Addendum to the Draft 2026 Integrated System Plan

25 March 2026

For the National Electricity Market

A report in response to the Australian Energy Regulator's transparency review of the Draft 2026 Integrated System Plan

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

Important notice

Purpose

The purpose of this publication is to address the issues raised in the transparency review report for the Draft 2026 Integrated System Plan (ISP) published by the Australian Energy Regulator (AER) and provide additional information on how key inputs and assumptions were derived and their contribution to the outcomes in the Draft 2026 ISP.

AEMO publishes this Addendum to the Draft 2026 ISP in accordance with clause 5.22.13(c) of the National Electricity Rules (NER). This publication is generally based on information available to AEMO as at March 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.

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1 Introduction

AEMO has prepared this report in response to the Australian Energy Regulator's (AER's) Transparency Review of AEMO's Draft 2026 *Integrated System Plan* (ISP)[1] ("transparency review report")[2]. This section provides an overview of this report, invites stakeholders to provide written feedback, and notes the process to finalise the 2026 ISP.

Background

In 2020, reforms to the National Electricity Rules (NER) and the National Electricity Law (NEL) converted AEMO's ISP into an actionable strategic plan. As part of this, the AER is required to review the adequacy of AEMO's explanations of how it has derived key inputs and assumptions, and how key inputs and assumptions influenced outcomes in the Draft ISP[3].

The AER's "transparency review report" acknowledged the increased size and scope of the ISP following rule changes implementing the Energy and Climate Change Ministerial Council's (ECMC's) 2024 ISP Review recommendations[4]. These changes require AEMO to consider new matters including gas development projections, demand side factors, and potential distribution developments to support the efficient development of the power system. The AER concluded that AEMO had provided some transparency on inputs and analyses but noted that some information guidelines and processes are still under development. The AER therefore stated its expectation that newer ISP components will be further improved in the next ISP cycle.

In addition, the transparency review report identified several aspects of the Draft 2026 ISP where AEMO could better explain how key inputs and assumptions contributed to the Draft 2026 ISP outcomes. AEMO provides further explanatory material on these matters in this Addendum, as follows:

- operational output changes from 2024 ISP – see **Section 2**,
- contribution of key inputs to the outcomes of the optimal development path (ODP) – see **Section 3**,
- process for determining scenario least-cost development paths – see **Section 4**,
- changes in consumer battery capacity – see **Section 5**,
- application of build limit constraint in the constrained delivery sensitivity – see **Section 6**, and
- results for the Northern Transmission Project – see **Section 7**.

Invitation to provide written submissions

AEMO has consulted with stakeholders on the Draft 2026 ISP. AEMO now invites stakeholders to provide written submissions giving feedback on the content of this Addendum. Submissions should be provided in PDF format to ISP@aemo.com.au by 6.00 pm (AEST), 15 April 2026.

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

[2] At https://www.aer.gov.au/documents/aer-review-report-draft-2026-integrated-system-plan.

[3] NER 5.22.13(a).

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

Where possible, submissions should provide evidence and information to support any views or claims that are put forward. AEMO will publish submissions on its website, subject to materiality and confidentiality requirements[5]. Please identify any parts of your submission that you wish to remain confidential and explain why.

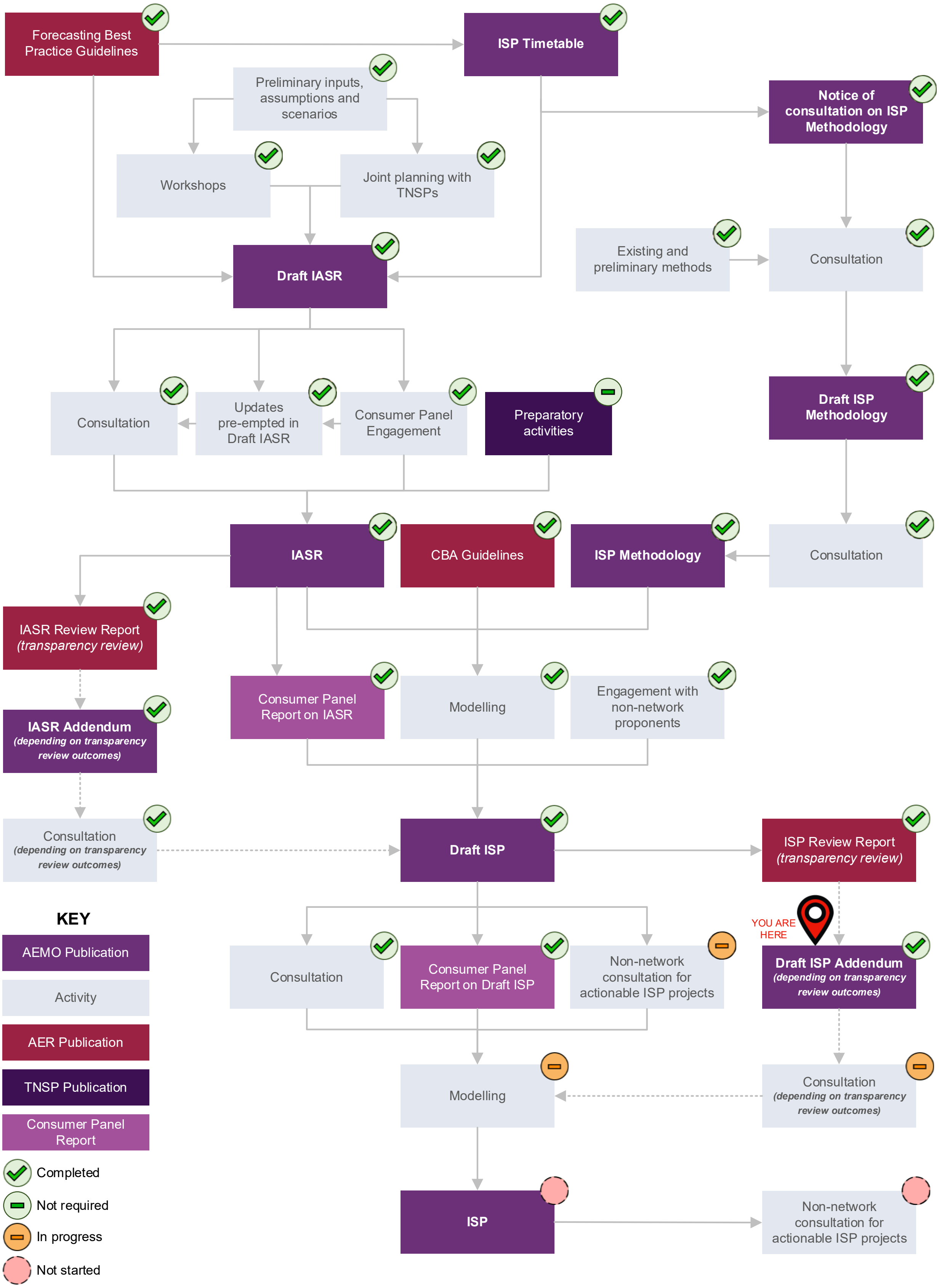
AEMO will take stakeholder submissions on this Addendum into account when developing the final 2026 ISP and will provide responses to these submissions, and to material issues identified in Draft 2026 ISP submissions, in the Consultation Summary Report released alongside the 2026 ISP.

Process to develop the 2026 ISP

This Addendum is published to improve the transparency and stakeholder understanding of the Draft 2026 ISP. **Figure 1** displays the process to develop the 2026 ISP, including publications and consultations required under the ISP regulatory framework.

[5] This is consistent with AEMO's obligations under section 54 of the National Electricity Law.

Figure 1 The *Integrated System Plan* process



2 Operational output changes from the 2024 ISP

This section addresses the transparency review report matters relating to operational output changes from the 2024 ISP.

Matters raised in the transparency review report

"*Figure 15 of the Draft ISP presents the expected amounts of capacity for a range of technologies to 2049-50, and Figure 16 presents a forecast of coal capacity. Figure 4 in Appendix 2 also presents the changes between capacity outcomes between the 2024 ISP and the draft 2026 ISP. However, these Figures present a stacked series for technologies that are operationally very different and for which operation will change over time.*

…

These differences would be elucidated by providing visibility to the graph of generation per technology over time and explaining differences from capacity graphs as well as changes since the 2024 ISP. Indeed, while the ISP contains information on efficient investment (capacity) and efficient use (demand and consumption) over time, the data on efficient operation (generation) is less transparent and available. Transparently presenting information on each of these 3 areas would more fully explain how the ISP meets the national energy objectives.

We expect AEMO to provide further explanation in their addendum on the most significant drivers and differences of each of the types of generation and storage. We also expect AEMO to present and explain the results for generation, how they have impacted the selection of the ODP and how they are different to the 2024 ISP."

AEMO's response

AEMO recognises that while the published capacity developments, by technology, in the Draft 2026 ISP provide stakeholders with transparency regarding the investment magnitude for generation technologies, they may not convey the expected share of the electricity produced over time, and may (in isolation) limit stakeholder's interpretation of the evolving energy mix in the National Electricity Market (NEM). Alongside the Draft 2026 ISP and its appendices, AEMO publishes the *Generation and Storage Development Outlooks* file containing Excel-based data that provides a range of detailed outcomes, including the generation and capacity mixes, by technology and region, for stakeholders to examine in further detail.

To improve transparency, this section provides commentary on the key drivers affecting the changing generation mix, including commentary on variations to those projected in the 2024 ISP.

An energy generation chart shows the actual electricity produced over a defined period (for example, terawatt hours [TWh] per year), reflecting how often and how intensively generators operate, and capturing the effects of demand, intermittency, outages, fuel availability, and operational constraints. In contrast, a generation capacity chart shows a stack of installed capacity of generators (for example, gigawatts [GW]), regardless of whether that capacity is utilised in practice. As a result, technologies with high installed capacity but variable output, such as wind and solar, may appear prominent in capacity terms but contribute a smaller share of total energy generation, while lower-capacity but high-utilisation technologies can deliver a disproportionate share of energy over time.

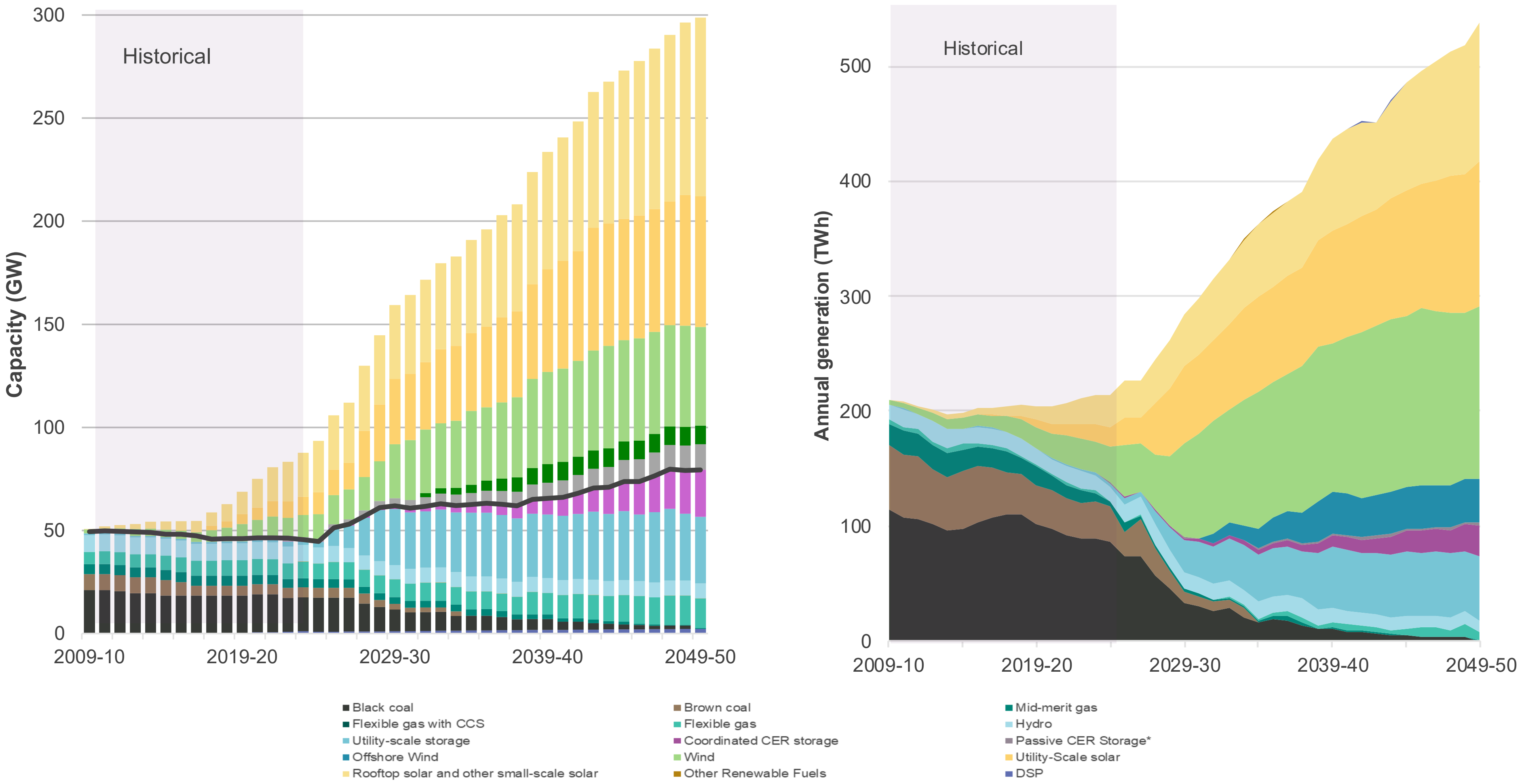
Figure 2 below shows the historical and projected volumes of electricity generated in the NEM in the *Step Change* scenario. The figure shows that the NEM is projected to rely significantly on renewable energy generation to produce much of the electricity consumed, particularly as coal generators retire and variable renewable energy (VRE) developments increase to meet various policy objectives and market opportunities. VRE is projected to account for 98% of total energy generation in the NEM in the *Step Change* scenario by 2049-50.

Compared to the 2024 ISP:

- **Coal-fired generation is projected to remain operational for longer** to align with the intent of the Queensland Energy Roadmap. In this projection, these plants would operate more flexibly, with periods where coal plants are not operating for up to months at a time. In these periods, solar generators (including consumer energy resources [CER]) provide much of the daytime electricity production previously produced by coal and gas generators. The Draft 2026 ISP projects coal-fired generation producing only approximately 3 TWh by 2048-49, reflecting a capacity factor of 20%. As Section 5.1 of the Draft 2026 ISP notes, investing in coal generators' operational flexibility is a key opportunity for emissions-intensive generators to potentially extend their operating life in a NEM with increasing VRE generation penetration.
- **Shallow and medium-depth utility-scale storage in the NEM is projected to increase**, due largely to additional committed and anticipated storage projects, as well as increased storage targets within policy such as the federal Capacity Investment Scheme (CIS) clean dispatchable capacity and the New South Wales storage targets[6]. Utility-scale storage is projected to generate 56 TWh in the Draft 2026 ISP, an increase from 24 TWh in the 2024 ISP, due to greater capacity of medium-depth storage in the latest ISP. 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**, because solar generation capital cost projections have reduced relative to wind. With increased investment in shallow and medium-depth storage that is now committed, anticipated, or supported by policy, development of solar is favoured as it is the lowest cost source of bulk energy production. These factors lead to 125 TWh of projected utility-scale solar generation in the Draft 2026 ISP, compared to a projected 119 TWh in the 2024 ISP.
- **Utility-scale wind is projected to produce less generation**, but still experience a greater share of the energy mix than the technology presently provides. This decrease relative to the 2024 ISP is driven by higher relative capital costs for wind in the Draft 2026 ISP, and a higher weighted average cost of capital (WACC) relative to utility-scale solar. In contrast, updated assumptions published in AEMO's 2025 *Inputs, Assumptions and Scenarios Report* (IASR) recognised that some wind farm locations across the NEM are now expected to achieve higher capacity factors than in the 2024 ISP. Further, as mentioned above, additional storage has favoured solar generation over wind. In combination, these factors (and the influence of other input changes from the 2024 ISP to the Draft 2026 ISP) reduce forecast wind generation from approximately 200 TWh to approximately 190 TWh in 2049-50.
- **Total energy consumption is lower** in the Draft 2026 ISP, due largely to reduced levels of hydrogen demand. By 2049-50, in the *Step Change* scenario, hydrogen electrolysers connected to the NEM are projected to consume around 32 TWh of electricity in the Draft 2026 ISP compared to 60 TWh in the 2024 ISP. Additionally, embedded solar generation, particularly CER connected to customer premises, is forecast to produce 30 TWh by 2049-50, a decrease to the 2024 ISP.

[6] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en .

Figure 2 NEM generation mix, *Step Change*, 2009-10 to 2049-40, capacity (GW) and annual generation (TWh)[A]



A. The generation chart on the right shows the total generation that has to serve the sum of the underlying demand, the hydrogen demand, and the losses incurred due to storage round-trip inefficiencies.

These combined drivers result in an ODP that balances least-cost investment with system reliability, emissions objectives, and policy alignment. Lower solar capital costs, supported by increasing shallow and medium-depth storage, favour solar as the primary source of bulk energy, while storage and transmission investments enable the system to manage variability and shift energy to periods of higher demand. Extended but increasingly flexible coal operation provides transitional firm capacity, reducing near-term reliability risks while accommodating higher variable renewable energy penetration. At the same time, relatively higher wind costs and financing assumptions moderate wind development, with transmission investment targeted to efficiently connect the most productive renewable and storage resources.

Together, this provides the least-cost coordinated mix of generation, storage, and transmission investments to meet both consumer and policy needs.

3 Contribution of key inputs to outcomes of the proposed optimal development path

This section addresses the transparency review report matters relating to the contribution of key inputs to the outcomes of the ODP.

Matters raised in the transparency review report

"Appendix 6 of the Draft 2026 ISP presents the cost benefit analysis process used to arrive at the network projects proposed in the Draft 2026 ISP. In this appendix, a list of changes to several key inputs and assumptions since the 2024 ISP is provided. However, AEMO has not provided discussion or analysis on how these changes to the key inputs have contributed to the outcomes in the draft 2026 ISP, and we were unable to trace outcomes back to these changes in inputs when reading Appendix 6. We therefore expect AEMO to provide information on how these key inputs have affected the outcomes in an addendum to the Draft 2026 ISP."

AEMO's response

AEMO has incorporated numerous changes since the publication of the 2024 ISP in response to stakeholder feedback, legislative changes, and market developments. AEMO consulted with stakeholders on these inputs and assumptions as part of the 2025 IASR. This section provides details on the individual changes and their impacts in isolation. Key changes are outlined in the following sections and include:

- inclusion of updated policy positions, as outlined in the Australian Energy Market Commission's (AEMC's) Emissions Targets Statement,
- revision of assumptions informing emission budgets,
- changes in generation and storage capital costs,
- updates to fuel prices forecasts,
- implementation of technology-specific WACC,
- revisions in elements of consumer demand for electricity,
- revision of rooftop solar and other small-scale solar capacity forecast,
- revision of energy consumption forecasts,
- reduction of hydrogen demand forecast,
- electrolyser location updated from ports to renewable energy zones (REZs),
- inclusion of distribution network constraint modelling,
- changes to transmission project assumptions,
- inclusion of gas development projections, and

- updated wind and solar resource data.

Inclusion of updated policy positions, as outlined in the AEMC's Emissions Targets Statement

Since the 2024 ISP, various updates to policy assumptions have occurred, such as:

- In July 2025, the Federal Government expanded the 2030 CIS generation and dispatchable targets[7], driving development of utility-scale storage, utility-scale solar, and wind.
- The Federal Government's Cheaper Home Batteries Program to encourage uptake of battery storage.
- The Queensland Renewable Energy Target (QRET) was repealed in October 2025 by the Queensland Government[8], which results in a slower retirement of coal-fired generation assets in Queensland in the Draft 2026 ISP.
- The South Australia Firm Energy Reliability Mechanism (FERM) to support dispatchable capacity in South Australia.
- Australia's 2035 Emissions Reduction Target of 62% to 70% reduction from 2005 levels.

See the 2025 IASR[9] for the full list of policies that were considered in the Draft 2026 ISP.

Revision of assumptions informing emission budgets

AEMO has updated the assumptions which inform the modelling of the 2030 emissions reduction target, 2035 emissions reduction target, and 2050 net zero emissions target. In the *Step Change* scenario, the NEM's temperature-linked emissions budgets have increased compared with the 2024 ISP due to greater assumed sequestration activities and revised existing land use, land-use change, and forestry inventories in recent years. The effect of a marginally higher emissions budget, if considered in isolation, has resulted in a slight increase in fossil fuelled generation in the *Step Change* scenario. In *Accelerated Transition*, the scenario's emissions budget was updated to align with the G1.5 scenario in the *Climate Change Authority's Sectoral Pathways Review*[10] and the *World Energy Outlook's* NZE scenario[11] which limits warming to 1.5°C. While the 2024 ISP's *Green Energy Exports* scenario also was 1.5°C aligned, these revisions enabled marginally higher emission budgets, with greater contribution in the medium term from other sectors. By contrast, the budgets in the *Slower Growth* scenario have decreased due to the inclusion of updated energy policies that AEMO must consider in the ISP, and their impact at reducing the operation of emissions-intensive technologies.

Changes in generation and storage capital costs

Capital costs in GenCost are assumed in the Draft 2026 ISP to be higher in the near term across all technologies compared with the 2024 ISP. The cost difference is larger for wind than utility-scale solar, which resulted in a lower development of wind capacity. The reduction in cost for solar and battery storages resulted in an increase in their capacities. The cost increase for mid-merit gas also resulted in a minor reduction in capacity built. The cost of pumped hydro increased which likely reduced the projection of pumped hydro in Draft 2026 ISP.

[7] See https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme.

[8] See https://www.parliament.qld.gov.au/Work-of-Committees/Committees/Committee-Details?cid=277&id=4554.

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

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

[11] See https://www.iea.org/reports/world-energy-outlook-2025/net-zero-emissions-by-2050.

Updates to fuel prices forecasts

AEMO has updated the fuel price forecasts for gas, coal, diesel and hydrogen used in the Draft 2026 ISP. Gas prices are projected to be higher for all scenarios across the outlook period than in the 2024 ISP, due to rising costs of production, tight supply conditions and observed increases in wholesale contract pricing since the introduction of the gas price cap. In the long term, gas prices are expected to stabilise due to increased global liquefied natural gas (LNG) supply, as they did in the 2024 ISP but at a higher price in the Draft 2026 ISP. These changes contribute to a lowering of the annual gas-powered generation (GPG) volumes in the Draft 2026 ISP relative to prior forecasts.

Implementation of technology-specific weighted average cost of capital (WACC)

AEMO implemented technology-specific WACC in the Draft 2026 ISP to account for the different financial risks and assumptions appropriate for each technology. The WACC used in this ISP also reflects the varying risk assumptions under each scenario. In the *Step Change* scenario, this change, in isolation, resulted in a slightly lower amount of wind capacity built and a higher level of transmission capacity developed compared with the 2024 ISP. This change in inputs has impacted network options consistently.

Revisions in elements of consumer demand for electricity

Compared with the 2024 ISP, virtual power plant (VPP) and vehicle-to-grid (V2G) capacity are lower in *Step Change* and *Accelerated Transition*, while higher in the *Slower Growth* scenario. In the *Step Change* scenario, this change, in isolation, resulted in increased utility-scale storage capacity and flexible gas generation capacity. Additionally, as most VPP and V2G are in sub-regions that have higher demand (that is, city centres), decreased forecasts for VPP and V2G have brought forward the economic case for networks that serve those sub-regions.

Revision of rooftop solar and other small-scale solar[12] capacity forecast

In the *Step Change* and *Accelerated Transition* scenarios, the rooftop and other small-scale solar capacity forecast is lower for the period between 2029-30 and 2044-45 compared with the 2024 ISP. This has resulted in an increase in utility-scale solar within this period. The forecast for rooftop and other small-scale solar in the *Slower Growth* scenario is higher across the outlook period compared with the previous forecast, and this resulted in a minor decrease in utility-scale solar capacity compared with the 2024 ISP.

Revision of energy consumption forecasts

In *Step Change*, consumption is consistently lower across the outlook period with the biggest divergence from the 2024 ISP forecast occurring from 2044-45. In the *Slower Growth* scenario, consumption is forecast to be lower than in the 2024 ISP until 2044-45, after which consumption increases slightly. In the *Accelerated Transition* scenario, consumption is significantly lower than forecast in the 2024 ISP. This resulted in an overall reduction in capacity required under all three scenarios.

Reduction of hydrogen demand forecast

The forecast hydrogen consumption is lower in the *Step Change* scenario and significantly lower in the *Accelerated Transition* scenario compared with the 2024 ISP, reducing the generation and electrolyser capacity required to meet hydrogen demand. AEMO has also updated its hydrogen modelling in the Draft 2026 ISP, making an assumption that hydrogen storage is sufficiently large to store a week’s worth of hydrogen based on an analysis by stakeholders in response

[12] Rooftop and other small-scale solar are rooftop photovoltaic (PV) and PV non-scheduled generation (PVNSG) capacities as forecast in the 2025 IASR.

to the results of the 2024 ISP[13]. Minimum utilisation requirements and lower hydrogen demand result in higher electrolyser utilisation rates in this ISP compared to the 2024 ISP.

Electrolyser location updated from ports to renewable energy zones

Following stakeholder feedback, AEMO considered external studies[14] indicating that, in most cases, transporting hydrogen via pipeline is lower cost than transmitting electricity over long distances prior to conversion. Reflecting this finding, electrolyser load is modelled within candidate REZs, rather than at load centres as assumed in previous ISPs. This revised locational assumption reduces electricity flows from REZs into the backbone transmission network, as a portion of renewable generation is consumed locally within the REZs for hydrogen production. Under the *Accelerated Transition* scenario, this reduces the need for network augmentation to supply hydrogen demand as there is less need to export energy from the REZs.

Inclusion of distribution network constraint modelling

AEMO has included two new types of constraints for the Draft 2026 ISP which reflect the capability of existing distribution networks to support higher levels of operation of CER and 'other distributed resources (ODR)'[15]. ODR refers to new-entrant solar photovoltaic (PV) and batteries that are distribution-connected with installation sizes ranging from 5 megawatts (MW) to 30 MW.

These constraints are included to:

- For CER, reflect the existing capability of distribution networks to facilitate export of CER generation from consumers' homes and businesses into the distribution network. The Draft 2026 ISP includes specific cost rates for each distribution network service provider for two types of investments that can increase distribution networks' capabilities to support higher levels of CER operation. These types of investments, and the associated cost rates, are distinct from those included for distribution network augmentations to support 'other distributed resources'. The constraints included for CER are discussed in detail in Appendix 9 of the Draft 2026 ISP.
- For ODR, reflect the existing capability of distribution networks to facilitate the uptake and generation from new entrant distribution-connected solar PV and batteries. The Draft 2026 ISP includes distribution network augmentation costs, allowing consideration of generic distribution network augmentations that could increase the distribution networks' capabilities to support these types of new generation assets.

These constraints limit the ability for CER and ODR generation to supply demand. This affects ISP modelling outcomes in two ways. First, there is a period at the start of the modelling horizon in which no new infrastructure can be delivered, beyond what is considered to be committed or anticipated, due to lead time assumptions. In this period, curtailment of CER and ODR is compensated for by increased generation from existing, committed and anticipated generators. Second, in later

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[13] The stakeholders' response suggests that there is only a need for storages capable of storing five to 12 days' worth of hydrogen or an average of approximately eight days. See Griffith University submission to 2026 ISP Methodology consultation, at https://www.griffith.edu.au/__data/assets/pdf_file/0030/2056197/Andrew-Fletcher-Huyen-Nguyen-2026-ISP-Methodolgy-Issues-Paper-Consultation.pdf.

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

[15] Note that for the rest of the document, 'other distributed resources' are included in either utility-scale solar or utility-scale storage, whichever is appropriate.

years, some CER and ODR generation is curtailed even after distribution network investments are delivered, and this curtailed generation is made up for by increased utility-scale VRE generation.

Changes to transmission project assumptions

Two new REZs have been added in Queensland and New South Wales, and some REZs in other regions were remapped and reallocated, to align with the Queensland Government's REZ Roadmap and 2025 Victorian Transmission Plan. In addition, the offshore candidate REZ in South-East South Australia Coast has been removed, in recognition that this area is not one of the Federal Government's priority areas for offshore wind development. Group constraints were updated to reflect the transmission network limitations between REZs.

Three new distribution REZs in New South Wales have been modelled in the Draft 2026 ISP. REZ resource limits have been updated and REZ import limits are introduced to ensure network limitations for serving loads within REZs, such as electrolyser loads, are captured.

Lastly, higher capital costs, network limits, and updated earliest in-service dates (EISDs) for flow paths and REZ network augmentations are reflected as per the 2025 IASR.

These changes resulted in a reduction of utility-scale storage capacity in Southern Queensland sub-region, likely due to less restrictive network constraints in that sub-region and increases to existing Queensland – New South Wales Interconnector (QNI) limits. In addition, more granular representation of Victorian sub-regional limits and additional REZ constraints also highlighted beneficial augmentations that were not previously included in the modelling – such as the Western Victoria Reinforcement program and staging of the Gippsland Offshore Wind Transmission network augmentations. Increases to network capital costs and updates to EISDs generally pushed optimal transmission timings back.

Inclusion of gas development projections

In response to the 2024 ISP Review and subsequent rule changes, AEMO expanded its consideration of gas market conditions in the Draft 2026 ISP. The gas development projections (GDPs) outline plausible pathways for gas infrastructure development and supply availability to complement the Draft 2026 ISP. The GDPs used for the Draft 2026 ISP include gas infrastructure and supply options such as transportation, storage, production, and regasification to meet the gas consumption needs of the East Coast Gas Market (ECGM). This change allows for consistent treatment of fuel supply availability across all candidate development paths (CDPs) including the counterfactual development path. The improved treatment of the gas development projections has not materially impacted the broader ISP outcomes.

Updated wind and solar resource data

Wind resource traces were updated based on the 2025 IASR, which resulted in increased capacity factors for wind generation, representing a higher level of production per MW of installed capacity, particularly in southern New South Wales and South Australia. Changes to the approach used to calculate REZ capacity factor estimates included adoption of the Bureau of Meteorology's BARRA2 reanalysis dataset which provides improved spatial granularity and representation of VRE potential across Australia compared to alternative datasets, an increase of the assumed hub height for wind generators to 150 metres, and an update to AEMO's resource-to-power conversion model to better reflect newer technologies[16]. This would make wind more competitive, with all else being equal, compared with the assumptions made in the 2024 ISP. In

[16] See 2025-inputs-assumptions-and-scenarios-report.pdf.

addition, time-of-day variable generation ratings were improved, resulting in higher midday solar and increased wind generation during early morning and night hours.

4 Process for determining scenario least-cost development paths

This section addresses the transparency review report matters relating to the process for determining scenario least-cost development paths.

Matters raised in the transparency review report

"In the Draft 2026 ISP, AEMO states that it considered around 2,000 potential development paths and modelled a shortlist of 23 candidates to identify the ODP.

Appendix 6 identifies that AEMO determines the least-cost development paths for each scenario, in the first step in determining the optimal development path. We understand that AEMO uses its Single-Stage Long-Term model to inform the formulation of many development paths in each scenario. In particular, the most recent ISP methodology notes that the linear network build decisions from this model provide a first indication of potential network investments for the formulation of development paths which are then assessed in the Detailed Long-Term model. We further understand that AEMO uses its Detailed Long-Term model to compare these development paths to find the least-cost development path which minimises system costs for each scenario.

It is less clear how the range of inputs and assumptions are used in 'whittling down' the set of potential development paths and deriving a least-cost development path for each scenario. We consider that there is a lack of transparency with respect to:

- *the differences between the 2,000 potential paths and which groupings, data and decision variables were used to reduce this down to the 23 candidate development paths*
- *the set of development paths which are considered in each scenario when finding the least-cost development path.*

We therefore expect that AEMO's addendum will provide further information and examples in relation to the data, main groupings and process AEMO used to determine both the least-cost development path in each scenario and the set of candidate development paths."

AEMO's response

To determine the ODP, AEMO identified almost 2,000 potential development paths (DPs), which it reduced to 23 CDPs. It compared these CDPs using the cost-benefit analysis required by the NER. The process of identifying and analysing the CDPs is detailed in the 2025 *ISP Methodology*[17], and in Appendix 6 of the Draft 2026 ISP.

The transparency review report has asked for further information and examples on the data, main groupings, and process that AEMO used to determine both the least-cost Development Path in each scenario and the set of CDPs.

[17] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp%20methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

In response, AEMO gives further detail of its three-step process to identify the 23 CDPs by using two interacting capacity outlook models to address different aspects of the long-term optimisation – the Single-Stage Long-Term (SSLT) model and the Detailed Long-Term (DLT) model:

- **The SSLT model** provides the longest look-ahead at lower granular level by optimising the total system cost over the entire outlook period in one step which allows consideration of emission budgets, potential development or retirement of thermal assets, and electrolyser development to supply hydrogen production requirements. While network, generation and storage expansion is fully co-optimised in this step, the SSLT model lacks the granularity required to precisely identify which combination of discrete network projects, and their timings, will best meet the needs of consumers. In effect, the SSLT modelling identifies the network flow paths and REZ networks that do or do not indicate a need for augmentation over the outlook period, as well as the network projects that may meet those needs.
- **The DLT model** divides the outlook period into multiple steps (each with a shorter outlook period) that are optimised sequentially but having more granular representation of each day's demand requirement and VRE availability. The DLT model leverages the outcomes of the SSLT such as the disaggregated carbon budgets, generator retirement decisions, and development of high-utilisation fossil-fuelled generation into each step.

Three-phase process using both SSLT and DLT models

The outputs from both models are used to identify the least-cost development paths (DPs) for each scenario which are, in turn, used as the basis for developing the full set of CDPs that are further investigated in the cost-benefit analysis phase of the modelling. The methodology and principles behind the search for least-cost DPs and CDPs are covered in detail in the Section 6 of the 2025 *ISP Methodology*[18].

The next sections explain the process of implementing this methodology for identifying the least-cost DP and CDPs for an ISP, which was applied in preparing the Draft 2026 ISP. **Figure 3** below summarises how AEMO uses the SSLT and DLT models sequentially to operate the *2025 ISP Methodology*.

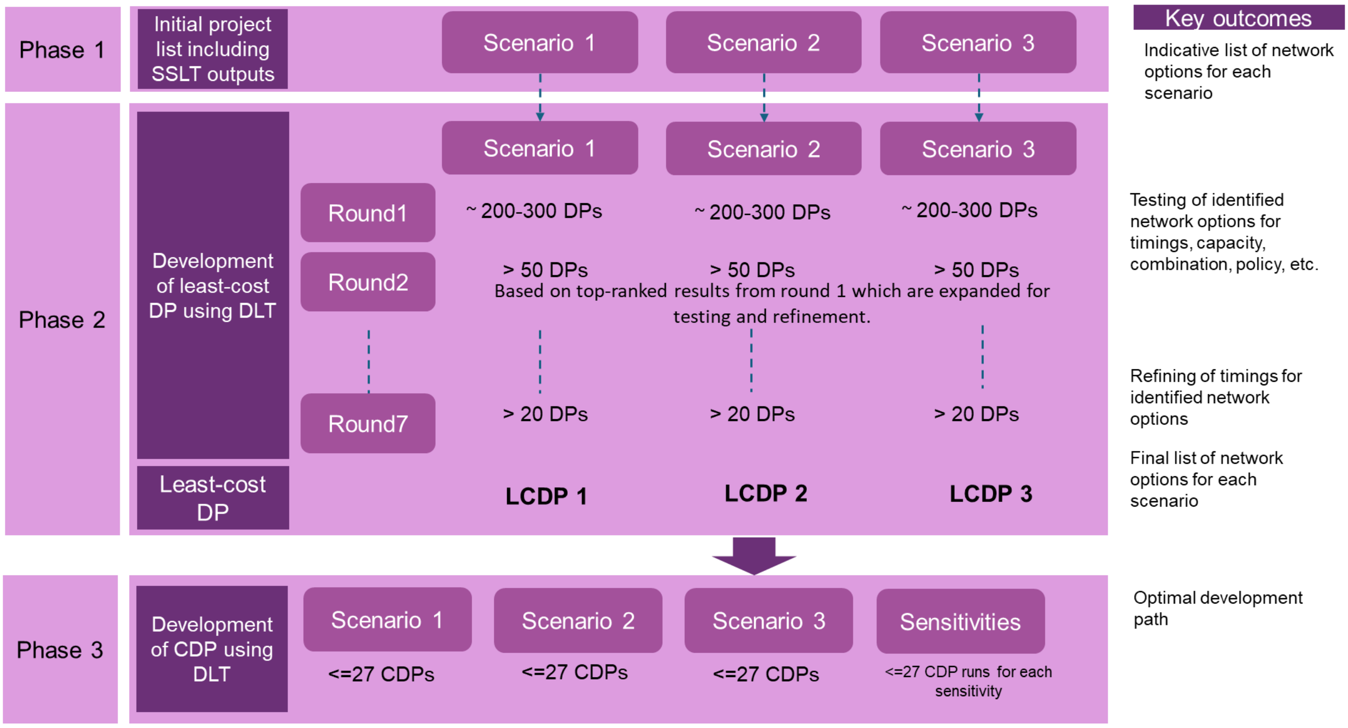
The process can be broken down into three phases:

- Phase 1 is to develop the initial and broad list of projects that would be considered for further investigation in succeeding phases. This includes identification of transmission projects that may potentially be actionable under each of the three ISP scenarios using the SSLT model and other approaches which are further detailed in proceeding sections.
- Phase 2 is the search for potentially actionable projects that form part of the least-cost DPs using Detailed Long Term (DLT) model and the outcomes of Phase 1. This phase identifies the potentially actionable projects and project combinations that would form the least-cost DP for each scenario using multiple runs of the DLT. Each run applies a 'branch and bound' technique to progressively identify, or eliminate, projects and project combinations that would (or would not) form part of the least-cost DP. The least-cost DPs and corresponding potentially actionable projects resulting from this phase inform the first three CDPs that will be investigated in the third phase.
- Phase 3 is the development of CDPs using the outcomes of Phase 2. This phase develops a further 20 CDPs that are variations of the initial three, and it assesses their net market benefits to consumers across the three scenarios using the DLT model.

[18] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp%20methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

AEMO then identifies the ODP as the CDP with the optimal balance of market benefits and risk mitigation across the three scenarios.

Figure 3 Process for development of least-cost DPs and CDPs for the Draft 2026 ISP



These phases are further detailed in the following sections.

Phase 1: Developing the initial projects list for further investigation in the DLT

The purpose of this phase is to identify the initial list of projects and combinations of projects that should be further investigated at a more granular detail in the second phase if they provide lower system costs. The initial projects list, composed of four kinds of network projects that may potentially be actionable, is developed by the following approaches:

- **Outputs from the SSLT model** – the SSLT model is the first screening tool used to identify the linearised[19] network options that are needed to minimise the total system cost for each scenario. With a linearised network representation, the SSLT model can build a percentage of a transmission augmentation in a given year rather than needing to make a choice of either building or not building the augmentation. The SSLT helps identify the timing and scale of capacity requirements for each of the selected linearised network options. It also identifies flow paths and REZ networks that do not need augmentation, for which network options are not considered in succeeding phase. The year in which the installed capacity of a network option reaches more than 50% of the stated capacity acts as an indication of the year for further testing the timings in Phase 2 for identifying the least-cost DPs.

[19] Linearised built decisions are applied to allow incremental development of network options and not restrict development of those options to just all or nothing. By doing so, the simulations are more tractable.

The identified timing needs further investigation in the succeeding phase as the SSLT model lacks the granularity to adequately capture the variability of VREs, electrolysers operations, and the value of storage and generation technologies such as peaking gas plants.

- **Existing actionable projects** – in addition to the projects identified in the SSLT model, AEMO also includes projects that are currently considered actionable in the most recent ISP in the initial projects list, regardless of whether the SSLT provided any indication that the project should be further investigated in the DLT or not. This ensures the actionability of existing actionable projects is retested in successive ISPs, consistent with the AER's *Cost Benefit Analysis Guidelines* (CBA Guidelines)[20].
- **Projects that are impacted by other generation and storage development or policies** – AEMO also includes those projects that are needed to meet policy or that are relevant to expected generation and storage developments in the NEM in the initial projects list.

An example of a transmission project relevant to policy is the Gippsland offshore wind transmission options (developed in three stages – Stage 1, Stage 2 Phase 1 and Stage 2 Phase 2) which are necessary to allow connection of offshore wind capacity to meet the Victorian Offshore Wind Target of 9 GW by 2039-40.

- **Other projects that are in geographical and electrical proximity to projects already included in the initial projects list** – Many transmission projects deliver more synergies when they are delivered together due to their geographical proximity to each other.

Examples of projects with geographical and electrical proximity are the New England REZ Network Infrastructure Project and QNI Connect which both allow higher renewable generation development in Northern NSW South Wales. This set of projects is considered in the initial projects list individually and collectively.

Phase 2: Identifying potential actionable projects

Phase 1 provides the initial list of network options that should be considered in each scenario. The network options in the initial projects list are then further tested in the DLT capacity outlook model.

In Phase 2, the search for the least-cost DP involves testing the network options identified in Phase 1 through an iterative process and multiple rounds of the DLT capacity outlook model, as shown above in **Figure 3** and explained below. For every round, the decision on which set of projects to be investigated further in succeeding rounds is based on the rankings of DPs according to their total system costs. The projects featured in the higher-ranked DPs that have similar total system costs in magnitude are further investigated in succeeding rounds.

Round 1: Assessing the base case and alternative development paths

In the first round of iteration, a base (starting case) DP is created for each scenario based on the identified network options from the preceding phase. The base DP consists of a network build schedule that features all the initial network options' full development at their EISDs. Then a significant number of DPs are created around the base/starting DP by adding or pruning network options in the initial projects list using a 'branch and bound' algorithm[21] wherein the following is tested:

[20] See https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines/current-cba-guidelines, p.18.

[21] More details on this at https://www.fico.com/fico-xpress-optimization/docs/dms2021-03/solver/optimizer/HTML/chapter4_sec_section4003.html.

a) network and non-network options delivered at different timings such as outside the EISD, or no development of the identified option;

b) staging of network capacity such as testing in stages or full capacity;

c) alternative options and non-network options for the same flow paths with different capacity and costs;

d) any combination of network options based on the proximity and timings of transmission flow path or REZ augmentation, or any potential impact of one on any other;

e) testing network options to support policy; and

f) for projects previously identified as actionable in the previous ISP, AEMO only tests those options at the proponent's timing, at the end of the actionable window or thereafter.

Example of testing for a network option in DPs

The Gladstone Project (CQ-GG Option 2) was previously identified as actionable in the 2024 ISP. It improves supply to the Gladstone Grid sub-region as coal generation retires by raising the transmission capacity from Central Queensland to Gladstone Grid by 2,600 MW. In Phase 1 analysis for the Draft 2026 ISP, the SSLT results identified that this network augmentation remains beneficial. So, CQ-GG Option 2 was included in the initial projects list for Phase 2.

Since it is already an actionable project, from the 2024 ISP, AEMO tested its timings at both its EISD (1 March 2029) and the year after the end of its actionable window (1 March 2033) as per the 2025 *ISP Methodology*. In addition to this, the CQ-GG Option 2 project delivery at EISD and at delayed timing (outside the actionable window) are also tested along with (and also substituted by) different combination of other projects such as CQ-GG Option 3, CQ-GG Option 4, SQ-CQ Option 1, SQ-CQ Option 2, SQ-CQ Option 3, SQ-CQ Option 4, SQ-CQ Option 5, SQ-CQ Option 6, CQ-NQ Option 2, NNSW-SQ Option 2, and CNSW-NNSW Option 1. The combination is selected such that it adequately represents the projects that may influence sub regions and inter-regional transmission flows and capacity builds in the NEM.

More than 200 DPs are investigated for each scenario in Round 1. This initial set of DPs are informed by results from Phase 1 and are meant to cast the net wider to check different combinations of network projects that could be included in the least-cost DP of each scenario. As such, the exact timing of each project is refined in the next rounds.

From the initial set of DPs, the advantage of one DP over another is primarily analysed through overall system cost reductions achieved for DPs in each scenario. The DP that results in least cost then becomes the base case (starting case) for the Round 2 of each scenario and this is complemented by other DPs that belong in the top ranked DPs for which the resulting estimate of total system cost are sufficiently low-cost and statistically close to the least-cost DPs. The projects in the top ranked DPs are to be considered for the succeeding round. This may mean that only a few, or potentially up to 50 DPs, progress to Round 2, for each scenario. This is further discussed in the next subsections.

The network projects that are featured in DPs that have relatively high total system costs (i.e. those projects that may not be used sufficiently if built) are dropped and not further examined in succeeding rounds. For example, the development of the WNV-SESA Option 1 flow path augmentation and N13 REZ augmentations in the *Step Change* scenario were delivering negative net market benefits in the first round of Phase 2 hence were not included in the network options that were tested in succeeding rounds.

Round 2 and onwards: Refining the network options, combinations, and timings

Round 2 and onwards are the iterations undertaken to refine network option timings and combinations. The DP with lowest system cost compared to all the other DPs in Round 1 acts as the starting DP for Round 2. Around this new starting case, additional DPs are created by using similar process of crafting the set of DPs in Round 1 but only considering the projects that made it through to the second round and excluding projects that are dropped for the succeeding rounds.

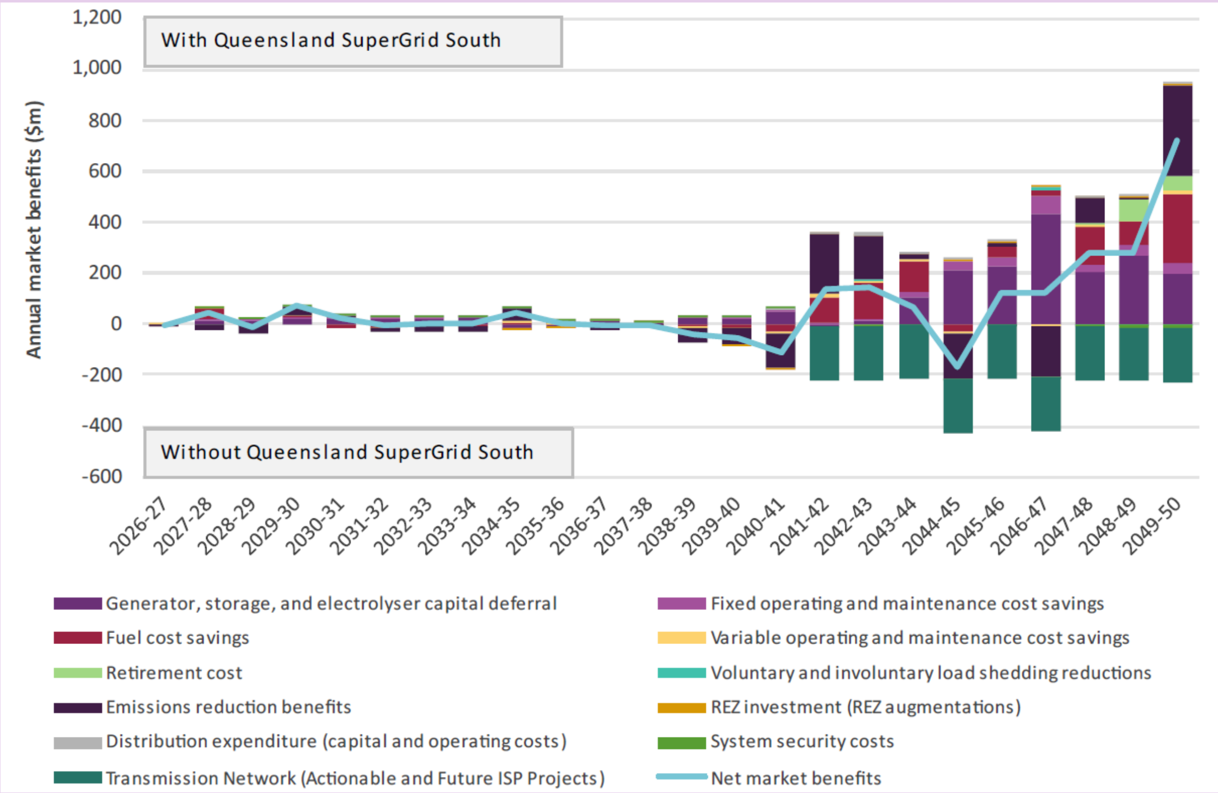
As projects are whittled down through this iterative process, more focus is given to the timings of delivery of network projects. The following example shows how the timing of a network option is ascertained.

Example of identifying timings for a network option

The analysis to determine the optimal timing for the Queensland SuperGrid South project is based on **Figure 4**, which appeared in Appendix 6 of the Draft 2026 ISP.

The figure shows the annual market benefit (above 0 on the Y-axis) of having Queensland SuperGrid South in 2041-42 compared to not having the network option at all. Positive values show benefits of the network option, whereas negative values show a benefit in not proceeding with the network option. Overall, the project delivers $404 million in net market benefits if delivered in 2041-42 compared to a no-development case. However, the annual market benefits become positive at two major points (i.e. in 2041-42 and in 2045-46). Post 2045-46, benefits remain positive throughout the modelling horizon which shows that there are benefits from having the Queensland SuperGrid South development compared to not having the option. Therefore, the timings for this network option are also tested in 2045-46 to ascertain which of the two timings is optimal and facilitates the higher overall benefits to NEM.

Figure 4 Annual relative market benefits of SuperGrid South in *Slower Growth* (2041-42 and never)



AEMO typically tests timing at the EISD, beyond the actionable window, at points where benefits become positive in previous simulations, and a counterfactual where it is not built.

A DP is dropped from further analysis once AEMO finds sufficient evidence that there are no advantages derived from a network option being tested at different timings (that is, the net market benefit line in the previous chart stays below zero until the end of the outlook period).

In the example above, if the DP that featured Queensland SuperGrid South had no cross-over (the point in which the net market benefits line crosses the x-axis) and stayed negative until the end of the outlook period, this would indicate that the project had no net market benefits under that scenario. Queensland SuperGrid South would then be dropped as a candidate network option for this scenario's least-cost DP and would not be tested in successive rounds.

If the DP that featured delivery of Queensland SuperGrid South at its EISD showed positive net market benefits (cross-over at the EISD), its delivery together with the delivery of QNI Connect and New England at their EISDs (for example) would form another DP to be tested in the next round. The choice of which network project to combine Queensland SuperGrid South with and be tested in the next round is based on the results for other DPs that feature those other projects. That is, AEMO also assesses the case for other projects, such as QNI Connect and New England, and checks that those projects provide net market benefits individually.

If that combination of three projects proved to be economic, AEMO would test delivery of those projects together with delivery of VNI West at its EISD in the next round. If that also proved to be economic, AEMO would test delivery of those projects together with SuperGrid North in the next round. If those five projects continued to provide net market benefits, AEMO would add another project for the next round, so on and so forth.

However, if those five projects were not economic, AEMO would take SuperGrid North out from contention and would test the next project that could be part of the least cost-DP for that scenario.

Generally, when implementing the next round, the least-cost DP for each scenario in any round will act as the base case for the next round, with new alternative DPs created. The result of that next round becomes the starting point for the proceeding round, so on and so forth. This iterative process continues until only one least-cost DP for each scenario is identified. For the Draft 2026 ISP, this took seven rounds.

Operating the process for Phase 1 and Phase 2 will lead to the least-cost DP for each of the scenario, which become the basis for Phase 3.

Phase 3: Identify the candidate development paths (CDP) used in the CBA process

The set of potentially actionable projects is identified from least-cost DPs of each scenario identified in the previous phase. The combinations of projects featured in each least-cost DP relating to each of the three scenarios form the first three CDPs. A CDP represents a collection of DPs that have similar set of potentially actionable projects.

The first three CDPs are complemented by creating additional CDPs that vary with respect to the potentially actionable projects and represent adaptable paths for investments in future projects (enabling future projects to be developed at a timing most appropriate for each scenario's needs, including potentially not developing the project across the outlook period). This additional set of CDPs is designed to assess the benefits of potential actionable projects by providing alternative CDPs that provide a comparison with key projects being delayed to future projects, or not developed at all, and assess the weighted benefits and regrets of delivering those key projects at actionable timings across the scenario collection.

The CDP collection can therefore be used to test whether a project should be actionable in the ISP, or listed as a future ISP project, or potentially not developing the project at all the project across the outlook period.

More details on the projects included in each CDP and key reasons for their selection is in Section A6.4.2 of Appendix 6 of the Draft 2026 ISP.

Cost-benefit analysis

Following the development of a short-list of CDPs, these paths are assessed to determine the ODP that best serves consumers' long-term interests under uncertainty. This assessment is undertaken through a cost-benefit analysis conducted in accordance with the AER's CBA Guidelines and is fully integrated with the ISP's market modelling framework.

The CDP selection and CBA process, as set out in Sections 6.3 to 6.5 of the 2025 *ISP Methodology*, enables comparison of alternative development paths across scenarios, accounting for differences in costs, benefits and timing of investments. This approach ensures that the relative performance of each CDP is evaluated on a consistent basis.

The ODP is ultimately selected as the development path that best balances net market benefits and risk, performs robustly across a range of plausible futures, and remains resilient under sensitivity testing, with AEMO's professional judgement applied transparently where required.

5 Changes in consumer battery capacity

This section addresses the transparency review report matters relating to changes in consumer battery capacity.

Matters raised in the transparency review report

"The Draft 2026 ISP states that, under the Step Change scenario, household and commercial battery capacity is forecast to grow to an estimated 5 GW in 2029–30, then 27 GW in 2049–50. This growth is attributed to lower costs, easier-to-use technology, and government policies such as the Cheaper Home Batteries Program. In the 2024 ISP, the Step Change scenario instead forecast capacity of about 7 GW in 2029–30 and 34 GW in 2049–50.

We note that the forecast household and commercial battery capacity has been reduced under the same scenario between the 2024 ISP and the Draft 2026 ISP, without an explanation or reference for this change.

We expect AEMO to provide a clearer explanation for the reduction in the residential and commercial battery."

AEMO's response

AEMO's forecasts can and do change between iterations of regular publications and also across the different publications (for example, ISP/*Electricity Statement of Opportunities* [ESOO]/*Gas Statement of Opportunities* [GSOO]). This evolution of forecast inputs and assumptions is important to ensure models are initialised using recent observations and factor in relevant forecast drivers; this can include updates in historical actuals, changes to policy, or upgrades to models. For publications that are produced annually (such as the Statements of Opportunities), annual updates are required to consider the most recent trends in these input components.

After the 2023 IASR, the 2024 ESOO incorporated revised forecasts as consulted on with stakeholders in the 2024 *Forecasting Assumptions Update*. This updated CER forecast reduced the level of battery capacity expected to be installed, due to a number of factors including slower reduction in PV and battery costs than was forecast in the 2023 IASR, lower actual battery installations in 2024 and due to the interaction with a lowering of the PV installations forecast from lower retail price and system size projections. The relevant 2024 *Forecasting Assumptions Update* forecasts were therefore lower than the 2023 IASR.

The 2025 IASR figures (used for the Draft 2026 ISP) included revised forecasts to reflect the most recent data and trends, while comparing to the most recent forecasts (in the 2024 *Forecasting Assumptions Update*, rather than the 2023 IASR scenarios). These 2025 IASR forecasts included revised assumptions on government subsidies and included further reductions in actual PV installations (reflecting that some new installations are replacing existing systems rather than adding entirely new capacity), resulting in a net decrease in capacity. The 2025 IASR forecasts also provided some consideration for the anticipated increase in short-term battery sales expected from the recently announced Cheaper Home Batteries Program (CHBP). The anticipated increase from the CHBP and increase in recent battery installations were further considered in the forecasts published in the Draft 2026 *Forecasting Assumptions Update*.

Reflecting these relative changes from 2023 to 2024 to 2025 forecasts, the overall result was that the Draft 2026 ISP includes lower capacity than the 2024 ISP, over the full modelling period.

6 Application of build limit constraint in the constrained delivery sensitivity

This section addresses the transparency review report matters relating to the application of build limit constraint in the *Constrained Delivery* sensitivity.

Matters raised in the transparency review report

"*AEMO modelled a sensitivity in the step change scenario where delivery is constrained, by introducing an annual build limit extrapolated from historical data but gradually increased in later years. The Draft ISP briefly discusses the overall outcomes of this sensitivity but does not explain how the outcomes over time and final technology mix are driven by the changes in inputs. As an example, there is a 7000 MW greater increase in wind generation capacity compared to the optimal development path in the step change scenario by 2034–35 although costs are assumed to be higher, and construction limited. Similar trends of interest exist to a lesser extent for utility scale solar buildout and a lower emissions trajectory for 2031–48.*

We expect AEMO to provide further analysis and explanation behind how the constraints impacted the modelled outcomes throughout the forecast period for this sensitivity."

AEMO's response

The technology-specific model outcomes in the *Constrained Delivery* sensitivity are primarily driven by the generation and storage annual build limits applied until 2034-35 and assumed offshore wind delays, while continuing to satisfy emissions budgets and meet NEM demand:

- **Utility-scale solar development.** From 2027-28 to 2029-30, the annual build limit assumed for utility-scale solar restricts up to 8 GW of developments being built when compared to *Step Change*, shown in **Figure 5** (reproduced from Appendix A2, Figure 44). This results in much lower solar generation over the period 2027-28 to 2030-31, as shown in **Figure 6** (reproduced from Appendix A2, Figure 45).
- **Utility-scale battery development.** Build limits have been applied for utility-scale battery development, alongside the reduced utility-scale solar build described above. A reduction in solar PV build tends to reduce storage build, as a significant component of storage value is derived from time-shifting solar production to later in the day. Together, these factors result in 12 GW less battery energy storage system (BESS) capacity by 2029-30 compared with *Step Change*. For the final 2026 ISP, AEMO is considering relaxing the annual build limits for utility-scale batteries to reflect the updated (that is, larger) pipeline of large-scale storage projects already progressing through the connections process.
- **Offshore wind development.** In *Constrained Delivery*, offshore wind projects are also impacted by development constraints, delaying all offshore wind build by three years. As shown in Figure 5, this results in 2 GW less offshore wind than *Step Change* by 2031-32, and 3 GW less offshore wind by 2033-34, with build and generation output catching up with *Step Change* by 2041-42.
- **Onshore wind development.** Initially, onshore wind build capacity is constrained by annual build limits, 2 GW lower than *Step Change* by 2029-30, as Figure 5 shows. However, after this point onshore wind build limits do not bind, and

instead there is 7 GW more onshore wind built by 2032-33 compared to *Step Change*. This is because the onshore wind steps in to take the place of the delayed offshore wind generation, and because of the lower solar and battery build (explained above). Ultimately this additional onshore wind development allows emissions budgets to be satisfied NEM demand to be met. Once this onshore wind capacity is built, it remains operational, and onshore wind capacity differences persist compared to *Step Change*, being 7 GW higher in 2036-37, and 5 GW higher in 2042-43, with the difference reducing to around 1 GW by 2042-43 as new utility-scale solar capacity replaces retiring generation and storage.

- **Coal and gas operation and retirements.** As **Figure 6** shows, initially GPG and black coal generate more in the period to 2029-30 than *Step Change* to meet the deficit left from the lower wind, solar and battery developments described above. When combined with a short extension of brown coal to meet demand, 1.2 GW higher than *Step Change* in 2030-31, this leads to increased emissions prior to 2029-30 compared to *Step Change,* shown in **Figure 7** (reproduced from the Draft 2026 ISP, Figure 27). These higher, earlier emissions must be offset later in the horizon to satisfy emissions budgets, and as a consequence some black coal generation retires earlier in *Constrained Delivery* from 2035-36 (**Figure 5**). As a result of this retirement, coal generates less in the period 2035-36 to 2044-45, resulting in a lower emissions profile between 2035-36 and 2044-45 than *Step Change*, shown in **Figure 7**. The reduction in generation from these retirements is offset by the previously mentioned onshore wind build, as well as higher solar build than *Step Change* from 2035-36 as shown in **Figure 5,** as the build limit constraints for solar no longer bind after 2030-31.

Figure 5 Projected capacity developments to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (GW)

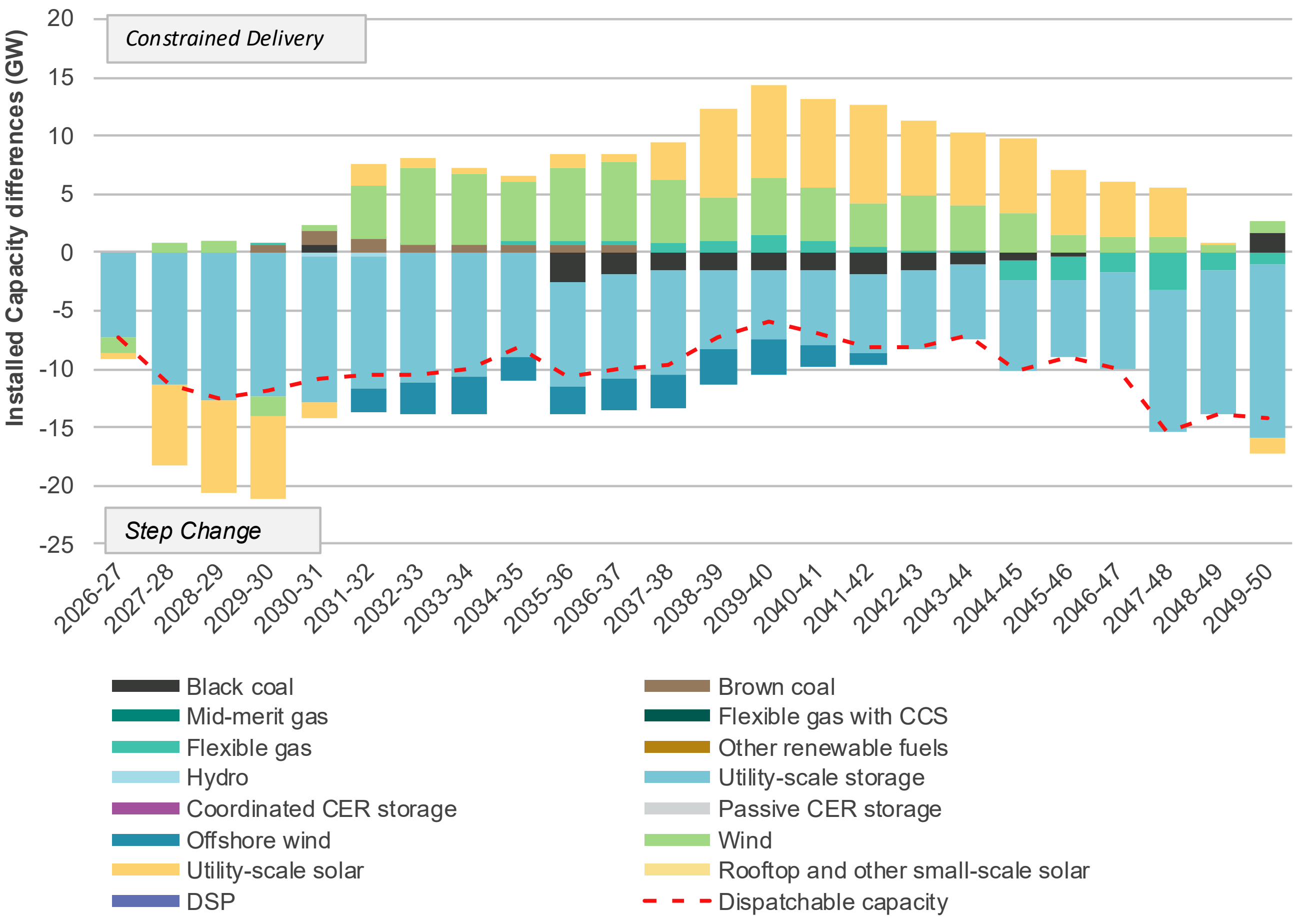


Figure 6 Projected generation to 2049-50 under the *Constrained Delivery* sensitivity compared with *Step Change* (TWh)

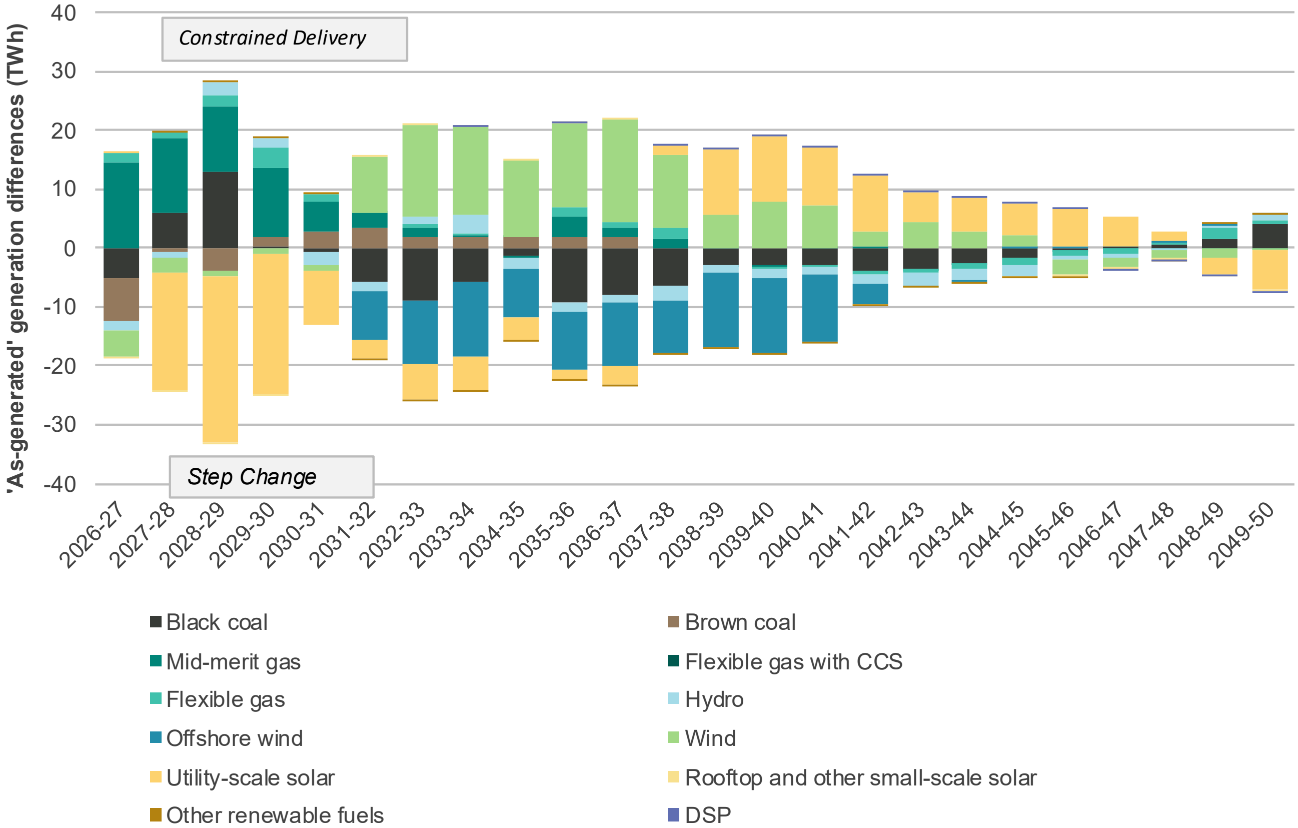
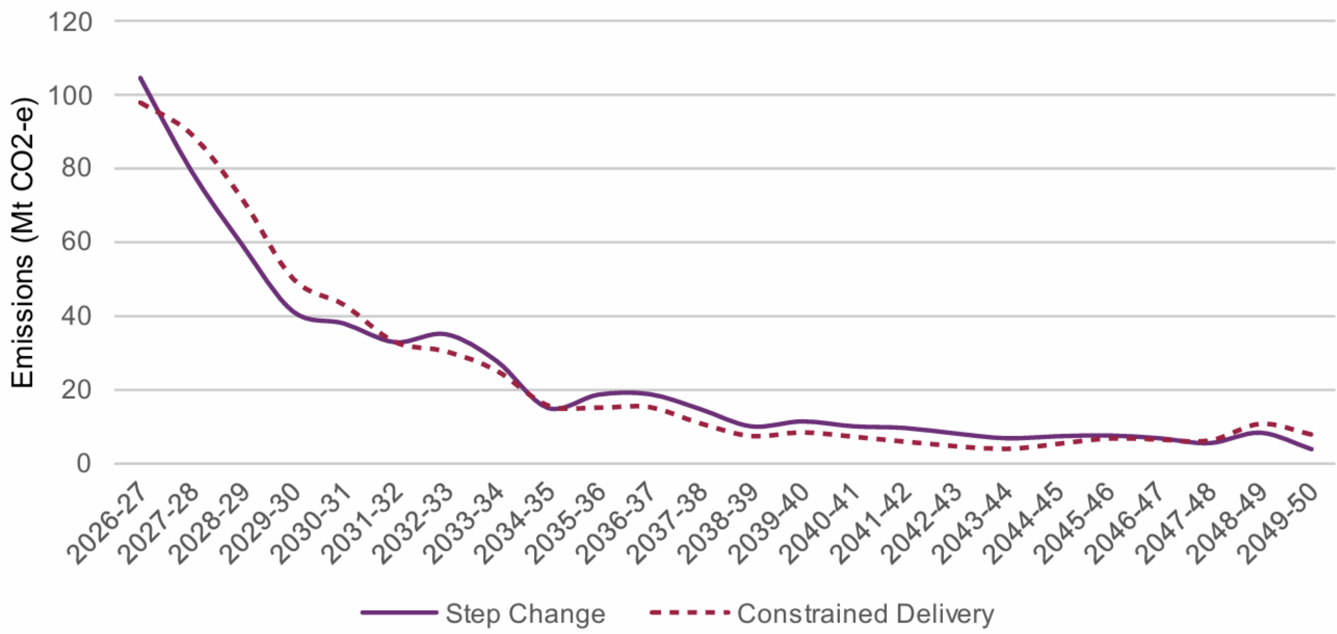


Figure 7 Forecast NEM emissions trajectory, *Step Change* versus *Constrained Delivery*, 2026-27 to 2049-50 (million tonnes of carbon dioxide equivalent [Mt CO_2-e])



7 Results for the Northern Transmission Project

This section addresses the transparency review report matters relating to the publication of results for the Northern Transmission Project.

Matters raised in the transparency review report

"The Northern Transmission Project (formerly the Mid North South Australia REZ Expansion) in South Australia is one of 2 projects that may be actionable depending on further analysis. AEMO noted that this project is not identified in the proposed ODP, ODP project counts, cost benefit assessment totals and other metrics in this Draft 2026 ISP.

AEMO included some description in Appendix 6 noting that this project is not optimal in the Draft 2026 ISP, but AEMO intends to analyse it further for the final ISP and will conduct stakeholder consultation to inform that analysis.

However, AEMO didn't include the analysis which was presented for other projects (Take-one-out-at-a-time, actionability or regrets analysis) which may have better informed the stakeholder feedback that they are seeking. Therefore, we expect AEMO's addendum to the Draft 2026 ISP include this analysis."

AEMO's response

AEMO did not present 'take-one-out-at-a-time', 'actionability' or 'regret analysis' for the Northern Transmission Project in the Draft 2026 ISP because it was not identified in the proposed ODP. As the project was neither included in, nor capable of being removed from or delayed within, the ODP, the standard analytical approaches set out in the *ISP Methodology* could not be directly applied. AEMO nevertheless recognises that additional transparency could have been provided to demonstrate how close the project was to being included in the ODP.

To support the assessment of the Northern Transmission Project, AEMO tested a CDP that included the project – CDP11, which comprised the ODP (CDP4) with the addition of the Northern Transmission Project. CDP11's performance relative to other CDPs is presented in Table 21 of Appendix 6 (Cost Benefit Analysis) of the Draft 2026 ISP, including its rank based on weighted net market benefits and worst weighted regrets.

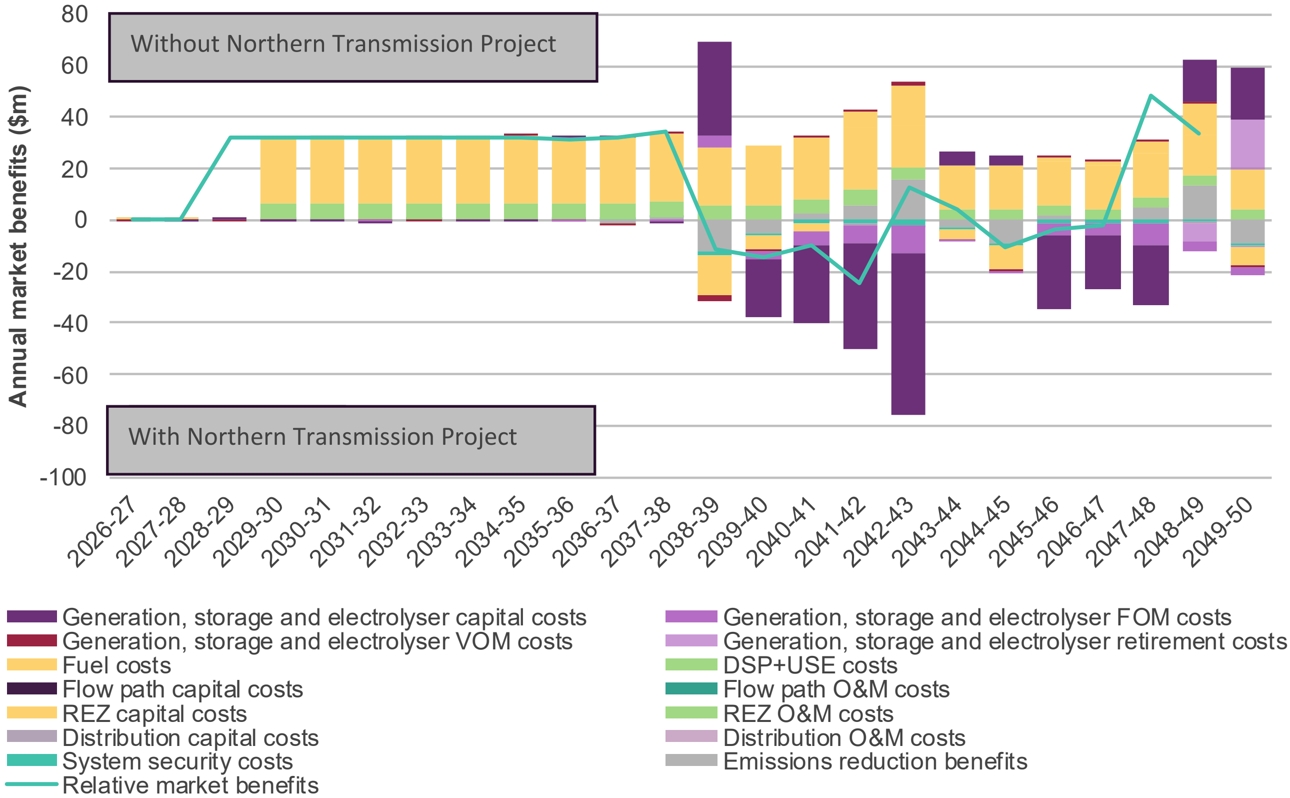
This information enables stakeholders to compare both the economic outcomes and system impacts associated with inclusion of the Northern Transmission Project. The transmission in CDP11 delivered a weighted net market benefit of $23.96 billion, compared with $24.2 billion in the ODP. The worst-weighted regret of transmission in CDP11 was $0.49 billion, compared with $0.42 billion in the ODP. Taken together with ElectraNet's modelling[22], these results suggest that that the economic case for potentially including the Northern Transmission Project on the ODP was finely balanced.

[22] ElectraNet. *Northern Transmission Project – Project Progress Report*, at https://electranet.com.au/wp-content/uploads/2025/12/Final-NTx-Project-Progress-Report-December-2025.pdf.

AEMO also reported the generation mix associated with CDP11 in the Generation and Storage Outlook Workbooks published alongside the Draft 2026 ISP[23]. These results show that with Northern Transmission Project included, less wind generation is projected and more utility-scale solar is projected instead.

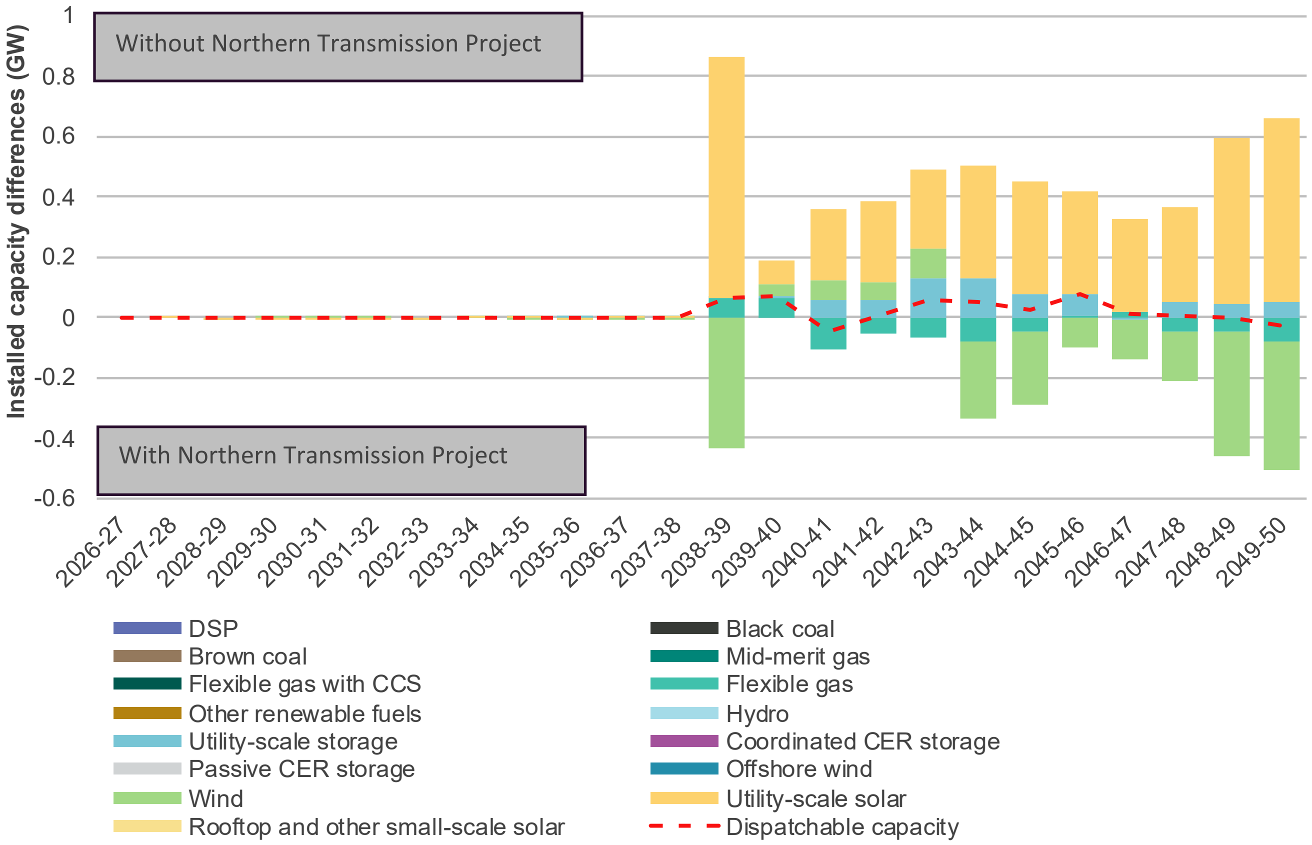
Figure 8 and **Figure 9** show a comparison of annual market benefits between the ODP and CDP11 and the difference in annual capacity between ODP and CDP 11.

Figure 8 Comparison of annual market benefits differences between the ODP (CDP4) and the ODP with Northern Transmission Project added (CDP11)



[23] Draft 2026 ISP generation and storage outlook, at https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation.

Figure 9 Comparison of annual capacity differences between the ODP (CDP4) and the ODP with Northern Transmission Project added (CDP11)



AEMO is continuing to investigate the material drivers of net market benefits for the Northern Transmission Project to inform its assessment for the final 2026 ISP. As stated in the Draft 2026 ISP[24], further analysis is needed to determine the extent of the projects' benefits. Key influences on net market benefits include assumptions regarding project costs, industrial load growth and its location, network capacity and the type and location of generation and storage development, including outcomes of the South Australian Firm Energy Reliability Mechanism (FERM) Tender Round 1, emerging policies, and emissions reduction trajectories.

AEMO is working closely with ElectraNet and the South Australian Government to understand the uncertainty in these assumptions prior to determining the project's status in the final 2026 ISP, and how these uncertainties could present risks to consumers. This engagement has included weekly or fortnightly meetings during the first quarter of 2026 and the progressive exchange of additional data and analysis as it has become available. At the time of publication of this addendum, joint planning activities remain underway to finalise any input changes relevant to the Northern Transmission Project ahead of final ISP modelling.

Submissions on the Draft 2026 ISP have now closed, and AEMO has received interest in the Northern Transmission project from a number of stakeholders. Given that work is ongoing to clarify key modelling inputs and assumptions, AEMO considers that providing further analysis at this stage may not accurately reflect how the project will be modelled in the final 2026 ISP, and therefore may not meaningfully assist stakeholder feedback.

[24] Page 80, Draft 2026 ISP, at https://www.aemo.com.au/-/media/files/major-publications/isp/draft-2026/draft-2026-integrated-system-plan.pdf?rev=8e38a5150ec2474791ee573a9981f07c&sc_lang=en.

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.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
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, 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.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.

Term	Acronym	Explanation
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.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Economic offloading	-	Refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price. This may also be referred to as economic 'spill' or 'spilled energy' as generators reduce output due to low market prices or lack of available demand.
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 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).
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.
National Electricity Rules	NER	The NER 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 NER also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The NER 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.
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 power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
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 high-quality resource areas where clusters 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.

Term	Acronym	Explanation
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 the Draft 2026 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 modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price. This can also be referred to as 'economic offloading'.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
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.