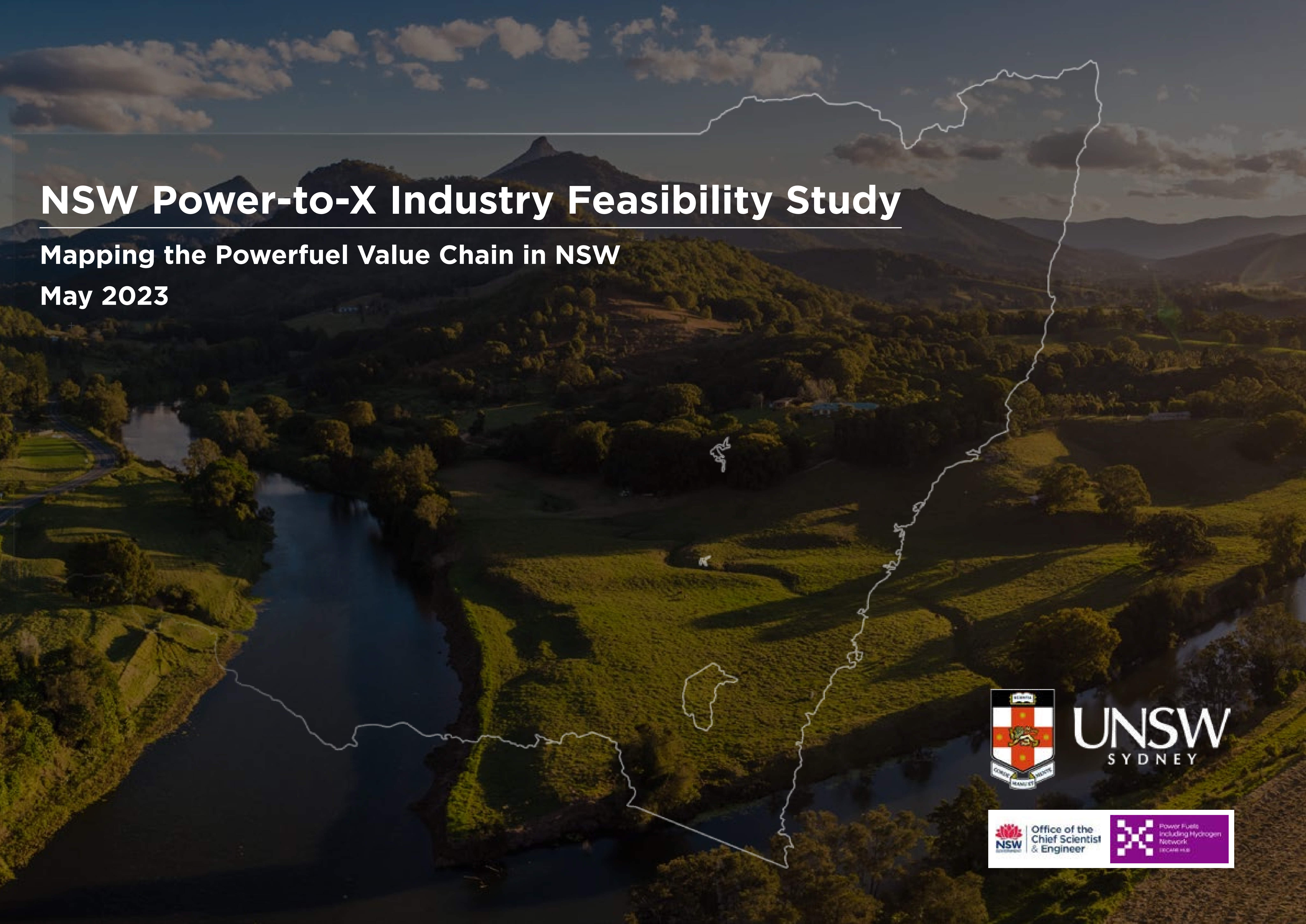
NSW Power-to-X Industry Feasibility Study

Mapping the Powerfuel Value Chain in NSW

May 2023



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Power Fuels including Hydrogen Network

This work was carried out by the University of New South Wales (UNSW), Sydney with the support from the NSW Decarbonisation Innovation Hub, the Powerfuels Including Hydrogen Network and the Office of the NSW Chief Scientist & Engineer.

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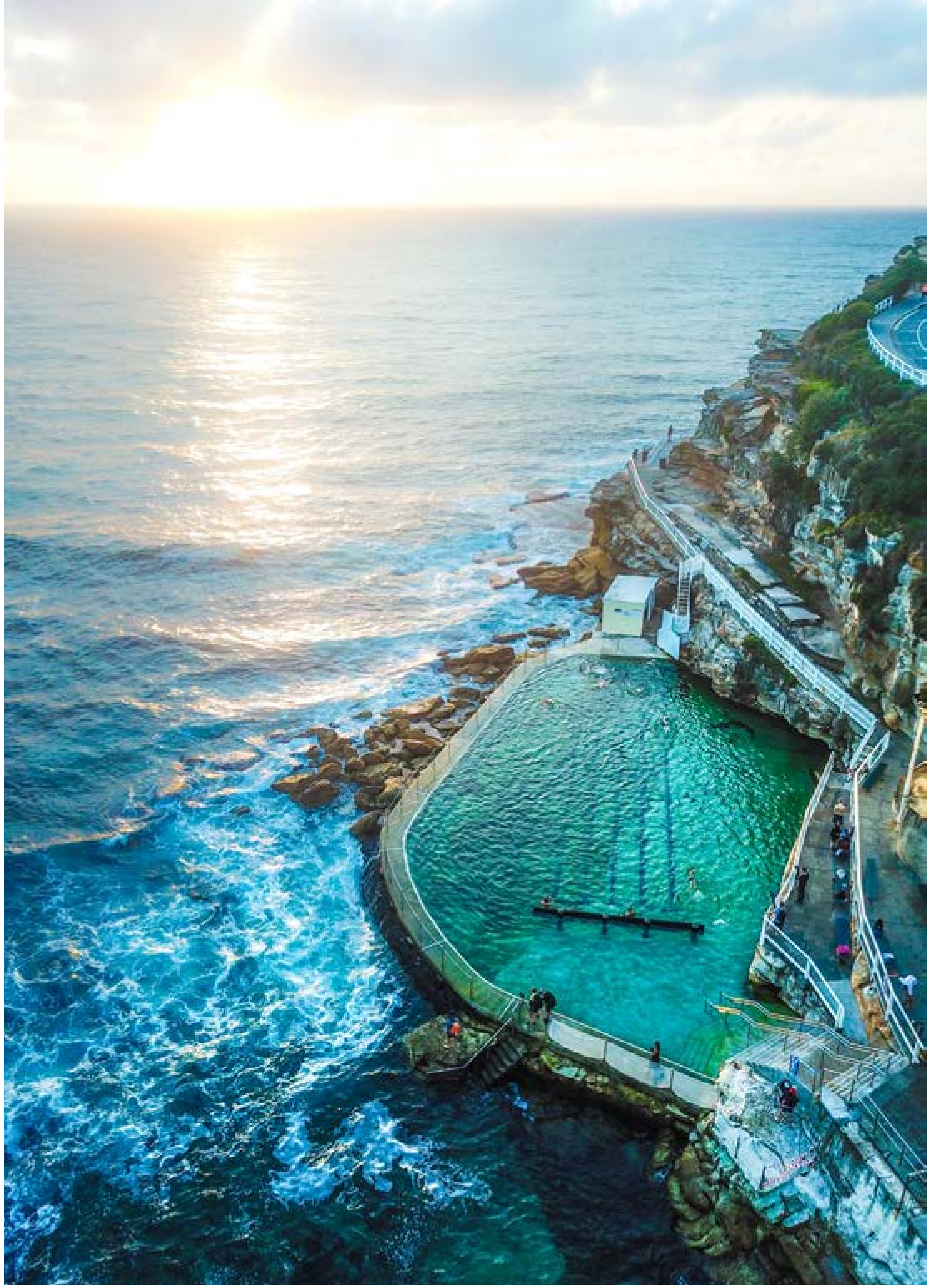
Note that this report provides indicative opportunities for establishing a Power-to-X economy in NSW and we acknowledge that detailed sectoral opportunity identification is required.



The Economics of NSW Power-to-X Value Chain

Considerable opportunity is present in New South Wales for the development of a Power-to-X economy. The state enjoys considerable endowment in renewable resources and feedstocks, a skilled workforce and strong Government commitments to decarbonise its economy in the short run. Power-to-X (P2X) is now recognised by industry, academia and Government to be a fluid solution to decarbonising hard-to-abate industries in NSW.

In October 2021, the Office of NSW Chief Scientist & Engineer (OCSE) released a NSW P2X Industry Pre-Feasibility Study investigating the state's opportunities and capabilities in establishing a domestic P2X economy. The Pre-Feasibility Study assessed the technological pathways of different P2X industries, identified prospective locations for large-scale production and proposed a roadmap for the future P2X economy in NSW. This report is a follow-up to the first study and is carried out by UNSW Sydney with support from the newly established NSW Powerfuels Including Hydrogen Network.

Despite opportunity identification and support from NSW State Government, most hydrogen and powerfuel activities within NSW are limited to specific regions (Hunter and Illawarra) with a few exceptions. This study extends beyond these locations to provide in-depth analysis of the potential for P2X hubs in each of the nine regions of NSW, considering the available resources and infrastructure. Validated through stakeholder engagement, the study identifies opportunities for the production of green chemicals/e-fuels (ammonia, methane, methanol and sustainable aviation fuel – SAF) for industrial use and export, and decarbonisation of fossil fuel sector using green hydrogen (mobility, industrial heating and blending in natural gas networks). These opportunities are summarised in **Figure A**.

Building on these opportunities, the study then maps out the current and future costs of establishing these hubs based on technology cost expectations and market scaling. For instance, the cost of delivered hydrogen in gaseous tube trailers at a distance of 100km is projected to be between \$8/kg - \$17/kg at present and is expected to be \$4/kg - \$8/kg by 2030 and further decrease by 2050. For ammonia, the cost of production is estimated to be between \$1/kg - \$1.4/kg by 2030 and expected to decrease to \$0.85/kg by 2050. The cost of P2X-based methanol can range between \$1.1/kg - \$3.3/kg by 2030, declining to \$0.8/kg - \$2.3/kg by 2050. Note while the current price of these powerfuels is higher than their current fossil fuel equivalent, the ongoing R&D in P2X technologies, falling prices of electrolysers and favourable renewable energy pricing, along with additional incentives and premiums falling into place as highlighted in our analysis, we expect these powerfuels to become viable for domestic and export opportunities. It should be noted that these price indications are merely estimates and that readers are recommended to input their assumptions into the open-source costing tool that will be released as a support to this study. The study further expands on potential export opportunity for these powerfuels from NSW, modelling the value chain costs for exports to Japan, South Korea, Singapore, Denmark and Germany.

While it is clear that there are considerable opportunities for developing a P2X economy in the state, there are of course a wide range of barriers which were identified during stakeholder consultations that would impede P2X hub development. Concerted effort by industry, government and academia is essential to address these barriers and position the state at the forefront of the hydrogen economy in Australia. These barriers and positions are highlighted in the accompanying NSW P2X State of Play report.

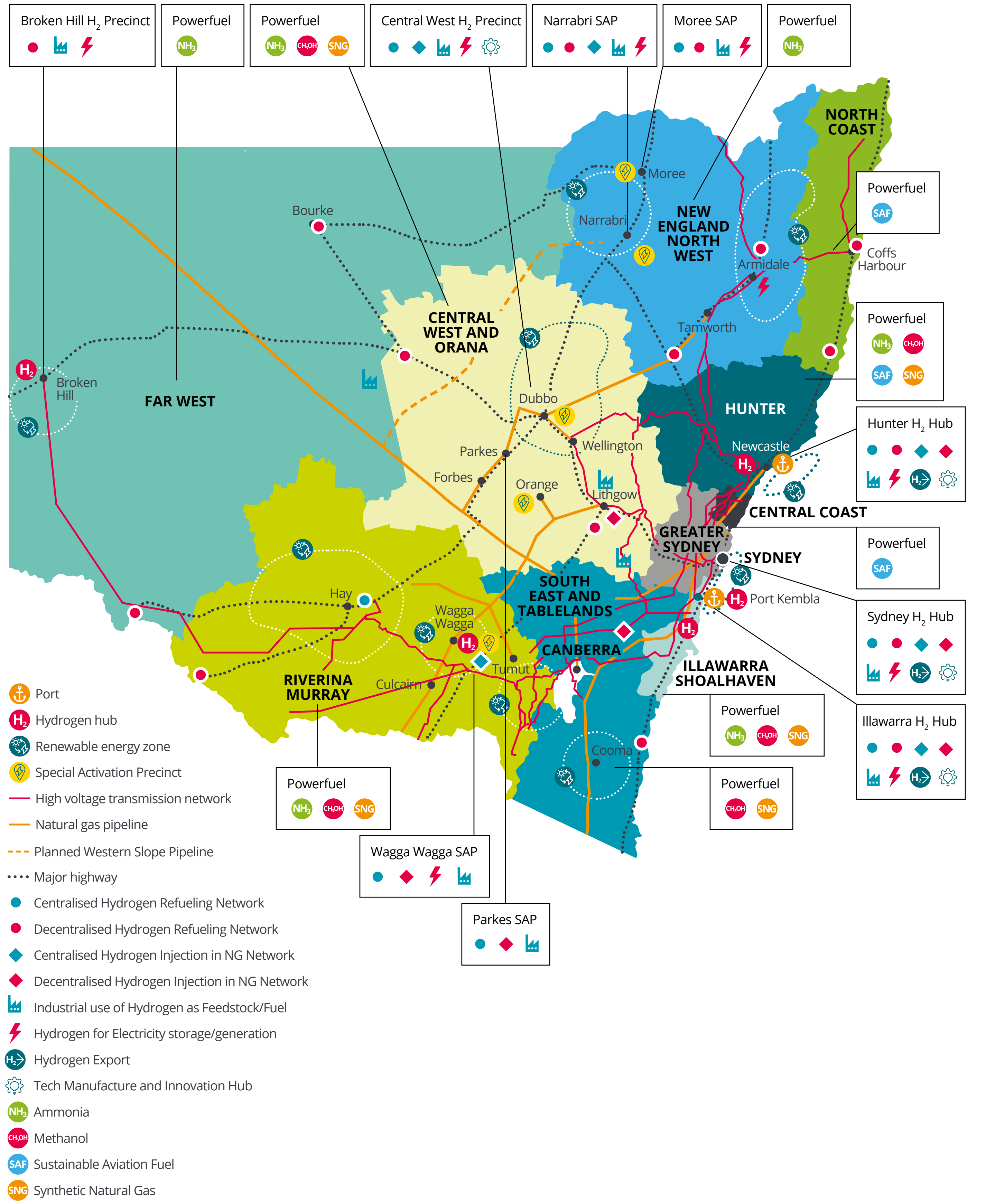


Figure A. Summary figure highlighting the potential Power-to-X (P2X) opportunities identified for NSW as part of this study.

In the context of the NSW Government's initiatives to drive economic growth and regional employment while reducing emissions, a P2X economy will be vital for the future prosperity of the state and will ensure that the manufacturing heartland of NSW thrives in a decarbonised future.

Contents of this Report

This report expands on the opportunities highlighted in the pre-feasibility report and the recent roadmapping activities carried out in establishing the NSW Powerfuels Including Hydrogen Network.

This report is an in-depth analysis of the potential for P2X hubs in each of the regions of NSW, considering the available resources and infrastructure. It then maps out the current and future costs of establishing these hubs and explores the opportunities through four major sections:

- **Section A (Chapter 2 and 3):** Outlines the framework under which P2X opportunities have been assessed and uses these to establish which of the NSW regions would be suitable locations and might provide suitable applications for P2X projects or hubs. The assessment framework key criteria include: (i) economic and industrial outlook, (ii) feedstock availability, (iii) existing infrastructure and (iv) approvals and risk. In **Chapter 3**, the findings from the assessment are used to propose the key locations where potential P2X applications can be developed in each of these regions.
- **Section B (Chapter 4 to 6):** Extends beyond opportunity identification and shifts towards demand modelling and value chain costing (Generation, Transport and Utilisation). **Chapter 4** introduces H_2 as a key vector in P2X pathways and provides a detailed cost outlook of its generation and supply (current and future). This is accompanied by an analysis of the end use of hydrogen for refuelling fuel cell vehicles (**Chapter 5**) and blending in natural gas pipelines (**Chapter 6**).
- **Section C (Chapter 7 to 10):** Looks beyond hydrogen by analysing the end use case of its conversion to hydrogen derivatives and other Powerfuel/P2X products such as ammonia (**Chapter 7**), methanol (**Chapter 8**), synthetic natural gas (**Chapter 9**) and sustainable aviation fuel (**Chapter 10**). The report looks at whether these derivatives can help the state achieve its net zero targets by helping to decarbonise the industry, energy and transport sectors in NSW, as well as reliability and energy security.
- **Section D (Chapter 11):** Explores beyond the nation's borders and provides an analysis for the export of hydrogen and hydrogen derivatives from NSW to key international markets to assess the state's ambitions as a global energy superpower.

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Chapter 1. The Power-to-X Landscape

The New South Wales (NSW) Government is committed to reducing the state's emission footprint to up to 70% by 2035 and achieving net-zero emissions by 2050. While electrification and the uptake of renewable energy have played — and will continue to play — a major role in attaining these targets, it is apparent that indirect electrification, via integrating powerfuels including hydrogen will be critical to decarbonising hard-to-abate industries.

1.1. What is Power-to-X?

Powerfuels or Power-to-X (P2X) refers to synthetic non-biofuels — in gas or liquid state — that draw energy from renewable electricity. These include:

- Hydrogen
- Ammonia
- Synthetic fuels (e.g. methane — synthetic natural gas (SNG) and methanol), and
- Sustainable Aviation Fuels (SAF) (e.g. synthetic paraffins and kerosene via the Fischer-Tropsch technology).

What makes these powerfuels promising is the sheer breadth of the value chain, as shown in **Figure 1**. At the forefront of this powerfuel value chain is green hydrogen (via renewable-driven electrolysis) which can be used as a clean fuel and industrial feedstock for decarbonising ammonia generation or manufacturing of steel and aluminium, among other applications. Additionally, renewable hydrogen can be integrated with powerfuel pathways involving carbon capture and utilisation (CCU) which could play an important role in the near-term transition of applications currently reliant on fossil carbon for feedstocks and fuels (methanol, SNG and SAF). However, it is important to flag the need for potential CO_2 sources to be compatible with net zero objectives, i.e. industrial and power generation flue gas. This will be discussed in more detail in later sections.

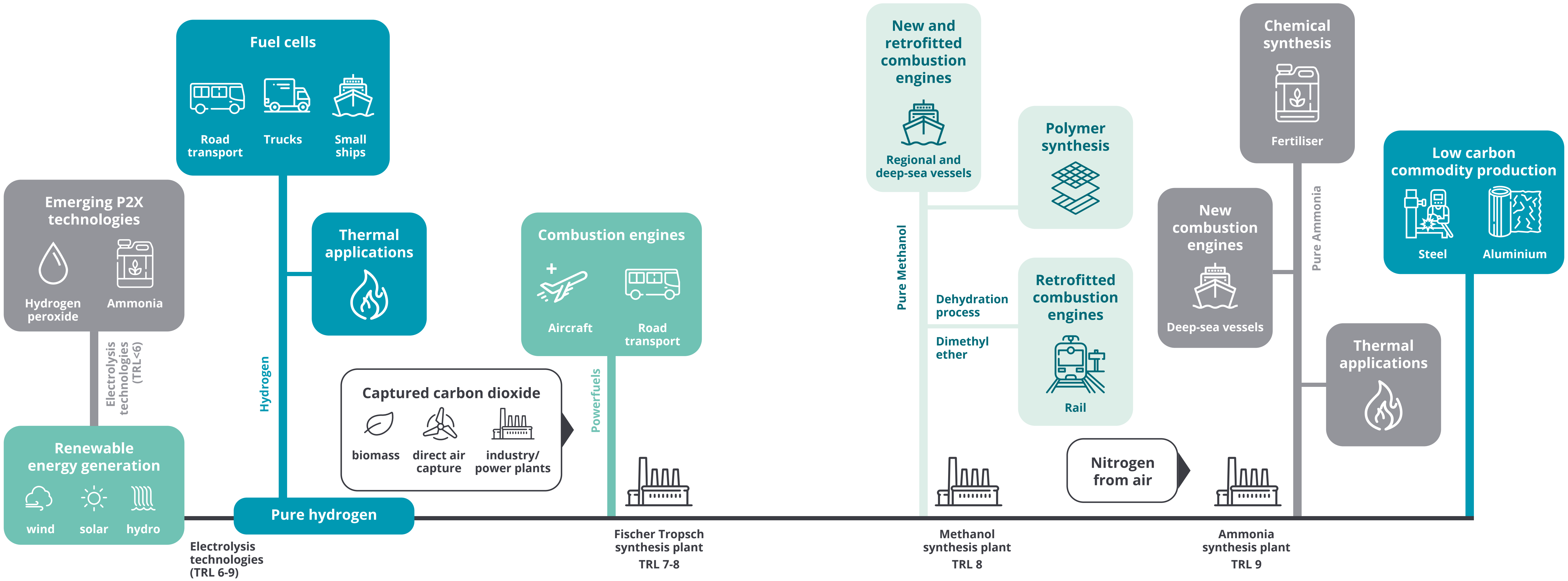


Figure 1. A Power-to-X Value Chain for NSW.

For our analysis in this report, for simplification, we break down the P2X value chain into two separate, but interlinked value chains based on end uses (**Figure 2**), as stated below:

- **Hydrogen Value Chain:** Hydrogen is the most abundant element in the universe and can react easily with other elements such as oxygen, carbon and nitrogen to form complex molecular structures. In this sense, hydrogen acts as a block of *'Lego'*. This analogy can also be applied to hydrogen's role within renewable P2X, given it is a common feedstock for the generation of many of the powerfuels. Its potential uses in NSW can be — but are not limited to use as a chemical feedstock, such as in steelmaking as a fuel for decarbonising heavy industry, e.g. aluminium processing; for renewable energy storage; for blending into the natural gas network (domestic and commercial heating or power generation); or as a transportation fuel for fuel cell vehicles (FCVs)
- **Beyond Hydrogen Value Chain:** The *'Beyond Hydrogen Value Chain'* encompasses the use of H_2 as a *'Primary Lego'* building block that can connect with *'Secondary Lego'* building blocks, such as nitrogen — to generate ammonia — and carbon dioxide (emissions from point sources/biomass resource) to make methanol, synthetic natural gas and sustainable aviation fuel (SAF). Note that there are emerging technologies that can convert the feedstocks directly into powerfuels but these are low TRL and hence not considered in this analysis.

The integrated chains include hydrogen generation from renewable-driven electrolysis, intermediate hydrogen storage and transportation prior to direct use/export (represented by the darker shade boxes in **Figure 2**), or conversion into powerfuels, and their subsequent storage and transportation prior to eventual use locally or for export (represented by the lighter shade boxes in **Figure 2**). These distinctions are used throughout the following chapters while assessing P2X opportunities.

Note: There are several other P2X products (in addition to those highlighted here) that can also be envisioned, however, based on stakeholder feedback for this analysis we focus on the products highlighted in **Figure 2**.

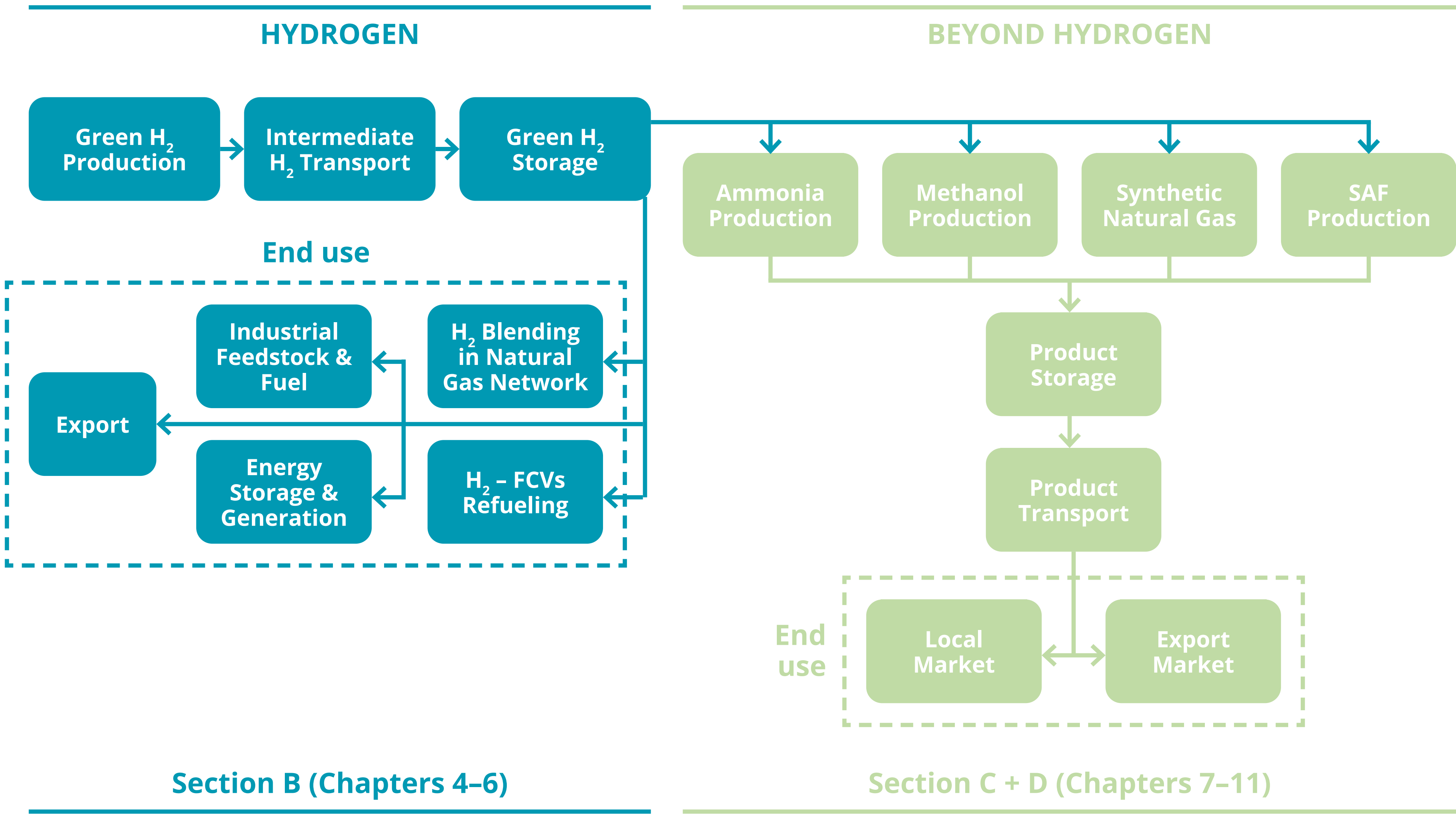


Figure 2. The Hydrogen and Beyond Hydrogen Value Chains. For simplification, our analysis splits the extensive P2X value chains (seen in **Figure 1**) into separate but interlinked sub chains.

1.2. NSW's Recognition for P2X

The NSW Government recognises the role these powerfuels can play in the state's transition to net zero. As such, the state has set out ambitious targets for powerfuels, as presented in **Figure 3**. The economic and environmental opportunities P2X can bring to NSW have been highlighted in the **NSW Hydrogen Strategy**[1]; **NSW 20-Year R&D Roadmap**[2], **NSW Decarbonisation Innovation Study 2020**[3], **NSW: A Clean Energy Superpower Industry Opportunities Report**[4] for the NSW Electricity Infrastructure Roadmap; and also recently in the **NSW P2X Industry Pre-Feasibility Study**[5] (carried out by OCSE).

Specifically, the NSW P2X Industrial Pre-Feasibility Study[5] establishes a strong business case for developing a powerfuel economy in a state that has all the successful ingredients required to establish competitive advantage. The study conducted a systematic review of different P2X technologies including:

- their development status and cost
- the key drivers towards achieving price-parity with their fossil-fuel counterparts
- their potential applications
- potential end-users within the NSW context, and
- local market size and global demand for P2X products.

The analysis has highlighted that Power-to-Hydrogen, Power-to-Ammonia, Power-to-Methane, Power-to-Methanol and Power-to-Syngas for Synthetic Fuels are potentially key pathways for P2X development in NSW. These pathways have been successfully demonstrated worldwide and are in the early stages of mass adoption. The deployment of these powerfuels can enable greater penetration of renewables across the energy and industrial sector, while improving energy availability and security. Additionally, it can create economic opportunities, deliver benefits to the environment and increase employment.

In addition to the deployment of P2X facilities, the state can also play a significant role in P2X technology development, with several startups and research initiatives already underway in NSW. Furthermore, the state hosts significant deposits of critical mineral resources such as gold, copper, platinum group metals and scandium, which are essential for the development and manufacture of P2X technologies.

These opportunities can be leveraged by building on the NSW Government's plans to establish Australia's first Critical Minerals Hub in the Central West Region, with the aim of making the state a global leader and supplier of critical minerals and high-tech materials. The hub will provide mining and recycling facilities for critical materials, supporting the development of high-tech equipment.

Additionally, the state government is supporting the development of recycling facilities for solar/wind power and batteries, which could further strengthen the local supply of critical minerals. As P2X facilities become more prominent in the future, this could be extended to include electrolysers and fuel cells. We will discuss these opportunities in more detail in **Chapter 3**.

1.3. Recent P2X developments in NSW

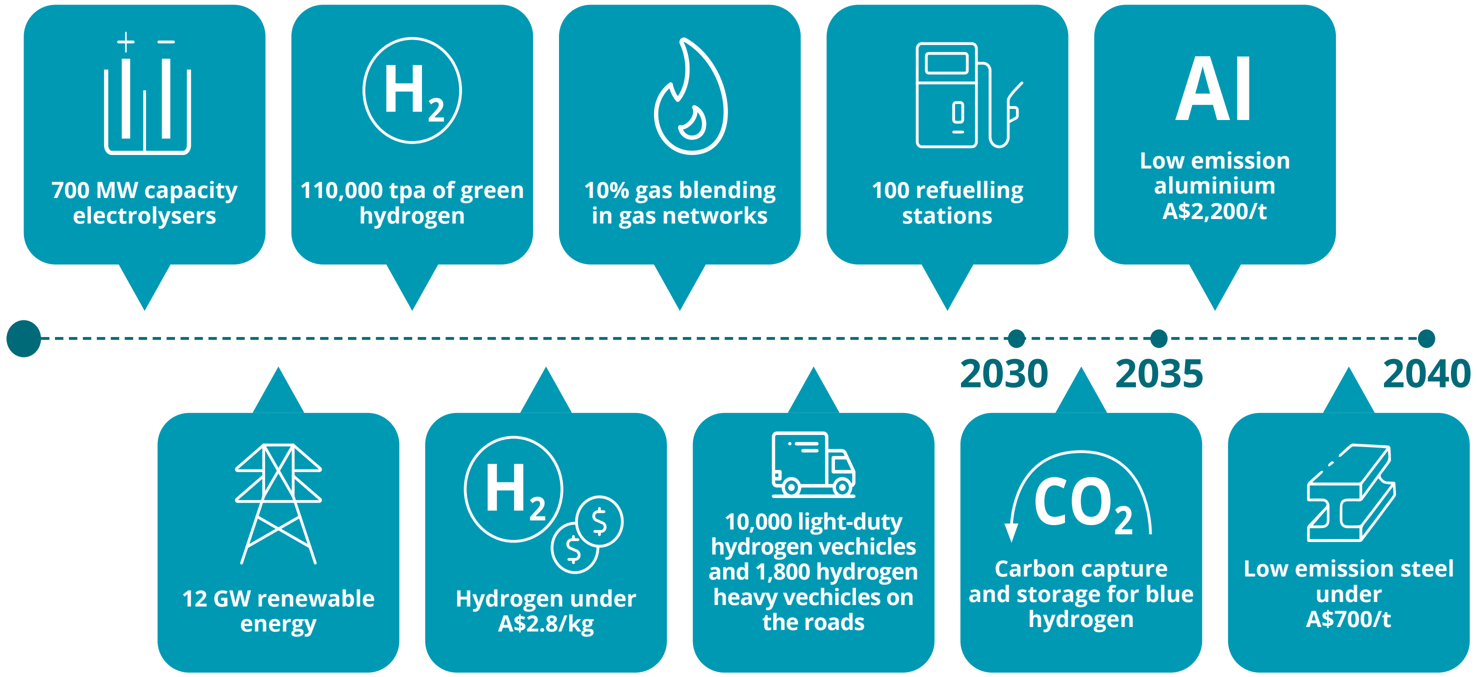
To enable the growth of this nascent powerfuel sector, the state government has commenced several initiatives including:

- establishment of the NSW Decarbonisation Innovation Hub, in which Powerfuels including hydrogen is one of three focus areas for coordination of research, government and industrial efforts
- instigated a regulatory and policy review
- invested in development of clean manufacturing precincts in the Hunter and Illawarra regions, and
- commenced research into commercialisation of powerfuels through the hydrogen-hub initiative.

These initiatives are in addition to the support provided under the NSW Net Zero Plan[8] and the Electricity Industry Roadmap[9] which includes development of renewable energy zones (REZs), special activation precincts (SAPs) and existing research and industry networks. The state and federal governments' action and plans to support the growth of a powerfuel economy in the state are summarised in **Table 1**.

In this manner, as a result of the initiatives and actions taken by the state and federal government to bolster key sectors across the P2X value chain, NSW and Australia have the right mix of enabling policies to lay the foundations for continued development, deployment and scale up of the commercial P2X industry. In the next chapters of the report, we build on the ongoing initiatives and actions, to identify and evaluate key market opportunities for P2X in the state.

1 - NSW Hydrogen Strategy. NSW Government. 2022. Link
2 - NSW 20-Year R&D Roadmap. NSW Government OSCE. 2022. Link
3 - NSW Decarbonisation Innovation Study. 2020. NSW Chief Scientist and Engineer Office. NSW Government. Link
4 - NSW: A Clean Energy Superpower. 2020. KPMG & NSW Chief Scientist & Engineer Office. NSW Government.
5 - NSW P2X Prefeasibility Study. UNSW. 2021 Link
6 - Critical Minerals and High-Tech Metals Strategy. NSW Government. Link
7 - Circular economy boost for solar panels. NSW EPA. 2022. Link
8 - NSW Net Zero Plan. NSW Government Climate and Energy Action. Link
9 - Electricity Infrastructure Roadmap. NSW Government Climate and Energy Action. Link



Investment Programs and Policies to Support NSW Hydrogen Industry

NSW Net Zero Industry and Innovation Program – A$1 billion

- A$360 million support for emission reduction of high emitting industries.
- A$470 million to enable new low carbon industry foundations (infrustructure, supply chain, clean manufacturing capabilities, hydrogen hubs and Hume hydrogen highway).
- A$190 million to support clean innovation technolgy (R&D and commercialisation).

NSW Hydrogen Strategy – A$3 billion

- Incentives to support reduction cost of green hydrogen by A$5.8/kg (including exemptions from government charges, electricity network charges and creation of Renewable Fuel Scheme to incentivise green production).

Hydrogen Refuelling Network

- A$10 million committed to support Hume highway refuelling network (additional A$10million in funding to be provided by Victorian Government).
- A$10 million allocated for hydrogen powered bus trial in Central Coast region as part of NSW 2022 - 2023 Budget.

NSW Renewable Gas Transistion

- Future of Gas statement released to support hydrogen- ready gas network and infrustructure.
- Energy Legislation Amendment Bill 2021 enables blending of hydrogen in natural gas networks.
- A$83 million in funding to support development of Tallawarra B dual capability hydrogen/gas power plant.

NSW Tech Development Support

- A$5 million in grant provided to LAVO Technology to develop their hydrogen storage tech manufacturing facility in Hunter region, through Hunter Regional Job Creation Fund.
- A$6.3 million made available in grants to support clean technology R&D development through NSW Environment Trust (A$1.5 million provided to Hysata to support development of their proprietary electrolysis technology).

Federal Support

- A$82 million provided to support Port of Newcastle Hydrogen Hub and Origin's Hunter Valley H_2 Hub via Regional Hydrogen Hubs Program (Federal 2022 - 2023 Budget).
- Additional funding of A$100 million allocated to support the Newcastle Port and Hunter hubs (Federal 2022 - 2023 Budget).

Figure 3. A Snapshot of Targets and Investments to Support Hydrogen Project Development in NSW.

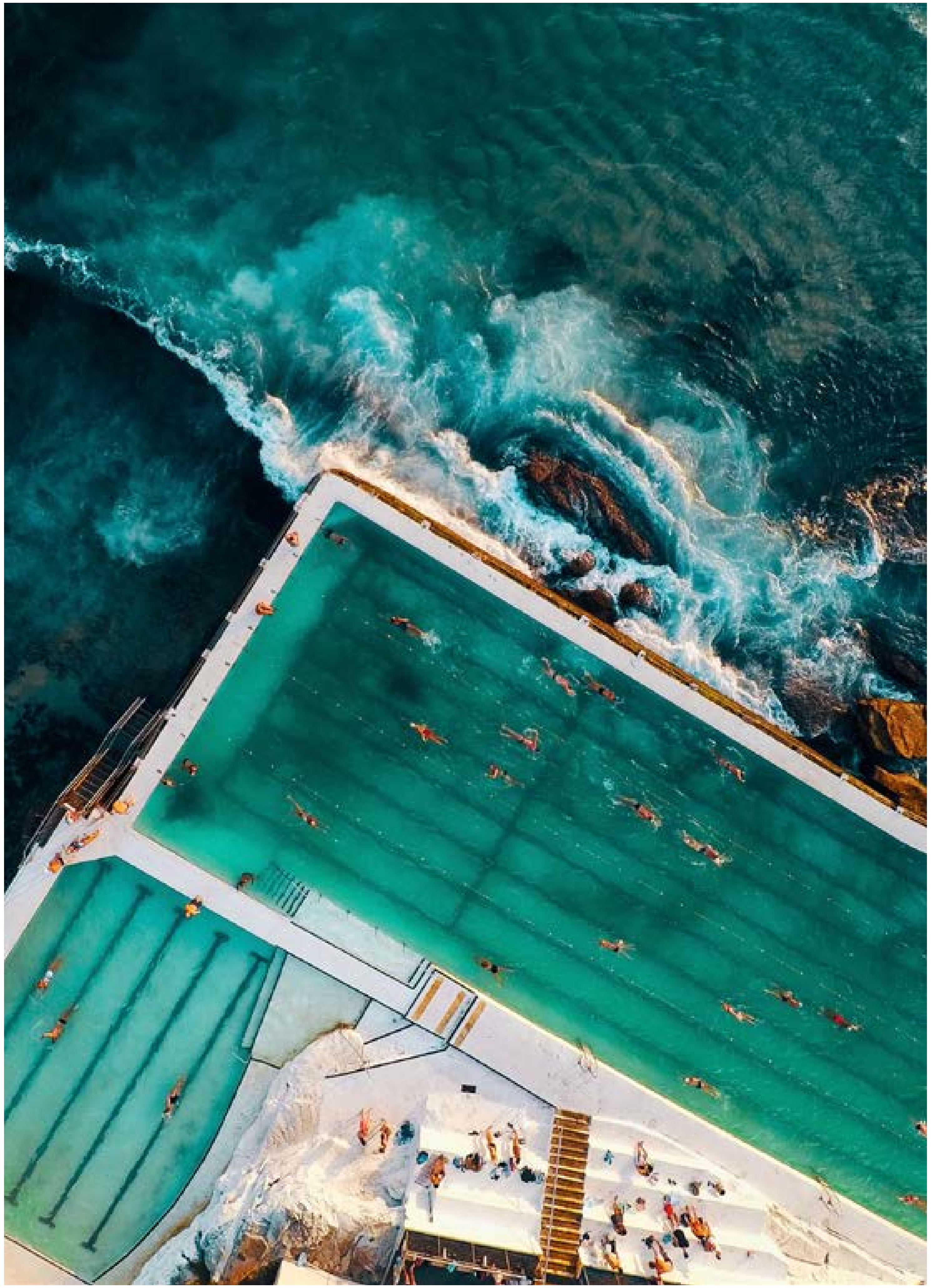


Table 1. NSW and Federal Governments actions and plans for development of P2X Economy in NSW.

SECTOR	FEDERAL AND NSW GOVERNMENTS ACTIONS/PLANS
Hydrogen production/utilisation	**NSW** The NSW Government-backed **Net Zero Industry and Innovation Program** aims to provide over A$1 billion to support decarbonisation of NSW. The investment plan includes A$360 million to support decarbonisation of high emitters and hardest to abate industries (A$305 million) and to develop low carbon infrastructure/clean manufacturing precincts (A$55 million). These would further enable hydrogen/P2X opportunities. • A sub-focus of the **Net Zero Industry and Innovation Program** is **Clean Technology Innovation**, which enabled a A$15 million investment to support the development of the **NSW Decarbonisation Hub** (which includes the NSW Powerfuels Including Hydrogen Network), A$40 million in grants to support clean technology R&D (part of the NSW Environmental Trust), A$45 million in grants to support clean technology infrastructure, A$40 million in grant initiatives to support commercialisation and pilots, A$10 million grants for clean technology ecosystems and an additional A$40 million (A$20 million by private sector) to support the climate technology venture capital fund. • Establishing green hydrogen hubs through an A$150 million initiative (for Illawarra and Hunter Region) and Hume Hydrogen Initiative (A$20 million) through the **New Low Carbon Industry Foundation Fund Extension**. The New low Carbon Industry Foundation Fund was expanded in 2022 by an additional A$300 million in funding. • Extension of the **Energy Security Safeguard** to deliver the **Renewable Fuel Scheme** that will become active in 2024 to enable renewable green hydrogen generation (up to 67 KTPA of green hydrogen by 2030). In addition, the **Energy Saving Scheme** and **Peak Demand Reduction Scheme** will further optimise the electricity supply and costs to reduce the electricity pricing in NSW, which could further support viable green hydrogen production. • **Electricity Infrastructure Roadmap/Electricity Infrastructure Investment Act 2020** will enable deployment of new renewable energy capacity though development of new Renewable Energy Zones (REZs) and transmission networks to provide bulk and low-cost renewable energy for decarbonisation of the state. • Altogether the **NSW Hydrogen Strategy** enables A$3 billion in incentives to support development of the hydrogen economy in NSW and reduce the cost of production to A$5.8/kg via incentives through the **Climate Change Fund**, **Energy Security Safeguard schemes**, **Electricity Infrastructure Roadmap** exemptions and Network cost concessions (up to 90% concession for electricity and distribution charges for green hydrogen production activities by 2030). • Exempting green hydrogen production from certification fees under the **GreenPower** program. • Funding development of Special Activation Precincts (SAPs) using the A$4.2 billion **Snowy Hydro Legacy Fund**, which will enable deployment of new infrastructure to increase community and industry water resilience (such as drought protection) along with improving digital connectivity, public transportation, freight linkages and industry investments through the SAPs in regional areas. These can then be leveraged for P2X opportunities. • Supporting **Australian Hydrogen Council (AHC)** programs related to skills and training, standards, technical regulatory policy development and strengthening powerfuel's social licence. **Federal** • As part of the **Federal Budget 2022 - 2023**, the Federal Government announced planned investments of A$526 million, of which A$41 million each were provided to Origin Energy and the Port of Newcastle for their respective Hunter Valley H_2 hub and Port of Newcastle Hydrogen Hub developments and A$5 million to support the Tallawarra B hydrogen-ready gas turbine. An additional A$100 million has been provisioned to support pre-Final Investment Decision activities and early works to make the Port of Newcastle 'hydrogen ready'. • Leading the development of the **Hydrogen Guarantee of Origin Scheme in Australia** to further incentivise green hydrogen production.
Manufacturing Industries/ industrial feedstocks	**NSW** • Supporting and incentivising projects that use green hydrogen at an industrial scale through the 'hydrogen hub' initiatives, such as green steel and/or green ammonia. • A$305 million in funding to help the highest emitting industries shift to net zero. This is provided under the **High Emitting Industries** funding as part of the **Net Zero Industry and Innovation Program** to reduce emissions. It includes introducing green hydrogen and helping the manufacturing sector to overcome technical and commercial barriers by supporting plant and equipment upgrades and adopting green pathways in NSW using carbon capture and storage technologies. • NSW Government has established the A$450 million **Emissions Intensity Reduction Program** as part of the Net Zero Plan Stage 1: 2020 - 2030 that will provide incentives for industry and business to shift to low emission alternatives. These could potentially include Hydrogen and P2X opportunities. **Federal** • The Federal Government has also committed to provide an additional A$450 million to the **NSW Climate Solutions Fund**.

SECTOR	FEDERAL AND NSW GOVERNMENTS ACTIONS/PLANS (cont.)
Gas Networks	**NSW** • Including hydrogen in the definition of a gas for blending with natural gas through *Gas Supply (Safety and Network Management) Amendment (Hydrogen Gas) Regulation 2020 under the Gas Supply Act 1996*. • Supporting gas blending projects (e.g. Jemena Gas Network) through the NSW hydrogen hub initiative. • Supporting and funding R&D organisations and industries investigating safety, standards, the injection of hydrogen and the economic benefits of gas blending. Also supporting GreenPower to include hydrogen in its Renewable Gas Certification pilot and other certification trials. **Federal** • Reviewing the regulatory framework and working with the National Hydrogen Project Team and gas providers to enable the use of hydrogen (10%) in the gas networks. Also, developing a legislative framework to incorporate natural gas equivalents (NGEs) in the *National Gas Rules and National Energy Retail Rules*.
Transport/mobility	**NSW** • Planning to introduce fuel-cell vehicles (20% hydrogen vehicles by 2030 in the NSW government's heavy vehicles fleet) as per **Future Transport 2056** (NSW Government) and **Future Transport Technology Roadmap 2021 - 2024** (NSW Government). This will involve feasibility studies, trials and models for the large-scale deployment of hydrogen buses, trucks and trains across NSW. • Collaborating with stakeholders to identify standards in the state that will accelerate the acceptance of hydrogen vehicles. • Funding and support for hydrogen refuelling stations for heavy vehicles through the A$175 million **New Low Carbon Industry Foundations** (under the **Net-Zero Industry and Innovation Program**) and A$70 million through the hydrogen hub initiative. This will support the roll-out of hydrogen refuelling networks in NSW. • Planning to update the NSW legislation such as *Dangerous Goods Act (Road and Rail) Act 2008*, *Heavy Vehicle (Adoption of National Law) Act 2013* and *Transport Administration Act 1988* to encourage the distribution and safe use of hydrogen in transport. • Recently NSW has partnered with Queensland and Victoria to coordinate and develop hydrogen-based refuelling networks and corridors across the states, starting with initial development on the Hume Highway, the Princes Highway and the Newell Highway by 2026. The project is being backed by A$10 million each in funding provided by Victorian and NSW Governments to build at least four renewable hydrogen refuelling stations between Sydney and Melbourne and provide grants for the country's first long-haul hydrogen fuel cell electric freight trucks.
Hydrogen and Powerfuels for Export	**Federal** • Supporting projects — especially Australian-based supply chain projects that secure overseas investment on clean hydrogen-based derivatives, such as clean ammonia, through the A$150 million **Australian Clean Energy Trade Program** funded by the Australian Government. • Facilitating the export of hydrogen by participating in forums such as the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). • Supporting the development of the Guarantee of Origin scheme through A$9.7 million funding from the Australian Government.

Section A: Assessing P2X Opportunities in NSW

Chapter 2. Opportunity Assessment Framework

Based on the review completed in Chapter 1, it is clear there is a growing support for developing a P2X sector in NSW. In this chapter, we outline a robust framework that was used to screen and identify the potential regional locations for P2X in NSW. This framework was broadly applied to all regions in NSW to assess opportunities based on their individual characteristics and features.

2.1. Assessment Framework

A site selection framework was used to evaluate each NSW region's potential to host P2X projects. A critical part of the assessment was to identify the available resources (locally or close to the region) and how they could be leveraged to develop potential P2X opportunities to either match an existing or projected local energy/chemical demand or establish an export market. The key criteria are categorised below, and framework is visualised in **Figure 4**. The assessment provided in this report is a preliminary analysis and more detailed study is required for each location.

The framework is based on the following interlinked criteria which include:

- Market Demand: A critical first step to support potential project development is availability of existing or potential offtake for powerfuels as well as local economic/technical resources to support P2X project development. To assess this criterion, we consider the industrial/commercial activities (including manufacturing & secondary industries), regional energy use, regional outlook of economy, competent technical skills, and upcoming regional policies/targets on economic/energy growth to identify market sectors that can be served via P2X products.
- Feedstock Availability: For this criterion, we assess the local renewable electricity generation potential (solar, wind and hydro potential) required to drive the electrolysis process, water availability to support hydrogen generation and secondary feedstocks i.e. nitrogen for ammonia generation and CO_2 to support methanol, SAF and SNG.
- Infrastructure Availability: Given the supply of feedstocks and products to end users will require supporting infrastructure, for this criterion, we highlight and assess the suitability of regional electricity network, natural gas network and road/rail network infrastructure to support development and operation of P2X facilities (Figure 5).
- Approvals and Risks: It is important to acknowledge regional constraints and risks that potential P2X proponents could face. To assess this criterion, we highlight land access (availability of special zones including economic/industrial zones, Special Activation Precincts (SAPs) and Renewable Energy Zones (REZs) which have specially designated areas for development of industrial projects), risks to health, safety, operations, environmental, social licence (these risks are highlighted and acknowledged given the assessment of these are critical requirements for industrial project development in the state). Additionally, we also highlight supporting policies that can be leveraged to implement P2X projects across the region.

Further details of the assessment framework are provided in **Appendix A**.

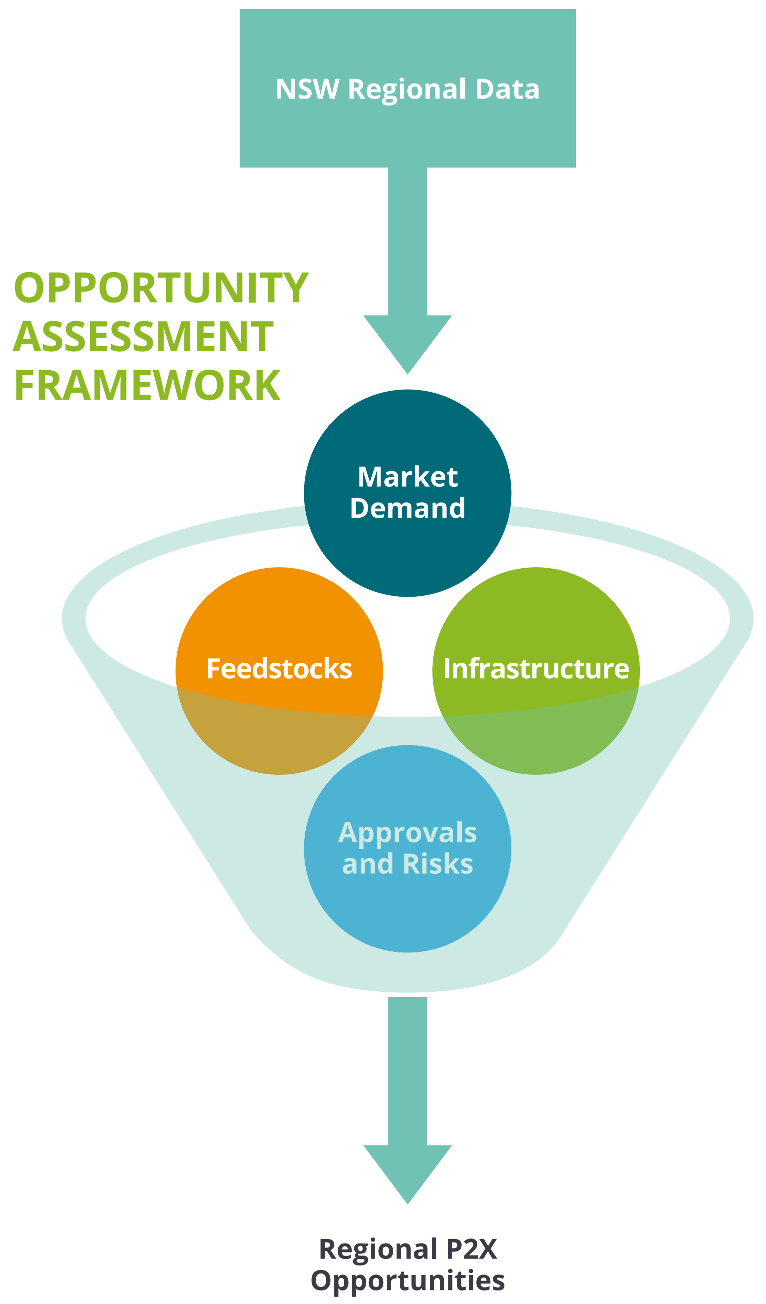


Figure 4. Visualisation of Opportunity Assessment Framework. The assessment framework acts as an interlinked filter through which the regional data for each relevant assessment criteria of the framework (represented by the circles) are filtered and assessed to determine the P2X opportunities that can be potentially developed in the region.

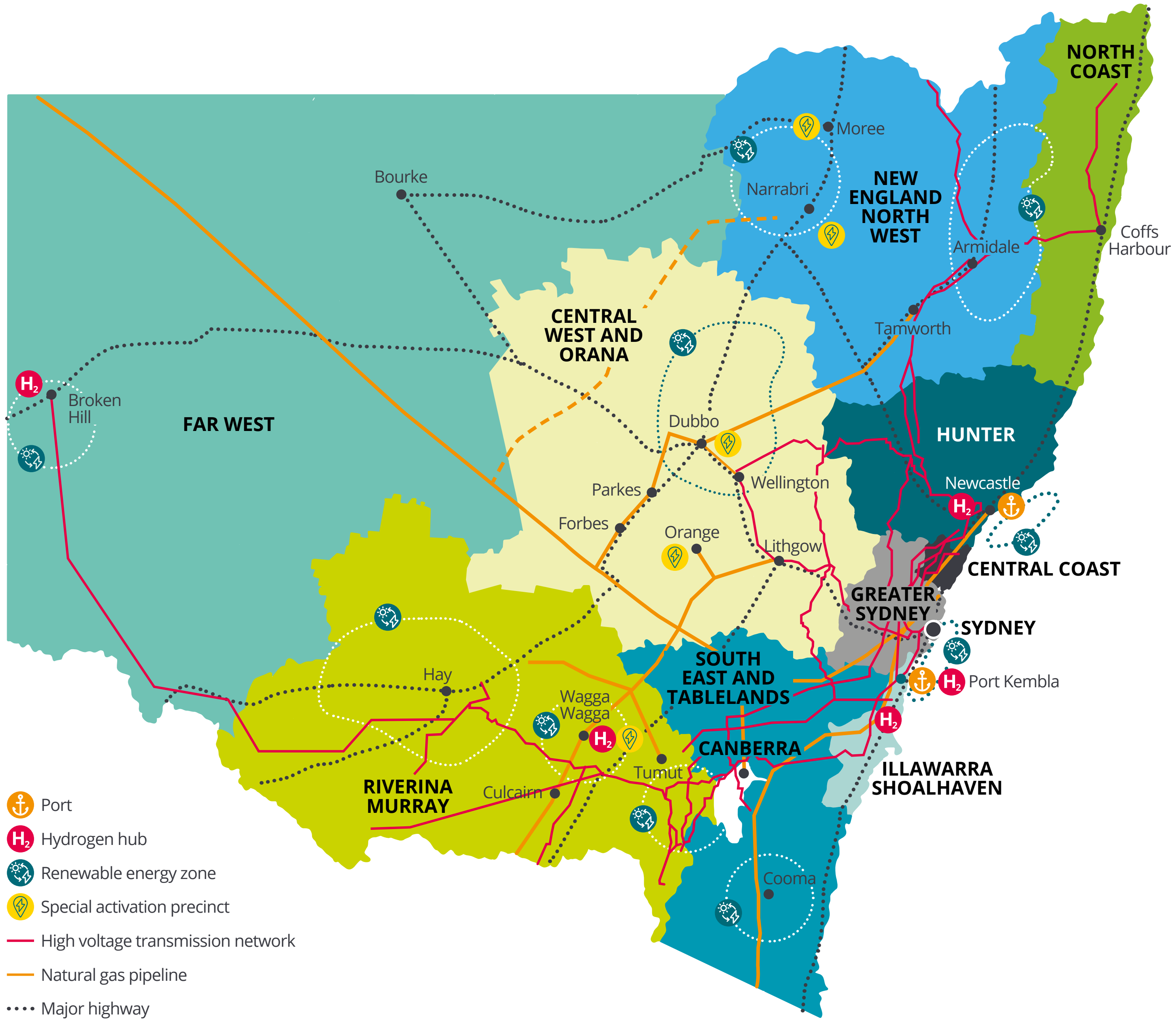


Figure 5. Regional Outlook of NSW with identified infrastructure, hydrogen hubs, renewable energy zones and special activation precincts. The figure provides an example of regional data (especially regarding infrastructure availability) that is adopted for the assessment framework application

In **Chapter 3**, the above framework has been applied across the state, and the results are presented for each region of NSW (shown in **Figure 5**). As part of the assessment, a summary of the region's resources (e.g. renewable energy availability, CO_2 sources, water availability, transmission networks, natural gas infrastructure, road, rail and maritime transport links) and industrial/economic outlook is provided to assess the region's competencies to host P2X facilities (based on the criteria ranking) and establish potential P2X opportunities that can be developed across the state.

Chapter 3. Mapping NSW P2X Opportunities

In this chapter, we used our assessment criteria to identify the P2X opportunities across the nine regions of NSW. What was clear from the exercise was the diversity of these regions in terms of resource distribution, economic outlook and their industrial and energy mix.

There are several potential P2X opportunities that could be realised to support regional industries and energy supply. Their development ties in with the key sector targets for P2X development and could serve the following purposes:

Hydrogen	• Blending into natural gas pipelines (state target of 10% by volume blends by 2030) • Fuel cell vehicles (mining and mobility applications) • Feedstock for existing facilities (steel making, refineries, and ammonia generation) • Storing variable renewable energy and integrating it into the grid.
Green ammonia	• For use as fertiliser to service local agriculture • An alternate fuel for existing natural gas/coal power plants (note, these facilities would need to be retrofitted to be able to combust ammonia).
Green methanol	• Energy and industrial use. This would enable waste CO_2 emissions and biomass to be leveraged for local use.
Sustainable Aviation Fuel (SAF)	• Consumption at domestic/international airports.

For each region, we show the assessment outcomes and present a summary snapshot that highlights the region's P2X outlook in relation to the available infrastructure. We then rank the region against the defined opportunity criterion and consider the type of opportunities and the potential issues that could inhibit project development.

What is clear is that the opportunities for P2X in NSW are significant. **Figure 6** shows them in detail.

DISCLAIMER

The opportunity mapping herein has been conducted through a desktop overview of current/future economic and market environment, regional policies and feedstock/infrastructure availability to provide a generic outlook of regional P2X opportunities. Further detailed analysis will be required to determine the optimum sites, scale and design opportunities for actual projects. While we do elaborate on the influence of these aspects on project design and economics in following chapters, these are subjective to projects on case to case basis, and this is beyond the scope of this analysis. In this manner the report provides indicative opportunities for establishing a P2X economy in NSW and we acknowledge that a detailed sectorial opportunity identification is required.

A view of the P2X opportunities across NSW

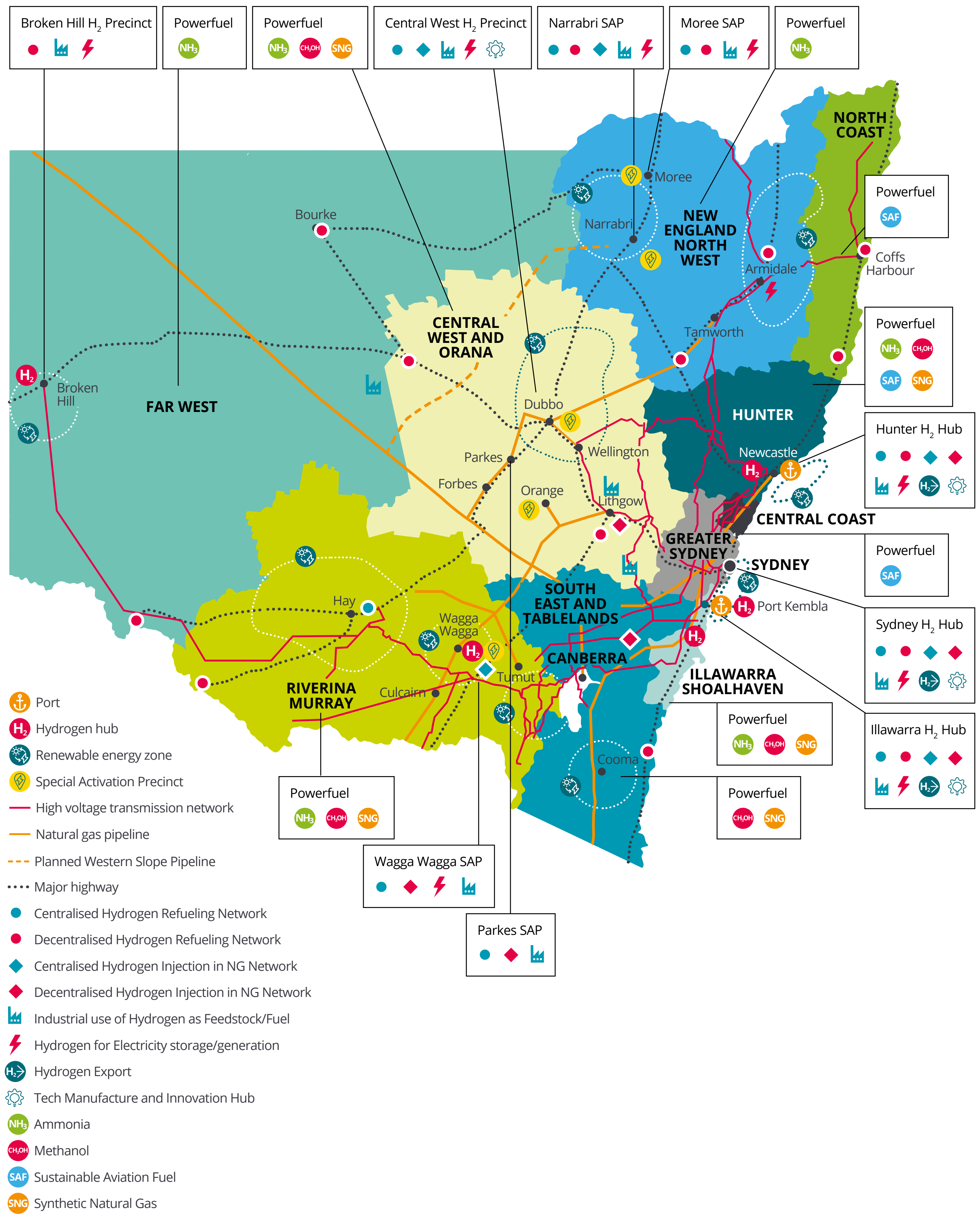


Figure 6. Regional Outlook of P2X Opportunities in NSW

3.1. Regional Outcomes

The outcomes of the assessment are provided for each region of NSW below. For each region, a summary snapshot is presented as an overview of the region's P2X outlook reflecting the region's key P2X opportunities and potential issues that could inhibit project development. This summary is then supported with details elaborated across the assessment criteria for each region.

3.1.1. Central West & Orana

The Central West and Orana Region (Figure 7) is the state's second largest region and contains the major centres of Bathurst, Orange and Dubbo, along with the growing regional centres of Lithgow, Parkes, Mudgee and Forbes. It is often referred to as the heart of the state and has opportunity to supply P2X products to local mines and agricultural sectors.

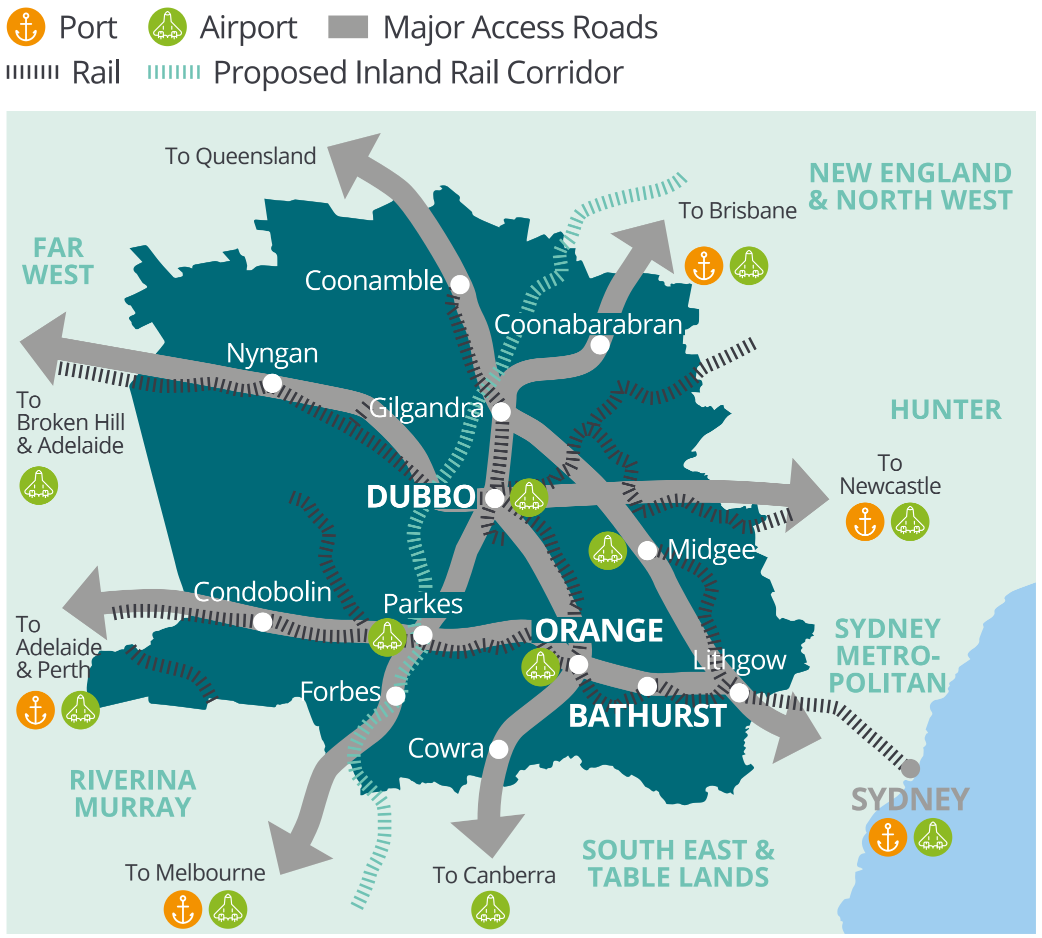


Figure 7. Map of Central West & Orana Region of NSW.

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen Gas Blending • Ammonia • Hydrogen • Methanol • Synthetic Natural Gas	• Water Availability • Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: The region's economy produces A$14 billion per annum with a high proportion coming from the agriculture, mining and manufacturing sector.[10] The local manufacturing sector mostly provides support services to the agribusiness (value addition and packaging) and mining operations (including equipment maintenance). The mining operations in turn contribute to a skilled labour force, with 15% of the 5,000 workers employed by the mining and resource sector in the region having engineering and technology degrees.[10] The region has significant deposits of gold, copper, platinum group metals and scandium, critical components in renewable technologies such as solar/wind generators, batteries and electrolysers. Because of this, the state government has declared the Central West Region as a Critical Minerals Hub, which will support mining of critical minerals for renewable energy development and the recycling of critical minerals from refurbished equipment.[11] This could further grow and benefit from the regional renewable energy sector, as several solar and wind farms are already operating in the region and the capacity is to rise further with the expected development of the Central West and Orana Renewable Energy Zone.

The mining and agribusiness have also supported the development of the regional highways and railway network. The town of Parkes has been designated as a National Logistics Hub and a SAP is being developed in Parkes to support industry, energy, and logistical operations.

P2X Opportunity: Given the agriculture driven nature of Central West and Orana's economy, generation of fertilisers made from green ammonia is a potential P2X opportunity. Additionally, the logistics hub and the mining sector provide an opportunity for hydrogen/methanol use for mobility applications. A future market may exist to supply powerfuels as diesel replacement in the region, especially to serve mining operations. Industrially, hydrogen can be used to provide heating options e.g. in industrial boilers. Similarly, hydrogen could be blended into the natural gas network, the region hosts major gas networks as elaborated below. Alternatively, local biomass/waste from agricultural activities could be leveraged to provide CO_2 for methanol (further conversion into other fuels like synthetic diesel) and SNG production that can be used locally. These P2X opportunities could benefit and support the upcoming REZ development by providing opportunities for new capacity development or firming services to the anticipated capacity installation (3 GW). The development of the Critical Minerals Hub could also enable an opportunity for P2X equipment manufacturing in the region.

Feedstock Availability

Renewable Energy Potential: The region exhibits good solar and wind potential (capacity factors of 23 - 24% and 43 - 49% respectively).

Water Availability: The Central West and Orana region relies on its fresh and ground water resources, serving the agriculture, domestic/commercial and industrial water demand. At present, all these water supplies have been allocated, with conditions for licensing of water expected to become more stringent as the current water resources come under pressure due to increasing population, agriculture and industrial activities. Nevertheless, the Central West and Orana regional plan acknowledges the potential for a P2X economy in the region and suggests given the economic incentive of such an economy, provisions to support licensing and diversion of leftover high security water licenses to P2X deployment should be considered as part of the upcoming regional water sharing plan. In absence of fresh/ground water sources for P2X, the region's wastewater resources could provide a potential pathway for project development.

10 - Central West and Orana. NSW Government, Accessed on 10th July 2022.. Link
11 - NSW Government (2021). Australia's first critical minerals hub to make NSW a global leader. Link

CO_2 and Biomass:[12] In addition to Direct Air Capture[13], the Mount Piper coal-fired power station near Lithgow could be used as a CO_2 source (7.1 MTPA CO_2) for potential methanol and SNG production. The region also has a selection of biomass sources (approx. 2.5 MTPA) that could be converted to CO_2 to produce hydrocarbon powerfuels, including cereal and non-cereal straw, sawmill residues, municipal solid waste (MSW), construction and demolition (C&D) organic waste and, to a lesser extent, dairy and poultry manure.

Supporting Infrastructure

Transport Network: Given the region's central location, it is a logistic and freight connection between all the other regional areas via highways and rail links. In addition, all the main regional centres have major airfields nearby.

Electricity Network: The region has an existing high-voltage transmission network that connects the major regional centres with the National Electricity Market (NEM). The network supports approximately 1 GW of solar and wind plants that are already in operation. In addition, the development of the Central West and Orana REZ will contribute a further 3 GW of renewable generation and transmission by the mid-2020s.[14]

Natural Gas Network: Branches of the Moomba-Sydney Pipeline, including the Central West and the Central Range Pipelines, connect with the regional centres of Forbes, Parkes and Dubbo.

Approval and Risk Factors:

Land Availability: Land availability is constrained near the regional centres and across the region due to agricultural activities. However, the regional plan for 2036 sets the target to increase land availability for industrial and energy development which will be complemented by the upcoming REZ and SAP.

Operational Risks: According to the AEMO ISP 2022, the Central West and Orana REZ has a high bushfire score. There is also potential for major rivers (Lachlan, Namoi and Macquarie) to flood.

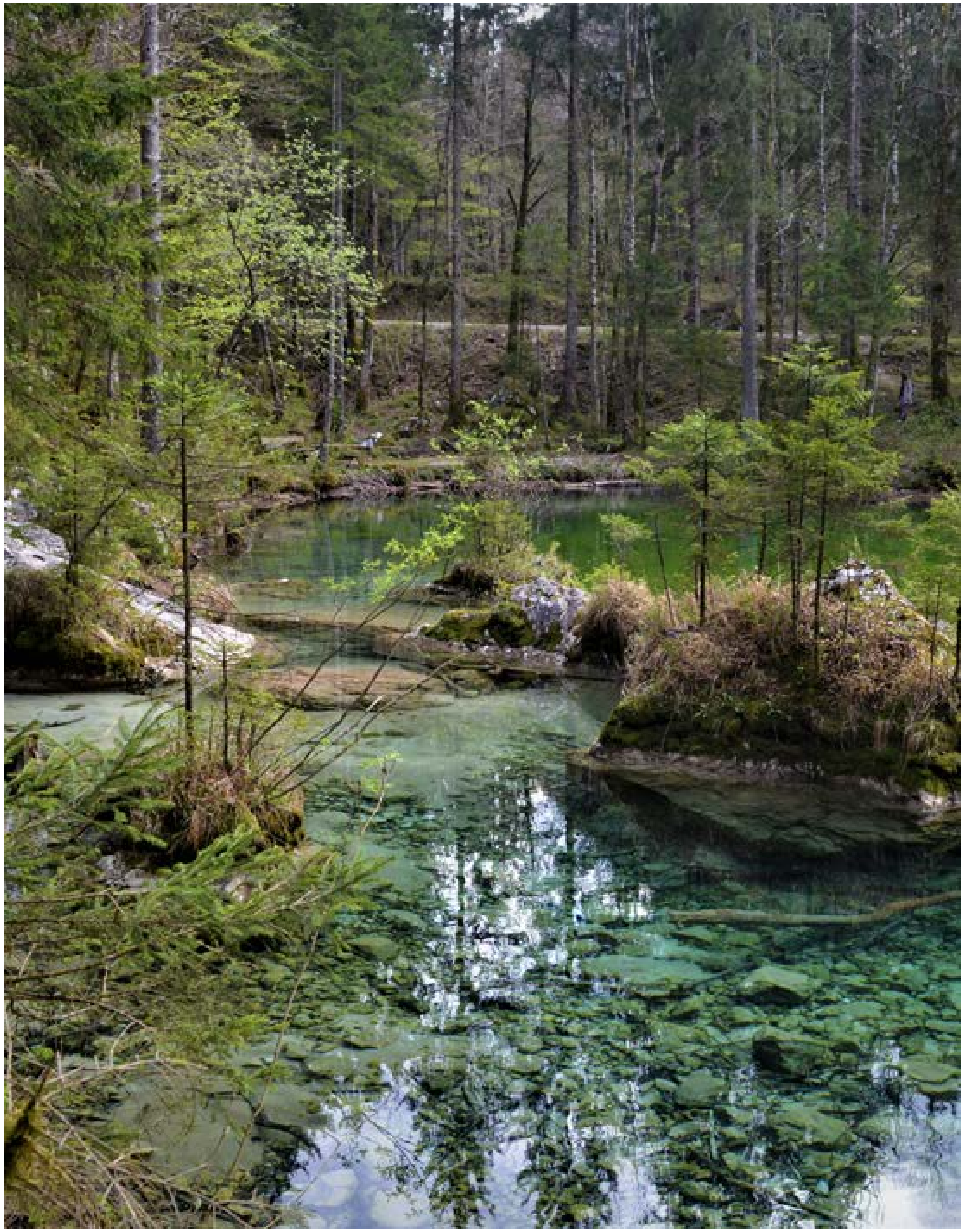
Supporting Policy: The development of the Central West and Orana REZ, and SAP at Parkes could create industrial demand for P2X products:

- ammonia to support local agriculture
- H_2 for transport fuel/blending.

The Critical Minerals Hub could support local manufacturing for renewable energy systems, batteries, electrolysers or catalysts for P2X.

The NSW P2X Pre-Feasibility Study supports the development of a P2X-led freight network as the Newell Highway and the upcoming 'Inland Rail' network, which will connect Brisbane to Melbourne, will pass through here and create opportunities to distribute P2X products, or for the direct use of P2X products (synthetic diesel or hydrogen) as a transport fuel for trains.

Note that for all regions, availability of skilled workforce is a critical barrier to P2X project development.



12 - Flue gas from industrial and power generation facilities (IFG) have several benefits over biomass and direct air capture as a source of recycled CO_2. However, due to net zero objectives across the manufacturing and energy sectors, these facilities carry increased risks of potential closure or being ruled out as an acceptable source of CO_2 for powerfuel certification and export.
13 - Direct air capture is applicable to all regions of NSW provided land availability.
14 - NSW Government (2022). Central-West Orana Renewable Energy Zone. Link

3.1.2. Far West

This is the largest region (Figure 8) and covers 40% of the state's area. It shares its borders with Queensland to the north, South Australia to the west and Victoria to the south. While most of the region is sparsely populated, there are small communities, such as Lightning Ridge and Walgett (near the Queensland Border), larger mining-based settlements, like Broken Hill and Cobar, in the central part of the region, and the townships of Wentworth and Balranald in the south. With remote communities and decentralised energy demands, there is opportunity for P2X in remote communities and off-grid applications.

Figure 8. Map of Far West Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen • Ammonia	• Limited P2X Demand • Water Availability • No Natural Gas Network • Operational Risk - Remoteness

Market Demand

Economic and Industrial Outlook: The region's economy produces A$2 billion per year and is based on agriculture and mining operations.[15] Of this, the agriculture sector contributes A$1.3 billion, dominated by cotton and food crops.[15] Mining is the largest employer in the region and is concentrated in Broken Hill, Wentworth and Cobar Shires and minerals mined include gold, copper, cobalt and mineral sands.

The Far West Regional Economic Development Strategy highlights the need for increasing renewable energy developments and integration with local industries.[16]

P2X Opportunity: The Far West region's agricultural sector provides market opportunity for P2X-driven fertiliser generation. Note that for the purpose of this report, we refer to only renewable ammonia as a fertiliser while acknowledging that majority of ammonia for use as fertiliser would potentially be converted into derivatives such as urea. In addition, hydrogen could be used to support local mobility and logistic applications, strengthening the region's energy reliance as presently the bulk of the fuels (especially gasoline and diesel) have to be transported from other regions (especially Port Botany, where the majority of NSW's fuel is imported and distributed from). Similarly, hydrogen can also be used to support mobility applications at the mining sites (forklifts and heavy trucks). Here, hydrogen can also be used to support development of microgrids especially in the remote part of the region (most of the north and eastern part of the region is off grid) where it can be used for on-demand combined heating and power applications.

Feedstock Availability

Renewable Energy Potential: The region has some of the best solar and wind potential in the state (capacity factors of >25% and >45% respectively). Current renewable energy projects are located at Broken Hill (53 MW Solar PV) and Silverton (200 MW Wind). The AEMO ISP 2022 suggests Broken Hill could host a REZ with up to 8 GW of solar and 5.1 GW of wind energy.[17]

Water Availability: The region has access to the Barwon-Darling River system, but this is a key resource for residential and commercial activities, and could be limited for P2X developments. Alternative water sources could be harnessed from Broken Hill's WWTPs including Will Street (1.5 GL/yr) and South (0.4 GL/yr).

CO_2 and Biomass: The region has a selection of biomass sources (approx. 0.5 MTPA) that could potentially be converted to CO_2 for SAF production, including MSW, C&D Waste and, to a lesser extent, cereal and non-cereal straw.

Supporting Infrastructure

Transport Network: The region has road, rail and airport infrastructure but the majority of this connects Broken Hill and Cobar to other parts of the state and interstate.

Electricity Network: The region presently has a limited high-voltage transmission network, which includes the transmission network connecting Broken Hill to the rest of the state's electricity grid in the southeast of the region and a separate network is present in the central west of the region that connects the mining region of Cobar to the state's eastern electricity grid via Central West and Orana Region. The rest of the region is considered off-grid and relies on local power generation and transmission.

Natural Gas Network: The region does not have natural gas distribution, although the Moomba to Sydney transmission pipeline does pass through.

Approval and Risk Factors

Land Availability: Across the region, vast areas of land are uninhabited and could potentially be used for development.

15 - Far West. NSW Government. Accessed on 10th July 2022. Link
16 - Far West Regional Economic Development Strategy. NSW Government. 2018. Link
17 - AEMO (2022). 2022 Integrated System Plan. Link

However, in locations closer to the region's demand centres there are limitations on the land linked to heritage, aboriginal and nature reserves. The region also has strong links to Aboriginal history and has the highest percentage of Aboriginal settlements in NSW (Brewarrina, Lightning Ridge and Wilcannia) and any development needs to be undertaken together with the Traditional Owners.

Operational Risks: According to the AEMO ISP 2022, the Broken Hill REZ has a medium bushfire score. There is also potential for the Barwon-Darling River to flood. Given the remoteness and long distance from supply chains, labour and machinery to develop P2X facilities would have to be transported from other regions.

Supporting Policy: The development of a REZ in Broken Hill could help to support P2X deployment and use of P2X products in the region for mobility and power generation applications.

3.1.3. Riverina Murray Region

The Riverina Murray region is in the state's south and shares a border with Victoria (Figure 9). Compared to the Far West, the region is more densely populated, and it includes the regional cities of Albury, Griffith and Wagga Wagga. The region is a hub for transport and P2X for the mobility sector presents an opportunity for the region.

Figure 9. Map of Riverina Murray Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen gas blending • Hydrogen • Ammonia • Methanol • Synthetic Natural Gas	• Water Availability • Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: Often referred to as the 'Food Bowl of NSW', this region has a dominant agriculture-based economy that contributes A$3 billion per year. It also boasts a growing specialised defence-equipment manufacturing sector and a world-class metal recycling facility.[18] The state's advanced manufacturing industry development strategy has identified the region as a potential hub for specialised engineering, target technology and aircraft structure manufacturing.[19]

P2X Opportunity: Riverina Murray region's agricultural sector also provides an opportunity for P2X-driven fertiliser generation. Moreover, the agriculture and biomass potential of the region can be leveraged to provide opportunities for generating methanol and SNG. Development of methanol could support local mobility especially the railway operations given major railway connections are present and the upcoming Inland Rail project also expected to pass through the region. The NSW P2X Pre-Feasibility study has already identified methanol use for the Inland rail project as a potential P2X option.[5] In addition, hydrogen could be used to support local mobility, for blending into the gas networks, industrial operations (energy supply especially heating requirements for manufacturing) or as a fuel for local power plants (the region has one of the state's largest natural gas plants).

Feedstock Availability

Renewable Energy Potential: The region has potential for both solar- and wind-generated power (capacity factors of 22-24% and 33-48% respectively). Current renewable energy projects across the region amount to 756 MW of solar.

The AEMO ISP 2022 suggests the region could host two REZs (Wagga Wagga REZ and South West REZ) with a combined capacity of 5 GW solar and 5 GW wind.[13]

Water Availability: The region has access to the Murray and Murrumbidgee river system, but this is a key resource for residential and commercial activities and could limit its use for P2X developments. Alternative water sources could come from the WWTPs across the region which currently discharge into the rivers. These include WWTPs in Albury (10.5 ML/yr), neighbouring Wodonga in Victoria (3.7 GL/yr), Griffith and Wagga Wagga (>5 GL/yr).

CO_2 and Biomass: The Uranquinty gas-fired power plant near Wagga Wagga could be used as a potential CO_2 source (0.104 MTPA of CO_2) for potential SAF production. The region has a selection of biomass sources (approx. 6.0 MTPA) that could also be converted to CO_2, including cereal and non-cereal straw, sawmill residues, municipal solid waste (MSW), construction and demolition (C&D) organic waste, dairy manure and almond-shell hulls.

Supporting Infrastructure

Transport Network: The region has road, rail and airport infrastructure connecting to other parts of NSW and interstate (SA and Victoria). Key rail links also connect the region to the major ports of Botany and Port Kembla on the east coast.

Electricity Network: The region has an existing high-voltage transmission (330 kV and 132 kV) network that connects the key centres (Albury, Griffith and Wagga Wagga) with the NEM. In addition, the South Australia – New South Wales electricity interconnector with a capacity up to 330 kV is now under construction and is expected to operate by the end of 2027.[20] This will bring considerable power capacity to the Wagga Wagga region.

Natural Gas Network: The region has natural gas transmission and distribution infrastructure. This includes the Wagga Wagga – Culcairn section of the Moomba Sydney pipeline system, which also connects to the Victorian Transmissions System and supplies gas to the Uranquinty gas-fired power plant, and the June-Griffith lateral pipeline that delivers gas to Griffith.

18 - Riverina Murray. NSW Government. Accessed on 10th July 2022. Link
19 - NSW Government (2018). NSW advanced manufacturing industry development strategy. Link
20 - NSW SA Interconnector. Link

Approval and Risk Factors

Land Availability: Land availability for large-scale P2X developments may be limited around the densely populated centres of Wagga Wagga, Albury and Griffith. Elsewhere in the region, competition with agricultural activities may limit the large-scale development of P2X technologies.

Operational Risks: The South West and Wagga Wagga REZs have a medium-to-high bushfire score, according to the AEMO ISP 2022. There is also potential for the Murrumbidgee and Murray rivers to flood.

Supporting Policy: The development of the Wagga Wagga and South West REZs, and Wagga Wagga SAP could create industrial demand for P2X products. The Inland Rail running through Wagga Wagga will also be key to supporting the development of P2X Hubs and open connections to Brisbane and Melbourne for P2X product distribution. In addition, the trains running on the Inland Rail could potentially use P2X products as a transport fuel (synthetic diesel or hydrogen).

3.1.4. New England North West

The New England North West region shares a border with Queensland in the north, the Far West and the Central West & Orana regions in the west, the Hunter region in the south and the North Coast region in the east (Figure 10). The regional local government areas of Tamworth and Armidale is home to almost half of the region's population and are supported by four regional centres: Gunnedah, Inverell, Moree and Narrabri. The region provides a prime opportunity for P2X-based fertilisers to support the agriculture sector, while the local renewable energy potential can be leveraged for hydrogen generation that can be used as a mobility fuel.

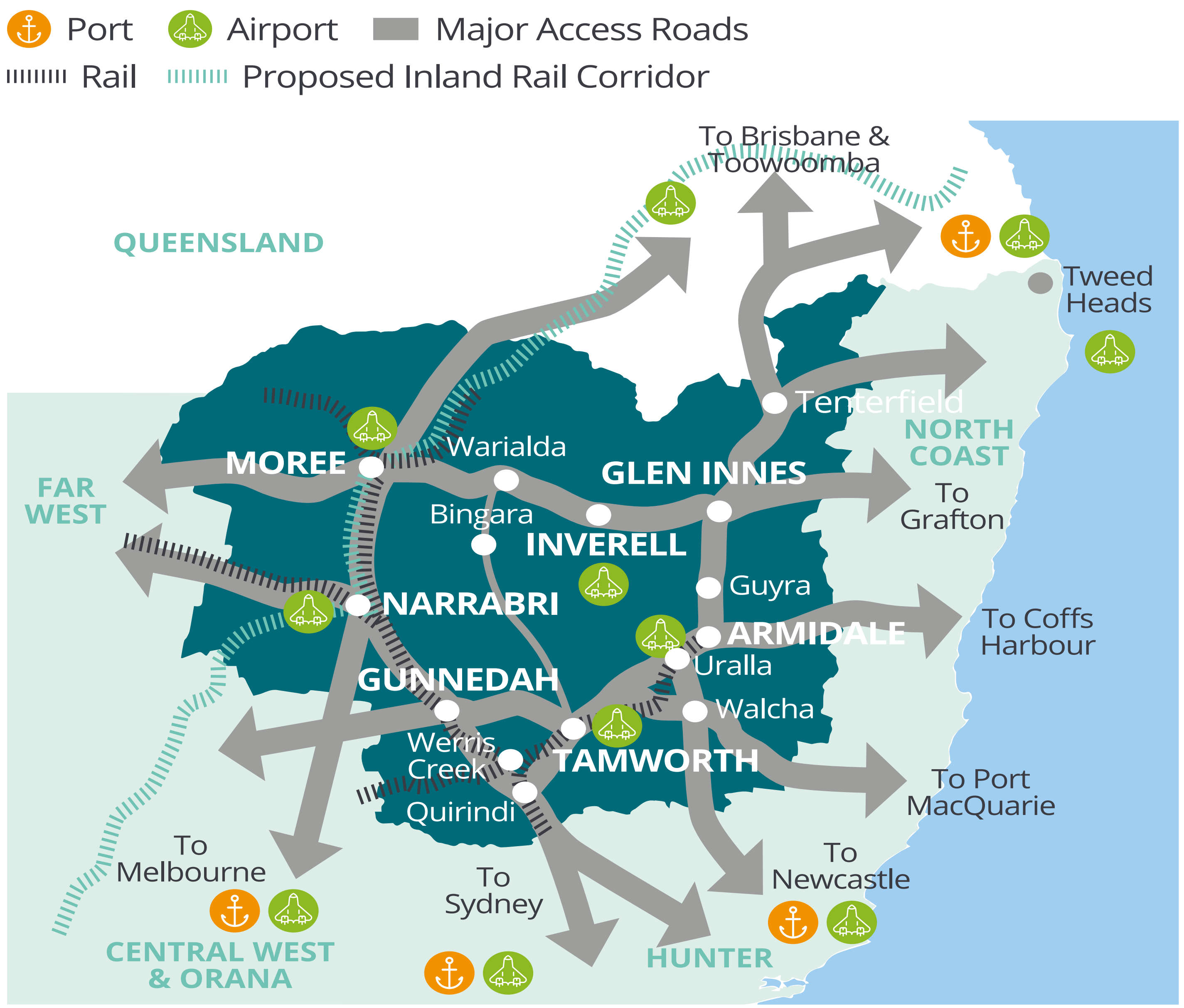


Figure 10. Map of New England North West Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen • Ammonia	• Water Availability • Land Availability • Operational Risk • Limited Gas Network

Market Demand

Economic & Industrial Outlook: The region contributes A$8 billion per year to the NSW economy and this is driven predominantly by agriculture-based activities.[21] Emerging businesses in the region are focused on transport, postal and warehousing activities, which have been established as a result of the plans to run Inland Rail through the region. The Moree and Narrabri Special Activation Precincts will also benefit from Inland Rail and will become key centres for regional development.

P2X Opportunity: The region's logistical operations provide an opportunity for use of powerfuels for mobility applications (e.g., hydrogen fuels for trucks and forklifts). Additionally, P2X can be used for grid firming (surplus energy from solar/wind farms converted and stored as P2X products that can be reused to generate power on demand during deficit) for the existing and new renewable energy plants under development. Presently, a similar project involving hydrogen-based storage at a solar power plant is being developed in Manilla (a town in the south of the region).

Feedstock Availability

Renewable Energy Potential: The region has potential for both solar- and wind-generated power (capacity factors of 23-24% and 36-41% respectively). Current renewable energy projects across the region amount to 76 MW of solar and 535 MW of wind (**Appendix A**). The AEMO ISP 2022 suggests the region could host the New England and North West REZ, with potential combined capacity of 9.4 GW solar and 7.4 GW wind.[17] However, realising this amount of renewable energy would require expansion of the transmission network and connection to the Hunter and Central West and Orana Regions.

Water Availability: The region has access to the Border and Gwydir River and Namoi River systems, but this is a key resource for residential and commercial activities and its use for P2X developments could be limited. Alternative water sources include groundwater from several alluviums with the potential to extract up to 260 GL of water. Other sources of water could also be harnessed from WWTPs in the region.

CO_2 and Biomass: The region has a selection of biomass sources (approx. 2.1 MTPA) that could be converted to CO_2 to produce SAF, including cereal and non-cereal straw, sawmill residues, MSW, C&D organic waste, and dairy and poultry manure.

Supporting Infrastructure

Transport Network: The region has good rail, road and airport infrastructure with links to other regions within the state and interstate. The Inland Rail will be a key transport link for the region and will connect it to markets in Victoria and Queensland.

Electricity Network: The region has an existing transmission network (330 kV and 132 kV) that connects key demand centres to the NEM, including the major interconnection with Queensland.

Natural Gas Network: The Central Ranges natural gas transmission pipeline runs up to Tamworth from Dubbo, and distributes to residential and commercial properties in Tamworth.

Approval and Risk Factors

Land Availability: Land availability will be restricted around areas with heavy agricultural activities that are designated as nature reserves and residential areas. With the SAPs located in Moree and Narrabri and the New England REZ, land could be made available for P2X developments.

Operational Risks: North West and New England REZ has a high bushfire potential according to the AEMO ISP 2022. There is also potential for the Border and Gwydir Rivers to flood.

Supporting Policy: The development of the New England and North West REZs, and Moree and Narrabri SAP could create

21 - New England and North West. NSW Government, Accessed on 10th July 2022. Link

industrial demand for P2X products. The Inland Rail running through Moree and Narrabri will also be a key improvement that could support the development of P2X hubs and open connections to Brisbane and Melbourne for P2X product distribution. Inland Rail also has the potential to use P2X products as a transport fuel.

3.1.5. Hunter Region

The Hunter Region is the state's largest regional economy and contains the major cities of Newcastle, Maitland and Lake Macquarie, with smaller regional centres of Cessnock, Muswellbrook, Port Stephens, Scone, Singleton and Taree (Figure 11). The Hunter region's diverse industrial sector provides opportunities for offtake of hydrogen fuels for mobility applications, natural gas blending and decarbonisation of local power generation plants and industries (including Ammonia production). Additionally, the biomass and waste emissions can be leveraged to generate SNG, Methanol and SAF, which can be used locally or exported out of Port of Newcastle.

Figure 11. Map of Hunter Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen gas blending • Hydrogen • Ammonia • Methanol • Synthetic Natural Gas • Sustainable Aviation Fuel	• Land Availability • Operational Risk

Market Demand

Economic & Industrial Outlook: The Hunter Region contributes A$35 billion per year to the NSW economy, most of which comes from the mining sector.[22] Coal is the dominant mining activity and a major export commodity for Australia through the Port of Newcastle.

The key business sectors include mining, health, tourism, manufacturing, agriculture and defence, and are serviced by a highly skilled and professional workforce. The Williamtown SAP is also a key development hub for the region with access to an RAAF base and Newcastle Airport.

P2X Opportunities: The Hunter region's manufacturing base provides an ideal opportunity for P2X products to enable decarbonisation. The NSW State government has already recognised this potential and is developing the Hunter Hydrogen Hub which could provide multifaceted P2X opportunities. Several projects are already underway including conversion of Orica's existing ammonia plant to generate green ammonia for local use and export, as well as generation of hydrogen for blending in natural gas pipelines, refuelling applications and industrial use.[23] The Port of Newcastle Green Hydrogen Hub is another ongoing key ARENA supported development that will drive growth and demand for P2X products in the Hunter region and enable an export market.[24] Regionally, P2X could also open the avenue for emission abatement from the local power stations and industries to support generation of methanol, SNG and SAF. The generated SAF could particularly be used to support operations at Newcastle Airport and RAAF base as well as other smaller airports and the rest of the state (NSW/Australia import almost all of the jet fuel as elaborated later).

Feedstock Availability

Renewable Energy Potential: The region has potential for both solar and wind-generated power (capacity factors of 22% and 41% respectively). It has also been identified as a possible location for offshore wind, with potential capacity factors up to 54%.

Water Availability: The Hunter region similar to other parts of the NSW state, relies on its fresh and ground water resources to fulfill the regional water requirement. Presently, all the available resources are fully allocated to secure the domestic/commercial, local agricultural and industrial water demand including power generation at the coal Power Plant operating in the region. Therefore, P2X projects will have to compete with these demand sectors for licensing. Nevertheless, with the expected closure of the Bayswater and Liddell coal power plant, 61 to 106 GL/yr of fresh water supply would become available, that can be leveraged for P2X.

Alternatively, several wastewater resources are available in the Hunter region including the wastewater from the breweries/distilleries in the region or the wastewater produced from some of the active wastewater treatment plants especially the south Hunter region that has ~19 active treatment plants (operated by the regional water supplier Hunter Water) that altogether treat ~200 ML/day of wastewater, while most of it is recycled for local irrigation, several of these plants discharge treated water into the ocean or local rivers/drains. This water can be reclaimed for P2X, however this is subject to quality of water (most likely secondary to tertiary treated) and spatial/temporal correlation with P2X facility to reduce the cost for pretreatment, transport to site and storage on site.

Desalinated water offers the most sustainable and scalable water supply for P2X, at present there are no desalination plants in Hunter region but these facilites can be built in conjunction with P2X facilities in locations like Newcastle Port and Kooragang Island that are emerging as P2X hubs. An incentive for development of these desalination facilities would be that additional capacity (in addition to the demand for P2X) can be

22 - Hunter. NSW Government. Accessed on 10th July 2022. Link
23 - Hunter Hydrogen Hub. HyResouce. CSIRO. Accessed on 10th July 2022. Link
24 - Port of Newcastle (2022). Port of Newcastle Green Hydrogen Hub. Link

put developed to provide excess water to shore up the regional water supply especially during the drought season.

CO_2 and Biomass: The region has several industrial CO_2 sources, including coal-fired power stations — at Bayswater (12.8 MTPA CO_2), Liddell (7.0 MTPA CO_2), Vales Point (6.4 MTPA CO_2), Eraring (12.7 MTPA CO_2) — an ammonia synthesis plant at Kooragang Island (0.54 MTPA CO_2) and a gas-fired power plant at Colongra (0.042 MTPA CO_2) that could be used as potential CO_2 sources to produce SAF. The region has a selection of biomass sources (approx. 0.88 MTPA) that could be converted to CO_2 to produce SAF, including sawmill residues, dairy and poultry manure, MSW, C&D organic waste and, to a lesser extent, cereal and non-cereal straw.

Supporting Infrastructure

Transport Network: The region has good road, rail, airport and seaport infrastructure that connect it to other parts of the state, interstate and internationally. The Port of Newcastle is a major export terminal with the capability to handle bulk commodities. Newcastle Airport is also undergoing an upgrade of its runway to accommodate larger planes that will open international routes to the Middle East, the US and North Asia.

Electricity Network: The region has an existing transmission network (550 kV and 330 kV) that connects the local coal- and gas-fired power generators to the NEM.

Natural Gas Network: The region is serviced by Jemena's gas distribution network, which supplies natural gas to Newcastle, Morisset, Hexham and Minmi.

Approval and Risk Factors

Land Availability: Land availability could be limited for large-scale P2X developments near key demand centres, due to the densely populated areas occupied by residents and commercial businesses. Outside the key demand centres, land availability could potentially be limited by agricultural activities and protected nature reserves.

Operational Risks: There are bushfire risks throughout the region and the potential for major rivers in the Hunter region to flood.

Supporting Policy: The Hunter Hydrogen Hub and Port of Newcastle Green Hydrogen Hub will be key developments that P2X Hubs can leverage to produce an array of powerfuels, including ammonia and methanol for use as marine fuels that could be utilised or exported from the Port of Newcastle.

3.1.6. Illawarra – Shoalhaven Region

The Illawarra – Shoalhaven Region runs along the east coast of NSW, to the south of the Hunter, Central Coast and the Greater Sydney Metropolitan Area. In this region, the major urban centres are Kiama, Nowra, Shellharbour and Wollongong. Berry and Kangaroo Valley serve as smaller towns and villages (Figure 12). The Illawarra and Shoalhaven region is a key industrial hub of NSW, which creates the opportunity for P2X led decarbonisation. Here the hydrogen can be used for mobility applications, blending into the natural gas network and industrial use (including supporting local steel-making facility). Additionally, synthetic fuels and ammonia can be generated for domestic consumption around the state and for export out of Port Kembla.

Figure 12. Map of Illawarra-Shoalhaven Region of NSW Potential Regional P2X Opportunities

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen gas blending • Hydrogen • Ammonia • Methanol • Synthetic Natural Gas	• Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: The region is the third largest contributor to the NSW economy, delivering approximately A$15.5 billion annually.[25] The key sector in the region is manufacturing, which includes steel, chemicals, food/beverages, construction and machinery.

P2X Opportunities: The state government has already realised the potential for P2X opportunities to support the Illawarra region's industry and manufacturing sector and is developing the Port Kembla Hydrogen Hub. The hub has the potential to support P2X facilities to enable hydrogen generation for industrial use, mobility applications and blending into natural gas network.[26] Presently, Coregas are developing a hydrogen refuelling station at Port Kembla, while the state and Federal governments in partnership are developing a new hydrogen-ready gas power plant as part of the Tallawarra power plant. Additionally, P2X facilities at the hub could be developed to generate and export P2X products like green ammonia and methanol, as well as support manufacturing facilities including operations at BlueScope's steel making facility, which can use green hydrogen for manufacturing as highlighted in the NSW Pre-Feasibility Study.[5]

Feedstock Availability

Renewable Energy Potential: The region has a low potential for both solar and wind generated power compared to other regions. (Capacity factors of 22% and 35% respectively.) It has also been identified as a possible location for offshore wind with potential capacity factors up to 55%. Current renewable energy in the region is based on the Shoalhaven Hydropower project – 240MW.[27]

Water Availability: The region has access to the southern rivers system, which includes the Hawkesbury-Nepean and Shoalhaven Rivers. Alternative sources include harnessing water from the region's WWTPs, which have a combined capacity of 177GL per year, or through developing desalination plants to use seawater.

CO_2 and Biomass: The region has a couple of industrial CO_2 sources, including BlueScope Steel at Port Kembla (5.0 MPTA of CO_2) and the Manildra Group ethanol plant near Nowra (0.225 MTPA of CO_2). The region has a selection of biomass sources (approx. 0.5 MTPA) that could be converted to CO_2 to produce SAF, including sawmill residues, dairy manure, MSW, C&D organic waste and, to a lesser extent, cereal and non-cereal straw.

Supporting Infrastructure

Transport Network: The region has good road, rail and seaport infrastructure that connect it to other parts of the state, interstate and internationally. Port Kembla is a major export terminal to international markets and is capable of handling products from the mining, agricultural, construction, energy and chemical industries.

Electricity Network: The region has an existing transmission network (330 kV) that connects the various power generators to the NEM.

Natural Gas Network: The region is supplied by the Eastern Gas Transmission Pipeline, with local distribution in the major demand centres.

Approval and Risk Factors

Land Availability: Land availability is restricted around the key demand centres such as Wollongong and Nowra as they are densely populated areas. In addition, the region has several nature reserves and a military zone that will limit the development of large-scale P2X hubs. Moreover, the mountainous terrain of the region would provide a constraint to development of solar/wind farms.

Operational Risks: There are bushfire risks throughout the region and the potential for flooding of the major rivers.

25 - Illawarra-Shoalhaven. NSW Government, Accessed on 10th July 2022. Link
26 - Port Kembla Hydrogen Hub Investment Prospectus. NSW Government. 2021. Link
27 - Origin Energy (2022). Generation. Link

Supporting Policy: The Port Kembla Hydrogen Hub will be a key development that P2X technologies can leverage to produce an array of powerfuels, including ammonia and methanol, for use as marine fuels that could be utilised or exported from Port Kembla.

3.1.7. Central Coast and Greater Sydney Metropolitan Area

This region is the centre of NSW's economic activity and its fastest-growing corridor. It connects to the industrial hubs of Central West & Orana, Illawarra – Shoalhaven and the Hunter Region. As well as Greater Sydney, it includes the regional centres of Gosford and Wyong (Figure 13). Locally P2X can be used to support blending of hydrogen into the natural gas network, mobility applications and decarbonisation of the local industries. In particular, there is significant opportunity for SAF use at Sydney's airports. The ongoing R&D in regional universities can further support development of renewable and P2X technologies.

Figure 13. Map of Greater Sydney Metropolitan and Central Coast Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen gas blending • Hydrogen • Sustainable Aviation Fuel	• Niche P2X Markets • Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: The region is mostly a service-driven economy with additional contributions from tourism, agriculture and food manufacturing, which are supported by logistical operations and several warehouse and distribution centres. The construction sector is also growing rapidly. Four universities are either based or have a presence in the region which, combined with multiple TAFE centres, makes higher education highly accessible. As a result, the workforce is highly skilled and involved in R&D including development of renewable energy and P2X technology.

P2X Opportunities: Given the region hosts most of the state's population and economic activity, it provides a wide range of P2X opportunity. Namely, there is a high potential for hydrogen blending in local natural gas distribution networks/ major pipelines especially in wake of the expected shortage of natural gas in NSW (the state could potentially see a supply shortfall in the coming years linked to undeveloped reserves and competition with LNG exports). Additionally, hydrogen could be used for mobility applications including for public transport use (a key target for the state as elaborated earlier) and other mobility applications (e.g. courier services, construction vehicles, garbage collection etc.). Industrially, the powerfuels could be used to decarbonise manufacturing facilities or enable decarbonisation by providing avenues for emission abatement (point sources for CO_2 that can be converted to powerfuels). Additionally, powerfuels like SAF could be used to support operations at Sydney's airports.

Feedstock Availability

Renewable Energy Potential: With a capacity factor of 22%, we estimate that the region has low solar potential. It has acceptable onshore wind potential (41% capacity factor) and it is believed factors of 55% can be achieved offshore.

Water Availability: Greater Sydney Metropolitan Area relies on supply of water from the Hawkesbury-Nepean River, a network of dams and the Kurnell Desalination Plant, through a supply network managed by Sydney Water. These systems, especially the river and dam flows, are already dedicated to supply critical water requirement including the commercial/domestic water requirement. Similarly, the Kurnell Desalination Plant has been be developed to sustain the water supply of the city in case of drought, shortage of water and future demand increase. While these sources are currently enough to sustain the water requirements of the city and region, especially due to the recent rainy season after extended drought, a future demand expansion of 120-250GL/year is expected in the future, that threatens to put pressure on a water supply that is prone to seasonal droughts. In this manner these sources are potentially non-viable and non-sustainable for deployment of P2X.

As an alternative, waste/recycled water offer a more viable solution. Most of the current waste water treatment (WWTP) and recycling plants are being operated to supply drinking water or for other applications such as irrigation of local parks. However, there are some recycling schemes that provide recycled water for industrial operations in locations such as Rosehill, Smithfield and Hoxton Park. Similar schemes could be used for P2X opportunities in these locations. Additionally, there are WWTP operating in the Northern Suburbs, Bondi and Malabar that are discharging partially treated waste water into the ocean, that can be leveraged for P2X providing an economic incentive and advantage to develop an additional treatment plants at these facilities that can serve both P2X demand and supplement the city's water demand. Similarly, an advanced water treatment and recycling facility is being developed as part of the new Sydney airport that can be leveraged for P2X opportunities.

The P2X opportunities at Port Botany and industrial complex could also incentivise development of new desalination plants that can support both projects as well as shore up the city's water supply.

CO_2 and Biomass: In addition to Direct Air Capture, the region has a potential industrial CO_2 source — the Smithfield gas-fired power plant (0.019 MTPA CO_2). There is also a selection of biomass sources (approx. 2.1 MTPA) that could be converted to CO_2 to produce SAF, including sawmill residues, poultry manure, MSW and C&D organic waste.

Supporting Infrastructure

Transport Network: The Pacific Highway connects the region with the Hunter, North Coast and Queensland, and the Princes Highway connects it to Illawarra-Shoalhaven, the Tablelands and Victoria. The latter is also connected to the additional highways that run to the regional centres in New England, the Central West and Orana Region and the Riverina Murray regions. There is a rail connection with the North Coast Line that links to the Hunter Region, Greater Sydney Metropolitan Area and the North Coast. There are also rail links to the central, western and southern regions. The region also boasts the state's largest port (Port Botany) and airport (Sydney's Kingsford Smith).

Electricity Network: The region is connected to TransGrid's east coast network. While there are no large-scale local solar and wind farms in the region, the existing network is expected to connect to the Central West and Orana as well as the New England REZs, which could be complemented in the future by offshore wind.

Natural Gas Network: The Greater Sydney Metropolitan Area is serviced via the MSP gas network and the Eastern Gas Pipeline network, which extends north through the Central Coast region before terminating near Newcastle.

Approval and Risk Factors

Land Availability: Land availability might be severely limited here as it is a densely populated residential and commercial area. However, small-scale P2X projects can be developed in the Botany Bay (Port Botany) industrial zone, business parks being developed across the Sydney region and in emerging industrial zones in Western Sydney, e.g. Jemena Western Sydney Green Gas Project. Moreover, the Central Coast regional government is working on providing affordable locations for industrial activities and these can be leveraged. However, these sites will be limited by nature reserves like Ku-ring-gai Chase National Park.

Operational Risks: Flooding is a key operational risk, especially if the projects are developed near the Hawkesbury and Nepean Region.

Supporting Policy: Development of P2X in the region will be supported by the growing infrastructure network, especially road, rail and airports that can leverage P2X fuels. Fuel-cell vehicles could be a key demand area and a refuelling network is targeted under the NSW Hydrogen Strategy. The Central Coast already hosts the state's first hydrogen bus trial, which could expand to the Greater Sydney Metropolitan Area and to transit trains and light rail — as well as niche applications, such as delivery trucks, forklifts or garbage collection.

Most of NSW's population lives in this region and P2X can also serve the growing regional energy demand, especially for natural gas. This is a key market and can be serviced with additional blending projects like Jemena's Western Sydney Green Hydrogen Hub. P2X can also leverage the upcoming regional REZ development to establish a local use for ammonia, methanol and SAF, as well as service export markets through Port Botany. The emerging P2X economy can be supported through local innovation hubs located at the UNSW Sydney and the University of Sydney, which are delivering technological developments in the hydrogen and greater P2X space.

3.1.8. North Coast

The North Coast Region acts as a corridor between the eastern coastal regions of NSW and Queensland. The main regional areas are Port Macquarie, Coffs Harbour, Grafton and Lismore (Figure 14). It is the most biologically diverse region in NSW and hosts several heritage and natural reserves that boost the local tourism industry. The North Coast provides a corridor connecting Queensland to the Hunter, Greater Sydney and Illawarra-Shoalhaven region, with major highways and railroads, operations of which can be supported with P2X fuels. Additionally, P2X generated fertilisers can be used to support the agribusiness sector, while the local biomass resources can be leveraged for SAF generation to support regional airports and across the state.

Figure 14. Map of North Coast Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Sustainable Aviation Fuel • Ammonia	• Low Solar and Onshore Wind potential • Limited Demand • Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: The regional economy is supported by the export of food and beverages, an industry that is underpinned by the agriculture sector and contributes A$17.8 billion to the state's economy.[28] There is also manufacturing in the region which contributes A$300 million and 7,000 jobs to the regional economy.[29]

P2X Opportunities: Given the agriculture sector is the backbone of the region's economy, local generation of ammonia through P2X provides a potential opportunity to enable a sustainable supply of fertiliser. Additionally, powerfuels could be generated via P2X to support the local railway and road network. There is significant opportunity for SAF generation, given biomass availability in the region.

Feedstock Availability

Renewable Energy Potential: Our estimates show that the region has low solar and wind potential capacity factors of 22 – 23% and 32 – 42% respectively. However, higher wind capacity factors of 52 – 55% can be leveraged offshore.

Water Availability: The region has a share of the northern river system, the largest of which are the Manning River, which flows south of Port Macquarie, and the Macleay River between Port Macquarie and Coffs Harbor. The river system provides 3,200 ML/yr of water to the region. In addition, due to its proximity to the coast, dedicated desalination plants can be developed to provide water for P2X projects.

CO_2 and Biomass: The region has a selection of biomass sources (approx. 1.8 MTPA) that could be converted to CO_2 to produce SAF, including emissions from the Rocky Point bagasse co-generation plant, sawmill residues, dairy and poultry manure, almond shells, MSW, C&D organic waste and, to a lesser extent, cereal and non-cereal straw.

Supporting Infrastructure

Transport Network: The Pacific Highway passes through the major regional centres of Port Macquarie and Coffs Harbour and connects the region with the Hunter (to the south) and Queensland (to the north). There are also road links to the regional centres in the New England Region. In terms of rail, the North Coast Line that connects the Hunter region to Queensland passes through the region. There are no major ports, however dedicated export facilities can be developed near the regional centres of Coffs Harbour and Port Macquarie for export projects. There are also airports/airfields in Port Macquarie, Coffs Harbour and Byron Bay.

Electricity Network: The region is serviced via the TransGrid Electricity Transmission network with a 132 kV transmission network that connects to the Hunter and New England regions. The local grid comprises the Codong (30 MW) and Broadwater (38 MW) biomass power plants near the Byron Bay area.

Additional parts of the network could be developed to leverage the offshore wind potential and provide power to the grid or provide renewable energy for P2X projects in the nearby demand centres of the Hunter, Central Coast & Greater Sydney Metropolitan and Central West and Orana regions. This could leverage the upcoming expansion of the New England and Central West & Orana REZ.

Natural Gas Network: None of the major gas pipelines are available in the region (the closest pipeline is the Eastern Gas Pipeline, which terminates near Newcastle). The region relies on LPG, which creates an opportunity for replacement with a P2X product (e.g., Synthetic Natural Gas).

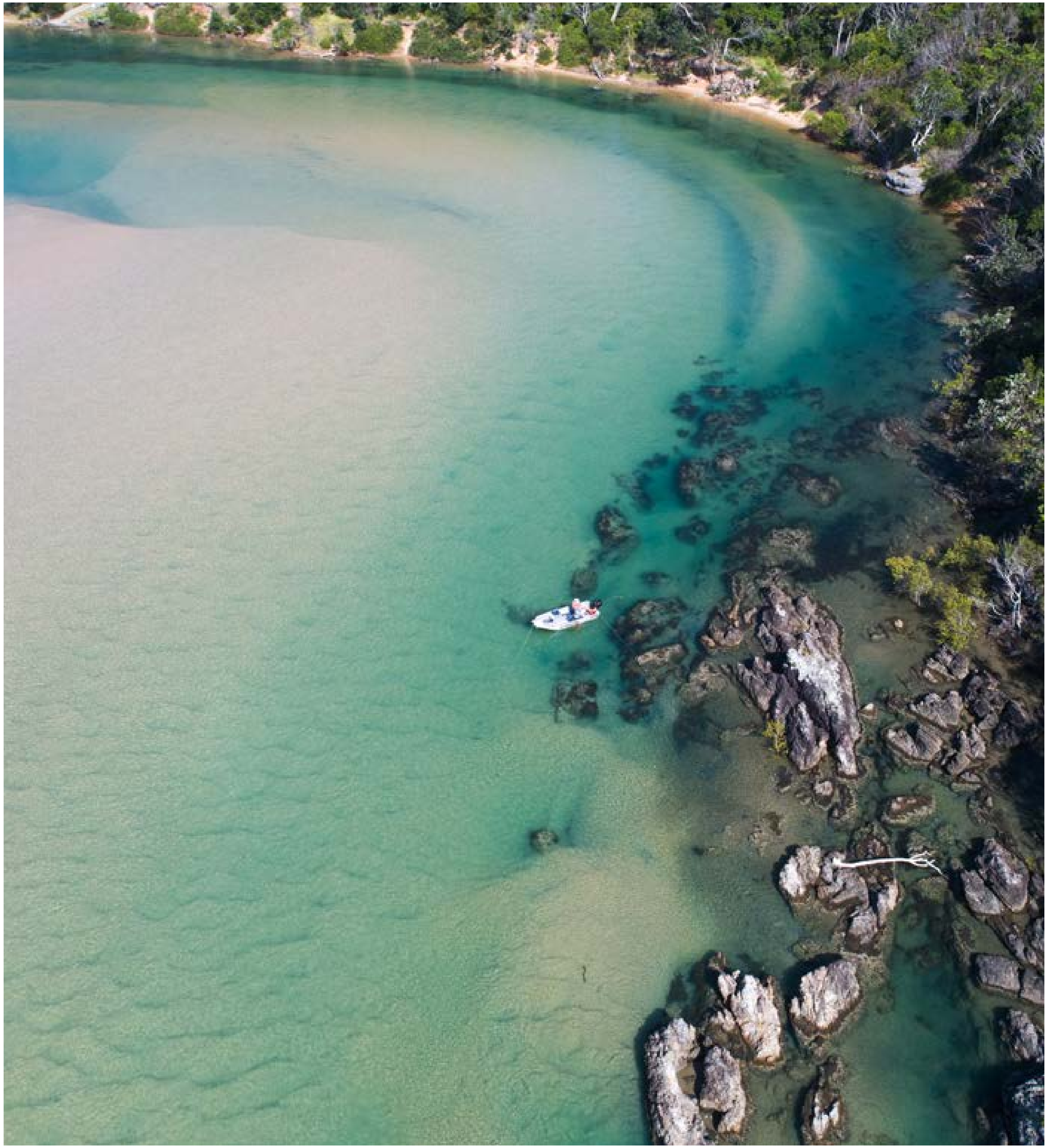
Approval and Risk Factors

Land Availability: Across the region, land availability will be constrained due to natural reserves and agricultural activities.

28 - North Coast. NSW Government. Accessed on 10th July 2022. Link
29 - Regional Development Australia (2022). Industries of the Mid North Coast. Link

Operational Risks: There are bushfire risks throughout the region and also the potential for the Macquarie and Macleay Rivers to flood.

Supporting Policy: Given the regional reliance on agricultural activities, there are avenues for manufacturing fertiliser locally via P2X-based ammonia generation. Similarly, a growing local maritime and air travel (tourism) industry could create the opportunity for alternative fuels, like methanol and SAF generation, by leveraging local biomass resources. In addition, the state government target for a hydrogen refuelling network and hydrogen highways could be leveraged to establish refuelling stations along the Pacific Highway.



3.1.9. South East and Tablelands Region

The South East and Tablelands Region (Figure 15) provides a southern link between NSW and Victoria, as well as the Australian Capital Territory (Canberra). The region covers a significant area and shares borders with the Riverina Murray Region, Central Coast and Orana, Greater Sydney Metropolitan Area and Illawarra – Shoalhaven Region. The main regional centres are Cooma, Goulburn and Batemans Bay. The regional economy is supported by tourism and the agribusiness. Therefore, P2X-based fuels to support mobility and supply chains can be employed. Additionally, the regional biomass can be used to generate SNG and methanol. The SNG and hydrogen blending can be used for blending into the Eastern Gas Pipeline that passes through the region and connects the state to natural gas facilities in Victoria.

Figure 15. Map of South East and Tablelands Region of NSW

Potential Regional P2X Opportunities	Key Barriers to P2X Deployment
• Hydrogen refuelling • Hydrogen gas blending • Methanol • Synthetic Natural Gas	• Low solar and onshore wind potential • Limited Demand • Land Availability • Operational Risk

Market Demand

Economic and Industrial Outlook: The regional economy is based on the generation of renewable energy, agricultural products and manufactured food, which form a major part of the region's A$10 billion contribution to the state.[30] The food industry relies on sheep and cattle farming and grain production. There is also a tourism market supported by the Snowy Mountains, Kosciuszko National Park, ski resorts, south coast and whale-watching attractions. The Port of Eden also has a berth that can host Cruise Ships. In addition, the region is a growing renewable energy production hub, with pumped hydro and several wind and solar farms already operational.

P2X Opportunities: Though the South East and Tablelands region has a limited industrial sector, regional P2X opportunities can be realised to support a potential hydrogen highway that can be established along the Princes Highway (the highway is included as a potential hydrogen highway as part of the ongoing collaboration between Victorian, NSW and Queensland governments to develop hydrogen refuelling networks across the east coast of Australia). Moreover, the major Eastern Gas pipeline passes through the region (as elaborated below), which could be used for hydrogen blending by leveraging the region's solar/wind and hydropower potential.

Feedstock Availability

Renewable Energy Potential: Our estimates reveal that the region has lower-end solar (22%) and wind capacity factors (37%). However, there is high wind potential offshore (capacity factor of 54 – 55%). There is also a significant hydro energy potential in the region, including active projects like the Snowy Hydro Scheme, which is based on nine hydro power stations that have a combined capacity of 4GWs.

Water Availability: For water, the region relies on its share of the Southern River systems, including the Snowy River, Shoalhaven River, Clyde River and Bemboka River, which supply a combined 1.8GL/yr of water. In addition, there is groundwater availability from the Lake George Alluvium (1.2GL). Locations near the coast could develop their own desalination facilities.

CO_2 and Biomass: The region has an industrial CO_2 source from the Berrima cement calcination plant (1.7 MTPA of CO_2). The region also has a selection of biomass sources (approx. 0.9 MTPA) that can be converted to CO_2 to produce SAF, including cereal and non-cereal straw, sawmill residues, dairy and poultry manure, MSW and C&D organic waste.

Supporting Infrastructure

Transport Network: The region is connected to the rest of the state and Victoria via the Princes Highway, which has branched connections to Canberra and the Riverina Murray Region. In addition, the Hume Highway passes through Yass and Goulburn before entering the Greater Sydney Metropolitan Area. There is no rail across the eastern part of the region, but the Main Southern Line passes through Yass and Goulburn in the western part of the region and connects to Wollongong and Canberra.

Electricity Network: The eastern side of the region also lacks an electricity transmission network, but there is an existing network on the north-west side that passes through Yass and Goulburn and connects to the local solar/wind farms and hydro facilities. At present 1GW of wind, 10MW of solar and 350MW of hydropower assets are installed here.

Natural Gas Network: There are major natural gas pipelines in the area, with the Eastern Gas Pipeline passing through Cooma and to the east of the ACT, while the MSP pipeline passes through Goulburn on the north-west side before crossing into the Greater Sydney Metropolitan Area and Illawarra – Shoalhaven region.

Approval and Risk Factors

Land Availability: The availability of land to host large-scale P2X projects will be limited

30 - South East and Tablelands. NSW Government, Accessed on 10th July 2022. Link

due to large parts of the region being covered by forest reserves and mountainous terrain.

Operational Risks: Labour and machinery would have to be transported from other regions to develop P2X facilities. This could be hampered by a lack of railroads on the eastern side of the region. The Tumut and Cooma-Monaro REZs have a high bushfire score according to the AEMO ISP 2022.

Supporting Policy: Given the ongoing development of solar and wind farms in the region, hydrogen-based energy storage could be developed to support the grid integration of large volumes of variable energy supply. Moreover, hydrogen-based microgrids could be developed on the eastern side of the region as these communities are off-grid. The local energy provider, Endeavor Energy, is already exploring the opportunity to develop a microgrid on the south coast. A key state hydrogen target of hydrogen blending in natural gas pipelines could be undertaken by leveraging the local renewable energy potential for large-scale hydrogen blending in the MSP and Eastern Gas Pipeline that pass through the region.

3.2. Summary of NSW P2X Opportunities

The preceding section provided an overview of each NSW region's suitability to generate and use powerfuels in driving decarbonisation. While these assessments are indicative and require further detailed investigations, they still provide a clear message that some power fuel markets are developing in NSW. These opportunities are summarised below.

3.2.1. Regional Opportunities

Our assessment criteria further highlight the diverse resource distribution, economic outlook, industrial and energy mix of NSW's regional economies. Given this diverse mix, several potential P2X opportunities might be realised across the regions of NSW to support the regional industries and energy supply. **Figure 16** provides a snapshot of potential P2X facilities that could be developed in NSW based on our regional assessment.

As observed, several P2X hubs to serve multiple demands can be created across the state. The development of such hubs will then tie in with the key sector targets for P2X development (as informed by the state and Federal targets highlighted earlier in **Chapter 1**) and could serve the following purpose:

- H_2 blending into natural gas pipelines (state target of 10% by volume blends by 2030).
- H_2 use for fuel cell vehicles (mining and heavy vehicle mobility applications).
- H_2 as a potential feedstock for existing facilities (steel making, refineries and ammonia production).
- H_2 as a means of energy storage of solar/wind for variable renewable energy integration with the grid.
- H_2/Green ammonia as an alternate fuel for existing natural gas/coal power plants (albeit with the additional need to retrofit these facilities to combust ammonia in this manner).
- Green Methanol generation for energy and industrial use and enable leveraging waste CO_2 emissions and biomass for local use.
- Sustainable Aviation Fuel (SAF) generation for domestic consumption at domestic/international airports.

Section B and C of this report further elaborate on these opportunities and also provide a near and long-term cost outlook of developing these P2X opportunities.

Impact of P2X Development In NSW:
The deployment of these envisioned P2X value chains in NSW will enable further economic growth and job creation in the state but also enable decarbonisation of the state's industrial and power sector. Yet, it is important to realise the deployment of P2X projects will also have a life cycle impact due to their interaction with land, energy, water resources and the surrounding environment. However, the planning process of these P2X projects involves rigorous planning, approval and life cycle impact of these projects. These aspects need to be highlighted and flagged as the long term benefit of P2X will be undermined by the associated negative impacts of these value chains. These would have to be analysed on project-to-project basis and is beyond the scope of this analysis.

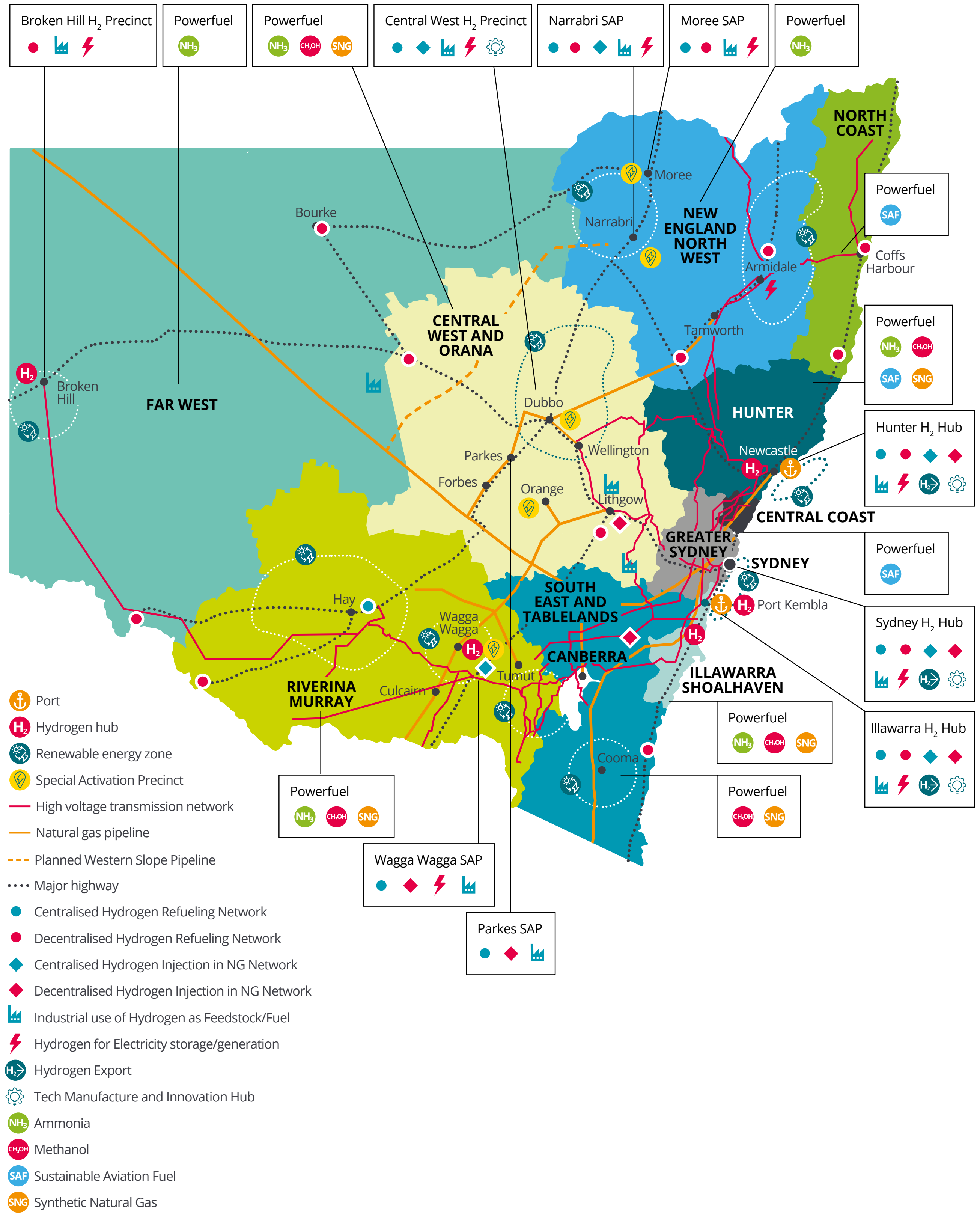


Figure 16. Regional Outlook of P2X Opportunities in NSW

3.2.2. Global Opportunities

Additionally, beyond Australia, the development of the P2X sector is ongoing rapidly, driven by an increase in investment and a policy push supported by a number of global economies that realise the potential of P2X. There is an emerging consensus that global P2X markets will be driven by the countries with high renewable energy potential, and that countries with strong economies and trade policy will have the most to gain from a global P2X economy. In this regard, Australia — and specifically NSW — has a first-mover advantage as the government is committed to making the state a renewable energy export superpower.

The **Australian Hydrogen Strategy** suggests that Australia can export hydrogen and additional P2X products (like ammonia and methanol) to emerging markets in Japan, Korea and Germany. Germany offers an interesting case study — given the latest findings from the **Australian-German Renewable Hydrogen Export Supply Chain Feasibility Study** which suggests that, despite the large distances between Germany and Australia, the cost of shipping P2X to Germany from Australia need not be a major cost driver in the context of the full supply chain.[31] Given this, Australia, and specifically NSW can be competitive with other potential exporters as it has the ability to leverage large-scale and low-cost renewable energy to produce P2X products.

In this manner, the state can be a key exporter of P2X products in regional Asian markets (including Singapore, Japan and South Korea) and beyond especially in the emerging markets of Europe (**Figure 17**). We elaborate on these opportunities further in **Section D** of the report.

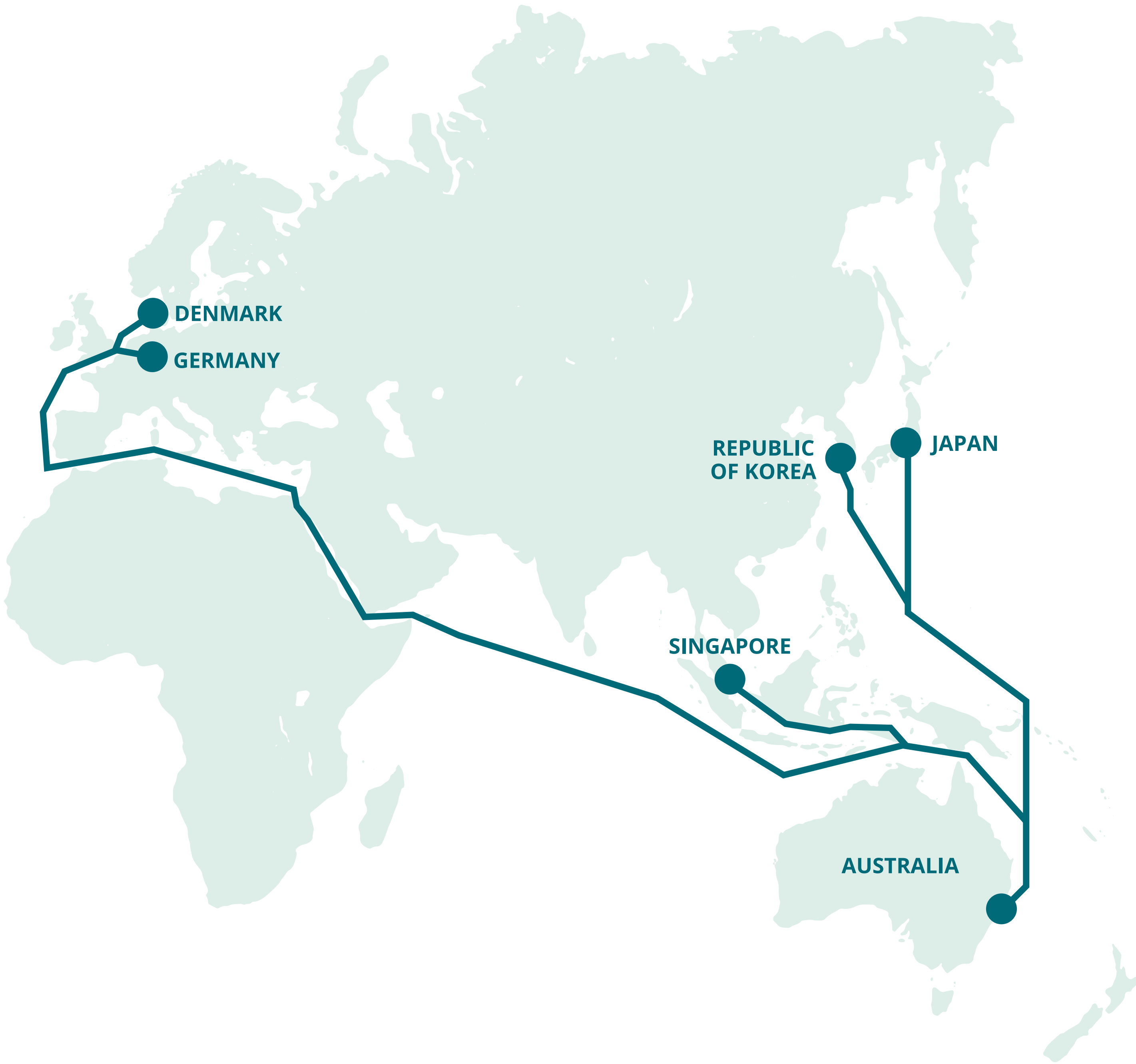


Figure 17. Potential international markets for NSW powerfuels.

31 - Daiyan et al (2021). The Case for an Australian Hydrogen Export Market to Germany: State of Play Version 1.0. UNSW, Sydney DOI: I: Link

Section B. Hydrogen – The Lego Block of P2X

In Section B, we provide an outlook on the hydrogen value chain in NSW. This entails highlighting key locations for hosting green hydrogen generation facilities (including already defined hydrogen hubs, REZs and SAPs), identification of potential end uses for hydrogen in NSW and providing a short-term (2022-2030) and long-term (2050) cost outlook across the state. In addition, the technical and economic outlook of the hydrogen value chain for key market activation sectors, such as hydrogen refuelling and gas blending, is highlighted.

Chapter 4 – Hydrogen Supply Opportunities in NSW

In previous publications, P2X opportunities have largely been identified at existing key industrial zones in the Hunter and Port Kembla region, and the Special Activation Precincts (SAPs). However, stakeholders have suggested the opportunities extend beyond current activities and locations and in this report we provide an outlook of hydrogen opportunities across the whole state.

The NSW Hydrogen Strategy sets stretch targets for 2030 that include:

- Reducing the cost of hydrogen to A$2.8/kg
- Deploying 12 GW of renewable energy capacity and 700MW electrolyser capacity
- The rollout of at least 10,000 hydrogen fuel-cell vehicles and
- 10% by-volume gas blending.

In line with this strategy, projects are already underway at various locations in NSW to blend hydrogen into natural gas networks, develop hydrogen refuelling projects and combust hydrogen in existing gas-fired power stations.

The Opportunities

In order to quantify the hydrogen opportunities, we developed a costing tool — the NSW Powerfuel Value Chain Cost Tool — to model various P2X pathways, including hydrogen and conversion to ammonia, methanol, sustainable aviation fuel (SAF) and synthetic natural gas (SNG). These pathways included power plant integration, market development scenarios and hydrogen supply.

The desktop analysis we completed shows that, at present, the cost of hydrogen is high but it could decrease by 75% in the lead up to 2050, which would result in hydrogen production costs of <A$2/kg. To achieve these cost reductions, economies of scale and cost learning are required, which means there will be a need to support higher cost projects in the short and medium term. A targeted project that would help reduce the cost while providing benefits to the state could be deployed.

The modelling indicates that the best performing sites in terms of hydrogen production cost are in the remote far-west regions of NSW, where demand for hydrogen will be low. Other regions, such as Central West & Orana, Riverina Murray and New England can also produce renewable energy competitively and can support local hydrogen generation or despatch their renewable energy potential to emerging hydrogen hubs along the east coast via a transmission network (which is expected to be built as part of the REZ development in the state).

For the Hunter and Illawarra regions, renewable energy generation from the highlighted REZs (most of which has already been committed) could be leveraged via newly built shared transmission lines to provide the required capacity of renewable power. While the cost of these lines requires significant capital investment, sharing of these costs will result in higher utilisation making the costs more competitive.

Finally, if large-scale high-capacity factor offshore wind farms can be developed at the reported costs then, by 2050, these systems could be at parity with onshore transmission-based systems.

4.1. Hydrogen's Role in NSW

A critical part of hydrogen's role in NSW is informed by the 'NSW Hydrogen Strategy', which provides a policy framework, targets, current competencies, roles and an action plan for developing the state's hydrogen economy.[32] The strategy highlights that the NSW Government has the feedstock, infrastructure, R&D and economic competencies (further corroborated by our analysis in **Chapter 3**) to establish a P2X sector, which would involve development of renewable energy grids. In the P2X economy, hydrogen will be used for energy storage, injection into the natural gas network, refuelling FCVs — especially trucks and buses — and green industrial applications (green steel, ammonia, sustainable chemicals and fuels — methanol and SAF).

To achieve this, the strategy sets stretch targets for 2030 (**Figure 18**), which include reducing the price of green hydrogen to A$2.8/kg, deploying 12GW of renewable energy capacity and 700MW electrolyser capacity, the rollout of at least 10,000 hydrogen fuel-cell vehicles and 10% by-volume gas blending.

These targets are also supported through legislative reform and initiatives, which are required for the development of a hydrogen economy. For instance, regulatory reform to introduce hydrogen into the state's natural gas network is already underway. Additionally, the government has set plans for conducting a pilot hydrogen bus project in the Central Coast region.[33] The government has also joined the Queensland and Victorian governments in committing to develop a hydrogen refuelling infrastructure to connect the east coast regions of Australia by 2026.[34] The initial part of this project includes funding for four refuelling stations between Sydney and Melbourne (A$10 million) and additional grants for introducing long-haul hydrogen fuel-cell freight trucks.

The development of Hydrogen Hubs is also paving the way for private sector investment into hydrogen projects, with the Hunter and Illawarra (Port Kembla) Hydrogen Hubs receiving proposals worth more than A$4 billion as part of the recent call for expressions of interest.[35] These include plans for 21 projects with a combined 5.9GW of electrolyser capacity (eight times more than the target of 700MW). Opportunities to blend hydrogen into the natural gas networks and hydrogen refuelling projects are already emerging as key drivers of market activity and projects are already underway. For instance, Jemena — one of Australia's largest natural gas network operators — has developed an operational natural gas blending facility in Western Sydney, which also serves as a pilot plant to assess the infrastructure and equipment suitability for hydrogen blends.[36] Although gas blending strategy is currently the easiest way to integrate hydrogen into existing gas network with minimal capital costs for new infrastructures and appliances, developing capabilities to replace natural gas with green hydrogen is essential in the longer term. Similarly, Coregas is developing the state's first hydrogen refuelling project in Port Kembla, which will cater to hydrogen trucks.[37] The state government is also supporting the development of Australia's first green hydrogen-ready gas power plant in NSW, which involves the installation of dual-fuel capable turbines at the Tallawarra natural gas power plant in the Illawarra region.[38]

32 - NSW Hydrogen Strategy. NSW Department of Planning, Industry and Environment. 2021. Link
33 - State's first hydrogen bus to hit Central Coast streets. Transport for NSW. NSW Government Press Release. 2022. Link
34 - Hydrogen highways to link Australia's East Coast. NSW Department of Planning, Industry and Environment. Media Release. 2022. Link
35 - $4 billion industry response to hydrogen hubs. NSW Department of Planning, Industry and Environment. Media Release. 2022. Link
36 - Jemena Western Sydney Green Gas Project. HyResource, Accessed on 25th July 2022. Link
37 - Port Kembla Hydrogen Refueling Facility. HyResource, Accessed on 25th July 2022. Link
38 - NSW Government (2021). Australia's first green hydrogen and gas power plant. Link

2030 STRETCH TARGETS

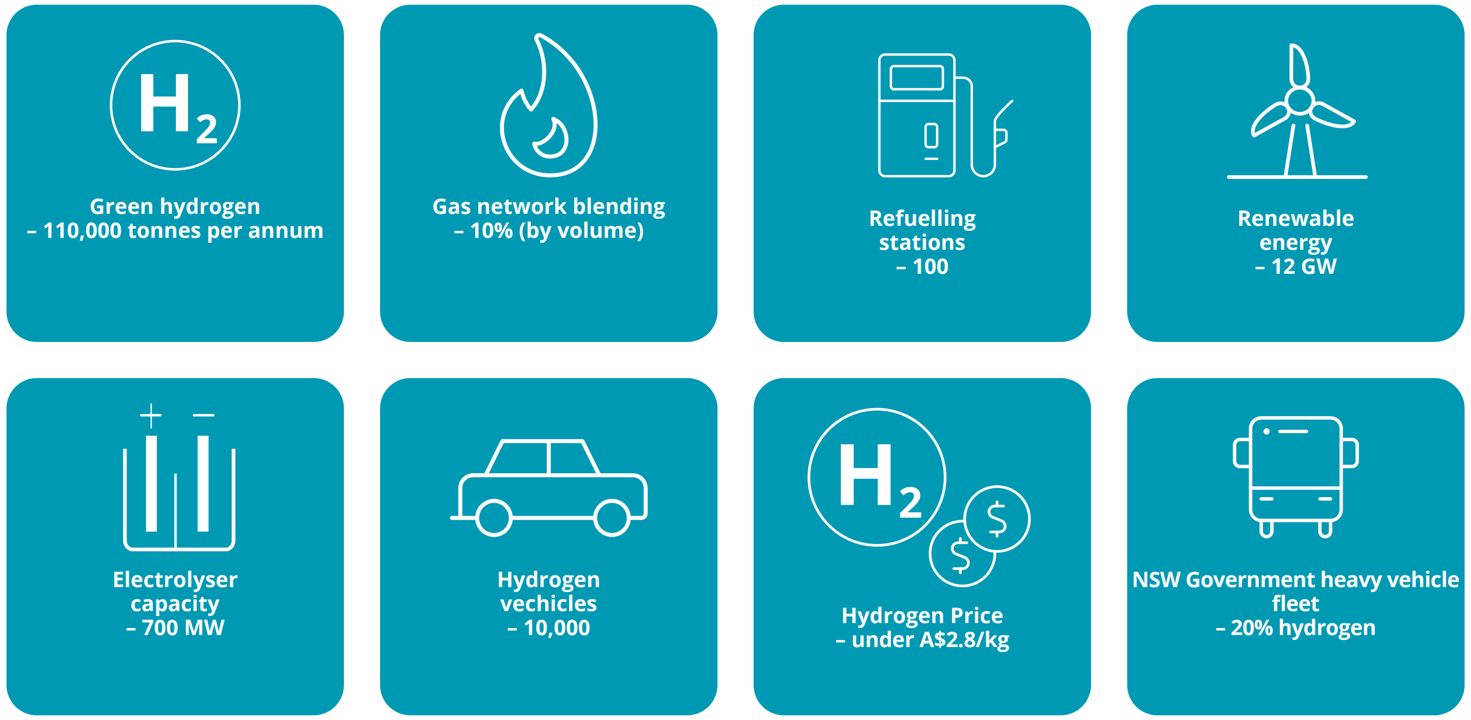


Figure 18. NSW H_2 Strategy Stretch Targets For 2030.

4.2. Hydrogen Opportunities in NSW

A common theme for prior opportunity identification (such as in NSW Hydrogen Strategy, NSW P2X Pre-Feasibility Study) has been that P2X opportunities (particularly H_2 applications) have been focused at existing key industrial zones including the Hunter and Port Kembla regions, and SAPs. Recent stakeholder consultations have indicated that in NSW, the opportunities for a hydrogen value chain extend beyond current activities and locations. In this study, we extend beyond the already specified industrial hubs/SAPs and provide an outlook of hydrogen opportunities across the whole state, as shown in **Figure 19**. The highlighted opportunities have been identified based on the findings from our opportunity mapping framework (elaborated in **Chapter 3**).

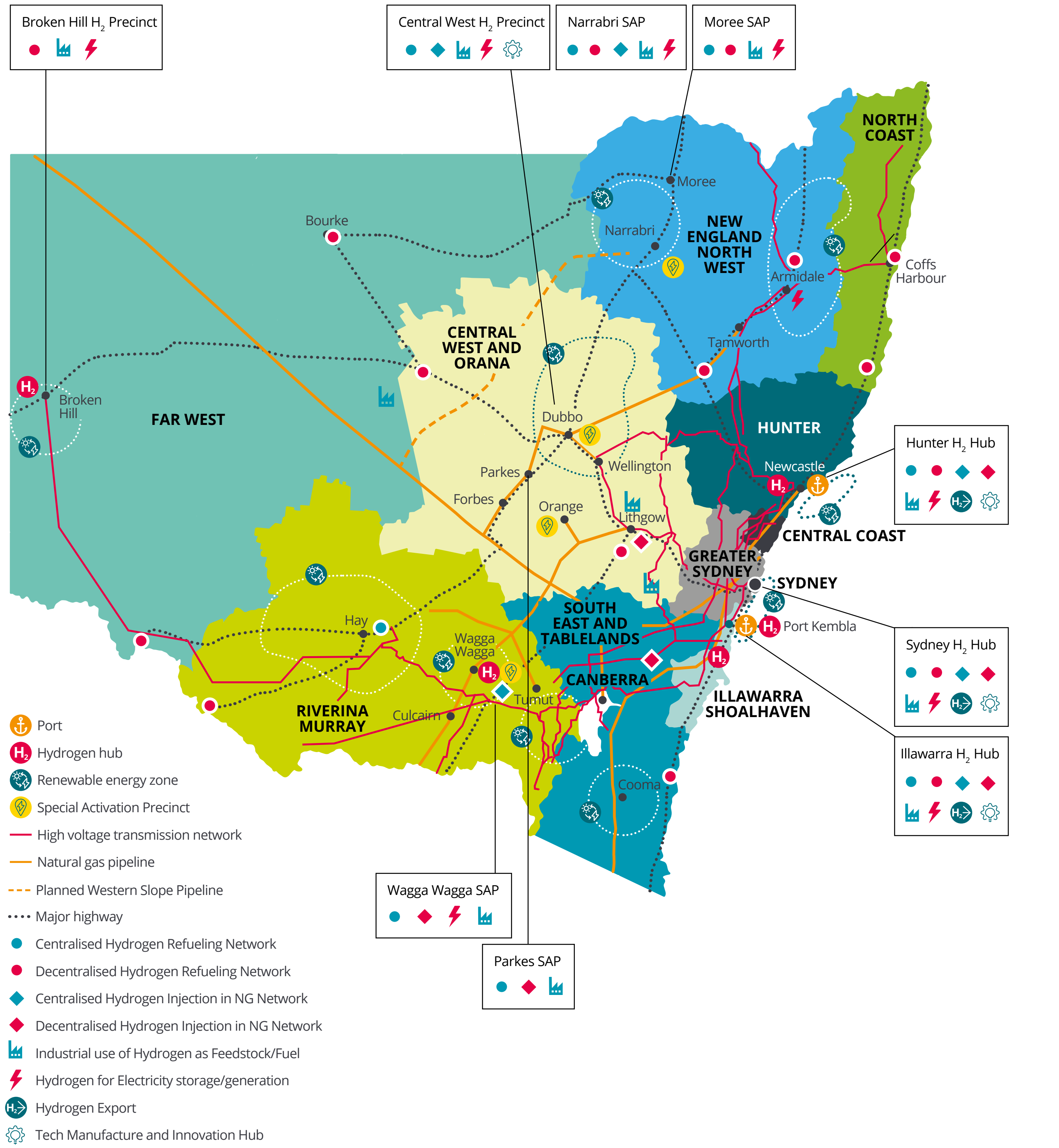


Figure 19. Map of Hydrogen Value Chain Opportunities in NSW
(The opportunities highlighted in the above figure are based on desktop evaluation of the location, feedstock, infrastructure, approvals and demands. As a next step, individual project studies should be completed that will further evaluate the feasibility of each region.)

4.3. Hydrogen Opportunity Costing

4.3.1. Costing Framework

A key indicator for viability of powerfuels is the economics. In this section, we model the costs of the value chain leveraging existing knowledge, HySupply modelling tool and the recently developed NSW Powerfuels Value Chain Cost Tool. The basic framework, key inputs and outputs for the modelling tool are shown in **Figure 20**.

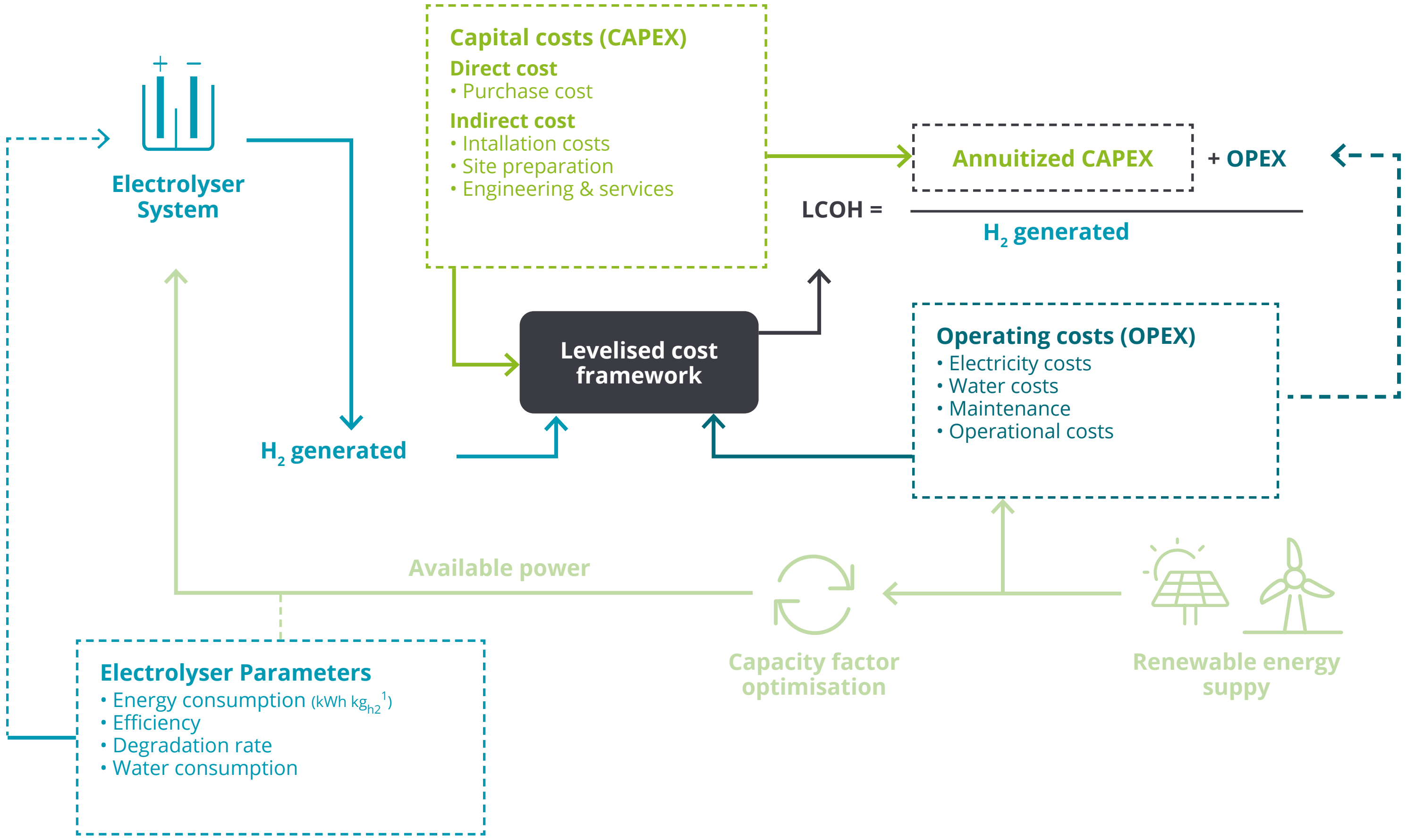


Figure 20. Hydrogen Cost Framework Used in This Study

Previous studies indicated that the major cost of hydrogen drivers include:

- the capital costs of the system (purchase and installation)
- the cost of capital
- integration with the electricity market, covering the cost of electricity and the type of connection (either as a standalone or via grid/transmission network connected system)
- the capacity factors achieved.

Studies have also indicated that system efficiency and O&M costs also play a role but are not significant cost drivers. Moreover, the costs integration with the electricity market and the capacity factor are highly location-dependent and should form a key part evaluation for site selection.

4.3.2. Costing Tool

The above framework was then converted into a costing tool, the NSW Powerfuel Value Chain Cost Tool that has been developed as an open-source resource (as elaborated below). The tool has been used to evaluate the green hydrogen costs in various regions of NSW for this study. The scope and outcomes of this analysis are elaborated below in the next sections of the chapter.

NSW Powerfuel Value Chain Cost Tool – Hydrogen Opportunity Analysis

The NSW Powerfuel Value Chain Cost Tool is a web-based package that is available as an open-access resource to support project proponents, governments, researchers and the general public to assess potential P2X projects across the state.

The tool can model various P2X pathways including hydrogen and conversion to ammonia, methanol and sustainable aviation fuel (SAF). The tool also models end-use applications such as hydrogen refuelling stations and natural-gas blending.

Specifically for the hydrogen opportunity, the backend calculation of the tool relies on user-defined electrolyser and power plant configurations that are complemented by capacity factor simulations based on local solar and wind data, and eventual costing based on the framework in **Figure 20**.

The tool can be used in two operating profiles:

- **Simplified – Quick Pass Analysis:** This profile provides a simplified input template catered towards the everyday user, allowing them to evaluate project economics, at a user-defined scale, such as a standalone dedicated hybrid combination of solar or wind farms, or a transmission network-based configuration with electricity supply costed as a Power Purchase Agreement (PPA).
- **Detailed – Comprehensive Analysis:** This profile builds on the functionality of the simplified profile but caters for an advanced and knowledgeable user, providing them with additional features like the inclusion of battery storage, the ability to define economies of scale, efficiency variations against load ratings, overloading of electrolyser and degradation profiles, amongst others. The tool can be used to analyse 24 potential scenarios using the electrolyser, power plant and battery combination.

The tool can be used to determine the levelised cost of hydrogen or develop high level key economic indicators, however the tool is not designed to develop a hydrogen sale price.

Note: The tool has been used to conduct the cost analysis for the P2X pathways for this report.

4.3.3.Hydrogen Generation Modelling Scenarios

For the costing analysis, we divided state into 22 zones (exploring >50 locations onshore and offshore) as shown in **Figure 21**.

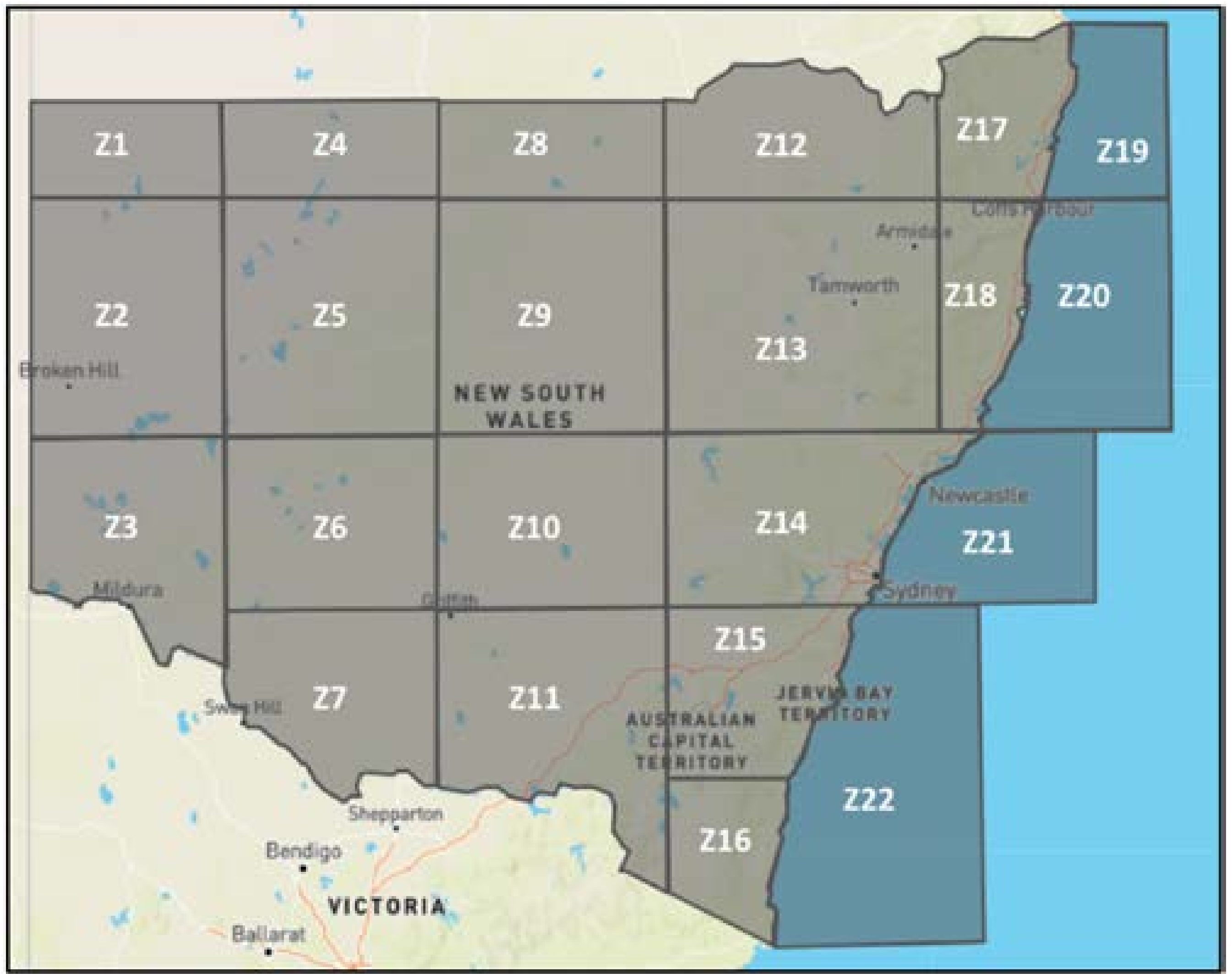


Figure 21. Zones Assigned For This Feasibility Study That Are Then Used For Evaluating Hydrogen And Powerfuel Value Chain Cost Profile.

Note: Here the zones are named as Z#. Note that there is no ordering or priority in the zone numbers, and they were assigned in arbitrary order.

These zones were then considered as case studies to provide a cost outlook of hydrogen generation across NSW. This cost outlook provides levelised cost estimates for renewable energy and H_2 generation, intermediate storage, and transport in the near term (current project development under 2022 cost estimates), medium term (development post 2030) and long term (development in 2050). In addition, we also compare different cases of power supply options to drive the electrolysis process and supply chain options for hydrogen to end use sectors as elaborated below.

4.3.3.1. Power Plant Integration

In our analysis, we focus on the standalone renewables integration as they are relatively simpler to build and operate. For such scenarios, we assume the solar and wind farms are developed in conjunction with the electrolyser as part of the P2X facility by the project proponent. For modelling the power supply, we consider: (i) purely solar PV, (ii) purely wind farm driven and (iii) hybrid solar-wind farm driven electrolyser projects. The subsequent electrolyser capacity factor and hydrogen generation modelling are conducted based on zonal solar and wind generation data (refer to **Appendix A**). For the zones in proximity to the coast, we also consider offshore wind supply and sub-sea transmission lines to the electrolyser facility (refer to **Appendix A**). The case study of Hunter and Port Kembla Hydrogen Hubs is used below as a comparison between the option of using offshore wind resources via a sub-sea transmission line against the alternate option of leveraging solar/wind resources in nearby REZs (Central West and Orana REZ) to source bulk and low-cost renewable energy via a dedicated transmission line connecting the REZ to the P2X facility.

In our analysis to cost the power supply, we assume that the power plant is developed by the H_2 project proponent as a standalone dedicated facility and hence the build cost and operating cost of the power plant is directly integrated into the levelised cost calculation. The assumptions and methodology are provided in **Appendix B**. For the transmission network costs we used the AEMO Transmission Cost Estimation Tool,[39] which provides the A$/km cost for constructing the transmission line (including the costs for designing, contracting the project, purchasing the land, as well as purchasing, installing and testing the equipment). Therefore, the total transmission network costs depend on the length of the network, transmission capacity (MVA and KV of transmission network) and nature of transmission line (overhead or underground including sub-sea). For our analysis, if a dedicated line is considered we include the cost of the transmission network as an upfront cost based on the distance from the chosen power generation site (assumed to be the closest REZ) and the H_2 generation facility with 10% of capital cost to account for operating costs.

Moreover, the cost of a dedicated transmission network could be mitigated if it is built and shared by multiple users in the same vicinity as the electrolyser project, allowing users the benefit of paying for use of the network rather than the capital required for dedicated use. This would involve the users paying a fixed A$/MWh of electricity to recover the cost of the network and an additional transmission service charge payable to the network operator.[40] To calculate the tariff of the shared network, we established the cost of developing the network that was estimated from the AEMO tool, as well as the operating costs of the network and grid usage charges as elaborated in **Appendix B**.

Note: Several options are available for integrating the electrolyser with solar and wind farms. These include standalone or grid connected systems. In this study, we did not consider grid-connected electrolysers owing to high price volatility at present in NSW and other complexities (elaborated in **Appendix A**). These complexities are project specific and beyond the scope of this study. Similarly, there are additional options to include battery storage to supplement solar/wind energy supply and providing a firmed electricity supply to the electrolyser, which is explored for hydrogen derivative production (**Chapter 6 – 10**). However, the NSW Powerfuel Tool has functionalities to model and cost grid connected scenarios and use of batteries if required.

39 - The AEMO Transmission Network Cost Tool has been used for costing the transmission network costs in this section. Link
40 - Transgrid (2022). NSW and ACT Transmission Prices. Link

4.3.3.2. Market Development Scenarios

In addition to the electrolyser/power plant integration scenarios, our analysis assumes a staged approach to project scales to match the expected market development of hydrogen in the state[41]:

- Development till 2030: For the near-term development, up to 2030, we expect it to be highly likely to involve small-scale pilot projects which scale up gradually as 2030 approaches and demand increases. Based on industry consultation, this could include 10MW scale projects in the first phase of project development (up to 2025), > 50MW in the second phase (2025 to 2028) and >100MW in the third phase (2028 to 2030).[42] We consider these scales (up to tens of kilotonnes per annum — KTPA) would be powered using either dedicated solar/wind power plants as standalone projects or connected to the grid via a dedicated transmission network (for larger scale project >100MW, especially in constrained areas where large-scale solar and wind facilities cannot be built on-site — as elaborated earlier).
- Development post-2030: Over the medium term, post-2030, based on stakeholder engagement, projects with several hundred KPTA production capacity that can cater to hydrogen hubs and precincts with multi-end use applications. As a case study for this stage, to evaluate the LCOH we consider the build capacity estimate for solar and wind farms for the REZs in 2030 based on the AEMO ISP 2022 plan (hydrogen superpower scenario).
- Development by 2050: Over the long-term transition, by 2050, based on stakeholder engagement we expect the project scales to potentially reach several GW electrolyser capacities each or millions of tonnes per annum (MTPA) hydrogen generation capacity. Similarly, to evaluate the LCOH of this stage we consider solar and wind farm build capacity estimates for the REZs by 2050 for costing and electrolyser capacity factor mapping.

4.3.4. Hydrogen Supply

In addition to the generation of hydrogen, we also evaluate the delivered cost of hydrogen to potential end users (the delivered cost includes the cost of hydrogen, its intermediate storage and eventual transport). The considered delivery options are shown in **Figure 22**, which involves centralised generation and compressed gas storage of hydrogen at the generation site, prior to transport to the end user via compressed gas (CG_{H2}) tube trailers, pipelines or liquified hydrogen (LH_2) and tube trailers (post liquefaction on site), has been adopted. We analysed the potential hydrogen supply network in NSW, with hydrogen generation in key centralised production hubs (REZs, SAPs and emerging H_2 Hubs/Precincts) before distribution to demand centres across the state (up to 1,000 km away from the production site).

To evaluate the delivery costs, we considered the assumptions suggested in the existing literature as shown in **Table 2**.

Table 2. Assumptions for Hydrogen Delivery Costs

Cost Component	Cost Range	Cost Inclusions
Storage Costs	A\$0.34/kg – A\$0.42/kg[43]	(Including cost of compression, storage tank and related infrastructure as well as additional energy use and operating costs to support storage in pressure vessels up to 350 bar)
Liquefaction of Hydrogen	A\$1.4/kg – A\$3.4/kg[44]	(Including cost of liquefaction facility and related infrastructure as well as additional energy use and operating costs)
Transport	CG_{H2} Tube Trailer: A\$0.8/kg – A\$1.09/kg[41] L_{H2} Tube Trailer: A\$1.09/kg – A\$3.77/kg[41] Distribution Pipelines: A\$0.09/kg – A\$2.03/kg[41] Large Scale Pipelines: A\$0.15/kg – A\$2.90/kg[41]	(Including cost of fleet, equipment and operations)

Note: These cost assumptions are detailed in **Appendix B**. We also assume a 1 – 2%/year decrease in costs to account for technology improvement.

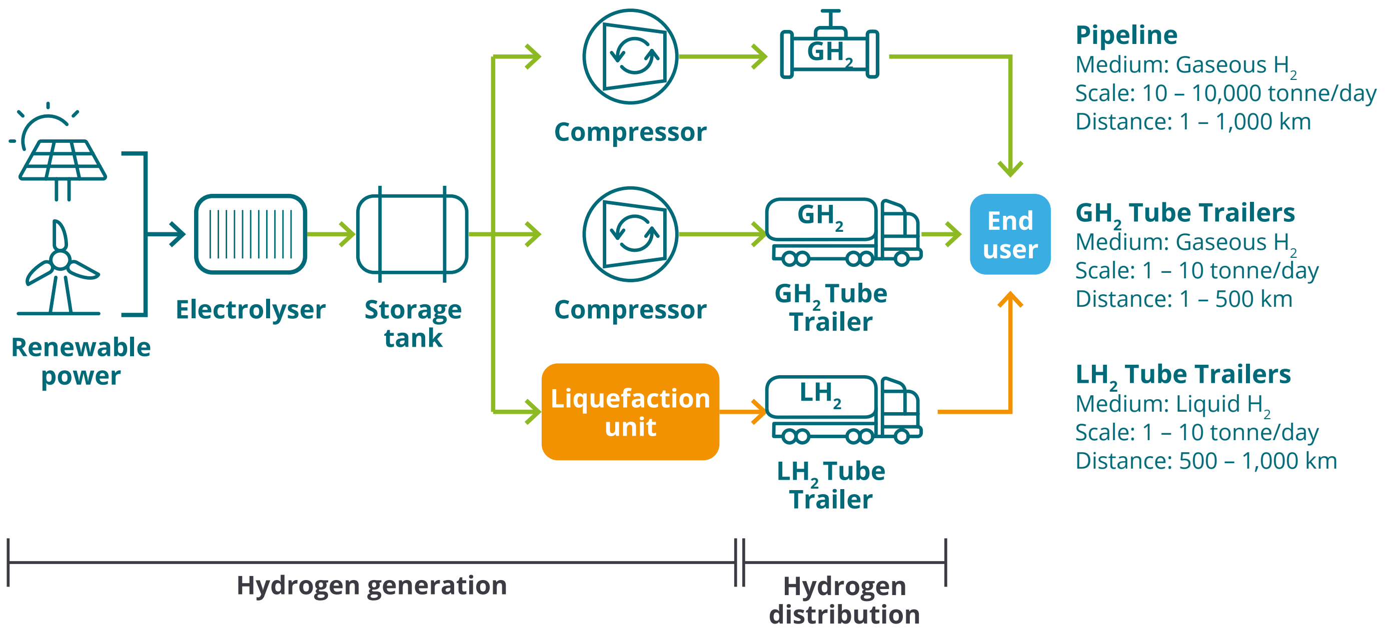


Figure 22. H_2 Supply Chain Based On Centralised H_2 Generation Then Distribution[45,46].

41 - Note these scales are assumed as a representation of future potential scales, we acknowledge that larger projects could be signed off and constructed as the market evolves.
42 - Inquiry into development of a hydrogen industry in New South Wales. Australian Hydrogen Council for State Development Committee by the Minister for Energy and Environment. 2021. Link
43 - National Hydrogen Roadmap. Bruce et al. CSIRO. 2018. Link
44 - The Case for an Australian Hydrogen Export Market to Germany: HySupply State of Play Version 1.0. Daiyan et al. UNSW Sydney. 2021. Link
45 - Given hydrogen supply chains are yet to be developed at scale in NSW, we use the cost estimates, scales and distances for the different supply options based on the latest analysis by IRENA[46]
46 - Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers. IRENA. 2022. Link

Hydrogen Supply Options for NSW

Presently, in NSW, the hydrogen distribution sector is limited and in the early stage of development. However, supply chains for hydrogen have been established and demonstrated in other markets such as the EU. To identify suitable hydrogen supply pathways, a technical and economic review was conducted to determine the likely most suitable technologies for hydrogen storage and transport with varied production and use case. The outcomes are presented in **Appendix A**, highlighting the pathways and comparing their advantages/disadvantages and suitability for NSW.

Gaseous Transport: Distribution of hydrogen as gas can be conducted via tube trailers or pipelines, with the advantage the hydrogen produced from the electrolyser can then be compressed and then injected into tube trailers or pipeline without any complex intermediate steps.

Pipelines provide the capacity for bulk storage and transport of hydrogen but are complex to construct (requiring large investment upfront and approvals). At present, there are no commercial pipelines for hydrogen in NSW/Australia, but demonstrations are underway to develop such pipelines especially in line with the state's aim to inject hydrogen into natural gas networks (including the Jemena Green Gas Project in Sydney). Moreover, amendments to the Australia's National Gas Regulatory Framework have been made that will pave the way for hydrogen to be transported/retailed using new and existing pipeline networks.[47]

In comparison, tube trailers, despite having a limited range and capacity, are more straightforward to deploy as they require less sophisticated equipment. The use of tube trailers is already earmarked for NSW, with Coregas operating tube trailers to supply hydrogen to consumers from its hydrogen production facility in Port Kembla. Coregas is also exploring opportunities for off-taking hydrogen from the Jemena Gas project for distribution to end users. The development of a tube trailer-based hydrogen distribution network however has a safety risk. In Australia, the Dangerous Goods Code (ADG Code Edition 7.7) applies to the transport of all forms of hydrogen, which allows transport of compressed hydrogen in the tube trailer. However their capacity is limited to a maximum of 1 metric tonne of hydrogen. Australian Standards are also working on developing standards for storage and transport of hydrogen which will further guide the development of hydrogen distribution in NSW.[48]

Liquid Transport: In liquid form hydrogen can be transported via liquid tube trailers, which offer larger capacity (liquid hydrogen is denser than gaseous hydrogen so allows for larger amount of hydrogen to be stored in similar volumes) and range. However, transporting hydrogen as a liquid requires liquefaction facilities which are absent in NSW (Australia only has one liquefaction plant in Victoria). In addition, during transport of liquid hydrogen there is risk of hydrogen losses due to boil off that would have to be considered.

Herein we evaluate the cost of all three options based on cost assumptions from literature.

4.4. Hydrogen Supply Cost Analysis

In this section, we provide the cost outlook of hydrogen supply in NSW at present up to 2050. The analysis is based on the state-of-the-art literature estimates for current and future costs and the performance of power plants and electrolyser systems. The modelling is completed using the NSW Powerfuel Value Chain Cost Tool and details of the costing method and the assumptions are available in Appendix B.

4.4.1. Electrolyser Development

It is widely reported that the capital cost of electrolyser systems, electricity costs and electrolyser capacity factors are major cost drivers for hydrogen generation. **Figure 23** shows the results of the analysis completed around the levelised production cost of hydrogen (LCOH). This LCOH value excludes the costs of storage, transport and conversion.

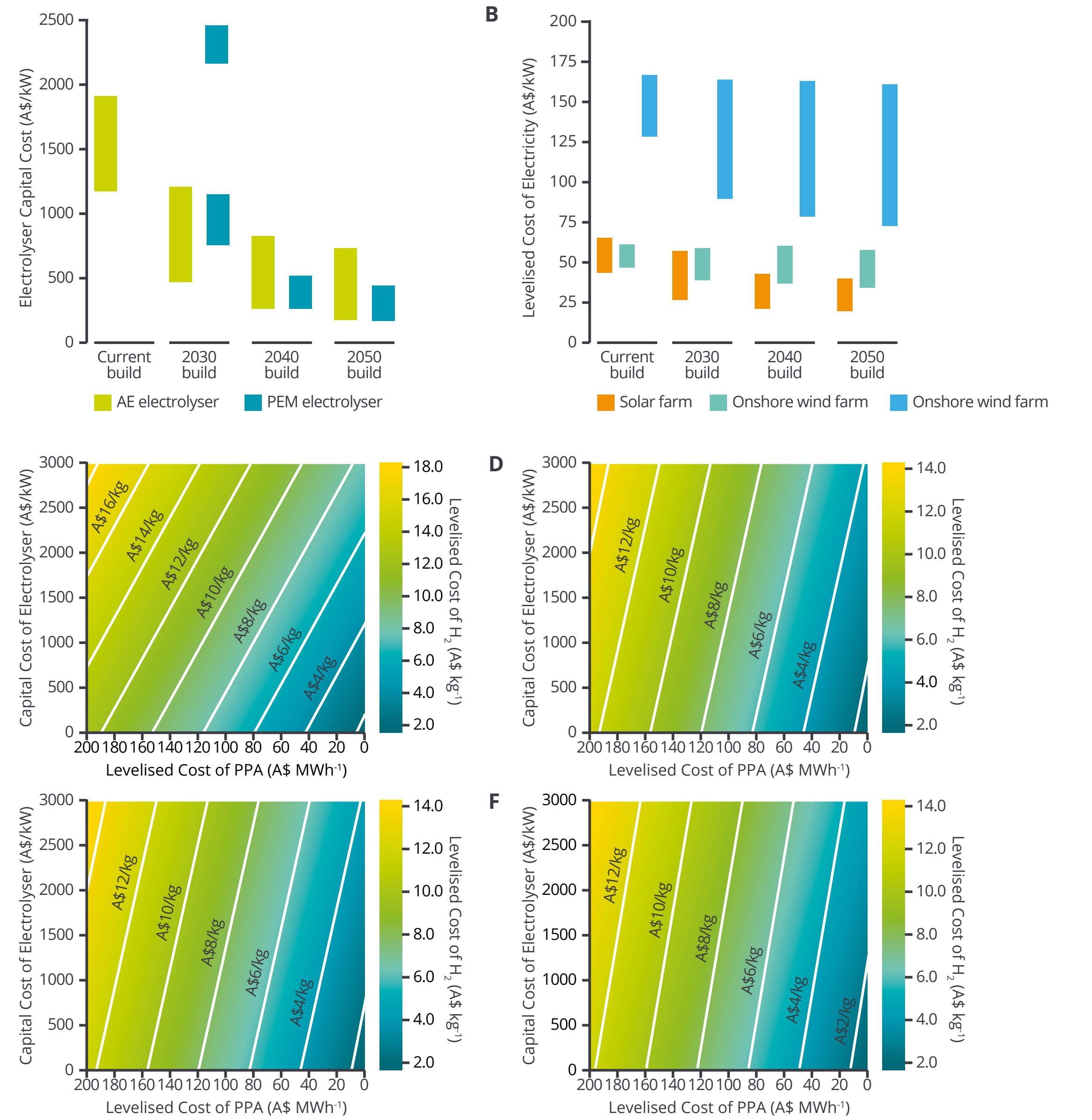


Figure 23. The Trade-off Between Electrolyser System Capital Costs, Electricity Purchase Costs And Operational Capacity Factors On The Levelised Cost Of Hydrogen.

47 - Transporting hydrogen via existing gas pipelines potentially a step closer. J.Hedge et al. Allens. Insight. 2022. Link
48 - The next frontier: challenges and developments in the transport of hydrogen in bulk. D. Brown. Allens. Insight. 2022. Link

In **Figure 23**, (A) represents the current and future range of costs for AE and PEME electrolysers in A$/kWh and (B) represents the current and future range of costs of solar, onshore and offshore systems in A$/MWh. (C) represents the LCOH as a function of electrolyser capital costs and cost of PPA at electrolyser operation of 30% capacity factor (inherent to solar driven scenarios), (D) represents 50% capacity factors (inherent to wind-driven scenarios), (E) represents 75% capacity factors (possible with oversizing, hybrid solar and wind combinations, and use of a battery) and (F) represents 100% capacity factors (possible with oversizing, hybrid solar and wind combinations, and use of battery). Note for the LCOH calculations we assume a project life of 20 years, cost of capital of 7% and electricity consumption of 60kWh/kg. Note The PPA costs assumes the cost of the renewables and additional cost of firming especially for high-capacity factors.

Below, we elaborate on this general outlook and evaluate the possible near-term and long-term hydrogen value chain costs (including generation, storage and transport to end users) for NSW based on the scope highlighted in **Section 4.3.3.2** which includes the staged approach to project development with comparison of scenarios including standalone onsite electricity generation and transmission network-based electricity sourcing from REZs. For the value chain analysis, we compare both options for hydrogen transport to the end user or electricity transport for onsite hydrogen generation and use, as elaborated in **Section 4.3.4**.

Note on LCOH

The LCOH is represented in A$ per kg of hydrogen with upper and lower sensitivities. The cost of storage, conversion (for LH_2) and transport respectively were added to the production cost to develop a delivered cost. The cost assumptions used in the analysis here are a basis to represent the general case of generating hydrogen in NSW. The economics of actual projects will depend on the individual build capacities, type of projects, technology and cost parameters that are highly unique to the projects. The NSW Powerfuels Value Chain Tool can be used to evaluate the economics of individual projects.

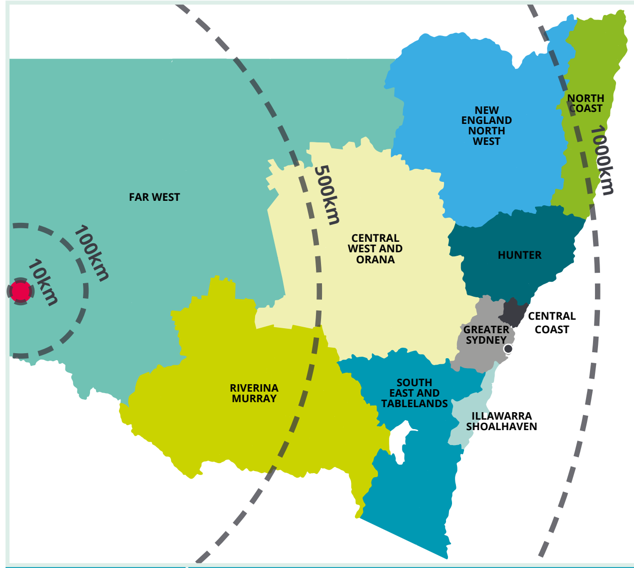
4.4.2. 2023 to 2025 Development

Modelling was conducted for hydrogen production during the present period, which was determined to be 2023-2025. For this period standalone solar and wind coupled with a 10MW electrolyser was modelled.

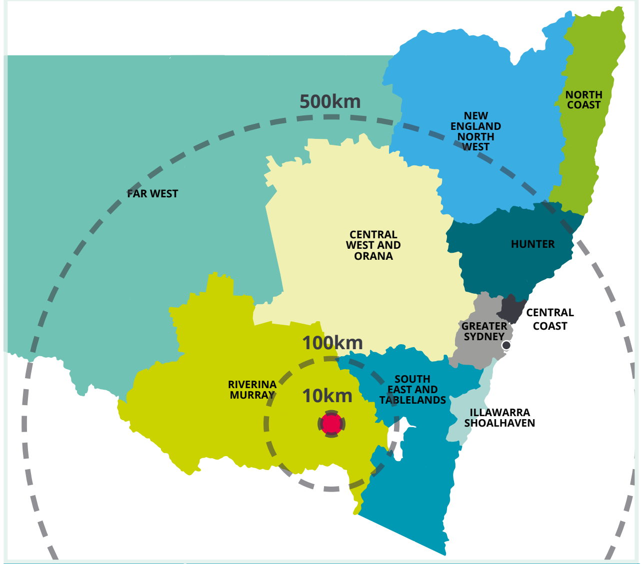
The key results of this modelling are summarised below:

- The hydrogen production costs result will range between A$6/kg – A$17/kg across NSW.
- The regions for solar-only powered hydrogen production are in the north-western and south-western regions of NSW (Z1, Z2, Z4, Z5, Z6 and Z8), where the LCOH will range between A$8/kg – A$15/kg, however these regions have limited demand for hydrogen.
- The regions for wind-only powered electrolysers were estimated to be located across northern, north-western, south-western and central NSW (Z1 to Z9), with the production cost ranging between A$6/kg – A$10/kg.

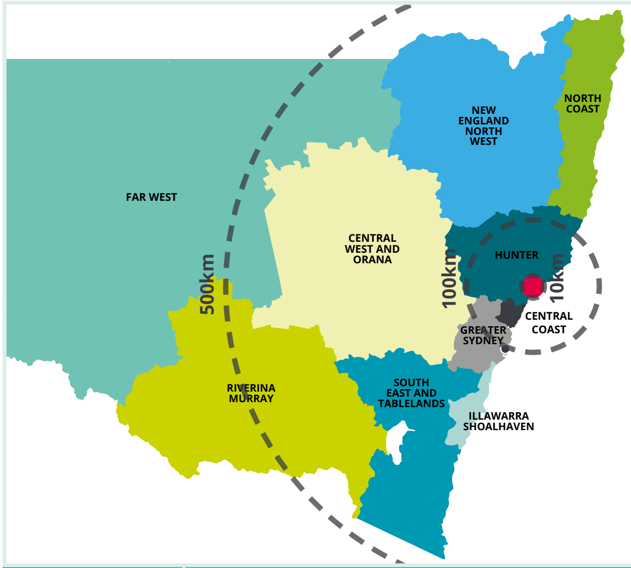
Estimated hydrogen generation costs for all zones are tabulated in **Appendix B**. As a representation of the delivered cost, in **Figure 24**, we evaluate the costs of delivering hydrogen (100 to 1,000 km) assuming centralised production locations such as Broken Hill, Wagga Wagga SAP, Hunter and Illawarra Hubs.[49] The analysis completed indicates that the scenarios that deliver gaseous hydrogen pipelines result in the lowest cost of delivered hydrogen. This option is reliant on having access to a gas distribution network and the suitability of blending. However there are significant technical and approvals challenges for this transport option.



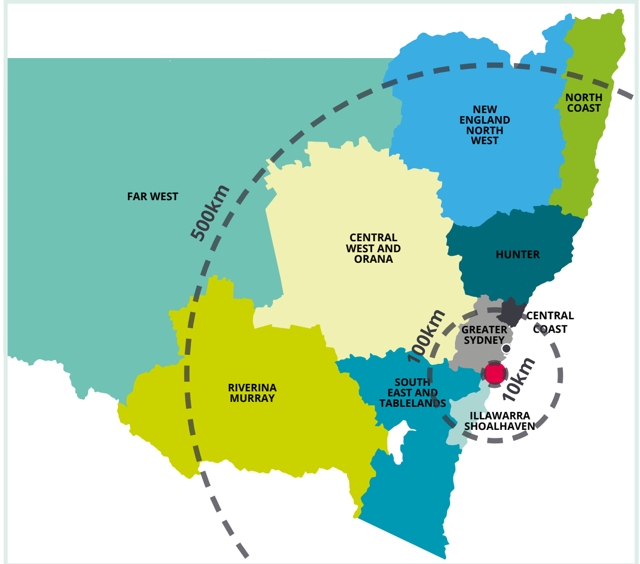
LCOH (A$/kg)	Broken Hill					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	6.13	15.21	6.84	15.92	9.85	19.42
100	6.32	17.51	6.84	15.92	11.43	21.00
500	6.34	15.42	7.13	16.21	13.74	23.31
1000	8.07	17.15	-	-	-	-



LCOH (A$/kg)	Wagga Wagga					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	9.23	17.51	9.94	18.22	12.95	21.72
100	9.42	17.70	9.94	18.22	14.53	23.30
500	9.44	17.72	10.23	18.51	16.84	25.61
1000	11.17	19.45	-	-	-	-



LCOH (A$/kg)	Hunter					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	7.63	17.21	8.34	17.92	11.35	21.42
100	7.82	17.40	8.34	17.92	12.93	23.00
500	7.84	17.42	8.63	18.21	15.24	25.31
1000	9.57	19.15	-	-	-	-



LCOH (A$/kg)	Illawarra					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	8.93	17.51	9.64	18.22	9.85	19.42
100	9.12	17.70	9.64	18.22	11.43	21.00
500	9.14	17.72	9.93	18.51	13.74	23.31
1000	10.87	19.45	-	-	-	-

Figure 24. Estimated hydrogen delivered cost from selected production locations in 2022.
Note: Here the given LCOH represents the total cost of hydrogen supply including generation, storage/conversion and transport of H_2.[50]

49 - Here Broken Hill, Wagga Wagga SAP, Hunter, and Illawarra Hubs are considered as an example of how the costs will vary.
50 - Note these costs are indicative, actual cost may vary based on scale route/fuel prices etc.

4.4.3. 2025 to 2030 Development

By 2025, it was assumed that the projects would reach 50MW of electrolysis. At this scale considering cost estimates for AE and PEME electrolysers (in 2025) including economies of scale as well as the cost reduction of solar/wind farms, the cost of hydrogen generation will range between A$4/kg – A$16/kg depending on the capacity factors of the region, which translates as a 5 – 35% decrease in LCOH compared to present development costs. The costs for all zones are tabulated in **Appendix B**. The results indicated that the estimated cost of 2025 solar-only powered electrolysers range between A$5/kg – A$16/kg. The cost estimates for 2025 wind-only powered electrolysers range between A$4/kg – A$12.5/kg.

4.4.4. 2030 to 2040 Development

For 2030, it was assumed the scale of electrolyser projects would potentially scale to 100MW or above. For this development both a standalone configuration as well as network connected (purpose built new transmission lines connecting REZs to potential H_2 hubs) was considered.

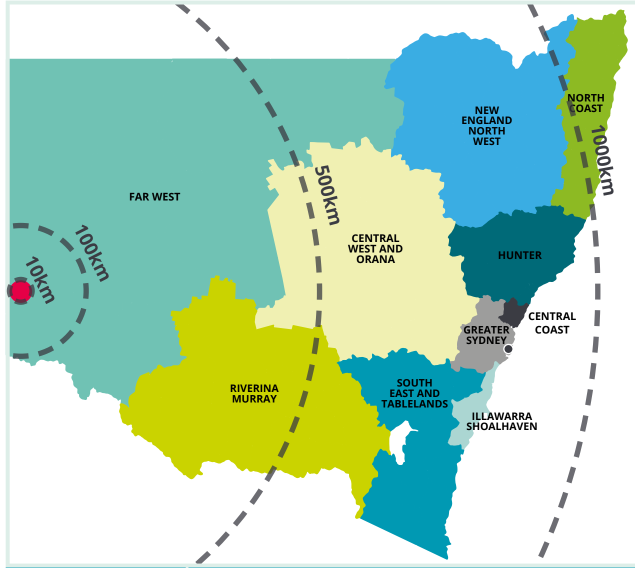
Overall, we estimate the LCOH to be between A$3.1/kg – A$7.8/kg as shown in **Table 3**. The results indicate that there could be a 50 – 65% decrease in LCOH compared to the present development (2022) cost scenario.

Table 3. Estimated cost of hydrogen production for 100MW H_2 electrolysers projects by 2030

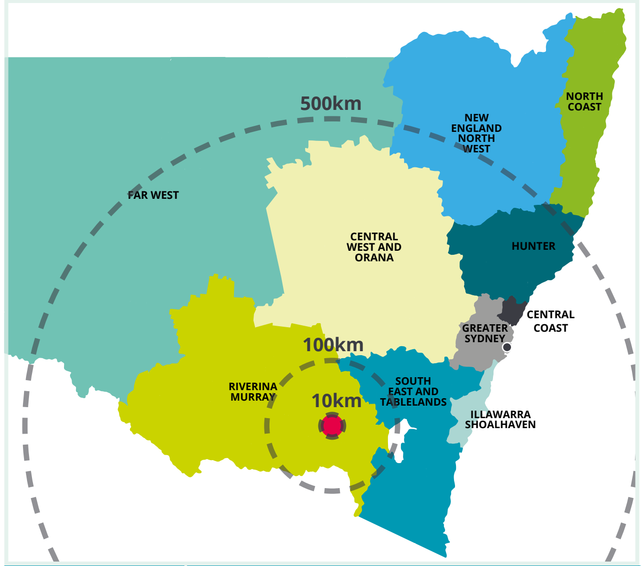
Electrolyser Scenario	Estimated Cost of Hydrogen Production (A$/kg)	
	Low CAPEX Assumption	High CAPEX Assumption
Solar Driven	AE: A$3.5/kg – A$4.1/kg PEME: A$4.5/kg – A$5.3/kg	AE: A$6.1/kg – A$7.2/kg PEME: A$6.6/kg – A$7.8/kg
Onshore Wind	AE: A$3.1/kg – A$4.7/kg PEME: A$3.8/kg – A$5.8/kg	AE: A$4.5/kg – A$6.9/kg PEME: A$4.5/kg – A$7.5/kg
Offshore Wind	AE: A$3.9/kg – A$4.0/kg PEME: A$4.5/kg – A$4.8/kg	AE: A$8.7/kg – A$9.2/kg PEME: A$9.4/kg – A$9.9/kg

Note: These costs are estimates for the standalone configuration assuming the solar/wind farm are built within the P2X facility and represent the cost of generation. Here the low CAPEX and the high CAPEX assumptions represent the hydrogen production costs based on lowest cost of electrolyser and renewable generator and the highest cost of electrolyser and renewable generator (details in **Appendix B**). The production costs for the offshore wind farms does not include the cost of transmission line, as these costs are unique to the type of transmission line and distance from the coastal facility, however the cases of leveraging offshore wind using sub-sea transmission lines in Hunter and Port Kembla Hydrogen Hubs are provided in the Appendix as an example. The location-wise breakdown of these costs is provided in **Appendix B**.

Figure 25 summarises the delivered hydrogen cost for a range of 10 – 1,000 km from the above REZs: Broken Hill, Wagga Wagga SAP (South West REZ), Armidale (New England REZ) and Dubbo (Central West and Orana REZ) at these scales. Moreover, if offshore wind can be developed at current cost estimates, they could be potentially leveraged for hydrogen production in the Hunter or Port Kembla Hydrogen Hub for LCOH of AS3.8/kg – A$9.6/kg. At this cost it is competitive with standalone systems at inland REZs when factoring the transport costs (e.g. road or pipeline). Offshore wind is still emerging in Australia and has uncertainty around the costs and timing which may impact development.

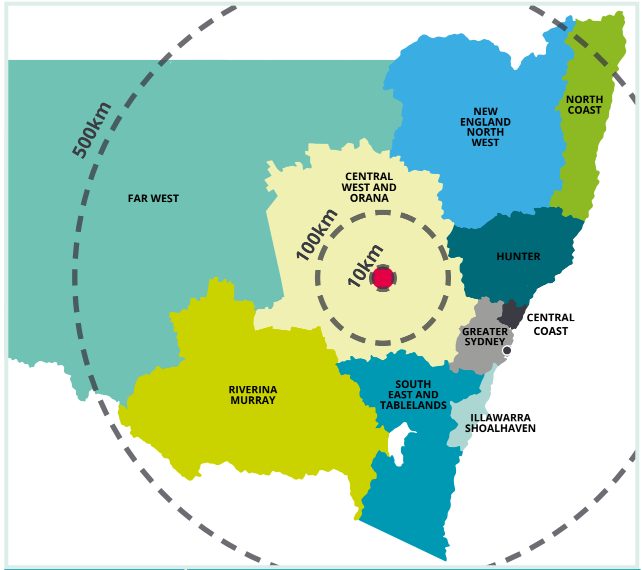


LCOH (A$/kg)	Broken Hill					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	3.42	7.18	4.05	7.80	6.68	10.86
100	3.59	7.34	4.05	7.80	8.08	12.26
500	3.62	7.37	4.31	8.06	10.12	14.30
1000	3.62	7.37	-	-	-	-



LCOH (A$/kg)	Wagga Wagga					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	4.98	8.25	5.61	8.87	8.24	11.93
100	5.15	8.41	5.61	8.87	9.64	13.33
500	5.18	8.44	5.87	9.13	11.68	15.37
1000	5.18	8.44	-	-	-	-

LCOH (A$/kg)	Armidale					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	4.11	7.63	4.74	8.25	7.37	11.31
100	4.28	7.79	4.74	8.25	8.77	12.71
500	4.31	7.82	5.00	8.51	10.81	14.75
1000	4.31	7.82	-	-	-	-



LCOH (A$/kg)	Dubbo					
Mode of Transport	GH2 Pipeline		GH2 Road		LH2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	3.56	7.57	4.19	8.19	6.82	11.25
100	3.73	7.73	4.19	8.19	8.22	12.65
500	3.76	7.76	4.45	8.45	10.26	14.69
1000	3.76	7.76	-	-	-	-

Figure 25. Estimated hydrogen delivered costs from selected location in 2030-2040.

Note: Here the given LCOH represents the total cost of hydrogen supply including generation, storage/conversion and transport of H_2.

Dedicated Transmission Network Connected Scenario

A network connected scenario was considered that included generating renewable electricity in Central West and Orana REZ (Dubbo) and transmission to the Hunter (Newcastle) and Illawarra (Port Kembla) H_2 hubs. The renewable electricity would then be used as a feedstock for the nominal 100MW hydrogen production facilities. Two options for transmitting the renewable energy were considered:

- a new built 100MW dedicated transmission line, and
- a new built 500MW shared transmission line. A larger capacity line was used to take advantage of firmed solar/wind input (via oversizing) to the electrolyser to boost capacity factor and get a lower production costs.

The costs of these lines assumed for this study are summarised in **Table 4**.

Table 4. Estimated cost of hydrogen production via dedicated transmission lines in Port Kembla and Illawarra H_2 Hubs by 2030.

Power plant Site	Electrolyser Site	Cost of Transmission Network/ Usage	Estimated Cost of Hydrogen Production (A$/kg)
Central West & Orana REZ	**Hunter H_2 Hub**	**100MW Dedicated Transmission Network:** A$231 million – A$268 million	**100MW Dedicated Transmission Network:** A$6.9/kg – A$14.3/kg
		500MW Shared Transmission Network: A$16/MWh	**500MW Shared Transmission Network:** A$3.9/kg – A$8.2/kg
	Port Kembla H_2 Hub	**100MW Dedicated Transmission Network:** A$295 million – A$343 million	**100MW Dedicated Transmission Network:** A$7.9/kg – A$16.2/kg
		500MW Shared Transmission Network: A$21/MWh – A$24/MWh	**500MW Shared Transmission Network:** A$4.2/kg – A$8.3/kg

Note: Here the transmission system costs were evaluated using the AEMO transmission cost tool[51] as elaborated in **Appendix B**. For the shared network, given the cost of the network is shared with other potential users, the cost of transmission network was considered as a fixed A$/MWh tariff to recover the cost of building and operating the network.[52] The lower and highest cost of network/tariff represents are based on the lowest and highest cost of building the transmission network (the AEMO transmission cost tool provides a range of costs based on the capacity of storage we considered both 132 kV/275 kV transmission capacity and the number of lines used).

The results of the modelling for the network-connected configuration indicated:

- For a dedicated 100MW transmission line, the modelling indicative that the delivered hydrogen cost for the Hunter scenario would range between A$6.9/kg – A$14.3/kg whereas for Illawarra, it would be A$7.9/kg – A$16.2/kg.
- Generating hydrogen in the Central West and Orana and transporting as compressed gas via pipeline or truck results in a lower delivered cost (**Figure 25**).
- Liquid hydrogen transported by truck to the Hunter and Illawarra hubs would be more expensive than a 100MW dedicated transmission line with the delivered cost ranging between A$10.26/kg – A$14.69/kg.
- For a shared transmission line, part of the 100 – 200MW transmission capacity could be dedicated for hydrogen production while the balance of the capacity could be accessed by other local users. This approach may allow the costs to be shared over multiple users. Given that both the Hunter and Port Kembla H_2 hub have a high energy demand, we assumed the line can be shared which resulted in a delivered cost of A$3.9/kg – A$8.2/kg for the Hunter Scenario and A$4.2/kg – A$8.3/kg for the Illawarra scenario. The development of a shared network is commercially complex and adds uncertainty and risk to a project.

2040 to 2050 Development

By 2040, it is assumed that GW scale hydrogen production facilities will be operational. Both standalone (especially for the REZs based on estimated build capacities of solar and wind farms) as well as network-connected configurations (purpose-built new transmission lines connecting REZs to potential H_2 hubs) were considered in this analysis. We estimate that by 2040, the hydrogen production costs would range between A$2.0/kg – A$5.1/kg, which is a 20 – 35% decrease in LCOH compared to development in 2030 and a 60% decrease compared to present development costs (**Table 5**).

Table 5. Estimated cost of hydrogen production for 1 GW H_2 electrolysers projects by 2040

Electrolyser Scenario	Estimated Cost of Hydrogen Production (A$/kg)	
	Low CAPEX Assumption	High CAPEX Assumption
Solar PV	AE: A$2.0/kg – A$2.4/kg PEME: A$3.3/kg – A$3.9/kg	AE: A$2.2/kg – A$2.6/kg PEME: A$3.1/kg – A$3.7/kg
Onshore Wind	AE: A$2.4/kg – A$3.8/kg PEME: A$3.3/kg – A$5.2/kg	AE: A$2.6/kg – A$4.0/kg PEME: A$3.2/kg – A$5.1/kg
Offshore Wind	AE: A$3.1/kg – A$3.3/kg PEME: A$3.2/kg – A$3.4/kg	AE: A$7.0/kg – A$7.4/kg PEME: A$7.1/kg – A$7.5/kg

Note: These costs are estimates for the standalone configuration assuming the solar/wind farm are built within the P2X facility and represent the cost of generation. Here the low CAPEX and the high CAPEX assumptions represent the hydrogen production costs based on lowest cost of electrolyser and renewable generator and the highest cost of electrolyser and renewable generator (details in **Appendix B**). The production costs for the offshore wind farms does not include the cost of transmission line, as these costs are unique to the type of transmission line and distance from the coastal facility, however the cases of leveraging offshore wind using sub-sea transmission lines are provided in the Appendix. The location wise breakdown of these costs is provided in **Appendix B**.

Significant development of solar and wind farms in REZs is expected in this period which could be leveraged for hydrogen generation. The AEMO ISP 2022 plan estimates the capacity of solar and wind development in NSW REZs to support the emerging H_2 economy (refer to **Appendix B** for details). Based on these the LCOH estimates for the standalone projects within REZs that would have capacities to support 1GW electrolyser projects are shown in **Table 6**. Dedicated transmission scenario for this timeline is presented in **Appendix B**.

51 - The AEMO Transmission Network Cost Tool has been used for costing the transmission network costs in this section. Link
52 - Similarly, throughout the section, the tariffs were calculated based on the cost of network estimated from the AEMO tool, operating costs and grid usage charges levelised over the electricity transmitted (assuming a network utilisation rate of 70%) as elaborated in **Appendix B**.

Table 6. Estimated cost of hydrogen production for 1GW H_2 electrolysers projects in select REZs by 2040

Renewable Energy Zone (REZ)	Power plant Capacity (GW)		Estimated Cost of Hydrogen Production (A$/kg)
	Solar Farm	Wind Farm	
South West NSW REZ	1.25GW		A$2.3/kg – A$3.7/kg
Central West NSW REZ	0.7GW	0.6GW	A$2.2/kg – A$3.1/kg
Wagga Wagga REZ	0.7GW	0.6GW	A$2.8/kg – A$4.0/kg
North West NSW	1.25GW		A$2.2/kg – A$3.5/kg
New England REZs	0.7GW	0.6GW	A$2.4/kg – A$3.4/kg

Note: These costs are estimates for the standalone configuration assuming the solar/wind farm are built within the P2X facility and represent the cost of generation. Here the lower and higher costs of the production cost range are based on lowest cost of electrolyser and renewable generator and the highest cost of electrolyser and renewable generator (details in **Appendix B**).

2050 and beyond Development

By 2050, it was assumed that 5GW hydrogen production facilities will be operational. Both standalone (especially for the REZs based on estimated build capacities of solar and wind farms) as well as network connected configurations (purpose built new transmission lines connecting REZs to potential H_2 hubs) were considered in this analysis.

By 2050, we estimate the LCOH range to further reduce to between A$1.6/kg – A$4.1/kg (**Table 7**), a 20 – 35% decrease in LCOH compared to 2040 development costs and 75% overall decrease compared to present development costs. Dedicated transmission scenario for this timeline is presented in **Appendix B**.

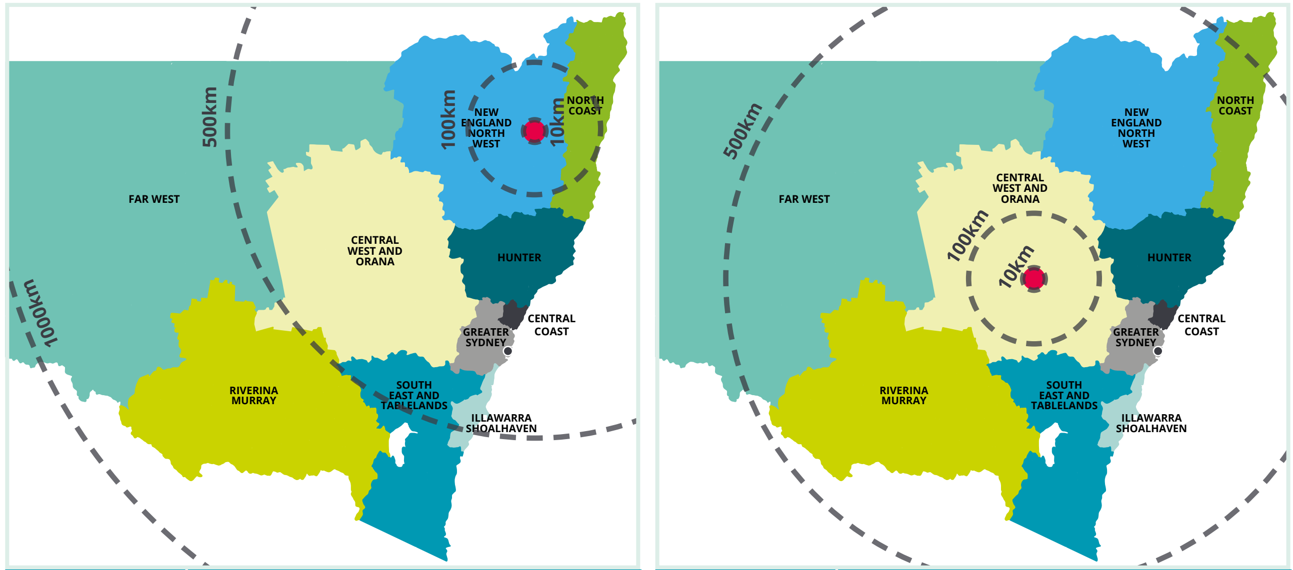
Table 7. Estimated cost of hydrogen production for 1 GW H_2 electrolysers projects by 2050

Electrolyser Scenario	LCOH Estimates (A$/kg)	
	Low CAPEX Assumption	High CAPEX Assumption
Solar Driven System	AE: A$1.6/kg – A$1.8/kg PEME: A$1.6/kg – A$1.9/kg	AE: A$2.3/kg – A$2.7/kg PEME: A$2.2/kg – A$2.6/kg
Onshore Wind Driven Electrolysers	AE: A$2.0/kg – A$3.0/kg PEME: A$2.0/kg – A$3.1/kg	AE: A$2.7/kg – A$4.2/kg PEME: A$2.7/kg – A$4.1/kg
Offshore Wind Driven Electrolysers	AE: A$2.7/kg – A$2.9/kg PEME: A$2.8/kg – A$3.0/kg	AE: A$6.0/kg – A$6.4/kg PEME: A$6.0/kg – A$6.3/kg

Note: These costs are estimates for the standalone configuration assuming the solar/wind farm are built within the P2X facility and represent the cost of generation. Here the low CAPEX and the high CAPEX assumptions represent the hydrogen production costs based on lowest cost of electrolyser and renewable generator and the highest cost of electrolyser and renewable generator (details in **Appendix B**). The production costs for the offshore wind farms does not include the cost of transmission line, as these costs are unique to the type of transmission line and distance from the coastal facility, however the cases of leveraging offshore wind using sub-sea transmission lines in Hunter and Port Kembla Hydrogen Hubs are provided in the Appendix as an example. The location-wise breakdown of these costs is provided in **Appendix B**.

For the REZs, the AEMO ISP Plan 2022, suggests only New England REZ and Central West & Orana REZ would have enough capacity to support 5GW electrolyser projects. For the New England REZ we estimate that a 6GW (3GW Solar and 3GW Wind Farm) can be developed to get the lowest LCOH. For the Central West & Orana REZ we estimate a 7GW hybrid power plant (4GW Solar and 3GW Wind) is required. The hydrogen supply chain costs from these potential hydrogen generation points are shown in **Figure 26**.

Figure 26. Estimated Hydrogen supply chain costs from selected locations in 2050.



LCOH (A$/kg)	Armidale					
Mode of Transport	GH_2 Pipeline		GH_2 Road		LH_2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	2.03	2.79	2.51	3.26	4.38	5.43
100	2.08	2.84	2.51	3.26	5.41	6.46
500	2.46	3.22	2.70	3.45	6.92	7.97
1000	2.26	3.02	-	-	-	-

LCOH (A$/kg)	Dubbo					
Mode of Transport	GH_2 Pipeline		GH_2 Road		LH_2 Road	
Distance (km)	Low	High	Low	High	Low	High
10	2.18	2.94	2.66	3.41	4.53	5.58
100	2.23	2.99	2.66	3.41	5.56	6.61
500	2.61	3.37	2.85	3.60	7.07	8.12
1000	2.41	3.17	-	-	-	-

Note: Here the given LCOH represents the total cost of hydrogen supply including generation, storage/conversion and transport of H_2.

4.5. Summary

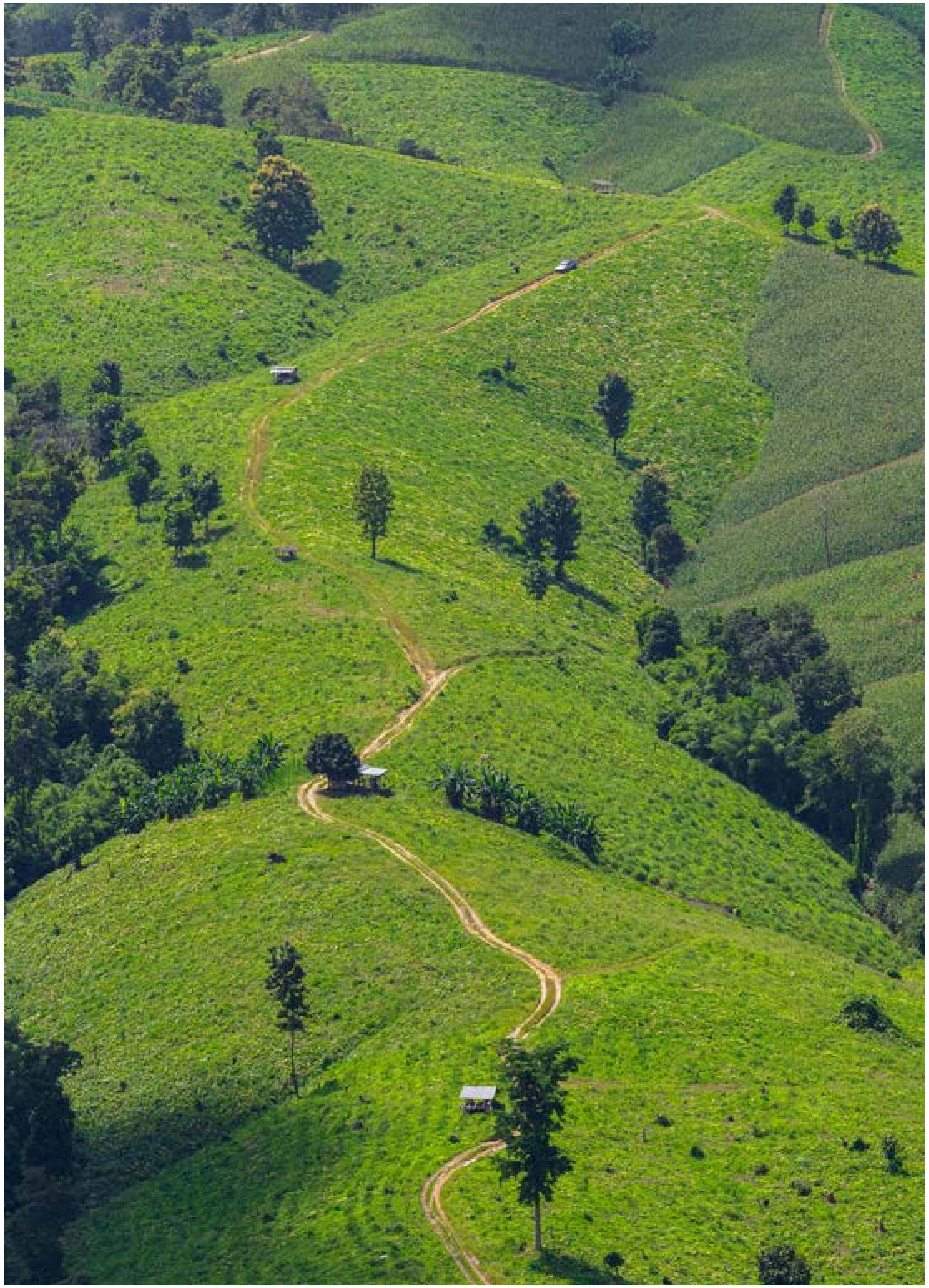
The analysis completed provides an overall cost outlook for a hydrogen value chain in NSW. In line with other reports, the present cost of hydrogen is high but could decrease by 75% leading up to 2050 which results in a hydrogen production costs <A$2/kg. To achieve these cost reductions, economies of scale and cost learning are required which means supporting higher cost projects in the short and medium term. Targeted projects could be deployed that help reduce the cost while providing benefits to the state.

The modelling indicates that the best performing sites in terms of hydrogen production cost are in the remote far-west regions of NSW (where demand for hydrogen will be low). Other regions, such as Central West & Orana, Riverina Murray and New England can also produce renewable energy competitively and can support local hydrogen generation or export their renewable energy potential to emerging hydrogen hubs along the east coast via a transmission network (which is expected to be built as part of the REZ development in the state).

For the Hunter and Illawarra regions, renewable energy generation from the highlighted REZs (most of which has already been committed) could be leveraged via newly built shared transmission lines to provide the required capacity of renewable power. While the cost of these lines requires significant capital investment, sharing of these costs will result in higher utilisation making the costs more competitive.

Finally, if large-scale high-capacity factor offshore wind farms can be developed at the reported costs then, by 2050 these systems could be at parity with onshore transmission-based systems.

In the next chapters (**Chapter 5 and 6**) of this section, we expand on these findings for the hydrogen delivered cost in NSW to evaluate the case for local use of hydrogen at hydrogen refuelling networks and for blending into natural gas pipelines.



Chapter 5: Hydrogen Refuelling

Delivering a hydrogen refuelling network is crucial to meet the NSW Government's ambitious plan to deploy hydrogen fuel-cell electric vehicles (FCVs) particularly for heavy-duty transport. In this chapter, we summarise the current state of play, evaluate the economics, suggest likely suitable locations and offer insights into how to overcome challenges for hydrogen refuelling stations within NSW.

When it comes to the cost of hydrogen at the bowser, the contribution made by the refuelling station itself to the overall price is relatively low. In contrast, the cost of producing hydrogen is a major driver. However, renewable energy generation is becoming cheaper — there is further room for prices to fall too — and while electrolysers are expensive, the cost will fall as their performance and scale increase over time.

The delivery costs depend on whether hydrogen can be generated on site or has to be delivered via road or pipeline (note, our analysis only considers road transport). The hydrogen refuelling costs themselves are known to be influenced by the station capacity. In this report, we therefore consider three different hydrogen station sizes; small, medium and large.

The optimum configuration for a hydrogen refuelling system (HRS) is dependent on the hydrogen supply conditions, on-board vehicle requirements and site constraints.

The type of hydrogen supply will also be dependent on the proximity to hydrogen demand and site constraints (e.g. electricity network connections and demand). The options for hydrogen supply include:

- produced locally via an electrolyser
- supplied via gaseous tube trailer, liquid tanker or a gas pipeline.

Our analysis suggests that hydrogen production and transport costs remain the bottlenecks in hydrogen refuelling. As a result, deploying hydrogen refuelling station networks with smaller-scale generation onsite or close to the stations is likely to be more attractive for hydrogen to achieve costs comparable for diesel for heavy-duty vehicles.

5.1. A summary of hydrogen refuelling

The NSW Government has committed to phase out petrol and diesel vehicles by increasing the uptake of electric vehicles (EVs), including battery and hydrogen fuelcell EVs (FCVs).[53] The deployment of FCVs powered by green hydrogen is an attractive solution to decarbonise some transportation sectors, especially heavy-duty vehicles — owing to the significant benefits of FCVs (e.g. fast refuelling and longer driving range). In its hydrogen strategy, the NSW Government has targeted 10,000 hydrogen vehicles, 100 refuelling stations and is aiming for 20% of its heavy vehicle fleets to be hydrogen-powered by 2030.[54] To achieve this ambition, a widespread hydrogen refuelling network across NSW is imperative and, as part its Net Zero Plan Stage 1: 2020-2030, the NSW Government is currently working to develop one.[55]

The NSW and Victorian Governments have committed to spend $20 million on hydrogen refuelling stations along Australia's busiest freight highway. The two governments will fund at least four refuelling stations along the 840 km Hume highway between Sydney and Melbourne.[56] In addition, hydrogen refuelling is being developed in a Port Kembla facility under the Port Kembla Investment Fund. This refuelling station will enable the introduction of hydrogen fuel-cell trucks to the Illawarra-Shoalhaven region of NSW.[57]

The optimum configuration for an HRS is dependent on the hydrogen supply conditions, on-board vehicle requirements and site constraints.

The type of hydrogen supply will be dependent on the proximity to hydrogen supply, site constraints (e.g. electricity network connection) and demand. The options for hydrogen supply include:

- produced locally via an electrolyser
- supplied via gaseous tube trailer, liquid tanker, or a gas pipeline.

As shown in **Figure 27**, there are two typical configurations for hydrogen refuelling stations: a gaseous HRS and a liquid HRS. Liquid HRS generally requires more space than gaseous HRS.

53 - NSW Department of Planning, Industry and Environment. 2021. NSW Electric Vehicle Strategy. Link
54 - Department of Planning, Industry and Environment. 2021. NSW Hydrogen Strategy. Link
55 - Energy NSW. Green Hydrogen in NSW. Link
56 - NSW Government. 2022. Delivering the renewable Hume Hydrogen Highway. Link
57 - CSIRO. 2022. Port Kembla Hydrogen Refuelling Facility. Link

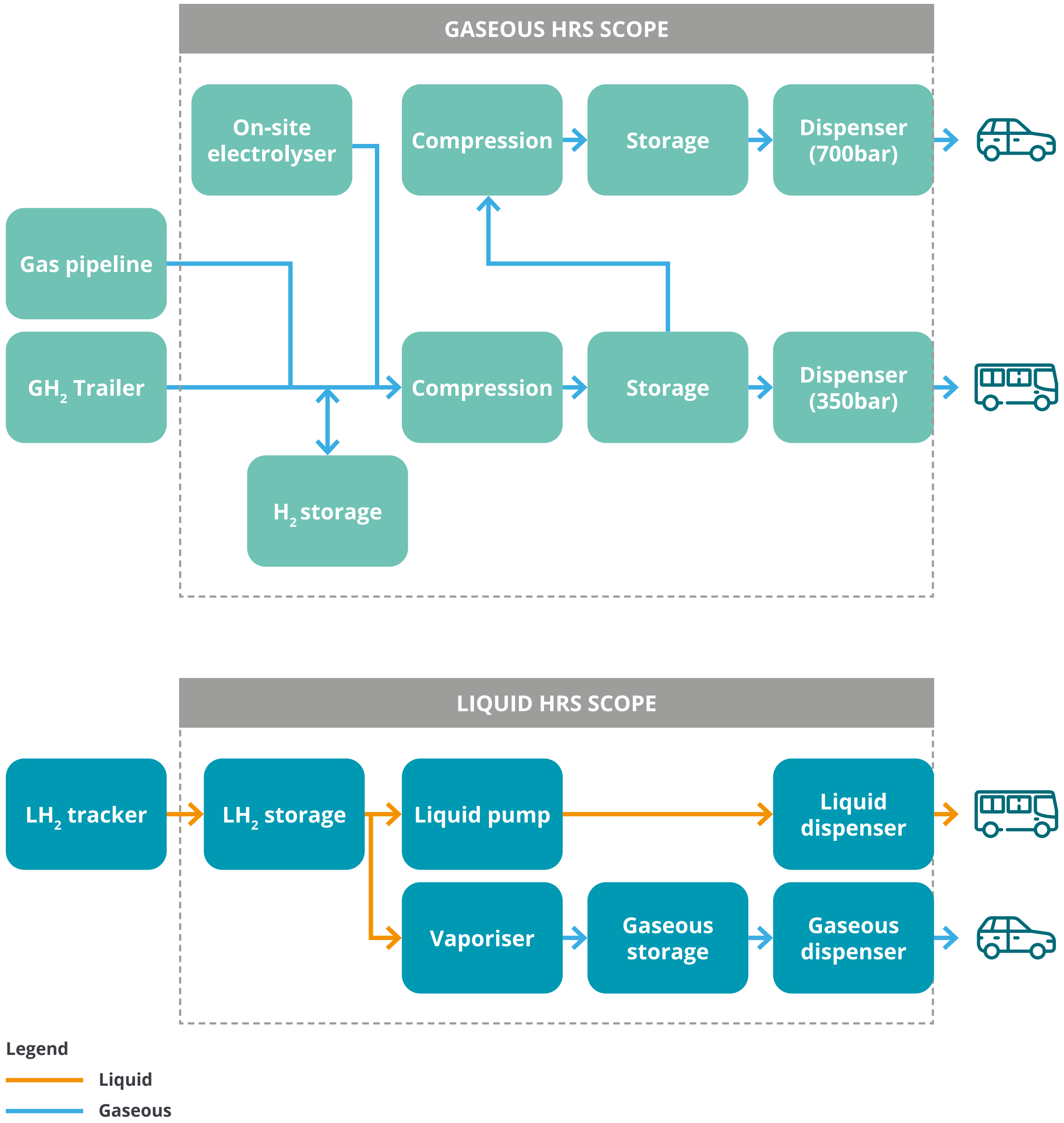


Figure 27. Schematic diagrams of gaseous and liquid hydrogen refuelling stations.

5.2. Our Analysis – Scope Definition and Framework

The potential development of a hydrogen refuelling network across NSW was explored using our NSW Powerfuel Value Chain tool.

The following approach was taken:

1. Estimate the potential hydrogen refuelling demand locations and volumes.
2. Determine the credible hydrogen supply locations and value chain scenarios.
3. Develop the costs of the various value chain components.
4. Calculate a final hydrogen bowser cost for each of the scenarios.

Potential hydrogen refuelling demand locations and volumes

Firstly, analysis of the potential hydrogen demand was completed. For this analysis the onboard storage capacity for the HDV is assumed to be 35kg.[58] To determine the size of the refuelling station in each proposed location, HDV traffic volume data in NSW's major highways (Pacific, Newell and Hume Highways) were collected from Transport for NSW's Traffic Volume Viewer.[59] **Figure 28** presents the results of this assessment and identifies the size of hydrogen refuelling stations required to meet the demand.

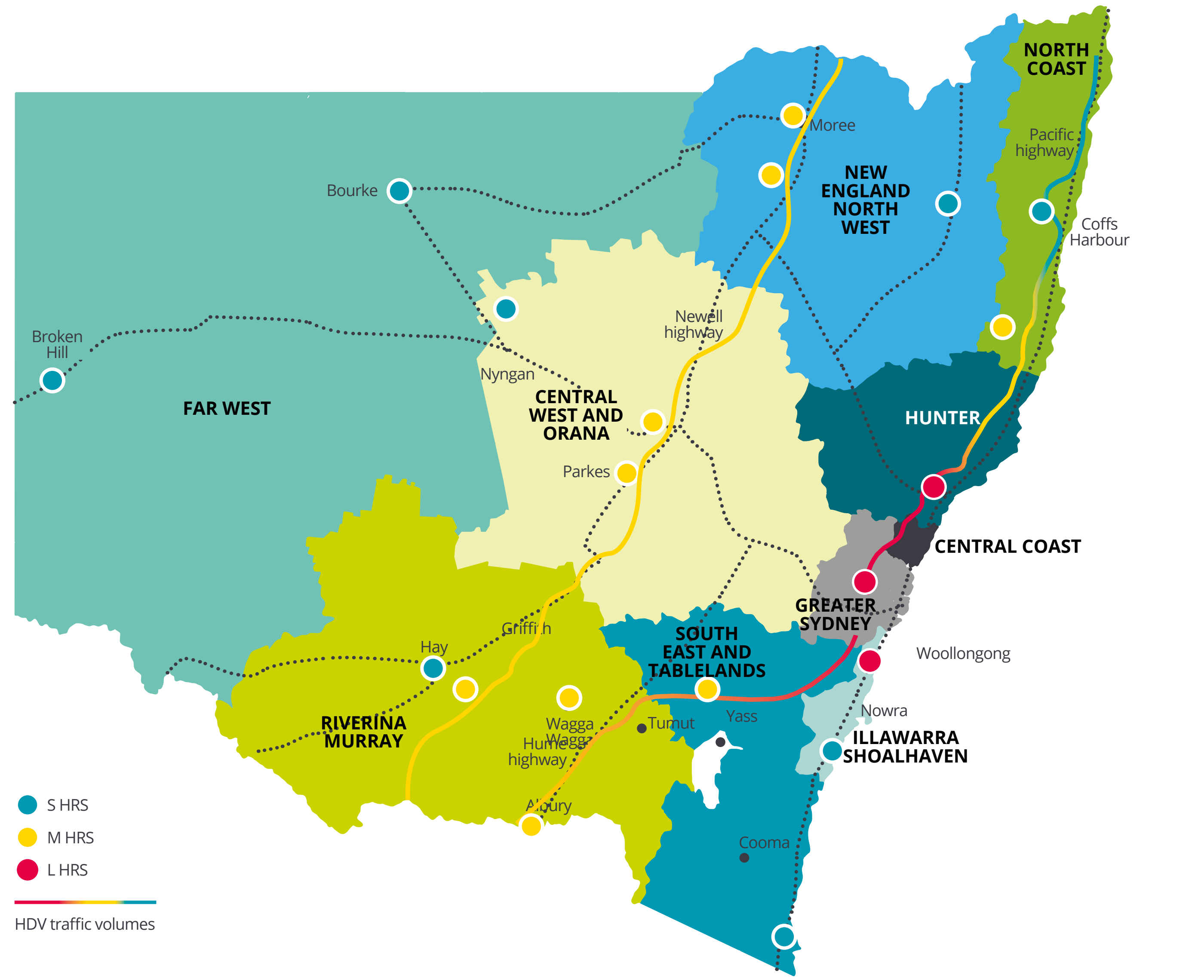


Figure 28. Determination of hydrogen refuelling station size based on heavy-duty vehicle (HDV) traffic volume in NSW's three major highways. HRS station size is broadly categorised as small (S), medium (M) and large (L) with H_2 capacities of 1,050, 2,100 and 3,500 kg/day, respectively. HDV traffic volume represent the average number of HDVs on the road obtained from Transport for NSW's Traffic Volume Viewer[59].

58 - Existing hydrogen fuel cell heavy duty vehicles have varying capacities. For simplicity, the capacity of heavy-duty vehicle is assumed to be 35 kg throughout this study.
59 - Transport for NSW. Traffic Volume Viewer. Link

Hydrogen supply locations and value chain scenarios

To determine the hydrogen supply locations and logistics, analysis of the locations for hydrogen production was completed. The results of this analysis are shown in **Figure 29**.

SAPs where industrial and commercial infrastructure projects are planned and delivered are anticipated to include centralised hydrogen production.[60] In these locations it was also assumed that a hydrogen refuelling station would supply hydrogen fuel for public transport and heavy duty vehicles, including buses, trucks and trailers. In this scenario, the refuelling stations were co-located with the hydrogen production. To realise this opportunity, it will be important to find a site that is located close to demand (e.g. on a main road) but able to incorporate a large production facility.

To support smaller demand centres, several locations for satellite hydrogen refuelling stations have been identified. These stations are in locations where it is cost effective to transport hydrogen from larger centralised production facilities. For small volumes and short-to-medium distances, compressed gaseous hydrogen trucks can be attractive, but as the volume and distance increase, the density needs to be increased and trucks carrying liquid hydrogen need to be used.[61]

Finally, where it was not economical to transport hydrogen in either liquid or gaseous state, decentralised hydrogen refuelling stations have been considered. At these locations, electrolysers will be included as part of the HRS. During site selection consideration needs to be given to the safety requirements (primarily separation distances) and utility availability (power, raw water and wastewater treatment facilities for recycled water).

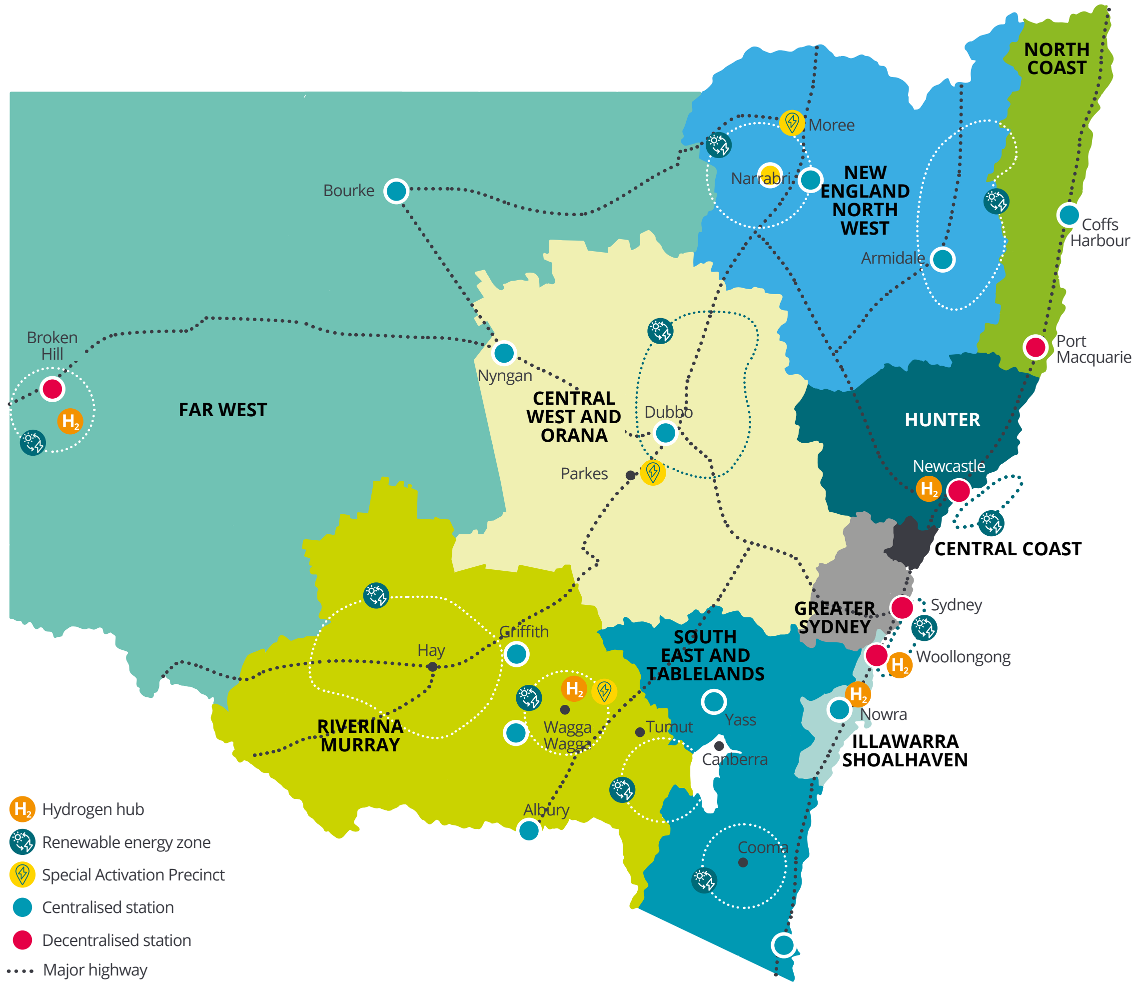


Figure 29. Proposed locations for hydrogen refuelling stations including centralised and decentralised systems across NSW.

Table 8 summarises the scenarios considered in the analysis. This shows the locations of the refuelling station, the transport type and distance, and the production locations considered.

Table 8 Hydrogen refuelling stations scenarios considered as part of this analysis

Scenario	Refuelling Station location	Refuelling Station demand (kg/day)	Supply type	Transport distance (km)	Production location
1	Wagga Wagga	2,100	On-site	N/A	Wagga Wagga
2	Parkes	2,100	On-site	N/A	Parkes
3	Moree	2,100	On-site	N/A	Moree
4	Eden	1,050	Tube trailer	515	Wagga Wagga
5	Nowra	1,050	Tube trailer	400	Wagga Wagga
6	Albury	2,100	Liquid tanker	130	Wagga Wagga
7	Yass	2,100	Liquid tanker	185	Wagga Wagga
8	Griffith	1,050	Tube trailer	180	Wagga Wagga
9	Narrandera	2,100	Liquid tanker	100	Wagga Wagga
10	Dubbo	2,100	Liquid tanker	120	Parkes
11	Nyngan	1,050	Tube trailer	230	Parkes
12	Bourke	1,050	Liquid tanker	434	Parkes
13	Narrabri	2,100	Liquid tanker	100	Moree
14	Armidale	1,050	Tube trailer	306	Moree
15	Coffs Harbour	1,050	Tube trailer	447	Moree
16	Port Macquarie	2,100	On-site	N/A	Port Macquarie
17	Sydney	3,500	On-site	N/A	Sydney
18	Newcastle	3,500	On-site	N/A	Newcastle
19	Broken Hill	1,050	On-site	N/A	Broken Hill
20	Port Kembla	3,500	On-site	N/A	Port Kembla

60 - NSW Department of Planning and Environment. Special Activation Precincts. Link
61 - IRENA. 2022. Global Hydrogen Trade to Meet The 1.5°C Climate Goal. Part II: Technology Review of Hydrogen Carriers. Link

Costs of the various value chain components

Hydrogen Production Cost

Hydrogen production locations for each scenario is listed in **Table 8**. For this analysis, it was assumed hydrogen is generated via an electrolyser with varying capacity driven by hybrid solar and wind energy. The electrolyser output capacities and the calculated hydrogen production costs assumed for this analysis are summarized in **Table 9**.

Table 9. Estimated H_2 production costs for centralised and onsite production facilities.

Production cost (A$/kg H_2)	Electrolyser size considered (MW)	2022	2030	2050
Centralised Production Facilities				
Moree	30MW (6,300 kg/day)	7.47-8.41	4.32-5.63	2.60-3.40
Parkes	30MW (6,300 kg/day)	7.64-8.44	4.36-5.64	2.52-3.54
Wagga Wagga	50MW (11,500 kg/day)	8.91-9.87	5.50-7.00	3.37-4.58
Onsite Production Facilities				
Sydney	15MW (3,500 kg/day)	7.88-8.76	4.59-5.93	2.62-3.65
Newcastle	15MW (3,500 kg/day)	7.88-8.76	4.59-5.93	2.62-3.65
Port Macquarie	10MW (2,100 kg/day)	8.00-8.86	4.57-5.93	2.61-3.70
Broken Hill	5MW (1,050 kg/day)	7.23-8.15	3.93-5.20	2.19-3.08
Port Kembla	15MW (3,500 kg/day)	8.94-10.31	5.32-6.91	3.23-4.45

As discussed in **Chapter 4**, the cost of electrolyser and renewable electricity are the major cost drivers for this aspect of the value chain. Electricity is the dominant cost in the production of green hydrogen but the journey to lower costs is already underway. Renewable electricity from solar and wind is becoming cheaper with significant potential for further cost reductions. The second dominant cost is the electrolyser cost and, while costs are expected to fall as the scale increases, technological innovation is also needed to further improve the performance of the technology.[62]

Hydrogen Delivery Cost

If not produced on site, hydrogen can be delivered to the hydrogen refuelling station via road or pipeline. For the purpose of this analysis only road transport has been considered. **Table 10** provides a summary of the transport methods that were considered as part of this analysis.

Table 10. Summary of transport methods for hydrogen.

Transport type	Description	Indicative hydrogen capacity (kg)	Indicative transport distance (km)	Indicative cost (A$/ kg/100 km)
Road – tube trailers	For distance up to around 500 km,[63] hydrogen can be distributed via road in compressed gaseous form in tube trailers. Current generation tube trailers range 200 to 350 bar, however there is development for tube trailers up to 500 bar. For trailers, the service price is composed of a fixed price, which depends on the number of leased vehicles (as a function of the delivery frequency) multiplied by the monthly trailer lease fee and a variable price in function of the travel distance which includes fuel cost, tolls, special purpose vehicle taxes, etc.	200-500 kg	0-500 km	3.00[61]
Road – liquid tankers	Liquid hydrogen tankers can also be used as a transport vector in some specific cases where the HRS capacity justifies the liquefaction and for longer road transport distance (up to around 4,000 km).[64]	3,000-4,000 kg (per tanker)	Up to 4,000 km	0.80[61]
Gaseous pipelines	For a more distributed system, a pipeline represents another alternative but requires extensive infrastructure development with very high upfront CAPEX (A$0.4 – A$0.7 million per km for pipeline distribution).[65] Additional variable delivery cost related to the energy consumption of the compressors and maintenance of the pipeline is added to the cost, according to the transported mass and distance.	Up to 100 tons per h[66]	> 1,000 km[67]	1.50[61]

62 - IRENA. 2020. Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal. Link
63 - Ball, M. & Weeda, M. 2016. The hydrogen economy – Vision or reality? Compendium of Hydrogen Energy. Link
64 - Hydrogen Europe. Hydrogen Europe – TECH (Overview). Link
65 - IEA. 2019. IEA G20 Hydrogen Report: Assumptions. Link
66 - Mazloomi and Gomes. 2012. Hydrogen as an energy carrier: Prospects and challenges. Renewable and Sustainable Energy Reviews 16(5), 3024-33. Link
67 - PwC Australia. n.d. Getting H2 right: Success factors for Australia's hydrogen export industry. Link

The final costs and method of transport is unique to each scenario and needs to be determined on a case-by-case basis as summarised in **Table 11**.

Table 11. Estimated H_2 transport costs for centralised H_2 refuelling network.

Transport cost (A$/kg)	Supply	2022	2030	2050
Moree SAP H_2 transport				
Coffs Harbour (447 km)	GH_2 (1,050 kg/day)	8.90-9.92	5.59-6.97	3.54-4.64
Narrabri (100 km)	LH_2 (2,100 kg/day)	10.70-12.29	7.15-8.96	4.64-6.08
Armidale (306 km)	GH_2 (1,050 kg/day)	8.83-9.85	5.53-6.91	3.50-4.59
Parkes SAP H_2 transport				
Dubbo (120 km)	LH_2 (2,100 kg/day)	10.93-12.38	7.25-9.03	4.60-6.02
Nyngan (230 km)	GH_2 (1,050 kg/day)	8.50-9.52	5.34-6.69	3.39-4.46
Bourke (434 km)	LH_2 (1,050 kg/day)	11.92-13.37	8.13-9.91	5.25-6.67
Wagga Wagga SAP H_2 transport				
Narrandera (100 km)	LH_2 (2,100 kg/day)	12.14-13.75	8.33-10.33	5.41-7.02
Albury (130 km)	LH_2 (2,100 kg/day)	12.23-13.84	8.41-10.41	5.47-7.08
Yass (185 km)	LH_2 (2,100 kg/day)	12.40-14.01	8.57-10.57	5.58-7.19
Eden (515 km)	GH_2 (1,050 kg/day)	10.34-11.38	6.90-8.47	4.70-5.96
Nowra (400 km)	GH_2 (1,050 kg/day)	10.06-11.10	6.59-8.16	4.32-5.58
Griffith (180 km)	GH_2 (1,050 kg/day)	9.90-10.94	6.45-8.02	4.22-5.48

Hydrogen Refuelling Costs

HRSs are equipped with compression, storage and dispensing units that contribute to the final hydrogen cost at the dispensing nozzle ('bowser price').[68] The CAPEX components include the equipment costs, site preparation, engineering and design, project contingency and upfront permitting costs. The OPEX is comprised of energy cost, labour, insurance, taxes, licensing and permits, operating, maintenance and repairs, overhead and G&A, and other fixed operating costs.

The hydrogen refuelling costs are known to be influenced by the station capacity. In this report, we consider three different hydrogen station sizes; small, medium and large, as shown in **Table 12**. The refuelling station sizing for heavy-duty vehicles (HDVs) is adapted from existing hydrogen refuelling cost modelling.[69,70]

Table 12. Hydrogen refuelling station size definition.

Size	Small	Medium	Large
Number of HDVs per day	30	60	100
Daily hydrogen demand (kg/day)	1,050	2,100	3,500

To provide cost projections for the medium to long term (2030 and 2050), we have estimated the cost reduction that could be achieved by an increase in the size of the market for FCVs. The refuelling station components were classified into three technology groups based on the current technology status. As presented in **Table 13**, we developed three market scenarios to estimate the cost reduction factor of each component group at different market sizes. The first market scenario represents the current state (2022) with limited number of FCVs on the road and is labelled as 'low' scenario. In contrast, the 'high' scenario reflects the projected situation in the long-term (2050) with widespread use of FCVs. The 'mid' scenario represents a transition period (2030) between the 'low' and 'high' scenarios.

Table 13. Cost reduction factors for different technology groups and market scenarios[71].

Technology Groups	Scenario		
	Low	Mid	High
Group 1: Mature (low cost reduction potential) e.g. cryogenic storage	1 to 100%	79%	75%
Group 2: Established (moderate cost reduction potential) e.g. high-pressure storage, pre-cooling equipment	1 to 100%	61%	55%
Group 3: Developing (high cost reduction potential) e.g. dispensers, compressors, control and safety equipment	1 to 100%	47%	40%

The refuelling station costs were estimated for heavy-duty vehicles with refuelling pressure of 350 bar. **Figure 30** shows the calculated gaseous HRS costs for centralised and decentralised networks with different station size. The liquid HRS cost was also compared with gaseous HRS with equivalent capacity as presented in **Figure 31**.

68 - Caponi et al. 2021. Hydrogen refuelling station cost model applied to five real case studies for fuel cell buses. E3S Web of Conferences 312, 07010. Link
69 - Nugroho et al. 2021. Cost of a potential hydrogen refuelling network for heavy-duty vehicles with long-haul application in Germany 2050. International Journal of Hydrogen Energy 46, 71, 35459-78. Link
70 - H_2 Mobility. 2021. Overview Hydrogen Refuelling for Heavy-Duty Vehicles. Link
71 - Argonne National Laboratory. Hydrogen Refuelling Station Analysis Model (HRSAM). Link

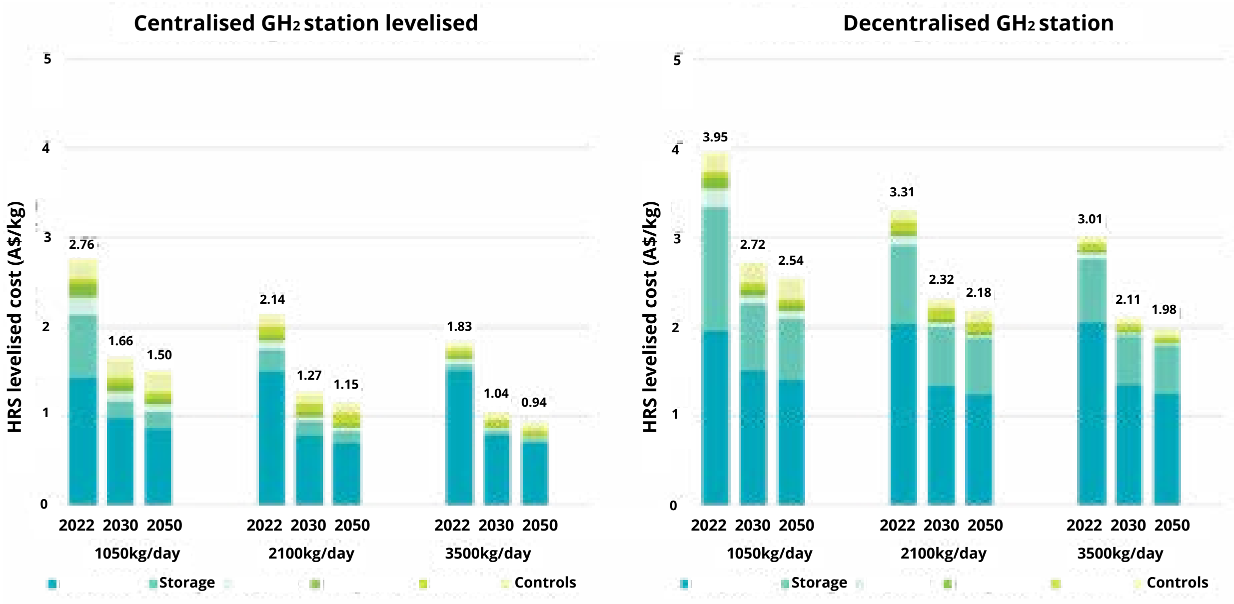


Figure 30. Estimated centralised and decentralised GH_2 station levelised costs with different capacity.

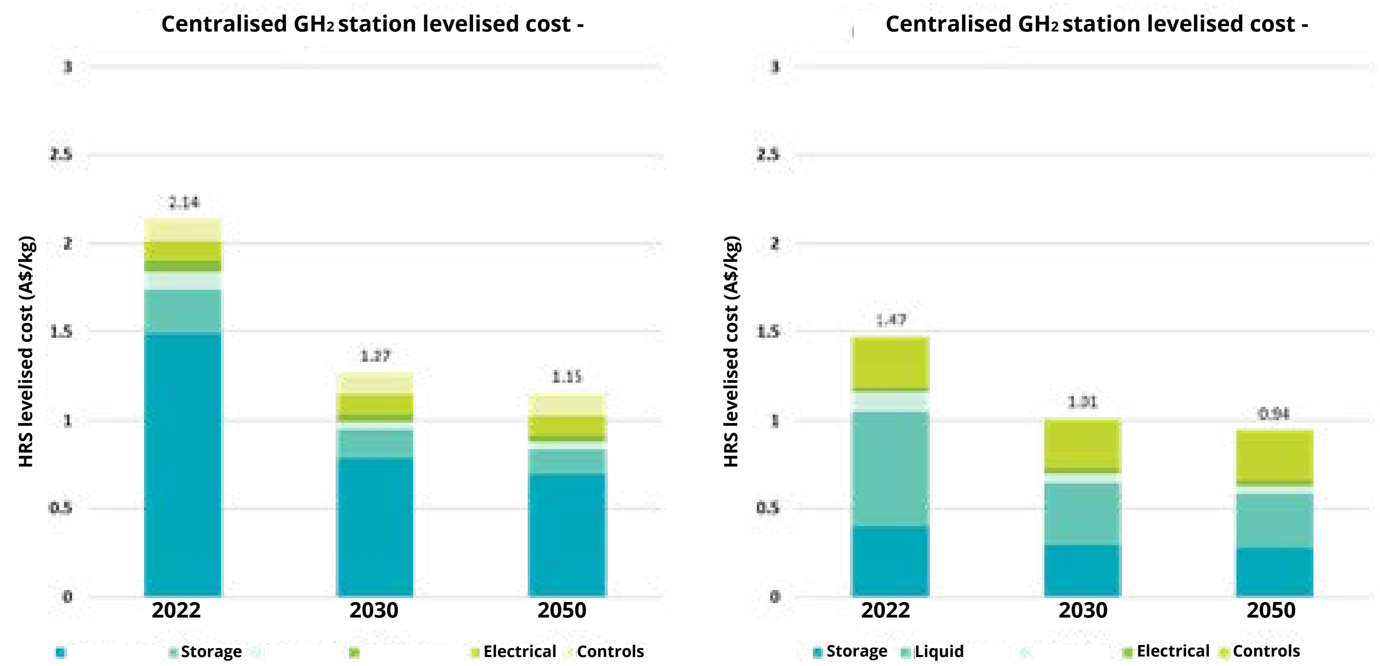


Figure 31. Estimated centralised GH_2 and LH_2 station levelised costs at 2100 kg/day capacity.

5.3. Our Analysis – Results

In this section, we estimate bowser costs for the scenarios developed in **Table 8**. To calculate this bowser cost, the costs associated with the value chain, from production to transport (in the case of decentralised station) and refuelling, were considered as shown in **Figure 32**.

By taking into account costs along the hydrogen value chain, the hydrogen bowser cost at the pump is shown in **Table 14** and **Table 15**, respectively. Our analysis revealed that the hydrogen bowser cost is dominated by the hydrogen production and delivery costs. The contribution of the refuelling station cost to the hydrogen price at the dispenser nozzle is relatively low.

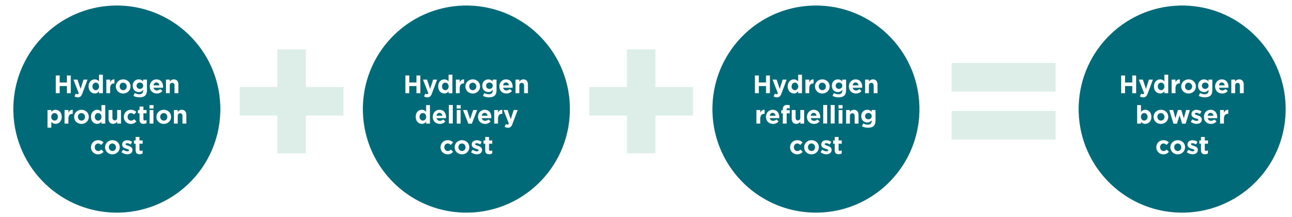


Figure 32. Cost components of hydrogen refuelling

The results indicate that the hydrogen bowser cost at a refuelling station with onsite hydrogen production was cheaper when compared to a centralised refuelling network due to the high transport cost of gaseous hydrogen. For instance, a refuelling station at Moree SAP, where hydrogen is generated on the same site, has the lowest estimated final hydrogen price of A$8.94-9.88/kg in 2022. On the other hand, the highest current hydrogen price is an estimated A$22.78-25.35/kg at Bourke refuelling stations in 2022 due to relatively high hydrogen production cost in Dubbo SAP and high transport cost to Bourke station, which is located 185 km away from Dubbo SAP.

Moreover, the results also indicated that the cost of infrastructure for the satellite refuelling station is lower compared to the decentralised one with equivalent capacity. In satellite refuelling station, less hydrogen compression is required onsite as the hydrogen supply in the tube trailer is already at quite high pressure. In addition to gaseous HRS, liquid HRS is also modelled where the hydrogen is liquefied in the central production site on demand before being transported using tube trailers. The liquid HRS cost is lower than the centralised gaseous HRS for the same station capacity (**Figure 31**). However, our analysis shows that liquid HRS requires a larger space, and the upfront capital investment is considerably higher due to the standards required for the cryogenic LH_2 equipment.

To achieve strict pricing parity with present diesel prices, a delivered hydrogen cost (hydrogen production cost plus hydrogen transport cost) of A$4-6/kg is required—subject to diesel price fluctuation.[72] Of course, such pricing does not reflect the environmental outcomes of green hydrogen use. In the long term, the model showed that a refuelling station with onsite hydrogen generation may reach the target price range. For example, Moree station is projected to have a hydrogen bowser cost of A$5.33-6.64/kg in 2030 and A$3.54-4.58/kg in 2050. On the other hand, the centralised network modelled in this report suffers from a higher future hydrogen bowser cost than the target range due to the significant contribution associated with hydrogen transport. Yass station, for instance, has a projected final hydrogen price of A$15.08-18.58/kg in 2030 and A$9.89-12.71/kg in 2050.

In summary, our analysis suggests that hydrogen production and transport costs remain the bottlenecks in hydrogen refuelling. As a result, deploying hydrogen refuelling station networks with smaller-scale generation onsite or close to the stations is likely to be more attractive for hydrogen to achieve costs comparable to diesel for heavy-duty vehicles. When hydrogen has wide uptake levels across different applications and a hydrogen transport network, (via pipeline for simultaneous distribution of hydrogen) is established, a centralised system may become more competitive. In addition, supporting policies such as carbon pricing for CO_2 emissions from heavy transport could help hydrogen to reach cost competitiveness with existing options.

72 - Cormack, L. (2022) Push for eastern seaboard truck corridor to go green with hydrogen. Link

Table 14. Estimated Hydrogen Bowser Costs For Centralised HRS Network At Selected Locations In NSW.

LCOH (A$/kg)	2022	2030	2050
Moree SAP refuelling network			
Moree station			
Low	8.94	5.33	3.54
High	9.88	6.64	4.58
Coffs Harbour station			
Low	19.13	11.57	7.64
High	21.09	14.26	9.78
Narrabri station			
Low	19.64	12.48	8.18
High	22.17	15.60	10.66
Armidale station			
Low	19.06	11.51	7.60
High	21.02	14.20	9.73
Parkes SAP refuelling network			
Parkes station			
Low	9.11	5.37	3.46
High	9.91	6.65	4.48
Dubbo station			
Low	19.87	12.58	8.14
High	22.26	15.67	10.60
Nyngan station			
Low	18.90	11.36	7.41
High	20.72	13.99	9.50
Bourke station			
Low	22.32	14.15	9.27
High	24.57	17.21	11.71
Wagga Wagga SAP refuelling network			
Wagga Wagga station			
Low	10.38	6.51	4.31
High	11.34	8.01	5.52
Narrandera station			
Low	22.52	14.84	9.72
High	25.09	18.34	12.54
Albury station			
Low	22.61	14.92	9.78
High	25.18	18.42	12.60

Table 14. cont.

Wagga Wagga SAP refuelling network cont.			
Yass station			
Low	22.78	15.08	9.89
High	25.35	18.58	12.71
Eden station			
Low	22.01	14.06	9.57
High	24.01	17.13	12.04
Nowra station			
Low	21.73	13.75	9.19
High	23.73	16.82	11.66
Griffith station			
Low	21.57	13.61	9.09
High	23.57	16.68	11.56

Table 15. Estimated Hydrogen Bowser Costs For Decentralised HRS Network At Selected Locations In NSW.

LCOH (A$/kg)	2022	2030	2050
Sydney station			
Low	10.89	6.70	4.60
High	11.77	8.04	5.63
Newcastle station			
Low	10.89	6.70	4.60
High	11.77	8.04	5.63
Port Macquarie station			
Low	11.31	6.89	4.79
High	12.17	8.25	5.88
Broken Hill station			
Low	11.18	6.65	4.73
High	12.10	7.92	5.62
Port Kembla station			
Low	10.89	6.70	4.60
High	11.77	8.04	5.63

Chapter 6: Hydrogen Blending in the Natural Gas Network

Blending hydrogen into the existing natural gas network is seen as a natural progression in industry development by some energy experts — indeed, legislation that enables the industry to run trials has already been passed in NSW. However, there are challenges throughout the process that will need to be addressed if domestic and industrial customers are to move to blended gas without the change impacting their equipment, the metering equipment and the transmission assets themselves. Other possible end uses supplied by the natural gas network are also being developed including co-firing hydrogen at peaking gas generators.

The infrastructure required to blend renewable hydrogen into the natural gas network primarily consists of a renewable energy supply and water supply connected to an electrolyser system. Downstream, a small hydrogen storage buffer tank and compressor may be required to match the hydrogen pressure with the natural gas system before injection. At the injection point, equipment will be required to control the hydrogen flow into the network to ensure it meets the safety and commercial requirements of the network.

Although small-scale projects are currently underway in the state, meeting the 10% blending by volume target would require approximately 32,000 tons of hydrogen and 512ML of water. Successful blending would mean overcoming challenges with end-use applications, managing the injection and blending threshold in gas networks, updating standards and safety codes and managing the risks associated with long-term exposure of pipelines to hydrogen.

In addition several gas-fired power stations currently under construction or in the planning phase will be capable of firing a dual-fuel mix in their gas turbines. With modifications, both Colongra and Uranquinty power stations have the potential to co-fire hydrogen up to 30% by volume.

Findings:

Our analysis considered both centralised and decentralised hydrogen blending and the results showed each delivered similar costs, though this may have been influenced by the scale of production — smaller, decentralised systems do not benefit from the same economies of scale achieved by larger, centralised systems.

Large-scale hydrogen blending in natural gas systems would need to be carried out at the gas receipt end of the transmission network e.g. Moomba in South Australia. The receipt locations may benefit from cost reductions resulting from economies of scale, but these benefits could be offset by the increased power requirements at the pipeline booster stations resulting from a change in the gas properties.

6.1. A summary of hydrogen blending

Blending 10% hydrogen (by volume) into the natural gas network is one of the 2030 targets of the NSW Hydrogen Strategy and the passing of the Energy Legislation Amendment Bill 2021 has paved the way for industry to act.[1] Projects are already underway to begin blending hydrogen in the natural gas network and include Jemena's Western Sydney Green Hydrogen Hub. Further projects are planned by Australian Gas Infrastructure Group, which will provide 10% hydrogen blended natural gas to customers in the Albury and Wodonga area by 2024 through its Hydrogen Park Murray Valley project.[73] To reach the 10% blending target by 2030, the number and size of projects across NSW will need to increase and the opportunity to blend hydrogen in various locations across the state is explored in this chapter. Based on the consumption of natural gas in NSW for 2021 (114PJ),[74] to meet the 10% by volume blending target would require approximately 32,000 tons of hydrogen and 512ML of water.

In addition to hydrogen blending, several gas-fired power stations currently under construction or in the planning phase will be capable of firing a dual fuel mix in their gas turbines. These projects include Energy Australia's Tallawarra B, the Snowy Hydro Hunter Power Project and the Squadron Energy Port Kembla Power Station. Furthermore, existing gas-fired power stations at Colongra and Uranquinty could potentially operate on dual-fuel mixtures with modifications to their gas turbines and upstream gas supply infrastructure. The opportunity for industrial gas blending is explored in this chapter.

There are challenges associated with blending hydrogen into the gas network that are being actively addressed by the industry and research institutions. The 2019 report prepared by GPA Engineering for the Government of South Australia[75] summarised the key challenges related to the end-use applications of blended gas, managing the injection and blending threshold in gas networks, updating standards and safety codes to cover the introduction of hydrogen into the natural gas network, and managing the risks associated with long-term exposure of pipelines to hydrogen, which could lead to potentially hazardous events.

73 - AGIG (2022). Hydrogen Park Murray Valley. Link
74 - AEMO (2022). National Electricity & Gas Forecasting. Link
75 - Government of South Australia (2019). Hydrogen in the Gas Distribution Network. Link

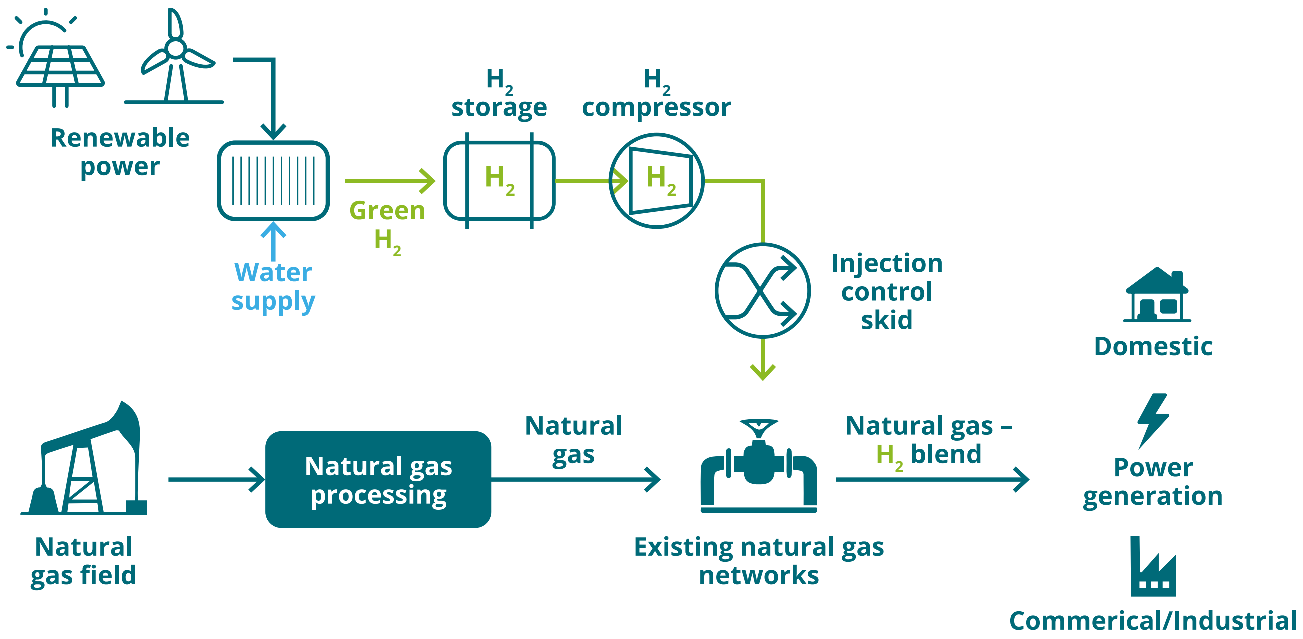


Figure 32. Schematic of hydrogen blended into the natural gas network.

End Use Applications

Under current regulatory gas frameworks, gas appliances can be categorised into two types:

- Type A for which type approval exists which could include domestic and light commercial cookers, space heaters and water heaters.
- Type B are appliances which require individual certification such as gas turbines, gas engines and boilers which are all designed to operate on a specific range of gas compositions.

Under existing standards (AS 3645 and AS/NZS 5263.0:2017), Type A appliances are tested with a N_b test gas which includes 13% hydrogen (by volume). This indicates the appliance may operate with 10% hydrogen blends, however, reduces the safety margin for gas quality excursions.

For Type B appliances the sensitivity to changes in gas composition is dependent on the type of design of the appliance and application. Gas engines can be sensitive to changes in gas composition with hydrogen concentrations above 2% potentially causing operational issues. Gas turbines are capable of handling higher concentrations of hydrogen with many equipment manufacturers offering modifications to existing units to handle 30% hydrogen blends[76,77] and new gas engines capable of operating on 100% hydrogen.[78] When the gas quality changes outside of the device approved gas quality limits, recertification of the appliance is required.

Note: Hydrogen combustion may lead to N_2O emissions, thereby detailed testing is required to assess direct hydrogen combustion applications.

Managing Injection and Blending Threshold in Gas Networks

The injection of hydrogen into the gas network must be carefully managed to ensure the gas specifications adhere to the characteristics outlined in *AS 4564:2011 - Specification for General-purpose Natural Gas*.[79] AS 4564, Table 3.1 describes a gas quality standard which sets a minimum and maximum value for certain gas characteristics including Wobble Index, relative density and higher heating values. The standard ensures that a consistent gas quality is achieved across a network and provides requirements that gas appliance manufacturers can design their appliances to meet. The quality and energy content in this standard is also used as the basis for commercial agreements.

Gas metering and measurement devices need to be reviewed for suitability with hydrogen blends to ensure that they will operate safety. Gas detection needs to be reviewed to ensure they can detect the hydrogen mixtures. Consideration needs to be given to the impact of hydrogen on odorant concentration levels.

From a technical perspective, blending hydrogen into lower pressure distribution networks is generally considered more feasible than blending in the larger transmission networks that would require a change in operation to maintain safe and reliable operation.[75] The safety risks associated with material compatibility (e.g. hydrogen embrittlement) are lower in the low-pressure distribution networks and the general view is that 10% hydrogen will not require major modifications to the system.

Gas Distribution Standards

The key mandatory standards covering gas distribution networks include:

- *AS/NZS 4645 – Gas Distribution Networks*
- *AS4564 – Specification for General Purpose Natural Gas*
- *AS 2885 – Pipelines-Gas and Liquid Petroleum (applicable at pressures above 1,050kPa)*
- *AS/NZS 60079 Explosive Atmospheres Series.*

Each one of the listed standards is required to be reviewed to ensure that they are suitable for hydrogen blends. Where gaps are found, the standards should be revised. This process is currently underway by the Australian Standards Committee, *ME-093 - Hydrogen Technologies*.

Safety Risks

Blending hydrogen in natural gas systems has raised several safety risks that need to be addressed. A large proportion of the gas distribution network in Australia uses plastic piping (nylon, polyethylene, polyvinyl chloride and polyamide) with the national average standing at approximately 79%. Whilst plastic piping is considered safe for use with hydrogen blended gas, for sections of the system that haven't been replaced in a long time, network operators (e.g. Jemena in NSW) are undertaking rehabilitation projects to replace aged plastic pipes. Other parts of the natural gas system are constructed of carbon steel and cast-iron pipes which are susceptible to deterioration through long-term exposure to hydrogen, a process known as hydrogen embrittlement. These carbon steel and cast-iron sections of the network — particularly those at higher operating pressures — need careful inspection and management to ensure the blended gas can be transported safely and reliably. Gas network operators are required to maintain their assets and review potential risks periodically (covered by AS 4645 – Gas distribution network management). In NSW, Jemena, Evoenergy, Australian Gas Networks and APA group are responsible for annual reporting of incidents along the gas network including integrity assessments and gas leaks.[80]

Gas detection is another area of potential risk given existing gas detection devices are configured to detect gas mixtures based on calibration with a known gas such as methane. Existing gas detection devices installed throughout the gas system need to be assessed for suitability with gas blends containing hydrogen, including higher concentrations of hydrogen that could result from operational errors.

76 - GE (2022). GT13E2 heavy duty gas turbine Link
77 - Siemens Energy (2022). SGT5-2000E heavy Duty Gas Turbine. Link
78 - GE (2022). 6B-03 Gas Turbine. Link
79 - For some gas networks across Australia, this standard may not apply.
80 - NSW Government (2022). NSW 2020-21 Gas Networks Performance Report. Link

6.2. Our Analysis – Scope Definition and Framework

The opportunity for blending 10% hydrogen into several locations across the NSW gas network was explored using the Powerfuel Tool. Two blending strategies were analysed:

1. Centralised blending in a natural gas transmission pipeline to serve several distribution networks
2. Decentralised blending at the city gate of a distribution network.

The average annual energy demand profile between 2018 and 2021 for each centralised and decentralised location, which was obtained from the AEMO online database,[81] was used to determine the volume of blended gas required to maintain a consistent energy supply. The electrolyser capacity was sized according to the average energy demand for each location to maximise the utilisation rate of the equipment whilst maintaining average blend rates as close to 10% as possible. The renewable power source was oversized by a factor of two to boost the capacity factor of the electrolyser and push the average blend closer to the target 10%. Alternative configurations are possible for assessing hydrogen blended into the natural gas network, for example hydrogen storage to provide a buffer for matching supply and demand. However, this could add significant cost to the system and has not been included in this analysis.

Several renewable energy supply configurations were assessed including a hybrid standalone system (50% wind, 50% solar PV), solar PV with battery and wind with battery. It should be noted that these configurations are not the only options for hydrogen gas blending but are used here to showcase some of the functionality of the Powerfuel Tool. Users will be able to run their own assessments to determine the best renewable energy configuration for their gas blending projects.

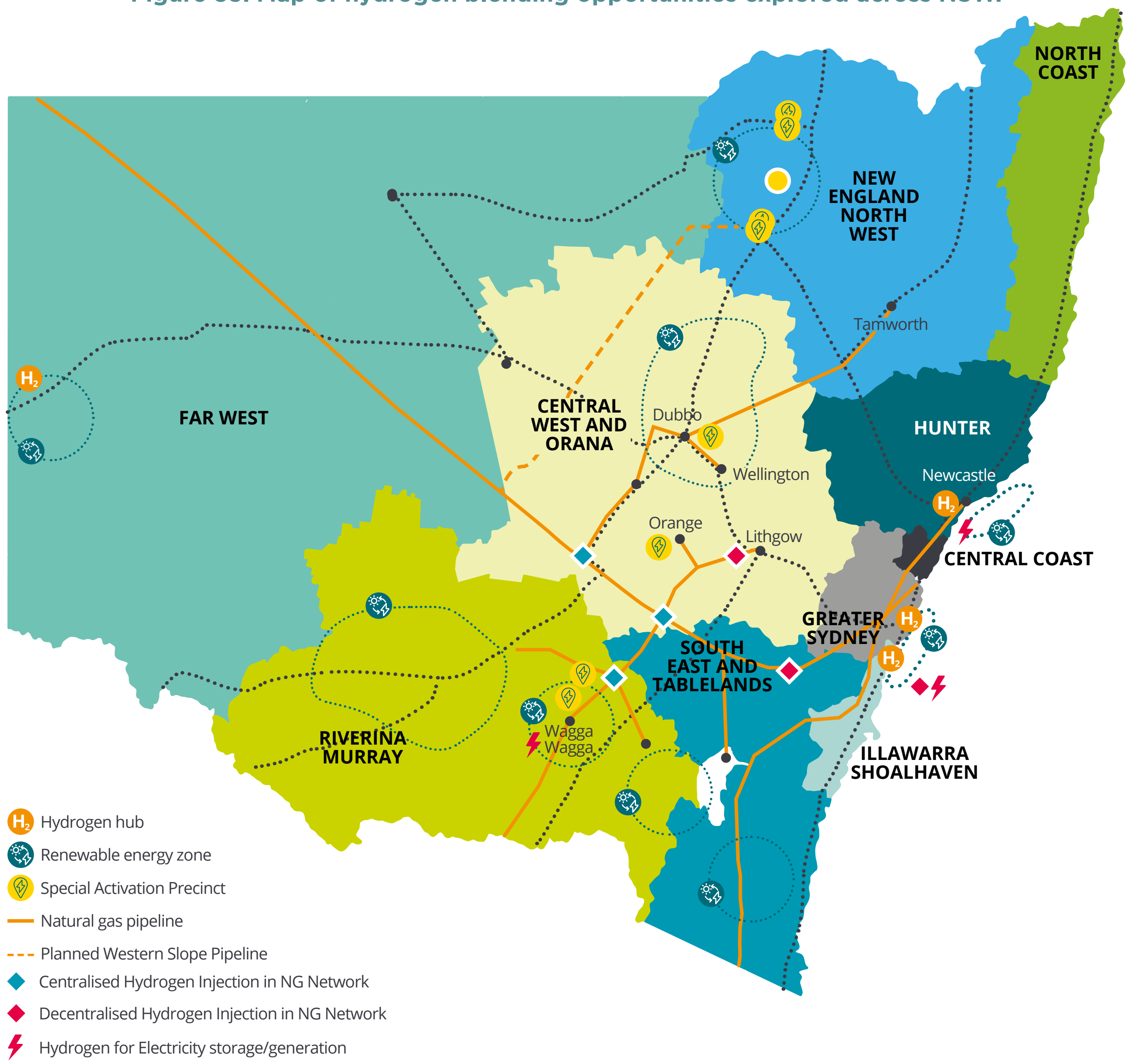
In addition, several gas-fired power stations (under construction and existing) were assessed for the potential to blend hydrogen in the natural gas feed at the power plant boundary. For the gas fired power plants, a hydrogen blend of 30% volume was used as a target for each site which is typically documented as the current limit for many gas turbine OEMs.[71,72,73] For peaking plants (open-cycle gas turbines) a capacity factor of 25% was assumed and for combined cycle gas turbines a capacity of 50% was used. These capacity factor estimates are higher than current values, but can be expected in an electricity network with greater renewables and reduced base load generation (e.g. from coal fired power plants). For simplification, the hydrogen production system was modelled to produce the equivalent of 30% volume annually for each gas-fired power plant and includes hydrogen storage with a capacity of up to six hours at peak demand. The renewable power source was oversized by a factor of two, to boost the capacity factor of the electrolyser and a 50:50 hybrid system (wind:solar PV) was used as the renewable energy configuration. Hydrogen production is assumed to take place at the industrial user site.

For the existing gas-fired power stations, the GE supplied GT13E2 gas turbines operating at Colongra have the capability to use up to 30% hydrogen with modifications[76] and the Origin Energy operated Uranquinty Power Station uses four Siemens SGT5-2000E (predecessor named V94.2) gas turbines that have the potential to use up to 30% of hydrogen in the fuel mix with modifications.[77] The cost of any modifications to the gas turbines is not included in the analysis and assumed to be marginal based on information provided by the manufacturers that says the equipment is capable of firing blends of hydrogen up to 30%.

This evaluation was completed to identify opportunities for NSW blending locations based on high level techno-economic inputs. Determining the technical feasibility of injecting hydrogen into a network is a phased approach and requires evaluation of network flows, materials, downstream appliances and operational processes. During this process, it may be determined that the network is not suitable or the costs to make it hydrogen-ready outweigh the benefits.

Figure 34 highlights the main natural gas transmission pipelines across NSW including the locations for centralised and decentralised blending of hydrogen. **Table 16** provides further details on each location evaluated. The locations for blending hydrogen into the natural gas system were selected based on the availability of energy demand data from AEMO and the opportunity mapping framework applied for each region. Further detailed feasibility is required to determine the suitability of these locations for gas blending.

Figure 33. Map of hydrogen blending opportunities explored across NSW.



81 - AEMO (2022). Gas Flows and Capacity Outlook. Link

Centralised and Decentralised Hydrogen Gas Blending

Table 16: Location details for centralised and decentralised hydrogen gas blending

Blending Strategy	Region	Potential Injection Point	Potential Distribution Networks
Centralised	Riverina Murray	Junee-Griffith Lateral	Junee, Coolaman, Ganmaln, Narrenderra, Rockdale, Leeton, Murrami, Griffith
Centralised	Central West & Orana	Central West Pipeline	Marsden, Forbes, Parkes, Narromine, West Dubbo, Dubbo
Centralised	South East & Tablelands/ Central West & Orana	Young-Lithgow Lateral	Young, Cowra, Millthorpe, Orange, Blayney, Bathurst, Oberon, Wallerawang, Lithgow
Decentralised	Central West & Orana	City Gate	Bathurst
Decentralised	South East & Tablelands	City Gate	Goulburn
Decentralised	Illawarra Shoalhaven	City Gate	Port Kembla

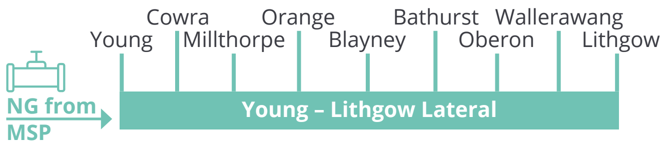
Hydrogen Blending for Power Generation

Table 17 summarises the gas-fired power plants evaluated for co-firing 30% volume of hydrogen, including details on announced co-firing plans.

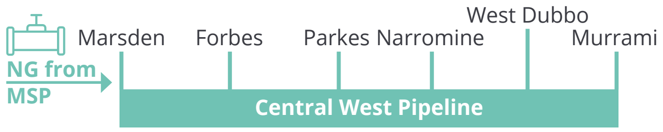
Table 17. Gas Fired Power Stations Evaluated for co-firing hydrogen

Power Station	Status	Planned Hydrogen Co-firing Target
Tallawarra B	Under Construction	5% vol. by 2025
Port Kembla	Planned	50% vol. from commissioning, with plant to co-fire 100% by 2030
Hunter Power Project	Planned	Initially 15% vol. and up to 30% vol. with additional investment
Colongra	Operational	None Documented
Uranquinty	Operational	None Documented

LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery	
Year	Low	High	Low	High	Low	High
2022	9.45	12.18	13.97	17.17	10.84	13.17
2030	5.79	8.23	7.72	11.28	7.65	9.83
2050	4.21	5.24	4.83	6.02	6.02	7.21
Average Blend	5%		4%		6%	

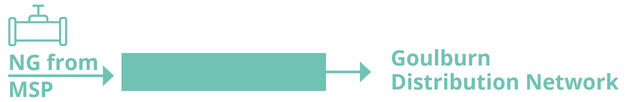


LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery	
Year	Low	High	Low	High	Low	High
2022	8.01	12.18	13.97	17.17	10.84	13.17
2030	5.00	8.23	7.72	11.28	7.65	9.83
2050	7.04	5.24	4.83	6.02	6.02	7.21
Average Blend	5%		4%		6%	

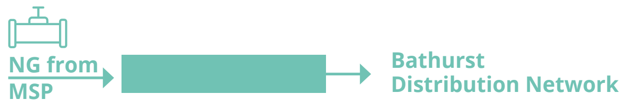


LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery	
Year	Low	High	Low	High	Low	High
2022	6.51	12.18	13.97	17.17	10.84	13.17
2030	8.25	8.23	7.72	11.28	7.65	9.83
2050	12.54	5.24	4.83	6.02	6.02	7.21
Average Blend	7%		4%		6%	

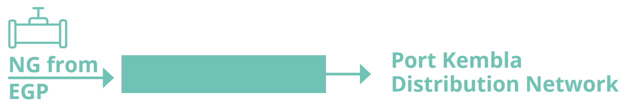
Figure 34: Centralised Hydrogen Gas Blending



LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery	
Year	Low	High	Low	High	Low	High
2022	9.71	12.65	14.23	17.05	10.92	12.94
2030	5.90	8.46	8.11	11.51	7.94	9.94
2050	4.28	5.32	5.22	6.42	6.35	7.55
Average Blend	6%		4%		6%	



LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery	
Year	Low	High	Low	High	Low	High
2022	9.15	11.94	13.60	16.80	9.21	11.46
2030	5.67	8.03	7.66	11.10	6.45	8.38
2050	4.20	5.13	4.98	6.10	5.09	6.10
Average Blend	3%		2%		4%	



LCOH (A$/kg)	Hybrid Standalone		Solar with Battery		Wind with Battery		Offshore	
Year	Low	High	Low	High	Low	High	Low	High
2022	9.15	11.60	13.42	16.26	10.46	12.5	12.95	16.82
2030	5.67	7.97	7.44	10.80	7.55	9.55	6.33	14.26
2050	4.16	5.17	4.67	5.82	6.03	7.22	5.61	11.86
Average Blend	3%		2%		4%		5%	

Figure 35: Decentralised Hydrogen Gas Blending

6.3. Our Analysis – Results

The results from the analysis show that hydrogen blending at the centralised level (**Figure 34**) results in very similar levelised costs compared to decentralised blending (**Figure 35**). One reason for this can be linked to the scale of system required for the centralised and decentralised locations we assessed, which have the same order of magnitude and do not benefit from the same economies of scale as larger systems. For example, the system designed for centralised blending in the Central West Pipeline located in Forbes required an electrolyser capacity of 2.5MW whereas the system designed for decentralised blending at the City Gates of Bathurst required an electrolyser capacity of 1MW. Centralised hydrogen gas blending for the Central West transmission pipeline generated the lowest levelised cost of hydrogen for the hybrid standalone, solar PV battery and wind battery configurations compared to the other locations. This can be attributed to the solar and wind capacity factors for the area which are higher than the other locations. Centralised hydrogen gas blending in the Junee–Griffith lateral transmission pipeline and decentralised blending at the City Gates of Goulburn had the highest levelised cost of hydrogen compared to the other locations, as a result of lower solar PV and wind capacity factors.

The average hydrogen blend for each location can be linked to the solar and wind capacity factors. When wind power is included in the renewable energy mix, we see the highest average blend for each location compared to solar PV power because of higher capacity factors for wind. To increase the average blend as close to 10% as possible, the capacity of the renewable power can be increased beyond the factor of two used in the analysis to help boost the capacity factor of the electrolyser — however this would result in a penalty with higher CAPEX and OPEX costs for the renewable power system. Increasing the renewable power capacity would also potentially result in curtailment of the renewable power and electrolyser when natural gas demand is low, in order to avoid blends greater than 10%. Alternative configurations could also be used to help increase the capacity factor of the electrolyser, such as using additional power sources to supplement the renewable power. This could include having a grid connection to provide additional power when wind or solar PV power is low or the use of a utility-scale battery to store excess renewable energy that can be used during periods of low wind or solar. In addition, oversizing the electrolyser and increasing the size of the hydrogen storage could provide a buffer to maintain the hydrogen gas blending target when wind and solar power is low but will result in a cost impact to the overall system. Blending system design requires careful optimisation for each location to maximise the average blend in the natural gas network in line with the energy demand of the users.

When considering large-scale hydrogen blending in natural gas systems, this would need to be carried out at the gas receipt end of the transmission network e.g. Moomba in South Australia. The receipt locations may benefit from cost reductions resulting from economies of scale, but these benefits could be offset by the increased power requirements at the pipeline booster stations resulting from a change in the gas properties.

The analysis for the industrial users of hydrogen blended natural gas (**Table 18**) shows the lowest levelised cost of hydrogen with a hybrid standalone power configuration is in the Hunter region, due to higher wind capacity factors. Gas-fired power plants in the Riverina Murray (Uranquinty) and Illawarra Shoalhaven region (Port Kembla and Tallawarra) have comparable levelised costs due to their similar solar and wind capacity factors. The estimated electrolyser capacity is highest for the combined cycle gas turbine users, in this case Port Kembla Power Station, due to the higher plant capacity factor requiring more hydrogen compared to the peaking power plants. The results provide an indication of the electrolyser capacity and levelised cost of hydrogen for one renewable power configuration (hybrid renewable power) using the Powerfuel Tool. Further analysis using alternative configurations such as grid-connected electrolysers under a power purchase agreement is also possible using the Powerfuel Tool and is shown in **Table 18** for Uranquinty power station to highlight the potential levelised cost. The price of electricity under the power purchase agreement is assumed to decrease from A$49/MWh in 2022 to A$38.5/MWh in 2030 and decrease further to A$31/MWh by 2050. The PPA electricity pricing and decrease rate is a hypothetical contract and is used here to highlight the potential levelised costs under such agreements. The Powerfuel Tool allows the user to input their own assumption on PPA pricing.

Table 18. Estimated levelised cost of hydrogen for blending 30% volume at existing and planned gas-fired power stations in NSW using a standalone hybrid renewable energy plant configuration and hybrid grid connected PPA for Uranquinty

Location	2022 (A$/kg$H_2$)	2030 (A$/kg$H_2$)	2050 (A$/kg$H_2$)	Electrolyser Capacity Factor	Est. Electrolyser Capacity
Tallawarra B	9.12 – 11.61	5.65 – 7.96	4.13 – 5.16	45%	80MW
Port Kembla Power Station	9.10 – 11.58	5.63 – 7.94	4.12 – 5.15	45%	220MW
Hunter Power Project	8.09 – 10.30	5.01 – 7.06	3.67 – 4.58	50%	180MW
Colongra Power Station	8.08 – 10.28	5.00 – 7.05	3.66 – 4.57	50%	170MW
Uranquinty Power Station	8.97 – 11.30	5.60 – 7.83	4.12 – 5.15	44%	190MW
Uranquinty Power Station (Hybrid Grid Connected PPA)	6.24 - 8.58	3.76 – 5.19	2.66 – 2.93	44%	190MW

Section C: Beyond Hydrogen

In Section C, we look beyond the direct use of pure hydrogen and explore using it as the primary building block to produce four key powerfuels, namely ammonia, methanol, synthetic natural gas and sustainable aviation fuel. Each powerfuel is assessed on its potential application across NSW and the associated farm gate levelised cost between 2022 and 2050. Further analysis is undertaken to determine the potential intrastate transport costs from key manufacturing locations to key demand centres.

The Global Alliance Powerfuels organisation estimates the demand for ammonia, methanol, synthetic natural gas (SNG) and sustainable aviation fuel (SAF) made from renewable hydrogen will increase progressively between 2030 and 2050 as these powerfuels begin to displace fossil-based fuels and chemicals.[82] Furthermore, the IEA estimates that by 2050, approximately one-third of hydrogen demand will be used to produce hydrogen-based fuels such as ammonia, methanol, SAF and SNG.[83] Given the strong renewable energy potential in NSW, the state stands to benefit from the development of powerfuel production facilities that can cater to domestic and international markets. Powerfuels have the potential to decarbonise via two key pathways. The first is to replace their carbon-sourced equivalents in traditional applications (e.g. for fertiliser, replacing ammonia made from natural gas with ammonia made from renewable hydrogen); the second is to supplement or replace existing fossil fuels where powerfuels are not traditionally used (e.g. replacing marine fuel oil with methanol or ammonia).

The sectors where these powerfuels can be used include:

- fertiliser manufacturing (ammonia)
- mining (ammonia and methanol)
- power generation (ammonia, methanol and SNG)
- aviation (SAF)
- maritime (ammonia, methanol and SNG)
- natural gas transmission and distribution systems (SNG)
- as a chemical feedstock (methanol).

Key Cost Drivers

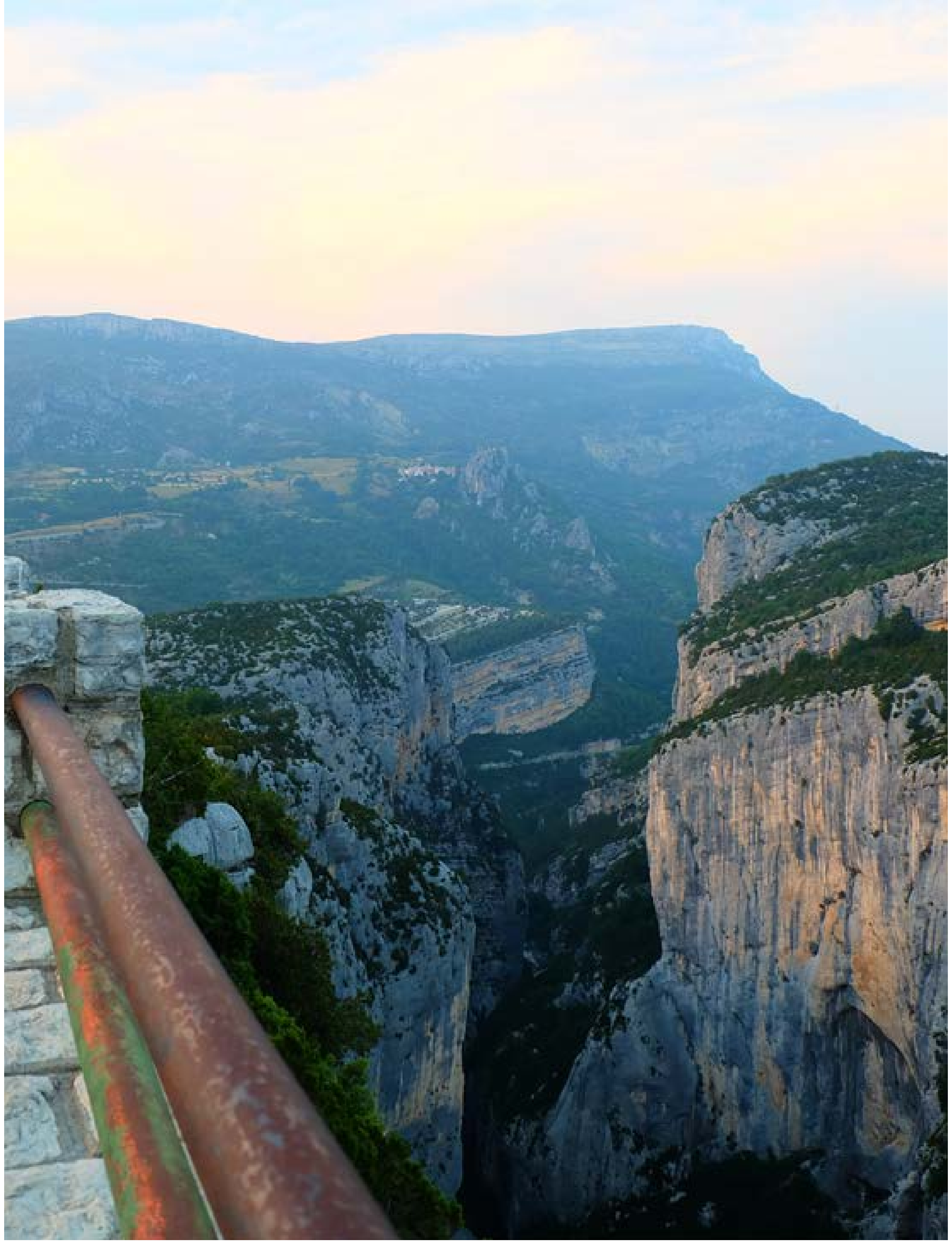
For each of the powerfuels assessed, we consider the cost of hydrogen production and intermediate storage, the process to convert it into a powerfuel and intrastate transport to a demand centre.

Table 19 provides a high-level breakdown that each component in the powerfuel value chain (up to the point of domestic delivery) contributes based on modelling of present costs from this report as well as previous work conducted by the team at UNSW[84] and can change depending on the location and cost assumptions used.

Table 19: Cost component breakdown for the powerfuel value chain

Cost Component	Ammonia	Methanol	SNG	SAF
Hydrogen Production	74%-80%	61%-77%	71%-87%	62%-73%
Intermediate Storage	4%-7%	11%-19%	6%-10%	11%-15%
Conversion	14%-16%	9%-24%	6%-20%	13%-25%
Transport	1%-3%	1%-3%	1%-2%	1%- 2%

The key cost driver common to all the powerfuels is the hydrogen production cost, which covers the renewable energy source (i.e. wind and/or solar PV) and electrolyser system. The conversion costs make up the next largest contribution to the overall powerfuel costs and include the synthesis reactor and non-hydrogen feedstock systems (e.g. CO_2 capture technology for methanol, SAF and SNG, and nitrogen for ammonia).



82 - Global Alliance Powerfuels (2020). Powerfuels in a renewable energy world. Link
83 - IEA (2021), Global Hydrogen Review 2021, IEA, Paris Link
84 - R. Daiyan et al, (2021). The case for an Australian Hydrogen Export Market to Germany. State of Play V1.0. UNSW, Sydney. DOI: Link

PowerFuel Comparison

Each of the powerfuels evaluated offer pathways for decarbonising existing and emerging applications. However, there are parameters that must be considered when developing the value chain for these powerfuels, including decarbonisation benefits, safety and storage conditions, which are summarised in the table below:

	NH_3 Ammonia	CH_3OH Methanol	SNG Synthetic Natural Gas	SAF Sustainable Aviation Fuel
Production, Storage & Transport Technology Readiness Level	TRL 9	TRL 8	TRL 9	Production via PtL[87,88]: TRL 7 – 8 Storage & Transport: TRL 9
Powerfuel Storage Conditions	Pressurised: Ambient temperature and 16-18 bar Low-Temperature Liquid: minus 33°C and 1.1-1.2. bar	Ambient conditions as liquid	Pressurised: 200-250 bar at ambient temperature Liquified: -162°C	Ambient conditions as liquid. Can use conventional jet fuel storage infrastructure
Volumetric Energy Density (MJ/L)[85,86]	12.7	16.0	20.6	33.2
Gravimetric Energy Density (MJ/kg)[85,86]	18.6	20.0	53.6	44.2
Decarbonisation Benefit (kg CO_2-e/kg fuel)[89,90]	0	0.25	0.18	0.33-0.52 for bio-based production. Lower values for PtL production
Safety	Flammable with toxic fumes and dangerous for the environment if released	Flammable, toxic and dangerous for the environment if released	Highly flammable and will explode at gas-to-air ratio between 5% and 15%	Aviation
End-Use Sectors	Agriculture, Mining, Power Generation, Maritime, Chemical Feedstock	Power Generation, Mining, Maritime, Chemical Feedstock	Power Generation, Residential Appliances	Aviation

References:

85.- H_2 Tools.Link

86.- IATA. Link

87.- Johnson Matthey. Link

88.- Collis, J., Duch, K. & Schomäcker, R. Techno-economic assessment of jet fuel production using the Fischer-Tropsch process from steel mill gas. Front. Energy Res. 10, (2022). DOI: 10.3389/fenrg.2022.1049229

89 - ICAO. Link

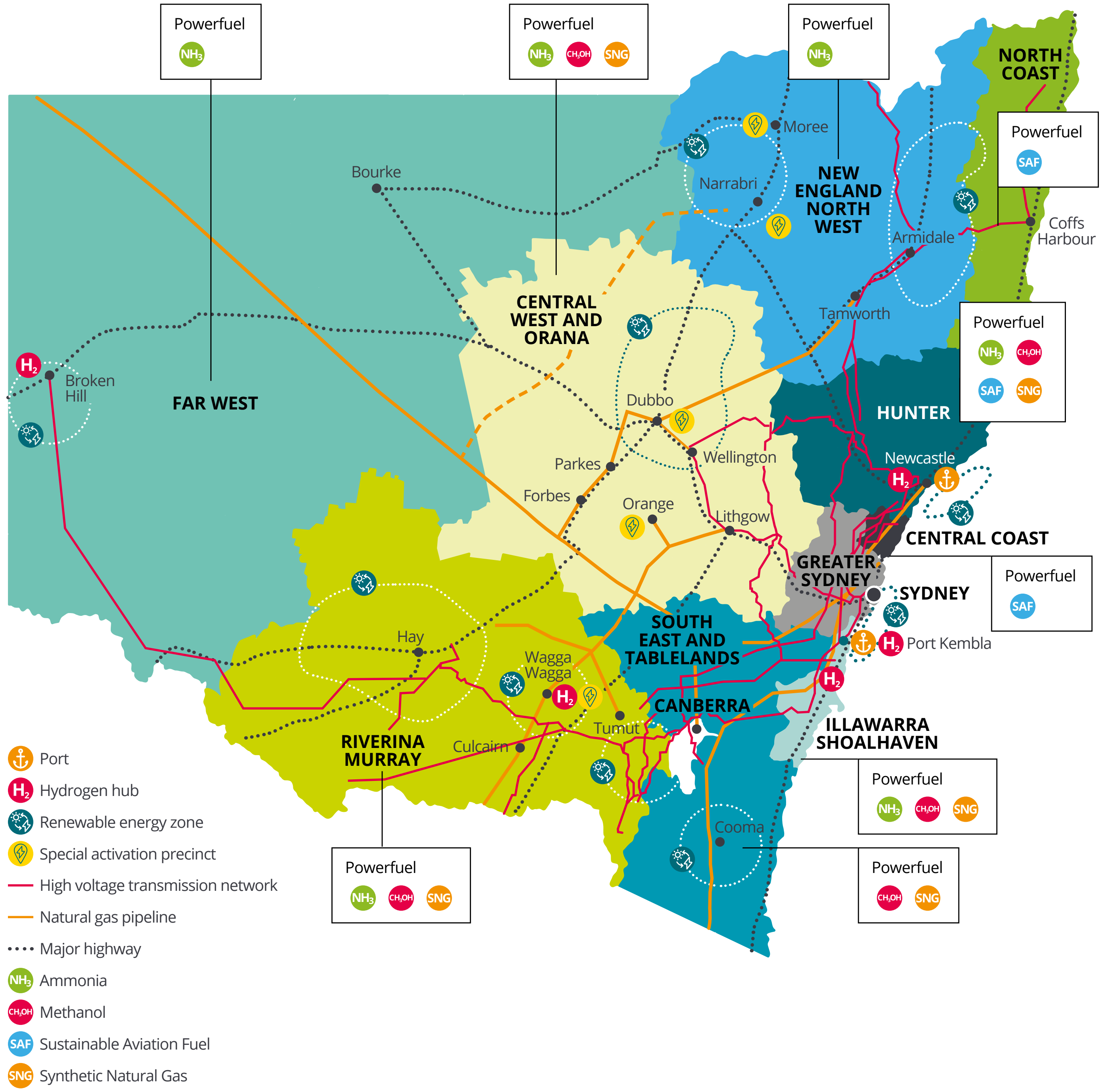
90- Sean M. Jarvis, Sheila Samsatli, Renewable and Sustainable Energy Reviews Link

PowerFuel Value Chain Cost Tool: Scope of Analysis

The PowerFuel Value Chain Cost Tool allows for a wide range of configurations to be assessed and for this analysis we focus on a few configurations to provide a comparison for each powerfuel.

	NH_3 Ammonia	CH_3OH Methanol	SNG Synthetic Natural Gas	SAF Sustainable Aviation Fuel
Power Configurations Explored	• 50% solar PV: 50% wind • Grid connected PPA • Offshore wind (where applicable)	• 40% solar PV: 60% wind • Dedicated transmission line (where onsite generation is not practical) • Offshore wind (where applicable)	• 40% solar PV: 60% wind • Dedicated transmission line (where onsite generation is not practical) • Offshore wind (where applicable)	• 40% solar PV: 60% wind • Offshore wind (where applicable) • 8 hr BESS for utilities
Hydrogen Production System	• PEM electrolyser with 25% oversizing • Hydrogen storage in buried pipelines	• PEM electrolyser with optimised oversizing • Hydrogen storage in above-ground pressure vessels	• PEM electrolyser with optimised oversizing • Hydrogen storage in above-ground pressure vessels	• PEM electrolyser with optimised oversizing • Dedicated transmission line (where onsite generation is not possible)
Conversion System	• Haber-Bosch synthesis unit capable of operating at 33% turndown • Nitrogen sourced from a cryogenic Air Separation Unit	• Methanol synthesis unit based on direct hydrogenation of CO_2 • Carbon dioxide sourced via direct air capture and industrial flue gases • 8 hr BESS for utilities	• SNG synthesis via the Sabatier methanation process • Carbon dioxide sourced via direct air capture and industrial flue gases • 8 hr BESS for utilities	• Carbon dioxide sourced via direct air capture and industrial flue gases • Synthesis based on RWGS reactor to form syngas and FT reactor with hydrocracker, to produce SAF • 8 hr BESS for utilities
Operating Assumptions	• >75% target capacity factor for ammonia production • 30 days' ammonia storage	• >85% target capacity factor for methanol production • 30 days' methanol storage	• >85% target capacity factor for methanol production • Direct use of SNG in power plant or gas network	• >85% target capacity factor for methanol production • 30 days' SAF storage

Figure 36 presents a summary of the NSW regions that might host production sites for ammonia,
methanol, synthetic natural gas and sustainable aviation fuel. Each of the regions has potential



domestic demand for the powerfuels and some also have potential export opportunities to

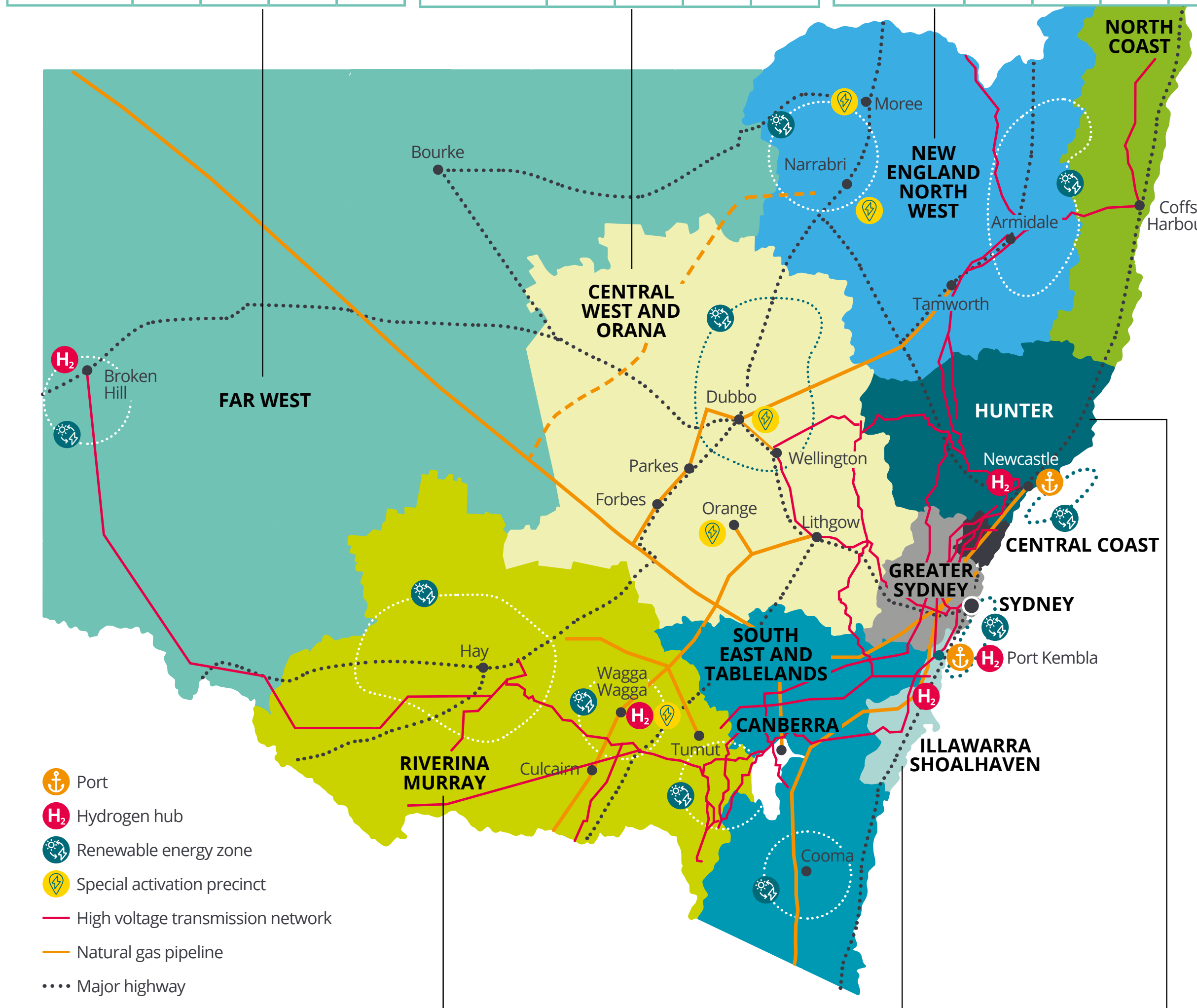
international markets.

Figure 36: Regions explored to produce ammonia, methanol, synthetic natural gas and sustainable aviation fuel.

LCOA (A$/tonne)	Hybrid Standalone		Grid Connected	
Year	Low	High	Low	High
2022	1,450	1,800	1,510	1,890
2030	1,030	1,370	1,140	1,450
2050	850	1,030	980	1,130

LCOA (A$/tonne)	Hybrid Standalone		Grid Connected	
Year	Low	High	Low	High
2022	1,610	1,950	1,540	1,900
2030	1,170	1,500	1,160	1,470
2050	980	1,150	1,010	1,150

LCOA (A$/tonne)	Hybrid Standalone		Grid Connected	
Year	Low	High	Low	High
2022	1,670	2,070	1,620	2,000
2030	1,190	1,570	1,230	1,550
2050	980	1,190	1,070	1,230



LCOA (A$/tonne)	Hybrid Standalone		Grid Connected	
Year	Low	High	Low	High
2022	1,900	2,290	1,720	2,120
2030	1,370	1,780	1,330	1,660
2050	1,130	1,370	1,170	1,320

LCOA (A$/tonne)	Hybrid Standalone		Grid Connected		Offshore Wind	
Year	Low	High	Low	High	Low	High
2022	1,940	2,330	1,710	2,110	2,140	2,770
2030	1,390	1,810	1,320	1,650	1,220	2,310
2050	1,150	1,390	1,160	1,310	1,090	1,920

LCOA (A$/tonne)	Hybrid Standalone		Grid Connected		Offshore Wind	
Year	Low	High	Low	High	Low	High
2022	1,710	2,080	1,620	2,000	2,160	2,790
2030	1,220	1,600	1,240	1,560	1,230	2,340
2050	1,010	1,220	1,090	1,240	1,110	1,960

The opportunities highlighted above in **Figure 36** represent an overview of the location resources and demands based on the findings from the mapping framework as described. Actual projects would of course be subject to project, social and environmental approvals, demonstration of financial feasibility and negotiation of offtake contracts — all aspects that are beyond the scope of this work.

Chapter 7: Ammonia

Our opportunity mapping framework identified six regions across NSW as potential development locations for Power-to-Ammonia. The indicative cost of producing ammonia in each location between 2022 and 2050 was analysed using the Powerfuel Tool developed, followed by an assessment of the potential ammonia demand at a regional and international level.

There is potential demand for ammonia in its traditional use in mining and in agriculture, but also in its emerging uses for power generation in fuel cells, as a clean shipping fuel, as a powerfuel and for co-firing with — or even replacing — coal in power stations. There is also an opportunity for international export from some locations.

Transport is key to any domestic or export use of ammonia and our analysis shows rail has the lowest levelised cost across all distances, though it does require increased logistics and time to unload the rail cars at the destination point. A pipeline is estimated to be the next lowest-cost mode of transport across all distances and is a potential option if there are several potential off-takers along the pipeline. Road is the most expensive mode of transport across all distances and would require multiple round trips due to the limited quantity that can be transported at any one time (27 tonnes). Road transport is generally reserved for transporting smaller quantities to end users across short distances.

Based on the analysis of deploying green ammonia facilities across NSW, we estimate a potential production capacity between 4 and 4.9 MTPA by 2050 to service domestic and export demand.

The current price for ammonia is heavily tied to the price of natural gas and reached a high of US$1,630/t (A$2,370/t) in the first quarter of 2022. It currently sits at approximately US$1,000/t (A$1,450/t).

While these recent prices for conventional ammonia are historically high, its production will always be tied to the volatility of natural gas pricing given its critical role as the source of hydrogen for the process. A green ammonia value chain, on the other hand, will be decoupled from the price of natural gas and linked to the build cost for renewable power and electrolysers, which is expected to decline between now and 2050.

The indicative cost from our analysis suggests the gate price for ammonia produced in NSW could be:

- between A$1,030/t (US$710/t) and A$1,390/t (US$960/t)
- between A$850/t (US$590/t) and A$1,150/t (US$790/t) by 2050.

Figure 37. Indicative Levelised Cost Of Ammonia Across Several NSW Regions With Potential To Host Power-to-Ammonia Facilities.

7.1. Ammonia Production Cost and End Use Analysis

Our opportunity mapping framework identified six regions across NSW as potential development locations for Power-to-Ammonia. The indicative cost of producing ammonia in each location between 2022 and 2050 was analysed using the Powerfuel Tool developed (**Figure 37**) followed by an assessment of the potential ammonia demand at a regional and international level.

For the Far West, Central West and Orana, Riverina Murray and New England North West regions, two configurations for the production of ammonia were compared. These were a standalone hybrid renewable energy power source and a grid-connected PPA power source from the nearest REZ. For the Illawarra Shoalhaven and Hunter region, a third configuration in the form of offshore wind was also analysed. The results for each region are described below.

Far West

The production of ammonia in Far West NSW has some of the lowest gate prices in NSW and which can be attributed to the capacity factors for solar and wind that rank among the best in the state. Grid connection costs in Broken Hill are assessed as the highest in the state at A$176/kW,[91] but, despite this, systems using a grid connection to supply their renewable energy power still have lower overall gate prices due to the higher capacity factors from the nearby REZ. However, compared to a hybrid standalone system, the grid connected system is more expensive by about 10 – 15%. The scale at which ammonia production can be deployed in Far West NSW will be limited by the availability of water and the infrastructure required to transport the product to the demand centres.

Within the Far West region, there is potential demand for the traditional use of ammonia at the Cobar and Broken Hill mine sites as a leaching agent in hydrometallurgical processes for the extraction of copper, silver, gold, cobalt and zinc, and as a component for making explosives. In the Far West agricultural sector, ammonia can be used as a fertiliser to support growth of the broadacre crops, namely cotton and wheat.[92]

In its emerging use as a fuel for power generation, ammonia could be used for small-scale decentralised power generation using fuel cells located in remote communities or at mine sites. GenCell[93] and AFC Energy[94] are demonstrating products that use ammonia to generate power in a fuel cell.

The ammonia fuel cell products are designed for decentralised power generation in small communities that traditionally rely on diesel-powered generators. With the need to decarbonise all forms of power generation along with the risks and costs associated with transporting diesel long distances, ammonia fuel cells might offer a viable alternative with careful deployment considering the safety issues of handling ammonia, e.g. safeguarding against leaks. A 4kW fuel cell system provided by GenCell has a maximum fuel consumption of 2.5 kg/h. Assuming a typical Australian household consumes 17 kWh of electricity per day this would amount to approximately 11kg of ammonia per day.

Given the long distance of the Far West from NSW export terminals, the potential to produce ammonia for international markets in this region is limited but could be potentially viable if exported through South Australian ports, which are closer. The transport costs from the Far West region to the eastern seaboard export terminals are analysed in **Section 7.2**

Based on the prospective regional demand for ammonia and considering the constraints on water, the Far West could potentially accommodate a small-scale ammonia plant with a capacity between 50 and 100 KTPA.

Riverina Murray

Production of ammonia in the Riverina Murray region is estimated to have one of the highest gate prices in NSW and can be attributed to the capacity factors for solar and wind, which are comparatively lower than those in other parts of the state. Grid-connected systems also have some of the highest gate prices as a result of the lower capacity factors of the nearest REZ. The scale at which ammonia production in the Riverina Murray region can be deployed will be subject to resource availability, including a reliable water source and access to land that doesn't compete or interfere with existing land use, e.g. agricultural activities.

The Riverina Murray region is described as the 'Food Bowl of NSW' and would be a prime location for ammonia to be used in its traditional form as a fertiliser for broadacre crops (cotton and cereals). If the ammonia produced is cheaper than their existing supply from out of state, this could bring potential cost savings to farmers.

Emerging uses for ammonia as a fuel for power generation could also be deployed in the Riverina Murray region. At the small-scale end, ammonia could be used for decentralised power generation, much as in the Far West.

91 - AEMO (2021). Transmission Cost Report Link
92- NSW DPI (2020). Link
93 - GenCell (2022). GenCell FOX off-grid solution. Link
94 - AFC Energy (2022). Technology Products. Link

The development of Inland Rail creates opportunities to transport ammonia out of the Riverina Murray region to other parts of the state or to the eastern seaboard, where it can then be exported to international markets. Further analysis on the transport of ammonia from the Riverina Murray region is provided in **Section 7.2**.

Based on the prospective regional demand for ammonia and with careful consideration of existing agricultural land use, the Riverina Murray region could accommodate an ammonia plant with a capacity of up to 250 KTPA.

Central West and Orana

Based on the cost data and assumptions used in the analysis, production of ammonia in the Central West and Orana region has a median gate price compared to the other regions. The median gate price can be attributed to the strong potential for solar and wind in the region and the ability to connect to the nearest REZ using the grid.

Like Riverina Murray, agriculture dominates this region, which creates opportunities for ammonia to be used as a fertiliser for its broadacre crops — mainly wheat and barley.[95] There are several mine sites across the region that could potentially use ammonia as a leaching agent in the hydrometallurgical processes for the extraction of copper and gold at Northparkes mine, and Tomingley and Peak Hill gold mines.

Ammonia could also be deployed as a fuel for power generation in the Central West and Orana region. At a small scale, ammonia could be deployed in a similar way to that discussed for the Far West. At a large scale, the use of ammonia in coal-fired power stations is gaining traction in Asia, particularly Japan, as a potential pathway to decarbonise the high-emission power generators. IHI and JERA have been spearheading the deployment of ammonia co-firing at their coal-fired power stations with the aim to transition to 100% ammonia.[96] The Mt Piper coal-fired power station near Portland could be a potential site for ammonia co-firing at 20%. Based on the same electricity produced during 2020-21 (8.1 TWh), co-firing at 20% would require approximately 800 KTPA of ammonia and result in a reduction of 1.4 MT CO_2-e per year (equivalent to 20%). Co-firing is a potential option to reduce CO_2 emissions from coal-fired power stations but air pollutants, such as NO_x, must still be monitored and remain in compliance. This option for decarbonising existing coal-fired power plants must be carefully considered with the required investment and additional safety requirements associated with the ammonia infrastructure, as well as the impact on the cost of electricity.

The development of Inland Rail and a Special Activation Precinct in Parkes creates opportunities to transport ammonia out of the Central West and Orana region to other parts of the state or to the eastern seaboard where it can then be exported to international markets. Further analysis on the transport of ammonia from this region is provided in **Section 7.2**

Based on the prospective regional demand for ammonia, and future developments with the Inland Rail, SAP at Parkes, and the renewable energy zone, the Central West and Orana region could potentially accommodate an ammonia plant with a capacity up to 1 MTPA.

Illawarra Shoalhaven

Based on our indicative cost analysis, ammonia production using a hybrid standalone renewable energy power supply in the Illawarra Shoalhaven region has the highest gate price in NSW. This can be attributed to the solar and wind capacity factors which are among the lowest when compared to the rest of the regions in NSW. Grid-connected PPA configurations provide lower gate prices for ammonia with access to the grid, with median connection costs in comparison to the other regions. The Illawarra Shoalhaven region has also been identified for potential offshore wind development and while the capacity factors exceed those for onshore wind, the overall gate price is high compared to the hybrid standalone and grid-connected systems, based on the cost data and assumptions used in the analysis.

Manufacturing dominates the economy in the Illawarra Shoalhaven region and includes steel, chemical, food and beverage, construction and machinery. The region also hosts several coal mines and a gas-fired power station at Tallawarra. Potential demand in the region for ammonia could be realised in its emerging use as a powerfuel. The coal mine sites at Wongawilli, Kembla Heights, Russell Vale and nearby Appin, Helensburgh and Tahmoor could use ammonia fuel cells as a replacement for backup diesel generators.

Another potential demand for ammonia in the Illawarra Shoalhaven region is in its emerging use as a clean shipping fuel. Port Kembla is a major export terminal and could host ammonia refuelling facilities for large vessels travelling internationally and smaller service vessels such as tugboats that operate locally. It is estimated that one ammonia-powered ocean-going vessel would require approx. 60 KTPA each year.[97] A 1 MTPA ammonia plant in the Illawarra Shoalhaven region would be able to meet annual fuel demand equivalent to 16 ammonia-powered ocean-going vessels.

Port Kembla also offers the opportunity to export ammonia to international markets, and this is explored further in **Section D**.

Based on the prospective regional demand and opportunity to export ammonia out of Port Kembla, the Illawarra Shoalhaven region could potentially host an ammonia facility with a capacity in excess of 1 MTPA.

Hunter

Based on the cost data and assumptions used in the analysis, ammonia production in the Hunter region has a medium gate price compared to the other regions assessed. This gate price can be attributed to a better capacity factor for wind compared to Illawarra Shoalhaven and Riverina Murray Region. Grid-connected PPA configurations provide lower gate prices for ammonia with access to the grid, with median connection costs compared to the other regions. The Hunter region has also been identified for potential offshore wind development and

95 - NSW DPI (2020). Link
96 - JERA (2021). JERA and IHI to Start a Demonstration Project Related to Ammonia Co-firing at a Large-Scale Commercial Coal-Fired Power Plant Link
97 - U.S. Department of Energy (2021). Ammonia as Maritime Fuel. Link

while the capacity factors exceed those for onshore wind, the overall gate price is high compared to the hybrid standalone and grid-connected systems, based on the cost data and assumptions used in the analysis.

Coal mining is the dominant sector in the Hunter region and accounts for most of the regional output. These mine sites could utilise ammonia as a power source via fuel cells that could replace carbon emitting diesel back-up generators. However, as a decarbonising strategy, this would only be impactful if the full value chain of coal is decarbonised using carbon capture during the combustion process.

The presence of coal-fired power stations in the Hunter region also presents an opportunity to use ammonia as a powerfuel. The coal-fired plants scheduled for closure between 2022 and 2029 would not benefit from the co-firing option described earlier for Mt Piper. However, these power plants could potentially benefit from the installation of ammonia-fuelled gas turbines to replace some of the capacity lost through closure. Mitsubishi is currently in the process of commercialising (expected 2025) a 100% fuelled ammonia gas turbine with capacities ranging from 41MW for open cycle to 60MW for combined cycle systems.[98] A 41MW open cycle system with an efficiency of 36.2%[99] would require approximately 50 KTPA of ammonia assuming a capacity factor of 25%. A combined cycle 60MW gas turbine with an efficiency of around 55% would require approximately 63 KTPA of ammonia assuming a capacity factor of 50%. Given Bayswater is scheduled for closure in 2033, it could potentially employ ammonia for co-firing. Based on the same electricity produced during 2020-21 (14.3 TWh)[75] co-firing at 20% would require approximately 1400 KTPA of ammonia and result in 2.5 MT CO_2-e per year avoided.

The emerging use of ammonia as a clean shipping fuel also has potential in the Hunter region. The Port of Newcastle is a major export terminal and could host ammonia refuelling facilities for large vessels travelling internationally and smaller service vessels such as tugboats that operate locally. Like the Illawarra Shoalhaven region, a 1 MTPA capacity ammonia plant could meet the annual fuel demand equivalent of 16 ammonia-powered ocean-going vessels.

The Port of Newcastle already hosts an ammonia plant on Kooragang Island, operated by Orica, and the location could be expanded to include ammonia exports to international markets. This is explored further in **Section D**.

Based on the prospective regional demand and opportunity to export ammonia out of the Port of Newcastle, the Hunter region could potentially accommodate an ammonia production capacity between 1.5 and 2 MTPA.

New England North West

Ammonia production in the New England North West region has a median gate price compared to the other regions assessed. The median gate price can be attributed to the strong potential for solar and wind in the region and the ability to connect to the nearest REZ using the grid.

As in Riverina Murray and Central West and Orana, agriculture dominates the region. This creates opportunities for ammonia to be used as a fertiliser for the broadacre crops, mainly cereals and cotton, that grow in the region.[100]

There are several coal mines across the region that could potentially use ammonia as a powerfuel. By using ammonia-powered fuel cells, the coal mines could replace carbon emitting diesel back-up generators.

The development of Inland Rail and a Special Activation Precinct in Moree and Narrabri creates opportunities to transport ammonia out of the New England North West region to other parts of the state or to the eastern seaboard, where it can then be exported to international markets. Further analysis on the transport of ammonia from the New England North West region is provided in **Section 7.2**.

Based on the prospective regional demand and opportunity to transport ammonia out of the region via the Inland Rail, the New England North West region could potentially accommodate an ammonia production capacity between 250 and 500 KTPA.

98 - Mitsubishi (2021). Creating a sustainable future through hydrogen generation Link
99 - MHI (2021). Hydrogen/Ammonia Solution Ecosystem. Link
100 - NSW DPI (2020). Link

7.2. Ammonia Transport Cost Analysis

The costs associated with intrastate transport of ammonia from the Far West, Central West and Orana, Riverina Murray and North England North West regions were explored. These four regions were chosen based on their long distance from the major exporting terminals located at Port Kembla, Port Botany and Port of Newcastle and to get an understanding of the costs associated with transporting bulk quantities of ammonia.

Three modes of transport that are currently used throughout the world to transport ammonia across land were considered. These transport modes are pipeline, rail and road and the assumptions used in the analysis are summarised below.

All modes of transport were based on delivering an annual quantity of 1 MTPA of ammonia, across a 25-year timeframe using a discount rate of 7%. The pricing is based on published estimates of current transportation costs. Future transportation costs could increase or decrease depending on the mode of transport. For example, transporting ammonia via road in 2030 may be more expensive if the vehicle uses hydrogen as the primary fuel.

- ***Pipeline[a]:*** The pipeline routing is based on passing through 80% rural and 20% urban areas with a CAPEX of A$2.11M/km and A$1.23M/km respectively. Booster stations are located every 128km with a CAPEX of A$3.19M per station. The OPEX included A$717/km for the pipeline and A$0.6M/station/year.
- ***Rail[b]:*** A rate of A$0.04/t km was used for the rail transport
- ***Road[b]:*** A rate of A$0.33/t km was used for the road transport

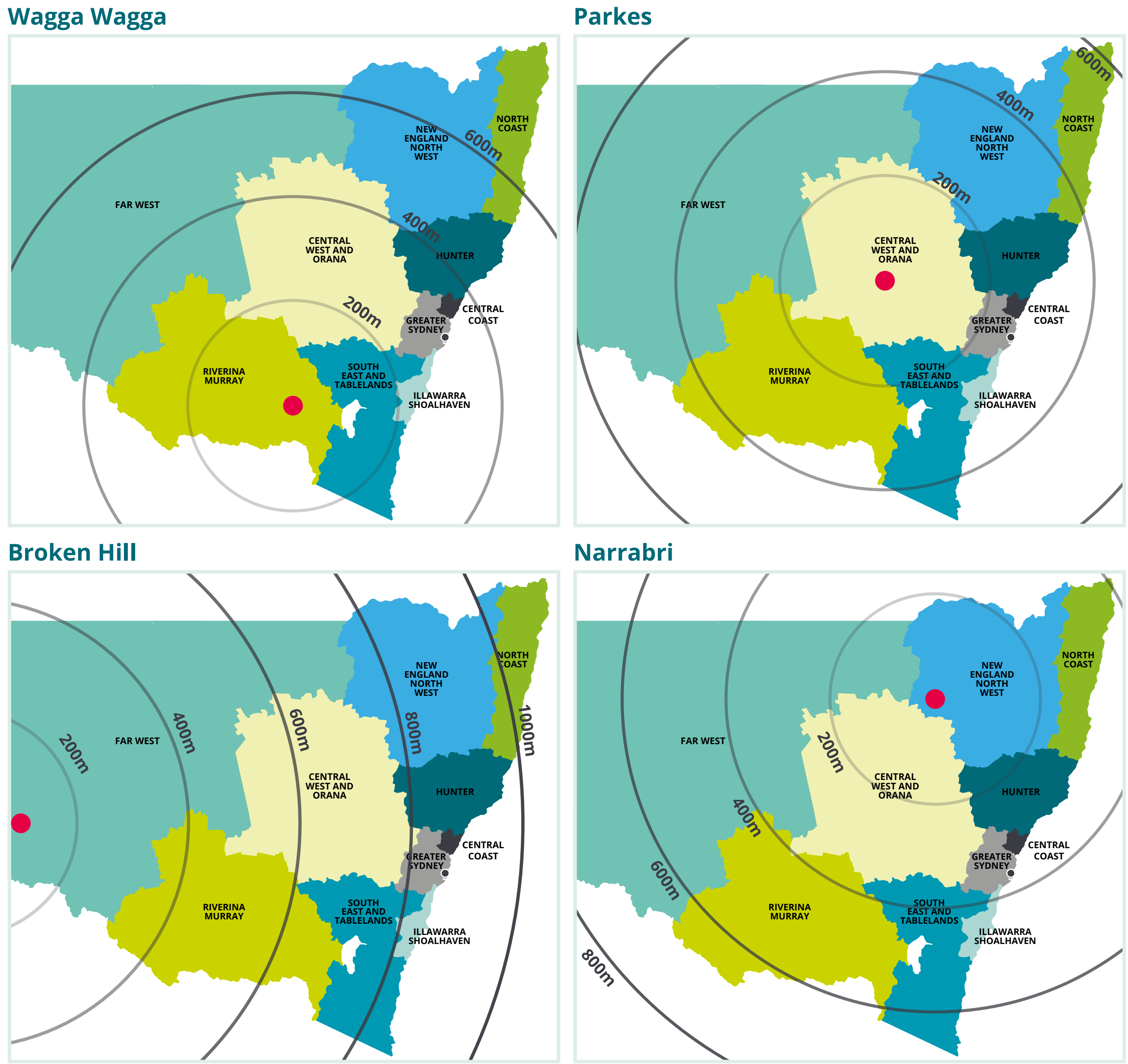
Cost References:

a - Techno-Economic Challenges of Green Ammonia as an Energy Vector (2021). Pg. 191-207
b - CSIRO(2019). National Hydrogen Roadmap.

Note: We acknowledge that ammonia transportation costs are decreasing over time but, owing to the infancy of the renewable ammonia industry, we refer to publicly available data for our estimates.

Figure 38 shows the levelised cost of transporting 1 MTPA of ammonia from four different regions of NSW (Far West, Riverina Murray, Central West and Orana, and New England North West). Overall, transport of ammonia via rail has the lowest levelised cost across all distances but does require increased logistics and time to unload the rail cars at the destination point. The pipeline is estimated to be the next lowest-cost mode of transport across all distances and is a potential option if there are several potential off-takers along the pipeline. But it does require careful routing to take the environmental and safety risks into consideration. The road option is the most expensive mode of transport across all distances and would require multiple round trips to transport an equivalent of 1 MTPA of ammonia due to the limited quantity that can be transported at any one time (27 tonnes). Road transport is generally reserved for transporting smaller quantities to end users across short distances.

The transport of ammonia from the Far West region, specifically Broken Hill, incurs the



Distance (km)	Pipeline (A$/kg)	Rail (A$/kg)	Road (A$/kg)
200km	0.03	0.01	0.07
400km	0.05	0.02	0.13
600km	0.08	0.02	0.20
800km	0.10	0.03	0.26
1000km	0.13	0.04	0.33

highest levelised cost to reach the eastern seaboard of NSW due to the long distance that needs to be covered (800 – 1000 km). Given its closer distance to Adelaide (500 – 600 km) and Melbourne (700 – 800 km), it could be more beneficial from a cost perspective to transport ammonia from the Far West to South Australia or Victoria.

The Central West and Orana (Parkes SAP) and New England North West (Narrabri SAP) regions can reach the eastern seaboard export terminals within 400 km and these regions could benefit from the Inland Rail by having greater access to markets in Queensland and Victoria. For the Riverina Murray (Wagga Wagga SAP) region the eastern seaboard terminals are between 200 and 600 km away and this region could also benefit from the Inland Rail that will pass through Wagga Wagga.

Figure 38. Incremental Levelised Cost Of Transporting 1 MTPA Of Ammonia Across NSW Based On Current Transport Costs.

The transport of ammonia to the eastern seaboard terminals creates export opportunities. However, transport of ammonia within the state should be considered where demand is highest. For example, an ammonia plant in the Central West and Orana region could transport ammonia via rail to Wagga Wagga via the Inland Rail for use in agriculture as a fertiliser. For the Illawarra and Hunter, these regions are located on the eastern seaboard with the potential to locate ammonia plants close to the export terminals, which would minimise the additional costs associated with inland transport.

7.3. Ammonia Summary

Based on the analysis of deploying green ammonia facilities across NSW, we estimate a potential production capacity between 4 and 4.9 MTPA by 2050 to service domestic and export demand. The IEA's Ammonia Technology Roadmap estimates the demand for ammonia by 2050 will be between 400 and 550 MTPA[101] and based on our analysis NSW might conceivably host between 0.7% and 1.2% of the global capacity. However, our estimates are purely indicative and should NSW negotiate trade partnerships with countries seeking to import ammonia (e.g. Japan, South Korea and Singapore), the total capacity in NSW could be significantly higher.

The indicative cost from our analysis suggests the gate price for ammonia produced in NSW could be between A$1,030/t (US$710/t) and A$1,390/t (US$960/t) by 2030 and between A$850/t (US$590/t) and A$1,150/t (US$790/t) by 2050. Current pricing for ammonia is heavily tied to the price of natural gas, with pricing in 2022 reaching a high of US$1,000/t (A$1,450/t) in the first quarter and currently sitting at approximately US$1,000/t (A$1,450/t).[102] While these recent prices for conventional ammonia are historically high, its production will always be tied to the volatility of natural gas pricing given its critical role as the source of hydrogen for the process. A green ammonia value chain, on the other hand, will be decoupled from the price of natural gas and linked to the build cost for renewable power and electrolysers, which is expected to decline between now and 2050.

101 - IEA (2021). Ammonia Technology Roadmap. Link
102 - Procurement Resource (2022). Ammonia Price Trend. Link

Chapter 8: Methanol

Methanol can serve as a transport fuel substitute suitable for marine vessels, heavy machinery, and other diesel and bunker fuel applications. It can also be used for decentralised power generation in fuel cell or diesel generators. Methanol also has potential as a fuel or energy carrier either for domestic use or export.

Power-to-Methanol involves the direct hydrogenation of captured CO_2 and renewable hydrogen. In this assessement, we looked at a number of carbon-capture sources, including Direct Air Capture (DAC) and various Industrial Flue Gas (IFG) sources such as cement, steel, coal- and gas-fired power generation, Steam Methane Reforming (SMR), and as a by-product of fermentation.

In terms of transport, moving methanol by rail is the lowest cost option across any distances. As there are well-established freight networks for similarly refined fuels, road transport by truck is the next best option. Pipeline options would require large investment, though they may be feasible at larger scale, i.e. larger than 1000 KTPA capacity. In several of the regions there are IFG producers that would be suitable for retrofitting post carbon capture technologies. These include power stations, steel plants and ammonia production facilities.

The opportunity mapping framework identified five regions across NSW as potential development locations for Power-to-Methanol (P2M). The indicative levelised cost of producing methanol in each of these locations was analysed and forecasted from 2022 through to 2050, using the NSW Powerfuel Value Chain Cost Tool (see **Figure 39**). This was followed by an assessment of the potential regional and international demand for methanol.

Findings:

Based on the analysis for deploying P2M facilities across NSW, we estimate the potential demand to be approximately 500 KTPA. However, our estimates are purely indicative and, should NSW negotiate trade partnerships with countries seeking to import methanol (e.g. Japan, Germany and Singapore), the total capacity in NSW could be a lot higher.

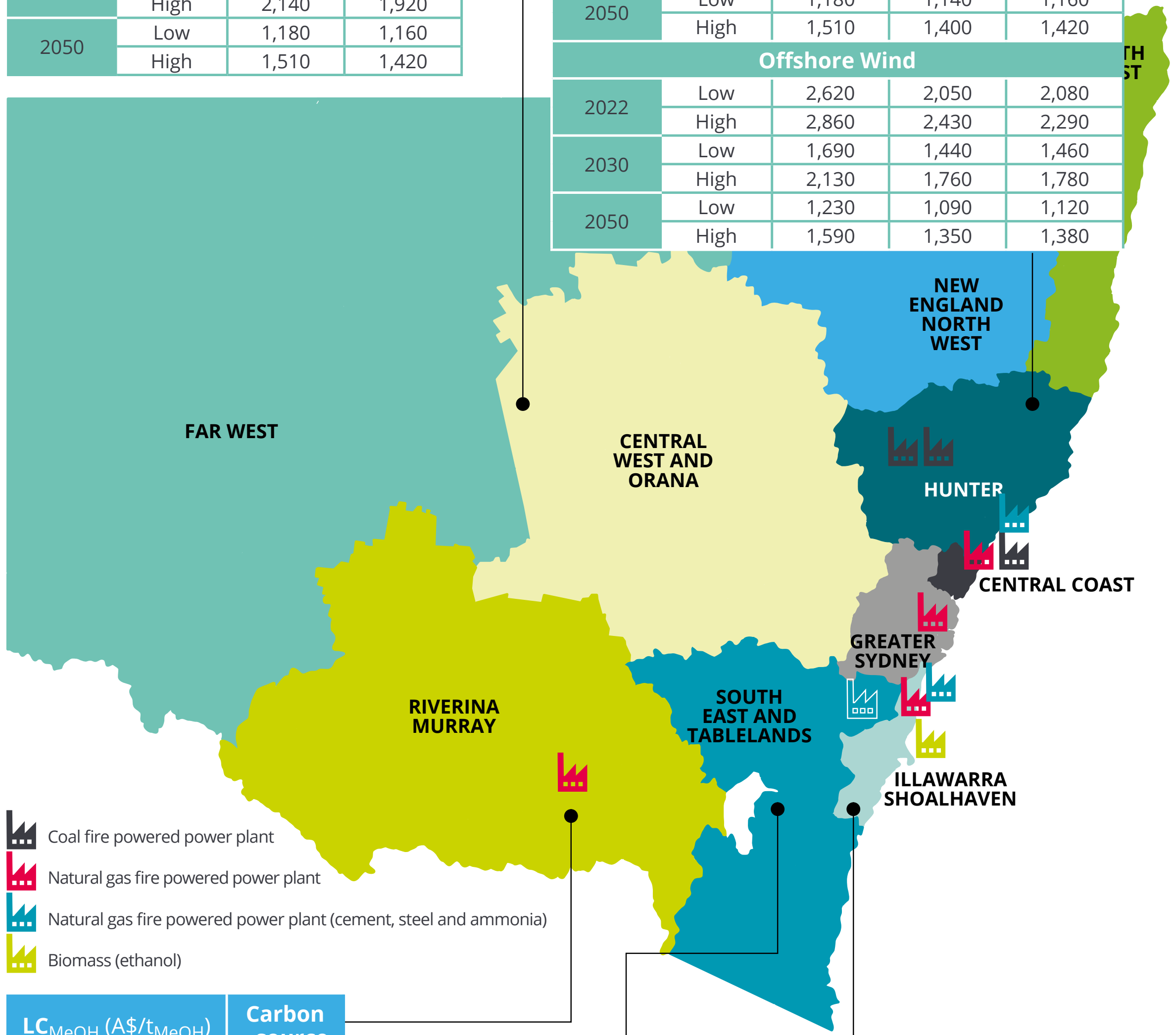
Depending on the power configuration and carbon dioxide source used, the indicative cost from our analysis suggests the gate price for methanol produced in NSW could be between:

- A\$1,140 and A\$3,300/t_{MeOH} by 2030
- A\$800 and A\$2,300/t_{MeOH} by 2050

The indicative cost analysis for producing Methanol in NSW. Here the production scale is assumed to 1,000 TPD unless otherwise specified.

LC_{MeOH} (A\$/t_{MeOH})		Carbon source	
Year		DAC	Coal power FG
Hybrid Standalone			
2022	Low	2,630	2,200
	High	2,950	2,500
2030	Low	1,690	1,570
	High	2,140	1,920
2050	Low	1,180	1,160
	High	1,510	1,420

LC_{MeOH} (A\$/t_{MeOH})		Carbon source		
Year		DAC	Ammonia IFG	Coal power FG
Hybrid – Dedicated Transmission Line				
2022	Low	2,630	2,180	2,200
	High	2,950	2,480	2,500
2030	Low	1,690	1,560	1,570
	High	2,140	1,910	1,920
2050	Low	1,180	1,140	1,160
	High	1,510	1,400	1,420
Offshore Wind				
2022	Low	2,620	2,050	2,080
	High	2,860	2,430	2,290
2030	Low	1,690	1,440	1,460
	High	2,130	1,760	1,780
2050	Low	1,230	1,090	1,120
	High	1,590	1,350	1,380



LC_{MeOH} (A\$/t_{MeOH})		Carbon source
Year		DAC
Hybrid Standalone		
2022	Low	2,840
	High	3,150
2030	Low	1,780
	High	2,250
2050	Low	1,200
	High	1,530

LC_{MeOH} (A\$/t_{MeOH})		Carbon source	
Year		DAC	Coal power FG
Hybrid Standalone			
2022	Low	2,710	2,220
	High	3,040	2,530
2030	Low	1,750	1,580
	High	2,220	1,950
2050	Low	1,230	1,150
	High	1,570	1,420

LC_{MeOH} (A\$/t_{MeOH})		Carbon source		
Year		DAC	Ammonia IFG	Coal power FG
Hybrid – Dedicated Transmission Line				
2022	Low	2,710	2,100	2,260
	High	3,040	2,430	2,580
2030	Low	1,750	1,470	1,620
	High	2,220	1,850	1,990
2050	Low	1,230	1,040	1,190
	High	1,570	1,320	1,460
Offshore Wind				
2022	Low	2,500	1,700	1,960
	High	2,730	1,930	2,170
2030	Low	1,560	1,140	1,370
	High	1,960	1,450	1,660
2050	Low	1,130	800	1,040
	High	1,480	1,050	1,290

Figure 39. (right). Locations Explored To Produce Methanol in NSW With indicative Cost Analysis.
Scales Are 1,000 TPD Methanol Production Unless Otherwise Specified.

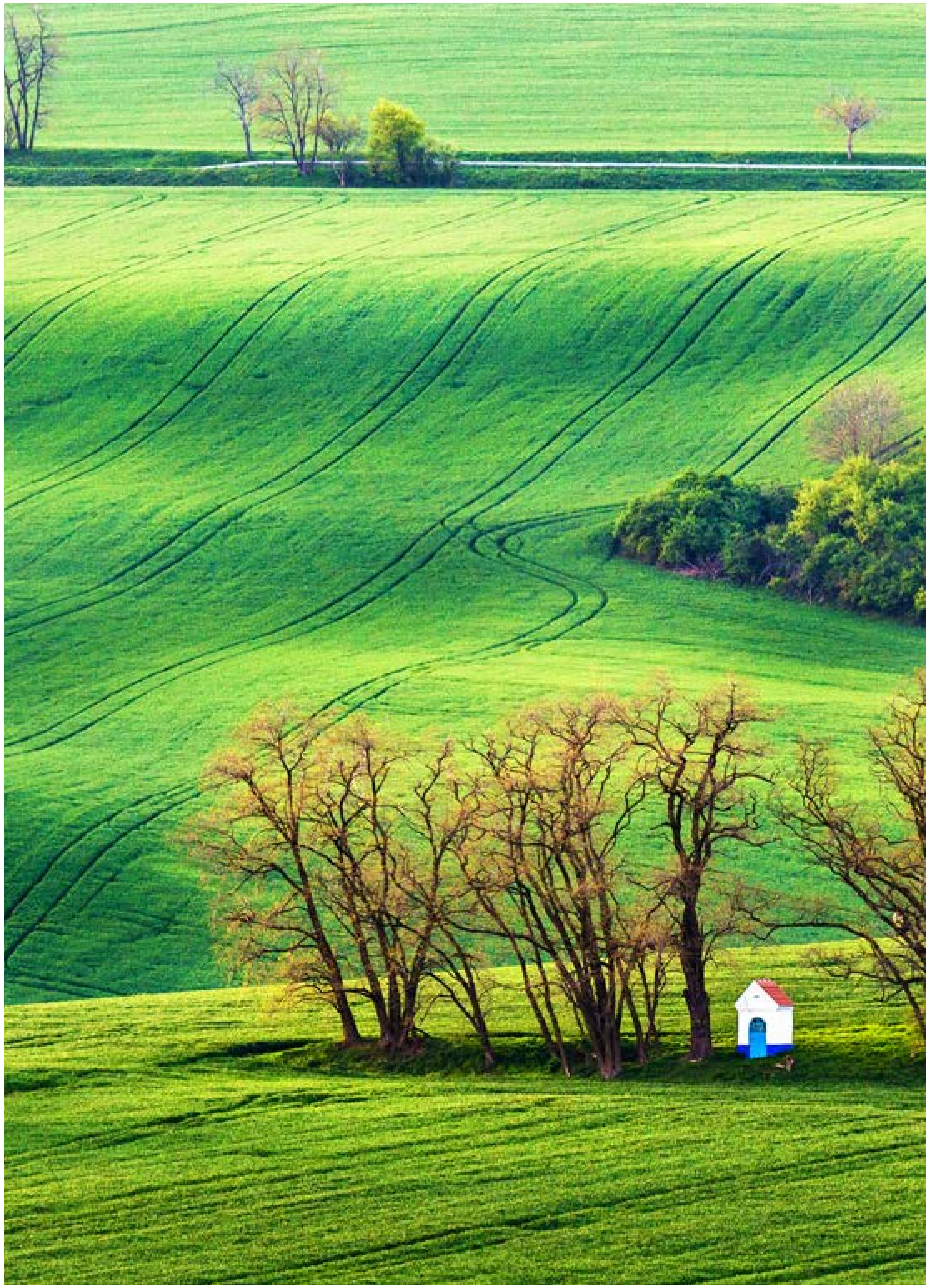
8.1. Methanol Production Cost and End-Use Analysis

The opportunity mapping framework identified five regions across NSW as potential development locations for Power-to-Methanol (P2M) based on the direct hydrogenation of captured CO_2 and hydrogen produced through renewable electrolysis. The indicative levelised cost of producing methanol in each of these locations was analysed and forecasted from 2022 through to 2050, using the NSW Powerfuel Value Chain Cost Tool (see **Figure 39**). This is followed by an assessment of the potential regional and international demand for methanol.

The range of carbon capture sources assessed include Direct Air Capture (DAC) and various Industrial Flue Gas (IFG) sources such as cement, steel, coal- and gas-fired power generation, Steam Methane Reforming (SMR), and as a by-product of fermentation. IFG capture technologies benefit from high flue gas CO_2 concentrations (>14%), which make them less capital- and energy-intensive options compared to DAC in the near term. However, IFG sources are likely to disappear in the future as the industries mentioned are committed to lowering their own carbon footprint. There has also been much discussion about whether the use of IFG sources tied to fossil-fuel consumption aligns with net zero objectives as transitional CO_2 sources, with power plant flue gas being a particular source of controversy. Hence CO_2 sourcing should be a key consideration for determining potential end use and export markets. These risks highlight the importance of continuing to develop long-term sources, such as DAC and sustainable biomass sourced CO_2. We note that gas-fired power generation facilities in NSW are in general small in scale compared to other flue gas sources, with the major sites also being peaking facilities. This means that they operate intermittently during high demand periods and thus have a low capacity factor. For these reasons gas-fired power IFG was not considered as a suitable CO_2 source in this assessment.

Post-combustion capture of biomass-based power generation flue gas is a potential renewable CO_2 source for methanol production. However, biomass-firing facilities face challenges including feedstock storage and handling, competing demand from other industries, and ongoing questions about the true sustainability of some agricultural and particularly forestry biomass sources. These facilities are currently limited to small scale in NSW and were hence not assessed in this work. We note that direct biomass to biofuel conversion technologies represent an alternative route to renewable methanol production. However, this was not considered herein as we explore only e-methanol production.

The power generation configurations considered include standalone hybrid solar and wind power, offshore wind power through a sub-sea transmission line, and offsite hybrid solar and wind power through a private onshore transmission line. For the Illawarra Shoalhaven and Hunter regions, a hybrid renewable power configuration with a dedicated transmission network connected to the REZ in the Central West and Orana region, is compared against an offshore wind power source since these regions have limited land availability for large-scale renewable energy projects.



Hunter

Based on the costing data and assumptions used in our analysis, the Hunter region has low-to-median gate prices relative to similar configurations across the regions considered in this report. Configurations assessed include Direct Air Capture (DAC) and a range of Industrial Flue Gas (IFG) carbon dioxide sources.

In addition to DAC, there are several IFG producers suitable for retrofitting of post combustion carbon capture technologies including the Bayswater, Liddell, Eraring and Vales Point coal-fired power stations, as well as the Kooragang Island SMR/ Ammonia production facility. Among these sites, coal-fired power and SMR IFG are the most economical carbon point sources in the near term, leading to methanol production costs as low as A$2,200 and A$2,180/T_{MeOH} respectively in 2022. We note there is significant narrowing of the gap between DAC and IFG sourced P2M configurations through 2030 and 2050 (see **Figure 40**). Offshore wind power generation off the coast of Newcastle might deliver slightly lower costs compared to onshore power generation configurations. These configurations benefit from high offshore wind power capacity factors, which has a cascading effect on the performance and hence the required sizing of renewable energy, electrolyser and buffer technologies.

Methanol can serve as a transport fuel substitute suitable for marine vessels, heavy machinery, and other diesel and bunker fuel applications. As a marine fuel, a 49,000 dead weight tonnage (DWT) vessel is estimated to require 12.5 KTPA of methanol annually.[103] A 500 KTPA methanol plant in the Hunter would provide enough fuel to power the equivalent of 40 methanol powered (49,000 DWT) vessels each year.

E-methanol generated in the region can be used by Port of Newcastle for end use as bunker fuel. Export as a renewable energy carrier or fuel out of the Port of Newcastle to international markets is another opportunity for the Hunter.

Illawarra Shoalhaven

The Illawarra region has some of the lowest gate prices obtained in this analysis. This is due to the combination of factors and opportunities such as high capacity factor offshore wind power generation, median capacity factor offsite hybrid power generation through private onshore transmission line and a variety of carbon sources including DAC, IFG from steelmaking, and low-cost CO_2 produced as a by-product of fermentation. Offshore wind configurations in this region outperform their onshore counterparts in present and future scenarios with significant cost reduction through lower required installed capacities of renewable power generation, electrolyser and buffer technology systems, which benefit from the increased operating stability that accompanies the high-capacity factor. P2M configurations utilising CO_2 produced as a by-product of fermentation was found to have the lowest gate price of A$1,700 and A$800/T_{MeOH} through 2022 and 2050 respectively. This is due to a very high CO_2 concentration of up to 99% by volume of fermentation by-product gas which results in significant cost savings for installation and operation of carbon capture facilities. However, fermentation processes are limited to small to moderate scale and demand of this high purity CO_2 by-product may be competing with other sectors including food, beverage and packaging. Median capacity factors for onshore solar and wind generation see median to high gate prices for hybrid standalone configurations.

Methanol can also serve as a transport fuel substitute suitable for marine vessels, heavy machinery, and other diesel and bunker fuel applications. E-methanol generated in the region can be used by Port Kembla for end use as bunker fuel. Export as a renewable energy carrier to international markets is also available out of Port Kembla.

Methanol could also be used for decentralised power generation for domestic use and in mine sites through fuel cell or diesel generator engines.

Central West and Orana

The Central West and Orana regions benefit from high-capacity factor inland solar and wind generation resulting in some of the lowest relative cost for DAC and coal-fired power IFG sourced P2M configurations.

The Central West and Orana region has strong potential for the production of DAC-sourced green methanol, which can be used as a fuel substitute for local diesel and bunker fuel applications. Transport by truck, rail and pipeline to nearby ports including the Port of Newcastle, Port Botany and Port Kembla enables trade for domestic use across the state as well as export to international markets.

Methanol could also be used for decentralised power generation for domestic use and in mine sites through fuel cell or diesel generator engines.

South East and Tablelands

The Southeast and Tablelands have median relative gate prices for P2M configurations. Cement IFG-sourced CO_2 configurations are the lowest-cost P2M opportunity in the region. Methanol can supplement the merchant methanol market in this region, which is currently supplied by international import. Methanol can also be used as a fuel substitute for diesel and bunker fuel applications, specifically in Port Kembla. Small-scale decentralised power generation through methanol fuel cells can also be used locally and for mining purposes. Shipping by rail, truck and pipeline allows for connection and trade with neighbouring regions, including international export through Port Kembla and Port Botany.

Riverina Murray

The Riverina Murray region has the highest gate cost compared to the other regions. This is due to the combination of less favourable capacity factors for standalone hybrid generation and limited availability of suitable IFG sources. The Riverina region hosts vast biomass resources, which could be considered for biomass conversion and fuel generation. This may be a competitive alternative to the high-cost direct air capture sourced P2M. However, this lies outside the scope of this work.

The end-use options from methanol produced in this region include fuel applications and decentralised power generation through fuel cell, or direct combustion. Transport from this region through truck and rail to neighbouring regions could open demand avenues with potential export from Port Kembla to international powerfuel markets.

Transport cost analysis for bulk transport of methanol by truck, pipeline and rail is presented in **Table 20** and **Table 21** by distance and type. Maps of the Riverina Murray (**Figure 40**) and Central West and Orana (**Figure 41**) regions are depicted with potential transport distances to neighbouring regions.

103 - The Maritime Executive (2021). Two New Vessels Illustrate Progress with Methanol-Fueled Ships. Link

8.2. Methanol Transport Cost Analysis

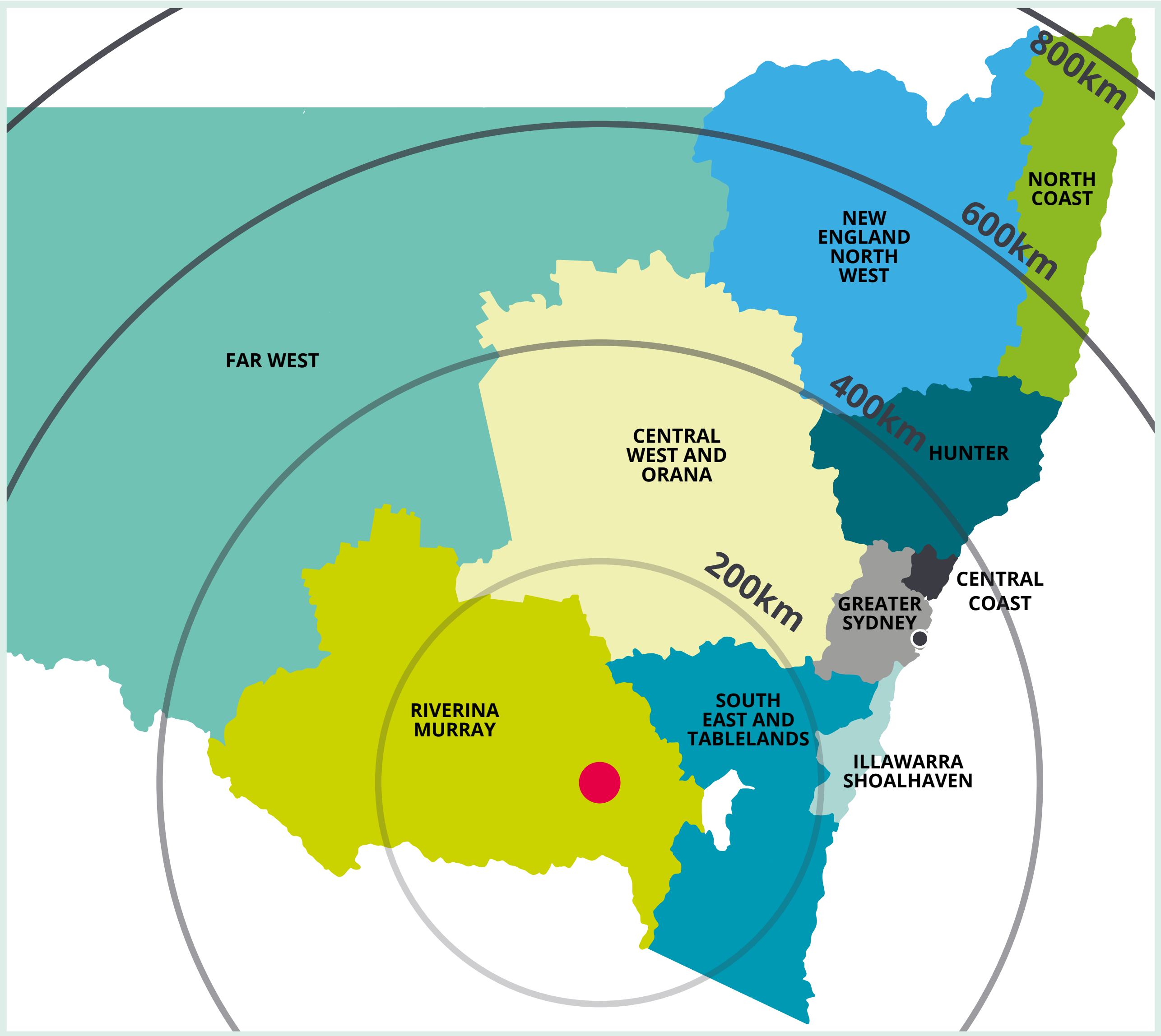


Figure 40. Methanol transport cost analysis Riverina Murray region.

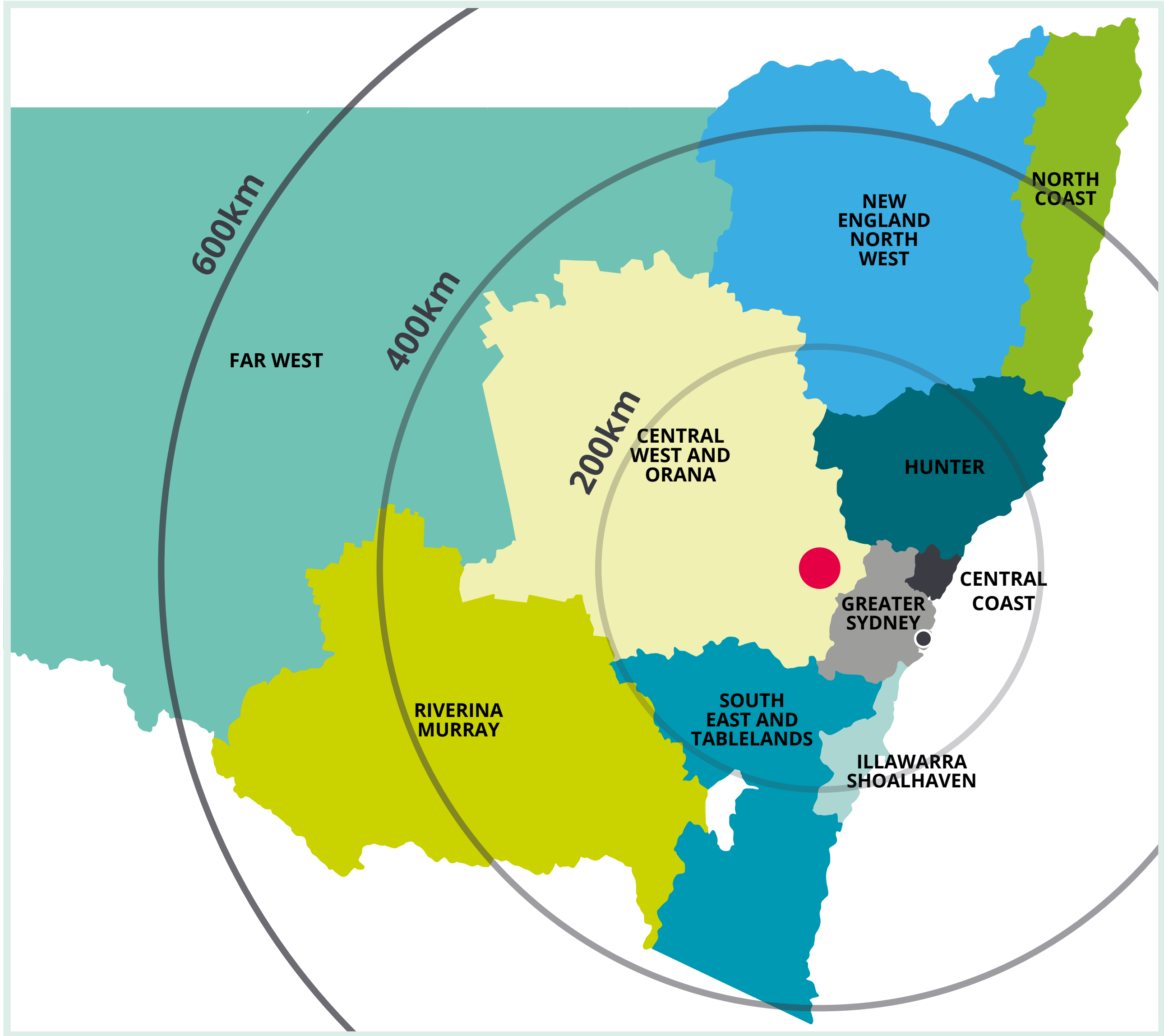


Figure 41. Methanol transport cost analysis Central West and Orana region.

Table 20. Incremental levelised cost for transporting methanol via pipeline, rail and road across distances ranging from 200 to 1,000km assuming 320 KTPA capacity.

Distance	Pipeline	Rail[104]	Road[43]
200 km	0.08 A$/kg	0.008 A$/kg	0.03 A$/kg
400 km	0.16 A$/kg	0.016 A$/kg	0.05 A$/kg
600 km	0.24 A$/kg	0.024 A$/kg	0.08 A$/kg
800 km	0.32 A$/kg	0.032 A$/kg	0.10 A$/kg
1,000 km	0.40 A$/kg	0.04 A$/kg	0.13 A$/kg

Table 21. Incremental levelised cost for transporting methanol via pipeline, rail and road across distances ranging from 200 to 1,000km assuming 1,000 KTPA capacity.

Distance	Pipeline	Rail	Road
200 km	0.03 A$/kg	0.008 A$/kg	0.03 A$/kg
400 km	0.05 A$/kg	0.016 A$/kg	0.05 A$/kg
600 km	0.08 A$/kg	0.024 A$/kg	0.08 A$/kg
800 km	0.10 A$/kg	0.032 A$/kg	0.10 A$/kg
1,000 km	0.13 A$/kg	0.04 A$/kg	0.13 A$/kg

104 - L.E.K Consulting Australia(2021), Fuel - Supply Chain Benchmarking Report Link

The costs associated with transporting methanol from two of the regions, including the Central West and Orana, and Riverina Murray were assessed (**Figure 41** and **Figure 42**). These two regions were chosen based on their long distance from the major exporting terminals located at Port Kembla, Port Botany and Port of Newcastle and to get an understanding of the costs associated with transporting bulk quantities of methanol. Three well-established modes of transporting methanol were considered, which include pipeline, rail and road and the assumptions used in the analysis are summarised below.

Inland Transport Analysis: Assumptions

All modes of transport were based on delivering an annual quantity of 320 KTPA of methanol, across a 25-year timeframe using a discount rate of 7%

- ***Pipeline[a]:*** The pipeline routing is based on passing through 80% rural and 20% urban areas with a CAPEX of A$2.11M/km and A$1.23M/km respectively. Booster stations are located every 128 km with a CAPEX of A$3.19M per station. The OPEX included A$717/km for the pipeline and A$0.6M/station/year.
- ***Rail[b]:*** A rate of A$0.04/t km was used for the rail transport.
- ***Road[c]:*** A rate of A$0.13/t km was used for the road transport.

Cost References:

a - Techno-Economic Challenges of Green Ammonia as an Energy Vector (2021). Pg. 191-207
b - CSIRO(2019). National Hydrogen Roadmap.
c - L.E.K Consulting Australia(2021), Fuel - Supply Chain Benchmarking Report

Overall, transport of methanol by rail has the lowest cost across all distances. Road transport by truck is the next lowest cost due to well-established freight networks for similar refined fuels. Pipeline transport costs are the highest due to the large investment required. This option may be more feasible at larger scales of production and transport i.e. larger than 1000 KTPA capacity.

8.3. Methanol Summary

Based on the analysis for deploying P2M facilities across NSW, we estimate the potential demand to be approximately 500 KTPA. However, our estimates are purely indicative and should NSW negotiate trade partnerships with countries seeking to import methanol (e.g. Japan, Germany and Singapore), the total capacity in NSW could be a lot higher.

The indicative cost from our analysis suggests the gate price for methanol produced in NSW could be between A\$1,140 and A\$3,300/t_{MeOH} by 2030 and between A\$800 and A\$2,300/t_{MeOH} by 2050 depending on the power configuration and carbon dioxide source used. The low ends of these ranges are between 1.3 and 2 times the current international methanol market price (approximately A\$600/t_{MeOH}). However, we note that the market price of methanol produced from natural gas and coal feedstocks is linked to volatile fossil fuel prices.

Chapter 9: Synthetic Natural Gas

SNG (also known as synthetic methane) is recognised by AEMO and AEMC as a primary gas that can be blended with other primary gases (e.g. natural gas, biomethane and hydrogen) to form a gas blend that is referred to as a covered gas.[105,106] The covered gas is a natural gas equivalent with a slightly lower carbon intensity than pure natural gas and can be used in existing gas systems and appliances. Given the near identical properties SNG has to conventional natural gas, the production capacity in the state could theoretically be increased significantly to replace all the natural gas in specific systems (e.g. gas-fired power stations). However, doing so would require a significant capacity of Direct Air Capture (DAC) to deliver a sustainable carbon dioxide source.

With natural gas shortages currently threatening NSW in years to come, the injection of SNG into natural gas systems could alleviate the problem. The blended gas will likely carry a premium in the short term but this would be expected to decrease in the long term as the cost of renewables, electrolysis and DAC technology reduces.

The analysis of SNG opportunities is based on the Sabatier methanation process that uses hydrogen, generated via renewable powered electrolysis, and carbon dioxide from DAC or industrial flue gases (IFG), to form synthetic methane. IFG capture technologies are currently more cost competitive since they benefit from high flue gas CO_2 concentrations (>14%), which make them less capital and energy intensive. However, net zero commitments across these industries mean that IFG sources are likely to disappear in the future. There has also been much discussion about whether the use of fossil based IFG sources align with net zero objectives as transitional CO_2 sources. Hence CO_2 sourcing may be a key factor in determining potential end use and export markets.

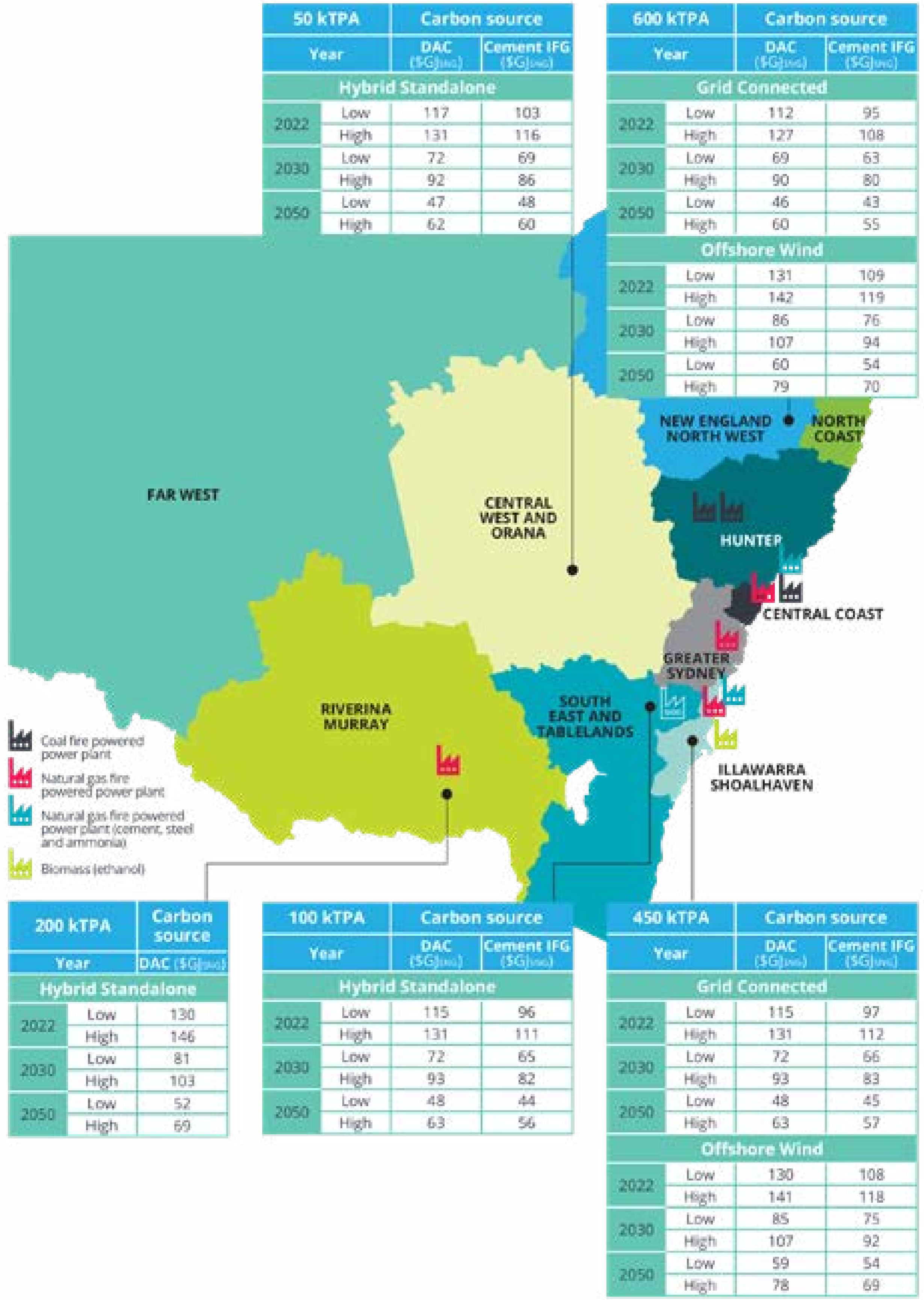
Findings:

Based on the analysis for deploying SNG facilities across NSW we estimate a potential production capacity of 1.4 MTPA by 2050 to service domestic demand.

The indicative cost from our analysis suggests the gate price for SNG produced in NSW could be between:

- A$63/GJ and A$107/GJ by 2030
- A$43/GJ and A$79/GJ by 2050.

Australia's east coast spot market gas prices have reached all-time highs in 2022, with the average price for the year around A$15/GJ. While our indicative pricing for SNG carries a premium over conventional natural gas, the volatility of the east coast gas market is coupled to international energy prices, creating uncertainty for many gas consumers.



50 kTPA		Carbon source	
Year		DAC ($GJ SNG)	Cement IFG ($GJ SNG)
Hybrid Standalone			
2022	Low	117	103
	High	131	116
2030	Low	72	69
	High	92	86
2050	Low	47	48
	High	62	60

600 kTPA		Carbon source	
Year		DAC ($GJ SNG)	Cement IFG ($GJ SNG)
Grid Connected			
2022	Low	112	95
	High	127	108
2030	Low	69	63
	High	90	80
2050	Low	46	43
	High	60	55
Offshore Wind			
2022	Low	131	109
	High	142	119
2030	Low	86	76
	High	107	94
2050	Low	60	54
	High	79	70

200 kTPA		Carbon source
Year		DAC ($GJ SNG)
Hybrid Standalone		
2022	Low	130
	High	146
2030	Low	81
	High	103
2050	Low	52
	High	69

100 kTPA		Carbon source	
Year		DAC ($GJ SNG)	Cement IFG ($GJ SNG)
Hybrid Standalone			
2022	Low	115	96
	High	131	111
2030	Low	72	65
	High	93	82
2050	Low	48	44
	High	63	56

450 kTPA		Carbon source	
Year		DAC ($GJ SNG)	Cement IFG ($GJ SNG)
Grid Connected			
2022	Low	115	97
	High	131	112
2030	Low	72	66
	High	93	83
2050	Low	48	45
	High	63	57
Offshore Wind			
2022	Low	130	108
	High	141	118
2030	Low	85	75
	High	107	92
2050	Low	59	54
	High	78	69

Figure 42 Locations explored to produce Synthetic Natural Gas in NSW with indicative cost analysis.

105 - AEMO (2022). Hydrogen Blends and Renewable Gases Procedures Review. Link
106 - AEMC (2022). Review Into Extending The Regulatory Frameworks To Hydrogen And Renewable Gases. Link

9.1. SNG Production Cost and End-Use Analysis

Five regions across NSW were identified as potential development locations for Power-to-Synthetic Natural Gas, based on the results of the applied opportunity mapping framework. The indicative cost of producing SNG in each location between 2022 and 2050 was analysed using the Powerfuel Tool, followed by an assessment of the potential demand at a regional level.

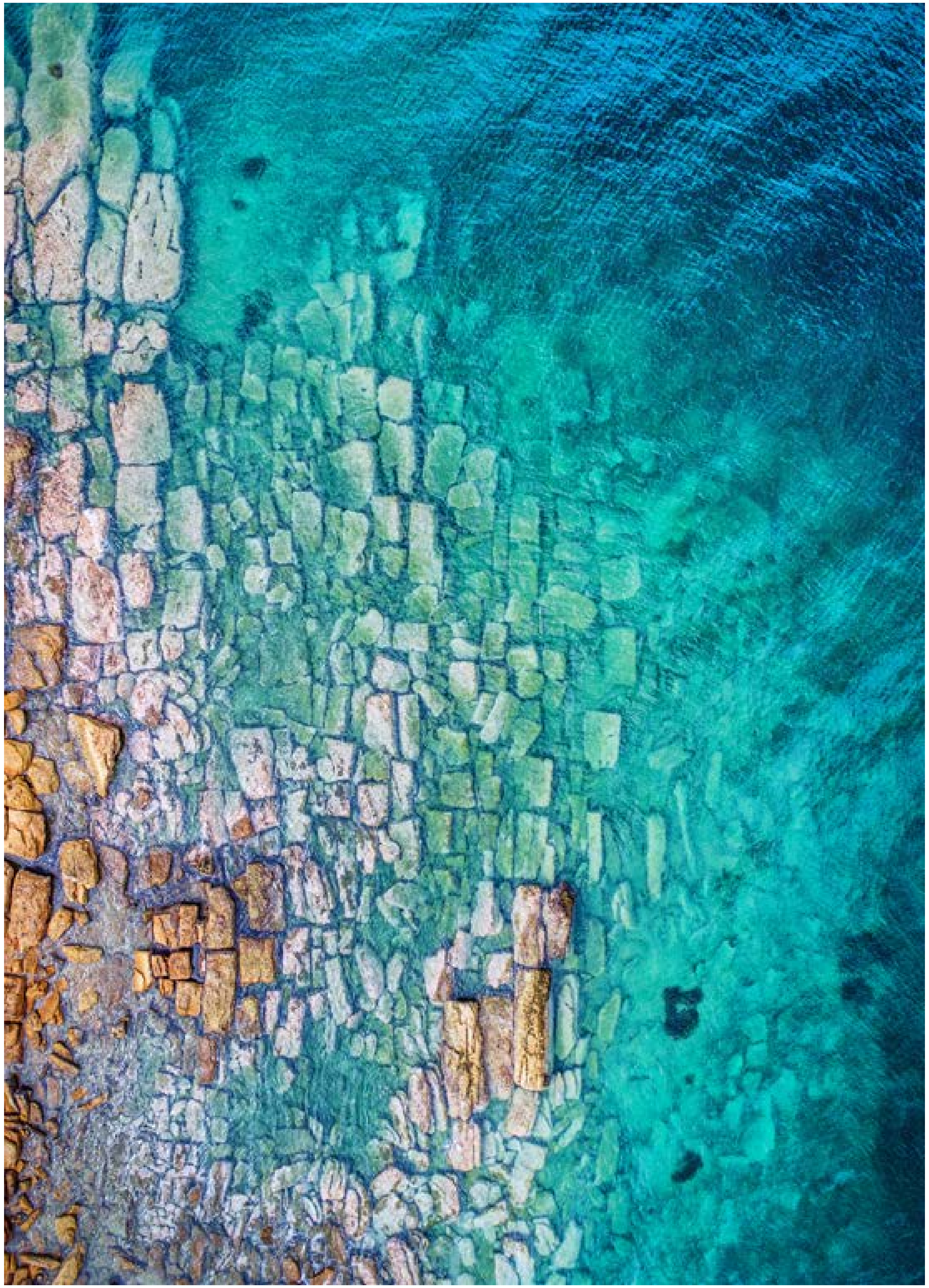
The SNG analysis is based on the Sabatier methanation process that uses hydrogen, generated via renewable powered electrolysis and carbon dioxide from direct air capture (DAC) or industrial flue gases (IFG), to form synthetic methane. For the Riverina-Murray, South East and Tablelands, and Central West and Orana regions, a standalone hybrid renewable power source is used and, where available, an IFG carbon dioxide source is compared against a DAC source.

IFG capture technologies are currently more cost competitive compared to DAC, since they benefit from high flue gas CO_2 concentrations (>14%), which make them less capital and energy intensive. However, net zero commitments across these industries mean that IFG sources are likely to disappear in the future. There has also been much discussion about whether the use of fossil-based IFG sources align with net zero objectives as transitional CO_2 sources. Hence CO_2 sourcing may be a key factor in determining potential end use and export markets. These risks highlight the importance of continuing to develop long-term sources, such as DAC and sustainable biomass-sourced CO_2.

Post-combustive capture of biomass-based power generation flue gas is a potential renewable CO_2 source for SNG production. However, biomass firing facilities face challenges including feedstock storage and handling, competing demand from other industries, and ongoing questions about the true sustainability of some agricultural, and particularly forestry biomass, sources. These facilities are currently limited to small scale in NSW and were hence not assessed in this work. We note that direct biomass to biomethane and syngas conversion technologies represent an alternative route to renewable methane. However, this was not considered in the assessment as it is beyond the scope.

For the Illawarra and Hunter regions, offshore wind and hybrid standalone power configurations were assessed. As seen in **Figure 42**, the levelised costs for offshore configurations were higher compared to onshore hybrid generation. This contrasts with results from Power-to-Methanol in a previous section, shown in **Figure 39**, where offshore wind configurations had lower costs. A key difference between the two pathways is that SNG production has a higher hydrogen demand. Wind power generation configurations have larger variability compared to hybrid systems and thus, while the average capacity factor of offshore wind is high, the level of intermittency has a larger impact on the supply of hydrogen to the SNG pathway as compared to methanol production. This means more oversizing of renewable energy and electrolyser systems.

For the Illawarra Shoalhaven and Hunter regions, a hybrid renewable power configuration with a dedicated transmission network connected to the REZ in the Central West and Orana region is compared against an offshore wind power source. In addition, an IFG carbon dioxide source is compared to a DAC source for the Illawarra Shoalhaven and Hunter regions.



Riverina-Murray

The production of SNG in the Riverina-Murray region of NSW was assessed using Direct Air Capture (DAC) as the carbon dioxide source with a 50:50 hybrid standalone renewable energy power configuration. Farm gate pricing for the SNG produced median results compared to other regions using DAC as the carbon dioxide source. The estimated cost of production between 2022 and 2050 remains higher than the cost of producing conventional natural gas, which can be attributed to the high costs associated with producing hydrogen from electrolysis and capturing the carbon dioxide using DAC technology.

SNG (also known as synthetic methane) is recognised by AEMO and AEMC as a primary gas that can be blended with other primary gases (e.g. natural gas, biomethane and hydrogen) to form a gas blend that is referred to as a covered gas.[102,103] The covered gas is a natural gas equivalent with a slightly lower carbon intensity than pure natural gas and can be used in existing gas systems and appliances.

Potential demand for SNG in the Riverina-Murray region includes blending with conventional natural gas and use as a fuel in the Uranquinty gas-fired power station.

The region has a large natural gas transmission and distribution network in which the SNG could be injected. For example, the Wagga Wagga-Culcairn Section that runs off the Moomba-Sydney transmission pipeline operated by APA Group, has a nameplate capacity of 233 TJ/d; or the Junee-Griffith Lateral pipeline that runs off the same transmission pipeline has a nameplate capacity of 13 TJ/d.[107] The near identical properties of SNG with conventional natural gas alleviate the potential concerns discussed previously in **Chapter 6** for blending hydrogen in natural gas networks.

The extent to which SNG can be injected into the natural gas network will be limited by the commercial viability and economic impact on the end user. For example, adding 50% SNG to the natural gas network in 2050 at a low cost of A$52/GJ would more than double the final wholesale price of the delivered gas to A$33.5/GJ (assuming a conventional natural gas wholesale price of A$15/GJ).[108] While the final cost of the wholesale gas price could be lowered through greater cost reduction associated with hydrogen production via electrolysis and carbon capture by DAC, this will take some time to be realised. In terms of SNG plant capacity, a 50% SNG gas blend in the Junee-Griffith lateral would require an SNG production capacity of 50 KTPA.

The use of SNG in the Uranquinty gas-fired power station could also be directly blended and fired with little to zero impact on the existing equipment, due to the similar properties of SNG and conventional natural gas. A 50% co-firing blend at Uranquinty would require an SNG production capacity of 150 KTPA assuming the power station has a capacity factor of 25% and efficiency of 36.5%. Like blending SNG in the gas network, the extent to which it is co-fired at Uranquinty will be limited by the commercial viability of the electricity produced from the gas-fired power plant.

South East and Tablelands

For SNG production in the South East and Tablelands region, two sources of carbon dioxide were assessed — a DAC source and industrial flue gas (IFG) source from the Boral cement works in Berrima. Production costs using the CO_2 sourced from the cement works results in a lower farm gate price for the SNG, which can be attributed to the lower capital and operating costs associated with the capture technology employed. From our indicative cost analysis, compared to SNG production from other non-DAC sourced CO_2 in NSW, the farm gate price in the South East and Tablelands region is slightly higher than using coal-fired-power-station sourced CO_2 and marginally lower than using steel-mill sourced CO_2. This can be linked to the solar and wind potential in the region, which dictates the size of the renewable energy capacity required to achieve the desired SNG output and consequently impacts on cost.

There is potential demand for SNG in

the South East and Tablelands region for blending with conventional natural gas in the transmission and distribution network. The Moomba-Sydney gas transmission pipeline operated by APA group passes through the South East and Tablelands region with a nameplate capacity of 443 TJ/d running from Marsden to Wilton.[102] Furthermore, the Young-Lithgow lateral gas pipeline coming off the Moomba-Sydney transmission pipeline has a nameplate capacity of 25 TJ/d and serves up to 10 community gas distribution networks. A 50% SNG blend in the Young-Lithgow lateral would be equivalent to approximately 100 KTPA of SNG whilst a 50% SNG blend in the Marsden-Wilton section of the Moomba-Sydney transmission pipeline would be equivalent to 1600 KTPA of SNG. Using CO_2 sourced via DAC has some benefits over IFG-sourced CO_2, including its limited land and water footprint and option to locate the plant on non-arable land[109] and could potentially meet the 50% SNG blend demand of the Young-Lithgow lateral pipeline and Marsden-Wilton section of the Moomba-Sydney transmission pipeline. The CO_2 sourced from IFG is limited by the quantity of CO_2 available for capture and, in this case, the Berrima cement works would be limited to producing 530 KTPA of SNG. Furthermore, capturing CO_2 from IFGs to make SNG still requires transport of the gas to the point of injection. For example, if SNG was to be produced close to the Berrima cement works, it would still require transport from the cement works to the point of injection in either the Young-Lithgow lateral pipeline or Marsden-Wilton section of the Moomba Sydney transmission pipeline.

Central West and Orana

The production of SNG in the Central West and Orana region has the option of sourcing CO_2 via DAC or from the Mt Piper coal-fired power station near Portland. SNG produced using industrial flue gases (IFG) from Mt Piper results in one of the lowest farm gate prices across the state compared to using other non-DAC CO_2 sources. This can be attributed to the higher capacity factor for wind and solar compared to the other regions analysed. SNG produced via DAC sourced CO_2 is also one of the lowest in the state because of the

107 - APA Group (2022). MSP Vertigan Schematics. Link
108 - AER (2022). Gas market prices. Link
109 - IEA (2021). Direct Air Capture, IEA, Paris Link

higher solar and wind capacity factors, but higher than using IFG-sourced CO_2.

There is potential demand for supplementing SNG with conventional natural gas in the transmission and distribution network in the Central West and Orana region. The Central West Pipeline that runs from Marsden to Dubbo has a nameplate capacity of 13 TJ/d and serves six community distribution networks. A 50% SNG blend in the Central West Pipeline would be equivalent to approx. 50 KTPA of SNG. The IFG CO_2 sourced from Mt Piper has the potential to produce up to 2200 KTPA of SNG, which would be more than adequate for blending 50% in the Central West Pipeline. However, the Central West Pipeline is between 280 and 300 km from Mt Piper coal-fired power station which would require additional infrastructure (e.g. pipeline) to transport the SNG to the point of injection.

Illawarra Shoalhaven

The production of SNG in the Illawarra Shoalhaven region has the option to use carbon dioxide sourced from DAC and IFG from the BlueScope steel mill located at Port Kembla, or the cement calcination plant at Berrima (in the South East and Tablelands region but within 80km of Port Kembla). Farm gate pricing for SNG produced using IFG from BlueScope is comparable to using IFG from the cement works. SNG produced with CO_2 sourced via DAC is about 3% more expensive in the Illawarra Shoalhaven compared to the Hunter because of the longer transmission network required to connect to the Central West and Orana REZ. Being located next to the coast provides an option to use offshore wind as the renewable energy source. However, this is more expensive compared to onshore hybrid (solar PV/Wind) sourced renewable power (between 5% and 25% higher depending on the year and CO_2 source used).

The shorter distance between the CO_2 source and demand location in the Illawarra Shoalhaven region makes using the BlueScope steel IFG more attractive. However, the long-term sustainable supply of IFG CO_2 sources from BlueScope needs to be carefully considered given the plans for the plant to reduce its carbon emissions.[110]

Potential demand for SNG in the Illawarra-Shoalhaven Region includes blending with conventional natural gas and use as a fuel in the existing and planned gas-fired power stations (Tallawarra (existing), Tallawarra B (under construction) and Port Kembla (planned)). SNG produced from the BlueScope IFG is limited to approximately 1.6 MTPA CO_2.

Options for natural gas displacement include the Eastern Gas Pipeline with a nameplate capacity of 355.5 TJ/d and several distribution pipelines including Port Kembla (88.7 TJ/d) and Albion Park (18.62 TJ/d).[111] A 50% blend in the Port Kembla distribution pipeline is equivalent to approximately 340 KTPA of SNG, which could potentially be met using the IFG from BlueScope steel. In addition to providing decarbonisation benefits from capturing the BlueScope IFG, the produced SNG can provide further decarbonisation benefits to the steel works through reduced conventional natural gas use in the fuel supply.

For power generation, SNG could be injected into the fuel mix for the existing Tallawarra gas plant. At 50% SNG co-firing and assuming a capacity factor of 25% and efficiency of 38.7% for the gas plant, the demand would equate to 100 KTPA of SNG.

The extent to which SNG is injected in the gas network or co-fired in the gas plants will depend on the commercial viability and economic impact on the end users as discussed for the Riverina-Murray region.

Hunter

The production of SNG in the Hunter region has the option to use carbon dioxide sourced from DAC and IFG sources, including a coal-fired power plant (Bayswater) and the ammonia plant at Kooragang Island. From our analysis the farm gate pricing for SNG produced using IFG from a coal-fired power plant in the Hunter (e.g. Bayswater) is one of the lowest in the state — primarily because of the economies of scale for a larger SNG plant capacity. However, the sustainability of carbon dioxide supply needs to be considered given the planned closure of several coal-fired power stations in the Hunter region. SNG produced using DAC-sourced carbon dioxide has a lower farm gate price than the Illawarra Shoalhaven region due to its closer distance to the Central West and Orana REZ and reduced transmission infrastructure cost.

The Hunter also has an option to use offshore wind as the renewable energy source. However, this is more expensive compared to onshore hybrid (solar PV/Wind) sourced renewable power (between 10% and 30% higher depending on the year and CO_2 source used) and marginally more expensive than offshore wind powered SNG production in the Illawarra Shoalhaven region.

Potential demand for SNG in the Hunter Region includes supplementing conventional natural gas and its use as a fuel in the existing and planned gas-fired power stations (Colongra (existing) Kurri Kurri (under construction) and Newcastle Power Station (planned)). SNG produced from the Bayswater coal-fired power station IFG is limited to approximately 3900 KTPA.

Options for gas blending include the Tomago Hexham pipeline with a nameplate capacity of 120 TJ/d.[106] A 50% blend in the gas network is equivalent to 455 KTPA of SNG which could potentially be met using the IFG from Bayswater coal-fired power station.

For power generation, SNG could be injected into the fuel mix for the existing Colongra gas plant. At 50% SNG co-firing and assuming a capacity factor of 25% and efficiency of 38% for the gas plant, the demand would equate to approx. 160 KTPA of SNG.

The long-term sustainable supply of IFG as a CO_2 source needs to be carefully considered where coal-fired power stations are used as the source. For example, Eraring, Liddell and Vales Point coal-fired power stations are scheduled for closure from 2022 through to 2029, with Bayswater scheduled for closure in 2033. This renders these sources as an unsustainable solution in the long term. Considering these factors, DAC-sourced CO_2 would provide a more sustainable source although at a higher cost. In addition, considering the land requirements, the estimated area required for a 1 $MTCO_2$/year DAC plant is between 0.4-0.5 square kilometres.[112] A 600 KTPA SNG production in the Hunter would require a DAC plant with a capacity of 1.7 MTPA which is equivalent to between 0.68-0.85 km^2.

110 - BlueScope (2021). Climate Action Report. Link
111 - Jemena (2021). Service and access information for JGN's gas network – general. Link
112 - World Resources Institute (2022). 6 Things to Know About Direct Air Capture. Link

9.2. SNG Summary

Based on the analysis for deploying SNG facilities across NSW we estimate a potential production capacity of 1.4 MTPA by 2050 to service domestic demand. This indicative demand is based on injecting SNG at 50% into the existing natural gas system and co-firing with conventional natural gas in the state's gas-fired power stations. Given the near identical properties SNG has to conventional natural gas, the production capacity in the state could theoretically be increased significantly to replace all the natural gas in specific systems (e.g. gas-fired power stations). However, doing so would require significant capacity of DAC as a sustainable carbon dioxide source compared to the IFG sources that in many circumstances have a limited supply of CO_2 or will be decommissioned before 2040 (e.g. coal-fired power stations in the Hunter).

The indicative cost from our analysis suggests the gate price for SNG produced in NSW could be between A$63/GJ and A$107/GJ by 2030 and between A$43/GJ and A$79/GJ by 2050. Australia's east coast spot market gas prices have reached all-time highs in 2022, with the average price for the year around A$15/GJ.[113] While our indicative pricing for SNG carries a premium over conventional natural gas, the volatility of the east coast gas market is coupled to international energy prices, creating uncertainty for many gas consumers. Furthermore, the natural gas shortages currently threatening NSW in years to come[114] could be alleviated through the production and injection of SNG into natural gas systems. The blended gas will likely carry a premium in the short term but this would be expected to decrease in the long term as the build cost of renewables, electrolysis and DAC technology reduces.

113 - Australian Government (2022). Gas market prices. Link
114 - Australian Government (2022). Gas prices increase as supply shortfall emerges for southern states. Link

Chapter 10: Sustainable Aviation Fuel (SAF)

Sustainable Aviation Fuel (SAF) is a liquid fuel with similar properties to conventional jet fuel. It can be distributed to the airports via established modes of transport, including road, rail and pipeline.

The SAF production process is based on a power-to-liquid configuration. The process relies on supplying hydrogen via renewable powered electrolysis and carbon dioxide from DAC or IFG sources. The H_2 and CO_2 are then passed through a Reverse Water Gas Shift Reactor (RWGS) to produce syngas, which is fed to a Fischer Tropsch reactor to produce liquid fuels including 50% sustainable aviation fuel (also known as e-SAF), 25% diesel and 25% naphtha. e-SAF produced via the Fischer Tropsch synthesis is an ASTM- and International Civil Aviation Organization (ICAO)-approved conversion process that can be blended with conventional jet fuel up to 50% by volume. The hope is that in the future e-SAF will be approved for use at 100%.

While e-SAF production using renewable power, electrolysis, DAC and Fischer-Tropsch synthesis is one method of production, alternative methods that use a biomass feedstock (e.g. municipal solid waste, straw, sugarcane) could be used to meet the state's SAF demand. In this manner a mixture of SAF production processes could be used to take advantage of the state's renewable power potential and biomass feedstock.

Across NSW, we identified three regions as potential development locations to produce Sustainable Aviation Fuel (SAF).

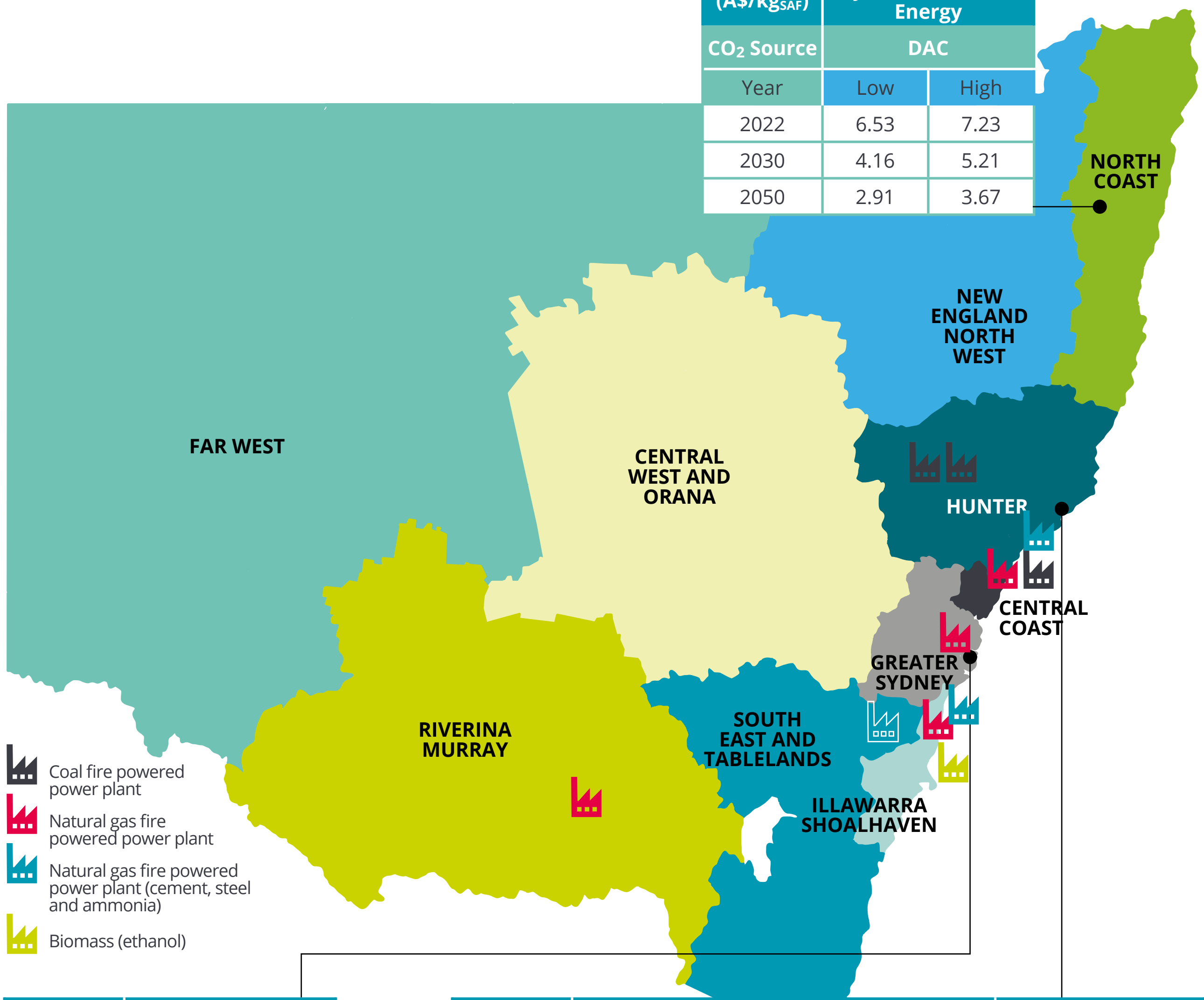
Findings:

Based on the analysis, we estimate the potential demand in NSW to be approximately 1.5 MTPA based on a 50% blend with conventional jet fuel. Most of this demand would be for Sydney Kingsford Smith Airport and at present there are no commercial e-SAF plants operating at this scale. In addition, the demand could be even greater if SAF is to be used across all the civilian and military airports in the state that provide refuelling facilities.

Depending on the power configuration and the carbon dioxide source used, our analysis suggests the indicative cost of SAF produced in NSW could be between:

- A$4,050 and A$6,550/t by 2030
- A$2,900 and A$5,200/t by 2050

These costs are between 3 and 4 times the current price of jet fuel (A$1,500/t) and would increase the overall fuel price at 50% blend — and consequently the cost of air travel. However, this pricing could potentially be reduced with economies of scale and the construction of larger SAF production units between now and 2050.



($A\$/kg_{SAF}$)	Hybrid Renewable Energy	
CO_2 Source	DAC	
Year	Low	High
2022	6.53	7.23
2030	4.16	5.21
2050	2.91	3.67

($A\$/kg_{SAF}$)	Hybrid Renewable Energy	
CO_2 Source	DAC	
Year	Low	High
2022	6.84	7.69
2030	4.48	5.67
2050	3.17	4.07

($A\$/kg_{SAF}$)	Hybrid Renewable Energy				Offshore Wind	
CO_2 Source	DAC		IFG		DAC	
Year	Low	High	Low	High	Low	High
2022	6.84	7.69	5.91	6.73	7.69	8.33
2030	4.48	5.67	4.20	5.18	5.29	6.54
2050	3.17	4.07	3.09	3.83	4.03	5.19

Figure 43. Locations explored to produce Sustainable Aviation Fuel in NSW with indicative cost analysis.

10.1. SAF Production Cost Analysis

Three regions across New South Wales (North Coast, Hunter, and Central Coast and Greater Sydney Metropolitan Area) were identified as potential development locations to produce Sustainable Aviation Fuel (SAF) based on the results of the opportunity mapping framework applied. The cost of producing SAF in each location between 2022 and 2050 was analysed (**Figure 43**) using the Powerfuel Tool and followed by an assessment of the potential demand at a regional level.

The SAF production process is based on a power-to-liquid configuration, like the plant being constructed by the Norsk e-fuel project in Norway.[115] The process relies on supplying hydrogen via renewable powered electrolysis and carbon dioxide from DAC or IFG sources. The H_2 and CO_2 are then passed through a Reverse Water Gas Shift Reactor (RWGS) to produce syngas, which is fed to a Fischer Tropsch reactor to produce liquid fuels including 50% sustainable aviation fuel (also known as e-SAF), 25% diesel and 25% naphtha. e-SAF produced via the Fischer Tropsch synthesis is an ASTM- and International Civil Aviation Organization (ICAO)-approved conversion process that can be blended with conventional jet fuel up to 50% by volume.[116] The hope is that in the future e-SAF will be approved for use at 100%.

As stated in the methanol and SNG sections above, IFG carbon capture and utilisation (CCU) may be a lower cost transitional source of CO_2 compared to DAC. However, given the controversy of utilising fossil-sourced CO_2, and the commitments by these industries to lower their own emissions, the CO_2 is an important factor in determining potential certification and end use markets for the produced SAF. These factors highlight the importance of continuing to develop long-term sources, such as DAC and sustainable biomass sourced CO_2.

Post-combustion capture of biomass-based power generation flue gas is a potential renewable CO_2 source for SAF production. However, biomass-firing facilities are currently limited to small scale in NSW and were hence not assessed in this work. Direct biomass to SAF conversion pathways represent an alternative route to SAF and is currently the preferred route among SAF developers. However, this was not considered in the assessment because it is not based on renewable energy and is therefore outside the scope of this work. We also note that biomass pathways face challenges including feedstock storage and handling, competing demand from other industries, and ongoing questions about the true sustainability of some agricultural and particularly forestry biomass sources.

For the North Coast, offshore wind and hybrid standalone power configurations with a DAC were assessed. As seen in **Figure 43** levelised cost for offshore configurations were higher compared to onshore hybrid generation. This contrasts with results from Power-to-Methanol in a previous section (shown in **Figure 39**), where offshore wind configurations had lower costs. A key difference between the two pathways is that SAF production has a higher hydrogen demand. Wind power generation configurations have larger variability compared to hybrid systems and thus, while the average capacity factor of offshore wind is high, the level of intermittency has a larger impact on the supply of hydrogen to the AF pathway as compared to methanol production. This means more oversizing of renewable energy and electrolyser systems.

For the Hunter and Greater Sydney Metropolitan and Central Coast regions, a hybrid renewable energy system located in the Central West and Orana REZ with a dedicated transmission network was assessed given the space constraints to host solar PV and wind capacity at scale in these regions. The results for each region are described below.

North Coast

The production of SAF in the North Coast region of NSW was based on Direct Air Capture (DAC) as the primary source of CO_2 since there were no suitable IFG sources identified in this region. We note that the region has considerable biomass resources, as well as a bagasse firing power station, however since this facility is small scale, and direct biomass conversion technologies do not fall under the scope of P2X, these options were not considered in this work. The levelised cost of SAF production is lower than in the Hunter and Sydney Metropolitan region due to a slightly higher wind capacity factor favouring a lower overall renewable energy capacity and subsequent cost.

The North Coast region is home to Coffs Harbour airport, which was the 25th busiest airport in Australia between 2018 and 2019 (pre-COVID) and handled approximately 400,000 passengers.[117] Assuming Coffs Harbour airport consumes 40 KTPA (50,000 m^3/yr) aviation fuel annually, at 50% blend this would equate to 20 KTPA (25,000m^3/yr) of SAF. At a 50% blend, the final price of the aviation fuel in 2030 might range between A$3,000/t to A$3,550/t and in 2050 might be between A$2,300/t and A$2,700/t (based on current Jet fuel pricing for Asia and Oceania of around A$1,500/t (US$1,000/t)[118]). While the blended aviation fuel appears to carry a premium compared to conventional jet fuel, the upside is a 50% reduction in CO_2 emissions assuming the SAF in the 50% blend is produced with net-zero carbon intensity. Furthermore, a carbon tax on conventional jet fuel could help push the price of the 50% SAF blend to parity.

Hunter (Williamtown – Newcastle Airport)

SAF production in the Hunter region was explored using a DAC and IFG carbon dioxide sources. SAF production using a dedicated transmission network from a hybrid renewable energy plant in the Central West and Orana region and IFG carbon dioxide source produced the lowest cost for the Hunter region by 2050 (A$3.09/kg). However, in the Hunter, the sustainability of an IFG source, which would come from the coal-fired power stations, is not reliable. A DAC unit would be a more reliable source of carbon dioxide and, based on our indicative cost assessment, is only 2.5% more expensive than using an IFG source by 2050. Offshore wind is another option for the Hunter as a power source, with indicative SAF costs about 27% (A$4.03/kg) higher than using a dedicated transmission network from the Central West and Orana region. Compared to the North Coast region, SAF production using DAC as the carbon dioxide source in the Hunter is approximately 9% more expensive. This increase in levelised cost for the Hunter can be linked to the added cost for installing a dedicated transmission network to the Central West and Orana region.

Newcastle airport, located near Williamtown in the Hunter region was Australia's 13th busiest airport in 2018 – 2019 and handled 1.26 million passengers. The airport is also home to RAAF Williamtown from which several types of military aircraft that could potentially use e-SAF in their fuel mix are based.

Assuming Newcastle airport uses an annual aviation fuel consumption of 100 KTPA (125,000 m^3/yr), at 50% blend this would equate to 50 KTPA (62,500m^3/yr) of SAF. At a 50% blend the final price of the aviation fuel in 2030 will be between A$2,850/t and A$4,000/t and in 2050 will be between A$2,350/t and A$3,350/t (based on current Jet fuel pricing of A$1,500/t).

Greater Sydney Metropolitan and Central Coast Region

SAF production in the Greater Sydney Metropolitan and Central Coast region is the same as the cost for producing SAF in the Hunter region using hybrid renewable power from the Central West and Orana region with a dedicated transmission network. Given the

115 - Norsk e-fuel (2022). Our Technology. Link
116 - ICAO (2022). Conversion Processes. Link
117 - Australian Government (2022). Airport Traffic Data. Link
118 - IATA (2022). Jet Fuel Price Monitor. Link

lack of IFG sources with a suitable scale in the Greater Sydney region, the carbon dioxide source is based on DAC.

The region is home to Sydney Kingsford Smith airport, which is Australia's busiest airport and handled approximately 44 million passengers in 2018-2019. In addition, the region hosts RAAF Richmond and is also going to be home to Western Sydney airport, which is expected to be operational by 2026.[119] All the airports provide options for e-SAF demand.

The existing Sydney airport has an average daily jet fuel demand of 10 million litres (equivalent to 2.92 MTPA).[120] To meet 50% of this jet fuel demand would require a SAF production facility with a capacity of 1.46 MTPA.

10.2. SAF Distribution

As a liquid fuel with similar properties to conventional jet fuel, SAF can be distributed to the airports via established modes of transport including road, rail and pipeline.

The existing multi-product pipeline between Sydney and Newcastle that is operated by Ampol could potentially be used to distribute SAF between the two regions. Road freight rates for refined fuels in Australia are estimated to be A$0.13 per tonne-kilometre.[121] Assuming a 50 KTPA plant in the Hunter region, supplying the new Western Sydney Airport (approximately 200 km away) with e-SAF would add approximately A$26/T to the price of the fuel.

Existing fuel distribution terminals such as Clyde, Kurnell and Port Botany could be used to store e-SAF providing options to supply the major Sydney airports and regional airports through established distribution routes.

10.3. SAF Summary

Based on the analysis for deploying SAF facilities across NSW we estimate the potential demand to be approximately 1.5 MTPA based on a 50% blend with conventional jet fuel. Most of this demand would be for Sydney Kingsford Smith Airport and at present there are no commercial e-SAF plants operating at this scale. In addition, the demand could be even greater if SAF is to be used across all the civilian and military airports in the state that provide refuelling facilities. While e-SAF production using renewable power, electrolysis, DAC and Fischer-Tropsch synthesis is one method of production, alternative methods that use a biomass feedstock (e.g. municipal solid waste, straw, sugarcane) could be used to meet the state's SAF demand. In this manner a mixture of SAF production processes could be used to take advantage of the state's renewable power potential and biomass feedstock.

The indicative cost from our analysis suggests the gate price for SAF produced in NSW could be between A$4,050 and A$6,550/T by 2030 and between A$2,900 and A$5,200/T by 2050 depending on the power configuration and carbon dioxide source used. These costs are between 3 and 4 times the current price of jet fuel (A$1,500/T) and would increase the overall fuel price at 50% blend — and consequently the cost of air travel. However, this pricing could potentially be reduced with economies of scale and the construction of larger SAF production units between now and 2050.

119 - Western Sydney Airport (2022). FAQs. Link
120 - Sydney Airport (2022). Jet Fuel. Link
121 - Fuel - Supply Chain Benchmarking Report. Freight Australia Link

Section D: Beyond NSW

NSW has ambitions to emerge as a leading exporter of green hydrogen and hydrogen derivatives to the Asia-Pacific and beyond. This is primarily driven by the state's long-established energy trading relationships with key markets and its potential ability to generate cost-competitive hydrogen and hydrogen derivatives at scale.

In Section D, we explore the opportunities to export powerfuels from NSW to key international market by providing an indicative value chain outlook.

Chapter 11: Exporting Hydrogen and Hydrogen Derivatives Beyond Australia

NSW has ambitions to emerge as a leading exporter of green hydrogen and hydrogen derivatives to the Asia-Pacific and beyond. This is primarily driven by the state's long-established energy trading relationships with key markets and its potential ability to generate cost competitive hydrogen and hydrogen derivatives at scale.

In this section, we explore the opportunities to export powerfuels from NSW to key international market by providing an indicative value chain outlook

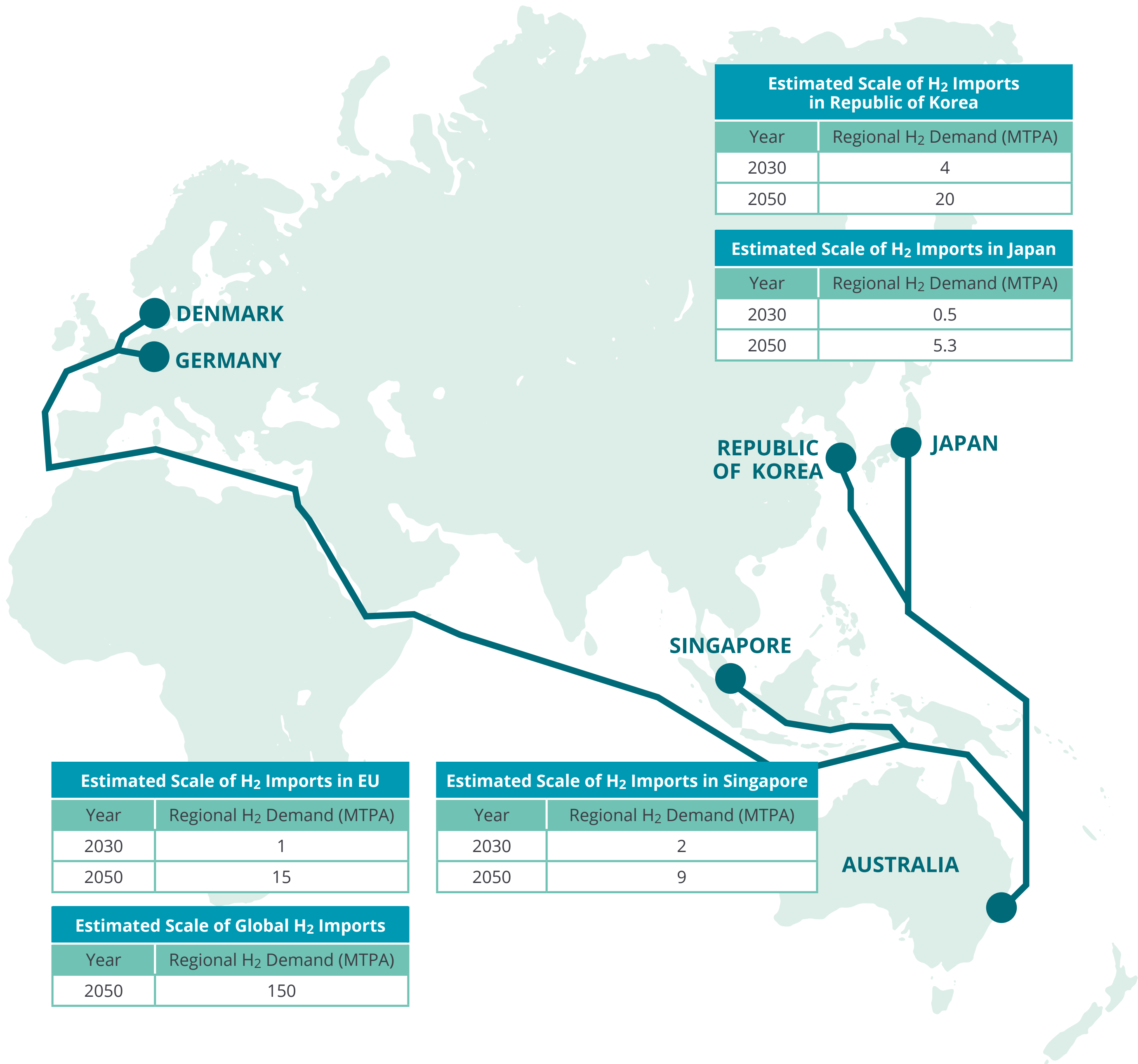
The delivered cost of P2X projects is mainly dependent on the production costs, rather than the transport costs — though it should be noted that shipping P2X products to Singapore is cheaper than shipping to Denmark, due to the increased sea transport distance. The recently completed HySupply Study showed that Australia can compete with the other potential regional H_2 exporters for shipping costs, which would give the country an advantage over competitors if it (including NSW) can leverage its low-cost renewable energy potential to generate bulk amounts of P2X products at low costs.[122]

As highlighted in previous chapters, there is strong potential for large-scale P2X projects in proximity to key export terminals and ongoing development of REZ and H_2 Hubs. In addition, the ongoing development of freight hubs and SAPs across regional parts of NSW will connect to the port facilities across the east coast via road and rail, allowing inland projects to access the growing export market. Port Kembla, Port Botany and the Port of Newcastle are recognised as the key export terminals in NSW with established trade connections to energy-hungry markets in Asia and beyond. In addition, these key export terminals have existing infrastructure to handle bulk fuel and chemical feedstock movements.

There are existing multi-billion dollar global markets for ammonia and methanol that NSW could export to. A hydrogen export market is developing and, further down the track — once the facilities are developed and the supply to the domestic market is stable — there could be opportunities for the export of SNG. But to claim a share of any of these markets, NSW would have to move quickly.

11.1. Current Market Status

The NSW Government has reported their ambition to convert the state into a global energy superpower, placing it in a position to not only achieve domestic energy security and sustainability targets, but leverage its extensive clean-energy potential to export P2X products to global markets.[4] This ambition is backed up by the strong potential for largescale P2X projects in proximity to key export terminals and ongoing development of REZ and H_2 Hubs, as highlighted in earlier chapters. Furthermore, the ongoing development of freight hubs and SAPs across regional parts of NSW will connect to the port facilities across the east coast via road and rail, allowing inland projects to access the growing export market. Port Kembla, Port Botany and the Port of Newcastle are recognised as the key export terminals in NSW with established trade connections to energy-hungry markets in Asia and beyond. In addition, these key export terminals have existing infrastructure to handle bulk fuel and chemical feedstock movements.



Estimated Scale of H_2 Imports in Republic of Korea

Year	Regional H_2 Demand (MTPA)
2030	4
2050	20

Estimated Scale of H_2 Imports in Japan

Year	Regional H_2 Demand (MTPA)
2030	0.5
2050	5.3

Estimated Scale of H_2 Imports in EU

Year	Regional H_2 Demand (MTPA)
2030	1
2050	15

Estimated Scale of H_2 Imports in Singapore

Year	Regional H_2 Demand (MTPA)
2030	2
2050	9

Estimated Scale of Global H_2 Imports

Year	Regional H_2 Demand (MTPA)
2050	150

Figure 44. Estimated scale of Global H_2 Imports.

122 - Daiyan et al (2021). The Case for an Australian. Hydrogen Export Market to Germany: State of Play Version 1.0. UNSW, Sydney DOI: I: Link

11.2. Potential Markets for NSW P2X Exports

Many countries have set targets and introduced policies to transition towards green fuels and chemicals to support their net-zero goals. **Figure 44** provides an overview of the key global markets and their reported demands analysed as potential trade partners for NSW powerfuels.

Findings:

The modelling suggests that there is an opportunity to export P2X products from NSW but there are challenges to overcome. There is significant competition starting to develop, both from other states and global energy powerhouses.

In the near term, the economics of P2X products are challenging and costs will be higher than fossil-fuel equivalents. However, the modelling completed does suggest that by the middle of the century, production costs for P2X products could be at parity or less. There is also opportunity for a 'green premium' and the threat of carbon taxes which will impact the economics. As the scale increases and technology improves, cost reductions are likely.

There is also an opportunity to bring down costs using common-user infrastructure.

11.2.1. Japan

Japan is one of the world's largest energy importers. The IEA estimates that in 2019, fossil fuels accounted for 88% of Japan's primary energy supply, and contributed significantly to the country's environmental footprint.[123] To tackle these issues, Japan is actively exploring clean alternative energy imports such as hydrogen and ammonia. The country's hydrogen strategy outlines the need to expand green H_2/ammonia uptake from 2 MTPA at present to 3 MTPA by 2030 and up to 20 MTPA by 2050, which is expected to be met using low-carbon hydrogen imports in the near-term from regional partners.[124] Japan also plans to import 3 MTPA of green ammonia by 2030, increasing to 30 MTPA by 2050. This will displace LNG and coal-based power generation.[125]

Australia is expected to be a key H_2 importer to Japan, and there are federal efforts to expand cooperation in hydrogen and green products between Australia and Japan[126] (which also includes a successful demonstration project of shipping hydrogen from Australia to Japan, highlighted below). In addition, the NSW Government is also playing an active role in this space; the former Premier engaged with Japanese stakeholders to open avenues for hydrogen and hydrogen derivative trade between the two countries.[127] While NSW potentially has the advantage of being able to deliver bulk amounts of green hydrogen and hydrogen derivatives to Japan, there is an urgent need to secure trade agreements as Japan is also exploring opportunities with Saudi Arabia and Brunei, among others, as a source of hydrogen products.

11.2.2. Republic of Korea

The Republic of Korea (South Korea) heavily relies on imported fuels to support its industrial activities. Statistics by the South Korean Government reveal that the country is the 8th largest energy consumer and relies on imports for 93.5% of its energy and natural resources,[128] which poses energy security challenges as the global markets transition towards decarbonised fuel sources. To address these challenges, South Korea's government and industrial sector is heavily invested in using hydrogen and hydrogen derivatives, with the expectation that the country will have a demand of 28 MTPA of H_2 in 2050 that will be met via blue and green hydrogen.[129] In the near term, blue hydrogen is expected to be the primary production route to meet South Korea's demand, with the expectation that it can be readily produced by imported natural gas onshore.[130] SK Group, one of South Korea's largest energy conglomerates, is investing in local blue hydrogen production (0.25 MTPA after 2025), which it expects to support via LNG imports (1.3 MTPA of LNG for 20 years). In this manner it is expected South Korea would still rely on fossil fuel-based processes for domestic H_2 production, estimated to be one-third of H_2 supply by 2040.[131]

In comparison, while the country has plans to increase renewable hydrogen capacity, the local renewable potential would be insufficient to meet its green hydrogen needs, both in the near and longer term.[124] Therefore, the country is also looking towards hydrogen imports. The hydrogen is expected to be imported for use in industrial activities, transport and power generation, with a target to achieve 14% to 21.5% of power generation via H_2- and NH_3-based gas turbines by 2050.[132]

Recently, the governments of South Korea and NSW have had discussions to develop trade agreements to expand green energy trade, including H_2.[133] If these discussions come to fruition, NSW can target a considerable portion of South Korea's anticipated demand of 4 MTPA (20 MTPA of green ammonia) and 20 MTPA (110 MTPA of green ammonia) of green hydrogen equivalents by 2030 and 2050 respectively.[134]

11.2.3. Singapore

Singapore is another key potential market for NSW hydrogen and hydrogen derivatives, given the country's strong intent to decarbonise its maritime and port operations. Singapore is yet to set a formal hydrogen uptake target but there is an emerging consensus that, by 2050, 60% of the country's energy supply would need to be replaced with low carbon hydrogen alternatives.[135] Additionally, the government has already planned to import up to 4GW of low-carbon electricity by 2035 from regional countries like Thailand, Malaysia, Laos and Australia, which would translate to 30% of the country's needs.[136]

Australia is already expected to play a role in fulfilling this demand, with the governments of both countries having agreed an MoU to accelerate low-emissions technology, including collaboration on hydrogen energy.[137] Moreover, Singapore has already invested in emerging hydrogen projects in Australia, like the Asian Renewable Energy Hub[138] (hydrogen and green ammonia export) and renewable energy projects like Suncable[139] (which aims to transmit Australian-generated renewable energy across the Indo Pacific Region via sub-sea cables). Recently, Keppel Infrastructure Holdings and Temasek, leading Singaporean infrastructure developers, also signed an MoU with Incitec Pivot (an Australian-based chemical and fertiliser manufacturer) to explore production of green ammonia in NSW (at Kooragang Island) for export to Singapore.[140]

123 - Japan Energy Policy Review 2021. IEA. 2021. Link
124 - Japan's Hydrogen Industrial Strategy. Jane Nakano. CSIS. 2021. Link
125 - Japan's Road Map for Fuel Ammonia. Trevor Brown. Ammonia Energy Association. 2021. Link
126 - Australian Government – Hydrogen Industry Policy Initiatives. HyResource. CSIRO. Accessed on 8th September 2022. Link
127 - Premier sells Japan on NSW green hydrogen. F. Farid. Canberra Times. 2022. Link
128 - Energy Policy Information. Republic of Korea Ministry of Foreign Affairs. Accessed on 8th September 2022. Link
129 - Hydrogen Expected to Become the Biggest Energy Source in Korea in 2050. Jung Min-hee. Business Korea. 2021. Link
130 - A clean start: South Korea embraces its hydrogen future. Perspective. Macquarie Group. 2021. Link
131 - South Korea's Hydrogen Industrial Strategy. J. Nakano. CSIS. 2021. Link
132 - Generate electricity from carbon-free fuels hydrogen and ammonia. Republic of Korea Ministry of Foreign Affairs. Accessed on 8th September 2022. Link
133 - New South Wales invites Korea to cooperate on clean energy. Kwon Mee-yoo. 2022. The Korea Times. Link
134 - S Korea to provide 27.9 mil mt/year of 'clean hydrogen' by 2050. S&P Global. 2021. Link
135 - Taking Singapore forward as a regional green hydrogen hub. S. Somani. Press Release. KPMG. 2022. Link
136 - Singapore plans electricity imports to boost security, diversify supply. J. Jaganathan et al. Reuters. 2021. Link
137 - Memorandum of Understanding between the Government of Australia and the Government of Singapore for Cooperation on Low-Emissions Solutions, Australian Government Department of Foreign Affairs and Trade. Accessed on 11th September 2022. Link
138 - Singapore backs WA green hydrogen mega-projects. A. Macdonald-Smith. Australian Financial Review. 2022. Link
139 - Sun Cable Australia – Asia Powerlink. Accessed on 9th September 2022. Link
140 - International partnership to investigate green ammonia supply from Australia's hydrogen hubs. Press Release. Keppel Infrastructure. 2021. Link

A recent study of hydrogen imports and downstream applications for Singapore, released by KBR (a global engineering company) and Argus (a Singapore-based private consulting firm), outlines a potential demand of 9 MTPA of hydrogen by 2050 and 2 MTPA by 2033 for use across power generation, transport and industry.[141]

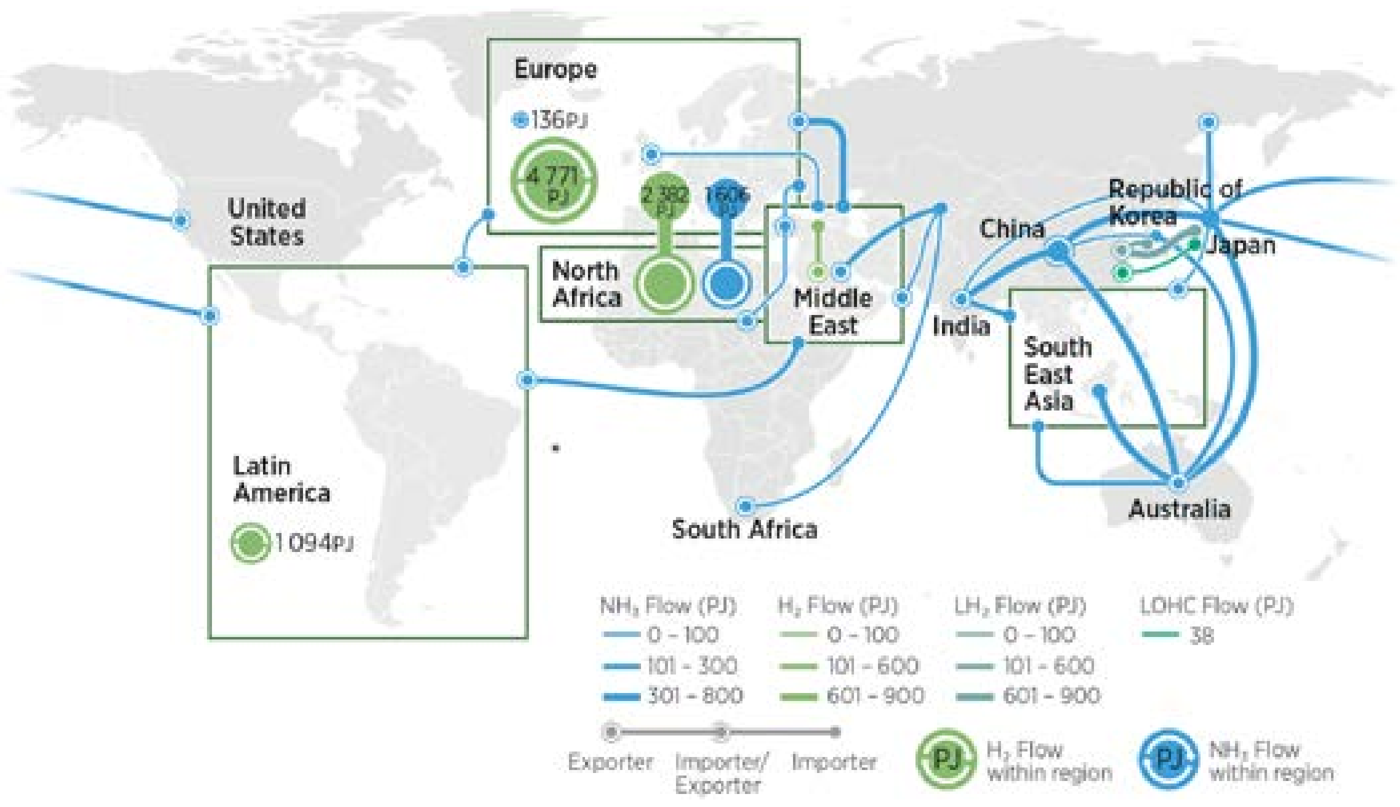


Figure 45. Estimated global hydrogen trade volumes by 2050 in from of different carriers as established by IRENA.

For Australia, it is expected that ammonia will be the key export carrier mainly to markets in Asia.

11.2.4. Europe Union

The EU Hydrogen Strategy proposes that for it to become climate neutral, up to 13 – 14% of the energy needs would need to be met through hydrogen and hydrogen derivatives. Recent estimates show that this would translate into a potential need for between 3 and 6 MTPA of H_2 equivalents in the near term (2025), rising to between 15 – 27 MTPA by 2030 and between 20 – 32 MTPA post 2030.[142] In particular, Germany is already exploring trade opportunities, including with Australia. As outlined in the recent Australian-Germany Hydrogen Supply chain pre-feasibility study, there is potential to export Australian-generated hydrogen and hydrogen derivatives to Germany and the EU region at competitive costs. If such opportunities are realised, it is suggested that Australia could potentially export 1 MTPA of H_2 equivalents to the EU by 2025 raising to 15 MTPA by 2030.[135] This also provides a significant opportunity for NSW, as it can tap into the EU market by shipping P2X products via the Port of Rotterdam to Germany and other EU countries such as Denmark. The NSW State Government has recently formalised an MoU with the government of Denmark to collaborate on net-zero emissions.[143]

11.2.5. The Rest of the World

In addition to the above key initial markets for hydrogen and hydrogen derivatives, it is projected that over time the rest of the world would catch up and powerfuels would make up a critical portion of the world's energy supply. The IEA Net Zero Plan by 2050, reveals that to achieve global decarbonisation goals, 120 MTPA of hydrogen derivatives are needed in the near-term (2025), increasing to 200 – 400 MTPA in 2030 – 2040) and >500 MTPA by 2050.[144] This includes the use of hydrogen directly as an energy source (replacement of natural gas and transport fuel), green feedstock and as an energy carrier such as ammonia (for the shipping industry), e-fuels like methanol (for the shipping industry and transport sector), SAF and SNG. Moreover, given the uneven distribution of renewable resources, there is an expectation that the global hydrogen economy would be underpinned by exports.

The latest IRENA report shows that by 2050, about 35% of the hydrogen demand would be fulfilled by trade, which would translate to 18.5 EJ/yr of H_2 or 150 MTPA of H_2 equivalents (given 120 MJ/kg of H_2). It is estimated 40% will be traded as ammonia (i.e. 400 MTPA of green ammonia) and 5% as LH_2 (8 MTPA of LH_2).[145] In this market, Australia is expected to be a dominant exporter (**Figure 45**), and is estimated to supply 1,800 PJ/yr of ammonia (to markets in South East Asia including China, Japan, South Korea and Indonesia/Singapore), which is equivalent to approximately 17 MTPA of hydrogen or 11% of the global hydrogen trade (based on LH_2 and ammonia trade).[145]

11.3. Outlook of NSW P2X Export Market

Above, we highlight the potential for NSW to participate in the emerging P2X export market. There is demand and an opportunity to attain a market share, given the state has agreements and understanding in place with potential partners. However, there is a need for the state to act fast and strengthen its position as a leading exporter within Australia and globally. Below we assess the state's readiness, competencies and the potential hurdles to exporting P2X products.

11.3.1. Liquid Hydrogen

Liquid hydrogen, which is 2-3 times denser than compressed gaseous hydrogen, is advocated as a derivative for pure hydrogen trade between Australia and Asia-Pacific. However, this is a debatable pathway given the challenges associated with LH_2, namely the cost and energy requirement for liquefaction, boil-off (loss during transport) and inherent safety risks.[146,147]

Figure 46. Suiso Frontier – the world's first LH_2 carrier ship.

Nevertheless, the use of LH_2 has been established commercially, with several

141 - KBR (2021). Study of Hydrogen Imports and Downstream Applications for Singapore. Link
142 - Securing Green Hydrogen for Germany and the EU. Green Hydrogen Task Force. 2022. Link
143 - NSW and Denmark join forces on road to net zero. NSW Government Department of Planning and Environment. Press Release. 2022. Link
144 - Net Zero by 2050 – A Roadmap for the Global Energy Sector. IEA. 2021. Link
145 - Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Trade Outlook for 2050 and Way Forward. IRENA. 2022. Link
146 - Not going to be a thing, it will be too expensive to ship hydrogen around the world, says Liebreich. P. Berrill. Recharge News. 2022. Link
147 - Special Report: Why shipping pure hydrogen around the world might already be dead in the water. L. Collins. Recharge News. 2022. Link
148 - Liquid Hydrogen Product Sheet. Air Products. Accessed on 10th September 2022. Link

liquefaction units operational globally. LH_2 is used for applications such as rocket fuel and for transporting H_2 over long distances in liquid road tankers.[148] In comparison, the

LH_2 export market has just started with only one commercial LH_2 shipping carrier (**Figure 46**) having just completed its first journey from Victoria (Australia) to a port in Japan, as part of the Hydrogen Energy Supply Chain (HESC) project. Therefore, there is value in developing liquefaction facilities in NSW and to reduce the high costs of these facilities the infrastructure could be shared for domestic use. For example, development of centralised hydrogen facilities in the upcoming hydrogen hubs (which are already near the ports) could accommodate liquefaction units for export and to load tube trailers for supply to other decentralised facilities. Nevertheless, the risk of hosting large-scale liquified hydrogen storage at port sites and close to residential and commercial activities would have to be acknowledged and mitigated.

11.3.2. Ammonia

Ammonia is a globally traded commodity, with Australia and NSW possessing considerable handling experience. In NSW, Orica, has partnered with Origin Energy to decarbonise

Figure 47. Orica's ammonia plant in Kooragang Island,

their operations using renewable hydrogen as part of their Hunter Hub project (**Figure 47**)[149] while Incitec Pivot is also exploring green ammonia export opportunities to Singapore from Kooragang Island.

At present the global market for ammonia is estimated to be worth US$65 billion, and if NSW can secure even a small share of the market (e.g. 1% share) it could be worth over A$100 million per year.[150] Moreover, with the shift to green ammonia, the global market is estimated to grow significantly, reaching US$110–117 billion by 2030, which would mean if NSW had at least 1% market share, it would be worth US$1.1 billion (A$1.6 billion).[150]

11.3.3. Synthetic Natural Gas (SNG)

There will be constraints and hurdles that would need to be addressed before an SNG export industry can be developed in the state. At present, there are no LNG export terminals in the state, but there is ongoing work on developing import terminals for LNG at Port Kembla[151] and Newcastle.[152] These import terminals are expected to shore up the state's natural gas supply to tackle natural gas supply shortages in the coming years.[153] The Australian Competition and Consumer Commission (ACCC) has recently suggested the need to curb LNG exports to support this east coast market.[154] On this basis, we conclude that SNG generation in the short-term would be better served to focus on the domestic NSW market. Nevertheless, if NSW can capture a share of Australia's current LNG export market (e.g. 1% of export volume), this would translate to a return of A$300 million per year.[155] Moreover, the return could increase as the global LNG market is estimated to grow by an average of 3.4% per year, with China and South Asia expected to be long-term LNG importers.[156]

11.3.4. Methanol

Methanol is also a key export commodity with about 28 MT of methanol worth US$9 billion (A$13 billion) exported.[157] Asia is the key export destination, with India and China the world's largest importers (10 MTPA), followed by Japan and South Korea, Germany and Taiwan, which import a combined 6 MTPA of methanol. Furthermore, given methanol is emerging as a hydrogen carrier and alternate fuel vector for the shipping industry, there is expectation that the global methanol market will reach US$66 billion (A$98 billion) by 2030.[158] In this scenario, achieving 1% of the global market share would fetch NSW, A$130 million per year which could grow to A$970 million by 2030.

At present, Australia is an importer of methanol with over 100 KT imported each year, mainly to produce formaldehyde for particle board and other manufacturing processes.[159] Therefore, development of P2X methanol projects in NSW could enable domestic supply as well as target the Asian market. Given the green nature of such methanol exports, a premium price could be achieved while also giving the state a competitive advantage over more established suppliers like Malaysia and Singapore, which export methanol generated from fossil-fuel processes. Moreover, an NSW methanol economy could also indirectly support the global shipping and export industry by providing clean fuel for ships as well as opportunities for emission trading where carbon offsets are offered to convert industrial CO_2 (as well as atmospheric CO_2 via DAC) to net-zero methanol.

11.3.5. Sustainable Aviation Fuel

Australia currently imports around 93% of its commercial jet fuel and the national aviation sector has consistently had to manage issues relating to aviation jet fuel supply and availability.[160] SAF provides another exciting opportunity for Australia, given the development of an export market could turn the table on one of its largest import commodities and strengthen the country's fuel security.

For NSW, pre-Covid statistics (2019 – 2022) show that the state consumed 2,757 ML of aviation fuel, 79% of which was imported.[161] Given the current price of aviation fuel — US$ 134/bbl[162] (average price of aviation fuel in Asia Oceania for 2022), which translate to A$1.23/L (assuming 1 bbl = 159 litres and A$1 = USD 0.67), this puts the import bill to be A$3.3 billion/yr. Based on this, if the state can displace and export even 1% of current use (276 ML/yr), this would not only save the state A$34 million/yr but add an extra A$34 million/yr to the economy. However, as highlighted above, due to high local demand, a domestic SAF market might be a state priority with the export driven by the value proposition of the savings from domestic use of SAF. Nevertheless, the market potential for SAF export is still there and expected to grow as the aviation sector shifts towards cleaner fuels. Additionally, as in the case of SNG and methanol, SAF provides an opportunity for global emission trading markets of carbon offsets in which NSW can participate by developing local SAF production.

149 - Orica and Origin to partner on Hunter Valley Hydrogen Hub. Press Release. Orica. 2022. Link
150 - Global Ammonia Market is estimated to be US$ 117.43 billion by 2030 with a CAGR of 6.1% during the forecast period. GlobeNewsWire. 2022. Link
151 - Construction under way at NSW LNG terminal. A. Macdonald-Smith. Australian Financial Review. 2021. Link
152 - NSW Government supports a boost for proposed Newcastle gas import terminal. Port of Newcastle. Press Release. 2019. Link
153 - Gas shortage looms for NSW and Victoria by 2024. M. Ludlow. Australian Financial Review. 2021. Link
154 - Australia considers curbing gas exports to avert domestic supply crunch. S. Paul et al. Reuters. 2022. Link
155 - The Australian LNG industry. Australian Government Department of Industry, Science and Resources. Accessed on 13th September 2020. Link
156 - Global Gas Outlook to 2050. Energy Insights. McKinsey. 2021. Link
157 - Rising Demand for Alternative Fuels to Spur the Global Methanol Market. IndexBox. Global Trade Magazine. 2021. Link
158 - Global Methanol Market to Reach USD 66.06 Billion by 2030; Rising Adoption of Methanol as a Marine Fuel to Propel Growth. Bloomberg Asia. Press Release. 2022. Link
159 - Unlocking Australia's hydrogen opportunity. White Paper. Australian Hydrogen Council. 2021. Link
160 - Over a barrel - Addressing Australia's Liquid Fuel Security. Discussion Paper. L. Carter et al. 2022. Link
161 - Australian Petroleum Statistics 2020. Australian Government Department of Climate Change, Energy, Environment and Water. 2020. Link
162 - Jet Fuel Price Monitor. IATA. Accessed on 8th September 2022. Link

Review of suitability for export of P2X from key NSW Ports

The major ports of NSW — Port Botany (Greater Sydney Metropolitan Region), Port Kembla (Illawarra – Shoalhaven Region) and Port of Newcastle (Hunter Region) — already have the infrastructure to host energy and chemical commodities. A summary of the current berths at each of the ports is provided in **Table 22**.

Table 22. Specification for berth as existing ports in NSW

Specification	Port Botany[163,164]	Port Kembla[164,165]	Port of Newcastle[166,167]
General details	• Is a deep-water shipping port with capacity to handle up to seven million TEUs (Twenty Foot Equivalent Unit) container ships. • Has bulk liquid and gas processing facilities (up to 5,500 ML/yr of bulk liquids and gases each year), two berths are dedicated to liquid fuels while there is also a 65 KT storage capacity for LPG at the port. • Well connected to the nearby industrial precincts, Sydney Airport (and will also be connected to the new Western Sydney Airport) and is the only port in Australia that has a direct connection to the terminals via rail track.	• A key large cargo vessel hub in NSW and equipped with deep-water shipping channels and berths. • Two berths dedicated for liquid imports including fuels and chemicals such as ethanol and sulphuric acid, as well as pipelines to support their storage in nearby facilities. • Expected to host one of the state's first hydrogen hubs, including P2X export projects. • Connected to the rest of the state via rail and road network.	• Is NSW's and one of the world's largest coal export ports. • The port has facilities to import, store and distribute bulk liquids with capacities up to 266ML and an additional 399ML capacity under development. These are supported with berths for large vessels up to LR2 capacity (size of most typical petrochemical tankers). • Has available land for upcoming projects and is already exploring P2X export opportunities. This could include linking with industrial operations in the Kooragang Island (including Orica's ammonia plant) or upcoming projects as part of the NSW-backed Hunter H_2 hub. • Connected to the rest of the state via rail and road network.
Channel Depth	15.7 m	16.5 m	15.2 m
Depth Alongside	14 – 17 m	16.5 m	15 m
Deadweight Tonnage (DWT)	75,000 – 90,000	232,000	70,000
Berth Pocket Size	320 x 55 m	300 x 50 m	300 x 55 m
Length Overall of Ship (LOA)	275 - 290 m	300 m	300 m

Berthing Requirements for P2X Shipping Vessels

Consideration should be given to the berth requirements for export of gases and liquids. It is expected that e-fuels (methanol and SAF) are likely to be shipped via marine tankers with specifications like those used for bulk liquids and fuels (refer to **Appendix C**). The export of methanol and SAF out of all of the NSW ports evaluated would likely be technically feasible based on the existing berth configuration.

In comparison, there is no present infrastructure to export natural gas at the three ports considered in this study. Port Kembla is currently going through construction of an LNG import terminal. The terminal is expected to have a capacity of 100 PJ of LNG per year and will provide storage, wharf and loading arms to offload LNG from ships. As part of this project, the berth infrastructure would be updated to accommodate medium gas carriers (MGC) LNG tankers and, these activities could pave the way for future Liquified SNG exports out of Port Kembla.

For LH_2 and there are ammonia-specific berth and port requirements. Typically, LNG uses higher capacity ships which are bigger. Berthing LNG and ammonia also has additional requirement and larger safety exclusion zones while filling, which must be considered. It is likely that all three ports could be upgraded to accommodate the larger vessel size, however, further assessment of the infrastructure should be completed. Specific requirements exist for cryogenic fluid around distance for storage to vessel, flaring and venting, loading and release.

163 - Berth and Channels. Port Authority of New South Wales. 2022. Link
164 - Port Botany. NSW Ports. Accessed on 13th September 2022. Link
165 - Port Kembla. NSW Ports. Accessed on 13th September 2022. Link
166 - Berth Information. Port of Newcastle. Accessed on 13th September 2022. Link
167 - Port of Newcastle. Accessed on 13th September 2022. Link

11.4. Cost of NSW P2X Exports

In this section we present indicative landed costs for P2X products exported from NSW to identified potential international markets (Japan, Republic of Korea, Singapore, Denmark and Germany). The ports considered for each one of the markets is listed in **Table 23**.

Table 23 Destination ports considered as part of this study

Country	Port	Basis
Japan	Kobe Port	Established as the world's first LH_2 offloading terminal and was a destination for the HESC project described earlier
Germany	Dutch Port of Rotterdam	One of the largest ports in the EU and is a gateway to mainland EU, including Germany. The port is already proactively invested in developing infrastructure to support P2X product imports as elaborated earlier.
Denmark	Port of Esbjerg	The port is already seeking green hydrogen supply to power ships.[168]
Republic of Korea	Yeosu Port	Expected to emerge as a potential hydrogen and hydrogen derivative import destination[169,170]
Singapore	Jurong Port	Expected to emerge as a potential hydrogen and hydrogen derivative import destination[171,172]

To model the landed costs (excluding any processing at the import terminal, e.g. cracking ammonia back to hydrogen), we build on the production cost of P2X products at Newcastle and Port Kembla, which were estimated in **Section B – C** by adding the cost of shipment (cost of buying and operating the loading terminal and carrier ships).

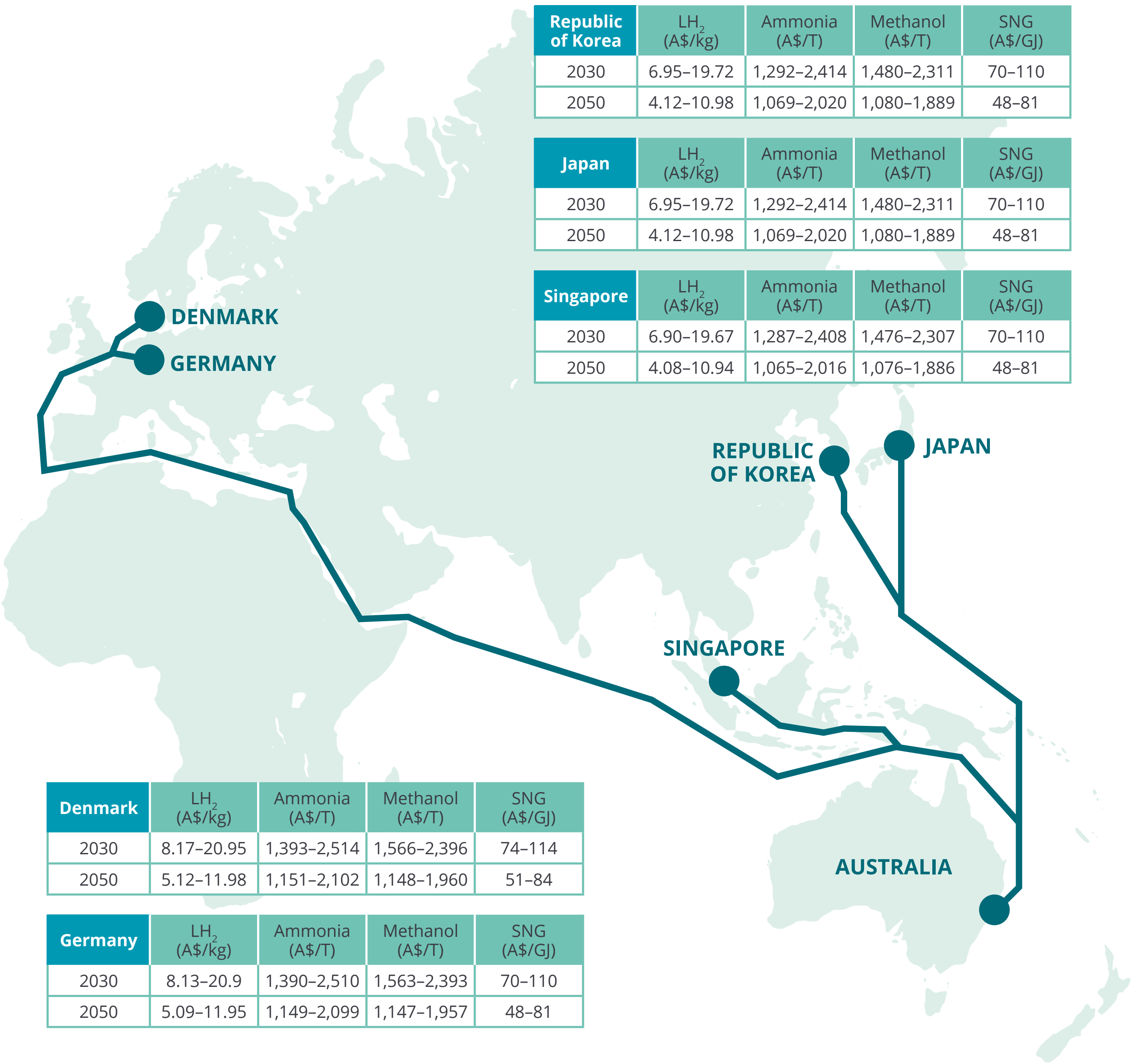
Shipping costs were calculated by using the HySupply Shipping Tool,[173] which is an open-source resource for costing green hydrogen and hydrogen derivatives export value chains (including ammonia, SNG and methanol). The tool was updated to include the latest parameters from literature and stakeholder engagement.[174] An assumption was made that the cost of equipment will reduce by 1% per year as the industry develops. The costing methodology and assumptions for the shipping costs are outlined in **Appendix B**.

The indicative delivered cost for the P2X product to the above destinations is summarised in **Figure 48**. The results indicate that the landed costs of P2X product to Singapore is the least expensive and the landed cost to Denmark is the most expensive. This is due to the increased sea transport distance. The main costs component for the landed price was the production cost of the P2X, which indicates that markets that are further away from traditional Australia trading markets may be viable if the production cost is low enough. This result aligns with the recently completed HySupply Study which showed that Australia can compete with the other potential regional H_2 exporters for shipping costs, whichwould give the country an advantage over competitors if it (including NSW) can leverage its low-cost renewable energy potential to generate bulk amounts of P2X products at low costs.[175]

The modelling suggests that there is an opportunity to export P2X products from NSW however there are challenges that need to be overcome. There is significant competition starting to develop, both from other states and global energy powerhouses. In the near term, the economics of P2X products are challenging and costs will be higher than fossil-fuel equivalents. The modelling completed does suggest that by the middle of the century, production costs for P2X products could be at parity or less. There is also opportunity for a 'green premium' and the threat of carbon taxes which will impact the economics. Cost reductions can be achieved through scale, technology cost reductions and learning curve cost reductions. Common user infrastructure is also an opportunity to further bring down costs.

The costs are provided as an estimate for a generic outlook of the export market in NSW and are subject to change as the market develops over time. Moreover, there is significant room for cost reduction based on scales (effect of economies of scale), optimisation (project capacity factors, capacity of shipping containers and shipping frequencies) and basic cost assumptions (lower CAPEX and OPEX costs are likely as market competition increases). All these aspects can be explored by using the open-source tools (NSW Powerfuel Tool

168 - European Energy to deliver green hydrogen for vessels in Port Esbjerg. A.Habibic. Offshore Energy. 2022. Link
169 - SK Group to Build South Korea Hydrogen Port. Hydrogen Central. 2021. Link
170 - PSA, Jurong Port, Others to Launch Hydrogen Import Study. World Maritime News. Offshore Energy. 2020. Link
171 - SK Group to Build South Korea Hydrogen Port. Hydrogen Central. 2021. Link
172 - PSA, Jurong Port, Others to Launch Hydrogen Import Study. World Maritime News. Offshore Energy. 2020. Link
173 - HySupply Shipping Analysis Tool. GlobH2E. Accessed on 10th September 2022. Link
174 - Shipping the sunshine: An open-source model for costing renewable hydrogen transport from Australia. C. Johnston et al. International Journal of Hydrogen Energy. 2022. Link
175 - R. Daiyan et al, (2021). The case for an Australian Hydrogen Export Market to Germany. State of Play V1.0. UNSW, Sydney. DOI: Link



Republic of Korea	LH_2 (A$/kg)	Ammonia (A$/T)	Methanol (A$/T)	SNG (A$/GJ)
2030	6.95–19.72	1,292–2,414	1,480–2,311	70–110
2050	4.12–10.98	1,069–2,020	1,080–1,889	48–81

Japan	LH_2 (A$/kg)	Ammonia (A$/T)	Methanol (A$/T)	SNG (A$/GJ)
2030	6.95–19.72	1,292–2,414	1,480–2,311	70–110
2050	4.12–10.98	1,069–2,020	1,080–1,889	48–81

Singapore	LH_2 (A$/kg)	Ammonia (A$/T)	Methanol (A$/T)	SNG (A$/GJ)
2030	6.90–19.67	1,287–2,408	1,476–2,307	70–110
2050	4.08–10.94	1,065–2,016	1,076–1,886	48–81

Denmark	LH_2 (A$/kg)	Ammonia (A$/T)	Methanol (A$/T)	SNG (A$/GJ)
2030	8.17–20.95	1,393–2,514	1,566–2,396	74–114
2050	5.12–11.98	1,151–2,102	1,148–1,960	51–84

Germany	LH_2 (A$/kg)	Ammonia (A$/T)	Methanol (A$/T)	SNG (A$/GJ)
2030	8.13–20.9	1,390–2,510	1,563–2,393	70–110
2050	5.09–11.95	1,149–2,099	1,147–1,957	48–81

Figure 48. Estimated cost of shipping select P2X products generated in NSW to potential trade partners.
The detailed breakdown of these costs are provided in Appendix

Conclusion

This report builds upon government, industry and academic interest in developing a powerfuel economy in NSW. It outlines the state-of-play on current policies, provides an assessment of feedstocks and constraints, and provides an overview of near-, medium- and long-term opportunities in P2X.

The report, the NSW Power-to-X State-of-Play Roadmapping Exercise and the open-source tools that accompany them are the result of exhaustive analysis and feedback from stakeholders. Together, they will serve as an informative and supportive resource for the ongoing P2X transition in NSW.

The findings show that the development of a P2X economy represents a chance for NSW to decarbonise its hard-to-abate sectors while creating new jobs and new economic opportunities as it transitions to a net-zero future.

However, there is much still to do. At present, most P2X activities are focused on specific hubs — particularly the proposed Port Kembla and Hunter H_2 Hubs — and specific markets, such as H_2 refuelling, natural gas blending/replacement for power generation and export projects. While these activities have positioned the state as a trailblazer, if it is to shift the market to the next frontier a more concerted effort from government, industry and academia is required.

In summary, if the state is to remain competitive in local and global markets, it must expand its P2X footprint and scale up the production of high-value P2X products, including ammonia, methanol and synthetic fuels.

for costing hydrogen and P2X derivatives and the HySupply Shipping Tool for costing their ultimate export).

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List of Abbreviations

AE	- Alkaline electrolyser
AEMO	- Australian Energy Market Operator
AHC	- Australian Hydrogen Council
ASTM	- American Society of Testing and Materials
ASU	- Air separation unit
BESS	- Battery energy storage system
BEVs	- Battery electric vehicles
C&D	- Construction and Demolition
CAPEX	- Capital Expenditure
CGH_2	- Compressed hydrogen gas
CO_2	- Carbon dioxide
DAC	- Direct air capture
e-SAF	- Synthetic aviation fuel produced through conversion of renewable energy
EU	- European Union
EVs	- Electric vehicles
FCVs	- Fuel Cell Vehicles
FEED	- Front-End Engineering Design
FT	- Fischer-Tropsch
G&A costs	- General and Administrative costs
GH_2	- Gaseous hydrogen
H_2	- Hydrogen
HDVs	- Heavy Duty Vehicles
HESC	- Hydrogen energy supply chain
HRS	- Hydrogen refuelling station
ICAO	- International Civil Aviation Organisation
IEA	- International energy agency
IFG	- Industrial Flue Gas
IRENA	- International Renewable Energy Agency
L	- Large
LCOH	- Levelised cost of hydrogen
LH_2	- Liquified hydrogen
LPG	- Liquified Petroleum Gas
M	- Medium
MoU	- Memorandum of understanding
MSW	- Municipal solid waste
NEM	- National electricity market
NH_3	- Ammonia
NSW	- New South Wales
O&M costs	- Operating and maintenance costs
P2X	- Power-to-X
PEME / PEM	- Proton exchange membrane electrolyser
PPA	- Power purchase agreement
PV	- Photovoltaic
R&D	- Research and development
RAAF	- Royal Australian Air Force
REZ	- Renewable energy zone
S	- Small
SA	- South Australia
SAF	- Synthetic Aviation Fuel
SAP	- Special activation precincts
SNG	- Synthetic Natural Gas
TAFE	- Technical and Further Education
tpa	- Metric ton per annum
VIC	- Victoria
WWTP	- Wastewater Treatment Plant
Z#	- Zone #
A$	- Australian Dollars
A$/GJ	- Australian Dollars per Gigajoule
A$/kg	- Australian Dollar per kilogram
A$/kWh	- Australian Dollar per kilowatt hour
A$/MWh	- Australian dollar per megawatt hour
A$/tkm	- Australian Dollar per ton kilometer
GL	- Giga Litre
GL/yr	- Gigalitre per year
GL/yr	- Gigalitres per year
GW	- Gigawatt
Kg	- kilogram
Km	- Kilometre
KTPA	- Thousand metric tons per annum
kV	- Kilovolts
kWh	- Kilowatt hour
L/kg	- Litres per kilogram
m^2/kW	- Meters squared per kilowatt
MJ	- Megajoule
ML	- Million litres
ML/day	- Million litres per day
MT	- Million metric ton
MTPA	- Million metric ton per annum
MVA	- Megavolt Ampere
MW	- Megawatt
MWh	- Megawatt hour
PJ	- Pentajoule
tCO_2eq.	- Equivalent Metric tons of CO2 emissions
tCO_2eq.p.a.	- Equivalent Metric tons of CO2 emissions per annum
TEUs	- Twenty foot equivalent units
TJ	- Terajoule