Appendix A2. Generation and Storage Development Opportunities

June 2026

Appendix to the 2026 Integrated System Plan for the National Electricity Market

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 is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. '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

This is Appendix A2 to the 2026 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 20 April 2026 unless otherwise indicated.

Disclaimer

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

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

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

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

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

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Copyright

Version control

Version	Release date	Changes
1	25/06/2026	First release

ISP appendices

Appendix A1. Stakeholder Engagement

- Stakeholder feedback
- Engagement approach
- Major engagements

Appendix A2. Generation and Storage Development Opportunities

- Summary of generation and storage development opportunities in the ODP across the scenarios
- Generation and storage development opportunities across scenarios
- The influence of sensitivities on generation and storage development opportunities

Appendix A3. Renewable Energy Zones

- REZ candidates
- REZ development overview
- Regional outlook and REZ scorecards

Appendix A4. System Operability

- The NEM's evolving demand profile
- System flexibility manages increased variability
- Implications for coal operation
- VRE penetration and curtailment
- Storage technologies will firm VRE by shifting energy
- Operating the power system during long dark and still conditions
- Maintaining reliability during the transition

Appendix A5. Network Investments

- Transmission development overview
- Committed and anticipated projects
- Actionable projects
- Future ISP projects
- Distribution projects

Appendix A6. Cost Benefit Analysis

- Approach to the cost-benefit analysis
- Determining the least-cost development path for each scenario
- Building candidate development paths
- Assessing the candidate development paths
- Selecting the preliminary optimal development path
- Sensitivity analysis to test resilience of candidate development paths
- Finalising the optimal development path

Appendix A7. System Security

- Recent reforms to the security planning frameworks
- AEMO's approach to system security planning
- System security concepts and requirements
- Projected outlook and opportunities

Appendix A8. Social Licence

- Social licence overview
- Social licence for new energy infrastructure development
- Consumer energy resources: adoption and coordination

Appendix A9. Demand Side Factors Statement

- Introduction to demand side factors
- Demand side factors and efficient development of the power system
- Opportunities for development of the distribution network to support CER export

Appendix A10. Gas Development Projections

- Gas system adequacy
- Gas development projections
- Forecasting the role of gas-powered generation
- Impacts of different gas development projections on the electricity capacity outlook

Contents

Tables

Figures

Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the National Electricity Market's (NEM's) transition, and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet both consumer needs and government policies, at least cost, to 2050.

The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies.

The ODP presented in this 2026 ISP has some differences compared to the ODP previously identified in the Draft 2026 ISP as it reflects changes based on latest available data, stakeholder feedback, and ongoing joint planning with transmission network service providers (TNSPs). Appendix A6 Cost Benefit Analysis details the identification and justification of the ODP.

This appendix presents the ISP development opportunities for electricity generation and storages in the ODP for three scenarios – *Step Change, Slower Growth*, and *Accelerated Transition*. These scenarios reflect different levels of economic and technical advancements over the coming decades, investments in consumer energy resources (CER), and pace of decarbonisation – influencing the emissions intensity of the generation mix that supplies electricity consumers, as well as the use of electricity to substitute traditional fuels through electrification. All scenarios incorporate the effects of various federal and state public policies relevant to the energy transition as outlined in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[1] that meet the National Electricity Rules (NER) requirements[2] and the Australian Energy Market Commission's (AEMC's) emissions targets statement[3].

This appendix also presents the impact on ISP development opportunities of key uncertainties through targeted sensitivity analysis. Development opportunities for distribution investments are discussed in Appendix A3 Renewable Energy Zones and Appendix A9 Demand Side Factors Statement.

ISP development opportunities in generation and storage across scenarios

The NEM's transition to renewables is well underway. About 40% of the coal fleet has retired, and renewables are approaching 50% of annual electricity supply. Investment in renewable energy is accelerating, supported by policy and declining technology costs. However, renewables are not a like-for-like replacement for coal and require complementary technologies to operate efficiently. A range of solutions – including network augmentation, storage across multiple durations, and flexible gas-fired generation – are supporting this transition by firming variable renewable energy (VRE) resources and maintaining system reliability and security, including during periods of dark and still renewable energy lulls as coal and mid-merit gas generators retire.

At the same time, demand for new generation and storage is increasing as electrification across transport, industry, and residential and commercial sectors lifts electricity consumption. Consumers are also continuing to invest in their own

[1] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[2] As per 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.

[3] AEMC, *Emissions targets statement under the national energy laws*, Guide, June 2025, at https://www.aemc.gov.au/sites/default/files/2025-06/Targets%20statement%20June%202025.pdf.

energy assets and are increasingly integrating these into the power system, including through virtual power plant (VPP) arrangements that enable coordinated response to market signals.

State and federal policies, including the Capacity Investment Scheme (CIS), and regional renewable energy targets, influence the pace and location of new investments in utility-scale wind and solar.

The 2026 ISP projects a significant increase in VRE generation capacities across all three ISP scenarios. By 2049-50, utility-scale VRE is projected to grow from 23 gigawatts (GW) in 2024-25 to 84 GW in *Slower Growth*, 117 GW in *Step Change*, and 211 GW in *Accelerated Transition*. Including rooftop and other small-scale solar, intermittent renewables account for 67%, 66%, and 70% of total generation capacity in these scenarios, respectively.

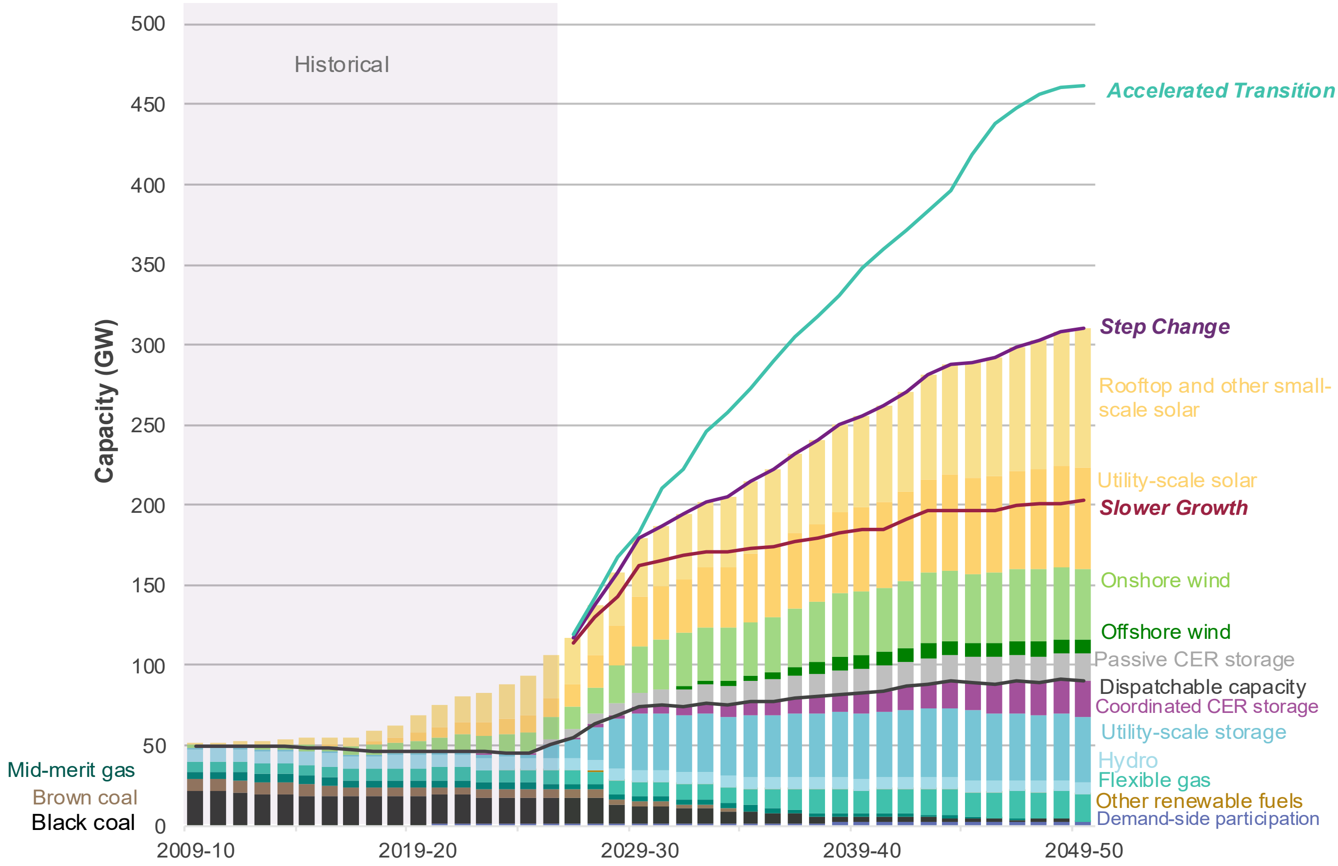
In the NEM's transition to 2029-30:

- Coal-fired generation capacity is approaching end-of-life, with capacity reducing from 21 GW currently to approximately 11.9 GW in *Slower Growth*, 13.6 GW in *Step Change*, and to 8.6 GW in *Accelerated Transition*.
- Renewable generation capacity is needed to replace coal, and meet rising demand and government targets, with significant growth forecast throughout the outlook period, buoyed by lower assumed installation costs over time as the technologies continue to mature. Utility-scale VRE capacity across the NEM is projected to reach approximately 56 GW, 61 GW, and 65 GW under *Slower Growth*, *Step Change*, and *Accelerated Transition*, respectively. In addition, the NEM's existing 7 GW of hydro-electric generation capacity remains in place.
- Rooftop and other small-scale solar is projected to offset a significant portion of consumers' own consumption and are increasingly expected to combine with batteries. Consumer investments are projected to have a major role in the energy transition, and can reduce the need for utility-scale investments, particularly if bundled and coordinated via VPPs or vehicle-to-grid (V2G) charging of electric vehicles (EVs). Rooftop and other small-scale solar is projected to grow to 32 GW, 36 GW, and 38 GW in *Slower Growth*, *Step Change*, and *Accelerated Transition,* respectively, with CER storages providing between 6 GW/12 gigawatt hours (GWh) and 16 GW/44 GWh of capacity across the scenarios.
- To complement and firm VRE developments, a mixture of storage depths is needed to provide intra-day energy shifting and seasonal firming when winter renewable energy output is lower than summer's. A total storage capacity of 42 GW/485 GWh is projected in *Slower Growth*, 48 GW/507 GWh in *Step Change*, and 53 GW/529 GWh in *Accelerated Transition*. This includes 31 GW/440 GWh of committed, anticipated and policy-supported[4] utility-scale storage capacity that is projected by 2029-30.

Figure 1 below shows the generation and storage development projected in the three scenarios for the ODP.

[4] Policy-supported projects are those generator and storage projects that have explicitly been awarded funding support through a relevant government tender or other associated instrument, that are not included in the January 2026 Generation Information update as Existing, Committed, or Anticipated projects. This includes the following funding frameworks - the 2020 amendment to the *National Electricity (Victoria) Act 2005* (NEVA), the Victorian Renewable Energy Target auction (VRET2), the New South Wales Long-Term Energy Service Agreements (LTESAs), Capacity Investment Scheme (CIS) and the Australian Renewable Energy Agency (ARENA) Large Scale Storage Funding Round. Projects that have won access support under the New South Wales Renewable Energy Zone (REZ) Access Rights framework are not treated as anticipated, but access rights are reflected in the modelling.

Figure 1 Historical and projected generation and storage capacity across the three core scenarios, 2009-10 to 2049-50 (GW)



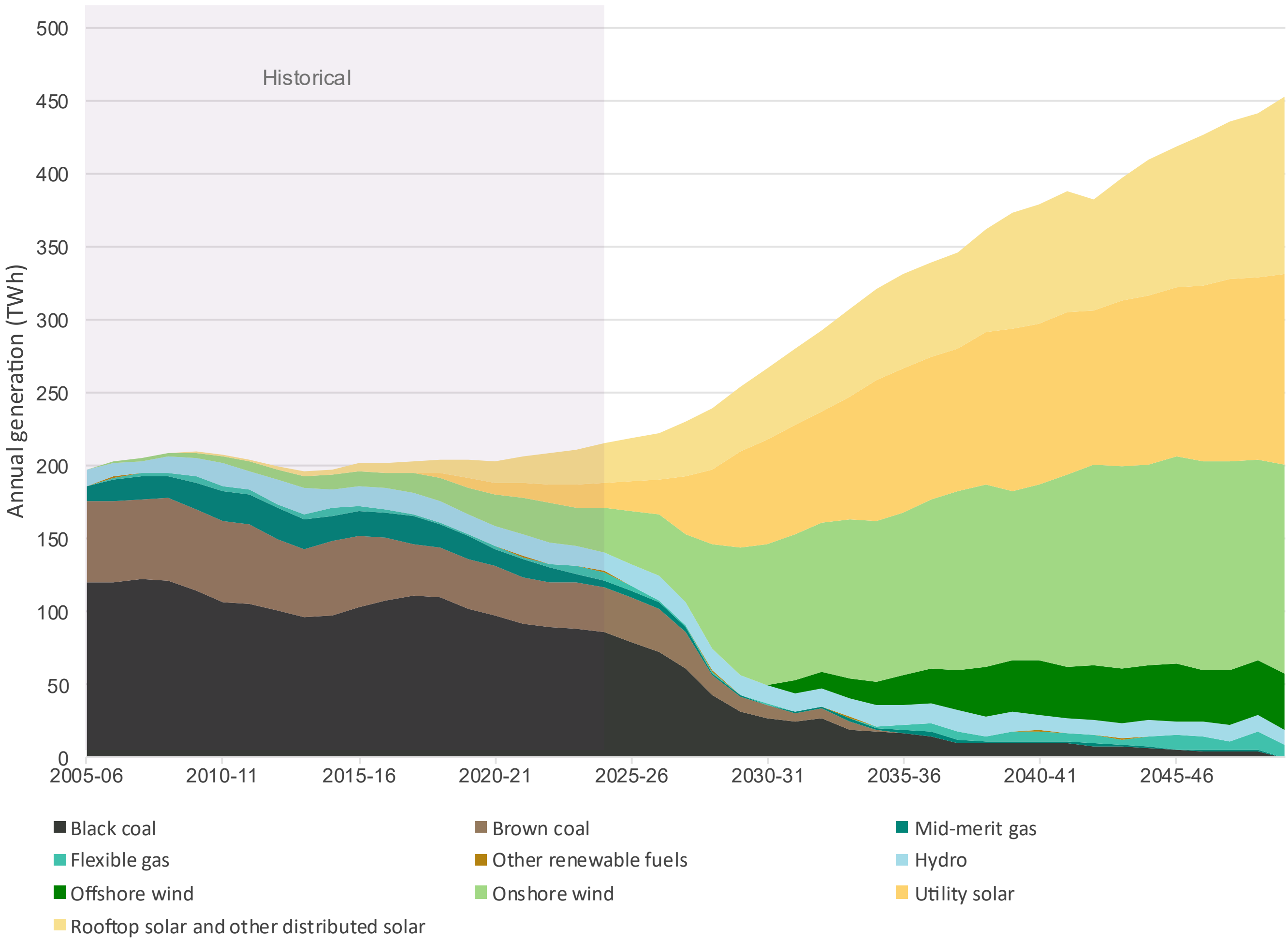
To provide critical back-up power supply during prolonged renewable energy lulls, a flexible gas fleet of between 14 GW and 20 GW in aggregate capacity is projected to be required by 2049-50 across all scenarios, replacing 9 GW of mid-merit and older peaking gas capacity that is forecast or announced to retire between now and 2050 as the plants reach end-of-life. Flexible gas plants will provide supply for peak demand events, enable continued reliability during renewable energy lulls and support ongoing grid security as coal plants withdraw.

Similarly, utility-scale storages of between 30 GW/518 GWh and 41 GW/591 GWh are projected by 2049-50 to contribute to managing the power system at times of supply scarcity or during times of oversupply of generation such as during daytime.

Figure 2 shows NEM generation is projected to grow from 223 terawatt hours (TWh) in 2026-27 to 453 TWh by 2049-50 to meet growing energy consumption needs. In 2026-27, coal generators produce around half of the annual generation; however, all coal capacity is forecast to retire by 2049-50. By 2050, electricity is predominantly produced by solar and wind facilities at utility-scale, as well as from rooftop PV and other small scale solar.

Energy storage developments of various depths and flexible gas, alongside existing hydro systems, ensure system reliability, and these developments operate alongside CER to meet electricity consumption across the year, and each year's peak demand periods. Consumer batteries (either coordinated via VPPs or not) play an increasingly key role with approximately 31 TWh stored from periods of energy excess and shifted to periods of energy scarcity in 2049-50. In combination with utility-scale storages of various depths, 91 TWh of generation (of which 31 TWh is from consumer batteries) is shifted in 2049-50 for *Step Change*, but this storage is inherently inefficient, with round-trip losses meaning that 110 TWh of charging is required to provide this shaping and firming role. Despite this round-trip inefficiency, the loss of a small proportion of stored electricity during periods of energy surplus is vastly outweighed by the benefits of shifting surplus generation into periods of energy scarcity.

Figure 2 Historical and projected generation in *Step Change*, 2009-10 to 2049-50 (TWh)

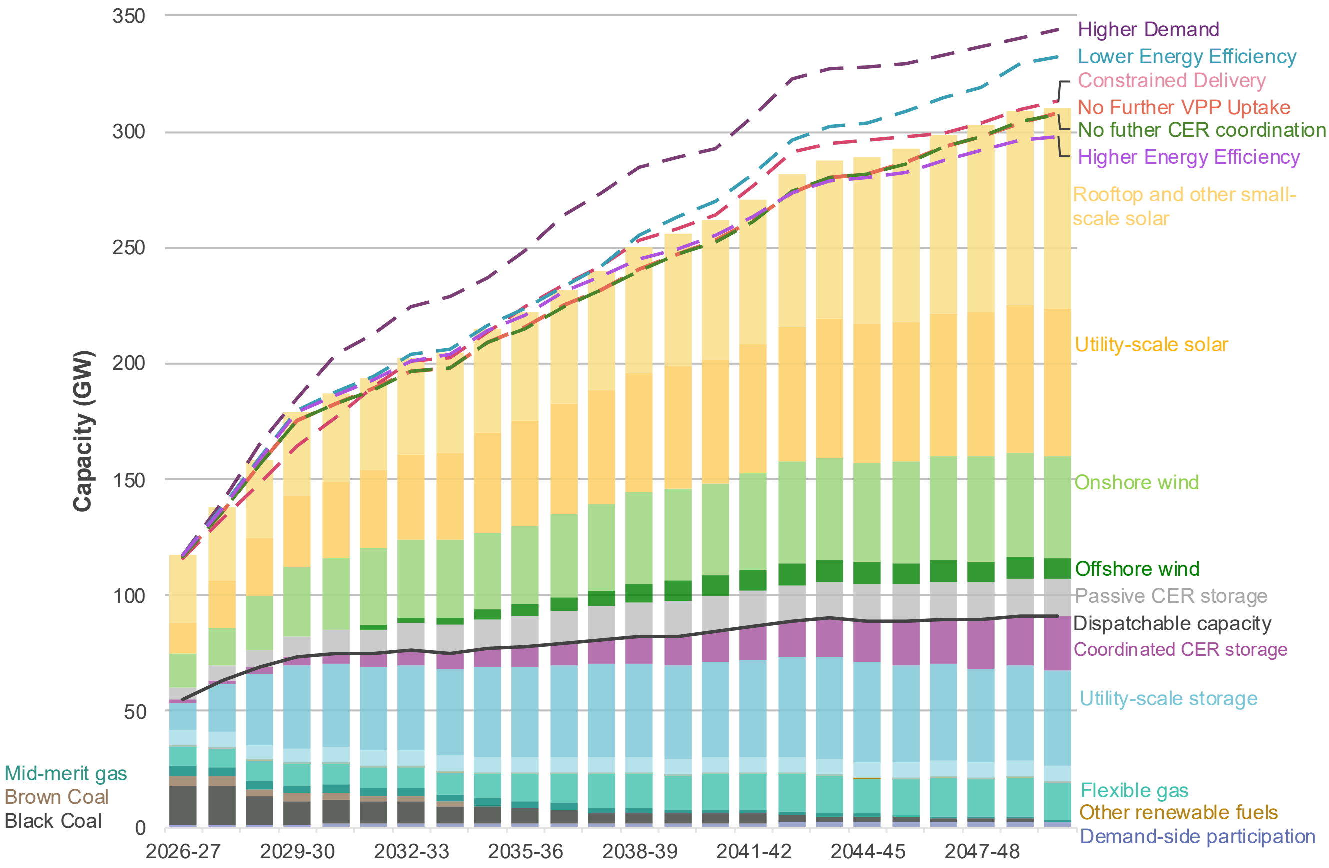


Sensitivity analysis demonstrates that generation and storage development needs will vary based on supply chain and other constraints, and the scale of electricity consumption

Using a scenario planning approach and assessment of individual uncertainties through sensitivity analysis and operability analysis, AEMO's modelling demonstrates that the ODP provides appropriate resilience, robustness, and adaptability to future uncertainties. The sensitivities modelled in the 2026 ISP explored a range of risks and uncertainties, including alternative assumptions on delivery constraints, demand from industrial and data centre developments, and other demand side factors (such as home battery coordination and energy efficiency savings).

Figure 3 shows that the trajectories of the total installed generation and storage capacities are relatively similar for *Step Change* and each of the sensitivities. While *Constrained Delivery* has slower developments due to delivery limitations and *Higher Demand* develops more capacity to supply higher demand from industrial growth and data centres, the remaining sensitivities provide similar aggregate development trajectories.

Figure 3 Generation and storage capacities in *Step Change* and sensitivities to *Step Change* (GW) to 2049-50



AEMO's 2026 ISP includes appendices to provide more information on generation, storage, and electricity network opportunities and benefits. In particular:

- Appendix A3 provides information on renewable energy zones (REZs),
- Appendix A4 provides information on the operability of the power system, considering the NEM's developments,
- Appendix A6 contains detail on the ISP's cost-benefit analysis (CBA),
- Appendix A9 includes insight on demand side factors, and
- Appendix A10 contains analysis on gas development projections.

The 2026 ISP's Generation and Storage Outlook Workbooks[5] provide details of the capacity developments, energy generated, and retirement outlook for all relevant NEM regions, by scenario. The workbooks also present emissions outcomes and comparisons of outcomes between different candidate development paths (CDPs) for each scenario.

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

Key changes since the Draft 2026 ISP

AEMO has incorporated several changes to key inputs and assumptions since publication of the Draft 2026 ISP in response to stakeholder feedback and recent market developments. Key changes include:

- including 15.8 GW/60.3 GWh utility-scale storage, 4.8 GW utility-scale solar, and 1 GW wind capacity by 2029-30, that now meet the criteria to be classified as additional existing, committed anticipated[6], and policy-supported projects as per the January 2026 Generation Information update,
- better representing the known pipeline of incoming generation and storage projects ahead of generic project builds to 2029-30 to better represent the known pipeline of incoming projects,
- updating consumer batteries forecasts to capture the Federal Government's Cheaper Home Batteries Program (CHBP)[7], increasing the forecast capacity of CER batteries,
- updating gas prices based on ACIL Allen's forecast[8] and revised capital costs of generation and storage technologies, as forecast in CSIRO's 2025-26 GenCost[9] publication,
- updating the representation of the CIS policy to reflect recent tender announcements,
- updating the formulation of South Australia's 100% net renewable electricity target to correctly represent the policy,
- improving network representations of some REZ and flow paths[10], in conjunction with addition of new network options and updated status of New England REZ Network Infrastructure Project as anticipated,
- reflecting technology-specific access right capacity limits for new wind and solar technologies as well as operating limits for oversized access right holders, and
- including site generation limits for hybrid stations to ensure co-located generation and storage assets do not exceed the registered site capacity.

[6] Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated. Projects with known timing, satisfying all five of the commitment criteria are assigned a commitment status classification of committed. More information is at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[7] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

[8] At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf?rev=91c2467e5f3c4aa1b9a2b2c6c75a976a&sc_lang=en.

[9] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

[10] 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.

A2.1 Introduction

This appendix of the 2026 ISP provides detailed insights on the ISP development opportunities for electricity generation, storages, and electrolysers to help meet both consumer needs and government policies, at least cost, for at least the next 20 years in each ISP scenario. In particular:

- **A2.2** summarises the generation, storage, and electrolyser developments that would be needed across the three ISP scenarios,
- **A2.3** provides more detailed examination of these developments for each scenario, and
- **A2.4** details the impact to those development opportunities of the various sensitivity analyses to key assumptions.

This appendix presents a NEM-wide view and regional breakdowns, where appropriate, of these developments. The 2026 ISP examines several CDPs in determining the ODP. The outcomes presented in this appendix are based on the ODP in the 2026 ISP. See Appendix A6 for details on the justification for the ODP selection.

The glossary at the end of this appendix provides a number of definitions. Terms defined in the NER, Australian Energy Regulator (AER) guidelines or the *ISP Methodology* have the meanings given in those documents. Some key terms used in this, and other relevant appendices are summarised below for reference:

- **Actionable ISP projects** are transmission projects (or non-network options) identified as part of the ODP and have a delivery date within an actionable window. More information on this is in Appendix A6.
- **Future ISP projects** are transmission projects (or non-network options) that address an identified need in the ISP, are part of the ODP, and are projected to be actionable in the future. More information on this is in Appendix A6.
- An **ISP development opportunity** is a development identified in the ISP that does not relate to a transmission project (or non-network option) may include generation, storage, demand-side participation, or other developments such as distribution network projects.
- **Distribution investment opportunities** are efficient investments in distribution network that specifically enable greater export of CER from consumers' homes and businesses into the distribution network, unlocking latent CER capacity to benefit all consumers. More information on this is in Appendix A9.
- **Gas development projections** identify combinations of investments that may be developed by the gas industry to address the investment opportunities highlighted in the 2025 *Gas Statement of Opportunities* (GSOO) and support the availability and operation of flexible gas in the NEM**.** More information on this is in Appendix A10.

In this appendix, all dates are on a financial year basis. For example, 2024-25 represents the financial year starting 1 July 2024 and ending 30 June 2025.

A2.1.1 Interpreting the graphics in this appendix

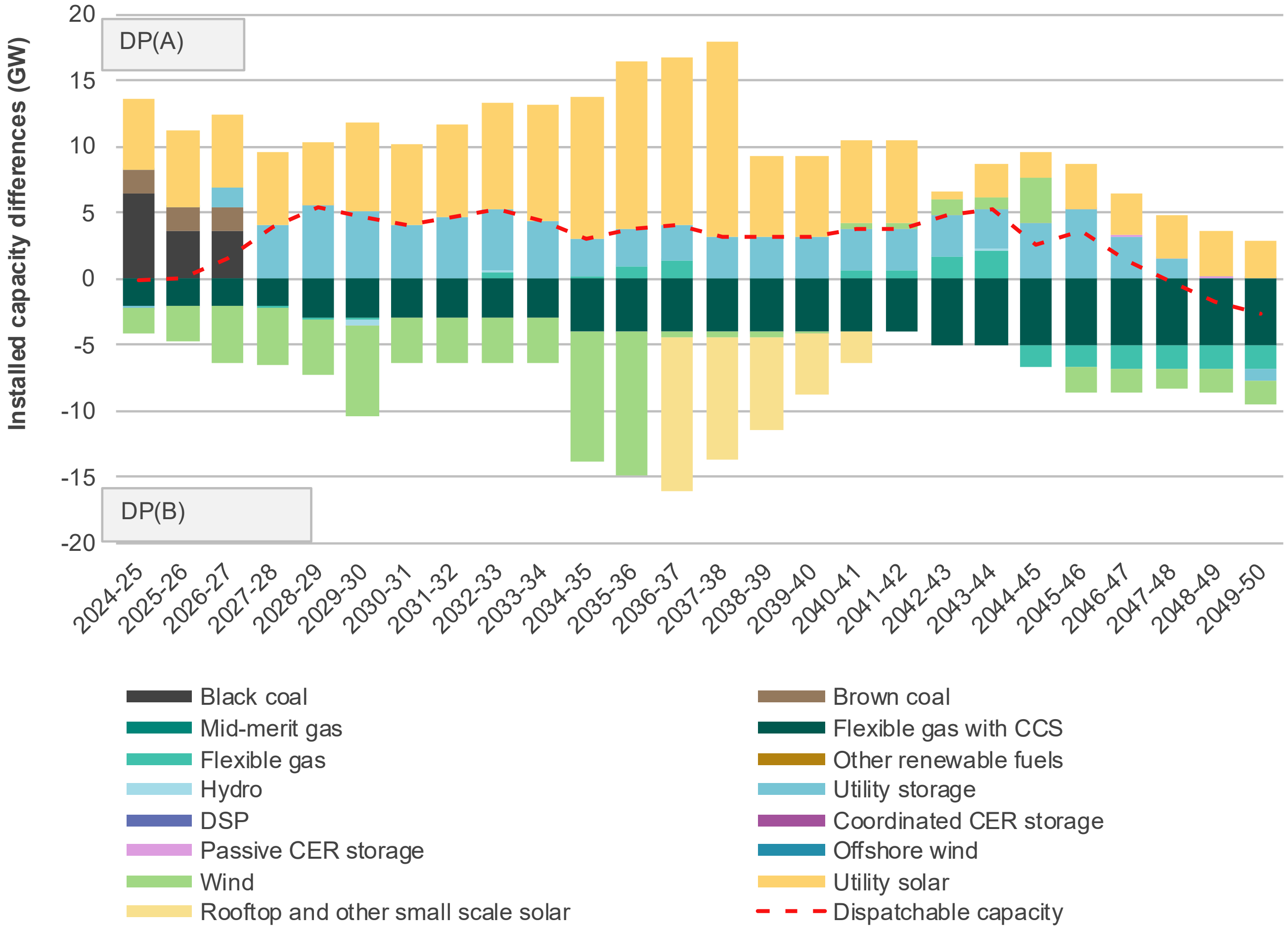
This appendix presents a number of charts comparing the projected capacity and generation over the outlook period of two different CDPs, or of a sensitivity and a CDP, as shown in the example figure below.

When interpreting the sample chart in **Figure 4**:

- The stacked columns show the projected values for different technologies on an annual basis.

- A positive value indicates the higher total capacity in the first development path, DP(A), relative to DP(B) – which, in some cases, is the 'no transmission' counterfactual development path or the impact of a sensitivity. A negative value indicates higher capacity in DP(B). For example, the yellow bar indicates there is higher capacity of utility-scale solar in DP(A) relative to DP(B).
- The line represents the projected difference in total dispatchable capacity between the two development paths. Dispatchable capacity refers to generation and storage capacity that can adhere to dispatch instruction including coordinated CER storages, being controllable and flexible, and can provide greater certainty on its availability in any given dispatch interval.

Figure 4 Example interpretation of projected capacity differences used in this appendix



For generation mix charts that include the role of storages, negative values for storages in the graph represent the storage charging and pumping load (for pumped hydro energy storage) while positive generation from the storages represent storage discharging and pumped hydro generation into the grid. Storages are net energy consumers due to energy losses over a full charge-discharge cycle.

A2.1.2 Key changes since the Draft 2026 ISP and summary impacts

The 2026 ISP reflects a number of changes in assumptions since the Draft 2026 ISP to capture updated information (as pre-empted in the IASR) and stakeholder feedback.

This section describes the key changes in inputs and assumptions that have been made in this ISP and the impact these changes have had on generation and storage development opportunities. This section mirrors Section A6.3 in Appendix A6 Cost Benefit Analysis.

Key changes to inputs and assumptions

Key changes to the inputs and assumptions are included in *the 2026 ISP Inputs and Assumptions Workbook* and summarised as shown in **Table 1**[11].

Table 1 Key changes since the Draft 2026 ISP and their impacts in isolation

Key changes since the Draft 2026 ISP	Impact of each change in isolation
Included 15.8 GW/60.3 GWh of utility-scale storage, 4.8 GW of utility-scale solar, and 1 GW of wind capacity by 2029-30 that now meet the criteria to be classified as additional existing, committed, anticipated[A], and policy-supported projects as per the January 2026 Generation Information update and recent tender results.	Increased the utility-scale storage capacity early in the outlook period.
Reflected known generation and storage developers' interests by including the connections pipeline until 2030 to increase the ISP's projected capacities' alignment with actual connection interests.	Some utility-scale solar replaced by wind and utility-scale storage in the near-term.
Improved the assumptions around the flexibility of coal by applying recent minimum continuous operating levels for coal plants which reflect more flexible operation of Victorian and New South Wales coal plants relative to historical flexibility, and relative to Queensland coal plants.	Contributed to the ability to defer transmission network augmentations.
Updated consumer battery forecasts to capture the Federal Government's CHBP[B], increasing the forecast capacity of CER batteries by 13 GW in 2040 in *Step Change*. The increased battery forecast resulted in an increase in forecast VPP capacity, as VPP participation rates remained the same as the 2026 Draft ISP.	Reduction in flexible gas and wind capacity in the back of the outlook period, replaced by an increase in utility-scale solar.
Revised the capital costs for new generation and storage technologies as per CSIRO's 2025-26 GenCost: Consultation draft publication[C], resulting in higher capital costs for open-cycle gas turbine (OCGT) and offshore wind and lower capital costs for utility-scale solar and pumped hydro.	Increased utility-scale solar capacity in place of wind.
Updated the Capacity Investment Scheme (CIS) trajectory based on the announcement of tenders 3 and 4[D] and updated the projects included in the New South Wales Electricity Infrastructure Investment (EII) generation and storage targets to align with the latest Generation Information dataset.	The change to the CIS trajectory resulted in a delay to further utility-scale storage development and including previous projects in the New South Wales EII target resulted in a reduction in solar capacity required in New South Wales.
Updated the constraint formulation of South Australia's 100% net renewable electricity target to correctly represent the policy.	Slight reduction in thermal generation in South Australia.
Updated the status of New England REZ Network Infrastructure Project to Anticipated from Actionable in the Draft 2026 ISP.	Impact not separately identifiable.
Unlinked the access to Borumba Pumped Hydro to the development of Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South).	Contributed to the ability to defer Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South).
Modelled Hunter-Central Coast REZ as two REZs to improve the network representation. This captured the REZ being located across Sydney, Newcastle and Wollongong (SNW) and Central New South Wales (CNSW) sub-regions. In addition, a new group constraint (HCC1) was introduced to limit new generation in this REZ without additional network augmentations.	Impact on results not separately identifiable, but improved network representation.

[11] AEMO has published all inputs and assumptions in the 2026 ISP Inputs and Assumptions Workbook, including a log of changes.

Key changes since the Draft 2026 ISP	Impact of each change in isolation
Improved the generic New South Wales access right constraints with technology-specific limits for wind and solar technologies to ensure their installed capacity mix reflects the awarded access rights.	Shifted utility-scale solar and wind capacity to REZs outside of the access scheme.
Included operating limits on oversized assets with access rights in Central-West Orana and South-West REZs in New South Wales to ensure their dispatches are capped at their awarded access-right capacities once they reach anticipated status.	Impact was minor.
Reflected the limit of five substation locations within Metropolitan Adelaide where utility-scale storages can be connected by constraining the amount of battery capacities that could be developed in the Central South Australia (CSA) sub-region.	Impact not separately identifiable, but improved network capacity representation.
Introduced total generation limits for hybrid generators to ensure co-located generation and storage assets do not exceed their registered site capacities as per the January 2026 update of AEMO's Generation Information dataset.	In isolation, this resulted in a slight decrease in utility-solar capacity that was previously overstated, and an increase in wind capacity.
Updated minimum capacity factors for gas generation based on the gas generation outcomes in 2026 GSOO[E] and updated daily gas limits based on updated gas consumption forecasts.	Impact not separately identifiable, but improved accuracy.
Updated gas fuel prices based on ACIL Allen's forecast[F].	In isolation this resulted in a small increase in generation from gas and reduction in wind capacity in the 2030s.
Modelled Brisbane Area 275 kilovolts (kV) Reinforcement as an explicit augmentation option to the flow path between Central Queensland and Southern Queensland rather than assuming to be going ahead as per the Draft 2026 ISP, therefore reducing the transfer capacity of Central Queensland to Southern Queensland flow path specified as 1,100 megawatts (MW) in the Draft 2026 ISP.	Impact not separately identifiable, but improved representation of network capacity.
Implemented a monthly hydrogen demand targets for electrolysers instead of weekly to improve flexibility of usage in response to stakeholder feedback that the utilisation factor was high.	Reduced electrolyser utilisation by approximately 10% on average.
Corrected V2G charging and discharging efficiencies from 83.7% to 92.2% and lowered maximum state of charge to 85% to align with the values stated in the 2025 IASR.	Slight reduction of utility-scale solar capacity.
Corrected battery auxiliary loads to align with the values stated in the 2025 IASR.	Slight reduction in utility-scale storage generation as a percentage is required for use in-house.

A. Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated. Projects with known timing, satisfying all five of the commitment criteria are assigned a commitment status classification of committed. More information can be found in the Generation Information publication at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
B. See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.
C. At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.
D. See https://asl.org.au/tenders/cis-tender-3-nem-dispatchable.
E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf?rev=58e84053c8d240a487cf274c91ebd284&sc_lang=en.
F. See Wholesale natural gas prices for AEMO at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf?rev=91c2467e5f3c4aa1b9a2b2c6c75a976a&sc_lang=en.

Overall, compared to the Draft 2026 ISP, key changes in generation and storage outcomes in this final 2026 ISP are as follows:

- Some coal-fired generation is projected to remain operational for longer, such as Eraring Power Station to align with its announced extension in January 2026 (after the publication of the Draft 2026 ISP). Further, the retirement of coal generators has been re-optimised to reflect updated assumptions, leading to changes in coal power plants' retirement schedules. In this projection, these plants would operate more flexibly, with periods where coal plant units are not operating for up to months at a time. The 2026 ISP estimates coal-fired generation producing approximately 5 TWh by 2048-49 (nearly 2 TWh more than in the Draft 2016 ISP), reflecting reduced coal flexibility assumptions for Queensland coal generation with the remaining fleet operating at a capacity factor of 32% in that year.
- Shallow and medium-depth utility-scale storage in the NEM is projected to increase, due largely to additional committed and anticipated storage projects and announced tenders. This reduces the additional new storage capacity requirements

beyond the existing, committed, and anticipated projects compared to the Draft 2026 ISP. By 2049-50, utility-scale storage is projected to enable the shifting of approximately 74 TWh of surplus generation to enable discharge of 60 TWh when it is most needed – an increase from the 69 TWh of generation shifted to enable 56 TWh of discharge in the Draft 2026 ISP, due to greater projected capacity of medium-depth storage. The energy discharged, which generally comes from stored renewable energy, is lower than the energy consumed due to the losses incurred from their cycling inefficiency.

- Higher utility-scale solar generation is projected due to the assumed reduction in capital costs from CSIRO's draft 2025-26 GenCost publication[12], with greater reduction for solar generators relative to wind generators and with increased investment in shallow and medium-depth storage that is now committed, anticipated, or supported by policy. These changes have led to greater relative development of solar as the lowest cost source of bulk energy production. These factors lead to 131 TWh of projected utility-scale solar generation in the 2026 ISP by 2049-50, compared to a projected 125 TWh in the Draft 2026 ISP.
- Utility-scale wind is projected to produce more generation and represent a greater share of the energy mix than in the Draft 2026 ISP until the mid-2030s.

Reflecting project status as per January 2026 Generation Information update

The 2026 ISP reflects generator and storage projects' commitment status as per the January 2026 Generation Information update (top chart in **Figure 5** below). This update also includes changes in capacity and 'full commercial use dates' (FCUD) for generators and storages already included in the Draft 2026 ISP.

The bottom chart in **Figure 5** shows the overall change in capacities for existing, committed, anticipated, and policy-supported projects reflected in the January 2026 Generation Information update compared with the Draft 2026 ISP.

Overall, the update has resulted in an increase in utility-scale storage of about 15.8 GW by 2029-30 as well as utility-scale solar increasing by 4.9 GW and wind increasing by 1 GW compared to the Draft 2026 ISP.

[12] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

Figure 5 Changes in generation and storage projects' status in 2029-30, Draft 2026 ISP versus 2026 ISP

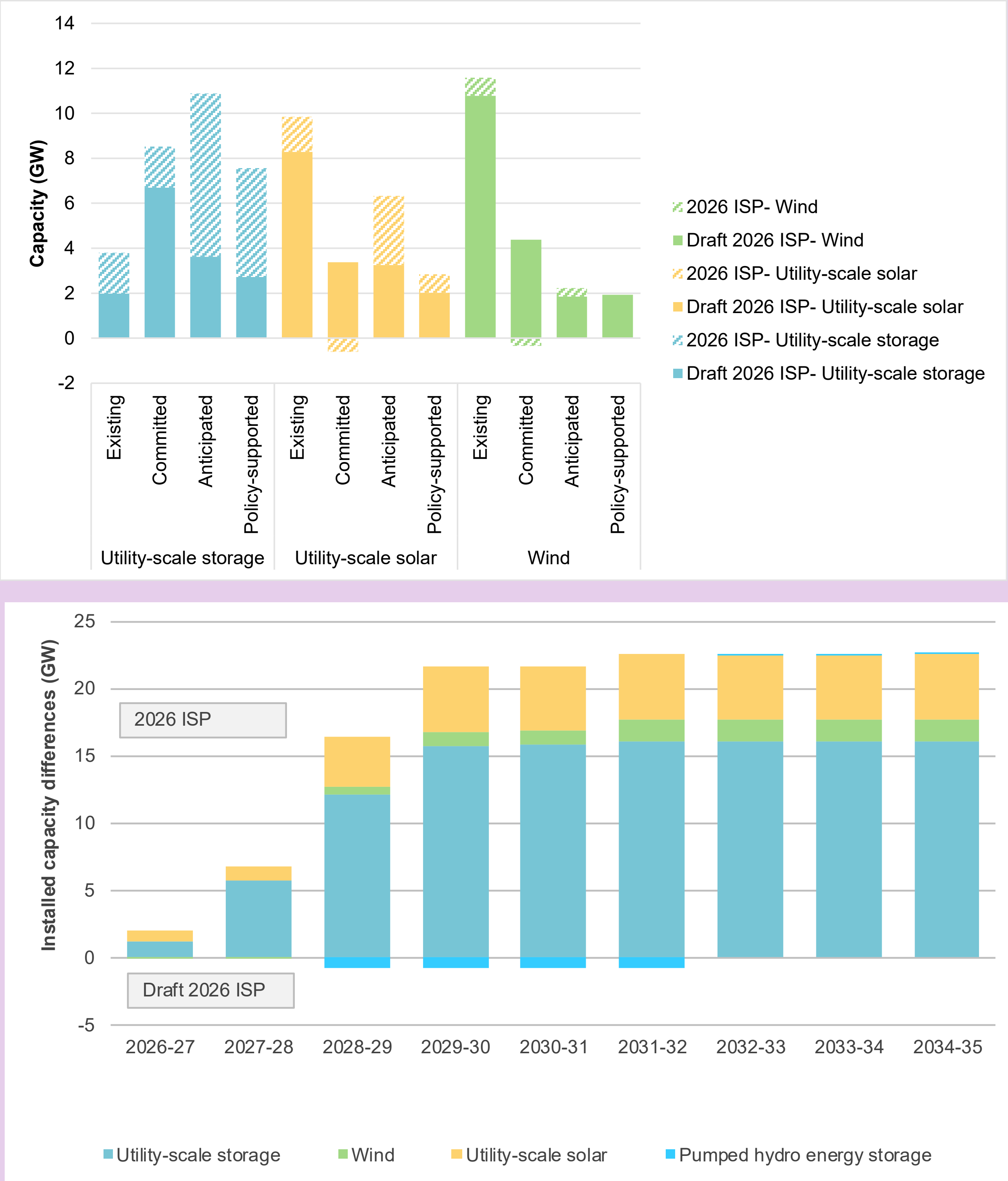
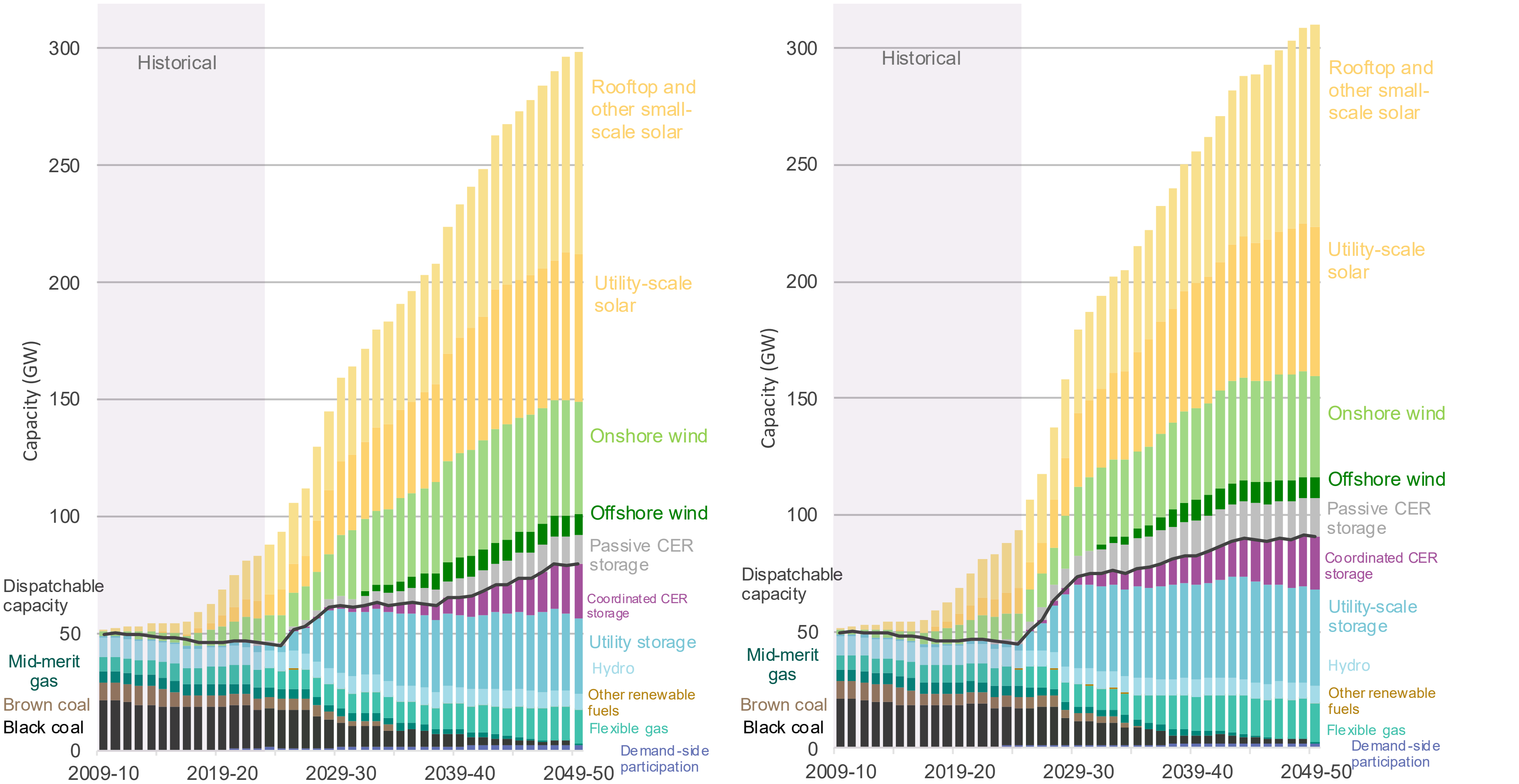


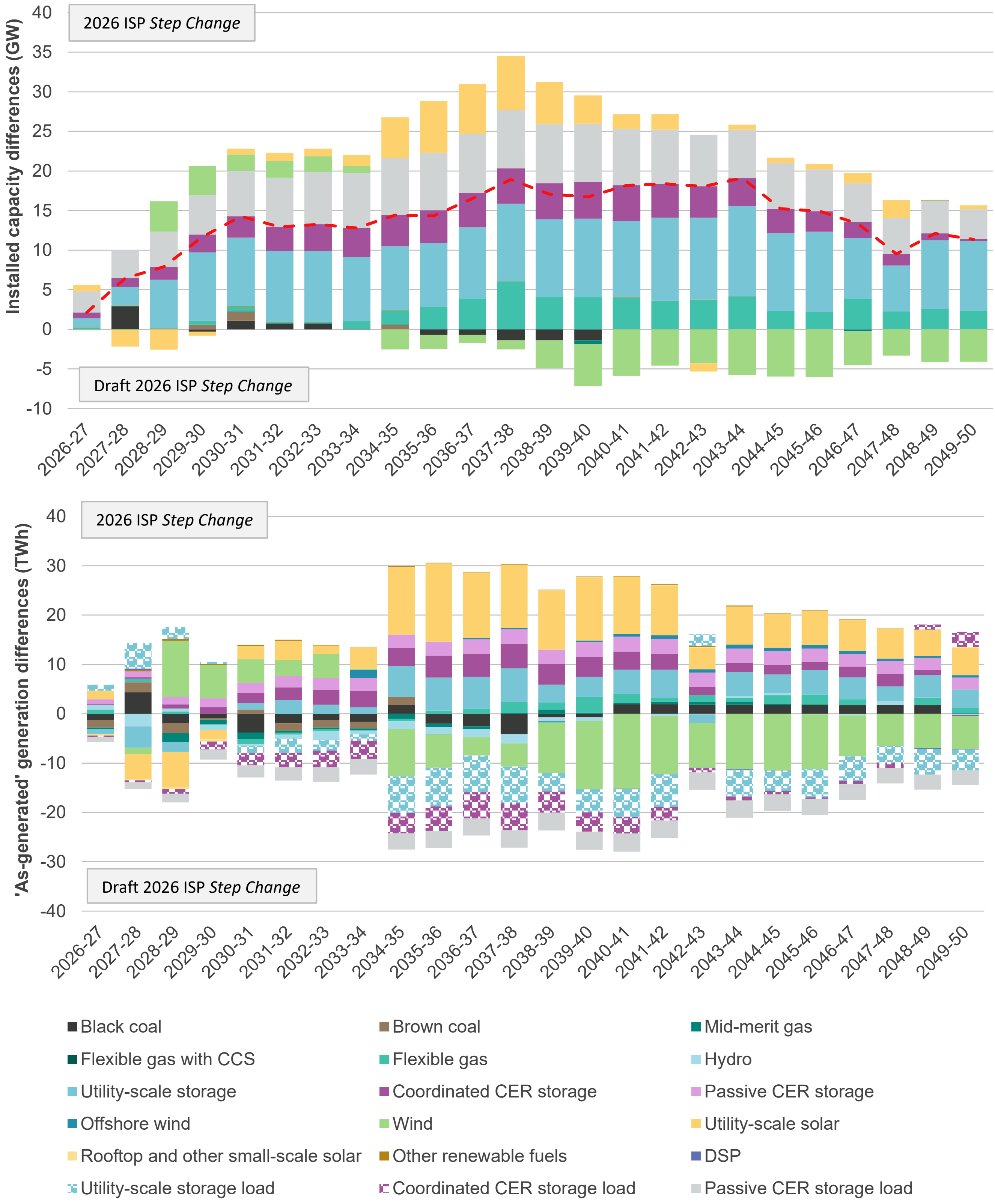
Figure 6 and **Figure 7** compare the generation and storage development opportunities in the ODP in *Step Change* in the Draft 2026 ISP to that in the 2026 ISP.

Figure 6 Generation and storage development opportunities in the ODP in *Step Change* in the Draft 2026 ISP (left) versus the 2026 ISP (right) (GW)



Notes: Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 IASR.
Rooftop and other small-scale solar includes forecast residential and commercial rooftop photovoltaic (PV) systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems.
"Utility-scale solar" also includes solar thermal and mid-scale generation. "CER storage" means consumer energy resources such as batteries and EVs.
"Flexible gas" includes gas-powered generation and potential hydrogen capacity.

Figure 7 Generation and storage development opportunities in the ODP in *Step Change* in the 2026 ISP (top) versus the Draft 2026 ISP (bottom)



A2.2 Summary of generation and storage development opportunities in the ODP across the scenarios

A2.2.1 A changing capacity and generation mix

The 2026 ISP considers a range of policies, alongside technical and market drivers, to identify the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire. A range of policies exist across all governments that influence the generation and storage development opportunities for the NEM's transition. As a result, significant capacity of new VRE generation is projected, across all scenarios.

Table 2 presents the capacity mix (development opportunities) for each of the three scenarios where the transmission investments under each scenario follow the transmission development identified in the ODP. See Appendix A5 Network Investments for transmission developments needed to connect generation and storage capacity across the NEM, and Appendix A6 Cost Benefit Analysis for more details on the cost-benefit analysis of the transmission developments that are included in the ODP.

Table 2 below shows that utility-scale VRE (including solar and wind technologies) increases from 23 GW in 2025-26 to 117 GW in *Step Change* by 2049-50, and to 84 GW and 211 GW, respectively, in *Slower Growth* and *Accelerated Transition*. This reflects 38%, 41%, and 47% of the total installed capacity for 2049-50 for *Step Change*, *Slower Growth*, and *Accelerated Transition*, refspectively. Rooftop and other small-scale solar are projected to have the greatest capacity of any technology, demonstrating the significant role that consumers are expected to continue to play in the transition. Including rooftop and other small-scale solar, the total VRE reflects 66%, 67% and 70% of the total installed capacity for 2049-50 for *Step Change*, *Slower Growth*, and *Accelerated Transition*, respectively.

Table 2 Installed capacity in 2025-26, 2029-30, 2039-40, and 2049-50 (GW)

Technology	Actual at January 2026	Slower Growth			Step Change			Accelerated Transition			Constrained Delivery		
	2025-26[A]	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50	2029-30	2039-40	2049-50
Black coal	16.5	8.5	5.3	0.0	10.2	3.9	0.0	5.2	0.0	0.0	11.2	2.4	0.0
Brown coal	4.8	3.4	0.0	0.0	3.4	0.0	0.0	3.4	0.0	0.0	3.4	0.0	0.0
Mid-merit gas	4.2	3.3	1.7	0.4	3.3	1.7	0.4	3.3	1.7	0.4	3.3	1.7	0.4
Flexible gas with carbon capture and storage (CCS)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible gas	7.5	8.7	10.9	14.0	9.1	14.5	16.7	8.7	18.8	19.6	9.8	16.3	18.2
Hydro	6.9	6.9	7.3	7.3	6.9	7.3	7.3	6.9	7.3	7.3	6.9	7.3	7.3
Shallow utility-scale storage	4.0	18.1	17.8	8.1	18.0	17.8	8.1	17.9	17.6	8.1	16.9	16.6	1.5
Medium utility-scale storage	0.6	15.3	16.6	16.4	15.3	17.6	27.7	16.8	22.0	22.6	15.2	18.4	29.3
Deep utility-scale storage	0.2	2.4	5.3	5.3	2.4	5.3	5.3	2.4	5.3	5.3	2.4	5.3	6.6
Coordinated CER storage	0.8	1.0	2.4	5.3	3.8	12.4	23.0	5.8	24.2	46.7	3.8	12.4	23.0
Passive CER storage	3.7	5.3	7.1	8.8	8.6	15.0	16.2	10.2	20.7	21.9	8.6	15.0	16.2
Offshore wind	0.0	0.0	9.0	9.0	0.0	9.0	9.0	0.0	9.0	10.5	0.0	6.0	9.0
Wind	11.7	28.2	29.1	36.1	29.8	39.4	43.8	34.0	56.0	76.4	20.3	42.0	42.1
Utility-scale solar	10.9	27.8	31.6	38.6	31.2	52.3	60.9	31.1	80.9	109.3	25.0	53.4	64.7
Mid-scale generation[A]	0.0	0.0	0.4	0.4	0.0	1.0	3.1	0.0	7.6	15.0	0.1	2.7	5.8
Rooftop and other small-scale solar	27.1	32.1	39.3	52.8	35.8	57.0	86.7	38.3	66.3	108.5	35.8	57.0	86.7
Other renewable fuels	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.0
Demand-side participation	1.0	0.9	1.1	1.2	1.2	1.8	2.3	1.5	3.3	5.4	1.2	1.8	2.3

Note: the generation mix includes generation and storage projects classified as committed and anticipated in the January 2026 Generation Information update. For definitions of each technology, refer to the Glossary section at the end of this appendix.
A. Mid-scale generation is considered part of Utility-scale solar unless otherwise stated.

Alongside the three scenarios in **Table 2** is a key sensitivity that AEMO has included in this 2026 ISP, which examines the impact of a slower rate of delivery for generation, storage and transmission developments in the near term – the *Constrained Delivery* sensitivity.

Constrained Delivery sensitivity

The *Constrained Delivery* sensitivity explores the impact of potential delivery constraints affecting generation, storage, and electricity network developments in *Step Change*.

There may be many reasons for development delays, such as through planning approvals and the need for social licence, the supply chain, or construction. The sensitivity only limited the rate of build, not what determined the delays. In this sensitivity, the costs of the projects were also assumed to rise, on average by 30%, due to these constraints. Again, there may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the rise in cost only.

Additionally, in this sensitivity, with the development of generation, storage and network slowed by delivery constraints, some policy outcomes would take longer to achieve. For example, the Victorian Offshore Wind Target was assumed to be delivered three years later in this sensitivity, and the NEM would generate approximately 75% from renewable energy by 2029-30, below the Powering Australia Plan's target of 82%.

This sensitivity is outlined in more detail in Section A2.4.1.

Transitioning from reliance on coal and mid-merit gas generation for bulk generation

The Federal Government has committed to an economy-wide emissions reduction target of 43% below 2005 levels by 2030, 62% to 70% below 2005 levels by 2035, and a net zero emissions economy by 2050. At the same time, electrification of households, transport, and industries – as well as the emergence of data centres and domestic hydrogen production – is driving electricity consumption, leading to a doubling of underlying consumption by 2050 as a key decarbonisation pathway for households, businesses and industry.

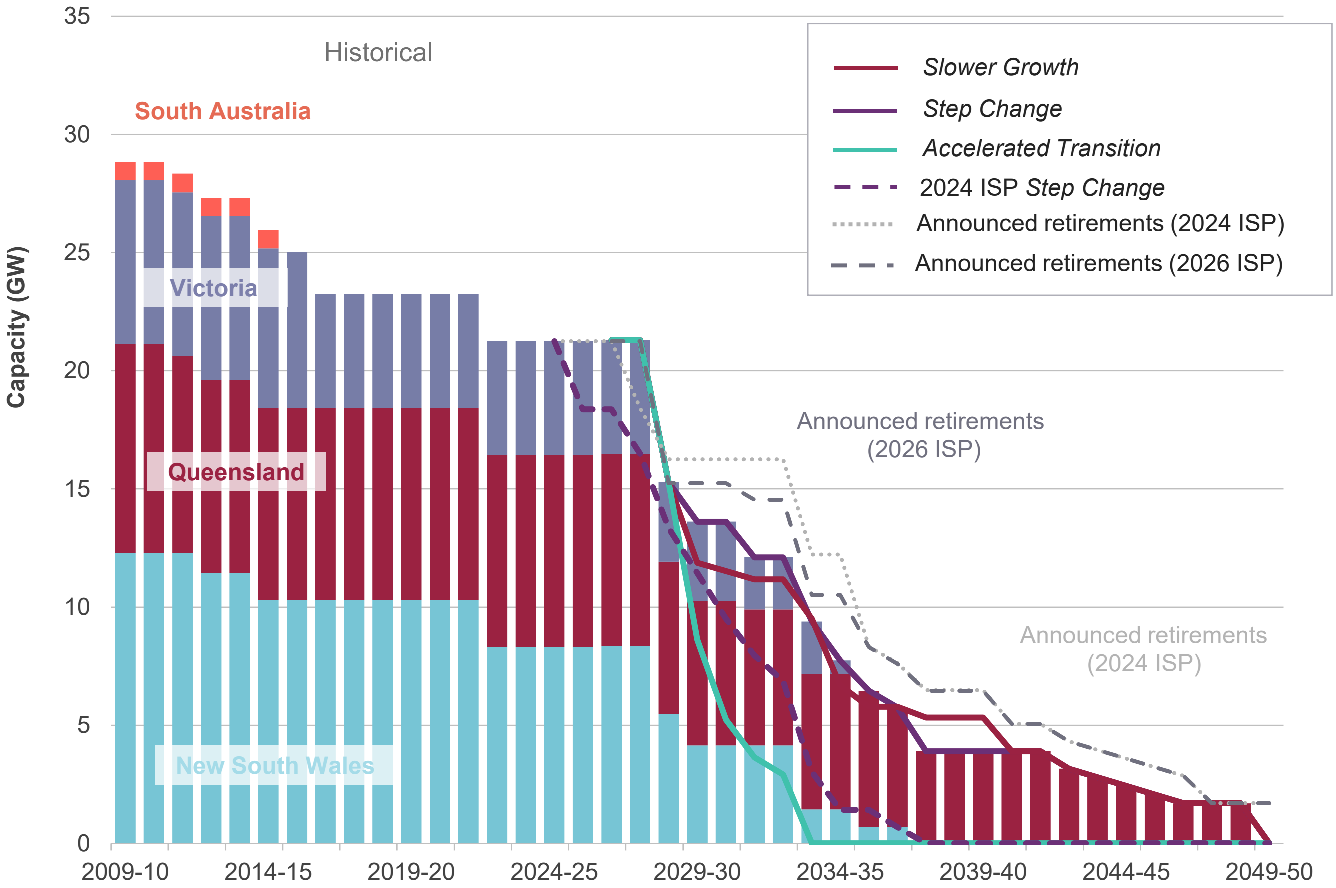
To meet government emissions and energy targets and the rising needs to supply new electricity consumption, the *Step Change* scenario projects development of 228 GW of small- and utility-scale generation capacity across the NEM in 2049-50. This includes approximately 124 GW of utility-scale renewable energy, and 87 GW of investments made by consumers in their rooftop and other small-scale solar. In addition, 80 GW of storage capacity (including committed and anticipated projects) is projected by 2049-50. These new generation and storage capacities are offsetting the retirement of approximately 25 GW of coal-fired and mid-merit gas generation.

Coal-fired capacity is projected to withdraw slower across all ISP scenarios compared to the 2024 ISP. Some coal operators are assumed to increase their capability to operate in more flexible operating modes[13] than was assumed in the 2024 ISP.

Figure 8 demonstrates the historical and projected coal closure outlook in *Step Change* against the announced retirement schedule for the NEM's coal-fired generation fleet and compares it with the projections in the other scenarios in the 2026 ISP. In *Step Change*, nearly 63% of coal-fired generation capacity is projected to be retired by 2034-35, driven by retirements in New South Wales, with some Queensland coal-fired generation capacity remaining in operation to align with the intent of the Queensland Energy Roadmap before closing in 2049-50.

[13] AEMO has aligned the assumptions on coal-fired generator flexibility based on the Minimum Continuous Operating Level, maintenance and average forced outage rates as published in the 2025 IASR which reflects recent observed changes in their operating regime.

Figure 8 Historical and projected coal capacity schedule, 2009-10 to 2049-50 (GW)



Mid-merit gas capacity is also projected to decline as plants approach their retirement dates, but some gas capacity is expected to remain in operation through to 2049-50 (if their currently indicated closure year supports this duration of service). Gas generation fleet is expected to expand with flexible gas capacity installed to backup storage developments and firm the highly renewable generation mix from 2030s onward.

Figure 9 shows the gas capacity development in *Step Change*. The solid line represents the change in total installed existing gas capacities in the NEM including both mid-merit gas and flexible gas after considering retirements. Further, the dashed line in the figure represents the total installed capacity after considering new entrant flexible gas developments and existing gas capacities. No new mid-merit gas capacity is projected in the ODP.

Generation from flexible gas[14] is also projected to increase over the outlook period, as it provides a critical backup role in firming the intermittency of renewable energy generation and providing dispatchable resources when required, complementing storage devices of various depths. This is most necessary during periods of low renewable resource availability, such as during winter which is more prone to prolonged renewable energy lulls that increase reliability risks. See Appendix A4 System Operability for NEM operability insights.

[14] Flexible gas units are open-cycle gas turbine technologies which can quickly ramp-up and -down to balance the grid and back-up renewable generation.

Figure 9 Projected gas capacity development, *Step Change*, 2026-27 to 2049-50 (GW)

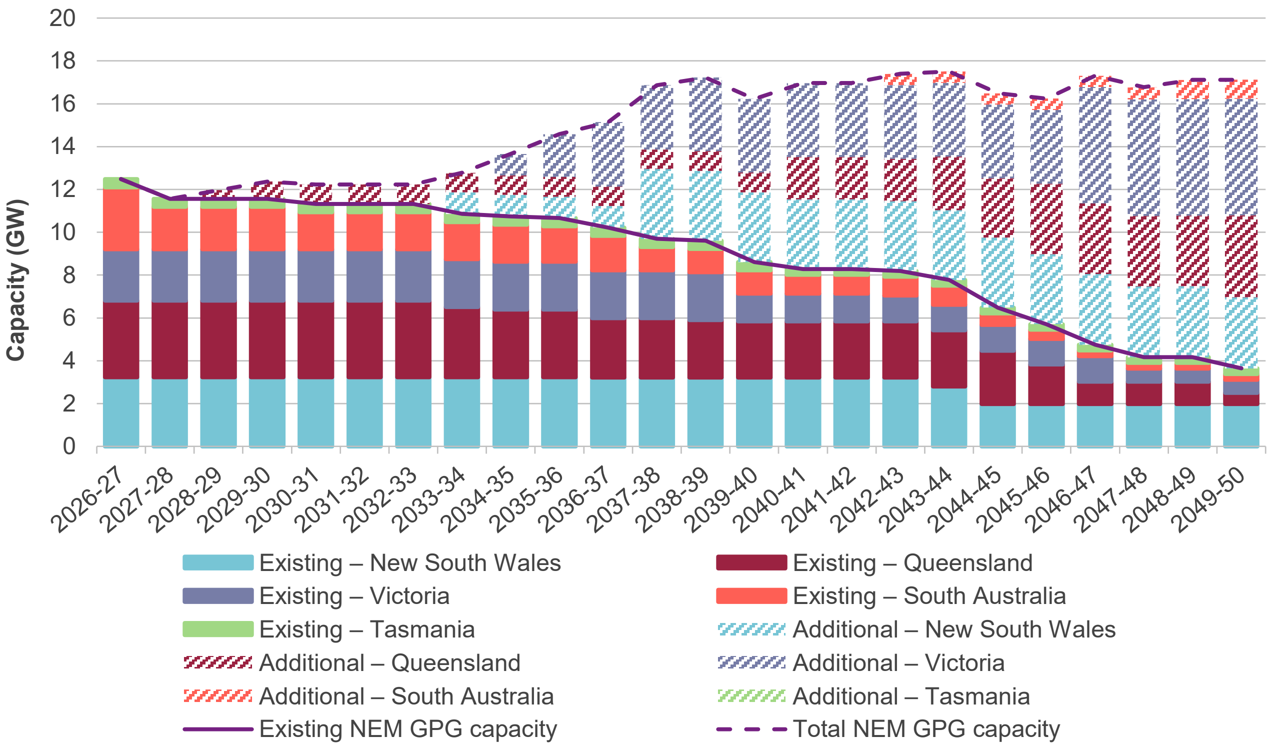
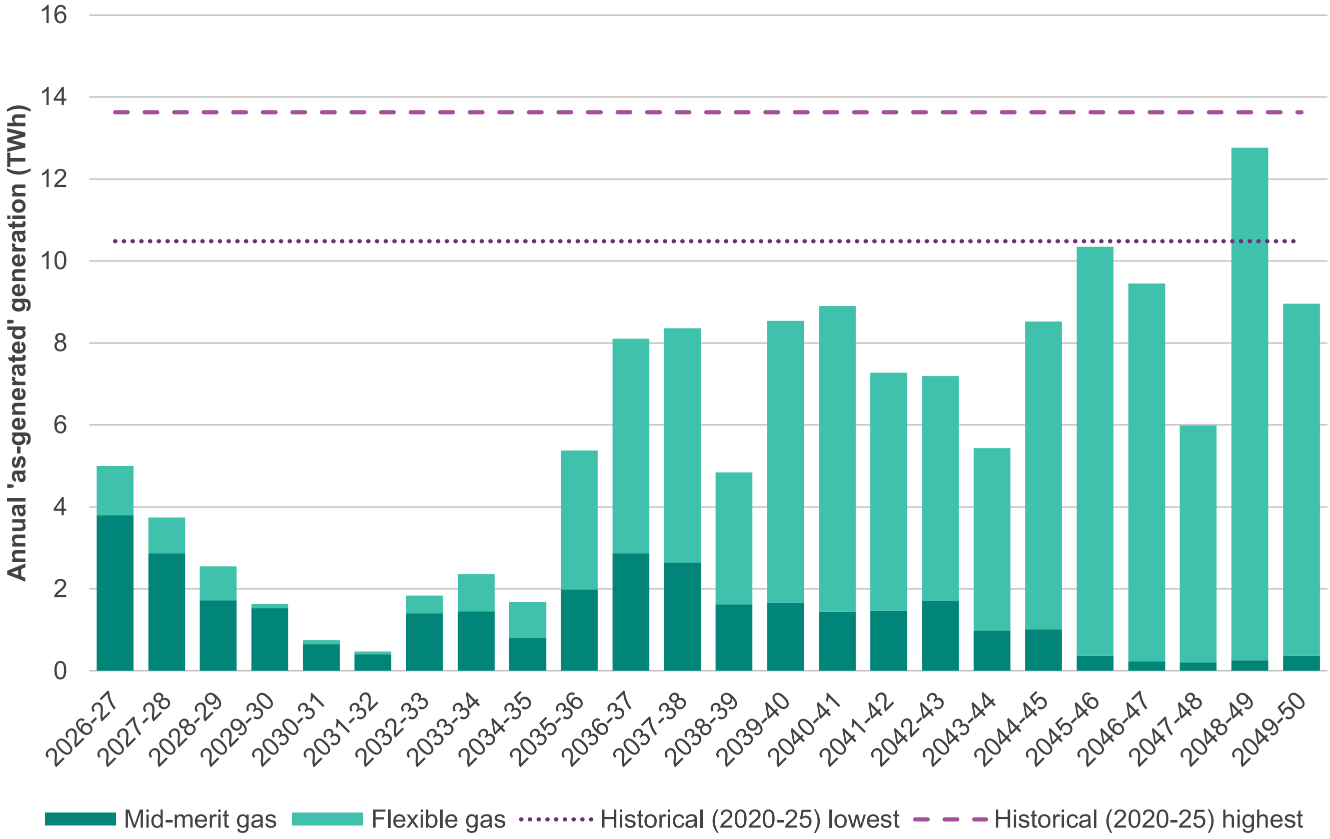


Figure 10 shows the change in gas generation mix in the NEM including both mid-merit gas and flexible gas. The volume of flexible gas-powered generation is projected to increase from close to 5 TWh in 2026-27 to up to 13 TWh in 2048-49 (with 9 TWh in 2049-50). Over the period to 2049-50 the gas fleet is projected to supply a similar share of the NEM's annual generation to today's 4%[15]. Forecasting gas generation accurately is inherently difficult, as flexible gas generation is often used in a back-up role, and therefore the availability of VRE and other generators (considering weather-based resources, or generator outages of thermal plant, or rainfall affecting hydro generators) will all influence the degree of back-up required. While these projections reflect a rising role for gas generation from today's levels, the estimates are reasonably within the historical level of gas generation of recent years, as shown.

More detailed analysis of gas-powered generation operating requirements is in Appendix A10.

[15] This varies from year to year depending on weather and operational conditions, and would average about 3.5% through to 2050, similar to today's level of 4%.

Figure 10 Projected annual gas generation, *Step Change*, 2026-27 to 2049-50 (TWh)

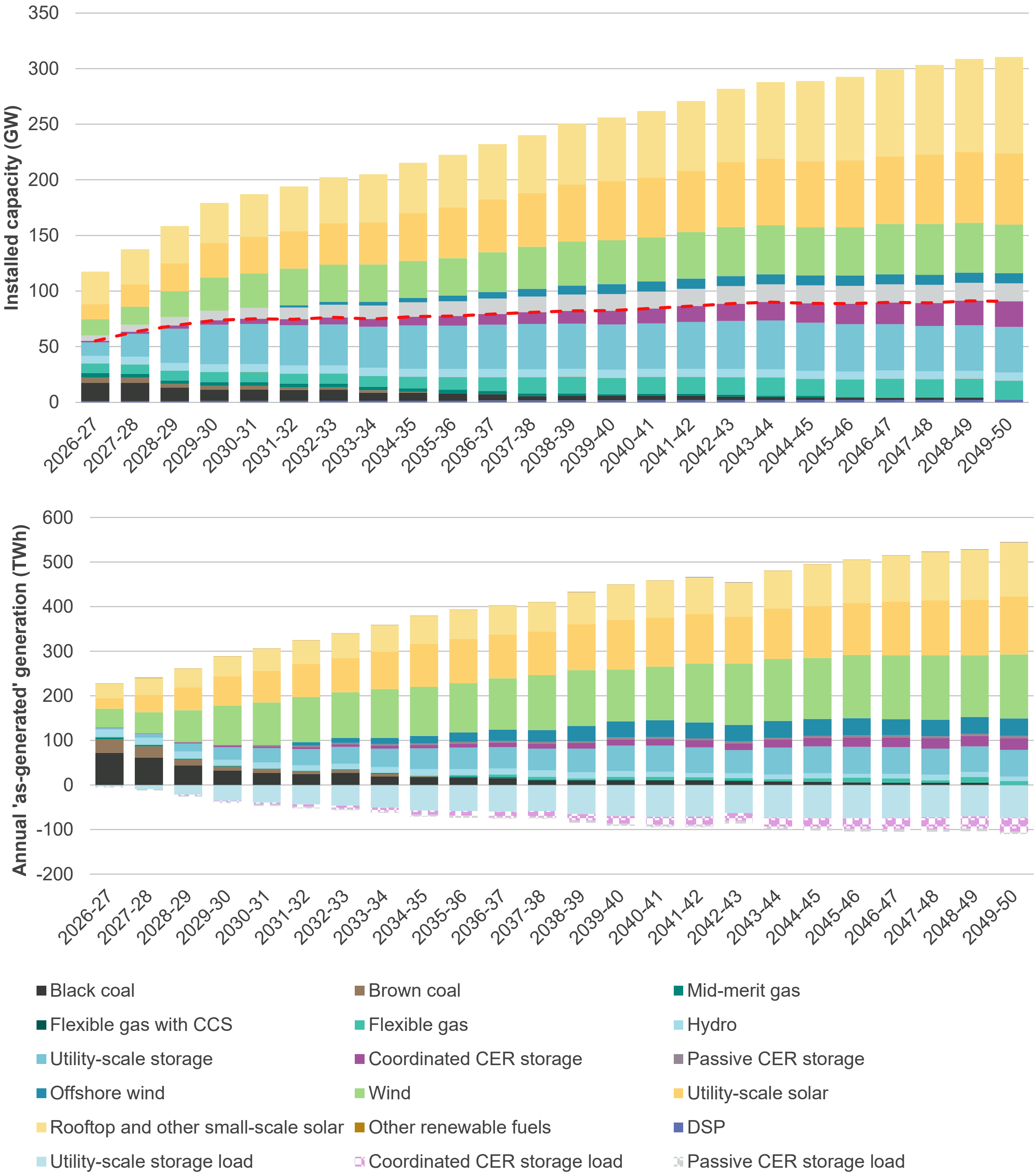


The chart at the top of **Figure 11** shows *Step Change*'s installed capacity and demonstrates that utility-scale VRE (solar and wind) are projected to have the strongest development opportunity, alongside projected rooftop and other small-scale solar[16].

The bottom chart of **Figure 11** also shows that the energy generated from renewable generators is projected to increase, and by 2029-30, projected total generation from all solar generation (utility-scale solar, rooftop and other small-scale solar) is 110 TWh (43%) of the NEM's total generation of 255 TWh, traditional hydro is projected to make up 13 TWh (5%), and wind generation makes up 88 TWh (35%). All the generation from solar, wind, and traditional hydro in *Step Change* achieves the national target of 82% renewable share of generation by 2029-30.

[16] Also referred to as distributed photovoltaics (PV).

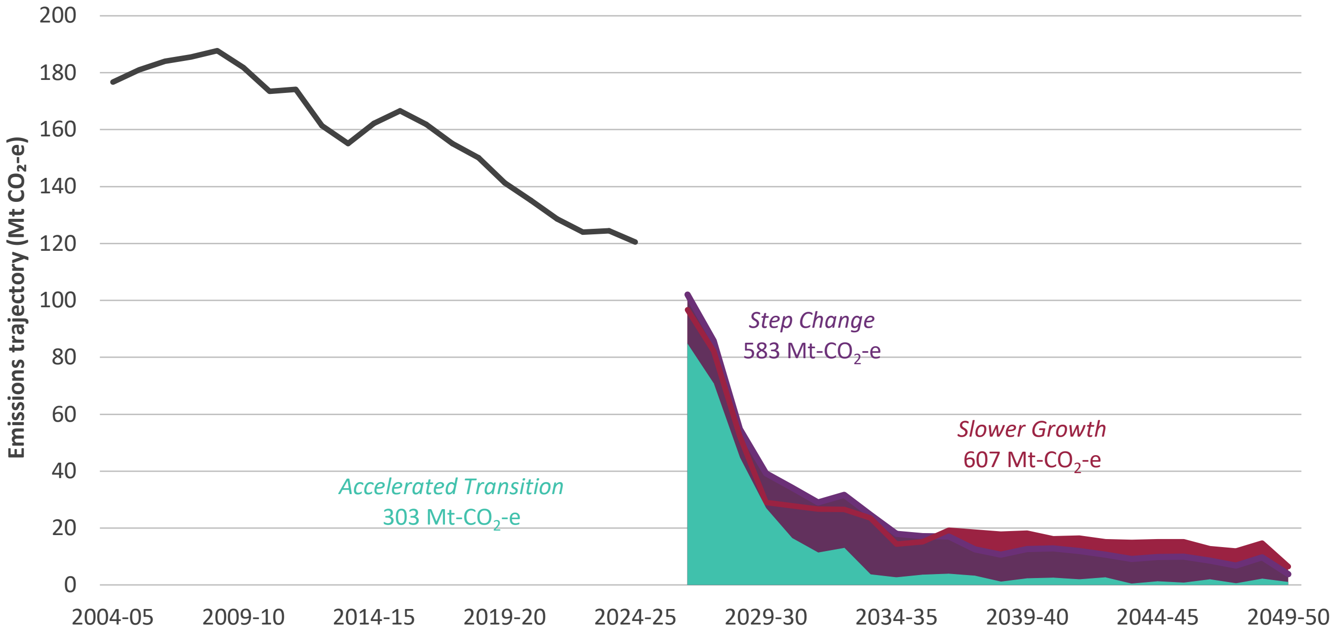
Figure 11 NEM-wide installed capacity (top) and energy generation (bottom), *Step Change*, 2026-27 to 2049-50 (GW and TWh)



A2.2.2 Emissions trajectory and renewable share

The transformation of the NEM to support Australia's transition to a net zero emissions economy by 2050 depends on rising investment in renewable generation at utility scale (wind and solar) to complement the high continued investment expected in CER. The shift from coal-fired generators and mid-merit gas generation to a high penetration of renewable energy will reduce the electricity sector's emissions intensity under all ISP scenarios, as shown below in **Figure 12** and **Figure 13**. The developments in renewable generation are supported by various eligible public policies, which are applied across all scenarios, shaping the emissions trajectory of each scenario.

Figure 12 Actual and projected annual NEM-wide emissions by scenario, 2004-05 to 2049-50 (Mt CO_2-e)



Note: Mt CO_2-e: million tonnes of carbon dioxide equivalent.

In *Step Change* and *Slower Growth*, strong policy support and rapid uptake of utility wind and solar drive steep and consistent emissions reductions to achieve the 2030 and 2035 emissions targets. After these policies are met, emissions still decline, but at a differing pace between scenarios. *Slower Growth* achieves higher emissions reduction relative to *Step Change* in the early years of the outlook period due to lower energy consumption, but the reduction slows significantly from 2030 onwards due to more modest investments in renewables.

In contrast, the *Accelerated Transition* scenario represents the most ambitious pathway to a net zero economy, with early retirements of coal-fired generation capacity and rapid expansion of renewables required to meet the lowest emissions budget in the NEM among the three scenarios.

By 2029-30, NEM emissions are projected to reduce by 78% in *Step Change* (from 176 million tonnes of carbon dioxide equivalent [Mt CO_2-e] in 2004-05 to 39 Mt CO_2-e in 2029-30), and by 85% in *Accelerated Transition* (from 176 Mt CO2-e in 2004-05 to 27 Mt CO_2-e in 2029-30). With lower relative consumption but renewable generation developments aligned with policy targets, *Slower Growth* sees an 84% reduction in emissions by 2029-30 (from 176 Mt CO_2-e in 2004-05 to 29 Mt CO_2-e in 2029-30).

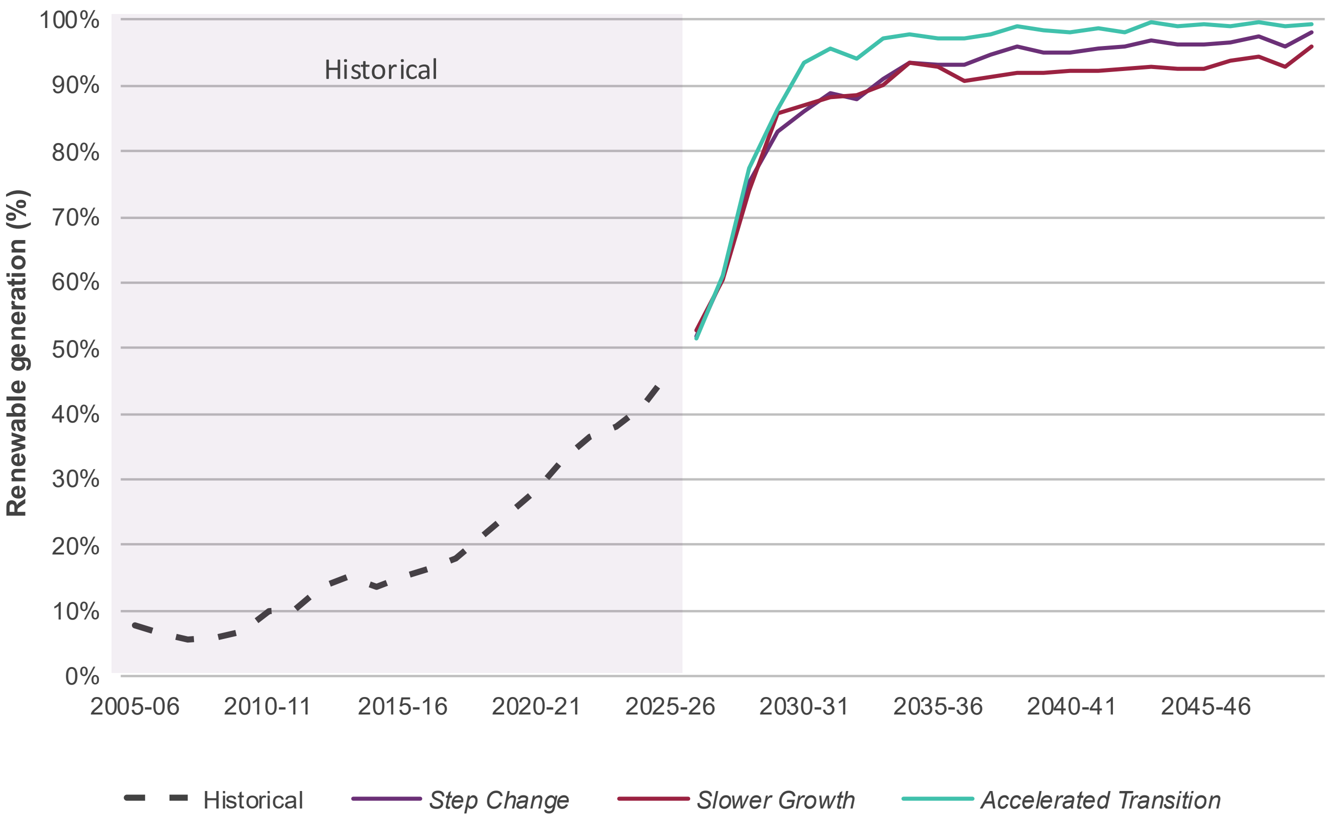
Australia's 2035 Nationally Determined Contribution (NDC)[17] announced Australia's 2035 target of 62-70% reduction in net national greenhouse gas emissions below 2005 emissions levels, covering all sectors of the economy and all greenhouse gases. This translates into an economy wide emission in the range of 184 to 233 Mt CO_2-e. The 2026 ISP projects by 2034-35

[17] At https://unfccc.int/sites/default/files/2025-09/Australias%20Second%20NDC.pdf

the NEM emissions from electricity generation to be 14 Mt CO_2-e in *Slower Growth* (92% reduction compared to 2004-05), 18 Mt CO_2-e in *Step Change* (90% reduction compared to 2004-05) and 3 Mt CO_2-e in the *Accelerated Transition* scenario (98% reduction compared to 2004-05) compared to 176 Mt CO_2-e in 2004-05.

Complementing **Figure 12** above, **Figure 13** below presents the projected level of renewable energy penetration to 2049-50 by scenario. It demonstrates the increasing role of wind and utility-scale solar as well as other renewable generation sources to reduce emissions to 2050. All scenarios achieve the Powering Australia Plan objective of 82% renewable energy by 2029-30. This demonstrates the high contribution that the NEM is projected to provide in terms of the overall economy-wide emissions reduction activities, particularly in the short to medium term. In *Step Change*, the share of renewable generation is projected to reach 98% by 2049-50.

Figure 13 Evolution of the annual share of total generation from renewable sources including rooftop and other small-scale solar, by scenario to 2049-50 (%)



A2.2.3 Energy storage needs

Energy storage has a crucial role in firming a high penetration renewable grid. To guide investment decisions across consumer, distribution, and transmission levels, AEMO considered a range of storage types:

- **CER storages** typically offer approximately two hours of storage capacity. These assets may be part of **coordinated CER storage** that are managed by aggregators in VPPs, enabling response to market signals, or operate as **passive CER storage** that are behind-the-meter and operating to service the household's needs in isolation.
- **Utility-scale storages** are grid-connected and classified by their storage duration: **shallow** (less than four hours), **medium-depth** (four to 12 hours) or **deep** (more than 12 hours).

- Shallow utility-scale storage includes utility-scale storage and those connected in the medium voltage network of the distribution network. Shallow and medium-depth storages are used for intra-day energy-shifting, discharging during morning or evening peak hours.
- In contrast, deep utility-scale storages are designed to support energy management across weeks or even seasons, helping meet extended periods of low renewable generation availability during renewable energy lulls.

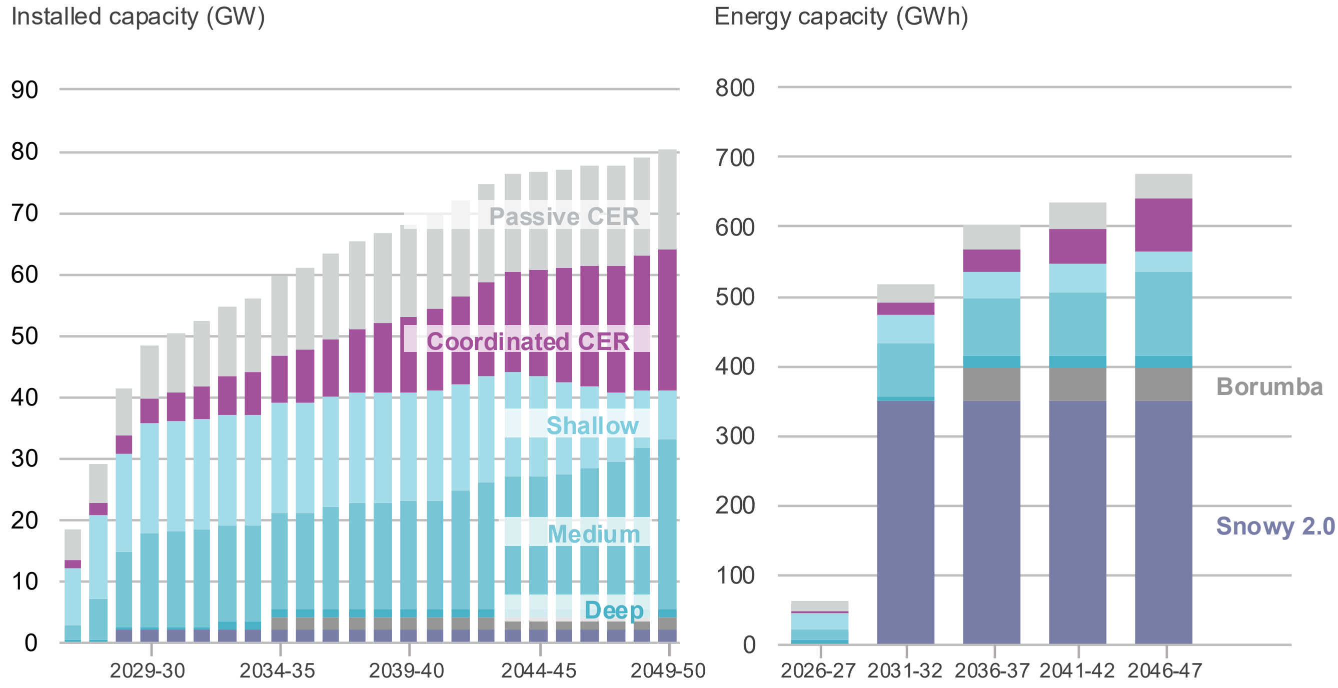
In all scenarios, the increased uptake of storage systems is primarily driven by existing commitments and policy support, and the need to complement high VRE penetration to reliably and securely meet growing energy consumption. Storage systems enable energy-shifting by soaking excess generation throughout the day and across seasons and discharging during periods of peak demand. The growth in energy consumption from electrification including the adoption of EVs, and the retirement of synchronous generators such as coal-fired power plants, place additional strain on grid management. Storage systems play a critical role in providing firming capacity and can assist in maintaining grid stability through provision of essential services such as system strength (that is, providing a stable voltage waveform), inertia, frequency control, and voltage support.

Figure 14 presents projected NEM-wide storage capacity by depth to 2049-50 in *Step Change*:

- A high level of storage capacity, most frequently of medium duration, is currently committed or anticipated. Some of these developments are supported by government schemes, such as the CIS.
- Utility-scale storage capacity is projected to reach 36 GW/473 GWh by 2029-30 with a projected mix of 2.5 GW/356 GWh as deep, 15 GW/74 GWh as medium, and 18 GW/43 GWh as shallow storage. In addition, CER storage is projected to reach 12.5 GW/33 GWh. The fastest growth occurs in medium-depth utility-scale storage and coordinated CER storage.
- Deep storage will be a critical contributor to system reliability, accounting for only 5% of installed capacity but about 70% of installed energy storage capacity[18] in 2029-30. Technologies such as pumped hydro energy systems can provide discharge duration exceeding 12 hours with appropriate reservoir developments, and several projects such as the Snowy 2.0 and Borumba Pumped Hydro projects are under development to expand deep storage capacity.
- Traditional hydro schemes (currently 7 GW installed capacity) also provide a critical role in storing water for future use in producing electricity (as well as servicing other users, such as water irrigation).

[18] Traditional reservoir hydro schemes are not included in this calculation of energy storages.

Figure 14 NEM-wide storage installed capacity (right) and energy storage capacity (left), *Step Change*, 2026-27 to 2049-50 (GW and GWh)



A2.3 Generation and storage development opportunities across scenarios

This section outlines the optimal mix of generation and storage for each scenario. The installed capacity projection differs between each scenario depending on the speed of emissions reduction, retirements of coal-fired generation capacity, and projected energy consumption. The magnitude of utility-scale VRE developments is driven by various renewable energy targets.

The total installed capacity for utility-scale solar and wind (including existing, committed and anticipated developments) reaches 56 GW, 61 GW, and 65 GW by 2029-30 in *Slower Growth*, *Step Change*, and *Accelerated Transition*, respectively. By 2049-50, utility-scale VRE developments diverge across scenarios more significantly and reach 84 GW, 117 GW, and 211 GW in *Slower Growth*, *Step Change*, and *Accelerated Transition* of installed capacity, respectively.

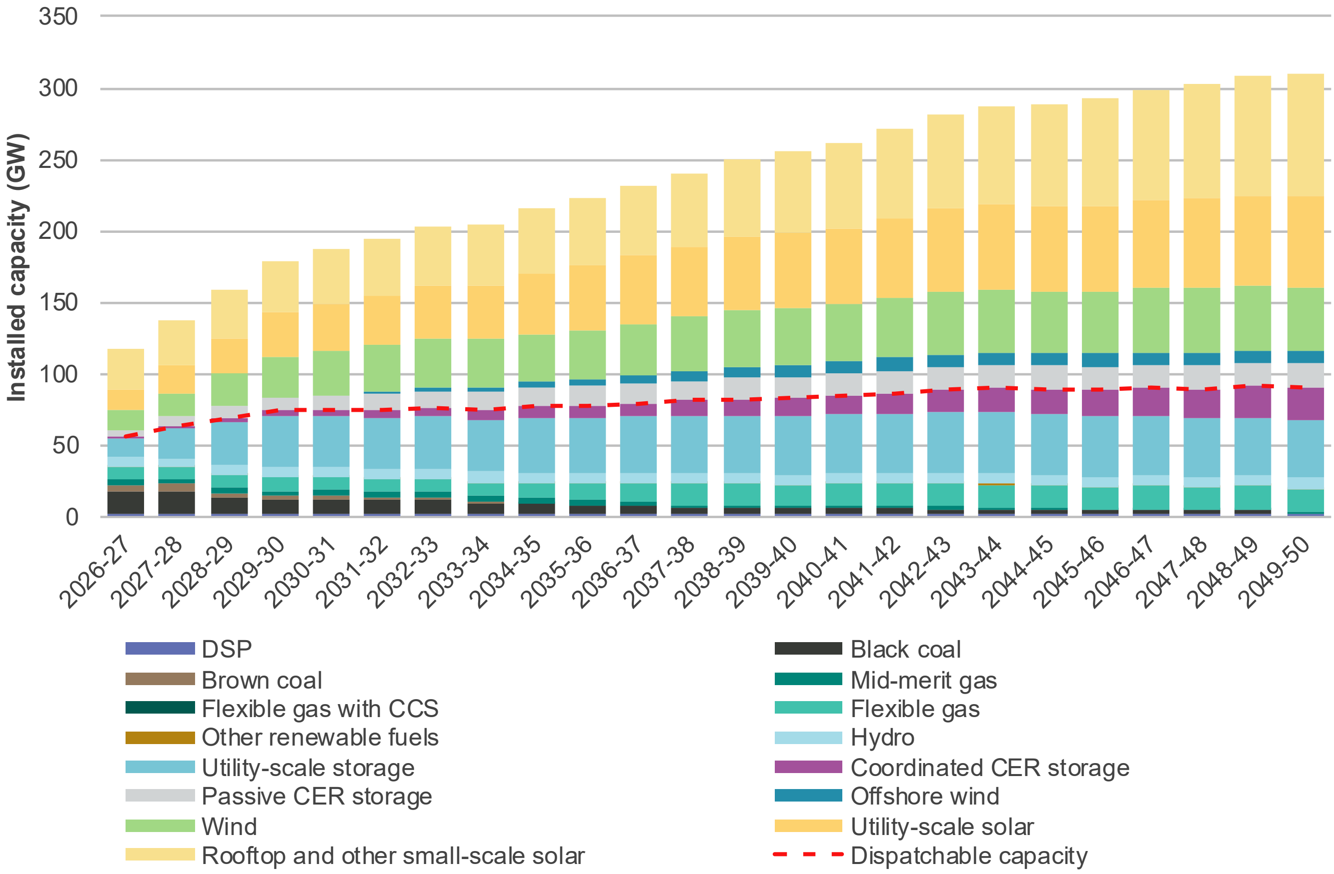
In *Step Change* under the ODP, utility-scale wind and solar capacity would rise from its current 23GW to 61 GW by 2030, then almost double to 117 GW by 2050.

A2.3.1 Step Change

Step Change presents a scenario where Australia achieves government policy objectives and transitions the energy system to support limiting global temperature rise below 2°C, with moderate economic and population growth, strong consumer investment in electrification and CER, and material new loads from transport and industry but limited domestic hydrogen industry growth.

Figure 15 presents the projected capacity mix for the NEM across the outlook period to 2049-50 in *Step Change*.

Figure 15 Projected NEM installed capacity, *Step Change*, 2026-27 to 2049-50 (GW)



Renewables to replace coal as bulk generation

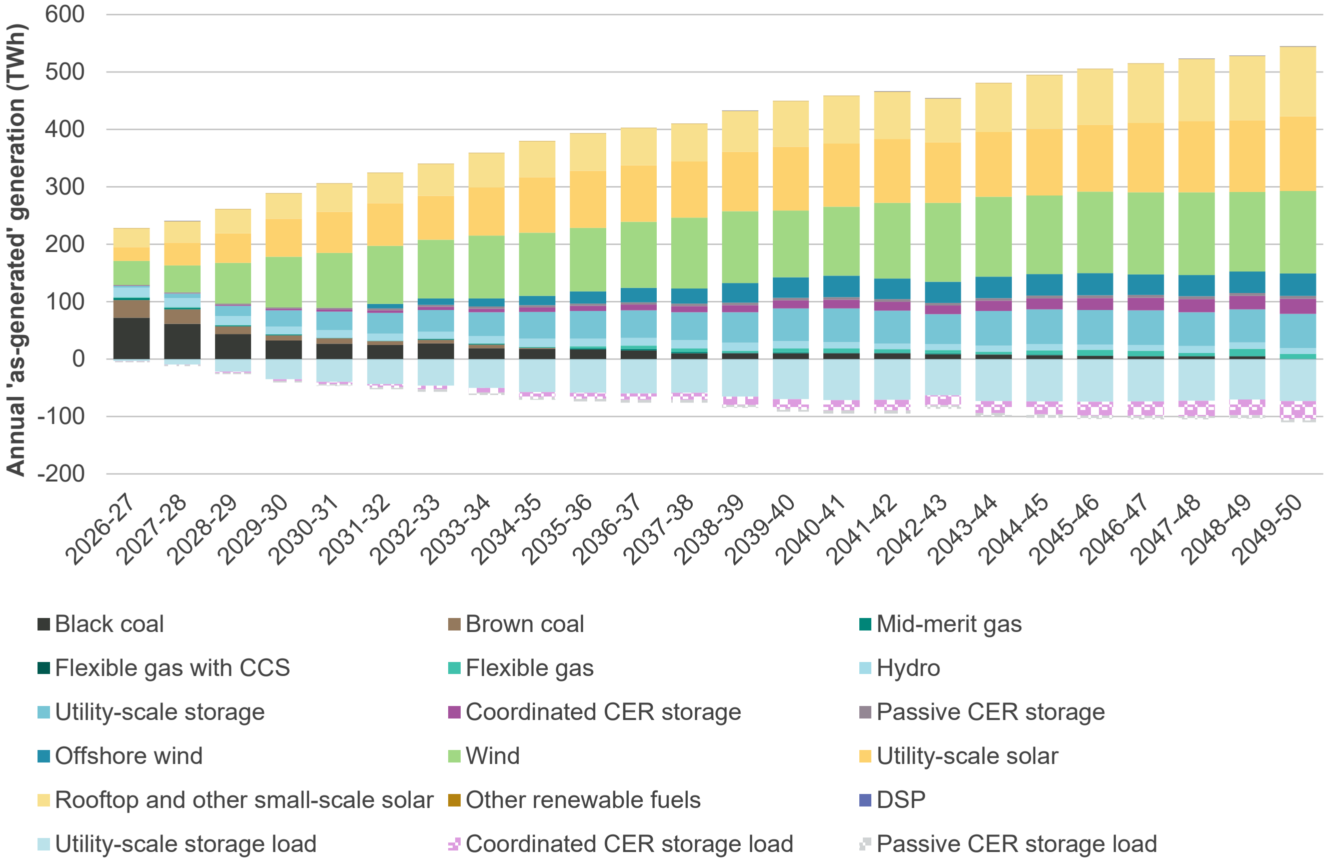
A large proportion of renewable energy developments are projected in New South Wales and Victoria, an outcome of relatively high forecast consumption growth (such as from rising data centre developments in these regions), retiring generators, supporting policy targets, and high relative resource quality for utility-scale wind and solar developments.

Significant volumes of committed and anticipated generation, particularly in storage devices, are currently under development, and various targeted state policies are supporting storage and VRE developments. The high development of storage capacity enables surplus renewable energy to be stored and shifted to be used when needed, meaning that supply is better matched to demand. The storage uptake supports a high level of utility-scale solar development, being the lowest cost renewable generation capacity that will complement storage capacity. By 2029-30, NEM-wide storage capacity including CER storage is 48.3 GW/507 GWh.

In *Step Change*, 7.7 GW of coal-fired generation capacity is projected to retire by 2029-30, and all coal generation capacity is projected to retire by 2049-50, with only 0.4 GW of mid-merit gas capacity remaining in 2049-50. These retiring generation capacities are replaced with renewable energy generation, storage and flexible gas capacity. VRE represents the most cost-efficient solution for new energy supply when firmed by storage and flexible gas and connected with appropriate network development. Utility-scale solar capacity is projected to increase to 64 GW and wind capacity to 44 GW. Complementing utility-scale developments are consumers' own investments in solar and battery solutions. By 2049-50, CER storages are projected to reach 39 GW/127 GWh, and rooftop and other small-scale solar developments are projected to reach 87 GW, representing 28% of NEM capacity.

Figure 16 illustrates the high degree of change expected to affect the NEM's generation mix, including the high penetration of renewable energy generation. Utility-scale wind and solar generation is projected to rise from 66 TWh in 2026-27 to 154 TWh by 2029-30, then double to 274 TWh by 2049-50. *Step Change* develops sufficient renewable energy capacity in 2029-30 to meet the 82% target set in the Powering Australia Plan, and the share of VRE generation is projected to increase to 93% by 2034-35 and 98% by 2049-50. The remaining 2% of non-renewable generation is provided by flexible gas[19], with 9 TWh of generation in 2049-50. Over the period to 2049-50, the gas fleet is projected to supply a similar share of the NEM's annual generation to today's 4%[20].

Figure 16 Projected annual generation, *Step Change*, 2026-27 to 2049-50 (TWh)



Dispatchable capacity to firm renewables

Firming capacity is required to ensure a reliable power supply and maintain grid stability. As coal-fired generation capacity retires from the NEM, a combination of CER storages, flexible gas, utility-scale storage (batteries and pumped hydro energy systems), and hydro will be required to provide these firming services, complementing activities that consumers can take to shift load away from peak load conditions such as may be available with industrial loads such as electrolysers. While operators are required by the NER to meet minimum notice of closure requirements, timely investment in replacement

[19] Weather conditions will influence the total level of generation from most generation sources, but gas generation in particular is expected to provide back-up to cover for renewable energy availability variation and high electricity demand during periods of extreme heat and cold. As such, generation forecasts for gas generation are more likely to vary than other technologies.

[20] This varies from year to year depending on weather and operational conditions, and would average about 3.5% through to 2050, similar to today's level of 4%.

assets is needed to ensure sufficient generation and firm capacity developments are online in-time to maintain reliability of supply for consumers.

In *Step Change*, flexible gas and energy storages provide dispatchable capacity during peak demand intervals. Flexible gas is projected to increase from 8.4 GW in 2026-27 to 17 GW in 2049-50 to ensure firm capacity requirements are met, such that retiring coal and mid-merit gas capacity is offset by flexible gas and storages. Utility-scale storage capacity increases from 12 GW in 2026-27 to 36 GW in 2029-30 and 41 GW in 2049-50. While installed capacity is projected to grow by 5.3 GW between 2029-30 and 2049-50, additional storage development is required to replace storage projects that reach their end of technical life in this time.

Coordinated CER storage capacity increases from 6 GW in 2026-27 to 36 GW in 2049-50 under this scenario, providing a significant contribution to maintaining reliability.

Figure 17 shows the change in dispatchable capacity projected in *Step Change* across the outlook period. The dispatchable capacity (including coordinated CER storage, which includes vehicle-to-grid) is projected to account for about 29% of the total installed capacity (including all CER storage capacities) in the NEM by 2049-50. This includes consideration for medium storage developments that replace retiring existing, anticipated and committed shallow storage as they reach the end of their technical lives.

Figure 17 Projected relative change compared with 2025-26 in dispatchable capacity, *Step Change*, 2026-27 to 2049-50 (GW)

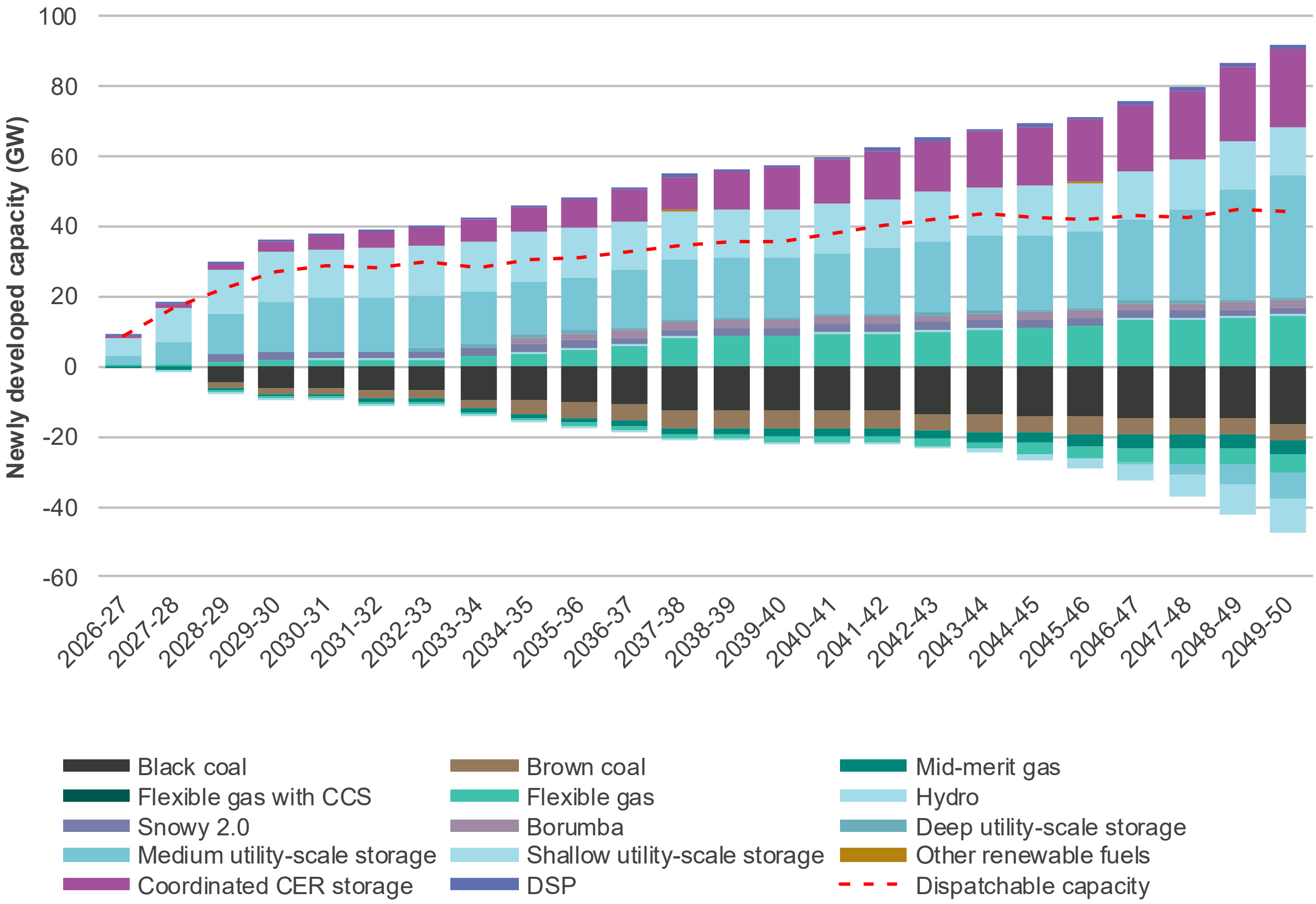
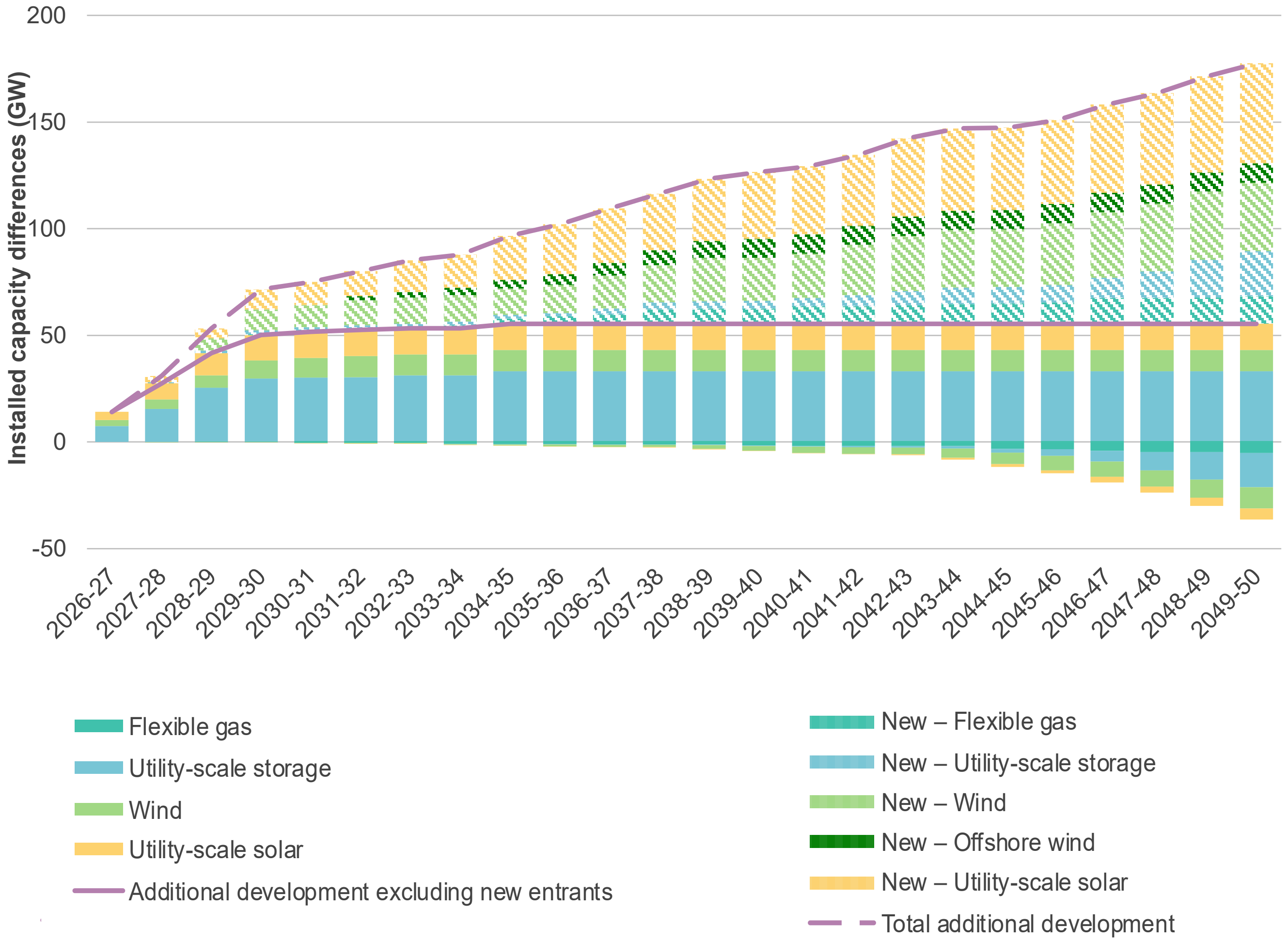


Figure 18 shows a net addition of 72 GW of generation and storage capacity (excluding CER) in *Step Change* by 2029-30 compared to 2025-26. In the figure, the solid columns show the level of capacity that is either existing, committed, anticipated or policy-supported, while the pattern-filled columns show the amount of additional development opportunities in the ODP.

Of these net additions to 2029-30, 20 GW is utility-scale solar, and 18 GW is wind. This amounts to a higher requirement than what is currently in AEMO's connections pipeline (19 GW of utility-scale solar and 9 GW of wind). This highlights the importance of efforts being made to streamline all aspects of development and delivery, as well as the ongoing need for continued investment.

Figure 18 Capacity developments for utility-scale storages, wind, utility-scale solar, and flexible gas compared with 2025-26, *Step Change*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

In this scenario, all coal-fired generation capacity is projected to retire by 2049-50 in the NEM, but the pace at which coal retires varies by region:

- In Victoria, more than half of brown coal is retired by 2031-32 (earlier than currently announced), with the remaining capacity retiring by 2035-36.

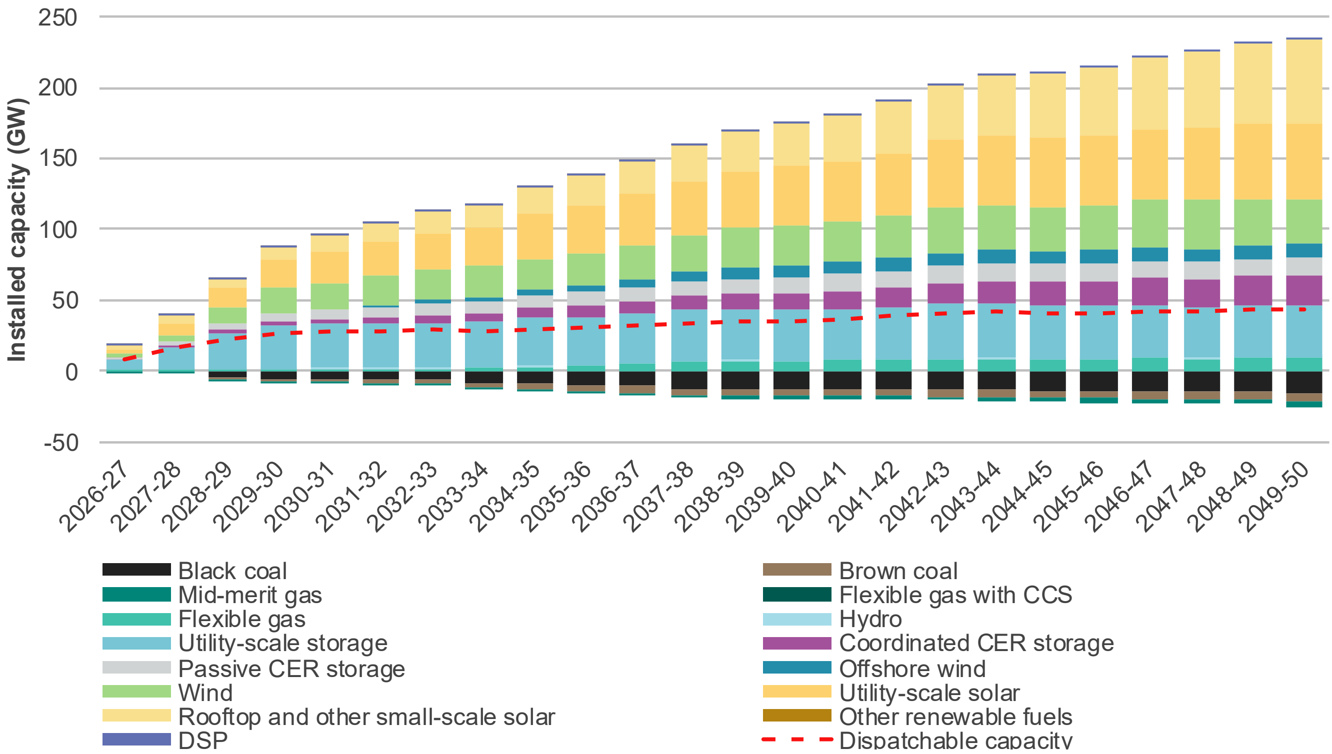
- In New South Wales, several generators are retired consistent with their currently announced closure schedule (for example, Eraring Power Station is scheduled to retire in 2028-29). The majority of the remaining coal-fired generators are projected to retire by 2037-38 to meet the emissions targets of the scenario.
- In Queensland, 50% of existing coal capacity is projected to retire by 2037-38, with some capacity available to 2049-50.

New developments and closures

Figure 19 shows the change in installed capacity over time. VRE capacity is projected to increase rapidly to meet renewable energy targets and policies, resulting in 97 GW of VRE capacity NEM-wide by 2029-30. This is comprised of 31 GW of utility-scale solar, 30 GW of onshore wind, and 36 GW of rooftop and other small-scale solar. Approximately 42% of utility-scale VRE capacity in 2029-30 is in New South Wales, driven by the New South Wales and CIS generation targets, as well as the increase in utility-scale storage.

NEM-wide VRE development continues to grow to 203 GW in 2049-50 to replace the generation no longer provided by retiring thermal generation capacities. This is comprised of 87 GW of rooftop and other small-scale solar, 64 GW of utility-scale solar, 44 GW of onshore wind, and 9 GW of offshore wind.

Figure 19 Projected relative change in new installations and closures compared to 2025-26 installed capacity, *Step Change*, 2026-27 to 2049-50 (GW)

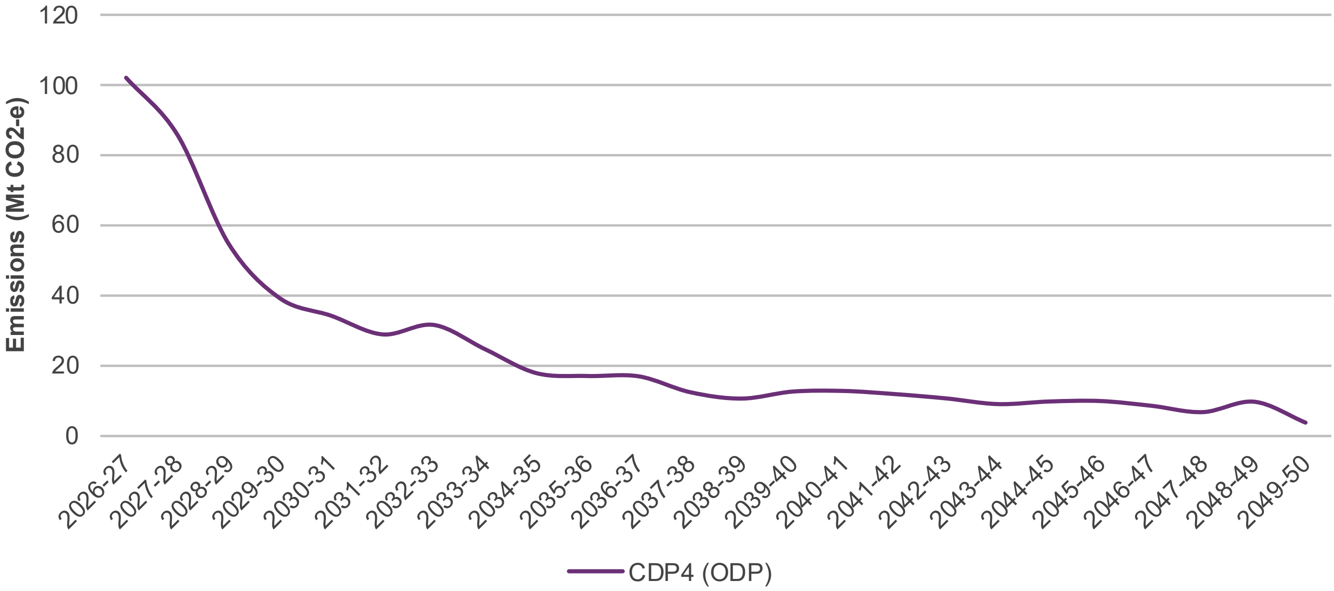


Impact on emissions

As a result of the changing energy mix, emissions are projected to decline rapidly between 2026-27 and 2029-30, due to renewable energy generation's increasing role in supplying energy consumption. By 2034-35, emissions are projected to reduce by 84% compared to 2005 levels in *Step Change* (from 176 million Mt CO_2-e in 2004-05 to 28 Mt CO_2-e in 2034-35), driven by policies and the 2030 emissions budget that has been allocated to the electricity sector in the 2025 IASR.

Emissions continue to reduce after 2034-35, but more gradually. **Figure 20** shows the projected decrease of emissions across the outlook period.

Figure 20 Projected NEM emissions trajectory, *Step Change*, 2026-27 to 2049-50 (Mt CO_2-e)



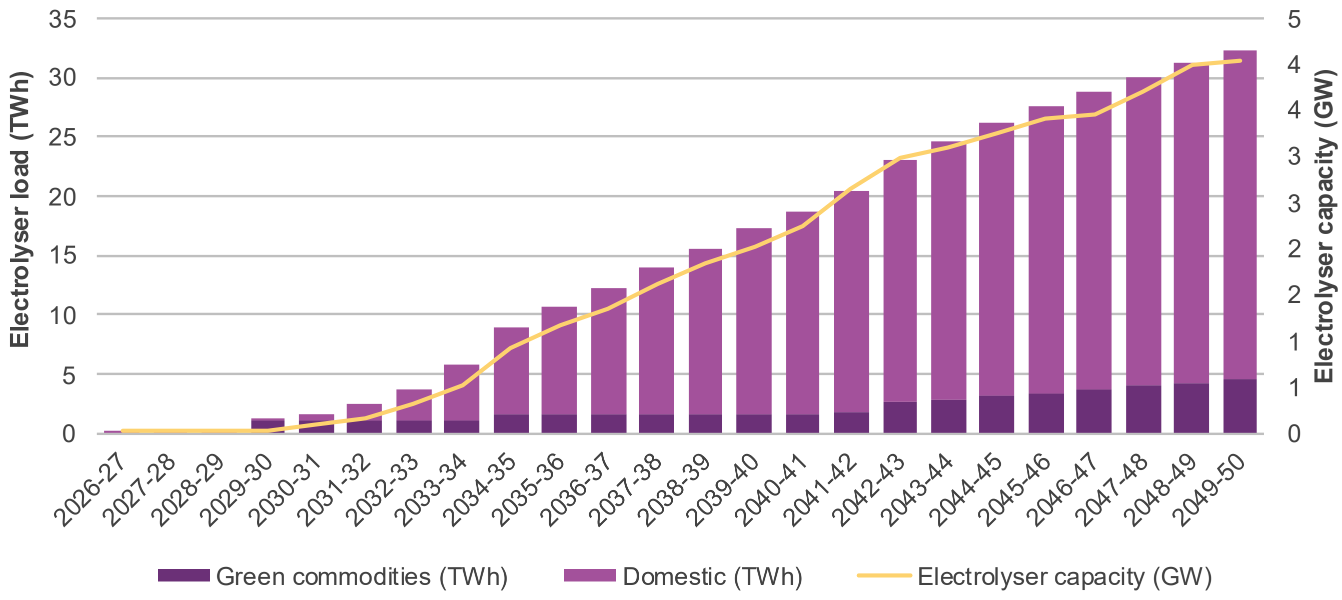
Hydrogen developments

The ISP modelling considered hydrogen developments for domestic use and the production of green commodities. The assumed demands were modelled as flexible loads. Additionally, it was assumed that there is hydrogen storage that is sufficiently large to store a month's worth of hydrogen for customers to use flexibly[21].

Figure 21 presents the assumed total electricity consumption to 2049-50 for hydrogen production in *Step Change*. By 2049-50, 4 GW of electrolyser capacity is developed, with flexible electrolysers operating with a load-weighted average utilisation factor of 84% over the outlook period.

[21] In response to stakeholder feedback, this assumption was updated from the Draft 2026 ISP, which assumed a week's worth of hydrogen storage to enable electrolysers to take advantage of lower prices through flexible operation while still meeting demand.

Figure 21 Electricity consumption associated with hydrogen production, *Step Change*, 2026-27 to 2049-50 (TWh)



Electrolysers are mostly developed in REZs that are closely located to end users (for domestic markets) and to production hubs for green commodities (that service domestic and international customers) to minimise costs of transporting hydrogen, particularly in Queensland, New South Wales, Victoria and South Australia. Electrolyser operating regimes are projected to attempt to minimise hydrogen production costs, grid utilisation, and impacts on the supply-demand balance, by deploying economies of scale where practical, including pipeline and hydrogen storage developments.

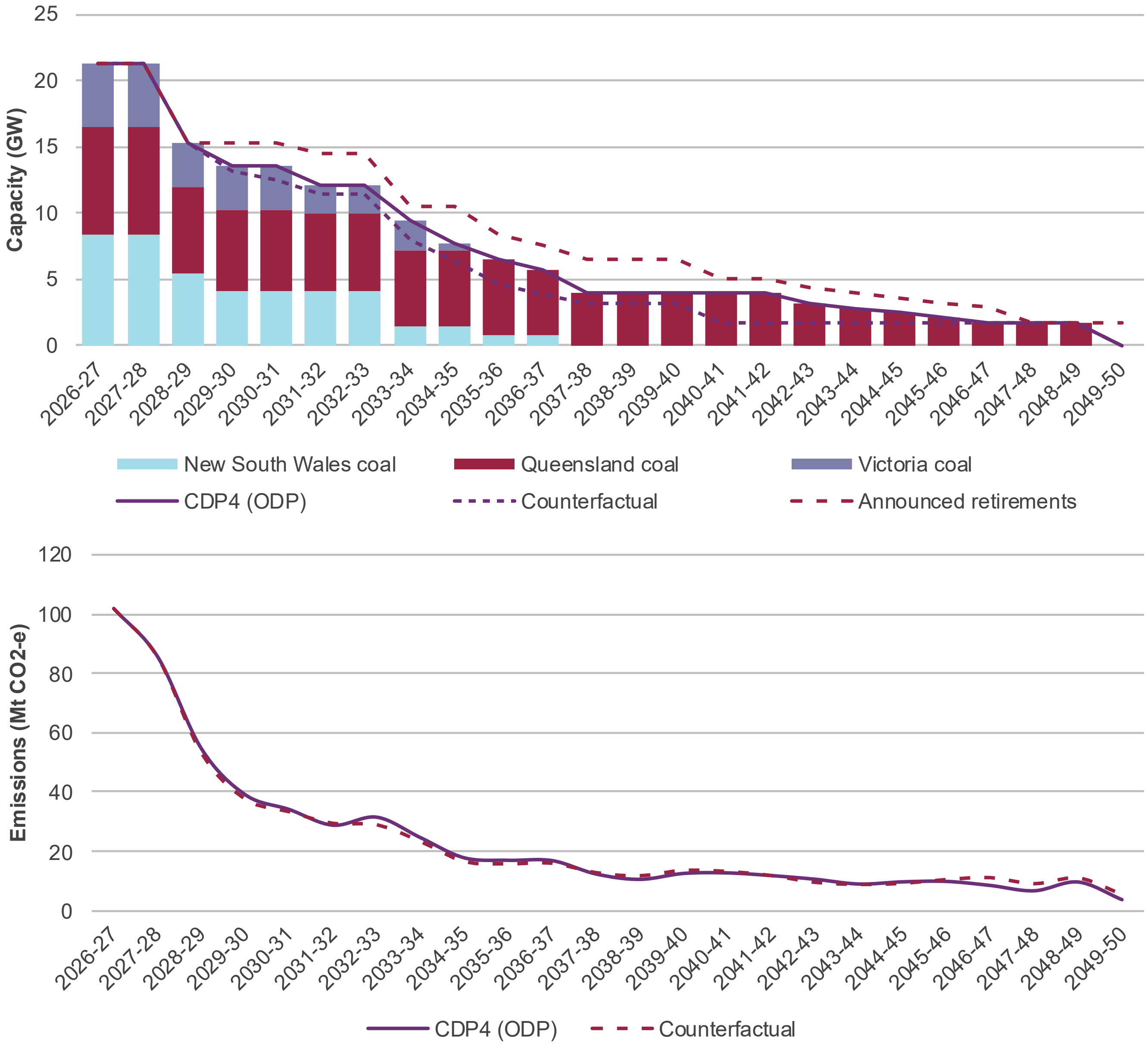
Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Step Change*

The 2026 ISP identifies material system cost savings through the expansion of the transmission network (see Appendix A6 for more details). Transmission investments help facilitate the transition to a lower emissions energy system by improving access to renewable energy resources developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

Impact of transmission development on retirements of coal-fired generation capacity

Figure 22 shows a comparison between retirements of coal-fired generation capacity between the 'no transmission' counterfactual development path which does not feature further expansion of major transmission beyond what is committed and anticipated (bars) and the ODP in the 2026 ISP (solid line), contrasted with the announced closure dates (dashed line). Below the first chart is a comparison of the emissions trajectory between the 'no transmission' counterfactual development path and the ODP.

Figure 22 Projected coal-fired generation capacity development (top) and emissions trajectory (bottom) to 2049-50, 'no transmission' counterfactual development path compared with *Step Change* (GW and Mt CO_2-e)



Impact of transmission development on capacity and generation mix

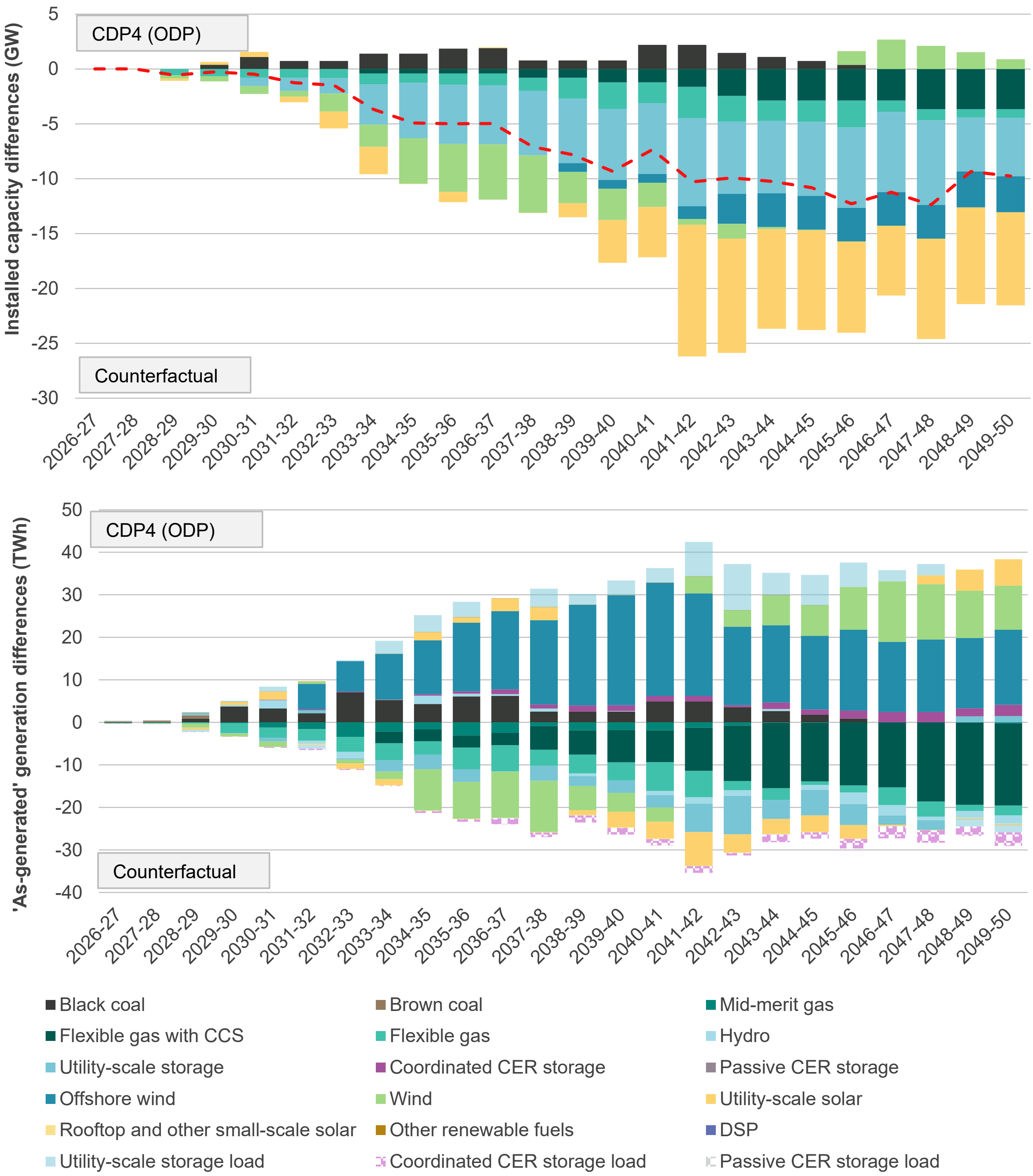
In the 'no transmission' counterfactual development path, limited availability of connection locations with strong transmission capacity results in a more diverse mix of technologies to meet the future needs of the NEM. With less ability to develop REZs, investments would be needed as early as 2033-34 in flexible gas with carbon capture and storage (CCS) capabilities to provide dispatchable capacity that can generate sufficient energy while achieving the emissions budget. Additional offshore wind capacity is developed in New South Wales as an alternative to augmenting transmission lines. Offshore wind generation overall, however, is lower, because while the capacity is built to meet the Victorian Offshore Wind Target, the generation is significantly constrained by the capability of existing transmission.

In the 'no transmission' counterfactual development path for *Step Change* and *Accelerated Transition*, the retirement of the Gladstone Power Station would cause significant system reliability risks in the Gladstone Grid sub-region, as there is insufficient local generation to service local demand due to fuel limitations. The gas fuel limits applied in 'no transmission' counterfactual development paths are the same as applied to the ODP and, as discussed in Appendix A10, the gas supply developments in Gladstone Grid are a direct response to forecast gas generation demand in this sub-region. As the 'no transmission' counterfactual development path has higher gas needs than the ODP, the gas supply limit in Gladstone Grid was assumed to be lifted and additional gas developments would be required to service this need, or gas generators may be able to source fuel from alternative supplies (for example, from capacity that services export facilities in this sub-region).

Figure 23 shows the differences in capacity and generation developments in *Step Change* between the ODP and the 'no transmission' counterfactual development path. A positive value indicates higher total installed capacity or generation in the ODP. In the 'no transmission' counterfactual development path, without major transmission expansion and limited access to VRE, coal plants would need to retire earlier to reduce emissions, enabling greater generation from flexible gas with CCS in later years to firm renewable generators. Greater use of solar connected to the distribution network is also a feature of the 'no transmission' counterfactual development path (bundled within solar in the figure).

This increases gas used for electricity production in the 'no transmission' counterfactual development path consequently increases the gas system utilisation, which would require additional gas supply investments compared to the gas development projection used for the ODP.

Figure 23 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Step Change* (GW and TWh)



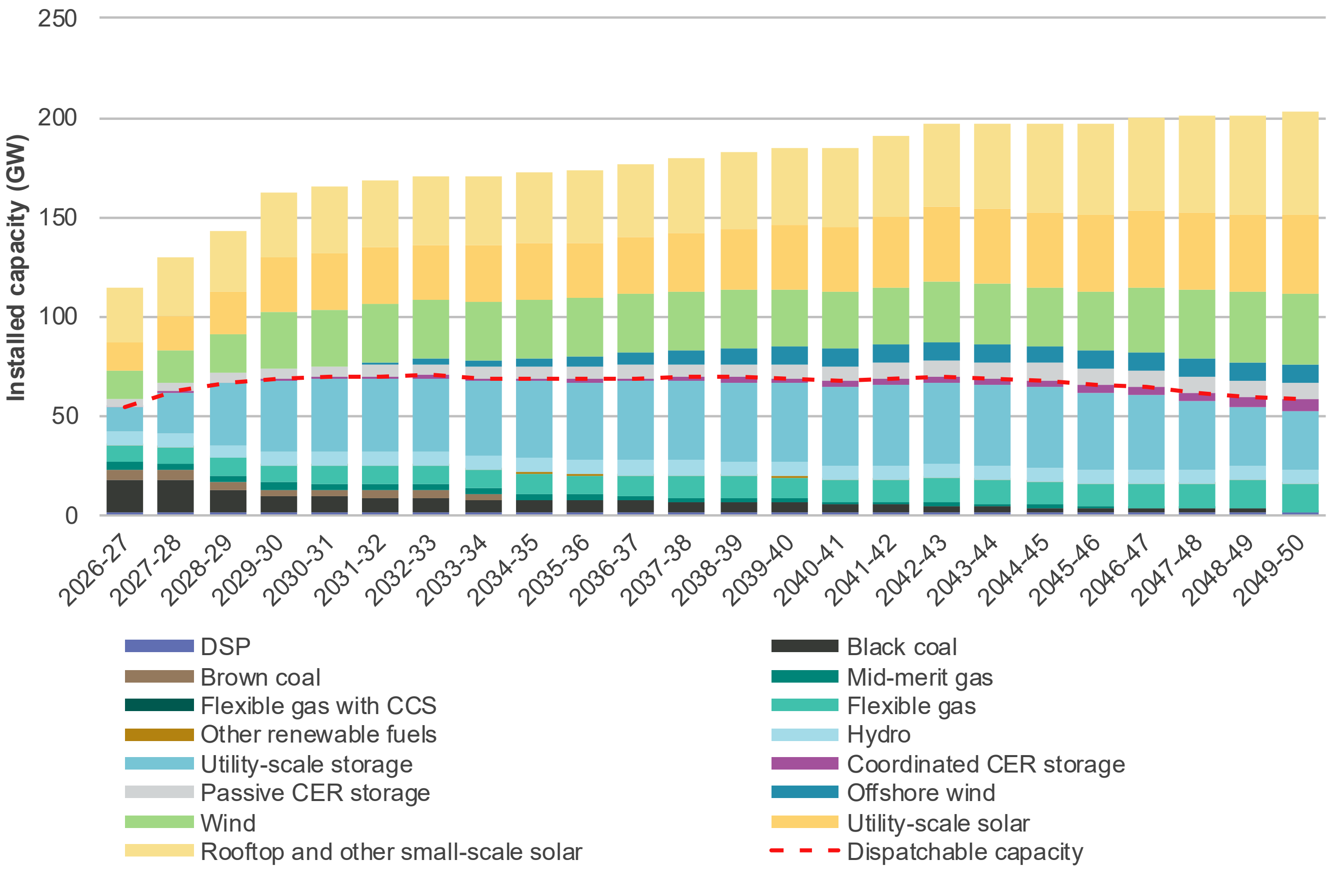
Note: 'as-generated' represents the total gross generation produced by a generator including its auxiliary loads, whereas 'sent-out' refers to the net generation delivered directly to the transmission or distribution network.

A2.3.2 Slower Growth

Slower Growth features a future where Australia reaches net zero emissions by 2050 amid weak economic conditions, slower technology cost declines, and more limited consumer and commercial business capacity to support the transition in a more challenging investment environment.

Figure 24 presents the projected capacity mix for the NEM across the outlook period to 2049-50 in *Slower Growth*.

Figure 24 Projected NEM installed capacity, *Slower Growth*, 2026-27 to 2049-50 (GW)



Renewables to replace coal as bulk generation

In all scenarios, renewable energy policies, such as the CIS and regional renewable targets at both the federal and state levels, are driving significant investment in VRE developments across the NEM, particularly utility-scale solar and wind. Although the reduction in coal-fired generation capacity is expected to occur more gradually in *Slower Growth* than in *Step Change*, it is still projected to decrease to approximately half of current levels by 2029-30 due to lower energy consumption driven by industrial closures assumed in this scenario, and as ongoing investments in new renewable energy projects and additional storages come online. New South Wales and Victoria experience the most significant reductions in coal-fired generation capacity, while Queensland is expected to have coal plants continuing to operate, aligned with the Queensland Energy Roadmap.

Slower Growth still incorporates significant volumes of committed and anticipated generation, particularly in storage devices, and various targeted state policies which are supporting storage and VRE developments, such as offshore wind in Victoria and the Tasmanian Renewable Energy Target (TRET). In this scenario, the need to expand Tasmanian renewable generation leads to increased need to export surplus generation to service load growth in mainland regions. This scenario features industrial load closures in Tasmania and on the mainland, and this increases the value of increased network transfer capability to export surplus renewable generation from Tasmania to the broader NEM. In the medium term, the greatest change to the regional generation mix is in New South Wales and Victoria, with utility-scale solar reaching around 17.3 GW and wind reaching around 19.9 GW by 2029-30, which accounts for 45% and 35% of total utility-scale solar and wind in the NEM, respectively.

By 2049-50, all coal-fired generation capacity is projected to have retired and been replaced by a mix of renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas. The NEM's generation mix in this scenario is made up mostly of utility-scale solar (19%), wind (22%), and rooftop and other small-scale solar capacities (26%); a total of 67% of overall NEM generation. As shown in **Figure 25**, flexible gas generation continues to provide a key role in backing up storages to maintain reliability and operability over the long term, supporting extended periods of low utility-scale wind and solar output. Compared with *Step Change* (as shown earlier in **Figure 9**), this represents a lesser need for new gas development.

Figure 25 Projected gas capacity development, *Slower Growth*, 2026-27 to 2049-50 (GW)

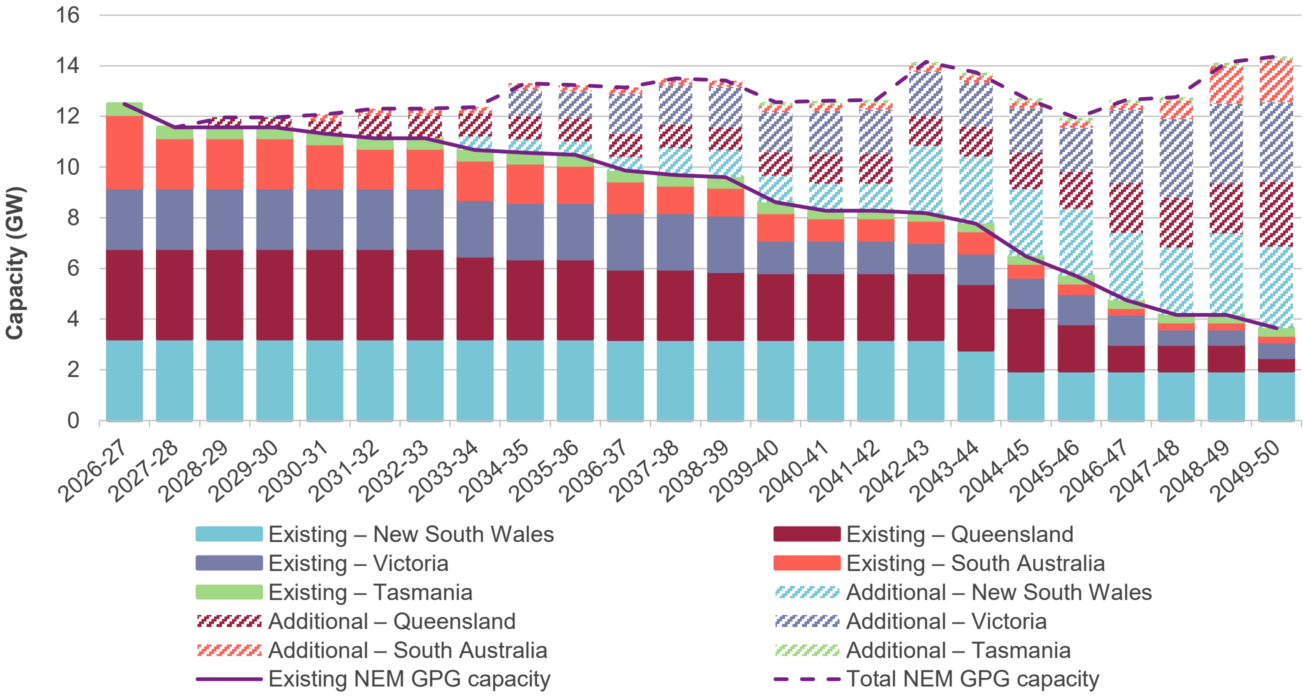


Figure 26 demonstrates the high degree of change expected to affect the NEM's generation mix in this scenario. Renewable generation is projected to account for 86% of generation by 2029-30 and 96% by 2049-50. Much of this change is driven by additional committed and anticipated developments as per the January 2026 Generation Information update and renewable energy policies at both the federal and state levels. In particular, targets that have a specific development or output-based target (in capacity installed or the level of electricity produced) such as the TRET or the Victorian Offshore Wind Target are more significant in this scenario, given the lower growth trajectory for electricity consumption. This leads

to these targets having a greater relative influence on generation and storage developments in this scenario to other scenarios, and the benefits of network developments to support efficient resource sharing.

The projected mix of VRE by the end of the outlook period is approximately 48% wind, 26% utility-scale solar, and 22% rooftop and other small-scale solar by 2049-50.

Figure 26 Projected annual generation, *Slower Growth*, 2026-27 to 2049-50 (TWh)

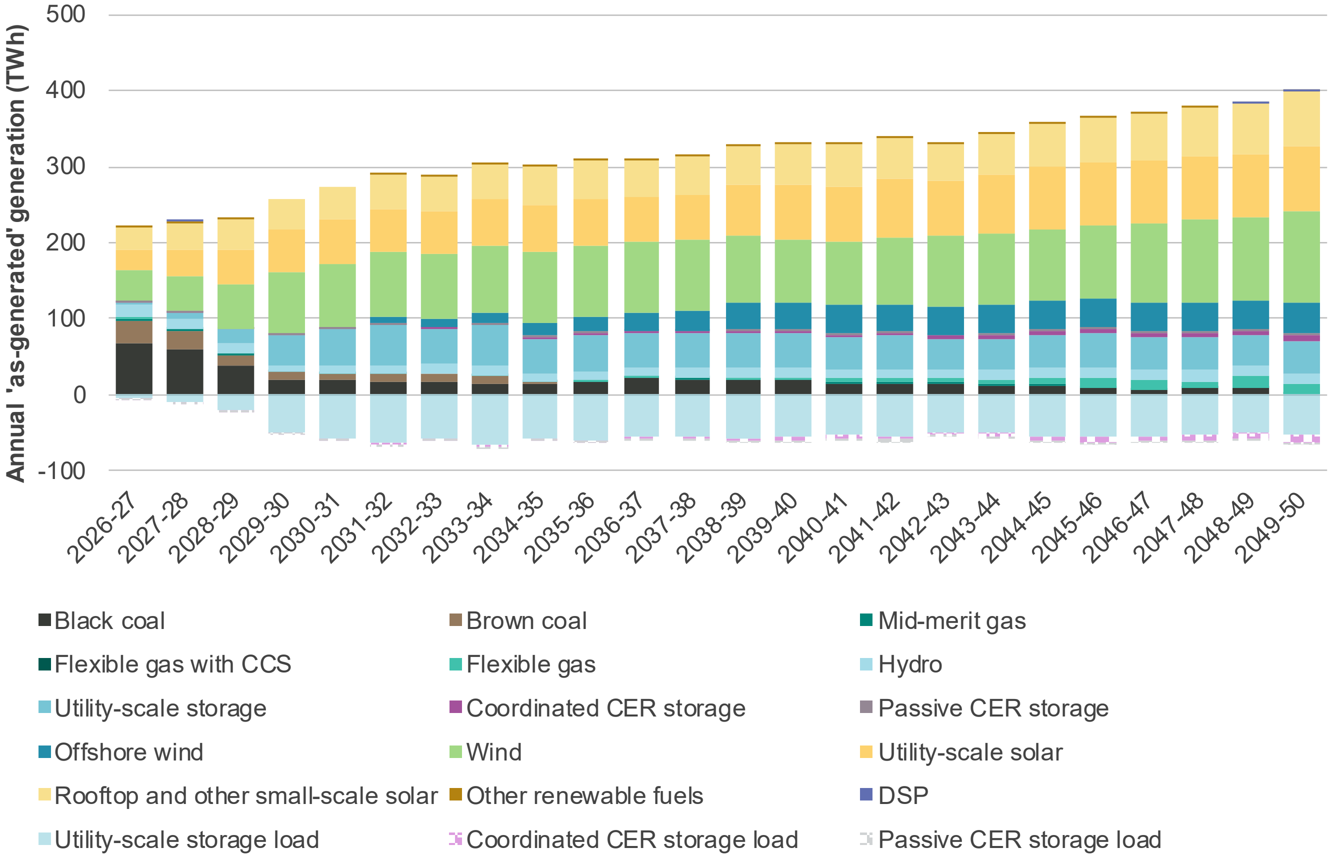
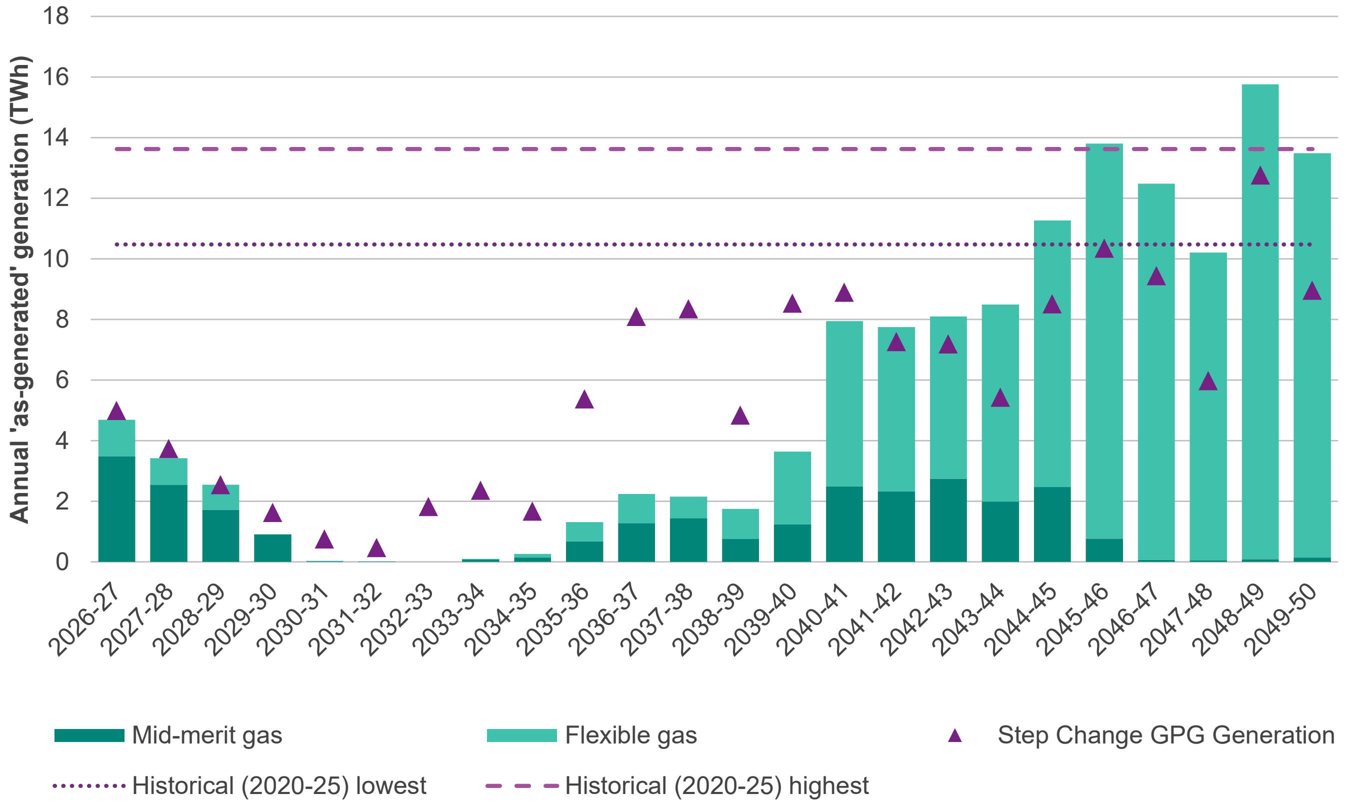


Figure 27 below shows that the need from gas-powered generation in *Slower Growth* is generally less than in *Step Change* until late in the outlook period, when less VRE is replaced at end-of-life. In *Step Change* more of this retiring capacity is replaced with new VRE and storage developments than *Slower Growth*, resulting in higher potential gas generation in this scenario (but still relatively low utilisation within historical gas operating levels).

Figure 27 Projected annual gas generation, *Slower Growth*, 2026-27 to 2049-50 (TWh)

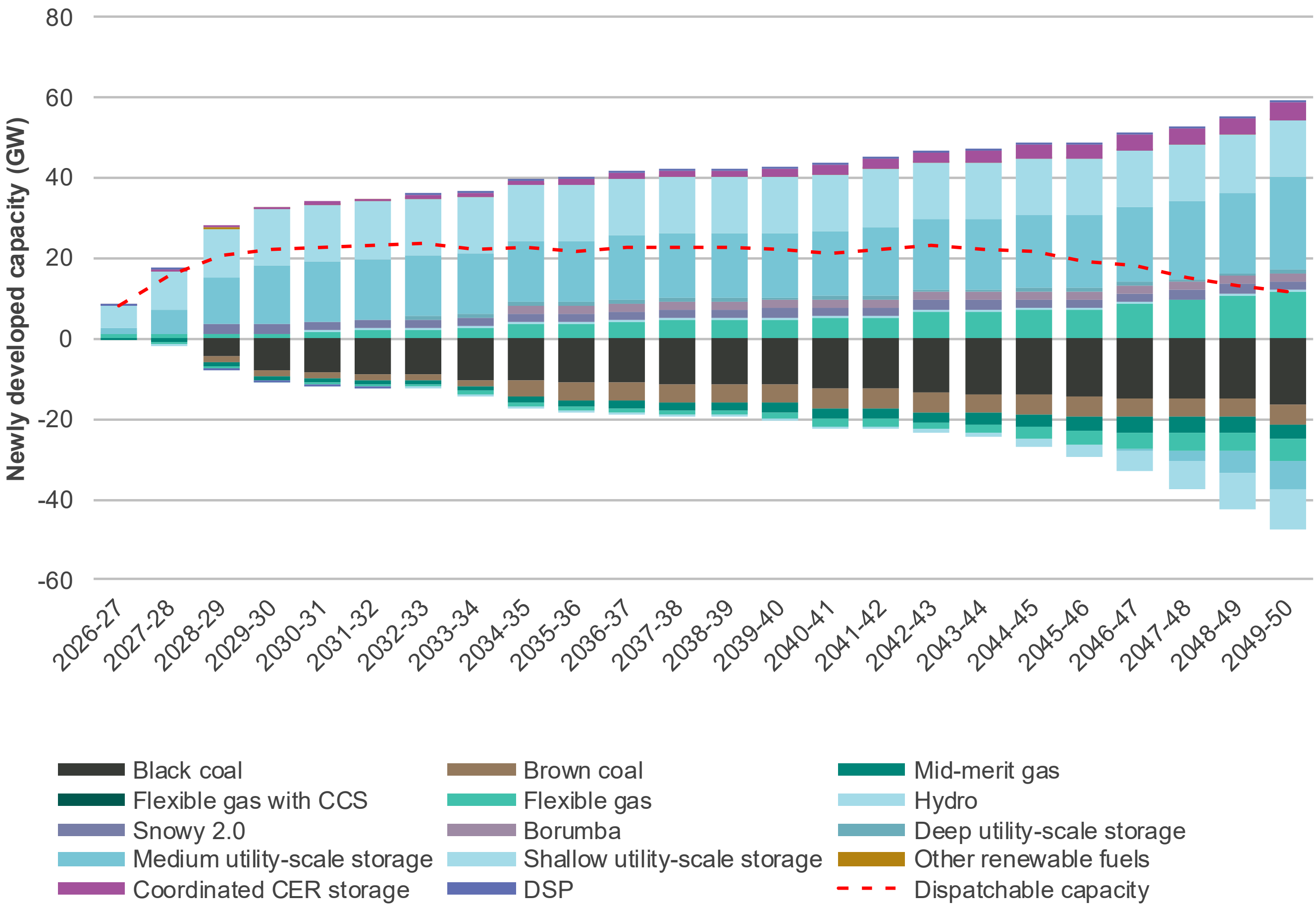


Dispatchable capacity to firm renewables

As VRE generation increases, dispatchable capacity is required to firm the significant penetration of renewable generation and ensure ongoing reliability. While the total level of dispatchable capacity is projected to decline by the end of outlook period due to an oversupply in early years with this scenario's industrial closures and lower demand growth, its technology make-up changes throughout the outlook period, and much of the retiring dispatchable capacity (coal and mid-merit gas generation) will need to be replaced. Medium-depth and deep utility-scale storage capacities, including pumped hydro energy systems, as well as hydro generators are critical for balancing the variability of VRE and maintaining system reliability. This is in addition to growth in flexible gas that provides new dispatchable capacity and complements the variable energy generated by VRE developments.

Figure 28 illustrates the change in dispatchable capacity projections across the outlook period. Dispatchable capacity (including coordinated CER storage, which includes V2G) is projected to account for about 28% of the total installed capacity in the NEM by 2049-50.

Figure 28 Projected relative change compared with 2025-26 in dispatchable capacity, *Slower Growth*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

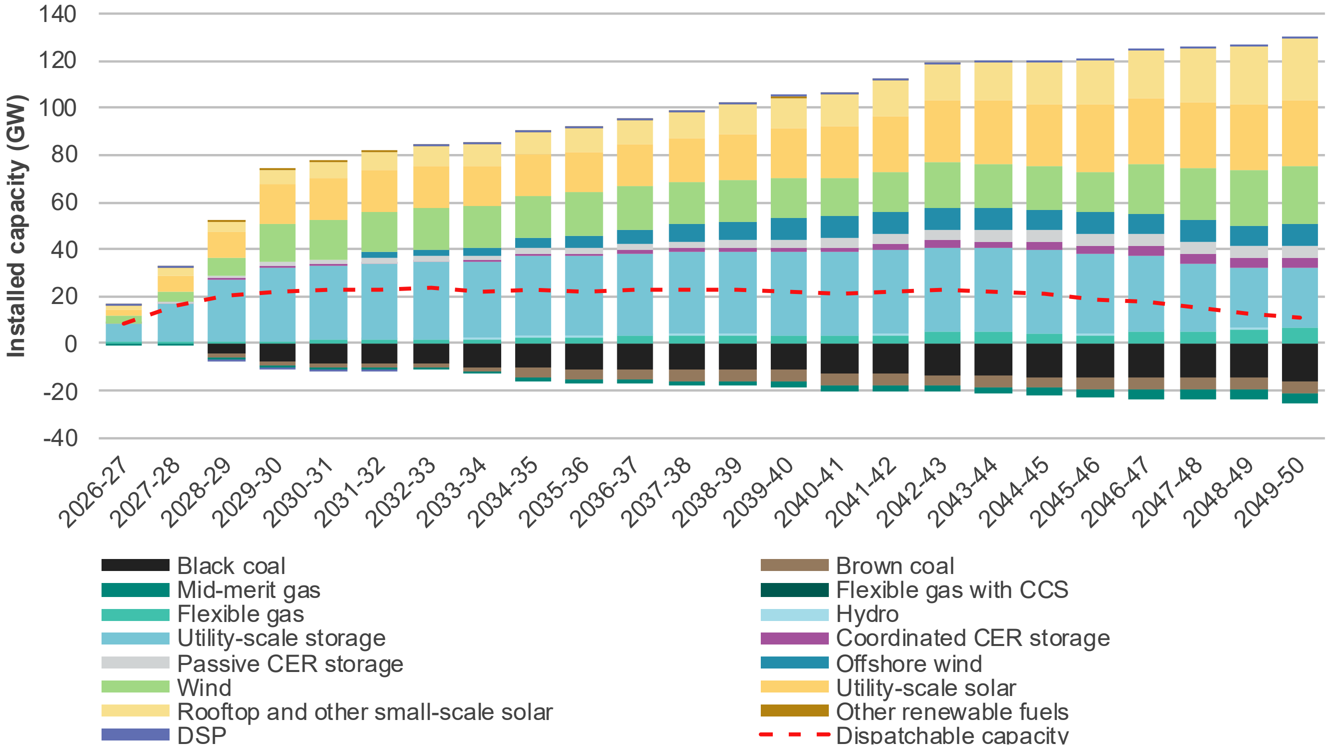
Figure 24 earlier shows that all coal-fired generation capacity is projected to retire by 2049-50 in the NEM, but the pace at which it retires varies by region:

- In Victoria, 30% of coal-fired generation capacity is projected to retire by 2029-30, with 100% of coal-fired generation capacity projected to retire by 2035-36.
- In New South Wales, retirements of coal-fired generation capacity start from as early as 2028-2029, and by 2040-41, all coal-fired generation capacity in the region is projected to retire. This early retirement is primarily driven by significant investments in VRE technologies supported by policies. In Queensland, 50% of existing coal capacity is projected to retire by 2037-38, with some capacity available to 2049-50.

New developments and closures

Figure 29 shows the cumulative change in investments and withdrawal by technology type projected over the outlook period. Due to the lower demand growth in this scenario relative to other ISP scenarios, and assumed industrial closures, the level of development opportunity beyond that which is committed, anticipated, or supported by various government policies is lower.

Figure 29 Projected relative change in new installations and closures compared to 2025-26 installed capacity, *Slower Growth*, 2025-26 to 2049-50 (GW)

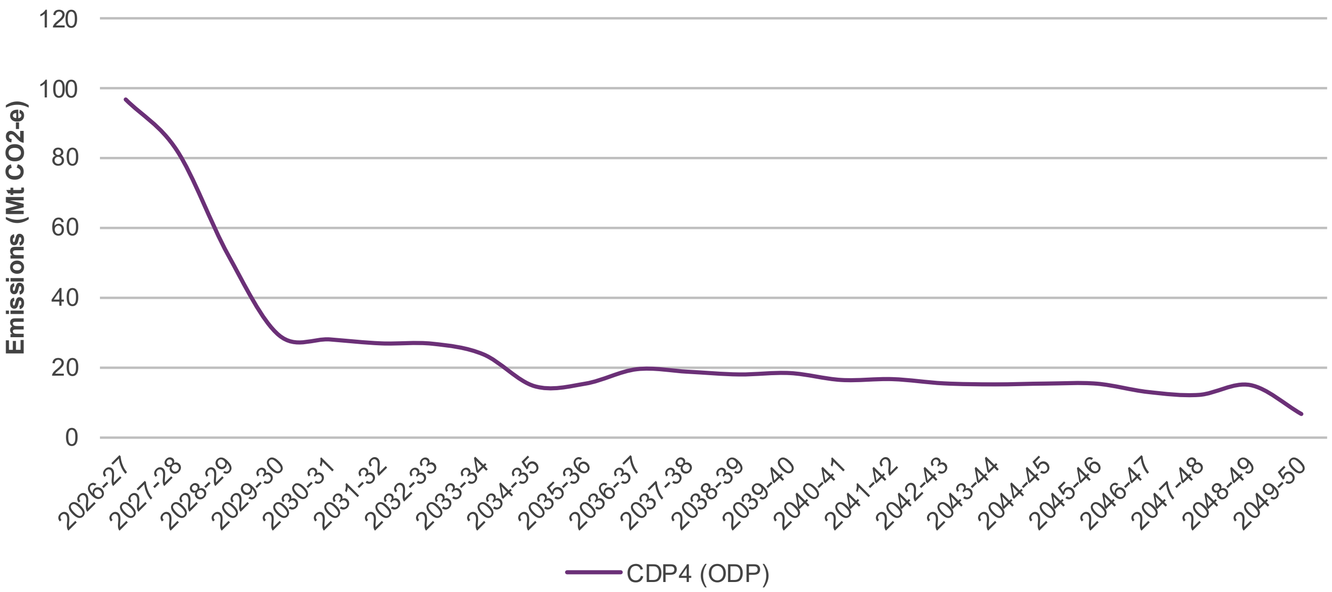


In *Slower Growth* by 2029-30, the NEM is projected to consist of 27.8 GW of utility-scale solar, 28 GW of wind, and 32.1 GW of rooftop and other small-scale solar to replace retiring coal. Including anticipated and committed projects, the NEM is projected to add 39 GW of utility-scale solar, 36 GW of wind, 9 GW of offshore wind, and 52.8 GW of rooftop and other small-scale solar to replace the existing capacity and meet increasing energy consumption by 2049-50. The majority of VRE generation is in New South Wales, largely driven by tendering processes to develop generation aligned with the infrastructure investments objectives of the *Electricity Infrastructure Investment Act 2020* (NSW).

Impact on emissions

Figure 30 shows the projected emissions trajectory to 2049-50 for *Slower Growth*. Emissions decline most steeply in the years leading up to 2034-35 – reaching 14 Mt CO_2-e, a 92% decrease from 2004-05 levels – due to federal and state renewable energy policies, targets and capacity addition from the January 2026 Generation Information, as explained in Section A2.2.1. By 2049-50, emissions are projected to be as low as 6 Mt CO_2-e per annum.

Figure 30 Projected NEM emissions trajectory, *Slower Growth* 2026-27 to 2049-50 (Mt CO_2-e)

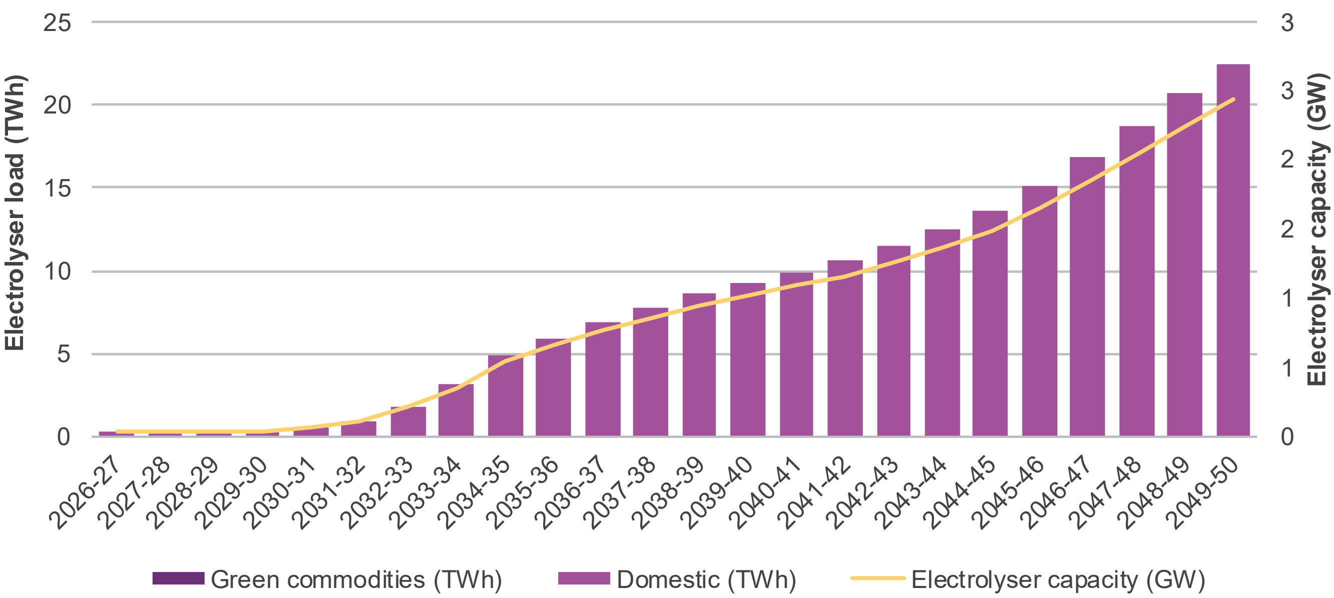


Hydrogen developments

In *Slower Growth*, hydrogen developments over the outlook period are for domestic use in the transport and industrial sectors, with minimal demand for hydrogen in green commodities and no hydrogen export, as discussed in the 2025 IASR.

Figure 31 demonstrates the projected scale of electricity consumption for hydrogen production requirements. The majority of hydrogen production is allocated to South-West Victoria REZ and Illawarra REZ, with 1.1 GW and 0.6 GW of electrolyser capacities allocated by 2049-50, respectively. South West Victoria and Illawarra REZs are preferred locations due to being located near assumed domestic hydrogen demand centres, in combination with high REZ import limits.

Figure 31 Electricity consumption associated with hydrogen production, *Slower Growth*, 2026-27 (TWh and GW)



Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Slower Growth*

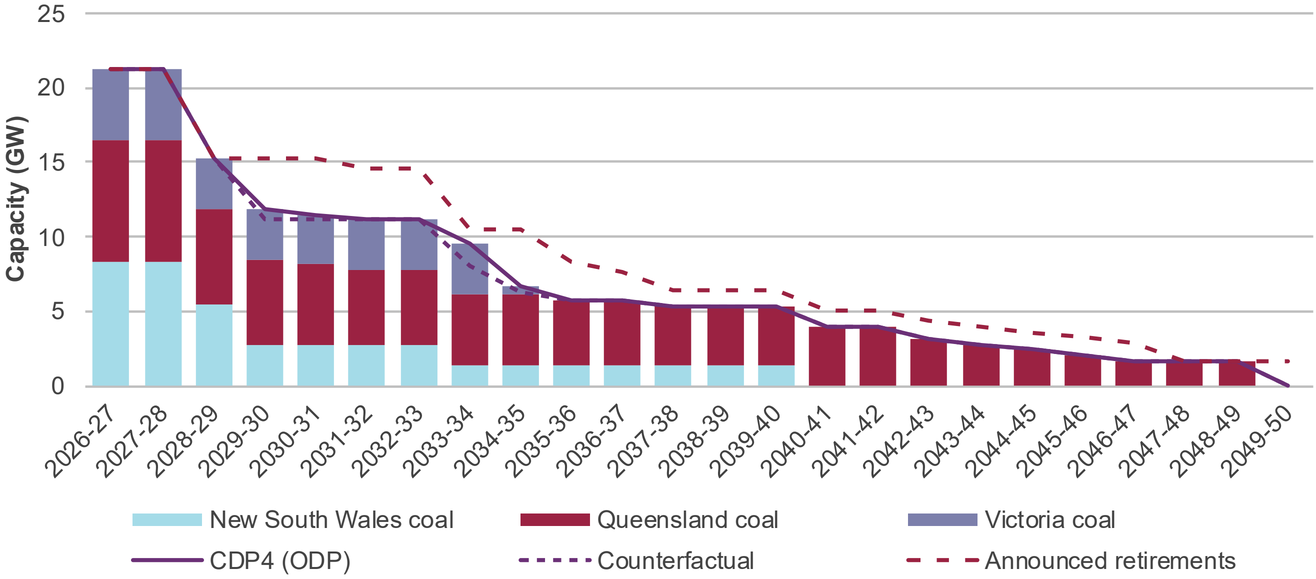
The 2026 ISP identifies material savings to consumers through the expansion of the transmission network (see Appendix A6 Cost Benefit Analysis for more details). Transmission investments help facilitate the transition to a lower-emissions energy system by improving access to renewable energy developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

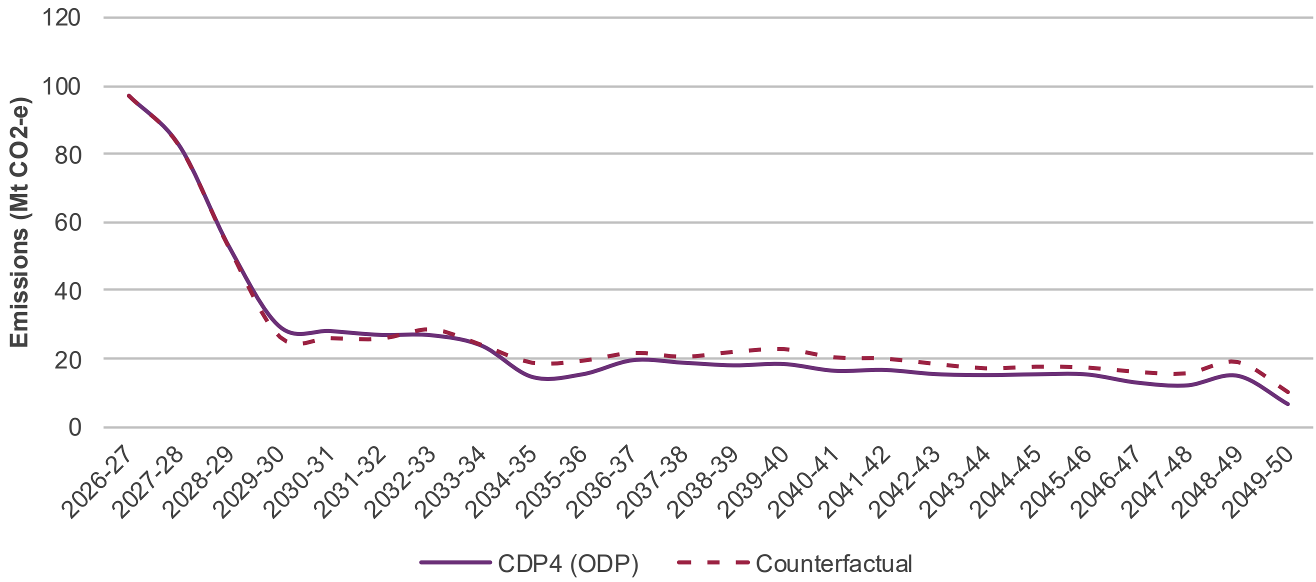
Impact of transmission development on retirements of coal-fired generation capacity and capacity mix

Figure 32 shows the equivalent coal-fired generation capacity retirement schedule in the 'no transmission' counterfactual development path (where there is no new major transmission network augmentation) compared with the ODP in *Slower Growth*.

Without major transmission augmentation, coal-fired generation capacity would need to retire faster to provide headroom on the NEM emissions budget so this can be used by flexible gas later in the outlook period, as without transmission expansion, greater utilisation of gas-powered generation is required. Additionally, there is a higher reliance on flexible gas generation over the outlook period as VRE generation is curtailed due to lack of additional transmission network augmentation. This leads to a slightly higher emissions trajectory to 2049-50 but still within the NEM emissions budget. The emissions trajectory is projected to be slightly higher than the ODP in *Slower Growth*, reaching 10.5 Mt CO_2-e compared to 6 Mt CO_2-e, with more gas used to maintain system reliability and meet demand.

Figure 32 Projected coal-fired generation capacity development (top) and emissions trajectory (bottom) to 2049-50, 'no transmission' counterfactual development path compared with *Slower Growth* (GW and Mt CO_2-e)

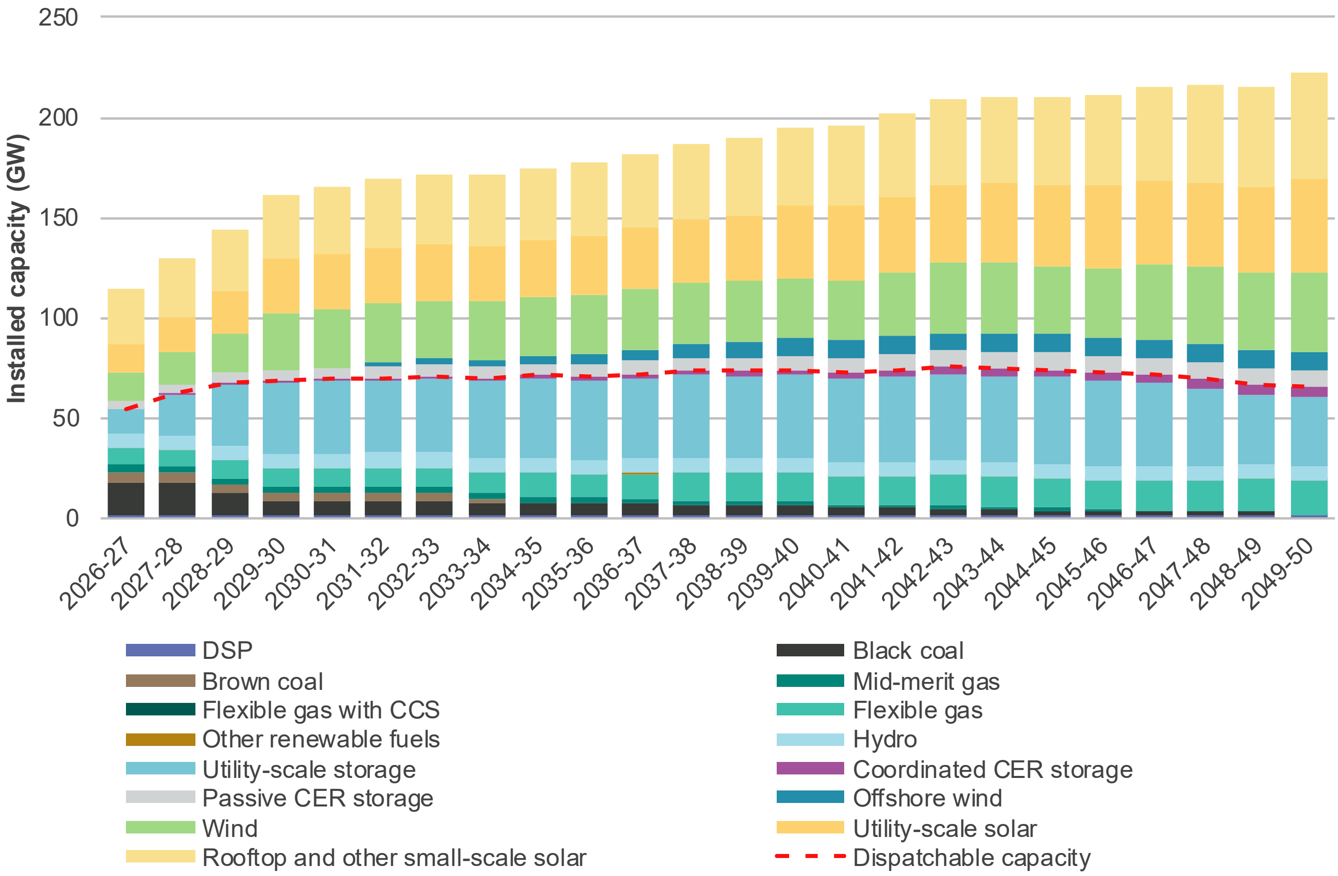




Impact of transmission development on generation mix

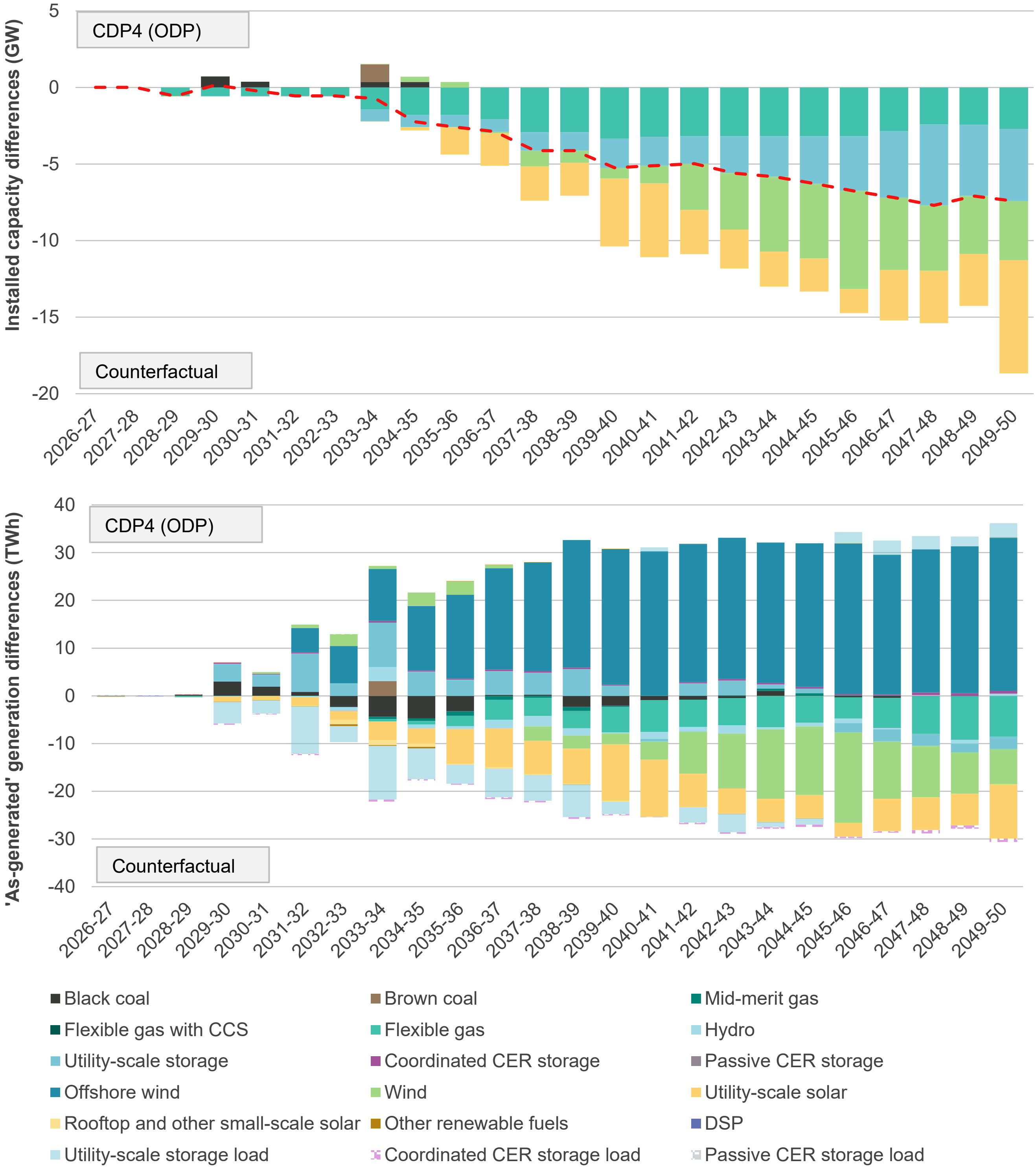
Figure 33 below shows that the 'no transmission' counterfactual development path incorporates rapid VRE development from 2029-30 onward, particularly wind and utility-scale solar generation (including mid-scale solar connected to the distribution network), to replace coal generation at a faster rate to meet emissions targets and emissions budgets.

Figure 33 Projected NEM installed capacity, *Slower Growth* 'no transmission' counterfactual development path, 2026-27 to 2049-50 (GW)



For comparison, **Figure 34** presents the difference in installed capacity and dispatched generation between the ODP and the 'no transmission' counterfactual development path. From the early 2030s, due to limited energy transfer across regions, localised gas generation is required during periods of VRE lulls, leading to greater reliance on flexible gas generation. Transmission limitations lead to greater reliance on alternative technologies that can be connected to existing transmission network near demand centres or within regions with available network capacity, rather than being optimised for resource quality. Generation from technologies like offshore wind, which rely heavily on transmission, is significantly reduced. This is particularly present in Victoria, where the absence of new transmission results in significantly higher levels of offshore wind curtailment and additional generation development requirement. Greater use of solar connected to the distribution network is also a feature of the 'no transmission' counterfactual development path (bundled within solar in the figure).

Figure 34 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Slower Growth* (GW and TWh)



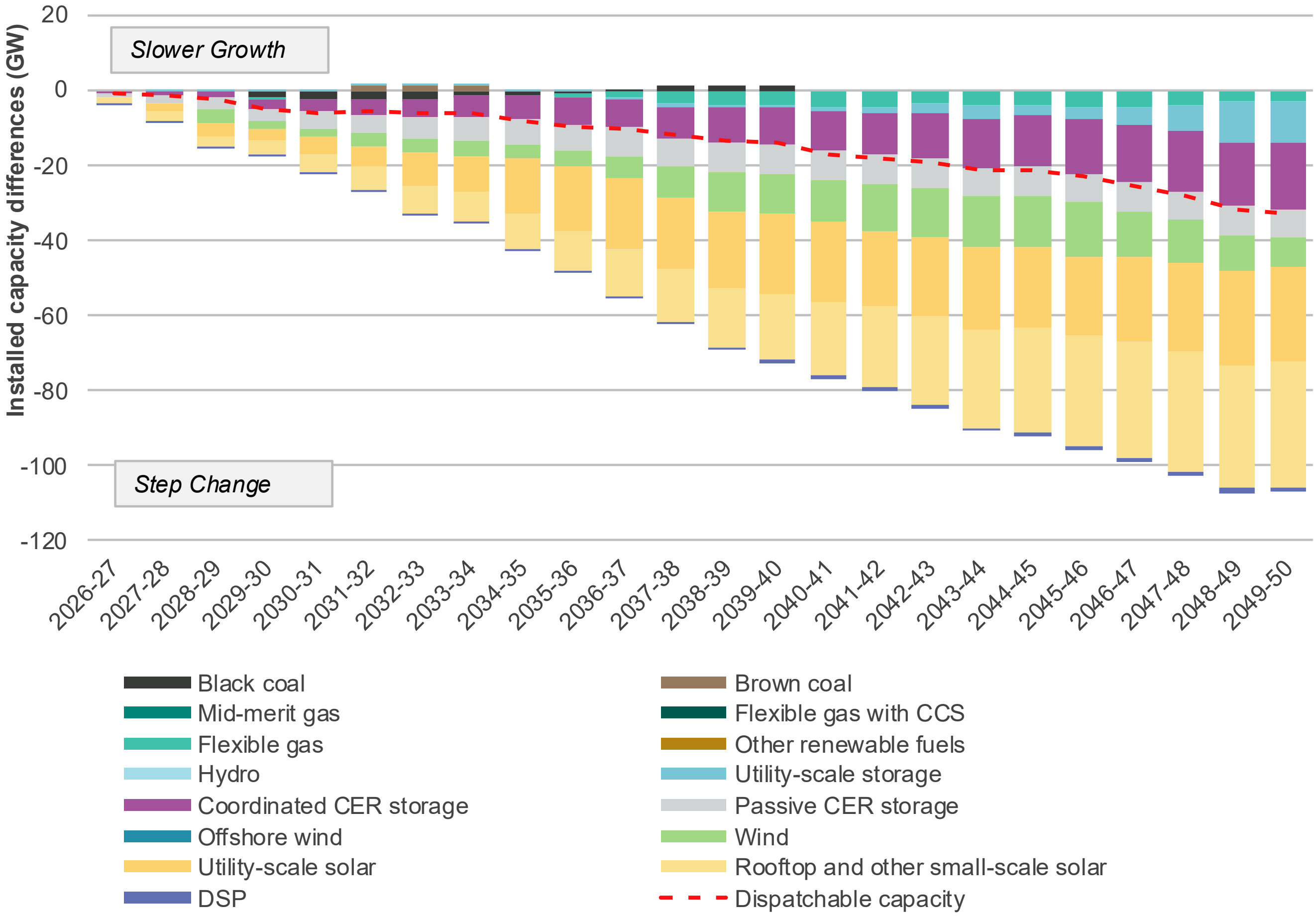
Contrasting the ODP's development opportunities in *Slower Growth* and *Step Change*

Figure 35 below presents the capacity difference between the results for the *Slower Growth* and *Step Change* scenarios. By the end of the outlook period, the difference between scenarios reflects the strong contribution from consumers, characterised by higher coordinated CER storage and higher rooftop and other small-scale solar uptake in *Step Change*. Conversely, *Slower Growth* features a weaker economic outlook, lowering generation requirements, with less industrial load relative to business and residential loads in the longer term.

The key differences from the results in *Step Change* are:

- VRE development is at a much slower rate, as lower economic and population growth reduce the overall scale of change required to achieve net zero by 2050. By the end of the outlook period, the difference in VRE capacity between scenarios increases due to differences in projected energy consumption and tighter emissions budget leading to more VRE developments in *Step Change*.
- Although recent uptake in CER storage technologies has been higher due to the Federal Government's CHBP, *Slower Growth* features lower medium- and long-term CER storage uptake compared to *Step Change*. The scenario's lower growth in consumer demand results in a reduction in the volume of flexible gas needed to meet firming requirements.

Figure 35 Projected capacity development to 2049-50 under *Slower Growth* compared to *Step Change* (GW)

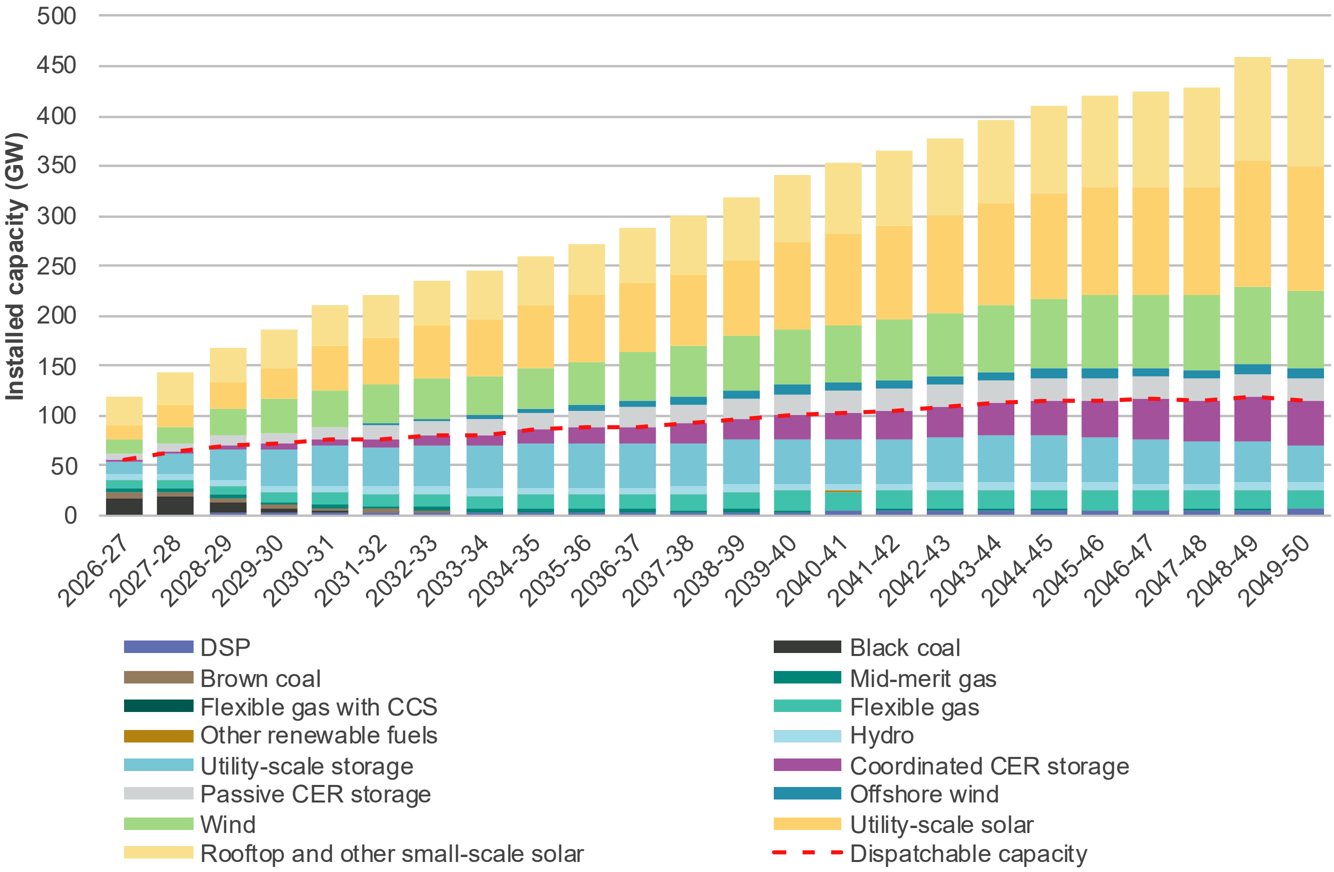


A2.3.3 Accelerated Transition

Accelerated Transition features faster economic growth and stronger commitment to decarbonise the economy, which drives rapid energy sector transformation through electrification, green commodity production, and high consumer uptake of CER and increased CER coordination.

The scenario features the quickest rate of transformation, with the greatest need for the development of infrastructure compared with *Step Change*. **Figure 36** presents the projected capacity mix for the NEM across the outlook period to 2049-50 in *Accelerated Transition*.

Figure 36 Projected NEM installed capacity, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



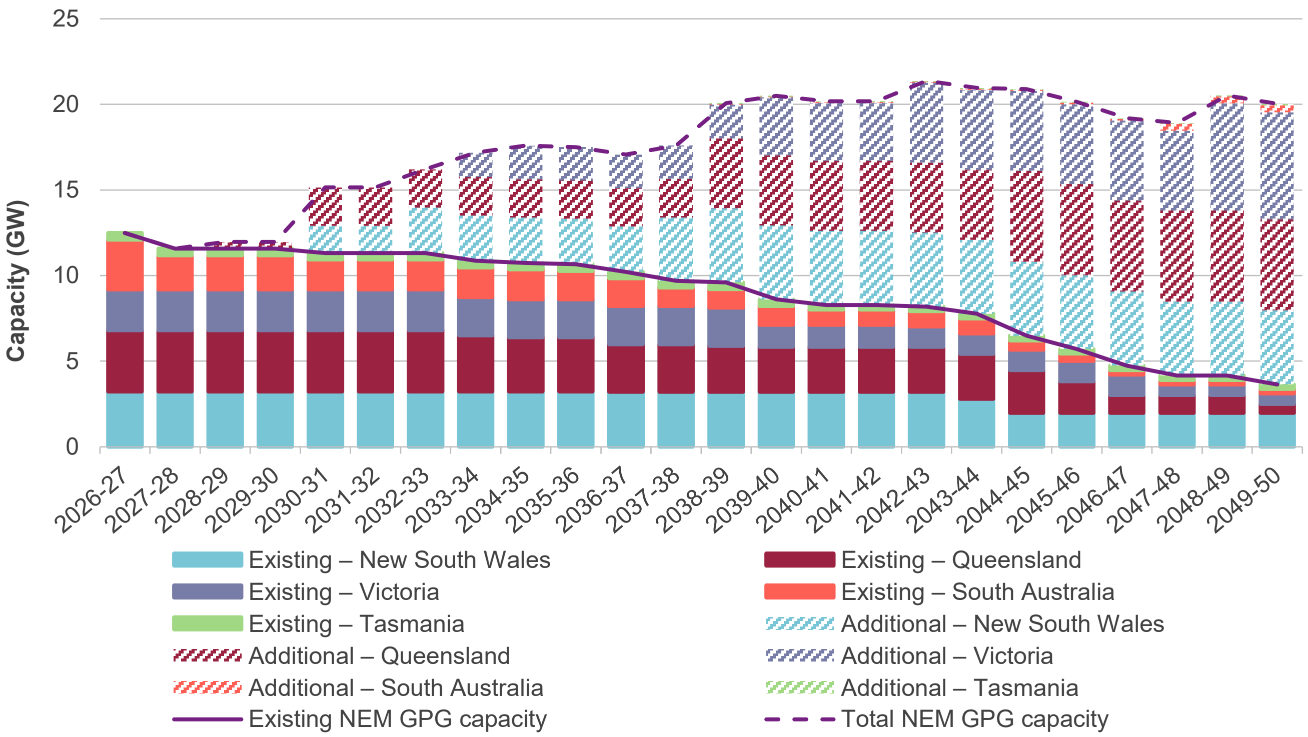
Renewables to replace coal as bulk generation

In *Accelerated Transition*, a large proportion of renewable energy developments are projected in New South Wales, Queensland and Victoria, influenced by significant load developments in those regions under this higher growth scenario and faster retirement due to a smaller emission budget. The relatively small emissions budget leads to rapid retirement of coal-fired generation capacity, with only 8.6 GW of coal-fired generation capacity projected to be operational by 2029-30. High uptake of utility-scale VRE replaces the generation no longer provided by coal-fired power stations, supported by a high contribution from CER. Storages of various depths are needed to support reliability and grid stability, including opportunities for storage developments within the distribution network.

By 2049-50, approximately 211 GW of utility-scale VRE and over 109 GW of rooftop and other small-scale solar will be needed. At a regional level, capacity expansion is most significant in New South Wales, followed by Queensland and Victoria. South Australia is projected to experience the fastest relative growth from 2029-30, particularly to support high industrial load developments projected in the scenario.

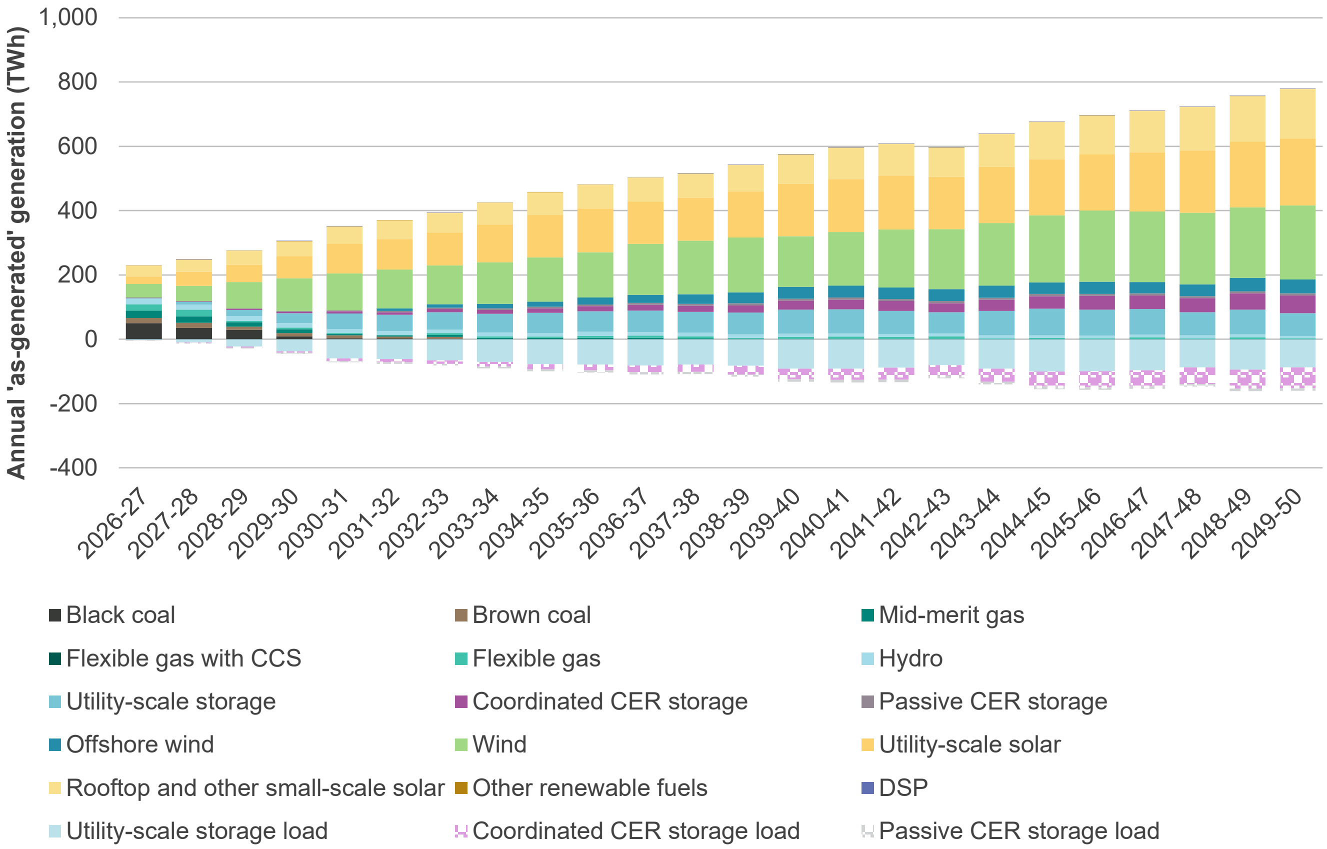
In addition to storages, flexible gas capacity is required to provide additional back-up capacity during extreme demand periods or when renewable generation output is low. As shown in **Figure 37**, the total gas capacity in 2049-50 is projected to be 20 GW in the *Accelerated Transition*, approximately 3 GW higher than *Step Change.*

Figure 37 Projected gas capacity development, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



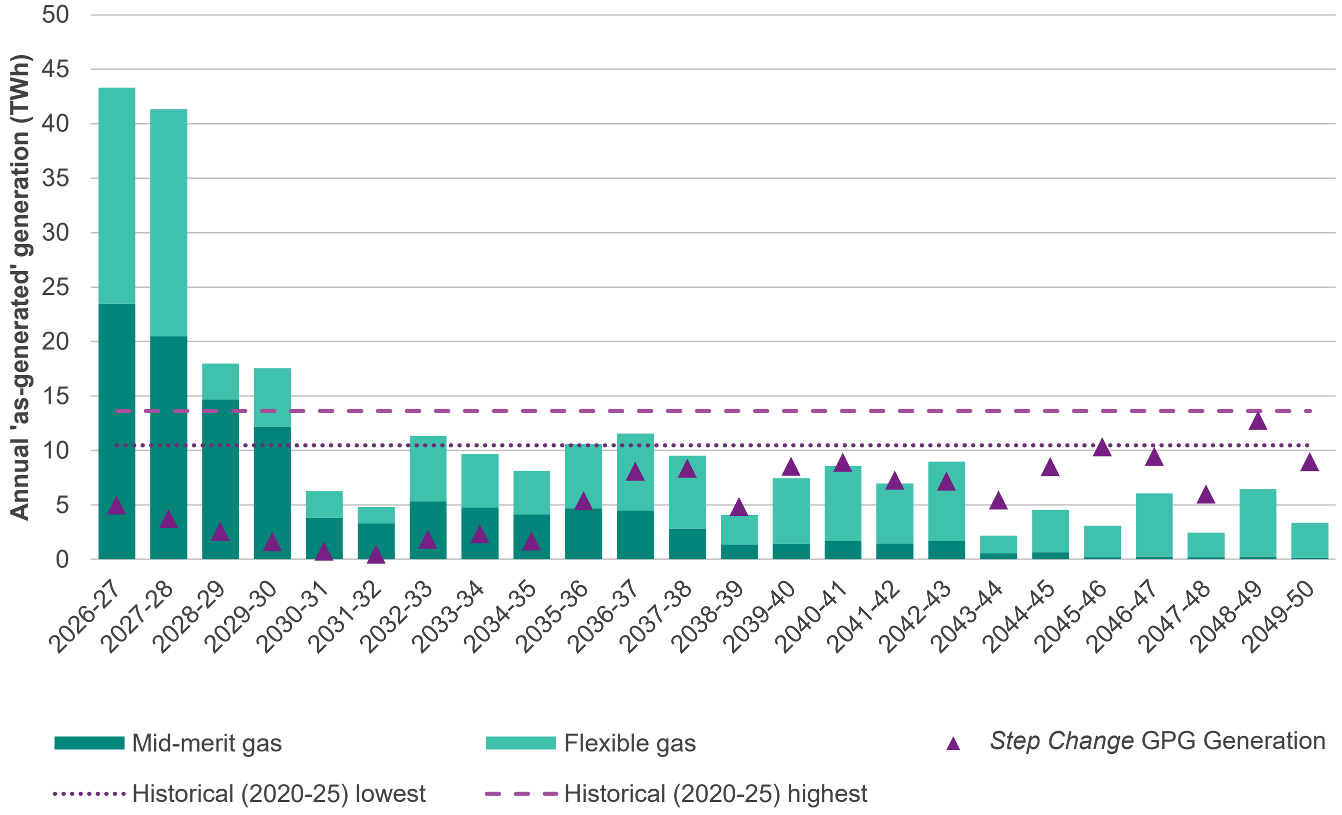
Similar to *Step Change*, significant new VRE capacity is projected to transform the NEM into a low-emissions energy system, underpinning the strong decarbonisation of Australia's economy. Renewable energy generation from wind and solar technologies is projected to grow throughout the outlook period, complementing the assumed development of CER (see **Figure 38**). By 2049-50, the projected share of renewable generation is projected to increase to 99% of all generated electricity; the remaining 1% is provided by flexible gas, which provides back-up supply during extreme demand periods and renewable energy lulls.

Figure 38 Projected annual generation, *Accelerated Transition*, 2026-27 to 2049-50 (TWh)



The increase in electricity consumption, smaller emissions budget and rapid retirement of coal-fired generation capacity led to increased generation from gas powered capacity in *Accelerated Transition* compared to *Step Change*, as shown in **Figure 39** in the early years. This degree of gas use may be more than current gas supply commitments will support, without impacting on supply to other gas users.

Figure 39 Projected annual gas generation, *Accelerated Transition*, 2026-27 to 2049-50 (TWh)



Note: while this scenario forecasts very high utilisation of gas for electricity generation in the first two years, available gas supply is unlikely to be able to support this without risking gas inadequacy for other gas users, and coal therefore may need to operate at higher levels for these years. This would lead to a level of emissions in excess of the emissions budget allowed in this scenario to align with 1.5 degrees.

Dispatchable capacity to firm renewables

Dispatchable capacity is projected to increase steadily across the outlook period, reflecting ongoing need for firming resources to support the growing share of renewable energy and growing customer demand.

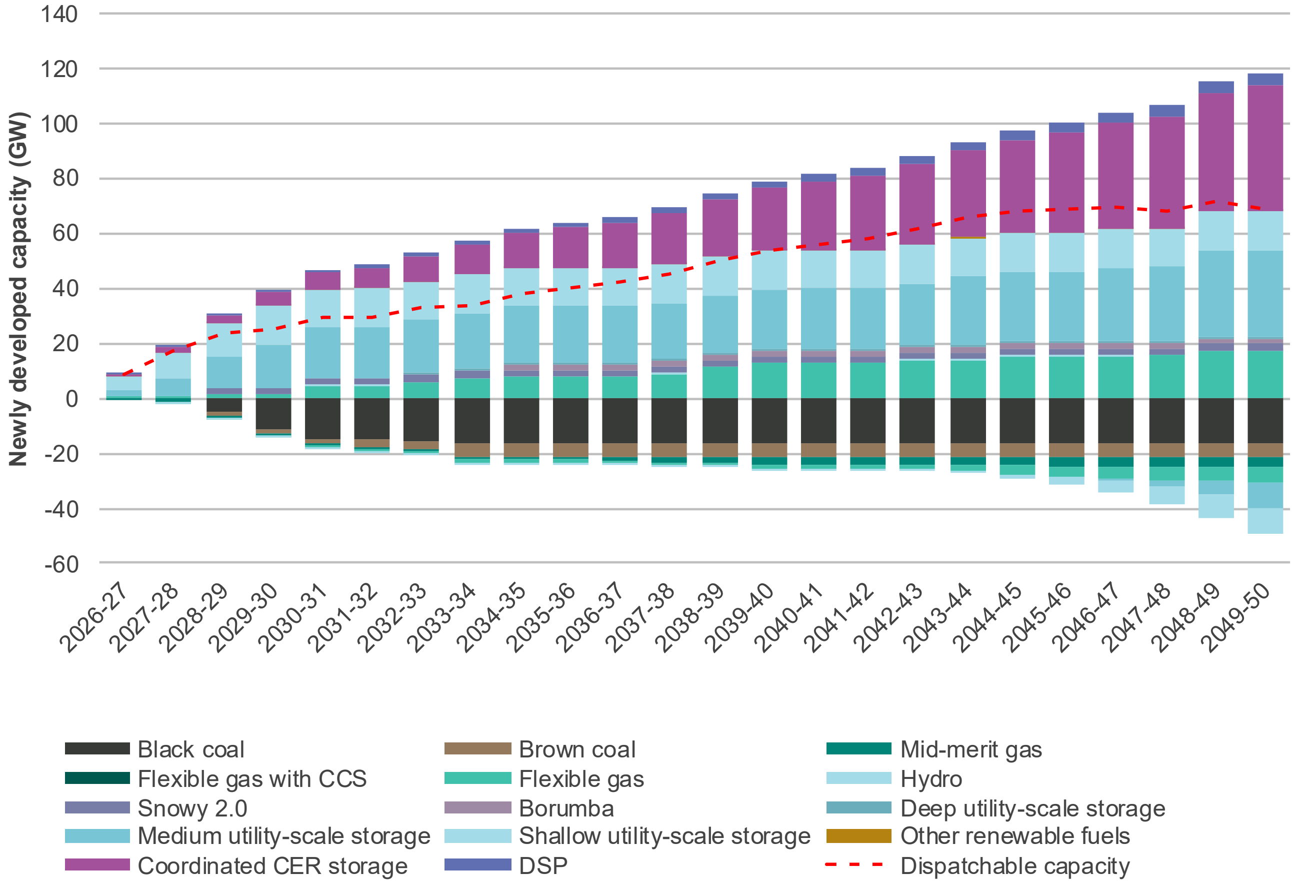
Figure 40 demonstrates the projected change in capacity across the outlook period. Consistent with the findings for *Step Change*, significant expansion of various storage technologies is projected. Total storage dispatchable capacity – which includes coordinated CER storages, utility-scale storages, and pumped hydro energy systems – provides sufficient dispatchable capacity to maintain reliability as coal-fired generation capacity retires. Dispatchable capacity (including coordinated CER storage which includes vehicle-to-grid) is projected to account for about 25% of the total installed capacity (including CER) in the NEM by 2049-50.

Towards the end of the outlook period, CER storage is expected to grow at a faster rate than utility-scale storage, driven by increased investments from households seeking to maximise the value of rooftop and other small-scale solar generation.

Retiring gas-powered generation capacities are largely being replaced by new flexible gas, which further complements the energy generated by VRE technologies.

The need for dispatchable capacity could be reduced if more demand side factors eventuate than are forecast in the scenario. This may include greater levels of demand flexibility from large loads such as electrolysers and data centres, or greater gains in energy efficiency or CER coordination.

Figure 40 Projected relative change in dispatchable capacity compared with 2025-26, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



Coal retirement schedule

All black and brown coal-fired generation capacities are projected to exit the market by 2033-34 under *Accelerated Transition* to meet the rapid emissions reduction requirements (in addition to the emissions targets, this scenario has the smallest emissions budget of 303 Mt CO_2-e from period 2026-27 to 2049-50), reflecting alignment with the ambition of limiting global temperature rise to 1.5°C by the end of the century. In 2029-30, only 8.6 GW of coal-fired generation capacity is projected to be operational (60% lower than existing coal-fired generator capacity).

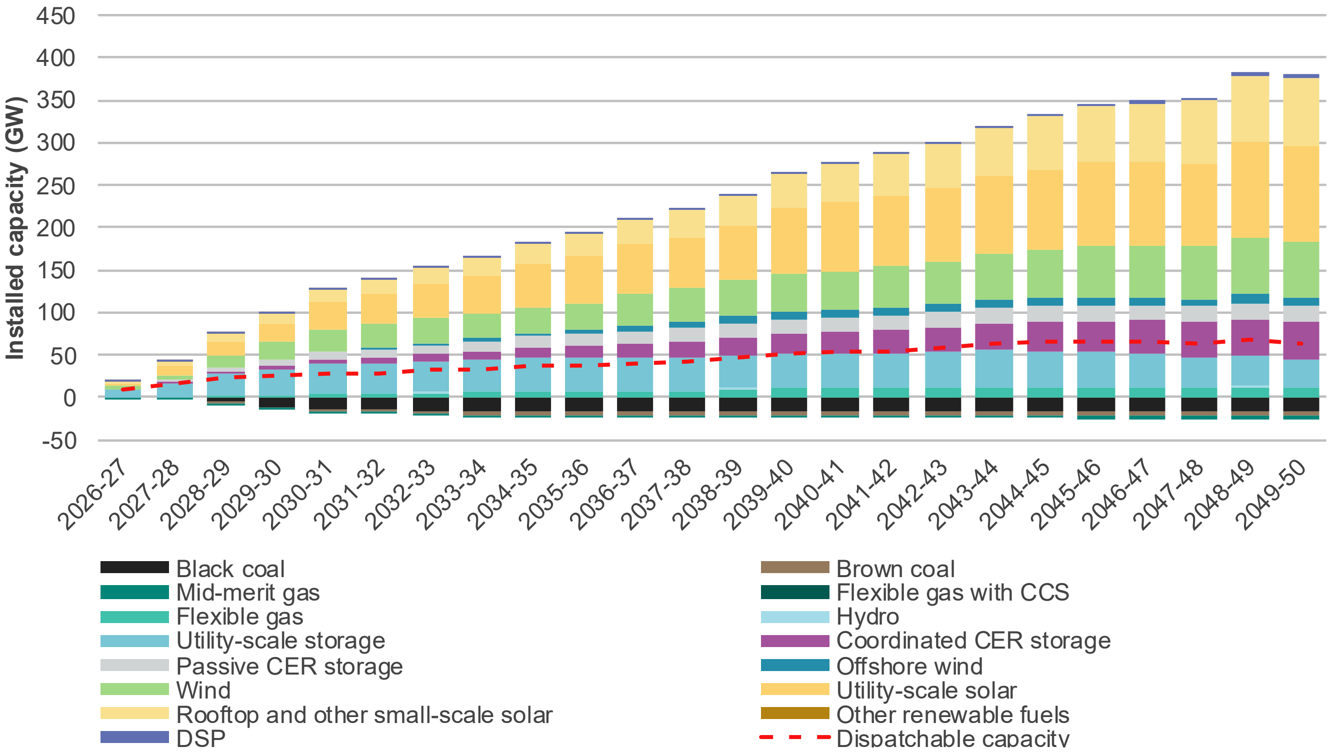
New developments and closures

Figure 41 shows the cumulative change in technology type projected over time. Significant development in new VRE capacities is projected throughout the outlook period, to replace retiring coal-fired generation and meet projected growth in energy consumption. In *Accelerated Transition*, total VRE capacity (including CER) increases from existing levels of 50 GW to 320 GW by 2049-50, representing 70% of total installed capacity. By the end of outlook period, the total VRE mix is projected to comprise approximately 27% wind, 39% utility-scale solar, and 34% rooftop and other small-scale solar.

Strong consumer investment in their own energy resources is assumed in this scenario, including relatively high assumed uptake and coordination of CER storages and higher rooftop and other small-scale solar.

VRE development is highest in New South Wales, supporting increasing electricity consumption in the NEM's largest region, including strong assumed growth in data centres.

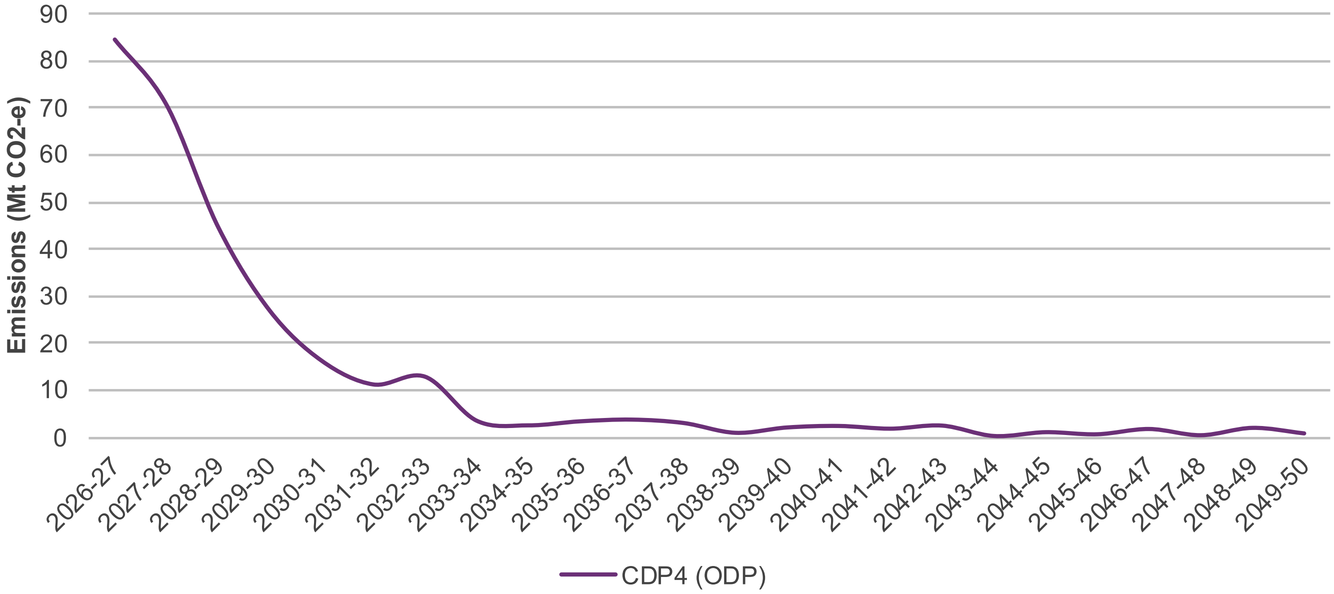
Figure 41 Projected relative change in new installations and closures compared to 2025-26 installed capacity, *Accelerated Transition*, 2026-27 to 2049-50 (GW)



Impact on emissions

Figure 42 shows projected emissions trajectories to 2049-50 for *Accelerated Transition*. Due to the strong decarbonisation goal in *Accelerated Transition*, its emissions trajectory is significantly lower than the other two scenarios. By 2029-30, emissions are expected to reach about 27 Mt CO_2-e, or 32% lower than in *Step Change*. In 2034-35, emissions are projected to reduce by 98% compared to 2005 levels (from 176 Mt CO_2-e in 2004-05 to 3 Mt CO_2-e in 2034-35). The low emissions budget drives the early retirements of coal-fired generation capacity and the expansion of renewable energy.

Figure 42 Projected NEM emissions trajectory, *Accelerated Transition*, 2026-27 to 2049-50 (Mt CO_2-e)



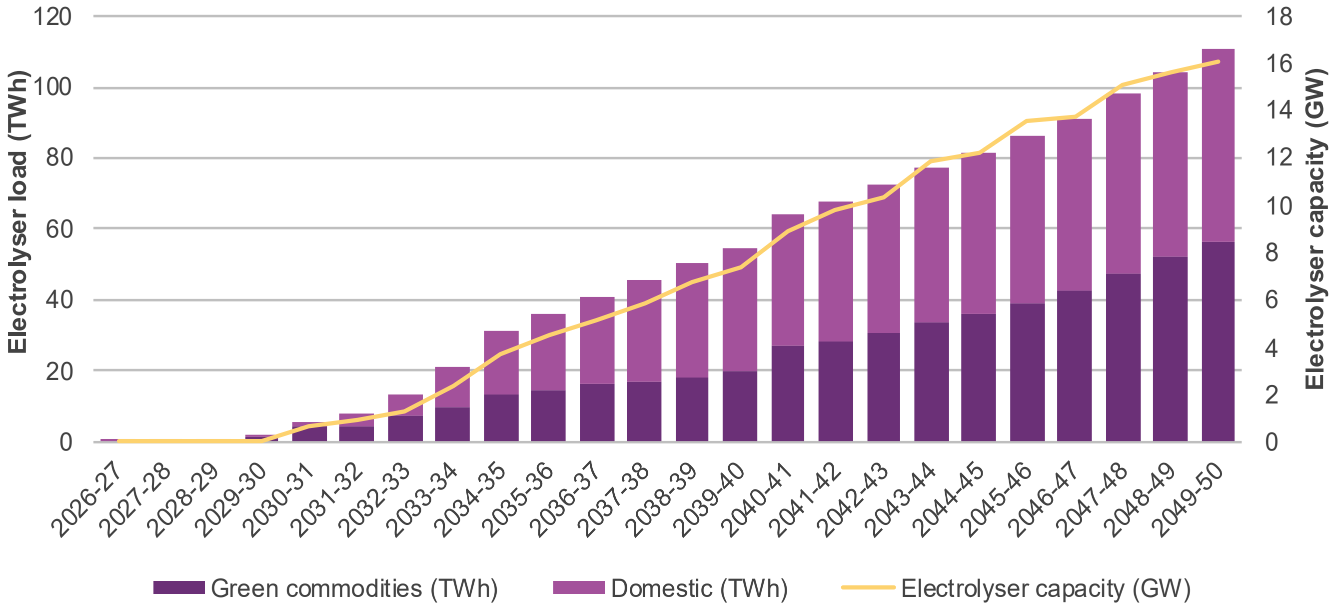
Hydrogen developments

Figure 43 presents the assumed total electricity consumption to 2049-50 for hydrogen production that is used for domestic use and green commodities production (including that used for electric-arc furnaces for green-steel manufacturing).

In *Accelerated Transition*, electricity consumption for hydrogen production is projected to be 111 TWh by 2050, substantially lower than the nearly 600 TWh in the *Green Energy Exports* scenario in the 2024 ISP, but still reflecting a significant opportunity at approximately half the current NEM operational consumption. The scenario assumed over 79 TWh more consumption for hydrogen production than in *Step Change* by 2049-50.

To service the hydrogen demand, over 16.1 GW of electrolysers are developed, with flexible electrolysers operating at 68% utilisation on a load-weighted average basis. The higher level of flexibility is to allow more effective integration of these loads within REZs, enabling local generation to be used to operate the facilities, rather than having to import electricity when local generation is low. Higher hydrogen flexibility reduces the need for gas-powered generation to operate, lowering emissions outcomes.

Figure 43 Electricity consumption associated with hydrogen production, *Accelerated Transition*, 2026-27 to 2049-50 (TWh and GW)



The 2025 IASR provided forecast geographical diversity of hydrogen loads in this scenario – Victoria and New South Wales have the highest domestic hydrogen production requirements, while hydrogen production for green commodities is concentrated in Queensland, New South Wales and South Australia.

By 2049-50, over 16.1 GW of electrolyser capacity is installed to meet almost 96.2 TWh of hydrogen load, with 96 TWh of flexible operations and approximately 14 TWh for less flexible operations, including electric arc furnace load.

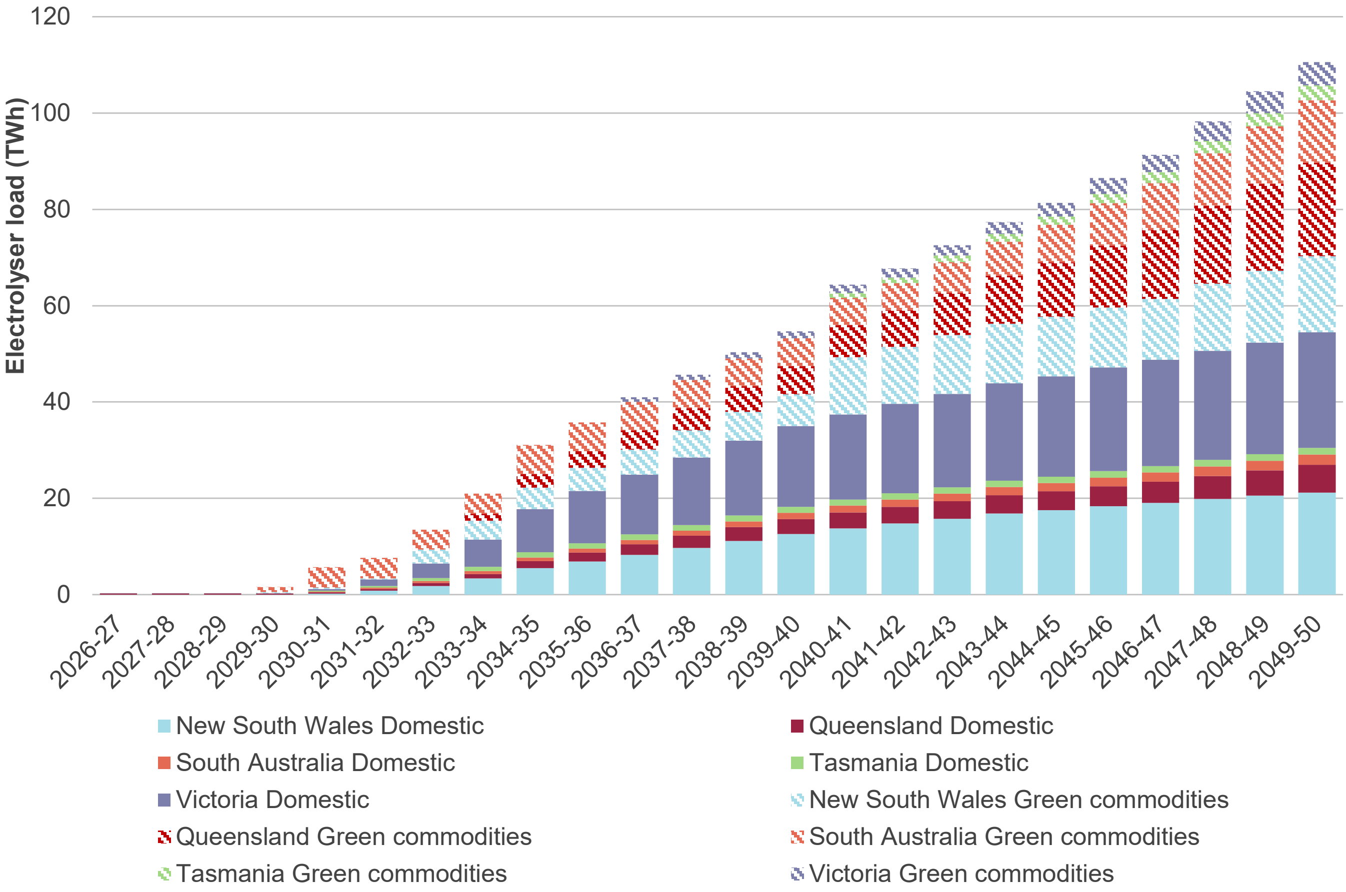
Electrolysers are expected to locate in areas that have good access to both renewable energy supply and the customers most likely to consume their product, to minimise the cost of transportation. For green commodities that can be consumed by domestic and international customers, access to export facilities will also be a locational influence[22].

A large portion of electrolysers that are built to serve demand for green commodities are in Fitzroy, Hunter-Central Coast and Northern South Australia REZs, as they are sufficiently close to export terminals and potential domestic consumers, and have sufficient transmission capacity to host electrolysers.

Figure 44 shows the locational growth in hydrogen consumption that has been assumed in this scenario in the 2025 IASR.

[22] The location and split of green commodity electrolyser load were pre-determined with the South Australian Department of Energy and Mining based on the locations of existing hydrogen projects.

Figure 44 Regional hydrogen consumption, *Accelerated Transition*, 2026-27 to 2049-50 (TWh)



Contrasting the ODP's development opportunities with the 'no transmission' counterfactual development path in *Accelerated Transition*

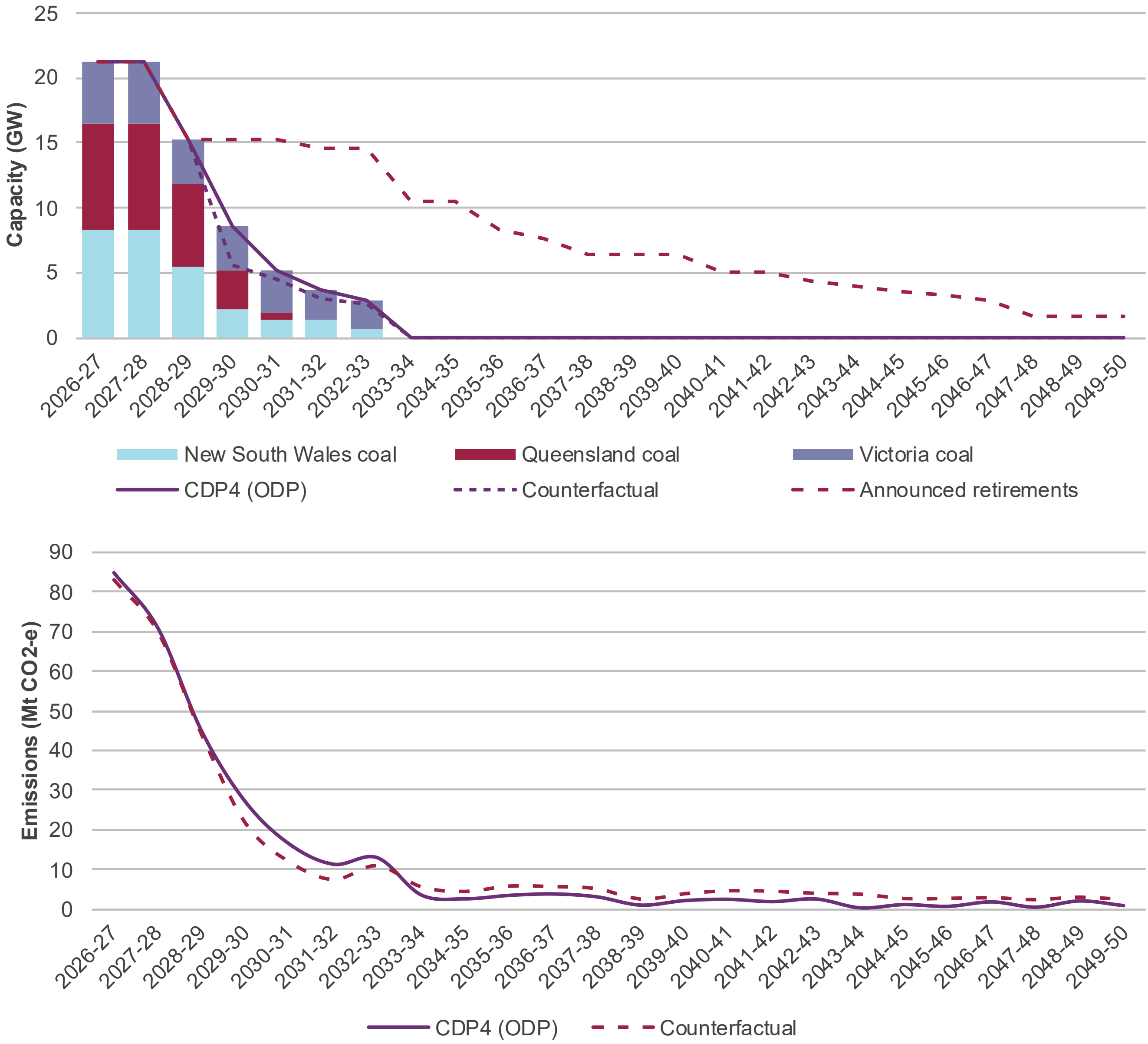
The 2026 ISP identifies material savings to consumers through the expansion of the transmission network (see Appendix A6 Cost Benefit Analysis for more details). Transmission investments help transition to a lower-emissions energy system by improving access to renewable energy developed in REZs and reducing potential VRE curtailment due to transmission limitations. At times of VRE curtailment due to network limitation, higher cost generation may need to generate, increasing overall costs and increasing emissions.

Impact of transmission development on retirements of coal-fired generation capacity

Figure 45 below shows a comparison between retirement schedule of coal-fired generation capacity in the 'no transmission' counterfactual development path which does not feature major transmission network augmentation beyond what is anticipated or committed (solid line) and in the ODP (bars), contrasted with the announced closure dates (dashed line). Below the first chart is a comparison of the emissions trajectory between the 'no transmission' counterfactual development path and ODP.

In the 'no transmission' counterfactual development path, without major transmission expansion and limited access to VRE, some brown coal plants in Victoria and some black coal plants in Queensland retire earlier compared to the ODP to save emissions that are later produced by other generation sources such as gas. In both cases, coal utilisation declines as utility-scale wind and solar, storages, and flexible gas increase operation. The two cases present minor differences in terms of overall emissions outcomes.

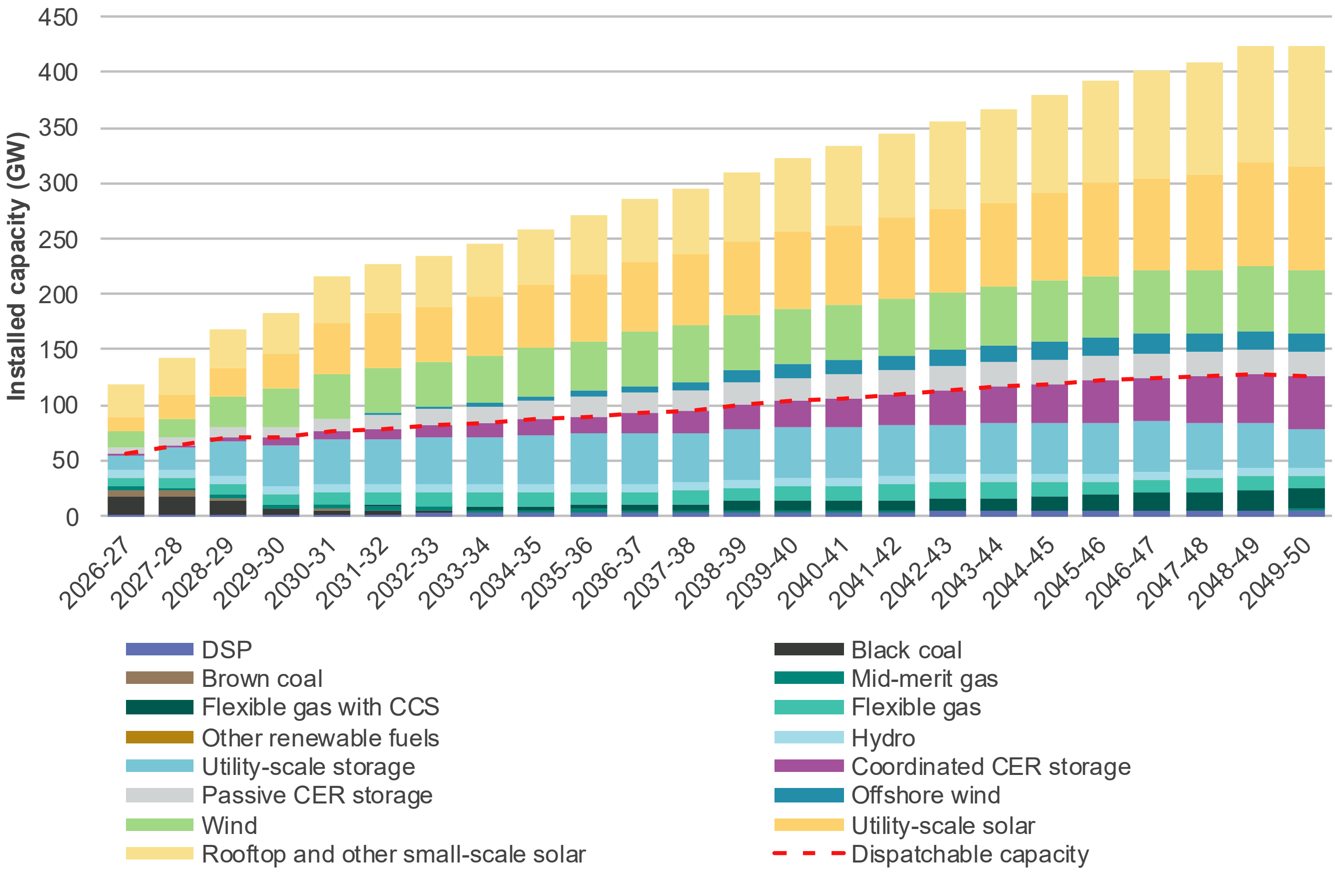
Figure 45 Projected coal-fired generation capacity development (top) and emissions trajectory (bottom) to 2049-50, 'no transmission' counterfactual development path compared with *Accelerated Transition* (GW and Mt CO_2-e)



Impact of transmission development on capacity and generation mix

Figure 46 shows the projected capacity mix in the 'no transmission' counterfactual development path.

Figure 46 Projected NEM installed capacity, *Accelerated Transition* 'no transmission' counterfactual development path, 2026-27 to 2049-50 (GW)



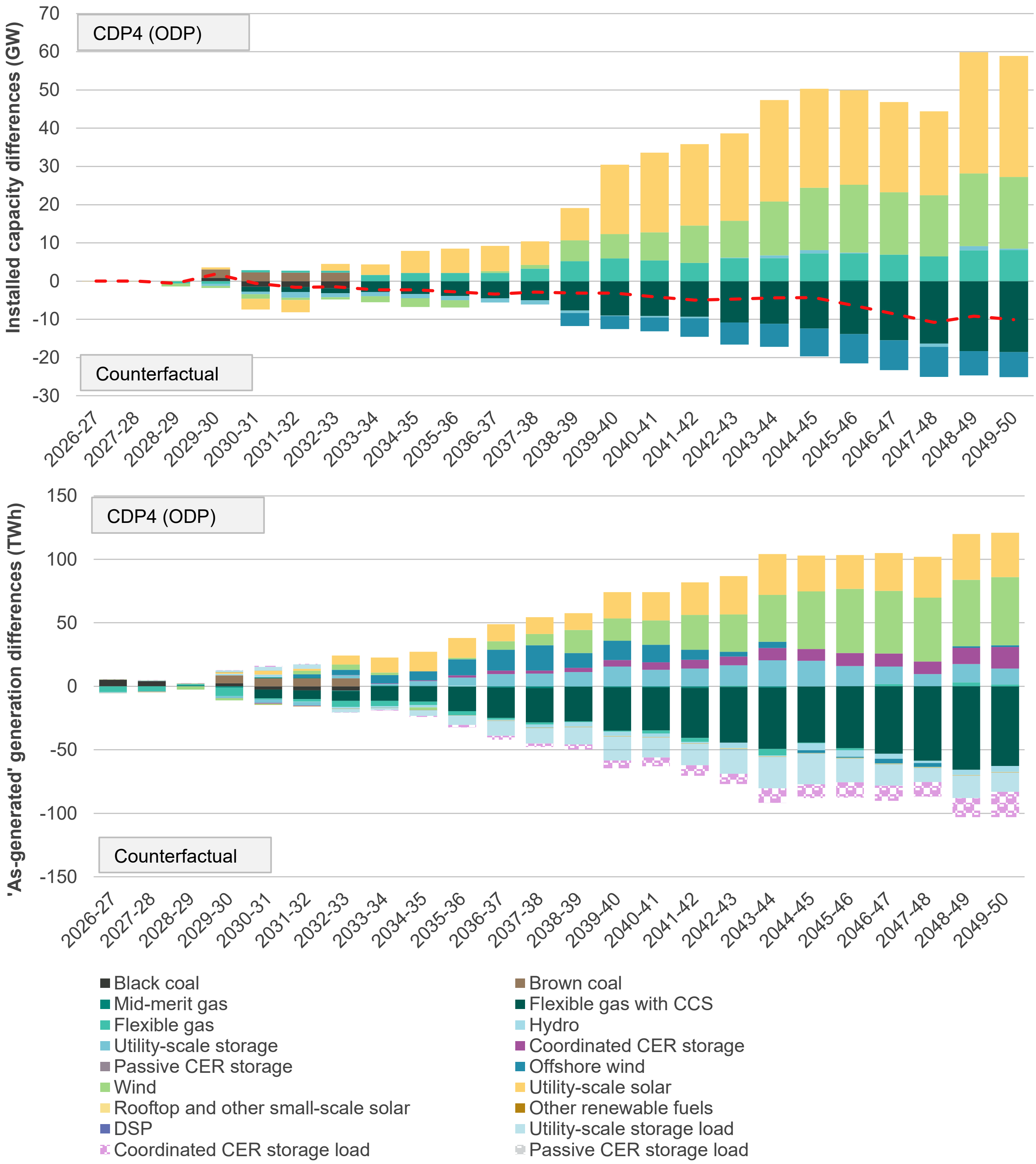
Under the *Accelerated Transition* scenario, in the 'no transmission' counterfactual development path a more diverse mix of low-emissions technologies is needed to meet future energy consumption. To continue to supply a growing NEM with limited capability to expand the network to connect new renewable generation locations, the 'no transmission' counterfactual development path features flexible gas with CCS from 2030-31.

As **Figure 47** shows, utility-scale solar, offshore wind and flexible gas with CCS across the NEM provide capacity while keeping emissions within the emissions budget. As CCS technologies do not capture all emissions, coal plant retirements are brought forward to ensure sufficient emissions budget is available to operate flexible gas with CCS across the outlook period.

In the 'no transmission' counterfactual development path for *Step Change* and *Accelerated Transition*, the retirement of the Gladstone Power Station would cause significant system reliability risks in Gladstone Grid, as there is insufficient local generation in the sub-region to service local demand due to fuel limitations. The gas fuel limits applied in the 'no transmission' counterfactual development path are the same as applied to the ODP and, as discussed in Appendix A10, the gas supply developments in Gladstone Grid are a direct response to forecast gas generation demand in this sub-region. As the 'no transmission' counterfactual development path has higher gas needs than the ODP, the gas supply limit was assumed to be lifted and additional gas developments would be required to service this need, or gas generators may be able to source fuel from alternative supplies (for example, from capacity that services export facilities in this sub-region).

Greater use of solar connected to the distribution network is also a feature of the 'no transmission' counterfactual development path (bundled within solar in the figure). Further, broader development of Australia's offshore wind potential is needed where the network at point of onshore connection can accommodate the additional capacity. While offshore wind is still developed to meet the Victorian Offshore Wind Target, without network augmentations this output is heavily curtailed by network limitations.

Figure 47 Projected capacity developments (top) and generation (bottom) to 2049-50 under 'no transmission' counterfactual development path compared with *Accelerated Transition* (GW and TWh)



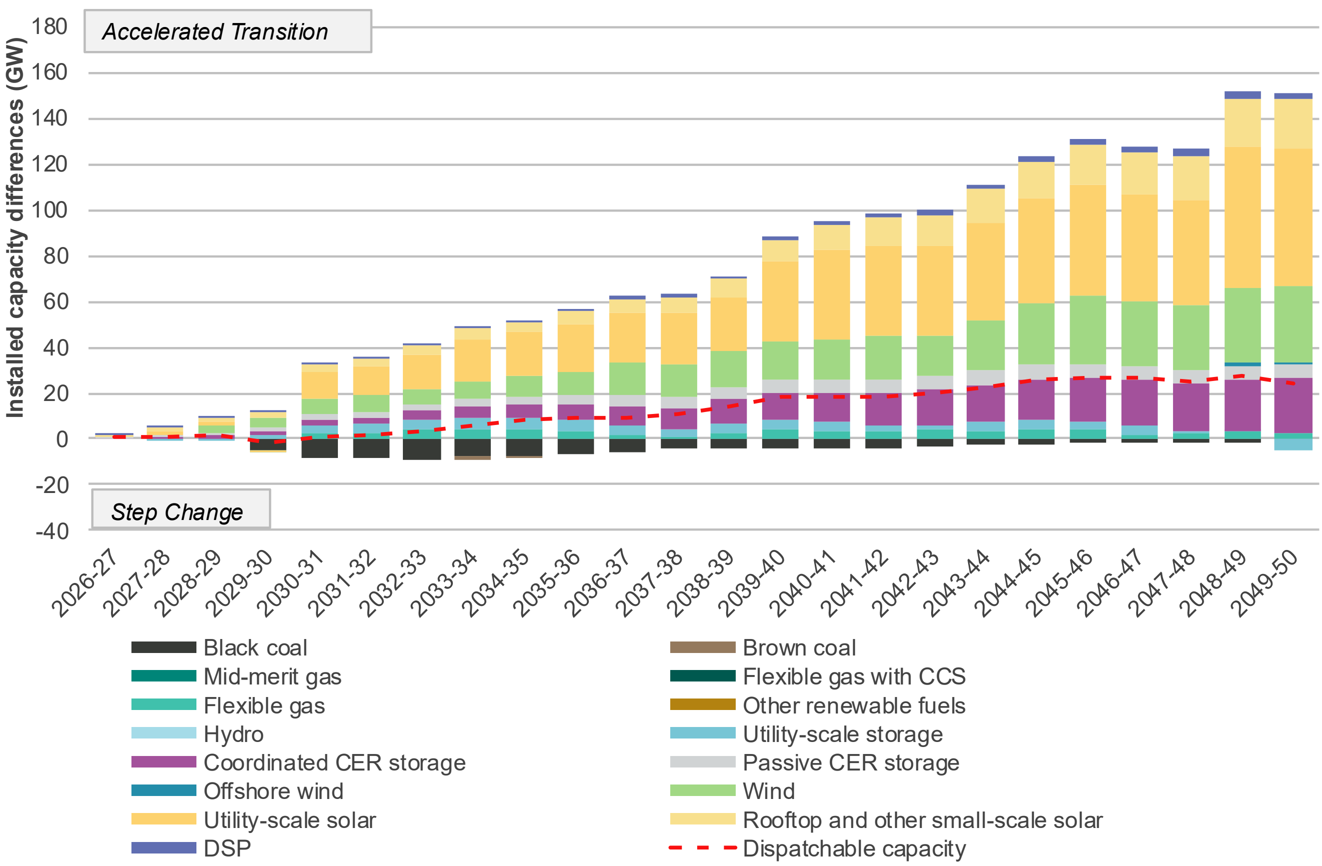
Contrasting the ODP's development opportunities in *Accelerated Transition* and in *Step Change*

Figure 48 presents the capacity difference between the developments for *Accelerated Transition* and *Step Change*.

By the end of the outlook period, total installed capacity is about 146 GW (47%) more relative to *Step Change,* due primarily to the higher electricity consumption (around 170 TWh or 42% greater) associated with *Accelerated Transition*, particularly from industrial loads and electrified transportation's charging demand.

Accelerated Transition's smaller emissions budget drives earlier retirements of coal-fired generation capacity than *Step Change*. To offset these retirements and meet higher energy consumption, significant development of utility-scale VRE and utility-scale storages are projected, alongside higher investments in CER developments. The ODP in *Accelerated Transition* also projects an additional 1.5 GW of offshore wind in the Hunter Coast[23] from 2048-49.

Figure 48 Projected capacity development to 2049-50 under *Accelerated Transition* compared to *Step Change* (GW)



[23] Hunter Coast (N10) is a REZ in New South Wales that could host offshore wind farms.

A2.4 The influence of sensitivities on generation and storage development opportunities

This section outlines the impact of changes in key assumptions made in the *Step Change* scenario on the generation and storage developments in the 2026 ISP. Each sensitivity explored the effect of a specific uncertainty on the CDPs and the robustness of the selected ODP to different assumptions; this is discussed in detail in Appendix A6 Cost Benefit Analysis. This section focuses on the impact of those sensitivities on the generation and storage developments in the ODP.

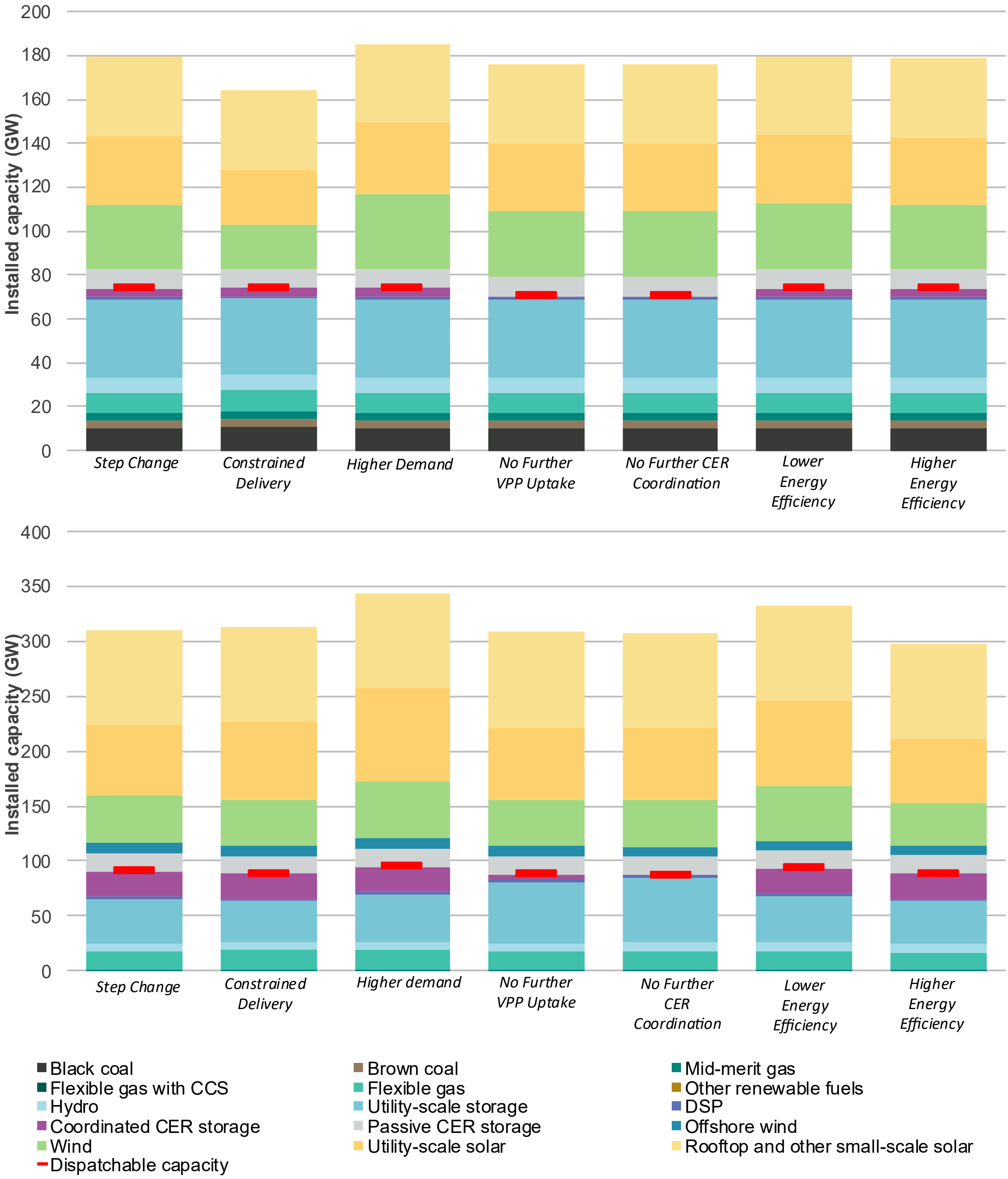
The 2026 ISP presents a range of sensitivities, including:

- *Constrained Delivery*, which explores the impact of limitations in supply chain, workforce availability, or other factors affecting the cost and timing of delivery of energy infrastructure,
- *Higher Demand*, which explores the robustness of the ODP to higher uptake of data centres and large industrial load across the NEM, and
- alternative assumptions on demand-side factors such as on CER and energy efficiency.

Additional information on the capacity developments, energy generated, retirement outlook, and emissions outcomes for the sensitivities are also included in the Generation and Storage Outlook Workbooks, with regional and sub-regional outlooks.

As shown in **Figure 49**, the scale of wind and utility-scale solar development is similar in these sensitivities as it is in *Step Change*, except under *Constrained Delivery* where the pace of development is more limited to 2029-30. By 2049-50, only sensitivities that explore materially higher or lower energy consumption (due to higher industrial and data centre demand, or due to changes in energy efficiency) produce notable changes in overall development outcomes.

Figure 49 Generation and storage capabilities by 2029-30 (top) and 2049-50 (bottom) in *Step Change* and sensitivities to *Step Change* (GW)



A2.4.1 Constrained Delivery

Step Change projects a high level of new investment in generation, storage and other energy infrastructure. The pace of delivery of these new assets depends on a range of factors including supply chains, social licence, planning approval, construction, materials, and workforce. The *Constrained Delivery* sensitivity assessed whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission, generation, and storage projects were unable to be delivered at the pace required. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction – but the sensitivity only limited the rate of build, not what determined the delays. Key assumption changes in this sensitivity are:

- NEM-wide technology-specific annual build limits are imposed on future wind, utility-scale solar, and utility-scale storages until 2034-35, see **Figure 50**. The limits were approximated by assuming a slower development of projects in the connections pipeline, with different capacity reductions assumed at various stages of the pipeline[24] to capture potential delivery delays or project cancellations for the reasons listed above. The amount of new capacity expected to come online following these reductions was smoothed to produce a steadily increasing trajectory over time, reflecting the expectation that pressures on infrastructure delivery will progressively ease. The delivery of committed, anticipated, and policy-supported projects as well as generic new entrant projects were assumed to be impacted by the same set of development and delivery conditions. Therefore, these delivery constraints were applied equally on all types of generation and storage projects. The impact of these limits is presented in **Figure 51** below.
- Delays to the earliest-in-service date (EISD) for flow path and REZ network augmentation options of up to three years (including committed and anticipated projects) were assumed to test impact if industry is unable to build capability to deliver above recent transmission line build rates. It was assumed that committed projects would be delayed six months, anticipated projects 12 months, and actionable projects an average of two years. These assumptions were set to allow a 5% year-on-year increase from recent transmission line build history (approximately 365 km/year during the construction of Stage 1 of Project EnergyConnect and Eyre Peninsula Link).
- Offshore wind projects are also impacted by the development constraints delaying the development trajectory to deliver 9 GW of capacity by three years.
- The cost of generation, storage and transmission rises as result of delivery delays, on average by 30% during this period of heightened limitation until 2034-35, calculated using the uncertainty band in technology costs from the CSIRO's *2025-26 GenCost Consultation Draft report*[25]. There may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the risk in cost only.

With these constraints slowing renewable energy and storage developments, various federal and state emissions reduction targets and renewable energy policies prior to 2035 are not met to the timetable that each policy intends, and coal generators may need to operate for longer (but not beyond their announced closure dates). After delivery constraints were assumed to alleviate, and as more VRE capacity is delivered, the remaining coal generation in this sensitivity retires faster than in *Step Change* to stay aligned with long-term emissions targets.

Figure 50 shows the NEM's annual build capability for utility-scale solar, wind, and utility-scale storage assumed in the *Constrained Delivery* sensitivity, relative to *Step Change*.

---

[24] The build limits assumed a 20% reduction in capacity for projects in the application stage where the performance of the plant "as designed" is assessed, and a 10% reduction for projects in the proponent implementation stage, which is when the proponent and the network service provider (NSP) execute the connection agreement, the NSP constructs the network interface, and the proponent constructs the plant and prepares registration application. This stage is considered complete when the registration package is submitted to AEMO.

[25] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

Figure 50 ***Constrained Delivery*** **annual build to 2034-35 considering build limits influenced by historical commissioning rate for onshore wind and utility-scale solar generation (GW)**

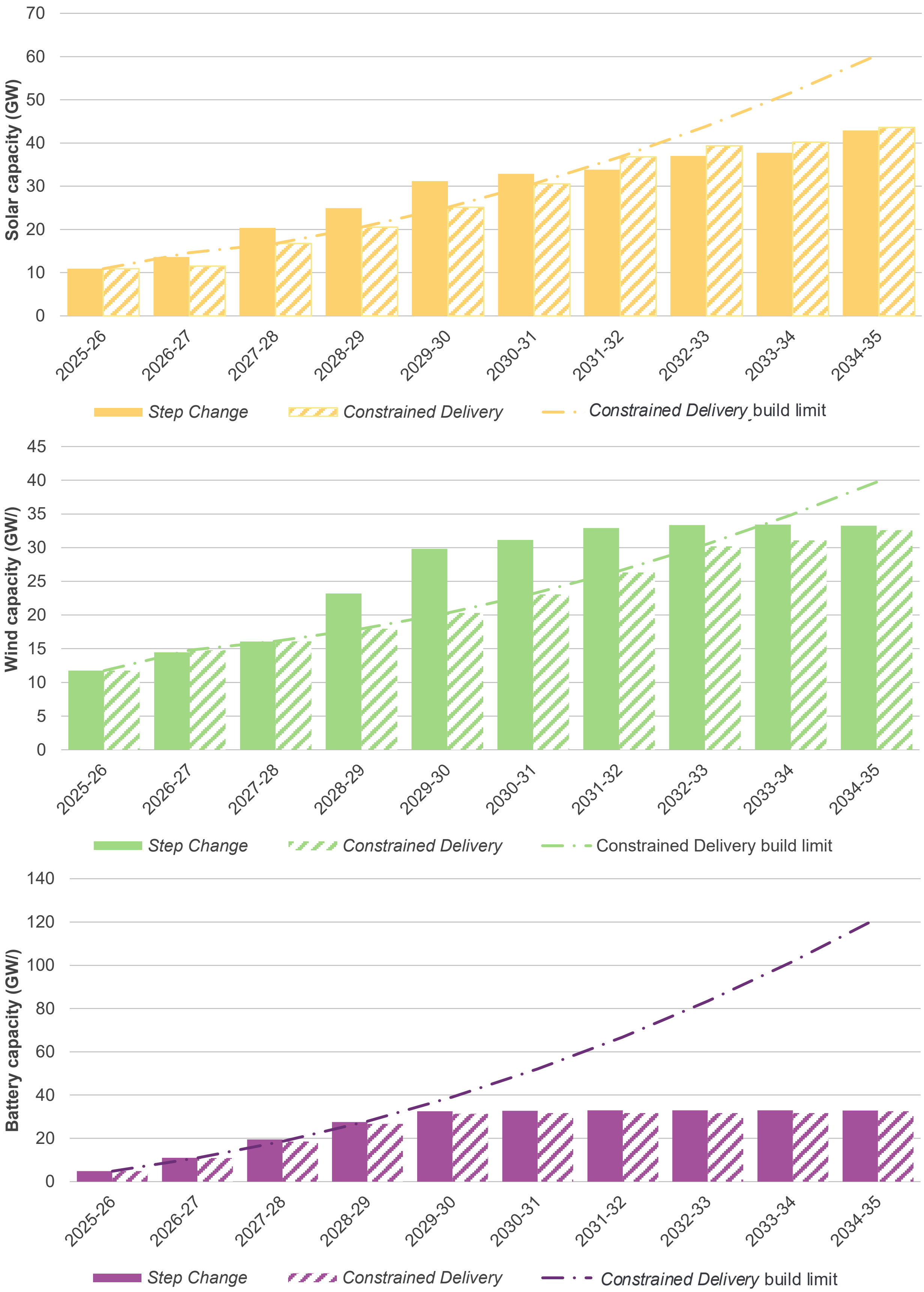
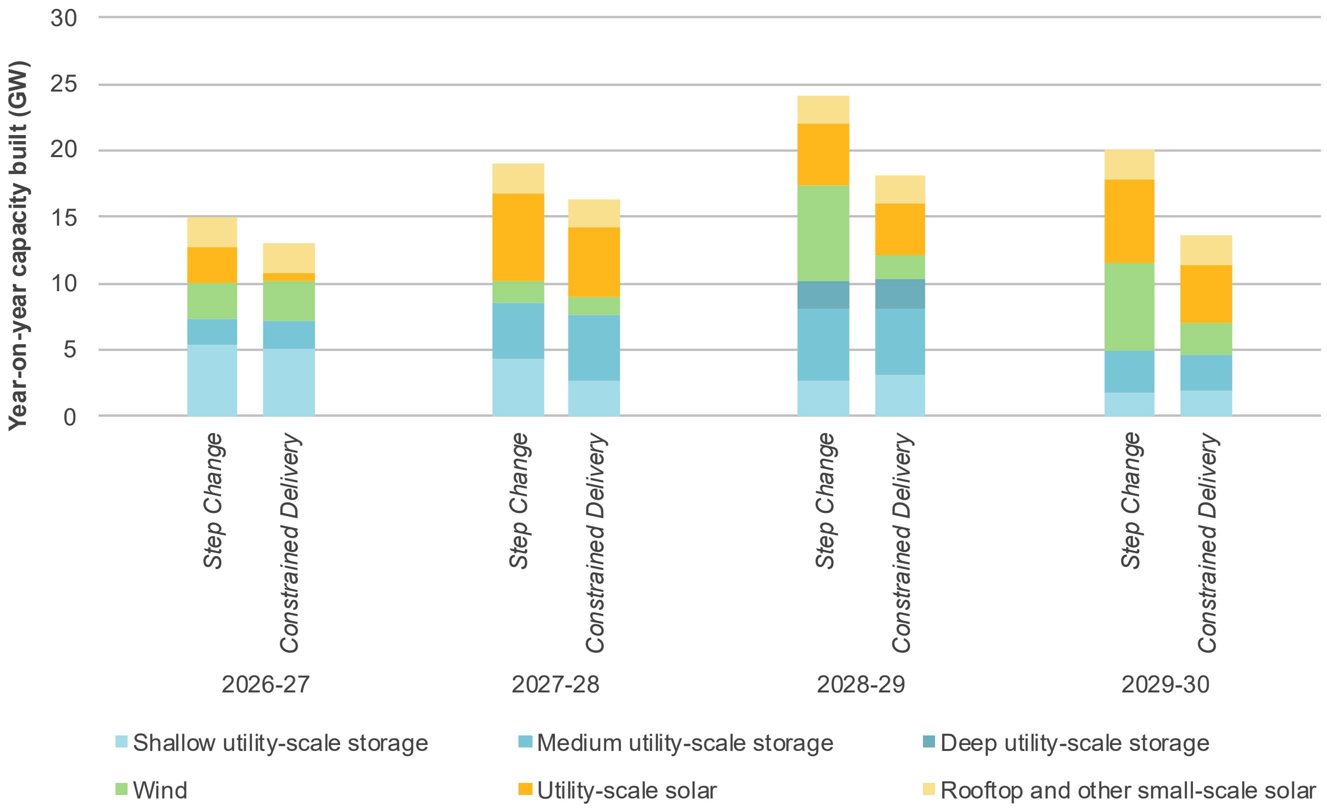


Figure 51 shows the annual build development for utility-scale renewable energy and utility-scale storage capacities to 2029-30 in the *Constrained Delivery* sensitivity.

In this sensitivity with development constraints, the NEM only builds an average of 5.7 GW per year of utility-scale VRE during the period 2025-26 to 2029-30 – including 3.6 GW per year of utility-scale solar and 2.1 GW per year of wind. This translates to about 14.2 GW additional utility-scale solar and 8.6 GW of wind by 2030, compared to 20.3 GW and 18.1 GW respectively in *Step Change*. In comparison, there is currently 19 GW of utility-scale solar and 9 GW of wind in the connections pipeline.

With the significant number of storage projects now identified as committed, anticipated, or explicitly supported by policies, the pace of total development slows in 2029-30, though VRE developments need to continue to develop at an increasing pace to 2030, including in *Constrained Delivery*.

Figure 51 NEM renewable annual build capacities, *Step Change* versus *Constrained Delivery* sensitivity, 2026-27 to 2029-30 (GW)



Note: all years present year-on-year growth.

Figure 52 presents historical and projected installed capacity for the *Constrained Delivery* sensitivity and *Step Change* up to 2049-50. It shows the near-term increase in build required in *Step Change* relative to recent history, and the impact that the delivery constraints would have on the *Step Change* development of these technologies. While these trajectories slow near-term progress, with *Constrained Delivery* building approximately 17 GW less utility-scale VRE and storage than *Step Change* to 2029-30, the sensitivity still makes significant progress towards a low-emissions power system (reaching a 75% share of renewables by 2029-30) before broadly catching up to *Step Change* in the longer term.

This reduction in installed capacity impacts the ability to meet federal and state policies and carbon budgets in the near term. From 2026-27 to 2034-35, the sensitivity has 6 GW less capacity installed on average compared to *Step Change*. Coal generation in this sensitivity is needed to operate for longer than in *Step Change* (but not beyond any generator's currently announced closure date), due to the slower delivery of new replacement generation from VRE. Coal still needs to reduce operation to achieve the emissions reduction targets by 2034-35 and 2049-50. Renewable energy and storage development would scale up progressively through the early 2030s to help meet the 2035 emissions reduction targets, with utility-scale VRE capacity broadly aligned to *Step Change* by 2034-35 (44 GW of utility-scale solar and 35 GW of wind in *Constrained Delivery*, compared to 43 GW and 37 GW in *Step Change* respectively).

Figure 52 Projected installed capacity to 2049-50 under the *Constrained Delivery* sensitivity and *Step Change* (GW)

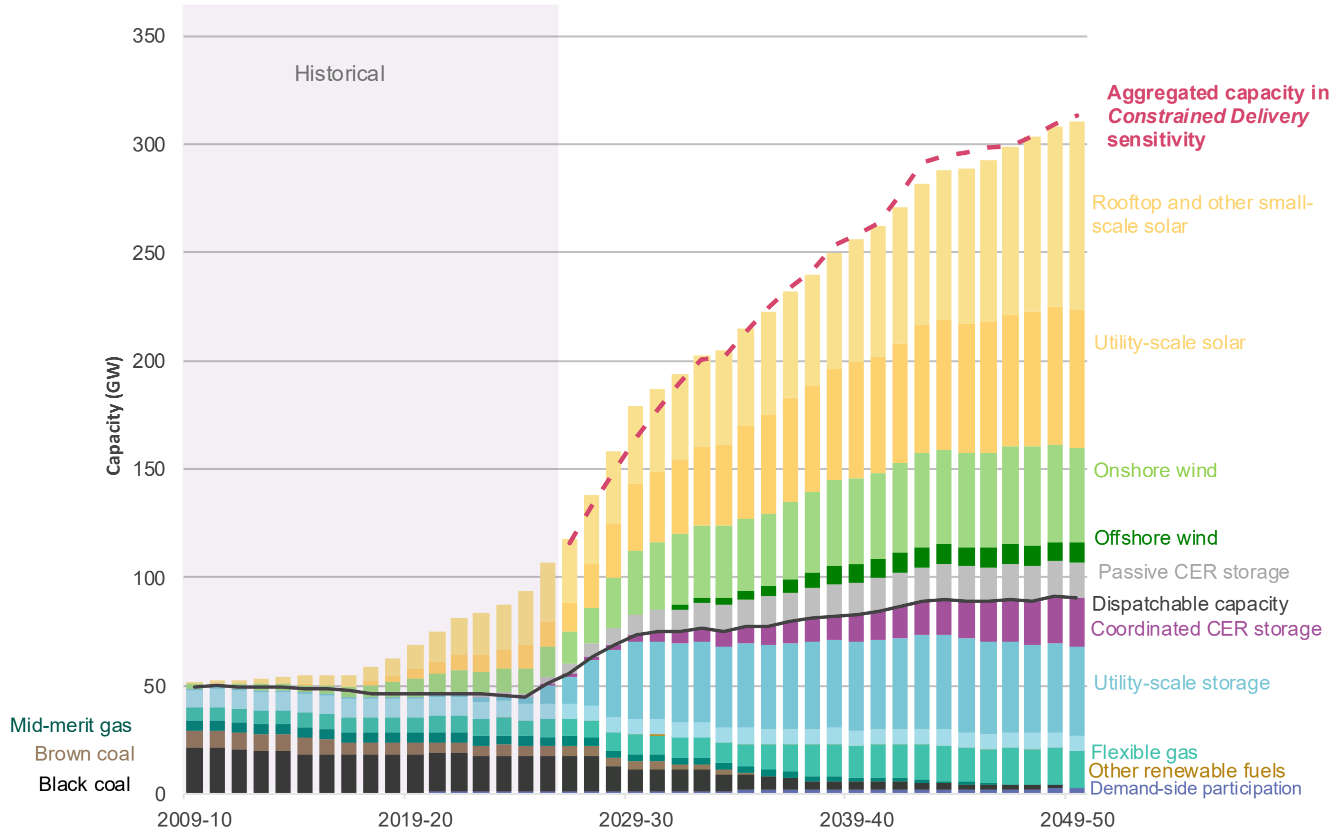


Figure 53 compares the generation and storage developments in the *Constrained Delivery* sensitivity with *Step Change.* It shows a reduction in the delivery of wind and utility-scale solar in the near term, followed by a gradual increase in capacity towards the end of the outlook period. With lower VRE uptake and slightly greater reliance on coal and flexible gas in the near term, a higher VRE capacity is projected to be developed over time to meet the 2050 carbon budgets.

This sensitivity reflects the projected developments in the connection pipeline. With a significant amount of utility-scale storages currently progressing through different stages of connection, the deliverable limits assumed in this sensitivity result in only a minor impact on utility-scale storage compared to VRE.

Figure 53 Projected capacity developments to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (GW)

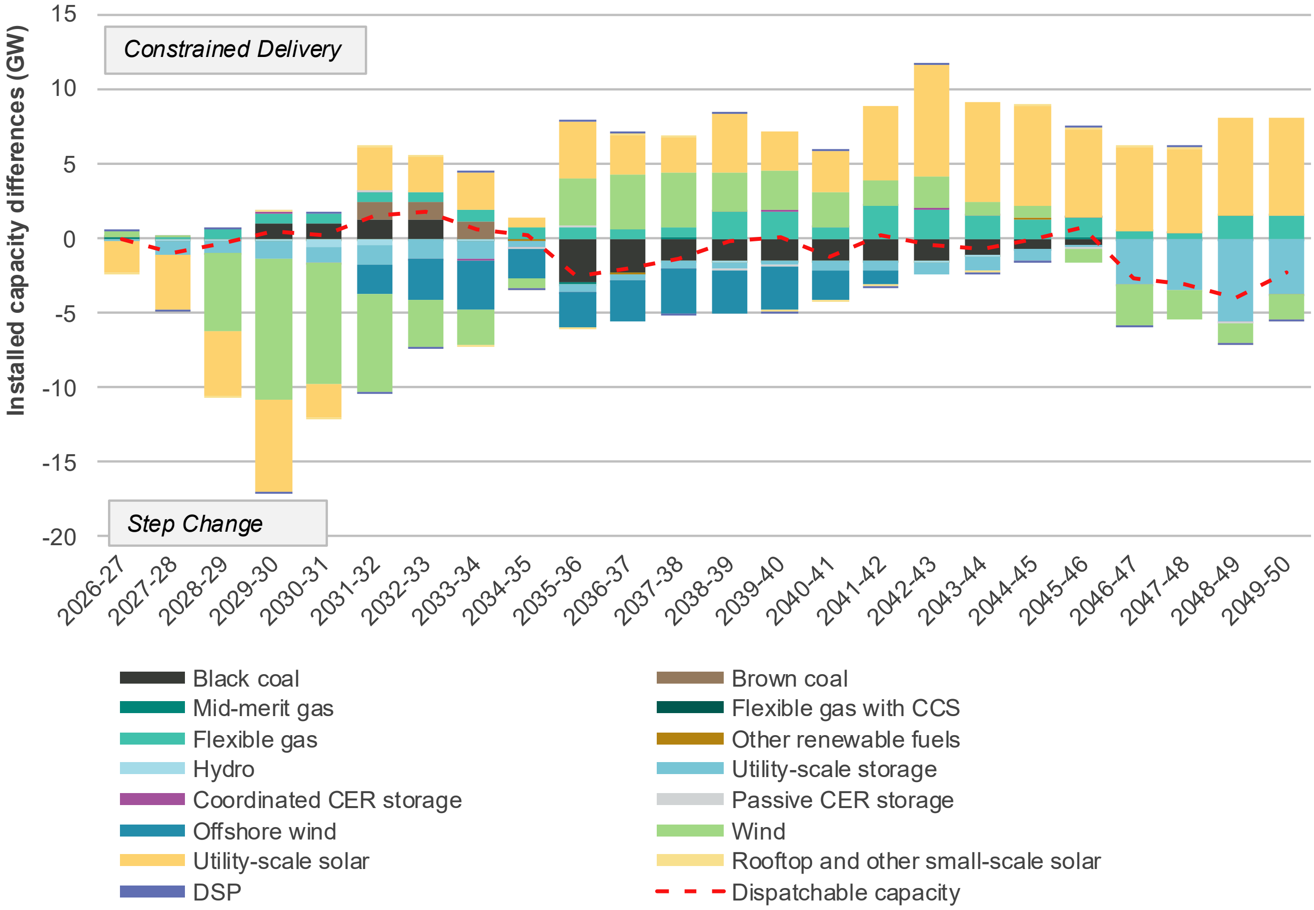
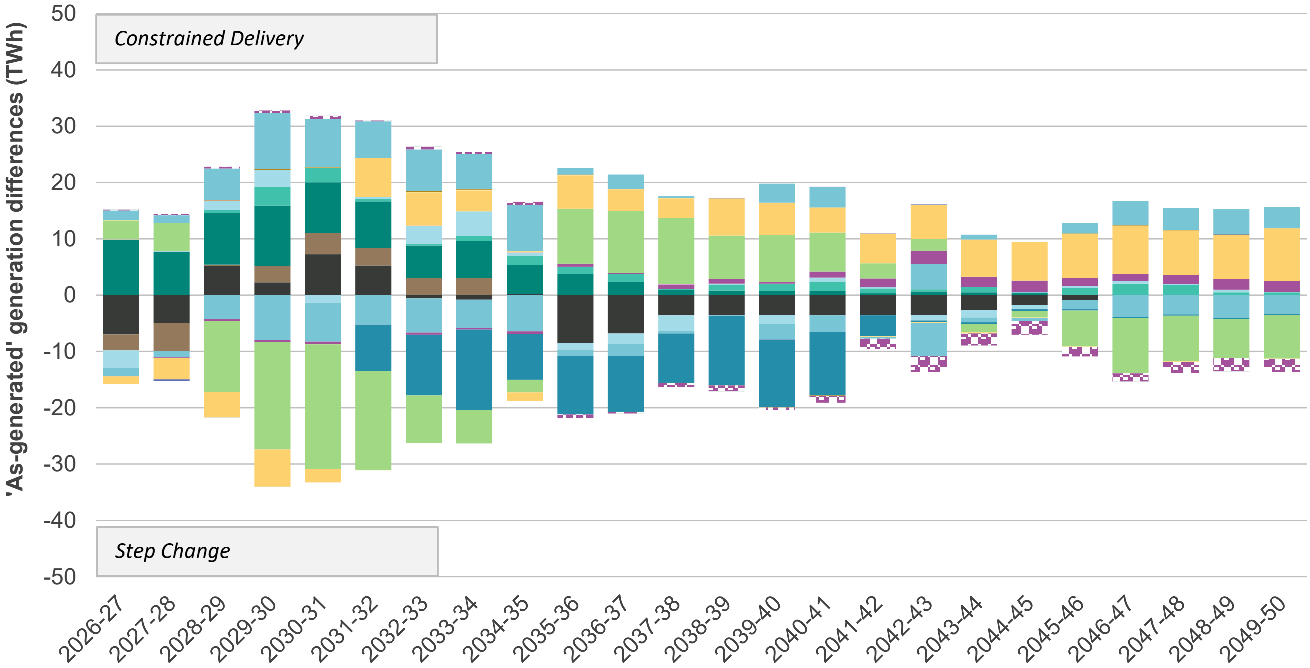
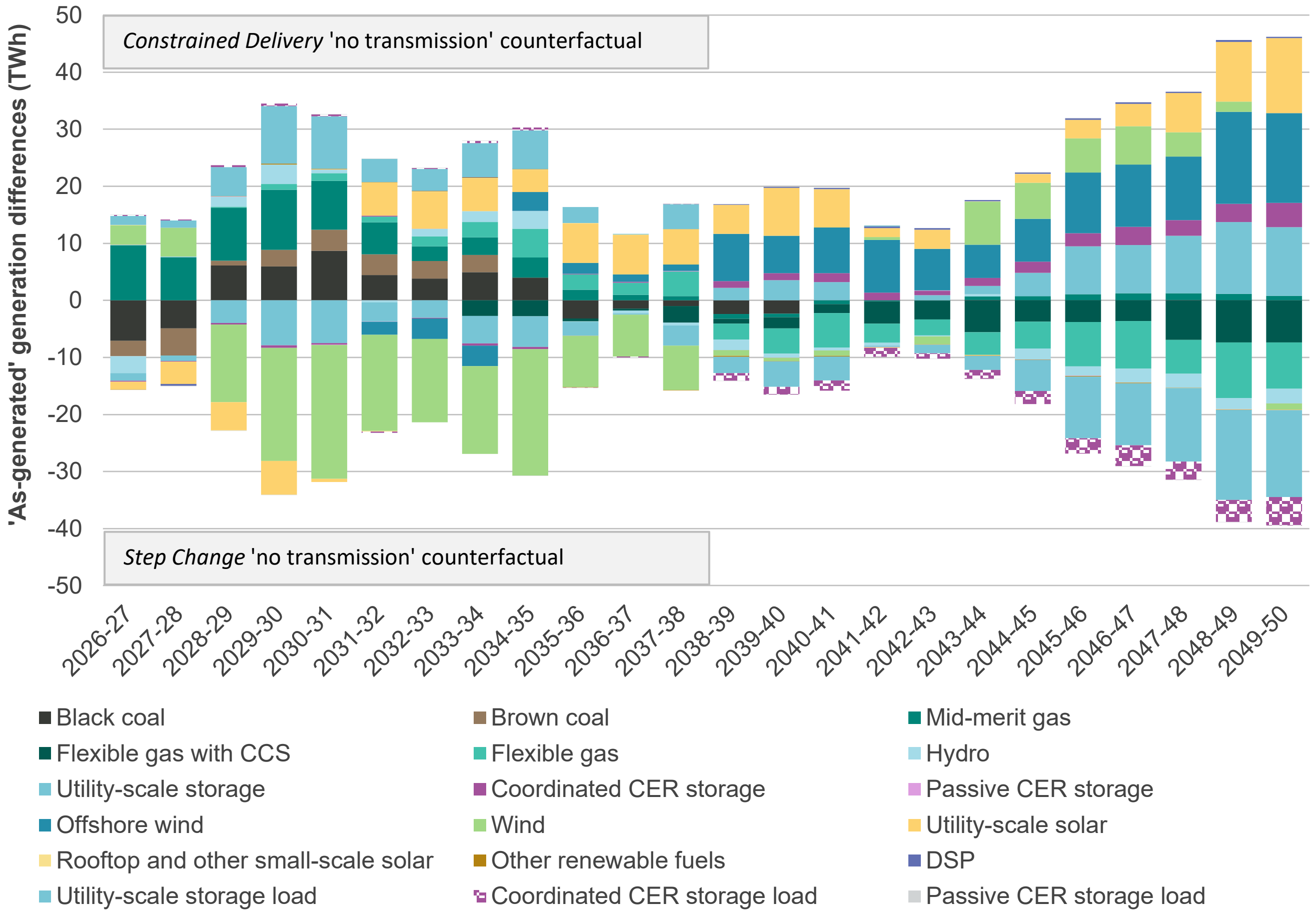


Figure 54 presents the generation mix difference between the *Constrained Delivery* sensitivity and *Step Change*. With slower development of renewable capacity, more thermal generation is dispatched in the sensitivity to meet projected energy consumption prior to 2034-35. NEM emissions are therefore slightly higher while development is delayed, and to meet 2050 carbon budgets, some capacity and generation differences endure over the long term. This same impact is even more pronounced when comparing the 'no transmission' counterfactual development path under *Step Change* and the *Constrained Delivery* sensitivity, which causes the network developments in the ODP to be even more beneficial under this sensitivity. The benefits provided by the ODP in *Constrained Delivery* are explored in further detail in Appendix A6 Cost Benefit Analysis.

In the *Constrained Delivery* sensitivity, the total renewable energy contributes to 75% of total energy consumption in the NEM by 2029-30 – less than the 82% renewable energy target. The emissions reduction target in 2030 is exceeded by 6.5 Mt CO_2-e (achieving 95% of the assumed electricity sector share of that target). Other targets and policies – such as the CIS generation and dispatchable targets by 2030, the TRET in Tasmania and the Victorian Offshore Wind Target – are all slower in achieving their stated objectives than intended, at approximately 2-3 years later.

Figure 54 Projected generation to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (TWh) – ODP (top) and 'no transmission' counterfactual development path (bottom)





A2.4.2 Higher Demand

Based on *Step Change*, the *Higher Demand* sensitivity features a very high assumption around industrial development and data centre load growth. This sensitivity has been developed in response to stakeholder feedback received on the Draft 2026 ISP, and tested implications on development needs under high demand growth, noting that there has been much interest in data centre development in recent months. It included additional loads from known large industrial load (LIL) and data centre projects in the pipeline to reflect the potential growth above the *Step Change* forecast[26]. Specific modifications from the assumptions made in *Step Change* are:

- all prospective large industrial loads indicated as committed or anticipated, as well as those named in feedback to the Draft 2026 ISP, were included at the connection date provided by NSPs,
- all prospective data centres indicated as committed or anticipated, as well as those named in feedback to the Draft 2026 ISP, were included, but applying a 50% project realisation factor to recognise ongoing digital load uncertainty – this reflects strong growth in the first 10 years of the forecast, with the longer-term growth trajectory reflecting a similar growth trend as *Step Change*,
- existing large industrial loads and data centres were assumed to operate according to *Accelerated Transition*, reflecting strong economic conditions, high utilisation of existing data centres and ambitious electrification of industry.

Other business and residential consumption was as per *Step Change*.

These factors result in a forecast that is stronger, particularly in the first 10 years, than in *Step Change*, with the longer-term growth trajectory reflecting a similar growth trend as *Step Change*. Forecasts of other business and residential customers are as per the *Step Change* scenario.

Figure 55 compares the forecast operational electricity consumption in *Step Change* with the *Higher Demand* sensitivity over the period to 2049-50. South Australia and New South Wales see the largest difference in load over the short to medium term, followed by Victoria.

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

Figure 55 Impact of *Higher Demand* sensitivity on operational consumption (TWh)

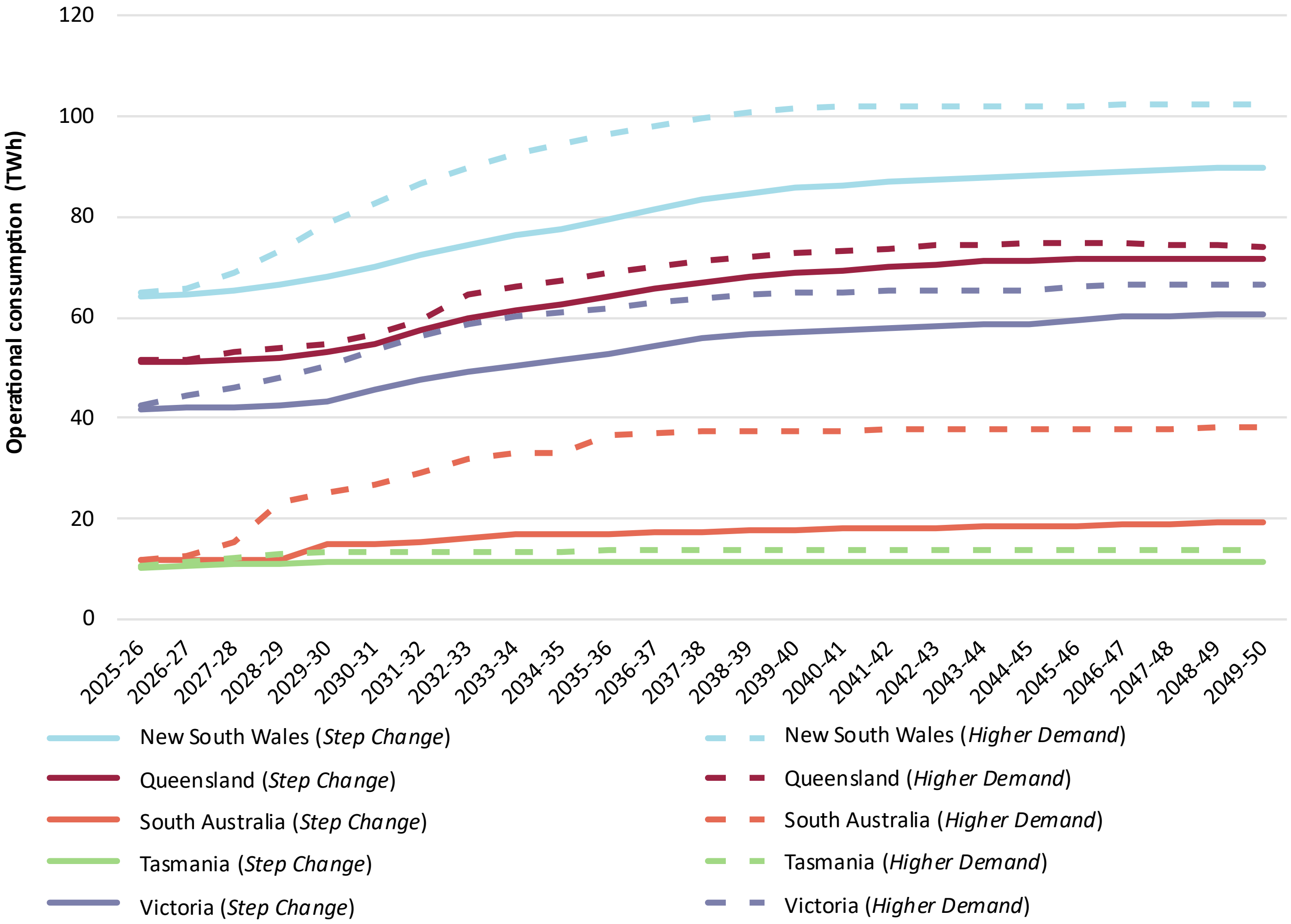


Figure 56 presents the change in energy consumption forecast by 2035-36 at a sub-regional level. In New South Wales, additional growth is concentrated in Sydney, Newcastle and Wollongong, while in Queensland, the majority is concentrated in the Gladstone Grid sub-region. In South Australia, demand grows more in Northern South Australia, followed by Central South Australia. In relative terms, energy consumption forecast by 2035-36 in Northern South Australia is 131% higher in the sensitivity than in *Step Change*, while it is 57% higher in Central South Australia.

This concentration in some sub-regions of industrial and data centre developments is expected to influence the spatial requirements for generation and storage development opportunities, as well as network augmentations.

Figure 56 Difference in energy consumption between *Higher Demand* sensitivity and *Step Change* in 2035-36 by sub-region (TWh)

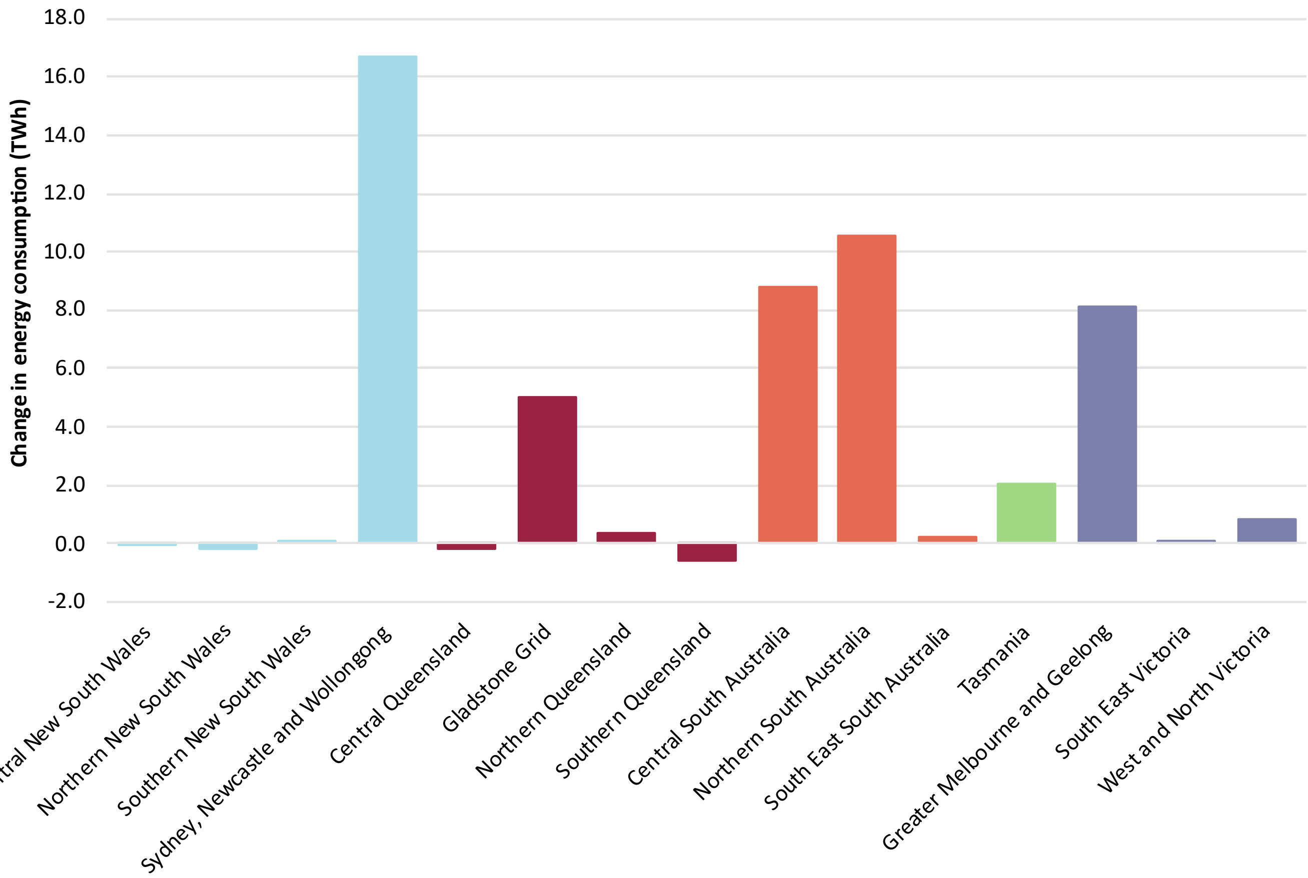


Figure 57 presents the additional capacity developments required to support the additional loads across the NEM. By 2031-32, an additional 8.3 GW of wind and 9.5 GW of utility-scale solar are required to provide sufficient generation to supply these loads. By 2039-40, the additional NEM-wide required capacity increases to 13.8 GW and 13.8 GW of wind and utility-scale solar, respectively.

The additional energy consumption also requires additional dispatchable capacity to maintain reliability of supply. By 2039-40, an additional 2 GW of flexible gas (mainly in Queensland and South Australia) as well as 3.4 GW of additional utility-scale storage are required.

As seen in **Figure 58**, the *Higher Demand* sensitivity sees reduced operation of coal generation and increased operation of all other technologies, including existing gas generation over the period to 2034-35. This higher gas generation supports the higher near-term load developments, while VRE is also developed at a faster pace than in *Step Change.* The use of greater gas, particularly in the short to medium term, highlights the importance of additional and timely investments in gas network infrastructure, as discussed in Appendix A10 Gas Development Projections.

Greater developments are forecast in South Australia and New South Wales, where a higher proportion of load growth is located in this sensitivity. Coal generation is reduced in this sensitivity to achieve the emission constraints, enabling more operation of gas generation which has lower emissions intensity than coal.

Locational developments of dispatchable capacity (utility-scale storages and gas generation) as well as VRE tend to reflect the locations of load developments shown in **Figure 56** above, with greater proportional development in South Australia (particularly Northern South Australia as well as Central South Australia), and to support load developments in Sydney, Newcastle and Wollongong, and the Greater Melbourne and Geelong area. These developments leverage the development of transmission between sub-regions to efficiently share energy and firm capacity within the technical capabilities of the network.

Figure 57 Additional projected capacity developments to 2049-50 under the *Higher Demand* sensitivity (GW)

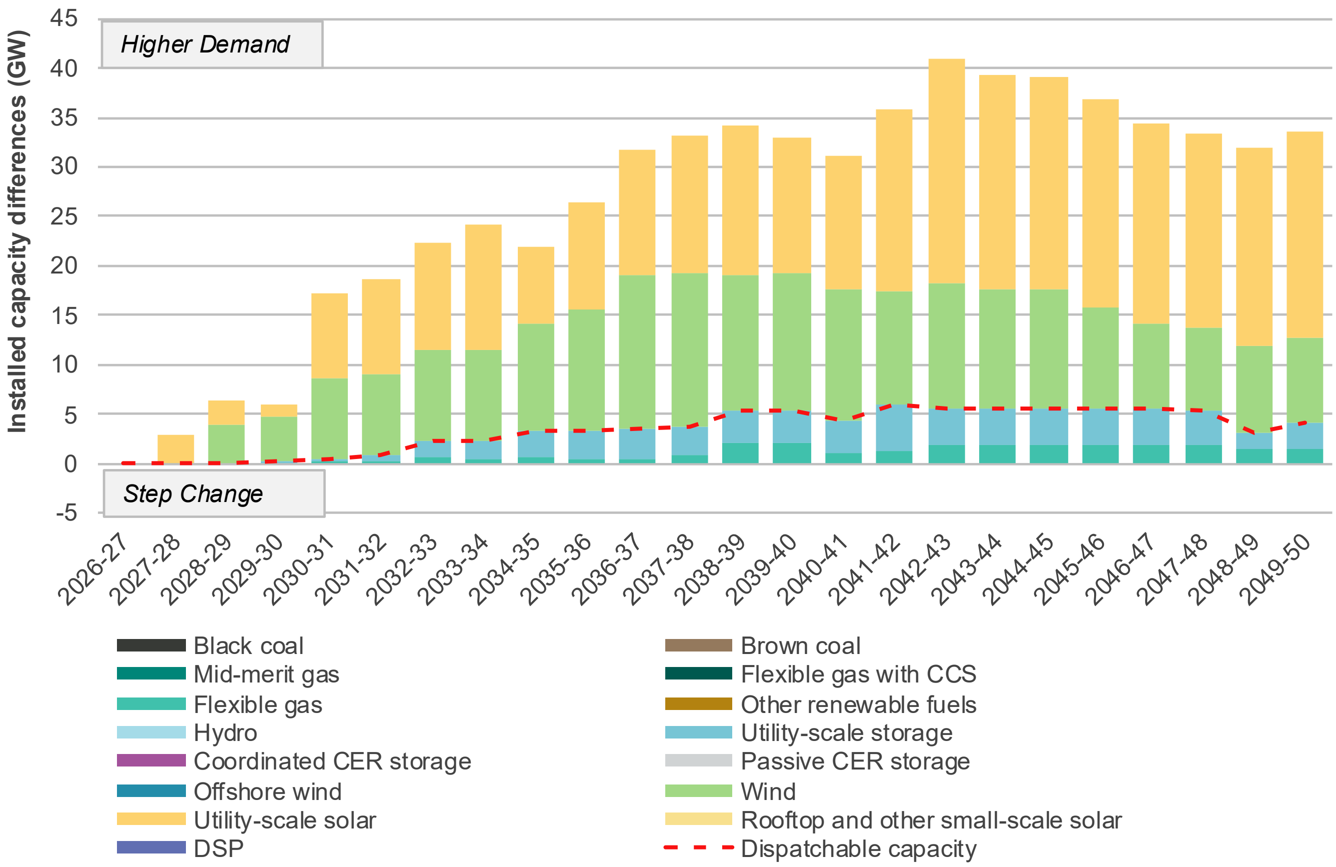
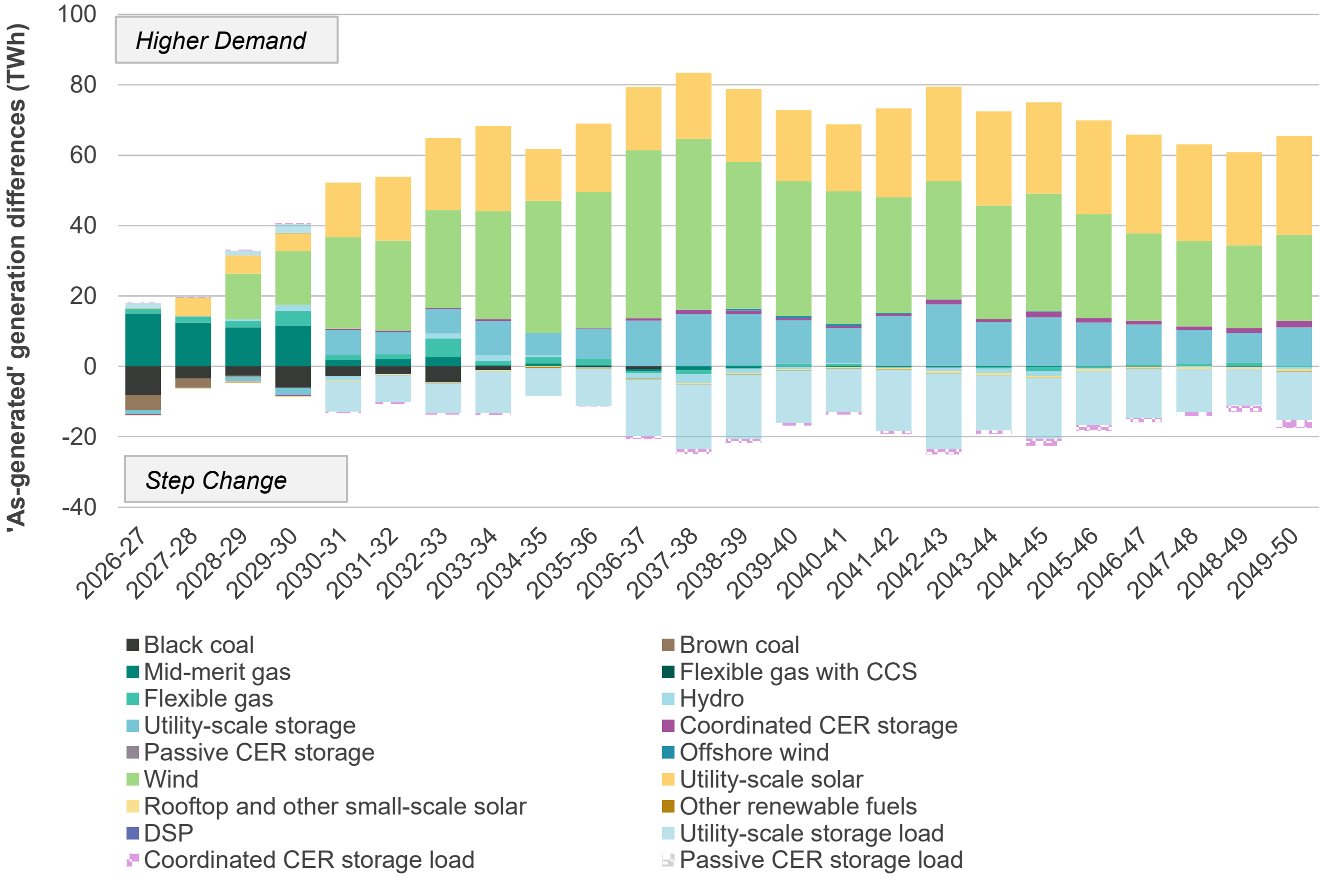


Figure 58 Projected generation to 2049-50 under the *Higher Demand* sensitivity compared with *Step Change* (TWh)



A2.4.3 Coordination of CER storages

This sensitivity assessed the impact of different levels of assumed coordination of CER storage on generation and storage development opportunities in *Step Change*. There are two variations to this assumption in *Step Change*:

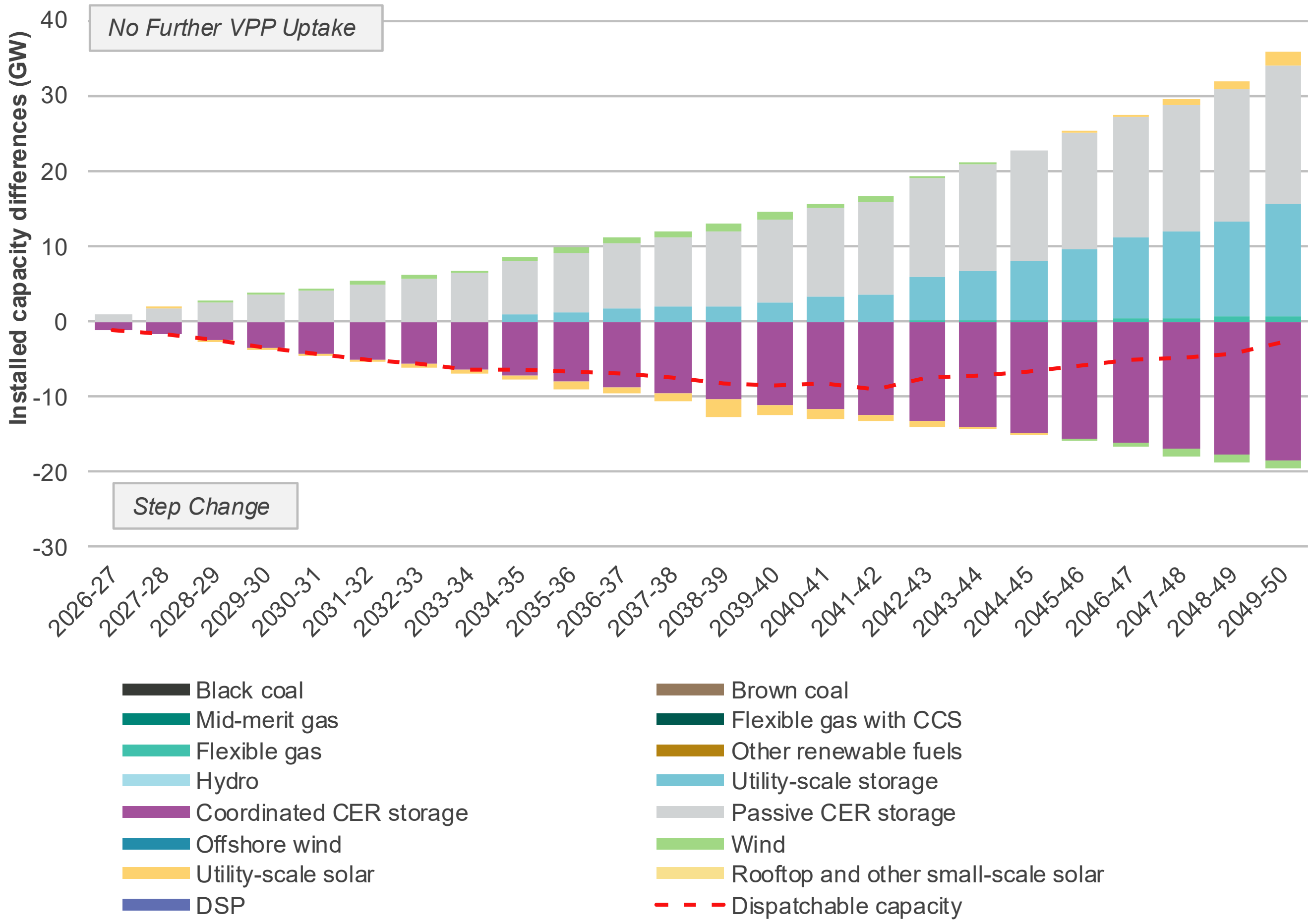
- *No Further VPP Uptake*, which assumed no additional VPP uptake in the NEM from 2024-25 levels – meaning that all forecast consumer batteries were assumed to not be coordinated, and
- *No Further CER Coordination*, which assumed no additional VPP and V2G coordination in the NEM from 2024-25 levels.

The results indicate that reducing coordination materially increases the need for additional utility-scale storage capacity by 2049-50. The *No Further VPP Uptake* sensitivity shows that without the forecast level of coordination from VPPs, additional medium-depth utility-scale storage would be required, with minor development differences for VRE developments (see **Figure 59**).

The *No Further CER Coordination* sensitivity shows a larger need for utility-scale alternatives without the forecast level of coordination from VPPs and EVs with V2G capabilities, with more additional utility-scale investment needed to offset the larger reduction in coordinated CER in this sensitivity (see **Figure 60**).

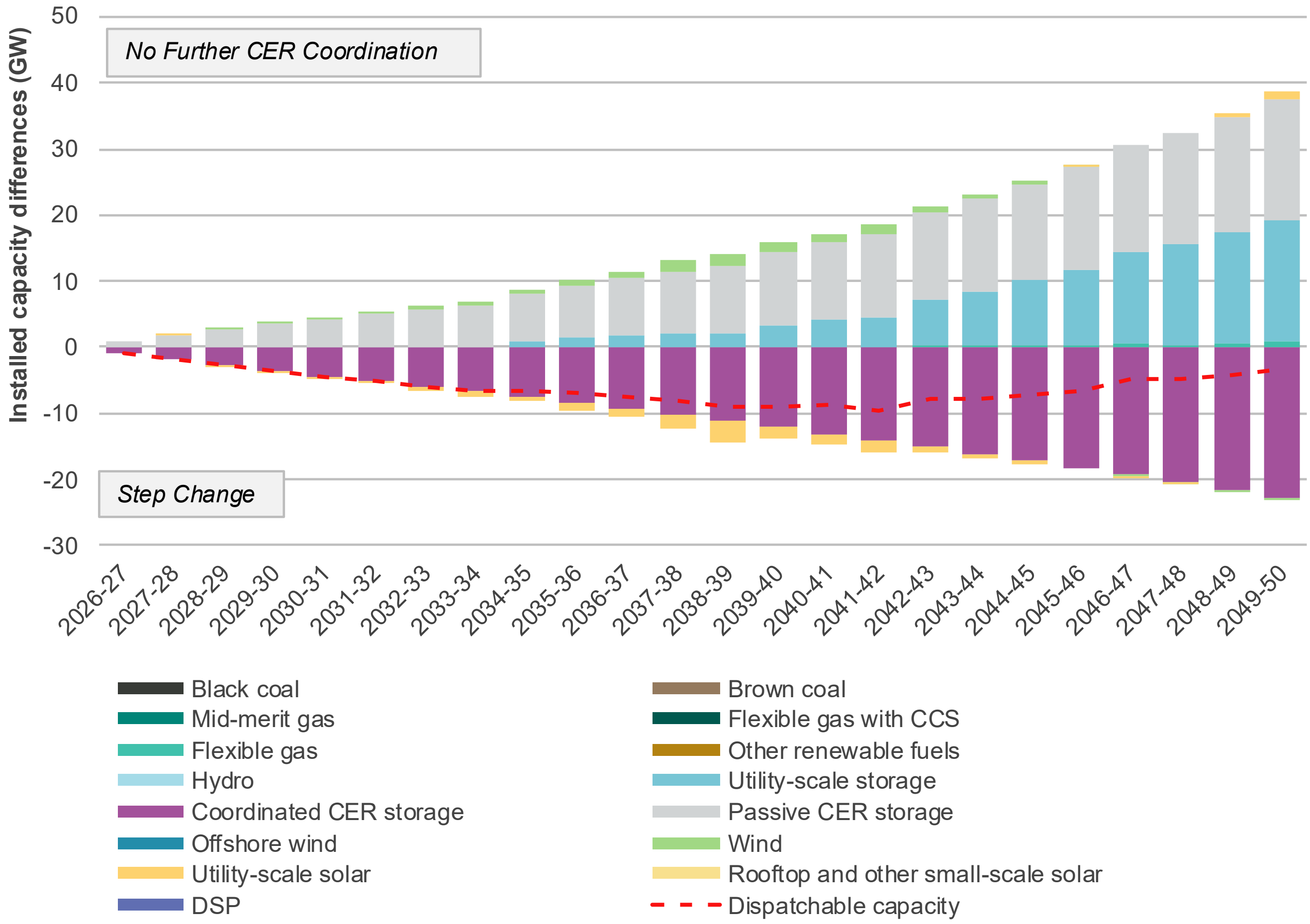
These findings highlight the system value of coordinated CER in reducing broader investment requirements which ultimately benefits all consumers; further detail is provided in Appendix A9 Demand Side Factors Statement.

Figure 59 Forecast capacity developments to 2049-50 under the *No Further VPP Uptake* sensitivity compared with *Step Change* (GW)



Note: coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

Figure 60 Forecast capacity developments to 2049-50 under the *No Further CER Coordination* sensitivity compared with *Step Change* (GW)



Note: coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

A2.4.4 Lower Energy Efficiency and Higher Energy Efficiency

These sensitivities assessed how changes in the level of consumer energy efficiency investment relative to *Step Change* affect long-term electricity consumption and, in turn, the utility-scale generation and firming capacity required to meet demand.

The *Lower Energy Efficiency* sensitivity tested the impact of weaker policy and market uptake, resulting in around 27 TWh higher consumption by 2049-50 and a corresponding increase in required utility-scale solar, wind, storage and flexible gas capacity. Conversely, the *Higher Energy Efficiency* sensitivity tested the impact of stronger uptake, resulting in around 21 TWh lower consumption by 2049-50 and a reduced need for utility-scale wind, solar and storage capacity. **Figure 61** demonstrates the relative differences in the sensitivities to *Step Change*.

Figure 62 and **Figure 63** further demonstrate the impact on development opportunities if energy efficiency growth deviates from the assumptions in *Step Change*, showing that the level of energy efficiency achieved by consumers can materially influence the scale and mix of future utility-scale generation and storage development. See Appendix A9 Demand Side Factors Statement for more detail.

Figure 61 Operational consumption for the NEM by energy efficiency trajectory, 2026-27 to 2049-50 (TWh)

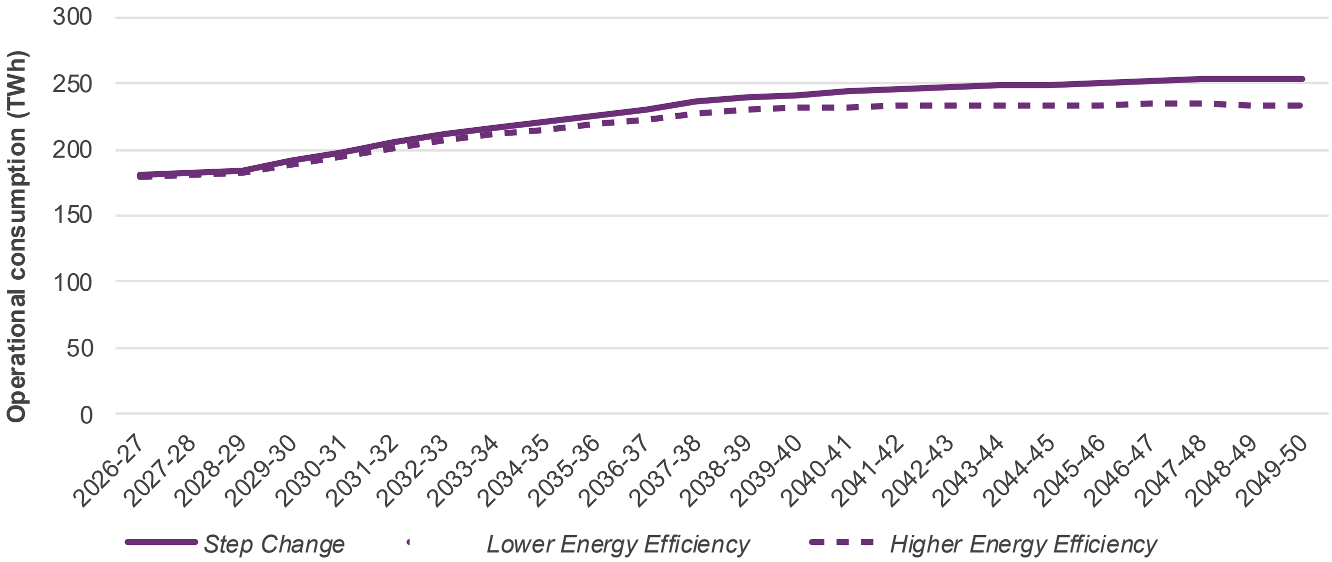
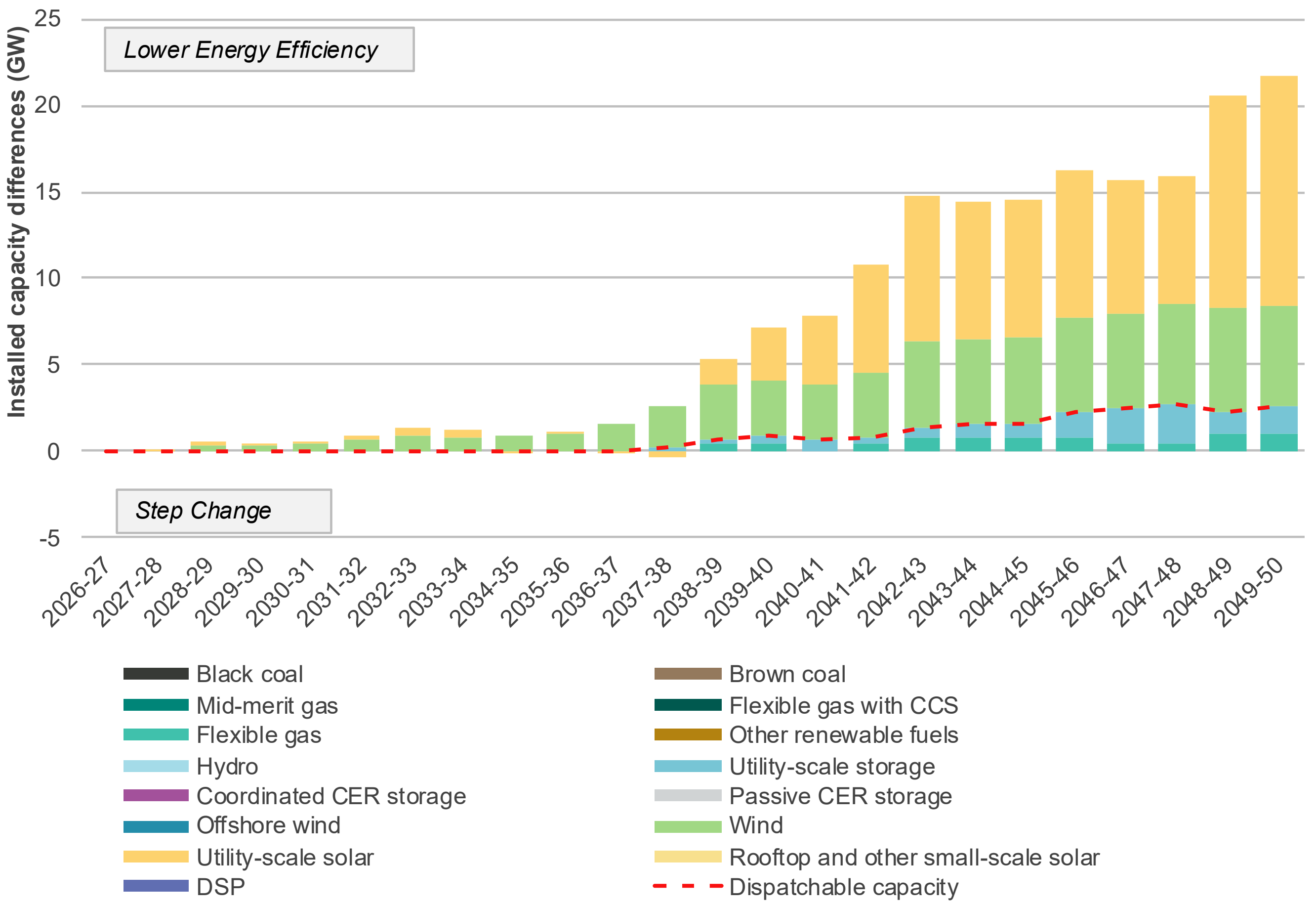
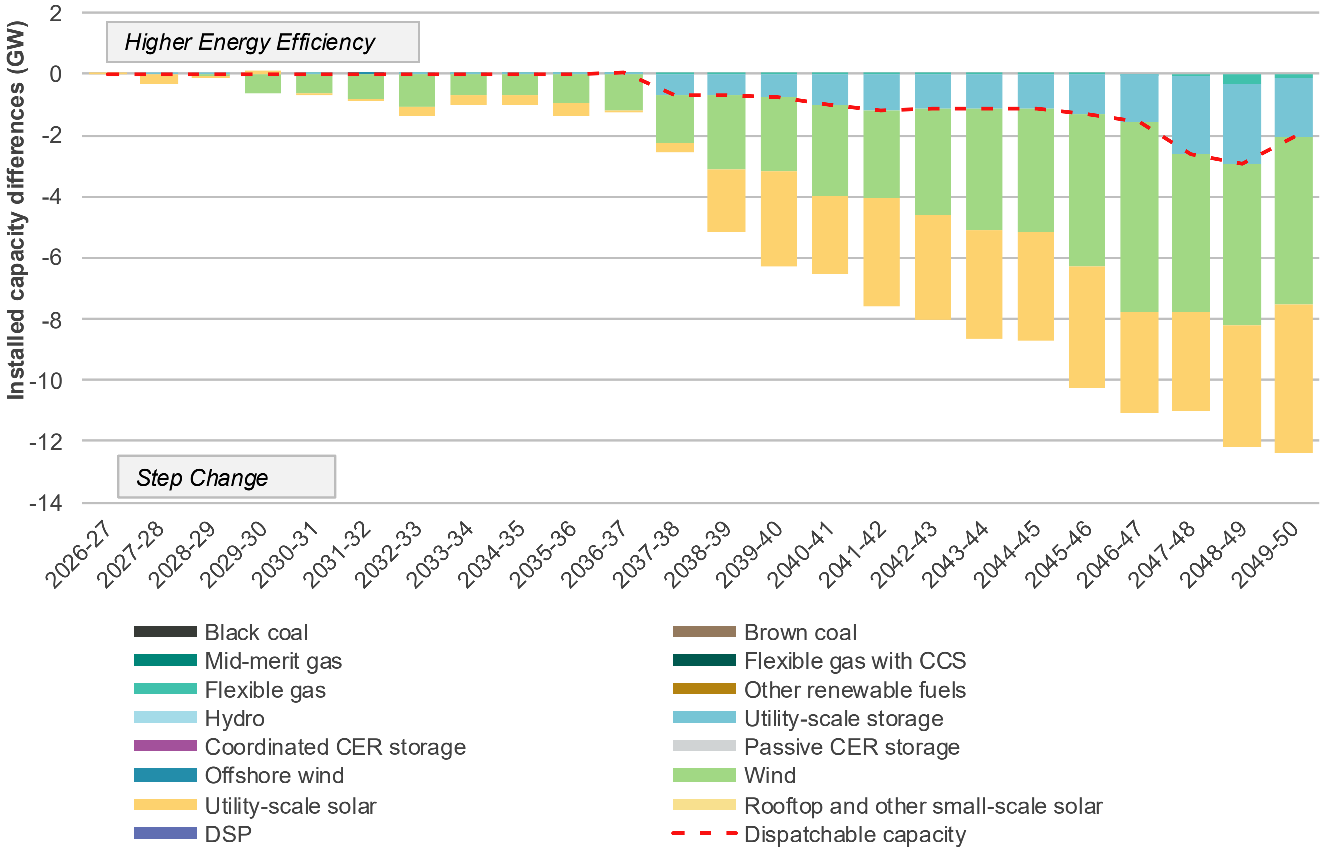


Figure 62 Forecast capacity developments to 2049-50 under the *Lower Energy Efficiency* sensitivity compared with *Step Change* (GW)



Note: coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity.

Figure 63 Forecast capacity developments to 2049-50 under the *Higher Energy Efficiency* sensitivity compared with *Step Change* (GW)



Note: coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity.

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand apply, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity, and is a form of 'demand flexibility'.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.

Term	Acronym	Explanation
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Economic offloading	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. This may also be referred to as economic 'spill' or 'spilled energy'. See 'Spill'.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Mid-scale	-	Generation and storage typically connected to the distribution network rather than to either the transmission network or behind the meter at a business or residence. For the 2026 ISP, these resources are assumed to have a generation or charge/discharge capacity of between 5 MW and 30 MW. For ease of reporting in this document, mid-scale generation and storage are sometimes included within the totals for utility-scale generation and storage. In other AEMO documents, such as the *Demand Side Factors Information Guidelines* and the *ISP Methodology*, these resources are sometimes referred to as 'other distributed resources'.
National Electricity Rules	NER	The Rules are legally binding rules made under the National Electricity Law, which govern the operation of the National Electricity Market and the ways in which AEMO manages power system security. The Rules also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The Rules are mainly made by the AEMC having regard to the National Electricity Objective.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines. The net market benefits of the ODP through to 2050 is the difference between the cost of the ODP and the cost of a 'counterfactual' development path which has no new transmission build.
'No transmission' counterfactual development path	-	The 'no transmission' counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the Counterfactual DP to calculate the economic benefits of transmission.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate energy to satisfy consumer demand, allowing for credible generation and transmission network contingencies.

Term	Acronym	Explanation
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as a high-quality resource area where a cluster of large renewable energy projects can be developed using economies of scale.
Renewable lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Rooftop solar and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For this ISP, AEMO has considered three scenarios: *Slower Growth*, *Step Change* and *Accelerated Transition*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how sensitive modelling outcomes are to a change in input or assumption (or a collection of related inputs and assumptions).
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Spill	**-**	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. Also referred to as 'economic offloading' or 'spilled energy'.
Utility-scale or utility	-	For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.