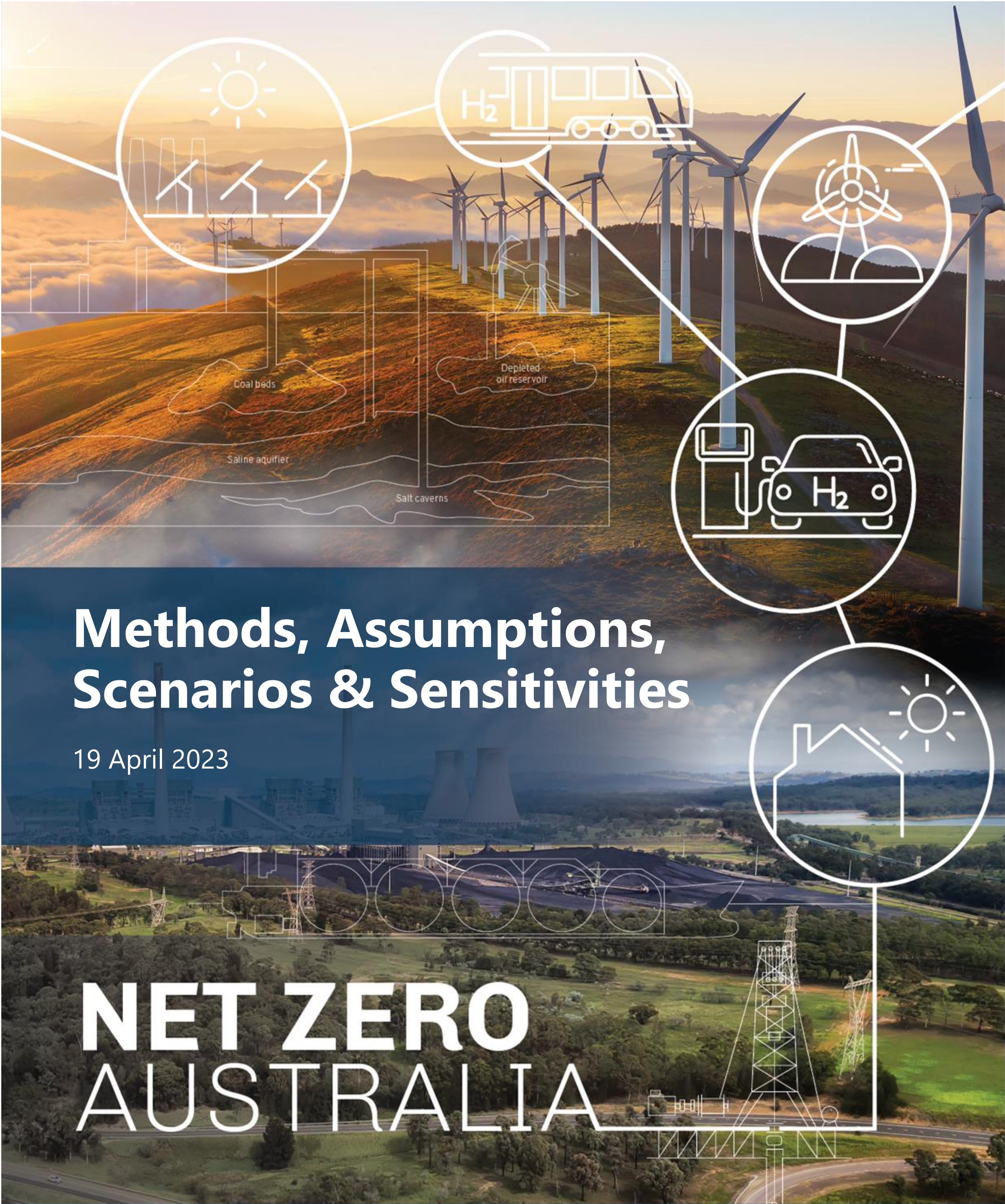

Methods, Assumptions, Scenarios & Sensitivities

19 April 2023

NET ZERO AUSTRALIA

THE UNIVERSITY OF MELBOURNE
PRINCETON UNIVERSITY
THE UNIVERSITY OF QUEENSLAND AUSTRALIA
CREATE CHANGE
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The Net Zero Australia (NZAu) project is a collaborative partnership between the University of Melbourne, The University of Queensland, Princeton University and management consultancy Nous Group. The study examines pathways and detailed infrastructure requirements by which Australia can transition to net zero emissions, and be a major exporter of low emission energy and products.

Net Zero Australia

Methods, Assumptions, Scenarios and Sensitivities

19 April 2023

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Document control

Rev	Date	Notes
1	25 August 2022	Initial publication on website, accompanying preliminary results.
2	19 April 2023	Text edits throughout. Updated Figs 48,49, 68, 78,79,85-90. Updated Transmission costing and supply curve sections. Updated Table 38 and 39 (brown coal gasification capital costs). Updated Cement table and plots in section 10.4.13. Updated all H_2 TX distances and costs in Table 72 and same for CO2 in Table 74. Clarified treatment of available biogas resource in section 9.6.2. Added note on option for export of clean FTL at end of section 10.4.8. Added note on option for LNG to Haber-Bosch repurpose at end of section 10.4.9. Added note on change in supply curve allocation from geographic region to the regional location of the load to which the project is connected (section 9.3.3). Added notes in Tables 72 and 73 on disallowing of certain cross-country H_2 and CO_2 corridors in E+RE− Scenario final model runs. Updated list of Sensitivities, section 1.4. Updated Core Scenarios section 1. General edits and clarification of E+RE– Scenario description. Updated Costs of Capital section 3 to include Social Discount Rate to WACC section. Updated technical parameters of DAC.

Overview

The *Net Zero Australia (*NZAu*)* Project is undertaking its modelling in two stages, as follows.

1. **Regional Investment modelling**

   This modelling determines the investments that will occur *in 15 defined regions across Australia,* such that net zero emissions is achieved for both our domestic energy system and for our energy exports by mid-century on a least-cost basis. This modelling includes projections of emissions from agriculture, waste and Land Use, Land Use Change and Forestry (LULUCF), along with projections of energy demand.

2. **Downscaling**

   This modelling integrates the outputs of our Regional Investment modelling with several important siting considerations, and locates investments on a granular, sub-regional basis. These siting considerations are numerous and include accommodation of high conservation value land and sea, Native Title and Land Rights, farm land, higher population density areas and structurally unsuitable land. Employment impacts are also be modelled in the downscaling effort.

*This document details the **Methods, Assumptions, Scenarios and Sensitivities (MASS)** for the Regional Investment modelling. It does not present results from this analysis, and only discusses some aspects of the Downscaling modelling such that transmission costs can be represented reasonably in this Regional Investment modelling. Documentation of our Downscaling methodologies has been published in companion Downscaling reports.*

It is also noted that drafts of this document have already been reviewed by the NZAu Advisory Group, several of their nominated specialists and several specialists nominated by the NZAu Steering Committee. Revisions to this document have then been made where the NZAu Steering Committee considered the views expressed to be reasonable and/or supported by evidence.

Context

Figure 1 is a schematic representation of the two modelling stages – the Regional Investment modelling and the Downscaling modelling – in the NZAu Project. The Regional Investment modelling that is discussed in this document uses the following two modelling tools from Evolved Energy Research (EER).

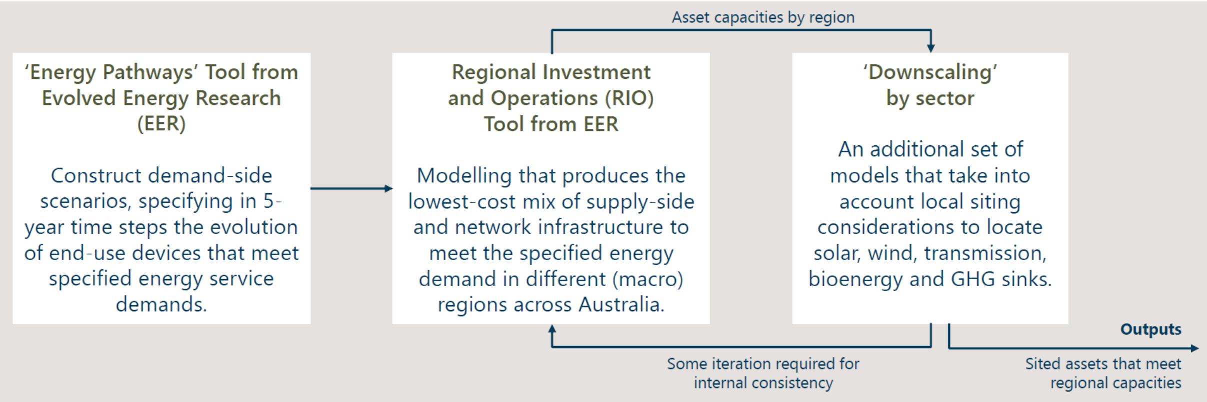
1. **The EnergyPATHWAYS (EP) modelling tool**

   The EP modelling tool enables us to develop demand pathways for a wide range of different energy services from today to mid-century. These pathways for different energy services are consistent with the Scenarios and Sensitivities that are defined in this document.

2. **The Regional Investment and Operations (RIO) modelling tool**

   The RIO modelling tool uses the demand pathways developed with the EP modelling tool. It determines the lowest cost mix of the required supply-side and network investments to meet this demand, whilst also meeting defined greenhouse gas emission (GHG) constraints. RIO's outputs are generated for each of 15 defined regions across Australia.

Figure 1 | Schematic of the overall modelling methodology for the *NZAu* Project.



This document is intended to present a comprehensive and transparent summary of the methods used to complete the EP and RIO modelling. This modelling is intended to be appropriate for the task at hand, and based upon input assumptions that are stated clearly and which use authoritative sources. This includes descriptions of how the following aspects of the Australian energy system are modelled:

- the emissions from agriculture, waste and LULUCF;
- domestic energy demand;
- demand for Australian energy exports;
- domestic energy supply;
- emissions constraints imposed on our domestic energy demand and energy exports; and
- capital and operating costs of our domestic energy system, such that domestic and exported energy demands are met at least cost subject to the specified GHG emissions constraints.

Given the large, uncertain and unprecedented changes that are required to achieve net zero emissions over the next few decades, there will inevitably be different views of the plausibility of different projections. Rather than seeking consensus on all aspects of this modelling, the NZAu Project therefore intends to develop a methodology that is transparently defined, appropriate and based upon input assumptions that are stated clearly and from authoritative sources. The NZAu Project will then examine different net zero pathways using a scenario-based approach, *without stating that any of these pathways are more or less plausible.*

Contents

1 Core Scenarios

Scenarios and scenario planning are well established methods that support long-term strategic decision making for organisations.[1,2] The *Net Zero Australia* (NZAu) Project has adopted such an approach by modelling Australia's domestic and export energy activities from 2020 to 2060 at 5-year timesteps, for six core Scenarios – a Reference Scenario which does not impose a constraint on GHG emissions and five net zero GHG emissions Scenarios. These are summarised in Table 1.

Table 1 | Scenario names and descriptions.

Scenario name	Scenario description
REF	Reference
E+	Rapid electrification
E–	Slower electrification
E+RE+	Rapid electrification with 100% primary energy from renewables
E+RE–	Rapid electrification with the build rate of renewables constrained above historically high levels and the CCS constraint also increased.
E+ONS (Onshoring)	Rapid electrification with imposed local production of iron and aluminium

For all Scenarios, including REF, the demand for exported energy is held constant at 15.08 EJ/year from 2020 to 2060. This is consistent with the International Energy Agency's World Energy Outlook 2020 (Stated Policies Scenario).[3] We also note that this required supply of energy for export is maintained at a constant level across every hour of the year (1.7 PJ/hour), as a conservative assumption that means the export system does not solve domestic renewable balancing, and explicitly represents export energy storage and associated costs in Australia.

Of course, the exported energy to 2060 will depend on many factors that are uncertain. Australia's exported energy could *increase or decrease* significantly depending on the growth and decarbonisation policies of our major energy importers *and* the prospects of other nations in producing low emission exports. This is especially so given the relative lack of land available for renewable energy production at our primary trading partners (e.g., Japan and South Korea) or at other significant, regional fossil fuel exporters (e.g., Indonesia and Malaysia). Such factors were considered out of scope for the NZAu Project but might be justified in another study. As a result, the limitations of our assumed constant demand for exported energy should be kept in mind.

A greenhouse gas emissions constraint is imposed for all net zero Scenarios (Figure 2).

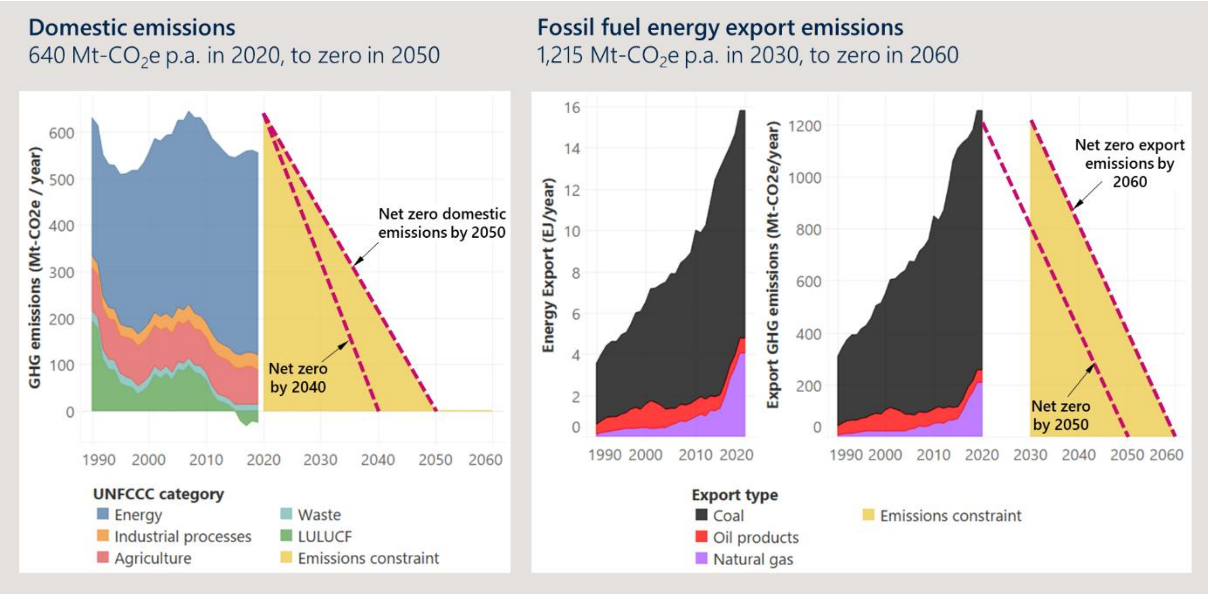
- Domestic emissions: a linear trajectory starting from 640 Mt-CO_2e in 2020 to zero in 2050, where the emissions in 2020 were set to be unconstrained, with all following years constrained.
- Exported emissions: a linear trajectory from 1,215 Mt-CO_2e in 2030 to zero in 2060 with no emissions constraint before 2030 and no new fossil export capacity from 2030. This is considered to be consistent with the Net Zero pledges announced in the lead up to COP26 by several of our major energy trading partners, several of whom have 2050 net zero emissions targets, whilst China and India target 2060[4] and 2070,[5] respectively.

Figure 2 also shows accelerated decarbonisation trajectories for both domestic and exported energy, with these reaching zero by 2040 and 2050, respectively. Nuclear power was not permitted in any of the core Scenarios, consistent with existing Commonwealth and State Laws.[6] However, the use of nuclear will be examined in a proposed sensitivity analysis. limits, notwithstanding the significant scale of the net zero transition.

Finally, in all Core Scenarios we apply constraints on the annual growth rate of utility-scale solar PV, onshore wind and offshore wind electricity generation capacities. This growth rate constraint acts as a smoothing function for the model and is intended to represent plausible limits, notwithstanding the significant scale of the net zero transition. In short it prevents the model from building all the capacity required for 2060 demand in the first timestep.

Specifically, the initial growth rate constraints are 2.5 GW/year and 1 GW/year from 2020 for solar PV and onshore wind, respectively. From this initial constraint in 2020 the actual modelled growth rate is allowed to compound year-on-year by a maximum of 30% in the 2020s, 20% in the 2030s and 10% from the 2040s onward. For offshore wind, the initial growth rate constraint is 0.5 GW/year from 2026, which is allowed to compound by a maximum of 30% until 2037, 20% until 2047 and 0% from then on. Note that while we model capacity additions in 5-year timesteps, we nevertheless account for compounding maximum growth rates in the intermediate years.

Figure 2 | Historical domestic and energy export emissions and applied constraint trajectories.



1.1 Reference Scenario

The Reference Scenario (REF) is included to model business-as-usual without policies to support emissions reductions on domestic and exported energy and includes investments to be made to continue energy supply to mid-century. The outputs of this analysis, such as the total costs, the built and retired generation capacities, and employment impacts, will then be a reference for comparison with equivalent outputs from the net zero emission Scenarios. The Reference Scenario will not be subject to downscaling given its likely significantly reduced use of land for renewable generation.

1.2 Demand side Scenarios

Demand side Scenarios vary with the uptake of electrification, particularly in transport and buildings. All other assumptions are held constant, including energy service projections (outlined in the following section) as well as the cost and performance of both demand-side and supply-side technologies. Electrification and energy efficiency improvements for the industrial sector are applied consistently across all core Scenarios.

In this study, *electrification* means the switching of combustion technologies to electric alternatives. These include, for example, the replacement of natural gas heating with electric heat pumps for heat provision in residential and commercial buildings, or replacement of liquid fuel powered transport with electric vehicles. *Energy efficiency improvements* are measures that increase the efficiency of providing an energy service for a specific energy carrier; for example, the improved efficiency of residential water heaters that arise through technological progress or reductions in fuel use per passenger km travelled in aviation. *Fuel switching* are measures that change the share of a delivered energy service satisfied by a specific energy carrier; for example, switching an industrial combustion process from natural gas to hydrogen.

1.2.1 E+ (Rapid Electrification) Scenario

The E+ Scenario assumes nearly full electrification of transport and building stocks by 2050. All residential and commercial building energy services will be electrified by 2050. These include:

- air conditioning and space heating
- ventilation
- water heating
- lighting
- refrigeration and freezing
- clothes washing and drying
- dishwashing and cooking.

The rollout follows an S-Curve trajectory with full saturation of building stocks achieved by 2050 (further detail in Section 7).

The transport sector is divided into:

- light-duty vehicles (LDVs), including passenger vehicles, light commercial vehicles, motorcyles;
- heavy-duty vehicles (HDVs); including rigid, articulated and other trucks; and
- buses.

The current breakdown of vehicles in each category is presented in Section 6.2. By 2040, 88% of LDV sales are battery electric vehicles (BEVs) and 11% are hydrogen fuel cell vehicles (HFCVs), whilst 65% of HDV sales are BEVs and 34% are HFCVs. The rollout follows an S-Curve trajectory with full saturation of BEVs and HFCVs in transport stocks by approximately 2050 (further detail in Section 7).

No constraints are applied to the supply-side energy mix.

1.2.2 E− (Slower Electrification) Scenario

The E− Scenario assumes a slower transition towards electrification of transport and building stocks, reaching full electrification by 2100, and thus a much lower degree of electrification by 2050, compared with E+. The rollout follows an S-curve trajectory, delaying the full saturation of building appliance and technology sales switching by 60 years, [7] and the full saturation of transport vehicle sales switching by 20 years (further detail in Section 7). The assumption under the E− Scenario is that non-electrified buildings are either challenging to retrofit because of their age, density or heritage status, or the peaks in heating demand during the coldest months cannot be met with heat pumps or reverse cycle air-conditioners. Energy services that are not electrified can then undergo fuel switching with energy demand met by hydrogen or synthetic methane.

For the transport sector, the transition of vehicle sales is delayed by 20 years, relative to E+. That is, in 2050 84% of LDV sales are BEVs and 10% are HFCVs, whilst 60% of HDV sales are BEVs and 31% are HFCVs. The balance of vehicle sales remain as the incumbent internal combustion engine technology, which may run on synthetic fuels by 2050. Their rollout follows an S-Curve trajectory with full saturation of BEVs and HFCVs in transport stocks by approximately 2070.

No constraints are applied to the supply-side energy mix.

1.3 Supply side Scenarios

Energy supply portfolios are selected using the Regional Investment and Operations (RIO) tool to provide the lowest cost energy supply mix to meet energy demand and emissions constraints. The E+ High Electrification Scenario was chosen as the base energy demand input for different supply-side Scenarios as initial modelling indicated this was the lower cost option compared to the E− Scenario.

1.3.1 E+RE+ (Full renewables rollout) Scenario

The E+RE+ Scenario assumes no fossil fuel use is allowed domestically by 2050 and for exports by 2060. Carbon Capture and Storage is only permitted for non-fossil sourced carbon. This includes but is not limited to:

- non-fossil process emissions from industry, e.g., CO_2 released from calcining calcium carbonate in cement production
- bioenergy carbon capture and storage (BECCS) for biofuels and hydrogen production through fast pyrolysis or gasification of biomass
- direct air capture (DAC) of CO_2.

1.3.2 E+RE− (Constrained renewables rollout) Scenario

The E+RE− Scenario imposes more restrictive constraints on the maximum annual build rates of utility-scale solar PV and onshore wind electricity generation capacities than the other Core Scenarios. Specifically, the same initial growth rate constraints of 2.5 GW/year and 1 GW/year from 2020 for solar PV and onshore wind are used, but this is allowed to compound at half the rate used in the other Core Scenarios. That is, for utility-scale solar PV the modelled growth rate is allowed to compound year-on-year by a maximum of 15% in the 2020s, 10% in the 2030s and 5% from the 2040s onward. For onshore wind, the modelled growth rate is allowed to compound year-on-year by a maximum of 15% in the 2020s, and 0% from the 2030s onward. This Scenario does not alter the growth rate constraints for offshore wind.

If utility-scale solar PV and onshore wind are installed up to these applied build rate constraints in every modelled year, the compounding of the build rates would allow 17 GW of solar PV and 7 GW of onshore wind to be installed in 2025 and 51 GW and 20 GW to be installed in 2030. These constraints were chosen to allow modelled build rates that are, in the near term, roughly 5-10 times the highest historical onshore build rates in Australia, and many times greater in the long term. For example, 1.76 GW of utility scale solar capacity was added in 2019, 3.3 GW of Rooftop PV capacity was added in 2021, and 1.7 GW of onshore wind capacity was added in 2021.[[8] Nonetheless, the constraints listed above were considered *optimistic but plausible* after consultation with the NZAu Advisory Group and other informed third parties.

This Scenario is designed to represent a future where wind and solar could not be built at the pace required to achieve domestic *and* export net-zero emissions systems by mid-century using solely renewables. Whilst the causes of the applied build rate constraints are not specified, these could include factors such as:

- delays in supply chains
- skilled labour shortages

- permitting delays
- delays in accessing transmission infrastructure.

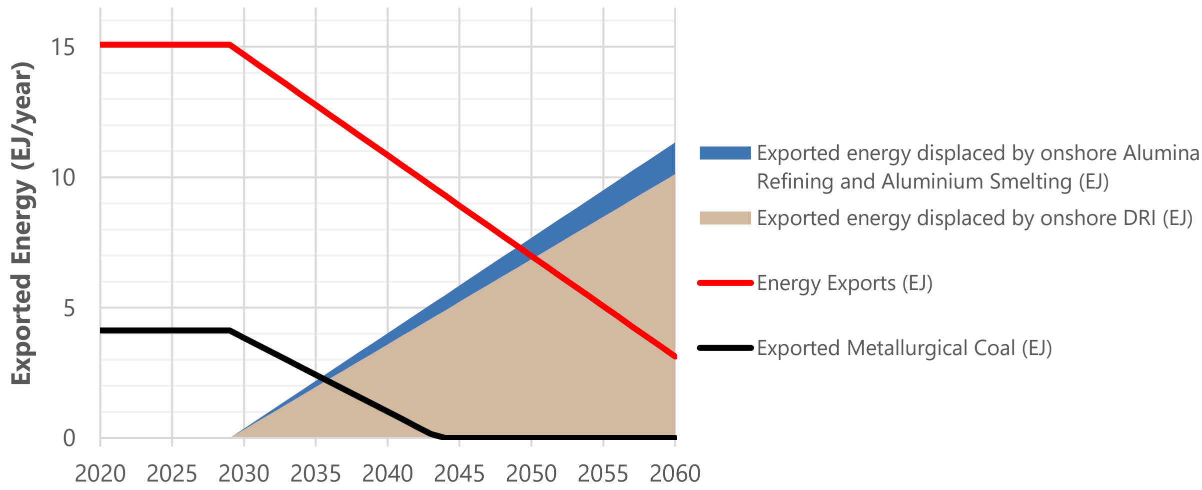
The CCS constraint is also expanded under this Scenario to a total possible injection of 1166 Mt-CO_2/year (Table 32). Given the build constraints on renewables in this Scenario, expansion of this CCS constraint is required to meet domestic and exported energy demand whilst helping provide a distinctive Scenario relative to the others that do not feature build constraints on renewables. Evidence supporting the choice of this expanded CCS constraint is provided in Appendix 0, and basin specific storage and injection constraints are provided in section 9.5. *We emphasise that inclusion of this constraint is not an endorsement of its practicality, just as the modelling of unconstrained renewable build rates in the other Scenarios is not an endorsement of their practicality.*

1.3.3 E+ONS (Onshoring) Scenario

In addition to being a major energy exporter, Australia is of course also a major exporter of other commodities. Of the numerous commodities that we export, the emissions generated offshore by processing these non-energy commodities are dominated by the reduction of Australian iron ore to iron, as well as the processing of Australian bauxite and alumina into aluminium.[12]

The Onshoring Scenario therefore seeks to examine how some of our energy exports might be used to displace our iron ore, bauxite and alumina exports with domestically processed pig iron and aluminium for export. In this Scenario, we treat the energy required for onshore alumina refining, aluminium smelting and iron ore reduction as taking away from the modelled energy exports, and not adding to it, as shown in Figure 3.

Figure 3 | Energy Exports in the E+ONS Onshoring Scenario.



As with all Scenarios, clean energy is exported primarily as liquid ammonia (as discussed in Sections 10.4.6 and 10.4.7). However, the energy required for iron reduction, alumina refining or aluminium smelting is either in the form of hydrogen or electricity. As such, the efficiency of ammonia conversion into hydrogen or electricity at the port of delivery is incorporated into the reduced energy exports as per Figure 4 and Figure 5. The conversion of ammonia to hydrogen uses typical reformer efficiency of 75%.[9] The conversion of ammonia to electricity assumes the thermal efficiency of a CCGT in AEMO's ISP.[10]

Figure 4 | Flowchart of ammonia energy export displaced by the onshoring of DRI in the E+ONS Onshoring Scenario, assuming that exported ammonia would have been used to process raw Australian iron ore in the importing country. This incorporates efficiencies of 75% for ammonia reforming and 50% for ammonia to power.[9,11]

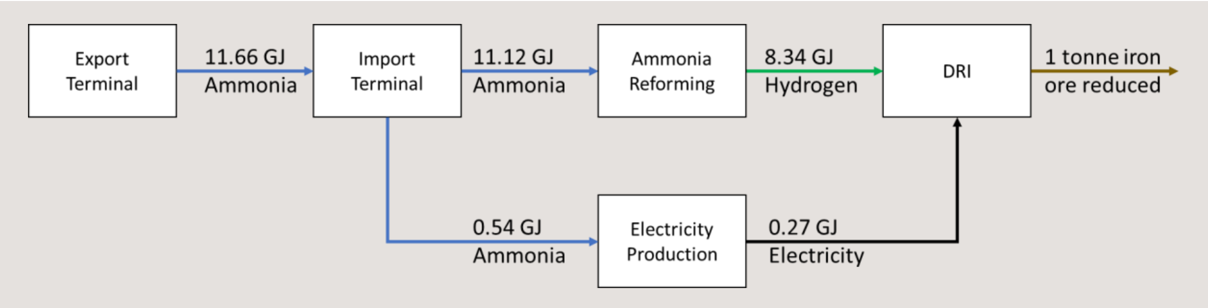
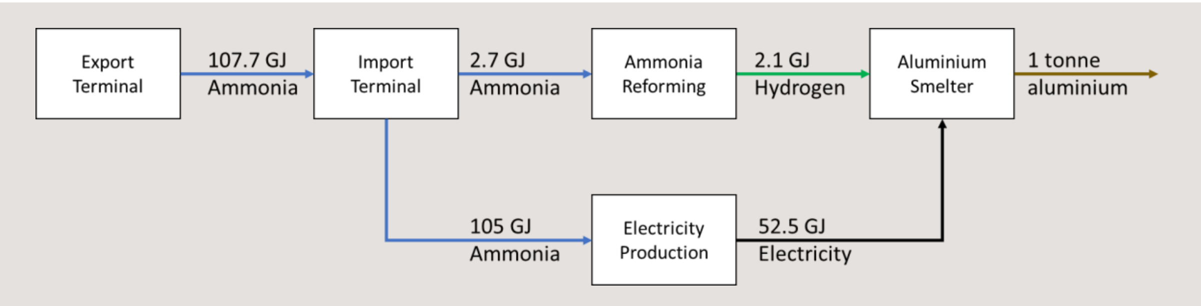


Figure 5 | Flowchart of ammonia export displaced by the onshoring of aluminium production in the E+ONS Onshoring Scenario, assuming that exported ammonia would have been used to process Australian bauxite or alumina in the importing country. This incorporates efficiencies of 75% for ammonia reforming and 50% for ammonia to power.[9,11]



Iron

The E+ONS Onshoring Scenario assumes that Australia's iron ore exports under the E+ Scenario will be progressively transformed into pig iron domestically by using hydrogen and the Direct Reduction Iron (DRI) process. Australia exported 867 Mt of iron ore and 172 Mt of metallurgical coal in 2020.[12] In this Scenario, these exports are held constant out to 2029 in line with our export emissions constraint described above. From 2030, iron ore exports are then reduced linearly to 0 by 2060 and a corresponding amount of domestic DRI production using locally produced, clean hydrogen is brought online using the data in Table 2. The energy exports that would have been used in the importing country to undertake the DRI are then considered as displaced by the onshoring process, and are subtracted from the total energy exports according to Figure 4; 1 tonne of onshored DRI displaces 11.66 GJ of exported ammonia

Table 2 | Inputs for iron ore reduction from coking coal compared to DRI using hydrogen.[14-18]

Input into process	Tonnes per tonne of pig iron
Iron Ore	1.6
Coke	0.45
Metallurgical Coal	0.68
Hydrogen (for Reduction only)	0.058
Hydrogen (for heating)	0.040
Electricity	0.45 (GJ)

We also make the following assumptions in this Scenario:

- The Circored process for DRI production[14-18] is used and is described in more detail in section 10.4.14.
- The DRI furnaces are located in the WA-port zone, which contains both hydrogen scheduled for export, existing iron ore export terminals, and sufficient electricity infrastructure for the production of pig iron at scale. The port facilities for export of pig iron are also placed within the WA-port zone.
- Capex costs of $600/t of annual pig iron production and fixed operating costs at 3% of CapEx are used. These are based on projections from recent DRI projects in the US.[16, 17]

Alumina and aluminium

The E+ONS Onshoring Scenario assumes that all of Australia's current bauxite exports under the E+ Scenario are refined to alumina domestically and that all alumina is smelted into aluminium domestically using a combination of electricity, inert anodes[19] and hydrogen for heat provision in either the Bayer process or an aluminium smelter. Australia produced 103 Mt of bauxite, 20.8 Mt of alumina and 1.58 Mt of aluminium metal in 2020.[12] The majority of bauxite is refined to alumina onshore already with only 0.35 Mt exported. Of the 20.8 Mt of alumina produced in Australia, 18.6 Mt are exported. Of the 1.58 Mt of aluminium produced, 1.40 Mt are exported. For the Onshoring Scenario the production of bauxite is held constant out to 2060. From 2030, more aluminium is produced onshore, scaling linearly so that by 2060 all bauxite is converted to alumina and all alumina is converted to aluminium within Australia. The inputs for the processing of alumina and aluminium are given in Table 3.

Table 3 | Inputs for alumina and aluminium for existing and net zero emissions technologies.

Process input	Energy (PJ) per million tonne of product
Alumina[1]	
Bauxite	4 tonne per tonne alumina
Thermal Coal	6.20
Fuel oil	0.05
Natural Gas	12.36
Diesel	1.19
Hydrogen (for heating)	19.81
Electricity	0.48
Aluminium	
Alumina	1.92 tonne per tonne aluminium
Fuel Oil (Casting[2])	0.37
Natural Gas (Casting)	1.70
Diesel (Casting)	0.004
Hydrogen (casting)	2.07
Electricity (Casting + smelting)	0.25 + 52.25

Australia's existing alumina and aluminium industry, comprising 6 refineries and 4 smelters, transitions to net zero emissions by 2050 as per the E+ Scenario. The location of each plant, the nameplate capacity and the upgraded capacity by 2060 is given in Table 4. The transition to domestically produced, clean alumina and

[1] The fuel mix was obtained on a per region basis from [https://international-aluminium.org/statistics/] and converted to a per tonne basis using the associated production numbers.

[2] Casting inputs were determined from [22] and adjusted to 2020 assuming a 13.8% improvement in all process heat efficiency from 2002-2020. This is based on the improvement in cell efficiency over the same time period.

aluminium involves swapping fossil fuelled heat for the same thermal energy from hydrogen in the alumina refinery, and the use of inert anodes rather than carbon anodes in the aluminium smelter. The direct GHG emissions from these expanded refineries and smelters are then zero, and the GHG emissions from and costs of their hydrogen and electricity supply forms part of our imposed National GHG emissions constraint trajectory and RIO's optimisation task.

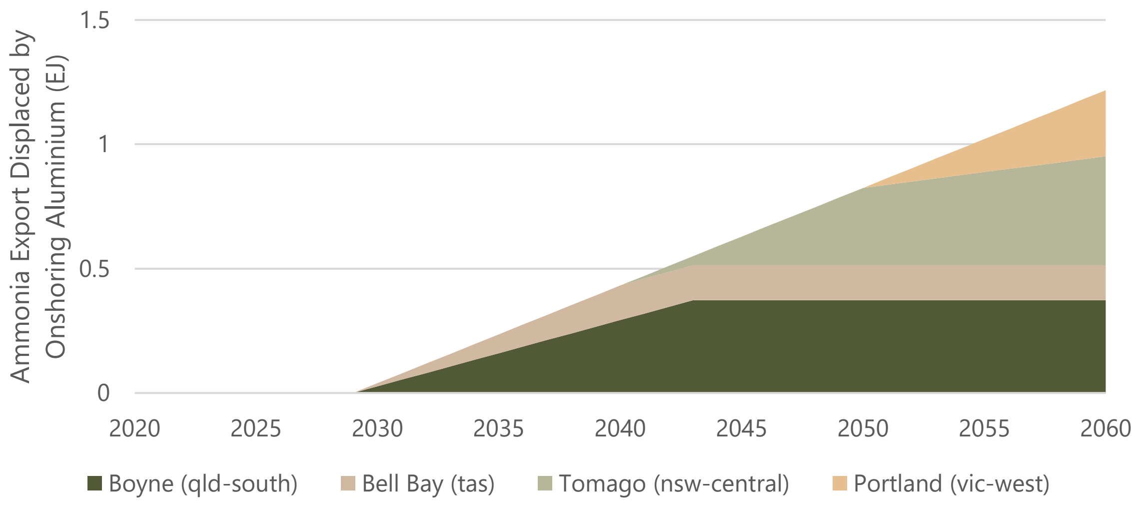
We also make the following assumptions for this Scenario:

- Additional alumina refinery capacity is required for the additional 5 Mtpa of alumina that must be processed onshore in this Scenario. We assume existing facilities are expanded to meet this additional capacity so that by 2060 the National distribution of production remains the same. The upgrade of existing facilities occurs in line with the age of the existing facilities as per the schedule in Table 4
  - Capex costs for alumina refining range from $1300-2125/t (2020 AU$) of annual alumina production for greenfield alumina refineries. We use $1300/t of annual alumina production (AU$ 2020) to reflect that we will instigate brownfield expansions of existing capacity rather than a single new build. Fixed operating costs are set as 2% of CapEx based on the maturity of Australian refineries.[20, 21] The cost of infrastructure to transport the alumina to the upgraded smelters for aluminium production is assumed to be equivalent to the existing export infrastructure.
- Additional aluminium smelting capacity is required for the additional 11.3 Mtpa of aluminium that must be processed onshore in this Scenario. We assume existing facilities are expanded to meet this additional capacity so that by 2060 the share of production remains the same. The upgrade of existing facilities occurs in line with the age of the existing facilities as per the schedule in Table 4 and Figure 6.
  - Capex costs for greenfield aluminium smelters range from to $4200 - $5600 (AU$ 2020) per tonne of aluminium production per year.[23] NZAu uses the lower range of $4500 per tonne of aluminium production per year (AU$ 2020) to reflect that we will instigate brownfield expansions of existing capacity rather than new greenfield projects at one of our export port regions. The cost of the upgrade of export facilities is assumed to be included in the brownfield facility upgrade. Operating costs are set at 2% CapEx based on the maturity of Australian smelters.
  - We impose a +/−20% per hour ramping rate constraint on the electricity load of the aluminium smelters for load balancing purposes.

Table 4 | Location of Existing Alumina and Aluminium Facilities.

Facility	Location	Nameplate Capacity (kta)	Upgraded 2060 Capacity (kta)
Alumina refineries		**21020**	**25,750**
Kwinana	WA-south	1870 (9%)	2,291
Pinjarra	WA-south	4700 (22%)	5,758
Wagerup	WA-south	2800 (13%)	3,430
Worlsey	WA-south	4600 (22%)	5,635
Yarwun	QLD-south	3100 (15%)	3,798
QAL	QLD-south	3950 (19%)	4,838
Aluminium Smelters		**1640**	**12,875**
Boyne	QLD-south	502 (31%)	3,941
Tomago	NSW-central	590 (36%)	4,631
Portland	VIC-west	358 (22%)	2,810
Bell bay	TAS	190 (12%)	1,492

Figure 6 | Scheduled Production for Aluminium Export by Region.



1.4 Scenario sensitivities

The purpose of Sensitivities is to explore their potential impact on key characteristics of the transition, e.g., supply-side technology and resource mix, costs, etc. The specific Sensitivities that were modelled are listed in Table 5.

Table 5 | Scenario Sensitivities – names and descriptions.

Core Scenario(s)		Sensitivity	Description
E+	E−	Faster	Domestic emissions are decarbonised by 2040 and export emissions are decarbonised by 2050 (both linear from 2020).
E+		Drivers+	GDP growth 3% pa from 2020; population growth 1.5% pa from 2020.
E+		Drivers−	GDP growth 1.5% pa from 2020; population growth 0.9% pa from 2020.
E+	E+ONS	Export+	Energy exports are linearly increased to 30EJ from 2040 to 2060.
E+		Export−	Energy exports decline linearly to 5EJ from 2040 to 2060.
E+		CleanExport−	Export embodied emissions do not need to go to zero (some importing countries may have option of sequestration). 50% export decarbonisation by 2060.
E+	E+RE−	RemoteCost+	Remote northern regions of Australia have higher capital costs.
E+	E+RE−	DistributedExport	Export task is more evenly distributed across the country. Each of SA, WA, NT and QLD can contribute individually at most 20% to export task.
E+		Solar−	Use a less ambitious capital cost trajectory for solar PV. 2050 solar PV cost is 1300 $/kW (cf. 653 $/kW in Core Scenarios).
E+		Transmission−	All inter-regional transmission is fixed at current capacities for electricity, CH_4, H_2 and CO_2.
E+RE−		Nuclear	Nuclear power is allowed from 2035 onwards. Modelled as a Nuclear SMR with capital cost: 7,200 $/kW.
E+	E+RE−	CheapNuclear	Cheaper nuclear power is allowed from 2035 onwards. Modelled as a Nuclear SMR with capital cost: 5,200 $/kW.
E+RE+		Land+	Combined land sector (agriculture, waste, LULUCF) go to modest net negative emissions by 2050 (−31.5 Mt-CO_2e/year in 2050).
E+	E−	Sequestration+	Constraint on geologic sequestration of CO_2 is expanded to 1166 Mt-CO_2/year, which is the upside of appraised capacities and is used in E+RE−.
E+RE−		Sequestration−	Constraint on geologic sequestration of CO_2 is reduced from 1166 Mt-CO_2/year to 150 Mt-CO_2/year, which is the same as other Core Scenarios.
E+		Sequestration+ WACC+	Elevated costs of capital using a multiplier of ×2 on real WACC assumptions across all asset categories and ×1.5 on social discount rate. We also expand the constraint on geologic sequestration of CO_2 to 1166 Mt-CO_2/year.
E+		Sequestration+ Fossil+	Fossil fuel costs are increased by factor of ×2. We also expand the constraint on geologic sequestration of CO_2 to 1166 Mt-CO_2/year.

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2 Projections of population, GDP growth and other primary drivers

Demand drivers are the characteristics of society that in part determine how people consume energy. Examples include population, metrics of heating and air conditioning use such as 'cooling degree days', and vehicle kilometres travelled. Sets of demand drivers are tied to services in particular subsectors (Section 7) and become the basis for projecting the future demand for these energy services.

A total of twelve energy service demand drivers were developed for this study, which are divided into:

- five base drivers (population, heating and cooling degree days required, median income and gross state product); and
- seven additional drivers which are an extrapolation of historical data based on assumed relationships with at least one base driver. For example, to arrive at a projection of residential floor area, population projections by state were gathered from the *Australian Bureau of Statistics* (ABS). A chain of relationships was then developed as follows: population → number of households → total number of residential dwellings → residential floor area. At each step, historical trends were used to inform the assumptions made.

For the gross state product base driver, historical data is sourced from the Australian Bureau of Statistics (ABS),[1] while projections of future growth are provided by the Australian Energy Market Operator (AEMO) 2022 Integrated System Plan,[2] with the assumption of 1.5% compound annual growth for years beyond those included in the ISP projection. The 1.5% number was chosen as a continuation of the 2020 – 2050 trend. Table 6 summarises these energy demand drivers used, the related extrapolation method and the data source.

A visualisation of key drivers is given in Figure 7.

Table 6 | The twelve energy service demand drivers developed in this work with data source and extrapolation method if data does not extend over the modelled years (2020 – 2060). SA2/SA4 refer to statistical divisions used to organise ABS data.

Energy services driver	Unit	Native geography	Native data years	Extrapolation method	Source
Population	people	State	2017 – 2066	Not needed	ABS, Population Projections, Australia 2017 (base) – 2066 [3]
Gross domestic product	2020 AU$	State	1990 – 2050	1.5% per year growth	Historical ABS data, [1] projections provided in AEMO 2022 ISP [2]
Annual heating degree days	hdd	SA2	1980 – 2080	Not needed	Interpolation between different HDD points and assuming 0.25 degrees warming per decade [4]
Annual cooling degree days	cdd	SA2	1980 – 2080	Not needed	Interpolation between different CDD points and assuming 0.25 degrees warming per decade [4]
Median income	AU$	National	2012 – 2018	1.5% per year growth	ABS, Personal Income in Australia [5]
Total number of dwellings	dwellings	SA4	2018	Tied to number of households	Australian Institute for Family Studies [6]
Number of households	households	National	1954 – 2050	Tied to population after 2050	Australian Institute for Family Studies [6]
Residential floor area	m^2	State	2018	Tied to total dwellings	ABS, Building Activity, Australia [7]
Total freight – articulated trucks	tonne-km	National	1974 – 2018	Tied to gross state product	Department of Infrastructure, Transport, Regional Development and Communication, Australian Infrastructure Statistics—Yearbook 2020, Table T 4.5 [8]
Total freight – light commercial vehicle	tonne-km	National	1974 – 2018	Tied to gross state product	Department of Infrastructure, Transport, Regional Development and Communication, Australian Infrastructure Statistics—Yearbook 2020, Table T 4.5 [8]
Total freight – rigid trucks	tonne-km	National	1974 – 2018	Tied to gross state product	Department of Infrastructure, Transport, Regional Development and Communication, Australian Infrastructure Statistics—Yearbook 2020, Table T 4.5 [8]
Clinker production	tonne	SA2	2020 – 2050	Tied to population after 2050	Internal calculations – based on 1.7% per year growth of domestic cement industry and assumed lifetimes of existing plants.

Figure 7 | Projections of GDP and population drivers in absolute units (top), and the relative change in the other 10 energy service demand drivers (middle and bottom) over NZAu's modelled time period, 2020 to 2060.

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3 Costs of capital

Energy supply models used in the NZAu generate deep decarbonisation pathways by minimising total system costs expressed as a net present value (NPV) over the transition period (e.g., 2020-2060), with 2020 Australian dollars (2020AU$) as the base currency. All scenarios are underpinned by assumptions about technology performance and costs over time, both of which become increasingly favourable over time, as each technology follows its respective learning curves. Alternate pathways are generated, in acknowledgement of the uncertainty around future costs and technology uptake, by imposing different constraints in relation to end use electrification and deployment of specific supply-side technologies.

The Net-Zero America study[1] and other studies which adopt such approaches, generally find that the incremental NPV of the total system costs of net-zero pathways relative to the reference case results in only a modest, if any, increase in energy service expenditures as a percentage of the nation's GDP.

Net-zero transitions are fundamentally much more capital intensive than traditional energy systems. These higher system capital costs are generally incurred up front, but the increased capital spend is at least partly offset by lower operating and fuel costs. The transition can result in affordable energy services, if the required rapid rate of capital mobilisation is met and maintained, with a low cost-of-capital applied to capital investments and low inflation (escalation) in relation to energy transition equipment and materials, construction services, and labour input costs.

In addition, the modelling framework uses a social discount rate to discount the future benefits and costs of the transition to society, to real (2020) dollars. The assumptions in relation to inflation (as a proxy for economic growth and input cost inflation on the energy sector), the Weighted Average Cost of Capital (WACC) and the social discount rate used in the model are therefore critical.

3.1 Literature and data sources

Inflation rates, population growth and productivity improvements effect projections for energy demand growth during the transition. Procurement costs for energy assets (plant, materials and labour) will also be subject to escalation over time and are likely to be at least partially linked to inflation metrics.

The WACC that can be attributed to energy investments is a function of the returns on equity appropriate to the firms making the investments and to the commercial lending rates charged by banks providing debt in the relative proportions that each contributes to the capital formation for the project. Each have dependencies on the other and relate to the risk profile of the project. The risk profile of a project is a complex mix of technology, completion, commercial, policy and market risks. WACC values are estimated for each asset category (renewable power, clean fuels, transmission, etc.,) ignoring heterogeneity due to individual project characteristics, with regard to their technology maturity, location, policy environment, experience of the developer, depth of supply and end-user market and the approach taken by the developer, etc.

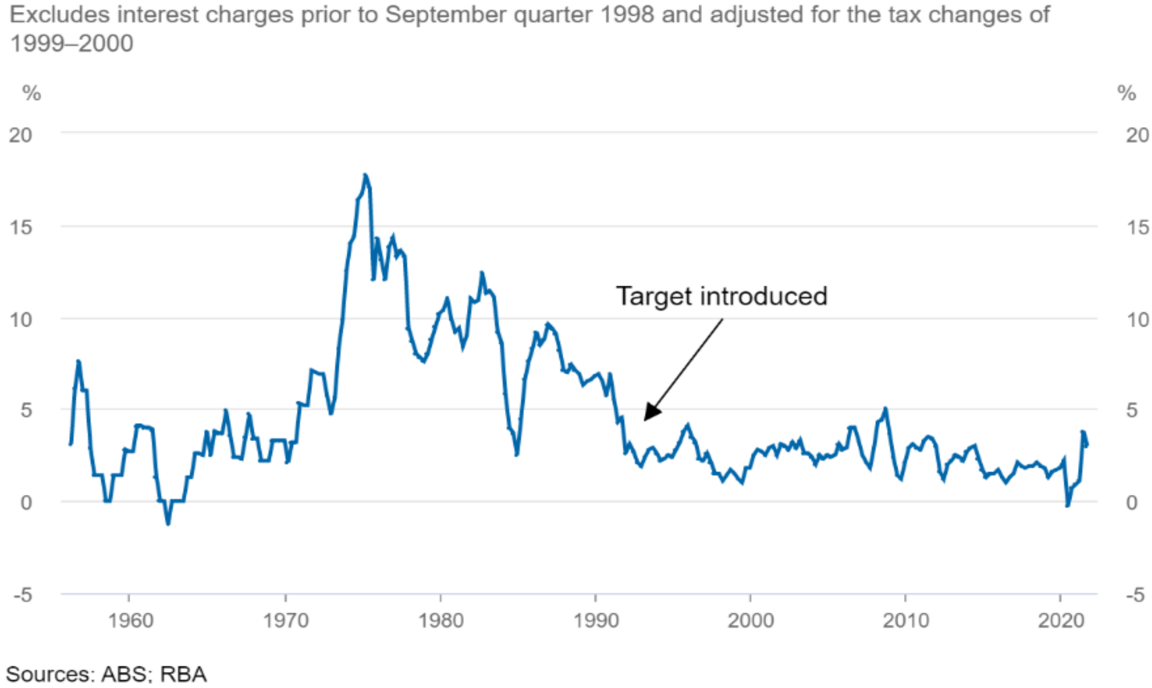
Finally, the social discount rate reflects how much we discount the benefits of the transition (including climate benefits) to society. A high social discount rate implies that society places less weight on the future and therefore is not prepared to invest now to guard against future costs (e.g. damages from climate change), and vice versa.

The following inflation and interest rate trends provide guidance in selecting operating and capital cost input escalation, values of the weighted average cost of capital applied to capital investment decisions, and the social discount rate, for the Australian context. In each case, the available data are averages, and lending rates and equity returns will vary according to a distribution based on the assessed risk profile of the project and investors, with the exception of the inflation and risk-free rates. Over a 30-year transition period, these lending rates and equity returns will vary significantly.

3.1.1 Inflation rate

Inflation in Australia has averaged 4.7% in the 60 years from 1951 until 2021 (Figure 8[2]). It reached a high of 23.90 percent in the fourth quarter of 1951 and a record low of −1.30 percent in the second quarter of 1962. Since 2000 inflation has trended lower, averaging around 2.6% with a high just over 6%, and a low during the COVID-19 pandemic of around −0.3%. The most recent 10-year average is 2.0%. We therefore assume an inflation rate of 2.6% for this project. In this work we have also nominated this inflation rate to inform the selection of the social discount rate (2.7%).

Figure 8 | Historical inflation rate (Consumer Price Index, CPI, year ended percentage change) in Australia.



3.1.2 Risk-free interest rate (the RBA cash interest rate)

Figure 9[3] shows the historical trend in the cash rate of the Reserve Bank of Australia (RBA) which is essentially the (near) risk-free rate for Australian dollars at which the RBA lends on an unsecured basis overnight to commercial banks. The risk-free rate has ranged from the current record low of 0.1% to almost 18% in 1980. The rate has averaged around 3.5% since 2000. The average since 2010 has been 2% and since November 2020 it has been held at the record low of 0.1%, in an effort to maintain economic activity during the COVID-19 pandemic.

Figure 9 | Historical RBA cash rate (risk-free rate) in Australia.

Source: RBA

3.1.3 Business credit rate

Figure 10[4] shows the historical lending rates to large businesses in Australia since 1980. Rates have ranged from the current lows of just over 3% to more than 20% in the mid to late 1980s, with an average of just over 6% since 2000.

Figure 10 | Historical large business interest rate (weighted average variable rate on credit outstanding).

Source: RBA

3.1.4 Equity returns

Equity returns are more variable, and as a result are difficult to generalise compared to interest rates. For the 200 largest companies listed on the Australian Stock exchange, equity returns have averaged 9.4% (after tax) over the last 30 years and 9.3% over the last 10 years.[5, 6]

For regulated assets, equity rates are lower and either in line with, or with a small premium over the business credit rate, shown at 3.1.3, which is consistent with the recent AER review.[7]

3.2 Basis of cost of capital assumptions

The WACC for projects is the percentage rate of return an investment needs to generate in order to compensate, on average, both the debt and equity capital providers to the business. It is determined using the following formula:

$$WACC_{nom} = \left[\frac{E}{E+D} \times \text{Cost of Equity}\right] + \left[\frac{D}{E+D} \times \text{Cost of Debt} \times (1 - \text{Tax Rate})\right]$$

$$WACC_{real} = \frac{1 + WACC_{nom}}{1+i}$$

$WACC_{nom}$	is nominal WACC
$WACC_{real}$	is real WACC
E	is the amount of equity
D	is the amount of debt
i	is the inflation rate

For the purposes of the NZAu transition modelling, real WACC assumptions are required for the different asset categories including:

- regulated assets (e.g., electricity transmission and H_2 and CO_2 trunk lines)
- mature[3] and relatively low-risk generation and production technologies (e.g., wind, solar, Lithium-ion batteries, pumped hydro, Open Cycle Gas Turbines)
- mature and moderate-risk generation and production technologies involving natural resources or elevated permitting risk (combined cycle gas and super-critical pulverised coal with CCS, bioenergy with CCS, blue hydrogen, green hydrogen, Fischer-Tropsch fuels production, direct air capture, subsea electricity cables)
- higher risk generation and production technologies (nuclear).

Each category will involve a different debt to equity ratio, and historical data and judgement have been used to set the values used in the study, which are shown in Table 7, with the full list of WACC values for the NZAu modelling provided in Appendix A.1.

[3] In the context of net-zero emissions, the scale and pace of investments is such that for Australia, principally a fast follower on many technologies, technologies adopted over the major part of the transition will have been matured.

Table 7 | Table of proposed Real WACC for project investment decisions across the asset categories in *NZAu* Modelling assuming an inflation rate of 2.6% and a corporate tax rate of 30%.

Asset Category	E	D	E Cost	D Cost	Nom. WACC	Real WACC
Regulated Assets	30%	70%	6%	6%	4.7%	2.1%
Low-risk Gen & Prod	40%	60%	12%	7%	7.7%	5.0%
Mod-risk Gen & Prod	45%	55%	12%	8%	8.5%	5.7%
High-risk Gen & Prod	50%	50%	15%	9%	10.7%	7.8%
Tax rate	30%					
Inflation rate	2.6%					

3.3 Sensitivity: E+ Sequestration+ WACC+

Figure 8 through Figure 10 show that the past decade has seen a period of historically low inflation, interest rates and equity returns, starting from the Global Financial Crisis and amplified during the COVID-19 pandemic. It is possible that Australia and other countries will experience considerable periods of higher inflation and costs of capital in future. One modelling sensitivity was run to explore the impact of elevated costs of capital – using a multiplier of 1.5× on inflation/societal discount rate and 2× on WACC assumptions across all asset categories.

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4 Emissions accounting

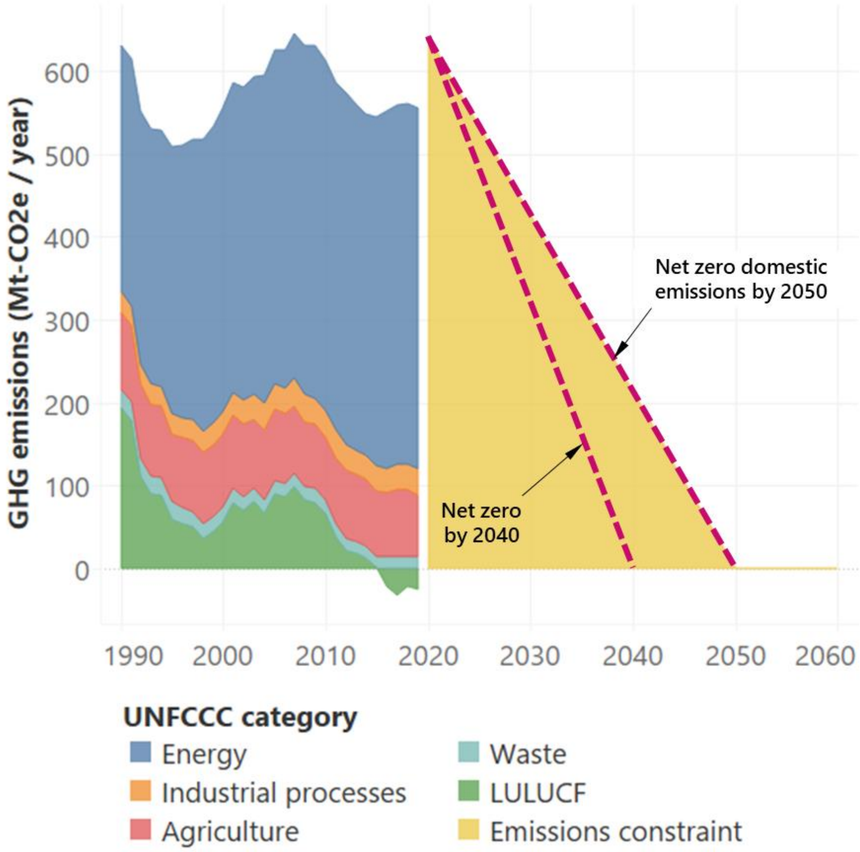
A rigorous net zero plan should specify the greenhouse gases (GHGs) to be abated, their sources, and the timeframe for meeting the net zero GHG emission target. [1] The NZAu project uses Australia's 2019 National Greenhouse Accounts[2] under the UNFCCC classification system as the starting point for its net zero emissions calculations, and therefore includes all anthropogenic GHGs and covered sectors.

Table 8 summarises the GHG emissions for each UNFCCC category and the specific gases included in the Australian GHG inventory for 2019, while a historical view of these GHG emissions trends is shown in Figure 11. Table 8 shows that carbon dioxide (CO_2) is the largest contributor to Australia's total domestic GHG emissions, but methane (CH_4) and nitrous oxide (N_2O) are also significant, particularly from agriculture, waste and Land Use, Land Use Change and Forestry (LULUCF). It should be noted that the GHG emissions of the various gases are aggregated on a carbon dioxide equivalent basis (CO_2e) using the 100-year global warming potentials (GWP-100) contained in the IPCC Fifth Assessment Report (AR5). [3] The GWP-100 values for CH_4 and N_2O are 28 and 265, respectively. Any update to the GWP-100 in future IPCC documents will have some impact on the required net-zero transition, however this is expected to be a second-order impact that mostly affects agriculture, waste and LULUCF.

Table 8 | Summary of Australia's 2019 greenhouse gas inventory, by sector and specific GHG. Emissions are presented on a carbon dioxide equivalent basis (Mt-CO_2e).[2]

UNFCCC category	GHG emissions (Mt-CO_2e)				
	Carbon dioxide	Methane	Nitrous oxide	Other	Total
Energy	394.5	36.8	2.7	0.0	**434.0**
Industrial processes	19.4	0.0	2.0	10.3	**31.8**
Agriculture	2.7	60.7	11.5	0.0	**74.8**
Waste	0.0	13.1	0.6	0.0	**13.8**
LULUCF	−42.7	14.8	2.9	0.0	**−25.1**
Total	**373.9**	**125.5**	**19.6**	**10.3**	**529.3**

Figure 11 | Historical Australian domestic GHG emissions and net zero trajectories modelled in this work.[1]



4.1 Domestic emissions

The net zero scenarios of NZAu are constrained to a linear trajectory to net zero domestic GHG emissions in 2050. This is applied as an upper limit on annual net CO_2e GHG emissions, for all UNFCCC sectors, and with the linear trajectory of this *domestic* limit taking effect from 2020 and reaching net-zero in 2050, as shown in Figure 11.

Net-zero emissions requires any residual flow of GHG emissions to the atmosphere to be offset by a permanent removal of the equivalent CO_2 from the atmosphere. To meet this domestic emissions constraint, the work first sets out projections for the plausible contribution to emissions abatement from the agriculture, waste and LULUCF sectors (outlined in Section 8). The total GHG emissions trajectory for those sectors is then fixed for the years 2020 to 2050. We then directly model emissions in the domestic energy and industrial sectors, such that GHG mitigation and fuel switching within those sectors, are least-cost optimised to meet the domestic emissions constraint, given the fixed trajectory of emissions from the agriculture, waste and LULUCF sectors.

Within the modelling of the energy and industrial processes sectors, the annual domestic emissions level is equal to the total direct GHG emissions arising from the domestic consumption of fuels and feedstock, plus fugitive emissions associated with the production of fossil fuels, less any permanently sequestered emissions in geologic formations. Table 9 provides the emissions factors used to account for direct consumption GHG emissions on an energy basis. These are based on the GHG emissions embodied in a unit of energy.

Table 9 | Emissions factors used to account for direct consumption GHG emissions on an energy consumed basis.

Fuel/feedstock	Embodied GHG emissions factor (kg-CO_2e / GJ)
Black coal	90.2
Brown coal	93.8
Natural gas	51.6
Oil	69.9
Refined fossil liquids	69.6
Uranium oxide	0
Biomass (incl. bagasse, municipal waste, waste methane)	0

Table 10 provides the fugitive emissions factors on a basis of energy content produced for a given fossil fuel. The *coal seam natural gas* (CSG) fugitive emissions factor for 2020 was calculated using reported losses in the Surat Basin of 0.25% from upstream activities and 0.07% from midstream and transmission activities. [4] The factor was then calculated to be 1.8 kg-CO_2e/GJ using methane's GWP-100 of 28 and higher heating value of 49 GJ/t-CH_4. We then incorporate reductions in this fugitive emissions factor, based on concerted industry effort to mitigate fugitives. For CSG it is assumed that fugitive emissions are halved by 2030 and eliminated by 2040 (Table 10).

The fugitive emissions factor of *conventional natural gas* for 2020 was estimated by first subtracting the estimated 2020 CSG fugitive emissions from the total oil and natural gas fugitive emissions in the national inventory[4] using the above calculated factor and the total CSG produced. [5] The remaining fugitive emissions in the national inventory were then divided by the total conventional natural gas produced, to obtain a factor of 6.1 kg-CO_2e/GJ. This factor is similarly assumed to reduce with time, based on industry effort to mitigate fugitive methane emissions. The remaining non-zero fugitive emissions factor for conventional natural gas in 2040 accounts for the carbon dioxide component extracted from existing natural gas reservoirs (which can be captured and stored from 2025 onwards, forming part of the CCS in all allowable scenarios).

The fugitive emission factor for brown coal is estimated from the factor 0.0003 t-CO_2e/t-raw coal reported in the National Greenhouse Accounts Factors report[6] for open cut mines in Victoria. The fugitive emissions factor of 0.03 kg-CO_2e/GJ was calculated with an energy content of 10.2 GJ/t for brown coal.[6] The black coal fugitive emissions factor of 2.2 kg-CO_2e/GJ was then estimated as the remainder of total coal fugitive emissions in the inventory per total energy content of black coal produced[5].

Table 10 | Emissions factors used to account for fugitive GHG emissions on an energy produced basis.

Fossil fuel production	Fugitive GHG emissions factor (kg-CO_2e / GJ)		
	2020	2030	2040
Black coal	2.18	2.18	2.18
Brown coal	0.03	0.03	0.03
Coal seam natural gas	1.83	0.91	0.00
Conventional natural gas	6.06	5.34	4.62

4.2 Export emissions

In addition to modelling domestic GHG emissions abatement, NZAu models the abatement of the emissions embodied in Australia's energy exports. Australia has historically been a significant exporter of fossil fuels (Figure 12), which have a GHG emissions footprint when used in the importing country.[5] The core scenarios of NZAu apply a constraint to these embodied export emissions, from 2030 onwards, as a linear trajectory to zero in 2060, as shown in Figure 12. Australia's production of energy exports is then optimised, such that the volume of exports (on an energy basis) remains constant at 2019-20 levels as the embodied emissions are decarbonised. The GHG emissions factors outlined in Table 11 are used to calculate the emissions associated with fossil fuel energy exports.

Table 11 | Embodied emissions factors for various energy exports on an export energy basis.

Energy export	Embodied emissions factor (kg-CO_2e / GJ)
Coal	90.2
Natural gas	51.6
Oil products	69.6
Hydrogen (or derivatives)	0
Biogenic (or direct air capture derived) hydrocarbons	0
Uranium oxide	0
Electricity	0

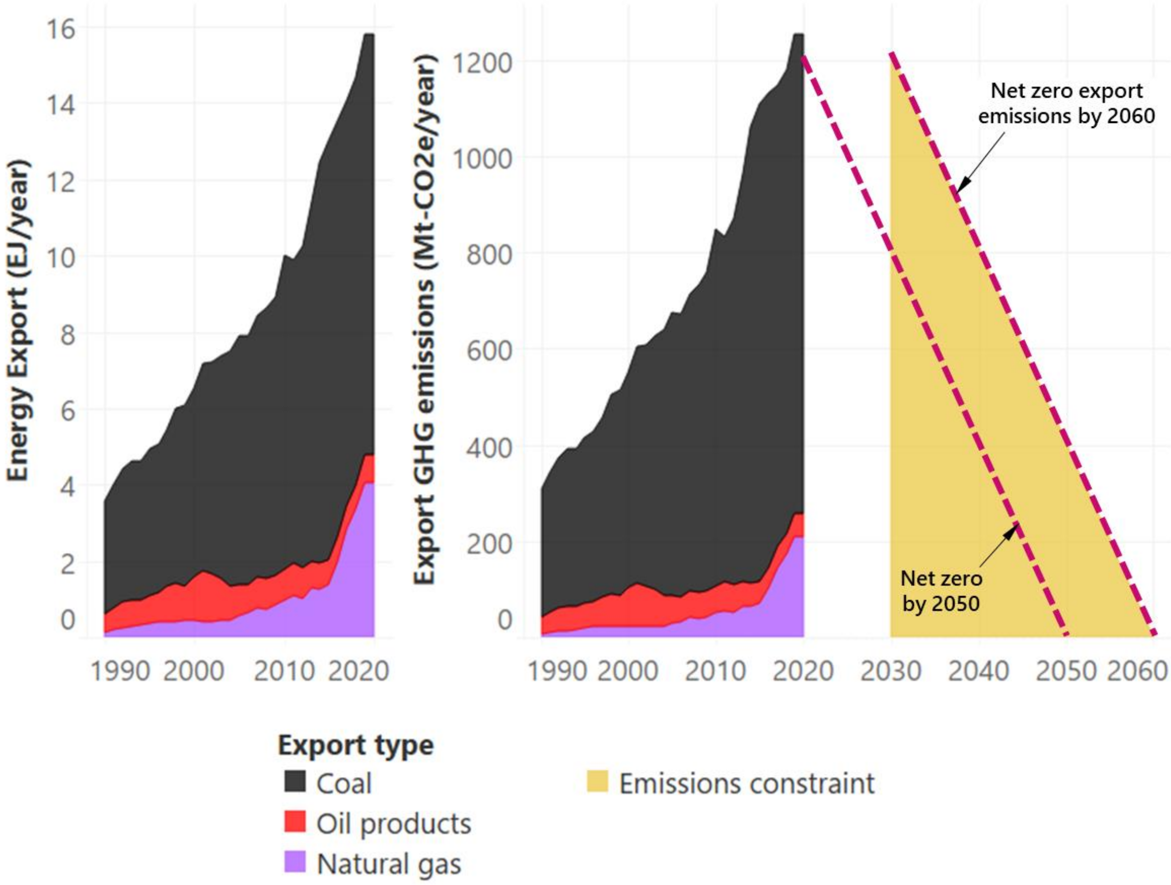
We assume that the zero export emissions constraint can be satisfied by replacing fossil exports with forms of energy that either have no associated GHG emissions when used (e.g., hydrogen, hydrogen derivatives and electricity) or the carbon content of which is biogenic or directly captured from the atmosphere. No allowance is made in the model for exported fossil fuels to be used in conjunction with carbon capture and storage in importing countries.

This work assumes the transport and use of hydrogen has no global warming impact, the validity of which is the subject of significant international debate.[7, 8] Nevertheless, our expectation is that any global warming impact of the hydrogen economy will be small. Additionally, this analysis does not account for GHG emissions associated with international shipping.

2060 was chosen as the year in which the zero export emissions constraint is achieved in the expectation that some of Australia's trading partners will not achieve net zero until around that date. This judgement has been vindicated to some degree by China's adoption of a 2060 target, and India's nomination of 2070. However, earlier decarbonisation timeframes will also be considered in key sensitivity studies, where the constraints on net-zero domestic and export emissions, are brought forward to 2040 and 2050 respectively (as also indicated in Figure 11 and Figure 12).

Finally, no international emissions offsets are allowed in this modelling as a means of reaching either the domestic or export net zero emissions constraint. These have been deliberately excluded because of the significant implications for land use, our conservative expectations of soil carbon sequestration, and the implicit contradiction in allowing for a major clean fuel exporting nation, to import offsets.

Figure 12 | Left: historical Australian energy exports. Right: Historical and constrained future export embodied GHG emissions.[5]



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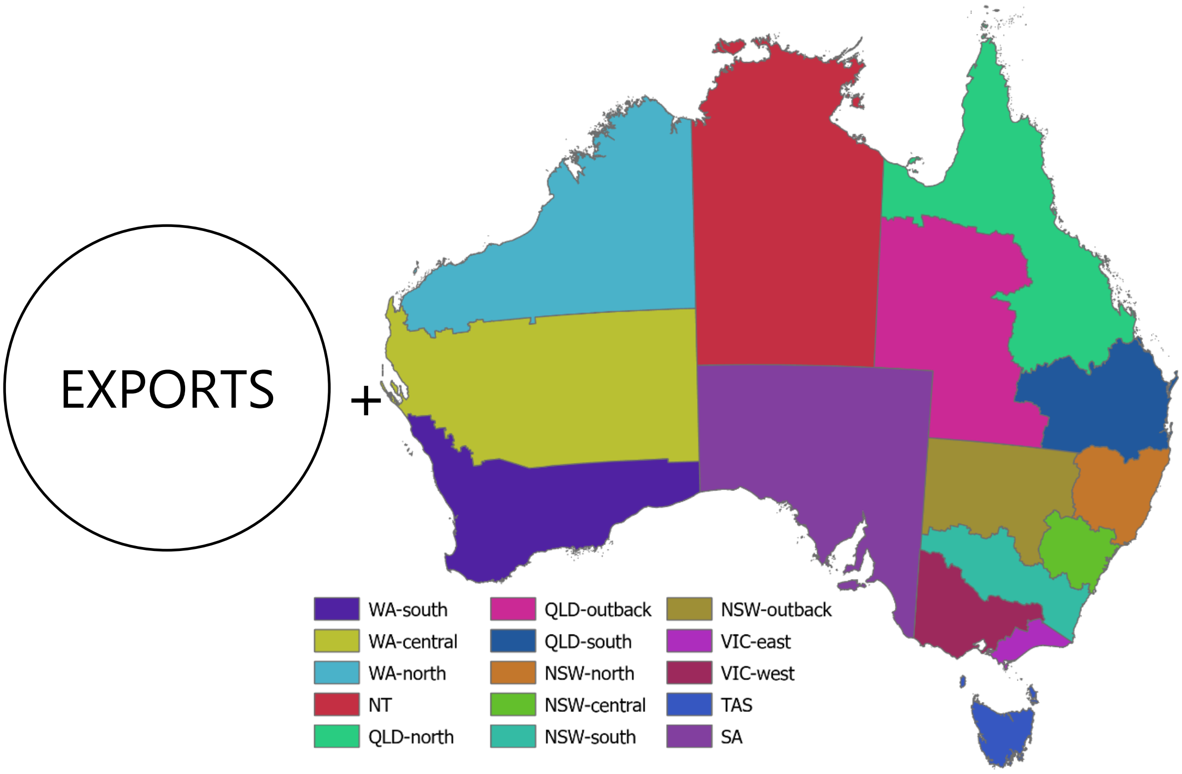
5 Modelled regions

NZAu's macro-energy system modelling incorporates the 15 domestic regions (NZAu zones) shown in Figure 13, each with its own energy service demand, initial stock of energy infrastructure and resources. The number of regions chosen is a balance between computational complexity of the macro-energy system modelling optimisation, and the spatial resolution required to thoroughly represent the geographically dispersed energy resources and infrastructure needed in highly carbon-constrained energy systems. The modelling considers the energy service demand and existing energy infrastructure in each modelled region along with the potential for energy and CO_2 flows between neighbouring regions. The modelling then optimises the required energy investments in each region, as well as incremental energy transmission builds between regions.

Figure 13 | The 15 domestic regions (NZAu zones) and one export region modelled with the macro-energy system model.



The choice of domestic regions in the eastern and southern states was informed by the sub-regional topology used in AEMO's modelling of the National Electricity Market with its Integrated System Plan.[1] The three most populous states – New South Wales (NSW), Victoria (VIC) and Queensland (QLD) – each have more than one modelled region, while the three least populous states/territories, South Australia (SA), Tasmania (TAS) and the Northern Territory (NT), are modelled each as a single region. The Australian Capital Territory is incorporated into the NSW-south region. Western Australia (WA) is modelled by three regions reflecting the divide between the southern population centres, and the central and northern extractive resource and export hubs.

The destination for Australia's export energy flows is modelled as a single additional export region, which has its own demand for energy that can be served by various forms, including solid, liquid and gaseous fuels, and in some cases electricity flows. We therefore do not differentiate between the various potential destinations for Australia's energy exports, as the main export trade partners in Asia are located at comparable distances from Australia and total shipping costs are typically not strongly dependent on the distance from port of origin to port of destination. Note that the export energy supply is subject to a separate emissions constraint to the 15 domestic NZAu zones as discussed in section 4. Energy flows supplied to the modelled 'export zone' can come from any of a range of domestic NZAu zones, through defined port locations that are discussed later in this document.

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6 Historical demand

6.1 Decomposition of final energy into energy use types

Historical Australian energy consumption (equivalent to total primary energy supply) was sourced from the Australian Energy Statistics (AES) Table F[1]. The AES data is decomposed by state and territory into economic sectors according to the Australian and New Zealand Standard Industry Classification (ANZISC).[2] The EnergyPATHWAYS database (which is described in more detail in section 7, with the full methodology described previously[3, 4]) uses different categorisations compared to the AES data, and the mapping between datasets is shown in Table 12.

EnergyPATHWAYS uses different categorisations of fuel types compared to the AES and the mapping of different categories is shown in Table 13.

Table 12 | Mapping Australian Energy Statistics industry categories with EnergyPATHWAYS input database.

Australian Energy Statistics Industry Categories	EnergyPATHWAYS Industry Categories
Mining	
Coal mining	N/A – modelled on the supply-side
Oil and gas extraction	N/A – modelled on the supply-side
Other mining	Other mining
Manufacturing	
Food, beverages and tobacco	Food; beverages and tobacco
Textile, clothing, footwear and leather	Textile; clothing; footwear and leather
Wood and wood products	Wood and wood products
Pulp, paper and printing	Pulp; paper and printing
Petroleum refining	N/A – modelled on the supply-side
Other petroleum and coal product manufacturing	Other petroleum and coal product manufacturing
Basic chemical and chemical, polymer and rubber product manufacturing	Basic chemical and chemical; polymer and rubber product manufacturing
Non-metallic mineral products	Non-metallic mineral products
Glass and glass products	Glass and glass products
Ceramics	Ceramics
Cement, lime, plaster and concrete	Cement; lime; plaster and concrete
Other non-metallic mineral products	Other non-metallic mineral products
Iron and steel	Iron and steel
Basic non-ferrous metals	Basic non-ferrous metals
Fabricated metal products	Fabricated metal products
Machinery and equipment	Machinery and equipment
Furniture and other manufacturing	Furniture and other manufacturing
Electricity, gas, water and waste services	
Electricity supply	N/A – modelled on the supply-side
Gas supply	N/A – modelled on the supply-side
Water supply, sewerage and drainage services	Water supply; sewerage and drainage services
Transport, postal and warehousing	
Road transport	Passenger vehicles

Australian Energy Statistics Industry Categories	EnergyPATHWAYS Industry Categories
	Motorcycles Buses Light commercial vehicles Rigid and other trucks Articulated trucks
Rail transport	Rail transport
Water transport – International bunkers	International water transport
Water transport – Coastal bunkers	Domestic water transport
Domestic air transport	Domestic air transport
International air transport	International air transport
Other transport, services and storage	Other transport; services and storage
Residential	
Residential	Residential clothes drying Residential clothes washing Residential dishwashing Residential freezing Residential refrigeration Residential IT & home entertainment Residential pools Residential cooktops and ovens Residential microwaves Residential air conditioning Residential space heating Residential water heating Residential lighting Residential fans Residential other appliances
Other	
Agriculture, forestry and fishing	Agriculture forestry and fishing
Construction	Construction
Commercial and services	Commercial and services
Solvents, lubricants, greases and bitumen	Solvents; lubricants; greases and bitumen

Table 13 | Mapping Australian Energy Statistics Fuel type categories with EnergyPATHWAYS input database.

Australian Energy Statistics Fuel Types	EnergyPATHWAYS Fuel Types
Black coal Coke Bitumen	Black coal
Brown coal Coal by-products Brown coal briquettes	Brown coal
Wood, wood waste Bagasse	Biomass wood
Liquid/gaseous biofuels	Biomass/biofuel
Natural gas Town gas	Natural gas
LPG	LPG

Australian Energy Statistics Fuel Types	EnergyPATHWAYS Fuel Types
Automotive gasoline – leaded Automotive gasoline – unleaded Aviation gasoline	Gasoline
Aviation turbine fuel	Aviation fuel – (kerosene)
Kerosene and Heating oil	Kerosene
Diesel	Diesel
Fuel oil	Fuel oil
Crude Oil and other Refinery feedstock Petroleum products	Other Petroleum
Solvents Lubricants and greases	Solvent
Electricity Solar energy	Electricity

Least-norm optimisation

In some categories above, particularly in the mining and manufacturing sectors, the sourced energy consumption was aggregated either across sub-categories, or across states. In order to fill in the missing data for each individual NZAu region, a least-norm optimisation was applied. An example is shown below for iron, steel, glass and wood products.

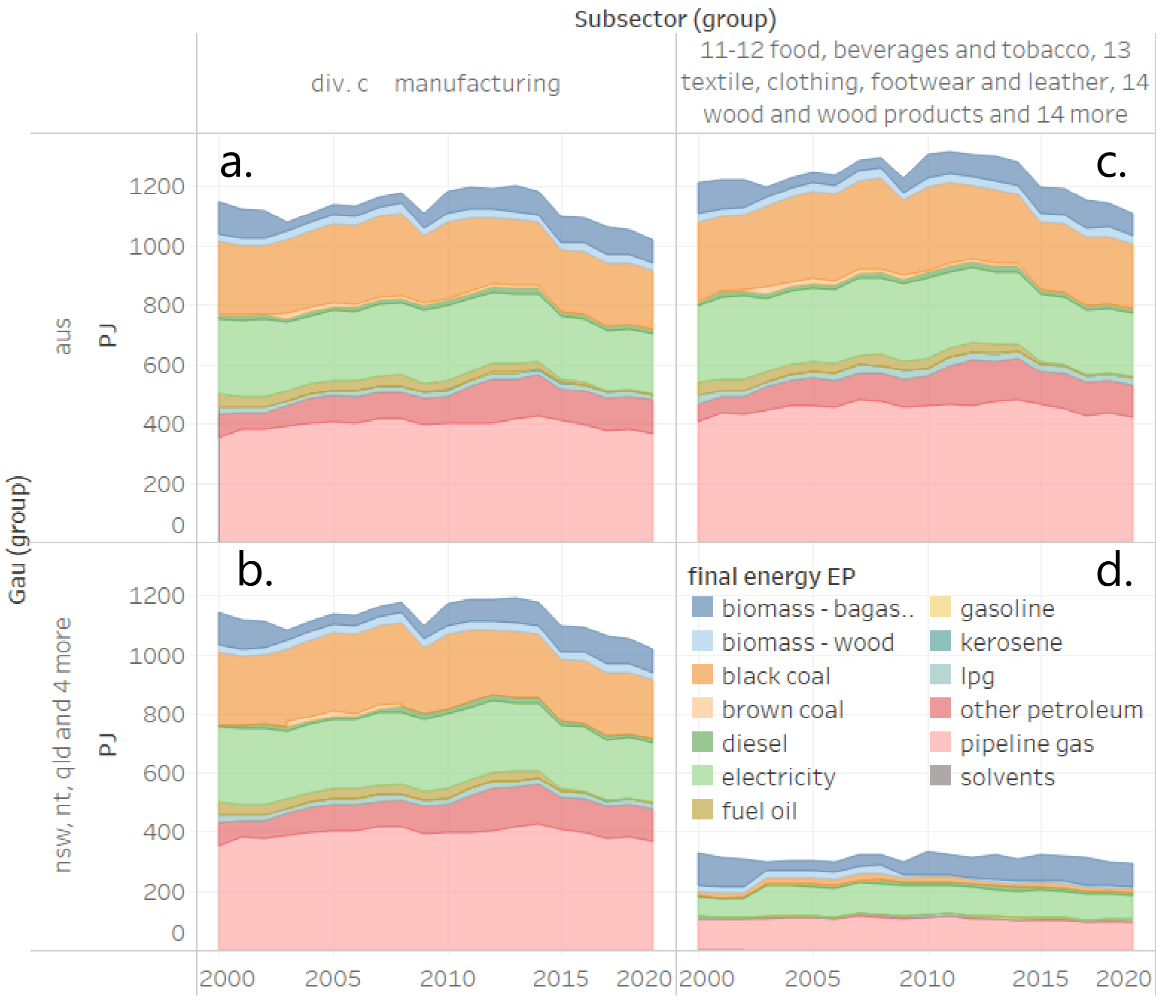
- The objective was to minimise: $\mathrm{sum}[(\boldsymbol{AX}-\boldsymbol{y})^2]$,
- subject to: $\boldsymbol{AX}=\boldsymbol{y}$,
- where:
  - $\boldsymbol{X} \geq 0$, contains the variables being solved for, that is the subdivision of final energy data at the state level, by sector (Figure 14d)
  - $\boldsymbol{A}$ is a logical matrix (with only 0 and 1) that maps $\boldsymbol{X}$ and $\boldsymbol{y}$,
  - $\boldsymbol{y}$ is populated with the available data that is aggregated to total state-based final energy (Figure 14c), and total sector-based final energy (Figure 14b).

$$\boldsymbol{AX}=\boldsymbol{y}$$

$$\begin{bmatrix} 1 & 1 & 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & 1 \\ 1 & 0 & 1 & 0 & 1 & 0 \\ 0 & 1 & 0 & 1 & 0 & 1 \end{bmatrix} \times \begin{bmatrix} \text{QLD iron and steel} \\ \text{VIC iron and steel} \\ \text{QLD glass and glass products} \\ \text{VIC glass and glass products} \\ \text{QLD wood and wood products} \\ \text{VIC wood and wood products} \end{bmatrix} = \begin{bmatrix} \text{Total iron and steel} \\ \text{Total glass and glass products} \\ \text{Total wood and wood products} \\ \text{Total QLD} \\ \text{Total VIC} \end{bmatrix}$$

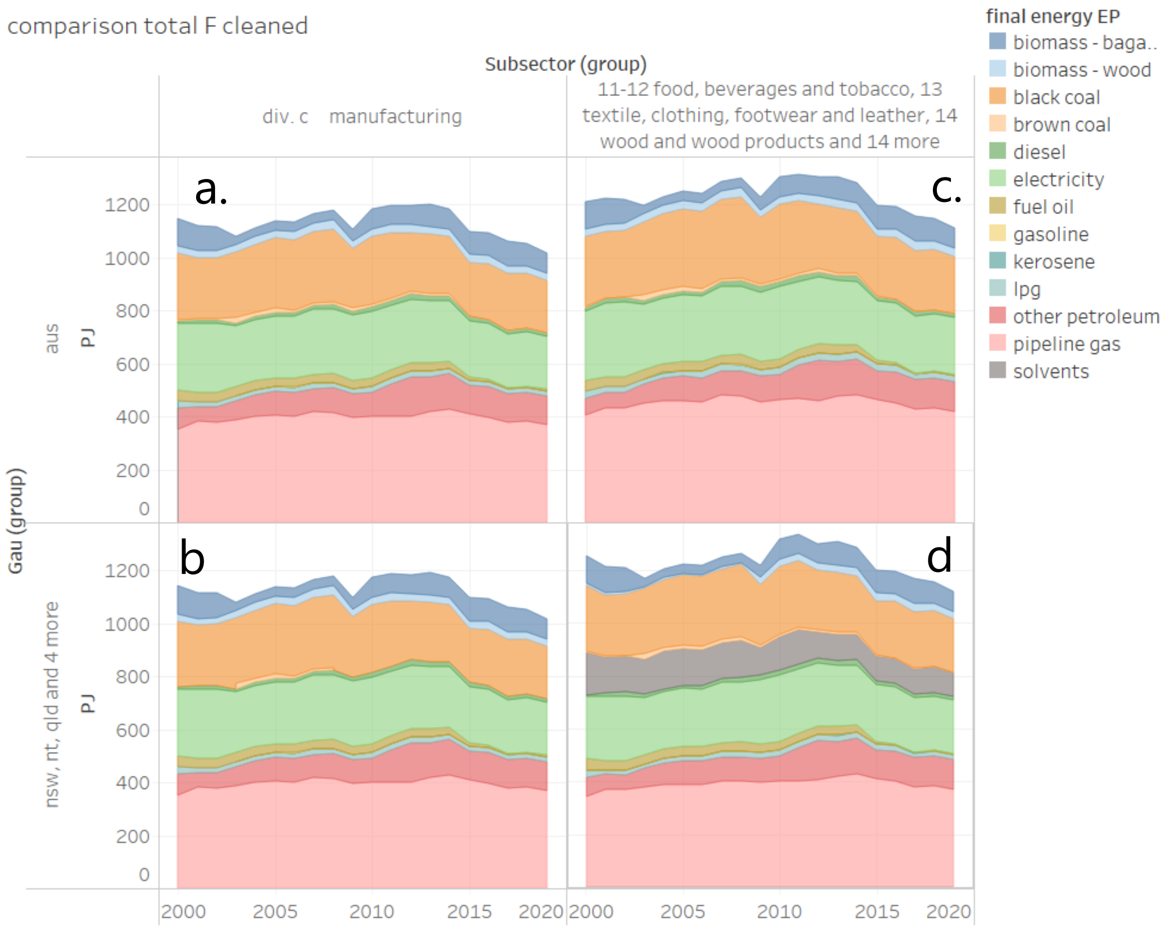
An example of the sourced (Figure 15) and then adjusted (Figure 15) energy demand by subcategory is shown below. For the final decomposition into the sub-state regions, employment figures[5] were used rather than population.

Figure 14 | AES Manufacturing energy consumption data before adjustments (see Note).



Note: Sub-figures present sourced manufacturing energy consumption data for (a) Australia under the total manufacturing division, (b) the sum each state's data for the total manufacturing division, (c) Australia by all subdivisions within manufacturing, and (d) the sum of each state's data for all subdivisions within manufacturing. Note that (d) should match (c).

Figure 15 | AES Manufacturing energy consumption data after adjustments (see Note).



Note: Sub-figures present the adjusted manufacturing energy consumption data for (a) Australia under the total manufacturing division, (b) the sum each state's data for the total manufacturing division, (c) Australia by all subdivisions within manufacturing, and (d) the sum of each state's data for all subdivisions within manufacturing (adjusted using least norm optimisation).

6.1.1 Decomposition of historical energy demand in the mining sector

Decomposition of the energy demand for the mining sector by state, commodity and fuel type was undertaken using the Australian Energy Statistics,[1] National Greenhouse Gas Inventory,[6] Resources and Energy Quarterly[7] and IBISWorld Database.[8] Coal mining (AES Table F,[1] Division B-06) was split out into black and brown coal by state. The division 'Other Mining' was split out into the major mined commodities using the Resources and Energy Quarterly.[7] These included: Iron Ore, Metallurgical Coal, Thermal Coal, Gas (LNG), Oil, Aluminium (Bauxite), Copper, Nickel, Gold, Uranium, Zinc and Lithium. In order to split each commodity out into regional production, the location of operated mines, annual production levels, mining methods and ore grades were collected from Geoscience Australia, IBISWorld Database and company reports.[8-51] Where production data was not available for specific mines, the unassigned production was spread evenly across the remaining mines for which production data was unavailable.

The energy demand for individual mines was either collected from Environmental Impact Statements or calculated from Run of Mine (ROM) and GHG emissions. ROM indicates the total moved material for each state and commodity and is directly related to the energy intensity of mining operations. The ROM per mine was calculated by dividing Annual Production by the average grade of the mine. In instances where there was no reported data on ore grade, the average grade of the ore in a particular state was applied to individual mines in that state. Then total ROM was calculated to determine percentage breakdown of commodity per state. The percentage of commodity breakdown, energy consumption per state and commodity market per state, were employed to calculate the energy intensity of each commodity per state as input data to the model.

The specific energy usage based on GJ/t-ROM was back calculated using greenhouse account factors that were reported in the relevant EIS reports. Diesel and electricity were identified as the major energy sources and the energy breakdown was reported based on Diesel vs Electricity and Machinery vs Transport for open-cut and underground mines (Table 14).

Table 14 | Energy Breakdown per fuel type and energy service for underground and open-cut mines. Values presented represent averages obtained across multiple EIS reports.[10-51]

Energy	Underground		Open-Cut	
	GJ/t-ROM	%	GJ/ROM	%
Diesel usage breakdown				
Diesel for Transport		43%		65%
Diesel for Stationary		57%		35%
Energy type break down				
Diesel	0.038	35%	0.346	75%
Electricity	0.07	65%	0.117	25%
Total Energy Demand	0.108	100%	0.463	100%

6.1.2 Decomposition of historical energy demand in the manufacturing sector

Decomposition of the energy demand for the manufacturing sector by state, sub-division and fuel type was calculated by assuming that the United States energy usage (according to the North American Industry Classification System[53]) applied in the NetZero America study, also applied for Australian manufacturing sectors. Exceptions were made for heating, ventilation and air-conditioning (HVAC) demand, which differ due to the regional climate. The AES data[1] organised by ANZSIC classifications, [52] was compared and normalised to USA equivalent.[53]

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6.2 On-road transport

On-road transport statistics were sourced from the *Australian Bureau of Statistics' Motor Vehicle Census* (MVC) for the years 2010 – 2020, [1] and S*urvey of Motor Vehicle Use* (SMVU) spanning the years 1998 – 2020.[2] These two sources provided data for the total number of vehicle registrations, average vehicle age, total fuel consumption and average fuel economy. These statistics were collected according to state/territory and post code of registration, vehicle type and fuel type.

Data for the following vehicle types were included as input to the NZAu modelling:

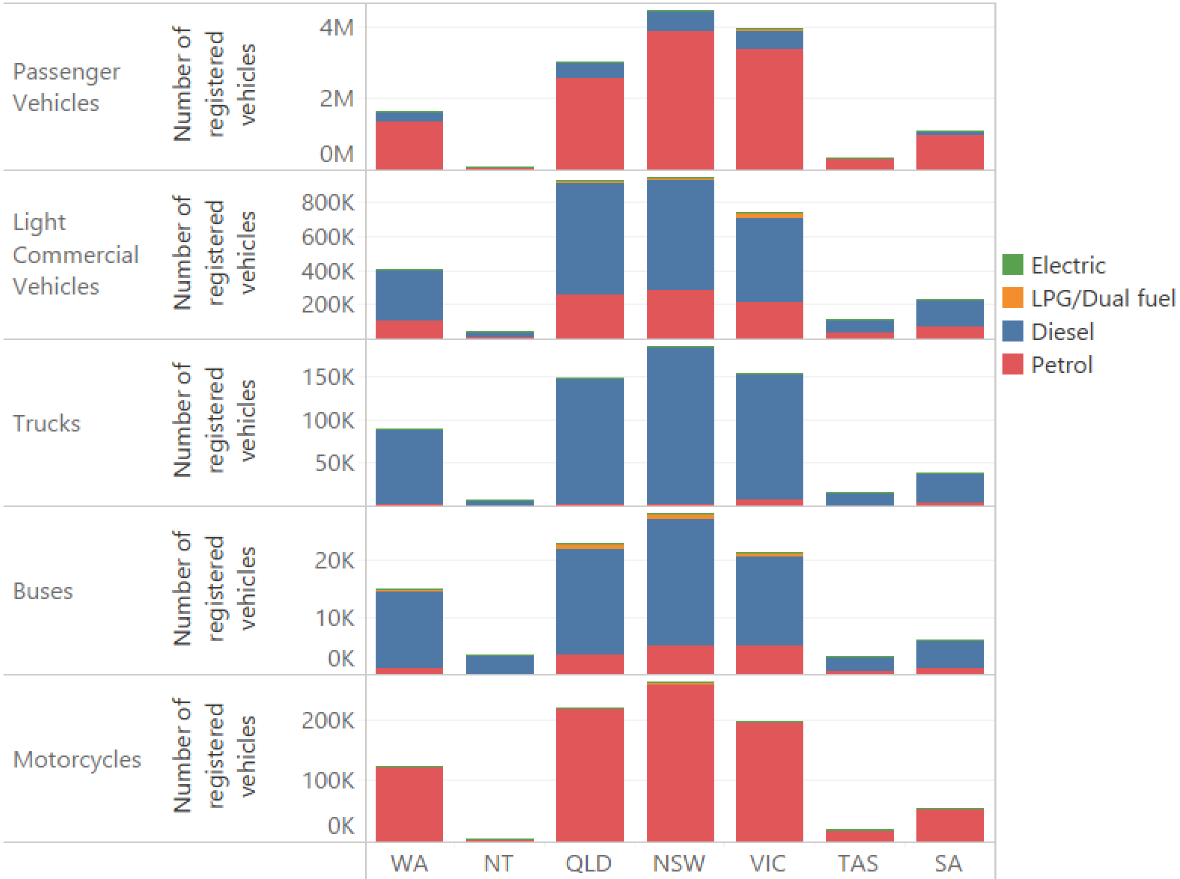
- passenger vehicles
- light commercial vehicles
- rigid trucks
- articulated trucks
- non-freight carrying trucks
- buses
- motorcycles.

The statistics for these vehicle types were also disaggregated by fuel type, including petrol, diesel, LPG/CNG/dual/other, and electric.

The initial stock (in 2020) of on-road registered transport vehicles numbered 19.7 million, the largest proportion being passenger vehicles (Figure 16). The MVC[1] provides data on this initial stock for each Australian post code, which was aggregated to the 15 modelled NZAu zones (section 5, Figure 13). The initial stock is presented in Figure 16 on a state/territory basis but used in the modelling on a NZAu zone basis.

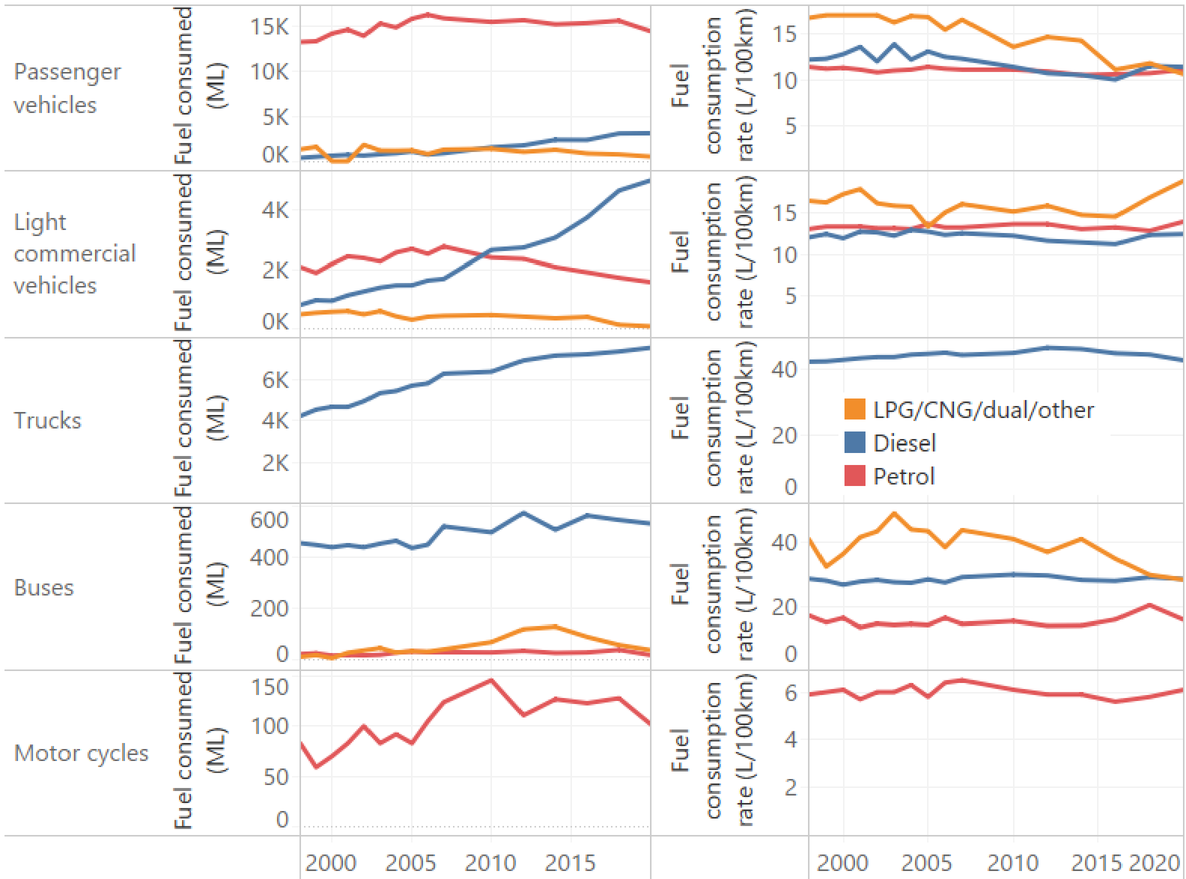
The SMVU[2] provides trends on historical on-road transport fuel consumption and fuel economy by state/territory, vehicle type, and fuel type, as shown in Figure 17. Although the data are presented here for the whole of Australia, state/territory-based data are used in the modelling. We assume that each NZAu zone within an Australian state has a fuel consumption that is proportional to the number of vehicles and vehicle-weighted fuel economy. This provides a general representation although different driving distances by zone are not captured. This was not seen as a material issue for the modelling.

Figure 16 | Initial stock of on-road transport vehicles, by vehicle type, fuel type, and state/territory of registration (see Note).[1]



Note: Vehicle numbers are presented here by state/territory of registration but were organised for the modelling into the 15 modelled NZAu zones. 'Trucks' here includes rigid trucks, articulated trucks and non-freight carrying trucks, which are each treated separately in the modelling.

Figure 17 | Left: historical Australian on-road transport fuel consumption, and right: historical Australian on-road transport fuel economy (see Note).[2]



Note: These data are presented for all of Australia, although state/territory specific data are used in the modelling. 'Trucks' here includes rigid trucks, articulated trucks and non-freight carrying trucks, which are each treated separately in the modelling.

References

1. Australian Bureau of Statistics, 2020, *Motor Vehicle Census*, Australia, https://www.abs.gov.au/statistics/industry/tourism-and-transport/motor-vehicle-census-australia/31-jan-2020.
2. Australian Bureau of Statistics, 2020, *Survey of Motor Vehicle Use*, Australia, https://www.abs.gov.au/statistics/industry/tourism-and-transport/survey-motor-vehicle-use-australia/12-months-ended-30-june-2020.

6.3 Buildings

6.3.1 Residential buildings

Existing residential building energy demands were characterised using the 2015 *Residential Energy Baseline Study*[1] with recent years benchmarked against residential consumption from the *Australian Energy Statistics.*[2]

Data from the Residential Energy Baseline Study was used to decompose household energy use into the 15 subsectors listed in Table 15. For most subsectors, historical energy service demand was represented by estimates of equipment stock; energy consumption as provided by the above two references,[1, 2] and stock efficiency sourced from Navigant North America[3], which allowed the tracking of sales of different technologies across future modelled years.

Table 15 | Residential sub-sectors used to decompose total residential energy use.

Subsector name	Representation
Residential air conditioning	Stock and energy
Residential clothes drying	Stock and energy
Residential clothes washing	Stock and energy
Residential cooktops and ovens	Stock and energy
Residential dishwashing	Stock and energy
Residential freezing	Stock and energy
Residential lighting	Stock and energy
Residential refrigeration	Stock and energy
Residential space heating	Stock and energy
Residential water heating	Stock and energy
Residential fans	Energy only
Residential IT & home entertainment	Energy only
Residential microwave	Energy only
Residential other appliances	Energy only
Residential pools	Energy only

All residential building stock and energy demand estimates were sourced on a state basis and apportioned to NZAu zones, based on the total number of households in each region, together with the projected heating and cooling degree days for space heating and cooling. The aggregate of the resulting residential energy use from these state-level stock and service estimates, showed close agreement with the Australian Energy Statistics data in recent years, and no additional adjustments were therefore considered necessary to align with top-down data.

6.3.2 Commercial buildings

Significant challenges were encountered when attempting to replicate the same stock-level representations of energy consuming equipment for commercial buildings. In analysing the state-level data in the 2012 Australian Commercial Buildings Survey,[4] it was found that building sampling was too sparse to provide estimates for the major commercial building energy use categories when aggregated back to a national level. In addition, commercial building energy use estimates from the Australian Energy Statistics are significantly higher than can be built from a bottom-up basis using the Commercial Buildings Survey. Both of these issues have been acknowledged by others,[5] and a new but currently unpublished Commercial Building Survey is expected to help fill gaps in current understanding.

As a workable alternative, a representation of total commercial building use by state and final energy type, was therefore taken from the Australian Energy Statistics data. Projections of future commercial building energy are then discussed in section 7.

References

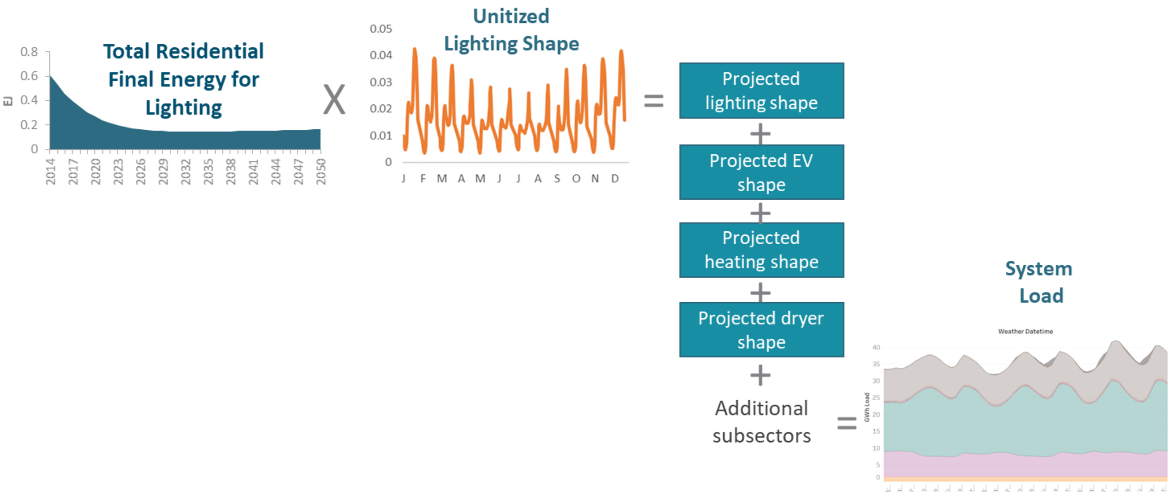
1. Australian Government Department of Industry and Science on behalf of the trans-Tasman Equipment Energy Efficiency (E3) Program, 2015, "Residential Energy Baseline Study for Australia 2000-2030", https://www.energyrating.gov.au/document/report-residential-baseline-study-new-zealand-2000-2030
2. Australian Government Department of Industry, Science, Energy, and Resources, 2020, "Australian Energy Statistics". https://www.energy.gov.au/publications/australian-energy-update-2020
3. Navigant Consulting Inc., 'Updated Buildings Sector Appliance and Equipment Costs and Efficiency', presented to U.S. Energy Information Administration, https://www.eia.gov/analysis/studies/buildings/equipcosts/.
4. Australian Government Department of Climate Change and Energy Efficiency, 2012, "Baseline Energy Consumption and Greenhouse Gas Emissions in Commercial Buildings in Australia", https://www.energy.gov.au/publications/baseline-energy-consumption-and-greenhouse-gas-emissions-commercial-buildings-australia.
5. Australian Government Department of Industry, Science, Energy and Resources, Office of the Chief Economist, 2021, 'Australia: end use energy efficiency data and reporting', https://iea.blob.core.windows.net/assets/a8dca053-d850-4f8d-bfde-3dff5bf98611/1.6_AUS_APECenergyefficiency-Australia.pdf.

6.4 Electricity load shapes including disaggregated rooftop solar PV

The specific hourly fluctuations of electricity demand across a full year are important for planning and operating electricity systems. In this work, hourly electricity load shapes for each of the future modelled years were therefore built using the EnergyPATHWAYS (EP) bottom-up process, illustrated in Figure 18. In this approach, each electricity-consuming sub-sector in the model has a normalised annual load shape with hourly time steps, which is multiplied by the electrical final energy demand of that subsector, to obtain the hourly load in absolute units. These are then aggregated to provide estimates of the bulk hourly system load.

The bottom-up aggregated load shapes are iteratively benchmarked and calibrated against historical system load shapes, to ensure that the calculated bottom-up load-shape in the first modelled year, matches historical system-wide electricity load. Correction factors used in this calibration are then carried forward and used for calculations of future load-shapes. The same process is used to create bottom-up demand shapes for key fuel blends including hydrogen and pipeline gas.

Figure 18 | Illustration of the bottom-up method used in EnergyPATHWAYS to build electricity load shapes from electricity-consuming sub-sectors.



The historical electricity load/demand data used for benchmarking the bottom-up demand shapes, has two components: *operational demand* met by utility-scale generators (typically >30 MW); and *demand met by behind-the-meter resources* (particularly rooftop solar PV generation).

Half-hourly operational demand data were sourced from AEMO for each Australian state and for the years 2014 – 2021 (by financial year, 1 July – 30 June).[1, 2] These half-hourly data were converted to hourly demand profiles, and are shown for FY2018 in Figure 19, plotted as load/demand duration curves. Load data for the Northern Territory were unavailable and instead load data from South Australia were decomposed by sector (residential, commercial, and industrial) based on assumed load factors, then re-scaled proportionally to those same sectors in the Northern Territory. The 2018 financial year (FY2018, i.e., 1 July 2017 to 30 June 2018) was chosen as the representative weather year for the annual demand and renewable generation profiles used in NZAu. The state-based data were disaggregated to the NZAu zones, assuming the same shape for each member zone.

Historical data for the hourly demand met by behind-the-meter electricity generation – particularly by rooftop solar PV generation – were then added to the operational demand data to obtain the hourly load/demand data used for benchmarking. This is a growing component of total electricity demand and can have significant influence on the need for ramping utility-scale generation in particular. Aggregate historical half-hourly rooftop solar PV generation data were sourced from AEMO for the NEM states.[1] However, because these data do not cover FY2018 and all regions, these were not used directly as inputs into the modelling, but were used as validation for simulations of hourly rooftop PV resource availability, as discussed below in section 9.4. The historical generation duration curves for rooftop solar PV in the NEM states during FY2020 are shown in Figure 20.

Figure 19 | Electricity operational demand duration curves for FY2018 and the 6 Australian states.

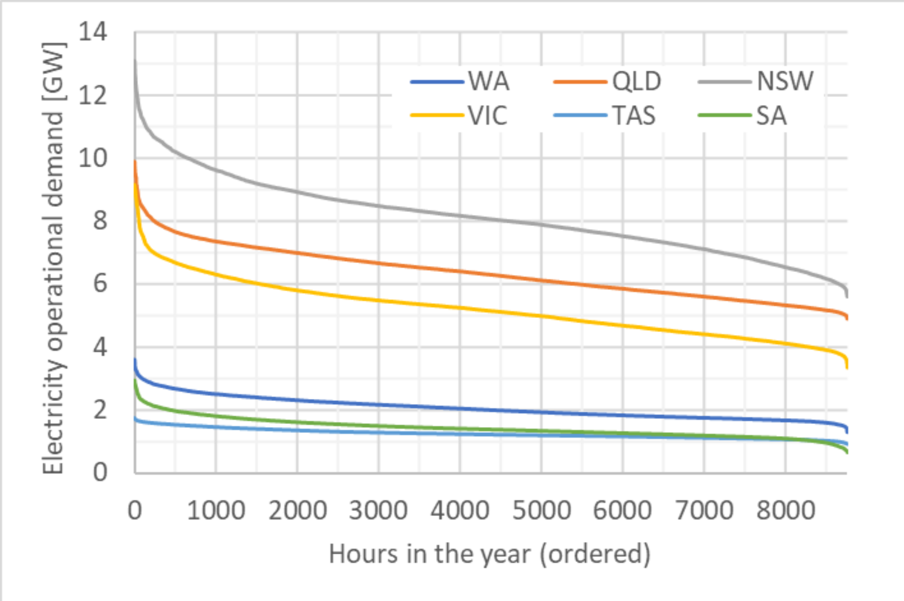
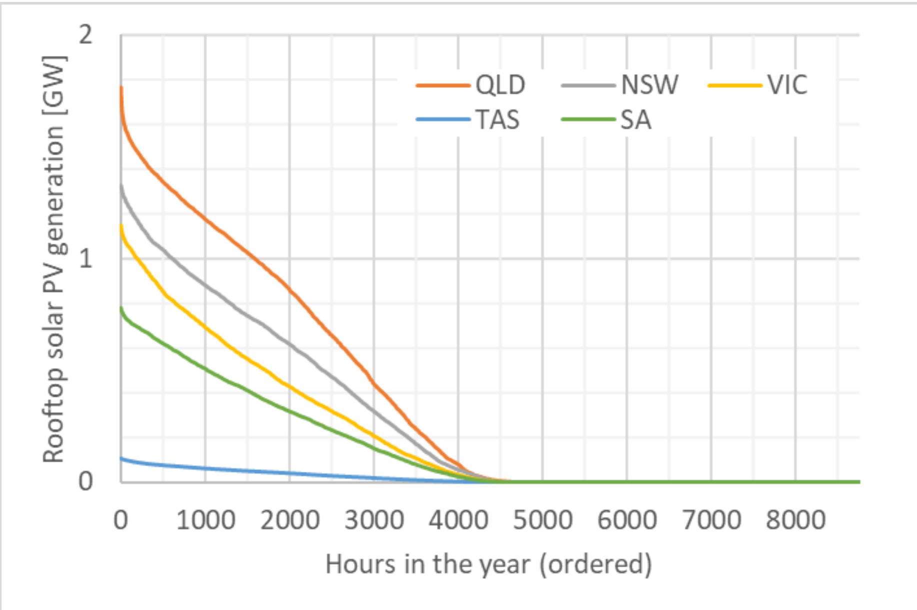


Figure 20 | Rooftop solar PV generation duration curves for FY2020 and the 5 states of the National Electricity Market.



References

1. Australian Energy Market Operator (AEMO) 2021 'Market Data NEMWEB', https://visualisations.aemo.com.au/aemo/nemweb, accessed 27 September 2021.
2. Australian Energy Market Operator (AEMO) 2021 'Market Data Western Australia', https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/market-data-wa, accessed 27 September 2021.

7 Projections of energy demand

To project future energy services, NZAu uses a model called EnergyPATHWAYS (EP), which is a bottom-up stock-rollover model of all energy-using technologies in the economy. The methodology for EnergyPATHWAYS has been published previously[1, 2] and its application to Australia is summarised in this section.

The EP model assumes decision-making stasis as a baseline. For example, when projecting energy demand for residential space heating, EP implicitly assumes that consumers will replace their water heater with a water heater of a similar type. This baseline does include efficiency gains and technology development which are anticipated based on techno-economic projections. Any departure from the decision-making stasis baseline is then explicitly specified in the scenario definition. For example, certain scenarios may specify the share of sales for a technology type, the adoption of a specific technology in a specific year, or changes of stock in a specific year.

Factors used to determine final energy demand include:

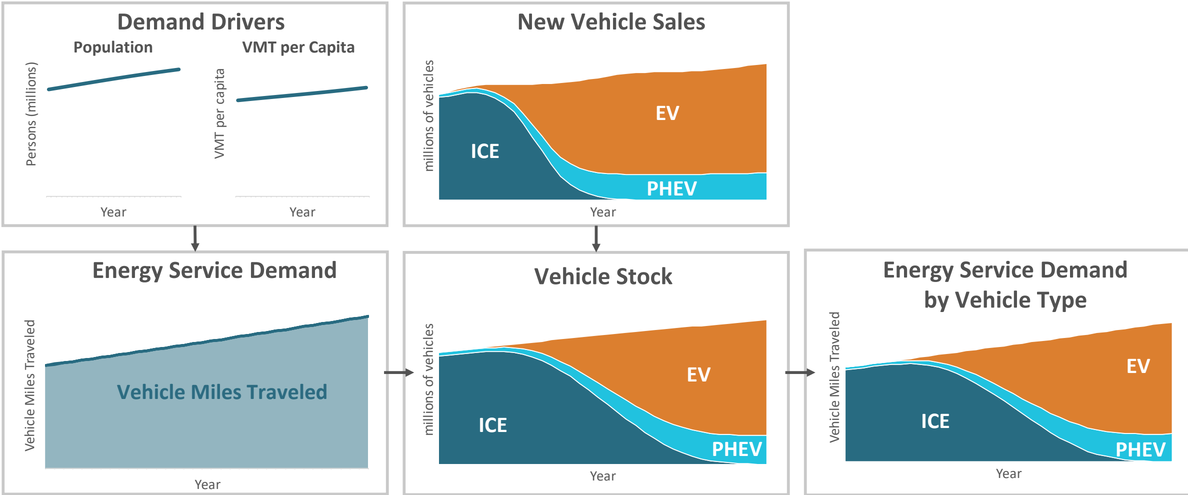
1. **Demand drivers** – the characteristics of the energy economy that determine how people consume energy over time.
2. **Technology efficiency** – how efficiently energy consuming technologies convert fuel or electricity into end-use energy services.
3. **Technology stock** – what quantity of each type of energy-using technology is present in the population and how that stock changes over time.

A total of 49 subsectors are used to represent the Australian energy system, as shown in Table 16. However, the availability of current stock data is only sufficient for 17 of these subsectors to project future energy service demand with energy *and* technology stocks. All these 17 subsectors are in the residential and transport sectors. For the remaining 32 subsectors, future energy services are projected with an energy-only representation. Different methods are therefore used to project future energy services for each subsector, depending on the availability of data for representing technology stocks. Additional detail on the methods of projecting future energy and service demand is reported in the documentation for the development of EnergyPATHWAYS.[1, 2]

For subsectors with technology stock representations, EnergyPATHWAYS determines energy demand for every year over the modelled time horizon using service demand and service efficiency estimates. A generic example (data not from NZAu) for the light duty transport subsector is shown in Figure 21. The demand drivers in this example include population and vehicle kilometres travelled per capita. The energy service demand – the total vehicle kilometres travelled in this instance – are then derived from these two drivers. In parallel, vehicle sales change over time, as the economics of different options change and/or new policies are put in place. Vehicle sales and retirement then result in changes to the composition of the vehicle stock. By dividing service demand by service efficiency for each vehicle type in the stock, the final energy demand for electricity and fuels in this subsector are then derived.

Prescribed technology type sales shares for the subsectors with stock representation are shown in Table 17, for the E+ Scenario and for 2020 and 2040 with an assumed S-curve for sales in the intermediate years. The stock rollover model and an accounting of the relevant technology lifetimes then determine the technology fleet composition, with all subsectors reaching their new technology saturation level by around 2050. Energy efficiency and fuel switching assumptions and their cost of implementation within these subsectors are therefore defined at the technology level by the efficiencies and composition of the technology stock modelled. Note that the E− Scenario delays the saturation of the sales share switching by 20 years for the transport sector, and by 60 years for the residential sector, as defined in Section 1.

Figure 21 | The process of calculating energy service demand for a subsector with stock representation, shown here as an example for the light duty vehicle fleet.



For subsectors that are modelled without technology-level detail EnergyPATHWAYS determines aggregate energy-only demands, over the modelled time horizon based on various demand drivers, and energy efficiency and fuel switching measures defined per scenario (Section 1). These energy efficiency and fuel switching measures are presented in Table 18, for the E+ Scenario.

Energy efficiency measures are applied as a year-on-year efficiency improvement, which has an associated levelised cost per unit of energy saved of $10/GJ in 2020, which increases linearly to $15/GJ in 2050. Fuel switching measures are applied by subsector and are based on expert judgment and previous experience.[1, 2] These fuel switching measures have an associated levelised cost per unit of fuel switched of $2/GJ for commercial buildings and $10/GJ for industry/transportation in 2020, which declines linearly to $5/GJ by 2040. This declining cost trend moves counter to the cost of energy efficiency accounts for technology learning that should reduce the cost of fuel switching to electric or hydrogen-based processes over time.

The timing of the fuel switching measures presented in Table 18 is delayed in the E− Scenario by 20 years for the transportation sector, and 60 years for the industry, residential and commercial sectors, as defined in Section 1). Because the present modelling ends in 2060 and fuel switching saturation does not occur until 2100 in the E− scenario, buildings and industrial sectors are still switching final energy types slowly when net-zero emissions are reached. This is made possible by the decarbonisation of fuels upstream of final consumption.

The final energy demand of all subsectors presented in Table 16 constitutes the final energy demand for the whole of Australia, to be supplied through the provision of electricity and fuels. The final energy demand for each subsector is then an input into the supply side optimisation step of the modelling, with supply determined separately for each modelled region.

Table 16 | List of all subsectors used in the EnergyPATHWAYS model for Australia, with details of the methodology for projecting energy and service demand.

Sector	Subsector	Model methodology	Projection basis
Industry	Agriculture forestry and fishing	Energy only	1% per year output growth
Industry	Other mining	Energy only	Tied to gross state product
Industry	Food, beverages and tobacco	Energy only	1% per year output growth
Industry	Textile, clothing, footwear and leather	Energy only	1% per year output growth
Industry	Wood and wood products	Energy only	1% per year output growth
Industry	Pulp, paper and printing	Energy only	1% per year output growth

Sector	Subsector	Model methodology	Projection basis
Industry	Other petroleum and coal product manufacturing	Energy only	1% per year output growth
Industry	Basic chemical, polymer and rubber product manufacturing	Energy only	1% per year output growth
Industry	Non-metallic mineral products	Energy only	1% per year output growth
Industry	Glass and glass products	Energy only	1% per year output growth
Industry	Ceramics	Energy only	1% per year output growth
Industry	Cement, lime, plaster and concrete	Energy only	Tied to clinker production estimates
Industry	Other non-metallic mineral products	Energy only	1% per year output growth
Industry	Iron and steel	Energy only	1% per year output growth
Industry	Basic non-ferrous metals	Energy only	1% per year output growth
Industry	Fabricated metal products	Energy only	1% per year output growth
Industry	Machinery and equipment	Energy only	1% per year output growth
Industry	Furniture and other manufacturing	Energy only	1% per year output growth
Industry	Water supply, sewerage and drainage services	Energy only	Tied to population
Industry	Construction	Energy only	1% per year output growth
Industry	Solvents, lubricants, greases and bitumen	Energy only	1% per year output growth
Transportation	Rail transport	Energy only	1% per year output growth
Transportation	Domestic water transport	Energy only	Tied to population
Transportation	International water transport	Energy only	Tied to population
Transportation	Domestic air transport	Service and energy	Tied to population and median income
Transportation	International air transport	Energy only	Tied to gross state product
Transportation	Other transport, services and storage	Energy only	1% per year output growth
Transportation	Passenger vehicles	Stock and service	Tied to population
Transportation	Motorcycles	Stock and service	Tied to population
Transportation	Buses	Stock and service	Tied to population
Transportation	Light commercial vehicles	Stock and service	Tied to light commercial freight
Transportation	Rigid and other trucks	Stock and service	Tied to rigid freight
Transportation	Articulated trucks	Stock and service	Tied to articulated truck freight
Residential	Residential clothes drying	Stock and energy	Tied to total number of dwellings
Residential	Residential clothes washing	Stock and energy	Tied to total number of dwellings
Residential	Residential dishwashing	Stock and energy	Tied to total number of dwellings
Residential	Residential freezing	Stock and energy	Tied to total number of dwellings
Residential	Residential refrigeration	Stock and energy	Tied to total number of dwellings
Residential	Residential IT & home entertainment	Energy only	Tied to residential floor area
Residential	Residential pools	Energy only	Tied to total number of dwellings
Residential	Residential cooktops and ovens	Stock and energy	Tied to total number of dwellings
Residential	Residential microwave	Energy only	Tied to total number of dwellings
Residential	Residential air conditioning	Stock and energy	Tied to residential floor area and cooling degree days
Residential	Residential space heating	Stock and energy	Tied to residential floor area and heating degree days

Sector	Subsector	Model methodology	Projection basis
Residential	Residential water heating	Stock and energy	Tied to residential floor area
Residential	Residential lighting	Stock and energy	Tied to residential floor area
Residential	Residential fans	Energy only	Tied to residential floor area
Residential	Residential other appliances	Energy only	Tied to residential floor area
Commercial	Commercial and services	Energy only	Tied to population

Table 17 | Technology type sales shares for the subsectors with stock representation, for the E+ Scenario (see Note).

Sector	Subsector	Technology group	2020	2040*
Transportation	Passenger vehicles and buses	Reference	98%	0%
		Electric	2%	90%
		Hydrogen	0%	10%
Transportation	Motorcycles (*sale saturation is reached in 2035)	Reference	97%	10%
		Electric	3%	90%
Transportation	Light commercial vehicles	Reference	100%	0%
		Electric	0%	80%
		Hydrogen	0%	20%
Transportation	Rigid and other trucks	Reference	100%	0%
		Electric	0%	70%
		Hydrogen	0%	30%
Transportation	Articulated trucks	Reference	100%	0%
		Electric	0%	50%
		Hydrogen	0%	50%
Residential	Residential clothes washing/drying, dishwashing, refrigeration/freezing (*sale saturation is reached in 2035)	Reference	100%	0%
		High Efficiency	0%	100%
Residential	Residential lighting (*sale saturation is reached in 2030)	Reference	90%	0%
		High Efficiency	10%	100%
Residential	Residential water heating	Reference	48%	3%
		Electric	52%	97%
Residential	Residential cooktops and ovens	Reference	59%	6%
		Electric	41%	94%
Residential	Residential air conditioning	Reference	100%	3%
		High Efficiency	0%	97%
Residential	Residential space heating	Reference	28%	5%
		Electric	72%	95%

Note: The E− Scenario delays the saturation of the sales share switching from the reference technology to electric/hydrogen by 20 years for the transport sector, and by 60 years for the residential sector.

Table 18 | Energy efficiency and fuel switching measures applied for subsectors with an energy-only representation, for the E+ Scenario (see Note).

Sector	Subsector	Energy efficiency	Fuel switching
Industry	Agriculture, forestry and fishing; Textile, clothing, footwear and leather; Machinery and equipment; Water supply, sewerage and drainage services	1%/year	All fossil fuel use is converted to electricity by 2045 (2050 for agriculture, forestry and fishing).
Industry	Other mining	1%/year	80% of diesel/gasoline use is switched to electricity by 2045. All remaining fuel use switched to hydrogen by 2045.
Industry	Food, beverages and tobacco	1%/year	80% of all fossil fuel use is switched to electricity, and 20% is switched to hydrogen by 2045.
Industry	Pulp, paper and printing	1%/year	80% of coal, gas and oil use is switched to electricity, and 20% is switched to hydrogen by 2045. All liquid fuels are switched to electricity by 2045.
Industry	Non-metallic mineral products	1%/year	30% of coal and gas use is switched to electricity, and 70% of coal use and 60% of gas use is switched to hydrogen by 2045. All other fossil fuel use is switched to hydrogen by 2045.
Industry	Glass and glass produce	1%/year	33% of gas use is switched to electricity, and 67% is switched to hydrogen by 2045.
Industry	Ceramics	1%/year	80% of diesel use is switched to electricity and 20% is switched to hydrogen by 2045. 67% of all other fossil fuel use is switched to electricity, and 33% is switched to hydrogen by 2045.
Industry	Basic non-ferrous metals; Other non-metallic mineral products	1%/year	30% of gas use is switched to electricity, and 70% of gas use is switched to hydrogen by 2045. All other fossil fuel use is switched to hydrogen by 2045.
Industry	Iron and steel	N/A	All coal use is switched to hydrogen, and all gas, petroleum, diesel use is switched to electricity by 2040.
Industry	Furniture and other manufacturing	1%/year	All non-diesel fossil fuels are switched to electricity by 2045.
Industry	Construction	1%/year	80% of non-diesel use is switched to electricity, and 20% is switched to hydrogen by 2050.
Industry	Wood and wood products; Other petroleum and coal product manufacturing; Basic chemical, polymer and rubber product manufacturing; Fabricated metal products; Solvents, lubricants, greases and bitumen.	1%/year	N/A
Industry	Cement, lime, plaster and concrete	N/A	N/A
Transportation	Air transport (domestic and international)	1.5%/year	N/A
Transportation	Water transport (domestic and international)	1%/year	100% of international shipping switched to ammonia by 2050. 67% of domestic shipping switched to ammonia/hydrogen and 33% switched to electric by 2050

Sector	Subsector	Energy efficiency	Fuel switching
Transportation	Rail	N/A	90% of fossil fuel use is switched to ammonia/hydrogen and 10% switched to electric by 2050
Residential	IT & home entertainment; pools; other appliances	1%/year	Any gas use is switched to electric by 2040
Residential	Microwaves; fans	N/A	N/A
Commercial	Commercial and services	1%/year	All gas and diesel use is switched to electricity by 2045

Note: Fuel switching measures are not applied to any current biomass use. The timing of this fuel switching for the E− Scenario is delayed 20 years in the transportation sector, and 60 years in the industry, residential and commercial sectors. The Reference scenario assumes 0.5% efficiency improvement per year across industry, but without any fuel switching.

References

1. Larson, E., Greig, C., Jenkins, J., et al. 2021, "Net-Zero America: Potential Pathways, Infrastructure, and Impacts – Final Report". Princeton University. https://netzeroamerica.princeton.edu/.
2. Williams, J. H., Jones, R. A., Haley, B., Kwok, G., Hargreaves, J., Farbes, J., & Torn, M. S. 2021, "Carbon-Neutral Pathways for the United States", *Agu Advances*, 2, e2020AV000284. https://doi.org/10.1029/2020AV000284.

8 Projections of agriculture, LULUCF and waste

NZAu has examined historical trends in GHG emissions (CO_2, CH_4, N_2O) from three sectors: agriculture; land use, land use change and forestry (LULUCF); and waste as shown in Table 19.

Table 19 | UNFCCC sectors and the activities covered within the emissions trajectories projected by NZAu and used as fixed input to the macro-scale energy system modelling.

Sector	Coverage
Agriculture	Emissions from livestock as enteric fermentation and manure management. Emissions from agricultural soil, application of nitrogen to soils.
Land use, land use change and forestry	Net emissions from activities occurring on forest lands, forests converted to other land uses, grasslands, croplands, wetlands, and settlements.
Waste	Emissions from the disposal of material to landfill and wastewater.

Estimates of two future net emissions trajectories within these sectors from 2020 to 2050 were then developed, based on different assumptions about the GHG emissions mitigation efforts at national and state levels. These two projections are:

- a business as usual (BAU) future, which assumes status quo within the established framework for Australian agricultural and environmental policies, meaning that substantial emissions mitigation measures were not included; and
- a future with mitigation measures (WMM), which assumes a plausible concerted effort to reduce emissions and enhance carbon dioxide sinks, resulting in uptake of mitigation-related strategies from 2021 to 2050.

The BAU trajectory is used in NZAu's reference scenario (Section 1), while the WMM trajectory is used in all other NZAu scenarios that model net zero emissions. Mitigation strategies projected in WMM were added to the BAU trajectory without fine-tuning, to give an estimated range of values for GHG reduction. A summary of the assumptions for the BAU and WMM trajectories is provided in Table 20.

This approach allows for collecting data regarding crop production and livestock activities, focusing on methane and nitrous oxide emissions. However, it only accounts for carbon storage change without attempting to estimate carbon soils stocks in the landscape or the marine environment. The collected information is assembled at a state level and aggregated to national level. Where possible, the report provides relevant national scale data against each industry. The historical GHG emissions were sourced from the Australian Government National GHG Inventory[1] for the period 1990-2019.

Table 20 | Two emissions trajectories projected for the agriculture, LULUCF and waste sectors.

Emissions trajectory	Narrative descriptor
'Business-as-usual' (BAU)	Emissions are projected forward using 2019 as the most recent year of reported emissions data. While GHG emissions vary with changes in agricultural production (e.g., methane emissions reflect changes in cattle and sheep populations), this trajectory does not predict changes in land use and livestock populations, nor associated changes in emissions. Agricultural emissions are comparatively hard to predict because their associated emissions are difficult to measure and to manage, and there are many contradictory arguments for how agricultural production may change in the future. For example, livestock production may increase to 2050 to meet the needs of a growing middle-class population, but also could decrease due to the impacts of a warmer and drier climate in southern Australia.
'With-mitigation-measures' (WMM)	The WMM trajectory implements current and emerging technologies to reduce GHG emissions. The logic behind this trajectory is that there will be pressure from the supply chain to reduce agricultural GHG emissions, plus incentives through government programs such as the Emission Reduction Fund and the supply chain where many export-focused companies and industry bodies have already set targets for carbon neutrality. There are existing technologies, such as precision fertiliser management, and emerging technologies, such as methane inhibitors and vaccines, that are expected to be available in the future. This project intended to make plausible assumptions about the potential emission reductions and adoption of these technologies into the future. These assumptions are detailed under each industry sector.

We note that activities within the sectors covered in this section are particularly sensitive to changing environmental conditions, particularly global average temperatures that are rising due to ongoing climate change. At the same time, we also note that a general feature of agricultural production is that technology of all forms should improve over the coming years so that agricultural practices will adapt to offset potential losses due to climate change. The following projections of agricultural and LULUCF activity incorporate a conservative estimate of future global warming – the relative concentration pathway to a 2100 radiative forcing value of 8.5 W/m^2 (RCP8.5)[2] – together with the expectation of improved agricultural production through technology learning. The resulting BAU projections maintain current production trends and emissions levels. Our specific assumptions for each activity are outlined below.

8.1 Agriculture

The agriculture sector made up 14% (74.8 Mt-CO_2e) of Australia's 2019 greenhouse gas (GHG) inventory.[1] Of this, enteric methane is the largest source of GHG emissions making up 72% of agriculture emissions, followed by nitrous oxide emissions from agricultural soils (15%), and methane and nitrous oxide emissions from manure management (9%). Urea application (2%), liming (2%), burning of agricultural residues (<1%), and rice cultivation (<0.1%) make up the remainder of agriculture emissions.

The agricultural sectors covered can be ranked by emissions from around 47% of GHG emissions from the beef sector, followed by 18% for the sheep sector, 10% from dairy sector, 3% from feedlots, 2% from the swine sector and 0.1% for the poultry sector. Sugar cane accounted for about 0.8%, and 0.5% from the cotton industry. Finally, GHG emissions are made up of 2% CO_2, 82% CH_4 and 16% N_2O on a carbon dioxide equivalent (CO_2e) basis.

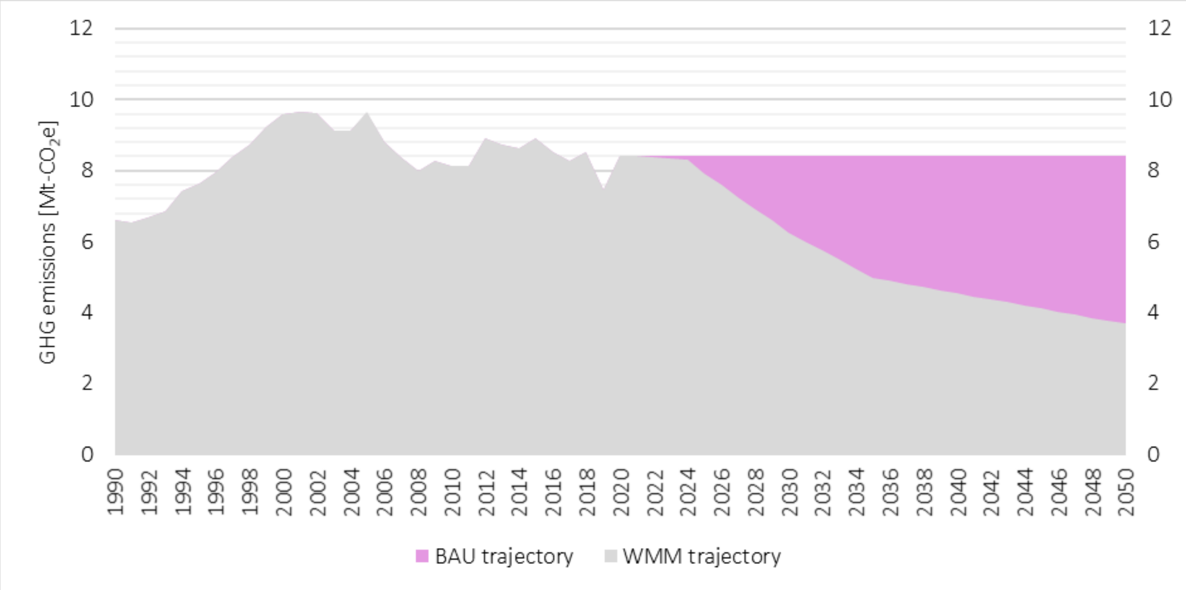
The details of both the BAU and WMM based emissions trajectories for agriculture emissions are provided below. Trade-offs and co-benefits between strategies for emission reductions on farms are also assessed. All mitigation measures addressed below are now considered to be no more speculative than giga-scale deployment of bioenergy with carbon capture and land sequestration options that are a feature of many global climate change mitigation pathways.[2, 3]

8.1.1 Dairy industry

The dairy industry GHG emissions accounted for 10% (7.3 Mt-CO_2e) of agricultural emissions in 2019. The majority of GHG emissions from the dairy sector is from farms and is primarily CH_4 emissions.[1] Overall, the values of direct emissions in 2019 for this sector was 6.3 Mt-CO_2e for enteric fermentation, 1.0 Mt-CO_2e for manure management and lastly 0.2 Mt-CO_2e for irrigated pastures. Further information on emissions from enteric fermentation is provided by Black et al.[4] and nitrous oxide emissions from fertiliser application by Eckard et al.[5] The dairy industry is mainly located in high rainfall areas or in areas that are irrigated to supplement rainfall. In this analysis, we considered dairy as the largest user of irrigated pasture in Australia when accounting for fertiliser (N_2O) emissions.[6]

The dairy industry expanded throughout the 1990's but since then, industry deregulation (in 2000) and the *Millennium drought* have impacted it, with severe droughts affecting almost all regions in Australia between 2002 and 2010.[7,8] According to the literature, the long-term drought impacts have resulted in a decrease of approximately 25% of the national dairy herd size with farmers responding to increasing debt and reduced fodder availability, rising feed prices and poor pasture growth during drought conditions.[9,10] The historical GHG emissions (Figure 22) reflect these industry trends.

Figure 22 | Historical (1990 – 2019) and projected (2020 – 2050) dairy sector GHG emissions, for both the BAU and WMM trajectories.[1]



The BAU trajectory projection shown in Figure 22 is based on the GHG emissions and dairy cattle population of 2.4 million animals in 2019. The BAU trajectory projects GHG emissions to be constant at 2019 levels through to 2050. It is important to note that this constant GHG emissions projection does not preclude increases in dairy production. This is because of an anticipated increase in milk yield per cow, which would result in a decrease in emission intensity of dairy cattle activity.[11,12,13]

The WMM trajectory includes the effect of three different strategies: those aimed at reducing emissions from enteric fermentation; manure management; and inorganic fertilisers. First, we estimated the potential change obtained from feeding 3-nitrooxypropanol (3-NOP) in the diet composition and determine how these affect enteric CH_4 emissions. The assumptions needed for this calculation include the uptake across the years, technology development, and the impact of the additive on the enteric methane yield was assumed that the fraction of the Australian dairy herd consuming this additive gradually increased, as shown in the summary in Table 21, resulting in a 50% reduction in enteric methane emissions in 2050 (3.6 Mt-CO_2e).[14,15,16]

Table 21 | GHG mitigation assumptions used in the WMM for the dairy cattle industry.

Source category	2019 GHGs (Mt-CO_2e)	2025	2030	2035	2040	2045	2050
Enteric fermentation	6.3	50% reduction in 10% of herd	50% reduction in 50% of herd	50% reduction in 80% of herd	50% reduction in 87% of herd	50% reduction in 93% of herd	50% reduction in 100% of herd
Manure management	1.0	100% reduction, 15% adoption rate	100% reduction, 32% adoption rate	100% reduction, 49% adoption rate	100% reduction, 66% adoption rate	100% reduction, 83% adoption rate	100% reduction, 100% adoption rate
Inorganic fertilisers	0.1	40% reduction, 10% adoption rate	40% reduction, 70% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate

The next strategy targets manure management. We project emissions reduction in the WMM trajectory through the installation of covered anaerobic ponds (CAPs) on dairy farms to reduce CH_4 from the existing reported storage units. Although this technology is readily available, CAPs are not likely to be adopted in

Australia unless strongly encouraged by new incentives, together with stricter regulations of manure effluents, even though dairy production systems in Australia are well-suited to the capture of methane from manure slurry.[17] CAPs allow for all CH_4 produced during the oxygen-free manure degradation to be captured and combusted in a flare, with no CH_4 emitted to the atmosphere (only biogenic CO_2).[18] Table 21 lists our assumptions of gradual uptake of CAPs, with 100% of emitted methane captured when adopted,[19] suggesting that emissions from dairy cattle manure management can be reduced to 0.02 Mt-CO_2e/year in 2050.

Finally, to address N_2O emissions from nitrogen fertilisers, slow-release nitrogen-based fertilisers (SRF) were considered as a possible alternative to conventional fertilisers as they improve the efficiency of nitrogen use, not only reducing emissions but with other co-benefits. These benefits include reduction of nitrogen loss through leaching and volatilisation, increased dry matter yield, and decreased overall costs for the farmers with a reduction in fertiliser application rates.[20,21] The projected plausible fertiliser strategy then encompasses management options and technologies currently available to farmers or deemed as current best management practice in Australia. The WMM trajectory assumes that SRF reduces N_2O emissions from 0.17 in BAU to 0.12 Mt-CO_2e from irrigated pastures in 2050.

8.1.2 Pasture-fed beef industry

The Australian pasture-fed beef industry is a significant contributor to GHG emissions in Australia, with an estimated emission of 35.3 Mt-CO_2e in 2019, or 47% of the agricultural sector. The main source of GHG emissions from beef cattle is again enteric fermentation, with the total amount produced directly related to the number of ruminant livestock.

The Australian beef herd and associated GHG emissions fluctuate according to seasonal and market conditions. In recent years, the Australian cattle herd has declined significantly from its high of 29.3 million head in 2013 to approximately 23.7 million in 2015. The fast decline in the national herd numbers was due to unfavourable seasonal conditions, lower calving rates, and higher than average mortality rates.[22] With the reduction in female cattle slaughter and improvement of seasonal conditions, producers have since rebuilt the herd somewhat, to approximately 26.4 million head by the end of 2020-21 encouraged by reasonable saleyard prices and strong international demand.[22,23]

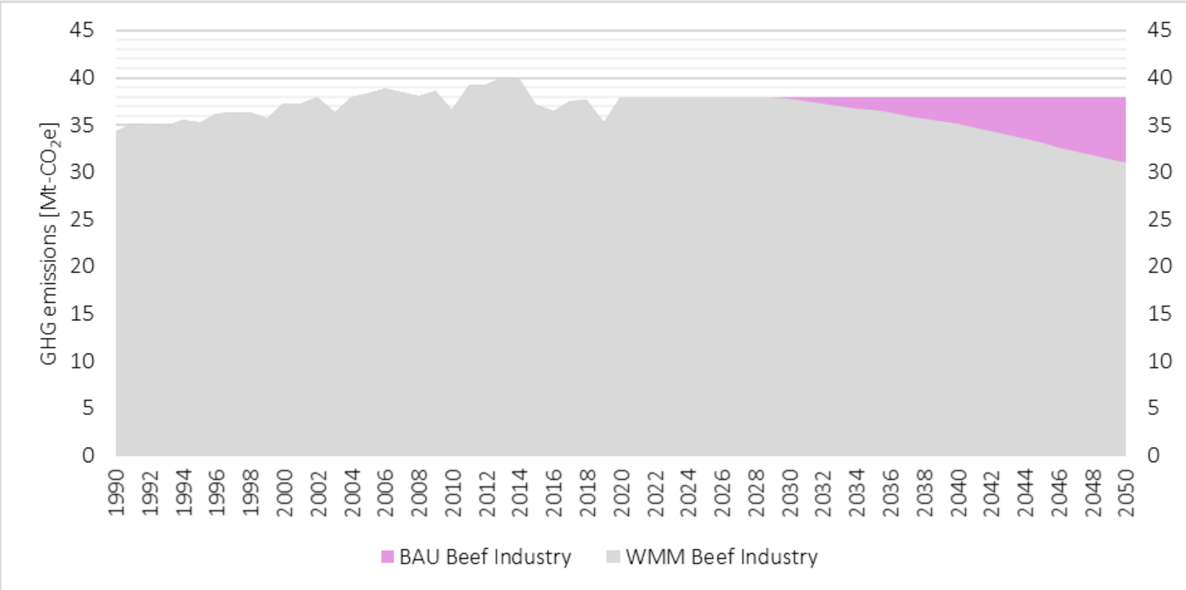
The BAU emissions trajectory assumes a steady state of the national herd, where calving, weaning, replacement and culling rates remain constant until 2050. This assumption estimates the national herd to be a beef cattle population of 22.5 million heads in 2019. On this basis, the GHG emissions were estimated to remain constant, as shown in Figure 23. While we have applied this simplifying assumption, trends in meat consumption are complex and changing. Beef consumption is predicted to decline over time, attributed partly to long-term trends in retail prices.[24]

The WMM trajectory focused on reducing enteric CH_4 fermentation emissions in this industry by estimating the plausible effect of dietary supplementation of 3-NOP for grazing ruminants, based on the experience in the literature.[4,14,25,26] Here we assume that when 3-NOP is fed, CH_4 emissions decrease by 40% with no effect on dry matter intake or average daily gain (Table 22). Although it is feasible to supplement diets for ruminants, it is also challenging to implement in grazing systems (e.g., feed additives are easier to implement in feedlot and dairy production where cows' diets are regularly supplemented, compared to the beef industry which is dominated by more extensive grazing systems). We have therefore assumed that a slow-release formulation or delivery mechanism would be developed to administer the required daily dose for grazing ruminants in the coming years.[4,14]. The projected WMM trajectory with this mitigation measure is shown in Figure 23. In modelling the effect of 3-NOP on methane emissions, we estimate that the percentage of the national beef herd consuming this additive will progressively increase, leading to a reduction of around 20% enteric methane in 2050 (27.7 Mt-CO_2e), as shown in Table 22.

Table 22 | GHG mitigation assumptions used in the WMM for the beef cattle industry.

Source category	2019 GHGs ($Mt\text{-}CO_2e$)	2025	2030	2035	2040	2045	2050
Enteric fermentation	32.3	No change from BAU	40% reduction in 1% of beef herd	40% reduction in 10% of beef herd	40% reduction in 20% of beef herd	40% reduction in 35% of beef herd	40% reduction in 50% of beef herd

Figure 23 | Historical (1990 – 2019) and projected (2020 – 2050) beef sector GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.3 Feedlot industry

Australia's feedlot industry grew by 60% between 2000 and 2017. The most significant growth was in Queensland, where the capacity increased by 89% followed by NSW (37%), Victoria (39%) and Western Australia (57%). In contrast, the South Australian feedlot capacity fell by 8% during this period. Queensland and New South Wales account for the largest feedlot activity mainly due to relatively easy access to primary inputs for the sector, such as grain and feed production. In the last 20 years, the sector shifted from 'opportunistic' operations in times of poor seasonal conditions towards the production of high-quality beef all year round to satisfy market demand, as producers seek to increase the value of their product.[27] Because of this shift, grain-fed cattle turnoff is less likely to fluctuate in response to seasonal conditions, with decisions on utilisation driven by factors such as demand growth and feed costs.[27]

To ensure that feedlot heads are not double counted, the national inventory report calculated feedlot cattle numbers from beef cattle numbers (pasture-fed), as grain-fed cattle spend on average 70-300 days in the finishing phase prior to slaughtering. Feedlot cattle are assumed to derive from steers that are greater than 1 year old from the beef cattle class, reaching up to 1.1 million heads in 2019. We assumed the Australian herd size will remain constant based on the historical trend, so that in the BAU trajectory, enteric CH_4 emissions and manure management of lot fed beef cattle start from a baseline of 2.4 $Mt\text{-}CO_2e$ in 2019 and remain constant to 2050, where the main methane source is associated with the intake of dietary carbohydrates derived from feedlot fed diets, consisting of main grains and concentrates.[1]

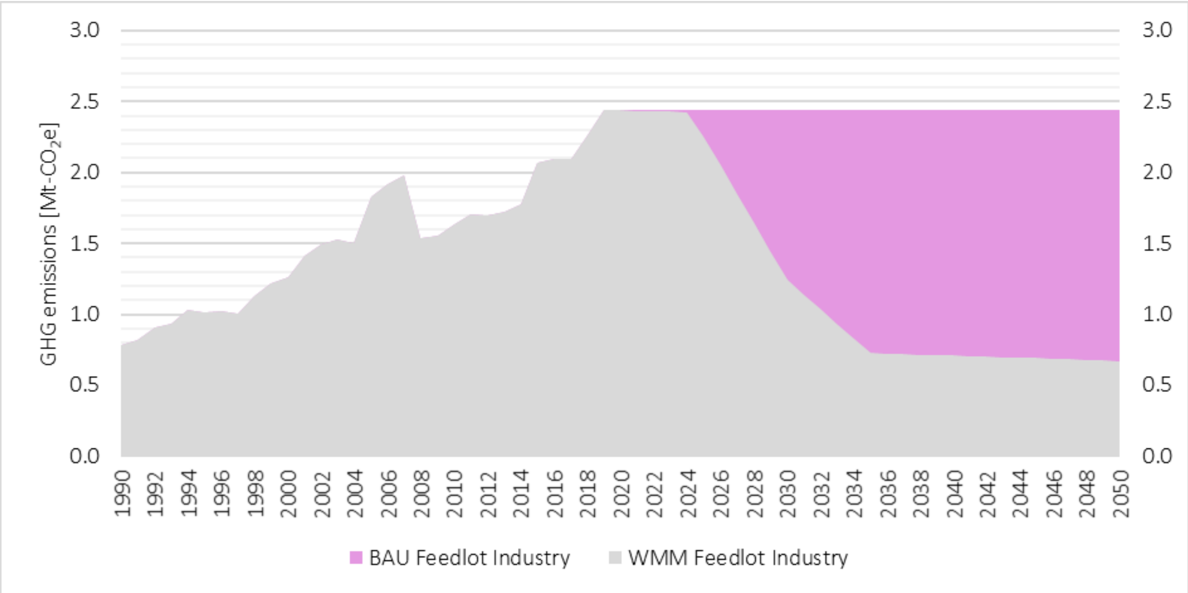
The WMM trajectory projects the reduction of methane emissions through the adoption of 3-NOP in intensive feeding systems. According to the literature,[14,28,29] the higher frequency of feeding the 3-NOP feed additive in intensive feeding systems, could significantly reduce CH_4 by about 80%. In addition, we assumed higher uptake rates than pasture-fed beef, as shown in Table 23, as this sector was assumed to have minimal adoption inhibitors, which increases uptake speed on individual farms, regionally and nationally.[28] Hence, combined with a gradual increase in adoption rates, the enteric emissions are projected to decline to about 0.4 Mt-CO_2e (80% reduction), resulting in higher efficiency production.

For the projection of manure management emissions in the WMM trajectory, methane capture with covered anaerobic ponds CAPs was again selected as a feasible method to reduce emissions from intensive livestock waste. Under Australian conditions, it was assumed that manure would be taken directly from the pen to the covered anaerobic pond resulting in 100% methane capture as a management practice with gradually increasing uptake rates (Table 23).

Table 23 | GHG mitigation assumptions used in the WMM for the feedlot industry.

Source category	2019 GHGs (Mt-CO_2e)	2025	2030	2035	2040	2045	2050
Enteric fermentation	2.1	80% reduction in 10% of the herd	80% reduction in 70% of the herd	80% reduction in 100% of the herd	80% reduction in 100% of the herd	80% reduction in 100% of the herd	80% reduction in 100% of the herd
Manure management	0.4	100% reduction 15% adoption rate	100% reduction 32% adoption rate	100% reduction 49% adoption rate	100% reduction 66% adoption rate	100% reduction 83% adoption rate	100% reduction 100% adoption rate

Figure 24 | Historical (1990 – 2019) and projected (2020 – 2050) feedlot sector GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.4 Sheep industry

The Australian wool industry has had relatively low wool returns over the last 15 years, with a steady reduction in sheep numbers, a drop in wool production and an increase in lamb returns. The main driver of the declines is the long-term reduction in raw wool demand, competition from substitute synthetic fibres, and the Millennium Drought that contributed to a steeper decline in sheep numbers.[9] Subsequently, this sector underwent a significant structural adjustment of wool towards mutton production and prime lamb, which led to increased specialisation within the sheep industry in accommodating the growing demand for Australian lamb exports.[30] Since the 1980s, the national sheep numbers have declined from a peak of 173 million head to 69 million in 2019, and are now projected to remain relatively stable.[31]

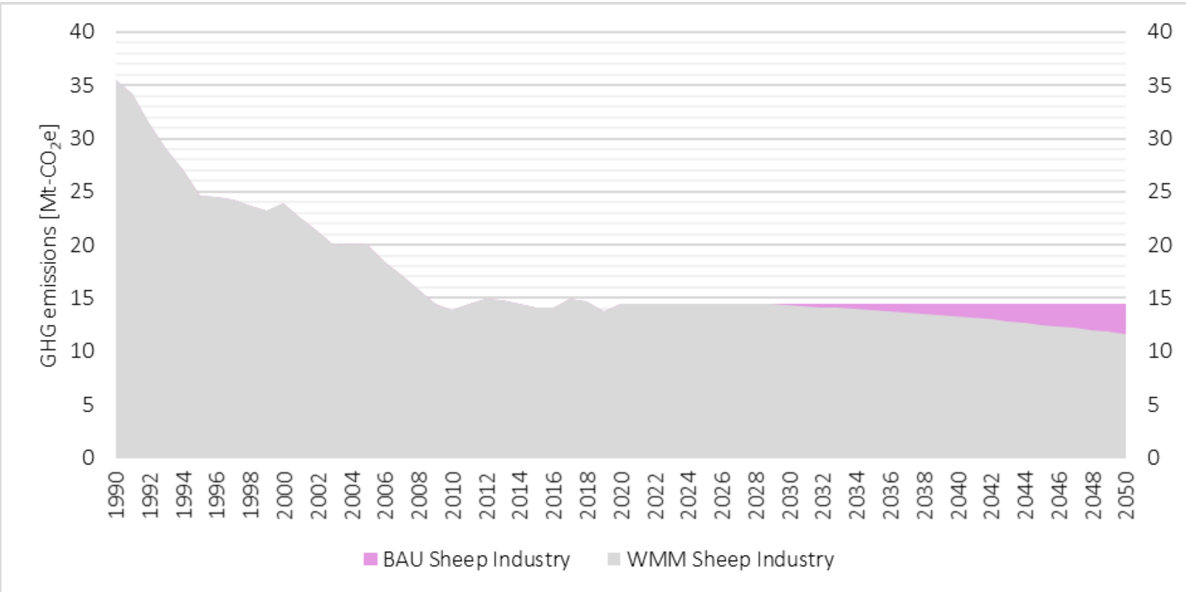
The BAU trajectory therefore depicts that the flock size would remain constant, thereby halting the previous downward trend, as shown in Figure 25. According to the national inventory report, emissions from the sheep industry consist entirely of methane with 90% methane from enteric fermentation and 10% from manure management.[1]

The WMM trajectory estimates the effects of 3-NOP in the CH_4 emissions of sheep, based on experimental demonstration that supplementing methane inhibitors to sheep led to an emissions reduction of 86-95%.[32] However, we assumed a decrease of 40% in methane emissions, with an adoption rate that reaches 50% by 2050, as listed in Table 24. While this compound offers a great mitigation potential, it effectively mitigates emissions only with frequent administration. This might not be feasible with grazing ruminants. Hence, we again assume the development of a slow-release formulation mechanism to provide the required daily dosage.

Table 24 | GHG mitigation assumptions used in the WMM for the sheep industry

Source category	2019 GHGs ($Mt\text{-}CO_2e$)	2025	2030	2035	2040	2045	2050
Enteric fermentation	13.04		40% reduction in 1% of the flock	40% reduction in 10% of the flock	40% reduction in 20% of the flock	40% reduction in 35% of the flock	40% reduction in 50% of the flock

Figure 25 | Historical (1990 – 2019) and projected (2020 – 2050) sheep sector GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.5 Swine industry

Over the last decade, there has been a relatively small fluctuation in herd size in the swine industry. Previously a declining trend started from 3.3 million head in 1973, then to about 2.3 million in 2011,[33] and to 2 million in 2020. Historically, the Australian pig industry was bound to dairy or grain farming. However, these industries changed due to deregulation of the dairy industry and the introduced wheat quotas which pressured producers to increase their production efficiency to remain in the industry and resulted in the swine industry becoming decoupled from dairy and grain, leading to a more stable herd size.[33]

Australian pig housing can be classified into three different types: outdoor, conventional, and deep litter, which employ various manure management systems.[34] In 2020, CAPs were reported to be used in 15.6% of total manure treatment in 2020, with solid storage (19%) and uncovered anaerobic ponds (56%) also used. The relatively low uptake of CAPs is mainly due to the investment required, which is a barrier for smaller scale piggery operations. Therefore, in an Australian context, the specific GHG emissions from piggeries vary across the country depending on the type of housing system and manure management system used, with the highest methane emissions stemming from open anaerobic ponds.[35]

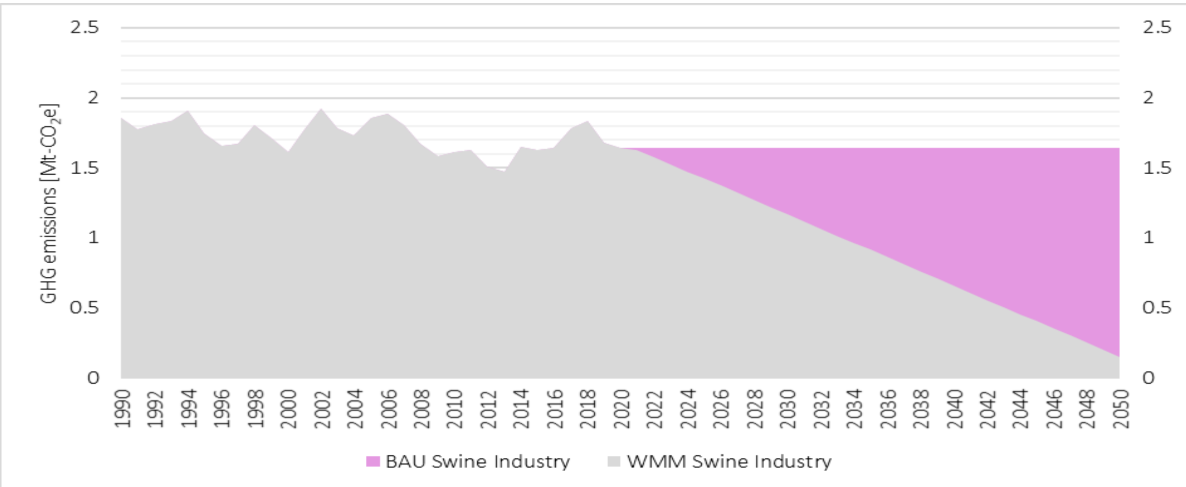
The BAU trajectory is projected to remain at a constant level (1.64 Mt-CO_2e/year), with this flatline likely due to improved herd productivity and enhanced environmental efficiency, with changes in land occupation and water management.[36] In comparison, as shown in Figure 26, the WMM emissions trajectory drops by 91% with the employment of covered anaerobic ponds (CAPs).

The WMM trajectory projects the installation of CAPs in all piggeries. All effluent from current operation of the industry was assumed to be treated in CAPs, with a gradual uptake out to 2050. Approximately 100% of the CH_4 emissions from manure management are projected to be captured in 2050, and any biogas produced is to be used in combined heat and power systems to satisfy the local demand for electricity and heat, with any remaining emissions flared (Table 25). Residual GHG emissions in the swine industry are attributed to enteric fermentation, for which we have not projected any mitigation measure.

Table 25 | GHG mitigation assumptions used in the WMM for the swine industry.

Source category	2019 GHGs (Mt-CO_2e)	2025	2030	2035	2040	2045	2050
Manure management	1.6	100% reduction 15% adoption rate	100% reduction 32% adoption rate	100% reduction 49% adoption rate	100% reduction 66% adoption rate	100% reduction 83% adoption rate	100% reduction 100% adoption rate

Figure 26 | Historical (1990 – 2019) and projected (2020 – 2050) swine sector GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.6 Poultry industry

In Australia, both the egg industry and broilers (chicken meat industry) are based on intensive animal production systems. Until the late 1990s, the production of chickens and eggs were often located in the hands of 'backyard' producers and larger family operations. This transitioned to vertically integrated enterprises or 'integrator' systems that consistently increased production in the industry. A surge in production was achieved through improved genetic selection, nutrition, and husbandry and the development of processing technologies.[37] Like the other agricultural industries following the millennium drought, the poultry industry was impacted by the rise of historically high grain prices due to the shortage of feed grains and raw material availability. Several companies have also recently shifted from traditional production in peri-urban areas towards regional Australia, accompanied by significant growth in the free-range sector.[37]

Demand for chicken meat in Australia is likely to continue at similar levels to current, supported by the income growth of consumers and the trend towards low-cost foods, which could likely compete with other more expensive meat products (e.g., beef and lamb).[38] On the other hand, the national flock size, which includes all laying stock (16 million head), meat chickens (101 million head) and other poultry (3 million head) were projected to diminish over the last few years.[38] We considered these historical records, in addition to the estimated emissions from the national inventory report,[1] to serve as a means of outlining assumptions to estimate possible trajectories for this industry conservatively.

The BAU trajectory assumes that emissions from manure management systems will remain constant. Despite the growth in domestic consumption of Australian chicken meat, we assumed a flatline in emissions then caused by improved production efficiency with the employment of best management practices when handling and storing poultry litter and manure to reduce GHG emissions.

The WMM trajectory projections are based on a study of the main environmental issue related to this sector: the emissions from the accumulation of waste such as manure and litter. Under this trajectory, we assume that effluent is treated with CAPs reducing the exposure of manure to air with a capture efficiency of 100% of CH_4 emissions. Likewise, we assume a gradual uptake (Table 26), and adoption will be dependent on the increasing demand for low-emissions production, the financial incentives related to the GHG markets and emissions reductions with the demonstration of economic advantages under local conditions to encourage farmers.[39]

Table 26 | GHG mitigation assumptions used in the WMM for the poultry industry.

Source category	2019 GHGs (Mt-CO2e)	2025	2030	2035	2040	2045	2050
Manure management	0.1	100% reduction 15% adoption rate	100% reduction 32% adoption rate	100% reduction 49% adoption rate	100% reduction 66% adoption rate	100% reduction 83% adoption rate	100% reduction 100% adoption rate

8.1.7 Cotton industry

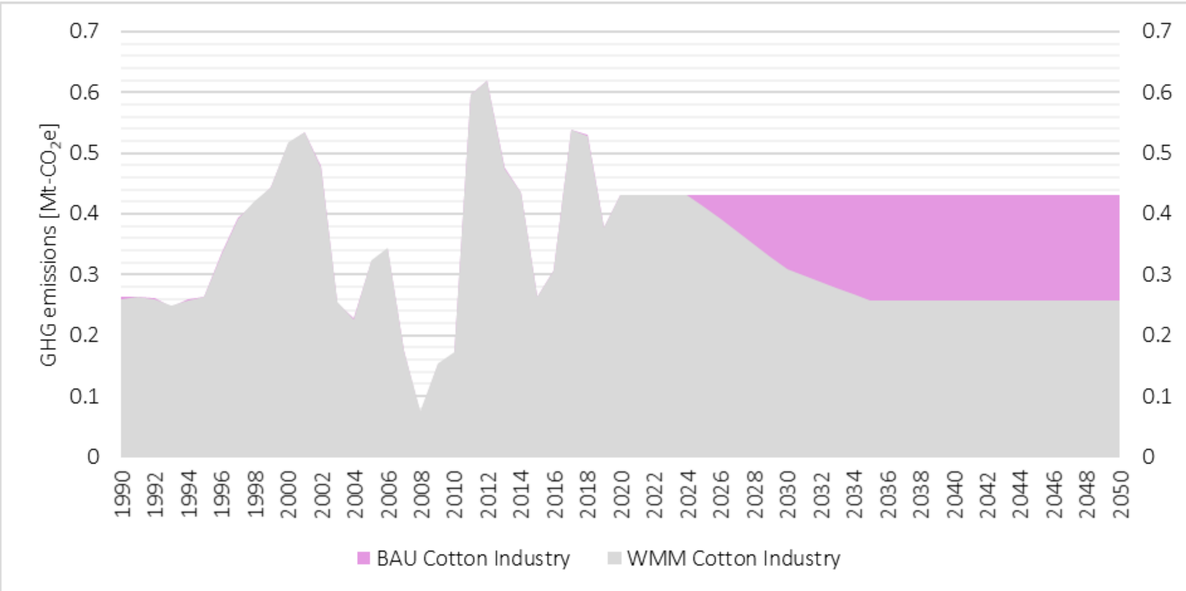
The Australian cotton industry is located mainly in New South Wales (66%) and Queensland (33%), with about 1,500 farms (53% increase since 2008), a large fraction of which belong to families (90%) producing about 80% of the total crop. Historically, the main factors influencing production have been seasonal conditions, market price, agricultural policy, fashion trends and synthetic fibre competition. Over the last decade, the price reduction from roughly $1,000 per bale to about $590 per bale[40] might also stem from the build-up in stocks, leading to a continued downward price pressure due to a fall in textile mill capacity.

The BAU trajectory assumes that that cotton production will remain, on average, constant over the next 30 years, with the projected 2050 fertiliser emissions of 0.4 Mt-CO_2e. In contrast, the WMM trajectory projects a 40% reduction in N_2O emissions (Figure 27), with a progressive uptake of slow-release nitrogen-based fertilisers as summarised in Table 27, and discussed above. We assumed a 100% adoption rate of this technology from 2035 onwards.[41]

Table 27 | GHG mitigation assumptions used in the WMM for the cotton industry.

Source category	2019 GHGs (Mt-CO_2e)	2025	2030	2035	2040	2045	2050
Inorganic fertiliser	0.4	40% reduction 10% adoption rate	40% reduction 70% adoption rate	40% reduction 100% adoption rate	40% reduction 100% adoption rate	40% reduction 100% adoption rate	40% reduction 100% adoption rate

Figure 27 | Historical (1990 – 2019) and projected (2020 – 2050) cotton industry GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.8 Sugar cane industry

The Australian sugar cane industry is one of the world's biggest sugar exporters, with approximately 80% of all raw sugar produced being exported as bulk raw sugar, primarily from Queensland. In 2016, around 4,000 farms grew sugar cane on approximately 380 thousand hectares. The distribution of sugar industry production is about 95% located in QLD and 5% in NSW, with growers' farms and mills located mainly along the eastern Australian coastline, from Mossman in far north QLD to Grafton in northern NSW. These sugar cane producing areas are still dependent on high rainfalls and humid, sunny conditions during the wet season period, which is from January to March.

The production of sugar cane relies heavily in the application of large amounts of inorganic nitrogen fertilizer.[42] However, fertiliser application in excess of crop needs can result in loss of nitrogen to the environment, which results in N_2O greenhouse gas emissions. This is of particular concern in Australia where the nitrogen pollution of sugar cane cropping is significant due to inefficiencies caused by mismatched nitrogen supply and crop demand over sugar cane's long nitrogen accumulation phase.

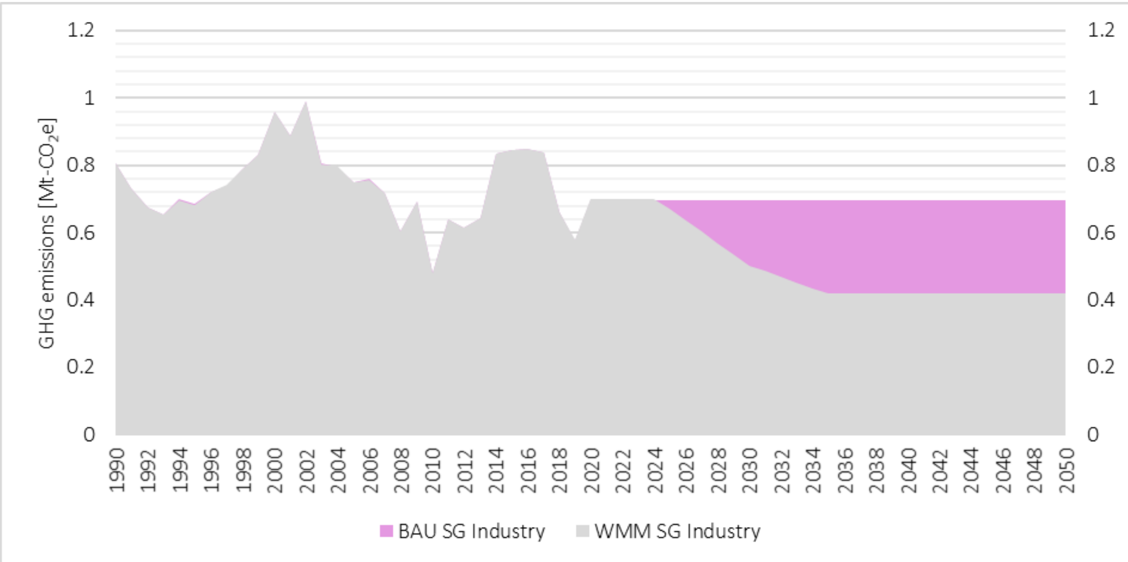
Moreover, the lost nitrogen in a sugar cane production system is mainly through (1) the removal of harvested produce, (2) the loss because of denitrification or leaching of nitrate to the environment, and (3) crop residue burning. (Note, the lost nitrogen from volatilisation of ammonia fertiliser is not considered in this approach). Similar to the cotton and dairy sectors (i.e., irrigated pasture), N_2O emissions reduction can be achieved by developing enhanced efficiency slow release fertilisers, aimed to delay nitrogen release or nitrogen stabilisation in urea with polymer coating.[43]

The BAU trajectory reflects the historical trend of GHG emissions, where the 1990 level was from 0.80 to around 0.6 Mt-CO_2e in 2019, a decline of 24% with existing harvesting management practices. Figure 28 shows the estimated reduction in the WMM emission trajectory of 40% (to 0.4 Mt-CO_2e in 2050) through the plausible application of SRF, with assumptions listed in Table 28.

Table 28 | GHG mitigation assumptions used in the WMM for the sugar cane industry.

Source category	2019 GHGs (Mt-CO2e)	2025	2030	2035	2040	2045	2050
Inorganic fertiliser	0.6	40% reduction 10% adoption rate	40% reduction 70% adoption rate	40% reduction 100% adoption rate	40% reduction 100% adoption rate	40% reduction 100% adoption rate	40% reduction 100% of adoption rate

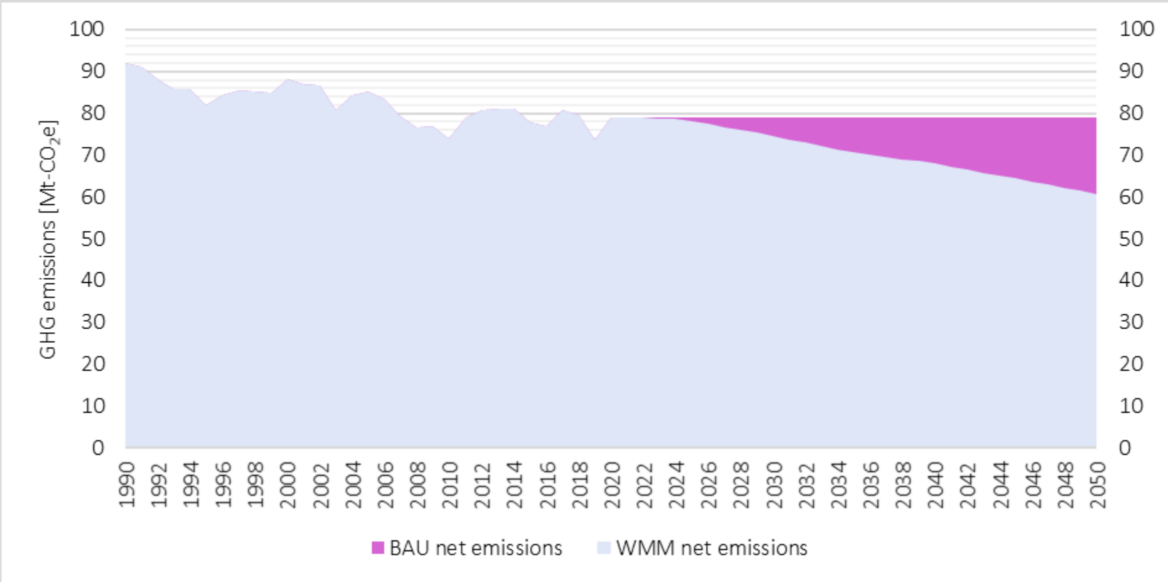
Figure 28 | Historical (1990 – 2019) and projected (2020 – 2050) sugar cane industry GHG emissions, for both the BAU and WMM trajectories.[1]



8.1.9 Projections of agriculture emissions trajectories

Figure 29 presents the aggregated BAU and WMM emissions trajectories for the agriculture sector. With the plausible mitigation measures detailed above, the WMM trajectory projects a reduction in total agriculture emissions of 23% (from 79.9 to 61.7 Mt-CO_2e) between 2020 and 2050 due to multiple actions detailed in the sections above.

Figure 29 | Historical (1990 – 2019) and projected (2020 – 2050) agriculture sector GHG emissions, for both the BAU and WMM trajectories. [1]



8.2 LULUCF

In recent years Australia's land use, land-use change, and forestry (LULUCF) sector has been a net sink of carbon dioxide emissions, accounting for −25.1 Mt-CO_2e in the 2019 GHG inventory.[1] While certain deforestation activities – such as clearing mature forest and harvesting native forests – cause net positive carbon dioxide flows to the atmosphere, net negative flows/removals from the atmosphere into terrestrial reservoirs are also possible through reforestation, afforestation, reduction of deforestation, and sustainable management of forests.

This section on Australia's LULUCF emissions comprises two sections: an overview of historical trends in GHG emissions/removals within each LULUCF category; and details of projected emissions trajectories of each LULUCF category in both a BAU future, and a future with plausible concerted reforestation and emissions abatement efforts, with discussion of the underpinning assumptions and the accounting rules of the Kyoto Protocol.[44]

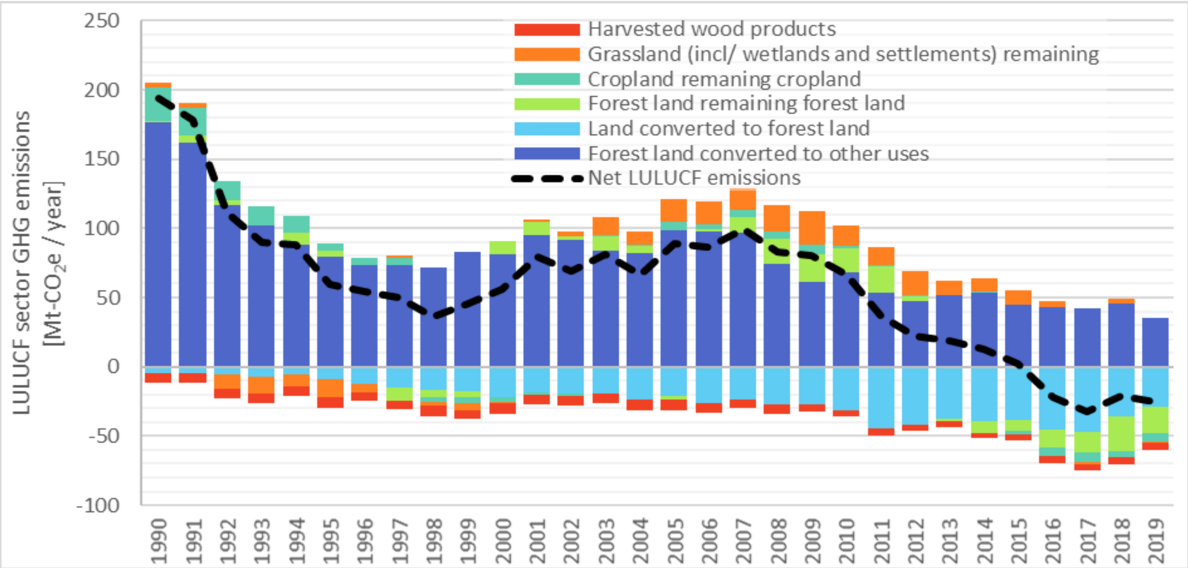
8.2.1 Historical trends in net LULUCF emissions

Australia's national greenhouse inventory accounts for net LULUCF emissions for the land uses and changes among:

- forest land
- cropland
- grassland
- wetland
- settlements
- as well as an estimation of emissions associated with harvested wood products.

Figure 30 presents the historical (1990 – 2019) GHG emissions from the various land types and use changes that make up the total LULUCF GHG emissions inventory [1]. We discuss these categories below.

Figure 30 | Historical (1990 – 2019) GHG emissions from the various land types and use changes that make up the total LULUCF GHG emissions.



Forest land converted to other land uses

This category accounts for the net change in carbon dioxide flows due to anthropogenic forest loss since 1990. It incorporates changes to lands where the forest has been removed due to direct human activities and has been replaced with other land uses. These land uses include conversion to cropland, grassland, wetlands and settlements, and the extent of this activity was estimated to contribute +35 Mt-CO_2e in 2019, as shown in Figure 30.[1]

Deforestation and land clearing have been major contributors to human-induced climate change, including in Australia, where peak deforestation and land clearing emissions had a value of 176 Mt-CO_2e/year or 30% of total GHG emissions in the base year of the Kyoto Protocol (1990).[44] Between 1990 and 2019, a long-term trend of gradual decline in the rate of land clearing has taken place due to policy reforms promoting biodiversity conservation, sustainable development, and regulations on deforestation to end broadscale clearing of remnant native vegetation.[44] Deforestation and land clearing emissions have then declined by 80% (a 141 Mt-CO_2e/year reduction) between 1990 and 2019, so that the average emissions from land converted to other land uses over the last decade has been 48.5 Mt-CO_2e/year.[1]

Land converted to forest land

According to the National Inventory Report, the emissions and removals under this category include those associated with grassland, cropland, settlements, and wetlands being converted to forest land, which results in a rise in woody vegetation cover. This is manifested in the establishment of new commercial plantations, environmental plantings, natural regeneration (from seed or rootstock) or, in other words, forest growth on land that has previously been cleared for other land uses. Over the past ten years (2010–2019), an estimated average of −39 Mt-CO_2e/year has been removed from the atmosphere through land being converted to forest land.

The data reported here for afforestation and reforestation of land converted to forest land, only includes forests established from 1 January 1990 on land that was clear of forest on 31 December 1989, according to the Kyoto Protocol Classification.[1,44,45] It can be seen in Figure 30 that net CO_2 removal in land converted to forest land increased to maximum levels between 2011 and 2017 due to the previous establishment of timber plantations in 1990-2007. However, this sink effect is projected to stabilise in the coming years, mainly because the rate of removals associated with the conversion to forest will gradually approach zero as these forests reach maturity, in contrast to younger trees that tend to have higher rates of growth and carbon fixation.[46]

Since the 1990s, growth in timber plantations has gradually increased to an average annual rate of 77,000 hectares (ha) in 2007.[45] During this period, the timber industry experienced significant growth, mainly attributable to private investment, influenced by incentives for plantation establishment such as the taxation treatment of Managed Investment Schemes. With a short rotation management for these plantations (10-15 years), their associated aggregate removals peaked in the period 2011 – 2017, due to the lag of several years between planting and the maximum rate of removals for a newly established plantation as it matures.[45]

However, there is emerging evidence that Australia's established plantation area has decreased in size over the last few years.[47] This is likely caused by the conversion of marginal plantations to other land uses, leading to a reduced capacity of the national plantation estate to support emissions removals. In 2019, around 12,000 ha in Australia's plantation estate were converted to other land use, which may lead to a gradually flattened (i.e., less negative) sequestration rate in this category of the emissions inventory.

Forest land remaining forest land

This category includes lands holding vegetation that meets the UNFCCC criteria for a forest on a permanent basis. The criteria require the vegetation to be at least 2 meters high with a minimum of 20% canopy coverage.[44] This category includes areas harvested for commercial timber products and silvicultural practices designed to enhance sinks. The accounted forests under this category are multiple-use public forests; plantations established prior to 1990 (that do not qualify for afforestation/reforestation under the Kyoto

Protocol); and privately-operated native forests. From data in National reports,[48] it is apparent that drivers of net emissions in this category are primarily the demand for Australian wood and wood products, the substitution of these supplies between plantations and native forests, and the incidence of wildfire.

Net emissions from forest land remaining forest land were −19.1 Mt-CO_2e in 2019. This net sink can be attributed to the trend of greater removals through forest regrowth on land that has been cleared in the past, and reduced net emissions from the harvest of native forests.[1,49] This native forest trend is a significant contributor, as there has been a significant decline in the clearing of native forest for plantation establishments, with new tree plantations instead being established on previously cleared land, such as former grazing lands Australia-wide. The effect of this trend is visible in the decreasing net emissions from both the *land converted to other* uses and *forest land remaining forest* land categories in recent years, as shown in Figure 30. As a supplementary effect, Australia's total pulpwood volumes harvested are increasing rapidly and, to some extent, keeping a relatively constant timber yield despite the decline in harvests from native forests.[49,50]

Figure 30 shows that the *forest land remaining forest land* category has therefore varied considerably between contributing a net source and a net sink of CO_2 since 1990. Forest regrowth corresponds with increased uptake of CO_2, but fluctuates considerably with prevailing climate conditions (e.g., drought), and to some extent, through the decomposition of dead biomass that naturally occurs over long-term periods. This principle underpins the balance between carbon stocks and the accumulated concentration of CO_2 in the atmosphere. Historical fire regimes also have a significant effect on carbon stock over various temporal scales. Fire (including bushfire) leads to carbon losses occurring over a short period, but can itself, subsequently lead to increased rates of carbon uptake, by regenerating vegetation during favourable climate conditions, counterbalancing the carbon losses to some extent.

Cropland remaining cropland

This category is estimated to have contributed a net sink of −6 Mt-CO_2e in 2019, which is a significant reduction on the 1990 level of +25 Mt-CO_2e. Emissions and removals from this category fluctuate from changes in land use, cyclical effects from climate variation, changes in management practices on cropping lands, and from changes in crop type, generating changes in the levels of soil carbon or woody biomass stocks over the longer term.

Grassland/wetland/settlements remaining grassland/wetland/settlements

This category includes the *grassland remaining grassland*, *wetland remaining wetland* and *settlement remaining settlement* classifications of the national GHG inventory.[1] According to the national inventory report, net emissions from grassland remaining grassland are related to changes in fire management from savanna rangelands, changes in soil carbon from grazing, and changes in shrubby vegetation.[1] Grassland remaining grassland accounted for a net sink in 2019 of −5 Mt-CO_2e.

In comparison, net emissions from wetlands remaining wetlands, are predominantly methane emissions from constructed ponds and reservoirs. Small amounts of nitrous oxide emissions are also present, stemming from aquaculture uses in tidal marsh areas and, while net carbon dioxide emissions from the dredging of seagrass, as well as changes in mangroves, are also accounted. The wetlands category was estimated as a net source of 4 Mt-CO_2e in 2019 and has remained relatively steady since the 1990s.[1]

Emissions/removals from the settlements remaining settlements category, account for very small net GHG emissions levels, −0.01 MtCO_2e in 2019. This estimate comprises net changes in sparse woody vegetation around urban infrastructure.[1] Although settlements have a very small sequestration capability, urban forests have in recent years played a role in the overall net increase in carbon sequestration.[49,50,51]

8.2.2 Projections of net LULUCF emissions

NZAu has developed estimates of future net emissions trajectories for the various LULUCF sector categories described above. The basis for these projections, as well as the central structure of the categories, is the National Inventory Report,[1] with assumptions on future trends drawn from expert advice.

We project two trajectories within the LULUCF sector:

1. Business as usual (BAU), which assumes no change in current LULUCF emissions abatement policies; and
2. With mitigation measures (WMM), which assumes a plausible concerted effort to make the LULUCF a net sink of emissions.

These trajectories combine top-down assumptions – such as existing policies, industry production trends, and climate variation – with bottom-up disaggregated sectoral information. We aimed to make these projections with assumptions judged as plausible by experts in the NZAu team.

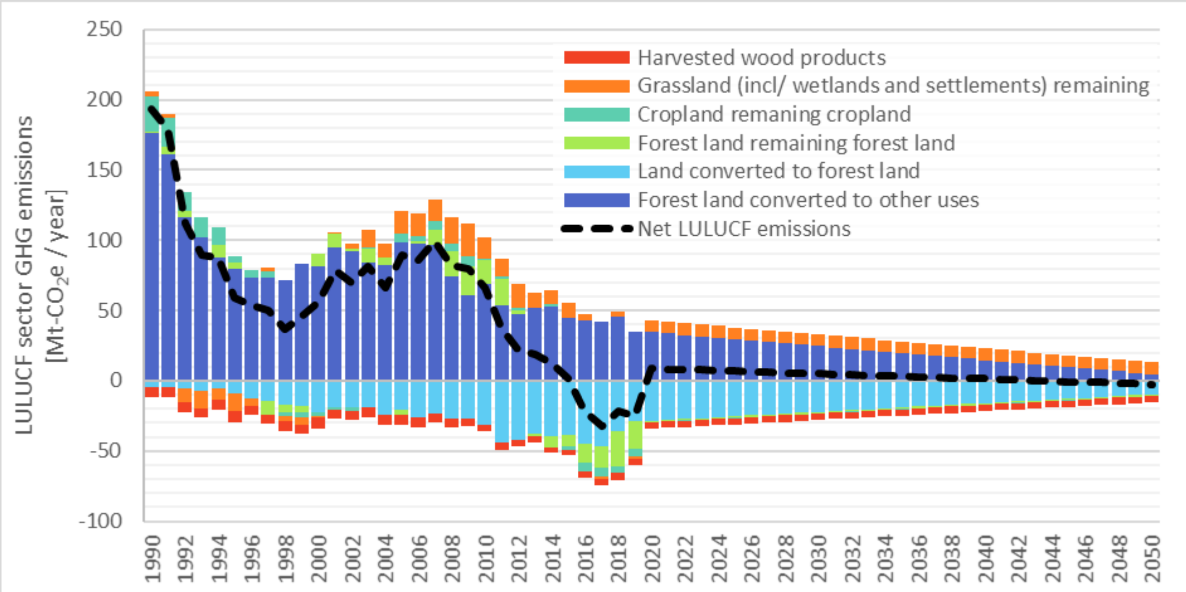
Business as usual

Figure 31 presents the historical and projected LULUCF emissions for the BAU trajectory. The *forest land converted to other land uses* category continues to decline as a net source of emissions, following the continued trend of a gradual decline in the rate of land clearing with current policies. The *land converted to forest land* category is projected to gradually become less of a sink without significant additional policy incentive, having reached peak negative emissions in 2011 – 2017.

Net emissions from the *forest land remaining forest land*, *cropland remaining cropland*, *grassland/wetland/settlements remaining grassland/wetland/settlements*, and *harvested wood products* categories have fluctuated around net zero emissions in recent years. We project this behaviour to continue in the future, with annual net emissions in each of these categories being equal to the average of the previous 10 years' (2010 – 2019) annual emissions. This is a simplifying assumption, noting that the actual net emissions will vary between years, due to differences in climate, climate policies, economic growth rates, etc.

Figure 31 also shows the total net emissions from the LULUCF sector for the BAU trajectory. It shows that the LULUCF sector is projected to be a small net source of emissions in 2020 with +9 Mt-CO_2e, and gradually becomes a small net sink by 2050 with −2 Mt-CO_2e. It should be noted that projecting plantation rates, climate variation and technological development 30 years into the future inevitably leads to significant uncertainty. The outlined trajectories should therefore be interpreted as a reasonable estimate of future emissions under business-as-usual conditions, based on current evidence and expectations.

Figure 31 | Historical (1990 – 2019) and projected (2020 – 2050) BAU GHG emissions from the LULUCF sector.



With mitigation measures

Figure 33 presents the historical and projected LULUCF emissions for the With Mitigation Measures (WMM) emissions trajectory. Here, we project that land clearing in the *forest converted to other land uses* category will continue to be a source of emissions only until 2030, at which point emissions will be net-zero in this category. To deliver this significant emissions abatement, an increase of regulatory control and market drivers are assumed to be established to reduce land clearing rates. This approach is consistent with the recent Australian Government commitment in Glasgow COP26.

Within the *land converted to forest land* category we project that – with a concerted effort – the balance of new commercial plantations, conversion of plantations to agriculture, environmental plantings and human-induced natural regeneration results in increased carbon removal, leading to a net sink of −60 Mt-CO_2e in 2050, as shown in Figure 33. This represents an additional −51 Mt-CO_2e of annual sequestration by 2050 compared with the BAU trajectory.

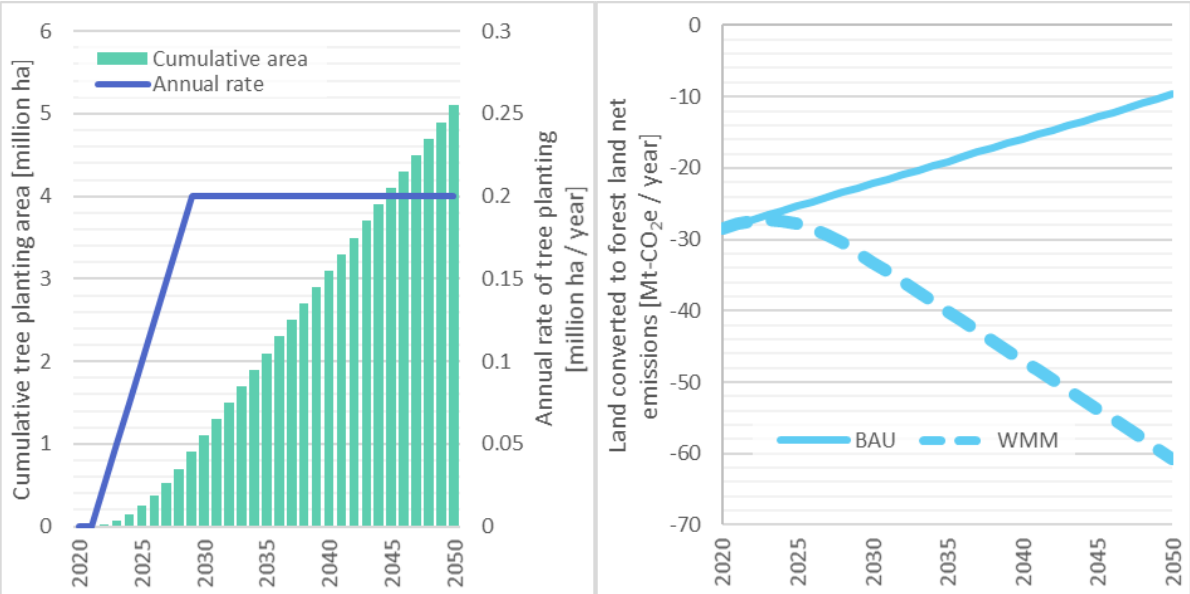
This projection of increased sequestration through conversion to forest land involves new investment to expand the forest area through a combination of trees integrated with farming, commercial plantations, environmental plantings, technology development, and active efforts to increase the establishment of new plantations, leading to larger forest land areas.

Figure 32 presents the assumed annual rate of tree planting area, and the cumulative area of tree planting, that enables the projected increased sequestration from 2022. The rate of carbon dioxide sequestration in these new plantations is assumed to be 10 t-CO_2/ha/year. Figure 32 also shows the resulting net negative emissions trajectories (WMM) from this enhanced sequestration in trees, as compared with the BAU trajectory.

We assume that these new tree plantings will be located predominantly on land designated by the ABS as *land mainly used for cropping and improved pastures*, which currently accounts for 67 million ha of Australian land area.[52] The land used for new tree planting represents 8% of this agricultural land area in 2050, with the regional distribution of these new plantings assumed to be proportional to the distribution of agricultural land.

This works also assumes that this enhanced sequestration would have minimal impact on farming production, through strategic placement of vegetation on agricultural land. In addition, there are some potential co-benefits, such as additional potential revenue streams, mitigation of wind erosion, improvement of dryland salinity, and improved livestock production through the provision of stock shade and shelter.[53]

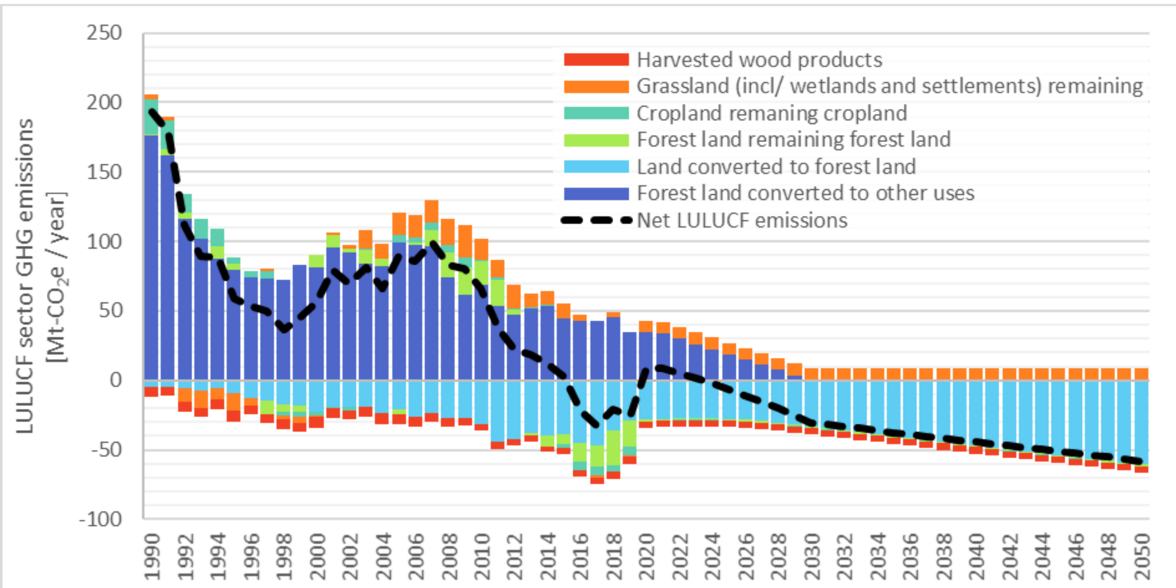
Figure 32 | (left) the assumed annual rate and cumulative area of new tree planting on agricultural land in the WMM trajectory, with (right) the resulting annual emissions sequestration.



The WMM trajectory also projects net emissions from the forest land remaining forest land, cropland remaining cropland, grassland/wetland/settlements remaining grassland/wetland/settlements, and harvested wood products categories to be the same as the BAU trajectory. These categories are not subject to significant mitigation effort, as they are, in general, small contributors to total net LULUCF emissions, and are therefore projected to be equal to the average of the previous 10 years' (2010 – 2019) annual emissions.

Figure 33 also shows the resulting net emissions from the LULUCF sector for the WMM trajectory. It shows that, with these mitigation measures discussed above, LULUCF is projected to be a net sink of −58 Mt-CO_2e by 2050. It is important to note that this net sink is not expected to fully compensate for agriculture and waste emissions by 2050.

Figure 33 | Historical (1990 – 2019) and projected (2020 – 2050) GHG emissions from LULUCF sector with assumed mitigation measures (WMM)



8.3 Waste

Emissions accounted under the *waste* sector include those produced during:

- solid waste disposal, via landfill and biological treatment (composting)
- incineration of waste
- wastewater treatment from domestic, commercial, and industrial wastewater.

The total GHG emissions from these activities accounted for +14 Mt-CO_2e in Australia's 2019 GHG inventory, and this is predominantly composed of emissions of methane from anaerobic digestion of organic matter.[1] The total GHG emissions from this sector have progressively decreased by 10% (3.2 Mt-CO_2e/year) over the last decade.[1]

Table 29 | List of the waste subsectors accounted for in Australia's GHG inventory under the UNFCCC classification, together with details of the emissions source.[1]

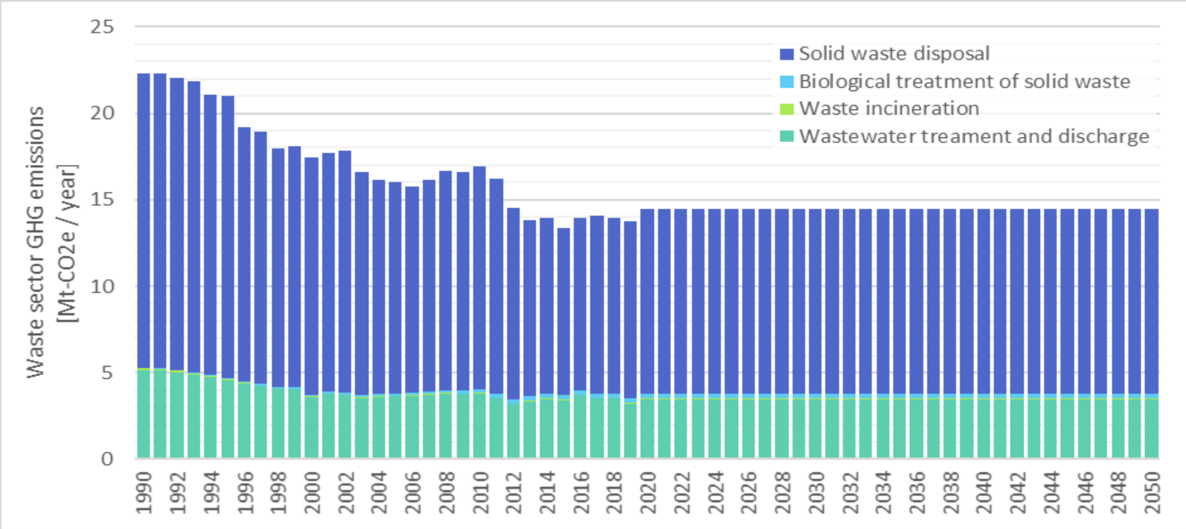
Waste subsector	Source
Solid waste disposal	The waste deposited into landfills, including municipal solid waste, commercial and industrial waste, and construction and demolition waste.
Biological treatment of solid waste	Composting and enclosed anaerobic digestion, for example.
Waste incineration	Solvents and municipal and clinical waste that contain fossil carbon.
Wastewater treatment and discharge	Anaerobic digestion of organic matter in domestic, commercial, and industrial wastewater.

Table 29 presents the waste subsectors accounted for in Australia's GHG inventory.[1] In 2019, the largest of these subsectors by total emissions was *solid waste disposal* in landfills (74%), followed by domestic and industrial wastewater treatment (23%), with small contributions from biological treatment of solid waste (2%) and incineration of waste (0.2%). The increased capture and combustion (flaring) of landfill gas since 2015 has led to a reduction in GHG emissions from this source,[54] with flaring of biogenic methane considered to be GHG emissions neutral. On a regional basis New South Wales (35%) had the largest share of emissions from the waste sector, followed by Victoria (21%), and Queensland (19%).

NZAu's BAU emissions trajectory projects waste sector emissions to be 14 Mt-CO_2e/year from 2020 to 2050, as shown in Figure 34. This assumes that current waste generation and emissions abatement measures remain in place and is calculated as the average annual GHG emissions over the last decade.

To date, the NZAu project has not considered the effect of any waste sector emissions mitigation measures. Therefore, the reference case emissions trajectory shown in Figure 34 is used in all NZAu modelled scenarios. This implies that the residual 14 Mt-CO_2e/year from the waste sector needs to be offset by negative emissions in other sectors.

Figure 34 | Historical (1990 – 2019) and projected (2020 – 2050) GHG emissions from the waste sector, by specific source[1].



8.4 Combined projections

Figure 35 presents the historical (1995 – 2019) and projected (2020 – 2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the BAU trajectory. The emissions trajectories are shown by state/territory (left), UNFCCC sector (middle), and specific GHG type (right). Net emissions are shown by the black line. This shows that under BAU future conditions, agriculture, LULUCF and waste emissions – which include CO_2, CH_4, N_2O – are projected in the long run to reduce slightly to +92.0 Mt-CO_2e/year by 2050.

Figure 35 | Historical and projected net GHG emissions from the agriculture, LULUCF and waste sectors, for the BAU trajectory.

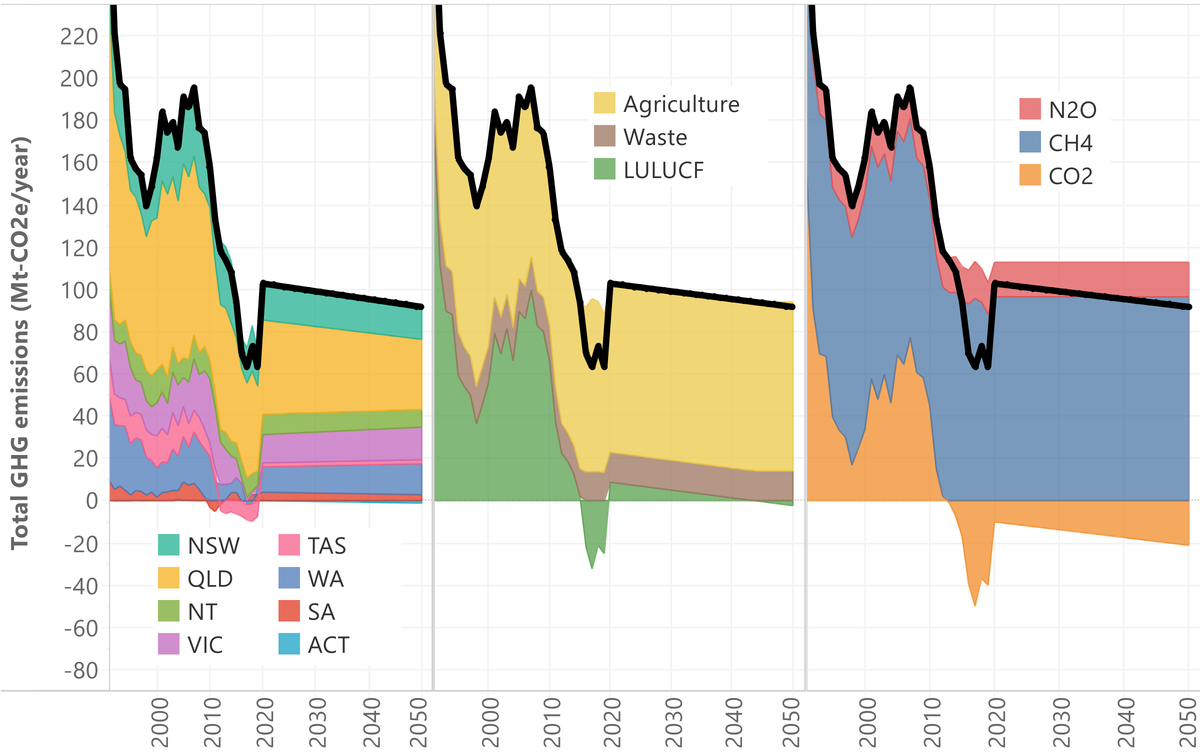
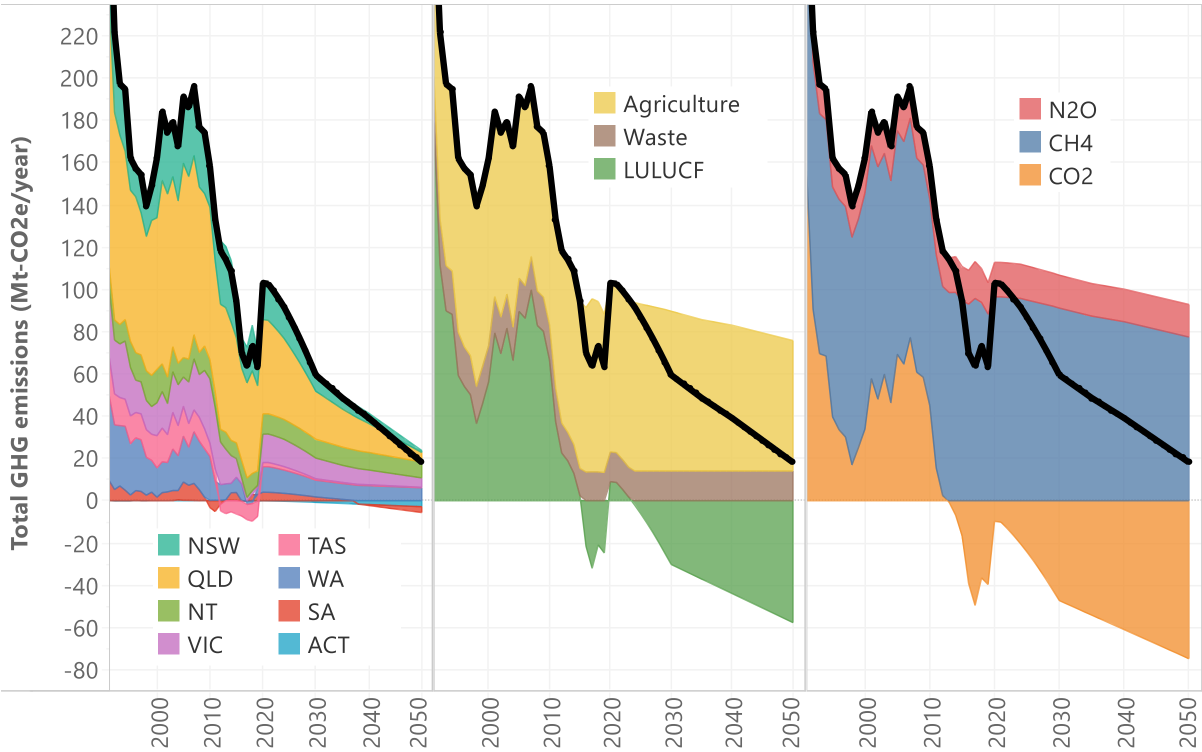


Figure 36 presents historical (1995 – 2019) and projected (2020 – 2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the WMM trajectory. The emissions trajectories are shown by state/territory (left), UNFCCC sector (middle), and specific GHG type (right). Net emissions are shown by the black line. It can be seen that a concerted effort to adopt plausible mitigation measures – particularly the active abatement of methane emissions from agriculture and enhanced CO_2 sequestration through new tree planting – the net emissions are projected to reduce to +19 Mt-CO_2e/year by 2050. It should be noted that these combined sectors do not reach net-zero and will therefore require negative emissions in another sector to offset the residual emissions shown here.

Figure 36 | Historical and projected net GHG emissions from the agriculture, LULUCF and waste sectors, for the WMM trajectory.



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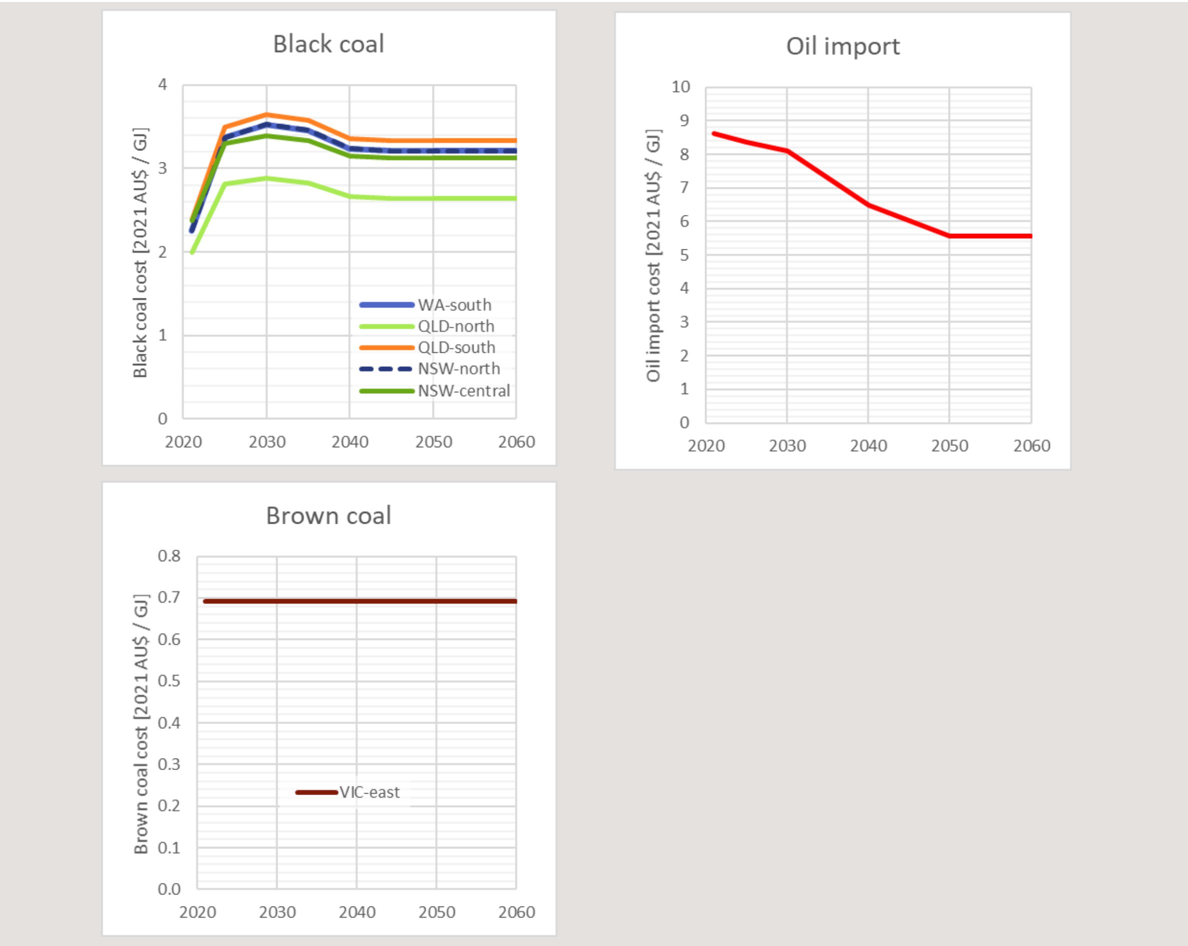
9 Resource availabilities

9.1 Coal, gas and oil costs and production

The coal cost projections from 2021 to 2050 are sourced from the AEMO *Integrated System Plan*[1] and the WA government's *Whole of System Plan*.[2] A summary of these cost projections is shown in Figure 37 by NZAu zone, with costs assumed to be constant from 2050 to 2060. This work also characterises all existing black and brown coal mining activity, with existing infrastructure having a capacity of 12,600 PJ/year of black coal and 500 PJ/year of brown coal, regionally allocated to the NZAu zones in which the existing mines are located.

This work also uses projections of international crude oil prices. Since NZAu examines deep decarbonisation pathways, it is appropriate to source these prices from the International Energy Agency's recent report detailing their modelled *Net Zero by 2050* scenario.[3] These oil prices are also shown in Figure 37, with units converted to 2021 AU$/GJ, and with prices assumed constant from 2050 to 2060. We also characterise the capacity and location of Australia's existing Geelong and Lytton oil refineries, which are included in the modelling as initial existing energy infrastructure.

Figure 37 | Black and brown coal cost and imported oil price projections used as input to NZAu modelling.[1,2,3] Oil import costs have been converted to 2021AU$/GJ from 2019US$/boe.

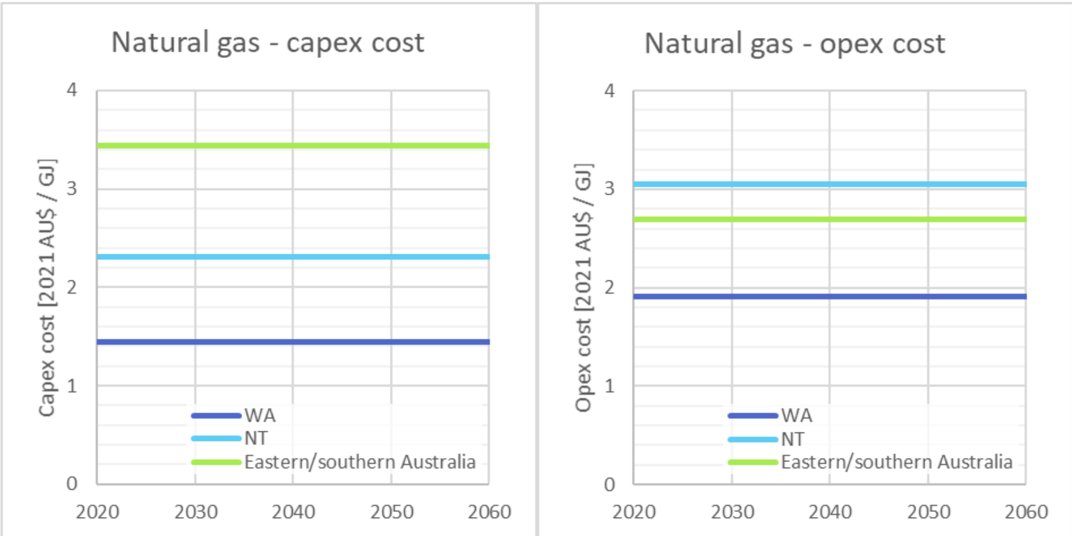


The cost of natural gas production from both conventional extraction and coal seam gas extraction methods is separated into fixed capex and variable opex components, as shown in Figure 38. These values are sourced from the Productivity Commission's Eastern Australia Gas Market Model[4] and the Western Australia Gas Statement of Opportunities.[5] We separate these cost components to account for changes in the utilisation of capital assets.

These production cost inputs also differentiate between the eastern states, Western Australia and the Northern Territory and are modelled as coal seam gas extraction in the *QLD-outback region*, conventional gas extraction in the *WA-north region,* and conventional gas extraction in the *NT region,* respectively. This simplified representation of regional production is due to current production in these regions and declining conventional natural gas production in the Cooper Basin and the Bass Strait, as discussed further in section 10.7.1. Finally, these natural gas *production* costs are related to equivalent *delivered* costs to different users using a modelling approach detailed in section 10.7.1.

We also characterise all existing conventional and coal seam gas extraction facilities, as well as existing LNG facilities and include these in the modelling as existing energy infrastructure. Existing conventional extraction capacity 4,000 PJ/year distributed across the country, existing CSG extraction capacity is 1,400 PJ/year located in QLD and NSW, and existing LNG capacity is 4,400 PJ/year, located in QLD, NT and WA. We also apply a constraint to any modelled future gas extraction activity, that approximately maintains the current proportional distribution of natural gas production between Western Australia and the rest of the country.

Figure 38 | Natural gas capex (left) and opex (right) production cost component inputs to NZAu modelling.[4,5]



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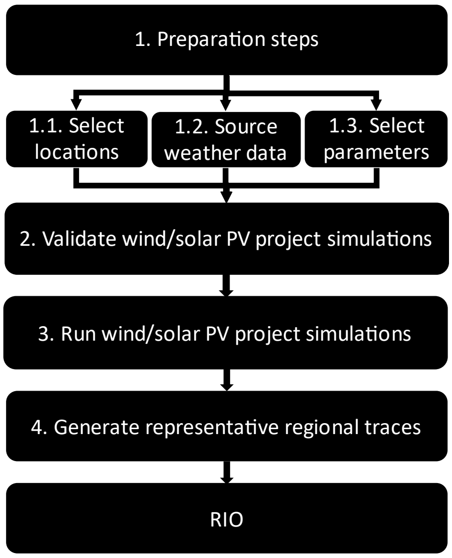
9.2 Renewable availability traces

Onshore renewable traces (generation availability profiles) are produced by simulating generation from potential solar PV and wind projects at selected locations in Australia, and are required to represent the temporal variability of electricity generation in highly carbon-constrained, sector-coupled energy systems. The process of producing these renewable traces follows the steps laid out in Figure 39, and involves the selection of locations, the sourcing of weather data, the selection of model parameters for use in NZAu, the simulation of wind/solar PV projects at the selected locations, and the aggregation of traces from individual wind/solar projects in a region into a representative regional wind/solar PV trace for use in RIO.

Figure 39 | NZAu process of producing renewable traces.



9.2.1 Preparation steps

Select locations

Simulation locations have been selected using the solar PV and wind supply curves generated for NZAu and discussed in section 9.3. More sites were considered for simulation in NZAu zones that have greater aggregate capacity in the NZAu supply curve, with fewer sites being selected in regions where the NZAu supply curve has less capacity.

Source weather data

Climate data used in solar PV simulations is sourced from the NREL National Solar Radiation Database (NSRDB).[1] The hourly parameters accessed from the NSRDB include:

- global horizontal irradiance (GHI)
- diffuse horizontal irradiance (DHI)
- direct normal irradiance (DNI)
- albedo (a)
- temperature (t)
- wind speed (ws)
- elevation (e).

Weather data used in onshore wind simulations is sourced from the Australian Bureau of Meteorology Atmospheric high-resolution Regional Reanalysis for Australia (BARRA) dataset.[2] The relevant single level variables accessed from the BARRA-R forecast dataset represent mean hourly wind speed at a 10-metres above ground level. The specific variables used are:

- METRE WIND U-COMP (Mean), x_wind, av_uwnd10m
- METRE WIND V-COMP (Mean), y_wind, av_vwnd10m.

Select modelling parameters

The simulation of wind and solar PV projects requires the selection of the technical parameters that characterise generation from the representative wind or solar PV plant at the select location. The technical parameters used in NZAu simulations are listed in Table 30.

Table 30 | Technical parameters used in NZAu simulations of renewable availability profiles.

Parameter	Utility-scale PV	Rooftop PV	Wind
Simulation year	FY2018	FY2018	FY2018
Simulation time-step	hourly	hourly	hourly
Orientation	Single-axis tracking	Fixed tilt at site latitude	NA
Panel Azimuth	0 degrees (North)	0 degrees (North)	NA
DC/AC nameplate ratio	1.3	1	NA
Inverter efficiency	0.955	0.955	NA
Module Type – for module temperature estimation[3]	Glass/cell/polymer sheet, open rack	Glass/cell/glass, Close Roof mount	NA
Shadow derating factor	no	Yes = (1−e^(−(altitude of the sun / weibull_l)**weibull_k)), where weibull_l = 0.308 and weibull_k = 1.98	NA
Non-inverter fixed system derating	0.9	0.9	NA
Cell temperature derating constant per °C	0.0045	0.0045	NA
Standard test conditions cell temperature °C	25	25	NA
Soiling factor	1	0.95	NA
Hub height	NA	NA	150 (100 offshore)
Turbine	NA	NA	Bounding power wind-speed curve [4] used to generate capacity factor layer [5]
Wind power law exponent	NA	NA	0.005 – 0.305

As listed in Table 30, the NZAu modelling team identified financial year (FY)2018 as the simulation year for all onshore renewable resources as it was the only crossover data year which was available in both:

- the climate data sets used for the simulation (The last complete financial year available in the BARRA[2] dataset is FY2018 and the first available site in the NSRDB[1] in FY2016, leaving FY2016, FY2017, and FY2018 as crossover years), and
- the historical electricity demand benchmarking data (see section 6.4).

Utility-scale solar PV simulation parameters were benchmarked against the reported annual FY capacity factors of existing utility-scale solar PV systems (known to have experienced little or no curtailment during the FY).[6] A discussion of the benchmarking for the rooftop PV can be found in section 9.4.

Wind simulation parameters, including most notably the wind power law exponent, were benchmarked against the capacity factor map supplied by Geoscience Australia[5] and Briggs et al.[15] The benchmarking of the wind power law exponent for each selected site involves:

1. Accessing the 10 metre hourly wind speeds for the simulation year from wind climate data,[2]
2. Iteratively estimating the capacity factor at the selected site by:
    - o estimating the wind speed at 150 metres height (or 100 metres height for offshore as that is the hub height used by the capacity factor layer from Briggs et al[15]) at each simulation site using the wind power law[7]

$$\text{wind speed at 150m} = \text{wind speed at 10m} \times \left(\frac{150}{10}\right)^{\text{wind power law exponent}}$$

    - o estimating the power output for a 3.6 kW turbine (maximum considered in reference study and capacity factor layer[4,8]) having a hub height of 150 metres (100 metres for offshore) at each simulation site, using the bounding power wind-speed curve data[4]
    - o estimating the hourly (and annual average) capacity factor of the turbine by dividing the estimated power output by the turbine's maximum power output of 3.6 kW for each hour (and then taking the average over the entire year)
    - o comparing the estimated annual average capacity factor with the capacity factor for the site in the Geoscience Australia supplied capacity factor layer at a 150 metre hub height[5], or with the Briggs et al[15] capacity factor layer at 100 metre hub heigh for offshore wind. If the estimated capacity factor is less than the benchmark capacity factor and more than 0.1% different from the benchmark capacity factor, then incrementally increase the wind power law exponents (which starts on the first iteration at 0.005) by +0.005 and iterate all of step two again.

Offshore wind capacity factor layer note

Two offshore wind (OSW) capacity factor layers have been developed specifically for use in Australian waters.

A team from the Blue Economy Cooperative Research Centre (BECRC) developed an offshore wind (OSW) capacity factor layer for use in the 2021 Offshore Wind Report.[15] The BECRC team provided that layer (hereafter BECRC2021) to NZAu on request in 2021. The BECRC2021 layer combines hourly ERA-5 global climate data[16] with the power curve for the IEA 15 MW reference wind turbine.[17] The BECRC2021 layer corresponds to a 100m hub height and is resolved to 30×30 km cells. BECRC2021's offshore capacity factors range from 0 to 91%. The BECRC report suggests that a layer having a 150m hub height would be more useful for offshore wind energy modelling around Australia and states that "capacity factors at 150m hub height can be up to ~4-5% greater" than those reported in the BECRC2021 layer.[16,p6]

In 2022, a team from Monash University, in collaboration with Geoscience Australia, released offshore wind capacity factor layers for three turbines at hub heights of 150m.[18] The layers are based on climate data supplied by the Australia Bureau of Meteorology's BARRA data[2] and are resolved to a ~13km grid. The turbines used to estimate capacity factors at the 150m hub height are the Vestas V126 3.45MW, the GE V130 3.2MW, and a generic turbine modelled using a 'bounded curve' approach.[18;4] Offshore capacity factors in the core layer on offer (hereafter GA2022) correspond to the generic 'bounded curve' turbine and range from 0 to 94%. A description of the method used to estimate capacity factors can be found in the supplementary materials provided with GA2022.

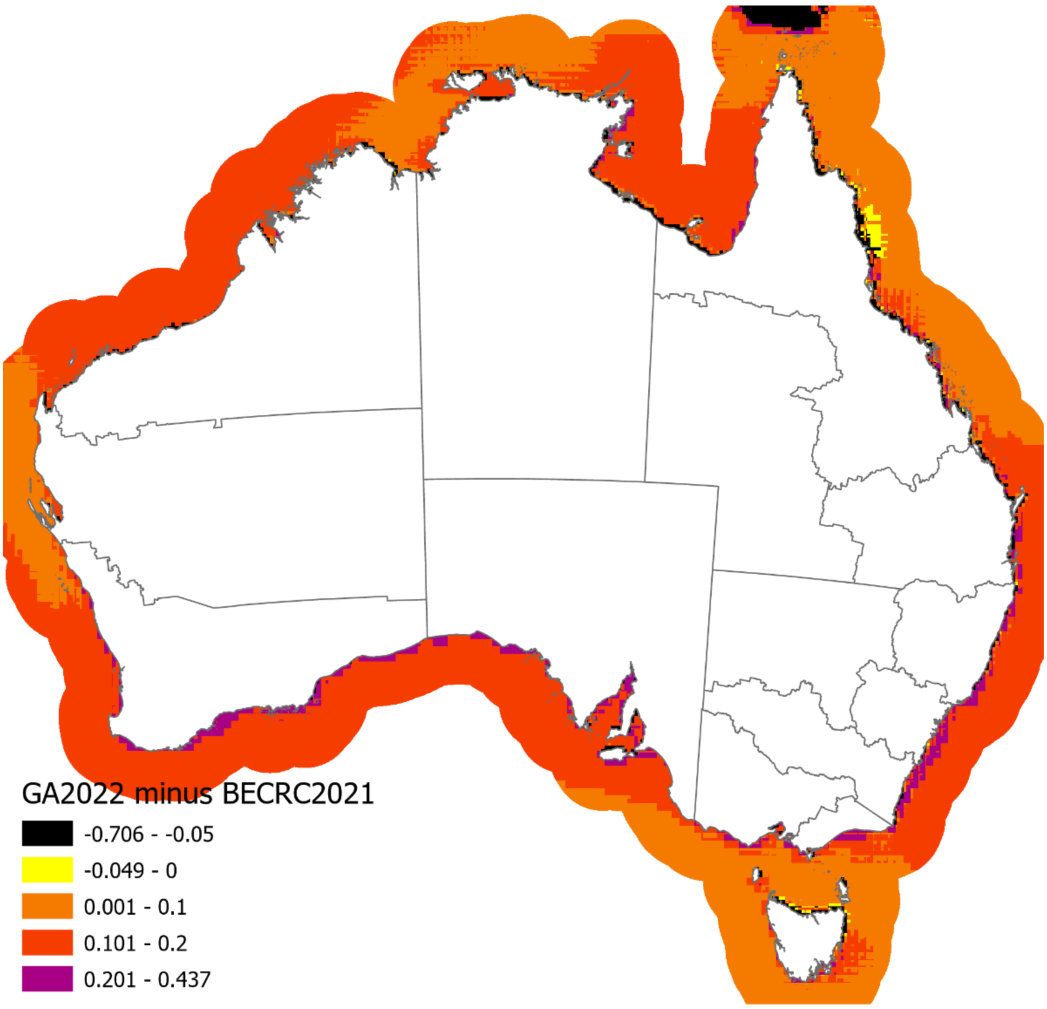
Comparison of the two OSW capacity factor layers (BECRC2021 and GA2022) is made difficult as the teams did not select the same turbine when generating capacity factor layers. When comparing the GA2022 layer with the BECRC2021 layer, the GA2022 layer reports higher capacity factors than the BECRC2021 layer in nearly all comparable regions (main exception being off the coast of Cairns – see Figure 40). The difference between the two layers (shown in Figure 40) appears to be less pronounced – having a difference of less than

10% between capacity factors – along Queensland's north-eastern coast from Gladstone around to Nanum, off the coast of Darwin, off the WA coast from Geraldton to Exmouth, and in the waters off Victoria and around Tasmania. Most other offshore areas have capacity factors at least 10% higher than the BECRC2021 layer. Due to differing grid sizes, the comparison fails in many nearshore areas.

Neither layer can be validated against actual OSW speeds and turbine/farm performance until such data becomes available.

Until validating data becomes available or GA2022 and BECRC2021 authors provide data with which to better compare the layers (e.g. average wind speed maps at rated hub heights along with wind speed data for a number of agreed on offshore location which might be used to simulate wind turbine/farm output – including losses – using the NREL's System Advisory Model[19], NZAu has elected to continue using the supplied BECRC2021 layer.

Figure 40 | Capacity factor difference found by subtracting the BECRC2021 layer from the GA2022 layer.



9.2.2 Validate simulation process

To validate the simulation process, the NZAu modelling team ran simulations at the sites of existing wind and solar farms. The actual technical parameters of existing projects (e.g. hub height, turbine model) were used in these simulations when such data was available. Figure 41 and Figure 42 show comparison of the simulated traces with data from Macarthur and Capital Hill Wind projects. Figure 43 and Figure 44 show comparison of the simulated traces with data from Nyngan and Broken Hill solar PV projects.

Figure 41 | Validation of wind simulation process against Macarthur wind farm data.

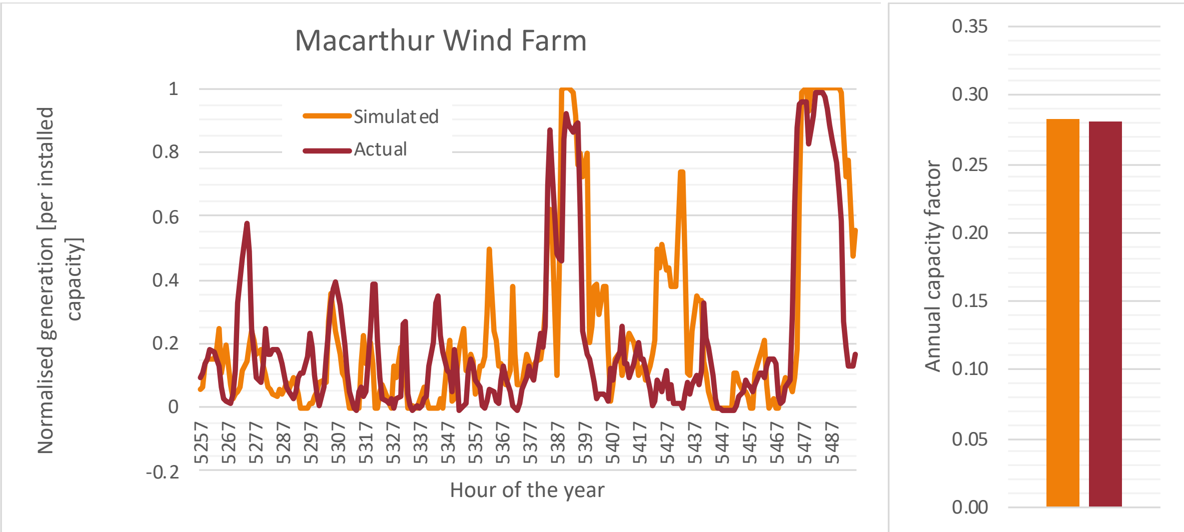


Figure 42 | Validation of wind simulation process against Capital Hill wind farm data.

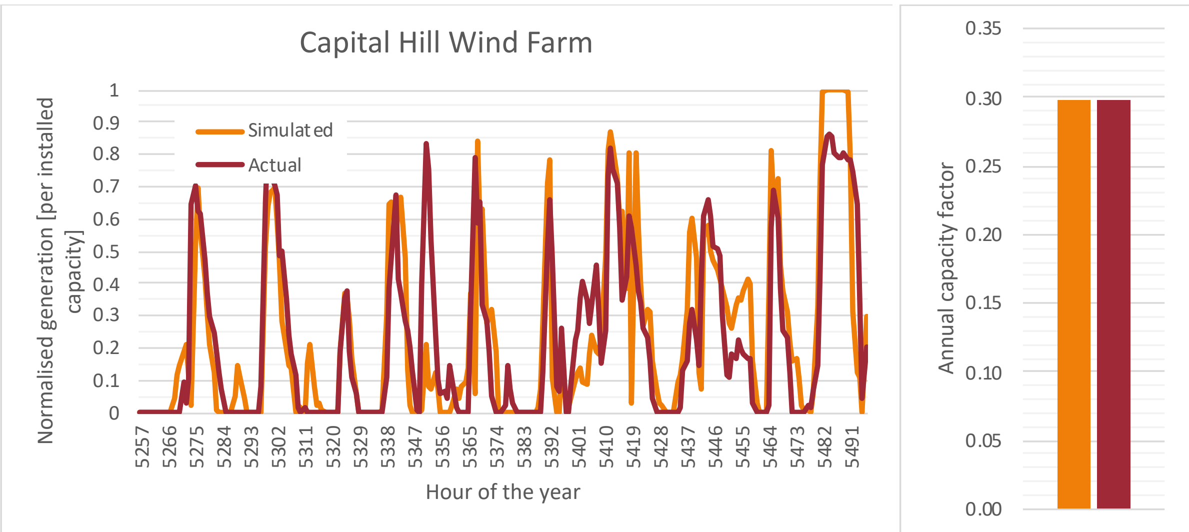


Figure 43 | Validation of solar PV simulation process against Nyngan solar PV farm data

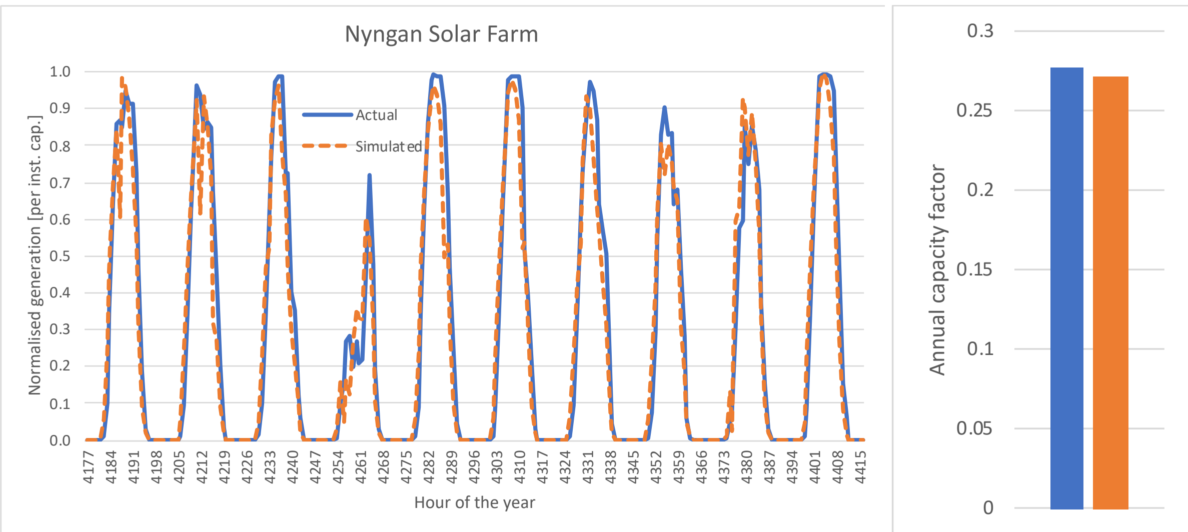
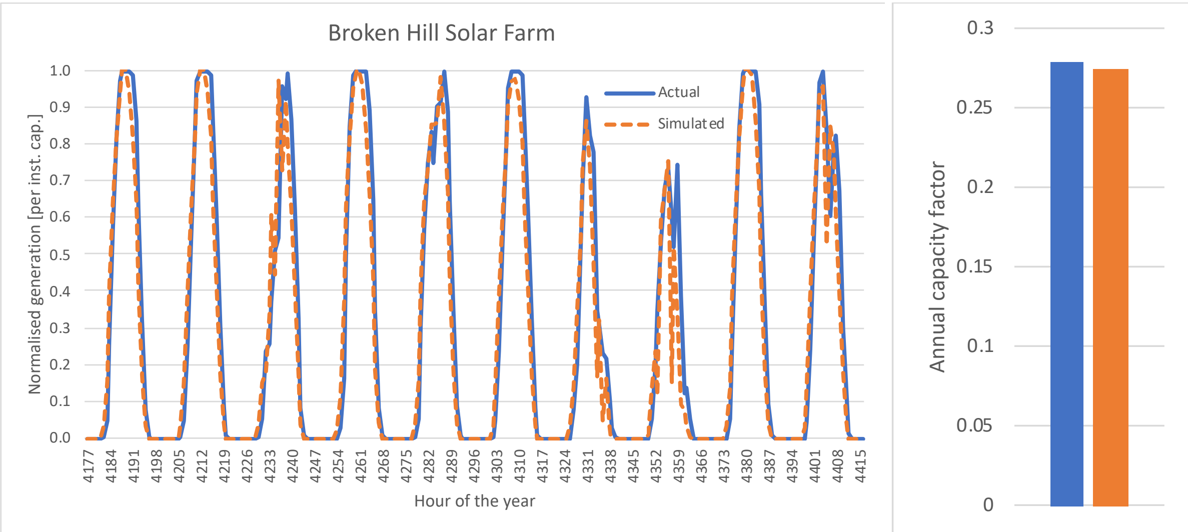


Figure 44 | Validation of solar PV simulation process against Broken Hill solar PV farm data



9.2.3 Run project simulations

Utility-scale solar PV

Solar PV simulations combine hourly climate data from the NREL National Solar Radiation Database (NSRDB)[1] with the model parameters listed in in Table 30, and a simplified version of the modelling steps prescribed by Sandia National Laboratories.[9] These steps are performed for every hour of the simulation year at every selected simulation site and consist of:

1. calculating solar angles (azimuth, zenith angles)[10]
2. calculating angle of solar radiation incidence using utility-scale solar PV parameters (orientation and panel azimuth) and the solar angles[11]
3. adjusting the NSRDB[1] reported DNI for the angle of incidence,[12] and the shadow derating factor
4. adjusting DHI using the NSRDB[1] reported DHI and GHI, solar angles, and orientation[13]
5. estimating the irradiance reflected from the ground using the NSRDB[1] reported GHI and albedo, and orientation[14]
6. estimating total insolation by adding the adjusted DNI, the adjusted DHI, and ground-reflected irradiance
7. estimating the temperature derating using the utility-scale solar PV parameter (module type, temperature derating constant, standard conditions cell temperature), and the NSRDB[1] reported wind speed and air temperature[3]
8. estimating the hourly capacity factor by multiplying total insolation (in watts) by the temperature derating and utility-scale solar PV parameters (non-inverter fixed system derating, inverter efficiency, DC/AC ratio, soiling factor)
9. estimating the annual capacity factor for the FY at the location by averaging the hourly capacity factors over the entire FY.

Rooftop PV

Please see section 9.4 for a description of the rooftop PV simulation and validation process.

Wind (onshore and offshore)

Wind project simulations combine hourly climate data from the BARRA dataset[2] with the model parameters listed in Table 30. The hourly (and annual) capacity factors of wind projects at selected sites are estimated using steps 1, 2a, 2b, and 2c from the wind simulation benchmarking in section 9.2.1. For wind simulations, the steps are not estimated iteratively, but only once using the weather data and estimated wind power law exponent for each hour at each simulation site.

9.2.4 Generate representative regional traces

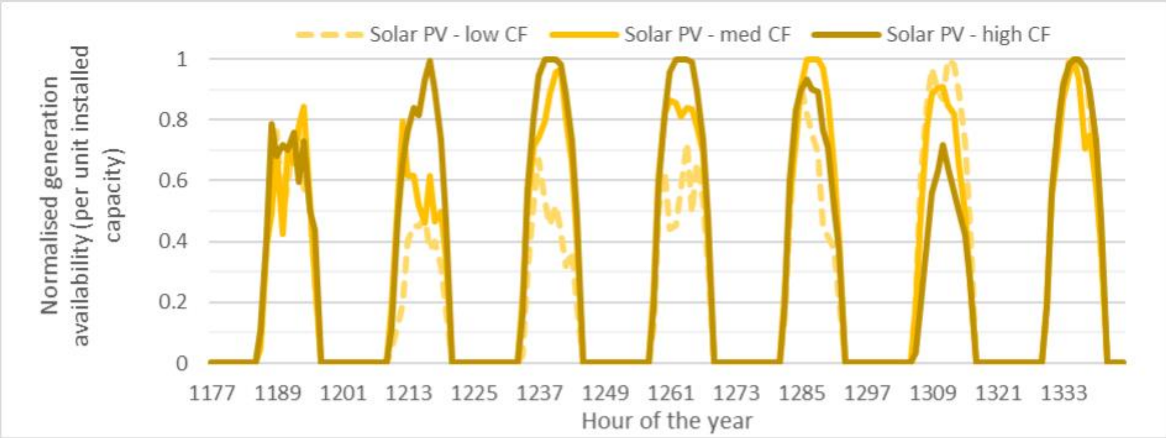
Utility-scale solar PV, wind and offshore wind

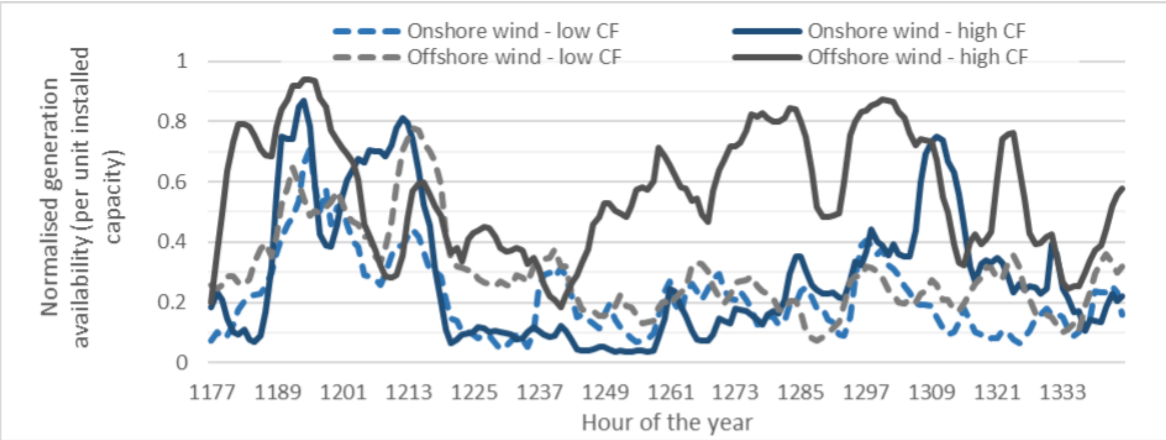
Three representative traces are generated for each resource (solar PV, wind, offshore wind) in each of the 15 NZAu regions (section 5). Representative traces are generated by:

1. apportioning all selected simulation sites of each resource into three national bins, based on capacity factor (lowest third of capacity factors, middle third of capacity factors, highest third of capacity factors), and
2. taking the average across all traces in each of the capacity factor bins of a region (maximum allowed in any regional bin is ten traces), for each resource and each hour of the simulation FY.

For NZAu zones in which the selected simulation locations are geographically dispersed, the aggregation of traces from the individual selected locations will likely result in traces that have greater smoothness and are less temporally-varying than those generated from closer more correlated sites. Figure 45 presents a one-week sample of the representative renewable availability traces in WA-south.

Figure 45 | A one-week sample of the solar PV (top), and onshore and offshore wind availability traces in WA-south.





Note that the medium capacity factor traces for onshore and offshore wind are not shown here for clarity.

Rooftop solar PV

One representative rooftop solar PV trace is generated for each of the 15 NZAu regions. Representative rooftop solar PV traces are generated by taking the average across all simulated rooftop solar PV traces in a region for each hour of the simulation FY. The locations of these rooftop solar PV simulations were chosen to be the centroids of select postcodes within each NZAu region that have significant existing installed capacity. See section 9.4 for further details.

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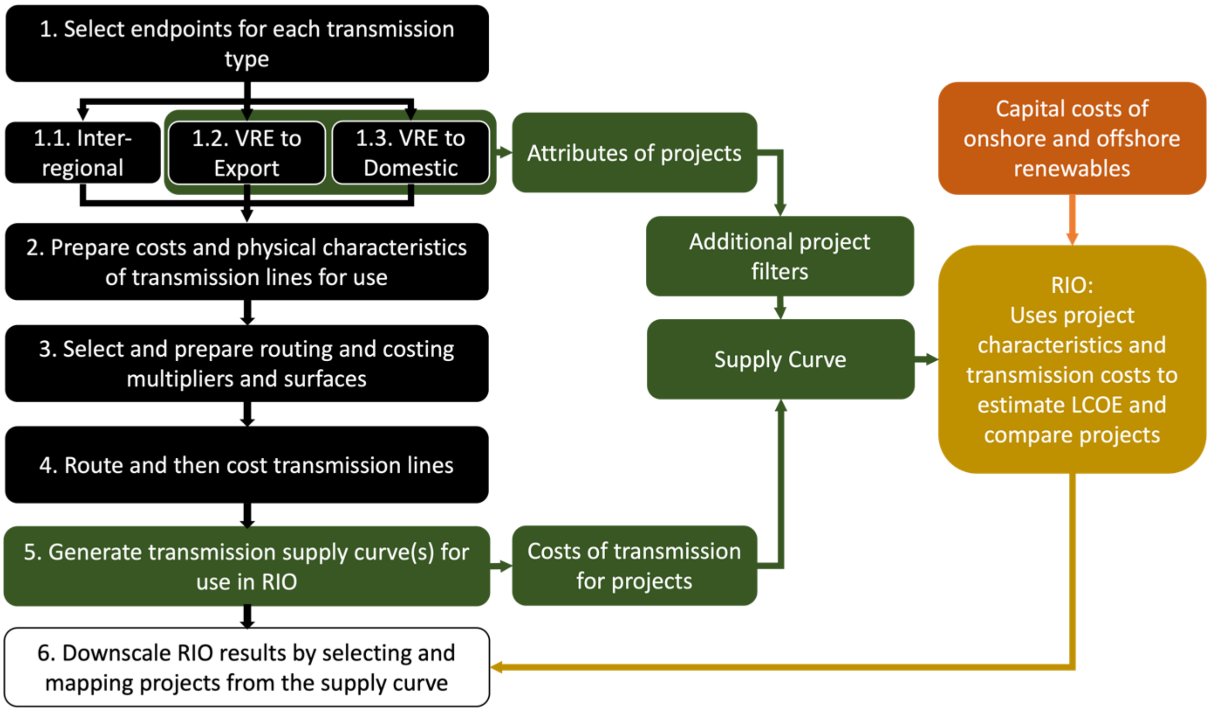
9.3 Renewables supply curves

9.3.1 Overview

The process described in this section involves using the attributes of VRE projects (hereafter called candidate project areas or CPAs in this document) and the associated transmission costs to determine a filtered and geospatially resolved list of candidate projects and related transmission costs, hereafter referred to as the VRE supply curve. This process is shown in green in Figure 46, and applies to both onshore and offshore CPAs.

Figure 46 provides an overview of entire VRE supply curve creation process followed in NZAu, with different colour boxes highlighting the portions of this process described in this section (green), transmission costing described in section 10.6 (black), capital costing of VRE projects described in sections 10.1 and 10.2 (orange), the final combination of supply curves and project costs in RIO to allow project selection (yellow), and the downscaling of RIO results which will be covered in project reports and outputs (white).

Figure 46 | Overview of entire VRE supply curve creation process followed in NZAu



9.3.2 Project attributes and selection of project filters

Project attributes leaving the CPA determination process (covered in section 10.6) are listed in Table 31 along with the attribute type (over the area of each project), and the filter settings. It is expected that interaction between project results and stakeholders may lead to changes in the selection of these filters in future modelling efforts (as part of NZAu or follow-on).

Table 31 | CPA attributes entering supply curve filtering and compilation process.

CPA Attribute	Attribute Type	Filters settings		
		Solar PV	Onshore wind	Offshore wind
Population Density [1]	Mean – the mean value for the CPA	<100 people/km^2 (domestic); <0.1 people/km^2 over SA2 area (export)	<100 people/km^2 (domestic); <0.1 people/km^2 over SA2 area (export)	NA
Elevation/ocean depth [2]	Mean	NA	NA	0 to −60 metres = Fixed bottom; −61 to −1,000 metres = Floating platform; > −1000 metres = not allowed
Capacity Factor [3,4] (for export only)	Mean	NA	Exclude < 0.28	Exclude < 0.45
Distance to nearest existing VRE project	Distance	Exclude <5km until assumed retirement of existing site	Exclude < 5km until assumed retirement of existing site	NA
Distance to node for export energy aggregation – straight line	Distance	< 200 km	< 200 km	< 320 km
Region for energy delivery based on least-cost determination of transmission run (see transmission section 10.6)	NZAu Region	Each potential resource is assigned to the supply curve of load delivery region rather than energy production region.		
Aggregate population at nearest load destination (for domestic only) [5]	Sum	Project availability in the supply curve is proportionately tailored to the aggregate population at nearest load centre as well as the aggregate population in each region's largest load centre.		NA

While most filters in Table 31 arise from simple geospatial analyses and metrics (distance to existing or planned infrastructure, mean value over an area, the majority value over an area, geospatial overlap), the last item involves a more complex method.

The tailoring of project availability based on populations at the nearest load destinations builds on prior work from Princeton's *Net-zero America* (NZA) project,[6] the Nature Conservancy's *Power of Place West* project,[7] and the Princeton Zero Lab's *REPEAT* project.[8] The method is only applied to domestic resources and aims to maintain the availability of high-quality resources within each modelling region while also accounting for differences in the geographical distribution of population within regions. The method prevents high-capacity factor projects near to remote load centres (especially those that are not connected to the NEM or SWIS) from dominating supply curves that will largely serve distant and much larger cities.

Figure 47 and Figure 48 show the location and capacity factors of the projects with the lowest levelized cost of capital (LCC) (payment function using the NZAu Weighted Average Cost of Capital) left in the solar PV (4.0 TW) and onshore wind (3.1 TW) and offshore wind (2.3 TW) supply curves for *domestic* and *export* markers respectively after applying all filters in Table 31 and Table 63.

Figure 47 | Location and capacity factors of projects having the lowest LCC in the solar PV (4.0 TW) and onshore wind (2.1 TW) and offshore wind (2.3 TW) domestic supply curves after applying the filters in Table 31 (note that m_cf_noloss represents the mean capacity factor with no losses).

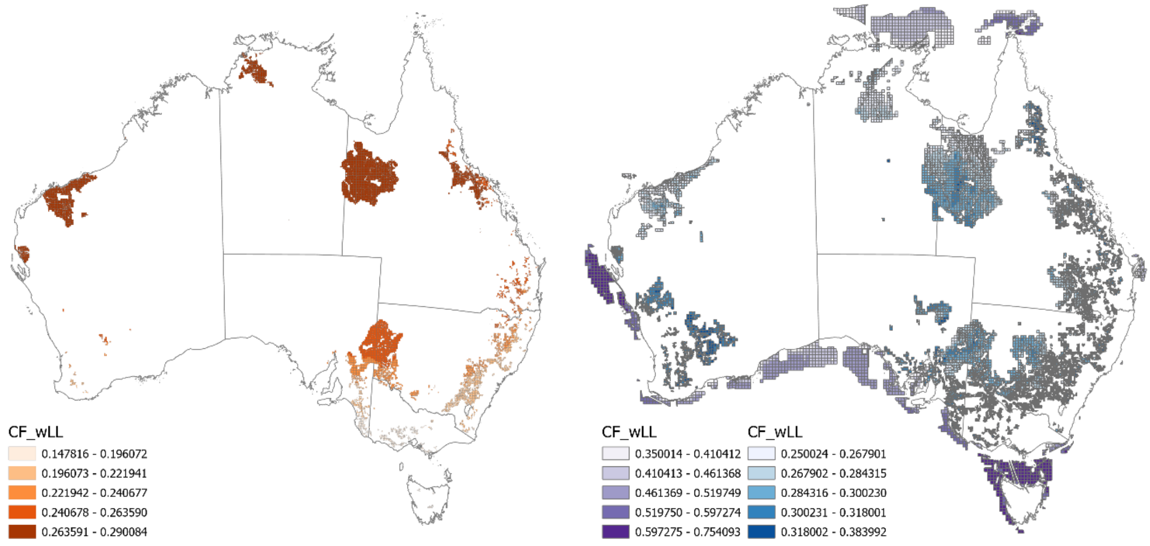
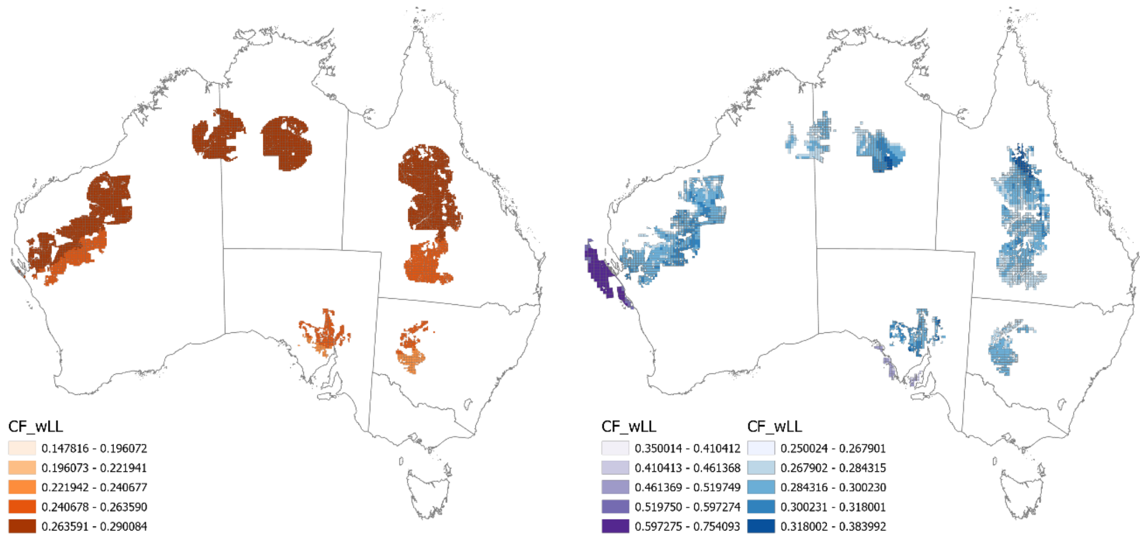


Figure 48 | Location and capacity factors of projects having the lowest LCC in the solar PV (7.1 TW) and onshore wind (1.9 TW), and offshore wind (0.3 TW) export supply curves after applying the filters in Table 31 (note that m_cf_noloss represents the mean capacity factor with no losses).



9.3.3 The use of supply curves in regional investment modelling (RIO)

Renewable supply curves are combined with the capital costs of renewable projects (section 10.1 and 10.2) and transmission losses as part of the regional investment modelling's least cost optimisation of energy supply. As noted in Table 31, supply curves are constructed in RIO according to the region of the load they are mapped to serve (using the least-cost transmission path mapping in section 10.6) rather than the region they are geographically located in. While this change may have political implications when a state boundary is crossed as a project's transmission moves from resource to load, the change was made to better reflect the geospatial distribution of resources in modelling.

This integration of the supply curves into the RIO modelling first involved comparing the value of the solar PV capacity factor layer[3] with actual data from 21 sites over the years 2017 – 2021[9] (when available and without curtailment). We found that the capacity factors of existing projects were systematically higher than those in the layer supplied by Geoscience Australia.[3] To adjust for the observed discrepancy, the capacity factors of all solar PV projects considered in RIO were increased by 15% (of reported capacity factor, not absolutely). A more robust treatment of solar PV capacity factors for Australia would involve using Himawari [10] data to generate a new capacity factor layer for NZAu. This however is a substantial undertaking which is expected to yield marginal benefits.

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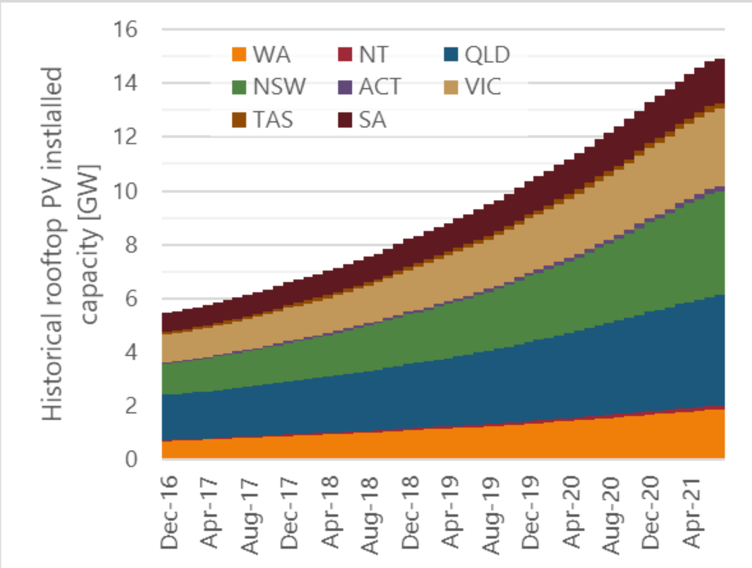
9.4 Rooftop solar PV

NZAu's macro-scale modelling does not optimise the installation of rooftop solar PV, but rather uses historical installed capacity data and projections of future growth from various sources. The Australian Government *Clean Energy Regulator* provides historical monthly installed capacity data for each postcode in the country.[1] This postcode data is then aggregated to NZAu zone level and used as the initial capacity input to the modelling. Figure 49 presents the historical rooftop PV installed capacity in Australia, noting that capacities are shown here by state/territory of installation, but are used in the modelling by NZAu zone.

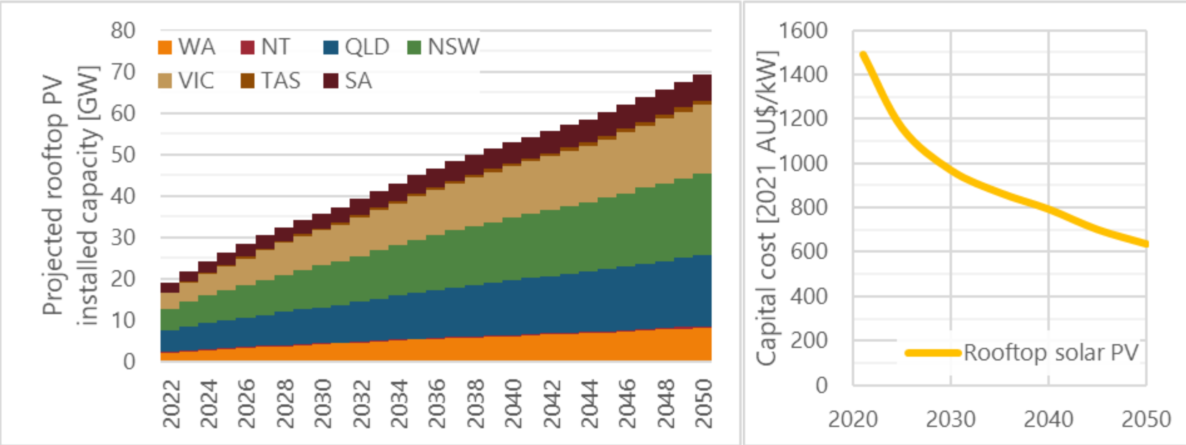
Figure 49 | Historical installed capacity of rooftop solar PV by state/territory.[1]



Projections of future rooftop solar PV capacity across Australia have been undertaken by CSIRO[2] and Green Energy Markets (GEM),[3] which are both inputs to the AEMO ISP.[4] *NZAu* uses the same assumptions as the ISP's Net Zero 2050 scenario as input to the macro-scale modelling; namely the average of the CSIRO and GEM projections of rooftop solar PV. This input is shown in Figure 50 (left hand side), again by state/territory, but is used by NZAu zone in the modelling. The disaggregation of state-based projections to NZAu zone assumes a proportional distribution of capacity between NZAu zones within a state. Furthermore, as projections for the rooftop solar PV growth in the NT were not made, this work assumes a growth rate in the NT that is the average of all other regions.

The cost of rooftop PV is provided by the CSIRO GenCost project, which is the same source as other cost data,[5] and is shown in Figure 50 (right hand side)

Figure 50 | Projected installed capacity of rooftop solar PV by state/territory[2,3] and capital cost.[5]



To incorporate the contribution of rooftop solar PV generation to Australia's electricity supply (in RIO) and to historical aggregate system load shapes (see section 6.4), hourly rooftop PV generation – and therefore also annual generation – is simulated following a similar method to that discussed for utility-scale solar generation (section 5). That is, the same source of historical solar radiation data is used[5] for the same FY2018 reference year, and the same combination of simulation steps[6] and packages[7] is used, but with different PV generation settings and different representative locations.

We simulate the aggregate rooftop solar PV generation in each NZAu zone by first simulating the normalised generation at the centroid of the 10 postcodes in each zone with largest current installed capacity of rooftop solar PV.[1] The key settings for the rooftop solar PV generator located at each of these locations are:

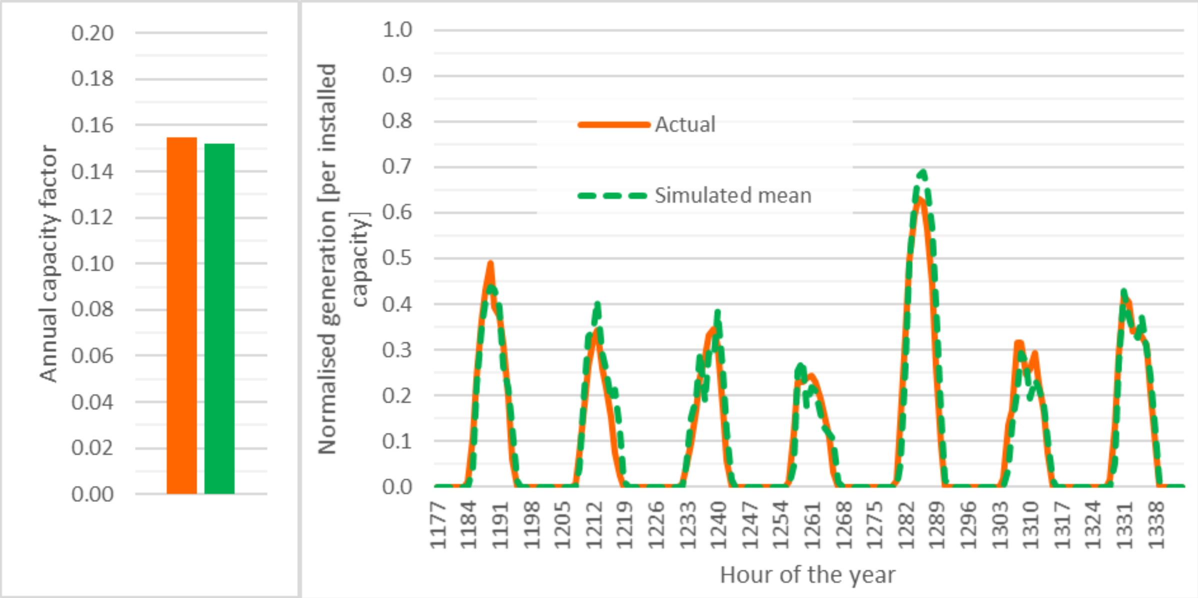
- a fixed orientation (0 degrees - North)
- a tilt angle equal to the latitude of the simulation location (the centroid of the geographic shape of each postcode selected) – this is the default tilt for small-scale fixed solar PV installations
- a shadow derate factor as in Table 30
- a soiling factor of 0.95
- a DC:AC ratio of 1
- module temperature settings provided by Sandia National Laboratories [9], as in Table 30.

The average of the 10 postcodes' simulated normalised generation profiles is then taken as the profile for the NZAu zone. Figure 51 shows a comparison of the simulated rooftop solar PV generation profiles and annual capacity factor for South Australia in FY2020, against actual data sourced from AEMO.[8] This same comparison was made for all the NEM states over two years (FY2019, FY2020), noting that actual rooftop solar PV generation data were not available for WA and NT.

The simulated normalised rooftop solar PV generation profiles are then used:

1. in historical electricity demand benchmarking (section 6.4) by multiplying the normalised profile by the FY2018 monthly installed capacity, and
2. as input into RIO for modelling of future rooftop solar PV generation (with the normalised profile multiplied by the projected future capacity of rooftop solar PV in Figure 50).

Figure 51 | The annual capacity factor (left) and a select 7-day hourly profile (right) of rooftop solar PV generation in South Australia during FY2020, showing the comparison between simulated mean (of top 10 post-codes) and actual data.[8]



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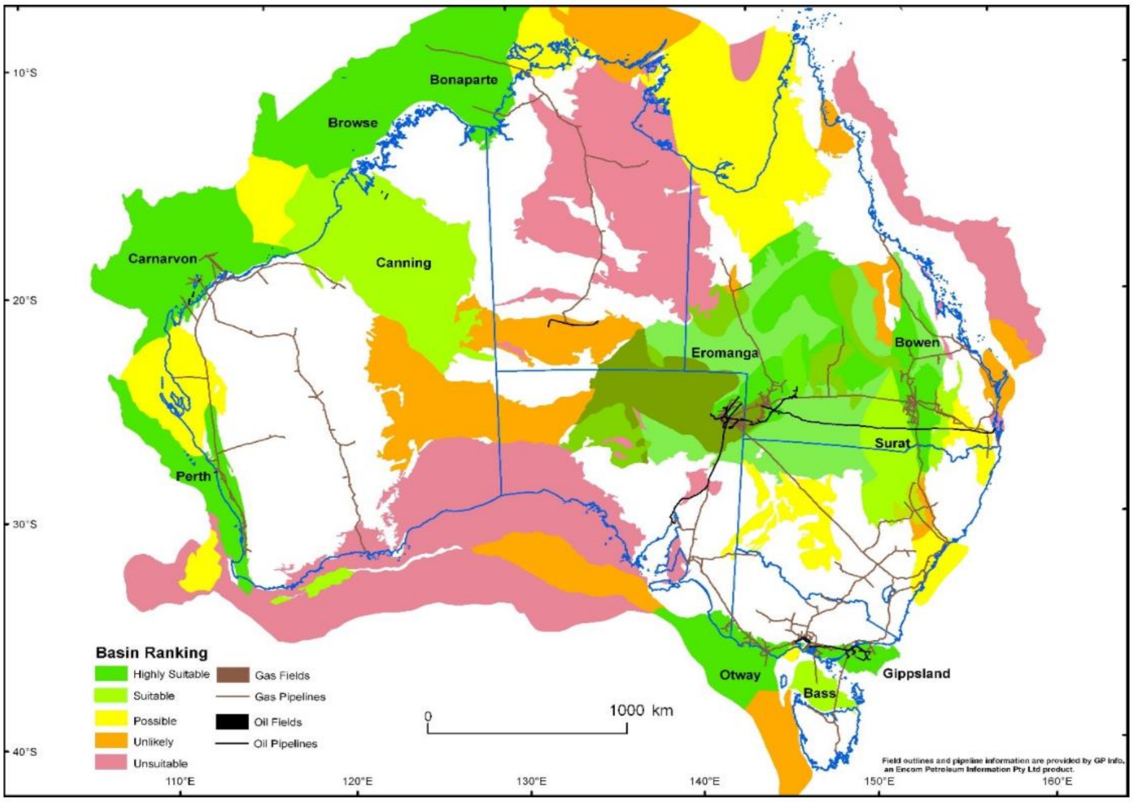
9.5 CO_2 geological storage capacities and unit costs

Carbon capture, utilisation and storage (CCUS) refers to a suite of techniques which either capture CO_2 from stationary point sources or engineer the direct carbon dioxide removal (CDR) from the atmosphere, before then either recycling this CO_2 into products such as low-carbon fuels and building materials (utilisation), or permanently sequestering it in deep underground geologic formations (storage). Ultimately, CCUS achieves mitigation via reducing CO_2 emissions to the atmosphere or withdrawing it from the atmosphere. The *Net Zero Australia* study has adopted a similar analytical framework as the *Net-Zero America* study, in which CCUS was one of the six pillars of decarbonization.[1] This section sets out the basis for the assumed supply curves defining the location of prospective basins to host geological storage of CO_2 in Australia, the associated unit costs of storage, and the relationship between CO_2 transportation costs, flowrate and distance between CO_2 emissions point sources and geologic sinks. These supply curves are used in the RIO energy supply optimisation models.

9.5.1 Literature and data sources

Australia is prospective for the deployment of CCUS, with several sources of CO_2 located close to suitable geological storage basins.[2,3] An overview of the geological storage basis is illustrated in Figure 52.

Figure 52 | Overview of Australia's sedimentary basins and the Carbon Storage Taskforce assessment of their suitability for CO_2 storage.[2]



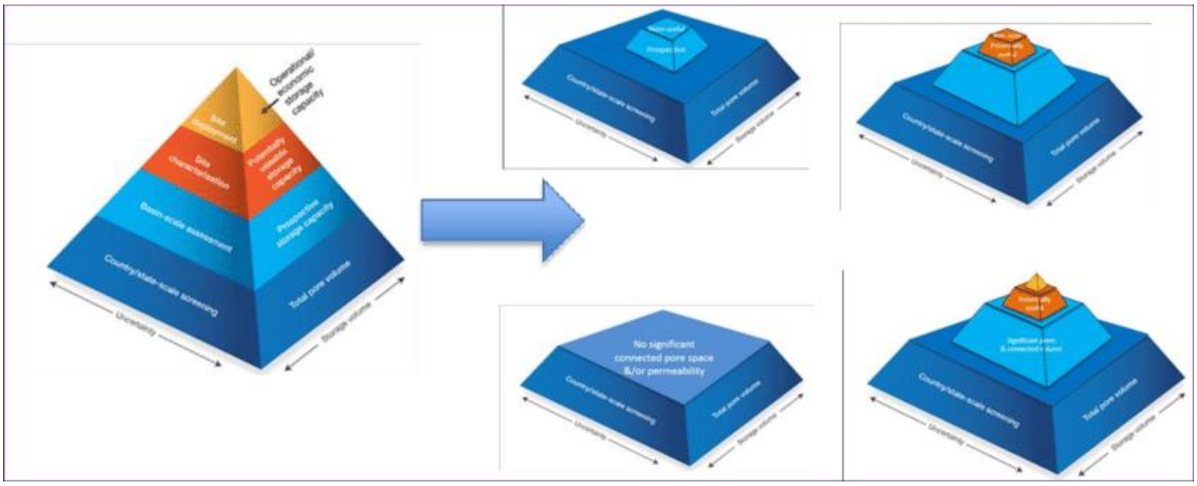
The Global CCS Institute's 2021 CO_2 Storage Resource Catalogue,[3] identified a total potential CO_2 storage capacity in Australia of 502.4 Gigatonne CO_2 storage of which just 0.1 Gigatonne is declared capacity and with approximately 18.0 Gigatonne classified as contingent, 13.40 Gigatonne inaccessible (sub-commercial) and the balance being prospective.[3] While these figures are estimated using the Society of Petroleum Engineers Storage Resources Management System (SRMS), they do not shed light on the CO_2 storage capacity likely to be commercialised, with less than 0.1% of the total resource having been appraised as 'storage' and less than 4% as 'contingent'.

9.5.2 The importance of storage dynamics

There are two reasons to be cautious about the available published storage estimates. Firstly, the available estimates classified as contingent are static (volumetric) estimates, which have limited utility for planning and investment decision-making. The i*njection rate* rather than the volume of pore space, determines the feasibility of storage as they determine the rate at which CO_2 injection that can be sustained with a given field design (injection, well design, and configuration) and hence the capital and operating costs. Therefore, a meaningful expression of storage capacity requires the explicit combination of a dynamic term (the rate of injection) over a defined period of time.[4, 5]

This connection between static and dynamic estimates of CO_2 storage capacity is illustrated in Figure 53. Two important messages are implied by this CO_2 storage capacity pyramid. Firstly, capacity estimates reduce as we advance the evidence for storage capacity through different classifications. Secondly, how much the capacity estimate reduces is uncertain and could in fact be negligible.

Figure 53 | Modified version of CO_2 storage capacity pyramid (Garnett[6] after Kaldi & Gibson-Poole[7]).



9.5.3 Basis of estimate CO_2 storage capacity and cost estimates

In this section we focus only on establishing plausible locations, capacities and unit costs of CO_2 storage following a similar approach to that adopted for the *Net-Zero America* study.[1] For that other study, CO_2 transport costs were estimated using published guidelines and models were developed for the US by the Department of Energy's National Energy Technology Laboratory.[8,10]

A challenge for establishing CO_2 sequestration supply curves is that they are reliant on the availability of subsurface geological data sets, exploration and appraisal results and engineering and field development studies. Such activities can involve several years to a decade of expert work and cost \$100's of millions.[5] Limited studies of this type have been undertaken in Australia. Notable exceptions include the following projects which have successfully completed site appraisal and are either operational or awaiting a final investment decision. Note that the appraised capacity figures are notional and obtained through media releases or through discussions with the project proponents.

- Chevron Gorgon project on Barrow Island in Western Australia's Southern Carnarvon Basin (WA).[11, 12] Notional capacity appraised: 4 Mtpa; status: operational; integrated CCS project for natural gas processing.
- CarbonNet project in Victoria's Gippsland Basin.[13] Notional appraised capacity: 5 Mtpa; status: awaiting CO_2 capture project opportunities.

- Santos Moomba project in South Australia's Cooper Basin.[14] Notional appraised capacity: 2.5 Mtpa; status: awaiting FID on integrated CCS project for natural gas processing.
- CTSCo project in Queensland's Surat Basin.[15] Notional appraised capacity: 2.5 Mtpa; awaiting FID on integrated CCS project for coal fired power with post-combustion capture retrofit.

It is also understood that several other LNG project operators may have considered the prospects for CCS in the Browse and Bonaparte Basins although no information is available in the public domain. These project sites are identified in Figure 54.

Figure 54 | Overview of Australia's sedimentary basins showing CO_2 storage appraisal sites.

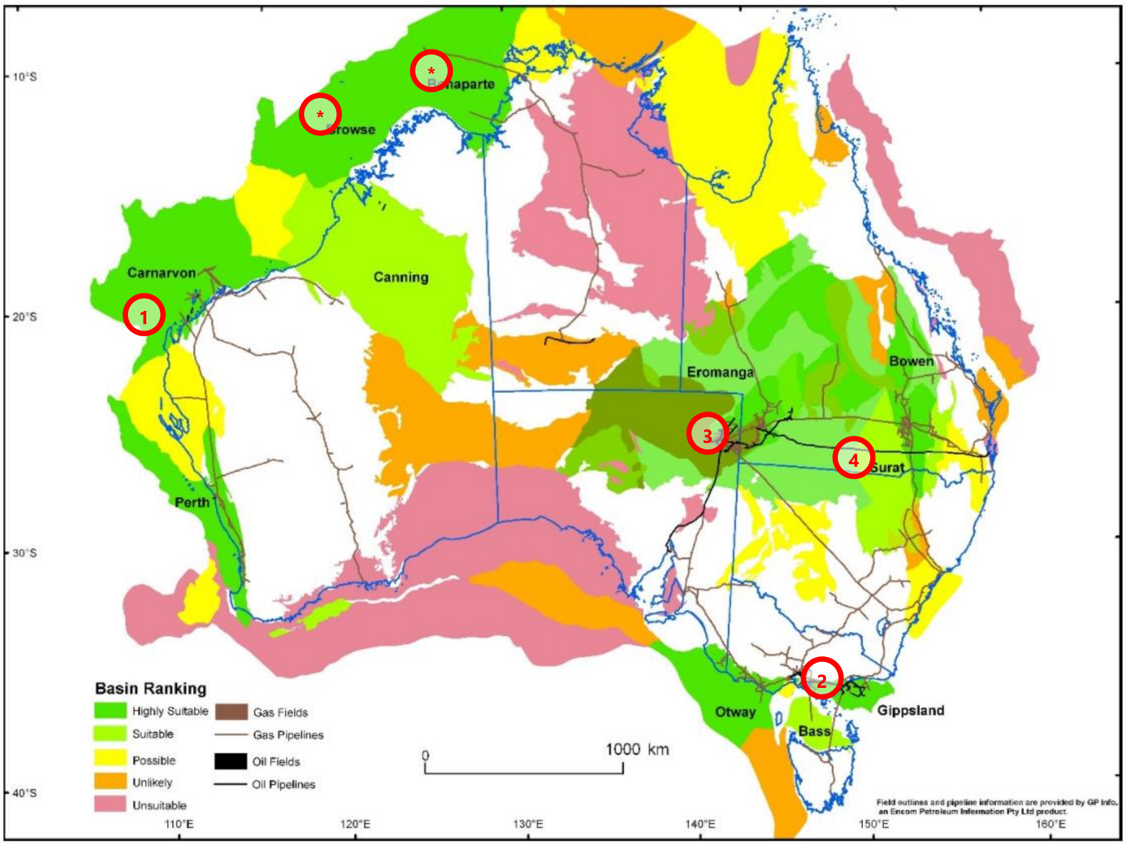


Figure notes: (1) Chevron Gorgon; (2) CarbonNet Gippsland; (3) Santos Cooper; (4) CTSCO Surat. Also highlighted are additional locations consider prospective for development – Browse and Bonaparte (*).

To establish plausible estimates of (dynamic) CO_2 storage rates that might be available for commercial CO_2 storage by the middle of the –transition, notionally 2035, we reviewed project information in the public domain including media reports and elicited the views of a variety of expert views with experience developing CCS projects. The latter included four project operators, along with Prof Andrew Garnett (with prior experience of CO_2 projects at Shell, Schlumberger Carbon Services, Queensland Geological Survey and ZeroGen) and Dr Christopher Consoli (Senior Consultant, Storage at the Global CCS Institute, Appendix 0). A co-author of this MASS document, Dr. Chris Greig is also a former CEO of ZeroGen.

As a result of these enquiries, a base-case estimates of capacity (a sustainable injection rate over at least a 50-year period) and overall notional storage costs were developed. These included unit 'finding' costs (exploration, appraisal and permitting), unit development costs (wells, local distribution pipelines and facilities), operations (operations and maintenance) and compliance (measurement, monitoring, verification and reporting). We have also constrained the target basins to the locations in which current CO_2 appraisal activities have been indicated plus the Browse and Bonaparte Basins due to the development capabilities of oil and gas operators in those locations.

Notional capacities and unit costs are also based on expert elicitation and, where available, site-specific analysis.[4, 6] These will be applied to the E+, E−, E+RE+ and E+ONS Core Scenarios. Upside case estimates are based on a simple assumption that 50% of the P10 estimate of capacities published by Australia's 2009 Carbon Storage Taskforce[2] are able to be fully appraised and developed, resulting in the ability to inject safely, steadily and cost-effectively into a formation over a 50-year period. The upside estimate will be applied to the E+RE− Scenario, in which wind and solar expansion is constrained, and fossil fuel utilisation coupled with CCS plays a significantly larger role.

Note that these notional estimates assume a steady supply of on-specification CO_2 and a minimum scale of development to be viable, but do not consider the nature of CO_2 source or its location. For reference, the Commonwealth Government's Australian Technology Road Map has set a target price of AU\$20/t-CO_2 as a competitive benchmark for CO_2 Compression, Hub transport and storage.[8]

Table 32 | Potential CO_2 storage capacities (dynamic) available in 2035 in key Australian basins.

Basin name	Type	Storage resource P10 (Mt-CO_2)	Appraised capacity – 2021 est. (Mt-CO_2/year)	Potential capacity in 2035 (Mt-CO_2/year)		Unit costs of storage (AU\$/t-CO_2) – Note 1
				Notional	Upside	
Gippsland	Offshore	30,100	5	50	301.0	10
Cooper/Eromanga	Onshore	15,700	2.4	20	157	20
Carnarvon	Offshore	25,500	4	20	255.0	15
Browse	Offshore	7,000	N/A	20	70.0	15
Bonaparte	Offshore	32,200	N/A	20	322.0	15
Surat	Onshore	6,100	1.5	20	61.0	20
Total		**116,600**		**150**	**1166**	

Note 1: The Levelised cost of CO_2 storage includes the capital cost of exploring/appraisal, site development (wells/unit facilities e.g., additional compression/local pipelines) and operating and maintenance costs. This excludes transmission pipelines and the required infrastructures.

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9.6 Biofuel

9.6.1 Biomass

Estimates of the Australian biomass resource that can potentially be diverted for new bioenergy uses were informed by CSIRO studies published by Farine et al.[1] and Crawford et al.[2] and are aligned with estimates of potential bioenergy demand in the recent Australian Government *Bioenergy Roadmap*.[3] The CSIRO estimates observe resource use constraints that avoid clearing of native vegetation, minimising impacts on domestic food security, retaining a portion of agricultural and forest residues to protect soil, and minimising the impact on local processing industries. The types of biomass appraised are:

- crop stubble
- native grasses
- pulpwood and residues (either from forest harvesting or wood processing) from plantation and native forests
- bagasse
- organic municipal solid waste
- potential future sustainable managed short-rotation tree crops grown specifically for bioenergy.

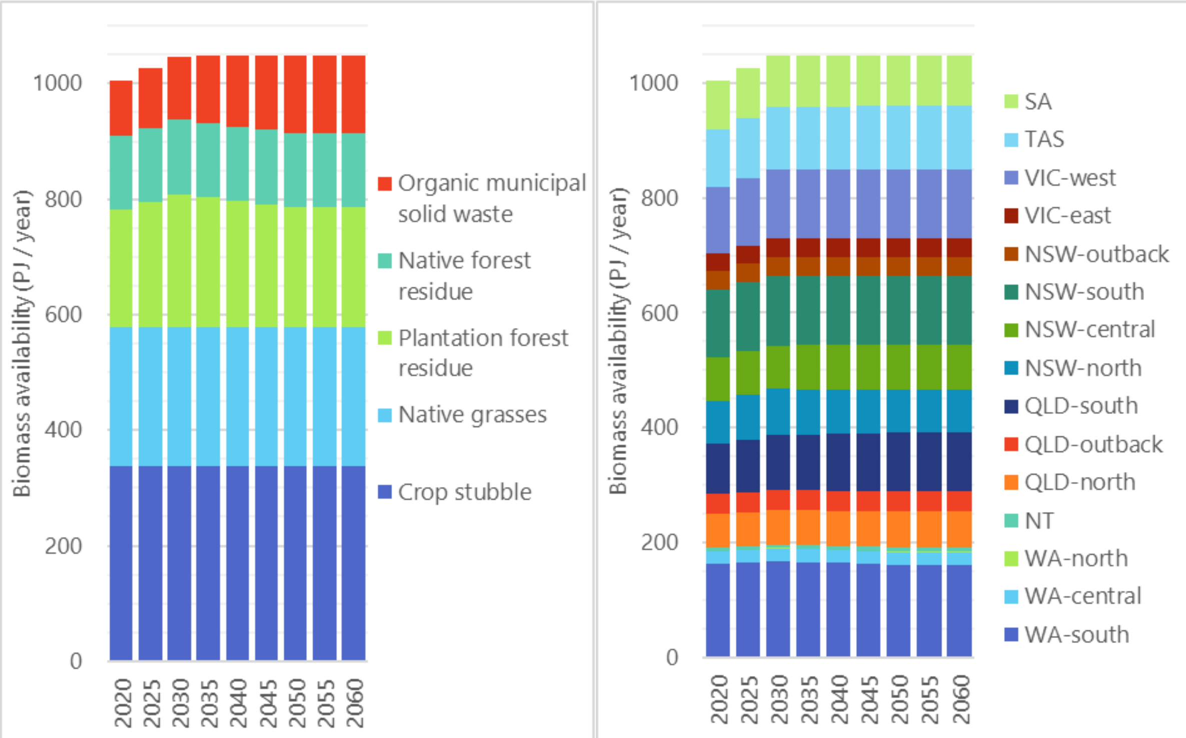
Crawford et al.[2] estimate the dry mass of each of these types of biomass in each of 60 statistical divisions (administrative areas) across Australia for 2010 and projected to 2030 and 2050.

NZAu uses the Crawford et al.[2] estimates for the 2010, 2030 and 2050 availability of crop stubble, native grasses, *residues* from plantation and native forest processing, and municipal solid waste, with the resource for the intermediate years then calculated as a linear interpolation of this data. Figure 55 presents the energy values of this annual biomass availability, which is used as the input to this work, calculated with energy densities of 12.2 GJ/t for stubble, grasses and waste, and 16.2 GJ/t for woody residues.[7]

We note that certain biomass types, such as crop stubble and native grasses, can have significant interannual variability which is not captured in this work. It is assumed that the annual biomass availability is constant across the 5 years contained within each modelled timestep, and that variations across 5-year timesteps are the result of the resource availability analyses performed by Crawford et al.[2] Furthermore, while Queensland and New South Wales' bagasse resource is not incorporated here for new bioenergy practice, its continued use in small-scale heat and power applications is captured in the overall modelling through the projections of domestic industry energy demand (Section 7).

The biomass availability of ~1000 PJ/year is less than the 2600 PJ/year *theoretical* resource potential quoted in the recently published Australian Government Bioenergy Roadmap.[3]. This is because our estimates observe technical and sustainable resource constraints that will naturally preclude a significant portion of *any theoretical* bio-resource appraisal. In addition, the Bioenergy Roadmap's modelling has identified potential demand for bioenergy of 559 PJ/year by 2030 and 870 PJ/year by 2050 in their most ambitious 'Targeted Deployment' scenario, which is aligned with NZAu's bioenergy resource estimates.

Figure 55 | Annual Australian biomass resource availability by biomass type (left) and by NZAu zone (right).[2]



Biomass for use in bioenergy has low density, high moisture content and is typically harvested and transported from diffuse sources, so that the cost of biomass is highly case specific and sensitive to transportation distances[5]. While noting that biomass will follow a complex supply cost distribution, we use a simplified supply cost curve, by dividing the biomass resource in each NZAu zone into three even bins of resource (on an energy basis) and using biomass supply costs for those bins of 5, 9 and 12 \$/GJ for municipal solid waste and 6, 8 and 10 \$/GJ for all other biomass types.[6]

We also note that Australia's potential sustainable biomass availability (Figure 55) represents a significant difference between the NZAu and the *Net Zero America*[7] studies. *Net Zero America* sourced biomass availability and cost data from the U.S. Department of Energy's 2016 *Billion Ton Study* [8], which provided year-by-year county-level projections of biomass feedstocks potentially available for energy uses, with corresponding costs in the U.S. through to 2040. Total resource estimates in the Billion Ton Study are an order of magnitude greater than the present study. Also, to date, no biomass resource appraisal of comparable detail has been undertaken for Australia.

This work assumes that any CO_2 emissions associated with the use of the biomass resource (whether through combustion or other chemical conversion processes) are biogenic and, therefore, do not contribute to GHG emissions. On the other hand, if the biogenic CO_2 emissions are captured with CCS facilities and permanently sequestered, this contributes a net negative flow of CO_2 from the atmosphere. This net negative emissions contribution is estimated to be −89 kg-CO_2/GJ, less any CCS capture efficiency losses.[10] Fossil fuels used in the production, collection and transport of biomass fuel are also accounted for elsewhere in the modelling, with their use subject to decarbonisation constraints. These are, however, typically small, accounting for less than 10% of the embodied carbon in the biomass.[9,10]

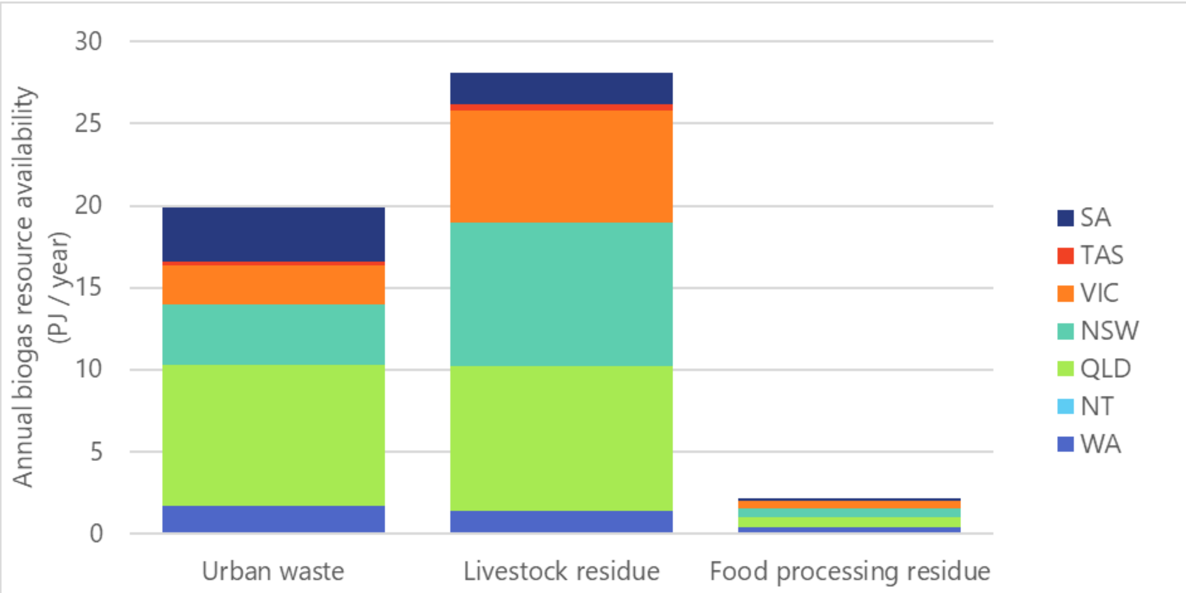
This work also assumes best practice large-scale use of biofuels for energy purposes. Any collection of organic material from forestry and agriculture should minimise impacts on soil, water, biodiversity and local industries, and will also need to manage any environmental and social impacts of large-scale change in land use or management.[1, 11, 12] A further consideration for the use of biomass for bioenergy, is the competition for food and feed crops. As a result, *NZAu*'s biofuel resource inputs mostly comprise residues and waste organic matter, which are less likely to provide significant competition to existing agriculture and forestry industries. The use of these waste streams may even be complementary to current agricultural and forestry production through the establishment of new revenue streams.[1,6,13] However, any policy that promotes the use of waste organic streams for bioenergy should also carefully consider the impacts of incentivising this use on the production of the primary bio-product.[13]

9.6.2 Biogas

A recent report has found that an estimated 371 PJ per annum of organic material is available for the production of biogas in Australia.[14] This resource is comprised of urban waste, agricultural crop residues, livestock residues, and food processing residues. Of these resources, the wet waste streams are likely to have lower cost and better suitability to biogas production through anaerobic digestion than the drier, agricultural crop residues. Furthermore, agricultural biomass resource will have greater emissions intensity due to the need for fertilisers and agricultural production processes and will be subject to land use competition.[14-15]

NZAu therefore considers the annual amount of biogas available in each region to be that available from urban waste, livestock residues and food processing residues, which is approximately 50 PJ/year, as shown in Figure 56. This 50 PJ/year biogas resource is not included as an available resource in NZAu's macro-scale energy system modelling with RIO. However, the prospects of biogas are assessed during downscaling, by reference to the energy system optimised with RIO in NZAu's Core Scenarios.

Figure 56 | Annual Australian biogas availability by the source of organic waste and region.[14]



The delivered cost of biogas is composed of raw biogas production costs (building and operating a digester, feedstock costs), any gas treatment and upgrading costs, and any gas network injection costs. The delivered cost can vary widely depending on the source of the feedstock, the transport requirements, and the scale of production.[15,16] Indeed, there is typically a trade-off between the low cost of waste feedstocks used locally, and the higher cost of aggregating such streams from diffuse sources in a larger processing hub.[11,15] We therefore use a nominal biogas fuel cost of 7 $/GJ across all years.

The use of biomethane in the energy sector provides the opportunity to avoid emissions in the agriculture sector. This is possible by diverting biowaste feedstocks to anaerobic digestion and avoiding manure and waste handling that otherwise results in methane emissions.[12,17] There is significant value in avoiding these methane emissions given methane's relatively high global warming potential. In addition to avoided methane emissions, the solid by-product of anaerobic digestion – the digestate – can be used to displace fossil-derived mineral fertilisers, thereby also avoiding GHG emissions associated with their energy-intensive production.[15,17] This provides further justification for using wet waste streams as the major feedstock for biogas production, rather than agricultural crop residues for which the cultivation, harvesting and transport is relatively emissions-intensive.[17]

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9.7 Existing electricity generation and storage

Data for existing electricity technologies in:

- the NEM are sourced from AEMO's *Integrated System Plan*,[1] specifically the 2020-21 Inputs, Assumptions and Scenarios report and workbook,[2]
- the Western Australian SWIS are sourced from the WA government's Whole of System Plan,[3] and
- the Northern Territory's Darwin-Katherine, Alice Springs and Tennant Creek power systems are sourced from the Utilities Commission of the NT's *Northern Territory Electricity Outlook Report*.[4]

The current installed capacity of existing technologies is shown in Figure 57, presented according to technology type and regional distribution (i.e., NZAu zone). This work considers only projects listed as *existing* in the 2022 ISP,[2] and not those listed as either committed or anticipated. The one exception is the high-profile, very large-scale pumped hydroelectric storage project, Snowy 2.0. This is currently expected to come into operation in 2026 with capacity of 2.04 GW/343 GWh.[2]

It can be seen from Figure 57 that the entire WA SWIS is located within the WA-south region, with no existing capacity located in WA-central and WA-north. The current and future electricity demand of off-grid locations in these zones are captured by the projections of energy demand outlined in Section 7.

Figure 57 shows the national electricity market's 18.4 GW of coal (black and brown) is located in just four NZAu zones while other resources are distributed across the modelled zones, with most zones having at least some wind and solar capacity. Australia's hydroelectric resource is located in the Victoria-New South Wales alpine region and Tasmania. Batteries have recently been deployed in the SA and VIC-west zones, with their energy capacity (number of hours of storage duration) also included as input data sourced from the 2022 ISP.[2]

In addition to current installed capacities, a schedule of expected retirement years is incorporated in the modelling, so that in each year modelled there is a maximum capacity of existing generation remaining in the system. Figure 58 shows this schedule of expected capacity retirements, noting that the modelling optimisation may choose to retire some capacity early if it is economic to do so, given the emissions constraint applied.

For each existing plant, their current fixed and variable operating and maintenance costs are included in the cost optimisation. These costs are shown in Figure 59, as capacity-weighted values for each plant type. It is assumed that the capital costs of all existing plant are sunk, and therefore are not included in the cost optimisation. Early retirement of course avoids O&M costs for existing capacity.

In addition to those data already mentioned, this work incorporates thermal efficiency and capacity factor data from the various planning studies.[2,3,4] Figure 60 presents the capacity-weighted thermal efficiencies of the existing thermal plant, noting that in the modelling, each existing plant is given its own thermal efficiency. We also observe a 75% maximum capacity factor for NSW coal plant, based on data in the 2022 ISP, which "represent a number of factors such as coal rail limitations that broadly impact all generators".[2] To avoid coal plant (existing and any new) running at extremely low capacity factors, we also apply a minimum capacity factor of 10%, so that coal plant are retired if the model's annual requirement of their electricity is less than this minimum capacity factor.

Figure 57 | Existing installed capacity of electricity technologies, by NZAu zone.

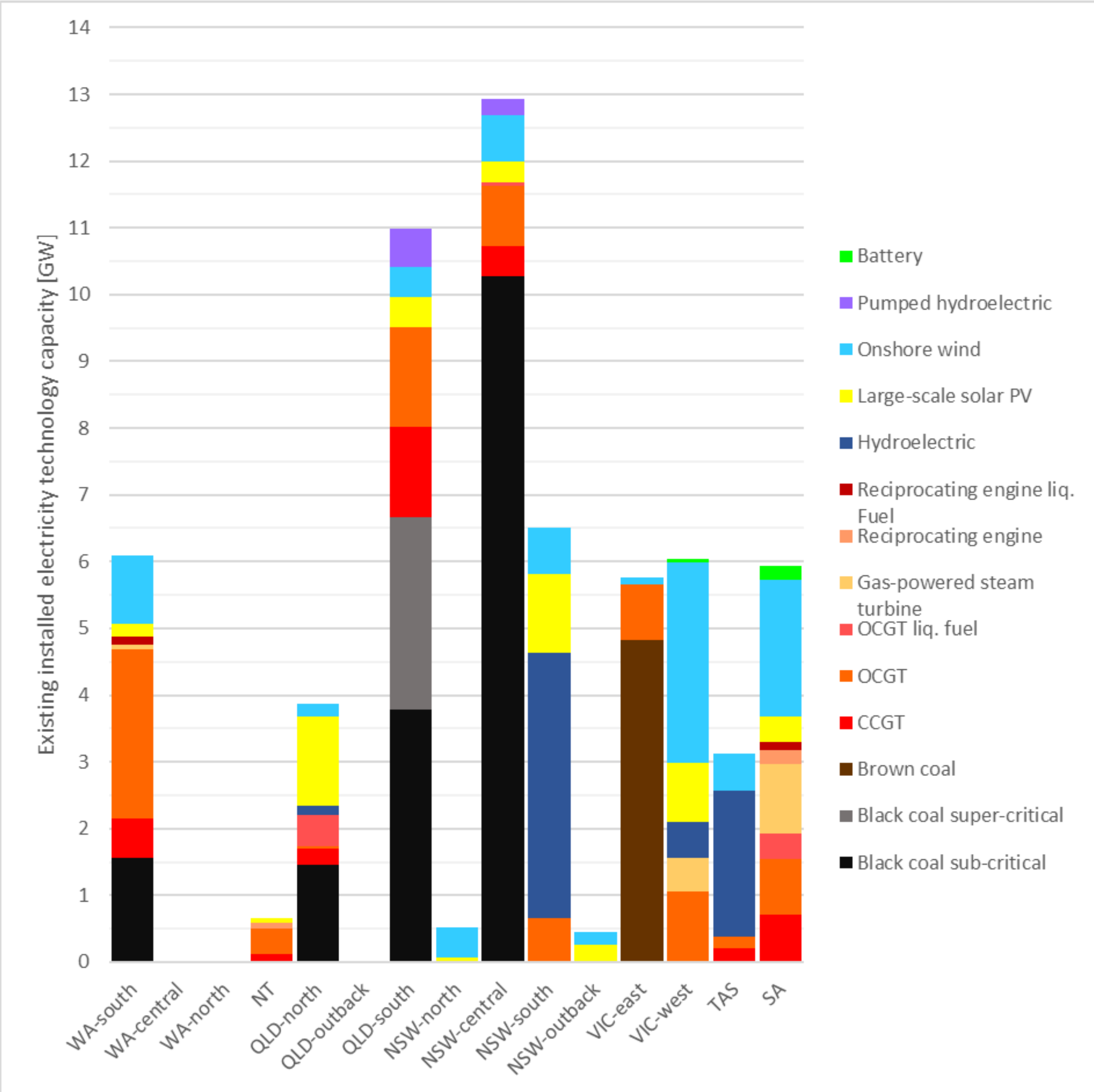


Figure 58 | Maximum yearly installed capacity of currently existing electricity technologies, based on the expected retirement year listed in the various planning studies.[2,3,4]

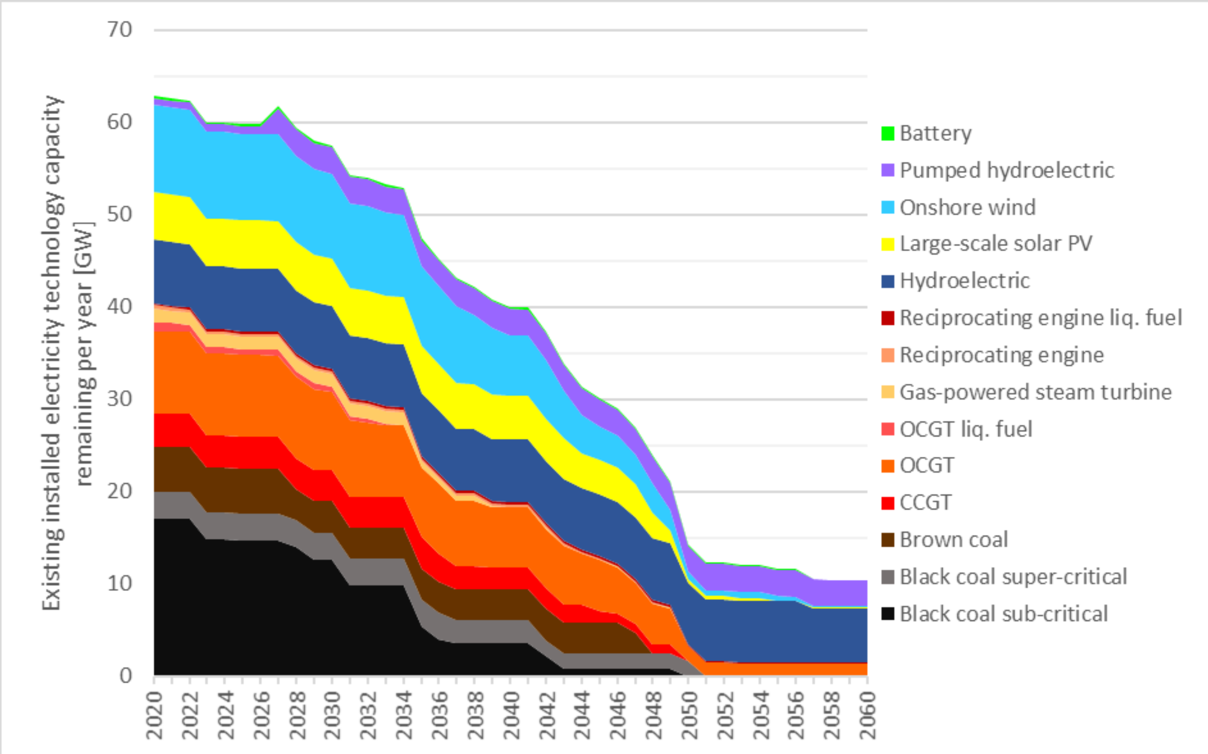


Figure 59 | Capacity-weighted fixed (left) and variable (right) operating and maintenance costs of existing electricity generation technologies.

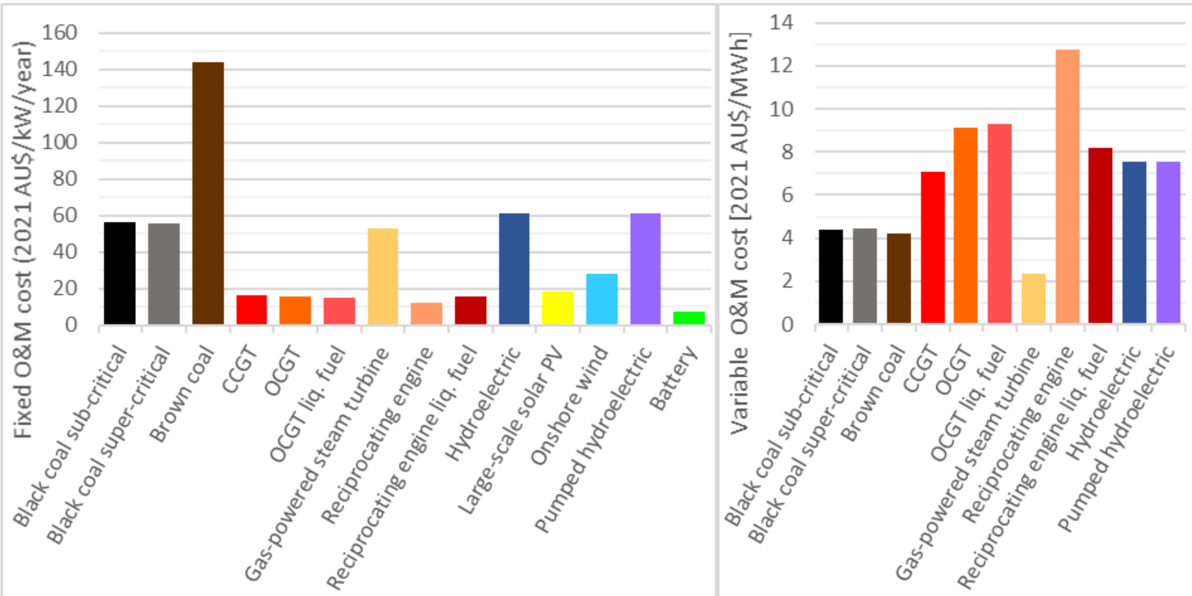
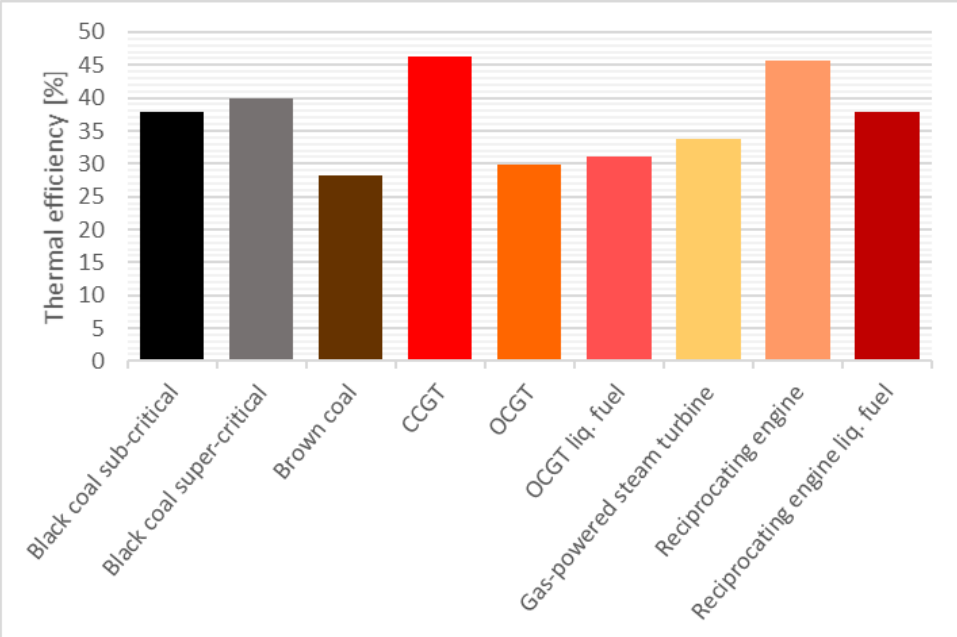


Figure 60 | Capacity-weighted thermal efficiency of existing electricity generation technologies. Note that in the modelling, each existing plant has its own thermal efficiency, which will vary around the values presented here.



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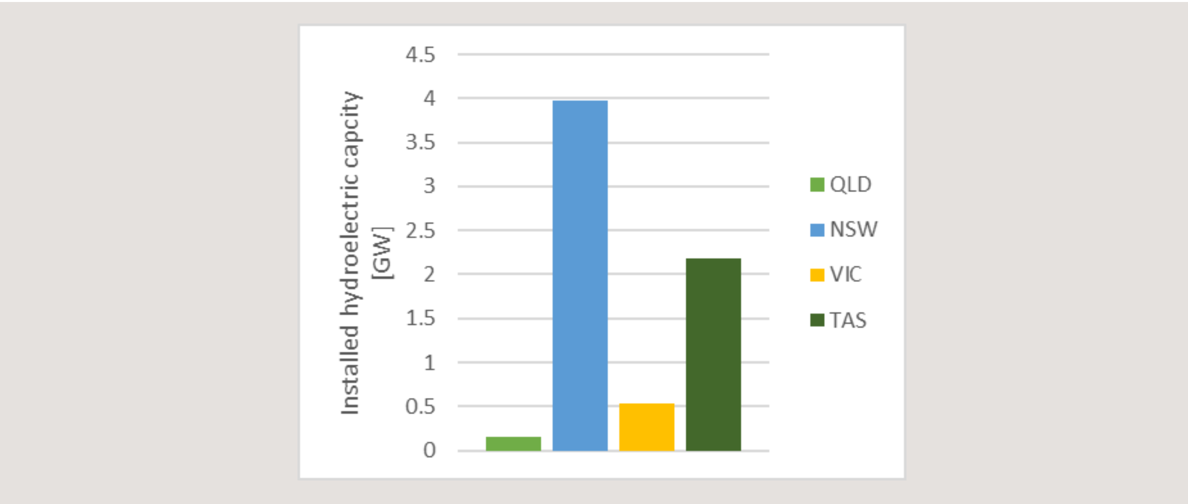
9.8 Hydroelectric generation

Australia currently has 6.8 GW of grid-connected hydroelectric generation,[1] not including pumped hydroelectric, all of which participates in the National Electricity Market (NEM). Figure 61 shows the distribution of this installed capacity by state. NZAu includes all this existing capacity and does not allow any new, non-pumped hydroelectric generation.

Figure 61 | Regional distribution of installed hydroelectric capacity.



For the existing sites, a daily generation envelope is developed by considering historical average and minimum/maximum generation data sourced from AEMO.[2] Figure 62 shows the average historical generation in each month over the years FY2015 – FY2020 for all hydroelectric sites in a given region. This monthly budget for each region is converted to a capacity factor, which is then applied to the regional hydroelectric generation in each day, so that each day in a month has the same assumed capacity factor.

In addition, a minimum and maximum hourly generation limit is applied based on historical maximum and minimum generation to replicate the historical extent to which hydroelectric generation is used as peaking generation. Figure 63 presents the mean historical capacity factor of each day against the maximum and minimum (normalised) generation in any hour of that day for the existing hydroelectric plant aggregated to their regions. Each data point represents a day in the years FY2015 – FY2020. These scatter plots are used to determine the constraints on maximum and minimum hourly generation, which are shown in Figure 64. These scatter plots show that NSW and VIC hydro are used as peaking generation, more often than hydroelectric generators in TAS.

Figure 62 | Monthly hydroelectric generation budget, based on average historical generation.

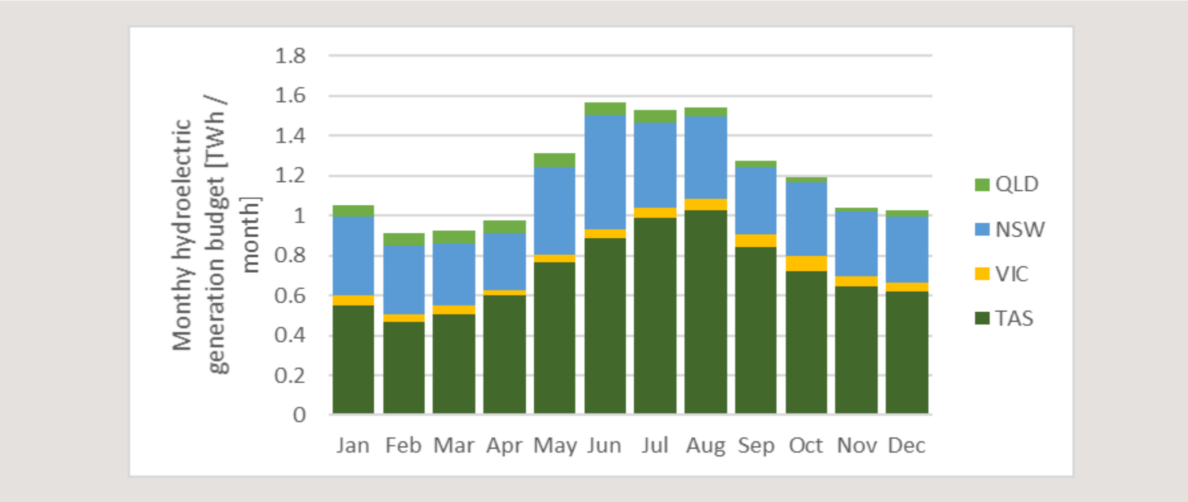


Figure 63 | The mean capacity factor of each day, against the maximum and minimum (normalised) generation in any hour of that day, for the aggregated hydroelectric plant in QLD, Snowy Hydro (NSW/VIC), VIC (non-Snowy Hydro) and TAS.[2]

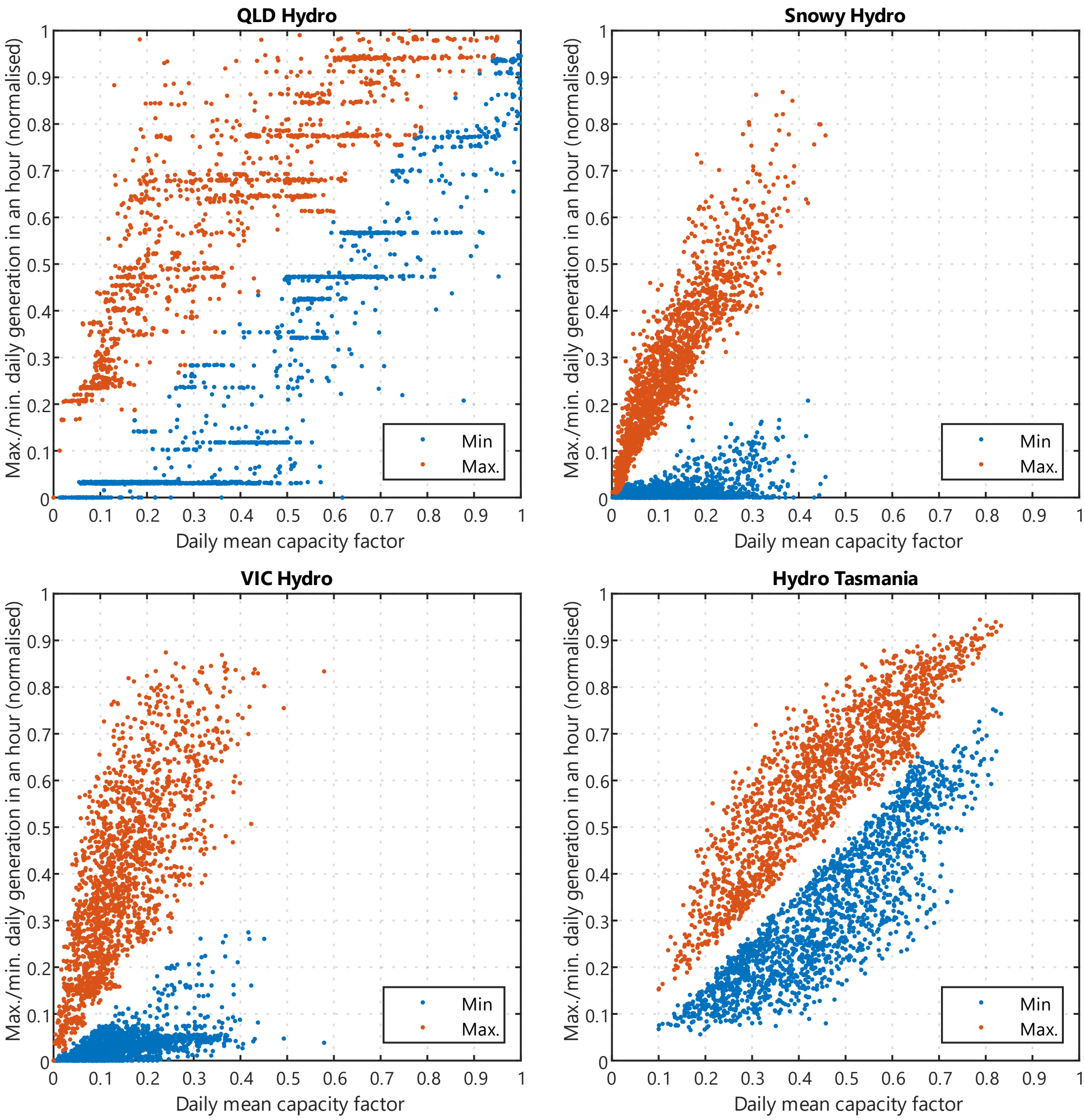
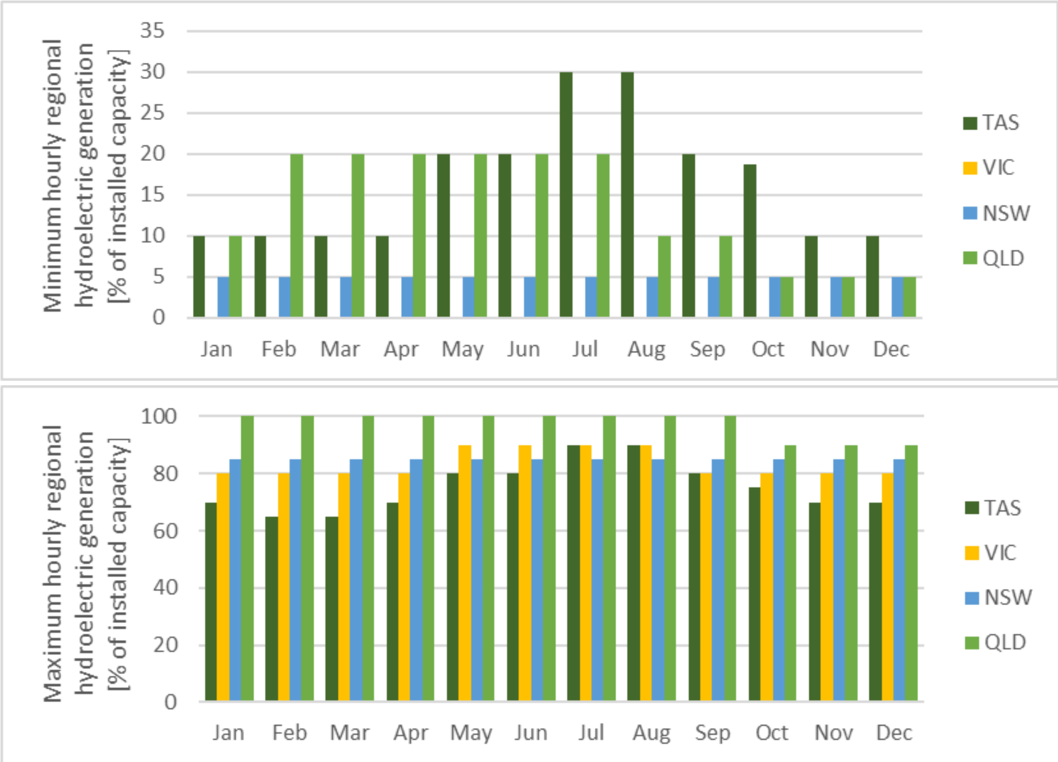


Figure 64 | Minimum (top) and maximum (bottom) hourly hydroelectric generation envelopes, by region and month.



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10 Capital and operating costs

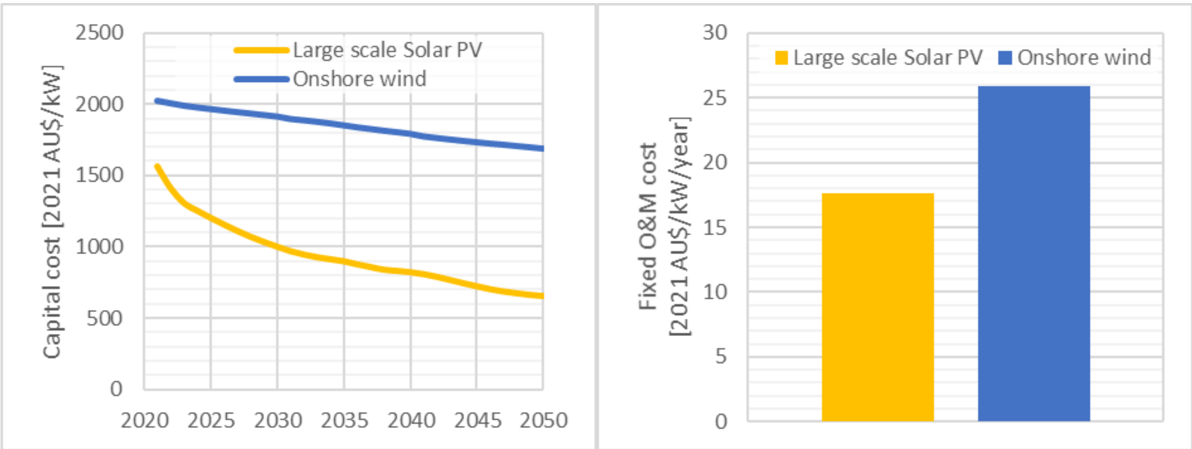
10.1 Onshore renewables

Capital and operating costs of onshore wind and solar PV electricity generation are sourced from AEMO's 2022 *Integrated System Plan* (ISP),[1] specifically the *2020-21 Inputs, Assumptions and* Scenarios report and workbook,[2] as well as CSIRO's GenCost project.[3] These are the most recent and authoritative sources of Australian-specific electricity system technical and cost data. Where available, NZAu uses 2022 ISP data from its 'Net Zero 2050' scenario.

Figure 65 presents the capital cost projections for large-scale solar PV and onshore wind generation. These cost projections – undertaken by the CSIRO GenCost project[3] – feature significant technology learning for both wind and solar PV. A 17% capital cost reduction by 2050 is projected for onshore wind, while a 58% reduction is projected for solar PV.

The fixed operating & maintenance (O&M) cost for these types of plant are also shown in Figure 65, noting that this fixed O&M cost takes into account the costs normally levied as variable O&M costs for wind and solar PV, as is also done in the ISP.[1] Variable O&M costs are typically very small for wind and solar PV generation.

Figure 65 | Capital cost projections for onshore renewables (left), and their fixed operating & maintenance cost (right).



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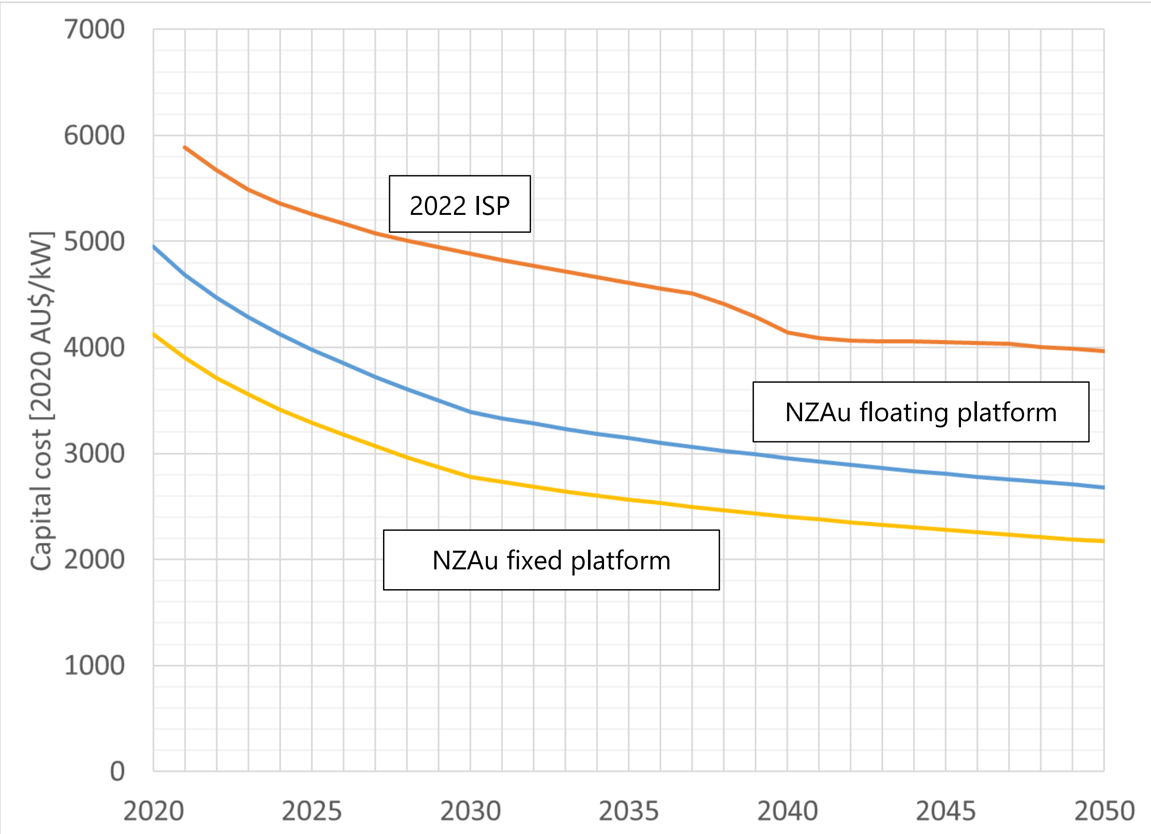
3. Graham P, Hayward J, Foster J, Havas L 2021, "GenCost 2020-21: Final report", CSIRO Newcastle, https://doi.org/10.25919/8rpx-0666.

10.2 Offshore renewables

Offshore wind is not yet present in Australia and Australian-specific costs are therefore quite uncertain. Also, the AEMO 2022 ISP[1] and CSIRO GenCost[2] reports provide capital cost estimates that are significantly higher than overseas studies, and in the view of the NZAu team, this will likely understate offshore wind's prospects in the NZAu project. For this reason, an alternative source of offshore wind capital cost data is used: the United States National Renewable Energy Laboratory (NREL) *Annual Technology Baseline* (ATB) study.[3] This provides capital cost estimates based on number of characteristics including depth, distance to shore and wind class. The NZAu capital costs used in all scenarios are derived from the NREL ATB offshore wind capital cost data, and are adjusted for the average ocean depths, wind resources, and distances to shore in each region. Figure 66 shows a comparison of offshore wind capital cost estimates between the AEMO 2022 ISP[1] and average NZAu costs for fixed and floating platforms.[3,4]

A fixed O&M cost of AU$163/kW/year is used for all offshore wind, as provided by the ISP.[1]

Figure 66 | Comparison of offshore wind capital cost estimates between the AEMO 2022 ISP and average NZAu costs for fixed and floating platforms[1,2,3,4]



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10.3 New non-renewable electricity generation and storage

The new electricity generation and storage technology candidates considered in NZAu are listed in Table 33. In addition to variable renewable technologies, a range of conventional electricity generation technologies are available to be built in the modelling, as well as various types of electricity storage. We note that the emissions constraint does not necessarily preclude gas turbines without CCS from operating in the system, due to the possibility of hydrogen blending. We therefore allow new CCGT and OCGT plant to be fired on any blend of natural gas and hydrogen from 2035 onwards.

Table 33 | New electricity generation and storage technology candidates (see Note).

Variable renewable	Solid fuel	Gaseous fuel	Storage
Large-scale solar PV	Black coal	Combined cycle gas turbine	Li-ion battery
Onshore wind	Black coal with CCS	CCGT with CCS	Pumped hydro (PHES)
Offshore wind	Brown coal	Open cycle gas turbine	
Rooftop solar PV	Biomass		
	Biomass with CCS		
	Nuclear SMR (allowed in certain sensitivities)		

Notes on candidate technology availability: We only allow nuclear technology in select sensitivity studies, not in Core Scenarios. When allowed, nuclear can be built from 2030. We allow new CCGT and OCGT plant to be fired on any blend of natural gas and hydrogen from 2035 onwards.

Capital costs for the technologies listed in Table 33 are sourced from AEMO's 2022 ISP,[1,2] with cost projections to 2050 undertaken by CSIRO's GenCost project.[3] Figure 67 presents the capital cost projections for the electricity generation technologies not previously presented in this work. None of these thermal technologies feature significant learning over the years to 2050.

In addition to technologies listed in AEMO's 2022 ISP and CSIRO' GenCost, we allow Biomass with CCS as a candidate technology (shown in Table 33). Capital costs for these technologies are provided by Princeton[4] and are the same those used in the *Net Zero America* project. Biomass with CCS allows for electricity generation with net negative associated GHG emissions.

Figure 68 presents the capital costs for the electricity storage technologies considered here. The costs provided in the 2022 ISP for lithium-ion batteries and pumped hydroelectric storage (PHES) with varying storage duration (1 – 48 hours) have been decomposed here into power unit costs ($/kW) and energy unit costs ($/kWh). This is so that the energy capacity of any required storage can be optimised in RIO, alongside the power capacity. We note that we also apply regional cost factors to the PHES costs, as informed by the 2022 ISP,[2] so that PHES may be built at lower cost in some regions (particularly TAS) than others.

Fixed and variable operating and maintenance costs for candidate new technologies are provided by the 2022 ISP[2] and are presented in Figure 69.

In addition to the costs of candidate electricity technologies, we also source a range of technical parameters from the 2022 ISP.[2] These include:

- thermal efficiencies of thermal generators at their minimum and maximum generation levels (Figure 70)
- minimum generation levels for thermal plant
- round-trip energy efficiencies of 85% for batteries and 75% for PHES
- regional capacity build limits for PHES
- hourly ramping constraints for the least flexible generators as proportion of capacity (50% for CCGT, 30% for existing large-scale hydroelectric and biomass, 20% for coal plant, 10% for any CCS plant). These

applied constraints can be considered as *effective* ramp rates, informed by ramping data from the ISP, but also including an allowance for other unit commitment constraints (e.g., min up/down times, startup/shutdown times) that are not explicitly modelled, to ease computational burden.

The supply-side modelling of electricity generation and storage optimises hourly, daily and annual energy supply operations to maintain system reliability across each modelled year. This includes tracking of the state of charge of energy storage (within Li-ion battery, pumped hydroelectric storage, hydrogen storage in underground engineered caverns, as candidate storage technologies) across 365 days. We further model dynamic electricity reliability constraints that track planning reserve margins across all modelled hours rather than only historical gross-load peaks. This capacity reserve margin trends from 7% in 2020 to 11% in 2060, which reflects the need for greater firm capacity reserves with potentially more extreme future weather events and with conservatism in planning for a system with very high penetration of variable renewable resources.

Figure 67 | Capital cost projections for new electricity generation candidate technologies.

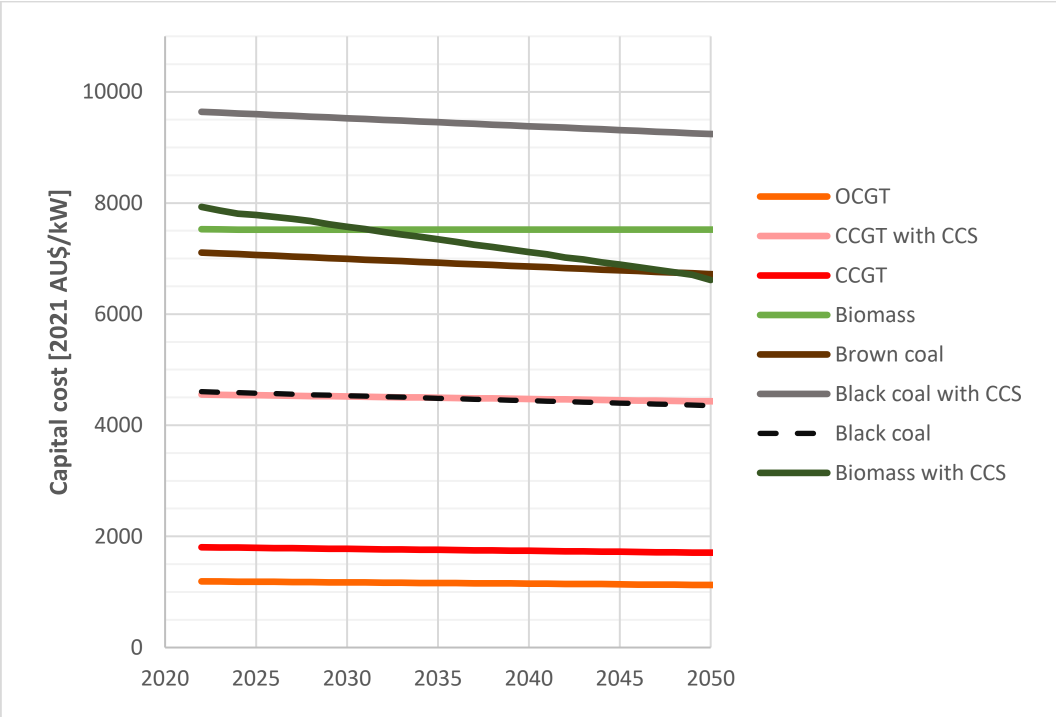


Figure 68 | Capital cost projections for new electricity storage candidate technologies. The capital costs are decomposed into energy capacity ($/kWh) and power capacity ($/kW) cost components.

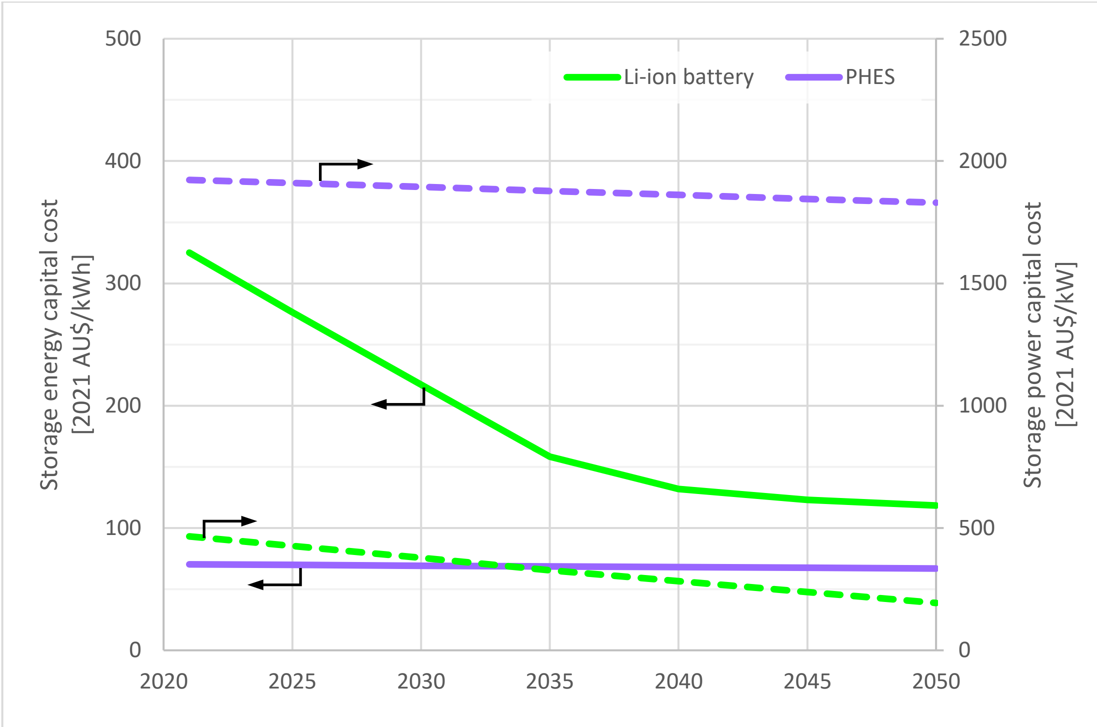


Figure 69 | Fixed (left) and variable (right) operating and maintenance costs for new electricity generation and storage technology candidates.

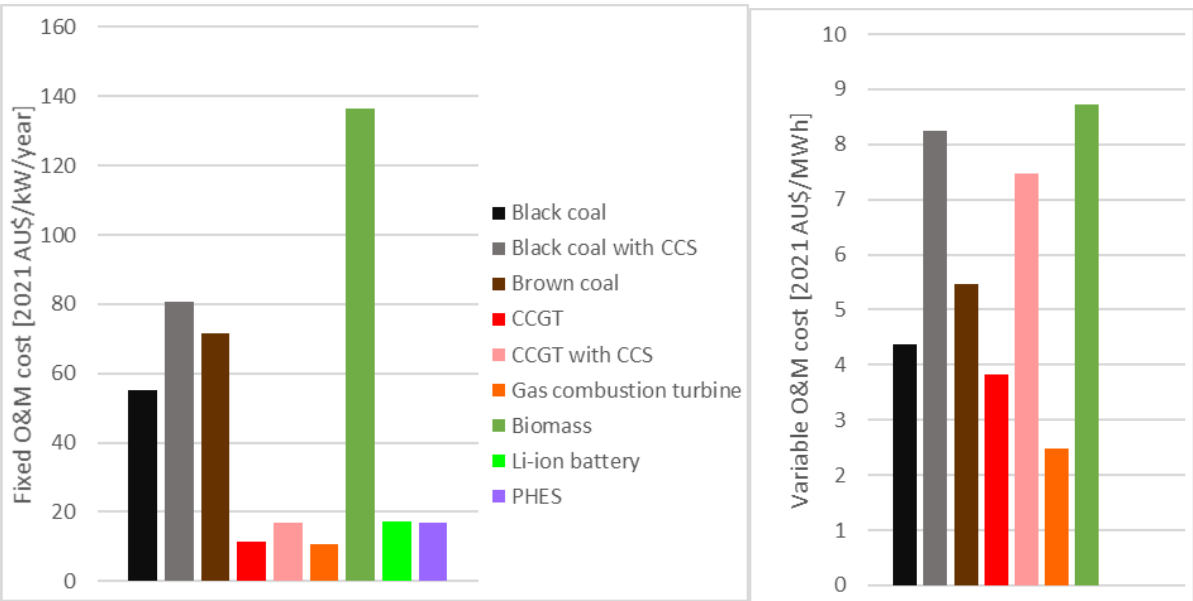
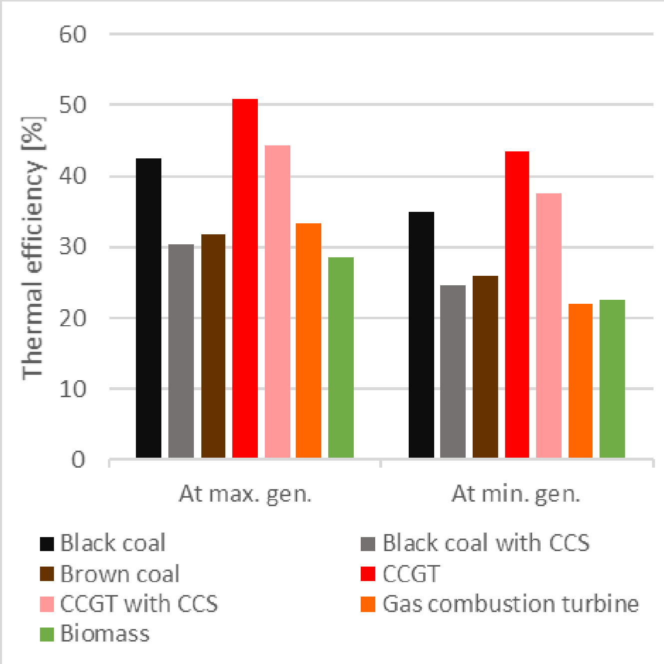


Figure 70 | Thermal efficiency of new electricity generation and storage technology candidates at maximum and minimum generation levels.



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3. Graham P, Hayward J, Foster J, Havas L 2021, "GenCost 2020-21: Final report", CSIRO Newcastle, https://doi.org/10.25919/8rpx-0666.
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10.4 Industrial sector (including alternatives to natural gas and oil processing)

The NZAu Project only considers hydrogen and ammonia as the non-electrical alternatives to natural gas and oil products. Since ammonia is made using hydrogen, much of this discussion considers hydrogen production. The hydrogen production and transformation technologies considered are listed in Table 34. We adopt the common colour scheme for classifying hydrogen production routes. Only green (hydrogen produced from renewable electricity or biomass) and blue hydrogen (hydrogen produced from fossil fuels incorporating carbon capture utilisation and storage) are included in the Core Scenarios.

Table 34 | Hydrogen production and transformation technologies.

Green Hydrogen	Blue Hydrogen	Hydrogen Carriers
Alkaline Electrolysis	Autothermal Reforming (Natural Gas) with CCS	Liquified hydrogen
Proton Exchange Membrane Electrolysis	Brown Coal Gasification with CCS	Ammonia via Haber Bosch processing, using green and blue hydrogen feedstocks
Biogasification with and without CCS	Black Coal Gasification with CCS	Fischer-Tropsch liquids

10.4.1 Electrolysis technologies

Electrolysis is a mature process that makes approximately 2% of global hydrogen production as of 2020.[1] Two types of electrolysis are currently used in practice: alkaline electrolysis (ALK) and proton exchange membrane electrolysis (PEM).

Table 35 provides a summary of Australian specific cost and technical parameters for alkaline and PEM electrolysis plants using the CSIRO GenCost 2020 final report.[2, 3] Whilst other studies present different parameters,[4, 5] the use of the GenCost 2020 report is Australia-specific and is also consistent with several other important inputs used in the NZAu project.

Table 35 | Cost and technical parameters for hydrogen electrolysis plants.[2, 3]

Technology	Unit	Alkaline	PEM
Capital Cost (Note 1, 2, 3)	\$/kW-e (electrical input)	1580	1868
Capital Cost (Note 1, 2, 3)	\$/kW-th H_2 (hydrogen output)	2748	3028
Additional Power for H_2 Compressor	kWh-e/kg-H_2	1.41	
Cooling System Two options for cooling were considered given the scale and plant locations: Air cooling (Note 4) Cooling tower (Note 5)	 kWh-e/kg-H_2 kWh-e/kg-H_2	 0 0.45	
Plant Lifetime – Stack	hours	80,000	
Output pressure	bar	30	
Overall Energy for electrolysis	kWh/kg-H_2	57.7	61.7
Feedstock Water [6] (Note 6) Air cooled Cooling tower	 kg-H_2O/kg-H_2 kg-H_2O/kg-H_2	 10 37	
Fixed O&M (Note 7)	\$/kW-th H_2	82.44	90.84
Scaling factor		95%	
Variable O&M (Note 8)	\$/MWh-th H2	6.27	6.91

Table notes:

1. Advised by industry stakeholders to consider the GenCost projected data for its Central Scenario at 2023
2. 2020 AU\$
3. H_2 Compressor cost is included. Land is excluded
4. Air cooling is the default option in NZAu and already incorporated the cooling demand
5. Cooling towers have increased demand relative to air cooling due to additional pumping requirements
6. This assumes a 10% loss in the electrolyser plant. Water entering the electrolyser plant is assumed to be either desalinated from coastal desalination plants or pre-treated water from inland dam or river systems. The desalination plant is assumed to use ultra-filtration (UF) for pre-treatment and double pass reverse osmosis (RO) to reduce the total dissolved solids (TDS) to ≤5mg/L. The electrolyser plant itself has an electro-deionisation (EDI) pre-treatment step to polish the water before it enters into the electrolyser stack. EDI waste will be concentrated in brine ponds at each electrolyser site
7. 3% of Total Capex
8. 1% capital cost per year as per *Net Zero America*.

Table 36 shows the projected capital cost reductions for Alkaline and PEM electrolysers based on the CSIRO GenCost 2020 report for the central scenario.[2] We note, through discussions with industry advisors, that technology costs are decreasing faster than those reported in the GenCost report due to increased global deployment of small to moderate sized electrolysers. As a result, we time shifted the cost reductions forward by 3 years to match current commercial advice, i.e., 2020 costs used in NZAu correspond to 2023 costs in the GenCost report.

Table 36 | Projected technology capital cost out to 2050 for hydrogen electrolyser plants

Year	Capital cost (2020 AU$/kW-e)	
	Alkaline	PEM
2020	1580	1868
2025	1264	1086
2030	1068	738
2040	777	474
2045	739	446
2050	725	436

Electrolyser stack efficiencies are also predicted to increase through technology development, with the thermodynamic limit for electrolysis being roughly 40 kWh/kg-H_2. In consultation with industry stakeholders and commercial providers, we therefore also use an overall plant efficiency in NZAu with 2020 efficiencies of 69% and 65% (57.7 and 61.7 kWh/kg-H_2) for Alkaline and PEM technologies. These are projected to increase to 69% and 74% respectively by 2050.

10.4.2 Natural gas to hydrogen

Hydrogen from natural gas is the most common current production route, accounting for roughly 76% of global production in 2020.[1] Steam methane reforming (SMR) dominates current global production, although autothermal reforming (ATR) is increasingly favoured for new, large scale facilities, especially when CCS integration is required.

The primary difference between these two technologies is the heat provision to the reactor section. For SMR, the heat is provided externally through combustion of natural gas in a furnace, while for ATR the heat is generated internally through the partial oxidation of the natural gas. Therefore, the concentration of CO_2 in the product stream leaving the reactor is significantly higher in the ATR process than in the SMR process, making CO_2 capture easier. The ATR process also typically operates at a higher process efficiency than SMR. Both technologies have similar downstream units including water gas shift reactors, heat recovery for steam generation and hydrogen purification sections. ATR also requires a high purity oxygen stream for the partial oxidation reaction, while SMR requires a higher steam to carbon ratio, and thereby increased water consumption, to facilitate the required conversion.

10.4.3 Coal to hydrogen

Hydrogen production from coal gasification is the second most common route for hydrogen production, accounting for roughly 22% of global production in 2020.[1] Coal gasification reacts coal with air or oxygen and steam at high temperature and moderate pressure to produce ‘synthesis gas’ or ‘syngas’. The syngas is then shifted ($CO + H_2O \rightarrow H_2 + CO_2$) using a water gas shift (WGS) reactor. Various gasification technologies have been developed since the 1920’s including fixed bed (updraft, downdraft and cross-draft), entrained flow, plasma and fluidised bed (bubbling, circulating, spouted, and swirling).[8,9,10] For the NZAu study we considered only entrained flow reactors for both black and brown coal as these appear most technically compatible and economically competitive for the likely scale of production and for the characteristics of the coals used.[2]

10.4.4 Blue hydrogen production costs

Numerous techno-economic analyses have been conducted for blue hydrogen production through different reforming and gasification processes combined with CO_2 capture, although few have focussed on the Australian context. Table 37 shows a summary of cost and technical parameters for fossil-fuel-based hydrogen plants for producing 100 kt-H_2/year in the Australian context.[7]

Table 37 | Cost and technical parameters for 100 kt-H_2/year blue hydrogen plants in 2020 AU$.

Hydrogen Production Technology (Note 1)		SMR + CC (Note 2)	ATR + CC (Note 2)	Brown coal Gasif. + CC (Note 2)	Black coal Gasif. + CC (Note 2)
Onstream Factor		95%		91%	
Feed	GJ/t-H_2	159.5	182	231.9	303
Natural gas fuel	GJ/t-H_2	38.5	0	0	0
Electricity	MWh-e/t-H_2	1.8	3	5.05	7.9
CO_2 captured	t-CO_2/t-H_2	9.05	8.34	16.12	19.71
CO_2 emitted	t-CO_2/t-H_2	1.15	1.04	5.63	7.62
Treated Water	t-water/t-H_2	21.8	16.6		
Capital cost	AU$/kg-$H_2$ /year	8.04	9.73	15.67	17
Fixed operating cost (Note 3)	AU$/kg-$H_2$	0.23	0.27	0.49	0.51
VOM – chemical + catalyst	AU$/kg-$H_2$	0.013	0.015	0.018	0.078
VOM – water	AU$/kg-$H_2$	0.085	0.069	0.053	0.078

Table Notes:

1. Plant lifetime 30 years, H_2 pressure of 80 bar at plant BL [7].
2. Gasif: Gasification, SMR: Steam methane reforming, ATR: Autothermal reforming, CC: Carbon Capture.
3. Tax and insurance are excluded.

The production capacity of an individual plant plays a significant role in the amortised capital charge for each technology. Whilst Table 37 provides Australian specific data, 100kt-H_2/year is not suitable for production facilities aiming to maintain Australia's energy exports with blue hydrogen. For example, the H21 North of England project[11] has conducted similar assessment for the transition to a Hydrogen Economy. They examined larger production capacities for both SMR and ATR plants; specifically, 1.5 GW_{th}-H_2 or ~316 kt-H_2/year, which is commensurate with Australian export ambitions and represents a current world scale.

Table 38 therefore reports revised production costs in 2020 AU$ after scaling the Table 37 data. This scaling uses a factor of 0.65, which is appropriate for scaling complex processes with solids and gas handling[11,12] for the ATR + CCS and brown coal gasification + CCS technologies. Table 39 shows the resulting projected capital cost trajectory out to 2050, also using a 0.5% annual cost reduction.

Table 38 | Current production costs of a 316 kt-H_2/year blue hydrogen plant using ATR+CC or Brown coal gasification in 2020 AU$.

Hydrogen Production Technology – Updated data		ATR + CC	Brown Coal gasif. + CC
Capital Cost	AU$/kg-$H_2$ /year	6.5	11.6
Fixed Operating Cost	AU$/kg-$H_2$	0.18	0.49
VOM – chemical + catalyst	AU$/kg-$H_2$	0.015	0.018
VOM – water	AU$/kg-$H_2$	0.069	0.053

Table 39 | Projected cost reduction for a 316 kt-H_2/year blue hydrogen plant using ATR+CC and brown coal gasification+CC out to 2050 in 2020 AU$.

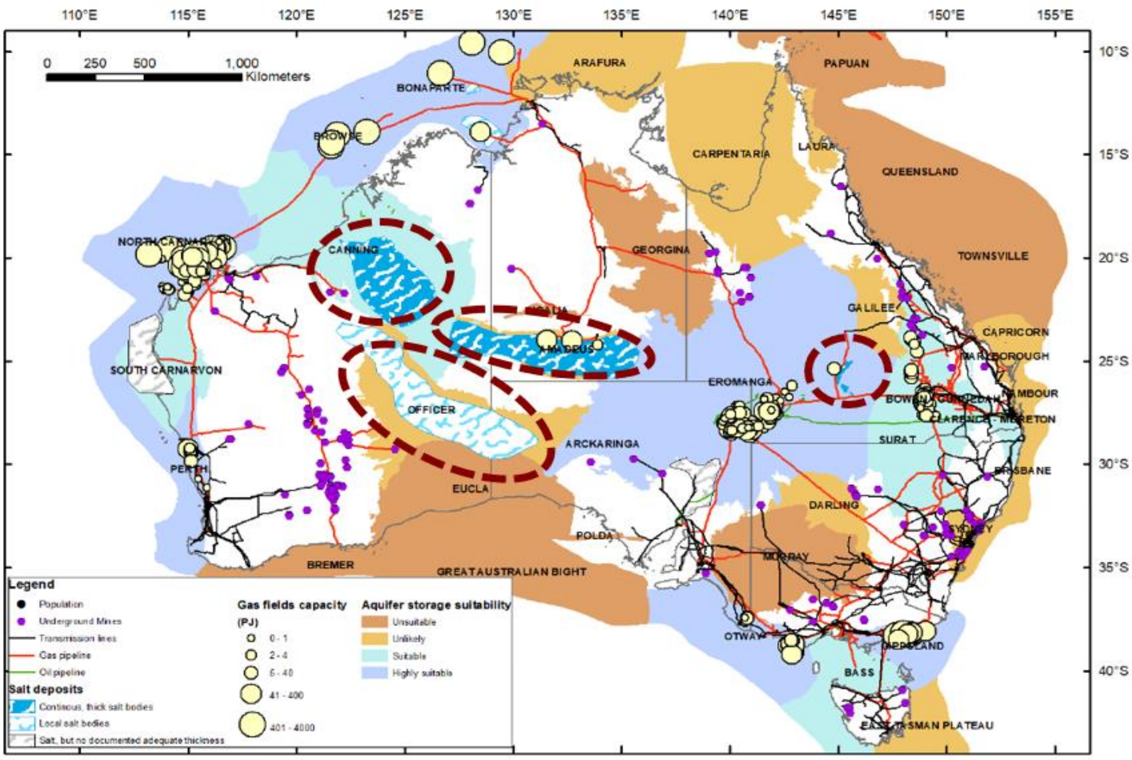
Year	ATR + CC	Brown coal gasif. + CC
	$/kg-$H_2$/year	$/kg-$H_2$/year
2021	6.50	11.6
2025	6.37	11.3
2030	6.21	11.0
2035	6.06	10.8
2040	5.91	10.5
2045	5.76	10.3
2050	5.62	10.0

10.4.5 Hydrogen storage

Storage costs at the production facility or export terminal are not considered in the above data. Underground hydrogen storage (UHS) will be a key component associated with large-scale hydrogen production facilities to support reliability and operability of the energy system. UHS is also considered potentially useful for balancing seasonality and may be required to balance supply for domestic use and export. There are a small number of sites for underground hydrogen storage around the world, typically in salt cavern formations, for example in the United Kingdom (Teesside) and the United States (Clemens Dome, Spindletop, Moss Bluff).[13-16] However, there are currently no underground storage sites that utilise depleted oil and gas reservoirs.

CSIRO[17] developed a methodology for assessing the suitability of UHS options in Australia. Their analysis showed that various Australian sedimentary basins contain salt deposits that are potentially suitable for the creation of storage caverns. The map in Figure 71 shows the potential locations (dotted lines). However, there is no data on potential storage capacities in these regions. We therefore exclude the use of salt caverns for UHS in this study.

Figure 71 | Map of potential salt cavern storage sites in Australia.[17]



Depleted oil and gas reservoirs are an alternative underground storage option.[17] These are well characterised and the potential storage capacity is listed in Table 40. However, we note that the majority of selected basins overlap with CO_2 storage basins. There is high uncertainty that both H_2 and CO_2 could be stored in the same formation, even within different, apparently unconnected strata. Therefore, further investigation is required to determine whether these reservoirs are suitable for combined storage. They are therefore excluded from this study.

Table 40 | Estimated Underground Hydrogen Storage capacity in depleted reservoirs.

Location	State	Estimated storage capacity	
		(PJ-H2)	(kt-H2)
Perth	WA	205	1,667
North Carnarvon	WA	23,710	193,194
Northwest Shelf	WA	5,507	44,875
Amadeus	NT	131	1,055
Eromanga	SA/QLD	2,806	22,860
Bowen-Surat	QLD	316	2,573
Gippsland	VIC	4,837	39,660
Otway	VIC	484	4,001
Total		**37,996**	**~309,885**

Abandoned underground mines are another potential storage site, although the technology currently has a lower technology readiness level (TRL). There are many underground mines in Central VIC, QLD and WA but this kind of storage is still under development and faces several technical challenges. It has therefore not been considered for NZAu.

Table 41 gives the capital cost of different types of storage which includes the associated compressors, tanks and infrastructure.[18] This data is taken from a recently completed Argonne National Laboratory study on the technical and economic aspects of bulk hydrogen storage.[19] For NZAu only the costs associated with engineered caverns has been considered as the data on the location and viability of natural salt cavern formation is too uncertain at the time of this study.

Table 41 | Cost of hydrogen storage.

Technology		Natural Salt Caverns	Engineered Underground Caverns
Pressure	(bar)	120	150
H_2 stored per cavern [19]	(tonnes)	6000	500
Capital cost (note 1)	(AU$/kW H2 delivered)	70	70
	(AU$/kWh H2 stored)	1.25	2.6

Note 1: Plant lifetime 40 years.

10.4.6 Ammonia production, terminal storage and shipping

Ammonia is a potential hydrogen carrier and is included in NZAu as the preferred hydrogen carrier for export due to the current commercial status and maturity of the supply-chain relative to other potential carriers like liquid hydrogen (see Section 10.4.7). A large-scale, single train ammonia plant currently has a production rate up to 3300 tpd and capacities up to 4700 tpd have been investigated.[20] A modern, optimised and highly efficient Haber-Bosch process using natural gas as the feedstock produces about 1.22 t-CO_2/t-NH_3.[21] For the NZAu study, we chose a production capacity of 5000 tpd or 1734 kt-NH_3/year ammonia for a single plant. This necessitates estimating the relative cost of conversion rather than traditional integrated H_2 to NH_3 production facilities. To conduct this estimation, we broke down the cost of production for both blue and green ammonia based on available literature and commercial feasibility studies. To note, the conversion of H_2 to ammonia only happens at export locations in the RIO model.

The H21 North of England project[11] conducted an extensive assessment on ammonia production cost using autothermal reforming with carbon capture (ATR+CC) for hydrogen production. The estimated cost for a 5000 tpd ammonia production capacity is £MM1717 (or AU$ 3198 million using currency exchange rate of 0.573£ for AU$). Therefore, the capex of $1.84/kg-$NH_3$ can be estimated for a large-scale blue ammonia plant. Table 42 also provides the estimated cost breakdown of a green ammonia plant based on a 2019 feasibility study for the Queensland Nitrate Pty Ltd (QNP) Green Ammonia project.[22] That design produced 20 kt-NH_3/year of green ammonia through the Haber-Bosch process using green hydrogen.

Table 42 | Cost of green ammonia plant – reference, 20 tpd.

Major units	AU$MM	Breakdown
Electrolysers	47.7	29.2%
Hydrogen Storage	24.95	15.3%
Ammonia	55.7	34.1%
High voltage	18.535	11.4%
Balance of plant	16.35	10.0%
Total	163.23	100%

Based on this, we estimated the CAPEX for the 5000 tpd ammonia synthesis (i.e., excluding hydrogen production costs, but including air separation costs) plant at AU$1520 million. We used a scale-up factor of 0.7[12] and the AU$ 55.7 million for plant capital from Table 42. This also includes an additional 10% for balance of plant and an extra 10% for process contingency to account for the significant uncertainty in CAPEX for standalone ammonia plants using a green hydrogen feedstock. The energy demand of the Haber Bosch plant (primarily air separation and compressors) was estimated from previous literature reports.[23, 24] Table 43 then reports the cost and energy demand of the 5000 tpd plant used in NZAu.

Table 43 | Cost and energy demand of ammonia plant – reference, 5,000 tpd.

Item	Units	Updated data
CAPEX	$/t-$NH_3$/year	876
OPEX (4% of CAPEX)	$/t-$NH_3$	35
Air separation unit	kWh/kg-NH_3	0.11
Ammonia Synthesis plant (Note 1)	kWh/kg NH_3	0.42

Note 1: Including main compressor up to 140 bar, refrigeration & recycle compressors.

Table 44 gives the additional costs associated with ammonia export, namely storage (100k tonnes for 20 days storage) and the export terminal facilities themselves (scaled down using an exponent of 0.67[22,12] to accommodate a 105,000 m^3 ship on a 46 day round trip schedule – Table 45).

Table 44 | Costs associated with ammonia export terminal.

Component	Capacity		CAPEX (Note 1, 2, 3)			OPEX (Note 4)	
	Storage	Per year	Given	AU$MM 2020	AU$/GJ/year	2020AU$MM /year	AU$/GJ
Storage	100 kt 20 days	1734 kt/year (Note 5)	£MM 113 (2018)	207	5.3	4.15	0.11
Terminal	NA	1734 kt/year (Note 5)	EUR 2.3 (2019)	3.5	0.09	0.07	0.0018

Table Notes:

1. £= 1.87 AU$ & 1 EUR = 1.57 AU$
2. CECPI 2018-603.7 2019-607.5, 2020-593.6
3. HHV of ammonia =22.5 MJ/kg
4. 2% capex
5. 95% operation per year, kta (1000 tonnes per year)

Table 45 | Costs associated with ammonia shipping.

Capacity ($Mt-NH_3$/year)	CAPEX			OPEX		
	Given	2020 AU$MM	AU$/GJ/year	Given	2020 AU$MM/year	AU$/GJ
0.548 (1x 55kt ship)[30]	2020 US$MM 106.7	146.2	11.86	2020 US$M 7.96 /year	10.9	0.88
0.880 (2x 55kt ship)[32]	2019 US$MM 140	189.0	9.55	Not given	N/A	N/A
0.600 (3x 25kt ship)[30]	2019 US$MM 156	210.63	15.60	Not given	N/A	N/A

Table Notes:

1. 0.62 EUR = 1 AU$
2. 0.73 USD = 1 AU$

10.4.7 Potential alternative hydrogen carriers for energy export

Finally, we note that blue or green hydrogen can be exported in several forms, with liquified hydrogen (LH_2) export arguably the most prospective alternative to ammonia. There are now several studies of the costs of large-scale hydrogen liquefaction[9,29,30,32,14] and seaborne transport.[34,35,36] Comparison of these studies with those of large-scale ammonia production and export suggest that both are prospective hydrogen carriers, where the uncertainty of each supply chain's economic and technical performance is comparable to and likely greater than the observed differences between the two hydrogen carriers in these studies.

The NZAu Project has therefore chosen to model ammonia export only and will revisit this decision should further information come to light during the Project. In doing so, we emphasise that this isn't an endorsement of one hydrogen carrier over others. Indeed, it may turn out that several hydrogen carriers are prospective given emerging customer preferences, technology learning and numerous other factors.

10.4.8 Synthesised fuels

Performance and cost estimates for the technologies found in the RIO model for converting biomass, natural gas, or electricity to liquid or gaseous hydrocarbon fuels are presented in Table 46. These estimates are based on publicly available studies of N^{th} of a kind plant designs. Recognising that there are considerable uncertainties in future performance and cost estimates, we assume that the estimated N^{th} plant estimates remain at their initial values for the entire transition period: no performance improvements or cost reductions are assumed to occur.

Table 46 | Inputs, costs and emissions data for synthetic green fuels. Parameters are provided per unit of liquid fuel output.

Technology	Inputs, all HHV basis (GJ /GJ-liqfuel)	CO_2 captured or input (Note 1) (kg-CO_2 /GJ-liqfuel,HHV)	Installed capital cost (Note 2) (2020 AU$ /kW-liqfuel,HHV	Fixed O&M (Note 2) (2020 AU$ /kW-liqfuel,HHV /yr)	Variable O&M (Note 2) (2020 AU$ /GJ-liqfuel,HHV)
BioFT	1.96 (biomass) 0.052 (electricity	0	6,120	203	10
BioFT +CC	2.15 (biomass) 0.114 (electricity)	−82	6,370	206	11
Pyrolysis (BioPyr)	1.54 (biomass)	0	3,855	115	7.5
BioPyr +CC	1.54 (biomass)	−74	6,178	185	7.5
RWGS-FTS	1.54 (H2)	68	1,382	50	0.6

Table Notes

1. Negative values indicate CO_2 captured. Positive values indicate CO_2 input.
2. All costs are expressed in 2021 AU$. To convert costs to 2020 AU$ from other dollar years in the original literature sources, the Chemical Engineering Plant Cost Index, GDP deflator, or other indices were applied.

Parameters for biomass to liquid fuels using Fischer Tropsch (i.e. BioFT) technologies are based on[34], which reports the following for a facility converting woody wastes to FTL:

- FTL output capacity of 290 MW FTL_{LHV}
- biomass input capacity of 600 MW_{LHV}.

Additionally, for BioFT and BioFT+CC, respectively:

- total installed capital cost in 2017 € of 1200 MM $€_{2017}$ and 1222 MM $€_{2017}$;
- fixed O&M costs (assuming 8,000 hours/year operation) of 6.9 $€_{2017}/GJ_{FTL,LHV}$ and 7 $€_{2017}/GJ_{FTL,LHV}$; and
- variable O&M costs of 4.9 $€_{2017}/GJ_{FTL,LHV}$ and 6.1 $€_{2017}/GJ_{FTL,LHV}$.

For BioFT+CC, approximately 70% of the carbon input as biomass is not converted to FTL and is assumed to be captured. Also, HHV:LHV ratios were used to express biomass and FTL quantities on a HHV basis, and an exchange rate of 1.1 $/€ (average for 2017) was assumed.

Parameters for pyrolysis processes (BioPyr and BioPyr+CC) are based on two configurations of a catalytic hydropyrolysis technology described in.[38] One configuration has no CO_2 capture (BioPyr) and the other has maximum CO_2 capture (BioPyr+CC). Each has a biomass input rate of 687 MW_{LHV} and liquid fuels output rate of 446 MW_{LHV}. Electricity is co-produced in each case: 55 MW_{el} and 13 MW_{el}, respectively, without and with carbon capture. Annual fixed O&M is 4% of the installed capital cost. The variable O&M cost is the sum of catalyst cost (4.87 $US\$_{2014}$/t-biomass) and refining cost (4.51 $US\$_{2014}/GJ_{FTL,LHV}$). Ratios of HHV to LHV were used as needed to convert to HHV amounts. Estimated installed capital costs are 1224 M US$$_{2014}$ and 1990 M US$$_{2014}$ respectively, for the designs without and with CO_2 capture. For the design with CO_2 capture, 94% of the biomass carbon not contained in the liquid fuels is captured.

Reverse water-gas shift (RWGS) followed by Fischer-Tropsch synthesis (FTS) to convert input H_2 and CO_2 into refined synthetic diesel, jet fuel and LPG utilised the following calculations to estimate the H_2 input required per unit of FTL output:

- FTS, which synthesises liquids from H_2 and CO, requires a fresh syngas feed of 2 moles of H_2 for each mole of CO
- A "once-through" FT synthesis configuration, *i.e.*, with no internal recycle of unconverted syngas or reformed light-ends, will produce 76.2 MJ/s (LHV) of liquid fuels from a fresh syngas feed containing 0.79 kg/s of H_2 (0.395 kmol/s) and 5.49 kg/s of CO (0.196 kmol/s)[39]
- With internal recycle, the liquid fuels output increases 43% for the same syngas input. Thus, the H_2 flow in the input syngas corresponds to 0.79 kg/s * 142 MJ_{HHV}/kg-H_2 = 112 $MJ_{H2,HHV}$/s, or 112 / (76.2*1.43*1.05) = 0.98 MJ_{HHV} of H_2 per MJ_{HHV} of FT fuels (using HHV:LHV for FT fuels)
- Additional H_2 input is needed for the RWGS used to produce CO from CO_2. RWGS requires 1 kmol of H_2 to produce 1 kmol of CO ($H_2 + CO_2 \rightarrow CO + H_2O$), so the overall H_2 requirement for the RWGS-FTS process is 3 kmol of H_2 for each kmol of CO_2
- Thus, the total H_2 required is: (3/2)*0.98 = 1.47 $MJ_{H2,HHV}/MJ_{HHV,FTL}$.

The installed capital cost includes FT synthesis + refining and light ends processing, and a balance-of-plant cost estimated as the sum of line items GT, HRSC and BOP multiplied by the fraction of syngas converted to liquids in the RC-B design.[39] No explicit cost is included for the RWGS process, because the RC-B design includes the cost for a water gas shift reactor. This results in an estimated total capital cost for the RWGS-FTS process of 244 MM US$$_{2015}$, which converts to the unit capital cost estimate shown here in Table 46. Fixed and variable O&M costs for the RWGS-FTS process is based on De Vita *et al.* [13] In our modelling, fixed O&M costs are assumed to decrease over time, reaching the value shown here by 2050. To maintain more realistic and consistent capacity factors over a least-cost optimized net zero transition, we have allowed clean FTL to compete with other clean energy export carriers in all net-zero scenarios.

10.4.9 Liquified Natural Gas

The majority of Australia's natural gas developments (either conventional or coal seam gas) are tied to liquefaction projects with export contracts in place to support the strong natural gas demand in Asia. Conventional natural gas is largely produced in the offshore Carnarvon Basin in north-western Australia, and the Bonaparte Basin in northern Australia. There are also fields in the Cooper Basin in central Australia and the Gippsland Basin in south-eastern Victoria, although these (especially Gippsland) are declining and forecast to be depleted by the mid-2030s.[40] Australia's main source for coal bed methane is Queensland with over 25% of total natural gas production in 2019-20.[41] Natural gas production grew by 8 per cent in 2019–20, underpinned by increased production in the northwest for export as LNG with a growth rate of 6%.[42] Western Australia and Queensland are the main LNG producers.

LNG production accounts for 44.3% of total energy consumption in the mining sector in 2019-20 and for over one-quarter of Australia's gas consumption. The energy efficiency and breakdown of energy use for each facility, was estimated using the published Environmental Impact Statements for individual projects.[43-50] Table 47 shows a summary of the plant efficiency for LNG production using coal seam gas as the feedstock.

Table 47 | Energy efficiency for LNG production (incl LNG plant and upstream gas fields[43-46]) from coal seam gas.

CSG (QLD)	Capacity (Mtpa)	LNG plant efficiency	Upstream plant efficiency
GLNG	7.8	90.0%	87.3%
QCLNG	8.5	91.0%	87.3%
APLNG	9	91.0%	87.6%
Average	8.43	90.7%	87.4%

The actual efficiencies reported in Table 47 are based on existing plant operations in Australia; however, there are several potential ways to improve the power efficiency, including electrification of plant, using high efficiency plant, employing waste heat recovery and operating at or less than nominal capacity.[47] NZAu uses these high efficiency scenarios. Table 48 summarises the energy breakdown for an LNG plant and the associated upstream facilities under actual and high efficiency scenarios.

The total power demand of 0.368 kWh/kg of LNG is estimated by considering high power efficiency of gas turbine of 33% in the LNG plant and 25% in the gas field.[46] The heat load in an LNG plant is associated with removal of CO_2 from the incoming gas. For coal seam gas, the CO_2 content is typically 0.19 mol%[44] and NZAu has estimated the required heat load to remove CO_2 based on 3 GJ heat per tonne of CO_2 for amine technology.[47] Upstream of the LNG facility, the coal seam gas field is divided to extraction operations and gas processing plants. Extraction operations include wellhead facilities and compressors to deliver gas to the processing plant. Gas processing includes water separation, dehydration (which has both heat and electricity loads) and compression units. The reported electricity consumption for transferring gas from the gas field to the LNG plant (i.e. both extraction and processing) is ~5.7 MWh-e/TJ.[43-46,48] Using available data from Arrow Energy's gas expansion project in the Surat Basin, this power was split 37% for extraction and 63% for processing.[48] NZAu assumes the required heat for dehydration units within the gas processing plants are provided through the waste heat recovery, with the ratio of 40/60 between heat/electricity.

Table 48 | Energy breakdown of LNG production from coal seam gas, for plant capacity of 8.5 Mtpa.[47,48]

Energy Type		Extraction		Processing		LNG plant	
		High eff	Actual	High eff	Actual	High eff	Actual
Electricity	MWhe/tLNG	0.156	0.177	0.268	0.305	0.368	0.471
	MWe	162.58	184.75	280.00	318.18	383.96	490.91
Heat	MWth/tLNG			0.25		0.012	
	MWth			260.33		10.734	

The energy breakdown of LNG production from conventional gas fields was estimated using the Ichthys and Gorgon LNG operations and are summarised Table 49.

Table 49 | Energy breakdown of LNG production (including LNG plant and upstream facilities) from conventional gas.[49,50]

	Ichthys (Inpex)	Gorgon+CCS
Statistics		
Production (Mtpa)	8.4	15.6
Reservoir CO_2	0.29 t-CO_2/t-LNG	0.48 t-CO_2/t-LNG (Note 1)
Captured 85% (assumed)	0.243 t-CO_2/t-LNG	0.408 t-CO_2/t-LNG
Energy consumption		
Offshore/Extraction Energy	312 MW-e power 60 MW-th heat	580 MW-e power 586.7 MW-th heat (Note 2)
Process-onshore energy	220 MW-e power 120 MW-th heat	
LNG energy	280 MW-e power	480 MW-e power
Total energy	812 MW-e power 180 MW-th heat	1060 MW-e power 586.7 MW-th heat
Summary (used for NZAu)		
Extraction + process plant	0.597 MWh-e/t-LNG 0.202 MWh-th/t-LNG	0.35 MWh-e/t-LNG 0.354 MWh-th/t-LNG
LNG	0.314 MWh-e/t-LNG	0.29 MWh-e/t-LNG
Total	**0.911 MWh-e/t-LNG** **0.202 MWh-th/t-LNG**	**0.64 MWh-e/t-LNG** **0.354 MWh-th/t-LNG**

Table Notes:

1. Assumed based on 14 mol% CO_2 in the gas reservoir
2. The gas turbines in LNG trains were integrated with waste heat recovery systems; therefore, the heat load was estimated using a 55/45 ratio between heat and power.[50]

In addition to the electrification of LNG plants, we have given the model the option to retire LNG plants at the end of their projected lifetime and repurpose LNG sites to host ammonia production facilities having a similar energy export capacity. The substitution development of ammonia production facilities at repurposed LNG sites is assumed to attract a 20% discount on the capex costs of new greenfield ammonia production facilities due to the likely availability of permits and environmental monitoring records and reuse of existing useful services and infrastructure.

10.4.10 Capex of LNG facilities (including upstream)

There are many factors that influence the capital expenditure of LNG production facilities (including both upstream and the LNG plant itself), including: feedstock composition, project complexity, location, scale of plant and the degree of modularization.[51] Table 50 provides a list of existing LNG plants in Australia with their associated capital costs broken down into the extraction and processing facilities, and the LNG plants themselves. LNG facilities account for 45% to 60% of total project cost (extraction, processing and liquefaction) and these rose $300 to $1200/tpa from 2000 to 2013; twice the rate of upstream facilities over the same time period.[51] NZAu adopts an average of these figures (scaled for industrial inflation and currency) as shown in Table 51.

Table 50 | Cost breakdown of existing LNG facilities (including upstream facilities).[54]

Plant Name	Train	Nominal Capacity	Total cost	Extraction + Processing	LNG plant (2014)		
		Total-Mtpa	Total US$B	$US/t LNG	US$B	%LNG	$US/t LNG
Gorgon-trains 1&2	2	15.6	53	1288.5	32.9	62.1%	2109.0
Gorgon-train 3	1						
Gladstone-GLNG	2	7.8	19	1141.	10.1	53.2%	1294.9
QCLNG	2	8.5	20	941.2	12	60.0%	1411.8
APLNG	2	9	26	1588.9	11.7	45.0%	1300.0
Ichthys	2	8.4	36	2357.1	16.2	45.0%	1928.6
Wheatstone	2	8.9	34	1831.5	17.7	52.1%	1988.8
Prelude Floating LNG	1	3.5	12	1371.4	7.2	60.0%	2057.1

Table 51 | Cost breakdown of LNG facilities (including upstream facilities) used in NZAu.

Feedstock / Plant Name	Trains	Nominal Capacity (Mtpa)	Extraction + Processing (AU$/kW)	LNG plant (AU$/kW)
Coal seam gas	3	21	1218	1632
Conventional gas (incl CCS for extraction and processing)	3	21	614	1632
Existing LNG Plant retrofit for electrification	NA	NA	NA	100

10.4.11 Operating cost of LNG facilities

The operating cost of upstream operations and LNG facilities were estimated from existing gas fields and operating plants [43-45, 48-50] and are summarised in Table 52.

Table 52 | Operating Cost of LNG Plant.[43-45, 48-50]

Plant		Fixed costs
Labour (Note 1)	**LNG Plant**	4.05 AU$/t-LNG (one train) 2.87 AU$/t-LNG (two trains) 2.48 AU$/t-LNG (three trains) 3.13 AU$/t-LNG(average)
	Gas field	11.57 AU$/t-LNG (coal seam gas) 1.96 AU$/t-LNG (conventional gas)
Material for maintenance		1.5% of total project cost (TPC)
Variable - Others		0.2% of TPC
Tax and insurance		Not included

Note 1: Salary; Technician AU$100k, Operator AU$130k, Admin AU$80k. Note: the number of operators in the coal seam gas field are order of magnitude higher than a conventional gas field.

10.4.12 Cement industry

Australia's demand for cement was more than 11.3 Mtpa in 2019.[52] Of that 0.9 Mtpa was imported as cement, 4.1 Mtpa was imported as clinker and 5.6 Mtpa of clinker was produced in Australia. Table 53 provides a summary of the existing facilities in Australia, including plant location and clinker production capacity. With the existing fleet, Australia could produce up to ~6.2 Mtpa of clinker.

Table 53 | Cement production plants.[52]

Plant name (Note 1, 2)	Company	NZAu region	Build year	Closure year	Fuel type	Clinker capacity (design-Mtpa)
Railton	Cement Australia Pty Ltd	TAS	1923		Coal	1.1
Waurn Ponds	Boral	VIC-west	1970		Gas	0.5
Birkenhead	ADBRI	SA	1913		Gas	1.3
Angaston	ADBRI	SA	1952		Gas	0.25
Munster	ADBRI	WA-south	1997		Gas/Coal	0.57
Kandos	Cement Australia Pty Ltd	NSW-central	1914	2011	Coal	0.45
Berrima	Boral	NSW-central	1929		Coal	1.56
Maldon	Boral	NSW-central	1951	2014	Coal	0.3
Gladstone	Cement Australia Pty Ltd	QLD-south	1998		Coal	1.6
Rockhampton	Cement Australia Pty Ltd	QLD-north	1960	2009	Coal	0.14

Table notes:

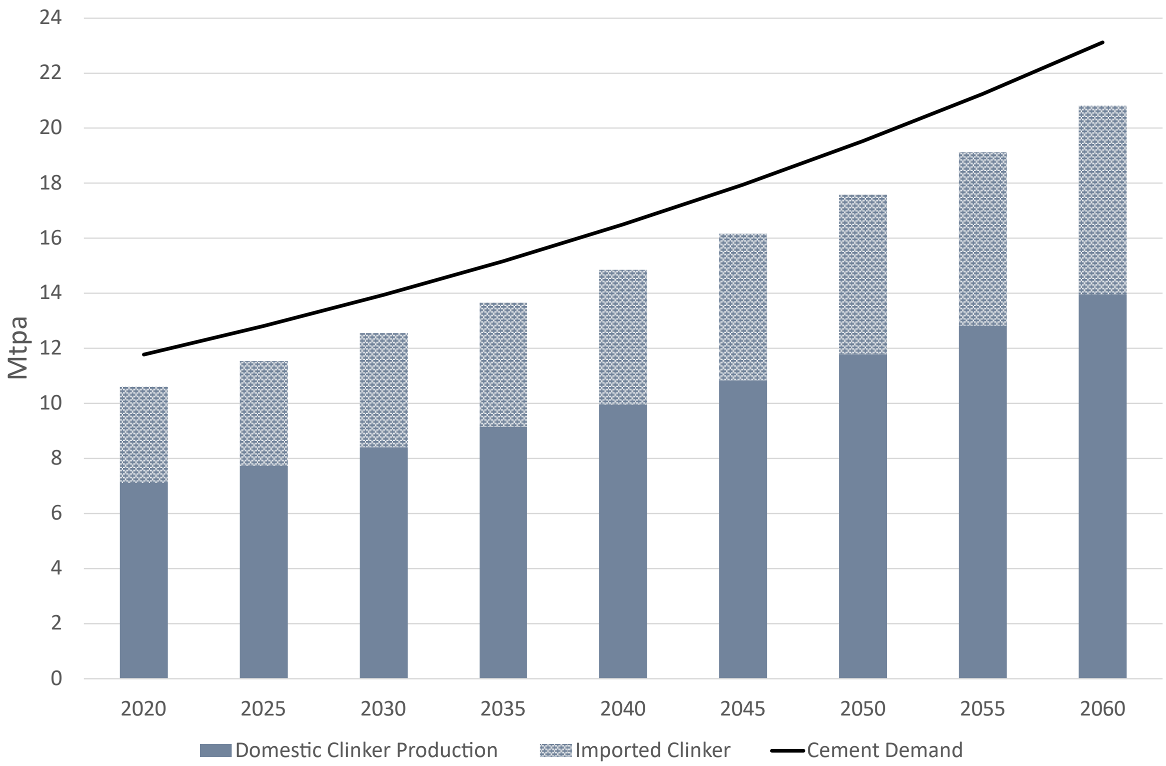
1. There are five integrated manufacturing facilities in Australia operated by CIF member companies – Adelaide Brighton (ADBRI), Boral Cement and Cement Australia.
2. Closed facilities are not included in the RIO model but are listed as potential brown field sites for expansion under downscaling

10.4.13 CO_2 emissions from the cement industry and emission reduction plan

In Australia over 97% of clinker production is fuelled by coal and gas with total emission intensity of 975 kg-CO_2/t-clinker where 55% is associated with process emissions (CO_2 released from calcination of limestone), 26% is associated with heat provision, 12% from electricity and 7% from transportation of materials.[53] Various decarbonisation methods comprising cleaner fuels, improvement of process efficiency and increasing the use of supplementary cementitious materials are currently discussed in various decarbonisation roadmaps.[54,55] However, integration with carbon capture, utilisation and storage technologies is necessary to reach to a net-zero emission target. To achieve the net zero target within NZAu, we consider upgrades to, or retirement and rebuild of, existing plants to the newest technologies with 90% of these emissions captured and stored via CCS.

In order to meet growing demand for cement in the NZAu scenarios, we kept the ratio of domestic clinker production and imported clinker constant out to 2060. The required growth in production capacity was therefore estimated using a growth rate of 1.7% between 2020-2050. This was based on the decadal average from 2010-2020.[52] Figure 72 shows the projection of cement demand up to 2050. The demand increases around 67% with a similar growth rate demand for domestic clinker production and import. The energy demand is predicted to proportionally increase. The ABS energy data[56] was used to estimate the current and future energy consumption of energy in the cement; lime; plaster and concrete sector.

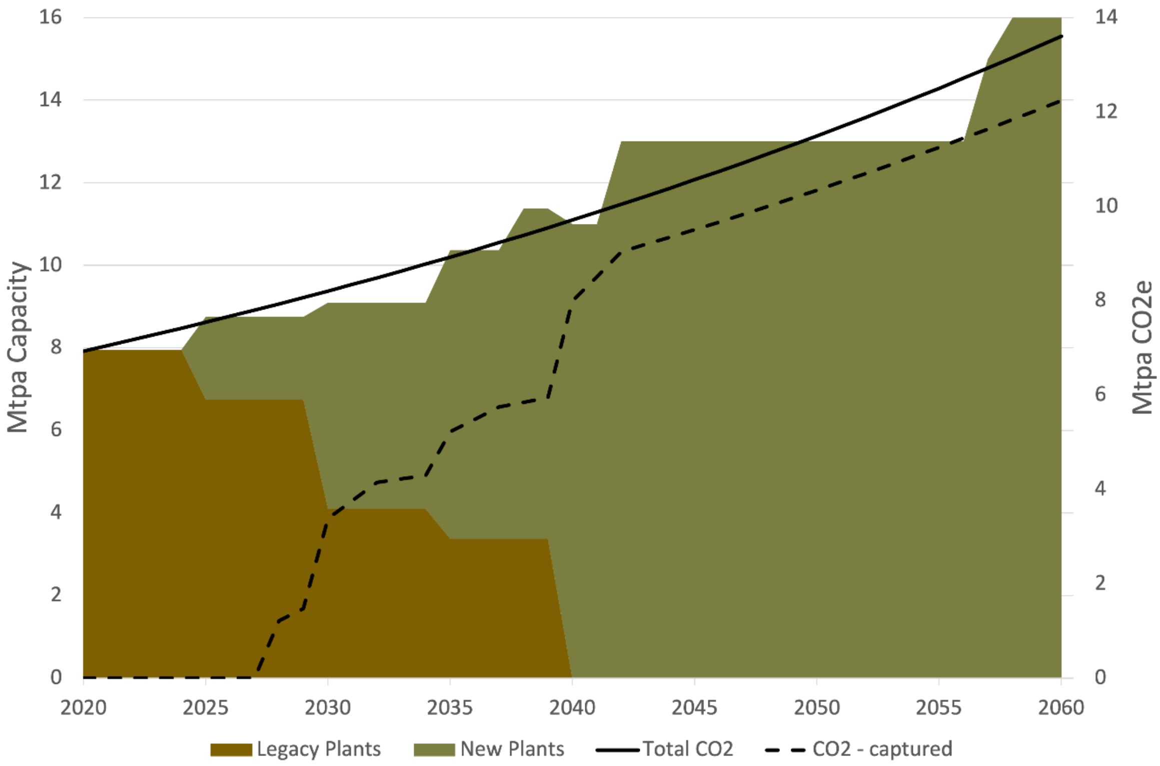
Figure 72 | Projection of production and import of Clinker, together with Cement demand.[52]



In line with *Net Zero America*[57], it is assumed that the transformation of the industry begins after 2025, allowing a lead time for industry stakeholder engagement, the conduct of feasibility studies, permitting, and investment decisions to be made in advance of the first plant construction. The industry commissions its first state-of-the-art kiln/plant with integrated CCS to be operated from 2025. The retirement plan and replacement with new plant is scheduled as follows:

- Retirement of the oldest plant happens in 2025 when the first new integrated plant is commissioned, and retirements of existing plant extend out to 2040, at which time all legacy plants have been retired or upgraded
- Plants are retired from oldest to largest and follow the retirement schedule outlined in Figure 73. Carbon capture and storage is integrated in the same order as plant replacement
- Plants located in NSW are retired permanently and replaced with upgraded capacity in TAS, VIC-west and QLD-south. These plants are closer to CO_2 storage reservoirs and/or CO_2 transport pipelines
- Plants located in WA-south are retired permanently and the required capacity is provided by upgraded SA facilities
- CO_2 capture rate is 90% (ramping linearly from 65% over the first 3 years of operation).

Figure 73 | Capacity of new integrated cement plant vs old plant.



For NZAu we assumed new cement plants (integrated with CCS) have a clinker production capacity of 3.75 Mtpa (operating with a 90% capacity factor).[57] We assume a clinker to cement ratio of 90%. The total installed capital and operating costs for a new cement plant with CCS are given in Table 54.

Table 54 | Capital and Operating Cost of new cement plant integrated with CCS.

Total installed capital cost	1300 AU$/tpa
Variable operating cost (excluding fuel)	26 AU$/tpa [58]
Fixed operating costs	65 AU$/tpa [58]

10.4.14 Iron and steel industry

The steel industry is a significant contributor to greenhouse gas emissions, with an estimated 7-9% of global carbon dioxide emissions attributed to the steel industry, with an emissions intensity of 1.4 t-CO_2 per tonne of steel in direct emissions or 1.85-2.15 t-CO_2 per tonne of steel when indirect emissions are included.[59, 60] Current domestic production of steel is ~5.7 Mtpa [61] at two locations: Bluescope Steel at Port Kembla (NSW-north region) has an annual capacity of ~3 Mtpa, largely meeting domestic demand and exporting ~0.8 Mtpa to overseas markets. Arrium (previously known as OneSteel) at Whyalla (SA region) produces ~2.6 million tonnes for the domestic market [62]. Both steelworks use primary production methods to produce steel (i.e. the blast furnace-basic oxygen furnace route) with only small amounts of scrap used.

Primary production of steel sees iron ore and coke fed into the top of a blast furnace (BF) while hot air and pulverised coal (sometimes natural gas or hydrogen) are injected into the lower part of the furnace. The reducing atmosphere converts iron ore into molten iron (called pig iron) and the coke, pulverised coal and natural gas are converted into CO_2. Typically, 1 tonne of pig iron requires 1.6 tonnes of iron ore and 0.45 tonne of coke. The molten iron is then fed into a basic oxygen furnace where oxygen is injected to reduce the carbon content of the steel and alloying elements are added to produce steels of various grades. To produce one tonne of pig iron, a blast furnace will typically consume 1.66 tonnes of iron ore.[55,60] Whilst the

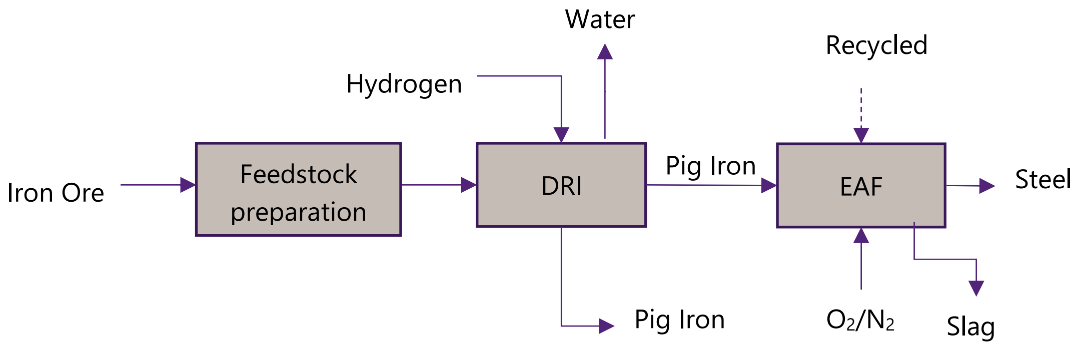
BF process is the most well-known and commonly used technology; there are more than 100 commercial direct reduction iron (DRI) production plants operating, producing around 105 Mtpa;[63] using shaft furnaces manufactured by Midrex and Energiron and typically using natural gas or syngas to generate the reducing atmosphere.

The only commercially demonstrated DRI process with the ability to produce iron without the use of fossil fuels was the Circored process in Trinidad between 1999 and 2006.[64] This process involved multistage reduction of iron ore fines (<1 mm) with pure H_2 in a series of fluidised beds. Several smaller demonstration projects exist to further develop pure H_2 reduction of iron ore, including: Midrex H_2 (at the lab scale), HYBRIT (Hydrogen Breakthrough Ironmaking Technology) and HYFOR (Hydrogen-based Fine-Ore Reduction) at the pilot scale.[65-67] Only the Circored process is considered at the appropriate TRL for NZAu. DRI can be combined with basic-oxygen furnaces (BOF), open-hearth furnaces (OHF) or electric-arc furnaces (EAF) for converting the DRI pig iron to raw steel.

10.4.15 CO2 emission reduction technologies for the steel industry

The IEA Iron and Steel Tracking report[59] highlights the need for rapid expansion of scrap based, hydrogen based and CCUS-based production technologies to meet global net zero emissions ambitions. Other aspects of the iron and steel roadmap include improving material efficiency in steel end-users and process efficiency improvements for existing manufacturers. NZAu adopts the pathway outlined in *Net Zero America*[68] for steel production via a hydrogen based DRI-EAF route (Figure 74), as the most commercially mature pathway for decarbonising steel production in Australia.

Figure 74 | Circored to EAF process used as the basis for new future DRI and EAF facilities in our iron and steel industry.



We assume the production of steel remains constant from 2020 levels out to 2060 in all scenarios. In the E+ONS onshoring scenario we assume that Australia's iron ore exports will be progressively transformed into pig iron domestically using hydrogen and the DRI process. CCS will not be employed in the steel industry in NZAu, nor will scrap-based methods (increased use of scrap steel and EAF technology) be considered due to the relatively small amount of scrap steel available in Australia for recycling. For all scenarios, it is assumed that existing plant will be retired/upgraded to the DRI-EAF production route (in the same location) to accommodate domestic demand.

The Circored DRI process[64] as originally demonstrated used natural gas and electricity as inputs. For future DRI facilities in NZAu, it is assumed that the natural gas for heat provision is replaced by an energy-equivalent amount of hydrogen. Table 55 provides the assumptions on energy demand and capital costs for the DRI process, while Table 56 provides the energy consumption and the capital cost for the EAF technology.

Table 55 | DRI technology model assumptions including energy demand, capital and operating costs.

DRI characteristics	Existing 2020→ 2050 (Note 1)	Future 2020→ 2050
Iron ore to pig iron ratio (moist iron ore)	1.61	1.61
Electricity demand (million Btu/metric t)	1.3 → 2.0	0.44 [71]
Natural gas demand (million Btu-HHV/metric t)	0.8 → 2.1	0
Steam coal demand (million Btu-HHV/metric t)	0.1→0.5	0
Coking coal demand (million Btu-HHV/metric t)	10→0.2	0
Hydrogen demand (million Btu-HHV/metric t)	0	13.36 [71]
Maximum capacity factor (Note 2)	85	85
Annual electricity efficiency improvement	0.98%	0.98%
Overnight installed capital cost, $ per metric t/y (2021 AU$)	580 (Note 3)	1070 (Note 4)

Table notes:

1. As indicated by AEO[69, 72 ,73], unless otherwise noted. AEO projections include a notable transition over time in fuel inputs to existing DRI facilities, with coal and coke-based technology retired in the 2030's and replaced by natural gas and electricity as the main energy inputs. See[69] for year-by-year details starting from 2015. Existing refers to transition of current iron plants, future refers to newly built plants.
2. We assume existing and future DRI facilities operate at up to 85% capacity utilization.
3. Average of two recent DRI plants built in the US.[74-76]
4. The cost of future DRI technology is our guesstimate. We expect it to be higher than the costs of a recently completed 1.9 Mtpa plant in the Great Lakes region of the U.S. The final cost of the plant was projected in 2017 to be US$526 per metric t/y.[77] In 2019, a final cost of US$437 per metric t/y was projected, excluding construction contingencies.[78]

Table 56 | EAF technology model assumptions including energy demand, capital and operating costs.

EAF characteristics	Existing 2020→ 2050 (Note 1)	Future 2020→ 2050
Feedstock to product ratio	1.0	
Electricity demand (million Btu/metric t raw steel output)	1.1 – 1.2	2.0 [71]
Natural gas demand (million Btu-HHV/metric t)	0.4	0.8 [71]
Coal (charge carbon) demand (million Btu-HHV/metric t) for 1% carbon steel	0 (Note 2)	0.495 [71] (Note 3)
Average loss of input materials in EAF process (%) (Note 4)	5	5
Maximum capacity factor (%) (Note 5)	90	90
Annual Coal efficiency improvement	1.23%	1.23%
Annual electricity efficiency improvement	0.98%	0.98%
Overnight installed capital cost, $ per metric t/y of output (2021 AU$)	670	670 [69]

Table notes:

1. As indicated by AEO,[69,70,73] unless otherwise noted. Existing refers to transition of current steel plants, future refers to newly built plants.
2. AEO,[69,70,73] does not specify a value for charge carbon input in its EAF model.
3. Half of amount used in Otto et al.[71] to achieve 2% carbon in steel from a 100% DRI charge.
4. AEO,[69,70,73] does not explicitly specify a value for losses. Losses for new, state-of-the-art EAFs are reported to be 5%,[70, 71] and we assume this value for all EAFs.
5. We assume existing and future EAFs operate at up to 90% capacity utilization.

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10.5 Direct air capture

Estimates for direct air capture cost and performance are based on estimates for a Nth of a kind (NOAK), 1 Mt-CO_2/year plant.[1] The configuration runs in a continuous process using an aqueous potassium hydroxide sorbent coupled to a calcium caustic recovery loop. The recovery loop requires heat energy input to desorb the CO_2. We considered that after the recovery loop the CO_2 is compressed to 150 bar for transmission. For context, a capital recovery factor of 10% and plant utilisation of 90% yields a levelised carbon capture cost of:

- US$102/tonne with a natural gas fired calciner (i.e., providing the heat input for the recovery loop) not including the cost of energy inputs, and
- US$175/tonne with a resistive heating calciner (i.e., proving the heat input for the recovery loop) assuming an electricity cost of $40/MWh.

To avoid having to capture the emissions from a natural gas fired calciner and remain consistent with the Net Zero ambitions, we assumed a resistive heating approach. Hence, electricity is assumed to be the only energy input to the process and all recharging of the sorbent is done with resistive heating. This modification leads to minor changes on the CAPEX and OPEX compared with those initially was estimated by Keith et al.[1] We assumed the efficiency of an all-electric calciner is the same as a NG-fired calciner.[2] The input parameters are shown in Table 57. Table 58 shows the projection of costs for NOAK plant from 2032 with 0.5% reduction per year.

Table 57 | Cost and performance parameters for direct air capture systems.

Parameter	Unit	FOAK (up to 2032)	NOAK (from 2032)
Capital Cost	2016 US$ / (t-CO_2 / year)	935	647
Fixed O&M	2016 US$ / (t-CO_2 / year)		15.4
Variable O&M	2016 US$ / t-CO_2		8
Electricity input*	kWh-e/t-CO_2, 15 MPa	1660	1660
Plant Lifetime	Years	30	30

*Electricity input for base case outlined in Keith et al.[1] this is adjusted below for the local climatic conditions

Table 58 | Cost projections for direct air capture from 2032-2060 (2020 AU$).

Year	CAPEX (AU$/ (t-$CO_2$/year))	O&M (AU$/t-$CO_2$)
2032	1000.8	36.2
2035	985.9	35.3
2040	961.5	34.4
2045	937.7	33.6
2050	914.4	32.8
2055	891.8	31.9
2060	869.9	31.2

The performance of solvent based capture system is influenced by the local climatic conditions.[3] DAC siting considerations are discussed more fully in the Downscaling report; however, briefly DAC sites were chosen to be close to the storage basins to minimise CO_2 transport between regions. CO_2 capture rate, water loss (the amount of water lost to the exhaust air stream in the CO_2 contactor) and energy intensity of the DAC process modelled in NZAu were adjusted for the local climate conditions (air temperature and relative humidity) of the CO_2 basins described in Section 9.5. Specifically, data from An et al., was used to generate functions for CO_2 capture and water loss based on temperature and humidity inputs. Surfaces of best fit were established using the 'cubicinterp' function in MATLAB. The energy intensity of the process was established as a function of CO_2 capture rate using a power law where:

$$E = c + aX^b$$

Where E = energy intensity, X = capture rate; and a, b, c are constants based on the curve fitting.

The resulting functions were used to calculate expected energy intensity (GJ/tCO_2 captured) and water loss (t-H_2O lost / t-CO_2 captured) at the storage basin locations (Table 59).

Table 59 | Water loss and energy intensity of DAC process at specific storage basin locations used in NZAu

Basin name	Energy Intensity of Capture (GJ/tCO_2 Captured)	Water Loss (tH_2O lost / tCO_2 Captured)
Gippsland	6.7	4.4
Cooper/Eromanga	6.6	10.8
Carnarvon	6.5	10.6
Browse	6.5	10.6
Bonaparte	6.5	7.8
Surat	6.3	6.9

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10.6 Transmission of electricity

10.6.1 Overview

This section covers NZAu's modelling of the transmission of electricity

- between regions (NZAu zones);
- from a new variable renewable energy (VRE) project to domestic loads; and
- from a new VRE project to export-appropriate loads.

The determination of the NZAu electricity transmission routes and costs builds on prior work from Princeton's *Net-Zero America* (NZA) project,[1] the Nature Conservancy's *Power of Place West* project,[2] and the Princeton Zero Lab's *REPEAT* project.[3] The transmission routing and costing used here follows least-cost path methods as described by ESRI,[4] which involve selecting end points for a potential transmission line, and then determining the least-cost path between the points.

Table 60 lays out the transmission infrastructure included and excluded in the modelling of each of these transmission categories.

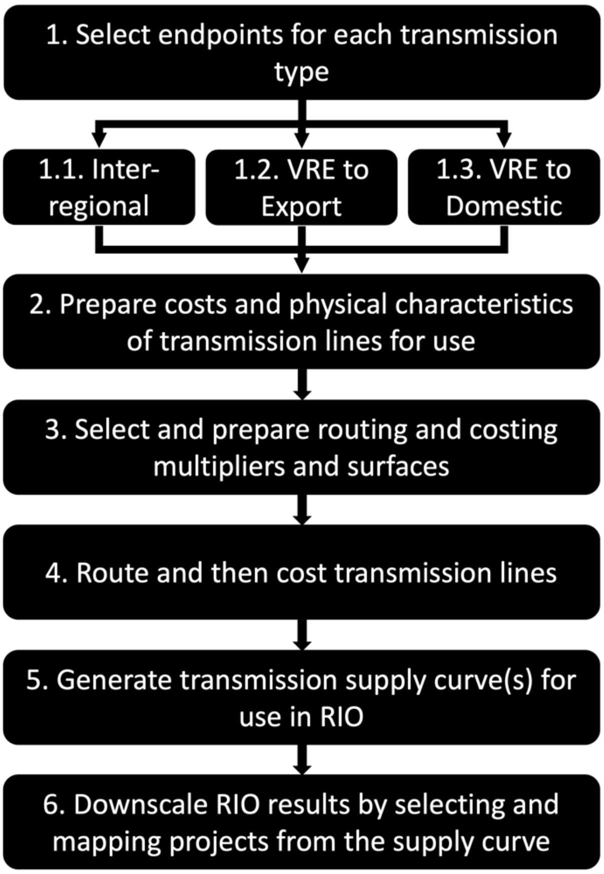
Table 60 | Transmission (TX) infrastructure included and excluded for each of the modelled transmission types.

Infrastructure component	Between model regions (inter-regional)	VRE to domestic load	VRE to export node
Sending converter / substation (terminal)	YES	YES (without transformers which are included in project costs)	
TX line to existing transmission grid	N/A	YES (spur)	N/A
New substation at connection to existing transmission grid (intermediary endpoint)	N/A	YES – transformers only if total distance from VRE to load < 250km	N/A
TX line to final destination	YES (transmission to receiving substation)	YES (sub-transmission to domestic load)	YES (transmission to export node)
New substation at destination (endpoint)	YES	YES (without transformers which are included in distribution costs)	NO
New substation(s) to maintain power quality over longer TX lines (booster)	YES	YES	YES
Distribution network upgrades to loads	NO (not included in downscaling, but included in costing in RIO model)		

An overview of the process followed in modelling transmission expansion for NZAu is provided in Figure 75 and has six steps. More information on each of these six steps is provided below.

1. Select the endpoints for each transmission type modelled in NZAu.
2. Select and prepare transmission costs and their physical characteristics to use in NZAu.
3. Prepare routing and costing multipliers and surfaces used both in GIS software and when finalising costs after GIS processing.
4. Undertake routing and costing of all possible transmission routes considered for inclusion in the RIO tool.
5. Generate transmission supply curves for use in the RIO tool
6. Downscale RIO results by selecting and mapping projects from the supply curve.

Figure 75 | Process followed in modelling transmission expansion for NZAu.

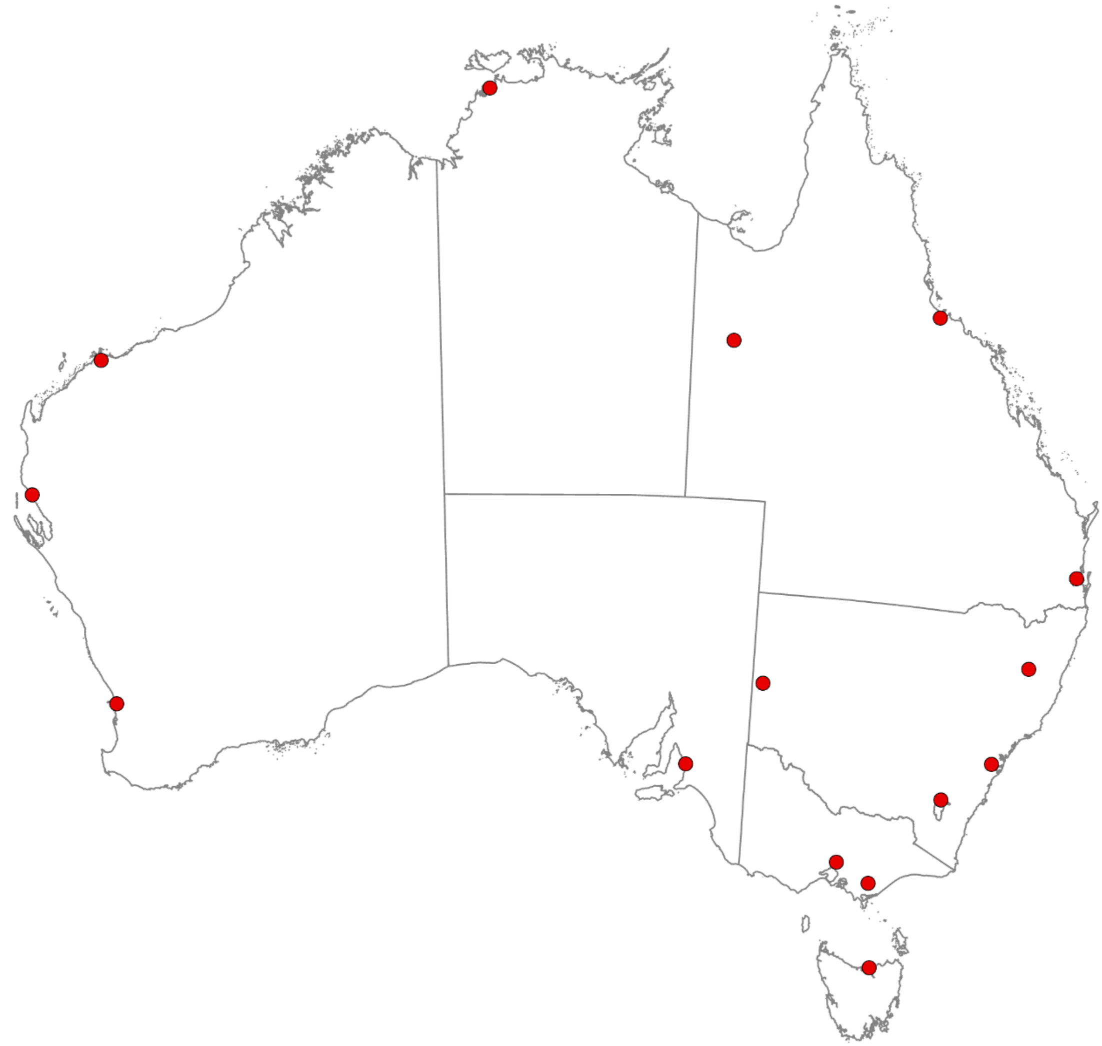


10.6.2 Step 1: Select endpoints for each transmission type

Between model regions (inter-regional)

Inter-regional transmission lines are used by the NZAu model when a region has an oversupply of electricity during a modelled period and a bordering region has a deficit during the same period. Figure 76 shows the regional endpoints used for the mapping of candidate inter-regional transmission lines.

Figure 76 | The regional endpoints used for the mapping of potential inter-regional transmission lines.



To model inter-regional electricity transfer, each region was assigned a node or 'reference point' through which electricity can be transferred to and from other regions. Of course, in practice electricity transfer may occur through multiple lines. Therefore, for this approximation to be reasonable, the reference points must be chosen to represent the bulk of the electricity transfer between the regions.

The selection of reference points is expedient and used to provide a more accurate indication of inter-regional transmission distance than the distance between regional centre-points. The reference points for each region within this study were chosen from an existing set of substations using the following principles, in decreasing order of preference.

1. **Choose AEMO Regional Reference Nodes as reference nodes[5]** – given the use of Regional Reference Nodes by AEMO, these nodes can also be utilised in the current study. A key example of this is South Pine in Queensland. The Regional Reference Nodes utilised by AEMO in financial year 2021/2022 are summarised in Table 61.
2. **Choose a reference point based on major load centres** – area with the largest population or significant industrial energy demand in a region will have the largest electricity demand and hence transfer. Examples of this are Darwin for the NZAu region 'NT', Canberra for 'NSW-south', and Broken Hill for 'NSW-outback'.

3. **Choose a reference point based on a 'well-connected' substation** – for some regions without an AEMO Regional Reference Node or significant population or load centres, substations which connect several transmission lines can be used as a reference point. An example of this is the Hazelwood substation for the NZAu region 'VIC-east' and Ross for 'QLD-north'.

Table 62 summarises the substation names and justification for the chosen reference points for each region.

Table 61 | Regions and regional reference nodes in the NEM, Table 25 in [5].

Region	Regional Reference Node
Queensland	South Pine 275 kV node
New South Wales	Sydney West 330 kV node
Victoria	Thomastown 66 kV node
South Australia	Torrens Island PS 66 kV node
Tasmania	George Town 220 kV node

Table 62 | NZAu reference points, with NZAu region and selection justification.

NZAu Region	Reference Point (Substation name)	Justification
WA-south	Perth	AEMO Regional Reference Node
WA-central	Carnarvon	Large population centre
WA-north	Karratha	Large population centre
NT	Darwin	Largest population centre, large substation
QLD-north	Ross	High-capacity and well-connected substation, discussed regularly in AEMO reports
QLD-outback	Mt Isa	Industrial centre
QLD-south	South Pine	AEMO Regional Reference Node
NSW-north	Armidale	Large population centre with large and well-connected substation
NSW-central	Sydney West	AEMO Regional Reference Node
NSW-south	Canberra	Largest population centre with large and well-connected substation
NSW-outback	Broken Hill	Industrial centre
VIC-east	Hazelwood	Large and well-connected substation
VIC-west	Thomastown	AEMO Regional Reference Node
TAS	George Town	AEMO Regional Reference Node
SA	Torrens Island	AEMO Regional Reference Node

VRE to domestic loads

VRE

As in NZA, the variable renewable projects considered for use in NZAu are geospatially determined using the MapRE toolbox [6]. This toolbox accepts resource capacity data,[7,8] VRE exclusion areas, and the VRE project parameters listed in Table 63 as inputs. The toolbox returns a list of candidate project areas (CPAs) each having the attributes listed in Table 64 as outputs. Note that there are several onshore wind CPAs shown in a different colour in Figure 77 that have been identified as useful for export energy production. These have been handled differently to the CPAs for domestic use, as discussed in the next section.

Table 63 | MapRE exclusion areas, and the VRE project parameters.

Input type	Item	Solar PV (buffer m)	Wind onshore (buffer m)	Wind offshore (buffer m)
Exclusion, techno-economic	Active mines [9]	100% (1000)	100% (1000)	NA
Exclusion, techno-economic	Built up areas [10]	100% (500)	100% (2000)	NA
Exclusion, techno-economic	Inland water bodies[56,13], salt lakes, wetlands[13]	100% (250)	100% (250)	NA
Exclusion, techno-economic	Defence restricted – practice, training, prohibited [11]	100% (1000)	100% (3000)	100% (3000)
Exclusion, techno-economic	Transport infrastructure – roads (no buffer), airports, landing grounds, heliports, runways [12]	100% (1000)	100% (6000)	100% (6000)
Exclusion, techno-economic	Land cover types – irrigated farmland, sugar, pasture [13]	100% (0)	100% (0)	NA
Exclusion, techno-economic	Land cover types – rainfed farmland [13]	100% (0)	NA	NA
Exclusion, techno-economic	Slope [14]	>10 degrees	>19 degrees	NA
Exclusion, techno-economic	Capacity factor [8]	NA	<20%	NA
Exclusion, techno-economic	Straight line distance from built up area	>242km	>242km	NA
Exclusion, techno-economic	Offshore shipping lanes [15]–[17]	NA	NA	>1 vessel per km2 over a three-month sample (Jan, May, Sept 2019)
Exclusion, environmental	Reserves – forestry, indigenous, water supply, nature conservation land, nature conservation marine, prohibited [18]	100% (1000)	100% (1000)	100% (1000)
Exclusion, environmental	Collaborative Australian Protected Area Database [19], [20]	100% (1000)	100% (1000)	100% (1000)
Exclusion, environmental	The likely habitats of critically endangered, endangered, and vulnerable Species[57] and Ecological Communities [58] of National Environmental Significance < 6,600 km^2 in size	100% (0)	100% (0)	100% (0)
Parameter	Power Density in MW/km^2	45 [1]	2.7 [1]	4.4 [21]
Parameter	Minimum project size MW	20	50	100
Parameter	Maximum project size MW	900	1080	2200

Of specific note in Table 63, the offshore wind power density has not been taken from the NZA [1] report which used a fixed density of 5 MW/km^2 and a floating density of 8 MW/km^2. The 4.4 MW/km^2 figure used for NZAu represents the maximum power density of all proposed and presented projects in Australia through 2030, and corresponds to 2,200 MW over 496 km^2 for the Star of the South project.[21]

Figure 77 | Onshore wind projects considered as candidates for domestic (dark blue) and export (light blue) use by NZAu.

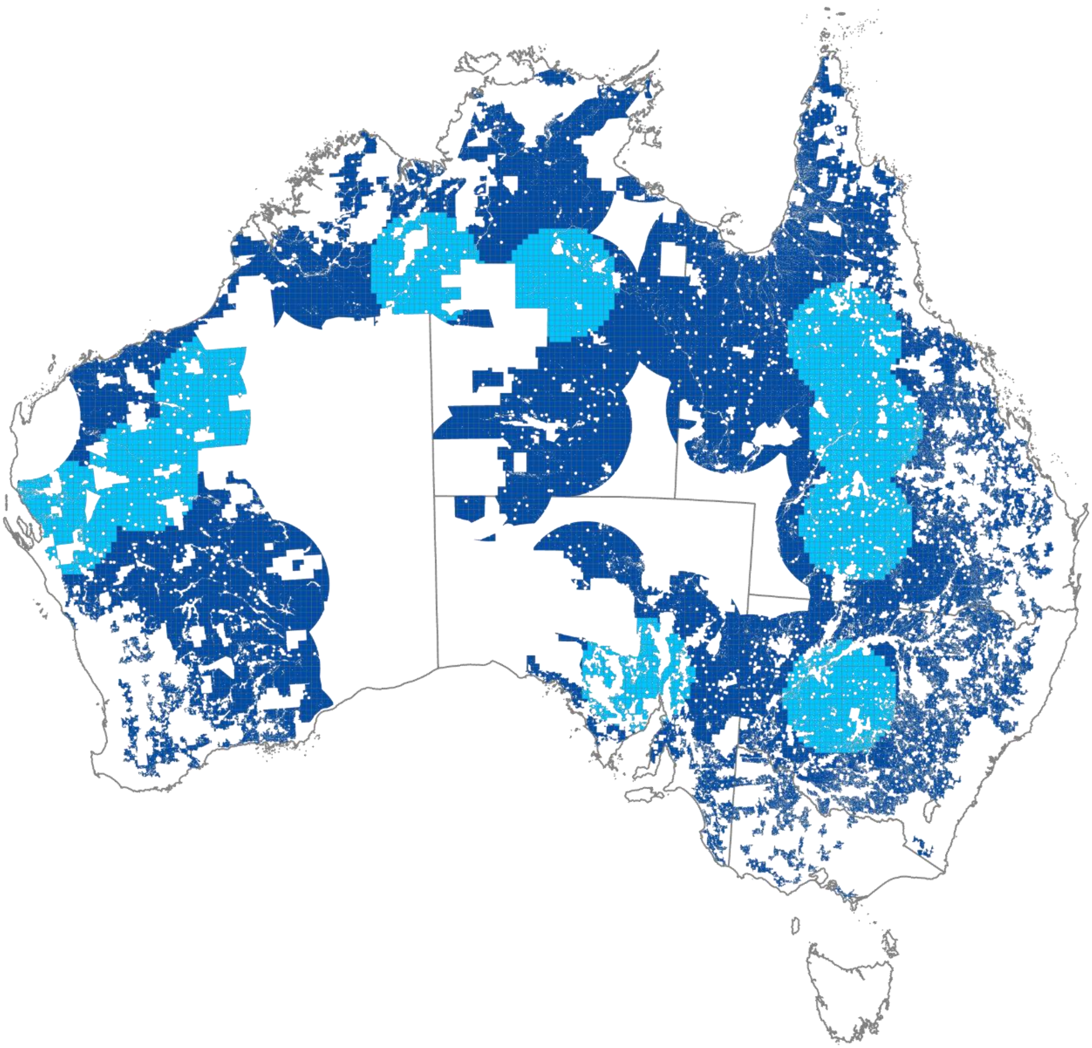


Table 64 | CPA attributes leaving MapRE.

Attribute	Type
Land Cover Type [13]	Majority
Slope [14]	Mean
Capacity Factor [8]	Mean
Distance to selected load centres	Distance
Population Density [23]	Mean
Cyclone Hazard [24]	Mean
State/Region	Majority
NZAu Region	Majority
Distance to export aggregation node	Distance
Distance to nearest existing VRE project	Distance

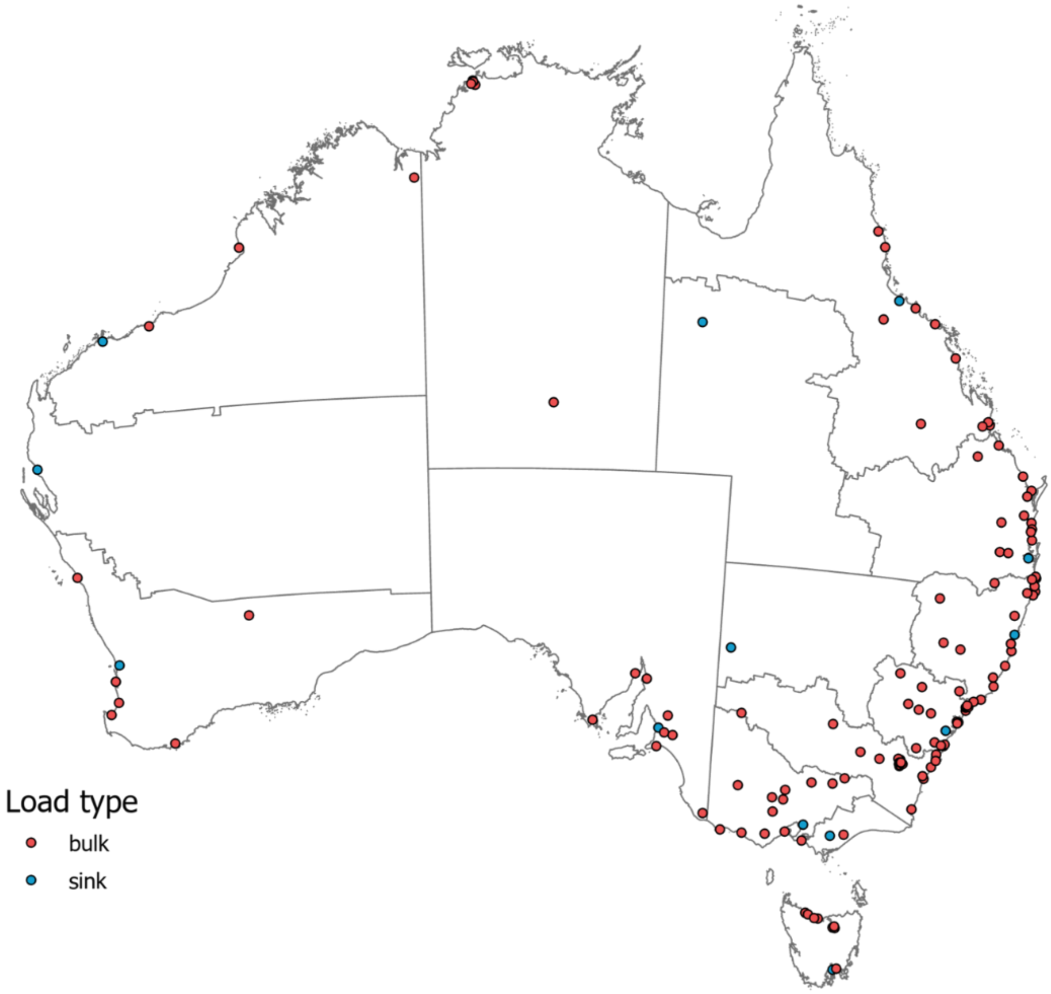
Domestic loads

The load centres used for domestic transmission are shown in Figure 78 and are:

- aggregated areas of Australia having the Australian Bureau of Statistics' second smallest statistical division for the release of its census data (SA2) and "represent[s] a community that interacts together socially and economically"[23]
- a population of greater than 5,000 people
- a population density of greater than 100 people per square kilometre.

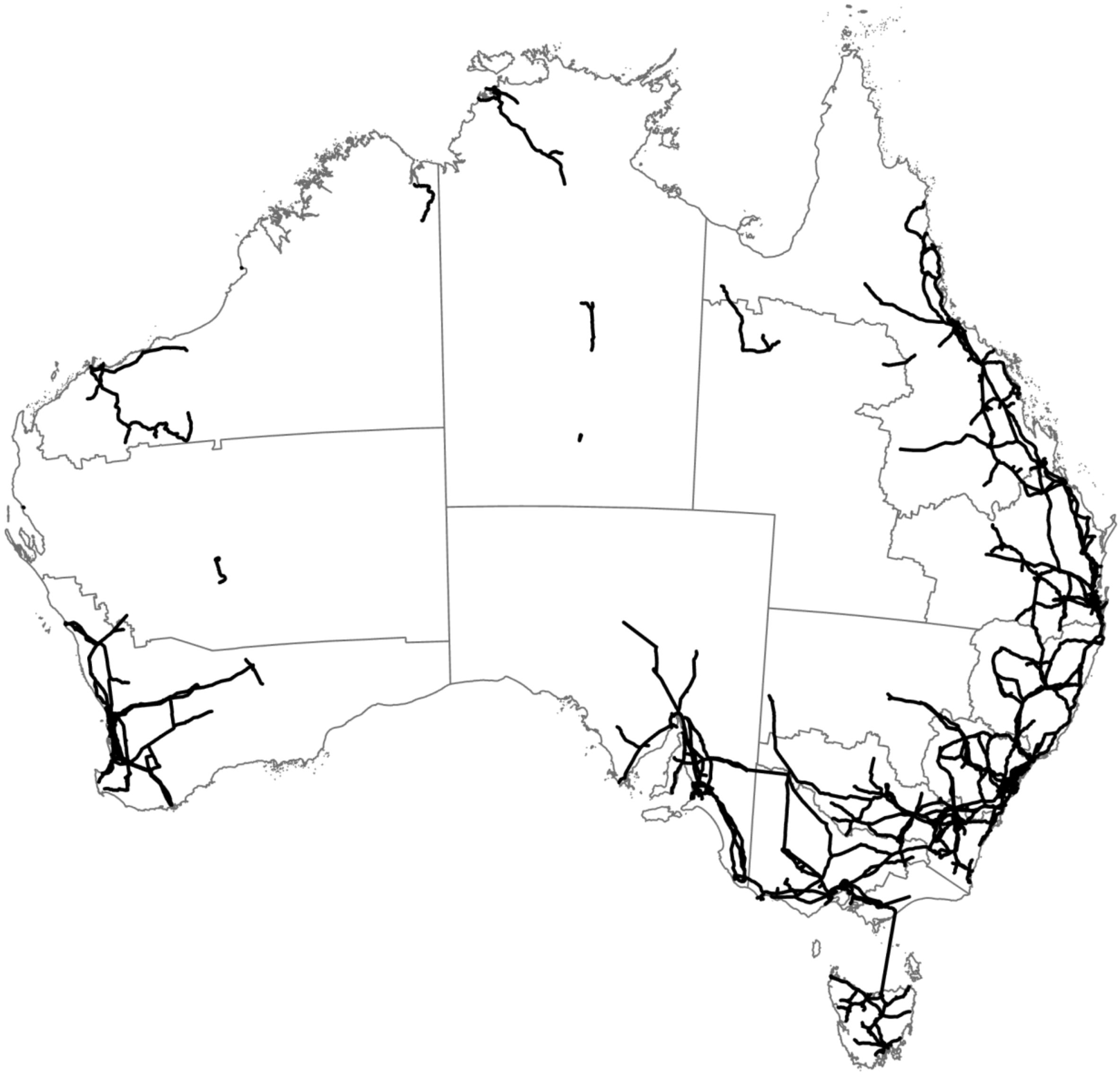
By aggregating SA2 areas with shared borders, the number of load centres used in modelling decreases from 1,379 to 141.

Figure 78 | Map of the 141 load centres considered as final destinations for domestic CPAs. Load centres are shown as points. One point in every NZAu region – usually corresponding to a major town or city – has been specified as a sink location to which all remaining wind and solar capacity will be routed after the load at other destinations in the region has been fully met.



Transmission from the centre of a project area to domestic loads always routes from generation to a 'least-cost' destination on the existing transmission grid (shown in Figure 79) before making its way to a load (centre point of destination SA2). A new converter/substation is costed at the point of grid connection. In the event that the 'least-cost' destination on Australia's existing transmission grid is already inside one of the destination SA2s, then no further transmission mapping is pursued for that project. In the case of an offshore transmission line coming onshore, en route to the 'least-cost' destination on Australia's existing transmission grid, the transmission line is assumed to transition from subsea to overhead without and additional sub/converter station.

Figure 79 | Map of the existing transmission network in Australia.[26]



VRE to export

A selection of existing ports are used as candidate end points for exported energy, and are shown in Figure 81 (in black). The NZAu team selected these ports based on the recent Australian Hydrogen Hubs study.[27] This study covered a list of current or anticipated locations suitable for hydrogen exports and was based on desktop research and interviews with targeted industry and government stakeholders. The study identified the ports listed in Table 65 for the development of hydrogen export facilities.

Table 65 | Potential Hydrogen Export Locations (listed alphabetically), Table 6 in reference [27].

State/Territory	Potential Site
New South Wales	Newcastle (Kooragang Island suggested), Port Botany / Kurnell, Port Kembla
Northern Territories	Darwin (Middle Arm suggested), Gove (near town of Nhulunbuy)
Queensland	Abbot Point, Brisbane (Bulwer, Gibson Island suggested), Bundaberg, Gladstone, Karumba, Port Alma, Townsville, Weipa
South Australia	Myponie Point, Port Adelaide, Port Augusta, Port Bonython, Port Giles, Port Lincoln / Cape Hardy, Port Pire, Whyalla
Tasmania	Bell Bay, Hobart
Victoria	Altona, Port Anthony, Port of Hastings, Port of Melbourne, Port of Geeling, Portland
Western Australia	Ashburton / Onslow, Albany, Dampier, Geraldton, Oakajee, Port Hedland

Further assessment of the ports listed in Table 65 used three steps:

- Set selection criteria (see Table 66)
- Gather data on each port[28-46]
- Rank ports, using the rankings in Table 67 to identify the most suitable locations for NZAu.

Table 67 indicates that the NZAu team gave existing LNG export facilities the highest ranking as they were deemed the most suitable for large shipping export and are expected to have the lowest additional infrastructure cost. The lowest rank in Table 67 is given to ports which are currently used for small volume commodity export/import and for which additional infrastructure should require higher associated costs.

Table 66 | Selection criteria for NZAu hydrogen export location.

Parameter	Unit
Channel depth	14.2m
Depth alongside	15.7m
Dead weight tonnage	80000 tonnes
Berth pocket size	350m × 90m
Length overall	300m
Other	Current export commodity/mineral/coal/fuel Availability of infrastructure

Table 67 | NZAu hydrogen export port ranking criteria.

Best to worst	Criteria	Cost	Note
5	Existing LNG export	Low	LNG can be replaced by H_2/Ammonia and existing port facilities can be used
4	Coal & large mineral export	Moderate (−)	Can use existing berths but need extra facilities for storage and a jetty for liquid export
3	Large commodity / petroleum import/export	Moderate (+)	Needs expansion and new berths, a jetty and storage
2	Commodity export/import – low capacity	High	New facilities and additional infrastructure are needed to handle large commodity volume

Best to worst	Criteria	Cost	Note
1	No infrastructure / is recommended to build a new port	Very high	Construction infrastructure and a new port is required
0	Major location constraints	NA	Land constraints on construction of a new facility, such as defence or special land use

The 18 ports listed in Table 68 were shortlisted as prospective hydrogen export hubs given publicly available information. Of those 18 ports, ten were selected as final candidates, with the final choice of port in each region based on both this ranking and the judgement of the NZAu Team. For example, Port Bonython was chosen over Port Adelaide in SA, as there was concern from the Team regarding the high-volume commodity import/export into a city port. Of the two ports that were deemed suitable in NSW, only one of the ports was chosen due to the other having a lower availability of high-quality renewable energy resources. Despite the attention paid to the Bell Bay during stakeholder interactions, we found that Bell Bay does not meet the requirements for an export port as the depth alongside is 12.0m or less in all berths (15.7m required in Table 66), and all berth pockets are significantly smaller than the minimum 350m x 90m specified in Table 66.The selected candidate port locations give good coverage across all mainland Australian states/territories.

Table 68 | The 18 port location candidates used in NZAu modelling. Red denotes those candidates that were not chosen in our shortlisting.

Number	State	Shortlisted Ports	Ranking	Selected port candidates
1	VIC	Port of Melbourne	3	
2		Port of Hastings	4	Port of Hastings
3	NT	Port of Darwin	5	Port of Darwin
4	SA	Port Adelaide	4	
5		Port Lincoln	2	
6		Port Bonython	3	Port Bonython
7	QLD	Port of Abbot point	4	Port of Abbot point
8		Gladstone port	5	Gladstone port
9		Hay point	4	Hay point
10	WA	Ashburton	5	Ashburton
11		Dampier	5	Dampier
12		Port Hedland	4	Port Hedland
13		Geraldton port	2	
14		Oakajee port	1	
16	NSW	Newcastle	4	Newcastle
17		Kembla	4	
18	TAS	Bell Bay	2	

The (red) nodes in Figure 81 represent candidate locations from which exported renewable energy may be supplied via either electricity transmission or hydrogen pipeline. (Note that the RIO tool decides which of electricity or hydrogen transmission will be used.). These supply nodes have been selected from the set of all possible node locations that are proximate to high quality VRE resources and are located in SA2 regions with population densities below 0.1 people per square kilometre (Figure 81).

Figure 80 | Map of candidate export ports (black) and supply nodes (red) used in the modelling. In the case of offshore wind energy used to support exports in Victoria (VIC), Port Hastings itself was used as a supply node as no inland node has been specified to collect onshore resources in VIC.

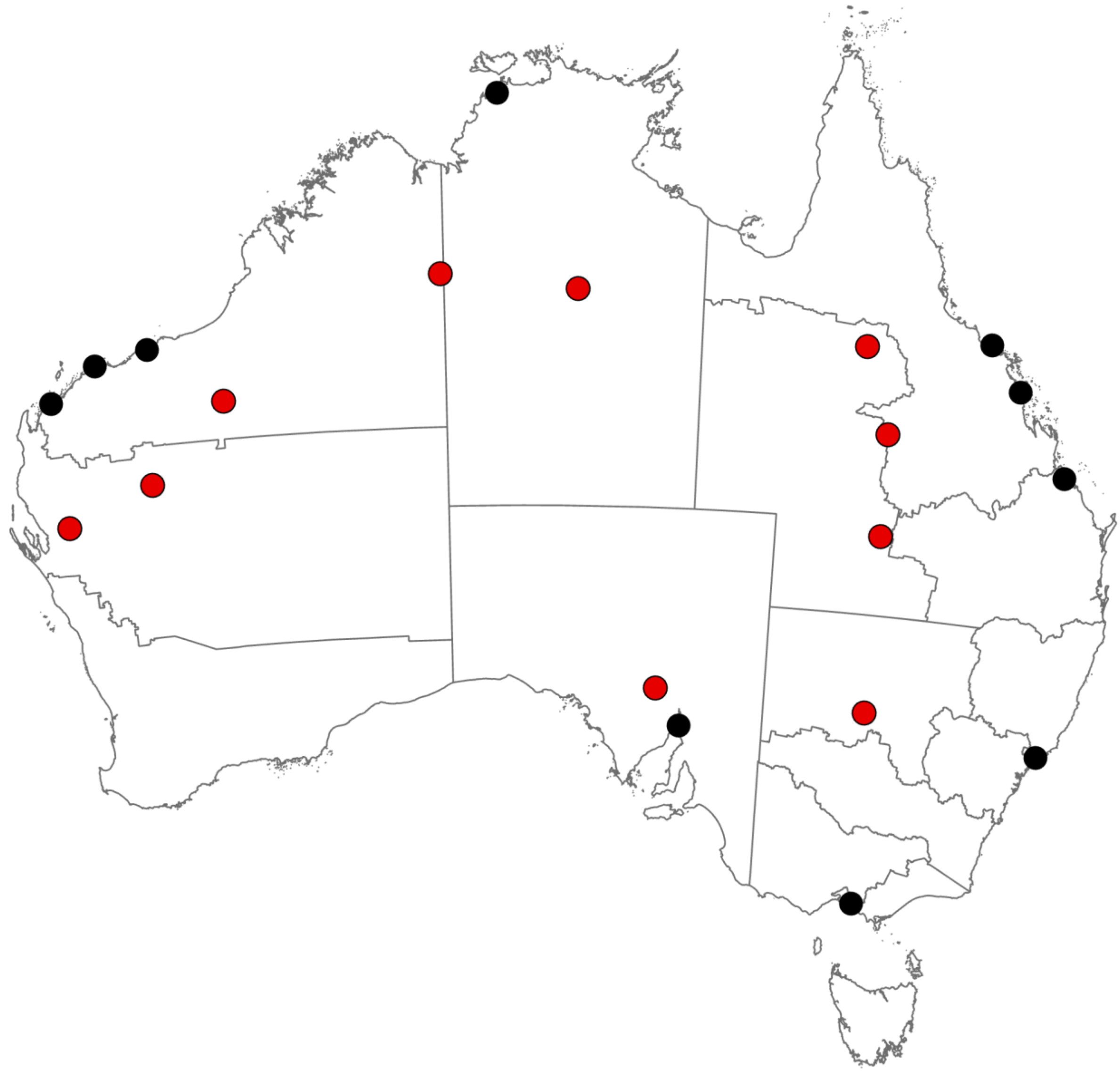
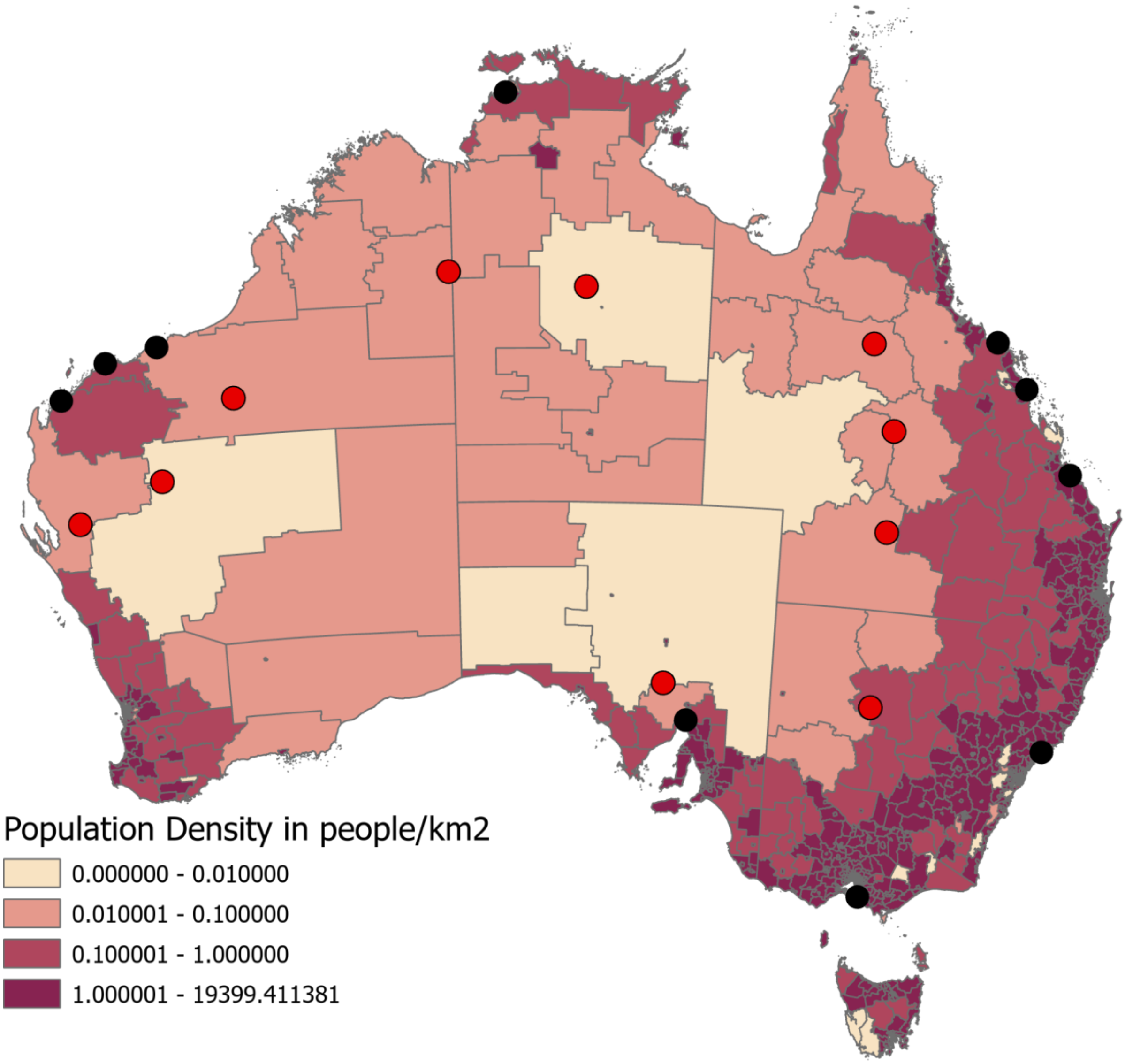


Figure 81 | Map of selected export ports (black) and nodes (red) used in modelling, along with SA2 population densities as estimated using the ABS supplied SA2 GIS layer.[47]



10.6.3 Step 2: Prepare costs and physical characteristics of transmission corridors and lines for use

Table 69 lists the assumed 2020 starting capacities of inter-regional corridors used by RIO. Table 70 lists the characteristics of the representative transmission types modelled. The following additional assumptions/decisions were made about the transmission types listed in Table 70:

- For all spur lines, the new substation added at the sending end of the line does not include transformers which are covered in the AEMO project costs.[48,49] All domestic project spur lines include another new substation at the spur line's destination; unless the total transmission distance to the nearest load centre is less than 250 km, in which case a substation without transformers is included if the spur line goes directly to load, or only transformers are included at point of connection to existing transmission if the spur line does not go directly to a load. All export project spur lines do not include a new substation at the aggregation node. For all other transmission lines, new substations are assumed to be needed at each end of the new transmission line. For longer HVAC transmission lines, a substation is then added at 251 km and then with each addition of 160 km of additional line distance, i.e., 411 km, 571 km, etc.

- Projects that connect to existing transmission corridors before reaching their load destination do so using a 330 kV transformer if the project has a capacity less than 1200 MW, and with a 500 kV transformer if the project's capacity is more than 1200 MW.
- Added power conditioning substations for line lengths over 250km consist of the same equipment as relevant grid-tie substations
- Transmission losses are assumed to be 1% per 100 km for HVAC and are 0.5% per 100 km plus 3% for HVDC
- No OPEX costs are assumed for transmission lines[49,50]
- New inter-regional transmission corridors are all assumed to be 500kV with HVAC or HVDC transmission types being determined by total transmission length as well as whether the corridor involves subsea cabling
- All inter-regional transmission corridors over 700km long and offshore wind spur lines are assumed to be HVDC
- Reactive power support plant has been added to all HVAC inter-regional transmission corridors at a cost of 52 million AU$ per substation[50]
- Learning curves for offshore wind transmission[51] are applied to the transmission costs for offshore wind.

Table 69 | The assumed 2020 starting capacities of inter-regional corridors considered by RIO.[52]

Corridor (endpoint || endpoint)	Forward Capacity (MW)	Reverse Capacity (MW)
WA-south||WA-central	0	0
WA-south||SA	0	0
WA-central||NT	0	0
WA-central||WA-north	0	0
WA-central||SA	0	0
WA-north||NT	0	0
NT||SA	0	0
NT||QLD-north	0	0
NT||QLD-outback	0	0
QLD-north||QLD-outback	0	0
QLD-north||QLD-south	2100	1000
QLD-outback||QLD-south	0	0
QLD-outback||SA	0	0
QLD-outback||NSW-outback	0	0
QLD-south||NSW-outback	0	0
QLD-south||NSW-outback	0	0
QLD-south||NSW-north	1205	745
NSW-north||NSW-central	1025	910
NSW-north||NSW-outback	0	0
NSW-outback||SA	0	0
NSW-outback||NSW-south	38	38
NSW-outback||NSW-central	38	38
NSW-central||NSW-south	2590	2950
NSW-south||VIC-east	0	0
NSW-south||VIC-west	1000	400
VIC-east||VIC-west	1750	1750
VIC-east||TAS	478	478
VIC-west||TAS	0	0
VIC-west||SA	650	650
SA||NSW-south	220	200

Table 70 | Representative transmission types used in the modelling along with the carrying capacity, maximum rated distance (km), cost per km of line (million 2021AU$), and per substation costs (million 2021AU$).

Voltage (kV)	Circuits	Type	Description of selected representative transmission type, cut and pasted from AEMO [50]	Carrying capacity (MW) (Note 2)	Max Rated distance km (Note 3)	Cost mAU$2021 / km [50]	New substation cost m2021AU$ (cost at sending end of spur line) (Note 4)
132	double	HVAC	Overhead lines double circuit single tower, twin conductor per phase - 2 × Lemon DCST 500MVA	250	250	1.128	28 (21)
275	single	HVAC	Overhead lines single circuit single tower, twin conductor per phase - 2 × Orange SCST 800MVA	400	250	1.270	36 (23)
275	double	HVAC	Overhead lines double circuit single tower, twin conductor per phase - 2 × Olive DCST 1900MVA	950	250	1.563	53 (27)
330	single	HVAC	Overhead lines single circuit single tower, triple conductor per phase - 3 × Mango SCST 1200MVA	600	250	1.469	41 (23)
330	double	HVAC	Overhead lines double circuit single tower, triple conductor per phase - 3 × Mango DCST 2400MVA	1200	250	1.794	62 (27)
500	double	HVAC	Overhead lines double circuit single tower, quad conductor per phase - 4 × Orange DCST 6080MVA	3040	250	2.542	70 (35)
500	twin	HVDC	Overhead lines with appropriate pole/tower configuration and conductor configuration for this technology - 2 × Asymmetrical Monopole (Bipole metallic return), 2 × 1500 MW	3000	1000	2.016	633 (597)
500	single	HVDC	HVDC subsea cable - 375 MVA - Subsea Cable single monopole375MVA circuit (offshore windfarm)	385	300	1.077	185 (167)
500	twin	HVDC	HVDC subsea cable - 750 MVA - Subsea Cable - twin 375 MVA symmetrical monopole circuits	750	300	1.923	330 (295)
500	twin	HVDC	HVDC subsea cable - 1500 MVA - Subsea Cable - twin 750 MVA symmetrical monopole circuits	1500	300	3.158	633 (597)

Table Notes:

1. Assumed to be half of MVA rating.
2. Maximum rated distance of line without adding a repeater substation to maintain power quality.
3. Costs for the sending substation on spur lines (in parentheses) are the same as the cost of the new substation minus transformers in AEMO's VRE project costs.[48,49]

10.6.4 Step 3: Select and prepare routing and costing multipliers and surfaces

Routing multipliers

Routing multipliers are applied to a routing surface and reflect weightings placed on obstacles or easements that constrain or ease a transmission line's siting, approval, construction, maintenance and impacts. The use of routing multipliers was pioneered by Wu et al.[2] to incorporate various environmental policy levers in the US. For example, the extensive and costly fires caused by existing transmission lines in California in recent years led Wu et al.[2] to employ high routing multipliers in areas having the greatest fire danger.

In NZAu, the modelling team employed a multiplier value of 100 to exclude transmission completely from selected areas. A complete list of areas using multipliers values of 100 in the NZAu routing surface is provided in Table 71. A multiplier of 100 entering the least-cost routing algorithm can be understood as presenting the algorithm with the choice of crossing this grid cell at 100 times the cost of crossing a neighbour with a multiplier of 1.

Following the method of NZA [1] the modelling team removed all full exclusion layers from existing transmission corridors. Following the method of Wu et al.,[2] the modelling team used a multiplier on all cells outside of existing transmission corridors in order to create a further preference for new transmission routes to follow existing transmission. The NZAu modelling team selected a multiplier value of 5 as this is well below the exclusion value of 100, but approximately 3.6 times greater than the next highest (aggregate) multiplier on the surface, thus creating a moderate preference for the siting of new transmission in existing corridors. For comparison, NZA[1] used a multiplier of 100, creating a very strong preference on a simple routing surface, and Wu et al.[2] used a multiplier of 9 on a more complex routing surface.

Costing multipliers

Costing multipliers are used to help determine the cost of a given transmission line and are listed in Table 71. All cost multipliers have been derived from the project attribute and known risk factor sections of AEMO's 2021 Transmission Cost Database.[50] The derivation of multipliers from AEMO[50] uses the following steps. For each multiplier type listed in Table 71:

1. Multiply the component cost of each representative transmission type by the component project attribute or known risk percentages
2. Sum the adjusted component costs of each representative transmission type to calculate the total adjusted cost for each representative transmission type
3. Divide the total adjusted cost for each representative transmission type by the total unadjusted cost for each representative transmission type to arrive at an overall adjusted percentage for each representative transmission type
4. Take the average of the overall adjusted percentages for:
    a. all overhead representative transmission types to arrive at an average onshore multiplier
    b. all submarine representative transmission types to arrive at an average offshore multiplier.

Routing and costing surfaces

After routing and costing multipliers have been determined and prepared, they are transferred to a geospatial surface (raster) resolved to grid cells of 250 metres x 250 metres. This is a decision based on computing power and the resolution of the GIS layers available to build/assign each multiplier value to the surface (see 'Layer' column in Table 71). Princeton's NZA[1] used 500m x 500m cells. Wu et al.[2] and Jenkins et al.[3] used 250m x 250m cells.

The transfer of each multiplier relies on the mapping layer listed in the 'Layer' column in Table 71. Each grid cell in the final routing and costing surfaces represents the product of the individual multipliers sharing the same cell. An inspection of Table 71 highlights that NZAu routing and costing layers are identical except for the exclusion multipliers.

Figure 82 | Urban, regional and remote multipliers employed for onshore and offshore routing and costing of transmission. This is a purpose-built layer, informed by the 2020-21 ISP Inputs, Assumptions and Scenarios.[49]

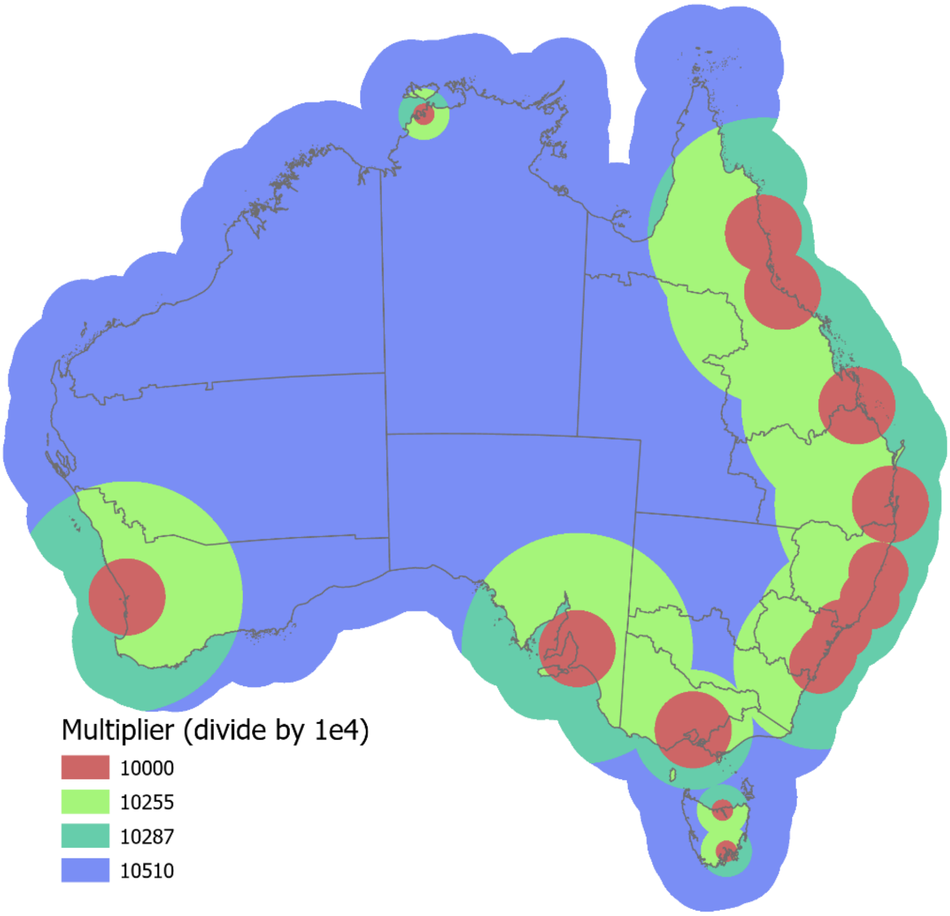


Table 71 | Multipliers and GIS layers used in generating transmission routing and cost surfaces.

Type (selections within layers or adjustment if needed)	Layer	Buffer (km)	Multiplier value source	Routing multiplier ONSHORE	Routing multiplier OFFSHORE	Costing multiplier ONSHORE	Costing multiplier OFFSHORE
Extraction Sites	Australian Critical Minerals Operating Mines And Deposits [9]	1	NZAU	100.00000	100.00000	1.00000	1.00000
Airports, landing grounds, helipads	NM Transport Infrastructure (MapServer) [12]	1	NZAU	100.00000	100.00000	1.00000	1.00000
Defence prohibited	Defence Prohibited and Practice Areas – training is not included as one export port in WA is inside a defense training area [11]	0	NZAU	100.00000	100.00000	1.00000	1.00000
Protected Area Database - terrestrial	Collaborative Australian Protected Areas Database [19]	1	NZAU	100.00000	100.00000	1.00000	1.00000
Protected Area Database - marine	Collaborative Australian Protected Areas Database – Marine [20]	1	NZAU	100.00000	100.00000	1.00000	1.00000
Inland Waterbodies , Salt Lakes, Wetlands, Irrigated Cropping, irrigated Pasture, Irrigated Sugar (layers 3, 4, 5, 6, 7, 11),	Dynamic Land Cover Dataset Version 2.1 [13]	0	NZAU	100.00000	100.00000	1.00000	1.00000
Outside of existing >= 132 kV transmission, pipeline (oil, gas, water), railroad, and conveyor corridors	Foundation Electricity Infrastructure [26], National Map Culture and Infrastructure (MapServer) [54], NM Transport Infrastructure (MapServer) [12]	0.5	TNC [2]	5.00000	5.00000	1.00000	1.00000
Jurisdiction – SA	State Layer [53]	0	AEMO [50]	0.94471	1.00000	0.94471	1.00000
Jurisdiction – TAS	State Layer [53]	0	AEMO [50]	0.94471	1.00000	0.94471	1.00000
Jurisdiction – VIC	State Layer [53]	0	AEMO [50]	0.96051	1.00000	0.96051	1.00000
Jurisdiction – NSW (used for ACT too)	State Layer [53]	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Jurisdiction – QLD (used for WA/NT too)	State Layer [53]	0	AEMO [50]	0.94471	1.00000	0.94471	1.00000
Land use – Desert (layers 22, 16)	Dynamic Land Cover Dataset Version 2.1 [13]	0	AEMO [50]	0.88864	1.00000	0.88864	1.00000
Land use - Scrub (layers 19, 24, 25)	Dynamic Land Cover Dataset Version 2.1 [13]	0	AEMO [50]	0.90522	1.00000	0.90522	1.00000
Land use – Grazing (layers 14, 18, 33, 34)	Dynamic Land Cover Dataset Version 2.1 [13]	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Land use – Farmland (layers 5 – 10)	Dynamic Land Cover Dataset Version 2.1 [13]	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Land use - All other (layers 15, 35, 31, 32)	Dynamic Land Cover Dataset Version 2.1 [13]	0	NZAU	1.00000	1.00000	1.00000	1.00000
Land use - Developed area	AREMI Buildings WM (Map Server) - Built Up Areas [10]	0	AEMO [50]	1.11847	1.00000	1.11847	1.00000

Type (selections within layers or adjustment if needed)	Layer	Buffer (km)	Multiplier value source	Routing multiplier ONSHORE	Routing multiplier OFFSHORE	Costing multiplier ONSHORE	Costing multiplier OFFSHORE
Brownfield	Foundation Electricity Infrastructure [26]	0	AEMO [50]	1.06537	1.04458	1.06537	1.04458
Greenfield	Not brownfield	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Regional	Purpose built layer (Figure 82) to approximate medium location cost area in 2020-21 ISP Inputs Assumptions and Scenarios [49]	0	AEMO [50]	1.02551	1.02872	1.02551	1.02872
Remote	Purpose built layer to approximate high location cost areas in 2020-21 ISP Inputs Assumptions and Scenarios [49]	0	AEMO [50]	1.05102	1.05743	1.05102	1.05743
Non-cyclone region (<145 km/hr on 100 year risk profile layer RP100)	Tropical Cyclone Hazard Assessment 2018 (Map Server) [24]	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Cyclone region (>=145 km/hm on 100 year risk profile layer RP100)	Tropical Cyclone Hazard Assessment 2018 (Map Server) [24]	0	AEMO [50]	1.06180	1.13254	1.06180	1.13254
Terrain – Flat (< 1 degree)	GEODATA 9 Second, DEM and D8, Digital Elevation Model Version 3 and Flow Direction Grid [14]	0	AEMO [50]	1.00000	1.00000	1.00000	1.00000
Terrain - Hilly/Undulating (1 - 4 degrees)	GEODATA 9 Second, DEM and D8, Digital Elevation Model Version 3 and Flow Direction Grid [14]	0	AEMO [50]	1.03791	1.02585	1.03791	1.02585
Terrain – Mountainous (> 4 degrees)	GEODATA 9 Second, DEM and D8, Digital Elevation Model Version 3 and Flow Direction Grid [14]	0	AEMO [50]	1.10109	1.06892	1.10109	1.06892
Project network element size (<1km)	NA – implemented in code	NA	NA	NA	NA	1.46578	1.49480
Project network element size (1 to 5km)	NA – implemented in code	NA	NA	NA	NA	1.27373	1.29079
Project network element size (5 to 10km)	NA – implemented in code	NA	NA	NA	NA	1.11322	1.12027
Project network element size (10 to 100km)	NA – implemented in code	NA	NA	NA	NA	1.04012	1.04262
Project network element size (100 to 200km)	NA – implemented in code	NA	NA	NA	NA	1	1
Project network element size (>200km)	NA – implemented in code	NA	NA	NA	NA	0.96417	0.96193

10.6.5 Step 4: Route and then cost transmission lines

The cost for each transmission line is determined over six steps.

1. Determine a route for each transmission line using the routing surface and Cost Path as a Polyline function in ArcGIS Pro.[54]
2. After constraining the costing surface to only the routes determined in the prior step, re-run the Cost Path as a Polyline function in ArcGIS Pro[54] using the constrained costing surface. This step results in a least-cost transmission route for every pair of endpoints, each having a total distance and a total 'cost'. 'Cost' is in quotations here to emphasise that the 'cost' quantity at this point consists of the sum of the multipliers found in each grid cell crossed by the transmission line's route. This 'cost' does not represent a cost in AU$ until it is multiplied in the next step by the per unit cost (in AU$) of the appropriately sized transmission line.
3. Compare the size of the project connected to each spur transmission line with the carrying capacity of each representative transmission type listed in Table 70 and multiply the total 'cost' of each line by the appropriate per unit cost.
4. Use the line's total distance to apply the appropriate distance specific multiplier found in Table 71.
5. Add the costs for the substations required by the line type (onshore spur, offshore spur, bulk) and length to the line-only cost from the prior step.
6. Pro-rate the costs of the new transmission infrastructure built to service a single project by the capacity of the project. In the case of the spur line portion of the transmission build, the pro-rating uses the ratio found by dividing the VRE project capacity by the carrying capacity of the line serving the VRE project. In the case of the portion of the new transmission line intended to carry electricity from a point of connection to the grid to a load destination, the cost of the new bulk line is pro-rated by two times the originating project's capacity factor. This adjustment acknowledges that from point of connection with the grid, the new line will not be serving just the new VRE project, but other diverse users.

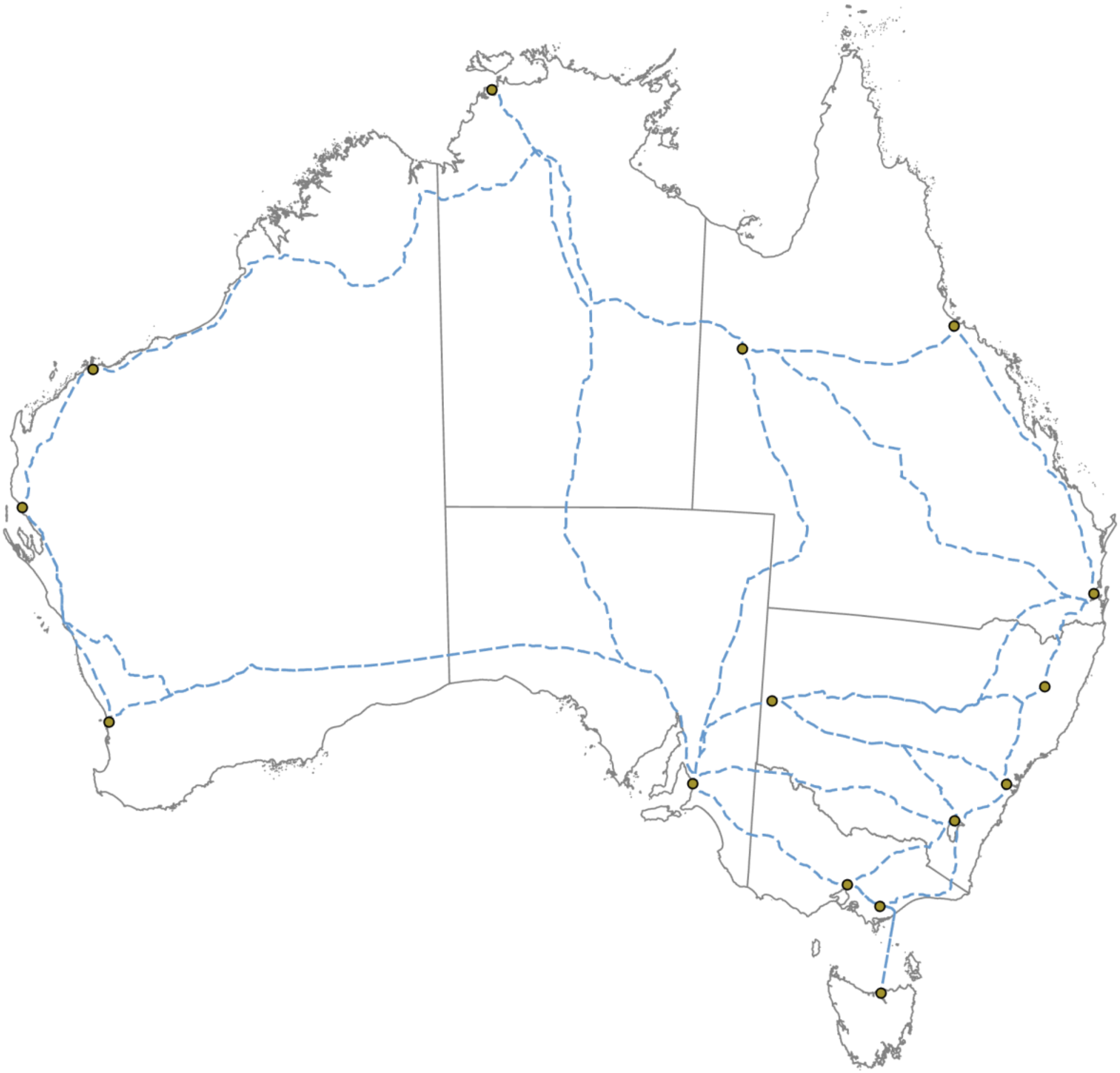
We finally note that, as part of our energy exports, we include an undersea electricity export cable from the Northern Territory to Southeast Asia. The cable is modelled on the Sun Cable project, which aims to start transferring power from Darwin to Singapore in 2027 via approximately 4,200 kilometres of submarine HVDC transmission cable.[55] The NZAu undersea electricity export cable is included in the supply side model and can expand from a minimum of 4,000 MW capacity in 2027 to a maximum of 24,000 MW capacity in 2060 (minimum of 6,000 MW capacity in 2060). The cost of this export technology is 4,500 2020AU$ per kilowatt with a fixed O&M cost of 135 2020AU$ per kW.

10.6.6 Routing and costing results

Inter-regional Transmission

Figure 83 shows an example of the set of *potential* inter-regional bulk transmission options, the cost of which has been estimated and input to the RIO tool.

Figure 83 | The set of candidate inter-regional bulk transmission options downscaled and used in RIO.



VRE to domestic

The process by which transmission was routed for onshore wind for use in the domestic supply curve is as follows:

- select all candidate wind projects for domestic use (Figure 84)
- route spur lines between candidate projects and aggregation nodes (Figure 85)
- route bulk transmission lines connecting the point of intersection between spur lines and existing transmission lines, and final load/transmission destinations (Figure 86).

Figure 84 | Map of all potential domestic onshore wind projects (blue), shown with existing transmission (black) and final load/transmission destinations (red).

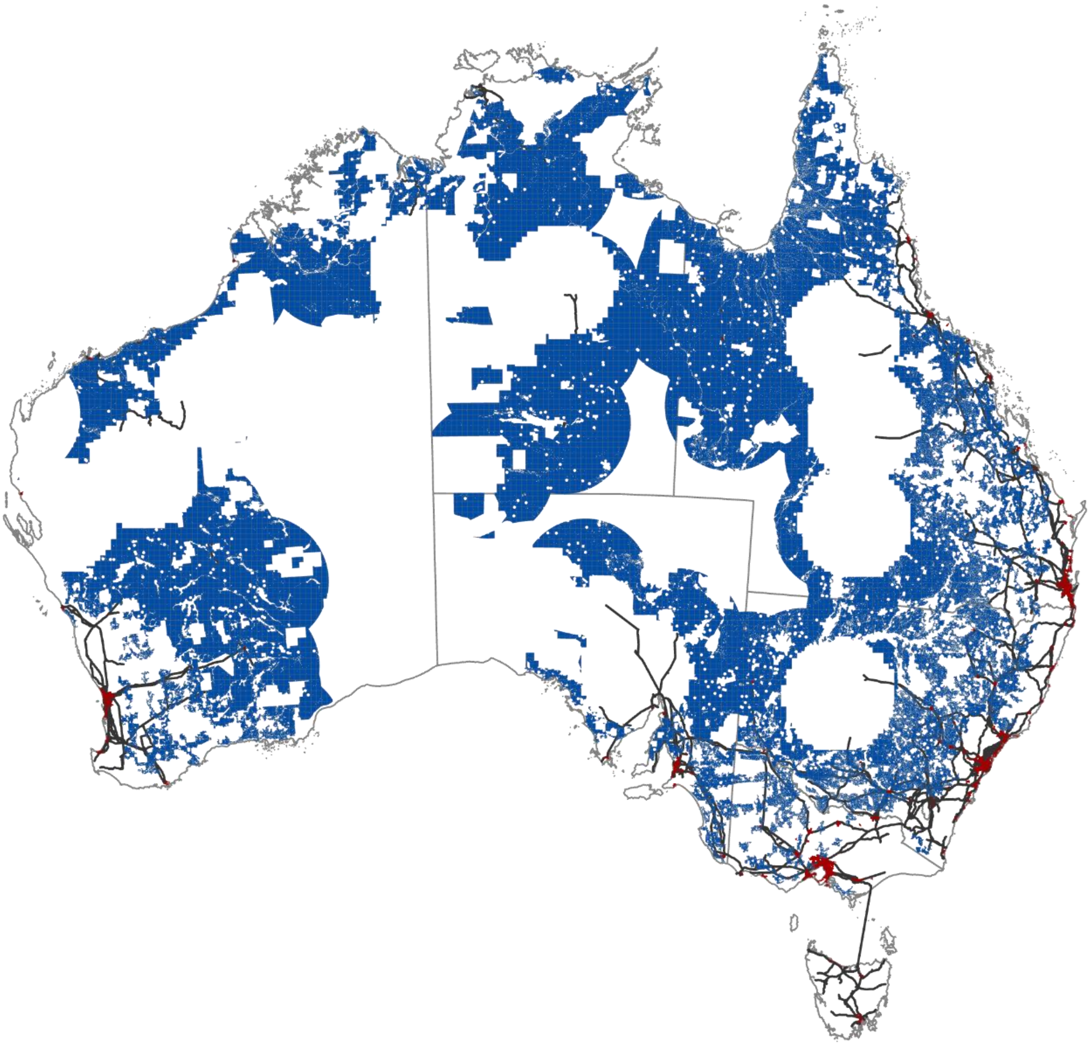


Figure 85 | Map of spur lines (light blue) connecting all potential domestic wind projects (dark blue) with existing transmission lines (black), and final load/transmission destinations (red).

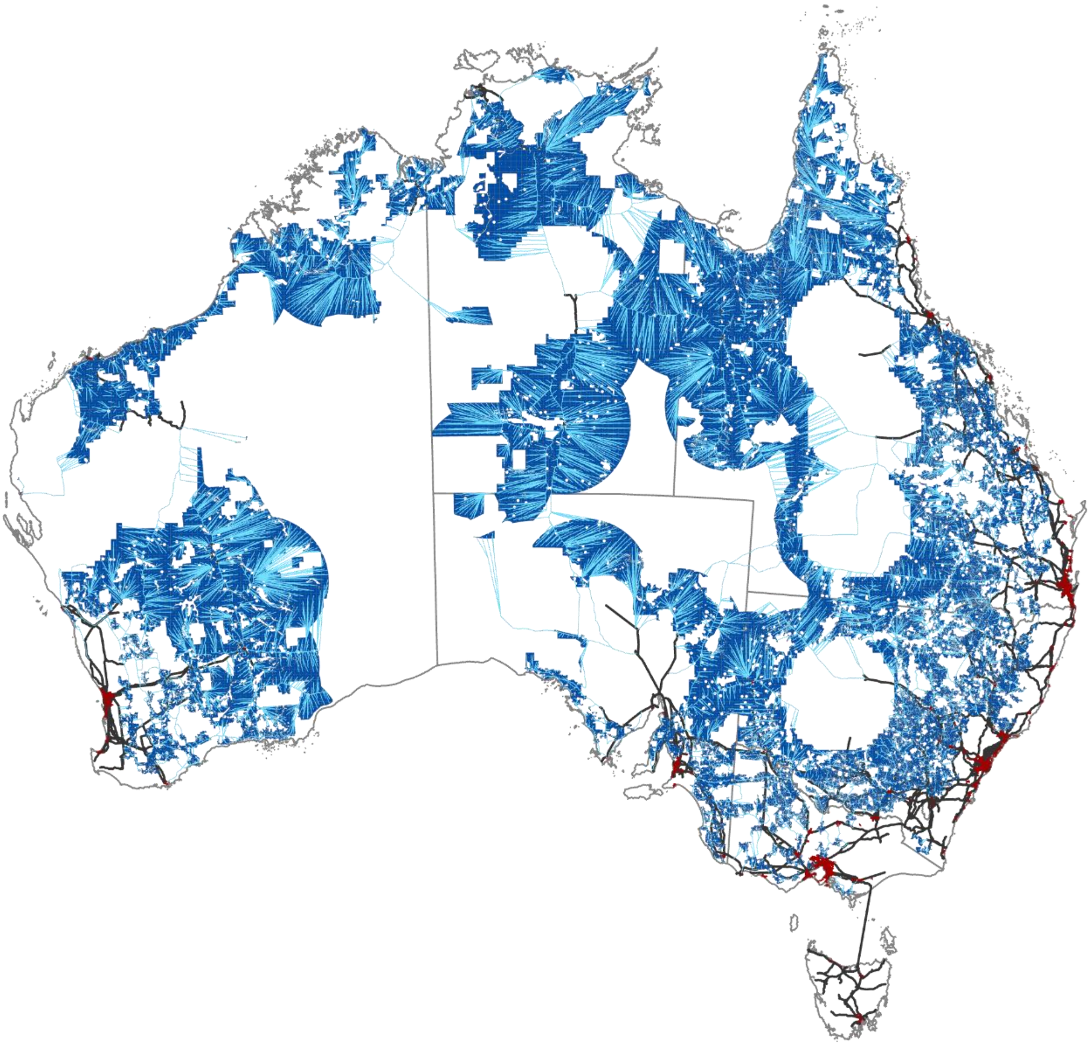
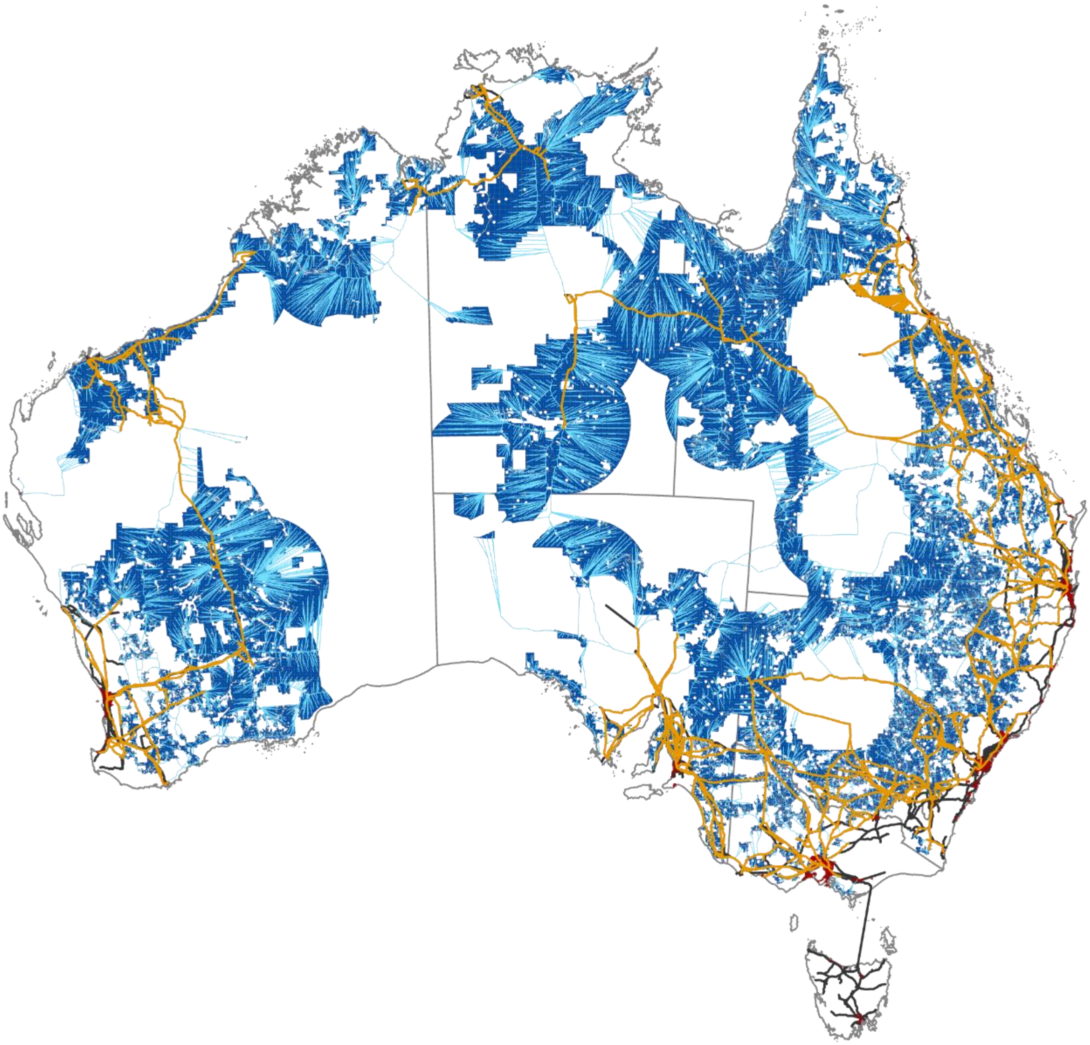


Figure 86 | Map of all possible bulk transmission lines (orange) connecting the point of intersection between spur lines (light blue) and existing transmission lines (black), and final load/transmission destinations (red).



VRE to export

The progression by which transmission was routed and costed for onshore wind used in the export supply curve is as follows:

- select all potential wind projects for export (Figure 87);
- route spur lines between potential projects and aggregation nodes (Figure 88); and
- route transmission corridors (electricity or pipeline) between aggregation nodes and export ports (Figure 89) using routing surface;
- cost electricity lines in each transmission corridor.

The transmission of hydrogen (rather than electricity) in each corridor was undertaken to provide RIO with the flexibility to build either electricity, or pipeline infrastructure, in each corridor based on the relative costs of each. The costing process for pipeline infrastructure is described in the next section.

Figure 87 | Map of all potential wind export projects (blue), shown with ports (black) and aggregation nodes (red).

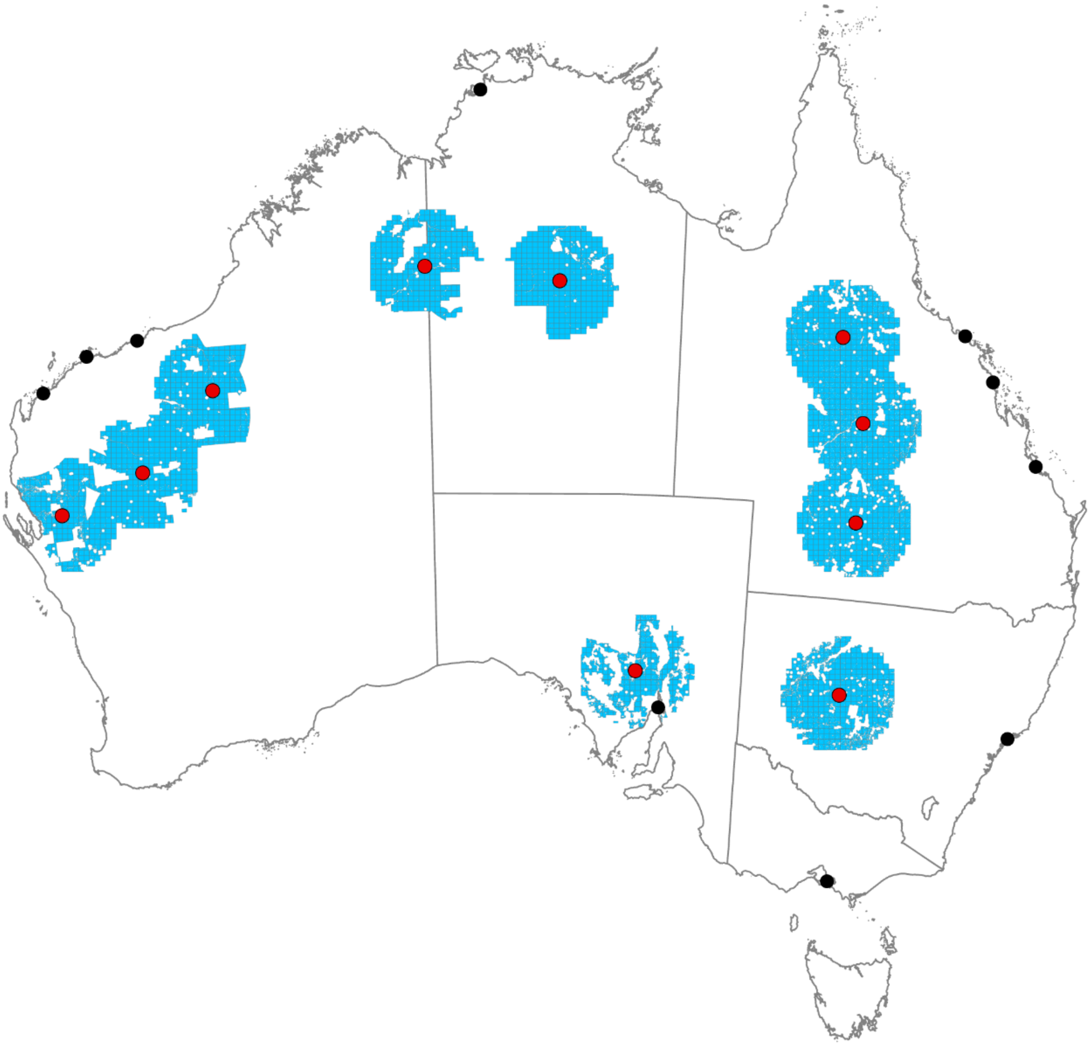


Figure 88 | Map of spur lines (black) connecting selected wind export projects (blue) with nodes (red). Selected export ports are shown in black.

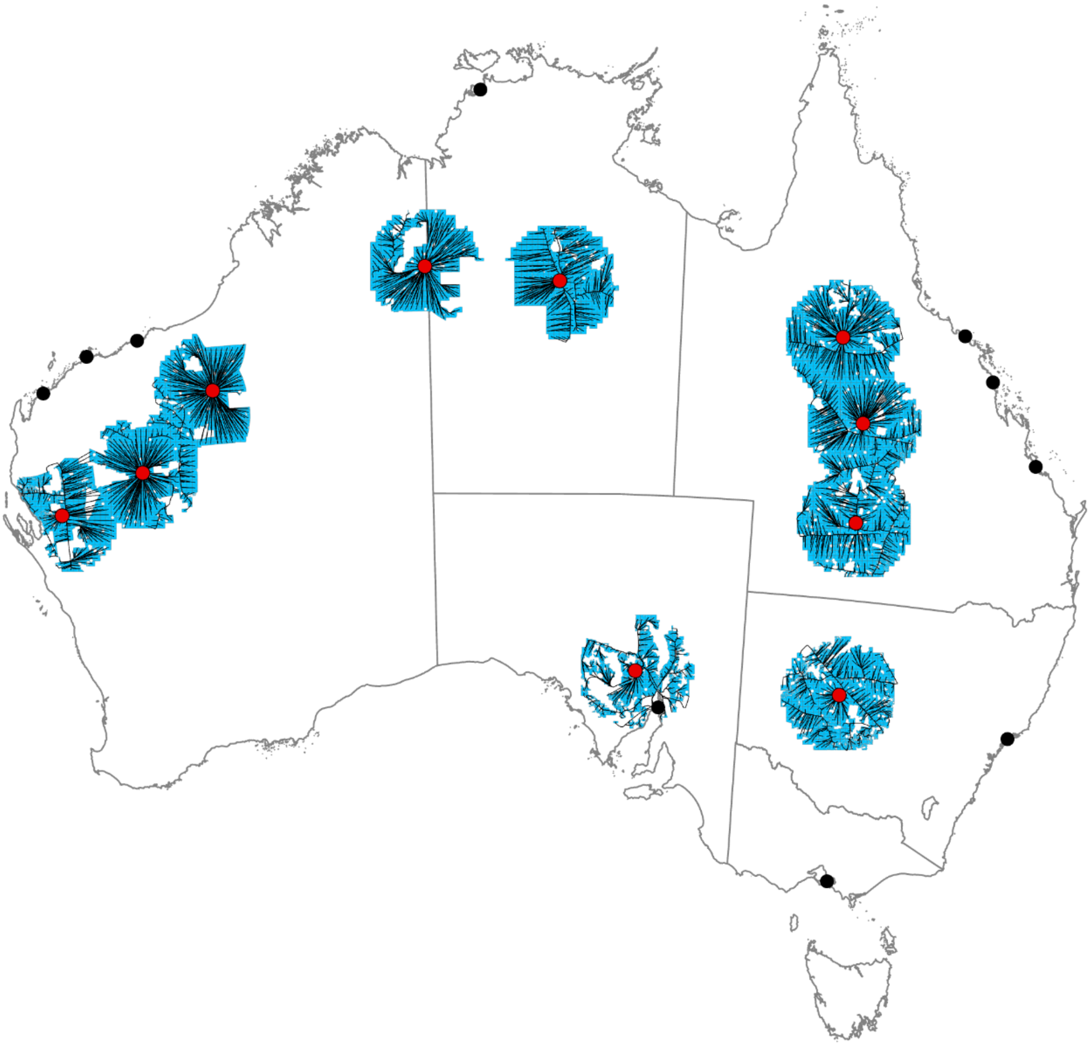
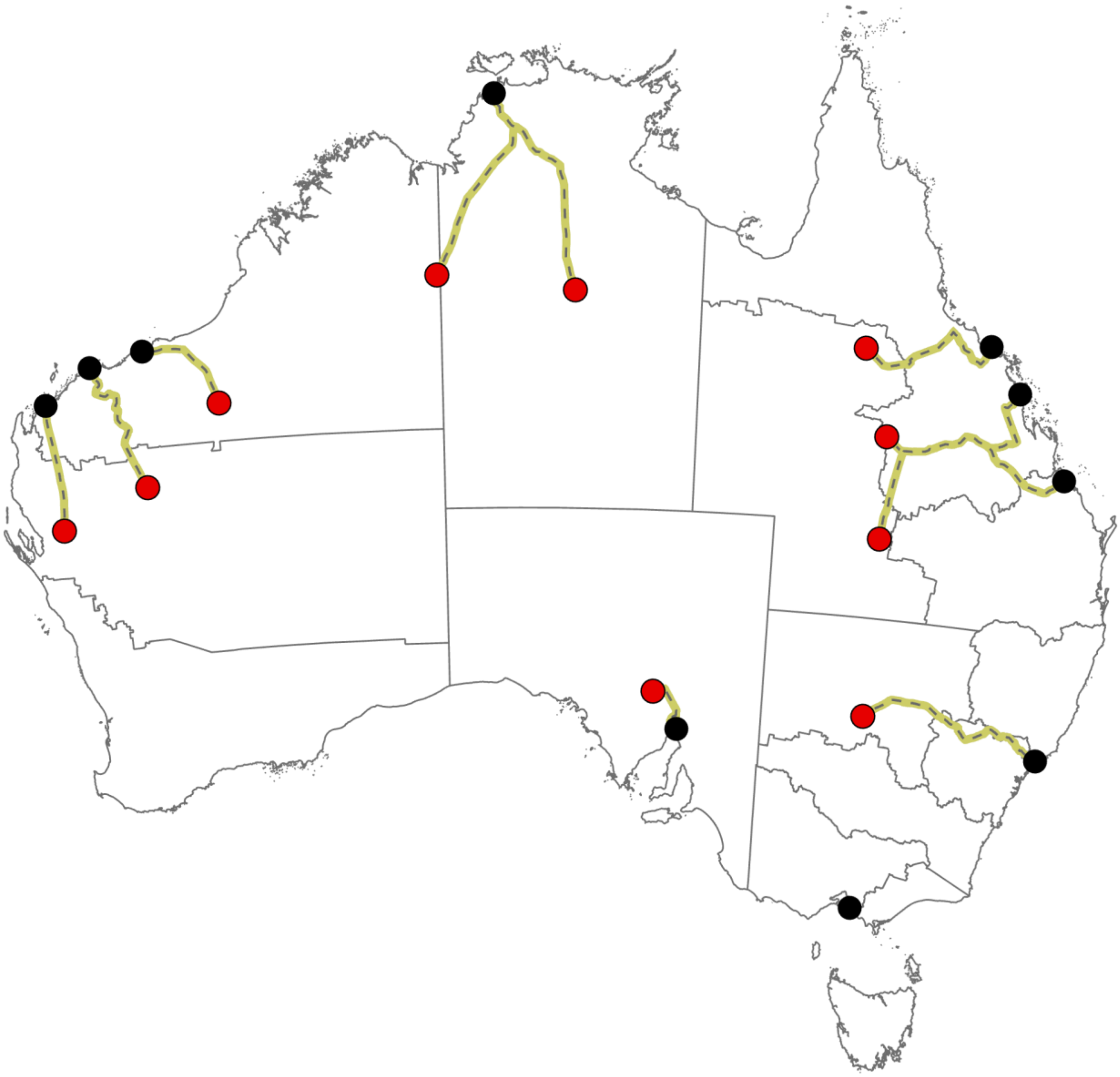


Figure 89 | Map of transmission corridors (yellow & black) connecting aggregation nodes (red) with selected export ports (black).



We finally note that, as part of our energy exports, we include an undersea electricity export cable from the Northern Territory to Southeast Asia. The cable is modelled on the Sun Cable project, which aims to start transferring power from Darwin to Singapore in 2027 via approximately 4,200 kilometres of submarine HVDC transmission cable.[55] The NZAu undersea electricity export cable is included in the supply side model and can expand from a minimum of 4,000 MW capacity in 2027 to a maximum of 24,000 MW capacity in 2060 (minimum of 6,000 MW capacity in 2060). The cost of this export technology is 4,500 2020AU$ per kilowatt with a fixed O&M cost of 135 2020AU$ per kW.

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10.7 Transmission of natural gas, hydrogen and carbon dioxide

10.7.1 Natural gas

Natural gas in Australia is currently extracted from conventional and unconventional reservoirs. The extracted gas from the wellhead is routed and treated in a processing plant before transmission to domestic and overseas markets. Therefore, a pipeline system can be divided into four categories in the natural gas supply chain (Figure 90):

- gathering lines from wellheads to the processing plant
- transmission lines including compressor stations to deliver gas from processing plants' gates or storage facilities to major consumers (e.g., cities, power plants, LNG facilities or industry zones)
- main distribution lines
- smaller distribution lines that service local consumers.

There are also LNG storage tanks and underground storage facilities that benefit system performance.

Figure 90 | Schematic of natural gas supply chain.

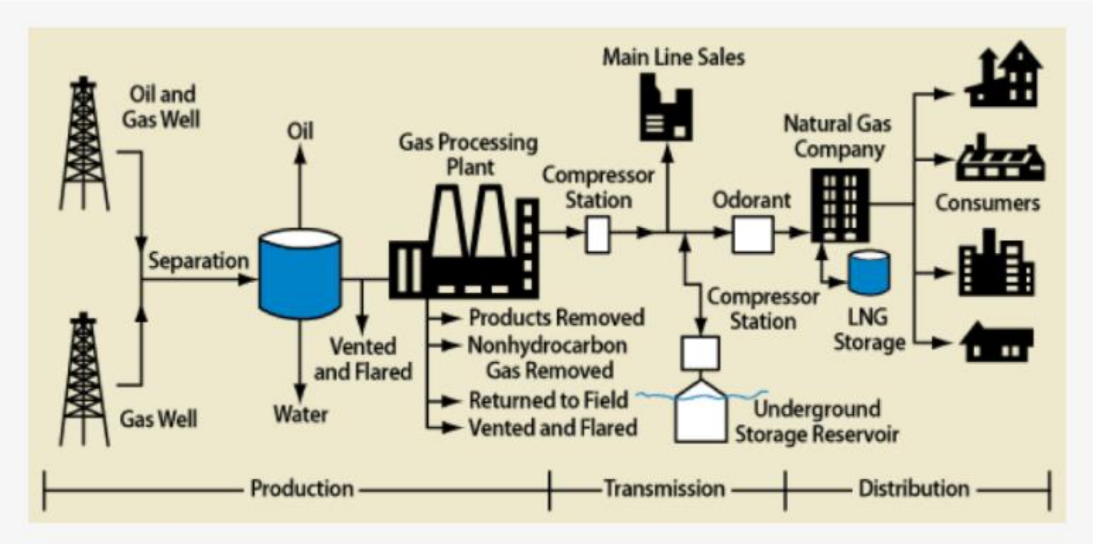
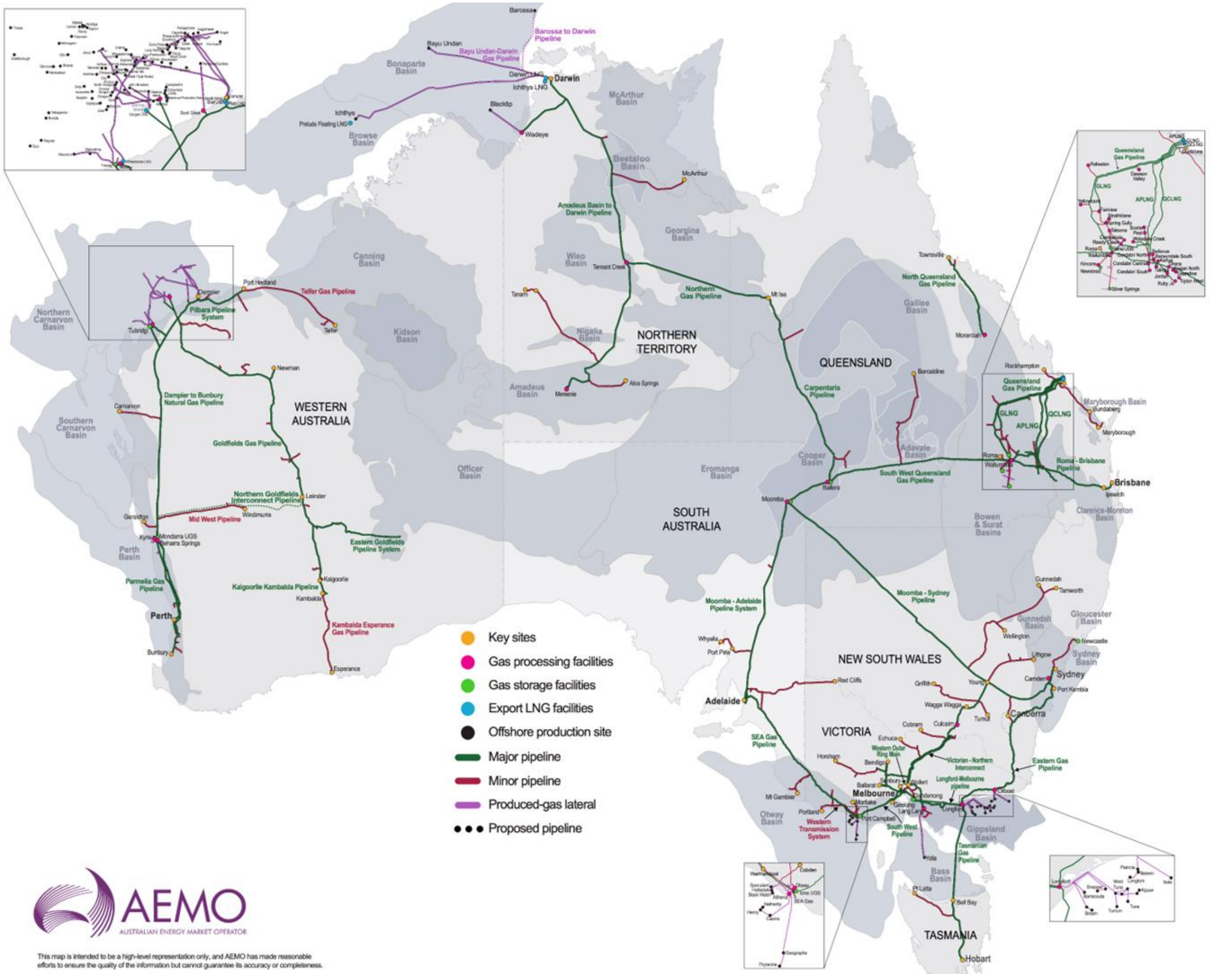


Figure 91 shows the current Australian natural gas transmission network and basins.[1] Conventional natural gas in Eastern Australia is currently produced in the Gippsland, Otway, Bass and Cooper basins.[2] Coal seam gas (CSG) is produced in the Surat-Bowen and Sydney basins. Of these basins in the Eastern states, the dominance of the Surat-Bowen basin is likely to increase in future as production in SA and Vic decline. Conventional natural gas is also produced in the Carnarvon and Perth basins in Western Australia and the Bonaparte Basin in the Northern Territory.[2] These fields across the Nation supply both domestic consumption and LNG exports[2-6].

Figure 91 | Australia's current natural gas transmission network and basins.[1]



The NZAu Project takes a simplified approach to relating the natural gas *production* costs defined in section 9.1 to equivalent *delivered* costs to different users. This is done as follows:

Delivered cost ($/GJ)
= (production cost) + (intra-regional transmission cost) + (inter-regional transmission cost) + (a connection or distribution cost).

In this expression, the *production cost* is that discussed in section 9.1 and includes all from the well to the processing plant exit gate. The *intra-regional transmission cost* is 0.7 $/GJ and levied on all gas production within a given NZAu region. The *inter-regional transmission cost* is set to either 1 $/GJ or 2 $/GJ for existing or new transmission respectively, multiplied by the following fraction that accommodates the transmission line length:

$$\frac{\text{Distance between the regional consumption node and the regional production node}}{\text{Distance from the QLD-outback node to the VIC-east node}}$$

This definition means that inter-regional transmission costs at most 1 $/GJ for existing natural gas transmission and 2 $/GJ for new transmission, such as will occur in the model if CSG produced in QLD-outback is moved to one of the Victorian regions.

The *connection or distribution costs* are 1.5 $/GJ, 7 $/GJ and 13.6 $/GJ for industrial, commercial, and residential customers. Further information on the distribution cost for residential consumers is presented in section 10.8.

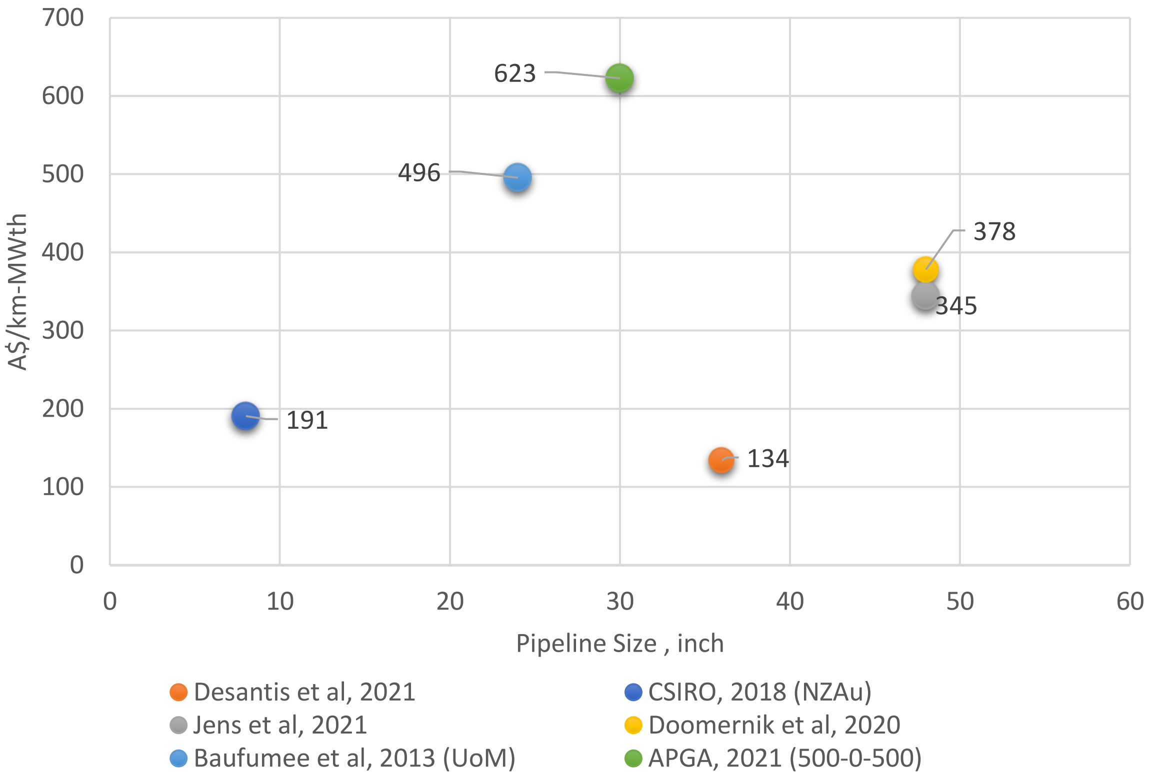
Finally, we only allow natural gas transmission *between* the NZAu regions in the Eastern states and *between* the regions in Western Australia. Trans-continental natural gas transmission is not permitted.

Overall, the resulting delivered costs are thought to agree reasonably with publicly available data, e.g., section 10.8. This approach also avoids use of the significantly more computationally expensive approaches used when the NZAu Project models electricity, hydrogen and carbon dioxide transmission, as detailed later in this section and in other sections of this document.

10.7.2 Hydrogen

No hydrogen pipelines exist in Australia, but there are several feasibility studies that have explored this possibility.[9] The cost of hydrogen transmission via pipeline is a function of the size and the material of the pipeline. The risk of embrittlement is also significantly higher in the transmission network due to increased operating pressure. Operating pressures of between 70 to 100 bar are recommended by the Australian National Hydrogen Road Map and the US DOE.[9-11] Figure 92 provides an overview of pipeline cost for various sizing using the recent studies.[9,12-17] The cost was updated based on Australian dollar 2021 to be comparable.

Figure 92 | Capital cost of hydrogen pipeline based on AU$2021



The above capital cost compare based the size of pipeline in AU$/in/km in Table 72. The result shows that the hydrogen pipeline cost is in range of AU$108k/in-km to AU$125 k/in-km. As the majority of hydrogen pipeline is used for transferring hydrogen to the ports, the cost of pipeline was adjusted to 280 AU$/MW-km for the maximum size of 56 inch using Jens et al.[17]

Table 72 | Capital Cost of Hydrogen Transmission Cost.[9]

	Size	Capital Cost -2021	
	Inch	AU$ /MW-km	AU$/in/km
Desantis et al,[20]	36	134	34,027
APGA (500-0-500)[23]	30	623	118,876
Doomernik et al, [24]	48	378	125,274
Jens et al,[25]	48	345	108,272
Estimated based on Jens et al, [25]	56	280	108,272

The method for calculating the costs of hydrogen transmission is similar to that employed in electricity transmission (section 10.6). Using this GIS-based approach, cost data was determined for connections between regions (Table 73) and for connections between ports and H_2 production nodes (Table 74). According to industry stakeholder advice, 1.5% of capital cost is considered for total operating cost including both fixed and variable costs.

Table 73 | Cost of hydrogen transmission between regions assuming shared electricity and hydrogen transmission routes in section 10.6.

Region to region	Distance (km)	H_2 pipeline Capital Cost (AU$/GJ pa)	H_2 pipeline Operating Cost (AU$/GJ)
WA-south to WA-central	869	7.715	0.135
WA-south to SA (not allowed in E+RE–)	2,514	22.321	0.359
WA-central to NT	3,121	27.707	0.352
WA-central to WA-north	602	5.349	0.082
WA-central to SA (not allowed in E+RE–)	3,277	29.094	0.400
WA-north to NT	2,519	22.369	0.278
NT to SA (not allowed in E+RE–)	2,861	25.402	0.374
NT to QLD-north	2,386	21.187	0.314
NT to QLD-outback	1,556	13.816	0.194
QLD-north to QLD-outback	832	7.386	0.121
QLD-north to QLD-south	1,150	10.213	0.158
QLD-outback to QLD-south	1,773	15.739	0.278
QLD-outback to SA	1,795	15.934	0.219
QLD-outback to NSW-outback	1,850	16.425	0.172
QLD-south to NSW-outback	1,484	13.172	0.317
QLD-south to NSW-north	434	3.853	0.078
NSW-north to NSW-central	424	3.768	0.111
NSW-north to NSW-outback	1,097	9.740	0.239
NSW-outback to SA	478	4.248	0.068
NSW-outback to NSW-south	882	7.832	0.133
NSW-outback to NSW-central	955	8.483	0.167
NSW-central to NSW-south	255	2.261	0.038
NSW-south to VIC-east	538	4.776	0.079
NSW-south to VIC-west	485	4.307	0.080

Region to region	Distance (km)	H_2 pipeline Capital Cost (AU$/GJ pa)	H_2 pipeline Operating Cost (AU$/GJ)
VIC-east to VIC-west	152	1.349	0.022
VIC-east to TAS	362	3.213	0.048
VIC-west to TAS	511	4.541	0.070
VIC-west to SA	720	6.397	0.116
SA to NSW-south	1,054	9.359	0.195

Table 74 | Cost of hydrogen transmission between hydrogen carrier export ports and hydrogen production nodes assuming shared electricity and hydrogen transmission routes in section 10.6.

Ports	Nodes	H_2 pipeline capital cost (AU$/GJ pa)	H_2 pipeline Operating Cost (AU$/GJ)
Port of Darwin	Darwin 1	6.71	0.101
Port of Darwin	Darwin 2	7.36	0.110
Port of Abbot Point	Abbot Point	5.59	0.084
Ashburton	Ashburton	3.77	0.057
Port Hedland	Port Hedland	3.37	0.051
Hay Point	Hay Point	6.63	0.100
Dampier	Dampier	4.85	0.073
Newcastle	Newcastle	7.23	0.108
Port of Gladstone	Gladstone	9.00	0.135
Port Bonython	Port Adelaide	1.81	0.027

10.7.3 Carbon dioxide

Carbon dioxide (CO_2) pipelines can transport large volumes of supercritical CO_2 at high pressures through relatively small diameter pipes. To maintain its supercritical state, the CO_2 is transported at pressures ranging from about 120 to 190 atmospheres. Globally, the transport of CO_2 through pipelines began in the 1970's for enhanced oil recovery (EOR). As such CO_2 pipeline costs are relatively well-known in places where EOR is common, like North America [18].

As there are no large CO_2 trunklines in Australia, we adapted the National Energy Technology Laboratory transport cost model[18], a pipeline capacity of 10 Mt-CO_2/year and a base cost of $0.2/t-$CO_2$/km. According to industry stakeholder advice, 1.5% of total capital cost is assumed for total operating cost of the pipeline. The method for establishing the cost of individual CO_2 transmission pipelines is similar to that of hydrogen transmission, with the costs of CO_2 transmission between regions given in Table 75.

Table 75 | Cost of CO_2 transmission pipeline between regions.

Region to region	Distance (km)	CO_2 pipeline capital cost (AU$/t-$CO_2$ pa)	CO_2 pipeline operating cost (AU$/t-$CO_2$)
WA-south to WA-central	869	173.8	3.03
WA-south to SA (not allowed in E+RE–)	2,514	502.8	8.08
WA-central to NT	3,121	624.1	7.94
WA-central to WA-north	602	120.5	1.84
WA-central to SA (not allowed in E+RE–)	3,277	655.4	9.01
WA-north to NT	2,519	503.9	6.26
NT to SA (not allowed in E+RE–)	2,861	572.2	8.42
NT to QLD-north	2,386	477.3	7.08
NT to QLD-outback	1,556	311.2	4.37
QLD-north to QLD-outback	832	166.4	2.72
QLD-north to QLD-south	1,150	230.1	3.56
QLD-outback to QLD-south	1,773	354.5	6.27
QLD-outback to SA	1,795	358.9	4.94
QLD-outback to NSW-outback	1,850	370.0	3.87
QLD-south to NSW-outback	1,484	296.7	7.15
QLD-south to NSW-north	434	86.8	1.77
NSW-north to NSW-central	424	84.9	2.50
NSW-north to NSW-outback	1,097	219.4	5.38
NSW-outback to SA	478	95.7	1.54
NSW-outback to NSW-south	882	176.4	2.99
NSW-outback to NSW-central	955	191.1	3.76
NSW-central to NSW-south	255	50.9	0.85
NSW-south to VIC-east	538	107.6	1.78
NSW-south to VIC-west	485	97.0	1.79
VIC-east to VIC-west	152	30.4	0.50
VIC-east to TAS	362	72.4	1.09
VIC-west to TAS	511	102.3	1.59
VIC-west to SA	720	144.1	2.60
SA to NSW-south	1,054	210.8	4.38

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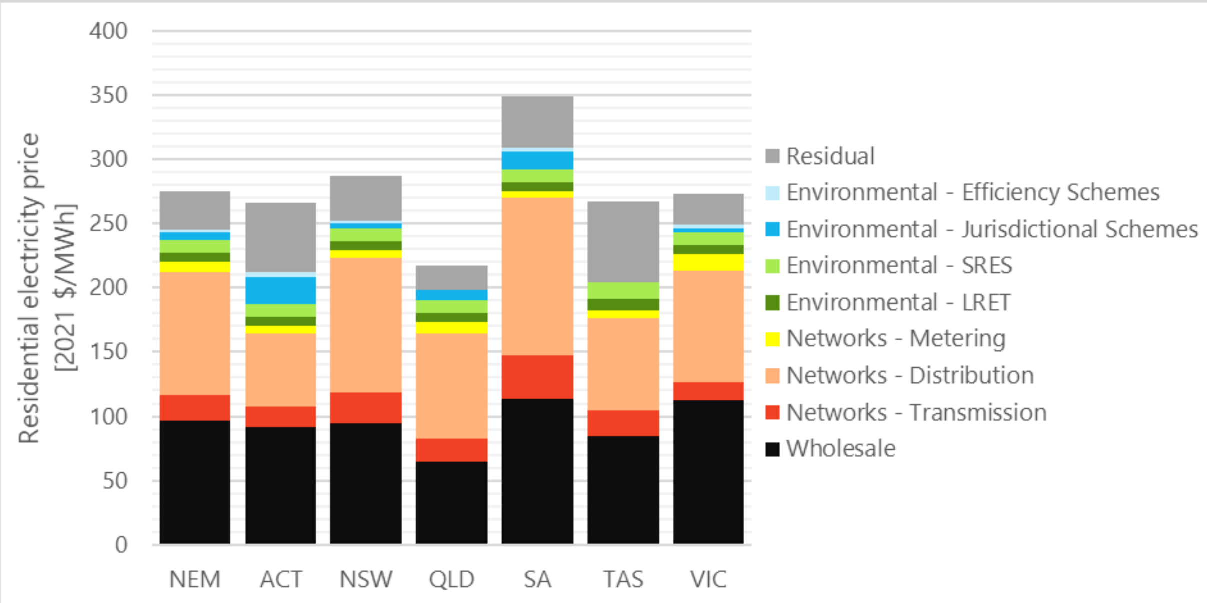
10.8 Electricity and natural gas distribution

The costs of electricity and natural gas distribution are incorporated into the modelling by examining the network tariff component of current electricity and natural gas prices. Data for the cost component breakdown of current energy bills is sourced from the *Australian Energy Regulator* (AER) State of the Energy Market 2021 report[1] and *Australian Energy Market Commission* Residential Electricity Price Trends 2021 report.[2]

10.8.1 Electricity distribution

Figure 93 presents the average 2021 residential electricity price by region and bill component.[1,2] On average, regulated network costs comprise 45% of residential electricity prices, 8% of which is a transmission network tariff and 35% of which is a distribution network tariff (the remainder being network metering costs). These distribution and transmission network tariffs are used as input to the NZAu modelling. Data for the NT and WA were not presented in these sources.

Figure 93 | Average 2021 residential electricity prices, by region and bill component.[1,2]



In addition to current electricity bills, we examine electricity network charges levied by Australia's distribution network service providers (DNSP) and regulated by the Australian Energy Regulator. These regulated costs are published by the AER,[3] with indicative costs for various tariff classes, including residential, small business, and limited large business coverage. These costs are shown in Figure 94 by network cost component, by tariff class, and for each NZAu modelled zone, where available. Where a specific DNSP is the sole network in a given NZAu zone, the specific costs of that DNSP are presented, e.g., SA Power Networks costs are presented for the SA NZAu zone. Where multiple DNSPs have networks within a NZAu zone, the average cost between those DNSPs is presented for the zone.

It can be seen in Figure 94 that NZAu zones have higher distribution costs if they do not feature large city load centres or have low population density. Limited information for large business network costs was available. For NZAu zones where network cost data was unavailable, the data for small business in that zone was scaled in proportion to the average difference between large and small business cost for the zones with available data.

Based on these sources, NZAu uses electricity distribution costs of:

- 106 $/MWh for residential consumers

- 67 $/MWh for commercial consumers
- 48 $/MWh for industrial consumers
- 86 $/MWh for transport sector consumers.

These costs are used in the modelling to set the 2020 annual distribution network revenue requirement, 60% of which is assumed to cover capital costs and 40% to cover O&M (and other) costs, which is representative of Australian electricity distribution as shown in Figure 95.[4] This revenue requirement is then scaled in the modelled years after 2020 with the capital component (in $ rather than a %) scaling linearly with the peak demand for each sector (residential, commercial, industrial, and transport) and with the O&M component remaining constant. This annual revenue requirement can be interpreted in the modelling as the electricity distribution cost to the various consumer types, following previous work[5,6].

In addition, we incorporate distribution network electricity losses of 4%, following previous work.[4,5]

Figure 94 | Electricity network costs levied by Australia's distribution network service providers, by network cost component and the relevant NZAu zone that hosts the various DNSPs.[3]

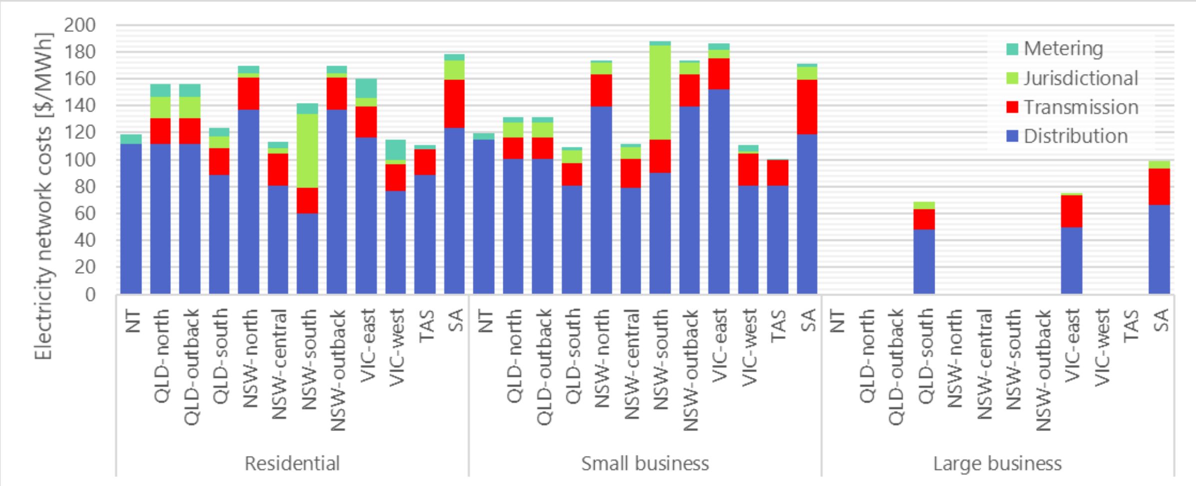
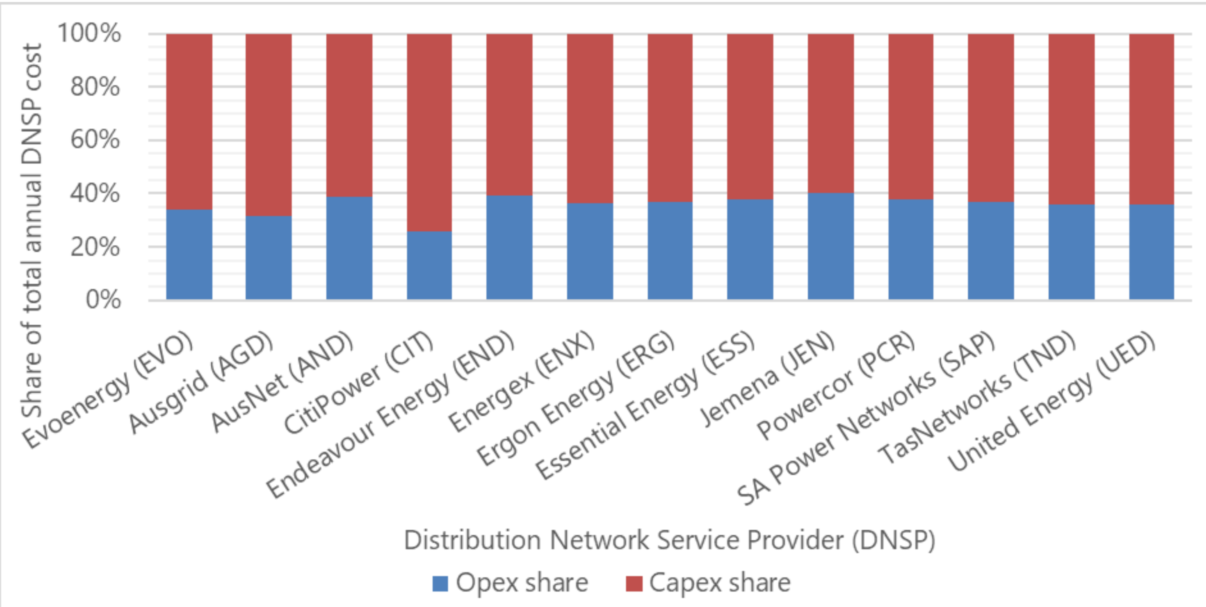


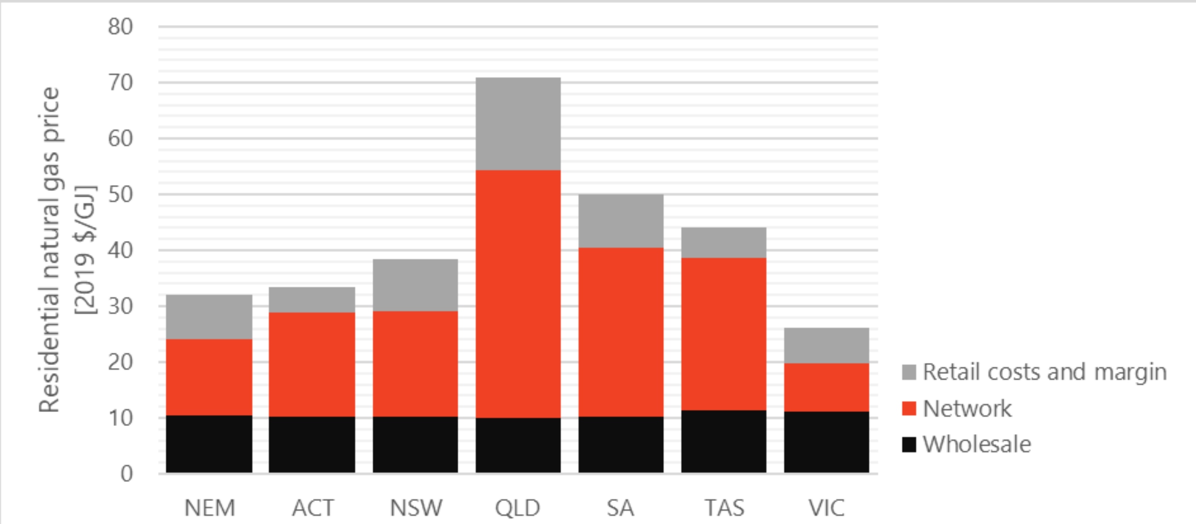
Figure 95 | Capex and Opex share of total annual distribution network cost for 2021 [4].



10.8.2 Natural gas distribution

Figure 96 presents the average 2017 residential natural gas price by region, broken down by component.[1] These are estimates presented in the State of the Energy Market 2021 report, which covers only the eastern and southern states. The component of natural gas prices that varies most among regions is the network tariff component. This is lowest in VIC, which has the highest level of gas use per customer and a high connection penetration, while network costs are highest in the regions with lower residential natural gas use.[1] The NEM-averaged network tariff component, shown in Figure 96, is used as an input to the macro-scale energy modelling to represent the cost of natural gas distribution to residential customers, with further details on the delivered cost of gas to various other user types provided in section 10.7.1. In addition we incorporate a gas distribution network loss value of 3%, following previous work.[4,5]

Figure 96 | Average 2017 residential natural gas prices, by region and bill component.[1]



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10.9 On-road transport

Projections for on-road transport vehicle costs were sourced from CSIRO's *Electric vehicle projections 2021* report[1]. This report provided upfront costs for:

- internal combustion engine (ICE) vehicles;
- short- and long-range battery electric vehicles (BEVs);
- plug-in hybrid electric vehicles (PHEVs); and
- fuel cell vehicles (FCVs);

across the range of vehicle classes:

- light/small car;
- medium car;
- large/heavy car;
- rigid truck;
- articulated truck; and
- bus.

The upfront costs for these vehicles are presented in Figure 97, where passenger vehicles and light commercial vehicles are CSIRO's medium car and large/heavy car classes, respectively. Note also that we only use the long-range BEV cost projections in this work.

The projections in Figure 97 show that ICEs have the lowest upfront costs across all vehicle classes, but that BEVs, PHEVs and FCVs are projected to experience significant technological learning and associated cost reductions, such that by around 2040 they reach near cost parity with ICEs. The timing of this approximate parity being reached depends on the vehicle class. The cost projections do not show BEVs reaching precise cost parity with ICEs because this work has used the projections for the long range BEVs in the CSIRO works.

Figure 98 presents the modelled annual fixed operating and maintenance (O&M) costs for these same vehicles. Note that the CSIRO report does not present vehicle O&M costs, and so the data presented here, are sourced from a number of reports used previously in the *Net Zero America* project.[2, 3] These data show that BEVs have lower fixed O&M costs than ICEs in all vehicle classes.

Figure 97 | Upfront vehicle cost across the range of vehicle classes and propulsion systems considered in NZAu.[1]

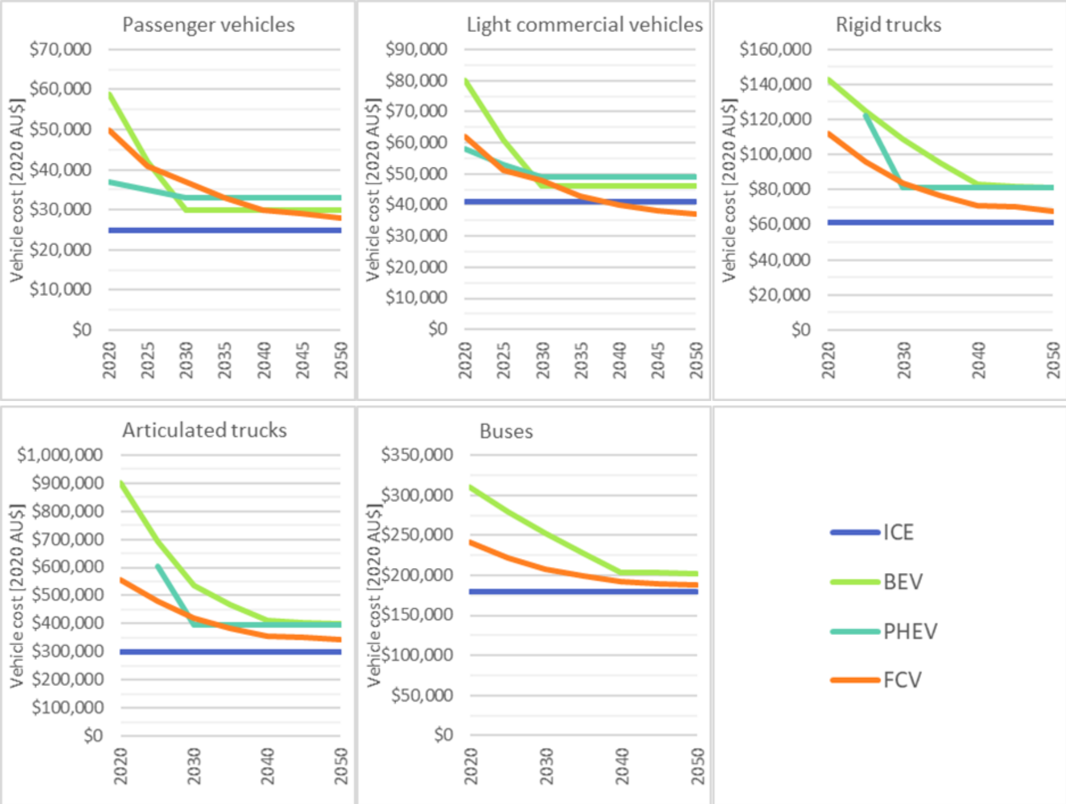
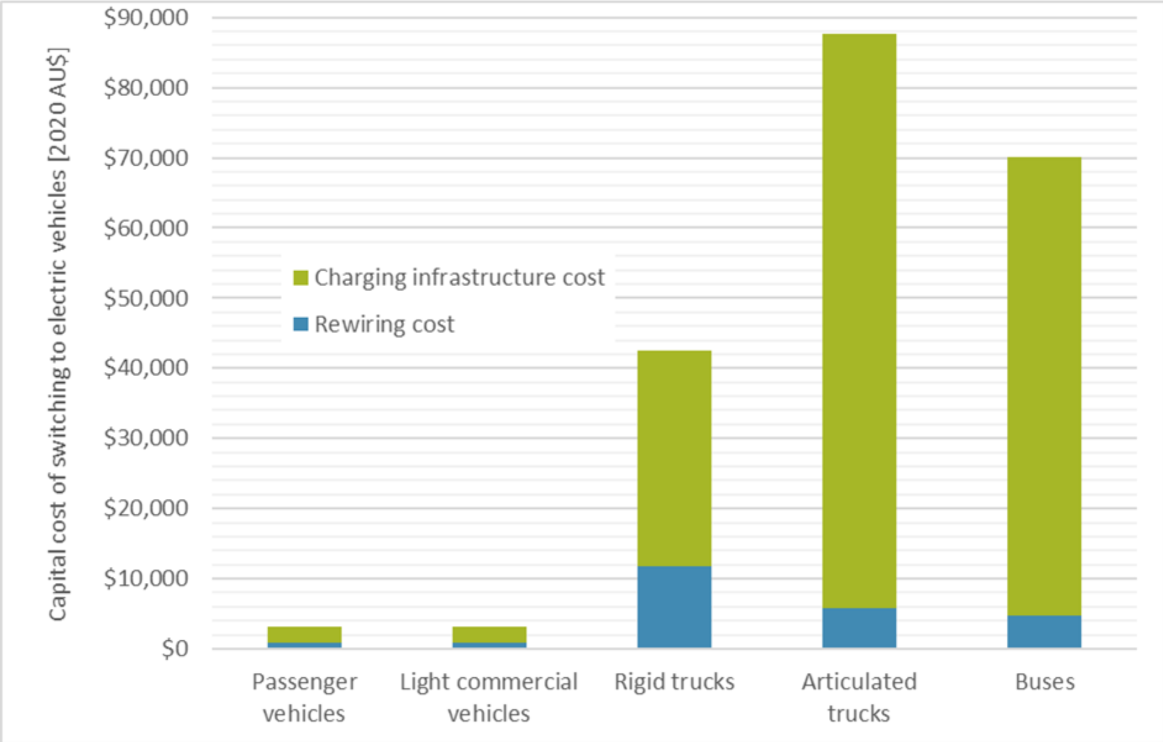


Figure 98 | Annual fixed operating and maintenance (O&M) costs for vehicles across the range of vehicle classes and propulsion systems considered in *NZAu* [2, 3].

The NZAu modelling also incorporates the capital costs associated with distribution network modifications to accommodate electric vehicles. This cost is represented by a *rewiring cost* and a *cost of charging infrastructure*, as shown in Figure 99. The rewiring component is a one-time cost incurred when a ICEV is switched for a BEV and represents the cost of EV charger installation. The charging infrastructure component represents the actual capital cost of EV chargers and is incurred for every EV sold (regardless of whether that sale represents a switch or not). These associated costs amount to about $3,200 for passenger vehicles and LCVs, significantly higher $42,000 – $88,000 for larger vehicles, and represent the aggregate costs of both residential and non-residential EV charging infrastructure. These data are sourced from a number of reports used previously by EER in their modelling of *Net Zero America*.[2,3]

Finally, note that the stock of *rail*, *sea* and *air* vehicles are not tracked or explicitly modelled in *NZAu*, and hence their projected vehicle costs are not used in this modelling. Nonetheless, decarbonisation of rail, sea and air transport *is* modelled via efficiency improvements and switching to clean fuels, and these are discussed in the projections of energy demand (section 7).

Figure 99 | Estimated capital cost of charging infrastructure and rewiring required when switching to electric vehicles, for the range of electric vehicle classes modelled in *NZAu* [2, 3].



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Appendices

Appendix A: Full list of WACC values

Asset type	Nom. WACC	Asset type	Nom. WACC
Electricity export cable	8.5%	Steam reforming w/cc	8.5%
Brown coal gasification w/cc	8.5%	Li-ion	7.7%
Black coal gasification w/cc	8.5%	Pumped hydroelectric storage	8.5%
LNG plant	8.5%	Biomass power	8.5%
LNG plant electric	7.7%	Biomass power Allam w/cc	8.5%
Electric LNG plant retrofit	8.5%	Biomass power w/cc	8.5%
H_2 storage salt cavern	8.5%	Black coal power w/cc	8.5%
H_2 storage underground pipes	8.5%	Black coal power	8.5%
Autothermal reforming w/cc	8.5%	Brown coal power	8.5%
Bio-gasification	8.5%	Gas combined cycle	8.5%
Bio-gasification w/cc	8.5%	Gas combined cycle w/cc	8.5%
Bio-gasification Fischer-Tropsch	8.5%	Gas combustion turbine	8.5%
Bio-gasification Fischer-Tropsch w/cc	8.5%	Gas combined cycle Sllam w/cc	8.5%
Biomass fast pyrolysis	8.5%	Generation IV nuclear	10.7%
Biomass fast pyrolysis w/cc	8.5%	Rooftop solar PV	7.7%
Direct air capture	8.5%	Large-scale solar PV	7.7%
Electrolysis	8.5%	Onshore wind	7.7%
Fischer-Tropsch liquids	8.5%	Offshore wind	7.7%
Fischer-Tropsch LPG	8.5%	HV transmission	4.7%
Haber-Bosch	8.5%	CO_2 Trunklines	4.7%
Methanation	8.5%	H_2/NH_3 Trunklines	4.7%
Steam reforming	8.5%		

Appendix B: Advice from Global CCS Institute

GLOBAL CCS INSTITUTE

03 November 2021

CO2 storage in Australia: Capacity, Resources and Injection Rates

Since the National Carbon Mapping and Infrastructure report in 2010 (Carbon Storage Taskforce, 2010), little progress has been made in understanding the storage resources and injection sites across Australia.

The exception to these broad conclusions is a few critical basins, which have undergone additional formation to site-scale analysis, including the acquisition of CO_2-specific data modelling and analysis. The basins are the offshore Gippsland (Victoria), Bonaparte (Northern Territory), Browse (Western Australia), Northern Carnarvon (Western Australia), Surat (Queensland), and the Eromanga/Cooper (South Australia and Queensland). The additional exploration and appraisal work in these basins have generally supported the estimates published by the Taskforce. The ongoing evaluation of these basins also means a shorter timeframe to initial project deployment.

Based on the conservative storage resource (P10[1]) estimates of Carbon Storage Taskforce (2010) report, the Global CCS Institute has detailed the potential injection rates in those basins above. The results are detailed in the table 1 below.

The limitations and assumptions to these estimates include:

- Potential Injection Rates columns (10 and 50%) represent the realistic and optimistic ranges, respectively, for the accessible "P10" pore space for CO_2 storage over a sustained injection period of 50 years
- Potential Injection Rates do not consider the source of CO_2
- Potential Injection Rates are theoretical until appraisal and injection tests are completed across multiple sites in each basin.

[1] According to the Carbon Storage Taskforce (2010), P10 is "Proven" used where there is at least a 90% probability that the storage capacity is able to be utilised will equal or exceed the estimate.

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The Potential Injection Rates assume a major change in Australia's commitment to the deployment of CCS. To reach those injection rates, we assume that after the 50-year timeframe, Australia has:

- Long term, supportive policies to enable the deployment of CCS in a broader net-zero climate policy environment
- Regulations to enable the exploration, appraisal, and storage of CO_2 across every state and territory
- Major funding initiatives from both the private and public sector
- Optimised CO_2 infrastructure and injection in each basin

Table 2. Potential Injection Rates in key Australian basins.

Basin Name	**Carbon Storage Taskforce CO_2 Storage Resources (CO_2; million tonnes)**	**Potential Injection Rates (CO_2 million tonnes per year)**	
	P10	**10%**	**50%**
Gippsland – offshore	30,100	60.2	301.0
Eromanga - SA	26,800	23.2	116.0
Cooper	4,100	8.2	41.0
Carnarvon – North	25,500	51.0	255.0
Browse	7,000	14.0	70.0
Bonaparte – NT	32,200	64.4	322.0
Surat	6,100	12.2	61.0

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