NSW Power to X Industry Feasibility Study

Appendices

October 2023

Disclaimer:

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Appendix A:

Opportunity Assessment Framework

A. Opportunity Assessment Framework

In Chapter 2 of the main report, we established the opportunity assessment framework for identifying P2X opportunities in New South Wales (NSW). The framework was based on four interlinked criterion that included market demand, feedstock availability, infrastructure availability, and project approvals/risks. In this appendix, we elaborate on the feedstock availability and underlying infrastructure across the NSW local government regions.

A1. Regional Boundaries

For our analysis, we distributed the states into the zones (**Figure 20** of the main report). These zones are listed in **Table A1**.

Table A1. Zonal distribution of the NSW State

Zone #	Regional Locations	Key Cities/Regional Centers	REZs, H_2 Hubs and SAPS underdevelopment
Z1	Far North West NSW		
Z2	Central Far West NSW – Western Part	Broken Hill and Silverton	Broken Hill REZ
Z3	South Far West NSW	Mildura	South West REZ
Z4	Central North West NSW	Wannaring	
Z5	Central Far West NSW – Eastern Part	Wilcannia and Cobar	
Z6	Central South Far West NSW	Ivanhoe	
Z7	West Riverina Murray Region	Hay	South West REZ
Z8	Central North NSW	Walgett and Lightning Ridge	
Z9	Central Orana Region	Bourke, Nyngan and Dubbo	Central West NSW and Orana REZ
Z10	Central West NSW	Parkes and Forbes	Parkes SAP
Z11	East Riverina Murray Region	Wagga Wagga, Griffith, and Albury	Wagga Wagga SAP or H_2 Hub /Wagga Wagga REZ and Tumut REZ
Z12	North East NSW	Moree	Moree SAP/North West REZ
Z13	New England Region	Narrabri, Tamworth, and Armidale	Narrabri SAP/North West REZ and New England REZ
Z14	Hunter and Greater Sydney Metropolitan Area	Orange, Bathurst, Cowra, Lithgow, Sydney, Gosford, and Newcastle	Hunter Hydrogen Hub/Hunter Offshore REZ
Z15	Illawarra – Shoalhaven Region	Wollongong, Nowra, Batesman Bay and Australian Capital Territory (ACT)	Illawarra Hydrogen Hub/Illawarra Offshore REZ
Z16	South East NSW	Cooma	Cooma Monaro REZ
Z17	North Coast Region	Lismore, Byron Bay, and Grafton	

Z18	Central Coast Region	Coffs Harbor and Port Macquarie	
Z19	Offshore North Coast Region	Byron Bay	
Z20	Offshore Central Coast Region	Coffs Harbor and Port Macquarie	
Z21	Offshore Hunter Region	Newcastle and Greater Sydney Metropolitan Area	Hunter Offshore REZ
Z22	Offshore South East Coast	Wollongong, Nowra, and Batesman Bay	Illawarra Offshore REZ

A2. Feedstock Availability

A2.1. Renewable Electricity

Solar and Wind Potential of NSW

As part of our analysis, we consider the opportunity of developing new renewable energy facilities to power the P2X facilities. To this end, the solar and wind potential maps of NSW (**Figure A1**) can act as a resource for primary zoning of sites, with the principle that the site with high solar and wind potentials make for better sites as they would have the ability to drive the electrolysers at high-capacity factors, identified as a critical parameter for achieving economical electrolysis projects.[1]

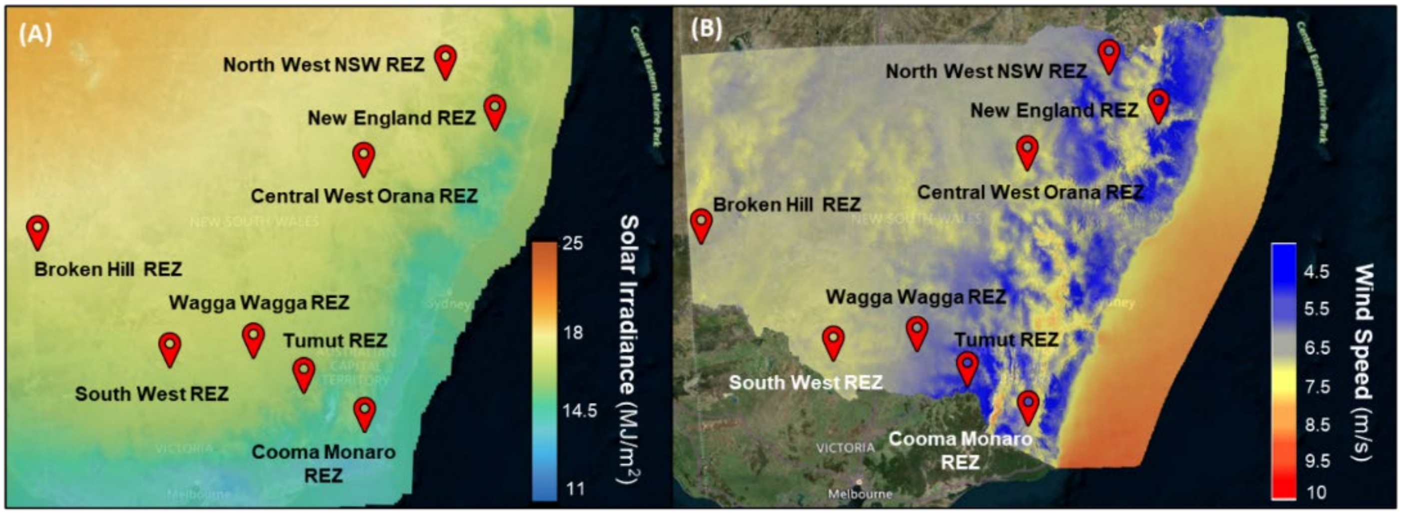

Figure A1. Solar and Wind energy potential of NSW. Here **(A)** represents the solar irradiance potential, while **(B)** represents the wind speeds recorded at 100 meters across NSW. The map was prepared using the Commonwealth National Map tool and database[2], and additional notations for the REZs were added as an approximate representation of their location.

The maps show some of the highest solar generation potentials (>20 MJ/m^2) are present across the north-west part of the state with most of the state showing moderate to high solar potential (17 – 20 MJ/m^2). For wind, the potential is high most of western and central NSW as well across the Great Dividing Range and Snowy Mountains region (>6 m/s^2), while most of the off-coast areas (>20 km of the shore) show very high wind potential (>8.5 m/s^2) especially

[1] Khan *et al*. An integrated framework of open-source tools for designing and evaluating green hydrogen production opportunities. Nature Communications Earth & Environment. 2022. https://doi.org/10.1038/s43247-022-00640-1
[2] Australia National Map. https://nationalmap.gov.au/

across the Central Coast and the southern seaboard. To qualitatively measure the solar and wind potential of NSW, we evaluate the capacity factors of potential solar and wind farm development across the state as elaborated in **Appendix B**.

Existing Capacity

NSW hosts Australia's largest renewable generation capacity, producing a record 17,829 GWh of electricity in 2022. The renewable energy generation capacity in NSW has grown by roughly 40% over the last five years (2016-2022) and during this period, the renewable energy penetration in the state's grid has increased from 12% to 26%.[3] Yet, NSW is still lagging behind the rest of the states in Australia (above only Queensland) in terms of renewable energy penetration with ~3/4th of the state's energy demand being served using fossil fuel sources..

Hydroelectric Power: Hydropower currently accounts for 2,110 GWh of renewable energy generation in NSW (3% of the generation capacity of the state).[3] The state currently hosts Australia's largest hydropower project, Snowy Mountains Hydro Power Scheme. The power scheme consists of nine power stations, 16 major dams, 80 kilometres of aqueducts and 145 kilometres of interconnected tunnels, with a combined capacity of 4,100 MW. As an addition to this scheme, Snowy 2.0 is being developed which is expected to extend the capacity by a further 2,100 MW with first power expected to be generated by 2025 (followed by the progressive commissioning of the rest of the generators). Moreover, the state is currently exploring large scale development of pumped hydro as a means for renewable energy storage.[4]

Solar Farms: Currently, the state hosts an installed solar farm capacity of 2,123 MW (with 22 solar farms > 30 MW capacity) with a further 940 MW committed over the next few years and a further 62 MW capacity of PV farms currently in early stages of planning.[5] The state is also home to one of Australia's largest solar plants, i.e., Darlington Point (324 MW), Limondale Solar Farm (306 MW) as well the under construction New England Solar Farm stage 1 (400 MW).

Wind Capacity: The state also hosts 2,225 MW of current installed wind farm capacity (19 wind farms with greater than 100 MW capacity each and a further 3 under construction as of 2022) with additional 2,629 MW committed by 2030 and 7,610 MW of wind capacity proposed post 2030.[6] Some notable large-scale plants include the Sapphire Wind Farm (270 MW), Silverton Wind Farm (200 MW) and the Bango Wind Farm (236 MW) and Collector Wind Farm (228 MW) both under construction.

Figure A2 maps out the operational solar, wind and hydroelectric powerplants in NSW.

Bioenergy: Bioenergy holds considerable potential for electricity generation in NSW. Currently, biomass is being used to generate electricity and heat via biomethane as well as biofuel – ethanol or biodiesel. Particularly, bagasse generated as a by-product of sugar mills is used to generate electricity, and NSW has 3 sugar mills that have such cogeneration plants in their mills, these include[7]:

- Broadwater Bioenergy Plant (38 MW),
- Condong Bioenergy plant (30 MW)
- Harwood Sugar Mill (4.5 MW)

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[3] Australian Energy Update 2021. Department of Industry, Science, Energy and Resources. https://www.energy.gov.au/publications/australian-energy-update-2021
[4] NSW Pumped Hydro Roadmap. NSW Government 2018. https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/pumped-hydro-roadmap
[5] https://www.ecogeneration.com.au/wp-content/uploads/2022/03/Solar-Map-2022.pdf
[6] https://www.ecogeneration.com.au/wp-content/uploads/2022/02/ECO-WindMap-2022.pdf
[7] Bioenergy in NSW. NSW Government. https://www.energy.nsw.gov.au/renewables/renewable-generation/bioenergy

Other electricity generating bioenergy facilities in NSW include:

- Tumut Visy Paper Bioenergy Facility that generates 32 MW from residual waste from the paper manufacturing process to power the plant and provide excess energy to the grid,
- Lucas Heights Bioenergy powerplants that generate a combined 21.5 MW from biomethane generated in landfills,
- Eight of Sydney Water's wastewater treatment plant that are connected to cogeneration facilities that generate electricity from sewage-based methane to generate a combined 9.9 MW of power.
- EarthPower Technologies operates a 3.9 MW capacity plant that converts food waste to biogas and is situated the suburb of Camellia of Sydney. This facility is the first of its kind in Australia.
- The Manildra Ethanol Plant in Nowra (Shoalhaven Region) generates 300 million litres of ethanol from starch waste from the local agri industry, the ethanol is then used for blending into fuels for mobility.
- In Rutherford (Hunter Region), there is a 20 million litre per year biodiesel facility that generates biodiesel from vegetable and cooking oil.

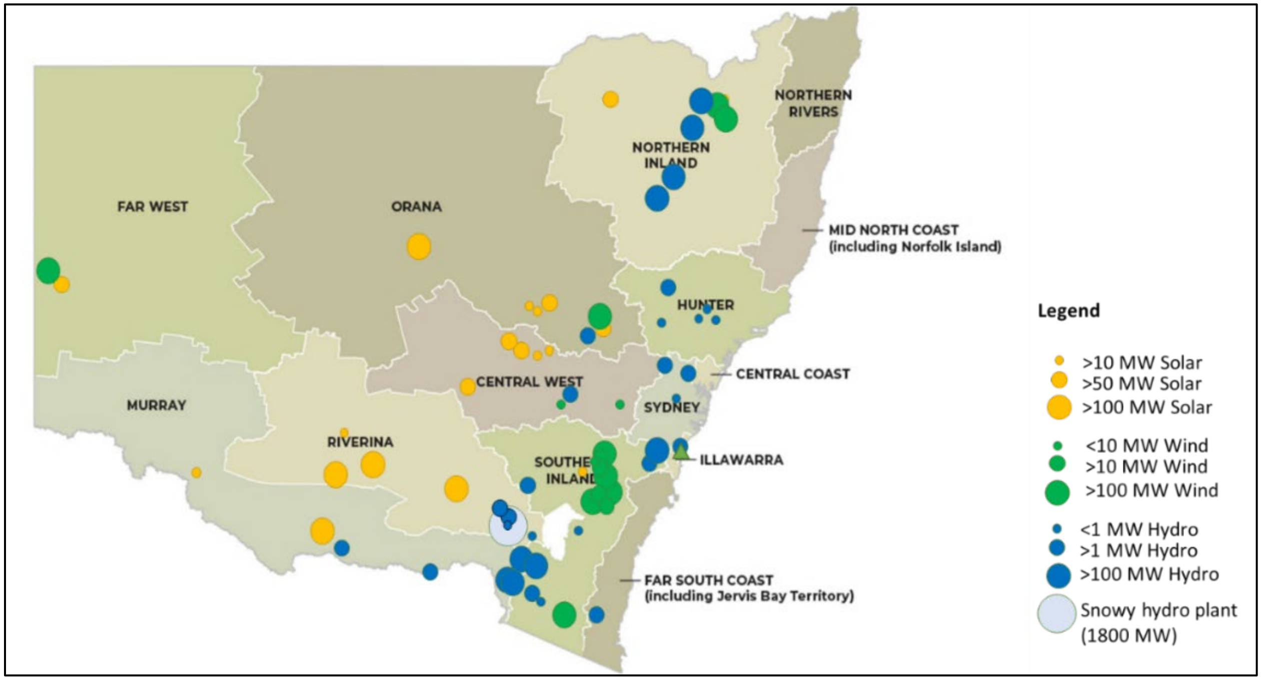

Figure A2. Map of NSW's operational Hydropower projects, Solar and Wind Farms.

Planned Capacity

In addition, capacity expansion is expected in form of the development of Renewable Energy Zones (REZs) and this expansion is detailed in the main report. The Australian Energy Market Operator (AEMO) as part of its recent Integrated System Plan (ISP 2022) suggests potential development of REZs shown in **Figure A3**. Off these, the NSW government has already declared intentions to develop 5 REZs, the scope and status of which are provided in **Table A1**.

Table A2. Status of REZ Development in NSW.[8]

REZ Name	Status	Target Capacity	Current Progress
Central West & Orana	Development Phase	3 GWs by mid 2020s	Initial expression of interest has attracted proposals of 27 GWs
New England	Early Planning	8 GWs	Initial expression of interest has attracted proposals of 34 GWs
South West	Early Planning	2.5 GWs	Initial expression of interest has attracted proposals of 34 GWs
Hunter – Central Coast	Early Planning	1 GWs initial declaration	Initial expression of interest has attracted proposals of 40 GWs including offshore wind farms
Illawarra	Early Planning	1 GWs initial declaration	Initial expression of interest has attracted proposals of 17 GWs including offshore wind farms

[8] https://www.energyco.nsw.gov.au/renewable-energy-zones

For our analysis, we also consider the capacity development expectations for each REZ as suggested by AEMO ISP 2022, especially for their hydrogen superpower scenario that suggests the capacity development up until 2050 under the constraints of land availability, network congestions and regional/global hydrogen demand.[9] This is elaborated in the main report.

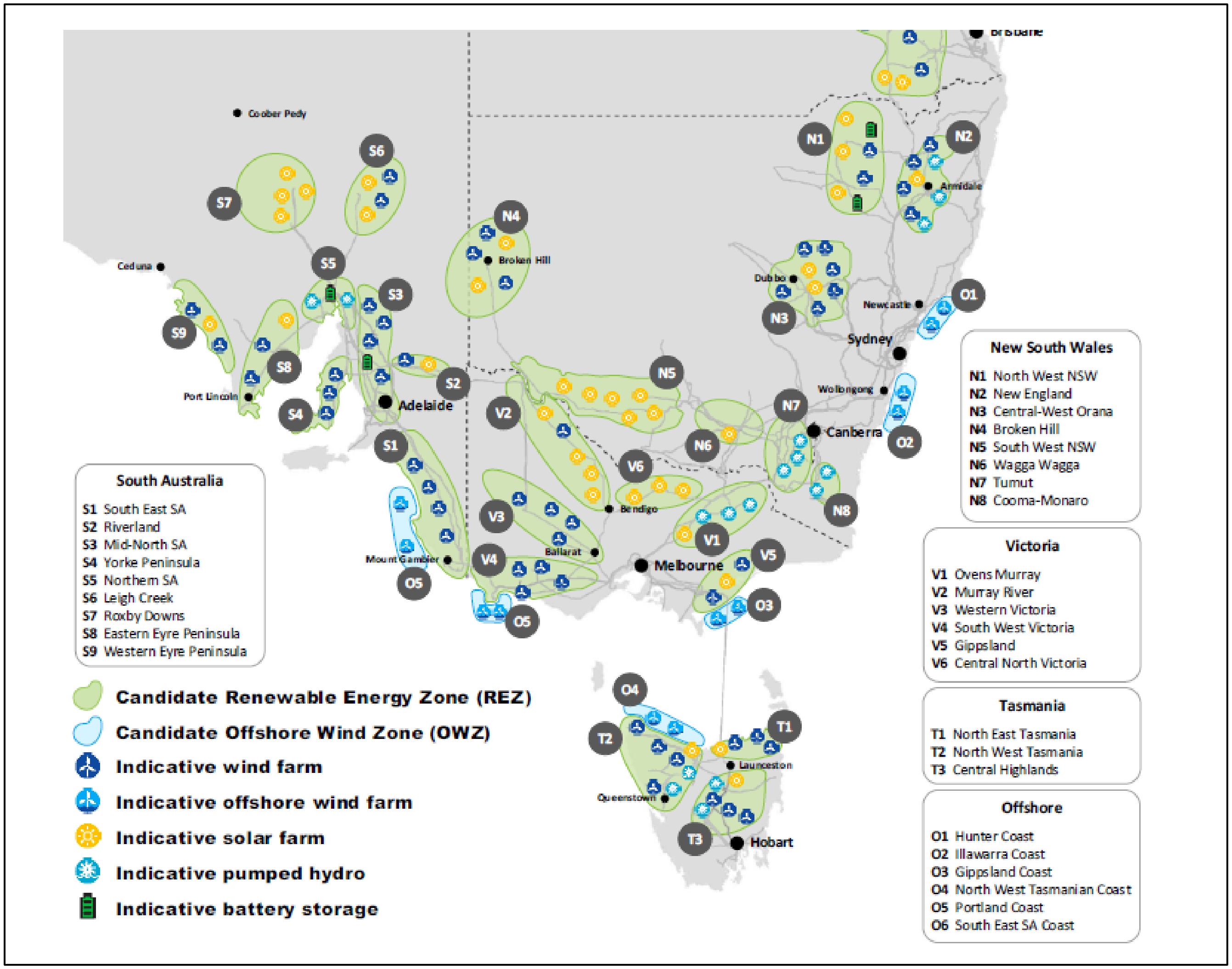

Figure A3. Map of potential REZs across the National Electricity Market suggested by AEMO.[9]

A2.2. Water Availability

Water, in addition to the provision of renewable electricity is the primary driver of the electrolysis process. Theoretically (on the stochiometric basis), around 9 kilograms of water are required to generate a kilogram of H_2. However, a recent GHD analysis, actual water footprint for hydrogen production extends beyond the theoretical limit of 9 L per kg of hydrogen and can amount up to 60 L per kg.[10] Herein, we assume an average water consumption of 20 L per kg of hydrogen. The additional water consumption is associated due to losses and other requirements such as for cooling purpose in downstream processes.

Water Requirement for Electrolysis

Water integration with electrolysis systems is not straightforward as the quality of water needs to be ensured to match electrolysis feedstock requirement. Electrolysers generally require deionised water as a feedstock, i.e., generally Type I or II Water as defined by the American Society for Testing and Materials with conductivity at least below 5 μS/cm.[11]

Modern electrolyser systems have a pre-installed deionisation step but pre-treatment of water to remove dissolved impurities etc. is still expected. Therefore, in any water consumption pathway, pre-treatment steps are required these are highlighted in **Table A2**.

Table A3. Water pre-treatment requirement for Electrolysis depending on water source.[12]

Source	Main Pollutant of Concern	Pre-Treatment Operation Required
Fresh Water	Suspended Solid (TSS), BODs	Fine Screening, coagulation/filtration, and optional Reverse Osmosis
Groundwater	Dissolved Solids	Depending on water composition, ions might have to be removed through Reverse Osmosis
Water Supply Network	Dissolved Solids	Reverse Osmosis
Industrial Wastewater	Suspended Solids, BODs, CODS, Toxicity	Will depend on if the wastewater has been treated before discharge, if it has been treated then coagulation and filtration followed by Reverse Osmosis will be required and if it has not been treated then more stringent coagulation + filtration + ion exchange + chemical treatment and Reverse Osmosis might be required
Urban Wastewater	Suspended Solids, BODs, CODS, Toxicity	Will depend on if the wastewater has been treated before discharge, if it has been treated then coagulation and filtration followed by Reverse Osmosis will be required and if it has not been treated then more stringent coagulation + filtration + ion exchange + chemical treatment and Reverse Osmosis might be required
Seawater	Salinity	Fine screening, filtration and Reverse Osmosis or alternate Desalination process
Rainwater	Dissolved Solids. BODS, TSS	Filtration and Reverse Osmosis

[10] Water for electrolysis. Coertzen et al. 2020. GHD. https://www.ghd.com/en/perspectives/water-for-hydrogen.aspx
[11] Simoes *et al*. Water availability and water usage solutions for electrolysis in hydrogen production. Journal of Cleaner Production. 2021. https://doi.org/10.1016/j.jclepro.2021.128124
[12] Water availability and water usage solutions for electrolysis in hydrogen production. Simones et al. 2021. Journal of Cleaner Production. https://doi.org/10.1016/j.jclepro.2021.128124

Water Availability in NSW

In NSW and generally across Australia, given the uneven distribution of freshwater resources and the reliance of most of our critical sectors on them (e.g., agriculture, domestic and industrial use), finding a reliable and sustainable water supply becomes a design concern when developing hydrogen projects. This is critical for Australia, where there are periodic droughts, already heavily allocated water resources, and high-water demand for agriculture.[13]

To identify available water resources, herein this report these sources are categorised as surface water (water in streams, rivers, lakes, and dams), groundwater (water in the underground reservoirs), wastewater treatment (salvageable and recyclable water from industry effluents and wastewater treatment plants) and desalination projects. All these sources for water have been demonstrated for electrolysis use and found to be technically viable for scaling electrolysis in Australia.[14]

A critical resource for water in NSW is the surface and groundwater resources, to ensure demand matching these water resources are managed through allocations/water sharing plans and extraction limits.[15] The surface water is allocated on basis of the portion of a licensed water supply that is credited to a user based on their entitlement to account for their water use and share of supply. These allocations are determined annually and updated regularly until all licensed categories are fully allocated based on the regional water sharing plans (that ensure long term sustainable water supply and prioritised access to water sources across the state) and on the water available in dams, river flows, and the prevailing weather conditions. These allocations are prioritised in the order of domestic and stock, town water supply, high security (industrial and commercial use), conveyance and general security (recreation etc) based on the NSW Water Management Act 2000 and local water sharing plans.[16] Currently, almost all regulated and unregulated rivers have over 100% allocation or are fully allocated. Similarly, the groundwater in the basins for the current year have also been allocated. Given the critical water situation in the state and the vulnerability to floods its highly likely that P2X projects will have to be designed keeping in mind the overall benefit and critical nature of applications for it to be able to get water allocations. Nevertheless, below and in the main report we highlight the potential sources of fresh and ground water reserves in NSW and how allocation issues will potentially affect the P2X projects.

If wastewater can be reclaimed, it can be used as a significant resource for scaling and sustaining P2X projects, offering a low cost and low competition water source. The NSW H_2 strategy estimates show that ~30 Mt of H_2/yr can be generated from wastewater resources in the state.[17] However, it is important to note that currently in general waste water treatment plants (WWTP) and recycling plants in NSW use this water for local gardening (watering of parks, racecourse fields etc.), supplement residential water use (water for washing etc) and shoring up water flows in rivers, lakes etc by supplementing their inflows. Yet, some of these WWTP are tied into the local water supply networks that are offering recycled water for industrial use, while other WWTP are dumping water into ocean these could be potentially leveraged for P2X.Nevertheless, use of wastewater is subject to quality of water, as low quality water source would need additional pre-treatment at additional costs as well as spatial/temporal correlation with the P2X facility, as the need to transport and store water to meet the P2X demand will also incur additional costs and need for additional infrastructure development.

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[13] Water access for hydrogen projects: don't let your options dry up. Bergman et al. 2021. Allens. https://www.allens.com.au/insights-news/insights/2021/10/Water-access-for-hydrogen-projects/
[14] Australia's pursuit of a large scale hydrogen economy. Shwisher *et al*. 2019. Jacobs. https://www.jacobs.com/sites/default/files/content/article/attachments/Hydrogen_White_Paper_May2019.pdf
[15] https://www.industry.nsw.gov.au/water/allocations-availability/allocations/how-water-is-allocated
[16] https://www.industry.nsw.gov.au/water/allocations-availability/allocations/how-water-is-allocated/principles-for-allocating-regulated-river-water-in-nsw
[17] NSW Hydrogen Strategy. 2021. NSW Department of Planning, Industry and Environment. https://www.energy.nsw.gov.au/sites/default/files/2021-10/govp1334-dpie-nsw-hydrogen-strategy-fa2_accessible_final.pdf

If desalination is used, there is a common understanding that the cost of water from desalination is higher than other sources as they are costly to build and operate. The key advantage of desalination is that it can supply water reliably and when needed.[18] This is advantageous in applications like hydrogen generation, that needs a sustainable, scalable, and reliable supply of water and the cost of water use on the overall economics is not significant. Therefore, projects close to coastal areas could potentially seek to rely on dedicated desalination plants. However, there are environmental impacts like excess brine production, effect on the aquatic life and the energy intensive nature of desalination that need to be considered.[19]

In addition, to the quality concerns, cost of sourcing water would also have to be considered. Prior analysis shows that water is not a critical driver as it contributes to less than 10% to the eventual cost of hydrogen generated and even if the costlier process of desalination is used the economics do not vary significantly. However, this analysis does not consider additional cost of transporting water to the site.

Disclaimer: Note for our analysis we consider the source and wholesale pricing of the water. For a given project these aspects will vary from case to case, therefore the impact of water choice and its subsequent effect on the economics would need to be carried out in detail during the front-end design and certification of the projects. Projects in Australia have already been discarded due to issues with water sustainability.[20]

For our analysis we consider water availability from surface, groundwater, and recyclable sources as elaborated below:

Surface Water: Surface water provides a straightforward resource for water as it includes water stored in rivers, streams, lakes, or natural reservoirs. Surface water resources in New South Wales is divided into regions such as the Border Rivers/Gwydir, Northern Rivers, Namoi, Central West, Hawkesbury, Hunter, Western, Murray, Lachlan, Sydney Metro, and Southern Rivers, all of which have major coastal or inland rivers as seen in **Figure A4.**[21,22]

These water resources contain around 18,400 GL of water and receive up to 51,533 mm of rainfall every year, however most of these water resources are tied into serving agriculture, domestic and industrial demand including local councils, water utility organisations, irrigational purposes, livestock grazing, fishing, forestry, tourism, etc. These are all critical activities and use of these resource for P2X Hubs would have to compete and rely on excess generation. While these resources could be leveraged for water use, the long-term viability of these water resources are questionable due to the seasonal variation in the water supply, periodic droughts in the region and the potential need to treat the water to reach desired quality for use as feedstock.

Statistics from FY2020 show that roughly 12 ML of water were consumed by industrial applications while an additional 0.55 ML were consumed by domestic consumers in NSW.[23] Water consumption by industry has decreased from an average of ~20 ML/yr between FY2015 – 2018 while domestic consumption has remained somewhat constant. While the water consumption by the agriculture sector was recorded as 1,280 GL of which 0.4 GL were taken from special irrigation lines, while an additional 0.3 GL and 0.6 GL were taken from rivers and groundwater resources, respectively.

[18] Do desalination plants make economic sense? C. Olszak *et al*. 2019. Australian Water Association. https://www.awa.asn.au/resources/latest-news/business/assets-and-operations/do-desalination-plants-make-economic-sense
[19] https://sciencing.com/advantages-disadvantages-desalination-plants-8580206.html
[20] Bella Peacock. Green hydrogen megaproject in SA discontinued. PV Magazine. 2022. https://www.pv-magazine-australia.com/2022/05/31/green-hydrogen-megaproject-in-sa-discontinued/
[21] Major Rivers Database. NSW Department of Planning, Industry and Environment. https://www.environment.nsw.gov.au/vegetation/MajorRivers.htm#brgcma
[22] NSW Water Catchments. Australian Museum. https://australian.museum/get-involved/citizen-science/streamwatch/water-catchment/streamwatch-nsw-catchments/
[23] https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release

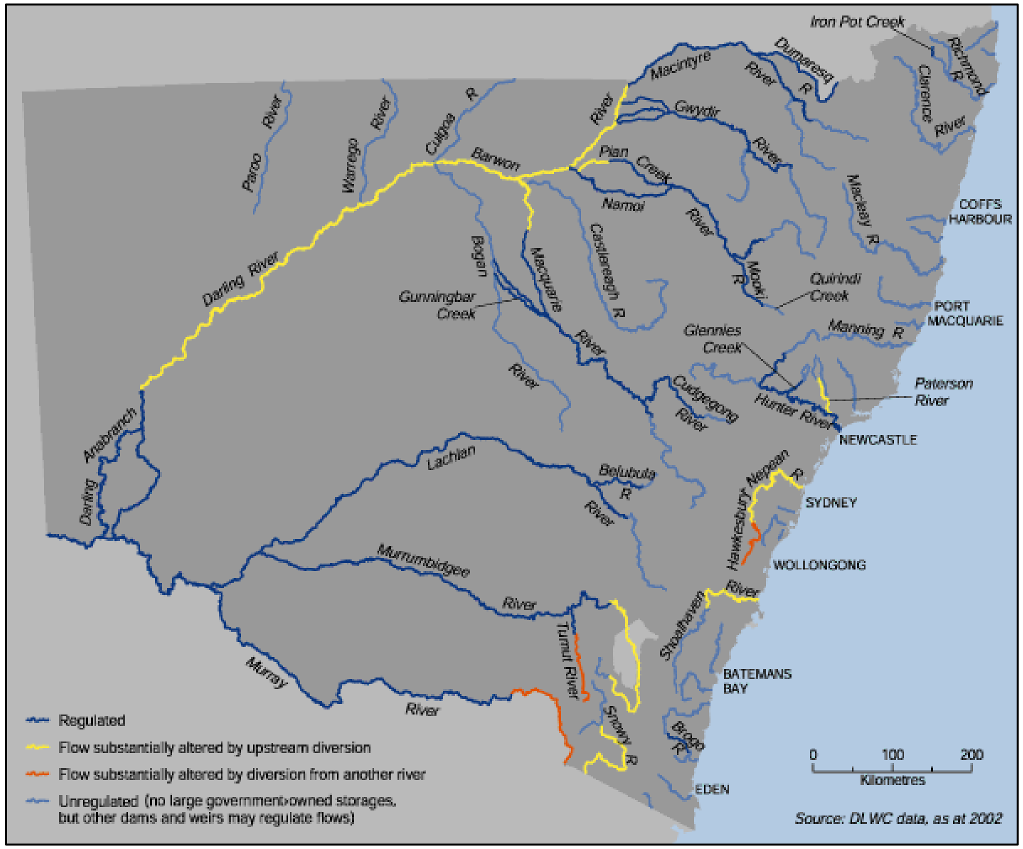

Figure A4. Map of Major NSW Rivers.[24]

Ground Water: Groundwater represents all the water that is present underground and can be accessed for use. In NSW, there are six major inland alluvial systems that account for approximately 94% of all metered groundwater use in NSW include the Gwydir alluvium (3%), Namoi alluvium (19%), Macquarie alluvium (7%), Lachlan alluvium (18%), Murrumbidgee alluvium (36%), and the Murray alluvium (11%).

Figure A5 maps out these reservoirs available in the state, and it can be observed that ground water is available across the state. However, the most productive reservoirs are noted to be in the north and across the eastern and southern part of the state. This would favour development of projects in the New England, Illawarra, Hunter and the Central West Orana REZs as well as some of those defined by AEMO (Tumut, Wagga Wagga, Cooma Monaro).

[24] Map 5.1: Regulated and unregulated sections of NSW rivers. NSW State of Environment 2003. NSW EPA. https://www.epa.nsw.gov.au/about-us/publications-and-reports/state-of-the-environment/state-of-the-environment-2003

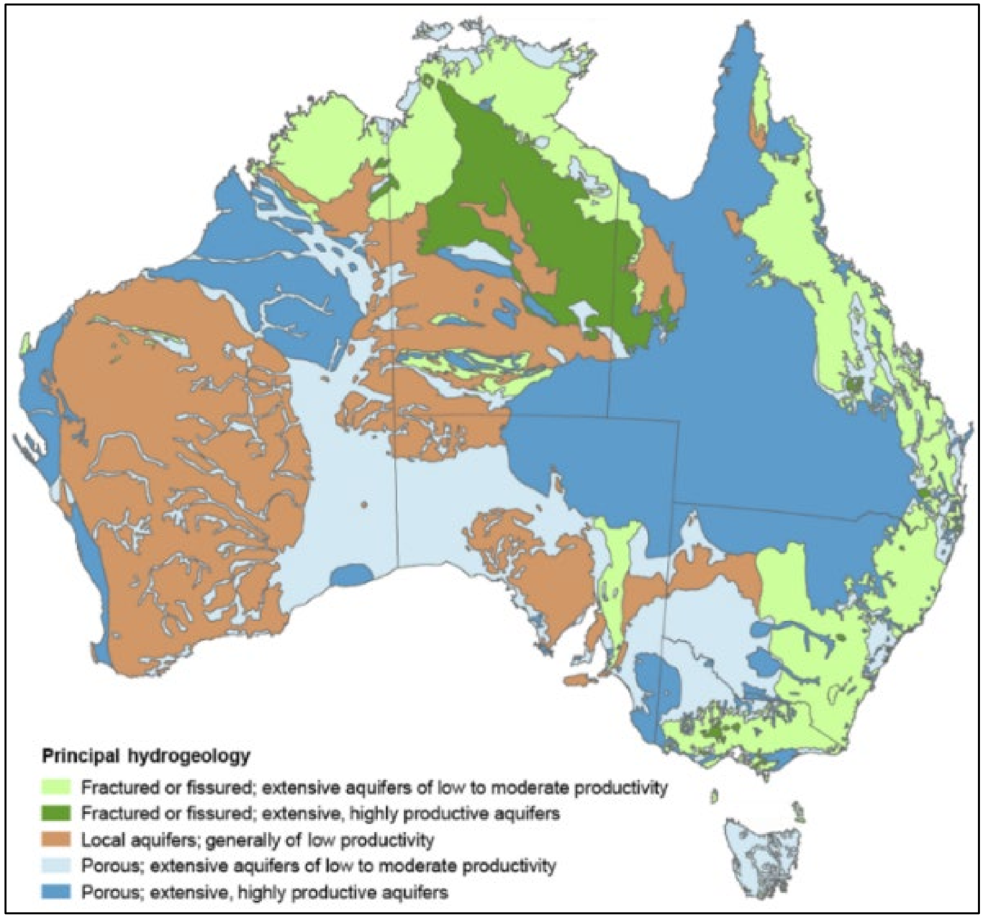

Figure A5. Map of Australia's groundwater reservoirs.[25] The image is a copyright of Geoscience Australia.

Statistics by NSW Department of Primary Industries estimate that ~1,700 GL/yr of water is available in the State's ground water reserves, of which 782 GL/yr is currently being extracted. This shows that roughly 900 GL/yr of water can be accessed for further demand, which could include electrolysis (i.e., roughly equivalent to 90 Mt of H_2/yr – given 10 L/kg of H_2). The breakdown of groundwater availability is shown in **Table A4.**

[25] A. Feitz *et al*. Prospective hydrogen production regions of Australia. Record 2019/15. Geoscience Australia. 2019. http://dx.doi.org/10.11636/Record.2019.015

Table A4. Available and current extraction volumes of groundwater in NSW in 2015/2016. [26, 27, 28, 29, 30, 31, 32, 33]

Groundwater	Regions	Water Available for Extraction (GL)	Annual Extraction (GL)
Gwydir Alluvium	New England/North West NSW Region (Moree Plains)	50	35
Upper Namoi Alluvium	New England/North West NSW Region (Narrabri)	210	80
Lower Namoi Alluvium		150	90
Upper Macquarie Alluvium*	Central West and Orana NSW (Macquarie-Castleragh Catchment Area)	32.5	22.5
Lower Macquarie Alluvium		95	45
Belubula Alluvium	Central West and Orana NSW Region	10.5	1
Upper Lachlan Alluvium	Central West and Riverina NSW Region	205	50
Lower Lachlan Alluvium	Central West and Far West NSW Region	160	90
Lake George Alluvium	Southern Tablelands NSW	1.2	0.6
Mid-Murrumbidgee Alluvium	Riverina Region	0.1	0.03
Lower Murrumbidgee Shallow Alluvium		10	3
Lower Murrumbidgee Deep Alluvium		500	270
Lower Murray Deep Alluvium	Western Riverina Region	125	80
Lower Murray Shallow Alluvium		85	2.5
Upper Murray Alluvium	Riverina Region (Albury-Wodonga)	58	10
Billabong Creek Alluvium	Eastern Riverina Region	10	2.5

[26] NSW State of Environment. Groundwater. https://www.soe.epa.nsw.gov.au/all-themes/water-and-marine/groundwater
[27] NSW Department of Industry. Gwydir Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0020/192323/Gwydir-alluvium-resource-description-report.pdf
[28] NSW Department of Industry. Namoi Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0017/230804/Namoi-Alluvium-WRP-resource-description.pdf
[29] NSW Department of Industry. Upper Macquarie Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0003/350175/upper-macquarie-alluvial-groundwater-source-summary-report.pdf
[30] NSW Department of Industry. Macquarie-Castlereagh Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0017/192221/macquarie-castlereagh-alluvium-appendix-a-water-resource-description.pdf
[31] NSW Department of Industry. Lachlan Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0010/175969/Lachlan-alluvium-appendice-a-water-resource-description.pdf
[32] NSW Department of Industry. Murrumbidgee Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0017/313127/appendix-a-murrumbidgee-alluvium-wrp-groundwater-resource-description.pdf
[33] NSW Department of Industry. Murray Resource Description. https://www.industry.nsw.gov.au/__data/assets/pdf_file/0004/230674/appendix-a-murray-alluvium-wrp-groundwater-resource-description.pdf

Recycled Water: Recycled water can be primarily recovered from discarded water from Wastewater Treatment Plants (WWTP) in NSW, most of which discharge water into rivers, and this effluent is usually of high quality. Currently, there are three levels of water treatment; (i) the primary level involves screening, (ii) secondary treatment involves the removal of organic matter and excess nutrients like phosphorous and nitrogen (lowering of Biological Oxygen Demand/BOCs and Chemical Oxygen Demand/CODs) and (iii) tertiary level involves the filtering, disinfection, and recycling processes for treated water.

Figure A6 maps out the location of NSW's wastewater treatment plant (WWTP) and most of them are in the Greater Sydney Region, with a few in Hunter, Illawarra and the Northern Inland region which can be leveraged due to their proximity to REZs.

Wastewater plants in and around Sydney region generate ~6,230 ML/day that are mostly dumped into rivers and streams, while an additional 121,600 ML/yr generated by plants outside the Sydney region (although most of these are used for recycling water for urban and irrigational use). All together, these add up to a maximum capacity of 2,395 GL/yr which if leveraged can support 2,395 Mt/yr of H_2 production. As elaborated earlier, the NSW H_2 strategy also suggests that ~30 Mt/yr of H_2 can be generated from existing wastewater resources in the REZs.

Desalinated Water: In terms of desalination in NSW, the Kurnell plant remains the sole desalination plant in the state (**Figure A6**) which operates to provide 250 million litres (ML) of drinking water per day in Sydney. The plant was built to provide long-term drinking water supply, independent of rainwater and dams as the state of NSW is vulnerable to drought. Recently, the planning of a desalination plant in Belmont for Hunter Water was approved in response to the drought in 2019-2020. The plant aims to provide up to 30 ML a day of drinking water to the Lower Hunter community.

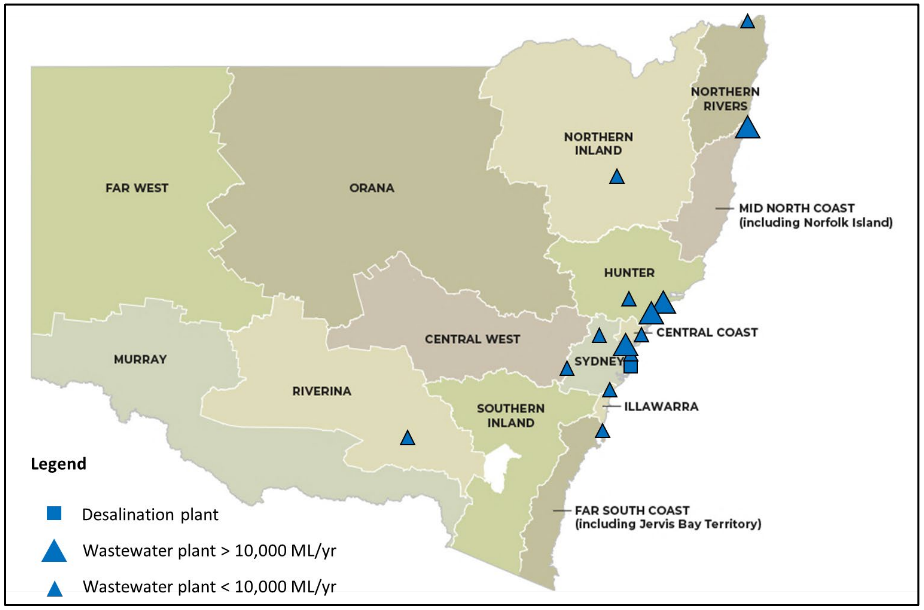

Figure A6. Map of active wastewater and desalination plants in NSW.

A2.3. Carbon Dioxide Sources

Carbon capture and utilisation combined with renewable hydrogen and further processing enables the generation of carbon neutral fuel substitutes including methanol, methane, and other synthetic equivalents to fossil derived fuels. Carbon dioxide is captured and repurposed in this way either from the atmosphere or from sources that would otherwise be released into the atmosphere, essentially offsetting the end-of-life emissions generated by the combustion or use of these carbonaceous power fuels (i.e., unavoidable sources of carbon). This emission offset represents significant emission reduction compared to the use of conventional fossil alternatives. Certification schemes to monitor the generation and use of green fuels is required to ensure legitimacy especially in regions where carbon taxes or credits apply.[34]

Note: The choice of CO_2 is an ongoing discussion that is subjective to policy and technology availability, herein we consider both waste emission (industrial and powerplant) and natural resources (Direct air capture and bioresources) to provide a technical and economic comparison of the potential technologies in the NSW context.

Industrial and Powerplant Emissions

Flue gas produced through combustion or processing of fossil fuels in power generation, transport, chemical, and manufacturing industries are a major source of carbon dioxide (CO_2) emissions. Since industrial flue gas (IFG) typically contains much higher concentrations of CO_2 compared to the atmosphere, combined with the potential for retrofitting of existing infrastructure, post combustion capture technologies are less capital and energy intensive compared to direct air capture technologies. Flue gas from industrial and power generation facilities 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.[35] While the emission reduction impact is the same for CCU from both renewable (direct air capture, biomass, etc.) and currently unavoidable non-renewable (industrial flue gas) sources, at present schemes being developed for this purpose distinguish between renewable and non-renewable capture sources for the designation of green and blue certifications. This may impact how potential carbon tax rates, and carbon credits are applied to the fuel produced.

Table A4 lists some potential CO_2 point sources identified in NSW along some key parameters. Power generation, steel and cement calcination sources are at scales compatible with GW scale P2X projects. Fuel-ethanol fermentation emissions are high purity and require minimal processing to capture, however this is typically sold as product CO_2 to the food and packaging industries.

[34] M. Altmann, C. Fischer and A. Sicheneder, Benchmark of international practices on low-carbon and green H2 certification mechanisms, 2020. https://energia.gob.cl/sites/default/files/documentos/green_hydrogen_certification_-_international_benchmark.pdf
[35] Dena & World Energy Council. Global Harmonization of Hydrogen Certification. (2022). https://www.weltenergierat.de/wp-content/uploads/2022/01/dena_WEC_Harmonisation-of-Hydrogen-Certification_digital_final.pdf

Table A5. List of potential CO2 emission sources suitable for carbon capture in NSW.

Source type/industry	Facility/Location	Approximate scope 1 (MTPA $CO_{2\text{-eq.}}$)	Composition (Volume % CO_2)	CO_2 classification [36]
Black coal fired power station	Bayswater	12.8	10-12%	Non-renewable
	Liddell	7.0	10-12%	Non-renewable
	Vales Point	6.4	10-12%	Non-renewable
	Mount Piper	7.1	10-12%	Non-renewable
	Eraring	12.7	10-12%	Non-renewable
Cement Calcination	Berrima	1.7	14 – 33%	Non-renewable
Steel Smelting	Port Kembla	5.0	22%	Non-renewable
Ammonia Synthesis (SMR)	Kooragang Island	0.54	19-19.5%	Non-renewable
Fuel Ethanol	Nowra	0.225	Near 100%	Renewable
Gas fired power station	Tallawarra	0.259	3-8%	Non-renewable
	Uranquinty	0.104	3-8%	Non-renewable
	Colongra	0.042	3-8%	Non-renewable
	Smithfield	0.019	3-8%	Non-renewable
Direct Air Capture	-	-	399 ppm	Renewable
Woody biomass combustion	-	-		Renewable
Biogas combustion	-	-	3-8%	Renewable

Note:

- **Scope 1 Emissions** are defined as direct process or onsite emissions.
- **Scope 2 Emissions** cover indirect emissions from the generation of purchased utilities where emissions are generated off site.
- **Scope 3 Emissions** include all other value chain related indirect emissions.
- Renewable and non-renewable refer to the long-term sustainability of the point sources. Power plant and Industrial plants are classified as non-renewable because of the expectation that fossil fuel processes will be abated or shut down as part of the State's decarbonisation activities.

[36] International Renewable Energy Agency (IRENA). Innovation Outlook: Renewable Methanol. (2021).

Biomass Resources

Biomass can also be used as a renewable source for CO_2. **Figure A7** maps out the biomass availability in NSW. These key resources can potentially include bagasse (sugarcane residue), crop residue, grass, wood, and domestic sewage/urban waste.[7] Additionally, biomass combustion for power generation represents an opportunity for 'renewable' post combustion capture and utilization of CO_2 for the generation of carbonaceous powerfuels.

The potential for biomass and bioenergy in NSW has been by the NSW Department of Primary Industries.[37] The state is blessed with large resources of agricultural and forestry areas and generates waste resources that can be leveraged for bioenergy uses. This includes the ABBA project (Australian Biomass for Bioenergy Assessment) which involved the collection and mapping of geospatial data including location, volume, and availability of various biomass sources across all Australian states.[38] Key biomass sources mapped for NSW include residues from cropping, forestry, horticulture, and livestock, as well as organic waste. Data for these biomass sources has been incorporated into the National map.[39] Moreover, the NSW State sponsored "Biomass for Bioenergy project" under the 'Primary Industries Climate Change Research Strategy' is investigating the potential to utilize sustainable biomass and bioenergy for electricity generation across NSW, including a series of trials, technoeconomic assessment, and raising public awareness.[40]

As an alternate process, direct use of biomass to biofuels or to produce syngas via gasification for subsequent conversion additional green chemicals and other synthetic fuels can be utilised, however, this comparison is beyond the scope of this work.

Atmospheric Carbon Dioxide

Atmospheric carbon dioxide is a virtually limitless and renewable source of CO_2 which can be captured using direct air capture technologies. However, these technologies are currently capital and energy intensive since CO_2 is found in very low concentrations in the atmosphere (around 400ppm).[41]

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[37] https://www.dpi.nsw.gov.au/dpi/climate/energy/clean-energy/bioenergy
[38] Australian Government. Australian Biomass for Bioenergy Assessment Project. Aust. Renew. Energy Agency (2020). https://arena.gov.au/knowledge-bank/australian-biomass-for-bioenergy-assessment-final-report/#main
[39] Australian Government, CSIRO, Data61. National Map. Available at https://nationalmap.gov.au/
[40] https://www.dpi.nsw.gov.au/forestry/science/forest-carbon/biomass-for-bioenergy
[41] X., Wang, X. and, C., Song, Carbon Capture From Flue Gas and the Atmosphere: A Perspective. Front. Energy Res. 8, (2020).

Figure A7. Map of NSW's biomass generation potential. This data is adopted from the Australian Biomass for Bioenergy Assessment (ABBA) Final Report by ARENA.[38]

A3. 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 hubs.

A3.1. Electricity Transmission Network

Availability of local electricity transmission network is needed to support leveraging of renewable energy from areas like REZs to locations where large scale powerplants cannot be built on site as elaborated in the main report. To account for this in our analysis, we consider new specially built transmission networks as they have significant advantages as outlined below:

Powerplant and P2X Facility Integration Opportunities in NSW

There are several electricity supply configurations that can be developed to support electrolysis, below the advantage and disadvantages of each are elaborated below:

Onsite Standalone Power Supply: The most common approach is to develop dedicated solar/wind powerplants in conjunction with the electrolyser/P2X facility. The key advantage is that given the electrolyser serves as the primary load of the power plant, the capacities of the power plant can be oversized with respect to the electrolyser to optimise and enable high capacity factor operations of the electrolyser which has been demonstrated to provide better economics for hydrogen generation (albeit at the cost of needing the power plant to be curtailed which can lead to excess electricity that could otherwise be sold to other users if the power plant was connected to the grid).

Moreover, this approach to standalone electricity supply also provides additional advantage that the integration of the electricity supply is more straightforward compared to a connection with a shared transmission network (especially the State's electricity grid that is part of the Australian National Energy Market – NEM) which entails issues such as grid usage charges (NSW's Hydrogen Strategy aims to reduce these charges for electrolysers but this is expected to take shape over the next decade), varying electricity pricing and other supply issues (including competition with other users, breakdown of network and congestion of network). However, such a standalone approach ties the electrolyser operation with the intermittent nature of local solar/wind resources resulting in variable hydrogen production which can produce a negative cascading effect downstream of electrolyser especially if the hydrogen is used for steady state operations like ammonia generation which are more suited to steady state operations.

Potential use of buffer hydrogen storage or use other electricity supply firming options like batteries or backup generators can address these challenges but these systems are costly to build and complex to operate (elaborated in later chapters of the report).

Offsite Transmission Line Connected Power Supply: An alternate option is to develop the power plant offsite potentially in regions with better renewable energy potential or offshore to leverage higher solar/wind energy potential. This option could be a potential pathway for project development in NSW, given the potential end user (emerging hydrogen hubs and committed projects) are being developed in regions with generally lower solar/wind potential or densely populated regions where large scale solar/wind farms cannot be built in conjunction to the P2X facility. Here, dedicated transmission lines can be developed to connect with solar/wind farms developed in regions with high renewable energy potential and land capacity (e.g., REZs) to the P2X facility built close to the end users.

Nevertheless, building a dedicated transmission line is costly, the AEMO Transmission Cost Estimation Tool suggests that at present an overhead HVAC line-based transmission network would cost between A$834,000/km to A$2,655,000/km to build depending on the network capacity, while the underground line (including subsea) based network would cost between A$1 million/km to A$44 million/km depending on the type of underground infrastructure required. There are also other issues including approvals, securing land rights to develop equipment and transmission lines, etc. We assume that the costs and risks can be mitigated if there is a shared network but establishing shared transmission lines is also complex such as securing partners to share the network including its costs and risks as well as managing the subsequent supply on the network and its end use (which are highlighted in the behind the meter supply). Yet these approaches could be possible, the upcoming REZ development in NSW is expected to unlock new renewable energy capacities and transmission networks which will connect to high demand and industrial zones (elaborated in Appendix A) where future P2X facilities are expected to be built. Herein, we consider this case to provide a case study of this option. Yet in practice the above complications would have to be acknowledged.

Behind the Meter Power Supply: The alternate approach is to put the electrolyser facility behind the meter and connect it to an existing grid. TransGrid, which is the major operator of NSW's existing grid has developed 119 substations and 13,204 km of high-voltage transmission lines that connect the regions within the state and the greater National Electricity Market (NEM).[42] This grid connects most of the major demand areas of the central, eastern, and southern parts of the state plus the Broken Hill region.

A key advantage of this approach is that by connecting to grid, especially the NEM in the case of NSW, ensures a constant and reliable supply of energy to operate the electrolysers at high-capacity factors given a wide range and number of power plants are always actively supplying power onto the grid. However, the use of the grid network has limitations and challenges, some of which are elaborated above, especially for the NEM which is predominantly supported via fossil fuel supply and highly competitive would expose electrolyser users to variable spot pricing (in 2021, the NSW grid recorded over 500 intervals with over A$300/MWh[43]) and hydrogen certification concerns due to fossil fuel-based electricity supply. While the effect of spot pricing and environmental concerns can be addressed by negotiating Power Purchase Agreements (PPAs) with renewable energy providers connected to the grid that ensure fixed volume and cost long term contracts, the constraints on the transmission network remain. Particularly the issue of network congestion and at present, no compensation is payable to generators constrained down due to transmission constraints which may be primarily driven by the behaviour of other generators. Scheduling the electrolyser operation can mitigate these issues but again this will affect integration with steady state downstream operations as highlighted above. However, electrolysers could also offer firming services to the grid, by serving as flexible load to offtake surplus energy that must be curtailed or congesting the network, but this is beyond the scope of the analysis.

Existing Transmission Network

The electricity network in NSW will play a vital role in the energy transition to enable the connection of new generation capacity from the renewable energy zones and deliver the clean power to the load centres. NSW is part of the National Electricity Market (NEM) and the 119 substations, 13,204 km of high voltage (HV) transmission lines, underground cables and interconnectors between QLD and VIC are owned and operated by TransGrid.[44] The existing HV transmission network comprises four different voltages as depicted in the network map (**Figure A8**) along with two interconnectors between NSW and QLD and three between NSW and VIC. The available capacity on the electricity network is limited and has become a major constraint for new power generation

[42] Transgrid (2021). New South Wales Transmission Annual Planning Report. https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf
[43] State of Energy Market 2022. Australian Energy Regulator. 2022. https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2022
[44] Transgrid (2021). New South Wales Transmission Annual Planning Report. https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf

assets to be added. Significant investment in the transmission network is required to facilitate the connection of renewable power generating assets and to decongest the system. The requirements for a reliable, affordable, and sustainable electricity future are set out in the 2019 NSW Electricity Strategy.[45]

The connection of new renewable power generators is required in what TransGrid considers as weaker parts of the transmission system. It is within these parts that upgrades and expansion to the transmission network is required. In the 2021 TransGrid Annual Planning Report[44], major developments are highlighted that fall in line with AEMO's ISP 2020 and the NSW Electricity Infrastructure Roadmap[46] and these are summarized in **Table A5.**

Beyond TransGrid's HV transmission network, there are three electricity distribution companies serving different geographic regions across New South Wales to deliver power to homes, hospitals, schools, and businesses. These companies are Endeavour Energy, Essential Energy and Ausgrid. Each distributor manages their own sub network.

Table A6. TransGrid proposed major transmission developments for New South Wales.

Status	Description	Transmission Capacity
Committed	Expand QLD to NSW transfer capacity (QNI Upgrade)	190 MW
	VIC to NSW interconnector upgrade (VNI Upgrade)	170 MW
Regulatory Consultation Completed	New interconnector between NSW and SA (EnergyConnect)	800 MW
Under Regulatory Consultation	Reinforcement of Southern NSW network (HumeLink)	2,570 MW
	VIC to NSW interconnector West (VNI West)	1,800 MW
	Improving stability in South-West NSW	600 MW
Planned Projects	Central-West Orana REZ	3,000 MW
	Medium/large Queensland to New South Wales Interconnector (QNI Medium/Large)	2,130 MW
	New England REZ	5,000 to 6,000 MW
	Reinforcement to Sydney/Newcastle/Wollongong load centers	5,000 to 6,000 MW
	North West Renewable Energy Zone	4,000 MW

Upcoming Network Development

Moreover, as the state's electricity network develops and more REZs come online additional transmission capacity will become available that can be leveraged. The NSW government already has set targets to enable hydrogen projects to be able to leverage these opportunities by reducing transmission charges as part of the Hydrogen Strategy.

[45] NSW Government (2019). NSW Electricity Strategy. https://www.energy.nsw.gov.au/sites/default/files/2019-11/NSW%20Electricity%20Strategy%20-%20Final%20detailed%20strategy_0.pdf
[46] NSW Government. Electricity Infrastructure Roadmap. https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap

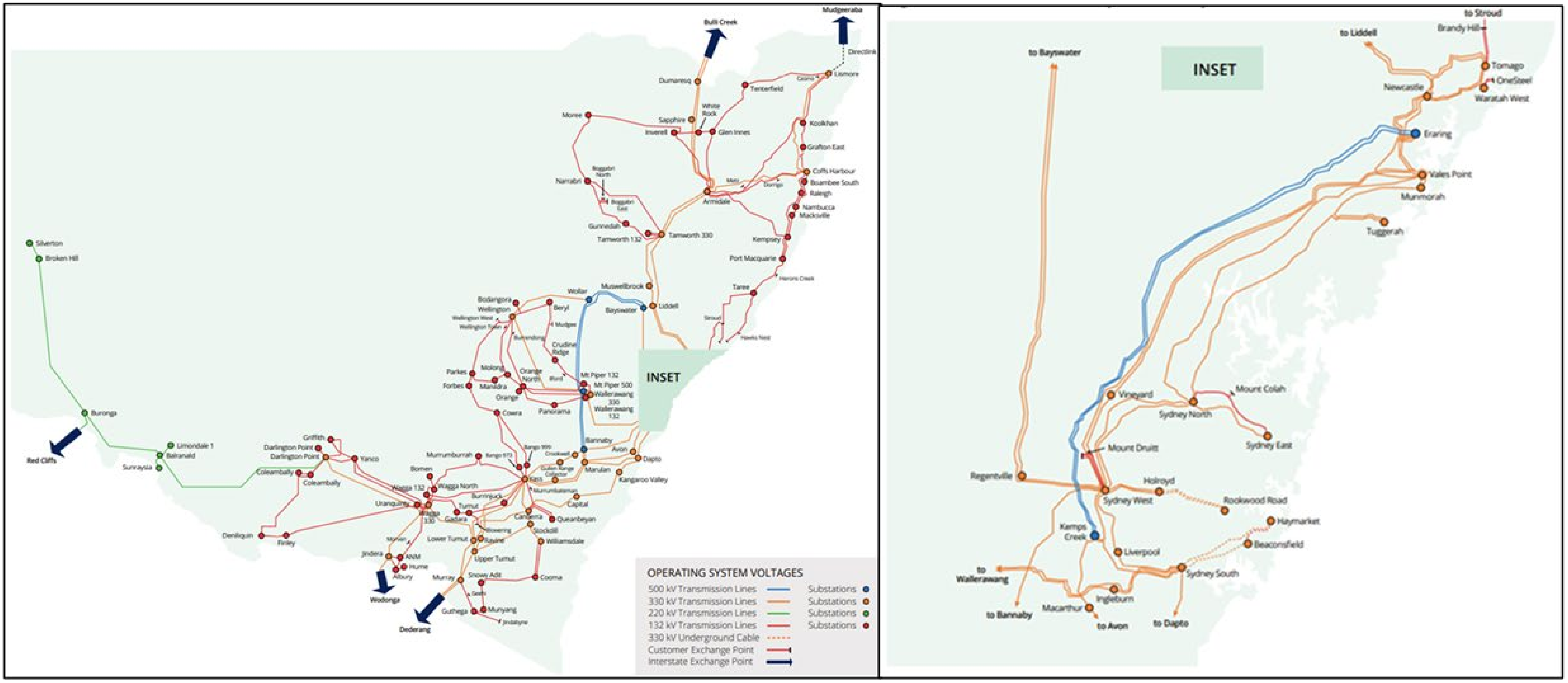

Figure A8. TransGrid transmission network map across NSW with detailed view of Sydney and Central Coast region. Image courtesy of TransGrid.

A3.2. Natural Gas Network

Natural gas pipelines have been suggested as a potential means for hydrogen blending, storage, and transport. NSW currently has a 2,650 km of major pipelines with ~1,050 TJ/day capacity. These are currently all occupied for natural gas transport, with NSW importing most of its natural gas from its neighbours (Victoria, South Australia and Queensland) as the local natural gas reserves depletes. However, recent analysis by AEMO suggests that NSW can face a natural gas shortage within the next few years unless alternative resources are integrated into the supply.[47] Hydrogen can potentially fill this energy gap , depending on the network's ability to offtake hydrogen and natural gas blends..

The major gas pipelines serving NSW are shown in **Figure A9**. The capacity of these pipelines is shown in **Table A7**.

Table A7. Capacity of major NSW Gas Pipelines.

Pipeline	Length (km)	Capacity (TJ/day)	Ownership	Regional Connections	Ref
Moomba to Sydney Pipeline	1,300	Upto 446	APA Group	Connects : — Moomba in South Australia to the ACT and Greater Sydney Metropolitan Area — The split between ACT and Sydney occurs via Golburn — In between the pipeline passes through the Far West Region and Central West and Orana Region.	48
Central Ranges Pipeline	294	13	APA Group	Connects: — Dubbo in the Central West and Orana region to Tamworth in New England Region. — Then connects to MSP via Central West Pipeline	49
Central West Pipeline	255	13	APA Group	Connects : — MSP via Marsden in the Central West and Orana region. — Terminates in Dubbo (Central West and Orana Region)	50
Eastern Gas Pipeline	797	350	Jemena Group	Connects: — the Greater Sydney Metropolitan Area — Illawarra & Shoalhaven Region (Wollongong to Norwa) — Tablelands (Comma) to Victoria	51
Vic – NSW Interconnect		223	Jemena Group	Connects: — The Riverina Murray Region to MSP	52

[47] South-east Australia risks temporary gas shortages by 2023 winter, energy review warns. Hannam. 2022. https://www.theguardian.com/australia-news/2022/mar/29/south-east-australia-risks-temporary-gas-shortages-by-2023-winter-energy-review-warns
[48] Moomba to Sydney Pipeline. APA. https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/moomba-sydney-pipeline/
[49] Central Ranges Pipeline. APA. https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/central-ranges-pipeline/
[50] Central West Pipeline. APA. https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/central-west-pipeline/
[51] Eastern Gas Pipeline. Jemena Group. https://jemena.com.au/pipelines/eastern-gas-pipeline
[52] State of Energy Market Report 2021. Australian Energy Regulator. 2021. https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2021

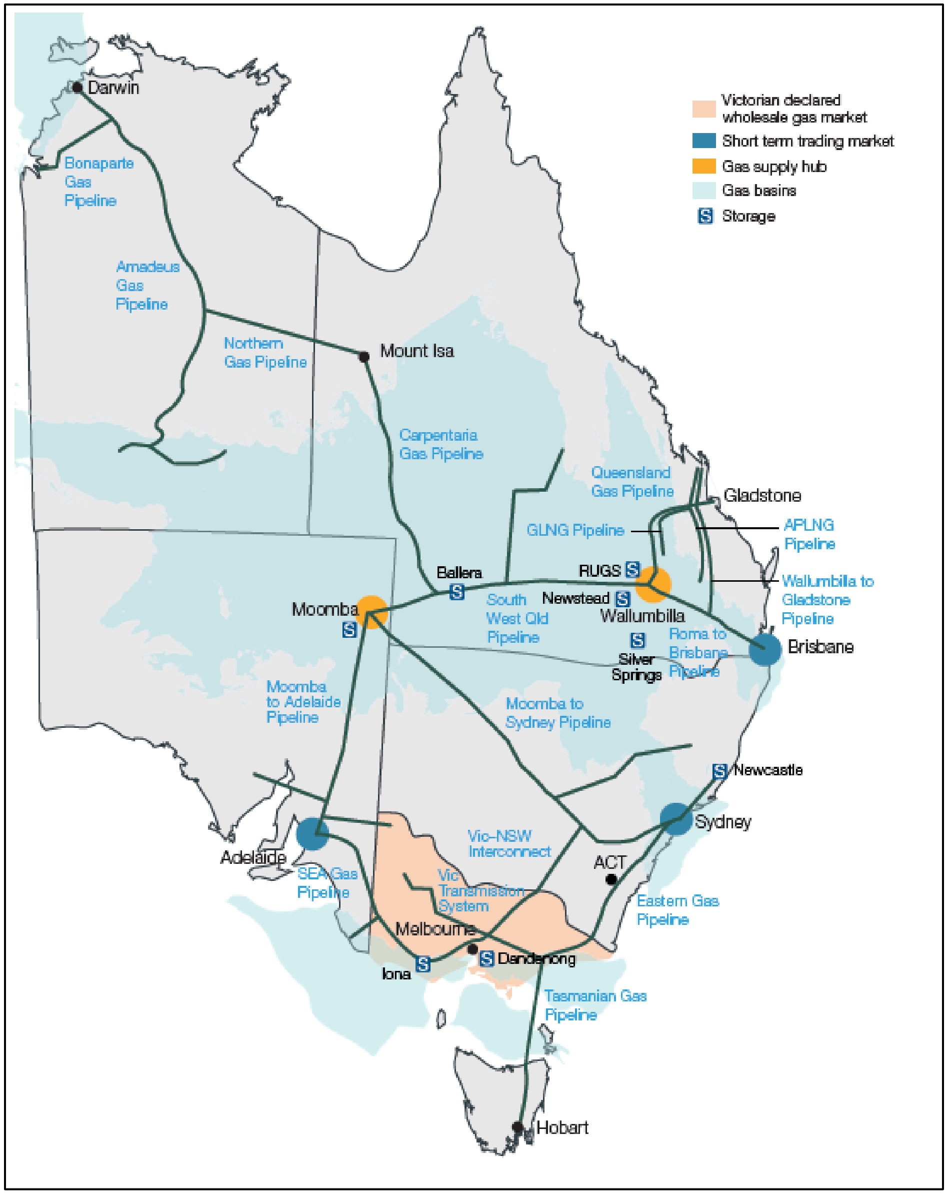

Figure A9. Map of the Eastern Gas Market.[53]

A3.3. Transport Infrastructure

The transport infrastructure (road network, rail network, airports, and ports) would also play a vital role in the development of a P2X economy in NSW. NSW has an extensive road and railway network with 185,000 km of roads[8] and 9,400 km of railway tracks.[9] A combined 478 megatonnes (MT) were freighted in NSW using road and rail in between 2020-21.[54]

Details of the road and railway network are available in the regional breakdown sections below. The existing rail network connects major industrial hubs, Renewable Energy Zones, Regional Centres, and the ports of NSW, therefore can act as a backbone for the NSW P2X industry. The rail network is further complemented by the road network which expands further into the regional areas. The Hume, Newell and Princess highway provide key logistic and freight routes within NSW and act as a connection between Victoria and Queensland. These are also expected to become Australia's hydrogen highways with the NSW, Victoria, and Queensland state government committing to collaborate to develop a renewable hydrogen refuelling network along the eastern coast.[55]

Road Network

The map of the major highways in the NSW is shown in **Figure A10.**

The major highways include:

— **The Far West Region Highways**: The Far West region has 4 major highways these include the:

(i) **Barrier Highway:** that connects South Australia to NSW via Broken Hill to Nyngan in the Central West and Orana region

(ii) **Silver City Highway:** that connects Mildura to Broken Hill and continues north into Queensland via Tibooburra in the very far northwest of the state

(iii) **Cobbs Highway**: that connects Wilcannia and Ivanhoe in the Far West Region to Hay and Deniliquin in the Riverina Murray Region

(iv) **Sturt Highway**: a section of the Sturt Highway passes through the region connecting South Australia to Mildura (Far West Region) to Wagga Wagga via Hay (in the Riverina Murray Region)

— **Riverina Murray Region Highways:** The Riverina Murray Region has 3 major highways these include the:

(i) **Sturt Highway:** that connects South Australia to Riverina Murray Region (Wagga Wagga and Hay) via Mildura in the Far West Region.

(ii) **Hume Highway:** that connects Victoria to NSW via Riverina Murray Region (Albury, Wagga Wagga) to Goulburn (Southeast and Tablelands Region) and the Greater Sydney Metropolitan Area).

(iii) **Newell Highway:** that connects Victoria to NSW and Queensland, by entering NSW in Finley (Riverina Murray Region), connecting to Parkes and Dubbo in the Central West and Orana region before passing through Narrabri and Moree in the North West and New England region into Queensland.

[54] Strategic Freight Forecasts – Commodity Forecast Map. 2022. https://www.transport.nsw.gov.au/data-and-research/freight-data-19/strategic-freight-forecasts/strategic-freight-forecasts-commodity
[55] Hydrogen Highways to link Australia's East Coast. NSW Government. Media Release. 2022. https://www.environment.nsw.gov.au/news/hydrogen-highways-to-link-australias-east-coast

Figure A10. Map of the NSW Road Network. [56]

— **Central West and Orana Region:** The Central West and Orana Region has 3 major highways these include the:

(i) **Newell Highway:** part of the Newell Highway that connects Victoria to NSW and Queensland, regionally it passes through Forbes, Parkes, and Dubbo, before entering the Northwest and New England region and passing into Queensland.

(ii) **Mitchell Highway:** that connects with the Barrier Highway at Nyngan and then passes through Warren, Dubbo to Bathurst.

[56] https://www.atn.com.au/nsw/nsw-roadmap.html

(iii) **Mid Western Highway:** that connects Hay in the Riverina Murray Region to Cora and Bathurst in the Central West and Orana region before connecting with the Greater Sydney Metropolitan Area.

— **North West and New England Region:** The North West and New England Region has 3 major highways these include

(iv) **New England Highway:** that connects Newcastle in the Hunter region to the regional centres of Tamworth, Armidale and Glenn Innes in the New England region before passing into Queensland. There are also connection to Lismore in the North Coast region.

(v) **Gwydir Highway:** that connects Walgett and Bourke in the Far West Region to Moree and Glen Innes in the New England region and Grafton in the North Coast region.

(vi) **Newell Highway:** part of the Newell highway passes through the region and connects Dubbo in the Central West and Orana region to Narrabri and Moree in New England before proceeding into Queensland.

— **Coastal Highways:** The Great Pacific Highway that travels around the coastal areas of Victoria, New South Wales and Queensland connects the Southern Tablelands Region (Batemans Bay and Narroma) to the Illawarra Shoalhaven Region (Nowra, Kiama and Wollongong), the Greater Sydney Metropolitan Area, the Central Coast Region (Gosford), Hunter region (Newcastle and Port Macquarie) and the North Coast Region (Coffs Harbor) before entering Queensland.

There are some branched connections to:

(i) **New England:** Port Macquarie in the Hunter Region is connected to Tamworth (North West and New England Region) via the Oxley Highway that ends near Nyngan (Central West and Orana region). Newcastle in the Hunter region is also connected to Muswellbrook and the New England region via the New England Highway.

(ii) **Central West and Orana Region:** the Greater Sydney Metropolitan Area is connected to Bathurst and Dubbo and Nyngan in the Central West Orana region via the Mitchell Highway that connects to the Barrier Highway at Nyngan that further connects to Cobar, Wilcannia and Broken Hill in the Far West region before entering South Australia.

(iii) **Riverina Murray Region:** Wollongong in the Illawarra and Shoalhaven region connects to Wagga Wagga and Albury in the Riverina Murray Region before proceeding into Victoria.

Note: Of these highways the critical highways are the Newell, Sturt, Hume, Barrier, and Great Pacific Highways are critical freight routes. Moreover, Hume, Pacific and Newell Highway are being considered as potential routes to host the Eastern Coast Hydrogen Highway by the NSW, Queensland, and Victoria Government.[57]

Railway Network

The railway network interconnecting the Greater Sydney Metropolitan Area and the Regional NSW is shown in **Figure A11**. The railway network is based on the following lines:

[57] https://www.environment.nsw.gov.au/news/hydrogen-highways-to-link-australias-east-coast

- **The Greater Sydney Metropolitan Area Lines**: These include the suburban railway connections for general commuters, the Sydney area is also connected to the Main North Line, Main West Line, the Main South Line and the Illawarra Line - which are freight capable.
- **North Coast Line:** This line connects the regional centres on the North Coast with Hunter region (Newcastle) and connects to Queensland. The line is freight capable.
- **Main North Line:** This line connects the Greater Sydney Metropolitan Area with Hunter region (Newcastle) and connects to the main regional centres of New England Region (Muswellbrook and Armidale)
- **Main West Line:** This line connects the Greater Sydney Metropolitan Area with the regional centres in the Central West & Orana Region (Orange, Dubbo and Nyngan)
- **Broken Line:** This line connects the Greater Sydney Metropolitan Area with the Far West region (Broken Hill) via Orange and Parkes in the Central West & Orana region.
- **Main South Line:** This line connects the Greater Sydney Metropolitan Area with the Riverina Murray Region (Albury via Junee and Goulburn)
- **Illawarra Line:** This line connects the Greater Sydney Metropolitan Area with the Illawarra and Shoalhaven Region (Wollongong and Nowra)

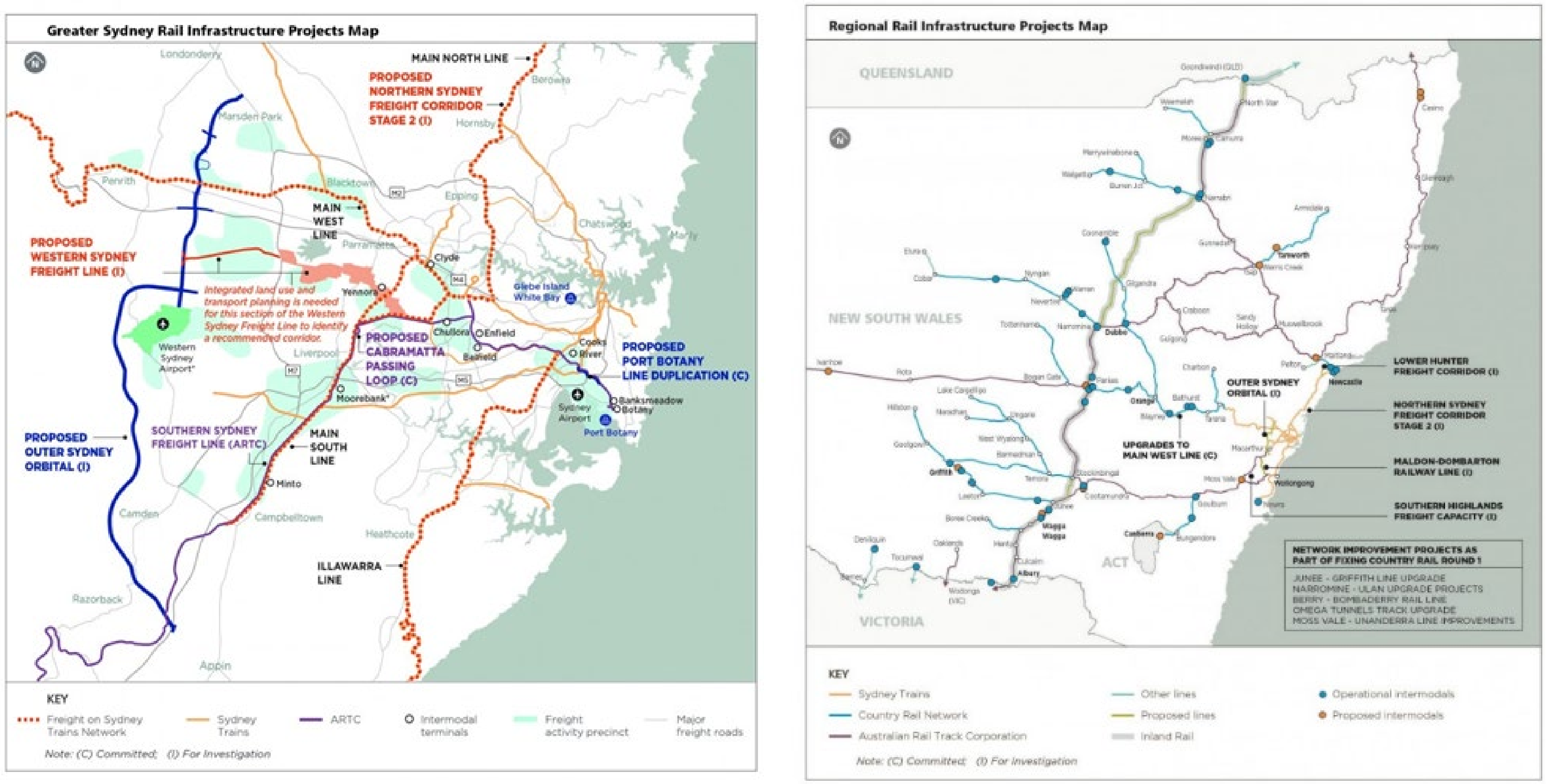

Figure A11. Map of the NSW Railway Network. [58]

NSW Airports

The road and rail network are also complemented with the availability of airports and airfields. There are around 38 airports in NSW. Off these, the largest is the Kingsford Smith Airport, Sydney, which is the only international airport in NSW, an additional airport being constructed in Western Sydney which will also serve as an international airport. Other regional centres like Newcastle, Broken Hill, Dubbo, Armidale, Wagga Wagga etc. also have small to medium

[58] NSW rail network. Transport NSW. Accessed on 10th July 2022. https://www.transport.nsw.gov.au/operations/logistics-network/nsw-rail-network

scale airports. While there are airfields available across the regional areas. In addition, the Royal Australian Air Force (RAAF) has airbases in Wagga Wagga, Newcastle, and Sydney.

These can support transport of equipment and personnel for P2X projects. As well as serve as local demand centres for SAF. Sydney Kingsford Airport has already committed to becoming net zero by 2030, the critical part of their strategy would see a shift towards 100% renewables and use of SAF.[59] The airport has already acquired infrastructure to support SAF use.[59] SAF could also be used as part of the new Western Sydney Airport which is expected to be linked to the Port Botany Area via pipelines. Therefore, SAF facility could be developed in Port Botany or Kurnell to supply both the new and existing airport (Kingsford Smith). Moreover, Newcastle Airport is expected to undergo expansion to facilitate additional international operations, and SAF can be developed as a potential onsite fuel supply. SAF development can also assist the decarbonisation of operation at the Canberra Airport.

Similarly, SAF facilities could be developed to establish local fuel supply in remote locations that have airfields like the mining operations in Broken Hill and Cobar or Lord Howe Island.

NSW Ports

The NSW Ports are also expected to play a vital role in development of a P2X export market. Most of these ports are already involved in import/export of fuels and ammonia. A preliminary study as part of the development of Australian National Hydrogen Strategy suggests that the ports of Kembla, Port Botany & Newcastle can be redeveloped to host hydrogen and P2X product export facilities.[60] Furthermore, with the development of ammonia and methanol as alternative shipping fuels[61], the key ports in NSW can potentially become bunkering locations for low carbon marine fuels. The suitability of these ports to host export facilities are provided in main report – **Chapter 11**

[59] Sydney Airport (2021). Sydney Airport commits to net zero by 2030. https://www.sydneyairport.com.au/corporate/media/corporate-newsroom/sydney-airport-commits-to-net-zero-by-2030
[60] Australian Hydrogen Hubs Study. ARUP. 2019. https://www.industry.gov.au/sites/default/files/2021-09/nhs-australian-hydrogen-hubs-study-report-2019.pdf
[61] DNV (2021). Maritime Forecast to 2050. https://eto.dnv.com/2021/about-energy-transition-outlook

Appendix B:

Technoeconomic

Methodology

B. Technoeconomic Modelling Methodology

B1. Scope of Work

The scope of the technoeconomic analysis (TEA), conducted as part of this report, spreads across the complete Power to X Value chain to provide the delivered cost of products to potential end users. In this regard, the value chain analysis is broken into the following steps:

1. **Renewable Energy Supply Modelling:** In terms of the renewable energy, the critical factors are the local renewable energy generation potential, i.e., the MWh/year generatable at the site, which ultimately dictates the scale of P2X project that can be established (the higher the potential, the greater the energy available to drive the P2X facility resulting in better costs – higher yields and economies of scale).

   Renewable Energy Generation Data: For our analysis, we consider solar and wind as the renewable energy sources, and to provide a quantitative assessment of the solar and wind energy generation potential of NSW, we establish the capacity factors and duration curves of the local solar and wind resources. The capacity factors then provide the MWh/year generation potential, while the duration curves provide the distribution of the generation potential as a function of the intermittent nature of the local solar/wind potential. To establish these capacity factors and duration curves, we use the solar and wind power generation data of the zones considered across NSW (**Figure 21** of the main report) which were extracted using Renewables Ninja – an open-source database that provides solar and wind generation data of location based on the solar irradiation and wind speed data.

2. **P2X Facility Simulation and Costing:** The next step of the TEA analysis is to establish the cost of product generation – farmgate cost that was determined using open-source tools developed by UNSW as elaborated below.

   Costing Tool: For establishing the economics of each P2X pathways, a set of modelling tools including US DoE Tool for Hydrogen Refuelling Network[62] and in house tools developed at UNSW GlobH2E for technoeconomic analysis of the hydrogen, gas blending, ammonia, methanol, SAF, methane and their export were used.

   Note: As mentioned in the main report, the NSW Powerfuel tool is currently being designed as a web-based package that will enable users to cost and design these pathways as per their own inputs, this resource will be made public in conjunction with the report and the pathways will be made available in phases. The tool would rely on pre-loaded solar/wind traces across NSW and provides the user a design template to define the scope of the project and input the technoeconomic parameters. Using these inputs, the tool then simulates the proposed P2X facility to establish the mass and energy balances (operating costs – like water/electricity consumption and other feedstocks e.g., nitrogen for ammonia and carbon dioxide required for methanol generation etc. and capital recovery costs – product generated) and infrastructural requirements i.e., electrolyser, powerplant and balancing requirements to counter the renewable intermittency via hydrogen storage/batteries (to establishing capital cost and operating costs like maintenance etc.).

   Farmgate Cost of P2X Products: These tools (including those mentioned above and the NSW PowerFuel tool) establish the farmgate price of the P2X product (levelised cost of product – A$/kg based on the framework shown in **Figure 20** of the main report). For the analysis as part of this report, these

[62] https://www.hydrogen.energy.gov/h2a_delivery.html

farmgate costs were based on current and future technoeconomic expectations as per literature resources and stakeholder engagements carried out by the authors. These assumptions are summarized in **Section B4.**

3. **Delivered Cost of P2X Products:** In extension of the farmgate of the P2X products, we also provide the current and future outlook of the delivered cost of P2X as part of the analysis. To achieve this the additional cost of storage and distribution costs were added onto the farmgate costs.

   Storage Cost:

   The cost of storage was also determined as a levelised cost of storage (as a A$/kg stored) by levelising the net present value of the capital cost requirement of the storage infrastructure and its lifetime operating costs against the net present value of the lifetime P2X stored.

   Distribution Cost:

   While the cost of distribution was established as A$/ton.km, which was determined by levelising the capital cost requirement of the distribution infrastructure and its lifetime operating costs (A$) against the net present value of the lifetime P2X product delivered (ton) and the range of the distribution vector (km). The quantity of product delivered, and range of distribution vary from vector to vector, e.g., the cost of transporting hydrogen will vary based on if it is transported as a gas or liquid, as the medium dictates the infrastructure requirement and the amount of product that can be transported safely per trip (depending on the delivery capacity of the transport medium and range e.g., commercial hydrogen tube trailers have a capacity of 1 – 10 tpd and a range of 1 – 1,000 km per trip).

   For the analysis in this report, the storage and distribution costs were based on current and future technoeconomic expectations as per literature resources and stakeholder engagements. These assumptions are summarized in **Section B5**.

   Delivered Cost:

   The delivered cost of the P2X products were then established by aggregating the levelised cost of production (A$/kg of product produced) with the storage costs (A$/kg of product stored that will vary based on medium of storage that in turn dictates the infrastructural requirement and storage scale/durations) and the distribution costs (A$/kg of product delivered also varies based on the mode of distribution that subsequently dictates the infrastructural requirement, distribution scales and range of distribution). These delivered costs are then represented in the report as a distribution cost vectors as a function of distance from the production site. For example, **Figure B1** (shown below) represents the distribution cost vector of hydrogen distributed out of the proposed facility in Broken Hill and Wagga Wagga as gaseous hydrogen (GH_2) using a gas tube trailers and pipelines and as liquified hydrogen (LH_2) using as liquid tube trailer.

LCOH (A$/kg)	Broken Hill					
Mode of Transport	GH_2 Pipeline		GH_2 Road		LH_2 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	GH_2 Pipeline		GH_2 Road		LH_2 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	-	-	-	-

Figure B1. Example of Distribution Cost Vectors. These vectors were used in the study to illustrate the delivery cost of P2X products using different distribution mediums as a function of distance from generation site.

B2. Renewable Energy Supply Modelling

To provide a qualitative as well as quantitative assessment of the solar and wind energy generation potential of NSW, we evaluate the capacity factors and duration curves of the local solar and wind resources. To conduct a capacity factor comparison, we considered the zonal breakdown suggested in the main report (**Figure 20**) and further distributed them into 50 locations as shown in **Figure B2**; which include the onshore/offshore REZs defined by NSW Government and AEMO ISP 2022 as highlighted above as well as additional 31 prospective onshore regions and 8 regions for offshore wind development across NSW.

The solar and wind traces for these regions were adopted using renewables ninja database, the methods for extracting and processing the traces into capacity factors and simulation of P2X facilities are provided in our other publication.[63]

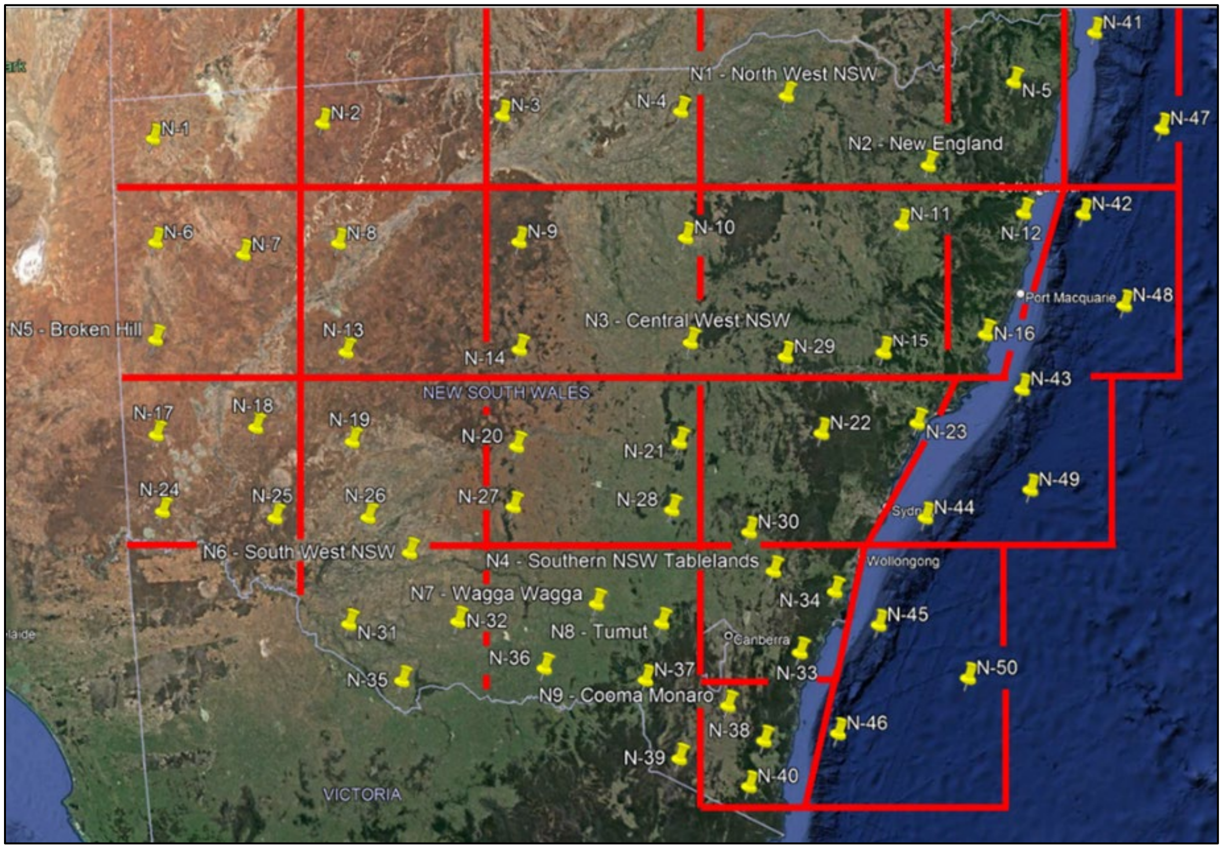

Figure B2. Maps representing are assumed zone distribution of NSW. Note: Here the naming conventions are N# were adopted to represent the AMEO and NSW Gov proposed REZs, while the locations with N-# are extra locations considered.

B3. Zonal Capacity Factors

The estimated solar and wind capacity factors of the locations assumed in **Figure B2** are listed below in **Table B1**.

Table B1. Estimated solar and wind farm capacity factors across the zonal regions.

Zone #	AEMO/NSW Defined REZs and Additional Locations in Each REZ	Solar Capacity Factor	Wind Capacity Factor
Z1	N-1	26.27%	50.47%
Z2	N5 (Broken Hill), N-6, N-7	25.79%	51.00%
Z3	N-17, N-18, N-24, N-25	24.30%	49.39%
Z4	N-2	25.75%	49.22%
Z5	N-8, N-13	25.02%	48.41%
Z6	N-19, N-26	24.10%	48.32%
Z7	N6 (South West NSW), N-31, N-32, N-35	23.19%	46.74%
Z8	N-3, N-4	24.75%	45.90%
Z9	N3 (Central West NSW), N-9, N-10, N-14	24.35%	48.60%
Z10	N-20, N-21, N-27, N-28	23.16%	42.89%
Z11	N7 (Wagga Wagga), N8 (Tumut), N-36, N-37	22.23%	33.16%
Z12	N1 (North West NSW REZs), N2 (New England)	24.15%	41.42%
Z13	N-11, N-15, N-29	23.27%	36.63%
Z14	N-22, N-23, N-30	22.71%	40.89%
Z15	N4 (Southern NSW Tablelands), N-33, N-34	22.34%	34.34%
Z16	N9 (Comma Monaro), N-38, N-39, N-40	22.36%	36.71%
Z17	N-5	23.61%	32.58%
Z18	N-12, N-16	22.79%	42.08%
Z19	N-41, N-47		52.58%
Z20	N-42, N-48		55.16%
Z21	N-43, N-44, N-49, Hunter Coast REZ (O1)		54.21%
Z22	N-45, N-46, N-50, Illawarra Coast REZ (O2)		55.39%

Note: The above capacity factors for each zone were evaluated as an average of the capacity factors (**Table E1**) of the constituent REZs and locations within the Zone.

[63] Khan et al. An integrated framework of open-source tools for designing and evaluating green hydrogen production opportunities. Communications Earth and Environment. 2022. https://doi.org/10.1038/s43247-022-00640-1

B4. Technoeconomic Assumptions

B4.1. Levelised Cost of Product – Farmgate Costs

To evaluate the costs for P2X product, the levelised cost of product (LC_{Prod}) was use as the metric. The LC_{Prod} is evaluated using the tools that calculate it based on the net present value of the capital costs, operating costs and the amount of hydrogen generated discounted over the project life as shown in **Equation 1**.

$$\text{Levelised Cost of Produc}\left(LC_{Prod}\left(\frac{A\$}{kg}\right)\right) = \frac{\sum_{i=(1:n)}^{n} \frac{(CAPEX + OPEX_i)}{(1+r)^i}}{\sum_{i=(1:n)}^{n} \frac{\text{P2X Product Produced}_i}{(1+r)^i}} \quad \text{Eq. 1}$$

Note: Here, the CAPEX represents the Total Capital Costs, OPEX represents the Annual Operating Costs and the hydrogen produced represents the annual hydrogen production rate in kg/year for year *I* and *n* represent the project life (herein considered to be 20 years).

B4.2. Levelised Cost of Product – Delivered Costs

To determine the delivered cost of product (A$/unit of product), the additional cost of storage and transport were added into these farmgate costs or product. These additional costs were either adopted directly as A$/unit costs from literature resources (elaborated below) or converted into levelised costs (A$/unit) through **Equation 1** by adopting capital and operating costs from literature resource (elaborated below).

B4.3. Electrolyser System Assumptions

The assumptions for modelling and costing the AE and PEM Electrolysers are provided in **Table B2**.

Table B2. The Electrolyser System Performance, Capital and Operating Cost Parameters Assumptions considered in this study.

Cost Parameter	Cost Assumption	
Capital Cost		
Electrolyser Capital Costs[63]	**<u>Alkaline Electrolyser:</u>** 2022: High – 1,773 A$/kW Low – 1,360 A$/KW 2025: High – 1,390 A$/kW Low – 808 A$/kW 2030: High – 1,208 A$/kW Low – 485 A$/kW 2040: High – 828 A$/kW Low – 272 A$/kW	**<u>PEM Electrolyser:</u>** 2022: High – 2,451 A$/kW Low – 2,164 A$/KW 2025: High – 2,847 A$/kW Low – 1,305 A$/kW 2030: High – 1,150 A$/kW Low – 758 A$/kW 2040: High – 513 A$/kW Low – 272 A$/kW

	2050: High – 732 A$/kW Low – 179 A$/kW	2050: High – 441 A$/kW Low – 179 A$/kW
Capital Cost Breakdown[63]	70% of Capital Cost = Equipment and 30% of Capital Cost = Construction/Installation	
Reference Scale[63]	10 MW	
Operating Cost		
Electrolyser O&M Cost[63]	2.5% of the AE Capital Cost per year	2.5% of the PEME Capital Cost per year
Electrolyser Stack Replacement Cost[63]	40% of the AE Capital Cost per replacement	40% of the PEM Capital Cost per replacement
Water Cost[63]	Maximum A$5/kL	
Performance Parameters		
Electrolyser Degradation[63]	1% efficiency loss per year for AE	1% efficiency loss per year for PEME
Electrolyser Efficiency	AE: 55 kWh/kg (71.7% HHV basis) ~0.7% Improvement per year to reach Efficiency below <45 kWh/kg by 2050 (IRENA KPI)[64]	PEME: 60 kWh/kg (65.7% HHV basis) ~1.02% Improvement per year to reach Efficiency below <45 kWh/kg by 2050 (IRENA KPI)[64]
Electrolyser Stack Life	60,000 hrs for AE Systems Estimated to reach 100,000 hrs by 2050 (IRENA KPI)[57]	65,000 hrs for PEM Systems Estimated to reach 110,000 hrs by 2050 (IRENA KPI)[57]
Water Consumption[63]	17.5 L/kg for AE System	25 L/kg for PEM System
Electrolyser Operation Range[63]	15 – 100% of Max Capacity (Current) 5 – 300% of Max Capacity (By 2050)	5 – 120% of Max Capacity (Current) 5 – 300% of Max Capacity (By 2050)
Financing Parameters		
Discount Rate	Assumed for our Analysis: 7%[63]/AEMO ISP 2022: 2% - 10%	
Project Life	20 Years[63]	

[64] Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal. IRENA. 2020. https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction

B4.4. Powerplant Cost Assumptions

The assumptions for modelling and costing the solar and wind farms are provided in **Table B3**.

Table B3. The Solar and Wind Farm Performance, Capital and Operating Cost Parameters Assumptions considered in this study.

Cost Parameter	Cost Assumption		
Capital Cost			
Powerplant Capital Cost[63]	**Solar PV Farm:** 2022: High – 1,441 A$/Kw Low – 1,020 A$/Kw 2025: High – 1,286 A$/Kw Low – 874 A$/KW 2030: High – 1,102 A$/Kw Low – 768 A$/Kw 2040: High – 778 A$/Kw Low – 569 A$/Kw 2050: High – 677 A$/Kw Low – 532 A$/Kw	**Onshore Wind Farm:** 2022: High – 1,936 A$/Kw Low – 1,805 A$/KW 2030: High – 1,932 A$/Kw Low – 1,642 A$/KW 2030: High – 1,910 A$/Kw Low – 1,583 A$/KW 2040: High – 1,863 A$/Kw Low – 1,548 A$/KW 2050: High – 1,830 A$/Kw Low – 1,416 A$/KW	**Offshore Wind Farm:** 2022: High – 5,632 A$/Kw Low – 4,649 A$/KW 2025: High – 5,424 A$/kW Low – 3,945 A$/KW 2030: High – 5,351 A$/kW Low – 2,336 A$/kW 2040: High – 5,010 A$/kW Low – 2,230 A$/kW 2050: High – 4,853 A$/kW Low – 2,217 A$/kW
Operating Cost			
Powerplant O&M Cost[63]	2% of the Solar Farm Capital Cost/year	2% of the Wind Farm Capital Cost/year	
Performance Parameters			
Powerplant Degradation[63]	1% power output of Solar Farm loss per year	1% power output of Wind Farm loss per year	
Financing Parameters			
Discount Rate	Assumed for our Analysis: 7%[63]/AEMO ISP 2022: 2% - 10%		
Project Life	20 Years		

B4.5. Transmission System Costs Assumptions

For our analysis, the transmission system costs were evaluated using the AEMO transmission cost tool.[65] The tool provides the capital cost (including equipment and installation) of the transmission system as a A$/km cost. To convert these into the total capital required the shortest distance between the assumed facility site and closest REZ was assumed and a correction factor of 20% was applied. The operating costs of the transmission network were assumed to be 1% of capital cost per year. These costs were then added into the capital and operating costs of the P2X facility to determine the farmgate costs of product.

[65] The AEMO Transmission Network Cost Tool has been used for costing the transmission network costs throughout the report: https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan

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. To convert the capital and operating costs, we assumed a capital recovery of 8.9% (WACC of 6.25% over 30-year project life). In addition, we assume a 70% utilisation factor of the network to determine the power through put (MWh/year) and a usage charge of A$10/MWh. For the analysis and results, 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).

B4.6. Hydrogen Storage Assumptions

For gaseous hydrogen storage (including compression and pressure vessels) we assume a cost of A$0.34/kg to A$0.42/kg and for liquid hydrogen storage (liquefaction and storage) we assume a cost of A$2.57/kg to A$3.14/kg.[66] To account for cost reduction due to economies of scale and R&D we assume a yearly reduction of 1.3 to 1.7%/year.

B5. Hydrogen Costing

B5.1. LCOH Cost Assumptions

The CAPEX includes the total system cost of the electrolyser, built cost of the solar/wind (onshore and offshore) farms plus additional cost of land and any interconnection and network usage charges. The capital cost of the electrolyser and solar/wind (onshore and offshore) were assumed based on AEMO GenCost report. Given the cost estimate variations between the cost scenarios in the GenCost reports, we assume the highest and lowest estimated costs across the scenarios for the LC_{H2} calculations to provide a comprehensive outlook. In addition, for the OPEX, we consider the general operation and maintenance (O&M) costs and stack replacement costs for the electrolyser systems and the O&M cost of the solar/wind farms. In addition, water to drive the electrolyser were assumed to be sourced at a maximum cost of A$5/kL (i.e., retail cost of desalinated water in Australia – most expensive source).

The amount of hydrogen generated was modelled using the local solar and wind profiles in the considered zones through the NSW PowerFuel tool. The tool evaluates the hourly capacity factors of the electrolyser and the powerplant to determine the energy available to drive the electrolysis (MWh) which is then correlated with the electrolyser efficiency to establish the amount of hydrogen generated over the year. Moreover, the tool considers the degradation rates of the electrolyser and the solar/wind farm to account for energy losses from the solar/wind farms and electrolyser efficiency due to stack degradation.

[66] HySupply Study: https://www.globh2e.org.au/hysupply-publication

B5.2. Farmgate Hydrogen Costs

2030 – Farmgate costs for 100 MW scale projects

Table B4. Estimated hydrogen farmgate costs in the considered zones for 2030. The zone breakdown is as per **Figure B2** and **Table B1.**

Quadrants	LCOH for dedicated solar farm driven system (A$/kg)				LCOH for dedicated wind farm driven system (A$/kg)			
	AE System		PEM System		AE System		PEM System	
	Low	High	Low	High	Low	High	Low	High
Z1	3.46	6.12	4.52	6.60	3.07	4.52	3.77	4.88
Z2	3.53	6.24	4.60	6.72	3.04	4.48	3.80	4.94
Z3	3.75	6.62	4.88	7.13	3.14	4.63	3.85	4.98
Z4	3.53	6.24	4.61	6.72	3.14	4.63	3.86	5.00
Z5	3.64	6.43	4.74	6.92	3.20	4.71	3.92	5.08
Z6	3.78	6.68	4.92	7.18	3.20	4.71	3.93	5.09
Z7	3.92	6.94	5.11	7.47	3.31	4.87	4.06	5.26
Z8	3.68	6.50	4.79	7.00	3.37	4.98	4.13	5.36
Z9	3.74	6.61	4.87	7.11	3.18	4.70	3.98	5.18
Z10	3.93	6.95	5.12	7.48	3.60	5.32	4.42	5.73
Z11	4.09	7.24	5.33	7.79	4.60	6.73	5.70	7.39
Z12	3.77	6.67	4.91	7.17	3.73	5.50	4.57	5.93
Z13	3.91	6.92	5.10	7.45	4.21	6.22	5.16	6.69
Z14	4.01	7.09	5.22	7.63	3.76	5.57	4.71	6.13
Z15	4.07	7.21	5.31	7.75	4.48	6.62	5.49	7.13
Z16	4.07	7.20	5.30	7.74	4.19	6.19	5.14	6.67
Z17	3.86	6.82	5.03	7.34	4.68	6.85	5.80	7.52
Z18	3.99	7.06	5.20	7.60	3.66	5.41	4.57	5.95

2040 - Best Case Farmgate Costs in REZs at 1 GW scale

Table B5. Estimated hydrogen farmgate costs in the considered REZs for 2040

REZ	Solar Farm	Wind Farm	AE System		PEM System	
			Low	High	Low	High
South West REZ	1.25 GW	-	2.28	3.66	2.44	3.5
Central West	0.7 GW	0.6 GW	2.15	3.08	2.28	3.00
New England	0.7 GW	0.6 GW	2.38	3.41	3.32	2.53
Hunter	-	1 GW (offshore)	3.15	7.12	3.32	7.23
Illawarra	-	1 GW (offshore)	3.09	6.97	3.25	7.07

2040 - Best Case Farmgate Costs in REZs at 5 GW scale

Table B6. Estimated Hydrogen farmgate costs in the considered REZs for 2040

REZ	Solar Farm	Wind Farm	AE System		PEM System	
			Low	High	Low	High
Central West	3 GW	3 GW	1.75	2.45	1.8	2.39
New England	4 GW	3 GW	1.89	2.63	1.95	2.57
Hunter	-	5 GW (offshore)	2.8	6.15	2.86	6.14
Illawarra	-	5 GW (offshore)	2.74	6.02	2.8	6

B5.3. Additional Dedicated Transmission Network Connected Scenario Results

2040 – Farmgate costs for 1 GW scale projects

The case of generating electricity in Central West and Orana REZ before transmitting it to Illawarra (Port Kembla) and the Hunter (Kooragang Island) was evaluated. This centralised power generation is assessed via three transmission options:

- a new built onshore 1 GW dedicated transmission line
- a new built onshore 5 GW shared transmission line
- connecting the hubs with the offshore wind REZs via a 1 GW subsea transmission network.

The results for this case are shown in **Table B7**.

Table B7. Estimated cost of hydrogen production projects via dedicated transmission lines in Port Kembla and Illawarra H_2 Hubs by 2040.

Powerplant Site	Electrolyser Site	Cost of Transmission Network/Usage	Farmgate LCOH (A$/kg)
Central West & Orana REZ	Hunter H_2 Hub	**1 GW Dedicated Transmission Network:** ~A$263 million – A$380 million **5 GW Shared Transmission Network:** ~A$11/MWh	**1 GW Dedicated Transmission Network:** A$2.9/kg – A$4.1/kg **5 GW Shared Transmission Network:** A$2.8/kg – A$3.5/kg
	Port Kembla H_2 Hub	**1 GW Dedicated Transmission Network:** ~A$337 million – A$487 million **5 GW Shared Transmission Network:** ~A$12/MWh	**1 GW Dedicated Transmission Network:** A$3.0/kg – A$4.3/kg **5 GW Shared Transmission Network:** A$2.8/kg – A$3.5/kg
Hunter Offshore REZ	Hunter H_2 Hub	**1 GW Subsea Transmission Network:** A$54 million – A$158 million	A$3.3/kg – A$7.1/kg
Illawarra Offshore REZ	Port Kembla H_2 Hub		A$3.3/kg – A$8.4/kg

Note: The cost of transmission was calculated through the AEMO Transmission Cost Tool (refer to **Appendix Section B4.5**)

The results of the modelling for network connected configuration indicated:

— For a 1 GW dedicated transmission network, the LCOH will range between A$2.9/kg – A$4.1/kg for the Central West & Orana REZ connected to Hunter H_2 Hub and A$3.0/kg – A$4.3/kg for the Central West & Orana REZ connected to Port Kembla H_2 Hub. In contrast, our results indicate that generating hydrogen in Central West and Orana followed by storage and transport as a compressed gas via pipeline or truck to the Hubs might results in a lower LCOH (however these costs are based on estimates and in practice the costs could vary significantly based on the scale of project, actual distance between sites and other factors). In contrast, liquid hydrogen transported by truck to the Hunter and Illawarra hubs would be more expensive than a 1 GW dedicated transmission line (LCOH between A$7.95/kg – A$9.07/kg).

— For the shared transmission line scenario, we estimate the LCOH will range between A$2.7/kg to A$4.0/kg. Note that shared transmission network configuration and cost in 2040 starts to become competitive with the alternative configuration of generating and storing hydrogen in Central West and Orana prior to transporting the hydrogen to the Hunter and Port Kembla H_2 Hubs. Transporting compressed gaseous hydrogen via pipeline however remains the lowest-cost option (A$2.40/kg – A$3.16/kg), but the shared transmission configuration has a lower LCOH than transporting hydrogen by road as a compressed gas (A$3.00/kg – A$3.76/kg) or liquid (A$7.95/kg – A$9.07/kg)

— For a subsea 1 GW transmission line scenario, we estimate the LCOH will range between A$3.3/kg – A$7.1/kg for the Hunter H_2 Hub and A$3.3/kg – A7.1/kg for the Port Kembla H_2 Hubs respectively. Overall, these costs show that if offshore wind farms can be established at the lower end cost assumption (A$2,230/kW) they can be competitive with the onshore connection to Central West and Orana with the added advantage of requiring lower capital to build the transmission network. In contrast, generating hydrogen in Central West and Orana followed by storage and transport as a compressed gas via pipeline or truck results in a lower LCOH. However, liquid hydrogen transported by truck to the Hunter and Illawarra hubs would be more expensive than a dedicated 1 GW subsea pipeline.

2050 – Farmgate costs for 5 GW scale projects

Similarly in this case, a scenario was developed that assumed electricity was produced in Central West and Orana REZ before transmitting it to Hunter and Port Kembla hydrogen hubs to generate hydrogen (5 GW facility each) via a newly built 5 GW dedicated transmission line. A second scenario considered a 5 GW subsea transmission line (for offshore wind plans) connecting to the Hubs. The results are shown in **Table B8** .

- By 2050, we estimate that the LCOH for the Central West and Orana REZ connected to Hunter H_2 hub will range between A$1.9/kg – A$2.2/kg. In comparison, the LCOH for the Central West and Orana REZ connected to Port Kembla Hub will range between A$1.9/kg – A$2.3/kg. In contrast, generating and storing the hydrogen in Central West and Orana REZ then transporting the product as a compressed gas via pipeline or road has a lower LCOH (A$2.61/kg – A$3.37/kg via pipeline and A$2.85/kg – A$3.60/kg via road as a gas). However, transporting hydrogen by road as a liquid is more expensive than the dedicated transmission line i.e., A$7.07/kg – A$8.12/kg as seen in **Figure 25** of main report.

- Alternatively, if a 5 GW subsea transmission network is established for both the hubs, we reveal that LCOH for the Port Kembla and Hunter H_2 Hubs would be between A$3.0/kg to A$6.2/kg and A$2.9/kg – A$6.1/kg, respectively. Similar to the 2040 case, if the offshore wind farms can be built at the lower end capital costs (the offshore scenarios will be at cost parity with the onshore based transmission network (electricity transported from Central West & Orana REZ) at half the capital cost required to construct the required transmission lines. Moreover, by 2050 we establish that the LCOH for both hubs via power distribution from Central West & Orana REZ or offshore would also be competitive with the cost of generating the hydrogen at the REZ (Dubbo) and transporting it to the Hubs via pipeline or truck (liquid or gaseous) for use i.e., ~A$2.61/kg – A$8.12/kg of main report.

Table B8. Estimated cost of hydrogen production projects via dedicated transmission lines in Port Kembla and Illawarra H2 Hubs in 2050.

Powerplant Site	Electrolyser Site	Cost of Transmission Network/Usage	Farmgate LCOH (A$/kg)
Central West & Orana REZ	Hunter H_2 Hub	**5 GW Transmission Dedicated Network:** ~A$417 million – A$473 million	**5 GW Transmission Dedicated Network:** A$1.9/kg – A$2.2/kg
	Port Kembla H_2 Hub	**5 GW Transmission Dedicated Network:** ~A$533 million – A$607 million	**5 GW Dedicated Transmission Network:** A$1.9/kg – A$2.3/kg
Hunter Offshore REZ	Hunter H_2 Hub	**5 GW Dedicated Subsea Transmission Network:** A$244 million – A$715 million	A$3.3/kg – A$7.1/kg
Illawarra Offshore REZ	Port Kembla H_2 Hub		A$3.3/kg – A$8.4/kg

Note: The cost of transmission was calculated through the AEMO Transmission Cost Tool (Refer to **Appendix Section B4.5**)

B6. Technoeconomic Assessment Approach for H_2 Refuelling Station

Technoeconomic assessment for H_2 refuelling station was carried out using the existing open-source Heavy-Duty Refuelling Station Analysis Model (HDRSAM) made by Argonne National Laboratory with some financial assumption adjustments. The model provides cost estimates of various H_2 refuelling configurations and uses a design calculation to size the components based on market demand scenarios, as illustrated in **Figure B3**. The analysis calculates the refuelling station levelised cost: the average total cost to build and operate a hydrogen refuelling station over its lifetime, divided by the total hydrogen dispensed over that lifetime.

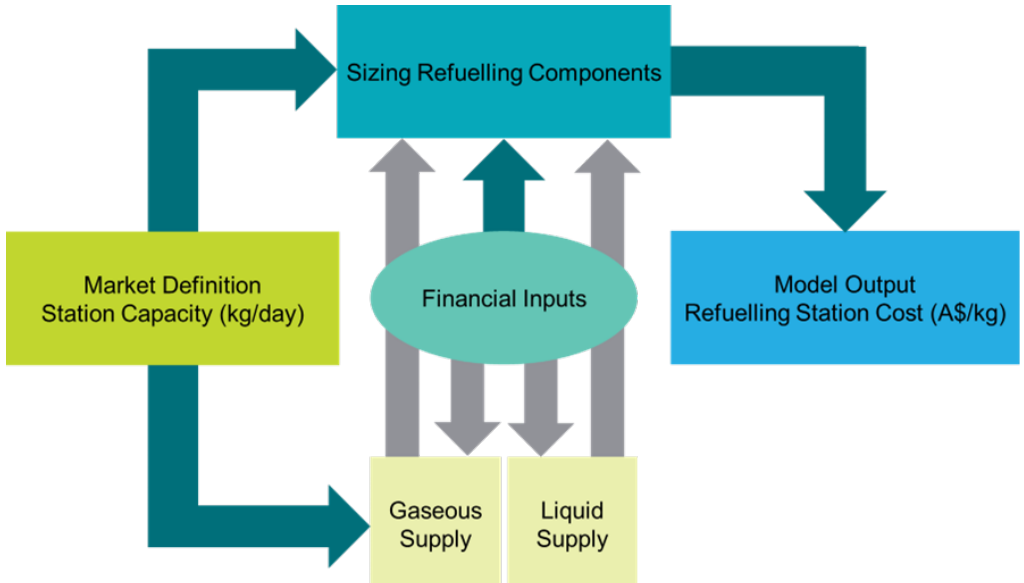

Figure B3. H_2 refuelling station costing approach based on Heavy-Duty Refuelling Station Analysis Model (HDRSAM).[67]

B6.1. Sizing of Refuelling Components

H_2 refuelling station configuration is primarily defined by the state of H_2 supplied to the station, i.e., gaseous or liquid. Gaseous H_2 is supplied through a tube trailer, a distribution pipeline network, or an onsite production unit. Liquid H_2 is stored in an onsite cryogenic tank, which is replenished by a liquid H_2 tanker. On-site H_2 production units are assumed to supply H_2 at a pressure of 20 bar. For distributed H_2 refuelling facility, tube trailer supplies gaseous H_2 to the station at a pressure of 500 bar or liquid tanker supplies liquid H_2 to the station.

[67] Argonne National Laboratory. Heavy-Duty Refuelling Station Analysis Model (HDRSAM). https://hdsam.es.anl.gov/index.php?content=hdrsam

The gaseous refuelling stations include a high-pressure compressor, which draws H_2 from the supply source and compresses it to 950 bar before storing in a high-pressure buffer storage system. The H_2 from the high-pressure system is later directed by a dispenser into the vehicle's onboard tank via a refrigeration unit, which pre-cools the H_2 to about -40 °C to allow fast fuelling without overheating the vehicle's tank.

For liquid H_2 refuelling stations, liquid H_2 from the cryogenic storage tank is pressurized by a cryogenic pump and then gasified via an evaporator. The high-pressure gaseous H_2 from the evaporator is stored in the high-pressure buffer storage system, which is later pre-cooled to -40 °C by the cooler before being dispensed into the vehicle tanks. The pre-cooling unit uses the cryogenic H_2 to cool the H_2.

The component capital cost formulas obtained from HDRSAM model were developed based on quotes from vendors, open literature, and input from industry consultations. The following sub-sections show the capital cost formulas for various station components, including the compressor, refrigeration unit, cryogenic storage unit, and evaporator.[68]

Compressor

$$P = Z \times n_{H_2} \times R \times T \times N_s \times \frac{\gamma}{\gamma - 1} \times \left(\frac{P_2}{P_1}\right)^{\frac{\gamma}{N_S \times \gamma - 1}} \quad \textbf{(Eq. 2)}$$

where P is compressor power (kW), Z is compressibility factor, n_{H_2} is molar flow rate of H_2 (kmol/s), R is gas constant, T is temperature (K), N_s is number of stages, γ is $\frac{C_p}{C_v}$, P_1 is inlet pressure and P_2 is outlet pressure.

$$CAPEX_{compressor} = 56{,}739 \times N_c \times P'^{0.4603} \quad \textbf{(Eq. 3)}$$

where $CAPEX_{compressor}$ is the capital cost of the compressor (A$), N_c is the number of compressors, and P' is the compressor power per unit (kW).

Refrigeration Unit

$$CAPEX_{refrigeration} = 1.25 \times 15{,}529 \times \left(\frac{100 \times m_{H_2} \times N_{cond}}{T}\right)^{0.8579} \quad \textbf{(Eq. 4)}$$

where $CAPEX_{refrigeration}$ is the capital cost of the refrigeration unit (A$), m_{H_2} is the refrigeration capacity (ton), N_{cond} is the number of condensing units, and T is maximum dispensing temperature (K) assumed in the analysis to be 293.15 K.

Cryogenic Storage Tank

$$CAPEX_{cryo\ storage} = 1{,}388.65 \times m^{0.6929} \quad \textbf{(Eq. 5)}$$

where $CAPEX_{cryo\ storage}$ is the capital cost of the cryogenic storage tank (A$) and m is the liquid H_2 storage capacity (kg).

[68] Reddi et al. 2017. Impact of hydrogen refuelling configurations and market parameters on the refuelling cost of hydrogen. *International Journal of Hydrogen Energy*, 42(34), 21855-65. https://doi.org/10.1016/j.ijhydene.2017.05.122

Evaporator

$$CAPEX_{evaporator} = N_{evap} \times (1{,}400m + 21{,}000) \quad \textbf{(Eq. 6)}$$

where $CAPEX_{evaporator}$ is the capital cost of the evaporator (A$), N_{evap} is number of evaporator units, and m is the mass flow rate (kg/h).

Apart from these components, the cost of the high-pressure H_2 gaseous storage is US$1800 or A$2,520 per kg of H_2, the cost of cryogenic pump is US$425,000 or A$595,000 per unit, while the cost of dispenser is US$100,000 or A$140,000 per unit.

The cost model, which is based on discounted cash flow (DCF) analysis, includes capital, utilities, operating expenses, and all other cash flows associated with owning, replacing, and operating the necessary refuelling system equipment over the project life.

B6.2. Simulation Setup

The station is assumed to fill 350-bar heavy-duty vehicles (HDVs). The number of HDVs served per day for small, medium, and large refuelling stations are 30, 60, and 100 HDVs, respectively. The amount of H_2 dispensed per vehicle is assumed to be 35 kg with a fuelling rate of 3.6 kg/min. The lingering time between HDV fills is assumed to be 2 mins. The model assumes 2 hoses per dispenser.

To determine the refuelling station locations and demand for each station, HDV traffic volume data in NSW's major highways (Pacific, Newell, and Hume Highways) were obtained for available sampling points from Transport for NSW's Traffic Volume Viewer (**Table B9**).

Table B9.HDV traffic volume obtained for available sampling points.[69]

Location	HDV traffic volume (average number of HDVs per day)
Pacific Highway	
Wardell	127-138
Kempsey	520-537
Kiwarrak	2271-2515
Calga	4834-5253
Mount White	3263-3284
Wahroonga	3926-6686
Hume Highway	
Bargo	4267-4301
Marulan	1044-1086
Manton	2138-2180
Bowning	2692-2702
Gundagai	2116-2173
Newell Highway	
Tannabar	475-512
Biddon	347-396
Gilgandra	509-554
Eumungerie	435-485
Tomingley	466-513
Forbes	477-512
Wyalong	444-509
Jerilderie	441-452
Hunter	
Buchanan	1921-2056

[69] Transport for NSW. Traffic Volume Viewer. https://roads-waterways.transport.nsw.gov.au/about/corporate-publications/statistics/traffic-volumes/aadt-map/index.html#/?z=6

B6.3. Financial Parameters

The financial variables assumed for analyzing the station economic performance include construction period, discount rate, project lifetime, and equity ratio as presented in **Table B10**. The model uses a discounted cash flow (DCF) method for each refuelling equipment, summed together to provide the cash flow of the entire refuelling station. The sum of contributions from all refuelling components provides an estimate of the total levelised cost of a refuelling station in A$ per kg of H_2.

Table B10. Refuelling station economic parameters considered for the analysis.

Parameter	Value
Construction period	1 year
Discount rate	7%
Project lifetime	30 years

B7. Natural Gas Blending Costs

B7.1. Levelised Cost of Natural Gas Blending Assumptions

See section **B5. Hydrogen Costing** for assumptions related to renewable energy and hydrogen production. Downstream of the electrolyser, several key pieces of equipment were included to facilitate blending of the hydrogen into the natural gas network. These included a hydrogen storage tank with a six-hour storage capacity to provide some buffering capacity to maintain the blend ratio and to facilitate consistent injection rates, a compressor to boost the hydrogen pressure to the natural gas pressure and an injection skid to facilitate blending of the hydrogen into the natural gas system. The capital costs for the hydrogen storage and compressor equipment were obtained from literature [70] whilst the capital cost for the blending skid was assumed to be in the order of A$100,000/unit for the purposes of the analysis.

The quantity of hydrogen blended into the natural gas grid was modelled at an hourly resolution using the local solar and wind profiles for the zones considered and the natural gas energy flow data at each node which was obtained from the AEMO database.[71] The target for blending was to maintain the same flow of energy through the natural gas pipeline using hydrogen to displace natural gas up to a maximum of 10%.

The assumptions for costing and modelling the gas blending are summarized in **Table B11.**

Table B11. Cost Parameters for Natural Gas Blending[70]

Cost Parameter	Cost Assumption
Capital Cost	
Hydrogen Storage Capital Cost	878 A$/kg
Compressor Capital Cost	100,000 A$/unit
Gas Blending Skid Capital Cost	100,000 A$/unit
Operating Cost	
Hydrogen Storage Operating Cost	2% of Hydrogen Storage CAPEX
Compressor and Gas Blending Skid Operating Cost	2% of CAPEX
Performance Parameters	
Target Hydrogen Blend	10% by volume
Financing Parameters	
Discount Rate	7%
Project Life	25 years

[70] Papadias D.D., Ahluwalia R.K. Bulk storage of hydrogen. International Journal of Hydrogen Energy. 2021; 46: 34527-41.
[71] AEMO (2022). Gas Flows and Capacity Outlook. https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/gas-flows

B8. Ammonia Costing

B8.1. Levelised Cost of Ammonia Assumptions

See section **B5. Hydrogen Costing** for assumptions related to renewable energy and hydrogen production. The ammonia synthesis unit, ammonia storage tank, air separation unit and hydrogen storage capital and operating costs were obtained from literature.[70, 72, 73] Using process simulation software, the ammonia synthesis unit and storage tank system were modelled to obtain the specific energy consumption for the plant. Through utilization of the high-pressure hydrogen coming from the electrolyzer, energy savings were obtained by injecting hydrogen into the nitrogen gas from the air separation unit at the second stage feed compressor.

The quantity of ammonia produced was modelled at an hourly resolution using the local solar and wind profiles for the zones considered. The strategies employed to maintain high availability of the ammonia synthesis unit included oversizing the renewable energy plant, oversizing the electrolyzer and using hydrogen storage as a balancing source of hydrogen when the renewable energy plant is unable to meet the power demand for producing hydrogen via the electrolyzer.

The assumptions for costing and modelling the ammonia plant are summarized in **Table B12**.

Table B12. Cost Parameters for Ammonia Generation[74]

Cost Parameter	Cost Assumption
Capital Cost	
Ammonia Synthesis Unit Capital Cost	520 A$/t
Reference scale.	1 Million Tonnes Per Annum (2740 t_{NH3}/day)
Ammonia Storage Tank Capital Cost	1370 A$/t
Reference Scale	30 Days (82,200 t_{NH3})
Air Separation Unit Capital Cost	251 A$/t
Reference Scale	0.83 Million Tonnes Per Annum (2278 t_{N2}/day)
Hydrogen Storage Capital Cost	878 A$/kg
Reference Scale	500 t_{H2}
Operating Cost	
Ammonia Synthesis Unit Operating Cost	2% of Ammonia Synthesis Unit CAPEX
Ammonia Storage Tank Operating Cost	2% of Ammonia Storage Tank CAPEX

[72] Osman O., Sgouridis S., Sleptchenko A. Scaling the production of renewable ammonia: A techno-economic optimization applied in regions with high insolation. Journal of Cleaner Production. 2020; 271:

[73] Jussi I., Juha K., Robert W., Hannele H. Power-to-ammonia in future North European 100 % renewable power and heat system. International Journal of Hydrogen Energy. 2018; 43: 17295-308.

[74] J. Shepherd et al. Open-source project feasibility tools for supporting development of the green ammonia value chain. Energy Conversion and Management. 2022. https://doi.org/10.1016/j.enconman.2022.116413

Air Separation Unit Operating Cost	2% of Air Separation Unit CAPEX
Hydrogen Storage Operating Cost	2% of Hydrogen Storage CAPEX
Performance Parameters	
Conversion	99%
Ammonia Synthesis Unit Specific Energy Consumption	0.41 kWh/kg_{NH3}
Air Separation Unit Specific Energy Consumption	0.23 kWh/kg_{N2}
Financing Parameters	
Discount Rate	7%
Project Lifetime	25 years

B9. Methanol Costing

B9.1. Levelised Cost of Methanol Assumptions

See section **B5. Hydrogen costing** for assumptions related to renewable energy and hydrogen production. Methanol plant CAPEX costs were calculated through process simulation combined with cost correlations from literature.[75] For OPEX we considered general operational and maintenance costs (O&M). Process utilities for the methanol and carbon capture plants were assumed to be fully electrified. Simulated methanol plant energy consumption was used for dynamic modelling and integration with renewable and balancing technology power sources.

The amount of methanol produced was modelled using local solar and wind profiles in the zones considered which fed into the selected electrolyser and balancing technology configurational parameters. The tool evaluates the hourly capacity factors of electrolyser, and powerplant to determine the energy available for hydrogen production, and other systems including balancing technologies, and process utilities for carbon capture and methanol production. Hydrogen storage was used as a balancing technology for a consistent supply of hydrogen feedstock to the methanol plant while battery storage was also used as a source of backup utility power. The level of these balancing technologies was also monitored on an hourly basis for determining the hourly capacity factor of the methanol plant and the amount of methanol generated over the year.

The assumptions for costing and modelling the methanol plant are summarized in **Table B13**.

[75] Sinnott, R. K. Coulson and Richardson's Chemical Engineering Volume 6, Chemical Engineering Design. (1999).

Table B13. Methanol Plant Performance, Capital and Operating Cost Parameters Assumptions considered in this study.[76] * The capital cost parameter here includes equipment purchase and installation, balance of plant, and indirect costs.

Cost Parameter	Cost Assumption
Capital Cost	
Methanol Capital Cost*	270 A\$/t_{MeOH}/a.
Reference scale.	1000 t_{MeOH}/day
Operating Cost	
Methanol Operating Costs	5% of Methanol Plant CAPEX
CO_2 Capture Costs	Refer to **Table B16**
Performance Parameters	
Methanol Yield	95% molar basis
Methanol Specific Energy Consumption	0.36 kWh/kg_{MeOH}
Financing Parameters	
Discount Rate	7%
Project Life	25 years

B10. Synthetic Natural Gas Costing

B10.1. Levelised Cost of SNG Assumptions

See section **B5. Hydrogen costing** for assumptions related to renewable energy and hydrogen production. SNG Methanation plant CAPEX costs were based on values reported in literature. [77] For OPEX we considered general operational and maintenance costs (O&M) which were assumed to be 5% of the initial capital investment. Process utilities for the SNG and carbon capture plants were assumed to be fully electrified. Literature based SNG plant energy consumption[78] was used for dynamic modelling and integration with renewable and balancing technology power sources.

The amount of SNG produced was modelled using local solar and wind profiles in the zones considered which fed into the selected electrolyser and balancing technology configurational parameters. The tool evaluates the hourly capacity factors of electrolyser, and powerplant to determine the energy available for hydrogen production, and other systems including balancing technologies, and process utilities for carbon capture and SNG production. Hydrogen storage was used as a balancing technology for a consistent supply of hydrogen feedstock to the SNG plant while battery

[76] Van Antwerpen *et al*. A model for assessing pathways to integrate intermittent renewable energy for e-methanol production. *International Journal of Hydrogen Energy*. (In Press).
[77] Bassano, C., Deiana, P., Vilardi, G. & Verdone, N. Modeling and economic evaluation of carbon capture and storage technologies integrated into synthetic natural gas and power-to-gas plants. Appl. Energy 263, 114590 (2020).
[78] Becker, W. L., Penev, M. & Braun, R. J. Production of Synthetic Natural Gas From Carbon Dioxide and Renewably Generated Hydrogen: A Techno-Economic Analysis of a Power-to-Gas Strategy. (2019) doi:10.1115/1.4041381.

storage was also used as a source of backup utility power. The level of these balancing technologies was also monitored on an hourly basis for determining the hourly capacity factor of the SNG plant and the amount of SNG generated over the year.

The assumptions for costing and modelling the SNG plant are summarized in **Table B14**.

Table B14. SNG Plant Performance, Capital and Operating Cost Parameters Assumptions considered in this study.

Cost Parameter	Cost Assumption
Capital Cost	
SNG Capital Cost[79]	290 A$/$t_{SNG}$/a.
Reference scale	2600 t_{SNG}/day
Operating Cost	
SNG Operating Costs	5% of SNG Plant CAPEX
CO_2 Capture Costs	Refer to **Table B16**
Performance Parameters	
SNG Yield[80]	95% molar basis
SNG Specific Energy Consumption[81]	0.51 kWh/kg_{SNG}
Financing Parameters	
Discount Rate	7%
Project Life	25 years

[79] Bassano, C., Deiana, P., Vilardi, G. & Verdone, N. Modeling and economic evaluation of carbon capture and storage technologies integrated into synthetic natural gas and power-to-gas plants. Appl. Energy 263, 114590 (2020).
[80] Chauvy, R., Verdonck, D., Dubois, L., Thomas, D. & De Weireld, G. Techno-economic feasibility and sustainability of an integrated carbon capture and conversion process to synthetic natural gas. J. CO2 Util. 47, 101488 (2021).
[81] Becker, W. L., Penev, M. & Braun, R. J. Production of Synthetic Natural Gas From Carbon Dioxide and Renewably Generated Hydrogen: A Techno-Economic Analysis of a Power-to-Gas Strategy. (2019) doi:10.1115/1.4041381.

B11. Sustainable Aviation Fuel Costing

B11.1. Levelised Cost of SNG Assumptions

See section **B5. Hydrogen costing** for assumptions related to renewable energy and hydrogen production. Fischer Tropsch (FT) SAF plant CAPEX costs were based on values reported in literature.[82,83] For OPEX we considered general operational and maintenance costs (O&M) which were assumed to be 2.5% of the initial capital investment.[84] Process utilities for the SAF and carbon capture plants were assumed to be fully electrified. Literature based SAF plant energy consumption[85] was used for dynamic modelling and integration with renewable and balancing technology power sources.

The amount of SAF produced was modelled using local solar and wind profiles in the zones considered which fed into the selected electrolyser and balancing technology configurational parameters. The tool evaluates the hourly capacity factors of electrolyser, and powerplant to determine the energy available for hydrogen production, and other systems including balancing technologies, and process utilities for carbon capture and SAF production. Hydrogen storage was used as a balancing technology for a consistent supply of hydrogen feedstock to the SAF plant while battery storage was also used as a source of backup utility power. The level of these balancing technologies was also monitored on an hourly basis for determining the hourly capacity factor of the SAF plant and the amount of SAF generated over the year. It was assumed that all produced FT Fuel factions other than SAF can be sold to recover their cost of production.

The assumptions for costing and modelling the SAF plant are summarized in **Table B15**.

Table B15. SAF Plant Performance, Capital and Operating Cost Parameters Assumptions considered in this study.

Cost Parameter	Cost Assumption
Capital Cost	
RWGS Reactor Capital Cost[86]	120 A$/$t_{CO}$/a.
Reference scale	1344 t_{CO}/day
FT Reactor Capital Cost[87]	100 A$/$t_{feed}$/a.
Reference scale	1678 t_{Feed}/day
Hydrocracker Capital Cost[88]	420 A$/$t_{FT\text{-}Fuels}$
Reference scale	100 $t_{FT\text{-}Fuels}$/day
Operating Cost	

82 Rezaei, E. & Dzuryk, S. Techno-economic comparison of reverse water gas shift reaction to steam and dry methane reforming reactions for syngas production. Chem. Eng. Res. Des. 144, 354–369 (2019).
83 König, D. H., Freiberg, M., Dietrich, R. U. & Wörner, A. Techno-economic study of the storage of fluctuating renewable energy in liquid hydrocarbons. Fuel 159, 289–297 (2015).
84 König, D. H., Freiberg, M., Dietrich, R. U. & Wörner, A. Techno-economic study of the storage of fluctuating renewable energy in liquid hydrocarbons. Fuel 159, 289–297 (2015).
85 Rezaei, E. & Dzuryk, S. Techno-economic comparison of reverse water gas shift reaction to steam and dry methane reforming reactions for syngas production. Chem. Eng. Res. Des. 144, 354–369 (2019).
86 Rezaei, E. & Dzuryk, S. Techno-economic comparison of reverse water gas shift reaction to steam and dry methane reforming reactions for syngas production. Chem. Eng. Res. Des. 144, 354–369 (2019).
87 König, D. H., Freiberg, M., Dietrich, R. U. & Wörner, A. Techno-economic study of the storage of fluctuating renewable energy in liquid hydrocarbons. Fuel 159, 289–297 (2015).
88 König, D. H., Freiberg, M., Dietrich, R. U. & Wörner, A. Techno-economic study of the storage of fluctuating renewable energy in liquid hydrocarbons. Fuel 159, 289–297 (2015).

SAF Operating Costs	2.5% of SAF Plant CAPEX
CO_2 Capture Costs	Refer to **Table B16**
Performance Parameters	
FT-Fuels Yield	95% molar basis
RWGS Specific Energy Consumption	0.4 kWh/kg_{CO}
FT Fuels Product Distribution - SAF [89]	43%
FT Fuels Product Distribution - Diesel [90]	21.5%
FT Fuels Product Distribution - Naphtha	21.5%
FT Fuels Product Distribution - LPG	4.5%
FT Fuels Product Distribution - Methane	9.5%
Financing Parameters	
Discount Rate	7%
Project Life	25 years

[89] Li, J. et al. Integrated tuneable synthesis of liquid fuels via Fischer–Tropsch technology. Nat. Catal. 1, 787–793 (2018).
[90] Fasihi, M., Bogdanov, D. & Breyer, C. Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants. Energy Procedia 99, 243–268 (2016).

B12. Carbon Capture Costing

Table B16. Carbon Capture Facility Costs Assumptions

Cost Parameter	Cost Assumption
Capital Cost[91]	
Coal power flue gas	370 A$/$t_{CO2}$/a.
Cement flue gas	240 A$/$t_{CO2}$/a.
Fermentation off gas	0 A$/$t_{CO2}$/a.
Steel flue gas	290 A$/$t_{CO2}$/a.
SMR/Ammonia flue gas	370 A$/$t_{CO2}$/a.
Direct Air Capture[92, 93]	1167 A$/$t_{CO2}$/a.
Operating Cost	
Carbon Capture Operating Costs	5% of Carbon Capture Plant CAPEX
Performance Parameters	
CO_2 capture rate	90%
Coal power flue gas Specific Energy Consumption (SEC)[94]	0.86 kWh/kg_{CO2}
Cement flue gas SEC	0.78 kWh/kg_{CO2}
Fermentation off gas SEC	0 kWh/kg_{CO2}
Steel flue gas SEC	0.78 kWh/kg_{CO2}
SMR/Ammonia SEC	0.78 kWh/kg_{CO2}
Direct Air capture SEC	1.53 kWh/kg_{CO2}
Financing Parameters	
Discount Rate	7%
Project Life	25 years

[91] Danaci, D., Bui, M., Mac Dowell, N. & Petit, C. Exploring the limits of adsorption-based CO2 capture using MOFs with PVSA-from molecular design to process economics. Mol. Syst. Des. Eng. 5, 212–231 (2020).
[92] Keith, D. W., Holmes, G., St. Angelo, D. & Heidel, K. A Process for Capturing CO2 from the Atmosphere. Joule 2, 1573–1594 (2018).
[93] Fasihi, M., Efimova, O. & Breyer, C. Techno-economic assessment of CO 2 direct air capture plants. J. Clean. Prod. 224, 957–980 (2019).
[94] Just, P. E. Advances in the development of CO2 capture solvents. Energy Procedia 37, 314–324 (2013).

B13. P2X Product Export Costing

B13.1. Market Demand

Table B17. Hydrogen and ammonia equivalent import targets in key emerging overseas market

Destination	Demand				
	H_2 (MTPA)		Ammonia (MTPA)		Demand Sector
	2030	2050	2030	2050	
Japan	0.5	5.3	3	30	Based on Japan's H_2/Ammonia Target for Power Sector[95]
Republic of Korea	4	22	20	110	Based on South Korea's demand expectation by 2050 – 28 MTPA of H_2 of which 2/3rd is green[96]
Singapore	~2	~9			Based on KBR analysis for Singapore H_2 demand to cater power, transport, and industry.[97]
EU	1	15			Based on estimates for Australian based export to EU by Green Hydrogen Task Force[98]
Global Share				150	Based on IRENA's Global H_2 trade report 2022.[99]

Disclaimer: The scale values used are estimates based on the expected demand of hydrogen equivalents in the mentioned countries based on each country and industry targets and estimates for green H_2/ammonia demand to support clean power generation (replacement of LNG or coal). These are subject to change as the market and demand evolves in each destination. For example, in case of Japan, the demand is based on H_2/ammonia targets to support the country's power sector. Similarly, for the Republic of Korea the demand is based on the government target for green hydrogen use in the country by 2050 and the global market share is based on IRENA's estimate for the global hydrogen economy by 2050.

B13.2. Export Costing

To determine the cost of shipping (A$/unit of product), the HySupply Shipping Tool[100] was used by adopting the assumption parameters from our recent publication[101] and shipping routes shown in **Table B18**. The total delivered costs of products to the considered markets are shown in **Table B19**.

[95] Japan's Road Map for Fuel Ammonia. Trevor Brown. Ammonia Energy Association. 2021. https://www.ammoniaenergy.org/articles/japans-road-map-for-fuel-ammonia/
[96] S Korea to provide 27.9 mil mt/year of 'clean hydrogen' by 2050. S&P Global. 2021. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/112621-s-korea-to-provide-279-mil-mtyear-of-clean-hydrogen-by-2050
[97] KBR (2021). Study of Hydrogen Imports and Downstream Applications for Singapore. https://file.go.gov.sg/studyofhydrogenimportsanddownstreamapplicationsforsingapore.pdf
[98] Securing Green Hydrogen for Germany and the EU. Green Hydrogen Task Force. 2022. https://www.fmgl.com.au/in-the-news/media-releases/2022/06/24/australian-german-business-coalition-produces-a-roadmap-for-large-scale-green-hydrogen-import-to-germany
[99] Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Trade Outlook for 2050 and Way Forward. IRENA. 2022. https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook
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Table B18. Shipping routes considered.

Origin	Destination	Route Distance	
		km	Nautical Miles
Singapore			
Port Botany – Sydney	Jurong Port	8,083	4,364
Port Kembla - Wollongong		8,118	4,383
Kooragang Island - Newcastle		7,962	4,299
Japan			
Port Botany – Sydney	Kobe Port	8,787	4,745
Port Kembla - Wollongong		8,822	4,763
Kooragang Island - Newcastle		8,908	4,810
South Korea			
Port Botany – Sydney	Yeosu Port	8,733	4,715
Port Kembla - Wollongong		8,768	4,734
Kooragang Island - Newcastle		8,854	4,781
Germany/European Union			
Port Botany – Sydney	Port of Rotterdam	23,679	12,786
Port Kembla - Wollongong		23,714	12,805
Kooragang Island - Newcastle		23,800	12,851
Denmark			
Port Botany – Sydney	Port Esbjerg	24,124	13,026
Port Kembla - Wollongong		24,159	13,045
Kooragang Island - Newcastle		24,245	13,091

Table B19. Estimated cost of shipping select P2X products generated in NSW to potential trade partners.

H_2 Carrier	Generation Cost			Shipping Cost			Delivered Cost to Port		
	Present	2030	2050	Present	2030	2050	Present	2030	2050
Asian Markets									
Destination: Port of Jurong in Singapore									
LH_2 (A$/kg)	8.34 – 19.42	6.18 – 18.94	3.49 – 10.34	0.78 – 0.79	0.72 – 0.73	0.59 – 0.60	**9.12 – 20.21**	**6.90 – 19.67**	**4.08 – 10.94**
Ammonia (A$/ton)	1,620 – 2,790	1,220 – 2,340	1,010 – 1,960	73 – 74	67 – 68	55 – 56	**1,693 – 2,864**	**1,287 – 2,408**	**1,065 – 2,016**
Methanol (A$/tonne)	2,010 – 3,060	1,420 – 2,250	1,030 – 1,840	60 – 61	56 – 57	~45.6 – 46	**2,070 – 3,121**	**1,476 – 2,307**	**1,076 – 1,886**
SNG (A$/GJ)	102 – 157	68 – 108	46 – 79	2.36 – 2.39	2.18 – 2.21	1.78 – 1.80	**105 – 159**	**70 – 110**	**48 – 81**
Destination: Port of Kobe in Japan									
LH_2 (A$/kg)	8.34 – 19.42	6.18 – 18.94	3.49 – 10.34	0.84 – 0.85	0.77 – 0.78	0.63 – 0.64	**9.18 – 20.27**	**6.95 – 19.72**	**4.12 – 10.98**
Ammonia (A$/ton)	1,620 – 2,790	1,220 – 2,340	1,010 – 1,960	78 – 79	72 – 73	59 – 60	**1,698 – 2,869**	**1,292 – 2,414**	**1,069 – 2,020**
Methanol (A$/tonne)	2,010 – 3,060	1,420 – 2,250	1,030 – 1,840	65 – 65.5	60 – 60.5	49 – 49.4	**2,075 – 3,126**	**1,480 – 2,311**	**1,080 – 1,889**
SNG (A$/GJ)	102 – 157	68 – 108	46 – 79	2.53 – 2.55	2.33 – 2.36	1.91 – 1.93	**105 – 159**	**70 – 110**	**48 – 81**
Destination: Port of Yeosu in Republic of Korea									
LH_2 (A$/kg)	8.34 – 19.42	6.18 – 18.94	3.49 – 10.34	0.83 – 0.84	0.77 – 0.78	0.63 – 0.64	**9.17 – 20.26**	**6.95 – 19.72**	**4.12 – 10.98**
Ammonia (A$/ton)	1,620 – 2,790	1,220 – 2,340	1,010 – 1,960	78 – 78.9	72 – 72.8	59 – 59.5	**1,698 – 2,869**	**1,292 – 2,414**	**1,069 – 2,020**
Methanol (A$/tonne)	2,010 – 3,060	1,420 – 2,250	1,030 – 1,840	64.5 – 65.2	59.6 – 60.1	48.7 – 49	**2,075 – 3,126**	**1,480 – 2,311**	**1,080 – 1,889**
SNG (A$/GJ)	102 – 157	68 – 108	46 – 79	2.52 – 2.54	2.32 – 2.35	1.90 – 1.92	**105 – 159**	**70 – 110**	**48 – 81**

European Markets									
Destination: Port of Rotterdam in Netherlands (Gateway to Germany and Mainland EU)									
LH_2 (A$/kg)	8.34 – 19.42	6.18 – 18.94	3.49 – 10.34	2.12 – 2.13	1.95 – 1.96	1.60 – 1.61	**10.46 – 21.55**	**8.13 – 20.9**	**5.09 – 11.95**
Ammonia (A$/ton)	1,620 – 2,790	1,220 – 2,340	1,010 – 1,960	184 – 184.7	169.5 – 170	138.7 – 139	**1,804 – 2,975**	**1,390 – 2,510**	**1,149 – 2,099**
Methanol (A$/tonne)	2,010 – 3,060	1,420 – 2,250	1,030 – 1,840	154.7 – 155.5	142.7 – 143	116.7 – 117	**2,165 – 3,216**	**1,563 – 2,393**	**1,147 – 1,957**
SNG (A$/GJ)	102 – 157	68 – 112	46 – 79	5.92 – 5.95	5.47 – 5.49	4.47 – 4.49	**108 – 163**	**70 – 110**	**48 – 81**
Destination: Port of Esbjerg in Denmark									
LH_2 (A$/kg)	8.34 – 19.42	6.18 – 18.94	3.49 – 10.34	2.16 – 2.17	1.99 – 2.01	1.63 – 1.64	**10.50 – 21.59**	**8.17 – 20.95**	**5.12 – 11.98**
Ammonia (A$/ton)	1,620 – 2,790	1,220 – 2,340	1,010 – 1,960	187 – 188	172 – 174	141 – 142	**1,807 – 2,978**	**1,393 – 2,514**	**1,151 – 2,102**
Methanol (A$/tonne)	2,010 – 3,060	1,420 – 2,250	1,030 – 1,840	157.7 – 158.5	145.5 – 146	119 – 119.6	**2,168 – 3,219**	**1,566 – 2,396**	**1,148 – 1,960**
SNG (A$/GJ)	102 – 157	68 – 108	46 – 79	6.04 – 6.07	5.57 – 5.60	4.56 – 4.58	**108 – 163**	**74 – 114**	**51 – 84**

Note: Here the generation costs include the generation cost of hydrogen, conversion to carrier and onsite storage at port. While the Shipping costs include the cost of onloading terminal for loading on ship and the cost of buying and operating carrier for the complete return trip. The L and H represent the low and high cost respectively, for the generation costs these include the lowest and highest cost of generating the products as elaborated in **Section B – C of main report**. Similarly, for shipping represent the lowest cost of shipping which is from Port of Newcastle which is the closest port to destination and the highest cost of shipping which is from Port Kembla which is the farthest port from the destination. For SNG we assume it as a primary energy carrier so cost it as a A$/GJ, the SNG costs also include the cost of liquefaction of SNG.