Draft 2025 Inputs, Assumptions and Scenarios Report

February 2025

Draft report – Stage 2

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 Draft 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 14 February 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.

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Version control

Version	Release date	Changes
1.0	11/12/2024	Initial release
2.0	28/2/2025	Stage 2 release – content unchanged from Stage 1 has been greyed out.

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 eastern and south-eastern Australia, and the *Integrated System Plan* (ISP) for the NEM.

Formal consultation commenced in December 2024 with the publication of Stage 1 of the Draft 2025 *Inputs, Assumptions and Scenarios Report* (Draft 2025 IASR) on the scenarios, inputs and assumptions proposed for use in AEMO's 2024–25 forecasting and planning activities, including the 2026 ISP. While most assumptions that will apply to AEMO's planning publications are consulted on through this document's formal consultation process, some inputs and assumptions operate on different update cycles, as set out in the summary box under relevant sections of this report. AEMO encourages interested stakeholders to get involved in engagement opportunities to consult with AEMO on these additional inputs.

The Draft 2025 IASR has been released in two stages for consultation with this second stage providing additional inputs and assumptions

The 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 IASR includes additional inputs relative to previous IASRs, to acknowledge additional breadth needed in AEMO's planning models, particularly the ISP, to meet the requirements of the Energy and Climate Change Ministerial Council (ECMC) ISP Review, and subsequent Australian Energy Market Commission (AEMC) rule changes[1].

AEMO has released the Draft 2025 IASR in two stages for consultation to enable improved transparency and stakeholder engagement opportunities for traditional and new inputs. Stage 1, published on 11 December 2024, included a range of inputs and assumptions, and the remainder are published in this Stage 2 release.

AEMO recognises that several other activities are related to the 2026 ISP's development, including consultation on the *ISP Methodology*[2] with the Draft ISP Methodology being published on 13 March 2025, with submissions due 14 April 2025. AEMO's ISP Timetable[3] has details on all major milestones specific to the ISP development process.

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

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

Updates since Stage 1

The majority of this Draft 2025 IASR Stage 2 release is unchanged from Stage 1. New content added for this Stage 2 release describes the pace of decarbonisation in the Australian economy in each of AEMO's planning scenarios, particularly emissions reduction expected in the energy sector, and emissions reduction expected outside the energy sector including through sequestration (mainly in the land-use sector). Stage 1 included a significant volume of traditional assumptions, outlining policy settings that AEMO applies to its planning function under the relevant national electricity rules, the scenarios that AEMO proposes to apply to its scenario planning framework, economic and other consumer demand influences that vary by scenario, generation and storage costs for new entry developments, and other infrastructure assumptions that will influence AEMO's assessment of reliability, security or power system needs.

This Executive Summary does not attempt to summarise specific trends or insights for these new assumptions.

AEMO thanks stakeholders for the submissions that have been provided on Stage 1. Among other topics, stakeholders submitted on the proposed scenarios to be assessed in AEMO's planning activities. This Stage 2 release continues to reflect the narratives that were published in Stage 1, and AEMO will reflect on the submissions as it conducts the Stage 2 consultation.

Throughout this report, sections containing updates or new contents since the Stage 1 release start with the wording ***'This section contains updates for Stage 2'***. Other sections that are unchanged from the Stage 1 publication apply lighter text formatting for easier visual identification, as applied to this text. The following table lists sections with new content, for which AEMO is seeking feedback.

Table 1 Summary of Stage 2 updates

New/revised Stage 2 content	Location in report
Updates since Stage 1	Executive summary, Section 1
Updated consultation process	Section 1.1
Scenario updates	
Comparing energy end-use across the scenarios	Section 2.2.1
Sensitivities	Section 2.4
Inputs and assumptions	
Policy settings	Section 3.1
Translating international climate scenarios to NEM-wide carbon budgets	Section 0
Multi-sectoral modelling, including key assumptions and outcomes and carbon sequestration	Section 3.3.4
Fuel-switching expectations away from fossil fuels to zero or near-zero emissions alternatives, including electrification and alternative renewable gases	Sections 3.3.5, 3.3.6
Electric vehicles	Section 3.3.7
Energy efficiency investments to improve energy productivity and save energy	Section 3.3.12
Table 26 List of generation and storage technology candidates – Distributed resources and footnote on Biomass generation – electricity and heat	Section 3.5.2
Impacts of planning, environmental and supply chain considerations	Section 3.5.6
Gas infrastructure	Section 3.12

The forecasts and datasets in this Draft 2025 IASR reflect information available as recently as 14 February 2025. New information available after this date will be considered by AEMO in finalising the 2025 IASR by July 2025.

Notice of Consultation: Invitation for written submissions

AEMO is committed to continued engagement on the Draft 2025 IASR, increasing transparency, and utilising stakeholder feedback for the benefit of energy consumers and the energy sector. This commitment to engagement is also consistent with the principles outlined in the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines.

Feedback is welcome on all updated content in this report, and AEMO has included 'Matters for Consultation' as a guide throughout this document. Feedback is particularly helpful where views are accompanied by supporting information. AEMO requests that, where possible, submissions should provide evidence that supports any views or claims that are put forward.

Submissions for Draft 2025 IASR Stage 2 (this publication) should be sent in PDF format via email to forecasting.planning@aemo.com.au and are required by 6.00 pm AEDT on Monday 31 March 2025. Please note that submissions will be published, other than confidential material, subject to AEMO's Consultation submission guidelines[4].

AEMO will update the Stakeholder Engagement web page[5] to outline any other engagement opportunities, including use of the Forecasting Reference Group (FRG)[6] and any other forums, as appropriate.

Proposed scenarios and sensitivities

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.

AEMO uses a scenario planning approach coupled with cost benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers while meeting the policies of Australia's governments that are supporting the energy transition.

Scenarios represent 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. While some scenarios may be more likely than others, no single scenario is expected to be

[4] At https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines---march-2023.pdf.

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

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

the definitive version of the future that will occur; the value of the scenario collection is in describing uncertainties from which further analysis identifies benefits or regrets of various alternative investments.

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

The scenarios, representing plausible future worlds within which the energy transition occurs, all reflect and consider the policies that Australia's governments have committed to in order to transition Australia's economy to net zero emissions by 2050[7]. The scenarios provide a mechanism to explore the investment needs of the energy system with consideration of various pathways to that outcome. 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.

- 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).
- Test the risks of under- and over-investment.

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 (CBA) guidelines[8].

The scenarios explore critical dimensions and uncertainties affecting the energy sector. Key uncertainties include:

The growth of the Australian economy, and associated population trends and economic activity that may be expected across Australia's industrial, commercial, manufacturing, mining and transportation sectors (and others), including emerging commercial loads such as data centres.

The pace and scale of consumer energy resources (CER) investments, which comprise small-scale embedded generation and storage technologies, such as residential and commercial photovoltaic (PV) systems, battery storage, and electric vehicles (EVs), as well as consumer appetite for the coordination of these active devices.

Cost trends for the range of technologies that may be developed across electricity generation, storage and network developments.

The opportunities for emerging energy technologies affecting Australia's decarbonisation pathway and export economy, including hydrogen production and manufactured products that utilise hydrogen (such as green iron and ammonia products), and other technologies (such as biomethane) that may impact the emissions intensity of energy.

AEMO has defined three scenarios in this Draft 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

[7] 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.

[8] See https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

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

The proposed scenarios are as follows:

- ***Step Change*** – refines the 2023 *Step Change* scenario. This scenario is centred around achieving a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to preindustrial levels consistent with international efforts to the same goal. Compared to the 2023 *Step Change* scenario, while consumer investment in the energy transition remains strong (with energy efficiency and electrification investments, as well as aggregators of consumer resources, being a key part of the transition), consumers are tentative to share control and coordinate the operation of their consumer energy devices through a third party such as their electricity retailer. 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 their self-supply. The scenario captures some of the ambition in developing hydrogen associated opportunities, reflecting the economic challenges of establishing this new industry, while trends in artificial intelligence and other data-heavy applications encourage continued growth in data centres in Australia.
- ***Progressive Change*** – continues to explore a transition to net zero emissions within an economy that features less growth and greater challenges than other scenarios. In response to weaker economic circumstances, investment in decarbonisation is more gradual at sufficient pace to meet the requirement of Australia's current 2030 Paris Agreement commitments (and other state-based policy commitments) resulting in greater aggregate emissions even in achieving current commitments. Conversely, slower economic activity and population growth reduces the pace of electrification that increases electricity demand while energy-intensive industry are at greater risk of closure due to the weak economic circumstances, with a material proportion of large energy-intensive businesses in each NEM region shut down in the short to medium term. Consumers continue to invest in CER, yet with relatively less growth than other scenarios, and 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.
  - As a result, the scenario has a less robust economy and a smaller population base consuming less electricity. A weaker and slower energy transition globally, higher technology costs, and tighter supply chains affecting consumer investments relative to other scenarios, combine to slow the pace of change to limit the medium-term ambition beyond current policy targets. As a result, this scenario requires less investment to achieve the decarbonisation goals.
- ***Green Energy*** (which will examine one of two variants, *Green Energy Exports* or *Green Energy Industries*) – refines the 2023 *Green Energy* Exports scenario, and is this IASR's most ambitious scenario, with the strongest decarbonisation and strongest economic growth. The scenario features a rapid transformation of Australia's energy sectors, utilising all available pathways to net zero including strong adoption of electrification, and action to reduce the emissions intensity of molecular forms of energy. Australia's energy transition in this scenario is commensurate with global actions underway to limit temperature increases to 1.5°C.
  - 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.

Higher economic growth internationally (and locally) increases global demand for green energy, enabling greater development of green energy products for both domestic and international customers (particularly green iron and ammonia products). Compared to the 2023 *Green Energy Exports* scenario, NEM-connected hydrogen production is lower reflecting that the scale of hydrogen developments remains uncertain and the opportunity for embedded electricity supply is expected to reduce grid investment. Two scenario variants are proposed that include, or exclude, some hydrogen export opportunities, and AEMO seeks stakeholder feedback on both in this consultation. In the ISP, AEMO is likely to examine one of the variants as one of the three scenarios, and explore the investment impacts of the other variant as a sensitivity. Further detail on the two variants and AEMO's proposed treatment of them in the ISP context 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 early consultation.

AEMO is exploring two variations to its most ambitious energy transition scenario, and seeks stakeholder feedback on the more appropriate variant for its scenario planning activities in the ISP.

Sensitivities

To increase confidence in the robustness of the investment conclusions developed in the ISP and to test the resilience of investment outcomes against various uncertainties, AEMO employs sensitivity modelling. Most commonly, this involves changing a single variable at a time.

AEMO invites stakeholders to submit their views on what sensitivities to explore in the 2026 ISP. An indicative list of sensitivities that AEMO will consider for the 2026 ISP will be published in the final 2025 IASR in July 2025.

Inputs and assumptions

This Draft 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.
- Employment factors that will be used to estimate the workforce requirements needed to implement the ISP.

AEMO publishes the Draft 2025 Inputs and Assumptions Workbook[9] alongside this Draft 2025 IASR to provide more detail on the various inputs.

Recognising policy uncertainty

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.

If there is a significant change to energy policies that may materially change AEMO's planning analysis, AEMO would adopt the updated policy as appropriate. This would involve consultation and could result in the requirement to restart planning activities, depending on the magnitude of the change and the type of planning analysis being undertaken.

Invitation for submissions

This section contains updates for Stage 2

This second stage of the Draft 2025 IASR provides additional information not available in the first release of the Draft 2025 IASR, released in December 2024. These new inputs, as well the scenarios, inputs and assumptions contained within the first stage, are proposed for use in AEMO's forecasting and planning activities, including the 2026 ISP.

All stakeholders are invited to provide a written submission on the Draft 2025 IASR Stage 2, which should be sent in PDF format to forecasting.planning@aemo.com.au by 6.00 pm AEDT on Monday 31 March 2025.

Table 2 Matters for consultation for Stage 2

Matters for consultation - Stage 2	Location in report
Sensitivities	Section 2.4
• Do you have any further views on the proposed sensitivities? • What additional uncertainties are valuable to explore with sensitivity analysis?	
Alignment with the Inter-governmental Panel on Climate Change's Relative Concentration Pathways	Section 3.2.2
• Do you consider the proposed carbon budgets to be appropriate?	
Multi-sectoral modelling influences to demand forecasts	Section 3.3.4
• Are the key assumptions and outcomes described in Table 15 suitably aligned with scenario definitions?	
Fuel switching to alternative gaseous fuels	Section 3.3.6
• Do you agree with the assumed portion of on-grid electrolysers by region?	
Consumer energy resources – electric vehicles section	Section 3.3.7
• Is the projected long-term trend of PHEV reasonable? • Is the projected split of higher public charging and lower unscheduled charging reasonable?	
Energy efficiency forecast	Section 3.3.12
• Are the energy efficiency savings projected by the consultants suitable for their respective scenarios? • Are SPR's results sufficiently aligned with the role of energy efficiency in optimised decarbonisation pathways (as revealed by CSIRO's multi-sectoral modelling approach)? • What other considerations may influence energy efficiency?	

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

Matters for consultation - Stage 2	Location in report
Impacts of planning, environmental and supply chain considerations	Section 3.5.6
• Do you consider the installation cost escalation forecasts for each technology to be reasonable? • Do you support AEMO's proposal to apply lead time adjustments in the Constrained Supply Chains sensitivity?	
Production cost and capabilities	Section 3.12.1
• Do you agree with the assumed minimum electrolyser utilisation factors?	
Gas infrastructure	Section 3.12.2
• Do you have feedback on the hydrogen supply pathways for use in the ISP model? If so, please address this feedback to the ISP Methodology consultation. • Do you have feedback on the location of candidate hydrogen hubs and ports?	

AEMO thanks all stakeholders for their continuing engagement and submissions to support the 2025 IASR.

Contents

Sections unchanged since Stage 1

Sections containing Stage 2 updates

1 Introduction

This section contains updates for Stage 2

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 National Electricity Market (NEM) or the Wholesale Electricity Market (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 East Coast Gas Market 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 Energy and Climate Change Ministerial Council (ECMC) endorsement of the actions recommended by the ISP Review, the Australian Energy Market Commission (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 *Inputs, Assumptions and Scenarios Report* (IASR). Appendix A1 includes a table that shows the publications that AEMO proposes to amend 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 draft scenarios, and their respective draft inputs and assumptions, that will be finalised after 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 consumer energy resources (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 Draft 2025 *Inputs and Assumptions Workbook*[10], 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 2024 Australian dollars unless stated otherwise.

Consultation on the draft inputs and assumptions released in two stages

This section contains updates for Stage 2

The IASR includes a wealth of inputs and assumptions that apply to AEMO's planning publications, and are used across the industry to inform other planning purposes, including for use in RIT-T assessments. Several of the rule changes flowing from the ISP Review involve material expansions to the scope and breadth of considerations within the ISP, and as such AEMO has needed to consider the breadth of the inputs and assumptions appropriate for this.

To extend the IASR to include these additional factors, AEMO chose to release the Draft 2025 IASR in two stages for consultation:

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

- Stage 1 release was published on 11 December 2024. The submission window for this stage closed on 11 February 2025, and AEMO received 36 submissions.
- Stage 2 (this release) includes all the Stage 1 information plus new information to describe the pace of decarbonisation in the Australian economy in each of AEMO's planning scenarios, particularly emissions reduction expected in the energy sector and activities emissions in other sectors, along with other assumptions affecting fuel-switching forecasts, EV forecasts, energy efficiency forecasts and other assumptions affecting the representation of gas within the ISP.

Sections containing updates or new contents start with the words ***'This section contains updates for Stage 2'***. Other sections are unchanged from the Stage 1 publication and apply lighter text formatting for easier visual identification, as applied to this text.

Table 3 summarises the updated Stage 2 content.

Table 3 Summary of Stage 2 updates

New/revised Stage 2 content	Location in report
Updates since Stage 1	Executive summary, Section 1
Updated consultation process	Section 1.1
Scenario updates	
Comparing energy end-use across the scenarios	Section 2.2.1
Sensitivities	Section 2.4
Inputs and assumptions	
Policy settings	Section 3.1
Translating international climate scenarios to NEM-wide carbon budgets	Section 0
Multi-sectoral modelling, including key assumptions and outcomes and carbon sequestration	Section 3.3.4
Fuel-switching expectations away from fossil fuels to zero or near-zero emissions alternatives, including electrification and alternative renewable gases	Sections 3.3.5, 3.3.6
Electric vehicles	Section 3.3.7
Energy efficiency investments to improve energy productivity and save energy	Section 3.3.12
Table 26 List of generation and storage technology candidates – Distributed resources and footnote on Biomass generation – electricity and heat	Section 3.5.2
Impacts of planning, environmental and supply chain considerations	Section 3.5.6
Gas infrastructure	Section 3.12.2

1.1 Consultation process

This section contains updates for Stage 2

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, policymakers, 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[11].

In developing the 2025 IASR, AEMO has appropriate regard for the consultation requirements set by the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines[12]. 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 Forecasting Reference Group (FRG). These engagement opportunities seek to improve transparency and clarity on AEMO's decision-making processes, modelling approaches and preliminary inputs, and provide transparency on how AEMO has considered stakeholder feedback.

Ahead of the publication of this Stage 2 release of the Draft 2025 IASR, AEMO has undertaken a variety of engagement activities including:

- Consulting selected key stakeholders, including 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[13], 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 contents, covering the refined scenarios, and core assumptions released in December 2024. AEMO received 36 submissions to this consultation and is actively considering the feedback received.
- 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.

Table 4 below summarises key engagement activities conducted to date and planned to support the development of the 2025 IASR[14].

[11] Priority 3: Engaging our stakeholders. See *AEMO Corporate Plan FY 2025*, at https://aemo.com.au/about/corporate-governance/corporate-plan.See *AEMO Corporate Plan FY 2025*, at https://aemo.com.au/about/corporate-governance/corporate-plan.

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

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

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

Table 4 Stakeholder engagement on the 2025 IASR

Activity	Date
Activity to 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
Planned activities following the Draft 2025 IASR Stage 2 publication:	
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
Draft 2025 IASR submissions reflections webinar	May 2025
2025 IASR publication	By 31 July 2025

For more information about related engagement including engagement for the broader 2026 ISP, see the 2026 ISP Stakeholder Engagement Plan[15].

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

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 proposed 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 cost benefit analysis (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 proposed 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.
- The development of demand side factors, including CER (including rooftop solar, battery storage and 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.
- The changing nature of commercial and industrial loads, including the potential for closures and the growth of data centres.

AEMO proposes to develop 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.

AEMO's proposed scenario collection predominantly re-uses the 2023 IASR names to support comparison of modelling outcomes.

Stakeholders have provided input in developing the scenarios

Preliminary stakeholder input throughout 2024 has helped shape the proposed scenarios and their inputs and assumptions in this Draft 2025 IASR. In July 2024, AEMO published the *Draft 2025 IASR Scenarios consultation paper*[16] and received submissions from 50 stakeholders with feedback and suggestions, which have helped shape the revised scenarios in this Draft 2025 IASR.

A summary of stakeholder feedback to the scenarios and AEMO's considerations is in the consultation summary report on AEMO's website[17].

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 NEM power system. The scenarios intentionally span a range of current and future trends in energy consumption, consumer energy investments, and technology costs.

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

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 assumptions regarding forecast growth in CER coordination,

Increased consideration of emerging commercial loads, in particular the growing role of data centres associated with increased digital services provided in Australia.

AEMO considers that the proposed 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 is useful for ongoing planning activities.

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

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

The scenarios provide a breadth of plausible futures to consider power system needs for a range of planning purposes.

Step Change

This proposed scenario refines the 2023 *Step Change* scenario. It is centred around achieving a scale of transformation that supports 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 their self-supply.

Emerging commercial and industrial loads have moderate growth outcomes, with data centres and electrification of larger industries leading to material new electricity consumption, but with greater potential growth unrealised. While ambition remains for hydrogen production opportunities to develop, these are slower and more focused on domestic opportunities, 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, but the coordination of these resources is more gradual than it could be, with initial difficulties to demonstrate to consumers the great potential value in coordinating these assets as well as reward consumers' choice to provide increased access to their resources to improve the efficiency and effectiveness of the transition.

Progressive Change

This proposed scenario describes a world that aims to achieve Australia's current Paris Agreement commitments of 43% emissions reduction by 2030, 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. While achieving current decarbonisation commitments, 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, major industrial loads are much more likely to wind up Australian operations in favour of offshore alternatives. 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 loads in each NEM region. 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.

Progressive Change slows the pace of decarbonisation from consumers and from industry, meaning local benefits from new green industry opportunities are relatively unrealised. 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, this scenario examines possible over-investment risks in a more slowly growing economy.

Green Energy

This proposed 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. 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 economy is boosted from hydrogen production opportunities to service domestic and international interest in hydrogen and in green energy products, particularly commodities produced with green energy, 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 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. Australia therefore is a relatively strong contributor to global efforts to embrace low/zero emissions alternatives through this transition, with hydrogen replacing declining coal and gas exports.

The scale of the *Green Energy* scenario is smaller relative to previous versions of AEMO's scenarios, reflecting that the scale of hydrogen developments remains uncertain and the opportunity for embedded electricity supply is expected to reduce broader power system needs.

In relation to green commodity exports, exports of hydrogen and value-add commodities are a focus; as the world's largest iron ore exporter for example, and with high renewable energy opportunities, Australia in this scenario is well placed to service the growing global need for green energy commodities.

Considering stakeholder feedback to date, the *Green Energy* scenario will reflect one of two alternatives that are focused around 1.5°C scale decarbonisation actions in Australia, but with more/less embracement of Australia's export potential in this world. In the ISP, AEMO anticipates that one of the scenario variants will be adopted as the scenario narrative, while the other will enable, exploration of the investment impacts of the other variant through sensitivity analysis.

The proposed scenario variants are:

- *Green Energy Exports* – includes development of a hydrogen industry, focusing on value-add hydrogen products such as green iron and steel, for domestic and export. Also includes significant opportunity for hydrogen production and associated manufacturing users to develop products for export, including hydrogen as an energy carrier.
- *Green Energy Industries* – includes development of a hydrogen industry, focusing on value-add hydrogen products such as green iron and steel, for domestic and export. The variant excludes those developments that are expected to support hydrogen exports as an energy carrier, thereby representing a materially smaller hydrogen impact on investment requirements than the *Green Energy Exports* variant.

Both variants are very similar to the 2023 IASR scenario, with domestic and export opportunities, with a reduced level of hydrogen activity – particularly for exports – relative to the 2023 IASR. Value-add commodity developments represent a key potential driver of Australia's economic activity in the medium to long term in this scenario, and Australia is well-placed with strong renewable energy generation potential and critical access to raw materials that may benefit from green energy in conversion processes. The *Green Energy Industries* variant is thematically identical to *Green Energy Exports* in all areas of the scenario's key parameters except for a lower level of new investment in value-add commodities and hydrogen exports.

Scenario purpose

To explore investment needs in a world embracing very rapid decarbonisation to support the strong potential economic benefits Australia's renewable generation potential. It will therefore identify the scale and speed of investments that may be required to realise this potential in a rapidly decarbonising global economy.

This Draft 2025 IASR may use either the *Green Energy* or the *Green Energy Exports* names in this report when referring to inputs and assumptions that are identical between the two variants. Where the two variants lead to alternative inputs and assumptions, *Green Energy Industries* is also described. Many of the differentiated inputs will be available in the second stage of the Draft IASR release, however AEMO is seeking stakeholder feedback on the appropriateness of the scenario narrative to apply as the scenario.

Matters for consultation from Stage 1

Are the scenarios, and the scenario collection, suitable for use in AEMO's planning publications including the 2026 ISP? Does the scenario collection support the exploration of a diverse range of possible futures that could occur over the planning horizon?

Which of the two described scenario variants for the *Green Energy* scenario is the more appropriate variant for application as the scenario in AEMO's 2025 IASR scenario collection (depending on the planning analysis, AEMO may apply the alternate variant in sensitivity analysis).

2.2 Key scenario parameters

Table 5 summarises decarbonisation targets, key demand drivers, technological trends and other key parameters for each of the scenarios. Details are in the Draft 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 5 Key parameters, by scenario

Parameter	*Green Energy* [A]	*Step Change*	*Progressive Change*
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	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher, with near-term economic growth impacted somewhat by current economic challenges	Moderate economic growth, with near-term economic growth impacted by current economic challenges	Lower
Electrification	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Electrification is tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances
Emerging commercial loads	Emerging sectors such as data centres match opportunities associated with higher domestic economic drivers	Emerging sectors such as data centres match opportunities associated with moderate domestic economic drivers	Emerging sectors such as data centres experience lower growth as weaker economic circumstances limit technology uptake
Coordination of CER (VPP and V2G)	High long-term coordination, with faster acceptance of coordination	Moderate long-term coordination, with gradual acceptance of coordination	Low long-term coordination, with gradual acceptance of coordination
Energy efficiency	Higher	High	Moderate
Hydrogen use and availability	High production for domestic industries, with moderate exports in the short term, and high exports in the longer term	Moderate-low production for domestic use, with minimal export hydrogen	Low production for domestic use, with no export hydrogen

Parameter	*Green Energy* [A]	*Step Change*	*Progressive Change*
Industrial load closures	No specific load closures	No specific load closures	Weak economic conditions provide challenging commercial conditions, resulting in load closures across key commercial and industrial facilities
Demand side participation uptake	Higher	Moderate	Lower
CER investments (batteries, PV and EVs)	Higher	High	Lower
Renewable gas blending in gas distribution network [B]	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases
Potential for supply chain limitations affecting demand forecasts	Low	Moderate	High
Global/domestic temperature settings and outcomes [C]	Applies Representative Concentration Pathway (RCP) 1.9 where relevant, consistent with a global temperature rise of ~ 1.5°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) 4.5 where relevant, consistent with a global temperature rise of ~ 2.6°C by 2100
International Energy Agency (IEA) 2024 World Energy Outlook scenario alignment	*Net Zero Emissions by 2050* (NZE)	*Announced Pledges Scenario* (APS)	*Stated Policies Scenario* (STEPS)

A. Both the Green Energy scenario variants, *Green Energy Exports* and *Green Energy Industries*, are equivalent in terms of these key parameters and their qualitative descriptors for each key parameter.
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. Higher blends than ~10% by volume are assumed possible for industrial use but may require equipment change and/or shifts to dedicated hydrogen transmission pipelines.
C. RCPs were adopted in the Intergovernmental Panel on Climate Change (IPCC) first Assessment Report, see https://www.ipcc.ch/report/ar5/syr/.

Matters for consultation from Stage 1

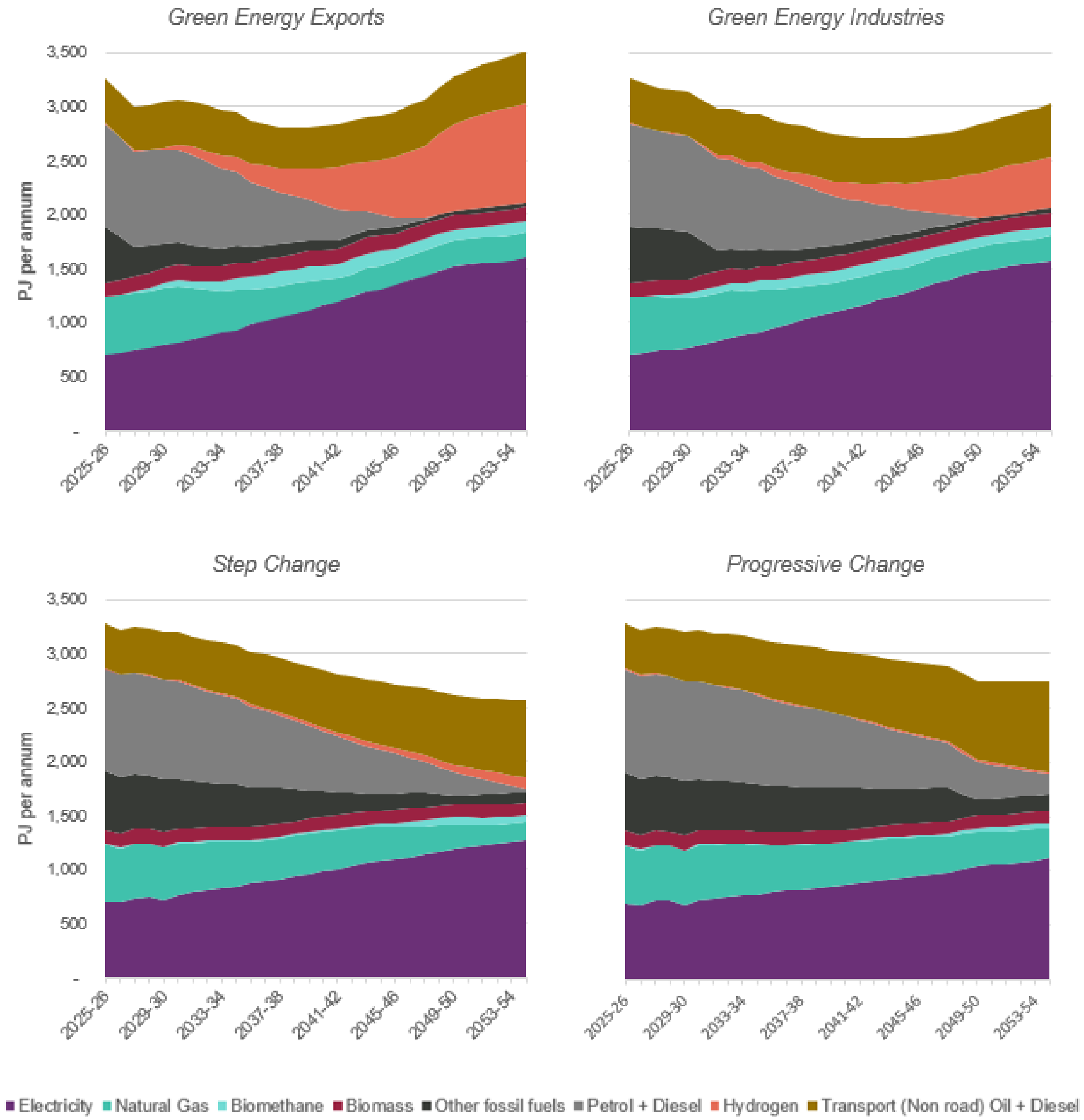
- Are the scenario parameters, and parameter values, clear and suitably aligned with their respective narratives?

2.2.1 Comparing energy end-use across the scenarios

This section contains updates for Stage 2

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 3.3.8), 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:

- *Green Energy Exports* 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, as well as to support emerging opportunities to create a green manufacturing sector of Australia's economy, and provide green commodities to international markets. 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.

- *Green Energy Industries* follows a similar path as *Green Energy Exports*, although with a smaller contribution from hydrogen with lesser identified green commodity exports.
- Electrification investments provide a primary means to reduce fuel use in *Step Change* and *Progressive Change*. These scenarios consider limited hydrogen developments, and have a slower rate of electrification and decarbonisation, as shown in the figure.

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 Draft 2025 IASR. AEMO prefers to examine scenario likelihood at a point closer to when these scenario weightings are applied, to ensure that 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 the key milestones for this particular scenario 'input'.

2.4 Sensitivities

This section contains updates for Stage 2

The three proposed 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.

All AEMO's planning publications tend to 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. Most commonly, this would involve change to a single variable at a time to single out 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.

For the 2026 ISP, AEMO intends to explore the following themes through sensitivity analysis to address actions from the ECMC's response to the ISP Review[18] (Response to the ISP Review):

- **Alternative coal retirement schedule(s)** – exploring the implications of alternative coal-fired generation retirement schedule(s) on new generation, storage and network investments, particularly additional or earlier investments in firming capacity such as large-scale storage. This sensitivity has been proposed to address an action from the Response to the ISP Review to analyse the sensitivity of the optimal development path to alternative coal-fired generation shutdown schedules.
  - Within the scenario modelling in the ISP, retirements of coal-fired generators may be brought forward ahead of expected closure years (for example, due to policies or carbon budgets), as described in the *ISP Methodology*. For this sensitivity, AEMO proposes to impose alternative coal retirements to those assessed in the scenario modelling, to examine the impacts on future power system requirements and the optimal development path.
- **Alternative CER uptake** – to examine the impacts of alternative levels of CER uptake to what is forecast under core scenarios. This sensitivity (and other demand-side focused sensitivities) is intended to support the Demand Side Factors statement that will be published with the ISP as required under NER 5.22.6A. This sensitivity is intended to explore the effect of lower or higher CER uptake on the efficient development of the power system, in particular distribution networks.
- **Constrained supply chains** – exploring the potential impact of limitations to supply chains, workforce availability, or other factors which slow infrastructure development. This will be tested by imposing slower and/or more costly development of new generation, storage and transmission projects in ISP modelling to mirror impacts of supply chains issues, which may subsequently impact on the ability to meet federal and state policy commitments. The sensitivity was conducted in a similar manner for the 2024 ISP.

The collection of sensitivities is not limited to those listed above, and AEMO invites stakeholder feedback on other important components or insights to deploy sensitivity analysis on for the 2026 ISP.

Matters for consultation for Stage 2

- Do you have any further views on the proposed sensitivities?
- What additional uncertainties are valuable to explore with sensitivity analysis?

[18] See https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

3 Inputs and assumptions

3.1 Policy settings

This section contains updates for Stage 2

Input vintage	February 2025
Source	Australian governments
Updates since 2023 IASR	Additional policies or aspects of policies have been incorporated since the 2023 IASR.

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 Draft 2025 IASR considers policies which AEMO must or may consider under 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 AEMC targets statement

AEMO must consider the emissions reduction targets stated in the Australian Energy Market Commission's (AEMC's) emissions targets statement[19] 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[20].

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.

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

[20] 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 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 (i.e. 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.

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[21], or the change may be included in the next ISP, depending on its timing.

3.1.3 Policies included in the Draft 2025 IASR

This section contains updates for Stage 2

Table 6 summarises the policies included in this Draft 2025 IASR. The sub-sections following Table 6 describe the various policy settings to be applied in the Draft 2025 IASR scenario collection.

[21] NER 5.22.15.

Table 6 Summary of policies included in the Draft 2025 IASR

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	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% below 1990 levels by 2050 (legislated) / 60% reduction below 2005 levels by 2030 and net zero by 2050[22].	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	Queensland Renewable Energy Target (QRET) of 50% by 2030, 70% by 2032, and 80% by 2035.	100% net renewable energy by 2030 (AEMC Targets Statement) / 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, 50% by 2030, 65% by 2030 and 95% by 2035; VRET auctions 1 and 2.

[22] AEMO will model the existing legislated 60% reduction by 2050 (compared to 1990 levels). Although not yet legislated, the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024* is expected to pass by publication of the 2025 IASR. AEMO proposes to model this policy, unless it is not sufficiently advanced by publication of the 2025 IASR.

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
Storage targets			Target of 2 GW/16 gigawatt hours (GWh) of deep storage by 2030 and 28 GWh of deep storage by 2034 under the NSW EII Act. Firming round tender including the Federal Government contribution under the Capacity Investment Scheme.	Borumba Dam Pumped Hydro (included as an anticipated project[23]).		Battery of the Nation (as development candidate).	Renewable Energy Storage target of 2.6 GW 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.		Hydrogen Jobs Plan including 250 megawatts (MW) electrolyser project, 200 MW hydrogen turbine.		
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 2032 development is considered to be anticipated with the Townsville to Hughenden connection			*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

[23] 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 accessible via 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	South Australia	Tasmania	Victoria
				being modelled quantitively as a REZ network expansion.			the Mortlake Turn-in as committed).
Transmission land payment programs			Strategic Benefit Payments Scheme.	SuperGrid Landholder Payment Framework.			Landholder Payments For A Fairer Renewables Transition.
CER-related policies	Small-scale Renewable Energy Scheme (SRES).	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, 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 integrated by 2040.	Stamp duty waiver, 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.

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)[24]. 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*[25]. 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[26], 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 $MtCO_2$-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 7.

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[24] 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.

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

[26] 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 7 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	South Australia A (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*	60% by 2050 relative to 1990 level as legislated via *Climate Change and Greenhouse Emissions Reduction Act 2007.* Proposed updates to 2030 and 2050 targets by the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024*, introduced in August 2024 to the South Australian Parliament.	*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**	**60% reduction (legislated)** **and** **Net Zero (amendment in Parliament)**		**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 legislations.

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[27], 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 sets out 'minimum infrastructure investment objectives'[28] to construct, by 31 December 2029, a minimum target of the equivalent of 12 gigawatts (GW) of new renewable energy capacity. This is within the AEMC Emissions Targets Statement, and therefore must be considered by AEMO.

The implementation of these objectives is underpinned by 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[29].

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 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 IIO Report is anticipated to be released prior to the finalisation of the 2025 IASR. Where practical, AEMO will consider any adjustments to the IIO development trajectories within that publication in the 2026 ISP.

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

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

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

REZ access schemes

Access schemes are a key part of the NSW EII Act, which 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) is applied, and is lifted if transmission augmentation increases the REZ capacity beyond the scope of the Central-West Orana REZ Network Infrastructure Project[30].
- **South West New South Wales** – a maximum connection limit of 3.98 GW of new VRE 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].

Queensland Energy (Renewable Transformation and Jobs) Act 2024

The *Energy (Renewable Transformation and Jobs) Act 2024* (Qld)[32] includes a range of measures for the development of renewable and firming generation in Queensland, including providing for the establishment of REZs and facilitating transmission investments.

The Act includes targets to achieve 50% of electricity generated in Queensland to be from renewable energy sources by 2030, 70% by 2032, and 80% by 2035. The Queensland Renewable Energy Target (QRET) will be incorporated in the modelling for all scenarios as it is a legislated target and is also included in the AEMC's emissions targets statement.

Additional Queensland Government measures include the development of Borumba Pumped Hydro and the hydrogen-ready Brigalow Peaking Power Plant. In addition, the Act establishes planning and governance frameworks for REZs, and requires the government to develop a Queensland SuperGrid Infrastructure Blueprint, the next of which is due for release by May 2025. 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 its consultation on the Draft 2025 *Network Expansion Options Report*.

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[30] 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.

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

Tasmanian Renewable Energy Target (TRET)

The TRET is a renewable energy target in the *Energy Co-ordination and Planning Act 1995* (Tas)[33] 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 emissions targets statement.

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

The South Australian Government has announced and is seeking to legislate for a target of net 100% renewable energy generation by 31 December 2027[34]. 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 (which remains in the emissions targets statement) that existed previously in South Australia.

AEMO proposes to model the 2027 target given the South Australian Parliament is considering legislation for the proposed new target. AEMO will continue to engage with the South Australian government to evaluate the appropriateness of this as the 2025 IASR is finalised.

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 Roadmap.

The *Renewable Energy (Jobs and Investment) Act 2017* (Vic)[35] 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[36]. 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[37]).

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[38] 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.

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

[34] *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.

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

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

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

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

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, 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.

Three Capacity Investment Scheme tenders have been launched to date to support the scheme. A fourth upcoming tender will announce successful bids in Q3 2025.

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 Capacity Investment Scheme tenders in its modelling, as well as the cumulative dispatchable allocations by jurisdiction. As the mechanism continues to develop, AEMO may incorporate further detail into the 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[39]. 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.

South Australia Firm Energy Reliability Mechanism

The Government of South Australia 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) is planned to be calculated as part of the annual South Australia Electricity Development Plan, to be supported by a form of tender process. Subject to the release of sufficient detail to define its impact upon power

[39] See unlocking-tasmania's-energy-capacity_december-2018.pdf for further information on the impact of greater interconnection on existing latent capacity.

system needs and a clear pathway to implementation before the finalisation of the 2026 ISP, AEMO intends to consider this policy further prior to finalising the 2025 IASR.

Jurisdictional policies regarding hydrogen development

This section contains updates for Stage 2

The Hydrogen Production Tax Incentive[40] has been legislated by the Federal Government and is part of the *Future Made in Australia* package[41] 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. AEMO proposes to include the following policies:

- The South Australian Government is supporting a number of projects, including the Hydrogen Jobs Plan[42] which seeks to establish hydrogen production and power generation in South Australia. The output from a 250 MW electrolyser project is included in the hydrogen production forecasts for each scenario. The electrolyser is expected to be complemented with a 200 MW hydrogen-capable generator. The generator is assessed according to AEMO's standard generation commitment criteria**.**
- The New South Wales Hydrogen Strategy[43] includes the Renewable Fuels Scheme, established in the *Electricity Supply Act 1995*[44]*.* The Scheme targets increasing production of renewable hydrogen up to 8 petajoules (PJ) per annum by 2030[45]. There is a consultation underway to expand the scheme to include other fuels. The effect of the currently legislated Renewable Fuels Scheme is considered in forecasting hydrogen production needs for each scenario. There is currently less than 1 MW total of committed projects in New South Wales, and the forward pipeline of supply is highly uncertain. At this stage AEMO has not applied the scheme's target hydrogen volumes to the hydrogen forecasts, given the opportunity for liable entities to pay a penalty rather than to surrender renewable fuel certificates to meet their obligations under the scheme.

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

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

[42] See https://www.ohpsa.sa.gov.au/about-the-project and https://www.statebudget.sa.gov.au/our-budget/jobs-and-economy/hydrogen.

[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 *Network Expansion 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.

AEMO will include concessional finance in the 2026 ISP where any of the benefit will be shared with consumers for projects where funding is publicly committed or an agreement is likely to be executed, consistent with the recommended approach in the AER's CBA Guidelines[47]. Details regarding concessional finance will be maintained on the Transmission Augmentation Information Page[48].

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[49], and is listed as a committed project in AEMO's transmission augmentation information page[50]. 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[51] and is listed as an anticipated project in AEMO's transmission augmentation information page[52]. 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 2032

The Queensland Government SuperGrid Infrastructure BluePrint[53] was released in 2022 and is scheduled to be updated in 2025. The Queensland REZ Roadmap[54], published in March 2024, laid out the framework to develop and connect grid-scale renewable energy.

AEMO will consider the development of the blueprint projects and the Queensland REZ Roadmap as transmission options in the Draft 2025 *Network Expansion Options Report.*

[47] AEMO. *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/industry/registers/resources/reviews/2024-review-cost-benefit-analysis-and-regulatory-investment-test-guidelines/final-decision.

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

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

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

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

[54] At https://www.epw.qld.gov.au/__data/assets/pdf_file/0036/49599/REZ-roadmap.pdf.

The Queensland Government has announced that it is working to deliver the CopperString 2032 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. CopperString 2032 is listed as an anticipated project in AEMO's transmission augmentation information page[55].

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.

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 model landholder payment schemes in New South Wales, Queensland and Victoria. If new landholder payment schemes are announced, AEMO will use reasonable endeavours to model them.

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.

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.

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.

[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.

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

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).

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[58].
- 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 Energy Upgrades (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)[59], 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.

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

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

- 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 PV.
- 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 which requires each manufacturer to meet per kilometre efficiency standards for new cars, 4WDs and utility vehicles.
- 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.
- 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.

New South Wales Energy Security Safeguard

New South Wales has a target for energy efficiency savings through its established Energy Security Safeguard[60], both in general through the Energy Savings Scheme[61], and at time of peak demand through the Peak Demand Reduction Scheme (PDRS)[62]. 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[63] in October 2022 (updated in 2023[64]) to support net zero emissions in Victoria in 2050 and halving emissions by 2030. The Roadmap outlines options for replacing gas usage (such as energy efficiency, electrification, hydrogen and biogas) to reduce emissions and

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

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

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

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

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

consumer costs. On 1 January 2024, the Victoria Planning Provisions were amended to ban new residential gas connections for developments requiring a planning permit[65].

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*[66], allowing the Australian Capital Territory Government to develop regulation banning new gas connections in the territory. Regulation preventing new gas network connections in most areas commenced on 8 December 2023[67].

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 Draft 2025 IASR will be underpinned by national carbon budgets that are compatible with global temperature targets (relating to Relative Concentration Pathways, 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 applies four decarbonisation pillars to reduce emissions in a growing economy:

- Electrification and other fuel-switching away from emissions-intensive fuels.
- Energy efficiency improvements to improve energy productivity.
- Decarbonising the electricity sector.
- Non-energy emissions reduction and 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 these four pillars (discussed in Section3.3.4), and earlier actions to decarbonise will reduce the need for more aggressive actions later.

The multi-sectoral modelling will translate the national carbon budgets to NEM-wide carbon budgets that ultimately underpin the ISP, as discussed in the current *ISP Methodology*[68]. These NEM-wide carbon budgets recognise that the electricity sector has a key role to play as an early mover by enabling the decarbonisation of other sectors via electrification and increased energy efficiency.

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[65] See https://www.gazette.vic.gov.au/gazette/Gazettes2024/GG2024S001.pdf.

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

[67] 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.

[68] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology.

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 0.

The multi-sectoral modelling commissioned by AEMO is ongoing and will be separately consulted on as part of the Draft 2025 IASR Stage 2, to be published in February 2025. As such, this section does not present the proposed carbon budgets to be modelled in the 2026 ISP.

3.2.1 Alignment to IEA World Energy Outlook scenarios

AEMO's Draft 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 Draft 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 Draft 2025 IASR.

The 2024 WEO scenarios and how they align with the Draft 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 Draft 2025 IASR, AEMO provides 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 ***Green Energy*** 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 ***Progressive Change*** 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's Relative Concentration Pathways

The Draft 2025 IASR scenarios also map to the RCPs framework used by the Intergovernmental Panel on Climate Change (IPCC)[69]. 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:

- AEMO's ***Green Energy*** 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 ***Progressive Change*** 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 Draft 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

2023 IASR scenario	2024 WEO scenario	RCP Framework
Green Energy	NZE	RCP1.9
Step Change	APS	RCP2.6
Progressive Change	STEPS	RCP4.5

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

3.2.3 Translating international climate scenarios to NEM-wide carbon budgets

This section contains updates for Stage 2

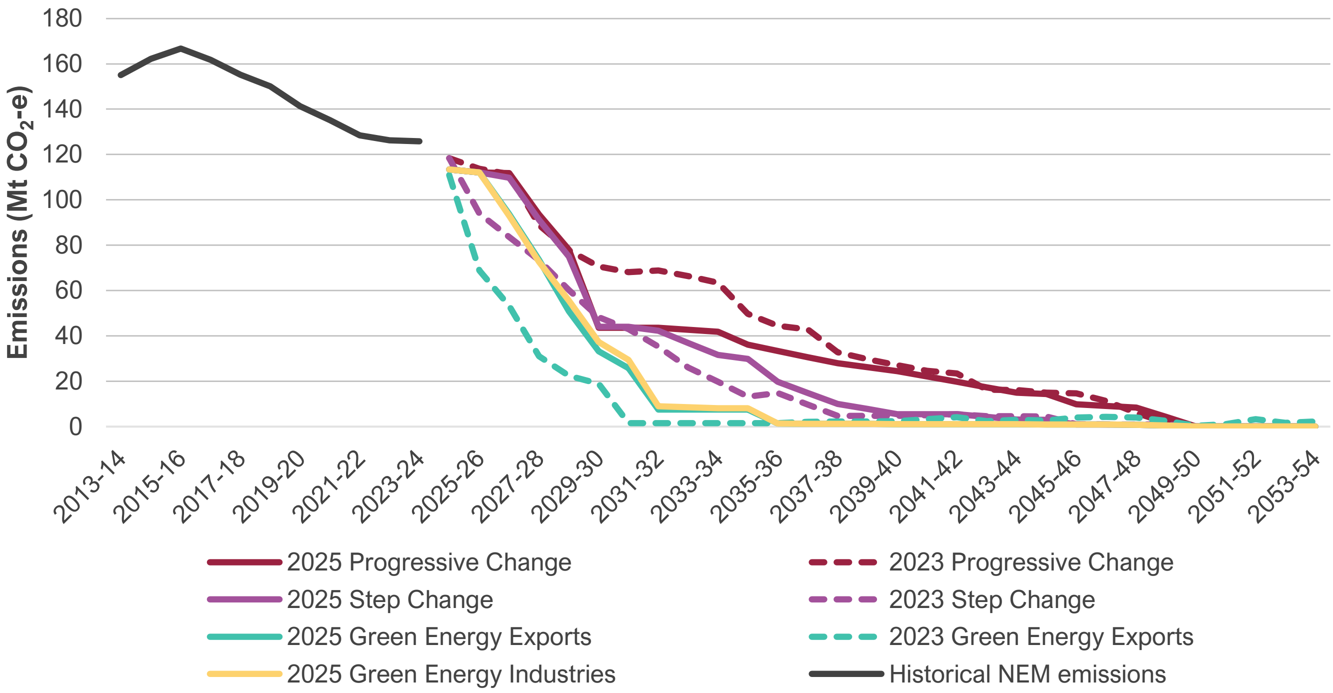
To ensure the scenarios adopt emissions abatement outcomes consistent with the scenario narratives and with mapping to the WEO scenarios and RCPs described above, multi-sectoral modelling has been conducted to produce carbon budgets for the Australian economy[70] (including a distinct budget for the electricity sector and the NEM) among other forecasting influences described in Section 3.3.4.

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 compared 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 are subject to ongoing examination of the interaction between electricity sector emissions reduction opportunities and emissions reduction and offsets in other sectors, calculated by the multi-sectoral modelling. AEMO welcomes stakeholder feedback on the suitability of these draft forecasts, that will inform the finalisation of the NEM carbon budgets.

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



[70] The economy-wide carbon budget is broadly consistent with the 2021 to 2030 carbon budget defined in the *Climate Change Act (2022).*

Compared to the 2023 IASR, NEM temperature-linked carbon budgets have reduced in *Progressive Change* and increased in *Step Change* and *Green Energy Exports:*

- In *Progressive Change*, 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 the 2023 IASR which did not include them, leading to an overall reduction in carbon budget.
- 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 *Green Energy Exports*, 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 2023 IASR.
- *Green Energy Industries* follows a similar trajectory to *Green Energy Exports*, as both scenarios are aligned to RCP1.9 targeting a 1.5°C future.

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 and 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
Step Change	418	586
Progressive Change	418	797
Green Energy Exports	418	321
Green Energy Industries	418	335

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

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

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 *Progressive Change* and increase in *Step Change* and *Green Energy Exports* 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
Step Change	681	811
Progressive Change	1,203	1,022
Green Energy Exports	353	546
Green Energy Industries	Not applicable	561

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.

To derive state-level carbon budgets, economy-wide emissions reduction targets for each state presented previously in Table 6 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 Draft 2025 *Inputs and Assumptions Workbook*.

Table 12 State-level carbon budgets (Mt CO_2-e)

Region	2026-27 to 2029-30	2030-31 to 2049-50	2026-27 to 2049-50
New South Wales	144	272	Not applicable
Queensland	188	269	Not applicable
South Australia [A,B]	Not applicable	Not applicable	52
Victoria [B]	125	142	Not applicable

A. Based on the currently legislated target of 60% reduction below 1990 levels by 2050. Should the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024* pass, AEMO will update the carbon budgets for South Australia as appropriate.
B. 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.

Matters for consultation for Stage 2

- Do you consider the proposed carbon budgets to be appropriate?

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.
- CER.
- Large industrial loads (LILs), informed by stakeholder surveys.
- Data centres.
- Electrification and other fuel-switching opportunities in the context of possible decarbonisation pathways.
- 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.
- 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].

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

[74] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/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://forecasting.aemo.com.au/.

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

3.3.1 Historical demand data

Input vintage	• November 2024 for demand data • November 2024 for loss data • November 2024 for auxiliary load data
Status	• Current view
Source	• SCADA/EMMS/NMI Data • Generation Information page • AER, WA-based retailer Synergy and network operators
Update process	• Continuously updated

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 large industrial load (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

[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.

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.

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	November 2024
Status	Current view
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 make available across Australia, as shown in 0, Table 14 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 region, except where weather stations have been discontinued, however AEMO is currently consulting on an updated *Electricity Demand Forecasting Methodology* that proposes to increase the spatial granularity of the forecasting approach. This intends to introduce greater consideration of sub-regional differences, which will require additional weather stations for each sub-region. Table 13 therefore includes the current regional weather stations, and Table 14 lists proposed weather stations for the sub-regions if the changed approach is adopted[78].

[78] The in-progress consultation on AEMO's forecasting approach is available at https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

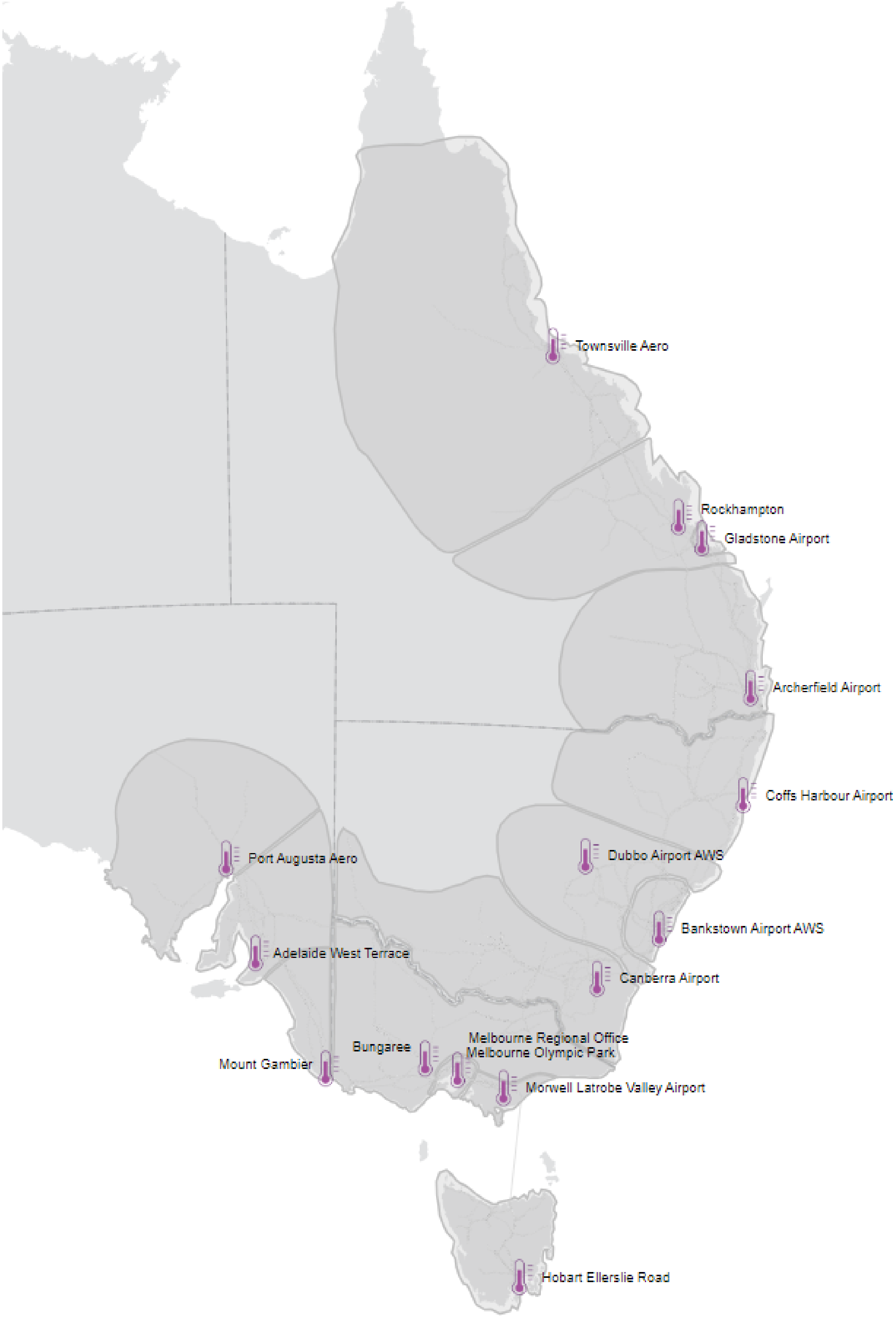
Table 13 Weather stations used in forecasting consumers electricity use (regional)

Regional weather stations			
Region	**Station name**	**Date range**	**BoM site number**
New South Wales	Bankstown Airport AWS	January 1968 – Now	066137
Queensland	Archerfield Airport	April 1929 – Now	040211
South Australia	Adelaide (Kent Town)	October 1993 – July 2020	023090
	Adelaide (West Terrace)	July 2020 – Now	023000
Tasmania	Hobart (Ellerslie Road)	January 1882 – Now	094029
Victoria	Melbourne Regional Office	January 1908 – January 2015	086071
	Melbourne (Olympic Park)	May 2013 – Now	086338
Western Australia	Perth Metro	February 1993 – Now	009225

Table 14 Weather stations used in forecasting consumers electricity use (sub-regional)

Proposed weather stations for NEM sub-regions				
Region	**Sub-region**	**Station name**	**Date range**	**BoM site number**
New South Wales	Central New South Wales	Dubbo Airport AWS	January 1946 – Now	065070
New South Wales	Northern New South Wales	Coffs Harbour Airport	August 2013 – Now	059151
New South Wales	Sydney, Newcastle & Wollongong	Bankstown Airport AWS	January 1968 – Now	066137
New South Wales	Southern New South **Wales**	Canberra Airport	September 2008 – Now	070351
Queensland	Central Queensland	Rockhampton	January 1927 – Now	039264
Queensland	Gladstone Grid	Gladstone Airport	October 1993 – Now	039326
Queensland	Northern Queensland	Townsville Aero	January 1940 – Now	032040
Queensland	Southern Queensland	Archerfield Airport	April 1929 – Now	040211
South Australia	Central South Australia	Adelaide (Kent Town)	October 1993 – July 2020	023090
		Adelaide (West Terrace)	July 2020 – Now	023000
South Australia	Northern South Australia	Port Augusta Aero	July 2001 – Now	018201
South Australia	South East South Australia	Mount Gambier (Blue Lake Holiday Park)	January 1975 – Now	026085
Tasmania	Tasmania	Hobart (Ellerslie Road)	January 1882 – Now	094029
Victoria	Greater Melbourne and Geelong	Melbourne Regional Office	January 1908 – Jan 2015	086071
		Melbourne (Olympic Park)	May 2013 – Now	086338
Victoria	West and North Victoria	Bungaree (Kirks Reservoir)	August 1881 – Now	087014
Victoria	South **East Victoria**	Morwell (Latrobe Valley Airport)	January 1984 – Now	085280

Figure 3 Map of weather stations used in forecasting consumers' electricity use, per NEM sub-region



Matters for consultation from Stage 1

- Will these weather stations provide appropriate weather information to apply to the NEM sub-regions when forecasting consumers' electricity use, including annual aggregate electricity consumption and importantly the peak maximum, and minimum, demand conditions?

3.3.3 Historical and forecast other non-scheduled generators (ONSG)

Input vintage	October 2024 for installed capacity (Generation Information page) October 2024 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, which is non-scheduled generation that excludes rooftop solar) using information from AEMO's Generation Information[79] 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 October 2024 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).

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

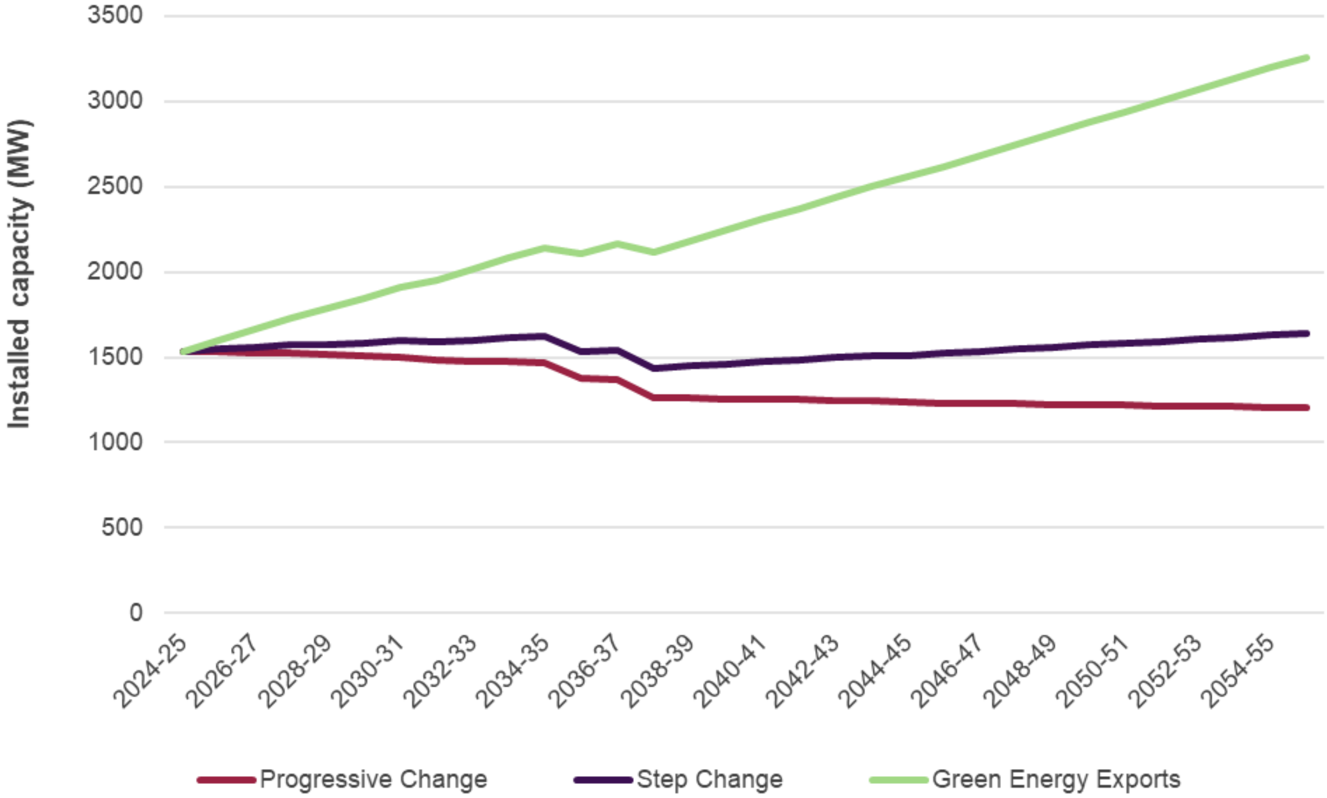
Figure 4 Aggregate ONSG capacity, by NEM region (MW)

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 biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) for the *Step Change* scenario in the long term.

For the *Progressive Change* scenario, the same withdrawal of capacity is modelled, but forecast growth is slightly slower. The *Green Energy* scenario, on the other hand, has significantly more growth assumed for renewable technologies (small-scale wind and biomass). Figure 5 shows the NEM-wide installed capacity for the three scenarios.

Historical capacity factors by technology type are used to forecast generation using the projected installed capacities, offsetting the electricity consumption in the forecast. AEMO's current view on ONSG for producing the forecasts is based on the Generation Information page released in July 2024.

Figure 5 Forecast NEM-wide other non-scheduled generation capacity (MW)



3.3.4 Multi-sectoral modelling influences to demand forecasts

This section contains updates for Stage 2

Input vintage	February 2025
Status	Draft
Source	Draft CSIRO multi-sectoral modelling

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, CER investments including road transport EV uptake. 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 and export opportunities, including the opportunity to electrify emissions-intensive residential and commercial appliances and industrial processes, the potential role of emissions sequestration, and the development need for alternative gaseous fuels (such as hydrogen and biomethane) for those applications that are difficult or cost-prohibitive to electrify.

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).

To transition Australia's economy, four pillars of decarbonisation are broadly identifiable, with each scenario utilising these pillars to varying degrees considering uncertainty around future technology improvements, costs, and barriers to deployment.

The four pillars are:

- **Energy efficiency** investments to improve energy productivity and reduce energy waste.
- **Decreasing carbon intensity of electricity generation** to near zero through increasing penetration of renewable energy generators.
- **Switching away from fossil fuels** to zero or near-zero emissions alternatives, including electrification and alternative gases.
- **Non-energy emissions reduction and offsetting** of residual emissions through sequestration and other opportunities to reduce emissions, primarily in the land-use and agriculture sectors).

Figure 6 illustrates the scale of utilisation of the four pillars across the scenarios.

Figure 6 Forecast utilisation of the four pillars of decarbonisation, by scenario

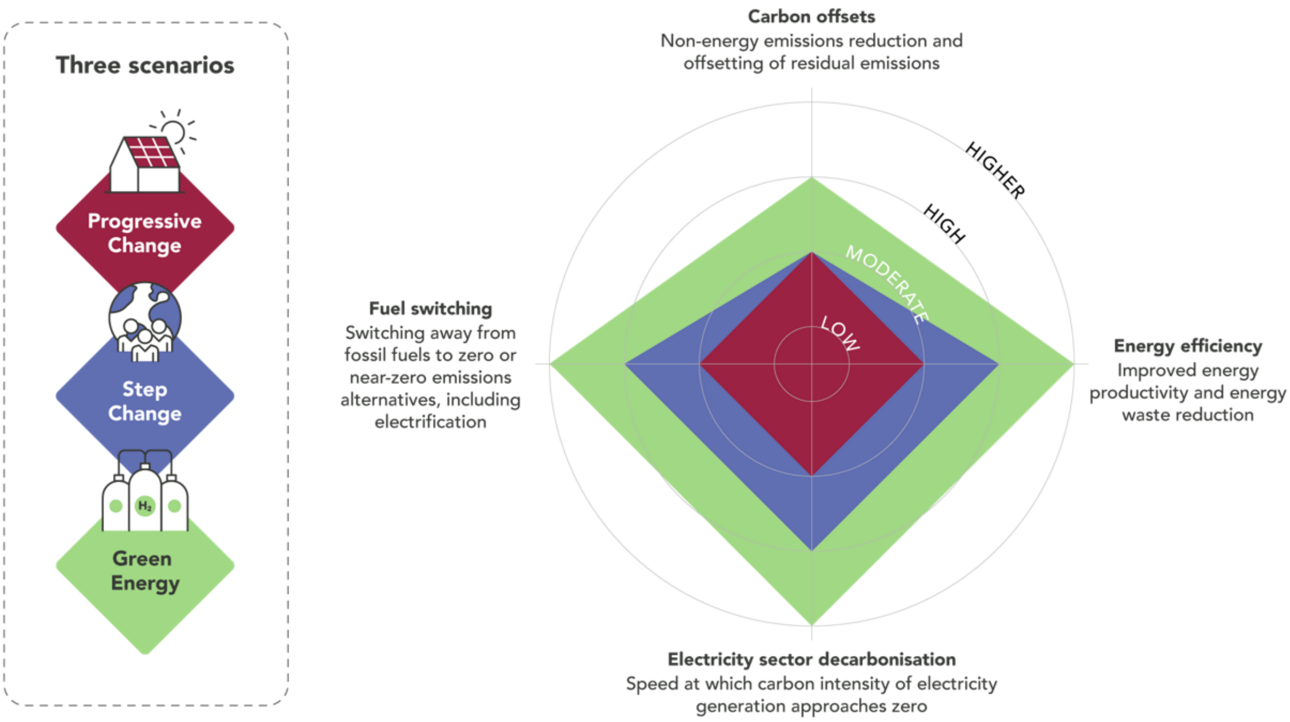


Table 15 describes, at a high level, the key assumptions and outcomes from the multi-sectoral modelling.

Table 15 Key assumptions and outcomes from the multi-sectoral modelling

	Green Energy Exports	*Green Energy Industries*	*Step Change*	*Progressive Change*
Electrification, excluding road transport, across NEM and WEM (Section 3.3.5)	Electrification is expected to provide aggressive emissions reduction objectives in this scenario in order to meet the scenario's carbon targets. Residential electrification 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.	Similar investment in electrification is forecast across sectors as in the *Green Energy Exports* scenario.	In this scenario, the degree of investment in electrification is high, especially in manufacturing and other industrial activities, although less than the *Green Energy* scenario variants. 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.	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 *Progressive Change*. Under this scenario, more challenging economic conditions slow down the uptake of residential electrification.
Energy efficiency (Section 3.3.12) **Note: multi-sectoral modelling energy efficiency outcomes presented here complement SPR's policy-driven energy efficiency forecasts.**	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.	The commitment to decarbonisation is the same as for *Green Energy Exports*, however lower export facing industrial output assumptions deliver less energy efficiency savings. Greater uptake of efficient LED lighting, heat pump hot water systems, and improved HVAC systems deliver savings in buildings. While in industry, process improvements, small equipment upgrades and large equipment upgrades occur at pace.	While energy efficiency is lower than in the *Green Energy* scenario variants, 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.	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 *Progressive Change*, energy efficiency contributes significantly to decarbonisation.
Carbon sequestration across NEM states (outlined in further detail below)	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 approximately 179 Mt CO_2-e/year by 2044-45. Direct air capture (DAC) is expected to support emissions reduction from the late 2030s.	Similar levels of carbon sequestration are required to those observed in *Green Energy Exports*, with both scenarios aligned to a 1.5°C future. Carbon sequestration activity begins at the same time as in *Green Energy Exports* and reaches 177 Mt CO2-e/year by 2044-45. DAC features in this scenario from the late 2030s.	With *Step Change* aligned to a <2.0°C future, the required pace of decarbonisation in the scenario is slower than in the *Green Energy* scenario variants, resulting in more gradual use of sequestration. Sequestration activities instead ramp up to 162 Mt CO_2-e/year by 2049-50. Sufficient use of land-based sequestration activities avoids the need for higher cost DAC in this scenario.	With *Progressive Change* 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 171 Mt CO_2-e/ year by 2049-50. DAC is not deployed in this scenario.

	Green Energy Exports	*Green Energy Industries*	*Step Change*	*Progressive Change*
Fuel-switching to alternative gaseous fuels (Section 3.3.6)	This pillar provides a moderate contribution to decarbonisation, though smaller than electrification. Decarbonisation is occurring through switching of natural gas to electricity, biomethane and small amounts of industrial hydrogen. Overall hydrogen volumes are lower than the 2023 IASR forecasts, due to reduced export assumptions and lower forecast domestic hydrogen demand, despite the inclusion of additional demand for hydrogen in green commodities. The majority of hydrogen demand is for green commodities, focused on ammonia and iron. Overall 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.	Hydrogen demand is similar to *Green Energy Exports*, except there is reduced demand for green commodities, with the scenario variant focusing on only on green iron and steel commodity development. Zero hydrogen exports are assumed. Hydrogen demand is split between domestic (mostly transport) and green iron. Biomethane uptake is comparable to the *Green Energy Exports* scenario with the majority replacing natural gas in the same sectors as *Green Energy Exports*.	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 transport sector. Biomethane volumes are higher compared to the 2023 IASR, with volumes replacing natural gas in the same sectors as the other scenarios.	The majority of hydrogen demand is for domestic use in transport, 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.

Matters for consultation for Stage 2

- Are the key assumptions and outcomes described in Table 15 suitably aligned with scenario definitions?

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[80] 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.

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

- Carbon capture and storage (CCS) technologies from emitting processes, such as capturing electricity generation emissions.

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.

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

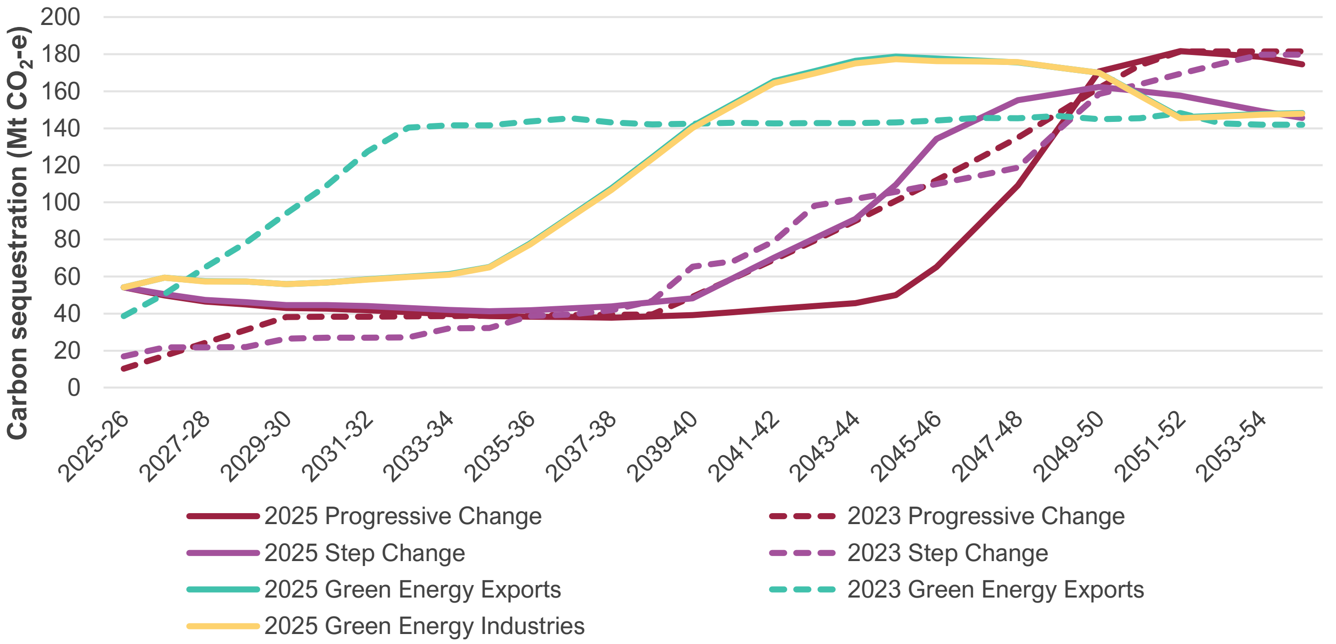
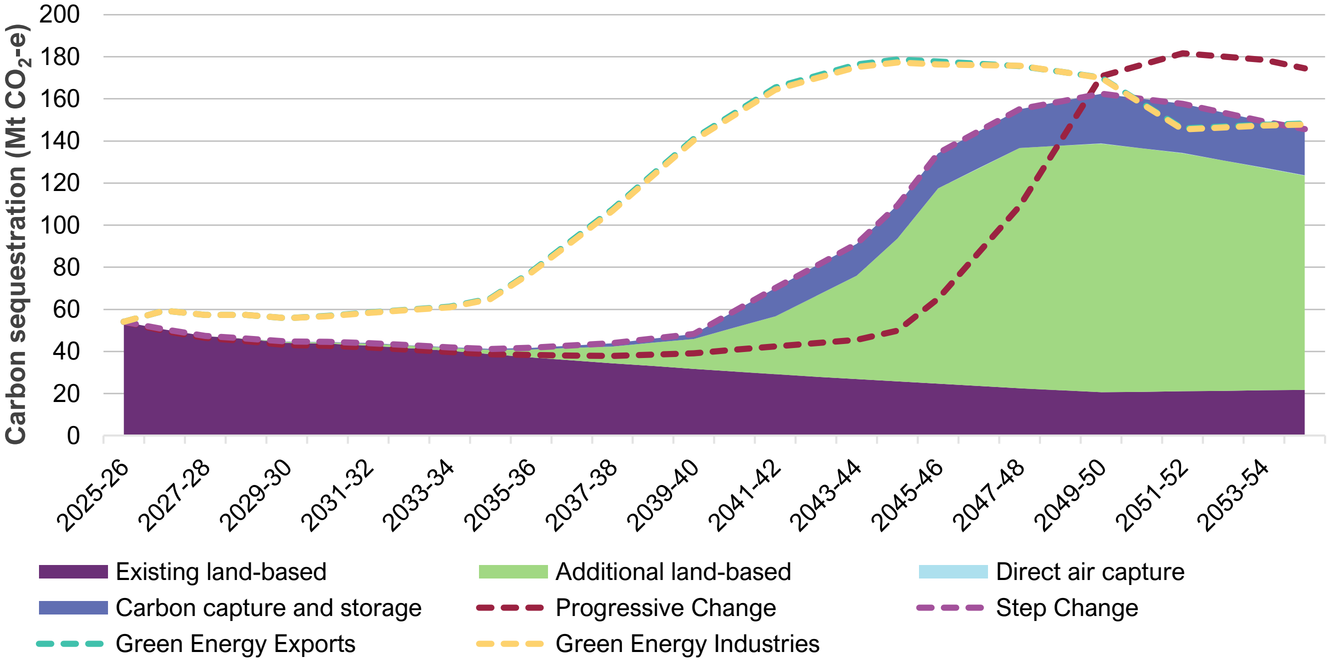


Figure 8 shows the contribution of each of the sequestration categories in *Step Change*. As existing land-based sequestration declines in effectiveness with age, additional land-based sequestration solutions begin to take effect from the mid 2030s as decarbonisation efforts accelerate. CCS across other sectors is required at a similar timing, while DAC does not play a role in *Step Change* due to its high cost.

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 15 above, DAC is assumed to be commercially feasible only in *Green Energy Exports* and *Green Energy Industries* from the late 2030s onwards, 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 decarbonisation outcomes earlier in these scenario variants despite DAC being assumed to be a relatively expensive option compared to other forms of abatement.

3.3.5 Electrification

This section contains updates for Stage 2

Input vintage	January 2025
Status	Draft
Source	Draft CSIRO multi-sectoral modelling for electrification excluding road transport
Update progress	Non-transport electrification updates based on latest multi-sectoral modelling consultancy

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.

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 the *Green*

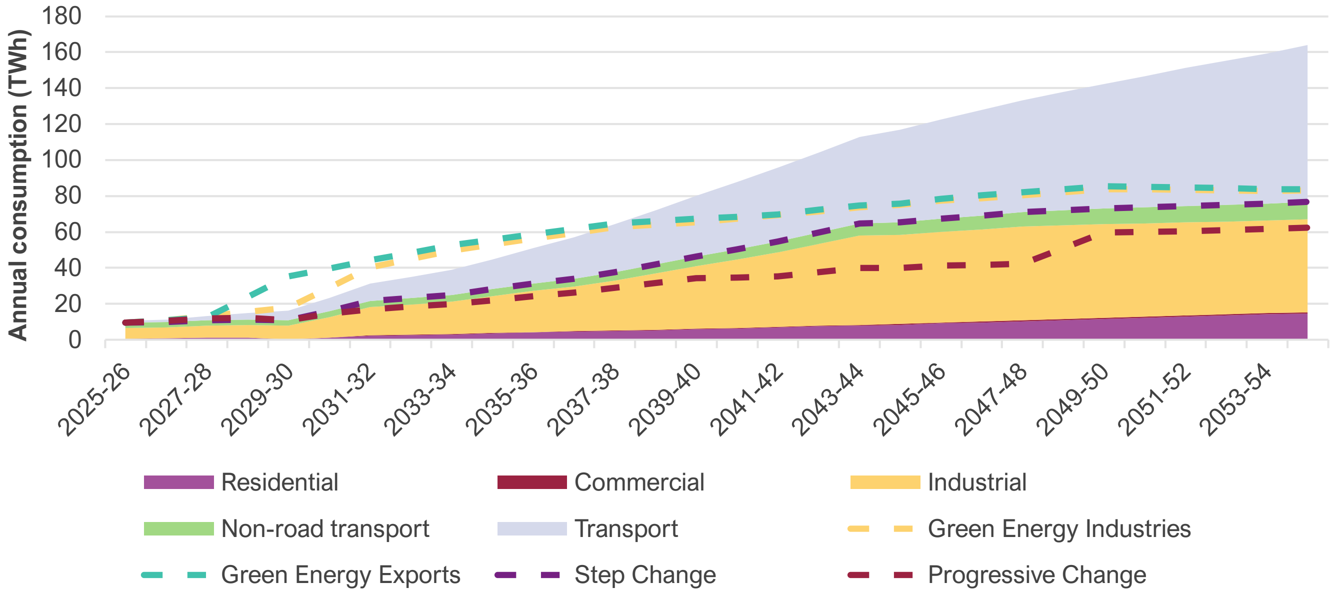
Energy scenario variants adopting both a high degree of electrification and fuel-switching to hydrogen to support higher economic growth.

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 transport sector is expected in all scenarios, although the pace and magnitude of electrified transportation also varies across scenarios (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 process for iron and steel, and high temperature blast furnaces. Scenarios that incorporate faster emissions reduction assume greater 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, which is further described in Section 3.3.7. By 2049-50, 142 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. Transport electrification is forecast to grow materially, from approximately 1 TWh in 2025-26 to 69 TWh by 2049-50 (representing 49% of all electrification), and to account for over 40% of all electrification by 2040-41 in all scenarios.

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)



Note: Transport electrification in the stacked area chart is excluded from values represented by the dashed lines. More details on EV forecasts can be found in Section 3.3.7.

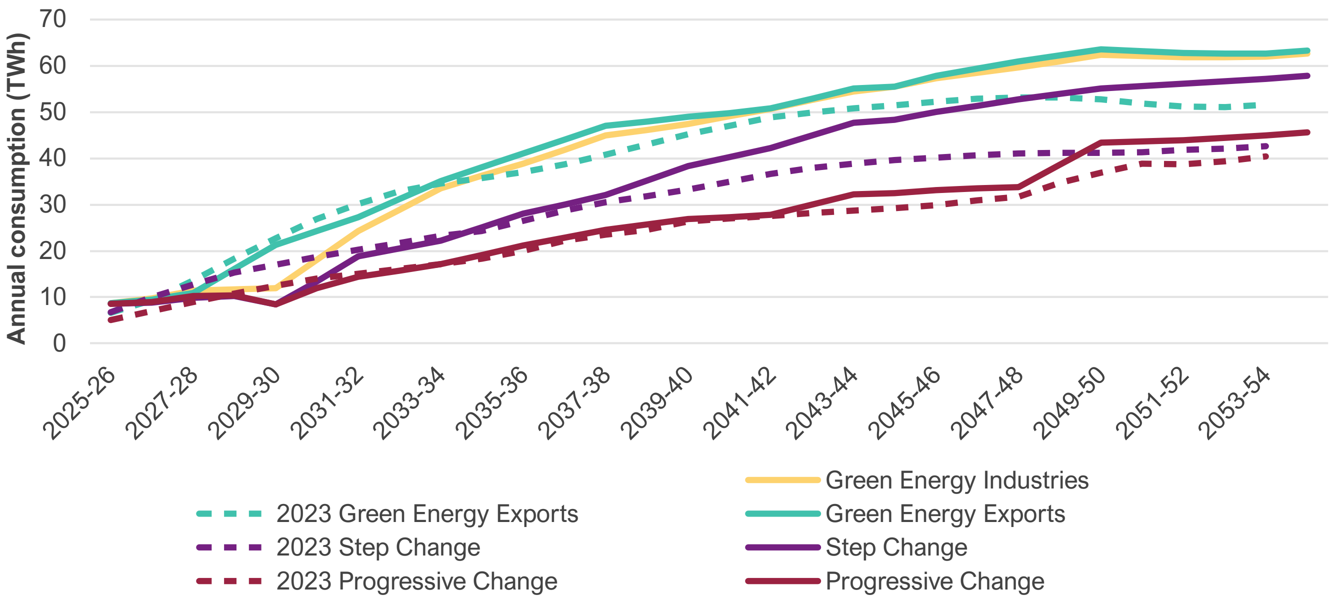
Industrial electrification accounts for the second largest share of electrification in all scenarios, as electricity is considered an appropriate alternative low-emission fuel for a spectrum of industrial heating processes. Technologies to electrify mining processes and a shift towards the uptake of on-site electric haulage trucks would also contribute to industrial electrification.

For some regions, particularly Victoria, residential electrification has high potential, given the penetration of gas heating and hot water system presently and the opportunity therefore to electrify these domestic appliances. Policies prohibiting new gas connections (in Victoria[81] and the Australian Capital Territory) are providing a driver for greater electrification.

The lines in Figure 9 reflect forecasts of electrification excluding the road transport sector for each scenario. Electrification investments occur earlier and faster in the *Green Energy* scenario variants 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 these scenarios. Conversely, the *Progressive Change* scenario exhibits slower adoption in line with more challenging economic conditions.

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

Figure 10 Electrification forecast per scenario (NEM only), excluding road transport



Compared to the 2023 IASR, electrification is lower in the *Green Energy* and *Step Change* scenarios until 2033-34 and 2034-35, respectively. This is due to slower investment in industrial electrification in the first five years, after which industrial electrification uptake in *Step Change* continues to increase at a greater rate than it did in the 2023 IASR. This acceleration in uptake from 2029-30 is most visible in manufacturing and agriculture. Conversely, the current forecasts project a lower level of electrification in the mining sector. The differences partially reflect the assumption that there are more barriers to electrify certain processes in these sectors than was assumed in the

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

2023 IASR. These assumptions translate to either slower initial uptake or lower total potential for electrification (noting that the multi-sectoral model does not always reach these limits).

Electrification forecasts in the multi-sectoral modelling for the residential and commercial sectors are presently lower in *Step Change* and *Progressive Change* compared to the 2023 IASR. AEMO is examining this draft forecast prior to finalising the IASR, and welcomes stakeholder feedback on the relative scale of electrification for all customer segments.

Impact of electrification on daily and seasonal load shape

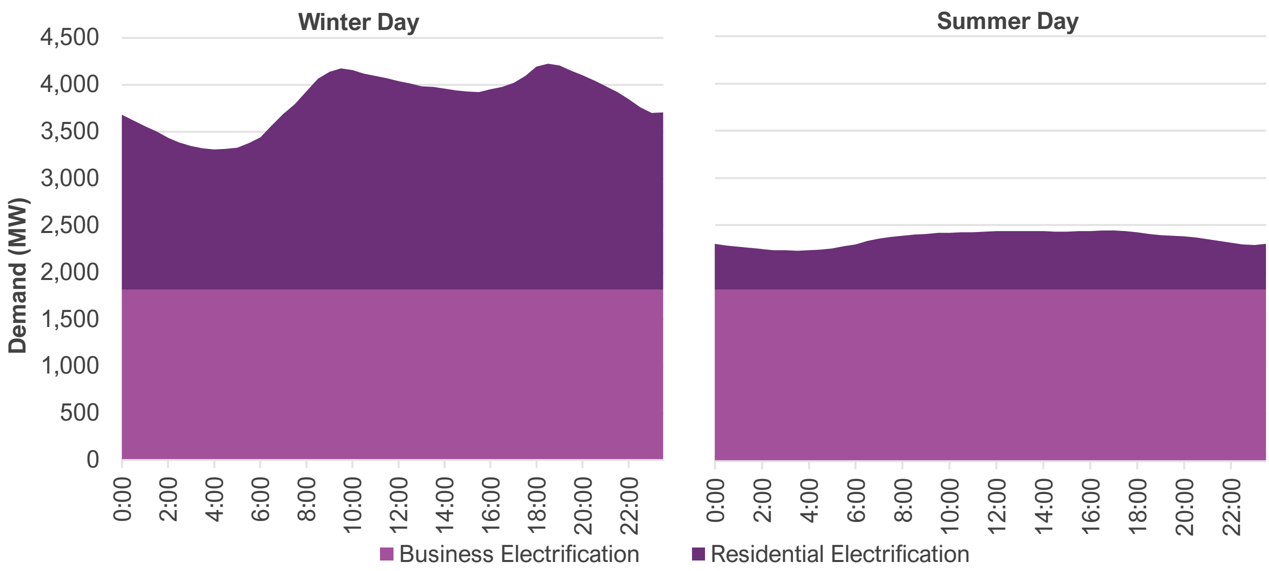
In converting non-transport electrification into half-hourly data, AEMO assumes:

- Business consumption shows relatively low seasonality, on aggregate, and therefore electrification of the business sector (including industrials) approximates a baseload.
- 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.

Newly electrified loads are assumed to mirror existing electricity consumption patterns, generally with more load in the day than overnight. Figure 11 contrasts two example daily load profiles of residential and business electrification (excluding the transport sector). The business electrification load is assumed to be flat across the year and across the day as large industrial loads electrify their processes. The residential load profile varies across the day and is much higher in winter compared to summer due to heating load.

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 within the energy efficiency component (see Section 3.3.12).

Figure 11 Example electrification daily load shape contrasting winter and summer



3.3.6 Fuel-switching to alternative gaseous fuels

This section contains updates for Stage 2

Input vintage	February 2025. Biomethane production cost estimates as at December 2024.
Source	ACIL Allen (Hydrogen export/commodity volumes, biomethane availability and production costs), 2024 Draft CSIRO Multi-sectoral modelling
Updates since 2023 IASR	Updates of fuel-switching to biomethane, all hydrogen forecasts

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

All Australian states have outlined strategies to support the development of hydrogen as part of each government's broader energy transition. A number of hydrogen production projects are announced[82] or under development across the eastern states of Australia, as listed in CSIRO's HyResource[83] project listing. While there are a large number of projects under development, and several small-scale projects are under construction or operating, only a handful with electrolyser sizes over 10 MW have reached financial close.

The cost, timing and scale of a potential hydrogen economy in Australia is highly uncertain, and may have a material influence on the future power system needs. Given the scale of uncertainty and impact of these potential developments, AEMO considers various hydrogen futures within the Draft 2025 IASR scenarios. In recognition of the uncertainty, AEMO is considering, and seeks stakeholder feedback on two potential variants for the *Green Energy* scenario, reflecting different levels of hydrogen use for green commodities and exports – see Section 2.1.

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) as outlined in the following sections. Specific assumptions are outlined as follows.

Policy

Federal legislation[84] has been passed which includes a $2/kg production tax incentive for hydrogen (see details, along with other state-based incentives, in Section 3.1). This policy was legislated in 2025, thereby is considered

[82] This Draft 2025 IASR has a cut-off date of 14 February 2025 for news and data; hence, among other things, the announcement regarding deferral of the proposed hydrogen electrolyser build for the Hydrogen Jobs Plan in South Australia is not taken into account in these forecasts. AEMO will consider new information when finalising the 2025 IASR.

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

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

consistent with other policies that meet the requirements of NER 5.22.3(b) (as outlined in Section 3.1). It was therefore considered within the economic forecasts and multi-sectoral modelling.

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' 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.

The 2024 multi-sectoral modelling allowed the potential development of steam methane reforming with CCS in the *Step Change* and *Progressive Change* scenarios[85]. The multi-sectoral modelling also found that electrolysis was lower cost over the assumed plant lifetime. AEMO proposes to continue to focus on electrolysis technologies within ISP modelling, and to assume no growth in steam methane reforming hydrogen production above existing levels.

Pipeline blending

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 distribution networks (which operate at lower pressure), with no blending for transmission networks (which operate at higher pressure). While it is technically feasible to increase the networks' capability to host higher blends, this would require pipeline and appliance investment. The Australian Hydrogen Centre[86] found that it may be more cost-efficient to switch appliances and invest sufficiently in pipelines to accept 100% hydrogen blends rather than at progressively higher blend levels. It is unclear whether social appetite for high hydrogen blends exists in Australia where such blends would require appliance change; a review of literature for gas conversion projects[87] found that there can be challenges gaining public acceptance of conversion of gas distribution to hydrogen. Furthermore, the multi-sectoral modelling forecast minimal hydrogen use in residential or commercial sectors, due to the higher cost of hydrogen compared to other alternatives such as biomethane and electrification.

AEMO therefore proposes to retain the 10% blend assumption for distribution networks which applied in the 2023 IASR. 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

[85] 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 SMR with CCS is not consistent with this expectation, as some emissions are not captured within the CCS process.

[86] See https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-Victoria-Feasibility-Study.pdf.

[87] See https://arena.gov.au/assets/2023/09/AHC-100-Hydrogen-Distribution-Networks-Victoria-Feasibility-Study.pdf - Appendix D.

strategies) will enable dedicated supply of hydrogen for industrial and transport customers that demand it, using transportation methods that do not use existing gas distribution or transmission networks.

Given the low volumes of fuel-switching forecast for residential and commercial users in the multi-sectoral modelling (see Forecast hydrogen consumption for domestic use below), AEMO considers this an appropriate blending assumption and welcomes stakeholder feedback on this position.

Grid connection

Electrolysis requires a source of electricity to be applied to purified water to produce hydrogen. The majority of electrolysers were assumed to be grid-connected in the early years. However, in later years there may be advantages in some larger hydrogen production projects being developed off-grid (for example, with the electrolyser located close to the renewable energy source but not connected to the transmission system), or with embedded renewable generation supply and a smaller connection to the grid. The *ISP Methodology*[88] provides detail around the potential supply pathways including electrolyser and hydrogen hub locations.

AEMO proposes to assume that electrolysers to supply export demand, domestic hydrogen demand, and green commodities will be located at REZs within each sub-region – this would potentially minimise additional network requirements and associated infrastructure for hydrogen operation.

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[89] on the optimal choice of pathway. The majority of studies found that it is cheaper to transport molecules, 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[90], and applying assumptions for future projects. These were smoothed by AEMO and are outlined in Figure 12. It is envisaged that larger potential developments in more remote areas away from the coast, such as in Queensland and South Australia, may be more likely to be developed off-grid. Only the on-grid 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.

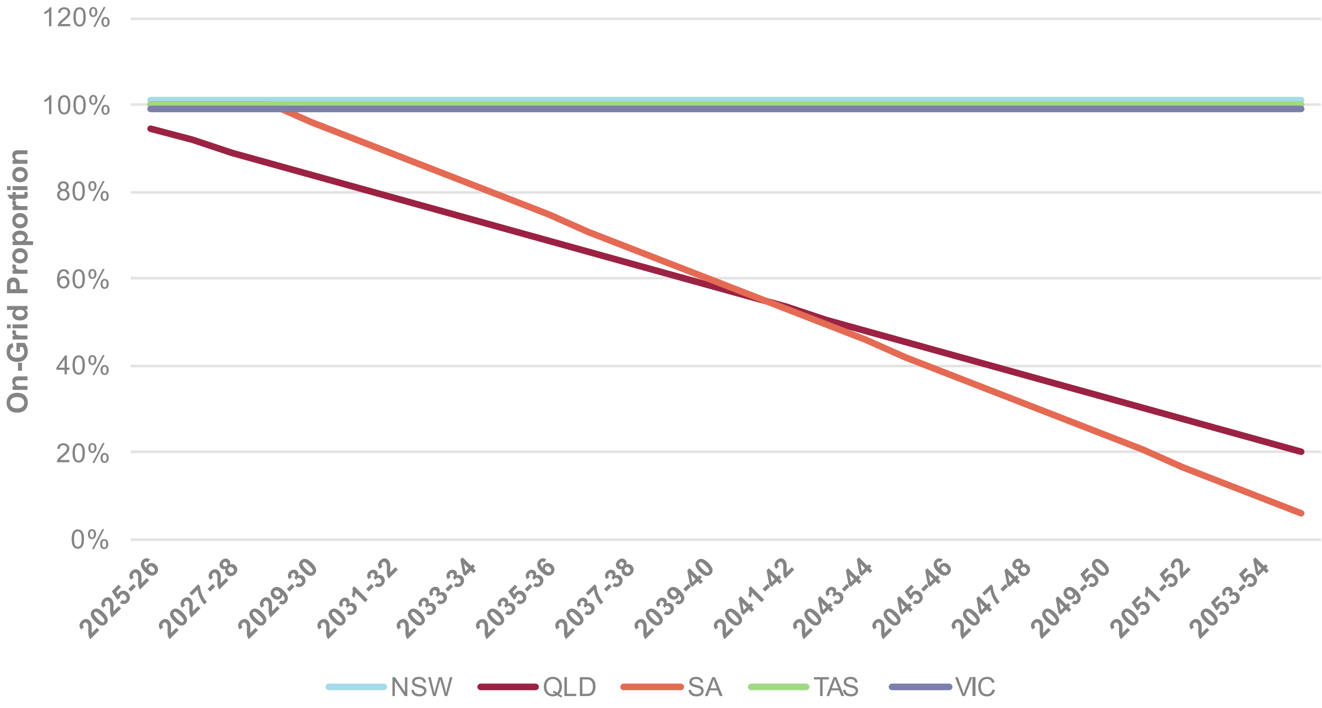
Stakeholders are invited to comment on the assumed on-grid proportions.

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

[89] 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/.

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

Figure 12 Assumed portion of on-grid electrolysis by region



Note: New South Wales, Tasmania and Victoria are assumed to remain at 100% on-grid developments, due to less remote areas.

Hydrogen cost

The main components of hydrogen cost are the capital cost of the electrolysers, and the operating cost of consuming electricity. When forecasting the potential scale of domestic hydrogen consumption, two additional costs were considered in the multi-sectoral modelling by applying cost premiums:

- 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 pillars such as alternative fuels including biomethane and electricity.
- The cost of water was applied as an additional cost premium at a rate of $11/kilolitre (kL) based on capital and operating cost forecasts for desalination from the Draft 2025 GenCost publication.

Utilisation factors

The economics of hydrogen production are highly influenced by the utilisation factor of the electrolysers (defined as the proportion of the maximum potential annual production from the electrolysers that is achieved in a year). 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 to commit to a project. This factor is assumed to reduce gradually to 35% by the 2050s, as capital costs decrease. AEMO proposes that this assumption is applied to AEMO's ISP modelling – see Section 3.12.

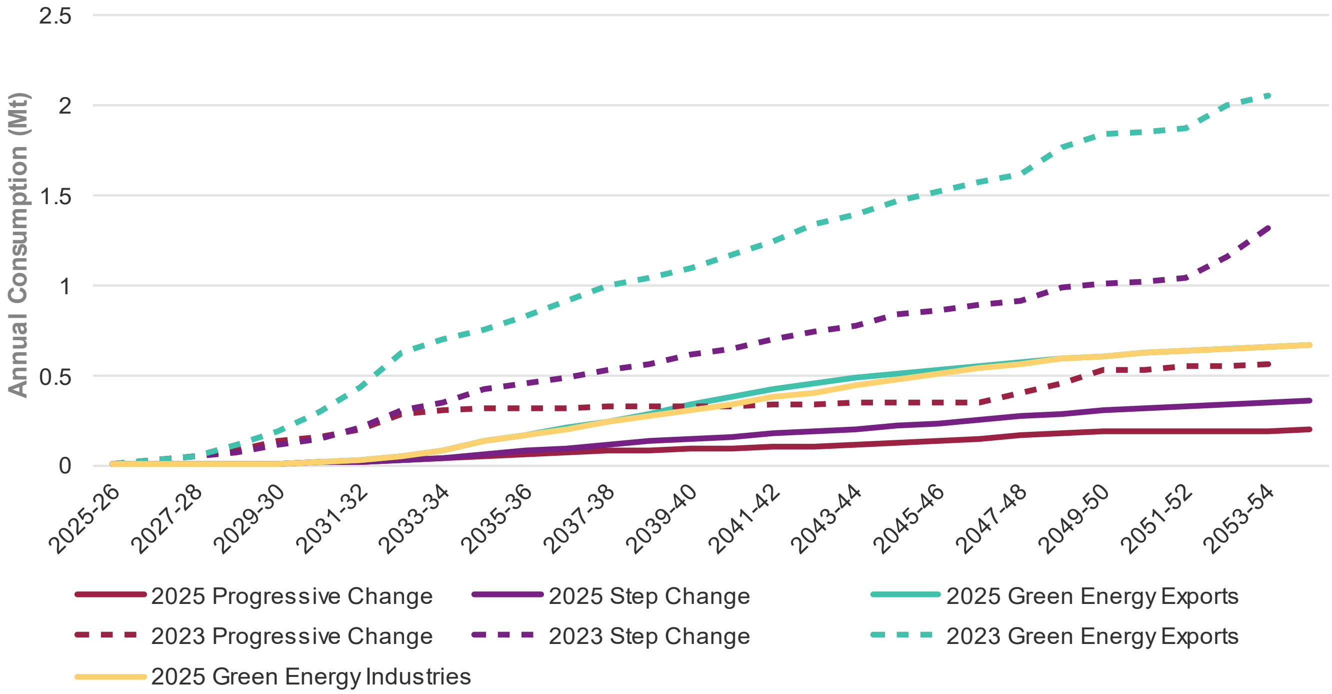
Forecast hydrogen consumption for domestic use

The forecast hydrogen used for domestic purposes (including residential, commercial, industrial, transport, 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 pillars, and CSIRO's forecasts of EV opportunities for road-based transport.

The majority of this domestic consumption is for 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). Minimal hydrogen was forecast in the multi-sectoral modelling to be used in residential or commercial sectors, due to the higher cost of hydrogen compared to other alternatives such as biomethane and electrification.

The forecast is shown in Figure 13 (representing the hydrogen production that is assumed to be supplied by grid-supplied electricity).

Figure 13 On-grid domestic hydrogen consumption across NEM (including transport, excluding green commodities)



Hydrogen for green commodities

The 2025 IASR includes a new category for potential hydrogen use in green commodities, which include the production and manufacture of iron and steel, ammonia, alumina and methanol. This reflects growing recognition across industry[91] 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 export.

[91] 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.

An initial forecast of hydrogen for green commodities was developed by ACIL Allen. Their 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[92], 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 relevant scenarios that feature strong global decarbonisation within the scenario narrative, it was assumed that there would be sufficient demand for green products, even with the expected price premium above traditional carbon-intensive commodities.

For the *Green Energy* scenario variants, AEMO scaled down the ACIL Allen forecast to match the National Hydrogen Strategy[93] central scenario (scaled by total [exports and commodities] hydrogen volumes), to align the forecasts to the potential magnitude outlined in that strategy. For *Step Change* and *Progressive Change*, the ACIL Allen forecasts were sufficiently minor to not warrant any adjustment prior to being considered within the multi-sectoral modelling.

The majority of green commodities produced are assumed to be exported, with limited manufacturing for domestic consumers. The *Green Energy Exports* scenario variant includes hydrogen for green iron and steel, alumina, ammonia and methanol production[94], plus hydrogen exported as an energy carrier. The *Green Energy Industries* scenario variant excludes hydrogen for export as an energy carrier, and represents a reduced level of green commodities, focusing on green iron production due to Australia's world-leading iron ore resource and competitive large scale VRE resources. In this scenario variant, the hydrogen volumes were derived from the higher *Green Energy Exports* forecast, but assuming the only green commodity produced at scale is green iron/steel, with the remaining commodities aligned with the lower volumes assumed for *Step Change*.

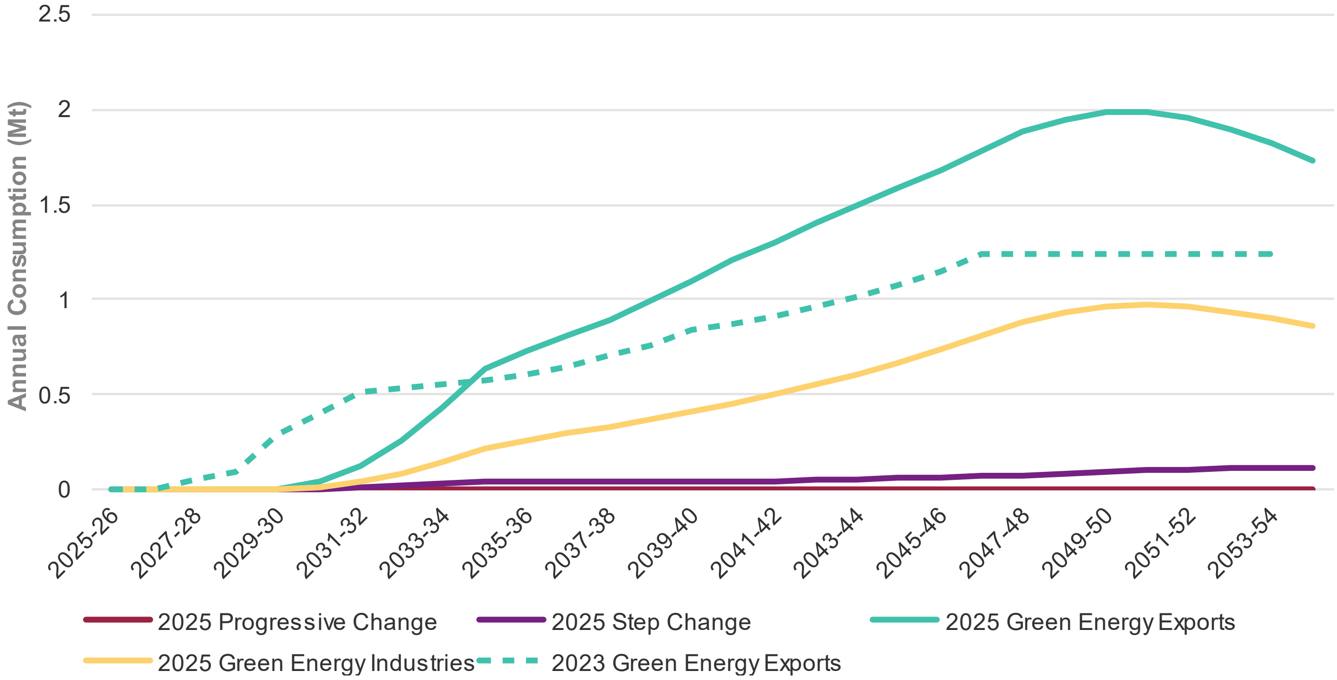
The resulting volumes were provided to the multi-sectoral modelling, which then applied the assumed off-grid proportions described above to derive the on-grid hydrogen demand, shown in Figure 14.

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

[93] See https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy.

[94] 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 3.3.8). Assumptions on existing general commodity growth in the multi-sectoral modelling are described further in the CSIRO report.

Figure 14 On-grid green commodity hydrogen consumption across the NEM



Significant volumes of hydrogen are included in *Green Energy Exports*, with approximately 40% of the demand attributed to green iron. As noted above, this reflects Australia's advantage in natural resources including minerals and renewable energy. A large portion (55%) is also used in ammonia production. Small quantities are assumed to be used for fuel switching from natural gas in alumina production, and for methanol production.

Green Energy Industries volumes are approximately half of those forecast for *Green Energy Exports*, due to the reduced volumes assumed for all commodities except 'iron and steel', which is retained at the same level as the other scenario variant.

For the other two scenarios, *Step Change's* hydrogen demand is primarily to support ammonia production, and minor amounts of green iron, and *Progressive Change* assumes minimal 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).

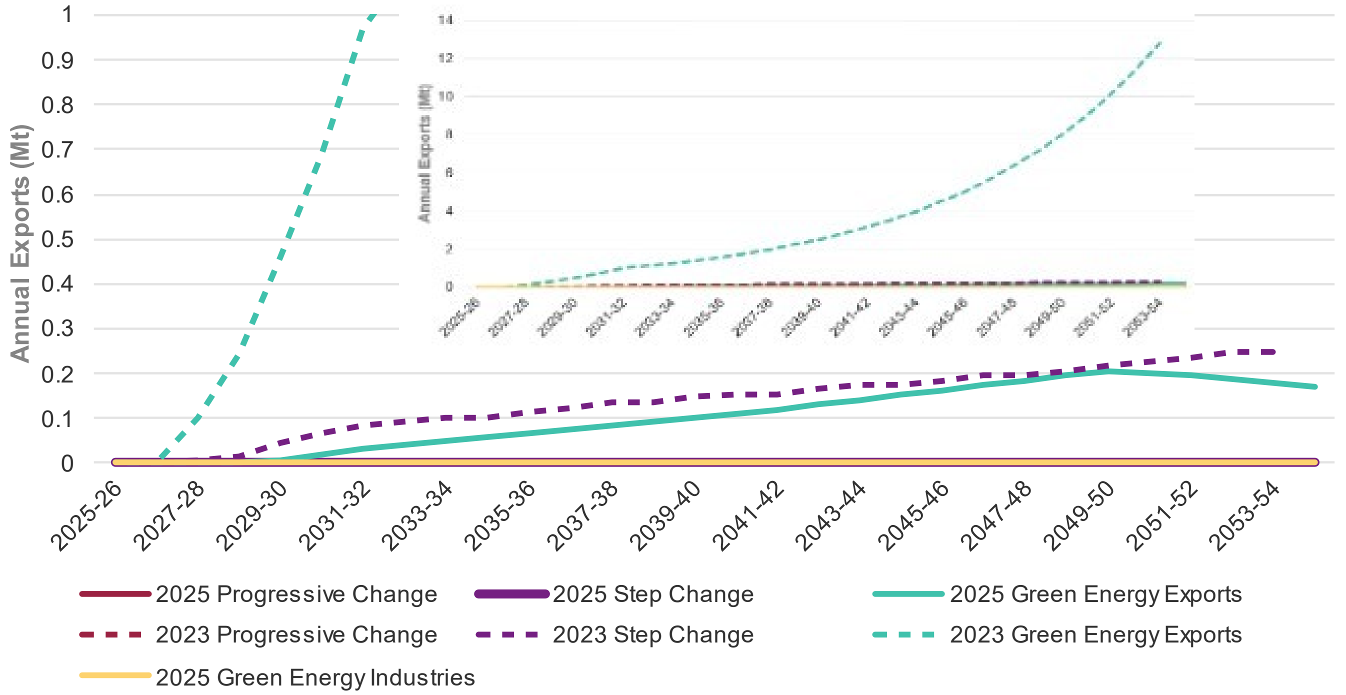
The method used to derive the export volumes was the same as for green commodities, as described above.

The on-grid hydrogen demand for exports is shown in Figure 15. The volumes in this category are materially lower across all scenarios than forecast in the 2023 IASR, reflecting the scenario narratives in Section 2.1 and emphasising the role for green commodity exports over exporting hydrogen as an energy carrier itself.

As noted above, the scenarios reflect the growing recognition across industry[95] of the potential benefits of using renewable hydrogen as a value-adding technology in the country of origin, and build 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 export. No exports are expected in *Green Energy Industries*, *Step Change* or *Progressive Change*.

Total hydrogen forecasts per scenario therefore reflect the combination of domestic, green commodity and energy export forecasts that will be grid-connected, as outlined in Figure 13, Figure 14, and Figure 15 respectively.

Figure 15 On-grid export hydrogen consumption across the NEM (full-scale for 2023 GEE in insert)



Note: Only GEE has non-zero exports, other scenarios are zero.

Matters for consultation for Stage 2

- Do you agree with the assumed portion of on-grid electrolysers by region?

[95] 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.

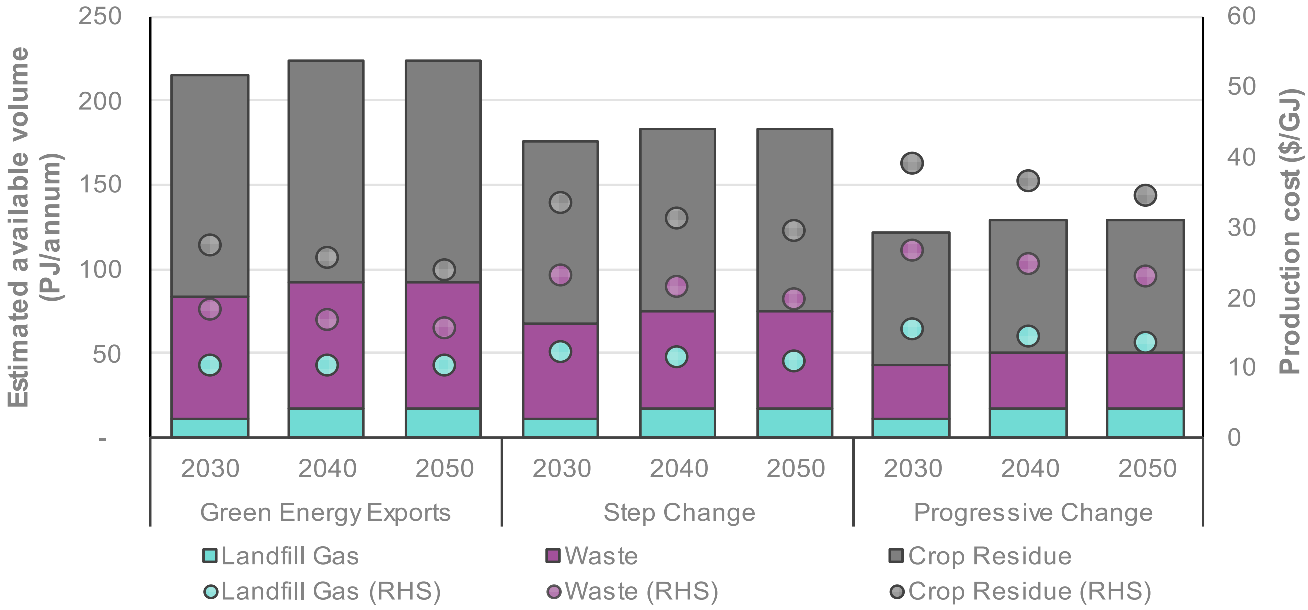
Biomethane

While biomethane is a proven technology widely used in Europe[96] 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[97]. 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.

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

For the Draft 2025 IASR, AEMO engaged consultant ACIL Allen to forecast long term biomethane production cost and available volumes by feedstock type, state, and scenario. Figure 16 shows a snapshot of ACIL Allen's forecast for the various feedstock available volumes by scenario, including production cost for selected years[98].

Figure 16 ACIL Allen biomethane available volume and production cost estimates by feedstock and scenario



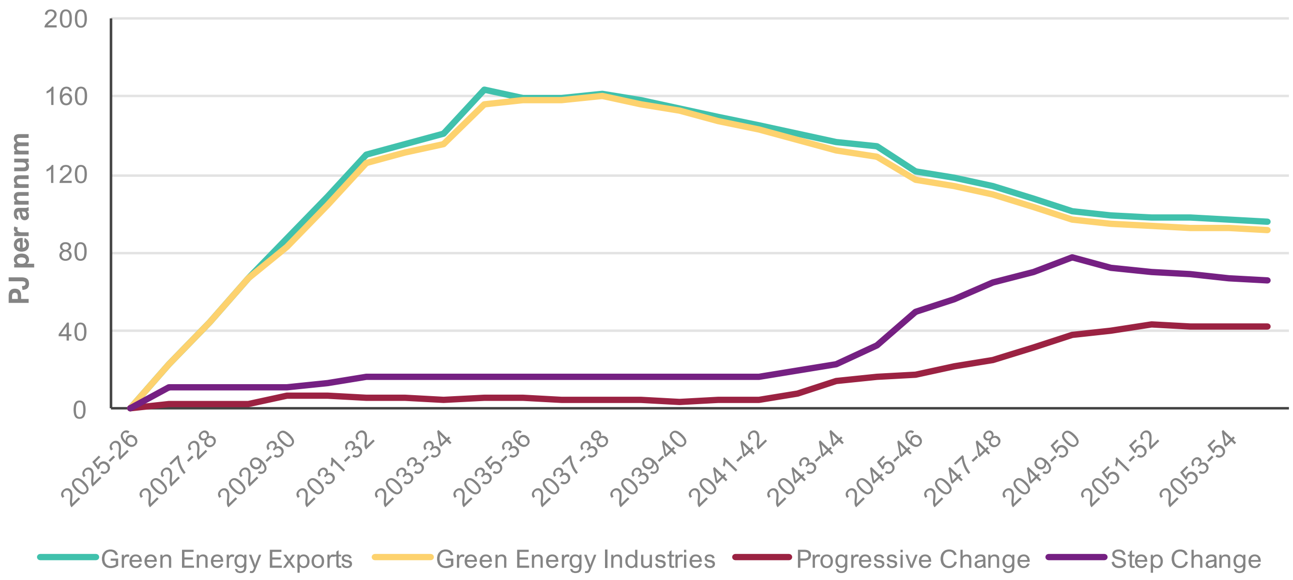
For the Stage 2 update, ACIL Allen provided the estimated biomethane volumes by feedstock and production cost described above, which were used in the multi-sectoral modelling, with the uptake by scenario shown in Figure 17.

[96] 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.

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

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

Figure 17 Biomethane use by scenario



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[99]. For the *Green Energy* scenario variants, early adoption to support decarbonisation activities is a key driver for biomethane's steady production increase until approximately 2035. In *Step Change* and *Progressive Change*, there is less urgency to develop this molecular alternative. In all scenarios, by 2050, biomethane production is forecast to reach levels at least sufficient to have exploited most if not all of the estimated landfill gas and waste volumes in Figure 17.

3.3.7 Consumer energy resources

Input vintage	December 2024
Status	Draft
Source	• CSIRO • Green Energy Markets • Clean Energy Regulator
Updates since 2024 Forecasting Assumptions Update	Updated with new consultant forecasts in 2024 and latest historical data

CER predominantly describes consumer-owned devices that can generate or store electricity and includes flexible loads that can alter demand in response to external signals. In AEMO's forecasting approach, CER refers to embedded solar systems and battery devices within the distribution system, while energy management systems are considered in AEMO's forecasting of demand flexibility (in demand-side participation forecasts) and energy efficiency. Customer's solar and battery devices may operate passively (such that they operate without regard to

[99] 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.

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.

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. Larger PV systems between 100 kW and 30 MW (referred to as PV non-scheduled generation, or PVNSG) may also be installed by larger energy consumers and are included in this section; rooftop PV and PVNSG forecasts are referred to as distributed PV.

Given the importance of CER in the energy transition, 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.

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 proposes 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 5). 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	*Green Energy*	*Step Change*	*Progressive Change*
Rooftop PV forecast mapping	Average	Average	CSIRO
PVNSG forecast mapping	GEM	GEM	CSIRO
Battery and VPP forecasts mapping	Weighted average (1/3 GEM + 2/3 CSIRO)	Weighted average (1/3 GEM + 2/3 CSIRO)	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 A2). The forecasts reflect up-to-date views on actual installations, and reflect the economic and population forecasts (in Section 3.3.8). The forecasts also consider each consultant's updated views on tariff options, technology 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. 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. The approach does not explicitly consider 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[100] will begin to explore distribution network interaction with CER operation. AEMO considers that the forecasting approach that does not consider distribution constraints, coupled with the *ISP Methodology*, will appropriately capture opportunities for distribution investments and other distributed resources in each scenario's development opportunities in the ISP.

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

Distributed PV

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

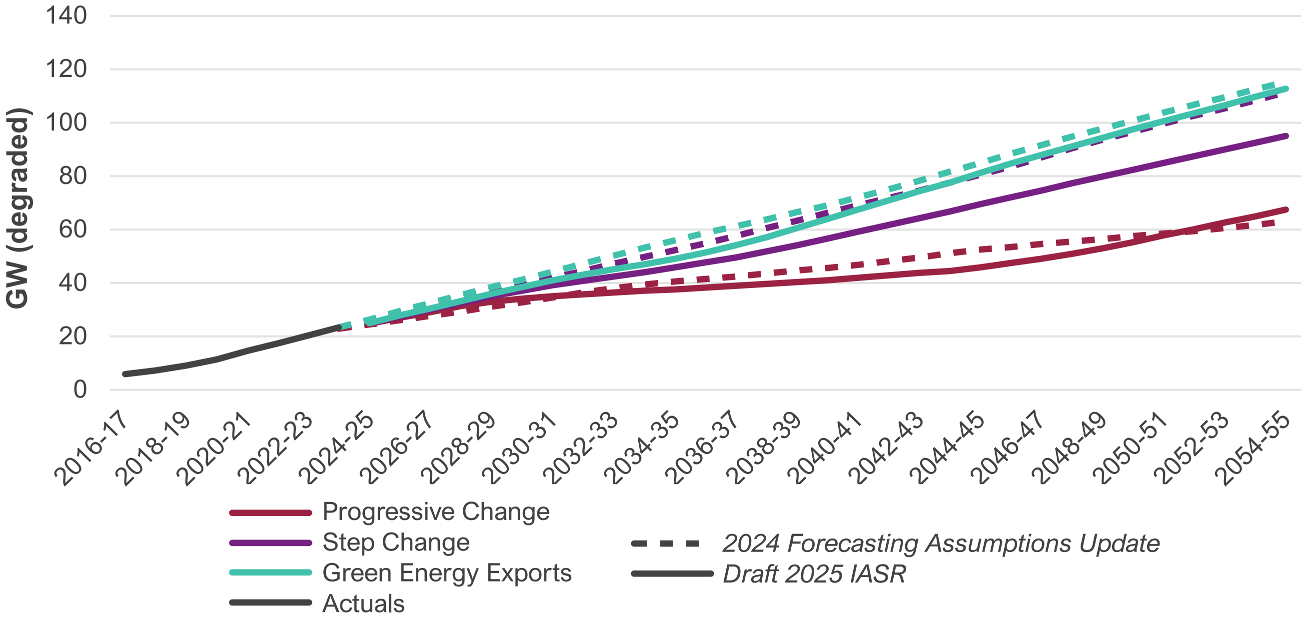
Current installed capacity estimates for distributed PV are sourced from the Clean Energy Regulator[101], with AEMO's DER Register available as a comparison. The forecasts were based on the latest actual installation data available at the time of production (end of June 2024), with 20.6 GW of installed capacity for rooftop PV in the NEM (23.2 GW including the WEM), and 1.48 GW for PVNSG in the NEM (1.53 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 69% (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%.

Figure 18 below demonstrates the forecasts for each scenario in terms of rooftop PV capacity.

Figure 18 Actual and forecast rooftop PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])



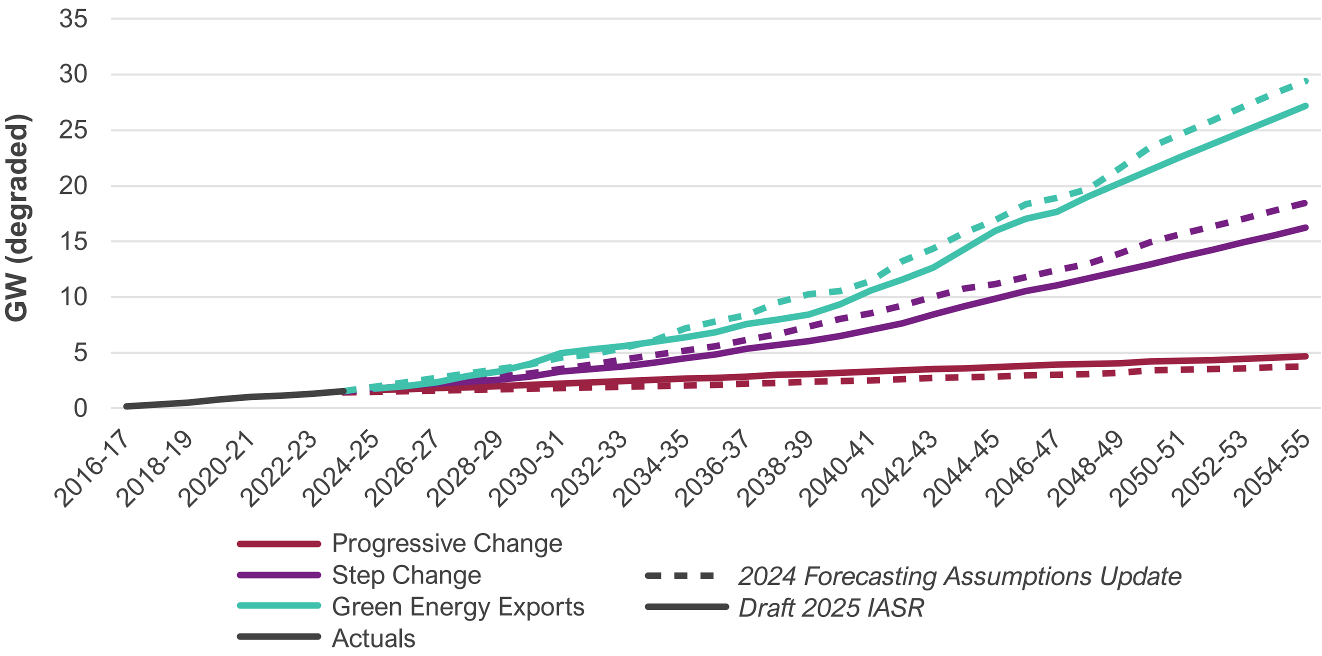
[101] Latest data is provided by the Clean Energy Regulator directly to AEMO and is complemented with data available through their website: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data.

The forecasts moderate those that were provided in AEMO's 2024 *Forecasting Assumptions Update*, particularly in the longer term, as AEMO has considered the causes for CSIRO's lower uptake forecast are appropriate to have a greater influence in the forward trend than was previously available. While average system size is still forecast to grow, AEMO considers that the growth of system sizes is more likely to reflect a trend 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.

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 19, there is reasonable uncertainty captured by the scenario spread, with PVNSG's overall capacity forecast at up to 8-22% of the rooftop PV capacity across scenarios by end of June 2050

Figure 19 Actual and forecast PVNSG capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])



Aggregate distributed PV

Figure 20 below aggregates the rooftop PV and PVNSG components, to construct the total aggregate distributed PV forecast.

Figure 21 shows a breakdown between rooftop PV and PVNSG for the *Step Change* scenario, demonstrating that rooftop PV provides the majority of distributed solar installations.

Figure 20 Actual and forecast distributed PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])

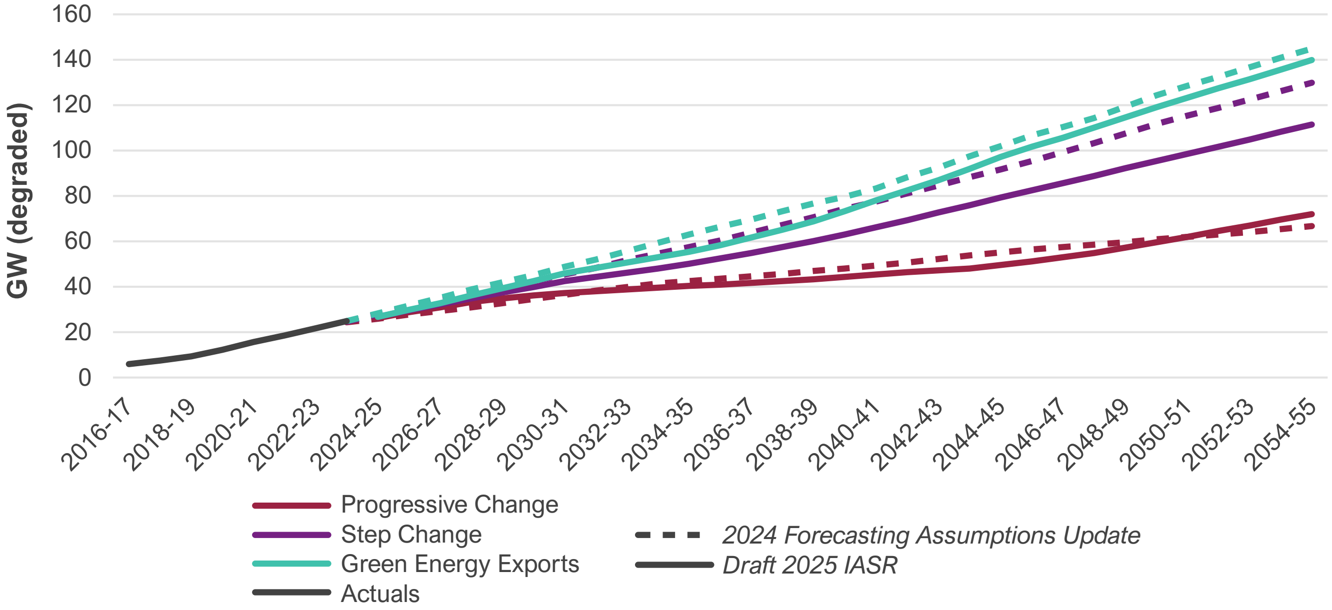
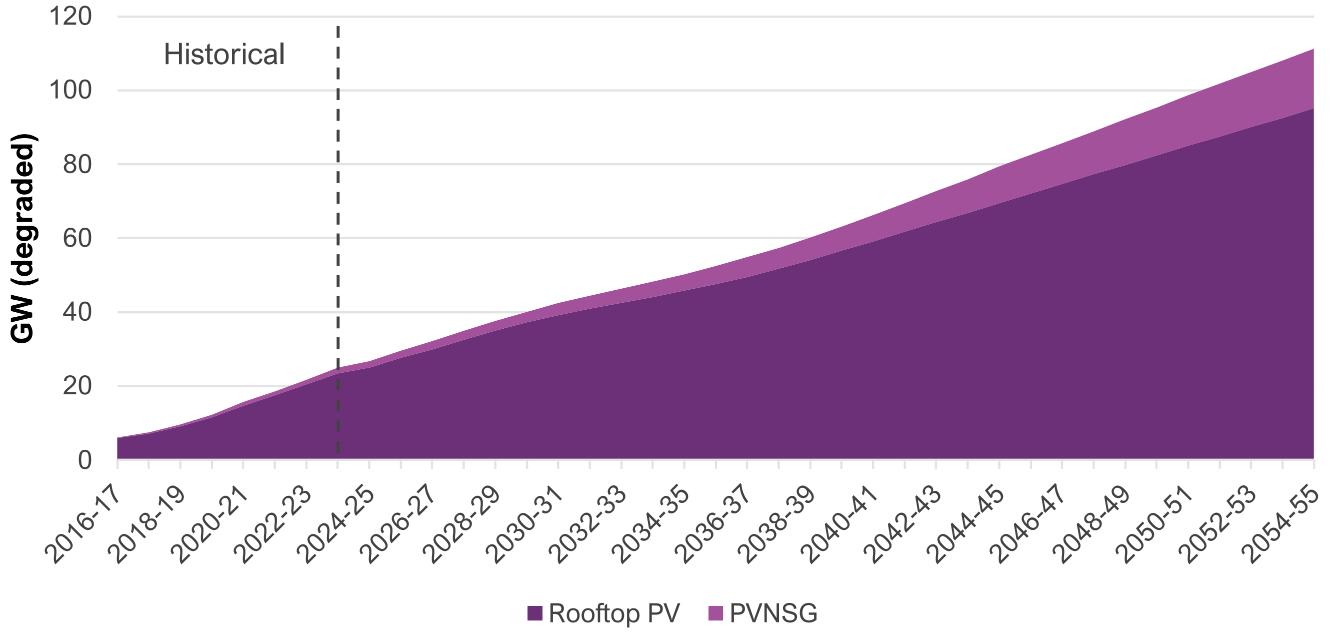


Figure 21 Actual and forecast rooftop PV and PVNSG installed capacity (NEM and WEM) for the *Step Change* scenario, 2016-17 to 2054-55 (GW [degraded])



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.

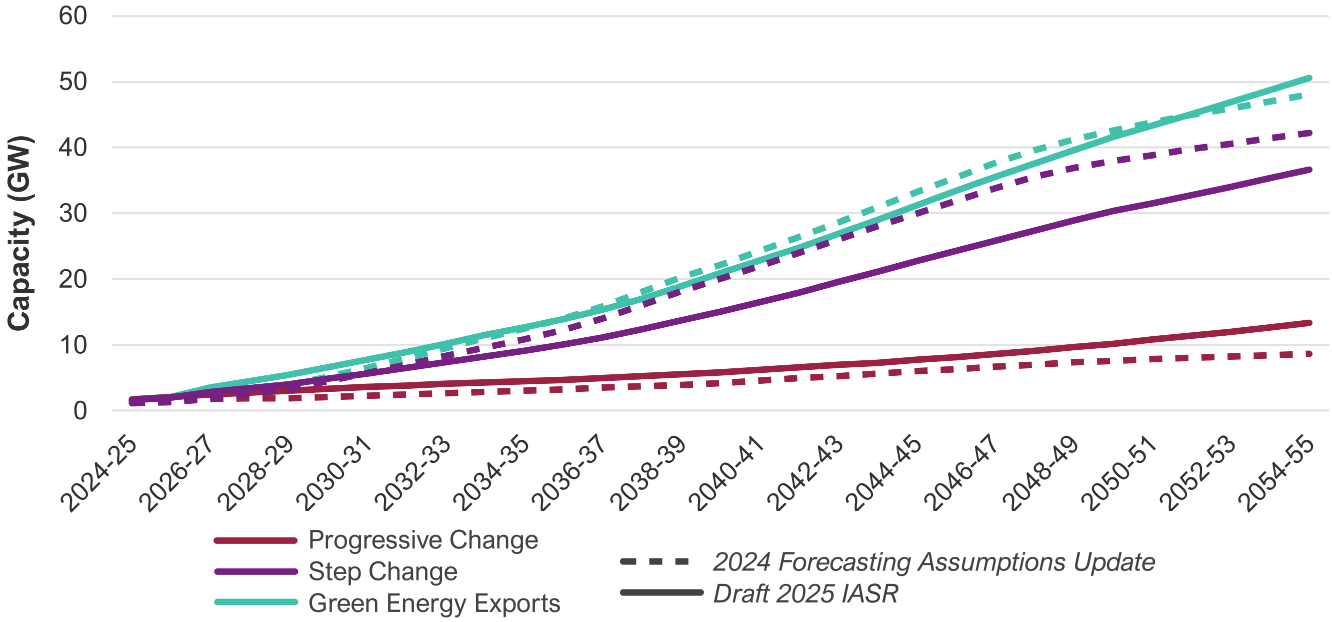
AEMO's forecast of embedded energy storages considers the insights provided by each of the CER consultants:

- 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 propose 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 *Progressive Change*, while recognising greater potential development in the other two scenarios. AEMO does not propose to evenly weight the two forecasts, considering that 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 considers this approach retains an appropriate trajectory with further upside potential.

The resulting forecasts are shown in Figure 22 below, which includes non-aggregated and aggregated batteries:

Figure 22 Distributed battery capacity forecast for the NEM+WEM (GW), including non-aggregated and aggregated 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 a significant proportion of consumers will 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. This is described in the section below.

Community batteries

An emerging sector for energy storage is "community" (or “neighbourhood”) batteries, which typically refers to sub-utility-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. AEMO’s CER forecasting approach does not specifically identify community battery installations, but the ISP may identify distributed resources to complement the CER forecasts.

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[102] and by Project EDGE[103]) have demonstrated the feasibility and end-to-end technical capabilities of the technology.

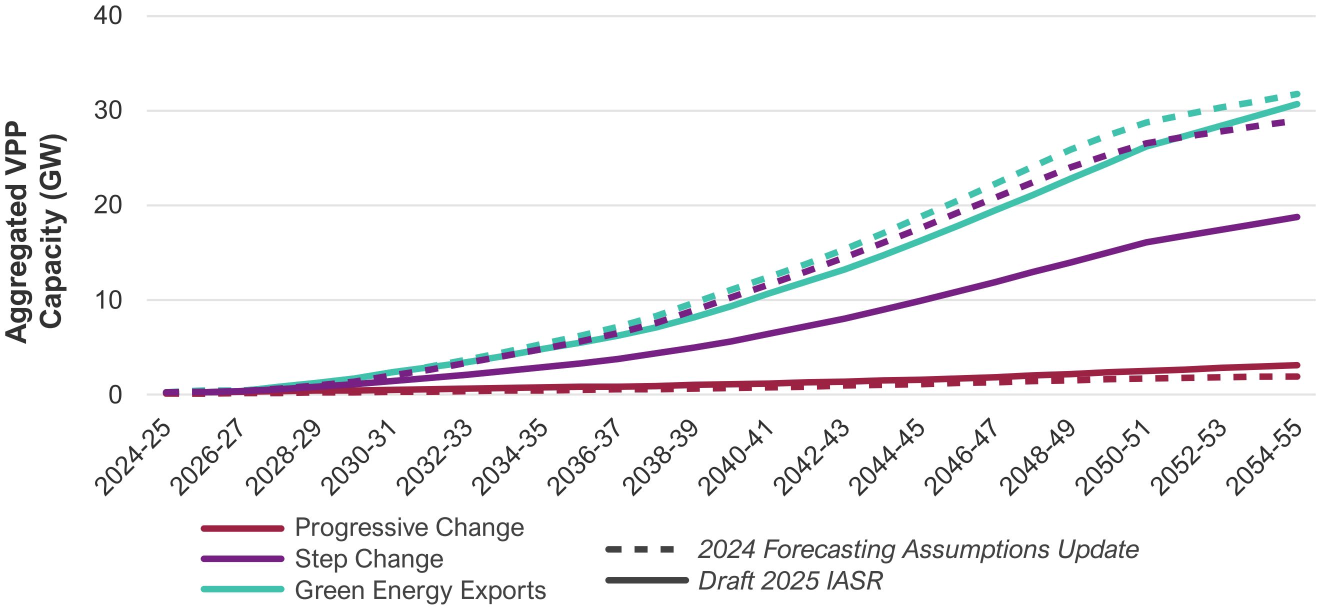
Despite the long-term potential, the uptake of VPP products to date has been modest. AEMO’s forecasts provide a wide band between the scenarios to reflect the uncertainty of both uptake and relative scale of coordination. The companion reports from AEMO’s consultants demonstrate differing views of success, 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 capacity outlook reflecting AEMO’s consolidation of the consultant inputs is shown in Figure 23 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 as compared with the 2023 IASR scenarios, and the most recent forecasts. Slower adoption also is anticipated for *Green Energy*, although the magnitude of that forecast is closer to the previous forecasts.

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

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

Figure 23 Aggregated VPP capacity for NEM+WEM (GW)



Matters for consultation from Stage 1

- Are the CER forecasts suitable for their respective scenarios? What strategic factors do you consider may influence CER projections?

Electric vehicles

This section contains updates for Stage 2

Input vintage	January 2025
Status	Final draft
Source	CSIRO
Update process	Updated with new consultant forecasts in 2024 and latest historical data

The impact and benefits of EV use to the electricity grid arise from a wide set of factors. 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. All of these factors have changed since the 2024 *Forecasting Assumptions Update* and the 2023 IASR.

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 Draft 2025 IASR, the scenarios explore different rates of uptake, as well as different levels of coordination, and this report is complemented with more detailed information within the 2025 IASR EV workbook[104].

To support the 2025 IASR, detailed modelling of EVs in the Australian transport sector was carried out by CSIRO. The EV forecast in this Draft 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 in Table 6 previously, include:

- The national New Vehicle Efficiency Standard (NVES)[105], 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[106], 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[107] for Victoria, Queensland and South Australia that are designed to incentivise vehicle sales. Funded policies in other states are outlined in Table 6.

More detail regarding the impact of state and federal policy on the uptake of EVs is available in the CSIRO EV report[108].

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 fuel cell electric vehicles (FCEVs), recognising the important role hybrids are still expected to play to meet the NVES targets.
- Improved data on EV efficiency[109] 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.

[104] At https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/draft-2025-iasr-ev-workbook.xlsx.

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

[106] 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.

[107] 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.

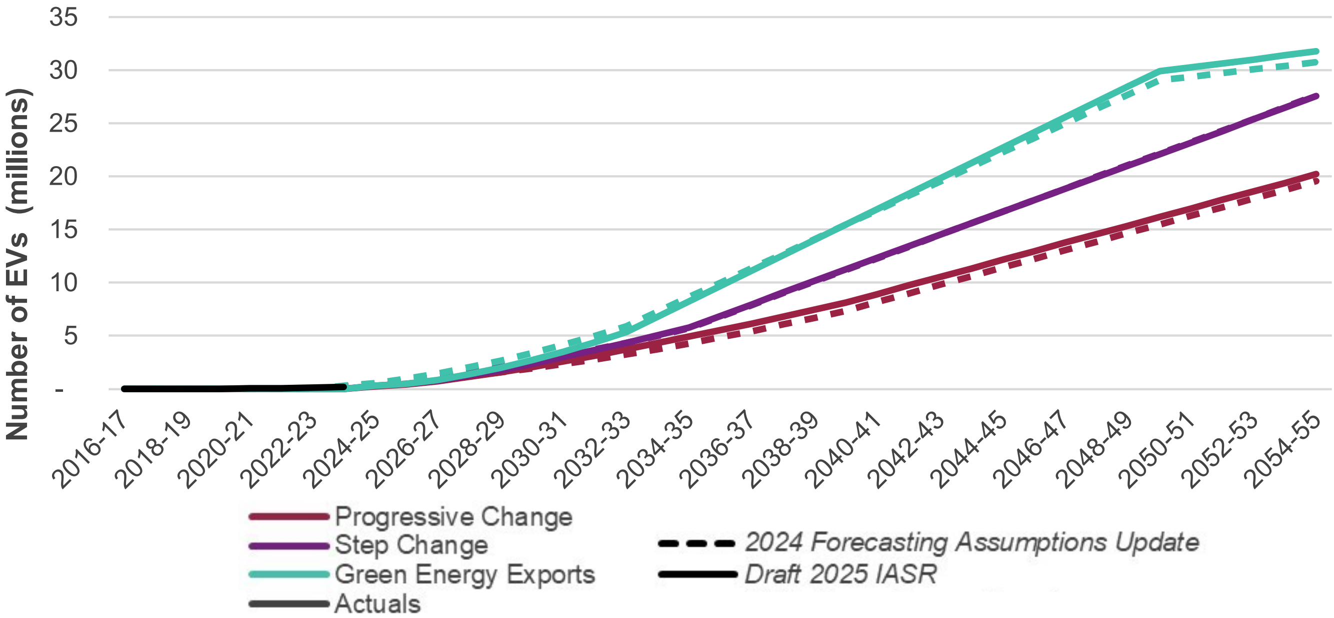
[108] CSIRO, Electric vehicle projections 2024, at https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/electric-vehicle-projections-2024.pdf.

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

- Greater consumer preferences for PHEVs, informed by stakeholder feedback in AEMO's FRG[110].
- Insights on increase in adoption of time-of-use tariffs, based on AER data[111], that is expected to reduce charging during peak electricity demand conditions.

Figure 24 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 Draft 2025 IASR for all scenarios, due to the higher population growth forecast than previously forecast, as outlined in Section 3.3.8[112]. EV fleet numbers are forecast to reach between 15 million and 26 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 24 Actual and projected BEV and PHEV fleet size (NEM and WEM) by scenario, 2016-17 to 2054-55



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:

- *Progressive Change* assumes greater penetration of hybrids and fewer EVs in this scenario.
- *Step Change* and *Green Energy Exports* assumes fewer hybrids and greater BEV uptake, with vehicle owners embracing a strong opportunity to contribute to emissions reduction.

[110] 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.

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

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

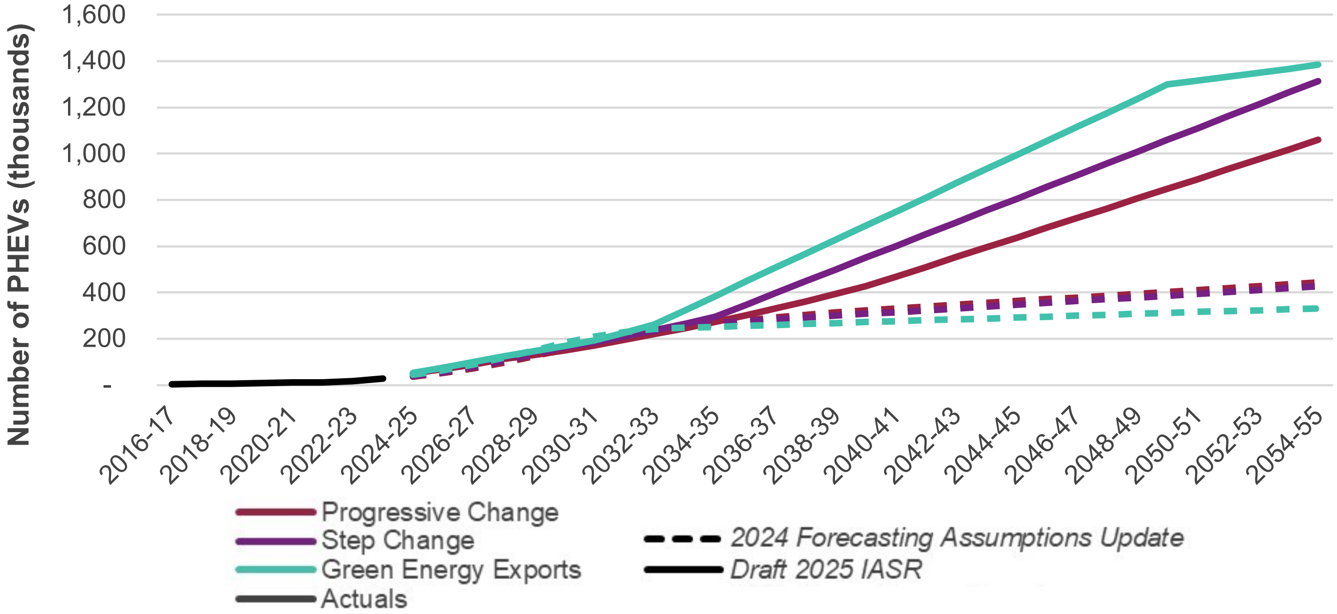
Figure 25 shows the actual and projected mix of car sales and fleet share of residential and light commercial vehicles, per vehicle technology type. It shows that while ICE sales may cease around the mid-late 2030s, ICE vehicles will remain a part of the fleet for much longer while owners maintain their vehicles 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 services that enable fuelling and maintenance will eventually reduce the commercial value of ICE ownership, accelerating scrapping across all scenarios at varying timelines.

Figure 25 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 Draft IASR provides an amended outlook for EV fleet size compared to the previous forecast, due to:

- 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 notes that the balance of consumer preferences between BEV and PHEV vehicle types is more favourable for PHEV than previously estimated. This preference will have a lingering impact on electricity consumption and charging behaviours.
- 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 26 shows forecast PHEV sales numbers across the outlook period.

Figure 26 Projected PHEV fleet size (NEM and WEM) by scenario, 2017 to 2055



Electricity consumption due to 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).
- Varying travelling distances.

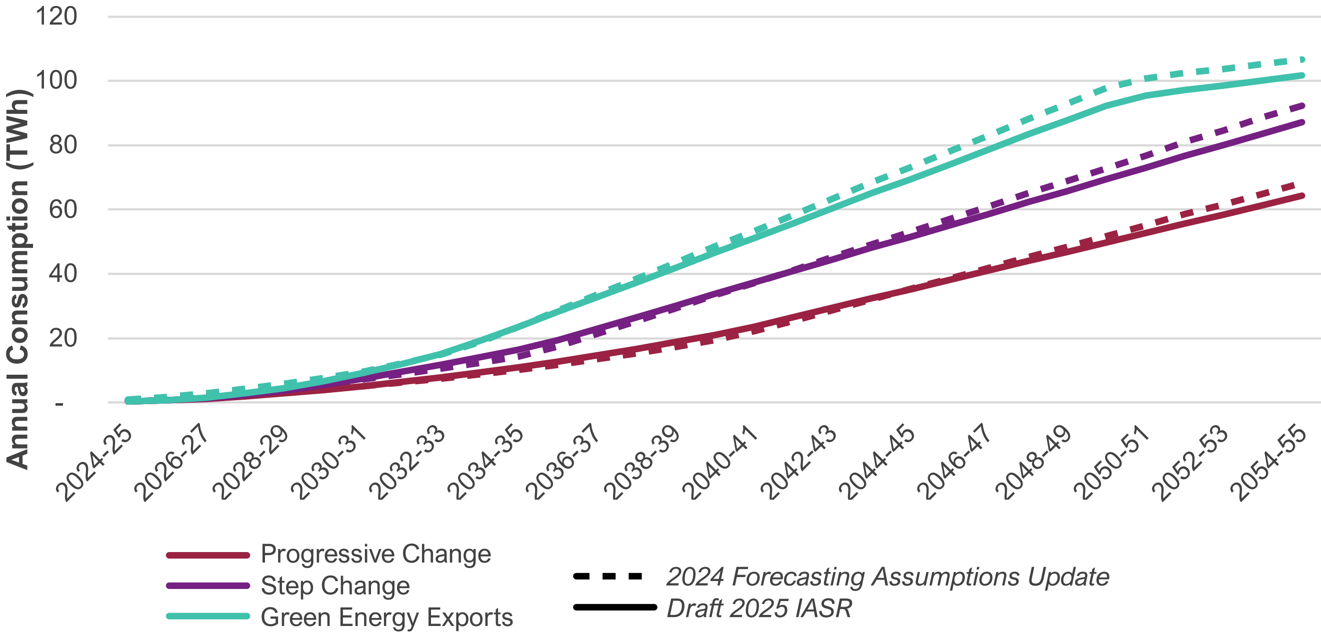
In this section, AEMO presents annual electricity consumption forecasts, as well as normalised vehicle charging profiles that represent the average vehicle across the population considering all these factors, rather than reflecting the behaviour of any individual consumer.

Annual consumption

Figure 27 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 24, 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 previous forecast is due to changes in the assumed shares of electric and FCEV trucks. FCEVs are expected to gain traction in heavy-duty transport (trucks) due to refuelling advantages and potential fuel savings, particularly in scenarios where hydrogen fuel is expected to have greater relative availability (such as in *Green Energy Exports*)[113].

Figure 27 Forecast BEV and PHEV electricity consumption (NEM and WEM) by scenario, 2024-25 to 2054-55



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.

[113] While the *Green Energy* scenario has lesser direct electricity consumption for EV usage than the previous forecast, greater hydrogen usage for FCEVs will require greater electricity consumption for hydrogen production purposes in that scenario. The electricity required for hydrogen production is not bundled into the EV consumption data presented in this section.

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*
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 updated Draft 2025 IASR considers new data that suggests that public charging may be more popular than previously estimated[114], and that more residential customers are adopting cost-reflective tariffs[115].

Key updates to the outlook for future charging behaviours include:

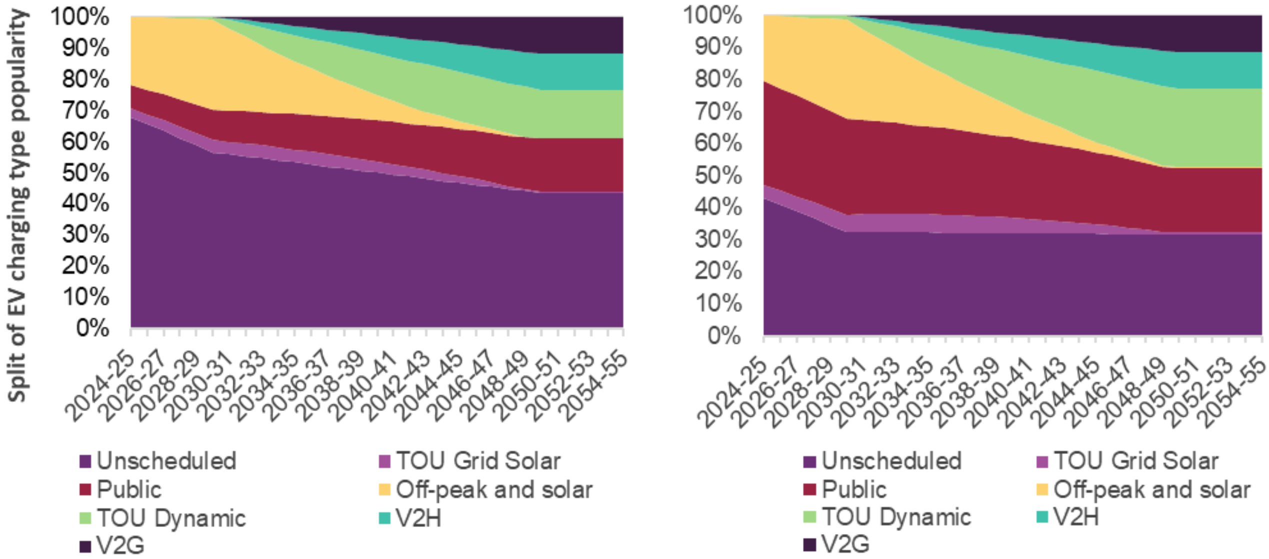
[114] Public charging companies reported higher market share, although this could not be independently verified due to data confidentiality.

[115] 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.

- Unscheduled and static time-of-use charging (off-peak and solar, 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 from the 2024 *Forecasting Assumptions Update* consultation.
- The forecast popularity of public charging is higher in this 2025 Draft 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 offstreet parking. Public charging though is forecast to plateau particularly if popularity leads to queuing-.
- 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.
- 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, however, the scenario narratives reduced their expectation for V2G forecasts based on stakeholder feedback.

Figure 28 shows the mix of charging types assumed for 2024 *Forecasting Assumptions Update* (left) and this Draft 2025 IASR (right) for medium residential vehicles in New South Wales in the *Step Change* scenario.

Figure 28 Split of charging types for medium residential vehicles: 2024 *Forecasting Assumptions Update* (left) and Draft 2025 IASR (right) for *Step Change* scenario



EV charging profile shape

Several trials (Energex and Ergon Energy Network[116], AGL[117], Jemena[118], Origin Energy[119], and the University of Queensland/Electric Vehicle Council of Australia[120]) 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 Draft IASR forecasts rely exclusively on Australian charging data trends to inform the revised load profiles.

As seen in Figure 29 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[121]) and normalised to 7 kWh daily charging, to enable easier 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's static charging profiles are detailed in the 2025 IASR EV Workbook[122]. Dynamic charging profiles are optimised within AEMO's supply modelling assessments, such as the ISP, reflecting the availability of electricity supply.

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

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

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

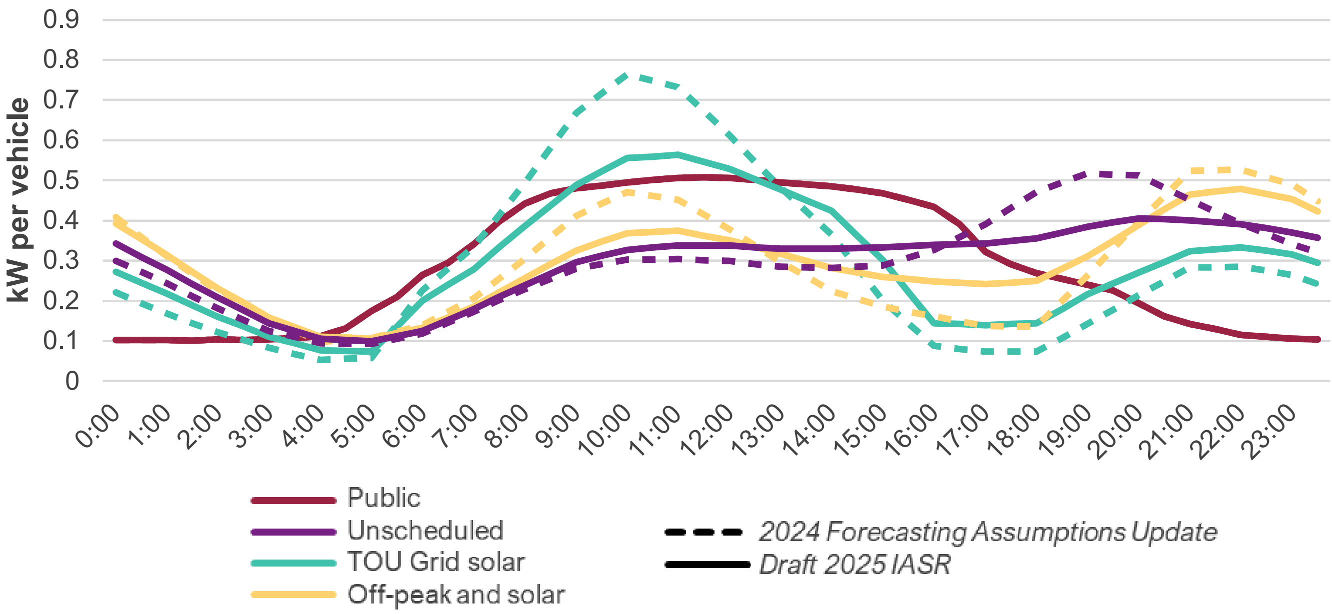
[119] Origin EV Smart Charging Trial 2021, 2022, at https://arena.gov.au/assets/2022/05/origin-energy-electric-vehicles-smart-charging-trial-lessons-learnt-2.pdf.

[120] 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.

[121] 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.

[122] At https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/draft-2025-iasr-ev-workbook.xlsx.

Figure 29 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.

Matters for consultation for Stage 2

- Is the projected long-term trend of PHEV reasonable?
- Is the projected split of higher public charging and lower unscheduled charging reasonable?

3.3.8 Economic and population forecasts

Input vintage	October 2024
Status	Final draft
Source	• Deloitte Access Economics (DAE) • ABS
Update process	Forecasts may be rebased using the latest release of the national accounts if required, prior to the publication of the Final 2025 IASR.

In 2024, AEMO engaged Deloitte Access Economics (DAE) to develop long-term economic forecasts 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[123]. Inputs and drivers to the economic model include factors such as domestic production, labour market conditions, and prices and wages, in addition to physical[124] and

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

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

transition[125] risks associated with climate change. The economic forecasts are used as a key input to AEMO's energy and demand forecasts.

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, including both variants of the *Green Energy* scenario. In total, four projections are therefore provided.

Table 18 Economic forecast details by scenario

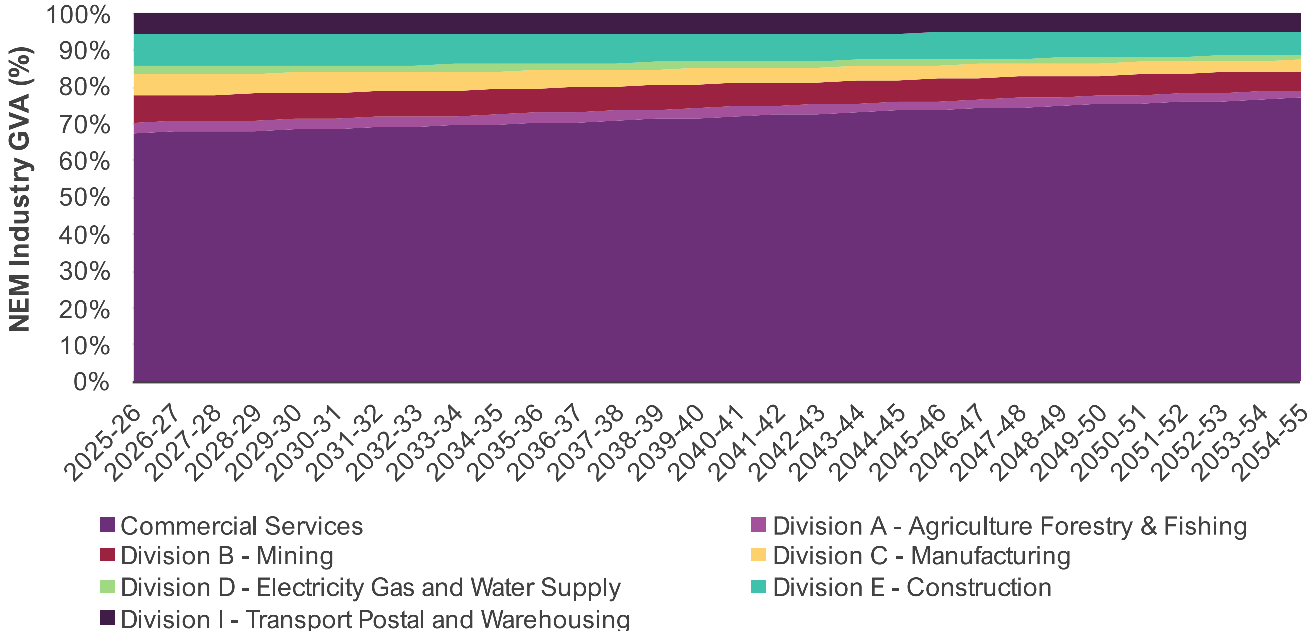
Scenario	Forecast annual economic growth (GDP)	Scenario details
Step Change	1.8%	• *Step Change* is the central scenario for the economic forecasts. • An ageing population and declining productivity growth place downward pressure on economic growth over the forecast period. Australia's decarbonisation 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.
Progressive Change	1.3%	*Progressive Change* is a downside scenario relative to *Step Change*. • *Progressive Change* 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.
Green Energy Exports	2.5%	*Green Energy Exports* is an export orientated upside scenario relative to *Step Change*. *Green Energy Exports* assumes higher population growth and productivity growth and lower climate change costs relative to *Step Change*. • Global decarbonisation efforts support Australia's green hydrogen industry. Mining activity slows, but critical minerals output increases due to strong demand and targeted industrial policy. • Investment in renewable energy infrastructure and hydrogen production supports the construction, manufacturing, and utilities industries.
Green Energy Industries	2.5%	• *Green Energy Industries* is a variation to the *Green Energy Exports* scenario. *Green Energy Industries* is underpinned by the same population and productivity assumptions as *Green Energy Exports*, but also assumes that Australia does not export renewable hydrogen. By the end of the forecast period, manufacturing industry output is smaller by 12% relative to the *Green Energy Exports* scenario.

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.

Figure 30 illustrates the predicted economic composition of the NEM over the forecast period for the *Step Change* scenario.

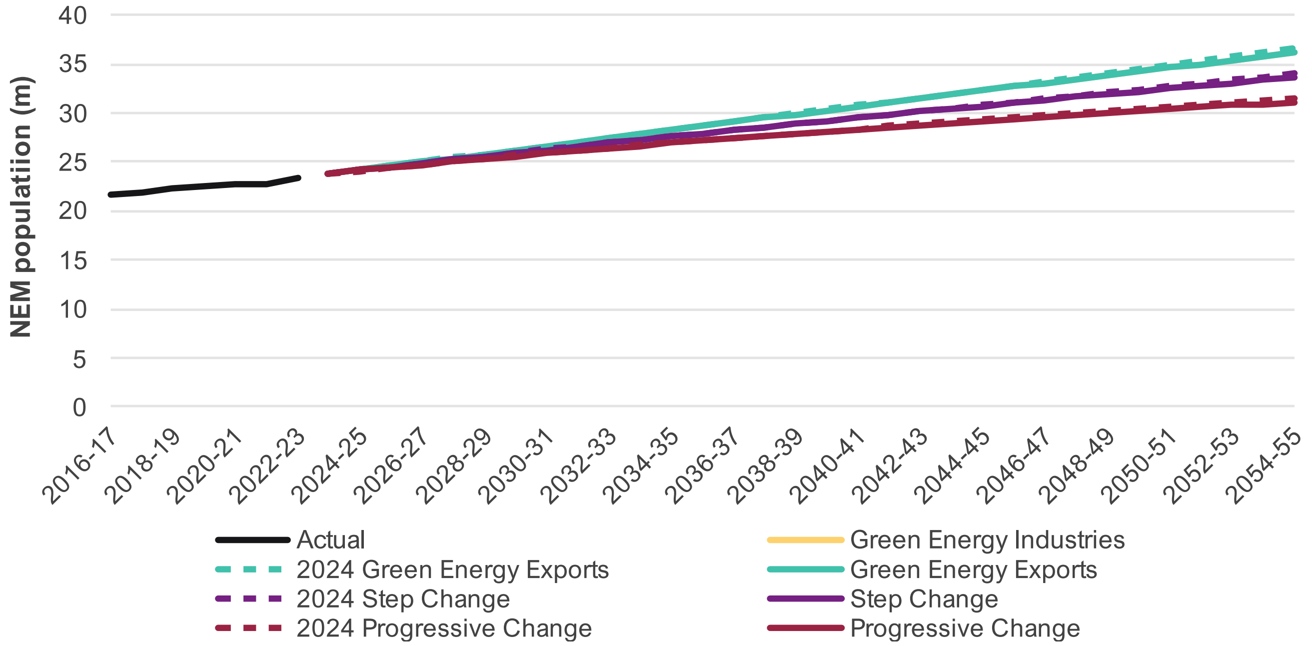
[125] Transition risks arise from the mitigating actions taken in response to climate change, including policy and regulatory change, technological developments, or shifting consumer preferences.

Figure 30 Economic composition of the NEM, *Step Change* scenario



Population growth rates underpin rates of economic and productivity growth. Lower population growth has the effect of Australia's population ageing more rapidly. 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 *Green Energy Exports* and *Green Energy Industries* scenarios forecast higher rates of population growth, whereas the *Progressive Change* scenario forecasts reduced population growth consistent with the scenario's exploration of weaker economic activity (see Figure 31).

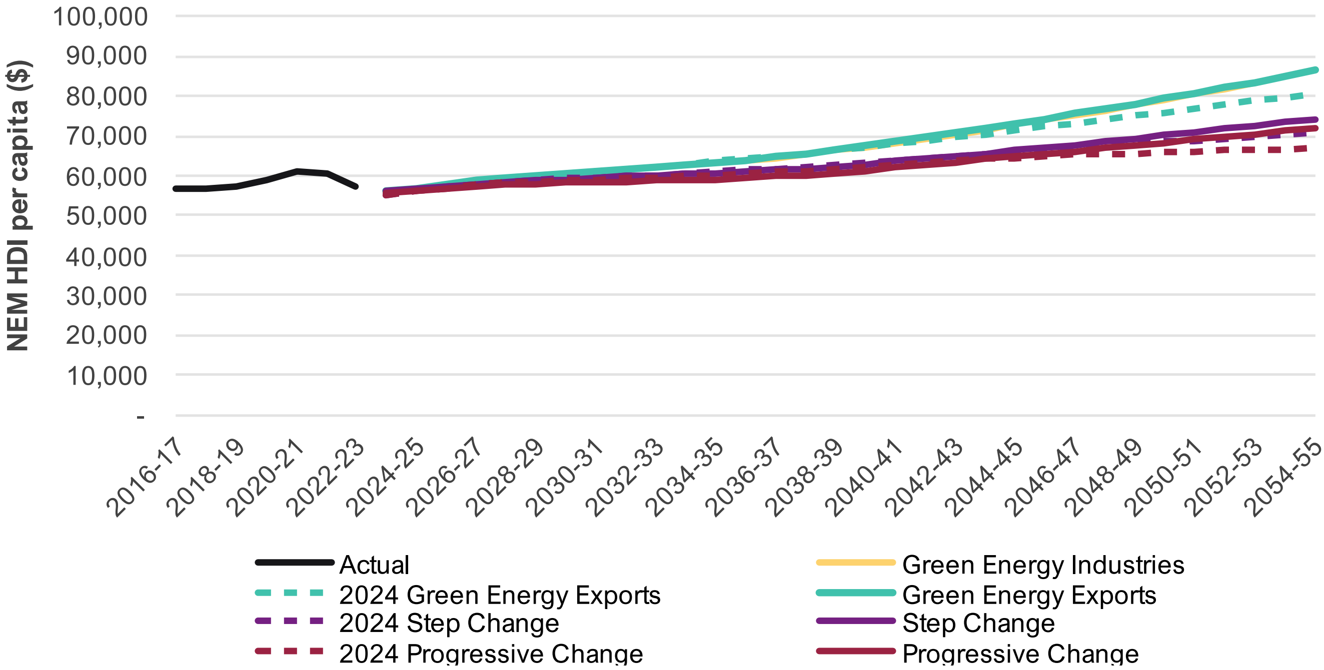
Figure 31 Population growth in the NEM by scenario



Note: The *Green Energy Industries* forecast follows a similar trajectory to Green Energy Exports, so it is not clearly visible in the figure above.

Economic growth is expected to remain relatively slow throughout 2024-25 due to tight monetary policy, cost-of-living pressures, and weakness in dwelling construction activity. In the short term, expected reductions in inflation and interest rate pressures are forecast to increase Household Disposable Income (HDI) (see Figure 32) and support economic growth as household consumption of goods and services accelerates throughout the economy. 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 *Green Energy Exports* and *Green Energy Industries* scenarios in particular, higher levels of forecast productivity growth drive faster wage growth and consequently higher levels of HDI relative to the *Step Change* and *Progressive Change* scenarios.

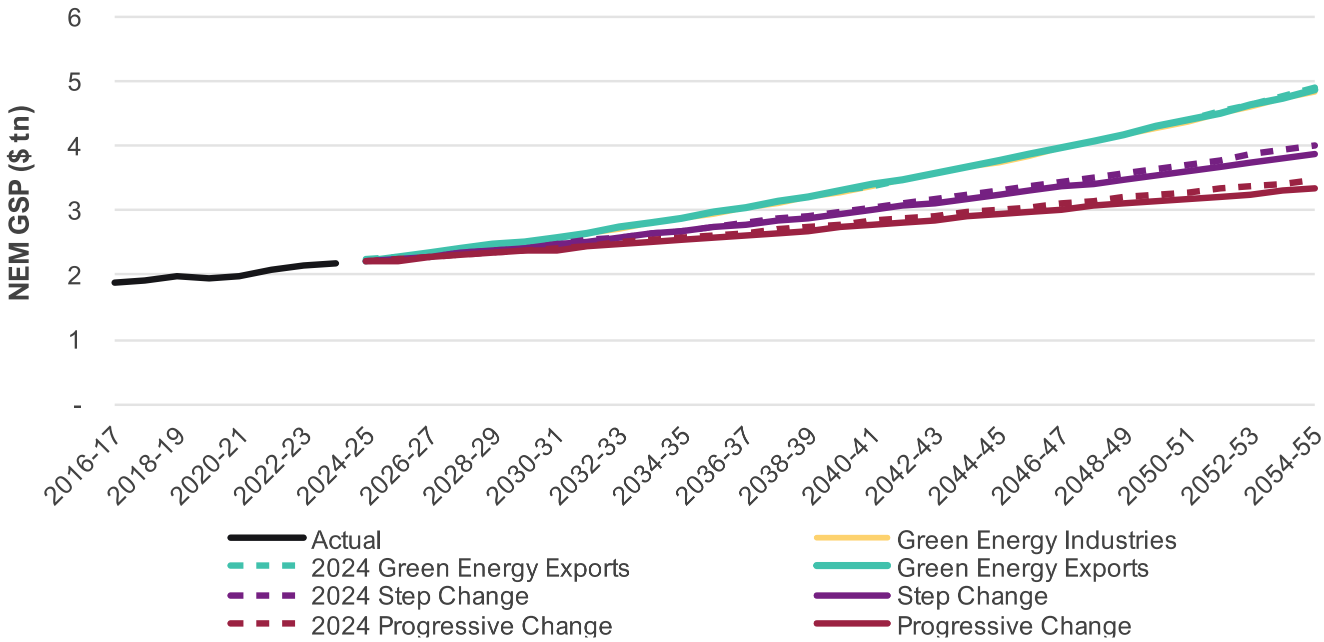
Figure 32 NEM household disposable income per capita by scenario



Note: The *Green Energy Industries* forecast follows a similar trajectory to *Green Energy Exports*, so it is not clearly visible in the figure above.

Economic growth diverges across the scenarios over the forecast period (see Figure 33). Higher population and productivity growth, alongside targeted industrial policy and investments in renewable energy infrastructure, drive increased economic growth in the *Green Energy* scenario variants (*Green Energy Exports* and *Green Energy Industries*). Lower population growth, lower productivity growth, and increased climate change costs decrease expected economic growth in the *Progressive Change* scenario.

Figure 33 NEM aggregated Gross State Product by scenario



Note: The *Green Energy Industries* forecast follows a similar trajectory to *Green Energy Exports*, so it is not clearly visible in the figure above.

3.3.9 Households and connections forecasts

Input vintage	June 2024
Status	Current view
Source	• ABS • DAE • AEMO meter database
Update process	Will be updated in mid 2025 with the latest dwellings forecast and AEMO's latest actual connections data
Get involved	FRG discussion in March/April 2025 (WEM) and May 2025 (NEM)

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.

AEMO estimates the number of new residential electricity connections by combining existing dwelling stock information from the ABS and AEMO metering data, with forecast dwelling completions (newly constructed dwellings net of dwelling demolitions) sourced from the economic consultancy.

AEMO uses the current number of connections as the starting point. The 2024 forecasts for the NEM (used in the 2024 NEM ESOO) started at a lower level compared to the 2023 forecasts, in part due to adjustments in how existing connections were reported, as well as low dwelling completions at the time.

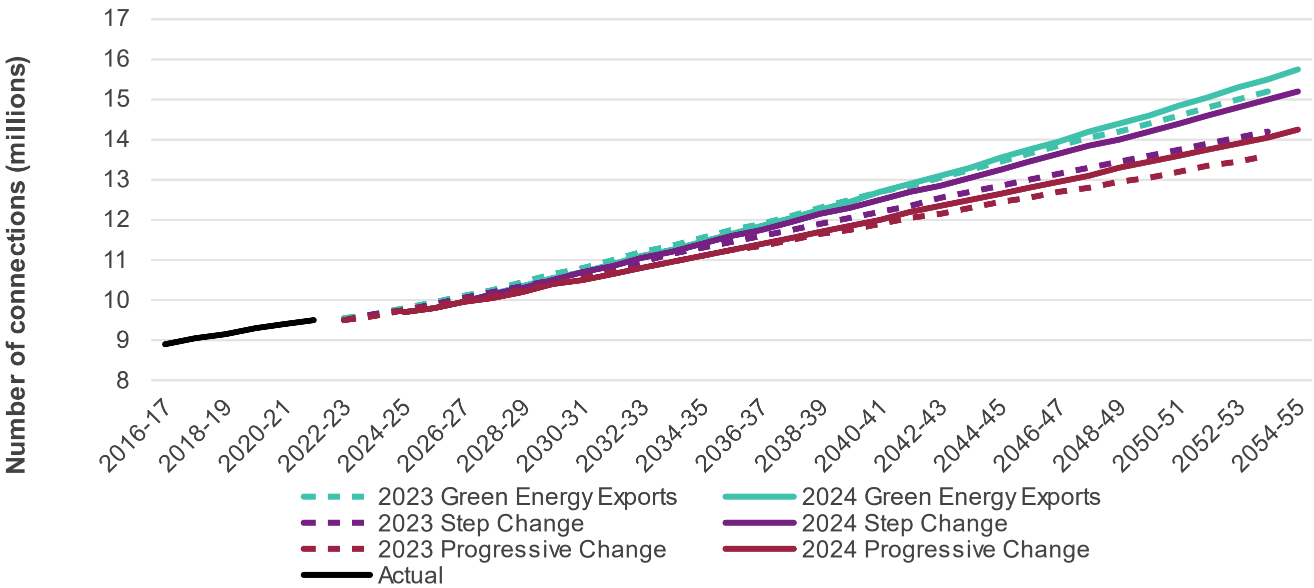
In the short term (3-5 years), lower dwelling completions persist, before recovering to an annual growth rate of around 1.5%. In the *Step Change* scenario, connections are forecast to grow to around 15 million connections by

2054, which is approximately 800,000 more than forecast in the 2023 *Step Change* scenario. These additional connections are backed by a higher population forecast in the longer term, compared to the 2023 forecasts.

The distribution of new connections is different between regions across the NEM, with increased connections in New South Wales, Victoria and Queensland and reduced activity in the Australian Capital Territory, South Australia and Tasmania compared to the 2023 forecasts.

Figure 34 shows the 2024 residential connections actual and forecast for all scenarios in the NEM. The connections forecasts for the NEM and WEM will be updated in time for the final 2025 IASR.

Figure 34 2024 Actual and forecast NEM residential connections, all scenarios, compared to the 2023 forecast



3.3.10 Large industrial loads

Input vintage	June 2024
Status	Current view
Source	• Surveys/Interviews • AEMO meter database • Network service providers • LIL forecasts of multi-sectoral modelling • Economic outlook • Media search/announcements
Update process	Will be updated in mid-2025 following AEMO's industrial load surveying processes
Get Involved	FRG discussion in March/April 2025 (WEM) and May 2025 (NEM)

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*[126] 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.
- Media searches and company announcements, such as on the ASX for Australian listed companies.

LIL forecasts therefore cover the projected energy consumption of all significant industrial customers, including existing ones, new market entrants, and prospective projects.

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. AEMO proposes to broaden the 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*[127].

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.

Figure 35 and Figure 36 compare the 2023 and 2024 LIL electricity consumption forecasts for the NEM and WEM, respectively. These forecasts will be updated in time for the final 2025 IASR, acknowledging the opportunity for engagement via the FRG outlined in the table at the start of this section.

Existing NEM LILs accounted for 27% of the total delivered electricity in 2023-24. Based on the 2024 forecasts, LIL growth is expected to be primarily driven by data centres, mining, and manufacturing expansions. In the medium to long term, the forecasts are informed by projected growth from mining and manufacturing sectors identified by multi-sectoral modelling, driven by decarbonisation objectives and declining electricity costs, particularly from renewables.

The *Progressive Change* 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. That scenario explicitly includes closures of major industrial facilities across the NEM to enable investigation of

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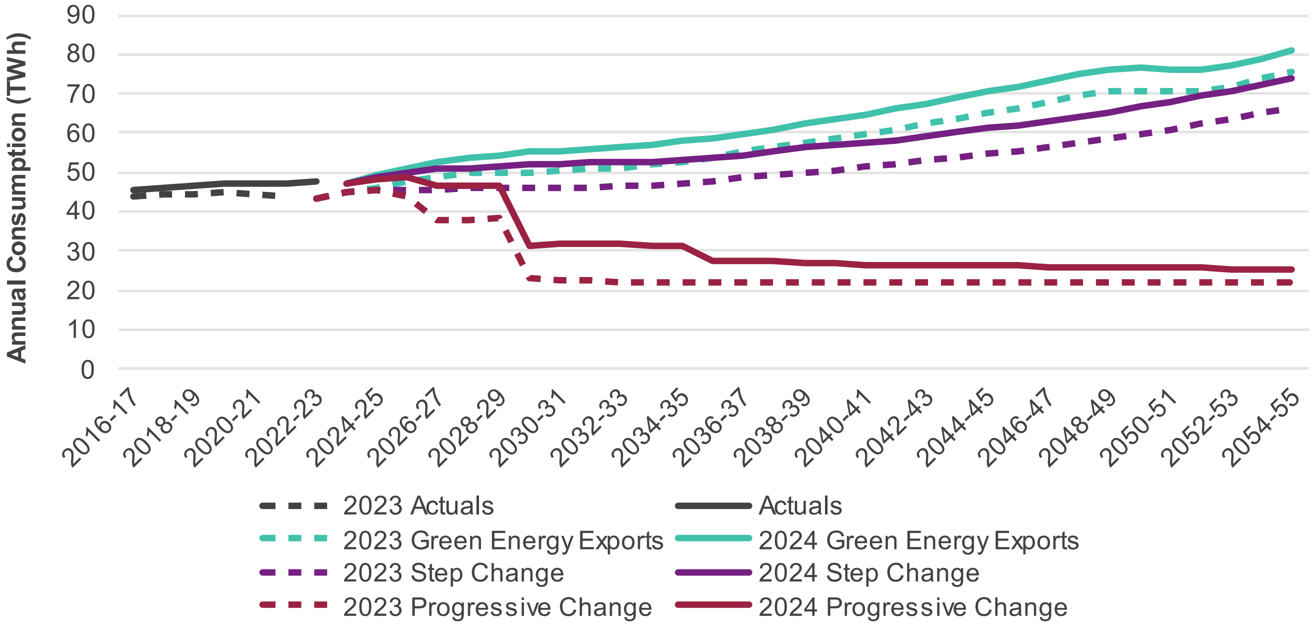
[126] AEMO is presently consulting on the *Electricity Demand Forecasting Methodology*, and while a change to this definition is not anticipated, the LIL definition will be determined in that document. The Draft 2025 IASR describes the current definition, and any changes to the method will be reflected in future LIL forecast updates.

[127] See Section 2.1 of the 2022 *Electricity Demand Forecasting Methodology* for criteria on committed projects, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf. This methodology is currently under consultation and may change – see https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

overinvestment risks in the ISP. The scenario is not forecasting the possible closure of key facilities, but is assuming possible closure outcomes to enable appropriate exploration of investment risks. This is a key feature of the scenario's narrative.

Existing WEM LILs accounted for 32% of total delivered electricity in the Capacity Year[128] 2023-24. WEM LIL growth in the 2024 forecasts is driven by expansions in lithium mining and refining, and a proposed desalination plant.

Figure 35 2024 NEM LIL electricity consumption forecast compared to the 2023 forecast (terawatt hours [TWh])

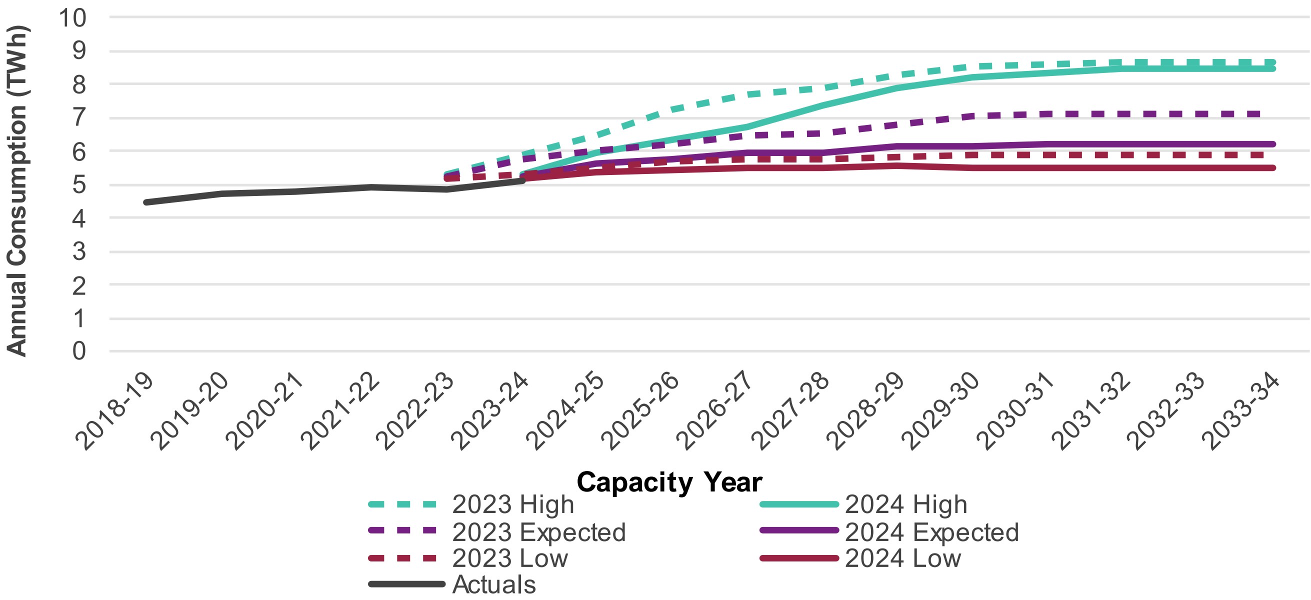


Notes:

- A number of industrial sites were re-classified as LILs for the 2024 NEM ESOO, lifting the forecast and historical data compared to the 2023 NEM ESOO.
- The forecasts contain loads from existing and committed data centres, however AEMO is proposing to treat data centres as a separate business customer segment for 2025 publications onwards.

[128] 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 36 2024 WEM LIL electricity consumption forecast compared to the 2023 forecast (TWh)



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 in 2024-25. Due to their significance, AEMO forecasts LNG loads separately for improved transparency.

Figure 37 shows the 2024 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 2034-35. Beyond then, the longer-term forecast is developed by extending the surveyed trend by scenario-dependent assumptions of global natural gas production and LNG demand, particularly in the Asia Pacific. AEMO shaped the long-term trajectory of scenarios in LNG forecasts based on trends observed in the 2023 IEA WEO[129], whereby:

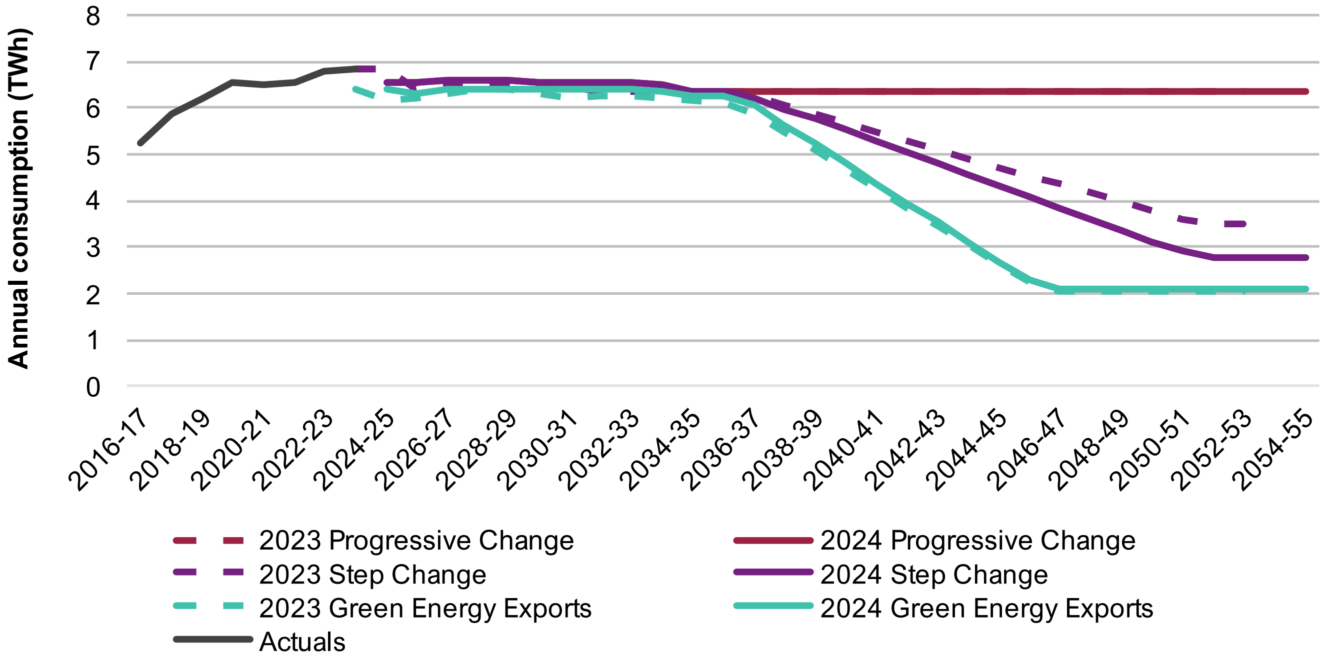
- The *Progressive Change* scenario has been aligned to the IEA's Stated Policies Scenario (STEPS). Lower global economic growth and reduced action towards global decarbonisation means LNG continues to be a valued energy form and LNG export consumption stays flat post 2035.
- The *Green Energy* scenario 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.
- The *Step Change* scenario features a moderate level of global decarbonisation ambition. In this scenario, LNG export consumption falls between levels projected in the IEA's Announced Pledges Scenario (APS) and AEMO's *Green Energy* scenario.

[129] Where possible, AEMO's LNG forecasts have been aligned with IEA forecasts of LNG export from Australia from the 2023 World Energy Outlook (see https://www.iea.org/reports/world-energy-outlook-2023).

The international LNG market faces an uncertain near-term future, affected by geopolitical uncertainties in Europe and the Middle East contributing to volatility, while large amounts of new liquefication capacity are forecast to come online from Qatar and United States by 2030, as the transition towards cleaner energy and focus on energy security are influenced by geographical locations. The degree of uncertainty regarding the future scale of LNG export demand is reflected by the spread in forecast LNG electricity consumption across AEMO's modelled scenarios.

The *Step Change* and *Green Energy* scenarios are slightly higher in the short term than those forecast in the 2023 IASR, while the *Progressive Change* scenario remains the same.

Figure 37 LNG electricity consumption forecast



3.3.11 Data centre forecast

Input vintage	N/A
Status	To commence early 2025
Source	• Surveys/Interviews • AEMO meter database • NSPs • Economic outlook • Media search/announcements
Update process	Will be developed in early to mid-2025
Get involved	FRG consultation in March/April 2025 (WEM) and May 2025 (NEM)

Data centres are a rapidly growing sector being driven by demand for cloud computing and artificial intelligencebased applications. AEMO proposes to forecast data centres as a separate business customer segment for 2025 publications onwards, and is consulting on this adjustment to its forecasting approach in the *Electricity Demand Forecasting Methodology*[130].

Industrial-scale data centres that meet the definition of an LIL will be forecast at an individual site level. Key parameters that may be considered include the ramp-up period (the duration for the new connection to reach full load [which may take years]) and the load realisation factor (a scaling factor representing the amount of load that will be realised, compared to the rated demand for that project).

For the remaining commercial-scale data centres, AEMO proposes to use either a regression-based approach based on historical data (similar to the BMM methodology) or scenario-based assumptions supported by consultant data.

Data centre sources of information include:

- Historical data at the NMI level.
- Surveys and interviews for large data centres (LIL size), with surveyed loads provided with forecast conditions consistent with the economic outlook for each scenario, to increase survey consistency.
- Information request responses from NSPs regarding prospective and newly connecting loads.
- Media searches and company announcements, such as on the ASX for Australian listed companies.
- Public and commercially available records containing information on data centres.

AEMO proposes to publish an aggregated forecast comprising both industrial-scale and smaller commercial-scale data centres, as a separate business customer segment.

3.3.12 Energy efficiency forecast

This section contains updates for Stage 2

Input vintage	January 2025
Status	Draft
Source	• Strategy. Policy. Research. (SPR) • CSIRO Draft multi-sectoral modelling
Update process	• SPR presented on preliminary policy-driven and autonomous energy efficiency forecasts to the FRG in October 2024. • CSIRO forecasts based on the 2024 multi-sectoral modelling consultancy.
Get involved	FRG discussion in March/April 2025 (WEM) and May 2025 (NEM)

AEMO engaged two consultants, Strategy. Policy. Research. (SPR) and CSIRO, to support forecasting energy efficiency for the 2025 IASR scenarios. 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

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

varying decarbonisation pathways, using a combination of annual uptake rates by sector and technology[131], and scenario specific variations based on relativities observed- in the IEA WEO 2024 scenarios.

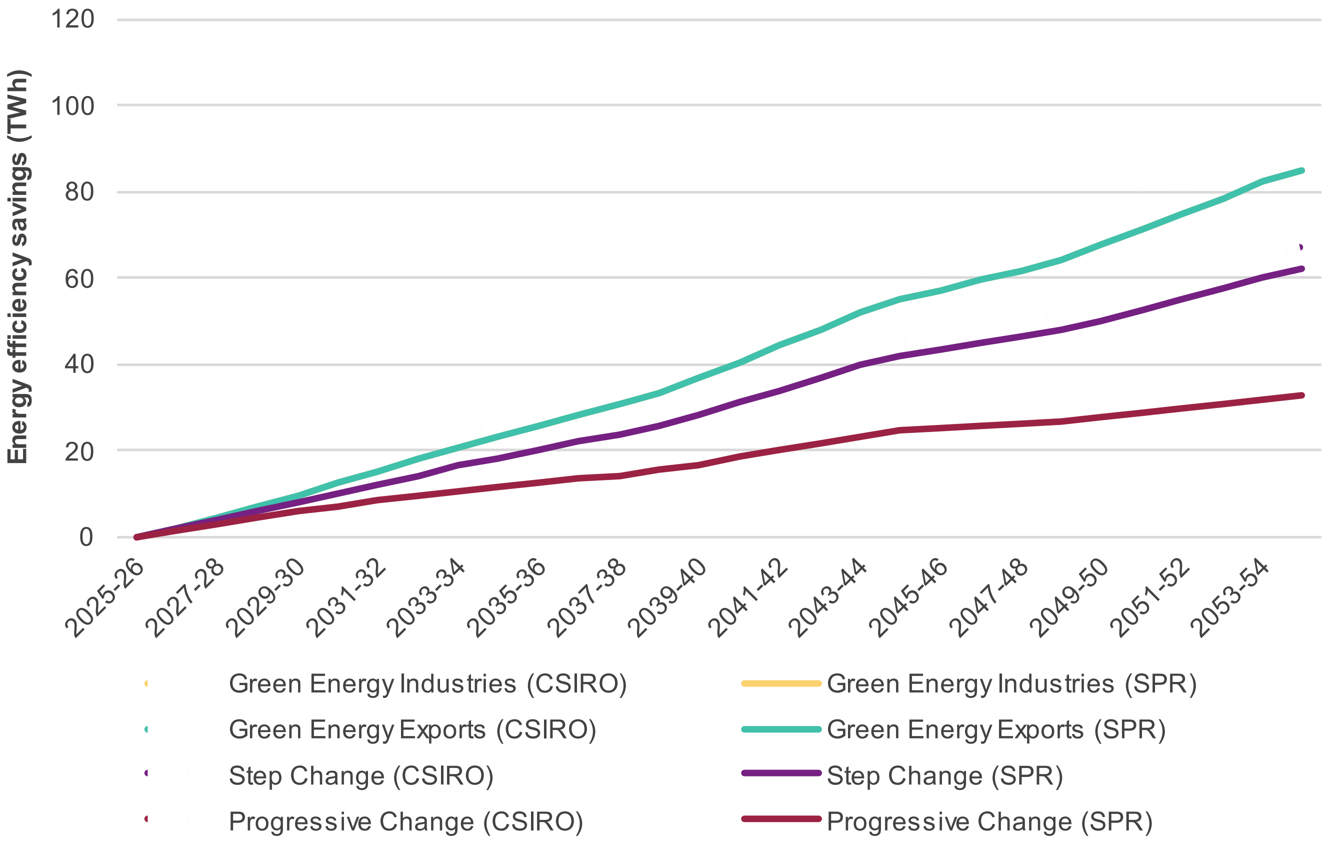
AEMO proposes to base the final 2025 IASR energy efficiency forecasts on SPR's results, using CSIRO's multi-sectoral modelling outcomes to validate these results (equivalent to the approach applied for the 2023 IASR).

Both consultants use scenario-specific economic, population, dwellings and connections forecasts as inputs to modelling energy efficiency for each scenario (outlined in Section 3.3.8). In the case of SPR, the scenario forecasts may exceed current levels of policy support representing expected growth in 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 results (see Section 3.3.5) and consumption of the fuel it is replacing, and not captured by any savings/dissavings shown here.

Figure 38 shows policy-led electricity savings modelled by SPR against endogenous electricity savings from CSIRO's multi-sectoral approach. Endogenous energy efficiency savings are any energy efficiency savings that have an associated cost, optimised alongside other decarbonisation options. CSIRO's results show a greater role for electricity efficiency savings in supporting decarbonisation in the short term, although there is approximate convergence between the two forecasts in the longer term.

[131] 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.

Figure 38 Forecast electricity efficiency savings from SPR (policy-led) and CSIRO (endogenous), Australia, 2025-26 to 2054-55 (TWh)



Note: SPR's *Green Energy Industries* forecast follows a similar trajectory as *Green Energy Exports*, and may be hidden in the figure above.

SPR's policy-led savings use a different analytical lens than CSIRO's endogenous approach. However, both consultancies each incorporate an autonomous efficiency component to their efficiency estimates (SPR refers to this as market-led improvement). New for the 2025 IASR is corroboration and alignment of autonomous energy efficiency assumptions between SPR and CSIRO, noting that their category definitions for autonomous improvement are not exactly the same[132]. While the building block 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 is important corroboration for the eventual results that are adopted for the 2025 IASR.

Multiple policy-led improvements modelled by SPR are assumed to be influential in driving energy efficiency improvements across the scenarios. For the residential sector, electricity savings in households stem from increased National Construction Code (NCC) stringency, and enhanced appliance standards from the national Greenhouse and Energy Minimum Standards (GEMS) and Equipment Energy Efficiency (E3) program, as well as subsidies from state schemes such as the Energy Savings Scheme (ESS) in New South Wales, the Victorian Energy Upgrades (VEU) program, and the South Australian Retailer Energy Productivity Scheme (SA REPS).

[132] 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.

The NCC is also assumed to drive efficiency improvements in the commercial sector, alongside expansions of the Commercial Building Disclosure (CBD) program, National Australian Built Environment Rating Scheme (NABERS), and state-funded incentives.

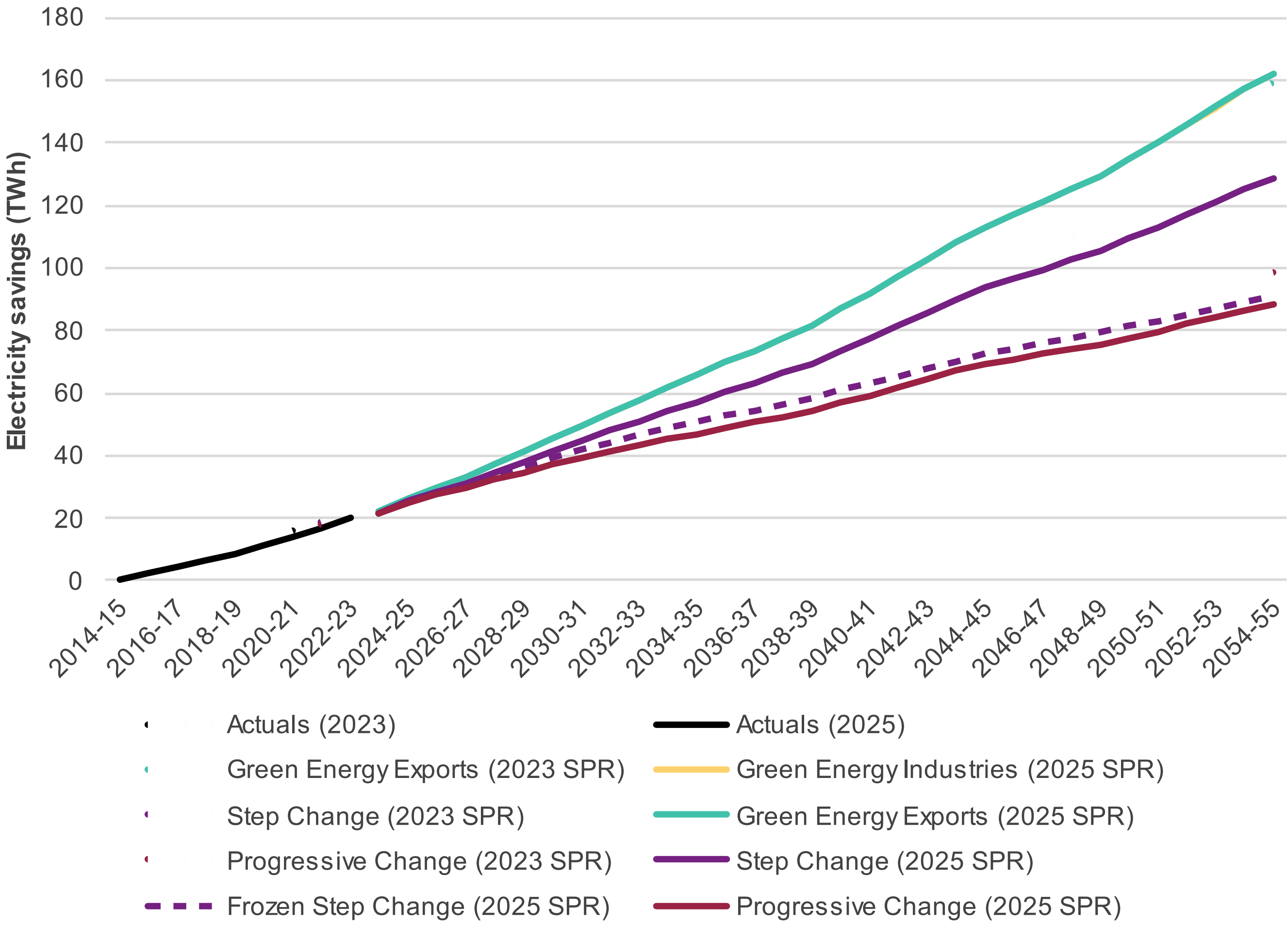
For industrial sector electricity efficiency, the largest gains are tied to autonomous (market-led) energy efficiency improvements, with smaller contributions from GEMS and the state-based schemes. The largest gains for the industrial sector occur for natural gas efficiency via updates to the Safeguard Mechanism, which came into effect in July 2023[133]. 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.

The combined market-led and policy-led electricity energy efficiency savings modelled by SPR are shown in Figure 39. Electricity savings for the 2025 IASR are broadly consistent with the 2023 IASR. Improved thermal shells, via more airtight windows and exterior building surfaces, investments in heating, ventilation and air conditioning (HVAC) systems and lighting are particularly impactful in continuing to drive electricity savings through the projection period in all scenarios.

AEMO also commissioned SPR to model *a Frozen Step Change* sensitivity, whereby all input assumptions remain the same, though no new energy efficiency policy development is assumed to occur. For electricity, the cessation of policy development results in almost 40 TWh less energy efficiency savings by the end of the projection period for this *Step Change* sensitivity.

[133] See Safeguard Mechanism Reforms, available at: https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism, accessed 4 February 2025.

Figure 39 SPR electricity energy efficiency savings, Australia, 2014-15 to 2054-55 (TWh)



Note: SPR attributes minor differences in actuals in 2023 and 2025 to updated data from the Commercial Building Baseline Study and replacement of Australian Energy Statistics (AES) data with AEMO meter data.

For the 2023 IASR, AEMO determined that SPR's energy efficiency forecasts were the most applicable for the scenarios developed, and were the basis for AEMO's planning purposes. For the 2025 IASR, AEMO notes that there is general alignment between the consultancies and is again proposing to adopt SPR's energy efficiency savings, having validated the similarity through CSIRO's multi-sectoral modelling outcomes.

Matters for consultation for Stage 2

- Are the energy efficiency savings projected by the consultants suitable for their respective scenarios?
- Are SPR's results sufficiently aligned with the role of energy efficiency in optimised decarbonisation pathways (as revealed by CSIRO's multi-sectoral modelling approach)?
- What other considerations may influence energy efficiency?

3.3.13 Appliance uptake forecast

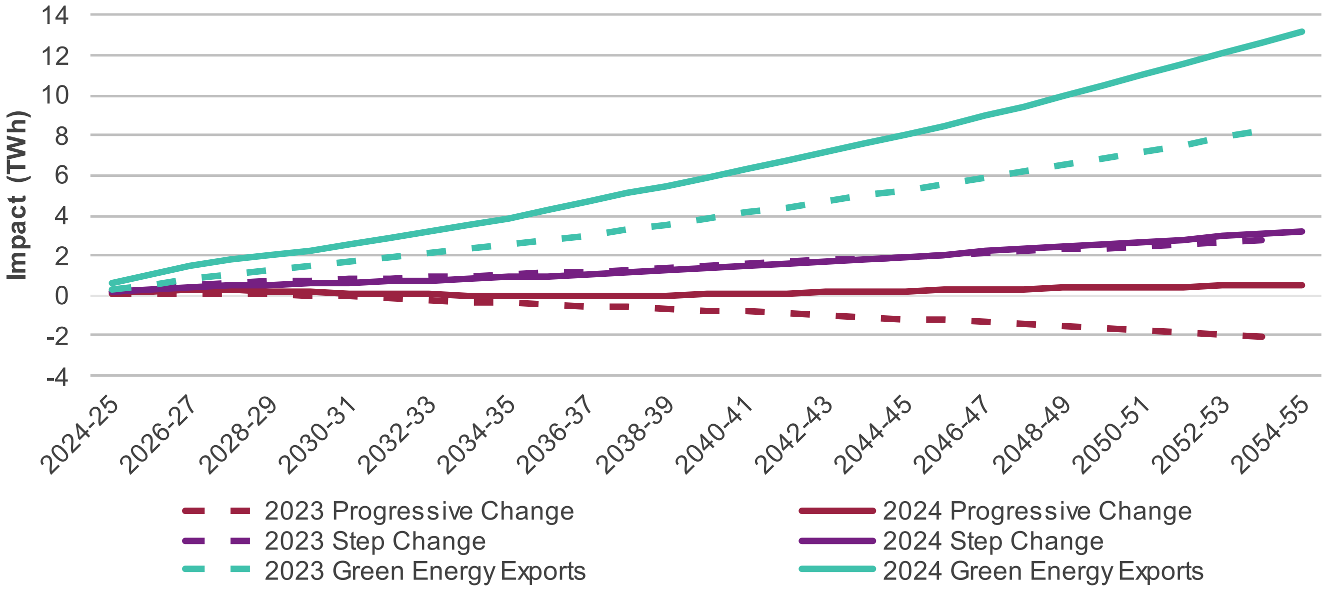
Input vintage	June 2024
Status	Interim
Source	• Department of Industry, Science, Energy and Resources (DISER), *2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040*, available at www.energyrating.gov.au • Economic forecasts (Section 3.3.8)
Update process	Update for latest economic forecasts
Get involved	FRG discussion in March/April 2025 (WEM) and May 2025 (NEM)

AEMO used data from the former Federal Government Department of the Environment and Energy (now the Department of Climate Change, Energy, the Environment and Water [DCCEEW]) to forecast the growth in appliances per connection in the residential sector. The data allowed AEMO to estimate changes to the level of energy services supplied by electricity per households across the NEM.

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 for details on the methodology used).

Figure 40 shows the appliance uptake trajectories applied to the consumption forecasts for the 2024 NEM ESOO, compared with the 2023 NEM ESOO. AEMO will update the trajectories before the release of the final 2025 IASR for both the NEM and WEM, using the latest economic forecasts available.

Figure 40 Residential appliance uptake trajectories for the NEM, consumption change relative to base year (2024), 2023-24 to 2054-55 (TWh)



3.3.14 Electricity price indices

Input vintage	June 2024
Status	Current view
Source	• AEMO internal wholesale price forecasts. Transmission costs from the 2024 ISP's optimal development path[134]. • ASX Energy Electricity Futures. • AER Determinations and Access Arrangements[135]. Australian Energy Market Commission (AEMC) annual Residential Electricity Price Trends, 2024 report[136,137]. • Australian Competition and Consumer Commission (ACCC) Inquiry into the National Electricity Market report - November 2022[138]. 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.
Get involved	FRG consultation in May 2025 (NEM).

Electricity prices are assumed to 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).

Figure 41 illustrates the retail price indices determined for the 2023 and 2024 NEM ESOOs for the Progressive Change, Step Change, and Green Energy scenarios. The retail price indices for the NEM and WEM will be updated in time for the final 2025 IASR.

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

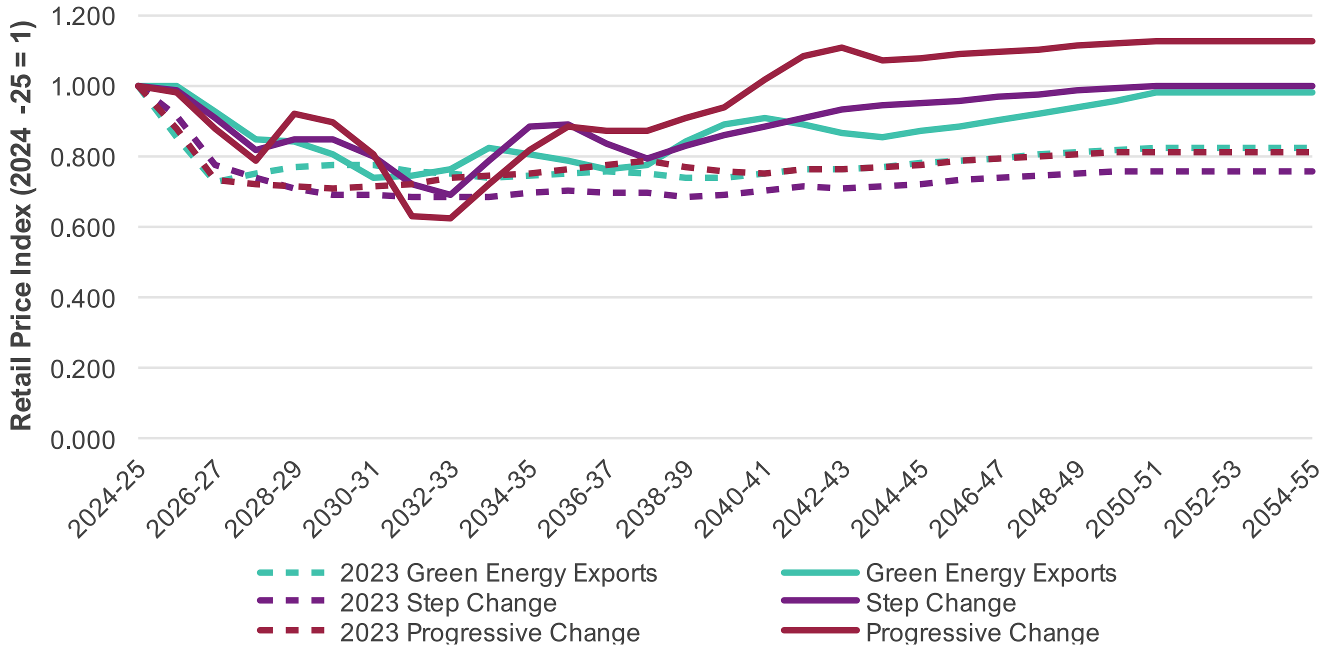
[135] At https://www.aer.gov.au/industry/registers/determinations.

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

[137] As outlined in Table 19, 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.

[138] 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.

Figure 41 NEM Residential retail price forecasts, 2024-25 to 2054-55



Note: Price weighted by household consumption per region.

Prices are expected to trend downwards until the early 2030s as significantly more low-cost renewable energy generation is expected to come online. Prices are expected to rise in 2028-29, driven by the expected retirement of coal power stations and forecast delays to some VRE and battery storage projects. Some price volatility is expected in the mid-2030s as traditional thermal generation is phased out and replaced by renewables with firming from utility-scale battery storage. Modest increases in wholesale prices in the 2040s are projected due to the increased penetration of flexible gas power generation. Gradual increases in network charges beyond the 2040s are driven by transmission investment costs required to meet the ISPs optimal development path for each scenario. 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.

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 2024 scenarios. AEMO proposes a similar treatment for the 2025 IASR scenarios, to apply in the 2025 ESOO and 2026 ISP, with updated inputs as available prior to applying AEMO's forecasting approach.

Table 19 Retail price input settings by scenario

Scenario	*Progressive Change*	*Step Change*	*Green Energy*
Wholesale component	• **Short term** (up to FYE 2027): Blend of ASX Futures and 2024 ISP Progressive Change. • **Longer term** (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP.	• **Short term** (up to FYE 2027): Blend of ASX Futures and 2024 ISP *Step Change* scenario. • **Longer term** (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP.	• **Short term** (up to FYE 2027): Blend of ASX Futures and 2024 ISP *Green Energy Exports* scenario. • **Longer term** (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP.
Transmission costs	• **Short term** (up to FYE 2029): AER pricing proposals and	• **Short term** (up to FYE 2029): AER pricing proposals and	• **Short term** (up to FYE 2029): AER pricing proposals and

Scenario	*Progressive Change*	*Step Change*	*Green Energy*
	determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Progressive Change* scenario.	determinations actuals (latest available). • **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Step Change* scenario.	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.
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 (2021) to FYE 2024 then decline to zero by FYE 2030.	AEMC (2021) to FYE 2024 then decline to zero by FYE 2030.	AEMC (2021) to FYE 2024 then decline to zero by FYE 2030.
Retail component	ACCC (2022) derived residual.	ACCC (2022) derived residual.	ACCC (2022) derived residual.

The retail price indices are only used to inform annual electricity consumption forecasts and consider the potential response from consumers to price. Consumption forecasts consider the price elasticity of demand; that is, the percentage change in demand for a given change in price. The underlying price elasticity of demand that is used to give effect to the price indices and influence the consumption forecasts is as per the 2023 IASR. Table 20 below provides the 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	*Progressive Change*	*Step Change*	*Green Energy*
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 2024
Status	Current view
Source	Historical meter data analysis and information submitted to the DSP Information portal in April 2024.
Updates since 2023 IASR	Current levels and committed/planned changes updated after summer 2023-24 to reflect most recent information. Target levels to be maintained.
Get involved	FRG consultation in May 2025 (DSP and WDR)

AEMO's forecasting approach considers DSP explicitly in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP[139]. DSP accounts for the demand flexibility which often does

[139] For further details, see Appendix 6 of 2024 ESOO, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

not have a regular and repetitive pattern; it occurs in response to a price trigger (to avoid high market prices) or lack of reserve (LOR) conditions (LOR2 or LOR3)[140]. Due to the often-irregular pattern of DSP responses, they are not captured by AEMO's demand or supply forecasts, so they need to be forecast separately. This approach, most recently updated in December 2023, remains relevant, yet may require further updates to address whether the assumed levels accurately reflect future DSP capabilities and are not overly conservative considering potentially increasing demand-side capabilities in near future (for example, load flexibility offered by VPPs).

AEMO estimates the current level of DSP using information provided by registered participants in the NEM through AEMO's DSP Information portal (DSP IP), supplemented by historical customer meter data. DSP responses are estimated for various price triggers and AEMO assumes the 50th percentile of observed historical responses is a reliable, central estimate of the likely response when the various price triggers are reached. The DSP forecast also includes Wholesale Demand Response (WDR) contributions based on the WDR dispatch data; WDR estimates are calculated as a weighted average response of dispatched WDR for each price trigger. Finally, to forecast the total reliability response, the estimated DSP response during reliability events (which AEMO defines as cases where an actual LOR2 or LOR3 is declared) is added to the price-triggered response. This process is completely documented in AEMO's *Demand Side Participation Forecast Methodology*[141].

In accordance with this methodology, AEMO uses existing and committed DSP only for the ESOO, representing the current level discussed above with adjustments for committed changes to DSP as reported to AEMO through the DSP IP, or through policy targets with supporting legislation implemented. For long-term planning studies like the ISP, the quantity of DSP is grown to meet a target level by the end of the outlook period; except for the Progressive Change scenario which assumes no growth in the current level of DSP participation. The target level, defined as the DSP's proportion relative to maximum demand, is linearly interpolated between the beginning and end of the outlook period. The target level at the end of the outlook period aims to reach 8.5% of maximum demand adoption scenario, informed by an international review of demand response potential (primarily in the United and Europe)[142,143]. This 8.5% figure represents an upper estimate, allowing for growth drivers both from technology and policy schemes (such as WDR).

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

- The *Green Energy*[144] scenario assumes high growth in DSP, representing a future with highly engaged consumers who, in addition to embracing CER technologies, value the savings from orchestrated DSP programs over the convenience of fixed tariffs and uncontrolled demand.
- The *Step Change* scenario assumes moderate growth in DSP, reflecting moderate economic growth and technology-led change.

[140] 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.

[141] See DSP 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.

[142] 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).

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

[144] Note that the DSP does not include the flexibility provided by electrolysers, which is modelled separately.

- The *Progressive Change* scenario assumes no growth in DSP, maintaining the current penetration level into the future due to a relatively poor economic outlook that limits the capability to install new technologies to increase flexibility, hampered also by supply chain issues affecting demand-side innovations.

For New South Wales, the Peak Demand Reduction Scheme (PDRS) policy[145] aims at creating a financial incentive to reduce electricity consumption during peak demand times in summer[146]. AEMO includes this scheme in all of the above scenarios. The PDRS has been applied since 2022-23 with the target growing to 10% of forecast peak demand by 2029-30, slightly fluctuating due to reaching the end-of-life for some batteries, and remaining flat from 2039-2040 onward. It is assumed that 25% of the PDRS target will be met through energy efficiency and battery storage rather than DSP, with DSP adjustments made to avoid double counting. For any given year in New South Wales, the higher value between the PDRS target and standard DSP growth will be used.

Table 21 Mapping of DSP settings to scenarios

Scenario	*Green Energy*	*Step Change*	*Progressive Change*
DSP growth target overall	High growth to reach 8.5% of peak demand by 2050, then remains flat.	Moderate growth to reach 4.25% of peak demand by 2050, then remains flat.	No change from current levels of DSP (0% growth).
New South Wales PDRS	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).

Matters for consultation from Stage 1

- Are the long-term DSP settings, grown to meet a target level by scenario informed by international review, suitable for use in AEMO's planning publications?

3.4 Existing generator and storage assumptions

3.4.1 Generator and storage data

Input vintage	October 2024
Status	Current view
Source	Participant survey responses
Update process	Updated quarterly

AEMO's Generation Information page[147] 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

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

[146] This is for the state of New South Wales only. The NEM region of New South Wales also includes the Australian Capital Territory, so adjustments are made to ensure the target reflects the New South Wales state demand only.

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

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 Draft 2025 *IASR Assumption Workbook* includes details from the October 2024 publication. Further updates will be made prior to the finalisation of the 2025 IASR, and these updates will be considered in the 2025 ESOO and Draft 2026 ISP (unless material changes are observed during the course of ISP modelling).

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
Status	Draft
Source	Various, see below
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Updated based on October 2024 Generation Information and Clean Energy Regulator's Electricity sector emissions and generation 2022-23.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies[148]. 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.
- AEP Elical, 2020 Assessment of Ageing Coal-Fired Generation Reliability.
- Generator surveys.
- Clean Energy Regulator, Electricity sector emissions and generation 2022-23.
- 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

[148] Consultant reports and data books from GHD, Aurecon and AEP Elical are available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

Source	Technical and cost parameters used in AEMO's inputs and assumptions
GHD 2018-19 AEMO Energy Technology Cost and Technical Parameter Review *(for use for existing generators as of 2018)*	• Heat rates • Maintenance rates • Fixed and variable operating and maintenance costs • Ramp rates • Minimum up and down time
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 • 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
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 2022-23	• 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 contained in the Draft 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 Draft 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 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 Draft 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.
- 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 can be found in AEMO's *ISP Methodology*[149].

3.4.3 Generator unplanned outage rates

Input vintage	April 2024
Status	Draft
Source	Generator surveys, AEP Elical 2020, and Aurecon 2024 Cost and Technical Parameter Review
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Unplanned outage rates were updated with latest data in April 2024 as part of data collection process for the ESOO. The updates were presented to the FRG in June 2024.

In April 2024, AEMO collected outage information for existing scheduled generators, including storage units, on the timing, duration, and de-rating of historical unplanned outages via an annual survey process. This data is then used to forecast the full and partial unplanned outage rates[150] (UORs) for each financial year, for each generator over the ESOO horizon consistent with the ESOO and Reliability Forecasting Methodology151. For small peaking plants and hydro generator technology types, technology aggregates are applied to individual stations. Where AEMO asked participants to provide outage rate projections, these projections were adopted in consultation with the station owners/operators.

[149] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology. This methodology is also under consultation for the 2026 ISP, at https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[150] Planned outages are not modelled in the ESOO, because these are assumed to be planned in lower demand periods or to shift if low reserve conditions were to occur, and therefore not impact USE outcomes.

[151] 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.

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 outages with a duration longer than five months (long duration outages) from historical outage data from 2010-11 to the most recent financial year, prior to calculation of the expected unplanned outage rate. AEMO used an extended historical period of all available data (all available years since 2010-11) to determine the (unplanned) long duration outage rates for each region and technology class.

The long duration outages used in 2024 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 shown in Table 23.

Table 23 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
All coal	0.91%	6,331
OCGT	0.73%	4,872
Hydro	0.17%	4,065
Other gas and liquid	0.54%	6,632

OCGT: Open cycle gas turbine.

Unplanned outage rate trajectories (excluding long duration outages)

The forecast equivalent full and partial unplanned outage rates by technology for 2024-25, the first year of the forecast horizon period in the 2024 ESOO, are based on participant-provided information as shown in Table 24.

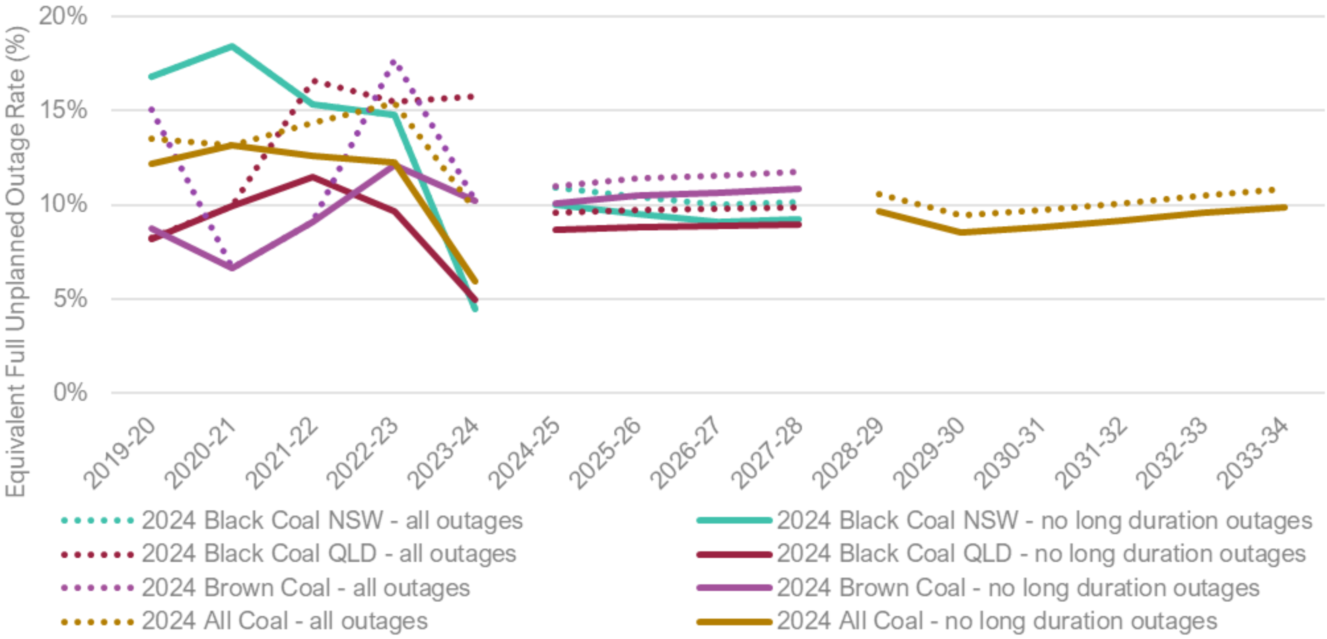
Table 24 Unplanned outage assumptions (excluding long duration outages) for 2024-25 financial year

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)
Brown coal	7.39	15.45	17.39	92	37
Black coal NSW	5.22	27.08	17.67	136	28
Black coal QLD	5.37	13.70	24.03	160	44
OCGT	8.25	2.32	9.86	57	130
Small peaking plant*	8.65	0.35	28.29	201	323
Hydro	4.56	1.06	13.30	51	436
Closed cycle gas turbine (CCGT) and gas-fired steam turbine	6.71	1.25	13.25	54	38
Batteries	1.84	N/A	N/A	141	N/A

*Small peaking plants are generally classified as those less than 150 MW in capacity, or with a very low and erratic utilisation (such as Colongra and Bell Bay/Tamar peaking plant)

The 10-year projections for the equivalent full unplanned outage rate[152] of all technology aggregates are shown in Figure 42, Figure 43 and Figure 44, with and without the effect of long duration outages. The annual equivalent unplanned outage rates are affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, unplanned outage trajectories are provided for the first 10 years of the horizon for technology aggregates only. Due to the small number of coal plants in later years, all regions have been further aggregated to an 'All Coal' value to protect confidentiality.

Figure 42 Equivalent full unplanned outage rate projections for coal-fired generation technologies



[152] Where equivalent full unplanned outage rate = Full outage rate + partial outage rate x average partial derating.

Figure 43 Equivalent full unplanned outage rate projections for OCGT, CCGT and steam turbine generation and small peaking plant technologies

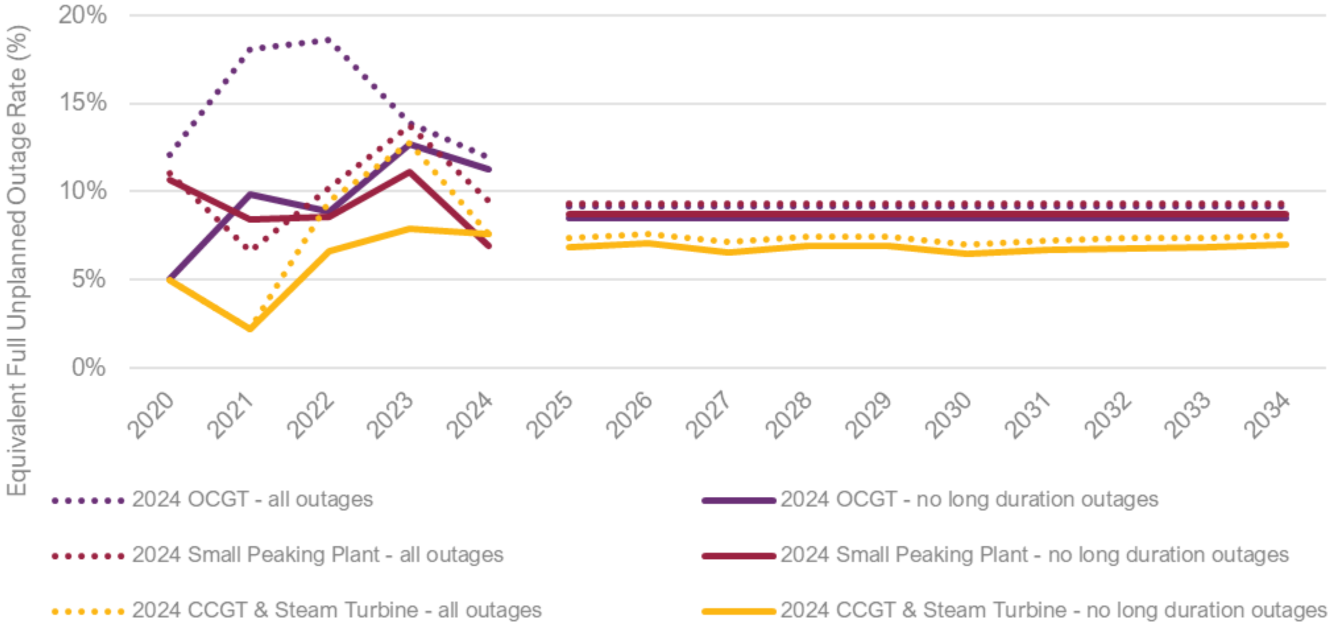
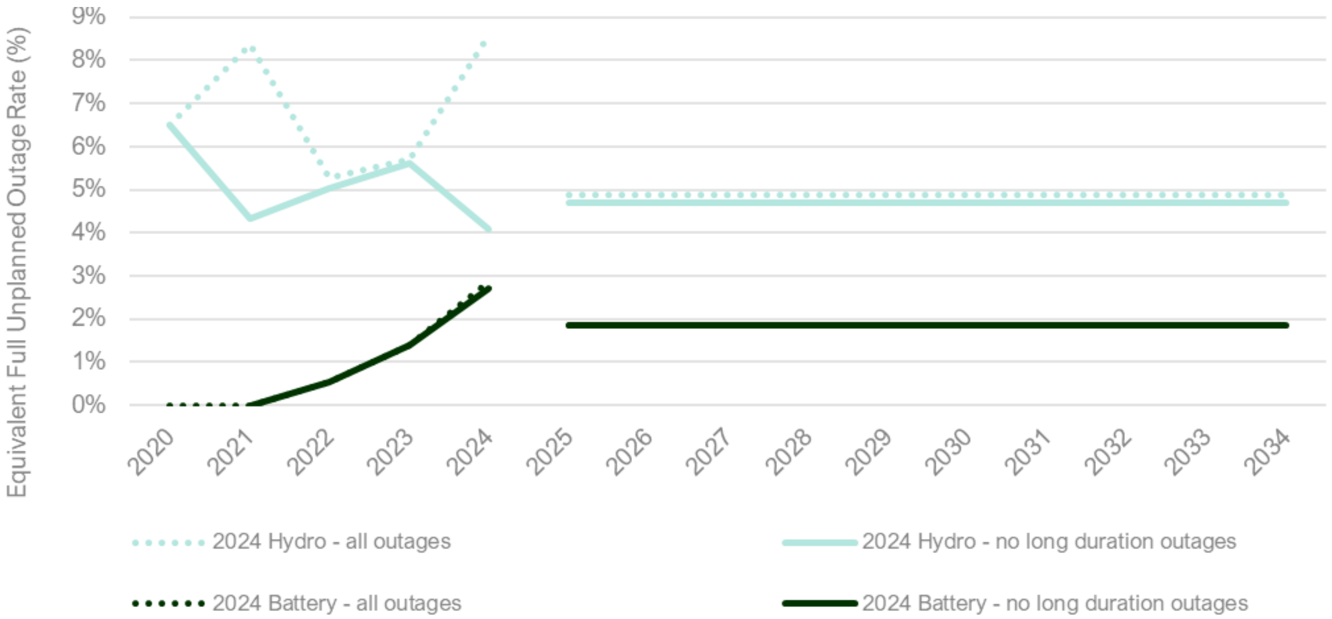


Figure 44 Equivalent full unplanned outage rate projections for battery and hydro technologies



Outage modelling assumptions for existing generators for ISP purposes

For ISP purposes, the forced 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*[153].

New entrant generation outage assumptions for all modelling purposes

The equivalent full 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. For new coal generation, Aurecon's EFOR is equally divided between full and partial outage/derating. Long duration outages are not applied to new entrant technologies.

3.4.4 Generator retirements

Input vintage	• Retirement costs: December 2024 • Retirement dates: Generation Information October 2024
Status	• Current view
Source	• Generation Information • GHD 2018
Update process	Updated quarterly
Updates since 2023 IASR	Expected closure years and closure dates have been updated to reflect the most recent data collection.
Get involved	FRG Consultation in May 2025

For existing generators, AEMO applies the expected closure year as provided by participants and published through AEMO's Generation Information[154] page as a latest retirement date, 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, 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 in relation to which there is an expected closure year tend to be projects that are scheduled to close in the near term, over the next few years or so, and are published in the Generating Unit Expected Closure Year subset of the 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

[153] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

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

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 Draft 2025 *Inputs and Assumptions Workbook*. A number of technologies (biomass, solar thermal, offshore wind) do not have a retirement cost estimate. Given the development lead times of these technologies (generally greater than six years) and the economic life (generally greater than 25 years), retirement costs would be incurred beyond the end of the ISP modelling horizon. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

AEMO is considering updating assumptions used for retirement and recycling costs and will consult on updated assumptions through the Forecasting Reference Group forum prior to the publication of the final 2025 IASR.

Matters for consultation from Stage 1

Are the retirement cost assumptions detailed in the accompanying Draft 2025 Inputs and Assumptions Workbook appropriate?

3.4.5 Hydro modelling

Input vintage	June 2023
Status	Current view
Source	Inflows – hydro operators, considering insights regarding long-term rainfall trends from the Electricity Sector Climate Information (ESCI) project[155].
Update process	Scheme inflows will be updated for the 2025 IASR.
Updates since 2023 IASR	Hydro scheme inflows have been updated based on data received from participants in April and June of 2023.

Hydro scheme inflows

AEMO models each of the large-scale hydro schemes using inflow data for each generator, with aggregation of some run-of-river generators.

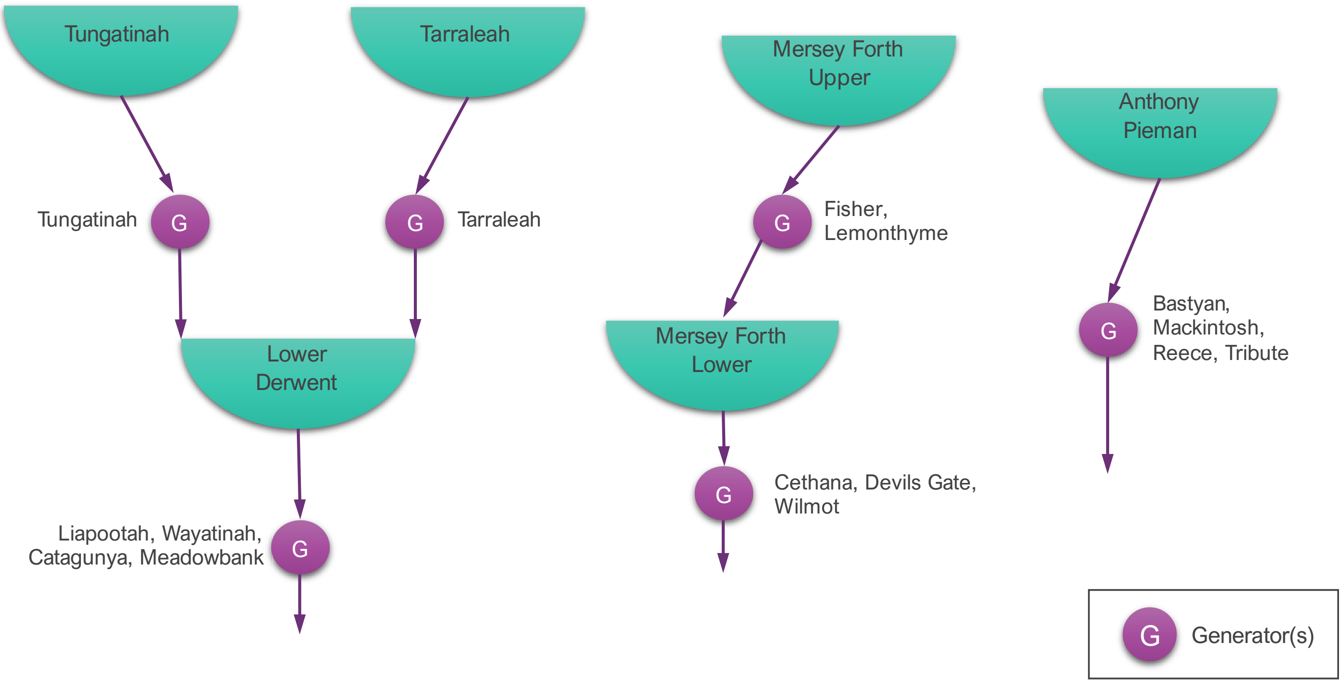
Tasmanian hydro scheme

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond[156] topology designed to capture different levels of flexibility associated with the different types of storage outlined above (see Figure 45).

[155] ESCI information available at https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

[156] The capacity outlook model may aggregate long-term storages together to reduce simulation time.

Figure 45 Hydro Tasmania scheme topology



Mainland hydro scheme

Some of the Victorian hydroelectric generators are modelled using maximum annual capacity factor constraints on each individual generator; these are West Kiewa and Bogong-Mackay[157]. The model schedules the electricity production from these generators across the year such that system costs are minimised within this energy constraint.

Other hydroelectric generators in Victoria and Queensland, as well as the Snowy scheme, are represented by physical hydrological models, describing parameters such as:

- Maximum and minimum volume.
- Initial storage volume.
- Monthly reservoir inflow rates reflecting historical inflows.

Monthly storage inflows used in market modelling studies can be found in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 46 presents a representation of the topology currently modelled for the Snowy scheme.

[157] 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 46 Snowy Hydro scheme topology

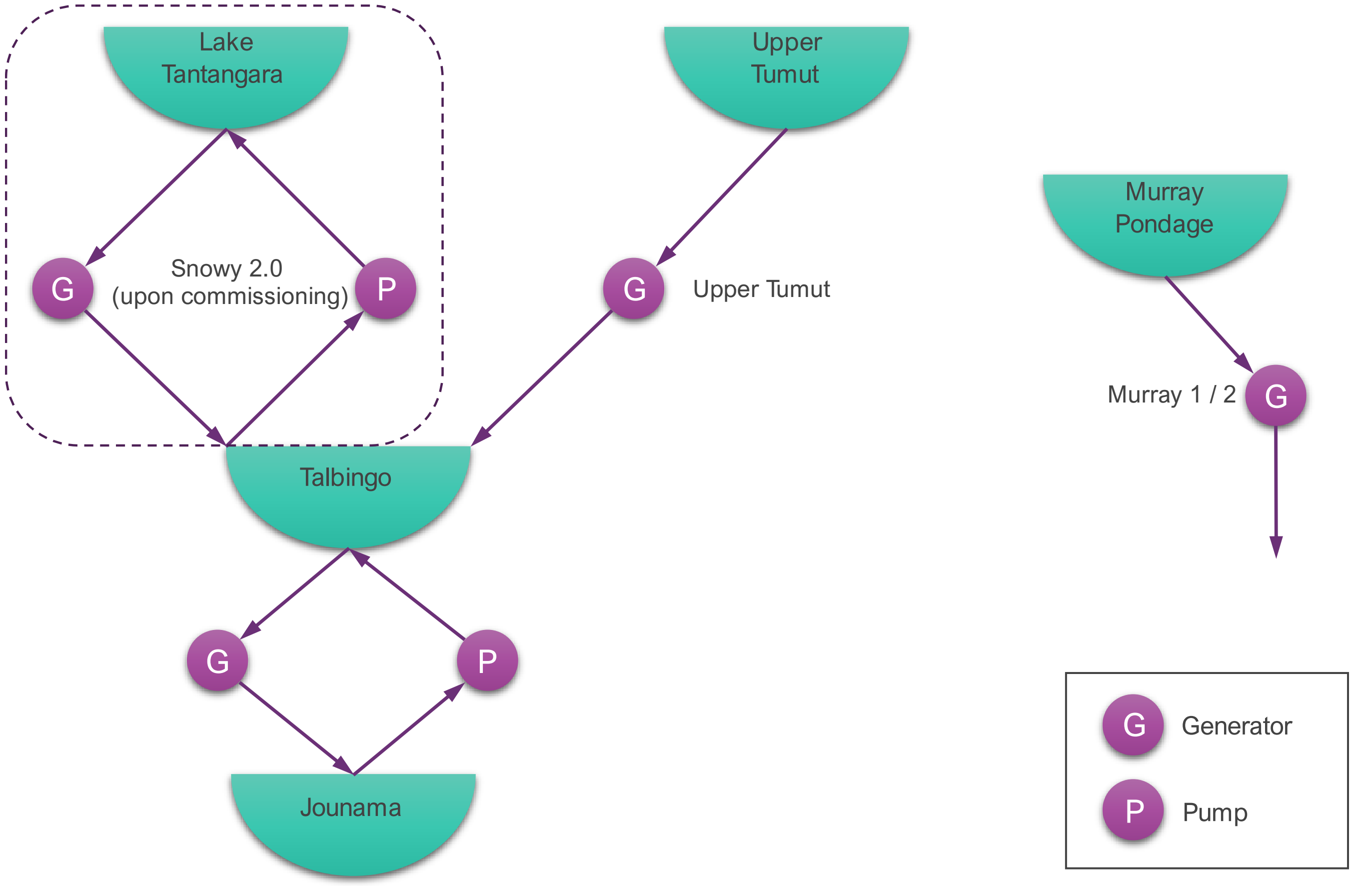
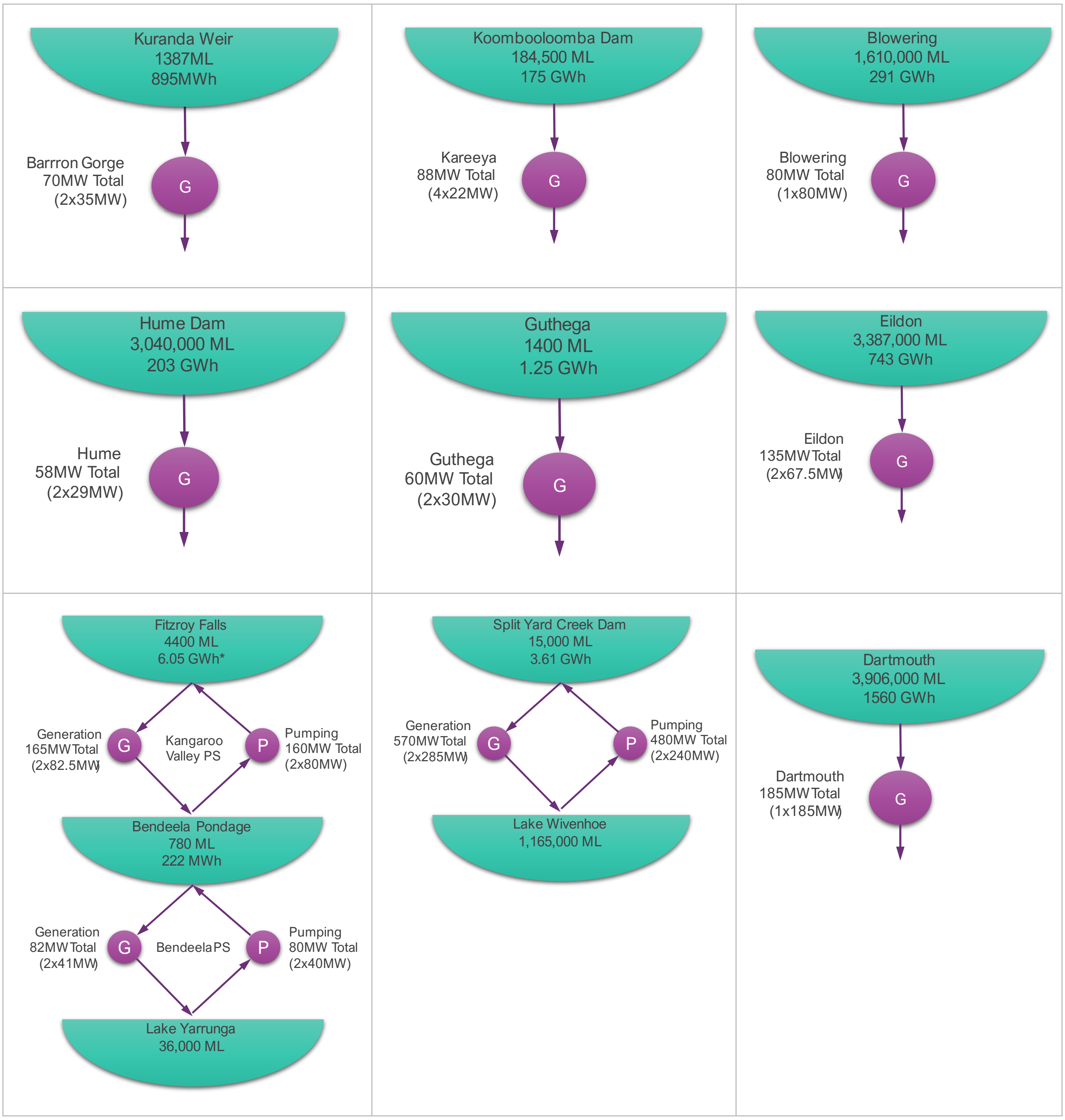


Figure 47 provides graphical representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units[158].

Figure 47 Hydro scheme topologies of other existing hydro power stations

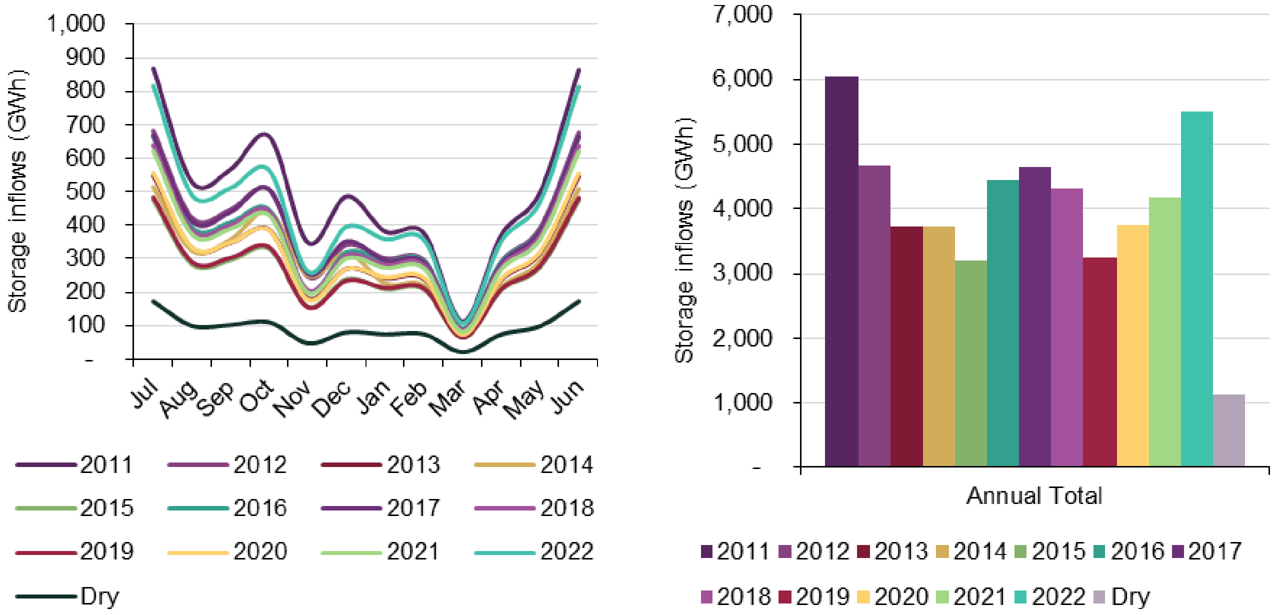


*Energy storage at Fitzroy Falls includes full drop through both power stations.

[158] Storage capacities are defined in megalitres (ML).

The Draft 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 48 below, for Snowy Hydro. The data will be updated in the 2025 IASR; it is updated based on observed inflows and participant received data, similar to other historical data.

Figure 48 Hydro inflow variability across reference weather years – Snowy Hydro



Australia-specific climate information on regional changes in long-term average rainfall over time has been estimated through close collaboration with CSIRO and the BoM as part of the Electricity Sector Climate Information (ESCI) project, sponsored by the Federal Government[159].

Streamflow change factor projection information was provided to AEMO as part of the ESCI project for 220 different natural streams in Australia. AEMO grouped many of these natural streams into three different areas based on their proximity to existing hydro generators, and the statistical stability of the change factor projections. The projections represent the median of an ensemble of streamflow projections and have been scaled to reflect the inherent climate narratives relevant to each scenario.

The median hydro change factor projections are shown in Table 25 for the *Step Change* scenario, as an example. Other scenario hydro climate factors are available in the Draft 2025 *Inputs and Assumptions Workbook*.

Table 25 Median hydro climate factors, *Step Change* scenario

Region	2020-21	2030-31	2040-41	2050-51
North Queensland	0%	0%	0%	0%
Southern Queensland, New South Wales, Victoria, and South Australia	-2.0%	-5.0%	-4.9%	-5.3%
Tasmania	-0.8%	-2.0%	-1.2%	-0.4%

[159] See https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

3.5 New entrant generator assumptions

3.5.1 Committed and anticipated projects

Input vintage	October 2024
Status	Current view
Source	Participant survey responses
Update process	Quarterly updated
Updates since 2023 IASR	Updated to incorporate the October 2024 Generation Information.

New generator or storage developments that are announced to market are assessed against commitment criteria published in AEMO's Generation Information page[160]. The commitment criteria cover five areas of a project's development, covering:

- Land/site acquisition.
- Contracts for major components.
- Planning and other approvals.
- Financing.
- Construction.

To classify the commitment status of generators or storages, AEMO uses information provided by both NEM participants and project proponents. 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.

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

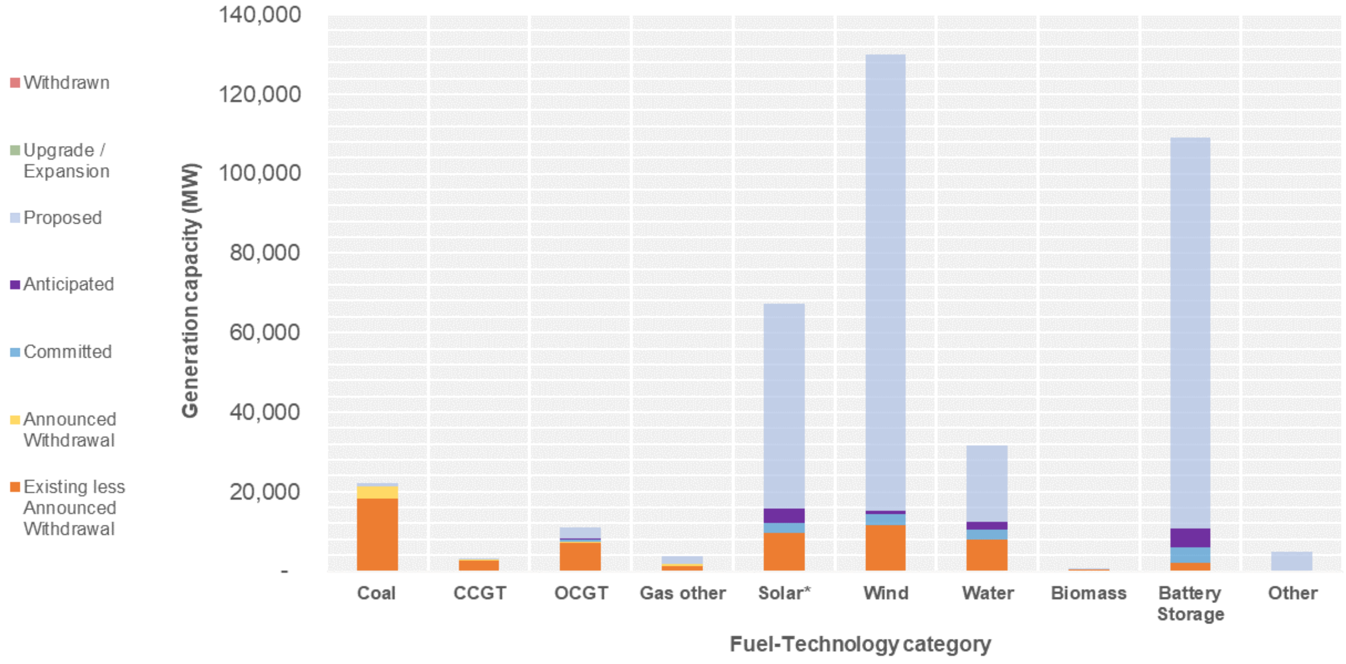
- **Committed* projects** are those projects that satisfy land, finance and construction criteria plus either planning or contracts criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.
  - For reliability assessment purposes, committed* 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[161] year for Retailer Reliability Obligation (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[162] 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 Draft 2025 IASR uses the Generation Information as at October 2024. A summary of existing, committed, and anticipated projects included in that release is provided in Figure 49 below.

[161] 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.

[162] 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 49 Generation and storage projects in October 2024 Generation Information page (MW)



In this figure, Committed* projects are included in the Committed category, and projects in commissioning are included in the Existing less Announced Withdrawal category.

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 was used in the assessment.

3.5.2 Candidate technologies

This section contains updates for Stage 2

Input vintage	December 2024
Source	CSIRO: *GenCost 2024-25 Consultation Draft* • Aurecon: *2024 Energy Technology Costs and Technical Parameter Review* • GHD: *2018-19 Costs and Technical Parameters Review*
Updates since 2023 IASR	Updated to reflect Aurecon's 2024 Energy Technology Cost and Technical Parameter Review

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 26 below presents the list of technologies that will be used in 2024-25 publications.

Table 26 List of generation and storage technology candidate

List of technologies for consideration in the 2026 ISP	Commentary
CCGT – with CCS	-
CCGT – without CCS	-
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

List of technologies for consideration in the 2026 ISP	Commentary
	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 dual fuel.
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 dual fuel.
Solar PV – single axis tracking	-
Solar thermal central receiver with storage (16 hr)	The storage component will be 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 will continue to be 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.
Lithium-Ion battery storage	AEMO includes storage sizes from one to 8 hours in its models. No geographical limits will apply to available battery capacity given its small land footprint.
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] currently under consultation, AEMO is proposing to include 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) will adopt the same costs and technical parameters as those used for their large-scale counterparts.

A. At https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost.
B. At https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-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** – as discussed in Table 26, 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*[163] 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 SAT164. 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	December 2024
Status	Draft
Source	CSIRO: GenCost 2024-25 Consultation Draft • Aurecon: *2024 Energy Technology Costs and Technical Parameters Review* • Hydro Tasmania information on Cethana project
Update process	Dependent on feedback received in this Draft 2025 IASR and the GenCost 2024-25 Consultation Draft
Updates since 2023 IASR	Updated to reflect CSIRO's *GenCost 2024-25 Consultation Draft*

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.

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

[163] At https://www.legislation.gov.au/Details/C2012C00248.

[164] Based on November 2022 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.

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 Consultation Draft* 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 Consultation Draft* scenarios based on the fit of the narratives against each other, as shown in Table 27.

Table 27 Mapping AEMO scenario themes to the *GenCost 2024-25 Consultation Draft report* scenarios

ISP scenario	*GenCost* 2024-25 Consultation Draft *scenario*	Explanation
Progressive Change	*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.
Green Energy	*Global NZE by 2050*	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.

* While *Progressive Change* 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 50, Figure 51 and Figure 52 below present a comparison of GenCost 2024-25 Consultation Draft'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 Draft 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*[165], 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 Consultation Draft*.

In recognition of this, AEMO proposes to modify the costs (as provided by GenCost) of offshore wind (both fixed and floating) and CCS technologies by applying a first-of-its-kind premium as build cost multipliers for the first wave of investments of these technologies within the ISP. This premium is proposed to apply directly to the generation costs forecast by GenCost, which recognises global technology learning rates, but does not factor domestic installation hurdles for first builds. These proposed premiums are intended to account for the demonstrated tendency to underestimate actual costs for a first-of-a-kind 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 (and are not explicitly within the forecast in *GenCost 2024-25 Consultation Draft*). AEMO

165 At https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

proposes that these factors, presented in Table 28 below, would be applied to offshore wind and technologies with CCS. These factors have been sourced from the US Energy Information Administration (US EIA)[166].

Table 28 First-of-its-kind generation cost premiums

Technology	Factor	Commentary
Wind - offshore (fixed)	1.25	It is proposed that this factor is applied to the year of built capacity of fixed offshore wind developed by the model, and then reduced to 0.
Wind - offshore (floating)	1.25	It is proposed that this factor is applied to the year of built capacity of floating offshore wind developed by the model, and then reduced to 0.
Technologies with CCS	1.04	Aligned with their use by the US EIA, This factor would be applied to the first year of built capacity that is developed by the model, and then reduced to 0.

In recognition of the recent inflationary cycle and the resulting cost pressures, CSIRO modified its modelling approach to better account for this influence. Taking Aurecon figures as a starting point, *GenCost 2024-25 Consultation Draft* 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 *Progressive* Change) sees slower learning and less pressures on technology costs and a relaxation of supply chain constraints earlier.

In the medium and longer term, the technology costs reflect forecast cost savings due to learning rates that are achieved through deployment.

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 Consultation Draft*.

Additionally, projections have been adjusted 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 Mott Macdonald underpinning figures in AEMO's Transmission Cost Database in 2023 for the land and easement component of the project cost.

As seen in Figure 51, *GenCost 2024-25 Consultation Draft* incorporates hydrogen fuel readiness for gas generation, which results in an increase in costs relative to previous estimates. Figure 52 shows a decrease in the cost of batteries, which, as discussed in *GenCost 2024-25 Consultation Draft,* 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.

More information on methodology adjustments from GenCost 2023-24 to *GenCost 2024-25 Consultation Draft* can be found in the *GenCost 2024-25 Consultation Draft.*

[166] More detail available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

Figure 50 2023 vs 2024 *Global NZE post 2050*: build cost trajectories forecasts for wind and large-scale solar

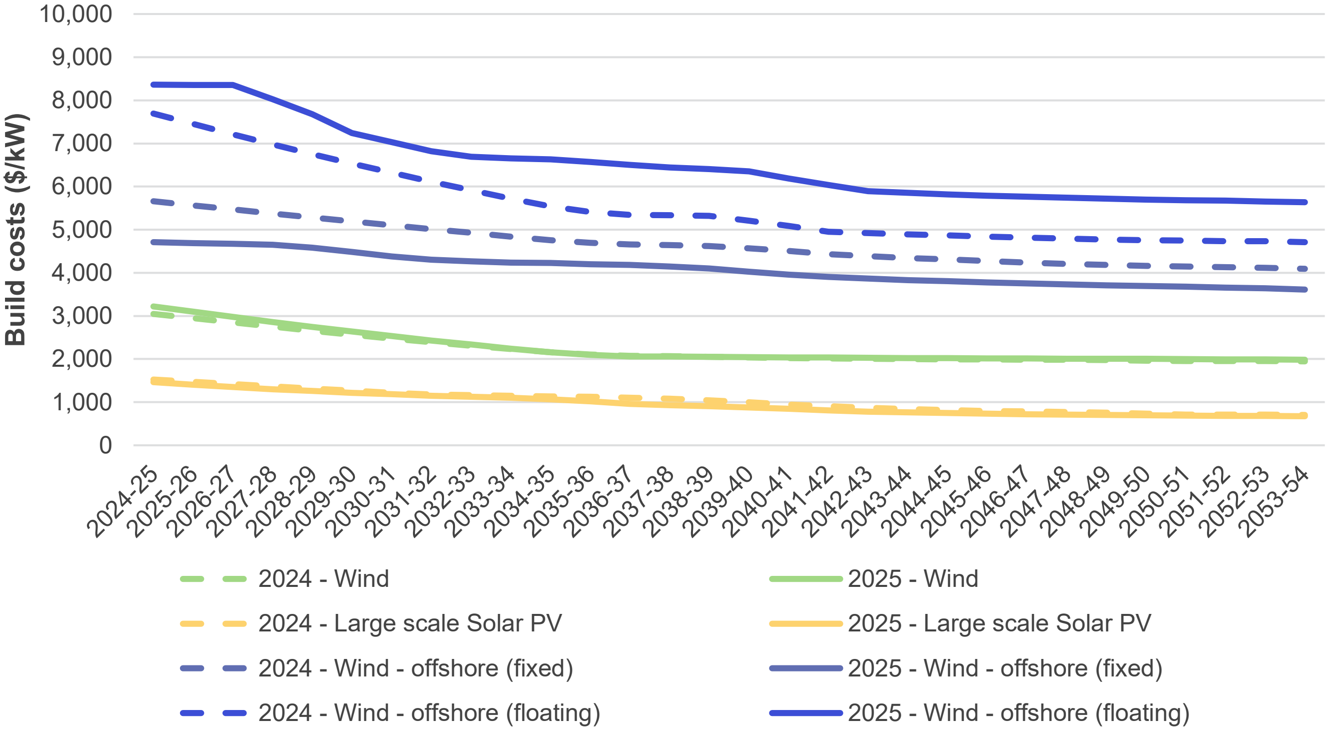


Figure 51 2023 vs 2024 *Global NZE post 2050*: build cost trajectories forecasts for gas generation

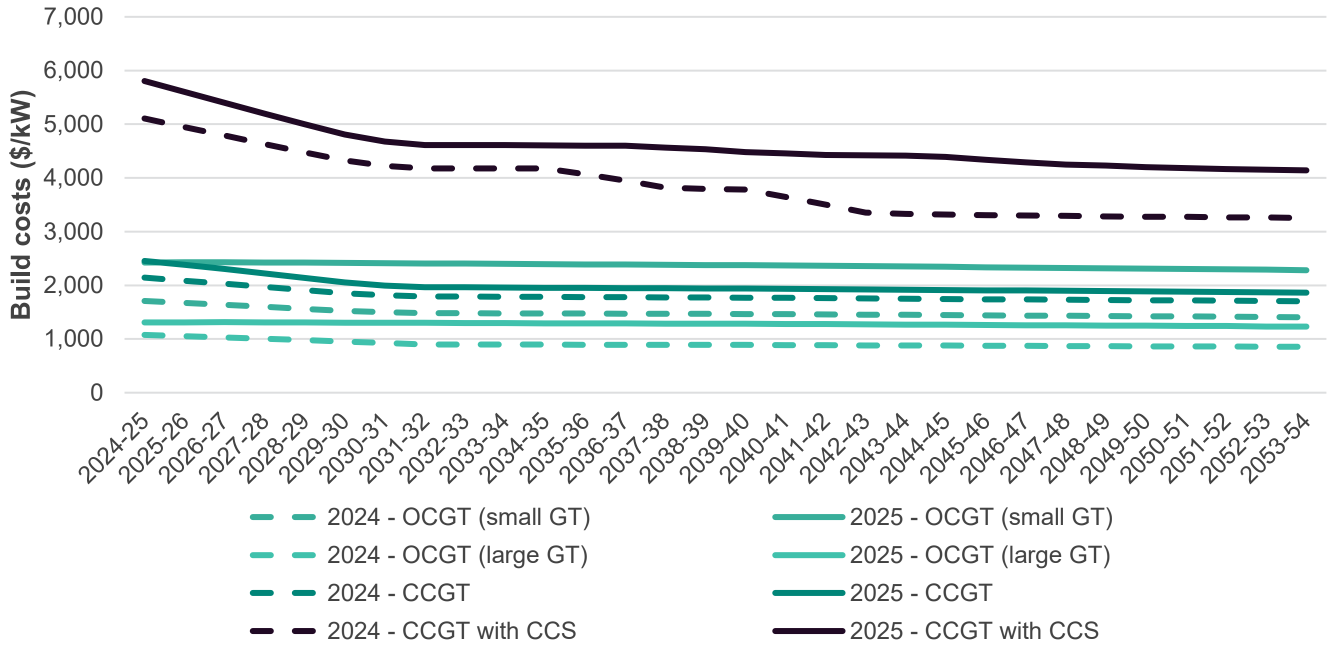
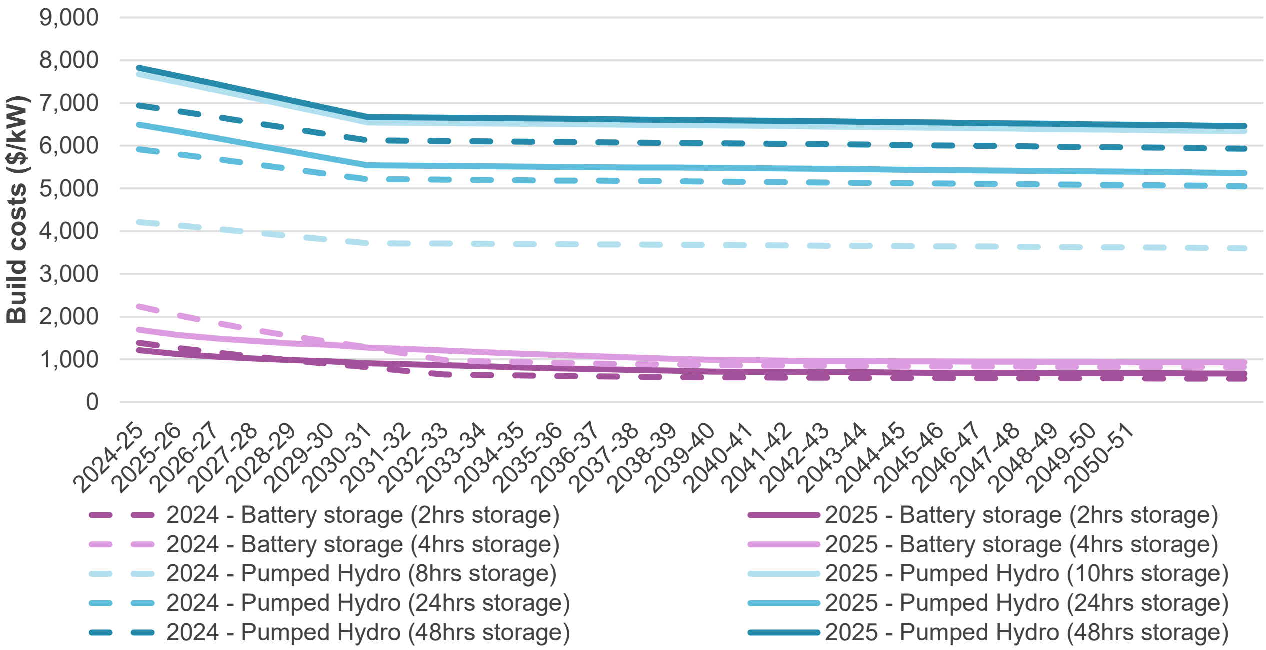


Figure 52 2023 vs 2024 *Global NZE post 2050*: build cost trajectories forecasts for selected storage technologies



Note: As discussed in Table 27, pumped hydro 8-hour has been replaced with 10-hour following advice from Aurecon.

In *GenCost 2024-25 Consultation Draft*, 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 Consultation Draft*'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 Consultation Draft* and therefore by AEMO[167].

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.

Matters for consultation from Stage 1

- Do you support the implementation of first-of-a-kind premiums for technologies that have not been deployed in Australia and with the underlying assumptions appropriate?
- Do you have any comments regarding the draft build cost projections?

If you have more substantive feedback to CSIRO's *GenCost 2024-25 Consultation Draft* report, please separate feedback to it from feedback to this Draft 2025 IASR, so that AEMO (and CSIRO as needed) may process both submissions as appropriate.

[167] 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.

Locational cost factors

Input vintage	December 2024
Source	• Aurecon: *2024 Energy Technology Cost and Technical Parameters Review* • AEMO revisions
Update process	Locational cost factors have been updated based on Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*, proposed for consultation and feedback in response to this Draft 2025 IASR. Land and development factors have been modified to reflect those applied from the 2023 update to AEMO's Transmission Cost Database, and will be updated again for the Final 2025 IASR following consultation on the 2025 *Network Expansion Options Report*.
Updates since 2023 IASR	Locational cost factors have been proposed to be updated to be REZ-specific as presented in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*. Locational cost factors for pumped hydro have been modified to reflect greater disaggregation in Victoria and South Australia.
Get involved	2025 *Network Expansion Options Report* consultation and FRG Consultation in May 2025

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 Draft 2025 *Inputs and Assumptions Workbook*.

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 now account for greater granularity by providing a factor at a REZ level, relative to metropolitan areas in the NEM region, and are intended to be a multiplier to the cost components resulting in a technology and location-specific multiplier.

The locational cost factors below, updated in the *2024 Energy Technology Cost and Technical Parameters Review*, consider the indicative cost of local accommodation, cost for resources, mobilisation and demobilisation based on project duration, cost for materials delivery, and labour productivity in each of the REZs. REZ locational cost factors were provided for a number of sub-regional areas within each REZ, which have been averaged to arrive at the REZ-level estimates.

The factors for land and development have been updated from those provided by Aurecon to those underpinning the update to AEMO's Transmission Cost Database used in the 2023 IASR. AEMO will update these factors again for the 2025 IASR following consultation through the 2025 *Network Expansion Options Report*, to ensure consistent treatment of land and development factors across transmission, generation and storage.

Locational cost factors are relative to metropolitan areas with a de facto factor of one. AEMO proposes to assign a locational factor of one to builds in sub-regional reference nodes. This will impact all/most builds not located within a REZ. Offshore REZs also have a factor of one (although as discussed above, it is proposed that offshore wind build costs will now be subject to a temporary first-of-a-kind premium).

The accompanying Draft 2025 *Inputs and Assumptions Workbook* provides additional details of these locational cost factors, including the resulting regional technology cost adjustment factors.

Figure 53 shows the effective impact of the changes in locational cost factors for all REZs for onshore wind generation. The greatest variance is in Queensland, with North Queensland Clean Energy Hub being 50% 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 the factors being benchmarked to the capital cities and rather than the nearest major port, due to greater differences for labour, installation, and O&M cost components. 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 A2).

Figure 53 Weighted REZ locational cost factors for wind in the 2023 IASR and the 2025 Draft IASR

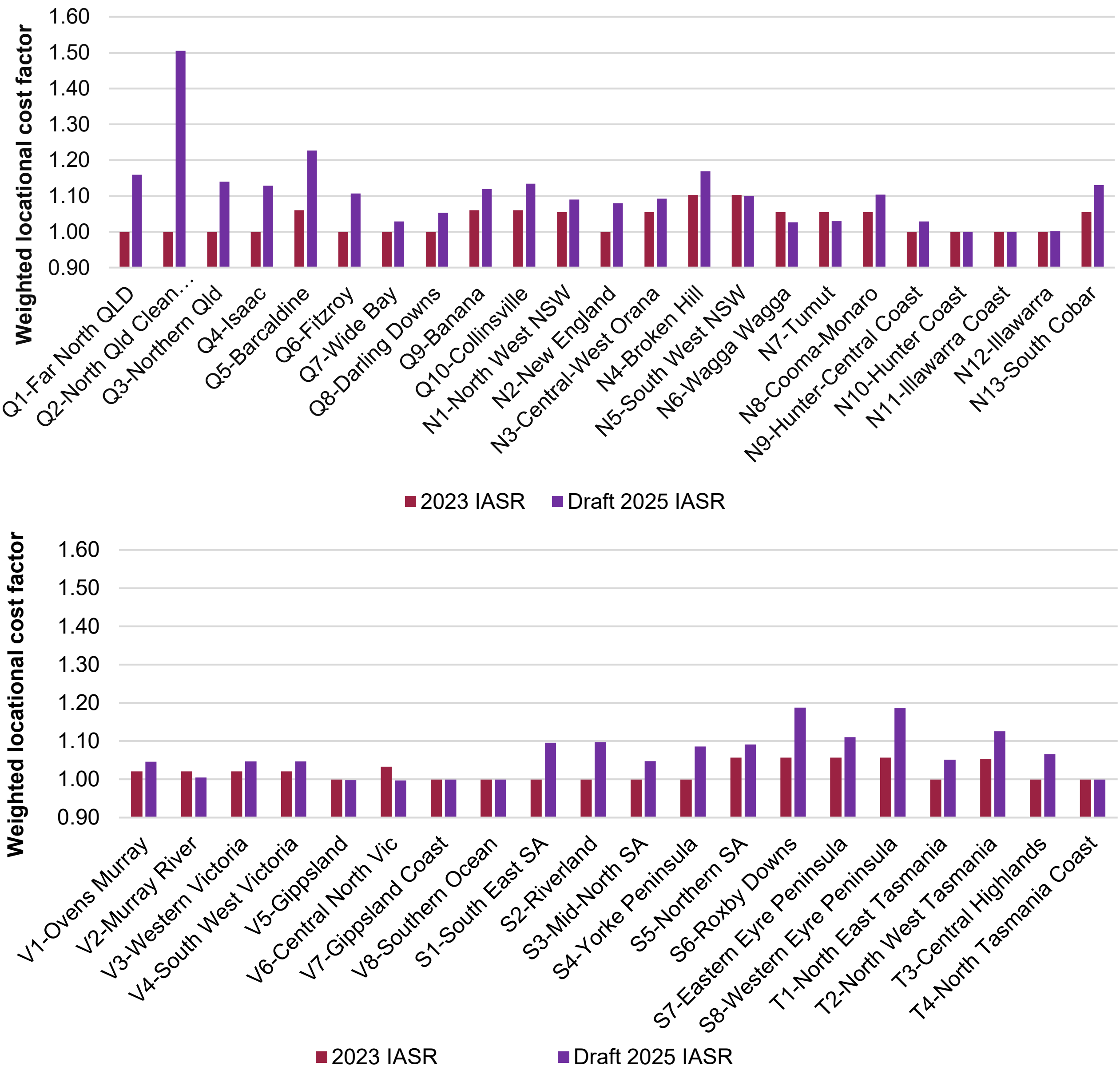
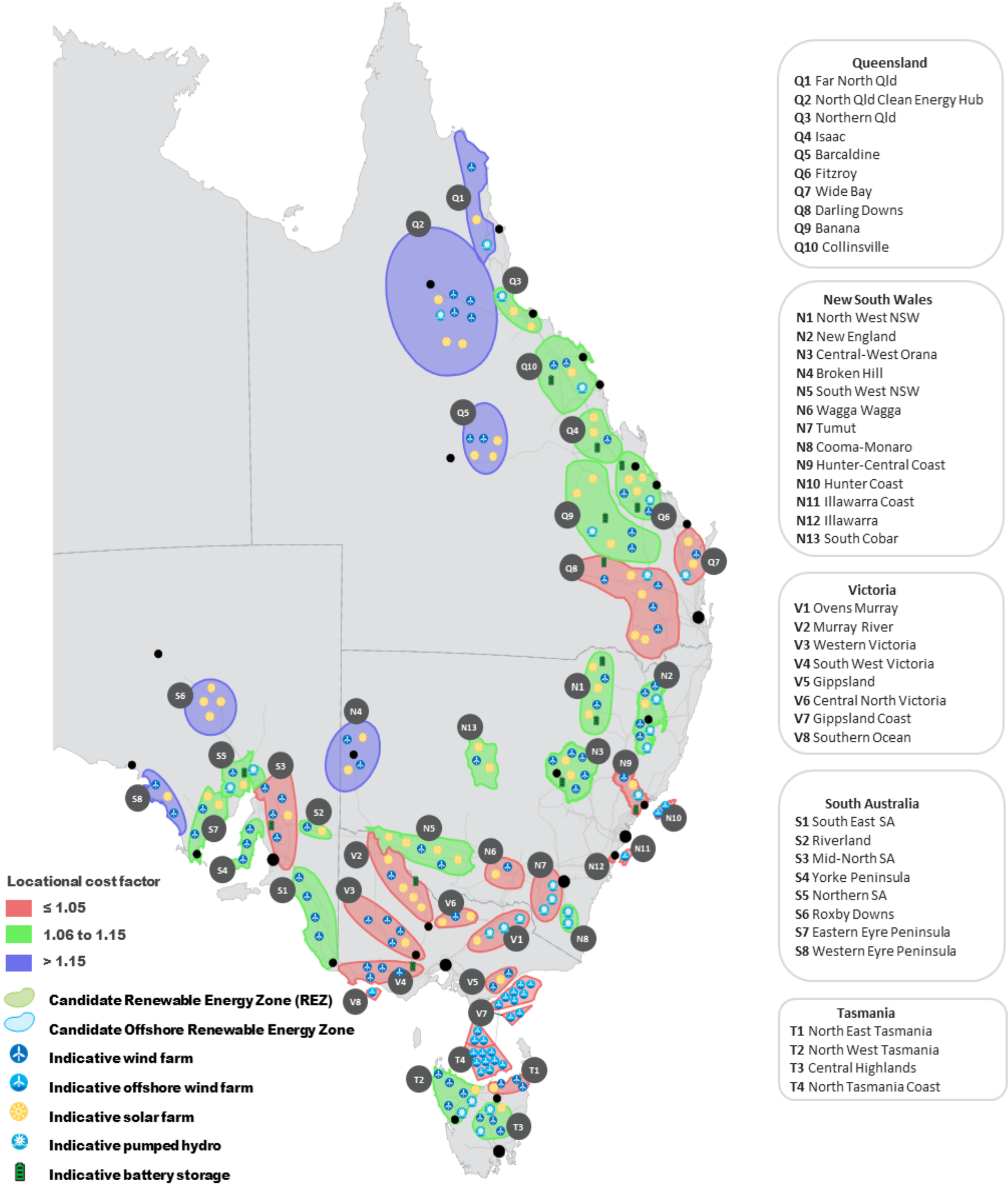


Figure 54 Weighted REZ locational cost factors for wind in the 2025 Draft IASR



AEMO proposes to further update the locational cost factors for the land and development cost component using the updates that will be made to the AEMO Transmission Cost Database through the consultation process on the Draft 2025 *Network Expansion Options Report.* These updated factors would be used in the Final 2025 IASR for the land and development cost component of generation and storage technologies in REZs.

Matters for consultation from Stage 1

- Is it appropriate for modelling to shift to locational cost factors derived at a REZ level?
- Are the proposed values assigned to REZ locational cost factors reasonable (if relevant, refer to the additional information provided in the accompanying consultant report)?

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 have been derived based on the relative cost of the natural resource and geology available within each location for PHES development. The factors have been sourced from Entura's 2018 *Pumped Hydro Cost Modelling* report and remain consistent with previous IASRs.

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. AEMO has adjusted these factors to account for the further disaggregation of Victoria and South Australia to more sub-regions.

Table 29 presents the locational cost factors for PHES. Tasmanian facilities[168] are at least approximately 25% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increase for deeper storage sizes.

Table 29 Pumped hydro energy storage locational cost factors

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hours	PHES: 48-hour
Northern Queensland (NQ)	Queensland	1.02	0.88	0.86
Central Queensland (CQ)	Queensland	1.02	0.88	0.86
Gladstone Grid (GG)	Queensland	Not applicable*	Not applicable*	Not applicable*
South Queensland (SQ)	Queensland	1.10	0.96	0.88
Northern New South Wales (NNSW)	New South Wales	0.87	0.82	0.62
Central New South Wales (CNSW)	New South Wales	1.05	1.08	1.12
South New South Wales (SNSW)	New South Wales	1.02	1.00	0.91
Sydney, Newcastle, Wollongong (SNW)	New South Wales	Not applicable*	Not applicable*	Not applicable*
West and North Victoria (WNV)	Victoria	1.00	1.00	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*
Northern South Australia (NSA)	South Australia	1.43	1.67	Not applicable*
Central South Australia (CSA)	South Australia	1.43	1.67	Not applicable*
South East South Australia (SESA)	South Australia	Not applicable*	Not applicable*	Not applicable*
Tasmania (TAS)	Tasmania	0.75	0.62	0.46

*Pumped hydro energy storage of this depth in this sub-region is not a credible candidate.

[168] These factors apply only to generic Tasmanian projects, as specific cost assumptions are used for the Cethana project.

AEMO is considering updating assumptions used for locational cost factors for PHES and will consult with stakeholders on any updated assumptions through the Forecasting Reference Group forum prior to the publication of the final 2025 IASR.

3.5.4 Storage-specific assumptions

Input vintage	December 2024
Source	• Aurecon: *2024 Energy Technology Cost and Technical Parameters Review* CSIRO: GenCost 2024-25 Consultation Draft Entura: 2018 Pumped Hydro Cost Modelling • Hydro Tasmania information on Cethana project
Updates since 2023 IASR	Updated to reflect latest *Energy Technology Cost and Technical Parameters Review*, and *GenCost 2024-25 Consultation Draft*. Modified to reflect greater disaggregation in Victoria and South Australia.
Get involved	FRG Consultation in May 2025

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 applies build limits for pumped hydro expansion candidates based on sub-regional estimates detailed by the Entura 2018 *Pumped Hydro Cost Modelling* report[169], modified where appropriate to reflect the latest generator development announcements in Generation Information (or announced government development policies).

AEMO has adjusted the limits to consider proposed projects across NEM regions since the publication of the Entura report. AEMO subtracted the generation capacity of these projects from the relevant original limit while maintaining Entura's sub-regional breakdown. AEMO also disaggregated the limits to account for the new sub-regions proposed for Victoria and South Australia, and adjusted limits to account for the modelling of 10-hour PHES.

The effective PHES sub-regional limits are shown in Table 30.

Table 30 Pumped hydro sub-regional limits (in MW of generation capacity)

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hour	PHES: 48-hour
Northern Queensland (NQ)	Queensland	1,000	5,000	111
Central Queensland (CQ)	Queensland	960	1,250	89
Gladstone Grid (GG)	Queensland	-	-	-
South Queensland (SQ) [A]	Queensland	2,400	600	300
Northern New South Wales (NNSW)	New South Wales	1,020	500	500
Central New South Wales (CNSW)	New South Wales	2,006	167	83

[169] Entura, Pumped Hydro Cost Modelling, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf.

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hour	PHES: 48-hour
South New South Wales (SNSW) [B]	New South Wales	2,000	583	167
Sydney, Newcastle, Wollongong (SNW)	New South Wales	-	-	-
West and North Victoria (WNV)	Victoria	2,160	700	400
Greater Melbourne and Geelong (MEL)	Victoria	-	-	-
South East Victoria (SEV)	Victoria	-	-	-
Northern South Australia (CSA)	South Australia	540	200	0
Central South Australia (CSA)	South Australia	135	-	-
South East South Australia (SESA)	South Australia	-	-	-
Tasmania (TAS) [C]	Tasmania	1,300	1,200	371

A. The South Queensland limits do not include Borumba Dam Pumped Hydro (2 GW), which will be modelled as a specific project.
B. Total value excludes the contribution of Snowy 2.0.
C. For Tasmania, this capacity does not include the Cethana project (750 MW).

The following considerations have been made in determining the pumped hydro sub-regional limits:

- New South Wales PHES limits are based on 24 energy projects shortlisted for potential development as part of the New South Wales Government Pumped Hydro Roadmap[170]. The limits have been further adjusted to provide sufficient capacity to reflect five projects that have been awarded funding under the New South Wales Pumped Hydro Recoverable Grants Program[171].
- Tasmanian PHES limits have been informed by analysis of the detailed project information within the Entura report, provided by contributors to the report (but not published). This data avoids misinterpretation of projects that may not be mutually exclusive and is aligned reasonably with Tasmanian PHES submissions to Generation Information.

Where applicable, PHES limits have been adjusted above Entura estimates to ensure proposed projects in Generation Information submissions can be accommodated.

AEMO is considering updating assumptions used for build limit for PHES and will consult with stakeholders on any updated assumptions through the Forecasting Reference Group forum prior to the publication of the final 2025 IASR.

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*.

[170] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/pumped-hydro-roadmap#-pumped-hydro-roadmap-.

[171] See https://www.nsw.gov.au/media-releases/pumped-hydro.

- Battery storage degradation, which Aurecon indicates is 1.8% annually, has been factored in by reducing the storage capacity of all battery storage by 16% which is an estimate of the average storage capacity over the battery life of 20 years after taking into account this degradation and estimated operating levels.
- 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	December 2024
Source	• Aurecon: *2024 Energy Technology Cost and Technical Parameters Review* CSIRO: *GenCost 2024-25 Consultation Draft* Entura: *2018 Pumped Hydro Cost Modelling* • Hydro Tasmania information on Cethana project • 2024 October update Generation Information
Updates since 2023 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.
- Storage parameters (including cyclic efficiency and maximum and minimum state of charge).

Details of these parameters are published in the Draft 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 October 2024 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 28 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	February 2025
Source	Oxford Economics Australia: *Planning and Installation Cost Escalation Factors*
Updates since 2023 IASR	N/A – new in this Draft 2025 IASR

This section contains updates for Stage 2

The energy transition will require significant development of new energy infrastructure projects to decarbonise the energy system. This will place pressure on supply chains as well as planning and environmental approvals processes.

In response to actions from the Energy and Climate Change Ministerial Council's ISP Review[172], AEMO has engaged Oxford Economics Australia to develop new assumptions for the 2026 ISP to assess how supply chains, and planning and environmental approvals may impact installation costs and development lead times for new generation and storage projects.

Additional information is available in the draft report by Oxford Economics Australia in the supporting material to this Draft 2025 IASR.

Real cost escalations due to supply chain issues

Installation costs[173] 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

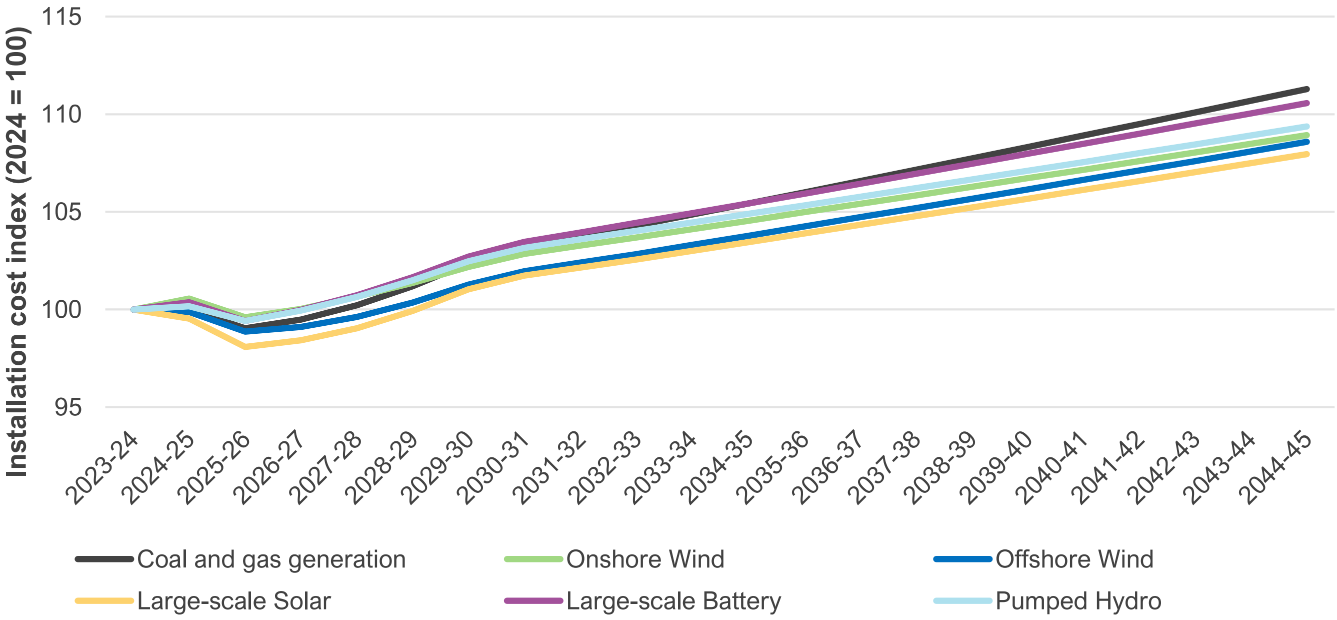
[172] At https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

[173] 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 (e.g. wind turbines, solar PV panels or transformers) or enabling infrastructure such as road widening.

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. 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 55. 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 are expected to be 10% higher on average than 2024 levels for the installation costs alone.

Figure 55 Installation cost escalation in real terms for various generation and storage technologies relative to 2024 costs



These installation cost forecasts will be provided as an input to CSIRO's GenCost modelling to inform assumptions used in GenCost around the impact of issues around supply chains on future technology build costs. The impact of supply chains on specialised equipment costs were not considered, because equipment cost projections are primarily driven by other factors such as learning rates 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 proposes to use these lead time adjustments in addition to the existing technology-specific lead times from Aurecon to inform the *Constrained Supply Chains* sensitivity. Details of this analysis are in the *Planning and Installation Cost Escalation Factors*[174] report from Oxford Economics Australia that is published with this Draft 2025 IASR.

Matters for consultation for Stage 2

- Do you consider the installation cost escalation forecasts for each technology to be reasonable?
- Do you support AEMO's proposal to apply lead time adjustments in the *Constrained Supply Chains* sensitivity?

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

AEMO sourced updated 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 Draft 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 A2).

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 updated natural gas price forecasts from ACIL Allen in November 2024. The 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.

[174] At https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-iasr-planning-and-installation-cost-escalation-factors.pdf.

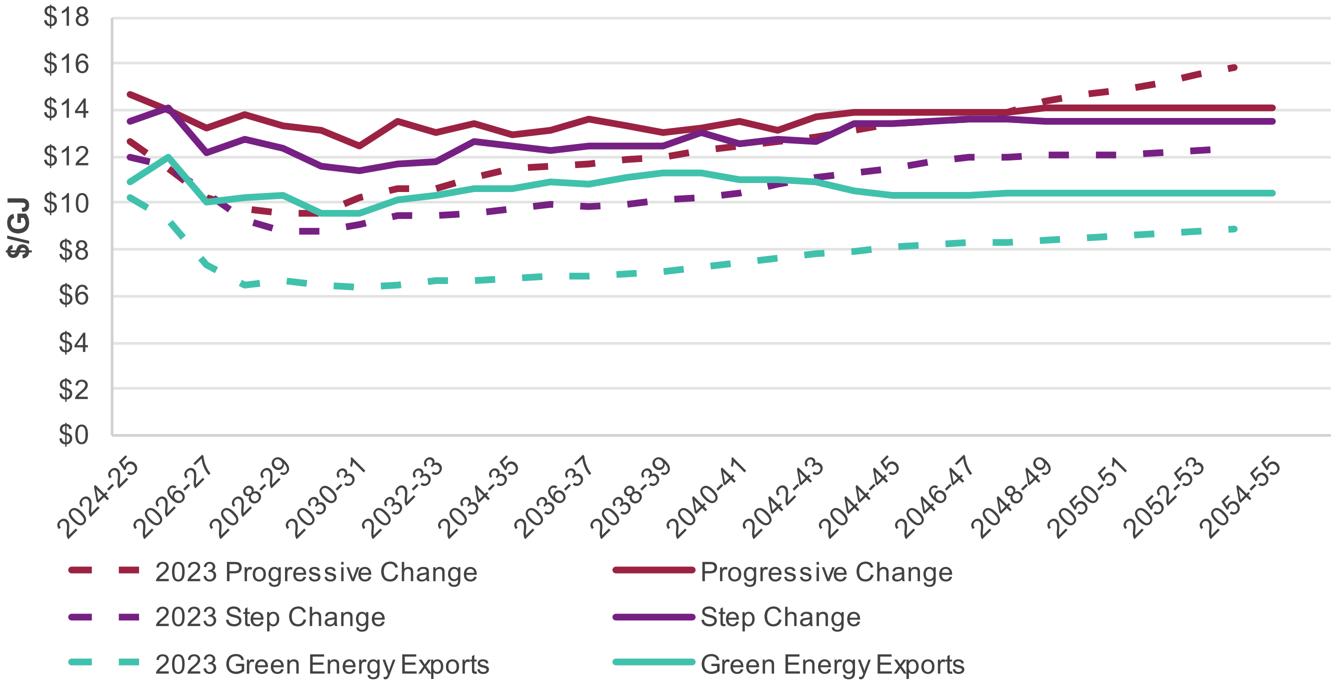
The Australian Domestic Gas Supply Mechanism (ADGSM) reforms commenced 1 April 2023 and are designed to make the ADGSM more responsive to domestic gas shortfalls, while protecting established long-term contracts. The effect of the ADGSM reforms and the Heads of Agreement with east coast gas exporters 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[175] was published in July 2023, and includes a reasonable pricing framework of a $12/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. A review of the Code must occur by 1 July 2025.

Figure 56 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 Draft 2025 *Inputs and Assumptions Workbook*.

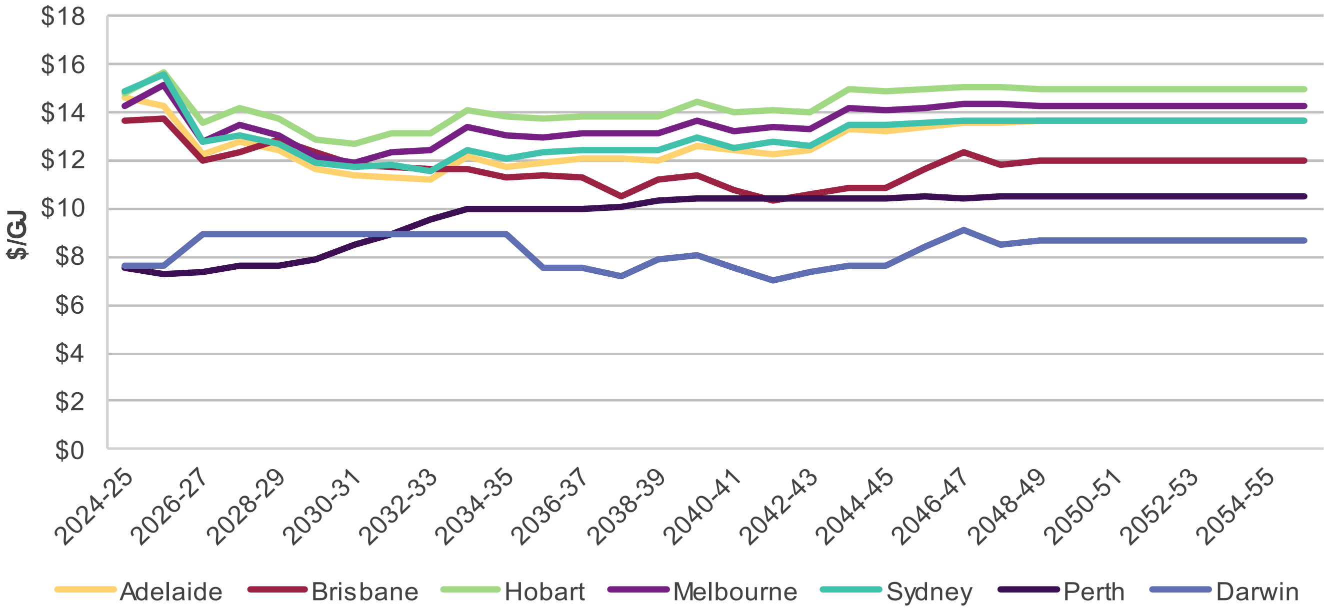
Figure 56 Forecast industrial gas prices by scenario – Melbourne, 2024-25 to 2054-55 ($AUD/GJ)



175 See https://www.energy.gov.au/government-priorities/energy-markets/gas-markets/mandatory-gas-code-conduct.

Figure 57 demonstrates the relationship between regions for the *Step Change* scenario.

Figure 57 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[176]. Gas prices in the long term are forecast to gradually increase, resulting from the combination of decreasing supply 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 Draft 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

[176] See https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

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 and Queensland Governments 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:

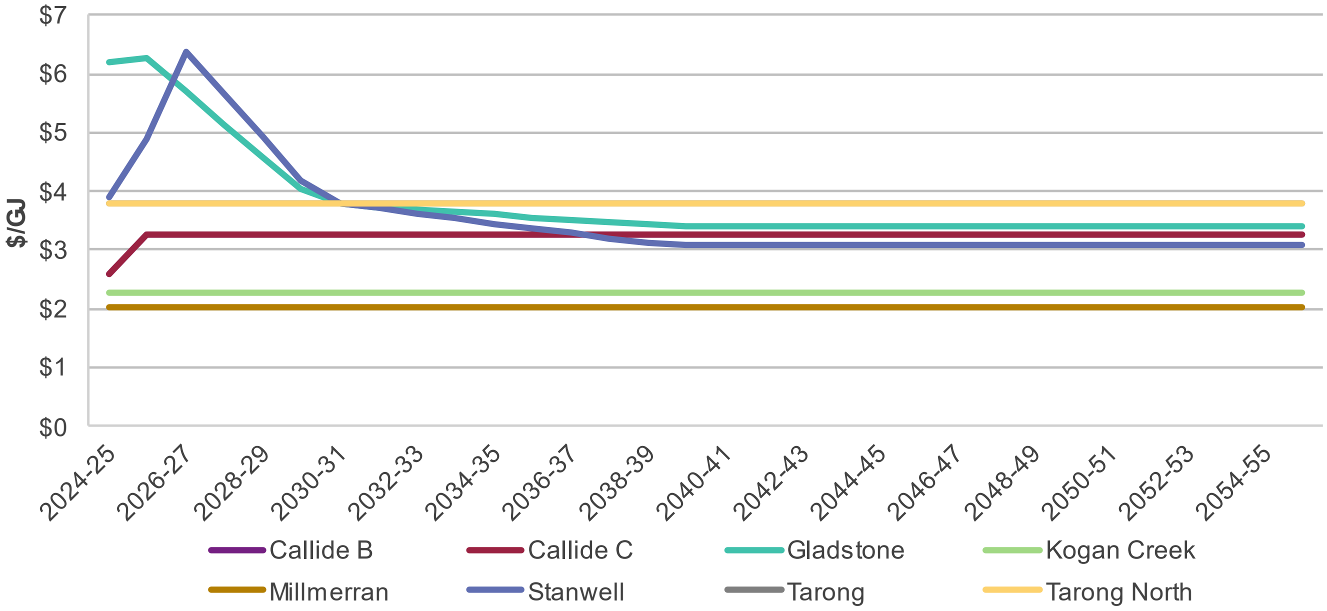
- *Step Change* – aligned to the IEA's STEPS scenario.
- *Progressive Change* – aligned to the IEA's APS scenario.
- *Green Energy Exports* – aligned to the IEA's NZE scenario.

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 Draft 2025 *Inputs and Assumptions Workbook*.

Figure 58 Forecast coal prices for existing generators in New South Wales, *Step Change*, 2024 to 2055 ($AUD/GJ)

Figure 59 Forecast coal prices for existing generators in Queensland – *Step Change*, 2024 to 2055 ($AUD/GJ)



Diesel prices

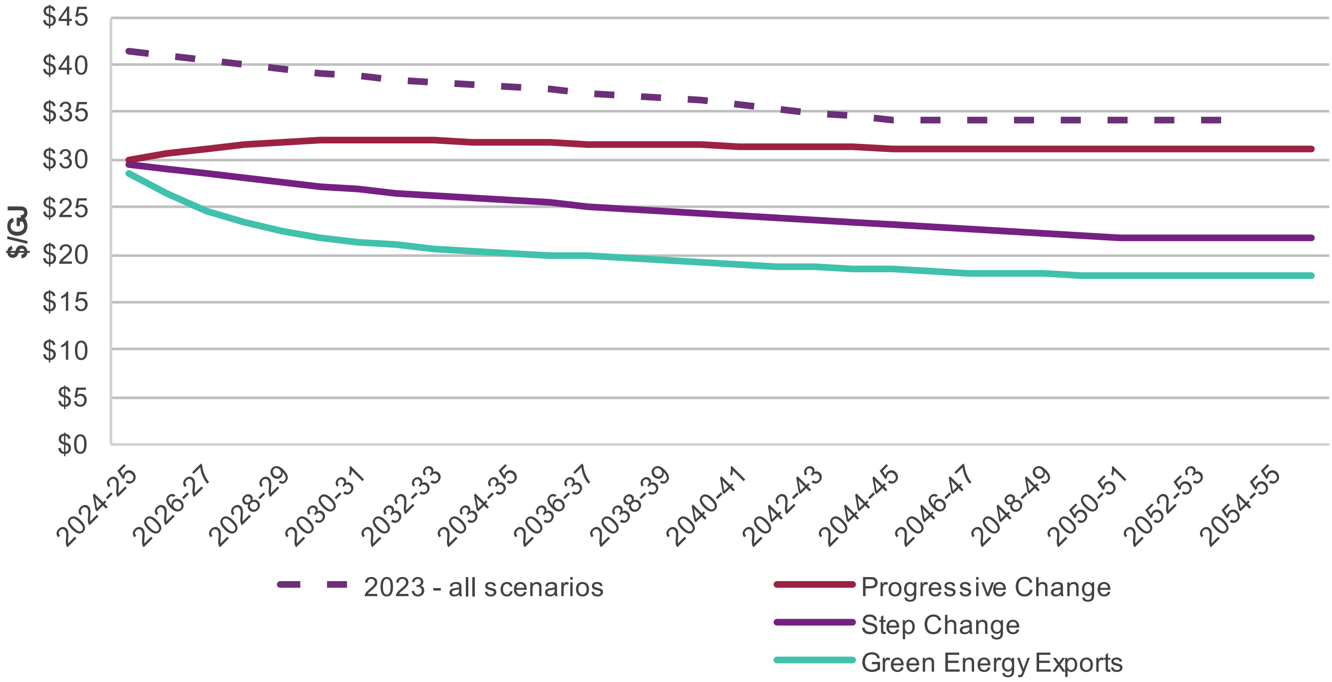
AEMO sourced diesel price forecasts from ACIL Allen to represent appropriate costs for the use of diesel at power stations in the NEM that can, or could, use liquid fuels as a primary, secondary or backup fuel. ACIL Allen's approach evaluates projections of crude oil prices to provide projections of 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.
- Strategies of producers in the Middle East to shore up their national budgets over the medium to longer term.

Figure 60 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 60 Forecast price for diesel by scenario – terminal gate price plus distributors margin, Victoria, 2024 to 2055 ($AUD/GJ)

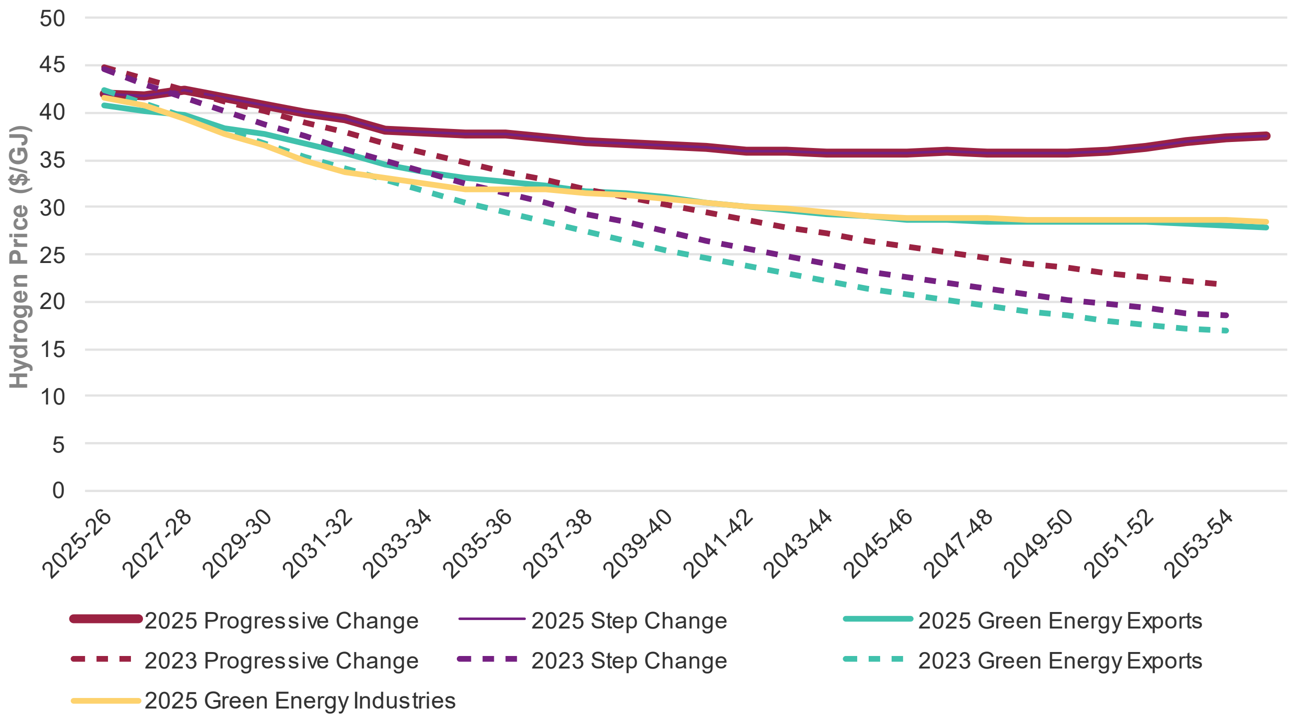


Hydrogen prices

Hydrogen prices are shown in Figure 61 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 the 2025 Green Energy scenario variants are lower than the other scenarios in the longer term, largely due to the forecast reduction in 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 61 Forecast price for hydrogen by scenario, 2026 to 2054



3.6.2 Renewable resources

Input vintage	December 2024
Source	Solcast irradiance and PV output analysis • BoM • AEMO SCADA data • Other relevant reanalysis providers
Updates since 2023 IASR	Updated to include the 2023-24 reference year, added additional REZs

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) from ERA5[177] reanalysis data from European Centre for Medium-Range Weather Forecasts.
- Solar irradiance reanalysis data from Solcast.
- Temperature and ground-level wind speed observation data from the BoM.
- 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

[177] At https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5.

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. Further detail on how AEMO estimates half-hourly generation availability profiles for existing, committed and anticipated VRE generators is provided in the *ESOO and Reliability Forecast Methodology*[178].

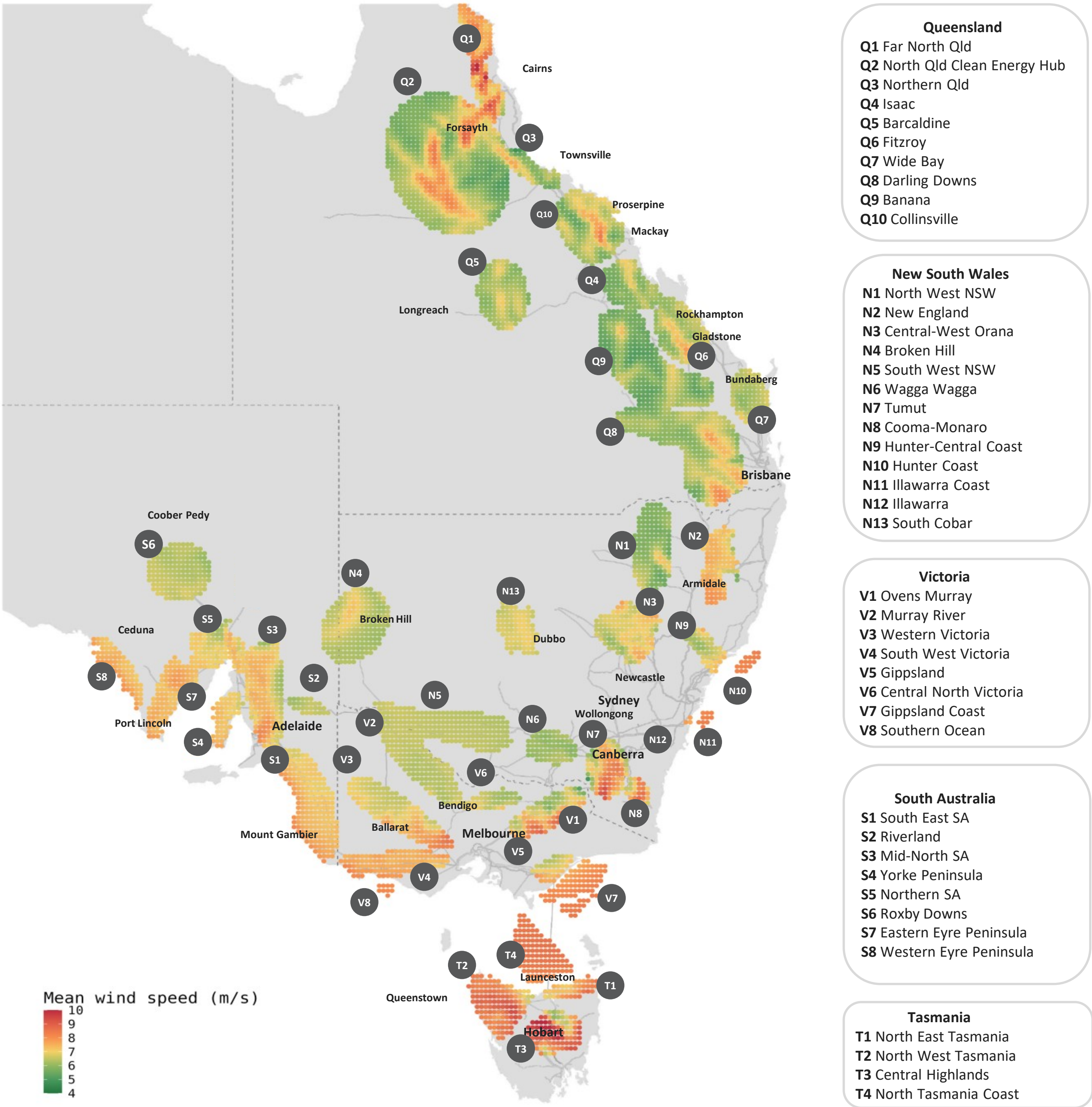
For new entrant VRE generators, AEMO represents onshore wind resource quality in each REZ in tranches representing sites of differing quality (typically two tranches per REZ), based on an assessment of all available datapoints that are considered suitable for wind development. AEMO represents solar resource 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 Draft 2025 *Inputs and Assumptions Workbook*. The methodology used to derive these will be further detailed and consulted on in the 2025 *ISP Methodology*.

Wind and solar resource quality for each REZ is shown below in Figure 62 and Figure 63 respectively.

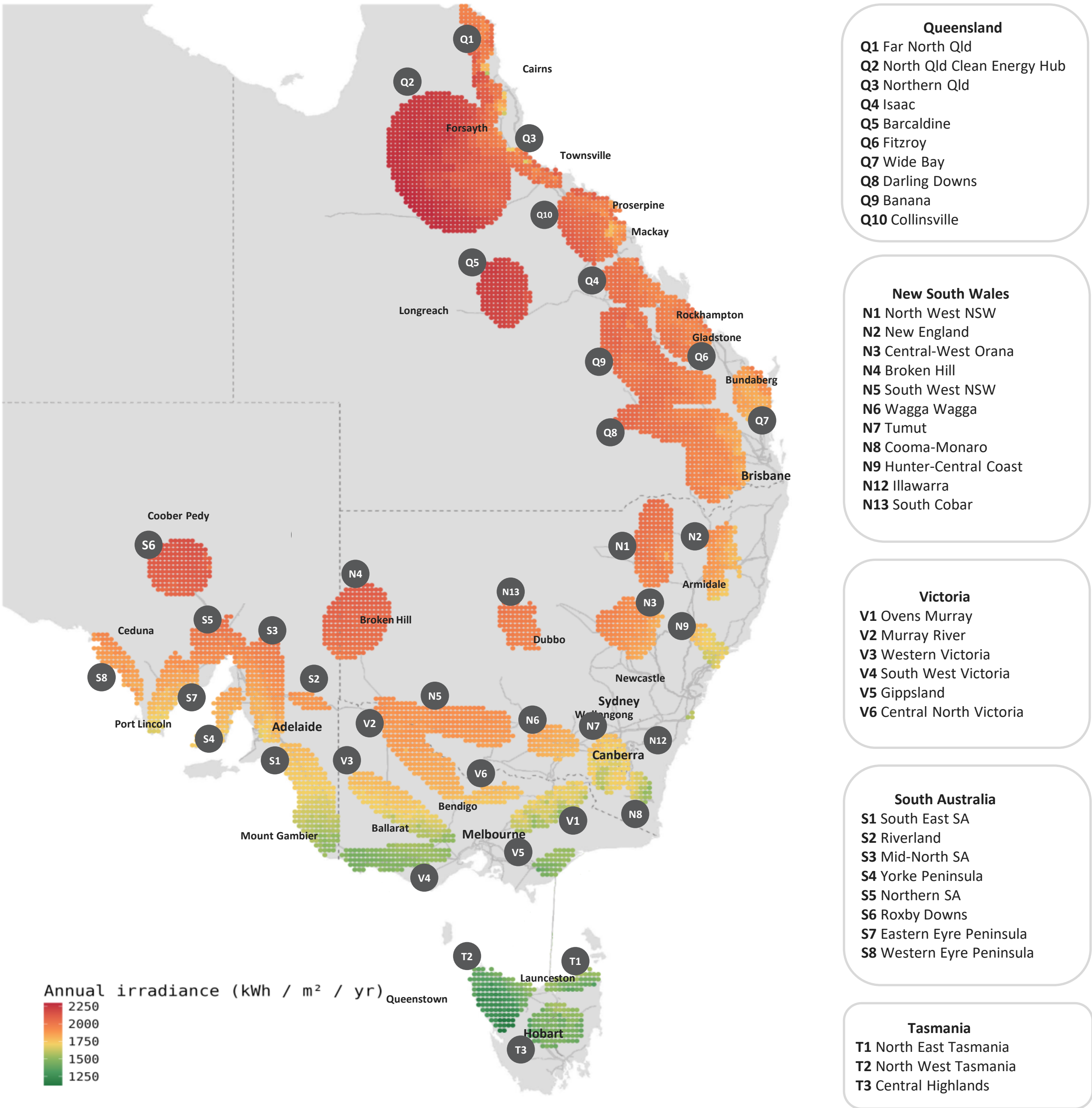
[178] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf.

Figure 62 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 63 Solar resource quality map – average annual global horizontal irradiance (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	December 2024
Source	Oxford Economics Australia
Updates since 2023 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) for a project is used in combination with the project's economic life to calculate the annuity payments required. As WACC reflects the cost of financing a project, it impacts the overall project cost and the overall system costs. On the other hand, a discount rate is used to compare costs and benefits received at different points in time as well as to calculate the present value of future cash flows, accounting for the time value of money.

The AER's Cost Benefit Analysis Guidelines[179] 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[180]. Following stakeholder feedback and using insights from a survey of developers in the NEM regarding their cost of capital and other inputs[181], AEMO proposes to use different values for WACCs for different technologies to capture different financial assumptions appropriate for each technology. 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 Cost Benefit Analysis Guidelines.

AEMO engaged Oxford Economics Australia to examine three alternative approaches to determine the latest WACC for each technology across the ISP forecast horizon, and to provide the appropriate discount rate. Oxford Economics Australia's analysis revealed that some technologies may face higher hurdle rates if they are deemed risky 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. Some technologies that have yet to be developed and penetrate the Australian market such as offshore wind farms are considered lower risk due to available government offtake agreements.

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 31 below.

[179] At https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf.

[180] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/synergies-discount-rate-report.pdf?la=en.

[181] See Oxford Economics Australia's discount rate report – listed in Appendix A2.

Given these findings, AEMO considers it appropriate to set different WACCs for different technology options as it reflects the reality observed in capitals markets. Table 31 below shows the proposed lower, central, and upper WACC for relevant technologies.

Table 31 Pre-tax real weighted average cost of capital

Technology	Lower bound	Central estimate	Upper bound
OCGT (small gas turbine)	7.0%	9.0%	12.0%
OCGT (large gas turbine)	7.0%	9.0%	12.0%
CCGT[A]	8.5%	10.5%	13.5%
CCGT with CCS[A]	8.5%	10.5%	13.5%
Biomass[A]	8.5%	10.5%	13.5%
Large scale Solar PV	5.0%	7.0%	10.0%
Solar Thermal (16hrs storage)	8.5%	10.5%	13.5%
Battery storage (1hr storage)	6.5%	8.0%	11.5%
Battery storage (2hrs storage)	6.5%	8.0%	11.5%
Battery storage (4hrs storage)	6.5%	8.0%	11.5%
Battery storage (8hrs storage)	6.5%	8.0%	11.5%
Pumped Hydro Energy Storage (10 hrs)	6.5%	8.5%	11.5%
Pumped Hydro Energy Storage (24 hrs)	6.5%	8.5%	11.5%
Pumped Hydro Energy Storage (48 hrs)	6.5%	8.5%	11.5%
Wind - onshore	5.5%	7.5%	10.5%
Wind - offshore (fixed)	5.5%	7.5%	10.5%
Hydrogen Electrolysers	6.0%	8.0%	11.0%
Electricity - Transmission and Distribution (Regulated)	3.0%	3.0%	4.5%
Electricity - Transmission and Distribution (Unregulated)	4.5%	6.5%	9.5%
Gas - Transmission and Distribution (Regulated)	3.0%	3.0%	4.5%
Gas - Transmission and Distribution (Unregulated)	5.5%	7.5%	10.5%

A. AEMO assumes that the WACC for CCGT, CCGT with CCS and Biomass are the same.

Considering the insights provided from the WACC survey, Oxford Economics Australia has recommended that the appropriate discount rate, for use in the 2025 IASR and 2026 ISP, that promotes competitive neutrality is 7% – based on their macro-economic assessment. This choice of discount rate aligns with Infrastructure Australia's guideline for economic appraisal[182], and is commensurate with commercially-orientated 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% to 15% across asset types, with the WACC being reflective of the level of risk of each technology.

[182] At https://www.infrastructureaustralia.gov.au/sites/default/files/2021-07/Assessment%20Framework%202021%20Guide%20to%20economic%20appraisal.pdf.

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[183], 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 32 presents the values for discount rates in this Draft 2025 IASR, with 2024 ISP values for comparison.

Table 32 Pre-tax real discount rates

	Lower bound	Central estimate	Upper bound
2024 ISP	3.0%	7.0%	10.5%
Draft 2025 IASR	3.0%	7.0%	10.0%

Matters for consultation from Stage 1

- Is the proposed application of technology-specific WACC's for different technology types appropriate and reasonable for the ISP?
- Is the discount rate, including its upper and lower bounds, reasonable?

3.7.2 Value of customer reliability

Input vintage	December 2023
Source	• AER: 2019 Values of Customer Reliability Review • AER Values of Customer Reliability – Annual adjustment – December 2023
Updates since 2023 IASR	VCR updated to reflect AER December 2023 update and adjusted to real June 2024 values.

Values of Customer Reliability (VCRs) are usually expressed in dollars per kilowatt hour (kWh) 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 Cost Benefit Analysis Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER releases annual updates to its VCRs based on the Consumer Price Index for that year, with the most recent adjustment coming in December 2023[184]. The current VCRs are summarised in Table 33 below.

Table 33 AER Values of distribution and transmission customer load-weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR ($/MWh)	50,359	49,271	47,861	51,687	38,451

[183] 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.

[184] At https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2019.

3.7.3 Value of greenhouse gas emissions reduction (VER)

Input vintage	February 2024
Source	Value of greenhouse gas emission reduction (VER) to 2050 as agreed by Australia's Energy Ministers and set out in the AER Guidance May 2024.
Updates since 2023 IASR	Interpolated to convert to financial years and adjusted to account for inflation.

Emissions reduction is a new 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 February 2024, and set out in the AER's explanatory statement[185].

Table 34 Value of greenhouse gas emissions reduction

Year	VER ($/tonne CO_2-e)	Year	VER ($/tonne CO_2-e)
2024-25	75.26	**2037-38**	194.64
2025-26	80.45	**2038-39**	208.14
2026-27	85.12	**2039-40**	222.15
2027-28	89.80	**2040-41**	237.21
2028-29	95.51	**2041-42**	253.30
2029-30	103.81	**2042-43**	269.91
2030-31	113.67	**2043-44**	287.55
2031-32	123.53	**2044-45**	306.76
2032-33	134.43	**2045-46**	327.00
2033-34	145.85	**2046-47**	348.28
2034-35	157.27	**2047-48**	371.12
2035-36	169.21	**2048-49**	395.52
2036-37	181.67	**2049-50**	421.99

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. The impact of reduced precipitation on dam inflows is described in Section 3.4.5. The following sections describe other impacts considered in AEMO modelling.

AEMO recognises that a changing climate may also lead to greater potential challenges in maintaining the operability of a NEM that is predominantly reliant on intermittent generation for its electricity production, particularly 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

185 AER. *Valuing emissions reduction – AER guidance and explanatory statement*, at https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf.

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, ESCI (see ClimatechangeinAustralia.gov.au)
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 ESCI data published on the CSIRO and BoM's website Climate Change in Australia[186]. For more information on this, see Appendix A.2.3 of the *Electricity Demand Forecasting Methodology*[187].

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[188,] 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 (often just 4.5 and 8.5) to reflect the likely outcome.

Figure 64 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions[189]. 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.

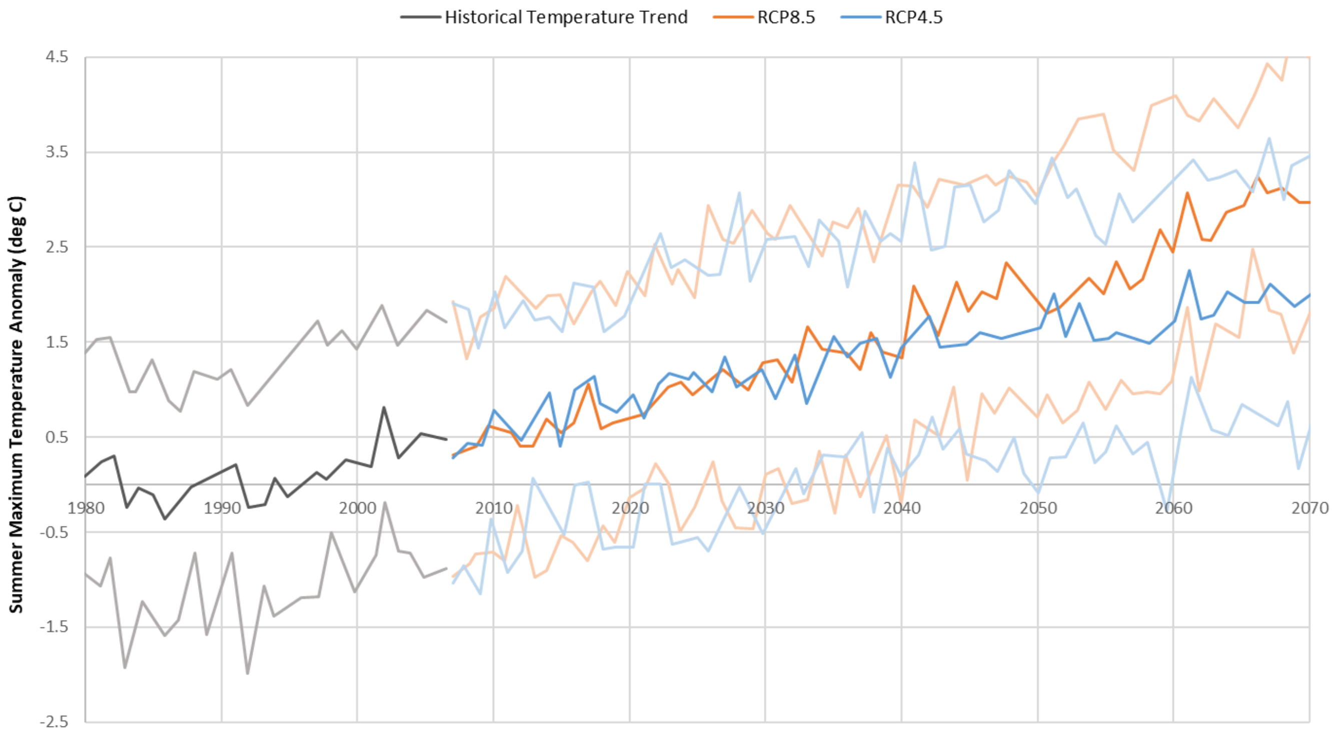
186 At https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/.

187 At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf.

188 See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings.

189 Data sourced from www.climatechangeinaustralia.com.au.

Figure 64 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.
- 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 the 2024 ISP. AEMO now proposes another evolution to the candidate REZs.

This section describes the proposed 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 0.
- REZ augmentations and network costs – Section 3.9.4.

3.9.1 REZ geographic boundaries and resource areas

Input vintage	December 2024
Status	Draft
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.
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2023 IASR	Updated following joint planning and collaboration with TNSPs, jurisdictional bodies and governments. The following revisions are proposed: New South Wales: Additional candidate REZ called South Cobar. Queensland: Additional candidate REZ called Collinsville, boundary changes for Far North Queensland and Isaac candidate REZs, and addition of more wind resource tranches within the Darling Downs candidate REZ. South Australia: Expansion of Northern South Australia candidate REZ to include the Whyalla West area, and removal of South East South Australia Coast and Leigh Creek candidate REZs.

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 the 2024 ISP.

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2025 IASR consultation page[190]. 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).
- The GIS data for candidate REZs is approximate in nature. The polygons were derived by replicating the candidate REZ illustration (see Figure 65 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.

[190] 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[191]:

- 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 is proposing 43 candidate REZs for inclusion in the 2026 ISP.

Proposed 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 are proposed:

- 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[192] 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 proposes to include multiple resource areas for Darling Downs REZ[193], as well as expansion of 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.

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[191] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

[192] 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

[193] 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, is proposed 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 would allow exploration of the benefits of a more westerly additional REZ in that jurisdiction.
- An expansion of the Northern South Australia REZ is proposed to include the Whyalla West area in the vicinity of Central West South Australia. This is proposed 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[194], 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[195].
- 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.

Further consultation on Victorian REZs

VicGrid is a division within the Victorian Government's Department of Energy, Environment and Climate Action, and is responsible for coordinating the planning and development of REZs in Victoria. VicGrid recently carried out public consultation on a REZ study area for potential future REZs for inclusion in the 2025 Victorian Transmission Plan (VTP)[196]. AEMO recognises that candidate REZs for inclusion in the 2026 ISP may need to change as the VTP is finalised, and will continue to work closely with VicGrid between the release of the draft and final 2025 IASR and as the 2025 VTP is prepared. VicGrid will publish a draft 2025 VTP for feedback in early 2025, and stakeholders may wish to engage in that consultation process. AEMO will engage closely with VicGrid as the VTP consultation is finalised and as the VTP outcomes are prepared, and will incorporate VTP outcomes in the final 2025 IASR where appropriate.

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

[194] Federal Government. 'Australia's offshore wind areas', accessed in November 2024. At https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas.

[195] South Australia Government. 'Offshore renewable energy development in South Australia', August 2024. At Statement-on-offshore-renewable-energy-generation_August-2024.pdf.

[196] VicGrid. 'Developing the 2025 Victorian Transmission Plan', accessed in November 2024. At https://engage.vic.gov.au/victransmissionplan.

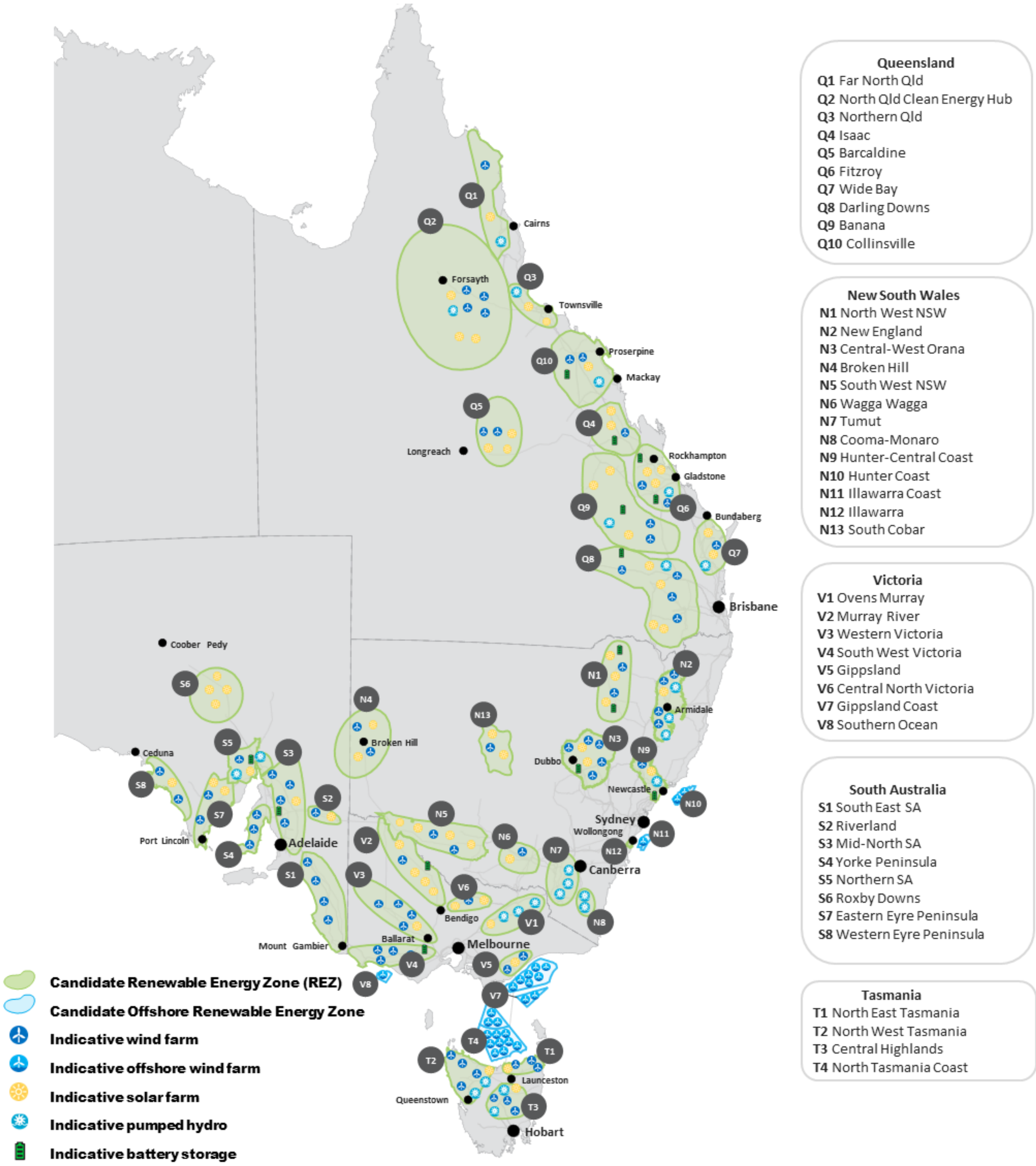
hosting capacity, or where generation retirement is expected to result in additional network capacity. These areas are known as "non-REZs". These lower quality resource areas are included in all simulations, in all scenarios, not just the counterfactual studies. This ensures the ISP's capacity outlook 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 Draft 2025 *Inputs and Assumptions Workbook*.

Candidate REZ geographic boundaries

Figure 65 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 65 Candidate renewable energy zone map



Matters for consultation from Stage 1

- Do you have any specific feedback on the proposed updates to the candidate REZs?

3.9.2 REZ resource limits and social licence

Input vintage	December 2024
Status	Draft
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.
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2024 ISP	The following revisions have been made to align resource limits with the proposed amendments to the REZ geographic boundaries, and/or to reflect updated information received from TNSPs and jurisdictional bodies: • New South Wales: Resource limits provided for the new South Cobar candidate REZ. • Queensland: Revised resource limits for Isaac and Darling Downs candidate REZs, as well as limits for the new Collinsville candidate REZ. • South Australia: Resource limits amended to reflect revised boundary for the Northern South Australia candidate REZ to extend to the Whyalla West area. • Victoria: Addition of a wind resource limit for the Murray River candidate REZ.

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.

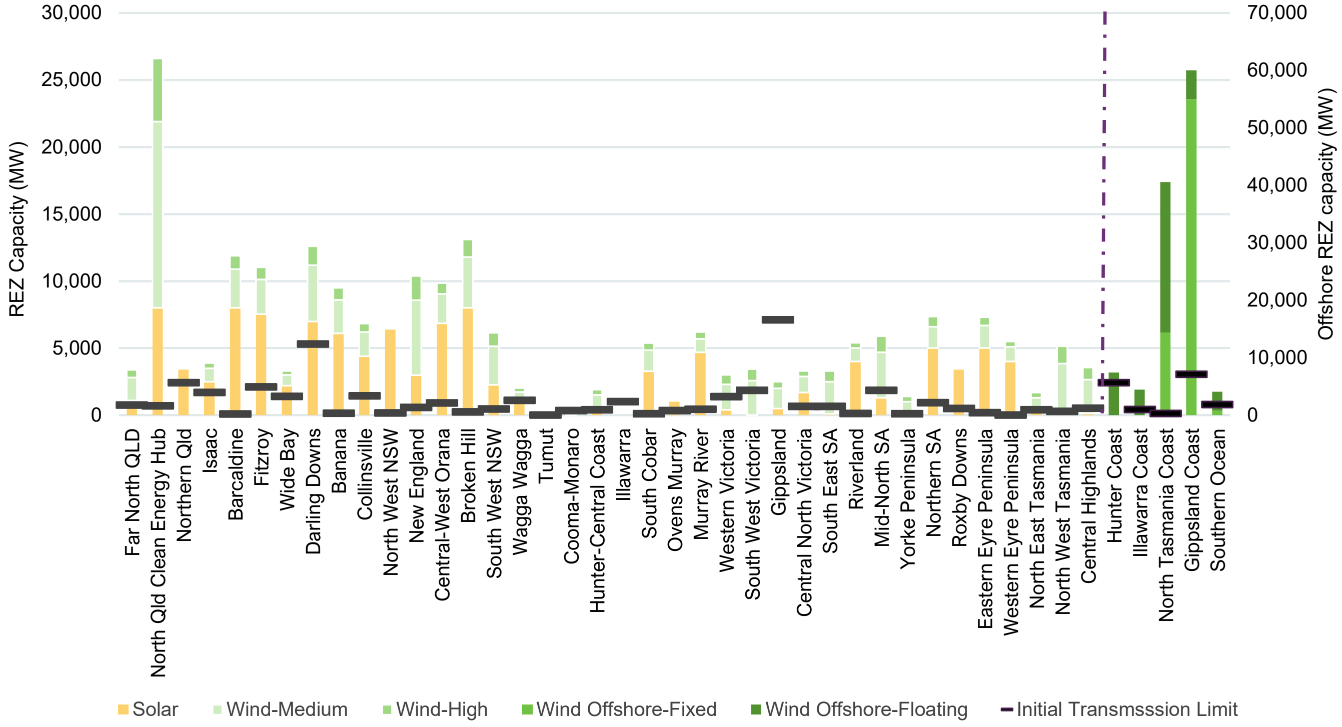
AEMO adjusts REZ resource limits when the boundary of a REZ changes or when appropriate evidence becomes available from localised consultation and studies. As desktop studies and stakeholder engagement have already been completed to prepare the existing REZ resource limits, AEMO expects that any further changes will need to be based on localised evidence as REZ projects are developed and delivered.

AEMO proposes the following changes since the 2024 ISP:

- Revised resource limits for Isaac REZ to reflect proposed 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 proposed 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 proposed 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.
- Added a wind resource limit for Murray River REZ based on updated TNSP advice around increased connection interest from wind farm proponents in this zone.

The updated resource limits are shown in Figure 66 and provided in detail in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 66 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.

Onshore wind farm resource limits

Maximum REZ wind generation resource limits were initially calculated based on a DNV-GL[197] estimate of:

- Typical wind generation land area requirements.
- 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[198] (see Section 3.5.1 for more information on classification of generation projects). In response to the latest updates of the committed and anticipated generation[199], AEMO proposes to add an onshore wind resource limit to Murray River REZ in Victoria in recognition of increased connection interest since the 2023 IASR.

The resource limits are shown above in Figure 66, and are further detailed in the Draft 2025 *Inputs and Assumptions Workbook*.

[197] 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.

[198] 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.

[199] AEMO. NEM Generation Information October 2024, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

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.
- 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].

No changes are proposed for the existing REZ resource limits for the 2026 ISP. The resource limits are shown in Figure 66 above and are further detailed in the Draft 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 now proposes to remove 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 35 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 35 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	54,996	5,000	14,999
V8 – Southern Ocean	780	3,330	1,030
T4 – North Tasmania Coast	14,400	26,150	10,136

The maximum offshore REZ wind generation resource limit in Table 35 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.
- 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, AEMO proposes a land use penalty factor of $0.3 million/MW, 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 proposes to apply for the 2026 ISP also.

The land area within a REZ can be found in the Draft 2025 *Inputs and Assumptions Workbook*.

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 will include 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 proposes to seek input and advice from the CCRG for the 2025 IASR and 2026 ISP where appropriate, in addition to undertaking extensive joint planning with TNSPs on this matter.

In the 2024 ISP, AEMO included social licence and community sentiment in a number of ways, as listed below. In this Draft 2025 IASR, AEMO welcomes stakeholder views and advice on how any of these considerations can be enhanced for the 2026 ISP.

- Selection of **forecasting and planning scenarios**, and their narratives (see Section 2).
- Selection of **sensitivity analyses**, including a 'social licence' sensitivity for the Draft 2024 ISP.
- 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. 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 will consult on transmission and distribution augmentation cost, generator connection costs and project lead times in the 2025 *Network Expansion Options Report* consultation (formerly known as the *Transmission Expansion Options Report*). However, AEMO is also seeking stakeholders' views on how community sentiment can be incorporated in the development of these parameters in this Draft 2025 IASR consultation.

Matters for consultation from Stage 1

- Do you have specific feedback on the proposed REZ resource limits?
- Is the maximum land use assumption of 5% for the REZ hard limits appropriate?
- Do you have specific feedback on the incorporation of community sentiment in the development of REZs?

3.9.3 REZ transmission limits

Input vintage	December 2024
Status	Draft
Source	Based on the 2023 *Transmission Expansion Options Report* and feedback to the 2023 *ISP Methodology* consultation
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2024 ISP	The following revisions have been made to align REZ transmission limits with the proposed 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: transmission limits provided for the new South Cobar candidate REZ and the SWNSW1 secondary transmission limit has been updated to incorporate the N4 Broken Hill REZ contribution. South West NSW REZ limit has been revised consistent with updates to SWNSW1. Queensland: transmission limits for Isaac REZ have been updated to reflect the new REZ boundary, and the Northern Queensland REZ limit will be represented by NQ1 group constraint, replacing NQ2. A new group constraint CQ1 has been added to account for generation south of Isaac REZ. Limits for the new Collinsville REZ will be modelled with the CQ-NQ sub regional limit. Finally, the SWQLD1 group constraint has been updated to reflect the additional resource traces in Darling Downs REZ. • South Australia: transmission limits amended to reflect revised boundary for the Northern South Australia REZ to extend to the Whyalla West area. The MN1 North and S1-TBMO limits have been replaced respectively by the new CSA-NSA and SESA-CSA flow paths. Eastern Eyre Peninsula REZ has been updated based on revised line ratings. • Victoria: the SEVIC1 group constraint has been replaced by the new SEV-MEL flow path limit.

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*.

The following changes are proposed to the 2025 IASR transmission limits and generation constraints:

- The new Collinsville REZ limit will 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 will be modelled as part of the CQ1 group constraint limit.
- Northern Queensland REZ limit will 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.

Table 36 REZ transmission limit constraints

Transmission constraint name	REZ	Co-efficient	Constraint terms	Transmission-limited total build (MW)
SWQLD1	Darling Downs	0.12	Generation in Western Downs area	2,600
		0.36	Generation in Darling Downs area	
		0.95	Generation in Southern Downs area	
		0.78	North New South Wales to South Queensland flow (Queensland – New South Wales Interconnector [QNI])	
		-0.09	South Queensland to Central Queensland flow	

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 change is proposed 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.

Table 37 REZ secondary transmission limits

REZ	Constraint terms	Transmission constraint	Transmission limit (summer peak/summer typical/winter reference) in MW
N5 (Existing)	Limondale 1 & 2 Solar Farm • Sunraysia Solar Farm • Coleambally Solar Farm • Finley Solar Farm • Darlington Point Solar Farm and Battery Energy Storage System (BESS) • Hillston Sun Farm • Riverina BESS 1 and 2	SWNSW1	1,200/1,200/1,200
N4 (Existing)	• Broken Hill Solar Farm and BESS • Silverton Wind Farm • Silver City Energy Storage		
V3	• Refer to Draft 2025 *Inputs and Assumptions Workbook* for full constraint definitions	V3-EAST	600/600/800
		V3-WEST	780/780/980

Matters for consultation from Stage 1

- Do stakeholders have any other suggestions for representation of REZ transmission limit constraints and the secondary REZ transmission limits?

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. Table 38 below shows the group constraints that apply in the capacity outlook model. 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 to the REZ group constraints are proposed:

- With the Central Queensland – Northern Queensland (see Section 3.10.5) sub-region boundary regional reference node shifting south from Chalumbin 275 kV to Ross 275 kV, the NQ2 group constraint will be removed and the Northern Queensland limits will be represented by the NQ1 group constraint previously included in the 2022 ISP.
- A new group constraint CQ1 will be added to reflect the network limits south of Q4 Isaac.
- The SEVIC1 group constraint will be removed and instead represented via the new South East Victoria – Greater Melbourne and Geelong (SEV-MEL) flow path.
- The MN1 North group constraint will be replaced by the new Central South Australia – North South Australia (CSA-NSA) flow path.
- The MN1 South group constraint will be updated to include an NSA to CSA sub-regional flow term.
- The SWQLD Darling Downs REZ Group Constraint will be updated to include separate terms and coefficients for the additional resource trace locations.
- The S1-TMBO limit will be removed as the change to the SESA-CSA boundary now incorporates this cut-set limit.

Table 38 REZ group transmission constraints

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
Q1	Far North Queensland	NQ1	2,420/2,420/2,650
Q2	North Queensland Clean Energy Hub		
Q3	Northern Queensland		
-1 x CQ-NQ	Central Queensland - North Queensland	CQ1	1,700/1,700/2,070
Q4	Isaac		
-0.5 x SQ-CQ	Central Queensland - South Queensland	SQ1(Before Queensland SuperGrid)	1,400/1,400/1,400
Q7	Wide Bay		

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
Q7	Wide Bay	SQ1 (After Queensland SuperGrid)	-
0.42 x Q8	Darling Downs		
-0.82 x CQ-SQ	CQ-SQ sub-regional flow		
0.75 x BPH	Borumba Pumped Hydro		
0.51 x Q8_Coal	Existing South West Queensland coal and gas generation (Tarong, Tarong North, Kogan Creek, Darling Downs, Braemar)		
-VIC-SA	Heywood Interconnector	SWV1	1,850/1,850/1,850
V4	South West Victoria		
V8	Southern Ocean		
S3	Mid-North SA	MN1	1,630/1,630/1,860
S4	Yorke Peninsula		
NSA-CSA	Flow from NSA to CSA		
0.75 x S5	Northern SA new entrant VRE	NSA1	585/585/585
S5 West	Existing generation in west of S5		
S7	Eastern Eyre Peninsula		
S8	Western Eyre Peninsula		
-CSA Export Electrolyser load	H2 Electrolyser load in NSA area		
-0.34 NSA demand	Industrial load in NSA area		
- 0.75 x S5	Northern SA new entrant VRE	NSA1 North	590/590/590
- S7	Eastern Eyre Peninsula		
- S8	Western Eyre Peninsula		
- S5 West	Existing generation in west of S5		
CSA Export Electrolyser load	H2 Electrolyser load in NSA area		
0.34 NSA demand	Industrial load in NSA area		
T1	North East Tasmania	NET1	1,600/1,600/1,600
T4	North Tasmania Coast		

Matters for consultation from Stage 1

- Do stakeholders have any other suggestions for representation of inter-related constraints across multiple REZs and/or REZs and flow paths?

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:

- 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 'Build limits' tab of the Draft 2025 *Inputs and Assumptions Workbook*. 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 2024
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data
Update process	Transmission Cost Database update and the 2025 *Network Expansion Options Report* consultation
Get involved	***2025*** Network Expansion Options Report *consultation*

For the 2024 ISP, AEMO published the 2023 *Transmission Expansion Options Report* with an expanded scope of the earlier 2021 *Transmission Cost Report*. This 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.
- System strength remediation costs.

For the 2026 ISP, AEMO will continue this initiative by publishing a *Network Expansion Options Report* with a scope including transmission network augmentation options and costs as well as some aggregated distribution network augmentation information. 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 draft report will be published in early May 2025, followed by a period of consultation. AEMO will then publish the final 2025 *Network Expansion Options Report* alongside the 2025 IASR in July 2025.

For the 2025 IASR, AEMO is proposing to allocate the efficient level system strength remediation costs to REZ connection costs, to form a collective connection point limit cost. This proposed change seeks to align with the recently updated system strength framework[200], 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.

Matters for consultation from Stage 1

- Do stakeholders agree with the proposed approach to allocate system strength remediation costs to REZ connection costs, consistent with the updated System Strength Impact Assessment Guidelines?

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).
- **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 Section3.10.4).
- **Flow path augmentation options** – this will be consulted on through the Draft 2025 *Network Expansion Options Report* and will include 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 will be updated and consulted on through the Draft 2025 *Network Expansion 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).

[200] AEMO. System Strength Impact Assessment Guidelines, June 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/ssiag/system-strength-impact-assessment-guidelines-v22.pdf?la=en.

- **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 *Network Expansion 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 where appropriate (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	December 2024
Status	Draft
Source	AEMO internal – based on 2024 ISP inputs, and adjusted based on AEMO assessments, supplemented by advice from TNSPs via joint planning
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Updates proposed to: • Create three sub-regions for the Victoria region. • Create a third sub-region in South Australia and amend the definition between the existing sub-regions in South Australia. • Amend the definitions of the North Queensland and Central Queensland sub-regions.

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 proposes to make the following changes to the sub-regional topology since the 2024 ISP:

- **Separating Victoria into three sub-regions** – AEMO proposes to divide 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 proposes to divide 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 proposes to change 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 proposes to change 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.

Table 39 lists all the regions and sub-regions that AEMO proposes to use in its studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 39 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**	-
	South East Victoria (SEV)	Hazelwood 500 kV	V5 and V7
	West and North Victoria (WNV)	Moorabool 220 kV	V1, V2, V3, V4, V6 and V8

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 proposing 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 67 and Table 40. 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 67 ISP sub-regional model

Table 40 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 (WRL) 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 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 41. 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 proposed to support enhanced visibility of constraints in the network for meeting Greater Melbourne and Geelong demand.

Table 41 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.
Northern New South Wales (NNSW)	Armidale 330 kV	Within New South Wales, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within New South Wales, all load and generation including west of Wallerawang, Wollar, Bayswater, Liddell, Muswellbrook and Bannaby substations.
South New South Wales (SNSW)	Canberra 330 kV	Within New South Wales, all load and generation including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West New South Wales.
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.

Sub-region	Sub-region reference node	Load and generation representation
West and North Victoria (WNV)	Moorabool 220 kV	Within Victoria, all load and generation including and north and west of Moorabool, Eildon, Dederang, Winchelsea and Bacchus Marsh substations.
South East Victoria (SEV)	Hazelwood 500 kV	Within Victoria, all load and generation in Gippsland region including at Hazelwood, Loy Yang, Yallourn, Jeeralang and Morwell substations.
Greater Melbourne and Geelong (MEL)	Thomastown 66 kV	All load and generation within Victoria, except in WNV and SEV sub-regions.
Northern South Australia (NSA)	Davenport 275 kV	All load and generation including and north of Davenport and Eyre Region.
Central South Australia (CSA)	Torrens Island 66 kV	All load and generation within South Australia except NSA and SESA sub-regions load and generation.
South East South Australia (SESA)	South East SA 132 kV	All load and generation including and south of Tailem Bend within South Australia.
Tasmania (TAS)	George Town 220 kV	All load and generation within Tasmania.

Matters for consultation from Stage 1

- Does the proposed sub-regional model reasonably represent the network?

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.
- Are modified to cater for different transmission development pathways and scenarios assessed in an ISP.

3.10.2 Existing transmission capability

Input vintage	December 2024
Status	Current view
Source	AEMO internal supplemented by advice from TNSPs via joint planning
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2024 ISP	Updated to reflect the transmission capability of the flow paths proposed to define the boundaries between the new and amended sub-regions discussed in Section 3.10.1. These transmission capabilities were prepared by reviewing historical transfer performance and undertaking power system analysis, as well as through joint planning with TNSPs.

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 proposes the following changes since the 2024 ISP:

- Revision of flow path limits between Central Queensland (CQ) and Northern Queensland (NQ) to align with the proposed 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[201] report).
- Inclusion of flow path limits between Greater Melbourne and Geelong (MEL) and West and North Victoria (WNV) to align with the proposed new sub-region boundaries.
- Inclusion of flow path limits between South East Victoria (SEV) and Greater Melbourne and Geelong (MEL) to align with the proposed new sub-region boundaries.
- Revision of flow path limits between South East South Australia (SESA) and Central South Australia (CSA) to align with the proposed updated sub-region boundaries.

The proposed Draft 2025 IASR notional transfer limits are in Table 42. 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 Draft 2025 *Inputs and Assumptions Workbook*.

Table 42 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 proposed in this Draft 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

[201] 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. AEMO is working with Transgrid to further refine this limit for the final 2025 IASR.
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. AEMO is working with Transgrid to further refine this limit for the final 2025 IASR.
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 coefficients for generators in NNSW, CNSW and SNSW. These generator coefficients are presented in the "Network

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**	
							capability" worksheet in the Draft 2025 *Inputs and Assumptions Workbook*. See the Draft 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 Draft 2025 *Inputs and Assumptions Workbook*. See the Draft 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.
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

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**	
							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	2,300	2,550	4,880	2,300	2,550	4,880	New flow path proposed in this Draft 2025 IASR. Generation from MEL is not expected to supply WNV (Forward direction) at times of high demand periods. The forward direction transfer limits are assumed to be equal to reverse direction limits. These limits will be 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 Draft 2025 *Inputs and Assumptions Workbook*.
SEV – MEL	7,100	7,430	8,170	7,100	7,430	8,170	New flow path proposed in this Draft 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. Transfer limits with Western Renewables Link and post Yallourn power station closure are available in the "Network Capability" worksheet in the Draft 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 to release 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 Draft 2025 *Inputs and Assumptions Workbook*.

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**	
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 are available in the "Network Capability" worksheet in the Draft 2025 *Inputs and Assumptions Workbook*.
SESA – CSA	750	750	800	790	790	820	Amended flow path boundary proposed in this Draft 2025 IASR. This transfer limit considers Project EnergyConnect Stage 1 in service. The transient and oscillatory stability limits may be applicable on this flow path. AEMO is working with ElectraNet to refine this limit for the final 2025 IASR.
CSA – NSA	1,070	1,070	1,230	1,150	1,150	1,200	New flow path proposed in this Draft 2025 IASR. A transient or voltage stability limit lower than the thermal limit may be applicable for this flow path. AEMO is working with ElectraNet to further refine this limit for the final 2025 IASR.
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 Draft 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 Draft 2025 *Inputs and Assumptions Workbook*.

Matters for consultation from Stage 1

- Do you have any specific feedback on the existing and proposed flow path transfer capabilities?
- Do you have any feedback on the uplift factors applied to flow paths as a result of committed and anticipated projects?

3.10.3 Committed transmission projects

Input vintage	December 2024
Status	Current view
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Update process	As projects receive committed status, these are updated in the Input and Assumptions Workbook and the Transmission Augmentation Information page.
Updates since 2024 ISP	Yass-Wagga Line Overload Scheme (LOLS) Expansion (NCIPAP) project by Transgrid received committed status.

AEMO applies the five-criteria definition of a committed project from the AER's regulatory investment test[202]; 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.

This Draft 2025 IASR applies the committed projects listed in the Transmission Augmentation Information page[203], December 2024 release. For further details on these projects please see the Draft 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.

[202] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

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

3.10.4 Anticipated transmission projects

Input vintage	December 2024
Status	Current view
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Update process	As projects receive anticipated status, these are updated in the Input and Assumptions Workbook and the Transmission Augmentation Information page.
Updates since 2024 ISP	HumeLink has advanced to anticipated status.

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[204] 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 Draft 2025 IASR applies the anticipated projects listed in the Transmission Augmentation Information page[205], December 2024 release. For further details on these projects please see the Draft 2025 *Inputs and Assumptions Workbook* or the Transmission Augmentation Information page.

3.10.5 Flow path augmentation options

Input vintage	June 2024
Status	Interim
Source	AEMO, 2024 ISP, TNSP
Updates process	2025 *Network Expansion Options Report* consultation and through further TNSP engagements
Get involved	2025 *Network Expansion Options Report* consultation

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

[204] 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.

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

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 will consult on flow path augmentation options, including the capacity gained and lead time to deliver the project, through the Draft 2025 *Network Expansion Options Report*. Please see Section 3.9.4 for more details.

3.10.6 Transmission augmentation costs

Input vintage	June 2024
Status	Interim
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 process	• 2025 *Network Expansion Options Report* consultation
Get involved	2025 *Network Expansion 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 has engaged expert consultant GHD to update the Transmission Cost Database. The update to the Transmission Cost Database will include:

- Review and update the cost and risk data to align with latest changes in market costs.
- Review and update the cost forecasting tool and methodology.
- Incorporate the latest transmission project information in the update and calibrate escalation factors.
- Prepare an updated Cost and Risk data workbook and forecasting tool, and associated reporting.

AEMO is undertaking extensive joint planning and collaboration with TNSPs and jurisdictional bodies to update the Transmission Cost Database. The updated Transmission Cost Database will be used to develop draft cost estimates for transmission augmentation options for use in the 2026 ISP.

AEMO will release the draft updated Transmission Cost Database, and associated cost estimates, for consultation as part of the Draft 2025 *Network Expansion Options Report* in April 2025. Outcomes of the consultation will be incorporated in the final 2025 *Network Expansion Options Report* and final 2025 *Inputs and Assumptions Workbook*.

3.10.7 Preparatory activities

Input vintage	June 2024
Status	Final
Source	TNSPs
Update process	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)[206], 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.
- 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[207].

While TNSPs must commence preparatory activities as soon as practicable for actionable ISP projects (if not yet already commenced)[208], 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 43. The TNSPs' preparatory activities reports are published on the AEMO website[209].

[206] These terms are defined in NER 5.10.2 and Chapter 10. At https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules.

[207] Preparatory activities and community engagement expectations are both defined in NER 5.10.2.

[208] NER 5.22.6(c)&(d)(1)

[209] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

Table 43 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	April 2025
Status	Not started
Source	DNSPs
Update process	2025 *Network Expansion Options Report*
Updates since 2024 ISP	These inputs have not been included in previous ISPs
Get involved	2025 *Network Expansion Options Report*

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[210] 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 is currently considering a rule change to implement information provision arrangements to support the delivery of this action[211]. As such, AEMO is currently considering how to introduce representation of distribution network capabilities and opportunities into the ISP models.

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.*

[210] 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.

[211] AEMC. Improving consideration of demand-side factors in the ISP. At https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp.

- *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.*

AEMO will engage extensively with DNSPs to understand existing and future distribution network capabilities and opportunities for incorporating CER and other distributed resources. This will include 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. The representation of these capabilities will be informed by inputs from the DNSPs, to be gathered and consulted on through AEMO's Draft 2025 *Network Expansion Options Report*, which will also include cost curves for potential distribution network augmentations associated with accommodating higher levels of CER operation. AEMO expects that this data will necessarily evolve and improve over successive ISPs.

3.10.9 Non-network options

Input vintage	September 2024
Status	Draft
Source	Previous projects, stakeholder submissions
Update process	2025 IASR and progression of RIT-Ts
Get involved	*2025* Network Expansion Options Report

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 will seek input on and consider non-network options 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 TAPR, 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.

At this stage, AEMO is seeking information on non-network technologies or proponents so ISP modelling can flag opportunities for competitive non-network investment. In order to model non-network technologies, AEMO is seeking information on:

- Specific non-network concepts and proposals.
- The resultant network capacity gained.
- Cost of the non-network solution.
- Project lead time.

Matters for consultation from Stage 1

- Is there any information on non-network technologies or proponents regarding opportunities for competitive non-network investment?
- Given that non-network investments generally involve commercial arrangements with plant with multiple revenue streams, how should AEMO estimate their cost transparently?

3.10.10 Network losses

Input vintage	December 2024
Status	• Current view for existing network inter-regional loss factor equations, loss equations and proportioning factors. • Interim view for future inter-regional/intra-regional loss factor equations, and loss equations and proportioning factors. • Draft view for existing network intra-regional loss factor equations, and loss equations and proportioning factors.
Source	AEMO *Marginal Loss Factors Report* 2024-25 Financial Year and internal processes
Update process	• Updated in line with AEMO's *Marginal Loss Factors Report* published in July 2024. • For existing network intra-regional loss factor equations, loss equations and proportioning factors, the Draft 2025 *Inputs and Assumptions Workbook* has been updated. • For future augmentation options, the draft and final 2025 *Network Expansion Options Report.*
Updates since 2024 ISP	• Added new intra-regional loss and loss factor equation for Central South Australia (CSA) to Northern South Australia (NSA). • Updated the Central Queensland (CQ) to Northern Queensland (NQ) and Southern Queensland (SQ) to Central Queensland (CQ) loss and loss factor equations to reflect the revised sub-regional boundary definition.
Get involved	• 2025 *Network Expansion Options Report* consultation

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. While the sub-regional model does split some regions into smaller sub-regions, inter-regional losses will continue to be modelled across regional boundaries – consistent with the design of the NEM. Where inter-regional losses do not sufficiently account for geographically remote subregional flow paths (for example Far North Queensland, Central Queensland and Northern South Australia), additional sub-regional losses have been modelled.

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*[212] report and are presented in the 'Network losses' tab of the Draft 2025 *Inputs and Assumptions Workbook*.

For committed, anticipated and future projects that impact interconnector flows, AEMO will be consulting on these inter-regional loss equations, loss factor equations and proportioning factors through the 2025 *Network Expansion Options Report*, for inclusion in the final 2025 *Inputs and Assumptions Workbook*.

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 in some cases 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 2024 ISP, AEMO identified Northern Queensland as being remote from load centres under all scenarios except *Green Energy*, based on insights from the 2022 ISP's *Hydrogen Superpower* scenario outcomes. AEMO used the sub-regional model to capture the network losses through intra-regional equations, between the Northern Queensland, Central Queensland and Southern Queensland sub-regions. This approach was applied to Far North Queensland and Queensland Clean Energy Hub in all scenarios except the *Green Energy* scenario.

In this Draft 2025 IASR, AEMO is proposing the addition of a new Northern South Australia (NSA) sub-region. In this case, AEMO has identified that the sub-regional reference node for NSA would be remote from the regional reference node for South Australia. As such, AEMO proposes to add a new intra-regional loss equation between

[212] 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.

Northern South Australia and Central South Australia to ensure losses associated with the transfers between these two sub regions are catered for.

The Draft 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 2024
Status	Current view
Source	AEMO *Marginal Loss Factors Report* 2024-25 Financial Year and internal processes
Update process	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 Large-scale Renewable Energy Target (LRET).

MLFs are an outcome of applying the methodology for the calculation of Forward-Looking Transmission Loss Factors (updated in December 2024), and are updated every financial year with the publication of AEMO's *Marginal Loss Factors* report[213]. 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 Draft 2025 *Inputs and Assumptions Workbook*.

[213] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

3.10.12 Transmission line unplanned outage rates

Input vintage	June 2024
Status	Current view
Source	AEMO Network Outage Schedule and other AEMO sources
Update process	Updated in June 2024 as part of data collection process for the ESOO
Get involved	FRG Consultation in June 2025

AEMO models some outages on a limited selection of transmission flow paths that are required for inter-regional power transfer. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts. Table 44 shows the rates and method used in the 2024 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 44 Inter-regional transmission flow path outage rates

Flow path	ESOO 2024 transmission UOR (%)	ESOO 2024 Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.2	16	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.62	4	Annual static
Murraylink – Credible Contingency	1.37	72	Annual static
Basslink – Credible Contingency	5.27	192	Annual static
Mortlake – South East (Victoria to South Australia) Credible Contingency	0.03	2	Annual, set to 0% post Project EnergyConnect (PEC) stage 2
Mortlake – South East (Victoria to South Australia) Reclassification	0.01	5	Annual, set to 0% post PEC stage 2

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)[214], 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

[214] 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.

services. AEMO's *Power System Requirements* document[215] 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
Status	Draft
Source	AEMO internal, *System Strength Report*, Transmission Cost Database, and *Network Expansion 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 *Network Expansion 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.

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.

[215] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

- 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*[216]. 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.

To calculate the effective system strength remediation cost component for each unit, AEMO will implement outcomes from the 2022 and 2023 Network Support and Control Ancillary Services (NSCAS) reports, which found a need for approximately 22 strategically located synchronous condensers[217] 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

[216] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[217] 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.

technology. Options such as retrofitting existing units, adding clutches to gas turbines, or leveraging grid-forming technology in the medium term[218] are all likely to contribute towards these requirements.

The Power System Security tab of the Draft 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 $50 million per coal unit retirement. These costs, and the underlying technical parameters of synchronous condensers, will be updated to reflect the latest Transmission Cost Database and *Network Expansion Options Report*.

See the 'Power System Security' worksheet in the Draft 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 proposes to use a weighted[219] 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[220]. 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 Draft 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 will be updated to reflect the latest Transmission Cost Database and *Network Expansion Options Report.*

See the 'Power System Security' worksheet in the Draft 2025 *Inputs and Assumptions Workbook*.

Synchronous unit commitment assumptions

Input vintage	December 2024
Status	Current
Source	AEMO internal
Updates since 2024 ISP	Updated timing

[218] 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.

[219] 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%.

[220] 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.

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 *Green Energy* 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 (PEC) stage 2 is fully commissioned, with all necessary protection and control schemes in place to manage credible loss of either PEC 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 PEC 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 68 and Figure 69 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 68 Minimum synchronous unit commitment requirements, all scenarios except *Green Energy*

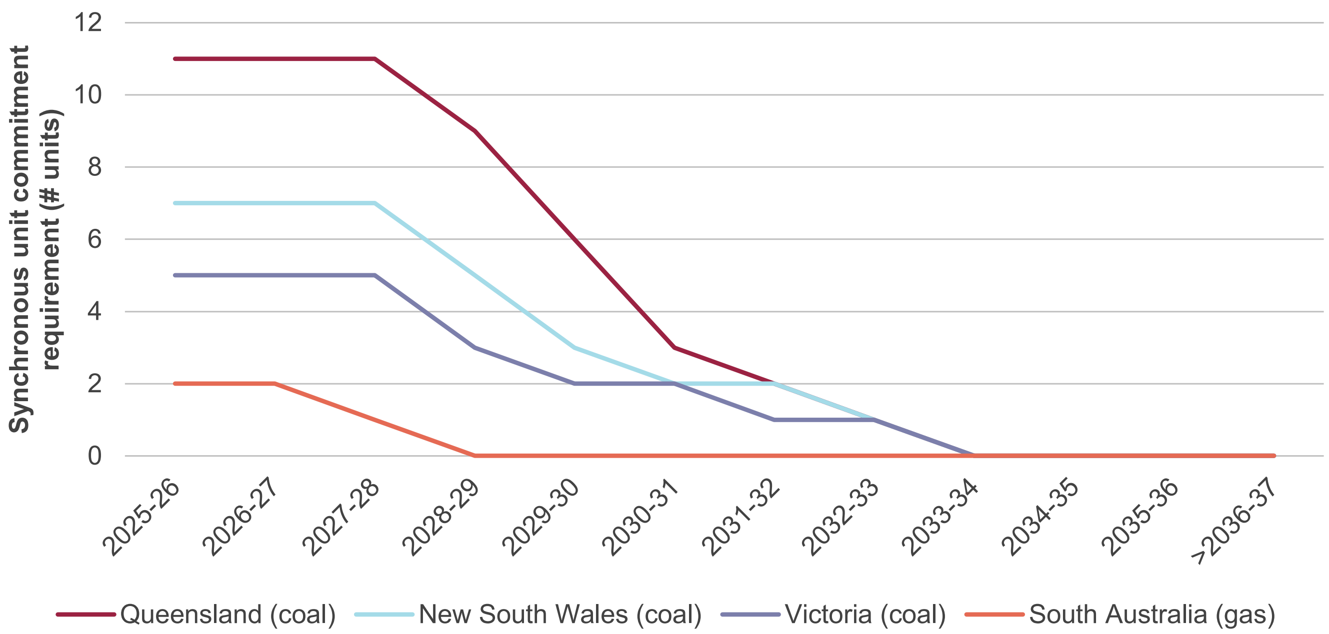
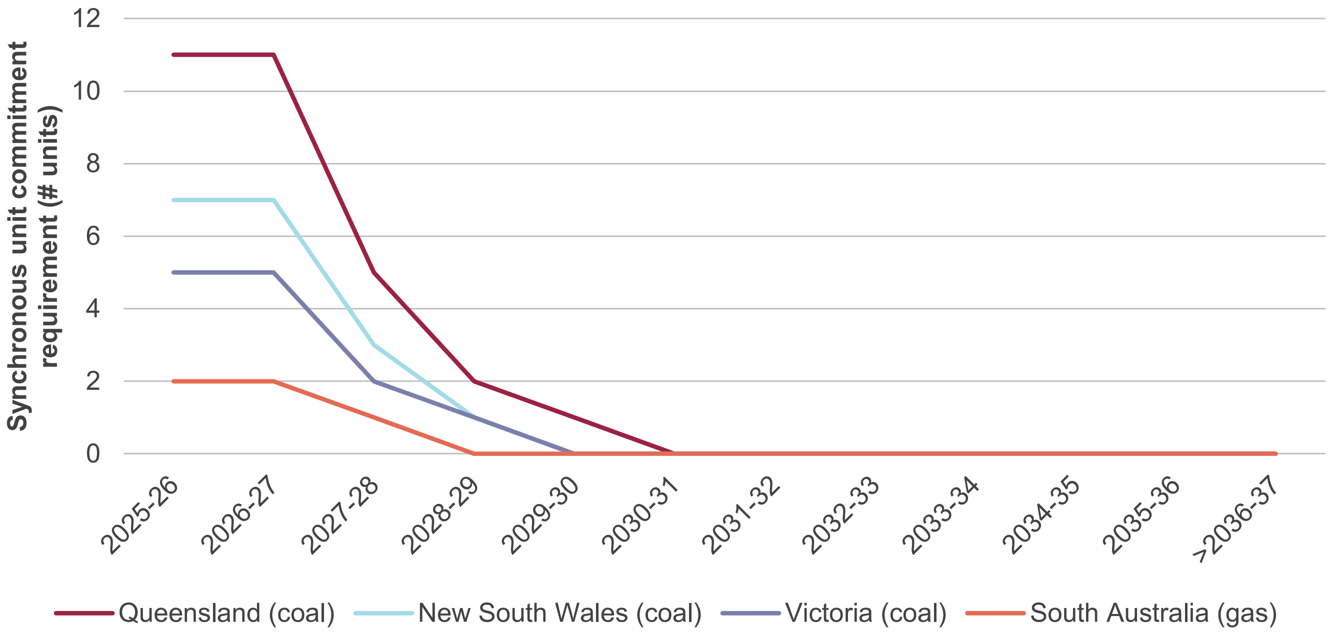


Figure 69 Minimum synchronous unit commitment requirements, *Green Energy* scenario



3.11.2 Inertia requirements

Input vintage	December 2024
Status	Current
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*[221] and AEMO's assessments for each region are published at least annually on AEMO's website[222].

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.

[221] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[222] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

AEMO's security assessments as part of the 2022 and 2023 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
Status	Current
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.
- Oscillatory stability – for managing damping of power system oscillations following a credible contingency.
- 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[223].

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.

[223] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

3.12 Gas infrastructure

This section contains updates for Stage 2

Input vintage	February 2025
Status	Draft
Source	CSIRO: *GenCost 2024-25 Consultation Draft;* AEMO analysis
Updates since 2023 IASR	PEM Cost has been updated to reflect *GenCost 2024-25 Consultation Draft*; Updates to: Balance of plant load, minimum utilisation factor, electrolyser location, hydrogen consumption location, water supply.

This section outlines key inputs and assumptions related to hydrogen and biomethane production technologies, and infrastructure needs for natural and renewable gases.

Hydrogen demand assumed across scenarios is discussed in Section 3.3.6 .

3.12.1 Production costs and capabilities

Hydrogen production

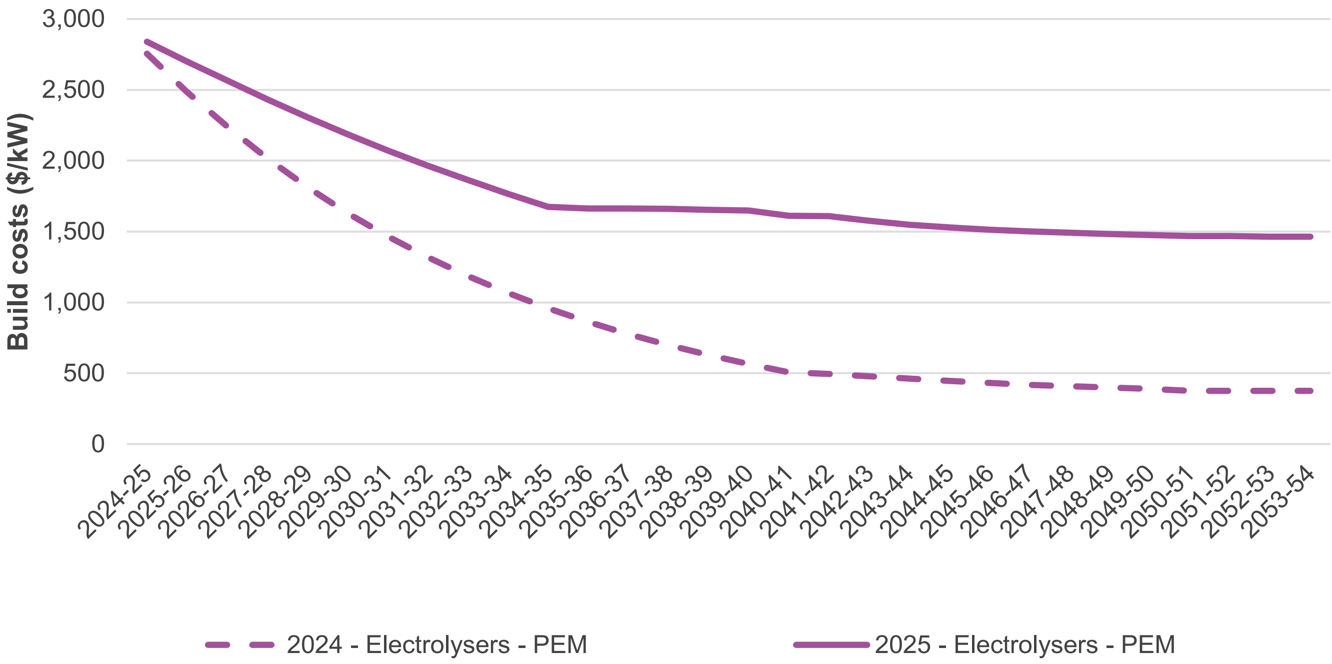
AEMO's hydrogen production forecasts assume that electrolysis will be the technology deployed at large scale to support the energy transition[224]. Electrolysis uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from zero-emissions generation it creates 'green hydrogen'. Proton exchange membrane (PEM) technology is most commonly proposed for development in the NEM, and AEMO's forecasts apply this technology choice.

Figure 70 below presents the capital cost projections for new PEM installations as forecast in *GenCost 2024-25 Consultation Draft* for its Global NZE post 2050 scenario, compared to GenCost 2023-24 Final report projections. Relative to the 2023-24 projections there has been an increase in hydrogen electrolyser cost, driven by updated analysis of balance of plant costs, and a slower reduction in costs over the longer term. See Section 3.5.3 for more detail on the scenario mappings between the *GenCost 2024-25 Consultation Draft* and Draft 2025 IASR scenarios.

Cost projections for PEM electrolysers for each scenario are available in the accompanying Draft 2025 *Inputs and Assumptions Workbook*.

[224] 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.

Figure 70 Forecast build cost trajectories for electrolysers (PEM), 2023 vs 2025 Global NZE post 2050 scenario ($/kW)



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 PEM 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%[225], applied as a baseload operating level.

AEMO proposes to apply an initial *minimum utilisation factor* of 70% for electrolyser operations, to reflect industry feedback on feasible economic operation. This is assumed to reduce linearly to 35% by 2058 as electrolyser costs reduce.

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.

Matters for consultation for Stage 2

- Do you agree with the assumed minimum electrolyser utilisation factors?

[225] Bloomberg New Energy Finance (BNEF) report: Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech (March 2024).

Natural gas and biomethane production

AEMO will use relevant information developed for the 2025 GSOO[226] 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.

3.12.2 Gas infrastructure

Hydrogen infrastructure needs

Electrolyser location

The 2026 *ISP Methodology*[227], currently under consultation, is reviewing 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.

Hydrogen consumption location

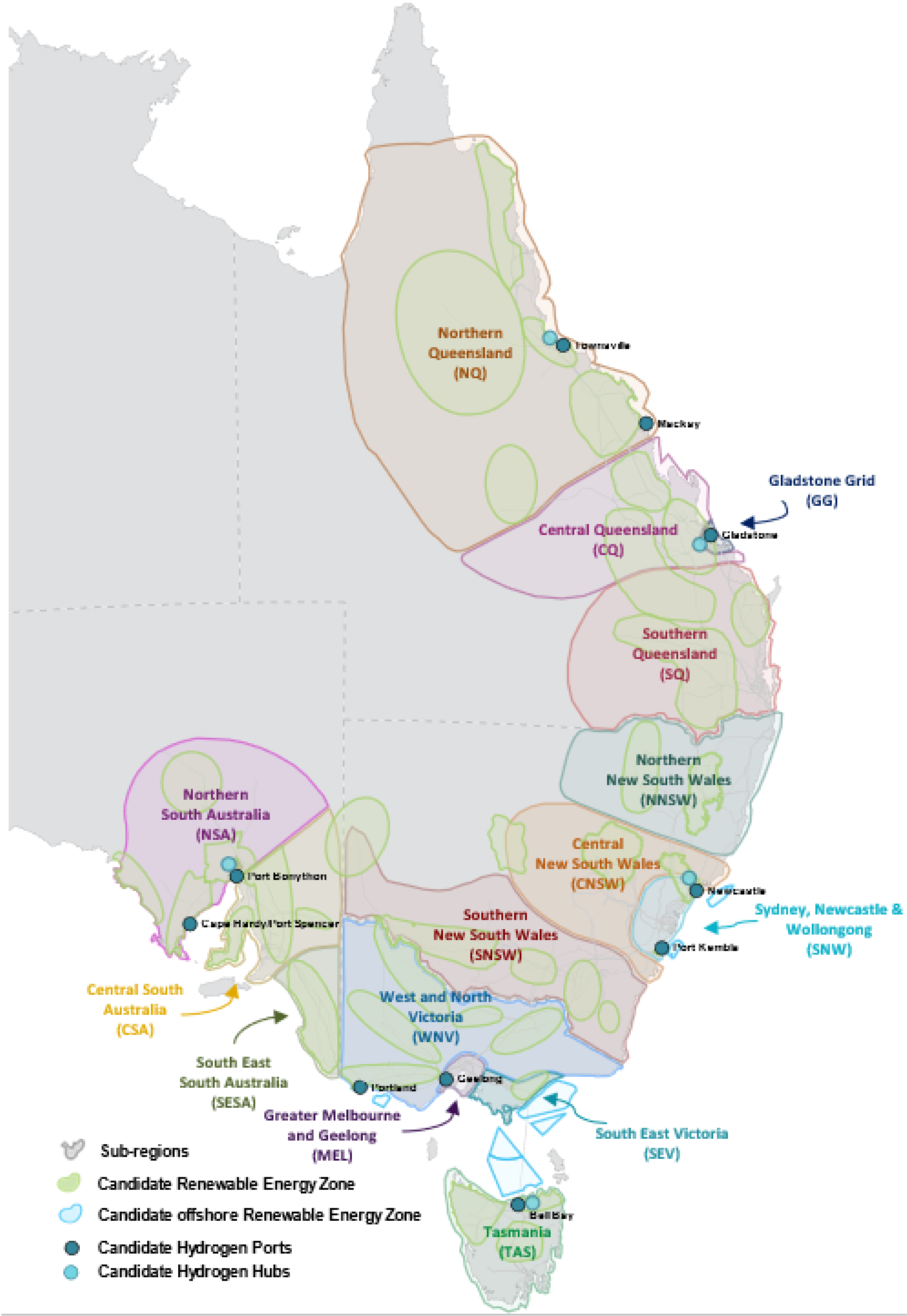
It is assumed that hydrogen consumption will occur in general industrial areas close to cities, in new industrial precincts that may support commodity manufacture (expected to be close to major ports for commodity and hydrogen export), and/or in distributed transport stations located along major trucking 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 map below shows the distribution of candidate hydrogen hubs, and ports for export of hydrogen and green commodities, overlaid with the Draft 2025 IASR's proposed sub-regions and candidate REZs.

[226] At https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

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

Figure 71 Candidate hydrogen and green commodity export ports, and hydrogen hubs



For the purpose of ISP modelling, hydrogen consumption for each subregion is assumed to be located as follows (in priority order):

Type of subregion	Assumed location of hydrogen consumption
Contains a candidate hydrogen hub	Hydrogen hub
Contains a candidate hydrogen port but no hub	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)

The candidate hydrogen hubs include locations aligned with recent Federal Government announcements[228], 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 notes the inclusion of water costs in the multi-sectoral modelling, however, water is not a costed component of electrolyser operation within the ISP modelling. Water is assumed to be supplied using desalination facilities located at the coast, with pipelines to the electrolyser locations. The water pipelines are assumed to be able to be laid in the same easement as the hydrogen pipelines, and water supply will represent a small increment to the overall hydrogen supply cost.

Matters for consultation for Stage 2

- Do you have feedback on the hydrogen supply pathways for use in the ISP model? If so, please address this feedback to the *ISP Methodology* consultation.
- Do you have feedback on the location of candidate hydrogen hubs and ports?

Natural gas infrastructure needs

AEMO's gas supply model evaluates the reserves, production, and transportation capacity of Australia's East Coast Gas System to calculate the delivery of gas supply to gas consumers. The gas supply model can be incorporated with gas expansion options for pipeline, gas storage, and/or production augmentations, informed by industry engagement, to identify natural gas infrastructure needs.

The gas production capacities, mid-stream gas delivery limits, production cost and potential costs of augmentation projects are key input assumptions into the gas supply model. They 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 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[229]. The 2025 GSOO will publish gas demand, existing production capacity, as well as anticipated and uncertain new developments. In addition,

[228] See https://www.dcceew.gov.au/energy/hydrogen/building-regional-hydrogen-hubs.

[229] 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.

AEMO's upcoming *Network Expansion Options Report* consultation will provide further gas development options for use in identifying the 'gas development projections' to support the energy transition.

Table 45 summarises key inputs and related data sources for the gas supply model, consistent with the GSOO.

Table 45 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, 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
Transmission costs	Gas industry participants and publicly available data
Pipeline, processing, storage facility capabilities and daily rates	Gas industry participants Gas Bulletin Board (GBB), 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

Further information on inputs to be used in developing gas development projects will be published with the *Draft 2025 Network Options Expansion Report*.

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[230].
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2023 IASR	Updated job-years for generation, storage and transmission development per outcomes of 2024 ISP.

Electricity sector employment is forecast to increase by 74% by 2050 (from 33,300 full time workers[231] in 2024 to 57,900 in 2050), in the *Step Change* scenario from the 2024 ISP[232]. 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[233] and with proactive planning, this challenge could represent an opportunity.

[230] At https://aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.

[231] These numbers represent number of full time equivalent jobs.

[232] At https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

[233] 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.

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.

Table 46 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 47 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.

Matters for consultation from Stage 1

- Do you have any feedback on the proportion of manufacturing that is assumed to be onshore, and how it may vary over time in response to state policies?

A1. ISP Review implementation measures

Over 2023 and early 2024, the Federal Government undertook a review of the ISP (Review of the ISP), and on 5 April 2024 the Energy and Climate Change Ministerial Council (ECMC) published its *Response to the Review of the Integrated System Plan*[234] (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, transforming Australia's energy mix, jurisdictional policy interactions, and supporting the timely delivery of ISP projects.

In December 2024, the AEMC made new rules[235] that addressed specific 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 will be documented in the *ISP Methodology*, while new inputs needed to apply AEMO's updated methods will have been outlined in Stage 1 and Stage 2 of the Draft 2025 IASR.

Table 48 below shows the publications that AEMO proposes to amend to address each ISP Review action to help inform stakeholders on appropriate engagement opportunities.

[234] See https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

[235] 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 48 Proposed implementation for actions in the Energy Ministers' response to the Review of the ISP

Action in the response to the Review of the ISP	Process for implementation			
	2025 IASR	*ISP Methodology*	*2025* Network Expansion Options Report[A]	*Enhanced Locational Information report*[B]
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	✔ [D]			
Clarifying policy inclusions	✔ [D]			
Improving the accessibility of the ISP[C]	✔			
Incorporating community sentiment			✔	
Additional planning inputs	✔			

A. The *Network Expansion Options Report* is consulted on as part of the IASR. This 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 *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.
C. AEMO will consider opportunities throughout the ISP development process to enhance consumer understanding of key elements.
D. These actions are to be implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions.

A2. Supporting material

In addition to the Draft 2025 *Inputs and Assumptions Workbook*, Table 49 documents additional information related to AEMO's inputs and assumptions.

Table 49 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
	2024 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/major-publications/isp/2025/2025-IASR-Scenarios-Consultation-Summary-Report
	2024 Electric Vehicles workbook	https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/draft-2025-iasr-ev-workbook.xlsx
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 Costs and Technical Parameter Review	https://aemo.com.au/-/media/files/major-publications/isp/2025/Aurecon-2024-Energy-Technology-Costs-and-Technical-Parameter-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	To be published ahead of the final 2025 IASR, no earlier than March 2025.
	GenCost 2024-25 Consultation Draft	https://www.csiro.au/en/research/technology-space/energy/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
	Electric Vehicle Projections 2024	https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/electric-vehicle-projections-2024.pdf
Entura	Pumped Hydro cost modelling	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.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	Discount rates for energy infrastructure	https://aemo.com.au/-/media/files/major-publications/isp/2025/Oxford-Economics-Australia-2024-Discount-Rate-report
	2025 Planning and Installation Cost Escalation Factors	https://aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-iasr-planning-and-installation-cost-escalation-factors.pdf
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

Tables

Figures

Abbreviations

Abbreviation	Meaning
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
APS	Announced Pledges Scenario
BESS	battery energy storage system
BEV	Battery electric vehicle
BMM	business mass market
BNEF	Bloomberg New Energy Finance
BoM	Bureau of Meteorology
CBA	cost benefit analysis
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
CNSW	Central New South Wales
CQ	Central Queensland
CSA	Central South Australia
CWC	ClimateWorks Centre
DAC	direct air capture
DAE	Deloitte Access Economics
DAT	dual-axis tracking
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISER	Department of Industry, Science, Energy and Resources
DSP	demand side participation
DSP IP	DSP Information portal
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection
ECMC	Energy and Climate Change Ministerial Council
EFOR	equivalent full forced outage rate
EMMS	electricity market management system
ESCI	Electricity Sector Climate Information
ESOO	Electricity Statement of Opportunities

Abbreviation	Meaning
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
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
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
ISP	Integrated System Plan
kL	kilolitre/s
kW	kilowatt/s
kWh	kilowatt hour/s
LIL	large industrial load
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
MEL	Greater Melbourne and Geelong
MLF	marginal loss factor

Abbreviation	Meaning
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
NNSW	Northern New South Wales
NQ	Northern Queensland
NSA	North South Australia
NSCAS	network support and control ancillary services
NSW EII Act	New South Wales Electricity Infrastructure Investment Act 2020
NVES	New Vehicle Efficiency Standard
NZE	Net Zero Emissions by 2050
OCGT	open cycle gas turbine
ONSG	other non-scheduled generation
PDRS	Peak Demand Reduction Scheme
PEC	Project EnergyConnect
PEM	proton exchange membrane
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicle
PJ	petajoule/s
POE	probability of exceedance
PV	photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
RCP	Representative Concentration Pathway
Response to the ISP Review	Energy and Climate Change Ministerial Council response to the ISP Review

Abbreviation	Meaning
RET	Renewable Energy Target
REZ	renewable energy zone
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
SESA	South East South Australia
SEV	South East Victoria
SNSW	South New South Wales
SNW	Sydney, Newcastle, Wollongong
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
UNFCCC	United Nations Framework Convention on Climate Change
UOR	unplanned outage rate
US EIA	US Energy Information Administration
V2G	vehicle-to-grid
V2H	vehicle-to-home
VCR	Value of Customer Reliability
VEU	Victorian Energy Upgrades
VNI	Victoria – New South Wales Interconnector
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
ZEV	zero emission vehicle