2025 Inputs, Assumptions and Scenarios Report

July 2025

For use in Forecasting and Planning studies and analysis

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO publishes this 2025 Inputs, Assumptions and Scenarios Report (IASR) in accordance with National Electricity Rules (NER) 5.22.8. This report includes key information and context for the inputs and assumptions used in AEMO's Forecasting and Planning publications for the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM) in Western Australia. This publication is generally based on information available to AEMO as at 31 July 2025 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (which includes information and forecasts from third parties) should independently verify its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Copyright

Version control

Version	Release date	Changes
1.0	31/07/2025	Initial release

Executive summary

Background

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM) and Wholesale Electricity Market (WEM), including the *Electricity Statement of Opportunities* (ESOO) for both markets, the *Gas Statement of Opportunities* (GSOO) for Western Australia and for the East Coast Gas Market (ECGM), and the *Integrated System Plan* (ISP) for the NEM.

The *Inputs, Assumptions and Scenarios Report* (IASR) includes a wealth of inputs and assumptions that apply to AEMO's planning publications, and are used across the industry for other planning purposes, including for use in regulatory investment tests for transmission. This final 2025 IASR details several planning scenarios, developed through collaboration with a broad range of industry participants, governments and consumer representatives. It reflects refinement of inputs and assumptions from stakeholder feedback from workshops, webinars, public forums, other engagements and submissions to formal consultation. The 2025 IASR includes additional inputs relative to previous IASRs, to enable consideration in the ISP of a wider scope of modelling needed to meet the requirements of the Energy and Climate Change Ministerial Council (ECMC) ISP Review, and subsequent rule changes[1] completed by the Australian Energy Market Commission (AEMC).

Formal consultation on the Draft 2025 IASR commenced in December 2024 with much of the key inputs and assumptions that underpin AEMO's planning scenarios, and was followed by additional inputs and assumptions consulted on from February 2025. AEMO has used feedback received from 73 formal submissions across the two stages of the Draft IASR consultation period and subsequent formal consultation opportunities with AEMO's Forecasting Reference Group (FRG), as well as informal feedback provided to AEMO during various engagement opportunities in preparing this 2025 IASR.

This report is accompanied by a separate consultation summary report[2], which provides AEMO's considerations of the extensive stakeholder feedback received throughout the consultation process on the Draft 2025 IASR, including how the feedback has led to refinements of this 2025 IASR.

AEMO recognises that one of the most significant of AEMO's planning functions is the development of the ISP, and acknowledges that stakeholders also keenly engaged on the *ISP Methodology*[3], finalised on 25 June 2025, which details several methods that will rely on the expanded inputs and assumptions contained in this 2025 IASR. In addition, this 2025 IASR is complemented by a *2025 Inputs and Assumptions Workbook*[3], with all granular information within this Excel-based databook, as well as two additional reports – the *2025 Electricity Network Options Report* and *2025 Gas Infrastructure Options Report*, which together have enabled detailed engagement on electricity and gas infrastructure to be modelled in the 2026 ISP. AEMO's ISP Timetable[4] has details on all major milestones specific to the ISP development process.

---

[1] See https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp and https://www.aemc.gov.au/rule-changes/better-integrating-gas-and-community-sentiment-isp.

[2] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[3] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[4] At https://aemo.com.au/-/media/files/major-publications/isp/2026/2026-isp-timetable.pdf.

Scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios therefore purposefully capture the key uncertainties and material drivers of these possible futures in an internally consistent way.

In this 2025 IASR, AEMO has generally maintained a scenario collection that represents plausible future 'worlds' that cover a collection of circumstances and external variations that influence Australia's continued energy transition, effectively exploring alternative consumer needs for energy and differing assumptions affecting potential energy supply. These scenarios are subsequently used in investment, reliability, security and operability assessments across AEMO's planning publications to identify a range of investment needs and the risks of inaction, and therefore do not themselves focus on investment outcomes or specific solutions. By providing a range of alternative futures, the scenarios support broader decision making for industry, consumers and governments to influence the energy transition. While some scenarios may be more likely than others, no single scenario is expected to be the definitive version of the future that will occur, and AEMO typically explores key uncertainties through sensitivity analysis where appropriate.

The scenarios in this 2025 IASR reflect a similar scenario collection to the 2023 IASR scenarios applied in the 2024 ISP, as well as the 2025 ESOOs and GSOOs, with adjustments based on stakeholder feedback received across various engagements since the Draft 2025 IASR was released. These changes are described further in Section 2.1.

The scenarios provide a mechanism to explore the investment needs of the energy system with consideration of various pathways to achieve the policies that Australia's governments have committed to, including to transition Australia's economy to net zero emissions by 2050[5]. As such, the scenarios continue to provide a broad range of environments on which to:

- Plan the energy system, supporting decision makers in identifying overall investment needs and applying them to AEMO's statutory functions to assess electricity system reliability and security, and gas system adequacy.
- Test the risks to consumers of under- and over-investment in Australia's infrastructure requirements, particularly as this investment relates to electricity transmission development.
- Inform regulatory network and non-network investment processes, including both the development of the ISP and application of the regulatory investment test for transmission (RIT-T) for relevant network solutions.

In developing the scenarios, AEMO focused on the principles that scenarios should remain broad, distinct, internally consistent, and plausible, and take into consideration the requirements and guidance provided in the AER's *Cost Benefit Analysis Guidelines* (CBA Guidelines)[6].

AEMO has defined three scenarios in this 2025 IASR for its planning activities, including the 2026 ISP. Scenarios may be supported by sensitivity analysis to explore the effect of specific uncertainties on AEMO's planning

[5] As per National Electricity Rules (NER) 5.22.3(b), which acknowledges that AEMO must (or may) consider eligible government policies when identifying power system needs and in developing how the ISP contributes to achieving the national electricity objective. See Section 3.1.

[6] See https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines/current-cba-guidelines.

publications, including the power system development outlook in the ISP, or emerging electricity/gas supply availability in the statements of opportunities.

Considering stakeholder feedback, and to improve clarity of the scenario collection, **AEMO has refined the names given to the three scenarios that were consulted on in the Draft 2025 IASR**.

AEMO considered this a necessary change to improve understanding of the key drivers and features of the scenarios. In this Executive Summary, and when outlined in Chapter 2 and the broader report, this 2025 IASR uses the new scenario name, with the previous name bracketed on first use to connect to the previous scenario name.

As outlined below, in the scenario collection:

- *Progressive Change* is now ***Slower Growth***,
- *Step Change* continues to be named ***Step Change***, and
- the proposed *Green Energy* scenario, for which two variants were described in the Draft 2025 IASR, has been renamed to ***Accelerated Transition***, and reflects the *Green Energy Industries* variant described in the Draft 2025 IASR (the variant that provided a greater domestic focus on green energy and hydrogen opportunities than its companion, *Green Energy Exports*).

The scenarios are as follows:

- ***Step Change*** (previously named *Step Change*) – this scenario achieves the objectives of Australia's government policies in transitioning the energy system, and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels. Similar to the 2023 *Step Change* scenario, consumers continue to embrace opportunities to support the transition through continued investment in consumer energy resources (CER), energy efficiency and electrification, or other investments that can contribute to reducing emissions. While consumers' own energy assets (that is, investments in rooftop solar, batteries and electric vehicles) are a key part of the transition, consumers are more tentative to share control and coordinate the operation of their energy devices through a third party than previously assumed in this scenario, relative to the 2023 IASR's *Step Change*. In this scenario, Australia's economy grows similar to historical trends, while emerging trends in artificial intelligence and other data-heavy applications encourage growth in data centres in Australia.
- ***Slower Growth*** (previously named *Progressive Change*) – this scenario achieves the objectives of Australia's government policies in transitioning the energy system, and reflects domestic action to contribute to lesser global ambition to extend specific commitments to limit temperature rise. It is a future that is challenged by lesser economic growth and greater challenges than other scenarios, and AEMO has reflected on stakeholder concerns that the previous *Progressive Change* name did not reasonably convey this key distinguishment relative to other scenarios. The new *Slower Growth* name provides increased clarity that while Australia's economy continues to grow in the long term, it has slower growth and lesser continued action beyond current commitments. Amidst weaker domestic and international economic conditions, Australia's energy-intensive industry and businesses are at greater operating risk, and a material proportion of the business sector closes in this scenario in the short to medium term. Energy efficiency, CER and electrification investments naturally

lower due to the weaker economic circumstances, and consumers lower their enthusiasm for offering their assets to third-party coordination.

- ***Accelerated Transition*** (previously named *Green Energy Industries,* one of two scenario variants in the Draft 2025 IASR) – this scenario achieves the objectives of Australia's government policies in transitioning the energy system, and provides an 'upside alternative' that explores the possible drivers for rapid emissions reduction domestically and globally. The scenario refines the 2023 *Green Energy Exports* scenario – it continues to feature a rapid transformation of Australia's energy sectors greater than that required by current domestic and global decarbonisation commitments, to limit temperature rise to 1.5°C above pre-industrial levels. This acceleration in the energy transition is fundamental to the scenario, and the scenario's new name captures this key driver more clearly than previous names that described a specific solution. The acceleration in investments across the economy is supported by positive economic conditions domestically and internationally, increasing the local population through migration and assuming a faster growing economy than other scenarios. With these conditions, consumers' own investments in CER, energy efficiency and electrification, and emerging opportunities in green commodity development, all provide key contributions to consumers' energy demand. Compared to the 2023 *Green Energy Exports* scenario, the role for hydrogen production is significantly lower, reflecting current uncertainties affecting commercial investment and supportive policy.

Further detail on the three scenarios is in Section 2.1.

AEMO considers that this scenario collection provides consistency for comparison with the 2023 IASR collection, used in the 2024 ISP and other planning assessments, and suitably reflects developments since then, including stakeholder feedback during consultation. Although the scenario names have changed, much of the scenario fundamentals remain well-aligned with previous scenarios.

Table 1 below provides a high-level comparison of key scenario settings at a given future year, in this case in 2040. For ease of understanding the relative scale of activities, investments or opportunities, a reference value typically reflecting the current level is also provided to compare with the settings at 2040.

Table 1 Scenario comparison at 2040, NEM states

	Reference value for scenarios	Slower Growth	Step Change	Accelerated Transition
Electrification and energy efficiency savings				
% of road transport that is EV	2024-25: 2%	34%	43%	55%
% of residential EVs still relying on unscheduled charging	2024-25: 43%	35%	32%	24%
Business electrification (terawatt hours [TWh])	Max potential: 57[A]	22	34	38
% increase from current business consumption	n/a	15%	23%	26%
Residential electrification (TWh)	Max potential: 13[A]	5	6	8
% increase from current residential consumption	n/a	9%	11%	13%
Energy efficiency savings (TWh)	n/a	27	41	52
Underlying consumption				
NEM underlying consumption (TWh) excluding hydrogen consumption	2024-25: 198	231	301	341
Hydrogen consumption[B] (domestic) (TWh)	2024-25: <1	9	15	33
Hydrogen consumption[B] (green commodities, including green steel) (TWh)	2024-25: 0	0	2	19
Total underlying consumption (TWh)[B]	2024-25: 198	241	319	399
Supply				
Distributed photovoltaic (PV) generation (TWh)	2024-25: 32	50	72	84
% of household daily consumption potential stored in batteries	2024-25: 2%	7%	15%	20%
% of underlying consumption met by distributed PV generation	2024-25: 16%	21%	23%	21%
Share of electricity emissions in economy-wide net emissions	2024-25: 28%	8%	5%	3%
Estimate of NEM emissions (million tonnes of carbon dioxide equivalent [$MtCO_2$-e])	2024-25: 121	20	10	1

A. For the purposes of this table, the 'maximum potential electrification' reflects the 2050 electrification forecast for the *Accelerated Transition* scenario. This scenario assumes that residential buildings are able to fully electrify by 2050 and that industries that are theoretically able to electrify have adopted those electrification technologies by 2050. In this way, the 2040 electrification values for each scenario can be put into context by comparing to this 'maximum potential electrification' value.
B. Total underlying consumption includes an allowance for Balance of Plant (BoP) associated with hydrogen production. The exact volume of BoP load depends on electrolyser capacity determined by ISP modelling, and is not reflected in the other components listed in this table.

Sensitivities for the 2026 ISP

AEMO often employs sensitivity analysis to increase confidence in the robustness of the conclusions its planning publications provide, and to test the effectiveness and resilience of investment outcomes against various uncertainties. Most commonly, this involves changing a single variable at a time.

AEMO received a wide array of stakeholder suggestions on valuable sensitivities for the 2026 ISP through the consultation process. Exploring key uncertainties relies on evaluating the degree of uncertainty that is present within the scenario collection, and particularly the scale of impact that particular assumptions may have on the developments, costs and benefits that may arise. Historically, key assumptions such as supply chain availability, generator retirements, carbon emissions trajectories, financial parameters such as the value of current versus future investments and costs, and the role of demand-side investments have all been key points of exploration in AEMO's analysis, particularly in the ISP.

For the 2026 ISP, AEMO expects to conduct similar analyses to explore the robustness and resilience of the power system developments that will be required to support the NEM's transition. With expanded consideration of several key components, such as the availability of gas for power generation given gas infrastructure investments, and the opportunity and influence of distribution investments to support CER operation and reduce potential curtailment, AEMO has expanded its modelling methodology significantly since the 2024 ISP. The scale of analysis therefore within the base scenario collection, and the influence of sensitivities for the 2026 ISP, is therefore more uncertain than in previous ISPs.

This 2025 IASR therefore does not define explicitly an expected minimum sensitivity collection that has been provided and expanded on in previous IASRs. AEMO acknowledges the breadth of suggestions provided by stakeholders, and intends to provide stakeholders with a wealth of modelling intelligence through its base models and sensitivity analyses to support engagement on the 2026 ISP. This 2025 IASR describes some of the potential sensitivities in Section 2.4, including suggestions provided by stakeholders. As is sometimes necessary in complex modelling processes, AEMO will flexibly explore the key uncertainties during the ISP process, using a dynamic, and often recursive process, to explore the benefits and impacts of necessary investments. This will include greater transparency regarding the opportunities for consumers to contribute to the transition, including a new Demand Side Factors statement to be included with the Draft 2026 ISP.

Inputs and assumptions

This 2025 IASR describes in detail the inputs and assumptions in relation to:

- government policy inputs, including settings that reflect carbon emissions constraints,
- energy consumption forecasting components, including CER,
- generation and storage assumptions affecting existing assets, and new entrant technologies, including capital cost projections and fuel price assumptions,
- renewable energy zones (REZs),
- transmission modelling,
- other power system security inputs,
- financial and economic parameters,
- gas modelling inputs, and assumptions relating to hydrogen production and hydrogen demand, and
- employment factors that will be used to estimate the workforce requirements needed to implement the ISP.

AEMO publishes the 2025 *Inputs and Assumptions Workbook*[7] alongside this 2025 IASR to provide more detail on the various inputs.

Policy settings

Government policy is included as an input for the purpose of AEMO's planning analysis. The range of policies included is set out in the IASR. As required by the ISP framework, AEMO considers the investments needed to meet the committed policies of Australia's governments, recognising that inefficient outcomes are likely to emerge where power system planning does not adequately consider committed government policy.

If there is a change to an energy policy included in the 2025 IASR or a policy not previously included requires consideration, AEMO will assess the materiality of the change on its planning analysis and reflect that change in subsequent publications if appropriate. This may require additional consultation depending on the materiality of the change and the type of planning analysis being undertaken.

[7] See https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

Contents

1 Introduction

AEMO develops publications that provide stakeholders with key forecasting and planning advice, including:

- ***Electricity Statement of Opportunities* (ESOO)** – provides operational and economic information about either the NEM or the WEM over a 10-year outlook period, with a focus on electricity supply reliability. The NEM ESOO includes a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO). The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps. The WEM ESOO includes the 10-year long-term projected assessment of system adequacy, used to assess reserve capacity requirements. The ESOO also includes forecasts of annual electricity consumption, maximum demand, and demand-side participation (DSP). It is published annually for each jurisdiction, with updates if required.
- ***Gas Statement of Opportunities* (GSOO)** – provides AEMO's forecasts of annual gas consumption and maximum gas demand and uses information from gas producers about reserves and forecast production, to project the supply-demand balance and potential supply gaps in either the ECGM or in Western Australia. It is published annually for each jurisdiction, with updates if required.
- ***Integrated System Plan* (ISP)** – is a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure that will meet future energy needs. It sets out the needed generation, storage and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers. It identifies transmission projects that should be progressed urgently by relevant network service providers, as well as providing information on broader opportunities to invest in generation, storage and other non-network investments to achieve the decarbonisation objectives of governments and deliver an efficient energy transition for electricity consumers. AEMO published the inaugural ISP for the NEM in 2018, and publishes it every two years.

Following ECMC endorsement of the actions recommended by the ISP Review, the AEMC has made final determinations on two rule change proposals (Better integration of gas and community sentiment in the ISP, and Improving consideration of demand-side factors in the ISP) and made new rules implementing its determinations. The new rules require AEMO to expand the technical scope of the ISP, and consider broader inputs and assumptions, affecting both the *ISP Methodology* and the IASR. Appendix A1 includes a table that shows the publications that AEMO is amending to address each ISP Review action to help inform stakeholders on appropriate engagement opportunities.

AEMO forecasts and models the future in these publications through a scenario planning approach, relying on scenario assumptions that are documented in the IASR.

This report documents the scenarios and their respective inputs and assumptions, incorporating stakeholder feedback, ahead of deploying them in the relevant planning publications.

The scenario set traverses a range of plausible futures based on key uncertainties facing the energy sector as it decarbonises:

- The **growth of the Australian economy**, and the role the energy sector will play in decarbonising it towards net zero emissions by 2050.

- The **role of demand-side factors** in the energy transition through ongoing consumer investments in increasingly energy efficient appliances and buildings, new preferences in electric and other low emissions technology alternatives, and in particular the uptake and potential coordination of CER.
- **Emerging commercial and industrial sectors** including electrification (switching from other fuels to electricity) in the business, industrial and transport sectors, the development of hydrogen production and manufactured products that utilise hydrogen (such as green iron, green steel and ammonia products), and emerging commercial developments in data centres to support a growing demand for Australian digital technology services.
- The **trends in technology costs** affecting the potential developments required to meet consumers' energy needs in electricity generation, storage and transportation, as well as costs and potential infrastructure developments to maintain and improve Australia's gas networks and markets, including potential gas supply developments that support broader energy consumers and Australia's electricity needs through flexible gas-powered generation facilities.

The scenarios are of critical importance in AEMO's planning and forecasting publications, but also in the regulatory investment test for transmission (RIT-T) assessments conducted by transmission network service providers (TNSPs). The use of scenarios is enhanced by sensitivity analysis. Sensitivities enable deeper analysis on key uncertainties and the impacts of alternative solutions to those uncertainties.

The information in this report is supported by the 2025 *Inputs and Assumptions Workbook*[8], which provides more granular detail about the inputs and assumptions for use in 2025-26 forecasting, modelling, and planning processes and analyses.

All dollar values provided in this report are in real June 2025 Australian dollars unless stated otherwise.

1.1 Consultation process

Engaging with stakeholders on planning inputs, assumptions and methodologies is essential to shape their development and ensure their effective implementation both in AEMO publications, and to enable action by stakeholders, policy-makers, investors and consumers.

Being transparent and building trust in the way AEMO engages with stakeholders is not only a key part of planning 'best practice', but also one of AEMO's four Corporate Priorities[9].

In developing the 2025 IASR, AEMO has had appropriate regard for the consultation requirements set by the Australian Energy Regulator's (AER's) *Forecasting Best Practice Guidelines*[10]. In considering these minimum requirements, AEMO strives to at least meet, and where appropriate exceed, these guidelines, leading to regular consultation and engagement opportunities using both formal and informal channels such as through AEMO's formal stakeholder consultations, and through various relevant forums such as the FRG. These engagement opportunities seek to improve transparency and clarity on AEMO's decision-making processes, modelling

[8] See https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[9] Priority 3: Engaging our stakeholders. See *AEMO Corporate Plan FY 2026*, at https://aemo.com.au/about/corporate-governance/corporate-plan.

[10] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

approaches and preliminary inputs, and provide transparency on how AEMO has considered stakeholder feedback.

Formal consultation commenced in December 2024 with the publication of Stage 1 of the Draft 2025 IASR, followed by additional inputs (a Stage 2 release) in February 2025. The Draft 2025 IASR, via its two releases and consultation windows, provided information on the scenarios, inputs and assumptions proposed for use in AEMO's 2025-26 forecasting and planning activities, including the 2026 ISP. AEMO has used feedback received from 73 formal submissions, as well as the wealth of stakeholder insight provided across a range of webinars, public forums and direct discussions, in preparing this 2025 IASR[11].

In addition, ahead of the Draft 2025 IASR publication, AEMO conducted a variety of engagement activities including:

- consulting TNSPs, jurisdictional bodies and AEMO's ISP Consumer Panel to reflect on the 2023 IASR scenario collection and identify issues and opportunities impacting future scenarios and how the existing collection should evolve,
- consulting all interested stakeholders on the 2025 IASR scenarios via formal consultation, to support early verification of the scenario collection and their narratives,
- consulting with stakeholders on preliminary forecast components through the FRG[12], an open forum that provides an opportunity to engage on key inputs as they are under development,
- consulting with stakeholders on the Draft 2025 IASR Stage 1 and 2 contents, covering the refined scenarios, and core assumptions and receiving 63 formal submissions,
- consulting on further inputs through FRG Consultations and discussions and receiving 10 formal submissions, and
- engaging regularly with the ISP Consumer Panel to consult on the scenarios, ensuring that the Panel's experience and consumer perspectives remains at the centre of development of the 2025 IASR.

The 2025 IASR is also complemented by two additional reports that provided targeted engagement opportunities on infrastructure development options, in the *2025 Electricity Network Options Report*, and the inaugural *2025 Gas Infrastructure Options Report*. This 2025 IASR frequently refers to these reports; stakeholders should refer to those publications to learn more about them, and the outcomes of stakeholder engagement in developing those assumptions.

Table 2 below summarises key engagement activities conducted to date and planned to support the development of the 2025 IASR[13].

For more information about related engagement, including engagement for the broader 2026 ISP, see the 2026 ISP Stakeholder Engagement Plan[14].

---

[11] The consultation summary report at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[12] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

[13] Presentations and recordings of webinars are at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

[14] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/opportunities-for-engagement.

Table 2 Stakeholder engagement on the 2025 IASR

Activity	Date
Pre-development scenario discussions with TNSPs, jurisdictional bodies and the ISP Consumer Panel	April 2024
2025 IASR Scenario Consultation Paper publication	16 July 2024
Forecasting Reference Group – scenario consultation	31 July 2024 and 25 September 2024
2025 IASR Scenarios – consumer verbal submission session	12 August 2024
2025 IASR Scenario Consultation Paper submissions close	13 August 2024
Forecasting Reference Group – preliminary component forecasts	August 2024 – December 2024
ISP Consumer Panel consultation	August 2024 – December 2024
Draft 2025 IASR Stage 1 publication	11 December 2024
Draft 2025 IASR Stage 1 webinar	23 January 2025
Draft 2025 IASR Stage 1 – consumer verbal submission session	11 February 2025
Draft 2025 IASR Stage 1 submissions close	11 February 2025
Draft 2025 IASR Stage 2 publication	28 February 2025
Draft 2025 IASR Stage 2 webinar	18 March 2025
Draft 2025 IASR Stage 2 – consumer verbal submission session	31 March 2025
Draft 2025 IASR Stage 2 submissions close	31 March 2025
FRG Consultation on Data centres	30 April 2025
FRG Consultation on Multi-sectoral modelling	22 May 2025
FRG Consultation on Pumped Hydro	28 May 2025
FRG Consultation on Cost escalation factors	17 June 2025
2025 IASR publication	31 July 2025

Stakeholder feedback incorporated in inputs and assumptions for the 2025 IASR

AEMO considered the submissions received, and has made the following key changes to the inputs and assumptions from the Draft 2025 IASR to the final 2025 IASR:

- **Refined scenarios,** including new, clearer names for two of the three scenarios, and a clearer focus on domestic opportunities for green energy commodities over exports of green energy.
- **Updated cost and technology assumptions,** including new distribution-connected mid-scale solar and battery assumptions, and updated pumped hydro energy assumptions.
- **Updated REZ assumptions,** including geographic areas, land use limits, resource limits and transmission limits.
- **Updated CER assumptions,** including the removal of fuel cell electric vehicles (FCEVs), enhancements to vehicle lifetime assumptions, and an expanded set of public charging categories.
- **Updated hydrogen assumptions,** including improved detail on hydrogen consumption locations, new forecast components for gas-powered generation and industrial hydrogen feedstock fuel-switching, refined committed projects, and refined minimum utilisation factors.

- **Updated multi-sectoral modelling assumptions,** including updated hydrogen prices, added market-led energy efficiency savings, and refinements to the descriptions for improved transparency.
- **Updated policies,** including the addition of the Federal Government Cheaper Home Batteries, and the removal of the Peak Demand Reduction Scheme.

While this 2025 IASR does not provide a definitive list of sensitivities for use in the 2026 ISP, a refined set of potential sensitivities are outlined that may be explored, pending insights that are observed across the scenario collection.

2 Scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios are designed to cover the breadth of potential and plausible futures impacting the energy sector and capture the key uncertainties and material drivers of these possible futures in an internally consistent way. AEMO uses a scenario planning approach to assess system adequacy with existing and expected investments, and (coupled with cost benefit analysis) to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition.

While some scenarios may be more likely than others, no single scenario is expected to be the definitive version of the future that will occur. The scenario collection helps to build understanding for the potential benefits or regrets of developments when investing amidst uncertainty, and to identify various risks to the energy transition.

In developing the scenarios, AEMO has focused on the principles that scenarios should remain broad, distinct, internally consistent, and plausible, and has taken into consideration the guidance provided in the AER's CBA Guidelines:

- **Internally consistent** – the underpinning assumptions in a scenario must form a cohesive picture in relation to each other.
- **Plausible** – the potential future described by a scenario narrative could come to pass.
- **Distinctive** – individual scenarios must be distinctive enough to provide value to the planning activities undertaken by AEMO and other stakeholders.
- **Broad** – the scenario set covers the breadth of possible futures.
- **Useful** – the scenarios explore the risks of over- and under-investment.

The scenarios explore critical dimensions and uncertainties affecting the energy sector while meeting emissions reductions objectives set by the commitments of Australia's governments. Key uncertainties include:

- the growth of the Australian economy, and the global dynamics that influence it (particularly regarding the level of global support and action for reducing emissions),
- the development of demand-side factors, including CER (including rooftop solar, battery storage and electric vehicles [EVs]), alongside the potential coordination of these resources, and other consumer investments in demand flexibility and energy efficiency,
- cost outlooks for technologies across electricity generation, storage and transportation, as well as costs and potential infrastructure developments to maintain and improve Australia's gas networks and markets,
- the emergence of hydrogen and related value-added products, as well as biomethane, and
- the changing nature of commercial and industrial loads, including the potential for closures and the growth of data centres.

AEMO developed three scenarios to inform its scenario planning approach used across its forecasting and planning publications to examine a plausible range of variations in the pace and directions of the transition.

Stakeholders have provided input in refining the scenarios and their assumptions

Preliminary stakeholder input throughout 2024 helped shape the scenarios and their inputs and assumptions in this 2025 IASR. In July 2024, AEMO published the Draft 2025 IASR Scenarios consultation paper[15] and received submissions from 50 stakeholders with feedback and suggestions, which helped shape the revised scenarios in this 2025 IASR. A summary of stakeholder feedback to the scenarios and AEMO's considerations is in the consultation summary report on AEMO's website[16].

Stakeholders continued to provide feedback on the scenarios and their assumptions, and provided additional considerations for the names of the scenarios – either explicitly, or through feedback that implied that the scenario collection could be better understood with improved names that provided greater description of their distinguishing qualities.

Considering stakeholder feedback, and to improve clarity of the scenario collection, **AEMO has refined the names given to the three scenarios that were consulted on in the Draft 2025 IASR**.

AEMO considered this a necessary change to improve understanding of the key drivers and features of the scenarios. This 2025 IASR uses the new scenario name, with the previous name bracketed on first use to connect to the previous scenario name.

As outlined below, in the scenario collection:

- *Progressive Change* is now ***Slower Growth***,
- *Step Change* continues to be named ***Step Change***, and
- the proposed *Green Energy* scenario, for which two variants were described in the Draft 2025 IASR, has been renamed to ***Accelerated Transition***, and reflects the *Green Energy Industries* variant described in the Draft 2025 IASR (the variant that provided a greater domestic focus on green energy and hydrogen opportunities than its companion, *Green Energy Exports*).

2.1 Scenario narratives and descriptions

Scenarios describe plausible future worlds, being a collection of circumstances and external variations that determine the environment in which the energy transition occurs, driving different conditions for energy supply and demand. Scenarios do not describe the outcomes of the planning process and are thus not focused on particular solutions. The collection of scenarios in the IASR enables consideration of combinations of various uncertainties from which further analysis identifies benefits or regrets of various alternative investments to meet the future needs of the power system. The scenarios intentionally span a range of current and future trends in energy consumption, consumer energy investments, and technology costs.

The scenarios in this 2025 IASR reflect a similar scenario collection to the 2023 IASR scenarios, applied in the 2024 ISP, with adjustments reflecting stakeholder feedback including:

[15] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/consultation-paper.pdf.

[16] See https://aemo.com.au/-/media/files/major-publications/isp/2025/2025-IASR-Scenarios-Consultation-Summary-Report.pdf.

- reduction in anticipated hydrogen developments associated with exports, yet greater recognition of the diverse production opportunities associated with green commodities (such as green iron, steel, alumina and ammonia),
- moderation of the pace and scale of consumers' adoption of measures to increase CER coordination, and
- increased consideration of emerging commercial loads, in particular the growing role of data centres associated with increased digital services provided in Australia, and the expected development of prospective industrial loads.

AEMO considers that the scenarios continue to provide a broad range of futures to inform regulatory network and non-network investment purposes, and enable identification of emerging system adequacy risks (for reliability and security assessments) as well as test the risks of under- and over-investment (for investment planning purposes).

2.1.1 AEMO's scenario collection

This 2025 IASR scenario collection provides consistency for comparison with the 2023 IASR collection, used in the 2024 ISP and other planning assessments, which AEMO considers useful for ongoing planning activities. The scenarios provide a breadth of plausible futures to consider power system needs for a range of planning purposes.

Step Change

(formerly Step Change)

The scenario refines the 2023 *Step Change* scenario. It is centred around achieving a scale of transformation that achieves the objectives of Australia's government policies in transitioning the energy system while supporting Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. With broader decarbonisation activities outside the electricity sector, Australia's contribution may approach 1.5°C alignment also, though investments to deliver the energy transition would be equivalent to those needed to achieve 2°C alignment only.

The scenario experiences moderate economic conditions on average, with population growth that is also moderate, reflecting long term average trends. Recent economic challenges and current economic conditions affect the starting conditions for the scenario.

In this scenario, consumers continue to provide a key role in the transition, with strong investments in electrification, CER and energy efficiency measures. There is also strong transport electrification, driven by consumer preferences and supported by ongoing government support across various government programs. Investment in CER, particularly in rooftop solar and batteries, reflects that households place high value on the benefits provided by these systems, and typically install relatively large household systems to improve self-supply.

Australia's businesses follow growth trends observed historically, with growing opportunities for emerging commercial and industrial loads. Data centres and electrification of transportation and larger industries, as well as the establishment of likely prospective industrials, lead to material new electricity consumption. Limited growth is expected from a domestic hydrogen industry, with slower and more focused domestic opportunities than applied in the 2023 IASR *Step Change* scenario, reflecting the economic challenges of establishing this new industry.

Notably, compared to the 2023 *Step Change* scenario, consumers are more hesitant to share control of their CER with third-party aggregators or their retailer, such as via virtual power plants (VPPs) and vehicle-to-grid (V2G), although there remains moderate long-term growth in coordinating these resources, and aggregators of consumer resources do become a strong contributor of the transition.

Scenario purpose

To explore the investment needs in a world with strong decarbonisation of the electricity sector, supporting other sectors decarbonising their current energy activities through electrification. Consumers increase their investment in CER, potentially reducing the need for utility-scale alternatives, with emerging coordination of these resources that grows cautiously in the short term.

Slower Growth

(formerly Progressive Change)

This scenario describes a world that aims to achieve Australia's current Paris Agreement commitments of 43% emissions reduction by 2030, and other government policies to support the energy system's transition, amid **economic circumstances that are more challenging**. The scenario features slower and weaker economic growth domestically, and global ambition to address climate change is less ambitious after current commitments. The magnitude and/or pace of global action is insufficient to meet the intent of the Paris Agreement to limit temperature rise to less than 2°C, and aggregate emissions over the coming decades are higher than other scenarios as Australia more gradually reaches a net zero emissions economy by 2050.

With weaker economic conditions, consumers and commercial businesses face a challenging investment environment and industrial loads are at greater risk of winding up Australian operations in favour of offshore alternatives in this future world. Australia's emissions-intensive industries are therefore at much greater operational risk, and the scenario explicitly reflects this risk with closures to large energy-intensive industrial loads in each NEM region, although this closure risk could be felt across the business sector rather than only by the industrial sector. Lesser economic and population growth reduces the overall scale of change required to achieve net zero. Lower global investment reduces the speed of technology cost decline, and supply chain challenges relative to other scenarios slow the pace of change affecting Australia's demand for energy. As a result, this scenario requires less investment to achieve the decarbonisation goals, and reflects conditions that challenge investor confidence.

Beyond the actions needed to address current government policies, *Slower Growth* does not feature the sort of domestic or international conditions that allows new green industry opportunities to thrive. With weaker economic activity, consumers continue to embrace ways to support the transition, but with less capacity to invest in demand-side factors such as energy efficiency savings and CER, and are even less willing also to give operational control of their resources to third parties, instead preferring to maximise their individual benefits, leading to less coordination of these valuable assets. Consumer adoption of measures to share control of their devices to aggregators is lowest of all the scenarios, reducing the coordination opportunity for these assets.

Scenario purpose

To explore investment needs in a world with headwinds to decarbonisation, including lesser growth across Australia's economy. As a consequence, despite the scenario driving to achieve current government policy, this scenario examines possible over-investment risks in a more slowly growing economy.

Accelerated Transition

(formerly Green Energy Industries, one of two 'Green Energy' scenario variants in the Draft 2025 IASR)

This scenario refines the 2023 *Green Energy Exports* scenario. It reflects very strong decarbonisation activities domestically and globally to limit temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, utilising all available pathways to net zero including a strong use of electrification, and transformation of other sectors at pace, including action to reduce the emissions intensity of molecular forms of energy. This acceleration in the energy transition is fundamental to the scenario, and the scenario's new name captures this key driver more clearly than previous names that described a specific solution.

Higher economic growth internationally (and locally) increases technology developments and leading to more rapid cost decline for new tech, and the global demand for green energy is very high given the strong global appetite for low and zero emissions fuel sources. Australia's buoyant economy and renewable energy potential enables creation of emerging industries such as green commodity production, while broader opportunities to develop and export hydrogen as an energy carrier are not a focus. Rather, production opportunities focus on domestic and international interest in products produced from green energy, particularly commodities such as green iron and steel.

Consumers in this scenario continue to invest in CER, with the greatest relative uptake of these assets, and the greatest relative acceptance of coordination opportunities.

In this future, Australia also embraces a rapid change to the emissions intensity of the energy sector. With strong renewable energy penetration, the opportunity for large-scale development of prospective industrial loads, data centres, as well as hydrogen and associated commodities is greater than other scenarios, offsetting emissions intensive components of Australia's economy. Australia's international trading partners, particularly in Asia, provide great opportunities for Australia's potential to develop and deliver green commodities to support their decarbonisation actions. For example, as the world's largest iron ore exporter and with high renewable energy opportunities, in this scenario Australia is well placed to service the growing global need for green energy commodities. The scenario features a materially smaller outlook for hydrogen associated investment than the 2023 IASR's *Green Energy Exports* scenario, used in the 2024 ISP, given the stronger focus on commodity opportunities for domestic (and international) customers.

Scenario purpose

To explore investment needs in a world embracing very rapid decarbonisation, with strong potential economic benefits for Australia given its high renewable generation potential and the potential this offers to support commoditisation of its minerals and resources. It will therefore identify the scale and speed of investments that may be required to realise this potential in a rapidly decarbonising global economy.

2.2 Key scenario parameters

Table 3 summarises decarbonisation targets, key demand drivers, technological trends and other key parameters for each of the scenarios. Details are in the 2025 *Inputs and Assumptions Workbook*. Scenarios vary by the pace of the transition to net zero, considering global, national and sectoral influences, leading to variations in future energy system needs while achieving the emissions reduction policy objectives of Australia's governments.

Table 3 Key parameters, by scenario

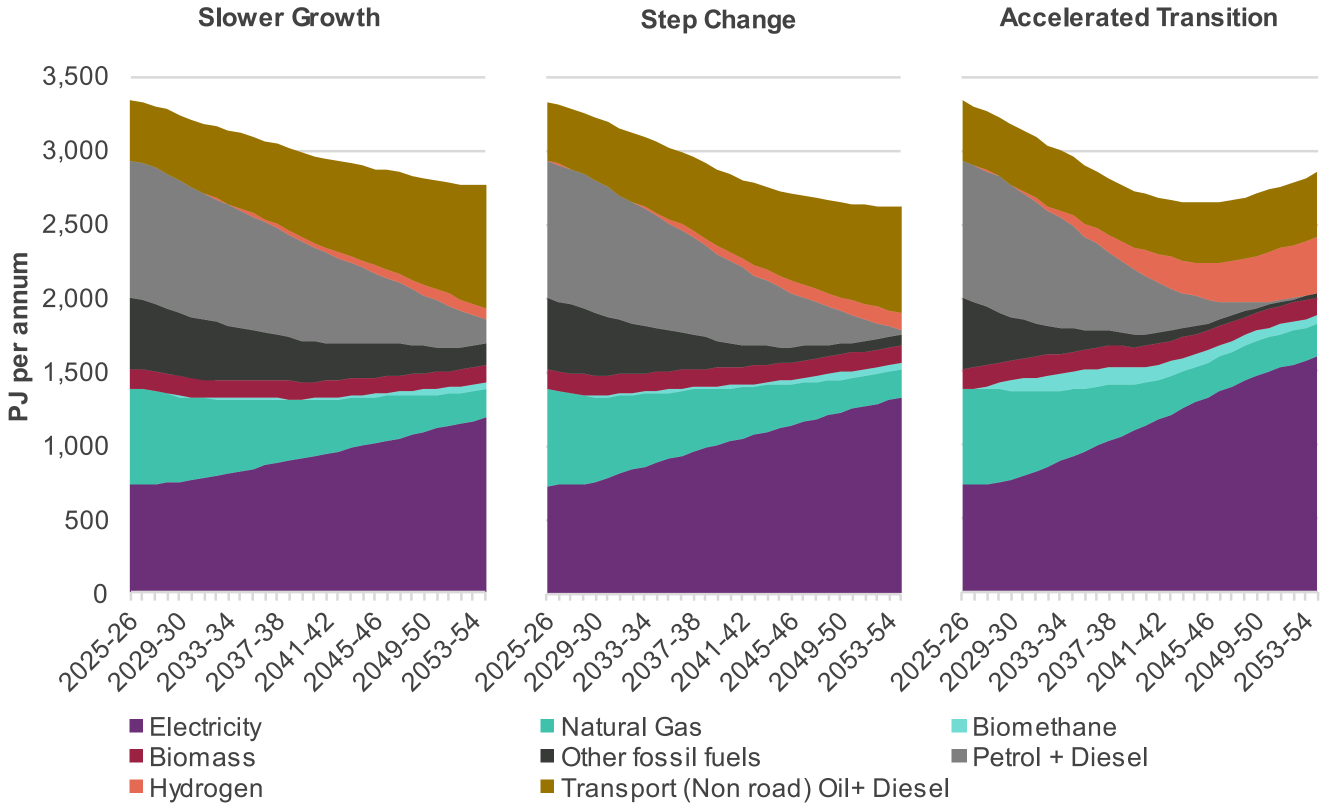
Parameter	*Slower Growth*	*Step Change*	*Accelerated Transition*
National decarbonisation targets	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower, with near-term economic growth calibrated with current economic conditions	Moderate economic growth, with near-term economic growth calibrated with current economic conditions	Higher, with near-term economic growth calibrated with current economic conditions
Electrification	Electrification is tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption
Emerging commercial and industrial loads	Emerging sectors such as data centres experience lower growth as weaker economic circumstances limit technology uptake	Emerging sectors such as data centres match opportunities associated with moderate domestic economic drivers	Emerging sectors such as data centres match opportunities associated with higher domestic economic drivers
Coordination of CER (VPP and V2G)	Low long-term coordination, with gradual acceptance of coordination	Moderate long-term coordination, with gradual acceptance of coordination	High long-term coordination, with faster acceptance of coordination
Energy efficiency	Moderate	High	Higher
Hydrogen use and availability	Low production for domestic use, with no export hydrogen	Moderate-low production for domestic use, with no export hydrogen	Moderate production for domestic industries and green commodities, with no export hydrogen
Industrial load closures [A]	Weak economic conditions provide challenging commercial conditions, resulting in closures of industrial loads	No specific load closures	No specific load closures
Demand-side participation uptake	Lower	Moderate	Higher
CER investments (batteries, PV and EVs)	Lower	High	Higher
Renewable gas blending in the gas distribution network (vol%) [B]	Up to 5% hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases	Up to 2% hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases	Negligible hydrogen blending by 2050, with unlimited blending opportunity for biomethane and other renewable gases
Potential for supply chain limitations affecting demand forecasts	High	Moderate	Low
Global/domestic temperature settings and outcomes [C]	Applies Representative Concentration Pathway (RCP) 4.5 where relevant, consistent with a global temperature rise of ~ 2.6°C by 2100	Applies RCP 2.6 where relevant, consistent with a global temperature rise of ~ 1.8°C by 2100	Applies Representative Concentration Pathway (RCP) 1.9 where relevant, consistent with a global temperature rise of ~ 1.5°C by 2100
International Energy Agency (IEA) 2024 World Energy Outlook scenario alignment	*Stated Policies Scenario* (STEPS)	*Announced Pledges Scenario* (APS)	*Net Zero Emissions by 2050* (NZE)

A. While the scenario may implement industrial load closures, the risk of disrupted operations would apply across Australia's business sector, including the commercial sector.
B. Hydrogen blending into the gas distribution network will need to accommodate the technical requirements of distribution pipelines, as well as the capabilities of connected gas appliances.
C. RCPs adopted in the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report, see https://www.ipcc.ch/assessment-report/ar5.

2.2.1 Comparing energy end-use across the scenarios

Figure 1 shows end-use fuel consumption by scenario across the NEM, identified by multi-sectoral modelling conducted by CSIRO (see Section 3.3.4). The figures demonstrate that despite rising economic activity across the decades that are forecast (see Section 0), the energy forms that are expected to be used in Australia's economy will likely reduce, as energy efficiency increases and energy intensity falls, supported by fuel-switching to more energy-conversion efficient processes. The economic activity associated with green commodity developments (for domestic and/or international use) may drive increased energy consumption, else large savings are forecast to be gained from fuel-switching, particularly in the transportation sector, from gas consumers and from other fossil fuels.

Figure 1 End-use fuel consumption by scenario (petajoules [PJ]/year)



Key points are:

- *Accelerated Transition* shows a long-term increase in energy use reflecting stronger economic and population growth and significant development of energy-intensive green commodity and hydrogen industries. Electricity is the largest provider of energy, increasing two-fold during the forecast horizon with electrification of natural gas and other fossil fuels a key decarbonisation pathway. Most domestic hydrogen use provides energy for green commodities in hard-to-abate industries (domestically and internationally), as well as to support emerging opportunities to create a green manufacturing sector of Australia's economy. Biomethane may substitute for natural gas in sectors that are technically or commercially difficult to electrify, while petrol and diesel use declines towards zero as decarbonisation of the on-road sector occurs.

- Electrification investments provide a primary means to reduce fuel use across the scenarios, although the pace and scale differs across the scenario collection.
- While gas use declines due to decarbonisation over time, the gas system will continue to play an important role in the energy transition.

2.3 Scenario likelihoods

The scenario collection defines three broad scenarios that each are plausible and internally consistent and will challenge the scale, timing and need for new investments. Each scenario therefore is not expected to explore uncertainties in the transition that are equally likely. As such, for some planning processes that influence investment planning, it is appropriate to develop a view on the likelihood of each scenario to subsequently identify projects that are optimal across the scenario collection on a scenario-weighted basis. This is particularly important for the ISP, while other analyses such as the gas and electricity statements of opportunities may focus primarily on the most likely scenario, or each scenario individually, when assessing reliability and system adequacy.

AEMO is not providing the weightings of the scenario collection in the 2025 IASR. AEMO prefers to examine scenario likelihood at a point closer to when these scenario weightings are applied, to ensure the latest market or policy developments are incorporated into this consideration.

AEMO will identify stakeholder engagement opportunities prior to assessing scenario weightings, to ensure interested stakeholders are kept informed of key milestones relevant to the development of scenario likelihoods.

2.4 Sensitivities

The three scenarios capture a range of plausible futures that feature a variety of inputs and assumptions to allow the risk of under-investment (or overdue investment) and over-investment (or premature investment) to be assessed in the ISP. The scenarios will also be used to examine reliability and security of the electricity and gas systems appropriately.

There is inherent uncertainty around the specific impacts of an assumption under any given scenario; sensitivity analysis is often used to complement scenario-based planning to examine the degree to which outcomes may be influenced by individual (or a subset of) scenario settings. Sensitivities can be used to test the impact of varying key input assumptions in the scenarios.

AEMO's planning publications typically include some degree of sensitivity analysis. The specific sensitivities are identified by either evaluating stakeholder feedback on the uncertainty surrounding any of the inputs, or by adapting the modelling to develop deeper and richer insights after examining the outcomes of the scenario modelling. In developing the ISP, sensitivity analysis is used to test the resilience of the investments and increase confidence in the robustness of the investment conclusions and to test the impact of a specific assumption on the overall development path of the energy system. Most commonly, this involves making changes to a single variable at a time to isolate the effect of a specific input assumption. Sensitivities based on simultaneous changes to multiple variables are less common, as it would not isolate which variable was the primary driver for any result variation.

In determining which sensitivities to model and which uncertainties to prioritise, AEMO considers their relevance and usefulness to support the conclusions of the planning advice being provided, and to support broader decision making through enhanced insights on risks and opportunities. Sensitivities should continue to depict a future world that is plausible, distinctive, broad, and useful, and remain internally consistent after the assumption change.

For the 2026 ISP, with consideration of the expanded scope and breadth of the ISP analysis to support gas integration and demand-side factors, the complexity of the base forecasting and modelling methods has expanded, providing opportunities to explore new analysis but increasing the complexity of the base analysis as well. While AEMO expects to explore a range of uncertainties in the Draft 2026 ISP and in the final 2026 ISP, the specific sensitivities will depend dynamically on the insights of the modelling throughout the ISP's development. Potential sensitivity themes that may be explored may include, but not be limited by the list that follows. :

- **The impact of gas system development** – as the *ISP Methodology* describes, by integrating gas developments into the ISP's modelling, the ISP will now explore the impacts of gas supply development on the operability and reliability of gas-powered generation in the NEM. This new analysis is within the ISP's core modelling method, rather being a traditional sensitivity analysis, but will demonstrate the robustness of electricity investments and the ISP's optimal development path to different gas infrastructure development paths.
- **Other key assumptions to demonstrate the resilience of the ISP's optimal development path, such as:**
  - **Constrained supply chains** – exploring the potential impact of limitations to supply chains, workforce availability, or other factors which slow infrastructure development on the ability to meet government policies such as the decarbonisation and renewable energy targets. This will be tested by imposing slower and/or more costly development of new generation, storage and network projects in ISP modelling to mirror impacts of supply chain issues. This sensitivity therefore may be deployed to identify the impact of delivery delays to projects and the optimal investments considering these supply chain risks, as well as the impact to the broader development needs if circumstances preclude the ability to achieve federal and state policy commitments.
  - **Coal retirements** – coal retirements are optimised to minimise cost and balancing emissions within the ISP's carbon budget. The ongoing availability of coal generation impacts the development need for new generation, storage and network investments, particularly in firming capacity.
  - **Financial parameters affecting the cost-benefit analysis –** comparing costs and benefits received at different points in time in the ISP cost benefit analysis using a discount rate appropriate for the analysis of private enterprise investment in the electricity sector across the NEM is an important consideration. The ISP has historically explored alternative discount rates to understand the influence of this financial parameter on the selection of the optimal development path.
- **Key insights regarding the role and impact of alternative demand-side investments, such as**:
  - AEMO has historically explored the value of various investments by consumers in **energy efficiency** and **CER coordination**, to demonstrate the potential savings that may be delivered by achieving the forecast investments in the *Step Change* scenario. With expanded consideration of demand-side factors in the 2026 ISP, new insights on the value of demand-side investments may focus on these assumptions, and alternative levels of **CER uptake**. In addition, it may be prudent to explore under- or over-investment risks if the forecast level of **prospective industrial loads** and **data centre** developments differ from the scenario's

forecast, or the expanded consideration of international exports of hydrogen as an energy carrier, referred to in the Draft 2025 IASR as ***Green Energy Exports***

- These types of sensitivities may also help demonstrate the appropriateness of the optimal development path.

The above outlines preliminary sensitivity options, and is not intended as an exhaustive or definitive list. AEMO will prioritise the deployment of sensitivity analysis given the insights available to it as the ISP is developed, which may lead to more or less sensitivity analysis than the above list, as required.

Relationship between the IASR, the sensitivities described in this section, and the ISP's new Demand Side Factors statement

On 19 December 2024, in response to a rule change request from the Minister for Climate Change and Energy following the ECMC's Response to the ISP Review, the AEMC made a new rule to improve AEMO's consideration of demand-side factors in the ISP. The new rule includes requirements on AEMO to publish a demand-side factors statement in the ISP to provide a transparent and consolidated explanation of the expected development of the demand side of the market and the distribution network. AEMO will publish the statement as an appendix to the draft and final 2026 ISP.

To increase consideration of demand-side factors in the ISP, AEMO has established new datasets regarding the capability of the distribution network to support the operation of CER. As outlined in the *ISP Methodology*, this new information (provided by distribution network service providers [DNSPs] voluntarily for the 2026 ISP, ahead of guidelines that will oblige them to provide detailed information in future) will enable consideration of the role the distribution network will play in hosting CER and enabling two-way energy flow, and identify potential to efficiently host other distributed resources, if appropriate. The key assumptions for this analysis are described in the 2025 *Electricity Network Options Report*.

The statement will identify the approximate scale of distribution network developments alongside transmission investment required in the ISP and a summary of the inputs and assumptions on which the development of those distribution opportunities is based. Rather than identifying individual distribution assets for development, this statement will explain how developments at the distribution level may contribute to the efficient development of the power system. For example, alleviating constraints at the distribution level to facilitate the operation of CER may delay or reduce the need for utility-scale generation at the transmission level.

For the 2026 ISP, information provided by DNSPs on a voluntary basis will be used to inform these distribution opportunities and AEMO expects fuller information gathered in accordance with AEMO's Demand Side Factors Information Guidelines (to be released by December 2025) will allow improvements in the consideration of distribution opportunities for the 2028 ISP.

In addition, the statement will seek to describe the value of various demand-side investments in such areas as those listed in the Sensitivities section above, such as CER uptake and coordination (subject to the capability of the distribution network to support their operation), energy efficiency investments, prospective industrial load developments and the influence of emerging data centre loads. The statement may rely on qualitative or quantitative analysis, which would leverage existing IASR work, rather than additional technical assumptions.

As part of the Draft 2026 ISP, stakeholders will have the opportunity to engage on the Demand Side Factors statement to support its evolution in the final 2026 ISP and beyond.

3 Inputs and assumptions

3.1 Policy settings

Input vintage	July 2025
Source	Australian governments
Updates since Draft 2025 IASR	Updates including new, modified and removed policies have been incorporated.

Australia's governments have a critical role in setting the pace and breadth of the energy transition through policy direction and international commitments. Efficient investments in the energy transition therefore must have visibility of, and regard to, the direction that is provided through government policy. As a roadmap for the development of the NEM power system to support the energy transition, which informs further policy-making and investment decisions, it is important that the ISP reflects government policy settings to ensure these decisions can be made efficiently. The 2025 IASR considers policies which AEMO must or may consider under National Electricity Rules (NER) 5.22.3(b) in determining the power system needs to be met by the ISP and how the ISP contributes to achieving the national electricity objective (NEO).

3.1.1 Identifying the policies to be considered

The framework in the NER that underpins the ISP recognises that policy settings are a key influence on the future investment needs of the power system. Under NER 5.22.3(b), the provision for two separate types of policy collections is outlined:

- Policies that governments have created to meet emissions reduction objectives, provided by them to the AEMC and included in the AEMC Emissions Targets Statement. By providing these policies to the AEMC for this purpose, jurisdictions are outlining those policies that market bodies, including AEMO, must consider, at minimum, in having regard to the emissions reduction element in the national electricity objective. AEMO considers these policies as inputs to the ISP and does so by recognising their influence within AEMO's forecasting, modelling and scenarios.
- Policies that governments have committed to by sufficiently progressing the policy such that it meets at least one of the eligibility criteria in NER 5.22.3(b)(2), described in the section below. By meeting clear eligibility criteria (for example, by legislating a policy target or by allocating material funding in the jurisdiction's State or Territory budget papers), jurisdictions are demonstrating a sufficiently high standard of commitment to the policy to indicate that AEMO, in the context of the ISP, should incorporate the policy into its forecasting, modelling and scenarios, with the power system needs to meet the policy at lowest cost identified through the ISP modelling and evaluation process.

The following sub-sections describe how AEMO assesses the eligibility of jurisdictional policies under NER 5.22.3(b) to be considered in the ISP. Section 3.1.2 then provides a description of how AEMO considers eligible policies within its forecasting and modelling approach, and across its scenarios.

Emissions reduction targets in the AEMC emissions targets statement

AEMO must consider the emissions reduction targets stated in the AEMC's emissions targets statement[17] as required by NER 5.22.3(b)(1). Emissions reduction targets are defined in the NER to mean targets set by jurisdictions for reducing greenhouse gas emissions or which are likely to contribute to reducing emissions. The targets statement is structured to reflect these two categories of targets. The requirement for AEMO to consider the targets supports Australian governments' intention that the targets statement provides a publicly available, up-to-date list of government targets that decision-makers, including AEMO, must take into account at a minimum when having regard to achieving the emissions reduction element of the NEO[18].

AEMO therefore includes all policies in the AEMC targets statement as inputs to the ISP's development, meaning the ISP modelling results will demonstrate collectively what is required to meet these policies.

Other policies eligible to be considered

Additionally, the NER allow AEMO to consider an environmental or energy policy that is not in the targets statement if:

- it is sufficiently developed for AEMO to identify its impacts on the power system; and
- it meets at least one of the following criteria specified in NER 5.22.3(b)(2):
  - a commitment has been made in an international agreement to implement the policy;
  - the policy has been enacted in legislation;
  - there is a regulatory obligation in relation to that policy;
  - there is material funding allocated to that policy in a budget of a relevant participating jurisdiction; or
  - AEMO has been advised by the Ministerial Council of Energy to include the policy.

By engaging with jurisdictions, AEMO will assess the degree to which each policy is sufficiently developed to enable incorporation into its forecasting and modelling, and whether it sufficiently meets at least one of the five minimum requirements for consideration. This engagement enables AEMO to determine the degree to which the detail of each policy position is compatible with AEMO's various ISP models and forecasts, ensuring that the policy collection includes only those policies that are sufficiently detailed to influence the ISP's development outcomes.

If AEMO assesses that such a policy is eligible to be considered, AEMO's practice is to include these policies that may be considered under the NER alongside the targets in the AEMC targets statement that must be considered under the NER, to ensure the ISP identifies an appropriate scale of investment requirements and power system needs that reflects the governments' aggregate policy positions.

[17] At https://www.aemc.gov.au/regulation/targets-statement-emissions.

[18] Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Bill, Second Reading Speech, Minister for Infrastructure and Transport, Minister for Energy and Mining, the Hon. A. Koutsantonis, 14 June 2023, at https://hansardsearch.parliament.sa.gov.au/daily/lh/2023-06-14/38?sid=68968ae9a2ec4e84aa. Section 32A(5) of the National Electricity Law (NEL) requires decision-makers who are required to have regard to the NEO under the NEL, National Energy Regulations or the NER to consider, at a minimum, the targets stated in the targets statement.

3.1.2 How AEMO includes policies in the ISP

Having considered policies for inclusion, including the targets in the AEMC emissions targets statement and other policies eligible to be considered (collectively, 'included policies'), the ISP process then identifies the power system needs required to collectively meet the objectives of included policies at lowest cost while meeting reliability and security requirements.

Policies influence demand-side factors, supply investments and transmission development

As outlined in this section, jurisdictions have developed a wide range of policies to support and drive Australia's net zero transition that AEMO assesses to be included policies. These policies traverse many parts of Australia's economy, focusing on consumers, industry, energy suppliers, and other infrastructure developers.

AEMO's incorporation of these policies may therefore impact the inputs and assumptions for forecasting consumers' energy consumption and demand patterns (including residential, commercial and industrial consumers), as well as the development of supply and transmission developments in the ISP. Incorporating the policies may therefore influence AEMO's energy forecasts, having regard to its forecasting approach, or influence supply and/or network infrastructure developments identified by the ISP models through explicit development constraints (for example, targeting a particular amount of generation technology to be deployed).

AEMO applies included policies in all scenarios

AEMO considers that taking a consistent approach to both emissions targets and other eligible policies best meets the purposes for consideration of the included policies and satisfies the requirements in the AER's CBA Guidelines for how AEMO must conduct its cost-benefit analysis in the ISP.

This analysis requires AEMO to apply a 'weighted average net-economic benefit' approach to all scenarios in assessing the net market benefits of each development path used to select the optimal development path. This means that, when assessing the combination of investments that will be selected as the optimal development path, AEMO's analysis combines the outcomes from all assessed scenarios.

While the optimal development path must demonstrate positive benefits in the most likely scenario, all scenarios are still intrinsically part of the cost benefit analysis, necessitating consistent consideration of policies across each scenario. AEMO considers that an approach in which only some policies are selectively considered in the scenarios would result in inconsistent consideration of the policies across the scenario collection, once the weighted net economic benefits of each scenario are combined to select the optimal development path. AEMO has not identified a need to develop a different approach based on how a policy is assessed to be an included policy under NER 5.22.3(b).

This approach recognises that inefficient outcomes are likely to emerge where power system planning does not adequately consider committed government policy (that is, the included policies). While it is possible that an included policy's objectives or the actual pace of achievement of those objectives may change after the publication of the ISP, AEMO considers it appropriate for each of the ISP scenarios to model for the stated objectives of these policies. For those policies that require specific targets at specific years, such as jurisdictional renewable energy targets, AEMO applies a time-based trajectory to reflect that policy targets generally require investments to occur over a number of years.

Recognising policy uncertainty

The ISP rules in the NER do not require AEMO to assess the merits or feasibility of such policies. However, in accordance with the CBA Guidelines and ISP rules, AEMO may explore the robustness of the power system needs set out in the ISP through sensitivity analysis, in the event that the implementation of included policies is not able to achieve their targeted timeframes due to uncertainties in key assumptions (such as the availability of supply chains).

If an included policy is discontinued or materially amended or new policy is developed and this would result in a change to a key planning input or assumption that may materially change AEMO's planning analysis, such as selection of the optimal development path in the ISP, AEMO would incorporate the changes to the policy in its analysis (or remove it if discontinued). This would involve consultation and may take some time. As the IASR is used for a range of planning assessments, such as the ESOO and GSOO, the extent to which these other assessments are impacted would need to be considered at the time. In terms of the ISP, the rules in the NER enable AEMO to address a material change through consulting on the changed inputs, and consulting on and issuing an ISP update[19], or the change may be included in the next ISP, depending on the extent of the change and the associated consultation and analysis and the timing of the next ISP.

3.1.3 Policies included in the 2025 IASR

Table 4 summarises the policies included in this 2025 IASR. The sub-sections following **Table 4** describe the various policy settings to be applied in the 2025 IASR scenario collection.

[19] NER 5.22.15.

Table 4 Summary of policies included in the 2025 IASR

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland[20]	South Australia	Tasmania	Victoria
Emission reduction	43% below 2005 levels by 2030 and net zero by 2050 under the *Climate Change Act 2022.* Safeguard Mechanism		Economy-wide emission reduction target relative to 2005 levels of 50% by 2030, 70% by 2035 and net zero by 2050 under the *Climate Change (Net Zero Future) Act 2023*.	30% reduction below 2005 levels by 2030, 75% reduction by 2035, and net zero by 2050 in the *Clean Economy Jobs Act 2024.*	Emission reduction target of 60% reduction below 2005 levels by 2030 and net zero by 2050.	Net zero or lower (already achieved since 2015)	Emission reduction target of 28-33% below 2005 levels by 2025, 45-50% by 2030, 75-80% by 2035 and net zero by 2045 under the *Victoria's Climate Change Act 2017* and the *Climate Change and Energy Legislation Amendment (Renewable Energy and Storage Targets) Act 2024.*
Renewable energy development support	82% renewable energy target by 2030. Capacity Investment Scheme		Construct new renewable generation by end of 2029 that can produce the same electricity as 8 gigawatts (GW) in New England REZ, 3 GW in Central-West Orana REZ, and 1 GW elsewhere (*New South Wales Electricity Infrastructure Investment Act 2020* [NSW EII Act]). REZ Access Schemes to support the coordination of renewable energy and storage investment in REZs		100% net renewable energy by 2027 (pending legislation).	150% Tasmanian Renewable Energy Target (TRET) by 2030 and 200% by 2040.	Victorian Renewable Energy Target (VRET) of 40% by 2025, 65% by 2030 and 95% by 2035; VRET auctions 1 and 2.
Storage targets			Target of 2 GW/16 gigawatt hours (GWh) of deep storage by 2030 and 28	Borumba Dam Pumped Hydro (included as an anticipated project[21]).		Battery of the Nation (as development candidate).	Renewable Energy Storage target of 2.6 GW

[20] The Queensland Government has committed to releasing a new Energy Roadmap by the end of 2025. This will include repealing existing legislation and introducing imminent policy changes. Where feasible, current Queensland policies reflected in the 2025 IASR may be updated prior to finalisation of the Draft 2026 ISP. More information is available at https://statements.qld.gov.au/statements/102355.

[21] Projects are modelled as committed or anticipated based on criteria covering five areas of development: land/site acquisition, contracts for major components, planning and other approvals, financing, and construction. Further information is available on AEMO's Generation Information and Transmission Augmentation Information pages at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information and https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland[20]	South Australia	Tasmania	Victoria
			GWh of deep storage by 2034 under the NSW EII Act. Firming round tender including the Federal Government contribution under the Capacity Investment Scheme.				by 2030 and 6.3 GW by 2035.
Offshore wind targets							Offshore wind targets of 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040.
Hydrogen policies	Hydrogen Production Tax Incentive offering a $2/kg refundable tax offset for eligible facilities for up to 10 years between 1 July 2027 and 30 June 2040.		Renewable Fuels Scheme of the New South Wales Hydrogen Strategy.				
Transmission support policies	Concessional Finance		REZ network infrastructure projects and priority transmission infrastructure projects under the NSW EII Act, including Waratah Super Battery System Integrity Protection Scheme as committed and Central-West Orana Transmission Project as anticipated.	SuperGrid Infrastructure Blueprint and Queensland Renewable Energy Zone (QREZ) infrastructure will be treated as options. CopperString development is considered to be anticipated with the Townsville to Hughenden connection being modelled quantitively as a REZ network expansion.			*National Electricity (Victoria) Act 2005* (NEVA)-supported transmission projects and VicGrid planning of REZs, including some projects treated as development options and others as committed or anticipated projects (for example, Western Renewables Link as anticipated and the Mortlake Turn-in as committed).
Transmission land payment programs			Strategic Benefit Payments Scheme.	SuperGrid Landholder Payment Framework		Strategic Benefit Payments Scheme (under development)	

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland[20]	South Australia	Tasmania	Victoria
CER-related policies	Small-scale Renewable Energy Scheme (SRES). Cheaper Home Batteries Program	Sustainable Households Scheme and other CER incentives.	Funded actions under New South Wales Consumer Energy Strategy.		Voluntary retailer contributions feed in tariff.		Solar Homes Program and Solar for Business Program.
Electric vehicles	New Vehicle Efficiency Standard (NVES), EV fringe benefits tax (FBT) exemption, infrastructure funding (Driving the Nation) and fleet purchases.	ACT Zero Emissions Vehicle strategy 2022-2030. 80-90% of sales ZEV by 2030.	Funded infrastructure initiatives under the New South Wales EV Strategy.	Zero Emission Vehicle (ZEV) Strategy 2022-2032. 50% of new passenger vehicle sales ZEV by 2030, 100% by 2036.	170,000 EVs by 2030. 1,000,000 EVs[22] integrated over the next 20 years.	100% government vehicles by 2030.	Zero Emissions Vehicle Roadmap – 50% of light vehicle sales ZEV by 2030.
Energy efficiency	National Construction Code (NCC) 2022 and NCC 2025; National Australian Built Environment Rating Scheme; Greenhouse and Energy Minimum Standards; National Energy Performance Strategy and National Energy Productivity Target; Household Energy Upgrades Fund.	ACT Energy Efficiency Improvement Scheme.	New South Wales Energy Savings Scheme and Peak Demand Reduction Target under the New South Wales Energy Security Safeguard.		South Australian Retailer Energy Productivity Scheme.		Victorian Energy Upgrades program.
Other government policies		Policy on new gas connections.					Gas Substitution Roadmap.

[22] Note that due to differing long-term expectations of South Australian vehicle sales and total numbers across the scenario collection (for example, due to differences in population growth), the modelling has not achieved the policy target value of 1 million vehicles by 2045 in all scenarios, despite reaching 100% EV sales by 2045, as the policy intends.

3.1.4 Australia's emissions reduction targets

Climate Change Act (2022) (C'th)

In September 2022, the Federal Government legislated Australia's economy-wide emissions reduction target, committing to reducing greenhouse gas emissions by 43% below 2005 levels by 2030 and achieving net zero emissions by 2050. These targets are complemented by an emissions budget for the period 2021-2030 amounting to 4,381 million tonnes of carbon dioxide equivalent ($MtCO_2$-e)[23]. AEMO must consider these targets as they are in the emissions targets statement, and the target has also been submitted to the United Nations Framework Convention on Climate Change (UNFCCC) as Australia's updated Nationally Determined Contribution (NDC) under the Paris Agreement. AEMO expects to include Australia's 2035 NDC when it is determined.

Powering Australia Plan

The Federal Government has committed to achieve an 82% share of renewable generation by 2030 as announced in the Powering Australia Plan[24]. AEMO must consider this target as it is specified in the emissions targets statement.

Safeguard Mechanism

The Safeguard Mechanism is a federal policy, enacted through legislation[25], aimed at reducing emissions at Australia's largest industrial facilities in line with Australia's 2030 and 2050 emission reduction targets. It was reformed in 2023 and sets out a number of targets for participating industrial facilities, including the requirement that net emissions from all Safeguard facilities should not exceed 100 MtCO2-e in 2030 (and net zero in 2050). AEMO may consider the policy given it meets the legislative requirements of NER 5.22.3(b)(2); it does not feature in the AEMC Emissions Targets Statement.

The Safeguard Mechanism is expected to influence industrial electrification volumes, energy efficiency investments, and operational efficiency improvements. AEMO captures these within its electrification and energy efficiency forecasts (both are supported by forecasts that AEMO engages suitably qualified consultants to provide), as well as within its large industrial load forecasts (informed by industrial surveys).

State-based emissions targets

All states and territories in Australia have net zero emissions ambitions that are either legislated or currently introduced in state parliaments. AEMO must consider each of these that are captured within the AEMC Emissions Targets Statement.

State-based positions regarding emissions reduction are shown in **Table 5**.

---

[23] The emissions budget is not directly found in the Act but is referenced in Australia's Nationally Determined Contribution; see https://unfccc.int/sites/default/files/NDC/2022-06/Australias%20NDC%20June%202022%20Update%20%283%29.pdf.

[24] At https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia.

[25] At https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism. Enacted via the *National Greenhouse and Energy Reporting Act 2007* and other legislation.

Table 5 State-level economy-wide emission reduction ambitions relative to 2005 levels (in financial year unless otherwise stated)

	New South Wales	Australian Capital Territory [A,B]	Queensland [C]	South Australia (Calendar year)	Tasmania [B]	Victoria (Calendar year)	Western Australia	Northern Territory
Instrument	*Climate Change (Net Zero Future) Act 2023*	*Climate Change and Greenhouse Gas Reduction Act 2010*	*Clean Economy Jobs Act 2024*	*Climate Change and Greenhouse Emissions Reduction Act 2007* as amended by the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024*.	*Climate Change (State Action) Act 2008* as amended by the *Climate Change (State Action) Amendment Act 2022.*	2050 legislated via *Victorian Climate Change Act 2017*; other targets formalised via the *Climate Change and Energy Legislation Amendment (Renewable Energy and Storage Targets) Act 2024.*	*Climate Change Bill 2023,* introduced in Parliament in November 2023 but not yet passed. Sets out a net zero target as well as the requirement to set interim targets (not yet announced, to be set as soon as practicable following Australia's submission of an NDC).	Aspirational target published in "Climate Change Response – Towards 2050", not legislated
2025		50-60% reduction				28-33% reduction		
2030	50% reduction	65-75% reduction	30% reduction	60% reduction	Net zero or lower	45-50% reduction		
2035	70% reduction		75% reduction			75-80% reduction		
2040		90-95% reduction						
2045		Net zero				Net zero		
2050	Net zero		Net zero	Net zero			Net zero	Net Zero

Notes: Timing of emissions reduction ambition may be rounded to the nearest five-yearly increment, for presentation purposes.
A. Relative to 1990 levels.
B. While Tasmania's and Australian Capital Territory's legislated climate change targets aim to achieve net zero emissions, AEMO recognises the low emissions intensity of the electricity sector for the jurisdictions, and considers that an electricity-sector equivalent carbon budget would be inappropriate to reflect the economy-wide application of the legislation.
C. The Queensland Government has committed to releasing a new Energy Roadmap by the end of 2025. Where feasible, current Queensland policies reflected in the 2025 IASR may be updated prior to finalisation of the Draft 2026 ISP. More information is available at https://statements.qld.gov.au/statements/102355.

For the 2026 ISP, AEMO proposes to exclude the targets for Tasmania and Australian Capital Territory on the basis that neither are appropriate to quantify within the ISP models:

- Tasmania has already achieved its net zero target (in 2015).
- The Australian Capital Territory has already achieved its objectives through direct support to inter-state renewable energy projects (which is an implementation that is not modellable within AEMO's ISP models).

3.1.5 Relevant federal and state energy policies

New South Wales Electricity Infrastructure Roadmap

In 2020, the New South Wales Government released its Electricity Infrastructure Roadmap[26], and enabling legislation, the *Electricity Infrastructure Investment Act 2020* (NSW EII Act), was passed that provided a plan to transform New South Wales's electricity system reliably and affordably. The NSW EII Act section 44(3) sets out 'minimum objectives'[27] to construct, by 31 December 2029, a minimum target of the equivalent of 12 gigawatts (GW) of new renewable energy capacity. This is contained within the AEMC Emissions Targets Statement, and therefore must be considered by AEMO.

The NSW EII Act (section 44(2)) specifies overall objectives for the construction of this infrastructure, being:

(a) construction of generation infrastructure that is necessary to minimise electricity costs for NSW electricity customers, and

(b) construction of long-duration storage infrastructure that is necessary to meet the reliability standard, and

(c) construction of firming infrastructure that is necessary to meet the energy security target and the reliability standard.

The implementation of these objectives is underpinned by the electricity infrastructure investment safeguard described in the NSW EII Act Part 6 which includes Long-Term Energy Service Agreements (LTESAs) with the New South Wales Consumer Trustee that provide revenue protection to project developers.

Although these objectives are specified for these REZs, the generation constructed and operated under LTESAs are not required to be located in a REZ if the Consumer Trustee is satisfied the project demonstrates "outstanding merit". This target is proposed to be implemented as a trajectory to 33,600 gigawatt hours (GWh) by 2030, in line with the 2023 *Infrastructure Investment Opportunities Report*.

The NSW EII Act also sets an infrastructure investment objective for the construction of long-duration storage infrastructure (classified as storage with capacity that can be dispatched at full power for at least eight hours) with at least storage of 16 GWh and 2 GW capacity by the end of 2029. The New South Wales Government has legislated a second target for long-duration storage, of an additional 12 GWh, for a cumulative 28 GWh, to the end of 2033, in addition to Snowy 2.0[28].

[26] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap.

[27] *Electricity Infrastructure Investment Act 2020* (NSW), s.44, at https://legislation.nsw.gov.au/view/whole/html/inforce/current/act-2020-044.

[28] See https://www.parliament.nsw.gov.au/bills/Pages/bill-details.aspx?pk=18673.

The target of 16 GWh of long duration storage capacity is within the AEMC Emissions Targets Statement, and therefore must be considered by AEMO, and the additional 12 GWh of long duration storage which is legislated will also be considered.

The infrastructure investment objectives in the NSW EII Act section 44 exclude any generation capacity that was either existing or committed at or before AEMO's November 2019 Generation Information page. Therefore, any generation that has progressed to committed or existing since that time is included as contributing to the achievement of these objectives.

The 2025 *Infrastructure Investment Opportunities Report* is anticipated to be released in the near future. Where feasible, AEMO will aim to consider the *Infrastructure Investment Opportunities Report* development pathways in the 2026 ISP, in accordance with the NSW EII Act objectives as the minimum generation and storage infrastructure targets for New South Wales,

REZ access schemes

Access schemes are a key part of the NSW EII Act and support the coordination of renewable energy and storage investment in REZs. Generation and storage projects that seek to connect to the network infrastructure where a REZ access scheme applied may be subject to access rights – either through application or competitive tender. The fees paid to gain access rights contribute to community benefit and employment purposes in the region.

A REZ access scheme can provide investor certainty, streamline the grid connection process, and govern the volume of projects that may connect into REZ network infrastructure. AEMO proposes to model REZ access schemes as they are developed by EnergyCo, currently including:

- **Central-West Orana** – a maximum connection limit of 7.7 GW of new variable renewable energy (VRE) generation and storage is applied, and is lifted if transmission augmentation increases the REZ capacity beyond the scope of the Central-West Orana REZ Network Infrastructure Project[29] or when the term of the access rights lapses. For this REZ Access Scheme, that term is set to 33 years[30].
- **South West New South Wales** – a maximum connection limit of 3.98 GW of new VRE generation and storage is applied, and is lifted if transmission augmentation increases the REZ capacity beyond the scope delivered by Project EnergyConnect, HumeLink and Victoria – New South Wales Interconnector West (VNI West)[31] or when the term of the access rights lapses. For this REZ Access Scheme, that term is set to 15 years[32].

Queensland Energy (Renewable Transformation and Jobs) Act 2024

The *Energy (Renewable Transformation and Jobs) Act 2024* (Qld)[33] includes legislated renewable energy targets, infrastructure frameworks and governance arrangements. The Queensland Government has announced a commitment to repeal the renewable energy targets and, by the end of 2025, deliver a new Energy Roadmap. The

[29] EnergyCo. Notification of Draft Headroom Assessment in the Central-West Orana REZ, at https://www.energyco.nsw.gov.au/sites/default/files/2024-08/Notification%20of%20Draft%20Headroom%20Assessment%20for%20the%20Central-West%20Orana%20REZ%20Access%20Scheme.pdf.

[30] See https://www.energyco.nsw.gov.au/industry/access-schemes/central-west-orana-access-scheme.

[31] EnergyCo. South West REZ access rights tender update, at https://www.energyco.nsw.gov.au/news/south-west-rez-access-rights-tender-update.

[32] See https://aemoservices.com.au/tenders/-/media/a5a9eae4e1324b07911da0a112fdf32f.ashx?la=en.

[33] See https://www.legislation.qld.gov.au/view/whole/html/inforce/current/act-2024-015.

targets have already been removed from the AEMC Emissions Targets Statement. Given the imminent policy changes, AEMO will not model Queensland's Renewable Energy Targets contained within the Act, and will include updated measures from the Energy Roadmap, where feasible.

Additional Queensland Government measures include the progression of Borumba Pumped Hydro, Brigalow Peaking Power Plant, and the Mount Rawdon and Big T pumped hydro projects. AEMO will incorporate these other developments in accordance with its normal project commitment assessments as evaluated in AEMO's regular Generation Information and Transmission Augmentation Information processes and the 2025 *Electricity Network Options Report*.

Tasmanian Renewable Energy Target (TRET)

The TRET is a renewable energy target in the *Energy Co-ordination and Planning Act 1995* (Tas)[34] requiring development of sufficient renewable energy capacity to double current electricity consumption (or 21,000 GWh of production) by 2040 with an interim target of 150% (or 15,750 GWh) by 2030.

This policy will be incorporated in all scenarios as it is legislated and published in the AEMC emissions targets statement.

South Australia's net-100% renewable energy generation target

The South Australian Government has legislated and included in the AEMC emissions target statement a target of net 100% renewable energy generation by 31 December 2027[35]. This means that South Australia will target generation of enough additional renewable energy (to be consumed within South Australia and exported interstate) to net the volume of local fossil fuel generation. This is an update of the net 100% renewable energy generation by 2030 target that existed previously in South Australia. AEMO will model the 2027 target.

Victoria's renewable energy, storage, and offshore wind targets

Underpinning Victoria's electricity sector contributions to emissions reductions are the Victorian Renewable Energy Target (VRET), the Victorian Energy Upgrades (VEU) program, and a target for 50% zero-emission vehicles new sales by 2030 as outlined in the Zero Emissions Vehicle (ZEV) Roadmap.

The *Renewable Energy (Jobs and Investment) Act 2017* (Vic)[36] contains the VRET, which mandates 40% of the region's generation (including CER) be sourced from renewable sources by 2025, and 65% by 2030, and 95% by 2035[37]. These targets will be included in all scenarios of the 2024-25 forecasting and planning activities (including specific projects that are funded via VRET auctions conducted to date[38]).

[34] *Energy Co-ordination and Planning Act 1995* (Tas) s.3C, at https://www.legislation.tas.gov.au/view/html/inforce/current/act-1995-047.

[35] *Climate Change and Greenhouse Emissions Reductions (Miscellaneous) Amendment Bill 2024* (SA), clause 4, at https://www.legislation.sa.gov.au/lz?path=/b/current/climate%20change%20and%20greenhouse%20emissions%20reduction%20(miscellaneous)%20amendment%20bill%202024.

[36] See https://www.legislation.vic.gov.au/in-force/acts/renewable-energy-jobs-and-investment-act-2017/003.

[37] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[38] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret1.

The legislation includes offshore wind energy generation targets of at least 2 GW of offshore generation capacity by 2032, 4 GW by 2035, and 9 GW by 2040. The legislation also includes energy storage targets[39] of at least 2.6 GW of storage and dispatch capacity by 2030, and at least 6.3 GW of storage and dispatch capacity by 2035.

AEMO will include these three targets (VRET, the offshore wind target and the storage target) in all scenarios as all are included in the emissions targets statement.

Large-scale Renewable Energy Target (LRET)

Australia's Renewable Energy Target (RET) established targets for large-scale and small-scale renewable investments. The LRET aims to deliver 33,000 GWh of electricity from renewable sources each year until 2030. AEMO modelling captures the operation the LRET until the end of the currently legislated targets in 2030.

Capacity Investment Scheme

In December 2022, the Federal Government announced the Capacity Investment Scheme (CIS), which provides a national framework to drive new renewable and dispatchable capacity. The scheme provides a revenue underwriting mechanism aimed at unlocking around $10 billion of investment in clean dispatchable power to support energy reliability and security.

In November 2024, the Federal Government released a *Market brief on Renewable Energy Transformation Agreement allocations by jurisdiction November 2024*, outlining updated allocations by jurisdiction as agreed as part of Renewable Energy Transformation Agreements between the Federal Government and other jurisdictions.

AEMO will incorporate the outcomes of CIS tenders in its modelling, as well as the cumulative allocations by jurisdiction as outlined in the 2024 *Market brief*. As the mechanism continues to develop, AEMO may incorporate further detail into the 2026 ISP.

Three CIS tenders have been launched to date to support the scheme, The fourth upcoming CIS tender, expected in Q3 2025, will be considered in the final 2026 ISP.

Battery of the Nation

The Battery of the Nation project announced by Hydro Tasmania represents an increase in capacity of existing hydro generators, as well as the development of additional pumped hydro generation in Lake Cethana[40]. Hydro Tasmania suggests that with further interconnection, upgrading assets and adapting hydropower operation can result in up to 390 megawatts (MW) of additional capacity across Western Tasmania, Gordon Power Station and Tarraleah Power Station.

AEMO proposes to model the Cethana pumped hydro station as a separate build candidate with its potential development optimised within the ISP models. Further interconnection with Tasmania allows for more efficient redevelopment of Tarraleah, Gordon Power Station and West Coast hydro generation by repurposing maintenance expenditure resulting in collective additional capacity.

[39] At https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[40] See https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/unlocking-tasmania's-energy-capacity_december-2018.pdf?sfvrsn=8d159828_6 for further information on the impact of greater interconnection on existing latent capacity.

South Australia Firm Energy Reliability Mechanism

The South Australian Government has developed a framework to support the provision of long duration firm capacity to enable a reliable and resilient power system for the state. The Firm Energy Reliability Mechanism (FERM) sets a firming target determined by the Minister, informed by the annual South Australia Electricity Development Plan, to be supported by a form of tender process. No target had been set at the time of this publication and AEMO will consider this policy further prior to finalising the Draft 2026 ISP, subject to the timely release of sufficient detail to define its impact upon power system needs and a clear pathway to implementation.

Jurisdictional policies regarding hydrogen development

The Hydrogen Production Tax Incentive[41] has been legislated by the Federal Government and is part of the *Future Made in Australia* package[42] that was allocated over $22 billion in the 2024-25 federal budget. It is offering a refundable tax offset of $2 per kilogram of hydrogen produced from eligible facilities, for up to 10 years between 1 July 2027 and 30 June 2040, for facilities that reach a final investment decision by 30 June 2030. Facilities must be located in Australia and, among others, meet the minimum capacity requirement (10 MW electrolyser) and emissions intensity thresholds (less than or equal to 0.6 kg CO_2-e).

Various jurisdictions have also announced funding to support the establishment of hydrogen technologies, particularly renewable hydrogen production, although some have also been discontinued or delayed in recent months. For example, the South Australian Hydrogen Jobs Plan has been discontinued.

The New South Wales Hydrogen Strategy[43] includes the Renewable Fuels Scheme, established in the *Electricity Supply Act 1995*[44]*,* which targets increasing production of renewable hydrogen up to 8 petajoules (PJ) per annum by 2030[45]. The effect of the currently legislated Renewable Fuels Scheme is uncertain, given the opportunity for liable entities to pay a penalty rather than to surrender renewable fuel certificates to meet their obligations under the scheme. As such, the scheme has not been required to be achieved in AEMO's scenario forecasts for hydrogen.

Changes to hydrogen policies since the 2023 IASR include:

- introduction of the Hydrogen Production Tax Incentive,
- discontinuation of the South Australia Hydrogen Jobs Plan, and
- delay of start date for the New South Wales Renewable Fuels Scheme.

[41] *Future Made in Australia (Production Tax Credits and Other Measures) Act 2025*. See https://www.legislation.gov.au/C2025A00009/asmade/text.

[42] See https://futuremadeinaustralia.gov.au/index#plan.

[43] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/renewable-fuel-scheme#:~:text=The%20Renewable%20Fuel%20Scheme%20was%20established%20under%20the,will%20commence%20in%202024%20and%20run%20until%202044.

[44] See https://legislation.nsw.gov.au/view/whole/html/inforce/current/act-1995-094.

[45] *Electricity Supply (General) Regulation 2014* (NSW), at https://legislation.nsw.gov.au/view/whole/html/inforce/current/sl-2014-0523.

3.1.6 Transmission project support

National Electricity (Victoria) Act 2005 (NEVA) – 2020 amendment for expedited transmission approval

The NEVA facilitates expedited approval of transmission system upgrades, enabling Victoria's Minister for Energy and Resources to approve or accelerate approvals for augmentations of the Victorian transmission system. Several projects are currently supported under the NEVA and have advanced to the point where they are considered committed or anticipated developments. These include the specified augmentations for Western Renewables Link, the Mortlake turn-in, the Murray River REZ, Western Victoria REZ, South West Victoria REZ and Central North REZ minor augmentations, and the Koorangie Energy Storage System, as well as other projects providing system strength services. For more information on these developments, see Section 3.9.3.

The VNI West project is also subject to NEVA Orders which act to accelerate the project and specify requirements for its configuration. These orders relate only to the Victorian side of VNI West. VNI West is currently an Actionable ISP project.

AEMO will consider the development of projects supported under the NEVA as transmission options in the Draft 2025 *Electricity Network Options Report*, or as committed or anticipated projects in some cases, as outlined in AEMO's Transmission Augmentation Information page[46].

Rewiring the Nation

In 2022, the Federal Government announced the Rewiring the Nation program, which aims to modernise the grid and ensure the country's transmission networks are ready for the renewables and storage investment needed for the decarbonisation task ahead. The framework aims to prioritise transmission projects of national significance and support a transition to renewable energy. The Rewiring the Nation program provides up to $20 billion in finance at concessional rates to minimise the cost of investments that will help strengthen, grow and transition Australia's electricity grids. Managing the Rewiring the Nation fund, the Clean Energy Finance Corporation is administering $19 billion of low-cost finance for Rewiring the Nation. An additional $1 billion has been allocated to the Rewiring the Nation Special Account, which enables the Government to invest in the timely delivery of eligible projects. The Federal Government has so far entered the following agreements with NEM states:

- The Federal Government has committed $4.7 billion (which joins 3.1 billion from the New South Wales Transmission Acceleration Facility) to help New South Wales realise its Electricity Infrastructure Roadmap and unlock priority projects including VNI West, HumeLink, Sydney Ring, and the Central-West Orana, New England, Hunter Central Coast, and South-West REZs.
- The Federal Government has committed to provide low-cost finance to Marinus Link as well as support for eligible Battery of the Nation and grid-firming projects in Tasmania.
- The Federal Government has committed $2.25 billion of concessional financing to Victorian projects, including $750 million for VNI West as well as concessional financing for Victorian REZ projects, including offshore wind projects.

[46] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Electricity Infrastructure Investment Act (New South Wales) 2020 (NSW) – REZ network infrastructure projects and priority transmission infrastructure projects (PTIPs)

The New South Wales Minister for Energy and Minister for Climate Change may direct that REZ network infrastructure projects and PTIPs be carried out.

Waratah Super Battery is a PTIP under the NSW EII Act[47], and is listed as a committed project in AEMO's Transmission Augmentation Information page[48]. It is being delivered with a System Integrity Protection Scheme (SIPS) to improve transfer capabilities from: Central New South Wales (CNSW) to Sydney, Newcastle and Wollongong (SNW); Southern New South Wales (SNSW) to CNSW; and Northern New South Wales (NNSW) to CNSW, while the scheme is in place.

The Central-West Orana Transmission project will provide new network infrastructure for the Central-West Orana REZ including high-capacity transmission lines and energy hubs to transport power from solar and wind generators and storage systems to major load centres.

The Central-West Orana Transmission project is a REZ network infrastructure project under the NSW EII Act[49] and is listed as an anticipated project in AEMO's Transmission Augmentation Information page[50]. EnergyCo is overseeing the planning and approval processes for the project and has selected ACE Energy as the first ranked network operator for the project.

Queensland SuperGrid Infrastructure Blueprint, Queensland REZ Roadmap, and CopperString

The Draft 2025 IASR considered the development of the Queensland SuperGrid Infrastructure Blueprint[51] (the Blueprint) and the Queensland Renewable Energy Zone Roadmap[52]. However, following the change of government in October 2024 and the April 2025 announcement of a new Energy Roadmap by the end of 2025, no further updates to the Blueprint or REZ developments will be considered. Where feasible, AEMO will incorporate outcomes from the anticipated Energy Roadmap, including details relating to grid infrastructure, into the final 2026 ISP.

The Queensland Government has announced that it is working to deliver the CopperString transmission project – approximately 1,100 km of transmission lines from Mount Isa to south of Townsville – to connect the North West Minerals Province to the NEM. This includes $2.4 billion in funding in the recent 2025-26 state budget. CopperString is listed as an anticipated project in AEMO's Transmission Augmentation Information page[53].

Only the Townsville to Hughenden connection will be modelled as a REZ network expansion. Insufficient data is available to AEMO at this time to capture the currently off-grid load and development opportunities at Mount Isa and the broader western minerals province; the full connection may be considered in future planning activities.

[47] For more information, see https://www.energyco.nsw.gov.au/projects/waratah-super-battery.

[48] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[49] See https://www.energyco.nsw.gov.au/cwo.

[50] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[51] At https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

[52] At https://www.epw.qld.gov.au/__data/assets/pdf_file/0019/36037/draft-2023-queensland-rez-roadmap.pdf.

[53] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Concessional finance

AEMO will seek to include concessional finance benefits in the 2026 ISP to the extent those benefits will be shared with consumers for projects where funding is publicly committed or an agreement is sufficiently likely to be executed, consistent with the recommended approach in the AER's *Cost Benefit Analysis Guidelines*[54]. Details regarding concessional finance will be maintained on the Transmission Augmentation Information Page[55].

Given the ISP includes the consideration of projects prior to the RIT-T stage (or equivalent for jurisdictional investment frameworks) that are at a relatively early stage of development, it may be premature to consider concessional finance benefits for such projects in the ISP.

AEMO will rely on advice from the relevant government funding body and the AER on the appropriateness of including concessional finance for a specific ISP project. In applying this approach, AEMO does not expect that concessional finance benefits will be used to identify a newly actionable ISP project as actionable that would not otherwise be actionable without concessional finance. Instead, concessional finance is typically expected to be applied on projects that the ISP has already identified as actionable and have firm or imminent concessional finance agreements.

AEMO's approach to the treatment of concessional finance in the 2026 ISP is detailed in Section 2.8 of AEMO's *Electricity Network Options Report*.

Jurisdictional landholder payment schemes

In some jurisdictions, landholder payment schemes have been established to provide payments to landholders for hosting transmission infrastructures. These payments are in addition to any compensation that is paid under conventional land acquisition frameworks. AEMO will consider the inclusion of landholder schemes listed in this section in the ISP. If new landholder payment schemes are announced, AEMO will use reasonable endeavours to model them.

In accordance with the AER's *Cost Benefit Analysis Guidelines*, the cost of schemes that are funded by governments will be treated as an externality which does not influence the ISP's cost benefit analysis (CBA) as this is a transfer of wealth between parties external to the market (from governments to landholders). On the other hand, schemes that are funded by consumers (for example, via regulated transmission charges) will be included in the modelling and CBA.

New South Wales

In October 2022, the New South Wales Government established a Strategic Benefit Payments Scheme[56] for new major transmission projects. Under this scheme, private landowners hosting new high voltage transmission projects critical to the energy transformation and future of the electricity grid will be paid a set rate of $200,000 (in real 2022 dollars) per kilometre of transmission hosted, paid out in annual instalments over 20 years.

[54] At https://www.aer.gov.au/industry/registers/resources/reviews/2024-review-cost-benefit-analysis-and-regulatory-investment-test-guidelines/final-decision.

[55] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[56] See https://www.energyco.nsw.gov.au/sites/default/files/2023-01/overview-strategic-benefit-payments-scheme.pdf.

Queensland

Taking effect from May 2023, Powerlink's SuperGrid Landholder Payment Framework[57] offers payments to landowners that host new transmission infrastructure. Powerlink has also become the first transmission company in Australia to offer payments to landholders with properties adjacent to new transmission infrastructure. To represent this framework, AEMO will apply a cost of $230,000 (in 2023 dollars) per km of new transmission, paid out in a lump sum – noting that landholders can decide between a lump sum or annualised payments.

Tasmania

TasNetworks is establishing a Strategic Benefit Payments Scheme[58] to compensate landholders impacted by major transmission developments for the North West Transmission Developments. These payments will be in addition to those afforded under the *Land Acquisition Act 1993 (Tas)*. Once the specific details of the Strategic Benefit Payments Scheme are finalised, AEMO will include the costs in the ISP if appropriate.

Victoria

The Victorian Government announced in 2023 it will pay landholders whose properties host new power transmission lines $200,000 over a 25-year period in annual instalments indexed to inflation, to help smooth the state's transition to a 95% renewable grid by 2035. As this scheme is government-funded to landholders, and therefore an externality to the CBA, it will not be included in the modelling.

3.1.7 Nuclear technology

AEMO is technology-agnostic in its planning functions, and in particular in its assessment of generation options in identifying power system needs in the ISP. Rather, AEMO's analyses identifies efficient combinations of generation, storage and network developments to provide a reliable and secure power system for consumers.

Currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act (1999)* (C'th) prohibits the Federal Government from approving the construction or operation of a nuclear installation that is for the purpose of generating electricity. This is current legislation that prohibits a particular electricity generation technology, and as such AEMO cannot consider the technology option in any of its scenarios.

If this legislation were changed, AEMO would endeavour to include the new policy, noting that AEMO would need to develop and consult on the new inputs and assumptions relevant to each technology.

3.1.8 Policies affecting consumer demand

Numerous state and federal policies support investment in energy savings measures and the development of CER, including small-scale technology certificates (STCs) and Australian carbon credit units (ACCUs).

[57] See https://www.powerlink.com.au/sites/default/files/2023-05/SuperGrid-Landholder-Payment-Framework.pdf.

[58] See https://www.tasnetworks.com.au/poles-and-wires/planning-and-developments/north-west-transmission-developments/information-for-landholders.

Energy efficiency policies

Australian governments have implemented a range of energy efficiency policies that encourage investments in activities to lower energy consumption, including:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2010, the National Construction Code (NCC) 2019, NCC 2022, and NCC 2025[59].
- The Nationwide House Energy Rating Scheme (NatHERS), which is a pathway for new dwelling designs to demonstrate compliance with the NCC 2022.
- Building rating and disclosure schemes of existing buildings such as the National Australian Built Environment Rating System (NABERS) Energy for Offices and Commercial Building Disclosure (CBD).
- National Framework for Disclosure of Residential Energy Efficiency Information sets out high-level policy settings for future energy performance disclosure regimes.
- The Equipment Energy Efficiency (E3) program (or Greenhouse and Energy Minimum Standards [GEMS]) of mandatory energy performance standards and/or labelling for different classes of appliances and equipment.
- State-based schemes, including the New South Wales Energy Savings Scheme (ESS), the Victorian VEU program, the South Australian Retailer Energy Productivity Scheme (SA REPS), and the Australian Capital Territory's Energy Efficiency Improvement Scheme.
- The National Energy Performance Strategy (NEPS)[60], which provides a framework for policies that improve energy performance through energy efficiency, demand flexibility, and electrification or fuel switching. Energy efficiency policies such as the NCC are considered supporting actions under the NEPS.
- The Clean Energy Finance Corporation (CEFC) Household Energy Upgrades Fund (HEUF).

CER and electric vehicle (EV) policies

Australian governments have announced numerous policies to encourage CER investment, including:

- The Small-scale Renewable Energy Scheme (SRES) to encourage investment in small-scale photovoltaics (PV).
- The Federal Government's Cheaper Home Batteries Program to encourage uptake of battery storage.
- The New South Wales Consumer Energy Strategy, which includes funded actions to give one million households access to rooftop solar and a battery system by 2035, rising to nearly 1.5 million by 2050.
- The Victorian Government's Solar Homes Program to enable the installation of solar systems, hot water systems and batteries, for over one million homes to be powered by renewable energy.
- Governments have also promoted increased uptake in EVs through:
  - The Federal Government's New Vehicle Efficiency Standard (NVES) which requires each manufacturer to meet per kilometre efficiency standards for new cars, 4WDs and utility vehicles.

---

[59] NCC 2025 is undergoing continued development. See https://consultation.abcb.gov.au/engagement/ncc-2025-public-comment-draft/.

[60] See https://www.dcceew.gov.au/energy/strategies-and-frameworks/national-energy-performance-strategy.

- EV infrastructure initiatives funded under the New South Wales Government's EV Strategy to ensure that EVs represent most new car sales by 2035.
- Victoria's Zero Emissions Vehicle Roadmap, which aims for 50% of light vehicle sales to be zero emission vehicles (ZEVs) by 2030, and for all public transport buses to be ZEVs from 2025.
- Queensland's Zero Emission Vehicle Strategy 2022-2032 which plans for ZEVs to account for 50% of new passenger vehicle sales by 2030, and 100% by 2036. Queensland has also committed to reducing tailpipe emissions from all government vehicles by 10% by 2030.
- The South Australian Government's goal for 170,000 EVs by 2030 and one million EVs to be integrated into the electricity system over the next 20 years.

In addition to the above, other jurisdictional schemes exist that support consumer investments in the energy transition. For example, Tasmania's 'Energy Saver Loan Scheme' provides interest-free loans for a range of potential investments in cooking, heating, energy efficiency and CER applications, including EV chargers. While not directly influencing the CER uptake forecasts, AEMO acknowledges the positive contribution that other supporting schemes may have on consumer energy affordability.

New South Wales Energy Security Safeguard

New South Wales has a target for energy efficiency savings through its established Energy Security Safeguard[61], both in general through the Energy Savings Scheme[62], and at time of peak demand through the Peak Demand Reduction Scheme (PDRS)[63]. Both are modelled, with details in Section 3.3.12 for energy efficiency and Section 3.3.15 for the PDRS (the PDRS is explicitly included in the emissions targets statement).

Victoria Gas Substitution Roadmap

The Victorian Government released its Gas Substitution Roadmap[64] in October 2022 (updated in 2024[65]) to support net zero emissions in Victoria. The Roadmap outlines options for replacing gas usage (such as energy efficiency, electrification, hydrogen and biogas) to reduce emissions and consumer costs. On 1 January 2024, the Victoria Planning Provisions were amended to ban new residential gas connections for developments requiring a planning permit[66].

Australian Capital Territory ban on new gas connections

The Australian Capital Territory Parliament in June 2023 passed the *Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Act 2023*[67], allowing the Australian Capital Territory Government

[61] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard.

[62] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/energy-savings-scheme.

[63] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme.

[64] See https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap.

[65] See https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap/gas-substitution-roadmap-update-2024.pdf.

[66] See https://www.planning.vic.gov.au/guides-and-resources/strategies-and-initiatives/victorias-gas-substitution-roadmap.

[67] See https://www.legislation.act.gov.au/b/db_66446/.

to develop regulation banning new gas connections in the territory. Regulation preventing new gas network connections in most areas commenced on 8 December 2023[68].

3.1.9 Summary of changes in policy settings

Table 6 below provides changes in policy settings and their inclusion in this 2025 IASR compared to the Draft 2025 IASR.

Table 6 Policy changes since the Draft 2025 IASR

Jurisdiction	Federal	New South Wales	Queensland	Tasmania	South Australia
Policy	Cheaper Home Batteries Program	Peak Demand Reduction Scheme	Renewable Energy Targets	Vehicle Stamp Duty Exemption (EVs)	Hydrogen and Jobs Plan
Draft 2025 IASR Status	Not announced	Included	Included	Included	Included
2025 IASR Status	Included	Removed	Withdrawn	Concluded	Discontinued

Table 7 provides changes in policy settings and their inclusion in this 2025 IASR compared to the 2023 IASR.

Table 7 Policy changes since the 2023 IASR

Policy area	Jurisdiction	Change type	Details
Emission reduction	Federal	Added	Safeguard Mechanism
	Queensland	Added	30% reduction below 2005 levels by 2030, 75% reduction by 2035, and net zero by 2050 in the *Clean Economy Jobs Act 2024*
	Victoria	Updated	Targets now legislated under *Climate Change and Energy Legislation Amendment (Renewable Energy and Storage Targets) Act 2024*
Renewable energy (targets)	Federal	Added	Capacity Investment Scheme
	New South Wales	Expanded	Now also includes REZ Access Schemes
	South Australia	Added	Target is 100% by 2027 (pending legislation)
	Queensland	Removed	Queensland Renewable Energy Target (QRET) targets (50% by 2030, 70% by 2032, 80% by 2035) removed in 2025 IASR
Storage targets	New South Wales	Expanded	Expanded to 2 GW/16 GWh by 2030 and 28 GWh by 2034
	Queensland	Updated	Borumba now listed as anticipated project
Hydrogen policies	Federal	Added	$2/kg Hydrogen Production 10-year Tax Incentive
	South Australia	Removed	Hydrogen and Jobs Plan removed (250 MW electrolyser, 200 MW generation)
Offshore wind	Victoria	Updated	Legislated offshore wind targets of 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040.
Transmission support	Federal	Added	Concessional Finance
Electric vehicles	Federal	Added	New Vehicle Efficiency Standard, Driving the Nation, and government fleet purchases.
	Australian Capital Territory	Expanded	New ZEV sales target 80-90% by 2030

[68] See https://www.climatechoices.act.gov.au/energy/canberras-electrification-pathway/preventing-new-gas-network-connections#:~:text=Compliance%20and%20enforcement-,Overview,and%20electrify%20Canberra%20by%202045.

Policy area	Jurisdiction	Change type	Details
	Queensland	Added	ZEV 50% sales by 2030, 100% by 2036
	South Australia	Expanded	EV target 170,000 by 2030, 1 million over 20 years
	Tasmania	Added	100% government fleet EV by 2030
	Tasmania	Removed	Stamp duty waiver (concluded)
	Victoria	Expanded	ZEV Roadmap target 50% light vehicles sales by 2030
Energy efficiency	Federal	Added	Household Energy Upgrades Fund
	Australian Capital Territory	Added	ACT Energy Efficiency Improvement Scheme
Other government policies	Queensland	Removed	Clean energy hubs conversion no longer listed

3.2 Emissions and climate assumptions

Decarbonisation is a significant driver affecting the pace of the energy transition. Traditional drivers of energy infrastructure development such as load growth or asset replacement need to be considered alongside actions needed to reduce emissions. Additionally, the pace of change will be affected by both domestic and global influences.

AEMO scenarios in this 2025 IASR are underpinned by national carbon budgets that are compatible with global temperature targets (relating to Representative Concentration Pathways [RCPs], see Section 3.2.2 for more details) by aligning to International Energy Agency (IEA) World Energy Outlook (WEO) 2024 scenarios.

AEMO develops carbon budgets to apply to the electricity sector by engaging multi-sectoral modelling to identify the decarbonisation efforts across the economy needed to meet the temperature rise goals associated with each scenario. The model leverages a collection of technologies that will contribute to reduce emissions in a growing economy, with four of the critical levers being:

- producing low carbon electricity,
- electrifying, and fuel-switching away from emissions-intensive fuels,
- investing in energy efficiency improvements to increase energy productivity, and
- delivering other emissions savings from non-energy sectors, such as through improved approaches to agriculture and forestry, as well as the development of technologies to capture and store emissions (known as emission sequestration).

To achieve the emissions pathways therefore relies on actions not just within the energy sector but also in other parts of Australia's economy, including the agriculture and land use sectors. Least-cost solutions for Australia's economy will consist of a mixture of technologies (discussed in Section 3.3.4), and earlier actions to decarbonise will reduce the need for more aggressive actions later.

The multi-sectoral modelling translates the national carbon budgets to NEM-wide carbon budgets that underpin the ISP, as discussed in the *ISP Methodology*[69]. These NEM-wide carbon budgets recognise that the electricity

[69] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology.

sector has a key role to play as an early mover by enabling the decarbonisation of other sectors via electrification and increased energy efficiency.

AEMO must consider the policies in the AEMC emissions targets statement under NER 5.22.3(b)(1) in determining the power system needs to be met by the ISP and how the ISP can contribute to achieving the emissions reduction targets as part of achieving the national electricity objective. The scenarios therefore also include a number of complementary carbon budgets and state government policy as described in the previous sections. The derivation of NEM-wide and state-level targets is further discussed in Section 3.2.3.

3.2.1 Alignment to IEA World Energy Outlook scenarios

AEMO's 2025 IASR scenarios have been aligned to the IEA 2024 WEO scenarios to anchor them to global narratives on developments and commitments to the Paris Agreement. This means AEMO's scenarios are consistent with global economic settings and temperature goals. IEA's scenarios provide a global backdrop to economic and multi-sectoral modelling. They describe the transition towards a lower carbon economy with differing levels of ambition and the associated changes in energy consumption and production at international and regional level.

AEMO's 2025 IASR scenarios align to the WEO scenarios which inform the economic settings and forecasts. The scenarios also help provide context for Australia's share of meeting various temperature outcomes as well as guidance to the multi-sectoral modelling regarding fossil fuel export projections and uptake rate and limits on energy efficiency and electrification across scenarios.

The 2024 WEO did not contain the *Sustainable Development Scenario* (SDS) which was aligned with the 2023 IASR *Step Change*. However, as discussed below, the narrative of the *Announced Pledges Scenario* aligns closely with the *Step Change* scenario as presented in the 2025 IASR.

The 2024 WEO scenarios and how they align with the 2025 IASR scenarios are summarised in **Table 8**.

Table 8 The 2024 IEA WEO scenario summaries

IEA scenario	Summary narrative
***Net Zero Emissions by 2050* (NZE)**	This is a normative scenario that maps a transition pathway limiting global warming to within 1.5°C by the end of the century with a 50% probability but with limited overshoot. This scenario sees the most ambitious deployment of electrification and energy efficiency, with consumption declining by 2030. By 2050, clean energy meets 90% of global energy demand with around one-third of the remaining fossil fuel demand being fully abated and another third offset by negative emissions.
***Announced Pledges Scenario* (APS)**	The *Announced Pledges Scenario* was added in the 2021 WEO. It explores the full and timely implementation of national energy and climate goal, including net zero emission targets, and its impact on the energy sector. In this scenario, electrification and energy efficiency, as well as deployment of low-carbon hydrogen, increases relative to STEPs. Consumption peaks in 2030 and then slowly declines. The share of clean energy in global energy demand increases to nearly three-quarters by 2050. This scenario results in an increase in median surface temperatures over pre-industrial levels of 1.7°C with a 50% probability.
***Stated Policies Scenario* (STEPS)**	This scenario is based on current policy settings and also considers the implications of industrial policies that support clean energy supply chains as well as measures related to energy and climate. The scenario sees a decline in the share of fossil fuels in primary energy demand from 80% in 2023 to 58% by 2050. Electrification of transport and heat, as well as energy efficiency, all play a role. By the end of the century, the scenario is aligned with median surface temperature increases over pre-industrial levels of 2.4°C with 50% probability.

In mapping the IEA's 2024 scenarios to the scenarios in this 2025 IASR, AEMO makes the following observations:

- With a more stringent emission target aiming to achieve the aspirational 1.5°C target of the Paris Agreement and with significant structural changes in global energy consumption underpinning its narrative, the ***Accelerated Transition*** scenario is most closely aligned to NZE.
- The IEA's APS scenario is consistent with the Paris Agreement target of limiting temperature increase to well below 2°C, which aligns to AEMO's ***Step Change*** scenario.
- The ***Slower Growth*** scenario aligns best to STEPS as it reflects currently legislated or funded policy positions only. It also fails to meet the Paris Agreement globally despite Australia fulfilling its commitments under its Nationally Determined Contribution submitted to the United Nations Framework Convention on Climate Change.

3.2.2 Alignment with the Inter-governmental Panel on Climate Change (IPCC) Representative Concentration Pathways (RCPs)

The 2025 IASR scenarios also map to the RCPs framework used by the IPCC[70]. There are multiple RCPs defined, representing trajectories of emissions and land-use and their resulting impact on temperate increases. AEMO scenarios map to these temperature pathways as follows:

- The ***Accelerated Transition*** scenario sees a global drive to limit temperature rise to 1.5°C by the end of the century. It is best aligned to RCP1.9 which targets that 1.5°C outcome.
- The ***Step Change*** scenario is aligned to RCP2.6, which is consistent with a temperature rise less than 2°C by the end of the century and in line with the Paris Agreement.
- The ***Slower Growth*** scenario is aligned to RCP4.5, which is consistent with a temperature rise of approximately 2.7°C by the end of the century.

The mapping of scenarios to IEA scenarios and RCP temperature targets is summarised in **Table 9**.

By mapping the 2025 IASR scenarios to global outlooks in this manner, forecast components that are influenced by global conditions and broader economic narratives may be developed in a more internally consistent manner.

Table 9 Mapping of scenarios between studies

2025 IASR scenario	2024 WEO scenario	RCP Framework
Slower Growth	STEPS	RCP4.5
Step Change	APS	RCP2.6
Accelerated Transition	NZE	RCP1.9

3.2.3 Translating international climate scenarios to NEM-wide carbon budgets

To ensure the scenarios adopt emissions abatement outcomes consistent with the scenario narratives, CSIRO's multi-sectoral modelling applies Australian economy-wide cumulative carbon budgets that are aligned to the WEO scenarios and RCPs described in the previous section for each scenario. Australia's Nationally Determined Contribution of 43% emissions reduction below 2005 levels by 2030 under the Paris Agreement and commitment to net zero emissions by 2050 are also imposed in the multi-sectoral modelling to ensure alignment with federal

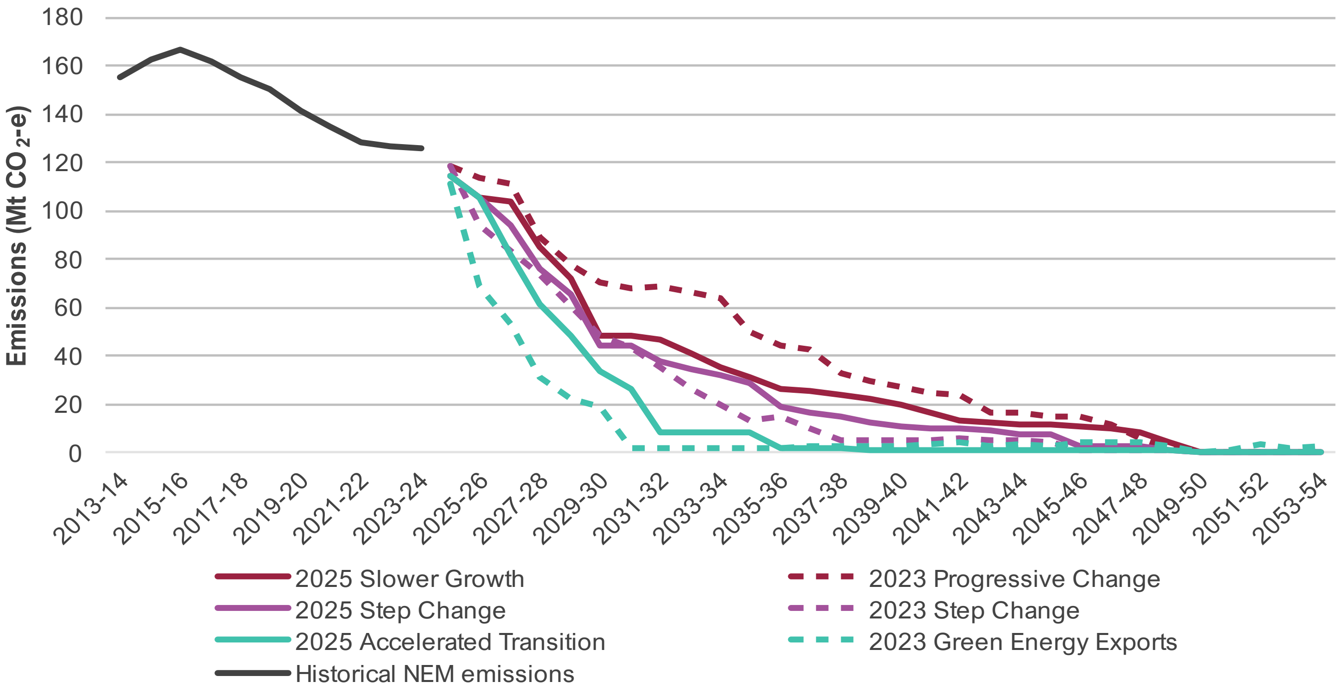
[70] See, for example, page 65 in https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_LongerReport.pdf.

emissions reduction policy. The emissions outcomes from the multi-sectoral modelling are then used to derive a carbon budget for the NEM to be applied in AEMO's modelling, taking into consideration the key role that the electricity sector has in broader decarbonisation of the Australian economy.

NEM-wide carbon budgets

Figure 2 presents the NEM emissions trajectories produced by the multi-sectoral modelling from 2024-25 to 2053-54 by scenario and compares it with historical NEM emissions. The emissions trajectories from the 2023 IASR (as produced by multi-sectoral modelling from 2023) are also included for comparison. These emissions trajectories are driven by assumptions regarding long-term temperature outcomes that are scenario-specific, as discussed in previous sections. These trajectories reflect the interaction between electricity sector emissions reduction opportunities and emissions reduction and offsets in other sectors, as observed in multi-sectoral modelling outcomes.

Figure 2 Actual and forecast NEM emissions trajectories from multi-sectoral modelling, all scenarios



Compared to the 2023 IASR, NEM temperature-linked carbon budgets have reduced in *Slower Growth* and increased in *Step Change* and *Accelerated Transition:*

- In *Slower Growth*, the inclusion of updated federal and state energy policies that AEMO assesses as eligible to be considered in the ISP (as outlined in Section 3.1), applied in the multi-sectoral modelling, results in a sharper reduction in emissions in the period to 2030 compared to outcomes from *Progressive Change* in the 2023 IASR which did not include them, leading to an overall reduction in carbon budget. The consistent inclusion of these policies in all three scenarios also drives the closeness in emissions trajectories across scenarios up to 2030.

- In *Step Change*, greater assumed sequestration activities across the modelling horizon and upward revisions to existing land use, land-use change, and forestry (LULUCF) inventories is allowing for greater NEM emissions.
- In *Accelerated Transition*, the economy-wide carbon budget applied in the multi-sectoral modelling has been updated to align with recent modelling conducted for the G1.5 scenario in the Climate Change Authority's *Sectoral Pathways Review*[71], which is similarly aligned with the WEO's NZE scenario in limiting warming to 1.5°C. This change has resulted in an increase to the NEM cumulative carbon budget compared to the *Green Energy Exports* scenario from the 2023 IASR.

In line with the *ISP Methodology*, AEMO will apply the aggregate NEM emissions from the multi-sectoral modelling as cumulative carbon budgets across the ISP modelling horizon. **Table 10** presents the cumulative carbon budgets that will be applied for each scenario.

An additional carbon budget to 2030 is applied across all scenarios in ISP modelling to ensure consideration of the emissions reduction targets stipulated in the *Climate Change Act (2022)*. The Act sets out an Australia-wide carbon budget of 4,381 $MtCO_2$-e over the period from 2020-21 to 2029-30, as well as a 43% reduction in emissions below 2005 levels by 2030. To convert this to a NEM-wide carbon budget, a trajectory for future economy-wide emissions was derived by fitting annual emissions to 2030 to satisfy the mentioned economy-wide targets then calculating the NEM's share of this trajectory as a pro-rata share based on historical NEM emissions according to Australia's National Greenhouse Accounts[72]. The carbon budget is then calculated as the cumulative sum of emissions targets to 2030, resulting in a budget of 418 $MtCO_2$-e to be applied across all scenarios.

Table 10 NEM cumulative carbon budgets in 2025 IASR modelling ($MtCO_2$-e)

Scenario	Federal Government's 2030 carbon budget from 2026-27 to 2029-30	Long-term temperature-linked carbon budget from 2026-27 to 2049-50
Slower Growth	418	727
Step Change	418	583
Accelerated Transition	418	303

Table 11 compares the NEM temperature-lined carbon budgets to those presented in the 2023 IASR over comparable horizons, highlighting the reduction in budget in *Slower Growth* and increase in *Step Change* and *Accelerated Transition* as discussed above.

Table 11 Comparison of long-term temperature-linked carbon budgets over the period from 2024-25 to 2049-50 between 2023 IASR and 2025 IASR ($MtCO_2$-e)

Scenario	2023 IASR	2025 IASR
Slower Growth [A]	1,203	943
Step Change	681	798
Accelerated Transition [B]	353	518

A. Compared to the *Progressive Change* scenario from the 2023 IASR.
B. Compared to the *Green Energy Exports* scenario from the 2023 IASR.

[71] See https://www.climatechangeauthority.gov.au/sector-pathways-review.

[72] At https://www.greenhouseaccounts.climatechange.gov.au/.

State-level carbon budgets

As discussed in Section 3.1, all NEM jurisdictions have legislated state-based emissions reduction targets, which AEMO incorporates as carbon budgets for NEM activities within each jurisdiction. The targets for New South Wales and Queensland are newly legislated since the publication of the 2023 IASR, while South Australia's target has been updated by the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Act 2025*.

To derive state-level carbon budgets, economy-wide emissions reduction targets for each state presented previously in **Table 4** are scaled to electricity sector targets using factors based on NEM emissions figures from the Clean Energy Regulator and economy-wide emissions figures from Australia's National Greenhouse Accounts.

The state carbon budgets are developed by applying a linear trend between key milestone years that are stated in any state target (for example, if needing to meet a specific target by 2030 and by 2050, then the trajectory for achieving these is applied linearly between the first modelling year and 2030, and again from 2030 to 2050). Carbon budgets are then calculated as the cumulative carbon targets across all years.

Table 12 below presents the resulting carbon budgets that will be modelled for each of the states. More information is available in the 2025 *Inputs and Assumptions Workbook*.

Table 12 State-level carbon budgets ($MtCO_2$-e)

Region	2026-27 to 2029-30	2030-31 to 2049-50
New South Wales	126	228
Queensland	175	248
South Australia [A]	7	15
Victoria [A]	123	139

A. Carbon budgets for South Australia and Victoria have been re-calculated to use a consistent approach to mapping calendar to **financial** years.

As discussed in Section 3.1.4, targets for Tasmania and the Australian Capital Territory have already been achieved and therefore do not need to be explicitly included in the modelling.

3.3 Consumption and demand: historical and forecasting components

AEMO updates its projections of energy consumption and demand at least annually[73]. AEMO's Forecasting Approach applies methodologies that examine electricity and gas customer segments, and enables forecasting of key forecast components affecting those customer segments. This approach enables appropriately granular models to be deployed in a way that provides transparency of method and influence on energy consumption, and enables scenario diversity where key uncertainties exist. Updates to these forecast components are informed by stakeholder consultation through the FRG and other engagement opportunities where appropriate, and consider a range of forecasting components, including:

- economic and population growth drivers,
- climate and weather,

[73] Updated forecasts (within a year) can be issued in case of material change to input assumption.

- CER,
- large industrial loads (LILs), informed by stakeholder surveys,
- data centres,
- electrification and other fuel-switching opportunities in the context of possible decarbonisation pathways, and
- energy efficiency.

AEMO uses a range of historical data to train models for developing electricity consumption component forecasts. Historical data are updated at varying frequencies, from live meter data to monthly, quarterly, or annual batch data, and include:

- operational demand meter reads,
- estimated network loss factors,
- other non-scheduled generators,
- distributed PV uptake,
- battery storage uptake,
- gridded solar irradiance and resulting estimated distributed PV normalised generation, and
- weather data (such as temperature and humidity levels).

The *Electricity Demand Forecasting Methodology*[74] and *Gas Demand Forecasting Methodology Information Paper*[75] detail how model inputs are applied to develop electricity and gas forecasts for energy consumption, and maximum and minimum demand. The resulting aggregate forecasts that consider these components, and apply AEMO's forecasting approach described in these methodologies, are available on AEMO's Forecasting Portal[76].

The following sections describe the individual model inputs and component forecasts. Where appropriate, comparisons are made with this 2025 IASR's scenarios against relevant 2023 IASR scenarios.

3.3.1 Historical demand data

Input vintage	April 2025 for demand data April 2025 for loss data April 2025 for auxiliary load data
Source	SCADA/electricity market management system (EMMS)/National Metering Identifier (NMI) Data Generation Information page AER, Western Australia-based retailer Synergy and network operators
Update process	Continuously updated

[74] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

[75] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/gas-demand-forecasting-methodology-2024.pdf.

[76] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal.

Operational demand

Operational demand 'as generated' is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator. Operational demand 'as generated' refers to the demand that is served from electricity that is generated from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units[77].

Generator auxiliary load

Estimates of historical auxiliary load are determined by using the auxiliary rates provided by participants through AEMO's Generation Information survey process. This is used to convert between operational demand 'as generated' (which includes generator auxiliary load) and operational demand 'sent-out' (which is net of the auxiliary component).

Network losses

The AER and network operators provide AEMO with annual historical transmission loss factors. The AER also provides AEMO with annual historical distribution losses which are reported to the AER by distribution companies. AEMO uses the transmission and distribution loss factors to estimate half-hourly historical losses across the transmission network for each region in megawatts or megawatt hours (MWh).

Large industrial loads

AEMO's *Electricity Demand Forecasting Methodology* defines a methodology for identifying large loads for inclusion in the LIL sector. AEMO collects the historical consumption of existing LILs from National Metering Identifier (NMI) meter data.

Residential and business demand

AEMO splits historical consumption data (excluding industrial loads identified above) into business and residential segments using a hybrid bottom-up and top-down approach, as detailed in Appendix A6 (Residential-business segmentation) of the *Electricity Demand Forecasting Methodology*. The hybrid approach is required given the inconsistent level of interval meter penetration in some regions, meaning that if insufficient penetration exists for interval data (bottom up), then basic meter analysis is required (top down). The bottom-up approach is based on sampling of AEMO residential meter data. The top-down approach considers consumption data provided by electricity distribution businesses to the AER as part of their Economic Benchmarking Regulatory Information Notice (RIN). AEMO must perform some calibration of the RIN data to bring it into alignment with AEMO's definition of delivered energy, as described in Appendix A6 of the *Electricity Demand Forecasting Methodology*.

In the WEM, AEMO applies the segmentation of residential and business historical consumption using a simplified top-down approach. This process makes use of aggregated residential data provided by the Western Australian Government owned retailer Synergy, combined with AEMO metering data for LILs.

[77] A small number of exceptions are listed in Section 1.2 of https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 3.3.7 for details.

3.3.2 Historical weather data

Input vintage	April 2025
Source	Bureau of Meteorology (BoM)
Update process	Continuously updated

AEMO uses historical weather data for training the annual consumption and minimum and maximum demand models as well as developing forecast reference year traces that provide a half-hourly representation of future demand and supply patterns.

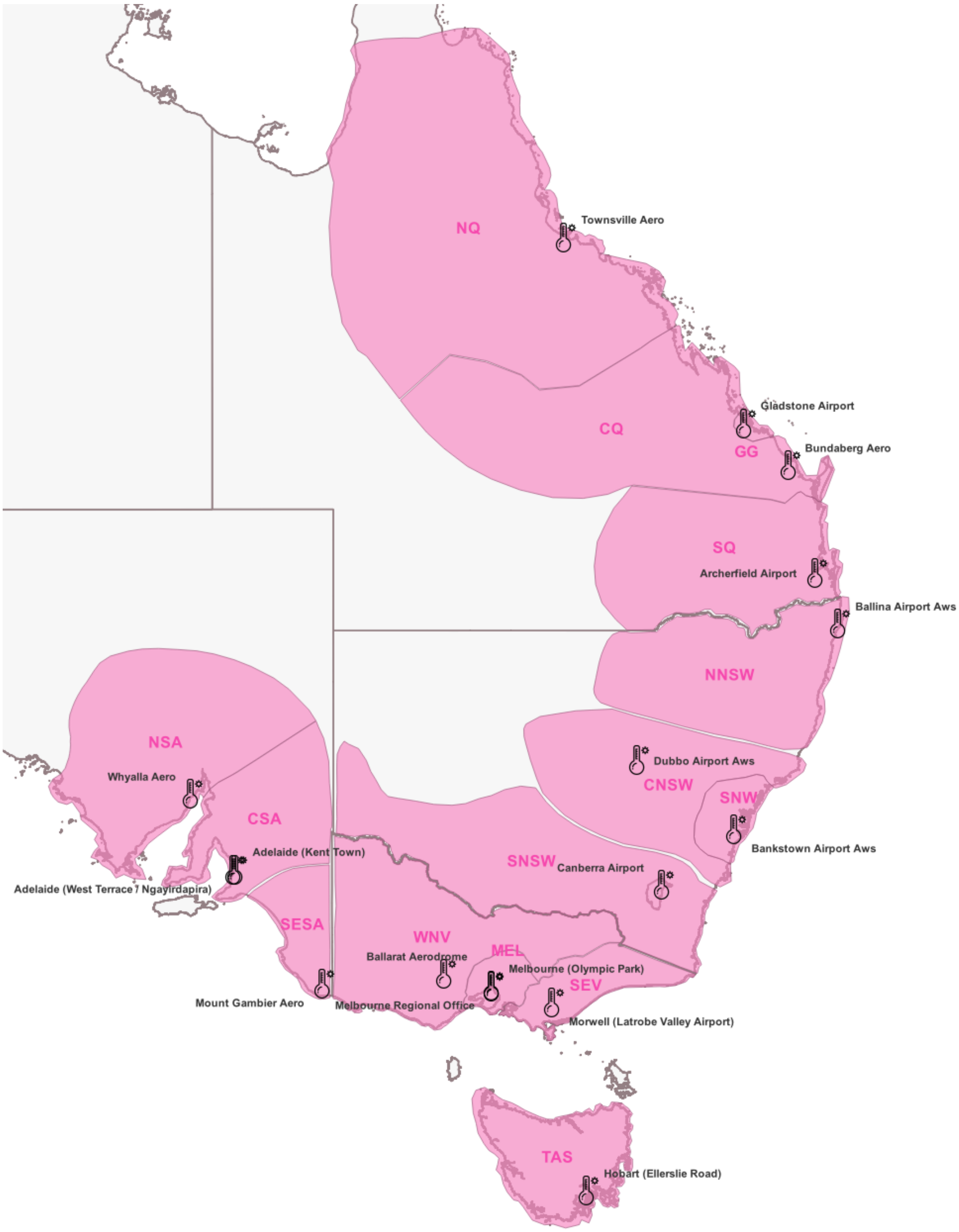
The historical weather data comes from the Bureau of Meteorology (BoM), using a subset of the weather stations that BoM makes available across Australia, as shown in **Table 13** and **Figure 3**. AEMO selected these weather stations based on data availability and correlation with forecast consumption or demand. AEMO's current *Electricity Demand Forecasting Methodology* uses one weather station per sub-region, except where weather stations have been discontinued, meaning that several weather stations are applied per region. This allows for appropriate consideration of weather differences that will apply across regions and sub-regions, when forecasting consumer demand. **Table 13** lists the weather stations for the sub-regions.

Table 13 Weather stations used in forecasting consumers' electricity use (sub-regional)

NEM sub-regional weather stations				
	Sub-region	**Station name**	**Date range**	**BoM site number**
New South Wales	**Central New South Wales (CNSW)**	Dubbo Airport AWS	January 1946 – Now	065070
New South Wales	**Northern New South Wales (NNSW)**	Ballina Airport AWS	November 1992 – Now	058198
New South Wales	**Sydney, Newcastle, Wollongong (SNW)**	Bankstown Airport AWS	January 1968 – Now	066137
New South Wales	**South New South Wales (SNSW)**	Canberra Airport	September 2008 – Now	070351
Queensland	**Central Queensland (CQ)**	Bundaberg Aero	January 1942 – Now	039128
Queensland	**Gladstone Grid (GG)**	Gladstone Airport	October 1993 – Now	039326
Queensland	**Northern Queensland (NQ)**	Townsville Aero	January 1940 – Now	032040
Queensland	**South Queensland (SQ)**	Archerfield Airport	April 1929 – Now	040211
South Australia	**Central South Australia (CSA)**	Adelaide (Kent Town)	January 1977 – July 2020	023090
		Adelaide (West Terrace)	July 2020 – Now	023000
South Australia	**Northern South Australia (NSA)**	Whyalla Aero	January 1945 – Now	018120
South Australia	**South East South Australia (SESA)**	Mount Gambier Aero	January 1941 – Now	026021

NEM sub-regional weather stations				
Tasmania	**Tasmania (TAS)**	Hobart (Ellerslie Road)	January 1882 – Now	094029
Victoria	**Greater Melbourne and Geelong (MEL)**	Melbourne Regional Office	January 1908 – Jan 2015	086071
		Melbourne (Olympic Park)	May 2013 – Now	086338
Victoria	**West and North Victoria (WNV)**	Ballarat Aerodrome	March 1908 – Now	089002
Victoria	**South East Victoria (SEV)**	Morwell (Latrobe Valley Airport)	January 1984 – Now	085280

Figure 3 Map of weather stations used in forecasting consumers' electricity use



3.3.3 Historical and forecast Other Non-Scheduled Generators (ONSG)

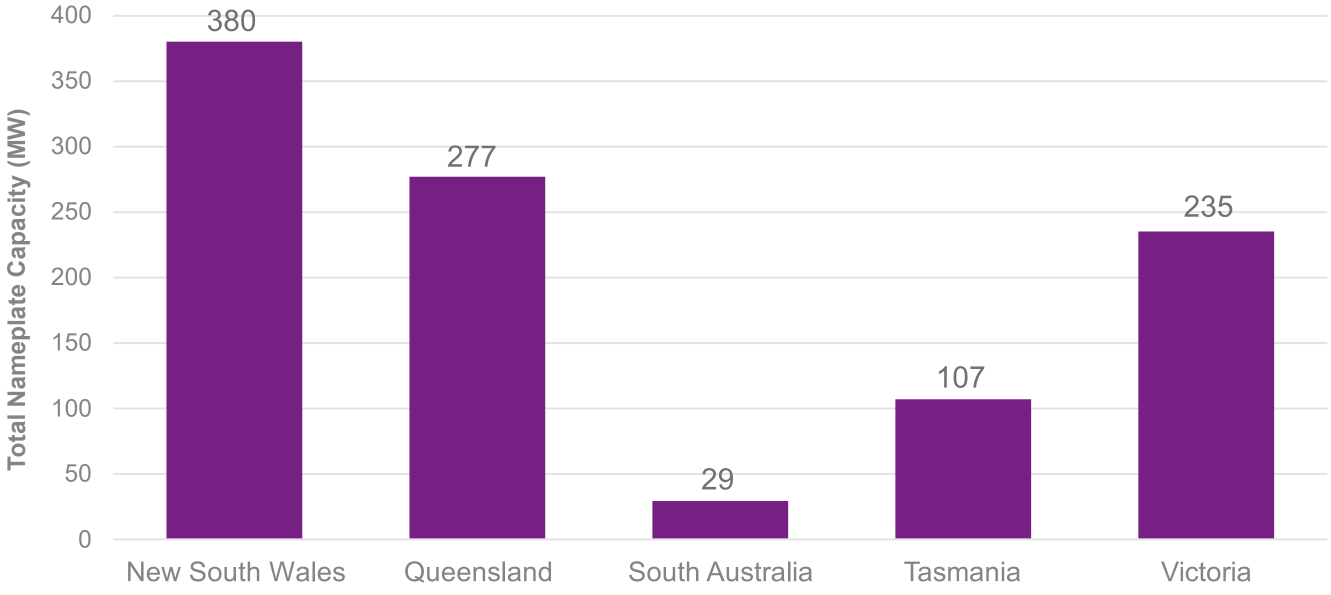
Input vintage	April 2025 for installed capacity (Generation Information page) June 2025 for historical and forecast ONSG generation
Source	Generation Information page Settlements data NMI data DER Register
Update process	Updated quarterly

AEMO reviews its list of other non-scheduled generation (ONSG), defined as in service generation under 30 MW and are not PV, using information from AEMO's Generation Information[78] dataset obtained through surveys, and supplements where applicable with submissions from network operators, the DER Register and relevant publicly available information where appropriate.

For ONSG generation, AEMO uses the generators' Dispatchable Unit Identifier (DUID) or NMI to collect historical generation output at half-hourly frequency.

AEMO's current view of ONSG is contained in the Generation Information page. As at the April 2025 release of Generation Information page, used for the development of the energy and demand forecasts, aggregate capacity by region is shown in **Figure 4** below. Note that this excludes any ONSG that is used solely as peaking capacity, as these generators are modelled as part of AEMO's DSP forecast instead (see Section 3.3.15).

Figure 4 Aggregate ONSG capacity, by NEM region (MW)



AEMO forecasts commissioning or withdrawal of ONSG generators based on firm commitment statuses of these generators in the short term and applying historical trends of ONSG by technology type (for example, gas or

[78] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

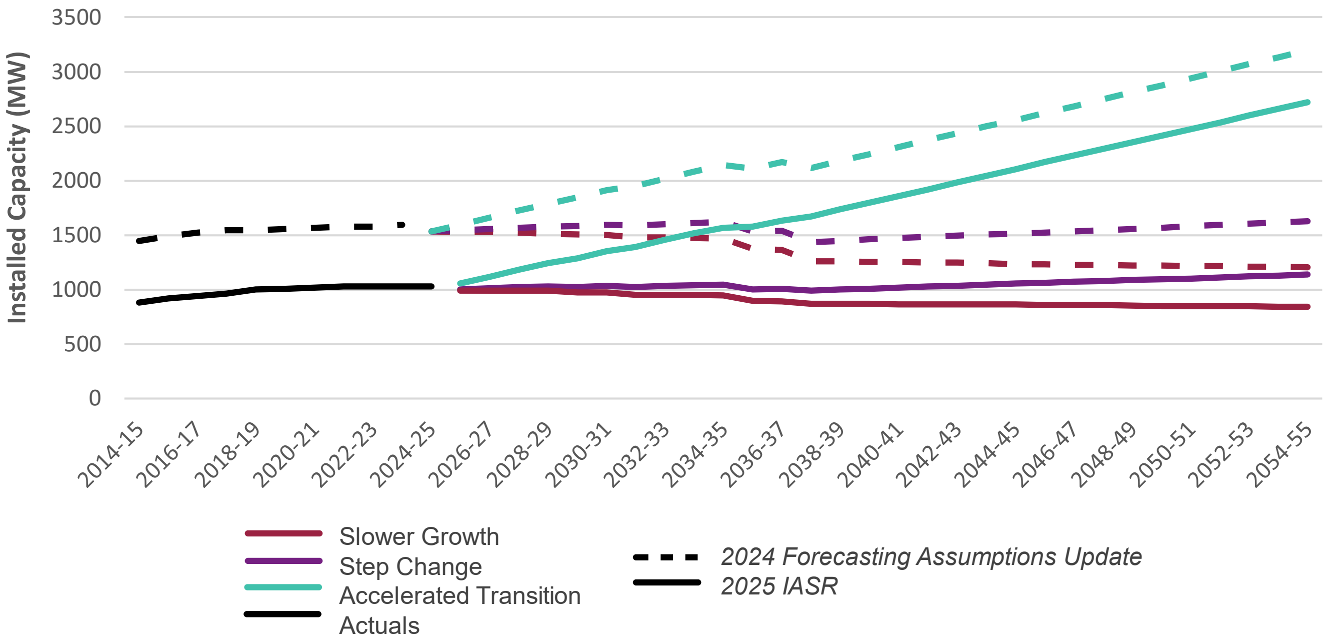
biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) on a scenario basis in the long term:

- For the *Step Change* scenario, the historical trend is applied without adjustment.
- For the *Slower Growth* scenario, the historical trend is lowered.
- For the *Accelerated Transition* scenario, significant growth is assumed, reflecting greater actions in decentralised renewable technologies – particularly small-scale wind farms, which are easier to integrate into the distribution networks, and biomass cogeneration plants that harness farm waste, sawmill residues, and sugar mill by-products, that would be aligned with accelerated actions to decarbonise Australia's economy to net zero, consistent with the scenario's objectives.

Figure 5 below compares the updated NEM-wide installed capacity forecasts for ONSGs under the three scenarios, alongside the historical actuals and the 2024 *Forecasting Assumptions Update* projections (shown as dashed lines). The chart highlights a general downward revision in forecast capacity compared to previous projections, primarily due to the refinement of the underlying generator list. This refinement reflects the removal of project survey records for all existing non-registered non-scheduled generating units, as outlined in the Generation Information table[79].

Historical capacity factors by technology type are used to forecast generation using the projected installed capacities, offsetting the electricity consumption in the forecast.

Figure 5 Forecast NEM-wide ONSG capacity (MW)



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

[79] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

3.3.4 Multi-sectoral modelling influences on demand forecasts

Input vintage	June 2025
Source	CSIRO multi-sectoral modelling
Updates since Draft 2025 IASR	Updated multi-sectoral modelling results based on AEMO and stakeholder feedback to CSIRO

AEMO engaged CSIRO to model least-cost pathways for the Australian economy to achieve the scenario-based emissions targets that consider demand drivers such as economic growth, energy efficiency, and CER investments including road transport EV uptake[80]. The scenarios also define the scale of activity to support export opportunities for global decarbonisation, such as the establishment of hydrogen and green commodity industries. This multi-sectoral modelling identifies the mix of energy forms appropriate to achieve these decarbonisation targets while supporting the economic activity described in the scenarios, including the opportunity to electrify emissions-intensive residential and commercial appliances and industrial processes, the potential role of emissions sequestration, the development opportunity for alternative gaseous fuels (such as hydrogen and biomethane) for those applications that are difficult or cost-prohibitive to electrify, and other emerging opportunities such as the creation of new, green manufacturing opportunities.

Using the CSIRO and Climateworks Centre (CWC) AusTIMES model, the multi-sectoral modelling approach provides whole-of-economy interactions, by simultaneously considering a range of options available to meet scenario-specific emissions targets at the least cost. The emissions targets align to specific global temperature outcomes, informed by the RCP and IEA WEO scenario definitions defined for each scenario (see **Table 8** and Section 3.2). While AusTIMES is inherently an economic model, non-economic considerations such as thermal comfort, health, and energy independence are implicit in the outcomes of the uptake of energy efficiency, electrification, and consumer energy resources.

To transition Australia's economy, the AusTIMES model seeks solutions across a range of alternative and often complementary technologies that will be key enablers of the decarbonisation of Australia's growing economy, with each scenario utilising these key decarbonisation levers to varying degrees considering uncertainty around future technology improvements, costs, and barriers to deployment.

In this modelling, four of the key levers are:

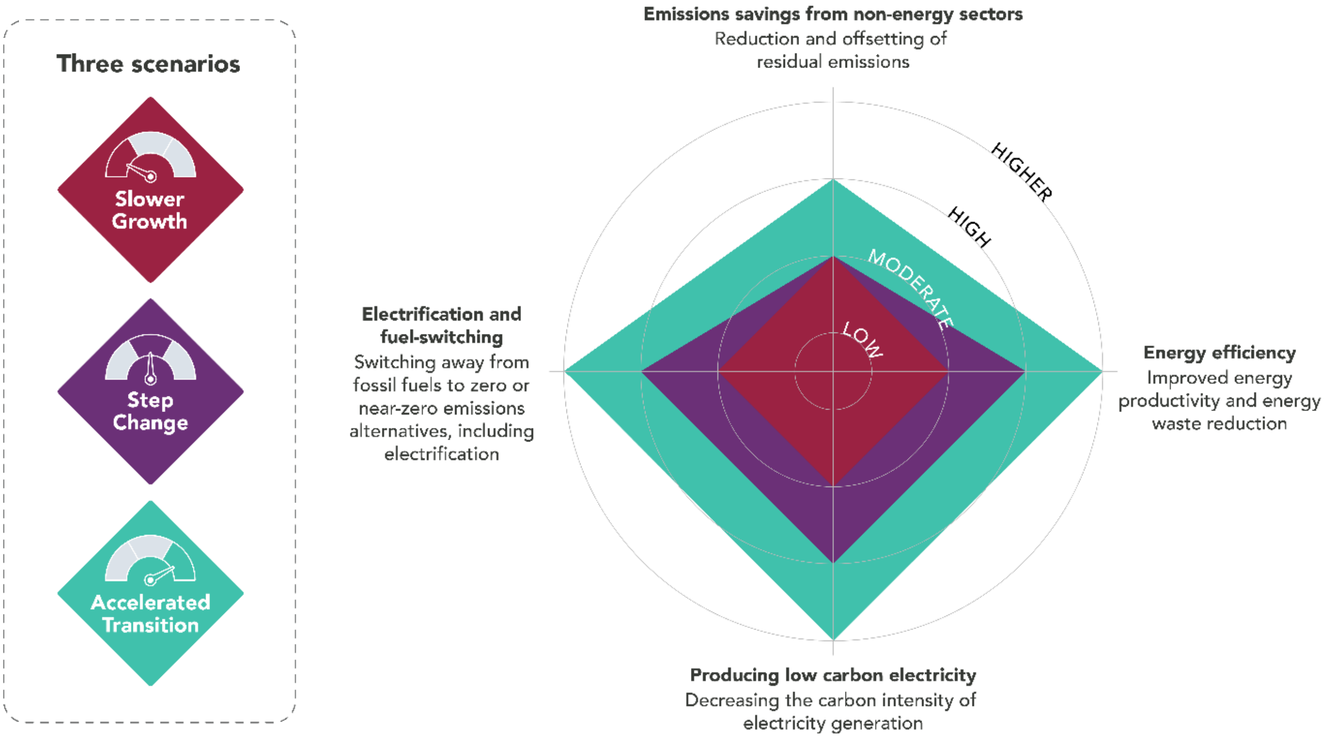
- **Producing low carbon electricity** – decreasing the carbon intensity of electricity generation to near zero through increasing penetration of renewable energy.
- **Electrification and fuel-switching** – switching away from fossil fuels to zero or near-zero emissions alternatives, including electrification and alternative gases.
- **Investing in energy efficiency** – investments to improve energy productivity and reduce energy waste.
- **Delivering other emissions savings from non-energy sectors** – reduction and offsetting of residual emissions through sequestration and other opportunities to reduce emissions, primarily in the land-use and agriculture sectors).

[80] Note, EV uptake projections are provided by an external consultant and are inputs to the multi-sectoral modelling. For more information, see Section 3.3.7.

AEMO's scenarios utilise these key levers in an internally consistent manner, supporting different paces of economic activity and decarbonisation levels.

Figure 6 illustrates the scale of utilisation of these decarbonisation levers across the scenarios.

Figure 6 Forecast utilisation of the key levers to reduce emissions, by scenario



AEMO incorporates selected components of the multi-sectoral modelling into this IASR. **Table 14** describes, at a high level, those key assumptions and outcomes.

Table 14 Key assumptions and outcomes from the multi-sectoral modelling

	Slower Growth	*Step Change*	*Accelerated Transition*
Electrification, excluding road transport, across NEM and WEM (Section 3.3.5) Note: EVs contribute significantly to electrification and are separately discussed in Section 3.3.7.	Weaker economic growth curtails investment in electrification across all sectors. Consistent with the other scenarios, electrification in the industrial sector drives electrification despite being relatively slower in *Slower Growth*. Under this scenario, more challenging economic conditions slow down the uptake of residential electrification.	In this scenario, the degree of investment in electrification is high, especially in manufacturing and other industrial activities, although less than *Accelerated Transition*. Gas consumption in the residential sector, such as that used for cooking and space or water heating, is displaced mainly by electricity, although a smaller portion is replaced with alternative gases such as biomethane.	Electrification is expected to provide aggressive emissions reduction objectives in this scenario in order to meet the scenario's carbon targets. Residential electrification occurs regardless of the age of existing appliances and is gradual initially but accelerates as dwellings increase and appliances reach end of life. The industrial sector is expected to have high uptake of electric alternatives in various applications, such as machinery, heating processes, and onsite transport. This scenario has the strongest amount of electrification overall.

	Slower Growth	*Step Change*	*Accelerated Transition*
Energy efficiency (Section 3.3.12) Note: multi-sectoral modelling energy efficiency outcomes presented here complement Strategy.Policy. Research. (SPR) policy-driven energy efficiency forecasts	Energy efficiency improvements are generally lower, although higher for residential natural gas due to greater assumed gas connections. The scale of energy efficiency improvements that contribute to meeting decarbonisation pathways alongside electrification, other fuel-switching, and carbon sequestration is a result of cost competitiveness and assumed uptake of the energy efficiency options within the multi-sectoral model. Even in *Slower Growth* energy efficiency contributes significantly to decarbonisation.	While energy efficiency is lower than in *Accelerated Transition*, sustainability is still a strong focus, with consumers and governments supporting the need to reduce Australia's collective energy footprint through adoption of greater energy efficiency measures. Energy efficiency improves by changes in building design, smart appliances, and digitalisation, amongst others.	The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles, supported by a higher degree of energy efficiency investments across many sectors. A higher uptake of savings occurs in industrial subsectors compared to buildings, particularly in the alumina and iron and steel industries. Greater uptake of efficient LED lighting, heat pump hot water systems, and improved heating, ventilation and air-conditioning systems deliver savings in buildings. While in industry, process improvements, small equipment upgrades, and large equipment upgrades occur at pace.
Carbon sequestration across NEM states (outlined in further detail below)	With *Slower Growth* aligned to a higher temperature outcome than other scenarios, sequestration activity begins later than other scenarios. Despite a slower start, sequestration activities are still a key part of the decarbonisation activities in Australia's economy, reaching 179 $MtCO_2$-e/ year by 2049-50. DAC is not deployed in this scenario.	With *Step Change* aligned to a <2.0°C future, the required pace of decarbonisation in the scenario is slower than in *Accelerated Transition*, resulting in more gradual use of sequestration. Sequestration activities instead ramp up to 162 $MtCO_2$-e/year by 2049-50. Sufficient use of land-based sequestration activities avoids the need for higher cost DAC in this scenario.	Significant levels of carbon sequestration are forecast to be necessary in this scenario to maintain alignment with the 1.5°C decarbonisation pathway for the Australian economy. Investments in new carbon sequestration solutions take effect from the mid 2030s, with increasing use to a peak of approximately 165 $MtCO_2$-e/year by 2043-44. Direct air capture (DAC) is expected to support emissions reduction from the early 2040s.
Fuel-switching to alternative gaseous fuels (Section 3.3.6)	The majority of hydrogen demand is for domestic use in the transport and industrial sectors, with minimal demand for hydrogen in green commodities, and no hydrogen export. Biomethane volumes are higher compared to the 2023 IASR, which had no volumes, although with small uptake replacing natural gas in the same sectors as the other scenarios.	Overall hydrogen volumes are lower than the 2023 IASR forecasts, due to zero exports assumption and lower calculated domestic hydrogen demand, despite the inclusion of small additional demand for hydrogen in green commodities. The majority of hydrogen demand is for use in the industrial, commodity and transport sectors. Biomethane volumes are higher compared to the 2023 IASR, with volumes replacing natural gas in the same sectors as the other scenarios.	Decarbonisation is occurring through switching of natural gas to electricity, biomethane and small amounts of industrial and transport hydrogen. Zero hydrogen exports are assumed. Hydrogen demand is split between domestic (mostly transport and industry/feedstock) and green commodities. Development of biomethane is comparable to the 2023 IASR forecast, with the majority replacing natural gas in the gas network in sectors that are technically or commercially difficult to electrify, manufacturing, domestic and commercial buildings.

Carbon sequestration

Varying levels of carbon sequestration are forecast in the multi-sectoral modelling to support the emissions reduction pathways for each scenario. Sequestration investments primarily are expected from:

- existing land-based sequestration (capturing carbon via natural biological processes), which are accounted for in the National Greenhouse Accounts[81] and exogenously imposed in the multi-sectoral modelling,
- additional land-based sequestration from new forestry plantings and other activities within the LULUCF sector,
- deployment of direct air capture (DAC) technologies, after such technologies are assumed to become commercially viable, and
- carbon capture and storage (CCS) technologies from emitting processes, such as capturing electricity generation emissions.

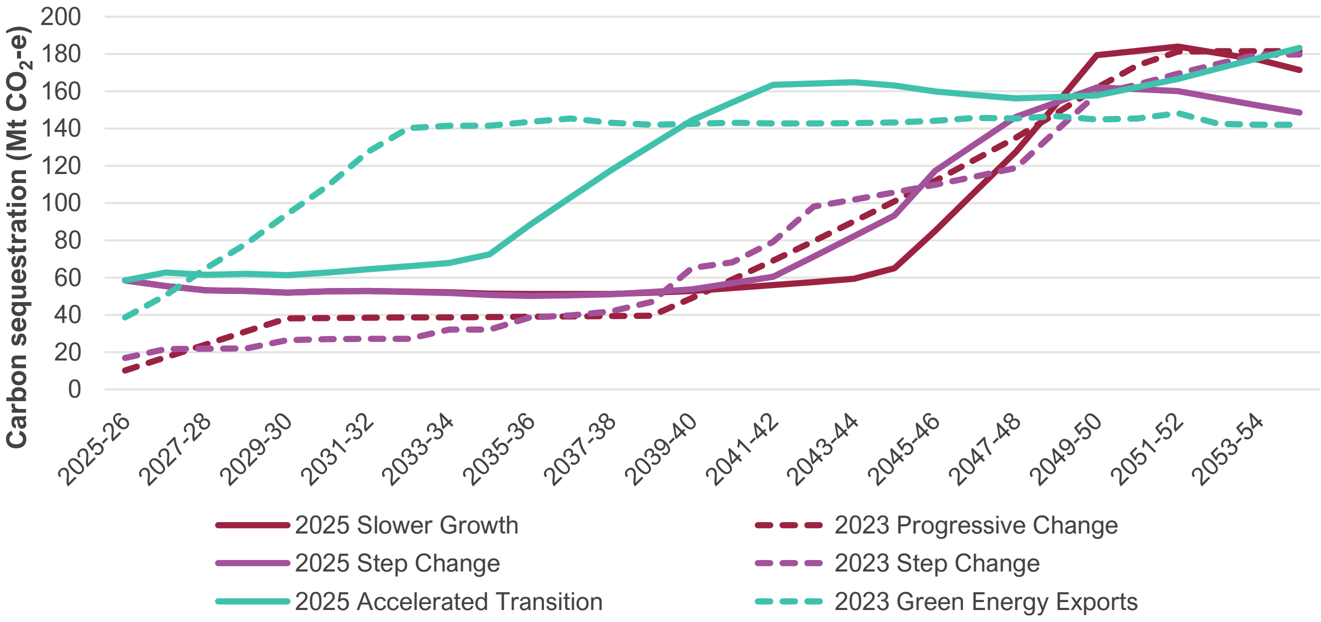
Land-based sequestration options in the multi-sectoral modelling are costed using a cost-supply curve derived from CSIRO's Land-Use Trade-offs (LUTO) model. This model calculates the volume of sequestration that would be profitable to operate compared to other competing agricultural land uses. The model does not consider the use of international offsets to meet climate targets. Assumptions for technical sequestration options (DAC and CCS), which are generally considered to be more expensive options than land-based sequestration, are sourced from best available estimates from literature[82], with assumptions on improvements over time in line with analysis from the International Energy Agency.

Figure 7 presents the estimated emissions captured from sequestration activities in the NEM regions in each scenario, with the 2023 IASR scenarios presented for comparison.

[81] At https://www.greenhouseaccounts.climatechange.gov.au/.

[82] Fasihi, M, Efimova, O & Breyer, C, 2019. 'Techno-economic assessment of CO2 direct air capture plants', *Journal of Cleaner Production*, vol. 224, pp.957-980.

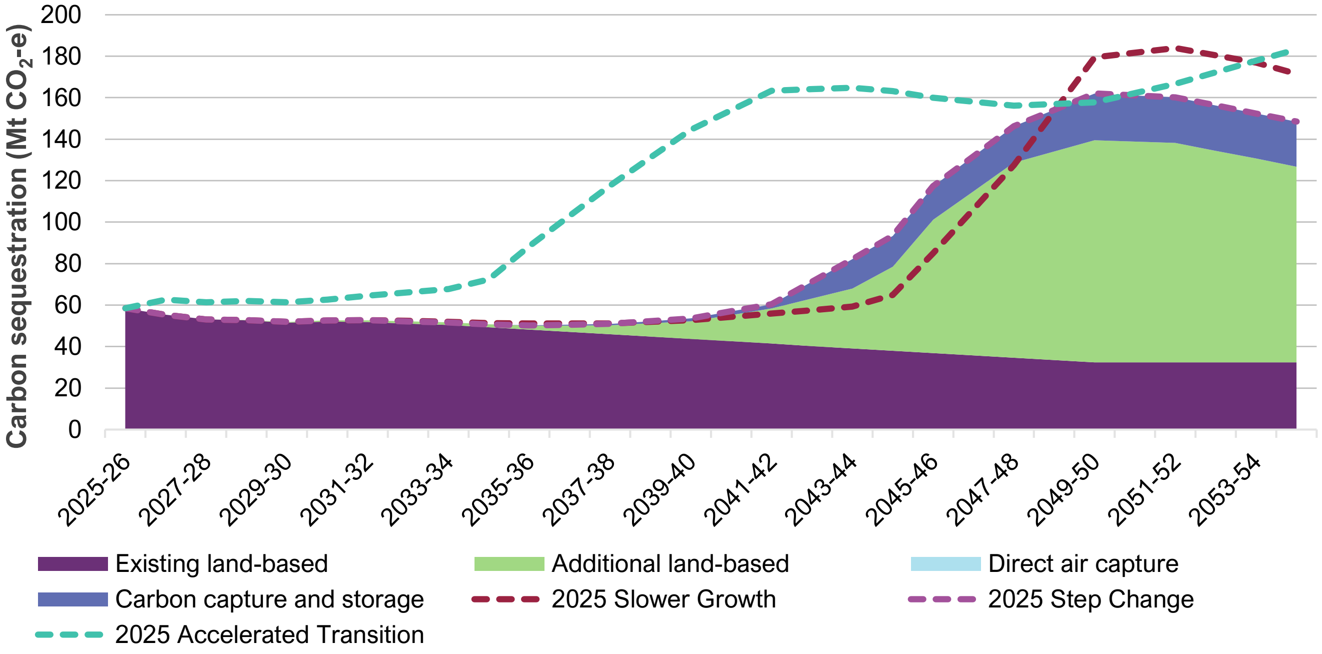
Figure 7 Carbon sequestration due to land-based sequestration and process-based carbon capture and storage in the NEM



An upward revision to existing land-based sequestration inventories from the National Greenhouse Accounts has resulted in an increase to the starting level of sequestration across all scenarios compared to the 2023 IASR. Improvements have also been made to the representation of sequestration in the LULUCF sector to account for its effectiveness over time – in particular, the declining sequestration capabilities of plantings as they mature, and the additional lead time required for new plantings to reach their full potential. This has led to a delay in the timing of new sequestration compared to the 2023 IASR.

Figure 8 shows the contribution of each of the sequestration categories in *Step Change*. As existing land-based sequestration declines in effectiveness with age, additional land-based sequestration solutions are invested in from the mid 2030s as decarbonisation needs accelerate to achieve the carbon budgets. CCS across other sectors is also deployed at a similar timing to contribute to emissions reduction outcomes, while DAC does not play a role in *Step Change* due to its high cost. Sequestration outcomes by category for the other scenarios are available in CSIRO's multi-sectoral modelling report.

Figure 8 Carbon sequestration by category in the NEM in *Step Change*



The potential emergence of DAC is subject to technological deployment and cost uncertainty but may provide a level of emissions abatement to enable net negative emissions outcomes in the future. As discussed in **Table 14** above, DAC is assumed to be technically feasible from 2030 onwards but commercially feasible only in *Accelerated Transition* from the early 2040s, as the scale of global decarbonisation ambition in the scenario may deliver greater international investment in the technology to encourage greater technical and commercial improvements. A significant amount of sequestration is forecast as necessary to achieve the deep carbon emissions reductions that is a key influence on this scenario's investment needs, despite DAC being assumed to be a relatively expensive option compared to other forms of abatement. These sequestration outcomes, including the deployment of DAC, are consistent with similar studies that have explored 1.5°C futures, such as the Climate Change Authority's *Sectoral Pathways Review*[83].

3.3.5 Electrification

Input vintage	June 2025
Source	CSIRO multi-sectoral modelling for electrification excluding road transport LIL surveys
Updates since Draft 2025 IASR	Updated multi-sectoral modelling results based on AEMO and stakeholder feedback to CSIRO Reconcile LIL survey-based electrification with multi-sectoral modelling industrial electrification.

Decarbonisation of the Australian economy requires emissions-intensive energy sources for residential, commercial and industrial processes to shift towards low and no emissions alternatives. In considering electrification, AEMO includes the potential electrification of future NEM and WEM loads (including the transport sector), and expansion of existing grid-connected loads.

[83] See https://www.climatechangeauthority.gov.au/sector-pathways-review.

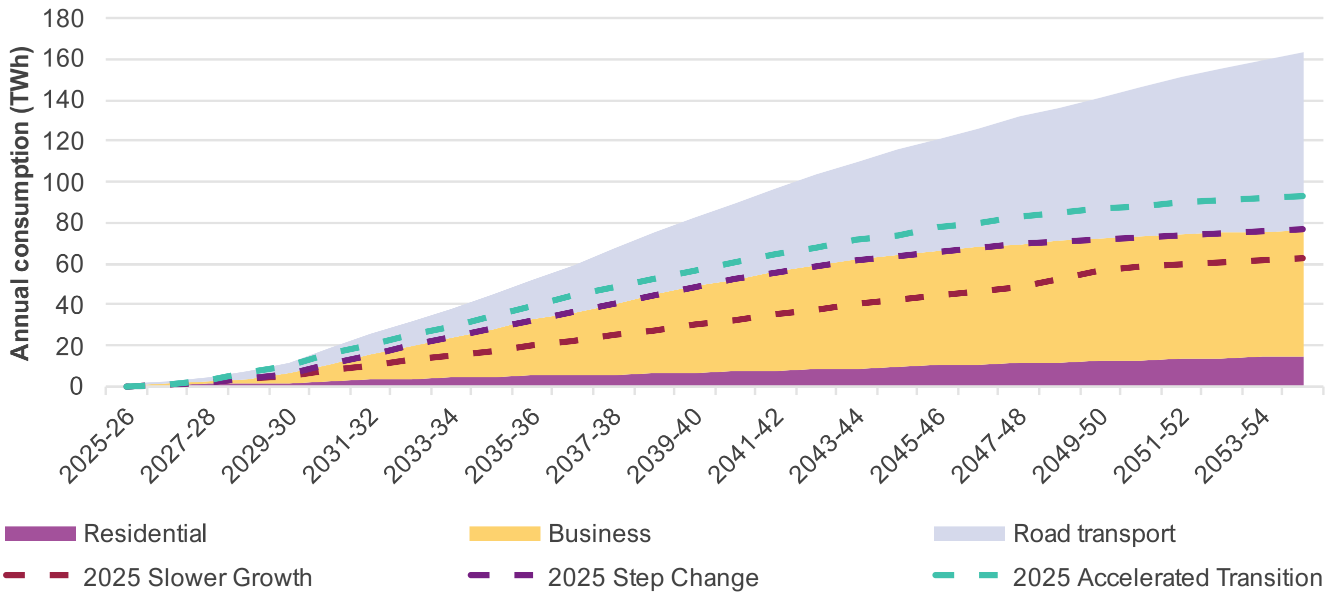
The cost-efficiency of electrification depends on many factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative low emissions fuels, such as hydrogen and biomethane. The 2025 IASR scenarios therefore consider a range of electrification outcomes, with *Accelerated Transition* adopting both a high degree of electrification and fuel-switching to support higher economic growth.

In the residential and commercial building sectors, space heating, cooking, and water heating appliances can all be electrified from gas or liquefied petroleum gas (LPG). Electrification of the road transport sector is expected in all scenarios, although the pace and magnitude of electrified transportation also varies across scenarios (road transport sector electrification is described in detail in Section 3.3.7).

The industrial sector comprises a range of subsectors, each with their own fuel use characteristics. While most oil and gas demand can be electrified (or switched to alternative gases), high-heat processes may be challenging to electrify without further technological advances and may be economically prohibitive depending on specific energy and heat requirements. Examples of such processes are the direct reduction of iron (DRI) for iron and steel production, and high temperature blast furnaces. Scenarios that target faster emissions reduction assume greater global (and domestic) investment in technological advances to achieve the emissions reduction goals (potentially driven by domestic or international research initiatives, or early-adopter or policy support).

Figure 9 shows electrification forecasts in the NEM and WEM. The stacked chart presents a sectoral breakdown of electrification in the *Step Change* scenario including the road transport sector (see Section 3.3.7 for further details). By 2049-50, 141 terawatt hours (TWh) – around three quarters of current operational consumption in the NEM and WEM – of new electricity consumption, including the road transport sector, is forecast to assist in the transition to a net zero economy. Road transport electrification is forecast to grow materially, from approximately 1 TWh in 2025-26 to 69 TWh by 2049-50, representing around 50% of all electrification in the *Step Change* scenario.

Figure 9 Total electrification forecast (NEM and WEM) for *Step Change* scenario (stacked area chart) and electrification excluding road transport for all scenarios (dashed lines), 2025-26 to 2054-55



Notes:

- *Slower Growth* and *Accelerated Transition* in the *2025 IASR* represent the *Low* and *High* scenario respectively for the WEM.
- The dashed lines exclude road transport electrification. See Section 3.3.7 for more details on the EV forecasts.

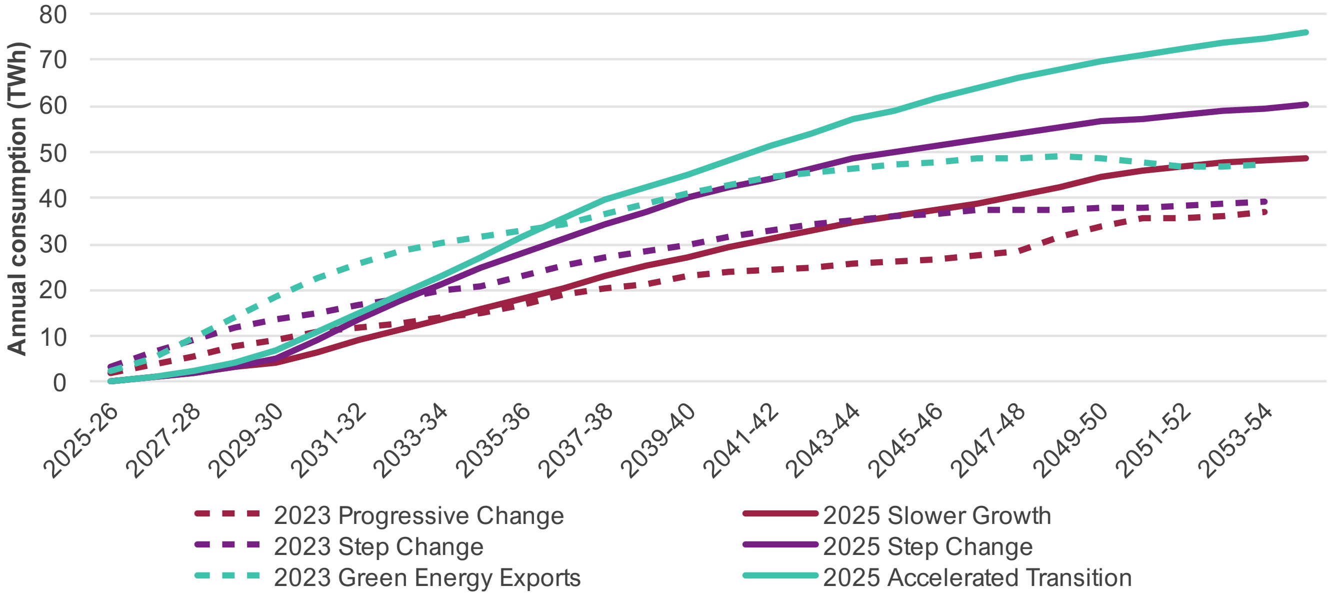
After transport electrification, the industrial sector is forecast to provide the second largest share of electrification in the *Step Change* scenario, as electricity is considered an appropriate alternative low-emission fuel for a spectrum of industrial heating processes. In alumina production, the high-temperature calcination process is fully electrified across all scenarios by 2050. Adoption of electric arc furnaces and DRI for iron and steel production also contributes to electrification, primarily in the *Accelerated Transition* scenario. Additionally, technologies to electrify mining processes, including the uptake of on-site electric haulage trucks, would also form part of industrial electrification[84].

Electrification of the residential sector offers considerable potential given the prevalence of gas heating and hot water systems in selected jurisdictions. Recent policy initiatives in Victoria[85] and the Australian Capital Territory prohibiting new gas connections further drive residential and commercial electrification.

The scenario trend lines in **Figure 9** reflect forecasts of electrification excluding the road transport sector. Electrification investments occur faster in the *Accelerated Transition* scenario compared to the other scenarios. This reflects the greater potential for industrial electrification and higher willingness to commit to relevant investment to meet the more ambitious decarbonisation objectives in this scenario. Conversely, the *Slower Growth* scenario exhibits slower adoption in line with more challenging economic conditions.

Figure 10 presents electrification forecasts (excluding road transport). The chart includes the NEM only to facilitate comparison with the 2023 IASR, which was NEM-focused.

Figure 10 NEM electrification forecasts excluding road transport, all scenarios, 2025-26 to 2054-55



Note: To facilitate comparison, 2023 IASR electrification forecasts have been recalibrated to start at zero in 2024-25.

Compared to the 2023 IASR, electrification is lower in the *Step Change* scenario until 2034-35 and in *Accelerated Transition* (relative to 2023 *Green Energy Exports*) and *Slower Growth* scenarios until 2038-39. This is due to slower investment in industrial electrification in the first five years. From 2029-30, industrial electrification uptake

[84] For more details on industrial electrification and fuel-switching, see Section 4.7 of *Multi-sectoral modelling 2024*: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf.

[85] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

increases at a greater rate than it did in the 2023 IASR across all scenarios. This acceleration in uptake is most visible in manufacturing in the *Step Change* scenario until the late 2040s and agriculture for all scenarios after 2039-40. Conversely, the current forecasts project a lower level of electrification in the mining sector throughout the outlook period relative to the 2023 IASR forecasts, largely due to a reduction in coal mining activity, especially in the *Accelerated Transition* scenario.

Electrification forecasts for the residential and commercial sectors in the NEM and WEM are lower compared to the 2023 IASR. There are regional differences in the electrification forecasts compared to the 2023 IASR, owing to assumptions relating to population and dwellings, relative fuel costs, changes in the nature of industrial activity, and preferences between alternative decarbonisation levers.

Impact of electrification on daily and seasonal load shape

In converting non-transport electrification into half-hourly data, AEMO assumes:

- business consumption shows relatively low seasonality, on aggregate, and therefore electrification of the business sector (including industrials) approximates a baseload, and
- residential electrification is primarily driven by gas to electricity fuel-switching. To maintain heating load seasonality, AEMO assumes that electrified loads maintain the shape of current residential and small commercial volumetrically tariffed (“Tariff V”) gas loads.

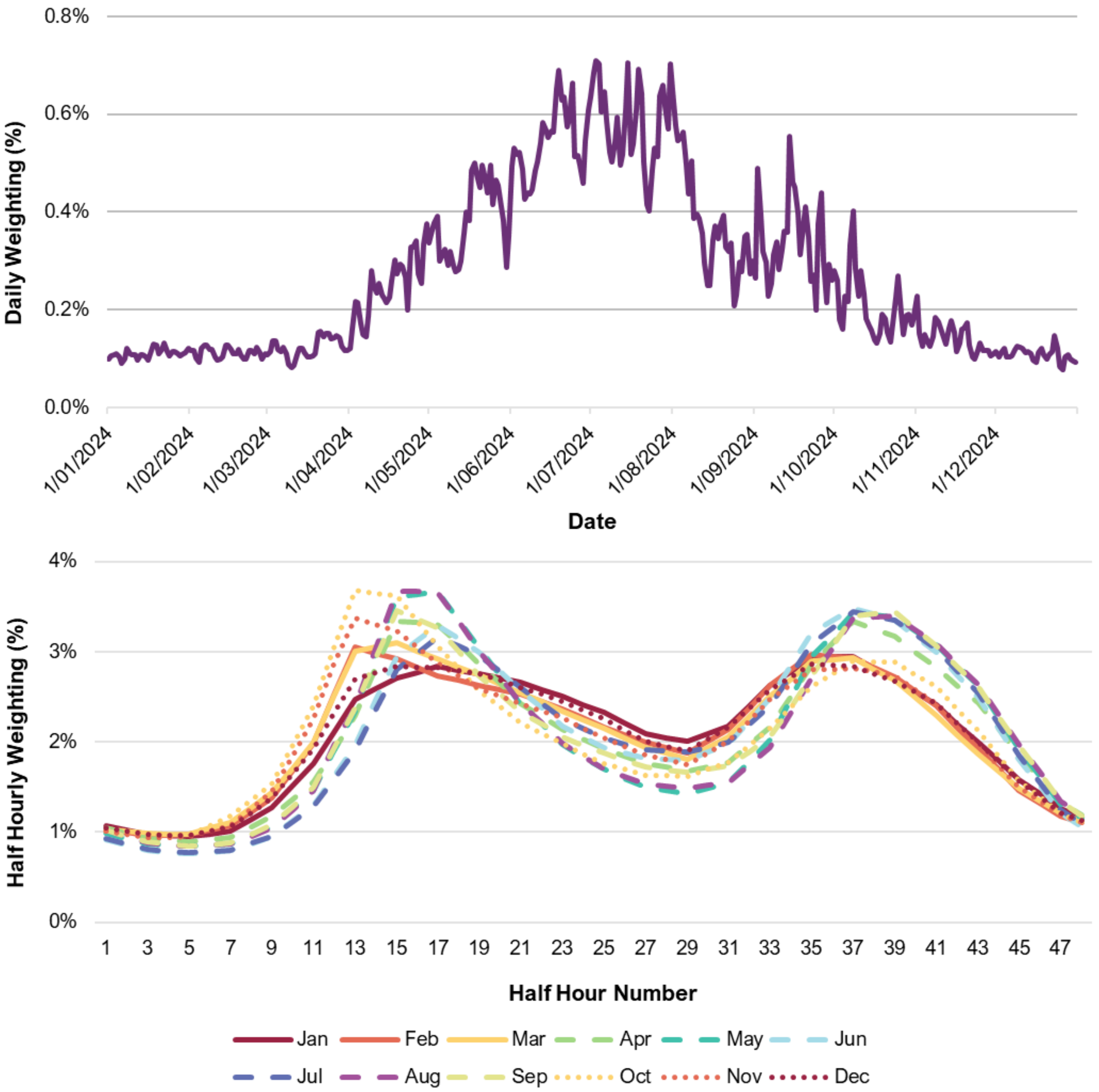
Annual residential electrification is disaggregated to half-hourly values through a two-stage process:

- First, annual residential electrification is disaggregated into daily values using the proportion of daily gas consumption to annual gas consumption, based on daily tariff V gas consumption data in each region.
- Second, daily electrification was further disaggregated to half-hourly values. Half-hourly weight profiles are derived from hourly tariff V gas consumption data interpolated to half-hourly values from Victoria in 2024 for each month of the year. The half-hourly profile shape is dependent on temperature, with distinct seasonal patterns and shift of day-light savings forward or backward.

This profile is used in other regions by adjusting the impact of temperature and daylight saving changes. Weightings used for disaggregating annual to half-hourly residential electrification are illustrated in **Figure 11**.

The electrification component only captures the energy needed to perform the activities previously performed by alternative fuels, with inherent fuel-conversion efficiency gains as appropriate. Changes in the efficiency of the individual appliances over time are captured separately in the energy efficiency component (see Section 3.3.12).

Figure 11 Weightings of annual to daily (top) and daily to half-hourly values (bottom) for residential electrification using historical gas consumption in 2024



3.3.6 Fuel-switching to low or zero emissions alternative fuels

Input vintage	July 2025. Biomethane production cost estimates as at December 2024.
Source	ACIL Allen (Hydrogen export/commodity volumes, biomethane availability and production costs), 2024 CSIRO Multi-sectoral modelling, AEMO analysis
Updates since Draft 2025 IASR	Updates of fuel-switching to biomethane, hydrogen forecasts updated: removed South Australia Hydrogen Jobs Plan, revised hydrogen proposed projects inclusions, on/off grid electrolysers and minimum utilisation factors

To achieve the emissions reductions targets outlined in the scenario narratives, fuel-switching away from fossil fuels is required over time in all sectors. In many applications, natural gas can be substituted by electricity (discussed in Section 3.3.5), or alternative low or zero emissions molecular fuels such as hydrogen or biomethane.

For other applications, fuel switching may be technically or commercially prohibitive. This section reports the forecast activities to fuel-switch from solid, liquid and gaseous fossil fuels to alternative gaseous fuels, particularly those that are low or zero emissions alternatives to electrification.

Hydrogen production

The development of hydrogen is supported by various strategies developed by Australia's governments, including a recent revision to the National Hydrogen Strategy (2024)[86]. The implementation of these strategies remains a key uncertainty, and while a number of hydrogen production projects are announced or under development across the eastern states of Australia, as listed in CSIRO's HyResource[87] project listing, several large-scale projects have recently been deferred or cancelled. Currently, only a handful of projects with electrolyser sizes over 10 MW have reached financial close.

The cost, timing, scale and location of a potential hydrogen economy in Australia is highly uncertain, and may have a material influence on the future power system needs. In the Draft 2025 IASR, AEMO sought stakeholder feedback on the appropriate consideration of hydrogen within the scenario aligned with the greatest decarbonisation activity, and AEMO adopted the *Green Energy Industries* variant (now *Accelerated Transition*), which focuses on the domestic opportunities for manufacturing (including products that could be consumed domestically, or exported). Stakeholder feedback broadly supported a focus on these domestic opportunities rather than on exports of hydrogen as an energy carrier.

Hydrogen assumptions

Hydrogen forecasts developed for each scenario were based on the multi-sectoral modelling described in Section 3.3.4, with separate treatment of subsectors (including hydrogen for domestic customers, green commodities, and exports). Domestic hydrogen forecasts were based on optimisation by the multi-sectoral modelling, while hydrogen forecasts for green commodities and exports were based on a study by ACIL Allen. Assumptions and further detail is provided in the following sections.

Policy support for fuel-switching

Federal legislation[88] has been passed which includes a $2/kg production tax incentive for eligible hydrogen production volumes (see details, along with other state-based incentives, in Section 3.1). This policy is identified in the National Hydrogen Strategy and was legislated for in 2025, therefore meeting the requirements of NER 5.22.3(b) to be considered (as outlined in Section 3.1). It was therefore considered within the economic forecasts and multi-sectoral modelling.

The South Australian Hydrogen Jobs Plan was deferred in 2025 and has been removed from the committed projects list for this IASR; this includes both the planned electrolysers and gas turbines.

[86] National Hydrogen Strategy 2024. See https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy.

[87] CSIRO, HyResource, at https://research.csiro.au/hyresource/.

[88] *Future Made in Australia (Production Tax Credits and Other Measures) Act 2025* (Cth), at https://www.legislation.gov.au/C2025A00009/asmade/text.

Hydrogen production technology

The two main technologies in use or under consideration globally for hydrogen production are electrolysis and steam methane reforming of natural gas. Electrolysis uses electricity to split the water (H_2O) molecule into its component parts, separating hydrogen and oxygen atoms. Steam methane reforming reacts methane (the main component of natural gas) with water vapour at high temperatures to produce hydrogen and carbon dioxide (CO_2). Steam methane reforming is currently used in existing applications, such as hydrotreating for desulphurisation of petroleum products, or fertiliser manufacture, but is not assumed to be developed further, due to its high carbon emissions (unless CCS is added to the process, which may make the technology cost-prohibitive). Carbon emissions occur both in the steam methane reforming production process, and also as 'fugitive' natural gas emissions associated with the extraction and transport of the natural gas to the processing plants. Steam methane reforming with CCS was excluded as an option in the 2023 IASR, due to stakeholder feedback that it was not aligned with the scenario narratives; it continues to be excluded from the *Accelerated Transition* scenario in the 2025 IASR for the same reason.

The 2024 multi-sectoral modelling allowed the potential development of steam methane reforming with CCS in the *Step Change* and *Slower Growth* scenarios[89], but was not selected by the model due to the requirement to meet emissions reductions. The multi-sectoral modelling also found that electrolysis was lower cost over the assumed plant lifetime.

Pipeline blending of alternative gases

Hydrogen's chemical characteristics differ from natural gas, and as a result, some existing pipelines are not suited to blends of natural gas containing hydrogen above a certain maximum level, particularly at higher pressures.

AEMO assumes that a maximum blend of 10% by volume is an appropriate technical limit for gas distribution networks (which operate at lower pressure), with no blending for transmission pipelines (which operate at higher pressure). The multi-sectoral modelling results did not reach the assumed 10% blending constraint in any scenario, due to the very low forecast uptake of hydrogen in residential and commercial sectors.

AEMO notes that modern gas distribution networks in NEM areas could be readied for higher hydrogen blends, up to 100% hydrogen, with some modifications. In some pilot projects[90], there are plans to demonstrate up to 20% (vol) blending. However, challenges remain with moving to high hydrogen blends in existing gas distribution systems, particularly around the timing, cost and logistics of appliance change outs and switch over.

Rather than relying on high blends in shared pipelines, AEMO anticipates that new hydrogen supply infrastructure including 100% hydrogen pipelines and hubs (as often described by government development strategies) will enable dedicated supply of hydrogen for industrial and transport customers that demand it.

[89] For the *Green Energy* scenario, AEMO expects that exports of hydrogen or green commodity customers will require the lowest possible emissions technologies to meet stringent targets and customer requirements. Including steam methane reforming (SMR) with CCS is not consistent with this expectation, as some emissions are not captured within the CCS process.

[90] Examples include projects by Southern California Gas Co. (USA – H2 Home) https://www.socalgas.com/newsroom/stories/assembly-of-award-winning-h2-hydrogen-home-begins and ATCO (Canada) https://gas.atco.com/en-ca/community/projects/fort-saskatchewan-hydrogen-blending-project.html.

Grid connection of hydrogen facilities

Electrolysis requires a source of electricity to be applied to purified water to produce hydrogen. The *ISP Methodology*[91] provides detail on the potential supply pathways including electrolyser and hydrogen hub locations. AEMO assumes that electrolysers using grid-supplied electricity to supply hydrogen to domestic users and for green commodities will be located at REZs within each sub-region – this will potentially minimise additional network requirements and associated infrastructure for hydrogen production.

This represents a change from the 2023 IASR, where AEMO assumed that many electrolysers would be located at ports, supplied with electricity via transmission from REZs. AEMO has made this change following stakeholder feedback, and review of external studies[92] on the optimal choice of pathway. The majority of studies found that it is cheaper to transport molecules than electrons, although this can be project-dependent.

There are many factors influencing optimal electrolyser location, including distance from the electricity source to the hydrogen user, planning considerations and community expectations.

For the multi-sectoral modelling, CSIRO assumed on-grid proportions based on a review of current projects listed in HyResource[93], and applying assumptions for future projects.

For the ISP modelling, the concept of on/off-grid electrolysers has been expanded to include four different categories of hydrogen production, as described in **Figure 12** below:

- **Non-REZ based hydrogen production** – electrolyser is not located within a REZ and is not grid-connected.
- **Fully grid-sourced** – electrolyser is located within a REZ and electricity is sourced only from the grid.
- **Not-connected, REZ-located** – electrolyser is located within a REZ but electricity is sourced entirely from behind the meter generation.
- **Partially grid-sourced** – electrolyser is located within a REZ and electricity is sourced partially from the grid and partially from behind-the-meter generation.

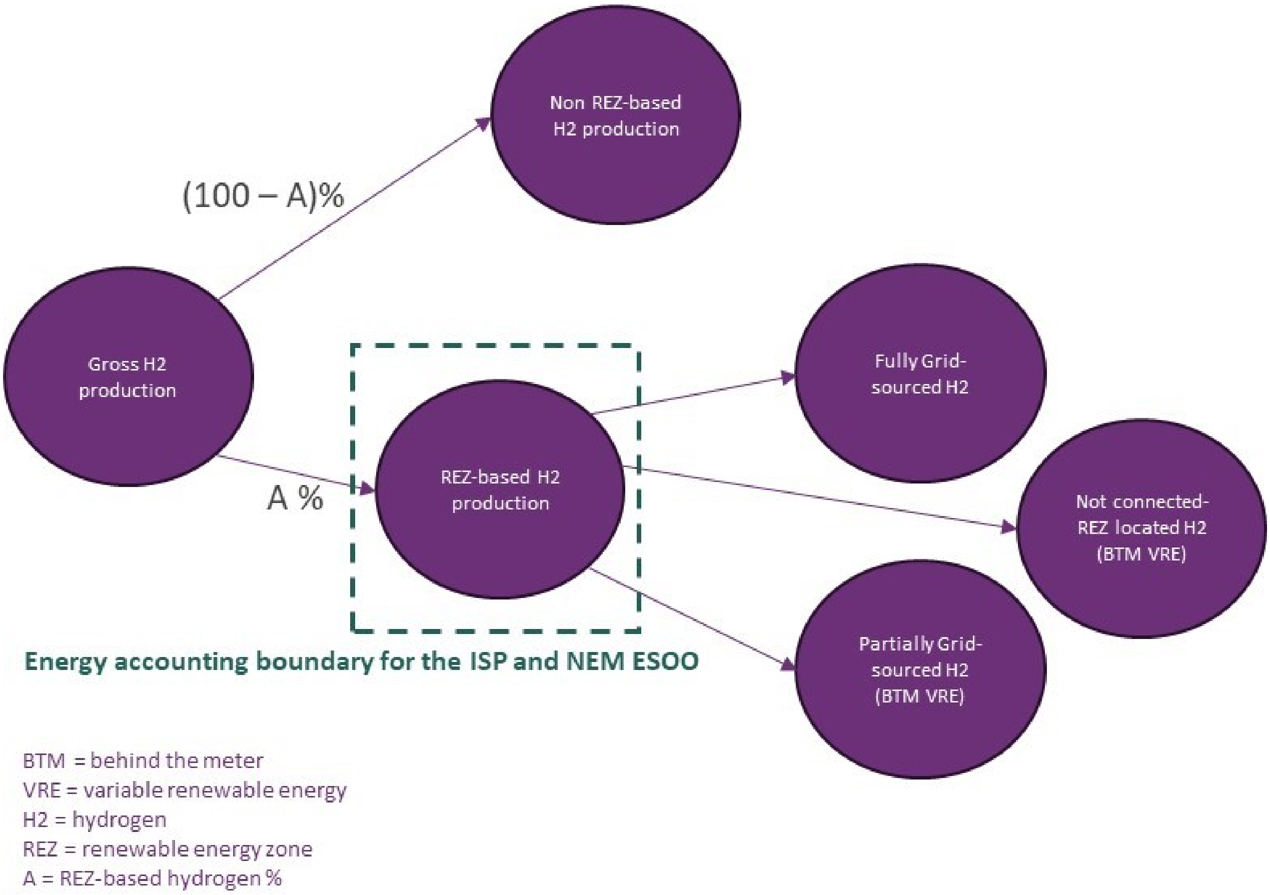
The last three categories from this list are grouped into 'REZ-based hydrogen production'. This includes production from any electrolyser geographically located in a REZ, whether fully on-grid, fully off-grid or a hybrid.

[91] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[92] DeSantis et al, 2021, Cost of long-distance energy transmission by different carriers, https://doi.org/10.1016/j.isci.2021.103495; Patonia et al, 2023, Hydrogen pipelines vs. HVDC lines:Should we transfer green molecules or electrons? https://www.oxfordenergy.org/publications/hydrogen-pipelines-vs-hvdc-lines-should-we-transfer-green-molecules-or-electrons/; DCCEEW, 2023, National Hydrogen Infrastructure Assessment, https://www.dcceew.gov.au/energy/publications/national-hydrogen-infrastructure-assessment; Net Zero Australia, 2023, https://www.netzeroaustralia.net.au/final-modelling-results/.

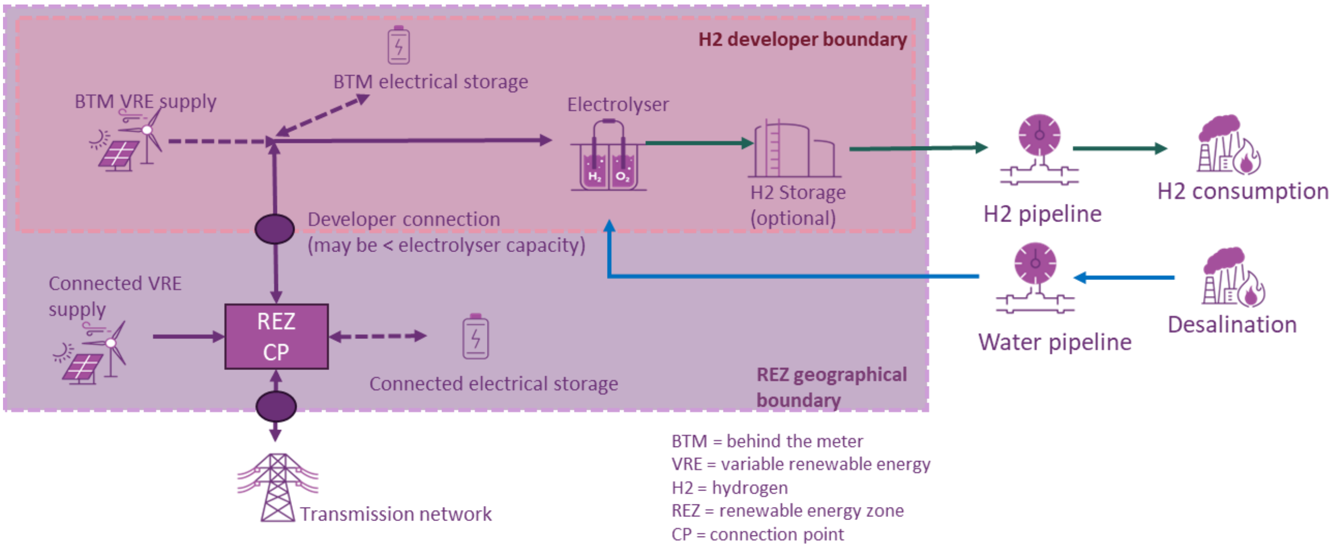
[93] See https://research.csiro.au/hyresource/.

Figure 12 REZ-based hydrogen production definition



All REZ-based hydrogen production is included as hydrogen demand in the ISP, as outlined in **Figure 13**, which means the full amount of renewable energy capacity in the REZs is available to meet that load (regardless of connection status of the renewable energy). In the absence of sufficient information regarding the volume of ’partially grid-sourced’ or ‘not-connected, REZ-located’ hydrogen, AEMO treats all REZ-based hydrogen production as being ‘fully grid-sourced’ in the 2026 ISP. This approach ensures that the available renewable energy capacity in each REZ and sub-region considers the full hydrogen production forecast. It also acknowledges that developers may initially source most or all of the energy for hydrogen production from the grid, but may elect to develop their own additional behind-the-meter generation later (possibly coupled with expansion of the electrolyser facilities), while retaining a restricted connection to the grid. Off-grid electrolysers that are not located in a REZ are not included in the ISP hydrogen demand forecast.

Figure 13 REZ-based electrolyser connections schematic



With the abundance of potential development locations for new hydrogen production facilities, particularly in some regions with large geographical areas, AEMO does not assume that all hydrogen facilities will necessarily be located within, or within close proximity to, the ISP's REZs. For Queensland and South Australia, AEMO is assuming that a significant proportion of hydrogen production will locate outside the REZs. The REZ-based production proportions are outlined in **Table 15**, and are applied as static values across the modelling horizon.

Table 15 REZ-based hydrogen production percentages

Region	REZ-based production proportions
New South Wales	100%
Queensland	40%
South Australia	40%
Tasmania	100%
Victoria	100%

Only the REZ-based portion of the forecast hydrogen production is included in the IASR and *Inputs and Assumptions Workbook*, for use in modelling AEMO's planning publications, including the ISP.

Hydrogen cost

The main components of hydrogen cost are the capital cost of the electrolysers, and the operating cost of consuming electricity.

The multi-sectoral modelling applied the following cost premiums when forecasting the potential scale of domestic hydrogen consumption:

- The cost of hydrogen production allowed for an assumed proportion of hydrogen storage and transport costs based on hydrogen pipeline storage. This premium increases the capital and operating costs of hydrogen use relative to alternative decarbonisation options such as alternative fuels including biomethane and electricity.

- The cost of water was also considered as an additional cost premium at a rate of $11.08/kilolitre (kL). This cost premium considers the capital and operating cost (including electricity consumption) forecasts for demineralisation and desalination and was derived from AEMO's analysis of the 2024 Energy Technology Costs and Technical Parameter Review[94].

For the ISP modelling it is assumed that all water for hydrogen will be supplied by desalination with pipelines from the coast to the REZs. While noting that the cost of provision of water is small (<5% of the overall cost of hydrogen), AEMO has:

- reflected the energy required for desalination of water for hydrogen in electricity consumption forecasts,
- included the cost of desalination and purification as operating costs in the ISP models, and
- added a premium to the electrolyser cost in the ISP models to allow for the assumed capital cost of water pipelines.

Details are provided in the 2025 *Inputs and Assumptions Workbook*. AEMO recognises that this approach appropriately allows for a high level cost estimate when considering hydrogen production, but is not intended to identify specific water or storage or environmental considerations of these developments. Further consideration of these factors may be required in broader planning processes, including whether the forecast hydrogen production and their specific locality is a key influence on the evolving needs of the power system.

Utilisation factors

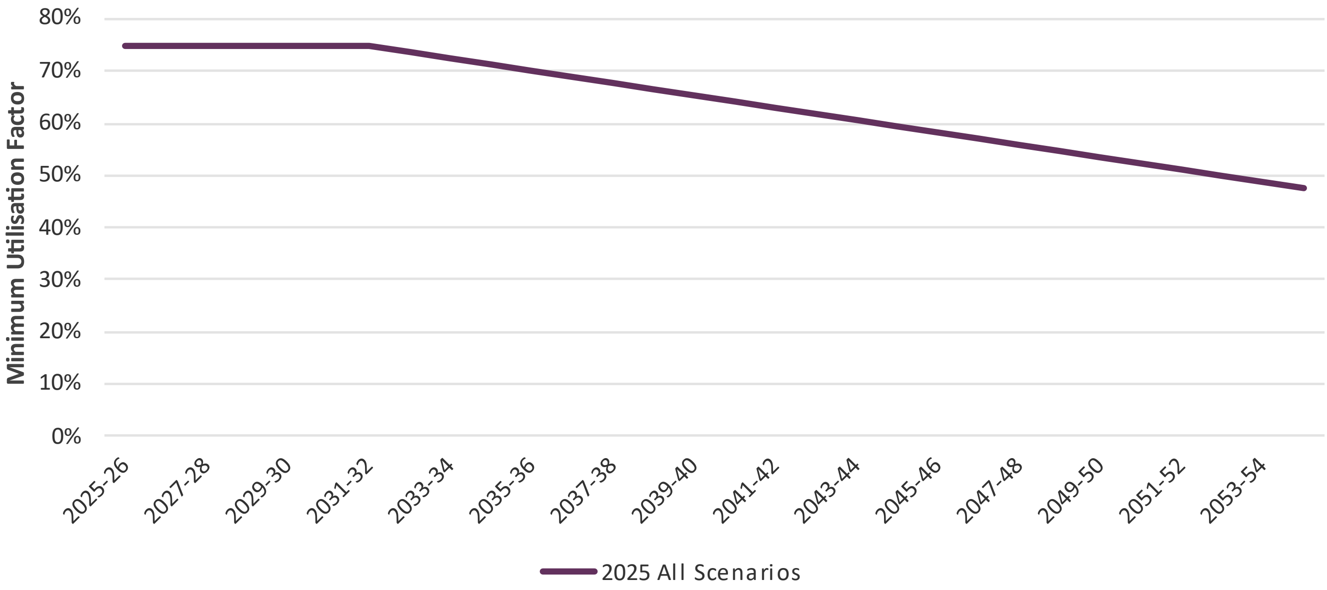
The economics of hydrogen production are highly influenced by the utilisation factor of the electrolysers, which is defined as the proportion of hydrogen produced in a year, relative to the maximum potential annual production from the electrolysers. In early years, while electrolyser costs are high, AEMO (based on industry feedback) assumed in the multi-sectoral modelling that utilisation factors of at least 70% would be required by developers, reflecting the likely need for high utilisation to gain maximum cost efficiency.

Considering stakeholder feedback from the Draft 2025 IASR consultation, the minimum utilisation factor is assumed to reduce slightly over time, as the technical and economic efficiency of these facilities is assumed to improve, encouraged by technical improvements, economic improvements, and potential competitive forces.

This reducing utilisation factor is applied to all of the scenarios equally, as shown in **Figure 14**.

[94] See https://aemo.com.au/-/media/files/major-publications/isp/2025/aurecon-2024-energy-technology-costs-and-technical-parameter-review.pdf?la=en.

Figure 14 Minimum electrolyser utilisation factor for ISP modelling



Other hydrogen assumptions

Hydrogen is considered as a potential fuel for gas-powered generation in the ISP, but only in the *Accelerated Transition* scenario , which assumes lower costs and higher available volumes of hydrogen. AEMO includes an estimated maximum volume of hydrogen for gas-powered generation in the hydrogen production forecast, for energy accounting, while the final (potentially lesser) amount of hydrogen used for gas-powered generation will be optimised by the ISP model.

All electrolysers in the ISP modelling are assumed to be alkaline, due to their lower cost compared to Proton Exchange Membrane (PEM) electrolysers.

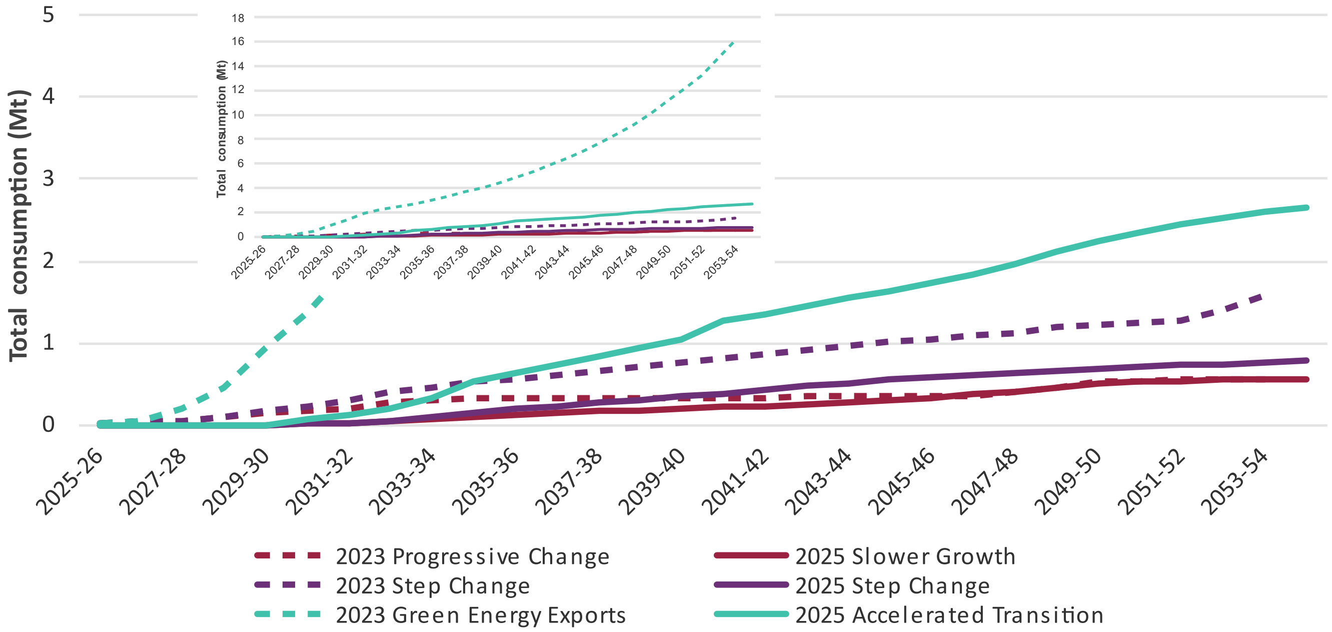
Forecast hydrogen consumption

Forecast hydrogen volumes are described in this section, for NEM states, including production that is expected to be located within the ISP's REZ. A breakdown by sector is also included, for domestic, green commodities and export as an energy carrier.

Total NEM hydrogen consumption

Total NEM REZ-based hydrogen consumption is shown in **Figure 15** and is the aggregate of domestic, green commodity and energy export forecasts, as outlined in **Figure 16**, **Figure 17**, and **Figure 18** respectively.

Figure 15 Total REZ-based hydrogen consumption across the NEM (full-scale of the 2023 IASR *Green Energy Exports* scenario in the insert)



Hydrogen for domestic use

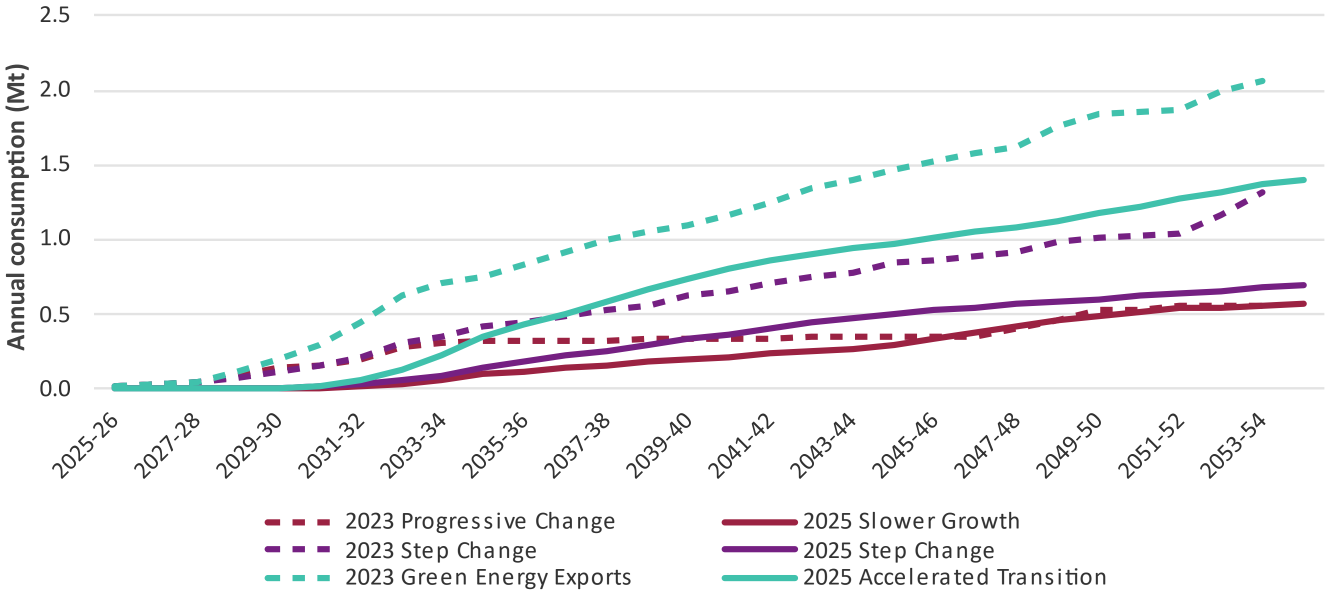
The forecast hydrogen used for domestic purposes (including industrial, transport and blending in gas distribution networks for residential/commercial use, and excluding green commodities and exports) was optimised by CSIRO's multi-sectoral modelling, based on the available fuel types and the relative costs and benefits of other decarbonisation options, and CSIRO's forecasts of EV opportunities for road-based transport.

The primary contributors of forecast domestic hydrogen consumption are on-road transport, particularly for heavier vehicles, with smaller proportions due to off-road transport (aviation, shipping, rail) and direct supply to industry (assumed via new dedicated hydrogen pipelines). The multi-sectoral model forecast minimal[95] hydrogen for use in the gas distribution network, blended with other gases, due to the higher cost of hydrogen compared to other alternatives such as biomethane and electrification.

The aggregate domestic hydrogen consumption forecast by scenario forecast is shown in **Figure 16** and represents the hydrogen production that is assumed to be REZ-based.

[95] Hydrogen blending in distribution networks varies in the NEM across all scenarios and years, with approximately 5%vol H2 in *Slower Growth,* 2%vol H2 in *Step Change* and 0%vol H2 in *Accelerated Transition* in 2049-50.

Figure 16 REZ-based domestic hydrogen consumption across the NEM (excluding green commodities)



Hydrogen for green commodities

The 2025 IASR includes a new category for potential hydrogen use in producing green commodities, which include the production and manufacture of iron and steel, ammonia, alumina and methanol, and renewable fuels such as synthetic sustainable aviation fuel produced from renewable energy (e-SAF). Biogenic renewable liquid fuels such as biodiesel, bio-SAF and ethanol are also considered in the multi-sectoral modelling. This reflects growing recognition across industry[96] of the potential benefits of using renewable hydrogen as a value-adding technology in the country of origin, and builds on Australia's advantage in natural resources including minerals and renewable energy. This has prompted AEMO to reduce the assumed exports of hydrogen as a carrier for direct energy consumption relative to the 2023 IASR, and assume increased use of hydrogen to make green commodities for potential domestic use and for export in the *Accelerated Transition* scenario. The *Slower Growth* and *Step Change* scenarios do not assume any material development of this emerging opportunity.

An initial forecast of hydrogen for green commodities was developed by ACIL Allen[97]. Its forecast was derived by modelling demand for green commodities, based on the IEA's World Energy Outlook, and Australia's relative share of key global resources[98], for all AEMO scenarios. The green iron and steel forecast also factored in Australia's relative global share of iron ore resources. This assessment focused on resource availability, rather than attempting an economic forecast of Australia's green hydrogen production costs relative to other international competitors, including delivery considerations to international trading partners; such an economic analysis was not possible given the significant complexity of such a significant modelling task. In the *Accelerated Transition* scenario that features strong global decarbonisation within the scenario narrative, it was assumed that

[96] See Grattan Institute, *Green metals: Delivering Australia's opportunity*, 2024, at https://grattan.edu.au/wp-content/uploads/2024/07/Green-metals-consultation-paper-2024.pdf.

[97] ACIL Allen assumed that hydrogen would not be used in aluminium smelting, so ACIL's reported aluminium commodity growth does not influence the hydrogen forecasts. Aluminium commodity growth in ACIL's report therefore has not influenced the multi-sectoral modelling, rather the multi-sectoral modelling considered the hydrogen forecast from ACIL Allen, as well as general economic activity from the Deloitte economic growth forecasts by sector (see Section 0). Assumptions on existing general commodity growth in the multi-sectoral modelling are described further in the CSIRO report.

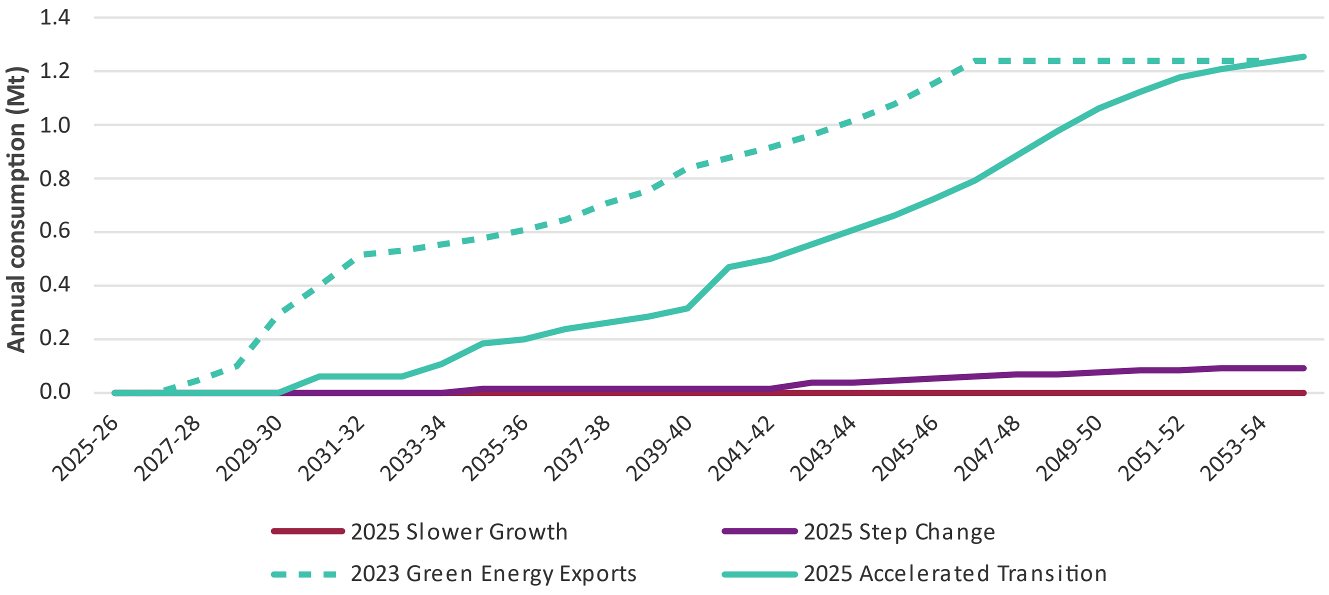
[98] See https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf?la=en.

there would be sufficient demand for green products, even with the expected price premium above traditional carbon-intensive commodities. The *Accelerated Transition* hydrogen forecast was developed by firstly scaling ACIL Allen's green commodity forecast to match the National Hydrogen Strategy's central scenario, and then further scaling to reflect the scenario narrative focus on green iron and steel. For *Step Change* and *Slower Growth*, the ACIL Allen forecasts were sufficiently low to not warrant any adjustment prior to being considered within the multi-sectoral modelling.

The majority of the green commodities produced are assumed to be exported, with limited consumption by domestic consumers. The *Accelerated Transition* scenario excludes hydrogen for export as an energy carrier, and represents a moderate level of green commodities, focusing on green iron production due to Australia's world-leading iron ore resource and competitive large scale VRE resources. The *Green Energy Exports* sensitivity retains the green commodity volumes for green iron and steel present in the *Accelerated Transition* scenario, with additional hydrogen for ammonia, methanol and alumina.

The resulting REZ-based hydrogen volumes associated with green commodities are shown in **Figure 17**.

Figure 17 REZ-based green commodity hydrogen consumption across the NEM



The stepwise increases in hydrogen production in the early 2030s and 2040s reflect the expectation that sufficient commodity demand will be required to maintain a minimum operating level for these facilities, leading to a non-linear growth when establishing new facilities in each NEM region.

Moderate volumes of hydrogen are included in *Accelerated Transition* with approximately 89% of the green commodity demand attributed to green iron and approximately 9% for ammonia by 2054-55. Small quantities are assumed to be used for fuel-switching from natural gas in alumina production.

For the other two scenarios, *Step Change's* hydrogen demand is primarily to support ammonia production, while *Slower Growth* assumes no green commodity production.

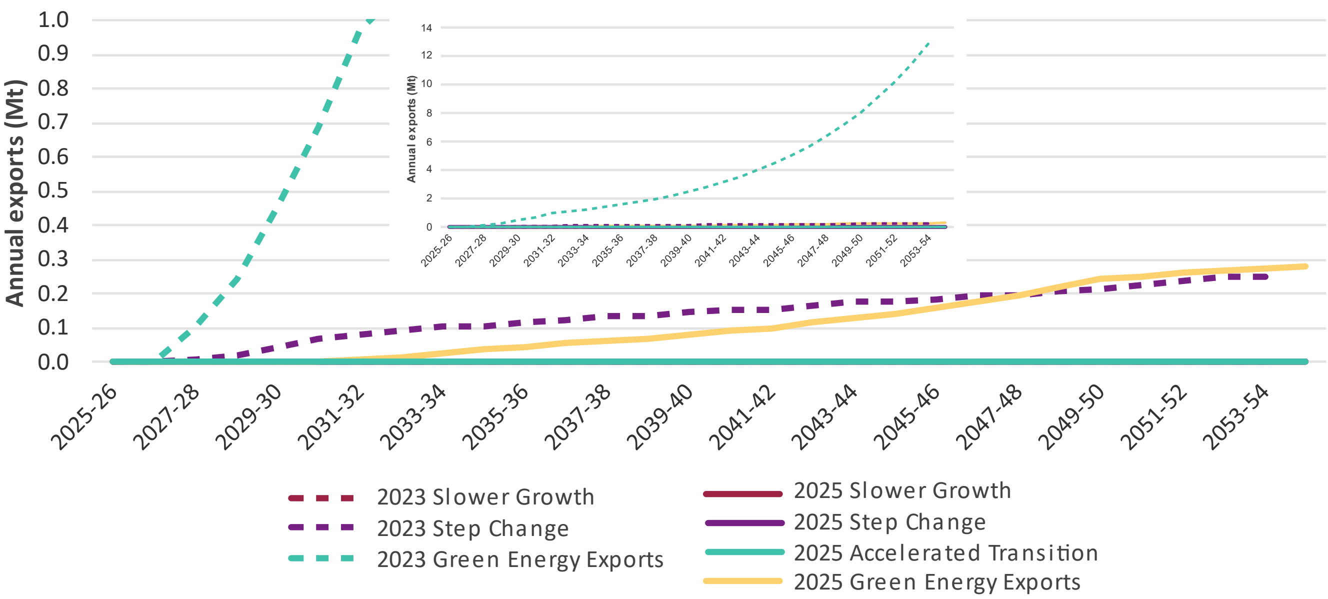
Hydrogen for energy export

Hydrogen for energy export is assumed to be either shipped as liquified hydrogen, or via a carrier such as ammonia, which could then be converted back to hydrogen for end use. This category has changed in definition since the 2023 IASR, as it excludes shipping of ammonia for direct use as a chemical or fuel (this is included in green commodities above).

The method used to scale the export volumes forecast by ACIL Allen relative to the National Hydrogen Strategy was the same as for green commodities, as described above.

The REZ-based hydrogen demand for exports is shown in **Figure 18**. The volumes in this category are materially lower across all scenarios than forecast in the 2023 IASR, reflecting the slow pace of development of the industry since the 2023 IASR, as well as the scenario narratives that emphasise the greater expected role for green commodity exports than hydrogen exported as an energy carrier itself.

Figure 18 REZ-based export hydrogen consumption across the NEM (full-scale of the 2023 IASR *Green Energy Exports* scenario in the insert)



Note: Only the *Green Energy Exports* potential sensitivity has hydrogen exports within the forecast; the three 2025 IASR scenarios do not contain hydrogen exports.

Biomethane

While biomethane is a proven technology widely used in Europe[99] and other countries, there is relatively low existing production in Australia. Biomethane has the potential to provide a low or zero emissions molecular fuel source to blend into gas pipelines, lowering the emissions intensity of gas use[100]. As such, it provides a decarbonisation alternative to electricity for industries that cannot easily electrify their industrial processes, and would have a significantly lower impact on gas infrastructure than hydrogen.

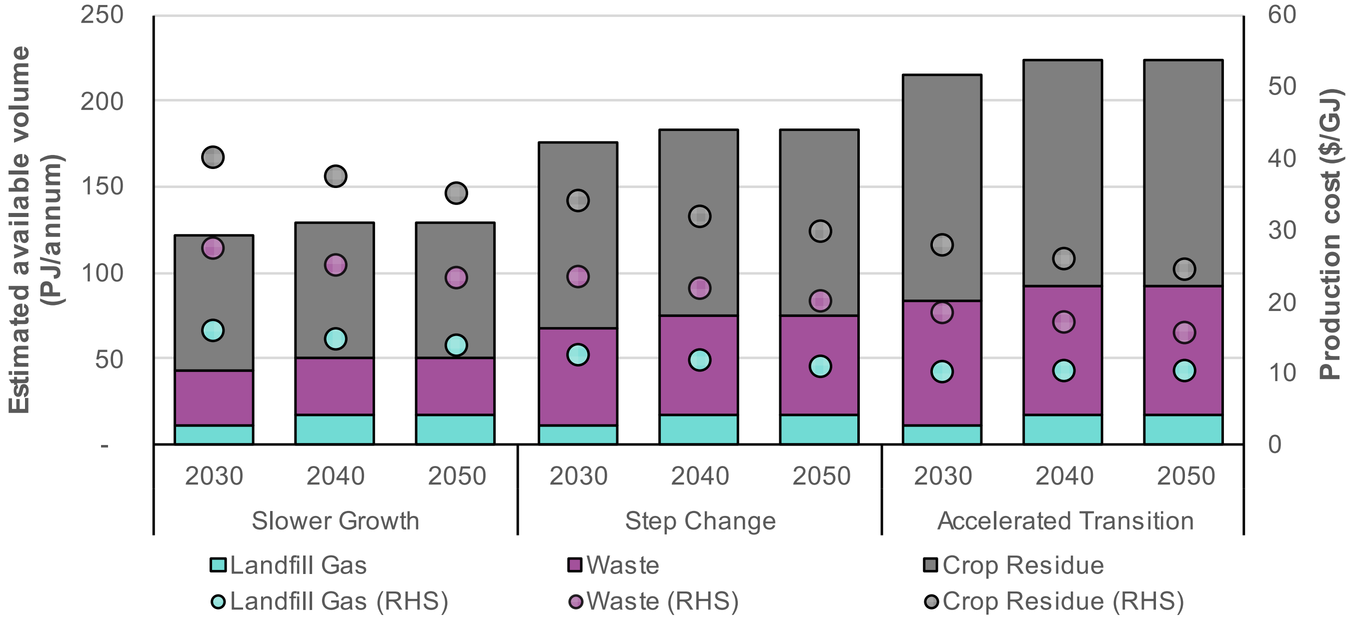
[99] See https://www.europeanbiogas.eu/strongnew-record-for-biomethane-production-in-europebrshows-eba-gie-biomethane-map-2022-2023-strong/ and https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20(BIP,of%20its%20potential%20by%202050.

[100] See https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-accounts-factors-2022.pdf (page 13).

Each scenario's biomethane uptake forecast considers existing and anticipated production consistent with the most recent ECGM GSOO, as well as the multi-sector modelling forecast that considers estimated available volumes and forecast biomethane costs.

AEMO engaged ACIL Allen to forecast long-term biomethane production cost and available volumes by feedstock type, state, and scenario. **Figure 19** shows a snapshot of ACIL Allen's forecast for the various feedstock available volumes by scenario, including production cost for selected years[101].

Figure 19 ACIL Allen biomethane available volume and production cost estimates by feedstock and scenario



Considering these volumes and production cost, the multi-sectoral modelling then forecast the expected utilisation of biomethane per scenario, as shown in **Figure 20**.

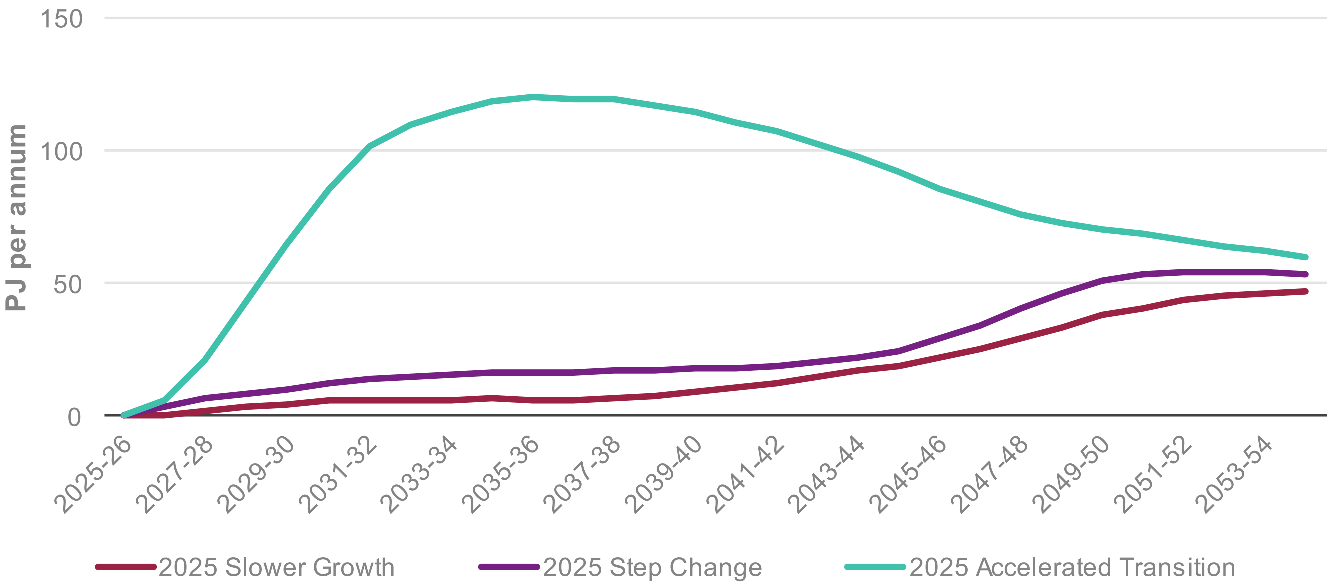
In all scenarios, the majority of biomethane volumes substitute for natural gas use in sectors that are technically or commercially difficult to electrify, such as manufacturing, residential and commercial buildings[102]. For the *Accelerated Transition* scenario, early adoption is forecast to support decarbonisation activities, especially in residential buildings, delaying the transition of gas appliances in the short to medium term, while in the longer term, the eventual electrification of residential buildings (and their appliances) reduces the relative demand for gaseous fuels, including biomethane[103]. In *Step Change* and *Slower Growth*, slower development is forecast as other decarbonisation alternatives that are assumed to be lower cost are deployed ahead of biomethane developments. In all scenarios, by 2050, biomethane production is forecast to reach levels at least sufficient to have exploited most of the estimated landfill gas and waste volumes in **Figure 19** above.

[101] Detailed data sets can be found in the ACIL Allen reports at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[102] While residential and commercial consumers have electrification options for heating, cooking and hot-water applications, not all consumers may be capable of affording these fuel-switching options, or may have limits due to rental arrangements or building heritage considerations.

[103] See CSIRO Multi-sectoral modelling report here for further information: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf?la=en.

Figure 20 Biomethane use by scenario



3.3.7 Consumer energy resources

Input vintage	April 2025
Source	CSIRO Green Energy Markets Clean Energy Regulator
Updates since Draft 2025 IASR	Distributed PV forecasts have been rebased using latest actuals from the Clean Energy Regulator Battery forecast updated to incorporate recently announced battery subsidies

CER often describes consumer-owned devices that can generate or store electricity and includes flexible loads that can alter demand in response to external signals. AEMO's forecasts of CER includes embedded solar systems and battery devices installed within the distribution system, including the uptake of EVs and their charging interactions with the power system. The sub-sections which follow outline each of the major forecast CER components. Energy management systems that may increase the flexibility of consumer demand are considered separately in AEMO's forecasting of demand flexibility (in demand-side participation forecasts – see Section 3.3.15) and energy efficiency (see Section 3.3.12).

AEMO's CER forecasts include small-scale embedded generation such as residential and commercial rooftop PV systems (less than 100 kilowatts [kW]), battery storage, and EVs, as well as larger PV systems (between 100 kW and 30 MW, referred to as PV non-scheduled generation or PVNSG). Customers' solar and battery devices may operate passively (such that they operate without regard to the broader power system conditions but instead with a customer-centric behaviour), but also may have the 'smarts' to actively manage and minimise a customer's energy import and export from the grid.

Opportunities may also exist for larger systems to be installed within the distribution system that complement consumer devices, including mid-scale installations that are community-owned. These are referred to as 'other distributed resources'; in the context of AEMO's planning functions, these resources are not part of the CER forecast, but will be an outcome of ISP modelling to identify the magnitude of economically efficient investment alongside the capacity for the distribution networks to support CER operation. The *ISP Methodology* provides more detail on the modelling methodology for assessing investments in other distributed resources, and distribution augmentations to support CER operation.

Given the importance of CER in the energy transition and the significant embrace of CER observed to date by consumers, AEMO commissioned two expert consultants – CSIRO and Green Energy Markets (GEM) – to support the development of the CER forecasts. The two consultant forecasts use the same scenario narratives, and both use uptake models that focus on purchase decisions from an economically rational consumer-focused behaviour perspective, while considering historical uptake that may be influenced by non-economic drivers of uptake (such as behavioural factors).

AEMO's forecasts of CER per scenario have been consolidated from the two consultants' forecasts according to **Table 16** below, with 'average' indicating a simple average of GEM and CSIRO. AEMO adopted this scenario mapping, considering that this selection maintains the integrity of the drivers of CER uptake presented in each consultant's forecast, while matching appropriately to the expected contributions from CER within each scenario's key parameters (outlined earlier in **Table 3**). In general, GEM's forecasts reflect a more buoyant outlook, whereas CSIRO's forecasts reflect a relatively more conservative consumer adoption.

Table 16 Consultant scenario mapping for CER

Scenario	*Slower Growth*	*Step Change*	*Green Energy*
Rooftop PV forecast mapping	CSIRO	Average	Average
PVNSG forecast mapping	CSIRO	GEM	GEM
Battery and VPP forecasts mapping	CSIRO	Weighted average (1/3 GEM + 2/3 CSIRO)	Weighted average (1/3 GEM + 2/3 CSIRO)

Details of the key assumptions and methodologies of each consultant's forecast are provided in the consultant reports that supplement this IASR (see Appendix A3). The forecasts reflect up-to-date views on actual installations, and reflect the economic and population forecasts of each scenario (in Section 0). The forecasts also consider each consultant's updated views on tariff options, technology and other installation costs, and system size projections.

AEMO notes stakeholder interest in how distribution network limitations may impact the growth and operation of CER. Each consultant's forecast approach focuses on the economic value for PV and battery installation for the customer. That value is primarily derived from reducing or avoiding electricity purchases from the grid, with very low payback from grid exports given low feed-in-tariffs. Given the low value of exports, the forecasting approach does not explicitly consider potential distribution network constraints. The National CER Roadmap is providing renewed focus on the challenges and opportunities to integrate CER into the power system, and AEMO's adjusted

ISP Methodology in response to the Energy and Climate Ministers' ISP Review[104] will begin to explore distribution network interaction with CER operation. This dual approach of considering consumer-driven investments based on value to the customer of increased energy independence, coupled with the revised *ISP Methodology* that considers distribution network interactions and the opportunity for other distributed resources, will appropriately provide the spread of consumer-scale and mid-scale development opportunities in the ISP.

Distributed PV

This section comprises rooftop PV and PVNSG forecasts, which together make up total distributed PV. The 2025 *Inputs and Assumptions Workbook* provides greater detail on each CER component.

Current installed capacity estimates for distributed PV are sourced from the Clean Energy Regulator[105], with AEMO's DER Register available as a comparison. The forecasts were based on the latest actual installation data available at the time of production (end of March 2025), with 22.7 GW of installed capacity for rooftop PV in the NEM (25.5 GW including the WEM), and 1.67 GW for PVNSG in the NEM (1.73 GW including the WEM). Consumers have continued to install larger PV systems, with the average rooftop PV system size now being approximately 8.5 kW per installation (although the most common installation size remains approximately 6-7 kW per installation). This trend of larger systems is expected to continue as consumers increase their electricity consumption with electrification (particularly for EVs). It is expected that system sizes will reach a natural limit over time, as roof space availability and/or the size of the customer load will eventually cap the current trend.

Rooftop PV

AEMO forecasts that the market penetration of rooftop PV will continue to rise. PV system penetration on houses and semi-detached dwellings (prime candidates for PV installations) currently sits at around 39%, and in 2050 that is projected to increase to 56% (for the *Step Change* scenario). While there is no defined saturation point in AEMO's forecasts, the effect of shading, dwelling size and consumer's financial capacity to invest in these resources will limit uptake to well below 100% of suitable dwellings.

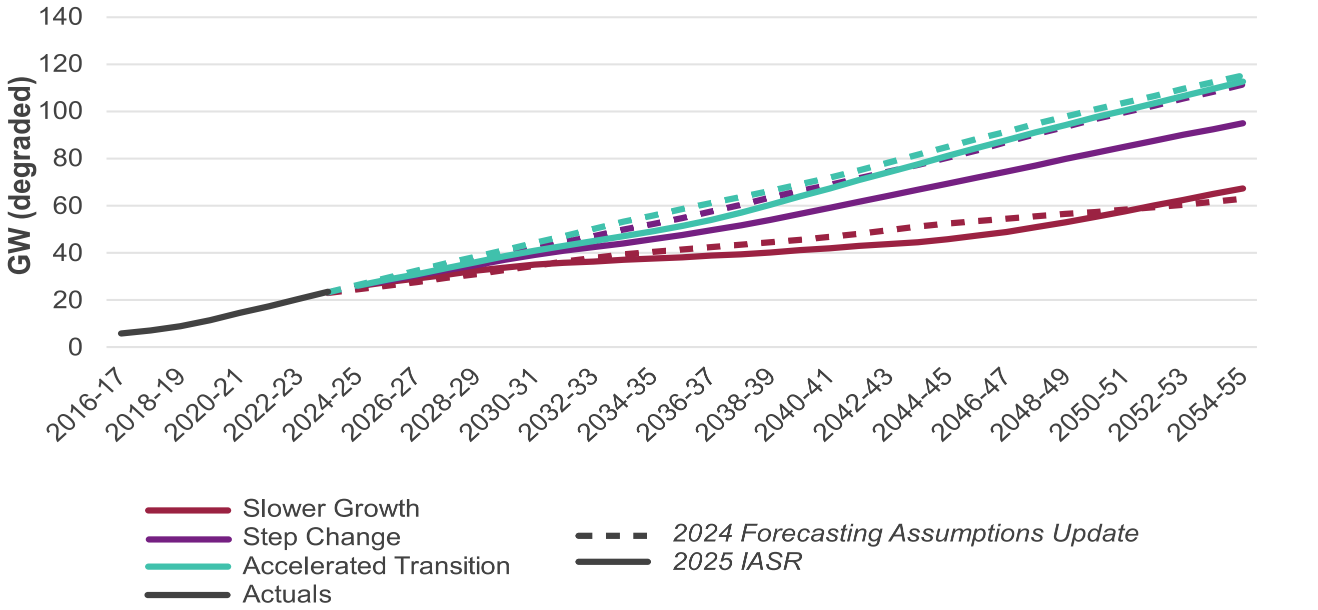
Figure 21 below demonstrates the forecasts for each scenario in terms of rooftop PV capacity.

The forecasts moderate those that were provided in AEMO's 2024 *Forecasting Assumptions Update*, particularly in the longer term, as AEMO has had greater consideration of several influencing factors than was previously considered, including household energy demand, reductions in the support provided by the SRES, suitable dwelling roof space and the perception of customer value for larger, over-sized systems while feed-in-tariffs are reducing. As a result, while average system size is still forecast to grow, AEMO considers that the growth of system sizes is more likely to reflect a lower trend than previously forecast, between the forecasts of each consultant, and in applying this lesser system size growth trajectory, the uptake trajectory in some scenarios (particularly *Step Change*) is lower.

[104] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan.

[105] Latest data is provided by the Clean Energy Regulator directly to AEMO and is complemented with data available through their website: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data.

Figure 21 Actual and forecast rooftop PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW degraded)

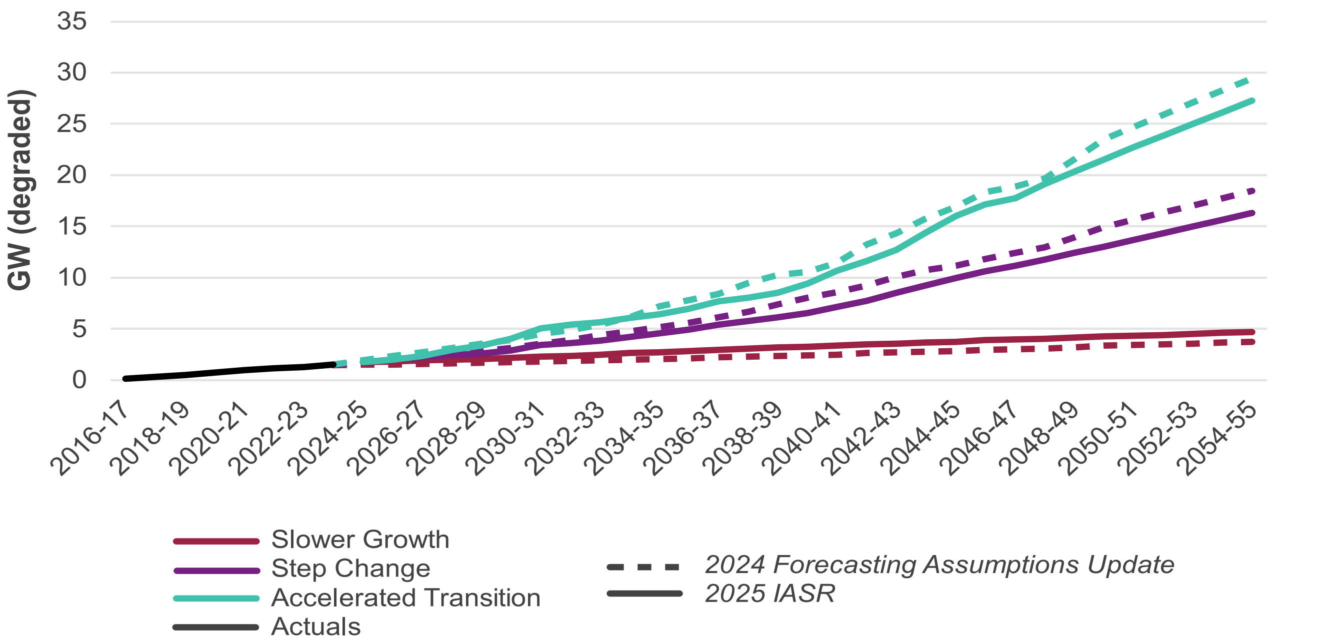


Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

PV non-scheduled generation

Growth in larger-scale PV systems (on commercial or industrial facilities for example) is expected to provide a growing contribution as technology costs decline, however at a much lower scale than rooftop PV systems. As shown in **Figure 22**, there is reasonable uncertainty captured by the scenario spread, with PVNSG's overall capacity forecast at up to 7-22% of the rooftop PV capacity across scenarios by end of June 2050.

Figure 22 Actual and forecast PVNSG capacity (NEM and WEM), 2016-17 to 2054-55 (GW degraded)

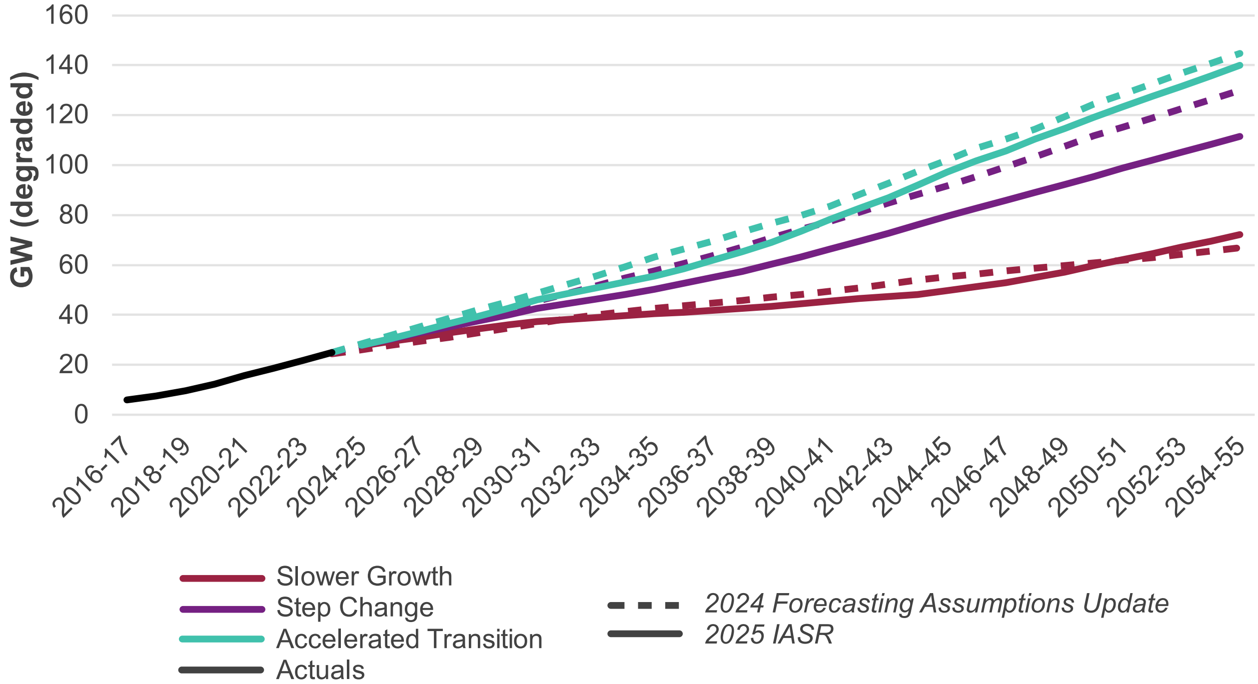


Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

Total distributed PV

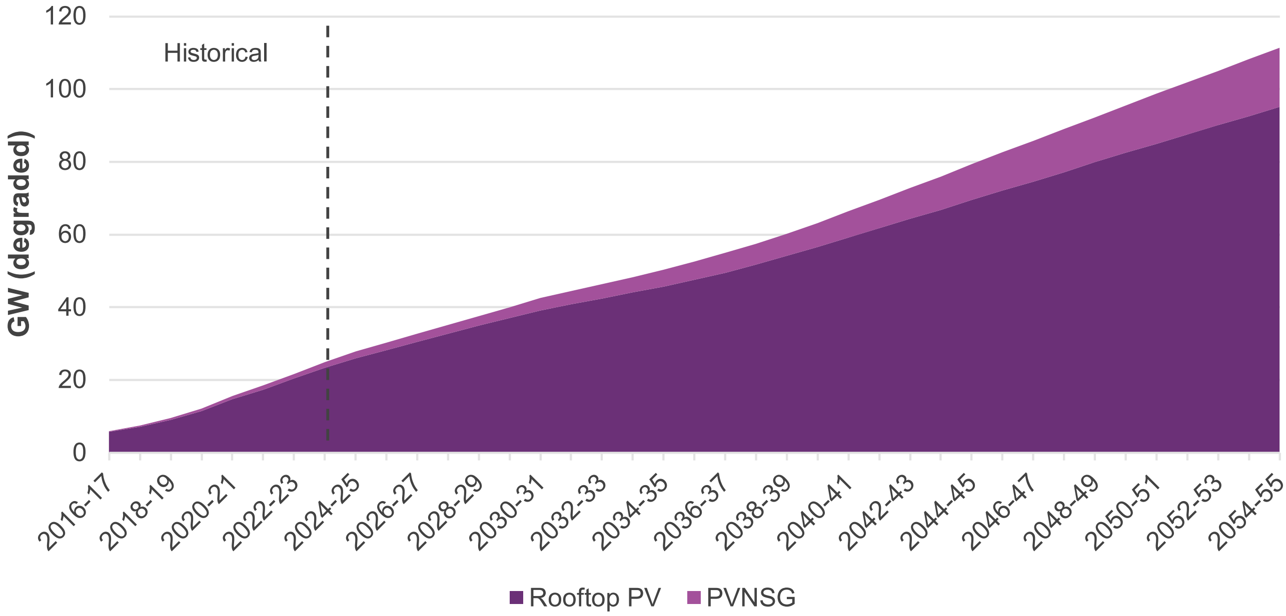
Figure 23 below aggregates the rooftop PV and PVNSG components, to construct the total aggregate distributed PV forecast. **Figure 24** shows a breakdown between rooftop PV and PVNSG for the *Step Change* scenario, demonstrating that rooftop PV provides the significant majority of distributed solar installations.

Figure 23 Actual and forecast distributed PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW degraded)



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

Figure 24 Actual and forecast rooftop PV and PVNSG installed capacity (NEM and WEM) for the *Step Change* scenario, 2016-17 to 2054-55 (GW degraded)



Embedded energy storage

Distributed residential and commercial battery systems are an emerging consumer energy resource, and one that provides significant opportunity to increase the flexibility of consumer load. Investment, and in particular coordination, of these assets (and other controllable devices) can provide a means to change the demand profile of the power system, reducing the magnitude of maximum demands and reducing the challenges associated with operating during minimum load conditions. Coordination of batteries may also be referred to aggregation.

AEMO's forecast of embedded energy storages considers the insights provided by each of the CER consultants:

- GEM's forecasts assumed that battery costs to consumers will fall significantly in the next 10 years, while battery systems will increase in size, to approximately 20 kilowatt hours (kWh) by 2050. Much of this growth is anticipated as consumers are financially rewarded to embrace coordination, through VPPs.
- CSIRO forecasts a more gradual cost reduction, approximately half the rate of decline to GEM, with battery system growth largely mirroring the pace of PV system size growth.

AEMO has considered these broad trajectories and proposes to weight the two forecasts to produce each scenario's outlooks, as per **Table 16** above. This approach recognises the slower growth in CSIRO's forecasts for *Slower Growth*, while recognising greater potential development in the other two scenarios. AEMO does not propose to evenly weight the two forecasts, considering the scale of positive change required to produce GEM's outcomes as ambitious. Considering the potential opportunity for the ISP to identify distribution investments and distributed resources beyond the CER forecasts, AEMO assesses that this approach retains an appropriate trajectory with further upside potential.

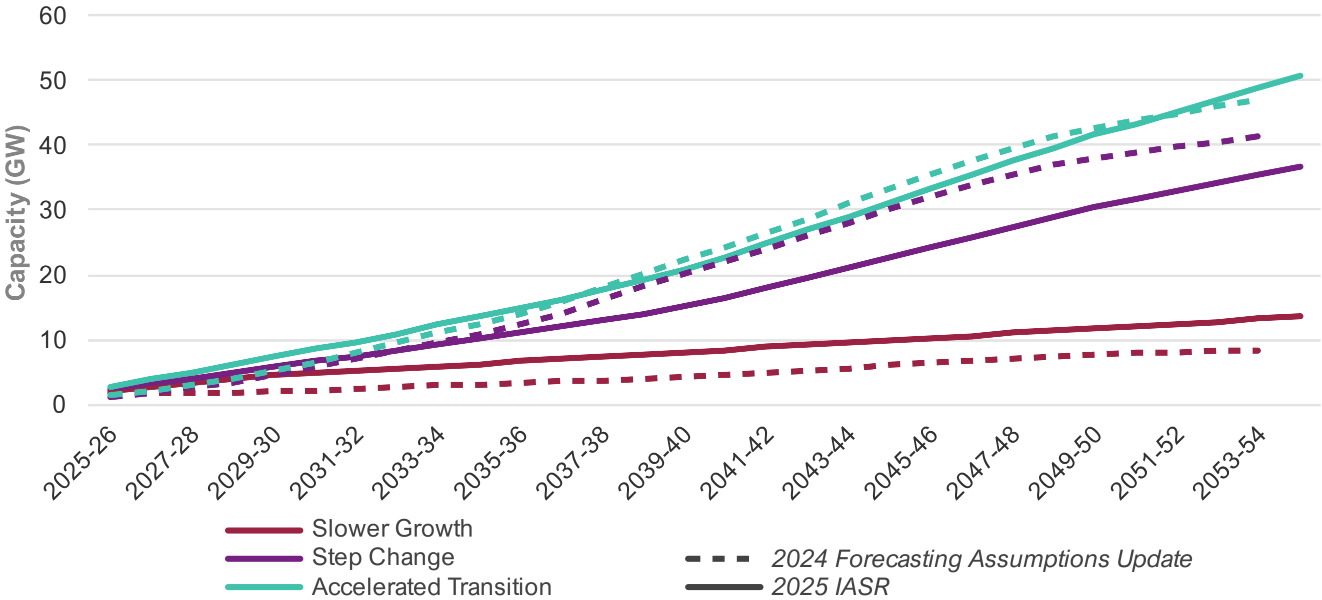
Since the Draft 2025 IASR, the battery forecasts have been adjusted to account for the expected impact of the Federal Government's Cheaper Home Batteries Program and the Western Australia Residential Battery Scheme. This adjustment resulted in an uplift across all scenarios in the early part of the forecast period. While the consultants' forecasts already included some level of assumed subsidies, as described in the individual consultant's reports, the confirmed government support packages have been considered to improve the benefit to consumers of earlier installations.

The resulting forecasts are shown in **Figure 25** below, which includes coordinated and uncoordinated batteries.

Battery operation is likely to be a mix of simple "solar shifting" and more sophisticated time-based or price-based operation to maximise the value to the householder. In practice, there may be little difference between the operating modes with most charging occurring during periods of high solar PV output and most discharging occurring at periods of high consumption.

AEMO's forecasts include varying levels of coordination across each of the scenarios. In the *Step Change* scenario, a significant proportion of consumers are assumed to choose to join VPPs to gain greater (potential) financial reward from their batteries via the coordination provided by their retailer or a third-party aggregator, consistent with the scenario narrative. This is described in the next section.

Figure 25 Distributed battery capacity forecast for the NEM+WEM (GW), including coordinated and uncoordinated batteries



Slower Growth and Accelerated Transition in the 2025 IASR are compared with Progressive Change and Green Energy Exports respectively in the 2024 Forecasting Assumption Update.

Community batteries

An emerging sector for energy storage is "community" (or "neighbourhood") batteries, which typically refers to sub-utility or "mid-scale" batteries installed in the distribution networks. Batteries at this scale are expected to help support the distribution networks in managing volatility in local demand, driven largely by the ongoing uptake of rooftop solar installations. The majority of community batteries expected to be installed in the short term are funded by federal and state government programs, or support development opportunities identified by NSPs. AEMO's CER forecasting approach includes a level of community and neighbourhood batteries in the "large commercial" sector of the battery forecasts but does not specifically identify them in the aggregated results. The ISP may identify additional distributed resources, including storage options, to complement the CER forecasts, as outlined in the *ISP Methodology*.

Aggregated energy storage – virtual power plants

A VPP broadly refers to the involvement of an aggregator to coordinate (or 'orchestrate') CER via software and communications technology, to deliver energy services similar to large-scale inverter-based generation and storage developments. This contrasts with household battery installations which are configured to offset household energy costs by reducing the volume of grid-supplied energy and increase self-consumption of complementary PV generation.

While battery operation and management will be very similar for each approach, AEMO's modelling methodologies assume that VPP aggregators can improve the that batteries can provide to discharge when most valuable to the power system during tight supply conditions, and charge when most valuable to the power system during low load conditions.

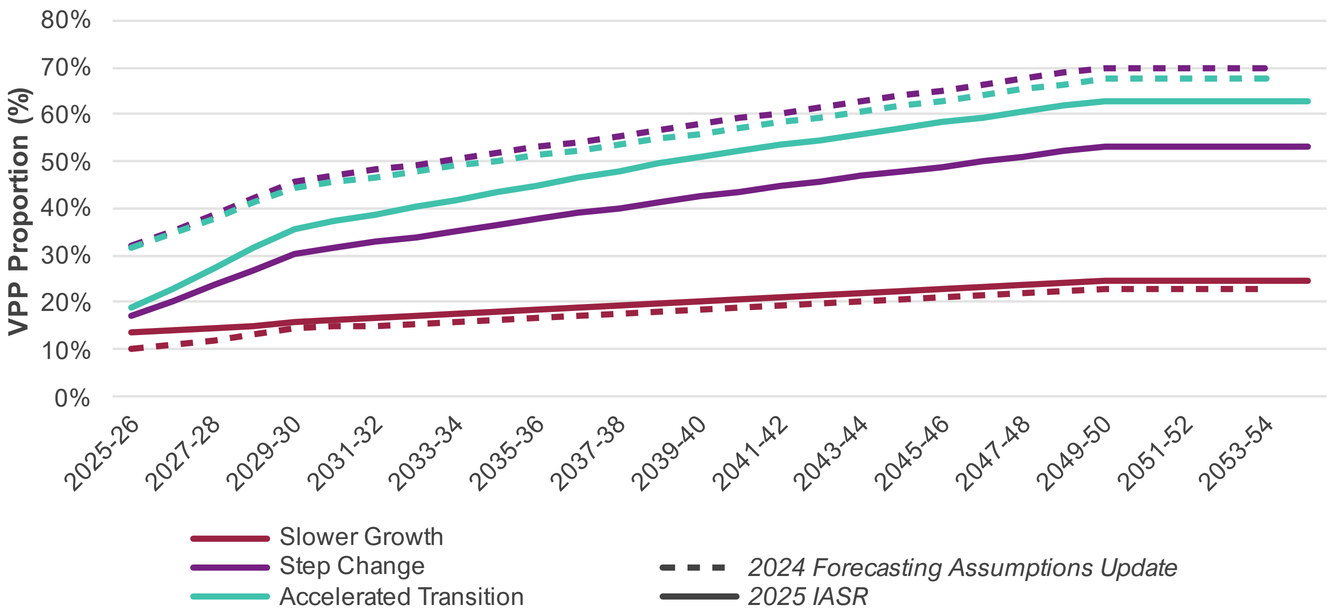
If CER is coordinated at scale and in a predictable and reliable manner, there may be a significant reduction for the scale of network and utility-scale investments needed to firm renewable energy supplies to maintain reliable and secure supply.

There are currently around 20 VPP providers in the NEM+WEM, and technical work programs (for example by Project Symphony[106] and by Project EDGE[107]) have demonstrated the feasibility and end-to-end technical capabilities of the technology.

Despite the long-term potential, the uptake of VPP products to date has been modest. AEMO's forecasts provide a wide band between the scenarios to reflect the uncertainty of both uptake and relative scale of coordination. The companion reports from AEMO's consultants demonstrate differing views of success, with success hinging on what support is provided to consumers to adopt battery systems, considering the various state government policies supporting battery uptake. Likewise, the National CER Roadmap is also focused on improving CER integration, which may influence the social licence and technical capability of battery systems to be coordinated in the manner that is forecast.

The VPP proportion of embedded storages and the resulting capacity outlook reflecting AEMO's consolidation of the consultant inputs is shown in **Figure 26** and **Figure 27** below. For *Step Change*, the 2025 scenario is purposefully designed to recognise the slower embrace of battery uptake and has a slower pace of adoption compared with the 2023 IASR scenarios, and the most recent forecasts. Slower adoption also is anticipated for *Accelerated Transition*, although the magnitude of that forecast is closer to the previous forecasts.

Figure 26 Proportion of embedded energy storage systems participating in a VPP for NEM+WEM

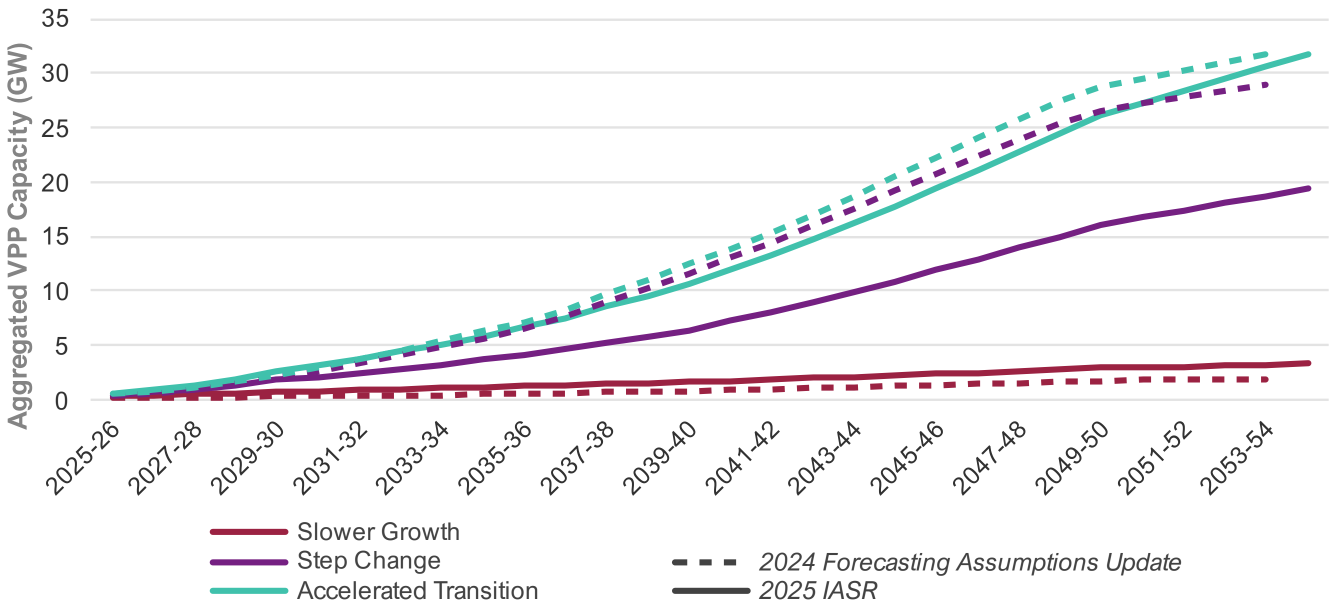


Slower Growth and Accelerated Transition in the 2025 IASR are compared with Progressive Change and Green Energy Exports respectively in the 2024 Forecasting Assumption Update.

[106] See https://aemo.com.au/en/initiatives/major-programs/wa-der-program/project-symphony.

[107] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge.

Figure 27 Aggregated VPP capacity for NEM+WEM (GW)



Slower Growth and Accelerated Transition in the 2025 IASR are compared with Progressive Change and Green Energy Exports respectively in the 2024 Forecasting Assumption Update.

Electric vehicles

Input vintage	January 2025
Source	CSIRO
Update since Draft 2025 IASR	Fixed errors in historical data 2023-2025, public charging definition expanded to include overnight kerbside charging, FCEV residential and commercial cars removed from *Slower Growth* and *Step Change*

The impact and benefits of EV use to the electricity grid arise from a wide set of factors, and the electrification of vehicles is a key lever in supporting the decarbonisation of the transport sector. This section describes updates to uptake of various types of EVs, their aggregate electricity use, and the mix and shape of the EV charging profiles.

Note that annual electricity consumption figures include the NEM and the WEM, and the term EVs is used as the collective term for battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

EV adoption has been growing in recent years, and is expected to continue to grow as more consumers embrace electrified transport options as opportunities to further contribute to reducing emissions, or to embrace economic benefits of EV vehicle ownership rather than internal combustion alternatives. As consumers shift from petrol and diesel fuelled vehicles to those that will rely on electric charging, their charging behaviours will play a key role in power system outcomes. Consumer participation in schemes that allow coordination of charging will be valuable to reduce the impact of EVs on power system needs. In this 2025 IASR, the scenarios include different rates of uptake, as well as different levels of coordination, consistent with the narrative of each scenario, and this report is complemented by more detailed information within the 2025 IASR EV workbook[108].

[108] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/AEMO-2025-IASR-EV-workbook

To support the 2025 IASR, detailed modelling of EVs in the Australian transport sector was carried out by CSIRO. The EV forecast in this 2025 IASR considers a range of new government policies introduced since the 2023 IASR that support the uptake and operation of EVs and that meet the criteria for consideration as described in Section 3.1. Key existing policies that meet AEMO's requirements under NER 5.22.3(b), as outlined earlier in **Table 4**, include the following:

- The national NVES[109], which starts in 2025 and runs until 2029. Under NVES, manufacturers must meet per-kilometre efficiency standards and may face penalties for falling short of these requirements or receive credits for exceeding them. NVES is expected to drive down EV costs and increase the number of EV models being marketed to Australians by manufacturers as they seek to meet their obligations under the targets, leading to higher EV sales.
- The Commonwealth's Fringe Benefits Tax exemption[110], which allows consumers to pay for novated leases for EVs from pre-tax income, thereby increasing tax savings.
- Several state policies are identified in the AEMC's Emissions Targets Statement[111] for Victoria, Queensland and South Australia that are designed to incentivise vehicle sales. Funded policies in other states are outlined in **Table 4**.

More detail regarding the impact of state and federal policy on the uptake of EVs is available in the CSIRO EV report[112].

The 2025 IASR refines the EV forecasts since the 2024 *Forecasting Assumptions Update* using:

- the latest actual vehicle sales figures (until December 2024) which show stronger growth for hybrids and PHEVs,
- further breakdown of vehicle technology types into hybrids along with BEV, PHEV, internal combustion engine (ICE), and FCEVs, recognising the important role hybrids are still expected to play to meet the NVES targets,
- improved data on EV efficiency[113] that reveals that mid-sized EVs are more efficient than previously assumed,
- changed assumption on average vehicle size as fewer large vehicle models are expected to be available in the short term, during the NVES policy period,
- greater consumer preferences for PHEVs, informed by stakeholder feedback in AEMO's FRG[114], and
- insights on increase in adoption of time-of-use tariffs, based on AER data[115], that is expected to reduce charging during peak electricity demand conditions.

---

[109] See https://www.legislation.gov.au/C2024A00034/asmade/text. This was considered in the 2024 *Forecasting Assumptions Update* and the Draft 2025 IASR.

[110] See https://www.ato.gov.au/businesses-and-organisations/hiring-and-paying-your-workers/fringe-benefits-tax/types-of-fringe-benefits/fbt-on-cars-other-vehicles-parking-and-tolls/electric-cars-exemption.

[111] See https://www.aemc.gov.au/sites/default/files/2024-06/Emissions%20targets%20statement%20under%20the%20National%20Energy%20Laws%20%E2%80%93%206%20June%202024.pdf, June 2024.

[112] CSIRO, Electric vehicle projections 2024, at https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/electric-vehicle-projections-2024.pdf.

[113] See variable Energy *Consumption (kWh/100km)* of Table 7 ('Vehicle Specification information') in https://www.aaa.asn.au/research-data/electric-vehicle/.

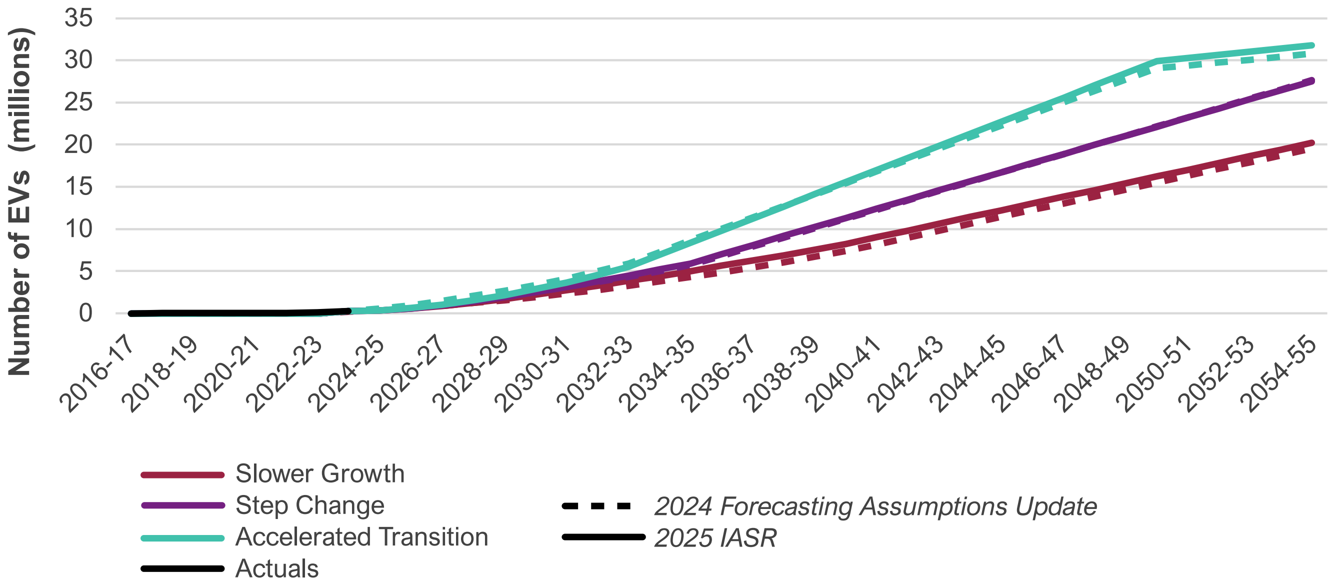
[114] See FRG Meeting held 16 October, 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2024/frg-meeting-7---meeting-pack_.zip?la=en.

[115] See https://www.aer.gov.au/about/strategic-initiatives/network-tariff-reform.

The updated modelling by CSIRO places more weight to policy drivers such as the NVES and state targets to reflect the growing role of regulation in shaping EV uptake, reducing the need to rely only on vehicle purchase and operational costs.

Figure 28 shows the projections for EV fleet size in the NEM and WEM by scenario, compared to the 2024 *Forecasting Assumptions Update*. Vehicle numbers are higher in this 2025 IASR for all scenarios, due to the higher population growth forecast, as outlined in Section 0[116]. EV fleet numbers are forecast to reach between 16 million and 30 million (64% to 95% of the whole fleet) by 2050 across the scenarios, with the *Green Energy* scenario reaching market saturation by 2050, meaning EVs have almost fully replaced the ICE fleet.

Figure 28 Actual and projected BEV and PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

The EV model relates adoption directly to time using a logistic function calibrated to three key points: the 2025 EV sales share projection; the 2029-30 sales rate required to meet the NVES target; and an endpoint (between 2035 and 2060, depending on the scenario) where EVs dominate the fleet, with further disaggregation by spatial, technological, and vehicle type factors. To obtain the sales share in 2029-30, the following plausible shares of electric and non-electric vehicle types are assigned to meet the NVES target period:

- *Slower Growth* assumes greater penetration of hybrids and fewer EVs in this scenario.
- *Step Change* and *Accelerated Transition* assumes fewer hybrids and greater BEV uptake, with vehicle owners embracing a strong opportunity to contribute to emissions reduction.

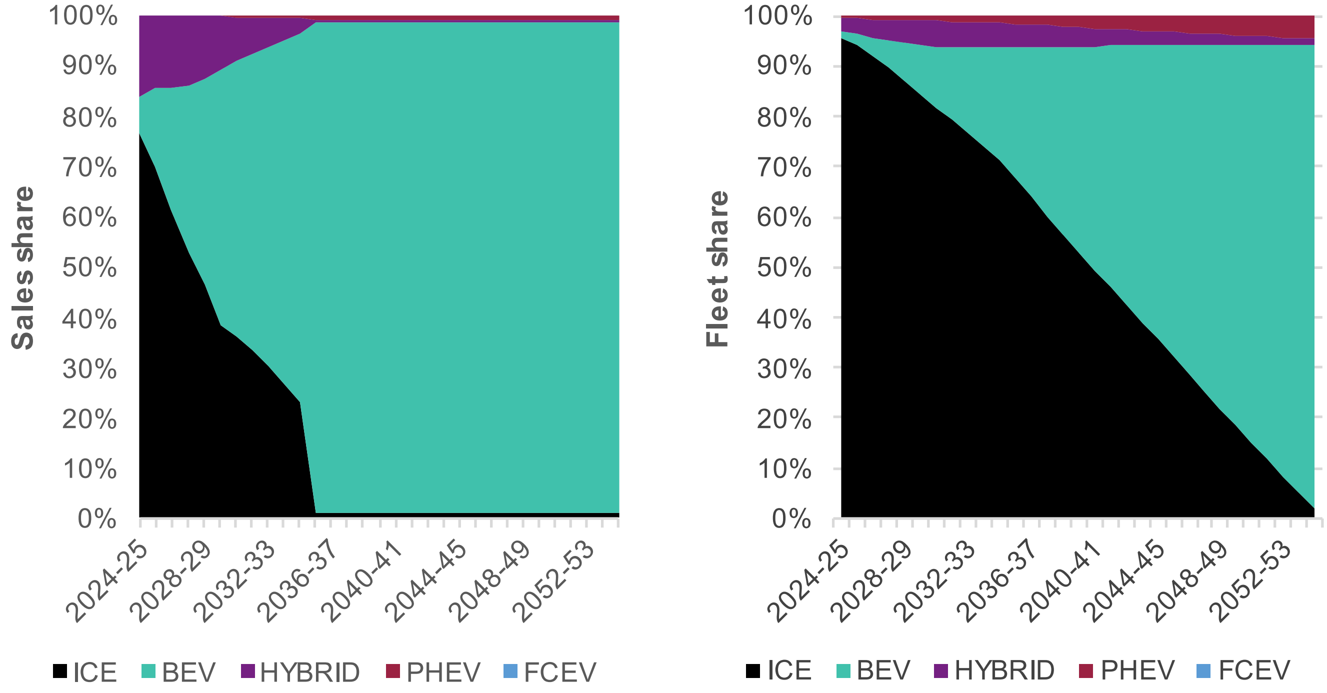
Figure 29 shows the actual and projected mix of car[117] sales and fleet share of residential and light commercial vehicles, per vehicle technology type. It shows that only a small share of ICE sales (1%) are expected to persist after the mid-late 2030s due to specific use cases such as remote driving, heavy-duty towing, long-distance travel

[116] The 2024 *Forecasting Assumption Update* EV forecast used population forecasts from October 2023 rather than the Economic Consultancy forecasts from 2024.

[117] Cars refer to all motorcycles, passenger vehicles and light commercial vehicles, and excludes buses and trucks (rigid and articulated).

or vehicular preferences (such as sports vehicles or four-wheel drives). However, ICE vehicles will remain a part of the fleet for much longer (falling below 10% only after 2053) while owners maintain their vehicles (assumed lifespan of 12 years) and second-hand markets remain. The projected fleet share is the combined result of growth in EV sales share and accelerated scrapping of ICE (relative to the present) in the latter half of the projection period. Declining fuelling and maintenance service availability will eventually reduce the commercial value of ICE ownership, accelerating scrapping across all scenarios at varying timeframes. AEMO has removed FCEV residential and commercial cars in the *Slower Growth* and *Step Change* scenarios based on stakeholder feedback recognising declining FCEV sales and limited refuelling station development. However, FCEV trucks remain as a feature of the forecasts with a very low penetration.

Figure 29 Forecast sales share (left) and fleet share (right) across vehicle technology types for *Step Change* (NEM and WEM), 2024-25 to 2054-55

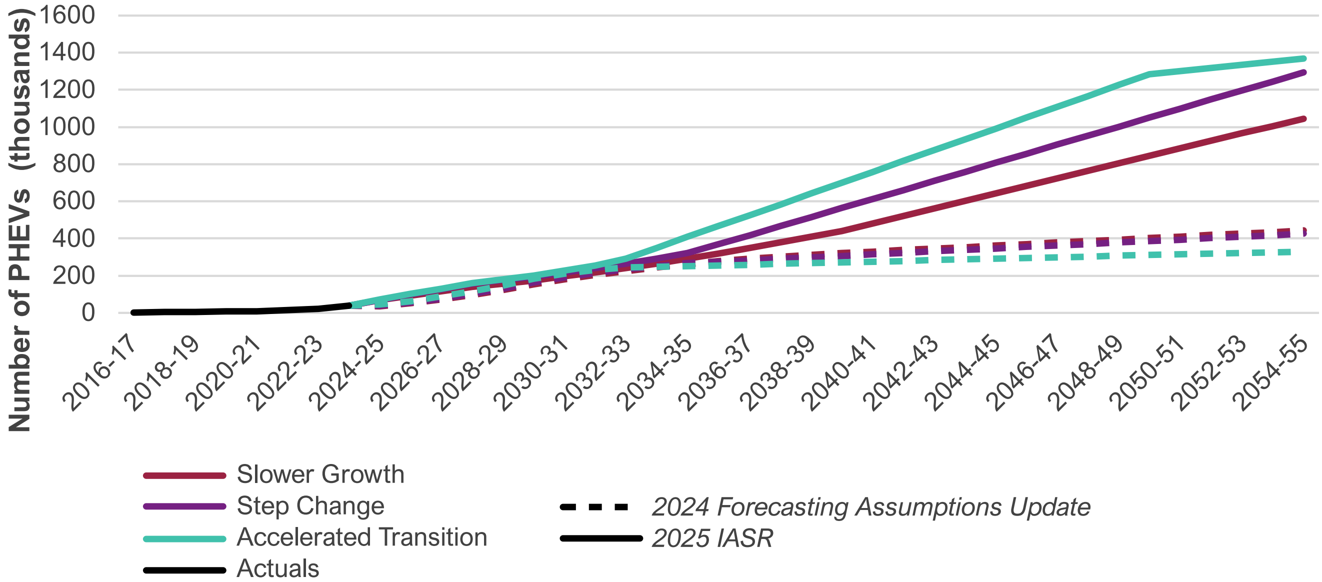


The 2025 IASR provides an amended outlook for EV fleet size compared to the previous forecast from the *2024 Forecasting Assumptions Update*, due to:

- Impact of the NVES – this is anticipated to increase hybrid, BEV and PHEV sales given these vehicle types all positively contribute to the policy targets. Hybrids and PHEVs are likely to appeal to those seeking range reliability, while BEVs' expected decreasing costs and expanding model count are expected to support continued adoption. The influence of PHEVs is anticipated to be limited to short-term sales effects, as PHEVs are currently less costly than many BEV alternatives and offer greater flexibility to some customers, providing improved heavy-duty features such as towing, off-road and remote travel capabilities than many BEVs. In the longer term, BEV costs are assumed to continue to fall, while maintenance requirements of the dual-engine design of PHEVs increases relative operating costs. PHEVs are therefore expected to maintain a more niche market share over the longer term. **Figure 30** shows forecast PHEV sales numbers across the outlook period.

- Updated sales data – although EV sales are now approximately 8% of the sales share, the 2024 calendar year sales trend indicated that BEV sales for the second half of 2024 had fallen below the average rate for 2023, and, in contrast, the PHEV sales rate had accelerated. AEMO, based on stakeholder feedback to previous publications, has increased consumer preferences toward PHEV relative to BEV in the forecasts. This preference has long-term impacts on electricity consumption and charging behaviours. However, it is expected that the recent sales results will not overturn long-term trends driven by declining battery costs and manufacturer commitments through NVES, both of which are expected to drive BEV adoption.
- Relevant state policy targets – AEMO's forecasts consider the impact of relevant EV policies and targets across jurisdictions, for example, Victoria's ZEV Roadmap (which mandates 50% of new light vehicle sales to be zero-emission by 2030), Queensland's Zero Emission Vehicle Strategy (targeting 50% of new passenger vehicles to be ZEV by 2030, rising to 100% by 2036) and targets in South Australia to provide for 170,000 EVS on the road by 2030.

Figure 30 Projected PHEV fleet size (NEM and WEM) by scenario, 2017 to 2055



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

Electricity consumption to support the use of EVs

EV users are expected to adopt a wide range of charging behaviors that will likely change over time as electrified transport becomes commonplace, and infrastructure, charging technologies and tariffs adapt to this emerging sector. Individual users will switch between different charging methods day to day, depending on the convenience of each option given their personal circumstances, and the incentives that encourage them. AEMO's EV electricity consumption forecast allows for:

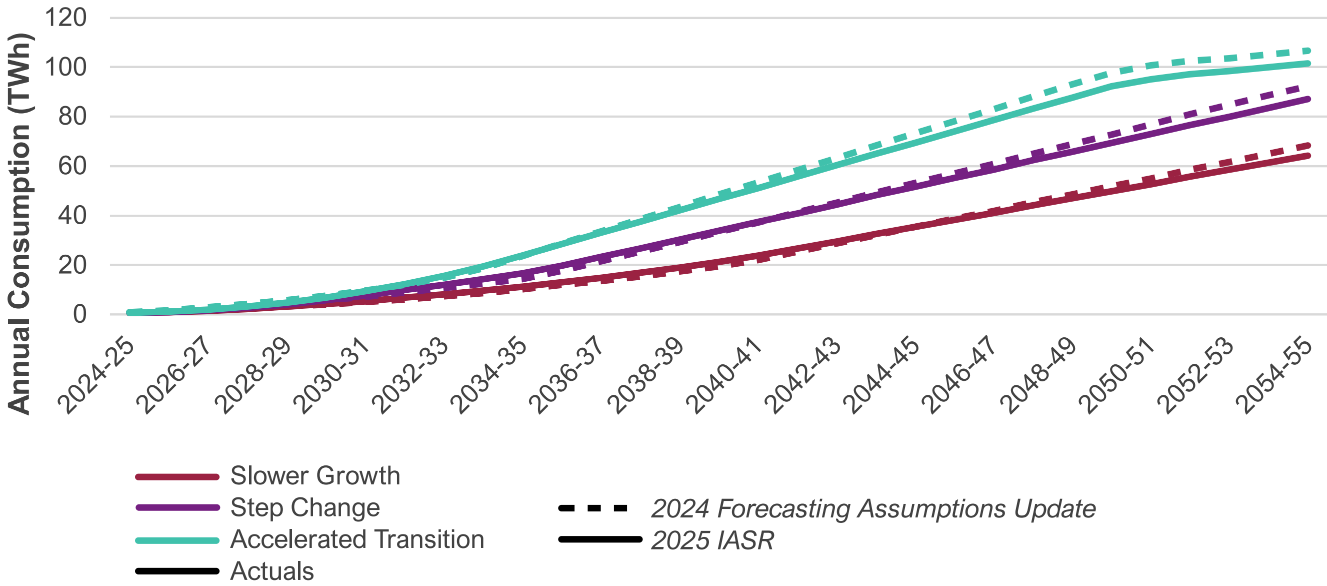
- the availability, popularity, and technical characteristics of home, business and public charging facilities,
- an evolving vehicle mix (including motorcycles, passenger and commercial vehicles of different sizes, trucks and buses), and
- varying travelling distances.

In this section, AEMO presents annual electricity consumption forecasts, as well as normalised vehicle charging profiles that represent the average vehicle across the population considering all these factors, rather than reflecting the behaviour of any individual consumer.

Figure 31 shows forecast electricity consumption from EVs, compared to the 2024 *Forecasting Assumptions Update*, highlighting that the annual consumption forecast is similar (or slightly lower) to the previous forecast. Given the slightly higher forecast vehicle projections shown above in **Figure 28**, the similar energy forecast in the short term results from improved outlooks for efficiency of mid-size EVs and greater proportion of small and mid-sized EVs.

The longer-term fall in electricity consumption relative to the previous forecast is due to changes in the assumed shares of electric and FCEV trucks, including the reduced level of FCEVs in smaller vehicles (as described previously).

Figure 31 Forecast BEV and PHEV electricity consumption (NEM and WEM) by scenario, 2024-25 to 2054-55 (TWh)



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

EV charging profiles

AEMO uses a number of static and dynamic vehicle charging profiles that are reviewed and updated annually:

- Static charging refers to charging profiles that are not affected by electricity prices and grid conditions, typically seen with wall socket and dedicated high power chargers available at homes, car parks, shopping centres or workplaces.
- Dynamic charging adjusts charging based on weather, grid demand or the vehicle's battery state. Dynamic charging may be encouraged by cheaper tariffs to compensate users for potential loss of flexibility. Although typical home chargers can be used for dynamic charging with manual adjustments, dynamic charging is expected to be more commonly achieved through smart L2 chargers (unidirectional) or V2G chargers (bidirectional), which use advanced algorithms to optimise charging sessions.

The different charging types are described in **Table 17**, relating tariffs and charger types to charging behaviour and hence the time-specific load on the power system.

Table 17 EV charging profiles and description

Type	Charging profile name	Previous name (used in 2023 IASR)	Description
Static	Unscheduled	Convenience	Unscheduled home charging that occurs on a flat tariff, typically using home chargers *An EV owner adopting this charge profile typically would charge their vehicle when returning to the home each evening, with some workplace or carpark charging as well. This simple charging preference has little regard to electricity costs.*
	Off-peak and solar	Night	Traditional time of use (TOU) tariff without day incentives, other than use of home solar *An EV owner adopting this charge profile would have high overnight charging predominantly, typically at home, but after the household's peak evening loads. Some charging occurs in the day, if convenient, to benefit from the user's own PV generation.*
	TOU Grid solar	Day	Newly emerging TOU tariff which includes middle of the day charging incentives with reduced day-time pricing such that all customers (those with PV systems and those without) are incentivised to use electricity during daytime hours. *An EV owner adopting this charge profile typically would take advantage of daytime charging opportunities at home, or away from home, absorbing low cost solar production.*
	Public	Fast/Highway (FHWY)	Public L2 and fast charge *An EV owner adopting this charge profile would typically charge rapidly while stopped at public charging facilities, on highways, at carparks, or workplaces with dedicated facilities. Given these activities typically occur during daytime hours, this profile has a daytime bias. Based on stakeholder feedback to the Draft 2025 IASR, AEMO has expanded this category to include charging that occurs near drivers' homes, typically overnight.*
Dynamic	TOU Dynamic	Coordinated	TOU tariff, but dynamically priced to reflect solar energy availability day to day, and within each day. *This profile does not include energy flows from the EV battery to the home or grid.*
	V2G/V2H	V2G/V2H	The EV owner opts into a dynamic charging scheme that allows use of the vehicle as a battery, storing energy which can be called on by a retailer or aggregator to supply back into the grid (V2G) or home (Vehicle-to-home [V2H]).

Evolution in the mix of EV charging types

The popularity of charging types will evolve over time, varying across scenarios, vehicle types and NEM regions. AEMO has refined the outlook on future charging type popularity, incorporating new data and insights on how different charging types interact with varying levels of technology improvements, infrastructure availability, tariff availability and relative cost-effectiveness under different scenarios.

This 2025 IASR considers new data that suggests that public charging may be more popular than previously estimated[118], and that more residential customers are adopting cost-reflective tariffs[119].

Key updates to the outlook for future charging behaviours include:

- Unscheduled and static time-of-use charging *(*off-peak and solar, time of use [TOU] grid solar) are expected to reduce in relative popularity in the short to medium term despite initial preferences, with corresponding growth in cost-reflective tariffs in the short term. This aligns with stakeholder feedback to the 2024 *Forecasting Assumptions Update* and Draft 2025 IASR consultations.
- The forecast popularity of public charging is higher in this 2025 IASR compared to the 2024 *Forecasting Assumptions Update*, based on AEMO's liaison with the charging industry. Public charging is assumed to continue to play an important role while there is limited penetration of suitable home and business charging facilities. In the longer term, public charging infrastructure is expected to support diverse charging needs, such as facilitating longer journeys and providing opportunities for those with limited off-street parking. Public charging, however, is forecast to plateau, particularly if popularity leads to queuing. This view is supported by stakeholders' feedback to the Draft 2025 IASR consultation.
- A growing trend towards TOU dynamic charging is forecast, particularly if public charging becomes more congested leading users to prefer suitably timed home charging. Time of use dynamic charging is expected to become more appealing than static alternatives, as it is assumed that this charging type will offer improved customer pricing that reflects pricing signals (for example encouraging charging when solar power is abundant, and discouraging charging when solar availability is more limited). Each scenario has differing assumptions regarding the pace of technologies that may impact this evolution, such as the development pace of smart charging technologies, growing consumer awareness and acceptance of dynamic charging mechanisms. AEMO notes there is limited data available to calculate the rate at which TOU static charging should transition to TOU dynamic charging. As such, AEMO applies an assumed proportion that varies by scenario and over time. Under the *Step Change* scenario, the proportion is assumed to be zero (2025) increasing to 20% by 2030 and reaching 50% by 2040 and 100% by 2050. The *Accelerated Transition* scenario follows an earlier and higher uptake trajectory, while *Slower Growth* follows a slower and lower trajectory compared to *Step Change*.
- The outlook on V2G/vehicle-to-home (V2H) has not been updated since the 2024 *Forecasting Assumptions Update* due to countervailing considerations. While progress is being made towards the availability of V2G charging technology, the scenario narratives reduced their expectation for V2G forecasts based on stakeholder feedback.

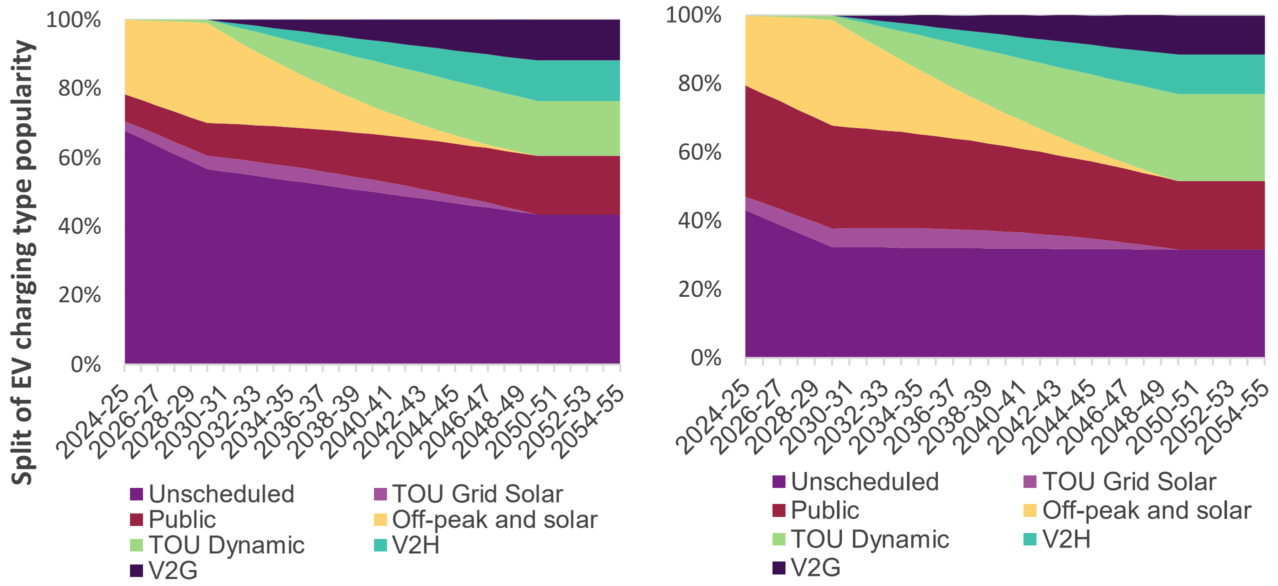
Figure 32 shows the mix of charging types assumed for 2024 *Forecasting Assumptions Update* (left) and this 2025 IASR (right) for medium residential vehicles in New South Wales in the *Step Change* scenario.

---

[118] Public charging companies reported higher market share, although this could not be independently verified due to data confidentiality.

[119] See https://www.aer.gov.au/about/strategic-initiatives/network-tariff-reform#:~:text=In%20aggregate%2C%20at%2030%20June,5%25%20from%20the%20previous%20year.

Figure 32 Split of charging types for medium residential vehicles: 2024 *Forecasting Assumptions Update* (left) and 2025 IASR (right) for *Step Change* scenario



EV charging profile shape

Several trials (Energex and Ergon Energy Network[120], AGL[121], Jemena[122], Origin Energy[123], and the University of Queensland/Electric Vehicle Council of Australia[124]) have demonstrated the potential load shape of EV charging and are used as considered sources for AEMO's half-hourly charging profiles for each charging type. These profiles vary over NEM regions, vehicle type, time (months, years), and day types (weekdays/weekends), independent of the popularity of the profile.

The 2025 IASR forecasts rely exclusively on Australian charging data trends to inform the revised load profiles. As seen in **Figure 33** below, AEMO's revised TOU profiles have lower charging demand during daylight hours based on consideration of local charging profiles. This recognises that fewer vehicles are likely to have access to daytime charging infrastructure, or that daytime charging may be congested with limited availability of suitable public or private charging facilities. The charging types are affected in proportion to their weighting at that time. AEMO's consideration of local charging profiles provided by these public trials, rather than international charging profiles, reduces the degree of charging during peak demand periods for 'unscheduled' charging type. These profiles are both averaged (net of vehicle charging diversity[125]) and normalised to 7 kWh daily charging, to enable easier

[120] Energex and Ergon Energy Network 2023, at https://www.energex.com.au/__data/assets/pdf_file/0008/1096496/EV-SmartCharge-Queensland-Insights-Report.pdf.

[121] AGL Electric Vehicle Orchestration Trial 2023, at https://arena.gov.au/assets/2023/08/20230703-AGL-Electric-Vehicle-Orchestration-Trial-Final-Report.pdf.

[122] Jemena Dynamic Electric Vehicle Charging Trial Project 2023, at https://arena.gov.au/assets/2023/04/jemena-ev-grid-trial-knowledge-sharing-report.pdf.

[123] Origin EV Smart Charging Trial 2021, 2022, at https://arena.gov.au/assets/2022/05/origin-energy-electric-vehicles-smart-charging-trial-lessons-learnt-2.pdf.

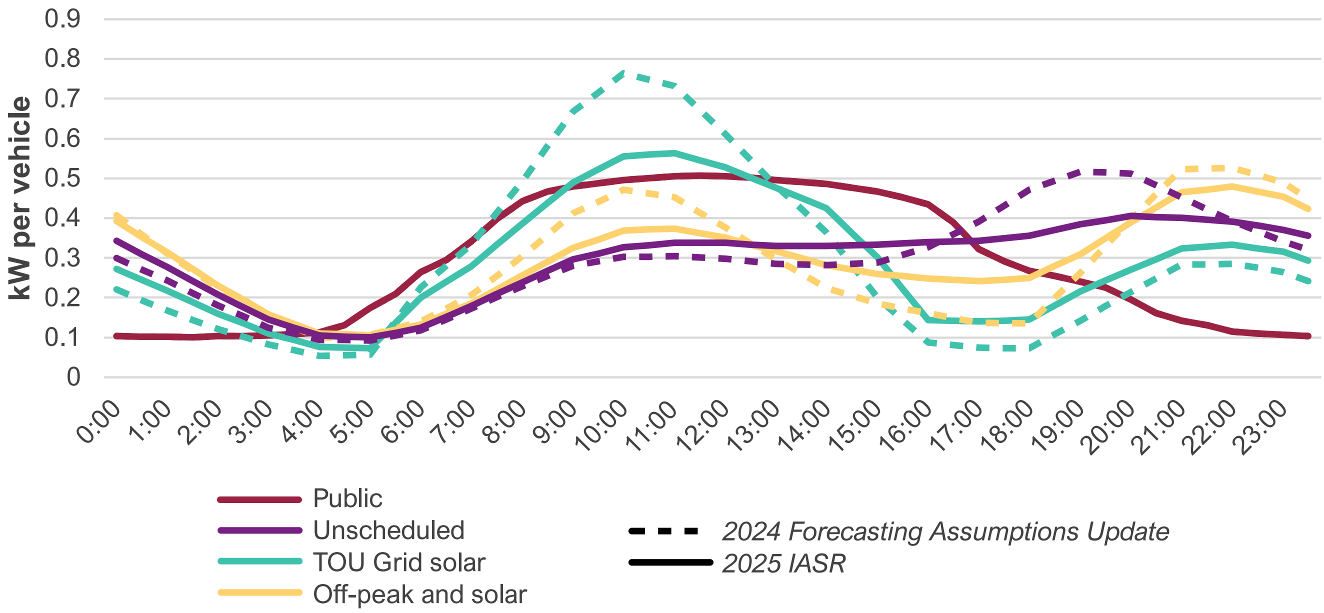
[124] See *Driving and charging an EV in Australia: A real-world analysis 2022*, at https://australasiantransportresearchforum.org.au/wp-content/uploads/2022/05/ATRF2022_Resubmission_80.pdf.

[125] The profiles are 'after diversity', reflecting the expected average load per vehicle on a given day, rather than representing a typical individual vehicle. This diversity-reflective profile is much lower than individual charger capacities, as each vehicle typically may only charge once or twice a week.

comparison between charging profiles. They represent a typical January weekday in New South Wales, under the *Step Change* scenario. A load of 7 kWh represents the approximate charge needed for a typical sized residential vehicle's daily travel distance of 30 km. The total charging load across each day is determined by factoring in the charging profiles' evolving shape and popularity over time. AEMO will continue to monitor developments as relevant pricing data becomes publicly available. The current EV forecast does not incorporate specific TOU pricing assumptions; rather, it is informed by empirical data based on observed charging behaviours from real-world trials.

AEMO's static charging profiles are detailed in the 2025 IASR EV Workbook[126]. Dynamic charging profiles are optimised within AEMO's supply modelling assessments, such as the ISP, reflecting the availability of electricity supply. The public charging profile is unchanged between the 2024 and 2025 charging profiles. AEMO received feedback to the Draft 2025 IASR consultation suggesting public kerbside charging should be included. AEMO considers, in consultation with CSIRO, that changes to the long-term profiles could only be improved with more data on overnight kerbside charging, or with greater clarity on the cost of this technology. Without greater data availability, forecasting models cannot reasonably incorporate the financial and technical distinction of kerbside chargers relative to other fast chargers.

Figure 33 Static after-diversity charging profiles of different EV charging types for medium residential vehicles in 2030



Note: The public charging profile is unchanged between the 2024 and 2025 charging profiles.

[126] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/AEMO-2025-IASR-EV-workbook

3.3.8 Economic and population forecasts

Input vintage	October 2024
Source	Deloitte Access Economics (DAE) Australian Bureau of Statistics (ABS)
Update since Draft 2025 IASR	Economic forecasts have been updated to real June 2025 dollars

In 2024, AEMO engaged Deloitte Access Economics (DAE) to develop long-term economic forecasts by scenario for each Australian state and territory. DAE developed the economic forecasts using its proprietary macro-econometric model, which is described in more detail in its report[127]. DAE's own in-house baseline forecasts form the basis of the economic forecasts prepared for AEMO. Inputs and drivers to the economic model include factors such as domestic production, labour market conditions, and prices and wages, in addition to physical[128] and transition[129] risks associated with climate change. The economic forecasts are used as a key input to AEMO's energy and demand forecasts.

In June 2025, AEMO re-engaged DAE to provide a comparison of changes to its latest available in-house baseline forecasts for key state and national indicators, considering global political, economic and trade conditions on the Australian economy[130]. This baseline comparison provided an indication of how AEMO's economic forecasts would also differ if they were to be updated.

Overall, there is slightly stronger GDP growth in the early years compared to previous baseline forecasts, driven by better-than-expected labour market conditions, elevated government spending, easing inflation, and modest real wage gains. The impact of uncertainties associated with the United States' trade policies on Australia's economic outlook is considered relatively low, owing to Australia's comparatively limited exposure to the United States import market, as well as DAE's assumption that reductions in Chinese demand are expected to be offset by stimulus measures by the Chinese government, thereby cushioning the Australian economy. The long-term outlook remains broadly consistent, although it is now expected to be slightly weaker due to slower population growth. Drawing on these insights, AEMO concluded that the economic forecasts prepared in October 2024 remained relevant and that an update was not warranted.

Across all scenarios over the forecast period, assumed variations in the drivers of economic growth (demographic profiles, labour productivity growth, decarbonisation pathways, and global conditions) result in divergent economic futures. **Table 18** details the key assumptions and summary results for the three scenarios.

Across all scenarios, the economic composition of the Australian economy is expected to change over time. Throughout the forecast period, the share of Gross Value Added (GVA) attributed to the manufacturing and mining industry is expected to decline, as industries which are relatively emissions-intensive come under pressure from the physical and transition risks associated with climate change. Conversely, the share of GVA attributed to commercial services is expected to increase.

[127] *Deloitte Access Economics: Economic forecasts 2024-25*, at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[128] Physical risks associated with climate change in Australia cover the damages that are likely to affect land, labour, and capital.

[129] Transition risks arise from the mitigating actions taken in response to climate change, including policy and regulatory change, technological developments, or shifting consumer preferences.

[130] Prepared for AEMO's internal use, the comparison draws on DAE's baseline macroeconomic forecasts released in late April 2025, and takes into account US trade policies announced as of 16 April 2025.

Table 18 Economic forecast details by scenario

Scenario	Forecast annual economic growth (GDP)	Scenario details
Slower Growth	1.3%	*Slower Growth* is a downside scenario relative to *Step Change*. *Slower Growth* assumes slower population and productivity growth, as well as reduced climate change action coordination. A smaller and less productive economy (relative to *Step Change*) contends with a heavier climate change burden.
Step Change	1.8%	*Step Change* is the central scenario for the economic forecasts. An ageing population and declining productivity growth place downward pressure on economic growth over the forecast period. Australia's decarbonisation pathway limits emissions and constrains economic growth. States and territories with emissions intensive industries see lower rates of economic growth relative to the national average.
Accelerated Transition	2.5%	*Accelerated Transition* is the upside scenario relative to *Step Change*. *Accelerated Transition* assumes greater population growth and productivity growth alongside lower climate change costs. Mining activity slows, but critical minerals output increases due to strong demand and targeted industrial policy.

Figure 34 and **Figure 35** illustrate the predicted economic composition of the NEM and the WEM over the forecast period for the *Step Change* scenario.

Figure 34 Economic composition of the NEM, *Step Change* scenario, 2025-26 to 2054-55

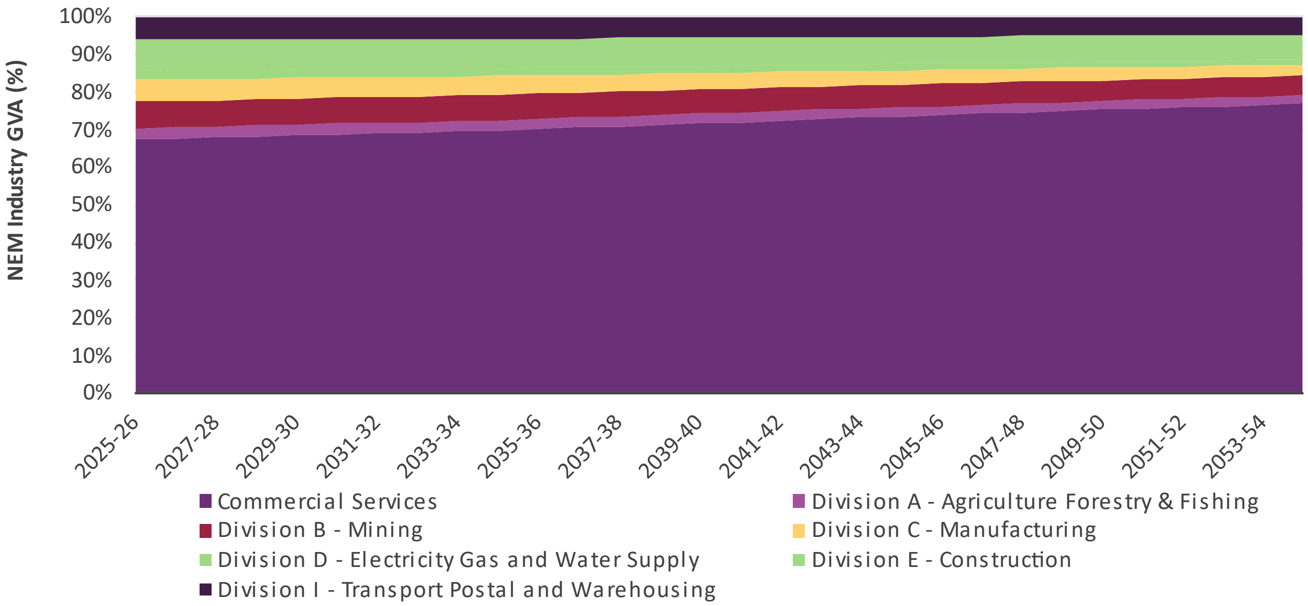
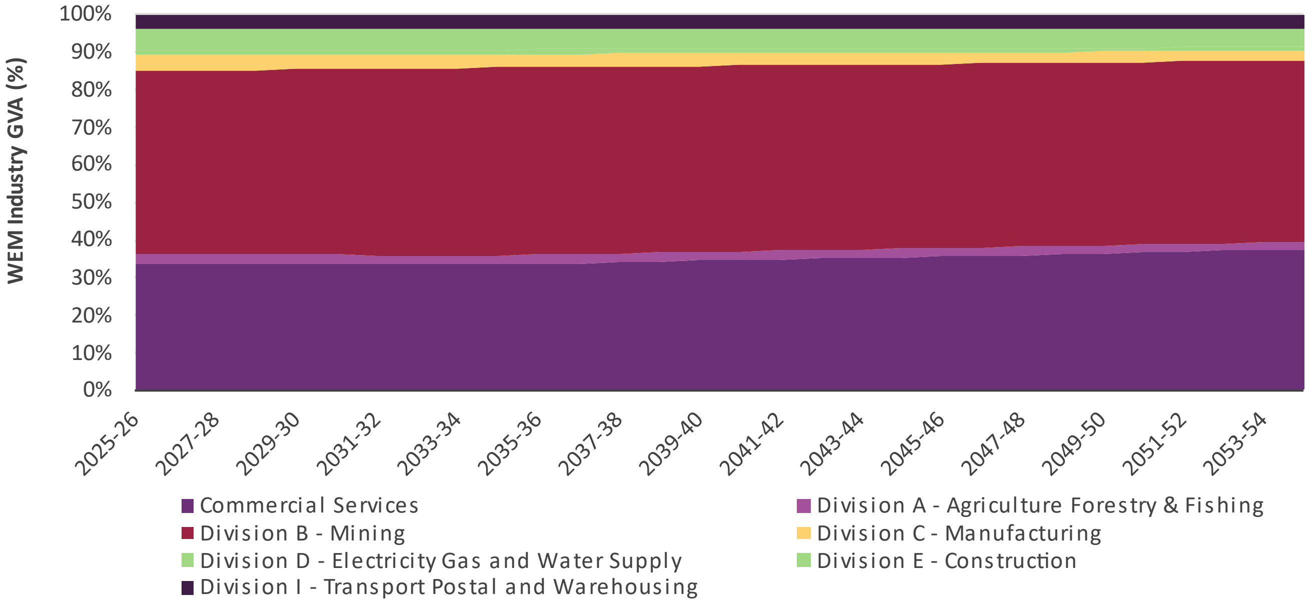
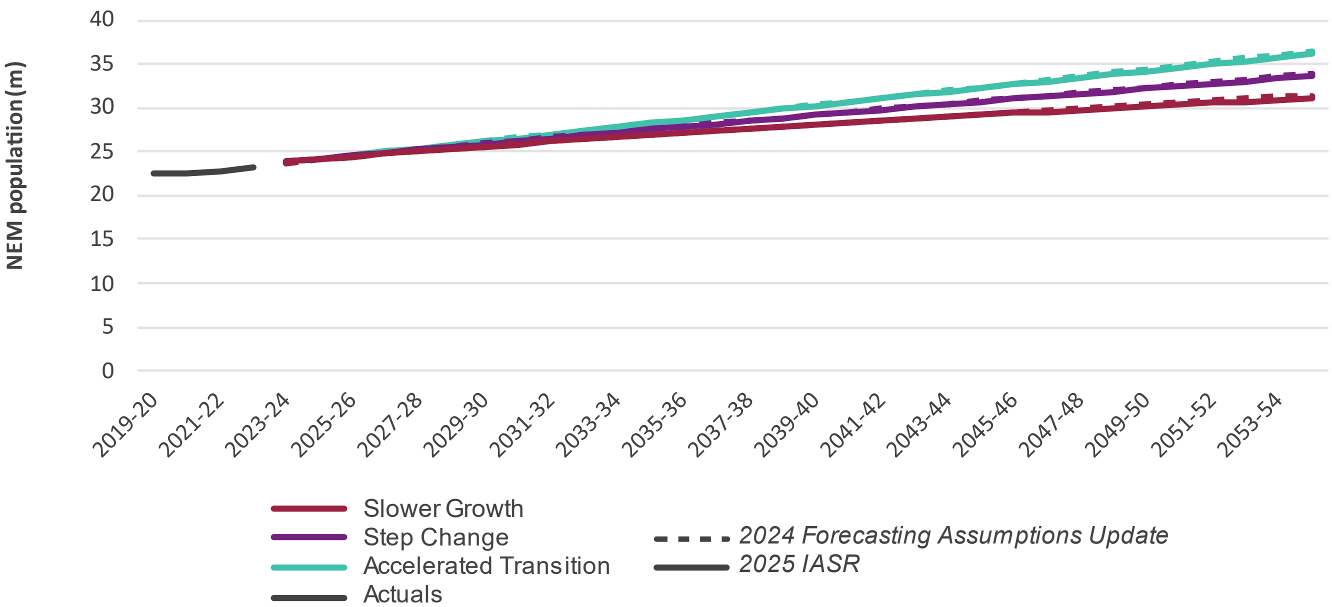


Figure 35 Economic composition of the WEM, *Step Change* scenario, 2025-26 to 2054-55



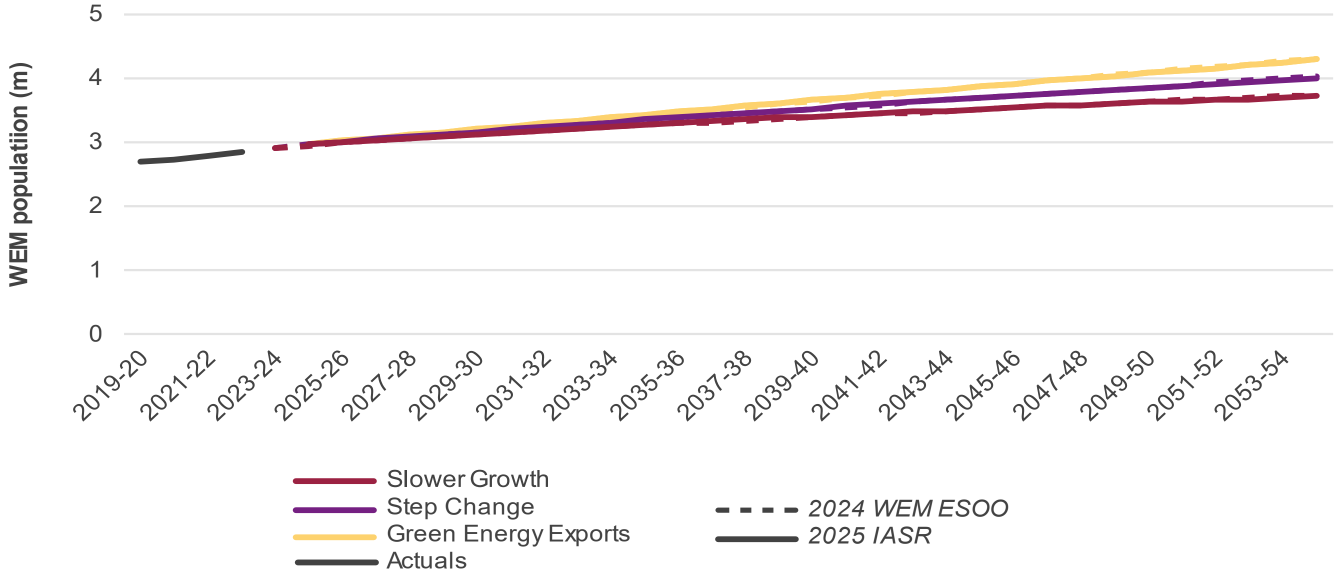
Population growth rates underpin rates of economic and productivity growth. An ageing population weighs on productivity growth as labour force participation decreases. Population assumptions are varied across the scenarios. Relative to the *Step Change* scenario, the *Accelerated Transition* scenario forecasts higher rates of population growth, whereas the *Slower Growth* scenario forecasts reduced population growth consistent with the scenario's exploration of weaker economic activity (see **Figure 36** and **Figure 37**).

Figure 36 Population growth in the NEM, all scenarios, 2019-20 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

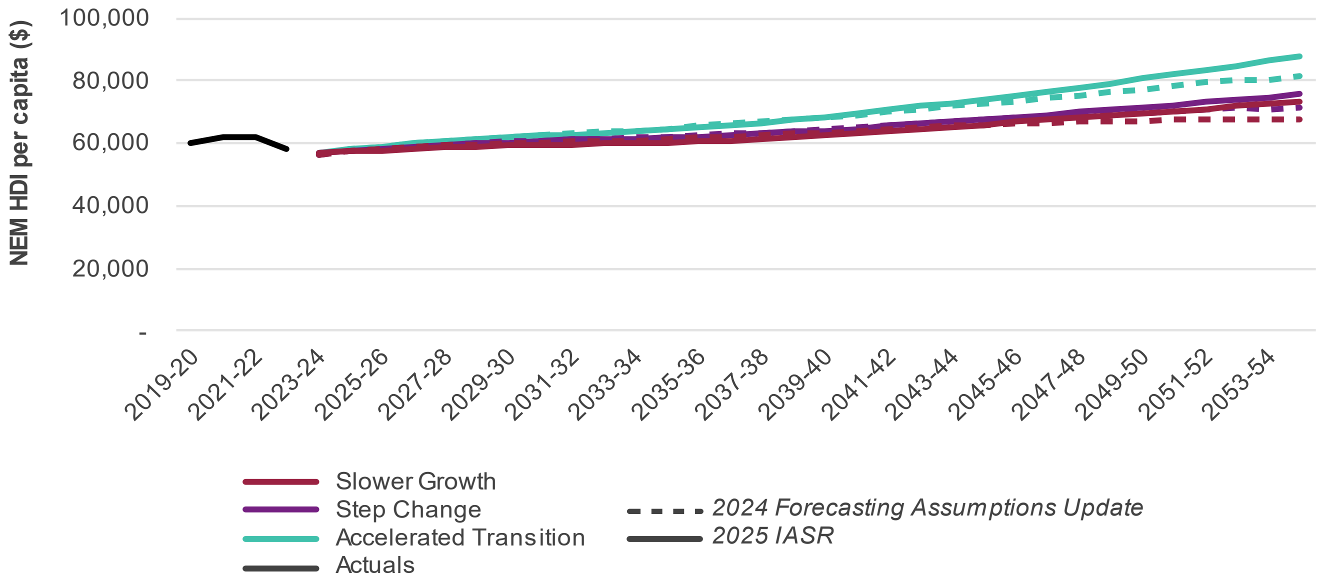
Figure 37 Population growth in the WEM, all scenarios, 2019-20 to 2054-55



Note: *Slower Growth* in the *2025 IASR* is compared with *Progressive Change* in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

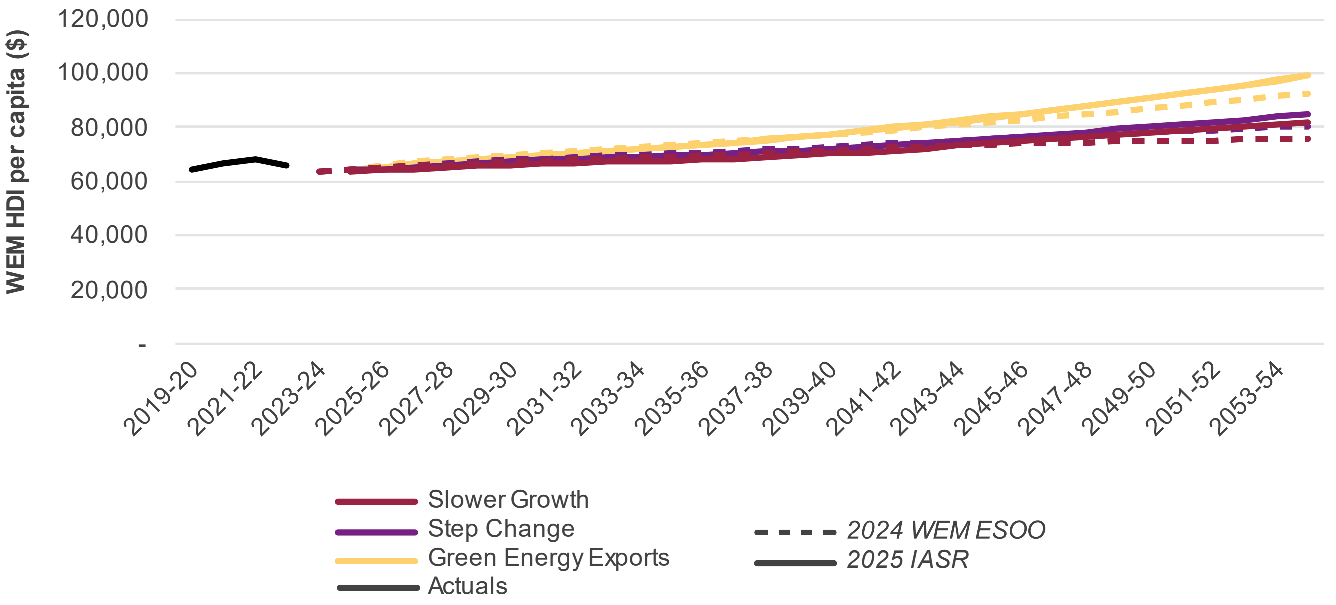
Economic growth has recovered in the post-pandemic period. In the short term, expected reductions in inflation and interest rates are forecast to increase Household Disposable Income (HDI) (see **Figure 38** and **Figure 39**) and support economic growth. Real HDI is not, however, projected to return to the peak levels observed in 2020-21 until the mid 2030s. HDI is driven by employment and wages growth and limited by cost of living pressures. Higher HDI particularly benefits industries producing discretionary and luxury goods, such as retail and hospitality. In the longer term, in the *Accelerated Transition* scenario in particular, higher levels of forecast productivity growth drive faster wage growth and consequently higher levels of HDI relative to the *Step Change* and *Slower Growth* scenarios.

Figure 38 NEM household disposable income per capita by scenario, all scenarios, 2019-20 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

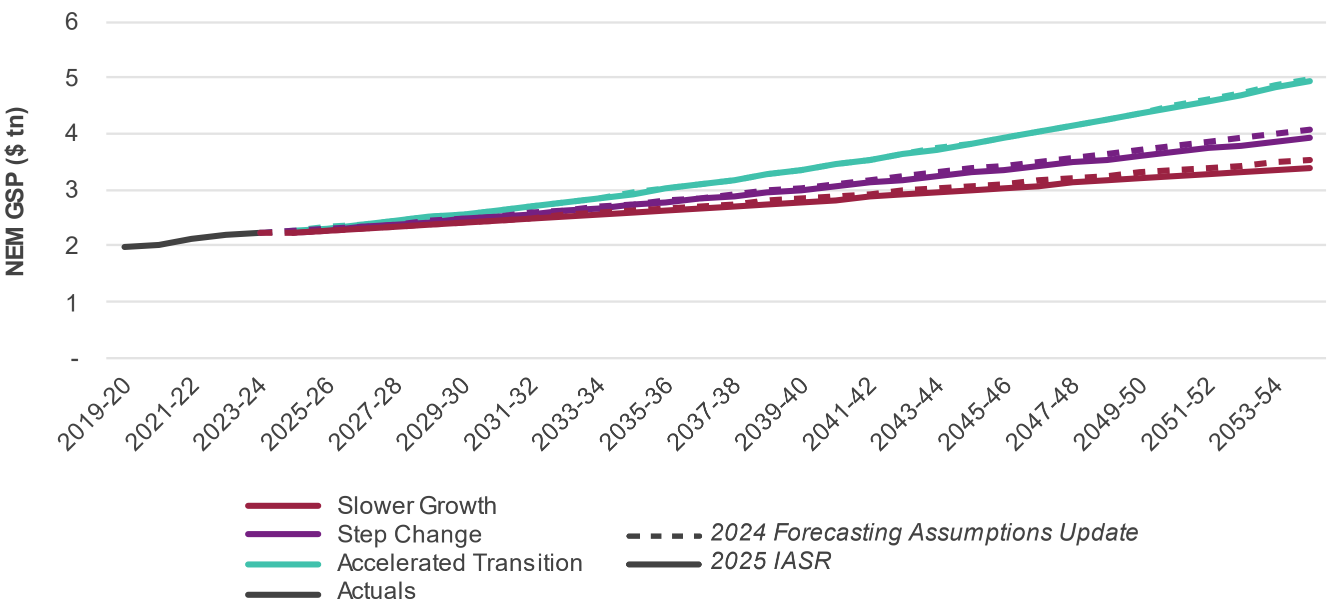
Figure 39 WEM household disposable income per capita by scenario, all scenarios, 2019-20 to 2054-55



Note: *Slower Growth* in the *2025 IASR* is compared with *Progressive Change* in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

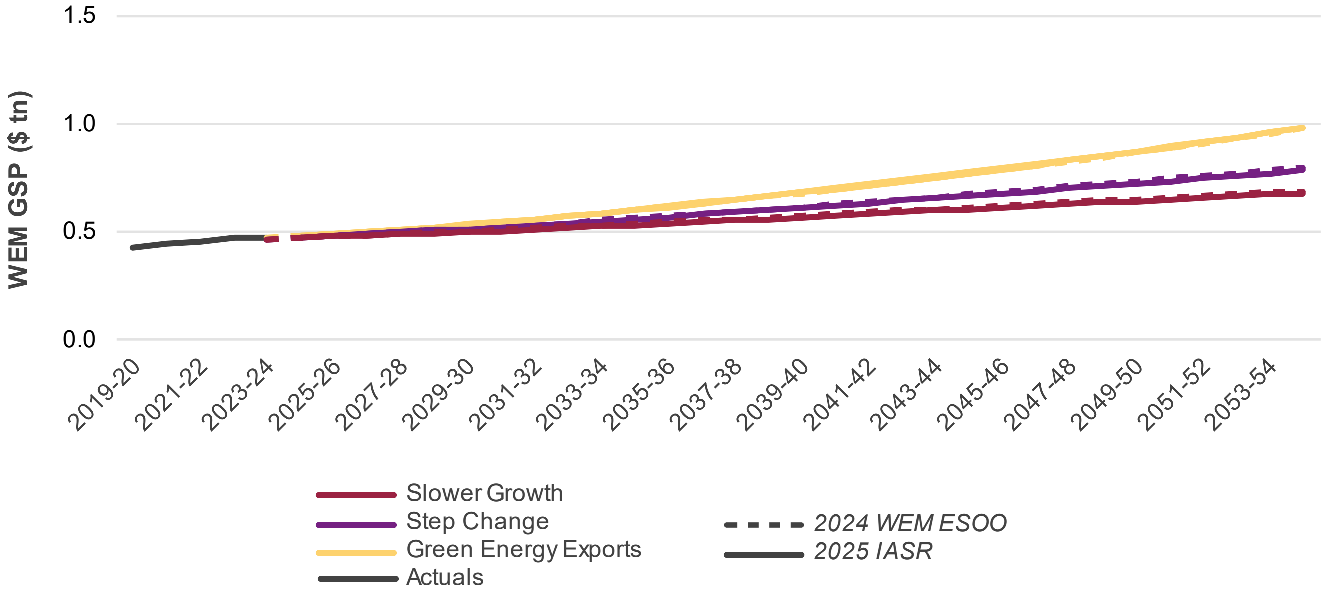
Economic growth diverges across the scenarios over the forecast period (see **Figure 40** and **Figure 41**). Higher population and productivity growth, alongside targeted industrial policy and investments in renewable energy infrastructure, drive increased economic growth in the *Accelerated Transition* scenario. Lower population and productivity growth decrease expected economic growth in the *Slower Growth* scenario, although economic activity is still forecast to expand. In this scenario, a key disruptor is the continued operation of large industrial loads due to the weaker economy; see Section 3.3.10 for more detail.

Figure 40 NEM aggregated Gross State Product, all scenario, 2019-20 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

Figure 41 WEM aggregated Gross State Product, all scenario, 2019-20 to 2054-55



Note: *Slower Growth* in the *2025 IASR* is compared with *Progressive Change* in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

3.3.9 Households and connections forecasts

Input vintage	June 2025
Source	ABS Economic forecasts (DAE) AEMO meter database
Update since Draft 2025 IASR	Updated with AEMO's latest connections data

AEMO's forecast of underlying residential electricity consumption is mainly driven by forecast growth in electricity connections. As Australia's population increases, so does the expected number of new households, which require electricity connections.

Existing connections are extracted from AEMO's metering database. Forecast new connections are informed by dwelling completions (newly constructed dwellings net of dwelling demolitions) sourced from the economic consultancy as well as dwelling stock information sourced from the Australian Bureau of Statistics (ABS).

The 2025 forecast for the NEM sits at higher levels compared to the 2024 forecast, particularly in the later years of the outlook period.

This growth is attributed to an increase in dwelling completions informed by population estimates. It is important to note that the growth in new households is expected to marginally outpace the growth in total population, as the average household size steadily declines.

In the *Step Change* scenario, connections in the NEM are forecast to grow to around 16 million by 2054-55, which is approximately 400,000 more than the 2024 forecasts due to comparatively higher projected population growth.

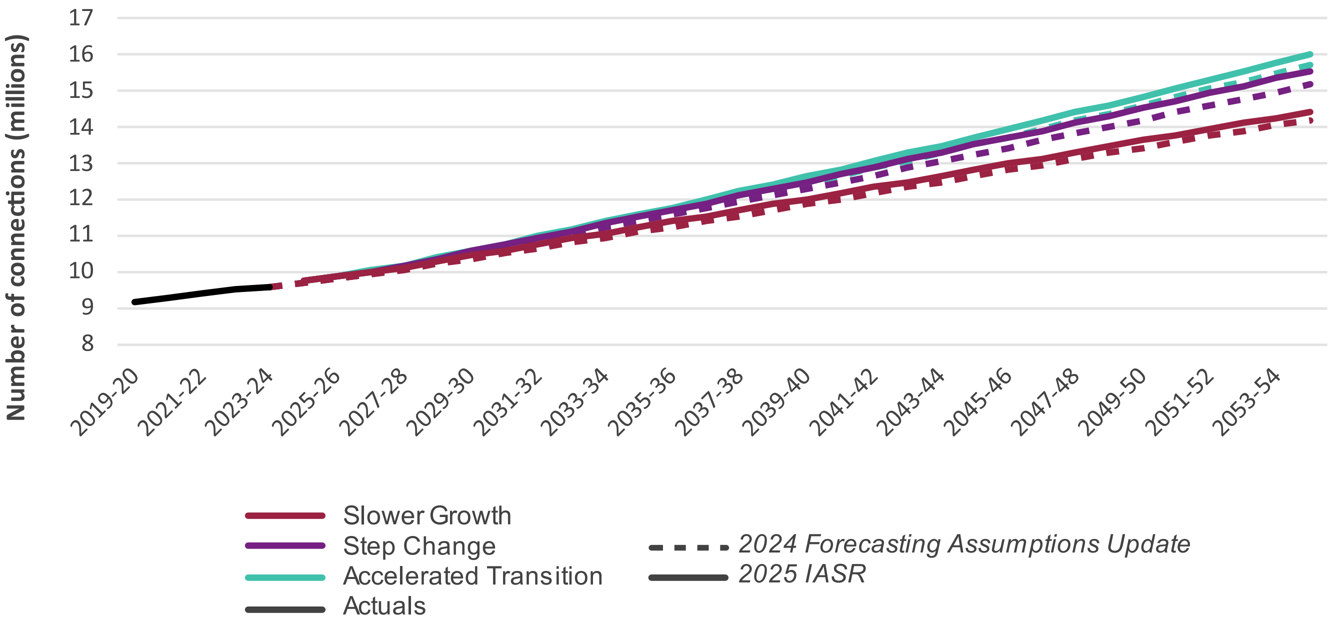
These additional connections are backed by a higher population forecast in the longer term, compared to the 2024 forecasts.

The growth of new connections varies across the NEM, with increased connections in Victoria, South Australia, Queensland, and Tasmania, and steady growth in the Australian Capital Territory and New South Wales compared to the 2024 forecasts.

For WEM, the connections growth is steady for *Step Change* and *Green Energy Exports*, with lower projections in *Slower Growth* due to lower dwelling builds compared to the 2024 forecasts.

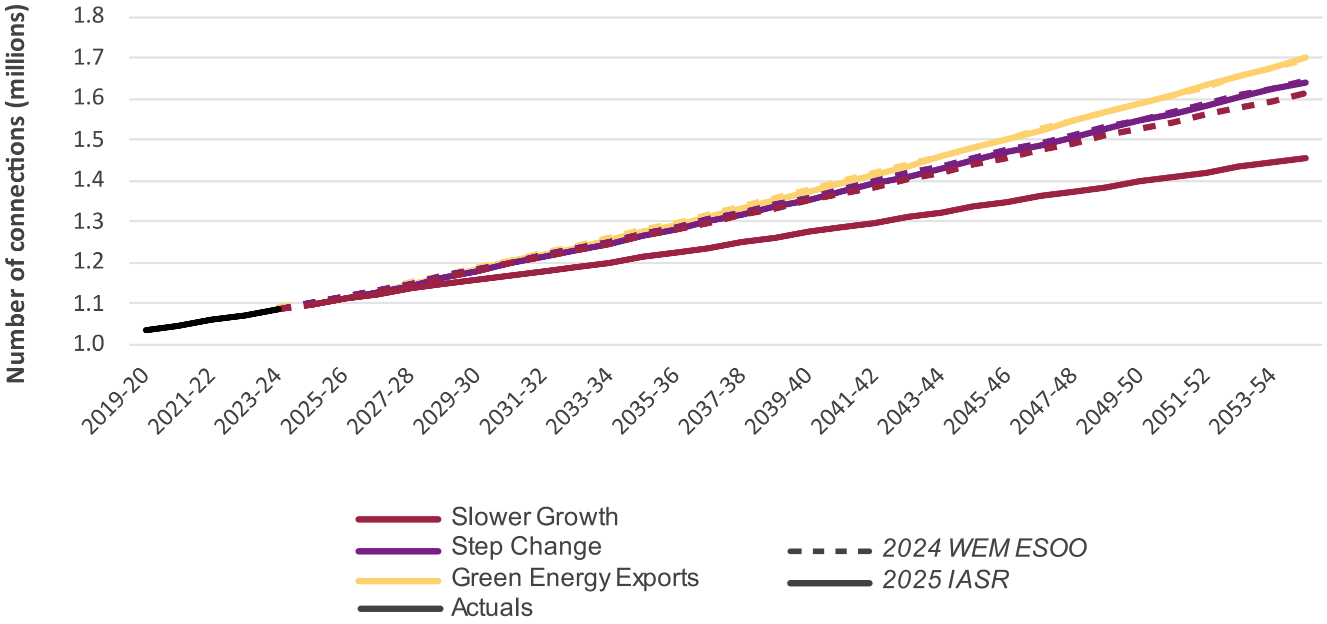
Figure 42 and **Figure 43** show the actual and forecast residential connections actual and forecast for all scenarios in the NEM and WEM, respectively. Furthermore, **Figure 44** shows the forecast annual growth of new connections on an aggregated basis for the NEM.

Figure 42 2025 Actual and forecast NEM residential connections, all scenarios, 2019-2020 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

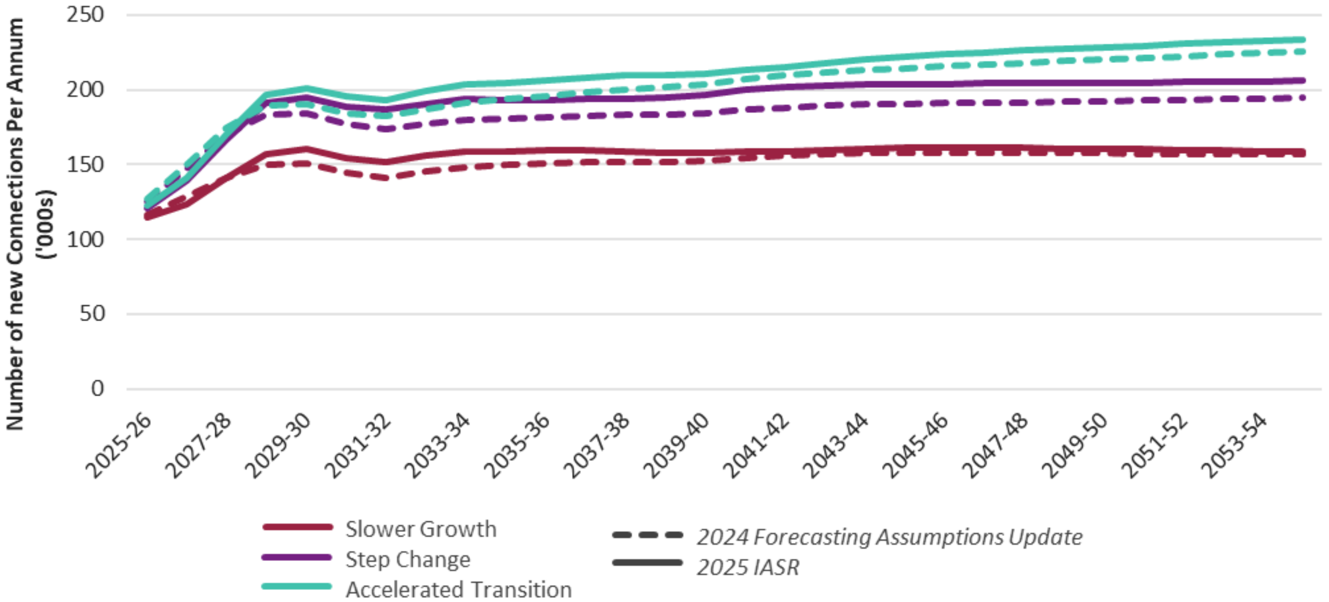
Figure 43 2025 Actual and forecast WEM residential connections, all scenarios, 2019-20 to 2054-55



Note: *Slower Growth* in the *2025 IASR* is compared with *Progressive Change* in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

As reflected in **Figure 44** for the NEM, in the short term (3-5 years), AEMO's 2025 forecast indicates a spike in the growth of new connections, supported by State and Federal Affordable Housing[131] Incentives. Overall, the forecast for new connections is projected to grow at an annual growth rate of around 1.6%.

Figure 44 Forecast NEM new connections growth per annum, all scenarios, 2025-26 to 2054-55



Note: *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

[131] At https://www.pm.gov.au/media/meeting-national-cabinet-working-together-deliver-better-housing-outcomes.

3.3.10 Large industrial loads

Input vintage	June 2025
Source	LIL surveys and Interviews AEMO meter database Network service providers (NSPs) CSIRO multi-sectoral modelling of industrial sector consumption growth Economic forecasts (DAE) Media search/announcements
Update since Draft 2025 IASR	Updated with AEMO's industrial load surveys

AEMO forecasts LILs independent of smaller medium and commercial business customers (termed the business mass market [BMM] customer segment), to better account for their considerable energy consumption and specific business circumstances, avoiding potential limitations of more general econometric models. Industrial loads also tend to exhibit a different time-of-day and seasonal load profile to other electricity customers.

The *Electricity Demand Forecasting Methodology*[132] defines LILs as loads that are over 10 MW at least 10% of the latest financial year. AEMO currently sources information regarding LILs from:

- historical data at the NMI level,
- surveys and interviews, with surveyed loads provided with forecast conditions consistent with the economic outlook for each scenario, to increase survey consistency,
- information request responses from NSPs on prospective and newly-connecting loads, and
- media searches and company announcements, such as on the ASX for Australian listed companies.

The LIL forecasts therefore cover the projected energy consumption of all significant industrial customers, including existing sites, new market entrants, and prospective projects. Note that the forecasts in this section do not include additional electricity consumption from electrification[133].

The LIL forecasts include prospective projects that are considered committed loads, and take into account start dates and likely growth rates over the outlook period. In 2025, AEMO broadened its consideration of prospective loads that are not currently committed but are likely to impact electricity consumption in the medium to longer term. A detailed description of AEMO's consideration of prospective projects is described in the *Electricity Demand Forecasting Methodology*[134].

When information on the expected energy consumption of prospective projects is not available, AEMO applies the load factor of similar existing industrial loads to the rated demand. Further, based on information from NSPs and media searches, AEMO may reduce annual consumption and rated demand depending on the likelihood of a project being developed, and revise the timing of projects if delays are identified. AEMO may also consider gradually ramping up consumption of a prospective project, if the full load is not likely to be reached shortly after commissioning.

[132] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

[133] See Section 3.3.5 for electrification forecasts.

[134] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

Figure 45 and **Figure 46** compare the 2024 and 2025 LIL electricity consumption forecasts for the NEM and WEM, respectively.

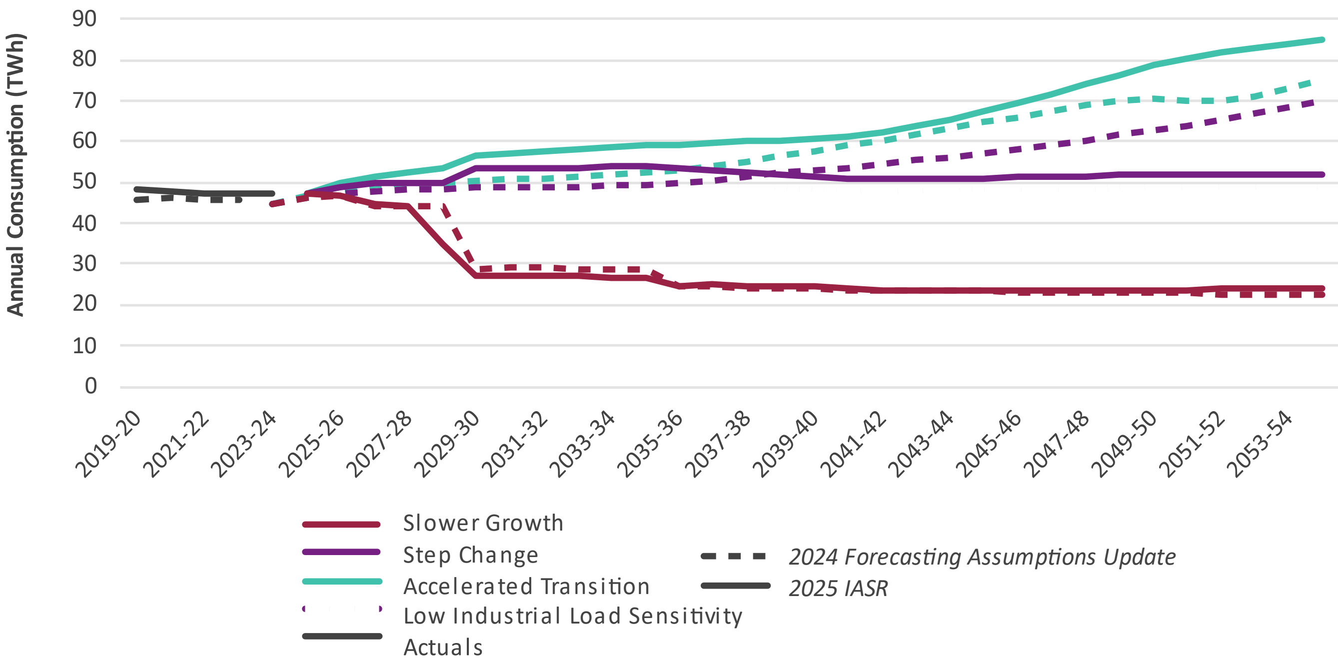
Existing NEM LILs accounted for 27% of the total delivered electricity in 2024-25. In the medium to long term, the forecasts are informed by projected electricity consumption growth of the mining and manufacturing sectors, from multi-sectoral modelling. Recent updates to the multi-sectoral modelling for these sectors indicate a significantly slower long-term growth trajectory in *Step Change* and larger opportunities in *Accelerated Transition*.

The *Slower Growth* scenario for the NEM shows drops in consumption in the short to medium term, accounting for challenging economic conditions resulting in closure risks for major electricity consumers. The scenario is not forecasting the possible closure of key facilities but is assuming possible closure outcomes to enable appropriate exploration of over-investment risks. This is a key feature of the scenario's narrative.

AEMO has developed a potential *Low Industrial Load* sensitivity to explore the potential for over-investment in generation and network infrastructure if a significant number of prospective industrial developments in South Australia do not proceed.

Existing WEM LILs accounted for 30% of total delivered electricity in Capacity Year[135] 2024-25. WEM LIL growth in the 2025 forecasts is less pronounced due to the softened lithium market and reductions in manufacturing.

Figure 45 2025 NEM LIL electricity consumption forecasts compared to the 2024 forecasts, all scenarios, 2019-20 to 2054-55 (TWh)

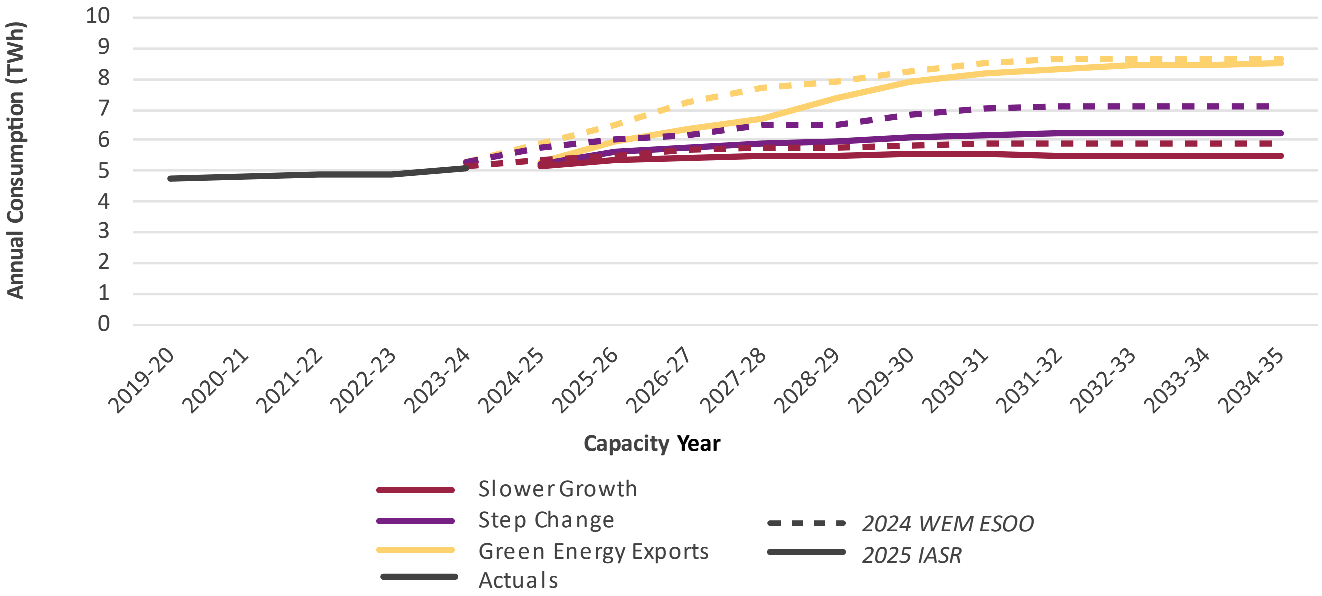


Notes:

- *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.
- Several industrial sites were re-classified as LILs in 2025, lifting the forecast and historical data compared to the 2024 trajectories.
- This figure does not include data centre load, as this is now a separate forecasting component. For comparison, AEMO removed data centre load from the 2024 forecasts.

[135] A capacity year is a 12-month period used for planning and accounting in the WEM, commencing in 08:00 Trading Interval on 1 October and ending in 07:30 Trading Interval on 1 October of the following calendar year.

Figure 46 2025 WEM LIL electricity consumption forecast compared to the 2024 forecast, all scenarios, 2019-20 to 2034-35 (TWh)



Note: *Slower Growth* in the *2025 IASR* is compared with *Progressive Change* in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

Liquified natural gas

Queensland's LNG industry represents a substantial NEM load, consuming approximately 5% of AEMO's total business consumption category in the NEM. Due to their significance, AEMO forecasts LNG loads as a separate forecast component for improved transparency.

Figure 47 shows the 2025 forecast for LNG electricity consumption.

The LNG forecasts estimate the expected electricity consumption drawn from the NEM by operations of coal seam gas (CSG) fields, using data provided by the LNG consortia via the GSOO survey process.

This data considers the anticipated operating range of CSG facilities over the short to medium term until 2035. Beyond 2035, AEMO has assumed a scenario dispersion in line with trends observed in the IEA's WEO forecasts. AEMO shaped the long-term trajectory of scenarios in LNG forecasts based on trends observed in the 2024 IEA WEO[136], whereby:

- In the *Slower Growth* scenario, lower global economic growth and reduced steps towards global decarbonisation mean LNG exports have been forecast to be flat across the horizon, with greater continued use of current energy forms. The *Slower Growth* scenario has been aligned to the IEA's STEPS scenario.
- The *Step Change* scenario applies increasing levels of decarbonisation action globally, leading to lower energy sector emissions, so reducing levels of LNG export are forecast as many countries seek alternative energy forms with lower emissions footprints. In this scenario, LNG export consumption falls between levels projected in the IEA's APS and NZE scenarios.

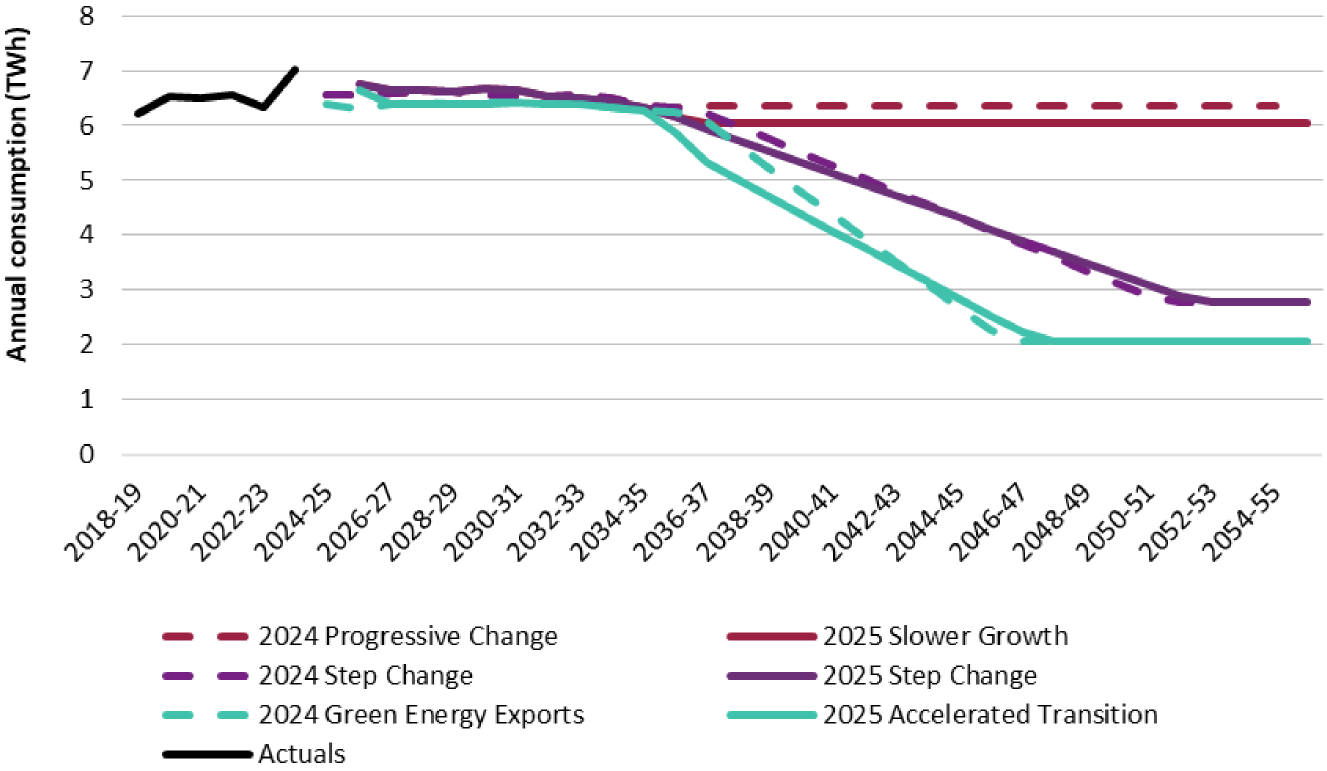
[136] From 2035, where possible, AEMO's LNG forecasts have been aligned with IEA forecasts of LNG export from Australia from the 2024 WEO (see https://www.iea.org/reports/world-energy-outlook-2024).

- The *Accelerated Transition* scenario features the greatest level of global decarbonisation action to reduce energy sector emissions and assumes the Queensland LNG industry will consolidate to the equivalent of a single remaining LNG train by 2050. This scenario is most closely aligned with the IEA's NZE forecast.

The wide range in long-term forecasts for LNG electricity consumption highlights the significant uncertainty surrounding future LNG export demand across different scenarios.

Forecasts for LNG electricity consumption in this 2025 IASR follow similar trends to the 2024 forecast until 2035, with a slight reduction driven by lower gas export forecasts provided by the LNG exporters to AEMO. Differences between the 2025 and 2024 forecasts after 2035 in all scenarios are driven by lower exporting assumptions aligned with the IEA WEO forecast.

Figure 47 LNG electricity consumption forecast compared to the 2024 forecast (TWh), all scenarios, 2018-19 to 2054-55



3.3.11 Data centre forecast

Input vintage	June 2025
Source	Oxford Economics Australia LIL surveys and interviews AEMO meter database Standing Information Request for existing and future grid connection information from the NSPs Economic forecasts (DAE) International Energy Agency data and reports Media search/announcements
Update process	Future updates will use NSP Standing Information Request data, AEMO's industrial load surveys, and economic indicators of demand for data services.

Data centres are a rapidly growing sector being driven by demand for cloud computing and artificial intelligence-based applications. AEMO forecasts data centres as a separate business customer segment as their growth behaves fundamentally different from that of other industrial customers.

The *Electricity Demand Forecasting Methodology*[137] outlines the approach to forecast data centre load. Briefly, the approach considers both project information on existing and prospective data centres, as well as macro-economic demand-side drivers, including factors linked to AI adoption and digital transformation consistent with each scenarios economic parameters.

AEMO engaged Oxford Economics Australia to assist in the development of these forecasts[138] for each of AEMO's scenarios. In alignment with AEMO's methodology to consider both project information and macro-economic drivers, Oxford Economics Australia used a blend of two independent methods, the first considering de-identified data across AEMO's LIL survey responses, data requests from NSPs, as well as other market research, while the second linked economic activity, technological adoption, potential efficiency gains and energy use for data centre services by sector.

Differences across AEMO's scenarios are driven by allocation of prospective projects to scenarios, and assumptions on economic growth, industrial composition and rates of technological adoption.

In 2024-25, data centres consumed around 4 TWh of energy across the NEM, accounting for 2% of grid-supplied electricity.

Under the *Step Change* scenario, data centre energy consumption increases by an average of 25% per year, reaching around 12 TWh by 2029-30, the equivalent to 6% of the NEM's grid-supplied electricity. Over the following two decades, growth is forecast to slow to an average of 6% per year, reaching around 34 TWh (or 12% of the grid supplied electricity) by 2049-50.

Under *Accelerated Transition*, energy consumption is projected to be around 13 TWh by 2029-30, 9% greater than *Step Change*. Under *Slower Growth*, the forecast by 2029-30 is projected to be around 8 TWh, 30% smaller than *Step Change*.

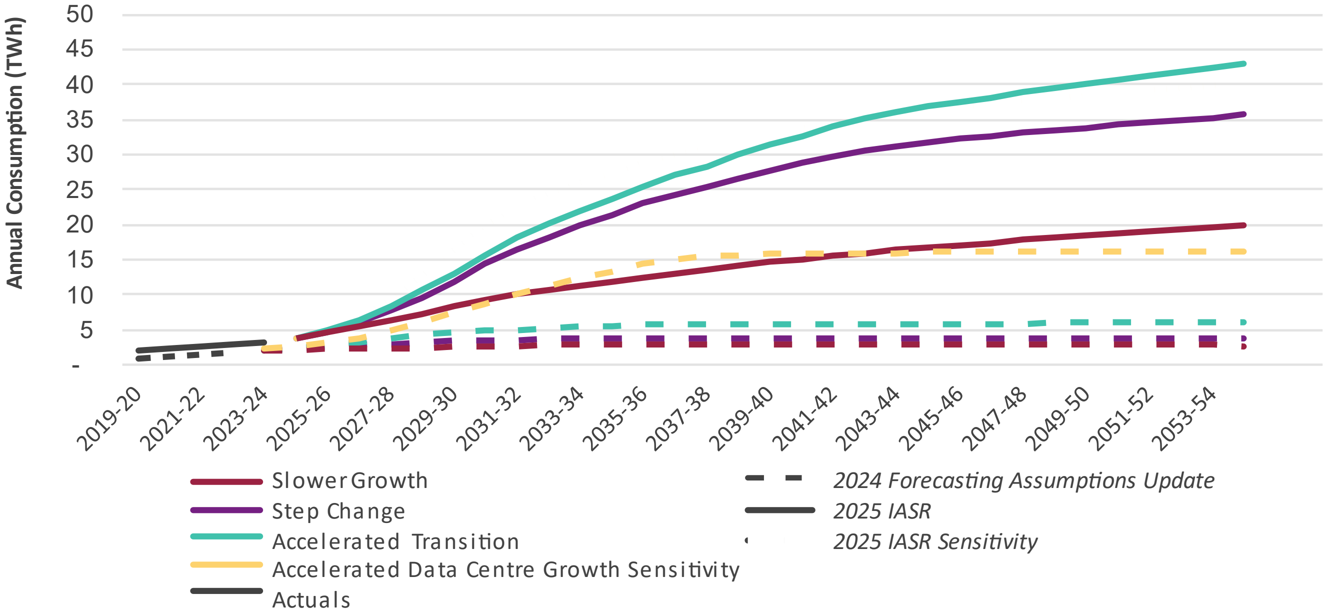
AEMO has developed a potential *Accelerated Data Centre Growth* sensitivity to explore more ambitious demand for data services relative to *Step Change*, by considering additional projects of a similar size where multiple connection requests exist for the same ISP sub-region, or where the same developer has made multiple requests. The sensitivity is forecast to reach 17 TWh by 2029-30, 40% greater than *Step Change*.

This bespoke approach for data centre forecasting is not yet applied to the WEM. No large data centres – that meet the demand definition of an LIL – exist in the WEM and prospective projects did not reach the threshold for inclusion into the 2025 forecast. Existing smaller data centres are included within the BMM component. AEMO will continue to monitor the data centre sector in the WEM.

[137] For further details see https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

[138] For further details see https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

Figure 48 NEM data centre electricity consumption forecast, all scenarios, 2019-20 to 2054-55 (TWh)



Note: Several sites were identified as data centres for the 2025 forecasts, lifting the historical data compared to the 2024 forecasts. *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

3.3.12 Energy efficiency forecast

Input vintage	January 2025
Source	Strategy.Policy.Research. (SPR) CSIRO multi-sectoral modelling Economic forecasts (DAE) AEMO connections forecast
Updates since Draft 2025 IASR	Updated CSIRO forecasts based on the 2024 multi-sectoral modelling consultancy were presented to the FRG in May 2025.

AEMO engaged two consultants, Strategy.Policy.Research. (SPR) and CSIRO, to support forecasting energy efficiency for the 2025 IASR. SPR's approach considers policy-led energy efficiency savings (expected to be delivered by federal and state government measures) and market-led energy efficiency (likely to occur without policy intervention). CSIRO's multi-sectoral modelling identifies the potential role of energy efficiency under varying decarbonisation pathways, using a combination of annual uptake rates by sector and technology[139], and scenario-specific variations based on relativities observed in the IEA WEO 2024 scenarios.

The 2025 forecasts are based on SPR's results, and use CSIRO's multi-sectoral modelling outcomes as a validation, equivalent to the approach applied for the 2023 IASR.

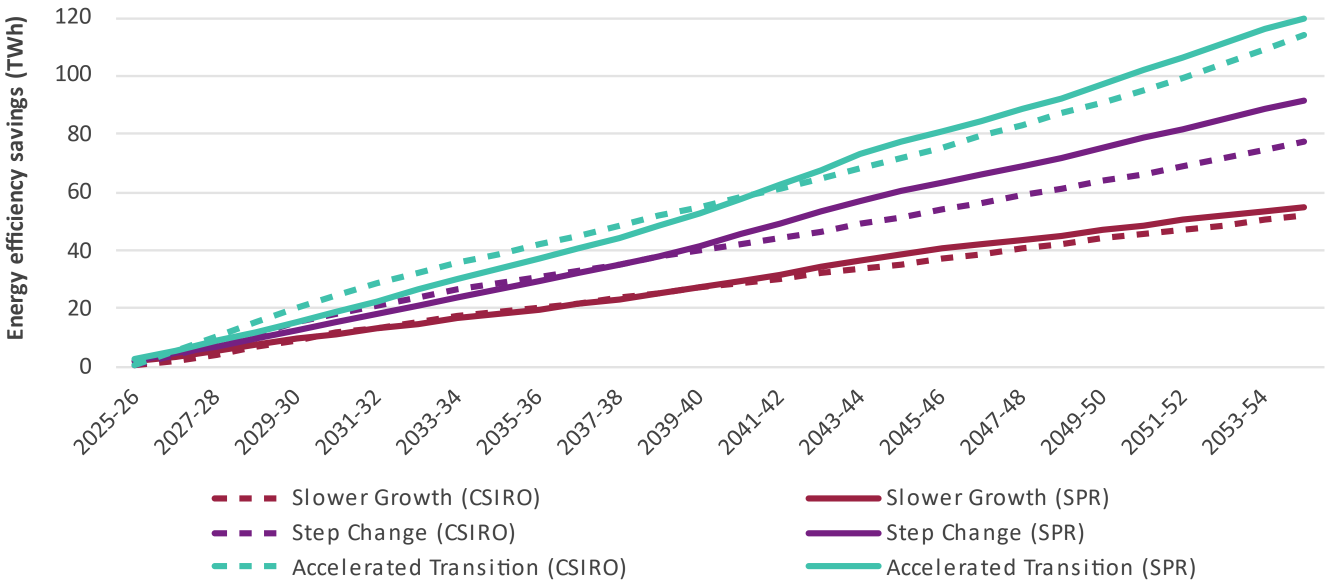
Both consultants use the scenario-specific economic, population, dwellings and connections forecasts as inputs to modelling energy efficiency (outlined in earlier sections of this 2025 IASR). In the case of SPR, the scenario

[139] Based on ClimateWorks Australia's (2014) Deep Decarbonisation Pathways Project, at https://www.climateworkscentre.org/wp-content/uploads/2014/09/climateworks_pdd2050_initialreport_20140923-1.pdf and ClimateWorks Australia's (2016) Low Carbon. High Performance: Modelling Assumptions, prepared for ASBEC (Australian Sustainable Built Environment Council), at https://www.asbec.asn.au/wordpress/wp-content/uploads/2016/05/160509-ClimateWorks-Low-Carbon-High-Performance-Modelling-Assumptions.pdf.

forecasts incorporate modelled policy support and market-driven developments that are aligned to the scenario parameters. Both consultancies have also sought to avoid double counting the effects of electrification, and other fuel-switching, on energy efficiency. For example, the thermal efficiency benefits of electrification are captured within the electrification forecasts (see Section 3.3.5) whereby reduced consumption of the fuel that was used prior to the electrification switch is reflected in relevant fuel forecasts (for example, a reduced natural gas forecast), rather than being part of the energy efficiency forecast. While SPR and CSIRO also provide forecasts of industrial energy efficiency savings, AEMO considers the effect of efficiency improvements for LILs within that forecast component, based on insights from the LIL surveys.

Figure 49 shows SPR's market-led and policy-led electricity savings for residential and commercial sectors against CSIRO's autonomous and endogenous electricity savings for buildings[140].

Figure 49 SPR's residential and commercial electricity savings compared to CSIRO buildings electricity savings, NEM and WEM, 2025-26 to 2054-55 (TWh)



Note: For the WEM, *Slower Growth* and *Accelerated Transition* in the *2025 IASR* incorporate *Progressive Change* and *Green Energy Exports* savings respectively. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*.

While the categories of efficiency improvements are different between the consultancies, the broad alignment of total energy efficiency savings for most sector subsets and for different fuel types (such as what is shown in **Figure 49** for electricity) is important corroboration for the SPR results that have been adopted for the 2025 IASR.

Multiple policies targeting energy efficiency improvements are considered within the forecast:

- For the residential sector, electricity savings in households stem from increased NCC stringency, and enhanced appliance standards from the national GEMS and E3 program, as well as subsidies from state schemes such as the ESS in New South Wales, the VEU program, and the SA REPS.

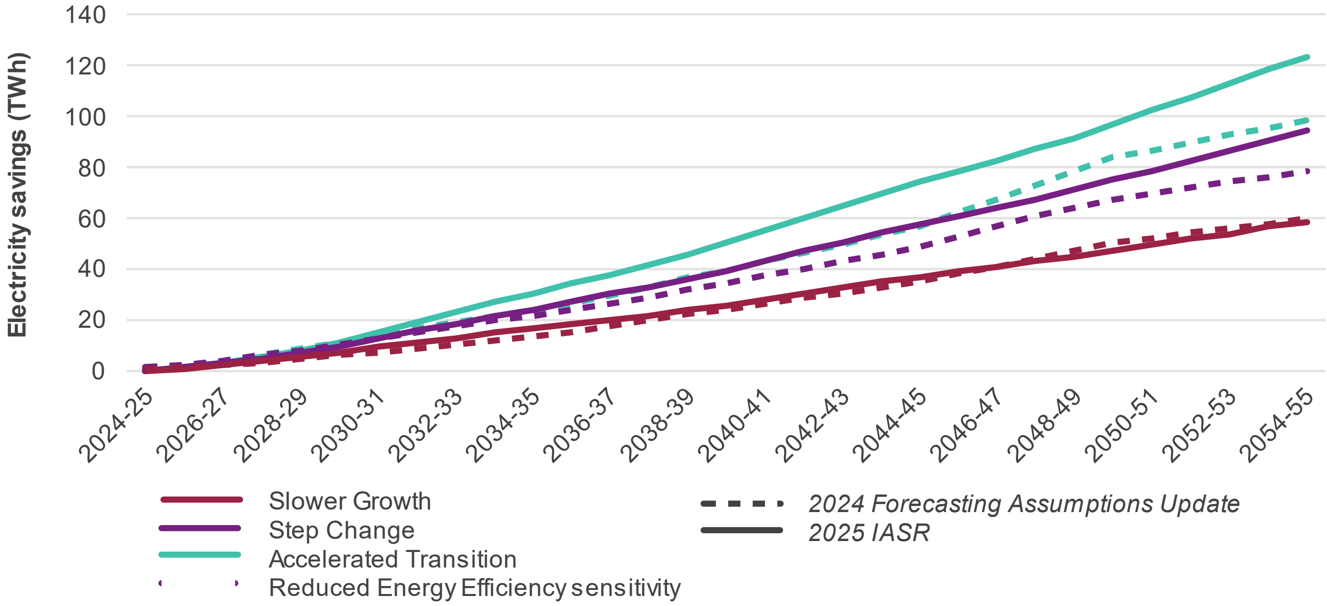
[140] CSIRO defines autonomous energy efficiency improvement as business-as-usual improvement at no cost whereas SPR defines autonomous, or market-led, energy efficiency improvement, as the level of improvement that would occur without policy and is not necessarily zero cost. SPR's market-led efficiency captures behavioural drivers such as cultural preferences, but these components are not modelled explicitly.

- The NCC is also assumed to drive efficiency improvements in the commercial sector, alongside expansions of the CBD program, NABERS, and state-funded incentives.
- For the industrial sector, the largest gains are tied to autonomous (market-led) energy efficiency improvements, with smaller contributions from GEMS and the state-based schemes. The largest gains for the industrial sector occur for natural gas efficiency via updates to the Safeguard Mechanism, which came into effect in July 2023[141]. The effect of the Safeguard Mechanism and other policy changes since the 2023 IASR has driven higher natural gas savings than were forecast for the 2023 IASR.

Residential and businesses electricity energy efficiency savings modelled by SPR for the NEM, and adopted by AEMO, are shown in **Figure 50**, with comparisons to the 2024 forecasts. Improved thermal shells, via more airtight windows and exterior building surfaces, investments in heating, ventilation and air conditioning systems, and lighting are particularly impactful in driving higher electricity savings through the projection period for this IASR. The notable exception is *Slower Growth*, where higher residential sector energy efficiency savings have been offset by diminished commercial sector savings.

AEMO also commissioned SPR to model *a Reduced Energy Efficiency* sensitivity, whereby no new energy efficiency policy development is assumed to occur. For electricity, the cessation of policy development results in 34 TWh less energy efficiency savings by the end of the projection period relative to *Step Change*.

Figure 50 Residential and business electricity energy efficiency savings, NEM, 2024-25 to 2054-55 (TWh)



Note: Business energy efficiency savings shown here are for the business mass market sector, capturing small industrial loads and commercial customers. Large industrial load energy efficiency savings are not included in these results. *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

[141] See Safeguard Mechanism Reforms, at https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism, accessed 4 February 2025. The Safeguard Mechanism does not incentivise electricity efficiency savings given its focus on direct (scope 1) emissions.

3.3.13 Appliance uptake forecast

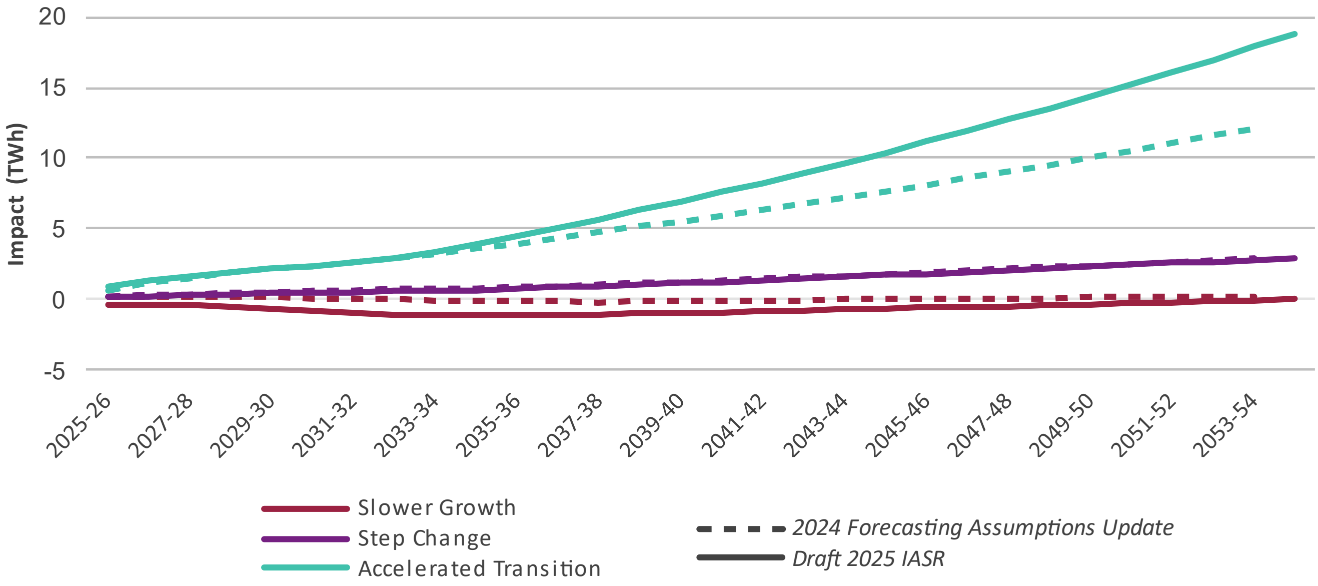
Input vintage	June 2025
Source	Department of Industry, Science, Energy and Resources (DISER), *2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040*142, available at www.energyrating.gov.au Economic forecasts (DAE)
Update process	Updated with latest economic forecasts

The appliance uptake forecasts represent the energy services supplied by electricity, to meet the growth in household appliances over the outlook period. Energy services here is a measure based on the number of appliances per appliance category, their usage hours, and their capacity and size. See Appendix A5 of *AEMO's Electricity Demand Forecasting Methodology*[143] for further details.

The underlying data is from the latest available Department of Climate Change, Energy, the Environment and Water's 2021 Residential Baseline Study[139]. Growth in household connections and economic indicators, such as Household Disposable Income, result in variations across the scenarios.

Figure 51 shows the appliance uptake trajectories applied to the 2025 consumption forecasts, compared with the 2024 forecasts. *Step Change* and *Slower Growth* include mild growth or remain at similar levels respectively, whereas *Accelerated Transition* increases over time, driven by the increasing HDI forecast.

Figure 51 Residential appliance uptake trajectories for the NEM and WEM, consumption change relative to base year (2025), 2025-26 to 2054-55



Notes:

- For the NEM, *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.
- For the WEM, *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 WEM ESOO*. The *Green Energy Exports* scenario was proposed in the *Draft 2025 IASR* as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this *2025 IASR*. For the purpose of this figure, the *2024 WEM ESOO* uptake trajectories have been added to the *2024 Forecasting Assumptions Update*.

[139] At https://www.energyrating.gov.au/industry-information/publications/report-2021-residential-baseline-study-australia-and-new-zealand-2000-2040.

[143] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

3.3.14 Electricity price indices

Input vintage	July 2025
Source	AEMO internal wholesale price forecasts. Transmission costs from the 2024 ISP's optimal development path144. ASX Energy Electricity Futures. AER Determinations and Access Arrangements[145]. AEMC annual Residential Electricity Price Trends, 2024 report[146,147]. Australian Competition and Consumer Commission (ACCC) Inquiry into the National Electricity Market report - November 2022[148]. Synergy wholesale prices (WEM). Western Australia State Budget (WEM).
Update process	Retail price forecasts are updated with components from the latest available AER pricing proposals and transmission determinations, AEMO wholesale price forecasts, and transmission costs associated with the latest available ISP. Retail price forecasts are updated annually. Transmission and distribution inputs are updated biannually alongside the ISP.

Electricity prices influence consumption through short-term behavioural changes (such as how electric-powered devices are used, or how energy consumption is managed), and through longer-term structural changes (such as decisions to invest in CER).

AEMO's retail price forecasts are formed from bottom-up projections of the various components of retail prices. **Table 19** details the various price inputs used, and their incorporation into the 2025 scenarios.

Table 19 Retail price input settings by scenario

Scenario	*Slower Growth*	*Step Change*	*Accelerated Transition*
Wholesale component	• **Short term** (up to FYE 2028): Blend of ASX Futures and 2024 ISP *Progressive Change*. • **Longer term** (FYE 2029 onwards): Solely based on wholesale price trends informed from the 2024 ISP.	• **Short term** (up to FYE 2028): Blend of ASX Futures and 2024 ISP *Step Change* scenario. • **Longer term** (FYE 2029 onwards): Solely based on wholesale price trends informed from the 2024 ISP.	• **Short term** (up to FYE 2028): Blend of ASX Futures and 2024 ISP *Green Energy Exports* scenario. • **Longer term** (FYE 2029 onwards): Solely based on wholesale price trends informed from the 2024 ISP.
Transmission costs	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Progressive Change* scenario and its transmission costs.	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Step Change* scenario and its transmission costs.	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Green Energy Exports* scenario and its transmission costs.

144 At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

145 At https://www.aer.gov.au/industry/registers/determinations.

146 At https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024.

147 As outlined in Section 3.3.14, AEMO uses ASX Energy electricity futures to inform the short-term wholesale price trends rather than the 2021 AEMC derived forecasts. An updated AEMC Residential Electricity Price Trends report was released in November 2024, and AEMO will consider its insights before consulting on and finalising this component.

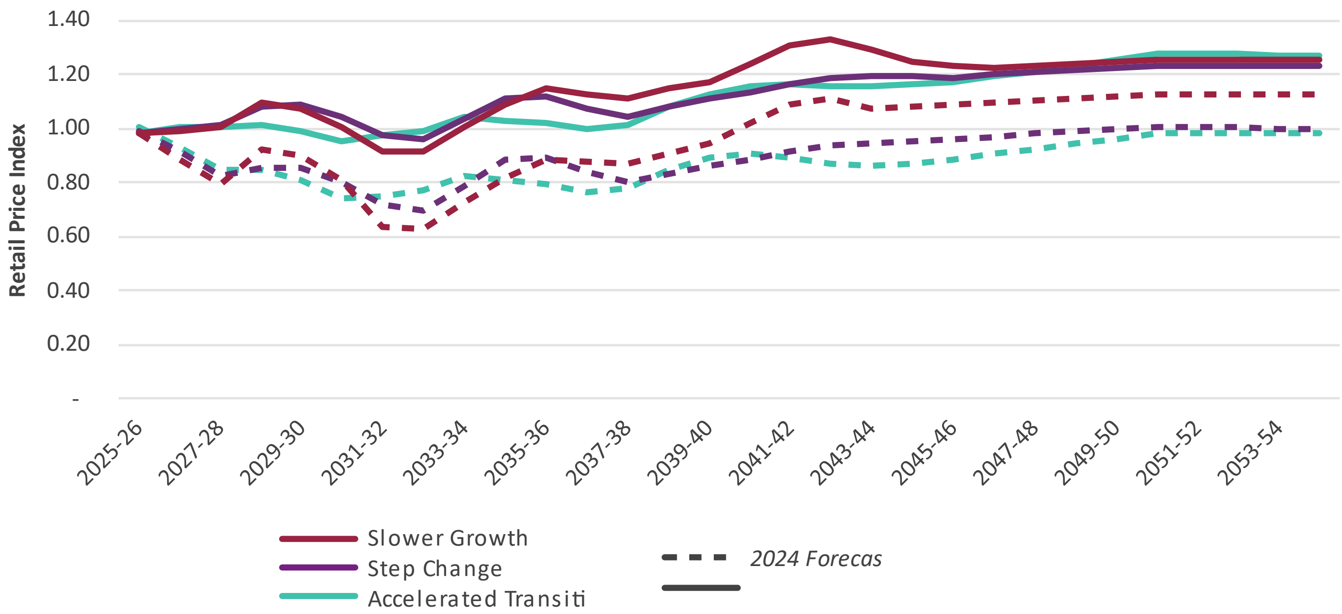
148 At https://www.accc.gov.au/about-us/publications/serial-publications/inquiry-into-the-national-electricity-market-2018-25-reports/inquiry-into-thenational-electricity-market-report-november-2022.

Scenario	*Slower Growth*	*Step Change*	*Accelerated Transition*
Distribution costs	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs.	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs.	• **Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs
Environmental costs	AEMC (2024) to FYE 2025 then decline to zero by FYE 2030.	AEMC (2024) to FYE 2025 then decline to zero by FYE 2030.	AEMC (2024) to FYE 2025 then decline to zero by FYE 2030.
Retail component	ACCC (2022) derived residual.	ACCC (2022) derived residual.	ACCC (2022) derived residual.

For the WEM, retail prices are expected to align to the prescribed price increases outlined in the 2025-26 Western Australia State Budget[149]. Beyond the budget period, prices are assumed to increase in line with inflation.

Figure 52 shows the 2025 residential retail price indices for the NEM, compared to the 2024 forecasts.

Figure 52 NEM Residential retail price forecasts, 2025-26 to 2054-55



Notes:

- Price weighted by household consumption per region.
- For the NEM, *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

NEM retail prices are expected to trend gradually upwards through the 2030s as traditional coal generation assets (near end of technical life) are replaced by new investments into VRE, utility-scale battery storage and pumped hydro energy storage (PHES) to replace capability in both firmed capacity and energy production, and greater dependence on gas-powered generation as additional firming backup. In order to maintain energy reliability, this may necessitate an overlap in these investments before the coal generation assets exit the market.

149 Refer to Table 8.8 in Appendix 8 of Budget Paper 3 of the 2025-26 Western Australia State Budget. At https://www.ourstatebudget.wa.gov.au/budget-papers.html.

Increased price volatility is expected in the mid-2030s as additional traditional thermal generation is forecast to retire and be replaced. Modest increases in retail prices in the 2040s are projected due to network investment costs and an increased reliance on gas-powered generation for periods of very low VRE energy production.

The difference in residential retail price trajectories between scenarios represents a differing pace and pathway of decarbonisation, including the shift to renewables and the transformation of the transmission and distribution networks.

Price elasticities

The retail price indices are only used to consider the potential response from consumers to price when developing the annual electricity consumption forecasts. In this context, price elasticity of demand refers to the percentage change in demand for a given change in price. **Table 20** below provides the assumed price elasticities of demand adopted across the modelled scenarios, where negative values indicate a reduction in consumption resulting from a price increase.

Table 20 Price elasticities of demand for various appliances and sectors

Scenario	*Slower Growth*	*Step Change*	*Accelerated Transition*
Residential: baseload appliances	0	0	0
Residential: weather-sensitive appliances	-0.10	-0.10	-0.10
Business: all load components	-0.10	-0.10	-0.05

3.3.15 Demand-side participation (DSP)

Input vintage	June 2025
Source	Historical meter data analysis and information submitted to the DSP Information portal in April-May 2025.
Updates since Draft 2025 IASR	Current levels and committed/planned changes updated after summer 2024-25 to reflect most recent information. Target levels for NSW are changed, following the recent changes in the state's demand flexibility schemes (for example, PDRS and ESS).

AEMO's forecasting approach captures demand flexibility at times of extreme price signals and reliability risks explicitly as a dynamic component within its market modelling, meaning that AEMO's published demand forecasts reflect what peak demand would be expected in the absence of DSP. While customers frequently will adjust their electricity usage, DSP is that response that may occur in response to irregular, event-based triggers – such as high market prices or Lack of Reserve (LOR2 or LOR3)[150] conditions. The infrequency of these events mean that DSP does not follow a regular or predictable load pattern that can be captured in normal operational demand forecasts.

[150] See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/%20reserve-level-declaration-guidelines.pdf.

The DSP forecasts apply a specific forecasting methodology[151], most recently reviewed in December 2023[152].

AEMO estimates the current level of DSP using information submitted by registered participants via the DSP Information portal (DSP IP), supplemented by historical customer meter data. For each defined price trigger, DSP response levels are estimated using the 50th percentile of observed historical responses. This is treated as a central and reliable indicator of expected response. In addition, Wholesale Demand Response (WDR) contributions are incorporated based on dispatch data, using a weighted average response for each trigger level. DSP responses to reliability events – defined as periods where AEMO declares LOR2 or LOR3 conditions – are added to the price-triggered response to generate a total reliability response.

AEMO uses only existing and committed DSP in the ESOO, incorporating updates reported through the DSP IP or supported by legislated policy mechanisms. For longer-term planning studies such as the ISP, DSP may be scaled to meet target levels across the outlook period, depending on the appropriateness of the expected degree of customer engagement with energy in line with each scenario's narrative:

- *Accelerated Transition* assumes high DSP growth, driven by strong consumer engagement and flexible demand programs in response to market conditions.
- *Step Change* assumes moderate DSP growth, reflecting a technology-led but somewhat constrained economic environment.
- *Slower Growth* assumes no further growth, maintaining current DSP penetration levels due to slower technological rollout and economic limitations.

For scenarios with DSP growth, the target is defined as a proportion of maximum demand and is linearly interpolated from the current level to the end-of-outlook target. The long-term target is informed by international assessments of demand response in the United States[153] and Europe[154]) allows for growth in both price-responsive DSP and dispatchable flexibility enabled by market and technology developments, including WDR expansion. AEMO acknowledges that the assumed level of DSP development across the scenarios is an uncertainty, based on international benchmarks reflective of maturing opportunities for demand response, and will review the forecasting method for this component ahead of the 2028 ISP.

The settings for the current IASR scenarios are provided in **Table 21** below.

Table 21 Mapping of DSP settings to scenarios

Scenario	*Slower Growth*	*Step Change*	*Accelerated Transition*
DSP growth target overall	No change from current levels of DSP (0% growth).	Moderate growth to reach 4.25% of peak demand by 2050, then remains flat.	High growth to reach 8.5% of peak demand by 2050, then remains flat.

[151] See *DSP Forecast Methodology* at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/dsp-forecasting-methodology-and-dsp-information-guidelines-consultation/final-stage/2023-dsp-forecast-methodology.pdf.

[152] AEMO next plans to review the *DSP Forecast Methodology* by June 2026 as part of its minimum four yearly review of the Forecasting Approach. As the NEM load evolves, it is possible that increased demand-side flexibility may occur through mechanisms such as smart appliance control, increased customer exposure to wholesale price signals through shifts in retail pricing mechanisms, and policy-driven uptake of other coordination technologies.

[153] See Federal Energy Regulatory Commission (FERC), "A National Assessment of Demand Response Potential" (at https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response_1.pdf) validated against DSP uptake statuses across the United States (from https://www.ferc.gov/power-sales-and-markets/demand-response/reports-demand-response-and-advanced-metering).

[154] See https://www.sia-partners.com/en/news-and-publications/from-our-experts/demand-response-study-its-potential-europe.

Note: the New South Wales Peak Demand Reduction Scheme (PDRS, see https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme) is no longer included in AEMO's DSP forecast. While the PDRS was initially designed to incentivise dispatchable peak demand reductions—particularly during summer—the scheme has shifted its focus toward supporting energy efficiency and distributed energy uptake (such as battery storage), which would not contribute to demand responses consistent with AEMO's DSP component.

3.4 Existing generator and storage assumptions

3.4.1 Generator and storage data

Input vintage	July 2025
Source	Participant survey responses
Update process	Updated quarterly

AEMO's Generation Information page[155] publishes data on existing, committed, and anticipated generators and storage projects (size, location, capacities, seasonal ratings, auxiliary loads, full commercial use dates and expected closure years), and information provided to AEMO on the pipeline of future potential projects. This information is updated quarterly, with the most recently available information adopted for each of AEMO's planning publications (and clearly identified in each publication). The 2025 IASR Assumption Workbook includes details from the July 2025 publication.

The resource availability for existing, committed, and anticipated VRE generation is modelled using half-hourly generation profiles as described in Section 3.6.2. Timings for generator closures and their application in AEMO's forecasting and planning approaches are described in Section 3.4.4.

3.4.2 Technical and other cost parameters (existing generators and storages)

Input vintage	December 2024
Source	Various, see below
Updates since 2023 IASR	Updated based on July 2025 Generation Information, Clean Energy Regulator's Electricity sector emissions and generation 2023-24, and GHD's 2025 Energy Technology Retirement Costs.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies[156]. They include:

- AEMO's Generation Information page,
- Aurecon, 2020 to 2024 Energy Technology Cost and Technical Parameter Review,
- GHD, 2018-19 AEMO Energy Technology Cost and Technical Parameter Review,
- GHD, 2025 Energy Technology Retirement Cost and O&M Estimate Review,
- AEP Elical, 2020 Assessment of Ageing Coal-Fired Generation Reliability,
- Clean Energy Regulator, Electricity sector emissions and generation 2023-24,

[155] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[156] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-Inputs-Assumptions-and-Scenarios-Report.

- generator surveys, and
- specific adjustments to the above sources if required, based on confidential or non-confidential engagement with specific generators or developers.

The specific parameters obtained from these sources are summarised in **Table 22** below.

Table 22 Sources for technical and cost parameters for existing generators

Source	Technical and cost parameters used in AEMO's inputs and assumptions
AEMO's Generation Information page	• Maximum capacities • Seasonal ratings (10% probability of exceedance [POE] summer, typical summer and winter) • Auxiliary loads • Reserves • Commissioning and retirement dates
GHD 2018-19 AEMO Energy Technology Cost and Technical Parameter Review (for use for existing generators as of 2018)	• Heat rates • Maintenance rates • Ramp rates • Minimum up and down time
GHD 2025 Energy Technology Retirement Cost and O&M Estimate Review	• Fixed and variable operating and maintenance costs (for existing generators) • Retirement costs
Aurecon 2020 to 2024 Energy Technology Cost and Technical Parameter Review (primarily for new entrant generators but also referred to for some existing generators since 2019)	• Heat rate curves used for calculating complex heat rates • Heat rates • Fixed and variable operating and maintenance costs(for new entrants) • Ramp rates • Minimum stable levels
Generator surveys	• Unplanned outage rates
AEP Elical 2020 Assessment of Ageing Coal-Fired Generation Reliability	• Assessment of forward-looking coal-fired generator reliability (complementing generator surveys)
AEMO internal studies	• Complex heat rates, informed by Aurecon and GHD • Minimum stable levels • Ramp rates • Minimum and maximum capacity factors
Clean Energy Regulator, Greenhouse and energy information by designated generation facility 2023-24	• Scope 1 emission intensity for existing generators
Department of Climate Change, Energy, the Environment and Water (DCCEEW), 2023 Australian National Greenhouse Accounts Factors	• Emission factor for biomass

The specific assumptions on the parameters documented in the above table are in the 2025 *Inputs and Assumptions Workbook*.

Capacity outlook model assumptions in the ISP

In long-term planning studies, AEMO applies assumptions related to operational characteristics of plant to project future investment needs. Actual limits and constraints that would apply in real-time operations will depend on a range of dynamic factors which may not be appropriate to incorporate without simplification to more static assumptions.

The relative coarseness of the ISP's capacity outlook models requires that some operational limitations are applied using simplified representations such as minimum stable levels or capacity factor limitations to represent technical constraints and power system security requirements. This helps ensure that relatively inflexible generators, such as coal-fired generators, are not dispatched in a manner that exceeds their technical capability or that would not be commercially viable. The current view of these operational limits is described in the accompanying 2025 *Inputs and Assumptions Workbook*. They may also be refined during the ISP as described in the *ISP Methodology*, as an outcome of the iterative market modelling process.

Minimum stable levels for existing generators are based on AEMO's analysis of historical generation and operational experience. Minimum stable levels for new entrant generators are sourced from Aurecon. For the purposes of the capacity outlook model, these minimum stable levels are converted into minimum annual capacity factors.

In the ESOO, station-level auxiliary rates are applied based on the information provided in the Generation Information survey. This information is kept confidential. For the ISP and other publications, technology aggregated auxiliary rates are used so that they may be published in the accompanying 2025 *Inputs and Assumptions Workbook* while continuing to protect the confidentiality of information provided by participants.

Additional properties used in time-sequential modelling in the ISP

Additional technical limitations may be incorporated in the time-sequential models, including:

- minimum up time and down times,
- complex heat rate curves, and
- unit commitment optimisation and minimum stable levels, if the model granularity warrants the additional complexity.

AEMO may apply these assumptions when performing specific analyses that warrant the higher degree of technical complexity; they may not always be applied to balance the simulation complexity.

Further details on the implementation of these technical limitations are in AEMO's *ISP Methodology*[157].

Additional coal generator minimum stable levels

Two new series of coal generator minimum stable levels have been provided in the 2025 *Inputs and Assumptions Workbook*:

- Typical Lowest Band – this value is representative of the power level typically offered in the lowest band of a generator's bid stack. This represents a 'preferred' minimum power level, where negative price exposure risk is not material. Across the coal fleet, this is a reduction of 527 MW (6%) in baseline minimum stable levels compared to the previous IASR and is a reflection of growing negative price exposure risk.
- Minimum Continuous Operating Level – this forward-looking value is representative of the minimum continuous power level which the generator could foreseeably offer in their bid stack in response to increasing negative price exposure risk. This represents a 'tested' bid at this power level which was dispatched for sustained periods as part of typical generation (not during startup or shutdown) for the specific unit, or it has been

[157] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology.

observed that most units at the station have demonstrated that capability. Across the coal fleet, the observed potential reduction in minimum stable levels from the current baseline is a 1,317 MW (20.7%) reduction relative to the previous IASR.

The typical lowest band for existing generators is based on AEMO's analysis of historical generation and operational experience and will be applied in the time-sequential model as a representation of a generator's typical minimum stable level. The minimum continuous operating level values may be applied in the time-sequential model to represent the future behaviour of coal generators, which is expected to become more likely as coal generators increasingly seek to avoid exposure to negative prices.

3.4.3 Generator unplanned outage rates

Input vintage	June 2025
Source	Participant survey responses *AEP Elical 2020*
Updates since Draft 2025 IASR	Unplanned outage rates were updated with latest data in April 2025 as part of data collection process for the ESOO. The updates were presented to the FRG in June 2025.

In April 2025, AEMO collected unplanned outage information for all existing scheduled production units, through its annual survey process[158]. The data request covered the timing, duration, and de-rating of historical unplanned outages. This information is used to forecast the full and partial unplanned outage rates (UORs)[159] for each generator in every financial year across the 2025 ESOO outlook horizon, consistent with the *ESOO and Reliability Forecasting Methodology*[160].

Where AEMO requested unplanned outage rate projections from participants, such as for coal-fired stations and large combined-cycle gas turbines (CCGT), these projections were either adopted or adjusted in consultation with the station owners/operators, taking historical performance into account. For other gas- and liquid-fuelled stations, AEMO applied a single aggregated UOR forecast. This approach streamlines data collection and modelling while maintaining transparency.

For hydro generators and storage units, technology-level UOR aggregates are applied to individual stations, reflecting a flat projection based on the fleet's recent average performance.

Outage modelling assumptions for existing generators for ESOO and other reliability purposes

Long duration unplanned outages

As described in the *ESOO and Reliability Forecast Methodology*, AEMO models full unplanned outages lasting longer than five months (long duration unplanned outages) separately. This analysis uses historical outage data from 2010-11 to the most recent financial year. Long duration unplanned outage data is excluded from the

[158] All surveyed participants must provide historical data on full and partial unplanned outages. with the operators of coal-fired and certain large gas-fired generators are also required to submit forward-looking projections for these outage rates.

[159] In the 2025 ESOO, planned outages are modelled in an operational sensitivity to assess their potential impact on capacity and energy balancing throughout the year, and consequently, on USE outcomes.

[160] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

calculation of the historic full UORs. In 2025, AEMO used 15 years of long duration unplanned outage data (2010-11 to 2024-25) to determine the long duration UORs on a technology aggregate basis.

The long duration UORs used in 2025 ESOO modelling, and in other reliability assessments such as Medium Term Projected Assessment of System Adequacy (MT PASA) and Energy Adequacy Assessment Projection (EAAP), are summarised in **Table 23**.

Table 23 Existing generators – long duration unplanned outages

Fuel type/technology	Long duration unplanned outage rate (%)	Mean time to repair (hours)
All coal	0.91	6,062
All gas and liquid	0.53	6,223
Hydro	0.21	4,292

Unplanned outage rate trajectories (excluding long duration unplanned outages)

The forecast equivalent full and partial UORs by technology for 2025-26, the first year of the forecast horizon period in the 2025 ESOO, are based on participant-provided information and are shown in **Table 24**.

Table 24 Unplanned outage assumptions (excluding long duration outages) for 2025-26 financial year

Technology	Full unplanned outage rate (%)	Partial unplanned outage rate (%)	Partial derating (% of capacity)	Mean time to repair – full (hours)	Mean time to repair – partial (hours)
Black coal NSW	5.33	30.52	18.65	149	28
Black coal QLD	9.27	20.44	26.86	153	49
Brown coal	7.92	15.51	12.93	91	39
All coal	7.43	23.25	20.49	137	38
All gas and liquid	8.45	2.92	18.52	79	118
Hydro	5.96	0.68	26.78	60	266
Batteries	2.84	N/A	N/A	67	N/A

Figures 53, 54, and 55 present the 10-year projections for the equivalent full UOR[161] across all technology aggregates, both including and excluding the impact of long duration unplanned outages. These annual equivalent UORs reflect changes in assumed reliability and generator retirements over the forecast horizon[162].

To protect the confidentiality of individual station-level data, unplanned outage trajectories are published only at the technology aggregate level for the 10 years of the forecast horizon. For coal-fired stations, due to the small number of remaining coal plants, all regions have been combined into an 'All Coal' category to maintain confidentiality from 2028-29.

[161] Where equivalent full UOR = Full UOR + partial UOR x average partial derating.

[162] Generator retirement assumptions are consistent with the information published in the AEMO NEM July 2025 Generator Information, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 53 Equivalent full unplanned outage rate projections for coal-fired generation technologies

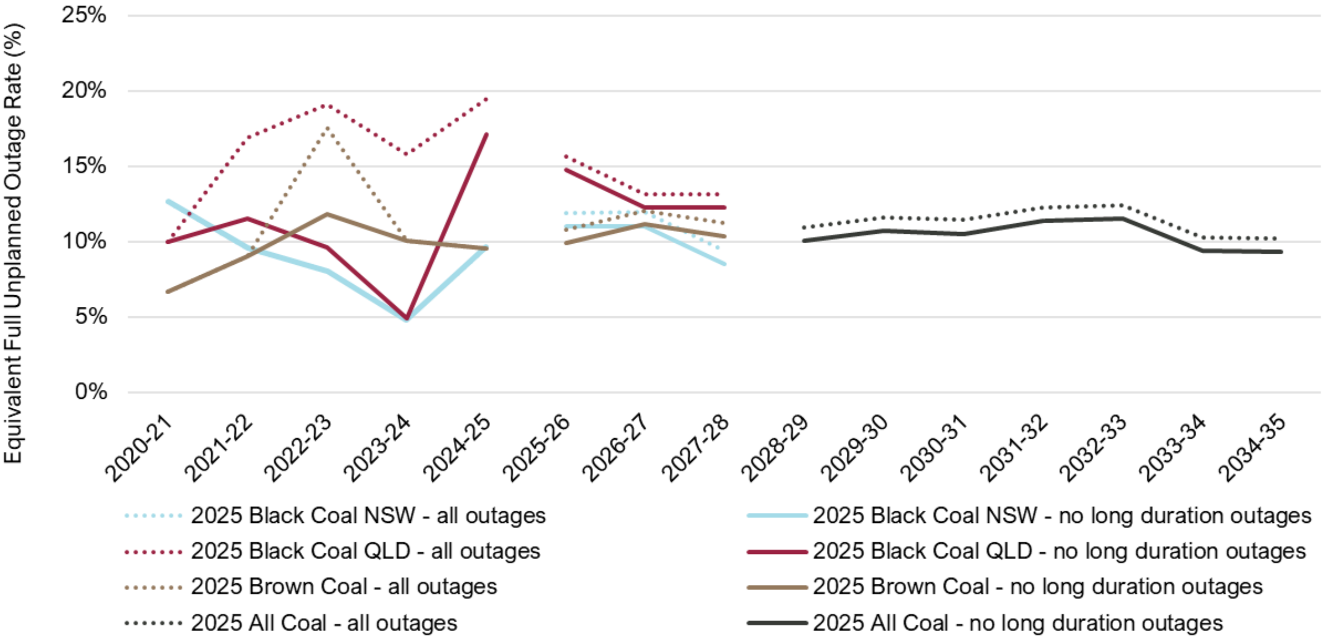
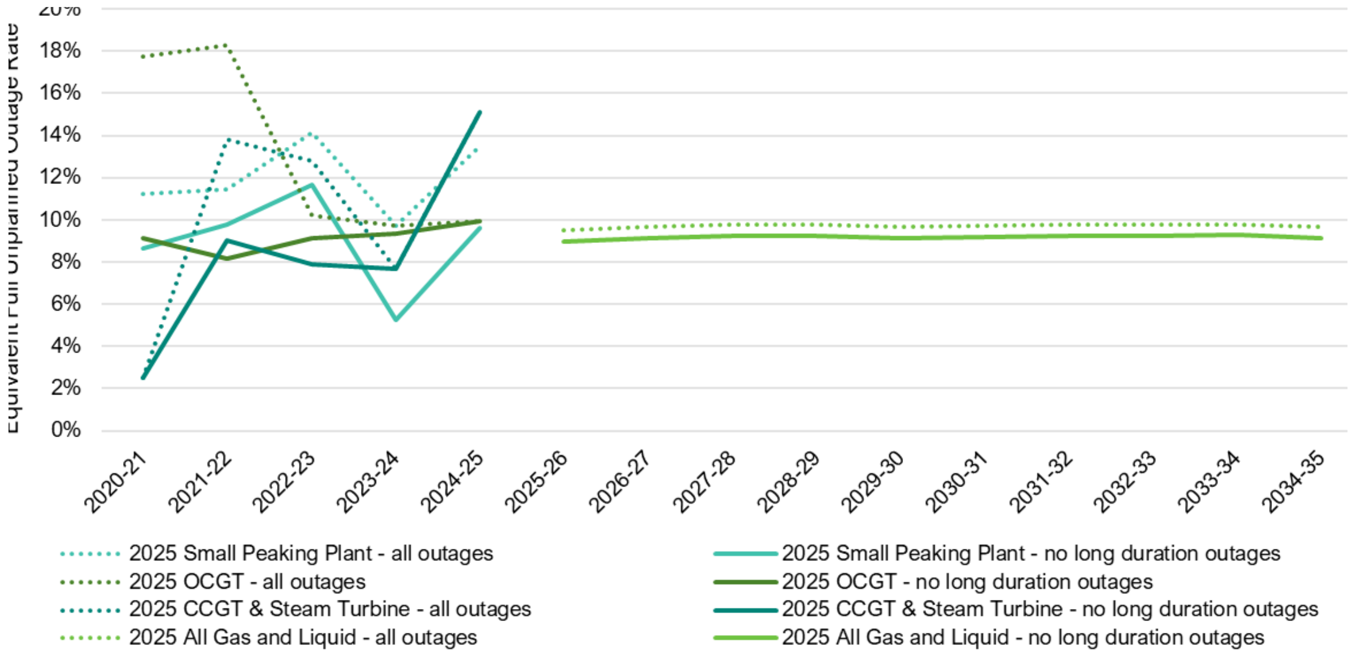


Figure 54 Equivalent full unplanned outage rate projectons for open-cycle gas turbine, closed-cycle gas turbine and steam turbine generation and small peaking plant technologies



OCGT: open-cycle gas turbine

Figure 55 Equivalent full unplanned outage rate projections for battery and hydro technologies

Outage modelling assumptions for existing generators for ISP purposes

For ISP purposes, the unplanned outage rate assumptions, which incorporate long duration outages, are held constant past the first 10 years. Although reliability may degrade as a plant ages and nears retirement, it is difficult to predict this trend with any accuracy beyond 10 years, particularly when timing of generation withdrawal may be dynamic. It is a level of complexity that AEMO does not consider warranted as it is not expected to introduce a material difference to ISP outcomes. More information on treatment of outage rates across AEMO's modelling is provided in the *ISP Methodology*[163].

New entrant generation outage assumptions for all modelling purposes

The equivalent forced outage rate (EFOR) for new entrants is provided by Aurecon. Calculations from Aurecon follow the formulas defined in IEEE Std 762 and source data is `based on indicative industry values by technology, like contractual or operational availability for onshore wind and solar. Long duration outages are not applied to new entrant technologies.

3.4.4 Generator retirements

Input vintage	Retirement costs: July 2025 Retirement dates: Generation Information July 2025
Source	Generation Information GHD: *2025 Energy Technology Retirement Costs*
Updates since Draft 2025 IASR	Expected closure years and closure dates have been updated to reflect the most recent data collection. Retirement cost estimates have been refreshed by GHD using more up-to-date information and assumptions.

[163] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

For existing generators, AEMO applies the expected closure year as provided by participants and published through AEMO's Generation Information[164] page as a latest retirement timing, as follows:

- In ESOO, MT PASA and EAAP, expected closure years are applied consistent with the participant-provided information.
- In the ISP, retirements may be brought forward ahead of the expected closure year if it reduces overall system costs while meeting the model's various policy or system constraints, as described in the *ISP Methodology*. As discussed in more detail in that document, retirements may be modelled to meet carbon budgets or broader policy constraints.

For reference, a *closure date* has the meaning specified in NER 2.10.1(c1) which specifies the date a generator will cease to supply or acquire electricity in the market or trade directly in the market, while an *expected closure year* is the year in which a generator expects to cease to supply electricity (as per NER 2.1B.3(a)). Generators that have identified a closure date tend to be those that are scheduled to close in the near term. Both closure dates and expected closure years are published in the Expected Closure Year file as well as in the Generation Information publication, both of which are published on AEMO's Generation Information page.

As discussed in the *ISP Methodology*, if a generator has notified its closure date (as opposed to its expected closure year) then earlier retirement of that unit is not considered. AEMO's approach therefore recognises the increased accuracy of closure date submissions, thereby locking these dates in across all analysis rather than contemplating alternative economics-triggered closure timings.

Retirement costs by generation technology have been provided by AEMO's technology cost consultants and are presented in the accompanying 2025 *Inputs and Assumptions Workbook*. These have been updated following stakeholder feedback on the Draft 2025 IASR. Retirement costs incorporate the cost of decommissioning, demolition, site rehabilitation, and the disposal and recycling of materials. For further information, see GHD's *2025 Energy Technology Retirement Cost and O&M Estimate Review*[165]. Additionally, system strength remediation costs will be considered when thermal plants are retired, see Section 3.11.

3.4.5 Hydro modelling

Input vintage	June 2025
Source	Inflows – internal analysis and hydro operators
Updates since 2023 IASR	Hydro scheme methodology and inflows have been updated

Hydro scheme inflows

AEMO models each of the large-scale hydro schemes, which broadly fall into the following five hydro scheme categories for modelling purposes:

[164] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[165] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/GHD-2025-Energy-technology-retirement-cost-OM-estimate-review.

- **Power-only** – where the storage and release of water at the actual hydro scheme is purely used for the purposes of power generation by the hydro scheme operator. This allows stored water to be used at any time, principally when it is most advantageous for power generation purposes.
- **Primary Hydroelectric** – where the storage and release of water is primarily used by the hydro scheme operator for power generation, which is typically managed within a one-year inflow release cycle.
- **Secondary Hydroelectric (Irrigation)** – where the storage and release of water is influenced by irrigation release requirements, with the management of water for power generation purposes being secondary to irrigation requirements.
- **Run-of-river (or operationally similar)** – where storage is small relative to water inflows and the hydro scheme operator has limited ability to hold water in storage for the purposes of managing power generation.
- **Pumped Hydro Schemes** – representing closed-loop systems where the storage and use of water is the primary means to support power generation, and natural water inflows (and evaporation) are not material in the operation of the scheme.

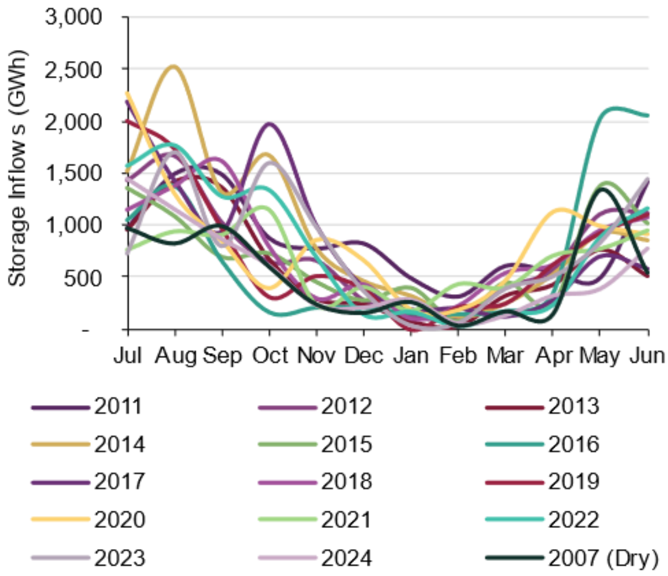
Significant hydroelectric schemes and stations exist already within the NEM, including:

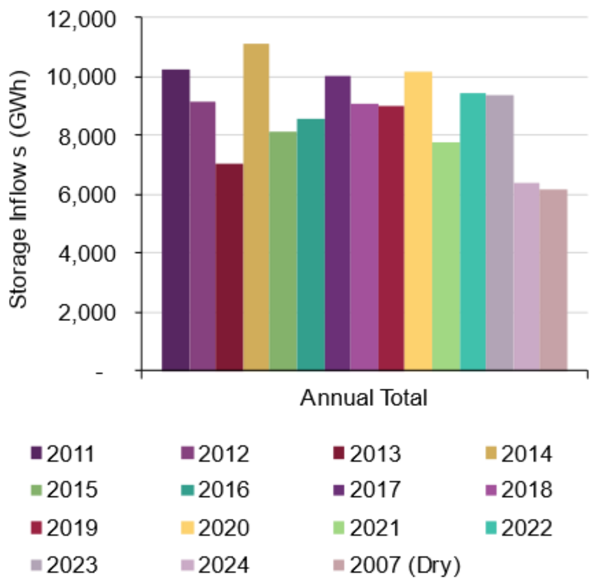
- Snowy scheme, including Guthega, Murray, Tumut (and Snowy 2.0),
- Tasmania's hydro stations,
- Queensland's hydro stations, including Barron Gorge and Kareeya, and
- Victoria's hydro schemes, including the Kiewa, Eildon and Dartmouth schemes.

Storage, generation capacity, and water flow arrangements on these schemes, and other specific projects, are provided in Appendix A2, and in the 2025 *Inputs and Assumptions Workbook*.

The 2025 *Inputs and Assumptions Workbook* provides the annual and seasonal variation in hydro inflows for key hydro schemes. An example of this is shown in **Figure 56** below, for Hydro Tasmania.

Figure 56 Hydro inflow variability across reference weather years – Hydro Tasmania (GWh)





3.5 New entrant generator assumptions

3.5.1 Committed and anticipated projects

Input vintage	July 2025
Source	Participant survey responses
Updates since Draft 2025 IASR	Updated to incorporate the July 2025 Generation Information.

Announced new generator or storage developments are assessed against commitment criteria published in AEMO's Generation Information page[166]. The commitment criteria cover five areas of a project's development, covering:

- land/site acquisition,
- contracts for major components,
- planning and other approvals,
- financing, and
- construction.

To classify the commitment status of generators or storages, AEMO uses information provided by the project proponent. In reliability assessments, some projects are subject to delays to manage the impact of commissioning risks in the short to medium term, whereas the ISP assumes that projects are delivered on schedule so that any infrastructure needed to extract the full value of these projects for consumers can be considered as part of the whole-of-system plan. The key classifications are defined as follows:

- **In Commissioning** are those projects that have met the requirements of the first commissioning hold point (typically at least 30% capacity commissioned).
  - For reliability and ISP assessment purposes, projects in commissioning are modelled as becoming fully available at the Full Commercial Use Date (FCUD) submitted by the project proponent.
- **Committed projects** are projects that have fully met all commitment criteria but have not yet met the requirements of their first commissioning hold point.
  - For reliability assessment purposes, committed projects are included in the modelling at six months after the FCUD submitted by the project proponent.
  - For ISP assessment purposes, committed projects are assumed to proceed at the FCUD submitted by the project proponent.
- **Committed* projects** are those projects that satisfy land, finance and construction criteria plus either planning or contracts criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.

[166] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

  - For reliability assessment purposes, committed* projects are included in the modelling at six months after the FCUD submitted by the product proponent.
  - For ISP assessment purposes, committed* projects are assumed to proceed at the FCUD submitted by the project proponent.
- **Anticipated projects** are those projects that have demonstrated progress towards meeting at least three of the commitment criteria and have updated their submission to AEMO in the previous six months.
  - For reliability assessment purposes:
    - To reflect the uncertainty in the commissioning of these projects, anticipated projects which have provided an expected commissioning date are assumed to become fully available at the latest date of either: one year after the date provided by the project proponent, or the first day after the T-1[167] year for RRO purposes.
    - Anticipated projects that are not yet sufficiently progressed to provide an expected commissioning date are assumed to become fully available on the first day after the T-3[168] year for RRO purposes.
  - For ISP assessment purposes:
    - Anticipated projects for which an expected commissioning date has been provided are assumed to proceed at the FCUD submitted by the project proponent.
    - Anticipated projects for which an expected commissioning date has not been provided are assumed to become fully available two years after the publication of the IASR (that is, July 2027 for the purposes of this IASR), subject to technology development lead time assumptions.
- **Proposed projects** are those projects that have not progressed sufficiently to meet the requirements of an Anticipated or Committed project.
  - Proposed projects are not considered explicitly in AEMO's reliability or ISP assessments but may be considered in sensitivities if relevant.

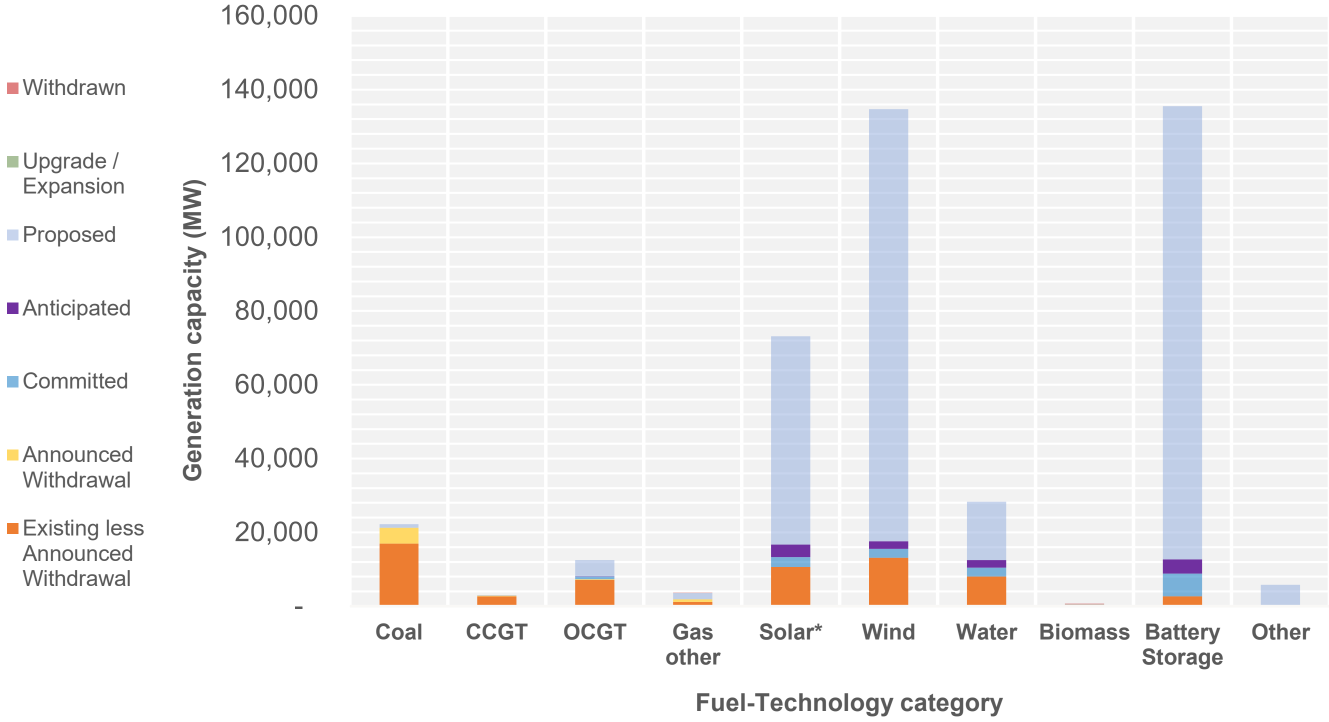
The 2025 IASR uses the Generation Information as at July 2025. A summary of existing, committed, and anticipated projects included in that release is provided in **Figure 57** below.

AEMO's modelling will reflect the most up-to-date information available at the time the modelling commences and will incorporate material updates if possible. Each publication will note what version of the Generation Information dataset was used in the assessment.

[167] T-1 refers to reliability assessments one year out. For example, for a reliability assessment conducted in August 2023, the T-1 period refers to the 2024-25 financial year.

[168] T-3 refers to reliability assessments three years out. For example, for a reliability assessment conducted in August 2023, the T-3 period refers to the 2026-27 financial year.

Figure 57 Generation and storage projects in July 2025 Generation Information page (MW)



Note: in this figure, Committed* projects are included in the Committed category, and projects in commissioning are included in the Existing less Announced Withdrawal category.

3.5.2 Candidate technologies

Input vintage	July 2025
Source	CSIRO: *GenCost 2024-25 Final Report* Aurecon: *2024 Energy Technology Costs and Technical Parameter Review* GHD: *2018-19 Costs and Technical Parameters Review*
Updates since Draft 2025 IASR	Updated to reflect Aurecon's 2024 Energy Technology Cost and Technical Parameter Review and include distributed resources.

For the 2026 ISP's capacity outlook modelling, a reduced list of technologies is considered based on technology maturity, resource availability, and energy policy settings. **Table 25** below presents the list of technologies that will be used in 2025-26 publications.

Table 25 List of generation and storage technology candidate

List of technologies for consideration in the 2026 ISP	Commentary
CCGT – with CCS	As discussed in Aurecon's *2024 Energy Technology Costs and Technical Parameters Review* there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new CCGT projects are expected to include provision/capability for hydrogen blending. As such, AEMO is now modelling all CCGTs as capable of using gas, hydrogen and/or diesel or liquid fuel (as needed).
CCGT – without CCS	As discussed in Aurecon's *2024 Energy Technology Costs and Technical Parameters Review* there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new CCGT projects are expected to

List of technologies for consideration in the 2026 ISP	Commentary
	include provision/capability for hydrogen blending. As such, AEMO is now modelling all CCGTs as capable of using gas, hydrogen and/or diesel or liquid fuel (as needed).
OCGT – dual fuel, without CCS, small unit size	As discussed in Aurecon's *2024 Energy Technology Costs and Technical Parameters Review* there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new open cycle gas turbine (OCGT) projects are expected to include provision/capability for hydrogen blending. As such, AEMO is now modelling all OCGTs as capable of using gas, hydrogen and/or diesel or liquid fuel (as needed).
OCGT – dual fuel, without CCS, large unit size	As discussed in Aurecon (2024) there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new OCGT projects are expected to include provision/capability for hydrogen blending. And as such, AEMO is now modelling all OCGTs as capable of using gas, hydrogen and/or diesel or liquid fuel (as needed).
Solar PV – single axis tracking	-
Solar thermal central receiver with storage (16 hr)	The storage component has increased from 15 hours to 16 hours, aligned with the *2024 Energy Technology Costs and Technical Parameter Review*
Wind – onshore	-
Wind – offshore (both fixed and floating)	Both fixed and floating offshore wind turbine structures are considered as distinct candidate options, with consideration for the ocean depth of the offshore REZ.
Biomass generation – electricity and heat	Since the *GenCost 2022-23 Final report*[A] and following stakeholder feedback, heat generated from biomass generation for electricity has now been reflected; however, as AEMO's capacity outlook modelling does not consider demand for heat or location explicitly, it is not able to consider the value of the heat generated from biomass.
Battery storage	AEMO includes storage sizes from one to eight hours in its models. No geographical limits will apply to available battery capacity given its small land footprint. AEMO uses the technical and economic parameters for Lithium – Ion battery.
Pumped hydro energy storage (PHES)	AEMO includes 10-hour (unlike in previous IASRs, which proposed an 8-hour option), 24-, and 48-hour PHES options across the NEM. Six- and 12-hour PHES options are consolidated into a 10-hour option to reflect likely future PHES developments across the NEM. The increase in depth from 8-hour to 10-hour reflects Aurecon's feedback on developer interest. These options are supplemented by announced projects where appropriate, for example the 20-hour Cethana project in Tasmania. This portfolio of candidates complements deep storage initiatives (such as the committed Snowy 2.0 and the anticipated Borumba Dam Pumped Hydro) and existing traditional hydro schemes.
Distributed resources	As discussed in the 2026 *ISP Methodology*[B], AEMO has included additional distributed resource candidates, complementing CER that is forecast exogenously (see Section 3.3.7). These candidates (representing both mid-scale PV systems and separately mid-scale battery systems) are assumed to be sized between 5 and 30 MW, and will use their own distinct costs and technical parameters as defined in Aurecon's *2024 Energy Technology Costs and Technical Parameters Review* and *2024 Energy Technology Cost and Technical Parameter Review – Mid Size Solar PV and BESS*.

A. At https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost.
B. At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology

The following technologies are excluded from modelling considerations to keep problem size computationally manageable:

- **New brown coal generation (with or without CCS) and advanced ultra-supercritical pulverised black coal (with and without CCS)** – given federal and state existing policies regarding net zero emissions, including this technology would present an internal inconsistency with those policy requirements. Considering also that there are lower cost dispatchable alternatives offering greater system flexibility, investment risks for new coal developments are therefore assumed to be too high to be commercially viable.

- **Reciprocating internal combustion engines** – reciprocating engines fuelled by natural gas/diesel are not modelled due to their high capital cost relative to open cycle gas turbines (OCGTs), as discussed in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*.
- **Hydrogen-only reciprocating engines or OCGTs** – AEMO proposes not to model hydrogen-only or natural gas-only technologies. Instead, dual fuel technologies that can run on natural gas or hydrogen are proposed to be modelled, in line with current trends as discussed in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*.
- **Nuclear generation, including small-modular reactors** – currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[169] prohibits the development of nuclear installations.
- **Geothermal technologies** – geothermal technologies are considered too costly and too distant from existing transmission networks to be considered a bulk generation technology option in the NEM.
- **Solar PV fixed flat plate (FFP)** and **dual-axis tracking (DAT)** technologies – while the best solar configuration depends on each individual project, **single-axis tracking (SAT)** generally presents greater value on a cost-per-energy-delivered basis given current cost assumptions. Presently, announced SAT projects also provide more proposed capacity than DAT and FFP projects, and almost all recent project commitments for large-scale solar are SAT[170]. Given this preference and the relative cost advantage, AEMO models all future solar developments using SAT configuration.
- **Tidal/wave technologies** – this is not sufficiently advanced or economic to be included in the modelling.
- **Hybrid technologies** – these are not explicitly considered but the *ISP Methodology* sets out how AEMO considers the benefits of co-locating VRE and storage in the assessment of potential actionable REZ augmentations.

3.5.3 Candidate technology build costs

Capital cost trajectories

Input vintage	July 2025
Source	CSIRO: *GenCost 2024-25 Final Report* Aurecon: *2024 Energy Technology Costs and Technical Parameters Review* Hydro Tasmania information on Cethana project
Updates since Draft 2025 IASR	Updated to reflect CSIRO's *GenCost 2024-25 Final Report*

AEMO's generator and storage capital cost trajectories are informed by the GenCost publication series – an annual publication of electricity generation technology cost projections conducted jointly through a partnership between CSIRO and AEMO. To support this forecast, Aurecon provided estimates of the current capital cost of each generation technology. CSIRO uses these current capital cost estimates in the Global and Local Learning Model (GALLM) to produce capital cost forecasts that are a function of global and local technology deployment.

[169] At https://www.legislation.gov.au/Details/C2012C00248.

[170] Based on July 2025 Generation Information, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

GenCost estimates include consideration of global demand for each technology which relates to, among other things, international policy and renewable targets. The GenCost scenarios have evolved over time to better reflect the uncertainty in the speed of global emissions reduction, which improves the alignment with AEMO's scenarios, and consideration of easement of supply-chain pressures over time.

The build cost projections are given for three *GenCost 2024-25 Final Report* scenarios: "*Global NZE by 2050*", "*Global NZE post 2050*" and "*Current Policies*". These scenarios are described in greater detail in CSIRO's *GenCost 2024-25 Consultation Draft*. AEMO maps the Draft 2025 IASR scenarios to the *GenCost 2024-25 Final Report* scenarios based on the fit of the narratives against each other, as shown in **Table 26**.

Table 26 Mapping AEMO scenario themes to the *GenCost 2024-25 Final Report* scenarios

ISP scenario	*GenCost 2024-25 Final Report* scenario	Explanation
Slower Growth	*Current Policies**	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.5°C warming future.
Step Change	*Global NZE post 2050*	Consistent with global action to limit temperature rises to less than 2°C, and with industrialised countries targeting net zero emissions by 2050.
Accelerated Transition	*Global NZE by 2050*	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.

* While *Slower Growth* does increase its emissions reduction ambition, achieving net zero emission domestically by 2050, the scenario also delays significant action to align with a higher warming future at a global scale and is not consistent with a "well below 2°" target.

Figure 58, **Figure 59** and **Figure 60** below present a comparison of *GenCost 2024-25 Final Report*'s Global NZE post 2050 compared with *GenCost 2023-24 Final Report*'s Global NZE post 2050 build cost projections (excluding connection costs) for selected technologies. Cost projections for each technology and scenario are available in the accompanying 2025 *Inputs and Assumptions Workbook*.

In line with findings in the previous GenCost, costs over the period to 2030 are driven by short-term supply pressures which result in higher costs relative to the cost paths determined by the CSIRO's learning model. As these impacts ease, costs converge closer to previous estimates in the longer term.

As detailed in Aurecon's accompanying *Energy Technology Cost and Technical Parameter Review*[171], since last year, fixed offshore wind has seen a more significant drop in costs. Some caution needs to be applied when translating these costs to an Australian context given these developments would be first-of-a-kind as highlighted in both Aurecon's *Energy Technology Cost and Technical Parameter Review* and the *GenCost 2024-25 Final Report*.

In recognition of this, AEMO will modify the costs (as provided by GenCost) of offshore wind (both fixed and floating), solar thermal and CCS technologies by applying a first-of-a-kind (FOAK) premium as build cost multipliers for initial investments in these technologies within the ISP. This premium will apply directly to the generation costs forecast by GenCost, which recognises global technology learning rates, but does not consider domestic installation hurdles for first builds. These premiums are intended to account for the demonstrated tendency to under-estimate actual costs for a FOAK unit. As discussed in GenCost, these are observable when a proponent fails to deliver the first project for the cost that had been planned, and as such, they are difficult to estimate. These factors, as presented in **Table 27**, have been sourced from CSIRO's *GenCost 2024-25 Final Report*, in which values have been derived based on a technology's construction time. This reflects the idea that

[171] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Aurecon-2024-Energy-technology-cost-technical-parameter-review-report and https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-Inputs-Assumptions-and-Scenarios-Report.

technologies that take longer to build will face higher FOAK premiums as their planning is more complex and cost overruns are more likely. The factors will be applied to the capacity of each relevant technology on the first year they are developed in the modelling, before halving in the second year and finally reducing to zero for all subsequent developments.

Table 27 First-of-a-kind generation cost premiums

Technology	Cost premium – first year of development	Cost premium – second year of development
Wind – offshore (fixed)	63%	31%
Wind – offshore (floating)	63%	31%
Solar thermal	37%	18%
Technologies with CCS	42%	21%

In recognition of the recent inflationary cycle and the resulting cost pressures, CSIRO has modified its modelling approach to better account for the recent trends in capital costs. Taking Aurecon figures as a starting point, *GenCost 2024-25 Final Report* now applies ‘basket-of-costs’ factors over the period to 2030 or 2027 (depending on the scenario) as less deployment in new technology in *GenCost’s Current Policies* (applied in *Slower Growth*) sees slower learning and less pressures on technology costs and a relaxation of supply chain constraints earlier.

The build costs for certain technologies – including but not limited to batteries, PV, and fixed offshore wind – have been observed to have returned to pre-pandemic levels. As a result, these technologies do not apply the supply chain constraint impacts and rather apply the standard learning rate approach described in *GenCost 2024-25 Final Report*.

In the medium and longer term, technology costs may reflect forecast cost reductions due to learning rates that are achieved through deployment. Long-term escalation of installation cost component due to real increases in labour costs and the cost of construction materials such as steel and cement, as forecast by Oxford Economics Australia, are now also reflected in *GenCost 2024-25 Final Report*. For further details see Section 3.5.6. The net cost of installation of technologies over time will be influenced by both of these separate factors that increase and reduce technology costs.

Additionally, projections have been adjusted since the 2023 IASR to recognise the fundamental scarcity of land and easements following stakeholder feedback. Projections will be adjusted using locational cost factors published in the report by GHD underpinning figures in AEMO’s 2025 Transmission Cost Database for the land and easement component of the project cost.

As seen in **Figure 59**, *GenCost 2024-25 Final Report* incorporates hydrogen fuel readiness for gas generation technologies, which results in an increase in costs relative to previous estimates. Figure 60 shows a decrease in the cost of batteries, which, as discussed in *GenCost 2024-25 Final Report,* are now at pre-pandemic levels in real terms. Finally, build cost estimates from pumped hydro have been updated based on Aurecon’s assessment, with 10-hour pumped hydro considered more expensive than 24-hour, and more in line with estimates for 48-hour durations. Pumped hydro build costs across all depths increase in real terms post-2030 due to escalating installation costs, the relatively high proportion of installation costs making up the total build cost, and a lack of other cost reductions through learning due to technological maturity.

More information on methodology adjustments from GenCost 2023-24 to *GenCost 2024-25 Final Report* can be found in the *GenCost 2024-25 Final Report.*

Figure 58 2024 versus 2025 *Global NZE post 2050*: build cost trajectories forecasts for wind and large-scale solar

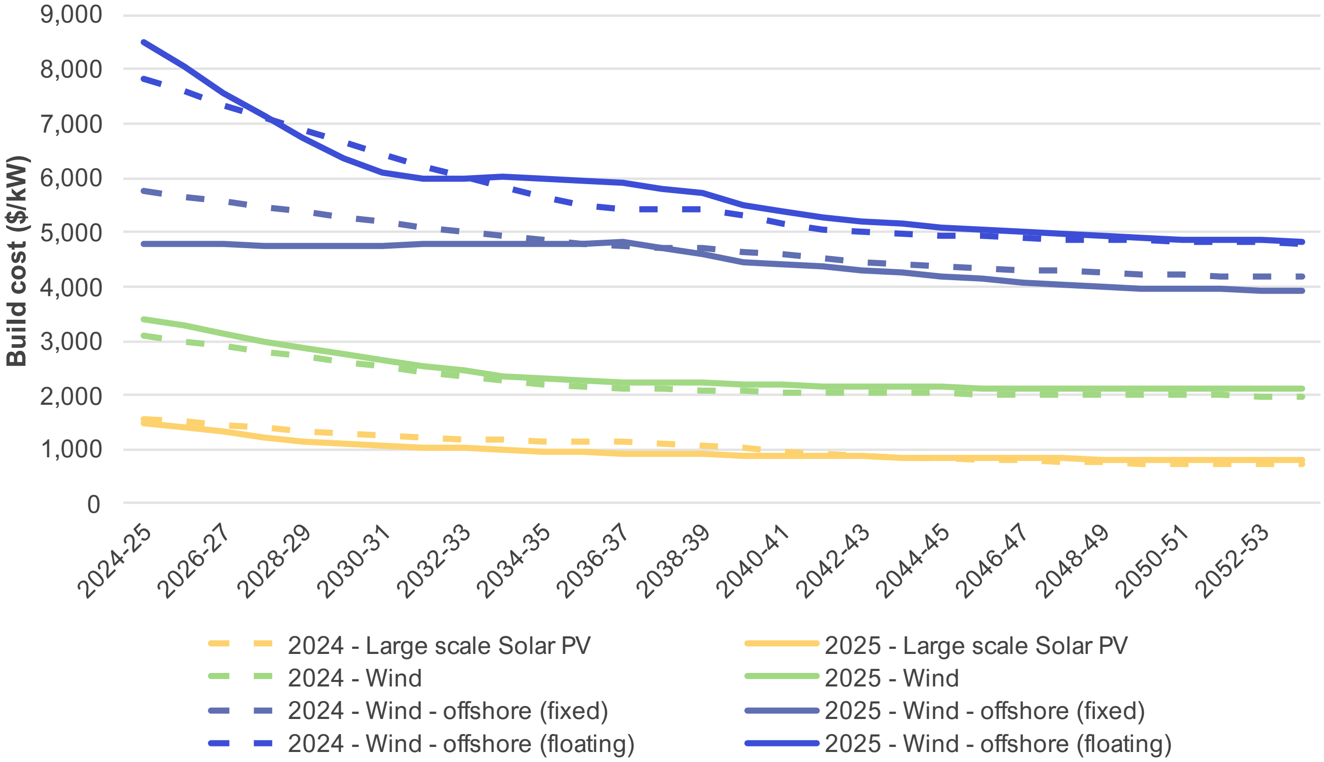


Figure 59 2024 versus 2025 *Global NZE post 2050*: build cost trajectories forecasts for gas generation

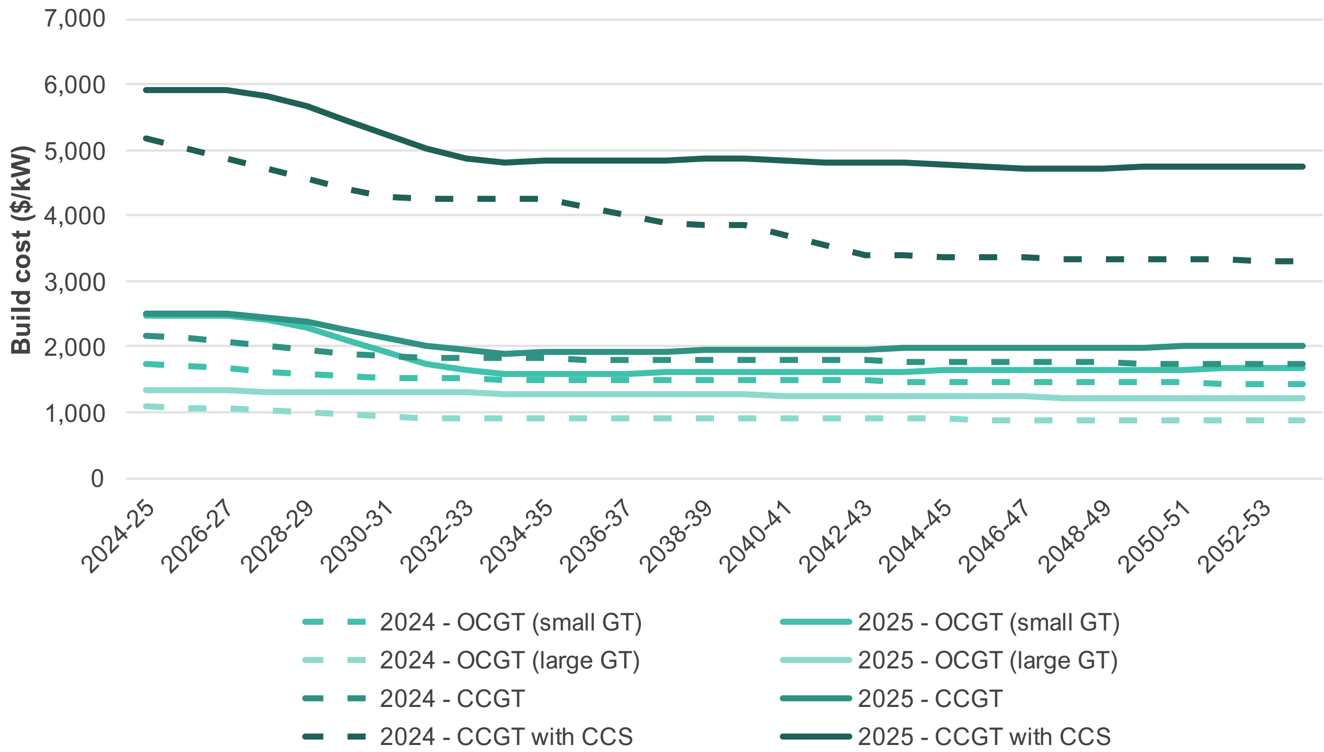
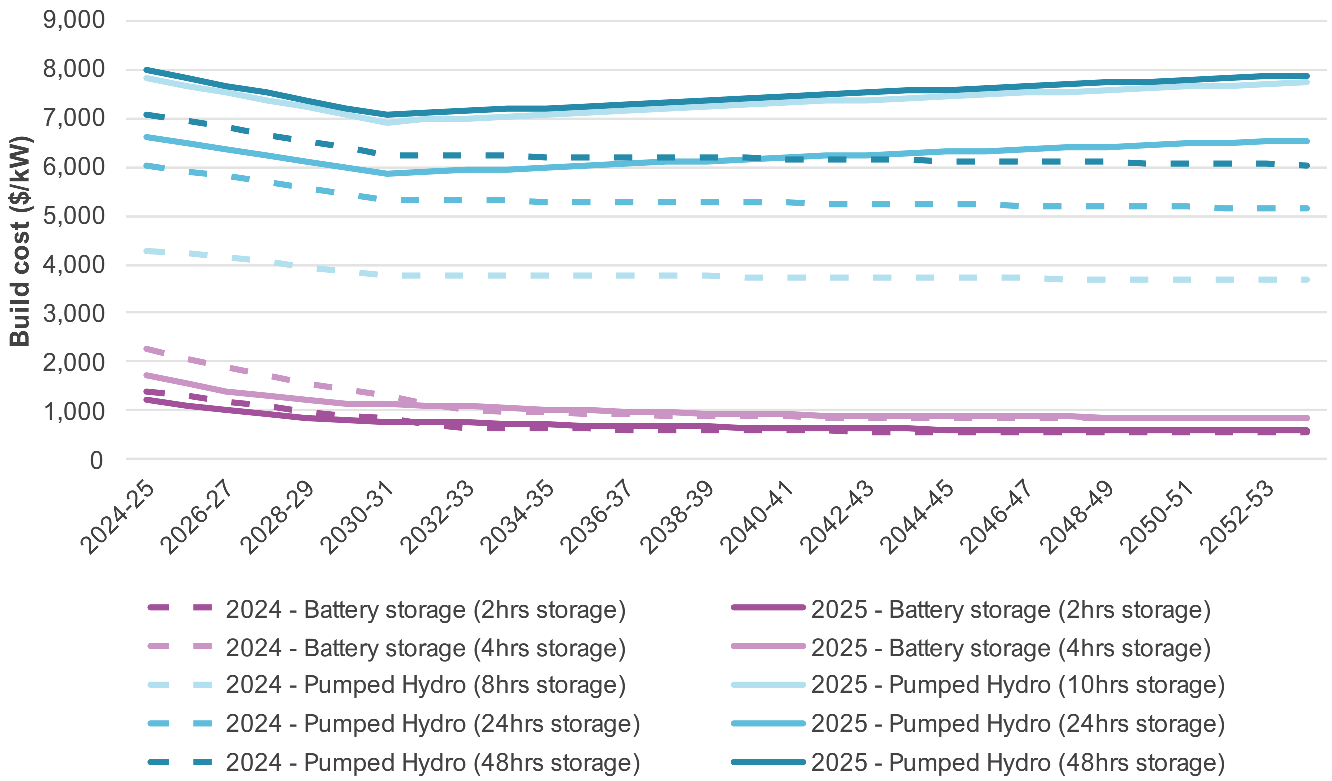
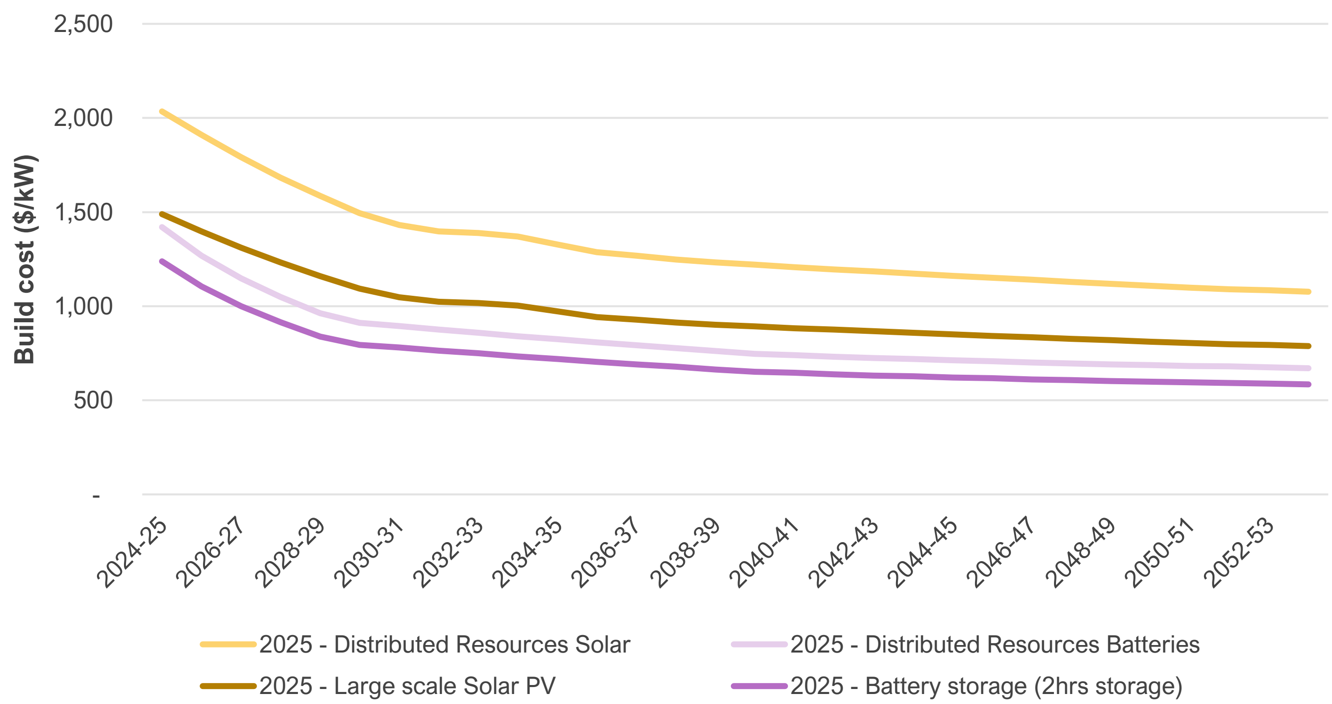


Figure 60 2024 versus 2025 *Global NZE post 2050*: build cost trajectories forecasts for selected storage technologies



Note: As discussed in Table 26, pumped hydro 8-hour has been replaced with 10-hour following advice from Aurecon.

Figure 61 Build cost trajectories forecast for large-scale versus smaller alternatives that may be developed as other distributed resources



In the *GenCost 2024-25 Final Report*, current costs (a key input to develop the projections) represent current typical contracting costs or costs demonstrated to have been incurred for projects completed in the current financial year and does not represent quotes for potential projects or project announcements.

It should also be noted that when comparing *GenCost 2024-25 Final Report*'s capital costs in $/kW with Aurecon, the latter does not include the cost of land in its presentation of $/kW capital costs, whereas this is included in the *GenCost 2024-25 Final Report* and therefore by AEMO[172].

Cost trajectories for distributed resource candidates (mid-scale solar PV and batteries) are not included in *GenCost 2024-25 Final Report*. AEMO has instead taken the current capital cost estimates for these technologies from Aurecon's *Energy Technology Cost and Technical Parameter Review* and *2024 Energy Technology Cost and Technical Parameter Review – Mid Size Solar PV and BESS* and applied the same cost trajectory as forecast by *GenCost 2024-25 Final Report* for their large-scale counterparts. As the underlying technology is similar, it is assumed learning rates and exposure to supply limitations will also be similar between mid-scale and large-scale technologies. The primary driver for differences in capital costs is reduced economies of scale for distributed resources which is reflected in the underlying cost estimates from Aurecon and is assumed to persist into the future.

Capital costs are not applied for existing, committed, and anticipated projects. AEMO does not have specific estimates for the cost of these projects. Importantly, as these projects are included in all ISP development pathways, including the counterfactual, the calculation of net market benefits are not influenced by the costs or benefits of these projects, as they are netted off.

Locational cost factors

Input vintage	July 2025
Source	Aurecon: *2024 Energy Technology Cost and Technical Parameters Review* GHD: *2025 Pumped Hydro Energy Storage Parameter Review* AEMO revisions
Updates since Draft 2025 IASR	Locational cost factors have been updated to be REZ-specific as presented in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*. Land and development factors have been modified to reflect those applied in the 2025 update to AEMO's Transmission Cost Database. Locational cost factors for pumped hydro have been updated based on GHD's *2025 Pumped Hydro Energy Storage Parameter Review*.

The breakdown of cost components for each technology is informed by updated data from Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*, in line with the approach followed in previous IASRs. These figures do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate. The updated breakdown of cost components is available in the 2025 *Inputs and Assumptions Workbook*.

[172] Build costs from GenCost are then weighted by regional costs factors (see the following section) where AEMO considers Aurecon's cost of land and other locational influences.

In previous IASRs, AEMO used cost zones that are attributed to each generation and storage candidate to estimate the capital costs of technologies developed in different locations. Each cost zone in each region has a specific set of locational cost factors which provides multiplicative scalars to the cost components (equipment, fuel connection, land and development, and installation) of each generation and storage technology type.

In 2023, AEMO commissioned Aurecon to update the locational cost factors as part of the *2023 Energy Technology Cost and Technical Parameters Review*. The factors account for greater granularity by providing factors at a REZ level, relative to metropolitan capital city areas in the NEM region, and are intended to be a multiplier to the cost components resulting in a technology and location-specific multiplier. These factors, updated in the *2024 Energy Technology Cost and Technical Parameters Review*, have been defined for a number of locations within each REZ which are then averaged up to the REZ level.

Equipment cost factors consider the cost of transporting material, plant and equipment for construction to a site, and are based on the distance of each location from the nearest suitable port. Installation cost factors consider the indicative cost of local accommodation, cost for resources, mobilisation and demobilisation based on project duration, and labour productivity in each location.

The factors for land and development have been updated from those provided by Aurecon to those underpinning AEMO's 2025 Transmission Cost Database, to ensure consistent treatment of land and development factors across transmission, generation and storage.

Locational cost factors provided by Aurecon are relative to metropolitan capital cities with a de facto factor of one. As such, equipment and installation cost factors of one are assigned to builds in sub-regional reference nodes (while land and development cost factors are based on land values in line with those applied in the Transmission Cost Database, as noted above). Offshore REZs also have a factor of one (although as discussed above, AEMO will apply a temporary first-of-a-kind premium to offshore wind build costs).

The accompanying 2025 *Inputs and Assumptions Workbook* provides additional details of these locational cost factors, including the resulting regional technology cost adjustment factors.

Figure 62 shows the effective impact of the changes in overall locational cost factors for all REZs for onshore wind generation. The greatest variance is in Queensland, with North Queensland Clean Energy Hub being 23% higher than the benchmark, and in South Australia, where Roxby Downs is 19% higher than the benchmark. This represents greater variation than in the 2023 IASR, with the change largely due to greater differences in labour, installation, and O&M cost components when benchmarked against capital cities. Additionally, disaggregation by REZs (rather than more coarse regional segmentation) further highlights underlying differences that may be masked by higher geographical aggregation. Further detail on differences to previous values is in Aurecon's accompanying *2024 Energy Technology Cost and Technical Parameters Review* report (see Appendix A3).

Figure 62 Weighted REZ locational cost factors for wind in the 2023 IASR and the 2025 IASR

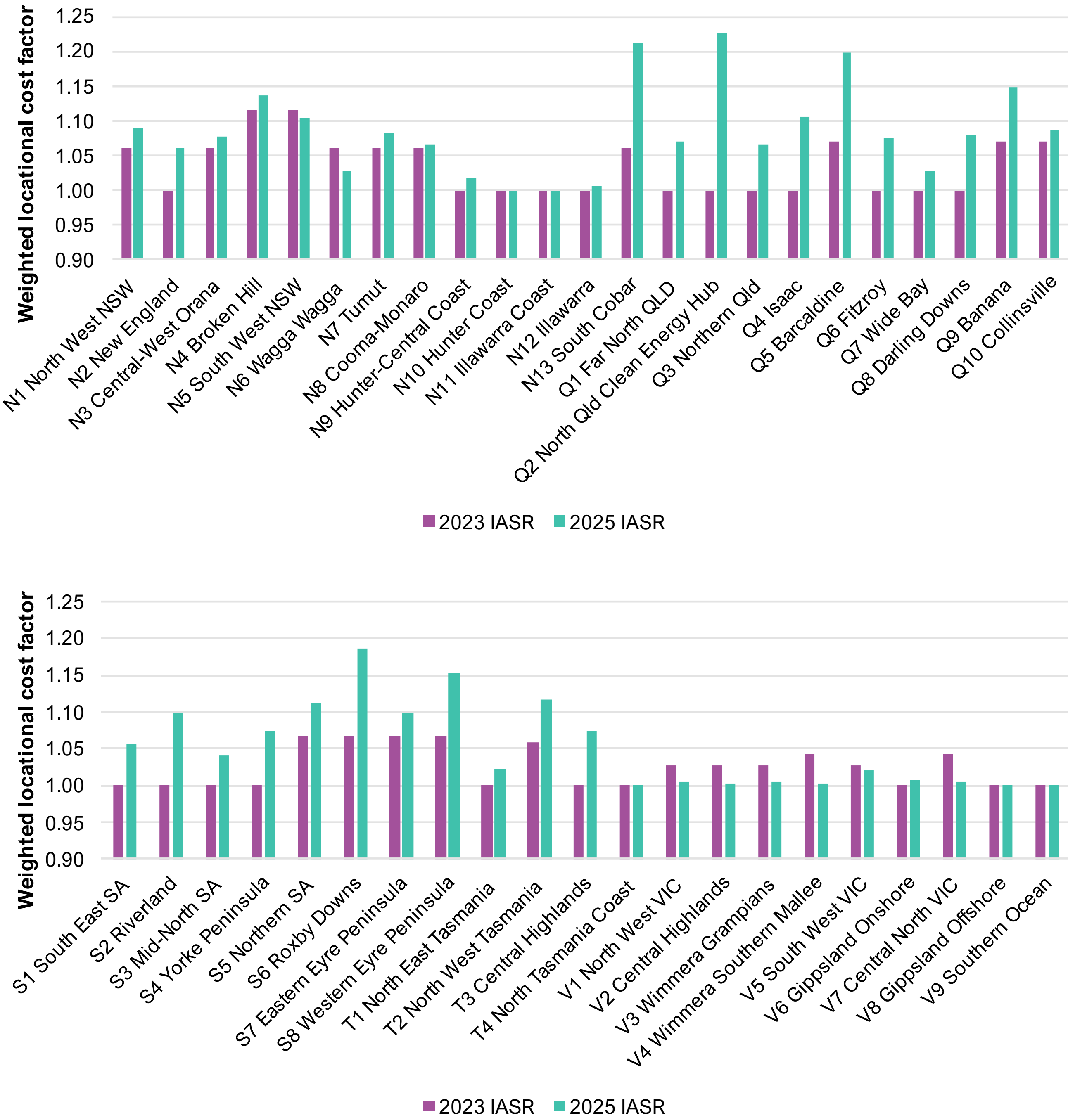
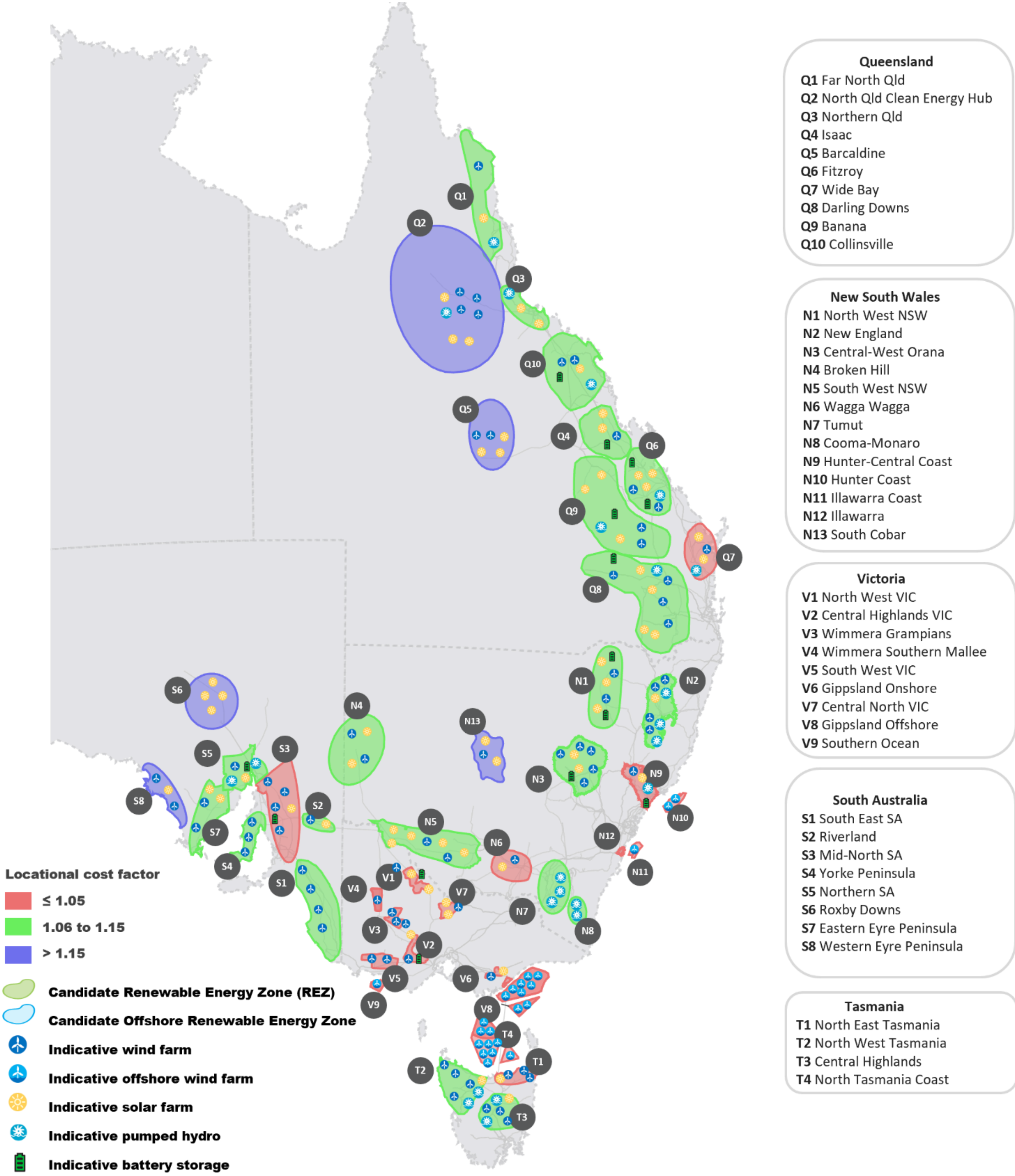


Figure 63 Weighted REZ locational cost factors for wind in the 2025 IASR



Locational cost factors for pumped hydro energy storages

In line with all other new entrant technologies, sub-regional locational cost factors are applied to PHES options. Unlike those for other technologies, locational cost factors for PHES are highly site-dependent and have therefore been derived based on the relative cost of the natural resource and geology available within each location for PHES development. These factors, shown in **Table 28**, have been updated for this 2025 IASR and are now sourced from GHD's *2025 Pumped Hydro Energy Storage Parameter Review*[173].

These factors do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate.

Table 28 Pumped hydro energy storage locational cost factors

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hours	PHES: 48-hour
Northern New South Wales (NNSW)	New South Wales	1.04	1.02	0.96
Central New South Wales (CNSW)	New South Wales	1.04	1.01	1.03
South New South Wales (SNSW)	New South Wales	1.13	1.08	1.18
Sydney, Newcastle, Wollongong (SNW)	New South Wales	1.02	Not applicable*	Not applicable*
Northern Queensland (NQ)	Queensland	1.08	1.01	0.99
Central Queensland (CQ)	Queensland	1.00	0.99	0.92
Gladstone Grid (GG)	Queensland	Not applicable*	Not applicable*	Not applicable*
South Queensland (SQ)	Queensland	0.92	0.99	1.01
Northern South Australia (NSA)	South Australia	1.03	1.06	1.13
Central South Australia (CSA)	South Australia	0.96	Not applicable*	Not applicable*
South East South Australia (SESA)	South Australia	Not applicable*	Not applicable*	Not applicable*
Tasmania (TAS)	Tasmania	1.01	1.01	1.01
West and North Victoria (WNV)	Victoria	0.98	0.93	1.00
Greater Melbourne and Geelong (MEL)	Victoria	Not applicable*	Not applicable*	Not applicable*
South East Victoria (SEV)	Victoria	Not applicable*	Not applicable*	Not applicable*

*Pumped hydro energy storage of this depth in this sub-region is not a credible candidate.

3.5.4 Storage-specific assumptions

Input vintage	July 2025
Source	Aurecon: 2024 Energy Technology Cost and Technical Parameters Review CSIRO: GenCost 2024-25 Final Report GHD: 2025 Pumped Hydro Energy Storage Parameter Review Hydro Tasmania information on Cethana project
Updates since Draft 2025 IASR	Updated to reflect latest *Energy Technology Cost and Technical Parameters Review*, *GenCost 2024-25 Final Report*, and *Pumped Hydro Energy Storage Parameter Review*.

[173] At: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/GHD-2025-Pumped-hydro-energy-storage-cost-parameter-review

AEMO includes a range of storage options in assessing the future needs of the power system. Storage expansion candidates in each region include PHES, large-scale batteries, concentrated solar thermal (CST), and embedded battery systems within AEMO's CER forecasts.

Pumped hydro energy storage build limits

AEMO has recently updated build limits for pumped hydro expansion candidates based on sub-regional estimates detailed by GHD's *2025 Pumped Hydro Energy Storage Parameter Review*[174]. These estimates consider both publicly-announced PHES projects at the time of the study (but excluding those already explicitly included in AEMO's modelling, such as Snowy 2.0), as well as a screened list of potential PHES sites identified in the Australian National University (ANU) PHES Atlas[175]. Sites from the ANU PHES Atlas were screened based on technical criteria, such as scheme size, cost class and head, and GIS-based criteria to exclude sites located in restricted zones such as national parks, urban areas and those distant from transmission infrastructure.

The effective PHES sub-regional limits are shown in **Table 29**.

Table 29 Pumped hydro sub-regional limits (in MW of generation capacity)

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hour	PHES: 48-hour
Northern New South Wales (NNSW)	New South Wales	2,500	9,400	19,500
Central New South Wales (CNSW)	New South Wales	1,000	5,200	3,900
South New South Wales (SNSW) [A]	New South Wales	1,500	2,100	2,300
Sydney, Newcastle, Wollongong (SNW)	New South Wales	300	0	0
Northern Queensland (NQ)	Queensland	1,000	6,500	10,200
Central Queensland (CQ)	Queensland	1,400	1,200	6,300
Gladstone Grid (GG)	Queensland	0	0	0
South Queensland (SQ) [B]	Queensland	1,000	1,000	1,600
Northern South Australia (NSA)	South Australia	100	1,000	800
Central South Australia (CSA)	South Australia	100	0	0
South East South Australia (SESA)	South Australia	0	0	0
Tasmania (TAS) [C]	Tasmania	1,100	500	3,900
West and North Victoria (WNV)	Victoria	1,600	4,700	9,400
Greater Melbourne and Geelong (MEL)	Victoria	0	0	0
South East Victoria (SEV)	Victoria	0	0	0

A. Total value excludes the contribution of Snowy 2.0.
B. The South Queensland limits do not include Borumba Dam Pumped Hydro (2 GW), which will be modelled as a specific project.
C. The Tasmania limits do not include the Cethana project (750 MW).

[174] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/GHD-2025-Pumped-hydro-energy-storage-cost-parameter-review.

[175] At https://re100.eng.anu.edu.au/pumped_hydro_atlas/.

Batteries

AEMO employs the following assumptions pertaining to large-scale batteries:

- Large-scale battery expansion candidates are modelled with fixed power to energy storage ratios, but with flexibility to charge and discharge to achieve the optimal outcome for the system within the fixed power to energy storage ratio limit.
- Assumptions for battery storages of 1-hour, 2-hour, 4-hour, and 8-hour duration depths are based on data provided by Aurecon in its *2024 Energy Technology Cost and Technical Parameter Review* and *2024 Energy Technology Cost and Technical Parameter Review – Mid Size Solar PV and BESS*.
- Battery storage degradation has been factored in by reducing the storage capacity of all new entrant battery storages based on an estimate of the average storage capacity over a battery's 20-year technical life, after considering annual degradation rates and estimated operating levels. For 1-hour and 2-hour batteries (which Aurecon estimates annual storage degradation rate to be 1.8%), storage capacity is reduced by 18%, while 4-hour batteries (1.4% annual degradation) and 8-hour batteries (1.2% annual degradation) are derated by 14% and 12%, respectively.
- AEMO's technology cost assumptions consider the usable storage capacity in defining project costs as sourced from Aurecon, and its modelling assumes a minimum and maximum state of charge of 0% and 100% respectively in line with Aurecon's advice.
- Exact storage locations are identified considering the storage needs of REZ and regional developments through time-sequential dispatch and power flow modelling, using AEMO internal expertise to determine suitable locations where transmission costs may be offset by locating storage.

Solar thermal technology

AEMO models new entrant solar thermal generators as a central tower and receiver with thermal storage. Based on previous stakeholder feedback reflected in CSIRO's *GenCost 2022-23 Consultation Draft report*, the capacity of the thermal storage component remains at 16 hours.

AEMO's capacity outlook modelling for previous ISPs used static discharge traces to represent operation. Following stakeholder feedback, AEMO modified the static discharge traces such that they discharge at night and during periods of high demand. If reasonable adoption of the technology occurs, subsequent simulations will include it as a controllable storage object to better represent its operation.

3.5.5 Other technical and cost parameters for new entrants

Input vintage	July 2025
Source	Aurecon: *2024 Energy Technology Cost and Technical Parameters Review* CSIRO: *GenCost 2024-25 Final Report* Hydro Tasmania information on Cethana project 2025 July Generation Information
Updates since Draft 2025 IASR	Updated inputs

Technical and other cost parameters for new entrant generation and storage technologies include:

- unit size and auxiliary load,
- seasonal ratings,
- heat rate,
- Scope 1 emission factors,
- minimum stable load,
- fixed and variable operating and maintenance costs,
- maintenance rates and reliability settings,
- lead time, economic life, and technical life, and
- storage parameters (including cyclic efficiency and maximum and minimum state of charge).

Details of these parameters are published in the 2025 *Inputs and Assumptions Workbook* as well as in the supporting material from Aurecon.

For new entrant generators (assets that are not existing and are developed over the modelling horizon), the technical life of each asset is observed such that new capacities will be decommissioned at the end of their respective technical lives. Replacement may not require a 'greenfield' solution (a 'brownfield' redevelopment may be appropriate for some assets), but technology improvements often mean that much of the original engineering footprint of a project may require redevelopment. Given that a brownfield solution would likely require site-by-site assessments and a more bespoke approach, AEMO applies no discount to asset redevelopments, with costs consistent with new entry greenfield developments. Likewise, there is no requirement for a retired generator to be replaced at similar location (except for a policy setting requiring a local response to meet a renewable energy target, for example) so a retirement could be effectively replaced at another NEM location if that minimises costs.

The technical life assumed for new wind and solar projects is 30 years. This assumption has been validated through the July 2025 Generation Information dataset, which shows that, on average, committed and anticipated VRE projects have submitted a technical life (reflecting the time between commissioning date and the expected closure year) of 31 years (solar projects) and 32 years (wind projects). AEMO considers this an appropriate and supportive benchmark of the assumption.

3.5.6 Impacts of planning, environmental and supply chain considerations

Input vintage	July 2025
Source	Oxford Economics Australia: *Planning and Installation Cost Escalation Factors*
Updates since Draft 2025 IASR	N/A – new in this 2025 IASR

The energy transition will require significant development of new energy infrastructure projects to decarbonise the energy system. This will place pressure on supply chains and planning and environmental approvals processes. In response to actions from the Energy and Climate Change Ministerial Council's ISP Review[176], AEMO has engaged Oxford Economics Australia to develop new assumptions for the 2026 ISP to assess how supply chains, and

[176] At https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

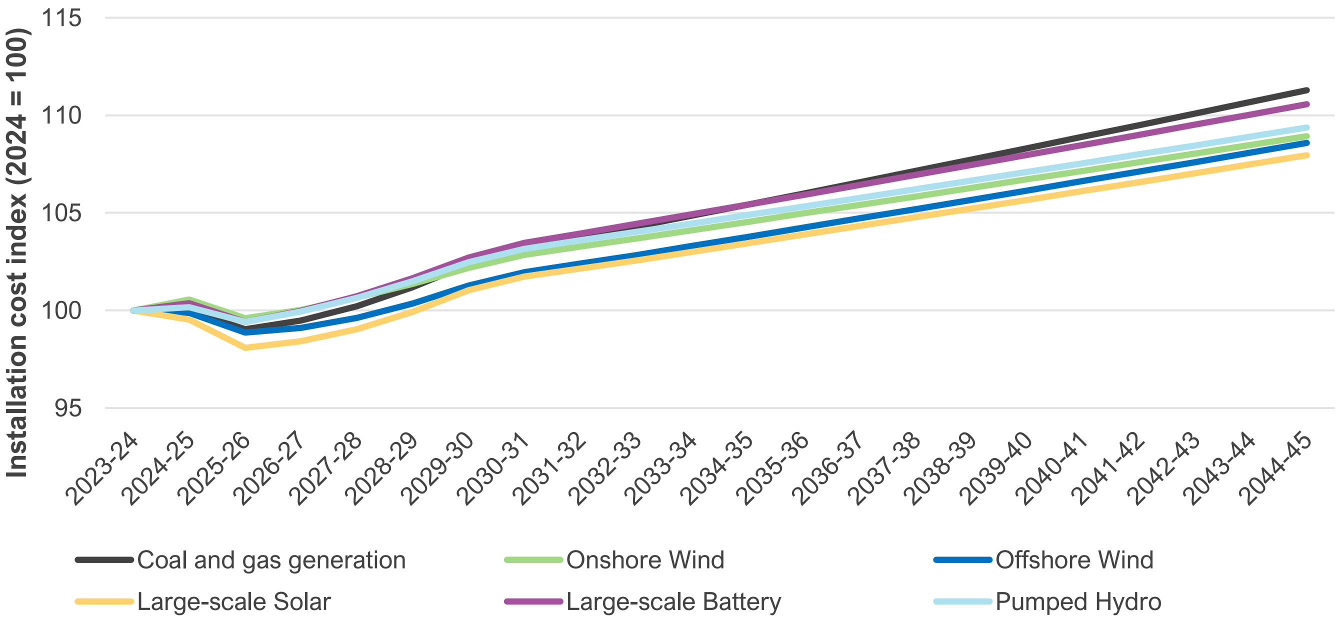
planning and environmental approvals may impact installation costs and development lead times for new generation and storage projects. Additional information is available in the report by Oxford Economics Australia in the supporting material to this 2025 IASR.

Real cost escalations due to supply chain issues

Installation costs[177] comprise a significant portion of the overall capital costs of new infrastructure developments. Potential issues around supply chains are expected to have a lasting impact on this due to increased competition for skilled labour in energy infrastructure projects as heightened levels of construction activity places strain on existing supply chains.

To account for this, Oxford Economics Australia has forecast the escalation of installation costs relative to 2024 costs for various energy infrastructure assets over time for each scenario. Real installation costs are initially projected to fall slightly due to falling prices for steel, concrete, machinery hire and freight in the near term, before rising in future years, as shown in **Figure 64**. This long-term growth (that is, growth above inflation) is driven primarily by real wage growth in the construction industry, especially for labour-intensive technologies such as fossil fuel generation. By 2044-45, installation costs in *Step Change* are expected to be 10% higher on average than 2024 levels for the installation costs alone.

Figure 64 Installation cost escalation in real terms for various generation and storage technologies relative to 2024 costs, *Step Change* scenario



These installation cost forecasts are considered as an input to CSIRO's GenCost modelling to inform future increases in installation costs due to the impact of issues around supply chains on technology build costs. The impact of supply chains on specialised equipment costs are not considered, because equipment cost projections

177 Installation costs measure the cost of installing or constructing a new generator or storage project on-site. It does not include the cost of specialised equipment (such as wind turbines, solar PV panels or transformers) or enabling infrastructure such as road widening.

are primarily driven by other factors such as learning rates through large-scale deployment which are already considered in the capital cost modelling for GenCost.

Planning and environmental approval

Oxford Economics Australia has analysed data from completed energy infrastructure projects to provide estimates for pre-construction and construction lead times, informed by actual development experiences and the various planning and environmental approval requirements in each region. Estimated lead time indices, relative to baseline lead times from Aurecon in the *2024 Energy Technology Cost and Technical Parameters Review*, have been provided for various new entrant generation and storage technologies and across each NEM region.

Oxford Economics Australia found that total lead times – mainly in the pre-construction phase where jurisdictional planning pathways are a key driver – vary between NEM regions and tend to be shorter when projects are developed near existing assets of the same type. Estimated lead times for generation and storage projects were found to be shortest in Queensland and South Australia, longest in New South Wales, and near the NEM average in Victoria and Tasmania.

AEMO will use these lead time adjustments in addition to the existing technology-specific lead times from Aurecon to inform the potential *Constrained Supply Chains* sensitivity. Details of this analysis are in the *Planning and Installation Cost Escalation Factors*[178] report from Oxford Economics Australia, published with this 2025 IASR.

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

AEMO sourced fuel price forecasts from ACIL Allen in November 2024, including natural gas, coal and diesel prices. Biomethane production costs were forecast by ACIL Allen, while delivered hydrogen prices were developed by the 2024 multi-sectoral modelling, combined with forecast transport costs from ACIL Allen. These are presented in the 2025 Inputs and Assumptions Workbook. This section summarises key insights for each fuel; more information on the derivation of these forecasts is provided in the accompanying ACIL Allen fuel price report (see Appendix A3).

Gas prices

Input vintage	November 2024
Source	ACIL Allen Consulting
Updates since the 2023 IASR	New gas price forecasts based on market analysis and modelling as at mid-2024

AEMO sourced the current natural gas price forecasts from ACIL Allen in November 2024. Gas supply development modelling for the Draft 2026 ISP will identify a set of gas development projections on which a new set of gas price forecasts will be based. These current gas price forecasts will apply for the initial development of

[178] At https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-iasr-planning-and-installation-cost-escalation-factors.pdf.

the gas development projections for the Draft 2026 ISP. AEMO will then consult on the gas development projections, and will refine the projections and the gas price impacts to support the finalisation of the 2026 ISP.

The current gas price forecasts consider fundamental inputs such as forecast gas production costs from existing and upcoming fields, reserves, infrastructure and pipelines, in addition to international gas prices, oil prices and measures of the domestic economy. The forecasts are also based on assumptions about the influence of international prices on east coast gas prices through LNG netback pricing, and the local level of competition.

The Australian Domestic Gas Supply Mechanism (ADGSM) reforms commenced 1 April 2023 and are designed to make the ADGSM more responsive to domestic gas shortfalls, while protecting established long-term contracts. The effect of the ADGSM reforms and the Heads of Agreement with east coast gas exporters are considered in the gas price forecasts.

These forecasts also consider the impact of the Federal Government's mandatory Gas Market Code (Code). The Code[179] was published in July 2023, and includes a reasonable pricing framework of a $12/gigajoule (GJ) price cap for wholesale gas contracts and pricing rules for non-urgent transactions (outside three days) at the Gas Supply Hubs. Small producers (less than 100 PJ per year) supplying the domestic market are exempt from the pricing rules, while other producers can apply for conditional exemptions.

The Federal Government is undertaking a combined review of the ADGSM, the Heads of Agreement with east coast gas exporters, and the Code[180]. The natural gas price forecasts considered these policies and the regulatory framework in their current form.

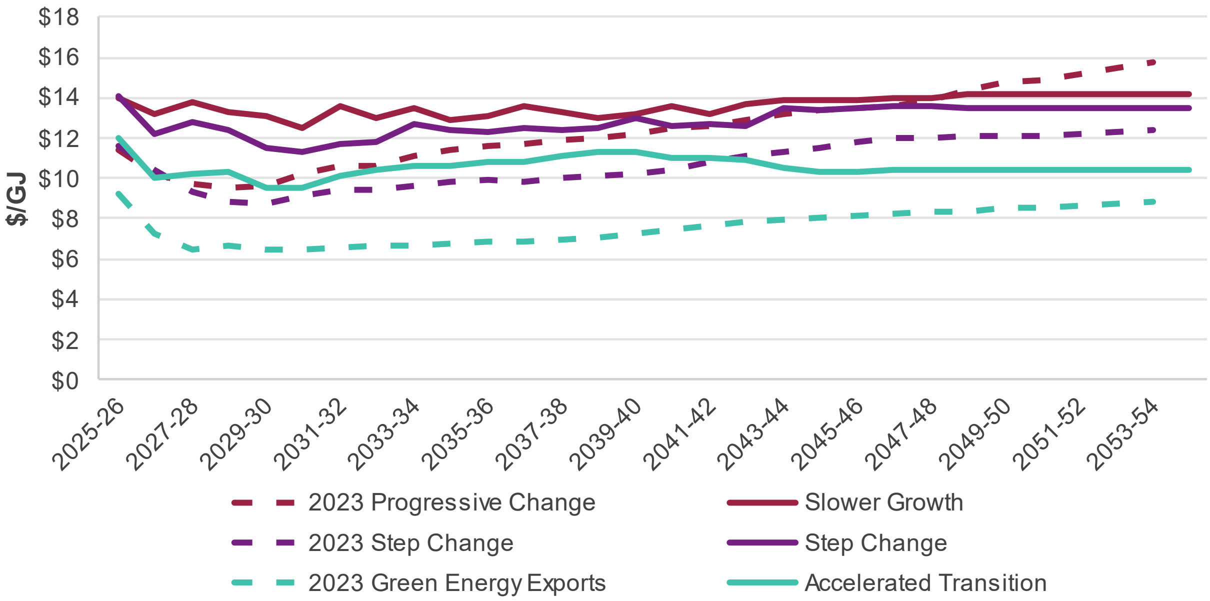
Figure 65 compares industrial gas price forecasts at Melbourne across the scenarios against forecasts presented in the 2023 IASR. The scenarios differ based on longer-term underlying costs of supply for each scenario and international demand for LNG. The forecast gas prices are higher than those presented in the 2023 IASR, primarily due to observed wholesale contract pricing since the introduction of the gas price cap in July 2023. Wholesale contract prices have been anchored at or around the $12/GJ price cap since it was introduced, and this market dynamic is expected to continue given tight supply conditions. Combined with rising costs of production, this results in domestic gas prices remaining steadier throughout the 2020s, despite an expected decrease in global LNG price due to increased supply from the United States and Qatar during this period.

All other regions are provided in the 2025 *Inputs and Assumptions Workbook*.

[179] See https://www.energy.gov.au/government-priorities/energy-markets/gas-markets/mandatory-gas-code-conduct.

[180] See https://consult.dcceew.gov.au/gas-market-review-consultation.

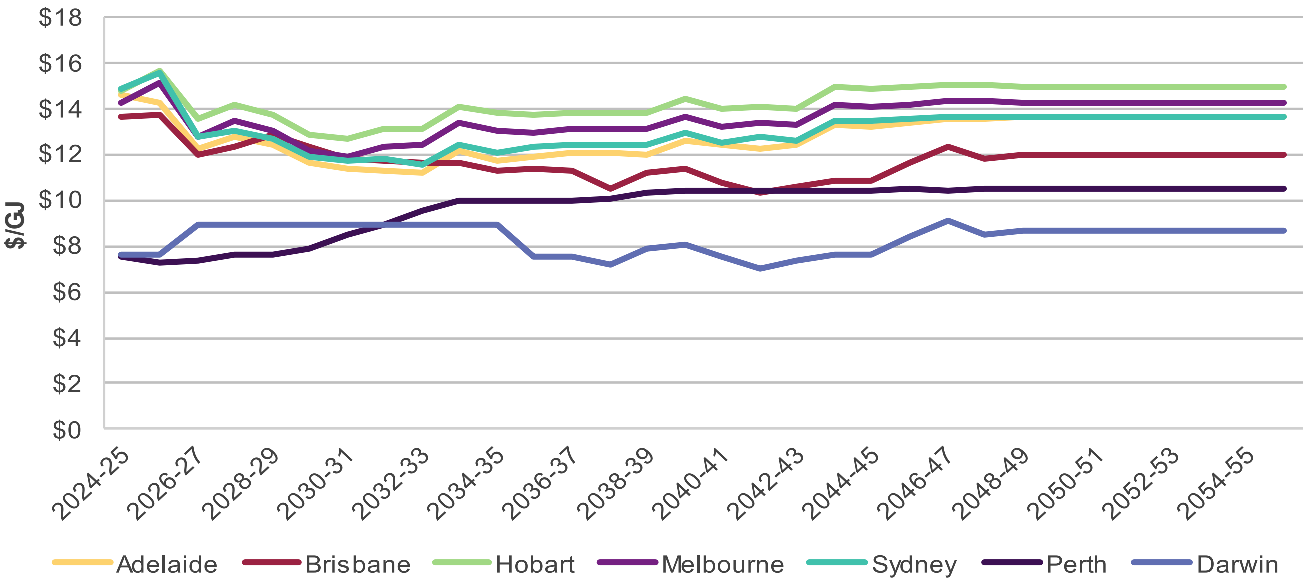
Figure 65 Forecast industrial gas prices by scenario – Melbourne, 2024-25 to 2054-55 ($AUD/GJ)



Note: the *Green Energy Exports* scenario was proposed in the Draft 2025 IASR as one of two potential scenario variants, and while *Accelerated Transition* is now the appropriate scenario, it remains a potential sensitivity in this 2025 IASR.

Figure 66 demonstrates the relationship between regions for the *Step Change* scenario.

Figure 66 Forecast industrial gas prices by location – *Step Change*, 2024 to 2055 ($AUD/GJ)



In the short term, prices are expected to remain largely influenced by the Federal Government's Code and gas price cap, with tight market conditions resulting in some price increases through 2026. Following this, the price forecasts decline to a minimum in the early 2030s, largely driven by a forecast reduction in LNG netback prices[181]. Gas prices in the long term are forecast to gradually increase, resulting from the combination of decreasing supply

[181] See https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

and increasing real production costs. Brisbane prices diverge from Southern markets over the long term as a result of the source of local gas supply assumed to concentrate in Queensland and the Northern Territory in these projections, resulting in higher transportation costs and potential reliance upon higher cost LNG imports for southern markets (depending on the infrastructure that is developed to provide access to additional supply to southern customers).

These gas price forecasts assume that new gas production becomes available when required, and makes no assumptions around access to finance for new gas developments. They also reflect the marginal cost for new wholesale gas supply in each region.

The gas prices associated with each gas-powered generator are provided in the 2025 *Inputs and Assumptions Workbook* and the ACIL Allen fuel price report. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission.

Coal prices

Input vintage	November 2024
Source	ACIL Allen Consulting
Updates since the 2023 IASR	Forecasts updated to reflect expiry of coal price cap

ACIL Allen's approach considers each generator's unique situation and takes into account mining costs, unique mine operational processes (such as wash plant, open cut, underground), export price, and freighting/handling costs.

In late 2022, the New South Wales Government and Queensland Government agreed to implement temporary coal price caps of $125 per tonne for power stations as part of the Federal Government's Energy Price Relief Plan. This temporary measure expired on 30 June 2024 and as a result the coal price forecasts for export exposed black coal generators now reflect their estimated apparent contract positions.

Coal generators across the NEM source coal in various ways. The three typical pathways are coal sourced from own mining supply, coal from netback linked contracts, and coal from export linked international spot markets. Estimated coal prices for each generator consider the specific sources of supply because not all coal generators are exposed to export pricing dynamics, particularly if they operate from captive mines, or are not using export or near-export grade black coal.

In setting long run coal prices, the forecasts refer to the IEA 2024 WEO for the Japanese and Coastal China regions which are most applicable to Australia.

The IEA coal forecasts are aligned to AEMO's three scenarios as follows:

- *Step Change* – aligned to the IEA's STEPS scenario.
- *Slower Growth* – aligned to the IEA's APS scenario.
- *Accelerated Transition* – aligned to the IEA's NZE scenario.

ACIL Allen's analysis indicates that for the NZE scenario post 2030, and the APS scenario post 2040, the prices forecast by the IEA are likely to be sub-economic under the assumed macroeconomic settings. As such, prices for the preceding period are held constant for the remainder of the price projection representing an expectation that a supply side response will occur to stabilise prices.

The coal price forecasts are provided in more detail in the 2025 *Inputs and Assumptions Workbook*.

Figure 67 Forecast coal prices for existing generators in New South Wales, *Step Change*, 2024 to 2055 ($AUD/GJ)

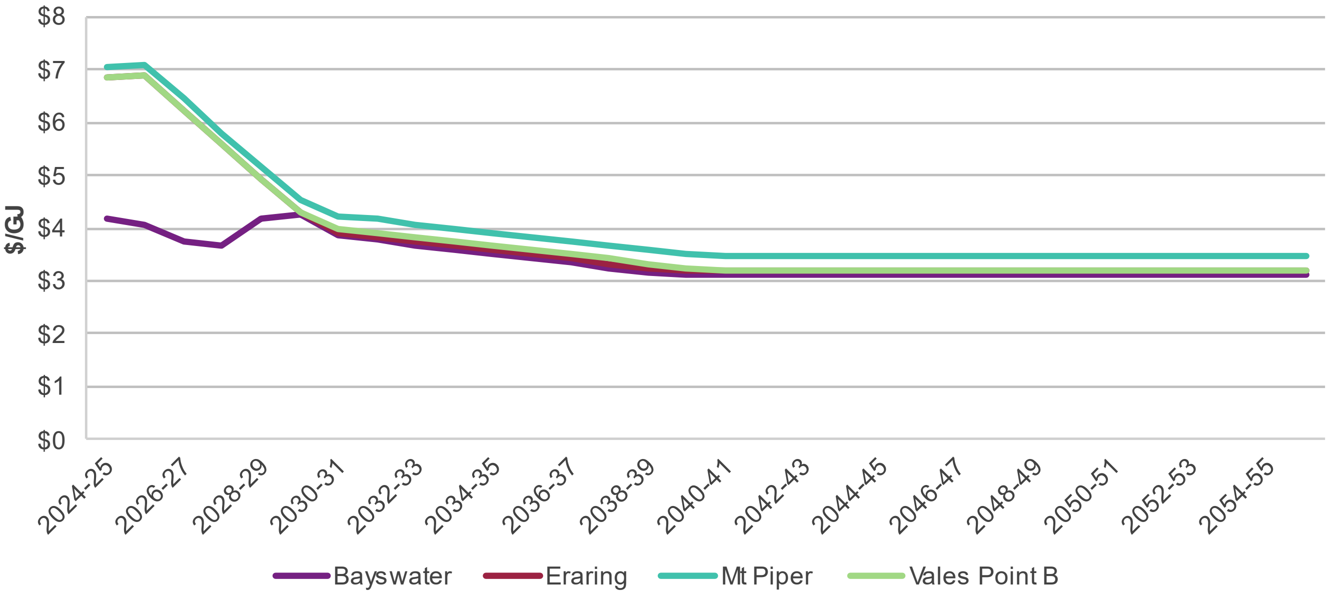
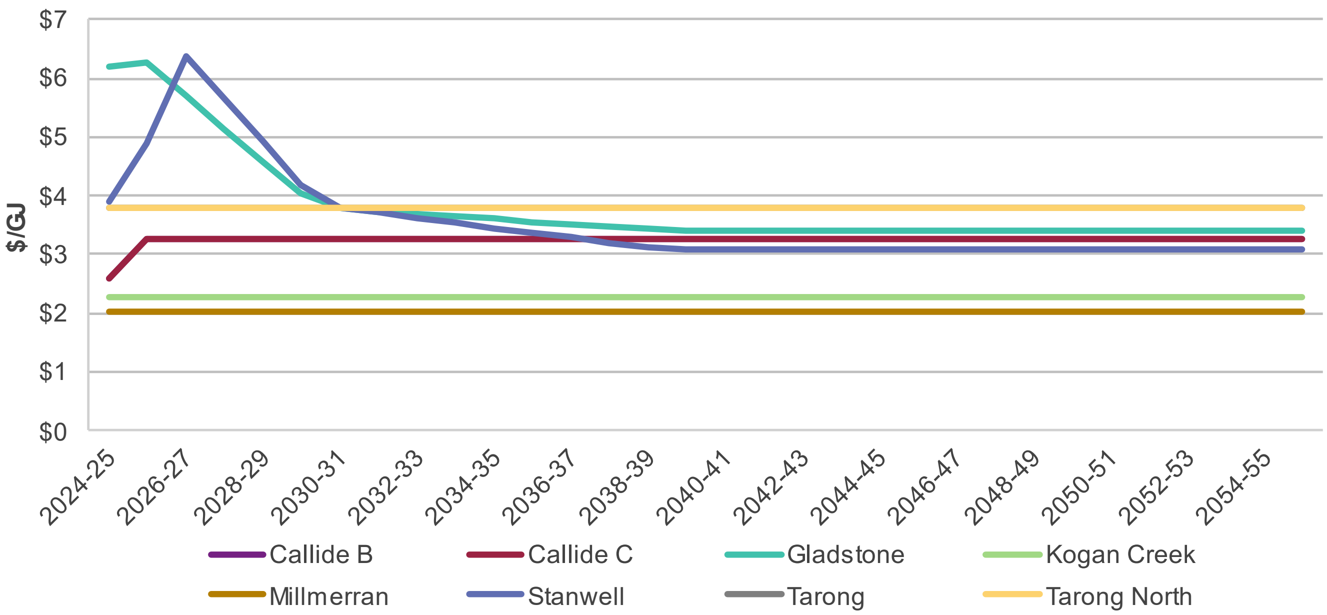


Figure 68 Forecast coal prices for existing generators in Queensland – *Step Change*, 2024 to 2055 ($AUD/GJ)



Diesel prices

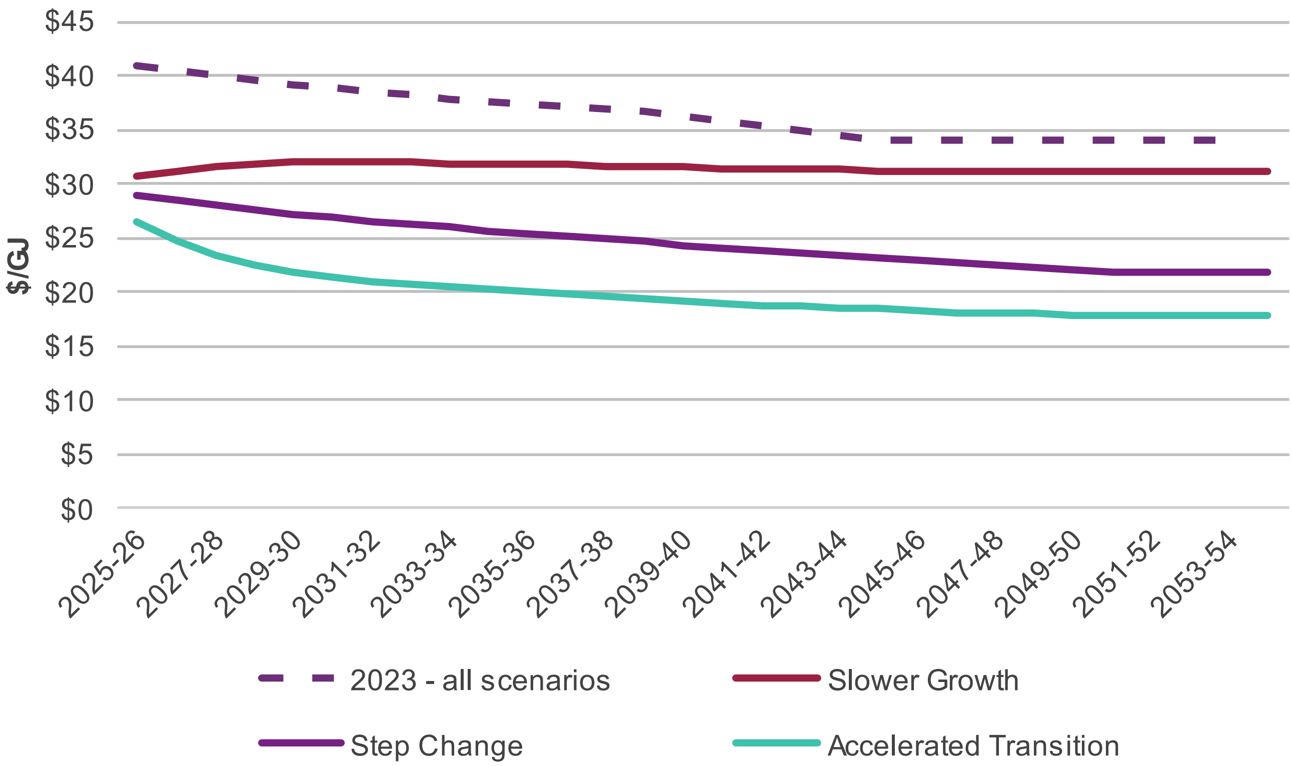
AEMO sourced diesel price forecasts from ACIL Allen to represent appropriate costs for the use of diesel at power stations in the NEM that can, or could, use liquid fuels as a primary, secondary or backup fuel. ACIL Allen's approach evaluates projections of crude oil prices to provide projections of Terminal Gate Prices for automotive diesel oil. A distributors' margin is added to the price and a charge for transport from the nearest petroleum terminal to the power station is calculated.

International oil price is the key consideration in forecasting diesel price, with the crude oil market in a period of transition and experiencing a decline in the rate of growth in demand for oil globally. Uncertainties considered in the price forecasts are:

- outlook for economic growth in advanced, emerging market and developing economies,
- rates of adoption of EVs, PHEVs and Hybrid light passenger vehicles,
- progress in improving fuel efficiency in all modes of transport,
- fuel-switching to biofuels, hydrogen in the longer term and oil to gas switching in the power sector in Middle Eastern Countries over the medium to longer term, and
- strategies of producers in the Middle East to shore up their national budgets over the medium to longer term.

Figure 69 compares Victorian price forecasts for terminal gate plus distributors margin across the scenarios against the single forecast presented in the 2023 IASR. Lower forecast diesel prices compared to the 2023 IASR are due to a lower crude oil price outlook.

Figure 69 Forecast price for diesel by scenario – terminal gate price plus distributors margin, Victoria, 2024 to 2055 ($AUD/GJ)

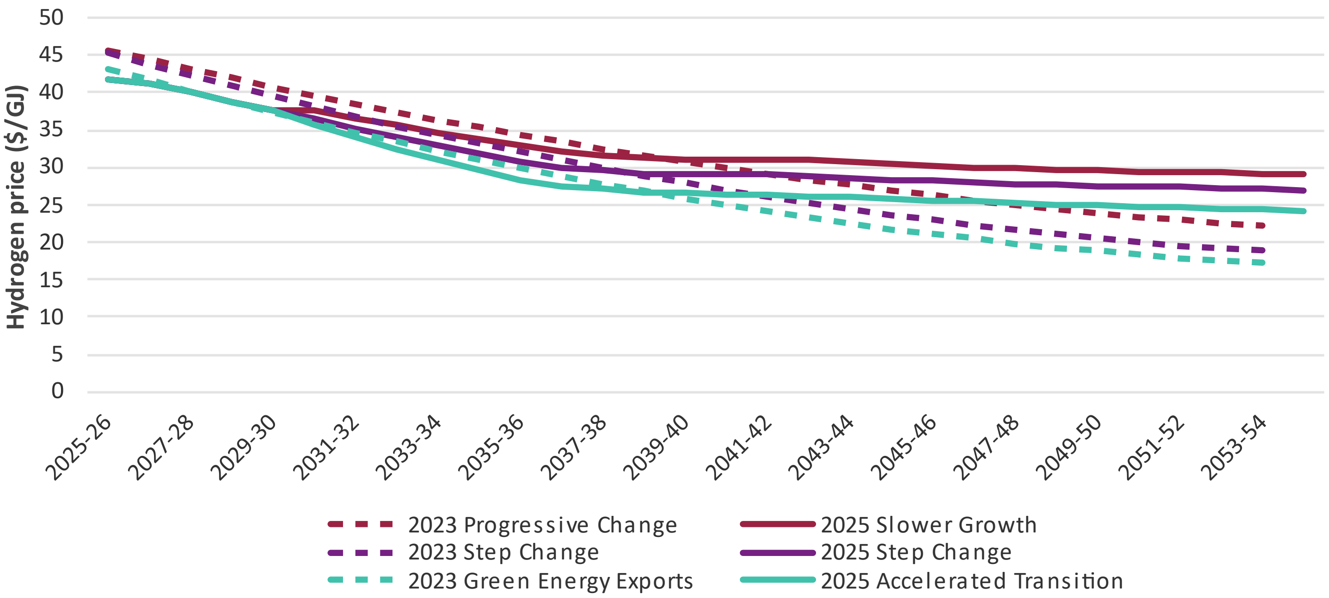


Hydrogen prices

Hydrogen prices are shown in **Figure 70** and were sourced from CSIRO using the 2024 multi-sectoral modelling. They include cost of equipment, fuel, water and operating and maintenance. These were combined with forecast transport costs from ACIL Allen (2025) to determine delivered prices (excluding distribution network costs).

The prices for *Accelerated Transition* are lower than *Slower Growth* or *Step Change* in the longer term, largely due to the forecast reduction in the cost of electrolysers. Prices in this 2025 IASR have increased since the 2023 IASR, due to a number of factors, including higher assumed cost of electrolysers.

Figure 70 Forecast price for hydrogen by scenario, 2026 to 2055



3.6.2 Renewable resources

Input vintage	July 2025
Source	Solcast irradiance and PV output analysis Australian Bureau of Meteorology BARRA2 reanalysis data AEMO SCADA data Other relevant reanalysis providers
Updates since Draft 2025 IASR	Source of wind speed and temperature data updated to BoM BARRA2, resource quality estimates updated to include the 2023-24 and 2024-25 reference years and reflect changes to REZ definitions.

Renewable resource quality and other weather variables are key inputs in the process of producing generation availability profiles for solar and wind generators. Resource quality data and other weather inputs are updated annually to include the most recent reference years. This data is obtained from several sources, including:

- wind speed (at a relevant hub height) and temperature from BARRA2[182] reanalysis data from the Australian BoM,

[182] Bureau of Meteorology Atmospheric high-resolution Regional Reanalysis for Australia – Version 2 (BARRA2). See https://opus.nci.org.au/spaces/NDP/pages/264241166/BOM+BARRA2+ob53.

- solar irradiance data from Solcast,
- temperature and ground-level wind speed observation data from the BoM, and
- historical generation and weather measurements from SCADA data provided by participants.

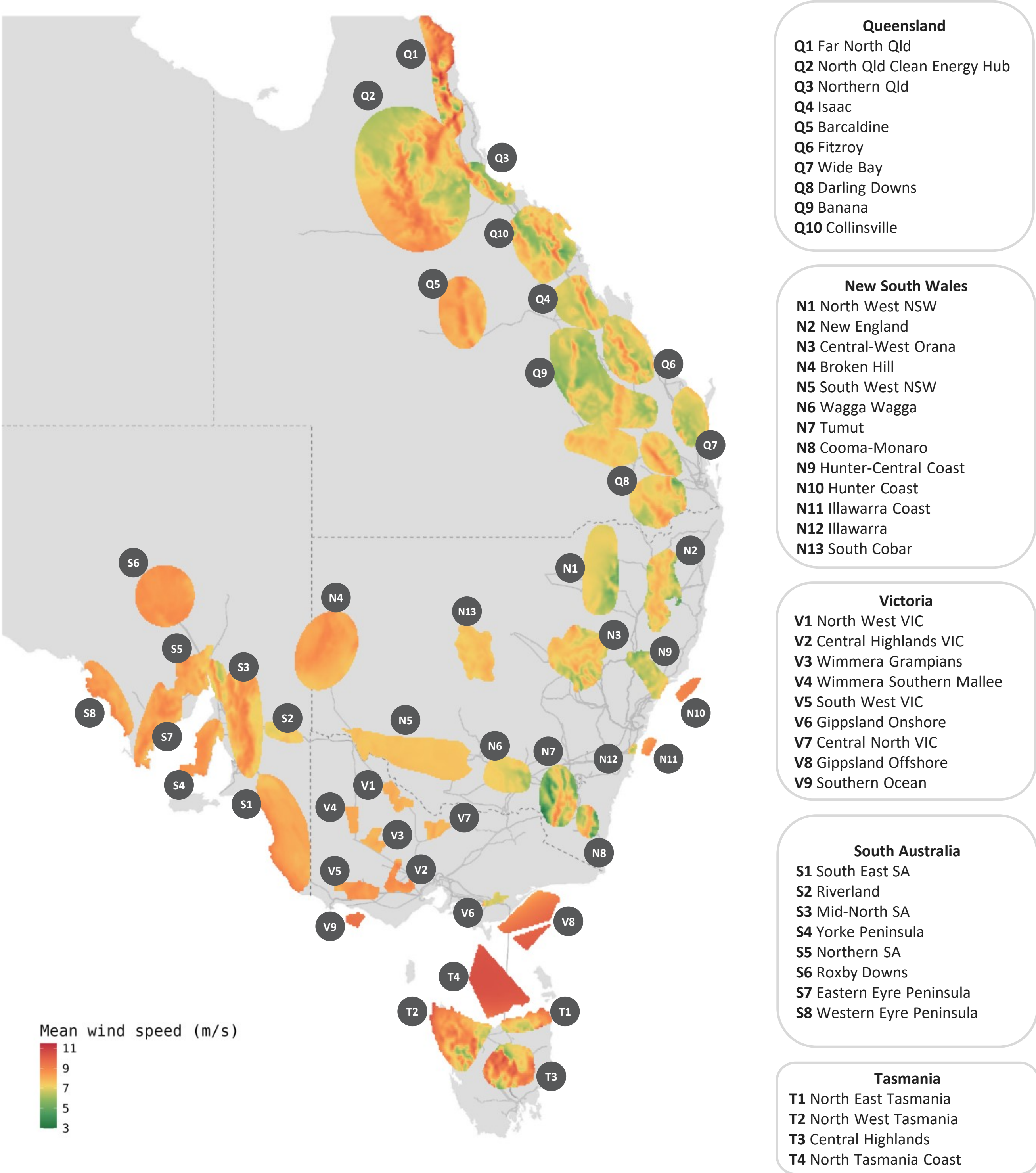
AEMO uses resource-to-power conversion models to estimate VRE generation potential as a function of meteorological inputs, and calibrates this to historical production levels for existing wind farms. Wind generation availability modelling, for example, uses an empirical machine learning model to estimate generator output as a function of wind speed and temperature, capturing the impacts of high wind and high temperature events observed in historical data (which may typically lead to generator cut-off protections). Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these models.

For new entrant VRE generators, AEMO represents onshore wind resource quality in each REZ in tranches representing sites of differing quality (typically two tranches per REZ), based on an assessment of all available datapoints that are considered suitable for wind development. AEMO represents solar resource quality based on an assessment of solar resource at a selection of existing and proposed solar generation sites within each REZ.

Capacity factors representing the resource potential for each REZ and technology are provided in the 2025 *Inputs and Assumptions Workbook*. Wind and solar resource quality for each REZ is shown below in **Figure 71** and **Figure 72** respectively.

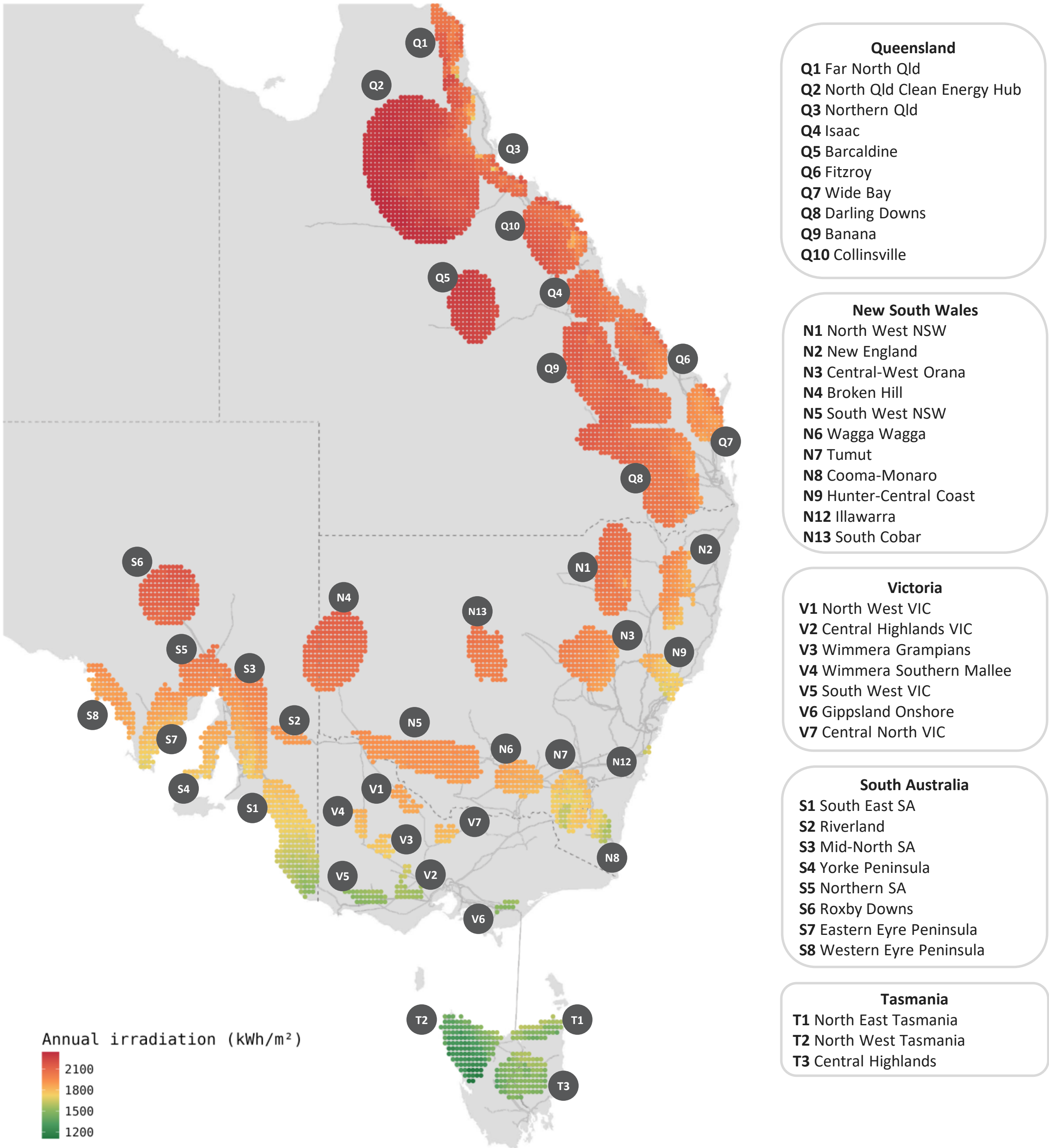
Following stakeholder feedback on the Draft 2025 IASR and Draft 2025 *ISP Methodology*, AEMO has revised the approach used to calculate REZ capacity factors estimates to reflect alternative data considered more appropriate for new project developments. Changes include adoption of the BoM's BARRA2 reanalysis dataset which provides improved spatial granularity and representation of VRE potential across Australia compared to alternative datasets, an increase of the assumed hub height for wind generators to 150 metres, and an update to AEMO's resource-to-power conversion model to reflect newer technologies better.

Figure 71 Wind resource quality map – average wind speed (m/s) at 150 m hub height



*Three sets of renewable energy resource profiles will be developed for REZ Q8 Darling Downs. They will be Darling Downs, Western Downs, and Southern Downs.

Figure 72 Solar resource quality map – average annual global horizontal irradiation (GHI) (kWh/m²/year)



*Three sets of renewable energy resource profiles will be developed for REZ Q8 Darling Downs. They will be Darling Downs, Western Downs, and Southern Downs.

3.7 Financial parameters

3.7.1 Weighted average cost of capital and discount rate

Input vintage	July 2025
Source	Oxford Economics Australia
Updates since Draft 2025 IASR	A macro-economic analysis and confidential survey of empirical cost of capital from across NEM stakeholders.

In the ISP, the weighted-average cost of capital (WACC) reflects the cost of financing debt, equity, and the proportion of debt and equity within a project's capital structure. It is used in combination with a project's economic life to convert upfront capital costs into a stream of annualised payments. As the financial risks of each technology will differ based on a variety of factors, the WACC is appropriate to also differ by technology in order to reflect the different rates of return that investors will require to compensate for that variable level of risk. As WACC reflects financing cost, it is a key influence on the overall project cost and therefore the overall system costs used in the ISP's CBA.

In contrast, the discount rate reflects the time value of money based on the opportunity cost that a developer or owner places on its investment (reflecting the value of alternative investments, including risk-free investment options, that the investor foregoes by investing in the project). It is used to convert a series of future cash flows into present value terms, which is necessary when comparing costs and benefits incurred at different times in the future. Further information on the application of WACC and discount rate in the ISP's CBA is in the *ISP Methodology*[183].

The AER's CBA Guidelines[184] state that the discount rate in the ISP is "*required to be appropriate for the analysis of private enterprise investment in the electricity sector across the NEM*", and that it should promote competitive neutrality across investment options. For this reason, AEMO previously used the same rate as both the discount rate for costs and benefits (to calculate the net present value) and the WACC for annualising capital costs across all generation and transmission investments.

A WACC reflecting an average investor view about required return on investments in the NEM has been employed in previous IASRs[185]. Following stakeholder feedback and using insights from a survey of developers in the NEM regarding their cost of capital and other inputs[186], AEMO will use different WACCs for each technology to capture different financial risk and assumptions appropriate for each technology and varying for each scenario. While WACCs may vary by technology, the ISP must use a singular discount rate that promotes competitive neutrality between network and non-network options, as required by the AER CBA Guidelines.

AEMO engaged Oxford Economics Australia to determine the appropriate WACC for each technology, for each scenario, across the ISP forecast horizon, and to provide the appropriate discount rate. Oxford Economics Australia's analysis revealed that some technologies may face higher risks, and therefore higher required rates of

[183] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology.

[184] At https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20guidelines%20-%202024%20-%20Version%203.pdf.

[185] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/synergies-discount-rate-report.pdf?la=en.

[186] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Oxford-Economics-Australia-Discount-rates-for-energy-infrastructure-report.

return, due to either the perceived lesser role in the energy transition such as coal plant and high-emitting assets, perceived merchant risks such as battery energy storage systems, or higher construction risks such as pumped hydro energy storages. In contrast, some renewable generation technologies that have access to available government offtake agreements are considered lower risk, even for globally established technologies that are yet to penetrate the Australian market such as offshore wind farms.

The survey identified merchant risk and construction risk to be important considerations for greenfield non-network energy projects. A project's capital structure also impacts on the WACC. The other risk drivers identified are revenue risk, grid connection risk, policy risk, and social licence. Survey results of pre-tax real WACC estimates across asset types are shown in **Table 30** below.

Given these findings, AEMO has set different WACCs for different technology options to appropriately reflect the reality observed in capital markets. **Table 30** shows the WACC for relevant technologies under each scenario, as well as upper and lower bounds on these estimates (as differences from the estimates applied to *Step Change*).

Table 30 Pre-tax real weighted average cost of capital

Technology	*Slower Growth*	*Step Change*	*Accelerated Transition*	Lower bound (delta)	Upper bound (delta)
OCGT (small gas turbine)	8.0%	9.0%	10.0%	-1.9%	3.1%
OCGT (large gas turbine)	8.0%	9.0%	10.0%	-1.9%	3.1%
CCGT [A]	9.5%	10.5%	12.0%	-1.9%	3.1%
CCGT with CCS [A]	9.5%	10.5%	12.0%	-1.9%	3.1%
Biomass [A]	9.5%	10.5%	12.0%	-1.9%	3.1%
Large scale Solar PV	6.5%	7.0%	8.0%	-1.9%	3.1%
Solar Thermal (16hrs storage) [A]	9.5%	10.5%	12.0%	-1.9%	3.1%
Battery storage (1hr storage)	7.5%	8.0%	9.5%	-1.9%	3.1%
Battery storage (2hrs storage)	7.5%	8.0%	9.5%	-1.9%	3.1%
Battery storage (4hrs storage)	7.5%	8.0%	9.5%	-1.9%	3.1%
Battery storage (8hrs storage)	7.5%	8.0%	9.5%	-1.9%	3.1%
Pumped Hydro Energy Storage (10 hrs)	7.5%	8.5%	9.5%	-1.9%	3.1%
Pumped Hydro Energy Storage (24 hrs)	7.5%	8.5%	9.5%	-1.9%	3.1%
Pumped Hydro Energy Storage (48 hrs)	7.5%	8.5%	9.5%	-1.9%	3.1%
Wind - onshore	7.0%	7.5%	8.5%	-1.9%	3.1%
Wind - offshore (fixed)	7.0%	7.5%	8.5%	-1.9%	3.1%
Wind - offshore (floating)	7.0%	7.5%	8.5%	-1.9%	3.1%
Hydrogen Electrolysers	7.0%	8.0%	9.0%	-1.9%	3.1%
Electricity - Transmission and Distribution (Regulated)	3.0%	3.0%	3.5%	0.0%	1.5%
Electricity - Transmission and Distribution (Unregulated)	6.0%	6.5%	7.5%	-1.9%	3.1%
Gas - Transmission and Distribution (Regulated)	3.0%	3.0%	3.5%	0.0%	1.5%
Gas - Transmission and Distribution (Unregulated)	6.5%	7.0%	8.0%	-1.9%	3.1%

A. AEMO assumes that the WACC for CCGT, CCGT with CCS, Biomass and Solar Thermal (16 hrs storage) are the similar.

Considering the insights provided from the WACC survey, Oxford Economics Australia recommended that the appropriate discount rate for use in the 2025 IASR and 2026 ISP that promotes competitive neutrality is 7%, based on its macro-economic assessment. This choice of discount rate aligns with Infrastructure Australia's guide to economic appraisal[187], and is commensurate with commercially-oriented investments considered for technologies included in the ISP.

Analysis of survey results and macro-economic studies found the pre-tax real WACC for non-regulated assets to be 6.98%, which further reinforces that the assumption of 7.0% is reasonable. In addition, Oxford Economics Australia found pre-tax real WACC estimates ranged between 3% and 15% across asset types under the *Step Change* scenario, with the WACC being reflective of the level of risk of each technology.

For the lower bound of the discount rate, AEMO will base it on the most recent AER revenue determination at the time of the final ISP. In the August 2024 return on debt update[188], the AER set the pre-tax real WACC to be 3.00%. This is consistent with the discretionary guidance in the AER's CBA Guidelines. For the upper bound of the discount rate, AEMO proposes to adopt 10% from Infrastructure Australia's guideline for economic appraisal.

Table 31 presents the values for discount rates in this 2025 IASR, with 2024 ISP values for comparison.

Table 31 Pre-tax real discount rates

	Lower bound	Central estimate	Upper bound
2024 ISP	3.0%	7.0%	10.5%
2025 IASR	3.0%	7.0%	10.0%

3.7.2 Value of customer reliability (VCR)

Input vintage	December 2024
Source	AER: *2024 Values of Customer Reliability Review*
Updates since 2023 IASR	VCR updated to reflect AER December 2024 VCR review and adjusted to real June 2025 values.

VCRs are usually expressed in dollars per kilowatt hour and reflect the value different customer types place on reliable electricity supply. VCRs are used in cost benefit analysis to quantify market benefits arising from changes in involuntary load shedding when comparing investment options.

In accordance with the AER's CBA Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER recently updated VCRs in its *2024 Values of Customer Reliability Review*[189]. These are summarised in **Table 32** below. For consistency with other costs in this IASR, the AER's values have been adjusted to real 2025 dollars in accordance with the AER's annual adjustment mechanism.

Table 32 AER distribution and transmission customer load-weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR ($/MWh)	31,428	36,356	26,165	33,857	19,296

[187] At https://www.infrastructureaustralia.gov.au/guide-economic-appraisal.

[188] Based on *AER - Transgrid FD PTRM - 2024-25 RoD update - Humelink S2 - August 2024 - Public*, at https://www.aer.gov.au/documents/aer-transgrid-fd-ptrm-2024-25-rod-update-humelink-s2-august-2024-public.

[189] At https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024.

3.7.3 Value of greenhouse gas emissions reduction (VER)

Input vintage	July 2024
Source	Value of greenhouse gas emission reduction (VER) to 2050 as agreed by Australia's Energy Ministers in July 2024 and set out in the AER Guidance.
Updates since 2023 IASR	Interpolated to convert to financial years and adjusted to real 2025 dollars.

Emissions reduction is a class of benefits in the ISP and the RIT-T framework. This new benefit class reflects the appropriate consideration of the amendments to the NEO and NER. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in July 2024 and set out in the AER's explanatory statement[190].

The values presented in **Table 33** reflect consistent assumptions with the 2024 ISP assumptions, adjusted for real 2025 dollars.

Table 33 Value of greenhouse gas emissions reduction

Year	VER ($/tonne CO_2-e)	Year	VER ($/tonne CO_2-e)
2024-25	76.64	**2037-38**	198.21
2025-26	81.93	**2038-39**	211.96
2026-27	86.69	**2039-40**	226.23
2027-28	91.44	**2040-41**	241.56
2028-29	97.26	**2041-42**	257.94
2029-30	105.71	**2042-43**	274.86
2030-31	115.76	**2043-44**	292.83
2031-32	125.80	**2044-45**	312.39
2032-33	136.90	**2045-46**	333.00
2033-34	148.53	**2046-47**	354.67
2034-35	160.16	**2047-48**	377.93
2035-36	172.31	**2048-49**	402.77
2036-37	185.00	**2049-50**	429.73

3.8 Climate change factors

The changing climate has an impact on a number of aspects of the power system, including consumer demand response to changing temperature conditions, and generation and network availability and capability. The impact of reduced water inflows into schemes is considered through the use of a broad range of inflow patterns captured in the reference years, including a very dry year (2006-07). The following sections describe other impacts considered in AEMO modelling.

AEMO recognises that a changing climate may lead to greater potential challenges in maintaining the operability of a power system that is predominantly reliant on intermittent generation for its electricity production, particularly

[190] AER. *Valuing emissions reduction final guidance*, at https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024.

during long periods of dark and still conditions that would lower renewable generation output. AEMO recognises that geographic and technological diversity are key means to lower the impact of extreme conditions in this regard, however it is possible that weather extremes will still impact the resilience of a renewable energy system and increase the magnitude of extreme demand conditions as well, beyond that which is already considered in AEMO's forecasting approach which passes through forecast average temperature rise over time (as described in the following section).

3.8.1 Temperature change impacts

Input vintage	January 2019 (CMIP5)
Source	BoM, CSIRO, Electricity Sector Climate Information (ESCI – see https://www.climatechangeinaustralia.gov.au/en/projects/esci/)
Updates since 2023 IASR	No update since the 2023 IASR

AEMO incorporates climate change temperature change factors in its demand forecasts, and transmission line thermal ratings in forecasting models where constraints are applied. For demand, AEMO adjusts historical weather outcomes to apply in future years based on the outcomes projected by forecast climate models. Climate data is collected from Electricity Sector Climate Information (ESCI) data published on the CSIRO and BoM's website Climate Change in Australia[191]. For more information on this, see Appendix A.2.3 of the *Electricity Demand Forecasting Methodology*[192].

For transmission line ratings, AEMO applies the most relevant temperature rating available for the equipment for the projected weather outcome. At present, AEMO applies seasonal ratings for most regions, as published in the transmission equipment ratings[193,] except for Victoria where forecast dynamic line ratings are available for some transmission lines for application in the reliability forecasting models.

Climate Change in Australia and ESCI data projects gridded daily minimum and maximum temperatures for each global climate model (GCM) for each of the RCP pathways (outlined in Section 3.2). Data is selected for the closest available RCP to the scenario specification. Climate science considers that warming over the next 20 years or so is largely locked in from historical emissions, so adjustments do not vary substantially between scenarios to 2050. Where the physical impacts associated with the RCPs referenced in the scenario narrative are not available, results are scaled between available RCPs to reflect the likely outcome.

Figure 73 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions[194]. The figure uses the lighter shaded lines to demonstrate uncertainty between climate models as represented by the 90th and 10th percentiles, however, shows a high level of agreement in the median (solid line) towards increasing temperatures in AEMO modelling timeframes for the emissions scenarios included.

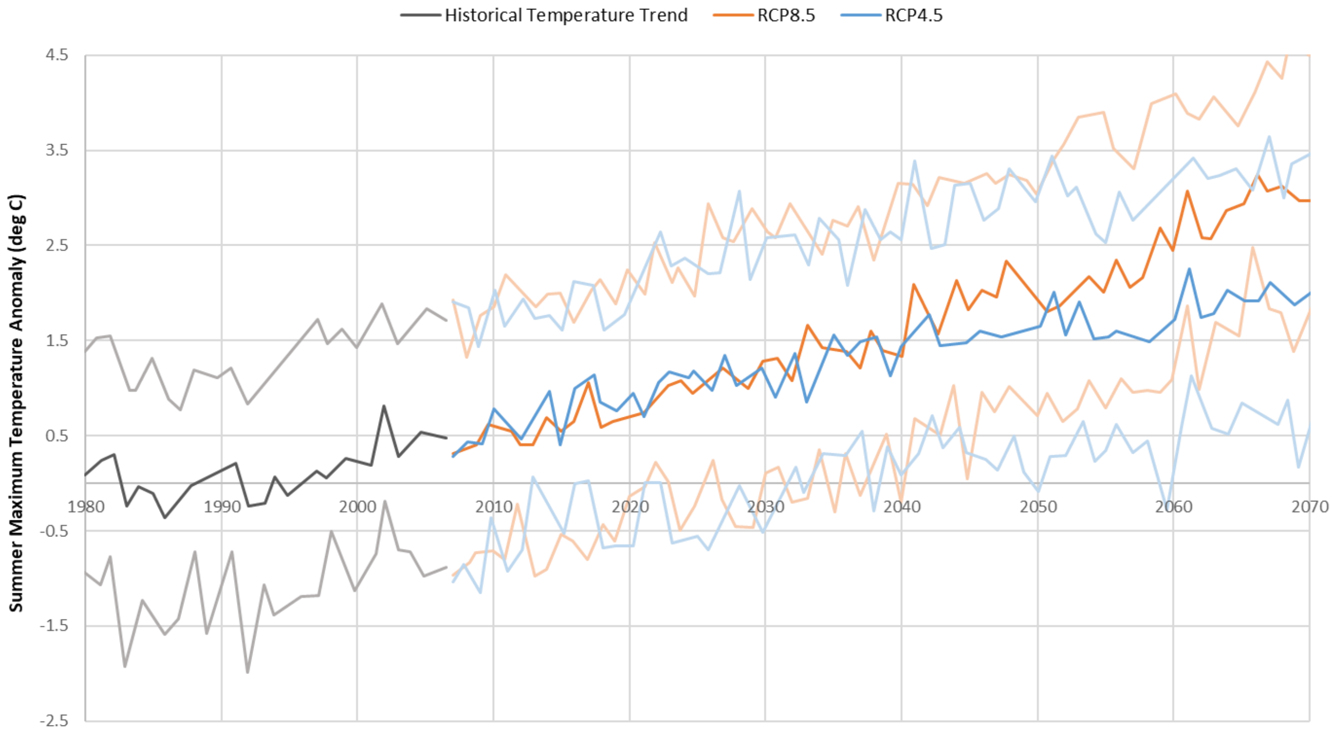
[191] See https://www.climatechangeinaustralia.gov.au/en/obtain-data/download-datasets/.

[192] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

[193] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings.

[194] Data sourced from https://www.climatechangeinaustralia.gov.au/en/.

Figure 73 Southern Australia summer maximum temperature anomaly



3.9 Renewable energy zones (REZs)

REZs are areas where clusters of large-scale renewable energy can be developed using economies of scale. REZs may include onshore and offshore areas and will be subject to jurisdictional land and environmental planning approval processes. With the relevant government support, AEMO could trigger REZ Design Reports to require the local TNSP to explore and report on any technical, economic or social issues that will need to be addressed for the REZ to be a valuable, sustainable and welcome development. However, most states are currently exploring state-based development schemes in preference to REZ Design Reports. AEMO will continue to coordinate with jurisdictions as REZ plans develop, to ensure planning alignment.

An efficiently located REZ can be identified by considering a range of factors, primarily:

- the quality of its renewable resources, diversity relative to other renewable resources, and correlation with demand,
- the cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers,
- its proximity to load, and the network losses incurred to transport generated electricity to load centres, and
- the critical physical must-have requirements to enable the connection of new resources (particularly inverter -based equipment) and ensure continued power system security.

REZ candidates were initially developed in consultation with stakeholders for the 2018 ISP, and used as inputs to the ISP model. To connect renewable projects beyond the current transmission capacity, additional transmission infrastructure will be required (for example, increasing thermal capacity, system strength, and developing robust control schemes). Since the 2018 ISP, the REZ candidates have been continuously refined through the ISP consultation process every two years up to and including this 2025 IASR.

This section describes the parameters for REZs for input to the 2026 ISP. These parameters are:

- Geographic boundaries and resource areas – Section 3.9.1.
- Resource limits – Section 3.9.2.
- Transmission limits – Section 3.9.3.
- REZ augmentations and network costs – Section 3.9.4.

3.9.1 REZ geographic boundaries and resource areas

Input vintage	July 2025
Source	AEMO – based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to every ISP up to and including the 2024 ISP and Draft 2025 IASR.
Updates since Draft 2025 IASR	Updated following joint planning and collaboration with TNSPs, jurisdictional bodies and governments. The following revisions have been made: • Victoria: The information in this section relating to REZs in Victoria will be updated following the release of the 2025 Victorian Transmission Plan. • Tasmania: The offshore REZ T4 North Tasmania Coast boundary was updated to align with the Federal Government DCCEEW declared area.

REZ candidates are geographic areas that indicate where new renewable energy generation might be developed using economies of scale. These were initially developed through consultation to the 2018 ISP and subsequently updated through ISP consultation every two years up to and including this 2025 IASR.

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2025 IASR consultation page[195]. When accessing this data, please note:

- only candidate REZ boundaries have been provided, not any GPS data for assets owned by third parties (for example, generation and network data), and
- the GIS data for candidate REZs is approximate in nature. The polygons were derived by replicating the candidate REZ illustration (see **Figure 74** below).

As the REZ polygons are approximate in nature, they should not be used to determine whether a project is within or outside of a candidate REZ.

In some cases, jurisdictional REZ plans are still under development and boundaries may not have been identified. Where updated REZ boundaries are available, AEMO will update its GIS data accordingly.

[195] See https://aemo.com.au/en/consultations/current-and-closed-consultations/2025-iasr.

Candidate REZ identification

Ten development criteria were used to identify candidate REZs[196]:

- Wind resource – a measure of high wind speeds (above 6 m/s).
- Solar resource – a measure of high solar irradiation (above 1,600 kW/m2).
- Demand matching – the degree to which the local resources correlate with demand.
- Electrical network – the distance to the nearest transmission line.
- Cadastral parcel density – an estimate of the average property size.
- Land cover – a measure of the vegetation, waterbodies, and urbanisation of areas.
- Roads – the distance to the nearest road.
- Terrain complexity – a measure of terrain slope.
- Population density – the population within the area.
- Protected areas – exclusion areas where development is restricted.

Using the resource quality and development criteria, along with feedback received from all four ISP consultations as well as recent joint planning and consultation with TNSPs, jurisdictional bodies and governments, AEMO has 43 candidate REZs for inclusion in the 2026 ISP.

Changes since the 2024 ISP

Based on AEMO analysis and recent feedback from existing and intending TNSPs and state and federal governments, the following changes to the 2024 ISP candidate REZs have been made:

- AEMO has revised the southern border of the Far North Queensland REZ to better cover locations with good wind resources, as well as to better match the Queensland Government's REZ Roadmap[197] identification of a Far North Queensland REZ location.
- AEMO has changed the boundary of the Isaac REZ, and added a nearby new candidate REZ – Collinsville REZ. These changes allow for mapping of these REZs to the proposed revised Central and Northern Queensland sub-region definitions (see Section 3.10.1), and to align with the Queensland Government's REZ Roadmap identification of REZs in that area.
- AEMO has included multiple resource areas for Darling Downs REZ[198], as well as expanded the north-west border, to better reflect the diversity of wind resource available across its large geographical area, as identified in the Queensland Government's REZ Roadmap.

---

[196] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

[197] Queensland Government, Queensland Renewable Energy Zone roadmap, March 2024. At https://www.epw.qld.gov.au/__data/assets/pdf_file/0036/49599/REZ-roadmap.pdf.

[198] This change is subject to the completion of AEMO's review of its *ISP Methodology.* AEMO is proposing to change the methodology to permit the use of additional wind resource tranches within a REZ, for example to reflect resource diversity across large geographical areas. For more information about the *ISP Methodology* review, see https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

- South Cobar, a new candidate REZ in the vicinity of Central West New South Wales, has been added following joint planning with Transgrid and EnergyCo, and in recognition of concepts explored in Transgrid's 2024 Transmission Annual Planning Report. This new candidate REZ will allow exploration of the benefits of a more westerly REZ in that jurisdiction.
- An expansion of the Northern South Australia REZ has been implemented to include the Whyalla West area in the vicinity of Central West South Australia. This has been updated to assess the potential benefits of renewable energy in the areas identified in the South Australian Government's land release framework for renewable energy.
- Removal of the offshore candidate REZ South East South Australia Coast, in recognition that this area is not one of the Federal Government's priority areas for offshore wind[199], and in recognition of the South Australian Government's statement that its immediate focus will be the identification of onshore locations for wind and solar resource development, and that offshore renewable energy policy will not commence until after the first onshore release areas have progressed[200].
- Removal of the Leigh Creek REZ in acknowledgement of environmental, cultural and social concerns relating to this location and recognising that it did not feature in the 2024 ISP under any scenario.
- Adjustment of the Northern South Australia and Mid North South Australia REZ borders to ensure they align with the new Northern South Australia and Central South Australia sub-regional boundaries.
- The information relating to Victorian REZs in this section will be updated following the release of the 2025 Victorian Transmission Plan. The map in **Figure 74** shows information for Victoria as was published by VicGrid in May 2025 for the Draft 2025 Victorian Transmission Plan.

Modelling renewable energy outside of REZs

When determining the economic benefits of a development path, AEMO must compare system costs against a counter-factual where no transmission is built. In this counter-factual, transmission that expands the capacity of REZs will generally not be allowed.

To conduct this analysis, it will become necessary to model renewable generation connecting to areas with existing network hosting capacity, but which may also have lower quality resources. For this reason, resource limits, resource quality, and network capacity are also determined for areas of the network that have existing hosting capacity, or where generation retirement is expected to result in additional network capacity. These areas are known as "non-REZs". These lower quality resource areas are included in all simulations, in all scenarios, not just the counterfactual studies. This ensures the ISP's capacity outlook model can determine the optimal trade-off between development of high-quality renewable resources in REZs, with associated network build, compared to developing lower quality resources in areas with spare hosting capacity.

No changes have been made for non-REZs since the 2024 ISP. The inputs and assumptions relating to non-REZs are provided in detail in the 2025 *Inputs and Assumptions Workbook*.

---

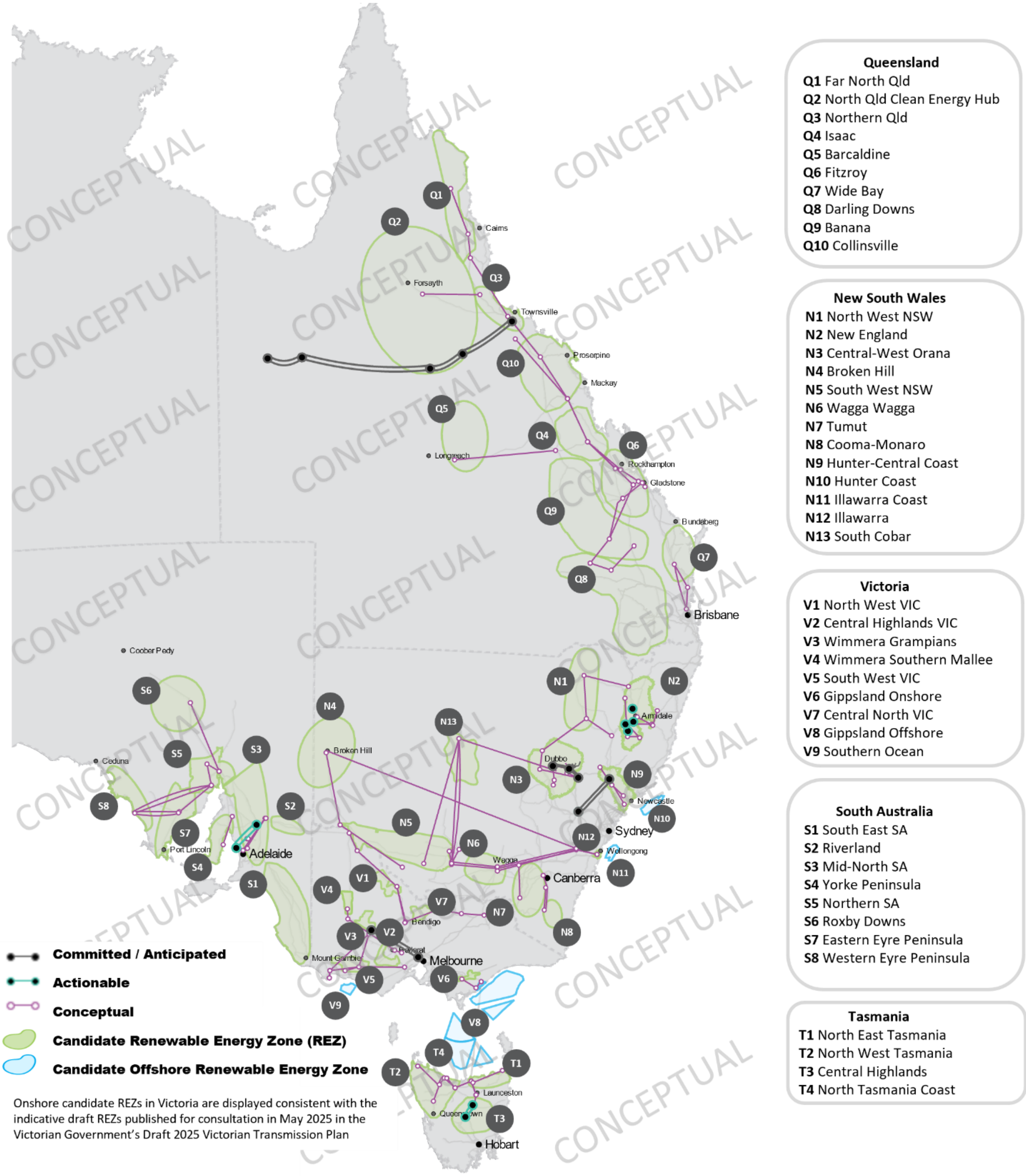
[199] Federal Government. 'Australia's offshore wind areas', accessed in November 2024. At https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas.

[200] South Australia Government. 'Offshore renewable energy development in South Australia', August 2024. At https://www.energymining.sa.gov.au/__data/assets/pdf_file/0009/1064988/Statement-on-offshore-renewable-energy-generation_August-2024.pdf.

Candidate REZ geographic boundaries

Figure 74 shows the geographic locations of REZ candidates. The location of generation symbols is illustrative only – these symbols do not reflect the location of actual projects or the location where projects should be developed.

Figure 74 Candidate renewable energy zone map



3.9.2 REZ resource limits and social licence

Input vintage	July 2025
Source	AEMO. Resource limits were derived by AEMO based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to every ISP up to and including the 2024 ISP and Draft 2025 IASR.
Updates since draft IASR	The following revisions have been made to align resource limits with the amendments to the REZ geographic boundaries, and/or to reflect updated information received from TNSPs and jurisdictional bodies: • New South Wales: Resource limits updated for Central West Orana, South West NSW, Wagga Wagga, Tumut, Cooma-Monaro and Hunter Central Coast REZ • Victoria: The information in this section will be updated following the release of the 2025 Victorian Transmission Plan. • Tasmania: Revised resource limits provided to align with the revised Tasmanian offshore REZ boundary declared by DCCEEW.

REZ resource limits reflect the total available land for renewable energy developments, expressed as installed capacity (MW). The availability is determined by existing land use (for example, agriculture) and environmental and cultural considerations (such as national parks), as well as the quality of wind or solar irradiance.

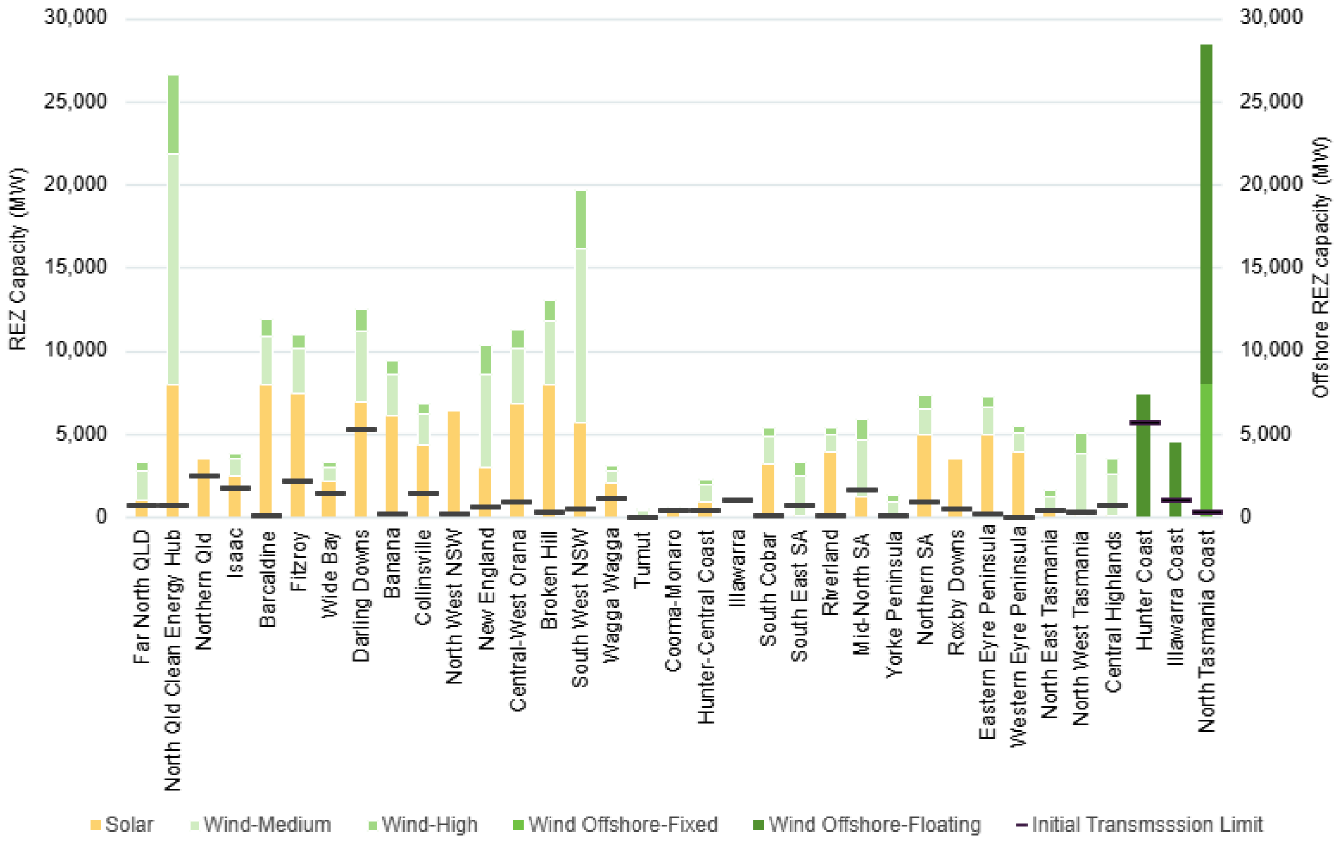
AEMO adjusts REZ resource limits when the boundary of a REZ changes or when appropriate evidence becomes available from localised consultation and studies. As desktop studies and stakeholder engagement have already been completed to prepare the existing REZ resource limits, AEMO expects that any further changes will need to be based on localised evidence as REZ projects are developed and delivered.

AEMO has made the following changes since the 2024 ISP:

- Revised resource limits for Isaac REZ to reflect updates to its geographical boundary, and included resource limits for Collinsville REZ based on the original REZ resource limits, but scaled for the new land areas.
- Included resource limits for the additional wind resource tranches in the Darling Downs REZ based on advice from Powerlink with respect to diversity of resources and connection interest.
- Included resource limits for the new South Cobar REZ in New South Wales based on advice from Transgrid, EnergyCo and developer interest.
- Included revised resource limits for the expanded Northern South Australia REZ to extend to the Whyalla West area, based on advice from jurisdictional bodies.
- Included revised resource limits for Central West Orana, South West NSW, Wagga Wagga, Tumut, Cooma-Monaro and Hunter Central Coast REZs based on EnergyCo feedback in respect to connection interest.
- The information in this section relating to Victorian REZs will be updated following the release of the 2025 Victorian Transmission Plan.
- Revised resource limits for North Tasmania Coast REZ to reflect updates to its geographical boundary to align with the DCCEW declared area.

The updated resource limits are shown in **Figure 75** and provided in detail in the 2025 *Inputs and Assumptions Workbook*.

Figure 75 REZ resource limits and initial transmission limits



Note: Offshore REZ capacities use right axis scale. The dotted purple line is to separate offshore and onshore REZs. The information in this chart will be updated following the release of the 2025 Victorian Transmission Plan.

Onshore wind farm resource limits

Maximum REZ wind generation resource limits were initially calculated based on a DNV-GL[201] estimate of:

- typical wind generation land area requirements, and
- land available that has a resource quality of high (in the top 10% of sites assessed), and medium (in the top 30% of sites assessed, excluding high quality sites), and an assumption that only 20% of this land area will be able to be utilised for wind generation, considering competing land and social limitations.

These resource limits have evolved through each ISP since the 2018 ISP to incorporate input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing, committed , committed* and anticipated generation in each REZ[202] (see Section 3.5.1 for more information on classification of generation projects). In recognition of consultation feedback on the Draft 2025 IASR, AEMO has provided updated wind resource limits for Central West Orana, South-West NSW and Tumut REZ in New South Wales. Additionally, the information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

[201] Multi-Criteria-Scoring-for-Identification-of-REZs DNV-GL, 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

[202] AEMO, NEM Generation Information July 2021, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2021/nem-generation-information-july-2021.xlsx.

The resource limits are shown above in **Figure 75**, and are further detailed in the 2025 *Inputs and Assumptions Workbook*.

Solar farm resource limits

Maximum REZ solar generation resource limits (both CST and PV) have been calculated based on:

- typical land area requirements for solar PV, and
- an assumption that only 0.25% of the approximate land area of the REZs will be able to be used for solar generation. This allocation is significantly lower than wind availability, as solar farms have a much larger impact on alternative land use than wind farms, which require reasonable distance between wind turbines.

The initial resource limits were adjusted in each ISP since the 2018 ISP to incorporate input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing, committed, committed*, and anticipated generation in each REZ[160].

The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

The resource limits are shown in **Figure 75** above and are further detailed in the 2025 *Inputs and Assumptions Workbook*.

Offshore wind resource limits

After considering announced projects and stakeholder feedback, AEMO included six candidate offshore REZs for the 2024 ISP. These zones were broadly located based on public information on offshore wind projects. AEMO has removed the South East South Australia Coast offshore candidate REZ for the 2026 ISP in recognition of that this area is not currently listed as an offshore wind area on the Australian Government's offshore wind website.

Table 34 provides the specific resource limits for each offshore REZ for both fixed and floating offshore wind turbine structures, prepared with consideration of the ocean depth of each offshore REZ.

Table 34 Offshore REZ resource limits

Offshore REZ	Resource limits – fixed structures (MW)	Resource limits – floating structures (MW)	REZ area (km^2)
N10 – Hunter Coast	0	7,420	1,854
N11 – Illawarra Coast	148	5,696	1,022
V7 – Gippsland Coast	The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.		
V8 – Southern Ocean	The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.		
T4 – North Tasmania Coast	8,024	20,360	7,096

The maximum offshore REZ wind generation resource limit in **Table 34** was calculated based on:

- assumed turbine capacity density of 5 MW/km^2,
- allowing for 80% of the offshore REZ area to be developed,

- fixed offshore wind turbine structures assumed to be built up to a depth of 70 metres, and
- floating offshore wind turbine structures are assumed at a depth above 70 metres but less than 1,000 metres.

Land use penalty factors in REZs allow for increases in resource limits

Land use reviews with governments indicate that the expansion of REZs is likely to become constrained by social licence factors, as opposed to purely on land availability (although varying between REZs).

In the 2024 ISP, AEMO applied an additional land use penalty factor of $0.29 million/MW to all new VRE build costs in a REZ, which applies only if generation is modelled above the original REZ total resource limits. This penalty factor was applied to capture the expected increase in land costs or difficulties in obtaining land.

For the 2026 ISP, a land use penalty factor of $0.3 million/MW will be applied, which has been adjusted to account for inflation since the 2023 IASR.

By using the REZ land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and engagement with community and traditional landowners as more renewable generation goes into a REZ.

It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible for AEMO's assessments of future REZ potential. This includes engagement with communities, title holders, and Traditional Owners. Early indications of sensitivities in proposed future REZ areas will assist in the assessment of potential expansion opportunities or limits, thereby improving the projections of future potential in the ISP candidate paths.

Even with a land use penalty factor, an upper land use limit is also applied to the REZ resources. For the 2024 ISP, this was based on 5% of land area within a REZ for wind resources and 1% of land area for solar resources, which AEMO will apply for the 2026 ISP. However, in recognition of consultation feedback, where sufficient evidence of community consultation and connection interest has been presented, the land use limits have been updated, notably, in South-West NSW and Central West Orana REZ. The land area within a REZ can be found in the 2025 *Inputs and Assumptions Workbook*.

Additionally, the information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

Social licence

In early 2024, Energy Ministers published their *Response to the Review of the Integrated System Plan* which included an action on AEMO to have regard to community sentiment when identifying the ISP's optimal development path (see Breakout box 1).

Breakout box 1 – Actions in the Energy Ministers' response to the Review of the ISP – Incorporating community sentiment

AEMO should have regard to community concerns or sensitive locations in the identification of the optimal development path, and consider existing and available data on community sentiment, where available for the 2026 ISP (for example, from CSIRO surveys or as the result of Transmission Network Service Providers' community engagement as part of preparatory activities).

'Social licence' is commonly used to refer to local community acceptance of new infrastructure development. The efficient and effective transition of the energy sector will rely on both government and the energy industry understanding and delivering the community's ambition and needs for the future power system, both broadly in the community, and in the places that host new development. Conversely, a lack of social licence could lead to significant project delays and increased cost. Information about 'community sentiment' can broadly be considered as one indicator of social licence relating to new infrastructure development.

AEMO has included input and feedback from external stakeholders in its overall consideration of social licence and community sentiment matters for the ISP. In November 2022, AEMO established an Advisory Council on Social Licence (ACSL), consisting of a diverse cohort of consumer and community organisation representatives and respected advocates with expertise and understanding in the energy sector, to serve as a strategic advisory body on social licence matters, including the 2024 ISP. In July 2024, the ACSL evolved into a new format known as the Consumer and Community Reference Group (CCRG), and membership for a new cohort of the CCRG was finalised in September 2024. AEMO has received input and advice from the CCRG for the 2025 IASR and will continue to engage with them in preparing the 2026 ISP where appropriate, in addition to undertaking extensive joint planning with TNSPs on this matter.

In the 2026 ISP, AEMO will include social licence and community sentiment in a number of ways, as listed below.

- Selection of **forecasting and planning scenarios**, and their narratives (see Section 2).
- Selection of **transmission augmentation options**, including cost, estimates, conceptual design and broad location, and application of transmission network augmentation costs and generator connection costs. For example, social licence consideration may require longer routes, additional landowner compensation and consideration for under grounding of some overhead components. This was included in transmission network options in the 2025 *Electricity Network Options Report* by incorporating the results of land use analysis as additional costs to represent the potential need to change proposed transmission line routes to avoid traversing particularly complex areas. Additional cost can also include the cost associated with engagement activities with land holders and communities.
- Consideration of community engagement in **project lead times**.
- Selection of **locations for candidate REZs** through consultation, and through map overlay with the 'National Native Title Tribunal, Native Title Determinations and Claimant Applications'.
- Preparation of **REZ parameters**, including **land use limits (and a land use penalty factor for exceedance**) (see above), and **resource limits** (above). For example, the use of land-use penalty factors is a reflection that REZ development is likely to be limited by social licence rather than renewable resources.

AEMO consulted on transmission and distribution network augmentation costs, generator connection costs and project lead times in the *2025 Electricity Network Options Report* consultation, and has included the final outcomes in the *2025 Inputs and Assumptions Workbook*.

3.9.3 REZ transmission limits

Input vintage	July 2025
Source	Based on the 2025 *Electricity Network Options Report* and feedback to the 2025 *ISP Methodology.*
Updates since Draft 2025 IASR	The following revisions have been made to align REZ transmission limits with the amendments to the REZ geographic boundaries, sub-regional flow path definitions, and/or to reflect updated information received from TNSPs and jurisdictional bodies: • New South Wales: New group constraint SWNSW2 has been applied to the South West NSW region. • Queensland: SWQLD1 group constraint has been updated to reflect the additional resource traces in Darling Downs REZ. • South Australia: The MN1 group constraint has been updated to include terms for the flow across the CSA-NSA cut-set and Project EnergyConnect flow. The NSA1 and NSA1 North group constraints have been amended to remove the H1 Electrolyser load term. • Victoria: The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

Individual REZ transmission limits

Network studies were undertaken to identify REZ transmission limits of the existing network. Since the 2022 ISP, REZ transmission limits have reflected total transmission limits rather than surplus hosting capacity. The REZ transmission limit is expressed as an intertemporal generation constraint. The purpose of the constraint is to limit the generation dispatch up to the transmission limit which can be increased when it is economically optimal.

Where flows across the transmission limit in a REZ are affected by generation, AEMO applies a generation constraint to reflect this dependency within the REZ. This was consulted on through the 2023 *ISP Methodology*.

Compared to the 2024 ISP, the following changes have been made in the 2025 IASR transmission limits and generation constraints:

- The new Collinsville REZ limit to be modelled as part of the Central Queensland – North Queensland sub-regional limit.
- The Isaac REZ modelling has been revised to consider the updated REZ boundary and to be modelled as part of the CQ1 group constraint limit.
- Northern Queensland REZ limit to now be modelled as part of the NQ1 group constraint limit.
- Limits are now provided for the new South Cobar REZ.
- The South West NSW REZ limit has been updated consistent with updates to the SWNSW1 secondary transmission limit.
- The Eastern Eyre Peninsula REZ limit has been reviewed based on updated ratings.
- In some cases, offshore REZ resources are anticipated to connect through to the transmission network via an onshore REZ. These resources will all be modelled within the individual REZ transmission limit for the onshore REZ.
- The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

Full details on the individual REZ transmission limits can be found in the *2025 Inputs and Assumptions Workbook – Build limits – REZs tab*.

Secondary transmission limits within a REZ

Where there are significant transmission limits that apply to only a subset of generation within a REZ, a secondary transmission limit can be modelled. It is noted that the inclusion of an additional limit can significantly impact on simulation complexity. These are only included where impacts are deemed significant, such as where existing generation is already seeing network congestion. No new additional secondary limits are proposed.

The following changes have been made to the 2025 IASR Secondary transmission limits:

- The SWNSW1 secondary limit has been updated to incorporate the Broken Hill REZ contribution as an explicit term, based on TNSP feedback.
- The SWNSW1 group constraint has been updated to allow additional capacity post Project EnergyConnect

Full details on the secondary transmission limits can be found in the *2025 Inputs and Assumptions Workbook – Build limits – REZs tab*.

Group constraints

The transmission network is a complex and interconnected system. Transmission flows are influenced by generation and system services across multiple locations. Within AEMO's capacity outlook model, simplifications are needed to represent the power system to keep the optimisation problem tractable, which may rely on flow limits being influenced by single REZ outcomes.

To address this need, "group constraints" are applied. These constraints combine either the generation from more than one REZ, or the generation within a REZ with the power flow along a flow path, to reflect network limits that apply to multiple areas of the power system. The group constraints that apply in the capacity outlook model are provided in the *2025 Inputs and Assumptions Workbook*. These have been developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Based on AEMO analysis and recent feedback from existing and intending TNSPs, the following changes have been made to the REZ group constraints:

- With the Central Queensland – Northern Queensland (see Section 3.10.5) sub-region, regional reference node shifting south from Chalumbin 275 kV to Ross 275 kV, the NQ2 group constraint has been removed and the Northern Queensland limits is represented by the NQ1 group constraint previously included in the 2022 ISP.
- A new group constraint CQ1 has been added to reflect the network limits south of Q4 Isaac.
- The MN1 North group constraint has been replaced by the new Central South Australia – North South Australia (CSA-NSA) flow path.
- The MN1 group constraint has been updated to include an NSA to CSA sub-regional flow term and a term to represent flows across Project EnergyConnect.
- The NSA1 and NSA1 North group constraints have been updated to remove the CSA Export Electrolyser term.

- The SWQLD1 Darling Downs REZ transmission limit constraint has been updated to include separate terms and coefficients for the additional resource trace locations.
- The SQ1 (After Queensland SuperGrid) future REZ group constraint has been updated to include separate terms and coefficients for the additional resource trace locations.
- The S1-TMBO limit has been removed as the change to the South East South Australia (SESA)-CSA boundary now incorporates this cut-set limit.
- A new group constraint SWNSW2 has been added to reflect limitations in the South West New South Wales region if Broken Hill and South Cobar REZ are developed.
- A new group constraint CWNSW1 has been added to reflect limitations in Central West New South Wales to access the shared transmission network near Wellington.
- A new group constraint SNW1 has been added to reflect the limitations within Sydney, Newcastle, Wollongong (SNW) if new gas-powered generation south of Sydney is developed.
- The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

Full details on the group constraints can be found in the 2025 *Inputs and Assumptions Workbook – Build limits – REZs tab*.

Modifiers due to committed and anticipated transmission augmentations

This section focuses on REZ transmission limit uplifts due to committed and anticipated transmission augmentations. REZ transmission limits can change due to either of the following:

- Flow path augmentations – a flow path is the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected system. When flow paths traverse REZs, flow path upgrades can improve a REZ's access through the shared transmission network.
- REZ network augmentations – the REZ network connects renewable generation in areas where large-scale renewable energy can be developed using economies of scale. REZ network augmentations increase, at an efficient cost, transmission access from the REZ to the NEM shared transmission network.

Committed and anticipated network augmentation projects may increase REZ transmission limits. The REZ transmission modifiers as a result of committed and anticipated network augmentations are presented in the 2025 *Inputs and Assumptions Workbook – Build limits – REZs tab*. Committed and anticipated transmission augmentation projects are defined in Section 3.10.3 and Section 3.10.4.

3.9.4 REZ augmentations and network cost

Input vintage	July 2025
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data
Updates since Draft 2025 IASR	Transmission Cost Database update and the *2025 Electricity Network Options Report* consultation. In addition, the information in this section will be updated following the release of the 2025 Victorian Transmission Plan.

For the 2024 ISP, AEMO published the 2023 *Transmission Expansion Options Report* with an expanded scope of the earlier 2021 *Transmission Cost Report*.

For the 2026 ISP, AEMO has published the 2025 *Electricity Network Options Report* with an expanded scope including transmission network augmentation options and costs as well as some distribution network opportunities for facilitating operation of CER and other distributed resources. This expanded scope responds to an action on AEMO in the Energy Ministers' Response to the ISP Review, to optimise demand-side modelling and enhance demand forecasting (see Breakout box 2, Section 3.10.8).

The 2025 *Electricity Network Options Report* included:

- transmission augmentation options for flow paths and for REZs including:
  - a description of the network option,
  - the expected increase in transfer capacity/network capacity:
    - for REZs, any modifiers due to flow path augmentations,
    - the project cost, including the class of estimate and associated accuracy,
    - project lead time, including consideration for community engagement and establishment of social licence,
- REZ connection costs,
- distribution network opportunities, and
- system strength remediation costs.

For the 2025 IASR, AEMO has allocated the efficient level system strength remediation costs to REZ connection costs, to form a collective connection point limit cost. This change seeks to align with the recently updated system strength framework[203], which states that generally, system strength remediation schemes must be implemented behind connection points where NSPs are required to undertake system strength impact assessments. Minimum fault level remediation costs are proposed to also be modelled, in addition to the efficient level of system strength costs, and are detailed in Section 3.11.1.

3.10 Network modelling

This section outlines the key inputs and assumptions relating to notional power transfers between different parts of the electricity transmission and distribution networks, as well as the status of nominated network projects and the capabilities and costs of potential augmentation of the networks. The inputs and assumptions are grouped into the following categories:

- **ISP sub-regions** – the power system is modelled in different ways depending on the analysis being performed. A 15 sub-region structure is proposed to provide more granularity of diverse load patterns for optimisations that were previously assessed across 12 sub-regions across the NEM (see Section 3.10.1).

[203] AEMO. *System Strength Impact Assessment Guidelines*, June 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/%20consultations/nem-consultations/2024/ssiag/system-strength-impact-assessment-guidelines-v22.pdf?la=en.

- **Existing network capacity** – this section summarises the existing capacity of the transmission network with relation to transferring power between sub-regions and includes the changes proposed for the revised sub-regional definition (see Section 3.10.2).
- **Committed transmission projects** – these projects are included in all scenarios. Once a project meets five criteria, the projects are classified as committed and will be modelled in all scenarios (see Section 3.10.3).
- **Anticipated transmission projects** – major transmission projects that are in the process of meeting three of the five commitment criteria are classified as anticipated. The treatment of anticipated transmission projects can vary depending on the type of modelling being performed (see Section 3.10.4).
- **Flow path augmentation options** – this was consulted on through the Draft 2025 *Electricity Network Options Report* and includes transmission upgrades that are not committed or anticipated, which will be assessed in the 2026 ISP (see Section 3.10.5).
- **Transmission augmentation costs** – the costs of transmission augmentation options and the building blocks used to estimate new augmentations as the need may arise. This was updated and consulted on through the Draft 2025 *Electricity Network Options Report* (see Section 3.10.6).
- **Preparatory activities** – the 2024 ISP did not trigger preparatory activities for any of the identified future ISP projects (see Section 3.10.7).
- **Distribution capabilities and potential augmentations** – the 2026 ISP will include analysis of distribution network capabilities and opportunities for CER and other distributed resources. Distribution network service provider (DNSP) inputs will be consulted on through the Draft 2025 *Electricity Network Options Report* (see Section 3.10.8).
- **Non-network options** – AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy (see Section 3.10.9).
- **Loss flow equations** – loss flow equations are used to reflect the energy lost when transferring energy between regions, and between sub-regions (see Section 3.10.10).
- **Marginal loss factors (MLFs)** – these values are used to reflect network losses and the marginal pricing impact of bids from a connection point to the regional reference node (see Section 3.10.11).
- **Transmission line unplanned outage rates** – forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments (see Section 3.10.12).

3.10.1 ISP sub-regions

Input vintage	July 2025
Source	AEMO internal – based on 2024 ISP inputs, and adjusted based on AEMO assessments, supplemented by advice from TNSPs via joint planning
Updates since Draft 2025 IASR	None – stakeholders supported the structure proposed in the Draft IASR

The power system is modelled in different ways depending on the analysis being performed. In market and economic modelling, the electricity network is represented as either a regional or sub-regional topology:

- In the regional topology, each of the five NEM regions is represented by a single reference node. In this topology, all loads are placed at the respective regional reference nodes, with generation represented across the power system considering the REZ transmission limits and group constraints described previously.
- The sub-regional topology breaks down some of the NEM regions into smaller sub-regions. In this topology, the regional load and generation resources are appropriately split between the different sub-regions. Flow path transmission constraints are added to reflect the capability of the network.

AEMO has made the following changes to the sub-regional topology since the 2024 ISP:

- **Separating Victoria into three sub-regions** – AEMO divided the Victorian region from the 2024 ISP into three sub-regions, namely Greater Melbourne and Geelong (MEL), South East Victoria (SEV) and West and North Victoria (WNV). These changes are intended to improve visibility of constraints in the network for meeting Greater Melbourne and Geelong demand, and better represent the load diversity in different parts of Victoria.
- **Separating Central South Australia sub-region into two sub-regions** – AEMO further divided the Central South Australia sub-region into two sub-regions, Northern South Australia (NSA) and Central South Australia (CSA). This new sub-regional model would better represent the load diversity and patterns in Northern South Australia distinct from the rest of South Australia, and assist to better capture network limitations on power transfers towards Northern South Australia and the Eyre Peninsula region.
- **Amending the sub-regional boundary of Central Queensland (CQ) to Northern Queensland (NQ) –** AEMO changed the sub-regional boundary between Central Queensland and Northern Queensland, to move the border to be south of Nebo. This updated boundary is to align and maintain consistency for measuring and reporting flows on flow paths across planning documents for Queensland. It is also expected to better represent flows from potential pumped hydro projects into the Northern Queensland sub-region.
- **Amending the sub-regional boundary of South East South Australia (SESA) to Central South Australia (CSA)** – AEMO changed the sub-regional boundary between South East South Australia and Central South Australia, to better align the sub-regional and REZ boundary of South East South Australia and provide improved visibility of constraints between the South East South Australia REZ and the Adelaide load centre.

0 lists all the regions and sub-regions to be used in AEMO studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 35 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Northern Queensland (NQ)	Ross 275 kV	Q1, Q2, Q3 and Q10
	Central Queensland (CQ)	Broadsound 275 kV	Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	South Queensland (SQ)	**South Pine 275 kV**	Q7, Q8 and Q9[A]
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3, N9 and N13
	Southern New South Wales (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	**Sydney West 330 kV**	N10, N11 and N12
South Australia	Northern South Australia (NSA)	Davenport 275 kV	S5, S6, S7 and S8
	Central South Australia (CSA)	**Torrens Island 66 kV**	S2, S3, S4
	South East South Australia (SESA)	South East 132 kV	S1
Tasmania	Tasmania (TAS)	**George Town 220 kV**	T1, T2, T3 and T4
Victoria	Greater Melbourne and Geelong (MEL)	**Thomastown 66 kV**	The information in this section will be updated following the release of the 2025 Victorian Transmission Plan.
	South East Victoria (SEV)	Hazelwood 500 kV	
	West and North Victoria (WNV)	Moorabool 220 kV	

Note: Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.
A. In scenarios with large hydrogen export development, Q9 will be modelled within CQ.

Capacity outlook model representation

In the 2024 ISP, AEMO used a 12-area sub-regional model for capacity outlook modelling. For the 2026 ISP, AEMO is using a 15-area sub-regional model. The sub-regional model provides more granular information on key intra-regional transmission limitations and augmentations which are not well approximated by interconnectors and REZ limits.

The sub-regional representation and flow paths are presented and described in **Figure 76** and **Table 36**. For each flow path, AEMO models the alternating current (AC) and direct current (DC) interconnectors separately, which can result in multiple parallel flow paths.

Figure 76 ISP sub-regional model

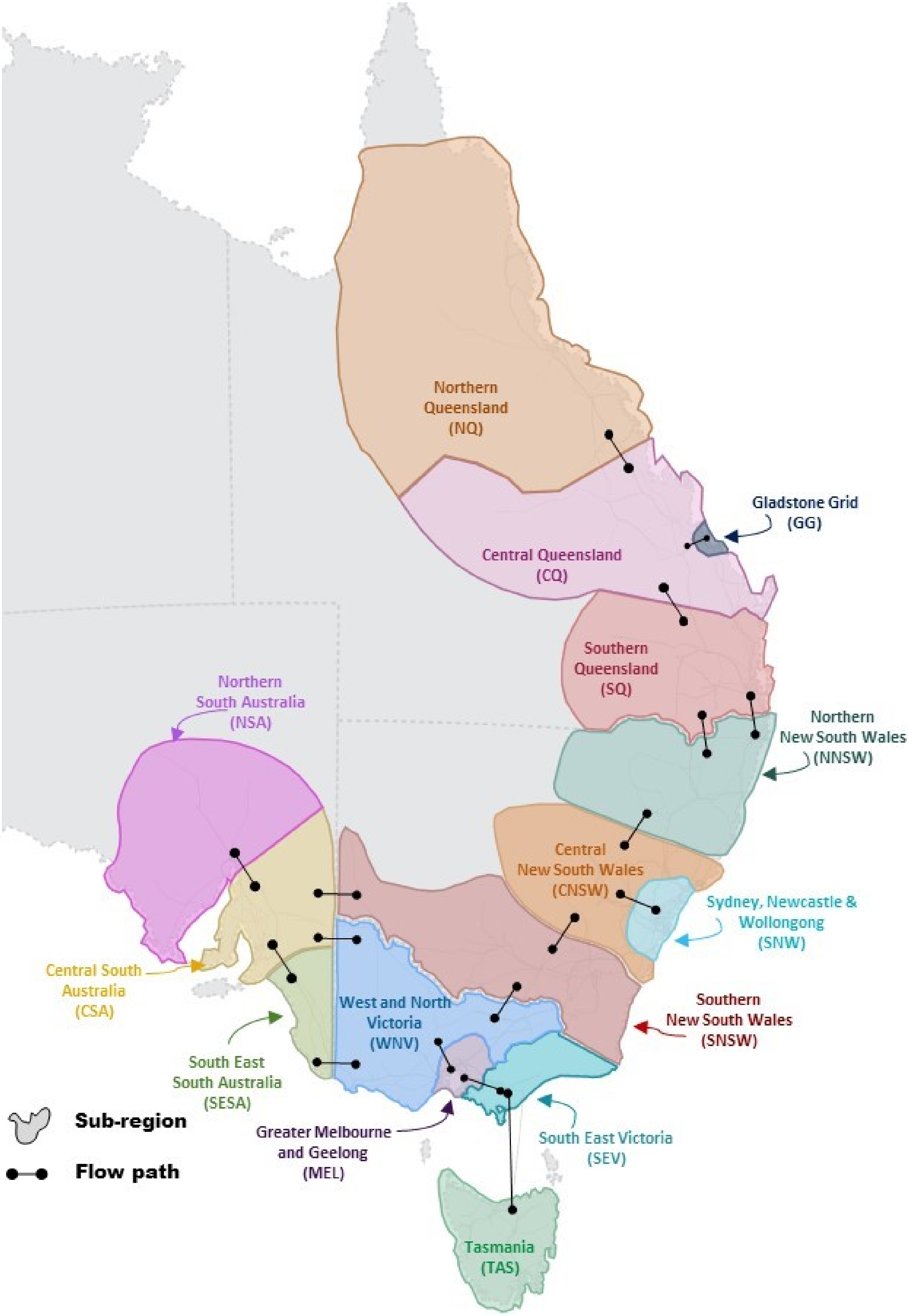


Table 36 Existing network flow path representation between sub-regions

Flow path definition	Inter-zonal flow path (forward direction of power flow)
CQ – NQ	Bouldercombe – Nebo 275 kV (1 circuit) Broadsound – Nebo 275 kV (3 circuits) Dysart – Peak Downs/Moranbah 132 kV (1 circuit) Dysart – Eagle Downs 132 kV (1 circuit)
CQ – GG	Bouldercombe – Calliope River 275 kV (1 circuit) Raglan – Larcom Creek 275 kV (1 circuit) Calvale – Wurdong 275 kV (1 circuit) Gin Gin – Calliope River 275 kV (2 circuits) Teebar Creek – Wurdong 275 kV (1 circuit)
SQ – CQ	Woolooga – Teebar Creek 275 kV (1 circuit) Woolooga – Gin Gin 275 kV (2 circuits) Halys – Calvale 275 kV (2 circuits)
NNSW – SQ (QNI)	Dumaresq – Bulli Creek 330 kV (2 circuits)
NNSW – SQ (Terranora)	Terranora – Mudgeeraba 110 kV (2 circuits)
CNSW – NNSW	Muswellbrook – Tamworth 330 kV (1 circuit) Liddell – Tamworth 330 kV (1 circuit) Hawks Nest tee – Taree 132 kV line (1 circuit) Stroud – Taree 132 kV line (1 circuit)
SNSW – CNSW	Crookwell – Bannaby 330 kV (1 circuit) Yass – Marulan 330 kV (1 circuit) Collector – Marulan 330 kV (1 circuit) Capital – Kangaroo Valley 330 kV (1 circuit) Yass – Cowra 132 kV (2 circuits)
CNSW – SNW	Wallerawang – Ingleburn 330 kV (1 circuit) Wallerawang – Sydney South 330 kV (1 circuit) Bayswater – Sydney West 330 kV (1 circuit) Bayswater – Regentville 330 kV (1 circuit) Liddell – Newcastle 330 kV (1 circuit) Liddell – Tomago 330 kV (1 circuit) Bannaby – Sydney West 330 kV (1 circuit) Marulan – Avon 330 kV (1 circuit) Marulan – Dapto 330 kV (1 circuit) Kangaroo Valley – Dapto 330 kV (1 circuit) Stroud – Brandy Hill 132 kV (1 circuit) Stroud – Tomago 132 kV (1 circuit) Hawks Nest tee – Tomago 132 kV (1 circuit) Singleton – Rothbury 132 kV (1 circuit which is normally open)
WNV – SNSW	Murray – Upper Tumut 330 kV (1 circuit) Murray – Lower Tumut 330 kV (1 circuit) Wodonga – Jindera 330 kV (1 circuit) Red Cliffs – Buronga 220 kV line (2 circuits) Jindabyne – Guthega 132 kV (1 circuit) Geehi Dam – Guthega 132 kV (1 circuit)
SNSW – CSA	Buronga – Bundy 330 kV (2 circuits)
MEL – WNV	Sydenham – Moorabool 500 kV (2 circuits) Sydenham – Bulgana 500 kV (2 circuits) – post Western Renewables Link Geelong – Moorabool 220 kV (2 circuits)

Flow path definition	Inter-zonal flow path (forward direction of power flow)
	South Morang – Dederang 330 kV (2 circuits) Thomastown – Eildon 220 kV (1 circuit) Geelong – Winchelsea 66 kV (1 circuit) Brooklyn – Bacchus Marsh 66 kV (1 circuit)
SEV – MEL	Hazelwood – South Morang 500 kV (2 circuits) Hazelwood – Rowville 500 kV (1 circuit) Hazelwood – Cranbourne 500 kV (1 circuit) Hazelwood – Rowville 220 kV (2 circuits) Yallourn – Rowville 220 kV (4 circuits)
WNV – SESA (Heywood)	Heywood – South East 275 kV (2 circuits)
WNV – CSA (Murraylink)	Red Cliffs – Monash high voltage direct current (HVDC) cable
SESA – CSA	Tailem Bend – Tungkillo 275 kV (2 circuits) Tailem Bend – Mobilong 132 kV (1 circuit)
CSA – NSA	Bungama – Davenport 275 kV (1 circuit) Brinkworth – Davenport 275 kV (1 circuit) Mt Lock – Davenport 275 kV (1 circuit) Belalie – Davenport 275 kV (1 circuit)
TAS – SEV	George Town – Loy Yang HVDC cable

Representation of load and generation within each of the sub-regions is presented in **Table 37**. Sub-region loads are represented at the sub-region reference node. The reference node for each sub-region is located close to the sub-region's major load centre, except in North and Central Queensland where the nodes have been selected to capture intra-regional loss equations, and in West and North Victoria where the node has been selected to support enhanced visibility of constraints in the network for meeting Greater Melbourne and Geelong demand.

Table 37 Load and generation representation within the sub-regional model

Sub-region	Sub-region reference node	Load and generation representation
Northern Queensland (NQ)	Ross 275 kV	All load and generation including and north of Nebo, Eagle Downs, Peak Downs and Moranbah.
Central Queensland (CQ)	Broadsound 275 kV	All load and generation including and north of Calvale, Gin Gin and Teebar Creek substations, except load and generation in GG and NQ sub-regions.
Gladstone Grid (GG)	Calliope River 275 kV	All load and generation at Calliope River, Boyne Island, Larcom Creek and Wurdong substations.
South Queensland (SQ)	South Pine 275 kV	All Queensland load and generation except load and generation in CQ, GG and NQ sub-regions. This includes the Brisbane area.
Northern New South Wales (NNSW)	Armidale 330 kV	Load and generation in northern New South Wales, including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Load and generation in central New South Wales, including and west of Wallerawang, Wollar, Bayswater, Liddell, Muswellbrook and Bannaby substations.
South New South Wales (SNSW)	Canberra 330 kV	Load and generation in southern New South Wales, including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West New South Wales.

Sub-region	Sub-region reference node	Load and generation representation
Sydney, Newcastle and Wollongong (SNW)	Sydney West 330 kV	All New South Wales region load and generation except load and generation in CNSW, SNSW and NNSW sub-regions. This includes Greater Sydney, Newcastle and Wollongong areas.
West and North Victoria (WNV)	Moorabool 220 kV	Load and generation in the north and west of Victoria, including and north and west of Moorabool, Eildon, Dederang, Winchelsea and Bacchus Marsh substations.
South East Victoria (SEV)	Hazelwood 500 kV	Load and generation in south east Victoria and Gippsland region including at Hazelwood, Loy Yang, Yallourn, Jeeralang and Morwell substations.
Greater Melbourne and Geelong (MEL)	Thomastown 66 kV	All Victorian region load and generation, except load and generation in WNV and SEV sub-regions. This includes Greater Melbourne and Geelong areas.
Northern South Australia (NSA)	Davenport 275 kV	Load and generation in northern South Australia, including and north of Davenport and Eyre Region.
Central South Australia (CSA)	Torrens Island 66 kV	All South Australian region load and generation except NSA and SESA sub-region load and generation. This includes the Greater Adelaide area.
South East South Australia (SESA)	South East SA 132 kV	Load and generation in south east South Australia, including and south of Tailem Bend.
Tasmania (TAS)	George Town 220 kV	All load and generation within Tasmania.

Detailed transmission constraint representation for time-sequential models

In the ESOO, and where required in the ISP time-sequential models, AEMO applies a more detailed transmission representation that is overlaid to the regional model. The NEM transmission network is represented using detailed transmission constraint equations over a regional topology, similar to what is used in the NEM Dispatch Engine (NEMDE). These constraints:

- consider the NEM's network at 220 kV or above, and other transmission lines under this voltage level that run parallel to the network at 220 kV or above,
- calculate the network flow capability (intra- and inter-regional) and the available generator output capacity in every dispatch interval of the model,
- are constantly updated to reflect changing power system conditions and outages, and
- are modified to cater for different transmission development pathways and scenarios assessed in an ISP.

3.10.2 Existing transmission capability

Input vintage	July 2025
Source	AEMO internal supplemented by advice from TNSPs via joint planning
Updates since Draft 2025 IASR	The following change has been made to reflect updated information received from TNSPs and jurisdictional bodies: • Updated Greater Melbourne and Geelong (MEL) to West and North Victoria (WNV) forward transfer limit to reflect notional transfer capabilities for likely load conditions.

Transfer capability across the transmission network is determined by thermal capacity, voltage stability, transient stability, small signal stability, frequency stability and system strength. It varies throughout the day with generation dispatch, load and weather conditions. In time-sequential market modelling, limits are represented through network constraint equations. For capacity outlook modelling, notional transfer limits between the regions or sub-regions are represented at the time of maximum demand in the importing region or sub-region.

AEMO has made the following changes since the 2024 ISP:

- Revision of flow path limits between Central Queensland (CQ) and Northern Queensland (NQ) to align with the updated sub-region boundaries.
- Revision of flow path limits between Northern New South Wales (NNSW) and Southern Queensland (SQ) to reflect the change in Queensland – New South Wales Interconnector (QNI) and Terranora limits (consistent with the April 2024 Interconnector Capabilities[204] report).
- Inclusion of flow path limits between Greater Melbourne and Geelong (MEL) and West and North Victoria (WNV) to align with the new sub-region boundaries.
- Inclusion of flow path limits between South East Victoria (SEV) and Greater Melbourne and Geelong (MEL) to align with the new sub-region boundaries.
- Revision of flow path limits between South East South Australia (SESA) and Central South Australia (CSA) to align with the updated sub-region boundaries.
- Inclusion of flow path limits between Central South Australia (CSA) and Northern South Australia (NSA) to align with the new sub-region boundaries.

The 2025 IASR notional transfer limits are in **Table 38**. They reflect current assessments and may change as further power system analysis is undertaken, or as the sub-regional representation is refined. Interconnector transfer capabilities are a subset of this information, and are listed in the 2025 *Inputs and Assumptions Workbook*.

Table 38 Notional transfer capabilities between the sub-regions of the existing network (December 2024)

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
CQ – NQ	1,200	1,200	1,400	1,440	1,440	1,910	Amended flow path boundary in this 2025 IASR. No change to CQ – NQ forward capability since 2024 ISP. Limits were determined with the inclusion of a minor Strathmore to Ross line upgrade. AEMO is working with Powerlink to further investigate possible voltage or transient stability limits associated with CQ – NQ reverse flow capability.
CQ – GG	700	700	1,050	750	750	1,100	No changes to 2024 ISP.
SQ – CQ	1,100	1,100	1,100	2,100	2,100	2,100	The maximum power transfer from CQ to SQ grid section is limited by transient or voltage

[204] AEMO. *Interconnector Capabilities,* April 2024. At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf.

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							stability following a Calvale to Halys 275 kV circuit contingency. It is assumed Powerlink will establish a new substation at Karana Downs for teeing-in both Blackwall – Rocklea 275 kV lines to South Pine. The maximum transfer capability from SQ to CQ is limited by thermal capacity of the Blackwall – South Pine 275 kV line following a credible contingency.
NNSW – SQ ("QNI")	950	950	950	1,450	1,450	1,450	These amended transfer limits include the completion of the QNI minor project. QNI Minor is currently undergoing inter-network testing to release the designed maximum capacity. Queensland to New South Wales transfer limit is influenced by generation output from Sapphire Wind Farm and Tilbuster Solar Farm.
NNSW – SQ ("Terranora")	0	50	50	130	150	200	No changes to 2024 ISP. The maximum transfer capability from NNSW to SQ is limited by thermal capacity of Lismore – Dunoon 132 kV lines and from SQ to NNSW is limited by thermal capacity of Mudgeeraba 275/110 kV transformers.
CNSW – NNSW	910	910	910	930	930	1,025	No changes to 2024 ISP. These transfer limits include the completion of the QNI Minor project.
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590	No changes to 2024 ISP.
CNSW – SNW Northern limit	4,490	4,490	4,730	4,490	4,490	4,730	No changes to 2024 ISP. This limit has been formulated for the detailed long term capacity outlook model and should not be used for other applications. For detailed long term capacity outlook modelling, the CNSW-SNW transfer limit can be represented as two limits. One as CNSW-SNW_South and other as CNSW-SNW_North. For DLT modelling, this limit is to be represented with generator

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							coefficients for generators in NNSW, CNSW and SNSW. These generator coefficients are presented in the "Network capability" worksheet in the 2025 *Inputs and Assumptions Workbook*. See the 2025 *Inputs and Assumptions Workbook* for more details on CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) network augmentations and System Integrity Protection Scheme (SIPS) control and Central-West Orana REZ Network Infrastructure Project. Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. Forward direction transfer limit will be assessed if of material importance.
CNSW – SNW Southern limit	2,540	2,540	2,720	2,540	2,540	2,720	No changes to 2024 ISP. This limit has been formulated for the DLT model and should not be used for other applications. For detailed long term capacity outlook modelling, CNSW-SNW transfer limit can be represented as two limits. One as CNSW-SNW_South and other as CNSW-SNW_North. For detailed long term capacity outlook modelling, this limit is to be represented with generator coefficients for generators in NNSW, CNSW and SNSW. These generator coefficients are presented in the "Network capability" worksheet in the 2025 *Inputs and Assumptions Workbook*. See the 2025 *Inputs and Assumptions Workbook* for more details on CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) network augmentations and System Integrity Protection Scheme (SIPS) control and Central-West Orana REZ Network Infrastructure Project. Power is not expected to frequently flow from SNW to CNSW since the major load

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							centre is SNW. Forward direction transfer limit will be assessed if of material importance.
WNV – SNSW	870	1,000	1,000	400	400	400	No changes to 2024 ISP. WNV-SNSW transfer limits assumes the full capacity provided by VNI Minor. Victoria SIPS with 250 MW battery storage in western side of Melbourne raises the thermal capacity in the reverse direction of Victoria – New South Wales interconnector. SNSW to WNV transfer limit during summer peak periods reduces to 250 MW from 400 MW on conclusion of the VNI SIPS agreement 31 March 2032.
MEL – WNV	3,000	3,000	3,000	2,300	2,550	4,880	New flow path added in this 2025 IASR. Generation from MEL is not expected to supply WNV (Forward direction) at times of high demand periods. For the forward direction transfer limits – a maximum transfer capacity of 3,000 MW may only be possible at times of low and/or medium demand in Victoria with a load between 4,000 MW to 6,000 MW. These limits have been reviewed in collaboration with AEMO (Victorian Planning) and VicGrid. Transfer limits associated with post Western Renewables Link are available in the “Network Capability” worksheet in the 2025 *Inputs and Assumptions Workbook*.
SEV – MEL	7,100	7,430	8,170	7,100	7,430	8,170	New flow path added in this 2025 IASR. This limit is applicable for the existing network before retirement of Yallourn Power Station. Power is not expected to frequently flow from MEL to SEV since the major load centre is MEL. Reverse direction transfer limit will be assessed if material importance.

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							A transient or voltage stability limit lower than the thermal limit may be applicable for this flow path. AEMO will continue to engage with AEMO (Victorian Planning) and VicGrid to further refine this limit. Transfer limits with Western Renewables Link and post Yallourn power station closure are available in the "Network Capability" worksheet in the 2025 *Inputs and Assumptions Workbook.*
WNV – SESA ("Heywood")	650	650	650	650	650	650	No changes to 2024 ISP. Heywood interconnector currently operates at 600 MW forward capability and 550 MW reverse capability. AEMO and ElectraNet work towards releasing the transfer capability to its designed capability of 650 MW in both directions.
WNV – CSA (Murraylink)	165	220	220	100	200	200	Murraylink forward direction is limited by HVDC cable thermal capability which is provided in the "Network Capability" worksheet in the 2025 *Inputs and Assumptions Workbook*.
SNSW – CSA **(Project EnergyConnect Stage 1)**	150	150	150	150	150	150	This is the design limit of Project EnergyConnect Stage 1. WNV - CSA and SNSW - CSA combined maximum transfer limit is 750 MW in forward direction (import into SA) and 700 MW in reverse direction (export from SA). This transfer limit will increase with full capacity release of Project EnergyConnect (Stage 2 completion). Additional transfer capacity after Stage 2 is available in the "Network Capability" worksheet in the 2025 *Inputs and Assumptions Workbook.*
SESA – CSA	750	750	800	790	790	820	Amended flow path boundary in this 2025 IASR. This transfer limit considers Project EnergyConnect Stage 1 in service.
CSA – NSA	1,070	1,070	1,230	1,150	1,150	1,200	New flow path added in this 2025 IASR.

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							A transient or voltage stability limit lower than the thermal limit may be applicable for this flow path.
TAS – SEV	594	594	594	478	478	478	No changes to 2024 ISP. Basslink interconnector currently operates at a peak transfer capability of 594 MW in forward direction and 478 MW in the reverse direction with allowable capability limited by a daily energy throughput limit as outlined in the 2025 *Inputs and Assumptions Workbook.*

Committed and anticipated projects may increase the capability of flow paths or result in new flow paths. The flow path uplift factors and new flow paths as a result of committed and anticipated projects are presented in the 'Network capability' tab of the 2025 *Inputs and Assumptions Workbook*.

3.10.3 Committed transmission projects

Input vintage	July 2025
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Updates since Draft 2025 IASR	Central-West Orana REZ Network Infrastructure Project Humelink Transmission Network Voltage Control (Adelaide Metro, Para and South East)

AEMO applies the five-criteria definition of a committed project from the AER's regulatory investment test[205]; specifically, a committed transmission project must meet all the following criteria:

- The proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statement.
- Construction has either commenced or a firm commencement date has been set.
- The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- Contracts for supply and construction of the major components of the necessary plant and equipment (such as transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- Necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

[205] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

This final 2025 IASR applies the committed projects listed in the Transmission Augmentation Information page[206], July 2025 release. For further details on these projects please see the 2025 *Inputs and Assumptions Workbook* or the Transmission Augmentation Information page.

Some projects currently categorised as anticipated (see Section 3.10.4) may become committed before ISP modelling commences. AEMO intends to update this list of committed projects if a project becomes committed during the development of the ISP.

3.10.4 Anticipated transmission projects

Input vintage	July 2025
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Updates since Draft 2025 IASR	Eyre Peninsula upgrade Option 1 Increase capacity for generation in the Molong to Parkes area (94T)

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. AEMO applies the criteria set out in the AER's regulatory investment test to determine anticipated projects. These projects must be in the process of meeting three out of the five committed project criteria (described in Section 3.10.3). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets.

The *Reliability Forecasting Methodology*[207] defines which categories of transmission projects are included (considered to be committed) in reliability assessments. This may include anticipated projects that have received regulatory approval and minor upgrades that are not subject to the RIT-T but judged to be committed for reliability assessment purposes. For ISP modelling, anticipated projects will be included in all scenarios.

Generally, transmission projects will be classified as anticipated once they have passed a contingent project application or similar funding approval. AEMO intends to update the status of anticipated projects if any other project becomes committed during the development of the ISP.

This final 2025 IASR applies the anticipated projects listed in the Transmission Augmentation Information page[208], July 2025 release. For further details on these projects please see the 2025 *Inputs and Assumptions Workbook* or the Transmission Augmentation Information page.

3.10.5 Flow path augmentation options

Input vintage	July 2025
Source	AEMO, 2024 ISP, TNSP
Updates since Draft 2025 IASR	2025 *Electricity Network Options Report* consultation and through further TNSP engagements

[206] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[207] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/forecasting-and-planning-guidelines.

[208] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Flow paths are a feature of power system networks, representing the main transmission pathways over which bulk energy is shipped. They are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the network to load centres. Flow paths change as new interconnection is developed, as a result of shifting large amounts of generation into new areas (such as in the case of major REZ development).

Flow path augmentation options represent new network and non-network options to increase the transfer capability between ISP sub-regions. Each option is a candidate to be built during capacity expansion modelling. While many flow path augmentation options increase REZ network capacities, distinct options to expand the network capacity within individual REZs are modelled through a separate process, outlined in Section 3.9.

When identifying flow path augmentation options across ISP sub-regions to connect REZs and pumped hydro storage, AEMO considers credible options including the following technologies:

- High voltage alternating current (HVAC) technology.
- High voltage direct current (HVDC) technologies.
- Virtual transmission lines (using grid-scale batteries).

AEMO has consulted on flow path augmentation options, including the capacity gained and lead time to deliver the project, through the 2025 *Electricity Network Options Report*. Please see Section 3.9.4 for more details.

3.10.6 Transmission augmentation costs

Input vintage	July 2025
Source	Actionable projects: RIT-T data with factors applied Projects with Preparatory activities: TNSP cost data, cross checked with AEMO's Transmission Cost Database Future projects: AEMO's Transmission Cost Database
Update since Draft 2025 IASR	2025 *Electricity Network Options Report* consultation

For the 2024 ISP, AEMO engaged independent expert consultant Mott MacDonald to update AEMO's Transmission Cost Database for use by AEMO in developing cost estimates. It comprised a Cost and Risk Databook and cost estimation tool, as well as a transmission cost forecasting methodology.

For the 2026 ISP, to reflect the latest changes in the market, AEMO engaged expert consultant GHD to update the Transmission Cost Database. The update to the Transmission Cost Database included:

- reviewing and updating the cost and risk data to align with latest changes in market costs,
- reviewing and updating the cost forecasting tool and methodology,
- incorporating the latest transmission project information in the update and calibrate escalation factors, and
- preparing an updated Cost and Risk data workbook and forecasting tool, and associated reporting.

AEMO has undertaken extensive joint planning and collaboration with TNSPs and jurisdictional bodies to update the Transmission Cost Database. The updated Transmission Cost Database was used to develop cost estimates for transmission augmentation options for use in the 2026 ISP.

AEMO consulted on the updated Transmission Cost Database, and associated cost estimates, as part of the Draft 2025 *Electricity Network Options Report* in April 2025. Outcomes of the consultation are incorporated in the final 2025 *Electricity Network Options Report* and 2025 *Inputs and Assumptions Workbook*.

3.10.7 Preparatory activities

Input vintage	June 2024
Source	TNSPs
Updates since the Draft IASR	Not applicable

Preparatory activities are activities to design and investigate the costs and benefits of actionable ISP projects, future ISP projects and REZ stages (as applicable)[209], including:

- detailed engineering design,
- route selection and easement assessment work,
- cost estimation based on engineering design and route selection,
- preliminary assessment of environmental and planning approvals, and
- engagement with stakeholders who are reasonably expected to be affected by the development of the actionable ISP project, future ISP project, or project within a REZ stage (including local landowners, local council, local community members, local environmental groups and traditional owners) in accordance with the community engagement expectations[210].

While TNSPs must commence preparatory activities as soon as practicable for actionable ISP projects (if not yet already commenced)[211], an ISP may specify whether preparatory activities must be carried out for future ISP projects and the timeframes for carrying out those activities. These are typically projects which may become actionable ISP projects, but more detailed information is required, such as improved cost estimates, network designs, and initial appraisal of land considerations. The initial high-level design and costing in preparatory activities reports is necessarily approximate, as the detailed requirements for robust costings and plant design will not yet have been undertaken.

AEMO did not trigger preparatory activities for any of the future ISP projects identified in the 2024 ISP. The TNSPs identified as a RIT-T proponent for a newly actionable ISP project in the 2024 ISP should commence preparatory activities as soon as practicable, if not already commenced.

The projects for which preparatory activities reports have been previously made available by TNSPs are outlined in **Table 39**. The TNSPs' preparatory activities reports are published on the AEMO website[212].

[209] These terms are defined in NER 5.10.2 and Chapter 10. At https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules.

[210] Preparatory activities and community engagement expectations are both defined in NER 5.10.2.

[211] NER 5.22.6(c)&(d)(1)

[212] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

Table 39 Preparatory activities

Project	Indicative timing (2024 ISP)	Responsible TNSP(s)
South East South Australia REZ expansion	N/A	ElectraNet
Darling Downs REZ Expansion	2030-31 to 2034-35	Powerlink
Gladstone Grid Reinforcement	2030-31	Powerlink
Mid-North South Australia REZ Expansion	2029-30 to 2030-31	ElectraNet
QNI Connect (500 kV option)	2034-35	Powerlink and Transgrid
QNI Connect (330 kV option – New South Wales scope)		Transgrid
South West Victoria REZ Expansion	2032-33 to 2033-34	AEMO Victorian Planning (AVP)
Sydney Ring South (Reinforcing Sydney, Newcastle and Wollongong Supply)	2028-29 to 2029-30	Transgrid

3.10.8 Distribution network capabilities

Input vintage	July 2025
Source	DNSPs
Update process	2025 *Electricity Network Options Report*
Updates since Draft 2025 IASR	These inputs were not included in the Draft IASR as they are newly added for the 2026 ISP.

AEMO considers CER to be of critical importance to the energy transition. By investing in CER, households and businesses are playing a transformative role in the future energy system, and will need to be supported by distribution networks, coordination systems and markets.

Energy Ministers' response to the Review of the ISP[213] included an action for AEMO to consider the role of distribution network capabilities and opportunities to support CER and other distributed resources in the future energy system (see: Breakout Box 2). The AEMC has published a rule change to implement information provision arrangements to support the delivery of this action[214].

Breakout box 2 – Actions in the Energy Ministers' response to the Review of the ISP – Enhanced demand forecasting, and optimising for the demand side

AEMO should enhance demand forecasting in the 2026 ISP by:

- Undertaking targeted stakeholder engagement to enhance assumptions underpinning CER and distributed resources projections in the ISP. The assumptions should reflect a comprehensive view of initiatives affecting CER and distributed resources uptake and evaluate the implications for operational demand.
- Subject to available information, analysing how DNSP investments, programs and annual plans, may impact CER and distributed resources development, and thereby the optimal development path for transmission, and include these findings in the ISP in order to send clearer signals to inform DNSP planning.

[213] ECMC. *Response to the Review of the Integrated System Plan*, April 2024. At https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan.

[214] AEMC. Improving consideration of demand-side factors in the ISP. At https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp.

The capability of the existing distribution network and scale of network upgrades to export more CER are new, important inputs to the 2026 ISP. AEMO has engaged extensively with DNSPs to understand existing and future distribution network capabilities and opportunities for incorporating CER and other distributed resources. This included the existing distribution network capabilities as they relate to the operation of CER such as rooftop solar and batteries – that is, understanding how network capabilities may impact CER operation with respect to exporting generation, as well as charging and discharging where relevant. AEMO will implement the approach and inputs outlined in the 2025 *Electricity Network Options Report* in the ISP model through a set of distribution network limitation constraints, at least one each per sub-region for operation of CER, and one each per sub-region uptake and operation of other distributed resources.

In addition, for the 2026 ISP, four regions of large utility-scale generation zones connected to distribution will be tested. The representation of these regions has been informed by inputs from the DNSPs, that were gathered and consulted on through AEMO's 2025 *Electricity Network Options Report.*

AEMO expects that the data relating to distribution network augmentations and opportunities will necessarily evolve and improve over successive ISPs.

3.10.9 Non-network options

Input vintage	July 2025
Source	Previous projects, stakeholder submissions
Update since Draft 2025 IASR	2025 IASR and progression of RIT-Ts

Non-network options are defined in the NER (Chapter 10, glossary) as a means by which an identified need can be fully or partly addressed other than by a network option. Non-network options include a range of technologies, for example:

- Generation investment (including embedded or large-scale).
- Storage technologies (such as battery storage and pumped hydro).
- Demand response.

AEMO requested input on non-network options as alternatives to transmission network augmentation options in the *2025 Electricity Network Options Report* consultation to consider in preparing the 2026 ISP.

As per Section 3.4.3 of the CBA Guidelines, prior to the Draft ISP, AEMO is required to:

- undertake early engagement with non-network proponents to gather information in relation to non-network options, and
- if there are any credible non-network options identified through early engagement and joint planning, but not included in a Transmission Annual Planning Report, include these in its process for selecting development paths.

AEMO must seek proposals for non-network options for actionable ISP projects identified in a Draft ISP.

In the ISP, AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy. Depending on their relative costs and benefits, the capital costs of large network augmentation could be deferred or avoided by delivering a non-network solution.

The Draft 2025 *Electricity Network Options Report* invited submissions for proposals from non-network proponents. AEMO received several non-network options for the South West NSW REZ. AEMO has retained the existing proposed non-network option for South West NSW REZ, and suggests the size of the non-network option be refined to take into account the limits of the new lines through engagement with Transgrid and EnergyCo. Further information is provided in response to that submission in the 2025 *Electricity Network Options Report* consultation summary report.

A formal notice requesting submissions for non-network options for any identified actionable ISP projects will be published alongside the Draft ISP.

3.10.10 Network losses

Input vintage	July 2025
Source	AEMO *Marginal Loss Factors Report* 2025-26 Financial Year and internal processes
Updates since Draft 2025 IASR	AEMO replaced inter-regional loss equations with individual intra-regional loss equations to more granularly model the losses between sub-regions.

This section describes the loss equations, loss factor equations and proportioning factors inter-regional and intra-regional flows for use in studies such as the ISP and ESOO.

Inter-regional loss equations, loss factor equations and proportioning factors

Inter-regional loss equations are used to determine the amount of losses on an interconnector for any given transfer level. These are used to determine net losses for different levels of transfer between regions so NEMDE or AEMO's capacity expansion model and time-sequential market model can ensure the supply-demand balance includes losses between regions.

Inter-regional loss factor equations describe the variation in loss factor at one regional reference node (RRN) with respect to an adjacent RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units.

Interconnector loss proportioning factors are used to separate the inter-regional losses into the amount belonging to each of the two regions. The existing network inter-regional loss equations, loss factor equations and proportioning factors are sourced from the *Marginal Loss Factors for the 2024-25 Financial Year*[215] report and are presented in the 'Network losses' tab of the Draft 2025 *Inputs and Assumptions Workbook*.

[215] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf.

Intra-regional loss and loss factor equations

Inter-regional loss factor equations describe the variation in loss factor at one RRN with respect to an adjacent RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units.

In addition, AEMO models intra-regional loss equations, to capture the change in network losses as more generation connects to capture declining MLFs as large generation is developed in parts of the network remote from demand centres. Another instance for defining an intra-regional loss equation is to capture the change in network losses when a new sub-region is created which is remotely located from the reference node of that region.

In the 2026 draft ISP AEMO will replace inter-regional loss equations with individual intra-regional loss equations to more granularly model the losses between sub-regions. This improvement will better capture the economic dispatch of large generators and REZ that are built between regional reference nodes.

The 2025 *Inputs and Assumptions Workbook* 'Network losses' worksheet captures the proposed intra-regional loss factor equations.

3.10.11 Marginal loss factors (MLFs)

Input vintage	April 2025
Source	AEMO *Marginal Loss Factors Report* 2025-26 Financial Year and internal processes
Update since Draft 2025 IASR	Updated in line with AEMO's latest *Marginal Loss Factors Report*

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the power flow over the connecting lines and on the AC system increases, and so do losses.

Electrical losses are a transport cost that need to be priced and factored into electrical energy prices. MLFs are used to adjust the price of electricity in a NEM region, relative to the RRN, in a calculation that aims to recognise the relationship between a generator's output and the energy that is actually delivered to consumers. The NEM uses marginal costs as the basis for setting spot prices in line with the economic principle of marginal pricing. The spot price for electrical energy is determined, or is set, by the incremental cost of additional generation (or demand reduction) for each dispatch interval. Consistent with this, the marginal loss is the incremental change in total losses for each incremental unit of electricity. The MLF of a connection point therefore represents the marginal losses to deliver electricity to that connection point from the RRN.

In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue in the NEM wholesale market is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale renewable generation certificates (LGCs) created if accredited under the LRET.

MLFs are an outcome of applying the methodology for the calculation of Forward-Looking Transmission Loss Factors (updated in June 2025), and are updated every financial year with the publication of AEMO's *Marginal Loss Factors* report[216]. AEMO updated the MLFs to reflect the latest available version of this report. Where a committed or anticipated generator does not have an MLF calculated in the *Forward-Looking Transmission Loss Factors* report, a 'shadow' generator is used. This is a generator which is located electrically close to the generator in question, and where possible, is the same technology. This same concept is applied to generic new entrant generators.

See the 'Marginal Loss Factors' worksheet in the 2025 *Inputs and Assumptions Workbook*.

3.10.12 Transmission line unplanned outage rates

Input vintage	June 2025
Source	AEMO Network Outage Schedule and other AEMO sources
Update since Draft 2025 IASR	Updated in June 2025 as part of data collection process for the ESOO

AEMO models some unplanned outages on a limited selection of transmission flow paths that are required for inter-regional power transfer. Consistent with the NER 3.9.3C definition of unserved energy, AEMO does not consider any planned or unplanned outages on transmission elements that do not contribute to inter-regional energy transfer.

Information is collected on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts. **Table 40** shows the rates and method used in the 2025 ESOO, consistent with the *ESOO and Reliability Forecast Methodology*. Transmission line unplanned outage rates apply only to some reliability modelling. The ISP capacity outlook modelling does not include transmission outage rates, given their low probability.

Table 40 Inter-regional transmission flow path outage rates

Flow path	ESOO 2025 transmission UOR (%)	ESOO 2025 Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.29	21.1	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.76	3.9	Annual static
Murraylink – Credible Contingency	1.32	65.3	Annual static
Basslink – Credible Contingency	4.53	189.5	Annual static
Mortlake – South East (Victoria to South Australia) Credible Contingency	0.03	2.2	Annual, set to 0% post Project EnergyConnect Stage 2
Mortlake – South East (Victoria to South Australia) Reclassification	0.01	4.7	Annual, set to 0% post Project EnergyConnect Stage 2

216 At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

3.11 Power system security

Planning studies focus on the reliability and security of the future power system under system normal conditions and following the first credible contingency, including the continued availability of various system services to be able to restore the power system to a secure operating state within 30 minutes following a contingency.

New generation and transmission investments may change the scale and location of services needed for power system security. A changing mix of technologies, from synchronous generation towards inverter-based resources (IBR)[217], creates both challenges and opportunities for planning the future power system.

Planning assumptions for power system security are applied when developing the ISP. These must cater to uncertainties in future operation of synchronous generating units, demand levels, regulatory change, operational measures, emerging technology, and new innovations that may enable IBR to provide sought-after system services. AEMO's *Power System Requirements* document[218] describes power system security services in more detail, and the capabilities of various technologies to supply these services.

This section describes the inputs and assumptions made for the following power system security issues:

- System strength requirements and costs.
- Inertia requirements.
- Other system security limits.

3.11.1 System strength requirements and cost

Input vintage	December 2024
Source	AEMO internal, *System Strength Report*, Transmission Cost Database, and 2025 *Electricity Network Options Report*
Update process	Minimum system strength requirements updated to reflect latest *System Strength Report* and the 100% renewable study in the *2023 NSCAS Report*, costs and technology options will be updated to reflect the latest Transmission Cost Database and *Electricity Network Options Report*.
Update since 2024 ISP	Assumptions and methodology updated to explicitly model fault current requirements and the cost impacts of system strength solutions towards meeting both the minimum and efficient level requirements. Existing system strength standards for the NEM are provided at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning and may be further updated following the release of AEMO's annual *System Strength Report* (or subsequent updates to requirements in response to changing circumstances). The Draft 2025 *Inputs and Assumptions Workbook* has been updated with latest system strength remediation costs.

System strength describes the ability of the power system to maintain and control the voltage waveform at a given location, both during steady state operation and following a disturbance. System strength is often approximated by the amount of electrical current available during a network fault (fault level), however the concept also encompasses a collection of broader electrical characteristics and power system interactions.

[217] IBR include wind farms, solar PV generators, and batteries. They do not have moving parts rotating in synchronism with the grid frequency, but instead are interfaced to the power system via power electronic converters which electronically replicate grid frequency.

[218] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

Key aspects of system strength include steady state voltage management, voltage dips, fault ride-through, power quality and operation of protection.

Under the current system strength framework, AEMO assesses and maintains a system strength specification for the NEM, updated annually. This defines a set of physical locations on the transmission network (system strength nodes) at which AEMO must specify two system strength requirements:

- A **minimum fault level requirement** – intended to represent a secure operability requirement that, when met, ensures correct operation of network protection systems, appropriate operation of voltage control devices, and overall system stability following credible contingencies or protected events.
  - This requirement is specified as a fault level value and must be met by solutions capable of delivering protection-quality fault current. Technology options may include synchronous condensers, contracts with market participants to provide fault level services, or the conversion of existing thermal units into synchronous condensers.
- An **efficient level requirement** – intended to deliver additional investment in system strength, at optimised network locations, sufficient to accommodate and encourage future IBR connections near those locations.

This requirement is specified as a capacity of IBR that must be able to connect without voltage stability or synchronisation issues, assuming all other generator performance standards are met. As such, it can be met by any existing or new technology capable of improving the resilience of the local voltage waveform. This could include synchronous machines, as well as dynamic reactive devices, network reconfigurations, or grid-forming technology customised to the needs of specific network locations.

There are currently 23 system strength nodes defined in the NEM, and the process AEMO follows to develop minimum and efficient level requirements for each is outlined in the *System Strength Requirements Methodology*[219]. From 1 December 2025, regional System Strength Service Providers (SSSPs) are required to take all necessary steps to ensure both requirements are met at all times.

As part of the 2026 ISP, AEMO is proposing to model the cost of both components of system strength.

Minimum fault level requirements

The 2024 ISP used a set of declining unit commitment constraints to reflect an initial need to rely on thermal generation for meeting minimum fault level requirements. This constraint was relaxed over time to reflect that SSSPs will gradually procure or contract with alternative sources of fault current to meet their obligations. SSSPs may source from a portfolio of network solutions (in the form of synchronous condensers), or non-network solutions (in the form of commercial arrangements with gas, hydro, or eventually new grid-forming battery energy storage system [BESS] providers).

For the 2026 ISP, AEMO proposes to continue to use a declining unit commitment constraint, and to also include an additional cost component to retiring thermal generation to represent the cost of replacing their fault current contributions towards the minimum fault level requirements. This has the effect of providing the optimisation engine with a more reflective system security cost impact when withdrawing existing thermal units from service.

[219] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

To calculate the effective system strength remediation cost component for each unit, AEMO will implement outcomes from the 2023 and 2024 Network Support and Control Ancillary Services (NSCAS) reports, which found a need for approximately 22 strategically located synchronous condensers[220] to operate the system under 100% renewable conditions (that is, without coal-fired generation online).

The cost of these synchronous condensers is allocated to the retirement cost of existing coal-fired generating units in proportion to its rated fault current contribution, as a percentage of the total regional requirement.

Although AEMO expects that a mixture of technologies will be applied to meet minimum fault level requirements, synchronous condenser costs are being used as a proxy to represent an upper bound as a known and proven technology. Options such as retrofitting existing units, adding clutches to gas turbines, or leveraging grid-forming technology in the medium term[221] are all likely to contribute towards these requirements.

The Power System Security tab of the 2025 *Inputs and Assumptions Workbook* presents the assumed cost of system strength remediation for the minimum fault level requirements over time required to replace each coal unit. The average of this cost in the NEM is approximately $80 million per coal unit retirement. These costs, and the underlying technical parameters of synchronous condensers, have been updated to reflect the latest Transmission Cost Database and *Electricity Network Options Report*.

See the 'Power System Security' worksheet in the 2025 *Inputs and Assumptions Workbook*.

Efficient level requirements

In the ISP modelling, AEMO incorporates a $/kW efficient level cost as an addition to the IBR connection costs within a REZ, noting that in practice these would be funded directly by the TNSP rather than the connecting party themselves.

AEMO will use a weighted[222] cost trajectory approach to model these remediation costs as an added component to IBR connections. The effectiveness of grid-forming BESS towards these requirements is assumed to be 1.7 times lower than an equivalently sized synchronous condenser (that is, a 17 megavolt ampere [MVA] grid-forming BESS provides equivalent voltage stabilisation to a 10 MVA synchronous condenser). This is based on analysis undertaken in Transgrid's recent System Strength RIT-T[223]. This 1.7 factor is used to scale the cost of both technologies relative to each other when producing the weighted sum.

Grid-forming BESS technology is assumed to be available to provide efficient level services immediately.

The system strength costs tab of the 2025 *Inputs and Assumptions Workbook* presents the assumed cost of network and non-network solutions, their relative effectiveness and mixture over time, and the resulting efficient level system strength costs (in $/kW) to apply for new IBR connections. The input technology costs and parameters have been updated to reflect the latest Transmission Cost Database and *Electricity Network Options Report.*

[220] This is additional to synchronous condensers being added in the network for committed augmentations such as Project Energy Connect and Central-West Orana REZ Network Infrastructure Project, as well as no fossil fuel units such as hydro being online.

[221] Based on work done for the Transgrid System Strength RIT-T, grid-forming BESS are assumed to be capable and sufficiently demonstrated to provide protection quality fault current from 2032-33.

[222] The weighting reflects what percentage of the solution built per year can IBR based. This starts at 20% of IBR in 2024-25, and increases 10% per year until it reaches 90%.

[223] See Section 4.1.3 at https://www.transgrid.com.au/media/wphjea0f/2406-baringa_meeting-system-strength-requirements-in-nsw-padr-modelling-report.pdf.

See the 'Power System Security' worksheet in the 2025 *Inputs and Assumptions Workbook*.

Synchronous unit commitment assumptions

Input vintage	July 2025
Source	AEMO internal
Updates since 2024 ISP	Unit commitment trajectories updated to reflect latest AEMO Generator Information Page retirement timings, and current remediation option timing from the regional TNSP RIT-Ts for system strength.

As described in the previous section, an ongoing synchronous unit commitment constraint trajectory is used as a proxy for the required contribution of these units towards meeting system security requirements in the initial years of the 2026 ISP modelling.

The trajectory initially reflects the current operational minimum unit requirements that apply in the NEM and then progressively relaxes this requirement over a five-year period from 2027-28. This reflects decreasing reliance on these sources of system strength as TNSPs progressively procure alternative solutions via their active RIT-T processes. This trajectory does not force units to withdraw as the value decreases, rather it prevents units from retiring until the value decreases, at which point it allows retirements where economic (including the need to pay for replacement system strength services). For the *Accelerated Transition* scenario, AEMO assumes a faster decline in this trajectory to align with the rapid transformation of the economy and rapid decarbonisation assumed by the scenario.

A short-term two-unit constraint is applied in South Australia until Project EnergyConnect Stage 2 is fully commissioned, with all necessary protection and control schemes in place to manage credible loss of either Project EnergyConnect or the Heywood interconnector, at which point this constraint is relaxed. This approximately mirrors expected operational requirements, although there may be some operational periods prior to Project EnergyConnect Stage 2 where 1 unit is allowed (this granularity would be difficult to capture in an ISP model). AEMO does not use a fixed assumption for unit commitment requirements in Tasmania, because the region has a large number of small, distributed hydroelectric generators and a large number of machine combinations that can be used for power system security purposes.

Figure 77 and **Figure 78** provide the minimum synchronous unit commitment trajectories derived through the above approach. These assumptions are developed for the purpose of ISP planning studies, and should not be used as operational advice.

Figure 77 Minimum synchronous unit commitment requirements, all scenarios except *Accelerated Transition*

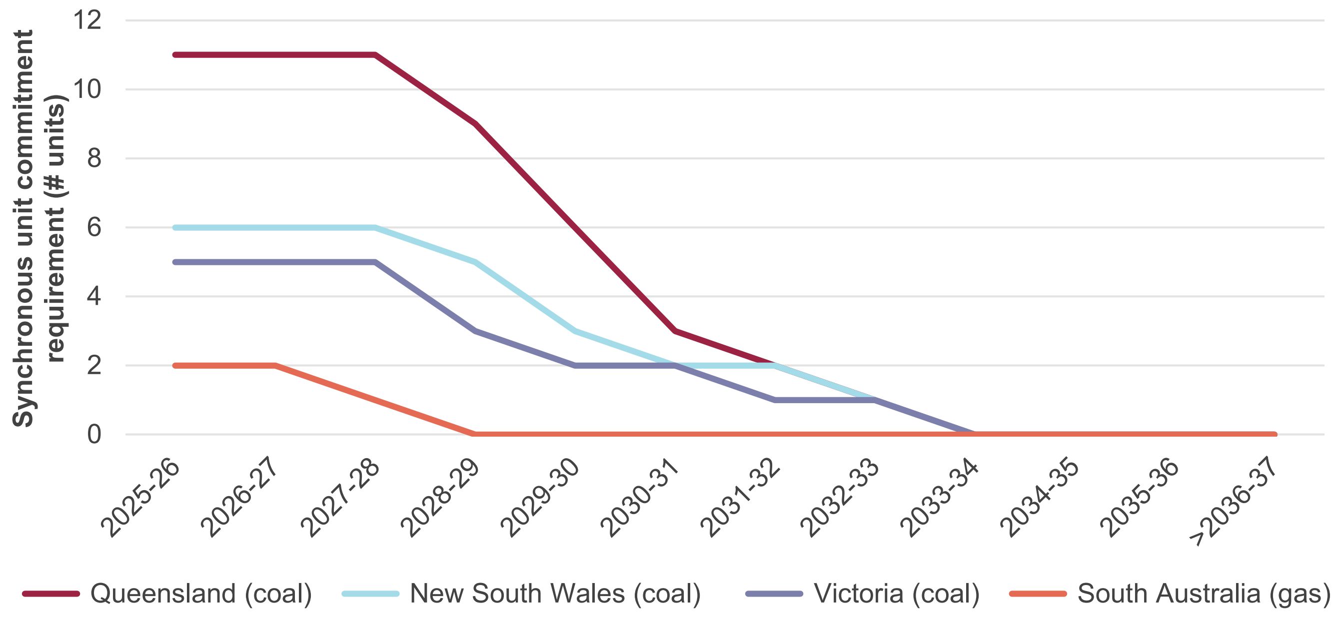
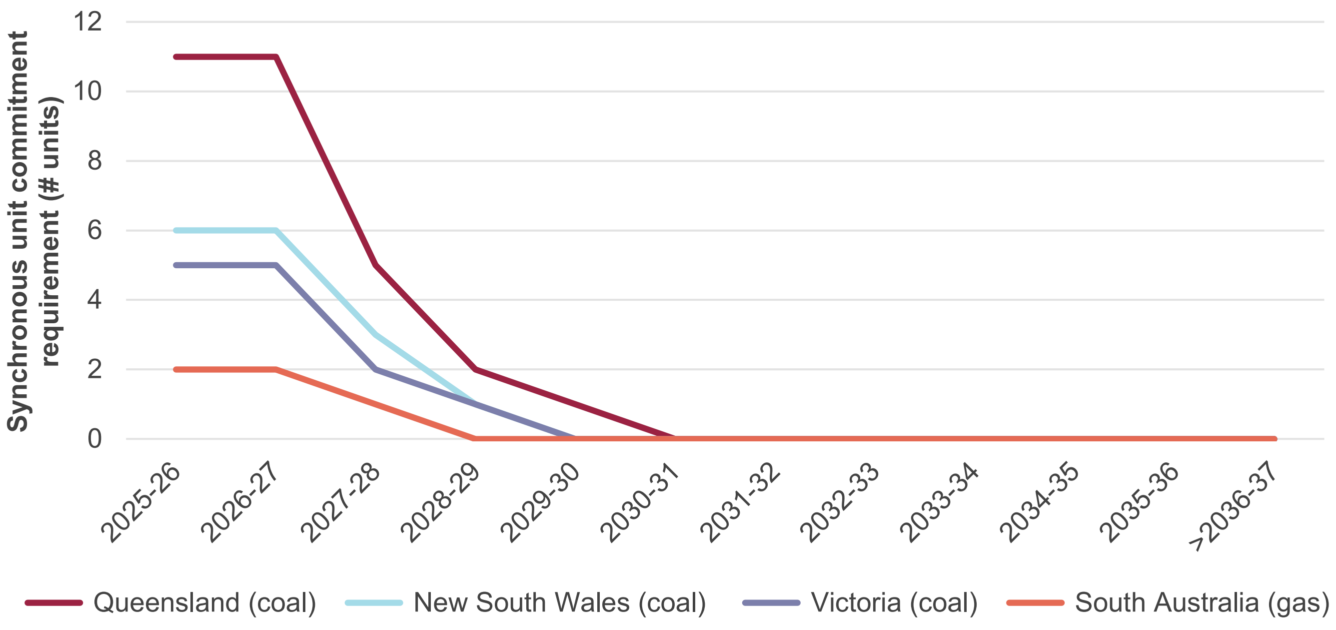


Figure 78 Minimum synchronous unit commitment requirements, *Accelerated Transition* scenario



3.11.2 Inertia requirements

Input vintage	December 2024
Source	Annual AEMO *Inertia Report*, applying the *Inertia Requirements Methodology*
Updates since 2024 ISP	Updated annually according to the latest inertia requirements calculation for each region of the NEM at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

Inertia allows the power system to resist large changes in frequency arising from an imbalance in power supply and demand due to a contingency event. Forecast inertia is continuing to decline across the NEM as synchronous generator behaviour changes, penetration of IBR increases, and minimum demand projections decline.

AEMO is required to assess and publish minimum inertia requirements for each region, under both islanded and interconnected operating conditions. AEMO's process for assessing these requirements is outlined in AEMO's *Inertia Requirements Methodology*[224] and AEMO's assessments for each region are published at least annually on AEMO's website[225].

Requirements are currently calculated based on the size of the largest credible contingency event in each region (or combination of regions). The full process AEMO follows to produce inertia requirements is outlined in the *Inertia Requirements Methodology*.

From 1 December 2027, regional TNSPs are required to take all necessary steps to ensure both the islanded and interconnected inertia requirements are satisfied in each region under the relevant system conditions.

AEMO's security assessments as part of the 2023 and 2024 NSCAS reports concluded that system strength would be the most onerous security requirement over the coming decades, and that delivering adequate services to meet those needs was likely to substantially resolve the need for additional inertia or voltage control investment. For example, technology solutions may include assets such as high-inertia synchronous condensers, or grid-forming technologies capable of providing both voltage stabilisation and synthetic inertia services.

In the ISP, AEMO will validate that all modelled outcomes satisfy the latest inertia requirements as published on AEMO's website. The costs associated with meeting these requirements are assumed to be second order, and therefore captured as part of delivering adequate system strength solutions (e.g. by ensuring some synchronous condensers have flywheels).

3.11.3 Other system security limits

Input vintage	July 2023
Source	AEMO internal and TNSP limits advice
Updates since 2024 ISP	None – consistent network constraint-based approach.

In NEMDE, a series of network constraint equations control dispatch solutions to ensure that satisfactory and secure network limitations are considered. The time-sequential model used in long-term planning studies contains a subset of the NEMDE network constraint equations to achieve the same purpose. This subset of network constraint equations is included in the ISP model to reflect power system operation within other security limits. In addition to system strength and inertia limits which are considered above, these include:

- voltage stability – for managing transmission voltages so that they remain at acceptable levels after a credible contingency,
- transient stability – for managing continued synchronism of all generators on the power system following a credible contingency,

[224] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[225] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

- oscillatory stability – for managing damping of power system oscillations following a credible contingency, and
- rate of change of frequency (RoCoF) – for managing the rate of change of frequency following a credible contingency.

The effect of committed transmission and generation projects on the network is implemented in NEMDE as modifications to the network constraint equations that control power flow. The methodology for formulating these constraints is in AEMO's Constraint Formulation Guidelines[226].

Other system security limits may need to be applied on a case-by-case basis as more information becomes available, for example to ensure frequency control services or to account for non-credible contingencies in some cases such as the trip of double-circuit interconnectors.

3.12 Gas infrastructure

Input vintage	July 2025
Source	CSIRO: *GenCost 2024-25; 2025 GSOO;* AEMO analysis
Updates since 2023 IASR	Gas supply model inputs have been updated to reflect the 2025 GSOO New gas supply development model inputs, published in detail in the 2025 *Gas Infrastructure Options Report* Electrolyser cost has been updated to reflect *GenCost 2024-25* Water costs included, moved to Section 3.3.6 Hydrogen consumption locations updated

This section outlines key inputs and assumptions related to natural gas, hydrogen and biomethane production and infrastructure. Hydrogen demand assumed across scenarios is discussed in Section 3.3.6 .

3.12.1 Natural gas and biomethane

Existing infrastructure

AEMO's gas supply model evaluates the production, storage, and transportation capacity of Australia's ECGM to assess the adequacy of gas supply to gas consumers.

The gas production capacities, midstream infrastructure gas delivery limits and production costs are key input assumptions into the gas supply model. These inputs are provided from gas industry participant surveys submitted for the development of the GSOO, and complemented with publicly available data or gas specialist consultants' insights. The 2025 GSOO published forecast gas demand, existing production capacity, and information relating to new gas supply and infrastructure developments.

AEMO will use relevant information developed for the 2025 GSOO[227] to support biomethane and natural gas production cost and technical capabilities. Assumptions for biomethane resource volumes and costs can be found in Section 3.3.6.

[226] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

[227] At https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Table 41 summarises key inputs and related data sources for the gas supply model, consistent with the 2025 GSOO.

Table 41 Key inputs and the related data sources for the gas supply model

Input	Source
Demand projections	AEMO Forecasting Portal, at http://forecasting.aemo.com.au
Capacity of reserves and resources	Gas industry participants via the Gas Bulletin Board (GBB), and publicly available data (in case of lack of data, Rystad Energy estimates), at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo)
Production costs	Rystad Energy and publicly available data; Rystad Energy data at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo
Gas transmission pipeline tariffs	Gas industry participants and publicly available data
Pipeline, processing, storage facility capabilities and daily rates	Gas industry participants and publicly available data GBB available at: http://gbb.aemo.com.au/
Annual and daily field production limits	Gas industry participants, and internal AEMO analysis

Gas infrastructure options

Building on the gas supply model, AEMO's gas supply development model will test a suite of potential gas development options to determine where supply, storage and infrastructure options or augmentations could be located to meet ISP development pathways using gas development projections under different scenarios and to maintain appropriate adequacy of gas supplies in the ECGM. The use of GSOO-specific datasets is enabled due to the rules made to implement the *Better integration of gas and community sentiment into the ISP* rule change[228].

The gas supply development model uses the same inputs and data sources as the gas supply model, as described in **Table 41**, as well as additional inputs and assumptions which are published within the 2025 *Gas Infrastructure Options Report*, including gas development options for use in identifying the gas development projections and cost estimates for gas infrastructure.

The known options in the 2025 *Gas Infrastructure Options Report* are informed by:

- projects and information provided by stakeholders via surveys for the 2025 GSOO or previously proposed projects provided to AEMO for past GSOOs – this may also include projects and information that may be provided to AEMO for the 2026 GSOO,
- analysis undertaken for the gas Victorian Transmission System as part of the 2025 *Victorian Gas Planning Report*, and
- other public projects or projects informed by stakeholder submissions.

In addition to known options, AEMO will include a set of generic options which are informed by typical augmentations that could be undertaken in future. The generic options will be limited to feasible sizes, technical capability and locations.

There are four categories of options:

[228] National Electricity Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024 No. 25. See https://www.aemc.gov.au/rule-changes/better-integration-gas-and-community-sentiment-isp-0.

- **Transport options** – including options that expand the transportation capacity of the ECGM, including compression and pipeline options.
- **Storage options** – including options that expand the gas storage inventory or injection capacity of the ECGM, including aboveground storage, underground storage and pipeline storage options.
- **Production options** – including options that expand the gas production plant capacity or production supply of the ECGM, including natural gas processing plant, biomethane processing plant and the processing of contingent resources.
- **Regasification options** – including options that expand the capacity of the ECGM to receive, store and process LNG back into its gaseous state before injecting the gas into the transmission pipeline network.

Gas infrastructure costs

AEMO engaged GHD to provide a comprehensive dataset to support its forecasting and planning functions related to the cost of expanding and operating traditional gas infrastructure, as well as renewable gas developments, and to include a cost forecasting approach across the planning horizon for use in the 2026 ISP.

The asset types studied by GHD include:

- natural gas pipelines, processing facilities, compression facilities, and storage facilities,
- LNG regasification terminals and all associated equipment,
- CCS-related infrastructure,
- new hydrogen transport options including trucking and pipelines,
- biomethane production,
- coal seam gas desalination plants, and
- water pipelines related to coal seam gas desalination plants.

Additional information is provided for new natural gas infrastructure such as:

- lead time for building,
- operating cost,
- cost of upgrading the capacity,
- cost of refurbishing existing assets,
- cost of retirement and decommissioning, and
- expected technical life for existing natural gas pipelines.

Refer to the 2025 *Gas Infrastructure Costs Report* and associated databases published with the 2025 *Gas Infrastructure Options Report* for detailed information on the data provided by GHD.

Gas supply zones

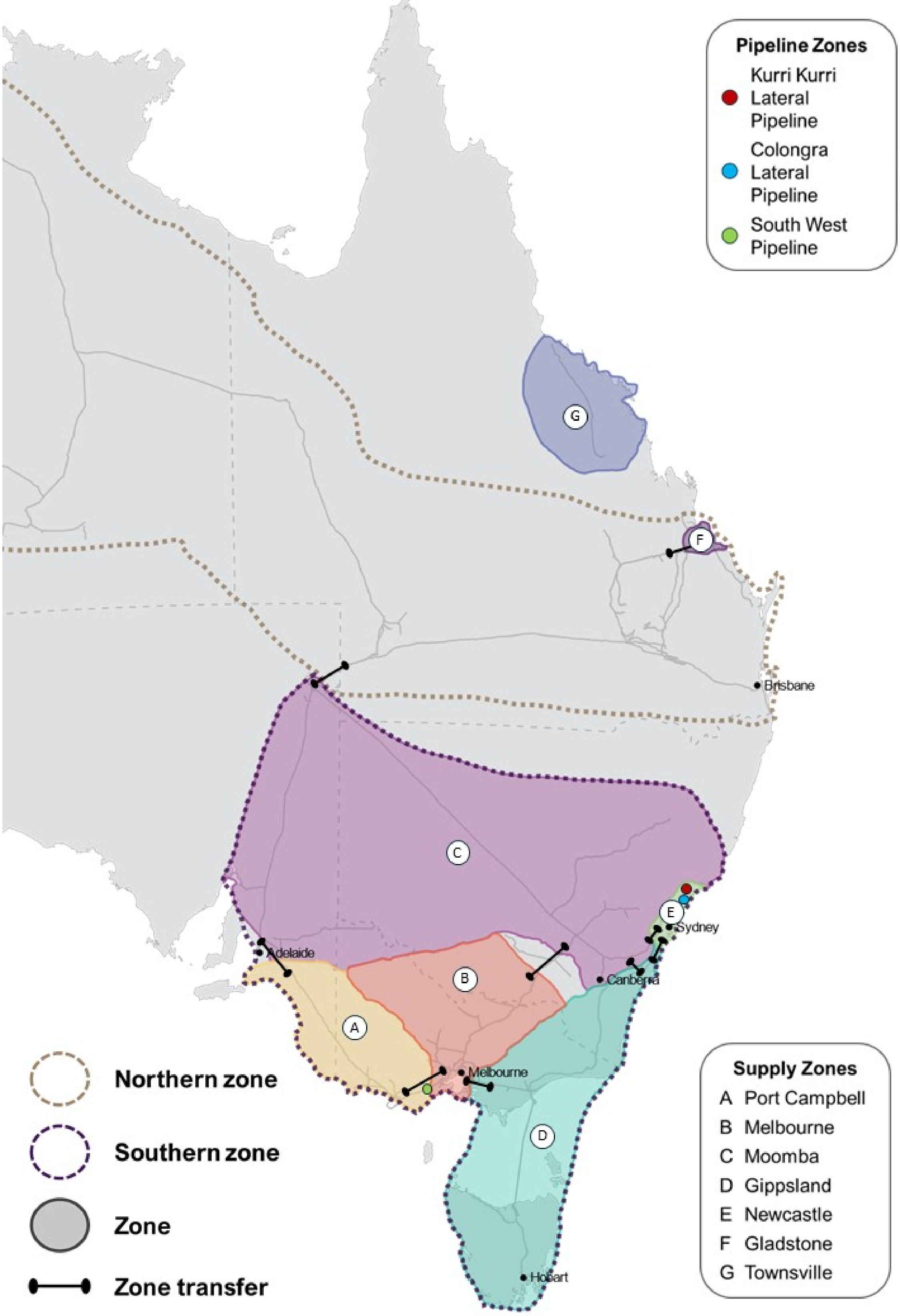
Gas fuel limitations for gas-powered generation will be input to the electricity capacity outlook model. Rather than applying daily gas fuel limits for each individual generator, which would be unnecessarily constraining, or at the

NEM sub-regional level, which would not accurately capture gas supply and transportation limitations, AEMO intends to calculate daily supply limits for 12 gas supply or pipeline zones. The daily gas fuel limit is the total gas supply available to all gas-powered generation in a given zone.

The daily gas fuel limit for gas-powered generation in each zone is calculated as the total supply capacity (including supply, storage and infrastructure capacity limitations) minus the forecast consumption from residential, commercial and industrial demand in that zone. The total supply capacity changes over time, and takes into account new supply or infrastructure identified in the gas development projections. All gas fuel limitations for gas-powered generation assume that residential, commercial and industrial gas demand is satisfied first.

The ECGM gas supply zones are shown in **Figure 79**.

Figure 79 Supply and pipeline zones for the East Coast Gas Market



3.12.2 Hydrogen

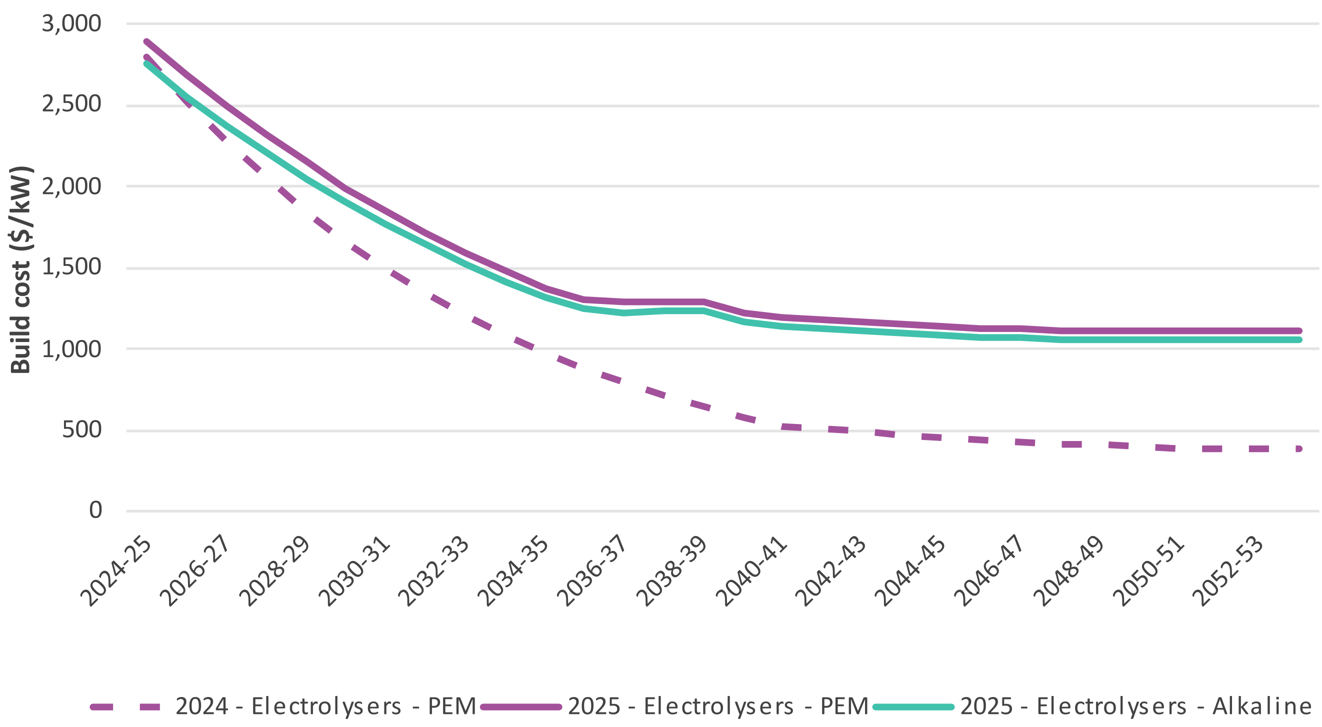
Production costs and capabilities

AEMO's hydrogen production forecasts assume that electrolysis will be the technology deployed at large scale to support future hydrogen demand in the energy transition[229]. Electrolysis uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from zero-emissions generation it creates 'green hydrogen'. Given projected costs for alkaline technology are lower than those for PEM technologies, and aligned with stakeholder feedback that alkaline is currently preferred over PEM for proposed electrolyser developments due to its cost and maturity, AEMO has aligned its cost and technical assumptions to alkaline electrolysers in the 2026 ISP.

Figure 80 below presents the capital cost projections for new alkaline electrolyser installations as forecast in *GenCost 2024-25 Final Report* for the Global NZE post 2050 scenario, compared to projections from the *GenCost 2023-24 Final Report* for PEM electrolysers (which were assumed for the 2024 ISP). Relative to the 2023-24 projections there has been an increase in hydrogen electrolyser cost in the long term, driven by updated analysis of balance of plant costs and slower cost reductions over time. See Section 3.5.3 for more detail on the scenario mappings between the *GenCost 2024-25 Final Report* and 2025 IASR scenarios.

Cost projections for alkaline electrolysers for each scenario are available in the accompanying 2025 *Inputs and Assumptions Workbook*.

Figure 80 Forecast build cost trajectories for electrolysers, 2024 versus 2025 Global NZE post 2050 scenario ($/kW)



[229] Some hydrogen is currently produced via steam methane reforming – this existing production is assumed to continue but with minimal growth, hence its infrastructure needs are not considered in the ISP.

Electrolysers are assumed to be capable of operating flexibly, providing capacity to ramp up and down rapidly, potentially even providing fast frequency response in a similar way to electrochemical batteries. AEMO models alkaline electrolysers with a flexible technical operating envelope with a minimum baseload component (covering balance of plant loads that require continuous operation), and a minimum utilisation factor as follows:

- Balance of plant load is assumed at 5.4%[230], applied as a baseload operating level.
- AEMO applies a *minimum utilisation factor* for electrolyser operations in the ISP models, to reflect industry feedback on feasible economic operation. This is described in Section 3.3.6.

The ISP modelling will include these factors to forecast the appropriate electrolyser capacity (and therefore flexibility) to meet the hydrogen production volume targets of each modelled scenario, meaning that the cost of either highly flexible (with high installed capacity) or minimal flexibility (with low surplus production capacity) is captured, considering the capital investment costs and operating costs of each.

Infrastructure

Electrolyser location

The 2026 *ISP Methodology*[231] details how the ISP model considers different hydrogen supply pathways. This includes consideration of electrolyser location for hydrogen production relative to location of hydrogen consumption. Hydrogen may be consumed either close to, or remote from, the location in which it is produced. As explained in the 2026 *ISP Methodology*, a shortlist of REZs that can potentially host hydrogen electrolysers are considered to reduce model complexity and computational burden by limiting potential combinations and constraints while maintaining accuracy in the modelling process.

Hydrogen consumption location

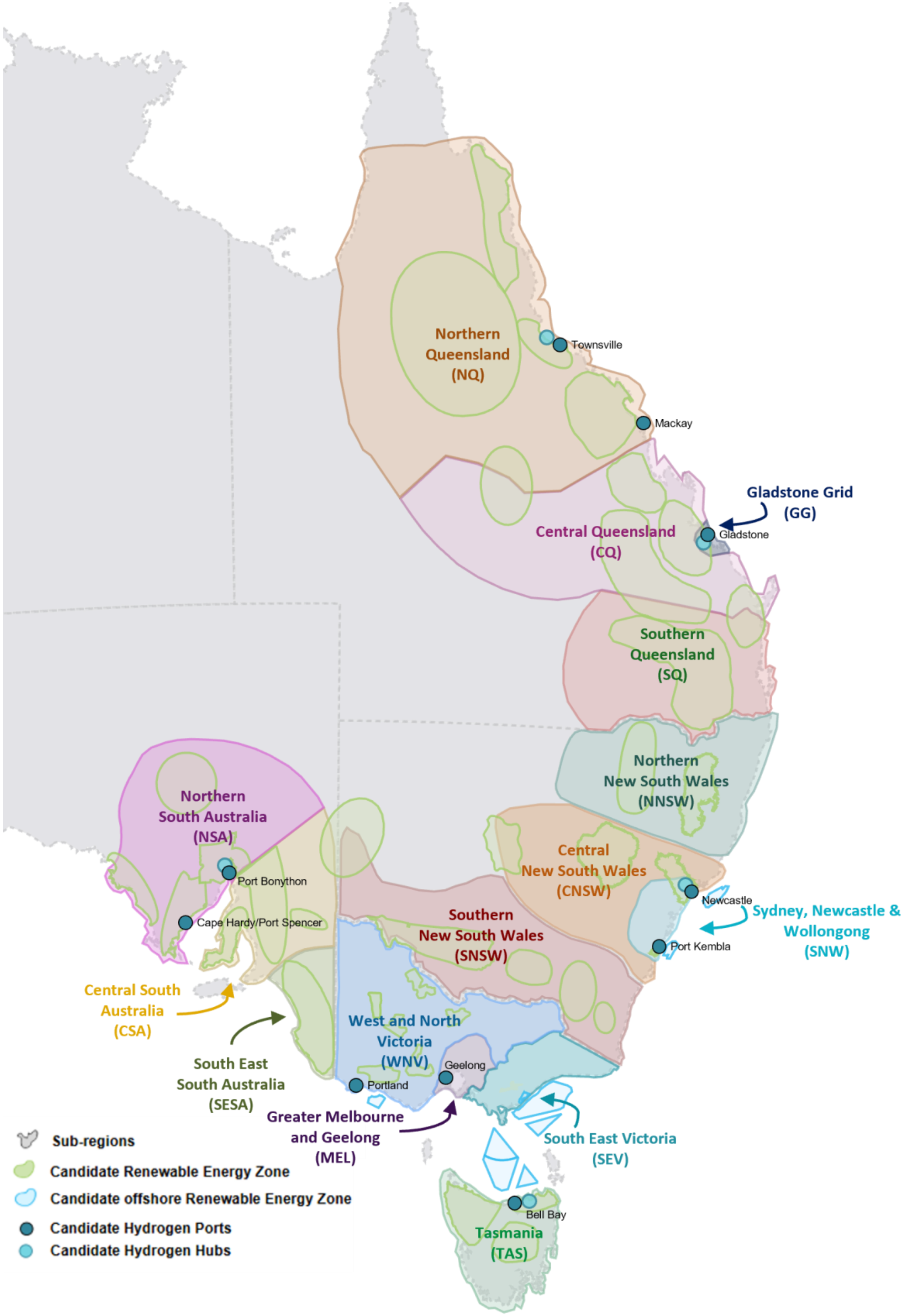
It is assumed that hydrogen consumption will occur in general industrial areas close to cities, in new industrial precincts that may support commodity manufacture (expected to be close to major ports for commodity and hydrogen export), and/or in distributed transport stations located along major trucking routes. Industrial use may be clustered around hydrogen hubs, which are locations where producers, users and exporters of hydrogen work side by side to share infrastructure and expertise. The currently nominated hydrogen hubs are all located in close proximity to a port.

Figure 81 shows the distribution of candidate hydrogen hubs, and ports for export of hydrogen and green commodities, overlaid with the 2025 IASR sub-regions and candidate REZs.

[230] Bloomberg New Energy Finance (BNEF) report: Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech (March 2024).

[231] At https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

Figure 81 Candidate hydrogen and green commodity export ports, and hydrogen hubs



For the purpose of ISP modelling, domestic hydrogen consumption for each sub-region is assumed to be located as shown in **Table 42** (in priority order)

Table 42 Assumed location of domestic hydrogen consumption by ISP sub-region type

Type of sub-region	Assumed location of hydrogen consumption
Contains a candidate hydrogen hub	Hydrogen hub
Contains a candidate hydrogen port but no hub	Hydrogen port
Contains neither a candidate hub nor port	Sub-regional reference node (note this is where the hydrogen is assumed to be consumed, but is not necessarily the location of the electrolysers)

Regional hydrogen consumption for exports and/or green commodities is assumed to be concentrated within a single sub-region and is located as shown in **Table 43** (in priority order).

Table 43 Assumed location of export and green commodity hydrogen consumption by ISP region type

Type of region	Assumed location of hydrogen consumption
Contains a candidate hydrogen hub	Hydrogen hub
Contains a candidate hydrogen port but no hub	Hydrogen port

The complete mapping of ISP sub-region to hydrogen consumption type is documented in the *Inputs and Assumptions Workbook*[232].

The candidate hydrogen hubs include locations aligned with recent Federal Government announcements[233], covering New South Wales, Queensland, Tasmania and South Australia. The potential hydrogen and green commodity export ports remain unchanged from the 2023 IASR.

Water supply

Section 3.3.6 describes the inclusion of water costs in the multi-sectoral modelling and the ISP.

3.13 Employment factors

Input vintage	September 2024
Source	Rutovitz, J., Gerrard, E., Lara, H., and Briggs, C. (2024). *The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050*. Prepared by the Institute for Sustainable Futures for RACE for 2030[234].
Updates since 2023 IASR	Updated job-years for generation, storage and transmission development per outcomes of 2024 ISP.

[232] See https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

[233] See https://www.dcceew.gov.au/energy/hydrogen/building-regional-hydrogen-hubs.

[234] At https://aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.

Electricity sector employment is forecast to increase by 74% by 2050 (from 33,300 full time workers[235] in 2024 to 57,900 in 2050), in the *Step Change* scenario from the 2024 ISP[236]. This growth will challenge engineering, procurement and construction (EPC) firms and regional communities, particularly if there are boom-and-bust cycles or if workers and contractors are engaged project-to-project. Governments are aware of these challenges in shaping new and existing labour force and skills policies[237] and with proactive planning, this challenge could represent an opportunity.

This section outlines the proposed employment factors that will be used to estimate the workforce requirements needed to implement the ISP. The focus on workforce requirements in this estimation is focused on infrastructure development requirements; it does not include the workforce requirements to deliver electrification developments or other factors affecting the evolution of the consumer load in the energy transition.

AEMO sourced employment factors for generation, transmission and storage from "The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050", a renewable energy industry report prepared by the Institute for Sustainable Futures (ISF) for Reliable Affordable Clean Energy (RACE) for 2030.

Employment factors are derived from industry surveys of developers, installers and original equipment manufacturers conducted by the ISF. These surveys collect a breakdown of occupational data across sectors for construction, installation, operations and maintenance of recent actual projects and activities.

3.13.1 Generation and storage

Employment factors are applied to the capacity of generation and storage build to estimate workforce requirements. Employment factors reduce over time in proportion with technology costs (see Section 3.5.3) to reflect productivity improvements.

[235] These numbers represent number of full time equivalent jobs.

[236] At https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

[237] SGS Economics and Planning Pty Ltd & UTS Institute for Sustainable Futures. *Towards A Renewable Energy Superpower*. April 2024. At https://www.uts.edu.au/sites/default/files/2024-04/Renewable%20Energy%20Superpower%20Report%202024%2060pp%20WEB%20SPREAD%201.pdf.

Table 44 Generation and storage employment factors

	Construction time[A]	Construction / installation[B]	Manufacturing[B]	Australian Manufacturing[B]	Operations and Maintenance (O&M)[B]	Fuel[B]
	Years	Job-years/MW[C]	Job-years/MW	Job-years/MW	Jobs/MW	Job-years/GWh
Black coal	5	11.08	5.41	1.62	0.22	0.04
Brown coal	5	11.08	5.41	1.62	0.22	0.01
Gas	2	1.27	0.92	0.28	0.14	0.07
Wind (onshore)	2	2.65	1.54	0.35	0.21	-
Wind (offshore)	3	1.50	13.68	0.90	0.20	-
Utility-scale PV	1	1.61	3.08	0.07	0.09	-
Rooftop PV	1	4.19	2.86	0.12	0.13	-
Utility-scale batteries	1	0.53	0.50	0.08	0.03	-
Distributed batteries	1	4.44	0.50	0.08	0.23	-
Pumped hydro	4	7.18	3.48	0.70	0.08	-
Hydro	5	7.36	3.48	1.04	0.14	-

A. Rutovitz, J., Langdon, R., Mey, F., Briggs, C. *The Australian Electricity Workforce for the 2022 Integrated System Plan: Projections to 2050. Revision 1.* January 2023. At https://aemo.com.au/-/media/files/major-publications/isp/2022/supporting-materials/the-australian-electricity-workforce-for-the-2022-isp.pdf.
B. Rutovitz, J., Gerrard, E., Lara, H., and Briggs, C. *The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050.* September 2024. At https://aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.
C. One job-year represents one job over the course of the year at full-time capacity.

3.13.2 Transmission

Employment factors are applied to transmission build to estimate workforce requirements. Because transmission construction is relatively mature, employment factors for transmission development do not reduce over time.

Table 45 Transmission employment factors

Transmission build	Construction/installation
Transmission line: single circuit	0.70 (job-years/km)[A]
Transmission line double circuit	3.7 (job-years/km)
Transmission (other)	1.90 (job-years/$million)

A. One job-year represents one job over the course of the year at full-time capacity.

A1. ISP Review implementation measures

Over 2023 and early 2024, the Federal Government undertook a review of the ISP[238] (Review of the ISP), and on 5 April 2024, the Energy and Climate Change Ministerial Council (ECMC) published the *Response to the Review of the Integrated System Plan*[239] (Energy Ministers' response to the Review of the ISP).

The response outlined a series of actions to enable the ISP to set a direction for the energy system as a whole, while maintaining the critical function of the ISP in transmission planning. The Review of the ISP focused on supporting emissions reduction, integrating gas and electricity planning, enhancing demand considerations, transformation of Australia's energy mix, jurisdictional policy interactions, and the timely delivery of ISP projects.

In December 2024, the AEMC made new rules[240] that addressed some of the ECMC-endorsed recommendations from the ISP Review. The new rules to improve consideration of demand-side factors and better integrate gas and community sentiment expand the scope of the ISP and AEMO is carefully considering the breadth of inputs and assumptions necessary to support this.

AEMO's approach to implementing new methods to address the actions identified in the Energy Ministers' response to the Review of the ISP is documented in the *ISP Methodology*, while new inputs needed to apply AEMO's updated methods are outlined in this 2025 IASR.

Table 46 below shows the publications that AEMO has amended or proposes to amend to address each Review of the ISP action or rule change, to help inform engagement by stakeholders on appropriate publications.

[238] Australian Government, Department of Climate Change, Energy, the Environment and Water. *Review of the Integrated System Plan – Final Report*, January 2024. At https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Energy_Planning_and_Regulation_in_Australia/EnergyPlanning/Additional_Documents.

[239] See https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

[240] See https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp and https://www.aemc.gov.au/rule-changes/better-integrating-gas-and-community-sentiment-isp.

Table 46 Implementation for actions in the Energy Ministers' response to the Review of the ISP

Action in the response to the Review of the ISP	Updated to reflect full/partial implementation				
	2025 IASR	*ISP Methodology*	*2025 Electricity Network Options Report*[A] and 2025 *Gas Infrastructure Options Report*[B]	*Enhanced Locational Information Report*[C]	Draft ISP and final ISP
Integrating gas into the ISP	✓	✓	✓		✓
Enhanced demand forecasting and optimising for the demand-side	✓	✓	✓		✓
Better data on industrial and consumer electrification					✓
Coal-fired generation shutdown scenarios					✓
Improving locational information				✓	✓
Enhanced analysis of system security	✓	✓			✓
Jurisdictional policy transparency	✓[E]				✓
Clarifying policy inclusions	✓[E]				✓
Improving the accessibility of the ISP	✓				✓
Incorporating community sentiment	✓		✓		✓
Additional planning inputs	✓				✓

A. The *Electricity Network Options Report* forms part of the IASR. It was previously known as the *Transmission Expansion Options Report*, but has been renamed to reflect the inclusion of both transmission and distribution in future ISPs.
B. The *Gas Infrastructure Options Report* was released as draft in May 2025 and final in July 2025 to support better integration of gas into the ISP.
C. The *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.
D. AEMO will consider opportunities throughout the ISP development process to enhance consumer understanding of key elements.
E. These actions were implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions. The guideline is available at https://aemo.com.au/-/media/files/major-publications/isp/2026/consultation-with-jurisdictions-for-the-integrated-system-plan.pdf?la=en.

A2. Hydro scheme details

This appendix includes descriptions of each of the hydro schemes as modelled by AEMO.

The detailed scheme representations described in this appendix apply to the time-sequential modelling and a simplified representation may be used in the capacity outlook modelling. For information on the functions of the different types of modelling, refer to the *ISP Methodology*.

As outlined in Section 3.4.5, the following categories of hydroelectric facilities are distinguished within AEMO's modelling:

- **Power-only** – where the storage and release of water at the actual hydro scheme is purely used for the purposes of power generation by the hydro scheme operator. This allows stored water to be used at any time, principally when it is most advantageous for power generation purposes.
- **Primary Hydroelectric** – where the storage and release of water is primarily used by the hydro scheme operator for power generation, which is typically managed within a one-year inflow release cycle.
- **Secondary Hydroelectric (Irrigation)** – where the storage and release of water is influenced by irrigation release requirements, with the management of water for power generation purposes being secondary to irrigation requirements.
- **Run-of-river (or operationally similar)** – where storage is small relative to water inflows and the hydro scheme operator has limited ability to hold water in storage for the purposes of managing power generation.
- **Pumped Hydro Schemes** – representing closed-loop systems where the storage and use of water is the primary means to support power generation, and natural water inflows (and evaporation) aren't material in the operation of the scheme.

A2.1 Snowy Hydro scheme (Primary Hydroelectric)

AEMO's has refined its approach to modelling and inflows for the two sub-schemes of Snowy Hydro, and includes key assumptions to reflect the operational mechanics of this sophisticated scheme, including:

- operational constraints between the cascading reservoirs (including each reservoirs significant volumes), and
- pumping capabilities, where appropriate, and other influences affecting water flow, including environmental releases.

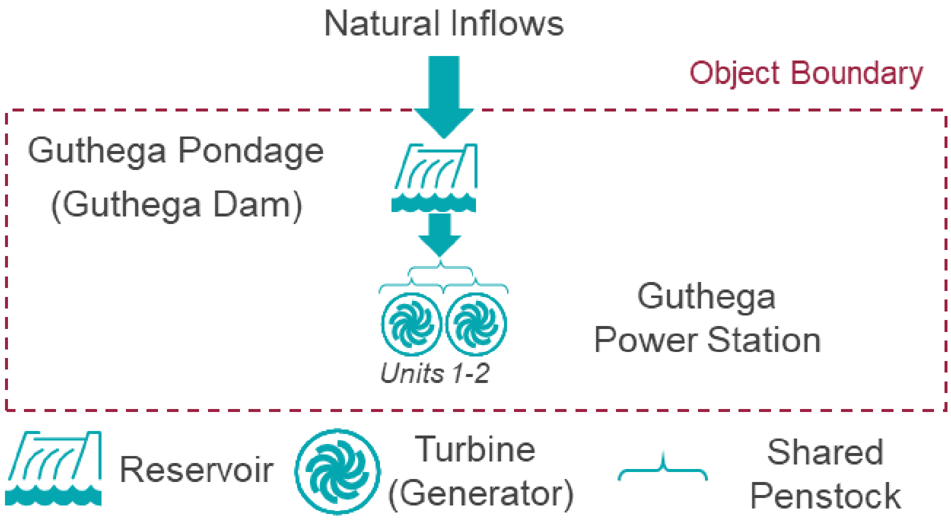
Detailed representations of each interrelated scheme are in the following sub-sections. While the Snowy scheme reflects a complex connection of multiple power stations, dams, reservoirs, pondages, pumping stations and tunnelling systems, AEMO's representation – as described in this section – may apply some simplifications to some of these interconnected elements that do not materially impact operational capabilities, and improve model performance. For specific information regarding the Snowy scheme, refer to the Snowy Hydro website[241].

[241] See https://www.snowyhydro.com.au/generation/the-snowy-scheme/.

A2.1.1 Guthega

Due to the small size of Guthega Pondage relative to potential inflows, Guthega Dam frequently spills during wet weather events and not all inflows can be converted into power (including a small portion of environmental releases below the dam). AEMO's storage assumptions allow inflows to effectively 'spill' depending on modelled weather conditions and modelled generator operations, and does not capture the connected nature of downstream storages with other hydros in the scheme.

Figure 82 Model Representation of Guthega (part of Snowy-Murray Scheme)



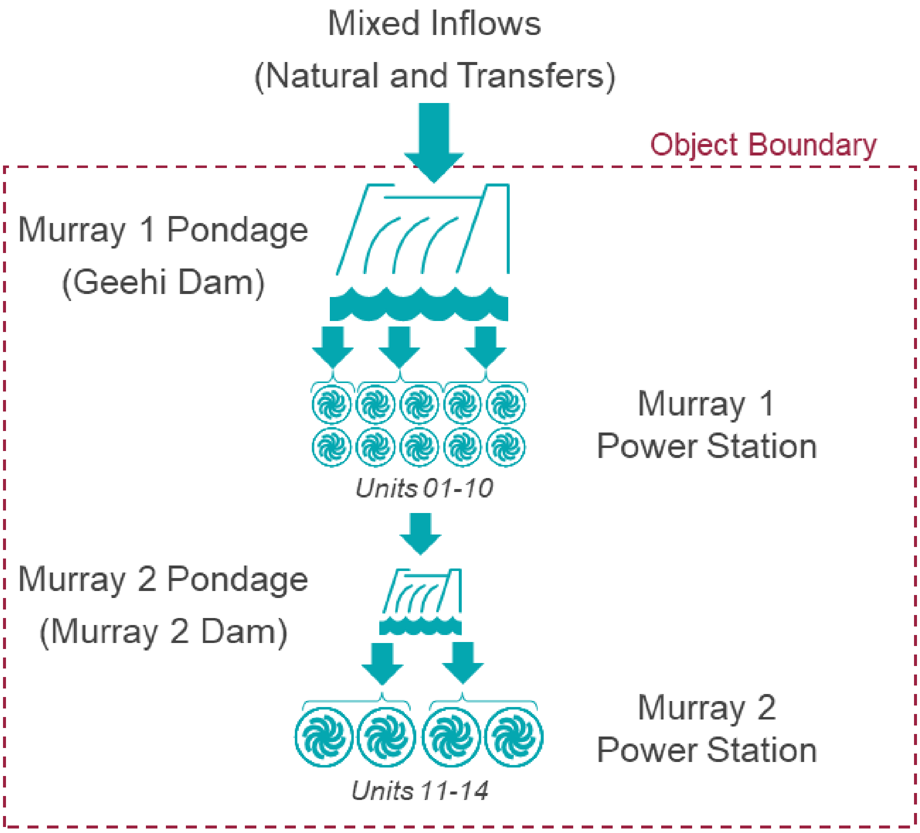
A2.1.2 Murray

Murray 1 Pondage, known as Geehi Dam, primarily receives direct inflows from the Geehi River and several other aqueducts. When inflows are low, scheme inflows previously stored in Eucumbene can be transferred to Geehi via gravity flow, and additional flows can be pumped up from Jindabyne Reservoir to preserve inflows in Eucumbene for later use.

Murray 2 Pondage can only receive water from Murray 1 via the Murray 1 generator tailrace, as under dam releases[242] and spillage do not physically flow downstream into the Murray 2 Pondage (this is not the case in the Tumut scheme). Due to the smaller size of the Murray 2 Pondage and larger size of the turbines in Murray 2 relative to Murray 1, Murray 2 can be readily constrained if insufficient Murray 1 units are discharging water for the larger Murray 2 units to maintain full power output. This material constraint can only be modelled with the cascading method as shown in **Figure 83**.

[242] Controlled outflows via the river outlet conduits, allowing water to be released through or under the dam.

Figure 83 Model Representation of Murray 1 & 2 (part of Snowy-Murray Scheme)

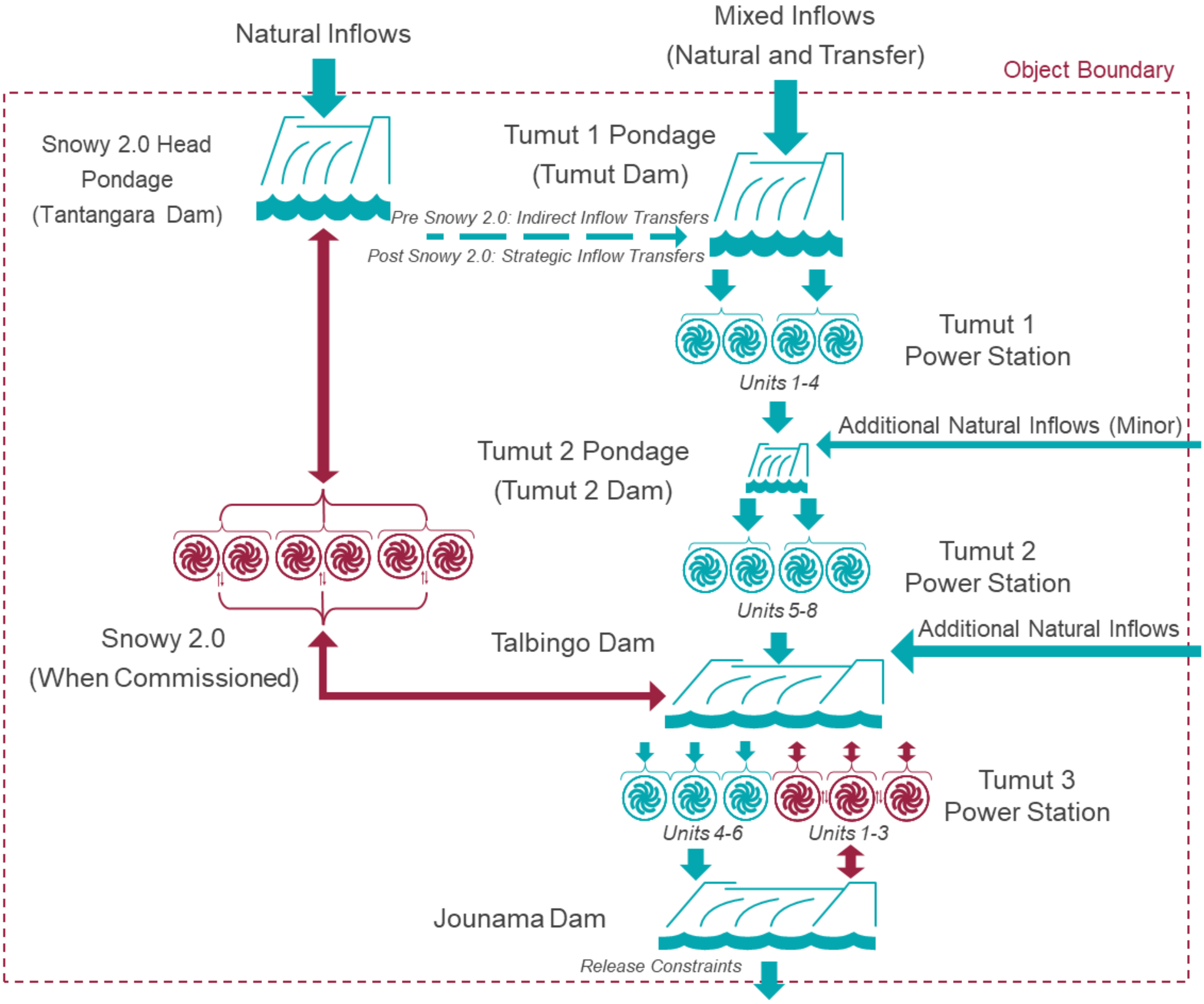


A2.1.3 Tumut (and Snowy 2.0)

Figure 84 shows the modelled representation of the Tumut sub-scheme. Tumut 1 receives inflows directly from aqueducts connected to the Tooma-Tumut tunnel and also spills from the small diversion dam Happy Jacks, which captures inflows from the Tumut River and Happy Jacks River (typically storing those inflows into Eucumbene during high flows to preserve head potential). Tooma Reservoir acts as an upstream storage capturing inflows from the Tooma River, providing additional inflows to Tumut 1 as required. Before Snowy 2.0 is commissioned, inflows into the Tantangara Reservoir (Murrumbidgee River) are typically strategically released into Eucumbene, and subsequently transferred to Tumut 1 during low inflows directly available to Tumut 1.

Once Snowy 2.0 is commissioned, due to the higher potential energy of Tantangara inflows if used directly through Snowy 2.0 instead of transfers to Tumut 1 (via Eucumbene), it is unlikely inflows into Tantangara will be transferred to Tumut 1 as occurred historically. The inflow traces into Tumut 1 reflect this.

Figure 84 Model Representation of Tumut 1, 2, 3, and Snowy 2.0 (part of the Snowy-Tumut Scheme)



Tumut 1 releases (or spills) flow downstream into the Tumut 2 pondage, and likewise Tumut 2 releases (or spills) flow downstream into Talbingo. This allows all downstream dams in Tumut to be pre-filled, particularly during negative price periods.

A2.2 Tasmanian hydro scheme (Primary Hydroelectric)

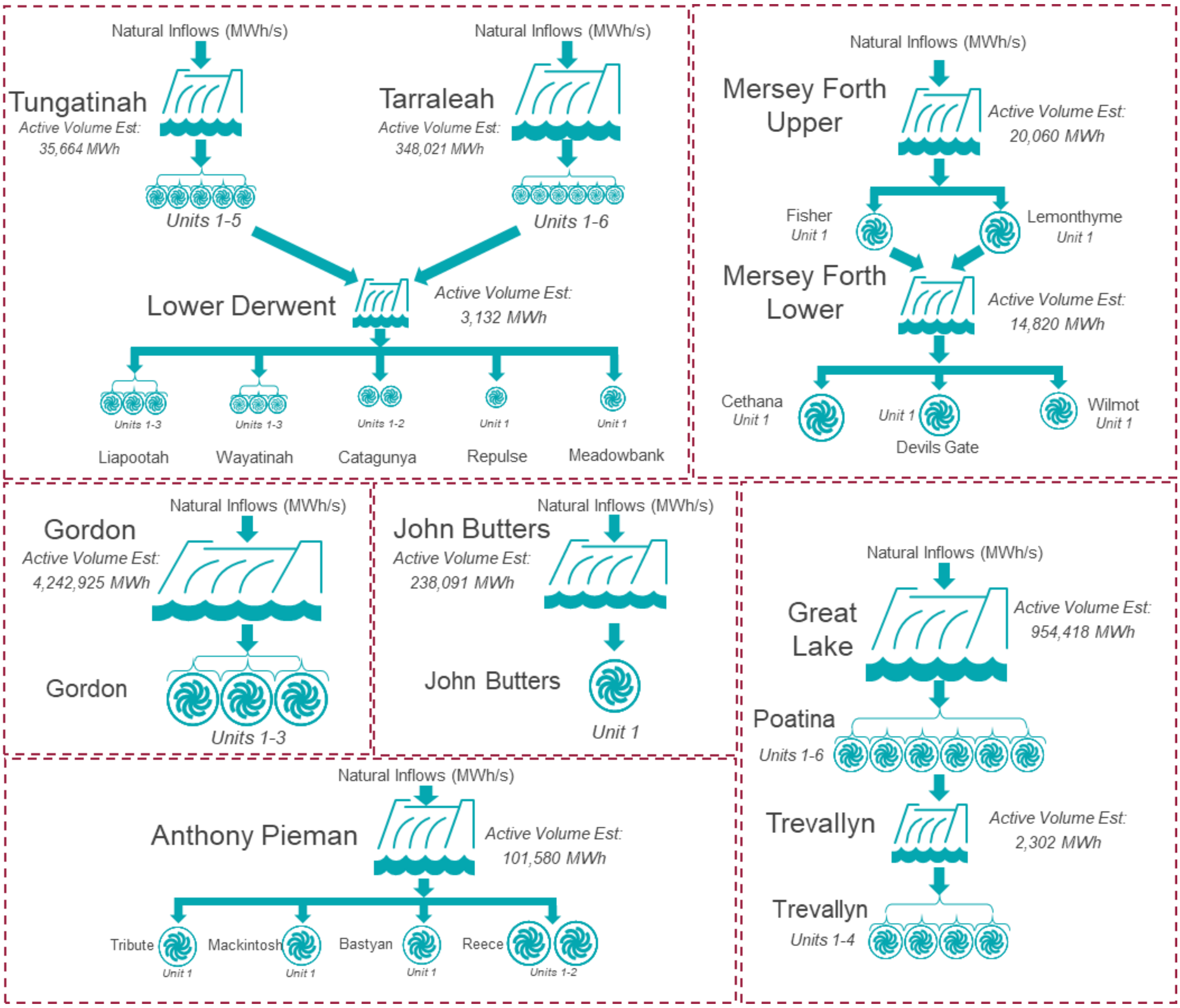
AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond[243] topology designed to capture different levels of flexibility associated with the different types of storage outlined in **Figure 85**.

This topology reasonably reflects the cascading relationships between generators while balancing computational complexity. Where a cascade has been simplified, typically the intermediate reservoirs are very large (enabling multi-day storage management) relative to generator discharge capacity, head effects are immaterial, and the

[243] The capacity outlook model may aggregate long-term storages together to reduce simulation time.

cascade of generators are operated in a run-of-river-like fashion to avoid accumulation effects in any intermediate storage.

Figure 85 Hydro Tasmania scheme topology

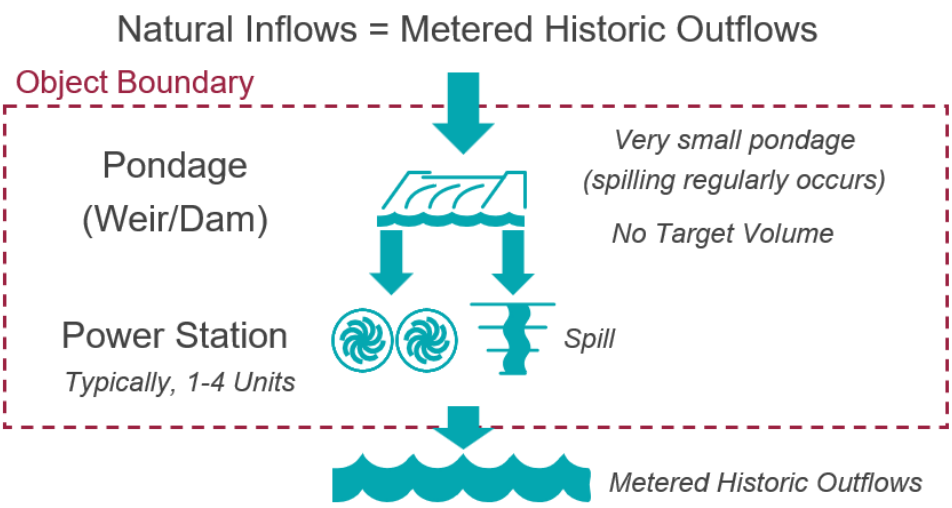


A2.3 Queensland's hydro schemes

Run-of-river (or operationally similar) – Barron Gorge (Kuranda Weir) and Kareeya

Both Barron Gorge (also known by Kuranda Weir) and Kareeya have large upstream reservoirs, however these reservoirs do not form head pondages for the main generation units. As such, water released from these upstream reservoirs flow into very small head 'pondages' and are rapidly discharged via generation or else spilled – effectively providing a 'run of river' scheme. AEMO's assumptions reflect the assumed water inflows, modelled with no effective water management capacity.

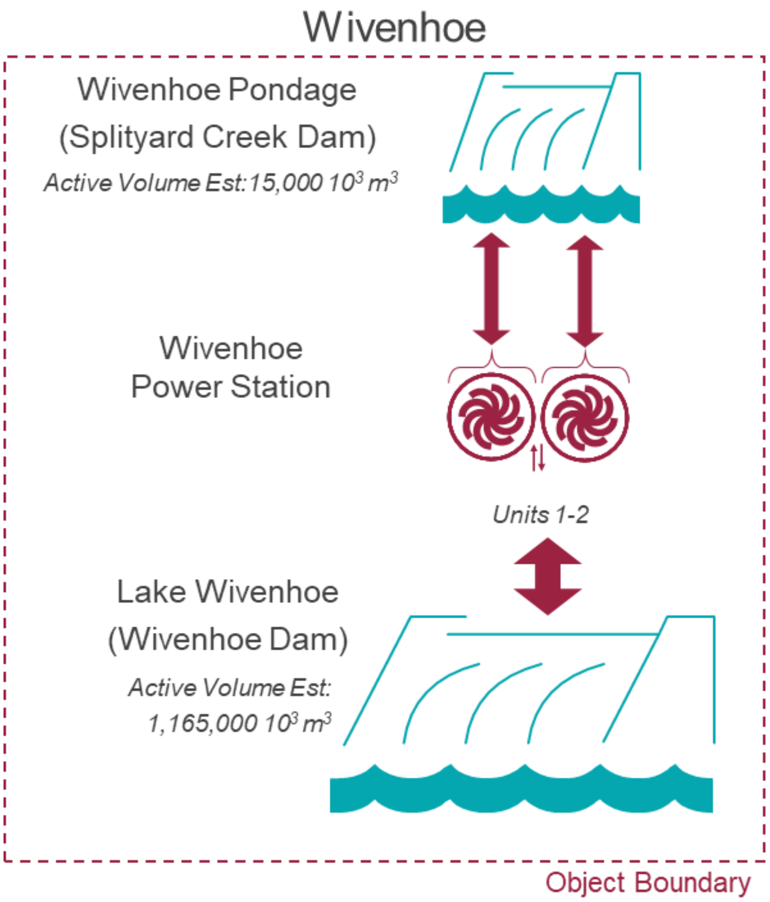
Figure 86 Model representation of Run-of-river schemes



Pumped Hydro Schemes – Wivenhoe

The configuration of Wivenhoe Dam is represented per the configuration in **Figure 87**.

Figure 87 Model representation of Wivenhoe pumped hydro



A2.4 Victoria's hydro schemes

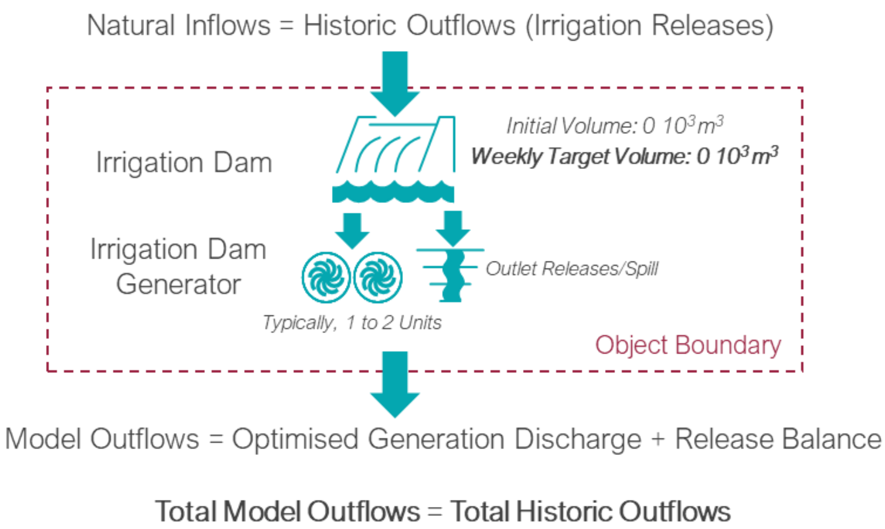
Kiewa hydroelectric scheme (Power-only)

This hydroelectric scheme is modelled using maximum energy constraints (yearly) on each individual generator object; these are West Kiewa and Bogong-Mackay[244].

Secondary Hydroelectric Schemes (Irrigation) – Hume, Blowering, Eildon, Dartmouth

For some generators, electricity generation is an opportunistic by-product of scheduled irrigation releases, and the scheduled releases must occur irrespective of discharge via generators, or outlet releases. For these generators, AEMO's assumptions respect a combination of water inflows and assumed scheduled irrigation releases, allowing the model some opportunity to manage the water that is available to it within those parameters.

Figure 88 Model representation of the Secondary Hydroelectric Schemes



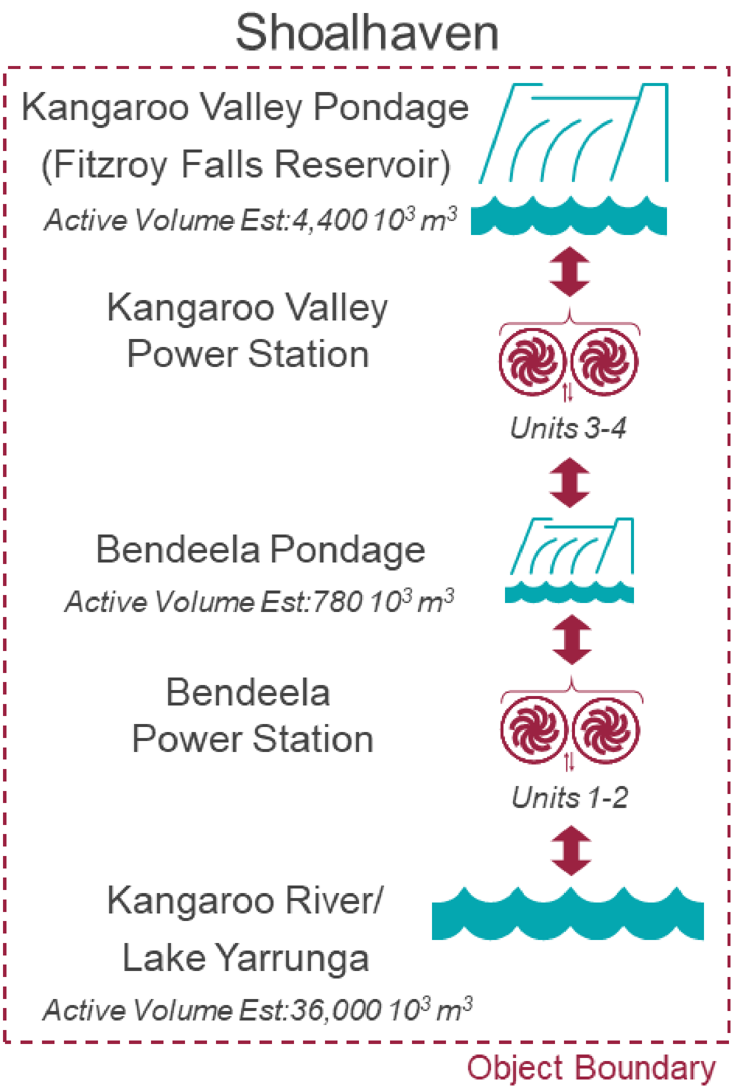
A2.5 Other hydro schemes

Pumped Hydro Schemes (where parameters known) – Shoalhaven

The NEM's other existing pumped hydro scheme, not described already, is Shoalhaven. This generator is represented as per the following configuration in **Figure 89**.

[244] These generators are fed from a very large storage (Rocky Valley Dam), which effectively means they have an annual energy supply from rain and snow that they can use flexibly throughout the year. Annual capacity factor constraints are therefore most appropriate to constrain the generation from these units.

Figure 89 Model representation of Shoalhaven pumped hydro



A3. Supporting material

In addition to the 2025 *Inputs and Assumptions Workbook*, **Table 47** documents additional information related to AEMO's inputs and assumptions.

Table 47 Additional information and data sources

Organisation	Document/source	Link
AEMO	Generation Information	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
	AEMO's Transmission Cost Database	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database
	2025 GSOO Stakeholder Surveys and gas supply input data	https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo
	2025 IASR Scenarios Consultation Summary Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-IASR-Consultation-Summary-Report
	2025 IASR EV workbook	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/AEMO-2025-IASR-EV-workbook
AEP Elical	2020 Assessment of Ageing Coal-Fired Generation Reliability	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-elical-assessment-of-ageing-coal-fired-generation-reliability.pdf
AER	Values of Customer Reliability (VCR)	https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024
Aurecon	2024 Energy Technology Cost and Technical Parameter Review	Report: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Aurecon-2024-Energy-technology-cost-technical-parameter-review-report Data: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Aurecon-2024-Energy-technology-cost-technical-parameter-review-tables
	2024 Energy Technology Cost and Technical Parameter Review – Mid Size Solar PV and BESS	Report: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Aurecon-2024-Energy-technology-cost-technical-parameter-review-report-solar Data: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Aurecon-2024-Energy-technology-cost-technical-parameter-review-tables-solar
GHD	Pumped Hydro Energy Storage Parameter Review	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/GHD-2025-Pumped-hydro-energy-storage-cost-parameter-review
	2025 Energy Technology Retirement Cost & O&M Estimate Review	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/GHD-2025-Energy-technology-retirement-cost-OM-estimate-review
Deloitte Access Economics	Economic forecast 2024-25	https://aemo.com.au/-/media/files/major-publications/isp/2025/Deloitte-Access-Economics-2024-Economic-Forecast
CSIRO	Multi-sector energy modelling 2024	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report
	CSIRO: *GenCost 2024-25 Final Report*	https://www.csiro.au/en/research/technology-space/energy/electricity-transition/GenCost
	2024 Projections for solar PV and battery systems	https://aemo.com.au/-/media/files/major-publications/isp/2025/CSIRO-2024-Solar-PV-and-Battery-Projections-Report

Organisation	Document/source	Link
	Electric Vehicle Projections 2024	https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/electric-vehicle-projections-2024.pdf
Green Energy Markets	2024 Projections for solar PV and stationary energy battery systems	https://aemo.com.au/-/media/files/major-publications/isp/2025/GEM-2024-Solar-PV-and-Battery-Projections-Report
ACIL Allen	Gas, liquid fuel, coal and renewable gas projections	https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf
Oxford Economics Australia	Data centre energy consumption	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Oxford-Economics-Australia-Data-centre-energy-consumption-report
	Discount rates for energy infrastructure	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Oxford-Economics-Australia-Discount-rates-for-energy-infrastructure-report
	2025 IASR planning and installation cost escalation factors	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/Oxford-Economics-Australia-Planning-installation-cost-escalation-factors-report
Strategy. Policy. Research.	2025 Energy efficiency forecasts final report	https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-energy-efficiency-forecasts-final-report.pdf

List of tables and figures

Figures

Abbreviations

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACCU	Australian carbon credit unit
ACSL	Advisory Council on Social Licence
ADGSM	Australian Domestic Gas Supply Mechanism
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ANU	Australian National University
APS	*Announced Pledges Scenario*
BCA	Building Code of Australia
BESS	battery energy storage system
BEV	battery electric vehicle
BMM	business mass market
BNEF	Bloomberg New Energy Finance
BoM	Bureau of Meteorology
BoP	Balance of Plant
CBA	cost benefit analysis
CBA Guidelines	*Cost Benefit Analysis Guidelines* (AER)
CBD	Commercial Building Disclosure
CCGT	Closed-cycle gas turbine
CCRG	Consumer and Community Reference Group
CCS	carbon capture and storage
CEFC	Clean Energy Finance Corporation
CER	consumer energy resources
CIS	Capacity Investment Scheme (Federal)
CNSW	Central New South Wales
CO_2	carbon dioxide
CQ	Central Queensland
CSA	Central South Australia
CSG	coal seam gas
CST	concentrated solar thermal
CWC	ClimateWorks Centre
DAC	direct air capture
DAE	Deloitte Access Economics
DAT	dual-axis tracking
DC	direct current

Abbreviation	Meaning
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISER	Department of Industry, Science, Energy and Resources
DNSP	distribution network service provider
DRI	direct reduction of iron
DSP	demand-side participation
DSP IP	DSP Information portal
DUID	Dispatchable Unit Identifier
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection
ECGM	East Coast Gas Market
ECMC	Energy and Climate Change Ministerial Council
EFOR	equivalent forced outage rate
EMMS	electricity market management system
EPC	engineering, procurement and construction
ESCI	Electricity Sector Climate Information
ESOO	*Electricity Statement of Opportunities*
ESS	Energy Savings Scheme (New South Wales)
EV	electric vehicle
FBT	fringe benefits tax
FCEV	fuel cell electric vehicle
FCUD	Full Commercial Use Date
FERC	Federal Energy Regulatory Commission
FERM	Firm Energy Reliability Mechanism
FFP	fixed flat plate
FOAK	first-of-a-kind
FRG	Forecasting Reference Group
GALLM	Global and Local Learning Mode
GBB	Gas Bulletin Board
GCM	global climate model
GEM	Green Energy Markets
GEMS	Greenhouse and Energy Minimum Standards
GG	Gladstone Grid
GIS	Geographic Information Systems
GJ	gigajoule/s
GSOO	*Gas Statement of Opportunities*
GVA	Gross Value Added
GW	gigawatt/s
GWh	gigawatt hour/s
HDI	Household Disposable Income
HEUF	Household Energy Upgrades Fund

Abbreviation	Meaning
HVAC	high voltage alternating current
HVDC	high voltage direct current
IASR	*Inputs, Assumptions and Scenarios Report*
IBR	inverter-based resource/s
ICE	internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISF	Institute for Sustainable Futures
ISP	*Integrated System Plan*
kL	kilolitre/s
kW	kilowatt/s
kWh	kilowatt hour/s
LGC	Large-scale Generation Certificate
LIL	large industrial load
LNG	liquefied natural gas
LOR	lack of reserve
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LTESA	Long-Term Energy Service Agreement
LULUCF	land use, land-use change, and forestry
LUTO	Land-Use Trade-offs
MEL	Greater Melbourne and Geelong
MLF	marginal loss factor
MT PASA	Medium Term Projected Assessment of System Adequacy
MtCO2-e	million tonnes of carbon dioxide equivalent
MVA	megavolt ampere/s
MW	megawatts
MWh	megawatt hours
NABERS	National Australian Built Environment Rating System
NatHERS	Nationwide House Energy Rating Scheme
NCC	National Construction Code
NDC	Nationally Determined Contribution
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEO	national electricity objective
NEPS	National Energy Performance Strategy
NER	National Electricity Rules
NEVA	*National Electricity (Victoria) Act 2005*
NMI	National Metering Identifier

Abbreviation	Meaning
NNSW	Northern New South Wales
NQ	Northern Queensland
NSA	North South Australia
NSCAS	network support and control ancillary services
NSW EII Act	*Electricity Infrastructure Investment Act 2020* (New South Wales)
NVES	New Vehicle Efficiency Standard
NZE	*Net Zero Emissions by 2050*
O&M	operating and maintenance
OCGT	open-cycle gas turbine
ONSG	other non-scheduled generation
PDRS	Peak Demand Reduction Scheme
PEM	proton exchange membrane
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicle
PJ	petajoule/s
POE	probability of exceedance
PTIP	priority transmission infrastructure project
PV	photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
RACE	Reliable Affordable Clean Energy
RCP	Representative Concentration Pathway
Response to the ISP Review	Energy and Climate Change Ministerial Council response to the ISP Review
RET	Renewable Energy Target
REZ	renewable energy zone
RIN	Regulatory Information Notice
RIT-T	regulatory investment test for transmission
RoCoF	rate of change of frequency
RRN	regional reference node
RRO	Retailer Reliability Obligation
SA REPS	South Australian Retailer Energy Productivity Scheme
SAT	single-axis tracking
SDS	*Sustainable Development Scenario*
SESA	South East South Australia
SEV	South East Victoria
SIPS	System Integrity Protection Scheme
SNSW	South New South Wales
SNW	Sydney, Newcastle, Wollongong

Abbreviation	Meaning
SPR	Strategy. Policy. Research.
SQ	South Queensland
SRES	Small-scale Renewable Energy Scheme
SSSP	System Strength Service Provider
STC	small-scale technology certificate
STEPS	*Stated Policies Scenario*
TAS	Tasmania
TNSP	transmission network service provider
TOU	time of use
TRET	Tasmanian Renewable Energy Target
TWh	terawatt hour/s
UNFCCC	United Nations Framework Convention on Climate Change
UOR	unplanned outage rate
V2G	vehicle-to-grid
V2H	vehicle-to-home
VCR	Value of Customer Reliability
VER	Value of Emissions Reduction
VEU	Victorian Energy Upgrades
VNI West	Victoria – New South Wales Interconnector West
VPP	virtual power plant
VRE	variable renewable energy
VRET	Victorian Renewable Energy Target
WACC	weighted-average cost of capital
WDR	Wholesale Demand Response
WEM	Wholesale Electricity Market
WEO	World Energy Outlook
WNV	West and North Victoria
WSB	Waratah Super Battery
ZEV	zero emission vehicle