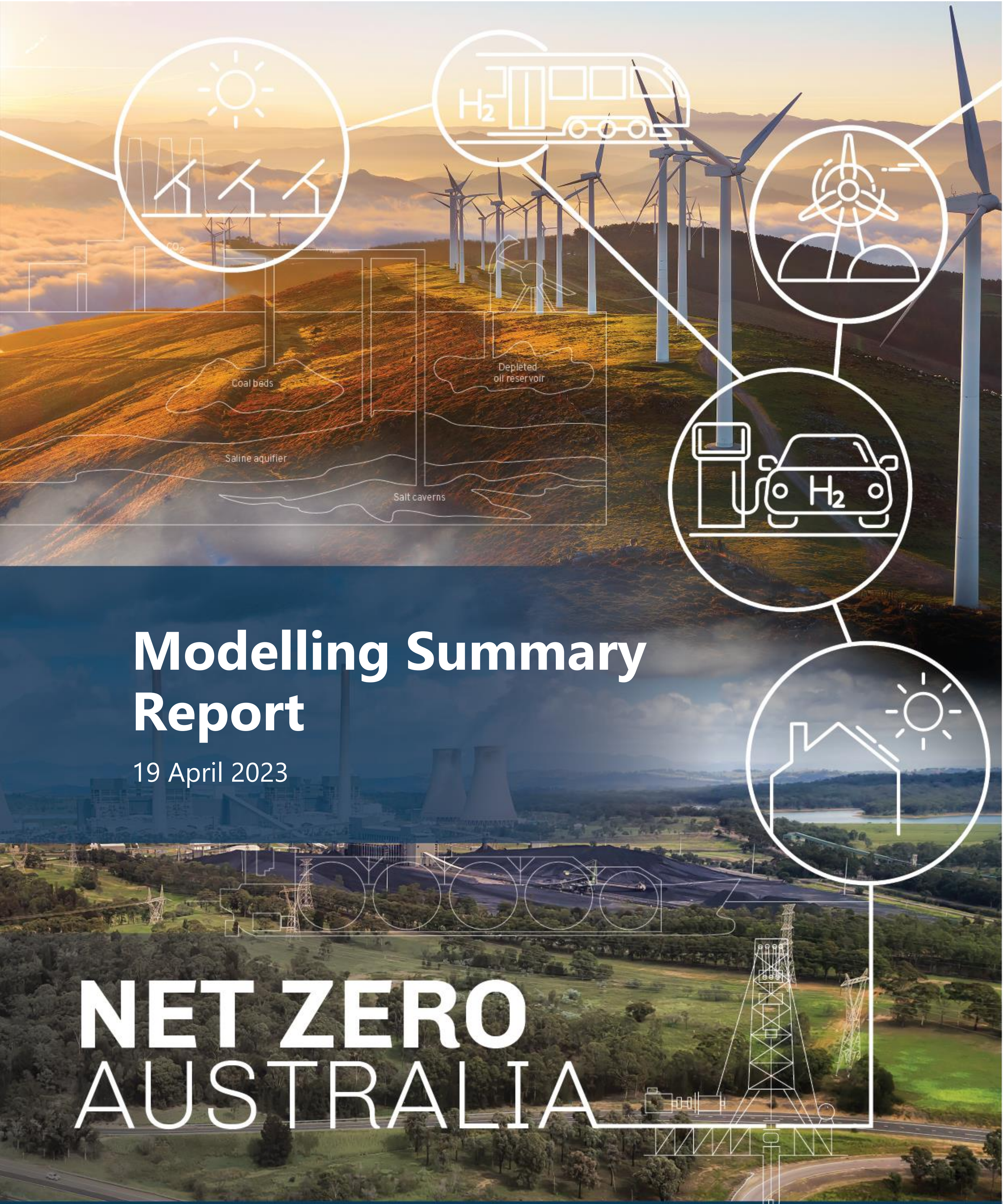

Modelling Summary Report

19 April 2023

NET ZERO AUSTRALIA

THE UNIVERSITY OF MELBOURNE

PRINCETON UNIVERSITY

THE UNIVERSITY OF QUEENSLAND AUSTRALIA
CREATE CHANGE

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

Net Zero Australia

Modelling Summary Report

19 April 2023

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Reports, data, and other resources available at: https://www.netzeroaustralia.net.au/

Executive Summary

The Net Zero Australia (NZAu) Project is a partnership between The University of Melbourne, The University of Queensland, Princeton University, and management consultancy Nous Group. NZAu uses the modelling method developed by Princeton University and Evolved Energy Research for its 2020 Net-Zero America study (Larson et al., 2021) and is analysing net zero pathways that reflect the boundaries of the Australian debate. In so doing, we intend that NZAu is rigorous and granular, evidence driven, technology neutral and non-political in its approach.

This *Modelling Summary Report* and its companion methodology and downscaling reports provide a complete description of these features of our modelling and results. This modelling

- imposes different, linear trajectories for greenhouse gas (GHG) emissions reduction for Australia's domestic and export energy systems,
- uses a scenario-based approach,
- uses the best available inputs and assumptions,
- uses a least cost optimisation approach, and
- 'downscales' our results to a regional and sub-regional basis.

Given the many sources of uncertainty and the contested nature of the net zero challenge, we intend that the NZAu Project reflects the boundaries of the Australian debate by varying the following parameters significantly across our Scenarios:

- the rate of electrification,
- renewable build rates,
- limits on fossil fuel use, and
- limits on the usage of carbon capture, utilisation and storage (CCUS).

In doing so, we do not state that any of these Scenarios is more or less desirable or achievable. Rather, in modelling very different pathways to net zero, we intend that the NZAu Project illustrates

- 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.

Irrespective of the pathway taken, our results nonetheless show that achieving net zero emissions for both Australia's domestic and export energy systems is an immense challenge and a once-in-a-generation, globally significant and nation-building opportunity. We can summarise what Australia must do in three points:

1. deliver an energy transformation that is unprecedented in scale and pace,
2. transform our exports as an essential contribution to global decarbonisation, and
3. invest in our people and our land to reduce impacts and share benefits.

These are easy to say, but each requires a transformation in *our thinking and our actions* in delivering greenhouse gas abatement whilst we continue to serve Australians and our export partners with the energy and other commodities that they need.

For example, ***the delivery of an energy transformation*** requires us to

- grow renewables as our main domestic and export energy source such that by mid-century we have 400-500 GW serving our domestic energy system and potentially several thousand GW producing energy exports, compared to roughly 25 GW today,
- establish a fleet of batteries, pumped hydro energy storage and gas-fired firming that is larger in capacity than our domestic energy system today,
- greatly increase electrification and energy efficiency across all sectors in many ways, ranging from the uptake of electric vehicles to the displacement of gas-fired heat with electrically driven equivalents in our homes and some businesses,
- develop a large carbon capture, utilisation and storage industry that can sequester of order 100 Mt pa of CO_2, compared to the nascent industry we have today,
- greatly expand our energy networks, not only by electrification but also by investment in the transmission of several new network delivered commodities, and
- attract $7-9 trillion of capital to 2060 from international and domestic sources and deploy this in investment-ready projects.

We also only see a potential role for nuclear electricity generation if its cost falls sharply and the growth of renewables is constrained.

Similarly, ***a transformation of our exports*** is an essential contribution to global decarbonisation task. This, in turn, requires us to transition to clean energy and clean mineral exports, justifying the potential for thousands of GW of renewable and other investments across the north of Australia and possibly also in the south. Since the onshore production of clean iron and aluminium could be of significantly lower cost than the offshore production of equivalent commodities, Australia could find that the export of clean non-energy commodities could play a major role in this transformation by aligning the global decarbonisation task, the interests of international customers and our domestic build task.

We must also ***invest in our people and our land*** to reduce the adverse impacts of the net zero transition and share in its benefits. This includes the expansion of a skilled workforce from about 100,000 today to about 700,000-850,000 by 2060, with many of these jobs in regional and remote Australia. We must also move the land sector towards net zero and potentially to net negative emissions, which requires several innovations that mean that we cannot assume that offsets from the land will be available for other sectors. Finally, we must carefully manage these major land use changes, being particularly mindful of the Indigenous Estate, natural ecosystems and agriculture. The physical and social changes of the transition to net zero emissions are immense and are not necessarily benign.

Since the NZAu Project's inception in early 2021, we have progressively placed detailed summaries of our methodologies, assumptions, results and feedback received on the Project website netzeroaustralia.net.au. Our gift-based sponsorship, a diverse Advisory Group, wide consultation and the progressive public release of all our work 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 methodologies or results.*

Contents

1 Introduction

The Net Zero Australia (NZAu) Project is a partnership between The University of Melbourne, The University of Queensland, Princeton University, and management consultancy Nous Group. NZAu uses the modelling method developed by Princeton University and Evolved Energy Research for its 2020 Net-Zero America study (Larson et al., 2021) and is analysing net zero pathways that reflect the boundaries of the Australian debate. In so doing, we intend that NZAu is rigorous and granular, evidence driven, technology neutral and non-political in its approach.

Generous financial support has enabled this study, and gift and equivalent grant agreements with the following organisations have helped protect the project's independence:

- APA Group,
- Dow Australia,
- Future Energy Exports Cooperative Research Centre,
- Future Fuels Cooperative Research Centre,
- the Minderoo Foundation and
- Worley.

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 Australian Council of Trade Unions,
- the Climate Council,
- Energy Consumers Australia,
- the Ethics Centre,
- the National Farmers Federation,
- the National Native Title Council and
- the St Vincent de Paul Society.

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

Since the NZAu Project's inception in early 2021, we have undertaken numerous briefings to different individuals and groups. This has included:

- Commonwealth Ministers and Departments;
- State Ministers and Departments;
- Non-government organisations; and
- research bodies.

Over this period, we have progressively placed detailed summaries of our methodologies, assumptions, results and feedback received on the Project website netzeroaustralia.net.au. This combination of gift-based sponsorship, a diverse Advisory Group, wide consultation and the progressive public release of all our work 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 methodologies or results*.

1.1 Project motivation, objectives and approach

The NZAu Project is analysing net zero pathways that reflect the boundaries of the Australian debate. In so doing, we intend that NZAu is rigorous and granular, evidence driven, technology neutral and non-political in its approach. Very briefly, our modelling

- imposes different, linear trajectories for greenhouse gas (GHG) emissions reduction for our domestic and export energy systems,
- 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.

Given the many sources of uncertainty and the contested nature of the net zero challenge, we intend that the NZAu Project reflects the boundaries of the Australian debate by varying the following parameters significantly across our Scenarios:

- the rate of electrification,
- renewable build rates,
- limits on fossil fuel use, and
- limits on the usage of carbon capture, utilisation and storage (CCUS).

In doing so, we do not state that any of these Scenarios is more or less desirable or achievable. Rather, in modelling very different pathways to net zero, we intend that the NZAu Project illustrates

- 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.

As such, the NZAu Project *does not*

- make predictions or express a preference on specific pathway/s;
- consider the impact of fossil fuel supply constraints, which we know are deeply uncertain over the 21st Century, and as the impact of the Ukraine War has shown starkly in the last 12 months;
- calculate or analyse the costs of inaction on climate change, which we know are far 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.

This *Modelling Summary Report* and its companion methodology and downscaling reports provide a complete description of all these features of our modelling and results.

1.2 Structure and scope of this document

This document provides a summary of NZAu's macro-energy system modelling and synthesises key sectoral downscaling analyses. We first characterise the Australian energy system that has been modelled, across both domestic and export systems, and summarise the modelling methodologies used to assess pathways to their decarbonisation. We then present modelling results according to 6 pillars of decarbonisation:

1. End use energy efficiency and electrification;

2. Clean electricity;
3. Zero-carbon fuels & feedstocks;
4. CO_2 capture, transport, utilisation & storage;
5. Reduced non-CO_2 emissions; and
6. Enhanced land sinks.

Finally, we draw out the implications of the modelled net-zero transition in different ways.

This *Modelling Summary Report* makes extensive reference to related reports that present all our modelling in detail; these more detailed reports themselves can be summarised as follows:

- our Methods, Assumptions, Scenarios and Sensitivities (MASS) report, which provides a complete summary of our input assumptions and methods; and
- our Downscaling reports on numerous aspects of the net zero challenge, providing granular results on employment, capital deployment, renewable and non-renewable resources, many different types of asset builds, bioenergy and forestry.

2 Summary of methodology and approach

This project undertakes its modelling in two stages, as follows.

1. **Regional Investment modelling**

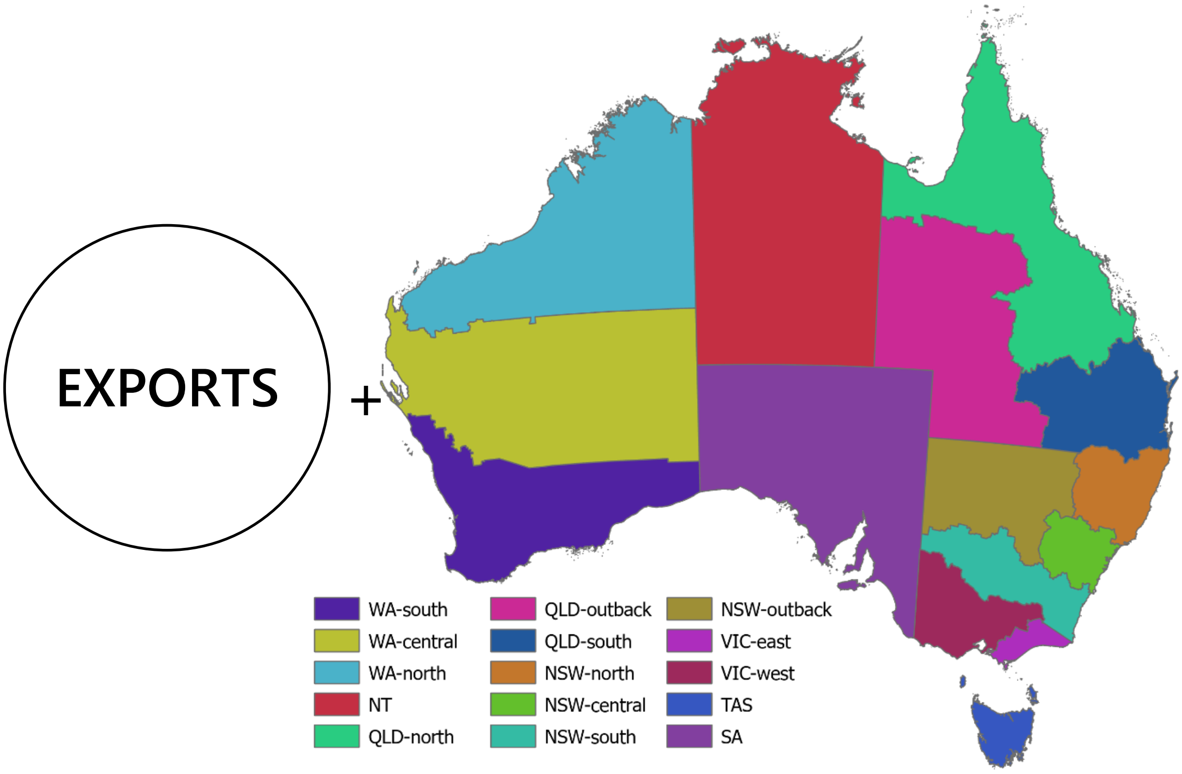
   This modelling determines the investments that will occur in 15 defined regions (Figure 1) across Australia, such that net zero emissions is achieved for both our domestic energy system and for our energy exports by mid-century on a least-cost basis. This modelling includes projections of emissions from agriculture, waste and Land Use, Land Use Change and Forestry (LULUCF), along with projections of energy demand.

2. **Downscaling**

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

NZAu's macro-energy system modelling incorporates the 15 domestic regions (NZAu zones) shown in Figure 1, each with its own energy service demand, initial stock of energy infrastructure and resources. The number of regions chosen is a balance between computational complexity of the macro-energy system modelling optimisation, and the spatial resolution required to represent the geographically dispersed energy resources and infrastructure needed in highly carbon-constrained energy systems. The modelling considers the energy service demand and existing energy infrastructure in each modelled region along with the potential for energy, water and CO_2 flows between neighbouring regions. The modelling then optimises the required energy investments in each region, as well as incremental energy transmission builds between regions.

Figure 1 | The 15 domestic regions (NZAu zones) and one export region modelled.



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

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

2.1 Modelling tools and stages

Figure 2 presents a schematic representation of the two modelling stages – the Regional Investment modelling and the Downscaling modelling – in the NZAu Project. The Regional Investment modelling that is discussed in this document uses the following two modelling tools from Evolved Energy Research (EER).

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

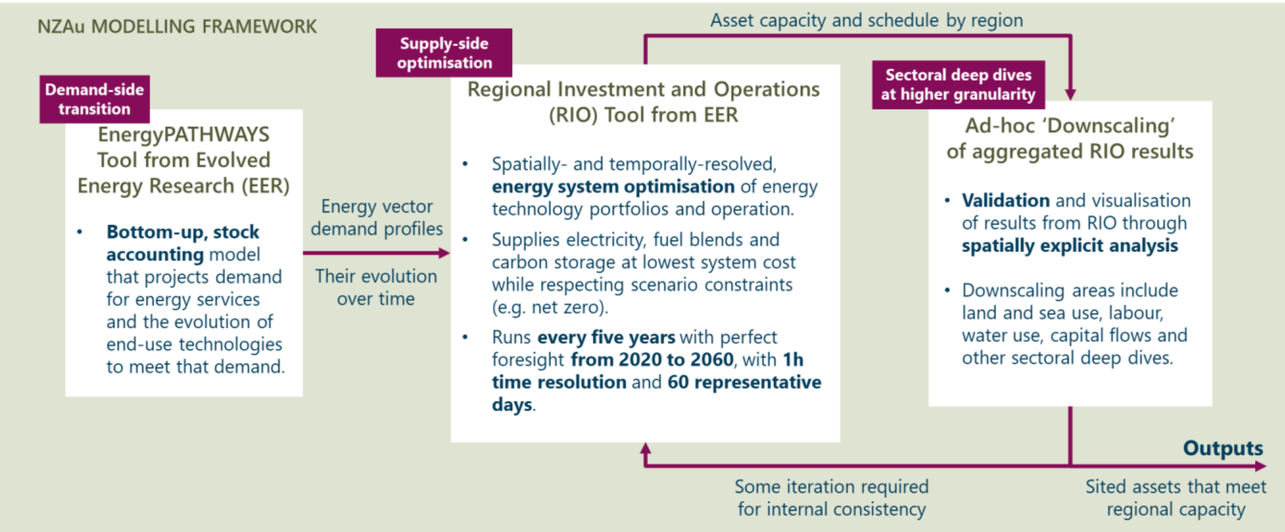
   The EP modelling tool enables us to develop demand pathways for a wide range of different energy services from today to mid-century. These pathways for different energy services are consistent with the Scenarios and Sensitivities that are defined in this document.

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

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

A complete description of the EP and RIO modelling is contained in the companion *Methods, Assumptions, Scenarios and Sensitivities* (MASS) document.

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



The modelling undertaken for the downscaling depended on the specific downscaling effort. For example, the siting of renewable generation and transmission of different forms was undertaken using its own least cost modelling using the ArcGIS software tool. This approach integrated renewable energy resource assessment that we developed along with numerous geographical overlays that constrained this optimisation in different ways. On the other hand, our employment modelling was downscaled to the regions defined in Figure 1. Further detail on the different downscaling methods is given in each of the companion downscaling reports.

2.2 The domestic and export energy systems

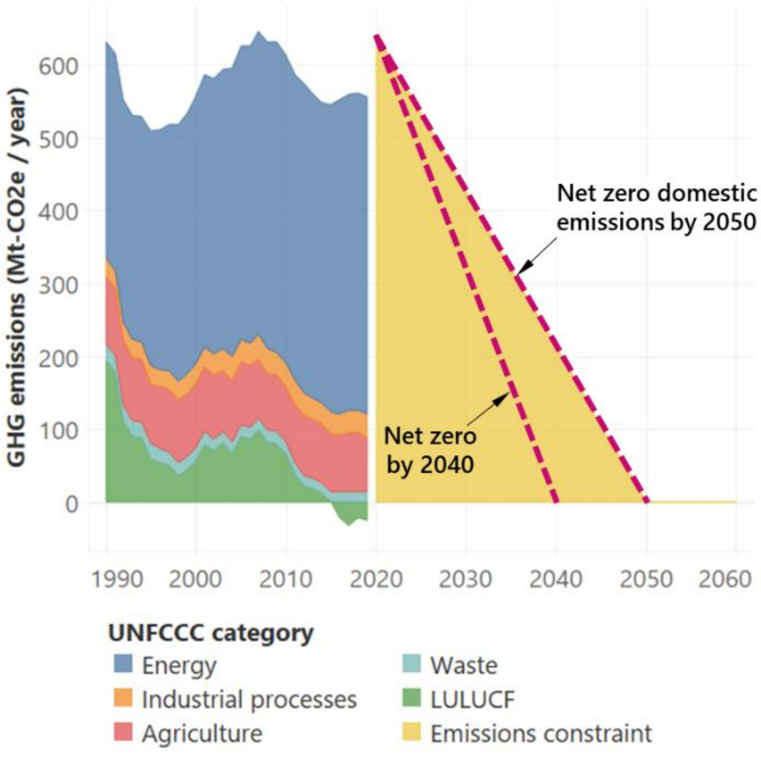
Greenhouse gas emissions constraints are imposed for all net-zero Scenarios considered in the NZAu Project.

- Domestic emissions (Figure 3): a linear trajectory starting from 640 Mt-CO_2e in 2020 to zero in 2050, where the emissions in 2020 were set to be unconstrained, with all following years constrained.
- Exported emissions (Figure 4): a linear trajectory from 1,215 Mt-CO_2e in 2030 to zero in 2060 with no emissions constraint before 2030 and no new fossil export capacity from 2030. This is considered to be consistent with the net zero pledges announced in the lead up to COP26 by several of our major energy trading partners, several of whom have 2050 net zero emissions targets, whilst China and India target 2060 and 2070 respectively.

Figure 3 and Figure 4 also show accelerated decarbonisation trajectories for both domestic and exported energy, with these reaching zero by 2040 and 2050, respectively. Nuclear power was not permitted in any of the Core Scenarios, consistent with existing Commonwealth and State Laws. However, the use of nuclear is examined in one of the Sensitivity analyses.

For all Scenarios, the demand for exported energy is also held constant at 15.08 EJ/year from 2020 to 2060 (Figure 4). This is consistent with the International Energy Agency's World Energy Outlook 2020 (Stated Policies Scenario). We also note that this required supply of energy for export is maintained at a constant level across every hour of the year (1.7 PJ/hour), as a conservative assumption that means the export system does not solve domestic renewable balancing, and explicitly represents export energy storage and associated costs in Australia.

Figure 3 | Historical Australian domestic GHG emissions and net zero trajectories modelled in this work.

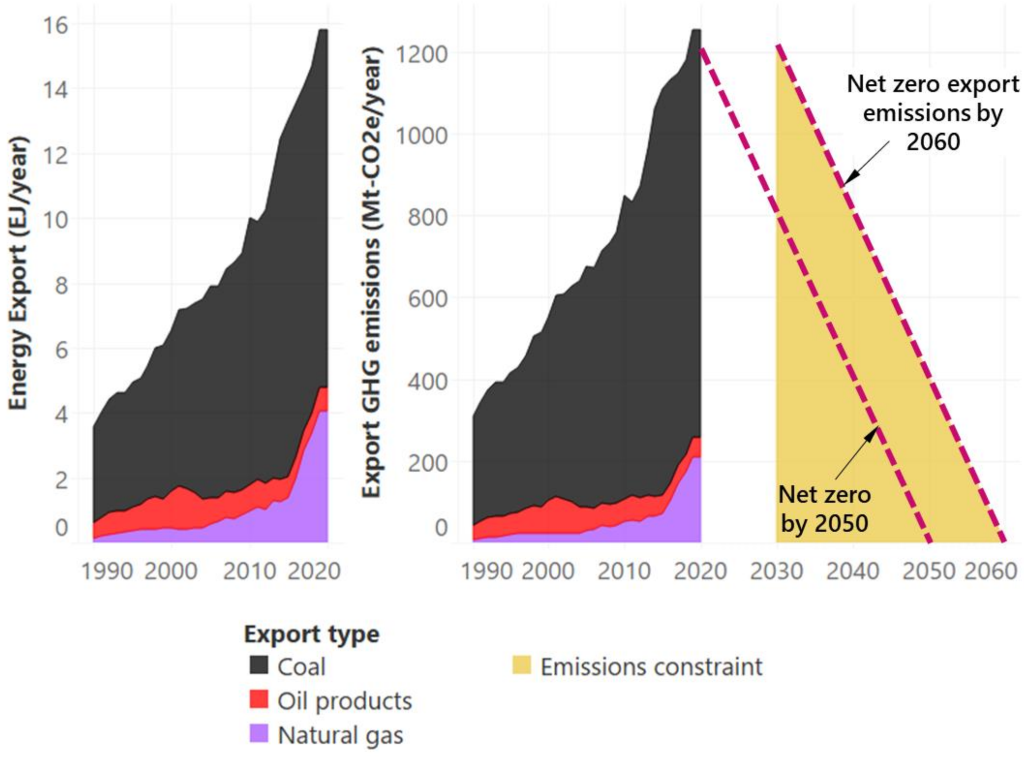


Of course, the exported energy to 2060 will depend on many factors that are uncertain. Australia's exported energy could *increase or decrease* significantly depending on the growth and decarbonisation policies of our major energy importers *and* the prospects of other nations in producing low emission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

The locations of *candidate energy export ports* were set as an input to the modelling after assessing 18 prospective ports around the Nation. This was a multi-criteria assessment that resulted in the 10 ports being selected as candidates: Port of Hastings (VIC), Port of Darwin (NT), Port Bonython (SA), Port of Abbot point (QLD), Gladstone port (QLD), Hay point (QLD), Ashburton (WA), Dampier (WA), Port Hedland (WA) and Newcastle (NSW).

The locations of *candidate* energy export *project zones* were then chosen based on the coincidence of high-quality renewable (wind and solar) energy resource and proximity to existing ports given geographical constraints that we impose in the GIS modelling. Whilst results often allow a clear demarcation between domestic and export energy systems, this is not always the case as we do permit energy transfers between these two systems.

Figure 4 | (left) Historical Australian energy exports (not including uranium exports); and (right) historical and constrained future export embodied GHG emissions.



2.3 Core Scenarios

This project has modelled Australia's domestic and export energy activities from 2020 to 2060 for six Core Scenarios – a Reference Scenario which does not impose a constraint on GHG emissions and five net zero GHG emissions Scenarios. These are summarised in Table 1.

Table 1 | Scenario names and descriptions.

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

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

In all Core Scenarios, we apply constraints on the annual growth rate of large-scale solar PV, onshore wind and offshore wind electricity generation capacities. This growth rate constraint acts as a smoothing function for the model. Specifically, the initial growth rate constraints are 2.5 GW/year and 1 GW/year from 2020 for large-scale solar PV and onshore wind, respectively. From this initial constraint in 2020 the actual modelled growth rate is allowed to compound year-on-year by a maximum of 30% in the 2020s, 20% in the 2030s and 10% from the 2040s onward. For offshore wind, the initial growth rate constraint is 0.5 GW/year from 2026, which is allowed to compound by a maximum of 30% until 2037, 20% until 2047 and 0% from then on. Note that while we model capacity additions in 5-year timesteps, we nevertheless account for compounding maximum growth rates in the intermediate years. Importantly, these constraints are all far above historical best rates of capacity addition and permit a fully renewable energy system by 2050 (domestically) and by 2060 (for exports) should the modelling wish to do this.

2.3.1 Demand side Scenarios

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

E+ (Rapid Electrification) Scenario

The E+ Scenario assumes nearly full electrification of transport and building stocks by 2050. Residential and commercial building energy services to be electrified include air conditioning and space heating, ventilation, water heating, lighting, refrigeration and freezing, clothes washing and drying, dishwashing and cooking. The rollout follows an S-Curve trajectory with full saturation of building stocks achieved by 2050.

The transport sector is divided into light-duty vehicles (LDVs), heavy-duty vehicles (HDVs) and buses. By 2040, 88% of LDV sales are battery electric vehicles (BEVs) and 11% are hydrogen fuel cell vehicles (HFCVs), whilst 65% of HDV sales are BEVs and 34% are HFCVs. The rollout again follows an S-Curve trajectory with full saturation of BEVs and HFCVs in transport stocks by approximately 2050.

E− (Slower Electrification) Scenario

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

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

2.3.2 Supply side Scenarios

E+RE+ (Full renewables rollout) Scenario

The E+RE+ Scenario assumes no fossil fuel use is allowed domestically by 2050 and for exports by 2060. Carbon capture and storage (CCS) is only permitted for non-fossil sourced carbon. This includes but is not limited to non-fossil process emissions from industry, bioenergy carbon capture and storage (BECCS) for biofuels and hydrogen production and direct air capture (DAC) of CO_2.

E+RE− (Constrained renewables rollout) Scenario

The E+RE− Scenario constrains the maximum annual build rates of large-scale solar PV and onshore wind electricity generation capacities more than the other Core Scenarios. Specifically, the same initial growth rate constraints of 2.5 GW/year and 1 GW/year from 2020 for large-scale solar PV and onshore wind are used, but this is allowed to compound at half the rate used in the other Core Scenarios. This Scenario does not alter the growth rate constraints for offshore wind.

If large-scale solar PV and onshore wind are installed up to these applied build rate constraints in every modelled year, the compounding of the build rates would allow 17 GW of large-scale solar PV and 7 GW of onshore wind to be installed in 2025 and 51 GW and 20 GW to be installed in 2030. These constraints were chosen to allow modelled build rates that are, in the near term, roughly 5-10× the highest historical onshore build rates in Australia, and many times greater in the long term. For example, 1.76 GW of large-scale solar capacity was added in 2019, 3.3 GW of rooftop PV capacity was added in 2021, and 1.7 GW of onshore wind capacity was added in 2021.

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

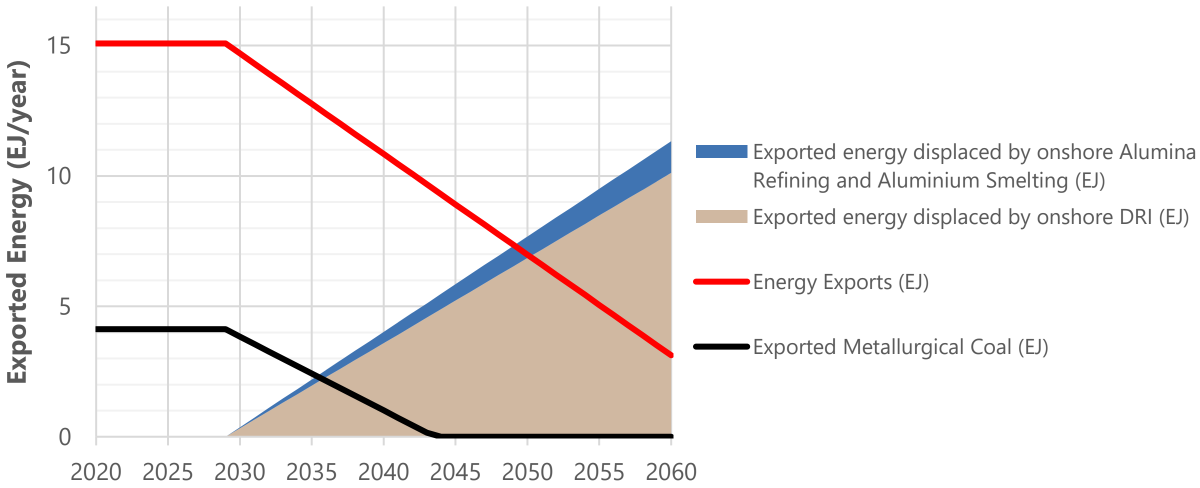
The CCS constraint is also expanded under this Scenario to a total possible injection of 1166 Mt-CO_2/year. Given the build constraints on renewables in this Scenario, expansion of this CCS constraint is required to meet domestic and exported energy demand whilst helping provide a distinctive Scenario relative to the others that do not feature build constraints on renewables. Evidence supporting the choice of this expanded CCS constraint is provided in the companion MASS document. *We emphasise that inclusion of this CCS constraint is not an endorsement of its practicality, just as the modelling of unconstrained renewable build rates is not an endorsement of their practicality.*

E+ONS (Onshoring) Scenario

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

The E+ONS (Onshoring) Scenario therefore seeks to examine how some of our energy exports might be used to displace our iron ore, bauxite and alumina exports with domestically processed pig iron and aluminium for export. In this Scenario, we treat the energy required for onshore alumina refining, aluminium smelting and iron ore reduction as taking away from the modelled energy exports, and not adding to it, as shown in Figure 5.

Figure 5 | Energy Exports in the E+ONS (Onshoring) Scenario.



As with all Scenarios, clean energy is exported primarily as liquid ammonia. However, the energy required for iron reduction, alumina refining or aluminium smelting is either in the form of hydrogen or electricity. As such, the efficiency of ammonia conversion into hydrogen or electricity at the port of delivery is incorporated into the reduced energy exports.

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

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

Australia's existing alumina and aluminium industry, comprising 6 refineries and 4 smelters, transitions to net zero emissions by 2050 as per the E+ Scenario. The transition to domestically produced, clean alumina and aluminium involves swapping fossil fuelled heat for the same thermal energy from hydrogen in the alumina refinery, and the use of inert anodes rather than carbon anodes in the aluminium smelter. The direct GHG emissions from these expanded refineries and smelters are then zero, and the GHG emissions from and costs of their hydrogen and electricity supply forms part of our imposed National GHG emissions constraint trajectory and RIO's optimisation task.

Additional alumina refinery and aluminium smelting capacity is of course required for the additional alumina that must also be processed onshore in this Scenario. We assume existing facilities are expanded to meet this additional capacity so that by 2060 the National distribution of production remains the same. We also impose a +/−20% per hour ramping rate constraint on the electricity load of the aluminium smelters for load balancing purposes.

3 Principles of land use and new energy asset siting

There are no generally accepted methods for integrating energy system planning with the Indigenous Estate, ecosystem conservation and agriculture. The NZAu modelling team developed an approach for identification of land areas that may host new energy assets, based on prior work and regular consultation with:

- The National Native Title Council (NNTC);
- The National Farmers Federation (NFF);
- The Australian Conservation Foundation (ACF) and biodiversity experts.

The team prioritised the use of public, best available and up-to-date data, but acknowledges that important data sets are continually evolving and that approaches to new energy asset siting require regular and timely updates.

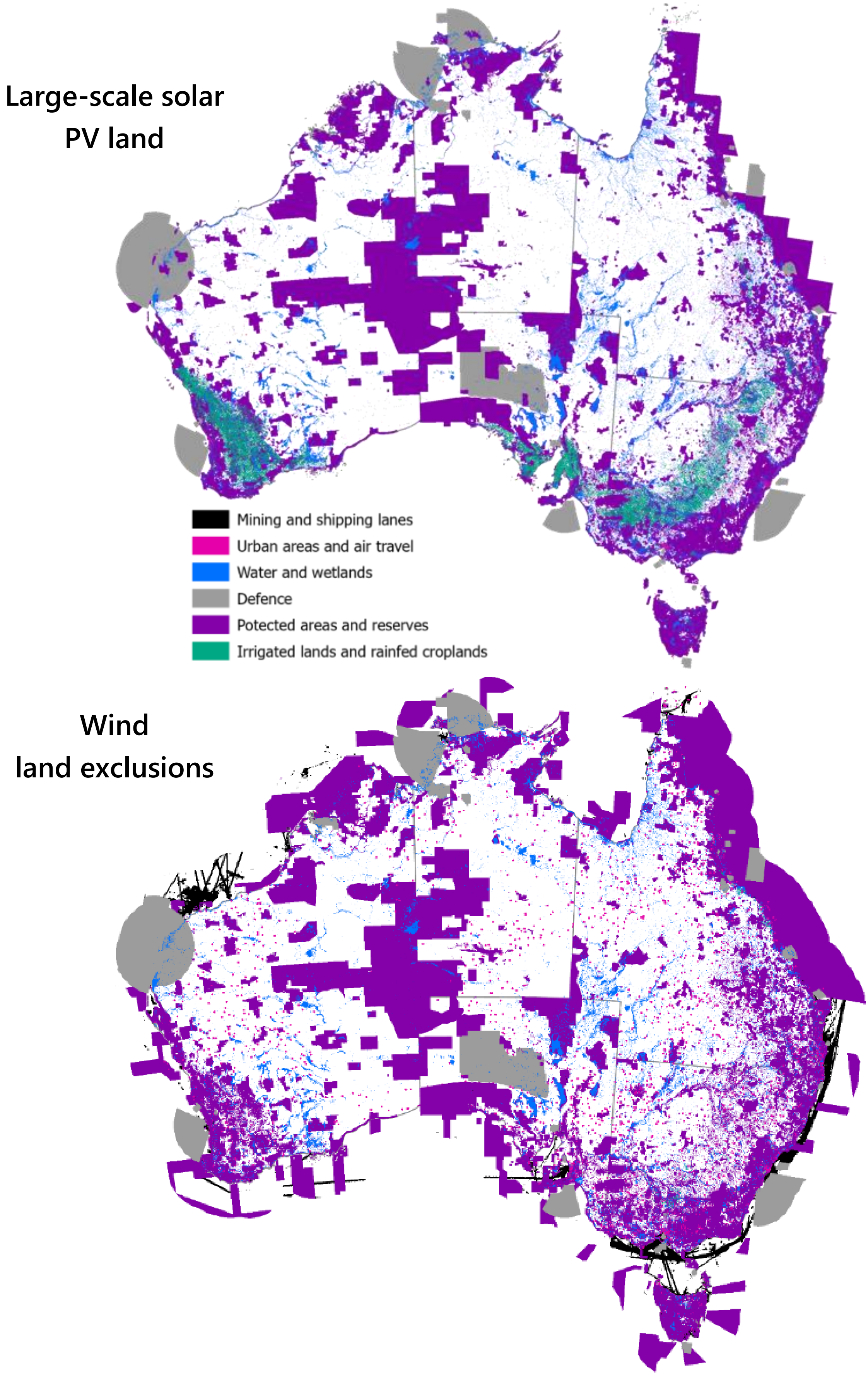
Net Zero Australia's principles of land use and new energy asset siting can be summarised as follows.

- Do not consider land and sea areas excluded by law.
- Remove from consideration all land areas for which empirical evidence, research, or stakeholder interaction provides reasonable cause and document transparently such exclusions in companion reports: *Methods, Assumptions, Scenarios and Sensitivities* (MASS) and *Downscaling – Solar, wind & electricity transmission siting*. Specific examples of land type exclusions are as follows.
    - No siting of new variable renewable energy (VRE) infrastructure on land cover categories specified as irrigated lands and no siting of new solar PV infrastructure on rainfed cropland (NFF consultation).
    - Unless specifically protected in a base exclusion dataset, all Indigenous Estate categories are included for the purposes of siting energy infrastructure (NNTC consultation).
    - Exclude the critical habitat of threatened species and ecological communities (ACF consultation).
    - Prefer existing transmission corridors over greenfield corridors.
    - Exclude national reserves, those in the Collaborative Australia Protected Area Database, and inland water, salt lakes and wetlands.
- Update the approach as our understanding of risks and threats evolve, collaborations deepen, and available data allows. A number of updates have been made throughout NZAu's two-year modelling period. Final rounds of stakeholder interactions have already identified the following areas for updating in future work.
    - Consideration of the Indigenous Estate in offshore areas.
    - Addition of Key Biodiversity Areas and intact biodiversity areas to exclusion areas, and updating of the biodiversity approach as new resources emerge.

Use of these principles resulted in a different set of land exclusions for the identification of solar PV and wind candidate infrastructure project areas, as shown in Figure 6. Additional VRE exclusions (e.g. slope, overlap with existing projects, ocean depth, distance from load, capacity factor, population density) were also considered before siting VRE projects. A similar process was followed in the siting of electricity transmission and both processes for VRE and electricity transmission siting are detailed in the *MASS* and *Downscaling – Solar, wind & electricity transmission siting* companion reports.

Candidate VRE project areas were identified after accounting for the land exclusions shown in Figure 6, each with an associated hourly generation availability profile. The regional investments tool (RIO) was then used to determine the least-cost optimal portfolio of VRE projects across the country, given the candidate project areas and the whole of system optimisation. These portfolios are presented in the aggregate system level results, and with granular geospatial detail in mapped infrastructure results that follow.

Figure 6 | Base large-scale solar PV (top) and wind (bottom) land exclusion layers used for the identification of candidate project areas.



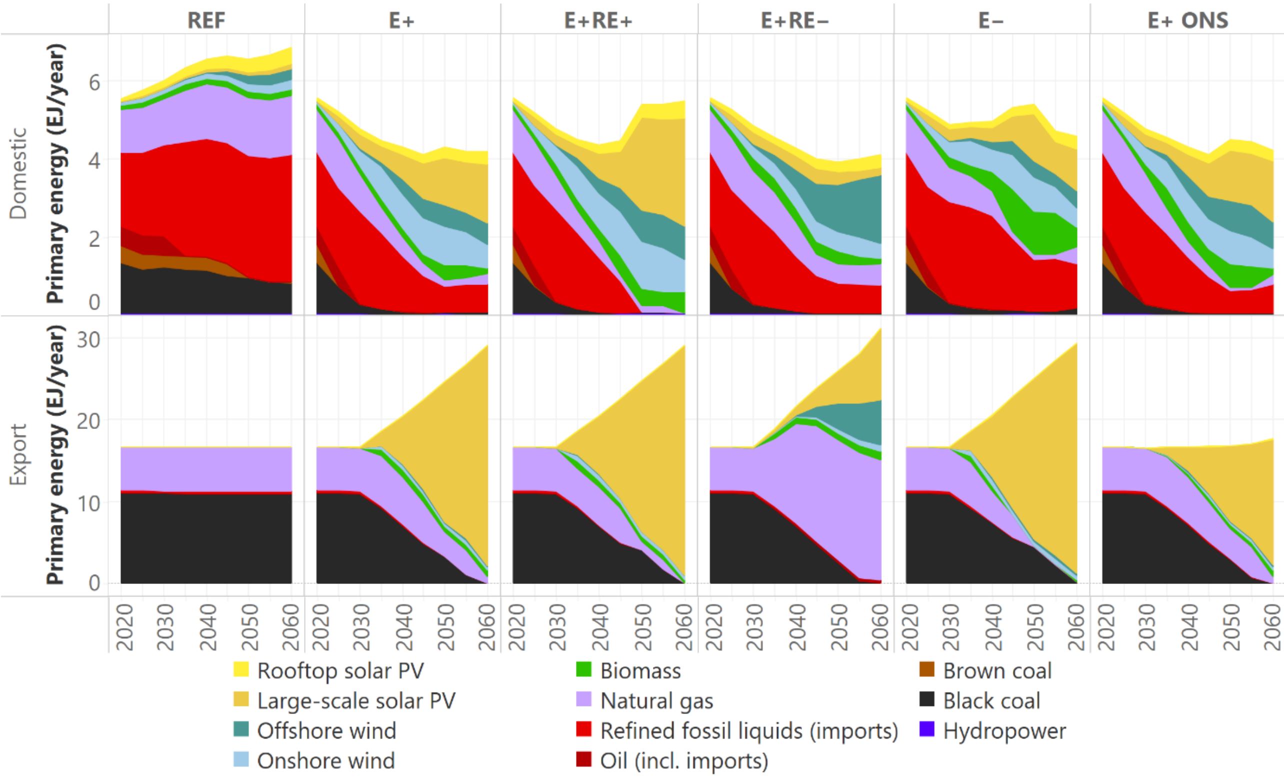
4 Overall energy, emissions and exports

4.1 Primary energy

Figure 7 shows the primary energy for the domestic and export energy systems by different sources. The primary energy supply for exports is much higher than for the supply of the domestic energy system, noting that final export demand is held constant at approximately 15 EJ pa. Renewable electricity leads energy supply except in E+RE−, where natural gas dominates exports due to constraints on renewable deployment and the associated, immense expansion to the maximum allowable rate of geological sequestration.

Figure 7 also shows that the total domestic primary energy supply is lower than REF in all net-zero Scenarios due to productivity gains from end-use electrification and efficiency improvements. The large rise in primary energy for exports is due to losses from converting renewable power to low-emission hydrogen carriers; in this case ammonia. Finally, offshore wind competes to supply the domestic energy system in all Scenarios and is most significant in E+RE− for both domestic supply and exports.

Figure 7 | Primary energy for the domestic and export energy systems, by different sources.



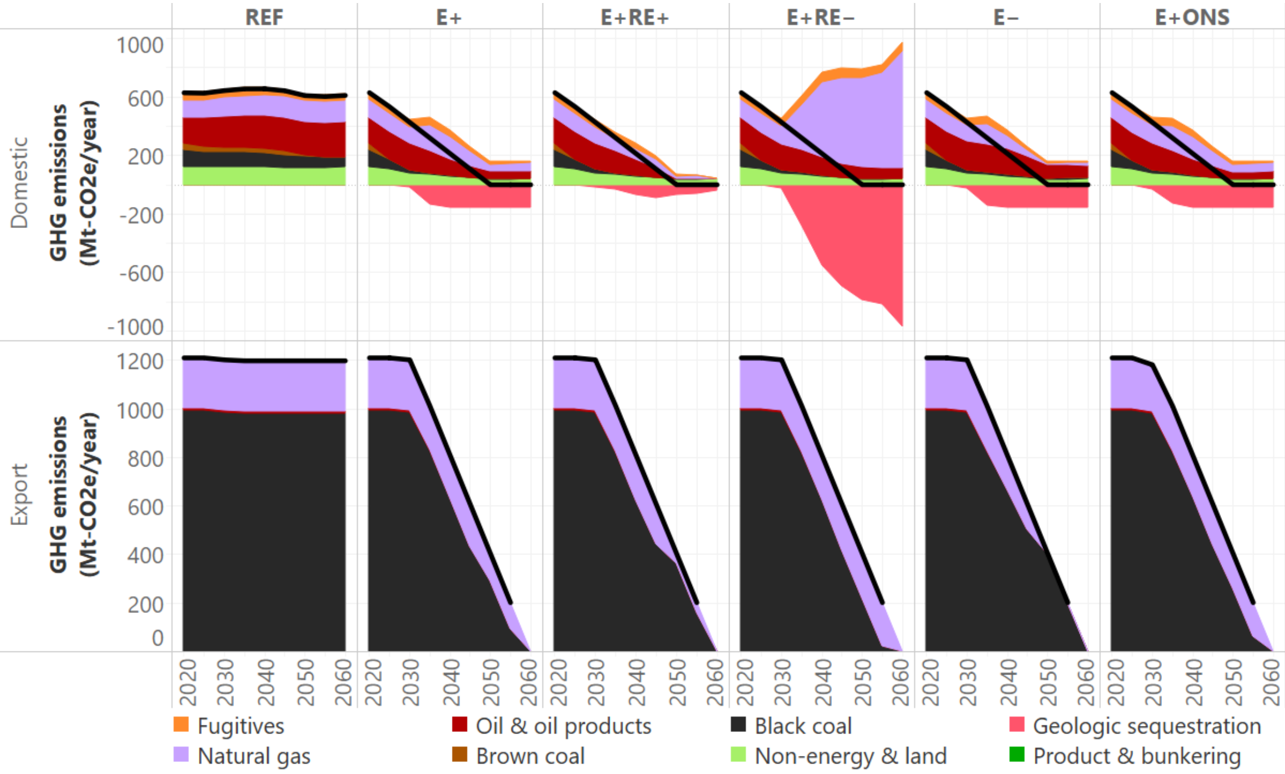
4.2 Emissions

Figure 8 shows the GHG emissions by primary energy source and carbon sink, along with the net emissions. As discussed in Section 2.2, the export decarbonisation task is roughly 2× abatement task of the domestic system. This underscores the importance of Australia's participation in the inherently global abatement task. Net emissions go to zero in 2050 for the domestic energy system. They start to fall in 2030 and go to zero in 2060 for the exports. Domestic coal emissions decline most rapidly, followed by oil and gas, as would be expected given these fuels' respective emissions intensities.

Figure 8 also shows that geologic sequestration plays an important role in all net-zero Scenarios. Geologic sequestration does not increase from 2040 in the E+, E− and E+ONS Scenarios when their 150 Mt pa CO_2 injection rate limit is reached, forcing further clean energy to be sourced from renewables. The E+RE− Scenario then shows an immense uptake of geologic sequestration, which is largely for 'blue' hydrogen production and export as ammonia.

Arguably of most significance is the result in Figure 8 for the E+RE+ Scenario, which features solely renewable new build for energy generation but which still relies significantly on geologic sequestration during the transition. In this case, geologic sequestration is used to offset sub-sectors such as steel and cement production and aviation via several different pathways. This result demonstrates that the uptake of renewables and geologic sequestration should not be considered as exclusive options. Rather, both are still needed even in a Scenario that does not permit the continued use of fossil fuels in the energy system.

Figure 8 | Domestic and export GHG emissions. The black line shows net emissions, which go to zero in 2050 for the domestic system, and in 2060 for the export system.



4.3 Exports

Figure 9 shows the contributors to the annual exported energy over the modelled export system transition. As stated in Section 2.2 energy export demand is held constant at approximately 15 EJ pa, which is about 3× domestic energy demand in 2050.

Once the export emissions constraint defined in Section 2.2 starts to bind in 2030, coal and LNG exports start to fall rapidly. This falling share of fossil exports is substituted with clean alternatives. This includes the expansion of an undersea electricity cable to Singapore, which is a modest share of the total export energy but still more electricity in 2050 than is currently consumed in Australia! Ammonia as our assumed hydrogen carrier nonetheless dominates energy exports except in E+ONS, where the onshore processing of Australian iron ore and bauxite to pig iron and aluminium displaces the majority of our current energy exports.

Figure 9 | The form of annual exported energy over the modelled export system transition.

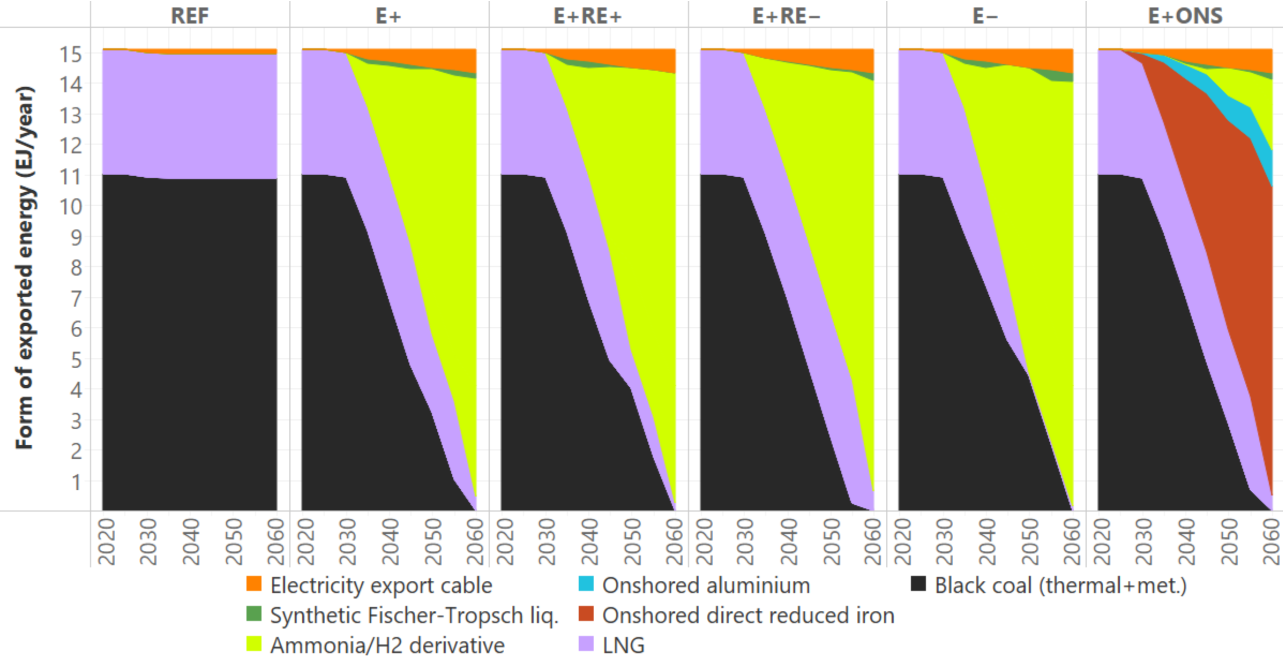


Figure 10 shows the contributors to and the State/Territory of origin of the annual exported energy in the E+, E+RE− and E+ONS Scenarios. The other Scenarios show intermediate results given their different input assumptions. Unsurprisingly, there is a strong heterogeneity of exported energy or clean commodity by state. As the transition to net zero progresses, Queensland and New South Wales no longer export coal, and ammonia exports originate from the states with the best solar resource. Perhaps surprisingly, Victoria also exports significant clean energy in the E+RE− Scenario, driven by offshore wind.

Figure 10 also shows that the onshore production of pig iron is exported from Western Australia in the E+ONS Scenario. This is because this state has both the iron ore and renewable energy resources to fulfill this role. The onshore production of aluminium is exported more uniformly across the Nation, from Queensland, New South Wales, Victoria and Tasmania, since our modelling assumes that existing alumina refineries and aluminium smelters are augmented to meet this demand.

Figure 11 shows the installed capacities of the export supply chains over the modelled export system transition. The scale of these generation and conversion capacities must be noted. These are in thousands of GWs and therefore are an order of magnitude larger than the current capacity of Australia's electricity system. This underscores the scale of our export industry and the decarbonisation challenge that it presents.

Figure 11 shows that large-scale solar PV across the sunbelt from northern Western Australia to northern Queensland is the dominant source of primary energy for clean energy exports. Almost all electricity serving the export market is generated from large-scale solar PV with a combined capacity of 1-3 TW, i.e. 1000-3000 GW. In this case, electricity from solar PV is converted to ammonia as the modelled energy carrier for shipping first via electrolysis and then using Haber-Bosch synthesis in all Scenarios. Where renewable build rates are constrained in the E+RE− Scenario, export energy is supplemented by autothermal reforming of natural gas with carbon capture (ATR w/cc) and hence the renewable build is reduced.

Also, since our modelling requires that the supply of energy to meet export demand is constant across every hour of the year, Figure 11 shows that we need significant hydrogen storage together with some battery storage (not shown here). This hydrogen storage is assumed to be undertaken in engineered underground caverns rather than natural underground formations since we were not able to characterise the available capacity of the latter in this study. However, we are aware of ongoing research on this very topic, and should significant natural formations for hydrogen storage be prospective, the capacity of hydrogen storage should at least stay the same as this study and potentially increase given the lower costs of storage in natural formations.

Figure 10 | The form and origin (states/territory) of annual exported energy over the modelled export system transition and the E+, E+RE− and E+ONS Scenarios.

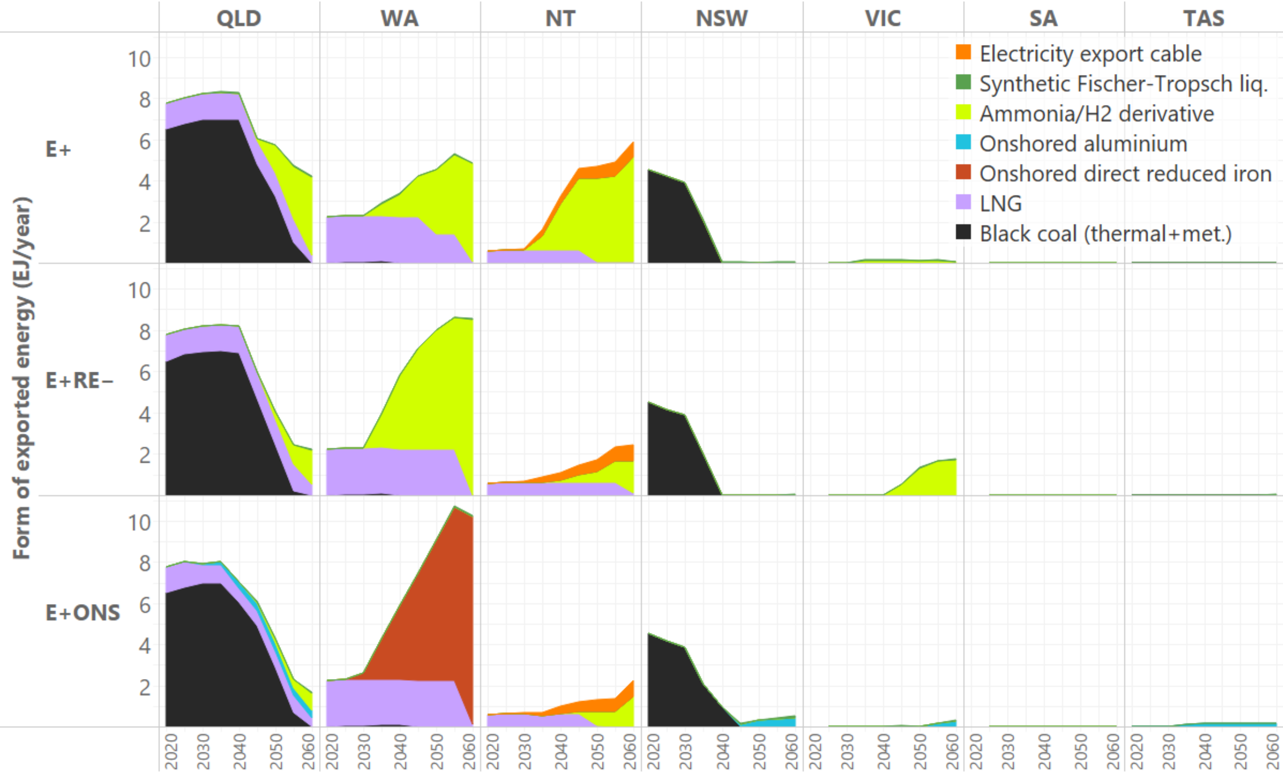
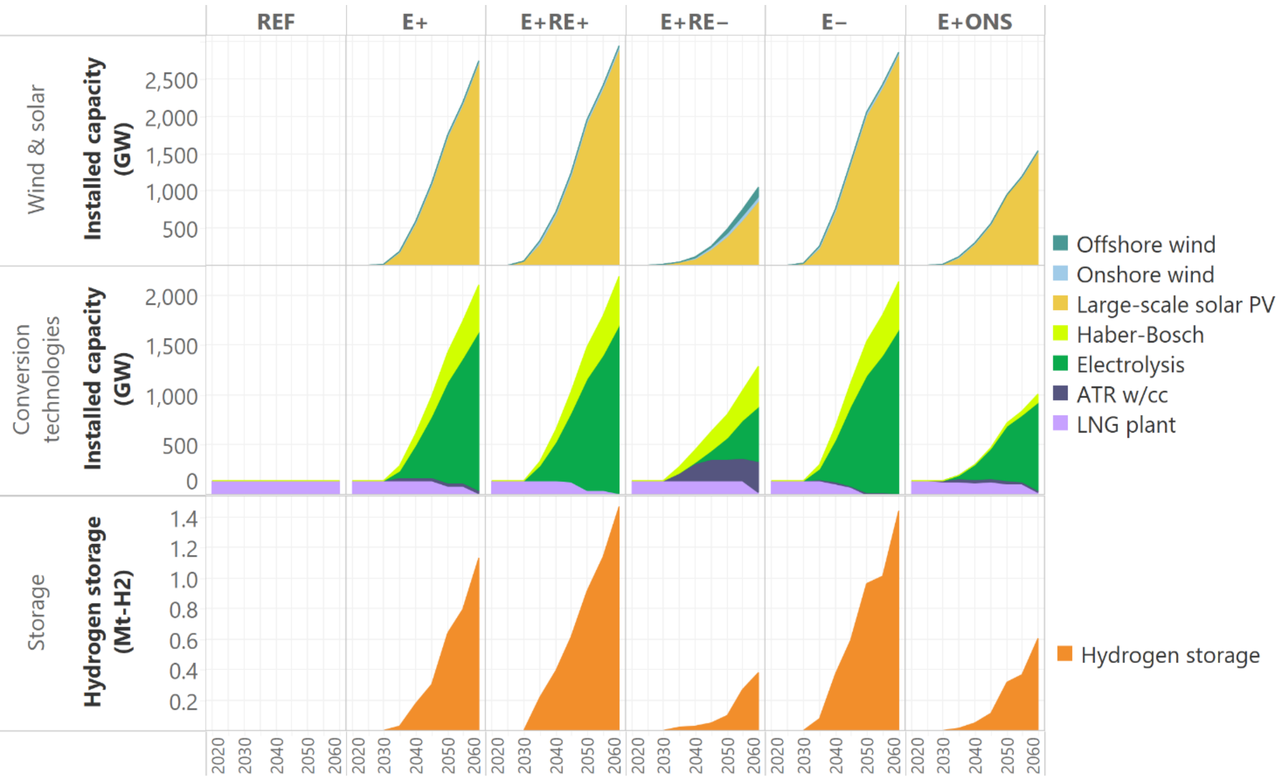


Figure 11 | The installed capacities of export energy supply chain over the modelled export system transition.



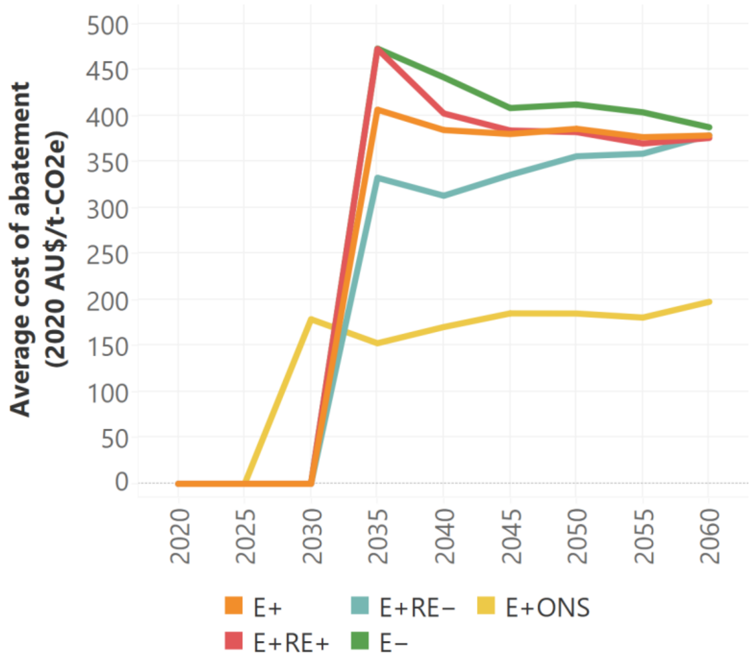
Finally, we now consider the costs of abatement (CoA) for these different export options in Figure 12. We define this cost of abatement by the differences in the levelised costs pa divided by the differences in their offshore emissions, i.e.

$$\text{CoA}\left(\frac{\$}{\text{t-CO}_2}\right) = \frac{\text{levelised export cost pa of a given net-zero Scenario} - \text{levelised export cost pa of the REF Scenario}}{\text{GHG emissions pa of the REF Scenario} - \text{GHG emissions pa of a given net-zero Scenario}}.$$

This measure is an indicator of what premium per tonne of GHG avoided our export customers would need to pay for our energy exports and non-energy exports (i.e. pig iron and aluminium) in a given year. Figure 12 shows that these costs of abatement all rise to about 400 $/t-$CO_2$ by mid-century in the Core Scenarios that feature ammonia export primarily displacing our fossil exports. Of note, onshoring (the E+ONS Scenario) has a significantly lower cost of abatement because of the avoided inefficiencies of producing and reconverting an exportable hydrogen carrier. This is consistent with this Scenario's reduced builds of wind, solar and hydrogen storage in Figure 11 above.

Indeed, the differences between the costs of abatement for the E+ONS Scenario and the other net-zero Scenarios is expected to be significant per tonne of GHG avoided or per tonne of exported pig iron or aluminium. This, in turn, suggests that the onshore production of clean pig iron and aluminium may significantly align the global decarbonisation task, the interests of international customers and our domestic build task. That is, on the assumption that Australia's clean energy exports are competitive in a future, decarbonising world, our international customers for these two commodities could find it in their commercial interest to buy these clean non-energy commodities produced in Australia rather than purchase them from production sites which do not have clean energy and non-energy resources co-located. This then makes the build task in Australia smaller per tonne of global GHG emissions abated since the onshore production of these non-energy commodities is more energy efficient.

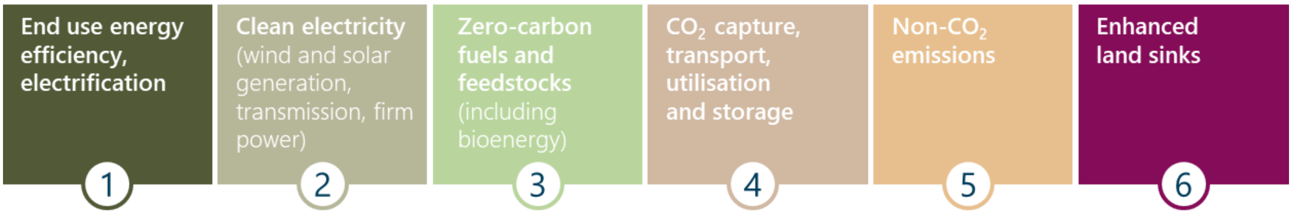
Figure 12 | The cost of abatement for the net zero export supply chains, relative to that of the REF Scenario.



5 Pillars of Decarbonisation

Key findings from the Net Zero Australia project are presented in this section, according to the Six Pillars of Decarbonisation shown in Figure 13.

Figure 13 | The Six Pillars of Decarbonisation, by which we present modelling results. are presented.



5.1 Pillar 1: End use energy efficiency and electrification

Two major changes to the use of energy underpin the net-zero transition. First, a higher end use energy efficiency, through improvement of incumbent appliance types and technological development of novel and emerging technologies, and second, a shift in energy consumption to different energy vectors, through fuels switching. Electrification is perhaps the most prevalent, yet not the only fuel switching mechanism: some inherently hard-to-decarbonise end use energy sectors like industry and transport where electrification may not be viable or practical will rely on the switching from fossil to clean fuels. Energy efficiency improvement and fuel switching are current trends which are set to experience a fast acceleration. For example, the International Energy Agency (IEA) expects energy efficiency-related investment to rise by 16% in 2022 – to just over USD 560 billion – and by a further 50%, to USD 840 billion/year from 2026 to 2030, under currently stated policies; strong customer spending, for instance in switching to electric cars, has been registered alongside. NZAu's two demand-side Scenarios, E+ and E−, explore alternative future uptake rates of end use energy measures. Associated demand-side costs were captured through a detailed account of individual technology uptake and associated costs, where possible, or through overall costs of energy efficiency and/or fuel switching measures. The resulting effect of such end use energy changes on domestic Australian final energy demand is shown in Figure 14.

Compared with the REF Scenario that considers limited energy efficiency improvement and no fuel switching, the domestic energy demand in both E+ and E− Scenarios drops significantly, from the projected 5.5 EJ/year in 2050 for REF, to 3.5 and 4.2 EJ/year for the E+ and E−, respectively. Notably, this reduction is observed despite the growth of in the main demand drivers (e.g. the ~40% Australian population increase by 2050 or the 1.5% annual increase in gross domestic product, as projected by the Australian Bureau of Statistics) incorporated in the NZAu modelling. Energy efficiency improvements drive ~40% of the overall productivity gains, averaging ~0.5% per annum for REF and ~1% per annum for both the E+ and the E− Scenario. Electrification drives the remainder ~60% of productivity gains.

The energy-system effect of end use energy changes is twofold. First, the total volume of domestic energy demand to be supplied changes: depending on the Scenario considered, it evolves to being about 20-30% the export energy demand, which is held constant at 15 EJ/year. Second, the share of different energy vectors supplying such domestic demand also changes: the share of electricity over the total grows from the current ~20% figures to 31% by 2050, in the E– Scenario, and almost 50% in E+. At the same time, residual demand for fuels in E− remains 69% of final energy demand because of this slower electrification, and therefore requires either decarbonisation of fuel supply upstream of final consumption, or offsetting of residual fossil fuel emissions.

Overall, all domestic sectors electrify, undergoing an increase in final demand for electricity, presented in Figure 15. However, the largest and most rapid demand growth is registered in transport, especially for the E+ Scenario, where the final electricity demand of the national transport sector increases from 6 TWh in 2020 to 137 TWh in 2050. Other projected energy vector shifts are highly sector-dependent; they are independently addressed in the sections below.

Figure 14 | Domestic final energy demand by end-use energy vector and its evolution over time.

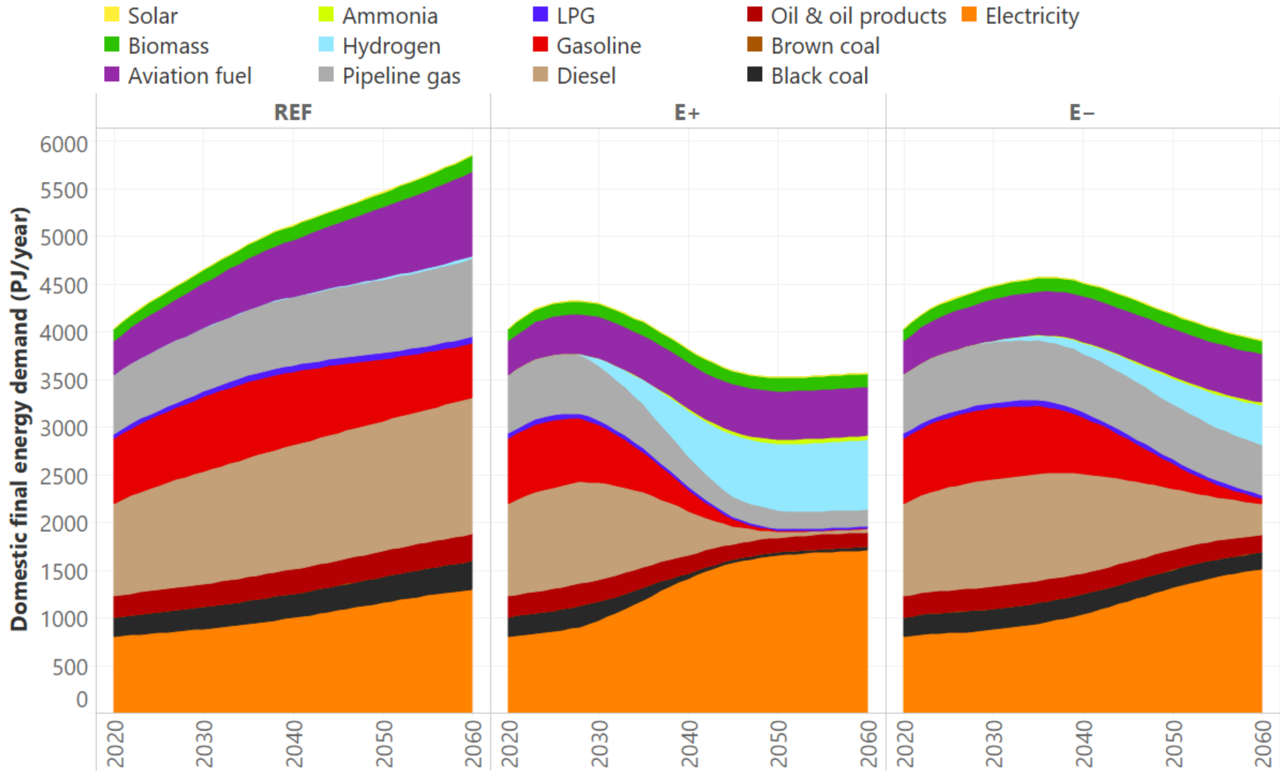
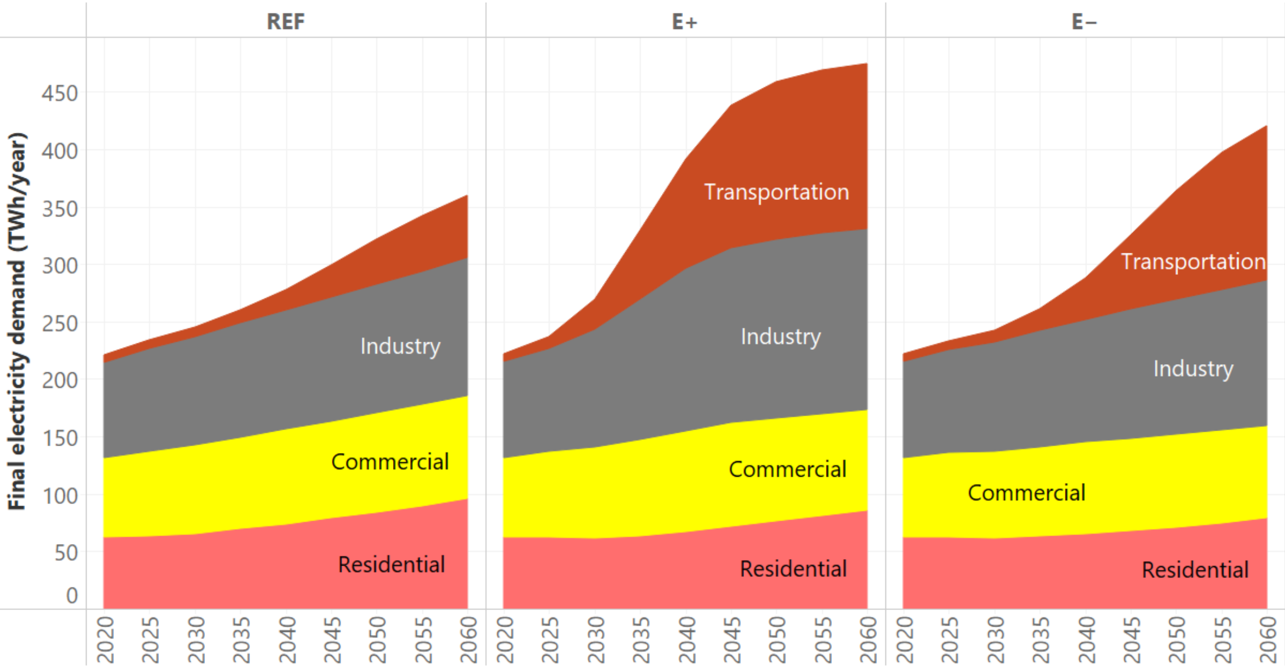


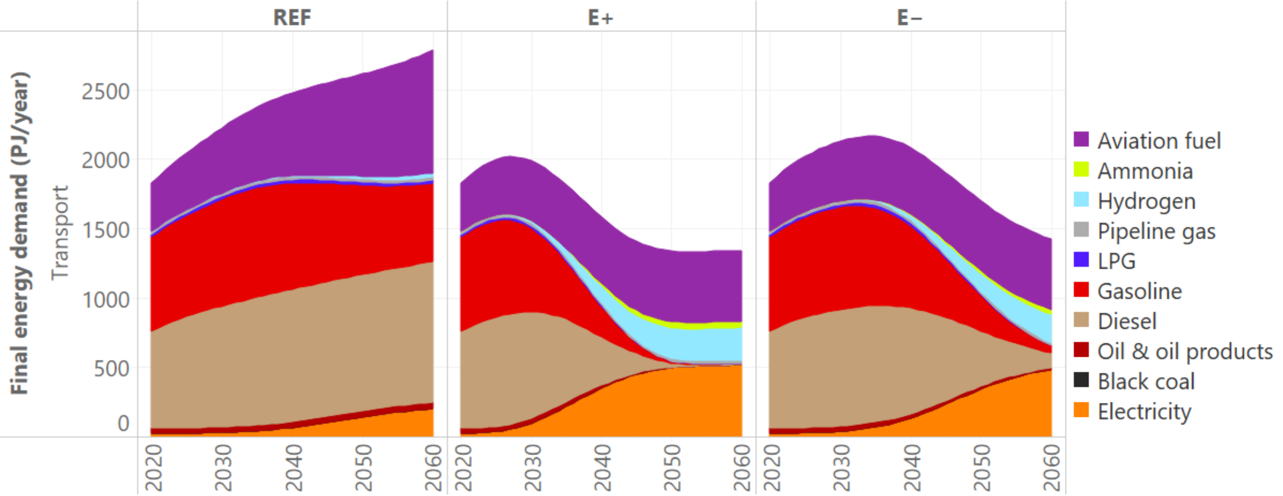
Figure 15 | Growth in domestic final electricity demand, by end-use sector.



5.1.1 Transport

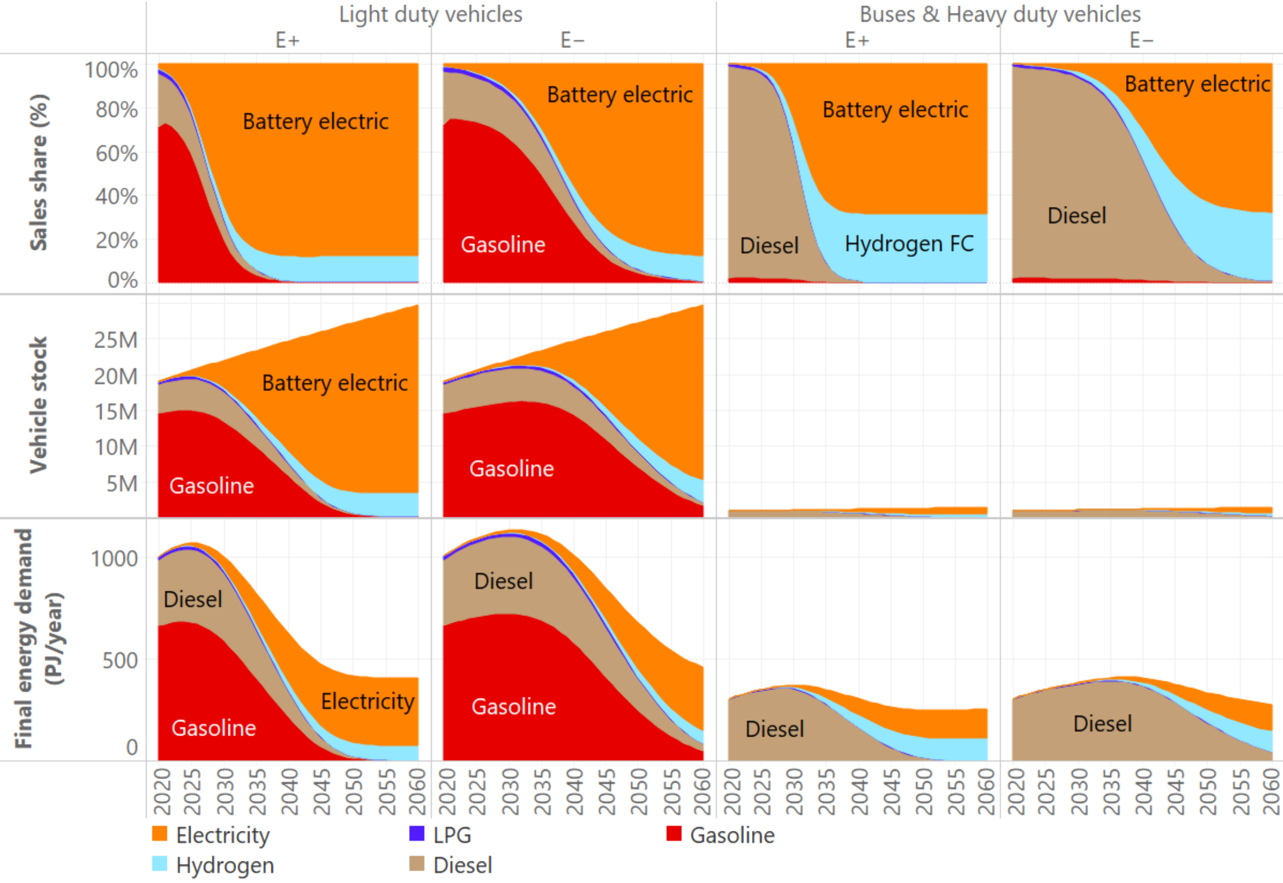
The projected evolution of transport final energy demand between 2020 and 2060 is reported in Figure 16. Transport undergoes extensive electrification, but fuels will still need to supply more than half the overall demand, especially in aviation, shipping and rail transport. More specifically, by 2050 international shipping is assumed to completely switch to ammonia, while 67% of domestic shipping is powered by ammonia/hydrogen and the remainder 33% electrified in the E+ Scenario; fossil fuels in the rail transport are replaced by 90% ammonia/hydrogen and 10% electricity. In the E− Scenario, the same fuel switching is delayed by 20 years. As a result, gasoline and diesel are almost completely phased out by 2050, in the E+ Scenario and contribute a residual ~650 PJ/year (about 40% of the overall transport demand) in the E− Scenario, where the electrification is slower.

Figure 16 | Transport final energy demand by end-use energy vector and its evolution over time.



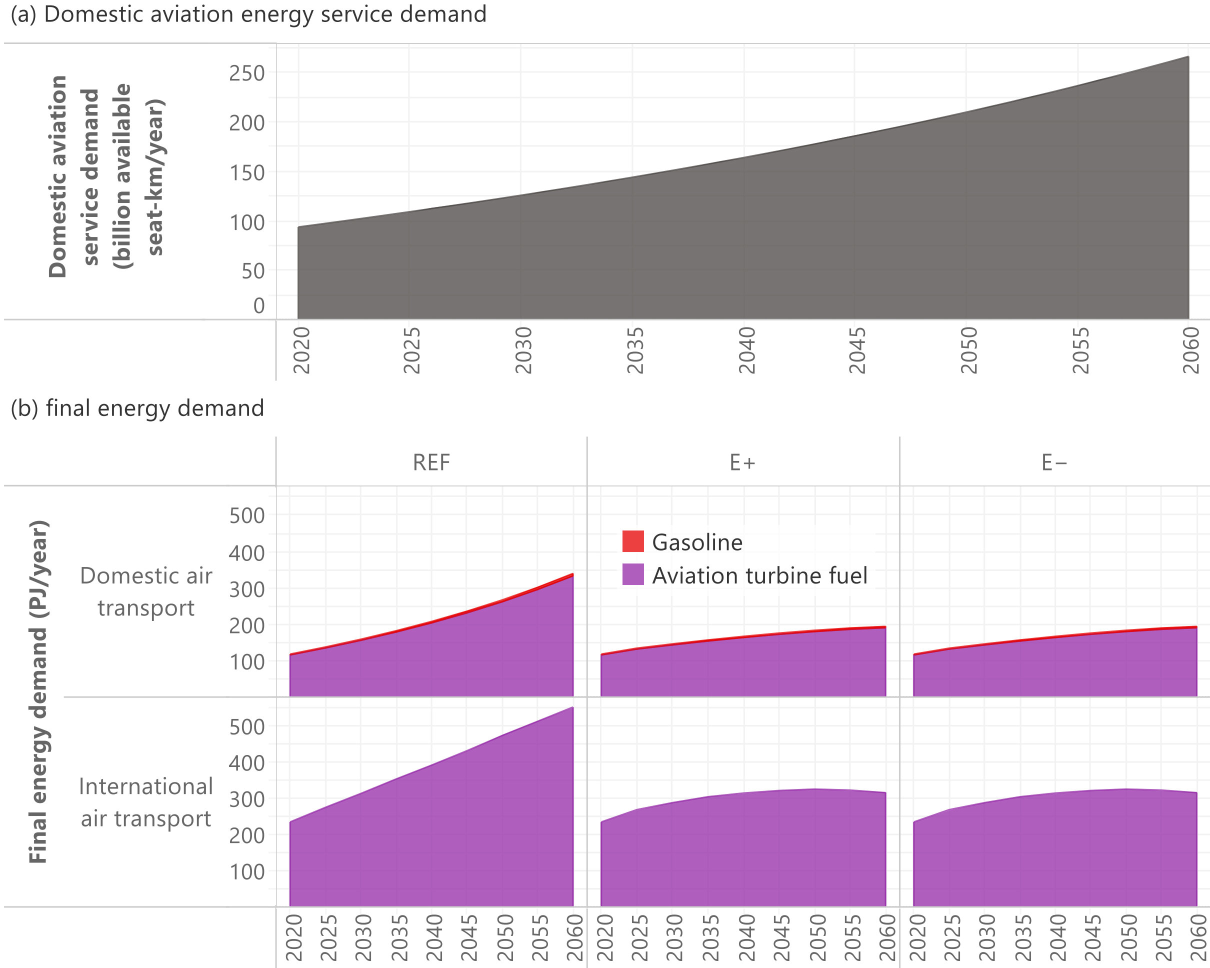
Electrification of road transport is achieved through vehicle stock replacement, the dynamics of which are presented in Figure 17, for LDVs (passenger and light commercial vehicles) and HDVs (rigid, articulated and other trucks), as well as buses. New LDV sales rapidly switch from internal combustion engine to electric-drive vehicles (EVs). In the E+ Scenario, 100% of new sales are emission-free vehicles in 2040. Of these, ~80% are EVs and the remaining ~20% use H_2 fuel cells; in both cases, these do not produce tailpipe GHG emissions, so that by 2050 the light-duty vehicle fleet is fully decarbonised. An analogous trend is reached for the HDVs fleet, but with a much larger proportion of H_2 fuel cells units in the final stock (about 40%). In the E− Scenario, the described shift is delayed: new sales are now fully decarbonised by 2060 but internal combustion engines are still in use for a residual portion of the fleet and residual tailpipe emissions for LDVs is on a downward trend, but not yet zero.

Figure 17 | Vehicles sales, stock evolution and final energy demand of the road transport fleet, by fuel and vehicle technology.



Alongside electrification, residual demand for liquid transport fuels, particularly in the E− Scenario, necessitates the use of bio-fuels, e-fuels, or alternative carbon offsetting. Aviation, for which no change in the fuel is envisioned in the NZAu modelling represents a stark example. Energy efficiency improvements will contain the rise in final energy demand for aviation, as reported in Figure 18, but either the development of cost-competitive clean fuels or the use of other types of offsets will nonetheless be required.

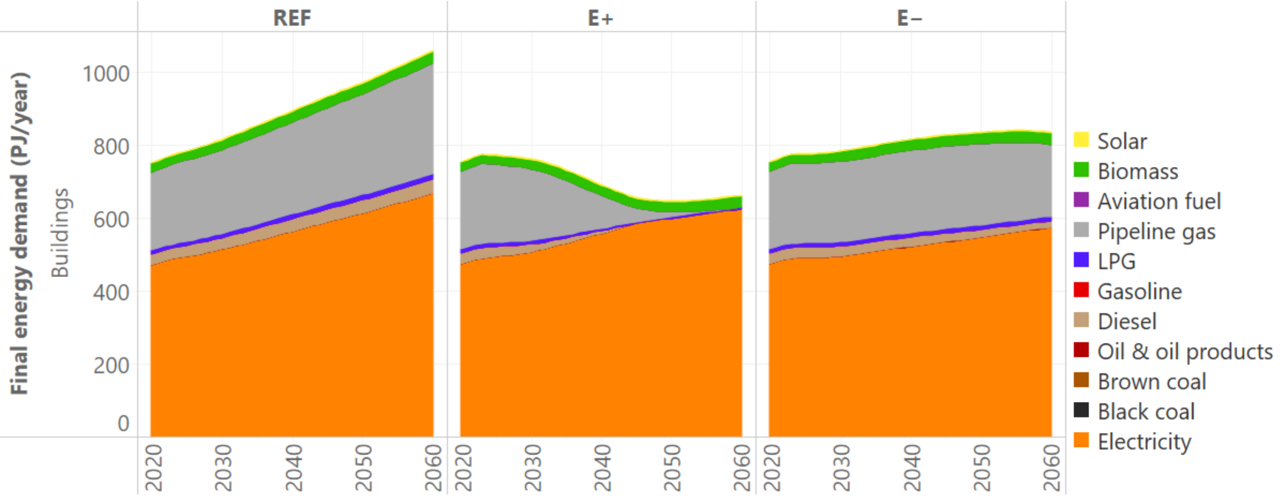
Figure 18 | (a) Domestic aviation service demand projection; and (b) final energy demand for both domestic and international air travel.



5.1.2 Buildings

Figure 19 shows the projected evolution of the domestic final energy demand of buildings, an aggregation of residential and commercial sectors, from 2020 to 2060. Compared with 2020 figures, two opposite trends are projected for the E+ and the E− Scenario, with an overall decrease in the final energy demand of buildings for the former by 2050, and an increase for the latter. As a consequence of energy efficiency improvements and electrification, the residential final energy demand can even be lower in 2050 than it is currently. Both the residential and the commercial sectors are nearly fully electrified by 2060 in the fast fuel switching E+ Scenario. E− retains high volumes of pipeline gas (mostly natural gas, but may be decarbonised gas) demand to 2050, which needs to be decarbonised upstream or offset.

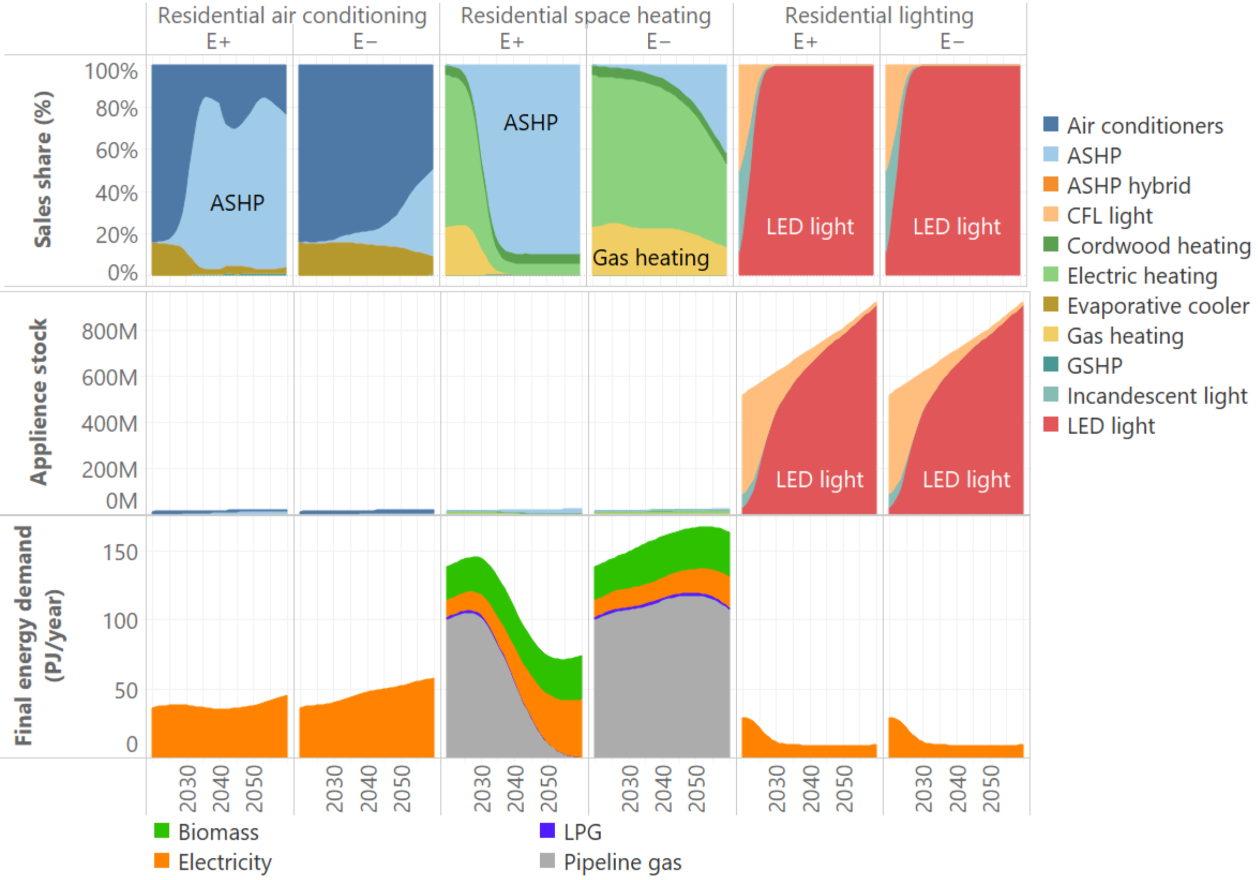
Figure 19 | Buildings final energy demand, by end-use energy vector and its evolution over time.



Between 2020 and 2050, energy service demand increases across all Scenarios, following the rise of most demand drivers. Both the total domestic final energy demand and the overall share attributed to buildings over the other demand sectors barely change. However, Figure 20 shows that different subsector contributions to buildings' final energy demand increase or reduce more significantly, as a result of variations in demand drivers and technology deployment. The highest growth is registered for air conditioning needs, which double by 2050 due to the compounding effects of population growth and an increase in cooling degree days. Space heating demand, on the other hand decreases over time despite population growth and the associated rise in the residential heated area, underpinned by energy efficiency increase and electrification through widespread installation of new electric heating supply technologies, mostly Air Source Heat Pumps (ASHPs), and other electric appliances. The predicted technology sales and stock evolution, together with associated energy demand for the residential air conditioning, space heating and lighting is presented in Figure 21.

Figure 20 | Change in the final energy demand of buildings between 2020 and 2050 and share of individual building appliance/technology groups; E+ and E– Scenario.

Figure 21 | Technology and appliance sales, stock evolution and final energy demand in the residential building sector; E+ and E− Scenarios.



Over time, a transition from electric heating to more productive ASHPs can be observed for both Scenarios. In the E+ Scenario, ASHP supply around 80% of the total energy required for space heating in 2050, while most of the total energy demand is provided by electric and gas heating technologies (with the potential use of bio- and synthetic methane) in the E− Scenario. Regardless of the Scenario, NZAu results suggest states that currently rely on gas for heating purposes given their proximity to gas reservoirs (e.g. Victoria and Western Australia) preserve a larger penetration of gas heating appliances also up to 2050. Similar to space heating and air conditioning, productivity gains are observed in residential lighting, this time mostly coming from the uptake of LED lighting, which reduces demand by almost 4% each year, despite service demand growth.

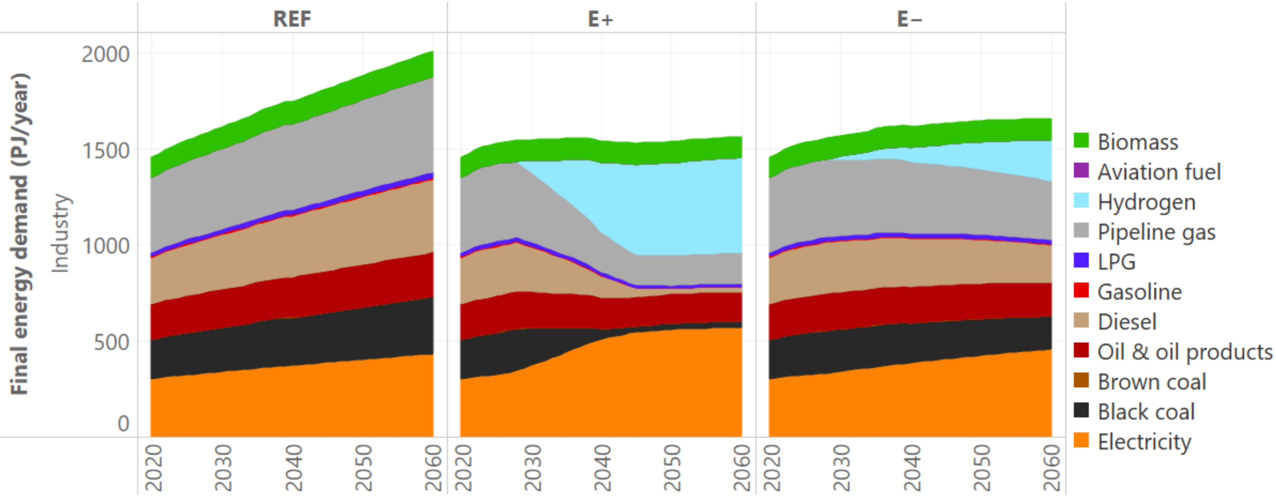
The buildings sector in the E+ Scenario is almost fully electrified by 2050, with a residual ~50 PJ/year (about 7% of the buildings energy demand) to be supplied by a mix of, mainly, biomass and pipeline gas. In NZAu, no change in the use of biomass for buildings space heating has been modelled, although it is likely that some of this biomass use would further undergo electrification, particularly to reduce levels of particulate emissions from biomass space heating systems. In the E− Scenario, the fuel switching is slower, and gas is used to supply about 23% of the energy demand.

Prompted by this change in electricity demand and associated peak loads, as well as pipeline gas demand, electricity and gas distribution networks will also evolve to accommodate the domestic users' demand from buildings, transport and industry. We have modelled the augmentation, depreciation and renewal of distribution assets during the net-zero transition, and have estimated an overall investment in electricity distribution networks of ~$360 billion and ~$230 billion, for E+ and E−, between 2020 and 2060. For gas distribution networks, these figures are $11 billion and $25 billion for the E+ and E− Scenarios. The country-wide regulatory asset base (RAB) of electricity distribution networks grows from ~$90 billion to ~$145-180 billion in 2050, depending on the Scenario. The RAB of gas distribution networks decreases from $14 to $4.4 billion in E+ and $13.5 billion in E−. Yet, very minor or no asset stranding is predicted, even for gas distribution networks, since a 20 – 30 year transition is aligned with the age of current assets, so that most of them reach their natural end-of-life. Although significant asset stranding does not appear to be inevitable, relevant associated questions remain about: how to best coordinate the net-zero transition without compromising network reliability due to withdrawal of network O&M as the gas distribution network ages; and the increased cost per customer of maintaining network O&M.

5.1.3 Industry

Figure 22 shows the modelled evolution of industry final energy in Australia, between 2020 and 2060. Contrary to other sectors, projected demand from industry consistently grows across Scenarios, despite an imposed increase in energy efficiency of 1% per annum across the whole sector. Aggregated final demand in 2050 is 1,500 PJ/year for the E+ Scenario and 1,600 PJ/year for the E− Scenario, as compared with the ~1,400 PJ/year in 2020. Only a minor portion of the industry demand (between 20% and 80%, depending on the specific industry sub-sector) is electrified by 2045 in the E+ Scenario and the same portions with a 60-year delay, for the E− Scenario. Hydrogen plays a major role in the decarbonisation of the industrial sector, especially for those activities where electrification is not a viable option. By 2050, one third (480 PJ/year) of the industrial demand is supplied by H_2 in the E+ Scenario and 140 PJ/year in E−. The residual demand for liquid and gaseous fuels requires production of clean fuels though the use of wind, solar and biomass, fossil fuels with CCS, or emission offsetting.

Figure 22 | Industry final energy demand by end-use energy vector and its evolution over time.

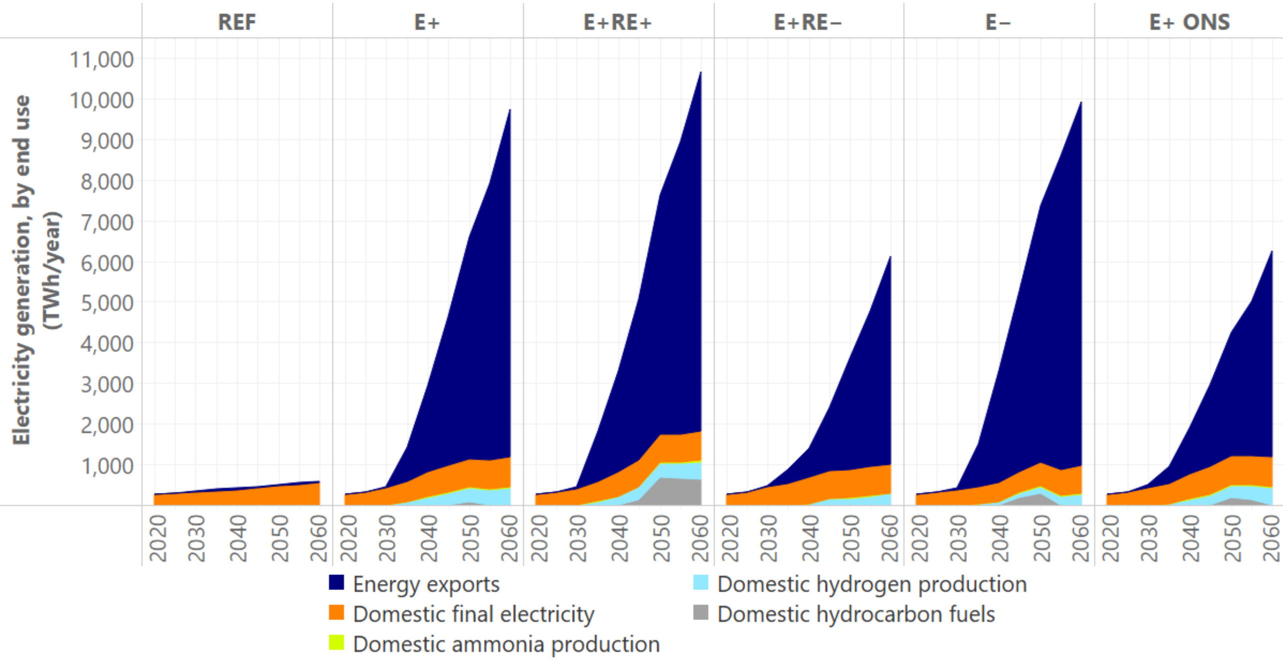


5.2 Pillar 2: Clean electricity

Clean electricity generation is a central enabler for the decarbonisation of the wider energy system. Australia's electricity system is currently decarbonising through the deployment of VRE sources across Australia with a 15.2% share of total electricity generation in 2019-2020 and record annual installation rates of 1.7, 1.8 and 3.3 GW/year for onshore wind, large-scale solar PV and rooftop PV between 2019 and 2021 (Clean Energy Council, 2022). The NZAu modelling finds that electricity generation from fossil fuels rapidly declines by ~80% from 2020 to 2030 across all Scenarios, so that most of the existing thermal generation fleet runs at low capacity factor or is ultimately retired well in advance of 2050. Alongside changes in electricity generation mixes, the electricity system transition also involves the expansion of electricity transmission infrastructure, which further unlocks renewable resources accommodating their inherent geographic variability through inter-regional connection.

Figure 23 highlights how 80% of the total electricity generation modelled in the NZAu project goes to serving energy exports, which drive total electricity generation in 2050 to 10-23× current levels with the associated infrastructural expansions, depending on the Scenario. In addition, 20-60% of electricity generation for domestic use is to produce clean gaseous and liquid fuels. Particularly in E+RE+, where fossil fuels are not allowed after 2050, about half of the domestic electricity will be required to produce e-fuels, particularly for aviation. In the E− Scenario, e-fuels are required in 2050 due to the larger residual demand for liquid and gaseous fuels across residential and industrial sectors, as a slower electrification progresses.

Figure 23 | Total electricity generation, by end use.



5.2.1 Deployment of domestic and export electricity system assets

Figure 24 shows the installed capacity in the domestic electricity system, by technology. Across Scenarios, VRE deployment scales up to install an aggregated 40-80 GW of new capacity every 5 years, which is about 5× the current rate of deployment observed for large-scale solar PV and onshore wind between 2019 and 2021 (Clean Energy Council, 2022). In all Scenarios other than E+RE−, deployment of offshore and onshore wind is greatest between 2020 and 2040. Then, favoured by significant technology learning and cost reductions, solar deployment picks up and continues until 2060, to eventually dominate the domestic and export electricity generation. This behaviour is well illustrated by Figure 25 and confirmed by the Sensitivities performed; even under a less ambitious cost trajectory for solar PV (our Solar− Sensitivity used a 2050 cost of 1,300 $/kW, as compared to 650 $/kW for the Core Scenarios), large-scale solar PV still remains the major export source, although wind becomes the main domestic source of electricity. The relative technology costs, compounded by different siting constraints and geographically diverse resource availability, also result in more onshore wind being deployed, as compared to the more expensive offshore solution. Offshore wind installed capacity is the highest only in the E+RE− Scenario, as the model reaches the constrained build rate for onshore wind.

Figure 24 | Domestic electricity system installed capacity, by technology. Note the independent vertical axis scales for the *wind & solar*, and *firm & storage* groupings.

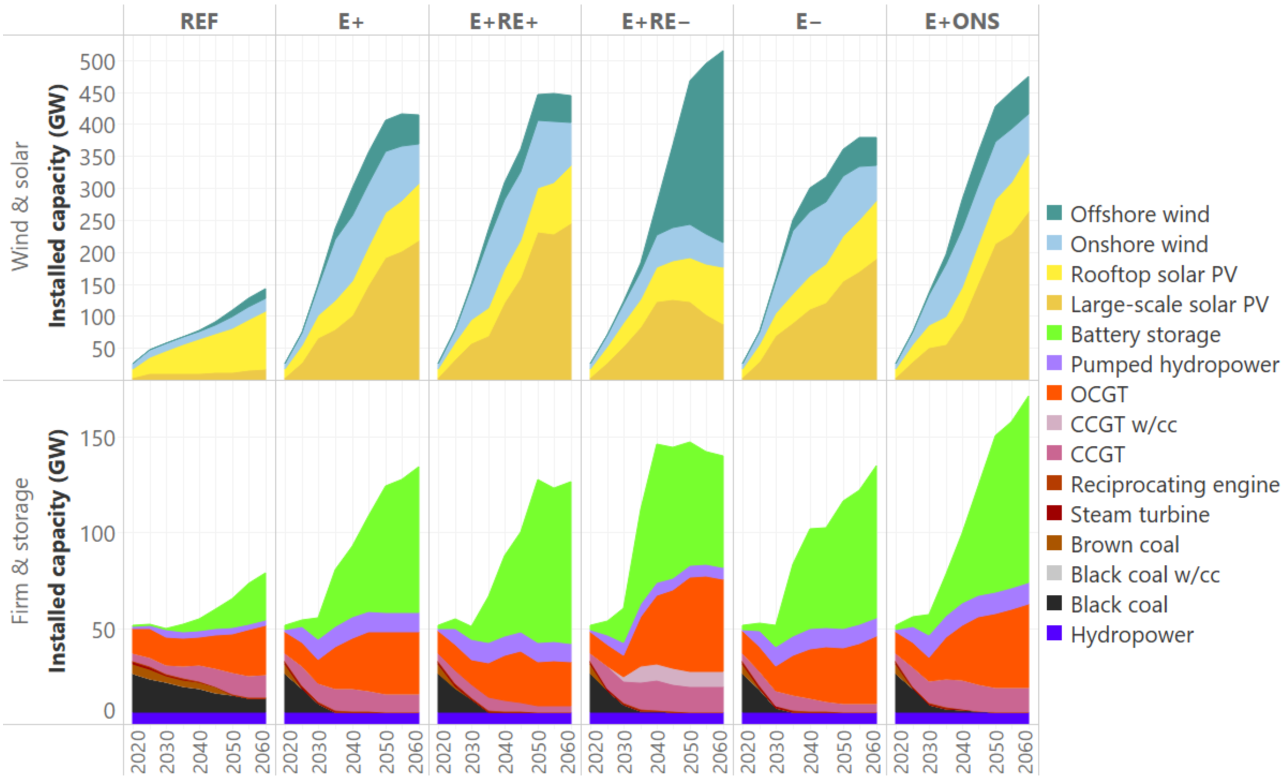
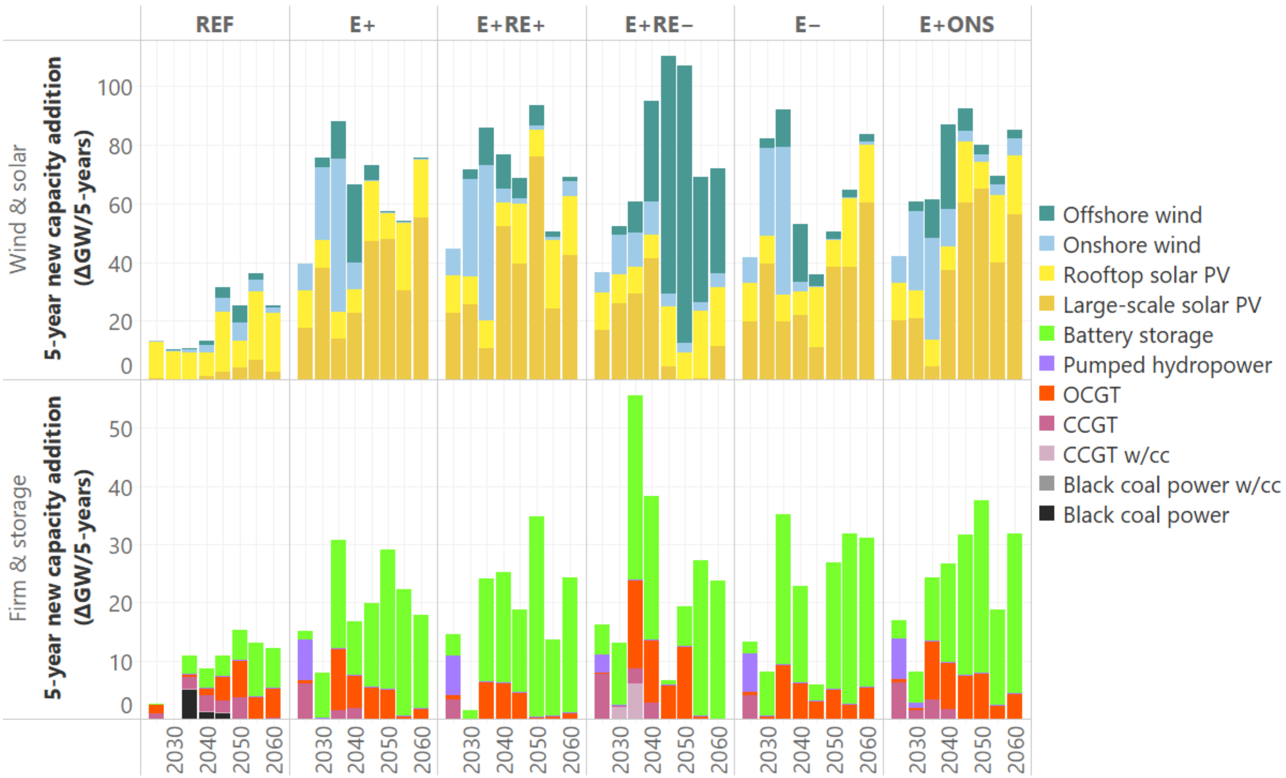


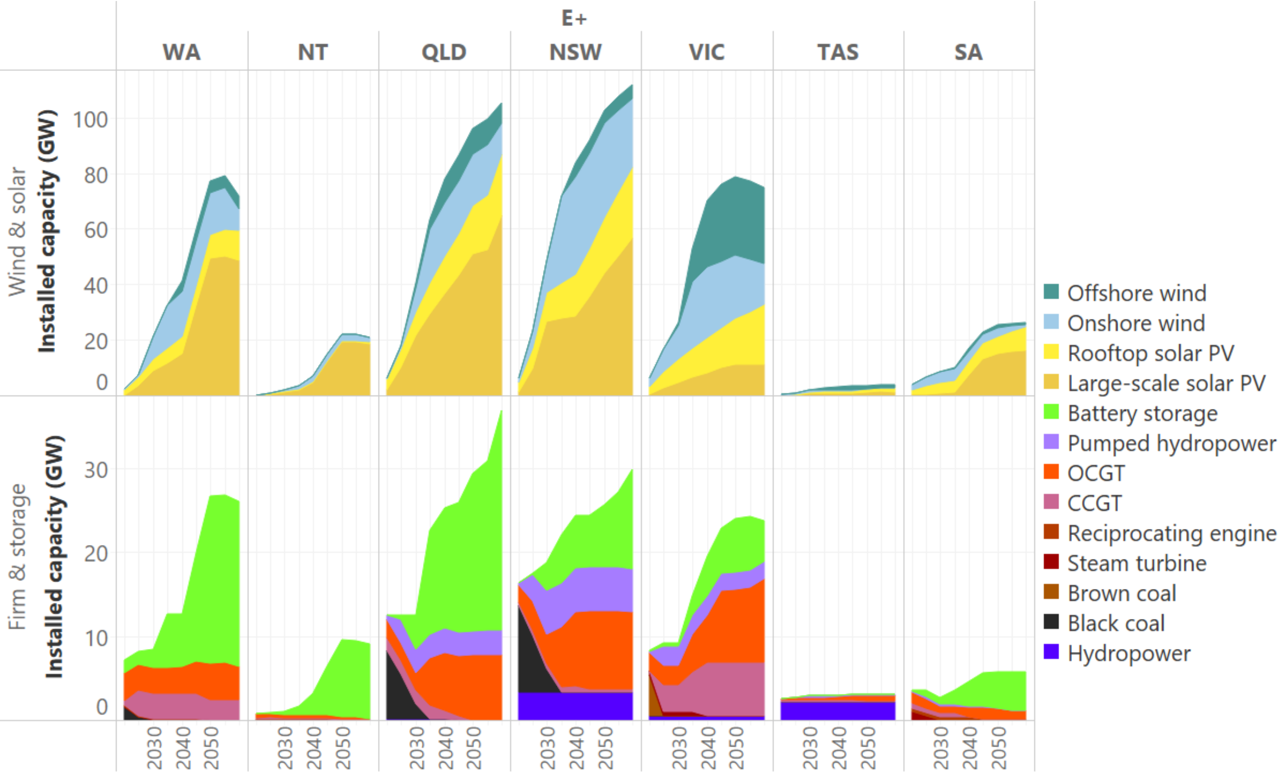
Figure 25 | 5-year capacity additions to the domestic electricity system, by technology. Note the independent vertical axis scales.



Alongside generation capacity, all Scenarios require 60-130 GW expansion of inter-regional electricity transmission, in conjunction with vast electricity storage deployment as behind-the-meter and utility-scale batteries. New gas capacity is also required in all Scenarios, with a build out occurring consistently across the transition, and particularly for the E+RE− Scenario, where offshore wind dominates generation deployment and the associated need for firming is achieved through greater gas power capacity due to the constrained deployment of renewables.

The make-up of each state's electricity system varies, based on population, demand composition and VRE resource, as presented in Figure 26, for the E+ Scenario only. Solar PV infrastructure dominates across most states, while in Victoria renewable generation is primarily wind (50 GW of wind capacity – including onshore and offshore – installed by 2050 in the E+ Scenario). The observed need for firming capacity is most stringent in populous states. Victoria requires ~17 GW of gas turbine capacity (OCGT and CCGT) in 2060, New South Wales requires ~9 GW of OCGT, but renewables firming is aided by the 3.4 GW of hydropower and ~5 GW of pumped hydro energy storage (with the large contribution of Snowy 2.0). Queensland rapidly installs ~20 GW of battery capacity over 2030 – 2060. Together with Western Australia, these two states experience the largest growth in battery storage, in part due to the larger proportion of solar power generation, which is particularly complemented by battery storage in shifting daytime generation to evening peaks.

Figure 26 | Domestic electricity system installed capacity for the E+ Scenario, by technology and state/territory.

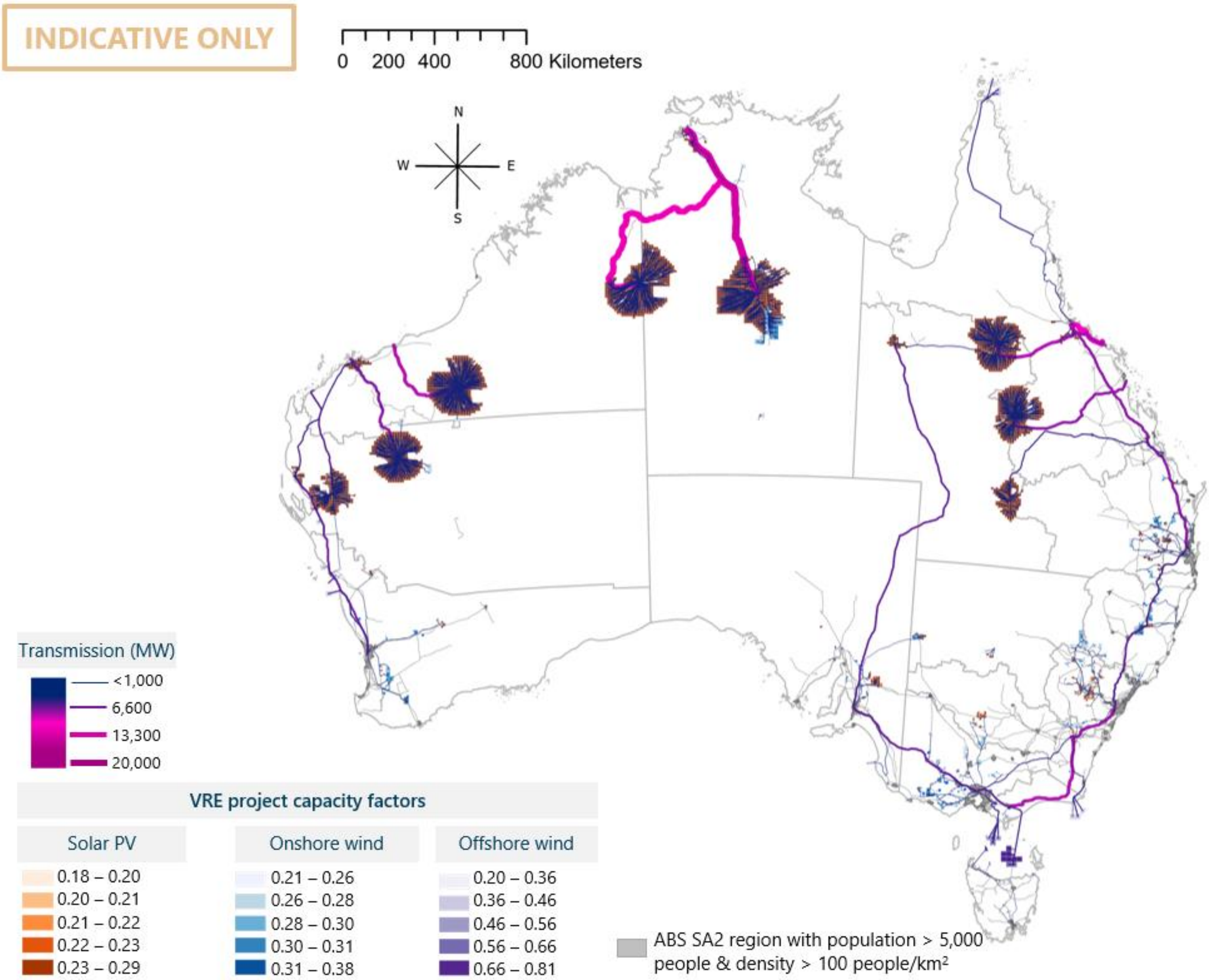


VRE capacity required to supply clean electricity to the very large energy export system can be observed in the top row of Figure 11, presented previously. Regardless of the Scenario, large-scale solar PV across the northern sunbelt provides the largest energy supply contribution for clean energy exports, requiring a buildout of 1-3 TW over the net-zero transition. Zero-emission electricity from solar generation is then converted into green H_2 through electrolysis and to the final energy carrier via Haber-Bosch synthesis in all Scenarios. Where renewable build rates are constrained, export energy is supplemented by blue H_2 generation via autothermal reforming of natural gas with carbon capture and storage. Conversion losses along different steps of the clean export supply chain (i.e. feedstock production, synthesis of the liquid carrier of choice, transport and finally cracking at the point of use) compound, driving the very large VRE build out for exports.

5.2.2 Mapping the infrastructure

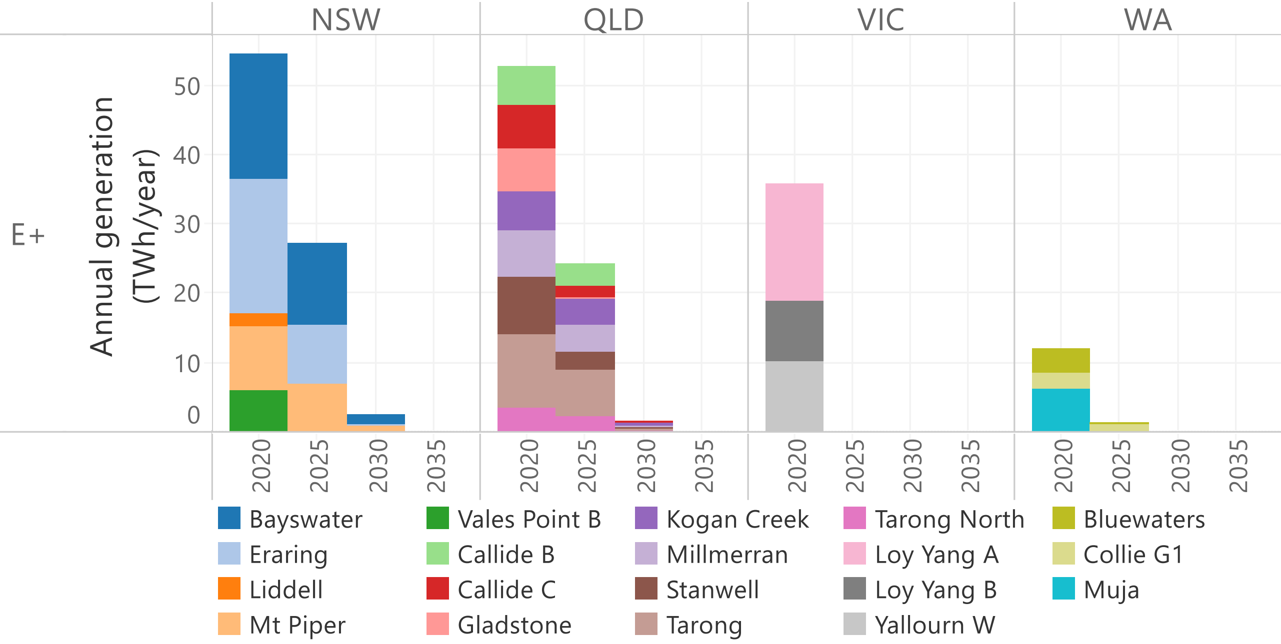
Given the relative scales of the domestic and exports decarbonisation task, the majority of new renewable generation and transmission additions is concentrated around the designated renewable energy export zones, where sites with large resources must be connected to the energy conversion, storage and export facilities. Figure 27 offers a glimpse of potential locations and scale of the renewable generation and transmission infrastructure in year 2060, for the E+ Scenario. About 3 TW of VRE (2.9 TW of large-scale solar PV and 100 GW of wind) are deployed, further expanding the 2.1 TW installed by 2050. Transmission network new builds in the export zones require a total capacity of 177,000 GW-km by 2050 and up to 293,00 GW-km by 2060, in the E+ Scenario. Conversely, the domestic electricity transmission remains constant at around 80,000 GW-km between 2050 and 2060, which still represents a factor of 2.9 augmentation of the transmission infrastructure from 2020, to move increasing electricity volumes over space and time.

Figure 27 | Downscaled electricity transmission and variable renewable electricity (VRE) generation infrastructure for the E+ Scenario in 2060.



Coal-fired and other liquid fuel generation undergoes a rapid retirement: no significant coal generation past 2040 is projected in any of the net-zero Scenarios. Additionally, between 21 and 29 GW of existing coal and other liquid fuel generation are set to be retired earlier than their intended end of life. This significant modelled reduction in annual power generation from coal-fired plants for the E+ Scenario is represented in Figure 28.

Figure 28 | Annual coal-fired power generation for the E+ Scenario.



5.2.3 Firming renewable rich electricity systems

On top of the installed capacity discussed so far, Other potential electricity system firming options were found to be less prospective. Fossil electricity generation with carbon capture is not found to play a significant role in most Scenarios, in part because the annual CO_2 storage capacity is limited and needed for hard-to-abate sectors. Only in the E+RE− Scenario with both constrained renewable deployment rates and expanded CO_2 storage capacity does CCS on power generation seem prospective, with ~10 GW of combined-cycle gas turbines with carbon capture (CCGT w/cc). Our Sensitivities found that nuclear technology at a nominal cost of ~7,200 $/kW never plays a role. Nuclear capacity is installed only when: a) its capital cost is ~5,200 $/kW; and b) VRE deployment rates are constrained (the E+RE−CheapNuclear Sensitivity).

Figure 29 demonstrates how the rapid growth in renewable electricity generation outpaces a rapid fall in fossil fuel generation (different vertical axis scales should be noted). In such renewable-rich power system, the primary role of dispatchable fossil fuel plants shifts from provision of the baseload to the firming of power generation – alongside electricity storage – to alleviate wind and solar variability. Fossil generation energy output falls to only ~20% of 2020 levels in a single decade. Capacity factors of CCGT reduce, from up to 85% in 2020 to a maximum of 10-12% by 2050 – 2060.

Alongside fossil fuel generation and hydropower, whose installed capacity is not envisioned to undergo significant future change, electricity storage represents a significant contributor to grid firming. We find that all Scenarios exhibit considerable reliance on storage, which is mainly provided by batteries and pumped hydro energy storage (PHES), with their fast-growing installed capacity (both in power and energy capacity terms) shown in Figure 30. Modelling results suggest that 70-110 GW of battery storage (which includes a potential 15-25% share as behind-the-meter installations) and ~10 GW of PHES will be needed in the domestic electricity system by 2050 – an estimate which is consistent with the Australian site availability identified by ongoing feasibility studies from PHES developers (*Private Discussions with Mr. Malcolm Rushin, Mr. Mike Westerman and Mr. Mark Locke of GHD on PHES Projects in Australia., n.d.*). Also, the range of selected storage duration reveals a fundamentally different balancing role to be played by the two. For batteries, affected by relatively high cost per unit storage capacity, the average value is ~7 h (7 GWh/GW), suggesting their use for intra-day balancing of diurnal variation in solar PV output. PHES durations are on average 15 h, implying power balancing and generation firming over longer timeframes, mostly to make up for wind droughts. One more point to observe is the rising storage energy capacity additions at constant installed power occurring later in the transition, as the larger share of VRE in the mix requires longer hours of storage capacity.

Other potential electricity system firming options were found to be less prospective. Fossil electricity generation with carbon capture is not found to play a significant role in most Scenarios, in part because the annual CO_2 storage capacity is limited and needed for hard-to-abate sectors. Only in the E+RE− Scenario with both constrained renewable deployment rates and expanded CO_2 storage capacity does CCS on power generation seem prospective, with ~10 GW of combined-cycle gas turbines with carbon capture (CCGT w/cc). Our Sensitivities found that nuclear technology at a nominal cost of ~7,200 $/kW never plays a role. Nuclear capacity is installed only when: a) its capital cost is ~5,200 $/kW; and b) VRE deployment rates are constrained (the E+RE−CheapNuclear Sensitivity).

Figure 29 | Domestic electricity generation, by technology. Note the independent vertical axis scales.

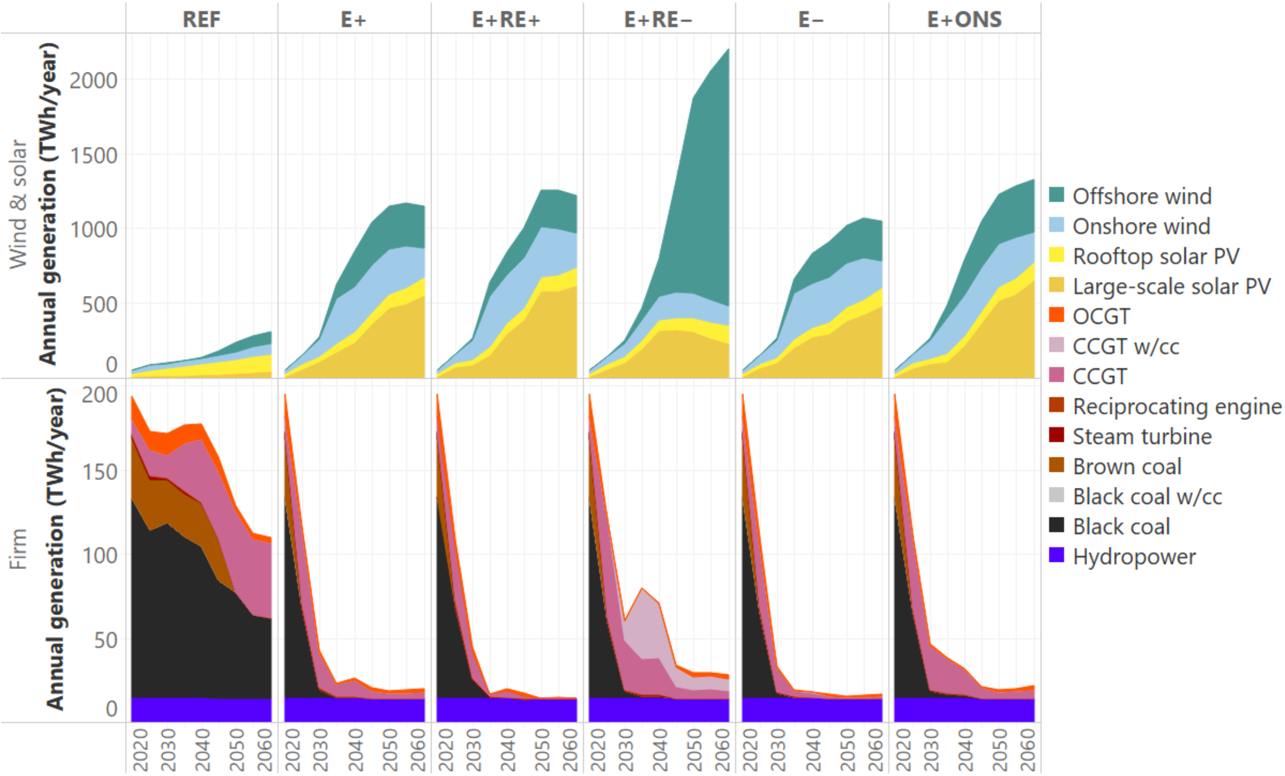
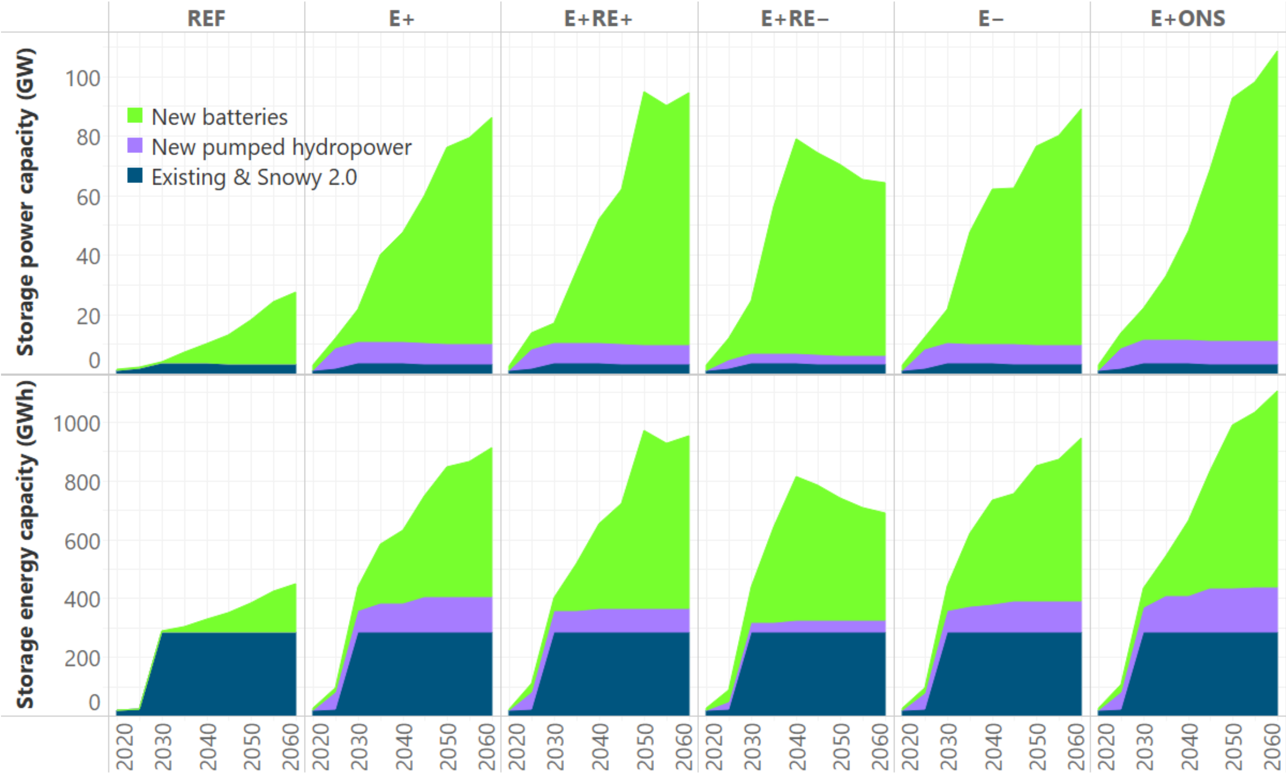


Figure 30 | Installed (power in GW and energy in GWh) capacity of domestic electricity storage technologies. Note independent vertical axes.



A glimpse of the potential power system operation in year 2050 matching hour-by-bour power load and generation, for the E+RE+ and the E+RE− Scenarios, is reported in Figure 31. Such results are the output of the hourly-resolved modelling adopted by the NZAu Project and the RIO tool. As the energy mix relies heavily on VRE in both Scenarios, matching supply and demand requires larger embedded overcapacity in the system. As a consequence, peak generation increases more than five-fold from 2020 to 2050. NZAu's results elucidate how such balancing may be performed differently, according to the specific power generation make-up. Higher reliance on large-scale solar PV in the E+RE+ Scenario (left tiles in Figure 31) results in a well-confined peak generation in the central hours of the day, to be balanced by ~600 GWh of batteries which shift daytime solar generation to evening peaks. On the other hand, higher shares of offshore wind generation (with higher capacity factors than onshore wind) in the E+RE− Scenario cause more overnight generation but a steadier, on average, power supply profile, requiring less (~410 GWh) battery storage.

Figure 31 also demonstrates a different role for thermal generation becoming a minor part of the daily generation mix, yet with new gas capacity still being needed across regions and Scenarios (see Figure 32). Natural gas plant's future use is limited to grid firming, mostly overnight, or responding to a handful of events per year, during prolonged periods of low renewables generation. Our projected costs show that this is a cheaper solution than using H_2 storage over these durations: although allowed, the model does find H_2 power generation to be prospective, largely due to efficiency losses and costs associated with the intermediate conversion steps involved. Indeed, as Figure 32 reports, minimal blending of hydrogen into gas power was found whilst, in some Scenarios, pipeline gas was made renewable via bioenergy (Section 7.2.2).

Finally, an indirect role in firming renewables is to be also played by transmission. Results from Sensitivities constraining the inter-regional transmission capacity to current levels (the E+Transmission− Sensitivity) find greater need for both gas turbine firm capacity (an additional 5 GW OCGT and 7 GW of CCGT) and battery storage (additional ~20 GW) nationwide, but with only a $130 billion higher total cost (i.e. 2% of the domestic system cost) over 2020 to 2060 (relative to E+ Scenario).

Figure 31 | Domestic load and generation hourly profiles in 2050, for the E+RE+ and E+RE− Scenarios. These present hourly dispatch on selected representative days.

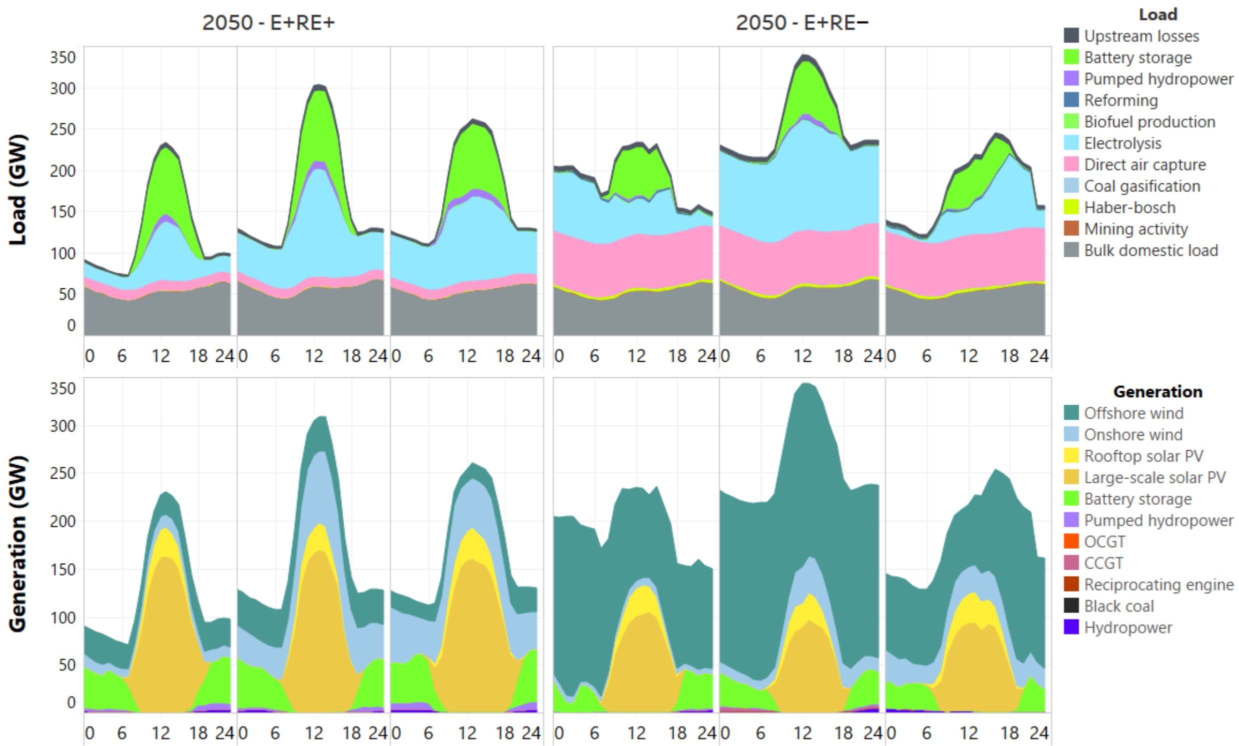
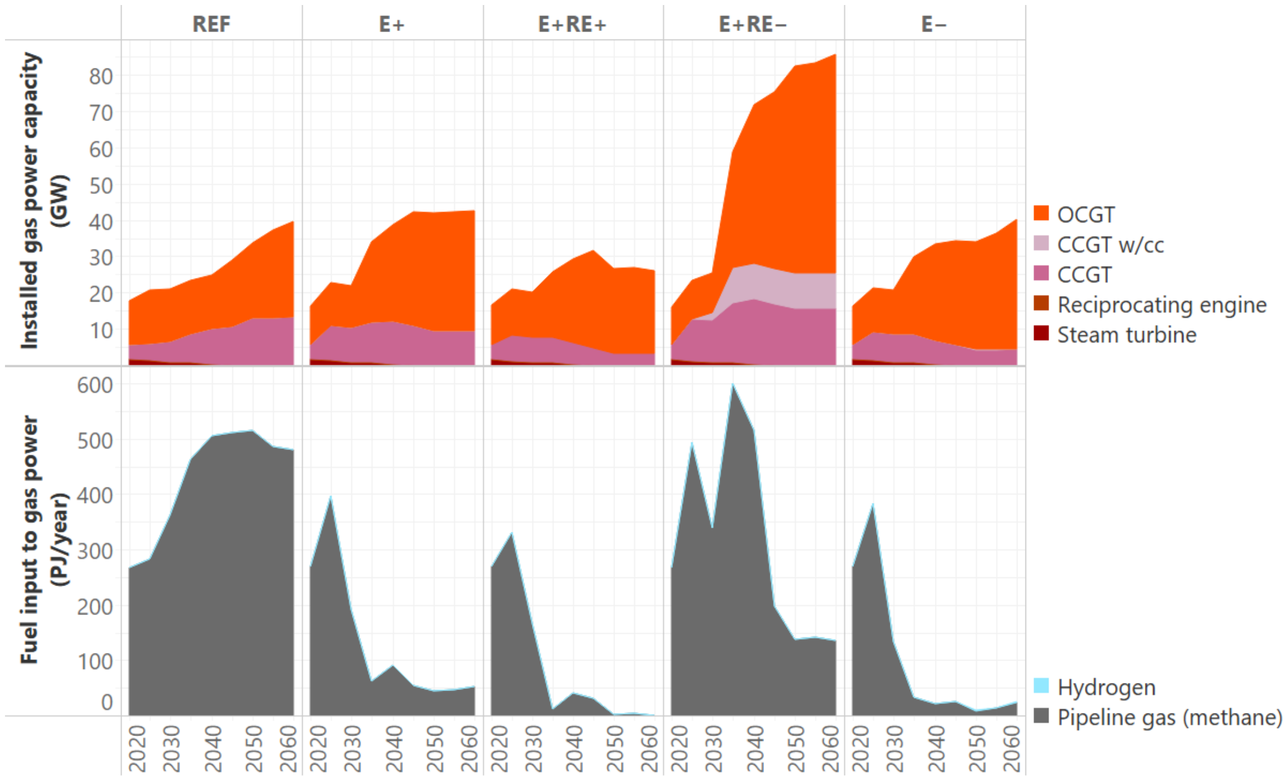


Figure 32 | Gas power (top) installed capacity; and (bottom) fuel input, by gas type.



5.3 Pillar 3: Zero-carbon fuels & feedstocks

The production of zero-carbon fuels is important both as a means of exporting clean energy, but also as a solution for decarbonising sectors that are not easily electrified, such as heavy-duty transport and certain heavy industries.

In such cases, energy consumption can either be switched to:

- hydrogen (or derivative, such as ammonia), a fuel which has no associated GHG emissions when used; or
- a drop-in hydrocarbon fuel, the carbon content of which is biogenic (biofuels) or directly captured from the atmosphere (synthetic fuels).

This work has considered fuel switching to hydrogen and ammonia as a decarbonisation measure that is exogenously specified for certain energy system activities, such as some proportion of heavy-duty transport switching to hydrogen fuel cell vehicles over the transition. For the residual fossil fuel energy consumption, the choice to use hydrogen-derived synthetic fuels or biofuels as drop-in fuels is part of the techno-economic optimisation undertaken in this work. Furthermore, the production pathways for producing clean energy vector to serve export energy demand via shipping is also subject to techno-economic optimisation.

In all cases, the means of hydrogen, synthetic fuel and biofuel production is optimised, given a range of candidate production pathways, their associated costs, process emissions and the wider emissions constraints. We expand on the resulting trends in the sections below.

5.3.1 Hydrogen & synthetic fuels

NZAu models significant production of hydrogen, increasing rapidly from 2030 to an annual production of 140 Mt-H_2 in 2060 in most Scenarios. This mostly substitutes current fossil energy exports with a clean energy carrier, while the domestic role for hydrogen is smaller.

We find hydrogen production via electrolysis (green hydrogen) to be the most prospective pathway over the net-zero transition, with only limited production via autothermal reforming of natural gas with carbon capture in the E+, E– and E+ONS Scenarios (Figure 33). ATR w/cc is used to a limited extent as hydrogen production ramps up around 2030 and before projected electrolysis plant cost reductions.

The main exception to this trend is the E+RE− Scenario, in which green hydrogen production is limited due to the constraint on the build rate of variable renewables. In this case, ATR w/cc is also used for hydrogen production, so that in 2060 the 135 Mt-H_2 produced is evenly split between green (67 Mt-H_2) and blue (68 Mt-H_2) production methods. Importantly, the need to use autothermal reforming of natural gas with carbon capture then results in significant fugitive and process GHG emissions, as well as captured emissions which must be managed. This is a significant drawback of the E+RE– Scenario, where, the 68 Mt-H_2 produced with ATR w/cc requires 12 EJ of natural gas which has an associated 44 Mt-CO_2e fugitive emissions, some of which are modelled to be captured and re-sequestered during conventional gas extraction. The ATR w/cc conversion of natural gas captures 530 Mt-CO_2 process emissions, and has residual uncaptured emissions of 70 Mt-CO_2e. The fugitive and uncaptured emissions are accounted under the domestic GHG emissions constraint, and therefore need to be offset through the use of direct air capture, or BECCS.

Figure 33 also shows that a small proportion (up to 750 kt-H_2) of the hydrogen could be produced via bio-gasification of woody biomass. However, alternative fossil-based methods of hydrogen production – steam methane reforming and brown/black coal gasification, both with carbon capture – were not found to be prospective in any net-zero Scenario. Although the cost of coal as a feedstock for hydrogen production may be relatively low, both the released emissions intensity, and captured emissions intensity of the coal-based pathway is more than double that of the natural gas pathway, resulting in the ATR w/cc being the preferred fossil-based hydrogen production method, when required.

Western Australia, the Northern Territory and Queensland are the major producers of hydrogen across all Core Scenarios (Figure 34), due to their strong solar resource. WA is the main producer of blue hydrogen, when used.

Finally, the E+RE− Scenario sees a shift of some hydrogen production to Victoria, which is driven mostly by the state's (and Tasmania's) significant offshore wind installation in that Scenario. Taken together, the clear trend emerging from our least-cost optimisation is to associate large VRE resource (should it be wind or sun) with green hydrogen production.

On the hydrogen demand and use side of Figure 33 we find that the majority of hydrogen produced (85-95%) is to serve energy export demand. The NZAu project has modelled the energy export vector for shipping to be ammonia, synthesised from hydrogen via the Haber-Bosch process. Figure 33 shows that around 130 Mt-H_2 in 2060 is used to produce ammonia for energy export, with only a very small proportion (<0.5%) of the ammonia used domestically. The E+ONS Scenario, however, differs in the production and use of hydrogen. A significantly lower 81 Mt-H_2 is produced in 2060, of which 22 Mt-H_2 is used for energy exports, with the remainder used for onshore processing of iron ore to direct reduced iron. Other notable uses for hydrogen across the Scenarios are to serve final energy demand in various industries and transport, and as a feedstock for synthetic liquid fuels production (Fischer-Tropsch liquids), using 1-8 Mt-H_2/year over 2050-2060. We find negligible need for hydrogen in electricity generation.

The production of synthetic liquid fuels is largest in the E+RE+ Scenario, which necessitates the elimination of fossil fuels, even for uses (such as aviation, and some industry) for which electrification or switching to hydrogen is not possible. Synthetic liquid fuels are also important for the E− Scenario, due to the slower electrification and fuel switching of that Scenario and the resulting greater residual demand for liquid fuels in industry and transport when the domestic net-zero emissions constraint binds in 2050. In this case, synthetic hydrogen-derived fuels are used as a means of decarbonising the supply of fuels to those sectors.

Figure 33 | (Left) hydrogen supply, by technology; and (right) hydrogen final demand and use by sector/technology. Note independent vertical axis scales. Note: 1 Mt-H_2/year = 388 TJ/day (based on HHV).

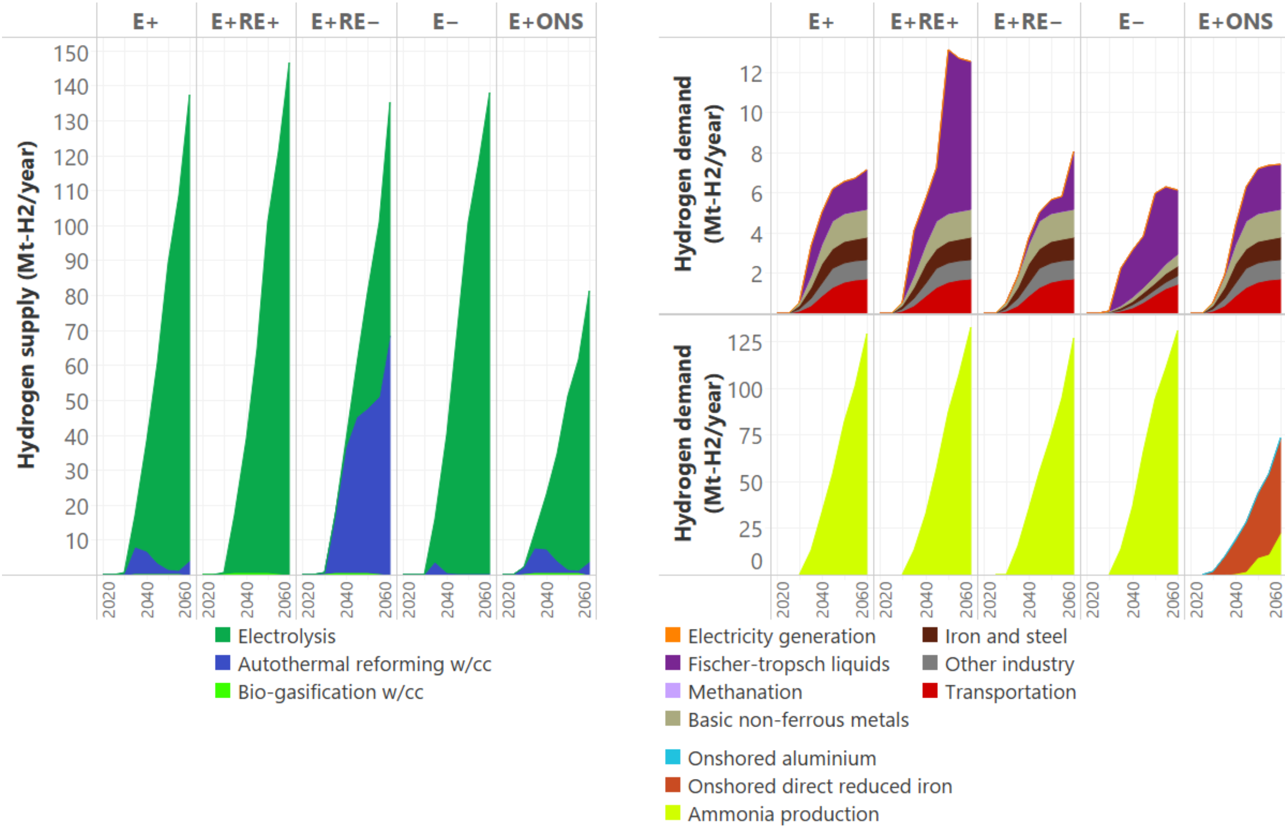
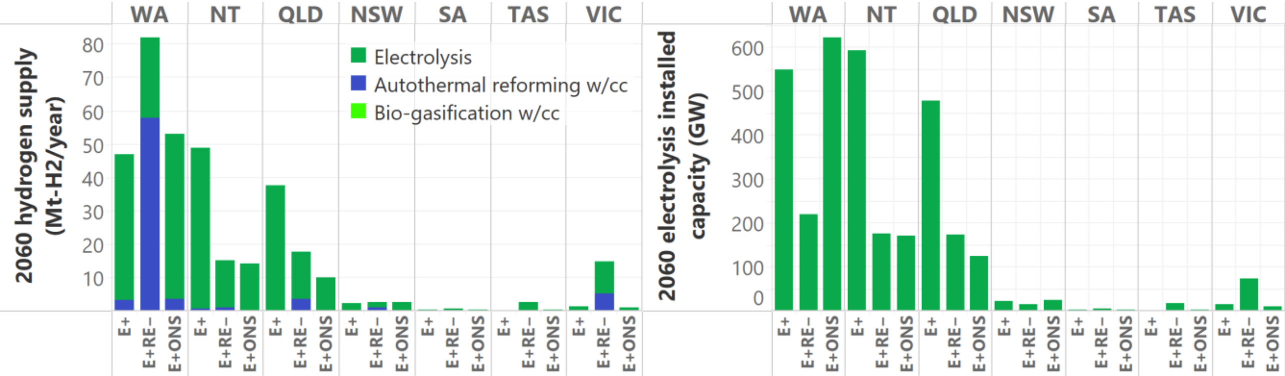


Figure 34 | (Left) hydrogen supply in 2060, by technology and state/territory of production; and (right) installed capacity of electrolysis in 2060, by state/territory. for selected Scenarios. E+RE+ and E− show similar trends to E+.



Major hydrogen storage is also needed for both the domestic and export systems. We find that hydrogen storage is rapidly installed into the domestic energy system from 2035 in all Scenarios and could comprise 40,000-100,000 t-H_2 (6-14 PJ, 1.6-3.9 TWh) energy storage capacity. Interestingly, this domestic hydrogen storage is not used for electricity system firming, but instead is used to ensure a steady and reliable hydrogen supply for transport and industry sectors across days, seasons and years.

The energy export system then is shown in Figure 35 to require 4-25× the hydrogen storage of the domestic system, at 0.5-1.5 Mt-H_2 (72-220 PJ, 20-60 TWh). This export system-based storage is located across the designated renewable energy export zones – which are also generally the point of hydrogen production – as well as at ports, where hydrogen is converted to shipping energy vector. Hydrogen storage is needed to ensure that a constant level of energy may be supplied to meet export energy demand in each hour of the year (1.7 PJ/hour). This steady supply requirement is, however, a conservative assumption that ensures export energy storage costs are explicitly represented in Australia.

Figure 35 | Capacity of underground hydrogen storage, by region and disaggregation of domestic and export systems. Note independent vertical axis scales. Note: 1 Mt-H_2 = 39.4 TWh (HHV).

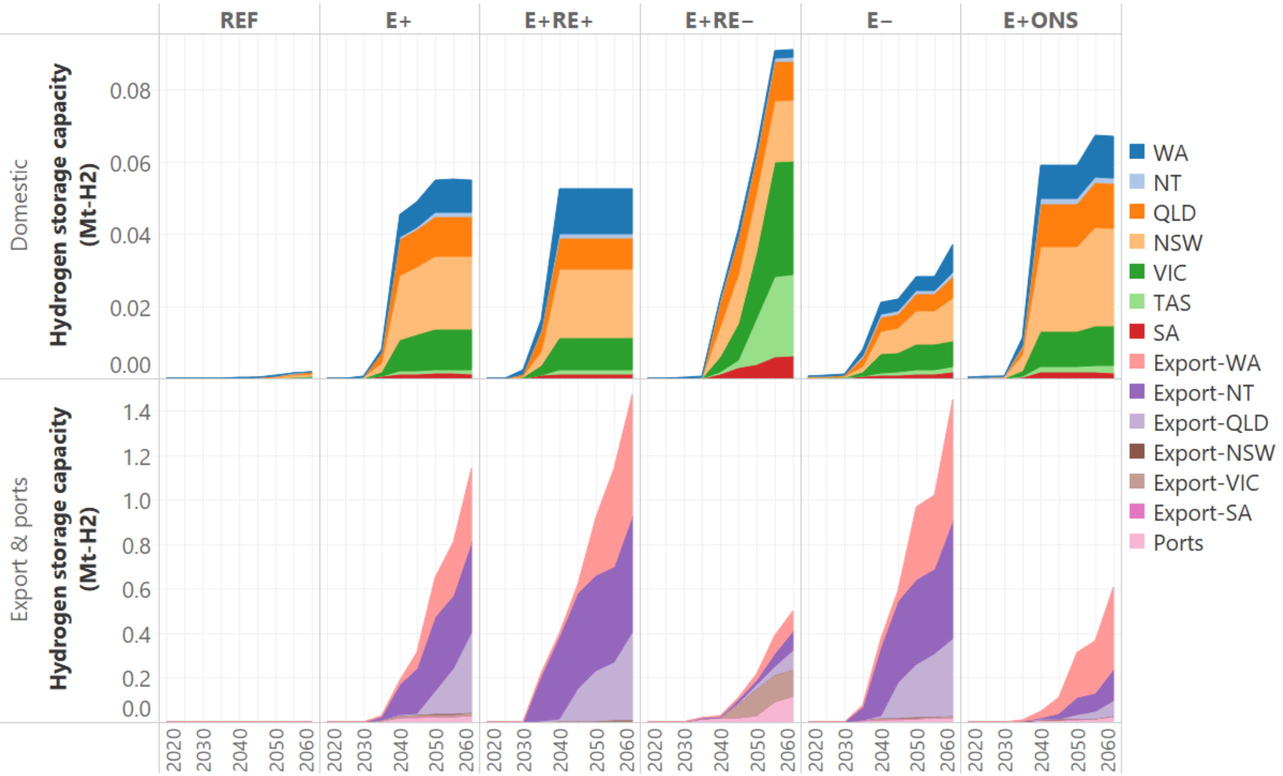
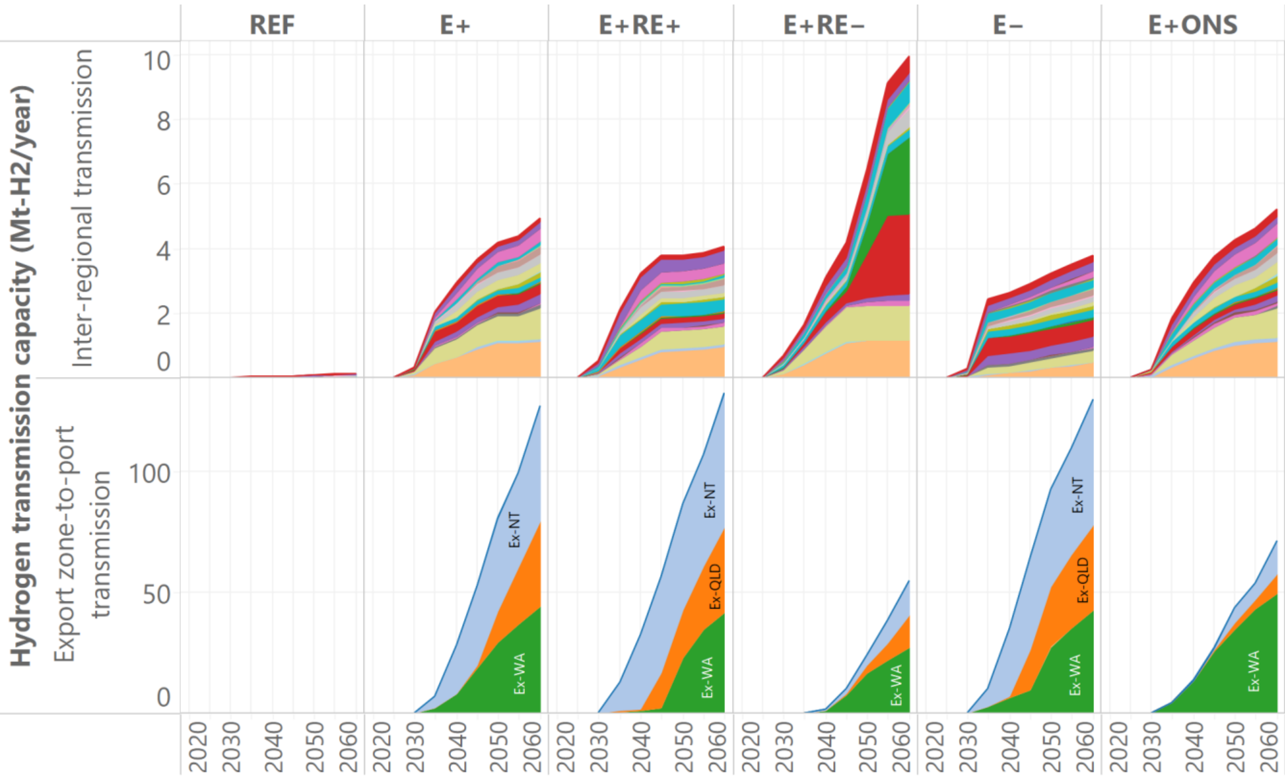


Figure 36 shows the hydrogen transmission capacity expansion outputs from macro-scale energy system modelling, demonstrating the need for significant hydrogen pipeline infrastructure across all Scenarios. The largest transmission build is largely associated with export projects, while domestic inter-regional hydrogen transmission infrastructure is much smaller.

3.2-6.5 Mt-H_2/year (1,300-2,500 TJ/day, 15-29 GW) of domestic inter-regional connections are built by 2050, with some further expansion to 2060. These connections are needed to transport hydrogen for domestic uses in synthetic fuels production, industry and transport, from regions of good renewable (and therefore green hydrogen) resource to locations of demand.

Hydrogen transmission via pipeline was found to be the favoured mode of bulk energy transport for the export system (as compared with electricity transmission). Figure 36 shows significant hydrogen pipeline infrastructure deployed from 2030 to transport energy from location of renewable energy generation (largely solar PV in designated export zones) to the point of energy export (conversion of hydrogen to shipping vector at ports). Figure 36 shows the three dominant export zone-to-port routes are those in northern WA, NT and QLD, each having hydrogen transmission capacities of 35-55 Mt-H2/year (14,000-21,000 TJ/day, 160-250 GW) in 2060, for the E+, E+RE+ and E− Scenarios. E+RE− shows lower capacities of export system hydrogen transmission, due to the reduced need to transport green hydrogen from designated export zones and with the modelling of blue hydrogen production in proximity to ports. E+ONS shows lower capacities in NT and QLD due to the majority of energy exports comprising onshored direct reduced iron from WA in that Scenario.

Figure 36 | Capacity of hydrogen transmission infrastructure, disaggregated by domestic inter-regional export zone-to-port connections. Note independent vertical axis scales, and 1 Mt-H_2/year = 388 TJ/day = 4.5 GW (HHV).



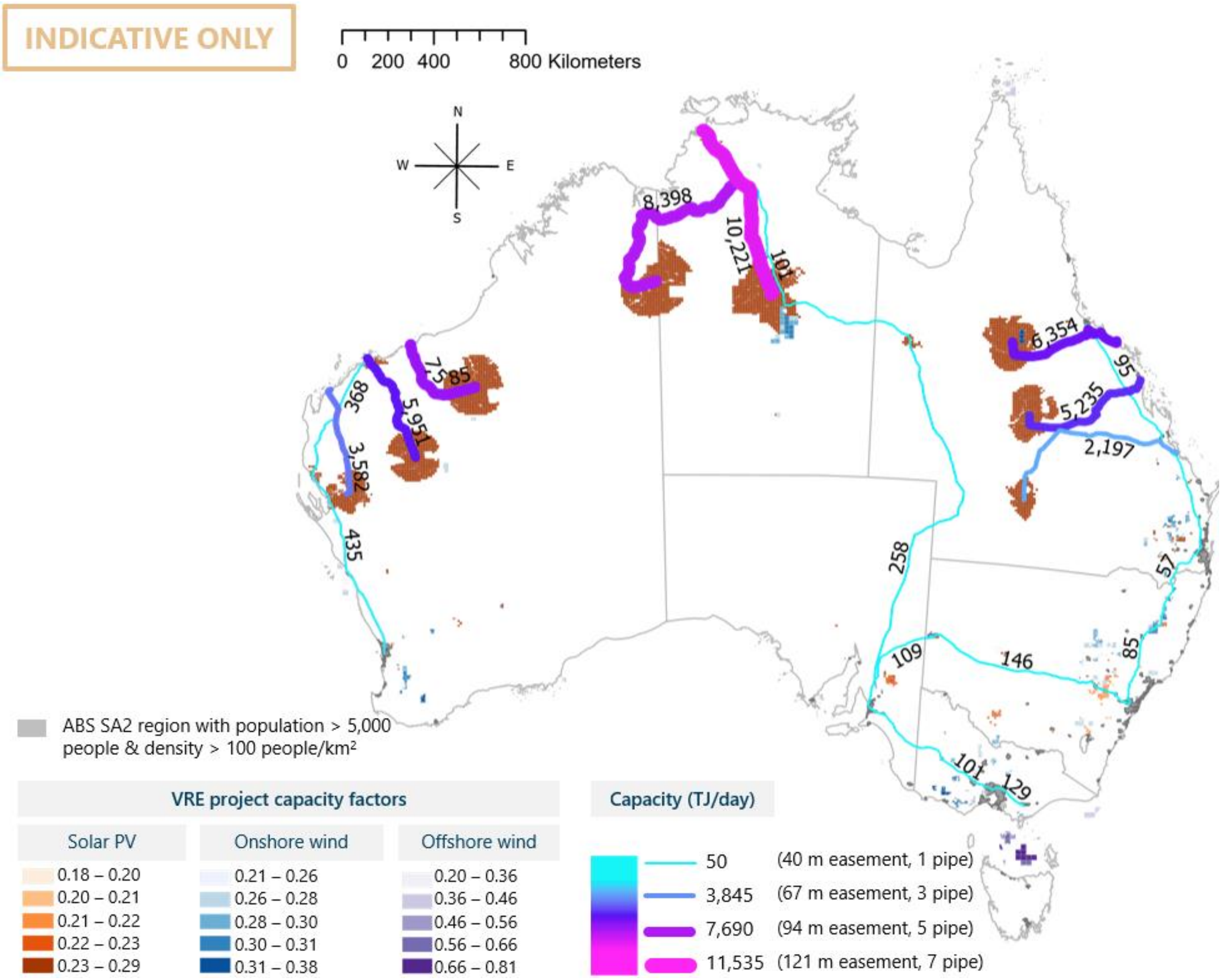
These hydrogen transmission capacity outputs from macro-scale energy system modelling (Figure 36) have been downscaled to specific routes and mapped, with considerations of the number of parallel pipelines (each allowing a maximum throughput 1,900 TJ/day), minimum pipeline capacity thresholds (50-100 TJ/day depending on route length), and estimated widths of hydrogen corridor rights-of-way (ROWs). Figure 37 presents notional mapping of the hydrogen transmission infrastructure for the E+ Scenario in 2060, along with variable renewable resources. The siting of extensive hydrogen infrastructure in the northern half of Australia is evident in Figure 37 for E+ in 2060, and is similar for most Core Scenarios. The export associated hydrogen transmission build accounts for 150,000-

450,000 GW-km, depending on the Scenario, and connects hydrogen supply (via electrolysis driven by renewable electricity) in designated export zones with ammonia production at ports for shipping.

In addition to these, Figure 37 shows the downscaled domestic hydrogen transmission infrastructure for E+ in 2060. This shows an interregional hydrogen transmission network that connects hydrogen demand hubs across the country to satisfy seasonal and annual demand for hydrogen in synthetic fuels production, industry and transport. Hydrogen supply in the domestic system was not sited and is assumed to occur in or along mapped pipeline routes or to be collocated at domestic demand centres.

We find that all Scenarios but the E+RE– see a north to south pipeline built between the NT, QLD and SA with the E+ and E+ONS having the largest builds. While all Scenarios have a pipeline from Townsville to Sydney, only the E+RE–, E– and E+ONS see that pipeline extend to connect with pipelines in Victoria. All Scenarios but E+RE– have a pipeline between Sydney and SA. This domestic inter-regional hydrogen transmission build accounts for 13,000-21,000 GW-km, depending on the Scenario. Furthermore, the downscaling analysis also indicates that outside of the WA, NT, and QLD export corridors, all other hydrogen pipeline corridors have a maximum ROW of 40 m (most corridors have single pipelines with a smaller capacity than the maximum size). The ROW widths in the WA, NT, and QLD export corridors will vary depending on the Scenario and year, with the NT export corridor reaching a maximum width of 189 m in the E+RE+ Scenario.

Figure 37 | Downscaled hydrogen transmission infrastructure for the E+ Scenario in 2060, together with locations of large-scale solar PV, onshore and offshore wind generation. Note: 1 Mt-H_2/year = 388 TJ/day (HHV).



5.3.2 Bioenergy

Bioenergy can be an important resource for decarbonising energy systems if the emissions arising from bioenergy consumption are wholly or partly offset by the carbon dioxide sequestered during the growth of the biomass feedstock. Biofuels can then also achieve negative emissions when paired with carbon capture and storage. Nonetheless, the establishment of an Australian bioenergy industry that supplies and processes biomass feedstock from regionally diverse and widespread locations will depend on the technical and economic assessment of the role of bioenergy in a net-zero transition with a spatially granular level of detail.

We have found that, while bioenergy potential is limited in Australia by sustainable supply of biomass, the use of biomass could expand to ~1,100 PJ/year, driven by the establishment of a biofuel production industry, together with continued use of biomass in industry (largely bagasse in sugar cane industry) and buildings sectors. Figure 38 shows a rapid deployment of bioenergy plants from 2035 to 2040, which process approximately 80 million dry tonnes per annum of biomass waste and residues (~1000 PJ/year) up to their sustainable resource availability, to produce approximately 600 PJ/year of zero-emissions gaseous and liquid fuels. Across the modelled Core Scenarios, synthetic natural gas is the dominant biofuel produced via biogasification, with hydrogen via biogasification and liquid fuels via pyrolysis also produced to lesser extents. 40-70% of biofuel production is coupled with capacity to capture bioenergy conversion process CO_2 emissions (BECCS), which represents a means of achieving net atmospheric CO_2 withdrawal of 20-30 Mt-CO_2/year that is largely sequestered in geological formations.

Figure 38 | Biomass use, by final demand and use by sector/technologies.

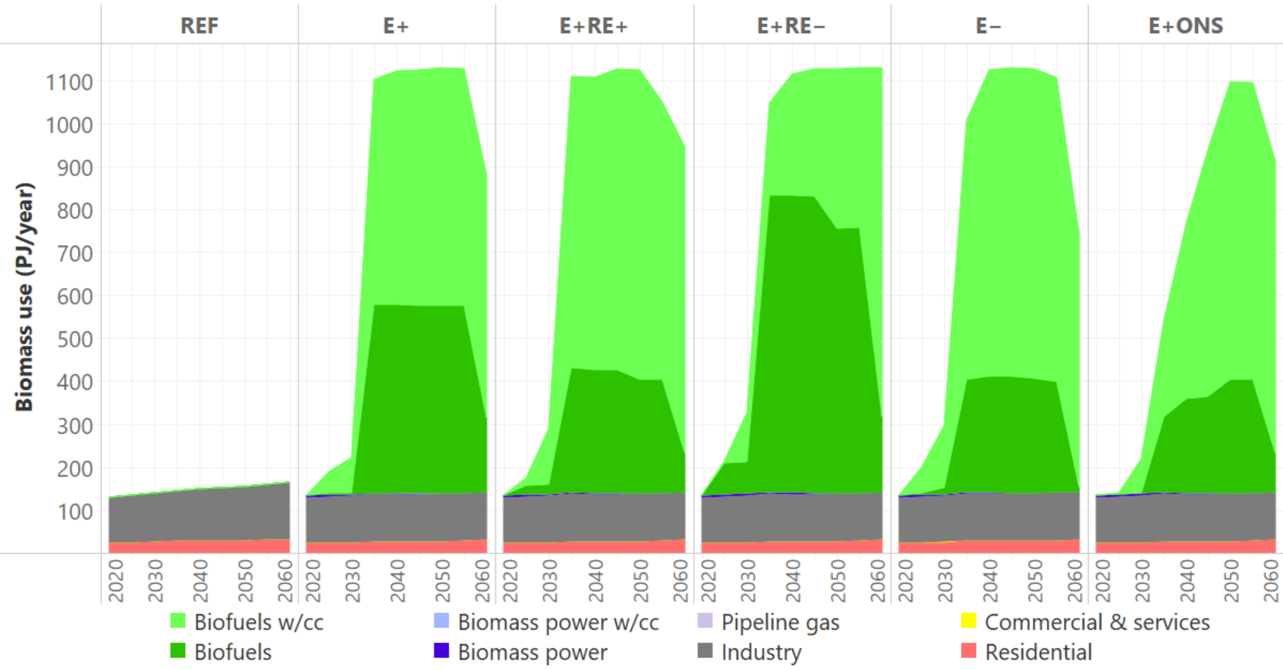


Figure 39 shows the distribution of various biomass resource types across Australia in 2050, with the resource distribution similar in other modelled years. The organic municipal solid waste resource is concentrated in Australia's major population centres, while other resources are more regional. Native grasses are available in Queensland and New South Wales, while crop stubble is in the more southern regions of New South Wales, Victoria, South Australia and Western Australia. Australia's forestry *residue* resource is also located in the southern regions, with most resource distributed in Victoria and Tasmania. This biomass availability of ~1,100 PJ/year is less than the 2,600 PJ/year *theoretical* resource potential quoted in the recently published Australian Government Bioenergy Roadmap (ENEA Consulting & Deloitte, 2021). This is because our estimates observe technical and sustainable resource constraints that will naturally preclude a significant portion of *any theoretical* bio-resource appraisal.

Figure 39 also shows a result from the downscaling of the modelled bioenergy activity, which sited approximately 100 bioenergy facilities across Australia, with those facilities concentrated in regions of greater biomass resource density. Furthermore, facilities that are paired with carbon capture were preferentially sited near to CO_2 transmission infrastructure (see mapping in Section 5.3.2). Each facility processes ~700 kilotonne-biomass annually. For the Scenario and year shown here, the majority of biofuel production comprises bio-synthetic natural gas, which is injected into gas pipelines and used across residential and industry sectors.

The bio-SNG is predominantly produced with carbon capture in QLD and SA, VIC and central WA, as these regions are located closest to the available CO_2 sequestration sites, while in NSW and TAS the majority of bio-SNG is produced without carbon capture. In addition to bio-SNG, the biomass resource is used in E+ to produce hydrogen through biogasification with carbon capture in eastern VIC, southern QLD and SA. The production of hydrogen from biomass via gasification with carbon capture represents the bioenergy conversion pathway with greatest potential for negative CO_2 emissions, with 81 kg-CO_2/GJ-biomass captured (from the biomass' embodied biogenic 89 kg-CO_2/GJ-biomass). This is significantly greater than the rates of CO_2 withdrawal possible through bio-SNG production via biogasification, 30 kg-CO_2/GJ-biomass.

We also find the production of liquid biofuels via fast pyrolysis of biomass is prospective in the E− Scenario. These are used to decarbonise solid or liquid fuel use in transportation and industry, which have significant mid-century residual demand for solid and liquid fuels due to the E− Scenario's slower electrification trend.

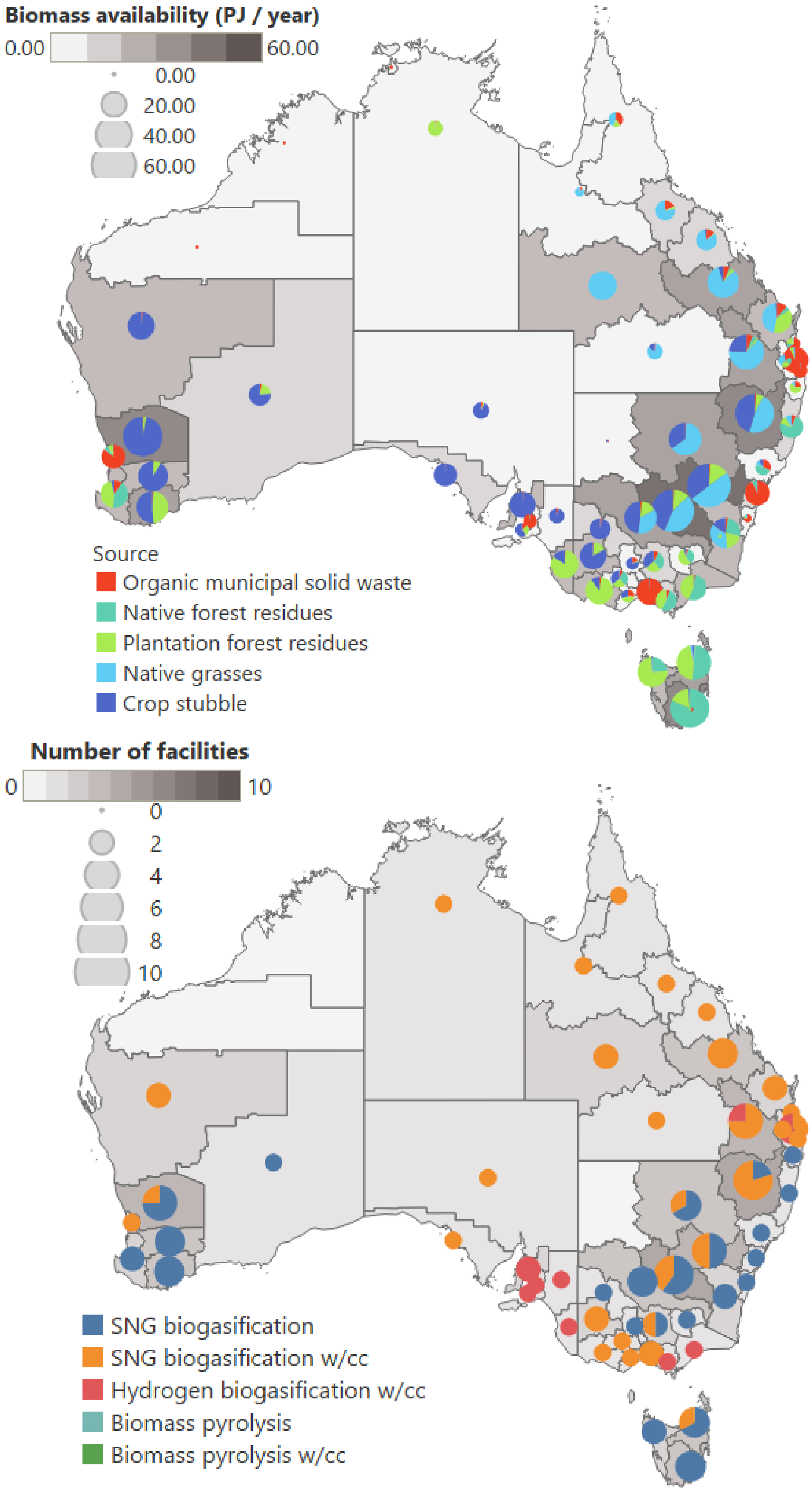
In total, the establishment of this bioenergy industry would require 80–90 $B of capital investment between 2025 and 2040, levied as a roughly 6–7 $B ongoing levelised capital cost. In addition, ongoing expenditure on the biomass feedstock and operating costs would account for around ~13 $B per annum.

The practical establishment of a new bioenergy industry as part of Australia's national pathway to net zero GHG emissions would require, among other things:

- studies that characterise the availability of biomass feedstock for bioenergy conversion, incorporating evaluations of biomass supply sustainability, economic potential, and competition with food and feed crops;
- analysis and optimisation of biomass feedstock supply chains, from growth to harvest and aggregation at bioenergy plants or hubs;
- research and development to bring the prospective bioenergy conversion technologies assessed here (biogasification, pyrolysis and carbon capture) to high levels of commercial readiness, particularly with respect to enabling the use of heterogeneous biomass feedstock in a particular bioenergy conversion facility; and
- the administering of regulations and standards that permit the substitution of biofuels (produced from biomass feedstock) for currently used conventional (fossil) fuels.

The use of biomass residues and waste feedstocks, as considered in this work, will need to be sustainably harvested to minimise impact on existing agriculture and forestry industries. However, the establishment of a bioenergy industry and new revenue streams may also be complementary to those industries. Nevertheless, any energy policy that seeks to incentivise the use of waste biomass and organic matter should also carefully consider the impacts of those incentives on the production of primary agricultural and forestry products.

Figure 39 | (Top) biomass resource availability in 2050; and (bottom) number of conversion facilities downscaled for the E+ Scenario in 2050, by ABS statistical division. Note: the precise location of facilities have been downscaled and are included with CCS infrastructure maps.



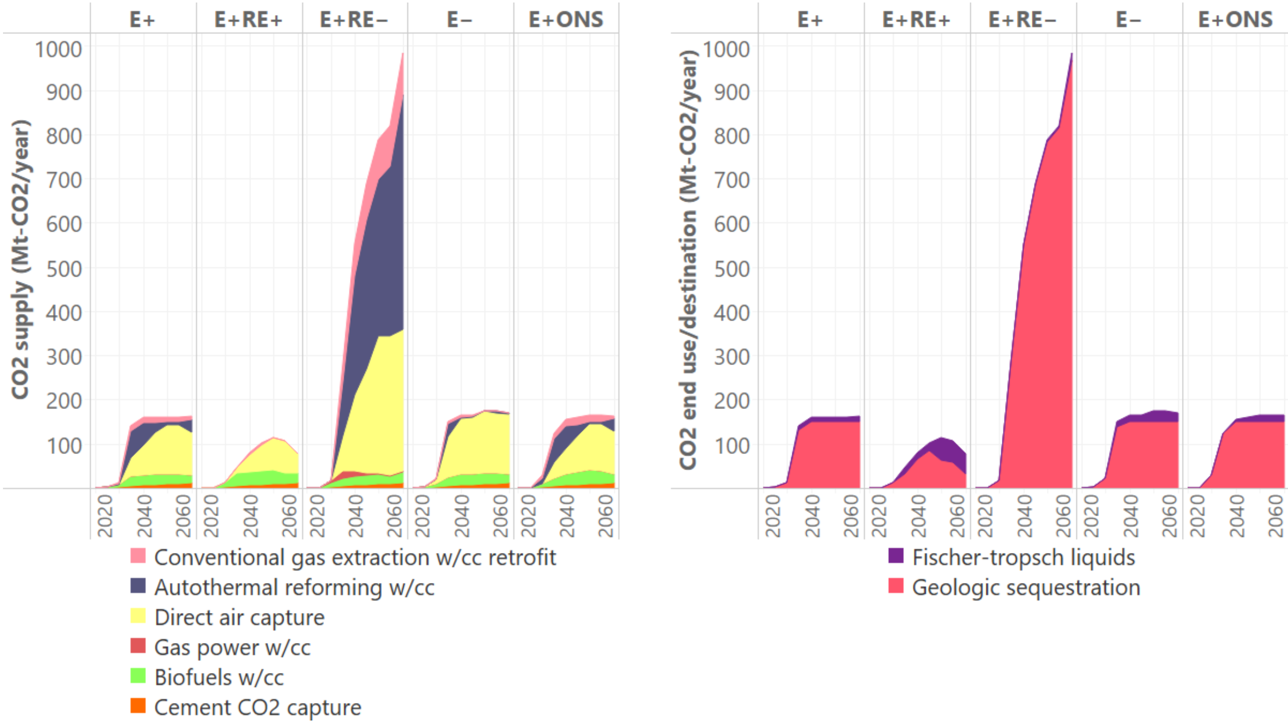
5.4 Pillar 4: CO_2 capture, transport, utilisation & storage

Carbon capture, transport, utilisation & storage (CCUS) is used to varying extents across all Scenarios, rapidly expanding from 2030 to reduce the GHG footprint of various energy and industrial activities, and to provide net atmospheric CO_2 withdrawals (negative emissions) via DAC or BECCS. The notional annual geologic sequestration limit modelled by the NZAu Project for Australia is 150 Mt-CO_2/year. However, under constrained renewable deployment in the E+ RE− Scenario this storage limit was found to be insufficient to meet both the domestic *and* export energy demands, given the linear net-zero trajectory imposed on each. This finding underscores the primarily economic drive to first cut emissions, and only at a second stage offset emissions, as well as the interlink between these two emissions abatement pathways. The following further expands on the role, solutions and requirements for carbon capture in the transition to net-zero, which is also the object of a dedicated companion downscaling report.

5.4.1 Trends of CO_2 supply, use and destination

Figure 40 reveals the processes mainly responsible as sources of CO_2 injection into pipelines across net-zero Scenarios, together with the modelled destination of such CO_2 flows, between 2020 and 2060. Downstream capture of cement process emissions, biofuels production with onsite carbon capture, and direct air capture are the three CO_2 supply pathways most consistently adopted across Scenarios, with the latter providing both the carbon feedstock for net-zero hydrocarbon synthesis via Fischer-Tropsch, as well as a means of net atmospheric CO_2 removal.

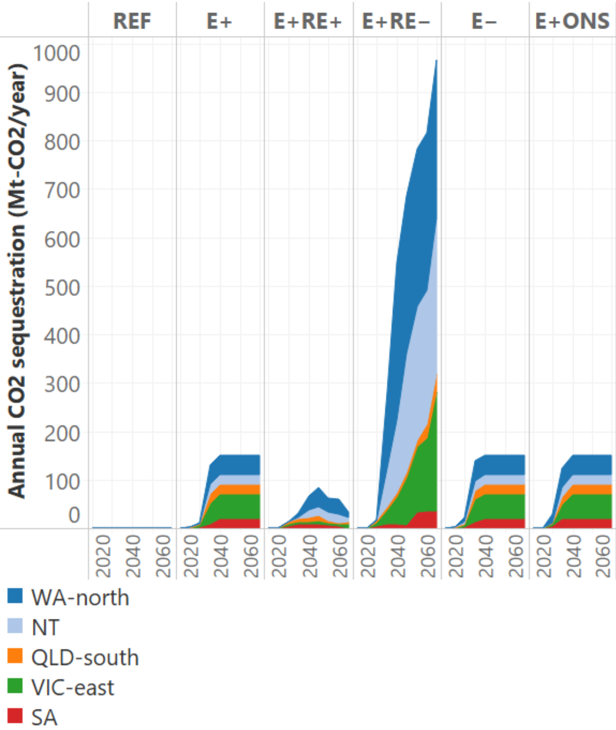
Figure 40 | (Left) supply/source of CO_2, by technology; and (right) end use/destination of CO_2.

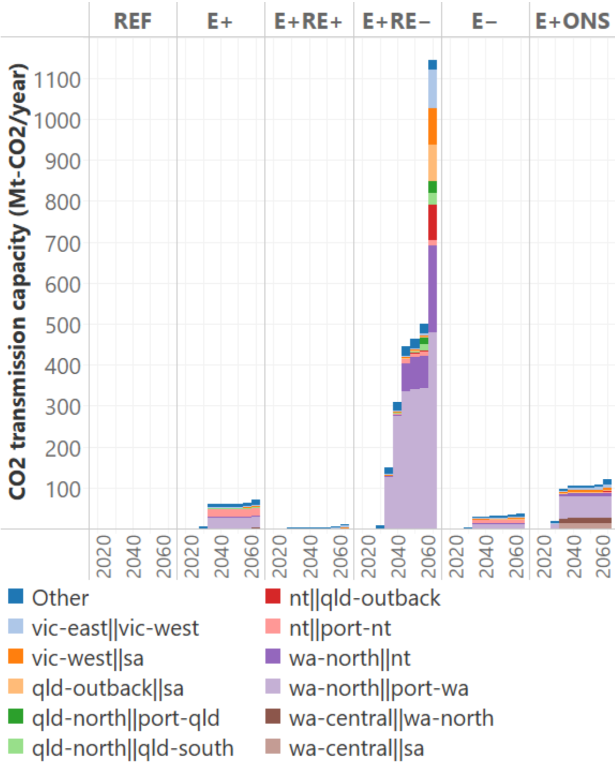


However, the extent of CCS contribution significantly depends on the rate at which VRE can be deployed, hence differing the trends across Scenarios. The right-hand plot in Figure 40 shows the annual geological sequestration limit is rapidly reached in E+, E−, and E+ONS by 2040. By contrast, with large VRE deployment in the E+RE+ Scenario CO_2 infrastructure is only required for limited hard-to-abate emissions (cement and other industry activity, plus residual transport emissions), and net withdrawals through the BECCS and/or DAC. The limitation on the annual geological carbon injection is not a binding constraint in this case. Furthermore, expansion of conventional gas production in the E+RE− Scenario requires extensive capture and sequestration of process CO_2 emissions from several points along the supply chain, but mainly gas extraction and autothermal reforming. Expanded geologic sequestration potential (limited in this case to 1166 Mt-CO_2/year) is a necessary requirement in order to supply the annual export energy demand in the E+RE− Scenario.

Autothermal reforming with CCS is, together with DAC, the activity that most contributes to CO_2 sequestration, with the respective share dependent on the considered Scenario, but together accounting for over 85% of CO_2 sources past 2050. Significant CO_2 transmission capacity is then required, in most Scenarios other than E+RE+, to enable transport of this CO_2 to sequestration and use sites, as presented in Figure 41. The largest geological sequestration and associated CO_2 transmission is required in E+RE−, mostly needed to for management of CO_2 from energy export activities. However, CO_2 transmission *capacity* is typically less than *total sequestered* because DAC can be located near sequestration sites, thus avoiding the need for extensive CO_2 transmission. The required CO_2 transmission capacity based on the outputs from macro-scale energy system modelling has been downscaled to specific routes and mapped as presented in Section 5.4.2.

Figure 41 | (Left) geological sequestration of CO_2, by region; and (right) capacity of the various inter-regional CO_2 transmission routes.

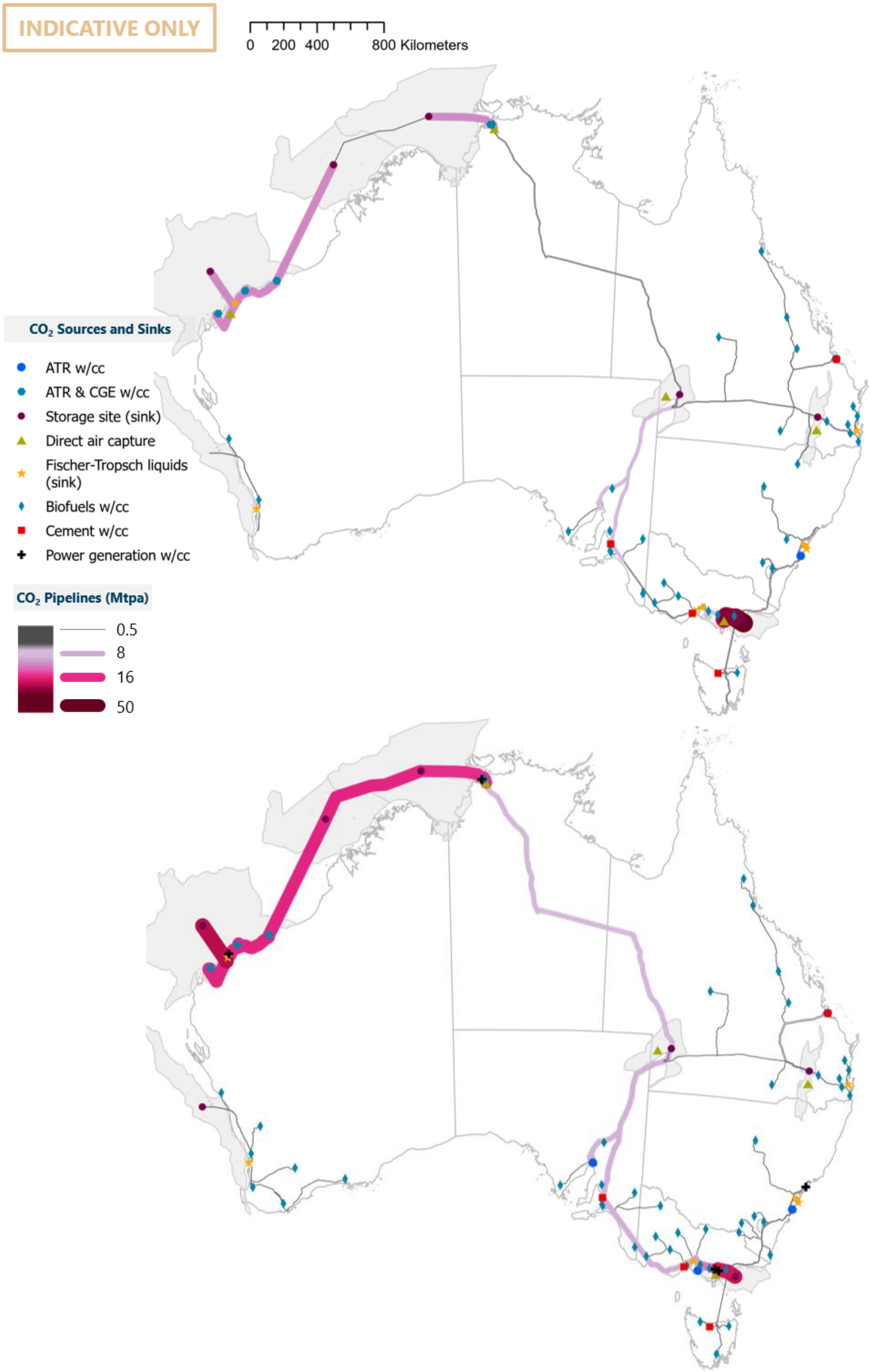




5.4.2 Mapping the CO_2 infrastructure

Figure 42 maps the CCUS infrastructure modelled in the E+ and E+RE− Scenarios in 2060, including CO_2 transmission routes, and the location of various carbon sources and sinks; the in-depth description of the adopted mapping methodology, additional results and implications are presented in the companion downscaling report. Similar transmission networks emerge between E+ and E+RE− but at a far greater scale for the latter, reflecting largely similar locations of CO_2 sources, but much different shares and larger supplied volumes in E+RE−. The cumulative CO_2 pipelines capacity for this Scenario is 13× larger than that required in the E+ Scenario (1062 Gtpa-km, as opposed to 83 Gtpa-km). Major offshore carbon transmission infrastructure will be needed – particularly from the Northern Territory, Western Australia and Victoria (Gippsland) – towards the offshore storage basins nearby. Onshore carbon transmission is to be mainly sited between Adelaide and Melbourne, and to connect Brisbane with the Cooper basin.

Figure 42 | Downscaled CCUS infrastructure for the (top) E+ Scenario and (bottom) E+RE− Scenario, in 2060, including CO_2 transmission routes, and location of various sources and sinks of CO_2.

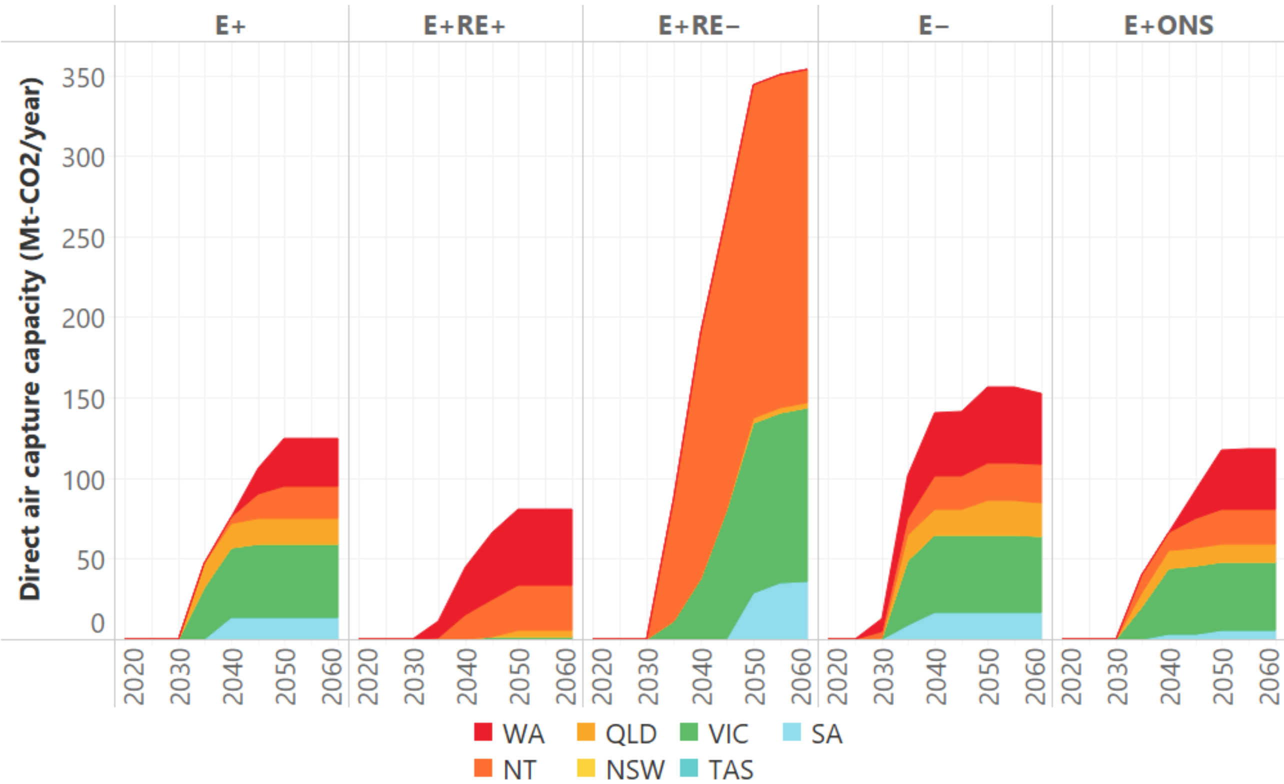


Concerning carbon sources, state-of-the-art kiln/plants with integrated CCS are deployed between 2025 and 2040 as an upgrade of existing plants. These are mapped in Figure 42, with no need to site new facilities. Over the same 2025 to 2040 time span, cement production plants in New South Wales and Western Australia are progressively fully retired, prioritising oldest assets, and substituted by augmented capacity with carbon capture extension for the existing plants in Victoria, Queensland, Tasmania and South Australia. Autothermal reforming plants with carbon capture were sited in the NZAu export port locations in each state, except for New South Wales, where Port Kembla was the designated location and is better served by both the pipeline gas network and NZAu's planned CO_2 pipelines.

Bioenergy plants for biofuel production, paired with CO_2 capture represent the largest carbon source – by number – across Australia. The NZAu macro-scale energy system modelling has also shown that 20-30 Mt-CO_2/year, in aggregate, are captured by these facilities, from 2035 onwards, across all Core Scenarios, which make up 2-3% of total CO_2 supply in E+RE− and 20-30% in E+RE+. The choice to build bioenergy with carbon capture is made by macro-scale energy system optimisation across 15 regions, given a biomass and sequestration resource at that 15-region level and with potential interconnection between regions. However, we have shown that Australia's biomass resource is in fact diffusely distributed across many smaller disaggregated regions, each characterised by different agricultural, forestry and other biomass-producing activities. This implies that bioenergy plants – which each act as point sources of CO_2 when paired with carbon capture – would also be diffusely distributed across the country. Indeed, the downscaling analysis undertaken for a future bioenergy industry has shown that point sources of CO_2 could be relatively concentrated in parts of WA, VIC and SA, but more widely spread in NSW and QLD, as can be appreciated by the Figure 42. Smaller CO_2 lines are deployed to connect scattered bioenergy plants to the main CO_2 transmission backbone.

Direct air capture, whose installed capacities by state/territory are reported in Figure 43, features in all Scenarios, but its uptake is at least 2× as high in the E+RE− Scenario as in any of the others (and up to 5×). DAC in E+RE− mostly offsets expanded natural gas use for export energy supply, in Victoria and in the Northern Territory. The advantage of DAC facilities over other means of carbon offset is they can be located directly in regions with CO_2 sequestration potential, thus avoiding the need for extensive CO_2 transmission lines. This is indeed the option pursued for mapping the DAC infrastructure in Figure 42.

Figure 43 | Direct air capture capacity, by state/territory.



5.5 Pillars 5 & 6: Reduced non-CO_2 emissions and enhanced land sinks

With a concerted effort, Australia's land sector (agriculture and forestry) may contribute to country-wide emissions abatement through the uptake of activities that, in aggregate, reduce biogenic GHG emissions and remove CO_2 from the atmosphere.

The agriculture sector made up 14% (74.8 Mt-CO_2e) of Australia's 2019 GHG inventory. Of this, enteric methane is the largest source of GHG emissions making up 72% of agriculture emissions, followed by nitrous oxide emissions from agricultural soils (15%), and methane and nitrous oxide emissions from manure management (9%). The waste sector also contributed 14 Mt-CO_2e, the majority of which is also methane. Land use, land-use change, and forestry (LULUCF), on the other hand, accounted for a net sink of carbon dioxide, −25.1 Mt-CO_2e in the 2019 GHG inventory.

In this section we provide projections for the plausible contribution to emissions abatement from the agriculture, waste and LULUCF sectors, assuming a plausible concerted effort to reduce emissions and enhance carbon dioxide sinks within those sectors. The detailed modelling assumptions used for these projections are provided in Section 8 of the accompanying *MASS* document. Here we provide a summary.

Figure 44 presents historical (1995 – 2019) and projected (2020 – 2050) net GHG emissions from the agriculture, LULUCF and waste sectors, accounting for the modelled emissions mitigation measures. This shows that we consider, as a conservative assumption, the GHG emissions level from these sectors in the initial modelling year (2020) to be the average annual emissions of the previous 10 years (2010 – 2019), which is significantly larger than the annual emissions recorded in the inventory in 2019. From this initial timestep we project the effects of various measures, as follows.

Within <u>agriculture</u>, emissions are projected to reduce to 2050 through the application of:

- feed additives (i.e. 3-NOP) to reduce enteric fermentation methane emissions across the dairy, pasture-fed beef, feedlot, and sheep industries – with varying degrees of emissions reduction and uptake in each industry, given the relative ease of application to each industry (i.e. 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);
- covered anaerobic ponds for manure management, with widespread (~100% uptake with ~100% emissions abatement) use across the dairy, feedlot, swine, and poultry industries – which allow for all CH_4 produced during the oxygen-free manure degradation to be captured and combusted in a flare, with no CH_4 emitted to the atmosphere (only biogenic CO_2); and
- precision agriculture (slow-release nitrogen fertiliser) in dairy, cotton and sugar cane industries, which improve the efficiency of nitrogen use and not only reduce emissions but have other co-benefits.

Figure 44 shows that these measures could reduce agriculture sector emissions by 23% (from 79.9 to 61.7 Mt-CO_2e/year) between 2020 and 2050, most of which comprises a reduction in methane emissions. We also note that to date, the NZAu project has not considered the effect of any waste sector emissions mitigation measures, and so projects waste sector emissions to be 14 Mt-CO_2e/year from 2020 to 2050 as a continuation of the 2010-2019 average. This means that agriculture and waste remain net GHG sources.

Within the <u>LULUCF sector</u>, the projected net emissions trajectories account for two emissions abatement strategies:

- reduced deforestation, so that emissions from conversion of forest land to other uses decline to zero by 2030 – potentially resulting from an increase of regulatory control and from market drivers (e.g. Meat and Livestock Australia's CN30 target) that will lead to reduced land clearing rates; and
- a concerted afforestation of a portion of suitable agricultural land, which involves new investment to expand the forest area through a combination of trees integrated with farming, environmental plantings, commercial plantations and human-induced regeneration.

Figure 44 | Historical and projected net GHG emissions from the Agriculture; Waste; and Land Use, Land Use Change and Forestry sectors: (left) by state/territory; (middle) by sector; and (right) by greenhouse gas. The black line shows net emissions.

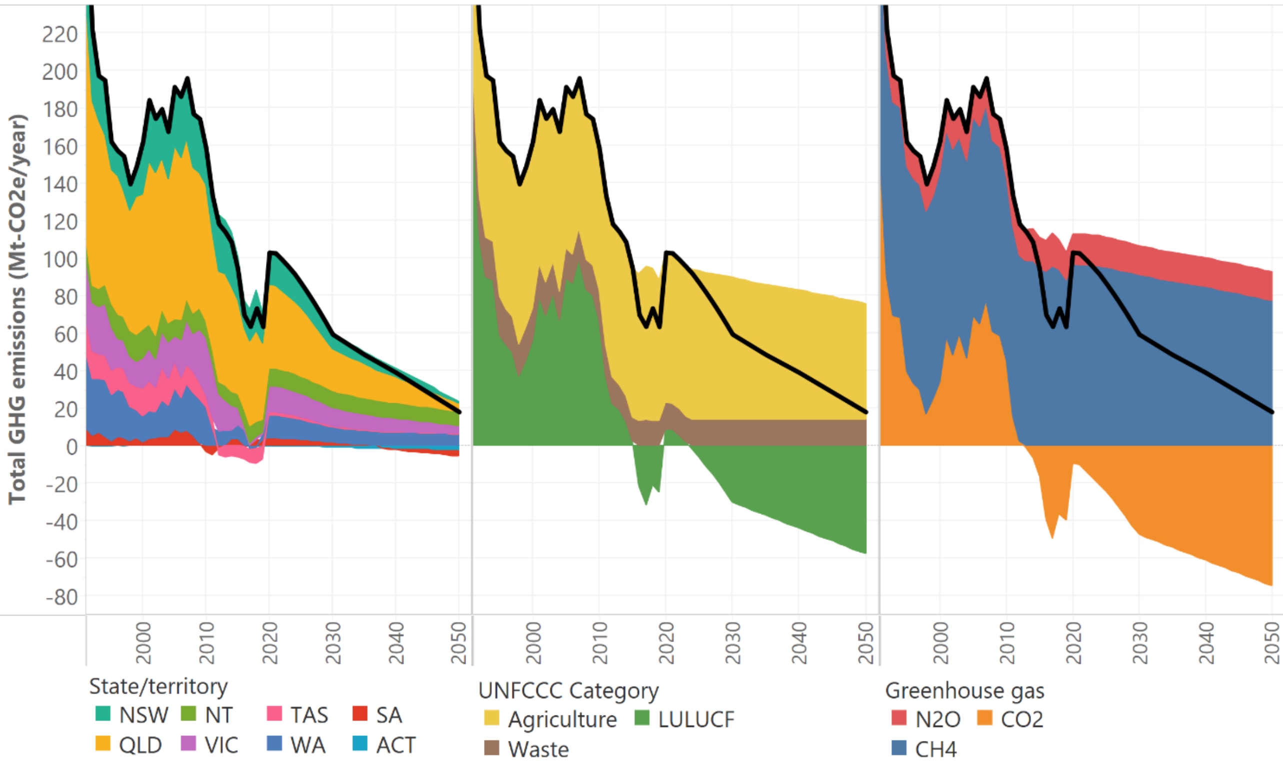
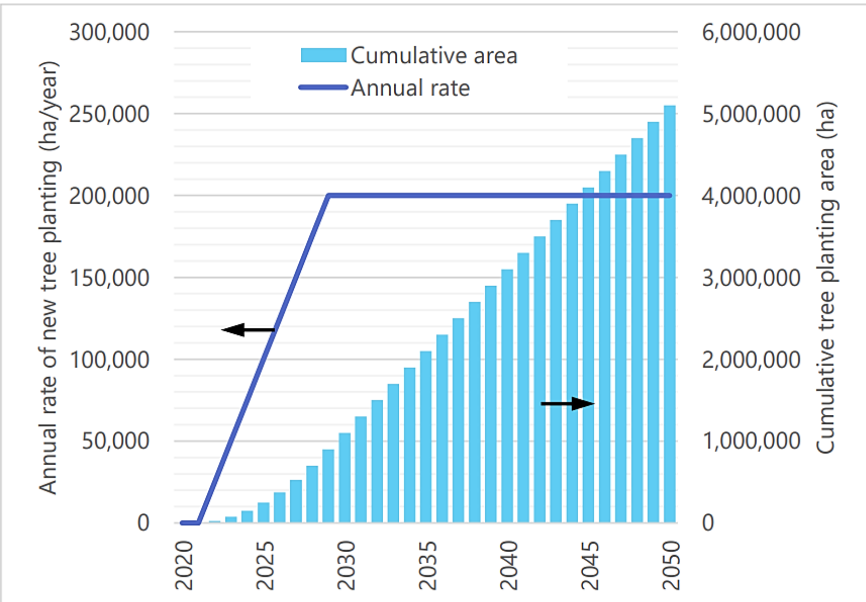


Figure 45 presents the modelled annual rate of new tree or forest establishment, which increases from the current low level to an annual rate of 200,000 ha/year by 2030 and continues to 2050, resulting in a total new forest area of 5.1 million hectares. The national average rate of carbon dioxide sequestration in these new forests was modelled to be approximately 10 t-CO_2/ha/year, resulting in −51 Mt-CO_2e of annual sequestration (net atmospheric CO_2 removal) by 2050.

Figure 45 | Projected annual rate and cumulative area of new tree planting on agricultural land.



Taken together, Figure 44 shows that a concerted effort to adopt plausible mitigation measures – particularly the active abatement of methane emissions from agriculture and enhanced CO_2 sequestration through new tree planting – could reduce emissions in the combined land (agriculture, waste and LULUCF) sector to be a small net source (19 Mt-CO_2e/year) by 2050. It should be noted that with these projections these combined sectors do not reach net-zero and therefore require negative emissions in another sector to offset the residual emissions shown here.

5.5.1 Downscaling of afforestation

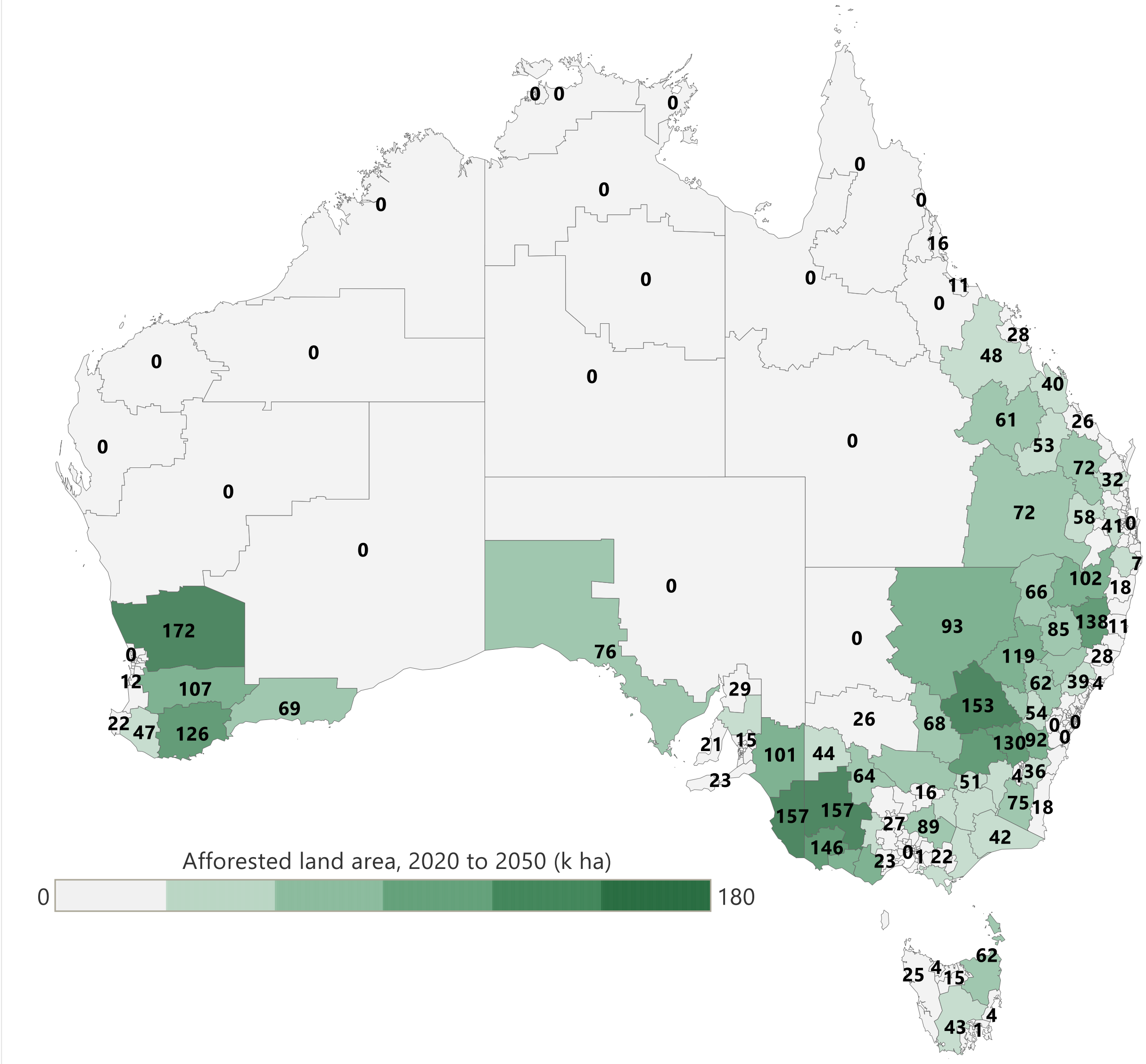
Further downscaling of the modelled afforestation of agricultural land has found that 5.1 million hectares of new trees could be sited on current Australian farmland, predominantly located in southern and eastern Australia, and preferentially on Australian pastureland. The regional distribution of this afforested land area with one particular siting strategy considered in downscaling work is shown in Figure 46, with the total modelled farmland afforestation by state/territory shown in Table 2. Depending on the siting strategy used, 2.9-3.4% of cropland would be required over 30 years to host new trees, while 14-15% of pastureland would be required, which represents the greater co-benefits of siting trees on pastureland, compared with cropland. We have also shown that a national average of 10 t-CO_2 of annual sequestration per afforested land area is plausible, assuming that environmental plantings are adequately managed to maintain sequestration rates, and that some small portion of the afforested land area (~10%) is established as timber plantations in areas with higher annual rainfall. Downscaling of this work has provided estimates of the regional variability of the annual sequestration rate, and future work could explore projected sequestration in more detail.

There are several considerations that any program seeking to establish the uptake of trees on Australian farmland should consider, in addition to those characterised in this report above. These relate to the impact of natural disturbances, the impact of climate change, the need for carbon monitoring improvement, the value of alternative options for emissions abatement or sequestration, and the impacts on stakeholders, such as farmers and indigenous Australian traditional landowners. Some of these considerations are discussed further in the companion downscaling report.

Table 2 | Total farmland afforestation by state/territory.

State/territory	Farmland afforestation
WA	0.66 M ha
NT	0.00 M ha
QLD	0.59 M ha
NSW & ACT	2.0 M ha
VIC	1.2 M ha
TAS	0.13 M ha
SA	0.57 M ha

Figure 46 | Downscaled 5.1 million hectares of farmland afforestation, showing afforested land area between 2020 and 2050 in thousand hectares, within each of the ABS' SA3 regions.



5.5.2 The possible emergence of methods for enhancing the land CO_2 sink

The projections shown in Figure 44 suggest that significant land-based emissions offsets may not be widely available to the energy and industrial sectors. Indeed, negative emissions in another sector may be required to offset residual land sector emissions. However, it is possible that, in addition to those land-based emissions abatement strategies considered above, several other options for reducing emissions or enhancing the land CO_2 sink may emerge in the coming years, with varying levels of uncertainty in estimates of carbon accounting, additionality, barriers to adoption and technical and social feasibility (Fitch et al., 2022). Such options include the following.

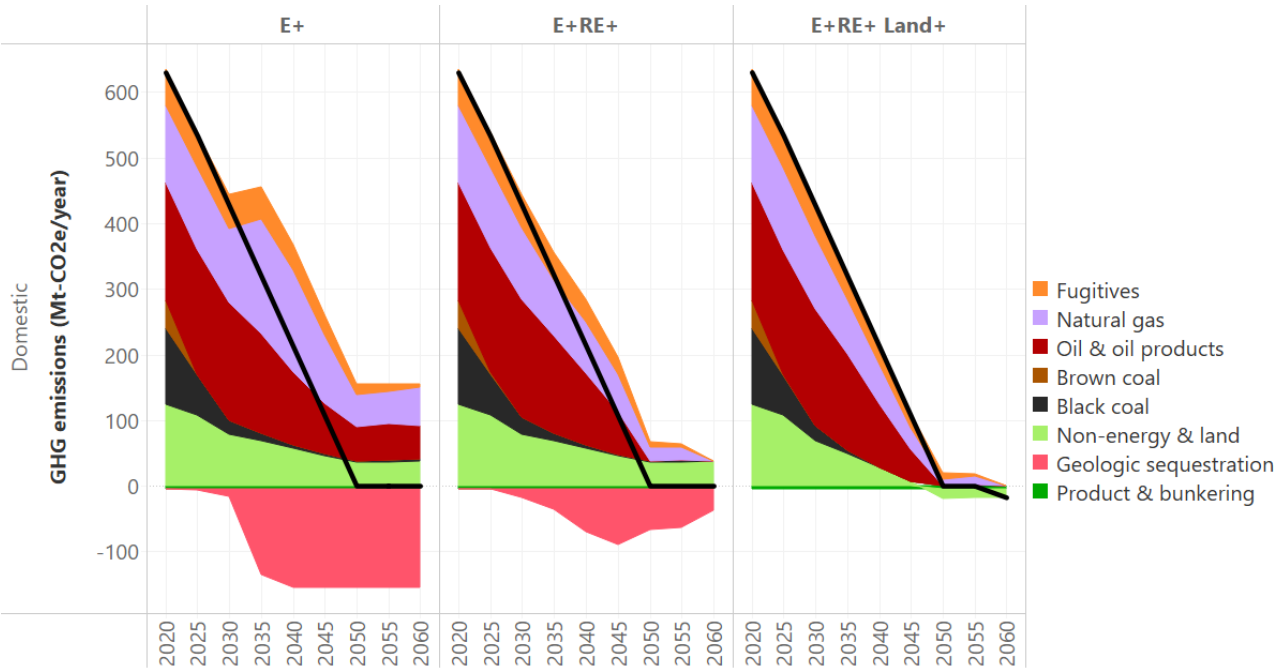
- A whole of landscape restoration approach, including:
  - integrated savannah burning (Cooke and Meyer, 2017; Russell-Smith et al., 2013); and
  - feral animal control (Drucker et al., 2010).
- Human-induced (re)generation of deep-rooted plant species (greater use of deep-rooted legumes in extensive rangeland and cropping and greater incorporation of forage shrubs, e.g. Eremophylia, that also reduces livestock methane).

- Early life rumen microbiota engineering – in which animals are weaned on a methane inhibitor to establish a microbiota that results in the animal producing lower levels of methane over the animal's lifetime (Meale et al., 2021).
- Reductions in over-grazing (e.g. drought preparedness) and continuous cropping (reduced soil disturbance).

We therefore examined the sensitivity of the modelled system to the possible emergence of such options for enhancing the Australian CO_2 sink, that would enable the land sector to reach modest levels of net emissions removal. Specifically, the sensitivity (denoted E+RE+ Land+) incorporates a linear increase in annual CO_2 sequestration from these nascent options from 2025, reaching −50 Mt-CO_2e/year by 2050. This results in the combined land sector reaching −31.5 Mt CO_2e/year in 2050.

Figure 47 then presents the modelled emissions trends for the domestic energy system resulting from the E+RE+ Land+ Sensitivity study (with E+ and E+RE+ for context). This shows that higher land sinks could displace the need for geologic sequestration when applied to the fully renewable E+RE+ Scenario. With this Sensitivity there is then also only limited use of direct air CO_2 capture and bioenergy with carbon capture, which provide the carbon required (up to ~20 Mt-CO_2/year) for synthetic fuels production. This highlights the complementary role of geologic and land-based sequestration, with each uncertain in their future feasibility and prospects. Nevertheless, land sector emissions could trend towards net zero, but other sectors should not necessarily plan for widely available offsets.

Figure 47 | Domestic GHG emissions for selected Core Scenarios and the Land+ Sensitivity. The black line shows net emissions.



6 System costs

System costs are disaggregated by domestic and export sectors, according to the proportion of total costs that are incurred in serving domestic final energy demand, and constant demand for exported energy, respectively. All costs are presented in 2020 Australian Dollars (2020 AU$)

6.1 Domestic system costs

The costs of the modelled net-zero transition for the domestic energy system are shown in Figure 48, presenting first the domestic energy supply costs, and then the total domestic system costs, which adds all demand-side equipment costs (vehicles, home appliances, costs of energy efficiency and fuel switching, etc.). We also present the Net Present Value (NPV), at 2.7% discount rate, of the total domestic system's modelled net-zero transition cost over 2020-2050. These costs do not account for any cost or avoided cost of climate change impacts or air pollution.

The NPV cost of the net-zero Scenarios were found to be $4.8-5.1 trillion, which are $600-900 billion greater than the REF Scenario. However, we note that the costs of REF reflect energy policy stasis, do not account for recent high fossil fuel prices or the costs of inaction on climate change, and assume fossil fuel costs remain consistently low over the course of the transition, an assumption which is deeply uncertain. Assessing the costs of the net-zero Scenarios against a counterfactual reference case with fossil fuel price volatility would serve to reduce their incremental $600-900 billion cost. The rapid electrification (E+) and slower electrification (E−) Scenarios were found to have the lowest NPV cost of the net-zero Scenarios, indicating that the fully renewable (E+RE+) and constrained renewable deployment (E+RE−) constraints only increase costs and that cost minimisation is served by preserving optionality in the energy supply mix.

The levelised annual costs in Figure 48 show that domestic energy system costs rise in absolute terms (1.3-1.5× reference case by 2050), with energy supply costs contributing around 50% to the total cost. The E− Scenario tends to have higher energy supply-side costs than the E+ Scenario, due to the need to supply more costly decarbonised fuels as the domestic emissions constraint tends to net-zero. However, these higher supply costs are counterbalanced by lower demand-side costs, so that E+ and E− have similar total domestic cost trends. Should the capital costs of high efficiency, electrified building appliances and transport vehicles reach cost parity with incumbent fuel-based technologies sooner than current modelling suggests, then the E+ Scenario could be expected to have lower total cost than E−. Interestingly, peak domestic energy system costs are coincident with the timing of the net-zero emissions constraint in 2050, but then ease as electrification, energy efficiency measures and the build out of renewables continue.

Figure 49 shows the levelised domestic supply and total costs as a proportion of gross domestic product (GDP), noting that GDP is an exogenous input to the modelling and would itself be influenced by both domestic and export decarbonisation. The general downward trend in costs as a proportion of GDP is due to the modelled reduction in energy intensity of the economy. Nevertheless, domestic energy system costs remain around or lower than the current share of GDP.

Figure 48 | Levelised (left) domestic energy *supply* cost; (middle) *total* domestic system total cost; and (right) Net Present Value (NPV) of the total domestic energy system cost over 2020 to 2050, calculated with 2.7% discount rate.

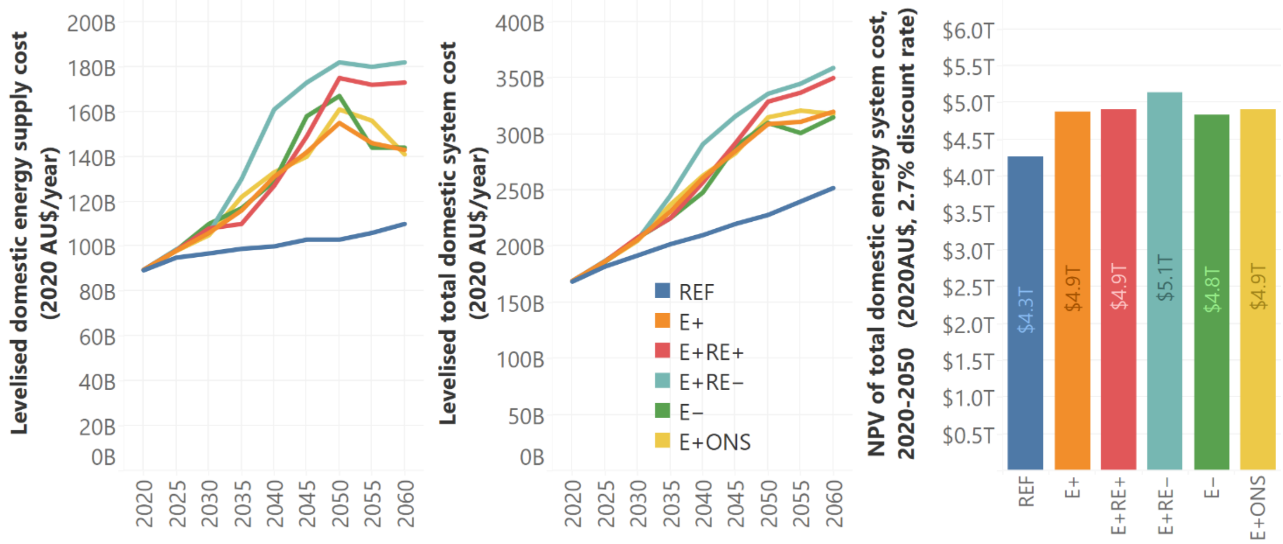


Figure 49 | Per GDP levelised costs of (left) domestic energy *supply*; and (right) *total* domestic demand and supply.

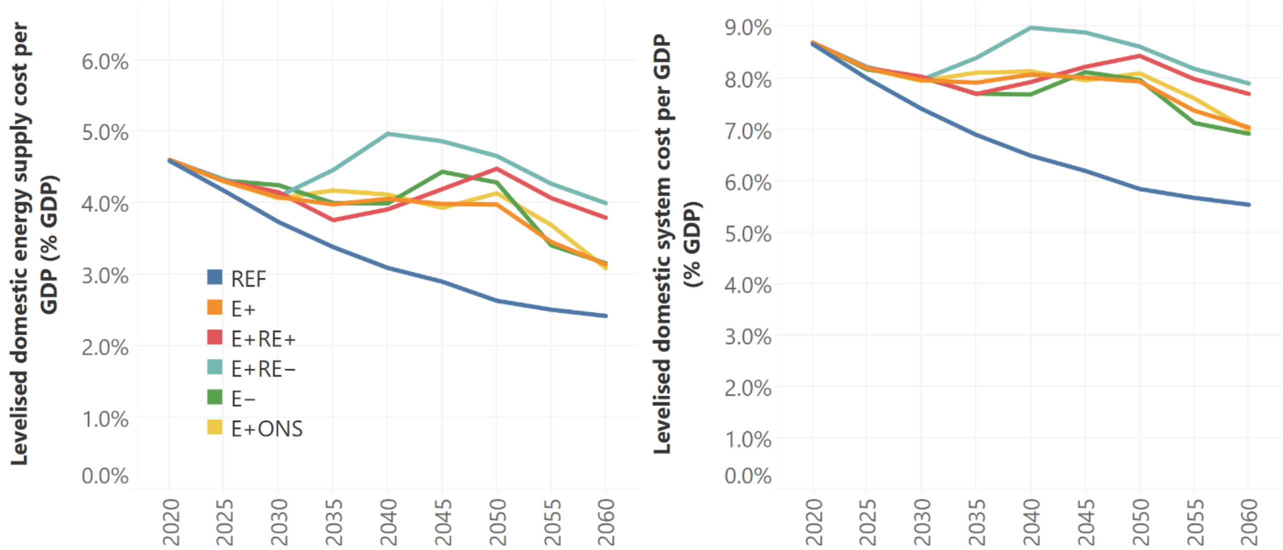
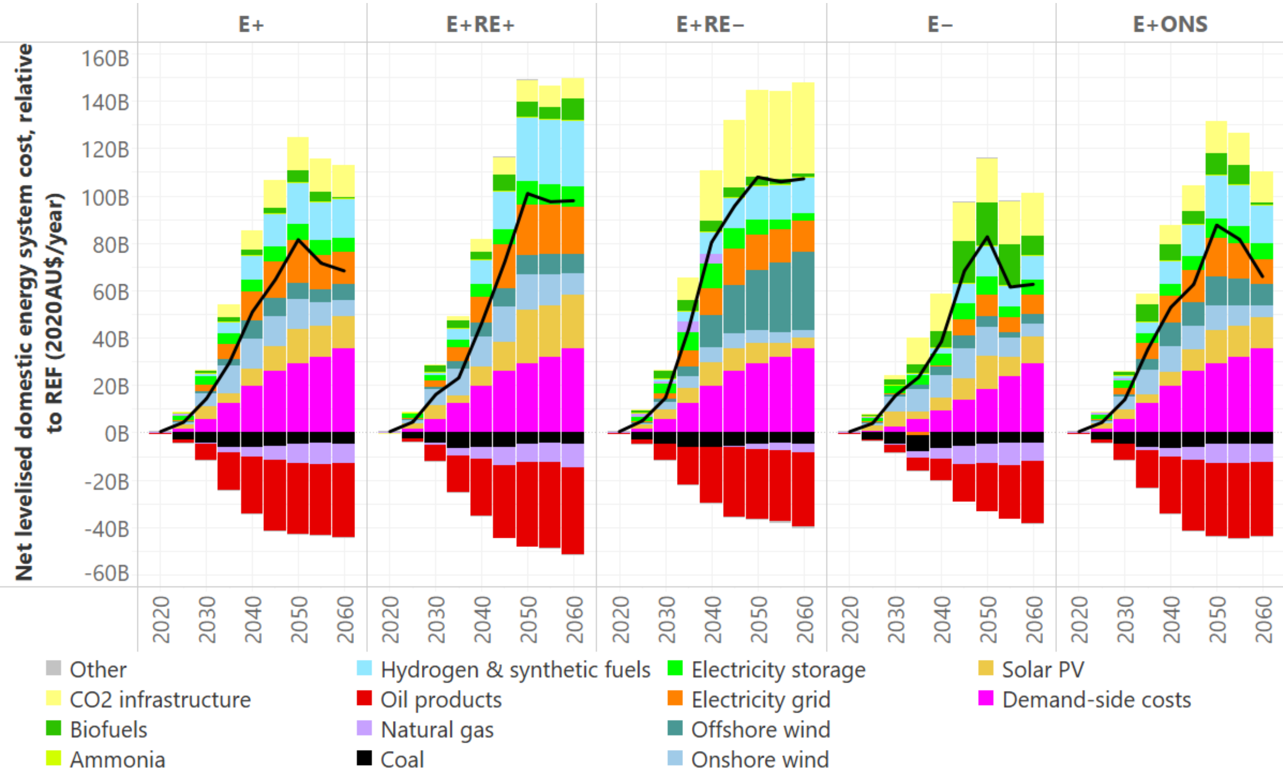


Figure 50 shows the *net* levelised total domestic system cost, relative to REF, by grouped cost component. This shows how, depending on the considered sectors, not only costs, but also savings are to be experienced in a net-zero transition. Energy supply costs are dominated by the capital costs of renewables, storage and electricity grid augmentations. At the same time, net-zero Scenarios exhibit cost savings (negative net cost) in activities relating to coal, gas and particularly oil products of ~$40-50 billion/year, relative to REF. As most oil products are imported, this represents a reduction in exposure to international oil price volatility. The E+RE+ fully renewable Scenario has both the highest net costs of renewable and grid infrastructure, and the highest costs of hydrogen infrastructure, reflecting the greater need for green hydrogen in that Scenario to displace all fossil fuel use by 2050. The E+RE− constrained renewable deployment Scenario interestingly has higher net costs of renewable infrastructure than E+ and E−, due to the need for significant offshore wind deployment (with constrained onshore renewables). In addition, E+RE− has significant net costs associated with CO_2 capture, transmission and storage infrastructure.

Net-zero Scenarios also have demand-side costs (vehicles, home appliances, energy efficiency measures, etc.) that are $18-30 billion/year greater than REF. While transport is the largest component (70-80%) of *total* demand-side costs, the *net increase* in demand-side costs shown here is evenly distributed between transport (mostly heavy-duty transport sector), residential (mostly high efficiency space heating and refrigeration), and industrial sectors.

Figure 50 | Net levelised domestic system cost, relative to REF Scenario, by technology/resource cost components.



6.2 Export system costs

Figure 51 shows the export energy system costs, as levelised annual cost, average cost per unit of energy exported, and the NPV (2.7% discount rate) of the export system's modelled net-zero transition cost over 2020-2060. These show that the decarbonised export system is modelled to cost 5× the reference case. The export system costs of the net-zero Scenarios are shown by cost component in Figure 52, and are dominated by the capital costs of the modelled energy export supply chain. That is, renewable electricity (mostly solar PV) generation; hydrogen production via electrolysis (some ATR w/cc); hydrogen transmission to and storage at ports; ammonia synthesis; and shipping (included in 'Other' category). Average energy export costs of >$30/GJ are relatively high costs for internationally traded energy, but in a carbon constrained world the cost of internationally traded energy is likely to increase. However, we have not modelled the impact of high energy costs on demand for Australian exports.

Export system cost differences between Scenarios are small, except for the E+ONS Scenario. This is because, direct processing of Australian resources (iron and aluminium ores) with Australian energy has significant energy efficiency benefit, and therefore also, lower cost, compared with the export of the equivalent energy. That is, clean hydrogen (ammonia or other H_2 derivative) export comprises a number of energy conversion processes, each with energy losses that require significant increase in primary energy production and associated costs. We note that only the energy costs required for onshore processing of iron and aluminium ores are included in the costs shown here for E+ONS, while the capital costs of new direct reduced iron and aluminium smelting plants are not. Nevertheless, the E+ONS Scenario is expected to be significantly cheaper than the other net-zero Scenarios.

It should finally be noted that the export system costs should not necessarily be borne by the Australian consumer, but instead by the export project developer and, in turn, the international trading partner.

Figure 51 | Levelised (left) total export system cost; (middle) total export system cost per unit of energy exported; and (right) Net Present Value (NPV) of the total export energy system cost over 2020 to 2060, calculated with 2.7% discount rate.

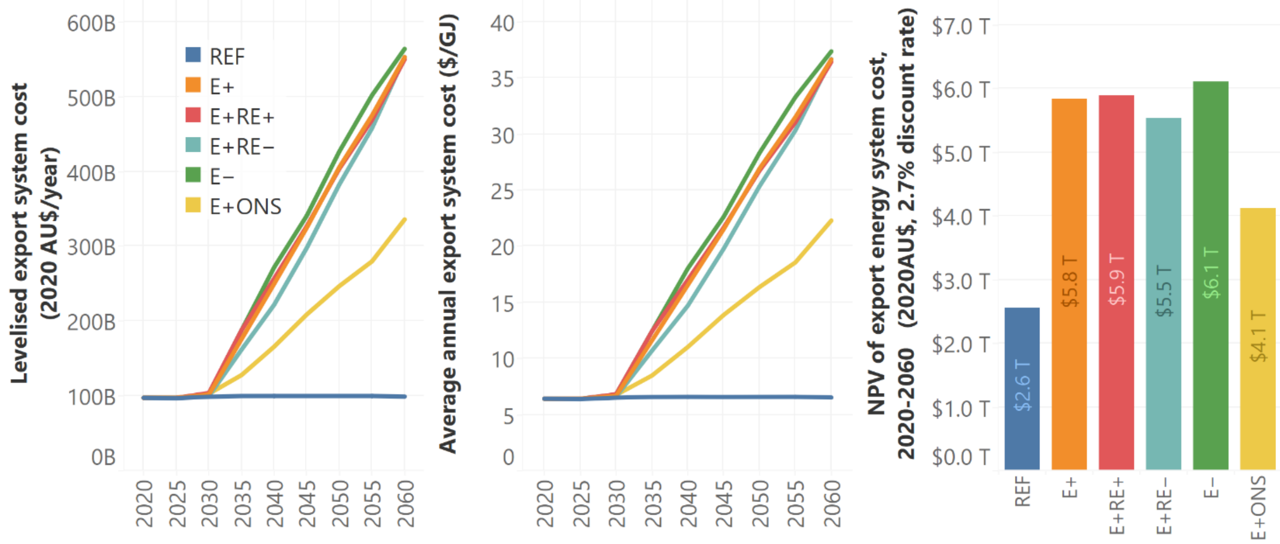
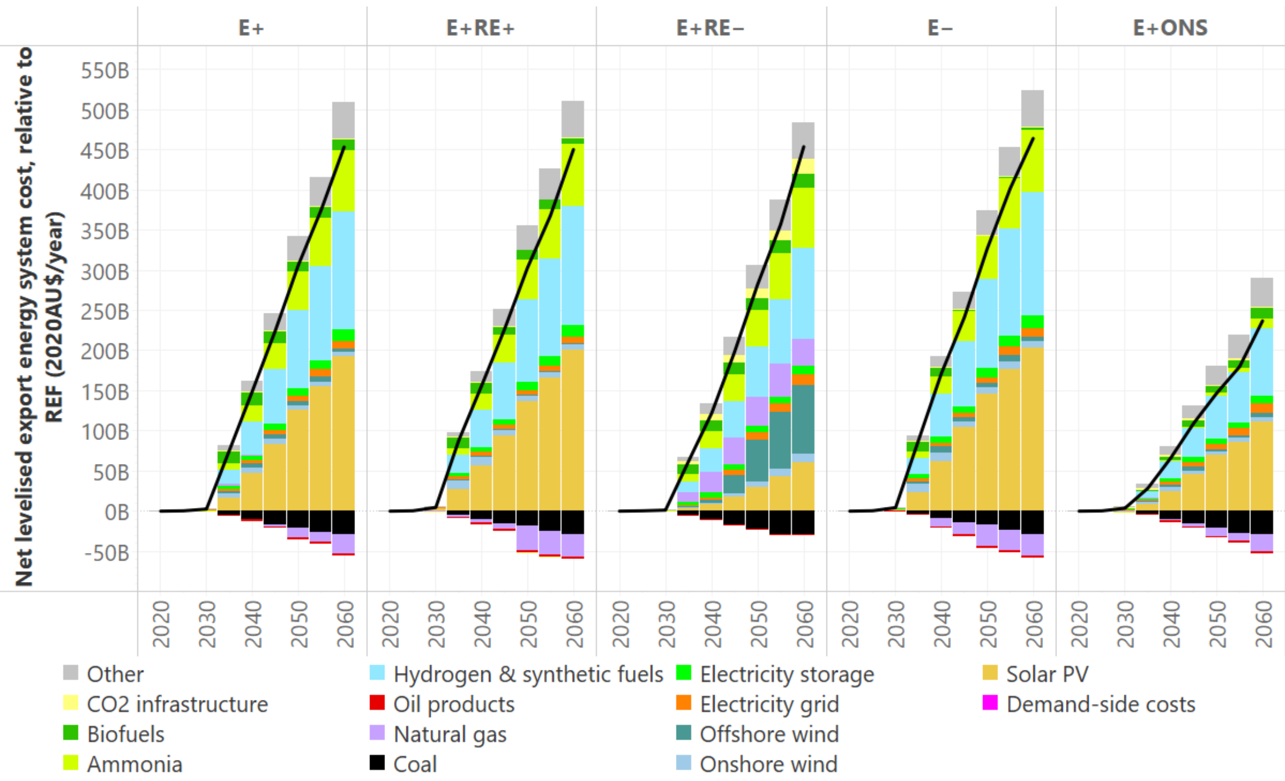


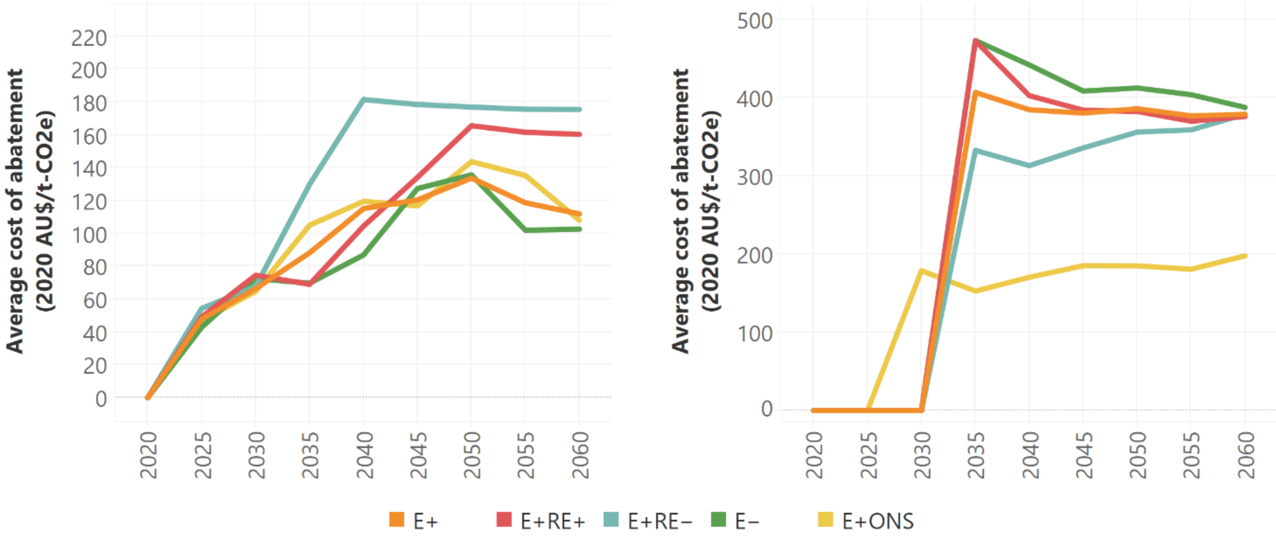
Figure 52 | Net levelised export system cost, relative to REF, by technology/resource cost components.



6.3 Costs of abatement

The average cost of GHG emissions abatement for the domestic and export energy systems is shown in Figure 53, and was previously defined and discussed for exports in Section 4.3. The costs of domestic emissions abatement rise to ~\$150/t-CO_2e in 2050, which is a similar value to that found for other countries' net-zero decarbonisation studies (e.g. Net Zero America). For the export system, average costs of abatement rise to >\$300/t-CO_2e from 2030, which reflects both the relatively high cost of the modelled clean energy export system, and the low cost of the current fossil fuel export system. Of particular note for the exports, the cost of abatement for the E+ONS onshoring Scenario is much lower than the other exports and comparable to domestic costs of abatement.

Figure 53 | Average costs of GHG emissions abatement for the (left) domestic, and (right) export energy systems.



7 Implications of the net-zero transition

Here we expand on some of the implications of the net-zero transition pathways presented above, noting that significant further detail can also be found across the numerous companion *Downscaling* reports. Furthermore, many of the implications of the net-zero transition examined in this work will be addressed in the forthcoming *Net Zero Australia Mobilisation* report.

7.1 The new build required

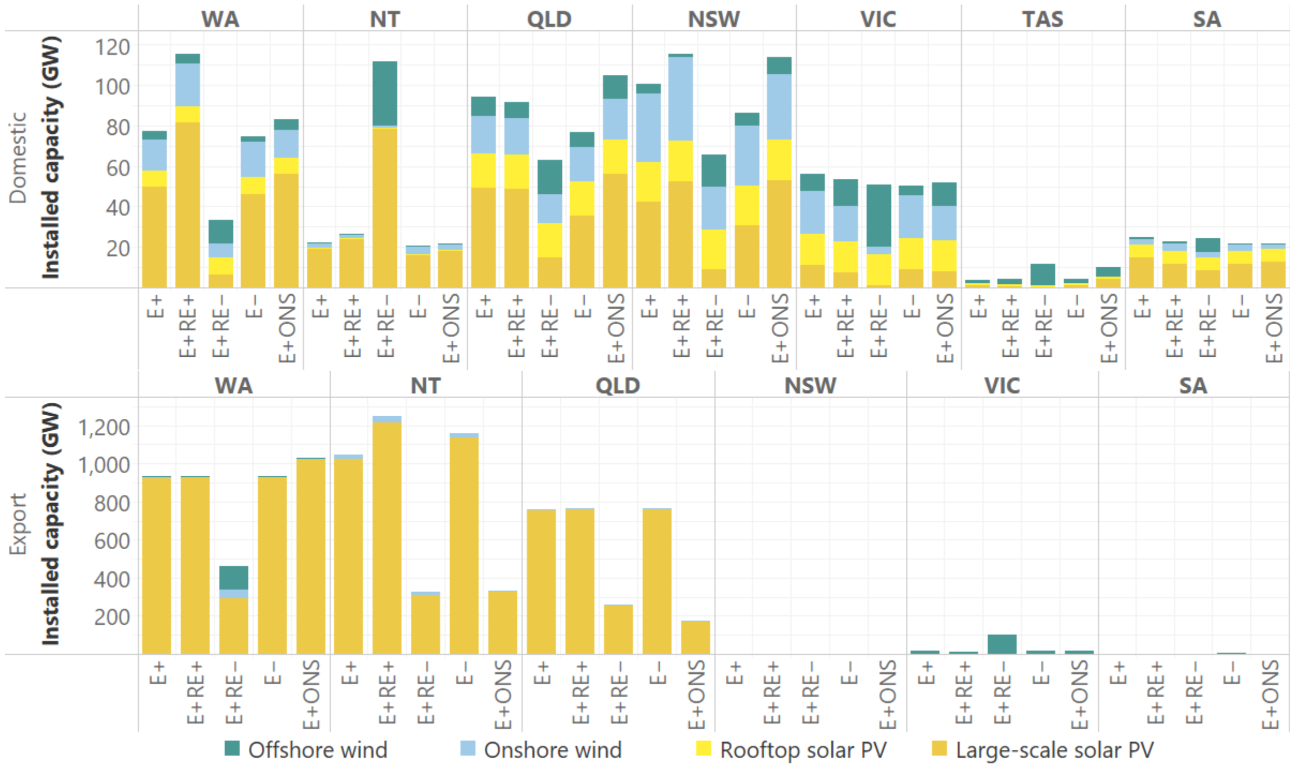
7.1.1 Renewable generation

In most net-zero Scenarios we find that decarbonisation of both domestic and export energy systems is led by the expansion of the electricity system through deployment of renewable electricity generators (solar PV and wind). Figure 54 shows the new build renewable electricity generation installed capacity, by state/territory in 2050 for the domestic electricity system, and in 2060 for the export energy system. Different Scenarios effect different mixes of technologies, however we find that large-scale solar PV comprises the greatest capacity of new build across all Scenarios, and that both onshore and offshore wind builds are also significant, particularly in Victoria and Tasmania. Importantly also, Australia's already extensive deployment of rooftop PV continues, so that installed capacities in 2050 are a similar order of magnitude to onshore wind generation.

New build solar PV for the export of clean energy is on the order of 1000 GW, across each of Western Australia, Northern Territory and Queensland, except for the E+RE− and E+ONS Scenarios which have reduced export system renewable requirements, due to constraints on deployment, and lower need for renewable generation. Also, the E+RE− sees some switching of export renewable build to offshore wind generation; 220 GW across Western Australia and Victoria.

Importantly also, we note that the demand-side measures discussed in Section 5.1 enable overall reductions in domestic energy demand by up to 40%, relative to the REF Scenario. Without these electrification and energy efficiency measures, the large capacities observed in Figure 54 would be even (possibly prohibitively) larger. That is, demand-side measures are vital to contain the required new build to manageable levels and are an integral part of the net zero transition; one that should not be downplayed.

Figure 54 | Installed capacity of modelled new build renewable electricity generators, by state/territory: (top) for the domestic electricity system in 2050; and (bottom) the export energy system in 2060.



7.1.2 Transmission

We find that domestic electricity transmission (capacity by route length, GW-km) is required to expand by a factor of 4 to 2050. That is, Figure 55 shows that electricity transmission networks in *domestic areas* expand from ~28,000 GW-km today, to 100,000 GW-km in 2050. Approximately 60% of this transmission expansion is associated with connecting variable renewable generation with regional demand centres (spur lines and shorter transmission routes), while 40% of this transmission comprises high voltage inter-regional connections for the bulk transfer or energy across longer distances. We also note that the E+RE− Scenario has a larger domestic transmission network, due to the greater coupling between domestic and export systems in that Scenario, particularly in transmission associated with offshore wind and energy exports from eastern Victoria.

While we find that hydrogen pipelines are the favoured mode of bulk energy transport for the export electricity system, Figure 55 nevertheless shows the establishment of export-based electricity transmission networks of around 300,000 GW-km. Of this transmission build, 85% is associated with aggregating renewable generation in the export zones to electrolysis hubs, while the remainder is then required for bulk transmission of electricity across longer distance, which of is associated with the Northern Territory's renewable energy export zone and direct electricity export via undersea cable.

Section 5.2.2 and the associated *Downscaling – Solar, wind and electricity transmission siting* report provide further detail and mapping of the transmission network expansion across the Scenarios and modelled years.

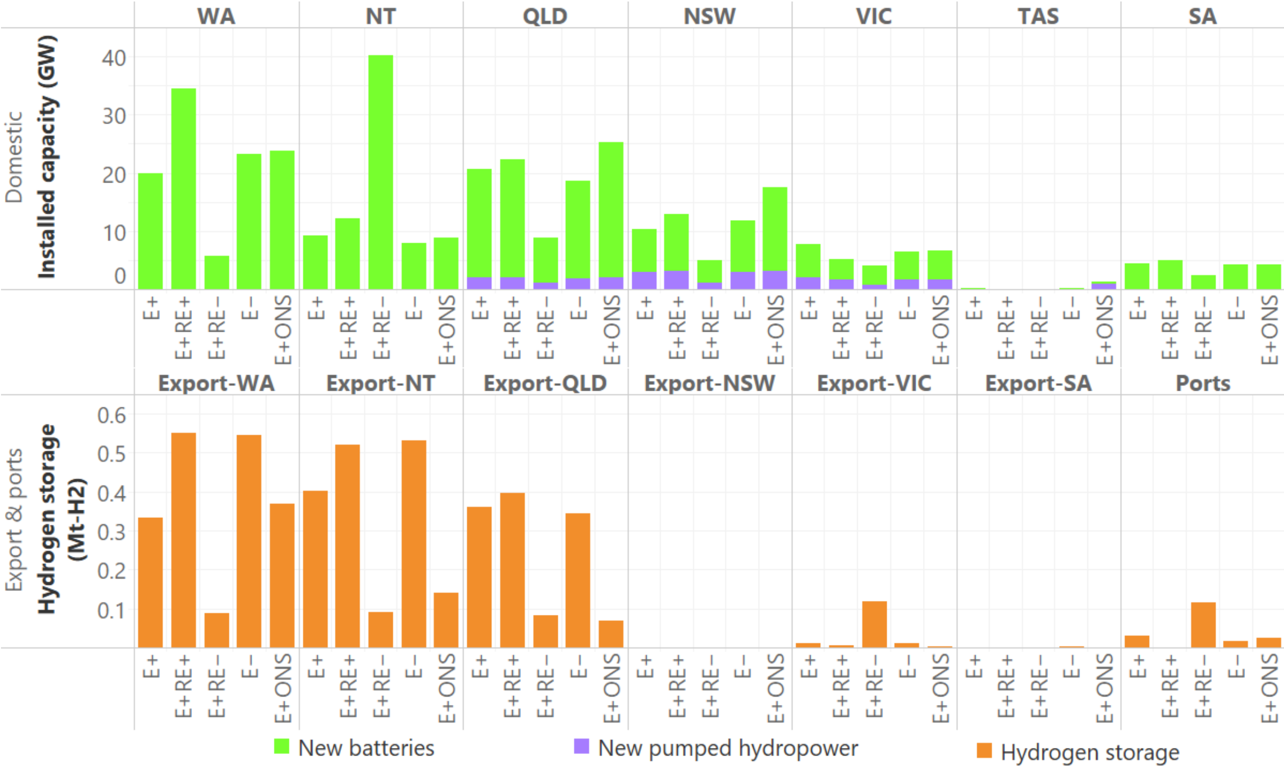
Figure 55 | Installed electricity transmission for the (left) domestic; and (right) export systems.

7.1.3 Storage

Decarbonised energy systems with high penetrations of variable renewable electricity generation, also need significant installed capacities of electricity (and other energy) storage. Figure 56 shows the new build domestic electricity storage required in 2050. This shows that the majority of *power* capacity is contributed by new batteries across all states and territories, accounting for 70-110 GW of (with a potential 15-25% share of behind-the-meter installations). Batteries tend to be more extensively deployed in the sunniest regions, due to the complementary role that batteries afford solar PV generation in shifting daytime generation to evening peaks. The new build batteries in operation in 2050 have an average energy storage duration of ~7 hours (7 GWh/GW). In addition, the domestic electricity system requires some longer duration energy storage, shown in Figure 56 in the form of new pumped hydropower systems accounting for ~10 GW of installed capacity (on top of Snowy 2.0) and having an average storage duration of ~15 hours. These are installed in Queensland, New South Wales and Victoria.

Hydrogen energy storage is also required for the export energy system, accounting for approximately at 0.5-1.5 Mt-H_2 (72-220 PJ, 20-60 TWh) of storage in the dominant export zones. This ensures continuous export energy supply. We also find a need for hydrogen storage to balance domestic supply and demand of hydrogen (40,000-100,000 t-H_2, 6-14 PJ, 1.6-3.9 TWh, not shown here).

Figure 56 | Installed capacity of modelled new build energy storage, by state/territory: (top) for the domestic electricity system in 2050; and (bottom) the export energy system in 2060.



7.1.4 Firm generation

Our modelling of electricity system supply and demand balancing shows that new gas *capacity* is required for firming. However these gas turbines operate at very low capacity factors (<10%) by 2050. Figure 57 shows the new build firm electricity generation required to be operational in 2050, by state/territory. These consist of open-cycle gas turbines and closed-cycle gas turbines of around 5-15 GW in each of Western Australia, Queensland, New South Wales and Victoria, and 1-5 GW capacity in South Australia, Tasmania and the Northern Territory. E+RE− is the only Scenario which shows a limited need for carbon capture and storage to be paired with CCGT plant, which is made more prospective in that Scenario because of both the constrained rates of renewable deployment and expanded CCS constraint. Note that these operate alongside existing firm hydropower, and the limited existing gas capacity that is still operational in 2050. These gas turbines respond to events just a handful of times per year, mostly associated with prolonged periods of low renewable generation. This nevertheless results in low, non-zero levels of GHG emissions from electricity generation, but are on average less than 20 Mt-CO_2e/year from 2030 and less than 5 Mt-CO_2e/year from 2045.

Downscaling analysis has found that much of the required *new* gas generation capacity could be sited on brownfield sites of *retiring* gas and coal generators. Figure 58 demonstrates the potential timing and location of this repurposing of brownfield sites, which may allow acceleration of permitting and exploitation of existing infrastructure. Indeed, our initial estimates suggest that the levelised costs of installing gas turbines on brownfield sites are 9-28% lower than greenfield installations. Specifically, we find that 14-22 GW of gas plants (30-70% of the new generation) could be sited on brownfields, with some variation across Scenarios. The majority of brownfield sites become available between 2030 and 2050. We also find that greenfield sites are required for 2.5-36 GW of residual new capacity (12-50% of the new generation) which we have considered could be located at ports, as shown in Figure 58.

Figure 57 | Installed capacity of modelled new build firm electricity generators, by state/territory, for the domestic electricity system in 2050.

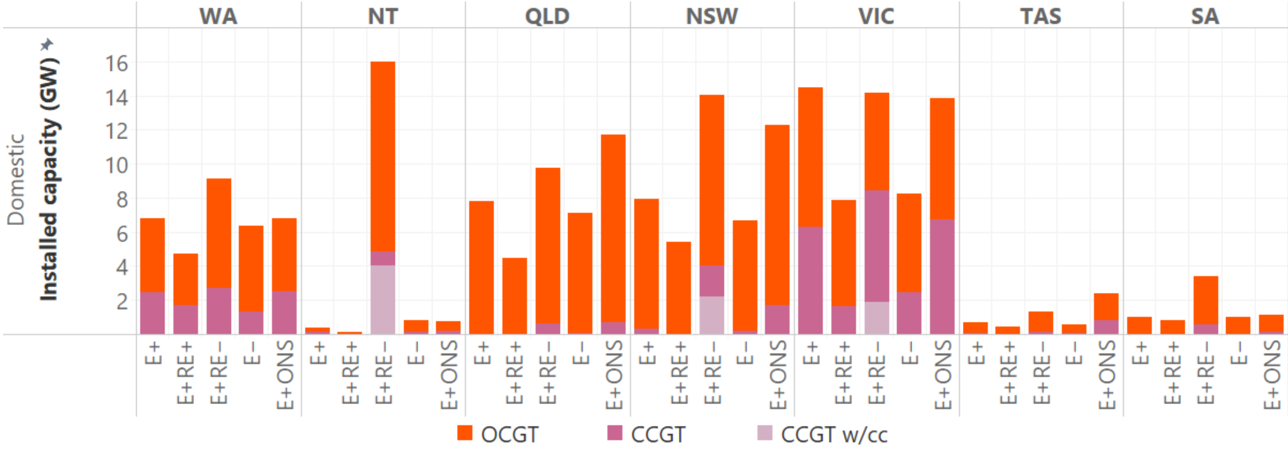
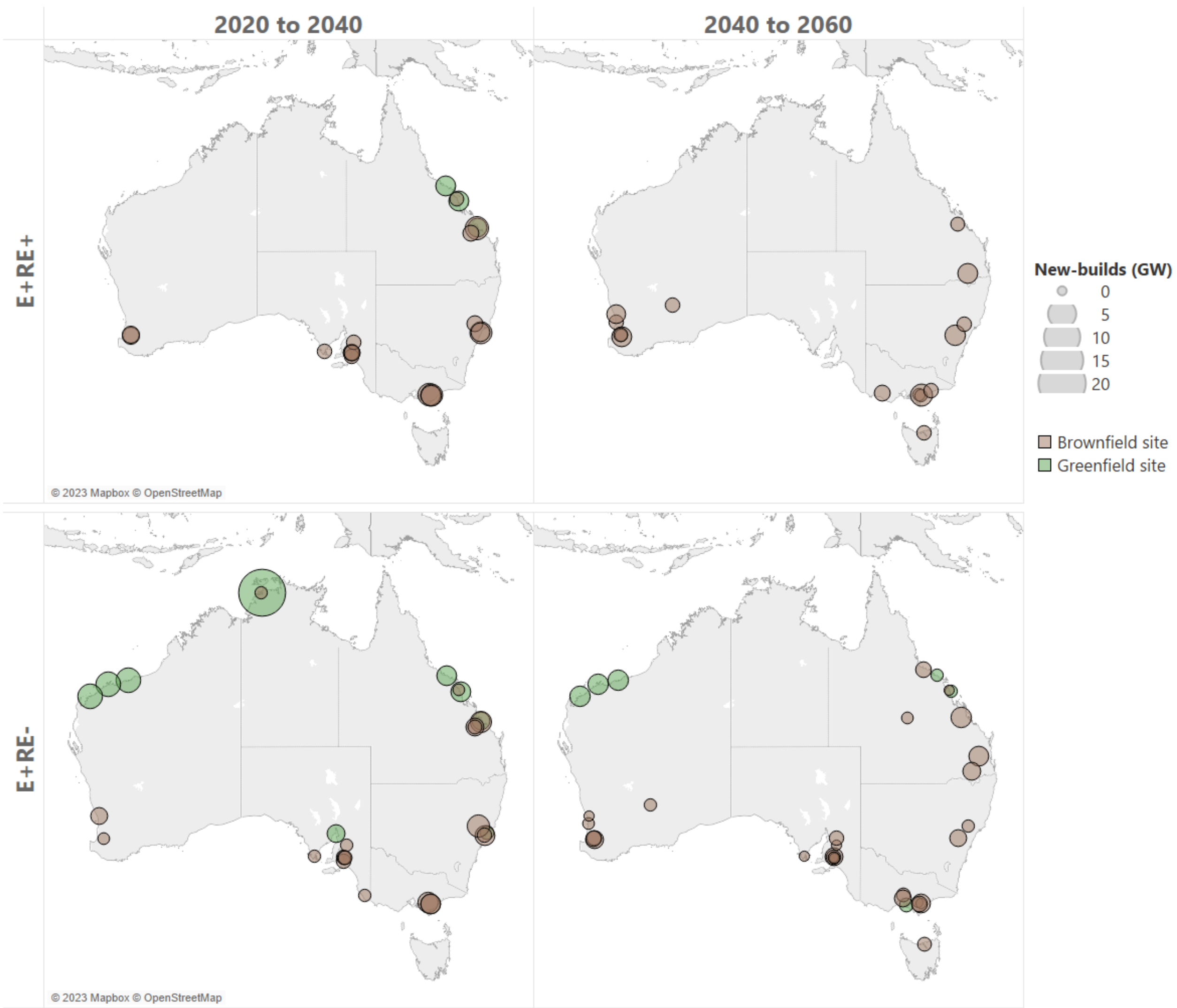


Figure 58 | Potential brownfield and greenfield siting of new build gas-fired generation, for the E+RE+ and E+RE− Scenarios. Each circle represents a new build gas generator that has been sited on a given brownfield/greenfield site in that 20-year time span; circle size is proportional to generator capacity.



7.1.5 Light-duty transport

The modelled transition for the light-duty fleet (passenger vehicles and light commercial vehicles) entails a rapid switch of new vehicle sales from internal combustion engine vehicles (ICEVs) to electric-drive vehicles (EVs) that do not produce tailpipe GHG emissions. As mentioned previously, this transition to vehicle fleets dominated by battery-electric vehicles (BEVs) also results in significant energy-service efficiency gains. Tailpipe emissions and energy-service efficiency improvements will be first apparent in the average new vehicle, as is shown in Figure 59. The average light-duty fleet efficiency and tailpipe emissions will then lag the average new vehicle, due to the remaining lifetime of the current vehicle stock.

We note that the current average new light vehicle efficiency and tailpipe emissions shown in Figure 59 is based on data for historical fuel consumption and consumption rate from the ABS' Survey of Motor Vehicle Use (Australian Bureau of Statistics, 2020). This historical data (not shown here) demonstrates that petrol (gasoline) consumption has remained relatively constant over recent years, while diesel consumption has grown. Significantly, fuel consumption rates across both passenger vehicles and light commercial vehicles, and across gasoline and diesel-fuelled vehicles has shown no decline in the last 10-15 years. This stands in contrast to global trends in passenger and light commercial vehicle fuel consumption rates, which have generally decreased over the last decades (Yang and Bandivadekar, 2017).

Figure 59 presents the average new vehicle tailpipe emissions which gives rise to the modelled LDV transition. This can be considered analogous to a *vehicle emissions standard*, which has been proposed as a means of regulating emissions from LDVs in Australia and globally. Such regulation could require the average emissions of all LDVs sold by a particular vehicle manufacturer across the country in a given year to meet some specified standard, with that standard being lowered in subsequent years.

We find in our rapid electrification E+ Scenario that average new vehicle tailpipe emissions quickly reduce from high current levels (>250 g-CO_2e/km) to 73 g-CO_2e/km in 2030 and 14 g-CO_2e/km in 2035. It should however be noted that LDV fuel-economy or GHG emissions standards are sensitive to the test procedure used to measure vehicle performance (e.g. CAFE's US combined cycle, or the EU's New European Driving Cycle), as well as the categorisation of vehicles into (and potential differentiation between) passenger vehicles and light commercial vehicles (Yang and Bandivadekar, 2017). Furthermore, it has also been shown that real-world LDV fuel-efficiencies and emissions diverge from those specified by various implemented vehicle standards, in some cases by more than 30% (Tietge et al., 2017). These are potential reasons for the current average fuel consumption rate and modelled current tailpipe emissions being significantly higher than recent global experience, but also highlights the need for any potential LDV emissions standard to seek vehicle testing procedures that accurately represent real-world LDV performance (Yang and Bandivadekar, 2017).

We note that our slower electrification E− Scenario exhibits a significantly slower trend with zero average new vehicle tailpipe emissions reached in around 2055, with significant residual tailpipe emissions in 2050 when the domestic net-zero constraint binds. This implies that slower rates of EV uptake will require either residual transport sector emissions to be offset or to be made carbon-neutral by the use of synthetic drop-in fuels made from renewable energy sources.

Figure 59 | Energy-service efficiency (fuel economy, L-gasoline-eq./100-vehicle-km); and tailpipe emissions ($g\text{-}CO_2e$/vehicle-km) of the light-vehicle fleet (passenger vehicles and light commercial vehicles). Here we assume tailpipe emissions only occur from ICEs with gasoline: 69.6 $g\text{-}CO_2e/MJ_{LHV}$, diesel: 70.4 $g\text{-}CO_2e/MJ_{LHV}$, LPG: 61.5 $g\text{-}CO_2e/MJ_{LHV}$; and noting that 1 L-gasoline-eq. = 32.0 MJ_{LHV}.

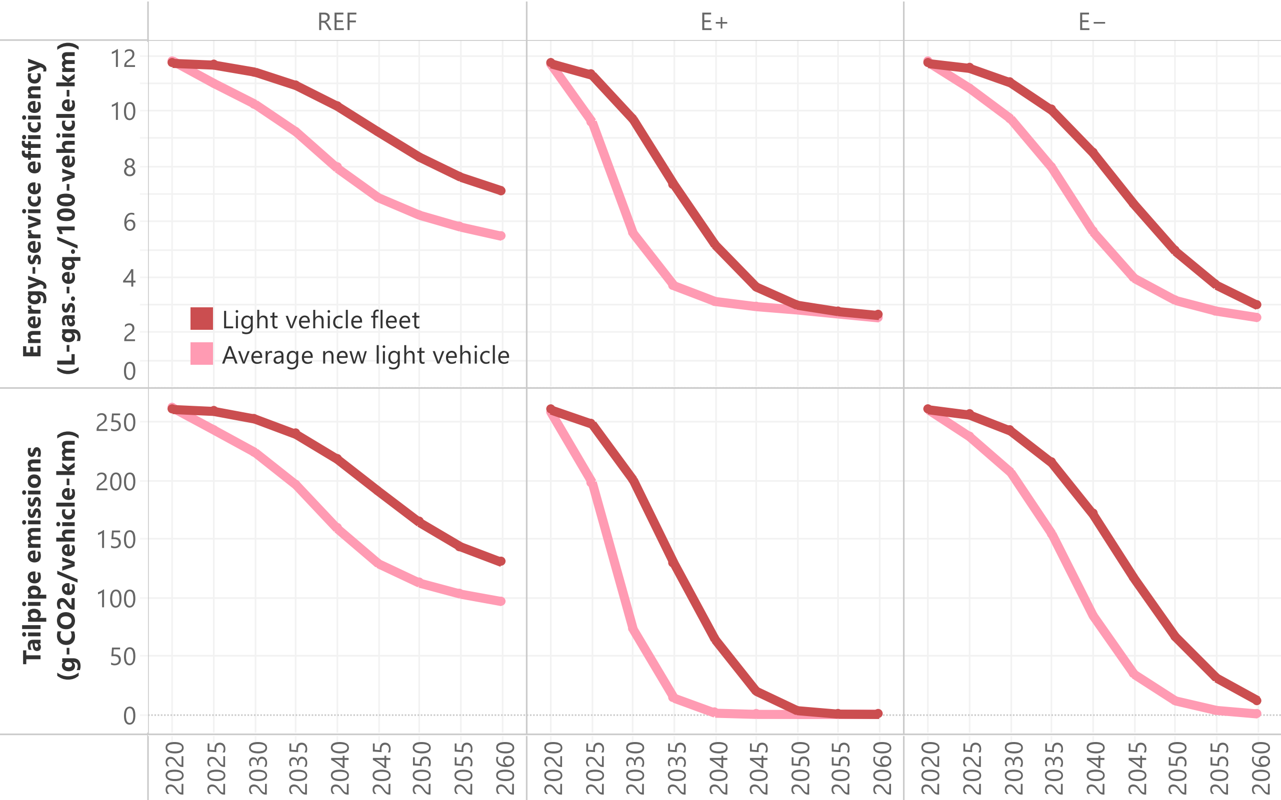


Figure 60 shows the modelled number of light-duty BEVs registered in postcodes across the 5 classes of Remoteness Structure used by the ABS (Australian Bureau of Statistics, 2021). Across the Scenarios and years modelled 64% of light-duty BEVs are located within *Major Cities*, with a further 22% located in *Inner Regional Australia*. This suggests that the vast majority of BEV enabling infrastructure could be located in capital cities and their surroundings.

A large degree of optionality exists in the modes and locations of BEV charging during BEV rollout. Much of the future BEV charging task will be performed at home with Level 1 (~2 kW charging power from standard AC power point) and Level 2 (~7 kW dedicated AC unit) chargers. Terrill et al. (2021) showed that nearly 90% of Australian households live in detached or semi-detached houses (and only around a quarter of whom are renters), suggesting that a majority of Australian households can install home chargers. However, it has also been shown that investment in non-residential charging infrastructure is needed to support and even incentivise the transition to BEVs (Hall and Lutsey, 2017), particularly:

- if workplace and destination charging is able to relieve pressure on distribution networks;
- for households without home charging availability, such as apartments, those without off-street parking and some rental properties; and
- to assuage (at least initial) public concern about BEV range.

The required number of public chargers per BEV appears to be highly region specific, and dependent on a number of conditions and behaviours (Bauer et al., 2021; Hall and Lutsey, 2017), namely:

- access to private and workplace parking;
- housing and population density;
- commuting patterns; and
- the penetration of BEVs, among others.

Notwithstanding uncertainties in the importance of each of these factors and limited BEV and charging infrastructure experience in Australia, we here provide estimates of the number of non-residential BEV charging plugs that may require investment in unison with the modelled rollout of electric light-duty transport.

Public charging can include:

- urban fast charging and motorway charging stations with dedicated DC fast chargers of 50-150 kW charging power, or even up to 250 kW in ultra-fast chargers;
- destination charging, e.g. consumer and public interest locations with car parking, such as supermarkets, museums; and
- other curb-side chargers open to public use.

In addition, workplace charging may be included along with public charging in a broadly defined non-residential charging category, however these classifications of public and workplace charging categories are not entirely exclusive, due to some workplace charging also being available to public.

Figure 61 presents the estimated number and total installed charging capacity of non-residential EV charging plugs rolled out alongside the light duty vehicle transition. In E+, with 24 million BEVs on Australian roads by 2050, we estimate that 2.1 million non-residential EV charging plugs would be required, comprised of 1.2 million workplace charging plugs, 810 thousand public level 2 chargers and 160 thousand DC fast chargers. Figure 61 also shows that the majority of these chargers would be located in the most populous regions of Australia, following the regional distribution of BEVs.

Our companion *Downscaling – Transport* report has further detail on implications for heavy-duty and other transport sectors.

Figure 60 | (Left) number of light-duty battery electric vehicles, by remoteness of postcode of registration; and (right) map showing the remoteness of Australian postcodes. *Remoteness* is an objective measure of relative access to services, used by the ABS.

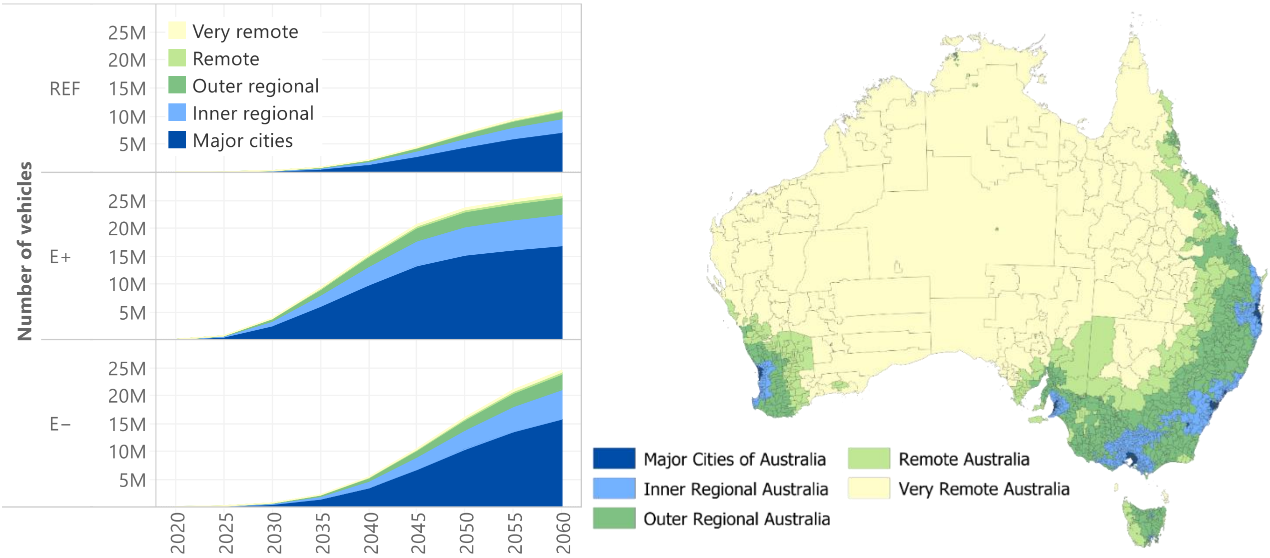
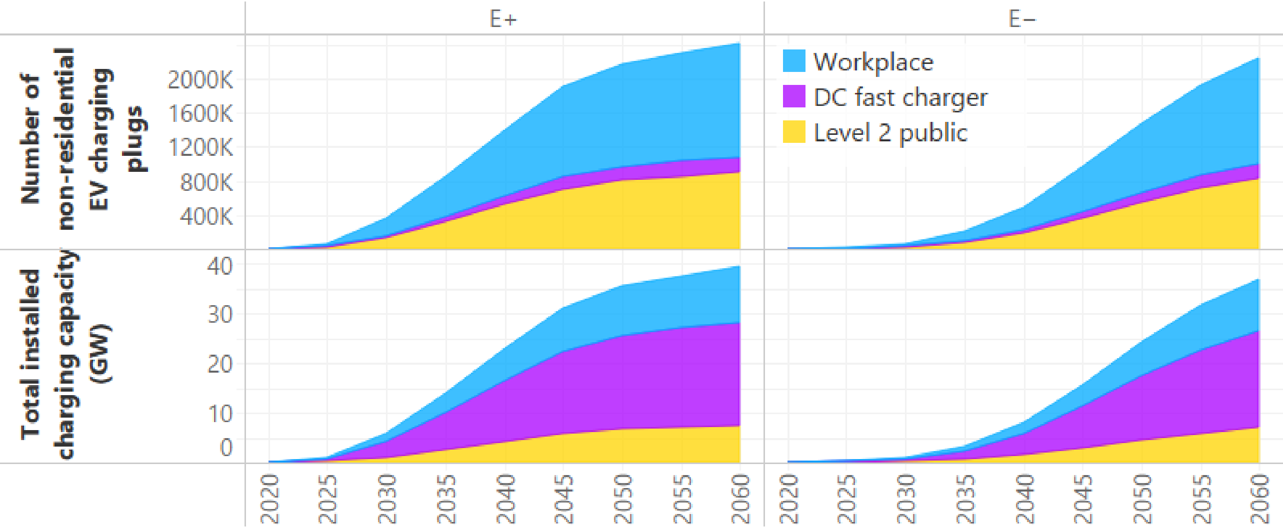
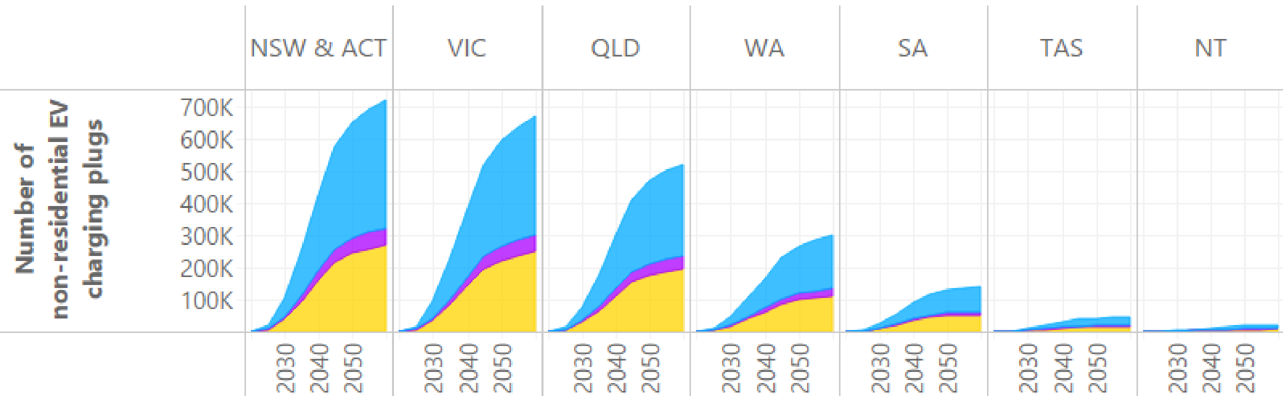


Figure 61 | (top) number of non-residential EV charging plugs and their total installed charging capacity; and (bottom) number of non-residential charging plugs by state for E+.





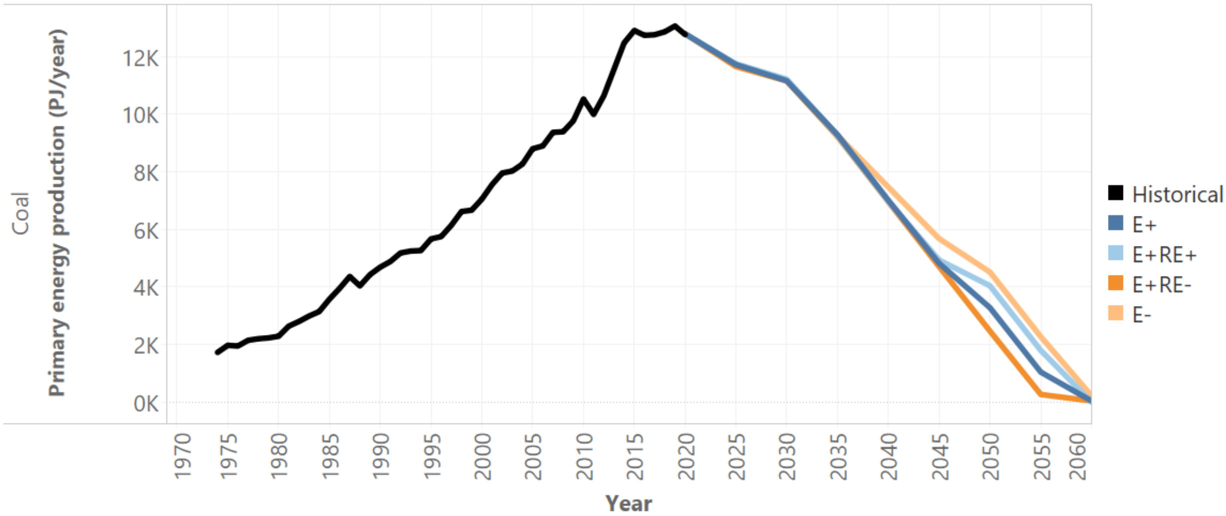
7.2 Fossil fuel industries

Besides the rapid shift away from fossil fuels to clean electricity discussed in Section 5.2, the unabated use of fossil fuels will significantly decrease or cease altogether across the main domestic energy and export sectors. In addition, the NZAu modelling finds that net-zero Scenarios heavily relying on natural gas with CCS require more than the discovered fossil fuel resources in Australia as of today. In the following sections, the impact of the modelled transition on the demand for and consumption of fossil fuels is detailed, along with discussion of the implications that projected changes will have on associated upstream extraction and conversion/refining activities.

7.2.1 Coal

Coal – metallurgical, thermal and brown – has the highest associated emissions factor among fossil fuels and it is the first to be phased out in the net-zero transition. NZAu modelling results shown in Figure 62 suggest an average reduction of 163 PJ/year in coal extraction for the first 10 years of the net-zero transition, escalating to 426 PJ/year, in the second decade. Noting Australia currently exports ~11,000 PJ/year of black coal (Australian Government, 2022) the observed greater contraction after 2030 is the result of the imposed export emissions constraint from 2030 onwards. Figure 62 also shows projections for the aggregated coal production in Australia which are consistent across Scenarios. Domestic coal use approaches zero post 2040, with only minor (of order 10 PJ/year) residual consumption in industry, while the residual extraction for exports purposes is set to steadily decrease and ultimately ceases by 2060 in all Scenarios.

Figure 62 | Primary production of coal (metallurgical, thermal and brown), historical and modelled by Scenario.



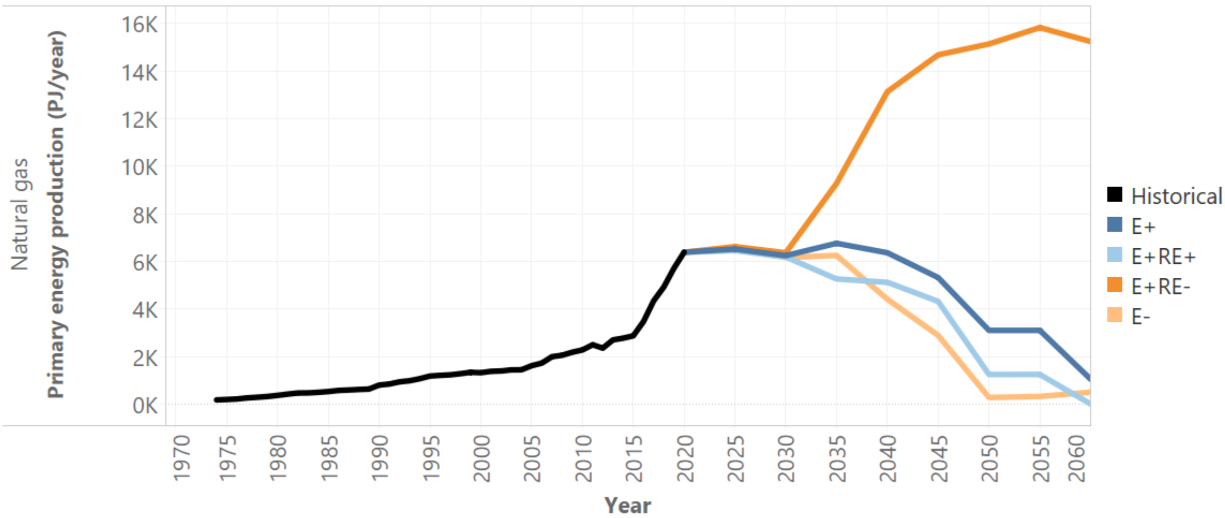
Both black and brown coal mines are quickly retired, with no capacity expansion. The E+RE+ Scenario shows the most rapid phase out of coal; yet early closure of black coal extraction facilities prior to their commercial end of life is found for all the net-zero Scenarios. Every five-year period, existing mines are retired, with a substantial decrease in the aggregated extraction capacity between 0.5 and 2.3 EJ per annum. Brown coal extraction is predicted to be completely abandoned in Victoria between 2025 and 2030.

Also coal power generation facilities undergo rapid decommissioning. For instance, NZAu finds that between 16.8 and 20.9 GW of coal capacity is to be retired by 2030 in the NEM – a result in good agreement with AEMO's ISP predictions for the Step Change Scenario, where a total of 14 GW coal plants (including an already-announced 8.4 GW capacity) is set to retire by 2030. After 2040, residual coal capacity is only envisioned in NZAu E+RE− Scenario 0.7 GW from Kogan Creek, retiring in 2042) and the E+ONS Scenario (1.3 GW from Kogan Creek and Millmerran, both retired by 2050).

7.2.2 Natural gas

Figure 63 shows the historical and projected trends of natural gas production to supply domestic and export demands during the energy transition. All the NZAu net-zero Scenarios show between 2020 and 2030 an inversion to the 410 PJ/year average increase trend of the last decade concomitant with the establishment of the LNG industry. Past 2030, natural gas production reduces in most Scenarios, except for the E+RE− constrained-renewables case. This latter Scenario registers a substantial increase in the production of natural gas, mainly due to blue H_2 production via autothermal reforming with CCS, which by 2050 reaches a value of more than 15 EJ/year, comparable with current levels of coal production.

Figure 63 | Primary production of natural gas, historical and modelled by Scenario.

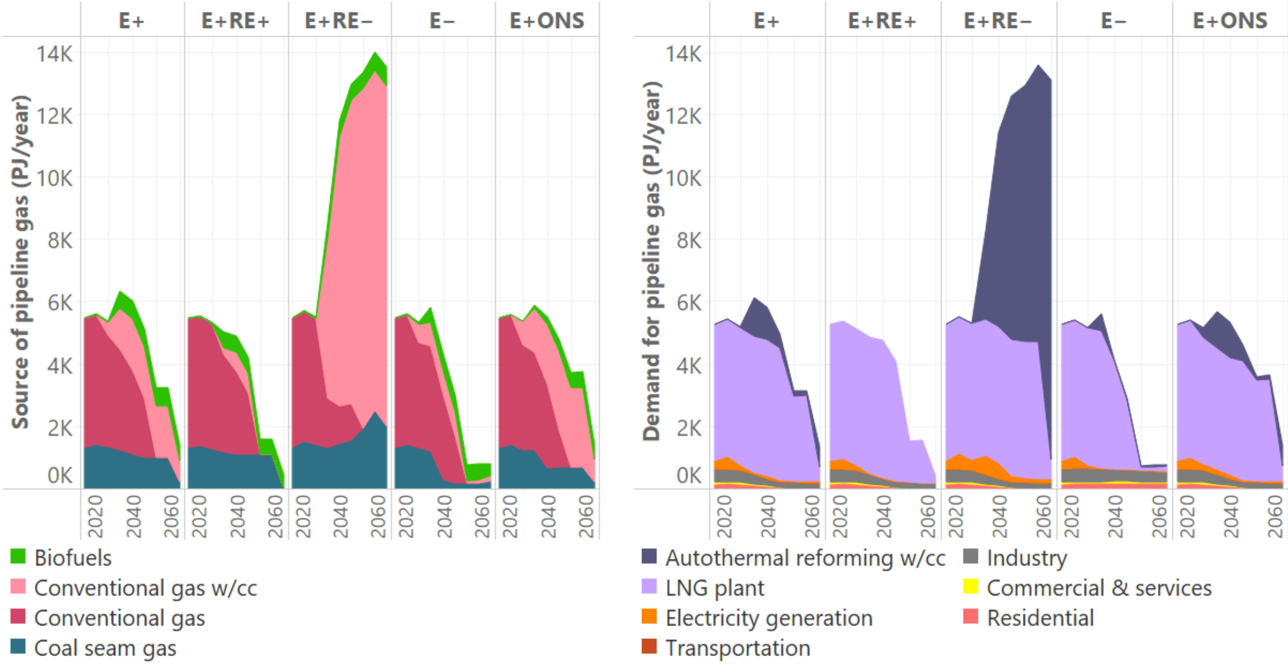


Further detail on the source and use of methane gas into pipelines for various NZAu Scenarios is presented in Figure 64. As methane consumption reduces significantly for most Scenarios across buildings, industry and the electricity generation sector (the slower electrification E− Scenario retains some <1000 PJ/year demand for gas in buildings and industry), as well as for LNG exports, the required volumes of conventional natural gas supplying this demand decrease. The emissions intensity of residual methane gas is reduced through two pathways: the production of bio-synthetic natural gas and the retrofit of carbon capture on conventional gas extraction facilities.

Almost no expansion of natural gas production capacity is predicted by NZAu, except for the E+RE− Scenario, which is the only one relying on new gas production facilities. Results in this latter case reflect the joint effect of the constrained renewables rollout and a fixed energy export task which, in the way it was modelled, does not allow any flexibility in the energy volume to be delivered and/or the time of delivery. It should also be noted that such a large expansion of natural gas production in the E+RE− Scenario is only feasible in our net-zero emissions modelling with the concerted pursuit of: capture of process CO2 and minimisation of fugitives associated with the gas extraction; the use of that gas in hydrogen production with carbon capture facilities; and the permanent sequestration of all captured CO_2 emissions.

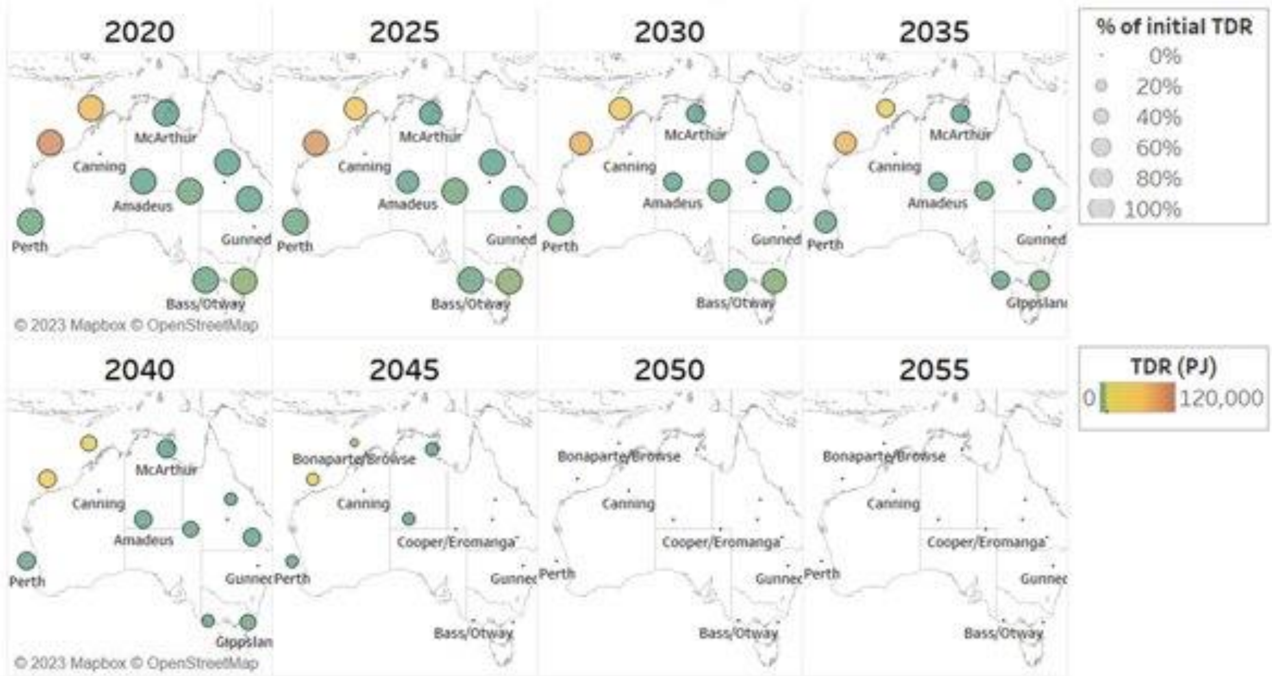
More than twice the current natural gas production (from 6.4 EJ, up to 15.2 EJ in 2060) would be needed in E+RE− to supply both exports and domestic needs. New gas production facilities in this case are built in the outback of Queensland (exploiting coal seam gas resources at the Bowen-Surat basin) and the northern regions of Western Australia (at the Northern Carnarvon conventional gas basin). They substitute existing facilities reaching the end of life, with minimal early retirements. The Northern-Carnarvon basin is preferentially selected given its proximity to the major industrial clusters for the production of export fuels and the ports of Western Australia and the Northern Territory.

Figure 64 | (Left) source of methane gas into pipelines; and (right) final demand and use of methane gas from pipelines, by sector/use.



Further NZAu modelling suggests current natural gas total demonstrated resources (TDR) according to Geoscience Australia (Geoscience Australia, 2022) are currently insufficient to supply the required natural gas volumes in the E+RE− Scenario. As shown in Figure 65, reporting the projected depletion of conventional gas resources over time for E+RE−, current TDR of Australian conventional natural gas resources could be depleted by 2050, and those of coal seam gas resources exhausted by 2055, should they fully serve the domestic and export energy demands modelled in the E+RE− Scenario. On the contrary, a larger uptake of renewables significantly relieves the pressure on gas resources and gas production is limited to 0.5-1.24 EJ in 2060. A residual 65 EJ of conventional gas and ~1 EJ of coal seam gas out of the current TDR values are envisioned in 2060 for the E+RE+ Scenario. Investments in further fossil fuel basin exploration – an overlooked yet seemingly necessary downside of a large reliance on fossil fuels over the net-zero transition pathway – can thus be avoided as a by-product of a greater use of renewable energy. The role of natural gas for electricity generation and its asset implications in the modelled transition is detailed in Section 5.2.

Figure 65 | Projected evolution of conventional gas total demonstrated resource (TDR) for the E+RE− Scenario. Maps present both the residual TDR, and its proportion of the initial (2020) TDR in each year, for each basin.

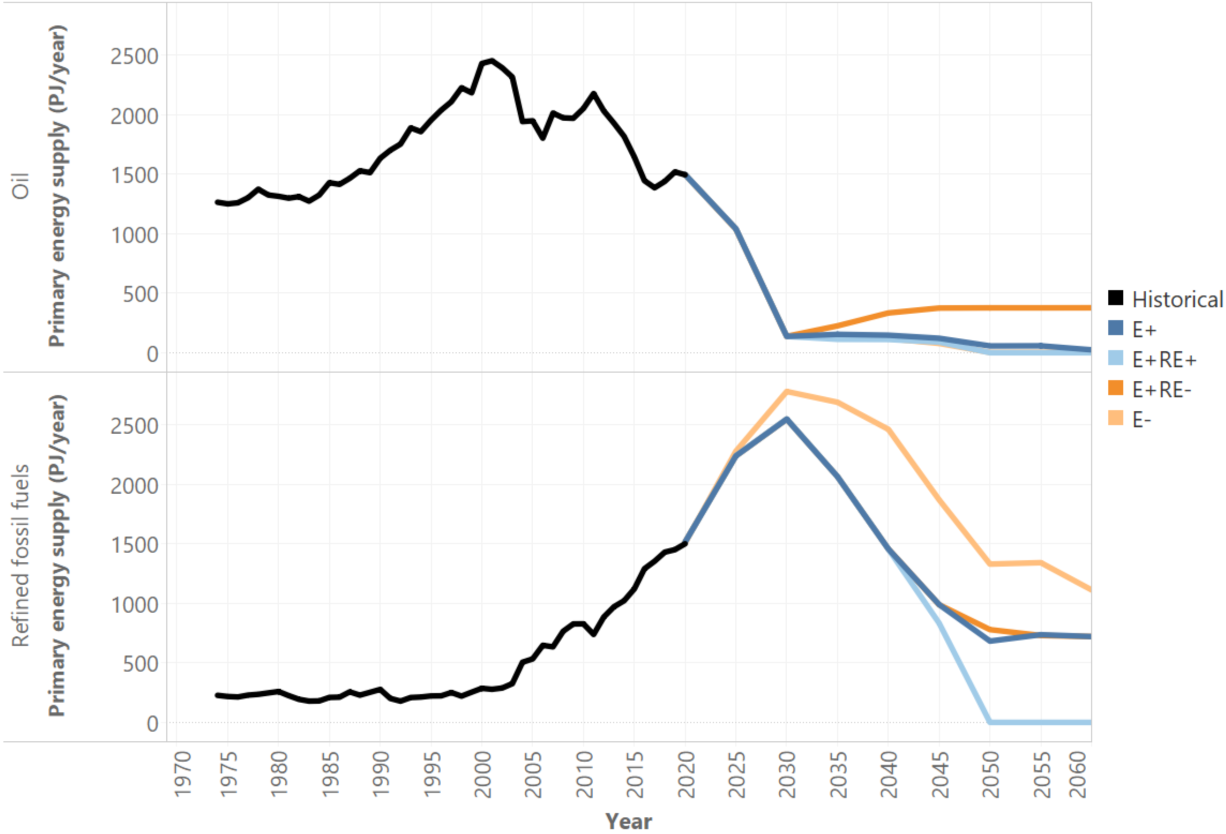


7.2.3 Crude oil and products

Figure 66 shows the historical and future primary energy supply of oil and refined fossil fuels consumed in Australia, as modelled by NZAu. We note that Note that *refined fossil fuels* here refers to imported products. Driven by fuel switching in industry and the transport sectors, as well as the progressive adoption of a largely electrified vehicle fleet, the domestic demand for primary oil decreases towards zero across all Scenarios. The envisioned trend follows a reduction of ~90 PJ/year in the first decade – more than twice the historical average decrease of 39 PJ/year from 2000 to 2020. On the other hand, the demand for refined fossil fuels initially increases, by ~100 PJ/year, in the first modelled decade, which is about 2× the observed upward trend from 2000 to 2020 of 62 PJ/year.

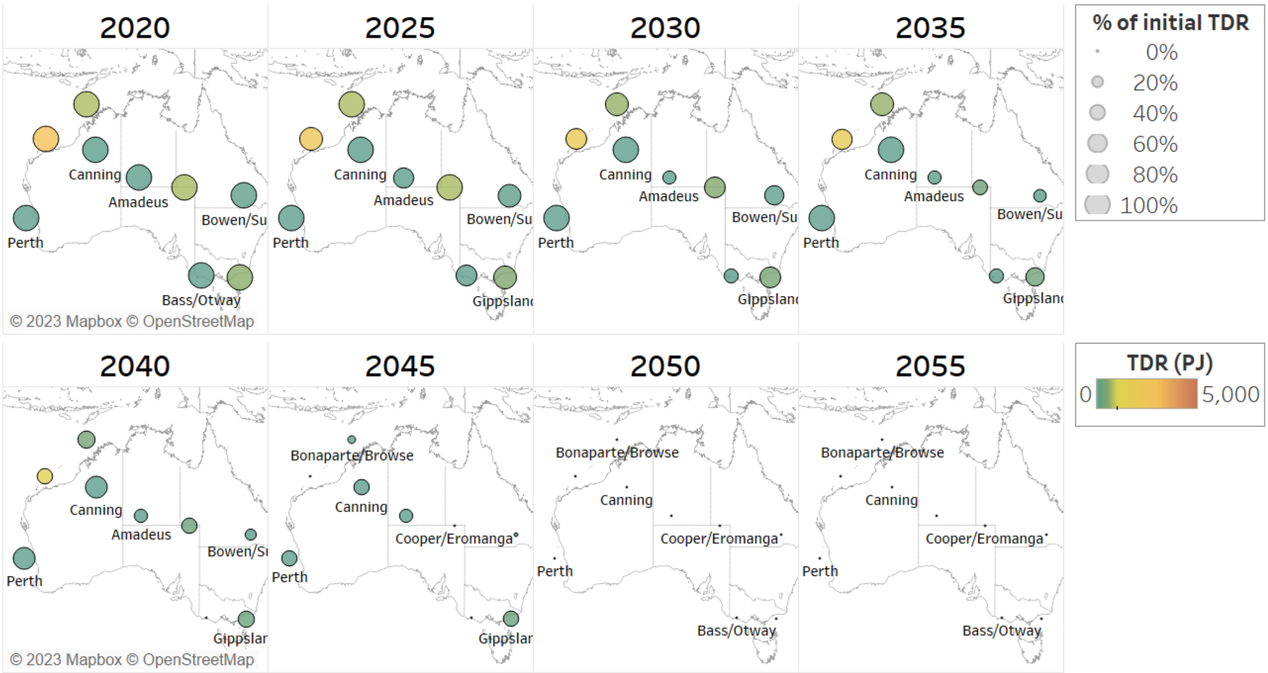
Domestic crude oil resources are mostly extracted and used locally. Consistently across Scenarios, The Bonaparte and Northern Carnarvon basins provide over 15 PJ/year each in the first transition years, supported by the Cooper/Eromanga, from 2025, onwards. These basins are all located close to the Western Australia northern region, where oil demand is tied to the extraction activity of large conventional gas quantities mainly supporting exports. Modest production from other minor basins such as the Gippsland, Perth and Canning contribute to the overall fulfilment of the domestic demand for primary crude oil. The assessment of the reported oil TDR in 2020 and its progressive depletion, as reported in Figure 67 for the E+RE− Scenario, shows also that crude oil TDR as of today is not sufficient to fully supply a net-zero transition pathway that largely relies on fossil fuels, since larger oil consumption is requested as a by-product of augmented conventional natural gas extraction activity.

Figure 66 | Primary energy supply of oil and refined fossil fuels, historical and modelled by Scenario. Note that refined fossil fuels here are imported.



For the E+RE+ Scenario, 1.5 EJ of residual oil demonstrated resources are still available in 2060. Additionally, as minor crude oil energy imports to Australia are set to terminate in 2030 with the closure of Lytton and Geelong refineries, all other liquid fossil fuel except refined fossil fuels are domestically extracted. Therefore, the E+RE+ Scenario eliminates Australia's dependence on energy imports altogether by 2050; Australia then becomes purely an exporter. Under this Scenario, the refined fuels still used post 2050 by the transport and the industrial sectors are substituted by domestically produced biomass and synthetic e-fuel alternatives. All other net-zero Scenarios retain a minor dependence on imported fossil fuels, particularly for aviation.

Figure 67 | Projected evolution of oil total demonstrated resource (TDR) for the E+RE− Scenario. Maps present both the residual TDR, and its proportion of the initial (2020) TDR in each year, for each basin.



7.3 Onshoring of industry

Australia exported more than 870 million tonnes of iron ore and 18 million tonnes of alumina in 2020, largely to the same trading partners that also took the majority of our 15 EJ of fossil energy exports. The E+ONS (Onshoring) Scenario highlights the potential technical and economic efficiencies gained (both here and overseas) by choosing to process our iron ore and alumina on Australian shores rather than continuing to export both our clean energy and raw minerals. In E+ONS we treat the energy required for iron ore reduction, alumina refining and aluminium smelting as taking away from the modelled energy exports, rather than adding to it. Table 3 indicates that by 2060 in the E+ONS Scenario, Australia avoids exporting 10.1 EJ of energy (or 67% of total energy exports in 2060 in other Scenarios) by onshoring iron production. A further 1.2 EJ of energy (or 8% percent of total energy exports in 2060 in other Scenarios) is avoided by onshoring aluminium production.

Table 3 | Energy exports in 2060 for NZAu Core Scenarios (EJ), along with export energy avoided by onshoring iron and aluminium production in the ONS Scenario.

Scenario	Ammonia	FT-Liquids	LNG	Clean LNG	Coal	Electric cable	Onshore DRI (avoided energy)	Onshore aluminium (avoided energy)	Total
REF	0	0	4.1	0	10.9	0.1	0.0	0.0	~15
E+	13.7	0.2	0	0.5	0	0.8	0.0	0.0	~15
E+RE+	14	0	0	0.2	0	0.8	0.0	0.0	~15
E+RE–	13.5	0.3	0	0.6	0	0.8	0.0	0.0	~15
E–	13.8	0.3	0	0.2	0	0.8	0.0	0.0	~15
E+ONS	2.4	0.2	0	0.5	0	0.8	10.1	1.2	~15

Onshoring iron production, through the Direct Reduced Iron (DRI) process, results in ~55% saving in hydrogen production in Australia, as compared to the counterfactual export of hydrogen (via ammonia) for use in DRI processing of Australian iron ore overseas. Likewise, onshoring aluminium production using clean electricity in Australia, compared to exporting ammonia for conversion into electricity overseas, results in ~50% energy saving.

The first practical implication of the E+ ONS Scenario is the reduction in the required VRE infrastructure, which can be clearly seen when comparing the downscaled E+ONS VRE and transmission infrastructure (Figure 68) to the downscaled E+ infrastructure (Figure 27), as follows.

- Significantly less solar PV infrastructure (~1.5 TW) is required in E+ONS compared to E+ (~2.7 TW). The Northern Territory and Queensland export zones are the most affected.
- By contrast, onshoring aluminium production expands in Queensland, New South Wales, Victoria and Tasmania – in line with existing aluminium smelters. The size of the onshored aluminium industry is not sufficiently large to shift production away from existing smelters.
- DRI facilities are located in northern WA due to the proximity of the iron ore industry, its existing use of the three WA ports and the high quality VRE resources nearby. This leads to a small increase in solar PV capacity in northern WA to support DRI.
- No Sensitivity was run combining E+RemoteCost+ and E+ONS so the impact of increased regional cost multipliers on the distribution of NZAu infrastructure has not been evaluated.
- By 2060, E+ONS requires approximately half the transmission infrastructure that was found for E+, but still and ~5× the current electricity transmission infrastructure.

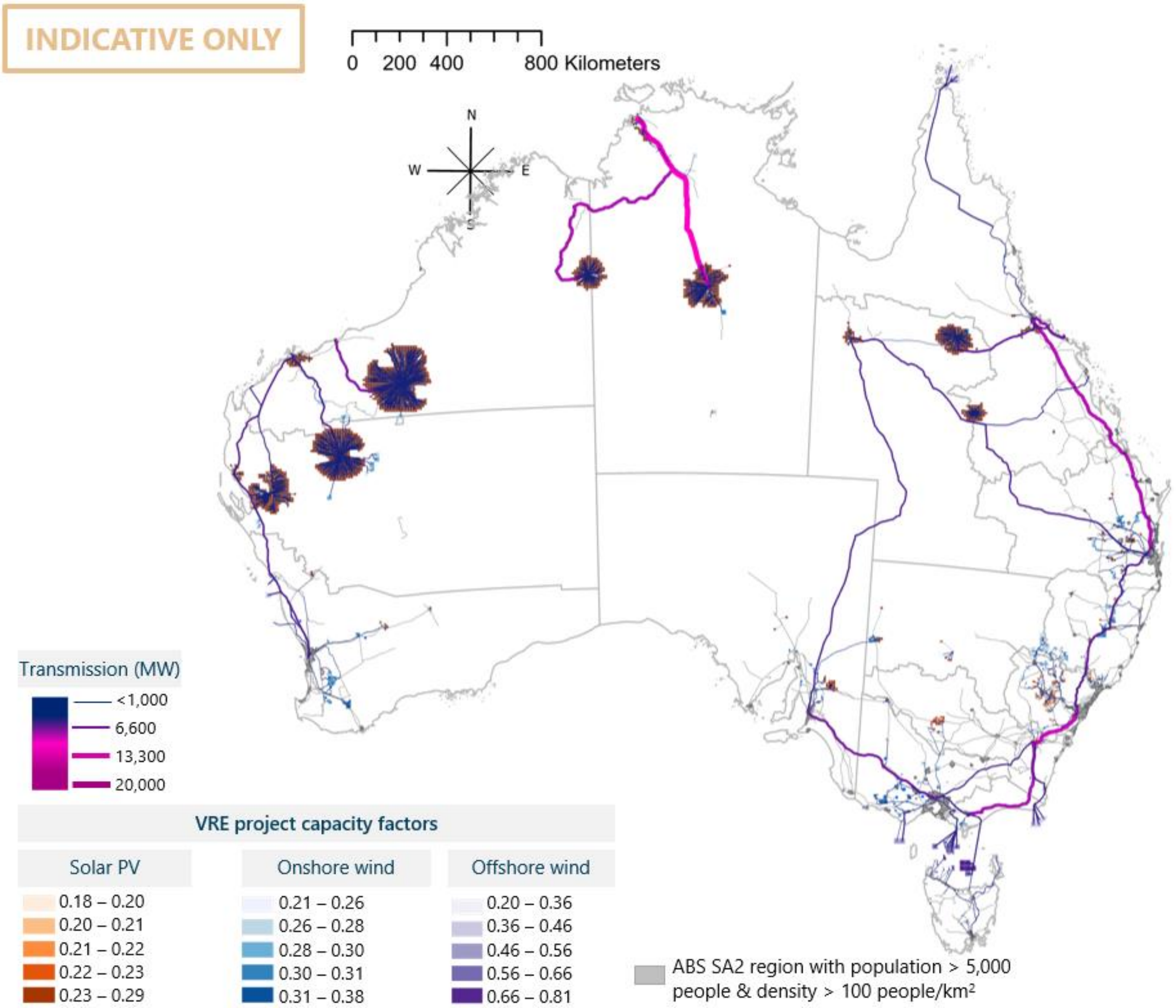
The second practical implication of the E+ONS Scenario is the change in port infrastructure that results from exporting pig iron compared to a clean energy carrier like ammonia.

- The co-location of DRI plants at the same ports that currently export iron ore avoids substantial port upgrades in these locations.
- Solids handling facilities that currently load iron ore require only minimal upgrades to load pig iron, compared with the substantial switch out required for ammonia handling and loading facilities.
- Pig iron is denser than both ammonia and iron ore and there is a corresponding reduction in the number of ship calls for the E+ONS Scenario compared with E+.
- For the iron industry, ship calls for Australia's iron/iron ore reduce from 3,170 in 2020 (entirely iron ore) to 1,991 in 2060 (entirely pig iron). Additionally, in 2060 in E+ONS, Australia also avoids the 6,381 ships calls connected to the export of 449.2 Mt of ammonia that occurs in the E+ Scenario from the three WA ports.
- Similarly, with onshoring aluminium – there are ~35 fewer ship calls for bauxite export, ~70 fewer ship calls for alumina export and ~750 fewer ship calls for ammonia that would have been exported in the E+ Scenario.

The third practical implication of the E+ONS Scenario is the reduction in both overall export system cost and the corresponding cost of abatement, compared with all other Scenarios:

- This suggests that importing countries could save significant expense by importing Australian refined commodities, while achieving costs of emissions abatement that are comparable to Australia and the US, even if they are major energy importers. This also suggests that Australia may be in a strong position to pivot to clean non-energy commodity exports if other countries end up producing more of their energy domestically.

Figure 68 | Downscaled electricity transmission and variable renewable electricity (VRE) generation infrastructure for the E+ONS Scenario in 2060.



7.4 Capital mobilisation

It is commonly asserted that an abundance of financial capital will be committed to a global net-zero economy. However, most such capital is typically seeking opportunities to invest in fully permitted clean energy assets that are supported by well-defined and predictable economics and the stability of developed markets. This section therefore projects the sequencing and levels of supply-side capital that would need to be mobilised in the net zero Scenarios relative to the 'business as usual' REF Scenario.

All NZAu Scenarios involve ambitious renewable energy deployment along with variations in end-use electrification, onshore and offshore wind deployment, CCUS, and clean export strategies. Net-zero energy supply systems that rely heavily on weather-dependent renewable energy sources have a greater *capital intensity*, which we define as the relative contribution that capital servicing costs make to overall energy systems costs, than conventional energy systems that rely mostly on fossil fuels. However, renewable resources also benefit from much lower operating costs. Steep reductions in the capital costs of wind and solar over the last 20 years, and more recently in the cost of battery technology, mean that these systems can now have similar or lower lifetime average unit costs.

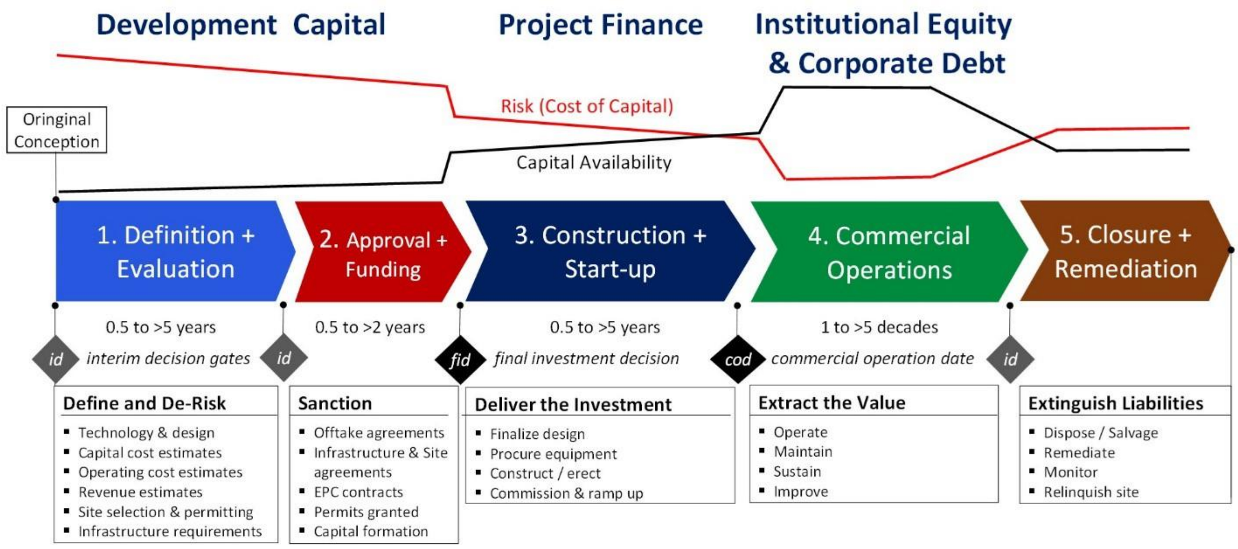
Nonetheless, for policies that require net-zero emissions targets to be met by mid-century, the significant increase in capital intensity requires that capital be allocated to develop and build net-zero energy sector assets at much faster rates than has been previously observed in the energy sector. Furthermore, the affordability of net-zero Scenarios hinges on capital being available at low cost. This is especially relevant because the recent rapid escalation in inflation and benchmark interest rates, and the increased uncertainty around mid- to longer-term costs of capital present another potential headwind to rapid deployment of renewables.

Macro-scale energy systems models like the one used for NZAu simulate capital being allocated and assets materialising overnight to ensure supply matches both demand and the applied emissions trajectory. A deeper examination of how real-world projects are developed and financed reveals the nuance of mobilising that capital and hence the need to consider capital formation in the NZAu mobilisation workstream.

Project developers manage the amount of capital at risk by cautiously advancing each proposition in stages. As shown in the stylised representation of the typical sequence in Figure 69, the stages are typically decision-gated, meaning decisions to advance from one stage to the next are subjected to rigorous reassessment of project risks and the value proposition. Within each of the five phases of this stylised sequence, there will often be a series of sub-phases and decisions, e.g. phase 1 will typically include an initial concept or scoping study, followed by a prefeasibility study and then a feasibility study, generally comprising activities and deliverables described in the boxes below each phase. As successful projects advance from left to right in the sequence, the level of project definition, confidence in the business case, and availability of capital increase, while the investment risk profile and cost of capital decrease. The most consequential decision gate is the *final investment decision (FID)* at which third party equity and debt providers join the developer in committing sufficient capital to build and commission the project.

The work of stage 1 in the pre-FID phase relies on 'development' capital that today is almost exclusively provided by a project developer's own balance sheet equity. It is the scarcest capital and hence demands the highest risk premium. This stage involves scoping and designing the project; securing a site and access to enabling infrastructure; estimating all costs and negotiating execution contracts; identifying customers and negotiating offtake deals; permitting; and qualifying for all necessary approvals. If, after stage 1, the developer has achieved a sufficient level of confidence that the project will generate sustainable levels of net income after all costs and taxes to generate an acceptable return on capital, it may elect to move into stage 2. Still in the pre-FID phase, stage 2 involves negotiating with additional investors and lenders to secure the full amount of capital needed to complete the project, i.e. finalise design, procure all equipment, and complete all construction, installation and commissioning, and start-up activities to achieve commercial operations. Once this capital is secured, the project has achieved FID. The development capital to complete stages and 1 and 2 is fully-at risk until FID is achieved, meaning that any project has the potential to be abandoned prior to FID.

Figure 69 | A stylised project investment decision sequence.



Methodology

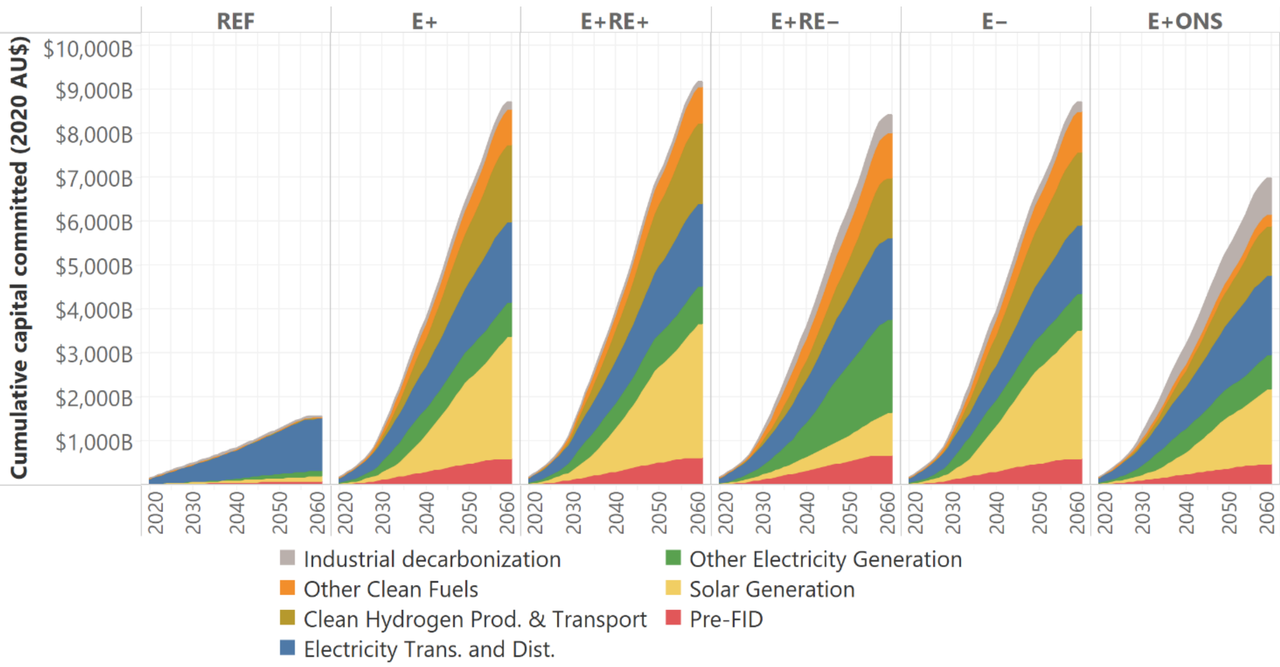
The RIO optimisation model minimises the net present value of the energy transition required to meet a linearly declining trajectory of emissions from energy and industrial systems to achieve economy wide net-zero emissions by the target date. In this scope of work, we disaggregate RIO's supply side cost outputs to extract the fixed capital that 'materialises' each year from 2021 to 2060. We then allocate estimates, based on experience and discussions with project developers, of the pre-FID costs for each technology (See the companion report *Downscaling – Capital mobilisation*). Note that for electricity distribution systems, RIO provides an estimate of the annual revenue needed to service national distribution networks rather than specific fixed capital estimates. To estimate the fixed capital invested per year we first deduct approximate allowances for operating and maintenance costs (4% of revenue), depreciation (2.4% of revenue), and tax and other non-capital related expenses (3% of revenue); and then divide the remaining revenue by the assumed weighted average cost of capital (WACC). Finally, we allocate all extracted and estimated fixed capital costs against the typical sequence and durations of pre-FID, construction, and commissioning activities for each of the supply side technologies, storage, connecting infrastructure (electricity transmission and distribution, hydrogen and CO_2 pipelines), significant industrial transformations (cement, iron and steel, ammonia production for export) and associated water infrastructure (desalination).

Results

The committed capital sequences for each Scenario are presented graphically in Figure 70. In our companion report, *Downscaling – Capital mobilisation*, these are broken out by technology for each of the Core Scenarios. The results highlight the very large capital mobilisation requirements of the net zero Scenarios, each being between approximately 4.8 to 7× the REF Scenario. The E+ONS Scenario is the least capital intensive of the net-zero Scenarios and the E+RE+ Scenario is the most capital intensive. Much of these capital demands are associated with the export transitions. Note that CO_2 transport and storage is excluded from the capital needs, however these are typically small relative to capital for CO_2 capture, which in turn is small relative to electricity infrastructure and other clean fuels.

The high capital intensity of the net-zero Scenarios was also a characteristic or the Net-Zero America study (Larson et al., 2021) and is the subject of ongoing research and engagement with the private sector. These levels of capital mobilisation clearly demand serious consideration in the planned NZAu mobilisation work stream and ongoing research and engagement with the financial sector globally.

Figure 70 | Cumulative supply side capital committed by year.



7.5 Implications for Australian communities, the land & sea

NZAu modelling is characterised by its highly spatially and temporally resolved outputs that enable siting – or downscaling – of the energy system assets required for the modelled transition, together with assessments of changes in land use and other implications for those who live on and are custodians of those lands. In most net-zero Scenarios we find that decarbonisation of both domestic and export energy systems is led by the expansion of the electricity system through deployment of renewable generators (solar PV and wind). Such a deployment of large-scale solar PV and wind electricity generation assets for both domestic and export energy systems represents a large increase in the land and sea area that is required to host energy system assets in Australia and the associated workforce.

With the following sections we seek to provide insight into the complexities of the land and sea use change associated with the net-zero transition by synthesising NZAu's macro-energy system modelling with the downscaling analyses of: renewable electricity generation and energy transmission infrastructure siting, employment modelling, and farmland afforestation. We have made an effort to be thorough, transparent and inclusive in the development of principles for the siting new energy assets and activities, while also acknowledging that the maps of NZAu infrastructure presented in this section and all other NZAu publications are notional outputs of a modelling exercise and should not be confused with actual processes – either under consideration or under construction – for the actual siting of wind, solar PV and transmission infrastructure in Australia. Also, the Net Zero Australia project has regularly consulted with the key stakeholder groups, The National Native Title Council (NNTC), The National Farmers Federation (NFF), and The Australian Conservation Foundation (ACF), who advised the development of our *principles of land use and new energy asset siting* (Section 3).

It is important to note that the location of NZAu's large *candidate* renewable energy export zones was not part of stakeholder consultation nor subject to any form of optimisation. Locations were chosen due to the coincidence of high-quality renewable (wind and solar) energy resource, low population density, and proximity to existing ports. Our Sensitivities suggest that there exists significant optionality in the locations of renewable energy projects, without large increases in total system costs. This suggests that stakeholders have significant choice in the siting of assets and associated employment, capital and biodiversity impacts. We therefore present in this section results from NZAu's Core Scenarios, as well as the E+RemoteCost+ Sensitivity, which strongly differentiates renewable energy and electricity transmission builds from the Core Scenarios. This demonstrates that impacts and trade-offs between strategies have complex impacts on land use.

In land use analyses of E+ and E+RemoteCost+ (Sections 7.5.2, 7.5.3, 7.5.5 and 7.5.6) we analyse the overlap of NZAu solar PV, wind and electricity transmission infrastructure with the Indigenous Estate, land tenure categories, locations of current agricultural activity, and locations of importance for ecosystem conservation and biodiversity. While selected map layers present each of those areas individually, we know that they are deeply interlinked and that the use of siloed analyses is limited and often problematic. For instance, the separation of the Indigenous Estate from biodiversity misses understandings gained from their simultaneous consideration.

7.5.1 Employment

We have estimated the labour impacts of the modelled net-zero transition using the DEERS model from Mayfield et al. (2021), projecting the evolution of gross and net jobs, as well as the changing makeup of the workforce. This includes the occupations, skills and education required.

Across all Scenarios, by mid-century, the total gross jobs created for the domestic and export sectors vary between 210-490 thousand and 350-510 thousand, respectively, as shown in Figure 71. This shows that there is little variation in total employment between the modelled Scenarios, with only the E+ONS Scenario having lower employment, due to the lower levels of energy production in that Scenario, notwithstanding an increase in employment in the onshore clean processing of minerals. Assessments of jobs by the project lifecycle stage (not shown here), find that while there are periodic booms in construction & installation, there is also a growing demand for a large workforce in ongoing operations & maintenance roles. O&M roles increase from ~50% of energy sector employment currently to ~75% by 2050-60. Manufacturing jobs consistently contribute between 1-3% of total jobs throughout 2030-2060, due to Australia's currently limited manufacturing capacity.

Figure 71 | Gross energy sector employment for the (left) domestic; and (right) export, energy systems.

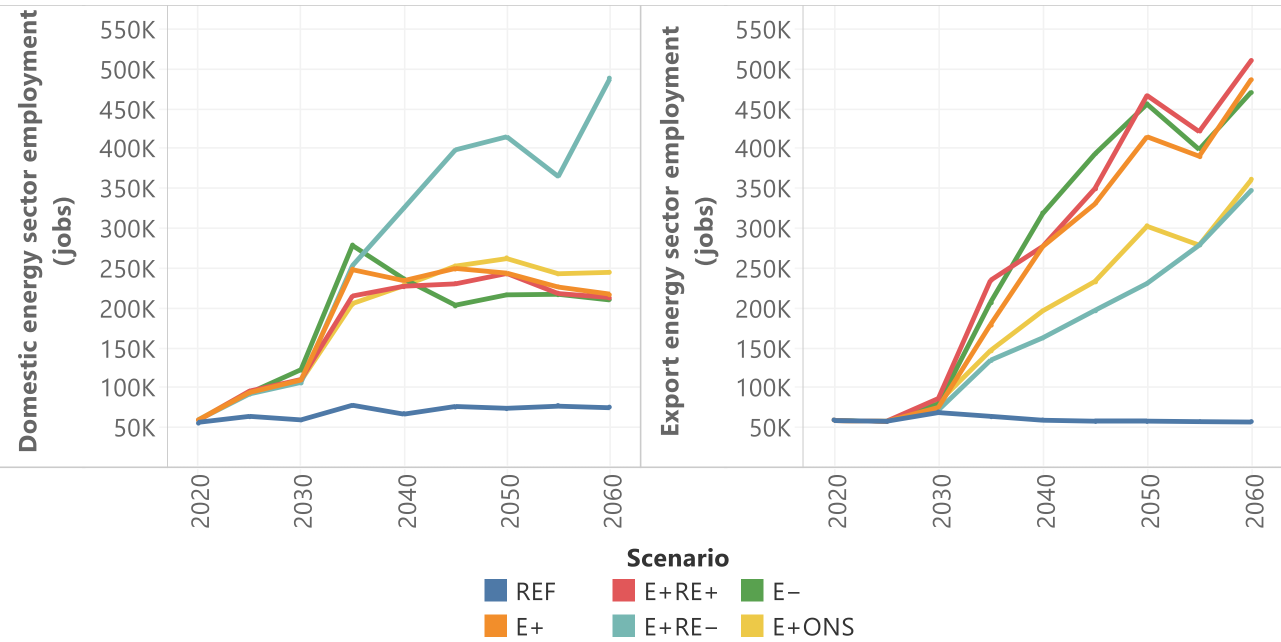


Figure 72 presents net jobs, by technology/resource. Here, *net jobs* describe the difference in gross employment between a given net-zero Scenario and the REF Scenario, and is therefore a measure of jobs that will be both created and lost because of the net-zero transition. In the domestic sector, net jobs results show that the large-scale deployment of utility solar PV, wind and batteries, and investment in electricity transmission and distribution result in significant growth in employment, offsetting the dominant role occupied by coal and natural gas at present. This occurs in all states and territories approximately in proportion to their energy demand. Interestingly, the establishment of clean fuels (hydrogen and biofuels) production and transmission has an associated ~50 thousand jobs. In addition, direct air capture and CO_2 transmission and storage, particularly in the E+RE− Scenario, induce significant growth in employment across regions with geological CO_2 sequestration availability.

The majority of new jobs serve export demand in technologies that dominate the export energy supply chain, i.e. utility solar PV, electricity transmission, batteries, electrolysis and hydrogen storage and transmission. These jobs rapidly displace export sector jobs in coal and natural gas. However, new export jobs growth is disproportionately located in the sunbelt of Western Australia, the Northern Territory and Queensland.

Further detail on the nature of the spatial distribution of net jobs in the E+ rapid electrification Scenario in 2030 and 2060 is presented in Figure 73. This shows that in 2030, job losses are primarily associated with closures of coal mining and power generation assets in central NSW, across Queensland, and in eastern Victoria. Job losses can also be observed in WA, associated with reductions in natural gas activity. We note that in 2030 – the first year of applying the export energy emissions constraint – growth in renewable energy exports is yet to occur and so the huge growth in export sector employment is yet to offset jobs losses in some regions. In 2030, the increase in net jobs is driven by a build out of renewable electricity and grid assets, which is not entirely coincident with the regions in which coal and gas jobs are lost.

Figure 73 shows that by 2060 growth in export jobs more than offset any job losses in most regions, while significant domestic sector job growth occurs in all regions. We note that in 2060 the reduction in brown coal jobs in eastern Victoria are no longer considered a net job loss due to the counterfactual REF Scenario also modelling closures of those brown coal assets.

Figure 72 | Net energy sector employment (relative to REF), by domestic and export energy sectors and by technology/resource of employment.

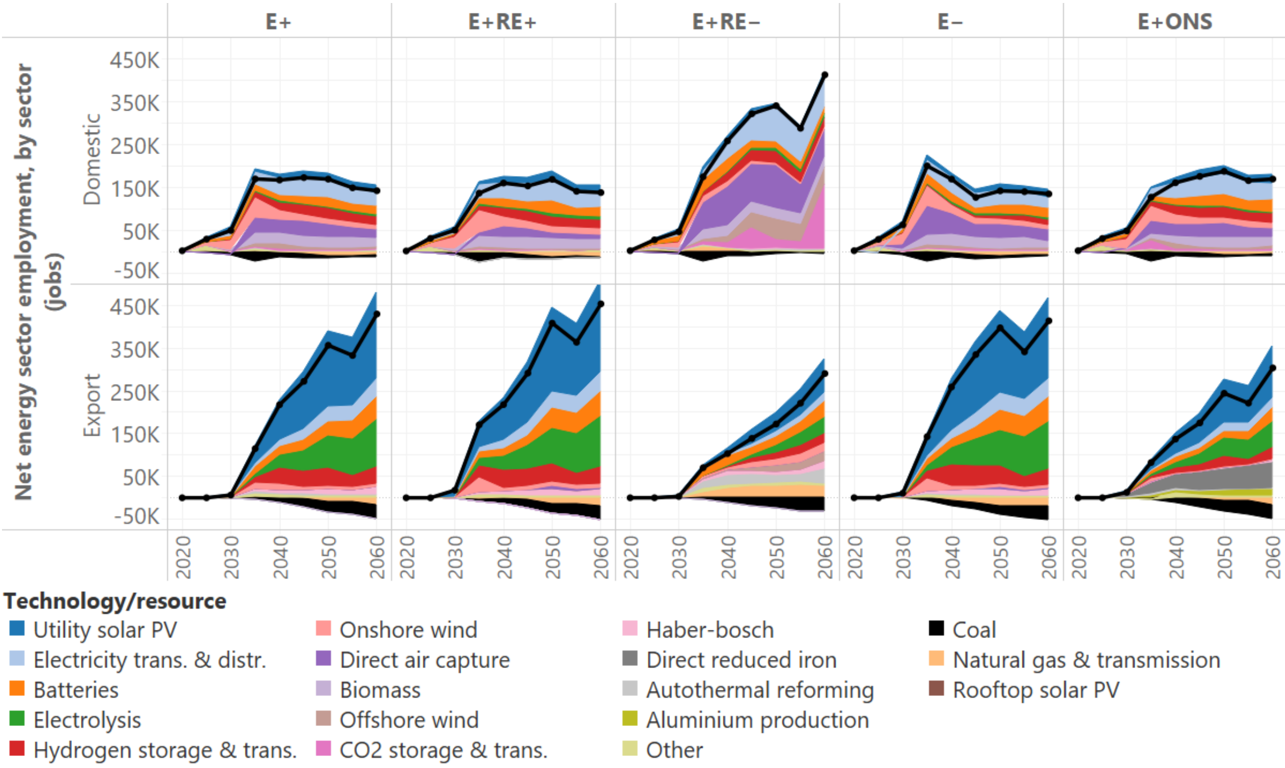
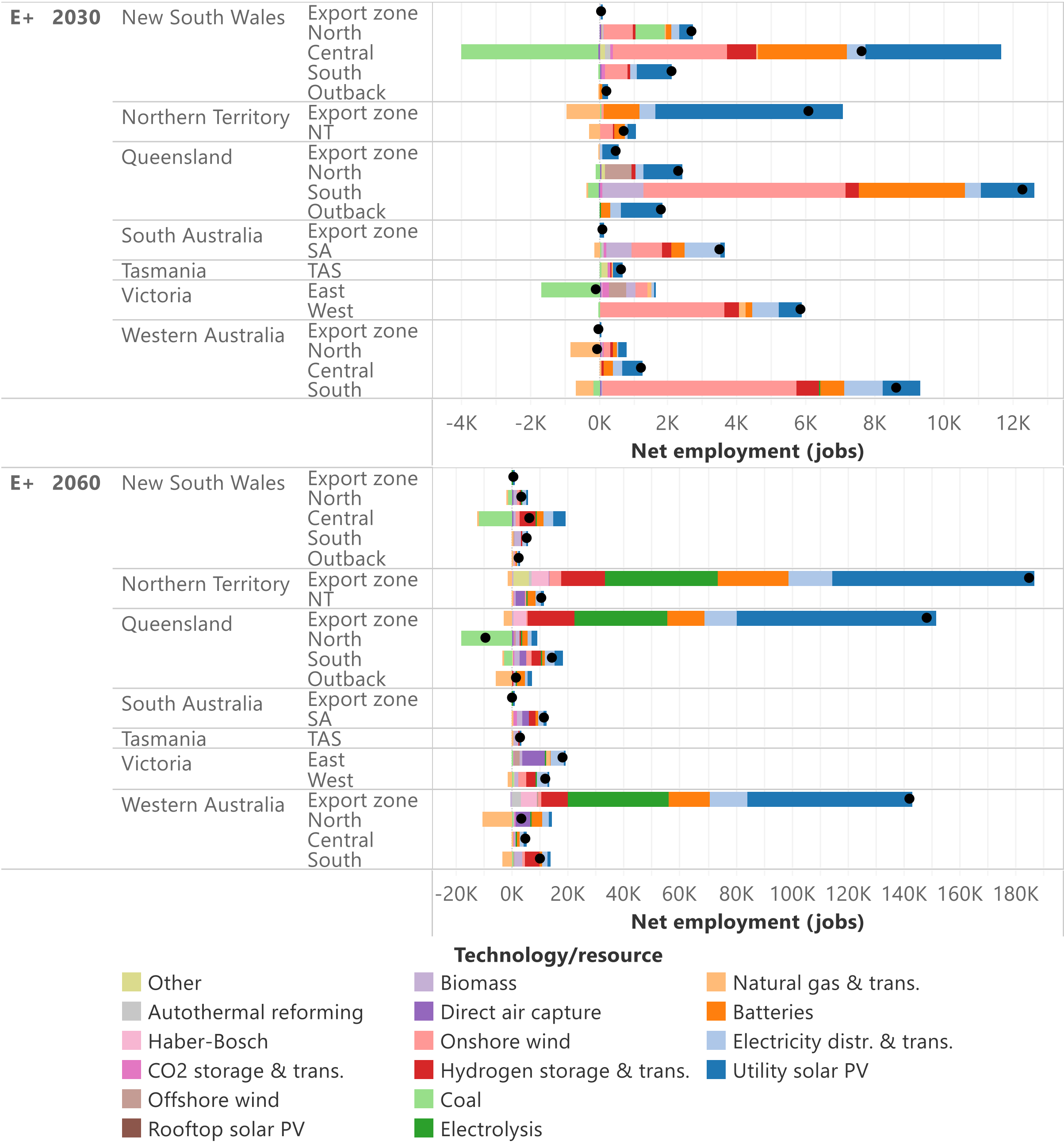
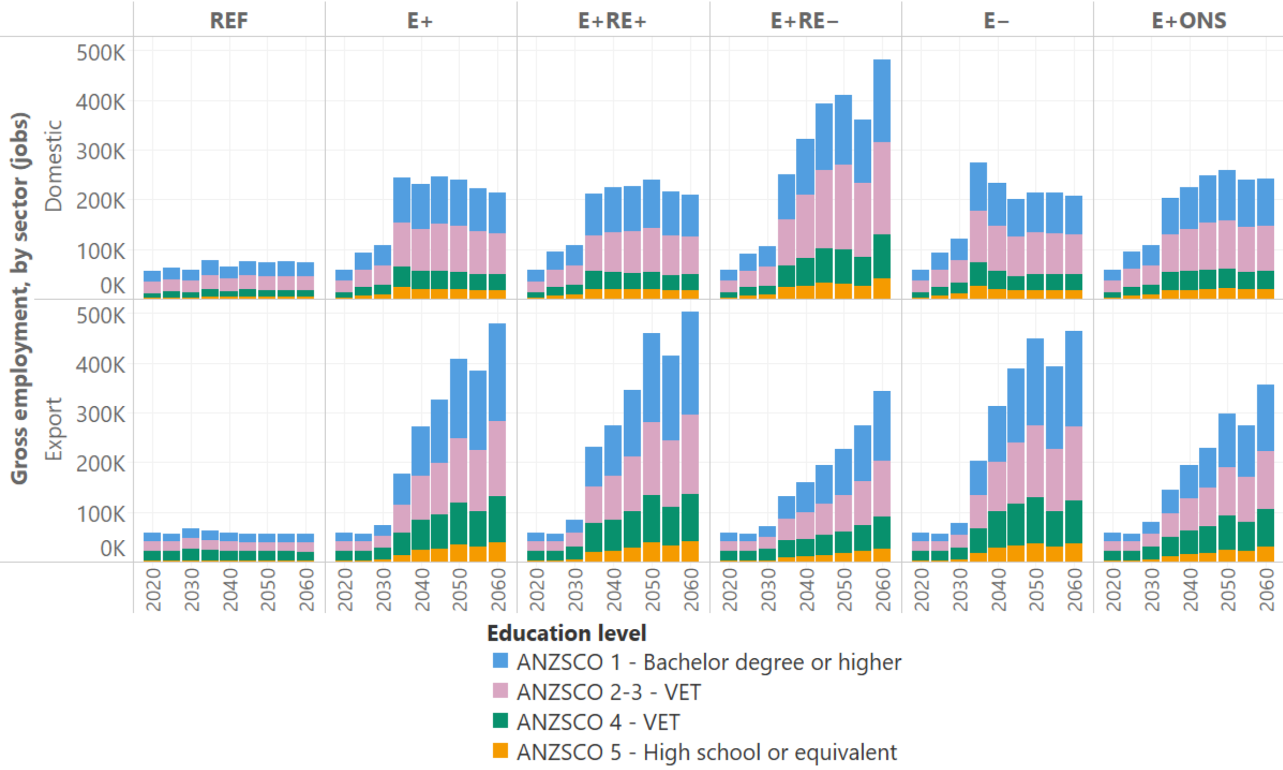


Figure 73 | Net jobs, by technology/resource across the 15 NZAu domestic zones and the defined export zones in 2030 and 2060, for the E+ Scenario. The net jobs in each region aggregated over all considered technologies/resources is shown with the black circle.



Occupation and skill level projections demonstrate significant increases in absolute jobs for many different types of worker. The most represented occupations include electricians, engineering professionals, project managers, associated trades workers and construction labourers. Figure 74 shows significant job growth at all levels of education, with the largest growth in roles for VET/TAFE graduates. Domestic sector proportional employment by skill level is generally stable, with most skill levels fluctuating a few percentage points throughout 2020-2060 but growing significantly. There is more change in the export sector as lower-skilled jobs in coal mining are replaced by occupations at skill levels 1-3. Specifically, this includes drillers, miners and shot firers which currently occupy a large proportion of the export energy sector workforce.

Figure 74 | Gross energy sector employment for the domestic and export energy systems, by the level of education.



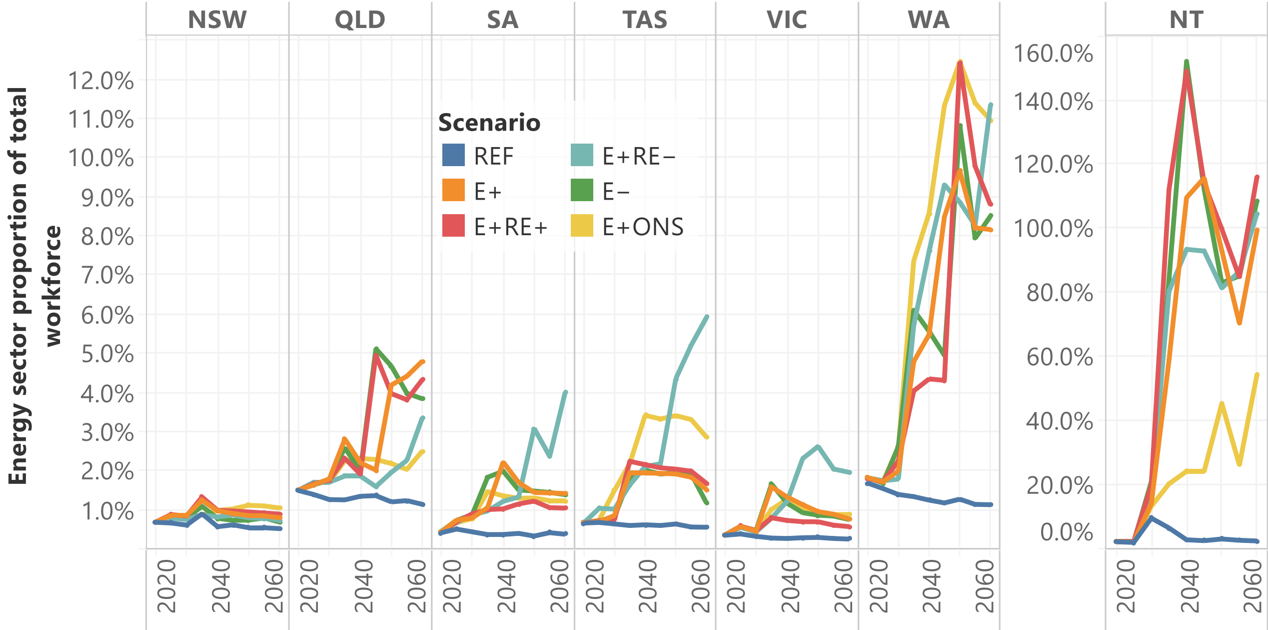
Overall, the number of people employed in the energy sector is projected to increase from less than 1% of the total workforce in 2020 to between 3-4% by 2060. Figure 75 shows that largest job opportunities are found to be in Australia's north, in WA, NT and Queensland, largely serving energy exports. However, this job creation is shown here to be disproportionate to population projections that anticipate workforce growth in existing population centres. For example, in WA the energy sector is modelled to account for up to 12% of all work in 2060 and in the NT, the energy sector workforce exceeds the total projected workforce in almost all Scenarios. This highlights a limitation in the modelling and the need to consider regional cost multipliers and workforce availability in energy system planning. Indeed, our Sensitivity have shown that the impacts of regional cost variations and other regional constraints will impact export system investment significantly. As such, our export jobs modelling needs to be interpreted with some care.

While the projected jobs growth of the energy sector is lower in absolute terms than has been experienced by several other Australian industries over the last 30-40 years (e.g. health care and social assistance; professional, scientific & technical services), in relative terms the sector is required to grow between five- to six-fold in this period, which is without precedent. Furthermore, most jobs will be in regional communities, which are a potential source of revitalisation, but also pose social, infrastructural, planning and investment challenges. This is also another, important reason to engage with different Indigenous communities.

We note that export sector jobs will also be sensitive to several important factors that are external to this analysis. This includes the need for contracted supply to export customers to underpin export investment before any construction starts.

Government involvement at state and federal levels is also essential to minimising the current and future potential for local unemployment or diminished employment conditions (in terms of both wages and job security), education needs, labour shortages due to internal competition between domestic and export sectors and states and territories, and potentially for facilitating the use of temporary and permanent skilled migration to mitigate labour capacity shortfalls. Considerable further research is required to evaluate such impacts further.

Figure 75 | Proportion of projected workforce employed in the (domestic and export) energy sector, by state/territory.



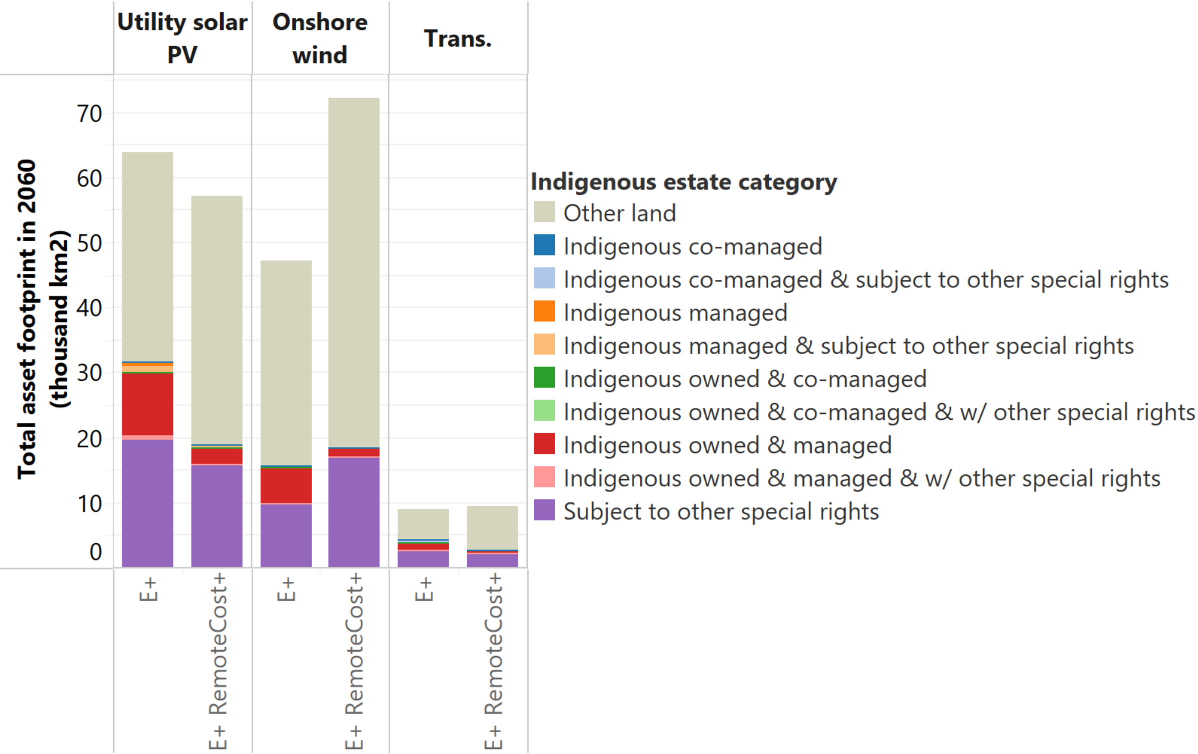
7.5.2 The Indigenous Estate

In the E+ Scenario in 2060, new energy system assets account for a total area footprint of 52 thousand km^2 (43% of sited asset area) on lands designated under the various categories of the Indigenous Estate (Figure 76). This land area is predominantly used for utility solar PV assets, the large majority of which sited on the Indigenous Estate is associated with the modelled energy export supply chain. It can also be seen that 27% of the sited infrastructure is located on land designated as *Subject to other special rights* (Land or forest subject to native title determinations, registered Indigenous Land Use Agreements, and legislated special cultural use provisions), 14% on *Indigenous owned & managed*, while the energy asset footprint is lower on other categories of the Indigenous Estate.

The effect of higher regional capital costs on siting of infrastructure in more remote regions of Western Australia, the Northern Territory and Queensland leads to ~14% less NZAu infrastructure being sited on the Indigenous Estate (~10 thousand km^2 less), although this figure needs to be understood in the context of not just a shift in the location of infrastructure, but also a shift in the footprint of the total infrastructure sited as more wind farms – having lower energy densities than solar PV farms – are sited in the E+RemoteCost+ Sensitivity.

Figure 77 provides an overlay of 2060 NZAu VRE and electricity transmission infrastructure for the E+ Scenario and the E+RemoteCost+ Sensitivity on the Indigenous Estate. We note that development of energy system projects (both generation and transmission) on Indigenous lands should involve fair and just agreement making and early engagement with respect to the protection of cultural heritage and the environment, as well as benefit-sharing for communities, including royalties and equity sharing, local energy security and employment opportunities to follow *free, prior and informed consent*, including a right to say no, throughout the project lifecycle.

Figure 76 | Total VRE and transmission infrastructure footprint area on the categories of Indigenous Estate, for the E+ Scenario and the E+RemoteCost+ Sensitivity in 2060.



Note: we have calculated the **total** and **direct footprints** on different land categories.

For utility solar PV projects:

- Total footprint = 20% of full candidate project area used for siting;
- Direct footprint = 91% of total footprint.

For wind projects:

- Total footprint = 100% of full candidate project area used for siting;
- Direct footprint = 1% of total footprint.

For transmission projects:

- Total and direct footprints are 100% of full project area estimated after prior pro-rating step.

The land use analyses of Sections 7.5.2, 7.5.3, 7.5.5 and 7.5.6 **only present total area impacts.**

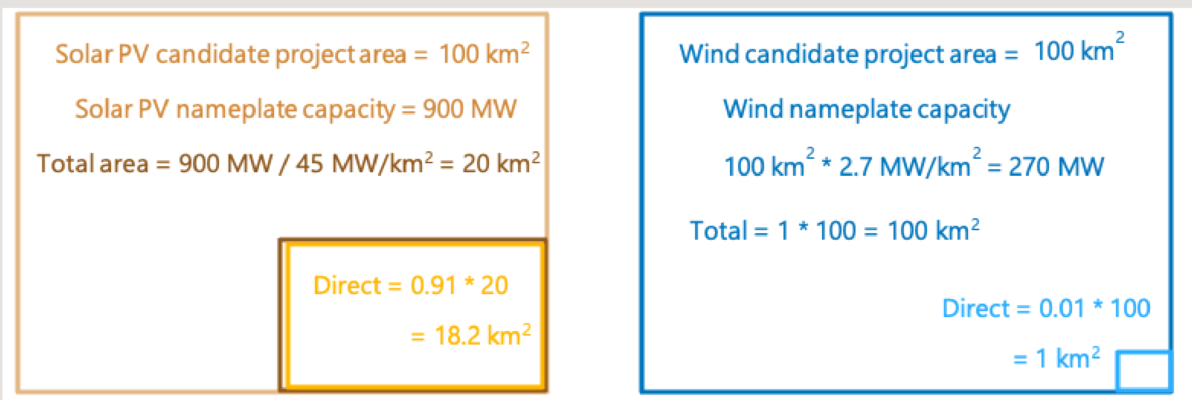
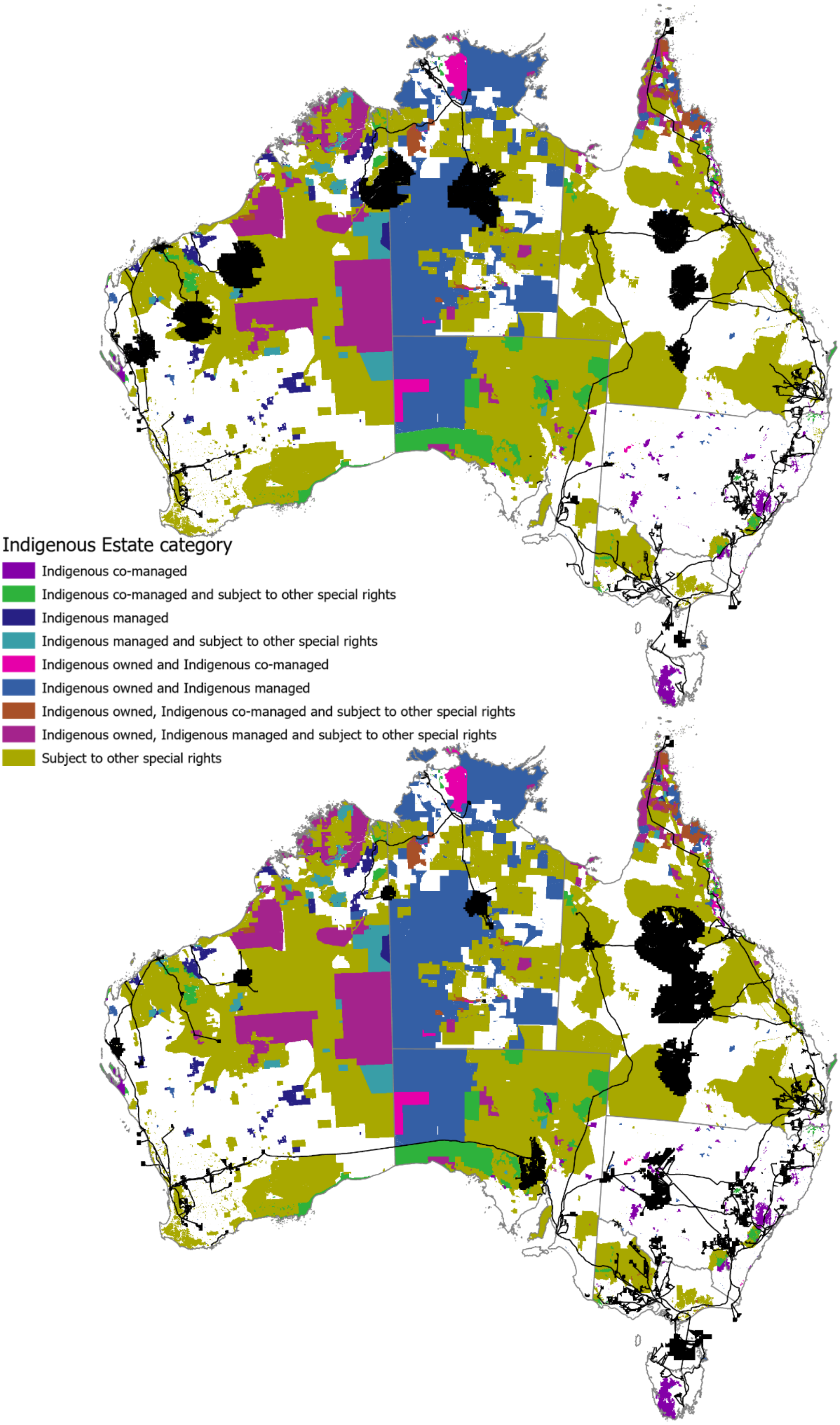


Figure 77 | Indigenous Estate map with overlay of 2060 NZAu VRE and electricity transmission infrastructure for the E+ Scenario (top) and the E+RemoteCost+ Sensitivity (bottom).



7.5.3 Land Tenure

Results for the land tenure analysis are shown in Figure 78 and Figure 79. For both the Scenario and Sensitivity presented, roughly 49% of the NZAu infrastructure sits on freehold land. For E+, approximately 40% of infrastructure is sited on leased land, with the remaining 10% being un-leased crown lands. Interestingly, it can be seen that utility solar PV is more likely to be sited on Pastoral term & perpetual lease, while wind generation assets are predominantly sited on Freehold land.

The major change in the E+RemoteCost+ Sensitivity, relative to E+, aside from the addition of ~20,000 km_2 of wind infrastructure land footprint, is a 7% swing from un-leased crown lands (3%) to leased lands (47%), with increase in land footprints on *Other pastoral leases* and *Pastoral term leases*. A broad interpretation of the move from crown land to leased land in the E+RemoteCost+ Sensitivity, is the potential for an increase in the complexity of negotiations over the use of the leased land, which may represent a bottleneck (unforeseen by modelling) in siting of some of the projects in these areas.

Figure 78 | Total VRE and transmission infrastructure footprint area on the various categories of Land Tenure, for the E+ Scenario and the E+RemoteCost+ Sensitivity in 2060.

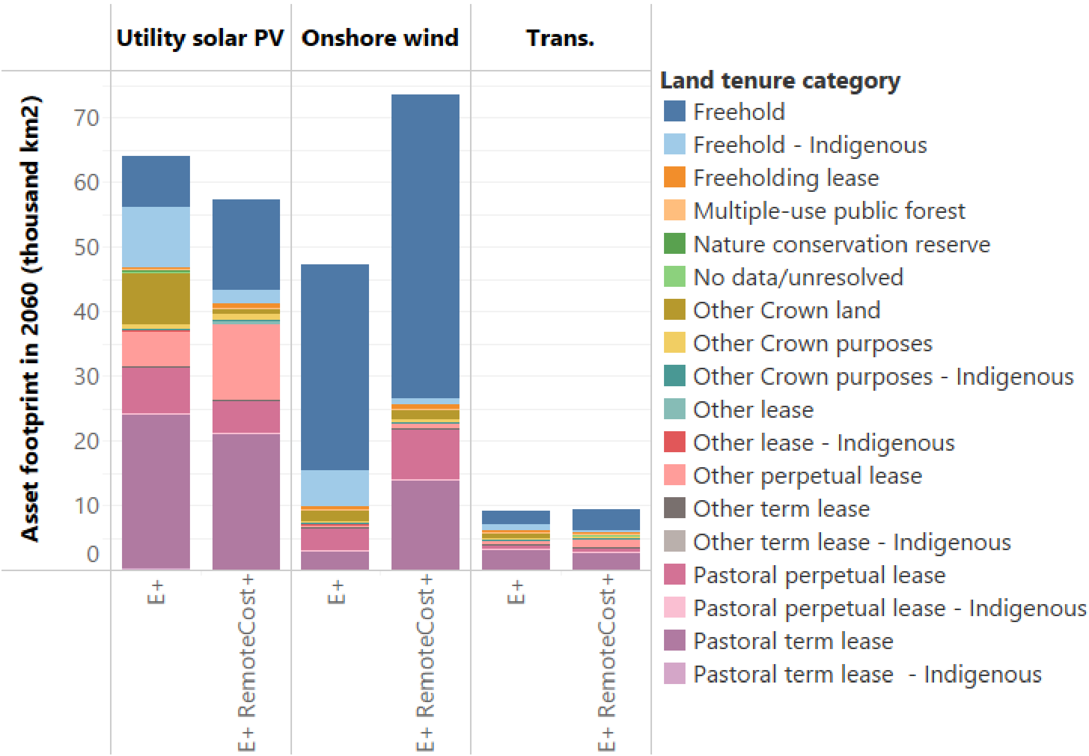
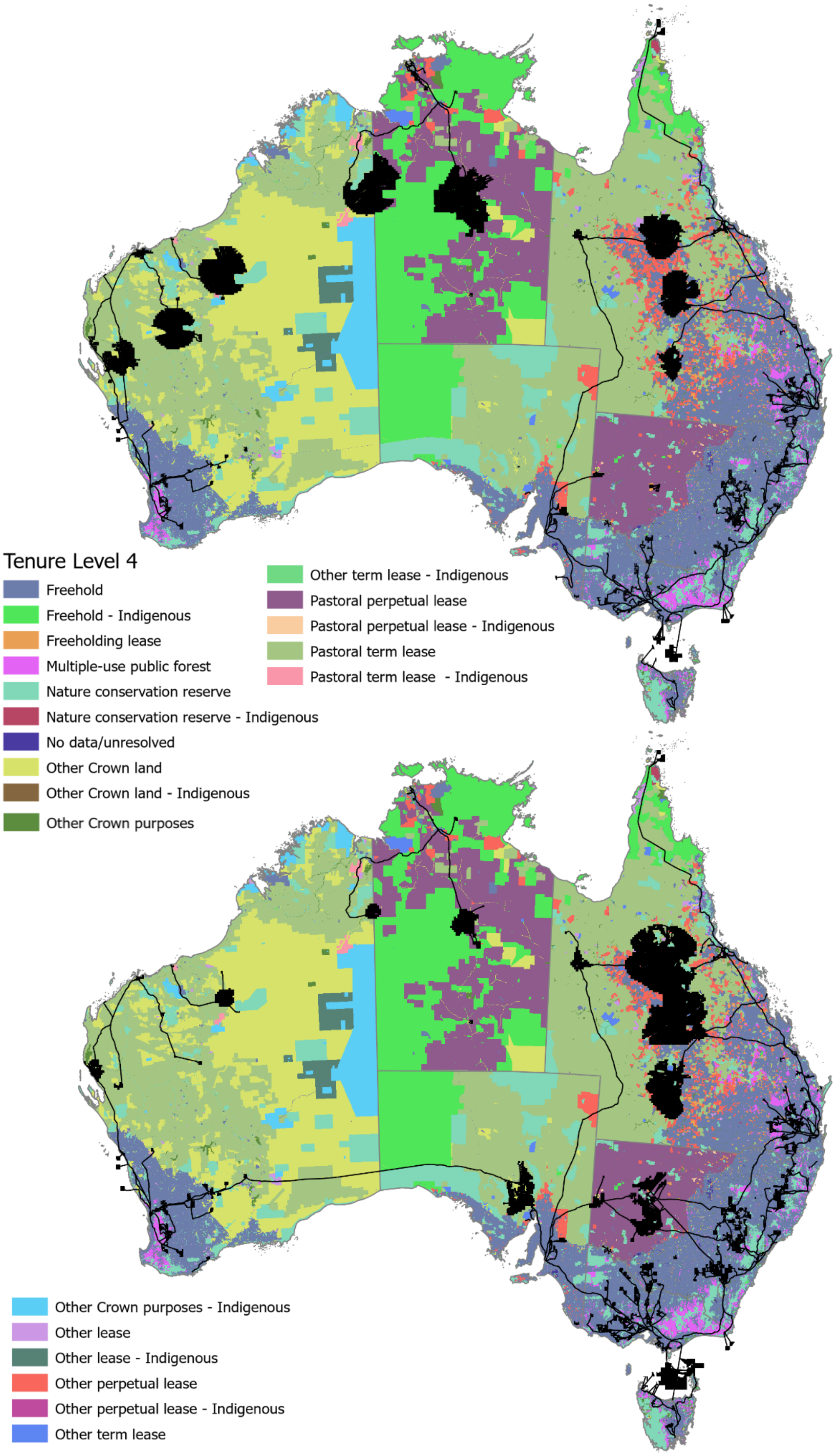


Figure 79 | Land tenure map with overlay of 2060 NZAu VRE and electricity transmission infrastructure for the E+ Scenario (top) and the E+RemoteCost+ Sensitivity (bottom).



7.5.4 Water use

Assessment of modelled energy system total water consumption shows an increase by factor of 2-3.5, relative to current levels (Figure 80). This increase is driven by water consumption associated with the hydrogen and energy export supply chains (electrolysis, ATR w/cc and Haber-Bosch ammonia synthesis), as well as by the need for direct air capture (DAC). We find that total water consumption is lowest in the E+ONS Scenario (3,000 GL in 2060), due to lower total hydrogen and ammonia production, while consumption is largest in E+RE− (5,500 GL in 2060), in large part because of the significant use of DAC in that Scenario. Across the Scenarios, electrolysis is the dominant technology consuming water.

To supply this increase in total water consumption, we have modelled the establishment of desalinated water networks, with associated cost and siting considerations for plants and pipelines. As a result, the net *fresh* water consumption of NZAu's Core Scenarios falls to 2060 by up to 60% (Figure 80). This is largely attributed to reduced water consumption for coal processing and is therefore most apparent in Queensland and New South Wales.

Figure 81 then presents downscaled energy sector water infrastructure for the E+ Scenario in 2060, including potential locations of desalination plants supplying water to various technologies, and locations of large-scale electrolysis production, direct air capture and water transmission routes.

Figure 80 | (Left) total energy sector water consumption in 2060; (middle) annual total water consumption, indexed at 2020 levels; and (right) annual fresh water consumption, indexed at 2020 levels.

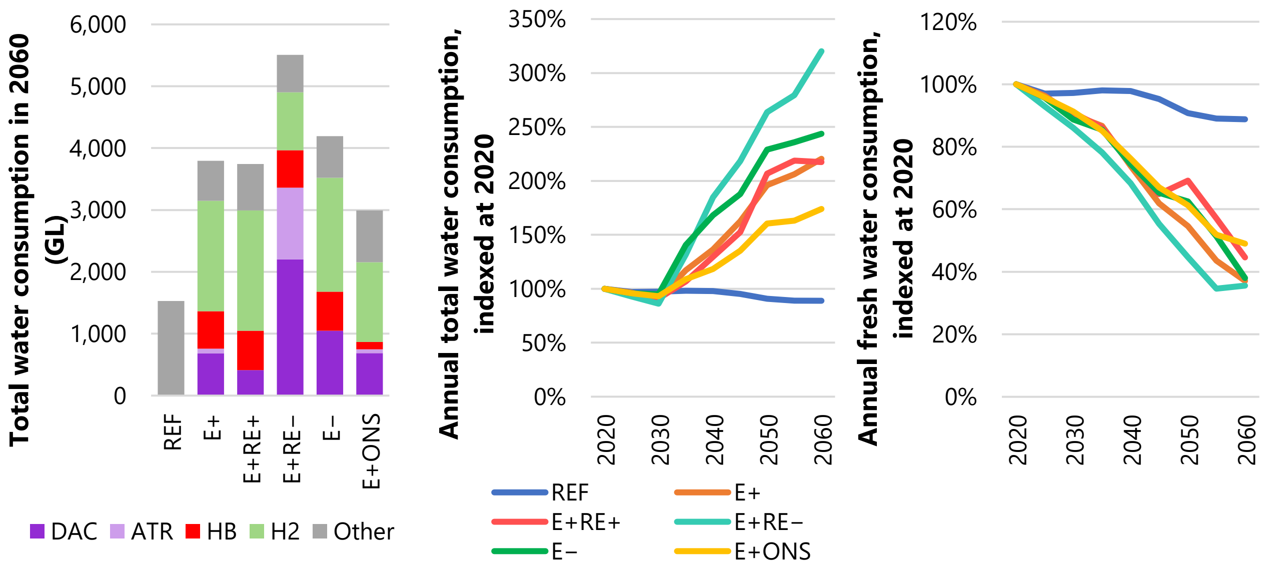
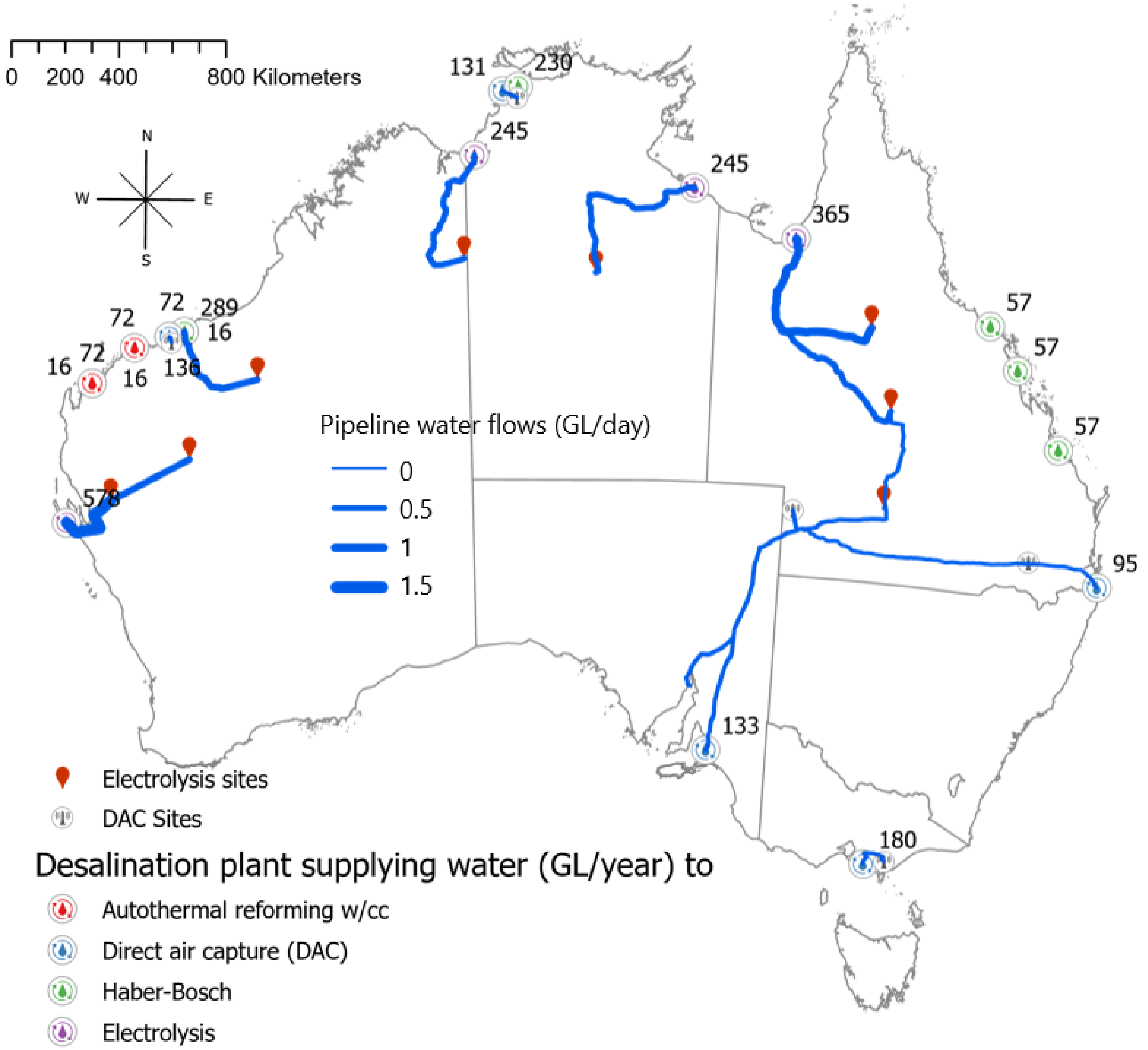


Figure 81 | Downscaled energy sector water infrastructure for the E+ Scenario in 2060, including potential locations of desalination plants supplying water to various technologies (with units of supplied water in GL/year), and locations of electrolysis, direct air capture and water transmission routes.



7.5.5 Biodiversity and conservation

A combined approach to safeguarding biological diversity in Australia includes avoiding development in protected areas (PAs), key biodiversity areas (KBAs), and Australia's last remaining intact bioregions (Allan et al., 2022). While work remains to be done to ensure comprehensive coverage of all those areas in a single map layer — while also laying out processes to update map layers as concerns and threats emerge over time — the following map layers form the bases of analysis of NZAu infrastructure footprint impacts on biological diversity in Australia, as shown together in Figure 83.

- Ecological communities of National Environmental Significance (ECNES, DCCEEW, 2022a)
- Species of National Environmental Significance (SNES, DCCEEW, 2022b)
- Collaborative Australian Protected Areas Database (CAPAD, Commonwealth of Australia, 2021a, 2021b)
- National Map Reserve Areas (Geoscience Australia, 2016)

- Inland waterbodies, wetlands and salt lakes (Lymburner et al., 2017, Krause et al., 2021)
- Intact Bioregions (Australia's KBA National Coordination Group 2022)
- Key Biodiversity Areas (KBAs, Australia's KBA National Coordination Group 2023)

When these maps are overlayed the combined terrestrial portions cover more than 35% of Australia's total land area.

Results for the biodiversity analysis are provided for the E+ Scenario and the E+RemoteCost+ Sensitivity in Figure 82, with Figure 83 then providing an overlay of 2060 NZAu VRE and electricity transmission infrastructure on the biodiversity land use analysis maps. These indicate that the conservation focused NZAu exclusion areas largely worked as intended as did the decision to push new transmission into existing transmission corridors, even when those corridors cross protected areas. The latter policy is the reason that Figure 82 reports transmission footprints in the excluded protected areas. The shift in NZAu infrastructure from the E+ Scenario's slightly more compact land area use in northern and Western Australia to the E+RemoteCost+ Sensitivity's aggregated land area that is 20,000 km^2 larger and covers more of eastern Australia, results in an additional ~3,500 km^2 crossover with KBAs (most driven by wind farm areas), with a similar sized decrease in the crossover with intact bioregions (due to a large decrease in solar PV encroachment).

Although NZAu has endeavoured to include conservation in modelling, our selected layers and process falls short of the comprehensive and systematic approach needed for biodiversity conservation, especially when considering the likely impacts of climate change itself on biodiversity. This is because to date there has been no comprehensive spatial assessment undertaken around the minimum levels of protection and restoration that are needed to ensure that Australia's biodiversity persists. Our companion report, *Downscaling – Net zero transitions, Australian communities, the land and sea*, provides further discussion on additional requirements to ensure biodiversity conservation in energy system planning, much of which necessitates development of maps that identify the sites most important for biodiversity conservation, including irreplaceable sites that cannot be recovered (e.g., old growth forests) and the facets of biodiversity we cannot afford to lose (habitat critical for species persistence).

Figure 82 | Total VRE and transmission infrastructure footprint area on the different biodiversity map layer types, for the E+ Scenario and the E+RemoteCost+ Sensitivity in 2060.

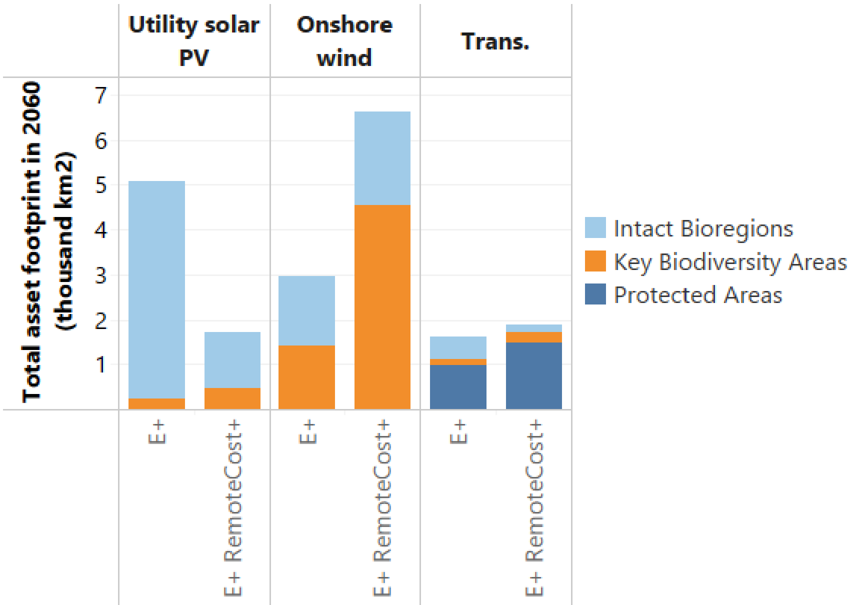
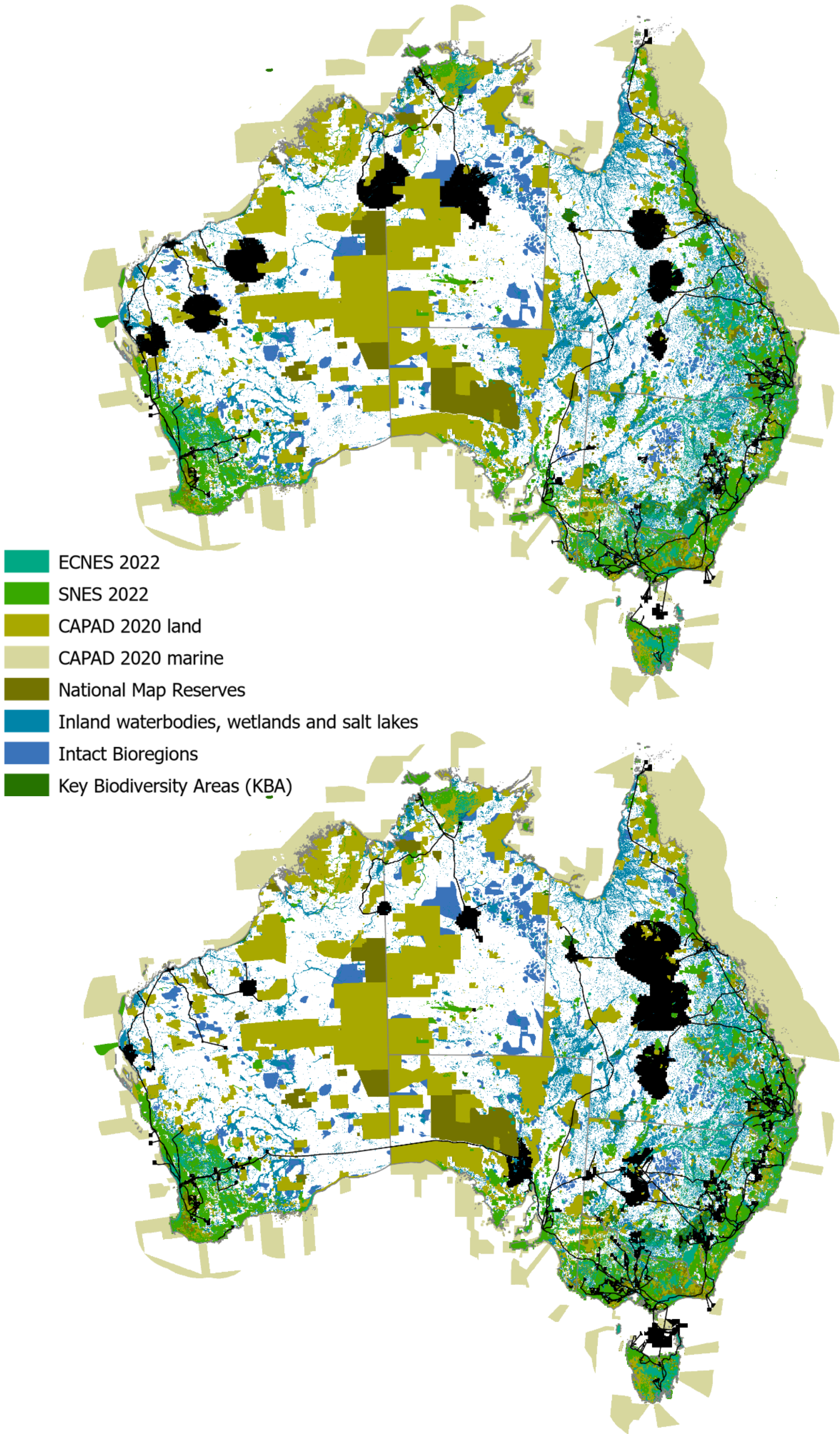


Figure 83 | Combined biodiversity map with overlay of 2060 NZAu VRE and electricity transmission infrastructure for the E+ Scenario (top) and the E+RemoteCost+ Sensitivity (bottom).



7.5.6 Agricultural lands

An analysis of the footprint of VRE and transmission infrastructure siting on farmland is provided in Figure 84, with Figure 85 then providing an overlay of 2060 NZAu VRE and electricity transmission infrastructure on different types of farmland. These show that VRE and transmission were not sited on irrigated lands, and solar PV projects not on cropping land, following the principles of land use and new energy asset siting (Section 3).

We find that Solar PV siting on rainfed pasture land is similar in both the E+ Scenario and E+RemoteCost+ Sensitivity. Wind assets then comprise the majority of the new energy assets sited on farmland, with 15,000 km^2 of wind projects sited on rainfed pastureland, 15,000 km^2 on rainfed cropping land, making up 17% of the sited assets in E+. The E+RemoteCost+ Sensitivity has increased use of farmland with an additional 12,000 km^2 of wind projects sited on farmland.

These results suggest that wind farms appear to be the best match for productive farmlands, after accounting for local biodiversity concerns. However, NZAu's blanket exclusion of solar PV on rainfed cropland misses potential synergies for siting on heavily degraded and unrecoverable crop lands, some of which may also have potential for biodiversity restoration. This highlights the importance of frameworks to support decision making on the use of farmlands for different clean infrastructure plant.

Net Zero Australia has also developed estimates of the emissions sequestration (net atmospheric CO_2 removal) that may be possible from a concerted afforestation of a portion of suitable agricultural land. This sequestration provides modest net negative levels of GHG emissions that enable important emissions abatement of agriculture and reduce the need for large net negative emissions from the energy sector modelling.

Section 5.5 provides details of this afforestation modelling. In summary, our analysis assumes that a concerted effort to expand Australian forest area by 5,100 km^2 through a combination of trees integrated with farming, environmental plantings, commercial plantations and human-induced regeneration could result in an additional net sink of −51 Mt-CO_2e of annual sequestration by 2050. These new trees could be sited on current Australia farmland, predominantly located in southern and eastern Australia, and preferentially on pastureland, rather than cropping land. Depending on the siting strategy used, 2.9–3.4% of cropland would be required over 30 years to host new trees, while 14–15% of pastureland would be required. Table 2 presented above shows the total modelled farmland afforestation by state/territory. This would require cultural change in the farming community, new investment and technology development to support more efficient establishment and more rapid tree growth.

Figure 84 | Total VRE and transmission infrastructure footprint area on the categories of farmland, for the E+ Scenario and the E+RemoteCost+ Sensitivity in 2060.

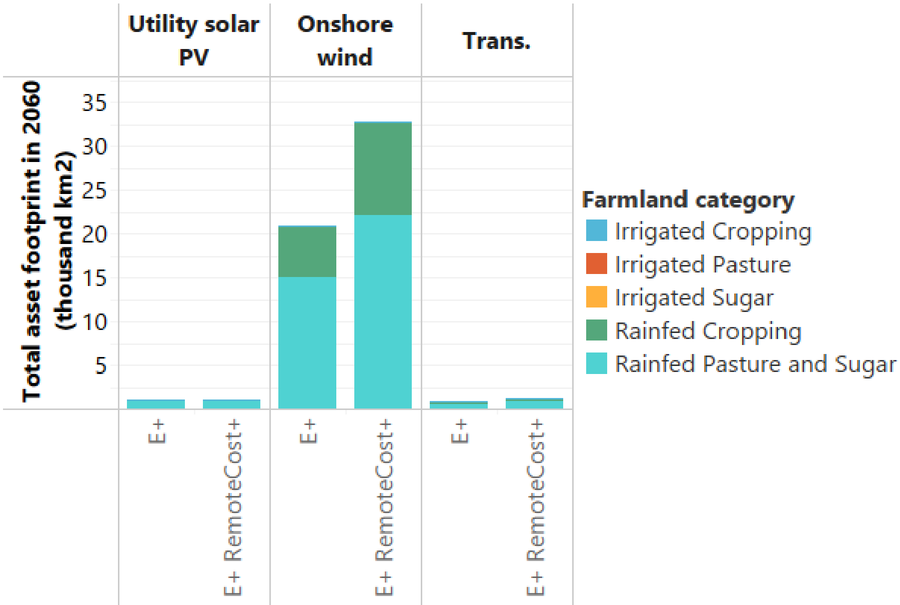
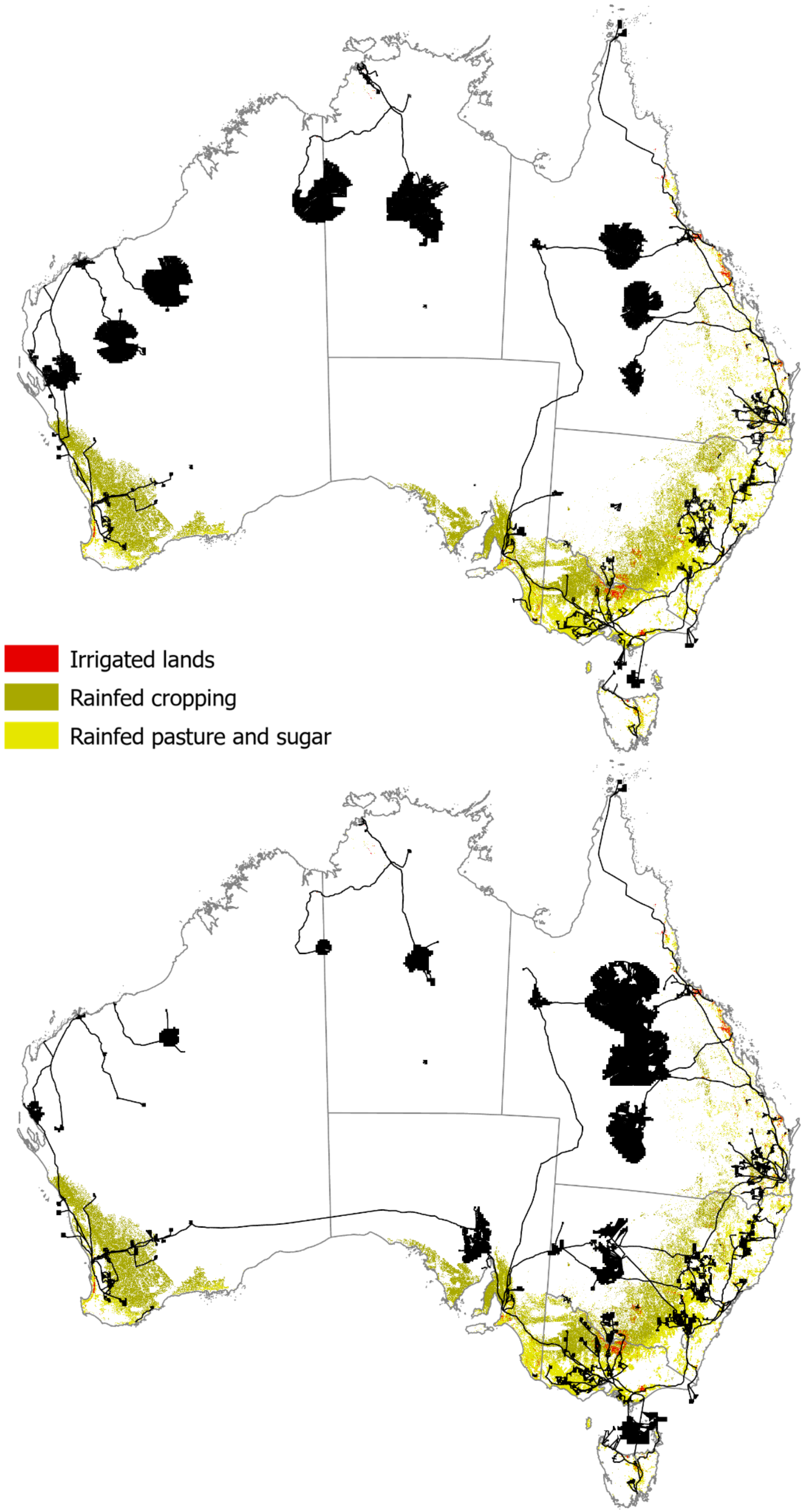


Figure 85 | Farm cover map with overlay of 2060 NZAu VRE and electricity transmission infrastructure for the E+ Scenario (top) and the E+RemoteCost+ Sensitivity (bottom).



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A Sensitivities

The Net Zero Australia project undertook 23 Sensitivity run on the Core Scenarios, as listed in Table 4. We do not provide a detailed set of results from these Sensitivity studies here, but have provided the key messages stemming from some of those studies below in Table 5. Furthermore, graphical results from the Sensitivity studies are provided in the *Final modelling results – full slide deck*.

Table 4 | List of Sensitivities, with the Core Scenario, on which the Sensitivity is based, and a short description of the Sensitivity settings used.

Core Scenario(s)		Sensitivity	Description
E+	E−	Faster	Domestic emissions are decarbonised by 2040 and export emissions are decarbonised by 2050 (both linear from 2020).
E+		Drivers+	GDP growth 3% pa from 2020; population growth 1.5% pa from 2020.
E+		Drivers−	GDP growth 1.5% pa from 2020; population growth 0.9% pa from 2020.
E+	E+ONS	Export+	Energy exports are linearly increased to 30EJ from 2040 to 2060.
E+		Export−	Energy exports decline linearly to 5EJ from 2040 to 2060.
E+		CleanExport−	Export embodied emissions do not need to go to zero (some importing countries may have option of sequestration). 50% export decarbonisation by 2060.
E+	E+RE−	RemoteCost+	Remote northern regions of Australia have higher capital costs.
E+	E+RE−	DistributedExport	Export task is more evenly distributed across the country. Each of SA, WA, NT and QLD can contribute individually at most 20% to export task.
E+		Solar−	Use a less ambitious capital cost trajectory for solar PV. 2050 solar PV cost is 1300 \$/kW (cf. 653 \$/kW in Core Scenarios).
E+		Transmission−	All inter-regional transmission is fixed at current capacities for electricity, CH4, H2 and CO2.
E+RE−		Nuclear	Nuclear power is allowed from 2035 onwards. Modelled as a Nuclear SMR with capital cost: 7,200 \$/kW.
E+	E+RE−	CheapNuclear	Cheaper nuclear power is allowed from 2035 onwards. Modelled as a Nuclear SMR with capital cost: 5,200 \$/kW.
E+RE+		Land+	Combined land sector (agriculture, waste, LULUCF) go to modest net negative emissions by 2050 (−31.5 Mt-CO2e/year in 2050).
E+	E−	Sequestration+	Constraint on geologic sequestration of CO2 is expanded to 1166 Mt-CO2/year, which is the upside of appraised capacities and is used in E+RE−.
E+RE−		Sequestration−	Constraint on geologic sequestration of CO2 is reduced from 1166 Mt-CO2/year to 150 Mt-CO2/year, which is the same as other Core Scenarios.
E+		Sequestration+ WACC+	Elevated costs of capital using a multiplier of ×2 on real WACC assumptions across all asset categories and ×1.5 on social discount rate. We also expand the constraint on geologic sequestration of CO2 to 1166 Mt-CO2/year.
E+		Sequestration+ Fossil+	Fossil fuel costs are increased by factor of ×2. We also expand the constraint on geologic sequestration of CO2 to 1166 Mt-CO2/year.

Table 5 | Selected key messages from findings from the Scenario Sensitivity analyses performed.

Sensitivity	Key message
What is required for faster emissions reduction?	Net zero 2040 requires us to build twice as much renewables in next 10 years as we would in net zero 2050. Offshore wind would play a greater role
Could nuclear energy play a role?	No, unless both renewable deployment is severely constrained, and nuclear capital costs are ~30% lower than our best estimate.
What if the land CO2 sink expands?	Enhanced land sinks could displace need for geologic sequestration and direct air capture in our full renewables rollout Scenario. Methods face high levels of uncertainty in estimates of carbon accounting, additionality, barriers to adoption and technical and social feasibility.
Is transmission expansion critical?	No, we could build marginally more storage instead
What if projected solar PV cost reductions are not realised?	More wind (onshore and offshore), and reduced, but still significant, need for batteries.
Could energy exports be more evenly distributed around the nation?	Yes, +/− 15 to 30% Capex swings in regional Australia are enough to shift export investment across the nation.
What is the impact of altering geological sequestration potential?	To meet export demand, sequestration and renewable build cannot both be constrained.

B List of methodology and downscaling reports

- Methods, Assumptions, Scenarios and Sensitivities
- Downscaling – Employment impacts
- Downscaling – Capital mobilisation
- Downscaling – Solar, wind and electricity transmission siting
- Downscaling – Land use impacts on Australian communities, the land and sea
- Downscaling – Firm generation and pumped hydro energy storage
- Downscaling – Transport sector energy transition
- Downscaling – Buildings, rooftop photovoltaics and batteries
- Downscaling – Electricity and gas distribution systems
- Downscaling – Hydrogen and synthetic fuel production, transmission & storage
- Downscaling – Water use and transmission
- Downscaling – Bioenergy systems
- Downscaling – CO_2 capture, transmission, use, and storage
- Downscaling – Natural gas and synthetic methane transmission
- Downscaling – The role of forestry in enhancing the Australian land CO_2 sink
- Downscaling – Fossil fuel industries
- Downscaling – Energy export systems
- Downscaling – Onshoring of industry