



Methods, Assumptions, Scenarios & Sensitivities

24 September 2025

NET ZERO AUSTRALIA

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Net Zero Australia

Methods, Assumptions, Scenarios and Sensitivities

24 September 2025

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Contents

1	Introduction	1
1.1	Project motivation, objectives and approach	2
1.2	Scope of this document	2
1.3	Modelling tools	4
2	Modelling methodology	5
2.1	Summary	5
2.2	Model introduction	5
2.3	General assumptions	6
2.4	Temporal resolution	7
2.5	Frequently asked questions	8
3	Core Scenarios	13
3.1	Domestic system modelling Scenarios overview	13
3.2	Reference Scenario	18
3.3	Current Policies Scenario	19
3.4	Net Zero 2050 Scenario	24
3.5	Net Zero Extended Timeline Scenario	26
3.6	Generating alternatives	26
4	Export modelling approach	29
5	Projections of population, GDP growth and other primary drivers	30
6	Costs of capital	34
6.1	Basis for WACC estimates	34
6.2	WACC values	35
7	Emissions accounting	37
7.1	Emissions overview	37
7.2	Modelled domestic emissions	38
8	Modelled regions	42
8.1	Regional boundaries	42
8.2	Summary of regional cost factors	46
9	Historical demand	50
9.1	Decomposition of final energy demand	50
9.2	On-road transport	57
9.3	Buildings	60
9.4	Electricity load shapes	62
10	Projections of energy demand	66

11	Projections of agriculture, LULUCF and waste	74
11.1	Combined projections	76
11.2	Agriculture.....	78
11.3	LULUCF.....	88
11.4	Waste.....	94
12	Resource availabilities and costs	97
12.1	Coal, gas and oil costs and production	97
12.2	CO ₂ geological storage capacities and unit costs.....	99
12.3	Biofuel	102
12.4	Existing utility scale electricity generation	105
12.5	Rooftop solar PV	108
12.6	Hydroelectric generation.....	110
12.7	Renewable availability traces	111
12.8	Renewables supply curves	119
13	Supply-side capital and operating costs	124
13.1	Electricity generation and storage.....	124
13.2	Liquid and gaseous fuel production and storage.....	129
14	Transmission and distribution network costs	140
14.1	Electricity transmission	141
14.2	Gaseous fuels transmission	144
14.3	Water transmission	153
14.4	Electricity and natural gas distribution	154
14.5	Energy transmission and distribution cost allocation.....	158
15	Demand-side capital and operating costs	161
15.1	Industrial sector.....	161
15.2	Direct air capture	172
15.3	Residential demand-side technologies	173
15.4	Road transport.....	176
Appendix A	WACC methodology and values	181
A.1	WACC estimation method	181
A.2	Range of WACCs estimated by Oxford Economics by technology (real, pre-tax)	183
A.3	Full list of WACC values used by NZAu (real, pre-tax)	184
Appendix B	Regional cost factors by technology	186
Appendix C	GenCost scenario selection	187
Appendix D	Global CCS Institute’s Advice	188



1 Introduction

The Net Zero Australia (NZAu) Project is a partnership between The University of Melbourne, The University of Queensland and Princeton University. The NZAu Project is intended to be rigorous and granular, evidence driven, technology neutral and non-political in its approach. Phase 1 of the NZAu Project ran from 2021 to 2023, with the Project now in Phase 2.

Once again, generous financial support has enabled this study, with gift and equivalent grant agreements with the following organisations for Phase 2 of the NZAu Project:

- APA Group,
- the Australian Pipelines and Gas Association,
- EnergyAustralia,
- Iberdrola Australia, and
- the Future Energy Exports Cooperative Research Centre.

Crucial input to this project has also been provided by a diverse Advisory Group, with nominees from the following organisations:

- the Australian Conservation Foundation,
- the National Farmers Federation,
- the National Native Title Council, and
- the St Vincent de Paul Society.

Our Advisory Group also has several distinguished independent members as well as nominees from our Sponsors.

This combination of gift-based sponsorship, a diverse Advisory Group and our open consultation on all our inputs, methods and results has supported the NZAu Project's independence from its Sponsors, Advisory Group and many stakeholders. *The NZAu Project therefore does not purport to represent Sponsors and Advisory Group member positions or imply that they have agreed to our input assumptions, methodologies or results.*

1.1 Project motivation, objectives and approach

The NZAu Project is intended to be rigorous and granular, evidence driven, technology neutral and non-political in its approach. Very briefly, our modelling:

- uses a scenario-based approach;
- uses the best available inputs and assumptions;
- uses a least cost optimization approach; and
- ‘downscales’ our results to a regional and sub-regional basis.

In 2023, Phase 1 of the NZAu Project released two reports that illustrated the scale, complexity and cost of the net zero challenge, irrespective of which specific pathway is preferred or taken; the implications of key choices; and the potential impacts across society, the economy and the environment by making these choices. We did this to reflect the boundaries of the Australian debate.

As such, Phase 2 of the NZAu Project now focuses on:

- *tracking* how the Nation is performing relative to what is needed;
- *analysing* major aspects of the decarbonisation challenge with sufficient depth and rigour for policy development and planning;
- *making practical recommendations* that can achieve deep decarbonisation while acknowledging environmental and social objectives and trade-offs; and
- *translating* these recommendations more strongly into policy, planning, investments and, ultimately, operational projects.

We note, however, that Phase 2 of the NZAu Project *still does not*:

- make predictions;
- calculate or analyse the costs of inaction on climate change, which we know are higher than the costs of abatement that we do study; and
- model demand for clean energy exports which, like global fossil fuel trade, is deeply uncertain.

1.2 Scope of this document

Given the large, uncertain and unprecedented changes that are required to achieve deep decarbonisation, there will inevitably be different views on the plausibility of projections made by ourselves and others. Rather than seeking consensus on all aspects of our modelling, the NZAu Project therefore intends to develop and present a methodology that is transparently defined, appropriate for the task and based upon input assumptions that are stated clearly and from 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.

This *Methods, Assumptions, Scenarios, and Sensitivities (MASS)* report therefore describes our modelling methods and its input assumptions and *does not present results*. The *Net Zero Australia (NZAu)* Project again considers our modelling at two levels of granularity, as follows.

1. Regional Investment Modelling

This modelling determines the investments that could occur in 21 defined regions across Australia (Figure 1) such that a least-cost national energy system is realised for different Scenarios, including some that feature net zero emissions by mid-century. 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, farmland, higher population density areas and structurally unsuitable land. Employment impacts are can also be modelled in the downscaling effort.

Figure 1 | Modelled regions in Phase 2 of the NZAu Project.



1.3 Modelling tools

Figure 2 presents a schematic representation of the three modelling stages in the NZAu Project. The NZAu Project uses two modelling tools from Evolved Energy Research (EER).

1. The EnergyPATHWAYS (EP) modelling tool from EER

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.

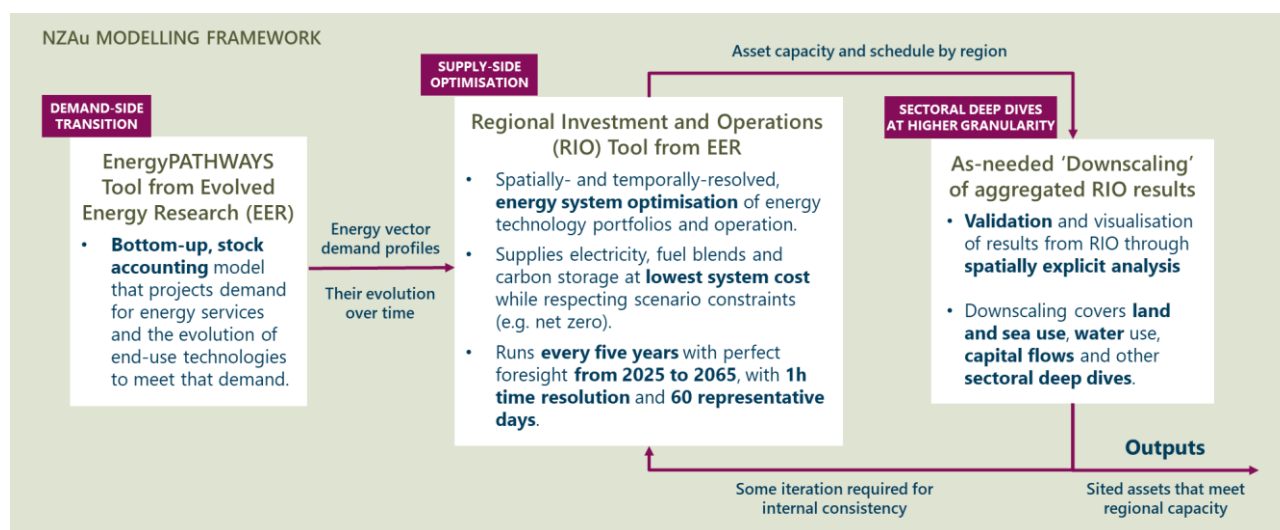
2. The Regional Investment and Operations (RIO) modelling tool from EER

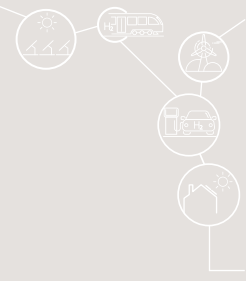
The RIO modelling tool uses the demand pathways developed with the EP modelling tool. It determines the lowest cost mix of the required supply-side and network investments to meet this demand, whilst also meeting defined greenhouse gas emission (GHG) constraints. RIO's outputs are generated for each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

3. Downscaling

The modelling undertaken for the downscaling depends on the specific downscaling effort. For example, the siting of renewable generation and transmission of different forms is undertaken using its own least cost modelling using the ArcGIS software tool. This approach integrates renewable energy resource assessment that we developed along with numerous geographical overlays that constrain this optimisation in different ways. The form of the specific downscaling effort will be specified in each report that presents our results.

Figure 2 | Modelling framework used in the Net Zero Australia (NZAu) Project.





2 Modelling methodology

2.1 Summary

This study uses a scenario modelling approach with two energy system modelling tools, as demonstrated in previous work^[1-9]. We develop emissions reduction Scenarios for the Australian energy and industrial (E&I) system that meet the same demand for energy services as a Reference Scenario. The Scenarios are a detailed representation of E&I infrastructure as it changes over time, due to greenhouse gas reduction and other policies, together with population, GDP and industrial production assumptions.

The modelling is undertaken using the RIO and EnergyPATHWAYS (EP) models developed by Evolved Energy Research, a U.S. based consultancy. These models were deployed and refined in the Net Zero America Project^[4] and again in the first phase of the Net Zero Australia Project^[2].

Detailed descriptions of the methods used by these two numerical models are included in other published reports. This Chapter is intended to provide a brief overview and highlight key assumptions that are specific to the modelling of the Australian energy system. We direct the reader to other relevant publications elsewhere for additional information.

2.2 Model introduction

Energy and energy-service demand projections were developed in EnergyPATHWAYS (EP), which is a bottom-up stock accounting model with 56 demand subsectors for Australia. The EP model is open source and the code and basic user materials can be found on GitHub^[10].

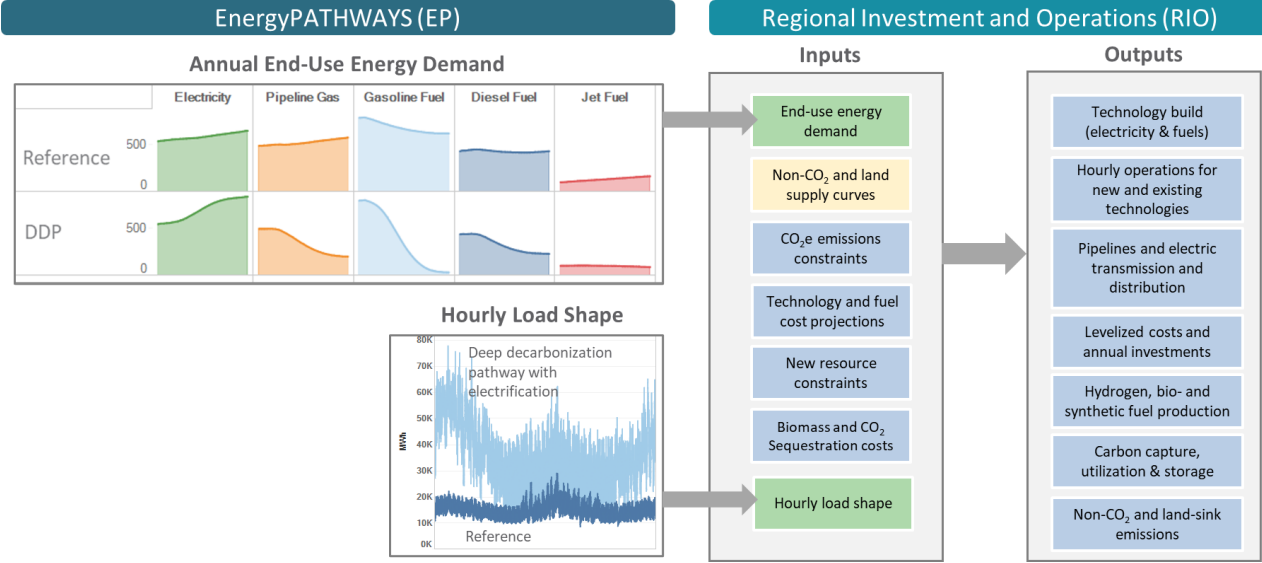
EP outputs, including time-varying electricity and fuel demand, are used as inputs to RIO, which is a linear programming model that combines capacity expansion and sequential hourly operations to find least-cost, supply-side pathways. The objective for the optimisation is to find the technology configurations that minimise the net present value of the sum of all energy system costs over the modelling period, 2025–2065. Because EP and RIO are run in series without iteration, all results are in partial equilibrium and do not account for elasticity in energy services. Although the RIO model is a proprietary tool developed by EER, a detailed methodology is published as part of the U.S. Annual Decarbonization Perspective^[11], which used the same version of the model as that used in the Net Zero Australia Project.

RIO has unique capabilities for analysing Australia’s energy system. It:

- models in detail the interactions between electricity generation, fuel production and CCUS, allowing evaluation of the coupling between these sectors;
- tracks the state of charge of energy storage over an entire year, allowing assessment of balancing requirements in electricity systems with high levels of variable renewable energy; and
- solves for all infrastructure decisions in five-year time-steps to optimise the energy system transition and not only the endpoint.

The steps of the modelling analysis are framed at a high level in Figure 3.

Figure 3 | NZAu’s energy system modelling framework pairs a scenario-based stock-accounting tool, EnergyPATHWAYS (EP), with an economy-wide optimisation model, Regional Investment and Operations (RIO).



2.3 General assumptions

Table 1 presents the model inputs that were employed across all scenarios for Net Zero Australia.

Table 1 | General assumptions common to all scenarios.

Assumption	Value	Notes
Social discount rate	2.7%	Pure time preference for valuing present costs and benefits more highly than those in the future. Used to formulate the optimisation’s objective function (the NPV of all system costs).
Hydro year	Average	Based on long-run average of hydro generation.
Hydro energy constraint	Fixed daily energy budgets	Does not allow daily generation to deviate from historical record; a conservative assumption.
Long duration storage capacity reservation period	Month	Storage capacity is reserved for long duration balancing over a monthly reservation window to prevent over optimisation with perfect foresight.
Number of electricity day samples	60	Electricity operations sampled with 60 days in each year (1440 hours). The 60 days modelled for future years were chosen independently based on clustering around gross load and renewable production features.
Generator retirements	Economic	Generators and other plant are assumed to retire at the end of a specified physical lifetime but can retire sooner to avoid fixed O&M cost and minimise total system cost.
Currency	AUD	
Currency year	2024	Calendar year

2.4 Temporal resolution

RIO is an optimisation model that can be configured for different temporal resolutions depending on the needs of the proposed analysis. The Net Zero Australia Project uses 60 days from each year that are sampled based on load and renewable shapes from a 2018 historical weather year. Different days are selected for different future years because increasing electrification and wind and solar development results in a different mix of 60 days providing the best approximation of a full year (365 days) of operations. The subset of days used for each modelled year is presented in Table 2. Within days, RIO optimises generator, storage and flexible load dispatch with hourly resolution.

Our Scenario modelling horizon spans 2025–2065 with 5-year timesteps. The first modelled year, 2025, represents our current energy system, with current demand for energy and energy-services based on recent data, and with only existing energy and industrial infrastructure participating. Any applied emissions constraints are formulated to not be binding in this first modelled year. Subsequent modelled years comprise projections of energy demand and optimisation of investments and operations to meet that demand, subject to any emissions constraints applied. Decisions to build or retire infrastructure are made every 5 years, but the costs of energy system operations, including capital costs that are annualised over plant lives, are accounted for all intermediate years. Build rates (and any applied constraints) are also accounted annually.

Table 2 | Modelled days from the 2018 weather year used when modelling future operations for snapshot years.

2025	2030	2035	2040	2045	2050	2055	2060	2065
22/1/2018	8/1/2018	14/1/2018	3/1/2018	10/1/2018	10/1/2018	13/1/2018	13/1/2018	13/1/2018
24/1/2018	13/1/2018	16/1/2018	10/1/2018	14/1/2018	13/1/2018	24/1/2018	24/1/2018	24/1/2018
26/1/2018	14/1/2018	24/1/2018	18/1/2018	16/1/2018	1/2/2018	1/2/2018	1/2/2018	1/2/2018
2/2/2018	24/1/2018	25/1/2018	25/1/2018	22/1/2018	10/2/2018	6/2/2018	6/2/2018	8/3/2018
8/2/2018	29/1/2018	1/2/2018	26/1/2018	23/1/2018	12/3/2018	8/3/2018	8/3/2018	12/3/2018
11/2/2018	30/1/2018	18/2/2018	1/2/2018	1/2/2018	13/3/2018	12/3/2018	12/3/2018	13/3/2018
25/2/2018	15/2/2018	19/2/2018	20/2/2018	8/2/2018	17/3/2018	13/3/2018	13/3/2018	18/3/2018
6/3/2018	17/2/2018	25/2/2018	23/2/2018	9/2/2018	18/3/2018	18/3/2018	18/3/2018	19/3/2018
14/3/2018	24/2/2018	16/3/2018	5/3/2018	23/2/2018	21/3/2018	21/3/2018	21/3/2018	21/3/2018
17/3/2018	13/3/2018	19/3/2018	7/3/2018	17/3/2018	26/3/2018	26/3/2018	26/3/2018	26/3/2018
27/3/2018	20/3/2018	26/3/2018	19/3/2018	21/3/2018	27/3/2018	27/3/2018	27/3/2018	27/3/2018
2/4/2018	26/3/2018	27/3/2018	21/3/2018	26/3/2018	31/3/2018	5/4/2018	5/4/2018	5/4/2018
8/4/2018	27/3/2018	10/4/2018	26/3/2018	27/3/2018	10/4/2018	7/4/2018	7/4/2018	10/4/2018
10/4/2018	1/4/2018	14/4/2018	27/3/2018	31/3/2018	13/4/2018	10/4/2018	10/4/2018	14/4/2018
16/4/2018	2/4/2018	23/4/2018	31/3/2018	10/4/2018	14/4/2018	14/4/2018	14/4/2018	19/4/2018
18/4/2018	4/4/2018	4/5/2018	10/4/2018	13/4/2018	23/4/2018	19/4/2018	19/4/2018	23/4/2018
29/4/2018	10/4/2018	8/5/2018	19/4/2018	14/4/2018	27/4/2018	23/4/2018	23/4/2018	29/4/2018
2/5/2018	23/4/2018	14/5/2018	26/4/2018	23/4/2018	29/4/2018	26/4/2018	26/4/2018	3/5/2018
9/5/2018	25/4/2018	19/5/2018	29/4/2018	29/4/2018	8/5/2018	29/4/2018	29/4/2018	8/5/2018
18/5/2018	26/4/2018	25/5/2018	2/5/2018	5/5/2018	9/5/2018	3/5/2018	3/5/2018	19/5/2018
19/5/2018	8/5/2018	4/6/2018	24/5/2018	8/5/2018	12/5/2018	8/5/2018	8/5/2018	4/6/2018
1/6/2018	20/5/2018	5/6/2018	5/6/2018	9/5/2018	16/5/2018	19/5/2018	19/5/2018	5/6/2018
5/6/2018	21/5/2018	20/6/2018	6/6/2018	12/5/2018	19/5/2018	4/6/2018	4/6/2018	17/6/2018
6/6/2018	31/5/2018	21/6/2018	10/6/2018	16/5/2018	4/6/2018	5/6/2018	5/6/2018	26/6/2018
16/6/2018	5/6/2018	2/7/2018	17/6/2018	19/5/2018	5/6/2018	17/6/2018	17/6/2018	7/7/2018
19/6/2018	14/6/2018	17/7/2018	21/6/2018	5/6/2018	26/6/2018	26/6/2018	26/6/2018	9/7/2018

2025	2030	2035	2040	2045	2050	2055	2060	2065
24/6/2018	16/6/2018	18/7/2018	26/6/2018	9/6/2018	7/7/2018	7/7/2018	7/7/2018	15/7/2018
25/6/2018	21/6/2018	22/7/2018	27/6/2018	21/6/2018	9/7/2018	15/7/2018	15/7/2018	17/7/2018
15/7/2018	27/6/2018	23/7/2018	17/7/2018	26/6/2018	12/7/2018	17/7/2018	17/7/2018	5/8/2018
17/7/2018	17/7/2018	5/8/2018	20/7/2018	27/6/2018	17/7/2018	5/8/2018	5/8/2018	11/8/2018
22/7/2018	20/7/2018	7/8/2018	5/8/2018	5/7/2018	31/7/2018	11/8/2018	11/8/2018	19/8/2018
4/8/2018	31/7/2018	17/8/2018	9/8/2018	17/7/2018	5/8/2018	19/8/2018	19/8/2018	27/8/2018
5/8/2018	3/8/2018	19/8/2018	16/8/2018	5/8/2018	21/8/2018	7/9/2018	7/9/2018	7/9/2018
11/8/2018	5/8/2018	21/8/2018	17/8/2018	22/8/2018	7/9/2018	16/9/2018	16/9/2018	16/9/2018
15/8/2018	17/8/2018	27/8/2018	22/8/2018	26/8/2018	12/9/2018	18/9/2018	18/9/2018	18/9/2018
19/8/2018	19/8/2018	30/8/2018	26/8/2018	12/9/2018	16/9/2018	20/9/2018	20/9/2018	20/9/2018
28/8/2018	31/8/2018	31/8/2018	31/8/2018	13/9/2018	23/9/2018	23/9/2018	23/9/2018	23/9/2018
1/9/2018	14/9/2018	11/9/2018	7/9/2018	8/10/2018	8/10/2018	8/10/2018	8/10/2018	8/10/2018
9/9/2018	24/9/2018	16/9/2018	14/9/2018	10/10/2018	21/10/2018	15/10/2018	15/10/2018	11/10/2018
18/9/2018	17/10/2018	23/9/2018	3/10/2018	22/10/2018	27/10/2018	21/10/2018	21/10/2018	15/10/2018
23/9/2018	4/11/2018	24/9/2018	22/10/2018	3/11/2018	3/11/2018	27/10/2018	27/10/2018	21/10/2018
10/10/2018	6/11/2018	8/10/2018	22/11/2018	10/11/2018	4/11/2018	22/11/2018	22/11/2018	1/12/2018
27/10/2018	11/11/2018	4/11/2018	28/11/2018	1/12/2018	1/12/2018	1/12/2018	1/12/2018	7/12/2018
31/10/2018	15/11/2018	17/11/2018	1/12/2018	7/12/2018	7/12/2018	7/12/2018	7/12/2018	10/12/2018
6/11/2018	7/12/2018	1/12/2018	7/12/2018	10/12/2018	10/12/2018	10/12/2018	10/12/2018	15/12/2018
24/11/2018	10/12/2018	7/12/2018	10/12/2018	15/12/2018	15/12/2018	15/12/2018	15/12/2018	16/12/2018
9/12/2018	19/12/2018	10/12/2018	17/12/2018	17/12/2018	18/12/2018	18/12/2018	18/12/2018	18/12/2018
10/12/2018	25/12/2018	25/12/2018	18/12/2018	18/12/2018	23/12/2018	23/12/2018	23/12/2018	23/12/2018
26/12/2018	26/12/2018	26/12/2018	23/12/2018	23/12/2018	25/12/2018	25/12/2018	25/12/2018	25/12/2018
28/12/2018	28/12/2018	28/12/2018	28/12/2018	28/12/2018	28/12/2018	28/12/2018	28/12/2018	28/12/2018

2.5 Frequently asked questions

To better help the reader understand the modelling methodologies used for Net Zero Australia, we have compiled frequently asked questions with references to the relevant external documents.

2.5.1 How is the demand for energy projected into the future?

See Chapter 10 of this report – Projections of Energy Demand.

2.5.2 Are these forecasts of what will happen?

No. The model results are scenarios, not forecasts. Each Scenario begins with a specific set of assumptions about demand, technology costs, resource limits and policy targets; RIO then finds the least-cost system that could satisfy those assumptions. Because these assumptions characterise only one of many plausible futures, the results are illustrations of how the transition might unfold and not predictions of what will occur.

Even though the real-world energy system will diverge in important ways, exploring multiple scenarios is still valuable: it exposes the fundamental trade-offs and key system dynamics, and helps decision-makers see which uncertainties matter most and where robust strategies are needed.

2.5.3 How does the modelling incorporate uncertainty?

Net Zero Australia deals with uncertainty in two main ways:

1. **Targeted Scenarios and sensitivities** – For specific policy or technology questions, we assess the sensitivity of transition pathways to key inputs (e.g. fuel prices, land use constraints, demand growth, etc.) by adjusting those inputs and re-running the model. Comparing these “what if” sensitivity cases to the main Scenarios then isolates cause and effect and quantifies how much each assumption can move costs, emissions, reliability or other important metrics.
2. **Ensemble exploration or ‘Generating Alternatives’** – Starting from the single least-cost pathway for a Scenario, we then use an automated ensemble routine that generates many alternative near least-cost pathways that are *maximally different* along other modelling dimensions (e.g. resource mix, transmission use), yet within a set tolerance of the optimal system cost. Further information on the particular *modelling to generate alternatives* method used in RIO is provided in Chapter 3, section 3.6.

2.5.4 How is the cost of decarbonisation accounted for?

The modelling objective is to **minimise the net present value (NPV) of the entire energy system's annual costs in each year from 2025 to 2065, discounted at the social discount rate of 2.7% real**. Costs are distributed across the supply-side and demand-side, as follows.

Supply-side costs include:

- capital costs for every new build plant, energy transmission, energy storage, and certain technology retrofits, which are incurred as *annualised costs* in each year from when the technology is first online, over an assumed financial life (capital costs are annualised using a specified real weighted-average cost of capital and financial life);
- fixed operating & maintenance (O&M) costs incurred annually for each unit of installed plant or transmission capacity;
- variable O&M costs incurred annually in proportion with annual plant production;
- fuel/feedstock costs incurred for each unit consumed in plants;
- start-up costs incurred for any plant modelled with unit commitment constraints;
- CO₂ transport & storage costs incurred for each unit of CO₂ geologically sequestered;
- commodity costs incurred for each unit of primary resources produced (e.g., coal, natural gas, biomass); and
- annualised transmission and distribution costs for existing networks, based on existing tariffs.

Demand-side costs include:

- the levelised costs of ownership for all end-use technologies, incurred as appliance/vehicle capital costs annualised over the life of the appliance/vehicle, plus annual O&M costs for those appliances/vehicles; and
- the incremental cost of efficiency improvement and fuel switching measures in the subsectors we represent with aggregated energy consumption trends (see Chapter 10 for details).

We note that demand-side costs and efficiencies account for the year in which an appliance/vehicle was sold (its vintage).

Economy-wide GHG reduction trajectories (e.g., a straight-line path to net zero in 2050) are enforced as constraints; the dual variable on that constraint is the model's marginal emissions abatement cost.

2.5.5 How do the models ensure reliability?

RIO embeds an hourly *planning reserve* constraint on top of the normal hourly demand-supply balance. For every model hour it (1) scales up load to a “**planning demand**” that covers forecast error, extreme weather and forced outages, and then (2) requires the **dependable capacity** (a derating of installed capacity) of every resource class to be greater than that planning demand.

Together, the scaling up of demand and derating of supply approximate a standard planning reserve margin of 15%-20%, defined as the additional capacity above the median (1-in-2) peak load. Conceptually, this planning reserve margin can be considered as accounting for: the exceedance in the median peak load forecast; and plant outages that mean that some dispatchable generating capacity is often unavailable.

Planning demand is set to 10% for the first year (2025) and is linearly increased to 13% in 2060. The starting value of 10% is slightly higher than the margin by which 1-in-10 peak load exceeds the 1-in-2 peak load and accounts for the fact that we are sampling days from a single weather year, and that the sampled days are unlikely to have loads that reach the 1-in-2 peak. The increase in planning demand over time is meant to cover the increasing frequency of extreme events due to climate change. It is reasoned that the historical weather year 2018, upon which power system operations is modelled, begins to perform poorly as a proxy for weather events in the second half of the century.

The 3% increase is based on expert judgement and is an area where more research is needed. However, because power systems are planned iteratively, and will use future weather data in future planning processes, the importance of trending planning demand may also be unique to long-term planning studies like this.

Dependable capacity is computed endogenously and differs by technology. Table 3 shows deratings that are applied by technology to form the other half of the reserve margin constraint.

This energy supply reliability constraint is enforced simultaneously with the sequential hour-by-hour dispatch to meet hourly demand, all as part of the multi-year capacity expansion. As a result, the solution RIO returns is the least-cost portfolio that can keep every zone reliable under both routine and stress conditions – even in systems dominated by variable renewables and storage. Additional detail on the modelling of reliability can be found in the U.S. Annual Decarbonization Perspective Technical Documentation Section 3.1.5.2^[11].

Table 3 | Deratings applied by technology to form the other half of the reserve margin constraint.

Resource Type	Derate	Explanation
Thermal power plants	5%-8%	Units contribute their nameplate capacity minus their forced outage rate based on plant type and historical data.
Variable renewables	33% for solar PV 50% for wind	Renewables get credit for their hourly output minus a derate for dependability and outage. These derates are based on analysis of the 2018 weather year and variability of renewable output within the day binning clustering process.
Hydro and storage	5%	Units contribute their hourly discharge minus their forced outage rates. By using hourly discharge, it forces the resources to have stored energy to support their operation.
Flexible loads	0%	Demand-side load flexibility is treated as a fundamental alteration of the load shape itself and doesn't receive additional derating.
Transmission flows	10% for all transmission flows except between Victoria East and Victoria West where no derates are included to reflect the fact that Victoria East is a dedicated exporter to the rest of the state.	Hourly imports are credited (and exports obligated) with a 10% derate. This derate reflects line outages and the need to maintain dispatchable resources, and inertia, across the system.

2.5.6 How much operational detail is included in the electricity system?

Capacity-expansion tools such as RIO simplify or omit many unit-level constraints that govern real-time system operation. This keeps the problem tractable: every additional block of operational detail (integer unit-commitment variables, non-linear heat-rate curves, inertia constraints, etc.) quickly multiplies computational solve time and can force trade-offs against geographic resolution, technology granularity or the breadth of uncertainty.

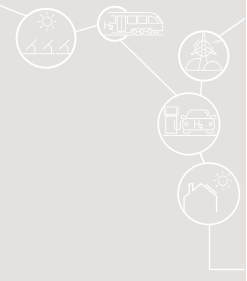
Table 4 summarises the operational detail included in modelling the electricity system. All else equal, the larger and more geographically diverse the system, the closer these simplifications come to the physical reality because individual unit constraints tend to average out. Even so, operational verification remains important.

Table 4 | Summary of the operational detail included in modelling the electricity system.

Operational detail	Representation	Rationale
Generator ramp rates	Included as hour-to-hour limits on each thermal and hydro generator.	Hourly resolution captures the dominant ramping requirement in a high-renewables system.
Unit commitment	Not represented (generators dispatch continuously between 0% – 100%).	Integer commitment variables would require modelling a mixed-integer linear program, which has significantly greater computational requirement than a linear program. At the Australian National Electricity Market (NEM) scale the commitment costs are a second-order effect for capacity-planning decisions over decades.
Ancillary services	Not represented explicitly ; reliability is handled through a planning-reserve margin.	Ancillary services change the distribution of hourly dispatch but have little influence on optimal long-run capacity mix.
Heat-rate curves (part-load efficiency)	Not represented ; each plant type uses a single average heat-rate.	Variable fuel cost dominates at high load factors; part-load penalties modestly shift hourly dispatch but do not alter capacity expansion choices enough to justify the additional non-linearity.
System inertia & primary-frequency response	Not represented in RIO.	Inertia needs are highly event-specific (<1 s timescale) and cannot be captured in an hourly linear model; instead we flag hours with low synchronous share for follow-up studies.

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3 Core Scenarios

This Chapter describes how the NZAu Project has defined the Scenarios that are modelled for Australia’s domestic and export energy activities. It includes the following sub-sections:

- 3.1 Domestic system modelling Scenarios overview
- 3.2 Reference Scenario
- 3.3 Current Policies Scenario
- 3.4 Net Zero 2050 Scenario
- 3.5 Net Zero Extended Timeline Scenario
- 3.6 Generating alternatives

3.1 Domestic system modelling Scenarios overview

3.1.1 Domestic modelling features by Scenario

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 in modelling Australia’s domestic and export energy system activities from 2025.

We model four Core Scenarios summarised in Table 5. These Scenarios do not predict the future but instead produce internally consistent pathways based on a set of assumptions. These provide valuable reference points for analysis and decision-making.

Table 5 | Domestic modelling features by Scenario.

Feature		REF	CPOL	NZ2050	NZEXT
Policy	Domestic emissions, see Figure 10 below	No constraint imposed, determined by model	No constraint imposed, determined by model	Linear to net zero in 2050	Linear to net zero in a future year determined by model
	Renewable energy targets	None imposed	Only supporting legislated mechanism(s) modelled	None imposed	None imposed
	Gov. support mechanisms	None modelled	Modelled if legislated	None modelled	None modelled
Supply	Electricity generation technology costs	GenCost 2024-25 final report, <i>Global NZE post 2050 Scenario</i>			
	Coal & gas plant closures	Early retirements possible, announced date at latest			
	Key asset build rates*	None binding	None binding	Annual capacity additions can grow by a maximum CAGR (see below for list of assets affected and detail on the approach)	
	Transmission build	Optimised in model			
	Weather year	FY 2017-18			
	Nuclear allowed?	No	No	Yes	Yes
Demand	Electrification	As per historic rates	As per historic rates, unless increased via legislated mechanism	Assumed rapid electrification (see Chapter 10)	Assumed slower electrification
	Fuel switching and energy efficiency	No fuel switching, 0.5% energy efficiency improvement per year in industry	As per REF, unless increased via legislated mechanism	Assumed rapid fuel switching to green alternatives (see Chapter 10)	Assumed slower fuel switching to green alternatives (see Chapter 10)
Other	Land sector emissions projections	<i>Business as usual</i> trajectory, see Chapter 11	<i>With mitigation measures</i> (WMM) trajectory		
	Physical climate change impacts	We do not model future climate change impacts on built infrastructure but do account for increased energy demand due to more cooling days.			
	Estimated global warming impact*	~4°C**	~3-3.5°C	~2-2.5°C	~3°C

*More detail provided in the sections below.

**Note this excludes the offshore emissions that result from the use of Australia's fossil fuel exports.

3.1.2 Estimating global warming impact by Scenario

As global emissions trajectories are outside the scope of this modelling and are highly uncertain, we use a simple approach for approximating the alignment of modelled NZAu Scenarios with global temperature changes. This approach is based on the assumption that Australia's share of global emissions remains consistent with most recent data at 0.83% (2019 figures, the latest official) ^[3,4]. Table 6 provides the cumulative emissions over 2025-2050 for each modelled Scenario, together with the cumulative global emissions using this simple assumption. We acknowledge that there are other approaches to the allocation of global emissions budgets, but that several important and uncertain assumptions must be made in all methods. We also acknowledge that our simple estimates focus on the years 2025-2050, while global warming scenarios depend on emissions over the century and longer.

Table 6 | Cumulative Australian emissions by NZAu modelled Scenario, and estimated global emissions (2025-50, Gt-CO₂e, AR6 GWP).

NZAu Scenario	Cumulative Australian emissions 2025-50, Gt-CO ₂ e	Estimated cumulative global emissions 2025-50, Gt-CO ₂ e
REF	12.3	1,481
CPOL	8.98	1,080
NZ2050	6.19	744
NZEXT	8.32	1,001

We then compare the estimated cumulative global emissions with those of the global warming Scenarios in the IPCC AR6 report, presented in Table 7. This allows for an approximate comparison between the NZAu modelled Scenarios and global warming outcomes, as shown in Table 8 below. Figure 4 presents this comparison graphically.

Table 7 | IPCC global warming Scenarios and cumulative global emissions (Gt-CO₂e, rounded to nearest Gt)^[3].

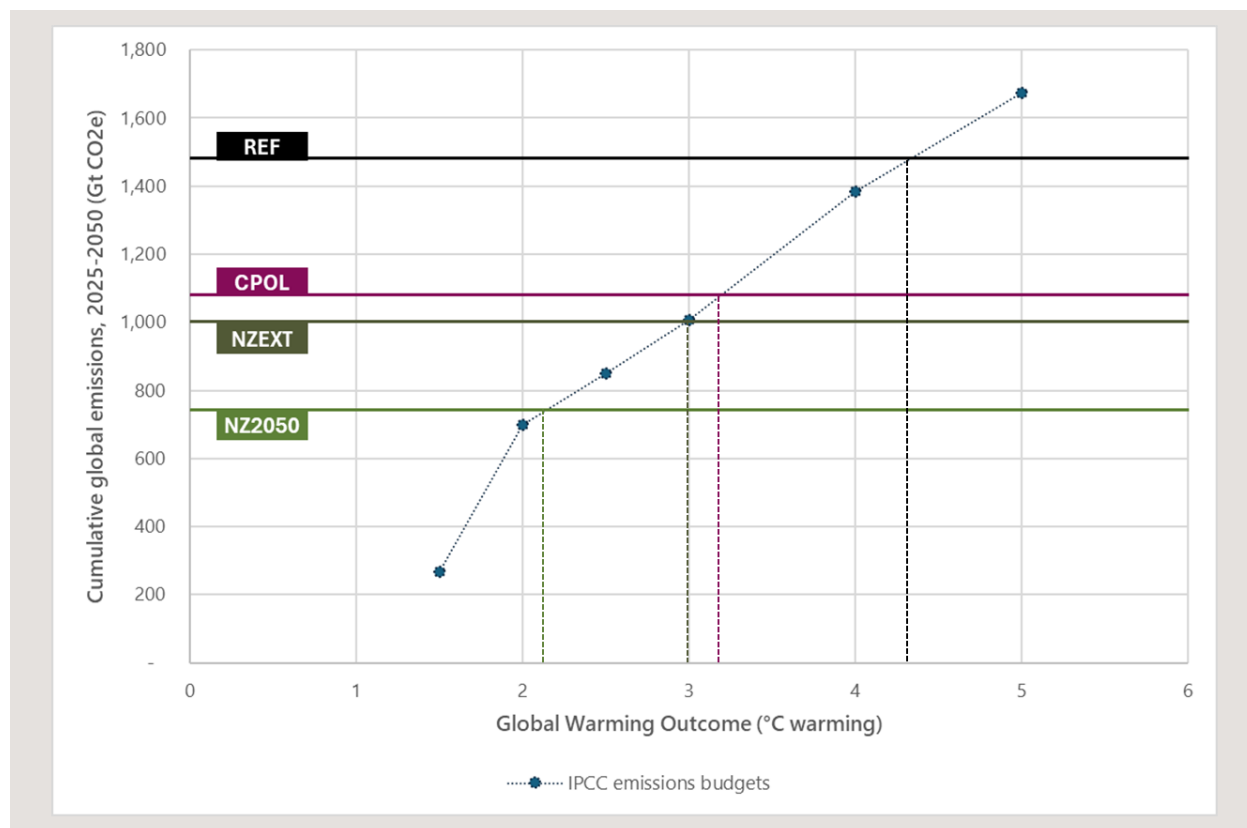
IPCC WGIII	Scenario name in WGI/II	Cumulative global emissions (2025-50, Gt-CO ₂ e)
1.5°C no overshoot (>50%)	Very low (SP1-1.9)	267
2°C (>67%)	Low (SP1-2.6)	700
2.5°C (>50%)	N/A	851*
3°C (>50%)	Intermediate (SP2-4.5)	1,007
4°C (>50%)	High (SP3-7)	1,384
>4°C (>50%)	Very high (5-8.5)	1,673

*Calculated by assuming the average of p5 and p95 values for this Scenario.

Table 8 | Alignment of NZAu Scenarios with IPCC global warming Scenarios.

NZAu Scenario	Estimated cumulative global emissions 2025-50, Gt-CO ₂ e	Nearest IPCC Scenario	IPCC Scenario cumulative global emissions 2025-50, Gt-CO ₂ e	Difference
REF	1,481	4°C (>50%)	1,384	7%
CPOL	1,080	3°C (>50%)	1,007	7%
NZ2050	744	2°C (>67%)	700	6%
NZEXT	1,001	3°C (>50%)	1,007	-1%

Figure 4 | Cumulative global emissions budgets (2025-2050) associated with different global warming outcomes from the IPCC [3], together with the estimated alignment of Net Zero Australia Scenarios.



3.1.3 Technology deployment rates

Achieving net zero by 2050 requires a large uplift in the annual capacity additions of all clean energy technologies. To remain technology neutral, we therefore adopt growth rate constraints on the deployment of key technologies, including renewable electricity generation capacity, geological CO₂ sequestration capacity, and retrofitting industrial processes with cleaner alternatives. These build limits are sufficiently high to ensure that the model can achieve resource adequacy in each year while achieving net zero emissions by 2050 but also do not allow very large clean energy industries to form over very short periods.

These constraints are formulated in RIO in two parts:

1. a **compound annual growth rate (CAGR) limit on annual capacity additions**: defined as the maximum growth in capacity of a technology built in year x , relative to the capacity built in year $x - 1$; and
2. a **'base rate'**: defined as the capacity that can always be built in year x , regardless of what was built in year $x - 1$. For certain technologies. This rate is zero until the year in which that technology is allowed (see below). For example, nuclear base rates are zero until 2035, when we assume the first nuclear power plant could be built.

Given the above definitions, the capacity *addition* $C_{y,x}$ for technology y in any year x is constrained as:

$$C_{y,x} \leq B_x + [C_{y,x-1}(1 + \text{CAGR})],$$

where, B_x is the base rate in year x .

A summary of the base rate capacity and when it is first greater than zero, as well as the CAGR by technology for the Net Zero 2050 Scenario is provided in Table 9 below. Base rates are assumed to be the same in every year once they are non-zero.

Table 9 | Assumed maximum growth rates (CAGRs) and base rates by technology.

Technology	Base rate, 2026	Base rate, 2027+	Year base rate is first non-zero	CAGR
Utility scale solar	2.3 GW**	0.4 GW	2026	10%
Onshore wind	2.1 GW**	0.2 GW	2026	10%
Offshore wind	0 GW	0.2 GW	2030	10%
Nuclear	0 GW	0.2 GW	2035	10%
Biofuel generation	0.1 GW	0.1 GW	2026	10%
Direct Air Capture	0 Mt p.a.	0.25 Mt p.a.	2035	10%
CO ₂ injection rate	0.25 Mt p.a.	0.25 Mt p.a.	2026	10%
Clinker production retrofits*	0 Mt p.a.	0.1 Mt p.a.	2030	10%
Bauxite refining retrofits*	0 Mt p.a.	0.3 Mt p.a.	2030	10%
Iron and steel production retrofits*	0 Mt p.a.	0.1 Mt p.a.	2030	10%

*For information about the clean technologies explored in heavy industrial processing, please see Chapter 15.

**Based on annual capacity additions in 2025.

The *Extended Timeline* Scenario assumes that deployment of net zero technologies takes longer due to challenges with transmission connections, environmental approvals, social licence, and other supply chain and financial blockers slowing down deployment. We continue to adopt the approach to constraining technology deployment as set out in the Net Zero 2050 section above but instead assume a 5% CAGR limit on annual capacity additions. All Base Rates remain the same.

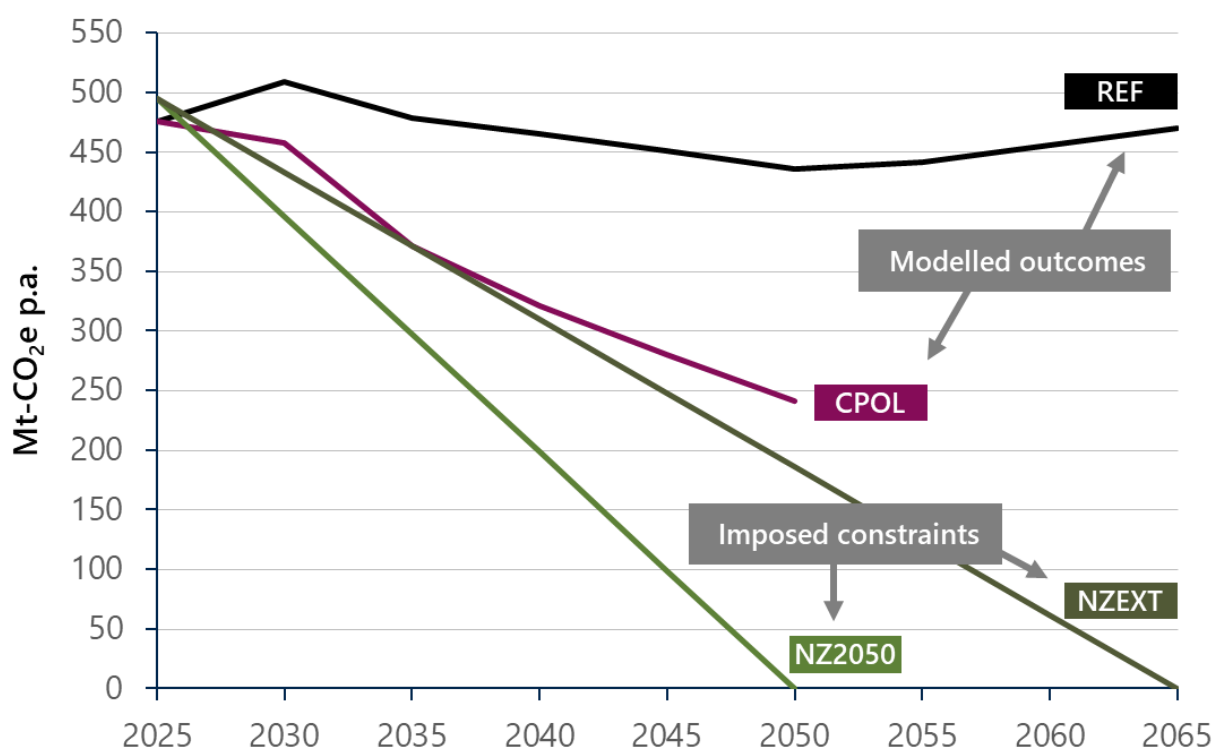
3.1.4 How the emissions constraint was set

For the net zero Scenarios, the emissions constraint in the first modelled period (2025) is not binding, so that the model reflects the current system without an emissions price and does not require additional renewable plants in that first period.

The emissions constraint in 2025 was set to 495 Mt-CO₂e. This is roughly the average of the 2023 net emissions inventory with and without LULUCF included and with international aviation and shipping added. This approximate average was used instead of the full inventory with LULUCF emissions included due to the large year-to-year variations in recent, historical LULUCF estimates. Our resulting emissions constraints are then better able to accommodate the evident variation and uncertainty in LULUCF estimates.

We then constrain emissions to reduce linearly from 495 Mt-CO₂e to achieve net zero in either 2050 or 2065 for the Net Zero 2050 and Net Zero Extended Timeline Scenarios, respectively. These emissions constraints, as well as the modelled Reference and Current Policies emissions trajectories, are shown in Figure 5 below. The year 2065 for the Net Zero Extended Timeline Scenario was found iteratively once the 5% CAGR constraint was set as detailed above, such that this was approximately the earliest year in which net zero could be reached with straight-line abatement while simultaneously achieving resource adequacy over the transition. As such, if the CAGR constraint was reduced further, the net zero year would also be later.

Figure 5 | Emissions trajectories by Scenario.



3.2 Reference Scenario

The *Reference Scenario (REF)* is included to model a world without policies to support emissions reductions on domestic and exported energy. It is intended to help understand what investments would be made anyway simply to continue energy supply to mid-century. The outputs of this analysis, such as the total costs, the built and retired technology capacities, and employment impacts, are then used as a reference for comparison with equivalent outputs from the other Scenarios. The Reference Scenario is not downscaled, given its likely significantly lower use of land for renewable generation than net-zero scenarios.

3.3 Current Policies Scenario

The *Current Policies Scenario (CPOL)* models our assessment of the impact of current, significant policies on Australia’s projected energy system and its emissions. To do this, we do not attempt to model every announced State and Australian Government policy. Rather, we include policies that we consider are likely to have a material impact on modelled emissions trajectories according to the following, two criteria:

1. Include a **funded mechanism** to implement the policy: For example, the Victorian Government’s 2035 Emissions Reduction Target^[5] of a 75-80% reduction in GHG on 2005 levels is not modelled in this Scenario as it does not yet have a funded mechanism to support it. However, the Victorian Renewable Energy Target (VRET)^[5] is included as it is supported by long-term Government contracts.
2. Make a **significant contribution** to the decarbonisation task: We define a policy with a ‘significant contribution’ as one that delivers at least 10% of the estimated 2050 net zero requirement for the category and the region that the policy is impacting, using the NZAu Project’s Phase 1 results^[6] as the reference. For example, Phase 1’s net zero Scenarios deployed between 97 and 132 GW of additional renewables, and 14-22 GW of energy storage between 2020 and 2030. The Capacity Investment Scheme (CIS) underwrites 26 GW of renewable capacity and 14 GW of dispatchable capacity including storage over 2025-2030. It could therefore contribute 26%-36% of Phase 1’s estimated requirement and is therefore included in the Current Policies Scenario. On the other hand, the national Community Batteries for Household Solar policy, an investment of \$200 million^[7] only contributes a small amount to the estimated storage task, as we demonstrate in Table 10 below.

Table 10 | Example showing how our two criteria for including a policy in our Current Policies Scenario applies to the Community Batteries for Household Solar Policy.

Target/mechanism	Community Batteries for Household Solar
Overview	\$200 million total over 3 years to support investment in battery electricity storage systems.
Is legislated?	Yes
Significance of impact	Comparison: the estimated battery investment required to achieve net zero in Net Zero Australia’s previous modelling was ~\$4-14 billion per year. Impact of mechanism: < 10% of required effort.
Overall assessment	Do not include.

Table 11 then summarises the policies that satisfy the criteria above for inclusion in our Current Policies Scenario, along with a description of how we incorporate the policy into the modelling. Importantly, we also extend some mechanisms to 2050 by assuming what we consider to be a reasonable continuation of annual activity, as denoted under ‘Extrapolation approach’.

Table 11 | Current policies modelled in NZAu’s CPOL Scenario.

Policy	Jurisdiction	Description	Incorporation into modelling framework	Extrapolation approach
1. Safeguard Mechanism ^[8]	National	Facility-specific scope 1 emissions reduction (e.g. 4.9% p.a.) to 2030. Baselines post 2030 to be announced in 5-year blocks (indicative 3.3%).	Non-electricity sectoral emissions cap. See the section below this table for more detail.	Ongoing reduction of baseline of 3.3% p.a. beyond 2030.
2. Capacity Investment Scheme (CIS) ^[9]	National	Revenue underwriting to unlock 26 GW of renewable capacity + 16GW of dispatchable capacity by 2030.	Awarded projects included + minimum build on renewables and storage by 2030 as per remaining CIS targets.	Assumes same capacity is underwritten each five-year period (2030-2050).
3. New Vehicle Efficiency Standard Act 2024 ^[10]	National	Decreasing yearly cap on average emissions from covered vehicles sold; related carbon offset market.	Yearly sales of EVs imposed to reflect the projected cap on average emissions. See further detail beneath this table.	N/A
4. Future Made in Australia ^[11]	National	\$2/kg production credit for green H ₂ up to 10 years from 2028-2040; \$6.7B total.	Production credit reduces green H ₂ costs until cumulative commitment is reached.	N/A
5. Hydrogen Headstart Program ^[12]	National	\$4B production credit for selected hydrogen projects up to 10 years from 2026/27.	Production credit reduces green H ₂ costs until cumulative commitment reached.	N/A
6. Queensland Renewable Energy and Hydrogen Jobs Fund ^[13]	Queensland	Government co-financing of awarded projects.	Projects are assumed to be included in CIS.	N/A
7. Electricity Infrastructure Investment Act 2020 ^[14]	New South Wales	Support to private sector investment to deliver, by 2030, 12 GW of renewables, 2 GW of long duration energy storage (LDES, 8h+), and an additional 1.5 GW of LDES by 2034. Additional powers given to EnergyCo to deliver 14 GW of transmission to REZs by 2033.	Projects are assumed to be included in the CIS.	Assumes same capacity is supported each decade (2035-2045, and 2045-2055).
8. Long-Term Energy Service Agreements ^[15]	New South Wales	Underwrite sell price for up to 950 MW (T1) and 930 MW (T2) of firming capacity.	Include awarded projects in energy system from intended commitment date.	N/A

Policy	Jurisdiction	Description	Incorporation into modelling framework	Extrapolation approach
9. NSW Hydrogen Strategy ^[16]	New South Wales	\$3B across 60 actions including up to \$5/kg production credit for green H ₂ up to \$1.5B. 2030 goal to achieve 110 kt/y green H ₂ production and 700 MWe electrolyser capacity.	Production credit reduces green H ₂ costs until cumulative commitment reached.	N/A
10. NSW Electric Vehicle Strategy ^[17]	New South Wales	Goal to boost EV sales to 52% of new vehicle sales by 2030/31, via: removal of stamp duties on EVs; \$3000 rebates; fleet incentives; support to charging network rollout, and an emissions offset scheme.	Goal is less aggressive than <i>New Vehicle Efficiency Standard Act 2024</i> , so no separate constraint was needed.	N/A
11. Victorian Renewable Energy Target Auctions ^[5]	Victoria	Long-term contracts to provide investment certainty for energy generation. VRET1 800 MW renewables generation; VRET2 623 MW renewables and 365 MW & 600 MWh of storage.	Projects are assumed to be included in the CIS.	Assumes same capacity is supported each 5-year period (2030-35, 2035-40, 2040-45, 2045-2050).

These 11 policies that are included in the Current Policies Scenario are roughly 25% of all current Commonwealth and State policies that we reviewed.

Modelling the Safeguard Mechanism

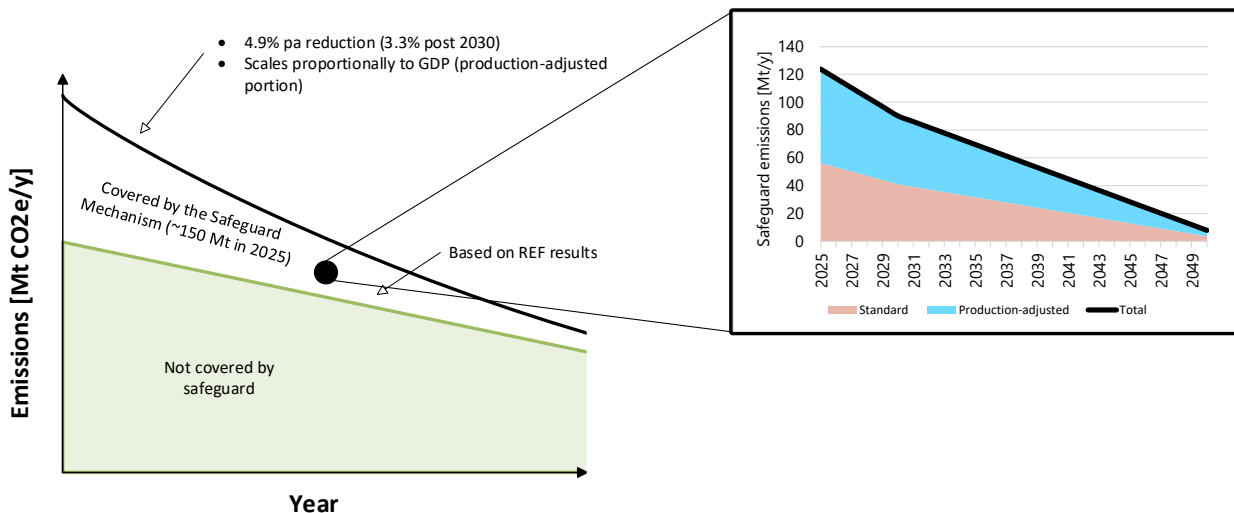
The Safeguard Mechanism targets industrial facilities of over 100,000 t-CO₂e p.a. (Scope 1) across all sectors, including mining, oil and gas production, transport, and manufacturing^[8]. Declining emission baselines are set for each of these facilities, while a 198 Mt-CO₂e p.a. sectoral baseline is set on the sum of emissions from all grid-connected electricity generators, based on the total scope 1 emissions from grid-connected generators from the 2009-10 to 2013-14 financial years^[8]. Some of these baselines are production-adjusted, thus scaling proportionally to the production level of each facility^[18]. Furthermore, the Safeguard Mechanism establishes a market for Safeguard Mechanism Credits (SMCs) that can be traded to offset emissions in excess of the set baselines, alongside Australian Carbon Credit Units (ACCUs)^[19].

In FY 2023-24, 233 facilities were covered by the Safeguard Mechanism for an aggregated 137 Mt-CO₂e emissions^[20]. Of these emissions, 89% are attributed to 7 subsectors, including aviation, iron and steel and gas extraction. To help model the effect of this policy, we note that ACCUs and SMCs allow for emissions trading between covered sectors and the broader economy. This means that assuming specific sectoral decarbonisation pathways isn't essential if we assume that the compliance obligations under the Safeguard Mechanism are met using these trading schemes, as several groups expect. e.g. ^[21,22]

The NZAu Project therefore models the Safeguard Mechanism as a whole-economy emissions cap. This cap comprises two elements (Figure 6):

1. *Emissions covered by the Safeguard Mechanism*: these decrease at a rate of 4.9% per year and 3.3% post-2030 as per the policy. We note that 55% of these emissions (75 Mt)^[20] are production-adjusted and scale proportionally to GDP.
2. *Other emissions*: starting from their 2025 value, these are projected to follow the trajectory resulting from the Reference Scenario.

Figure 6 | Conceptual schematic of the approach used to model the Safeguard Mechanism.



In addition, a 198 Mt-CO₂e p.a. sectoral baseline is imposed on all the grid-connected electricity generation.

Modelling of vehicles sales according to the New Vehicle Efficiency Standard

The *New Vehicle Efficiency Standard Act 2024* (Cth) applies to 'Type 1' and 'Type 2' vehicles, i.e. passenger vehicles and light-duty commercial vehicles respectively. For these segments, the standard defines headline limits (HLs) on the aggregated emissions intensity of new vehicles sales^[10]. The mandated values up to 2029 are presented in Table 12, followed by our linear projection to zero in 2050.

The NZAu Project estimates an average passenger vehicle's efficiency based on the 3 types of cars (compact, sedan and SUV) studied by Poursadegh et al.^[26] and these vehicles' respective 2023 sales share from the National Transport Commission^[27]. This is done for all powertrain options considered^[26]. The efficiency of pickups from the same study is used as representative of light-duty commercial vehicles. From 2025, a 1% per year efficiency gain is assumed for all new sales.

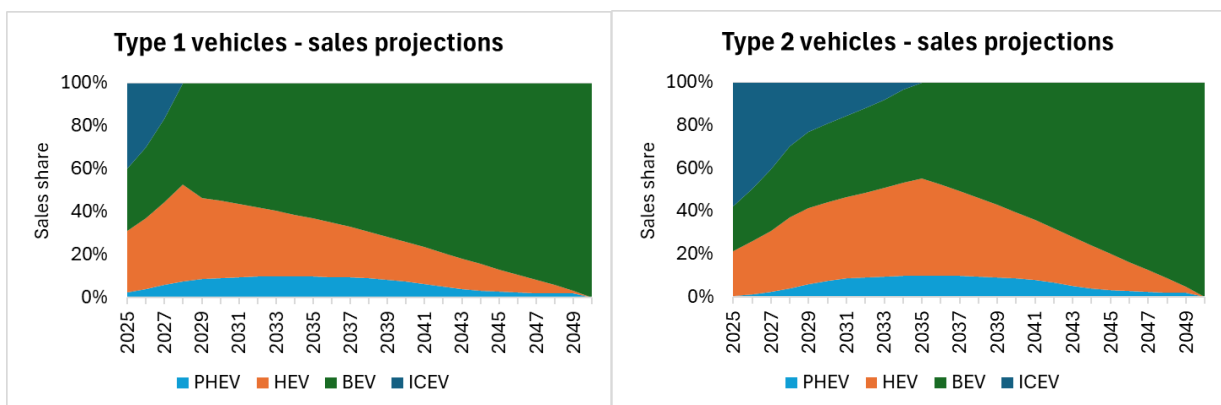
Based on the energy efficiencies of each relevant vehicle type and the emissions factors of each form of propulsive energy^[23], the sales of internal combustion engine vehicles (ICEVs) are modelled to be displaced by plug-in hybrids (PHEVs), hybrids (HEVs) and battery electric vehicles (BEVs), so that the New Vehicle Efficiency Standard's HLs are achieved with our estimates of a plausible fleet mix in each year. As HLs become too restrictive to be met with all powertrain types having significant market share, the share of BEVs is then increased and PHEV and HEV shares are scaled down accordingly so that the fleet-wide emissions target can be met. Eventually, reaching a (tailpipe) emission intensity of 0 g-CO₂e/km of new sales would require 100% BEVs. Figure 7 reports the projected sales share for both vehicle types.

Table 12 | Headline limits [g-CO₂e/km] and their decline imposed on aggregated new vehicles sales by the New Vehicle Efficiency Standard^[10].

Vehicle type in this modelling	2025	2026	2027	2028	2029	2035*	2040*	2045*	2050*
Passenger vehicles	141	117	92	68	58	41	28	14	0
Light-duty commercial vehicles	210	180	150	122	110	79	52	26	0

* projected by this modelling.

Figure 7 | Sales share projections for Type 1 (Passenger vehicles) and Type 2 (Light-duty commercial vehicles) vehicles used in the NZAu CPOL Scenario, reflecting our modelling of the New Vehicle Efficiency Standard Act 2024.



3.4 Net Zero 2050 Scenario

The *Net Zero 2050 Scenario (NZ2050)* imposes a linear emissions constraint to net zero by 2050.

3.4.1 Demand side assumptions

Residential buildings, and transport

Net Zero 2050 assumes nearly full electrification of transport and building stocks by 2050.

All residential and commercial building energy services are assumed to be electrified by 2050 with a stock rollout that follows an S-Curve trajectory and 100% of new sales being electric by 2040 (further detail in Chapter 10). Services include:

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

The transport sector is divided into:

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

As per building services, we assume a transport stock change-over that follows an S-curve trajectory of new vehicle *sales* that achieves full saturation of battery electric vehicle and hydrogen fuel cell vehicle *on-road stock* by approximately 2050. Further detail on these assumptions by individual vehicle category can be found in Chapter 10. We also note that none of these fleet stock change-over models use the modelling of the New Vehicle Efficiency Standard in the Current Policies Scenario, as described earlier in this Chapter.

Commercial and industrial sectors

See Chapter 10.

3.4.2 Supply side assumptions

Key asset compound annual growth rates

See section 3.1.3 above.

Fossil fuel exports

The extraction, processing and export of coal, oil and gas from Australia, is a significant contributor to Australia's *domestic* emissions inventory^[4]. For our Net Zero 2050 Scenario, we assume a reduction in the demand for Australia's fossil fuel exports that is consistent with the IEA's World Energy Outlook (WEO) 2024 Announced Pledges Scenario fossil fuel trajectories^[2]. We also keep Australia's share of global fossil fuel consumption

constant based on 2023 statistics (Table 13). The IEA's projections of coal, oil and gas energy consumption and Australia's assumed contribution via export is then presented in Figure 8.

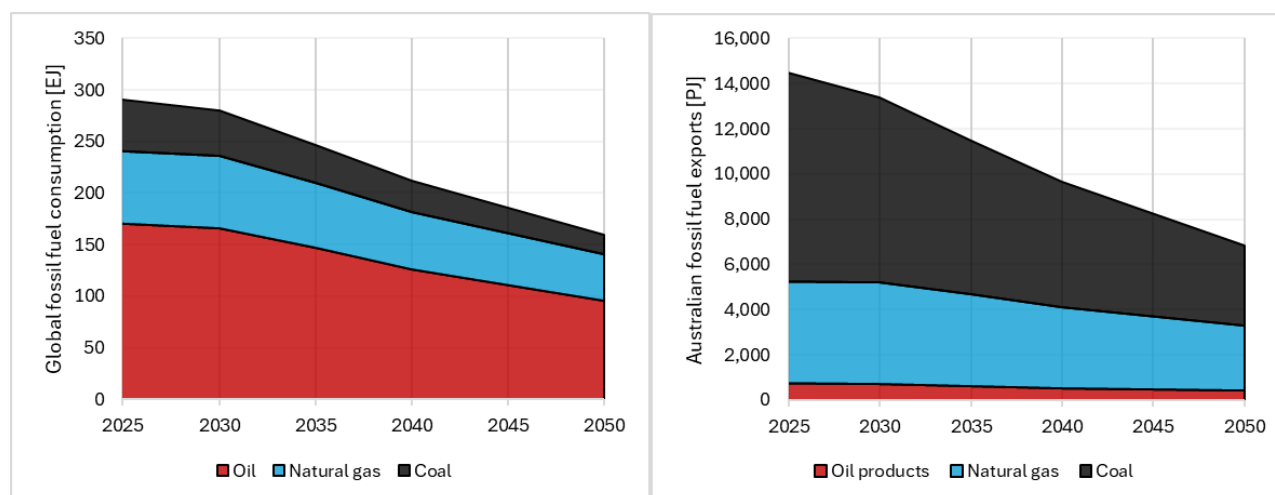
Table 13 | Australia fossil fuel exports compared to global consumption.

Commodity	Energy exported (EJ, 2022-23) ^[25]	Global consumption ^[2] (EJ, 2023)	2023 Australian share (%)
Coal	9.626	52.23	18.43%
Natural gas	4.541	70.49	6.44%
Oil*	0.617	171.84**	0.36%
LPG	0.120		0.07%
Total	14.904		

*Includes crude oil, ORF, and refined products

**Global demand for LPG specifically is not provided in the World Energy Outlook, instead part of the 'oil' category.

Figure 8 | Left: IEA WEO APS projections for coal, oil and gas energy consumption^[2]. Right: Australia's Our associated estimate of Australia's fossil fuel exports based on current shares of respective global consumption. Note different vertical axis scales and units.



Note: Australian oil products include crude oil, ORF, refined products, and LPG.

3.5 Net Zero Extended Timeline Scenario

The *Net Zero Extended Timeline Scenario (NZEXT)* models a net zero future with a less optimistic view on our ability to meet net-zero emissions by mid-century. The key differences of this Scenario, compared with NZ2050, are the slower demand-side transition (i.e. slower appliance and vehicle switching) and more constrained technology deployment rates (i.e. lower CAGRs).

3.5.1 Demand side assumptions

Residential and commercial buildings, and transport

Net Zero Extended Timeline assumes slower electrification of transport and building stocks than *Net Zero 2050*, commensurate with the extended timeframe for net-zero. We delay the saturation of the sales share switching to electric/hydrogen technologies by 20 years for the transport sector, and by 60 years for the residential sector, such that transport and building stocks reach full electrification by 2100. The assumption under this 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.

Commercial and industrial sector

See chapter 10.

3.5.2 Supply side assumptions

Key asset compound annual growth rates

See section 3.1.3 above.

Fossil fuel production

In the *Extended Timeline* Scenario, we adopt the same approach described in the *Net Zero 2050* Scenario to estimate the future extraction, production, and distribution of coal, oil and gas exports^[2].

3.6 Generating alternatives

Our energy system modelling framework first determines *one least-cost optimal energy system transition pathway* for each Scenario, given a consistent set of input data and the different Scenarios above. In addition to these pathways, we explore a set of transition pathways that are *near cost optimal*, featuring different portfolios of energy technologies but still delivering essentially the same GHG and total system costs as the *cost optimal pathways*. To do this, we use an approach called *Modelling to Generate Alternatives (MGA)*^[28,29,30]. This approach allows us to assess different technology choice trade-offs and reflects the often alternative and sometimes competing technology or pathway preferences that policymakers, industry practitioners and society have.

The MGA applies only to the supply-side optimisation (the RIO model) and involves relaxing the cost-optimality condition and allowing solutions within a specified tolerance (1% unless stated otherwise) of the least-cost solution of each main Scenario. When we consider plausible uncertainties in such modelling, that could easily exceed 10% of total transition costs, single digit tolerances are then effectively indistinguishable.

For each Scenario we generate an ensemble of *152 alternative pathways*, each of which minimises or maximises expenditure on specified technology subsets while ensuring that the present value of total system costs (2025–

2050) does not increase by more than the specified (1%) threshold. In each alternative pathway, a different randomly chosen set of technologies (Table 14) is targeted for minimisation or maximisation. In order to be computationally tractable, the MGA is implemented with reduced temporal resolution, simulating only the years 2025, 2035 and 2050. This reduced-form representation preserves investment decision and operational dynamics in important years for emissions reduction at the expense of intermediate detail.

The result of the MGA approach is a spread of outcomes (e.g. technology portfolios). A large spread of outcomes for a given technology indicates that investment in that technology can rise or fall substantially without meaningfully affecting overall system cost. Conversely, outcomes that remain unchanged across alternative pathways either cannot vary much without driving large increases in system cost or are otherwise constrained in some way.

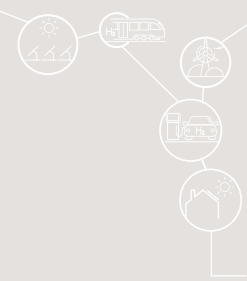
Table 14 | The technology subsets, in which expenditure is randomly maximised or minimised in the different runs of the *modelling to generating alternatives* (MGA) ensemble.

Large-scale solar PV	Onshore wind	Offshore wind
Rooftop solar PV	Black and brown coal production	Natural gas extraction
Biomass production	Hydrogen electrolysis	Low-carbon industry
Nuclear generation	Pumped hydro energy storage	Geologic CO ₂ sequestration
Electricity transmission	Hydrogen pipelines	CO ₂ pipelines

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4 Export modelling approach

The Net Zero Australia team is currently developing its approach to modelling the export system. We will update this Chapter once we have completed our analysis.

Export modelling premises

We model potential futures for Australia’s energy exports separately to the domestic system. Below we set out several premises that inform our export system modelling approach, informed by work completed previously by Net Zero Australia^[1]. Decarbonising Australia’s exports:

1. **Carries a higher cost.** Low/no emissions exports (energy and non-energy) are likely to be more expensive than fossil fuel exports or less processed, non-energy commodities.
2. **Requires trading partners.** To decarbonise our exports, it is likely that long-term commitments from trading partners will be required to justify large-scale investments.
3. **Is an immense task.** Fully displacing current energy and non-energy exports with clean alternatives is an immense task that may be impossible, barring disruptive innovation.
4. **Has uncertain demand, which is currently very low.** Estimating demand for Australian clean exports is hugely uncertain since it combines the estimation of several, uncertain parameters, e.g. demand trends of other nations, their demand elasticity for different imports, international supply competition, etc.
5. **Will have a complex impact on the domestic energy system.** There will be competition for capital, equipment and workforce between Australia’s domestic and export energy systems. Yet, large investments in export projects will build out supply chains and expertise at a scale that could also benefit the domestic system.

For Phase 2 of the NZAu Project, and instead of holding energy exports constant, we will look to examine the most cost-effective options for other countries to achieve significant abatement using exports from Australia.

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5 Projections of population, GDP growth and other primary drivers

This Chapter provides details on the assumptions used to inform projections of demand in the model.

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 (Chapter 10) 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.

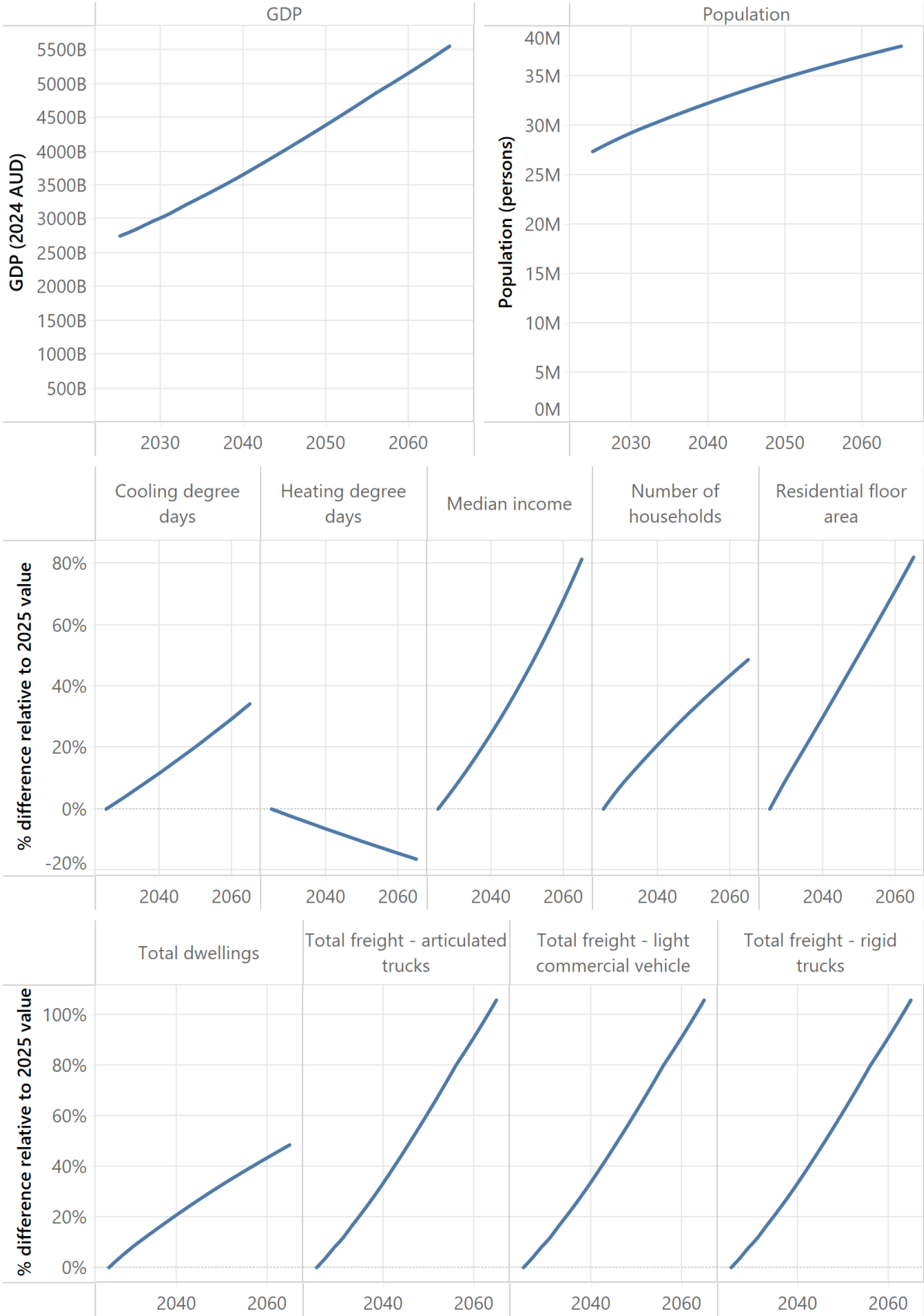
For the gross state product base driver, historical data is sourced from the Australian Bureau of Statistics (ABS) ^[1], while projections of future growth are provided by the Australian Energy Market Operator (AEMO) 2025 Inputs Assumptions and Scenarios document used to develop the 2026 Integrated System Plan^[2], adjusted to 2023-24 currency, 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 2025 – 2055 trend. Table 15 summarises these energy demand drivers used, the related extrapolation method and the data source.

A visualisation of key drivers is then given in Figure 9.

Table 15 | 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 (2025 – 2065). SA2/SA4 refer to statistical divisions used to organise ABS data.

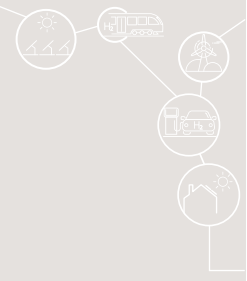
Energy services driver	Unit	Native geography	Native data years	Extrapolation method	Source
Population	people	State	2022-2071	Not needed	ABS, Population Projections, Australia 2022 (base) – 2071 ^[3]
Gross domestic product	2023-24 AU\$	State	1990 – 2056	1.5% per year growth	Historical ABS data, ^[1] projections provided in AEMO draft 2025-26 Inputs Assumptions and Scenarios for ISP ^[2]
Annual heating degree days	hdd	SA2	1961 – 2080	Not needed	Historic meteorological data ^[4] , projections estimated based on temperature warming projections using RCP 4.5 climate scenario ^[5]
Annual cooling degree days	cdd	SA2	1961 – 2080	Not needed	Historic meteorological data ^[4] , projections estimated based on temperature warming projections using RCP 4.5 climate scenario ^[5]
Median income	AU\$	National	2018 – 2022	1.5% per year growth	ABS, Personal Income in Australia ^[6]
Total number of dwellings	dwellings	State	2016 – 2022	Tied to number of households	ABS, Estimated Dwelling Stock ^[7]
Number of households	households	National	2021-2046	Tied to population	ABS, Household and Family Projections, Australia ^[7]
Residential floor area	m ²	State	2023	Tied to total dwellings	ABS, Building Activity, Australia ^[8]
Total freight – articulated trucks	tonne-km	National	1974 – 2022	Tied to gross state product	The Department of Infrastructure, Transport, Regional Development, Communications and the Arts, Australian Infrastructure Statistics—Yearbook 2023, Table 6.6 ^[10]
Total freight – light commercial vehicle	tonne-km	National	1974 – 2022	Tied to gross state product	The Department of Infrastructure, Transport, Regional Development, Communications and the Arts, Australian Infrastructure Statistics—Yearbook 2023, Table 6.6 ^[10]
Total freight – rigid trucks	tonne-km	National	1974 – 2022	Tied to gross state product	The Department of Infrastructure, Transport, Regional Development, Communications and the Arts, Australian Infrastructure Statistics—Yearbook 2023, Table 6.6 ^[10]

Figure 9 | 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 period (2025 to 2065).



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6 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., 2025-2060), with 2025 Australian dollars (2025AU\$) as the base currency. For detail on the capital and operating cost assumptions, including learning curves, used for the technologies considered in NZAu, please see Chapters 13, 14, and 15.

This Chapter outlines the assumed values of non-cost parameters that affect the NPV optimisation. This includes inflation (as a proxy for economic growth and input cost inflation on the energy sector), the social discount rate (used to discount the future benefits and costs to real (2025) dollars), and the weighted average cost of capital (WACC) for specific technologies.

The Chapter includes the following subsections:

- 6.1 Basis for WACC estimates
- 6.2 WACC values

6.1 Basis for WACC estimates

For the majority of technologies considered in the study, we use discount rates provided by Oxford Economics Australia (OE) in their report prepared for AEMO's 2026 ISP^[1].

A summary of the approach taken and key input parameters included in OE's calculation of WACC values is included below. For a full list of OE's WACC estimation approach and input parameters used, see Appendix A.1.

The WACC that can be attributed to energy investments is a function of the relative proportion of funding for a project that comes from investors (tied to returns on equity) and debt provided by banks (tied to commercial lending rates). Each have dependencies on the other and are influenced by the risk profile of the project. They also change as a project progresses through early development to construction to operation.

The risk profile of a project is a complex mix of technology, completion, commercial, policy and market risks. This includes individual project characteristics like technology maturity, location, policy environment, experience of the developer, and the depth of the supply and end-user market.

OE estimated pre-tax WACC using the following formula:

$$WACC_{nom} = \left(K_e \times \frac{1}{[1 - t(1 - \gamma)]} \times \frac{E}{V} \right) + \left(K_d \times \frac{D}{V} \right),$$

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

where:

$WACC_{nom}$	is nominal WACC
$WACC_{real}$	is real WACC
K_e	is the post-tax return on equity
K_d	is the post-tax return on debt
E/V	is the proportion of equity within the capital structure
D/V	is the proportion of debt within the capital structure
t	is the corporate tax rate
γ	is the value of imputation credits
i	is the inflation rate

6.2 WACC values

A full list of the range of WACC estimates developed by OE is outlined in Appendix A.2. In most instances, we use the *central estimate*.

Of the technologies investigated by OE, we deviate from their central estimate in two instances:

1. **Offshore wind:** OE estimated that offshore wind to have the same WACC as onshore wind (7.5%) in its *central estimate*. After consultation with energy project developers and financial sector experts, we increased the WACC of offshore wind to be higher than onshore wind, at **8.5%**. It is generally agreed that offshore wind is more complex to plan and build and has not yet been deployed in Australia, justifying its higher WACC.
2. **Coal power generation:** We adopt the *Upper Bound* of OE's WACC values for coal power generation (15%) given expert advice that no financial institution would fund it in Australia. We also only allow it to be built our REF Scenario.

For technologies considered in the NZAu Project that were **not** investigated by Oxford Economics, mainly emerging technologies, we determine WACCs via three methods:

1. When a technology is similar to one investigated by Oxford Economics, **we use the value provided by Oxford Economics** for that similar technology. This occurs as follows:
 - a. The OE utility solar WACC (7.0%) is used as a proxy for *rooftop solar*.
 - b. The OE CCGT WACC (10.5%) is used as a proxy for the *CCGT Allam with CCS*, and *CCGT with CCS* technologies.
 - c. The OE coal power generation WACC (15%) is used as a proxy for *black coal power with CCS*.
 - d. The OE regulated gas transmission and distribution WACCs (3.0%) are used as a proxy for *domestic carbon dioxide* and *hydrogen pipelines*.
2. We then **categorise all remaining technologies by their relative risk to build and operate**. For each category we assume a different return on equity and debt, and funding mix, which we use to calculate technology WACCs using the formula explained above. Historical data and judgment were used to make assumptions across these categories and are shown in Table 16. The two categories are:
 - a. **mature¹ and moderate-risk generation and production technologies** (e.g., bioenergy with CCS, blue and green hydrogen).
 - b. **higher risk generation and production technologies** (e.g. nuclear).
3. Finally, **we consider export-oriented pipelines** that are **not** considered by OE, namely carbon dioxide, hydrogen, and ammonia pipelines. We assume that any pipeline will form part of an integrated export project whose WACC will be equivalent to the highest WACC component of that project. For simplicity, we assume this to be the same as the moderate-risk generation WACC outlined in 2a above (9.5%).

The full list of WACC values per technology used in the NZAu modelling and grouped by category are provided in Appendix A.3.

¹ 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.

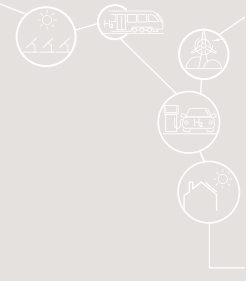
Table 16 | Table of proposed Real WACC for project investment decisions across asset categories in NZAu not covered in Oxford Economics Australia’s 2024 report^[1].

Asset Category	OE tech neutral for reference ^[1]	Moderate risk	Higher risk
Return on equity (<i>Ke</i>)	10.07%	12%	15%
Return on debt (<i>Kd</i>)	5.85%	8%	9%
Proportion funded by equity (<i>E/V</i>)	50%	50%	50%
Proportion funded by debt (<i>D/V</i>)	50%	50%	50%
Nominal WACC	9.4%	11.74%	14.18%
Real WACC*	7.0%	9.5%	11.5%
Corporate tax rate	30%		
Inflation rate	2.28%		

*Rounded to nearest 0.5% as per WACC convention.

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7 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. This Chapter provides details on Australia’s current domestic emissions and assumptions used to model their change over time.

This Chapter includes the following subsections:

- 7.1 Emissions overview
- 7.2 Modelled domestic emissions

7.1 Emissions overview

The NZAu project uses Australia’s 2023 National Greenhouse Accounts^[1] 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 17 summarises the GHG emissions for each UNFCCC category and the specific gases included in the Australian GHG inventory for 2023, while a historical view of these GHG emissions trends is shown in Figure 10. We have excluded external territories as these are not included in our model. Table 17 shows that carbon dioxide (CO₂) is the largest contributor to Australia’s total domestic GHG emissions, but methane (CH₄) is also significant, particularly from Agriculture, Waste and Land Use, Land Use Change and Forestry (LULUCF).

GHG emissions of the gases are aggregated on a carbon dioxide equivalent basis (CO₂e) using the 100-year global warming potentials (GWP-100) contained in the IPCC Sixth Assessment Report (AR6)^[2]. The GWP-100 values for CH₄ and N₂O are 27 and 273, respectively. Note that the 2023 GHG inventory uses AR5 values and includes external territories, so those listed in Table 17 will differ slightly to those reported in official Australian Government documentation. 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.

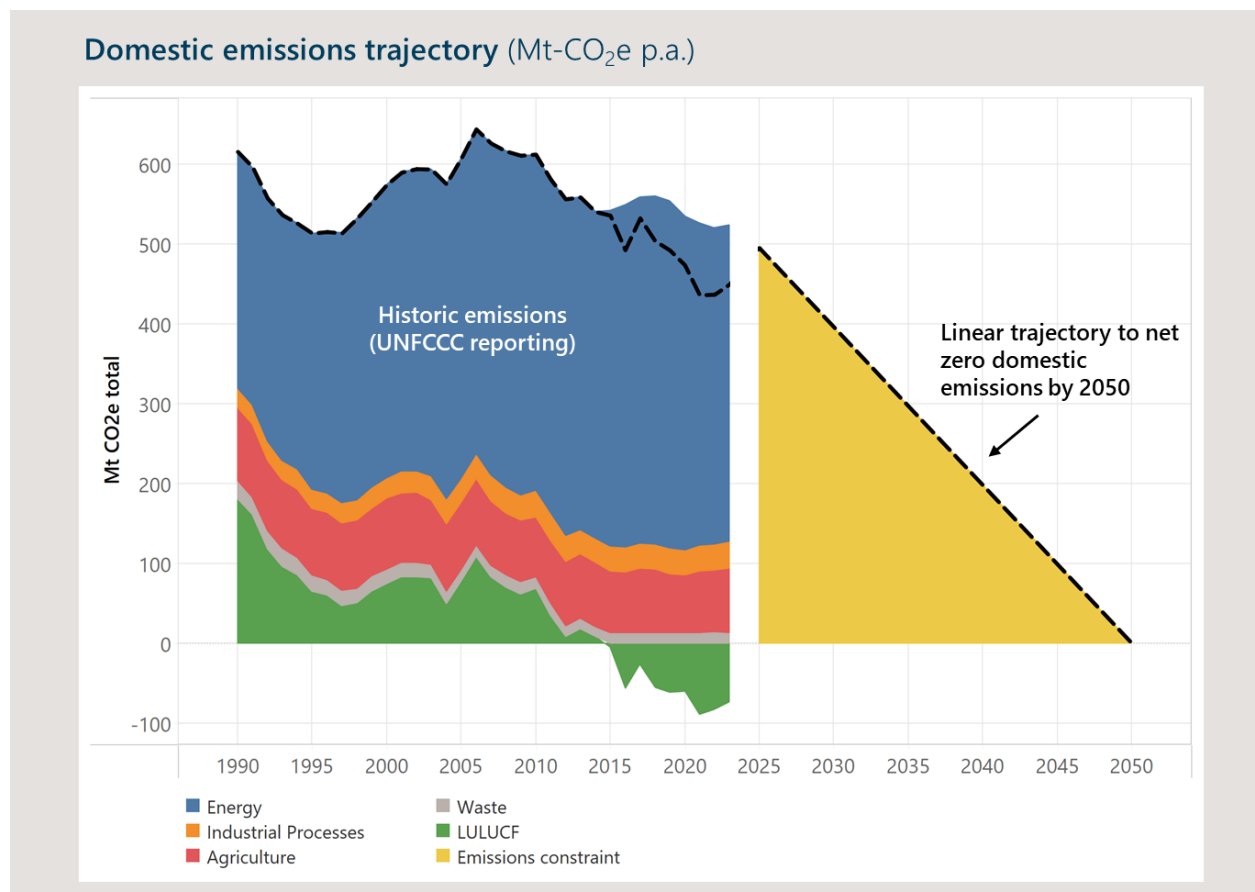
Table 17 | Summary of Australia’s 2023 greenhouse gas inventory (AR6), by sector and specific GHG, excluding external territories. Emissions are presented on a carbon dioxide equivalent basis (Mt-CO₂e)^[2].

UNFCCC category	GHG emissions (Mt-CO ₂ e)				
	Carbon dioxide	Methane	Nitrous oxide	Other	Total
Energy	360.3	33.4	2.1	0.0	395.8
Industrial processes	19.6	0.1	1.5	11.9	33.0
Agriculture	3.4	64.3	12.6	0.0	80.4
Waste	0.0	12.9	0.4	0.0	13.3
LULUCF	-95.8	17.3	4.3	0.0	-74.2
Total	287.4	128.0	20.9	0.0	448.3

7.2 Modelled domestic emissions

Domestic emissions in NZAu’s net zero scenarios are constrained with a linear trajectory from the first modelled year, 2025, to reach net zero in 2050 (or other target year, based on scenario definition), as shown in Figure 10. This is applied as an upper limit on annual net GHG emissions (CO₂e basis), for all UNFCCC sectors.

Figure 10 | Historic Australian domestic GHG emissions and the net zero trajectory modelled in this work^[1].



Net-zero emissions requires any residual flow of GHG emissions to the atmosphere to be offset by a permanent removal of the equivalent CO₂ from the atmosphere. To meet this constraint, we account for total emissions in two stages.

1. **We first model the land sector emissions trajectory** – accounting for a plausible contribution to emissions abatement from the Agriculture, Waste and LULUCF sectors (outlined in Chapter 11) over the modelling period, which is then fixed as an input into the nation-wide energy system modelling.
2. **Domestic energy and industrial sector emissions are then modelled, subject to the domestic GHG emissions constraint (Figure 10)** – GHG mitigation and fuel switching within these sectors are least-cost optimised to meet the domestic emissions constraint, accounting for the *fixed trajectory* of emissions from the Agriculture, Waste and LULUCF sectors.

For modelled emissions, 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.

The modelling approach used to account for emissions in these three areas is outlined below.

Total direct GHG emissions arising from the domestic consumption of fuels and feedstock

Table 18 provides the emissions factors used to account for direct consumption GHG emissions on an energy consumed basis.

Table 18 | Emissions factors used to account for direct consumption GHG emissions on an energy consumed basis^[3].

Fuel/feedstock	Direct consumption GHG emissions factor (kg-CO _{2e} / GJ)
Black coal	90.2
Brown coal	93.8
Natural gas	51.5
Oil products*	69.9
LPG	60.6
Uranium oxide	0
Biomass (incl. bagasse, municipal waste, waste methane)	1.8

*Includes crude oil, ORF, and refined products

Fugitive emissions associated with the production of fossil fuels

Table 19 provides the fugitive emissions factors on a basis of energy content produced for a given fossil fuel.

Table 19 | 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)		
	2022	2030	2040
Black coal	2.13	2.13	2.13
Brown coal	0.03	0.03	0.03
Coal seam natural gas	1.76	0.88	0
Conventional natural gas	4.09	3.38	2.66

The **brown coal** fugitive emissions factor is estimated from the factor 0.0003 t-CO_{2e}/t-raw coal reported in the National Greenhouse and Energy Reporting (Measurement) Determination 2008^[4] 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^[2].

The **black coal** fugitive emissions factor of 2.13 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].

The **coal seam natural gas** (CSG) fugitive emissions factor for 2022 was calculated using reported methane losses in the Surat Basin of 0.25% from upstream activities and 0.07% from midstream and transmission activities^[6]. The factor was then calculated to be 1.76 kg-CO_{2e}/GJ using methane's GWP-100 of 27 and higher heating value of 49 GJ/t-CH₄. We then assume 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.

The **conventional natural gas** fugitive emissions factor for 2022 was estimated by:

1. First estimating 2022 CSG fugitive (methane) emissions through the product of the emissions factor of 1.76 kg-CO₂e/GJ calculated above and CSG production in 2022 of 1,507 PJ^[5].
2. Estimating total *conventional* natural gas fugitive emissions by subtracting the CSG estimate calculated in step 1 from *total* natural gas fugitive emissions in the national inventory.
3. The figure in step 2 was then divided by the total conventional natural gas produced, to obtain a fugitive emissions factor of 4.09 kg-CO₂e/GJ.

This factor is similarly assumed to reduce with time, based on industry efforts 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, forming part of the CCS in all allowable scenarios).

We note that the economy-wide fugitive emissions factors calculated above are used to estimate fugitive emissions from any new production of fossil fuels determined in the model. These values are limited in two ways:

1. Black coal estimates do not distinguish between open cut or underground mines.
2. Conventional natural gas estimates do not account for variations in CO₂ content within individual gas field. The values above implicitly assume new gas production would occur across the country (rather than, for example, one project in a field with higher or lower than average CO₂ content).

Permanently sequestered emissions in geologic formations

See Chapter 12 section 12.2 for detail on CO₂ geologic storage capacities and unit costs.

Alignment between modelled 2025 emissions and most recent emissions inventory

Emissions in the first modelled year, 2025, are unconstrained and instead determined by our modelling of current energy consumption trends with existing energy and industrial infrastructure (specified in Chapters 9 and 10 of this methods document), together with emissions factors for different fuels and energy consumed.

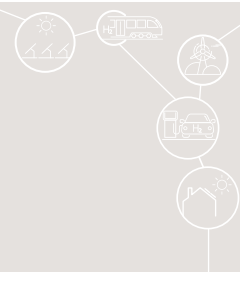
This results in 2025 modelled emissions being 6% higher than the 2023 national inventory, with the primary differences shown in Table 20. Note that unlike the national inventory, our modelling accounts for Australia's 'share' of international aviation and international shipping emissions, representing approximately 16 Mt-CO₂e p.a.. Emissions in these categories are not included in Australia's UNFCCC inventory, but are included in the energy consumption statistics set out in the Australian Energy Statistics, and can be found in the relevant tables in the chapters on historical demand (Chapter 9) and projections of energy demand (Chapter 10). If we remove these emissions, modelled 2025 emissions are within 2% of the 2023 inventory.

Table 20 | Breakdown of emissions, historic (2023) vs modelled (2025), using AR6 GWP, in Mt-CO₂e.

Sector	Historic emissions (2023 inventory)	Modelled emissions (2025)	Difference (%)
Electricity	153	127	-17%
Stationary energy	100	115	15%
Domestic transport	97	111	15%
International transport	0	16	-
Fugitives	48	52	10%
Agriculture	80	80	0%
Industrial processes	33	34	3%
Waste	13	13	0%
LULUCF	-74	-74	0%
Total	449	475	6%

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8 Modelled regions

This Chapter provides detail on the regions used to develop the energy system model. It includes the following subsections:

- 8.1 Regional boundaries
- 8.2 Summary of regional cost factors

8.1 Regional boundaries

The NZAu Project’s macro-energy system modelling incorporates the 21 domestic regions (NZAu regions) shown in Figure 11, each with its own energy service demand, initial stock of energy infrastructure and resources. These regions were constructed by aggregating Statistical Areas Level 2 (SA2) boundaries as defined by the Australian Bureau of Statistics^[1]. The number of regions chosen is a balance between the computational complexity of the modelling, and the spatial resolution required to represent geographically distributed energy resources and infrastructure, particularly those 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 CO₂ flows between neighbouring regions. This modelling then optimises the required energy investments in each region, as well as incremental energy transmission builds between regions.

Figure 11 | The 21 domestic regions (NZAu regions) 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 in its Integrated System Plan^[2]. New South Wales (NSW), Victoria (VIC), Queensland (QLD) and South Australia (SA) each have more than one modelled region, while 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 in various ways 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 not strongly dependent on the distance from port of origin to port of destination^[3]. Note also that the export energy supply is subject to a separate emissions constraint to the 21 domestic NZAu regions. Energy flows to the modelled ‘export zone’ can come from several domestic NZAu regions through defined ports.

NZAu Project’s defined export ports are selected from existing ports, based on the potential hydrogen export locations from ARUP’s Australian Hydrogen Hubs Study^[5]. The 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 21 for the development of hydrogen export facilities.

Table 21 | Potential Hydrogen Export Locations (Listed alphabetically)^[5].

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 Geelong, Portland
Western Australia	Ashburton / Onslow, Albany, Dampier, Geraldton, Oakajee, Port Hedland

Further assessment of the ports listed in Table 21 used three steps:

- Set selection criteria (see Table 22)
- Gather data on each port^[6-24]
- Rank ports, using the rankings in Table 23 to identify the most suitable locations for NZAu.

Table 23 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 23 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 22 | Selection criteria for NZAu hydrogen export ports.

Parameter	Criteria
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 23 | NZAu hydrogen export port ranking criteria.

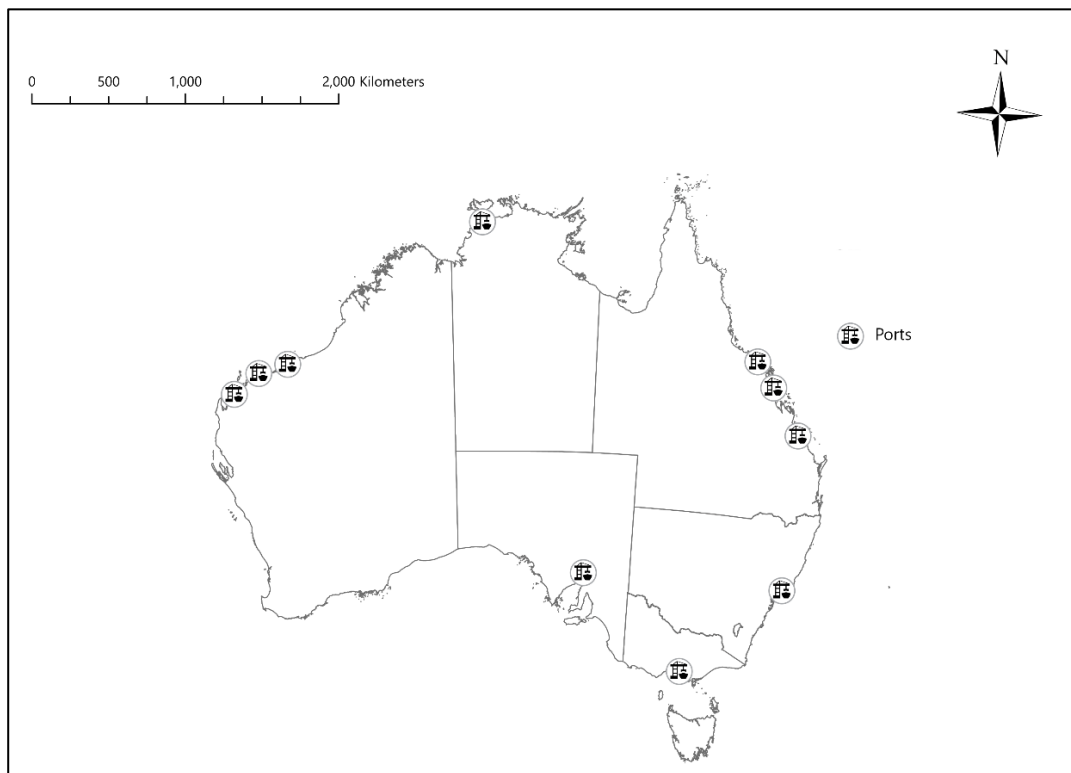
Best to worst	Criteria	Cost	Note
5	Existing LNG export	Low	LNG can be replaced by H ₂ /Ammonia and existing port facilities can be used
4	Coal & large mineral export	Moderate (-)	Can use existing berths but need extra facilities for storage and a jetty for liquid export
3	Large commodity / petroleum 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
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 17 ports listed in Table 24 were shortlisted as prospective hydrogen export hubs given publicly available information. Of those 17 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 22), and all berth pockets are significantly smaller than the minimum 350m × 90m specified in Table 22. The selected candidate port locations give good coverage across Australia (Figure 12).

Table 24 | The 17 port location candidates used in NZAu modelling. Red shading 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	
15	NSW	Newcastle	4	Newcastle
16		Kembla	4	
17	TAS	Bell Bay	2	

Figure 12 | NZAu defined export ports.



8.2 Summary of regional cost factors

The NZAu Project adjusts costs for energy technology builds based on the region in which the technology is built. These regional cost factors estimate variation in project costs between geographic regions due to differences in things like remoteness, geography, supply chains, and labour costs.

See Chapter 13 for detail on the non-adjusted capital cost inputs by supply-side technology.

Basis for cost factor estimates

NZAu regional cost factors are based on the draft 2025-26 ISP Inputs, Assumptions, and Scenarios Report (IASR) developed for AEMO's 2026 ISP^[1]. Capital cost data provided in the IASR is split by location (renewable energy zone (REZ), or ISP sub-region), by cost component (equipment and installation, fuel connection, or land development), and by technology. Technology component costs are calculated from estimates provided in Aurecon's Energy Technology Cost and Technical Parameter Review^[4]. Gas turbines and biomass generators report capital cost data split by ISP sub-region, while renewable generation and storage capital costs are provided at the REZ level.

Adjustments made for NZAu

The NZAu model needs cost factors to be provided at a regional level, yet some ISP data is available only at the REZ level. To address this, we first map REZs to NZAu regions. We then look at each NZAu region and average the cost adjustments provided by each REZ within that region to derive representative whole-of-region values.

Cost factors for WA and NT NZAu region are based on other NZAu regions or IASR REZs assumed to have similar regional characteristics (e.g. population density, access to road infrastructure, remoteness, etc.).

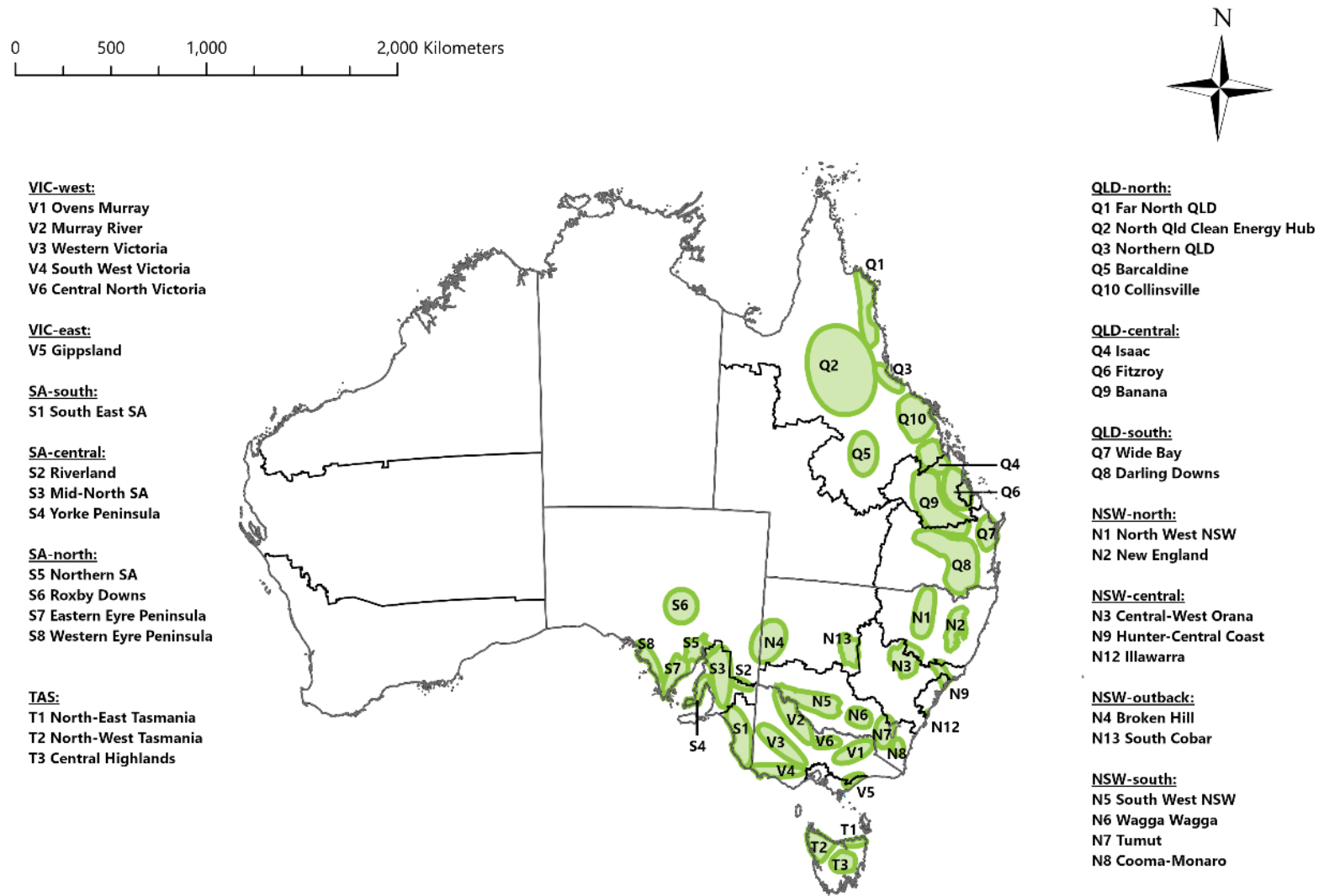
A summary of the regional cost factors by NZAu region and its link with the IASR REZs is outlined in Table 25 below. For a full list of locational cost adjustments, by technology, by NZAu region, please see Appendix B.

Table 25 | Summary of regional capital cost factors used in NZAu

NZAu region	NZAu regional cost factors				Based on?*
	Gas and biomass	Onshore renewables	Batteries	PHES	
nt	108%	116%	108%	106%	qld-north
nsw-snw	100%	N/A	100%	N/A	SNW
nsw-central	103%	105%	103%	106%	CNSW, N3 Central-West Orana, N9 Hunter-Central Coast, N12 Illawarra
nsw-north	106%	109%	105%	104%	NNSW, N1 North West NSW, N2 New England
nsw-south	101%	109%	105%	117%	SNSW, N5 South West NSW, N6 Wagga Wagga, N7 Tumut, N8 Cooma-Monaro
nsw-outback	106%	122%	112%	104%	For gas, biomass and PHES - nsw-north.
vic-mel	100%	N/A	100%	N/A	MEL
vic-west	100%	100%	100%	100%	WNV, V1 Ovens Murray, V2 Murray River, V3 Western Victoria, V4 South West Victoria, V6 Central North Vic
vic-east	100%	100%	100%	N/A	SEV, V5 Gippsland
qld-south	100%	106%	103%	100%	SQ, Q7 Wide Bay, Q8 Darling Downs
qld-central	110%	114%	108%	100%	CQ, Q4 Isaac, Q6 Fitzroy, Q9 Banana
qld-outback	108%	116%	108%	106%	qld-north
qld-north	108%	116%	108%	106%	NQ, Q1 Far North QLD, Q2 North Qld Clean Energy Hub, Q3 Northern Qld, Q5 Barcaldine, Q10 Collinsville
qld-gg	107%	N/A	104%	N/A	GG
sa-central	100%	108%	103%	101%	CSA, S2 Riverland, S3 Mid-North SA, S4 Yorke Peninsula
sa-south	109%	111%	106%	N/A	SESA, S1 South East SA
sa-north	104%	114%	107%	108%	NSA, S5 Northern SA, S6 Roxby Downs, S7 Eastern Eyre Peninsula, S8 Western Eyre Peninsula
wa-south	100%	106%	103%	100%	SQ, Q7 Wide Bay, Q8 Darling Downs
wa-central	108%	116%	108%	106%	NQ, Q1 Far North QLD, Q2 North Qld Clean Energy Hub, Q3 Northern Qld, Q5 Barcaldine, Q10 Collinsville
wa-north	108%	116%	108%	106%	For onshore renewables and batteries: Q1 Far North QLD, Q2 North Qld Clean Energy Hub For gas/biomass, and PHES: qld-north
Tas	100%	107%	103%	104%	TAS, T1 North East Tasmania, T2 North West Tasmania, T3 Central Highlands

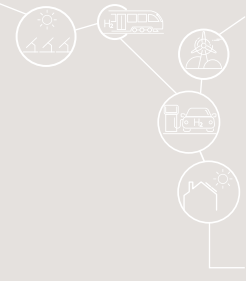
* Italics denotes subregions or REZs outlined in the IASR, non-italics references other NZAu regions.

Figure 13 | ISP onshore REZs mapped to NZAu regions.^[1]



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9 Historical demand

This Chapter provides an overview of Australia’s historic demand for energy, used to build the model. It includes the following sub-sections:

- 9.1 Decomposition of final energy demand
- 9.2 On-road transport
- 9.3 Buildings
- 9.4 Electricity load shapes

Historical energy demand in the NZAu Project refers to the yearly *final energy consumption*, as reported for Australia in the Australian Energy Statistics (AES)^[1].

9.1 Decomposition of final energy demand

Australian energy consumption data by state and territory, fuel type and industry classification are reported in the AES Table F. Demand estimates were built in the NZAu Project from this dataset.

The AES data is decomposed by state and territory into economic sectors according to the Australian and New Zealand Standard Industry Classification (ANZISC). The EnergyPATHWAYS database used in the modelling (which is described in more detail in Chapters 2, 3, and 10) uses different categorisations compared to the AES data. An initial mapping across end-use energy subsectors and fuel types was performed to harmonise the categories used by AES with this modelling, as shown in Table 26 and Table 27.

It is worth noting the AES maintains confidentiality on some of these energy data by aggregating them at higher levels. As an example, Figure 14 shows that not all data are reported for energy consumption by fuel type and AES manufacturing classification by state. The summation of each individual states’ data for all subdivisions within manufacturing (showing in sub-figure (d)) is significantly lower than the aggregated energy consumption reported for the whole sector, nationally, in sub-figures (a) and (c) and by state, in sub-figure (b). In all these cases, various breakdowns could all yield the same cumulative demand as per AES, when disaggregating into end-use subsectors and/or fuel types. Least-norm optimisation was applied to fill in for the missing data in these cases: accordingly, aggregated values were evenly spread across subsectors and/or fuel types, for each state or territory. Figure 15 shows the result of this allocation when applied to energy consumption for Australian manufacturing.

Energy consumption ultimately arises from supplying the *services* demanded by users through a specific mix of energy carriers. In order to allow for the switch to a diverse fuel mix that still ensures this evolving service demand is satisfied whilst aligning with emission targets over the net-zero transition, energy consumption was further decomposed into an end-use service demand for each of the NZAu regions. This process is described in the following sections.

Table 26 | Mapping between Australian Energy Statistics industry classifications and industry subsector in the EnergyPATHWAYS input database used in the NZAu Project.

Australian Energy Statistics industry classification	Industry subsector in EnergyPATHWAYS
Division B – Mining	
06 Coal mining	N.A. (modelled on the supply-side)
07 Oil and gas extraction	N.A. (modelled on the supply-side)
08-10 Other mining	Other mining

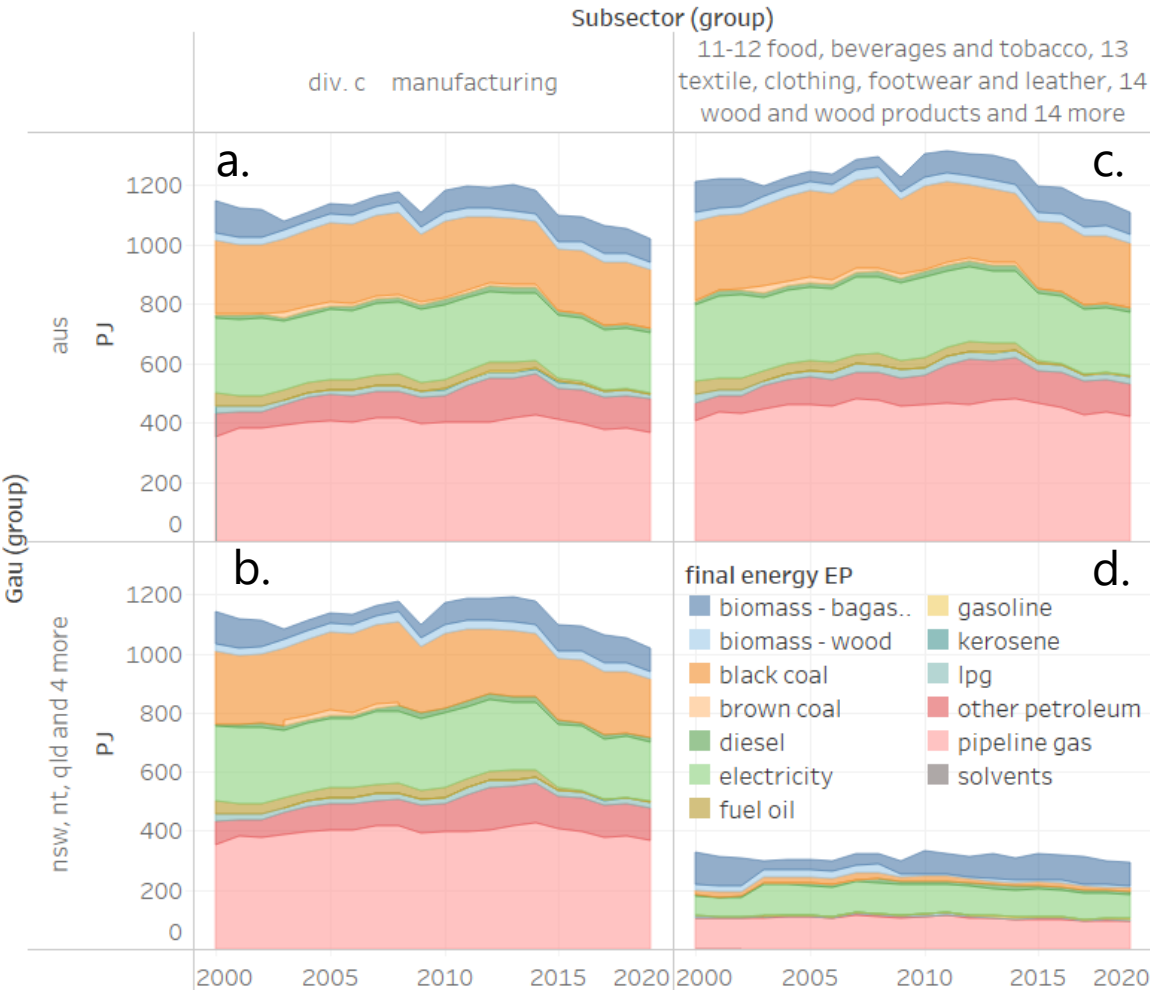
Australian Energy Statistics industry classification	Industry subsector in EnergyPATHWAYS
Division C – Manufacturing	
11-12 Food, beverages and tobacco	Food; beverages and tobacco
13 Textile, clothing, footwear and leather	Textile; clothing; footwear and leather
14 Wood and wood products	Wood and wood products
15-16 Pulp, paper and printing	Pulp; paper and printing
1701 Petroleum refining	N/A (modelled on the supply-side)
1709 Other petroleum and coal product manufacturing	Other petroleum and coal product manufacturing
18-19 Basic chemical and chemical, polymer and rubber product manufacturing	Basic chemical and chemical; polymer and rubber product manufacturing
20 Non-metallic mineral products	Non-metallic mineral products
201 Glass and glass products	Glass and glass products
202 Ceramics	Ceramics
203 Cement, lime, plaster and concrete	N.A. (modelled on the supply-side)
209 Other non-metallic mineral products	Other non-metallic mineral products
211-212 Iron and steel	N.A. (modelled on the supply-side)
213-214 Basic non-ferrous metals	N.A. (modelled on the supply-side)
22 Fabricated metal products	Fabricated metal products
23-24 Machinery and equipment	Machinery and equipment
25 Furniture and other manufacturing	Furniture and other manufacturing
Division D – Electricity, gas, water and waste services	
26 Electricity supply	N.A. (modelled on the supply-side)
27 Gas supply	N.A. (modelled on the supply-side)
28-29 Water supply, sewerage and drainage services	Water supply; sewerage and drainage services
Division I – Transport, postal and warehousing	
46 Road transport	Passenger vehicles Motorcycles Buses Light commercial vehicles Rigid and other trucks Articulated trucks
47 Rail transport	Rail transport
48 Water transport – International bunkers	International water transport
48 Water transport – Coastal bunkers	Domestic water transport
49 Air transport – Domestic	Domestic air transport
49 Air transport – International	International air transport
50-53 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

Australian Energy Statistics industry classification	Industry subsector in EnergyPATHWAYS
	Residential air conditioning Residential space heating Residential water heating Residential lighting Residential fans Residential other appliances
Other	
Division A – Agriculture, forestry and fishing	Agriculture forestry and fishing
Division E – Construction	Construction
Commercial and services	Commercial and services
Solvents, lubricants, greases and bitumen	Solvents; lubricants; greases and bitumen

Table 27 | Mapping between Australian Energy Statistics fuel types and fuel type in the EnergyPATHWAYS input database used in the NZAu Project.

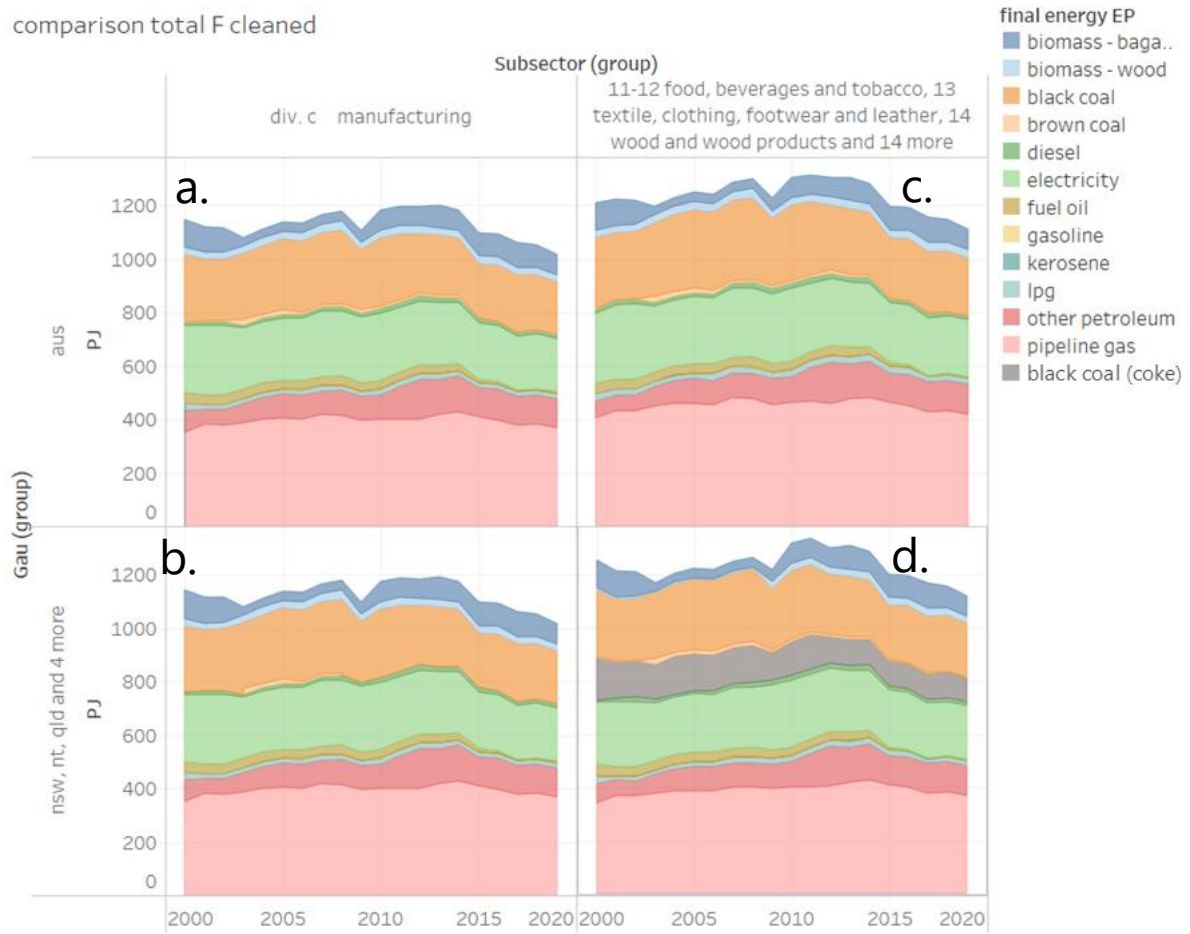
Australian Energy Statistics fuel type	Fuel type in EnergyPATHWAYS
Black coal Coke	Black coal
Bitumen	Bitumen
Brown coal Coal byproducts Brown coal briquettes	Brown coal
Wood, woodwaste	Biomass – wood
Bagasse	Biomass – bagasse
Natural gas Town gas	Pipeline gas
LPG	LPG
Automotive gasoline – leaded Automotive gasoline – unleaded Aviation gasoline	Gasoline
Aviation turbine fuel	Aviation turbine fuel
Kerosene & Heating oil	Kerosene
Diesel	Diesel
Fuel oil	Fuel oil
Crude oil & Other refinery feedstock	Crude oil
Petroleum products	Other petroleum
Solvents	Solvents
Lubricants & greases	Lubricant and greases
Electricity	Electricity
Solar energy	Solar

Figure 14 | Manufacturing energy consumption data as reported by AES for confidentiality (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 classifications within manufacturing, and (d) the sum of each state and territory’s data for all classifications within manufacturing. Note that (d) should match (c).

Figure 15 | Manufacturing energy consumption data after adjustments using least-norm optimisation (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 classifications within manufacturing, and (d) the sum of each state's data for all subdivisions within manufacturing (allocated using least-norm optimisation). Note black coal and black coal (coke) from panel (d) are both mapped onto black coal in EnergyPATHWAYS, hence reflecting reasonably well the overall black coal consumption in the other panels.

9.1.1 Further decomposition in the mining sector

Further pre-processing of the AES data for the mining sector was undertaken to characterise the energy demand by selected commodities, in each of the NZAu regions, according to these initial steps:

1. '06 Coal mining' consumption by state and territory was further apportioned to either black or brown coal, based on the respective production of each commodity from the Resource and Energy Quarterly^[2]; and
2. '06 Coal mining' and '08-10 Other mining' consumption were assigned to NZAu regions based on statistics on the local number of workers in the mining sector^[3].

Then, for the supply-side modelling of coal mining, the energy intensity (i.e. the energy consumed per unit of product extraction) had to be characterised for individual mines. Energy consumption for each site was either collated from Environmental Impact Statements – when available – or calculated from run-of-mine (ROM) and GHG emission data^[4-12].

ROM is defined as the total material moved by the mine operations and was computed as:

$$\text{ROM} = \frac{\text{Annual production}}{\text{Average grade}}$$

ROM and energy consumption by commodity enabled the calculation of the energy intensity of mining operations by energy type, which was used as an input to the modelling.

Energy intensity was determined this way for underground and open-cut mines. Average data in GJ/t-ROM of diesel and electricity are reported in Table 28.

Table 28 | Average energy intensity by energy type and service for underground and open-cut mines.

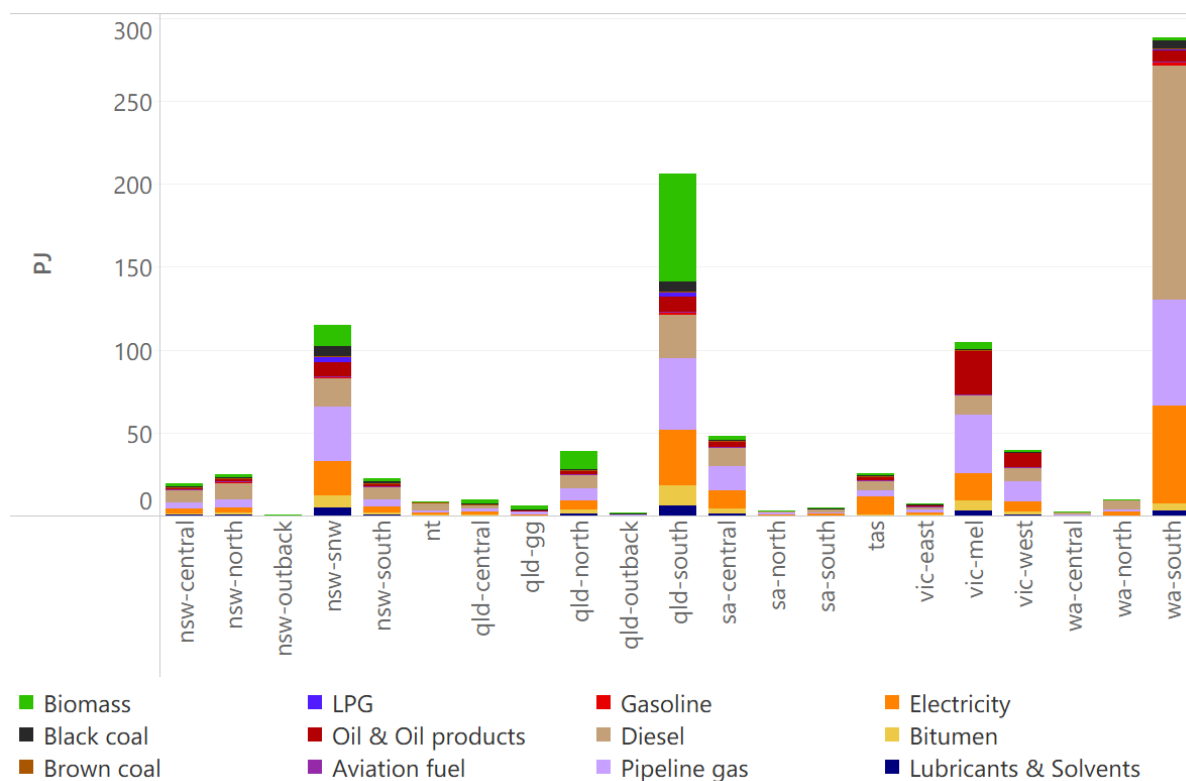
Energy type	Underground			Open-Cut		
	GJ/t-ROM	Share	Notes	GJ/ROM	Share	Notes
Diesel	0.038	35%	43% for transport; and 57% for stationary applications	0.346	75%	65% for transport; and 35% for stationary applications
Electricity	0.07	65%		0.117	25%	
Total demand	0.108	100%		0.463	100%	

9.1.2 Further decomposition in the manufacturing sector

Similar to mining, demand for the manufacturing subsectors was apportioned to regions based on the reported statistics on the local number of workers in the manufacturing sector^[3]. Energy breakdown by use type was further computed by comparing AES data to a normalised USA equivalent (based on the North America Industry Classification^[13]) from the NetZero America study^[14], and applying a correction for heating-ventilation and air conditioning (HVAC) demand to account for the different local climate. State breakdowns are presented in Figure 16.

Exceptions were the subsectors modelled on the supply side, namely iron and steel, cement, and aluminium, which are cumulatively responsible for almost 10% of the total energy consumption in Australia. For iron and steel, energy demand by fuel type was apportioned to regions based on the number of steel mills^[15]. For cement, existing clinker and cement refining facilities were assigned to each region and split by fuel type, as explained in Chapter 15. For aluminium, the existing refineries and smelters were assigned to each region. Their consumption based on the efficiency reported in Chapter 15 was subtracted from the '20 Non-metallic mineral products'. The remaining energy consumption, which includes aluminium casting, was assigned based on the number of workers in manufacturing. Such improved treatment for the demand in these subsectors allows for explicit optimisation of the supply technologies used, including process integration and upgrade which can prompt fuel switching and improved energy efficiency along the transition to net zero. This matter is further described in Chapter 15.

Figure 16 | Manufacturing energy demand by energy carrier and NZAu state in the financial year 2023-24.



9.2 On-road transport

On-road transport statistics were sourced from the Australian *Bureau of Infrastructure and Transport Research Economics*' (BITRE) *Road Vehicles Australia* (RVA) report for 2024^[16], and the ABS' *Survey of Motor Vehicle Use* (SMVU) spanning the years 1998 – 2020^[17]. 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:

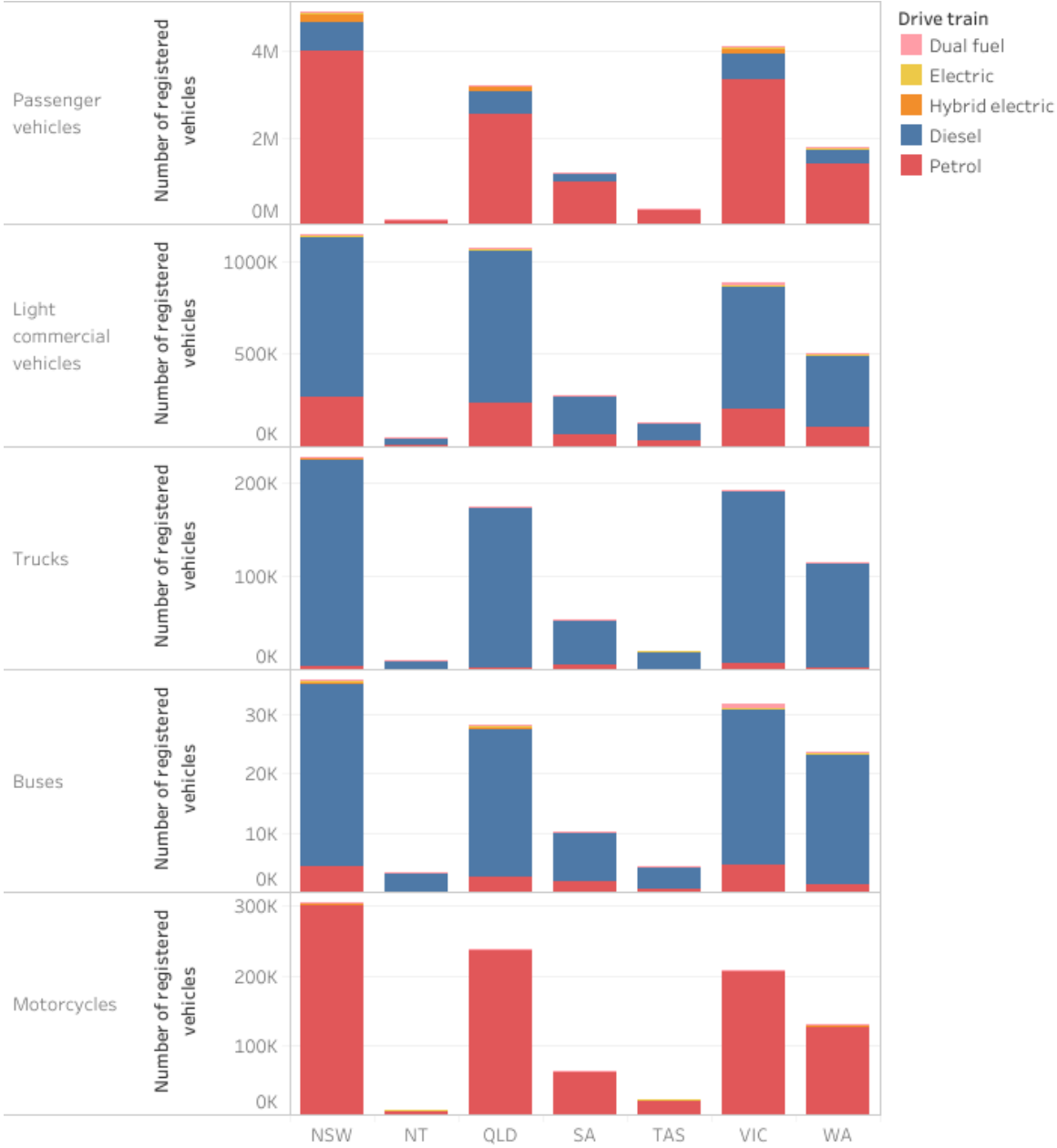
- passenger vehicles;
- light commercial vehicles;
- light and heavy rigid trucks;
- articulated trucks;
- non-freight carrying vehicles;
- light and heavy buses; and
- motorcycles.

The statistics for these vehicle types were also disaggregated by fuel type, including petrol, diesel, dual fuel, hybrid electric, and battery electric/fuel cell.

The initial stock (Jan 2024) of on-road registered transport vehicles numbered 21.7 million, the largest proportion being passenger vehicles (Figure 17). The BITRE^[16] provides data on this initial stock for each Australian postcode, which was aggregated to the 21 modelled NZAu regions (see Chapter 8 – modelled regions). The initial stock is presented in Figure 17 on a state/territory basis but used in the modelling on a NZAu region basis.

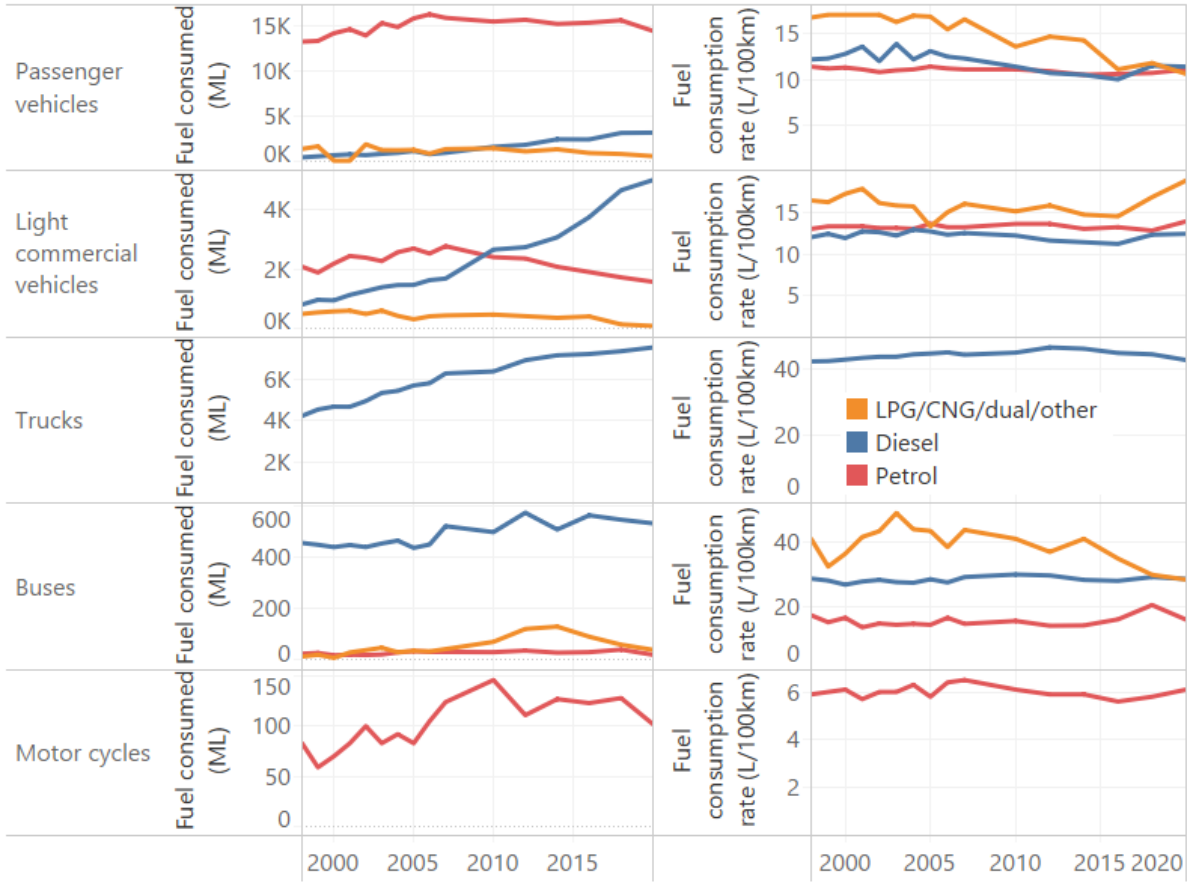
The SMVU^[17] provides trends on historical on-road transport fuel consumption and fuel economy by state/territory, vehicle type, and fuel type, as shown in Figure 18. Although the data are presented here for the whole of Australia, state/territory-based data are used in the modelling. We assume that each NZAu region 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. Data from the survey was only available to 2020, after which it was discontinued. No better source has been published since, so we assume no change in total fuel consumption or fuel economy for values from 2020 to 2025.

Figure 17 | Initial stock of on-road transport vehicles, by vehicle type, fuel type, and state/territory of registration (see Note)^[16].



Note: Vehicle numbers are presented here by state/territory of registration but were organised for the modelling into the 21 modelled NZAu regions. 'Trucks' here includes light and heavy rigid trucks, articulated trucks and non-freight carrying trucks, which are each treated separately in the modelling.

Figure 18 | Left: historical Australian on-road transport fuel consumption, and right: historical Australian on-road transport fuel economy (see Note)^[17].



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. Data is only available to 2020. We assume no change in total fuel consumption or fuel economy for values from 2020-2025.

9.3 Buildings

Energy demand in residential and commercial buildings refers to the final energy consumption reported by the AES within, respectively, the 'Residential' and 'Commercial and services' industry classifications^[18].

9.3.1 Residential buildings

State-based residential energy demand was decomposed into the 15 subsectors listed in Table 29, using the 2021 Residential Energy Baseline Study (REBS)^[19]. Additionally, the technology stock that supplies some of the energy services in this sector was derived from the REBS energy consumption (by use type) for individual dwellings^[19], combined with the aggregated residential energy demand from the AES^[18] and an account of technology efficiency from the US Energy Information Administration^[20]. The residential subsectors for which stock-based decomposition was pursued are presented alongside energy-only subsectors in Table 29.

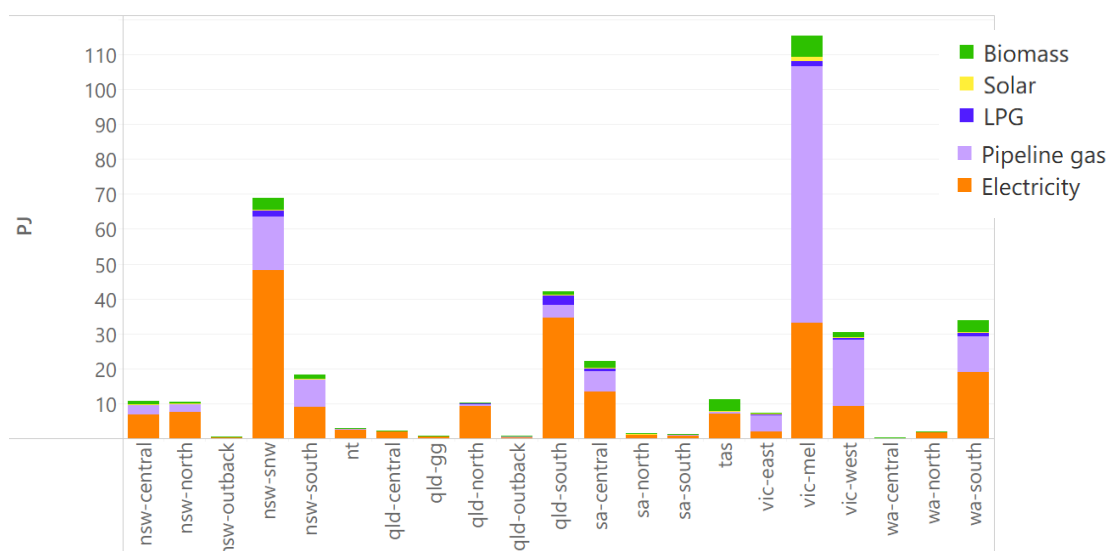
Demand and technology stock were then apportioned to NZAu regions based on the total number of dwellings in each region, from the Australian Bureau of Statistics^[21].

The residential energy demand by fuel and NZAu region in the financial year 2023-24 is presented in Figure 19. Bottom-up demand data obtained were obtained for each subsector as previously discussed. Aggregation of these data over the whole sector yielded close agreement with the annual residential demand figures from the AES, so no further adjustment was needed.

Table 29 | Residential subsectors into which the residential energy demand was decomposed.

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

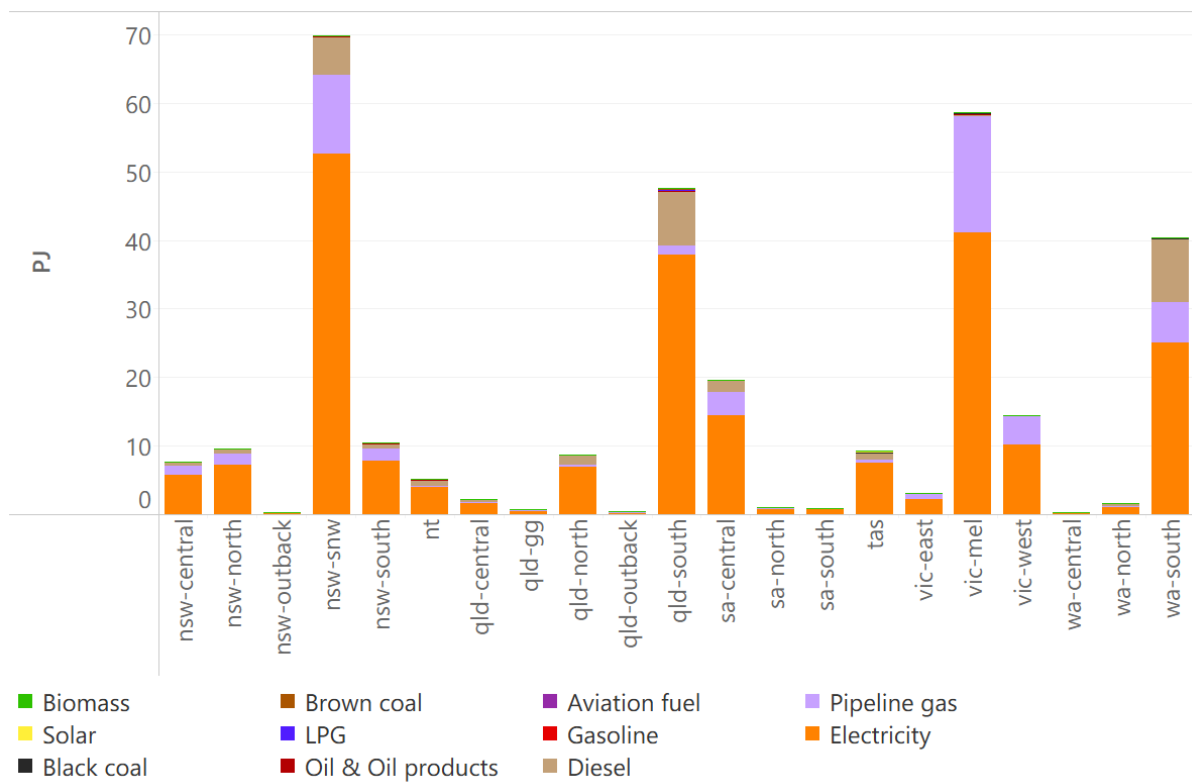
Figure 19 | Residential energy demand by energy carrier and NZAu region in the financial year 2023-24.



9.3.2 Commercial buildings

The most up-to-date reference on energy demand from commercial buildings is the 2022 Commercial Building Baseline Study (CBBS)^[22], which reports average energy consumption by service provided and energy carrier used in some of the main commercial building types, including offices, hotels, shopping centres and hospitals. These cover only a subset of buildings in the sector and a portion of the energy demand. Furthermore, the small sample size of building types for which energy consumption metering was available and the lack of data with sufficient granularity made a further disaggregation of commercial building demand not feasible. As a workable alternative, the total commercial building energy consumption (demand) by state and fuel type from AES was apportioned to NZAu regions based on their proportion of total national workers in the commercial buildings sector from the ABS^[22], but without further distinguishing between commercial subsectors. The commercial buildings energy demand by fuel and NZAu region in the financial year 2023-24 is presented in Figure 20.

Figure 20 | Commercial buildings energy demand by energy carrier and NZAu region in the financial year 2023-24.



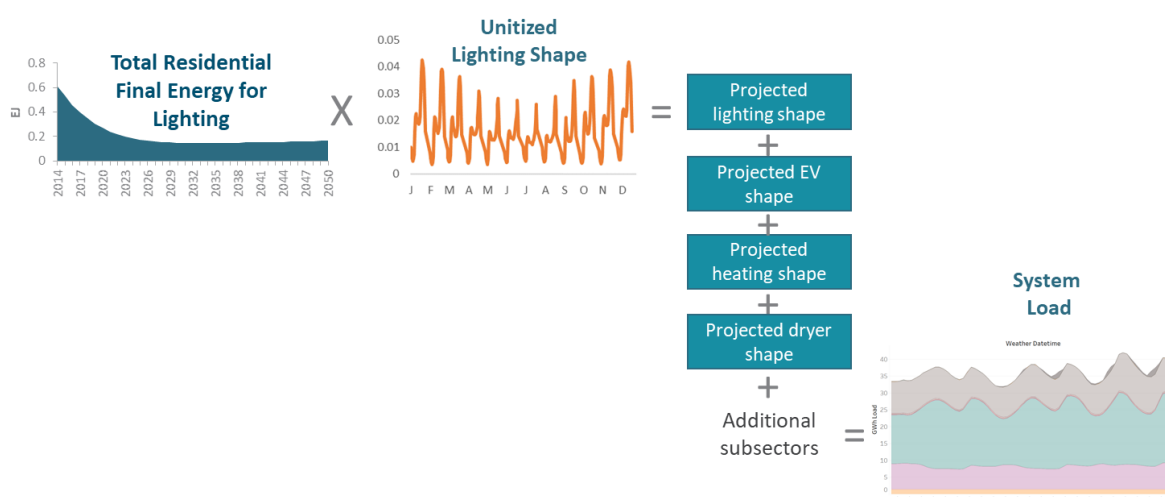
9.4 Electricity load shapes

9.4.1 Load shapes – operational demand

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 built using the EnergyPATHWAYS (EP) bottom-up process, illustrated in Figure 21. 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 the 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.

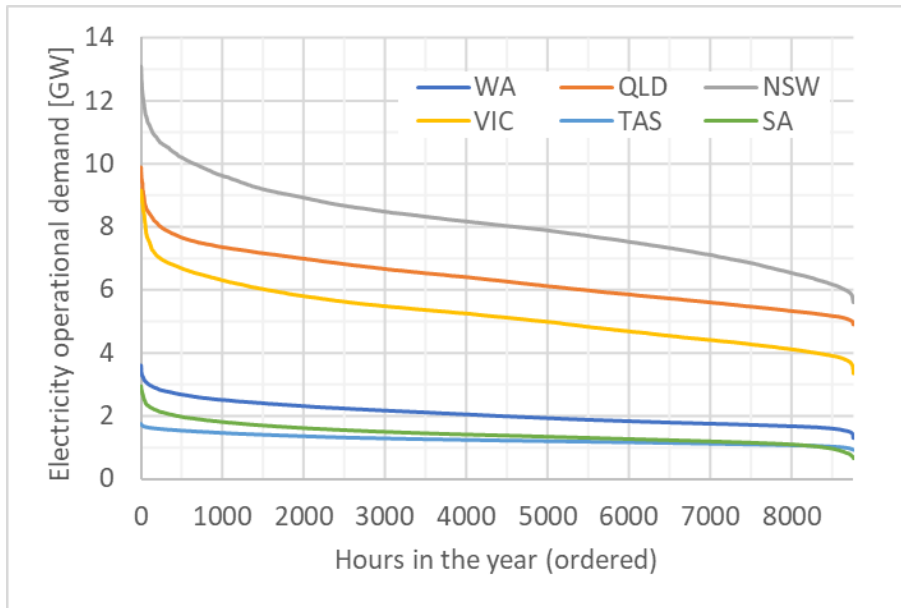
Figure 21 | Illustration of the bottom-up method used in EnergyPATHWAYS to build electricity load shapes from electricity-consuming sub-sectors.



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)^[23, 25]. These half-hourly data were converted to hourly demand profiles, and are shown for FY 2017-18 in Figure 22, 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 2017-18 financial year (1 July 2017 to 30 June 2018) was chosen as the representative weather year for the annual demand and renewable generation profiles used in the NZAu Project. The state-based data were disaggregated to the NZAu regions proportional to their population, assuming the same shape for each member zone.

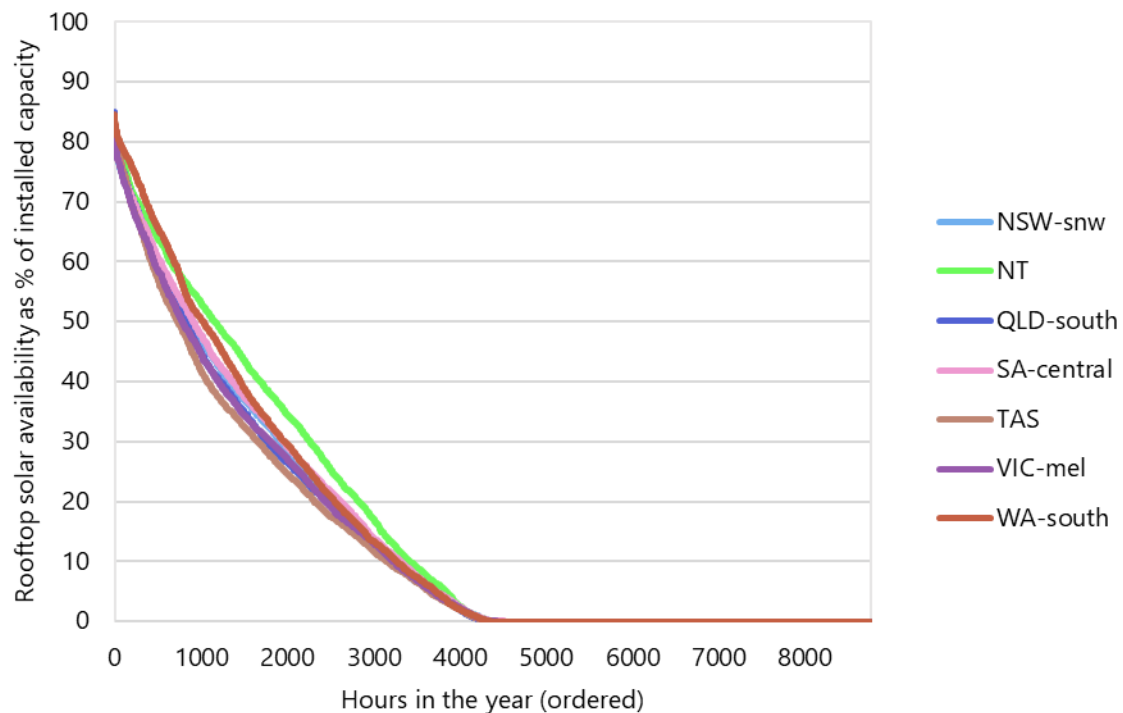
Figure 22 | Electricity operational demand duration curves for FY 2018 and the 6 Australian states.



9.4.2 Load shapes – rooftop solar PV

Historical data for the hourly demand met by behind-the-meter electricity generation from rooftop solar PV generation was 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 significantly affect the need for ramping utility-scale generation. The NZAu Project’s hourly rooftop PV resource availability trace in FY 2017-18 for each NZAu region was modelled by taking the average across all modelled rooftop solar PV traces in that region. 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. The rooftop PV model is detailed in Chapter 12 and is validated against AEMO’s rooftop solar PV generation data for the NEM states^[23]. Figure 23 shows a sample of the generation duration curves as a percentage of installed capacity for rooftop solar PV in FY 2017-18.

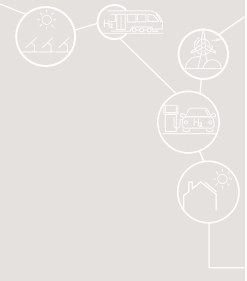
Figure 23 | A sample of rooftop solar PV generation duration curves as a percentage of installed capacity for FY 2018.



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10 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 EP is outlined in Chapter 2 and has been published previously^[1,2]. Its application to Australia is summarised in this Chapter.

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 accounts for 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 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 50 subsectors are used to represent the Australian energy system, as shown in Table 30. 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 33 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 24. 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.

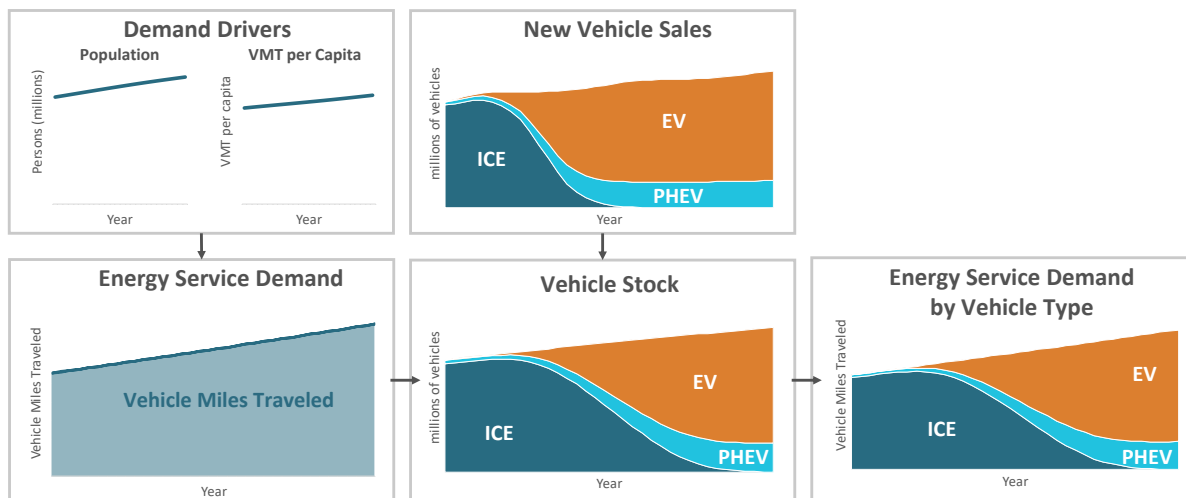
Prescribed technology type sales shares for the subsectors with stock representation are shown in Table 32, for the NZ2050 Scenario and for 2025 and 2040 with an assumed S-curve for sales in the intermediate years.

Table 31 shows the prescribed data used for the Reference Scenario and then explains how these change in the Current Policies Scenario based on the expected effect of various policies (e.g. the vehicle efficiency standard).

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 Net Zero Extended Timeline Scenario delays the saturation of the sales share switching by 20 years for the transport sector, and by 60 years for the residential sector.

Figure 24 | 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. These energy efficiency and fuel switching measures are presented in Table 33 for the NZ2050 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 2025, 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 2025, which declines linearly to \$5/GJ by 2040. This declining cost trend moves counter to the cost of energy efficiency and accounts for technology learning that should reduce the cost of fuel switching to electric or hydrogen-based processes over time.

The final energy demand of all subsectors presented in Table 30 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 30 | 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
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	RIO optimisation	1% per year output growth
Industry	Other non-metallic mineral products	Energy only	1% per year output growth
Industry	Iron and steel	RIO optimisation	1% per year output growth
Industry	Basic non-ferrous metals	RIO optimisation	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

Sector	Subsector	Model methodology	Projection basis
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
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
Commercial	Data centres	Service and efficiency	As per AEMO projections: ^[3] ~40% p.a. demand growth between 2026-2030 to 11.8 TWh. ~9% p.a. growth from 2030-2050 to 33.8 TWh.

Table 31 | Technology type sales shares for the subsectors with stock representation, for the Reference Scenario.

Sector	Subsector	Technology group	2025	2040*
Transportation	Passenger vehicles & buses	Reference	96%	96%
		Electric	1%	1%
		High Efficiency	3%	3%
Transportation	Light commercial vehicles	Reference	100%	100%
		Electric	0%	0%
Transportation	Motorcycles (*sale saturation is reached in 2035)	Reference	100%	100%
		Electric	0%	0%
Transportation	Rigid and other trucks	Reference	100%	100%
		Electric	0%	0%
		Hydrogen	0%	0%
Transportation	Articulated trucks	Reference	100%	100%
		Electric	0%	0%
		Hydrogen	0%	0%
Residential	Residential clothes washing/drying, dishwashing, refrigeration/freezing (*sale saturation is reached in 2035)	Reference	100%	100%
		High Efficiency	0%	0%
Residential	Residential lighting (*sale saturation is reached in 2030)	Reference	29%	29%
		High Efficiency	71%	71%
Residential	Residential water heating	Reference	51%	52%
		Electric	47%	46%
		High Efficiency	2%	2%
Residential	Residential cooktops and ovens	Reference	40%	40%
		Electric	60%	60%
Residential	Residential air conditioning	Reference	100%	100%
		High Efficiency	0%	0%
Residential	Residential space heating	Reference	31%	29%
		Electric	69%	71%

The Current Policies Scenario follows the same projections as those above, with an exception for transport. As described in Chapter 3 – Core Scenarios, we impose new sales shares for plug-in hybrids (PHEVs), hybrids (HEVs) and battery electric vehicles (BEVs), so that the New Vehicle Efficiency Standard’s headline limits on aggregated emissions intensity are achieved. This affects passenger vehicles, and light commercial vehicles. Please see Chapter 3 for more detail.

Table 32 | Technology type sales shares for the subsectors with stock representation, for the NZ2050 Scenario (see Note).

Sector	Subsector	Technology group	2025	2040*
Transportation	Passenger vehicles	Reference	85%	0%
		Electric	12%	100%
		High Efficiency	3%	0%
Transportation	Light commercial vehicles	Reference	98%	10%
		Electric	3%	85%
		Hydrogen	0%	4%
Transportation	Motorcycles (*sale saturation is reached in 2035)	Reference	67%	10%
		Electric	33%	90%
Transportation	Buses	Reference	98%	1%
		Hydrogen	0%	10%
		Electric	2%	89%
Transportation	Rigid and other trucks	Reference	97%	1%
		Electric	2%	70%
		Hydrogen	1%	30%
Transportation	Articulated trucks	Reference	97%	1%
		Electric	2%	49.5%
		Hydrogen	2%	49.5%
Residential	Residential clothes washing/drying, dishwashing, refrigeration/freezing (*sale saturation is reached in 2035)	Reference	90%	0%
		High Efficiency	11%	100%
Residential	Residential lighting (*sale saturation is reached in 2030)	Reference	11%	0%
		High Efficiency	89%	100%
Residential	Residential water heating	Reference	50%	6%
		Electric	48%	94%
		High Efficiency	2%	0%
Residential	Residential cooktops and ovens	Reference	38%	4%
		Electric	62%	96%
Residential	Residential air conditioning	Reference	89%	4%
		Electric	2%	38%
		High Efficiency	10%	58%
Residential	Residential space heating	Reference	30%	6%
		Electric	70%	95%

Note: The Net Zero Extended Timeline 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 33 | Energy efficiency and fuel switching measures applied for subsectors with an energy-only representation, for the NZ2050 Scenario (see Note).

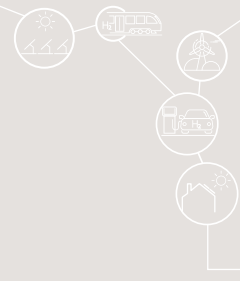
Sector	Subsector	Energy efficiency	Fuel switching
Industry	Agriculture, forestry and fishing; Textile, clothing, footwear and leather; Machinery and equipment; Water supply, sewerage and drainage services	1%/year	All fossil fuel use is converted to electricity by 2045 (2050 for agriculture, forestry 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 Net Zero Extended Timeline Scenario is delayed 20 years in the transportation sector, and 60 years in the industry, residential and commercial sectors. The Reference and Current Policy scenarios 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>.
3. Oxford Economics Australia, 2025, "Data Centre Energy demand, Final Report", https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf?la=en



11 Projections of agriculture, LULUCF and waste

NZAu has examined historical trends and has projected future trajectories of GHG emissions (CO₂, CH₄, N₂O) from the three sectors shown in Table 34: agriculture; land use, land use change and forestry (LULUCF); and waste. This Chapter outlines the assumptions used to estimate these trajectories and includes the following subsections:

- 11.1 Combined projections
- 11.2 Agriculture
- 11.3 LULUCF
- 11.4 Waste

Table 34 | UNFCCC sectors and the coverage of emissions abatement activities within the projected emissions trajectories. Combined projections of GHG emissions from these sectors are used as fixed input to the macro-scale energy system modelling.

Sector	Projected abatement activities
Agriculture	Livestock emissions from enteric fermentation and manure management. Emissions from application of nitrogen to soils.
Land use, land use change and forestry	Net emissions abatement from activities occurring on forest lands and forests converted to other land uses (grasslands, croplands, wetlands, and settlements).
Waste	Emissions from the disposal of material to landfill and wastewater remain constant.

Figures reported in this Chapter will differ slightly from the official government reporting of emissions from these sectors. For information on why, and how we have treated emissions, please see Chapter 7, Emissions Accounting.

We have developed projections of two future net emissions trajectories within these sectors from 2025 to 2050, 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 are 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 2026 to 2050.

The BAU trajectory is used in NZAu’s Baseline and Current Policies Scenarios, while the WMM trajectory is used in all Scenarios that model net zero emissions (see Chapter 3). Mitigation strategies projected in WMM were added to the BAU trajectory without any form of locational or cost optimisation, to give an estimated effect on the potential future GHG reduction. A summary of the assumptions for the BAU and WMM trajectories is provided in Table 35, with details for each subsector presented in sections 11.2, 11.3, and 11.4. The combined projections of these subsectors are first presented in section 11.1.

Our approach to projecting emissions trends uses data of crop production and livestock activities and focuses on methane and nitrous oxide emissions. While we account for carbon storage change in forest land accounting categories, we do not attempt to estimate carbon soils stock changes in the landscape or the marine environment. The collected information is assembled and projected at the state/territory level, and presented here at the national level, for the relevant industry. Historical GHG emissions were sourced from the Australian Government National GHG Inventory^[1] for the period 1990-2023.

Table 35 | Summary of the assumptions used in the two emissions trajectories projected for the agriculture, LULUCF and waste sectors.

Emissions trajectory	Narrative descriptor
<p>'Business-as-usual' (BAU)</p>	<p>Emissions are projected forward using 2023 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.</p>
<p>'With-mitigation-measures' (WMM)</p>	<p>The WMM trajectory implements current and emerging technologies to reduce net GHG emissions. The logic behind this trajectory is that there will be pressure from the supply chain to reduce agricultural and land sector GHG emissions, plus incentives through government programs such as the ACCU Scheme and Safeguard Mechanism 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. The LULUCF sector becomes a significant net sink of CO₂ through reduction of deforestation and a concerted afforestation of a portion of suitable agricultural land. Emission reduction activities in current forests are not included. This project makes assumptions about the potential emission reductions and adoption of these abatement activities into the future. These assumptions are detailed under each sector and industry.</p>

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. Our projections of agricultural and LULUCF activity incorporate a conservative estimate of future global warming combined 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.

We also note that:

1. The first year of the computational model used in this project is 2025, with optimisation occurring from 2026.
2. 2023 is the most recent detailed national emissions accounts.
3. There has been significant volatility in LULUCF emissions contributions in the past 10-15 years, including amendments to accounting methods that have shifted historic figures.

Given the above, for the purposes of this report we use the 2023 emissions accounts as a proxy for 2024 and 2025 emissions for agriculture, LULUCF, and waste. We recognise this is a simplistic assumption but believe it appropriate for the purposes of a 25-year outlook. Differences between the BAU and WMM trajectories will therefore only become obvious from 2026 onwards.

11.1 Combined projections

Figure 25 presents the historical (1990 – 2023) and projected (2024 – 2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the BAU trajectory. The emissions trajectories are shown by state/territory (left), and UNFCCC sector (right). Net emissions are shown by the black line. This shows that under BAU future conditions, agriculture, LULUCF and waste emissions – which include CO₂, CH₄, N₂O – are projected in the long run to be +56.9 Mt-CO₂e/year by 2050.

Figure 25 | Historical (1990-2023) and projected (2024-2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the BAU trajectory.

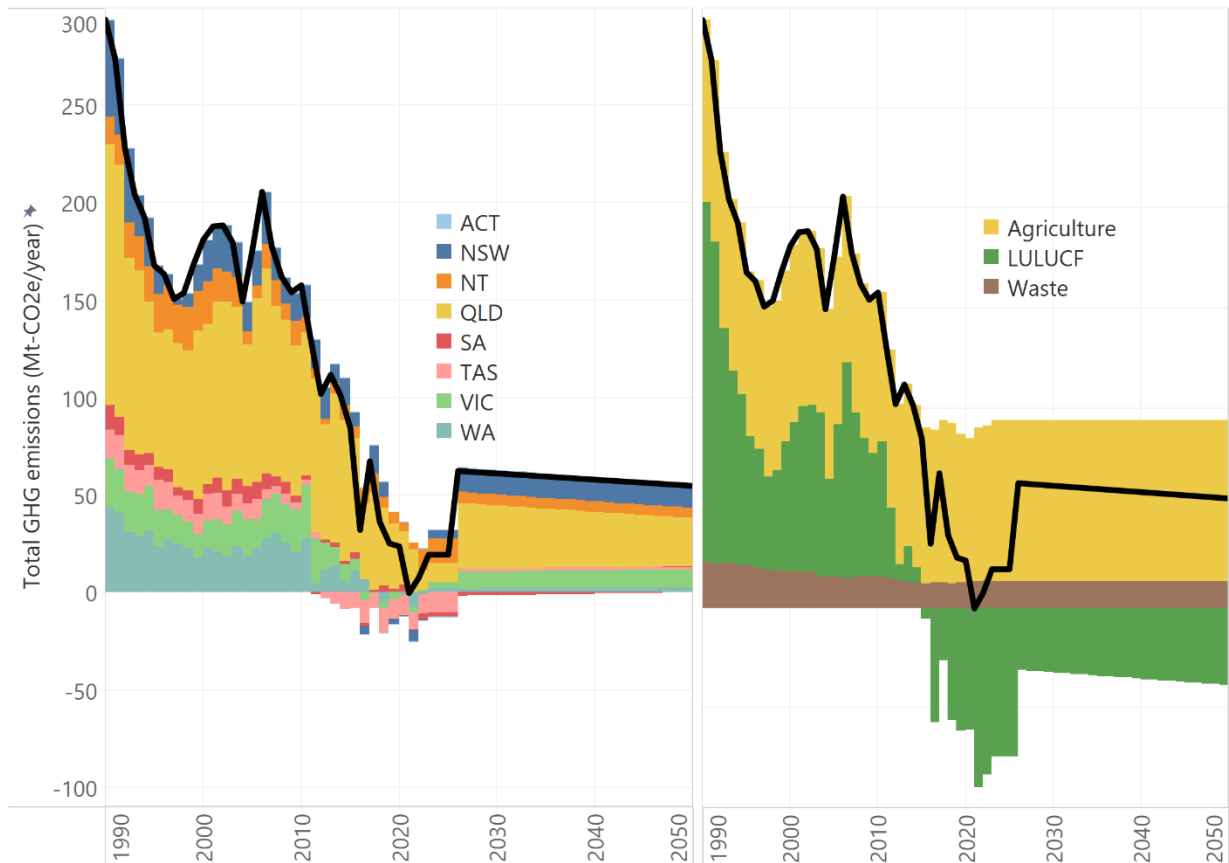
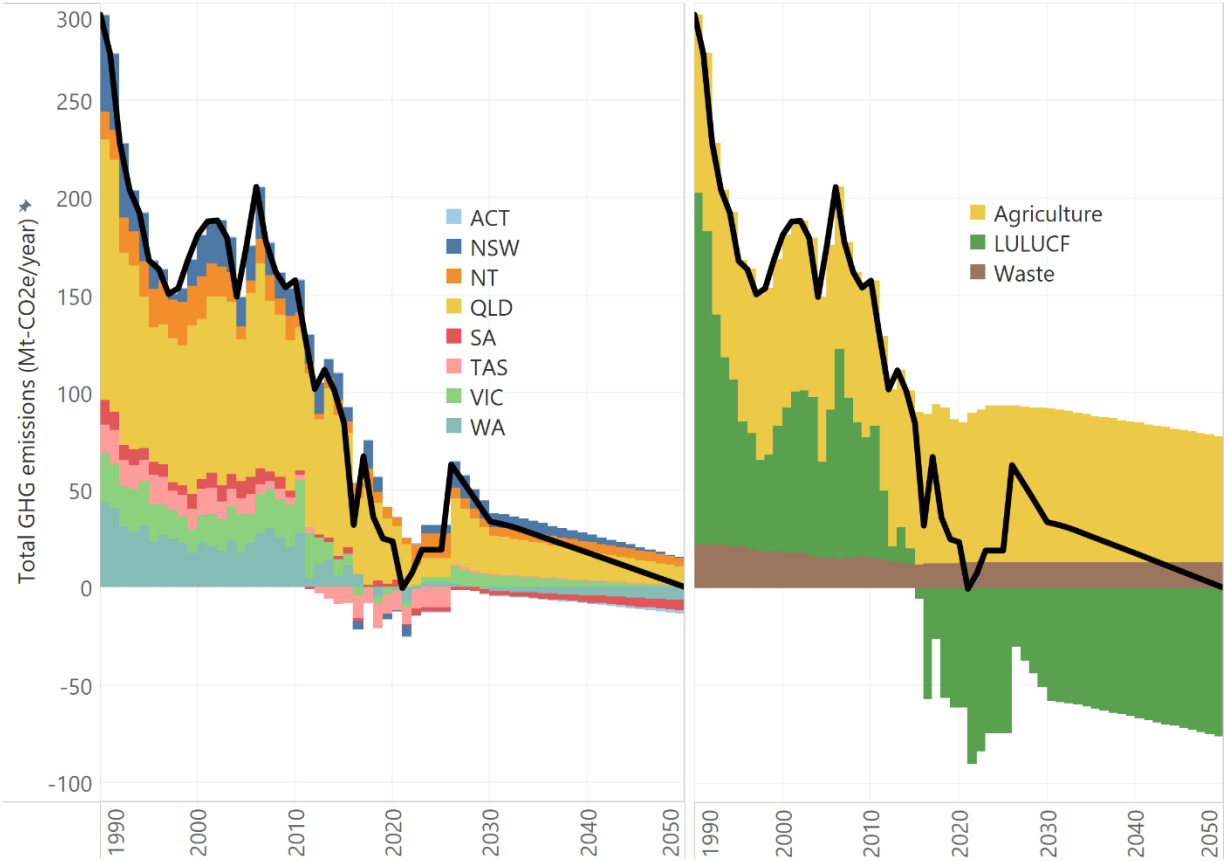


Figure 26 presents historical (1990 – 2023) and projected (2024 – 2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the WMM trajectory. The emissions trajectories are shown by state/territory (left), and UNFCCC sector (middle). Net emissions are shown by the black line. It can be seen that a concerted effort to adopt plausible mitigation measures – particularly the active abatement of methane emissions from agriculture and enhanced CO₂ sequestration through new tree planting – results in a reduction in net emissions to become close to zero, at 0.4 Mt-CO₂e/year by 2050.

Figure 26 | Historical (1990-2023) and projected (2024-2050) net GHG emissions from the agriculture, LULUCF and waste sectors, for the WMM trajectory.

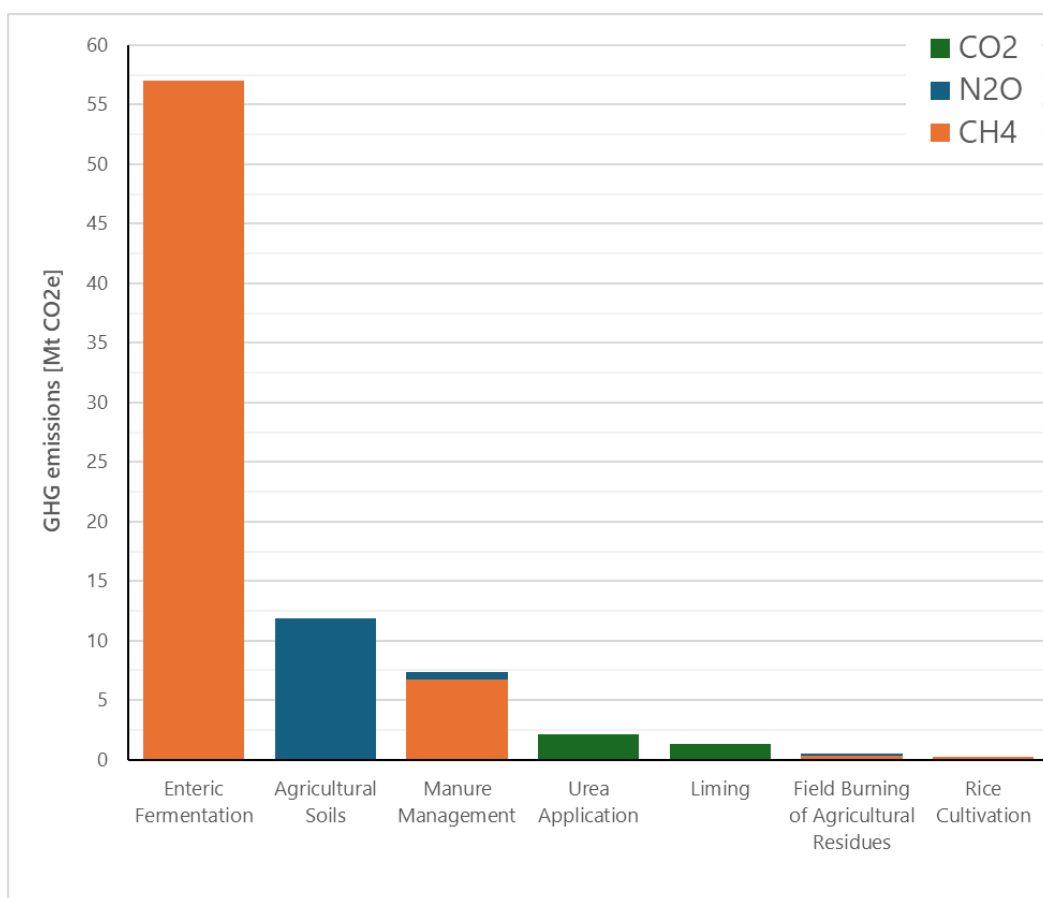


11.2 Agriculture

Figure 27 shows the 2023 agricultural GHG emissions, by gas and source. The majority of agricultural emissions comprise methane, produced by enteric fermentation (over 70%) and manure management.

The details of both the BAU and WMM emissions trajectories for agriculture emissions are provided for each industry 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^[3].

Figure 27 | 2023 national agricultural emissions by gas and source.

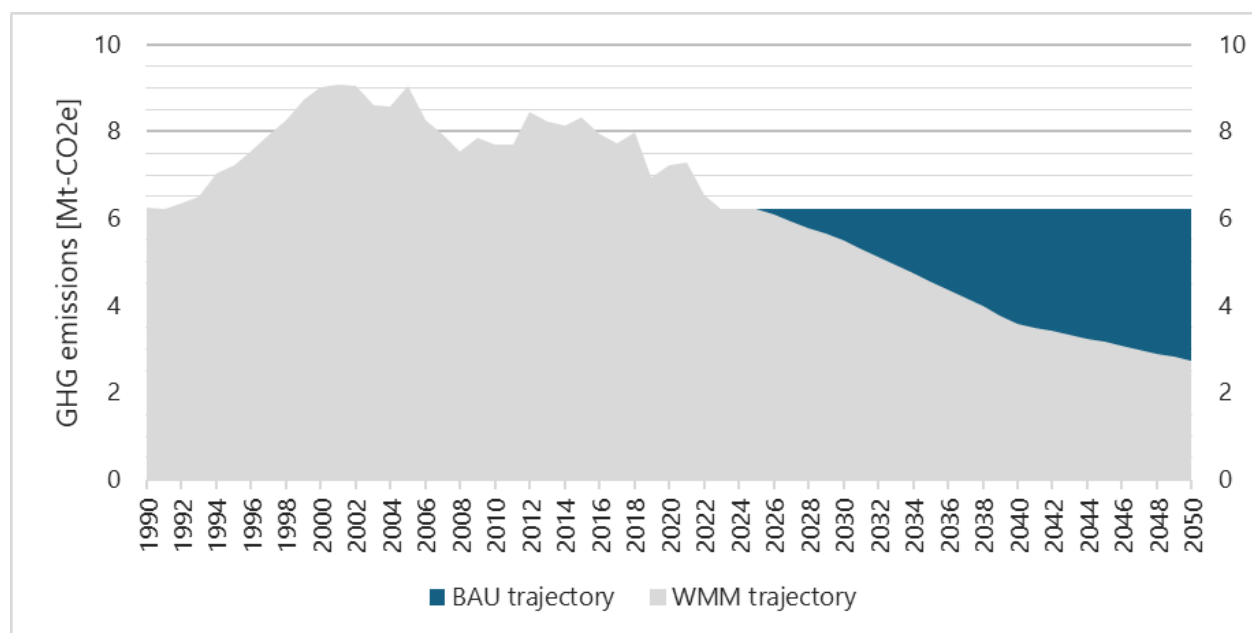


11.2.1 Dairy industry

The dairy industry GHG emissions accounted for 8% (6.2 Mt-CO₂e) of agricultural emissions in 2023. The majority of GHG emissions from the dairy sector is from farms and is primarily CH₄ emissions^[1]. 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 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^[6,7]. 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^[8,4]. The historical GHG emissions (Figure 28) reflect these industry trends.

Figure 28 | Historical (1990 – 2023) and projected (2024 – 2050) dairy sector GHG emissions, for both the BAU and WMM trajectories.



The BAU trajectory projection shown in Figure 28 is based on the GHG emissions and dairy cattle population of 2023. The BAU trajectory projects GHG emissions to be constant at 2023 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^[5,6,7].

The WMM trajectory includes the effect of two strategies: those aimed at reducing emissions from enteric fermentation and manure management.

First, we estimated the potential change from incorporating 3-nitrooxypropanol (3-NOP) into the herd diet and its potential effect on **enteric CH₄ emissions**. Note we use 3-NOP as a proxy representing a range of possible interventions. The assumptions needed for this calculation include the uptake over time and the impact of the additive on the enteric methane yield. We assume that the fraction of the Australian dairy herd consuming this additive gradually increases, as shown in the summary in Table 36, resulting in a 50% reduction in enteric methane emissions in 2050^[8, 9, 10].

Table 36 | GHG mitigation assumptions used in the WMM for the dairy cattle industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Enteric fermentation	5.4	50% reduction in 20% of herd	50% reduction in 50% of herd	50% reduction in 80% of herd	50% reduction in 90% of herd	50% reduction in 100% of herd
Manure management	0.8	100% reduction, 20% adoption rate	100% reduction, 40% adoption rate	100% reduction, 60% adoption rate	100% reduction, 80% adoption rate	100% 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 CH₄ 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^[11]. CAPs allow for

all CH₄ produced during the oxygen-free manure degradation to be captured and combusted in a flare, with no CH₄ emitted to the atmosphere (only biogenic CO₂)^[12]. Table 36 lists our assumptions of gradual uptake of CAPs, with 100% of emitted methane captured when adopted^[13].

11.2.2 Pasture-fed beef industry

The Australian pasture-fed beef industry is a significant contributor to GHG emissions in Australia, with an estimated emission of 39.9 Mt-CO₂e in 2023, or ~50% 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^[14]. Producers have since rebuilt the herd to approximately 27.1 million head in 2023^[15].

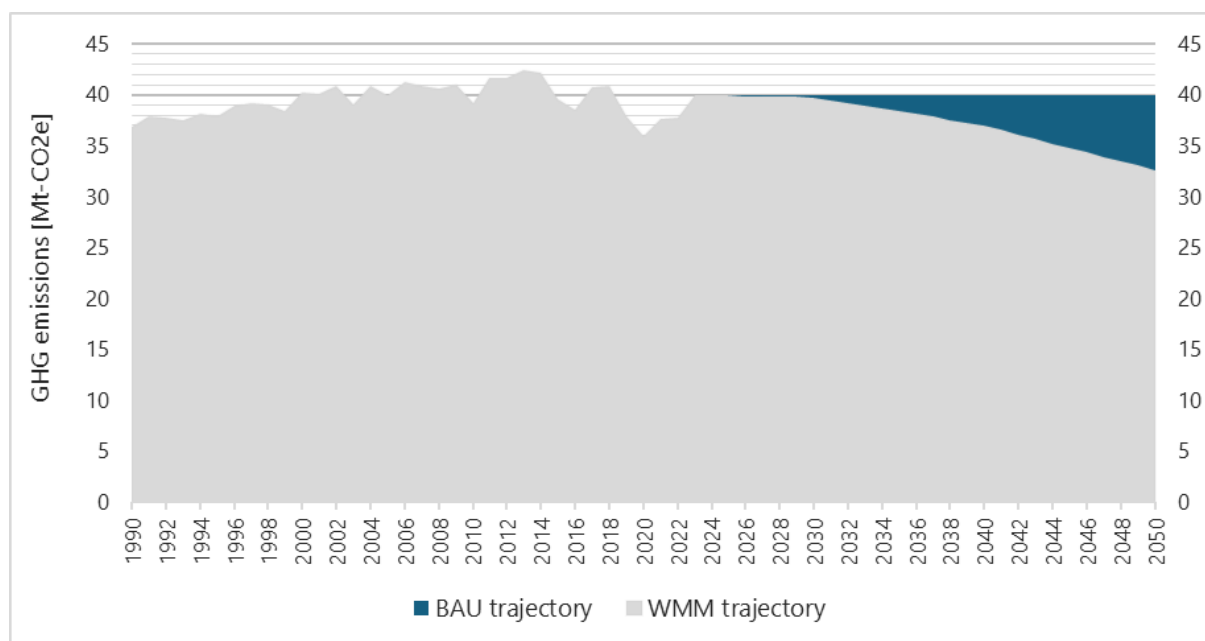
The BAU emissions trajectory assumes a steady state of the national herd, where calving, weaning, replacement and culling rates remain constant until 2050. On this basis, the GHG emissions were estimated to remain constant, as shown in Figure 29. While we have applied this simplifying assumption, trends in meat consumption are complex and changing. Beef consumption is predicted to decline over time, attributed partly to long-term trends in retail prices^[16].

The WMM trajectory focuses on reducing enteric CH₄ 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^[8,9,17,18]. Here we assume that when 3-NOP is fed, CH₄ emissions decrease by 40% with no effect on dry matter intake or average daily gain (Table 37). 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. The projected WMM trajectory with this mitigation measure is shown in Figure 29. 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 as shown in Table 37. Note again that 3-NOP is used as a proxy for emissions reduction methods. Other approaches that may achieve similar outcomes over time include breeding for lower methane cattle and introducing novel legumes.

Table 37 | GHG mitigation assumptions used in the WMM for the beef cattle industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Enteric fermentation	36.5	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 29 | Historical (1990 – 2023) and projected (2024 – 2050) pasture-fed beef sector GHG emissions, for both the BAU and WMM trajectories.



11.2.3 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^[19]. 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^[19].

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. For the BAU trajectory, we assumed the Australian herd size will remain constant based on the historical trend. This means enteric CH₄ emissions and manure management of lot fed beef cattle start from a baseline of 0.9 Mt-CO₂e in 2023 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.

The WMM trajectory projects the reduction of methane emissions through the adoption of 3-NOP in intensive feeding systems. According to the literature^[7,20,21], the higher frequency of feeding the 3-NOP feed additive in intensive feeding systems, could significantly reduce CH₄ by about 80%. In addition, we assume higher uptake rates than pasture-fed beef, as shown in Table 38, as this sector is assumed to have minimal adoption inhibitors, which increases uptake speed on individual farms, regionally and nationally^[20].

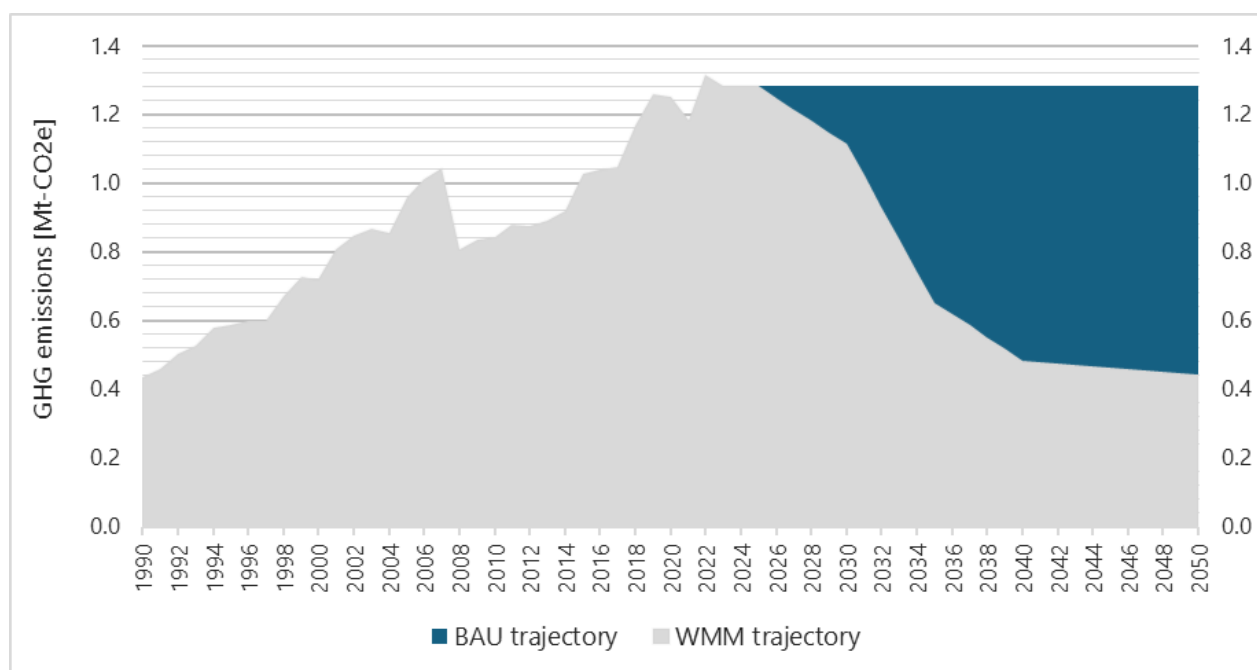
For the projection of manure management emissions in the WMM trajectory, methane capture with covered anaerobic ponds CAPs was again selected as a feasible method to reduce emissions from intensive livestock waste. Under Australian conditions, we assume that manure would be taken directly from the pen to the covered

anaerobic pond resulting in 100% methane capture as a management practice with gradually increasing uptake rates (Table 38).

Table 38 | GHG mitigation assumptions used in the WMM for the feedlot industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Enteric fermentation	0.9	80% reduction in 20% of the herd	80% reduction in 80% 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, 20% adoption rate	100% reduction, 40% adoption rate	100% reduction, 60% adoption rate	100% reduction, 80% adoption rate	100% reduction, 100% adoption rate

Figure 30 | Historical (1990 – 2023) and projected (2024 – 2050) feedlot sector GHG emissions, for both the BAU and WMM trajectories.



11.2.4 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 drivers of the declines are 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^[8]. 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^[22]. Since the 1980s, the national sheep numbers have declined from a peak of 173 million head to 79.1 million in 2024, and are now projected to remain relatively stable^[23].

The BAU trajectory therefore depicts that the flock size remains constant with associated constant GHG emissions, as shown in Figure 31.

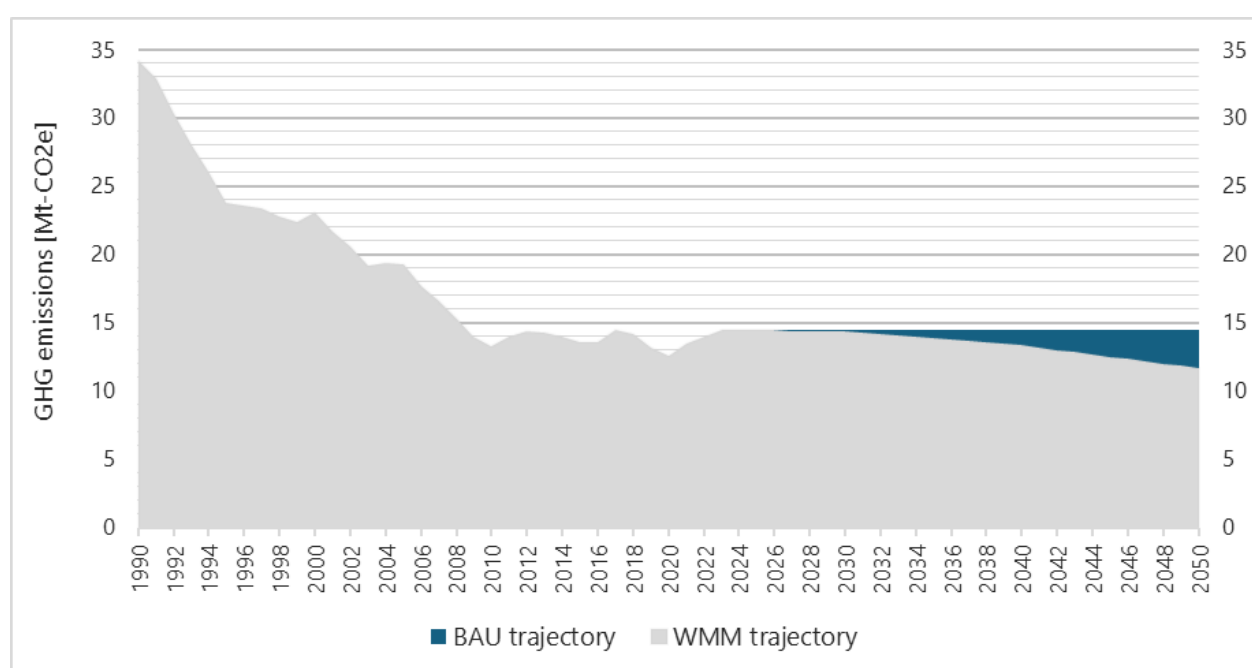
The WMM trajectory estimates the effects of 3-NOP in the CH₄ emissions of sheep, based on experimental demonstration that supplementing methane inhibitors to sheep led to an emissions reduction of 86-95%^[24]. As above, 3-NOP is used as a proxy for alternative mitigation measures, noting that improved breeding and legume

technology are emerging as primary mitigation strategies. However, we assume a conservative decrease of 40% in methane emissions, with an adoption rate that reaches 50% by 2050, as listed in Table 39. 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 39 | GHG mitigation assumptions used in the WMM for the sheep industry

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Enteric fermentation	13.7	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 31 | Historical (1990 – 2023) and projected (2024 – 2050) sheep sector GHG emissions, for both the BAU and WMM trajectories.



11.2.5 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^[25], and to 2.6 million in 2023.^[15] 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^[25]. Pigs themselves produce very few direct emissions, with 90% of emissions associated with methane from manure management.

Australian pig housing can be classified into three different types: outdoor, conventional, and deep litter, which employ various manure management systems^[26]. In 2020, CAPs were reported to be used in 15.6% of total manure treatment, 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^[27].

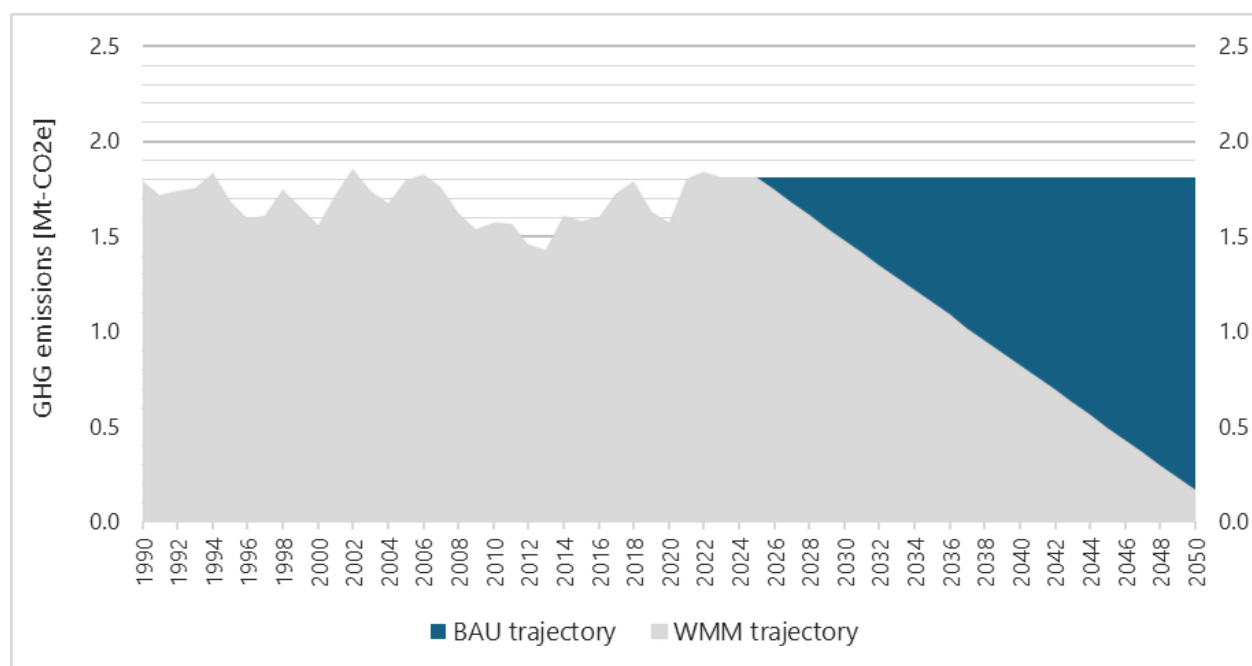
The BAU trajectory is projected to remain at a constant level (~1.7 Mt-CO₂e/year), with this flatline likely due to improved herd productivity and enhanced environmental efficiency, with changes in land occupation and water management^[28]. In comparison, as shown in Figure 32, the WMM emissions trajectory drops by ~90% with the deployment of covered anaerobic ponds (CAPs).

The WMM trajectory projects the installation of CAPs in all piggeries. All effluent from current operation of the industry is assumed to be treated in CAPs, with a gradual uptake out to 2050. Approximately 100% of the CH₄ 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 40). Residual GHG emissions in the swine industry are attributed to enteric fermentation, for which we have not projected any mitigation measure.

Table 40 | GHG mitigation assumptions used in the WMM for the swine industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Manure management	1.7	100% reduction, 20% adoption rate	100% reduction, 40% adoption rate	100% reduction, 60% adoption rate	100% reduction, 80% adoption rate	100% reduction, 100% adoption rate

Figure 32 | Historical (1990 – 2023) and projected (2024 – 2050) swine sector GHG emissions, for both the BAU and WMM trajectories.



11.2.6 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^[29]. 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^[29].

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)^[30]. 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^[30]. We considered these historical records, in addition to the estimated emissions from the national inventory report, 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 assume 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. ~83% of emissions are from manure management, but unlike swine are split between nitrous oxide and methane. 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 CH₄ emissions. Likewise, we assume a gradual uptake (Table 41), 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^[31].

Table 41 | GHG mitigation assumptions used in the WMM for the poultry industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Manure management	0.1	100% reduction, 20% adoption rate	100% reduction, 40% adoption rate	100% reduction, 60% adoption rate	100% reduction, 80% adoption rate	100% reduction, 100% adoption rate

11.2.7 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 \$600 per bale^[32] might also stem from the build-up in stocks, leading to a continued downward price pressure due to a fall in textile mill capacity.

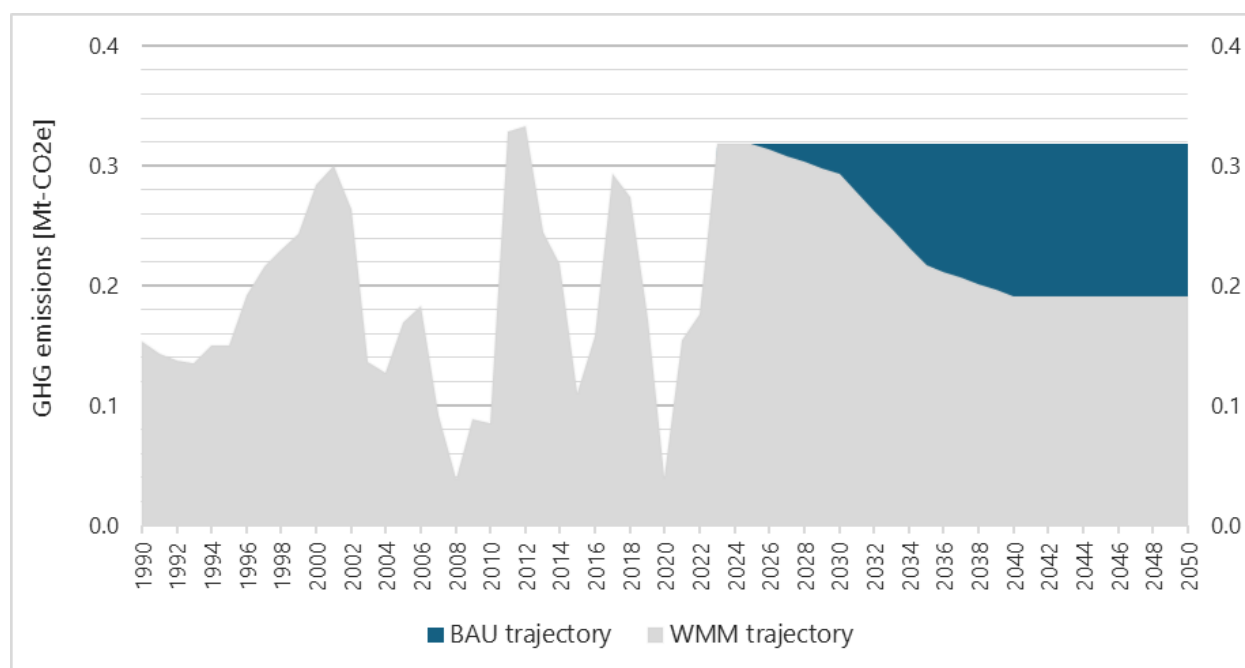
The BAU trajectory assumes that that cotton production will remain, on average, constant over the next 30 years, with the projected 2050 fertiliser emissions of 0.32 Mt-CO₂e. In contrast, the WMM trajectory projects a 40% reduction in N₂O emissions (

Figure 33), with a progressive uptake of enhanced efficiency fertilisers as summarised in Table 42, and discussed above. We assume a 100% adoption rate of this technology from 2035 onwards^[33].

Table 42 | GHG mitigation assumptions used in the WMM for the cotton industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Inorganic fertiliser	0.32	40% reduction, 20% adoption rate	40% reduction, 80% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate

Figure 33 | Historical (1990 – 2023) and projected (2024 – 2050) cotton industry GHG emissions, for both the BAU and WMM trajectories.



11.2.8 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^[34]. However, fertiliser application in excess of crop needs can result in loss of nitrogen to the environment, which results in N₂O 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.

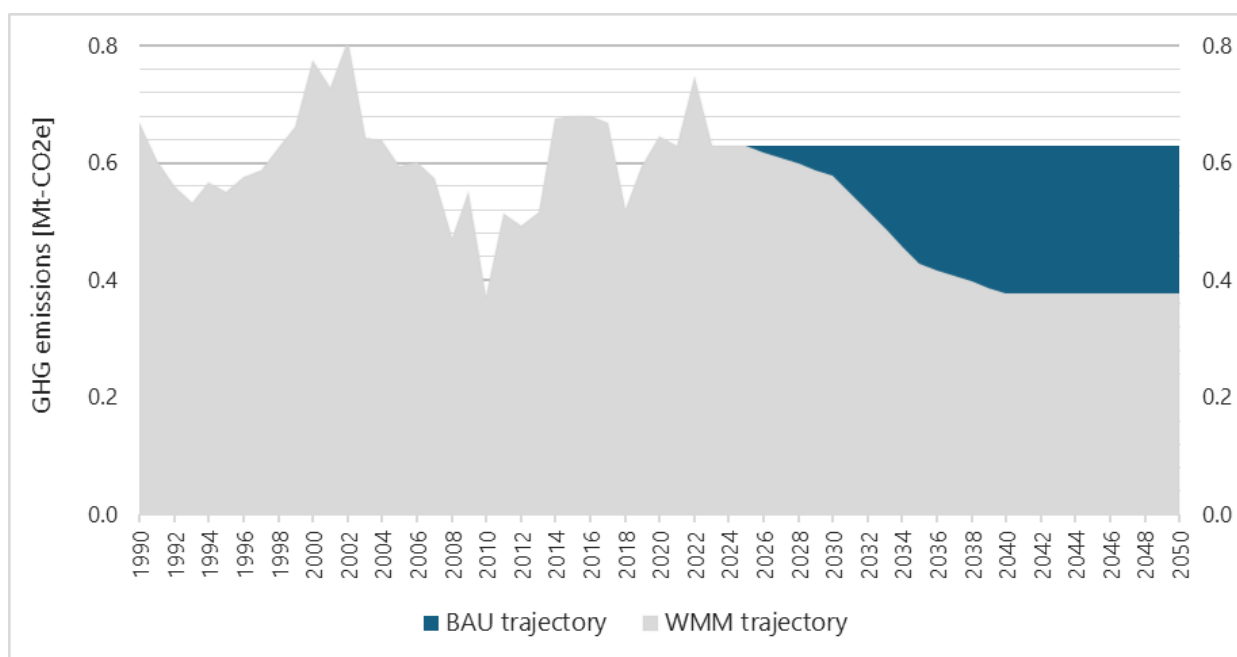
Moreover, the lost nitrogen in a sugar cane production system is mainly through (1) the removal of harvested produce, (2) the loss because of denitrification or leaching of nitrate to the environment, and (3) crop residue burning. (Note, the lost nitrogen from volatilisation of ammonia fertiliser is not considered in this approach). Similar to the cotton and dairy sectors (i.e., irrigated pasture), N₂O emissions reduction can be achieved by developing enhanced efficiency fertilisers (EEFs)^[35].

The BAU trajectory reflects the historical trend of GHG emissions. Figure 34 shows the estimated reduction in the WMM emission trajectory of 40% through the plausible application of EEFs, with assumptions listed in Table 43.

Table 43 | GHG mitigation assumptions used in the WMM for the sugar cane industry.

Source category	2023 GHGs (Mt-CO ₂ e)	2030	2035	2040	2045	2050
Inorganic fertiliser	0.63	40% reduction, 20% adoption rate	40% reduction, 80% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate	40% reduction, 100% adoption rate

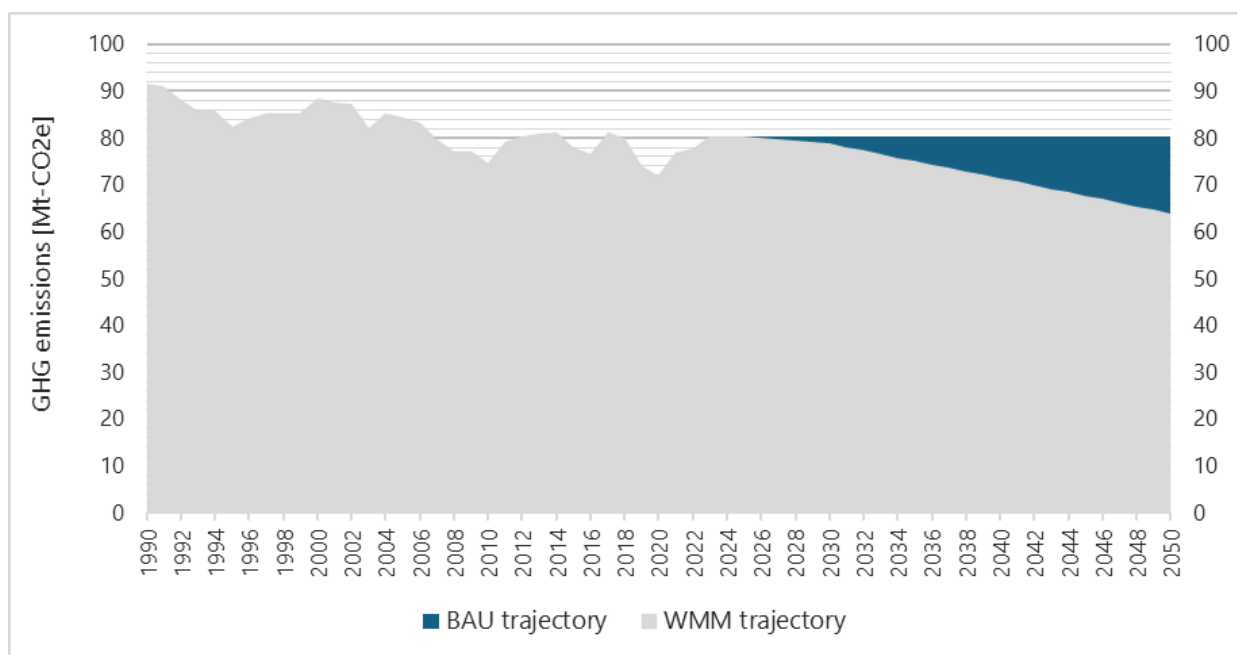
Figure 34 | Historical (1990 – 2023) and projected (2024 – 2050) sugar cane industry GHG emissions, for both the BAU and WMM trajectories.



11.2.9 Total agriculture emissions trajectories

Figure 35 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 21% (from 80.4 to 63.9 Mt-CO₂e) between 2024 and 2050 due to multiple actions detailed in the sections above.

Figure 35 | Historical (1990 – 2023) and projected (2024 – 2050) agriculture sector GHG emissions, for both the BAU and WMM trajectories.



11.3 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 -74.2 Mt-CO₂e in the 2023 GHG inventory^[1]. Forests are dynamic ecosystems with carbon fluxes changing over time due to seasonal variation, longer term climatic cycles and variation in natural disturbances such as bushfire. Certain activities – such as converting forest to agriculture or urban land uses or converting well-stocked mature forests to regrowth – cause long-term, net positive carbon dioxide flows to the atmosphere. Reducing deforestation or mature forest conversion will reduce emissions. Net negative flows/removals from the atmosphere into terrestrial reservoirs are possible through reforestation, afforestation and changing forest management practices, for example by reducing bushfire emissions.

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^[36].

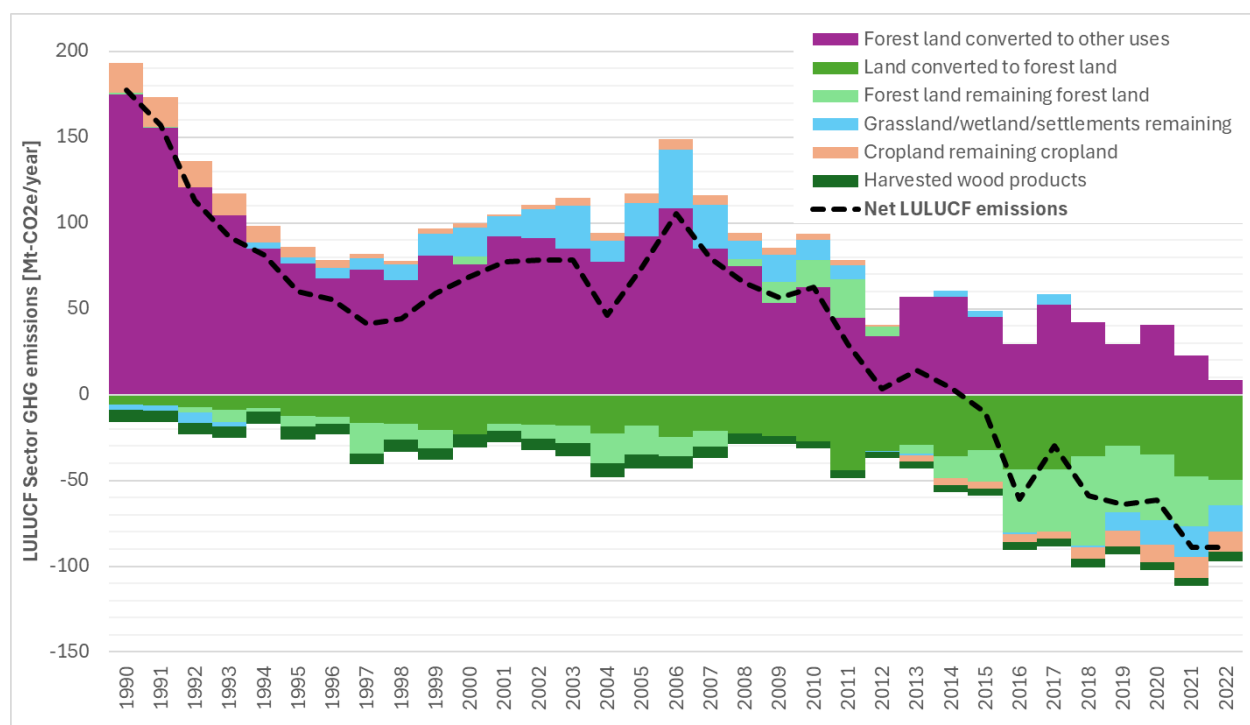
11.3.1 Historical trends in net LULUCF emissions

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 36 presents the historical (1990 – 2023) GHG emissions from the various land types and use changes that make up the total LULUCF GHG emissions inventory. We discuss these categories below.

Figure 36 | Historical (1990 – 2023) 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 +8.7 Mt-CO₂e in 2023.

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 175 Mt-CO₂e/year or 30% of total GHG emissions in the base year of the Kyoto Protocol (1990)^[36]. Between 1990 and 2023, 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^[36].

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 (2013–2023), an average of –39.3 Mt-CO₂e/year has been removed from the atmosphere in this way.

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^[1,36,37].

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^[36]. This category includes limited areas harvested for commercial timber products, with silvicultural practices implemented to maintain carbon stocks or 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-owned commercial native forests. From data in National reports^[1] it is apparent that drivers of carbon dynamics in this category are primarily the demand for Australian wood and wood products and the incidence of wildfire.

Net emissions from forest land remaining forest land were -16.5 Mt-CO₂e in 2023. 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^[38]. This native forest trend is a significant contributor, as there has been a significant decline since the early 1990s in the harvest of native forests and in clearing of native forest for plantation establishment, 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 *forest land remaining forest land* categories in recent years, as shown in Figure 36.

Figure 36 shows that the *forest land remaining forest land* category has varied between contributing a net source and a net sink of CO₂ since 1990. Forest regrowth corresponds with increased uptake of CO₂, 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 CO₂ 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 the recovery capacity in most Australian vegetation subsequently leads to increased carbon uptake, by regenerating vegetation during favourable climate conditions, largely counterbalancing the short-term carbon losses due to fires. More frequent, intense bushfires over the past 25 years in southern Australia, linked to climate change, is changing this picture.

Cropland remaining cropland

This category contributed a net sink of -7.8 Mt-CO₂e in 2023, which is a significant reduction on the 1990 level of $+17.1$ Mt-CO₂e. 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. 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 2023 of -5.6 Mt-CO₂e.

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 1.9 Mt-CO₂e in 2023 and has remained relatively steady since the 1990s^[1].

Emissions from the settlements remaining settlements category accounted for very small net removals, -0.08 Mt-CO₂e in 2023. This estimate comprises net changes in sparse woody vegetation around urban infrastructure^[1].

11.3.2 Projections of net LULUCF emissions

We have 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, 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

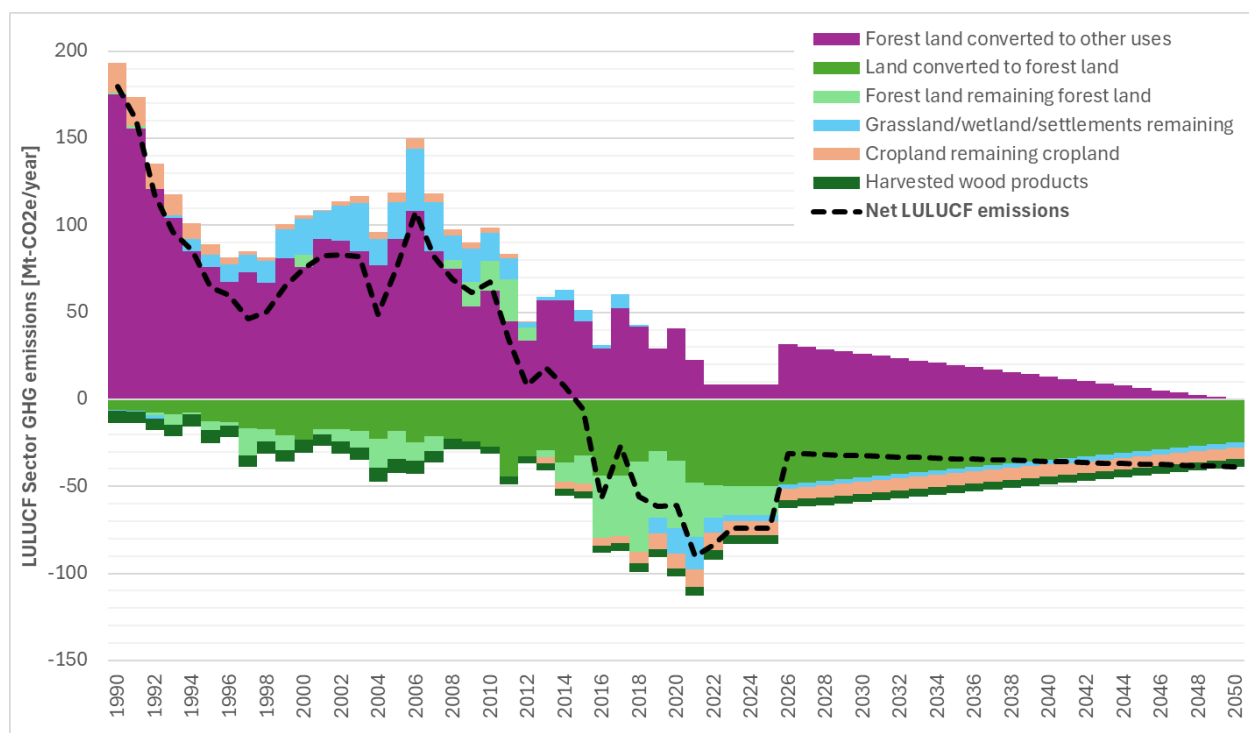
Figure 37 presents the historical and projected LULUCF emissions for the BAU trajectory. Assumptions for each category of LULUCF emissions outlined in Table 44 below:

Table 44 | LULUCF BAU assumptions by emissions category

Emissions category	Projection assumptions
<i>Forest land converted to other land uses</i>	We assume 2026 to be the average of the previous 10 years (to account for significant variation in recent years), then follow the continued trend of a gradual decline in the rate of land clearing trending to 0 in 2050. This is a conservative assumption that land clearing reductions are unlikely to continue at historic averages of –15% per year since 1990.
<i>Land converted to forest land</i>	Gradual reductions in negative emissions to become less of a carbon sink (2% per year on 2023 levels) without significant additional policy incentives.
<i>Forest land remaining forest land</i>	We set annual net emissions for this category to be zero from 2026-2050. Negative emissions from this category are primarily due to past reduction in native forest harvesting, a benefit with a limited time span as regrowth forests from past harvesting reaches maturity. We deem it unlikely that recent negative emissions from this category will be sustained to 2050, given any ongoing carbon sink due to decreased native forest harvesting across the country is potentially offset by the probability of more frequent bushfires as climate change continues. Emissions from forest plantations are assumed to be neutral with emissions from harvest balanced by removals in reforested areas with some carbon stored long-term wood products.
<i>Cropland remaining cropland</i> <i>Grassland/wetland/settlements remaining grassland/ wetland/ settlements</i> <i>Harvested wood products</i>	We project recent trends in these emissions categories to continue in the future, with annual net emissions in each of these categories being equal to the average of the previous 10 years' (2013 – 2023) annual emissions. We note this is a very simple assumption, as actual net emissions will vary between years, due to differences in climate, climate policies, economic growth rates, etc. We anticipate developing more sophisticated analysis as part of future work.

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 37 | Historical (1990 – 2023) and projected (2024 – 2050) BAU GHG emissions from the LULUCF sector.



With mitigation measures

Figure 39 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 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 –63.9 Mt-CO₂e in 2050 from forestland, as shown in Figure 39. This represents an additional –41 Mt-CO₂e 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.

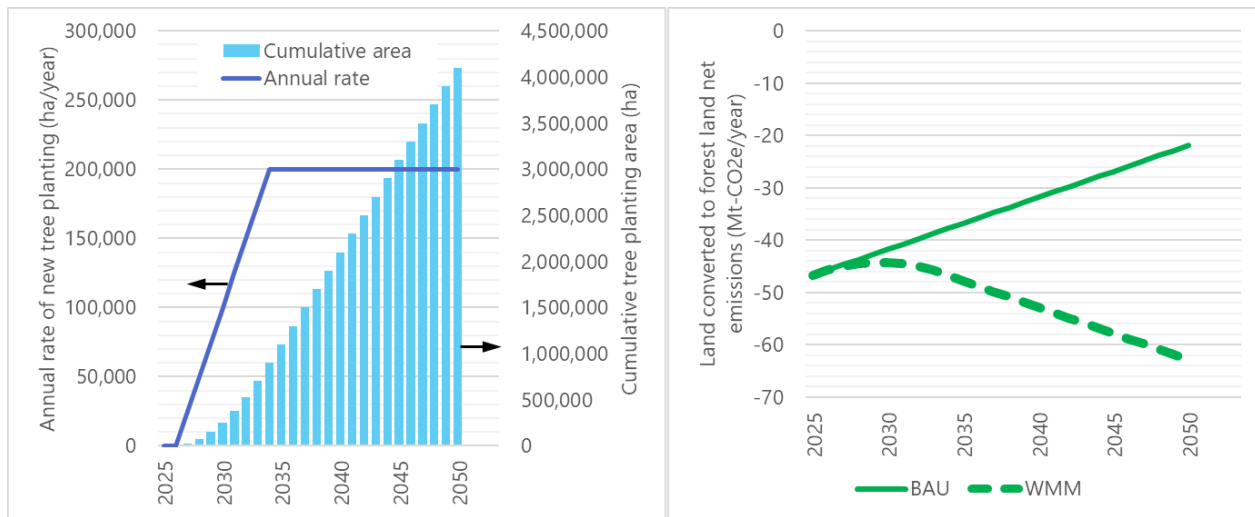
Figure 38 presents the assumed annual rate of tree planting area, and the cumulative area of tree planting, that enables the projected increased sequestration from 2027. The rate of carbon dioxide sequestration in these new plantations is assumed to be 10 t-CO₂/ha/year, based on the assumption that much of the tree establishment will be in lower rainfall areas. Figure 38 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^[39]. The land used for new tree planting represents ~6% of this agricultural land area in 2050 (4 million ha),

with the regional distribution of these new plantings assumed to be proportional to the distribution of agricultural land.

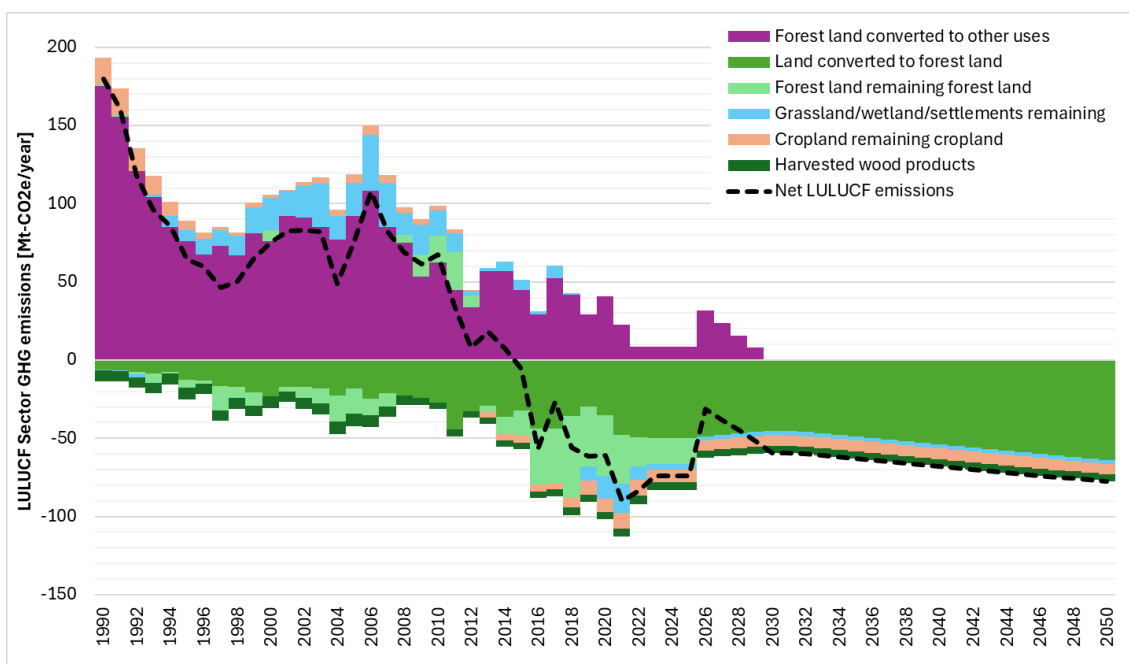
This work also assumes that this enhanced sequestration would have minimal impact on farming production, through strategic placement of vegetation on agricultural land. In addition, although not modelled, there are potential co-benefits, such as additional potential revenue streams, mitigation of wind erosion, improvement of dryland salinity, and improved livestock production through the provision of stock shade and shelter and improved biodiversity in farmland^[40].

Figure 38 | (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 compared to the BAU trajectory.



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.

Figure 39 | Historical (1990 – 2023) and projected (2024 – 2050) GHG emissions from LULUCF sector with assumed mitigation measures (WMM)



11.4 Waste

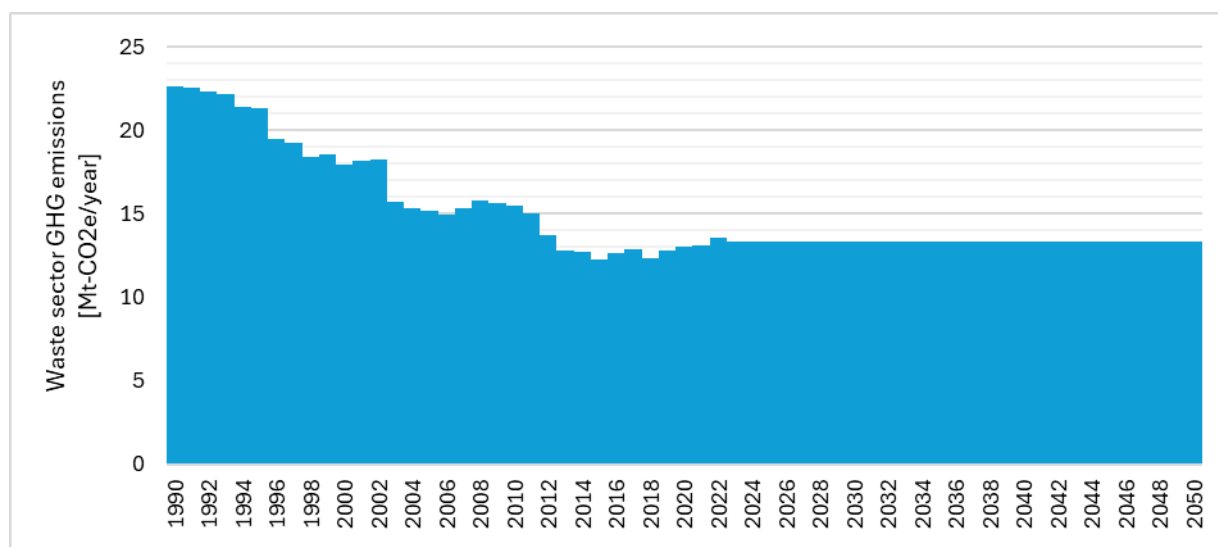
Emissions accounted under the *waste* sector include those produced during:

- 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 +13.3 Mt-CO₂e in Australia's 2023 GHG inventory. The 2023 emissions inventory does not distinguish between these sub-sectors, so figures below are presented as an aggregate for the waste sector.

NZAu's BAU emissions trajectory projects waste sector emissions to be 13.3 Mt-CO₂e/year from 2024 to 2050, as shown in Figure 40. This assumes that current waste generation and emissions abatement measures remain in place. 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 40 is used in all NZAu modelled scenarios. This implies that the residual emissions from the waste sector needs to be offset by negative emissions in other sectors.

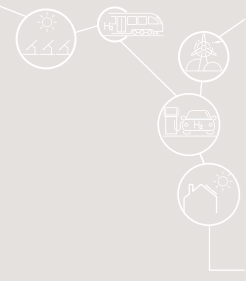
Figure 40 | Historical (1990 – 2023) and projected (2024 – 2050) GHG emissions from the waste sector^[1].



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12 Resource availabilities and costs

This Chapter describes the assumptions used to inform availability and cost inputs for renewable and non-renewable resources. It includes the following subsections:

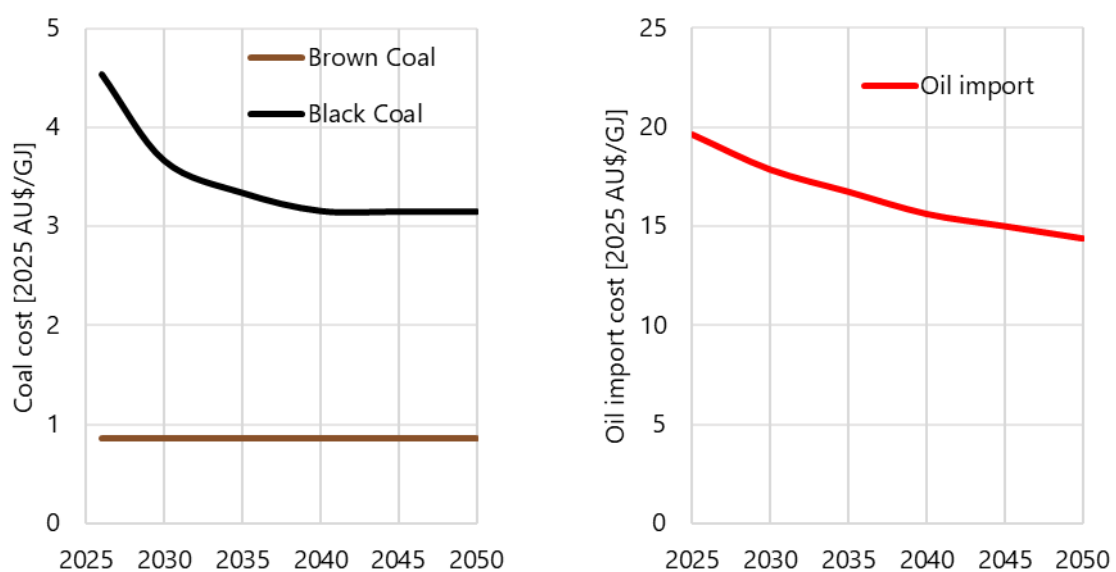
- 12.1 Coal, gas and oil costs and production
- 12.2 CO₂ geological storage capacities and unit costs
- 12.3 Biofuel
- 12.4 Existing utility scale electricity generation
- 12.5 Rooftop solar PV
- 12.6 Hydroelectric generation
- 12.7 Renewable availability traces
- 12.8 Renewables supply curves

12.1 Coal, gas and oil costs and production

The black and brown coal cost projections from 2026 to 2050 are sourced from the latest Inputs Assumptions and Scenarios report from AEMO^[1]. A summary of these cost projections is shown in Figure 41. For years beyond 2050, these costs are assumed to be constant. This work also characterises all existing black and brown coal mining activity, with existing infrastructure having a capacity of 11,216 PJ/year of black coal and 416 PJ/year of brown coal, regionally allocated to the NZAu regions in which the existing mines are located^[2].

This work also uses projections of international crude oil prices from the International Energy Agency's Announced Pledges Scenario^[3]. These oil prices are also shown in Figure 41, with units converted to 2025 AU\$/GJ, and with prices again assumed constant from 2050 to 2060. We also include the capacity and location of Australia's existing Geelong and Lytton oil refineries as existing energy infrastructure.

Figure 41 | Black and brown coal cost and imported oil price projections used in the NZAu modelling^[1, 3].

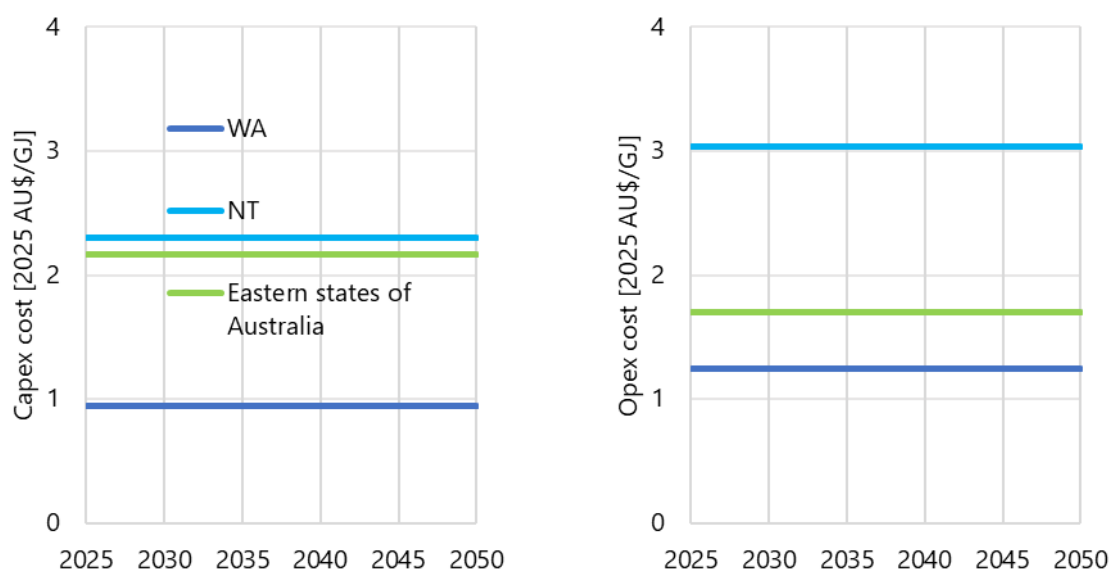


The cost of natural gas production from both conventional extraction and coal seam gas extraction methods is separated into capital cost and variable operating cost components, as shown in Figure 42. These values are sourced from the AEMO Gas Statement of Opportunities^[4] and the Western Australia Gas Statement of Opportunities^[5]. We separate these cost components to account for changes in the utilisation of capital assets^[6].

These production cost inputs 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 Chapter 13.

We also include all existing conventional and coal seam gas extraction facilities, as well as existing LNG facilities, in the modelling as existing energy infrastructure. The existing conventional extraction capacity is 4,569 PJ/year distributed across the country, and the existing coal seam gas extraction capacity is 1,507 PJ/year located in QLD and NSW^[2]. The existing LNG capacity is 4,400 PJ/year. We also apply a constraint to any future gas extraction activity that maintains the current proportions of natural gas production between Western Australia and the rest of the country.

Figure 42 | Natural gas capital (left) and operating (right) cost production inputs to NZAu modelling^[4-6].

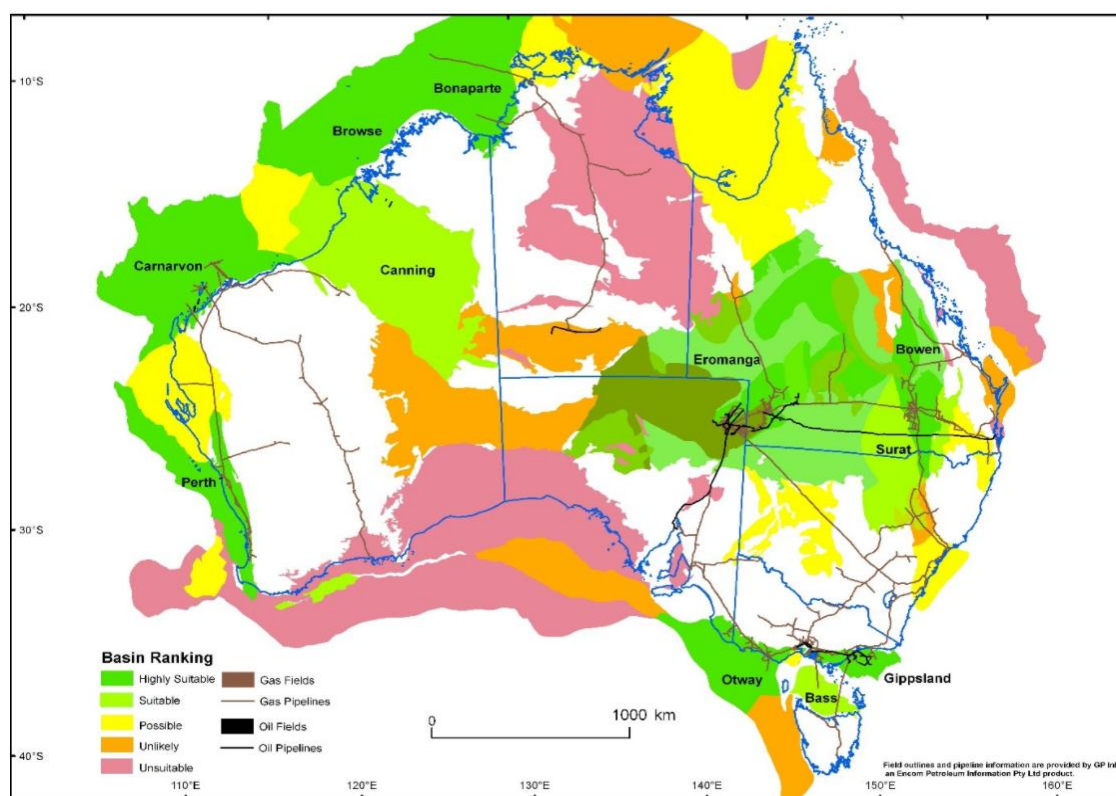


12.2 CO₂ geological storage capacities and unit costs

Carbon capture, utilisation and storage (CCUS) refers to a suite of techniques that either capture CO₂ from stationary point sources or engineer carbon dioxide removal (CDR) from the atmosphere, before either recycling this CO₂ into products such as low-carbon fuels and building materials (utilisation) or permanently sequestering it in underground geological formations (storage). Ultimately, CCUS achieves mitigation either by reducing CO₂ emissions to the atmosphere or withdrawing it from the atmosphere. This section sets out the basis for the assumed supply curves by defining the location of prospective basins to host geological storage of CO₂ in Australia, and the associated unit costs of storage. These supply curves are used in the RIO energy supply optimisation models.

Australia is prospective for the deployment of CCUS, with several sources of CO₂ located close to suitable geological storage basins^[7, 8]. An overview of the suitability of Australia's geological storage basins is illustrated in Figure 43.

Figure 43 | Overview of Australia's sedimentary basins and the Carbon Storage Taskforce assessment of their suitability for CO₂ storage^[7].



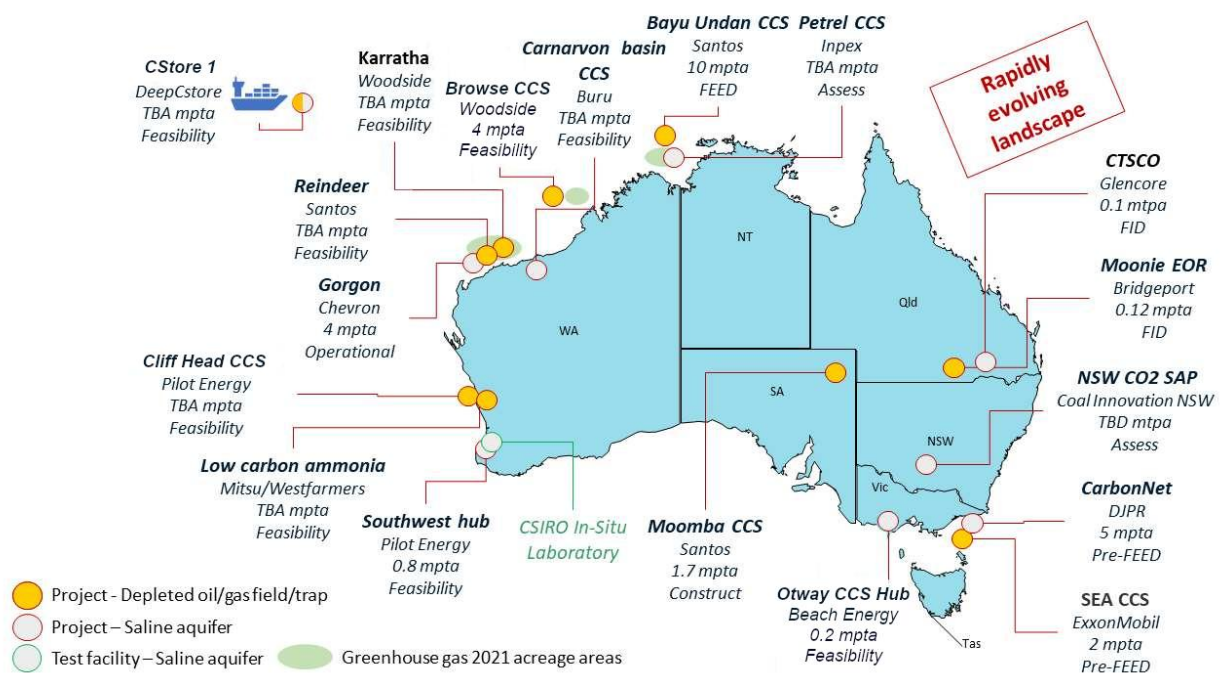
The total storage potential of all basins in Australia is estimated to be between approximately 112 Gt (conservative estimate) to 700 Gt (optimistic estimate)^[7-10]. However, only the Gippsland, Cooper, Carnarvon, Browse and Bonaparte basins appear to host either current activity or industrial interest, as shown below^[11]:

- **Gippsland Basin:** the CarbonNet project (5 Mtpa)^[12] and South East Australia (SEA) CCS Project (2Mtpa)^[13] are both in the pre-feasibility stage.
- **Cooper Basin:** the Moomba CCS project (1.7 Mtpa)^[14] is currently operational.
- **Carnarvon Basin:** the Gorgon project (4 Mtpa)^[15, 16] is currently operational, but not at capacity, and the Reindeer project (2.4 Mtpa)^[17] is at the feasibility study stage.
- **Browse Basin:** the Browse CCS project (4 Mtpa)^[18] is in the feasibility stage.
- **Bonaparte Basin:** the Bayu Udán CCS project (10 Mtpa)^[19] is in the front-end engineering design (FEED) stage.

This totals 23.1 Mtpa, which is not significant compared to even the conservative estimate of the storage potential in Australia^[7-10]. This is because the development of CO₂ sequestration projects is 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 of expert work and cost hundreds of millions of dollars^[20].

Figure 44 presents these projects along with a range of other CCS projects under investigation in Australia. It should also be noted, though, that CTSCO (0.1 Mtpa) and Moonie EOR (0.12 Mtpa) projects are no longer viable due to recent Queensland Government legislation^[21] that bans carbon capture and storage in the Queensland component of the Great Artesian Basin.

Figure 44 | Overview of Australia's CCS projects^[11].



To establish plausible estimates of (dynamic) CO₂ storage rates that might be available for commercial CO₂ storage, we reviewed project information in the public domain including media reports and elicited the views of a variety of experts with experience developing CCS projects. The latter included four project operators, along with Prof Andrew Garnett (with prior experience of CO₂ projects at Shell, Schlumberger Carbon Services, Queensland Geological Survey and ZeroGen) and Dr Christopher Consoli (Senior Consultant, Storage at the Global CCS Institute, Appendix A.2). 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 estimate of capacity (i.e. a sustainable injection rate over at least a 50-year period) and overall notional storage costs were developed (Table 45). These include 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 CO₂ 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. Upside case estimates are based on a simple assumption that 50% of the P10 estimate (i.e. a conservative estimate) of capacities published by Australia’s 2009 Carbon Storage Taskforce^[7] 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. Assuming that the maximum notional potential sequestration capacity of 130 Mt is reached in 2050, and is required for 50 years for decarbonisation, total sequestration from 2050-2100 is 13 Gt – significantly lower than the most conservative assessment of Australia’s carbon sequestration potential, suggesting that the NZAu estimation is conservative.

Note that these notional estimates assume a steady supply of on-specification CO₂ and a minimum scale of development to be viable, but do not consider the CO₂ source or its location. For reference, the Commonwealth Government’s Australian Technology Road Map has set a target price of AU\$20/t CO₂ as a competitive benchmark for CO₂ Compression, Hub transport and storage^[22].

Table 45 | Potential CO₂ storage capacities (dynamic) available in key Australian basins^[7-11].

Basin name	Type	Storage potential (Mt-CO ₂)		Project under development (Mt-CO ₂ /year)	Potential capacity (Mt-CO ₂ /year)		Levelised cost of CO ₂ storage (AU\$/t-CO ₂) ¹
		Carbon Storage Taskforce P10	CO ₂ Storage Resource Catalogue		Notional	Upside	
Gippsland	Offshore	30,100	30,426	7	50	301	13
Cooper	Onshore	15,700	15,700	1.7	20	157	27
Carnarvon	Offshore	25,500	36,600	6.5	20	255	20
Browse	Offshore	7,000	7,000	0.1	20	70	20
Bonaparte	Offshore	32,200	32,200	10	20	322	20
Total		98,900	114,926	25.2	130	989	

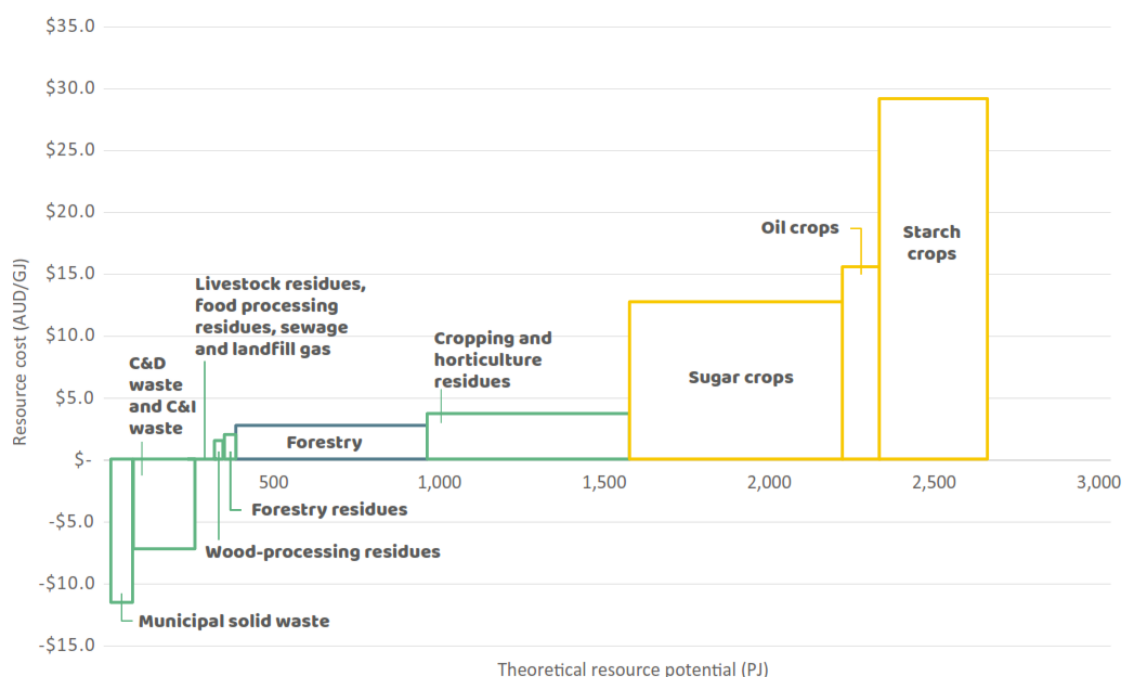
Note 1: The Levelised cost of CO₂ storage includes the capital cost of exploring/appraisal, site development (wells/unit facilities e.g., additional compression/local pipelines) and operating and maintenance costs. This excludes transmission pipelines and the required infrastructures. The Levelised cost assumes a lead time of five years, a project life of twenty years, and a real discount rate of 8.5%.

12.3 Biofuel

Biomass

Estimates of the Australian biomass resource that can potentially be diverted for new bioenergy uses were informed by the Australian Biomass for Bioenergy Assessment (ABBA) funded by the Australian Renewable Energy Agency (ARENA)^[23]. While not identical, this work is broadly consistent with CSIRO's previous studies published by Farine et al.^[24] and Crawford et al.^[25] and the Australian Government's Bioenergy Roadmap^[26].

Figure 45 | Annual Australia's bioenergy resource potential. Reprinted from the Bioenergy Roadmap^[26], showing resource cost in 2021 AU\$/GJ, which differs from the currency year used elsewhere in this report.



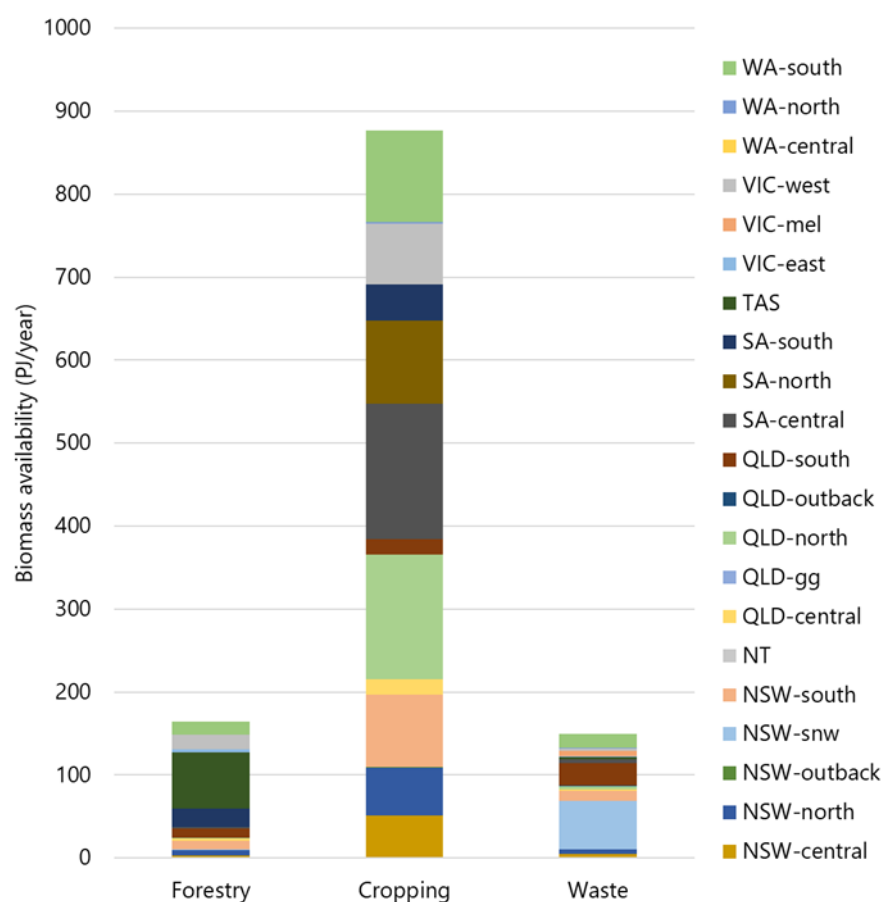
The ABBA estimates focus on agricultural residues and, therefore, minimise impacts on forestry and other biomass uses, e.g. domestic food supply and local processing industries. The resulting biomass potential includes:

- cropping (including horticultural) residues;
- forestry residues;
- organic municipal solid waste; and
- manure.

The NZAu Project uses the ABBA estimates of the availability of cropping and forestry residues and municipal solid waste, assuming the resources will be the same up to 2060. Note that ABBA does not cover biomass potential in the Northern Territory, so we also include Crawford et al.^[25]. The energy values of this annual biomass availability, which is used as the input to this work, are calculated with energy densities of 12.2 GJ per dry tonne for stubble, grasses and waste and 16.2 GJ per dry tonne for woody residues (Figure 46)^[27].

Overall, the NZAu Project's estimated biomass availability of approximately 1200 PJ/year (Figure 46) is lower than the 2600 PJ/year theoretical resource potential quoted in the Australian Government Bioenergy Roadmap (Figure 45)^[26]. This is because our estimates observe technical and sustainable resource constraints that will naturally preclude a significant portion of any bio-resource appraisal. Nevertheless, our estimated resources are still sufficient for the Australian Government's most ambitious 'Targeted Deployment' scenario of 870 PJ/year by 2050^[26].

Figure 46 | Annual Australian biomass resource availability by biomass type and NZAu region^[23, 25, 27].



Biomass for use in bioenergy has low density and high moisture content and is typically harvested and transported from diffuse sources, so its cost is case-specific and sensitive to transportation distances^[28, 29]. 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 region into three even bins of resource (on an energy basis) and using biomass supply costs for those bins of 7, 9 and 11 AU\$/GJ, which is the sum of a conservative resource cost of 5 AU\$/GJ for waste and agriculture residues^[26] and a transport cost ranging from 30 to 70 AU\$/t, i.e. 2 to 6 AU\$/GJ^[30].

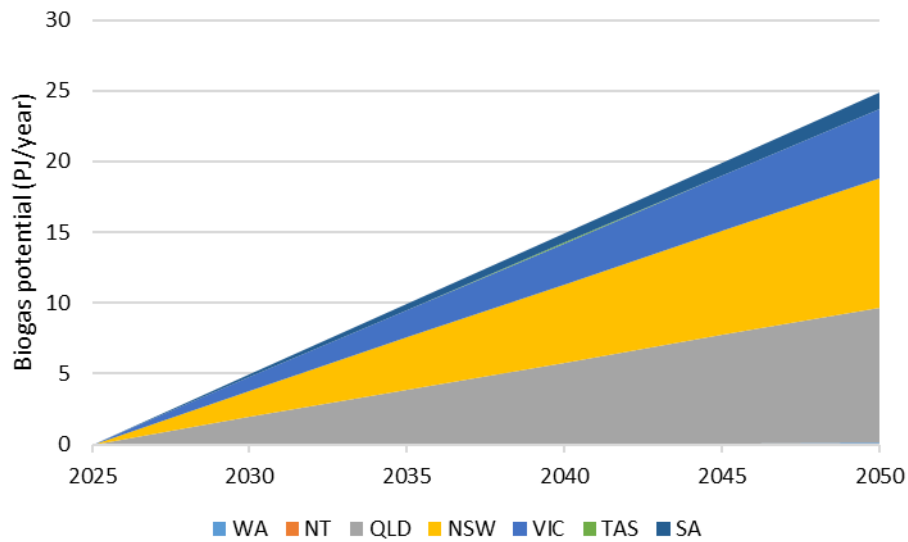
This work assumes that any CO₂ emissions associated with the use of the biomass resource are biogenic and, therefore, do not contribute to net GHG emissions. On the other hand, if the biogenic CO₂ emissions are captured with CCS facilities and permanently sequestered, this can result in a net flow of CO₂ from the atmosphere. The contribution from these net negative emissions is estimated to be -89 kg-CO₂/GJ, less any CCS capture efficiency losses^[31, 32]. Fossil fuels used in the production, collection and transport of biomass fuel are 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^[31, 32].

Biogas

A recent report by Future Fuel CRC^[30] highlights the potential for using biomass resources to produce biogas. According to the report, it is estimated that around 52 PJ of biogas can be generated at a cost ranging from AU\$10 to AU\$30 per GJ. However, it's important to note that this biogas potential is based on biomass resources from urban waste, and agriculture and livestock residue. Therefore, only livestock residue is considered as additional biofuel resources to the biomass resource discussed above. The reported livestock residue is converted to biogas potential using an energy density of 8.6 GJ per tonne of Volatile Solids (VS), resulting in approximately

27 PJ per annum, which is consistent with the Bioenergy Roadmap^[26]. It is also worth noting that the availability of livestock residue is linked to manure management practices. The NZAu Project predicts a linear increase in manure management adoption, achieving 100% by 2050 for the dairy, feedlot, swine, and poultry industries. However, manure from pasture-fed beef and sheep will remain unretrievable, resulting in a total of 25 PJ of biogas potential from livestock residue by 2050. More details on manure management assumptions are detailed in Chapter 10. Figure 47 shows the resulting biogas potential assumed as a resource to RIO by year, costed at 21 AU\$/GJ, which is the central assumption made in Future Fuel CRC's Integrated model for bio-methane injection in gas networks project^[30].

Figure 47 | Annual Australian biogas potential by state from 2025 to 2050^[23, 30].



12.4 Existing utility scale electricity generation

Data for existing electricity technologies in:

- The National Electricity Market (NEM) are sourced from AEMO's *Integrated System Plan*, specifically the draft 2025 Inputs, Assumptions and Scenarios Report (IASR) and workbook^[1];
- the Western Australian South West Interconnected System (SWIS) are sourced from AEMO's data on registered facilities in the WEM^[34]; 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 2023*^[35].

The installed capacity of existing technologies is shown in Figure 48, presented according to technology type and NZAu region. This work considers only projects listed as *existing* or *committed* in the NEM's draft 2024-25 IASR workbook^[1], and not those that are listed as anticipated or announced. Note that no existing capacity is listed for WA-central or WA-north, as the entirety of the SWIS is sited in the south of the state.

In addition to current and committed installed capacities, a schedule of expected retirement years is incorporated in the modelling. Figure 49 shows this schedule of expected capacity retirements, noting that the modelling may choose to retire some capacity early, as discussed in Chapter 3 of this report.

The current fixed and variable operating and maintenance costs of existing plant are included in the cost optimisation. These costs are shown in Figure 50 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 various planning studies^[1, 34, 35]. Figure 51 presents the capacity-weighted thermal efficiencies of the existing thermal plant, noting that each existing plant is given its own thermal efficiency in the modelling. We also apply a minimum capacity factor of 10% on all coal plant to avoid implausibly low-capacity factors. Coal plant are then retired if the model's annual requirement for their electricity is less than this minimum capacity factor.

Figure 48 | Installed capacity of existing and committed utility scale electricity generation by NZAu region^[1,34,35].

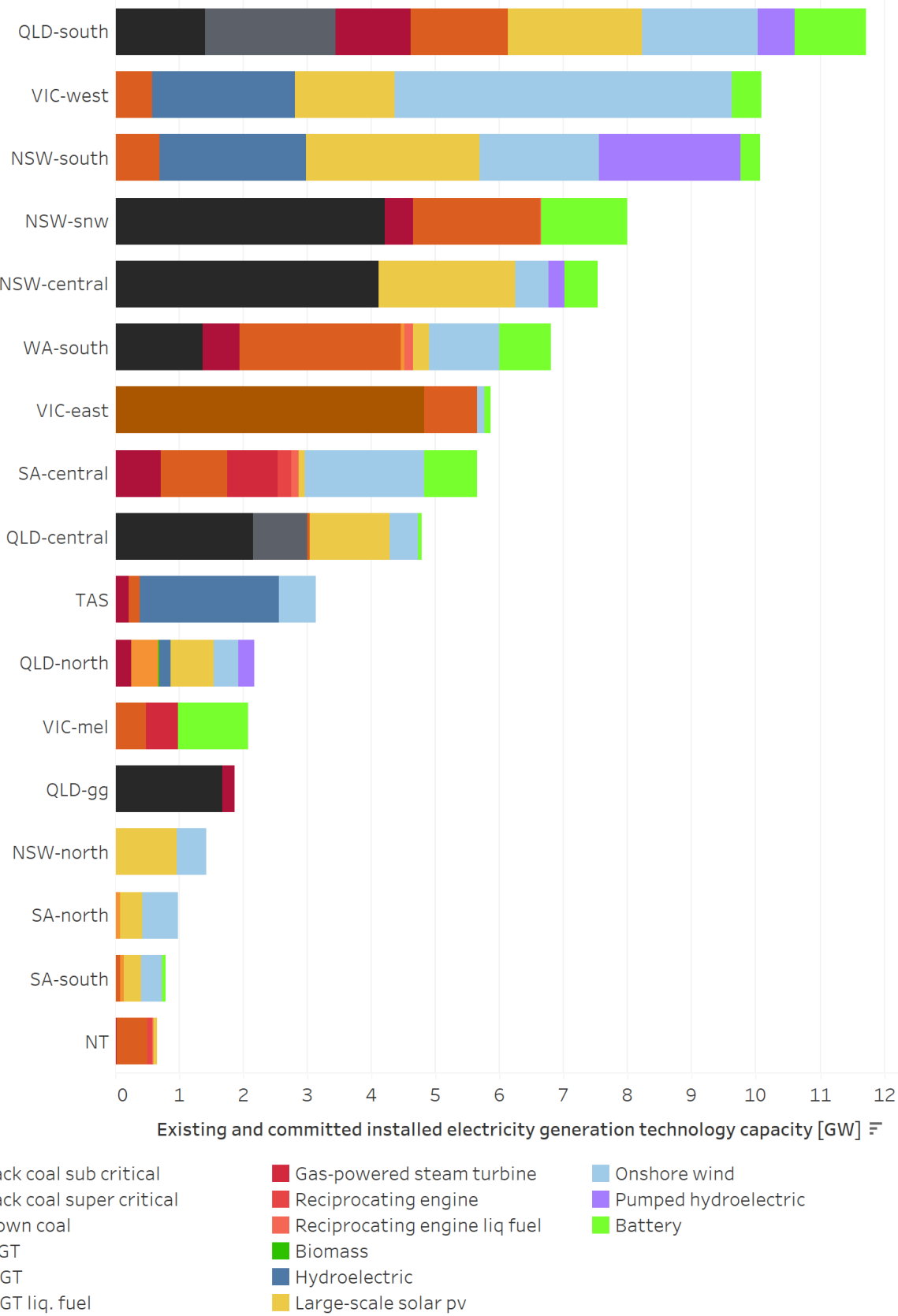


Figure 49 | Maximum installed capacity of existing utility scale electricity generation given their expected retirement year^[1,34,35].

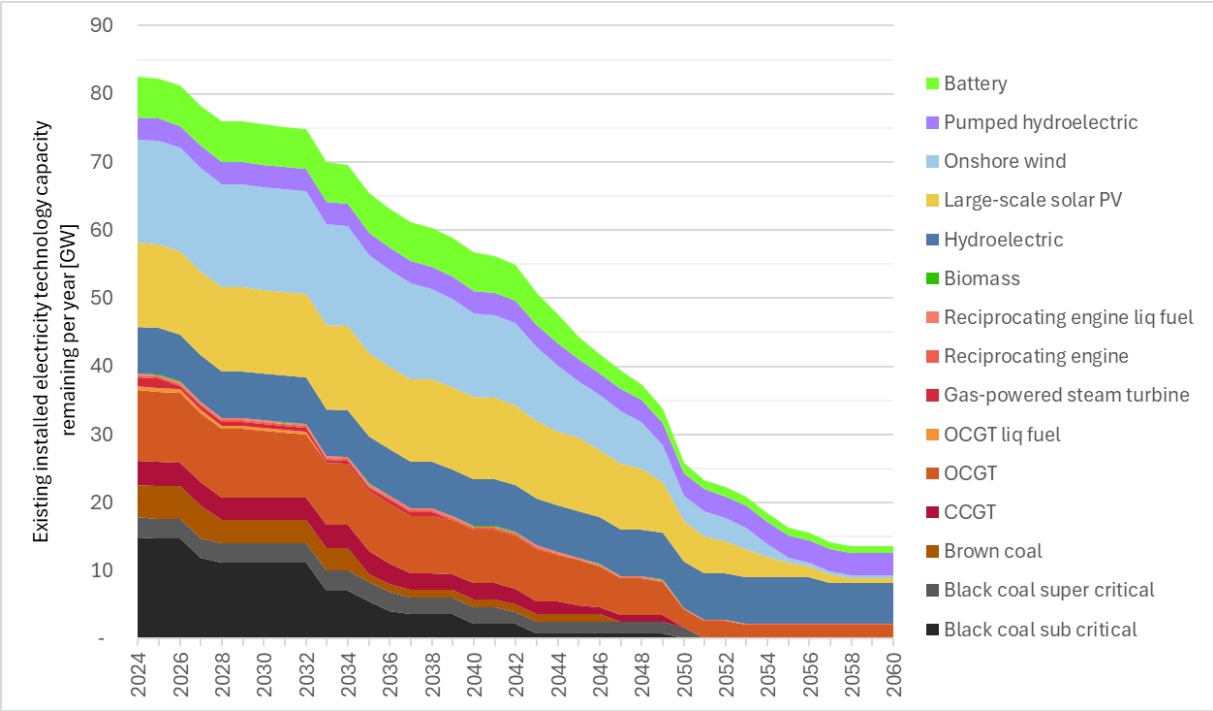


Figure 50 | Capacity-weighted fixed (left) and variable (right) operating and maintenance costs of existing electricity generation technologies.

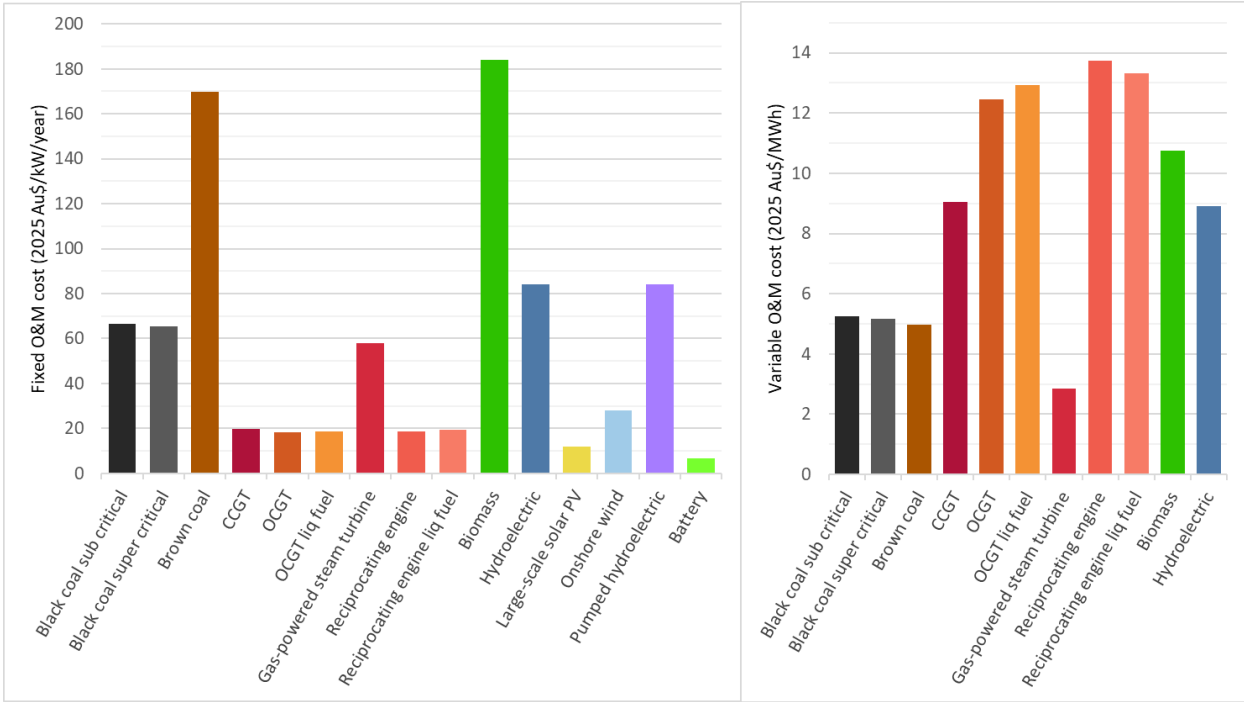
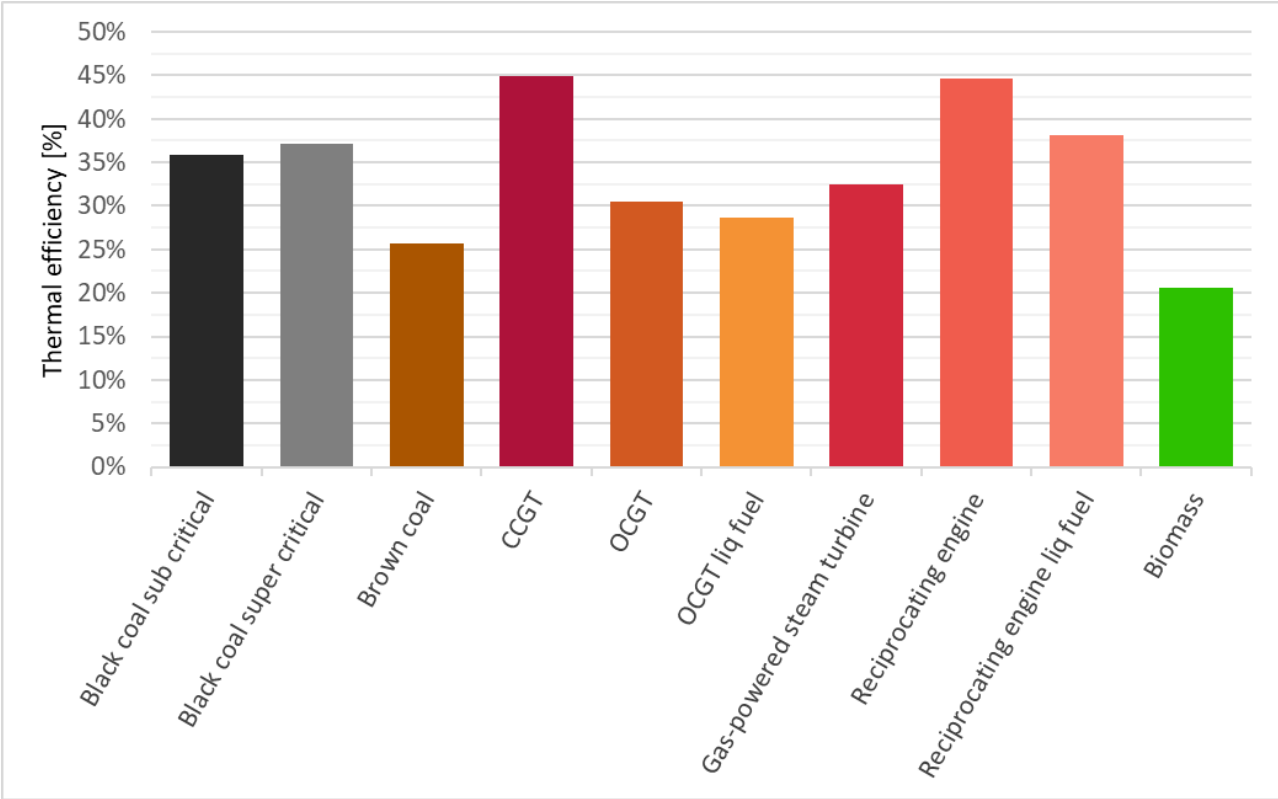


Figure 51 | Capacity-weighted thermal efficiency of existing electricity generation technologies^[1,34,35].

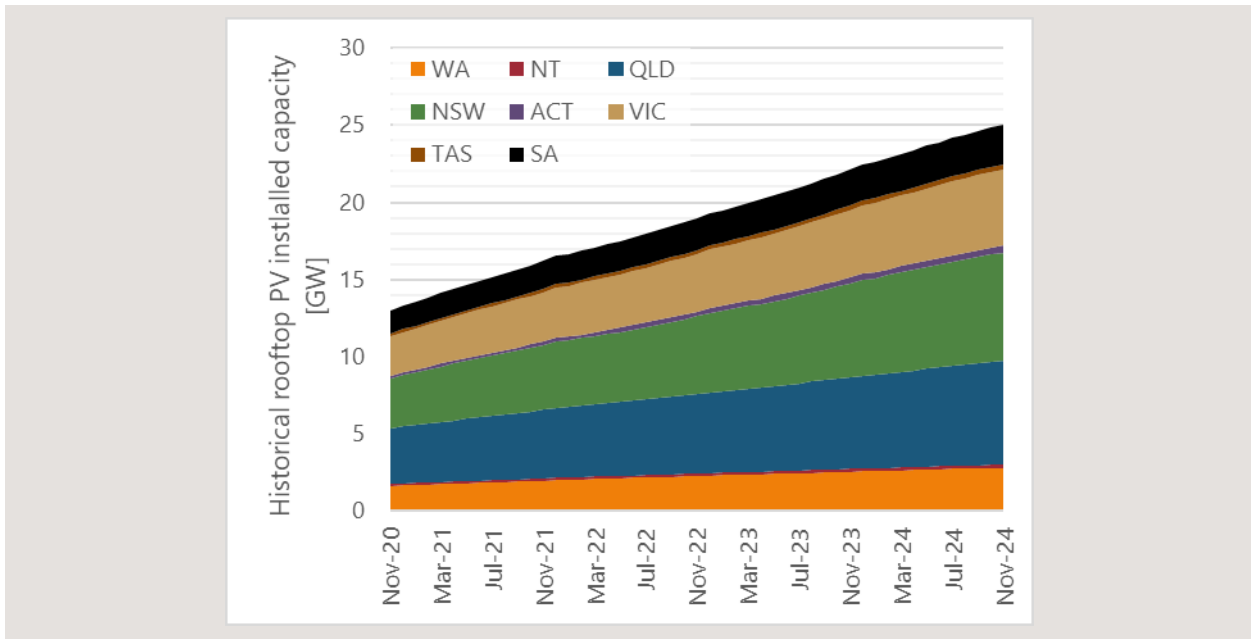


Note that the values in Figure 51 above are capacity weighted aggregate values based on Australia’s fleet of thermal electricity generation technologies of each type. Each existing plant has its own thermal efficiency which is used in the modelling. These values will differ to the aggregate values presented here, due to differences in plant age, location, and fuel composition.

12.5 Rooftop solar PV

The NZAu Project’s 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’s *Clean Energy Regulator* provides historical monthly installed capacity data for each postcode in the country^[36]. This postcode data is then aggregated to NZAu region level and used as the initial capacity input to the modelling. Figure 52 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 region.

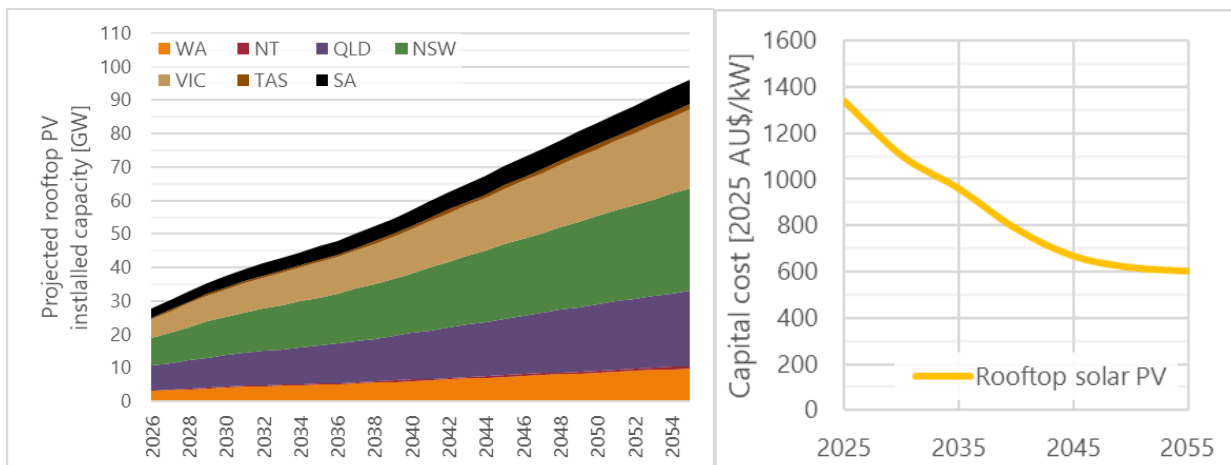
Figure 52 | Historical installed capacity of rooftop solar PV by state/territory^[36].



Projections of future rooftop solar PV capacity across Australia have been undertaken by CSIRO^[37] and Green Energy Markets (GEM)^[38], which are both inputs to the AEMO ISP^[39]. The NZAu Project uses the same assumptions as the ISP's Step Change scenario as input to the our modelling; namely the average of the CSIRO and GEM projections of rooftop solar PV. This input is shown in Figure 53 (left hand side), again by state/territory, but is used by NZAu region in the modelling. The disaggregation of state-based projections to NZAu region assumes a proportional distribution of capacity between NZAu regions 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^[40], and is shown in Figure 53 (right hand side).

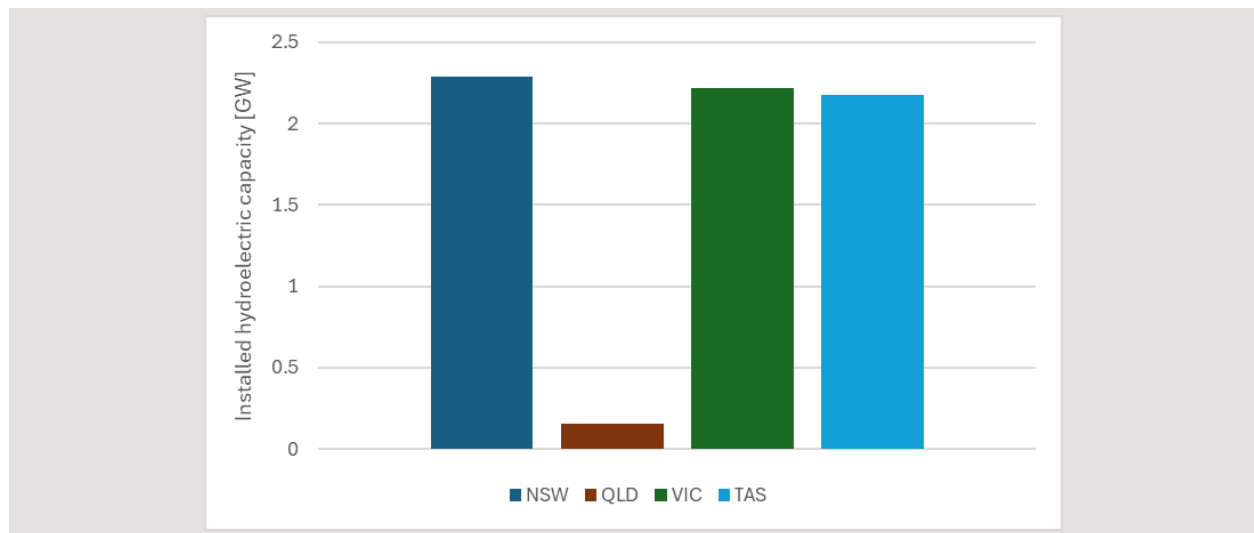
Figure 53 | Projected installed capacity of rooftop solar PV by state/territory^[37,38] and capital cost^[40].



12.6 Hydroelectric generation

Australia currently has 6.8 GW of grid-connected hydroelectric generation^[41], not including pumped hydropower energy storage, all of which participates in the NEM. Figure 54 shows the distribution of this installed capacity by state. The NZAu Project includes all this existing capacity without assuming a retirement date and does not allow any new, non-pumped hydroelectric generation.

Figure 54 | Regional distribution of installed hydroelectric capacity^[41].



For the existing sites, a daily generation envelope is developed by considering the historical average and minimum/maximum generation data sourced from AEMO^[42]. Figure 55 shows the average historical generation in each month over the financial years 2018-19 to 2023-24 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.

We also apply a minimum and maximum hourly generation limit based on historical maximum and minimum generation to replicate the historical extent to which hydroelectric generation is used as peaking generation. The constraints on maximum and minimum hourly generation are shown in Figure 56.

Figure 55 | Monthly hydroelectric generation budget, based on average historical generation FY 2018-19 to 2023-24^[42].

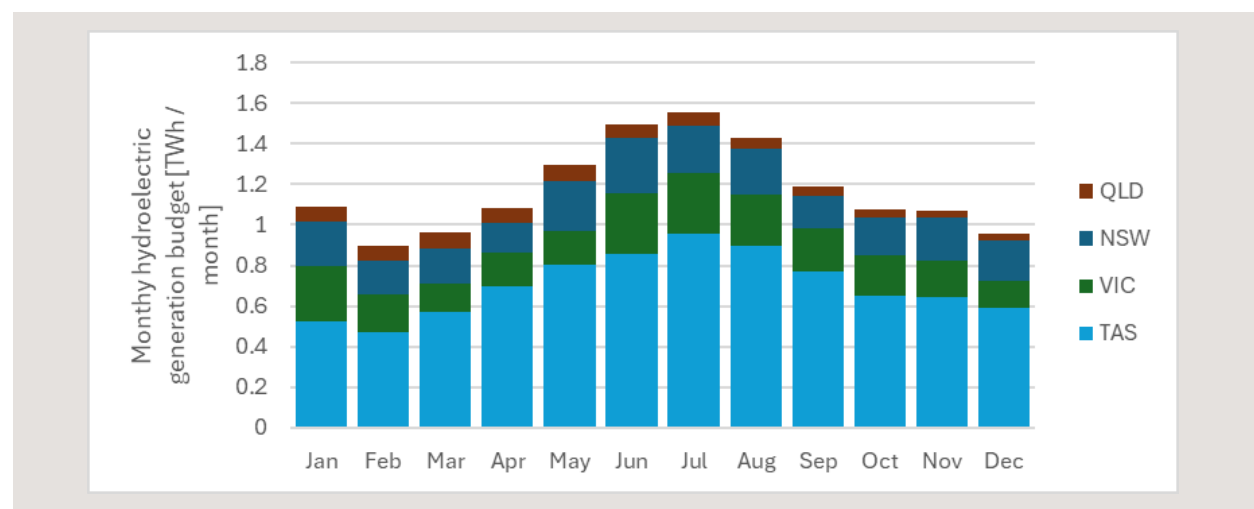
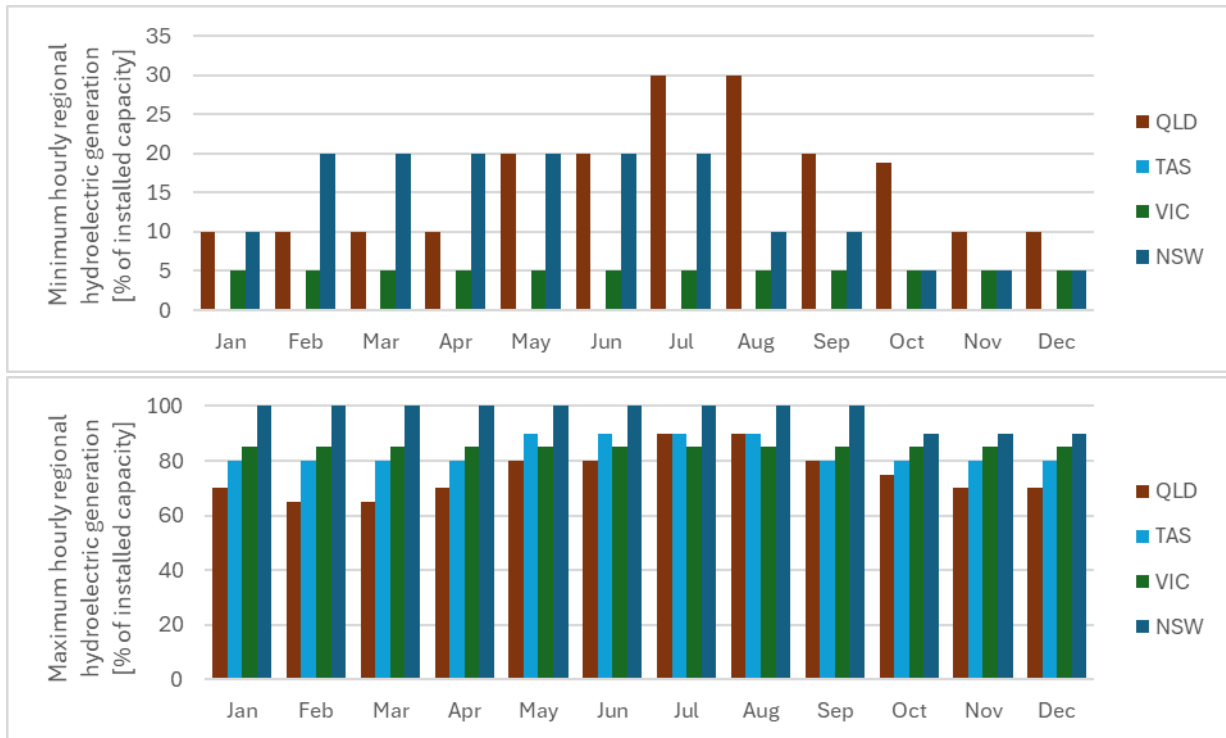


Figure 56 | Minimum (top) and maximum (bottom) hourly hydroelectric generation envelopes, by region and month^[42].



12.7 Renewable availability traces

The NZAu Project models hourly renewable availability traces using weather data from the Bureau of Meteorology's development of the kilometre-scale downscaled atmospheric reanalysis over Australia (BARRA-C2)^[43].

12.7.1 Wind and Solar PV modelling

Wind farm modelling

Wind speeds at 100 and 150 m heights taken from BARRA-C2 are utilised to build a wind speed profile using a wind power law^[44],

$$V_2 = V_1 \left(\frac{z_2}{z_1} \right)^p$$

where V_2 is the wind speed at height z_2 , V_1 is the wind speed at height z_1 , and p is the wind power law exponent. The hub height is as reported for existing wind farms. The hub height is then assumed to be 100 m for new onshore wind farms and 150 m for new offshore wind farms.

The wind speeds at the hub height are further adjusted by a factor α ,

$$V' = \alpha V.$$

This linear correction is necessary to correct the bias commonly seen in reanalysis^[45] and found to be 0.75 via a process detailed later in this Chapter.

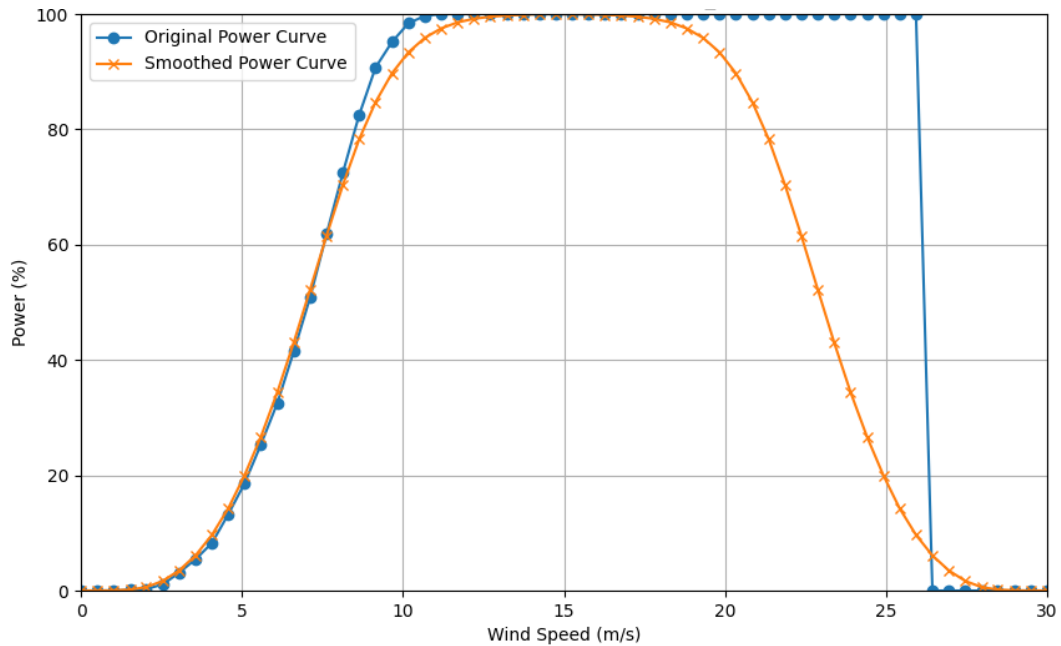
The adjusted wind speeds are converted to a wind power using a representative wind power curve which is smoothed to represent dispersed wind turbines in a wind farm. This smoothing process involves applying a

Gaussian filter for individual turbines to account for the distribution of wind speeds for individual wind turbines in the wind farm. Individual wind turbines are modelled using a bounding curve between power and wind speed^[46]. The width of the Gaussian filter, σ , is a function of wind speed^[45]:

$$\sigma = 0.6 + 0.2V.$$

The original bounding curve for individual wind turbines and the smoothed bounding curve for wind farms are in Figure 57.

Figure 57 | The bounding curve for individual wind turbines and the associated smoothed bounding curve for the wind farm^[45, 46].



Solar PV modelling

Two types of solar PV are modelled in this work:

- Utility-scale PV, and
- Rooftop PV.

The technical parameters used in the NZAu Project’s solar PV model are listed in Table 46.

Table 46 | Technical parameters used in NZAu solar PV modelling.

Parameter	Utility-scale PV	Rooftop PV
Time-step	hourly	hourly
Orientation	Single-axis tracking	Fixed tilt at site latitude
Panel Azimuth	0 degrees (North)	0 degrees (North)
DC/AC nameplate ratio	1.3	1
Inverter efficiency	0.955	0.955
Module Type – for module temperature estimation	Glass/cell/polymer sheet, open rack	Glass/cell/glass, Close Roof mount
Shadow derating factor	no	Yes ¹
Non-inverter fixed system derating	0.9	0.9
Cell temperature derating constant per °C	0.004	0.004
Standard test conditions cell temperature °C	25	25
Soiling factor	1	0.95
Utilisation rate	1	0.85

Note 1: Shadow derating = $1 - e^{-\left(\frac{\text{altitude of the sun}}{\text{weibull}_l}\right)^{\text{weibull}_k}}$, where weibull_l = 0.308 and weibull_k = 1.98^[47].

The solar PV model follows the method prescribed by Sandia National Laboratories^[47,48]. These steps are performed for every hour of the simulation year at every selected simulation site and consist of:

- calculating the solar angles using on site location (azimuth and zenith angles),
- calculating the Plane of Array (POA) radiation from radiation data, accounting for solar angles, panel tilt, orientation and the shadow derating factor^[49].
- estimating the temperature derating using the solar PV parameter (module type, temperature derating constant, standard conditions cell temperature), and the near-surface wind speed and temperature^[50].
- simulating the normalised power output adjusting for non-inverter fixed system derating, inverter efficiency, DC/AC ratio, and soiling factor.
- a utilisation rate of 0.85 is applied for rooftop solar PV, based on a historical analysis of existing rooftop PV in Australia.

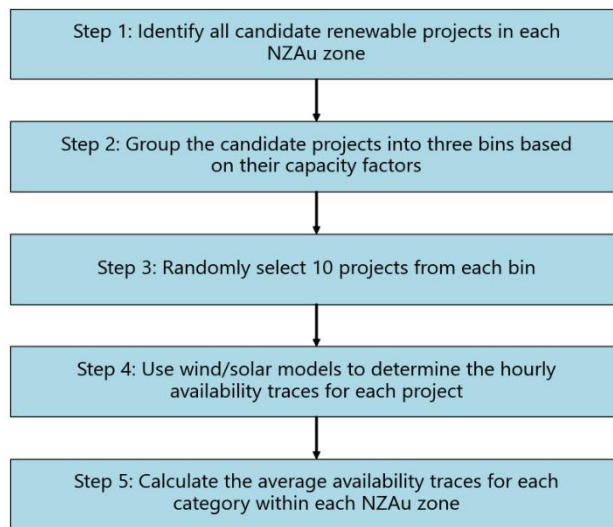
12.7.2 Representative regional traces

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 21 NZAu regions (Chapter 8). Representative traces are generated by five steps (Figure 58):

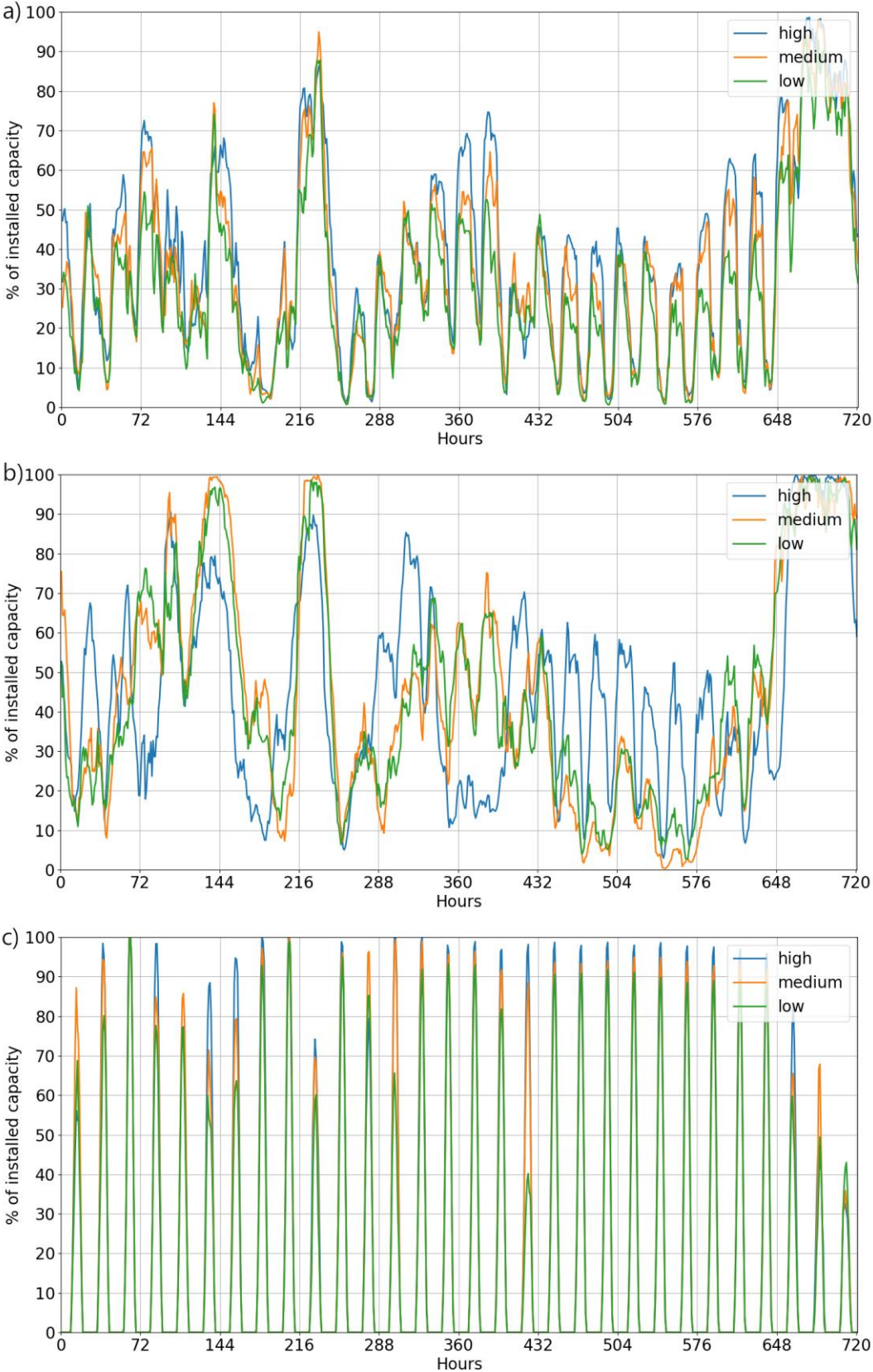
1. identify all candidate renewable projects in each NZAu region considering technical, economic and environmental factors detailed in subsection 12.8,
2. apportioning all candidate projects of each resource into three bins, based on capacity factor (lowest third of capacity factors, middle third of capacity factors, highest third of capacity factors),
3. randomly select 10 projects from each bin, resource and NZAu region,
4. use wind/solar models to determine the hourly availability traces for each project, and
5. taking the average across all traces in each bin, resource and NZAu region.

Figure 58 | Schematic of process in modelling representative regional traces.



For NZAu regions 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 variable than those generated from closer and thus more correlated sites. Figure 59 presents a one-week sample of the representative renewable availability traces in WA-south.

Figure 59 | A one-week sample of a) onshore wind, b) offshore wind and c) utility-scale solar availability traces in WA-south.



Rooftop solar PV

One representative rooftop solar PV trace is generated for each of the 21 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 year. 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 12.5 for further details.

12.7.3 Model validation

The NZAu Project validates our wind and solar model using historical generation in FY 2023-24^[51]. Given the limited data available in Western Australia, we choose five dispersed wind farms and four utility-scale solar farms in the Eastern States, as shown in Figure 60.

Figure 60 | The five wind farms and four utility-scale solar farms selected for validation.

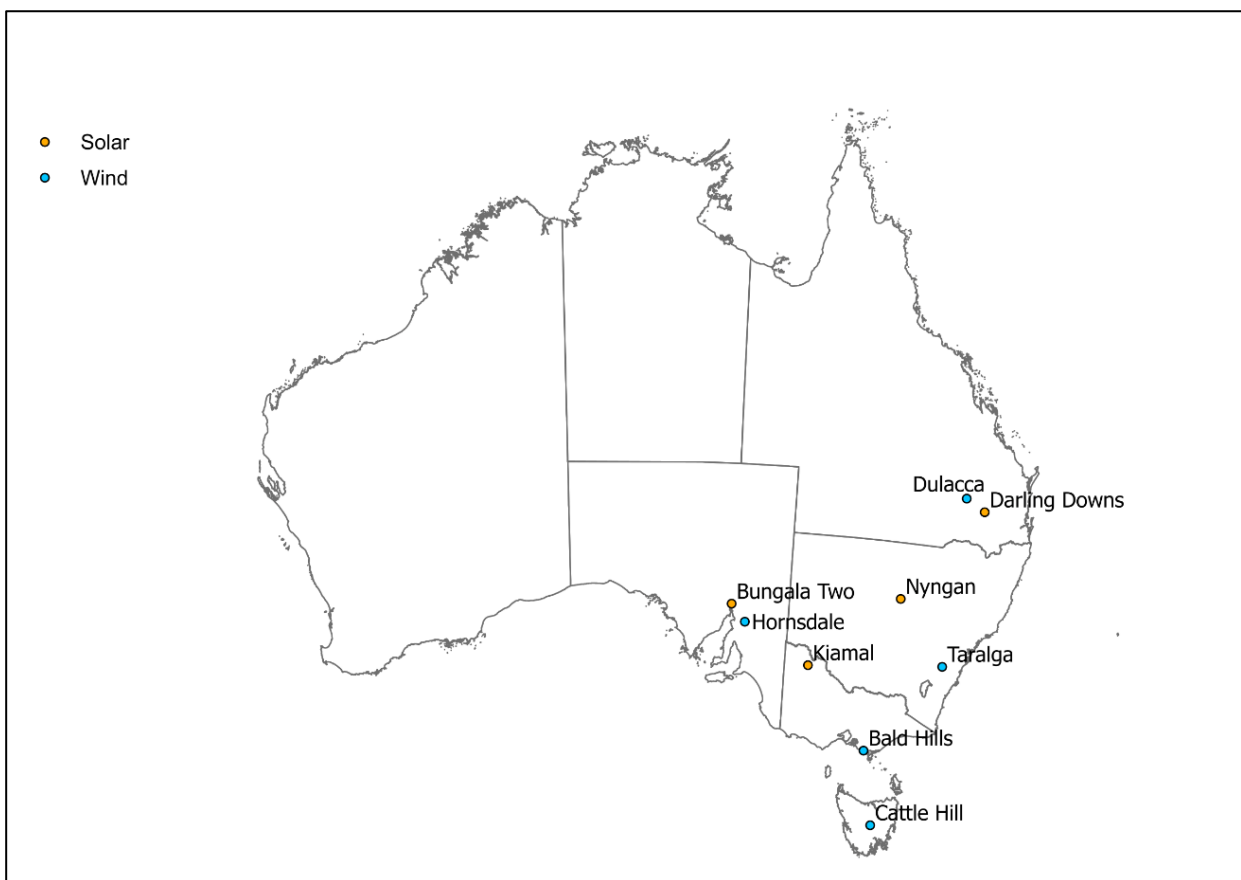
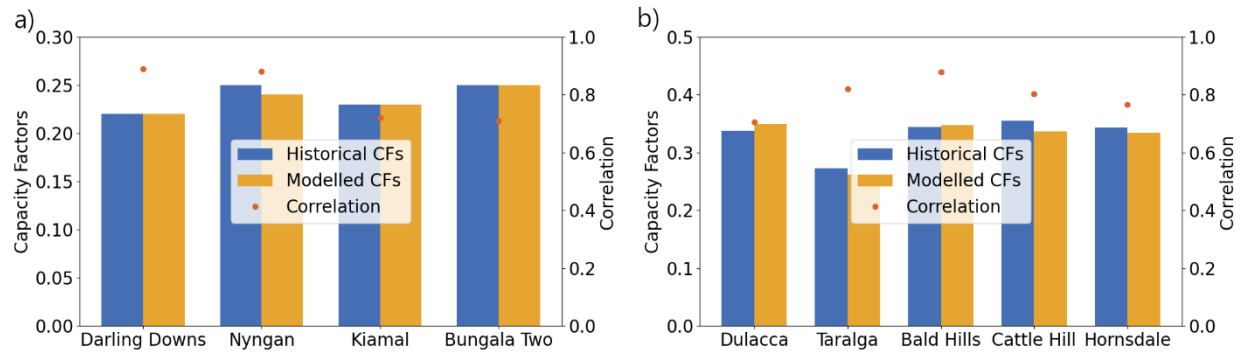


Figure 61 shows the historical and modelled annual capacity factors (CFs) of the selected wind and solar farms. For all modelled wind and solar farms, the difference between the historical and modelled annual capacity factors is less than 5%. Figure 61 also shows the correlation coefficient between the hourly historical and modelled hourly generation to be between 0.7 and 0.9. These levels of correlation are typical in resource assessment using reanalysis^[52].

Figure 61 | Historical actual and modelled capacity factors of the selected a) solar and b) wind farms, and the correlation coefficient between hourly historical and modelled generation over FY 2023-24.



Comparisons of historical actual and historical modelled generation of the Dulacca wind farm and Darling Downs solar farm are shown in Figure 61, Figure 62 and Figure 63. Figure 61 compares annual capacity factors and hourly correlation coefficients over FY 2023-24, whilst Figure 62 and Figure 63 plot historical actual and historical modelled time traces over a week in FY 2023-24. Similar results are observed for the other wind and solar farms in Figure 61.

Figure 62 | Hourly historical actual and modelled generation of the Dulacca wind farm over a week in FY 2023-24.

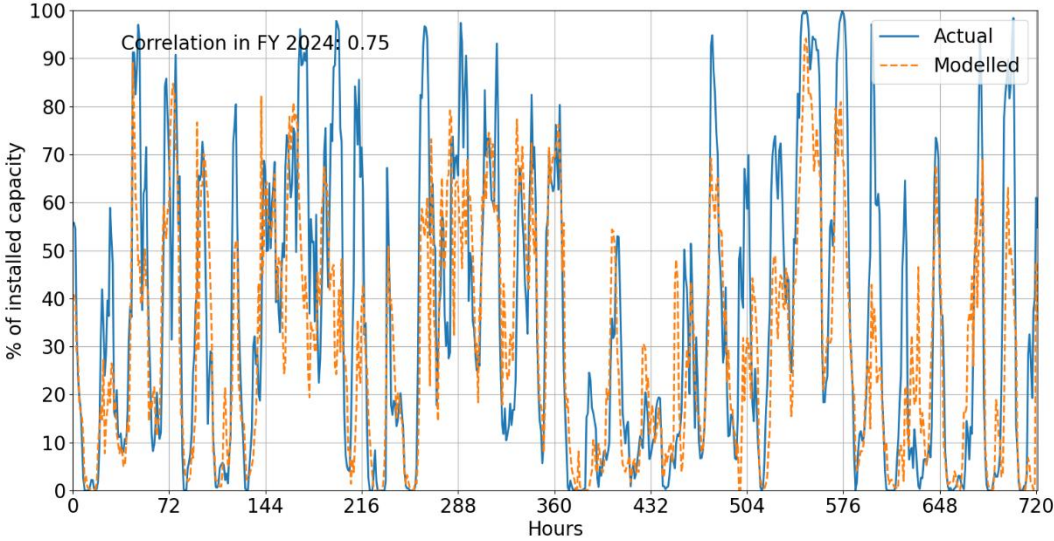
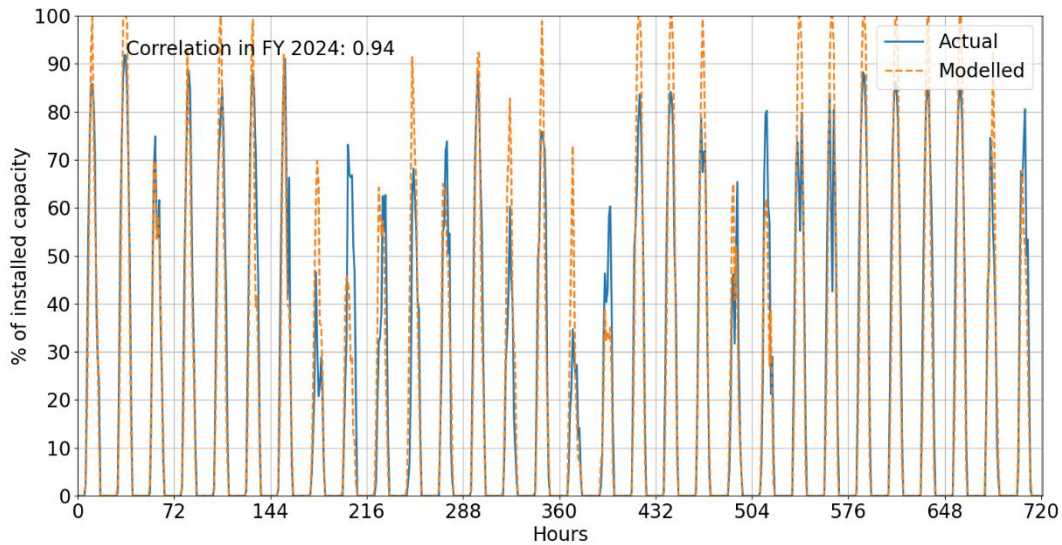
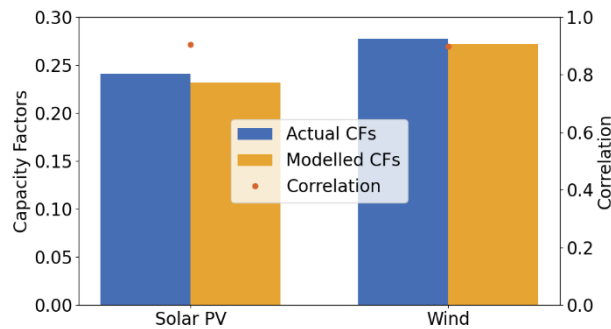


Figure 63 | Hourly historical and modelled generation of the Darling Downs solar farm over a week in FY 2023-24.



We also analysed the aggregation of wind and solar farms in NSW FY 2023-24 (Figure 64). We now found an hourly correlation coefficient of approximately 0.9 between historical and modelled generation, which is marginally higher than for individual farms. The maximum hourly ramp rates for wind generation are 29% for actual and 31% for the modelled data as a fraction of installed capacity, while for solar PV, they are 52% actual and 34% modelled, indicating likely smoothing in the modelled solar PV traces. This suggests that some care needs to be taken when examining the flexibility of firming modelled with dominant solar PV resource.

Figure 64 | Historical actual and modelled capacity factors for all operating wind and solar farms in NSW over FY 2023-24 and the correlation coefficient between hourly historical actual and modelled generation.



For rooftop solar PV, the average of the top 10 postcodes by installed capacity in each NZAu region is modelled. The modelled rooftop solar generation is then weighted and normalised to hourly state-level rooftop PV traces. Figure 65 presents a comparison of AEMO’s and the NZAu Project’s modelled rooftop solar annual capacity factors and correlations over FY2024. The difference between these modelled annual capacity factors is up to 8%, and the hourly correlation is over 0.95. Hourly modelled rooftop solar PV generation in QLD over a week in FY 2023-24 is shown in Figure 66, demonstrating the high correlation between these two modelled datasets.

Figure 65 | AEMO’s and the NZAu Project’s modelled capacity factors of rooftop solar PV by state, and the correlation coefficient between hourly historical and modelled generation over FY 2023-24.

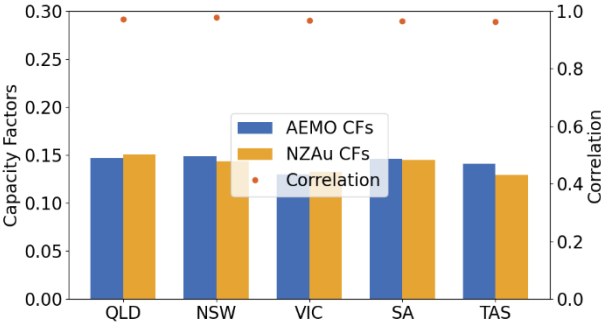
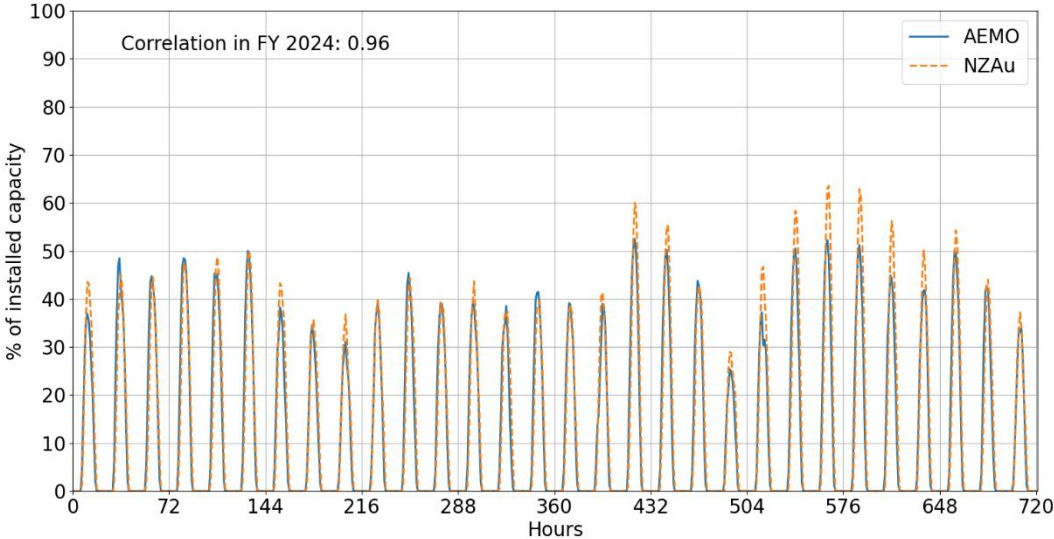


Figure 66 | Hourly AEMO’s historical and NZAu’s modelled weighted average QLD rooftop solar PV generation over a week in FY 2023-24.



12.8 Renewables supply curves

The process described in this section involves identifying available land area for variable renewable energy (VRE) and breaking them into individual candidate projects^[53]. The candidate VRE projects avoid being built on or around:

- active mines^[54];
- built-up or remote communities^[55];
- inland water bodies^[56];
- defence areas^[57];
- transport infrastructure^[58];
- existing energy infrastructure^[59];
- irrigated areas^[60];
- in areas with slope greater than 10 degrees^[61];
- offshore shipping lanes^[62];
- populated areas^[63];

- protected areas^[64];
- Species of National Environmental Significance (SNES)^[65]; and
- Ecological Communities of National Environment Significance (ECNES)^[66].

The remaining areas are then divided into individual candidate projects (Figure 67). The assumed sizes of these candidate VRE projects are shown in Table 47.

Figure 67 | Candidate Wind and Solar PV Projects.

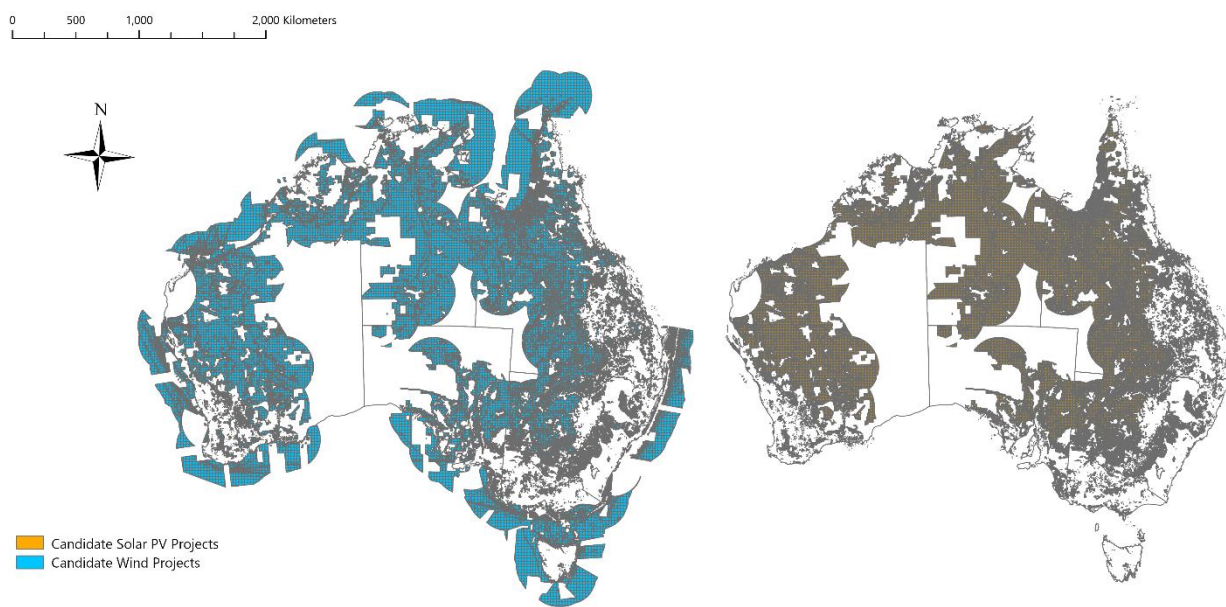


Table 47 | Summary of project size, project area, power density and land utilisation rate of VRE projects.

Parameters	Unit	Solar PV	Onshore Wind	Offshore Wind
Maximum project size	MW	900	1080	2200
Minimum project size	MW	20	50	100
Maximum project area	km ²	100	400	500
Maximum project area	km ²	2	19	23
Power density	MW/km ²	45	2.7	4.4
Land utilisation rate	%	20	100	100

Note that candidate projects are not directly used in the RIO optimisation but are represented by renewable regional traces (see section 12.7). The NZAu Project then selects projects through a downscaling process that identifies the lowest-cost options from the candidate pool. Specifically, during each evaluation period, this process assesses projects with the lowest overall costs, i.e. the lowest sum of generation technology costs (Chapter 13) and transmission costs (Chapter 14) to meet a calculated demand for VRE. Selected projects are then excluded from future consideration for their operational lifespan, preventing duplication in resource allocation.

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13 Supply-side capital and operating costs

This Chapter outlines cost estimates and assumptions used for:

- 13.1 Electricity generation and storage
- 13.2 Liquid and gaseous fuel production and storage

13.1 Electricity generation and storage

CSIRO’s GenCost 2024-25 final report^[1] is the most recent and authoritative source of Australian-specific electricity system technical and cost data. Where available, NZAu uses the 2024-25 GenCost data from its “Global NZE Post 2050” Scenario. Further justification on this Scenario selection is outlined in Appendix A.

Table 48 provides a summary of the capital costs of key electricity generation technologies input to the model. Storage costs (batteries and pumped hydroelectric storage) are decomposed into energy capacity (\$/kWh) and power capacity (\$/kW) cost components. More detail by technology is provided in the following subsections.

Table 48 | FY 2024-25 and 2049-50 electricity generation capital costs (\$/kW) considered in NZAu

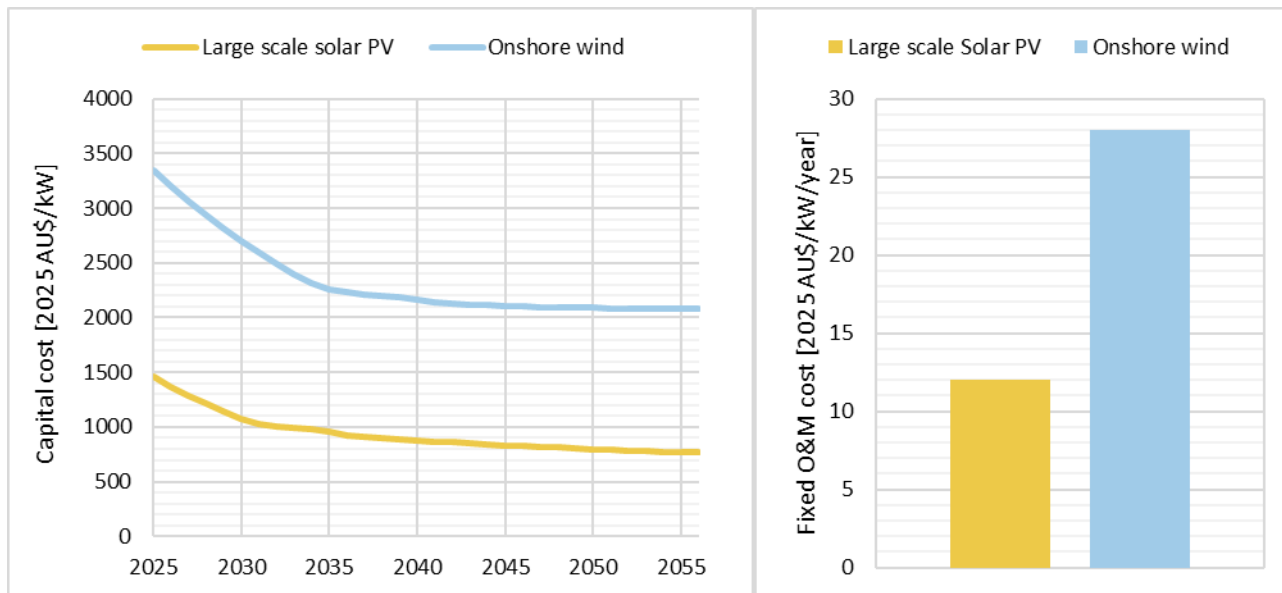
Category	Technology	Cost FY 2024-25*	Cost FY 2049-50*
Variable renewable	Large scale solar PV	1,463	797
	Rooftop solar	1,336	1,084
	Onshore wind	3,223	2,088
	Offshore wind (fixed)	4,710	3,903
	Offshore wind (floating)	8,362	4,806
Solid fuel	Black coal	6,037	5,803
	Black coal with CCS	12,263	11,134
	Brown coal	9,321	8,698
	Biomass	8,916	8,815
	Biomass with CCS	24,366	23,005
Gaseous fuel	Large-scale nuclear	8,984	9,567
	Combined cycle gas turbine	2,455	1,963
	CCGT with CCS	5,802	4,654
Storage	Open cycle gas turbine	1,310	1,200
	Li-ion battery (energy)	260 \$/kWh	143 \$/kWh
	Li-ion battery (power)	666	286
	PHES (energy)	55 \$/kWh	54 \$/kWh
	PHES (storage)	5,170	5,030

*All cost figures in real 2024-25 AU\$ / kW unless otherwise specified. The financial years in the table are mapped to the preceding calendar year in the GenCost 2024-25 Final Report.

13.1.1 Onshore renewables

Figure 68 presents the capital cost projections^[1] and the fixed operating and maintenance (O&M) cost for large-scale solar PV and onshore wind generation. Note that the fixed O&M costs are not provided in GenCost and so are sourced from AEMO’s ISP^[2]. These O&M costs account for the costs normally levied as variable O&M costs for wind and solar PV. Variable O&M costs are typically very small for wind and solar PV generation.

Figure 68 | Capital cost projections for onshore renewables (left), and their fixed O&M cost (right).



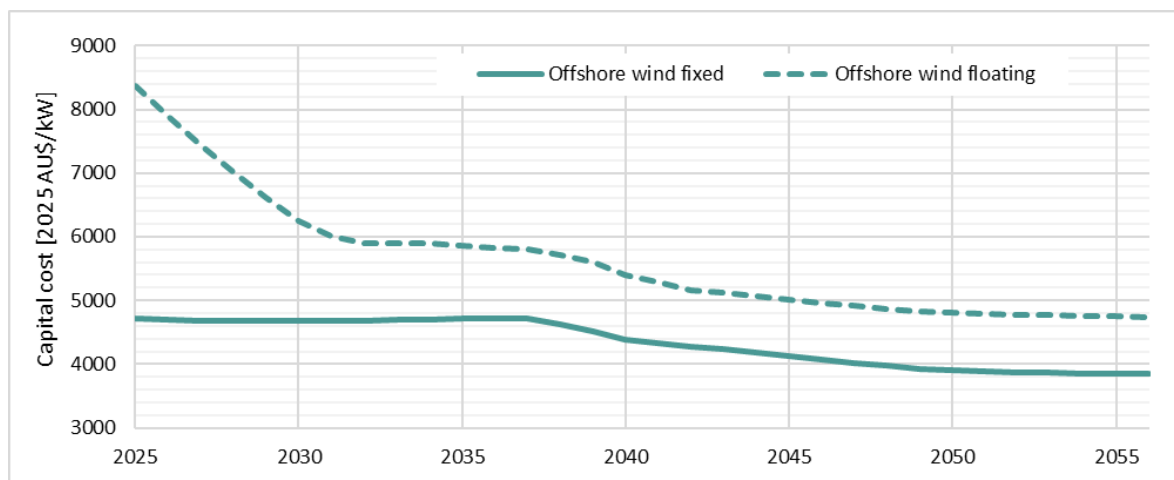
Cost projections for rooftop solar can be found in section 12.5 of Chapter 12.

13.1.2 Offshore wind

Offshore wind is not yet present in Australia and Australian-specific costs are therefore quite uncertain. As per CSIRO’s GenCost^[1], cost projections rely on global sources of offshore wind data until deployment in Australia. NZAu uses these GenCost capital cost projections, presented in Figure 69.

A fixed O&M cost of AU\$175/kW/year is used for fixed offshore wind, and AU\$247/kW/year for floating offshore wind, as provided by AEMO’s ISP^[2].

Figure 69 | Capital cost projections for offshore wind



13.1.3 New non-renewable electricity generation

The new electricity generation and storage technology candidates considered in NZAu are listed in Table 48 above. We allow a range of conventional electricity generation technologies to be built in the modelling alongside variable renewables, 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. The model can also choose to build direct air capture (DAC) technologies to extract CO₂ from the atmosphere, for example CO₂ from OCGTs burning natural gas or a blend with hydrogen which are not suited to flue gas capture due to their highly dynamic operation and low capacity factors^[4]. We therefore allow new CCGT and OCGT plant to be fired on any blend of natural gas and hydrogen from 2035 onwards. Unless otherwise specified, the CCS capture rate for generation technologies is 90%, as per GenCost data^[1].

Figure 70 presents the capital cost projections for the electricity generation technologies not previously presented in this work. Figure 71 presents the capital costs for the electricity storage technologies. The costs provided by GenCost 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.

Fixed and variable operating and maintenance costs for candidate new technologies are provided by GenCost and are presented in Figure 72.

In addition to the costs of candidate electricity technologies, we also source a range of technical parameters from AEMO's 2024-25 IASR for the 2026 ISP, and Aurecon's 2024 Cost and Technical Parameters Review workbook^[2,3]. These include:

- thermal efficiencies of thermal generators at their minimum and maximum generation levels (Figure 73)
- minimum generation levels for thermal plant (60% for biomass black coal with CCS and brown coal plant, 50% for CCGT with CCS and nuclear, 40% for biomass, black coal plant, and 30% for CCGT and OCGT).
- round-trip energy efficiencies of 85% for batteries and 76% 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, 10% for large-scale nuclear). 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, and 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 2025 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 70 | Capital cost projections for new electricity generation candidate technologies.

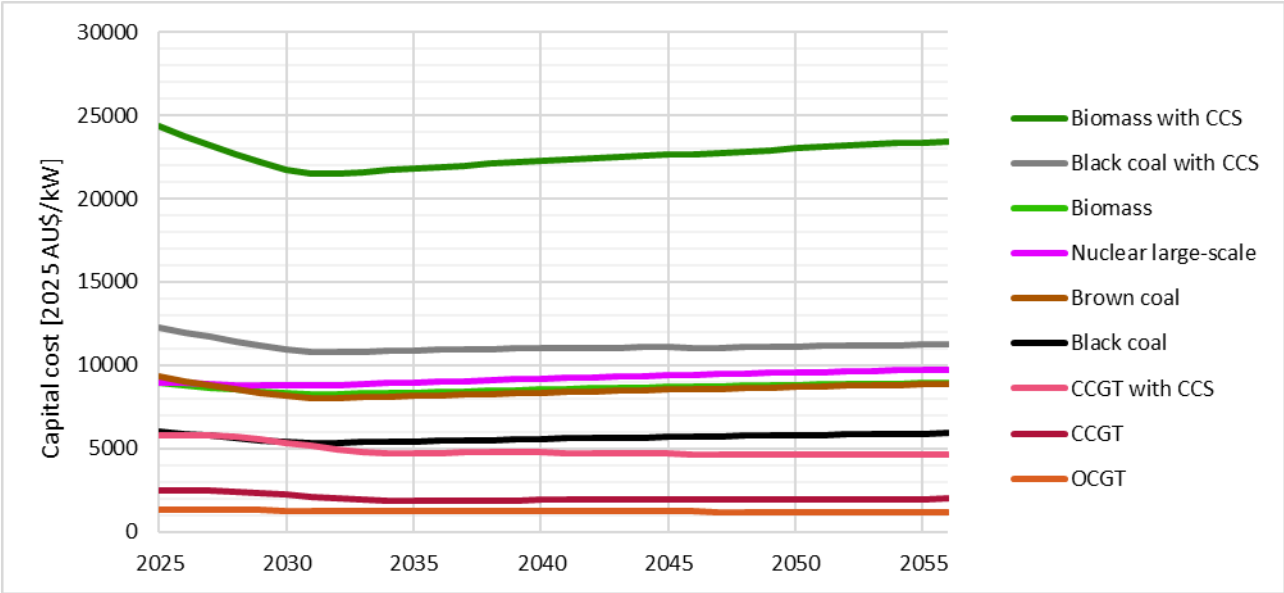


Figure 71 | Capital cost projections for new electricity storage candidate technologies. The capital costs are decomposed into energy capacity (\$/kWh) and power capacity (\$/kW) cost components.

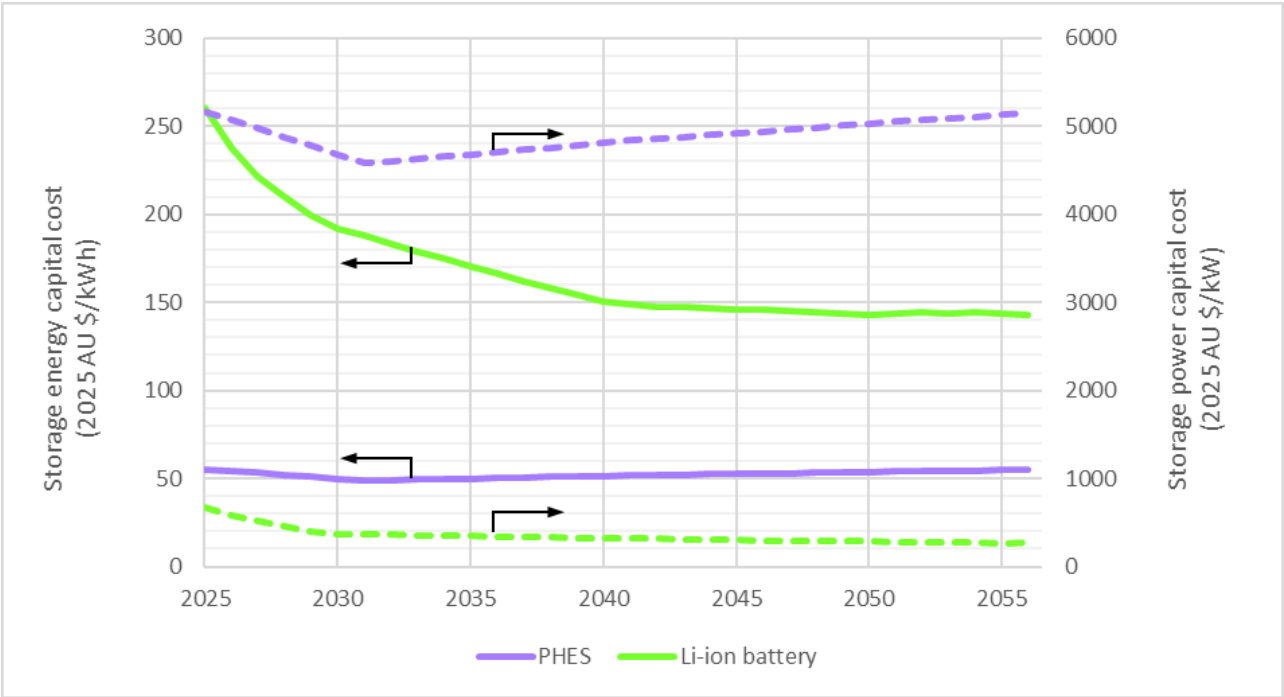


Figure 72 | Fixed (left) and variable (right) operating and maintenance costs for new electricity generation and storage technology candidates.

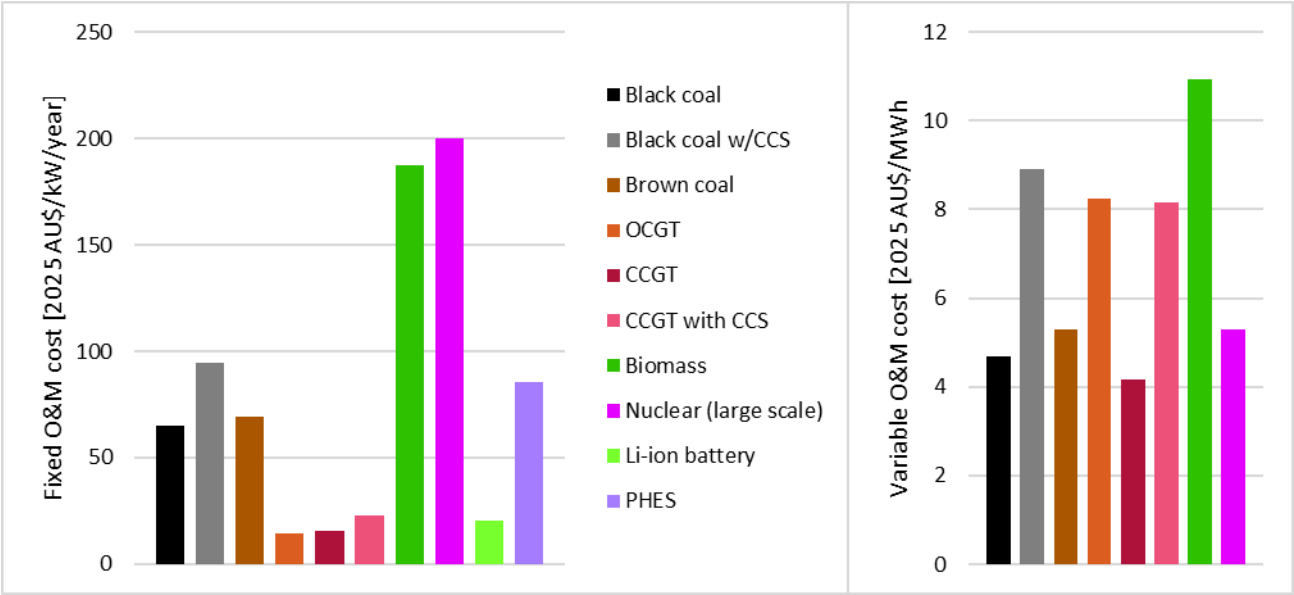
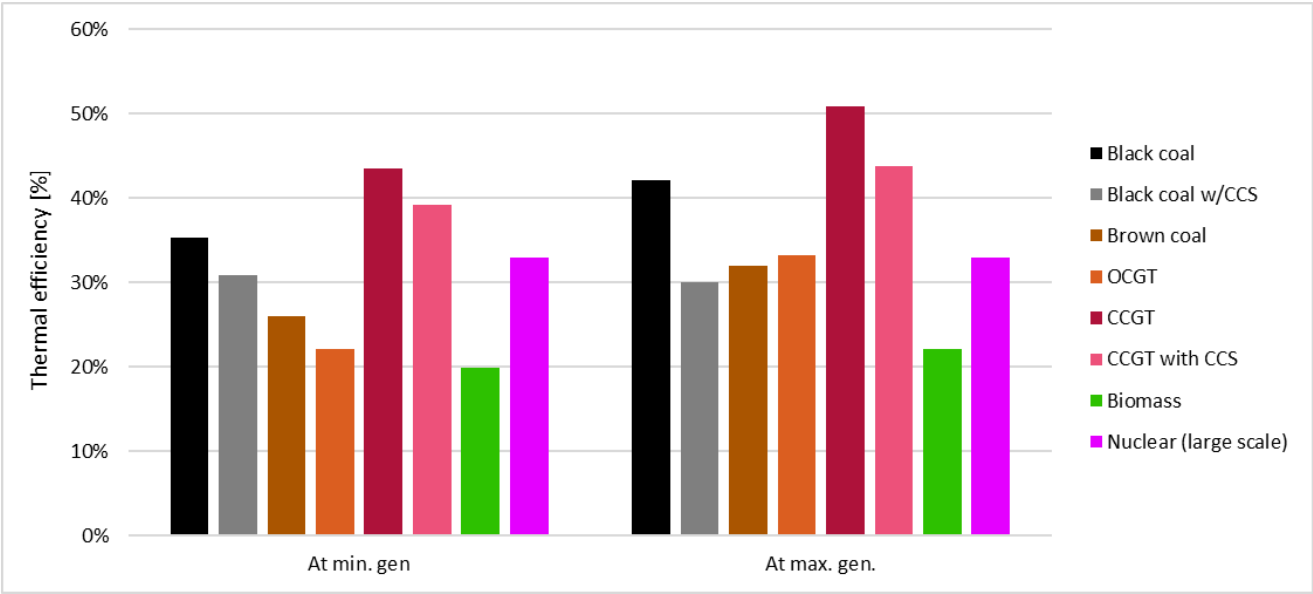


Figure 73 | Thermal efficiency of new electricity generation technology candidates at minimum and maximum generation levels.

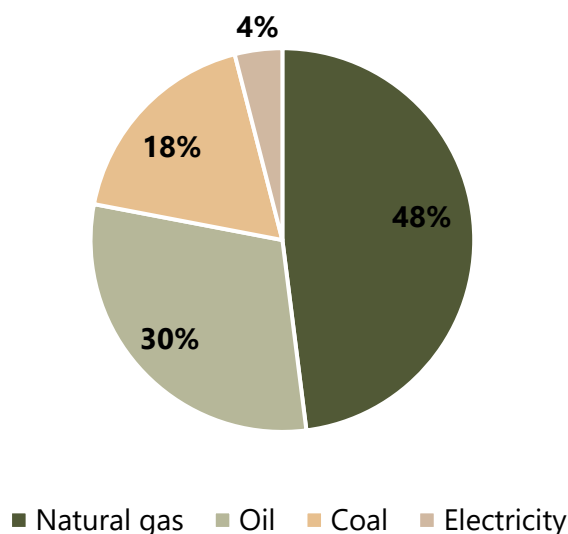


13.2 Liquid and gaseous fuel production and storage

13.2.1 Hydrogen production

Hydrogen is present in nature in many compounds, notably including water and fossil fuels like natural gas, coal or oil. Energy applications of hydrogen necessitate its separation to molecular form, breaking the chemical bonds by which it is bounded within these various compounds. This process is endothermic, i.e. requires an energy input. For this reason, hydrogen is not a primary energy source and rather should be regarded as an energy *carrier* or *vector*. Currently, hydrogen production relies heavily on fossil fuel feedstock, as shown in Figure 74.

Figure 74 | Global hydrogen production in 2023 by source. Data from Le Phuoc *et al.*^[5].



Given primary energy resource availability in Australia, four main routes of hydrogen production were considered in the NZAu Project: 1) steam-methane reforming (SMR) and 2) autothermal reforming (ATR) from natural gas feedstock; 3) gasification from either coal or biomass feedstock; and 4) from water, via electrolysis. Costs for each one of these routes are presented in the following subsections.

Carbon emissions are associated with most of these processes. However, noting biomass acts also as a carbon sink over its lifecycle, biomass gasification can be effectively considered a net-zero process. When supplied by clean electricity, electrolysis is also a zero-emission pathway to produce hydrogen: the so-called green hydrogen. Furthermore, beyond these two, all the other fossil fuel-based routes can produce hydrogen with low associated emissions if coupled with carbon capture technology. This is commonly referred to as the blue hydrogen pathway and it is considered among the other options in the NZAu Project. Table 49 summarises the hydrogen production and transformation technologies considered in the NZAu Project.

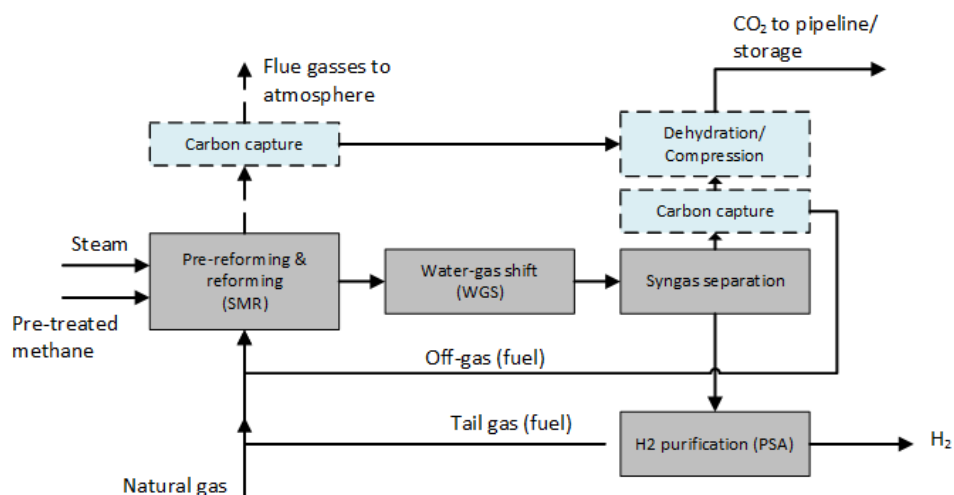
Table 49 | Hydrogen production and transformation technologies considered in the NZAu Project.

Green hydrogen	Blue hydrogen	Hydrogen carrier
PEM electrolysis	ATR w/cc	Liquid/compressed hydrogen
Bio-gasification w/cc	Brown coal gasification w/cc	Ammonia
	Black coal gasification w/cc	Fisher-Tropsch liquids

Steam methane reforming

SMR is currently the main route to hydrogen production globally^[6]. As illustrated in Figure 75, it involves the conversion of methane and steam into syngas (a mix of H₂ and CO) within a reformer, a downstream water-gas shift reactor and subsequent separation between the H₂ and CO₂ produced. The reforming process uses heat from the direct combustion of natural gas in a furnace, which, together with the CO₂ outlet from the water-gas shift reaction, is the source of carbon emissions in the process.

Figure 75 | Simplified block diagram of the steam methane reforming process with optional carbon capture capability.



The technical parameters considered for an SMR plant with carbon capture capability are reported in Table 50. These were sourced from a study of hydrogen-generating plants of 100 kt-H₂/y capacity in the Australian context^[7].

Table 50 | Conversion efficiency parameters for the steam methane reforming plants considered in this modelling.

Parameter	Units	SMR w/cc
Feedstock – natural gas	GJ/t-H ₂	159.5
Natural gas fuel	GJ/t-H ₂	38.5
Electricity	MWh/t-H ₂	1.8
CO ₂ released	t-CO ₂ /t-H ₂	1.15
CO ₂ captured	t-CO ₂ /t-H ₂	9.05

The reference costs for the SMR plants considered are reported in Table 51.

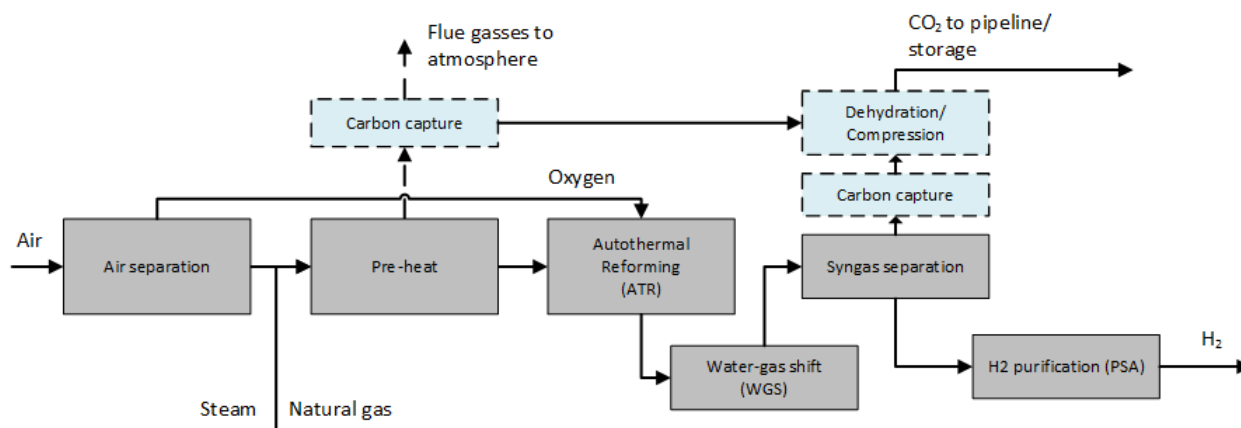
Table 51 | Input cost parameters for the steam methane reforming plants (2025 AUD).

Cost type	Units	SMR	SMR w/cc	Notes
Capital cost	AUD/kg-H ₂ /year	N.A.	9.91	80 bar H ₂ pressure
Fixed operating cost	AUD/kg-H ₂ /year	N.A.	0.28	Tax & insurance excluded
Variable operating cost	AUD/kg-H ₂	N.A.	0.12	Includes chemicals; catalyst; and water

Autothermal reforming

ATR process resembles SMR where heat for reforming is supplied by partial oxidation of natural gas instead of its direct combustion, as per Figure 76. As a consequence, a pure oxygen stream must be supplied for the partial oxidation reaction, but higher stack concentrations of CO₂ can be achieved. For this reason, as well as typically higher efficiencies, ATR currently represents the state-of-the-art in methane reforming, and is often preferred especially with the vision of coupling the process with carbon capture^[8].

Figure 76 | Simplified block diagram of the autothermal reforming process with optional carbon capture capability.



The technical parameters for ATR plants are reported in Table 52. Both plants using natural gas and natural gas liquids were modelled, which exhibit different environmental performance. The energy demand of an onsite air separation plant for producing the pure oxygen feedstock was accounted for as additional electricity consumption.

Table 52 | Conversion efficiency parameters for the autothermal reforming plants considered in this modelling.

Parameter	Units	ATR w/cc	ATR w/cc – Natural gas liquids
Feedstock – natural gas/natural gas liquids	GJ/t-H ₂	182	182
Electricity	MWh/t-H ₂	3	3
CO ₂ released	t-CO ₂ /t-H ₂	1.04	1.24
CO ₂ captured	t-CO ₂ /t-H ₂	8.34	9.92

Plant costs are reported in Table 53. They were obtained by adjusting costs reported for 100 kt/y plants in Australia^[7] to a notional 316 kt/y process, which is deemed of reasonable scale for the intended application^[9]. A 0.65 scaling exponent was used, as recommended for complex processes involving solids and gas handling^[10]. A reduction of 0.5% per annum on the capital and fixed O&M cost values reported in Table 53 was then considered for all the new ATR capacity deployed post 2025, to project the effect of technological learning on future costs.

Table 53 | Input cost parameters for the autothermal methane reforming plants (2025 AUD).

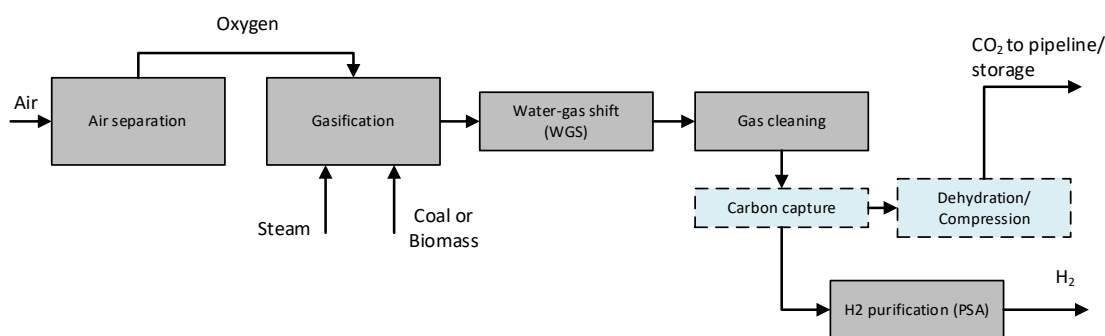
Cost type	Units	ATR w/cc*	Notes
Capital cost	AUD/kg-H ₂ /year	8.01	80 bar H ₂ pressure
Fixed operating cost	AUD/kg-H ₂ /year	0.22	Tax & insurance excluded
Variable operating cost	AUD/kg-H ₂	0.10	Includes chemicals; catalyst; and water

* The same cost parameters were used to model both plants using natural gas and natural gas liquids input.

Gasification of coal and biomass

Coal gasification reacts coal with air or oxygen and steam at high temperature and moderate pressure to produce syngas, which is later shifted into H₂ and CO₂ (see Figure 77). Alternatively, the gasification of carbon-based feedstock to hydrogen can be achieved in a similar process to that of where biomass substitutes the coal input, with the potential to be carbon-negative if carbon capture is performed downstream the water-gas shift reaction. Among the various gasification technologies in operation^[11-13] the NZAu Project models 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.

Figure 77 | Simplified block diagram of the coal/biomass gasification process with optional carbon capture capability.



The technical parameters for the coal and biomass gasification plants considered are reported in Table 54. They were sourced, respectively from a report of the Future Fuel CRC^[7] and independent review from NREL^[13].

Table 54 | Conversion efficiency parameters for the coal/biomass gasification plants considered in this modelling.

Parameter	Units	Black coal gasification w/cc	Brown coal gasification w/cc	Biomass gasification w/cc
Feedstock – coal/biomass	GJ/t-H ₂	303	231.9	282
Electricity	MWh/t-H ₂	2.2	1.4	0
CO ₂ released	t-CO ₂ /t-H ₂	7.62	5.63	0
CO ₂ captured	t-CO ₂ /t-H ₂	19.71	16.12	22.89

Costs for coal and biomass gasification are obtained from the same references used for autothermal reforming^[7,9] and are reported in Table 55. As above, we also reduce capital and fixed O&M costs by 0.5% per annum to project the effect of technological learning on future costs of the gasification capacity deployed post 2025.

Table 55 | Input cost parameters for coal/biomass gasification (2025 AUD).

Cost type	Units	Black coal gasification w/cc	Brown coal gasification w/cc	Biomass gasification w/cc	Notes
Capital cost	AUD/kg-H ₂ /year	21.75	14.47	35.09	80 bar H ₂ pressure
Fixed operating cost	AUD/kg-H ₂ /year	0.63	0.60	0.67	Tax & insurance excluded
Variable operating cost	AUD/kg-H ₂	0.19	0.09	0.03	Includes chemicals; catalyst; and water

Electrolysis

The NZAu Project considered proton exchange membrane (PEM) technology to model hydrogen production via electrolysis. PEM electrolyzers are more flexible and thus suited to complement variable generation at a comparable cost with alkaline^[14]. Technical parameters used to model electrolysis are gathered in Table 56: they include stack efficiency, and the auxiliary energy needed to compress hydrogen to 30 bar and to operate an air-based cooling system. The input parameters to the modelling should therefore be regarded as a comprehensive Balance of Plant (BOP) value. Furthermore, following advice from industry stakeholders, stack efficiencies were assumed to linearly increase from 64% in 2020 to 74% in 2050.

Table 56 | Conversion efficiency for PEM electrolyzers considered in this modelling.

Technology	Unit	Value
Electrolyser stack efficiency	%	64 - 74
Electrolyser stack energy input	kWh-e/kg-H ₂	53.2 - 61.7
Additional energy for H ₂ compression	kWh-e/kg-H ₂	1.4
Additional energy for air cooling	kWh-e/kg-H ₂	0
BOP energy input 2025	kWh-e/kg-H ₂	61.4
BOP energy efficiency 2025	%	64
BOP energy input 2050	kWh-e/kg-H ₂	54.7
BOP energy efficiency 2050	%	72

The CAPEX for a PEM electrolyser in the GenCost report^[1] was used for this modelling and is presented in Table 57; this is intended as per unit of electrical power input to the stack. CAPEX values per unit hydrogen produced were then computed using the BOP energy efficiency from Table 56. A progressive reduction in capital cost for PEM electrolyzers is envisioned. Fixed O&M costs were set at 3% of capital per year and variable O&M at 1%, as per the Net Zero America study^[16].

Table 57 | Cost parameters for the PEM electrolyser considered in this modelling (2025 AUD).

Year	CAPEX [AUD/kW _e]	CAPEX [AUD/kW _{th} -h2]	Fixed O&M [AUD/kW _{th} -h2/y]	Variable O&M [AUD/MWh _{th} -h2]
2025	2840	4426.5	132.8	5.1
2030	1821	2769.6	83.1	3.2
2035	1281	1902.4	57.1	2.2
2040	1171	1699.0	51.0	1.9
2045	1108	1571.4	47.1	1.8
2050	1085	1505.0	45.2	1.7
2055	1094	1485.0	44.5	1.7

13.2.2 Hydrogen storage

The hydrogen production costs presented so far do not account for hydrogen storage at the production facility. Rather, the NZAu Project considered underground hydrogen storage as a centralised option for large-scale and long-duration (e.g. seasonal) storage of energy. Its applications are not limited to bridging the time gap between periods of hydrogen generation during RES availability and its demand, particularly in industry or as an energy carrier for export purposes. They extend, for instance, to supporting the safe and reliable operation of the power system.

While underground hydrogen storage in salt caverns has been trialled in a few sites worldwide^[17,18], there are currently no examples of hydrogen storage in depleted oil and gas reservoirs in Australia, nor documented trials in other types of abandoned mines. Also, due to their remoteness, salt caverns are not considered a suitable storage method in Western Australia^[19]. For these reasons, the NZAu Project considers representative costs of hydrogen storage in engineered underground caves as a technically feasible option. These costs are presented in Table 58^[20], broken down into a power and a capacity component per hydrogen *delivered*. The former accounts mainly for compressors and other infrastructure whose size scales with the rated charging and discharging hydrogen flows; the latter accounts for cave lining and other structural interventions that scale with the intended storage capacity (i.e. for a fixed volume, with the design storage pressure). Costs for hydrogen storage in engineered caves are presented alongside those for salt caverns as a reference, although only the former option was considered in the NZAu modelling, given the large uncertainty surrounding the technical feasibility of the latter.

A maximum of 100 hours of hydrogen storage capacity was imposed on each domestic storage facility; a 1000 h capacity limit was considered for hydrogen storage at ports.

Table 58 | Input cost parameters for hydrogen stage (2025 AUD).

Technology	Units	Engineered Caves (150 bar)	Salt Caverns (120 bar)
Capital cost	AUD/kW-H ₂	86.3	86.3
	AUD/kWh-H ₂	3.2	1.5
Fixed operating cost		0.0	0.0
Variable operating cost	AUD/MWh-H ₂	1.2	1.2

13.2.3 Ammonia production

The Haber-Bosch process is used to fixate nitrogen and molecular hydrogen and produce ammonia. It was assumed these facilities are only available at ports. Technical performance parameters used to model ammonia synthesis are reported in Table 59, as projected for a 5000 tpd plant (1734 kt-NH₃/year)^[21]. Note the values only account for a co-located air separation unit including main compression to 140 bar, refrigeration equipment and a recycle compressor^[21] and ammonia synthesis^[23]. Hydrogen is generated by one of the described pathways (section 13.2.1) and supplied as feedstock.

Table 59 | Conversion efficiency parameters for the ammonia production plants considered in this modelling.

Process	Units	Value
Air separation unit	kWh/kg-NH ₃	0.11
Ammonia Synthesis plant	kWh/kg NH ₃	0.42

Costs estimated for the representative 5000 tpd ammonia synthesis process are reported in Table 60 and were used as model inputs. Figures from the QNP Green Ammonia project^[24] were manipulated, as discussed above, to exclude the costs associated with hydrogen production and adjusted with a 0.7 scaling factor. They fully account for nitrogen generation and ammonia storage onsite, as well as at the shipping terminal, and include a 20% addition for balance of plant and contingencies. This way, no explicit modelling of ammonia storage technologies was needed. Yet, time shift between carrier production and consumption was allowed by storage of hydrogen as the main ammonia precursor.

Table 60 | Cost parameters for the ammonia production plants considered in this modelling (2025 AUD).

Cost type	Units	Haber-Bosch process	Haber-Bosch retrofit	Notes
Capital cost	AUD/t-NH ₃ /year	1080.1	864.1	5000 tpd. 20% cheaper retrofit
Fixed operating cost	AUD/t-NH ₃ /year	30.8	30.8	4% of capital cost and no changes (split FOM and VOM)
Variable operating cost	AUD/t-NH ₃	17.1	17.1	+ storage and terminal (2% capital cost)

Finally, the development of ammonia production facilities at repurposed LNG sites was assumed to attract a 20% discount on the capex 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. The NZAu Project modelling enabled Haber-Bosch retrofits at ports in Western Australia, the Northern Territory, and Queensland.

13.2.4 Synthetic fuels production

Liquid or gaseous hydrocarbons can be synthesised from various feedstocks containing hydrogen and carbon either in molecular form or bound as part of other compounds. The processes modelled as part of the NZAu Project are:

- biomass to methane via gasification (both with and without carbon capture). The methane generated can then be turned into liquid synthetic fuels via Fischer-Tropsch (FT) conversion; and
- biomass fast pyrolysis (both with and without carbon capture).

All use dry biomass as the feedstock. Additionally, the conversion of green hydrogen to liquids via FT was considered. The synthesis of liquid fuels from biomass feedstock is also the modelled pathway to produce

sustainable aviation fuels (SAF) in the NZAu Project, with the costs and conversion efficiency parameters described hereafter.

The parameters describing the technical performance of each of these pathways is reported in Table 61, based on several sources investigating Nth of a kind plant designs. More specifically, pyrolysis efficiency was sourced from^[25], biomass gasification from^[26], FT conversion from^[27] and^[28].

Costs from the same references are reported in Table 62. For all technologies other than biomass gasification to methane, a linear reduction of 0.3% per annum on the capital and fixed O&M cost values reported in Table 62 was then considered for all the new capacity deployed post 2025.

Table 61 | Conversion efficiency parameters for the synthetic fuel production plants considered in this modelling.

Parameter	Units	Biomass gasification to CH4	Biomass gasification to CH4 w/cc	Biomass gasification + FT	Biomass gasification + FT w/cc	Biomass fast pyrolysis	Biomass fast pyrolysis w/cc	FT
Feedstock	GJ/GJ-fuel	1.51	1.55	1.96	2.15	1.54	1.54	1.54
Natural gas by-product	GJ/t-H ₂				0.097			0
Electricity	MWh/t-H ₂	0.021	0.021	0.052	0.114			5.05
CO ₂ released	t-CO ₂ /t-H ₂							5.63
CO ₂ captured	t-CO ₂ /GJ-fuel		0.046		0.082		0.074	0.067
Steam by-product					0.33			

Table 62 | Cost parameters for the synthetic fuel production plants considered in this modelling (2025 AUD).

Cost type	Units	Biomass gasification to CH4	Biomass gasification to CH4 w/cc	Biomass gasification + FT	Biomass gasification + FT w/cc	Biomass fast pyrolysis	Biomass fast pyrolysis w/cc	FT
Capital cost	AUD/kg-fuel/year	4348.8	4532.6	7546.0	7854.3	4753.3	7617.6	1704.0
Fixed operating cost	AUD/kg-fuel/year	130.7	135.6	250.3	254.0	141.8	228.1	61.7
Variable operating cost	AUD/GJ-fuel	1.7	1.7	12.3	13.6	9.2	9.2	0.7

13.2.5 LNG production

In the NZAu Project, LNG production costs and performance account only for the downstream processing, notably including liquefaction of the gas extracted at the domestic basins. Gas extraction cost and performance are accounted for separately, by defining individual models for conventional and coal seam gas extraction processes.

Australia features large resources of both conventional natural gas and coal seam gas, both feeding into LNG production mostly for export purposes. The technical performance used in the NZAu Project for LNG production are reported in Table 63. Several potential ways to improve the energy efficiency of LNG production have been suggested, including electrification of plant, employing waste heat recovery and operating at or below nominal capacity levels^[29]. NZAu considers the former, either as a retrofit option on existing plants or as a new plant solution altogether.

Table 63 | Energy input to produce a unit MJ of LNG in the different plants considered in this modelling.

Technology	Input	Value	Units
Lng plant	Natural gas	1.08	MJ/MJ
Lng plant electric	Electricity	0.06	MJ/MJ
Lng plant electric retrofit	Electricity	0.06	MJ/MJ

Table 64 provides a list of the capital cost for gas extraction and LNG plants that is the average from reported data for Australian facilities^[30-35] and scaled for industrial inflation and currency.

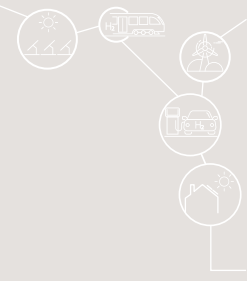
Table 64 | Cost parameters for the LNG production plants considered in this modelling (2025 AUD).

Cost type	Units	CSG extraction	NG extraction	LNG plant (both conventional & electric)	Electric retrofit	Notes
Capital cost	AUD/kW	1501.8	757.1	2012.3	123.3	60% higher extraction in NT; same w/cc
Fixed operating cost	AUD/kW	12.3	12.3	30.0	30.0	1.5% of capital cost for LNG plant
Variable operating cost	AUD/t-fuel	0.078	0.078	0.117	0.117	0.089 for w/cc

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14 Transmission and distribution network costs

This Chapter outlines the cost assumptions used for electricity, gas and water networks considered in the model.

Electricity and gas networks are classified as either transmission or distribution, while the water network is only considered at the level of transmission. The cost of these networks adds to the upstream (production and storage) cost of the transported commodity, so that the cost of any network-delivered commodity, as delivered to the end user, can be expressed as:

$$\text{As-delivered cost} = \text{Upstream cost} + \text{Transmission cost} + \text{Distribution cost.}$$

The NZAu Project models the regional specificity of these different cost terms. The approach followed for the upstream costs (including all extraction and processing until transmission) is presented in Chapter 13. Transmission and distribution costs are discussed in this Chapter for the transmission and distribution of natural gas and electricity, along with the transmission of hydrogen, carbon dioxide and water. We note the NZAu Project models costs, not prices, and so a retail margin in the equation above is not considered.

This Chapter includes the following subsections:

- 14.1 Electricity transmission
- 14.2 Gaseous fuels transmission
- 14.3 Water transmission
- 14.4 Electricity and natural gas distribution
- 14.5 Energy transmission and distribution cost allocation

14.1 Electricity transmission

14.1.1 Existing electricity transmission

The NZAu Project takes the existing electricity transmission map from Geoscience Australia’s Foundation Electricity Infrastructure^[1] and existing electricity transmission capacity from the AEMO’s Inputs, Assumptions, and Scenarios report for the 2026 Integrated System Plan^[1]. The capacity of existing inter-regional transmission (i.e. 2025 capacity) is presented in Table 65.

Table 65 | 2025 capacity of inter-regional electricity transmission.

Corridor (start point – endpoint)	Forward Capacity (MW)	Reverse Capacity (MW)
QLD-central – QLD-north	1200	1440
QLD-central – QLD-gg	700	750
QLD-south – QLD-central	1100	2100
NSW-north – QLD-south	950	1580
NSW-central – NSW-north	910	930
NSW-central – NSW-south	2320	2700
NSW-central – NSW-snw	7030	7030
VIC-west – NSW-south	870	400
VIC-west – VIC-mel	2300	2300
VIC-mel – VIC-east	7100	7100
VIC-west – SA-south	650	650
VIC-west – SA-central	165	100
SA-central – NSW-south	150	150
SA-central – SA-south	790	750
SA-central – SA-north	1070	1150

14.1.2 New electricity transmission routes

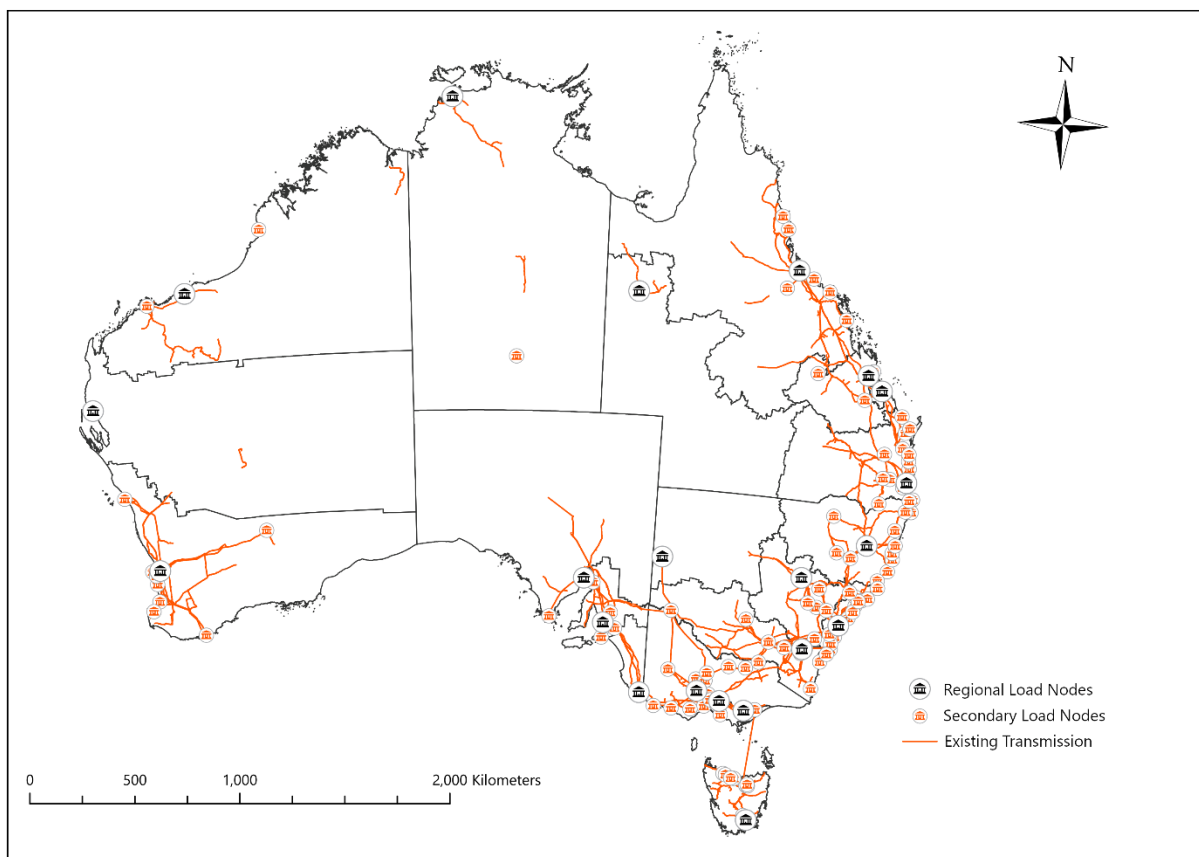
The NZAu Project models two types of domestic electricity transmission: intra-regional and inter-regional transmission.

Intra-regional transmission refers to the transmission that connects generation project sites (mostly, but not entirely, variable renewable energy (VRE) project sites) to load nodes within a specific NZAu region, defined in Chapter 8 and shown in Figure 78. The NZAu Project defines two types of load nodes: ‘regional load nodes’ and ‘secondary load nodes’, also shown in Figure 78. These load nodes are chosen from an existing set of substations.

- A **‘regional load node’** is a ‘reference point’ through which electricity can be transferred to and from other NZAu regions. Whenever possible, the NZAu Project chooses AEMO’s Regional Reference Node^[1] within each NZAu region as the ‘regional load node’. If no AEMO Regional Reference Node is available, we select the load centre in that NZAu region with the largest population^[3].
- The **‘secondary load nodes’** are defined as the centroids of other Statistical Area Level 2 (SA2) regions that have a minimum population of 5,000 and a population density exceeding 100 people per square kilometre.

Inter-regional transmission is defined as the electricity transmission that connects two ‘regional load nodes.’

Figure 78 | Regional load nodes, secondary load nodes, and existing transmission^[1] for the domestic energy system.



A route for each transmission line is created using the routing surface and Cost Path tool in ArcGIS Pro^[4]. Unless stated otherwise, the routing surface is adjusted with multipliers that account for technological, social, and environmental factors, as summarised in Table 66. These multipliers reflect the level of difficulty in the approval, construction, and maintenance of transmission lines in various areas. For instance, a multiplier of 100 means that constructing 1 km in that area is as challenging as building 100 km in a more favourable location with a multiplier of 1, effectively excluding this area and encouraging detours in the routing process. Cost factors from AEMO’s Transmission Cost Database, addressing aspects like jurisdiction, land use, and existing infrastructure, are also included^[5]. Exclusion zones containing Species of National Environmental Significance (SNES)^[6] and Ecological Communities of National Environment Significance (ECNES)^[66], in which renewable projects cannot be sited (as explained in Chapter 12), are **not applied** to the transmission routing surface as they would effectively block all routes to most regional nodes along the coast.

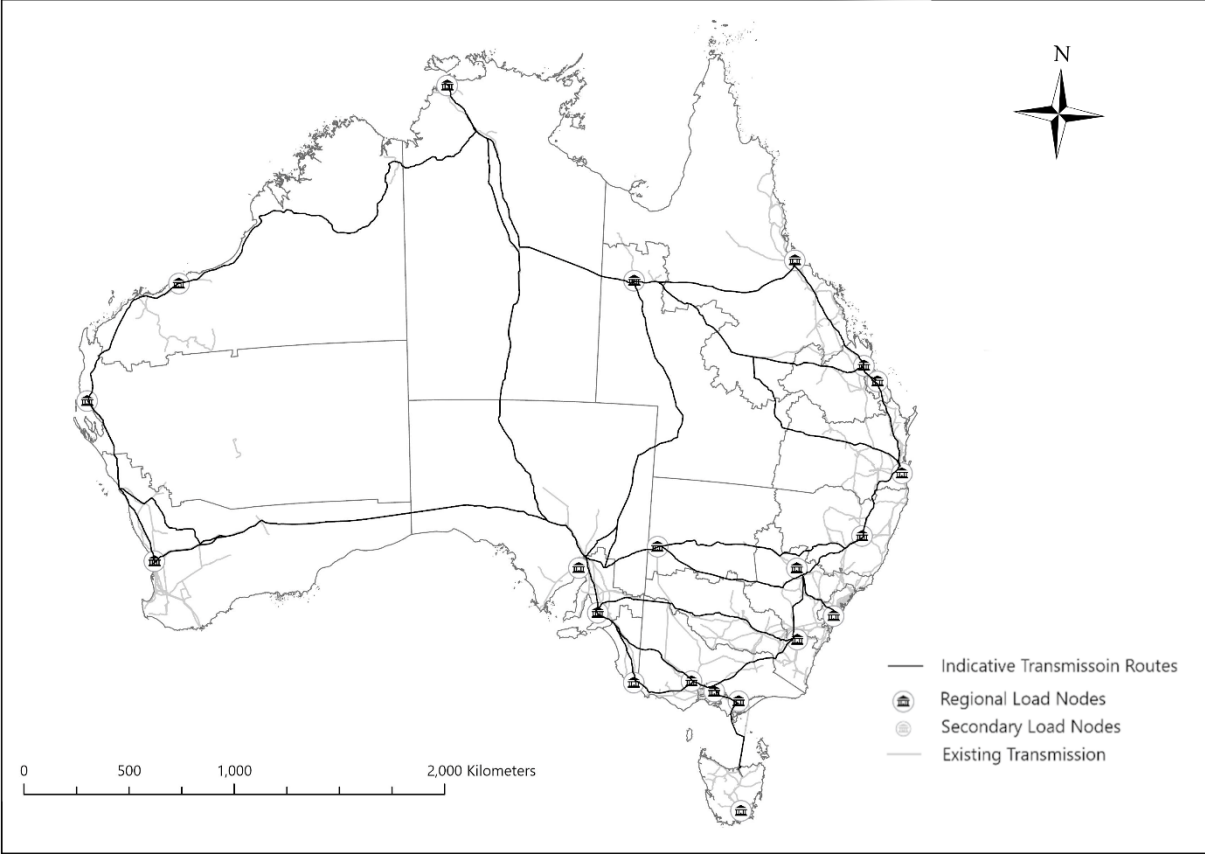
Variations of these multipliers will result in different transmission routes. This will be done in later stages of the NZAu Project, where any changes in the methods that are detailed in this document will be stated.

Table 66 | Multipliers that reflect technological, social, and environmental factors in transmission routing. High multipliers indicate more difficulty in the approval, construction, and maintenance of transmission lines. Buffer zones, if applicable, serve as protective measures surrounding designated areas.

Factor (buffer if applicable)	Multiplier
Extraction Sites (1000 m) ^[8]	100
Airports, landing grounds, helipads (1000 m) ^[9]	100
Defence prohibited ^[10]	100
Protected Area Database (1000 m) ^[11]	100
Inland Waterbodies, Salt Lakes, Wetlands ^[12, 13]	100
Irrigated Cropping, irrigated Pasture, Irrigated Sugar ^[13]	100
Existing transmission, pipeline, railroad, and conveyor corridors (500 m) ^[1, 14]	0.2
All other areas	1

Figure 79 below shows the indicative transmission corridors output by the Cost Path tool for interregional connections in domestic energy systems. These corridors have a width of 1 kilometre (500 meters on either side), allowing for the placement of multiple transmission lines with different easement widths.

Figure 79 | Indicative transmission routes for inter-regional transmission for the domestic energy system. Regional load nodes, secondary load nodes, and existing transmission^[1] are shown as references.



14.1.3 New transmission configuration and costs

The electricity transmission costs in this study come from the AEMO Transmission Cost Database^[5], which outlines costs for various voltages and capacities, as a part of the 2025 Electricity Network Options Report^[15]. Table 67 shows the capacity and base capital costs for different configurations. The projected increase in capital costs between 2025 and 2050 is primarily driven by higher labour and land costs. These costs are further adjusted using factors from the same database^[5]. Note that operating costs for the transmission lines are not included.

Table 67 | Representative transmission type, capacity, easement width and costs, and corresponding substation costs used in the modelling^[5-7].

Voltage (kV)	Circuits	Type	Capacity (MW) ¹	Easement width (m) ²	Line Cost (million 2025 AUD/ km) ³		New substation cost (million 2025 AUD) ^{3,4}	
					2025	2050	2025	2050
132	double	HVAC	268	50	1.8	2.3	35 (25)	43 (33)
275	single	HVAC	421	65	2.1	2.6	47 (35)	55 (42)
275	double	HVAC	921	65	2.6	3.3	68 (44)	77 (50)
330	single	HVAC	688	70	2.4	3.1	51 (35)	62 (45)
330	double	HVAC	1375	70	3.0	3.8	75 (44)	89 (56)
500	double	HVAC	3062	80	4.3	5.4	85 (51)	102 (65)
500	twin	HVDC	3000	60	2.4	3.1	1190 (1156)	1354 (1317)
500	twin	HVDC (subsea)	1500	-	5.8	6.5	1199 (1165)	1365 (1328)

1. Capacity is assumed to be half of the MVA rating.
2. The easement width from the AEMO Transmission Cost Database^[5] is more conservative than the guidelines from other sources, such as EnergySafe Victoria^[16].
3. Environmental offset costs are not included in our costing because our transmission planning methods feature biodiversity protection.
4. Costs in parentheses are for new sending substations without transformers.

All new inter-regional transmission lines are assumed to operate at 500 kV using HVAC or HVDC technology. HVDC is used for inter-regional lines longer than 700 km or for subsea cabling. Spur lines (i.e. from VRE project sites to terminal substations) of intra-regional or export transmission capacity are based on the VRE project's size. Electricity is then transmitted via double circuit 330 kV or 500 kV lines. The capacity of these bulk transmission lines exceeds that of individual VRE projects, with costs allocated accordingly^[17].

For intra-regional electricity transmission, three terminal substations are modelled at the VRE project sites, connection points to existing networks and load nodes, respectively. For inter-regional transmission or export systems, two substations are modelled at each end. In long-distance HVAC transmission, additional sending substations are modelled every 160 kilometres beyond the first 251 kilometres. A reactive power support plant, costing A\$63M^[5] is also included for all HVAC inter-regional transmission systems.

14.2 Gaseous fuels transmission

Transmission network infrastructure is currently operated in Australia for the transport of natural gas. This comprises high-pressure to progressively lower-pressure pipelines. Although currently not in place, hydrogen (H₂) and carbon dioxide (CO₂) transmission would share some similar features to those of natural gas.

Several studies have looked at the capital and operating costs of pipeline infrastructure, with a representative sample presented in Table 68. The NZAu Project investigated specific capital costs on an AUD/in-km basis (converted to 2025 currency) using the costs included in the studies highlighted by a star and shaded in Table 68 as the reference. A single, most relevant pipeline diameter for the transport of each one of the gases was

determined via a combination of literature review and expert consultation. Consistent with our electricity transmission assumptions, we've incorporated the same projected increases in real construction labour and land costs for the period 2025-2050. Values are reported in Table 69, alongside the specific pipeline capital cost (AUD/in-km), nominal throughput and normalised capital cost:

$$\text{Normalised capital cost} = \frac{\text{Specific capital cost} \cdot \text{Diameter}}{\text{Nominal throughput}}$$

The easement width for gas pipelines is set at 40 meters, providing 13.5 meters between pipeline centrelines when multiple pipelines are parallel. This was again based on expert advice.

Table 68 | Summary of the items included in the literature estimating the costs of building and operating transmission pipelines for natural gas, hydrogen and CO₂.

Gas	Reference	Materials	Labour/ Installation	Right Of Way	Other costs	Pump/ Compressor
Natural gas*	[18]	Y	Y	Y	Y	Y
Natural gas	[19]	Y	Y	Y	Y	Y
Natural gas	[20]	Y	Y	Y	Y	Y
Natural gas	[21]	Y	Y	Y	Y	N
Hydrogen*	[22]	Y	Y	Y	Y	Y
Hydrogen	[23]	Y	Y	Y	Y	Y
Hydrogen	[20]	Y	Y	Y	Y	Y
Hydrogen	[24]	Y	Y	Y	Y	N
Hydrogen	[25]	Y	Y	Y	Y	Y
Hydrogen	[26]	Y	Y	Y	Y	Y
CO ₂ *	[27]	Y	Y	Y	Y	Y

* Used as the main reference for costing of pipelines containing that gas.

Table 69 | Cost and technical characteristics of the transmission pipelines adopted for various gases.

Gas	Energy System	Capital cost [2025 AUD/in-km]		Diameter [in]	Throughput [TJ/d]*	Normalised capital cost [2025 AUD/MW-km]	Reference method
		2025	2050				
Natural gas	Domestic	76,221	89,482	24	274	577	[18]
Hydrogen	Export	129,928	140,386	48	1942	839	[22]
Hydrogen	Domestic	78,626	91,888	24	194	277	[22]
CO ₂	Domestic	170,499	203,318	20	10	0.34	[21]

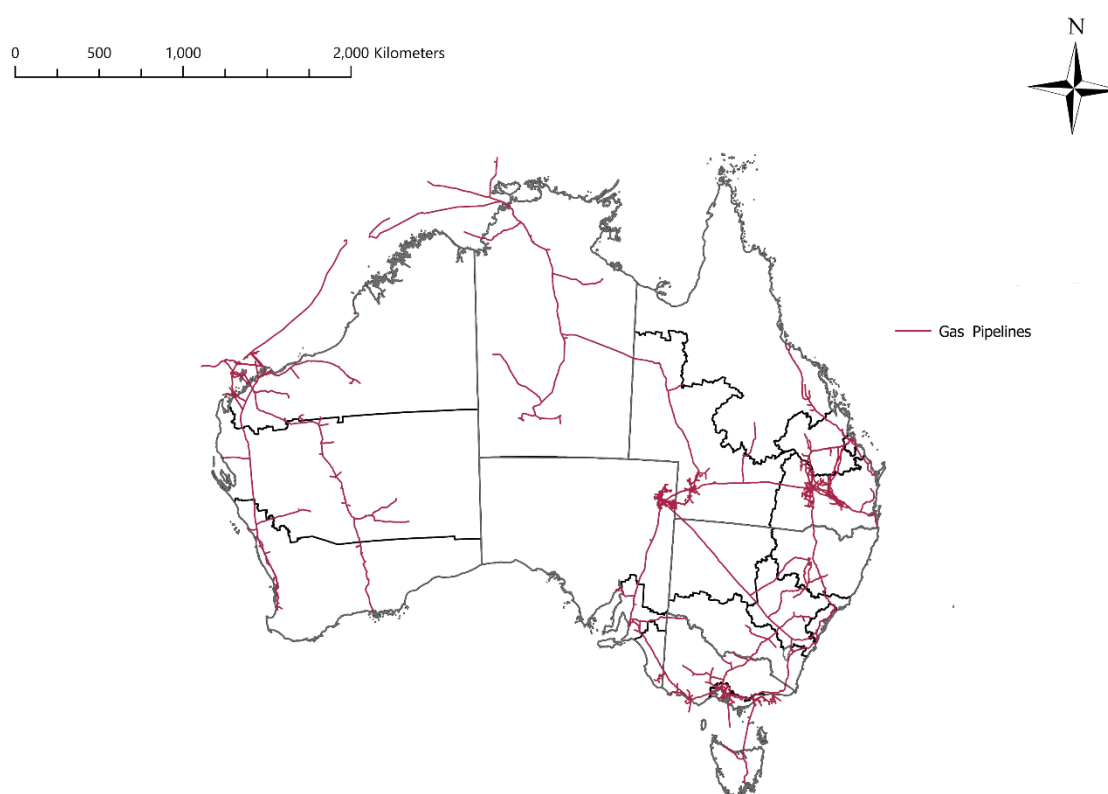
* For CO₂ pipelines, throughput is expressed in Mt/y and normalised capital cost in 2025 AUD/(t/y)-km.

14.2.1 Natural gas

Conventional natural gas in Eastern Australia is currently produced in the Otway, Bass and Cooper basins, while the production of the legacy fields from the Gippsland basin has continued to decline^[28]. Coal seam gas (CSG) is produced mainly in the Surat-Bowen basin. Conventional natural gas is also produced in the Carnarvon and Perth basins in Western Australia and the Bonaparte basin in the Northern Territory^[28].

The existing natural gas transmission network in Australia is shown in Figure 80^[29]. It mainly runs north to south and vice-versa, and there is no network connection between Western Australia and the rest of the country. Interconnected networks in the east coast, Tasmania, the Northern Territory, and Western Australia connect most gas-fuelled power generation assets. A few other pipelines connect extraction and specific points of use, particularly mines and some manufacturing activities.

Figure 80 | Current Australian natural gas transmission pipeline network^[29].



Modelling of existing natural gas transmission

In a coupled energy system with increasing interaction between the electricity and natural gas sectors, transmission bottlenecks can impact the capability to serve demand via different energy carriers. This has implications, including on reliability and hosting capacity, as well as other technical parameters^[30]. It is therefore important to provide a suitable representation of the evolving network infrastructure and its associated technical constraints.

A simplified version of the current Australian natural gas transmission network was modelled, which aggregates the existing pipeline capacity across the modelled NZAu regions^[31]. The dataset is based on the reported information from operators of the gas market or the related infrastructure and was post-processed to reflect inter-regional constraints on the gas transported (in TJ/day).

The aggregated transmission pipelines modelled, and their capacities, are presented in Table 70. This infrastructure constrains the natural gas flows both north-south and east-west on the east coast of Australia. Of note, there is no connection between WA, where some of the largest gas basins are located, and the east coast, where the largest demand hubs are.

Network augmentation is then allowed both as additional capacity to the existing network branches or as additional pipelines along the same corridors permitted for electricity transmission (see section 14.1 above).

Table 70 | Modelled capacities of current inter-regional natural gas transmission.

Start node	End node	Capacity [TJ/d]	Modelled pipeline
wa-north	wa-central	1047.5	Danpier-Bunbury + Goldfields
wa-central	wa-south	1047.5	Danpier-Bunbury + Goldfields
nt	qld-outback	90	Northern gas
qld-outback	sa-north	119	Carpentaria
qld-outback	qld-south	404	SouthWest Queensland
sa-north	sa-central	241	Moomba-Adelaide
sa-central	sa-south	314	SEA Gas
sa-south	vic-west	314	SEA Gas
vic-west	vic-mel	1030	Victorian transmission
vic-mel	vic-east	1030	Victorian transmission
vic-west	nsw-south	1388	Victorian transmission + Eastern gas
nsw-south	nsw-central	1388	Victorian transmission + Eastern gas
nsw-central	nsw-snw	847	Eastern gas + Moomba-Sydney
sa-north	nsw-outback	489	Moomba Sydney
nsw-outback	nsw-central	489	Moomba-Sydney
nsw-central	nsw-north	13	Central west
qld-outback	qld-north	6	Cheepie-Barcaldine
qld-south	qld-central	1588	Wallumbilla-Gladstone
qld-central	qld-gg	1588	Wallumbilla-Gladstone

Cost of natural gas transmission

Different costing approaches were applied to account separately for the costs of existing and new natural gas transmission.

Existing natural gas transmission costs

Current gas tariffs^[28] are used to estimate the cost to deliver final energy through existing natural gas transmission. For intra-regional transmission, we apply an additional cost of 0.7 AUD/GJ^[41]. For inter-regional transmission, costs were calculated as 1 AUD/GJ^[41] for existing infrastructure multiplied by the cost adjustment factor outlined below:

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

Implicit in this assumption is that future supply of natural gas to the eastern states via the existing transmission network will come solely from the Qld-outback node. While future supply may come online, such as potential LNG import terminals and new production sites in the eastern states, they are currently uncertain. The term on the denominator then represents the longest distance between two nodes connected by the transmission network, and thus this factor will vary between 0 and 1 in all cases.

New natural gas transmission costs

For new gas transmission that may be needed, the NZAu Project identified potential new routes connecting major load centres in adjacent regions using the least-cost path analysis and a routing surface adjusted with cost multipliers, as discussed in section 14.1.2 above.

The unit cost of natural gas transmission pipeline was determined from the literature and expert consultation for a diameter of 24" and is reported in Table 69. Table 71 shows the final values used to cost new inter-regional natural gas transmission using this unit cost and the distance between regional nodes. The computed capital cost outlined in Table 71 is annualised in RIO using a project life of 50 years and the WACC from Chapter 6. Operating costs are a function of the yearly pipeline throughput. Industry experts also estimated that operating costs, including both fixed and variable expenses, are 1.5% of the total capital cost.

Table 71 | Cost of new natural gas transmission network pipelines between domestic regions assuming shared electricity and natural gas transmission routes.

Region to region	Distance [km]	Pipeline capital cost [2025 AUD/(GJ/y)]		Pipeline operating cost [2025 AUD/GJ]	
		2025	2050	2025	2050
wa-south - wa-central	867	16	19	0.2	0.3
wa-south - sa-north	2229	41	48	0.6	0.7
wa-central - nt	3112	57	67	0.9	1.0
wa-central - wa-north	600	11	13	0.2	0.2
wa-central - sa-north	2997	55	64	0.8	1.0
wa-north - nt	2513	46	54	0.7	0.8
nt - sa-north	2583	47	55	0.7	0.8
nt - qld-north	2378	43	51	0.7	0.8
nt - qld-outback	1552	28	33	0.4	0.5
qld-central - qld-north	612	11	13	0.2	0.2
qld-central - qld-gg	97	2	2	0.0	0.0
qld-south - qld-central	536	10	12	0.1	0.2
qld-outback - qld-north	829	15	18	0.2	0.3
qld-outback - qld-central	1287	24	28	0.4	0.4
qld-outback - qld-south	1751	32	38	0.5	0.6
qld-outback - sa-north	1597	29	34	0.4	0.5
qld-outback - nsw-outback	1848	34	40	0.5	0.6
nsw-north - qld-south	430	8	9	0.1	0.1
nsw-north - nsw-outback	1091	20	23	0.3	0.4
nsw-central - nsw-north	433	8	9	0.1	0.1
nsw-central - nsw-south	328	6	7	0.1	0.1

Region to region	Distance [km]	Pipeline capital cost [2025 AUD/(GJ/y)]		Pipeline operating cost [2025 AUD/GJ]	
		2025	2050	2025	2050
nsw-central - nsw-snw	255	5	5	0.1	0.1
nsw-central - nsw-outback	775	14	17	0.2	0.2
vic-west - nsw-south	585	11	13	0.2	0.2
vic-west - vic-mel	101	2	2	0.0	0.0
vic-mel - vic-east	149	3	3	0.0	0.0
vic-west - sa-south	314	6	7	0.1	0.1
vic-west - sa-central	614	11	13	0.2	0.2
sa-central - nsw-south	1048	19	23	0.3	0.3
sa-central - sa-south	415	8	9	0.1	0.1
sa-central - sa-north	271	5	6	0.1	0.1
sa-north - nsw-outback	387	7	8	0.1	0.1
tas - vic-east	361	7	8	0.1	0.1

14.2.2 Hydrogen

No hydrogen pipeline network currently exists in Australia. Hydrogen blending in transmission lines has been suggested but never trialled at scale.

The modelling of new hydrogen transmission infrastructure follows the approach developed for electricity transmission as described in section 14.1.2. New hydrogen pipelines are permitted to connect the regional points of production to domestic demand nodes (for domestic use) and export hubs (for export). The GIS-based approach costs all pipeline options and selects projects that minimise costs while ensuring that demand is met.

Cost of hydrogen transmission

The cost of hydrogen transmission via pipeline is a function of several parameters, as with natural gas (see Table 68). Data was collated from several references reporting on different pipeline diameters (and associated pressures) and converted to 2025 AUD.

After consulting the literature and experts, hydrogen pipeline diameters of 48" and 24" were considered for the networks serving, respectively, the export and the domestic energy system. Note 24" coincides with the diameter suggested for natural gas domestic transmission pipelines.

The normalised capital cost computed for the considered pipeline diameters (see Table 69), together with GIS-based distances between NZAu regions, informed estimates of pipeline capital costs for specific routes. Table 72 shows cost estimates for inter-regional domestic transmission, and Table 73 shows cost estimates for pipelines that connect to export ports. These figures were then supplied as input to the modelling, again, using a 50 year project life and the WACC from Chapter 6 for domestic and export hydrogen pipelines, respectively. Industry experts again suggested that operating costs, including both fixed and variable expenses, were estimated at 1.5% of the total capital cost.

Table 72 | Cost of hydrogen transmission network pipelines between domestic regions assuming shared electricity and hydrogen transmission routes.

Region to region	Distance [km]	Pipeline capital cost [2025 AUD/(GJ/y)]		Pipeline operating cost [2025 AUD/GJ]	
		2025	2050	2025	2050
wa-south - wa-central	867	23	27	0.3	0.4
wa-south - sa-north	2229	59	69	0.9	1.0
wa-central - nt	3112	83	97	1.2	1.5
wa-central - wa-north	600	16	19	0.2	0.3
wa-central - sa-north	2997	80	93	1.2	1.4
wa-north - nt	2513	67	78	1.0	1.2
nt - sa-north	2583	69	80	1.0	1.2
nt - qld-north	2378	63	74	1.0	1.1
nt - qld-outback	1552	41	48	0.6	0.7
qld-central - qld-north	612	16	19	0.2	0.3
qld-central - qld-gg	97	3	3	0.0	0.0
qld-south - qld-central	536	14	17	0.2	0.3
qld-outback - qld-north	829	22	26	0.3	0.4
qld-outback - qld-central	1287	34	40	0.5	0.6
qld-outback - qld-south	1751	47	54	0.7	0.8
qld-outback - sa-north	1597	43	50	0.6	0.7
qld-outback - nsw-outback	1848	49	57	0.7	0.9
nsw-north - qld-south	430	11	13	0.2	0.2
nsw-north - nsw-outback	1091	29	34	0.4	0.5
nsw-central - nsw-north	433	12	13	0.2	0.2
nsw-central - nsw-south	328	9	10	0.1	0.2
nsw-central - nsw-snw	255	7	8	0.1	0.1
nsw-central - nsw-outback	775	21	24	0.3	0.4
vic-west - nsw-south	585	16	18	0.2	0.3
vic-west - vic-mel	101	3	3	0.0	0.0
vic-mel - vic-east	149	4	5	0.1	0.1
vic-west - sa-south	314	8	10	0.1	0.1
vic-west - sa-central	614	16	19	0.2	0.3
sa-central - nsw-south	1048	28	33	0.4	0.5
sa-central - sa-south	415	11	13	0.2	0.2
sa-central - sa-north	271	7	8	0.1	0.1
sa-north - nsw-outback	387	10	12	0.2	0.2
tas - vic-east	361	10	11	0.1	0.2

Table 73 | Cost of hydrogen transmission pipelines between hydrogen carrier export ports and hydrogen production domestic regions assuming shared electricity and hydrogen transmission routes.

Ports	Production nodes	State/territory	Pipeline capital cost [2025 AUD/(GJ/y)]		Pipeline operating cost [2025 AUD/GJ]	
			2025	2050	2025	2050
Port of Darwin	Darwin 1	NT	11	12	0.2	0.2
Port of Darwin	Darwin 2	NT	7	8	0.1	0.1
Port of Abbot Point	Abbot Point	Qld	5	6	0.1	0.1
Ashburton	Ashburton	WA	4	5	0.1	0.1
Port Hedland	Port Hedland	WA	4	4	0.1	0.1
Hay Point	Hay Point	Qld	6	6	0.1	0.1
Dampier	Dampier	WA	5	5	0.1	0.1
Newcastle	Newcastle	NSW	7	7	0.1	0.1
Port of Gladstone	Gladstone	Qld	8	9	0.1	0.1
Port Bonython	Port Adelaide	SA	2	2	0.0	0.0

14.2.3 Carbon dioxide

CO₂ may be transported from localised points of generation to storage/consumption in a supercritical state via transmission pipelines. This allows the use of relatively small pipes but requires keeping CO₂ at pressures above critical conditions (74 bar), and typically between 135 and 150 bar in practice^[32]. CO₂ pipeline transport has been used since the 1970s, mainly for enhanced oil recovery (EOR) in the US, Canada, China and other countries, so its costs are well-documented in these regions.

Cost of carbon dioxide transmission

Since Australia doesn't have large CO₂ pipelines, we adapted the National Energy Technology Laboratory's (NETL) transport cost model, assuming a pipeline capacity of 10 million tons of CO₂ per year. Pipeline diameters of 20" were considered for the CO₂ network. A normalised capital cost of 0.34 AUD/t-CO₂-y/km from NETL was used in this modelling, as reported in Table 69 together with other parameters for CO₂ pipelines. Operating costs were again estimated at 1.5% of the total capital cost as per expert recommendations. The cost calculation for CO₂ pipelines follows an analogous approach to hydrogen transmission and new natural gas transmission, with inter-regional CO₂ transport costs listed in Table 74 using a 50 year project life and the WACC from Chapter 6.

Table 74 | Cost of CO₂ transmission network pipelines between domestic regions assuming shared electricity and CO₂ transmission routes.

Region to region	Distance [km]	Pipeline capital cost [2025 AUD/(t-CO ₂ /y)]		Pipeline operating cost [2025 AUD/t-CO ₂]	
		2025	2050	2025	2050
wa-south - wa-central	867	295	355	4	5
wa-south - sa-north	2229	758	914	12	14
wa-central - nt	3112	1058	1276	16	19
wa-central - wa-north	600	204	246	3	4
wa-central - sa-north	2997	1019	1229	15	18
wa-north - nt	2513	854	1030	13	15
nt - sa-north	2583	878	1059	13	16
nt - qld-north	2378	808	975	12	15
nt - qld-outback	1552	528	636	8	10
qld-central - qld-north	612	208	251	3	4
qld-central - qld-gg	97	33	40	1	1
qld-south - qld-central	536	182	220	3	3
qld-outback - qld-north	829	282	340	4	5
qld-outback - qld-central	1287	437	528	7	8
qld-outback - qld-south	1751	595	718	9	11
qld-outback - sa-north	1597	543	655	8	10
qld-outback - nsw-outback	1848	628	758	9	11
nsw-north - qld-south	430	146	176	2	3
nsw-north - nsw-outback	1091	371	447	6	7
nsw-central - nsw-north	433	147	178	2	3
nsw-central - nsw-south	328	112	134	2	2
nsw-central - nsw-snw	255	87	104	1	2
nsw-central - nsw-outback	775	263	318	4	5
vic-west - nsw-south	585	199	240	3	4
vic-west - vic-mel	101	34	42	1	1
vic-mel - vic-east	149	51	61	1	1
vic-west - sa-south	314	107	129	2	2
vic-west - sa-central	614	209	252	3	4
sa-central - nsw-south	1048	356	430	5	6
sa-central - sa-south	415	141	170	2	3
sa-central - sa-north	271	92	111	1	2
sa-north - nsw-outback	387	132	159	2	2
tas - vic-east	361	123	148	2	2

14.3 Water transmission

Water transmission is modelled in the NZAu Project for transporting desalinated water from coastal locations and supplying it electrolysis plant and DAC plant inland. The NZAu Project investigates the capital cost of water pipelines on a \$/in/km basis. The capital cost is based on expert advice and includes pumping stations but not water treatment, which should be provided as part of the desalination process.

The design parameters of water pipelines are based on a series of expert consultations and a review of current Australian practices in water pipeline design (e.g. Southeast Queensland Water Grid, Fitzroy-Gladstone pipeline, etc.)^[33, 34]. The NZAu project chooses 12-inch water pipelines for domestic hydrogen production and 56-inch water pipelines for export hydrogen production. The easement for 12-inch water pipelines is set at 10 meters, and the easement for the 56-inch water pipeline is set at 20 meters. This is again based on expert advice and in accordance with guidelines from both Australia and abroad^[35-38]. The design parameters and costs are summarised in Table 75.

Table 75 | Cost and technical characteristics of the water transmission pipelines of different sizes^[33, 34].

Diameter [in]	Energy System	Capital cost [2025 AUD/in-km]		Throughput [GL/year]	Normalised capital cost [2025 AUD/tpa-km]	
		2025	2050		2025	2050
12	Domestic	169,943	201,844	7	0.30	0.36
56	Export	169,716	201,242	148	0.06	0.08

Similar to all forms of gas transmission, the capital cost of water transmission is annualised, assuming a project lifespan of 50 years and using the WACC from Chapter 6. The operating costs have been estimated at 1.5% of the total capital cost, in line with expert recommendations.

14.4 Electricity and natural gas distribution

The costs of electricity and natural gas distribution are incorporated into this modelling by examining the distribution network tariff component of current electricity and natural gas prices. As is typical for large-scale planning exercises such as the one undertaken by the NZAu Project, technical modelling of the distribution networks is not attempted. Furthermore, hydrogen blending was not allowed in natural gas distribution networks and distribution networks for hydrogen were not modelled.

14.4.1 Electricity distribution costs

To determine distribution costs we examine electricity network charges levied by Australia’s distribution network service providers (DNSP) and regulated by the Australian Energy Regulator (AER). These regulated costs are published by the AER^[39], with indicative costs for various tariff classes, including residential, small business, and limited large business coverage. These costs projected by DNSPs for FY 2024-25 are shown in Figure 81 by network cost component for residential and small business customers and for each NZAu state.

Figure 81 | Electricity network costs levied by Australia’s DNSPs on a) residential and b) small business costumers in FY 2024-25, by network cost component^[39].

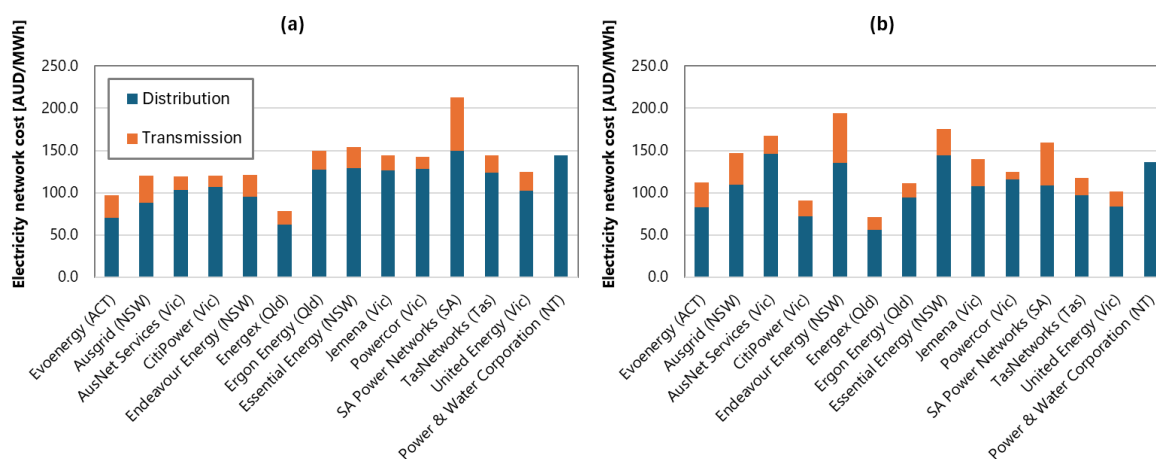


Figure 81 shows that distribution network costs exhibit significant variations across states, which is due both to local regulations and to different geographical features of the regions to serve (e.g. population density, terrain). We reflect these cost differences in the NZAu Project modelling by adopting a state-wide approach that reflects the current socialisation of distribution network costs and its split between the residential, commercial, industrial, and transport sectors.

The DNSPs data reported and presented in Figure 81 are only for residential and small businesses. The NZAu Project therefore uses the values in Figure 81 to determine electricity distribution network costs for the residential and commercial sectors. To do this, we assigned the state-averaged value of distribution network costs from the DNSPs active in each state (weighted by the respective energy consumption) to the residential or the commercial sectors in that state (Figure 81).

To estimate industrial and transport sector costs in FY 2024-25, we now refer to the Australian Energy Market Commission’s 2020 Residential Electricity Price Trends Report^[40] that breaks down distribution network costs by sector:

- Residential: 106 AUD/MWh
- Industrial: 48 AUD/MWh

- Transport: 86 AUD/MWh

We then use the proportions of these 3 sectors costs and the 2024-25 residential costs estimated from Figure 81, to estimate electricity distribution network costs by state and by sector for 2024-25. The final values are reported in Table 76 and adopted as model inputs. National average values (weighted by consumption) were used for distribution networks in WA since WA-specific data were not reported. The cost of distribution networks for the commercial sector in Figure 11 are the state averages obtained from Figure 81b.

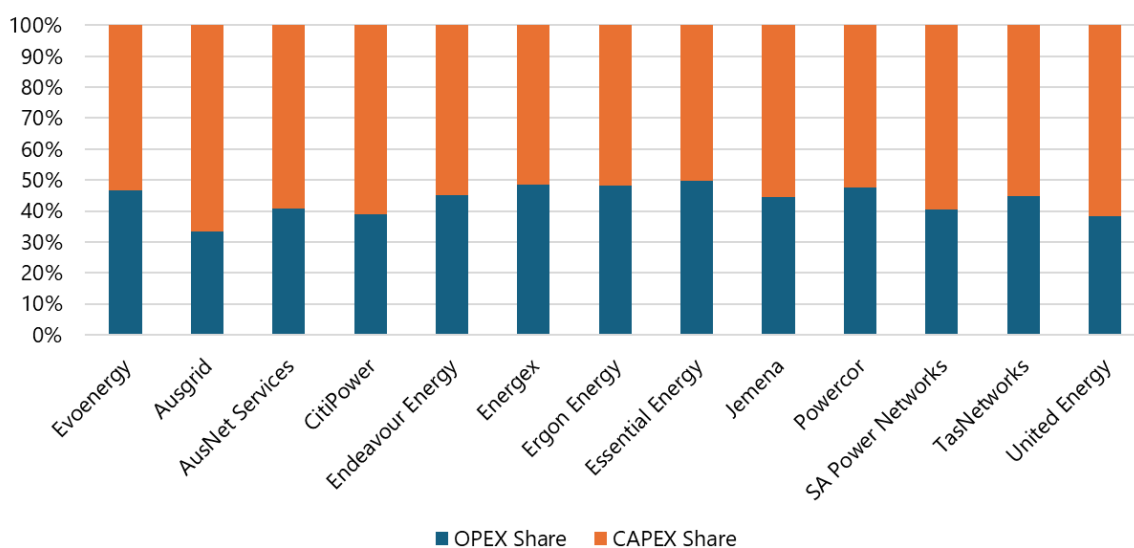
We note that industrial and transport distribution network costs are lower than residential since there is less infrastructure needed to supply more localised, higher voltage loads. These loads are typically not served by the low voltage (LV) lines that serve homes. We also note that 'transport' in this sense is electrically powered public transport such as trams and trains rather than on-road electric vehicles. Distribution network costs for the charging of on-road electric vehicles associated with homes and businesses is covered in these specific costs.

Table 76 | Electricity distribution network costs (2025 AUD) and their fixed and variable share by state and sector.

State	Residential [AUD/MWh]	Commercial [AUD/MWh]	Industry [AUD/MWh]	Transport [AUD/MWh]	Fixed share of costs [%]	Variable share of cost [%]
Vic	113.28	101.50	51.18	92.30	43	57
Tas	123.86	96.97	55.96	100.91		
NSW	98.34	129.04	44.43	80.12		
SA	149.51	108.74	67.55	121.81		
Qld	77.77	68.97	35.14	63.36		
WA	144.42	136.53	65.25	117.67		
NT	103.52	105.59	46.77	84.34		

We then need to estimate how these network costs are expected to evolve in the future. It is expected that the cost of building, maintaining and operating the network infrastructure to supply end users changes with both electricity demand and capacity requirements. This was captured in the NZAu Project by assuming operational costs remain fixed at the values for the first modelled year, while capital costs scale proportionally to the peak yearly capacity. The share of operational costs to variable cost items was retrieved from the average 2023 values reported by DNSPs in the NEM^[39]. The NEM-averaged values from Figure 82 were then assumed to reflect the share of fixed and variable electricity distribution network costs across all states and territories (Figure 11).

Figure 82 | CAPEX and OPEX share of total annual distribution network cost for FY 2023.



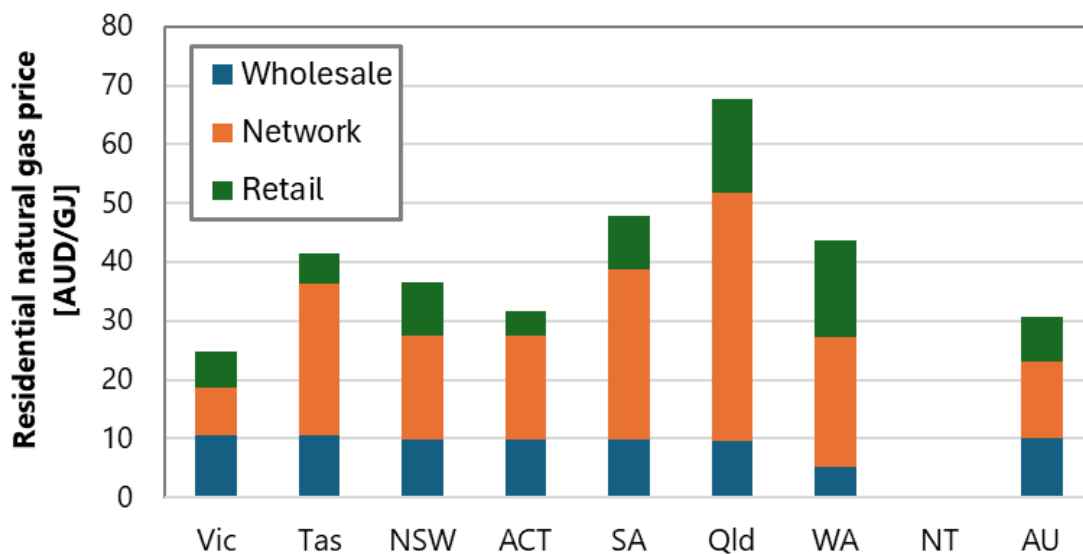
14.4.2 Natural gas distribution costs

The composition of retail gas bills is less straightforward to analyse than that for electricity. For example, the gas default market offer (DMO) data is only reported by providers across Queensland, NSW and South Australia. Given this situation, the most up to date and comprehensive account of the breakdown of gas bills across the nation appears to be a 2017 report from Oakley Greenwood^[41], which presents natural gas network costs broken down by state.

Figure 83 presents Oakley Greenwood’s average residential natural gas price by state converted to 2025 dollars from their reported values for FY 2017. 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. We use these state-based, average distribution network costs in the model, with Australian-average values used for NT for which data were not reported.

These figures are reflective of the cost of natural gas distribution to residential customers. As per the electricity distribution network, different infrastructure is needed to supply gas consumers from different sectors, which results in different, sector-specific costs for end-users. Oakley Greenwood^[41] reports a national average of 1.5 AUD/GJ, 7 AUD/GJ and 13.6 AUD/GJ for the gas distribution network costs of a large industry, a small industry and a residential consumer, respectively. Similar to the methods presented for electricity (Section 14.4.1), we used these proportions to scale residential gas distribution network to other sectors, assuming that small industry is representative of the commercial sector and large industry of the industrial sector. This gives the costs reported in Table 77.

Figure 83 | Average residential natural gas prices (2025 AUD), by region and bill component. Values have been converted from FY 2017-18^[41].



We project the yearly operational and capital costs of the gas distribution network based on the fixed and variable costs in the first modelled year, based again on a share of these two cost components from Oakley Greenwood’s figures^[41] (see Table 77). We assume operational costs to be fixed, and scale capital costs over the years proportionally to the network throughput.

Table 77 | Natural gas distribution network costs (2025 AUD) and their fixed and variable share by state and sector.

State	Residential [AUD/GJ]	Commercial [AUD/GJ]	Industry [AUD/GJ]	Fixed share of costs [%]	Variable share of cost [%]
Vic	8.14	4.19	0.90		
Tas	25.81	13.28	2.85		
NSW	17.66	9.09	1.95		
SA	28.87	14.86	3.18	23	77
Qld	42.31	21.78	4.67		
WA	22.00	11.32	2.43		
NT	13.01	6.70	1.43		

14.5 Energy transmission and distribution cost allocation

14.5.1 Transmission cost allocation

New build transmission costs are allocated proportionally between end users based on their final energy use. Starting costs for existing transmission within each zone is based on existing tariffs by state and such costs are scaled based on load growth with costs allocated based on final energy use.

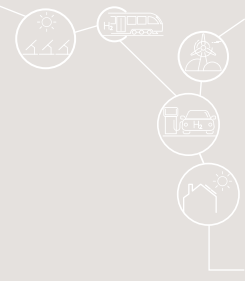
14.5.2 Distribution cost allocation

The energy distribution costs by state derived in the section above were also attributed to sectors based on their final energy use. Fuel production industries, including refineries, LNG processing, electrolysis, Fischer-Tropsch, and biofuels are all considered upstream of distribution networks, as were specific heavy industries (H2 DRI/ESF, bauxite refining; and aluminium smelting/casting). As such, these loads incur transmission but not distribution related charges.

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15 Demand-side capital and operating costs

This Chapter presents the capital and operating cost assumptions for energy consuming technologies in the industrial, residential, and transport sectors of the energy system modelled in the NZAu Project. It includes the following sections:

- 15.1 Industrial sector
- 15.2 Direct air capture
- 15.3 Residential demand-side technologies
- 15.4 Road transport

15.1 Industrial sector

Costs attributed to the industrial sector stem from capital expenses for technology purchase, installation and upgrade, and fixed and variable operation and maintenance. These are complemented by the cost of purchasing energy to sustain the processes.

The NZAu project adopted a granular, process-by-process, technological representation of the iron and steel, cement, and aluminium industry subsectors. Altogether, these industries are responsible for almost half of the energy consumption^[1], and over 50% of the direct GHG emissions from Australian manufacturing^[2]. Alongside existing plants, several options to transform raw materials into intermediate products of these three supply chains were considered. These options include process integration and upgrade and can be selected by RIO to supply the projected demand for these three commodities for the least system cost. The costs, as well as conversion efficiencies associated with these options, are described in the following.

For other industrial subsectors, the aggregate sum of cost contributions for energy efficiency and fuel switching was incorporated in the EP model. These data were obtained from several speciality reports and journal articles, and are described in Chapter 10.

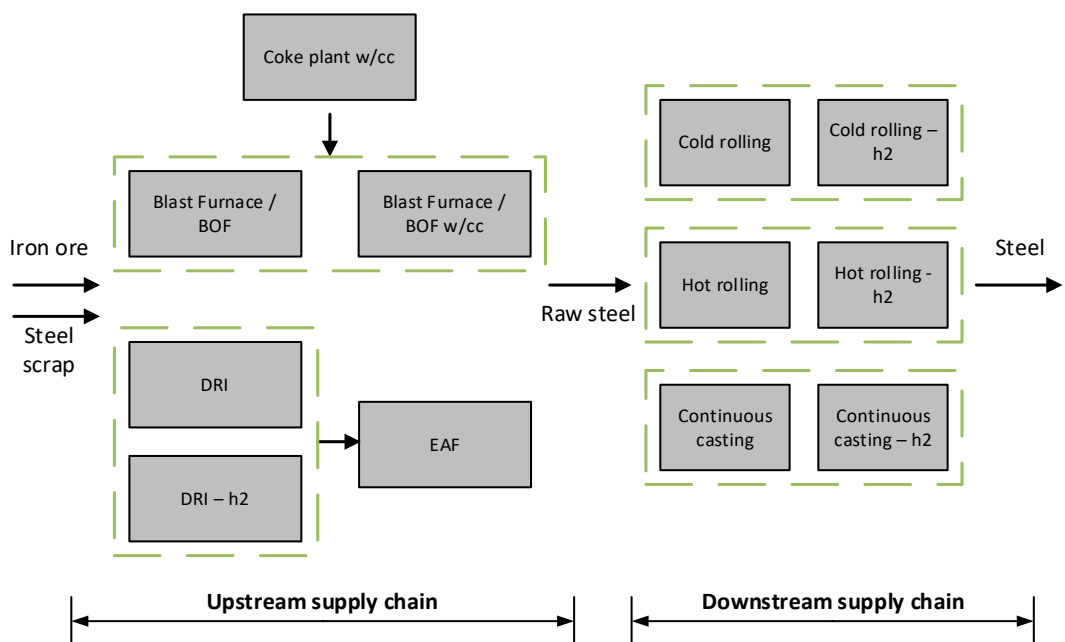
15.1.1 Iron and steel

The NZAu project models the following steps within the iron and steel supply chain:

1. upstream iron ore refining to raw steel;
2. downstream raw steel rolling; and
3. downstream raw steel casting.

The pathways modelled for each of these steps are presented in Figure 84. Steelmaking involves the initial smelting of iron ore to produce metallic iron, followed by its conversion to steel by removing excess carbon and adding various alloys in a basic oxygen furnace (BOF). Depending on the grade of the ores, direct reduction to pig iron and a downstream electric arc furnace (EAF) offers an alternative pathway. In the downstream supply chain, the NZAu project considers hot and cold rolling, as well as continuous casting as the manufacturing processes of interest.

Figure 84 | The processes modelled for each step of the iron & steel supply chain. Each block within dashed lines represents an alternative option.



Primary production of steel via the blast furnace (BF)/BOF pathway sees iron ore and coke fed into the top of a blast furnace 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 CO₂. Alternative methods of steel production include direct reduced iron (DRI) to produce pig iron, and then coupled with an Electric Arc Furnace (EAF) to produce raw steel. The DRI feedstock is primarily iron ore, but it can accept steel scrap. Conventionally, it mostly consumes natural gas as the reductant. Among clean iron and steel processes, the NZAu project considered both hydrogen-fuelled DRI (outlined in Net Zero America^[4]) and BF/BOF plants implementing carbon capture retrofits. In the downstream supply chain, raw steel can undergo hot/cold rolling and continuous casting where hydrogen substitutes natural gas for thermal energy supply.

Current processing facilities in Australia

Current domestic production of steel in 2022 was about 5.6 Mt^[5], mainly from BlueScope Steel plant (~3.2 Mt) in Port Kembla, NSW, and Liberty Primary Steel plant at Whyalla, SA, (~1.25 Mt). Both steelworks use traditional BF/BOF methods to produce steel. Coke and pulverised black coal are used as reductants and only small amounts of scrap are used. Both plants were included in the supply-side processes, with their rated processing capacity.

Costs and performance of iron and steel processing

Costs are reported in Table 79. Fixed O&M costs at 3% of CapEx were used. DRI/EAF costs are based on projections from recent DRI projects in the US.

Table 78 reports the conversion efficiency used to model the processing of iron ore into a steel product.

Costs are reported in Table 79. Fixed O&M costs at 3% of CapEx were used. DRI/EAF costs are based on projections from recent DRI projects in the US.

Table 78 | Material and energy inputs to the alternative processes considered for each step of the iron and steel supply chain per unit material output produced in each process (see Figure 84).

Technology	Input	Value	Units	Notes	Reference
Upstream supply-chain					
Coke plant w/cc	Coking coal	1.7	MJ/MJ	Based on HHV of coke output	[6]
Coke plant w/cc	Electricity	0.1	MJ/MJ	Based on HHV of coke output	[6]
Coke plant w/cc	Natural gas	0.0	MJ/MJ	Based on HHV of coke output	[6]
Coke plant w/cc	Fuel oil	-0.2*	MJ/MJ	Based on HHV of coke output	[6]
Coke plant w/cc	Steam	0.4	MJ/MJ	Based on HHV of coke output	[6]
Coke plant w/cc	Captured CO2	0.0	t/MJ		[6]
BF/BOF	Coal	1.0	GJ/t		[6]
BF/BOF	Coke	7.1	GJ/t		[6]
BF/BOF	Electricity	0.9	GJ/t		[6]
BF/BOF	Fuel oil	0.1	GJ/t		[6]
BF/BOF	Natural gas	1.3	GJ/t		[6]
BF/BOF	Cold rolling steel †	0.5	t/t		[6]
BF/BOF	Continuous casting steel †	0.9	t/t		[6]
BF/BOF	Hot rolling steel †	1.0	t/t		[6]
BF/BOF	Iron ore	1.6	t/t		[6]
BF/BOF w/cc	Coal	1.0	GJ/t		[6]
BF/BOF w/cc	Coke	7.1	GJ/t		[6]
BF/BOF w/cc	Electricity	0.9	GJ/t		[6]
BF/BOF w/cc	Fuel oil	0.1	GJ/t		[6]
BF/BOF w/cc	Natural gas	1.3	GJ/t		[6]
BF/BOF w/cc	Steam	3.0	GJ/t		[6]
BF/BOF w/cc	Captured CO2	-0.8*	t/t		[6]
BF/BOF w/cc	Cold rolling steel †	0.5	t/t		[6]
BF/BOF w/cc	Continuous casting steel †	0.9	t/t		[6]
BF/BOF w/cc	Hot rolling steel †	1.0	t/t		[6]
BF/BOF w/cc	Iron ore	1.0	t/t		[6]
DRI	Electricity	0.3	GJ/t		[7]
DRI	Natural gas	7.4	GJ/t		[7]
DRI	Iron ore	1.6	t/t		[7]
DRI - H ₂	Electricity	0.3	GJ/t		[7]
DRI - H ₂	Hydrogen	7.8	GJ/t		[7]
DRI - H ₂	Natural gas	1.7	GJ/t		[7]
DRI - H ₂	Iron ore	1.6	t/t		[7]
EHF	Electricity	1.9	GJ/t		[7]
EHF	EHF charge	1.1	t/t		[7]
EHF	Cold rolling	0.5	t/t		[7]
EHF	Continuous casting	0.9	t/t		[7]
EHF	Hot rolling	1.0	t/t		[7]
Downstream supply chain					
Cold rolling	Electricity	1.5	GJ/t		[6]
Cold rolling	Fuel oil	1.4	GJ/t		[6]
Cold rolling	Natural gas	1.8	GJ/t		[6]
Cold rolling - H ₂	Electricity	1.5	GJ/t		[6]
Cold rolling - H ₂	Hydrogen	3.2	GJ/t		[6]

Technology	Input	Value	Units	Notes	Reference
Hot rolling	Electricity	0.9	GJ/t		[6]
Hot rolling	Fuel oil	0.1	GJ/t		[6]
Hot rolling	Natural gas	2.1	GJ/t		[6]
Hot rolling - H ₂	Electricity	0.9	GJ/t		[6]
Hot rolling - H ₂	Hydrogen	2.1	GJ/t		[6]
Continuous casting	Electricity	0.1	GJ/t		[6]
Continuous casting	Natural gas	0.6	GJ/t		[6]
Continuous casting - H ₂	Electricity	0.1	GJ/t		[6]
Continuous casting - H ₂	Hydrogen	0.5	GJ/t		[6]

* Negative values represent output streams from the plant

† These inputs represent a recycled steel stream. Values have the units: tonnes of recycled steel per tonne of row steel produced

Table 79 | Capital, fixed and variable O&M costs of the alternative processes considered for each step of the iron and steel supply chain per unit of the respective material output produced.

Technology	Capital cost	Fixed O&M	Notes	Reference
Upstream supply-chain	2025 AUD/t-y	2025 AUD/t-y		
Coke plant w/cc	1740	57.3	Costs for coke plant w/cc are reported as 2025 AUD \$/kW based on the HHV of coke output	
BF/BOF	2333	294.4		[6]
BF/BOF w/cc	2540	316.3		[6, 8]
DRI	461	81.9		[9]
EAF	1138	84.0		[9]
H2 DRI	461	81.9		[9]
Downstream supply-chain	2025 AUD/t-y	2025 AUD/t-y		
Cold rolling	942	2.2		[6]
Cold rolling – H ₂	942	2.2		[6]
Hot rolling	407	2.2		[6]
Hot rolling – H ₂	407	2.2		[6]
Continuous casting	942	0.0		[6]
Continuous casting - H ₂	942	0.0		[6]

15.1.2 Cement

Cement is a binder material and a key ingredient in concrete which in turn has a core role in building and maintaining the infrastructure underpinning nearly all sectors of the Australian economy. Cement is manufactured by grinding clinker, an intermediate product formed by heating limestone and clay at high temperatures in kilns, with gypsum and other additives. Manufacturing clinker has a high emissions intensity.

Australia's demand for cement was 10.2 Mtpa in 2020-21, the latest information available^[10]. 0.9 Mtpa was imported as cement, 4.0 Mtpa was imported as clinker and 5.3 Mtpa of clinker was produced in Australia.

Current clinker processing facilities in Australia

Table 80 provides a summary of the existing clinker processing facilities in Australia, including plant location and clinker production capacity. With the existing fleet, Australia could produce up to ~6.4 Mtpa of clinker.

Table 80 | Integrated clinker and cement production plants.

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
Waurm Ponds	Boral	VIC-west	1970	2013	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-gg	1998		Coal	1.6
Rockhampton	Cement Australia Pty Ltd	QLD-gg	1960	2009	Coal	0.14

Table notes:

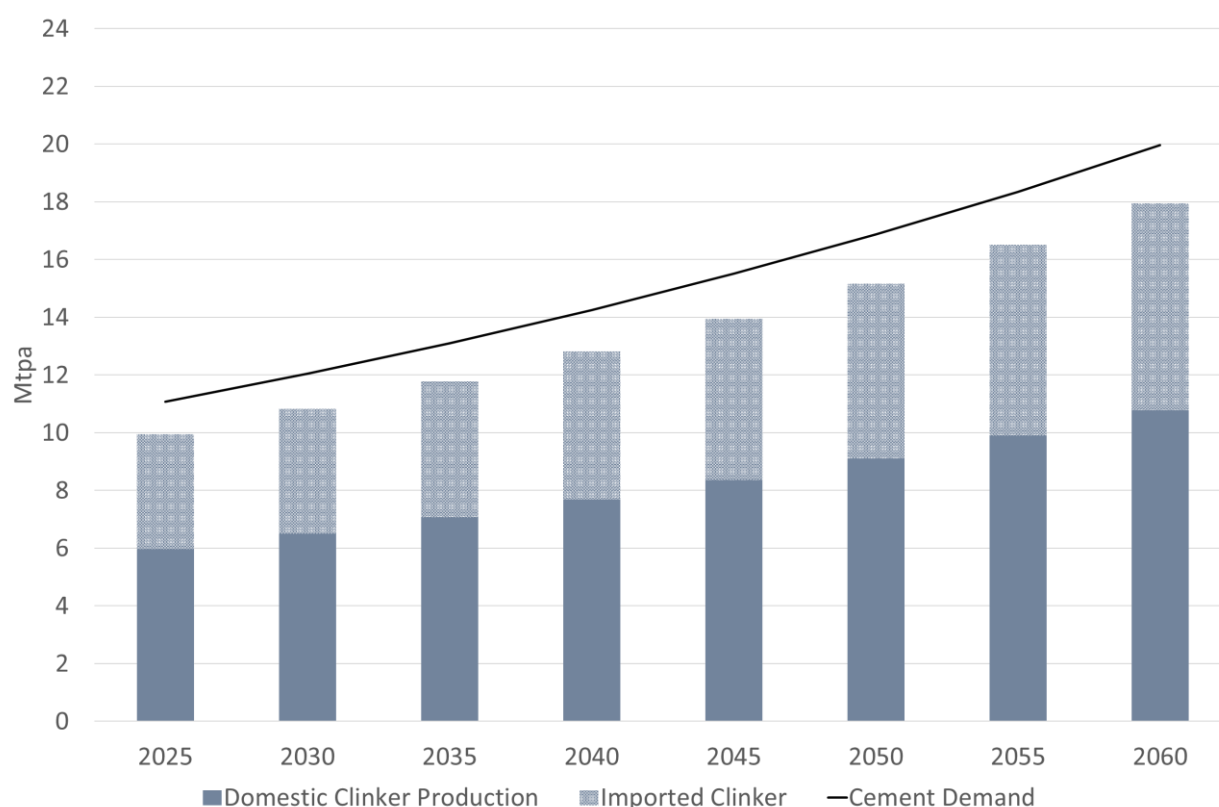
1. There are five integrated manufacturing facilities in Australia operated by CIF member companies – Adelaide Brighton (ADBRI), Boral Cement and Cement Australia.
2. Closed facilities are not included in the RIO model but are listed as potential brown field sites for expansion under downscaling.

Production projections

In Australia ~81% of clinker production is fuelled by coal and gas. The rest is produced using alternative fuels such as wood waste, solvents, used oil, spent pot liner and carbon powders^[10]. Clinker has a total emissions intensity of 791 kg-CO₂/t-clinker^[12]. 55% of this is process emissions (CO₂ released from calcination of limestone), 26% is associated with heat provision, 12% from electricity and 7% from transportation of materials^[12]. Various decarbonisation methods comprising cleaner fuels, improvement of process efficiency and increasing the use of supplementary cementitious materials are currently discussed in decarbonisation roadmaps^[13]. 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 at 40% imported. The required growth in production capacity was estimated using a growth rate of 1.7% between 2025-2050. This was based on the decadal average from 2010-2020^[11]. Figure 85 shows the corresponding projection of cement demand up to 2050.

Figure 85 | Projection of production and import of clinker, together with cement demand.



Costs and performance of cement processing

Following the same approach used to treat the iron and steel and aluminium sectors, several clean technologies are considered by the NZAu project in the cement sector. These include different technical implementations of carbon capture to the process and the use of alternative, low-emissions fuels to supply heat for heat provision. Technology selection to meet clinker/cement demand is determined by RIO based on the relative energy conversion efficiency, process emissions and cost.

Table 81 reports the conversion efficiency used to model the production of clinker. Figures are presented per unit of clinker produced and heat input to the cement kiln can either be provided by biomass, coal, hydrogen, natural gas or municipal solid waste. Costs are reported in Table 82.

Table 81 | Material and energy inputs to the alternative processes considered to produce clinker.

Technology	Input	Value	Units	Reference
Clinker production				
Conventional	Electricity	88	kWh/t	[7]
Conventional	Heat	2.8	GJ/t	[7]
Conventional	Process emissions	0.52	t/t	[7]
Direct separation CCS	Electricity	941	kWh/t	[7]
Direct separation CCS	Heat	1.17	GJ/t	[7]
Direct separation CCS	Process emissions	0.52	t/t	[7]
Direct separation CCS	Captured CO2	-0.46*	t/t	[7]
Oxyfuel biomass CCS	Electricity	278	kWh/t	[7]
Oxyfuel biomass CCS	Biomass	3.5	GJ/t	[7]
Oxyfuel biomass CCS	Process emissions	0.52	t/t	[7]
Oxyfuel biomass CCS	Captured CO2	-0.78*	GJ/t	[7]
Oxyfuel gas CCS	Electricity	257	kWh/t	[7]

Technology	Input	Value	Units	Reference
Oxyfuel gas CCS	Natural gas	3.5	GJ/t	[7]
Oxyfuel gas CCS	Process emissions	0.52	t/t	[7]
Oxyfuel gas CCS	Captured CO2	-0.62*	t/t	[7]

* Negative values represent output streams from the plant

Table 82 | Capital and fixed O&M costs of the alternative processes considered for clinker production per unit output capacity.

Technology	Capital cost	Fixed O&M	Reference
	2025 AUD/t-y	2025 AUD/t-y	
Clinker production			
Conventional	725	41.8	[7]
Direct separation CCS	786	46.0	[7]
Direct separation CCS - retrofit	314	46.0	[7]
Oxyfuel biomass CCS	910	52.3	[7]
Oxyfuel gas CCS	910	52.3	[7]

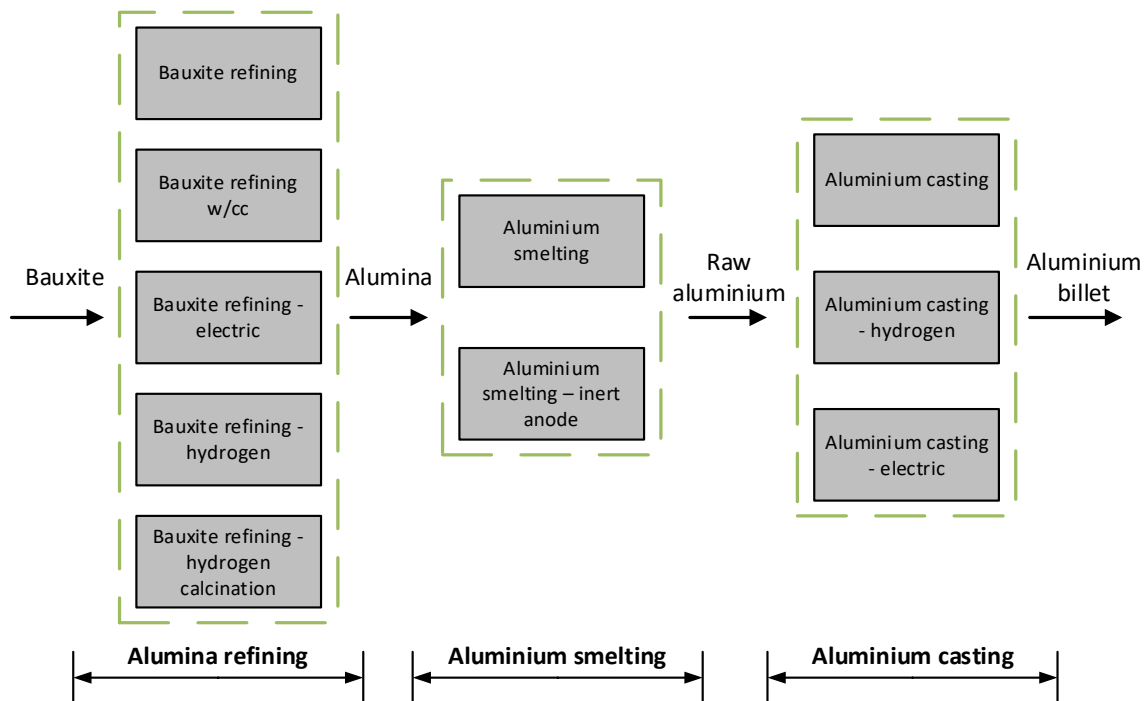
15.1.3 Aluminium

The NZAu project models the following steps within the aluminium supply chain:

1. bauxite refining to alumina;
2. alumina smelting to raw aluminium; and
3. its downstream casting into aluminium billets.

The pathways modelled for each of these steps are presented in Figure 86. Except for currently operating facilities which were modelled as traditional *'Bauxite refining'* and *'Aluminium smelting'* processes, any of these options can be selected by RIO to satisfy the projected demand for final and intermediate aluminium products. Each option has different energy needs, associated direct and indirect emissions, as well as costs.

Figure 86 | The processes modelled for each step of the aluminium supply chain. Each block within dashed lines represents an alternative option.



Traditional *'Bauxite refining'* in this modelling is based on the Bayer process^[15]. This involves the selective digestion of aluminium oxide from bauxite into a caustic solution of water and NaOH for the separation of impurities as red mud. The hydrated alumina is then calcinated to alumina. The energy consumption of Bayer refineries is mostly driven by process heat supply for: 1) low/medium temperature digestion and 2) high-temperature calcination, and averages around 14 GJ/t of produced alumina^[16]. Besides process retrofit with downstream carbon capture, the options for alumina refining entail the provision of different portions of this process heat via cleaner options. Fully electric and clean hydrogen-fuelled processes have been considered, alongside a hybrid process where electricity supplies low/medium temperature steam to digestion and hydrogen supplies calcination. These are at different levels of trialling and demonstration in the industry^[17-19]. Traditional *'Aluminium smelting'* uses the Hall-Héroult process and is more energy-intensive, with an average consumption of around 14-16 MWh of electricity per tonne of aluminium; a minor contribution comes from the combustion of natural gas to bake carbon anodes, and the subsequent oxidation of the anodes during smelting^[20]. Hence, clean smelting can be achieved with a zero-emission supply mix and inert anodes. Fuel switching to hydrogen or electrification of the process were considered to contain emissions from melting aluminium in the casting process.

Current processing facilities in Australia

Australia is a large producer and exporter of aluminium and its precursors. The country's bauxite resources – mainly in WA – provide the raw material to support a robust refining industry. In 2023, 19.5 Mt of alumina were refined from bauxite domestically, 15.9 Mt of which were exported, with Australia ranking as the second alumina exporter globally^[21]. Smelting then reduces alumina to aluminium via electrolysis. With 1.55 Mt of aluminium produced onshore, mostly (90%, or more) for export purposes, Australia was the seventh global producer in 2023^[21].

Table 83 summarises the existing bauxite refineries and aluminium smelting facilities in Australia, which were individually included in the modelling. The 2.2 Mt/y Kwinana alumina refinery in Western Australia was Alcoa's first, and was fully curtailed in 2024^[22] so it was not modelled. Aluminium casting is then operated at much smaller scales and distributed across NZAu regions.

Table 83 | Features of the operating alumina and aluminium processing facilities in Australia and modelled in the NZAu project.

Facility	NZAu region	Nameplate capacity [kt/y]	Product	Operating since
Alumina refineries		19,200		
Pinjarra	WA-south	4,700	Alumina	1972
Wagerup	WA-south	2,900	Alumina	1984
Worsley	WA-south	4,600	Alumina	1984
Yarwun	QLD-gg	3,200	Alumina	2004
QAL	QLD-gg	3,800	Alumina	1967
Aluminium smelters		1,638		
Boyne	QLD-gg	500	Aluminium	1982
Tomago	NSW-snw	590	Aluminium	1983
Portland	VIC-west	358	Aluminium	1986
Bell bay	TAS	190	Aluminium	1955

Costs and performance of aluminium processing

Table 84 reports the conversion efficiency used to model the processing of bauxite into an aluminium billet, as sourced from the regional inventory data from the International Aluminium Institute for Oceania^[24]. Bauxite refining uses the Bayer process and comprises mainly of digestion and calcination. Coal and natural gas provide the steam that supplies digestion and the heat for calcination in bauxite refining. These represent, respectively, about 59% and 41% of the total process heat demand^[25]. Potential fuel switching for their provision assumed a 99% efficient electric heating^[27], and 94% efficient boilers/furnaces^[26], both fossil fuels- and hydrogen-fired. Smelting requires mainly electricity as input, plus inert anodes for zero-emission operations, while the substitution of natural gas furnaces currently used for aluminium casting has been considered. For bauxite refining with downstream carbon capture, a required extra heat load of 3 GJ per tonne of CO₂ was considered, as reported for amine technology^[28] and all supplied by natural gas.

Table 84 | Material and energy inputs to the processes considered for each step of the aluminium supply chain per unit aluminium billet.

Technology	Input	Value	Units	Notes
Alumina refineries				
Bauxite refining	Bauxite	5.3	t	
Bauxite refining	Electricity	174.9	kWh	
Bauxite refining	Natural gas	13209.7	MJ	
Bauxite refining	Coal	6387.4	MJ	
Bauxite refining	Diesel	49.2	MJ	
Bauxite refining w/cc	Bauxite	5.3	t	
Bauxite refining w/cc	Electricity	174.9	kWh	
Bauxite refining w/cc	Natural gas	16942.3	MJ	
Bauxite refining w/cc	Diesel blend	49.2	MJ	
Bauxite refining w/cc	Captured CO ₂	1.2	t	
Bauxite refining - el	Bauxite	5.3	t	
Bauxite refining - el	Electricity	5357.3	kWh	99% efficient electric heating
Bauxite refining - H ₂	Bauxite	5.3	t	
Bauxite refining - H ₂	Electricity	188.6	kWh	
Bauxite refining - H ₂	Hydrogen	19597.1	MJ	
Bauxite refining - H ₂ calc	Bauxite	5.3	t	

Technology	Input	Value	Units	Notes
Bauxite refining - H ₂ calc	Electricity	3238.1	kWh	Digestion: 59% gas & coal use
Bauxite refining - H ₂ calc	Hydrogen	8034.8	MJ	Calcination: 41% gas & coal use
Aluminium smelters*				
Aluminium smelting	Alumina	1.9	t	
Aluminium smelting	Electricity	14540.4	kWh	
Aluminium smelting	Natural gas	1121.5	MJ	
Aluminium smelting	Diesel	299.6	MJ	
Aluminium casting facilities				
Aluminium casting	Raw aluminium	1.0	t	
Aluminium casting	Electricity	83.6	kWh	
Aluminium casting	Natural gas	486.0	MJ	
Aluminium casting	Diesel blend	121.0	MJ	
Aluminium casting – H ₂	Raw aluminium	1.0	t	
Aluminium casting – H ₂	Electricity	117.2	kWh	
Aluminium casting – H ₂	Hydrogen	486.0	MJ	
Aluminium casting - el	Raw aluminium	1.0	t	
Aluminium casting - el	Electricity	245.4	kWh	99% efficient electric heating

* Values equally apply to traditional aluminium smelters and smelters adopting inert anodes

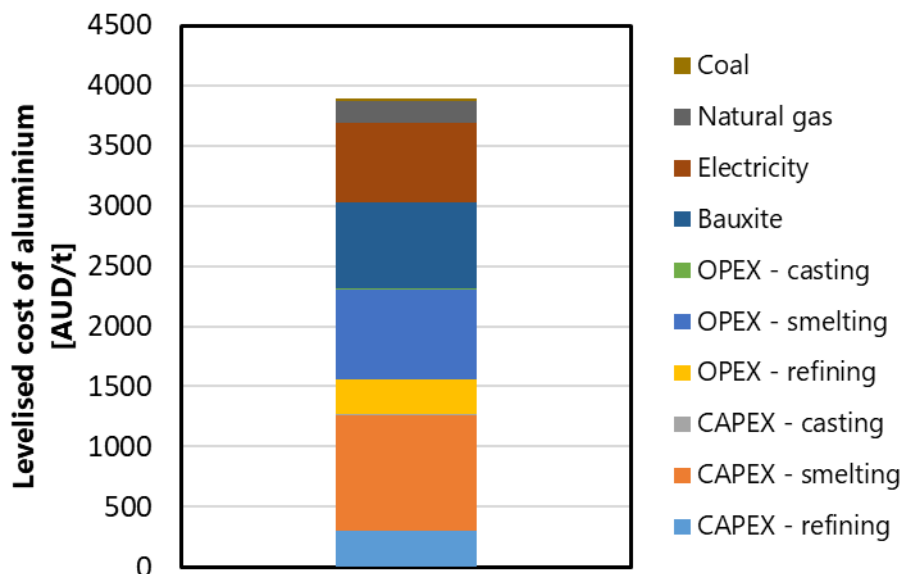
Table 85 reports the capital and O&M costs for the aluminium processing facilities, including capital costs for Australian refineries and smelters^[29], and for a wire rod aluminium casting facility^[30]. A carbon capture retrofit on bauxite refining of 160 USD/t-CO₂ was considered, as suggested for industrial facilities^[31]. While negligible changes in cost were considered for the hydrogen infrastructure onsite, 10% more expensive electric heating was assumed. Fixed O&M at 3% of capital costs were considered as per standard practice, while variable O&M costs were estimated individually for refineries and smelters from the proportion of fixed to material costs reported for Australia^[32]. Variable O&M costs of \$5 per tonne of aluminium billet produced were assumed for casting facilities.

Table 85 | Capital, fixed and variable O&M costs of the processes considered for each step of the aluminium supply chain per unit of the respective material output produced.

Technology	Capital cost	Fixed O&M	Variable O&M
Alumina refineries	2025 AUD/t-y	2025 AUD/t-y	2025 AUD/t
Bauxite refining	2921	87.6	66.5
Bauxite refining w/cc	3489	104.7	79.4
Bauxite refining - el	3213	96.4	73.2
Bauxite refining - H ₂	2921	87.6	66.5
Bauxite refining - H ₂ calc	3093	92.8	70.4
Aluminium smelters	2025 AUD/t-y	2025 AUD/t-y	2025 AUD/t
Aluminium smelting	18184	545.5	227.3
Aluminium smelting – inert anode	20002	600.1	250.0
Aluminium casting facilities	2025 AUD/t-y	2025 AUD/t-y	2025 AUD/t
Aluminium casting	120	3.6	7.8
Aluminium casting – H ₂	120	3.6	7.8
Aluminium casting - el	132	3.9	7.8

The above costs and efficiencies, together with indicated values for commodity and energy prices were used to estimate the levelised cost of aluminium from a notional supply chain of 1 Mt/y capacity. The cost breakdown from this analysis is reported in Figure 87: costs align well with current values reported for Australia, i.e. 3950.3 AUD/t for November 2024^[23].

Figure 87 | Cost breakdown for a notional 1 Mt/y aluminium billet supply chain based on traditional refining, smelting and rolling processes and using the input costs and efficiencies used in this modelling and comparison with the current price of aluminium.



15.1.4 Other industries

Costs for all other industries are linked with demand-side interventions and were incorporated in EnergyPATHWAYS. These are the results of energy efficiency and fuel-switching interventions, as presented by the industrial subsector, in Chapter 10. The levelised costs used to account for each intervention in any of the subsectors were:

- **energy efficiency:** 12.3 AUD/GJ in 2025, and linearly increasing to 18.5 AUD/GJ by 2060 for each unit of energy saved. This mimics diminishing returns from each intervention; and
- **fuel switching:** a decreasing cost of 10.8 AUD/GJ in 2025 to 6.1 AUD/GJ in 2040 and onwards to mimic the effect of growing market adoption in reducing intervention costs.

15.2 Direct air capture

Direct air capture (DAC) was considered by the NZAu project as an option to strip CO₂ directly from the air. The modelled technology uses potassium hydroxide as the solvent and features a calcium caustic recovery loop. Studies have shown that the performance of solvent-based capture, in general, depends on local temperature and relative humidity conditions^[33]. The NZAu project considered DAC to be co-located with storage basins described in Chapter 12, and, accordingly, adjusted CO₂ capture rate, water and energy consumption of the DAC process to the local climate. Table 86 reports the figures used to model DAC performance: these were obtained from the postprocessing of results in An *et al.*^[34] by:

1. fitting CO₂ capture and water consumption results as a function of local temperature and humidity; and
2. estimating then DAC energy intensity as a function of the CO₂ capture rate, based on the power law:

$$E = c + aX^b$$

where E stands for energy intensity, X for capture rate, while a , b , c are curve fitting parameters.

Table 86 | Specific values of water and energy consumption of DAC at the CO₂ storage locations used in NZAu per unit CO₂ captured.

CO ₂ storage basin	Energy consumption [GJ/t-CO ₂]	Water consumption [t-H ₂ O/t-CO ₂]
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

DAC costs are reported in Table 87. They were based on estimates for an Nth of a kind, 1 Mt/y plant^[34]. To remain consistent with the net-zero ambitions, resistive heating was assumed, with an all-electric calciner being as efficient as its natural-gas counterpart^[35]. Hence, electricity is the only energy input to the process. Variable O&M costs include CO₂ compression to 150 bar for transmission. A 0.5% cost reduction per year was also assumed. For context, under a 10% capital recovery factor and a 90% plant utilization, the estimated levelised carbon capture cost over the 30-year plant lifetime used for the modelling is USD 102/t, which excludes the cost of the energy input and is consistent with the projected 100-300 USD/t range for this technology^[36].

Table 87 | Cost projections for direct air capture from 2032-2060 (in 2025 AUD).

Year	CAPEX [AUD/t-CO ₂ /y]	Fixed O&M [AUD/t-CO ₂ /y]	Variable O&M [AUD/t-CO ₂]
2032	1,234.0	44.6	15.3
2035	1,215.6	43.5	15.0
2040	1,185.5	42.4	14.7
2045	1,156.2	41.4	14.3
2050	1,127.5	40.4	13.9
2055	1,099.6	39.3	13.6
2060	1,072.6	38.5	13.2

15.3 Residential demand-side technologies

As outlined in Chapter 10, the NZAu Project models the technology stock rollover of certain energy-consuming components of the residential sector of the energy system. This section describes the cost assumptions for each technology with a stock-rollover representation, which contribute to the total energy system transition costs. Cost projections for residential demand technologies were sourced from the US Energy Information Administration^[37] and include capital costs, fixed operations and maintenance (O&M) costs, and installation costs.

The following types of technology were modelled with a stock-rollover representation:

- air conditioning units;
- clothes dryers;
- clothes washing;
- cooktops/stoves;
- dishwashers;
- freezers;
- heating units;
- lighting;
- refrigerators; and
- water heaters.

These technology types were further categorised by their energy source and efficiency, as follows:

- reference electric;
- high efficiency electric;
- reference gas;
- reference LPG;
- biomass;
- reference geothermal;
- electric lighting; and
- solar thermal

The full list of residential stock by technology and energy type are then listed in Table 88 below.

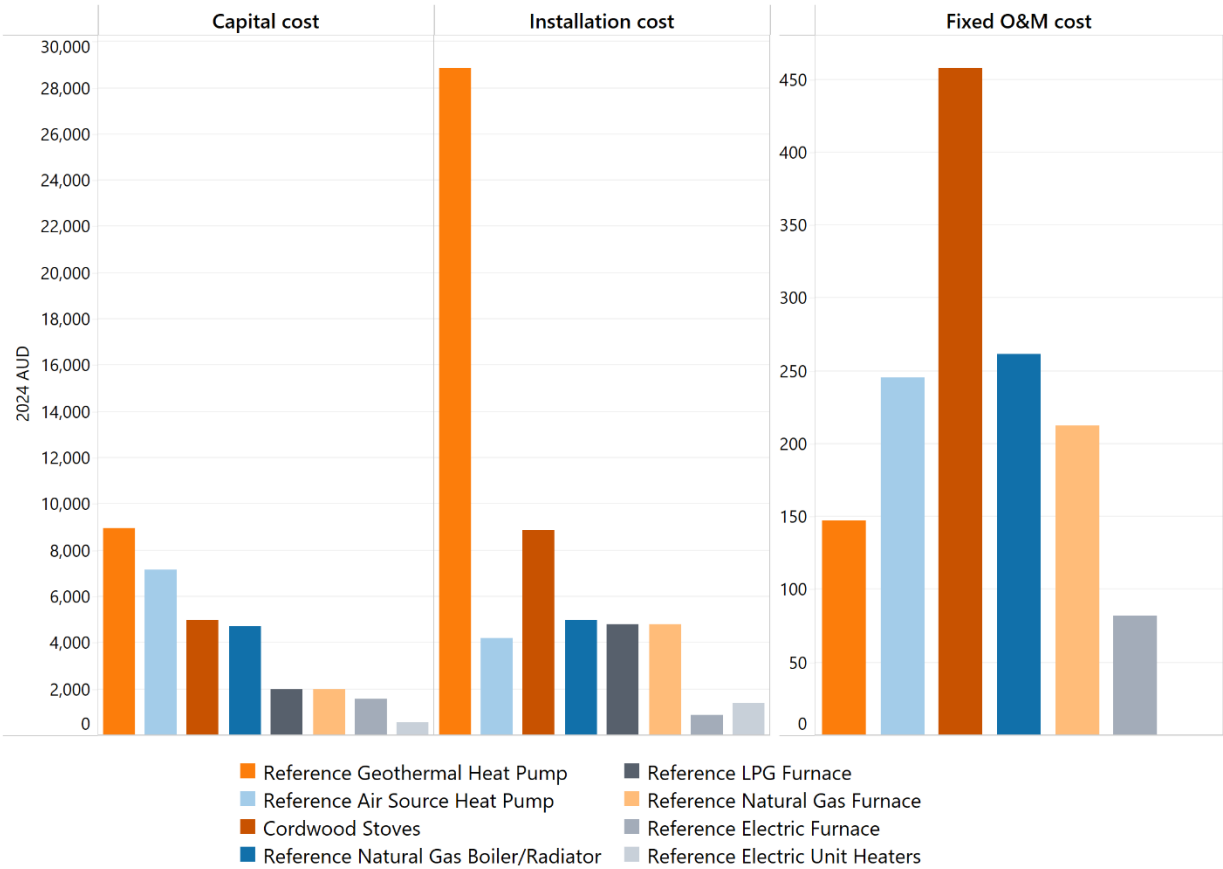
For brevity and readability, we do not include in this document detail on all costs for all technologies. Instead, we use Heating Units as an example for what type of data is available for each technology. These are outlined in Figure 88 below.

Table 88 | Residential demand-side stock by technology and energy type.

Group	Technology	Energy type
Air conditioning units	Evaporative Cooler	Reference electric
	High Efficiency Central Air Conditioner	High efficiency electric
	High Efficiency Room Air Conditioner	High efficiency electric
	Reference Central Air Conditioner	Reference electric
	Reference Room Air Conditioner	Reference electric
Clothes dryers	High Efficiency Electric Clothes Dryer	High efficiency electric
	Reference Electric Clothes Dryer	Reference electric
Clothes washing	High Efficiency Clothes Washer - Front Loading	High efficiency electric
	High Efficiency Clothes Washer - Top Loading	High efficiency electric
	Reference Clothes Washer - Front Loading	Reference electric
Cooktops/stoves	Electric Cooktop/Stove	Reference electric
	Reference Gas Cooktop/Stove	Reference gas
	Reference LPG Cooktop/Stove	Reference LPG
Dishwashers	High Efficiency Dishwasher	High efficiency electric
	Reference Dishwasher	Reference electric

Group	Technology	Energy type
Freezers	High Efficiency Chest Freezer	High efficiency electric
	High Efficiency Upright Freezer	High efficiency electric
	Reference Upright Freezer	Reference electric
Heating units	Cordwood Stoves	Biomass
	Reference Air Source Heat Pump - Heating	Reference electric
	Reference Electric Furnace	Reference electric
	Reference Electric Unit Heaters	Reference electric
	Reference Geothermal Heat Pump - Heating	Reference geothermal
	Reference LPG Furnace	Reference LPG
	Reference Natural Gas Boiler/Radiator	Reference gas
Lighting	Reference Natural Gas Furnace	Reference gas
	CFL GSL	Electric lighting
	Halogen Reflector	Electric lighting
	Incandescent GSL	Electric lighting
	LED Exterior	Electric lighting
	LED GSL	Electric lighting
	LED Linear Fluorescent	Electric lighting
	LED Reflector	Electric lighting
Refrigerators	T-8 Linear Fluorescent	Electric lighting
	High Efficiency Bottom Mount Refrigerator	High efficiency electric
	High Efficiency Side Mount Refrigerator	High efficiency electric
	High Efficiency Top Mount Refrigerator	High efficiency electric
Water heaters	Reference Side Mount Refrigerator	Reference electric
	Cordwood Water Heater	Biomass
	Reference Electric Heat Pump Water Heater	Reference electric
	Reference Electric Resistance Water Heater	Reference electric
	Reference Gas Water Heater	Reference gas
	Reference Instantaneous Gas Water Heater	Reference gas
	Reference Instantaneous LPG Water Heater	Reference LPG
	Reference LPG Water Heater	Reference LPG
	Solar Water Heater with Electric Backup	Solar thermal
Solar Water Heater with Gas Backup	Solar thermal	

Figure 88 | Heating units considered in the Net Zero Australia study and their capital, O&M, and installation costs in 2030 (2024 AUD)^[37]. Note differing vertical axes scales.



15.4 Road transport

Projections for on-road transport vehicle costs were sourced from CSIRO's *Electric vehicle projections 2022* report^[38] and more recent work completed by Poursadegh et al.^[40].

The CSIRO report provided upfront costs for rigid trucks, articulated trucks, and buses, split by:

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

Passenger vehicles costs were based on those reported for the 3 types of cars (compact, sedan and SUV) studied by Poursadegh et al.^[40], and weighted by their respective 2023 sales share from the National Transport Council (NTC)^[41]. This is done for ICEs, hybrid-electric vehicles (HEVs), PHEVs, and BEVs. For ICEs and HEVs, no changes to costs are assumed from 2025 onwards given the relative maturity of these technologies. However, PHEV and BEV costs are reduced out to 2030 according to a projected linear decrease in the battery pack cost from 140 to 75 \$/kWh, the battery capacity of each vehicle and a 1.5 markup factor, as per Poursadegh et al.^[40]. The same approach is applied to light-commercial vehicles, using the costs of a pickup truck reported in the study^[40]. No further reductions in the costs of any vehicles post 2030 are modelled.

Using the analysis of Poursadegh et al.^[40] and 2024 sales data from the RACV^[44], the model gives an average light duty vehicle (LDV) capital cost of \$58k per vehicle. This compares reasonably with a sales-weighted, average new LDV price of \$54k for the 10 most popular, new Australian LDVs in 2024, with lower and upper bounds of \$40k and \$71k for these vehicles' base and high-end models respectively^[45].

The projection of upfront costs for the vehicle classes above are presented in Figure 89. Figure 90 then presents the modelled annual fixed operating and maintenance (O&M) costs for these same vehicles. The data presented here are obtained from the bottom-up study of Burnham et al.^[42], which is work from the Argonne National Laboratories and therefore consistent with the study of Poursadegh et al.^[40] that also makes extensive use of Argonne National Laboratories modelling. These data show that BEVs have lower fixed O&M costs than ICEs in all vehicle classes. Notably, the O&M costs of Burnham et al. for conventional ICE vehicles also agree to within 10% with the recent survey data from the Australian Automobile Association (AAA)^[43], suggesting that this modelling is again reasonable for Australian conditions.

Figure 89 | Upfront vehicle cost across the range of vehicle classes and propulsion systems considered in the NZAu Project^[38,40]. Note differing vertical axis scales.

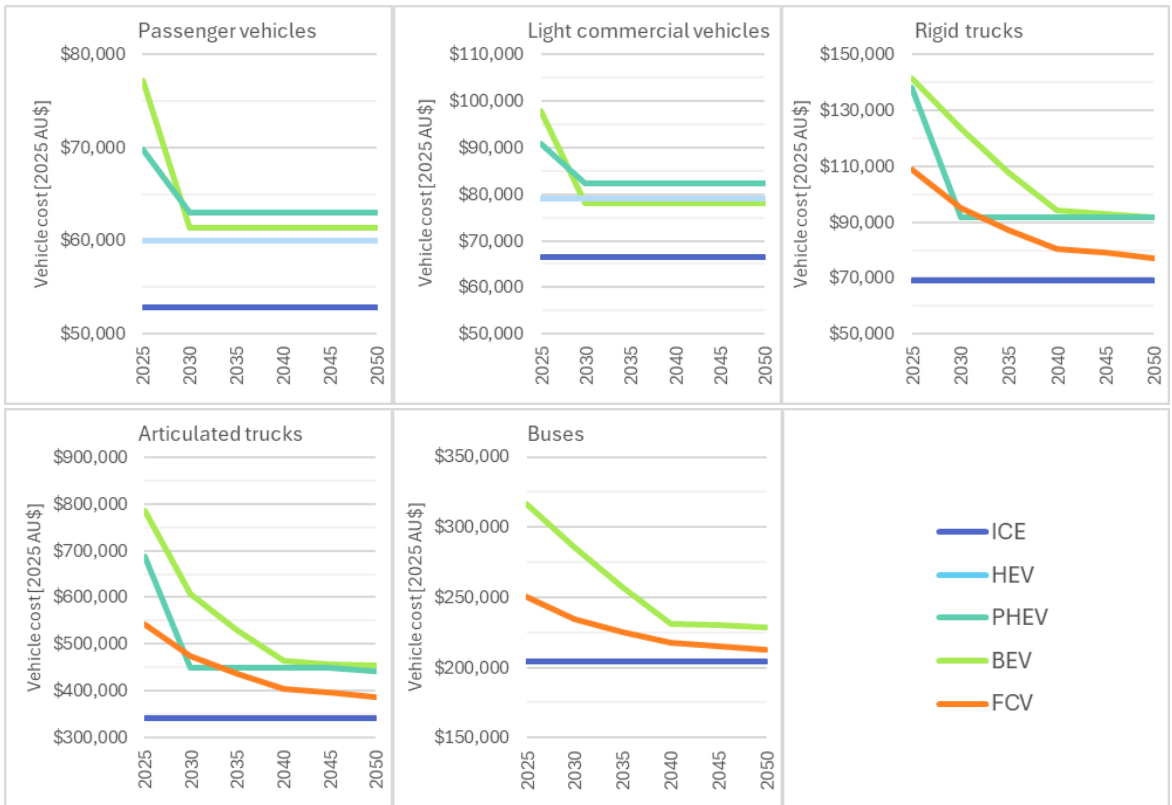
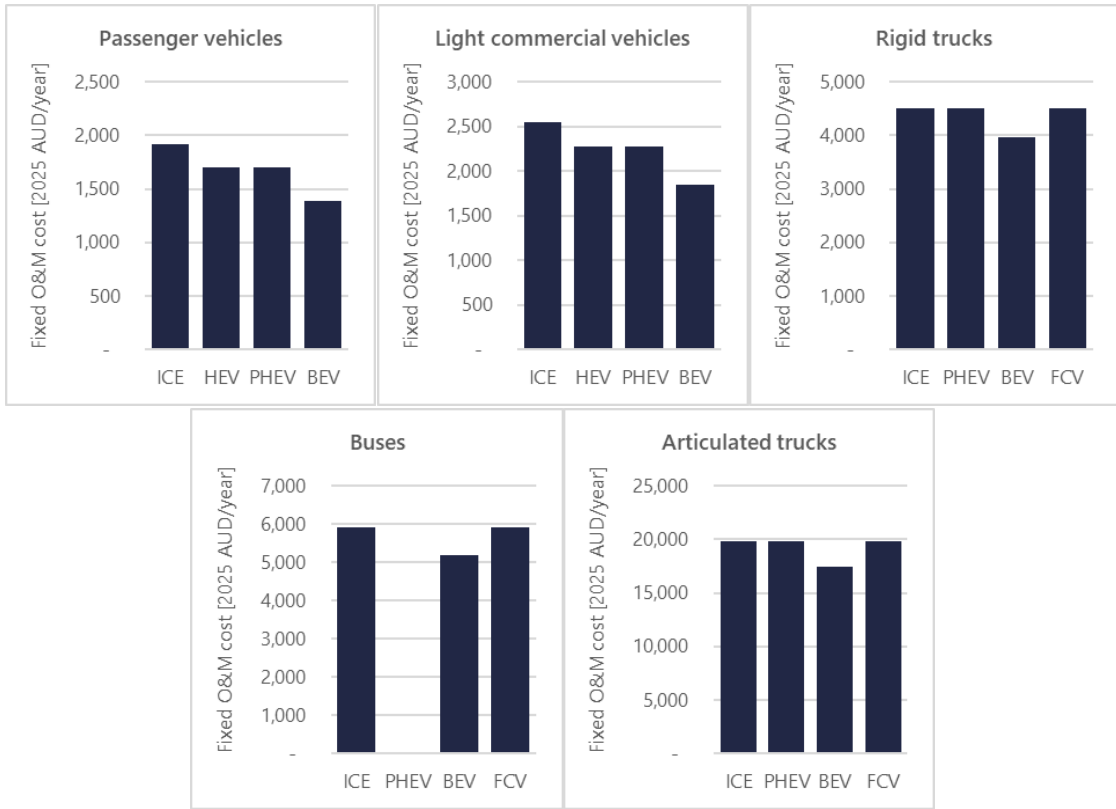


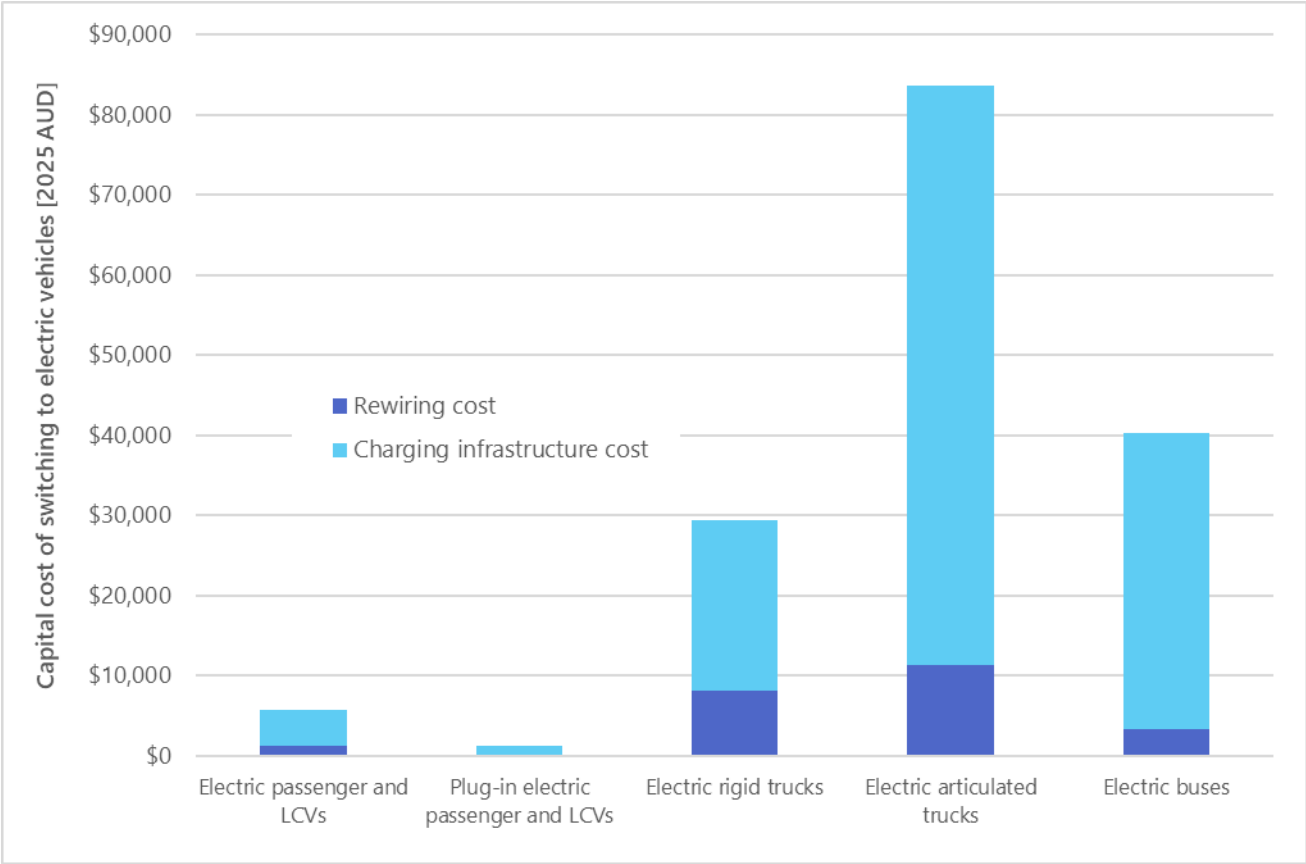
Figure 90 | Annual fixed operating and maintenance (O&M) costs for vehicles across the range of vehicle classes and propulsion systems considered in the NZAu Project^[42].



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 91. 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 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 \$5,800 for passenger vehicles and LCVs and range from \$30,000 – \$84,000 for larger vehicles. We also assume no rewiring costs for PHEVs. These costs 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*^[38,42].

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 (Chapter 10).

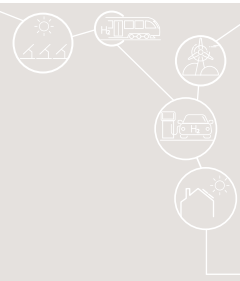
Figure 91 | Estimated capital cost of charging infrastructure and rewiring required when switching to electric vehicles, for the range of electric vehicle classes modelled in *NZAu*^[38,42].



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Appendix A WACC methodology and values

A.1 WACC estimation method

The WACCs estimated by OE are determined using the following formula:

$$WACC_{nom} = Ke * \frac{1}{\{1 - t * (1 - \gamma)\}} * \frac{E}{V} + Kd * \frac{D}{V}$$

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

Where:

$WACC_{nom}$	is nominal WACC
$WACC_{real}$	is real WACC
Ke	is the post-tax return on equity
Kd	is the post-tax return on debt
E/V	is the proportion of equity within the capital structure
D/V	is the proportion of debt within the capital structure
t	is the corporate tax rate
i	is the inflation rate

As summarised in the report, "post-tax return on equity is estimated using OE's Sharpe-Lintner Capital Asset Pricing Model (SLCAPM) – underpinned by three methodologies to estimate the Market Risk Premium (MRP):

- **Ibbotson:** deriving a historical long-run MRP based on observed market returns.
- **Siegel:** adjusting the Ibbotson approach for unexpected inflation.
- **Survey:** the average MRP reported by survey respondents.

In addition, OE estimate on-the-day debt "to determine the post-tax return on debt" expressed as:

$$K_d = R_f + DRP$$

Where:

K_d	is cost of debt
R_f	is risk-free rate
DRP	is debt risk premium (proxied by the credit rating)

OE use a survey of energy market stakeholders estimate technology-specific parameters.

Table 89 below outlines the method used to calculate other inputs to the WACC calculations.

Table 89 | WACC inputs, based on Oxford Economics Australia's report to AEMO unless otherwise stated^[1].

Parameter	Description/effect on NZAu modelling	Value	Approach
Inflation rate	Inflation erodes purchasing power over time which influences the relative cost-effectiveness of various technologies. High inflation increases the costs of materials, labour, and financing, making capital-intensive technologies more expensive to deploy. This can shift investment preferences toward technologies with lower upfront costs or faster returns, potentially	2.28%	Breakeven inflation method used, in line with Synergies ^[2] and replicated by CEPA in earlier AEMO reports ^[3] .

Parameter	Description/effect on NZAu modelling	Value	Approach
	delaying the adoption of long-term, high-capital solutions.		
Social discount rate	Reflects society's relative valuation of present vs future well-being. In this context, 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.	3%	Minimum discount rate used in AEMO's ISP ^[2] . NZAu has selected a lower social discount rate to attribute more value to the wellbeing of future generations given the length of the transition period.
Risk free rate	The theoretical rate of return on an investment that carries zero risk of financial loss. Typically represented by the 10-year Commonwealth bond yield.	4.20%	Based on 10-Year treasury bond yield 20-day moving average.
Gearing ratio	The proportion of a company's capital structure financed by debt compared to equity. Measures financial leverage.	50%	Financial market data of a sample of domestic and global listed utility companies in developed economies.
Corporate tax rate	Proportion of corporation's taxable income paid to government as tax.	30%	Current conditions.
Gamma	Parameter used to estimate the benefit that investors receive from imputation credits.	0.25	Global financial data.
Market risk premium (MRP)	Realised return the market portfolio makes above the risk-free rate.	5.87%	Simple average of the Ibbotson method, Siegel method and an average of survey responses.
Return on equity (SL CAPM)*	Expected rate of return on an investment based on its risk relative to the overall market.	10.07%	Calculated based on MRP, asset beta, and equity beta (calculated and surveyed to be 0.5 and 1 respectively).
Debt risk premium	Additional return required by lenders to compensate for the credit risk of a borrower compared to a risk-free investment. Reflects the likelihood of default.	1.55%	Based on financial market sample and survey results. Average credit rating from survey respondents is BBB. Differs per asset.
Return on debt (pre-tax)*		5.85%	Calculation.

*Changes per technology type in WACC calculations. Value here is 'technology neutral' value.

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A.2 Range of WACCs estimated by Oxford Economics by technology (real, pre-tax)

Technology	Lower Bound	Central Estimate	Upper Bound
1. Electricity – transmission and distribution (regulated)	3.0%	3.0%	4.5%
2. Electricity – transmission and distribution (unregulated)	4.5%	6.5%	9.5%
3. Gas – transmission and distribution (regulated)	3.0%	3.0%	4.5%
4. Gas – transmission and distribution (unregulated)	5.5%	7.0%	10.5%
5. Utility-scale solar	5.0%	7.0%	10.0%
6. Onshore wind	5.5%	7.5%	10.5%
7. Offshore wind	5.5%	7.5%	10.5%
8. Large-scale BESS	6.5%	8.0%	11.5%
9. Hydrogen electrolysers	6.0%	8.0%	11.0%
10. Pumped hydro energy storage	6.5%	8.5%	11.5%
11. Dual-fuel OCGT	7.0%	9.0%	12.0%
12. CCGT	8.5%	10.5%	13.5%
13. Coal generation	10.0%	12.0%	15.0%

A.3 Full list of WACC values used by NZAu (real, pre-tax)

Category	Technology	WACC	Estimation approach
Variable renewable energy	Utility solar	7.0%	Central estimate, Oxford Economics 2024
	Rooftop solar	7.0%	Based on <i>utility solar</i> .
	Onshore wind	7.5%	Central estimate, Oxford Economics 2024
	Offshore wind	8.5%	Increased by 1.0% on the <i>central estimate</i> , Oxford Economics 2024
Storage	Large-scale BESS	8.0%	Central estimate, Oxford Economics 2024
	Pumped hydro energy storage	8.5%	Central estimate, Oxford Economics 2024
Gas power generation	CCGT	10.5%	Central estimate, Oxford Economics 2024
	CCGT Allam w/cc	10.5%	Based on CCGT
	CCGT w/cc	10.5%	Based on CCGT
	OCGT (dual fuel)	9.0%	Central estimate, Oxford Economics 2024
Coal power generation	Coal power generation	15.0%	<i>Upper Bound</i> , Oxford Economics 2024
	Black coal power w/cc	15.0%	Based on <i>coal power generation</i> .
Nuclear	Nuclear large scale	12.5%	NZAu WACC calculations based on categorisation as 'higher risk'.
Transmission	CO2 transmission – domestic	3.0%	Based on <i>natural gas transmission and distribution – regulated</i> .
	CO2 transmission – export	9.5%	Based on assumption that any export-oriented transmission will form part of an integrated export project where the WACC will be equivalent to the highest WACC component, which we assume to be technology categorised as 'moderate risk'.
	Electricity transmission and distribution – regulated	3.0%	Central estimate, Oxford Economics 2024
	Electricity transmission and distribution – unregulated	6.5%	Central estimate, Oxford Economics 2024
	H2 transmission – domestic	3.0%	Based on natural gas transmission and distribution – regulated.
	H2 transmission – export	9.5%	As per <i>CO2 transmission – export</i> .
	Natural gas transmission and distribution – regulated	3.0%	Central estimate, Oxford Economics 2024
	Natural gas transmission and distribution – unregulated	7.0%	Central estimate, Oxford Economics 2024
	NH3 transmission	9.5%	As per <i>CO2 transmission – export</i> .

Category	Technology	WACC	Estimation approach
Hydrogen	Autothermal reforming w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Black coal gasification w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Brown coal gasification w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	H2 storage salt cavern	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	H2 storage underground pipes	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Haber-Bosch	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Hydrogen electrolyzers	8.0%	Central estimate, Oxford Economics 2024
	Steam reforming	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Steam reforming w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
Biomass/gas	Bio-gasification	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Bio-gasification Fischer-Tropsch	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Bio-gasification Fischer-Tropsch w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Bio-gasification w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Biomass fast pyrolysis	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Biomass fast pyrolysis w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Biomass power	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Biomass power Allam w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Biomass power w/cc	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
Other	Direct air capture	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Electric LNG plant retrofit	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Fischer-Tropsch liquids	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Fischer-Tropsch LPG	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	LNG plant	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	LNG plant electric	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.
	Methanation	9.5%	NZAu WACC calculations based on categorisation as 'moderate risk'.

Appendix B Regional cost factors by technology

Region	OCGT	CCGT	Biomass	Battery storage	Solar PV (utility)	Onshore wind	PHES	Electrolysers (PEM)
nt	108%	108%	110%	108%	118%	114%	106%	100%
nsw-snw	100%	100%	100%	100%	N/A	N/A	N/A	100%
nsw-central	104%	103%	104%	103%	105%	104%	106%	98%
nsw-north	106%	106%	107%	105%	109%	108%	104%	98%
nsw-south	101%	101%	101%	105%	111%	108%	117%	99%
nsw-outback	106%	106%	107%	112%	124%	119%	104%	98%
vic-mel	100%	100%	100%	100%	N/A	N/A	N/A	100%
vic-west	100%	100%	100%	100%	100%	100%	100%	95%
vic-east	100%	100%	100%	100%	100%	100%	N/A	100%
qld-south	100%	100%	100%	103%	107%	105%	100%	100%
qld-central	111%	110%	113%	108%	116%	112%	100%	96%
qld-outback	108%	108%	110%	108%	118%	114%	106%	100%
qld-north	108%	108%	110%	108%	118%	114%	106%	100%
qld-gg	107%	107%	109%	104%	N/A	N/A	N/A	96%
sa-central	100%	100%	100%	103%	109%	108%	101%	100%
sa-south	110%	110%	112%	106%	112%	109%	N/A	96%
sa-north	105%	104%	107%	107%	114%	113%	108%	97%
wa-south	100%	100%	100%	103%	107%	105%	100%	100%
wa-central	108%	108%	110%	108%	118%	114%	106%	100%
wa-north	108%	108%	110%	108%	118%	114%	106%	100%
tas	100%	100%	100%	103%	108%	106%	104%	100%

Appendix C GenCost scenario selection

CSIRO's 2024-25 GenCost report^[1] provides three different cost pathways for key energy technologies, based on three global scenario narratives. A summary of these scenarios is provided in Table 90.

Table 90 | Summary of GenCost 2024-25 scenarios and their key assumptions

Key drivers	Scenarios		
	Global NZE by 2050	Global NZE post 2050	Current policies
IEA WEO scenario alignment	Net Zero Emissions by 2050	Announced Pledges scenario	Stated Policies scenario
CO ₂ pricing / climate policy	Consistent with 1.5 degrees world	Based on NDCs and announced targets	Based on current policies only
Renewable energy targets and forced builds / accelerated retirement	High reflecting confidence in renewable energy	Renewable energy policies extended as needed	Current renewable energy policies
Demand / Electrification	High	Medium-high	Medium
Learning rates	Stronger	Normal maturity path	Weaker
Renewable resource & other renewable constraints	Less constrained	Existing constraint assumptions	More constrained than existing assumptions
Decentralisation	Less constrained rooftop solar photovoltaics (PV)	Existing rooftop solar PV constraint	More constrained rooftop solar PV constraints

Technology costs differ widely between these scenarios by 2050. Clearly, NZAu's selection of which cost pathway to use as the initial basis for technology costs in the model will affect Australia's final energy profile and the optimal development pathway for the EnergyPATHWAYS model.

Unless otherwise stated, NZAu adopts the costs associated with the "Global NZE post 2050" GenCost scenario:

1. **Why not the global NZE by 2050 scenario?** Declared net zero targets for China and India – ~36% of the world's population^[2] and 41% of its emissions^[3] in 2023 – are 2060 and 2070 respectively. It is therefore highly unlikely the world will achieve global net zero by 2050.
2. **Why not the Current policies scenario?** The current policies scenario, consistent with the IEA's 'stated policies scenario' results in a global emissions outcome consistent with approximately 2.4 degrees global warming by 2100^[4]. Australia's legislated emissions targets, its commitment to the Paris Agreement, and the qualitatively observed shift in political rhetoric from "should we decarbonise" to "how can we decarbonise" suggests that this outcome is not acceptable, and that further policy activity is likely.

Appendix references

1. Graham, P, Hayward, J, Foster, J, 2024, "GenCost 2024-25: Final Report", CSIRO, <https://doi.org/10.25919/atq9-p951>
2. United Nations Population Fund, 2024, "World Population Dashboard" <https://www.unfpa.org/data/world-population-dashboard>
3. International Energy Agency, 2023, "CO₂ Emissions in 2023": <https://iea.blob.core.windows.net/assets/33e2badc-b839-4c18-84ce-f6387b3c008f/CO2Emissionsin2023.pdf>
4. International Energy Agency, 2023, "World Energy Outlook 2023", <https://iea.blob.core.windows.net/assets/86ede39e-4436-42d7-ba2a-edf61467e070/WorldEnergyOutlook2023.pdf>

Appendix D Global CCS Institute's Advice



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 CO₂-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 (P10¹) 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 CO₂ storage over a sustained injection period of 50 years
- Potential Injection Rates do not consider the source of CO₂
- 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.

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 CO₂ across every state and territory
- Major funding initiatives from both the private and public sector
- Optimised CO₂ 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	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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