. In Queensland, the availability of a salt cavern in the Adavale Basin (SQLD1) heavily shapes the results of the techno-economic model.

In 2025 and 2030 the scale of hydrogen demand does not justify the development of the SQLD1 salt cavern, and all storage is carried out in the form of MCH tanks, with the related hydrogen conversion and reconversion facilities. However, once the critical scale for the development of the salt cavern infrastructure is reached, virtually all hydrogen storage is satisfied by this site. The salt cavern first appearance in the model results is in 2040 for both the central and low demand scenarios, while in the high demand sensitivity the salt cavern is already selected in 2030. By 2050, in all demand scenarios, all demand and production locations are either directly or indirectly linked to the salt cavern via hydrogen pipelines.

4.1.5 Hydrogen transport

In 2025, the limited hydrogen transport requirements are satisfied by compressed hydrogen trucks routes, established between hydrogen production areas and nearby demand locations.

By 2030, most locations are already linked by the first hydrogen gas pipelines, selected because of their favourable economics at large-scale compared to road transport. The hydrogen pipelines that first appear in 2030 are also present in the following timeframes and most sensitivity cases (although in the low demand scenario they only appear from 2040 onwards), highlighting their potential for investment. These main pipelines are:

- Between RE6 (Fitzroy) and Gladstone (~90km)
- Between RE3 (Northern Queensland) and Regional Queensland (~40km).

Both the above pipelines link a short distance directly from nearby dedicated renewable energy

[68] According to the ‘Advanced CO2 Geological Storage Sites 2030 (2021)’ dataset by Geoscience Australia, https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/145507

production locations to export demand locations. In the 2040 and 2050 timeframes, a growing network of pipelines are required to move hydrogen from production to demand locations, and to link the salt cavern with the other nodes.

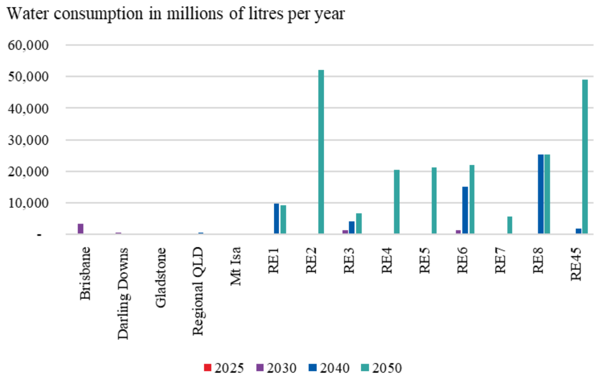
4.1.6 Wider techno-economic considerations

Water requirements

The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. In Queensland, the water consumption associated with hydrogen production is expected to grow considerably from 0.5 billion litres (GL) in 2025 to 212 GL in 2050. According to data from the Australian Bureau of Statistics[69], the estimated water demand for hydrogen in 2050 is roughly equivalent to what was consumed by the Queensland manufacturing sector in 2019-20 (213 GL), and it corresponds to 3% of Queensland total water consumption in 2019-20.

Figure 4.1.5 presents the annual water consumption for hydrogen production in Queensland, divided by location and timeframe (central demand scenario). The model results do not show a clear preference between producing hydrogen at REZs located near the coastline or inland, with the share of hydrogen production along the coast varying between 16% and 93% at different timeframes. However, in 2050, when the demand for hydrogen is the highest, most hydrogen is produced at inland locations, with no proximal access to water from coastal desalination plants.

Figure 4.1.5 Water consumption for hydrogen production in Queensland – Base case. [70]



Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

[69] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 5. Physical Supply and Use, by Water Type, Queensland https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

[70] Specific water consumption coefficients are presented in Section B-3.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential ‘red flag’ land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In Queensland, coastal infrastructure (e.g RE1, RE7 supply chains) is likely to be more constrained than regional inland infrastructure from a protected areas perspective. Potential impacts on the World Heritage Area of the Great Barrier Reef are also to be considered from a water quality (e.g desalination), port development and shipping perspective. Townsville has large areas of military prohibited areas (RE 2 supply Chain). South East Queensland (RE7, RE8 supply chains) is constrained due to fragmented protected areas in highly urbanised area. Whilst use of the salt cavern (SQLD1) for high volume storage is selected by the model for LCOH, the pipeline connections required are of significant distance to all demand centres. This increases the planning complexity considerably, particularly toward Gladstone and Brisbane demand centres. It is also noted that protected areas within REZs will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity.

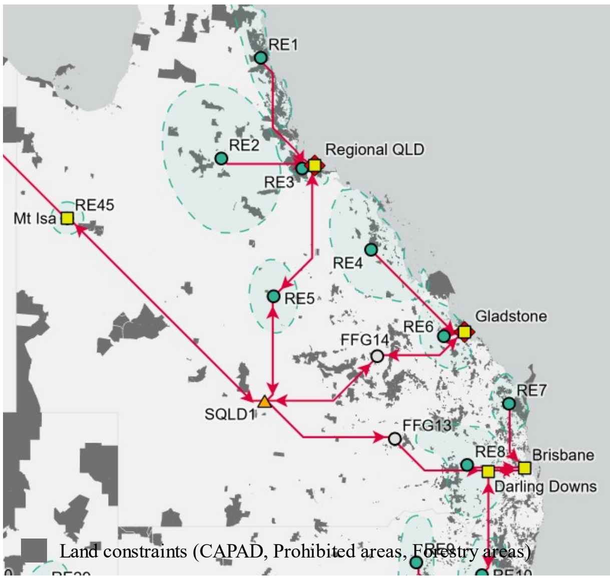


Figure 4.1.6 Constrained land in Queensland overlayed with the 2050 base case scenario results

4.2 New South Wales and Australian Capital Territory

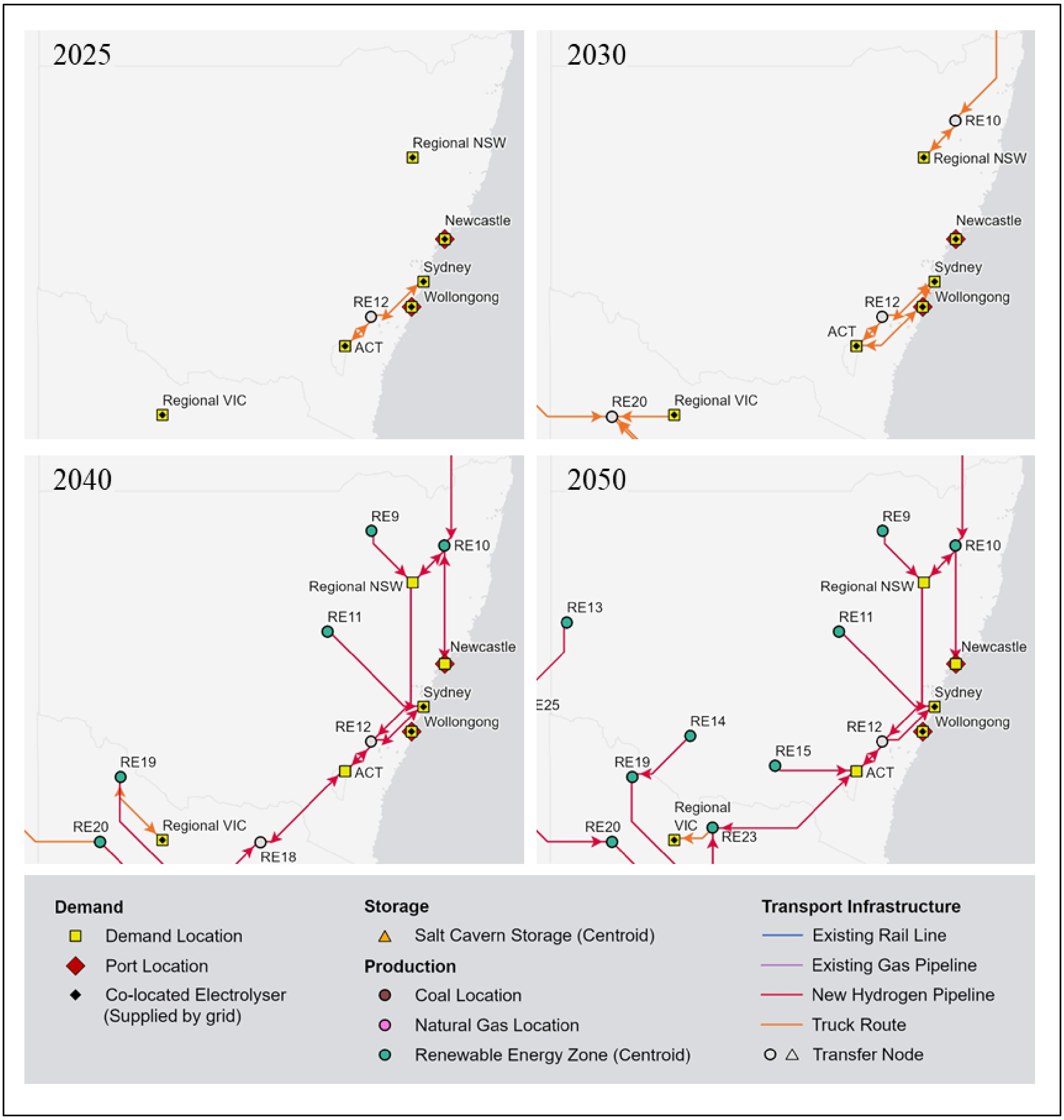


Figure 4.2.1 New South Wales: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case.

4.2.1 Overview

The hydrogen demand in New South Wales is estimated to grow substantially decade upon decade reflecting both a growing demand for transport and fuel switching in residential, mining, and industrial settings as well as for export as shown in Section 4.2.2. Main demand centres (model nodes) are identified at Sydney, Wollongong, Newcastle, ACT and Regional New South Wales.

New South Wales has resources for both blue and green hydrogen production available due to extensive fossil fuel and renewable energy resources. While no advanced geological storage sites for carbon dioxide have been identified by Geoscience Australia in New South Wales[71], the model assumes the future availability of underground storage in the vicinity to the gas extraction locations. Renewable energy zones identified by AEMO are proposed to house the renewable energy required for green hydrogen. Fossil fuel resources and locations were also selected based on the projects and their respective basins resources presented in the AEMO ISP 2020[6].

The model results for New South Wales in 2025 and 2030 show all the hydrogen demand being satisfied by electrolysers co-located with the demand locations, powered by grid electricity. In the following timeframes the production of hydrogen at the REZs (primarily in New England (RE10) and Central-West Orana (RE11)) and its transport in the form of gas is generally preferred to the transmission of electricity to power co-located electrolysers. The Australian Capital Territory is located along the hydrogen pipeline that develops between New South Wales and Victoria, providing the opportunity to access hydrogen without the need for local production. MCH tanks provide all the hydrogen storage capacity until 2040, when a pipeline connection to the Queensland hydrogen network provides access to the large-scale hydrogen storage in the Adavale Basin.

Blue hydrogen production from coal or natural gas is never selected in New South Wales in the low-emission technologies scenario, however in 2030 some hydrogen produced in South-East Queensland (SEQ) via steam methane reforming of natural gas is imported and used in Regional NSW.

[71] Based on 'Advanced CO2 Geological Storage Sites 2030 (2021)' dataset by Geoscience Australia, https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/145507

4.2.2 Hydrogen demand

The transport sector is expected to capture most of the initial domestic hydrogen demand in New South Wales, with about 19 kilotonnes of hydrogen required in 2025. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in populated areas and along major heavy haulage transport routes. In this regard, the governments of New South Wales and Victoria have introduced the Hume Hydrogen Highway initiative[72] to support the establishment of a hydrogen refuelling network between Sydney and Melbourne. While not directly positioned along the Hume Highway, the Australian Capital Territory also has the opportunity to support the hydrogen refuelling network for the traffic that moves within or that transits through the Territory. As hydrogen technologies develop and the cost of hydrogen reduces, more opportunities of decarbonisation are made available. The total domestic demand in New South Wales increases eight-fold in 2030 to 160 kilotonnes, three quarters of which is dedicated to transport and about 10% for use in mining and for residential applications. It is noted that the ACT Government has a plan to phase out the use of natural gas for residential and commercial users in favour of electrification, with a proposed ban of new gas connections from 2023[73]. The introduction of this regulation would effectively eliminate the future residential demand for hydrogen in the ACT.

In 2040 and 2050 the applications for hydrogen are more diversified. In 2040, transport and residential sectors are the main sources of demand, together responsible for over half of the 1,032 kilotonnes required. Mining and industry also increase their share, together totalling about 10% of the total. By 2050, industry is the second source of hydrogen demand after transport, followed by residential and mining generate about two thirds of the demand, while industry, power generation, and shipping fuel are responsible for about a fifth of the total demand. The total domestic demand in 2050 is 2,407 kilotonnes, requiring 108 TWh of electricity input and 25 GW of electrolyser capacity.

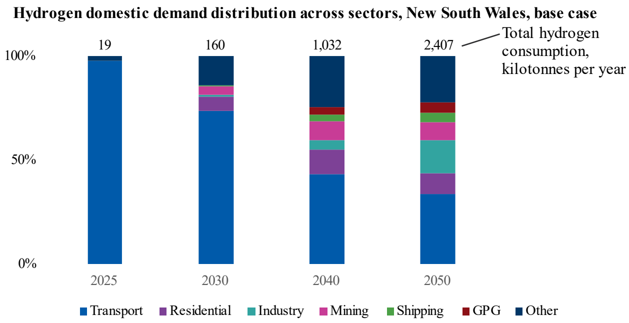


Figure 4.2.2 Modelled domestic hydrogen demand for New South Wales – Base case.

The base case scenario assumes an even distribution of export across all Australian port locations, which includes the two modelled ports in New South Wales, Newcastle and Wollongong. No export demand was included in the 2025 timeframe. For the other timeframes, export is responsible for 30-40% of the total hydrogen demand, leading to a combined domestic and export demand of 226 kt in 2030, 1,746 kt in 2040 and 4,267 kt in 2050.

[72] Hume Hydrogen Highway initiative, https://www.nsw.gov.au/media-releases/delivering-renewable-hume-hydrogen-highway

[73] https://www.climatechoices.act.gov.au/energy/switching-from-gas

4.2.3 Hydrogen production

Renewable hydrogen

According to the techno-economic model results, in the 2025 and 2030 timeframes all the hydrogen demand is satisfied by electrolysers co-located with the demand locations, powered by grid electricity. The economic advantage of co-located electrolysers is the higher utilisation factor allowed by the connection to the main grid (as opposed to the direct connection to variable renewable energy sources) and the minimum cost of hydrogen transport (assumed to be zero by the model).

On the other hand, in 2040 and 2050 demand locations are almost exclusively supplied by hydrogen produced remotely in REZs. This shift is due to the lower cost of renewable energy and to the lower electrolysers CAPEX, which reduced the advantage that grid-supplied plants have in terms of utilisation factor, as explained in Section 3.4.1. The only exceptions are a small local production in Sydney, and the 100% local production in Wollongong. The shift of local to remote production arises the issue of potential stranded hydrogen production assets at the demand point. If future detailed analysis were to confirm this transition, the installation of remote hydrogen facilities could be favoured in the earlier timeframes as well.

As it is the case for most areas of Australia, the ratio of solar PV and wind energy production dedicated to hydrogen remains relatively balanced throughout the scenarios, with a slight preference for wind in the first timeframe, shifting to a preference for solar PV towards 2050 due to the expected reduction in the costs of this technology.

RE9, RE10, and RE11 (Northwest NSW, New England, and Central-West Orana, respectively) are selected for remote hydrogen production in the 2040 timeframe, and continue to be a feature also in 2050. By this year, one additional renewable energy zone for the supply of hydrogen to New South Wales is engaged as the demand for hydrogen increases (RE15, or Wagga Wagga). In addition to this, in 2050 two additional REZs within New South Wales (RE13 and RE14) are selected by the model for the supply of hydrogen to South Australia and Victoria, due to their vicinity to the State border. It is also noted that RE12 (Southern New South Wales Tablelands) is never selected by the model as it has no available wind and solar PV capacity according to the input data from AEMO ISP[6].

The hydrogen production results are different for the scenarios testing the sensitivity to hydrogen demand. In the low demand scenario, co-located hydrogen production is preferred in all demand locations up to 2040, with no behind-the-meter production facilities. Hydrogen generation at the REZs is only generally preferred in 2050, with RE9 (Northwest NSW) and Queensland providing most hydrogen via a network of pipelines.

Conversely, in the high demand scenario the hydrogen production infrastructure is similar to that of the base scenario, however the early saturation of the available REZs leads to supplementary hydrogen production in the demand location all the way to 2050.

Power transmission

From an infrastructure point of view, one of the key aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. As mentioned in the section above, in 2025 and 2030 all the hydrogen in New South Wales is produced at the demand nodes.

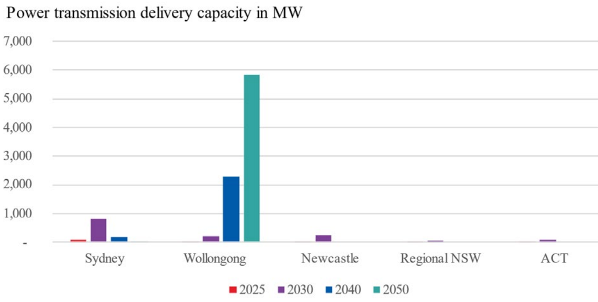
As shown in Figure 4.2.3, the electricity required to power the electrolysers in 2025 is somewhat limited, with 100 MW of power transmission required for Sydney and 10 MW or less for the other locations. The existing power infrastructure will likely be able to support this additional demand.

In 2030, the power transmission requirements increase significantly, with 800 MW of additional transmission to Sydney and up to 250 MW for the other locations. Augmentation of critical power lines between renewable energy production areas and demand locations could be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

As mentioned above, from 2040 only Wollongong is still supplied by co-located electrolysers. The sum of local and export hydrogen demand in the central demand scenario is significant, and the model satisfies it with the installation of 2.3 GW of electrolysers in 2040 and almost 6 GW in 2050 (including the relative power transmission infrastructure). The model is built on the assumption that sufficient renewable energy is available from the grid, however in reality there is the risk that this power demand will further saturate local REZs and increase competition for the purchase of electricity.

Shifting the hydrogen export demand from Wollongong to other port locations could alleviate part of the strain on the local grid. This scenario was tested in the 'Export north' sensitivity, where export demand is assumed to be satisfied only by the port locations in the north of Australia. In this scenario, the capacity of co-located electrolysers in Wollongong is reduced to 0.4 GW in 2040 and to about 1 GW in 2050.

Figure 4.2.3 Power transmission capacity for hydrogen production in New South Wales – Base case.



4.2.4 Hydrogen storage

In Australia, across all scenarios the two hydrogen storage technologies selected by the model are salt caverns and MCH tanks. In New South Wales, where no salt deposits suitable for hydrogen storage have been identified, all hydrogen storage installed is in the form of MCH tanks.

Initially, MCH storage tanks and conversion/reconversion facilities are distributed across the demand locations. However, as interconnected hydrogen networks are created, hydrogen storage becomes more centralised, with some locations (e.g. Sydney) servicing the others. More importantly, as a hydrogen pipeline network develops between Queensland and New South Wales, and NSW demand locations become in direct connection with the salt cavern storage in Queensland, a large amount of storage requirement is satisfied by the buffer provided by this salt cavern location. The very low cost of salt cavern storage justifies the construction and operation costs of the required pipelines.

4.2.5 Hydrogen transport

In 2025 and 2030, all transport of hydrogen is carried out with compressed hydrogen trucks. In these timeframes, the primary purpose of transport is for the sharing of hydrogen storage infrastructure rather than moving hydrogen from production to demand locations. Road transport of hydrogen between Canberra and Sydney is selected by model also in the low and high demand scenarios.

On the other hand, in 2040 and 2050 all transport is via dedicated compressed hydrogen pipelines, that connect production and demand locations, as well as storage locations. As mentioned in Section 4.2.4, hydrogen pipelines are used to access the low-cost salt cavern storage location.

This structure of the transport connections layout is largely unchanged in the high demand scenario, compared to the base case analysis. The same consideration is valid of the low demand scenario, however in this case the development of an interconnected pipeline system is delayed from 2040 to 2050.

4.2.6 Wider techno-economic considerations

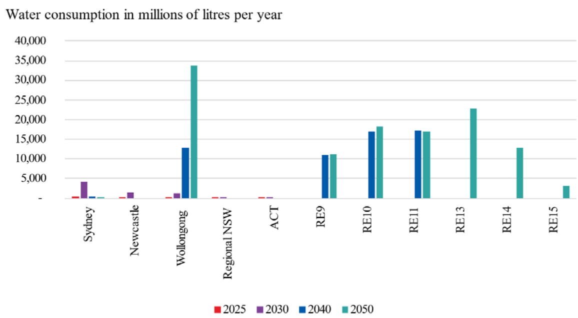
Water requirements

In New South Wales, all REZs are located inland, with no access to water from desalination plants. The only significant hydrogen production along the coast is in Sydney (2030 and 2040 timeframes) and Wollongong (all timeframes).

RE10 (New England) is the only hydrogen production location in a low water stress area. RE11 (Central West Orana) is in a high water stress zone, while the water stress level in RE9 (North West NSW) and RE15 (Wagga Wagga) is extremely high. Finally, RE13 and RE14 (Broken Hill and South West NSW, respectively), which are located in New South Wales for the supply of hydrogen to South Australia and Victoria, are also located in high risk areas from a water stress point of view, with the former located in an arid area and the latter in an extremely high water stress location.

All locations should be assessed in detail to evaluate the water availability for hydrogen production. The high and extremely high water stress levels in several hydrogen production location increase the social and political risk due to potential for water competition between different sectors.

Figure 4.2.4 Water consumption for hydrogen production in New South Wales and the ACT – Base case. [74]



[74] Specific water consumption coefficients are presented in Section B-3.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In NSW/ACT, coastal infrastructure (e.g RE12, RE16, RE41 supply chains) is likely to be more constrained than regional inland infrastructure from a protected areas perspective. It is also noted that protected areas within REZs (e.g RE16, RE9) will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity.

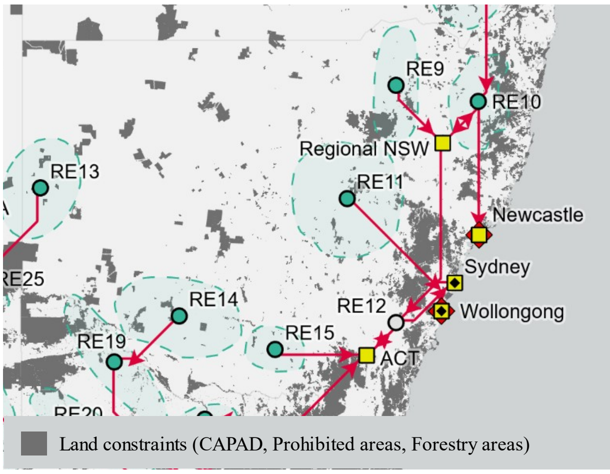


Figure 4.2.5 Constrained land in New South Wales and Australian Capital Territory overlayed with the 2050 base case scenario results

4.3 Victoria

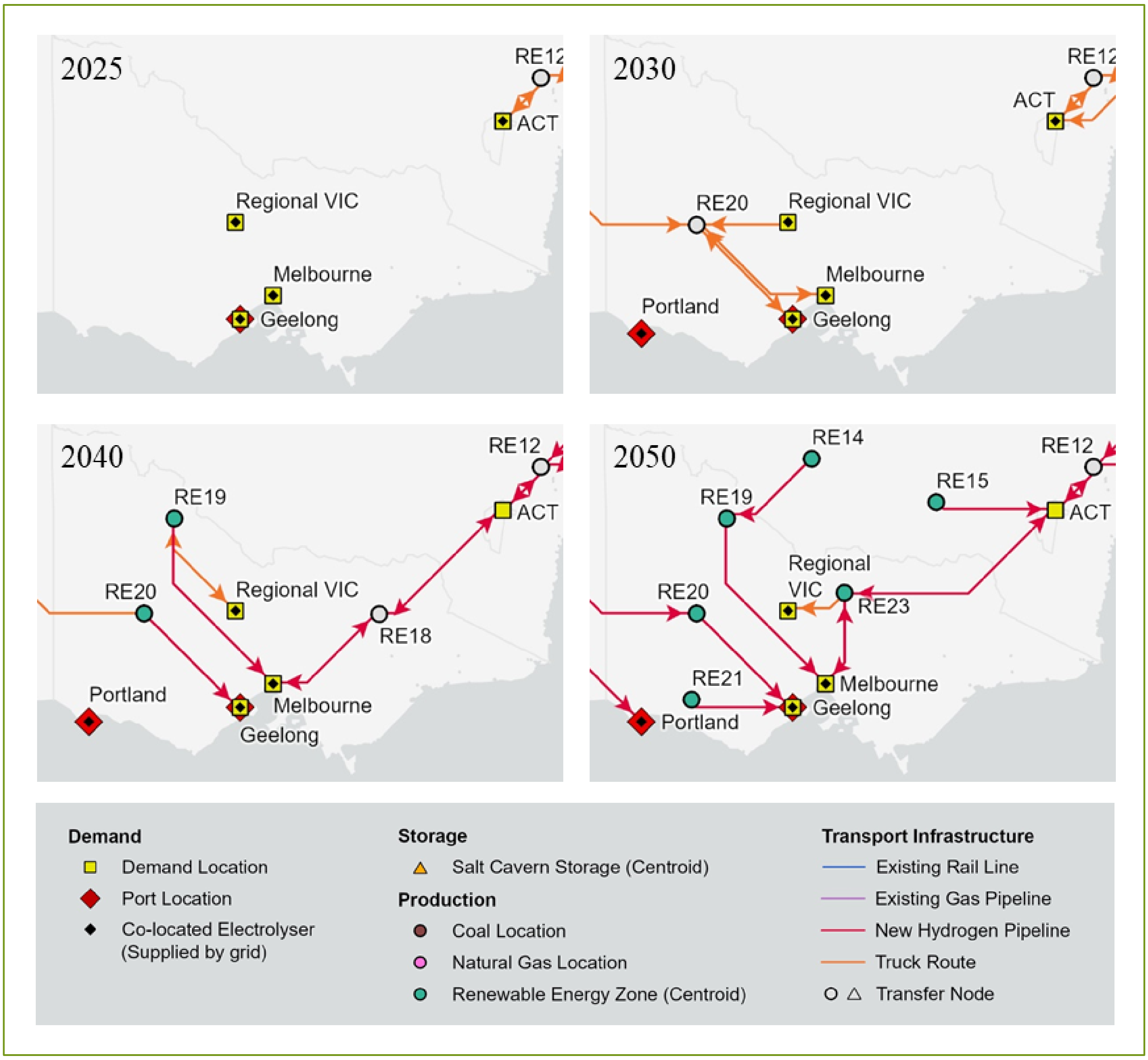


Figure 4.3.1 Victoria: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case.

4.3.1 Overview

The hydrogen demand in Victoria is estimated will be driven by fuel switching opportunities in the transport and residential sectors as shown in Section 4.3.2, with sustained growth throughout the 2025 to 2050 timeframes. Main demand centres (model nodes) are identified at Melbourne, Geelong, Portland and Regional Victoria.

Victoria has resources for both blue and green hydrogen production available due to extensive natural gas, brown coal and renewable energy resources. Renewable energy zones identified by AEMO are proposed to house the renewable energy required for green hydrogen. Fossil fuel resources and locations were also selected based on the projects and their respective basins resources presented in the AEMO ISP 2020[6]. In Victoria, the natural gas basins included in the model are all offshore (Bass, Otway and Gippsland). The locations of the potential facilities for blue hydrogen production from natural gas were assumed to be at the nearest onshore gas processing plant for each of the gas extraction projects (e.g. the Longfield gas processing plant for the Gippsland Basin Joint Venture project in the Gippsland basin).

The model results for Victoria in 2025 and 2030 show all the hydrogen demand being satisfied by electrolysers co-located with the demand locations, powered by grid electricity. In the following timeframes the production of hydrogen at the REZs and its transport in the form of gas is generally preferred to the transmission of electricity to power co-located electrolysers, however the large demand for hydrogen saturates the available REZs and the model is forced to continue to produce most hydrogen with grid-fed co-located electrolysers. This highlights the complexity of supplying hydrogen to Victoria's demand locations (Melbourne in particular), which could require the access to additional renewable resources in Victoria (e.g. offshore wind).

Hydrogen transport is carried out via road trucks until 2040, when the larger supply chains justify the construction of a network of dedicated hydrogen pipelines. MCH tanks provide all the hydrogen storage capacity. Blue hydrogen production from brown coal or natural gas is not selected by the model in the base case scenarios.

4.3.2 Hydrogen demand

The transport sector is expected to capture most of the initial domestic hydrogen demand in Victoria, with about 15 kilotonnes of hydrogen required in 2025. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in populated areas and along major heavy haulage transport routes. In this regard, the governments of Victoria and New South Wales have introduced the Hume Hydrogen Highway initiative[75] to support the establishment of a hydrogen refuelling network between Melbourne and Sydney. As hydrogen technologies develop and the cost of hydrogen reduces, more opportunities of decarbonisation are made available. The total domestic demand in Victoria increases ten-fold in 2030 to 153 kilotonnes, of which 60% is dedicated to transport and 20% for use in residential applications.

In 2040, the residential sector becomes the leading source of domestic demand, followed by transport. Together, these two sectors are responsible for 80% of the 1,121 kilotonnes required in 2040. By 2050, the share of industry and mining grows to 20% of the total domestic demand, while residential use and transport continue to contribute to over half the demand. The total domestic demand in 2050 is 2,441 kilotonnes, requiring 110 TWh of electricity input and 25 GW of electrolyser capacity.

[75] Hume Hydrogen Highway initiative, https://www.nsw.gov.au/media-releases/delivering-renewable-hume-hydrogen-highway

The large share of hydrogen demand for the residential sector in Victoria compared to other jurisdictions reflects the current Victorian energy system, which is characterised by an extensive natural gas distribution network and high natural gas consumption for buildings. The assumption of the base case scenario (central demand) is that most of the current customers will remain connected to the gas grid, which is assumed will be gradually converted to 100% hydrogen.

However, it is noted that recent developments in Victoria (the publication of the Gas Substitution Roadmap in particular) indicate that there might be a preference for electrification of the residential and commercial sectors, which would considerably reduce the domestic demand for hydrogen. To capture this, the low demand scenario assumes that residential and commercial applications would move to electrification.

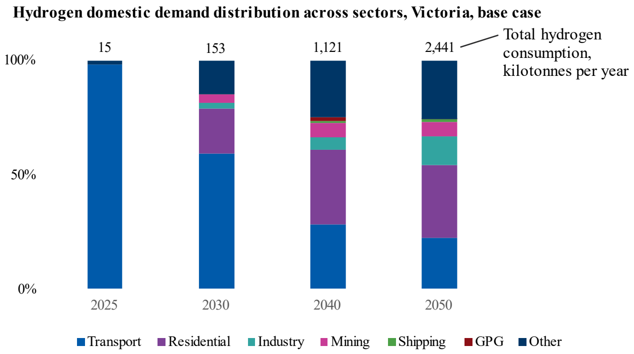


Figure 4.3.2 Modelled domestic hydrogen demand for Victoria – Base case.

The demand for export is in addition to the domestic demand. The base case scenario assumes an even distribution of export across all Australian port locations, which includes the two modelled ports in Victoria. These are the ports of Geelong and Portland, selected following advice from the Victorian Government. No export demand was included in the 2025 timeframe. For the other timeframes, the increase in the total hydrogen demand averages around 40% of the total, leading to a combined domestic and export demand of 219 kt in 2030, 1,836 kt in 2040 and 4,301 kt in 2050.

4.3.3 Hydrogen production

Renewable hydrogen

According to the techno-economic model results, in the 2025 and 2030 timeframes all the hydrogen demand is satisfied by electrolysers co-located with the demand locations, powered by grid electricity. The economic advantage of co-located electrolysers is the higher utilisation factor allowed by the connection to the main grid (as opposed to the direct connection to variable renewable energy sources) and the minimum cost of hydrogen transport (assumed to be zero by the model).

While in 2040 and 2050 all demand locations are partially supplied by hydrogen plants located in REZs, the largest source of hydrogen remains grid-fed co-located electrolysers. This differs from the results for most other states and territories, where instead there is a transition towards 100% hydrogen from REZs. The main reason for this is that while the cost of grid electricity is assumed to be the same for all locations in Australia, the renewable energy resources in Victoria tend to be less favourable than in other areas, leading to a higher cost of renewable electricity.

Also, the limited area available for the renewable power generation compared to other jurisdictions leads to the saturation of the RE19 (Murray River) and RE20 (Western Victoria) in 2040, with 4.7 GW and 3.2 GW of renewable generation capacity, respectively. In 2050, RE23 (Central North Victoria) and RE21 (South West Victoria) are also fully utilised. Conversely, in the sensitivity exploring low hydrogen demand none of the REZs are saturated in 2050. It is also noted that RE18 (Ovens Murray) is never selected by the model as it has no wind and solar PV availability according to the input data from AEMO ISP[6].

The local hydrogen demand in the central demand scenario is significant, and the model satisfies it with the installation of 5.6 GW of electrolysers in 2040 and 10.0 GW in 2050 (including the relative power transmission infrastructure). The model is built on the assumption that sufficient renewable energy is available from the grid, however in reality there is the risk that this power demand will further saturate local REZs and increase competition for the purchase of electricity.

About 9 GW of proposed offshore wind projects have been proposed in Victoria.[76] These projects could increase the total amount of renewable energy capacity in the State to ease the strain on the onshore renewable energy zones.

As it is the case for most areas of Australia, the ratio of solar PV and wind energy production dedicated to hydrogen remains relatively balanced throughout the scenarios, except in the Murray River area (RE19) where solar PV is responsible for all renewable energy production.

The results of the hydrogen demand sensitivity analysis show that in the low demand scenario the preference for hydrogen production location in 2030 remains unchanged compared to the base case, with all hydrogen produced at demand locations. While the supply chain structure changes in the base scenario for 2040, in the low demand sensitivity hydrogen continues to be produced within demand centres. The shift towards behind-the-meter production and transport via pipeline is only selected for the 2050 timeframe in the case of the low demand scenario. Conversely, the high demand scenario presents a hydrogen supply chain very similar to that of the central demand case, with the difference of additional hydrogen production at demand locations due to the saturation of the local REZs.

Power transmission

From an infrastructure point of view, one of the main aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. While hydrogen production at the renewable energy zones is assumed to be powered by behind-the-meter renewable energy systems, with no requirement for access to the existing power transmission infrastructure, electrolysers situated in demand locations are assumed to be supplied by electricity transported via the power transmission infrastructure.

According to the model, throughout all timeframes the generation of hydrogen will increase the load on the power transmission infrastructure as most hydrogen is produced directly at the demand nodes using electrolysers powered by grid electricity.

The electricity required to power the electrolysers at the demand locations in 2025 is already considerable, with 120 MW of power transmission required to supply Melbourne. Geelong and Regional Victoria on the other hand only require up to 7 MW of power transmission. The existing power infrastructure will probably be able to support the additional demand to Melbourne. If this were found not to be true, the limited time available to augment the power transmission lines could require a different approach to supply the required hydrogen.

In 2030, the power transmission requirements increase significantly, with 1150 MW of additional transmission to Melbourne, 290 MW to Geelong and up to 180 MW for the other locations. Augmentation of critical power lines between renewable energy production areas and demand locations is likely to be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

[76] Briggs, C., M. Hemer, P. Howard, R. Langdon, P. Marsh, S. Teske and D. Carrascosa (2021). Offshore Wind Energy in Australia: Blue Economy Cooperative Research Centre, Launceston, TAS. 92p., https://blueeconomycrc.com.au/offshore-wind-key-to-australias-clean-energy-future/

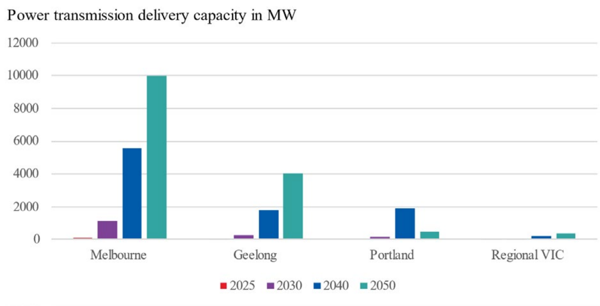
It is noted that in 2025 and 2030, since transport is the largest source of hydrogen demand, the location of hydrogen refuelling stations will define the spatial distribution of demand for hydrogen. While the model concentrates hydrogen demand for transport in the limited available modelled demand locations, in reality hydrogen could be produced at the refuelling stations (e.g. along major highways and at transport hubs and ports) or in a number of centralised locations along those key transport routes. If this was the case, the power transmission requirements to the main demand locations (Melbourne, Geelong, etc) would decrease.

In 2040, hydrogen production at the demand nodes continues to grow. With 5.6 GW of power required to Melbourne, and almost 2 GW additional demand in both Geelong and Portland, the power transmission for hydrogen production at the demand nodes is calculated to be higher than the total peak demand in Victoria in 2021.[77] By 2050, according to the model, the total power transmission required to power electrolysers in Victoria reaches 15 GW, almost twice the current peak power demand.

Shifting the hydrogen export demand from Geelong to other port locations could alleviate part of the strain on the local grid. This scenario was tested in the ‘Export north’ sensitivity, where export demand is assumed to be satisfied only by the port locations in the north of Australia. In this scenario, in the 2050 timeframe, the capacity of co-located electrolysers in Melbourne is reduced to 7.5 GW.

Considering such a high power demand, in addition to the electricity supply required for other economy sectors, it is unlikely that the model results will correspond to how the Victorian hydrogen supply chain will develop. Instead, these results could signal that supplying Melbourne with the hydrogen volumes in the central demand scenario could be challenging, and the constraints in the supply chain could lead to an increased LCOH and to a reduction in demand.

Figure 4.3.3 Power transmission capacity for hydrogen production in Victoria – Base case.



4.3.4 Hydrogen storage

The hydrogen storage infrastructure envisaged for Victoria by the model is limited. In 2025, when demand locations produce the required hydrogen locally and no hydrogen transport links are created, each location requires a small amount of storage, provided in the form of MCH tanks.

In later timeframes, when demand locations are either directly or indirectly connected to locations across the border, all storage requirements for Victoria are satisfied by hydrogen storage infrastructure installed interstate. It is important to note that this represents the layout that provides the lowest cost of hydrogen for the whole of Australia, and that State-based priorities could favour slightly different hydrogen networks.

If larger volumes of hydrogen will be required to be stored, Victoria could benefit from the extensive natural gas fields in the south-east and south-west of the state. If this hydrogen storage technology will be demonstrated, and the suitability of the underground formations in Victoria confirmed, depleted gas fields could provide the opportunity to store large volumes of hydrogen underground.

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[77] According to data from the Australian Energy Regulator, the peak power demand in Victoria during the 2021/22 summer was 8.6 GW. Source: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-regions

4.3.5 Hydrogen transport

In the first timeframe (2025) the model identifies no need for hydrogen transport. However, as noted in Section 3.5.1, this outcome is a result of the limitations of the model, which assumes hydrogen demand to be concentrated in single-point locations. In reality there will be some level of hydrogen transport via truck to move the gas within major centres and regional towns, and to supply refuelling stations. This is expected to be true across all timeframes. In 2030, the transport of hydrogen is carried out with compressed hydrogen trucks. In this timeframe, the purpose of transport is for the sharing of hydrogen storage infrastructure rather than moving hydrogen from production to demand locations.

On the other hand, in 2040 and 2050 virtually all transport is via dedicated compressed hydrogen pipelines, that connect production and demand locations, as well as storage locations. Pipelines that connect RE19 (Murray River) with Melbourne and RE20 (Western Victoria) with Geelong are established in 2040 and continue to be in use in the 2050 timeframe. Another pipeline selected for 2040 to connect Melbourne to the New South Wales network via RE18 is instead modified in the following timeframe to pass through RE23 (Central North Victoria), which is selected for hydrogen production in 2050. While passing through RE23 requires a longer pipeline, from an infrastructure investment point of view it should be considered to follow the 2050 path already in 2040, to avoid the risk of stranded assets.

Two links are still serviced by compressed hydrogen trucks in 2040, to service Regional Victoria from RE19 (Murray River) and Adelaide from RE20 (Western Victoria). The only road transport connection that remains by 2050 is to service Regional Victoria, in this case from RE23 (Central North Victoria).

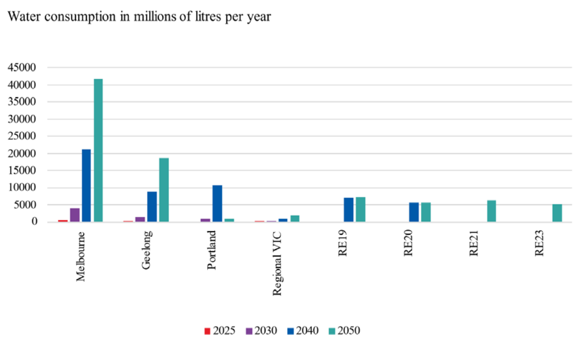
4.3.6 Wider techno-economic considerations

Water requirements

The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. In Victoria, the water consumption associated with hydrogen production is expected to grow timeframe after timeframe from 0.5 billion litres (GL) in 2025 to 88 GL in 2050. According to data from the Australian Bureau of Statistics [78], the estimated water demand for hydrogen in 2050 is about half what was consumed by the Victorian manufacturing sector in 2019-20 (163 GL), and it corresponds to less than 1% of Victoria total water consumption in 2019-20.

Figure 4.3.4 presents the annual water consumption for hydrogen production in Victoria, divided by location and timeframe. With the exception of RE21 (South West Victoria), all REZs are located inland, with no access to water from desalination plants.

Figure 4.3.4 Water consumption for hydrogen production in Victoria - Base case. [79]



[78] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 4. Physical Supply and Use, by Water Type, Victoria https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

[79] Specific water consumption coefficients are presented in Section B-3

Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

The adequacy of water infrastructure such as dams, water recovery from wastewater plants, etc should be considered in jurisdictions seeking to participate in the hydrogen industry, and developers will need to give equal consideration to their potential contribution to access to water resources and shared water infrastructure. In particular, hydrogen production project developers should explore whether there are long-term and sustainable recycled water sources available which could be used for hydrogen production. In Victoria, wastewater has been treated and used safely as recycled water for a range of non-drinking uses for decades. In some regions this water resource has been under-utilised and as such could present a viable long-term source of water.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In Victoria, infrastructure traversing the protected areas of the alpine region (e.g. RE23, RE15 supply chains) is likely to be highly constrained from both a protected areas and engineering perspective. Supply chains connecting to Melbourne from the north-west (RE20, RE19, RE23 supply chains) are constrained due to fragmented protected areas approaching highly urbanised area. It is also noted that protected areas within REZs (RE19, RE20, RE21) will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity. Existing natural gas and power transmission easement could provide a viable path for new hydrogen and power infrastructure. The pipeline connection between RE23 and the ACT would most likely follow a more northern path, similar to the Wodonga – Young and Moomba to Sydney pipelines, avoiding the most constrained land. In addition, if land use constraints in the Victorian REZs were found to reduce the maximum renewable capacity, a size increase and border modification for these REZs could be considered.

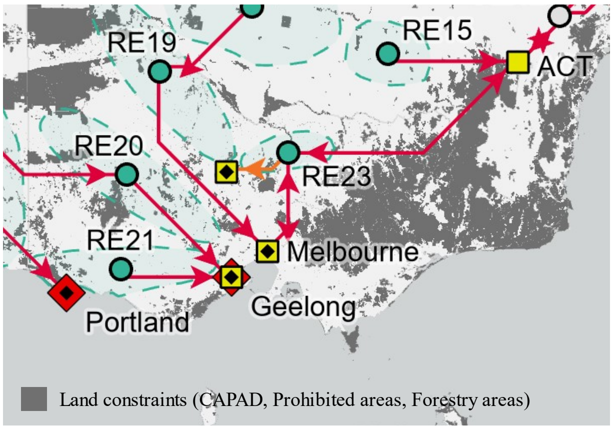


Figure 4.3.5 Constrained land in Victoria overlayed with the 2050 base case scenario results

4.4 Tasmania

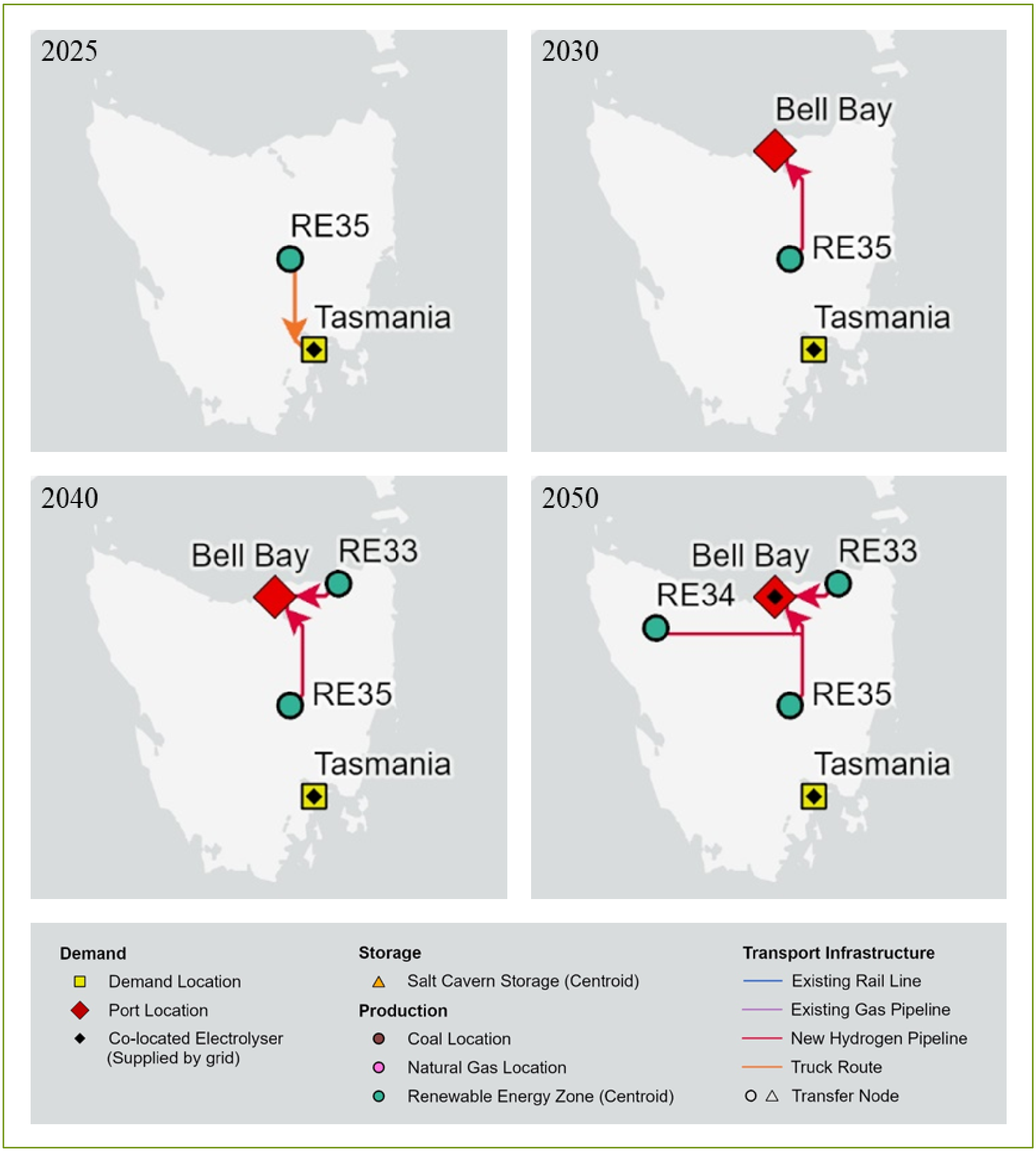


Figure 4.4.1 Tasmania: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case

4.4.1 Overview

The hydrogen demand in Tasmania is estimated to be primarily driven by hydrogen export from Bell Bay with sustained growth throughout the 2025 to 2050 timeframes, while fuel switching opportunities in the transport, industrial and power generation sectors constitute the bulk of domestic demand as shown in Section 4.4.2. Main demand centres (model nodes) are identified at Hobart (Tasmania) and Bell Bay.

Tasmania has extensive renewable energy resources and the renewable energy zones identified by AEMO are proposed to house the renewable energy required for green hydrogen. The renewable energy resources considered are solar PV and wind, while electricity from hydroelectric plants was not allowed to be used for behind-the-meter hydrogen production due to the assumption that only newly installed renewable power capacity would be considered and that dispatchable hydroelectric capacity would be dedicated to the supply of electricity for the grid rather than for the production of hydrogen.

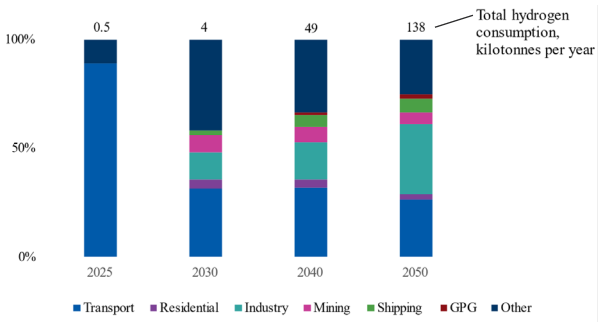
In 2025 Hobart (identified as 'Tasmania' in the map) is the only hydrogen demand location and it is entirely supplied by RE35 (Tasmania Midlands) with electrolysers powered by wind energy. From 2030 onwards, Hobart is supplied exclusively by co-located electrolysers. Bell Bay is instead linked to the available Tasmanian REZs. By 2050 all REZs are connected to Bell Bay, with additional hydrogen being produced locally with grid electricity.

Hydrogen transport is carried out via road trucks only in 2025. From 2030 the increased hydrogen demand justifies the construction dedicated hydrogen pipelines that link REZs to Bell Bay. MCH tanks provide the limited hydrogen storage required.

4.4.2 Hydrogen demand

The transport sector is expected to capture most of the initial domestic hydrogen demand in Tasmania, with about 500 tonnes of hydrogen required in 2025. This demand will be driven by the decarbonisation of the transport sector, particularly of heavy haulage. To achieve this, as mentioned in Section 3.1.1, hydrogen refuelling infrastructure will be required and will be likely concentrated in populated areas, particularly at the extremities of the Midland highway (Hobart and Launceston), with limited demand for stations along the main trucking route due to the short distances between main industrial centres. As hydrogen technologies develop and the cost of hydrogen reduces, more opportunities of decarbonisation are made available. The total domestic demand in Tasmania increases almost ten-fold in 2030 to 4 kilotonnes, one third of which is dedicated to transport, about 10% for use in industry, and the remainder shared across several industries, including mining and distributed power generation. The total domestic demand increases in 2040 to 49 kilotonnes, and it grows further to 138 kilotonnes by 2050, requiring 6 TWh of electricity input and 1.4 GW of electrolyser capacity. In 2040 and 2050 the share of hydrogen used in industry increases to become the largest source of domestic demand, covering about one third of the total. The use for transport continues to be an important factor, totalling about one quarter of the demand.

Figure 4.4.2 Modelled domestic hydrogen demand for Tasmania – Base case



Hydrogen demand for export is highly dependent on what share of Australian export is taken by each port location. The base case scenario assumes an even distribution of export across all Australian port locations, which includes the one modelled port in Tasmania, Bell Bay. No export demand is included in the 2025 timeframe. For the other timeframes, the demand for export contributes to the vast majority of hydrogen demand, averaging around 90% of the total demand. The overall demand, including both export and domestic uses, is 237 kt in 2030, 406 kt in 2040 and 1067 kt in 2050.

4.4.3 Hydrogen production

Renewable hydrogen

According to the techno-economic model results, in the 2025 timeframe Hobart (identified as 'Tasmania' in the map) is the only hydrogen demand location and it is entirely supplied by RE35 (Tasmania Midlands) with electrolysers powered by wind energy. Bell Bay is identified as an additional demand location in the following timeframes, due to its hydrogen export potential.

From 2030 onwards, Hobart is supplied exclusively by co-located electrolysers. Bell Bay is instead linked to the available Tasmanian REZs. By 2050 all REZs are connected to Bell Bay, with additional hydrogen being produced locally with grid electricity. However, all available REZs in Tasmania are saturated by this point and the model assumption that renewable electricity is always available hides the fact that there might not be sufficient energy production to satisfy the demand of electrolysers. However, additional renewable energy production could come from offshore wind projects, for example the 2 GW Bass Offshore Wind Project.

Unlike most areas of Australia, wind remains the main source of renewable energy throughout all timeframes. However, the solar PV portion does grow as the cost of the technology decreases, and it represents 40% of the total power generation by 2050. It is noted that the NHIA assumes no energy storage between renewable generation and electrolysers. Therefore, to maximise the utilisation of the electrolysers and reduce the cost of hydrogen in the absence of forms of energy storage, a still relatively high share of solar PV is selected by the model due to its output profile complementary to that of wind resources.

Power transmission

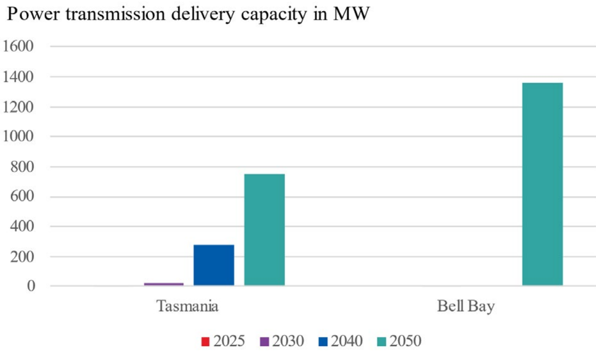
From an infrastructure point of view, one of the main aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. As mentioned in the section above, from 2030 onwards all hydrogen in Hobart is produced at the demand point.

As shown in Figure 4.4.3, the electricity required to power the electrolysers in 2030 is limited, with 22 MW of power transmission required. The existing power infrastructure will likely be able to support this additional demand.

In 2040 and 2050 the power transmission requirements to Hobart increase significantly, with 275 MW and 750 MW of additional power transmission, respectively. As REZs saturate in 2050, Bell Bay also requires a large portion of co-located hydrogen production and 1,360 MW of power transmission capacity. The total power transmission required to power electrolysers in 2050 is equivalent to 120% of the total electricity peak demand in Tasmania in 2021.[80] Significant augmentation of power lines between renewable energy production areas and demand locations would be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

[80] According to data from the Australian Energy Regulator, the peak power demand in Tasmania during the 2021 winter was 1.8 GW. Source: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-regions

Figure 4.4.3 Power transmission capacity for hydrogen production in Tasmania – Base case



4.4.4 Hydrogen storage

The hydrogen storage infrastructure envisaged for Tasmania by the model is limited, concentrated in Hobart in the form of MCH tanks.

4.4.5 Hydrogen transport

In the first timeframe (2025) there is one hydrogen transport link identified by the model, from RE35 (Tasmania Midlands) to Hobart. This connection is served by trucks transporting hydrogen in the form of compressed gas.

From 2030, the REZs are utilised for the supply of Bell Bay while Hobart produces hydrogen locally to satisfy its demand. Hydrogen transport links are established from the REZs to Bell Bay, in the form of new gas pipelines. In particular, the pipeline between RE35 (Tasmania Midlands) and Bell Bay is selected in all demand scenarios, with its first appearance in 2025, 2030 and 2040 in the high, central, and low demand scenarios, respectively. In the central demand scenario, three separate pipelines from the three active REZs are selected in 2050.

The 150 km pipeline between RE35 (Tasmania Midlands) and Bell Bay is the first to be selected by the model in 2030, and it is also in use in the 2040 and 2050 timeframes. The second pipeline to be required in operation by 2040 to service Bell Bay is the 50 km-long hydrogen supply from RE33 (North East Tasmania). The last pipeline, utilised in 2050, connects RE34 (North West Tasmania) to Bell Bay.

4.4.6 Wider techno-economic considerations

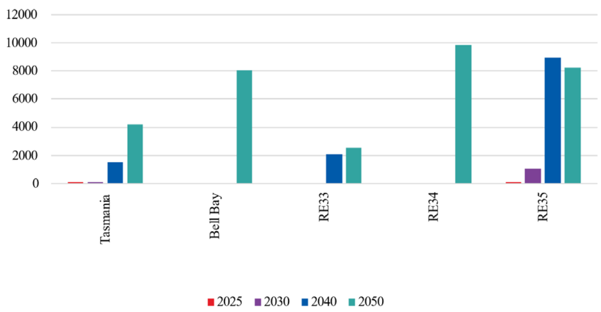
Water requirements

The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. In Tasmania, the water consumption associated with hydrogen production is expected to grow from 0.02 billion litres (GL) in 2025 to 33 GL in 2050. According to data from the Australian Bureau of Statistics[81], the estimated water demand for hydrogen in 2050 is about 80% what was consumed by the Tasmanian manufacturing sector in 2019-20 (42 GL), and it corresponds to 5% of Tasmania total water consumption in 2019-20.

Figure 4.4.4 presents the annual water consumption for hydrogen production in Tasmania, divided by location and timeframe. RE34 (North West Tasmania) and RE35 (Tasmania Midlands) are located inland, with no access to water from desalination plants.

[81] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 8. Physical Supply and Use, by Water Type, Tasmania https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

Figure 4.4.4 Water consumption for hydrogen production in Tasmania – Base case [82]



Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In Tasmania, coastal infrastructure (e.g RE33 and RE34 supply chains) are likely to be more constrained than regional inland infrastructure (RE35 supply chain) from a protected areas perspective. It is also noted that protected areas within REZs (RE33, RE34, RE35) will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity.

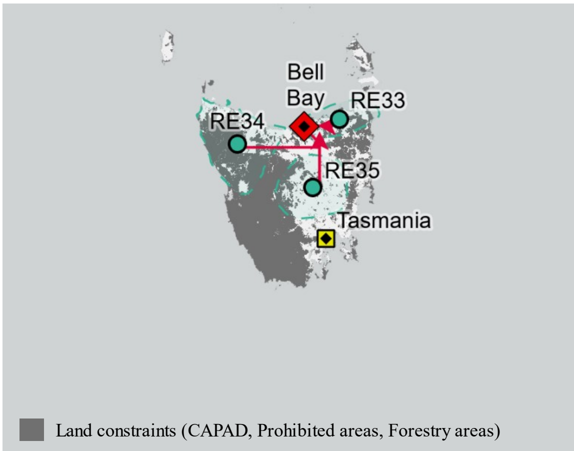


Figure 4.4.5 Constrained land in Tasmania overlayed with the 2050 base case scenario resul

[82] Specific water consumption coefficients are presented in Section B-3.

4.5 South Australia

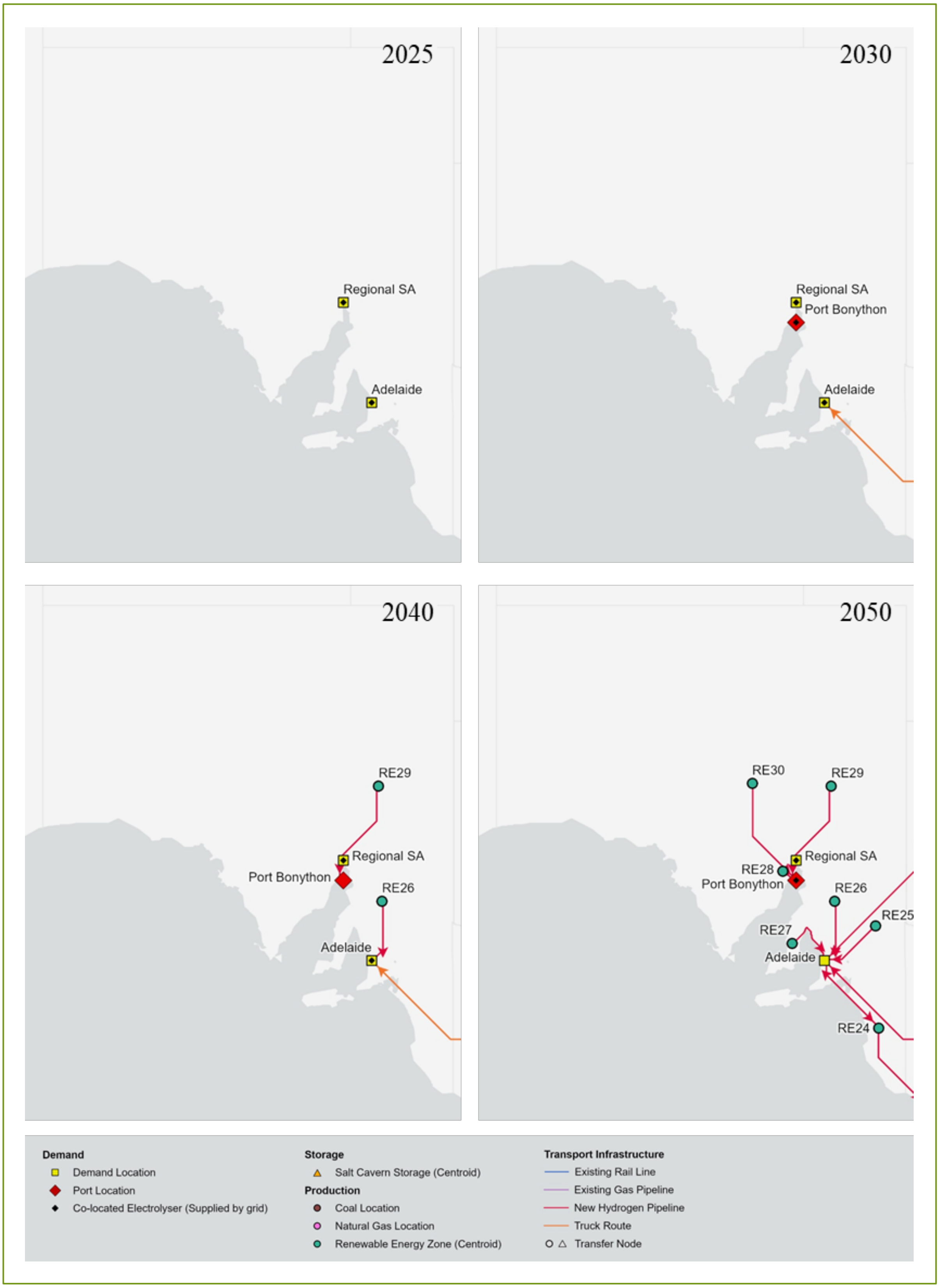


Figure 4.5.1 South Australia: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case

4.5.1 Overview

The hydrogen demand in South Australia is estimated to grow substantially decade upon decade reflecting both a growing demand for transport, residential use and industry as well as for export as show in Section 4.5.2. Main demand centres (model nodes) are identified at Adelaide, Port Bonython and Regional South Australia.

South Australia has resources for both blue and green hydrogen production available due to extensive fossil fuel, potential carbon storage (Moomba) and renewable energy resources. Renewable energy zones identified by AEMO are proposed to house the renewable energy required for green hydrogen. The Cooper Basin fossil fuel resources and location were also selected based on data presented in the AEMO ISP 2020[6].

The model results for South Australia show a hydrogen supply chain based on green hydrogen from electrolysis powered by behind-the-meter renewable energy primarily from the Mid North South Australia (RE26) and Leigh Creek (RE29) renewable energy zones. The production of hydrogen at the REZs and its transport in the form of compressed gas is generally preferred to the transmission of electricity to power co-located electrolysers. In 2050 significant hydrogen production capacity is also utilised to supply Victoria.

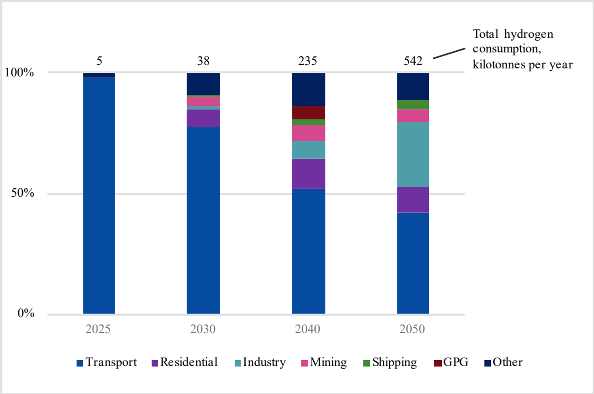
Hydrogen transport is limited in 2025 and 2030. In 2040, the first two links via pipeline are created to connect production with demand locations. By 2050, the hydrogen pipeline network develops further, including two pipelines to Victoria and one from New South Wales. MCH tanks provide all the hydrogen storage capacity. Blue hydrogen production from natural gas is not selected by the model in the base case scenarios.

4.5.2 Hydrogen demand

The transport sector is expected to capture most of the initial domestic hydrogen demand in South Australia, with about 5 kilotonnes of hydrogen required in 2025. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in Adelaide and along major heavy haulage transport routes (e.g. Duke highway). As hydrogen technologies develop and the cost of hydrogen reduces, more opportunities of decarbonisation are made available. The total domestic demand in South Australia increases eight-fold in 2030 to 38 kilotonnes, of which over three quarters is dedicated to transport and 10% is used by the residential and mining sectors.

In 2040 and 2050 the applications for hydrogen are more diversified. Transport accounts for half the total domestic demand, while the share of residential use grows to above 10% in both timeframes. In 2050 the use in industry increases significantly to account for over one quarter of the total domestic demand. The total domestic demand in 2040 is 235 kilotonnes, and it increases to 542 kilotonnes by 2050, requiring 24 TWh of electricity input and 5.6 GW of electrolyser capacity.

Figure 4.5.2 Modelled domestic hydrogen demand for South Australia – Base case



The demand for export is in addition to the domestic demand. The base case scenario assumes an even distribution of export across all Australian port locations, which includes Port Bonython in South Australia. No export demand was included in the 2025 timeframe. For the other timeframes, the increase in the total hydrogen demand due to export is significant, equivalent to 46% of the total demand in 2030 and growing to account for 60% of the demand in 2040 and 2050. When both domestic and export demand are considered, the total demand for hydrogen in South Australia becomes 71 kt in 2030, 592 kt in 2040 and 1,471 kt in 2050.

4.5.3 Hydrogen production

Renewable hydrogen

According to the techno-economic model results, in 2025 all the hydrogen demand is satisfied by electrolysers co-located with the demand locations, powered by grid electricity. The economic advantage of co-located electrolysers is the higher utilisation factor allowed by the connection to the main grid (as opposed to the direct connection to variable renewable energy sources) and the minimum cost of hydrogen transport (assumed to be zero by the model).

In 2030 the supply chain is very similar, with the addition of hydrogen export demand from Port Bonython and a small hydrogen transport link towards Victoria. The layout changes considerably in 2040, when the growing hydrogen demand is mostly satisfied by hydrogen produced remotely in REZs. While Regional South Australia continues to provide its own hydrogen with 100 MW of electrolyser capacity installed, 90% of hydrogen supplied to Adelaide is produced in RE26 (Mid-North South Australia) with a combination of solar PV and wind energy sources and transported via pipeline to the city. The export demand in Port Bonython is also satisfied by remote hydrogen production, in this case located at RE29 (Leigh Creek).

In 2050, additional REZs are selected to serve Adelaide and Port Bonython, while Regional South Australia continues to be served by co-located electrolysers powered by grid electricity due to the small magnitude of the modelled local demand, which does not justify new pipeline infrastructure.[83] The full renewable resources of RE28 (Northern South Australia), RE29 (Leigh Creek) and RE30 (Roxby Downs), equivalent to 15.5 GW of wind and solar PV capacity, are required to satisfy the export demand in Port Bonython. RE25 (Riverland), RE26 (Mid-North South Australia) and RE27 (Yorke Peninsula), with the addition of RE13 (Broken Hill) in New South Wales, produce hydrogen that is transported via pipeline to Adelaide. However, only 35% of the hydrogen is destined to supply the demand in the capital of South Australia while the remainder is transferred to Portland and Geelong in Victoria.

As it is the case for most areas of Australia, the ratio of solar PV and wind energy production dedicated to hydrogen remains relatively balanced throughout the scenarios, with the share of solar PV growing from approximately 50% in 2040 to 75% in the 2050 timeframe due to the modelled reduction in the costs of this technology.

Power transmission

From an infrastructure point of view, one of the key aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. As mentioned in the section above, in 2025 and 2030 all the hydrogen in South Australia is produced at the demand nodes.

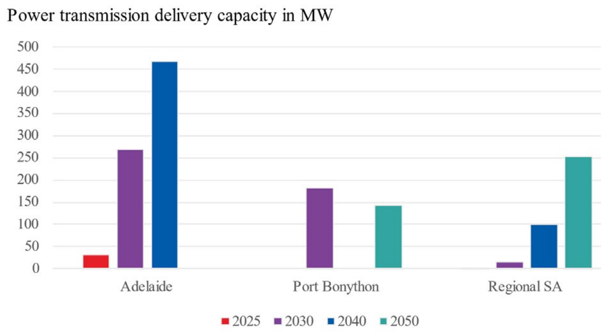
As shown in Figure 4.5.3, the electricity required to power the electrolysers in 2025 is limited, with 30 MW of power transmission required for Adelaide and 1.5 MW for Regional South Australia. The existing power infrastructure will likely be able to support this additional demand.

[83] In reality, Regional South Australia would be likely be supplied by a branch coming off the pipeline between Leigh Creek and Port Bonython. The model only allows pipeline branching at the available nodes, therefore it selects a different solution.

In 2030, the power transmission requirements increase considerably, with 270 MW of additional transmission to Adelaide, 180 MW to Port Bonython and 15 MW to Regional South Australia. Augmentation of critical power lines between renewable energy production areas and demand locations will likely be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

As mentioned above, in 2040 and 2050 Regional South Australia continues to be supplied by co-located electrolysers, requiring 250 MW of power transmission by the latest timeframe.

Figure 4.5.3 Power transmission capacity for hydrogen production in South Australia – Base case



4.5.4 Hydrogen storage

In Australia, across all scenarios the two hydrogen storage technologies selected by the model are salt caverns and MCH tanks. In South Australia, where no salt deposits suitable for hydrogen storage have been identified, all hydrogen storage installed is in the form of MCH tanks.

Across all timeframes, MCH storage tanks and conversion/reconversion facilities are located in the demand locations of Adelaide and Regional South Australia (Port Augusta) to create a buffer between hydrogen production and demand.

4.5.5 Hydrogen transport

In 2025 and 2030 no hydrogen transport is required by the model, except for a very limited hydrogen exchange between Adelaide and Victoria.

On the other hand, from 2040 dedicated compressed hydrogen pipelines are created to connect hydrogen production and demand locations, as well as to supply hydrogen to Victoria.

4.5.6 Wider techno-economic considerations

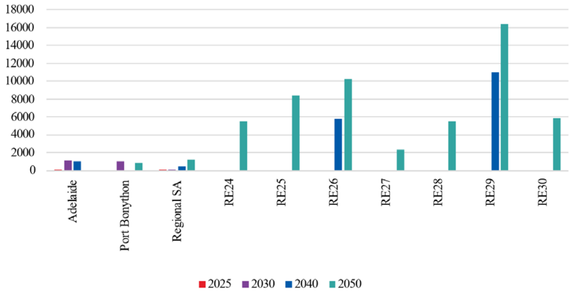
Water requirements

The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. In South Australia, the water consumption associated with hydrogen production is expected to grow from 0.1 billion litres (GL) in 2025 to 56 GL in 2050. According to data from the Australian Bureau of Statistics[84], the estimated water demand for hydrogen in 2050 is about 40% what was consumed by South Australian households in 2019-20 (136 GL), and it corresponds to 3.5% of South Australia total water consumption in 2019-20.

Figure 4.5.4 presents the annual water consumption for hydrogen production in South Australia, divided by location and timeframe. With the exception of RE27 (Yorke Peninsula) and RE28 (Northern SA), all South Australia's REZs are located inland, with no access to water from desalination plants.

[84] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 6. Physical Supply and Use, by Water Type, Tasmania https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

Figure 4.5.4 Water consumption for hydrogen production in South Australia – Base case [85]



Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken.

These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In South Australia, coastal infrastructure (e.g. RE24, RE27 supply chains) is likely to be more constrained than regional inland infrastructure from a protected areas perspective. It is also noted that protected areas within REZs (RE29, potentially RE30) will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity.

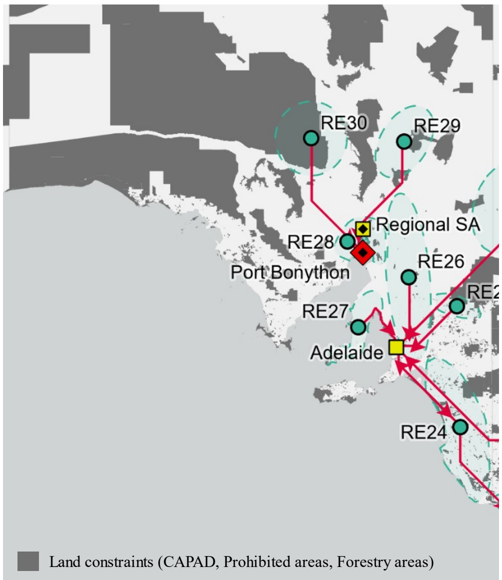


Figure 4.5.5 Constrained land in South Australia overlayed with the 2050 base case scenario results

[85] Specific water consumption coefficients are presented in Section B-3.

4.6 Western Australia

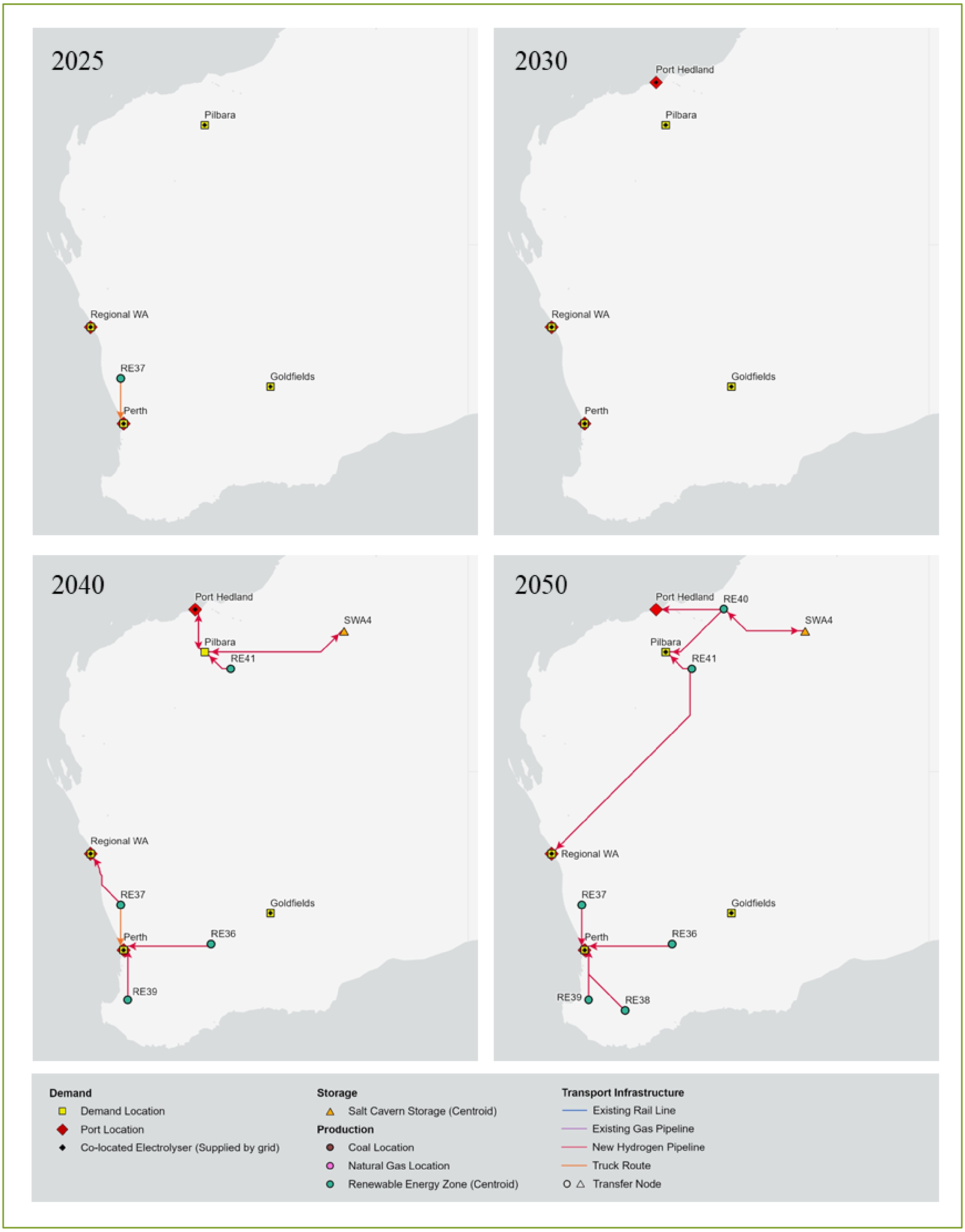


Figure 4.6.1 Western Australia: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case

4.6.1 Overview

The hydrogen demand in Western Australia is estimated to grow substantially decade upon decade reflecting both a growing demand for transport, mining and industry as well as for export as show in Section 4.6.2. Main demand centres (model nodes) are identified at Perth, Pilbara, Port Hedland, Goldfields and Geraldton (Regional Western Australia).

Western Australia has resources for both blue and green hydrogen production available due to fossil fuel, potential carbon storage and extensive renewable energy resources. Renewable energy zones identified during consultations with the Western Australia government are proposed to house the renewable energy required for green hydrogen. The natural gas location in the Carnarvon basin was selected based on the projects and basin resources presented in the Western Australia GSOO 2020. The Dampier peninsula was selected as the hydrogen production location in the model due to its central location within the basin and its co-location with existing natural gas projects.

The results for Western Australia are split between the Perth and Pilbara areas, which for the most part maintain separate infrastructure systems. The results show a hydrogen supply chain primarily based on green hydrogen from electrolysis powered by behind-the-meter renewable energy. The production of hydrogen at the REZs and its transport in the form of compressed gas is generally preferred to the transmission of electricity to power co-located electrolysers.

RE37 (Western Australia Mid West) is the first renewable energy zone selected by the model in the area around Perth, while RE41 (Western Australia Pilbara Inland) is the preferred one in the Pilbara. In 2050, the model saturates all the REZs in the State and additional hydrogen is produced at the demand locations using grid electricity, particularly in Perth. This highlights the need for access to additional renewable resources in Western Australia (e.g. offshore wind).

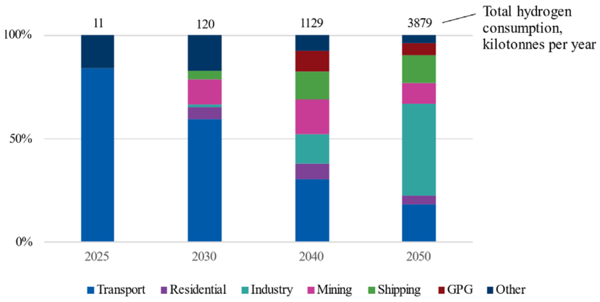
Hydrogen transport infrastructure is used from 2040 onwards, with several dedicated hydrogen pipeline connections between production and demand locations. A pipeline is also established to connect the salt cavern storage in the Canning Basin to the Pilbara network. Blue hydrogen production from natural gas is not selected by the model in any of the timeframes of the central scenarios.

4.6.2 Hydrogen demand

In the base case scenario, about 90% of the modelled hydrogen demand in the first timeframe is due to the use as fuel in low-emissions transport vehicles. This demand will be driven by the decarbonisation of the transport sector, particularly of heavy haulage. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in the Perth area and along major heavy haulage transport routes (e.g. Brand highway, North West Coastal highway, Great Northern highway and Great Eastern highway). As hydrogen technologies develop, more opportunities of decarbonisation are made available. The total domestic demand in Western Australia increases ten-fold in 2030 to 120 kilotonnes, 60% of which is dedicated to transport and 12% for use in mining.

In 2040 transport remains responsible for the largest share of domestic demand (30%), however the industrial, mining and shipping sectors grow considerably to account together for 45% of the total domestic demand. The generation of power also contributes to significant demand, equivalent to 10% of the demand in 2040 or 13 PJ of energy. In 2050 the largest source of demand is the industry sector, accounting for almost half of the total domestic demand of hydrogen. The main drivers for industrial hydrogen demand are ammonia production and the processing of minerals such as alumina, nickel and titanium. Other important sectors are transport, shipping and mining. The total domestic hydrogen demand in 2040 is 1,129 kilotonnes, and it grows to 3,879 kilotonnes by 2050, requiring 175 TWh of electricity input and 40 GW of electrolyser capacity.

Figure 4.6.2 Modelled domestic hydrogen demand for Western Australia – Base case



The demand for export is in addition to the domestic demand. The base case scenario assumes an even distribution of export across all Australian port locations, which includes the three modelled ports in Western Australia, Perth, Geraldton (Regional Western Australia) and Port Hedland. No export demand was included in the 2025 timeframe. For the other timeframes, the increase in the total hydrogen demand is between 45% and 50%, leading to a combined domestic and export demand of 219 kt in 2030, 2,201 kt in 2040 and 6,668 kt in 2050.

4.6.3 Hydrogen production

Renewable hydrogen

According to the techno-economic model results, in 2025 most hydrogen demand locations are supplied by co-located electrolysers, powered by grid electricity. The economic advantage of co-located electrolysers is the higher utilisation factor allowed by the connection to the main grid (as opposed to the direct connection to variable renewable energy sources) and the minimum cost of hydrogen transport (assumed to be zero by the model). The only exception is Perth, that is instead primarily supplied with hydrogen produced remotely in RE37 (Mid-West Western Australia). Significant dedicated renewable capacity at this location is required already in 2025, with 90 MW of wind and 60 MW of solar PV.

In 2030 the supply chain is similar, with the addition of hydrogen export demand from Port Headland and the supply of Perth's demand via co-located electrolysers rather than with dedicated renewable energy. The change in the hydrogen supply of Perth is due to the decrease in grid electricity cost in 2030 assumed by the model.

By 2040 the supply chain structure changes significantly, with the bulk of hydrogen produced at renewable energy zones. Several compressed hydrogen pipelines are developed to transfer the increasing flows of hydrogen from production to demand locations. Unlike in the 2025 timeframe, RE37 (Mid-West Western Australia) does not serve Perth but is rather utilised to provide hydrogen to Regional Western Australia. Perth is instead supplied by large-scale hydrogen production in RE36 (Western Australia Mid-East) and RE39 (Western Australia South West). In the Pilbara region, RE41 (Western Australia Pilbara Inland) supplies both Port Hedland and Pilbara with 12 GW of renewable energy capacity.

In 2050, the main driver in defining the structure of the hydrogen supply chain is the saturation of the available renewable energy zones. To satisfy the demand in Perth, the REZs around the city are fully utilised, with 21 GW of solar PV and 19 GW of wind capacity installed. As the demand in Perth is higher than the production limit of these renewable zones, the model utilises additional 7 GW of grid-powered electrolysers in Perth. In this timeframe RE37 is dedicated to the supply of the demand in Perth, while Regional Western Australia is linked to the renewable resources in the Pilbara (RE41). In the Pilbara region the REZs are also saturated, with RE40 and RE41 generating hydrogen from the 4 GW of wind and 42 GW of solar PV installed.

Power transmission

From an infrastructure point of view, one of the main aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. As mentioned in the section above, in 2025 and 2030 most hydrogen in Western Australia is produced directly at the demand nodes.

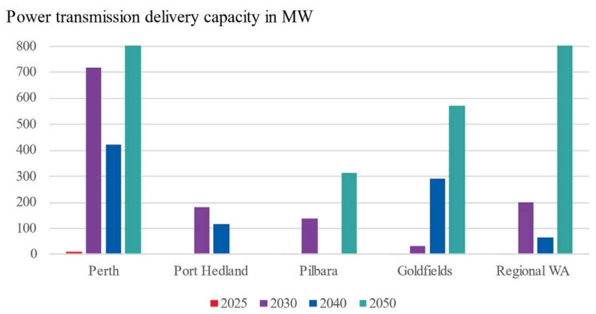
As shown in Figure 4.6.3, the electricity required to power the electrolysers in 2025 is limited, with 10 MW of power transmission required for Perth and 3 MW or less for the other locations. The existing power infrastructure will likely be able to support this additional demand.

In 2030, the power transmission requirements increase significantly, with 700 MW of additional transmission to Perth and up to 200 MW for the other locations. Augmentation of critical power lines between renewable energy production areas and demand locations will likely be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

In the 2040 timeframe, co-located hydrogen production decreases overall due to the decreasing cost of dedicated renewable power. An exception is Goldfields, where the growing hydrogen demand continues to be supplied by grid-powered electrolysers (300 MW of power transmission required).

The requirement for power transmission infrastructure greatly increases in the 2050 timeframe, when the saturation of the available REZs in the model force the hydrogen to be produced using gird electricity. 7 GW of additional power transmission is required to supply Perth's hydrogen production, and 1.5 GW are required for Regional Western Australia. However, it is noted that renewable energy sources would still be required to be installed to service the additional electricity demand of the grid, and it is more likely that additional hydrogen will be produced remotely in additional REZs and transported via pipeline to the demand locations.

Figure 4.6.3 Power transmission capacity for hydrogen production in Western Australia – Base case



Low-emissions hydrogen

In the base case scenario, blue hydrogen production from natural gas is not selected by the model due to the fact that green hydrogen is estimated to provide a lower overall infrastructure cost. However, blue hydrogen production is selected in Western Australia in the following scenarios that include low-emission technologies:

- High hydrogen demand scenario (in the 2030 timeframe), see Appendix E.7.2
- High electrolyser capex scenario (in the 2030 and 2040 timeframes), see Appendix E.7.3 and E.7.4.

By 2040 in the high hydrogen demand scenario, and by 2050 in the high electrolyser capex scenario the cost of renewable energy and electrolysers reduces to the extent that no blue hydrogen production is selected anymore by the model. This highlights the potential risk of stranded assets as the cost of hydrogen production from blue hydrogen plants could be higher than other alternatives before the end of the plant's life.

4.6.4 Hydrogen storage

Similarly to the results for the whole of Australia, the two types of hydrogen storage technologies selected by the model are MCH tanks and salt caverns. In the Pilbara region, the availability of a salt cavern in the Canning Basin (SWA4) shapes the results of the techno-economic model.

In 2025 and 2030 the scale of hydrogen demand does not justify the development of the required infrastructure to access the SWA4 salt cavern (except in the high hydrogen demand scenario), and all storage is carried out in the form of MCH tanks, with the relative hydrogen conversion and reconversion facilities. However, once the critical scale for the development of the salt cavern infrastructure is reached, all hydrogen storage in the Pilbara region is satisfied by this site. Due to the pipeline connection to the Pilbara in 2050, also Regional Western Australia has access to the storage capacity of SWA4 in this timeframe. On the other hand, the locations that are too far to be economically connected to SWA4 rely on hydrogen storage in MCH tanks across all timeframes.

4.6.5 Hydrogen transport

In 2025 and 2030, no hydrogen transport is required, with the exception of the connection from RE37 to Perth, serviced by compressed hydrogen trucks.

On the other hand, in 2040 and 2050 an extensive hydrogen transport network develops, almost exclusively via dedicated compressed gas pipelines. Main pipelines are those that connect hydrogen production with demand locations. Three pipelines in particular are consistently:

- 350 km between RE36 and Perth
- 200 km between RE37 and Perth
- 200 km between RE39 and Perth
- 150 km between RE41 and Pilbara.

The analysis of the hydrogen demand sensitivity scenarios shows that the development of a network of pipelines in the Perth and Pilbara areas is a constant feature, although shifted in time depending on the hydrogen demand growth rate. One noticeable feature is in the 2050 results for the high demand scenario, where the large hydrogen volumes justify the development of a pipeline system that connects south and north of Western Australia, as well as Western Australia to the Northern Territory. While such a large network might not be justified in practice, what is shows is that the access to low cost geological storage (salt caverns in the Pilbara in this case) can be a considerable driver for infrastructure development.

4.6.6 Wider techno-economic considerations

Water requirements

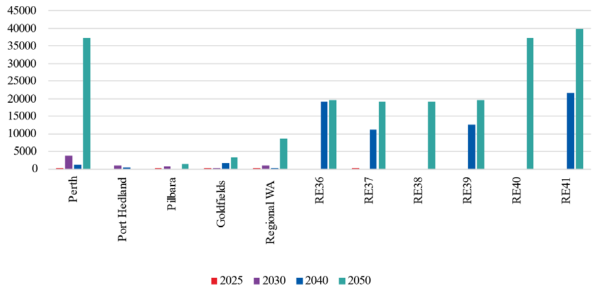
The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. Where hydrogen production locations are reasonably close to the coastline, water can potentially be resourced from desalination plants. For inland locations, water must be sourced from either surface or groundwater sources. In Western Australia, renewable energy zones are evenly distributed between coastline and inland locations.

In Western Australia, the water consumption associated with hydrogen production is expected to grow from 0.3 billion litres (GL) in 2025 to 205 GL in 2050. According to data from the Australian Bureau of Statistics[86], the estimated water demand for hydrogen in 2050 is about half what was consumed by the Western Australian mining sector in 2019-20 (136 GL), and it corresponds to 10% of Western Australia total water consumption in 2019-20.

[86] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 7. Physical Supply and Use, by Water Type, Tasmania https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

Figure 4.6.4 presents the annual water consumption for hydrogen production in Western Australia, divided by location and timeframe. Among the locations with high water demand is RE36 (Mid East Western Australia), which might require access to the Goldfields Water Supply Scheme pipeline.

Figure 4.6.4 Water consumption for hydrogen production in Western Australia – Base case [87]



Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In Western Australia, coastal infrastructure in the south-west (e.g RE36, RE37, RE38, RE39 supply chains) is likely to be more constrained than regional inland infrastructure from a protected areas perspective. It is also noted that protected areas within REZs themselves (RE36, RE37, RE38, RE39) will likely decrease their available land use for renewables and may decrease their assumed renewable energy capacity.

In the north-west, REZs and supply chain infrastructure is less constrained by protected areas, however the electricity/pipeline transmission connections required are of significant distance to all demand centres. This increases the planning complexity considerably, particularly toward Regional WA - Geraldton demand centre. Opportunities for REZ in closer proximity to Geraldton should be considered. It is notable that the salt cavern storage is used in later time scenarios which may influence planning considerations also.

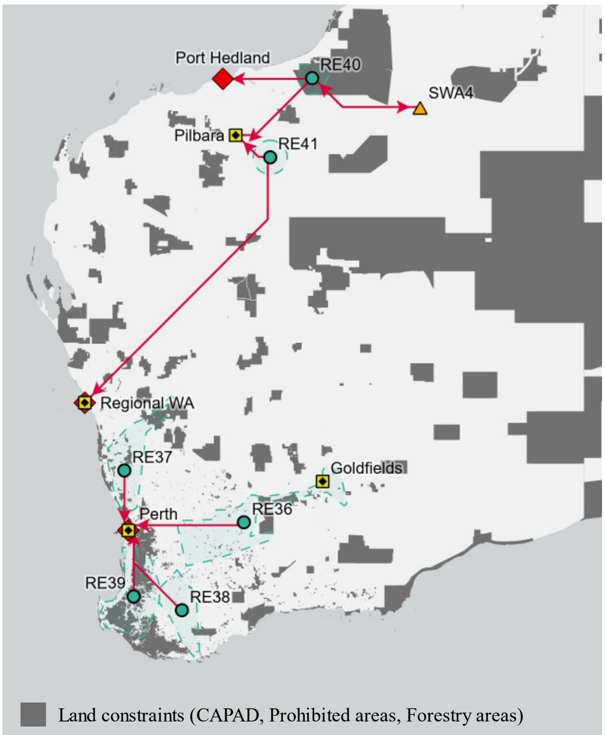


Figure 4.6.5 Constrained land in Western Australia overlayed with the 2050 base case scenario results

[87] Specific water consumption coefficients are presented in Section B-3.

4.7 Northern Territory

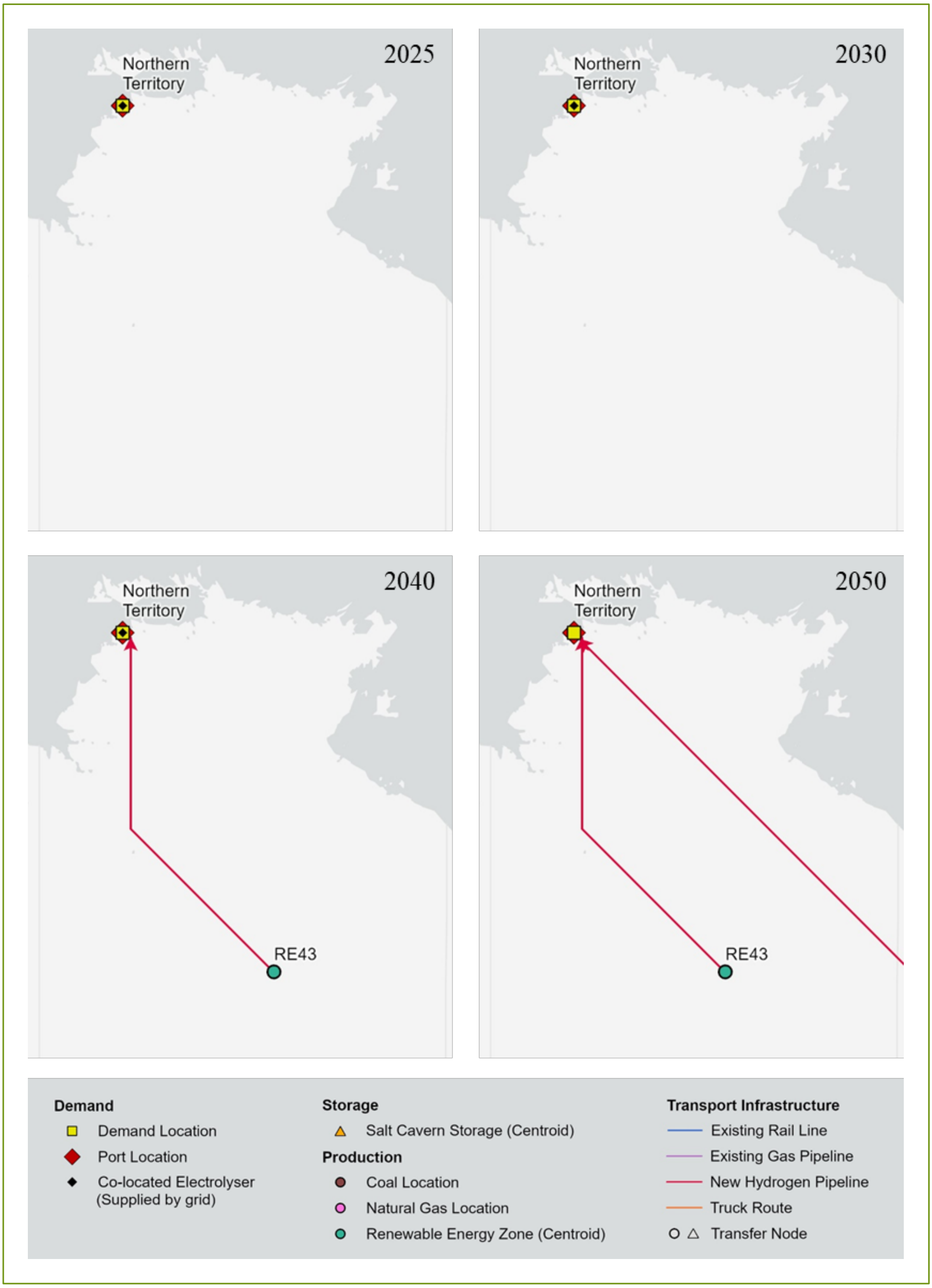


Figure 4.7.1 Northern Territory: Techno-economic model results for timeframes 2025, 2030, 2040 and 2050 – Base case

4.7.1 Overview

The hydrogen demand in the Northern Territory is estimated to grow substantially decade upon decade reflecting both a growing demand for transport, power generation and mining as well as for export as show in Sections 4.7.2 and 4.5.2. The only demand centre (model node) is identified at Darwin (Northern Territory) to cover both domestic and export demand.

The Northern Territory has resources for both blue and green hydrogen production available due to fossil fuel, potential carbon storage and extensive renewable energy resources. Renewable energy zones identified during consultations with the Northern Territory government are proposed to house the renewable energy required for green hydrogen. Fossil fuel resources and locations were also selected based on the projects and their respective basin resources as presented by Geoscience Australia[88]. In the case of the offshore Bonaparte basins, the location of the nearest onshore gas processing plant (Blacktip Yelcherr Gas Plant) was utilised as the hydrogen production location in the model.

The hydrogen infrastructure identified by the model for the Northern Territory is relatively simple due to the presence of only one hydrogen demand location. In 2025 and 2030 the results show all the hydrogen demand being satisfied by electrolysers co-located with the demand location in Darwin, powered by grid electricity.

In 2040, the RE43 (Tennant Creek) is developed and provides most of the hydrogen to Darwin, transported via a dedicated hydrogen pipeline. In 2050, as the capacity of RE43 is saturated, additional hydrogen is supplied by Mt Isa (RE45) in Queensland. The connection to this location also allows the use of the salt cavern in the Adavale Basins, Queensland, to provide large-scale hydrogen storage.

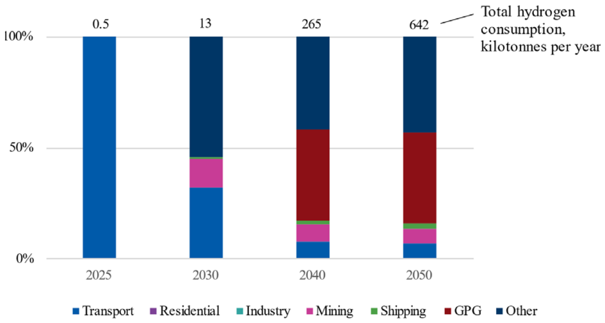
When allowed by the model, blue hydrogen production from natural gas is only favoured from the Bonaparte basin in 2030 but replaced by green hydrogen production afterwards.

4.7.2 Hydrogen demand

The transport sector is expected to capture most of the initial domestic hydrogen demand in the Northern Territory, with about 500 tonnes of hydrogen required in 2025. This demand will be driven by the decarbonisation of the transport sector, particularly of heavy haulage. As mentioned in Section 3.1.1, this demand will require the development of hydrogen refuelling infrastructure, which will be mainly located in the Darwin area. The lower traffic on the Northern Territory's highways compared to other Australian locations will limit the overall hydrogen demand and provide fewer opportunities for investment in refuelling infrastructure along major heavy haulage transport routes. As hydrogen technologies develop and the cost of hydrogen reduces, more opportunities of decarbonisation are made available. The total domestic demand in Northern Territory increases almost thirty-fold in 2030 to 13 kilotonnes as hydrogen is mostly implemented in the decarbonisation of diesel-based power generation, transport and in the mining industry. The total domestic demand increases to 265 kilotonnes in 2040, and it grows further to 642 kilotonnes by 2050, requiring 29 TWh of electricity and 6.6 GW of installed electrolyser capacity. In 2040 and 2050 the share of hydrogen used in power generation increases to become the largest source of domestic demand at 40% of the total domestic demand.

[88] https://www.ga.gov.au/digital-publication/aecr2021/gas

Figure 4.7.2 Modelled domestic hydrogen demand for the Northern Territory – Base case



Hydrogen demand for export is highly dependent on what share of Australian export is taken by each port location. The base case scenario assumes an even distribution of export across all Australian port locations, which includes Darwin (Northern Territory). No export demand was included in the 2025 timeframe. For the other timeframes, hydrogen export contributes to around 60% of the total demand leading to a combined domestic and export demand of 46 kt in 2030, 622 kt in 2040 and 1,572 kt in 2050.

4.7.3 Hydrogen production

Renewable hydrogen

In the techno-economic model, the Northern Territory presents only one hydrogen demand location, which corresponds to both a domestic and export demand point. According to the techno-economic model results, in the 2025 and 2030 timeframes all the hydrogen demand is satisfied by electrolysers located in Darwin (Northern Territory), powered by grid electricity. The economic advantage of co-located electrolysers is the higher utilisation factor allowed by the connection to the main grid (as opposed to the direct connection to variable renewable energy sources) and the minimum cost of hydrogen transport (assumed to be zero by the model).

In 2040, part of the hydrogen demand is still satisfied by co-located electrolysers, however most hydrogen is produced in RE43 (Tennant Creek) and transported to Darwin via pipeline.

In 2050, no co-located hydrogen production is left in Darwin as all hydrogen is produced either in RE43 or in Queensland (RE45, Mt Isa). At this timeframe, the capacity of RE43 is saturated, with 4.6 GW of solar PV and 5.4 GW of wind installed. RE44 (Katherine) is not selected as a hydrogen production location in the base case scenario due to the lower renewable energy resources (lower capacity factor).

The results of the model sensitivity that analyses the low hydrogen demand scenario differ from the base case in 2040 and 2050. In the former timeframe, hydrogen production continues to be co-located with the demand centre of Darwin. In 2050, hydrogen is primarily produced in behind-the-grid facilities in RE44 (Katherine) and transported to Darwin via pipeline.

Similarly, the results for the high demand scenario differ from the base case analysis. In this scenario, from 2040 onwards the supply chain in the Northern Territory is linked via pipeline to that of the Pilbara in Western Australia instead of being linked to Queensland via Mt Isa. In 2050, the large demand for hydrogen requires the utilisation of all the three REZs made available to the model in the Territory.

Power transmission

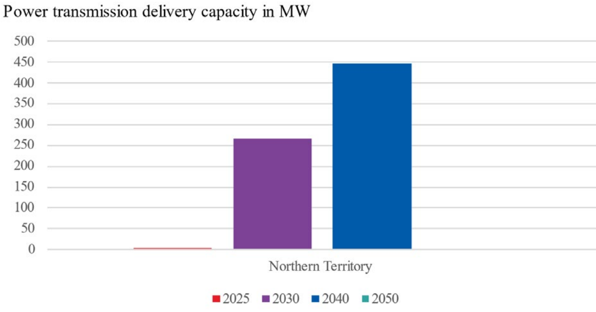
From an infrastructure point of view, one of the main aspects related to the production of hydrogen at the demand nodes is the need for power transmission infrastructure to deliver the required input electricity. As mentioned in the section above, in 2025 and 2030 all the hydrogen in Darwin is produced at the demand node.

As shown in Figure 4.7.3, the electricity required to power the electrolysers in 2025 is limited, with less than 4 MW of power transmission required. The existing power infrastructure will likely be able to support this additional demand.

In 2030, the power transmission requirements increase significantly, with 270 MW of additional transmission. Augmentation of critical power lines between renewable energy production areas and Darwin could be required and could be carried out at once with the augmentation for the electrification of other energy sectors.

In 2040, most hydrogen is produced in RE43, however the production in Darwin that will require power transmission capacity is still significant (450 MW). Conversely, in 2050 no hydrogen is selected to be produced in Darwin.

Figure 4.7.3 Power transmission capacity for hydrogen production in the Northern Territory – Base case



Low-emission hydrogen

In the scenario that includes blue hydrogen technologies, natural gas from the Bonaparte basin (FFG2), south-west of Darwin, is selected for the production of hydrogen in 2030.

The Petrel Sub-basin (offshore) is the closest carbon dioxide storage area at an advanced stage of characterisation and/or development[89].

By 2040 the cost of renewable energy and electrolysers reduces to the extent that no blue hydrogen production is selected by the model. This result discourages the development of blue hydrogen production plants as their cost of hydrogen production could be higher than other alternatives well before the end of the plant's life.

Figure 4.7.4 Northern Territory, 2030: Comparison of the model results for the base case and for the scenario with low-emissions technologies included

[89] According to the 'Advanced CO2 Geological Storage Sites 2030 (2021)' dataset by Geoscience Australia, https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/145507

4.7.4 Hydrogen storage

Similarly to the results for the whole of Australia, the two types of hydrogen storage technologies selected by the model are MCH tanks and salt caverns. In the Northern Territory, the connection to the salt cavern in the Adavale Basin (SQLD1) shapes the results of the techno-economic model.

In 2025, 2030 and 2040 the scale of hydrogen demand does not justify the development of the required infrastructure to access the SQLD1 salt cavern, and all storage is carried out in the form of MCH tanks, installed in Darwin with the relative hydrogen conversion and reconversion facilities. However, once the critical scale for the development of the pipeline to the salt cavern is reached, all hydrogen storage in the Northern Territory is satisfied by this site. The very low cost of salt cavern storage justifies the construction and operation costs of the required pipelines.

4.7.5 Hydrogen transport

In 2025 and 2030, no hydrogen transport is required. On the other hand, in 2040 and 2050 all transport is via dedicated hydrogen pipelines, which connect production locations to Darwin. Interestingly, in the base case scenario the model selects a pipeline to connect Darwin to the Queensland salt cavern via Mt Isa to take advantage of the economic opportunity of utilising large scale storage. This pipeline does not appear in the low hydrogen demand sensitivity results, since the reduced hydrogen volume does not justify the development of the required infrastructure. The pipeline to Queensland is also not selected in the high demand scenario. Instead, a pipeline link to the salt caverns in the Pilbara (Western Australia) is found to provide the lowest cost of hydrogen.

4.7.6 Wider techno-economic considerations

Water requirements

The water demand for hydrogen production is directly linked to the volumes of hydrogen produced. Where hydrogen production locations are reasonably close to the coastline, water can potentially be resourced from desalination plants. For inland locations, water must be sourced from either surface or groundwater sources. In the Northern Territory, all REZs are located inland, with no access to water from desalination plants. On the other hand, the limited water required for hydrogen production in Darwin could potentially be supplied by desalination plants in case the available surface and groundwater resources were found not to be sufficient or in case the highly seasonal nature of rainfall in the region was found to compromise surface water supply during the dry season.

In the Northern Territory, the water consumption associated with hydrogen production is expected to grow from 0.02 billion litres (GL) in 2025 to 23 GL in 2050. According to data from the Australian Bureau of Statistics[90], the estimated water demand for hydrogen in 2050 is in line with what was consumed by Northern Territory households in 2019-20 (26 GL), and it corresponds to 10% of the Northern Territory total water consumption in 2019-20.

Figure 4.7.5 presents the annual water consumption for hydrogen production in the Northern Territory, divided by location and timeframe. In 2050, the entirety of water demand for hydrogen production happens at the inland location of Tennant Creek (RE43). The water demand in 2050 is about half the 40 GL groundwater allocation that the Northern Territory government has recently granted to the Singleton Horticulture Project located near Tennant Creek, indicating both the availability of water resources and the potential for competition with other users.

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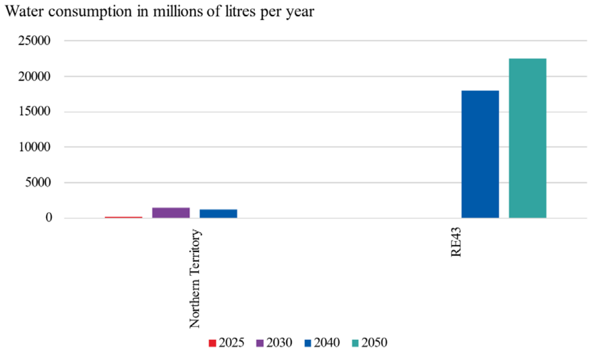
[90] Australian Bureau of Statistics, Water Account, Australia 2019-20 – Table 9. Physical Supply and Use, by Water Type, Tasmania https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#data-download

Figure 4.7.5 Water consumption for hydrogen production in the Northern Territory – Base case [91]



Although water availability is not included as a constraint in the model, it is recognised that availability of suitable water resources for hydrogen production in the volumes required is expected to necessitate infrastructure investment for water quality extraction, treatment and transport. Areas of higher water stress are expected to have higher competition for water resources that may impact options available for supplying hydrogen production, including considerations of social licence and environmental impacts.

Land Use, Environment and Planning

By overlapping the hydrogen supply chain links with the protected, prohibited and forestry area datasets (see Section 3.8 for more details), an initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

In Northern Territory, infrastructure east of Darwin is likely to be more constrained with protected areas. REZ 43 is located a substantial distance from the Darwin demand centre. The model has also identified potential supply from Queensland. These significant distances, increase the planning complexity considerably, including consideration of the large tracts of Regional NT which are indigenous protected areas (IPA).

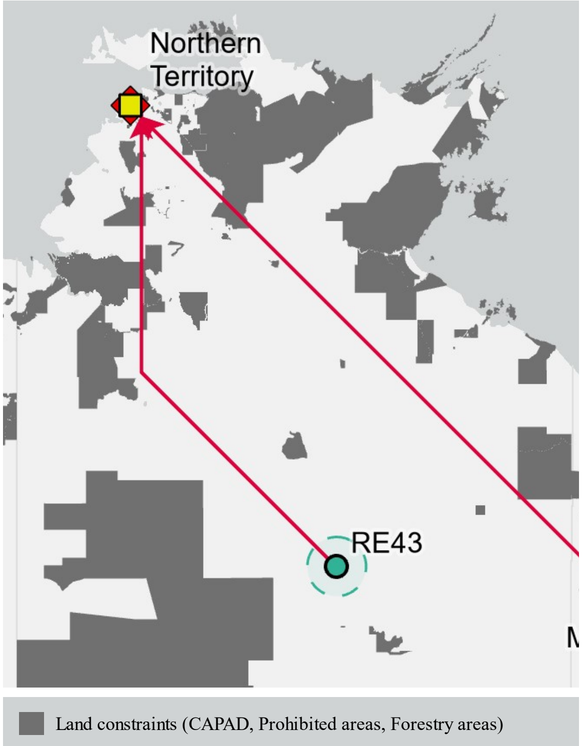


Figure 4.7.6 Constrained land in the Northern Territory overlayed with the 2050 base case scenario results

[91] Specific water consumption coefficients are presented in Section B-3.

5 Conclusions

5 Conclusions

The demand for hydrogen is expected to grow substantially decade upon decade across Australia reflecting a strong growth in both domestic and export demand.

As the global hydrogen economy moves from demonstration to large scale market activation, supply chain infrastructure is now a critical element in unlocking the full potential of domestic and international markets.

The hydrogen infrastructure assessment provides a review of existing infrastructure and a robust and transparent prioritisation of supply chain opportunities under various agreed scenarios considering economic, environmental and social outcomes. Strategic and timely investment in Australia's supply chain infrastructure will underpin the rapid scale up of a competitive hydrogen industry needed over the next decade to decarbonise our economy and secure our position as a major global hydrogen player and future energy supplier.

During the course of development of this inaugural NHIA, significant Federal and State Government investment in support of industry development has focussed on hub areas (e.g. Regional Hydrogen Hubs[17]). Alongside this, opportunities for domestic and international demand outside these hub areas are progressing and are captured in the NHIA where supply chains to service demand centres are identified. Beyond the demand centres in hubs, the hydrogen demand in regional locations has also been considered. For each State and Territory, this demand has been grouped into one single point location for modelling purposes. The locations selected as representative for the regional demand are those that were assumed to be the main demand centres in each region.

Whilst the future role of hydrogen in our global and domestic energy systems is not set, the challenge is to identify infrastructure to support the burgeoning industry growth opportunity whilst not risking stranded or underutilised assets which would undermine industry competitiveness and growth, particularly considering the typical supply chain development horizons of 7-10 years for major infrastructure.

The National Hydrogen Infrastructure Assessment aims to support targeted and coordinated infrastructure investment, through identifying infrastructure needs, gaps and where investments could be best prioritised to achieve maximum impact.

Regular and periodic updates of the NHIA will enable adaptive response to forecasted need as the hydrogen industry develops and evolves.

Hydrogen Demand Scenarios

Based on central case scenario, export demand is expected to approximately match the demand for domestic uses, accounting for slightly less than half of the total across all timeframes. We have also considered a higher and lower scenario of hydrogen demand. In this way the NHIA has looked at infrastructure requirements for both domestic and export hydrogen supply chains.

The domestic demand is initially driven by use in the transport sector. This assumes the establishment of hydrogen refuelling infrastructure in major cities and along major freight routes, in a similar manner to the existing petrol station network development and early Hydrogen and EV charging networks. Co-location of hydrogen production may occur at suitable locations. The use of hydrogen in the mining sector is also expected to contribute to hydrogen demand in the near term, particularly at off-grid and fringe-of-the-grid locations. As hydrogen technologies progress and the cost of hydrogen reduces, more sectors are expected to look at hydrogen to decarbonise their operations. Hydrogen is envisaged to have a growing role in industry, aviation, shipping and dispatchable power generation, as well as green steel production.

Priority infrastructure requirements

Renewable power

Since most hydrogen demand is expected to be satisfied by green hydrogen, the primary electricity infrastructure need is the implementation of additional renewable power supply. According to the results of the base case scenario, by 2050 the renewable electricity required from solar PV and wind will be nearly 20 times the renewable generation in 2020. This will require renewable installations at scales not seen anywhere globally as well as the acquisition of significant parcels of land.

Additional and/or larger renewable energy zones will also likely be required, since the renewable electricity required to meet the modelled green hydrogen demand alone is projected to saturate the capacity of REZs in several locations, particularly in Victoria, New South Wales and Western Australia. This does not take into account any additional renewable electricity or electricity storage needs for decarbonising our electricity grid for non-hydrogen related uses.

Alternatively, if the export demand were to be primarily satisfied by large-scale and remote hydrogen export projects, the strain on REZs in populated areas could be reduced. Investment in offshore wind could also be required to provide additional renewable electricity for hydrogen production and economy electrification. It should be noted that for behind-the-meter hydrogen production facilities, the techno-economic model does not assume the use of electricity buffer storage to increase the utilisation rate of electrolysers powered by variable renewable power sources. This is a conservative approach, and if battery storage continues with its trend of cost reduction there could be a case for installation of this type of storage at hydrogen production facilities with complementary improvement in LCOH.

Power transmission

The model suggests that the lowest cost of hydrogen would be achieved by co-locating hydrogen production with demand locations up to around 2030. This additional power transmission requirement will need a case-by-case analysis of the grid capacity to assess whether power transmission upgrades will be required. While the model identifies large power transmission needs to Perth, Melbourne and Wollongong all the way to 2050, this should be considered in the optic of the limitations of the model, which selects grid-powered electrolyser due to the saturation of local REZs. In reality it is expected that if sufficient REZs will be made available, the preference will be to produce hydrogen in behind-the-meter production facilities without the need for long distance power transmission.
After 2030, the power transmission upgrades that will have been implemented for the hydrogen economy could be partially repurposed to cater the likely growing demand for electricity due to the electrification of the economy.

Hydrogen production

Large scale electrolysis facilities will be required to meet the green hydrogen demand. By 2030, approximately 7 GW of electrolyser capacity is estimated to be needed Australia-wide to meet the demand in the central scenario. In this scenario, this capacity is modelled to grow to 130 GW by 2050. This very large-scale infrastructure is to be distributed across most REZs in Australia. If blue hydrogen from natural gas will also play a role, the development of CCS infrastructure will be required together with the facilities to convert natural gas to hydrogen.

Hydrogen pipelines

The model identifies hydrogen pipelines as the preferred mode of hydrogen transport, particularly after 2030 when high volumes justify their development. While there could be the possibility to repurpose some of the existing natural gas transmission network, most of the pipelines are expected to be newly build. Easement identification and environmental studies will be required in the short-medium term due to the typical long development timeframe for this type of infrastructure.

Hydrogen storage

Based on the cost inputs in the model, the preferred storage technologies are hydrogen carrier tanks (MCH or ammonia) for small and medium scale storage, and underground geological storage in salt caverns for large-scale compressed hydrogen storage, where available. Exploration of geological salt deposits, currently in early stages in Australia, must continue to allow the timely development of these facilities. Storage of hydrogen will require land acquisition in potentially constrained areas (e.g. at demand locations) and will require specific safety, risk and environmental assessments.

Ports

The primary infrastructure required to be located at the port includes shipping berth capability and capacity, as well as hydrogen carrier bulk storage. If liquid hydrogen was to be preferred in export projects, liquefaction plant and loading facilities will need to be co-located with the wharf to minimise boil off losses when loading onto ships. From an infrastructure point of view, the key requirements for a marine terminal to support the export of hydrogen are a deep sea (or dredged) port consisting of favourable metocean factors, a suitable sized wharf structure, dedicated pipelines and marine loading arms, onshore bunkering and a berth utilisation rate of typically less than 65%. Where deep sea ports or dredging are not feasible or environmentally possible, provisions will need to be made for long jetties or offshore marine loading buoys. Where the marine terminal is not located in an existing commercial port, supporting port functions such as tugboats, pilots, security, pollution response, maintenance and customs will need to be provided. While hydrogen carriers such as MCH and ammonia may be piped along jetties or the seabed to distances of 2 to 3 km, in the case of liquid hydrogen there are constraints on the length of cryogenic pipelines (typically less than 500 m) which might limit the number of ports that can support this type of export. During the production facility and marine terminal construction, consideration must be given to construction logistics. Typically for remote sites, and for some urban sites, a Marine Offloading Facility is constructed to support the import of materials and large modular processing units.

Water infrastructure

Water infrastructure will also be required for the extraction, treatment and supply of water for hydrogen production. Water volumes and infrastructure requirements vary considerably depending on the water quality source, supply method (e.g water pumps, pipeline), treatment requirements (e.g desalination, purification), cooling method (air or water cooling). For all green and blue hydrogen production methods considered in this analysis, water is also a feedstock. This NHIA assessment has estimated water demand at hydrogen production nodes, and it can be assumed that each supply chain will need a combination of the aforementioned infrastructure depending on site and project specific needs.

Refuelling infrastructure

The largest share of hydrogen demand in 2025 and 2030 is expected to be linked to the transport sector. A refuelling station network will therefore be required in the near term, at both main populated areas and along major road transport routes.

Insights on Lowest cost supply chains

Optimise shared infrastructure

The NHIA has assessed lowest cost hydrogen by enabling shared hydrogen supply chain infrastructure opportunities to be used to meet the demand in the modelled scenarios. This has been achieved by consideration of shared infrastructure benefit of the universal use of ‘compressed hydrogen’ in the model is to investigate the opportunities to enable a connected ecosystem of shared infrastructure, for lowest cost supply chains. In practice this will require consideration of losses related to carrier conversion for end use application, and also potential for higher costs if shared infrastructure opportunities are not realised.

Green from proximal REZ to demand

Overall, the preferred hydrogen production technology selected by the model is electrolysis powered by behind-the-meter wind and solar PV. The total power generation for hydrogen production in 2050 is estimated to be nearly 20 times the current renewable power generation. In the later timeframes, the renewable energy zones around Perth, Melbourne and Wollongong are saturated for hydrogen production. This is without considering the required renewable energy production for the decarbonisation of the power grid. Offshore wind and redistribution of hydrogen export demand to more remote areas could provide relief. Behind-the-meter large-scale hydrogen export projects in remote locations could be implemented to make use of renewable resources farther from power demand centres.

The role of Blue Hydrogen

Blue hydrogen can provide a lower LCOH typically in situations of incumbent existing asset use proximal to appropriate SMR and CCS facilities. There might be a role for blue hydrogen in the future of the hydrogen economy in Australia, however this would likely be limited to specific projects that have particularly favourable conditions and that might be able to share carbon transport and storage infrastructure.

Hydrogen from coal gasification is never selected by the techno-economic model due to the high CAPEX cost of the technology. The difference between the cost of blue hydrogen from coal and green hydrogen increases further as the timeframes progress due to the reduction in renewable technology costs.

In the base case scenario, hydrogen produced from natural gas is selected in particularly favourable locations in Queensland and Northern Territory. However, this is only true for the 2030 and by 2040 no blue hydrogen production is preferred Australia-wide. Blue hydrogen production in 2040 is selected by the model in the scenario that analyses what would happen if the cost of electrolysers reduced less than expected (high CAPEX electrolyser scenario), however in 2050 green hydrogen substitutes blue hydrogen even in this scenario. This highlights the risk of stranded assets, although there could be the possibility of repurposing the carbon transport and storage infrastructure for the sequestration of CO_2 from other industries.

Renewable electricity mix

The optimal share of solar PV and wind generation to power electrolysis plants varies depending on the cost of each technology and on the specific renewable resources of each location. The techno-economic model optimises the share of solar PV and wind power for each location and timeframe to minimise the LCOH from behind-the-meter hydrogen production. While the results of the analysis shows that the optimal balance between the two types of renewable generation is generally even across most locations in the first timeframe (approximately 50% solar and 50% wind), the share of solar PV tends to increase towards 2050 due to the modelled faster reduction in the cost of this technology compared to wind.

Preference for moving molecules over electricity for large volumes

The techno-economic model, based on the data used in input, finds the transport of large volumes of energy via hydrogen as the lower cost option compared to the transport of electrons. As a consequence, the model indicates the need for an increasingly complex network of hydrogen transmission pipelines to link production, geological storage, and demand locations, over time. Where possible, existing natural gas transmission pipelines could be converted to transporting hydrogen instead of requiring the installation of new infrastructure. It is noted however that the model has a simplified approach to calculating the cost of power transmission, with a constant cost per unit of energy transmitted independent from the position of demand locations and their distance to renewable energy production areas. Therefore, the model decision between transporting energy in the form of hydrogen rather than electricity is only indicative and it is recommended that further analysis on a regional basis would provide further insight on site-specific LCOH supply chain and infrastructure priorities.

In the initial timeframes (2025 and 2030), when hydrogen demand is still somewhat limited, most hydrogen is produced at the demand locations with electrolysers powered by the electricity grid. This power demand will increase the strain on power transmission infrastructure from renewable energy zones to demand locations (e.g. capital cities). While case-by-case analyses should be undertaken to ensure the availability of sufficient transmission capacity, the existing infrastructure is expected to be able to accommodate the additional demand in most locations. In later timeframes, when hydrogen demand increases significantly and the cost of renewable power generation improves, the model's preference for hydrogen production is to generate hydrogen at the renewable energy zones with behind-the-meter power generation and to transport it to demand locations in the form of gas.

With the exception of hydrogen pipelines used to supply Townsville and Gladstone in Queensland, in 2025 and 2030 the limited hydrogen transport between locations is based on compressed gas trucks. Conversely, in 2040 and 2050 most hydrogen transport is carried out via dedicated gas pipelines, to connect production areas, demand locations and large-scale hydrogen sites. When allowed by the model, rail infrastructure is used consistently until 2040.

Hydrogen storage

Small to medium volumes using existing technology for LOHCs. Cost-benefit only reached for large scale for storage as Liquid Hydrogen and for larger seasonal scale storage in salt caverns.

Two salt cavern locations (Adavale Basin in Queensland and Canning Basin in Western Australia) are consistently selected in 2040 and 2050 by the model for large-scale hydrogen storage, when the scale of hydrogen production and demand justifies their development and connection to hydrogen networks.

Small and medium-scale storage is provided by LOHCs in the form of methylcyclohexane (MCH) tanks and conversion/reconversion facilities. However, considering the uncertainties and developments around the cost and efficiency parameters for MCH storage, this result should not be considered as an indication of clear preference for MCH storage over other hydrogen storage technologies. In fact, the economies of hydrogen storage in other forms of organic compounds (e.g. methanol) or ammonia are within the uncertainty range of MCH storage, and could partially or completely substitute it. MCH was chosen as a representation of LOHC due to the level of information available to provide meaningful analysis for the techno-economic model.

In addition, the techno-economic model assumes the demand of hydrogen to be always in the form of hydrogen gas. However, the requirement for a different final product could define the hydrogen storage carrier (e.g. ammonia in the case of ammonia export).

Other considerations

Water

At an Australia-wide scale, the water consumption for the future hydrogen economy is considerable but not prohibitive relative to other industries. The water demand for hydrogen production in the base case scenario is expected to be similar to the current water use in the mining sector. In addition, design options are available to reduce the water demand from hydrogen production facilities. Shared water infrastructure investment opportunities (pipelines, water treatment plants / desalination) exist to support development of hydrogen hubs. Detailed consideration of water availability and infrastructure requirements will be required on a regional and project basis taking into account environmental, social and economic factors. Limited water availability will have an impact on the cost of water supply and will also create an additional hurdle for the development of hydrogen production plants to secure the social licence to access local water resource, in a similar way the gas industry has been facing challenges when developing gas fracking projects in remote areas.

Environment, land use planning

Hydrogen supply chains will be developed within existing regulatory regimes, albeit with some refinement to account for hydrogen specific operational and safety aspects. Infrastructure development is undertaken through regulatory planning approval processes to ensure that appropriate consideration of environmental, social and land use impacts are taken into consideration prior to approval to proceed to construction phase. An initial assessment of potential 'red flag' land use constraints for protection of nature conservation, indigenous, agriculture/ forestry and military uses when developing infrastructure can be undertaken. These constraints can be used as a proxy for project planning, approval and delivery risk of infrastructure in these locations, which may impact lowest cost of hydrogen delivery.

Demand locations are generally within the urban footprint of capital cities and regional centres and at Ports which generally have highly planned and competitive land use requirements, with multi-stakeholder and community interest. Blue hydrogen production is generally co-located with fossil fuel development and likely to be within a brownfield environment with complementary land use.

Green hydrogen however may be located within the REZs or at demand locations. Planning of the REZs has broadly been considered from an energy requirements perspective by AEMO and State and Territory Governments. However, land use planning is only just commencing in most jurisdictions. The REZs will need to consider renewable energy production from wind and solar as well as storage from batteries and pumped hydroelectric, and potential for hydrogen development. Some jurisdictions are already progressing infrastructure corridors (for electricity and/or pipelines) from REZs to demand centres. Linear infrastructure corridors must navigate numerous land parcels and account for landowners increasing the risk of incompatible land use and/or impacted stakeholders. Designated shared infrastructure corridors provide an opportunity to streamline approvals for projects and minimise potential impacts on surrounding land use.

Uncertainties

Energy Security & Geopolitical factors

The techno-economic model was built and run prior to the start of the invasion of Ukraine in 2022, and therefore does not consider the related impacts on the price of commodities and the sharp increase in natural gas and coal price, particularly for the East coast of Australia. These events would have an impact on the inputs and results of the model, however the main impact would be to further limit the use of hydrogen production from natural gas and coal, already limited in the results.

Technology

The technologies for green hydrogen production are expected to reduce significantly in the near-medium term, and to continue to decrease to 2050. On the other hand, the technologies involved in the bulk of the final cost of blue hydrogen production are mature and are not expected to decrease significantly with time. Additional issues include fugitive emissions in the fossil fuel extraction operations, the remaining direct carbon emissions, the risk of exclusions from export or additional tariffs such as the EU Carbon Adjustment Border Mechanism (CBAM).

Environmental and social impact

The techno-economic assessment is predicated on economic drivers of lowest cost of hydrogen based on quantified model inputs. These inputs do not consider the potential economic costs for individual projects associated with avoiding or mitigating environmental and social impacts. However, it is recognised that obtaining the regulatory approval for the construction and operation of hydrogen infrastructure will be a key requirement for the development of the hydrogen supply chain. Corporate reputation considerations of 'social licence to operate' will also apply to all new hydrogen infrastructure projects to some extent and will impact the industry as a whole. If not managed appropriately by the many stakeholders of the industry – including Government, proponents, research institutions and non-government agencies, these aspects could result in significant increased costs and delays in development of hydrogen supply chains. A summary of identified infrastructure opportunities to support lowest cost hydrogen supply chains is provided in Table 5.1. It is noted that, as mentioned above, a general risk will be the social licence to operate. This risk is common to all hydrogen infrastructure projects.

Table 5.1. Infrastructure opportunities

Infrastructure Opportunity	Region & State	Rationale	Main Risk	Investment Plan/timeline	Delivery Model options
Desalination Plant or Gladstone-Fitzroy Water Pipeline	Gladstone region (QLD)	Domestic and export demand water requirements warrant desalination plant by 2030. Desalination plant will support electrolysis across multiple local supply sites Existing in development projects will likely require use and further shared investment	Major environmental impact with brine discharge Potential impact on tourism sector	Initiate by 2025 to meet 2030 generation and scale up by 2040/50	Desalination will provide local water services as well so likely PPP or JV/consortium of major industrial users
Power grid network upgrades	Perth & region (WA)	Domestic and export demand will require significant capacity to support electrolysis One of largest demand region and lowest LCOH	Difficult to foster action without guarantee of hydrogen development Competition with alternative investment in network elsewhere	Initiate by 2030	Government and network operator partnership
Salt cavern development	Adavale Basin (QLD)	Large-scale and low cost hydrogen storage can reduce the overall hydrogen cost by providing a buffer between production and demand.	Suitability of salt deposit for hydrogen storage not confirmed. Will require development of transport infrastructure to production and demand locations	Continue geological investigations Could be developed in stages, first stage operative by 2040	
Salt cavern development	Canning Basin (WA)	Large-scale and low cost hydrogen storage can reduce the overall hydrogen cost by providing a buffer between production and demand	Suitability of salt deposit for hydrogen storage not confirmed. Will require development of transport infrastructure to production and demand locations in the Pilbara	Continue geological investigations Could be developed in stages, first stage operative by 2040	
Dedicated H2 pipeline	Norther QLD REZ / Regional QLD (QLD)	Local and export demand in Regional Queensland to be supplied from locally produced green hydrogen Existing development projects will likely require use and further shared investment	Securing easement and environmental impact of pipeline	Develop by 2025	Consortium between primary users

Infrastructure Opportunity	Region & State	Rationale	Main Risk	Investment Plan/timeline	Delivery Model options
Dedicated H2 pipeline	Fitzroy REZ / Gladstone (QLD)	Local and export demand in Regional Queensland to be supplied from locally produced green hydrogen Existing development projects will likely require use and further shared investment	Securing easement and environmental impact of pipeline	Develop by 2025	Consortium between primary users
Dedicated H2 pipeline	North West NSW REZ / Regional NSW (NSW)	The North West NSW REZ is a preferred location for hydrogen production in NSW. A pipeline to supply Regional NSW is selected in most scenarios, often extended south to supply Sydney	Securing easement and environmental impact of pipeline	Develop by 2040	Consortium between primary users
Dedicated H2 pipeline	Darling Downs REZ / Brisbane (QLD)	Local and export demand in Regional Queensland to be supplied from locally produced green hydrogen Existing development projects will likely require use and further shared investment	Securing easement and environmental impact of pipeline	Develop by 2030	Consortium between primary users
Dedicated H2 pipeline	Tasmania Midlands / Bell Bay (TAS)	The preferred supply location for Bell Bay is RE35 (Tasmania Midlands) across most timeframes and scenarios The local and export demand will justify the development of a dedicated pipeline	Securing easement and environmental impact of pipeline through conservation land	Develop by 2030	Consortium between primary users
Dedicated H2 pipeline	Western Australia Mid West / Perth (WA)	This pipeline is selected to supply hydrogen to Perth and is consistently identified as an investment opportunity in virtually all results for low, central and high demand from 2040 onwards	Securing easement and environmental impact of pipeline	Develop by 2040	Consortium between primary users

6 Next Steps

6 Next steps

During the delivery of this assessment, the hydrogen industry has grown in Australia in ways that could not have been predicted. Market participants, vertical integration of supply chains, mega project announcements, and government intervention have all occurred. This continuous change has impacted on where to demarcate the assessment boundaries. It is evident that there are a considerable number of decisions of 'where to' for the Australian hydrogen industry. These next steps will most certainly be influenced by the committed government incentivisation and intervention, and we will witness how market participants flourish in response to global and domestic changes in energy.

As a first-of-a-kind assessment for the hydrogen infrastructure in Australia, theoretical inputs for demand and supply were used, as no large-scale hydrogen projects have made final investment decision at the time of writing. This enabled a considerable amount of freedom for the modelling linkages between demand and supply nodes, at the same time testing the limits of the assumptions being made. Changes to the energy generation mix occurred during the delivery of this assessment; offshore wind becoming a central policy piece for the Victorian Government. This assessment had not included offshore wind, however it should be included in future analyses, given then market activity and investment that is now materialising.

Future assessments will also include a baseline of developed hydrogen projects across Australia. Even a single large scale hydrogen project can have an amplified impact on the timing of infrastructure development of an area.

Renewable energy resources in the model results are consistently saturated for use in hydrogen production around populated areas in Victoria, New South Wales and Western Australia by 2040. This will likely be incompatible with other efforts in decarbonizing the power grid and electrifying other sectors currently using on fossil fuels (e.g. residential, industry, transport).

We recommend that future assessments will consider the including of additional areas for renewable energy production. Renewable energy zones near demand centres could be prioritised to provide electricity to the grid, while additional locations, more remote but still with good renewable resources, could be dedicated to the generation of power for hydrogen production. Hydrogen could then be transported in pipelines along large distances to the demand and export centres. This approach would increase the total available renewable power generation while taking advantage of the lower cost and smaller footprint of hydrogen pipelines compared to power transmission, particularly for very large energy flows.

Regarding pipelines, further assessments should consider the potential and impact of converting existing natural gas transmission infrastructure to the transport of 100% hydrogen. This type of assessment, in addition to considering geographical location of existing pipelines and cost of conversion to hydrogen, should also include a pipeline-level assessment of the suitability to hydrogen conversion by considering parameters such as the pipeline's age, maximum operating pressure and fatigue history, since these parameters will determine whether the pipeline will be compatible with hydrogen operation. In addition, since several existing pipelines would be required to continue deliver natural gas to end users until right before the conversion to hydrogen, the management of a seamless transition of the transmission and distribution networks from natural gas to hydrogen should also be considered.

As project developments continue to mature and materialise, the models for the planning, delivery and operation of this integrated infrastructure and the associated supply chains need to be determined. Lessons learned from previous industry development such as mining and LNG sectors points to the need for appropriate Government incentivisation and intervention mechanisms to facilitate common user infrastructure in supply chains. Historical investment in energy infrastructure has evolved with deregulation and increased private ownership in generation, transmission, and distribution asset. The integrated nature of hydrogen supply chains creates opportunities for single ownership over major components of the supply chain. Governments will need to work with project proponents to avoid monopolisation or oligarchisation of these supply chains to ensure fair regulation and competition exists in the marketplace. Increased competition will lower product prices across the supply chain benefiting energy users no matter what their fuel.

At this stage of the assessment, it is unclear what the most appropriate delivery models or strategies required to facilitate a hydrogen economy and may vary at a jurisdictional and site-specific level. New models may need to be developed in conjunction with asset owners, project developers and governments. Depending on the stakeholders and the development timeframes, the level of government intervention will change, and this will impact on the delivery models. Looking to international examples such as California where hydrogen is underwritten by governments, or combined as part of the procurement of a product (i.e. a car), will reveal opportunities for delivery models.

The National Hydrogen Strategy envisaged timing of future assessments to occur every 5 years, and it is recommended as an outcome of this assessment that shorter timeframes may be appropriate in this early industry development stage. In order to streamline the assessment process and improve the consistency of outcomes, it would be beneficial for the methodology to stipulate the categorisation of stakeholders to engage with. Importantly, alignment with other government processes, assessments, or products should be integrated into the report, and similarly the NHIA should inform other energy infrastructure and regional development planning. For example, the AEMO's ISP which has already evolved during the course of this project from ISP 2020[6] which did not contain a hydrogen scenario, and then in 2022[7] contained the "hydrogen superpower" scenario, and in future could align scenarios with NHIA.

The methodology used to deliver this techno-economic assessment was developed specifically for the NHIA with the focus on providing an Australia-wide infrastructure prioritisation; and underpinned by a bespoke industry-leading energy system flow model. It is recommended that the approach to future NHIA consider sufficient consistency and alignment to enable meaningful comparison of the assessment outputs and infrastructure priority needs across each NHIA interval. This will provide valuable insight to stakeholders on the evolving industry development needs over time.

Future assessments could benefit from inclusion of targeted regional based assessments, perhaps initially focussed on hydrogen hub locations, to enable a more granular the investigation of site-specific infrastructure needs across water, transport, ports incorporating land use and other site-specific infrastructure development considerations. This would enable better co-ordination and integration with regional energy and economic planning and take into consideration individual hydrogen project details as the industry develops.

An important limitation in the techno-economic model is that in each timeframe, the model assumes a constant cost of grid electricity and cost of power transmission regardless of the position of demand locations and their distance to renewable energy production areas. Therefore, the model decision between transporting energy in the form of hydrogen rather than electricity (molecules vs electrons) is only indicative. Future infrastructure assessments could include a cost model for the power transmission cost, which could use as input the transmission distance, capacity and the existing infrastructure to estimate the actual cost of power transmission between renewable energy production area and demand locations.

The cost of grid electricity has major implications to the cost and configuration of the hydrogen supply chain, as it impacts both hydrogen production and the downstream hydrogen carrier conversion processes. Increased grid electricity costs would not only further increase the LCOH observed, however may result in the need for increased inter-seasonal hydrogen storage (to manage hydrogen production throughout winter with poorer solar PV performance), as well as providing credence to the need for greater behind-the-meter renewable capacity in general (to avoid the consumption of expensive grid electricity wherever possible). An increased need for behind-the-meter renewable capacity raises the importance of determining potential hydrogen production locations within a reasonable proximity to expected demand that have the area available to house large amount of behind-the-meter renewables. Identifying the optimal locations for hydrogen production, while not subverting the need for the significant grid connected renewables required to decarbonise the electricity network, could be a major focus moving forward.

Glossary & Terms

Glossary and Terms

Acronym	Definition
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AGIG	Australian Gas Infrastructure Group
AHC	Australian Hydrogen Council
AUD	Australian Dollar
BOSMA	Bureau of Steel Manufacturers of Australia
CAPAD	Collaborative Australian Protected Areas Database
CAPEX	Capital Expenditure
CBAM	Carbon Adjustment Border Mechanism
CCS/CCSU	Carbon Capture Storage/ Carbon Capture Storage and Utilisation
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
COAG	Council of Australian Governments
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISER	Department of Industry, Science, Energy and Resources
DRI	Direct Reduced Iron
EU	European Union
EV	Electric Vehicle
FEED	Front End Engineering Design
FID	Final Investment Decision
GIS	Geographic Information System
GJ	Gigajoule (10^9 Joules)
GL	Gigalitre, or one billion litres
GPG	Gas-fired Power Generation
GSOO	Gas Statement of Opportunities
GW	Gigawatt
H_2	Hydrogen
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gases
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
JV	Joint Venture
kgH_2	Kilogram of hydrogen
kt	Kilotonne (one thousand tonnes)

Acronym	Definition
ktpa	Kilotonne per annum
kW	Kilowatt (one thousand Watt)
kWh	Kilowatt-hour (unit of energy equivalent to 3,600,000 Joules)
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOS	Levelised Cost of Storage
LGC	Large-scale Generation Certificate
LH_2	Liquid Hydrogen
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
MCH	Methylcyclohexane
Mt	Megatonne (one million tonnes)
MW	Megawatt
NEM	National Energy Market
NERA	National Energy Resource Australia
NH_3	Ammonia
NHIA	National Hydrogen Infrastructure Assessment
NHS	National Hydrogen Strategy
NREL	National Renewable Energy Laboratory
NSW	New South Wales
NT	Northern Territory
NWIS	North-West Interconnected System
OPEX	Operational Expenses
PEM	Polymer Electrolyte Membrane
PHES	Pumped Hydroelectric Energy Storage
PJ	Petajoule (10^{15} Joules)
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PV	Photovolatic
QLD	Queensland
RAPS	Remote Area Power Systems
REZ	Renewable Energy Zones
SMR	Steam Methane Reforming
SWIS	South-West Interconnected System
TAS	Tasmania
tCO_2	Tonne of CO_2
TWh	Terawatt hour (one million kWh)
UK	United Kingdom

Acronym	Definition
USA	United States of America
USD	United States Dollar
VIC	Victoria
WA	Western Australia
WACC	Weighted Average Cost of Capital
WAGSOO	Western Australian Gas Statement of Opportunities
WEM	Wholesale Electricity Market
WOSP	Whole of System Plan
WRI	World Resources Institute

For the purposes of this study the following definition of terms is applied.

Term	Definition
Blue hydrogen	Hydrogen production derived from fossil fuels (natural gas or coal) in combination with CCS.
CarbonNet Project	The CarbonNet Project is a carbon capture and storage (CCS) project in Victoria that aims to establish a commercial-scale network to transport and store carbon dioxide from industries in the Latrobe Valley to offshore sites in the Bass Strait v ia an underground pipeline.
Demand scenario	Low, central, and high demand quantity scenarios were provided for each year, providing an indication of how hydrogen demand might vary based on sensitivities such as fuel switching and share of global export market.
Green hydrogen	Hydrogen production derived from a renewable energy source
Hydrogen Hub	Regions where various users of hydrogen across industrial, transport and energy markets are co-located as defined in National Hydrogen Strategy 2019.
Hydrogen demand scenarios	The annual hydrogen demand scenarios developed by Frontier Economics for 2025 to 2050.
Lowest cost hydrogen supply chain	The supply chain configuration produced as an output of the techno-economic model, which solves for lowest overall supply chain cost
Levelised cost of hydrogen	The LCOH represents the cost hydrogen would need to sold at to cover the cost of the infrastructure required for its production. Calculated by dividing the overall system cost by the hydrogen production it can achieve over its lifespan.
Levelised cost of electricity	The LCOE represents the cost electricity would need to sold at to cover the cost of the infrastructure required for its production. Calculated by dividing the overall system cost by the electricity production it can achieve over its lifespan.

Appendices

Appendix A

Model Location Summary

A.1 NHIA Context Map

The below image is a graphical representation of all the allowable production and demand nodes, geological storage locations and existing infrastructure links allowed to be utilised in the model.

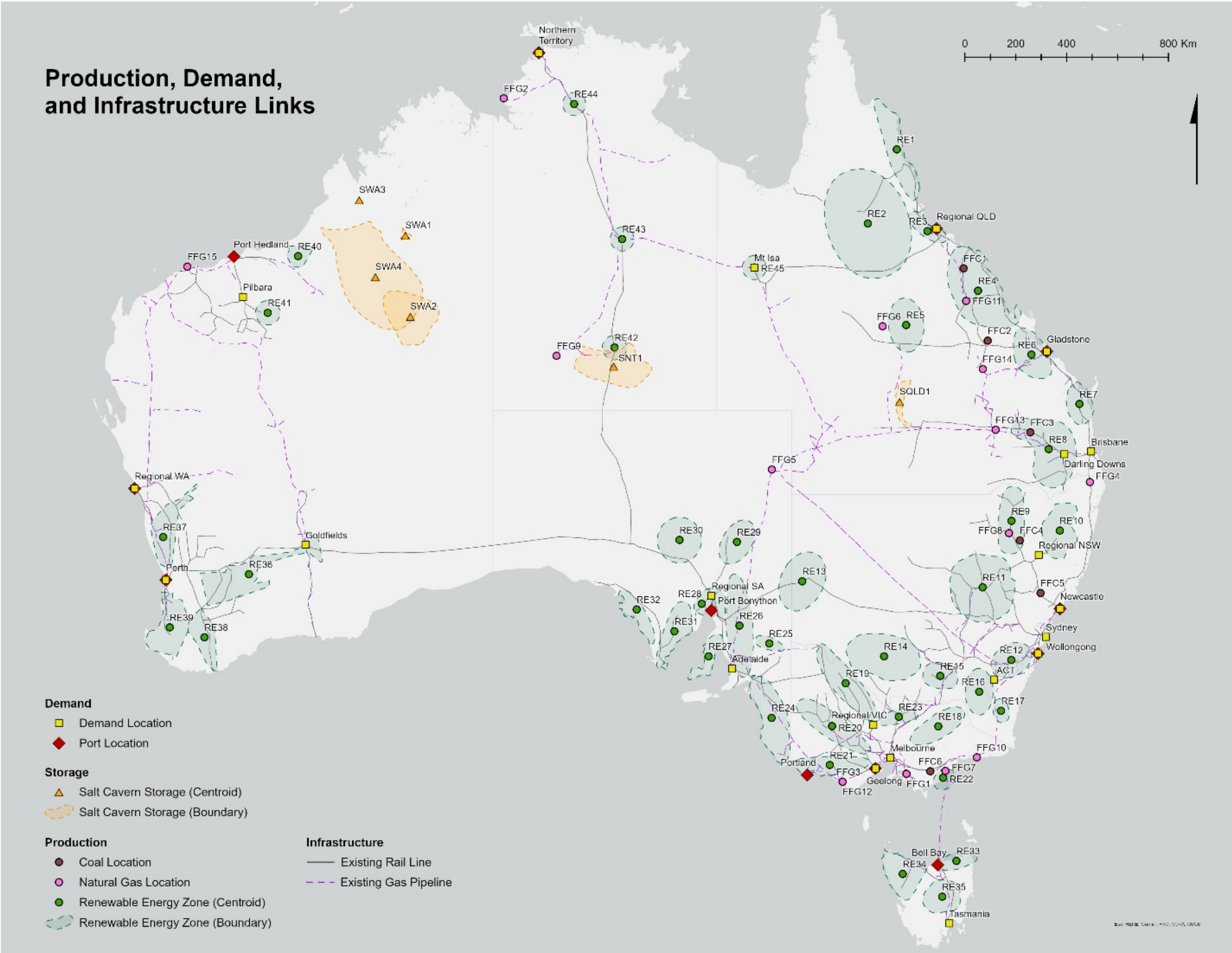


Figure A.1 1 NHIA Context Map

A.2 Demand Location Summary

General Demand

The demand locations provided by Frontier Economics and utilised in the model are presented in Table A.2 1.

Table A.2 1 Hydrogen demand locations and geographical coordinates

Demand Name (location[1])	State / Territory	Latitude	Longitude
ACT	ACT	-35.281961	149.128613
Sydney	NSW	-33.873081	151.208066
Newcastle	NSW	-32.928152	151.781281
Wollongong	NSW	-34.424835	150.893055
Northern Territory (Darwin)	NT	-12.463728	130.844433
Brisbane	Qld	-27.470448	153.026006
Gladstone	Qld	-23.842622	151.248770
Darling Downs	Qld	-27.564148	151.949273
Mt Isa	Qld	-20.725734	139.497709
Adelaide	SA	-34.928499	138.600746
Tasmania (Hobart)	Tas	-42.880144	147.328424
Melbourne	Vic	-37.812274	144.962263
Geelong	Vic	-38.149913	144.361719
Perth	WA	-31.952326	115.861302
Pilbara (Dampier / Karratha)[2]	WA	-20.733601	116.844025
Goldfields (Kalgoorlie – Boulder)	WA	-30.748762	121.464749

Note:

1. Locations utilised as point for regions / overall state demand. Latitude and longitude of these points was assigned by Arup
2. This location was utilised for the Pilbara demand as it is near the central Nunna junction. This accounts for the fact that a large portion of the Pilbara demand is attributed to mining and the potential production of green steel

Regional Demand

Some states and territories have been assigned a regional demand, i.e. a hydrogen demand that cannot be attributed to a single location within the state or territory. The following locations have been utilised in the supply chain model as regional demand centres to account for the full amount of regional hydrogen demand.

Table A.2 2 Hydrogen regional demand locations and geographical coordinates

Demand regions (location)	State / Territory	Latitude	Longitude
Regional NSW (Tamworth)	NSW	-31.092045	150.922834
Regional QLD (Townsville)	Qld	-19.259003	146.816925
Regional SA (Port Augusta)	SA	-32.493638	137.774323
Regional VIC (Bendigo)	Vic	-36.759616	144.278547
Regional WA (Geraldton)	WA	-28.782357	114.607431

Export Demand

The export demand nodes featured in the supply chain model are presented below.

Table A.2 3 Hydrogen regional demand locations and geographical coordinates

Demand Node (Location)	State / Territory	Latitude	Longitude
Newcastle*	NSW	-	-
Port Kembla (Wollongong*)	NSW	-	-
Darwin*	NT	-	-
Gladstone*	Qld	-	-
Townsville*	Qld	-	-
Port Bonython	SA	-32.984990	137.771401
Bell Bay	Tas	-41.130648	146.867384
Geelong*	Vic	-	-
Portland	Vic	-38.354523	141.616807
Pilbara (Port Hedland)	WA	-20.312327	118.589537
Mid-West (Geraldton*)	WA	-	-
Perth (Kwinana*)	WA	-	-

Note:

* Co-located with domestic demand location (latitude and longitude shown in tables above)

Demand scenarios summary

The series of tables below presents the figures for domestic and export hydrogen demand for all sensitivity scenarios used in this assessment.

Table A.2 4 Annual hydrogen demand split by State/Territory and timeframe, Central demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	17	164	1,175	2,556
	Export	0	66	714	1,859
	Total	**17**	**230**	**1,889**	**4,416**
NSW, ACT	Domestic	20	169	1,085	2,536
	Export	0	66	714	1,859
	Total	**20**	**235**	**1,800**	**4,396**
VIC	Domestic	15	153	1,121	2,441
	Export	0	66	714	1,859
	Total	**15**	**219**	**1,836**	**4,301**
TAS	Domestic	0	4	19	138
	Export	0	33	357	930
	Total	**0**	**37**	**406**	**1,067**
SA	Domestic	5	38	235	542
	Export	0	33	357	930
	Total	**5**	**71**	**592**	**1,471**
WA	Domestic	11	120	1,129	3,879
	Export	0	99	1,071	2,789
	Total	**11**	**219**	**2,201**	**6,668**
NT	Domestic	1	13	265	642
	Export	0	33	357	930
	Total	**1**	**46**	**622**	**1,572**

Table A.2 5 Annual hydrogen demand split by State/Territory and timeframe, Low demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	0	10	169	727
	Export	0	0	179	358
	Total	**0**	**10**	**348**	**1085**
NSW, ACT	Domestic	0	11	150	846
	Export	0	0	179	358
	Total	**0**	**11**	**329**	**1204**
VIC	Domestic	0	8	101	562
	Export	0	0	179	358
	Total	**0**	**8**	**280**	**920**
TAS	Domestic	0	0	2	22
	Export	0	0	90	179
	Total	**0**	**0**	**92**	**201**
SA	Domestic	0	3	34	187
	Export	0	0	90	179
	Total	**0**	**3**	**123**	**366**
WA	Domestic	0	7	127	1274
	Export	0	0	269	537
	Total	**0**	**7**	**395**	**1811**
NT	Domestic	0	0	33	136
	Export	0	0	90	179
	Total	**0**	**0**	**123**	**315**

Table A.2 6 Annual hydrogen demand split by State/Territory and timeframe, High demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	21	280	2596	5751
	Export	119	969	1749	4552
	Total	**140**	**1249**	**4345**	**10303**
NSW, ACT	Domestic	22	275	2482	5666
	Export	119	969	1749	4552
	Total	**141**	**1244**	**4231**	**10219**
VIC	Domestic	16	230	2202	4784
	Export	119	969	1749	4552
	Total	**135**	**1199**	**3950**	**9336**
TAS	Domestic	1	11	129	309
	Export	60	484	874	2276
	Total	**60**	**495**	**1004**	**2585**
SA	Domestic	5	59	521	1096
	Export	60	484	874	2276
	Total	**64**	**544**	**1395**	**3372**
WA	Domestic	18	288	3150	7567
	Export	179	1453	2623	6829
	Total	**197**	**1742**	**5773**	**14395**
NT	Domestic	1	24	500	1239
	Export	60	484	874	2276
	Total	**60**	**509**	**1374**	**3516**

Table A.2 7 Annual hydrogen demand split by State/Territory and timeframe, Central demand scenario, Export demand distributed evenly between three northern port locations (Port Hedland, Northern Territory, Gladstone)

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	17	164	1175	2556
	Export	0	132	1428	3719
	Total	**17**	**296**	**2603**	**6275**
NSW, ACT	Domestic	20	169	1085	2536
	Export	0	0	0	0
	Total	**20**	**169**	**1085**	**2536**
VIC	Domestic	15	153	1121	2441
	Export	0	0	0	0
	Total	**15**	**153**	**1121**	**2441**
TAS	Domestic	0	4	49	138
	Export	0	0	0	0
	Total	**0**	**4**	**49**	**138**
SA	Domestic	5	38	235	542
	Export	0	0	0	0
	Total	**5**	**38**	**235**	**542**
WA	Domestic	11	120	1129	3879
	Export	0	132	1428	3719
	Total	**11**	**252**	**2558**	**7597**
NT	Domestic	1	13	265	642
	Export	0	132	1428	3719
	Total	**1**	**145**	**1694**	**4361**

Table A.2 8 Annual hydrogen demand split by State/Territory and timeframe, 'New green steel' demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	17	164	1175	2556
	Export	0	66	714	1859
	Total	**17**	**230**	**1889**	**4416**
NSW, ACT	Domestic	20	169	1085	2536
	Export	0	66	714	1859
	Total	**20**	**235**	**1800**	**4396**
VIC	Domestic	15	153	1121	2441
	Export	0	66	714	1859
	Total	**15**	**219**	**1836**	**4301**
TAS	Domestic	0	4	49	138
	Export	0	33	357	930
	Total	**0**	**37**	**406**	**1067**
SA	Domestic	5	41	262	595
	Export	0	33	357	930
	Total	**5**	**74**	**619**	**1525**
WA	Domestic	11	355	3812	9191
	Export	0	99	1071	2789
	Total	**11**	**454**	**4884**	**11980**
NT	Domestic	1	13	265	642
	Export	0	33	357	930
	Total	**1**	**46**	**622**	**1572**

Table A.2 9 Annual hydrogen demand split by State/Territory and timeframe, 'Incumbent green steel' demand scenario, Export demand distributed evenly between port locations

State / Territory	Hydrogen demand, ktpa	2025	2030	2040	2050
QLD	Domestic	17	164	1175	2556
	Export	0	66	714	1859
	Total	**17**	**230**	**1889**	**4416**
NSW, ACT	Domestic	20	169	1085	2536
	Export	0	66	714	1859
	Total	**20**	**235**	**1800**	**4396**
VIC	Domestic	15	153	1121	2441
	Export	0	66	714	1859
	Total	**15**	**219**	**1836**	**4301**
TAS	Domestic	0	4	49	138
	Export	0	33	357	930
	Total	**0**	**37**	**406**	**1067**
SA	Domestic	5	38	302	608
	Export	0	33	357	930
	Total	**5**	**71**	**659**	**1538**
WA	Domestic	11	120	1129	3879
	Export	0	99	1071	2789
	Total	**11**	**219**	**2201**	**6668**
NT	Domestic	1	13	265	642
	Export	0	33	357	930
	Total	**1**	**46**	**622**	**1572**

A.3 Generation Location Summary

Renewable Energy Locations

The locations in which the model allows behind-the-meter renewable energy generation to be built to directly power electrolysers for green hydrogen production are presented in the table below.

Table A.3 1 Behind-the-meter renewable energy generation locations

Reference	Name	State / Territory	Latitude	Longitude	Solar Capacity Factor (%)[1]	Wind Capacity Factor (%)[1]
RE1	Far North QLD	Qld	-16.222076	145.217819	29%	59%
RE2	North Qld Clean Energy Hub	Qld	-19.060230	144.051926	30%	48%
RE3	Northern Qld	Qld	-19.348799	146.449783	30%	43%
RE4	Isaac	Qld	-21.590609	148.485687	30%	43%
RE5	Barcaldine	Qld	-22.866619	145.597046	34%	40%
RE6	Fitzroy	Qld	-23.960552	150.633881	31%	45%
RE7	Wide Bay	Qld	-25.762203	152.559982	30%	37%
RE8	Darling Downs	Qld	-27.388107	151.325211	31%	45%
RE9	North West NSW	NSW	-29.918724	149.827667	33%	31%
RE10	New England	NSW	-30.249725	151.764191	30%	38%
RE11	Central-West Orana	NSW	-32.204453	148.665588	29%	39%
RE12	Southern NSW Tablelands	NSW	-34.644108	149.821182	27%	41%
RE13	Broken Hill	NSW	-31.995802	141.426636	33%	36%
RE14	South West NSW	NSW	-34.516502	144.708145	30%	32%
RE15	Wagga Wagga	NSW	-35.164719	146.971298	28%	29%
RE16	Tumut	NSW	-35.680828	148.528580	26%	42%
RE17	Cooma-Monaro	NSW	-36.307407	149.412766	27%	38%
RE18	Ovens Murray	Vic	-36.804012	146.886139	25%	41%
RE19	Murray River	Vic	-35.405453	143.163345	30%	32%
RE20	Western Victoria	Vic	-36.795284	142.616089	26%	41%
RE21	South West Victoria	Vic	-38.043407	142.529175	24%	38%
RE22	Gippsland	Vic	-38.444283	147.083450	24%	30%
RE23	Central North Vic	Vic	-36.499950	145.300766	28%	33%
RE24	South East SA	SA	-36.530190	140.194153	24%	40%
RE25	Riverland	SA	-34.095772	140.096603	30%	31%
RE26	Mid-North SA	SA	-33.494881	138.901199	28%	40%
RE27	Yorke Peninsula	SA	-34.515766	137.657806	28%	38%
RE28	Northern SA	SA	-32.756706	137.383423	30%	39%
RE29	Leigh Creek	SA	-30.646578	138.802322	33%	42%

Reference	Name	State / Territory	Latitude	Longitude	Solar Capacity Factor (%)[1]	Wind Capacity Factor (%)[1]
RE30	Roxby Downs	SA	-30.578617	136.489899	33%	35%
RE31	Eastern Eyre Peninsula	SA	-33.687172	136.291153	28%	39%
RE32	Western Eyre Peninsula	SA	-32.954655	134.768616	30%	38%
RE33	North East Tasmania	Tas	-41.013279	147.612808	25%	44%
RE34	North West Tasmania	Tas	-41.407383	145.460098	22%	46%
RE35	Tasmania Midlands	Tas	-42.087879	147.044037	24%	55%
RE36	WA Mid East	WA	-31.758808	119.197525	29%	46%
RE37	WA Mid West	WA	-30.479380	115.746971	29%	46%
RE38	WA South East	WA	-33.886272	117.407005	27%	46%
RE39	WA South West	WA	-33.552204	116.015053	27%	47%
RE40	WA Pilbara	WA	-20.295994	121.166626	29%	41%
RE41	WA Pilbara Inland	WA	-22.415237	119.953552	31%	42%
RE42	NT Alice Springs	NT	-23.702345	133.883408	33%	48%
RE43	NT Tennant Creek	NT	-19.649149	134.189163	32%	55%
RE44	NT Katherine	NT	-14.463972	132.261246	26%	41%
RE45	Mt Isa[2]	Qld	-20.725734	139.497709	31%	51%

Note:

1. Capacity factors for solar and wind were primarily extracted from AEMO ISP Solar and Wind Traces (via HySupply State of Play25). The capacity factors of locations which do not coincide with AEMO renewable energy zones were determined from hourly solar and wind profiles downloaded via RenewablesNinja26.
2. A renewable energy production location (RE45) was also situated at Mt Isa, allowing the model to co-locate dedicated renewables with the Mt Isa demand.

Natural Gas Production Locations

The locations in which the model allows blue hydrogen production via steam methane reforming with CCS are presented in the table below. These are located at natural gas fields (or nearby onshore natural gas processing facilities). The storage of hydrogen in depleted gas fields is also allowed at these locations. The carbon storage location associated with each natural gas production location is not explicitly determined, instead a flat rate of carbon transportation and storage cost has been applied to the cost of blue hydrogen production.

Table A.3 2 SMR + CCS Hydrogen production locations

Ref	Basin	State / Territory	Latitude	Longitude	Reserve total (PJ)
FFG1	Bass	Vic	-38.321883	145.606972	650
FFG2	Bonaparte	NT	-14.242150	129.436027	16,911
FFG3	Otway	Vic	-38.572052	143.036496	151
FFG4	Clarence Moreton	Qld-NSW	-28.551616	152.976158	575
FFG5	Cooper	SA	-28.107824	140.203049	9,865
FFG6	Galilee	Qld	-22.913919	144.656152	2,789
FFG7	Gippsland	Vic	-38.225512	147.167989	6,825
FFG8	Gunnedah	NSW	-30.336041	149.729860	971
FFG9	Amadeus	NT	-23.999595	131.556963	438
FFG10	Gippsland	Vic	-37.797723	148.435266	457
FFG11	Surat & Bowen	Qld	-21.979133	148.004022	8,221
FFG12	Otway	Vic	-38.568023	143.042524	266
FFG13	Surat & Bowen	Qld	-26.694239	149.185886	73,603
FFG14	Surat & Bowen	Qld	-24.493150	148.672567	292
FFG15	Carnarvon Basin	WA	-20.684813	116.722954	108,427

Coal Production Locations

The table below presents the locations within the model with allowable blue hydrogen production via coal gasification with CCS. The carbon storage location associate with each coal production location is not explicitly determined, instead a flat rate of carbon transportation and storage cost has been applied to the cost of blue hydrogen production.

Table A.3 3 Coal gasification + CCS hydrogen production locations

Ref	Name	State / Territory	Latitude	Longitude	Coal Type	Economic Demonstrated Resources (PJ)
FFC1	North Queensland	Qld	-20.755662	147.900744	Black	766,377
FFC2	Central Queensland	Qld	-23.443759	148.869119	Black	766,377
FFC3	Southwest Queensland	Qld	-26.914621	150.746989	Black	189,017
FFC4	Northern NSW	NSW	-30.591851	150.159661	Black	55,805
FFC5	North-Central NSW	NSW	-32.392385	150.999324	Black	528,358
FFC6	Latrobe Valley	Vic	-38.235231	146.563621	Brown	716,026

A.4 Geological Storage Location Summary

Salt Cavern Storage Locations

The table below presents the locations within the model that allow for the use of salt caverns for large-scale storage of hydrogen. These locations were extracted from the Geoscience Australia Portal.[92] The amount of storage available at each location has been applied as a benchmark sizing for inter-seasonal storage, consistent across each storage location in the model.[93]

Table A.4 1 Salt cavern hydrogen storage locations

Ref	Basin	State / Territory	Latitude	Longitude	Estimated available storage (Tonnes H2)
SQLD1	Adavale	Qld	-25.675930	145.334839	1,604,411
SNT1	Amadeus	NT	-24.383520	133.846039	1,604,411
SWA1	Canning	WA	-19.507635	125.481094	1,604,411
SWA2	Canning	WA	-22.545031	125.679184	1,604,411
SWA3	Canning	WA	-18.157192	123.625534	1,604,411
SWA4	Canning	WA	-21.071951	124.273583	1,604,411

[92] Geoscience Australia, Hydrogen - Potential Locations For Underground Large Scale Hydrogen Storage - Known Thick Underground Halite Deposits, 2021, accessed: https://portal.ga.gov.au/metadata/hydrogen/potential-locations-for-underground-large-scale-hydrogen-storage/known-thick-underground-halite-deposits/f15d231c-819e-4b2d-8422-637462138294

[93] Northern Gas Networks, H21 Leeds City Gate Report, 2016, accessed: https://h21.green/app/uploads/2022/05/H21-Leeds-City-Gate-Report.pdf

Appendix B

Full Techno-Economic Modelling Inputs

B.1 Inputs and Assumptions

Inputs and assumptions related to each component of hydrogen model.

B.1.1 Financial and Utility

The overarching financial and utility cost inputs and assumptions are featured in the table below. Unless otherwise indicated, the inputs are assumed to remain constant over the 2025 to 2050 time period.

Table B.1 1 Financial and utility cost inputs and assumptions

Financial

Input	Baseline Value	Unit	Reference
Exchange rate (USD:AUD)	1.31	AUD/USD	Reserve Bank of Australia #, 94
Real pre-tax WACC	5.9%	%	AEMO ISP 20206 – Central Scenario
Payback period for capital investments	20	Years	Assumption

Utilities

Input	Baseline Value	Unit	Reference
Wholesale Electricity Cost	0.042 *	$/kWh	Calculated - average NEM wholesale electricity price for 2020 at 85% utilisation
Transmission Costs - % of wholesale cost	7%	%	Assumption[95]
Total Electricity Cost – including transmission and LGCs	0.065 *,^	$/kWh	LGCs cost included – ceasing after 2030
Water	2	$/kL	Assumption (taken from range of $1 - $4 for seawater desalination[96])

Notes:

* Tested as sensitivity to the model

^ Values vary across years considered in model (2025, 2030, 2040 and 2050). Total grid electricity cost decreases to $0.045 / kWh due to no expected costs of LGCs from 2030 onwards

Using the average of the last 25 years of the RBA Exchange Rates

[94] RBA, Historical Data: Exchange Rates, 2021, Australia, accessed: https://www.rba.gov.au/statistics/historical-data.html#exchange-rates

[95] Assumed flat-rate transmission cost of 7% utilised due to modelling existing network being outisde boundaries of techno-economic modelling – validity of assumption discussed with AEMO. Transmission cost does not include distribution network or environmental charges

[96] Desalination Fact Sheet, Australian Water Association Australia, accessed: https://www.awa.asn.au/resources/fact-sheets

B.1.2 Hydrogen Production

The main inputs and assumptions associated with the production of hydrogen from electrolysers, steam methane reforming with CCS, and coal gasification with CCS are listed below.

Table B.1 2 Hydrogen production technologies inputs and assumptions

Electrolyser

Input	2025	2030	2040	2050	Unit	Reference
Renewable Electricity: for co-located production at demand	0.065	0.045	0.045	0.045	$/kWh	CER – forecast ACCU-LGC price convergence p. 30[97]
Renewable Electricity: for renewable generation nodes[(a),(b)]	0.036	0.034	0.031	0.028	$/kWh	AEMO ISP, WA WOSP[27], CSIRO GenCosts
Energy efficiency (system)	50	48	46.5	45	kWh/ kg H_2	IRENA p. 65[98], BloombergNEF p. 33[99]
Water consumption (stoichiometric)	9	9	9	9	L/kg H_2	COAG Energy Council, p. xiv[4]
Water consumption (full process)	30.3[(f)]	30.3[(f)]	30.3[(f)]	30.3[(f)]	L/kg H_2	Argonne National Laboratory p. 32[100]
Hydrogen output pressure	30	30	30	30	bar (MPa)	CSIRO National Hydrogen Roadmap p. 28[28]
Electrolyser system – capex (high) [(d),(e)]	2,266	1,875	1,484	1,179	$/kW	IRENA p. 65
Electrolyser system – capex (medium) [(d),(e)]	1,271	979	856	756	$/kW	IRENA p.65, IEA p. 3
Electrolyser system – capex (low) [(d),(e)]	766	488	403	333	$/kW	IRENA p. 65
Annual operational cost	1.50%	1.50%	1.50%	1.50%	% of capex	IEA p. 3
LCOH – medium capex (grid electricity)	4.3	2.95	2.77	2.62	$/kg H_2	Indicative calculated LCOH, based on 85% utilisation factor
LCOH – medium capex (dedicated renewable generation)[(b)]	3.3	2.7	2.34	2.06	$/kg H_2	Indicative calculated LCOH, based on 50% utilisation factor – in the model, a different LCOH is calculated for each Renewable Energy area

[97] CER (Clean Energy Regulator), Quarterly Carbon Market Report – June Quarter 2021, 2021, accessed: http://www.cleanenergyregulator.gov.au/DocumentAssets/Documents/Quarterly%20Carbon%20Market%20Report%20-%20June%20Quarter%202021.pdf

[98] IRENA, Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, 2020, Abu Dhabi, accessed: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

[99] BloombergNEF, 2H 2021 Hydrogen Levelised Cost Update, p.33, 2021

[100] Argonne National Laboratory, Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels, p. 32, 2015

Steam Methane Reforming (SMR) with CCS

Input	2025	2030	2040	2050	Unit	Reference
Natural Gas[(a),(b)]	6.0 – 10.4	6.0 – 10.4	6.0 – 10.4	6.0 – 10.4	\$/GJ	CER – forecast ACCU-LGC price convergence p. 30[101]
Energy Efficiency	0.18	0.18	0.18	0.18	GJ gas/ kg H_2	CSIRO National Hydrogen Roadmap p. 81
Water consumption (stoichiometric)	4.5	4.5	4.5	4.5	L/kg H_2	COAG Energy Council p. xiv[4]
Water consumption (full process)	13.6[(f)]	13.6[(f)]	13.6[(f)]	13.6[(f)]	L/kg H_2	Argonne National Laboratory p. 32
Steam Methane Reformer with carbon capture – capex	2,200	1,800	1,750	1,700	\$/kW H_2	IEA p. 3
Carbon transport and storage	30	30	30	30	\$/tonne CO_2	Assumption within range - IEA p. 2, CSIRO National Hydrogen Roadmap p. 81, CarbonNet project estimate, Global CCS Institute p. 38[102]
Annual operational cost	3.00%	3.00%	3.00%	3.00%	% of capex	IEA p. 3
LCOH (with \$9/GJ gas)[(b)]	2.96	2.78	2.76	2.73	\$/kg H_2	Indicative calculated LCOH – in the model, a different LCOH is calculated for each Fossil Fuel source area

Coal Gasification with CCS

Input	2025	2030	2040	2050	Unit	Reference
Black Coal	2.5 – 3.1	2.5 – 3.1	2.5 – 3.1	2.5 – 3.1	\$/GJ	AEMO ISP 2020
Brown Coal	0.7	0.7	0.7	0.7	\$/GJ	AEMO ISP 2020
Energy efficiency	0.21	0.21	0.21	0.21	GJ coal/ kg H_2	IEA p. 3
Water consumption (stoichiometric)	9	9	9	9	L/kg H_2	COAG Energy Council p. xiv[4]
Water consumption (full process)	31.5[(f)]	31.5[(f)]	31.5[(f)]	31.5[(f)]	L/kg H_2	Argonne National Laboratory p. 32
Black coal gasification with carbon capture – capex	3,650	3,650	3,650	3,650	\$/kW H_2	IEA p. 3

[101] CER (Clean Energy Regulator), Quarterly Carbon Market Report – June Quarter 2021, 2021, accessed: http://www.cleanenergyregulator.gov.au/DocumentAssets/Documents/Quarterly%20Carbon%20Market%20Report%20-%20June%20Quarter%202021.pdf

[102] Global CCS Institute, March 2021, Technology Readiness and Costs of CCS, p38, accessed: https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCS-Tech-and-Costs.pdf

Input	2025	2030	2040	2050	Unit	Reference
Brown coal gasification with carbon capture – capex	4,307	4,307	4,307	4,307	$/kW H_2	Assumed – adjustment to IEA (p. 3) capex based on CSIRO National Hydrogen Roadmap (p. 82 & 83) capex
Carbon transport and storage	30	30	30	30	$/tonne CO_2	Assumption within range - IEA p. 2, CSIRO National Hydrogen Roadmap p. 81, CarbonNet project estimate, Global CCS Institute p. 38
Annual operational cost	5.00%	5.00%	5.00%	5.00%	% of capex	IEA p. 3
LCOH – black coal (with $3/GJ coal)	3.48	3.48	3.48	3.48	$/kg H_2	Indicative calculated LCOH – in the model, a different LCOH is calculated for each Fossil Fuel source area
LCOH – brown coal (with $0.7/GJ coal)	3.4	3.4	3.4	3.4	$/kg H_2	Indicative calculated LCOH – in the model, a different LCOH is calculated for each Fossil Fuel source area

Notes:

a) Values vary across years considered in model (2025, 2030, 2040 and 2050)

b) Values vary across locations in Australia

c) Average of the LCOE across featured renewable energy nodes

d) Tested as sensitivity to model

e) Includes cost of replacing stack after 10 years

f) Inclusive of all system losses including purification processes and cooling water required

Additional notes:

- Limitations on the size of blue hydrogen plants were introduced due to the minimum critical size of CCS installations. Based on this consideration, blue hydrogen plants were not included to the 2025 scenario due to the insufficient scale to justify the development of CCS facilities. The same limitation was not applied to the electrolysers due to their modular nature and commercial availability in small sizes.
- The table is populated with the main LCOH values from 2025 to 2050 to show efficiency improvements of electrolysers and other production processes developing over years.

B.1.3 Carrier Conversion and Reconversion

Summary of the LCOH of the processes for hydrogen conversion to carrier and for reconversion of the carrier to hydrogen.

Table B.1 3 Levelised cost of processes for carrier conversion and reconversion

Conversion

Input	Baseline Value - 2025[1]	Unit	Reference
Compressor – large-scale (30 bar to 350 bar compressed H_2) [2]	0.23	\$/kg H_2	Industry benchmarking
Compressor – medium-scale (30 Bar to 100 Bar Compressed H_2)[2]	0.10	\$/kg H_2	CSIRO National Hydrogen Roadmap p. 28 (electricity required)
Liquefaction plant (H_2 gas to liquid H_2)	1.48[3]	\$/kg H_2	CSIRO National Hydrogen Roadmap p. 78, IEA p. 7
Haber-Bosch converter (H_2 gas to ammonia)	1.16	\$/kg H_2	HySupply State of Play Report p. 97[25], CSIRO National Hydrogen Roadmap p. 86, IEA p. 5
LOHC conversion plant (H_2 gas to MCH)	0.75	\$/kg H_2	IEA Future of Hydrogen Assumptions p. 7[35]

Reconversion

Input	Baseline Value - 2025[1]	Unit	Reference
Decompression	-	\$/kg H_2	Assumed negligible
Regasification plant	0.59	\$/kg H_2	Calculated from Amos 1998
Ammonia cracker	0.57	\$/kg H_2	CSIRO (2017) p. 6 [103], IEA pg. 7-8
MCH reconversion	0.85	\$/kg H_2	IEA pg. 7-8

Overall cost: conversion and reconversion of carriers

Input	Baseline Value - 2025[1]	Unit	Reference
Compressed hydrogen (350 Bar)	0.23	\$/kg H_2	Calculated
Compressed hydrogen (100 Bar)	0.10	\$/kg H_2	-
Liquified H_2	2.07	\$/kg H_2	-
Ammonia (NH_3)	1.73	\$/kg H_2	-
Methocyclohexane (MCH) / Toluene	1.59	\$/kg H_2	-

Notes:

Values change between timeframes due to the dependence on grid electricity costs

The cost of storage is presented separately in the section below and is not included in the cost of conversion and reconversion

A significant portion of cost is linked to the electricity required during liquefication process

Additional notes:

[103] Giddey S., Badwal S., Munnings C., Dolan M., 2017, Ammonia as a Renewable Energy Transportation Media https://pubs.acs.org/doi/abs/10.1021/acssuschemeng.7b02219

- The LCOH for compressed hydrogen assumes an initial pressure of 30 bar. This cost would increase significantly if hydrogen were produced at a lower pressure.
- The electricity for the conversion and reconversion processes is assumed to be sourced from the grid. Therefore, grid electricity costs are used instead of the LCOE from dedicated renewable generation.
- All demand is assumed to be in the form of hydrogen gas.

B.1.4 Transmission

The cost of hydrogen transmission options for the different hydrogen carriers is summarised in the table below. Transport technologies include trucks, rail, pipelines and blending into natural gas pipelines.

Table B.1 4 Cost of hydrogen transmission options for different hydrogen carriers and transport technologies

Trucks

Input	Baseline Value	Unit	Reference
Compressed H_2 (at 350 bar)	2.98	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
Liquified H_2	0.92	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
Ammonia	1.86	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
MCH	5.73	\$/tonne H_2/km	HySupply State of Play Report p. 97

Pipelines – compressed H_2[(a)(b)]

Input	Baseline Value	Unit	Reference
Compressed H2 (3.65 PJ/year)	Compressed H2 (3.65 PJ/year)	Compressed H2 (3.65 PJ/year)	CSIRO National Hydrogen Roadmap p. 35, IEA p. 7
Compressed H2 (36.5 PJ/year)	Compressed H2 (36.5 PJ/year)	Compressed H2 (36.5 PJ/year)	
Compressed H2 (365 PJ/year)	Compressed H2 (365 PJ/year)	Compressed H2 (365 PJ/year)	

Rail (existing infrastructure)

Input	Baseline Value	Unit	Reference
Compressed H_2 (at 350 bar)	0.62	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
Liquified H_2	0.28	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
Ammonia	0.23	\$/tonne H_2/km	CSIRO National Hydrogen Roadmap p. 88
MCH	0.60	\$/tonne H_2/km	BITRE Freight Rates (2017)

Natural Gas Pipelines – Blending (existing infrastructure)

Input	Baseline Value	Unit	Reference
Blending capacity	10%	% of H_2	Assumption
Natural Gas Tariffs	0.0015	$/GJ/km	Derived from AEMO ISP
Hydrogen Benchmark Tariff	0.60	$/tonne H_2/km	Calculated
Cost of Extraction (without natural gas recompression)	1.05	$/kg H_2	NREL p. 43 [104]

Notes:

a) Values vary dependent on flowrate through the pipeline, i.e. diameter of pipeline required

b) Cost for pipeline transport of other carriers is comparatively shown in the pipeline cost-curves diagram

[104] NREL, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, 2010, accessed: https://www.nrel.gov/docs/fy13osti/51995.pdf

Pipeline cost-curves

A pipeline cost-curve was utilised in the model to determine the economical tipping points from truck, rail and natural gas pipeline transmission (when applicable) compared to building new dedicated hydrogen carrier pipelines. Calculations based on pipeline costing data from the IEA and CSIRO National Hydrogen Roadmap were utilised to build the pipeline cost-curves, which are presented in the diagram below.

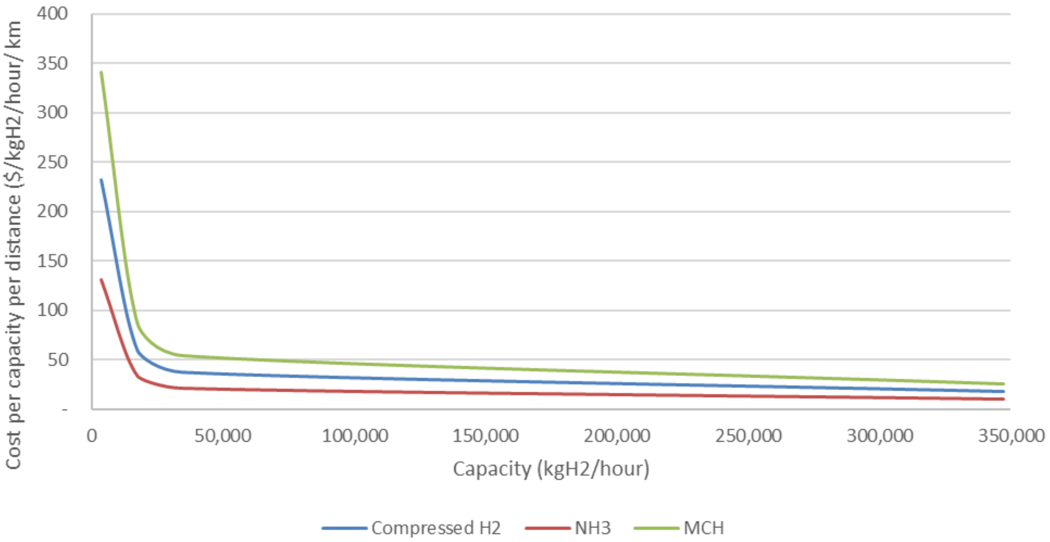


Figure B.1 1 Pipeline cost curves for different hydrogen carriers

B.1.5 Storage

The below table provides a summary of the cost inputs for the storage tanks of each hydrogen carrier, in addition to the geological storage of compressed hydrogen gas in depleted gas fields and salt caverns.

Storage tanks for each carrier are able to be located at either production or demand nodes featured in the model, whereas geological storage is either assumed to be co-located with the natural gas production facilities for depleted gas fields or specific salt deposits for salt cavern storage.

Table B.1 5 Summary of storage cost inputs and assumptions for hydrogen storage technologies

Capitals Costs

Storage tank

Input	Baseline Value	Unit	Reference
Compressed H_2	1,500	\$/kg H_2	Amos (1998), IEA Future of Hydrogen Assumptions p. 7, industry benchmarking
Liquified H_2	119.24	\$/kg H_2	
Ammonia	14.73	\$/kg H_2	
MCH	19.59	\$/kg H_2	

Geological hydrogen storage (compressed H_2)[(a)]

Input	Baseline Value	Unit	Reference
Depleted gas fields	13.25	\$/kg H_2	BloombergNEF p. 59 - 'Future Best Case' capex scenario
Salt cavern storage	5.97	\$/kg H_2	

Levelised Cost of Storage (LCOS)[(b),(c)]

Storage tank

Input	Baseline Value	Unit	Reference
Compressed H2	1.04	\$/kg H2	Calculated – assuming able to discharge full quantity of tanks in 24 hours
Liquified H2	0.083	\$/kg H2	
Ammonia	0.010	\$/kg H2	
MCH	0.014	\$/kg H2	

Geological hydrogen storage (compressed H_2)

Input	Baseline Value	Unit	Reference
Depleted gas fields	1.68	\$/kg H_2	Annual cycling
Salt cavern storage	0.12	\$/kg H_2	Bi-Monthly cycling

Notes:

a) 'Future best case' capital cost assumptions used which assumes a hydrogen economy is implemented to achieve future cost reductions for 2030 – 2050

b) Discounted annual cost per kilogram of discharged hydrogen equivalent

c) Not including conversion costs (compression, liquefication, etc.) of each carrier for LCOS

d) A baseline operational cost of 4% of the storage technologies capex is applied to each technology

e) Due to the curve of the hydrogen demand, large-scale storage technologies are generally only required to cycle once annually

B.2 Model Approaches

The table below provides a summary of the modelling approaches taken for major components of the technologies included in the scope of the modelled hydrogen supply chain:

Table B.2 1 Summary of the modelling approaches for the major components of the hydrogen supply chain

Component	Approach
Electrolysers	Locating electrolysers in renewable energy zones (as shown in the AEMO ISP) and points in WA and NT after discussion with state government bodies. Using a combination of behind-the-meter solar PV and wind generation to provide the electrolysers with dedicated renewable electricity. Allowing electrolysers (powered by grid electricity with LGCs) to be located at demand points.
Steam methane reformer with carbon capture and storage	Locating steam methane reformers in natural gas fields (point of extraction) with captured carbon assumed to use depleted gas fields for storage. Carbon capture built into capital and operating costs of SMR. This technology was excluded from the 2025 timestep because the required scale of plants is too small to justify the development of CCS infrastructure. This decision was further supported by the short timeframe available for the development of CCS infrastructure.
Coal gasification with carbon capture and storage	Locating coal gasification points at location of major coal processing plants with captured carbon assumed to use nearby depleted gas fields for storage. Carbon capture built into capital and operating costs of coal gasification. This technology was excluded from the 2025 timestep because the required scale of plants is too small to justify the development of CCS infrastructure. This decision was further supported by the short timeframe available for the development of CCS infrastructure.
Utilising natural gas pipelines	Allowing transportation of hydrogen via current natural gas pipelines, by modifying natural gas pipeline tariffs to account for an up to 10% hydrogen blend. Since the assumption of the model is that all demand is in the form of 100% hydrogen gas, the cost model for this transport option includes the cost of the hydrogen blending and deblending facilities.
Pipeline cost – capacity curve	The cost of building dedicated hydrogen carrier pipelines across Australia have associated cost-capacity curves associated with them – with the $ / capacity / km rate decreasing as the overall capacity of the pipeline increases.
Utilising freight railways	Allowing transportation of each hydrogen carrier via railway freight corridors. Assuming that 10% of the annual freight capacity can be reassigned to transporting hydrogen, with additional adjustments to account for the difference in commodity density between hydrogen carriers and currently transported commodities.
Geological hydrogen storage	Allowing storage in salt caverns and in depleted gas fields co-located with the modelled natural gas production points.

B.3 Model Limitations

Calliope is a linear optimisation tool, which has some limitations when conducting an assessment of infrastructure for the entirety of Australia. Some of the limitations of the model which were applied to allow the optimisation process to be completed are as follows:

Green hydrogen production

Due to processing limitations the optimisation of green hydrogen production (solar PV, wind and electrolyser sizing and capacity factors) was separated from the main supply chain optimisation model. A separate hourly renewables optimisation model was run to determine the optimum mixture of renewables for each production location over each timestep (2025, 2030, 2040, 2050) and then these renewables mixtures were utilised as inputs into the main supply chain optimisation model

Offshore wind has not been included – only considering behind-the-meter solar PV and wind generation in the model. Offshore wind was not included in the model due to at the time of model development offshore wind not being present in Australia

Hydropower, Pumped Hydroelectric Energy Storage (PHES) and large-scale battery storage have not been included in the model

Water infrastructure

This assessment did not analyse the specific water infrastructure required by each hydrogen production location. The impact of the water infrastructure cost was instead included as a flat rate cost of water supply.

Power transmission cost as flat rate

The grid has not been modelled as part of the hydrogen supply chain and hence power transmission and the wholesale grid electricity cost has been utilised as a flat rate

Modelling of pipelines

A pipeline cost-capacity curve was implemented in the model to capture the tipping point from utilising trucks for the transportation of hydrogen carriers to when the magnitude of the hydrogen demand was great enough to justify building dedicated hydrogen pipelines. The cost-capacity curve utilised aligns with the cost-capacity profiles as presented in; Energy Transitions Commission (2021), page 38 and BloombergNEF (2019), Hydrogen: The Economics of Transport, Guidehouse (2020), European Hydrogen backbone.

It is noted that the assumption that existing gas pipelines will only transport hydrogen in a blended state to be extracted as pure hydrogen may not represent the future use of existing gas pipelines. The use of existing natural gas pipelines to move blended hydrogen or 100% hydrogen may offer cheaper options for moving hydrogen rather than building new pipelines.

Modelling of storage

The ratio of discharge / charge capacity to overall storage capacity is restricted to ensure the storage technology cannot exceed the maximum number of full annual cycles. However each storage technology can cycle between discharge and charge freely between each timestep, i.e. the number of partial discharge / charge cycles cannot be explicitly restricted.

As the main supply chain optimation model is run at a monhtly time granularity, the daily storage requirements are not explored, however the requirements for inter-seasonal hydrogen storage can still be analysed

Modelling of CO_2 supply chain

Due to processing considerations the CO2 supply chain across Australia required if blue hydrogen were to be implemented has not been considered in the model, instead a standard cost of carbon capture, and cost of carbon transport and storage have been applied as additional 'service' costs based on Steam Methane Reforming and Coal Gasification's respective emissions factors

The 'link and node' model purely optimises for the lowest cost supply chain and is currently not setup to consider optimising emissions avoidance within the supply chain

Modelling of area requirements of infrastructure

Exact area requirements have not been modelled or restricted for infrastructure components within the techno-economic model. Limiting available area could influence model results, in particular in later years when the supply chain is heavily developed and thus finding the land available to support such large infrastructure developments are critical to developing a feasible supply chain. Storage tanks, solar PV and wind developments are of particular susceptibility to have their capacity or viable locations restricted by land availability.

Regional demand locations

Regional demand specified in the scenarios can encompass the demand distributed across a number of locations within a state. For the model to be solvable each demand quantity needs to be assigned to a specific point, in this case a 'regional hub' has been determined for each state to handle the regional demand. This allows the model to capture the overall hydrogen production required to meet the demand volumes in the scenarios, however does not cover the smaller in magnitude distribution infrastructure required within regional sectors of states within Australia

Demand as hydrogen gas

All demand in the model is assumed to be in the format of hydrogen gas. Further detailed assessment of the specific hydrogen carrier to meet each part of the hydrogen demand would be required to assess specific hydrogen carrier conversion requirements. For example; in practice at export locations hydrogen would need to be converted into another carrier suitable for shipping; i.e. liquified H2, ammonia or a LOHC. These conversion requirements and associated port infrastructure requirements have not been included within the techno-economic supply chain model, instead focusing on the lowest cost configuration to deliver hydrogen gas to each demand location

Export demand split evenly among ports

Export demand for all scenarios, except the Northern Export Demand scenario, has been split evenly across all ports featured in the model in an attempt to prevent bias towards certain ports or geographies

Private hydrogen projects in development

Private hydrogen projects in Australia have not been included in the techno-economic model as production locations and the demand associated with these projects as not been factored into the scenarios of hydrogen demand. This was decided to allow for independent analysis of possible supply chain configurations in Australia

Limitations to allowable links

Due to consideration of the distances across Australia not every production node can link to every demand node in the model. For example, to speed up processing time, production nodes in Western Australia are not allowed to link directly to demand nodes in Queensland

Minimum size of transportation links

A minimum size of viable transmission links has been applied in the model. This results in some demand locations with a small quantity of assigned hydrogen demand (particularly relevant for 2025 demand scenarios) needing to utilise grid electricity to operate co-located electrolysers at the demand nodes. This may have a noticeable negative affect on the Levelised Cost of Hydrogen (LCOH) of remote and small hydrogen demand nodes

Limitations on scenarios utilised for 2025 and available technologies

Due to scale of hydrogen demand modelled for 2025, development of large-scale geological storage and carbon capture facilities that utilise geological storage have not been considered due to not being economic or technically feasible at the scales required.

Costs of supply chains presented

As the model focuses on transmission-scale hydrogen supply chains the LCOHs presented should be interpreted as a 'starting point' or 'bare minimum' for the costs required. Further considerations into the daily and seasonal variations of demand will increase the amount of storage required in the model, in addition to fuel security considerations, thus increasing the overall cost of the supply chain in practice. The additional cost of hydrogen distribution and each case of converting hydrogen into appropriate use carriers will also add additional costs to the supply chains which are not currently considered in the presented costs.

It should also be noted that the model is solving for the overall lowest supply chain configuration, as opposed to trying to optimise the supply chain cost for each individual demand node. Theoretically the LCOH of one particular component of the supply chain may be less than optimal if it provides infrastructure sharing benefits to the wider supply chain.

Appendix C

Frontier Economics Hydrogen Demand Scenarios

The Hydrogen Demand Scenarios Modelling for the NHIA project has been undertaken by Frontier Economics. It should be noted that stakeholder engagement undertaken including with the Steel Industry represented by BOSMA resulted in an adjustment to the domestic demand for green steel production as outlined in Section 3.1.3 of the report

Appendix D

Stakeholder engagement list

Stakeholder list - Government
Australian Capital Territory
Chief Minister, Treasury and Economic Development Directorate
Environment, Planning and Sustainable Development Directorate
Utility Technical Regulation (UTR)
New South Wales
Australian Government - Department of Climate Change, Energy, the Environment and Water
Department of Planning Industry and Environment
Department of Regional NSW
Transport for NSW, Future Mobility
Northern Territory
Department of Environment and Natural Resources
Department of Infrastructure, Planning and Logistics
Department of Industry, Tourism and Trade
Department of the Chief Minister and Cabinet
Queensland
Department of Energy and Public Works
Department of the Premier and Cabinet
Queensland Treasury
South Australia
Department for Energy and Mining
Department for Infrastructure and Transport
Infrastructure SA
Renewal SA
Tasmania
Australian Government - Department of Climate Change, Energy, the Environment and Water
Department of State Growth
Victoria
Department of Environment, Land, Water and Planning
Department of Jobs, Precincts and Regions

Western Australia

Australian Government - Department of Climate Change, Energy, the Environment and Water
Department of Jobs, Tourism, Science and Innovation
Department of Planning. Lands and Heritage
Department of Training and Workforce Development
Department of Transport
Department of Water and Environmental Regulation
Energy Policy WA
Infrastructure WA

Stakeholder engagement – Industry
Gas
APA Group
Australian Gas Association
Australian Gas Infrastructure Group
Australian Pipelines and Gas Association
Business Development WA
Energy Networks Australia
Jemena
Origin Energy
Industry, Research and Advocacy Workshop
Australian Hydrogen Council
Australian Industry Group
Beyond Zero Emissions
Clean Energy Council
ClimateWorks Australia
Electric Vehicle Council
The Next Economy
NERA Clusters
Australian Government - Department of Climate Change, Energy, the Environment and Water
Clayton Hydrogen Technology Cluster (Clayton H2)
CQUniversity
EfficientSee
Gladstone Industry Leadership Group
Gladstone Regional Council
Greater Geelong Hydrogen Cluster
H2Q
Mallee Regional Innovation Centre
NERA

NewH2 Hunter Hydrogen Technology Cluster
Smart Energy Council
Ports
Australian Government - Department of Climate Change, Energy, the Environment and Water
Clayton Hydrogen Technology Cluster (Clayton H2)
CQUniversity
EfficientSee
Gladstone Industry Leadership Group
Gladstone Regional Council
Greater Geelong Hydrogen Cluster
H2Q
Mallee Regional Innovation Centre
NERA
NewH2 Hunter Hydrogen Technology Cluster
Smart Energy Council
Research
CSIRO
Deakin University, Deakin Energy Group
Future Fuels CRC
Monash University, Monash Sustainable Development Institute
UNSW Energy Institute
Victoria Hydrogen Hub
Resource & Industrial
Ampol Australia
BHP
BlueScope
Bureau Of Steel Manufacturers Of Australia Limited
ENGIE
Fortescue Future Industries
GFG Alliance
Incitec Pivot
J-Power
Kawasaki Heavy Industries
Marubeni Australia
Rio Tinto
Shell Australia
Sumitomo
Viva Energy
Woodside
Transport
Aurizon

Australian Logistics Council
Federal Chamber Of Automotive Industries
Foton Mobility
Hyundai Motor Company Australia
Hyzon Motors Australia
iMOVE Australia
National Heavy Vehicle Regulator
SeaLink Travel Group
Sims Resource Renewal
Tasmanian Logistics Committee
Toyota Australia
Transit Systems Australia
Truck Industry Council
TrueGreen Group

Appendix E

Full techno-economic model results

This section presents the infrastructure maps and LCOH diagrams for all scenarios and timeframes analysed during the study. It is included in a separate document 'National Hydrogen Infrastructure Assessment, Draft report – Model results'.