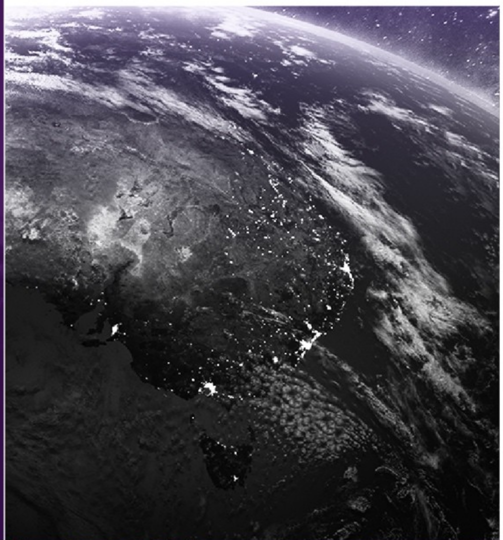
2026
Integrated System Plan

For the National Electricity Market

A roadmap for the energy transition

Embargoed to 12.01am Thursday 25 June 2026

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR



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.

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.

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

Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of 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.

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AEMO publishes the 2026 *Integrated System Plan* (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.

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Version control

Version	Release date	Changes
1.0	25/06/2026	Initial release

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CEO preface

Electricity consumption is expected to almost double over the coming decades, driven by population and economic growth, electrification across homes, businesses and industry and the emergence of new large loads such as data centres. Consumers are also playing an increasingly active role. At the same time, ageing coal-fired generation is retiring. Together, these developments are reshaping Australia's electricity system and increasing both its scale and complexity.

The 2026 *Integrated System Plan* (ISP) sets out AEMO's long-term roadmap for how the National Electricity Market (NEM) should evolve to meet these challenges through to 2050. It identifies the lowest-cost pathway to deliver reliable and secure electricity for homes and businesses, while supporting government policy and emissions reduction objectives.

The ISP confirms that the least-cost pathway is a system built around renewable energy, connected through transmission and distribution networks, firmed with storage and backed by gas. It also highlights the growing contribution of consumer energy resources and energy efficiency, with rooftop solar, batteries, electric vehicles and smarter energy use helping to reduce costs, support reliability and make better use of existing infrastructure.

The planning for this larger and more complex system is clear. The focus now is firmly on delivery. As demand grows and coal-fired generation retires, timely investment in generation, storage and transmission will be critical to maintaining reliability and keeping costs down for consumers. The ISP shows that while supply chain pressures and other constraints could slow the pace of the transition, the overall direction does not change. This reinforces the importance of maintaining progress through timely and coordinated investment to deliver the best outcomes for consumers.

The plan is underpinned by detailed analysis and extensive engagement. It is informed by modelling more than 1,000 potential development pathways and by engagement with around 2,000 stakeholders over the past two years, whose inputs across forums, workshops and submissions have directly informed the assumptions, modelling and outcomes.

Australia's energy transition is already underway. The ISP provides clarity for how this larger and more complex system should evolve. Delivering it will require sustained and coordinated action across industry, governments and consumers to maintain progress and ensure reliable and secure electricity for all Australians. I thank all of those who have contributed their expertise, perspectives and time in helping to shape this roadmap for Australia's energy future.

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Daniel Westerman
Chief Executive Officer, AEMO

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Executive summary

A roadmap for the energy transition

For much of the past 100 years, Australia has relied primarily on coal-fired generation for electricity supply. Now, most of the National Electricity Market's (NEM's) coal-fired plants are nearing retirement, consumers are investing in their own energy assets, and governments have set targets to reduce greenhouse gas emissions, in line with global agreements.

AEMO's *Integrated System Plan* (ISP) outlines an optimal path for generation, storage and network investments in the NEM to meet both consumer needs and government policies, at least cost, to 2050. It considers three plausible future scenarios that each meet government policies and for which the power system needs to be prepared. Its scope was increased in 2025 to consider more explicitly how grid-scale infrastructure, consumer energy resources (CER), distribution networks and gas markets all interact.

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.

In brief, the 2026 ISP sets out how:

- **The NEM's complex transition to renewables is well underway.** Nearly 40% of the coal fleet has retired, and renewables are fast approaching the milestone of delivering half the annual electricity needs of NEM consumers.
- **Consumers are taking more control of their rising electricity needs.** Already, 36% of suitable dwellings in the NEM have rooftop solar, and about 600,000 households have installed batteries. These assets are a critical part of Australia's energy mix, reducing grid demand and the need for grid-scale infrastructure. Many households are also investing in energy efficiency and forming 'virtual power plants' with others, further reducing demand and benefiting all consumers. Together with business, consumer resources met a record level of just over 60% of NEM energy demand on 4 October 2025, supported by more dynamic distribution networks. While households are increasingly relying on rooftop solar and batteries, industry is set to near double its use of grid-supplied electricity by 2050. That is to support electrified processes and freight, data centres and other new high-demand industries.
- **The ISP presents a least-cost optimal development path (ODP) for the NEM**. Delivery of renewable energy in the NEM has tripled from a decade ago, to approach 45% of energy in the NEM in 2025. Under this least-cost path, renewable energy would achieve the 82% national target by 2030, and deliver 98% by 2050. By then, the ODP would see almost 120 gigawatts (GW) of utility-scale wind and solar (about five times the current level), and almost 50 GW of utility-scale storage and hydro. New gas supply chain assets would be needed to support 17 GW of flexible gas-powered generation. To bring this power to industrial demand centres and across cities, the existing 44,000 km transmission network would need to expand by 6,000 km. Most of the NEM's remaining coal fleet would withdraw by 2038, with all to withdraw by 2049.

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- **New transmission in the ODP would deliver $28 billion in net market benefits to consumers,** weighted across the three scenarios, compared to not progressing new transmission beyond what is already committed or anticipated. This includes $26 billion in avoided system costs, and $2 billion of value in emissions reductions. In the *Step Change* scenario, the ODP requires $106 billion of investment to 2050 (in today's dollars), across utility-scale generation, storage, firming and network infrastructure. Across more than 1,000 alternatives, this pathway is the lowest-cost option overall.
- **This transmission should be delivered without delay.** AEMO has modelled a future in which the delivery of generation and transmission takes longer than planned, and consequently costs more. In this future, if the delivery of generation and storage is slower and more costly, then the value of the ODP transmission would increase, even though its own delivery experiences costly delays. The achievement of some 2030 policy targets would also be delayed. The analysis confirms that the choice of ODP is robust to these delays, and underscores the need to progress the planned and actionable transmission projects in the ODP, without delay. Delivery of transmission projects on the ODP not only protects consumer benefits, but mitigates against the risks of delayed generation or unanticipated coal outages or closures.
- **Concerted action is needed to continue delivery of the least-cost path for consumers.** All NEM governments have set policies for the energy transition, intended to deliver a wide range of benefits. Industry is responding, with a breadth of projects under development and delivery. Consumers are also contributing through their uptake of rooftop solar, batteries and other energy resources. The ODP's contribution is to identify the least-cost pathway for delivery. To deliver that pathway, continued coordinated action is needed from industry, government and market bodies, including in their engagement with communities.

Preparing the ISP is a two-year effort, informed by extensive consultation with consumers and advocates, industry, market bodies, governments, academics, environmental groups and consultants.

AEMO thanks all stakeholders for their valuable input into the 2026 ISP. AEMO will continue to work with all stakeholders to deliver the energy transition, to support reliable, least-cost energy to meet Australia's consumer and policy needs.

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The NEM transition is well underway

Markets and policies are favouring a mix of renewables to replace coal

Australia is relying more and more on renewable generation. Renewables from home-scale to grid-scale have met around 45% of all demand for electricity in the NEM in the 2026 financial year, over 50% in the December quarter of 2025, and reached close to 80% for a half-hour on 11 October 2025. Small-scale consumer resources alone met over 60% of energy demand across the NEM on 4 October 2025. These record levels vary with the year's seasons, but are consistently rising.

The shift to renewables is happening globally. Decisions on how best to replace the NEM's coal-fired plants are ultimately made by private investors. That investment favours renewable energy and supporting technologies over continued coal-fired generation. Globally in 2024 and again in 2025, renewable generation received three times as much investment as did coal[1]. In the first half of 2025 and for the first time, more of the world's energy was delivered by renewables than by coal[2].

Governments are acting to de-risk Australia's transition. As households continue to set the pace in adopting rooftop solar and batteries, government policies are ensuring there is enough grid-scale infrastructure in place as coal plants retire. These policies include recognising that de-carbonising the energy sector is essential if other sectors are going to rely increasingly on electricity as a means to reduce emissions in line with global agreements.

Renewables are being supported by other technologies

Renewables are not a like-for-like replacement for coal, and need supporting technologies to be harnessed efficiently. A range of solutions are supporting the transition, in the NEM and globally:

- **Transmission networks are being extended**, to bring renewable energy from high-resource areas to the industries, regions, cities and towns that need it, and share electricity between states.
- **Distribution networks are being upgraded** with optimised voltage management and other enhancements to better support consumer energy resources, support community batteries, allow two-way flows of electricity, and support population growth.
- **Batteries are becoming more common as costs decline and with government support.** They allow households, businesses and industry to store surplus renewable energy during the day for use in the evening and morning peaks, helping to moderate prices during evening peaks and to support grid reliability and security as coal plants withdraw.
- **Existing hydro generators and other deep storage such as new pumped-hydro** firm renewables through longer dark and still conditions, especially during winter, and also help manage planned network outages as new infrastructure is connected.
- **Flexible gas-powered generation plants** provide critical back-up power supply when renewables are not generating power (and help pre-charge batteries for those times), and when storages are exhausted. They also provide supply for peak demand events and support grid security as coal plants withdraw.
- **Alternatives to fossil fuels are available to maintain grid security and stability.** Synchronous generation from coal plants has kept the power system stable. Batteries and synchronous condensers can perform many of these services, as can flexible gas plants operating with a clutch (that is, spinning, but without needing to generate electricity or burn fuel).
- **Some coal-plant owners are testing ways to increase plant flexibility**, and so keep them economic. They may lower their minimum stable operating levels (which in turn supports times of low demand in the system), increase their ramp rates or take units offline for hours, days or even months at a time.

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[1] International Energy Agency (2026), https://iea.org/reports/world-energy-investment-2026.

[2] Ember Research (2025), https://ember-energy.org/latest-insights/global-electricity-mid-year-insights-2025/#executive-summary.

Consumers are taking more control over their energy needs

Electricity is becoming ever more critical in the digital age, with more and more uses from phones, computers and watches, to household cars and appliances, to industrial processes and artificial intelligence (AI). As they rely on it more, consumers are owning assets to generate and store power, and being more efficient in its use.

Households and businesses are investing in their own energy resources. Already, 36% of suitable dwellings[3] in the NEM have rooftop solar. By 2050, that is forecast to rise to 56%, with two-thirds having their own batteries. By then, consumers are forecast to have invested a total of 87 GW in rooftop and other small-scale solar and 35 GW in supporting batteries, and 80% of all vehicles in use are expected to be electric vehicles (EVs). Consumers are also starting to coordinate their resources to form 'virtual power plants' (VPPs) with others, and are investing in ways to be more energy efficient.

Consumer resources can reduce overall and peak demand from the grid, benefiting all consumers. Not all homes and apartments are suitable for rooftop solar or batteries, and renters and other households may not be in a position to invest in them. However, those that do are helping to reduce demand on the NEM, moderating wholesale prices in peak periods and reducing the need for grid-scale spend. Distribution networks are upgrading their networks to tap into this latent capacity, to the benefit of all consumers.

Energy efficiency continues to substantially reduce overall energy consumption. The strong dividend from energy efficiency over the past decade is forecast to continue so long as supportive policies exist, to reduce underlying consumption by 75 terawatt hours (TWh) by 2050[4]. The rollover of stock is the main driver, as new appliances, commercial fit-outs and building designs are typically more energy efficient than old ones. Higher-efficiency options are also preferred in state and federal standards and incentives, and by businesses seeking to cut operating costs. These options moderate the increase in energy use that would otherwise come with increases in population and living standards, and so reduce demand on the grid.

Total underlying consumption across the NEM is forecast to nearly double from the current 205 TWh to about 390 TWh in 2050. This is due to population growth, economic growth and electrification (the expected switch from petrol, diesel and gas to electricity for industrial processes, transport, freight, heating, cooling and cooking).

Data centres have emerged as potentially significant consumers of electricity. However, there are many uncertainties in their forecast consumption through the 2030s and 2040s, as industry expectations on both connection rates and technical frameworks are revised. The 2026 ISP assesses these uncertainties through the diversity of its three core scenarios and a *Higher Demand* sensitivity. In *Step Change,* the ISP assumes that data centres would reach almost 10% of the NEM's underlying demand by 2050 – four times the share it has today and the equivalent of 20% of today's total grid consumption.

Business use of grid-scale electricity may double while households may use 44% less. After drawing on their own rooftop solar, business and industry are forecast to need 280 TWh of electricity from the grid in 2050, double what it is today. Household grid-supplied energy needs would fall 44% to just 20 TWh – despite having more EVs and appliances. However, this is a net amount over the year: the future grid must cater for much larger

[3] Rooftop solar-suitable dwellings include detached houses and semi-detached dwellings (duplexes and townhouses), and excludes apartments. Of these, 43% of detached houses have rooftop solar installed.

[4] For forecasts and projections referenced in this report, in general a year refers to the financial year. So "2050" means 1 July 2049 to 30 June 2050.

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energy flows to and from home-scale systems, with some households generating more energy than they use, and others relying primarily on grid-supplied energy.

Grid-scale work is building momentum

Coal is being replaced by renewables, batteries and pumped hydro. In 2010, the NEM had 26 major coal stations generating about 30 GW of power. Today, there are 15 generating about 21 GW. Meanwhile, about 34 GW of grid-scale renewables and batteries were operating in the NEM at the start of 2026, and another 67 GW of projects are now progressing through the connections process. Of the progressing projects, 45 GW are grid-scale batteries, which absorb more and more renewable energy during the day, releasing it during evening peaks to help moderate prices during those high-demand periods.

Transmission work is building momentum. Each new project benefits consumers by sharing electricity more efficiently across and between states, reducing the need for stand-alone infrastructure in each region. In the past four years, completed projects have increased capacity between Queensland, New South Wales, South Australia and Victoria, and have helped supply reliable electricity to the Eyre Peninsula and in Far North Queensland. A further eight projects have been commenced across the NEM, with five in New South Wales and Victoria on track for completion by 2029.

The ISP's 'optimal development path' for the NEM's transition

To help guide this transition, AEMO has worked with consumers, governments and industry since 2018 to prepare and publish an ISP every two years. This was a recommendation of the 2016 Finkel Review, aimed to ensure major blackouts (such as those through the 2016 storms in South Australia) do not occur again. This section summarises the ISP's purpose, scope and process.

The ISP is "a whole of system plan for the efficient development of the power system that achieves power system needs for a planning horizon of at least 20 years". It informs investment by private companies and governments, flows through to planning by network operators, and triggers action on specific transmission projects.

The core element of the ISP is the 'optimal development path' (ODP). This is the optimised mix of grid-scale generation, storage and network investments to replace coal as it retires and to meet consumer needs and government targets, at least cost, between now and 2050. System-wide planning is essential for these large investments, so that they benefit energy consumers.

Consumer and distribution investments are taken into account. The ISP has always considered the forecast investments by consumers and distribution networks, though these are not co-optimised with the ODP. Similarly, the ODP is informed by gas industry development, but gas development is not co-optimised and remains the responsibility of the gas industry. In this 2026 ISP, these demand-side and gas considerations are covered more extensively.

The ISP seeks the least-cost path to achieving the National Electricity Objective: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity". Those long-term interests include the price, quality, safety and reliability of electricity supply, and the achievement of emissions reduction targets.

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To balance those interests, the ISP seeks the least-cost path that meets consumer and government policy needs. Candidate paths are compared, accounting for capital, fuel and operating costs for grid-scale generation, storage and network investments. The lower the total cost of this investment, relative to other paths, the lower energy prices will be over time, all else being equal in an efficient market.

The ISP acknowledges the need for social licence, and what is needed to earn it. Large new electricity infrastructure affects the communities that host it, which in turn influences how projects are designed, approved and delivered. Projects that have more complex community considerations typically have longer design and approval processes. The costs and lead times for these processes are incorporated into ODP modelling where they can be estimated. This effort is well spent, typically leading to better outcomes for the local community and for energy consumers.

The ISP incorporates all relevant government policies and targets. Targets that must be considered are published in the Australian Energy Market Commission's (AEMC's) Targets Statement. These targets and other policies relate to emissions, renewable energy, storage, offshore wind, transmission networks, CER, EVs, energy efficiency, hydrogen and household gas connections. National targets include an 82% share of renewables in the NEM by 2030, and the economy-wide target of 2030 emissions being 43% below 2005 levels, and 62-70% below 2005 levels by 2035.

Identifying the ODP takes two years of extensive consultation and analysis

Starting just after the 2024 ISP, AEMO has listened to valuable insights and feedback from all stakeholders and incorporated them into the 2026 ISP. AEMO has consulted with consumer representatives (including the ISP Consumer Panel), industry, NEM jurisdictional planning bodies including transmission and distribution networks, policy-makers, and market bodies. The consultation has refined the ISP's assumptions and findings in significant ways, which are outlined in Section 3.3 and detailed in the *2026 ISP Consultation Summary Report*.

In that consultation, AEMO formally engaged with over 1,940 stakeholders, including 1,607 webinar attendees and 333 written submissions. AEMO published 62 reports and reference materials, and hosted 19 webinars and workshops. The consultations spanned all aspects of the ISP's inputs and modelling approach, as well as the Draft 2026 ISP and an Addendum to it in response to the Australian Energy Regulator's (AER's) transparency review.

AEMO publishes its methodologies, inputs and assumptions. The consultation reports include the 2025 *ISP Methodology,* the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), the 2025 *Electricity Network Options Report,* and the 2025 *Gas Infrastructure Options Report*. These inputs include demand-side forecasts**,** technology capabilities and costs, power system reliability and security needs[5], and the interaction of the power system with other 'coupled' sectors such as transport, gas and hydrogen. Demand forecasts prepared using these inputs and applied in the ISP can be accessed on the ISP website. In addition, these forecasts are described in depth in the 2025 *Electricity Statement of Opportunities.*

AEMO also considered and published three scenarios of the future – *Step Change, Slower Growth* and *Accelerated Transition* – that each meet government policies and for which the power system needs to be prepared. Each of these scenarios is integrated into the ODP, weighted by a relative likelihood that was

[5] See https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper.

informed by 25 expert stakeholders. *Step Change* was considered the most likely of the three scenarios (46%), balanced by an equal 27% likelihood of *Slower Growth* and *Accelerated Transition*.

AEMO calculated the net market benefits of 34 candidate development paths, shortlisted from around 1,000 potential paths. These paths incorporate the transmission, the relevant distribution, the generation, storage, CER and gas supply chain investments[6] needed for each of the three NEM scenarios. They were compared with a 'counterfactual' path that has no new transmission projects (beyond those already committed or anticipated). Instead, in that path, more grid-scale generation and storage is needed in each region (including gas-powered generation both with and without carbon capture and storage, and mid-scale solar). That path comes at more cost, as less electricity can be shared across the NEM and some high-quality renewable resources cannot be accessed. Each path was assessed across the three scenarios. That analysis helps limit the risks of over- or under-investment in network assets, in a wide range of potential futures.

AEMO tested the leading candidates against changes in key assumptions, to assess their robustness to uncertainty or understand the impacts of important possible changes. The sensitivity analyses were on different levels of CER coordination, different levels of energy efficiency, higher demand from industrial loads including data centres, and constrained delivery of generation and transmission projects in the ODP.

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Generation, storage and network investments in the ODP

The ODP is the optimal mix of grid-scale generation, storage and network investments to replace coal as it retires, and meet consumer needs and government policies, at least cost, through to 2050.

This section sets out how each technology in the mix is projected to contribute to a secure and reliable electricity supply. By 2050, renewables and storage would account for 94% of the NEM's capacity investment[7] (**Figure 1** below), and renewables 98% of the total energy consumed (**Figure 2**). Each element in these figures is discussed in turn below them.

While the precise mix and location of future generation, storage and transmission will be determined by investors, network providers and, in some cases, governments, the ODP identifies a near-term development pathway that can be progressed with confidence to support a secure, reliable, least cost and lower emissions power system.

'NEM capacity' delivers 'annual generation' for consumer use

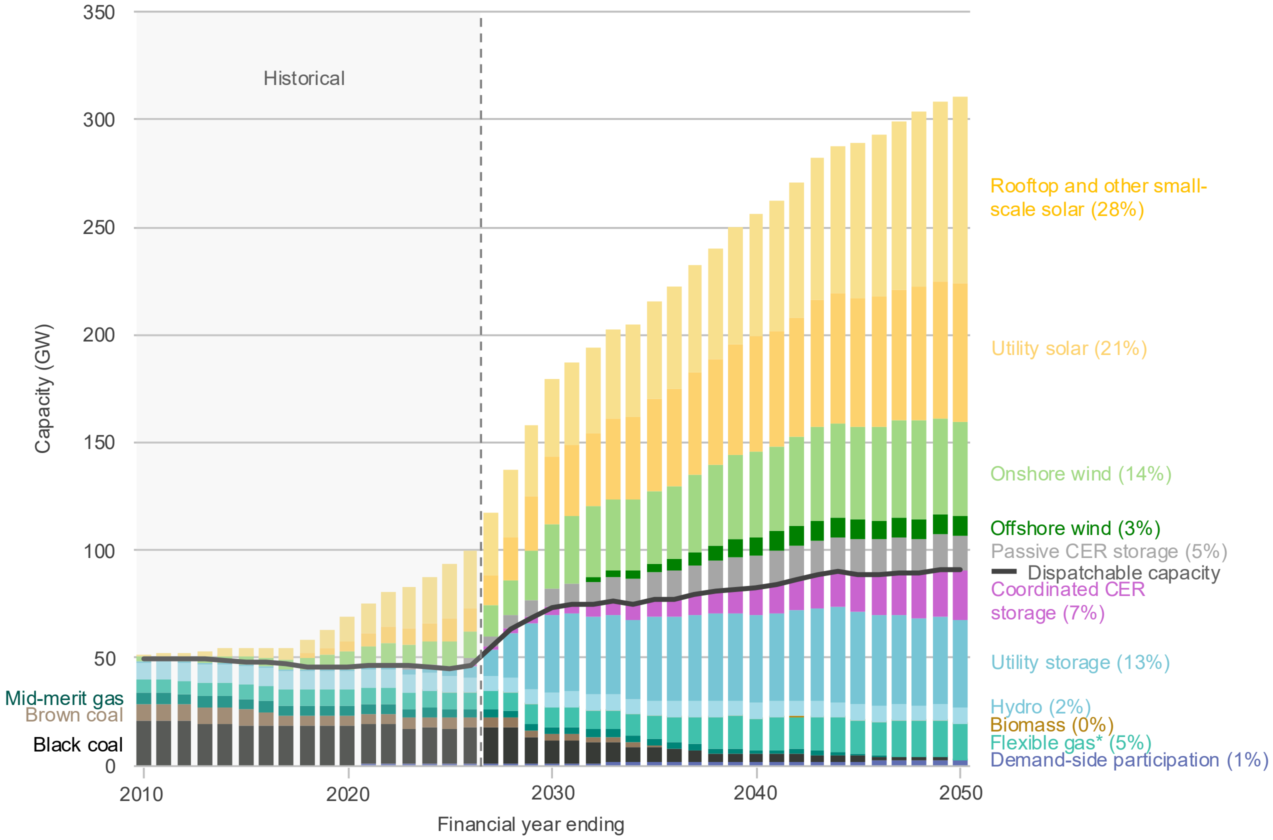
In AEMO's planning, generation and storage is measured in two ways, shown in the figures below. *NEM capacity* (**Figure 1**) is the projected investment in each technology that would make up the least-cost ODP. If all these resources were operating at full capacity all of the time, they would deliver a lot more power than is needed. No technology produces power all of the time, as they are limited by weather conditions, outages, fuel availability,

[6] Gas supply chains are explored to test the robustness of electricity generation and storage investments to gas availability with different combinations of gas investment.

[7] Unless otherwise stated, the ISP projections in this report are for the *Step Change* scenario, the most likely of the three plausible scenarios against which AEMO tests the ODP. All three scenarios meet government policies.

network congestion and other operational constraints. **Figure 2** then shows how much *Annual generation* of electricity is needed from each technology to meet consumer needs across the year.

Figure 1 NEM capacity (GW, 2010 to 2050, *Step Change*, financial year ending)



Notes: Percentages are listed for 2050 financial year ending projections, and are rounded. Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 IASR and the 2026 *Forecasting Assumptions Update*. "Rooftop and other small-scale solar" includes forecast residential and commercial photovoltaic (PV) systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems. "Utility solar" also includes other mid-scale distribution-connected PV systems, optimised through the ISP assessment process. "CER storage" means consumer energy resources such as batteries and EVs. "Flexible gas" includes gas-powered generation and potential lower-carbon fuel alternatives (including hydrogen).

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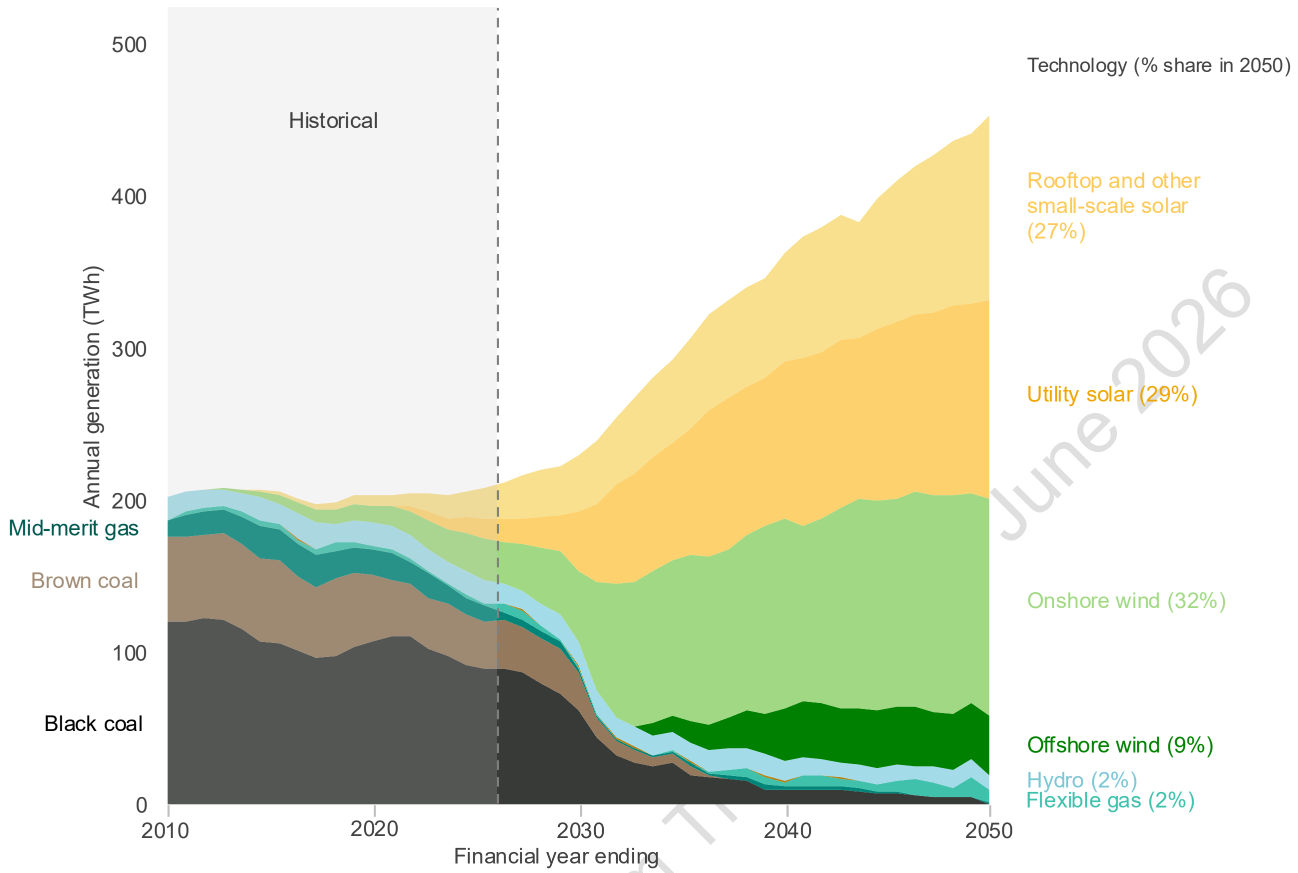
Figure 2 NEM annual generation (TWh, 2010 to 2050, *Step Change*, financial year ending)



Note: This chart is the projection of electricity generation by fuel type. Battery charge and discharge, and pumped hydro production, are excluded, as these technologies store electricity generation for use at other times such as in the evening and morning peaks. Contribution from demand side participation is not shown due to scale of chart.

Coal power stations are steadily retiring

Coal-fired generators are still currently needed for both generation and system security, but the remaining fleet is withdrawing and replacement services are being installed: see **Figure 3**. The coal plants in all but one region average 41 years in age, and have announced closure dates by 2038. Queensland's fleet is newer, averaging 31 years, with some assumed to continue to 2049 in line with the Queensland Energy Roadmap.

Coal plants may become increasingly unreliable as they approach end-of-life, and may retire even faster than these forecasts. The financial viability of some is increasingly challenged by higher fuel and operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market.

Some coal plant operators are investigating plant modifications to support more flexible operations. They may lower their minimum stable operating levels, enable two-shift operation[8], increase their ramping rates, reduce their hot restart times, or repurpose steam generating units to act as synchronous condensers. However,

[8] Two-shifting would involve switching off during the daytime peaks of solar generation, and returning for the evening peak and through the night and morning.

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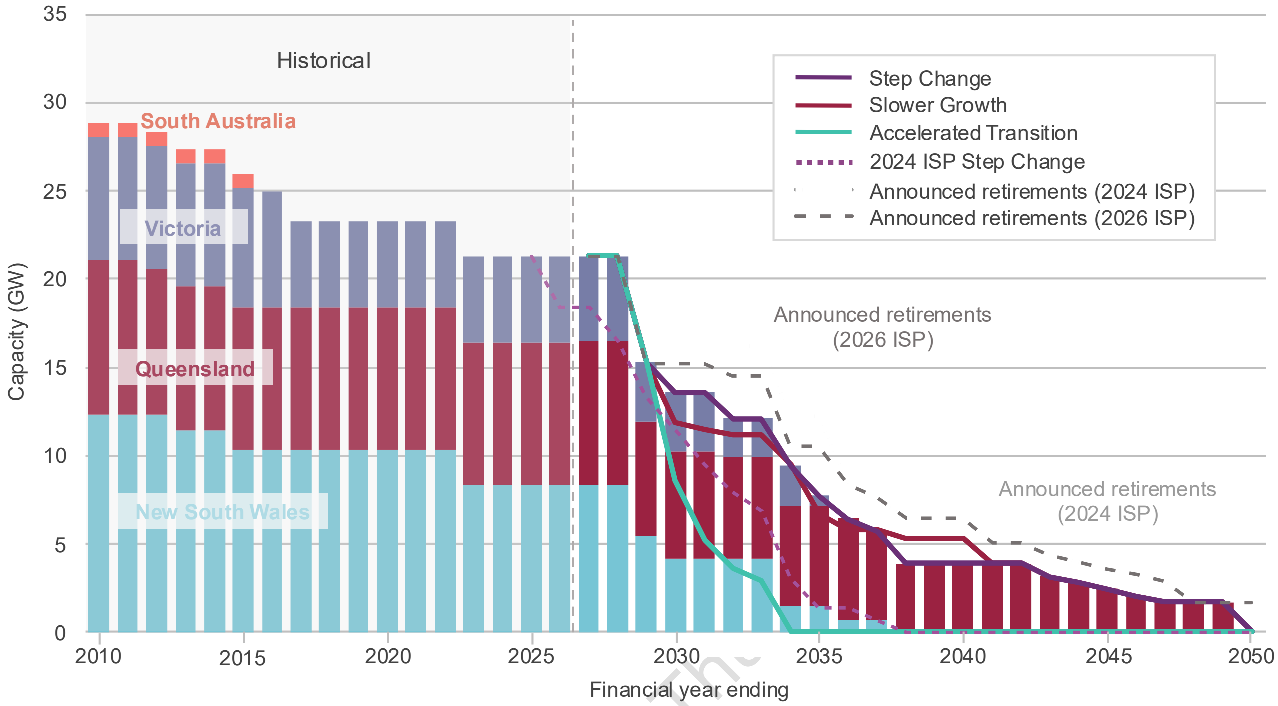
repurposing older coal plants for flexible operation has its challenges, including increased plant wear, maintenance costs and outage rates, and these challenges will need to be actively managed as the energy transition progresses.

Figure 3 Coal capacity, NEM (GW, 2010 to 2050 financial year ending)



Nearly 120 GW of grid-scale wind and solar to replace coal and meet higher demand

Renewables are needed to replace coal, and to meet rising demand and government targets. Under the ODP, grid-scale solar and wind capacity is projected to rise from the current 23 GW to 61 GW by 2030, then almost double again to 117 GW by 2050. Grid-scale solar would represent about half this mix in 2030, rising to 55% in 2050, the other 45% being wind.

The installed capacities of grid-scale solar and batteries would grow faster than wind (**Figure 1** above) as their relative costs decline. However, wind would have a greater share of annual generation (**Figure 2** above), as new wind turbines are more efficient and the wind in some locations is assumed to be stronger than previously modelled. By 2050, onshore and offshore wind combined is projected to contribute 40% of total annual generation, compared to 29% contribution from grid-scale solar.

While the connections pipeline is strong for new grid-scale solar and wind, more is needed to reach the ODP's projected 2030 target levels. About 20 GW of new grid-scale solar would be needed by 2030, with around 19 GW having applied for or progressing towards connection. Approximately 18 GW of new wind would also be needed, with about 9 GW in the connections pipeline. To date, both wind and solar projects have taken about four years on average to progress from connection application to full output, navigating sometimes lengthy financial, environmental, connection and planning approval processes before construction can commence. Concerted efforts are being made to streamline all aspects of development and delivery.

While the NEM's existing 7 GW of hydro-electric generation remains in place, additional gas-powered generation and pumped hydro is also needed, as noted below.

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Grid-scale generation would ideally be situated in renewable energy zones[9] (REZs) where there are high-quality resources close to existing transmission lines, and the potential to build economies of scale with a local skilled workforce.

Nearly 50 GW of dispatchable grid-scale storage and hydro

The ODP projects that by 2050 the NEM would need 35 GW of shallow and medium storage (able to dispatch electricity at full capacity for four to 12 hours), and 5 GW of deep storage (delivered by new pumped hydro energy schemes). This is in addition to the 7 GW capacity of the NEM's existing hydro-electric power stations.

Batteries are projected to be the primary source of medium storage. The decline in battery costs is now making its mark. Although there is only 4 GW of existing capacity, new storage in the connections pipeline[10] has increased substantially – from 3 GW in September 2022 to 17 GW in 2024 and to 45 GW in 2026. This is now well ahead of the 33 GW of battery storage that the ODP projects would be needed in 2030. To date, battery projects have taken just over two years to go through the connections process.

The NEM's existing hydro-electric power stations offer significant deep storage, as many have reservoirs to store rainfall and snowmelt as potential energy and add to system security and resilience when released. They shift energy over weeks or months (seasonal shifting) and, with gas, help to cover extended renewable lulls.

Pumped hydro projects would provide 6 GW of capacity by using surplus energy to first pump water upstream. Snowy 2.0 and Kidston are committed projects that would add 2.5 GW in storage by the end of 2028, with Borumba anticipated to add another 2 GW, and smaller existing and planned[11] projects making up the balance. Snowy 2.0 would provide up to 350 gigawatt hours (GWh) over a week, enough to meet the average needs of around 3 million households (about as many as in Sydney and Melbourne combined).

17 GW of flexible gas-powered generation

Gas-powered generation is changing from regular 'mid-merit' and 'peaking' operation, to a more strategic, back-up role by flexible generators that can also provide system security services. Currently, the NEM has 12 GW of gas-powered generation capacity (4 GW mid-merit and 8 GW peaking), of which 8 GW is forecast or announced to retire between now and 2050 as the plants reach end-of-life. This capacity would be replaced as they retire, and the fleet would be expanded to 17 GW of 'flexible' capacity – that is, able to both generate electricity when needed, and ideally to operate with a clutch to provide critical system security services without burning fuel. Through to 2050, the gas fleet is projected to supply a similar share of the NEM's annual generation to today's 4%[12], though gas use projections are highly uncertain as they vary due to weather and operational

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[9] This ISP uses the term 'renewable energy zone' to refer to high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale. Queensland adopted the term 'regional energy hub' in the 2025 Queensland Energy Roadmap.

[10] Committed and anticipated projects meet criteria set in the AER regulatory investment test for transmission (RIT-T) Guidelines and *Cost Benefit Analysis Guidelines*, are listed in the AEMO Generation Information page, and are assumed to be underway for delivery for ISP purposes. The connections pipeline refers to projects going through the AEMO and networks' connections process. Many projects are common to both lists.

[11] Specifically, the 800 MW Phoenix Pumped Hydro Project selected for a Long-Term Energy Service Agreement under the New South Wales Electricity Infrastructure Roadmap.

[12] 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%.

conditions. Individual plants are expected to generate up to 10% of their annual potential in 2050, but will be critical when they run.

New gas supply, production, transport and storage infrastructure would also be needed to ensure fuel is available for the dual demands of both gas consumers and electricity generation. When gas and electricity demand peak simultaneously, as they sometimes do in the southern states in winter, there may not be enough accessible gas supply. Several solutions exist to close this gap, with a combination of market-led gas infrastructure investments needed. These could include new supplies to production facilities, regasification terminals in southern Australia, new seasonal gas storages, and expansions to existing gas pipelines and storage. The Australian Government is also completing a gas market review which may lead to the introduction of a gas reservation scheme.

Demand flexibility can reduce broader investment requirements

Demand-side flexibility is a valuable method to support system reliability, including the agreement for certain consumers to reduce their loads during extreme conditions of system stress (known as demand-side participation). AEMO forecasts that 2.3 GW of this demand-side participation will be available for use by 2050 under *Step Change.* This is projected to form 1% of NEM capacity in the ODP by 2050, though not to be called on often.

Distribution networks and consumers reduce grid-scale investments

The growth in CER is materially reducing the need for grid-scale investment, even as the consumer need for electricity rises. In particular, households with solar and battery systems are often able to both meet their own needs and export to the grid during the evening peak. This reduces average evening peak grid demand by about 1 kilowatt (kW) per household, compared to solar-only households, which in turn reduces wholesale energy prices in peak demand periods, with flow-on benefits for all consumers in the NEM.

The benefits of CER to all consumers would be increased if CER is bundled and coordinated. VPPs and vehicle-to-grid (V2G) charging of EVs may respond to market signals, and contribute to system reliability and system security. Doing so would avoid up to $5 billion being spent on additional grid-scale storage in the NEM through to 2050. Greater community awareness, trust and acceptance is needed for higher levels of coordination to be reached.

More benefits are secured by the more efficient use of energy, where consumers are able to reduce or avoid its use, or shift it away from peak demand periods. These options are supported by current government policies, and similar policies are assumed to continue to 2050. If they did not continue, energy efficiency improvements are estimated to be about 35% lower than forecast, investment in grid-scale infrastructure would rise by almost $8 billion, and total system costs would rise by almost $10 billion. Every avoided kW of electricity makes each dollar of investment go further toward a successful energy transition.

Distribution networks are innovating to cater for much larger energy flows to and from households and business systems every day. They would make available 4 GW of latent CER capacity by optimising their voltage management and with other relatively lower cost innovations, the ISP modelling suggests. This includes projected expansions to accommodate 8 GW of grid-scale generation and storage within the network, and 3 GW of mid-scale generation.

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Transmission network being extended by one-seventh

Around 6,000 km of new transmission would be needed by 2050 under the *Step Change* scenario, an almost 14% extension of the current 44,000 km network. This includes 3,500 km from already committed or anticipated projects that are well underway for delivery. About 40% of the new transmission projects are needed to strengthen the connection between states, adding reliability and diversity to electricity supply across the NEM. The other 60% connects new capacity in REZs within each state, including to energy-intensive industries in regional hubs, or provides additional capacity within states to allow cost-effective generation to be transported to demand centres. The overall extent of new transmission is about 1,435 km less than in 2024 ISP[13], despite there being more projects, for the reasons noted below under 'Changes in transmission'.

Actionable and future ISP projects in the 2026 ODP

The ODP includes the following transmission projects, detailed in **Table 1** and **Figure 4** on the following pages:

- **eight committed and anticipated transmission** projects[14] are underway and will add 3,500 km to the network over the next eight years,
- **twelve actionable projects** to add 1,660 km over the next 12 years – five of these were already actionable, five were future projects in the 2024 ISP and now fall within the actionable window, and two are new projects in this ISP, and
- **a number of future ISP projects** which are forecast to be actionable under at least one future scenario, including two projects that were previously actionable.

The decisions guiding these assessments are detailed below in **Table 1**.

Some of these projects are being progressed under jurisdictional frameworks rather than the ISP framework. These frameworks arise from specific legislative and policy decisions by individual jurisdictions and are therefore not consistently available across the NEM. Where in place, they provide an alternative pathway to authorise and deliver priority transmission investments outside the regulatory investment test for transmission (RIT-T) process.

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[13] The total length of new major transmission projects is 1,435 km less than in the 2024 ISP. Compared to 2024, projects of about 165 km have progressed to operation and are no longer included, while 410 km has been added by scope increases. About 1,680 km of potential transmission is no longer needed as there is more generation and storage in particular locations, or due to policy changes.

[14] Note that transmission projects that are committed or anticipated are not included in the ODP costs discussed below.

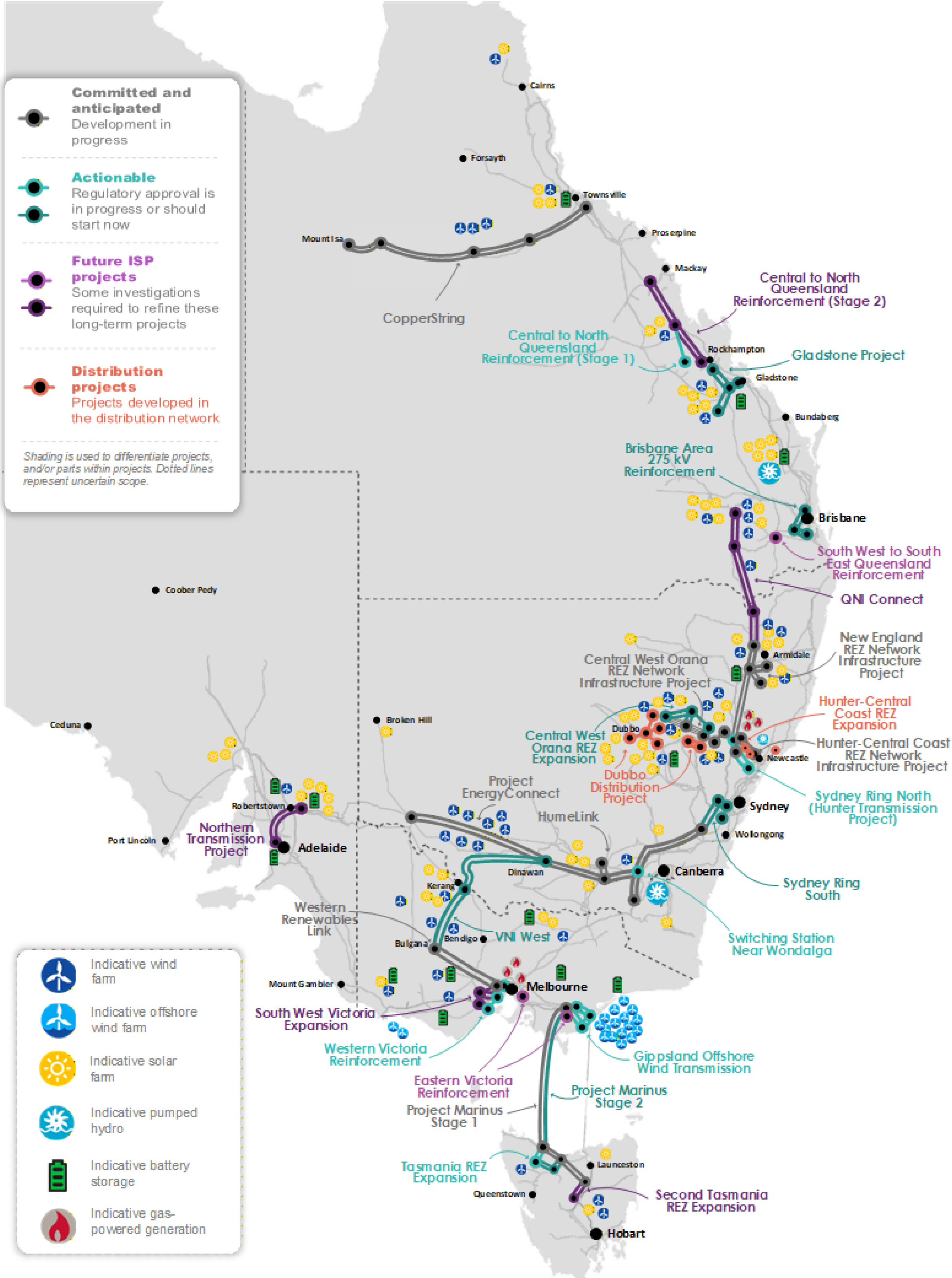
Table 1 Network projects in the optimal development path in the 2026 ISP

Committed and anticipated transmission projects		In service timing[A]	Full capacity timing[B]
Project EnergyConnect Stage 2		October 2026	November 2027
HumeLink		December 2027	December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central-West Orana REZ Network Infrastructure Project		December 2028	December 2028
Western Renewables Link		November 2029	November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		2032	2032[C]
New England REZ Network Infrastructure Project[D]		January 2034	January 2034
Already actionable projects (confirmed in this ISP)	**Framework**	**In service timing[A]**	**Full capacity timing[B]**
Gladstone Project	QLD[E]	March 2029	Mid-2030[C]
Sydney Ring North (Hunter Transmission Project)	NSW[E]	November 2029	November 2029
Sydney Ring South	ISP	Power flow control: July 2030 500 kV assets: July 2033	Power flow control July 2030 500 kV assets: July 2033
Victoria – New South Wales Interconnector West (VNI West)	NSW[E] ISP	South West REZ: August 2029 NSW-VIC: November 2030	South West REZ: August 2029[C] NSW-VIC: November 2031
Project Marinus Stage 2	ISP	June 2034	December 2034
Newly actionable projects (identified in this ISP)	**Framework**	**Earliest feasible full capacity timing[B]**	
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[E]	June 2029	
Tasmania REZ Expansion (future project in 2024 ISP)	ISP	July 2030	
Switching Station Near Wondalga	ISP	April 2031[C]	
Central to North Queensland Reinforcement (Stage 1) (smaller option of Queensland SuperGrid North in 2024 ISP)	ISP	July 2031[C]	
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC[E]	Stage 1: July 2031; Stage 2: (Phase 1) July 2033; (Phase 2): July 2038	
Brisbane Area 275 kV Reinforcement	ISP	June 2032	
Central-West Orana REZ Expansion (future project in 2024 ISP)	NSW[E]	March 2033	

Future ISP projects[F]	
Interconnector projects	**Queensland – New South Wales Interconnector (QNI Connect)**
Queensland	**Central to North Queensland Reinforcement (Stage 2), South West to South East Queensland Reinforcement**
South Australia	**Northern Transmission Project[G]**
Victoria	**Eastern Victoria Reinforcement, South West Victoria Expansion**
Tasmania	**Second Tasmania REZ Expansion**
Distribution projects	
New South Wales	**Hunter-Central Coast REZ Expansion, Dubbo Distribution Project**

A. The in-service date, advised by the project proponent, gives an indication of when construction and commissioning will be complete and equipment in service.
B. The capacity release and timing, advised by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.
D. This project is newly categorised as anticipated. It is progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).
E. These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), *Electricity Infrastructure Investment Act 2020* (NSW), or the *National Electricity (Victoria) Act 2005* (Vic), rather than the ISP framework.
F. This list shows future ISP projects which are identified as part of the ODP in *Step Change* or are subject to an ongoing RIT-T. Appendix A5 Network Investments provides information about additional future ISP projects identified in only one scenario.
G. AEMO considers ElectraNet should continue the Northern Transmission Project RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options.

Figure 4 Transmission projects in the 2026 ISP optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that include new transmission lines, increase capacity by 400MW or more, are required in *Step Change*, or have a regulatory test for transmission (RIT-T) underway. Transmission projects recently commissioned (for example, sections of Project EnergyConnect) are represented as thin light grey lines, consistent with the depiction of the existing network.

Drivers of the re-classification of transmission projects

The identified need for an ISP transmission project may occasionally change between ISPs, or between the Draft and final ISP. Different drivers may result in a smaller or larger project, an alternative solution, or no transmission in a given area. While these factors affect individual projects, the overall set of transmission investments in the ODP has remained broadly consistent over recent ISPs.

Consistency is important, as community engagement often starts once a project becomes part of the ODP, and stopping and restarting engagement can be disruptive, may erode trust, and could make it more difficult to build and maintain social licence for all projects over time.

The main drivers of the changes in ISP projects since 2024 have been:

- **Inclusion of opportunities in the distribution network**. Some transmission projects to connect generation and storage have been replaced by more cost-effective options within the distribution network, supported by transmission capacity as necessary.
- **Acceleration of battery investment**. The benefit of a transmission project may fall if well-located battery capacity is available, as both transmission and storage add reliability to the power supply and make the most of available renewable generation. The project's benefit would reduce further if its costs rise and battery costs fall.
- **Changes in generation capacity expected in an area.** Transmission benefits typically increase with the distance between generation capacity and demand centres. Where capacity is added close to demand (typically solar), the need for transmission falls. Where capacity is added in more remote areas such as South West New South Wales (typically wind) the need for transmission increases.
- **Increase in estimated transmission costs.** While some projects have had options to mitigate cost rises, others have not and have become too expensive to deliver a net benefit to consumers.
- **Change to treatment of financing costs.** After consultation on the 2025 IASR, AEMO has changed the assumed weighted average cost of capital for different types of infrastructure: see "Changes in costs since 2024" below.
- **Change in government policies.** A government may change policy and increase or reduce its support for a particular project.

Comparison of transmission project statuses since the 2024 ISP

There were 12 actionable ISP transmission projects in the 2024 ISP (although one, Project Marinus, has now been split into two separate projects). Of these, four projects have advanced to committed or anticipated status, five remain actionable, and four are no longer actionable in the 2026 ISP. As well, five future projects in the 2024 ISP now fall within the actionable window, and there are two new projects identified as actionable in this ISP.

Table 2 summarises the project status changes since the 2024 ISP.

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Table 2 Classification status of transmission projects between 2024 ISP and 2026 ISP

Status between ISPs	Projects
Advanced to in service, committed or anticipated status	• **Far North Queensland REZ** and **Project EnergyConnect Stage 1** are now in service. • **HumeLink** and **Hunter-Central Coast REZ Network Infrastructure Project** have advanced from actionable to committed. • **Project Marinus Stage 1** and **New England REZ Network Infrastructure Project** have advanced from actionable to anticipated.
Continue to be actionable	• **Gladstone Project** (previously Gladstone Grid Reinforcement) remains actionable, with Powerlink progressing through the Queensland Government's priority transmission investment assessment. • **Sydney Ring South** project continues to be actionable, but the ISP candidate option has now been updated from a power flow control option only to also include larger 500 kV upgrades to support the major load centre in New South Wales, consistent with the Project Assessment Draft Report (PADR) released by Transgrid in May 2026. • **Sydney Ring North (Hunter Transmission Project)** remains actionable, with EnergyCo having lodged reports required for the New South Wales planning approval pathway. • **VNI West** remains actionable. Delivery pathways for the New South Wales component, providing access to South West REZ, are now aligned to the New South Wales framework, and include three transformers at Dinawan Substation, as advised by Transgrid and EnergyCo. • **Project Marinus Stage 2** remains actionable, with Marinus Link and TasNetworks' RIT-T completed and the 2026 ISP re-affirming actionable status for Stage 2.
Newly identified as actionable	• **Western Victoria Reinforcement, Gippsland Offshore Wind Transmission Project, Central to North Queensland Reinforcement (Stage 1), Central-West Orana REZ Expansion** and **Tasmania REZ Expansion** (previously North West Tasmania REZ Expansion) have all moved into actionable timeframes due to the two-year progression between ISPs, as well as updated scopes and cost estimates, increased certainty in committed and anticipated generation and storage at defined locations, and improved alignment with the connections pipeline. • **Switching Station Near Wondalga** and **Brisbane Area 275 kV Reinforcement** are new transmission network options which have now been identified as actionable.
Reclassified from actionable to future ISP projects	• **QNI Connect** is identified as a future ISP project, with the change driven by updates to reduce assumed flexibility of Queensland coal generators and incorporate newly committed and anticipated batteries in the modelling. • **Northern** Transmission **Project** (previously Mid North South Australia REZ Expansion) delivers the greatest benefits in the *Accelerated Transition* scenario, particularly once significant industrial demand growth eventuates. ElectraNet's PADR identifies potential consumer benefits under a broader range of conditions. Given the project remains on the ODP and there is an active RIT-T underway, AEMO considers ElectraNet should conclude the RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options. Continuing community engagement may also help to narrow the corridor and reduce uncertainty for affected communities, while ensuring community considerations are reflected in future planning and decision-making. Stopping and restarting engagement can be disruptive, may erode trust, and could make it more difficult to build and maintain social licence for the project over time. • **Second Tasmania REZ Expansion** (previously **Waddamana to Palmerston transfer capability upgrade**) has moved to the future timeframe, delivering benefits in the *Accelerated Transition* scenario. TasNetworks will consider this augmentation as an option in the actionable Tasmania REZ Expansion project.
Continue to be future ISP projects	• **Eastern Victoria Reinforcement** and **South West to South East Queensland Reinforcement** (previously Darling Downs REZ Expansion).
Newly identified as future ISP	• **South West Victoria Expansion** has now been identified as a future ISP project.
No longer identified on the ODP	• **Central Queensland to Southern Queensland Expansion** (formerly Queensland SuperGrid South) was actionable, but is no longer identified on the ODP. Alternative connection arrangements for Borumba Pumped Hydro have been identified to meet consumer needs and deliver efficient dispatch outcomes. • **Cooma-Monaro REZ Expansion, Facilitating Power to Central Queensland, North Queensland Energy Hub Expansion** and **Central Highlands REZ Extension** were previously identified as future ISP projects but are no longer identified on the ODP. Changes to the Cooma-Monaro outcomes are as a result of taking into account other changes in New South Wales, including access rights arrangements, adjusting near-term ISP outcomes to prioritise the existing project pipeline, updated generation cost inputs, distribution network option changes, and more. Changes to the Queensland

Status between ISPs	Projects
	regional energy hub outcomes reflects changes to jurisdictional targets for renewable energy, and changed consideration of the Pioneer-Burdekin pumped hydro project. On the Central Highlands REZ Extension, while there continues to be a need to augment the Tasmanian transmission network, the need for this project is now captured by the actionable Tasmania REZ Expansion project and the future Second Tasmania REZ Expansion project.

Note: Some future ISP projects identified in single scenarios or identified towards the end of the modelling horizon which are expected to evolve from one ISP to the next are tabulated in Appendix A5 Network Investments but are not listed in this table.

The ODP meets consumer and policy needs at least cost

The 2026 ODP is a plan to supply secure and reliable power to consumers through to 2050 at least cost, while meeting rising demand and government policies.

Delivering the ODP would provide secure and reliable electricity, keep energy costs as low as possible while meeting government policies, support investment in CER and broaden access to its benefits, help reduce emissions across the economy, add to energy self-reliance and insulation from global shocks to the price or supply of fuel for generation and especially transport, and manage risks through a complex transformation.

Supplying secure and reliable electricity at least cost

The ODP's net market benefits to consumers are calculated across the three scenarios. Across the three scenarios, the net market benefits to consumers to 2050 from the actionable and future ISP transmission projects is $28 billion. By avoiding more costly investment across the NEM, they would repay their investment costs, save consumers $26 billion in additional capital and operating costs, and deliver emissions reductions valued at a further $2 billion. The 'scenario weighted' benefits are slightly less than in *Step Change,* as they are increased in *Accelerated Transition* less than they are reduced in the equally weighted *Slower Growth.*

In the most likely *Step Change* scenario, the ODP's annualised capital cost of all new generation, storage and network projects to 2050 would be $106 billion in present value terms (that is, in today's dollars). Of this, the ODP's actionable and future ISP transmission projects account for $6 billion. Together with system security investments estimated to be worth $3 billion, these transmission projects support $97 billion of generation, storage, firming and distribution. Additionally, the operating and fuel costs in the ODP are estimated to cost $77 billion. In the counterfactual path without new transmission, the capital cost of the other investments would be $123 billion, or $17 billion more than the ODP, and operating and fuel costs would be $12 billion higher. Far more solar, wind, storage and especially gas-powered generation capacity would be needed, with much of the emissions from this generation needing to be captured and stored underground[15].

AEMO recognises that the actionable and future ISP transmission projects will continue to deliver value after 2050 (the time horizon for the ISP's cost-benefit analysis). In the ISP, transmission lines are conservatively assumed to have an economic life of 50 years, and most will be built in the early 2030s. The total upfront capital cost of the ODP's transmission projects is $16 billion in present value terms. In this cost-benefit analysis, $6 billion is the annualised cost up to 2050. These assets would become part of a transmission grid to benefit consumers for many decades to come.

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[15] While this assessment includes the cost for gas-powered generation with carbon capture and storage (CCS) technology included, it does not include the costs of establishing CCS transport and storage infrastructure.

Changes in costs since 2024

The capital cost of the 2026 ODP is 7% higher than in the 2024 ISP, after accounting for inflation, the time value of money, costs incurred in the past two years, progression of projects to become committed and anticipated, changes to the weighted average cost of capital (WACC) and new scope items.

Other than transmission, the change in overall capital cost reflects both cost-reducing and cost-adding factors:

- Cost-reducing factors include a higher CER forecast (leading to less grid-scale investment), and lower capital costs of solar and batteries.
- Cost-adding factors include higher capital costs for wind projects, and two cost categories included in the ISP for the first time: distribution network development opportunities and an additional layer of system security services, both of which were previously assumed to occur without costs being allocated.

The overall cost of transmission in the ODP has been reduced. Although per kilometre capital costs are higher and there are more transmission projects, the overall length of transmission is about 1,435 km less and some projects use less equipment. This, combined with the progression of some transmission projects to ‘anticipated’, reduces the required actionable and future transmission build by around 50%. These factors outweigh the higher per kilometre costs and the increased number of transmission projects.

There has also been a material change to the WACC applied in the 2026 ISP. In previous ISPs, AEMO applied a WACC of 7% to all electricity infrastructure. During consultation on the 2025 IASR, the ISP Consumer Panel and other stakeholders recommended this be changed. AEMO now applies a different WACC to different types of infrastructure, to appropriately reflect their risk levels and therefore the returns that investors expect. The WACC for transmission projects has been reduced to 3%, recognising that the assets have regulated revenues, and so carry lower risk. It has increased to between 7% and 12% for generation and storage projects, depending on the technology, recognising their slightly higher investment risk in a competitive market.

Meeting policy needs

The ODP would meet all relevant government energy and environmental policies and targets. In the *Step Change* scenario, it would reduce NEM emissions from just over 100 million tonnes of carbon dioxide equivalent (Mt CO_2-e) today to about 40 Mt CO_2-e in 2029-30, then to about 10 Mt CO_2-e in 2038-39, and finally to 3 Mt CO_2-e in 2049-50. However, as noted below, delays to delivery of generation, storage and transmission delivery due to current supply chain pressures and other constraints would inhibit achievement of some 2030 policy targets.

ODP selection is robust to delays in delivery

The next five to 10 years are critical to delivering the transition. Most coal-fired capacity is projected to retire by 2038, while meeting the ODP would require infrastructure to be delivered at a rate faster than has been achieved to date.

The current connections pipeline is encouraging, but on its own would not reach the ODP’s projected level of generation capacity for 2030. Even if all the pipeline’s solar and wind projects are delivered as planned, they would only deliver three-quarters of the new capacity needed. Reaching the level projected in the ODP therefore requires both successful delivery of the existing pipeline and the continued development of additional projects,

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particularly in areas where the pipeline remains thin. This represents a material delivery challenge. Timely progression through development, financing, approvals, connection and construction will be critical.

While battery projects are progressing ahead of expectations, storage alone cannot close the supply gap. More renewable generation will be needed to meet rising demand and to use the storage effectively, so that reliability is maintained as the generation mix shifts.

AEMO has conducted a *Constrained Delivery* sensitivity analysis to explore what may happen if new generation, storage and transmission were delivered faster than so far achieved, but not as fast as required in the ODP. The sensitivity limits the rate of build without regard to the cause of delay. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction. The costs of the projects were also assumed to rise due to these constraints, on average by 30%. 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.

If infrastructure delivery is slower due to constraints, as in *Constrained Delivery*, the 2030 renewable energy targets would not be met on schedule. To ensure supply remains reliable, coal would remain in the system longer and gas generation would be used more extensively, slowing emission reductions and increasing exposure to gas supply risks.

Transmission investment would mitigate some of these impacts, even if it also experiences costly delivery delays. Even under constrained delivery, substantial volumes of renewable and storage capacity would require connection, with around 45 GW of renewable generation and 31 GW of storage expected by 2030. Transmission, delivered as soon as possible, supports access to this capacity, shares it efficiently across the NEM, and connects it to deep storages. These capabilities become increasingly important as coal plants age and the risk of unplanned outages or early closures rises.

Delivering infrastructure at the pace required to meet both consumer and policy needs, while listening to communities and responding to their concerns, remains a central priority for the energy transition.

ODP selection is robust to higher demand

The potential for stronger-than-expected demand growth, including from data centres and other electricity-intensive industries, would further increase the near-term delivery challenge. Given that uncertainty in future demand, AEMO also tested higher demand outcomes in a *Higher Demand* sensitivity. The results show that the selection of the ODP remains robust under these conditions. Additional demand increases the need for generation and storage and further strengthens the value of transmission, but does not materially change the relative performance of candidate development paths. The ODP continues to perform close to least cost, providing confidence that the selected transmission investment pathway remains appropriate even if data centre growth is faster than currently projected.

Coordinated action to ensure the ODP is delivered

The ODP is the least-cost path to supply secure and reliable electricity to consumers as coal retires, while meeting rising demand and government targets. Replacement generation and system security services must be available before coal power stations withdraw. The age and condition of some power stations may mean that

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delaying their closure is not an option, and periods of decommitment are anticipated well in advance of when they do. Delays to the ODP's delivery reduce consumer benefits and increase power system reliability and security risks.

Yet its delivery also relies on the projects and proponents, and the energy transition itself, attaining social licence in renewable energy zones and across the regions. While the energy transition is intended to deliver long-term benefits for consumers, there are several undeniable concerns in the near term. New energy infrastructure and its construction can affect daily life, local environments and community identity. There are concerns about the pace and scale of change, the visibility of infrastructure, whether all proposed investments are necessary, and how energy policy settings may evolve over time. These issues come on top of the cost-of-living pressures for households and businesses, and whether the upfront investment in new energy infrastructure is adding to those costs.

As described below, coordinated action is being undertaken across governments, industry and market bodies to address these challenges.

Significant progress on preparing for coal's retirement

Significant progress is being made towards the ODP. There is a growing wave of new generation and storage projects across the NEM. New transmission has been delivered, with more well underway. Distribution networks are continuing to innovate to cater for CER, which continues to grow at world-leading rates.

Collaborative action is also being taken to support this momentum and ensure the NEM is ready for coal's retirement. The three main fronts are:

- **Maintaining investment certainty.** The energy transition depends on timely investment decisions, which are hampered by uncertainty. To help reduce that uncertainty, governments have a range of targets, policies, mechanisms and initiatives to support energy infrastructure and investment. Examples include the federal Capacity Investment Scheme, the NEM Wholesale Market Settings Review, the Electricity Infrastructure Roadmap in New South Wales, the Firm Energy Reliability Mechanism and net 100% renewables target in South Australia, the Queensland Energy Roadmap, the Victorian Transmission Infrastructure Framework and State Electricity Commission of Victoria, the Tasmanian Renewable Energy Target, and battery programs in the Australian Capital Territory. However, Australia is competing for global investment in the energy transition, and will also need to invest in its gas supply infrastructure.
- **Ensuring system security is ready for periods of 100% renewables.** The NEM's energy markets, networks and operations are preparing for very high penetrations of renewable energy, and the eventual departure of coal. AEMO published a *Transition Plan for System Security* in December 2025, setting out the actions and investments in security services needed in the next 10 years to ensure a smooth transition and a secure and reliable future energy system. The AEMC published a consultation paper in March 2026 to consider changes to the National Electricity Rules (NER) planning and procurement frameworks for system strength and inertia.
- **Integrating consumer energy resources into grid operations.** In July 2024, the Energy and Climate Change Ministerial Council (ECMC) endorsed the National CER Roadmap, which sets out an overarching vision and plan to unlock the benefits of CER for all Australians and the electricity system. In December 2025, the ECMC endorsed a list of 18 minimum requirements for CER devices to support their integration into the

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grid. While work on all of the Roadmap's 16 priorities has commenced, this is the first to be completed. As distribution networks are the connecting point for consumer and mid-scale energy resources, recent ECMC recommendations and AEMC rules support more comprehensive planning for the distribution network[16].

- **Responding to the growth in data centres**. AEMO has been working with the ECMC and other energy market bodies on the energy implications of data centres since March 2025. This includes improvements to connection processes, demand forecasting and system security, and ensuring regulatory frameworks remain fit for purpose. The AEMC is currently considering feedback on a draft rule change, initiated by AEMO, for new technical standards for large data centres, and AEMO is preparing a rule change for Operational Integration and Visibility of large inverter-based loads (including data centres). These reforms respond to the current reliance on bespoke, case-by-case arrangements, which limit efficient investment signals and system operation. The proposed changes will introduce consistent operational requirements and streamline connection processes.

AEMC has commenced its scheduled review of the ISP framework to ensure it remains fit-for-purpose and continues to support the energy transition. AEMO welcomes this and other reviews of the ISP purpose and approach, and will continue working with network planners, governments, market bodies and consumer groups on reforms that drive benefits for all consumers.

Similar collaboration needed on infrastructure development delivery

To deliver the transition on time, further engagement is needed with communities, on approval processes, and with the global supply chain.

- **Continue to build social licence through engagement, benefits and clear roles.** Social licence – the ongoing acceptance and trust of communities – is essential to the success of the energy transition in three ways. It underpins the development of new infrastructure, the coordination of CER, and broader public support for national investment in the transition.

  Developers, network service providers, governments, and energy market bodies are working harder to build the trusting relationships with communities that underpin social licence. Specific guidelines, reviews and reforms are helping to ensure that CER and its coordination benefits all consumers, and policies such as Solar Sharer are aimed at equity and cost-of-living concerns. Initiatives such as the First Nations Social Licence Merit Criteria in the Capacity Investment Scheme aim for engagement, benefit sharing and economic empowerment for First Nations communities.

  Yet even with these initiatives in place, communities need greater clarity on who is responsible for meeting their concerns. The primary responsibility rests with project proponents, yet approvals are granted by government bodies, to which communities often look when concerns arise.

- **Continue to improve processes for infrastructure approvals.** Planning and environmental approvals would need to keep pace with the significant scaling-up of renewable generation projects in the ODP. For its part,

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[16] On 23 April 2026, the AEMC released a draft determination on the Enhancing Distribution Network Planning and Reporting rule change which would require DNSPs to adopt a new distribution network planning process. See https://www.aemc.gov.au/rule-changes/enhancing-distribution-network-planning-reporting .

AEMO is working with the Clean Energy Council, industry and governments to streamline the connection approvals process.

- **Secure the supply chain for critical energy assets and workforces.** Australia's energy transition depends on a skilled workforce and deep investment in CER, grid-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers. This is in competition with other countries around the world also transforming their power systems.

* * *

The 2026 ISP provides a roadmap for the transition of the NEM power system. It is a clear plan, the product of two years' work by all interested stakeholders, that sets out the least-cost way to supply secure and reliable electricity while meeting government policies, as electricity consumption doubles and coal plants retire through to 2050.

The momentum led by households and businesses is now being experienced at grid-scale. Concerted action must continue to overcome the acknowledged challenges, so that the ODP and the energy transition are delivered.

The 2026 ISP has benefited significantly from stakeholder feedback on the Draft 2026 ISP. Continued consultation has ensured that inputs and assumptions have kept up to date with the NEM's operating environment. The major updates are noted in the "Key changes" box below, and discussed in full in AEMO's *2026 ISP Consultation Summary Report*. This feedback also informs AEMO's preparation of the 2028 ISP, and AEMO remains open to further improvements.

AEMO thanks stakeholders for their input into the preparation of the 2026 ISP, and will continue to work with consumers, industry, governments and other stakeholders to deliver the energy transition and support reliable, least-cost energy for Australia.

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Key changes from the Draft 2026 ISP

The 2026 ISP sets out how AEMO has identified the optimal development path (ODP) for the NEM. AEMO has adjusted inputs and assumptions since the Draft ISP in cases where updated information has become available (as foreshadowed in the IASR), where stakeholder feedback and consultation has considered it important, and where the changes may be likely to materially impact the ODP.

AEMO notes the following key differences between the Draft 2026 ISP and this final 2026 ISP.

Changes in inputs

- **For transmission projects**, options, costs and network representation in the model were updated wherever needed through joint planning with project proponents. Based on updated information from the New South Wales Government, New England REZ Network Infrastructure Project progressed to anticipated status to reflect its advanced progress through the New South Wales framework, and therefore the actionability of the project was not retested in the 2026 ISP.
- **For generation and storage projects,** cost projections were updated to reflect the Draft 2025-26 GenCost values. In particular, the estimated cost of pumped hydro decreased from $6,500/kW to $4,400/kW.

Renewable energy project access rights for the Central-West Orana and South West New South Wales REZs were also updated to align with New South Wales government data.

- Between July 2025 and January 2026, an additional 5 GW of wind and solar projects and 11 GW/44 GWh of battery projects progressed to existing, committed or anticipated status. A further 1 GW of wind and solar projects and 5 GW/16 GWh of battery projects have now been publicly identified as being supported by government tenders.
- A January 2026 announcement to delay the Eraring Power Station retirement from August 2027 to April 2029 has also been incorporated into the ISP assessment.
- **For government policies**, the South Australian Government's new target of net 100% renewable energy by 2027 has been applied in perpetuity rather than as a 'point in time' target in response to advice from the South Australian Government.
- **CER storage (home batteries) uptake forecast** is updated to reflect an increase in expected uptake under the Federal Government's *Cheaper Home Batteries Program*. Forecast consumer investment in embedded storage by 2050 has increased from 27 GW to 35 GW.
- **For gas development projections,** more recent data from the 2026 *Gas Statement of Opportunities* was taken into residential, commercial and industrial gas demand forecasts; gas production forecasts; and project information relating to the gas infrastructure options. The 2026 ISP does not incorporate future gas market policies identified through the Federal Government's current Gas Market Review, including the domestic gas reservation scheme, as their detailed design and legislative framework was under consultation and had not yet reached the threshold certainty for ISP modelling.

Changes in assumptions and approach

- **Prioritise existing project pipeline before allowing new projects to be modelled.** AEMO's modelling better reflects current, on-the-ground developer interest and activity. The existing pipeline of projects (with a lodged application to connect) are counted towards 2030 targets before any generic 'new entrant' generation or storage could be built before 2030. This change has allowed the final ISP to better align with the reality of developer activity in the NEM, and better reflect time required for any new project that has not yet lodged a connection application to progress through development and delivery.
- **Region-based coal flexibility assumptions for the final 2026 ISP.** The Draft 2026 ISP assumed flexible operation of coal generation across the NEM as the transition progresses. Based on stakeholder feedback, and informed by the 2025 *Thermal Audit* for the NEM, AEMO has since re-considered generators' flexibility region-by-region. For the 2026 ISP, AEMO has assumed improved flexibility in New South Wales and Victorian coal plants as they continue to trial and implement changes, and considered that Queensland units would more likely focus on maintaining reliability under current operations.
- **Increased firming to ensure reliability in all regions across all years in the ISP horizon**. For the Draft 2026 ISP, AEMO undertook a preliminary reliability analysis for the proposed ODP. A complete reliability assessment for the final ODP demonstrated that more firming solutions would be needed to support the reliability of the power system. Gas-powered generation was assumed to be this firming solution, but

other alternatives, including demand-side flexibility, could be lower cost options and will be considered further in future ISPs.

- **Alignment with advice from jurisdictional planning bodies for transmission networks.** Joint planning with transmission network service providers and jurisdictional planning bodies accelerated in early 2026, including the exchange of modelling and analysis and advice from ongoing RIT-Ts. As a result, a number of network representation and transmission augmentation option changes were incorporated into the final 2026 ISP modelling, as detailed in the *2026 ISP Consultation Summary Report.*

Changes in outcomes

The key finding of the ISP is that AEMO continues to find that renewable energy connected with transmission and distribution, firmed with storage and backed up by gas is the least-cost way to supply electricity to homes and businesses through to 2050, as coal plants retire and while meeting government policies.

This is supported by similar projections to the Draft ISP:

- **A similar scale of capacity investment through to 2050** with a total of 117 GW grid-scale renewables, 64 GW/640 GWh dispatchable storage and 17 GW flexible gas, as coal continues to retire with most withdrawn by 2035 and all by 2049.
- **A similar length of new transmission**, adding about 6,000 km to the network. The changes in projects compared to the Draft ISP include one actionable project moving to the anticipated category, four relatively small new projects now being actionable, two projects requiring ongoing analysis now classified as future ISP projects, one actionable project now being a future ISP project, and the inclusion of several new future ISP projects.
- **An increase in net market benefits** from transmission investment (weighted across all scenarios), to $28 billion, up from $24 billion in the Draft 2026 ISP. The drivers of the increase are primarily reflective of realigning the generation and storage planting in the early years of the ISP horizon to the existing development pipeline, which increases congestion in the absence of transmission and therefore strengthens the value of network augmentation.

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PART A

The energy transition is well underway

Part A | Part B – Preparing a least-cost path for the NEM | Part C – Generation, storage and network investments in the ODP | Part D – Delivering the ODP

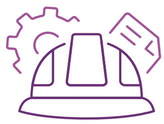
Part A
The energy transition is well underway

The NEM has delivered secure and reliable electricity to households and businesses for 27 years. It must now do so while coal generators retire, while consumers add their own solar and batteries, and while the economy switches to electricity.

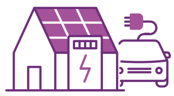
This transition is the biggest overhaul of Australia's power system for 100 years. It is a once-in-a-century change to the way energy is generated, stored, moved, and used across the economy.

This Part A sets out how and why the energy system is changing:

- **Section 1 – Industry and government are reforming a complex system.**
  The NEM spans home-scale to grid-scale power systems. Coal is retiring, and policies and markets are favouring a mix of renewables to replace it. Renewables met half of all demand for electricity in the NEM in the quarter ending December 2025, and reached close to 80% for a half-hour on 11 October 2025. However, renewables need support from multiple technologies to provide reliable and secure supply, and nearing 100% renewables will be challenging. Those challenges are being managed, and the direction is clear.



- **Section 2 – Consumers are taking more control of their energy needs.** Historically, consumers were at the end of energy supply chains, with little choice over the source of supply. Now, they can generate their own electricity, and store it in batteries for later use. Rooftop solar continues to be adopted at world-leading pace, and the Cheaper Home Batteries Program has accelerated battery installations. Consumers are also switching from fossil fuels to use more electricity for their industrial, transport, heating, cooling and cooking needs. New energy-intensive industries like data centres are being added. Altogether, electricity consumption in the NEM is forecast to nearly double by 2050. Yet by then, about 30% of demand would be met by consumers' own resources, to the benefit of both their owners and all other consumers.



Part B follows to set out how the ISP helps plan for the transition.

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1 Industry and government are reforming a complex system

The first section sets out how and why the NEM is being transformed:

1.1 **The complex NEM power system spans home-scale and grid-scale resources.** It interacts with the East Coast Gas Market, and is governed by the National Electricity Law and Rules.

1.2 **Investors and policies are favouring a mix of renewables to replace coal**, here and globally**.** Of the 26 major coal-fired generators operating in the NEM in 2012, 10 have already retired[17]. To replace them, policies have promoted renewables firmed by storage. Renewables reached the milestone of delivering half the NEM's electricity in the last quarter of 2025, and continue to attract private investment. To support them, investment in networks and system security services is building momentum.

1.3 **This essential transition has benefits and challenges.** Policies that support the market-based transition to both home-scale and grid-scale renewables are intended to bring a broad range of environmental, health and economic benefits. However, there are clear technical, social and economic challenges, and costs must be kept under control.

Section 2 follows to describe another dimension of the transition: the near doubling of electricity consumption in industry, business and transport.

1.1 The energy system spans home-scale to grid-scale resources

Australians rely on a complex energy system that integrates gas and electricity, large- and small-scale resources, and the markets and networks that connect them all.

Electricity and gas markets are interconnected

The ISP refers to two energy markets: the NEM and the East Coast Gas Market.

The NEM is the single wholesale electricity market and physical power system infrastructure which operates in the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria. It is one of the world's longest interconnected systems, covering about 44,000 km of transmission lines and undersea cables, connected to a distribution network of over 764,000 km. Western Australia and the Northern Territory each have their own electricity system, not connected to the NEM.

The 'East Coast Gas Market' refers to the various wholesale gas markets and interconnected gas pipelines that supply all of the NEM's states and territories as well as the Northern Territory. It is particularly important to the ISP as it supplies gas to the gas-powered generators which are an integral part of the electricity system.

[17] This excludes Redbank power station which is planned to convert to biomass generation.

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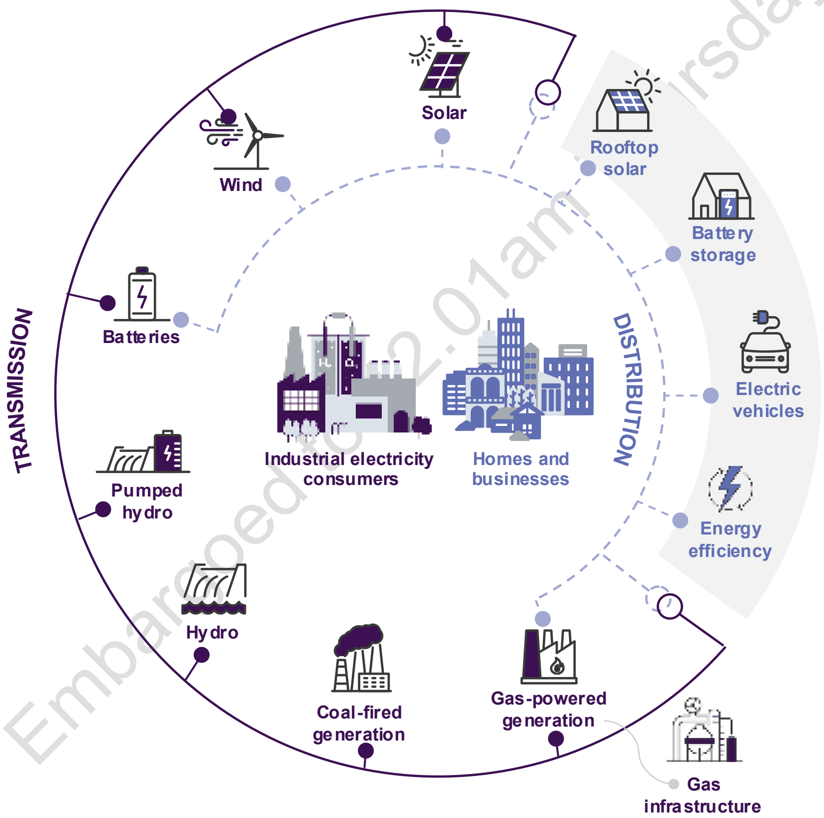
Gas is also delivered to large industrial customers and major population centres for domestic use, and to liquefied natural gas (LNG) facilities for export.

The NEM spans both grid-scale and consumer energy resources

The NEM is an intricate system of systems, with regulatory, market, policy and commercial parts. At its centre is the physical system that delivers power when and where households and businesses need it. **Figure 5** illustrates how the NEM meets consumer power needs through generation, storage and transmission, interacting with distribution and connecting consumers' own energy resources.

Three types of consumers (heavy industry, business and households) have different electricity needs. Heavy industry like aluminium or iron smelters typically draws electricity directly from the transmission grid. Business and household consumers have traditionally drawn their electricity from the distribution grid. Now, they are investing in CER (including rooftop solar, batteries and EVs), enabling not only generation for self-consumption, but also storing and sending electricity back into the grid when it is most valuable for all consumers.

Figure 5 A power system with both grid-scale and consumer energy resources



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AEMO manages the day-to-day operation of Australia's electricity and gas markets, and, as National Transmission Planner for the NEM, plans for Australia's energy future. Transmission network service providers, or TNSPs, in each state are then responsible for planning, building, and safely and securely operating the transmission lines in their regions, together with relevant jurisdictional bodies with distinct roles that vary by jurisdiction and project type. Similarly, distribution network service providers (or DNSPs) are responsible for planning, building, and safely and securely operating the distribution lines in their areas: see Section 3.1.

1.2 Policies and markets favour renewables to replace coal

Coal-fired generation has dominated Australia's electricity supply for generations. In 2010, the NEM had 26 major coal stations capable of generating about 30 GW or over 80% of its energy. Today, there are 15, capable of generating about 21 GW.

Most of the NEM's remaining coal plants, excluding Queensland, were built in the 1970s and 1980s and after an average 41 years of service are fast approaching retirement age[18]. Most have announced retirements, on average only 10 years away. Queensland's fleet is newer, on average 31 years old, and the Queensland Energy Roadmap sees their role continuing to 2049.

The older plants in the fleet are becoming less reliable and more expensive to maintain, and cannot always operate flexibly alongside renewable electricity supply. Reliability risks were exposed in June 2022, when 15% of the NEM's entire coal capacity was out of service for sustained periods. These outage rates can remain high: New South Wales black coal-fired generators were in full forced outage for 17% of the year 2020[19], while those in Queensland were out for 20% of the year in 2025.

To replace coal, Australia is transitioning to renewables. However, coal generation is still needed in the NEM for both generation and grid stability, until it is adequately replaced.

Consumers and governments have led the push to renewables

About 60 GW of renewables and batteries were operating in the NEM at the start of 2026. Rooftop solar, along with grid-scale solar, wind and hydro, met around 45% of all NEM demand for electricity through the 2026 financial year, including over 50% during the December 2025 quarter. They set a record for a half-hour on 11 October 2025, reaching almost an 80% share. On 5 October 2025, renewables had the potential to deliver almost 115% of demand, around half from rooftop solar, (though not all of that capacity could be used due to market and technical limits). These record levels vary seasonally, but are consistently rising.

This proportion of renewables – and solar in particular – is world leading for good reason. As well as our very large land area, Australia receives twice the solar energy per square metre as, say, Europe. That allows Australia to take full advantage of the globally falling costs of solar. Renewables have helped the emissions intensity of NEM generation fall from 0.96 to 0.59 tonnes of carbon dioxide equivalent (tCO_2-e) per megawatt hour (MWh) since 2010.

The rise of renewables in the NEM would not be possible without the strong take-up of consumer and utility-scale batteries. In early 2026 around 600,000 residential batteries had been installed in the NEM[20], and

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[18] For the 10 coal plants that have retired, their average age at retirement was 44 years. The exception is Redbank as it plans to be converted to biomass generation.

[19] AEMO, 2020 *Electricity Statement of Opportunities* p 48, Figure 21, https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[20] As reported by the Clean Energy Regulator, at https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data.

4 GW/10 GWh of utility-scale batteries were in operation. Together, these batteries are able to power 1.3 million households for 2.4 hours each day.

Government policies are in place to support industry in ensuring there is enough renewable generation and supporting infrastructure in place for coal's retirement. All of the current state, territory and federal energy policies considered in the ISP are listed in Section 4.2 below. As a whole, these policies recognise that de-carbonising the energy sector is essential if other sectors are to reduce emissions in line with global agreements and domestic targets, and are both maintaining the transition's momentum, and de-risking its delivery.

Global economics are driving down the cost of renewables

The decisions on how best to replace old coal-fired plants are ultimately made by investors. That investment favours renewable energy and supporting technologies over fossil fuels. Globally in 2024 and again in 2025, wind and solar received over three times as much investment as did coal[21]. In the first half of 2025 and for the first time, more of the world's energy was delivered by renewables than by coal[22].

That trend may have been kickstarted by commitments to decarbonise, but the primary driver is now economics. Consumers and governments the world over, seeking to reduce emissions and to be more energy independent, have driven decades of research and investment in renewable generation and battery storage. That investment has driven innovation and economies of scale, which has brought down costs.

In Australia, the capital cost of new grid-scale solar fell from $1,850 per kW to $1,620/kW in the five years to 2025, and is anticipated to continue falling to $930/kW by 2030. The capital cost of two-hour battery storage similarly fell from $1,300/kW to $1,050/kW and is forecast to drop again to $800/kW by 2030[23]. Meanwhile, the capital cost of new coal-fired power stations with carbon capture and storage (CCS) has risen from $7,650/kW to $12,900/kW over the last seven years[24]. Even taking into account the other complementary technologies required (see Section 1.3) and the differences in annual energy production and asset life, new renewable generation is less costly than new coal.

1.3 Renewables are supported by networks and other technologies

Renewables are not a like-for-like replacement for coal, and need supporting technologies to harness their full potential. For example, solutions are needed for 'dark and still' periods (a 'renewable lull'), and to cater for the flood of solar energy in the middle of the day. Others are needed for the system security services that have long been a by-product of coal-fired power generation.

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[21] International Energy Agency (2025), https://www.iea.org/reports/world-energy-investment-2025/executive-summary.

[22] Ember Research (2025), https://ember-energy.org/latest-insights/global-electricity-mid-year-insights-2025/#executive-summary.

[23] Historical values are taken from the 2022 ISP Inputs, Assumptions and Scenarios Workbook and converted to June 2025 dollars, while 2026 values are taken from the 2026 ISP Inputs and Assumptions Workbook.

[24] CSIRO (2026), GenCost 2025-26 Section 4.3.2, https://www.csiro.au/-/media/Energy/GenCost-2025-26-Draft/GenCost2025-26ConsultDraft_20251216-FINAL.pdf

A range of solutions support the transition from coal to renewables, in the NEM and globally, with the same investment (batteries and gas plants in particular) often serving multiple purposes:

- **Transmission networks are being extended**, to bring renewable energy from high-resource areas to the industries, cities and towns that need it, and share electricity between states.
- **Distribution networks are being upgraded** to better optimise voltages to support CER and larger distributed generation, allow flexible two-way flows of electricity and support population growth.
- **Batteries are becoming more common as costs decline and government support continues,** allowing households, businesses and industry to store surplus renewable energy during the day for use in the evening and morning peaks, helping to moderate prices during evening peaks and to support grid security and reliability as coal plants withdraw.
- **Existing hydro generators and other long-duration storage such as new pumped-hydro** firm renewables through longer renewable lulls, especially during winter, and also help manage planned network outages as infrastructure is connected.
- **New flexible gas-powered generation plants** provide critical back-up power supply during peak demand events and support hydro generation during 'dark and still' conditions (and to help pre-charge batteries for those times), as well as supporting grid security as coal plants withdraw.
- **Alternatives to fossil fuels are available to maintain grid security and stability.** Synchronous generation from coal plants has been essential to keep the power system stable. Batteries and synchronous condensers can perform many of these services, as can flexible gas plants operating with a clutch (that is, spinning, but without needing to generate electricity).
- **Some coal-plant owners are testing ways to increase plant flexibility.** Owners are investing to keep their coal plants economic as renewables put downward pressure on wholesale prices. They may lower their minimum stable operating levels (which in turn supports times of low demand in the system), increase their ramp rates and keep units offline for months at a time.

Doing all this at once is complex. Across the electricity sector, people are working on the operational and engineering solutions needed to support the transition to a high-renewables power system. AEMO's 2025 *Transition Plan for System Security* aims to help guide the sector through the next phase of the energy transition to lower emissions, focusing on the key transition points and actions needed to keep Australia's main power system stable and secure.

1.4 This challenging transition is intended to bring long-term benefits

Electricity is becoming ever more critical in the digital age, with more and more uses from phones, computers and watches, to household cars and appliances, to industrial processes and AI. As they rely on it more, consumers are owning assets to generate and store power, and being more efficient in its use.

Australia is in a globally enviable position to deliver a successful energy transition, if its resources are appropriately coordinated with good system planning. It has a strong regulatory and market environment, and wide availability of renewable energy, firming options and complementary services.

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The ISP contributes to that planning to help ensure the transition meets consumer needs and government policies. It does this by ensuring investment in Australia's transmission networks is efficient, emission reduction targets are met, consumers are supplied with secure and reliable electricity, and consumers have choices to invest in new technologies and benefit when they do.

This is a challenging transition. On the technical side, the NEM will need system security services from traditional sources like coal and gas to continue while new technologies are integrated piece by piece, keeping the whole system stable and secure. These needs are explored in Appendix A7 System Security and in AEMO's 2025 *Transition Plan for System Security*.

Socially, new infrastructure and its construction can affect daily life, local environments and community identity, often taking an emotional toll, and many believe these impacts outweigh the benefits. Whether or not the change is accepted or supported, the way those changes are implemented can put unwelcome pressure on communities – and the industry.

Economically (and socially), there are concerns about whether the upfront investment in new energy infrastructure is adding to today's cost of living, about policy uncertainty from decade to decade, that not all the new infrastructure is needed, and around what is driving energy prices. Much is already being done to address these challenges, and more is needed: see Part D.

All NEM governments have policies in place to support the transition, and to address its challenges, convinced that its long-term benefits are worthwhile. Those intended benefits are wide-ranging, and relate to: commitments to reduce emissions; energy independence, including for transport fuels; new sectors for skilled jobs; opportunities in energy-intensive industries like data centres, steel and aluminium, and critical mineral processing; transport costs; and the health and amenity of cleaner transport and gas-free homes.

AEMO will continue to work with industry, energy bodies, governments, consumer groups and communities with coordinated action, transparency, and a commitment to shared benefits.

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2 Consumers are taking more control over their energy needs

Electricity 'consumers' include all of the households, businesses and industries that use electricity, whether they draw it from the grid or from their own systems. Though the ISP must take a high-level view, AEMO acknowledges that consumers are as diverse as the Australian population and economy.

Consumers are in many ways leading the energy transition. Earlier, few households may have thought of what lay behind the three-point plugs, or even how much electricity they used. Now, there is everyday engagement on how they source electricity and big changes to how, and how much, they use it. Meanwhile, business and industry seek to take ever greater control over their power needs.

This section details how consumers will invest in and use more electricity through to 2050 – 'demand-side factors' that are changing the NEM.

2.1 **Consumers are investing in their own energy resources.** Many households and businesses are investing in 'consumer energy resources' (CER, see box below), with falling prices and government policies making them more accessible.

2.2 **Energy efficiency continues to substantially reduce consumption.** More energy-efficient appliances and buildings, particularly in business and industry, have delivered a strong dividend in reduced consumption over the past decade. The *Step Change* scenario assumes this dividend would accelerate so long as supportive policies are in place, reducing underlying consumption by 15% or 75 TWh by 2050.

2.3 **Total (or 'underlying') electricity consumption is forecast to nearly double by 2050.** Beyond population and economic growth, the additional consumption is due to emerging industries such as data centres, and the 'electrification' of the economy as consumers switch from petrol, diesel and gas to electricity for their industrial processes, transport, heating, cooling and cooking.

Section 9 below describes how consumer decisions to invest in CER and energy efficiency are likely to reduce the scale of grid-scale investments, to the benefit of all consumers. As CER and their benefits become more familiar, consumers also gain a broader interest in and understanding of the energy transition itself.

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ISP Explainer: Consumer energy resources (CER)

Many households and businesses are taking greater control over their power supply, seeking to reduce costs and emissions. They are investing in what the industry calls '**consumer energy resources'** or **CER**. In this ISP, they are rooftop solar and other on-site generation, batteries, EVs and EV charging devices.

CER can also become **'coordinated CER'** with technologies that enable them to be aggregated and operated by a third party, to then respond to market signals and provide a greater potential return to owners. This is done by 'bundling' CER through a retailer or an independent service to form a 'virtual power plant' or VPP, or by EV owners opting in to a dynamic charging scheme so the vehicle can be called on to supply energy back to the grid ('vehicle to grid' or V2G). While all CER reduces the total energy drawn from the grid, coordinated CER does so more predictably and efficiently.

CER can vary in scale from the familiar home-scale systems to larger commercial and industrial systems. What they have in common is that they are 'behind-the-meter', with only the electricity drawn from or fed into the grid being visible to AEMO's daily operations.

These resources are indispensable to the future NEM, and are considered in AEMO's planning, including the ISP. However, many renting and low-income households do not have the option to invest in or directly access CER. Policies and innovative retail offers are being advanced to overcome this equity challenge, for example the federal Solar Sharer scheme to offer free electricity in the middle of the day, drawing on the abundant output of rooftop solar. The distribution network is fostering this sharing of benefits, tapping into latent CER capacity to help moderate prices during peak periods and avoid further utility-scale investment.

2.1 Consumers are investing in their own energy resources

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Consumers are investing in rooftop solar, batteries and other resources, with falling prices and government policies making them more accessible to more consumers. CER are forecast to continue to grow rapidly over the next decade, before tapering off slightly to reach about 40% of the NEM's capacity by 2050.

CER do more than enable their owners to generate and store their own power: they allow their owners to participate in VPPs through an aggregator or retailer, and to charge EVs. Those with batteries can also change the time of day they use their power, using appliances when convenient without paying a higher price. They can also use smart energy systems to control hot water systems and other appliances such as pool pumps, to take advantage of cheaper daylight electricity and avoid the more expensive peaks.

These household and business investments, enabled by distribution networks, can reduce the scale of needed grid-scale investment. When it does, CER reduce broader system costs, delivering benefits to consumers who do not own rooftop solar, such as renters and apartment residents.

Rooftop solar continues to grow

Currently, over 36% of rooftop solar-suitable dwellings[25] in NEM regions have rooftop solar, which provide a total capacity of 20 GW[26]. By 2035 in the *Step Change* scenario, 47% of those dwellings would have rooftop solar, rising to 56% in 2050, driven by ever-falling costs. At that time, with many more dwellings, rooftop and small-scale solar capacity would be 87 GW. As rooftop solar generates mid-day surpluses, they need support from batteries and the distribution network to optimise their potential benefits for all consumers.

The total contribution of rooftop solar installed by homes and businesses is already very large. Over the summer (Q1) of 2026, they contributed almost 16% of the NEM's total electricity production, more than grid-scale solar (11%), wind power (15%), hydro (5%) or gas (3%)[27]. Even in the winter of 2025 (Q2), rooftop

[25] Rooftop solar-suitable dwellings include detached houses and semi-detached dwellings (duplexes and townhouses), and excludes apartments. A slightly higher 43% of fully detached houses in the NEM have rooftop solar.

[26] The number of rooftop solar systems in the NEM is subject to various and slightly differing estimates.

[27] AEMO. *Quarterly Energy Dynamics* Q1, April 2026, https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q1-2026.pdf?rev=f6c1205d357742108ff08563cc0da0e8&sc_lang=en&hash=8A56BC5D49D9C4CFB6233DD3C6E7901D.

solar supplied 10% of the NEM's mix, outstripping hydro (7%), grid-scale solar (7%) and gas (6%) – with wind showing its winter value (14% of supply)[28]. In aggregate, rooftop solar has met just over 60% of underlying electricity demand across the NEM, on a sunny weekend when industrial demand was low.

Small-scale batteries now accelerating

Residential and commercial batteries soak up the surplus daytime solar to be used later in the evening. Household and commercial battery installations are growing rapidly on the back of lower costs, easier-to-use technology, and government policies. High connections under the Cheaper Home Batteries Program in early 2026 have led to an update in the ISP's near-term forecasts. Under *Step Change*, small-scale batteries would grow from 5 GW/12 GWh in April 2026 to 12 GW/33 GWh in 2030, and then 35 GW/78 GWh in 2050. By 2050, around two-thirds of the dwellings with solar are forecast to have supporting batteries, and just over half of those batteries would be coordinated as part of a VPP.

Electric vehicle ownership is forecast to surge

Already, consumers are noticing falling EV prices, greater model choice and availability (assisted by new vehicle efficiency standards) and more charging infrastructure, and these trends are projected to accelerate through both domestic and commercial fleets. By 2050, to meet federal and state targets, up to 80% of all vehicles on the road are forecast to be battery or plug-in EVs.

EVs are ideally charged in peak solar daylight hours, avoiding the morning and evening peaks. To assist this, more investment is needed in workplace, kerbside, commuter carpark and on-road charging through the distribution network. Initial trials of V2G connection systems are underway to test how EV owners may in the future export any unused battery charge back to the home, or to the broader grid when needed, but this practice is not yet widespread. By 2050, just over 10% of household EVs are forecast to be able to charge and discharge electricity through V2G, which would add 4.3 GW/48.8 GWh of storage capacity to the NEM[29].

CER investments deliver benefits beyond participating households

Private investments in CER benefit the NEM in two ways that lower the ultimate cost of electricity for all consumers:

- the generation from rooftop solar reduces the amount of grid-scale generation needed, and
- storage in batteries and EVs helps harmonise demand with available supply, helping manage loads through the day.

The scale of these benefits through to 2050 is detailed in Section 9.2 below. Recognising that potential, CER are supported by both the energy sector and governments. Distribution networks are being upgraded to support CER and the export of surplus electricity to the grid. Retailers and other service providers can coordinate or bundle CER to form a VPP, and consumer confidence in these VPPs is forecast to rise. Regulators are enabling innovative new tariffs and other changes to pricing. These reforms are being accelerated through the National CER Roadmap, endorsed by the Energy and Climate Change Ministerial

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[28] AEMO. *Quarterly Energy Dynamics* Q2, July 2025, https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q2-2025.pdf?rev=8732b44ba628445da5883f92e84cd87d&sc_lang=en.

[29] The ISP assumes that a V2G system would not empty a battery below halfway, so the EV remains ready for use.

Council to unlock the benefits of CER for all Australians and the electricity system: see Section 12.2. Government policies can also help to broaden access to CER benefits, for example through mechanisms such as the federal Solar Sharer offer.

2.2 Energy efficiency is forecast to accelerate

In addition to CER, consumer investments in energy efficiency are significantly reducing their forecast needs from the grid through to 2050. Over recent years, improvements in building and appliance standards have delivered sustained reductions in energy use. The *Step Change* scenario assumes this energy efficiency dividend would accelerate, reducing consumption by 15% or 75 TWh by 2050.

The specific drivers of these reductions vary between the household, business and industrial sectors, though there are common themes. The rollover of stock is the main factor, as new appliances, commercial fit-outs and building designs are typically more energy efficient than old ones. Higher-efficiency options are also preferred in state and federal standards and incentives, such as the federal *Greenhouse and Energy Minimum Standards Act* (GEMS), and by businesses seeking to cut operating costs. These options moderate the increase in energy use that would otherwise come with higher standards of living, and so reduce demand on the grid.

- **Household efficiency driven by standards and incentives.** Energy savings stem from building codes that boost the efficiency of new dwellings, appliance standards, and incentives through programs like the New South Wales Energy Savings Scheme and the Victorian Energy Upgrades, which are helping to fund a range of household energy efficiency upgrades. In *Step Change*, household savings are forecast to reach 14 TWh by 2035 and 42 TWh by 2050.
- **Commercial building efficiency driven by investor and occupant demand.** New and refurbished commercial buildings offer significant energy savings, valuable to investors and occupants seeking to reduce their own environmental imprints. These are supported and validated by updates to the National Construction Code, by mandatory and voluntary disclosure of greenhouse gas emissions, by rating programs such as the Commercial Business Disclosure (CBD) program and the National Australian Built Environment Rating System (NABERS), and by state-funded incentives.
- **Industrial efficiency a continuing driver of cost savings.** Industrial savings are typically driven by the firm's own cost-reduction efforts, with contributions from GEMS and energy savings schemes in New South Wales, Victoria and South Australia. In addition, energy efficiency retrofits can complement the switching to electricity from gas to support compliance with the federal Safeguard Mechanism.

ISP Explainer: 'demand' and 'consumption'

In this ISP, AEMO uses the industry terms 'demand' and 'consumption' to refer to how much electricity use will be needed in the NEM:

- **'Demand'** is the electricity needed **at a point in time**, expressed in 'kilowatts' (kW), megawatts (MW), gigawatts (GW) or terawatts (TW).
- '**Consumption**' is the total electricity used **over a period of time**, expressed in 'kilowatt hours' (kWh), megawatt hours (MWh), gigawatt hours (GWh) and terawatt hours (TWh).

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There are three points of measurement for demand and consumption considered for the NEM:

- **'Underlying'** or 'total' consumption (or demand) is all the electricity that consumers use, whatever its source, excluding transmission and distribution losses.
- '**Delivered' consumption or** 'grid-supplied electricity' (or demand) is the utility-scale generation that actually reaches consumers. Importantly, delivered consumption is an aggregate or net figure for the period, representing all that consumers take from the grid *less* all that they have fed into it.
- **'Operational'** or 'grid' consumption (or demand) is the electricity dispatched through the NEM for consumers to use and includes the expected losses through the network.

2.3 Electricity consumption is forecast to near double

Even though consumers are investing significantly in CER and energy efficiency, their consumption of grid-supplied electricity will still rise. Industry rather than household demand is the main driver.

Electrification and new industries to increase overall consumption

Underlying consumption across the NEM is forecast to near double from the current 205 TWh to about 390 TWh in 2050. As consumers are forecast to supply 116 TWh from their own CER and mid-scale systems, the remaining 274 TWh of their needs would be supplied by utility-scale resources. As shown in **Figure 6** and explained below, business and industry would account for almost all of this net consumption.

This rise in consumption is due to population growth, economic growth, electrification (the switch from other energy forms such as petrol, diesel and gas to electricity for industrial processes, transport, heating, cooling and cooking), and large new users of electricity such as data centres and hydrogen production.

Electrification is the main driver of the rise in electricity consumption, adding 117 TWh by 2050 – more than half of the NEM's current total. Road transport is the largest single element of that shift, rising from today's 1 TWh up to 61 TWh by 2050[30]. This grid consumption would be split evenly between household EVs and commercial and freight EVs, with both also charging from CER when available.

In **Figure 6**, electrification is embedded within the residential, business and industry forecasts, with more detail of the role of electrification for each consumer type provided in **Figure 7** and **Figure 8** below.

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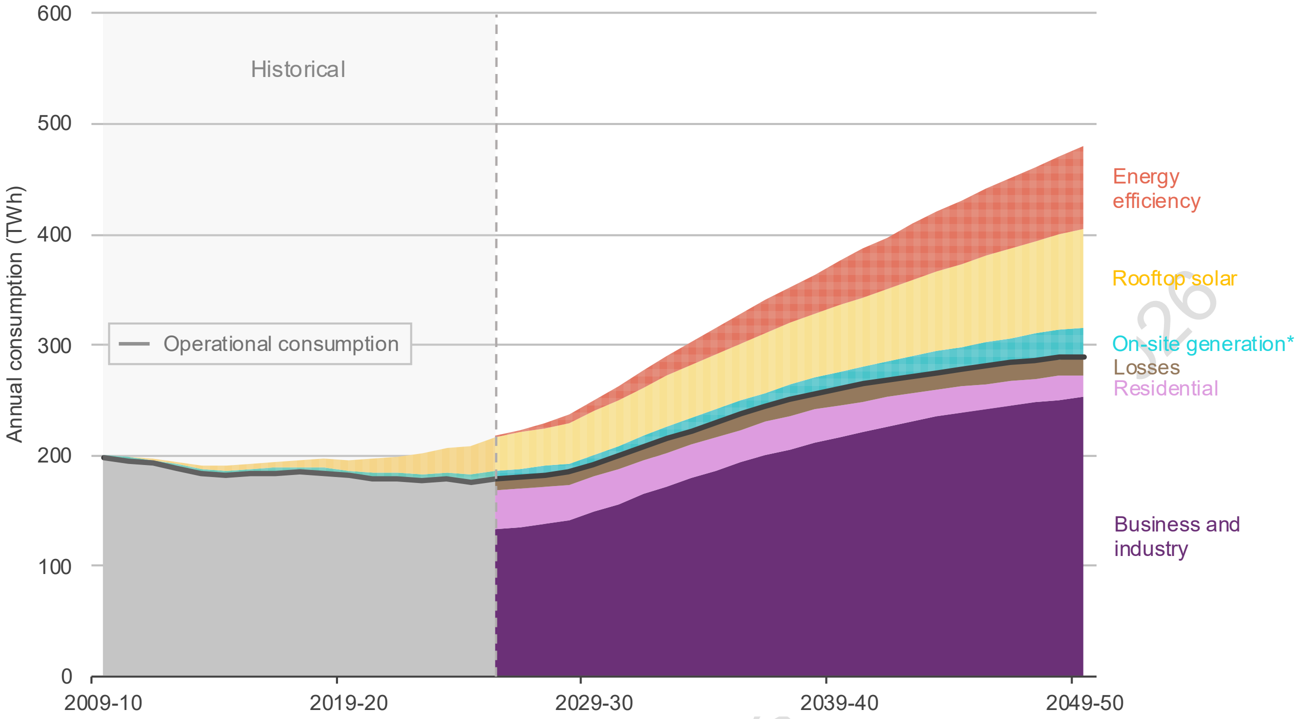
[30] AEMO 2025 IASR, p 65.

Figure 6 Electricity consumption, NEM (TWh, 2009-10 to 2049-50, *Step Change*)



Note: On-site generation (including "non-scheduled generation") is non-utility generation that includes on-the-ground PV and small wind and biomass, typically for industrial use.

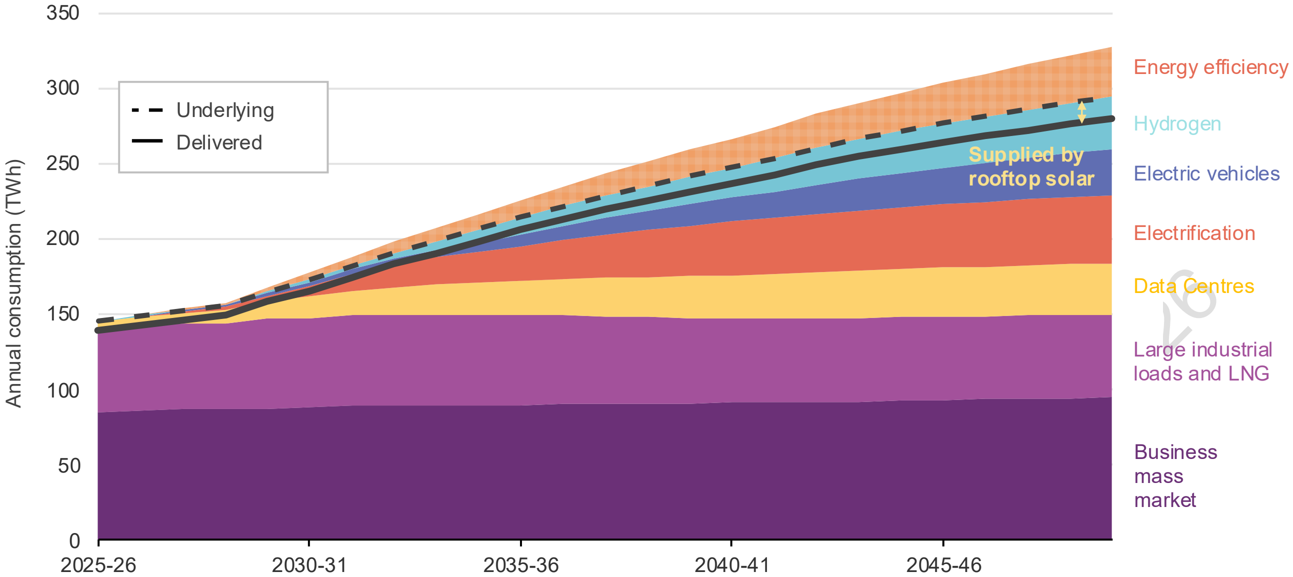
Business and industry use of grid electricity to double by 2050

Grid supply of electricity for business and industry is forecast to rise by 100%, from 140 TWh in 2026 to 280 TWh in 2050: see **Figure 7**. While economic growth is a factor, the main drivers are electrification and new industries. The expected switch to electricity is by corporate fleets and commercial vehicles (31 TWh) and by non-road freight and industrial processes (45 TWh). The major new sources of demand include data centres to support AI and cloud-based services (34 TWh) and hydrogen production (35 TWh). As the rate of future growth is uncertain for both industries, the ISP assesses different rates in its core scenarios and in particular a *Higher Demand* sensitivity: see Section 11.4.

Data centres have emerged as potentially significant consumers of electricity, with their development exceeding what had been forecast in previous ISPs. However, there are many uncertainties in their forecast consumption through the 2030s and 2040s, as industry expectations on both connection rates and technical frameworks are revised. In *Step Change,* the ISP assumes that data centres would reach almost 10% of the NEM's underlying demand by 2050 – five times the share it has today and the equivalent of 20% of today's total demand.

Businesses are forecast to provide more of their own electricity by investing in large on-site generation (27 TWh more by 2050), and to reduce their grid consumption by investing in 15 TWh more rooftop solar by 2050. These investments would give businesses more flexibility to take advantage of lower electricity costs when the grid supply is in surplus, and reduce grid reliance when supply is more scarce.

Figure 7 Business and industry electricity consumption, NEM (2025-26 to 2049-50, *Step Change*)



Note: On-site generation (or "non-scheduled generation") is non-utility generation that includes on-the-ground PV and small wind and biomass, typically for industrial use.

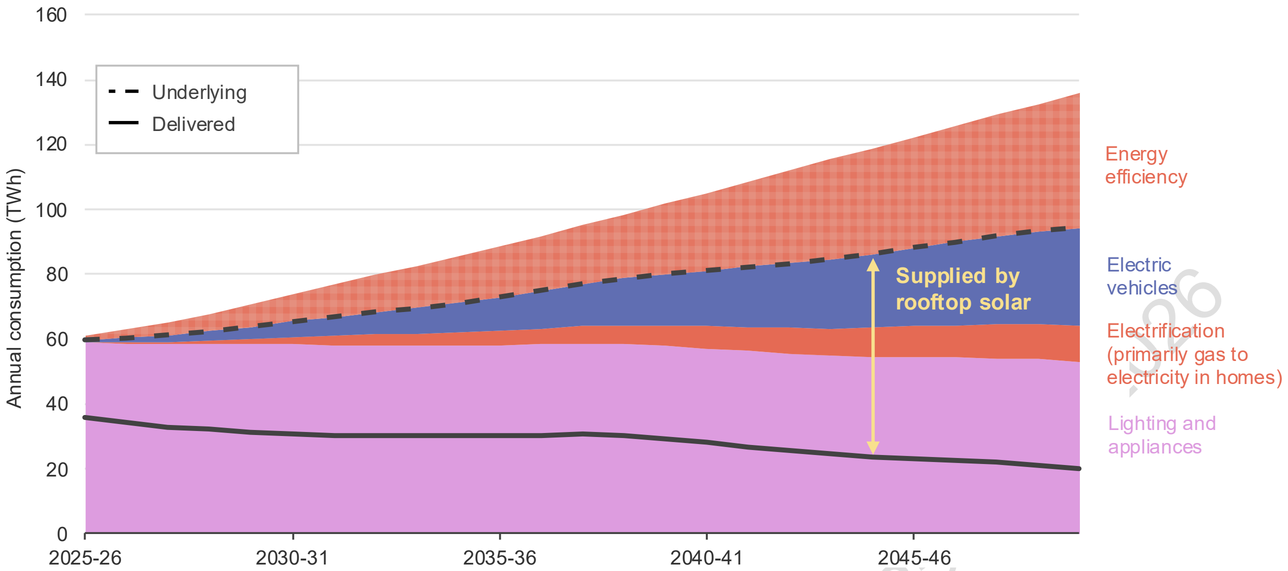
Household consumption of grid electricity to fall 44% by 2050

Households across the NEM are forecast to consume 20 TWh from the grid in 2050 – 44% less than they do now, despite EV charging and a growing population.

However, three factors lie underneath this headline. First, households' total electricity use is not falling; it is just that more of it is being supplied by their own and by other CER. Second, 20 TWh is a net figure over a year, a small amount that takes into account large flows of electricity between the grid and household CER: see Section 2.1. It represents all that consumers take from the grid *less* all that they have fed into it across the year. The future grid must cater for these larger flows to and from home-scale systems. Third, consumers vary greatly in their energy use: some using more than others, with some generating more than they use and others relying primarily on grid-supplied energy.

Figure 8 shows that home lighting and appliances currently account for most residential consumption. That consumption is forecast to rise to 136 TWh by 2050 as more households charge EVs and increase electricity use for heating, cooling and cooking, including the shift from gas appliances. However, their investment in energy efficiency is forecast to reduce that consumption to 94 TWh (see Section 2.2) and their investment in CER would reduce it further to 20 TWh (see Section 2.1).

Figure 8 Residential electricity consumption, NEM (TWh, 2025-26 to 2049-50, *Step Change*)



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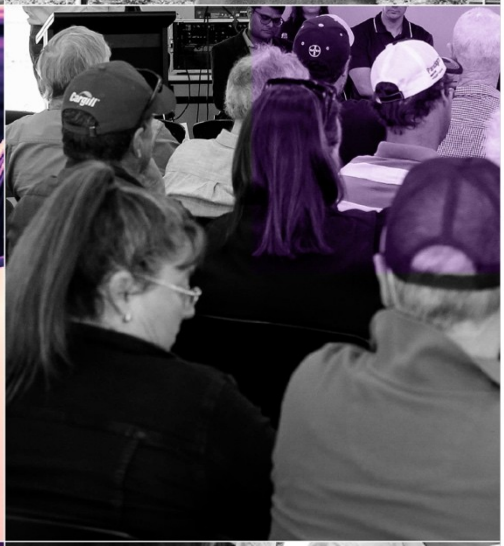


PART B

Preparing a least-cost path for the NEM

Part B
Preparing a least-cost path for the NEM

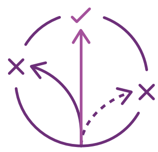
As set out in Part A, the energy transition is now well underway. To help guide this transition, AEMO has worked with industry since 2018 to prepare and publish an ISP every two years. Each ISP seeks the optimal mix of grid-scale generation, storage and network investment for at least the next 20 years.

In 2016, severe thunderstorms and tornadoes in South Australia led to a widespread blackout. The event prompted federal and state energy ministers to commission then Chief Scientist Dr Alan Finkel AO to conduct an 'Independent Review into the Future Security of the National Electricity Market', also known as the Finkel Review. The review aimed to ensure such blackouts do not recur, in a more reliable, secure, and sustainable NEM. The ISP was one of the Review's adopted recommendations, and is mandated by the NER.

This Part B sets out why and how AEMO prepares the ISP and its optimal development path:

- **Section 3 – The ISP is a roadmap for the NEM's transition.** It triggers action on specific transmission projects, flows through to broader network planning, and informs industry and government in their policies and investment. AEMO consults with consumers and their advocates, industry, governments and other stakeholders, through a two-year process that involves 62 preliminary reports.

- **Section 4 – The ODP is the least-cost path to meet consumer and policy needs.** The centrepiece of the ISP is an 'optimal development path' (ODP). After considering consumer and industry actions, government policies and future assumptions and scenarios, AEMO develops around 1,000 potential development paths and a shortlist of 34 candidates before identifying the ODP.



Part C follows to set out the ODP itself.

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3 The ISP is a roadmap for the NEM's transition

The ISP is AEMO's roadmap for the NEM's transition over at least the next 20 years. Under the NER, AEMO prepares and publishes the ISP every two years for essential electricity infrastructure.

The ISP has evolved considerably as it responds to continuous feedback from its stakeholders, more formal reviews of the energy sector and AEMO's own initiatives.

This section sets out how:

3.1 **The ISP is one part of the NEM's governance and planning.** It informs investment by private companies and governments, interacts with jurisdictional plans, and in particular triggers action on specific transmission projects.

3.2 **The ISP delivers an 'optimal development path' (ODP).** The ODP is a mix of grid-scale investments that takes into account consumer demand and CER, the important role of the distribution network and gas infrastructure.

3.3 **The ODP is developed over two years of extensive consultation** with consumer representatives, NEM jurisdictional planning bodies, transmission and distribution networks, policy makers, industry bodies and market bodies.

The 2026 ISP builds on previous ISPs to offer a comprehensive plan for the NEM's future.

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3.1 The ISP is one part of the NEM's governance and planning

The Australian and NEM state governments have agreed through the Energy and Climate Change Ministerial Council (ECMC) on a governance and planning framework for the NEM, with the ISP having both a specific transmission planning role and a broader NEM guidance role.

The NEM is governed by the National Electricity Law and Rules

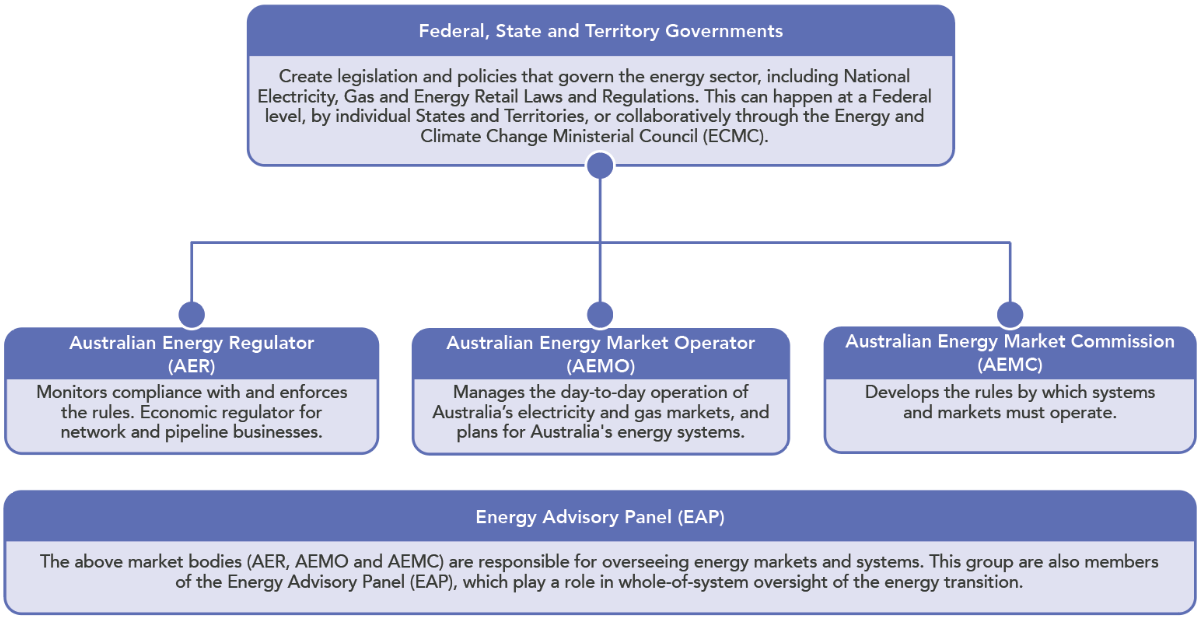
The NEM is planned and operated under the National Electricity Law and the NER. The three energy market bodies work closely together, each as an independent decision-maker with clear statutory functions, accountabilities and powers: see **Figure 9**.

- The **Australian Energy Market Commission (AEMC)** sets the electricity and gas rules and publishes the statement of governments' emissions targets, working with industry and governments on the trade-offs between cost, reliability and security.
- **AEMO** then works with industry to plan and operate energy systems and markets within those rules, to keep gas flowing and the lights on.

- The **Australian Energy Regulator (AER)** ensures that AEMO and industry participants comply with the rules, including for the ISP and its transparency, and regulates the revenue that electricity networks and natural gas pipelines can earn from consumers.
- An **Energy Advisory Panel** made up of the energy market bodies assists governments on reform initiatives that may be needed to keep our reliable and secure energy market on track.

This governance framework is in addition to and interacts with frameworks that operate at a jurisdictional level to plan, approve or deliver energy projects: see below in this section.

Figure 9 Australia's energy sector governance



This chart represents the arrangements for the National Electricity Market and East Coast Gas Markets. Arrangements are different for the Wholesale Electricity Market in Western Australia and relevant markets in the Northern Territory.

The ISP is a plan that guides grid-scale investment

Under the NER, AEMO is responsible for overall NEM transmission planning, which then cascades into planning actions taken by the NEM's transmission and distribution networks: see **Figure 10.** Each level informs and is informed by the next in a holistic approach to network planning:

- AEMO undertakes and delivers its NEM-wide planning responsibilities through the ISP and its Demand Side Factors statement, and with related documents such as the *Transition Plan for System Security* and *Electricity Statement of Opportunities*.
- Transmission planning across the NEM is undertaken by TNSPs together with relevant jurisdictional bodies, whose roles vary by jurisdiction and by project type, including REZ development and major interconnection planning. The relevant transmission planning bodies are Powerlink in Queensland, Transgrid in New South Wales and the Australian Capital Territory, VicGrid in Victoria, ElectraNet in South Australia, and TasNetworks in Tasmania. These bodies plan intra-regional and inter-regional transmission, including lines needed to connect new generation and major load centres. In New South Wales, Transgrid is the TNSP and transmission planner, while EnergyCo has a distinct role as the

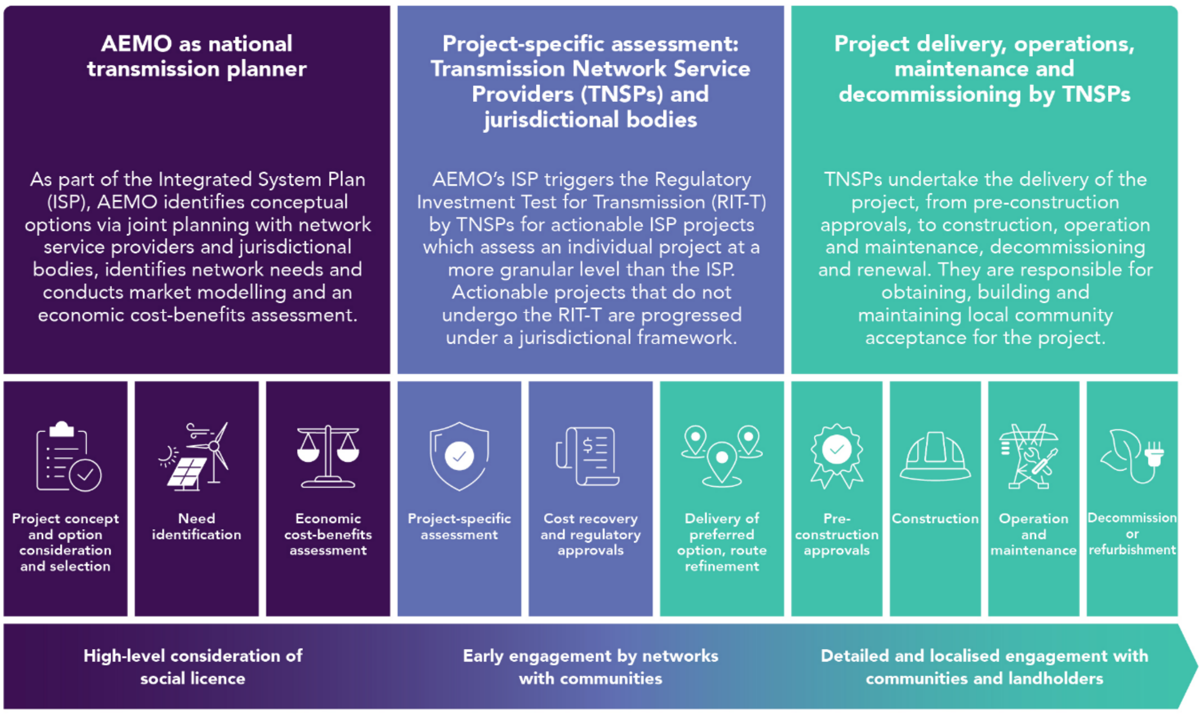
infrastructure planner for REZs and priority transmission projects under the New South Wales framework. For Project Marinus, Marinus Link is the planning body for Victoria–Tasmania interconnection.

- Finally, DNSPs plan and develop their networks across the NEM – Energex, Ergon Energy, Ausgrid, Endeavour Energy, Essential Energy, Evoenergy, CitiPower & Powercor, United Energy, AusNet Services, Jemena, SA Power Networks and TasNetworks.

The ISP can require transmission projects to commence their planning activities under the ISP regulatory framework. However, the ISP does not bind governments or private network operators in their investment decisions, and the regulatory investment test for transmission (RIT-T) continues to assess each project's benefits. If a government commits to a policy for a particular project or amount of infrastructure, then the ISP takes that into account: see Section 4.2 below.

How this planning flows through to particular grid-scale, distribution and CER investments is continued in Section 3.2 below. For grid-scale investment in generation, storage or distribution network (ISP development opportunities), the ISP offers guidance only. Decisions to propose and build any of that infrastructure rest with developers and distribution networks. The ISP does not directly plan or guide investment in CER, but does take into account the role that the forecast aggregated scale of those resources will play: see Section 9.

Figure 10 The national transmission network planning process



3.2 The ISP delivers an 'optimal development path'

Each ISP lays out an ODP for at least the next 20 years (which AEMO has extended through to 2050). Through AEMO's modelling, the ODP optimises investment in 'actionable ISP transmission projects', 'future ISP transmission projects', and 'ISP development opportunities' such as generation, storage, distribution network assets or demand side developments.

In April 2024 the ECMC published an ISP Review. In response, the 2026 ISP considers more explicitly the interactions between grid-scale electricity investment, CER, distribution networks, and gas market development: see 'Implementation of the ISP Review' at the end of this report. These factors are an important addition to the ISP's scope and modelling, increasing the information available to industry, government and consumers for potential future investments.

Optimisation of grid-scale investments

The ODP optimises 'grid-scale' or 'supply-side' investments, while considering actions by consumers and the gas industry. These investments include generation, firming and storage in the NEM, and the transmission and some larger distribution networks to which they connect: the left-hand side of **Figure 11** below. That is where system-wide planning is essential, so that large investments are made efficiently and effectively to benefit energy consumers.

Some larger investments in the distribution network are part of the ODP, and are considered 'ISP development opportunities' rather than actionable ISP projects. These projects have been jointly planned with the local DNSP to ensure they are cost-effective and timely solutions to connect utility-scale and mid-scale generation and storage, and that there is sufficient access to transmission network capacity.

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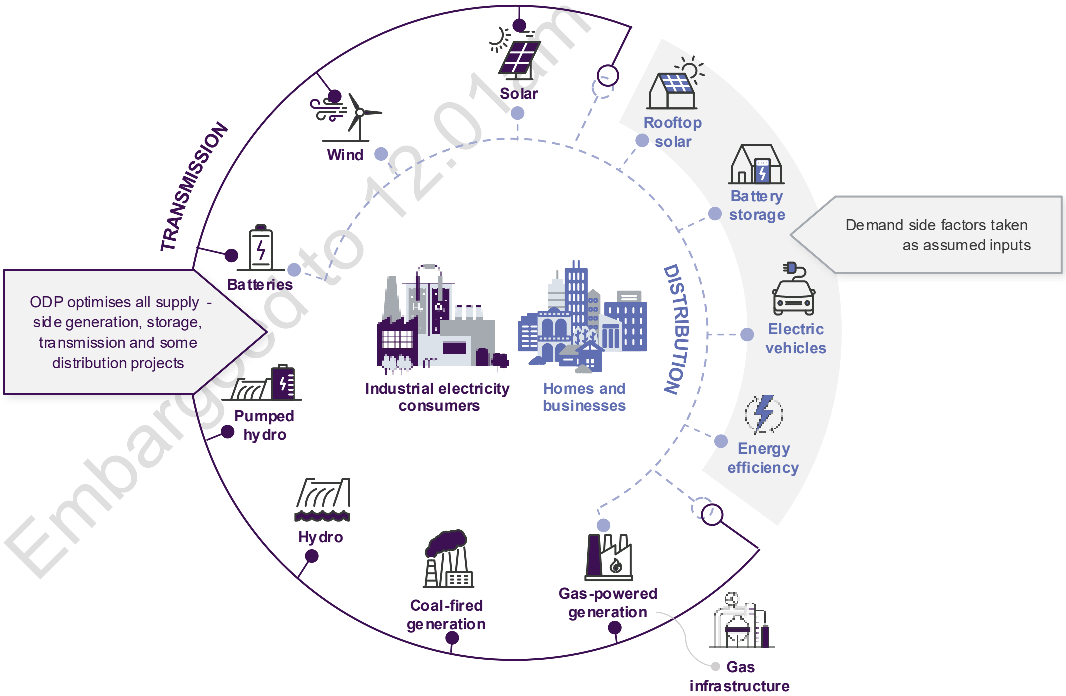
Figure 11 Grid-scale planning based on demand-side assumptions



Regulatory trigger for 'actionable' transmission projects

The ISP is a key trigger point for potential transmission projects in the NEM. A project may be 'actionable' if it has an identified need and is within a timing window to commence work. A large transmission project cannot continue down a regulatory approval pathway until it is actionable under the ISP or an equivalent jurisdictional scheme[31] .

For an actionable ISP project, the proponent undertakes a RIT-T. The RIT-T explores and consults on the most efficient way to meet the identified need by comparing the 'ISP candidate option' with other potential network or non-network options. AEMO then confirms that the preferred RIT-T option aligns with the most recent draft or final ISP (a 'feedback loop' assessment). The AER may then approve prudent and efficient investment to build the project, although early works[32] may be approved as soon as the project is actionable. This process may take several years to complete, but ensures the resulting project remains in consumers' long-term interests.

Projects progressing under a state framework follow that jurisdiction's approval process rather than the ISP framework noted above. Legislated jurisdictional frameworks currently exist: in New South Wales, where REZ projects and priority transmission are planned and delivered by EnergyCo and authorised by an independent consumer trustee; in Queensland, where projects are identified as priority transmission infrastructure projects; and in Victoria, where VicGrid coordinates delivery through the Victorian Transmission Investment Framework.

Consideration of demand side factors and the distribution network

Demand-side factors that may affect the power system include the development of assets, technologies and services available to end users, the rise of electrification, and demand management or energy efficiency schemes.

These demand-side elements, and projected growth in these elements, are input assumptions for the ODP modelling, and are not optimised with the grid-scale elements. The assumptions are the total impact of individual decisions and actions, from single households through to distribution network operators. AEMO engages continually with consumer and industry representatives to forecast these impacts into the future, with the final assumptions published in the 2025 IASR, and in some cases then updated from new data and stakeholder feedback.

In Appendix A9, the ISP sets out a statement on demand side factors that affect the power system, as well as opportunities for the distribution network to support CER and other distributed resources. AEMO has also conducted some sensitivity analyses to assess how changes in energy efficiency, CER and coordination levels may affect the ODP's benefits: see Section 9 and Appendix A9.

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[31] While the ISP identifies actionable projects which optimise benefits for consumers if progressed before the next ISP, AEMO may nominate certain projects as 'actionable jurisdictional projects' rather than 'actionable ISP projects' when the project will progress through a similar jurisdictional approval process rather than through the RIT-T assessment.

[32] 'Early works' are activities that are undertaken prior to the construction of the preferred option, which are undertaken to improve the accuracy of cost estimates for that project, and/or facilitate that project being delivered within the timeframes specified by the most recent ISP.

Inclusion of gas development projections

The ISP now analyses how different combinations of gas developments in the East Coast Gas Market would affect the power system's efficient development. The gas system may supply gas-powered generators and other consumers with natural gas, biomethane, and, in future, hydrogen. These gas development projections and analyses are in Appendix A10, and summarised in Section 7 below. The relevant assumptions are published in the 2025 *Gas Infrastructure Options Report* and the 2026 *Gas Statement of Opportunities*.

As with demand-side factors, the gas development projections have not been co-optimised with the electricity investments in the ODP. They do however inform investment by exploring the interactions and dependencies between the gas and electricity systems, as suggested by the AEMC rule determination[33]. Likewise, the projections do not provide an 'optimal development path' for gas, and the investments modelled are not actionable in the same way that electricity transmission projects identified as actionable projects in the ODP. Gas investment remains the responsibility of the gas industry.

3.3 The ISP has responded to two years' extensive consultation

AEMO publishes the ISP every two years, the result of a two-year industry-wide journey with consumer groups, governments, energy market authorities, investors and developers, network planners, industry bodies and research and technology institutions.

The overall engagement for the 2026 ISP began immediately after publication of the 2024 ISP, with significant feedback received for the 2025 IASR (including formal consultation on its two drafts) and subsequently the Draft 2026 ISP: see AEMO 2026 ISP Consultation Summary Report[34]. In all, AEMO has engaged with over 1,940 stakeholders, and considered 333 submissions.

This testing of the ISP's inputs and approaches and feedback from energy experts and community members is essential to ensure that AEMO's energy planning is in the long-term interest of consumers: see Appendix A1 Stakeholder Engagement. In particular, AEMO recognises the 2026 ISP Consumer Panel for its detailed consumer-focused perspective in the ISP development process, and the additional advice from AEMO's Consumer and Community Reference Group.

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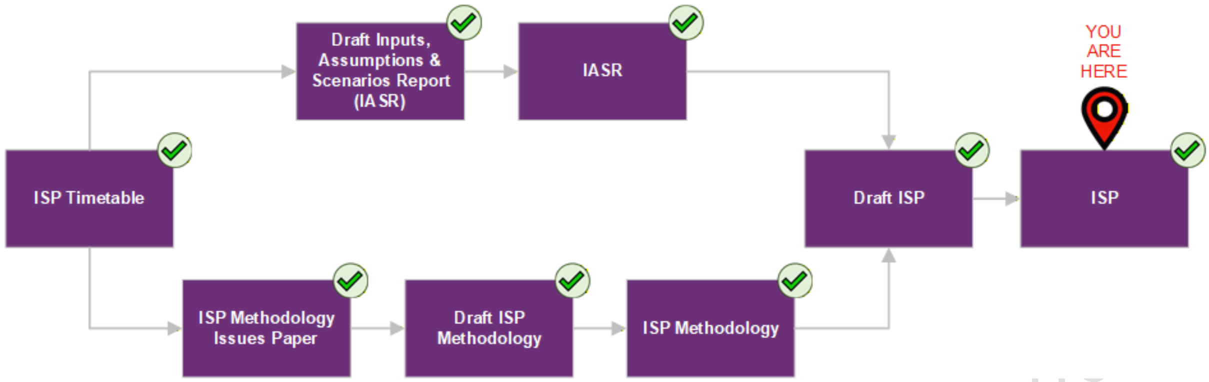
[33] AEMC, Better integration of gas and community sentiment into the ISP, https://www.aemc.gov.au/sites/default/files/2024-12/erc0395_final_determination_-_better_integration_of_gas_and_community_sentiment_into_the_isp.pdf.

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

Figure 12 ISP consultations



Consultation on inputs and assumptions up to the Draft 2026 ISP

Consultation prior to the Draft ISP (see Appendix A1) led to the following key changes to the ISP's inputs, assumptions and scenarios:

- A *Green Energy Industries* scenario (now renamed to *Accelerated Transition*) was selected over the previous *Green Energy Exports* scenario to better align with likely energy sector development.
- REZ boundaries and parameters were adjusted to reflect the latest local advice.
- Transmission project options were adjusted to reflect the latest advice, with costs from recent project delivery used to inform transmission cost increases.
- Distribution network inputs were incorporated for the first time following close engagement with networks. This engagement also informed the potential additions and upgrades to the transmission and distribution electricity networks in the 2025 *Electricity Network Options Report*.
- Cost benefit analysis and market modelling approaches were refined as set out in the 2025 *ISP Methodology*, including from responses to the Federal Government's 2024 review of the ISP.
- Better integration of gas and demand side factors led to changes to the NER, with potential gas pipeline, storage and supply developments in the 2025 *Gas Infrastructure Options Report*.
- Investments in different types of electricity infrastructure were assigned a different weighted average cost of capital (WACC), to appropriately reflect their risk levels and therefore the returns that investors expect.

These consultations fed into AEMO's work to determine the proposed ODP in the Draft ISP.

Development since the Draft 2026 ISP in response to stakeholder feedback

Significant work on the 2026 ISP continued after its Draft in December 2025. A great many changes to inputs, assumptions and messaging have now been incorporated in response to stakeholder feedback and submissions on the Draft. Other valuable suggestions were unable to be incorporated in the time available to deliver the final ISP, but will be appropriately considered in preparing the 2028 ISP.

The major changes brought into the 2026 ISP include:

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- **Terminology was updated,** in particular to improve clarity and avoid conflating community-owned assets with community-scale but network-owned assets.
- **For government policies**, the South Australian Government's target of net 100% renewable energy by 2027 has been applied in perpetuity rather than as a 'point in time' target in response to advice from the South Australian Government.
- **For demand**, an energy efficiency sensitivity was introduced to test uncertain future levels. The treatment of hydrogen electrolyser demand and storage flexibility was improved in modelling.
- **For transmission projects**, joint planning with TNSPs and jurisdictional planning bodies accelerated in early 2026, including the exchange of modelling and analysis and advice from ongoing RIT-Ts. As a result, a number of network and transmission option changes were incorporated into the final 2026 ISP modelling, as detailed in the ISP *Consultation Summary Report.* Options, costs and network representation in the model were updated wherever needed through joint planning with project proponents.
- **For the New England REZ Network Infrastructure Project**, following advice from the New South Wales Government[35], AEMO now considers the project as sufficiently progressed through the New South Wales framework to be classified as anticipated, and therefore the actionability of the project has not been retested in the 2026 ISP.
- **For renewable energy zones,** REZ constraints and transfer limits have been refined to better reflect access and network capability, and explicit and technology-specific access rights have been applied.
- **For renewables, gas and storage projects**, cost projections were updated to reflect the Draft 2025-26 GenCost values, with estimates for pumped hydro in particular decreasing from $6,500/kW to $4,400/kW for 2025-26. An additional 5 GW of wind and solar projects and 11 GW/44 GWh of battery projects progressed to existing, committed or anticipated status between July 2025 and January 2026, as well as 1 GW of wind and solar and 5 GW/16 GWh batteries which will be supported by government tenders and which have now been publicly identified. Gas price assumptions were updated to align with more recent price forecasts from the 2026 *Gas Statement of Opportunities*.
- **To better reflect developer interest**, AEMO has prioritised the existing project pipeline before allowing new projects to be modelled. The existing pipeline of projects (with a lodged application to connect) is counted towards 2030 targets before any generic 'new entrant' generation or storage is assumed to be built before 2030. This change has allowed the final ISP to better align with the reality of developer activity in the NEM, and better reflect time required for any new project that has not yet lodged a connection application to progress through development and delivery.
- **To stress-test resilience of the ODP**, the analysis of 'renewable droughts' was extended to include prolonged renewable lulls and strategic hydro reservoir management options.
- **For CER,** the storage (home batteries) uptake forecast was updated to reflect an increase in expected uptake under the Federal Government's Cheaper Home Batteries Program. Forecast consumer

[35] Letter from the Honourable Penny Sharpe MLC regarding the New England REZ Network Infrastructure Project, 12 May 2026, accessible at https://www.aemo.com.au/-/media/files/major-publications/isp/2026/supporting-materials/2026-isp-ministerial-letter-new-england-rez.pdf.

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investment in embedded storage by 2050 has increased from 27 GW to 35 GW. Fuel cell EVs were removed from AEMO forecasts and expanded public charging categories were introduced. V2G availability was reduced to reflect more realistic participation and usage patterns.

- **For gas development projections,** more recent data from the 2026 *Gas Statement of Opportunities* was taken into residential, commercial and industrial gas demand forecasts, gas production forecasts, and project information relating to the gas infrastructure options. AEMO also relaxed timing constraints for the projections to better reflect realistic gas development pathways, and improved modelling to better represent market dynamics and operations.
- **For coal,** AEMO adopted region-based coal flexibility assumptions for the final 2026 ISP. The Draft 2026 ISP assumed flexible coal-plant operation across the NEM as the transition progresses. Based on stakeholder feedback and informed by the 2025 *Thermal Audit* for the NEM, AEMO has since re-considered generator flexibility region-by-region. For the 2026 ISP, AEMO has assumed improved flexibility in New South Wales and Victorian coal plants as they continue to trial and implement changes, and assumed that Queensland units would more likely focus on maintaining reliability under current operations.

These changes were taken into the ISP analyses to determine the ODP, in the process set out in Section 4.

The 2026 ISP does not incorporate future gas market policies identified through the Federal Government's current Gas Market Review, including the domestic gas reservation scheme, as their detailed design and legislative framework were under consultation and had not yet reached the threshold certainty for ISP modelling.

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4 The process to identify the optimal development path

The ISP seeks the ‘optimal development path’ (ODP) for generation, storage and network investments across the NEM to meet power system needs and consumers’ long-term interests at least cost through to 2050, as coal plants retire and while meeting government policies.

Section 4 offers an understanding of how AEMO identifies the ODP: a methodology that rigorously models and analyses a range of market decisions, government policies and consumer initiatives. **Figure 13** sets out an overview of the process. The 2026 ODP is then set out in Part C.

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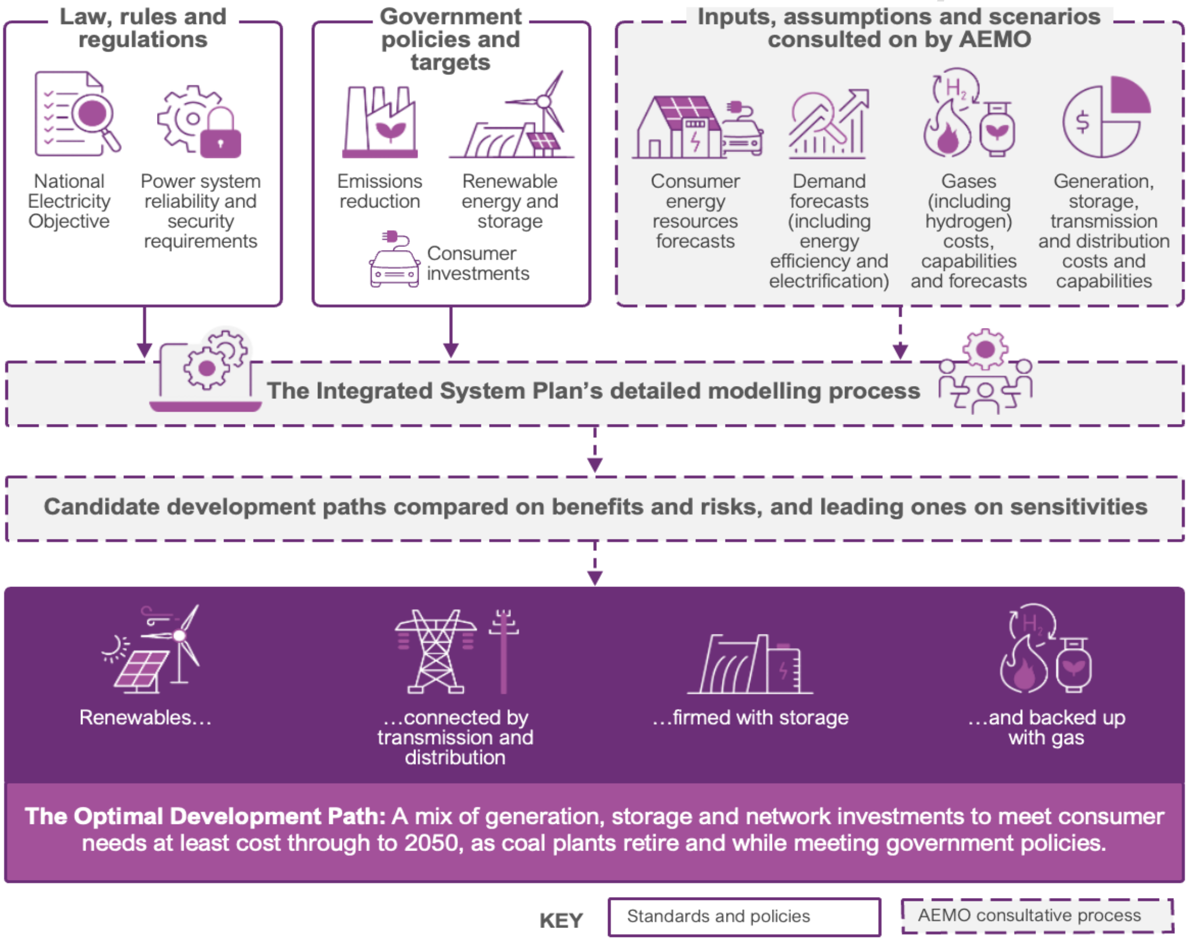
Figure 13 High level view of the *ISP Methodology*



This section sets out the elements of **Figure 13**:

4.1 **The ODP is identified in accordance with the National Electricity Law and NER**.

4.2 It considers government policies and targets, in particular on emissions reduction and renewable energy and storage development.

4.3 **It consults on and models a comprehensive set of market and technical inputs**, including forecasts of consumer energy resources and future electricity demand, the future technical capabilities and costs of all power system elements, and three scenarios for Australia's economic and energy future which each meet government policies.

4.4 **It identifies candidate development paths with a mix of generation, storage and network investments, and analyses them through an integrated set of models.**

4.5 **It identifies an ODP after comparing the benefits and risks of the candidates**, and testing the leading ones against various sensitivities.

As discussed in Section 3.3 above, AEMO identified a proposed ODP in the Draft 2026 ISP, and then considered stakeholder feedback before preparing the ODP in the 2026 ISP.

Each of these elements is also detailed in Appendix A6 and in the 2025 *ISP Methodology*.

4.1 Meeting consumer needs efficiently

AEMO prepares the ISP in accordance with NER requirements and AER guidelines. Its statutory purposes are to meet the power system needs, and to help achieve the National Electricity Objective (NEO). The NEO is:

> "*to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> a. *price, quality, safety, reliability and security of supply of electricity; and*
>
> b. *the reliability, safety and security of the national electricity system; and*
>
> c. *the achievement of targets set by a participating jurisdiction—*
>
>   i. *for reducing Australia's greenhouse gas emissions; or*
>
>   ii. *that are likely to contribute to reducing Australia's greenhouse gas emissions*."

To balance those diverse factors, the ISP seeks the least-cost path that meets power system, consumer and government policy needs.

This Section 4.1 first considers 'efficient investment in and operation of electricity services' with respect to the price of supply, and explains what AEMO means by 'least cost' in this ISP. It then presents how AEMO considers the power system's reliability and security needs, and government emissions targets.

Cost-benefit analysis to identify the 'least-cost' path

AEMO seeks an optimal development path (ODP) from a short-list of candidates that would meet consumer and government policy needs. Ideally, the ODP will have the lowest long-term system costs – or 'least cost'. The lower the total cost of this investment, all else being equal in an efficient market, the lower energy prices will be over time, relative to other paths. AEMO may select an ODP with slightly higher costs if it can demonstrate that it has greater resilience to risk and to changes in market conditions, however the ODP in the 2026 ISP is the least-cost candidate.

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A candidate ISP development path is a mix of potential generation, firming and network infrastructure that meets the government policies to 2050 reliably and securely. These candidates are compared to a ‘counterfactual’ development path, taking into account all capital, fuel and operating costs associated with the existing and new generation and storage and distribution network developments on the respective paths. The counterfactual represents future infrastructure development needs without any new transmission build beyond what is already committed or anticipated.

A candidate development path delivers a market benefit for consumers if it is lower cost than the counterfactual, that is, the transmission avoids or defers investment in other infrastructure, or reduces its fuel and operating costs. Theoretically, the counterfactual without transmission may be the lowest cost candidate, though to date candidates with transmission have had significantly lower costs.

The relevant costs of new transmission projects on a candidate ISP development path include the costs of planning and approvals (taking into account the estimated time and cost to secure appropriate social licence), financing, construction, operation and maintenance costs, and any costs of legal or administrative compliance. The benefits are cost reductions elsewhere as a result of those transmission projects being in place. These cost reductions are set out in **Table 3**, and more fully in the 2025 *ISP Methodology* and Appendix A6. This process follows the AER’s *Cost Benefit Analysis Guidelines*, last published on 21 November 2024.

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Table 3 Classes of market benefits considered in the ISP cost-benefit analysis

Category	Market benefit class	Description
Capital expenditure	Generator, storage and electrolyser capital deferral	Differences in the timing and scale of new generation, storage and electrolyser capital expenditure.
	Retirement costs	The cost of retiring and decommissioning generation and storage assets, which is separated from the cost of building new generation and storage.
	REZ investment	Differences in the timing and scale of REZ network infrastructure that is not considered as a potential actionable or future project.
	System security costs	Differences in the timing and scale of network investment may affect the retirement timing of synchronous generation and associated system security remediation costs.
Operating and maintenance expenditure	Fuel cost savings	Changes in fuel consumption arising through different patterns of generation dispatch, including the effect that this dispatch has on electrical losses for energy transported across the power system.
	Fixed operating and maintenance cost savings	Differences in recurring generation and storage costs incurred regardless of variation in generator and storage output but does not include depreciation and finance costs.
	Variable operating and maintenance cost savings	Differences in non-fuel, generation and storage costs relating to variation of generator and storage output, including labour costs and operation and maintenance costs.
Distribution	Distribution expenditure (capital and operating costs)	Differences in the timing and scale of both capital expenditure for distribution network augmentations and operating and maintenance costs associated with those augmentations.
Load	Voluntary and involuntary load shedding reductions	Reductions in voluntary load curtailment via demand-side participation and involuntary load shedding, converted into a dollar value using the value of consumer reliability (VCR).
Emissions	Emissions reductions	Reductions in Australia’s greenhouse gas emissions, converted into a dollar value using the value of emissions reduction (VER).

Note: AEMO does not consider changes in network losses, ancillary service costs or competition benefits in the selection of the ODP, as explained in the *ISP Methodology*. Where material, these and other benefits may be considered by TNSPs as part of subsequent RIT-T assessments for actionable ISP projects.

Power system reliability and security

The ODP must meet the ‘power system needs’ of the NEM for at least a 20-year planning horizon. The NEM power system needs to be reliable and secure, operating within engineering limits and operating standards[36] at all times. The ISP’s challenge is to ensure that these needs are met while diverse and variable forms of generation are competing across the power system.

System reliability

A *reliable* power system has enough generation, storage, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence[37]. The current reliability standard in the NEM requires at least 99.998% of forecast customer demand to be met on average each year. To meet this requirement, the NEM needs enough dispatchable capacity or demand flexibility, to respond to demand peaks during periods of extreme heat or cold, or to cover potentially long periods of dark and still ‘renewable lulls’ across the NEM: see Section 6. The NEM reliability standard is a planning standard based on expectations of future system conditions.

In day-to-day operations, to be *reliable*, there must be enough generation to meet consumer needs at any point in time. The power system must be maintained in a *reliable* operating state to ensure no customer supply is lost following a credible contingency event, such as the trip of a generator or line. See Appendix A4 System Operability for more detail.

System security

To be *secure*, the system must continue to operate safely within defined technical limits despite highly variable demand and renewable supply, with the ability to withstand credible disturbances, return to secure operation, and restart following a widespread outage. The purpose of maintaining a *secure* operating state is to prevent cascading failures following a credible contingency event.

Even if a major power system element (such as a generator or interconnector) is unexpectedly disconnected, the system must be maintained in, or returned to, a secure operating state as soon as practical, within 30 minutes.

Security depends on a broad set of technical requirements, including system strength, frequency and inertia, voltage control, transient and oscillatory stability, operability, and system restoration: see **Table 4** below and further in Section 5.1, Appendix A7, the 2025 *Transition Plan for System Security* and the 2026 *General Power System Risk Review*.

[36] NER 5.22.3(a), with detailed requirements set out in the NER including the reliability standard (NER 3.9.3C(a)), system security principles (NER 4.2.6), network performance requirements and system standards (Schedules 5.1 and 5.1a), and applicable regulatory instruments (defined in NER Chapter 10).

[37] See https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability.

Table 4 Power system needs considered in the ISP

Need	Operational requirements considered when developing the ISP	
Reliability	**Resource adequacy and capability to meet the NEM Reliability Standard**	Continuous real-time balancing of supply and demand, within the power system planning standard requirements. In addition, energy resources provide sufficient supply to match demand from consumers at least 99.998% of the time under the NEM reliability standard.
		Network capability is sufficient to transport energy to consumers.
Security	**Frequency and inertia**	Frequency control, minimum and secure levels of system inertia, and transient and oscillatory stability are maintained within operating and planning standards.
	Voltage management and system strength	Voltage control and fault levels are maintained within operating and planning standards and below equipment ratings.
	System restoration	The right mix of flexible resources are available to restore supply following a major disruption.

Note: The power system needs considered in the ISP do not include system restoration. Power system security needs in respect of system restoration are considered outside of the ISP, primarily under NER requirements to prepare a System Restart Plan and procure System Restart Ancillary Services.

4.2 Considering policies, including to reduce emissions

The ISP must also seek to further the NEO objective of reducing Australia's greenhouse gas emissions. The targets and policies to reduce emissions that AEMO must include in its analysis are set out in **Table 5** below. The ISP must consider the emission reduction and energy targets stated in the AEMC's *Emissions Targets Statement*. The ECMC, and ministers of participating jurisdictions, direct the AEMC what to include in or remove from that statement, and AEMO has no discretion to exclude any of them. Doing so "would reduce the reliability of the ISP as a plan to support coordinated investment that delivers the greatest net benefits"[38]. AEMO does not assess the merits or feasibility of these targets and policies.

AEMO does have the discretion to then consider any other state or federal environmental or energy policy if AEMO can identify its impacts on the power system, and the government has committed to it. The commitment is shown by meeting at least one of five NER criteria. AEMO engages with governments so that it only considers policies that are clear and detailed enough for AEMO to assess their impacts in developing the ISP. So, for example, AEMO has included the South Australian Firm Energy Reliability Mechanism policy in the ISP analysis, but not the Federal Government's Gas Market Review and its potential domestic gas reservation scheme[39], which were not finalised at the time of modelling.

All considered targets and policies are incorporated into the ISP as detailed in the 2025 IASR. AEMO considers that taking a consistent approach to both the *Emissions Targets Statement* policies and other eligible policies best satisfies the intent of the AER's Guidelines on cost benefit analysis. AEMO therefore incorporates each policy into each of the three ISP scenarios, with each of the 34 candidate development paths supporting the policies being met. If a policy is discontinued or amended, or new policy is developed that materially changes the ISP analysis, AEMO will incorporate the policy change into its analysis. Depending on the timing and impacts of the policy change, AEMO may be required to consult on and issue an ISP update, or address it in the next ISP[40].

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[38] As clarified in the AEMC's Draft Determination on the National Electricity Amendment (Clarifying the treatment of jurisdictional policies and system costs in the ISP) Rule change proposal, 2026.

[39] The 2026 ISP does not incorporate future gas market policies identified through the Federal Government's Gas Market Review, including the domestic gas reservation scheme. At the time of modelling, the detailed design and legislative framework for these measures had not been finalised to meet one of the five criteria for a committed policy.

[40] AEMO, 2025 IASR, Section 3.1, https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

Table 5 Policies and targets included in ISP modelling

Policy area	AEMC's Emissions Targets Statement	Other policies and targets considered in the ISP
Supply-side policies – incorporated as constraints on or inputs to the ODP modelling		
Emission reduction	**Federal** target of 43% below 2005 levels by 2030, by 62-70% by 2035, and net zero by 2050. Corresponding state and territory targets.	**Federal** Safeguard Mechanism affecting major business and industrial loads.
Renewable energy	82% of **national** supply by 2030. **State** targets that may be either in absolute terms (for example, New South Wales' target of 12 GW new renewable energy generation capacity by 2030, and the Tasmanian Renewable Energy Target that sets targets for 2030 and 2040 respectively) or proportional (for example, the Victorian target of 65% and 95% of electricity generated in Victoria to come from renewable resources by 2030 and 2035 respectively, and the South Australian target of 100% net renewable electricity generation from 2027 onwards)[A].	
Offshore wind	**Victorian** progressive targets building to 9 GW by 2040	
Storage and firming targets	Victorian targets building progressively to 6.3 GW by 2035, New South Wales targets for 2 GW/16 GWh of deep storage by 2030 and 28 GWh by 2034. Federal Government's expanded Capacity Investment Scheme target of 14 GW of dispatchable capacity by 2027.	South Australia's Firm Energy Reliability Mechanism.
Transmission, REZ and regional energy hubs		**(Including access and landholder payment schemes)**, including New South Wales' Electricity Infrastructure Roadmap, Queensland's Energy Roadmap, and Victoria's coordinated development under the *National Electricity (Victoria) Act*, and the landholder compensation schemes under those policies. These policies may also support specific transmission projects, such as the New England REZ Network Infrastructure Project progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).
Demand-side policies – incorporated as inputs to the ODP modelling		
Consumer energy resources	Victorian Solar Homes Program, gas substitution programs in the Australian Capital Territory and Victoria.	**Federal** Small-scale Renewable Energy Scheme and Cheaper Home Batteries Program. The Australian Capital Territory Sustainable Households Scheme, the New South Wales Consumer Energy Strategy, Victorian Solar for Business Program.
EV policies	**State** targets that may be either in absolute terms (for example, the South Australian target of 170,000 EVs by 2030) or proportional (for example, the Australian Capital Territory target of 80-90% and the Queensland target of 50% of sales by 2030), or be targeted at government fleets.	**Federal** New Vehicle Efficiency Standard and EV fringe benefits tax exemption.
Demand reduction and energy efficiency	**State** peak demand reduction schemes.	National and state building and construction codes, and specific rating, disclosure, efficiency and upgrade regulations.
Natural gas and hydrogen	Victorian gas substitution roadmap, including a ban on new residential gas connections.	The Australian Capital Territory ban on all new gas connections, and the New South Wales Hydrogen Strategy.

A. *Electricity Infrastructure Investment Act (NSW) 2020* (NSW), *Energy Coordination and Planning Amendment (Tasmanian Renewable Energy Target) Act 2020*, *Renewable Energy (Jobs and Investment) Act (VIC) 2017* (Vic), and *Climate Change and Greenhouse Emissions Reduction Act 2007* (SA). The South Australian legislation sets a target of 100% net renewable electricity generation in the State by 31 December 2027. On advice from the South Australian Government in March 2026, AEMO has adjusted the representation of the South Australia Renewable Energy Target in the 2026 ISP to be 100% net renewable energy from 2027, and to continue in perpetuity, as per the intent of the legislation.

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4.3 Consulting on inputs, assumptions and scenarios

The ISP relies on a number of market and technology inputs and assumptions. These inputs are set out in a number of AEMO publications, including the 2025 IASR, the 2025 *Electricity Network Options Report*, the 2025 *Gas Infrastructure Options Report,* the 2025 *Electricity Statement of Opportunities*, the 2026 *Gas Statement of Opportunities*, and Appendix A2 of the 2025 *Transition Plan for System Security*. Key inputs and assumptions applied in the ISP are as follows.

- **Demand-side forecasts** are the future trends in electricity consumption, taking into account various drivers including consumer energy resource developments (see next item), energy efficiency savings, and the electrification of transport, heating, cooling and cooking: see Section 2.
- **Consumer energy resources** forecasts are for on-site generation, batteries, EV chargers and the technology to control them: see ISP Explainer for CER in Section 2 above.
- **Gas and other 'coupled sectors'** take into account the interaction of the power system with other 'coupled' sectors such as transport, gas and hydrogen. The ISP considers the costs, capabilities and forecasts of gas-powered generation, electrolysers to meet domestic hydrogen consumption forecasts, and any gas infrastructure development projections that might be needed to supply gas consumers, including the supply of gas for gas-powered generation: see Section 7.
- **Generation, storage and transmission costs and capabilities** are future trends for existing and any new technologies. AEMO's generator and storage capital cost trajectories are informed by the GenCost publication series – an annual publication partnership between CSIRO and AEMO, last published in December 2025[41]. To support this forecast, Aurecon provided estimates of the current capital cost of each generation technology. These generator and storage capital cost estimates (both current and trajectories) are more complete than the levelised cost of electricity (LCOE) used by industry as a high-level guide, and ensure that the capital cost forecasts applied in the ISP reflect the local deployment of global technologies, including trends over time. AEMO's transmission cost estimates and trajectories are prepared using the AEMO Transmission Cost Database which is updated every two years through surveys and benchmarking exercises with cost estimation experts in the NEM to obtain accurate and market-reflective cost estimate data.
- **Design and implementation of REZ** assumptions are prepared through extensive consultation with the responsible jurisdictional bodies. In New South Wales, Queensland and Victoria, these bodies play a central role in the planning, design and implementation of REZs, regional energy hubs and their transmission, under their respective state frameworks, as noted in Section 4.2 above.

Three potential scenarios for the future that all meet government policies

AEMO uses scenario planning to assess future investment needs in the energy system. Through industry consultation, AEMO considered and published three scenarios in the 2025 IASR. When candidate development paths are assessed (see Section 4.5 below), their performance in each of the three scenarios is weighted by the likelihood of the scenarios.

[41] See https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/GenCost.

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The scenarios represent a broad range of global and domestic influences on Australia's energy transition, yielding different pathways to achieve government policies.

- ***Step Change*** reflects a pace of energy transition that supports Australia's contribution to limit global temperature rise to less than 2°C, with CER contributing strongly to the transition.
- ***Slower Growth*** also reflects Australia's current policies and commitments to decarbonisation, but more challenging economic conditions and supply chain constraints lead to slower investment in grid-scale assets and CER in future decades, with some larger energy-intensive industrial users assumed to close.
- ***Accelerated Transition***[42] reflects decarbonisation to support Australia's contribution to limit global temperature rise to 1.5°C. Its rate of transformation is greater than that required by current policy commitments, made possible by global technology progress and a faster growing economy than other scenarios.

The scenarios reflect 18 parameters[43] (decarbonisation targets, demand drivers and technological trends) which are inherently uncertain, but can materially influence the development of the future power system: see **Figure 14**.

Within each scenario, these parameters need to be internally consistent, so that the described future world is plausible. However, across the scenarios, these parameters are varied to ensure a reasonable range of possible futures are tested. Each scenario acknowledges the retirement of coal-fired generation and aligns with all eligible state and national policy commitments.

To determine the relative likelihood of the three scenarios, AEMO drew on 25 expert stakeholders through an independent facilitator[44]. The stakeholders identified *Step Change* to have a 46% likelihood to eventuate, with a 27% likelihood for both *Slower Growth* and *Accelerated Transition*. The balanced outcome is helpful to ensure that consumer risks are being explored more evenly – an over-emphasis on *Accelerated Transition* may lead to over-investment in infrastructure, and an over-emphasis on *Slower Growth* may lead to under-investment.

These results reflect some adjustments to the scenarios through the ISP's consultation processes. In earlier ISPs, the relative likelihood of the scenarios was assessed as a whole. This time, each of the 18 parameters was assessed for likelihood, then considered given the relative importance of the parameters to each scenario's narrative, and then combined to give an overall scenario weighting.

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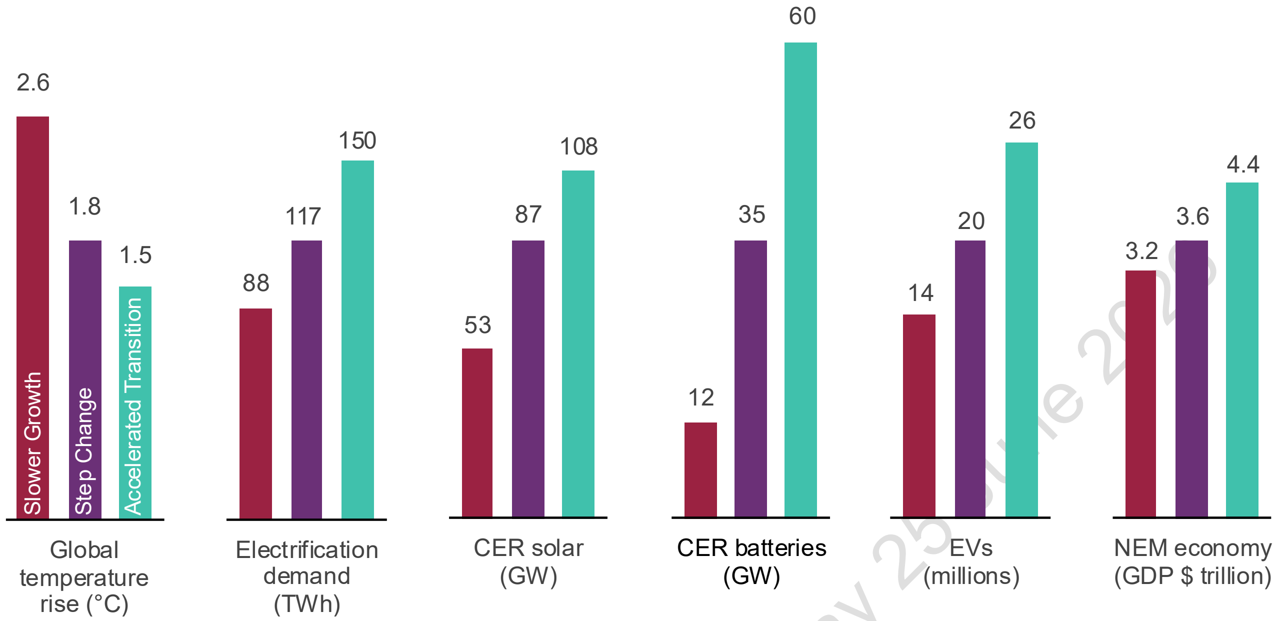
[42] This scenario replaces *Green Energy Exports* from the 2024 ISP, as consultation confirmed that the hydrogen development and energy export assumptions in that scenario were too optimistic.

[43] The IASR suggested 15 parameters, and another three were added in the later workshop to determine scenario likelihoods.

[44] For more information see https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-isp-scenario-weighting-overview.pdf?rev=4dae70ae407241f68e19e768a4ce2a14&sc_lang=en&hash=9608DA5C80FD980B7C003C61AC4A09B1.

Figure 14 Three scenarios of the future for ISP modelling at 2050, including six of the major parameters driving scenario differences



Note: Global temperature rise values are the mean temperature rise by 2100 based on assumed Representative Concentration Pathway (RCP).

4.4 Integrating five different models for analysis

Once the inputs, assumptions and scenarios have been confirmed through stakeholder consultation, AEMO applies them to an integrated suite of five complex models. These models explore generation, storage and network investments, and interact as shown in **Figure 15** below:

- The **demand, energy and CER forecasting models** integrate all the inputs and assumptions from the IASR consultations to form the set of consumer demands in need of being supplied in the subsequent gas, electricity and network models that follow. As noted above, this data is reviewed throughout the ISP period, considering stakeholder consultations and market developments from publication of the IASR through to the final ISP.
- The **gas supply development model** identifies gas development projections, and gas infrastructure limitations to be used in the capacity outlook and time-sequential models.
- The **capacity outlook model** uses these inputs to develop combinations of generation, storage and network developments to meet power system needs across each of the ISP scenarios, optimising these developments to minimise capital and operational costs while achieving the ISP's objectives.
- The **time-sequential model** then optimises electricity dispatch for every hourly or half-hourly interval. It validates the outcomes of the capacity outlook model, and feeds information back into it.
- The **power system assessment** tests these outcomes against the power system requirements: power system limits and constraints, and system security services such as system strength, and inertia. These assessments feed back into the two models to continually refine outcomes.

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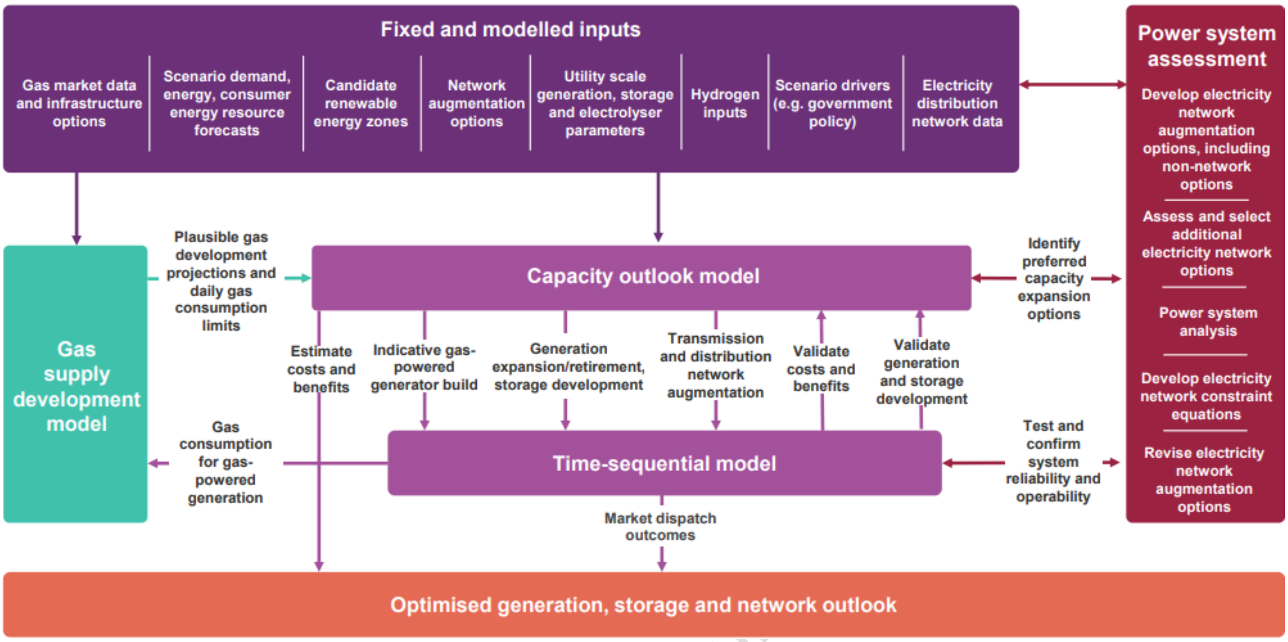
The interactions between these models are further explained in the *ISP Methodology.* Their outputs feed into the cost-benefit and sensitivity analyses (see Section 4.5) for each development path.

Figure 15 Detailed ISP modelling methodology



4.5 Selecting the ODP from 34 shortlisted candidates

AEMO follows the AER's *Cost Benefit Analysis Guidelines* to identify the least-cost development path for each of the three scenarios, and then develops and tests other 'candidate' development paths to identify the ODP. It then tests that ODP to ensure it is robust to changes in critical but highly uncertain assumptions through 'sensitivity analysis'.

Each development path is a combination of grid-scale transmission, generation and storage that would meet consumer and policy needs. AEMO seeks to identify an ODP that:

- offers the greatest net market benefits for consumers, while balancing them against the risks of over- and under-investment, premature and overdue investment, given all the uncertainties in the energy future,
- delivers positive net market benefits in the most likely of its scenarios (*Step Change*),
- ensures flexibility to respond to changing market conditions, by considering the option value of early works and other forms of project staging or timing where applicable, and
- is robust across changes in uncertain input assumptions.

This process is systematic, evidence-based and robust to uncertainty. Rather than testing a narrow pre-selected set of projects, AEMO begins with a very broad solution space, and tests hundreds of combinations of generation, storage and transmission investments for each scenario, and close to 1,000 potential development paths across the full process.

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Determine the least-cost development path for each of the three scenarios

For each scenario, the process begins with forecast consumer demands from the power system and the level of their own CER, as well as the existing, committed and anticipated NEM infrastructure developments. From this common position, the modelling explores a base set of transmission projects. This set includes all actionable ISP projects, relevant jurisdictional projects, and other options identified as potentially beneficial. All projects are assessed at their earliest feasible in-service dates.

This starting set of transmission projects is then combined with an optimal mix of generation and storage to form an initial potential development path. Variations of this path are then tested. Transmission projects may be delayed, removed or staged, and substitute or complementary projects introduced. For each potential path, the required generation, storage and distribution investments are re-optimised and the total system cost is assessed.

AEMO tests hundreds of these potential paths for each scenario. The transmission projects in the least-cost path become the basis for a second round of modelling. Again, variations are made to the timing, staging and selection of transmission projects. The required generation, storage and distribution investments are re-optimised and the total system cost is assessed to again identify the least-cost alternative.

This iterative process is a type of 'branch and bound' optimisation. This well-established technique explores new plausible combinations and quickly ignores those that cannot perform better than the current best solution. For the 2026 ISP, the process had seven iterations, testing over 1,000 potential development paths in this 2026 ISP, until just one least-cost development path remained for each scenario. Appendix A6 sets out this process in more detail, with examples of the treatment of specific projects.

Identify and rank a short-list of candidate development paths

Each scenario's least-cost development paths would maximise net market benefits for consumers in each of the respective futures in the absence of uncertainty. However, the ODP needs to be resilient against the uncertainty of not knowing which scenario will play out in future. The development path that performs best for a given scenario may not be the one that performs best across all three scenarios. Further detailed testing of a broader set of candidate development paths is needed, to allow appropriate consideration of resilience against uncertainty. The four steps that follow are:

1. **Determine a shortlist of candidate development paths**. Variations are made to the three least-cost development paths to form other candidate paths. Transmission projects may be added, pushed back to be delivered later, brought forward to be delivered earlier, or removed entirely. For the 2026 ISP, 34 such candidate development paths were short-listed, being a specific combination of potentially actionable transmission projects. For each candidate, the least cost mix of generation, storage and additional future transmission and distribution projects are identified, alongside forecast levels of CER, to ensure each development path includes only the efficient investments to meet the future needs of the power system and achieve government policies.
2. **Calculate the net market benefits of each candidate against a 'counterfactual'.** The net market benefits of each candidate are calculated, for each scenario. Their cost (all grid-scale generation, storage and network costs) is compared against that of a counterfactual development path. This 'counterfactual' is an alternate path with generation, storage and distribution projects, including the

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scenario's forecast levels of CER, but no new transmission projects beyond those already committed or anticipated.

3. **Rank the candidates by their net market benefits.** The candidates' net market benefits are weighted across the three scenarios to reflect the relative likelihood of the scenarios occurring: see Section 4.3. This calculation is a 'risk-neutral' assessment of a candidate's value to consumers in delivering secure and reliable electricity, at least cost.
4. **Consider risks arising to consumers from uncertainty**[45]. AEMO then conducts a 'risk-averse' assessment, to consider the lost benefits, or "regret", if projects are planned and delivered for one scenario, but another scenario plays out.

This process identifies the top-ranking candidates from both the risk-neutral and risk-averse assessments. Other assessments, including sensitivity analysis, may affect those rankings, as discussed below.

Test candidate development paths against sensitivities

Cost-benefit analysis inherently involves uncertainties, as inputs and assumptions used to estimate future costs and benefits cannot be known with certainty. Sensitivity analyses assess how uncertainties affect the results, and whether those effects materially change decisions, by testing a range of plausible values.

AEMO uses sensitivity analyses to test the robustness of the choice of ODP to changes in key assumptions. That analysis may indicate that an alternative CDP may be more robust. If so, AEMO may select that path as the ODP so long as its cost, benefit and risk trade-offs align with consumer risk preferences, and it provides positive benefits in the most likely *Step Change* scenario. This approach has not been required for the 2026 ISP, with the ODP remaining robust across the sensitivities tested.

Six different sensitivity analyses were conducted for the final 2026 ISP. The sensitivity analyses were on different levels of CER coordination for home and vehicular devices (Section 9.1), different levels of energy efficiency (Section 9.1), higher demand from industrial loads including data centres (Section 9.2), and constrained delivery of generation and transmission projects in the ODP (see Section 11).

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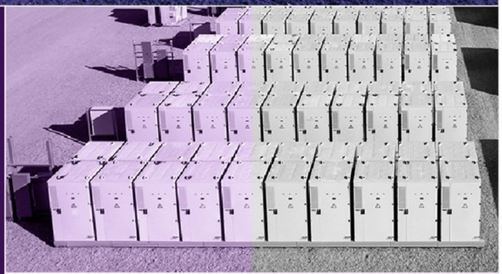
[45] NER 5.22.10(a)(5)(ii).








PART C

Generation, storage and network investments in the ODP

Part C
Generation, storage and network investments in the ODP

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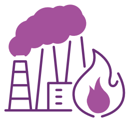
Part C sets out the ODP: the optimal mix, size, place and timing for grid-scale generation, firming and network investments to meet consumer needs at least cost through to 2050, as coal plants retire and while meeting government targets. Changing one element of the ODP is likely to render other elements, and the whole, less effective and more expensive. The risks and implications of delay are discussed in Part D.

- **Section 5 – Nearly 120 GW of grid-scale renewables by 2050, to replace coal and meet rising demand.** Three-quarters of the 38 GW of new generation required by 2030 is in the connections process, but more investment is needed.

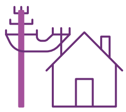
- **Section 6 – Nearly 50 GW of grid-scale storage and hydro by 2050, with battery costs falling.** Sufficient battery and pumped hydro projects are in the connections process to meet the 36 GW needed by 2030.

- **Section 7 – 17 GW of flexible gas-powered generation to back up renewables**, progressively replacing the current fleet, with investment in gas infrastructure to ensure gas is available.



- **Section 8 – A 14% extension of the transmission network**. The ODP would extend the current 44,000 km network by about **6,000** km, with projects to deliver about 3,500 km already well underway.

- **Section 9 – Consumer and distribution actions may reduce grid-scale investment.** Energy efficiency and coordinated CER, and voltage management by distribution companies, offer significant additional benefits to *all* consumers.



Solar would be the primary source of energy supply (from small- and grid-scale), supported by increasing amounts of batteries (again from small- to grid-scale), as the capital costs of both fall. Wind is relied on more at night and in winter, gas for rare peak demand periods, and deep storage for extended ‘renewable lulls’. Transmission overcomes the local variability of renewables, taps into hydro schemes and deeper hydro storage, and connects renewables energy zones to demand centres. Coal remains as a transitional resource, reducing near-term reliability risks. Finally, new and traditional spinning technologies add system stability, including existing coal units, synchronous condensers, hydro generators in spinning mode, or new gas turbines fitted with clutches to act as synchronous condensers, providing security services without needing to burn gas.

The ISP development opportunities set out in Sections 5–7 are detailed in Appendices A2 and A3, and the ISP transmission projects set out in Section 8 are detailed in Appendix A5. In this Part, the investments discussed are in the *Step Change* scenario, unless otherwise stated, with other scenarios in the appendices.

Given the risks of delay to infrastructure builds, Section 11 discusses how constrained delivery might affect that development. AEMO also acknowledges that coordination of both community consultation and the delivery of infrastructure will be critical to the pace of development and to the benefits of new infrastructure and REZs: see Section 12.

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5 Renewables to replace coal as bulk generation

Renewable energy connected by transmission and distribution, firmed with storage and backed up by gas, is 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 NEM must replace ageing coal plants as they retire with new, cost-efficient generation, while meeting government policies and a near doubling of consumer demand from the grid by 2050.

This Section 5 sets out how:

5.1 **'NEM capacity' delivers 'annual generation' for consumer use.** Generation is measured in two ways that flow through into investment needs.

5.2 **Two-thirds of the remaining coal fleet capacity is projected to retire by 2035.** Coal plants are needed to help meet both generation and system security requirements, until replacement services are installed. All are projected to retire by 2049. Based on recent history, coal plants are likely to experience deteriorating reliability as they age, and retirements may occur earlier than the projected closure dates.

5.3 **117 GW of renewables would be needed to replace coal, and meet rising demand.** Utility-scale (or grid-scale) solar and wind would increase from its current 23 GW capacity to reach 61 GW by 2030, then almost double by 2050. The NEM's existing 7 GW of hydro-electric generation capacity would remain in place.

5.4 **REZs would host most of the grid-scale generation assets.** Each state is developing some of the 44 potential areas being considered for concentrated renewable energy development. While they are the most efficient locations, they depend on industry and government building social licence so that host communities participate strongly in their planning and benefits.

The following Section 6 sets out the grid-scale storage capacity (batteries, new and existing hydro facilities and other potential storages) that would be needed under the ODP to firm up this variable grid-scale solar and wind.

As well, consumers are forecast to invest in 87 GW of rooftop and other small-scale solar by 2050 (and 35 GW of batteries). Section 9 below discusses how this CER might be increased and leveraged more efficiently through the investments being made in the distribution network.

5.1 'NEM capacity' delivers 'annual generation' for consumer use

Generation and storage are measured in two ways, shown in the figures below. **Figure 16** shows *NEM capacity* measured in megawatts (MW): the projected investment in each technology that is needed to

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deliver reliable electricity through to 2050 as part of the least-cost ODP. The total NEM capacity is the maximum power generation capability if all plant (generation and storage) were operating at full capacity at the same time. However, no technology operates at full power all of the time, as they are limited by weather conditions, outages, fuel availability, network congestion and other operational constraints.

Figure 17 then shows *Annual Generation* measured in megawatt hours (MWh): the volume of electricity produced across the year to meet consumers' needs.

A few observations can be made from the 2050 projections in these two charts:

- Rooftop and other small-scale solar would have a 28% share of total NEM capacity and, supported by consumer batteries and distribution networks, deliver a similar share of annual generation.
- Grid-scale solar would have a 21% share of NEM capacity and, supported by grid-scale batteries, deliver 29% of annual generation. This ISP projects a higher share of grid-scale solar and battery storage in the NEM capacity than previously, as their relative costs decline and battery connections increase.
- Grid-scale wind would have a smaller 17% share of NEM capacity, but has a high 40% share of annual generation. New wind turbines are more efficient and the wind in some locations is assumed to be stronger than previously modelled.
- All solar and wind together would have a 66% share of NEM capacity. Even though their output is variable, storage and transmission enable most of what they generate to be used, so that they deliver 96% of annual generation.
- Hydro's 2% of NEM capacity takes the renewable share to 68%, with solar, wind and hydro combined delivering 98% of annual generation.
- Flexible gas-fired generation plants would make up 6% of the NEM's capacity, and deliver a smaller share of annual generation[46].
- Batteries and pumped hydro storage would make up a 26% share of NEM capacity. They are not counted towards annual generation as they do not generate electricity, but rather charge from other generators and discharge later (with some energy lost during battery operation).

These projections are explored further in the relevant technology sections below.

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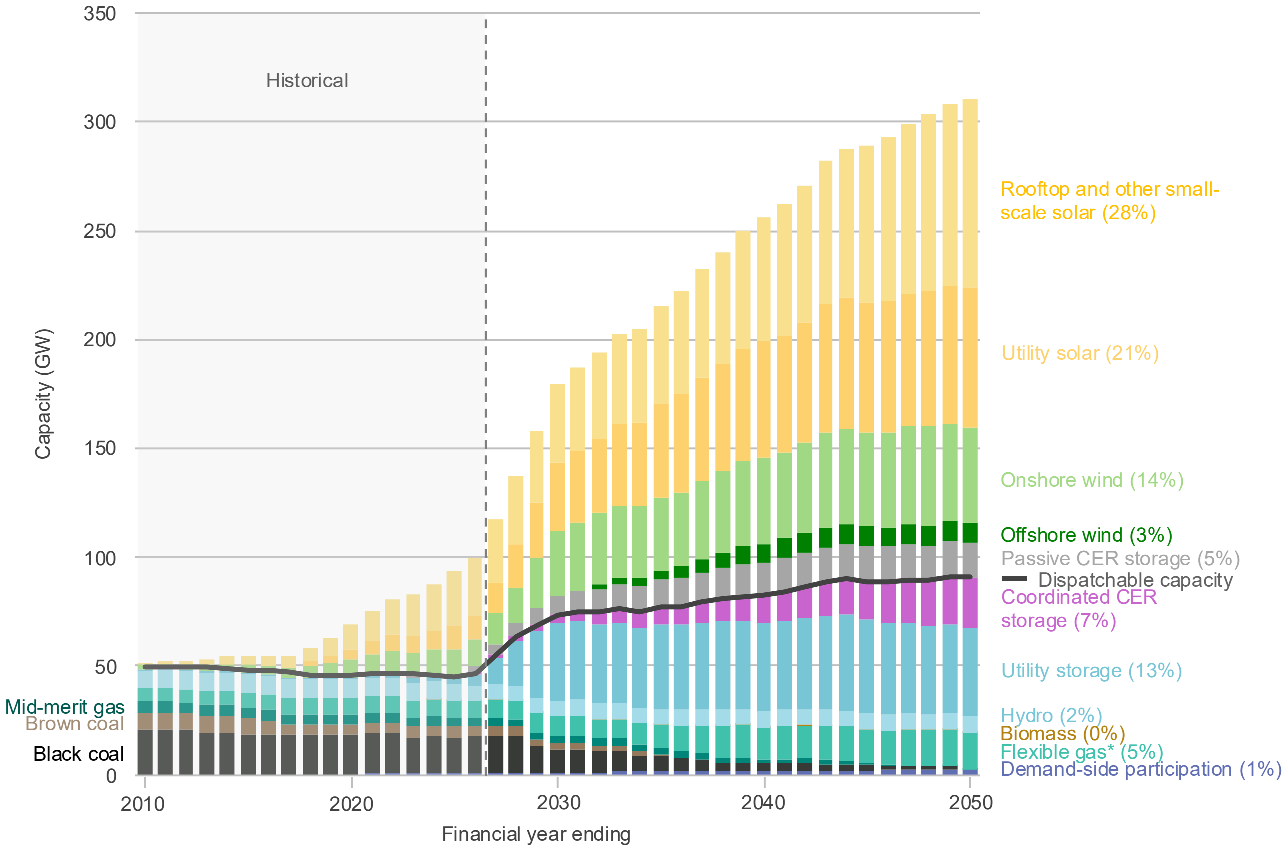
[46] Gas use projections are highly uncertain, as they vary from year to year depending on weather and operational conditions. Figure 17 shows a share of 2% due to the assumptions of that single year, however the gas share of generation through to 2050 is similar on average to today's share of 4%.

Figure 16 NEM capacity (GW, 2009-10 to 2049-50, *Step Change*)



Notes: Percentages are listed for 2050 financial year ending projections, and are rounded. Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 IASR and the 2026 *Forecasting Assumptions Update*. "Rooftop and other small solar" includes forecast residential and commercial rooftop PV systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems. "Utility solar" also includes other distributed PV systems, optimised through the ISP assessment process. "CER storage" means consumer energy resources such as batteries and EVs. "Flexible gas" includes gas-powered generation and potential lower-carbon fuel alternatives (including hydrogen).

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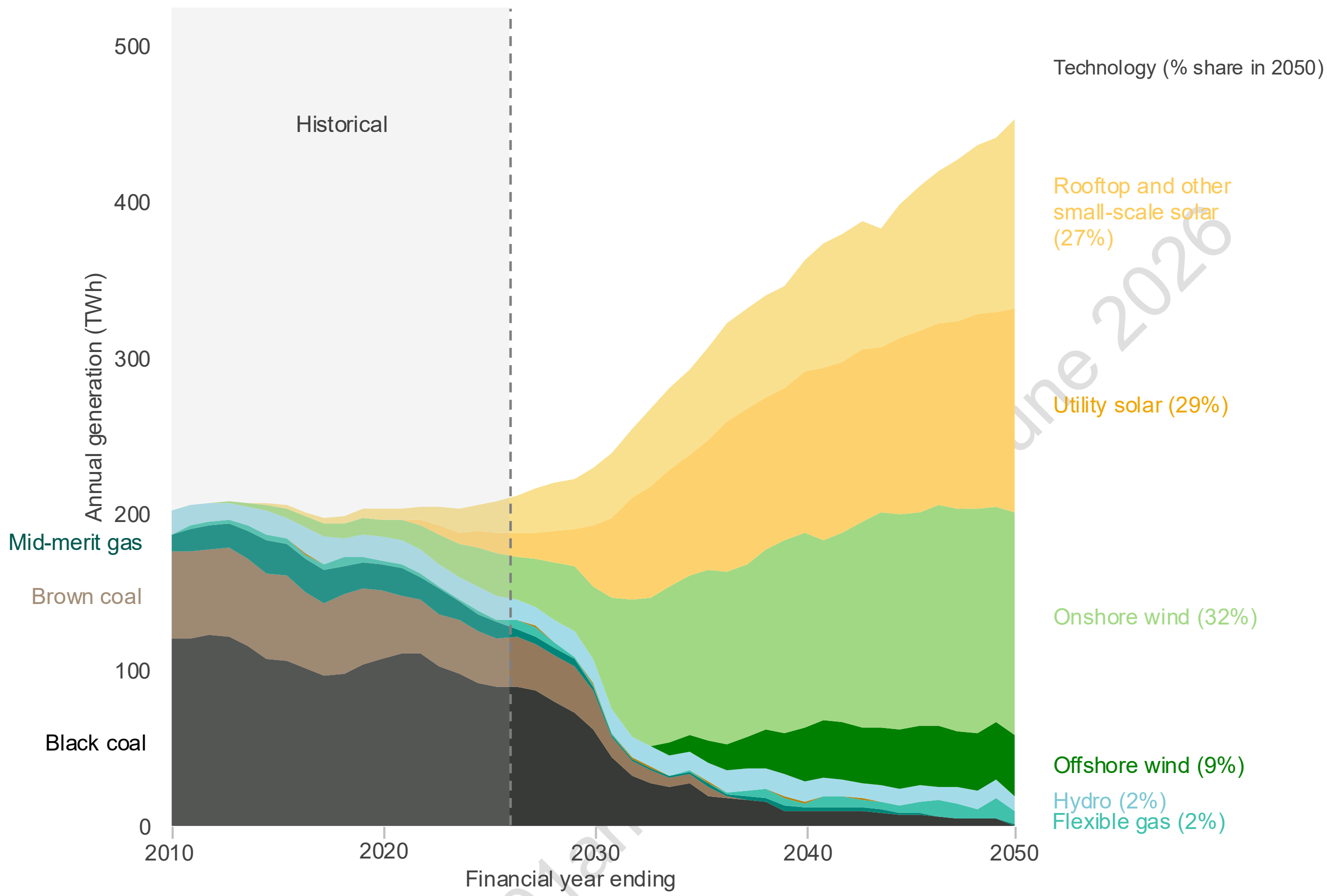
Figure 17 NEM annual generation (TWh, 2009-10 to 2049-50, *Step Change*)



Note: This chart is the projection of electricity generation by fuel type. Battery charge and discharge, and pumped hydro production, are excluded, as these technologies store electricity that has already been generated for use at other times.

5.2 Two-thirds of the remaining coal fleet could retire by 2035

Coal's share of NEM capacity began to decline in 2012, when 26 coal-fired plants were operating. Since then, 10 major coal-fired generators have retired. Owners of all but one power station in the remaining fleet have announced retirements between now and 2051, with over half announcing retirements by 2035.

Coal-fired generators are currently needed for both generation and system security, but the remaining fleet is withdrawing and replacement services are being installed. In the *Step Change* scenario, the ODP projects that nearly two thirds of the NEM's remaining coal fleet would retire by 2035 (faster than that announced), with all to retire by 2050: see **Figure 18**. From 2038, only Queensland coal plants would operate, with the Queensland Energy Roadmap intending to keep coal in the system for as long as needed or as technically viable[47].

Coal plants may retire even faster than these forecasts, including in Queensland. The financial viability of some is increasingly challenged by higher fuel and operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market. Some coal generators may

[47] Some Queensland coal plants are projected in this 2026 ISP to close earlier than the announced closure date, if and when no longer needed for reliability or security and where projected to operate at economically unsustainable levels. The Queensland Energy Roadmap acknowledges that, "going forward, decisions will be evaluated on system need, asset integrity and economic viability – a clear and credible decision matrix for the market".

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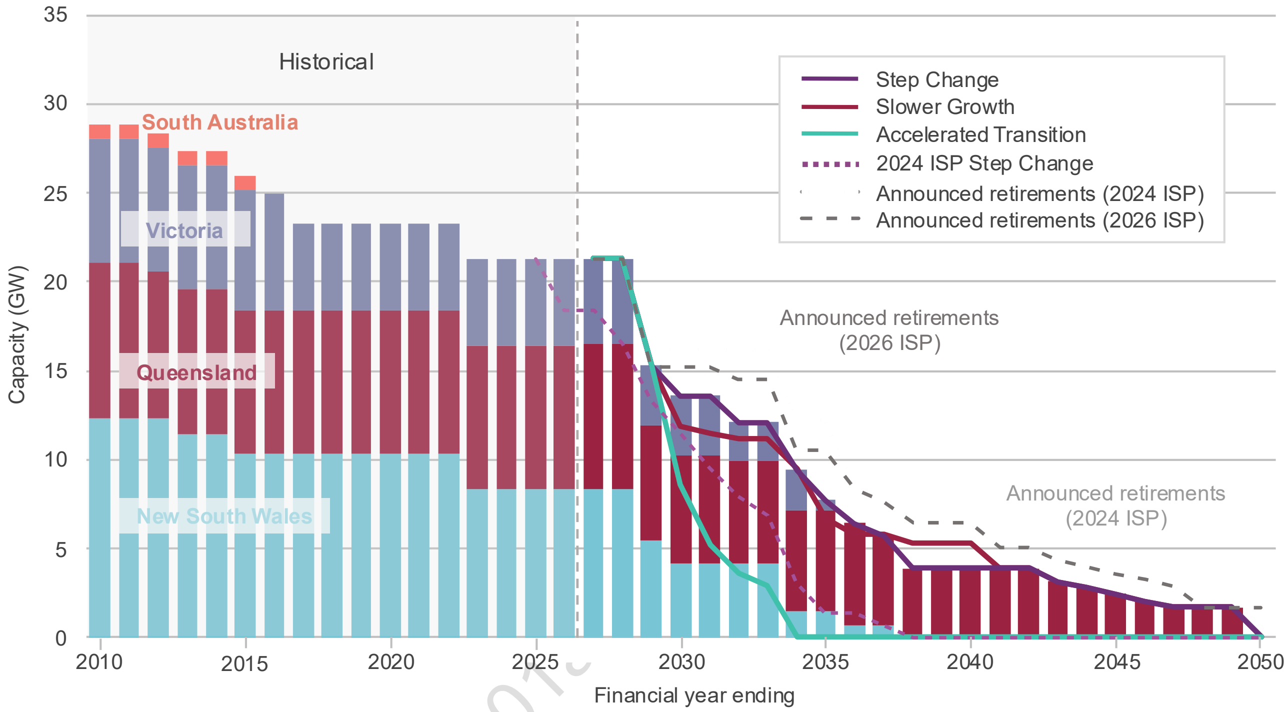
operate only during peak seasons – remaining active in summer and winter while shutting down during the shoulder periods.

Figure 18 Coal capacity, NEM (GW, 2009-10 to 2049-50)



Some coal operators are investigating plant modifications to support more flexible operations and so remain more competitive. For example, they may lower their minimum stable operating levels, enable two-shift operation[48], increase their ramping rates, reduce their hot restart times, or repurpose steam generating units to act as synchronous condensers.

However, repurposing older coal plants for flexible operation has its challenges. Flexible operation is expected to increase plant wear, maintenance costs and outage rates, as detailed in AEMO's 2025 *Transition Plan for System Security* and its 2025 *Thermal Audit* of the NEM. As failure rates rise, with new and perhaps unanticipated types of failures, plants with a short residual lifespan may become uneconomic to repair. AEMO has conducted sensitivity analyses to confirm the ODP in futures where coal plants are and are not able to operate more flexibly[49]. Addressing these challenges remains important priorities for industry and government.

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[48] Two-shifting would involve switching off during the daytime peaks of solar generation, and returning for the evening peak and through the night and morning.

[49] AEMO conducted two sensitivity analyses for the Draft 2026 ISP to test the proposed ODP's resilience: see Appendix A6 from the Draft 2026 ISP, at https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation. The *Slower Coal Retirement* sensitivity assumed more operational flexibility, with generators able to participate longer in the market at lower operating volumes. The *Faster Coal Retirement* sensitivity assumed less flexibility, with generators having to run at higher volumes, competing more often with cheaper renewable resources. Under both sensitivities, the proposed ODP would have remained the least-cost path to deliver secure and reliable power to consumers as coal plants retire. While these sensitivities were not reproduced for the final ISP, the limited variance between the two sensitivities strongly suggests that the ODP would remain robust to these sensitivities.

ISP Explainer: Decoupling reliance on coal generators for system security

The heavy spinning turbines of coal, gas and hydro generators have multiple intrinsic benefits beyond their actual generation. These 'system security services' help the power system stay stable and secure and have been a by-product of coal-fired generation for decades. For example:

- They spin at a rate that lines up with the electrical frequency of the power grid that they supply ('synchronous generation').
- This, coupled with the physical spinning momentum, adds 'inertia' to help resist unwanted changes to the system frequency.
- If a fault occurs somewhere in the system, the generators can add needed current to the system so that protection systems can operate to isolate the fault.

As coal generators retire the NEM will lose these services, so new assets will be needed ahead of their retirement. For example:

- Gas turbines fitted with clutches (at design or retrofit) can act as synchronous condensers, providing security services even when not generating power. If fitted with self-start capabilities, these units can also support system restart.
- Synchronous condensers fitted with a flywheel, or hydro generators in spinning mode[50], can provide both system strength and inertia.
- Grid-forming battery energy storage systems (BESS) are progressing rapidly to be able to deliver a wide range of system security services in the NEM such as frequency control, voltage stability and some aspects of system strength.

As well, there are opportunities for these assets to co-optimise both reliability and security to help keep costs of the transition as low as possible. For an explanation of how reliability and security needs are incorporated in the ISP assessment: see Section 10.1.

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5.3 Nearly 120 GW of grid-scale wind and solar by 2050

Renewables are needed to replace coal, and to meet rising demand and government targets. Under the ODP, the NEM would need approximately 117 GW of utility-scale (or grid-scale) solar and wind capacity by 2050 – about five times the current NEM capacity of 23 GW. Total capacity would rise to 61 GW by 2030 and 80 GW by 2035, ideally situated in REZs. Including hydro capacity (Section 6.2), grid-scale renewables would reach a 66% share of annual generation in 2030, rising to 71% in 2050.

More generation projects are needed to meet 2030 targets

The current pipeline of grid-scale renewables, if delivered as planned, would meet around three-quarters of the new capacity that the ODP projects would be required by 2030: see **Figure 19** and **Table 6** below.

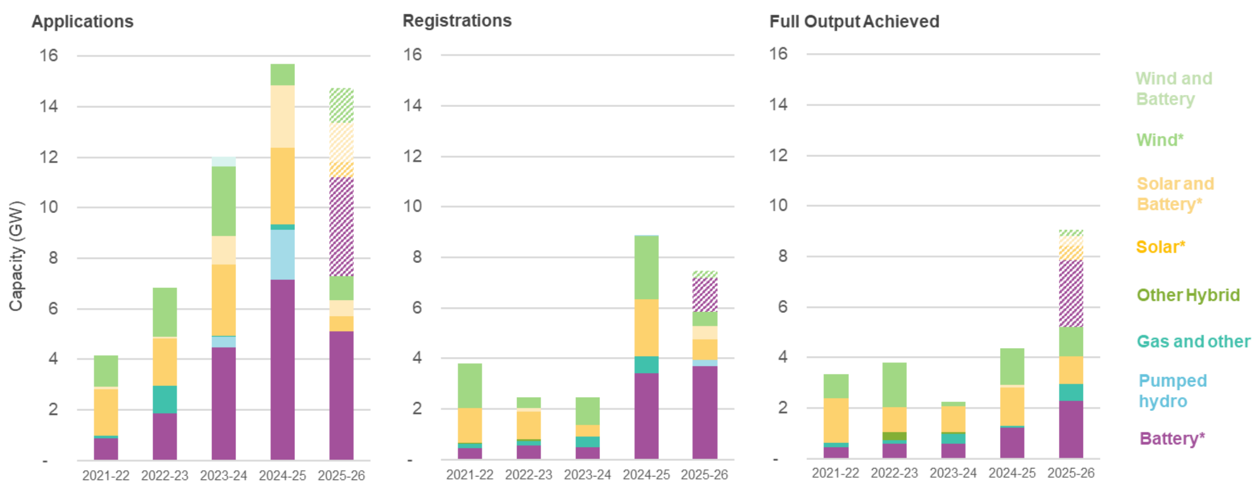
[50] A hydro unit in spinning mode means the generator is running and connected to the grid, but is producing little or no electricity—it is essentially 'spinning' and ready to respond if needed.

However, additional investment is needed – particularly in wind generation – to close the gap. Battery connections are progressing ahead of expectations, but storage alone cannot substitute for generation and will require sufficient renewable energy to operate effectively and meet consumer demand.

In total, approximately 38 GW of new grid-scale solar and wind is required by 2030 under the ODP. About 20 GW of new grid-scale solar would be needed, and projects to deliver about 19 GW have applied for connection. However, only 9 GW of the 18 GW of new wind is in the pipeline. To date, both solar and wind projects have taken about four years on average to progress through the connections pipeline from application to full output, navigating sometimes lengthy financial, environmental, connection and planning approval processes before construction can commence. Concerted efforts are being made to streamline all aspects of development and delivery.

Aware of current delivery risks, AEMO has analysed the effects of continuing the current rate of wind and solar build: see Section 11.

Figure 19 Connection milestones, NEM (GW, 2021-26)



Note: Patterned bars show projections for final quarter of 2025-26, as 2025-26 was not yet complete at time of publication. Technologies marked with an asterisk in the legend correspond to these patterned bars.

Table 6 Projected progress of renewable and storage capacity to 2030 (NEM, GW)

	Total capacity now (A)	In pipeline (delivery within 4 yrs) (B)	(A + B)	ODP projected need in 2030	Current (shortfall) or surplus for 2030
Solar	10.9	19.0	29.9	31.0	-1.1
Wind	11.7	9.3	21.1	30.0	-8.9
Subtotal	**22.6**	**28.3**	**50.9**	**61.0**	**-10.1**
Hydro	6.9		6.9	6.9	0.0
Total renewables	**29.5**	**28.3**	**57.8**	**67.9**	**-10.1**
Batteries (incl hybrids)	4.0	42.7	46.7	32.5	14.2
Pumped hydro	0.8	3.0	3.8	3.3	0.5
Total storage	**4.8**	**45.7**	**50.5**	**35.8**	**14.7**

A. More projects have actually applied for connection than shown in Column B. Historically 10% of projects apply but do not progress through to actual output. Accordingly, Column B figures represent (MW of applications received x 90%).

Mix and spread of renewable generation

Wind and solar are broadly complementary: wind generates variable energy overnight when solar cannot, and is typically stronger in the winter months when days are shorter. Solar is somewhat cheaper and easier to build than wind, and it pairs well with storage.

The ODP projects 31 GW of grid-scale solar by 2030 and 64 GW by 2050. More solar is projected than in the 2024 ISP as its costs have fallen compared to wind, and the increased investment in capacity of anticipated battery storage provides a natural complement for new solar projects. These factors lead to a projected 125 TWh of annual generation from utility-scale solar, up from 119 TWh in the 2024 ISP.

The ODP projects 30 GW of onshore wind by 2030 and 44 GW by 2050. The 2050 wind capacity (onshore and offshore) would be down 23% from the 69 GW in the 2024 ISP, but its share of annual generation would decline just 9% to 183 TWh: see earlier **Figure 17**. New wind turbines are more efficient and the wind in some locations is assumed to be stronger than previously modelled.

Offshore wind farms are expected to contribute to Australia's energy mix. Consistent offshore winds deliver valuable resource quality and diversity, if wind farms can harness it and connect to onshore transmission. Supported by government policies, 9 GW of offshore wind is projected to be online by 2040. However, as offshore wind is two-thirds more expensive than onshore wind to build and connect, no more is projected to be built through to 2050.

Strategies to manage surplus renewable generation

The ODP builds enough NEM generation capacity for reliability in all seasons. As grid demand and consumption is higher in winter than in summer, and solar output is lower in winter than summer, that implies there will be surplus capacity in summer, typically from daytime solar generation.

The first strategy is to absorb this daytime surplus either by storing it in batteries for later use, or encouraging consumers to actively shift usage patterns. Consumer incentives (including free power through the Solar Sharer policy and retailer initiatives) are being offered to extend access to cheap solar energy to households without rooftop solar, and EV owners can also charge during that time. Large industrial loads (in scheduled industrial processes and, potentially in future, the electrolysers that support hydrogen production) may be set to take advantage of surplus renewable generation, particularly during daylight hours. For example, the ISP indicates that co-locating up to 4.3 GW electrolysers with grid-scale solar generation could materially reduce the network investment in the ODP, assuming hydrogen industry develops at scale in Australia over time. Flexible loads such as electrolysers may also act to firm renewable generation by shifting demand to periods of high availability, with such loads projected across 15 candidate REZs.

After flexible demand, it would be inefficient to build network, storage and system services to use every last watt of summer solar output. Instead, some generation may be 'curtailed' when there are security constraints in the network, or 'spilled' when the supply is over-abundant. The ODP seeks the optimal investment in generation and storage, beyond which it is more efficient to spill or curtail generation than to build new network and storage. For the most efficient outcomes, the ODP projects that about 15% of grid-scale renewable generation would be spilled or curtailed by 2050. At the same time, less than 1% of rooftop and small-scale solar generation would be curtailed, given investment in the distribution network to harness latent rooftop solar capacity: see Section 9.

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5.4 Renewable energy zones as efficient development clusters

Much of the new grid-scale generation would be built in REZs[51] now being established in all NEM regions. They are selected for the quality of their renewable resource (strong wind and/or solar potential), existing land use, and their proximity to consumers, existing transmission and available skilled workforces. REZ benefits can only be realised if generation and transmission infrastructure are delivered as planned, underscoring the importance of maintaining social licence throughout their development.

Appendix A3 offers investors data on the locational need and opportunity for new capacity, and incorporates network capacity, system security, supply reliability, weather, climate, price and policy outlooks. The annual *Enhanced Locational Information* report combines these ISP insights with other AEMO data.

Efficient clusters of renewable energy development

REZ candidates were initially developed for the 2018 ISP[52], and have been continuously updated, refined and added to through both the ISP and state-based consultation processes: see Appendix A3. Jurisdictional energy infrastructure planners have engaged with relevant communities on both high-level and detailed planning and development. The industry is acutely mindful that people living in these communities carefully weigh up how these investments will affect them both personally and as a community – both the economic and social benefits and the potential costs and risks: see Section 12.2.

Governments responsible for the development of REZs highlight that[53], if they are well planned and supported by appropriate social licence, they may:

- greatly reduce the overall cost and disruption of the transition, and deliver significant regional benefits,
- meet the needs of the power system, with better grid reliability and security, and the option to scale up to address the future needs of the power system,
- allow for more coordinated and effective community consultation,
- share the costs of transmission, connection and support infrastructure (such as weather observation stations) across multiple projects,
- promote regional expertise and employment over long periods to build and maintain generation and storage assets and the equipment needed to ensure power system security, and
- reduce the community, environmental and aesthetic impacts of state-wide development.

Renewable energy zone and network design to optimise capacities

The details for each of the 44 considered REZs in the NEM are in Appendix A3. These include an assessment of their solar and wind resource, projected generation capacity, transmission implications, climate and event

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[51] This ISP uses the term ‘renewable energy zone’ as required by the National Energy Law, and its use incorporates the term ‘regional energy hub’ adopted by the 2025 Queensland Energy Roadmap.

[52] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2018/integrated-system-plan-2018_final.pdf.

[53] See ‘How NSW will benefit from renewable energy zones’ at https://www.energyco.nsw.gov.au/living-in-a-renewable-energy-zone/what-is-a-rez#why; Queensland Treasury (2025) *Queensland Energy Roadmap*, p 51; Tasmania (2022) *Renewable Energy Coordination Framework*, p 13-22; VicGrid (2025) *Victorian Transmission Plan*, ‘Our plan for renewable energy zones and transmission projects’, p 55.

risks, and projected curtailment and spill levels. By NEM region, the projected capacities of grid-scale solar and wind (including existing, committed and anticipated projects) are:

- **New South Wales (including Australian Capital Territory): 46 GW new grid-scale wind and solar by 2050.** Resource diversity would be opened by new networks such as Project EnergyConnect and HumeLink as well as the Central-West Orana, Hunter Central Coast and New England REZs, with an even mix of wind and solar across the state, including 14 GW new generation capacity in Central-West Orana, 11 GW in New England, 5 GW in South West New South Wales, and 5 GW in Hunter-Central Coast by 2050. These investments assist in meeting the NSW Electricity Investment Roadmap targets. No offshore wind is yet forecast for New South Wales.
- **Queensland: 33 GW new grid-scale wind and solar by 2050**. Targeted network investments such as CopperString and Central to North Queensland Reinforcement would allow new renewables in the regional energy hubs of North Queensland (2 GW), Isaac (3 GW, mainly solar), Fitzroy (8 GW, mainly solar). Regional energy hubs in the south of the state such as Darling Downs (11 GW of solar and wind). are projected to make use of existing network capacity as coal retires.
- **South Australia: over 10 GW new grid-scale wind and solar by 2050**. New generation in Mid North South Australia REZ (4 GW) and Northern South Australia REZ (3 GW) is forecast for the region by 2050. This generation investment supports meeting the South Australian Renewable Energy Target.
- **Tasmania: over 3 GW of new grid-scale wind and solar by 2050**. The Tasmania REZ Expansion established from 2030-31 onward would allow access to cost-effective generation including through the interconnection capacity as a result of Project Marinus. This additional generation supports meeting the Tasmanian Renewable Energy target.
- **Victoria: 24 GW new grid-scale wind and solar by 2050 including 9 GW offshore wind.** Increased network capacity from Victoria – New South Wales Interconnector West (VNI West) and Western Renewables Link (WRL) allows more wind generation in the Central Highlands REZ and the Western Victorian REZ. Transmission network connections are modelled to support connection of offshore wind, providing access for offshore wind to supply both Victoria and the NEM. This additional generation would help to meet the Victorian Renewable Energy targets and Offshore Wind targets.

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6 Storage to firm renewables

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.

Section 5 highlights that almost 120 GW of grid-scale wind and solar would be needed to replace coal and meet rising industry demand.

Energy storage is essential in this renewables-based and weather-driven system. It adds to reliability by helping to manage the peaks and troughs in renewable generation, and to match energy supply to consumer demand. If designed to, it can also help to maintain grid stability and inertia, smooth out volatile frequencies, and balance out fast changes in supply and demand. Well-designed projects may co-optimise these reliability and system security services to deliver further efficiency gains to the NEM.

This section sets out how grid-scale batteries and hydro would contribute to the ODP by 2050:

6.1 **Different types of storage are needed for different roles.** Grid-scale capacity is needed for shallow, medium and deep storage, in addition to consumer-owned batteries.

6.2 **35 GW of shallow and medium storage is needed by 2050** for intra-day firming. About 33 GW would be needed by 2030, a target which the connections pipeline suggests would be met or even exceeded. Batteries would be the primary source of medium storage.

6.3 **5 GW of deep storage is needed by 2050 to complement the existing 7 GW existing hydro-electric schemes,** to ensure reliable supply through seasonal demands and renewable lulls. All of this pumped hydro is already committed, anticipated or planned.

Section 7 then sets out how gas-powered generation is needed to back up renewables.

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ISP Explainer: categories of energy storage

Storage technologies can store electricity when available supply is greater than demand, then discharge or 'dispatch' it when needed. In this way, they help firm and shape supply by moving electricity to when it is needed.

Different forms of energy storage are needed to firm both consumer-owned and grid-scale renewables at different times of the day and year.

As with generation, there is a difference between the installed capacity of storage, and what it can actually be called on to deliver to consumers.

- The '**installed capacity**', measured in GW, is the rate at which the battery or hydro scheme can deliver power. For example, a battery with an installed capacity of 100 MW can inject up to 100 MW into the grid at any moment.

- The **'depth'** is measured in hours as the length of time that electricity can be injected into the grid at maximum output before the stored energy is exhausted.
- The '**energy capacity**' is measured as GWh, being the total amount of energy stored when fully charged.

The installed capacity of the NEM's storage is then categorised by its size:

- **CER storage** (or consumer-owned storage) is less than 5 MW, being behind-the-meter batteries owned by households and businesses, including EVs that may be able to send electricity back into the grid.
- **Mid-scale storage** is battery storage between 5 MW and 30 MW capacity, typically connected to the distribution network. This is also referred to as 'other distributed resources' in some other AEMO publications.
- **Utility-scale storage** is battery or pumped-hydro over 30 MW, typically connected to the transmission network.

Mid-scale and utility-scale storage are then categorised by their 'depth' of storage, or the length of time that they can dispatch electricity if operating consistently at full output. All can provide system security services.

- **Shallow storage** can dispatch electricity for less than four hours, and are typically batteries.
- **Medium storage** can dispatch electricity for four to 12 hours. This may be battery or pumped hydro (or other emerging technologies in future) which can shift large quantities of electricity to meet evening or morning peaks.
- **Deep storage** can dispatch electricity for more than 12 hours, to firm renewable energy over weeks or months (seasonal firming) or help cover long periods of low sunlight and wind (renewable lulls). These include many of the NEM's existing hydro-electric power stations, and pumped hydro schemes currently under development.

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6.1 Different types of storage are needed for different roles

Different types of storage have different strengths. Batteries can store surplus energy from wind and from daytime solar to use in the evening and morning peaks, shifting supply to better match demand. Existing hydro generators and new pumped-hydro storages add to system resilience in several ways, in particular through longer 'dark and still' periods that are more likely during the winters.

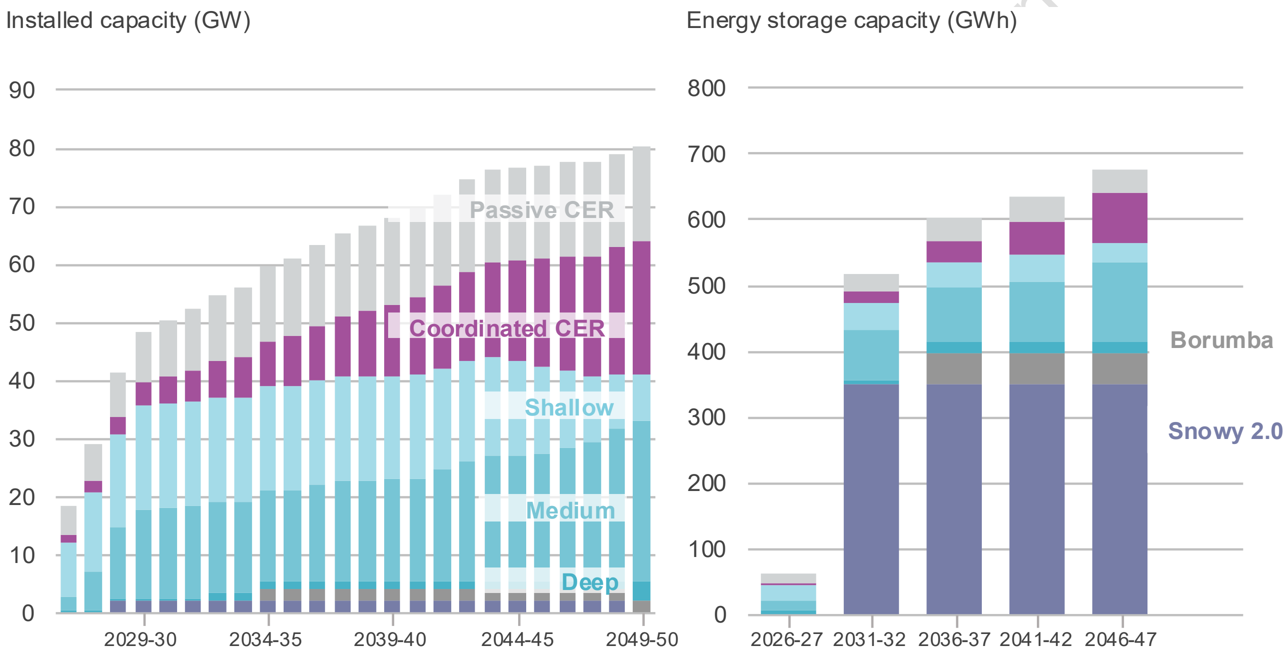
Both consumer and utility-scale capacity would cover the needed mix of shallow, medium and deep storage. The ISP seeks the most efficient balance between different types of storage to meet cost, reliability and emission priorities. For example, the optimal mix in 2030 is projected to be 2.4 GW deep storage[54], 15.3 GW medium and 18 GW shallow. However, these capacity figures disguise the strong role of deep storage. By 2030, deep storage will account for about 70% of energy capacity, and be a critical contributor to system reliability: see Section 6.3 and **Figure 20.**

[54] This number does not include contribution from the existing 7 GW of the NEM's existing hydro-electric power stations, which are expected to continue to provide capacity across the ISP horizon.

This mix would change by 2050, as most shallow storage would by then be offered by CER, and grid-scale investment would focus on medium storage. CER are forecast to rise from today's 5 GW to 12 GW in 2030, benefiting from strong recent incentives. They would continue to build to reach 35 GW in 2050 – by then making up 50% of the NEM's installed storage capacity: see Section 9.1.

A number of governments are supporting the development of new deep (or medium) storages. The Federal Government's Capacity Investment Scheme offers incentives for deep storage, as does South Australia's Firm Energy Reliability Mechanism, while New South Wales has a 2 GW target for storage of at least eight hours duration by 2030. Queensland is developing the Borumba and Kidston pumped hydro projects noted above, while Hydro Tasmania is investigating a new pumped-hydro 'Battery of the Nation' initiative at Cethana.

Figure 20 Projected storage installed capacity and energy capacity, NEM (2026-27 to 2049-50, *Step Change*)



6.2 35 GW shallow and medium storage for intra-day firming

Intra-day firming absorbs renewable energy during the day and releases it during evening peaks, helping moderate prices during those high-demand periods. It is provided by shallow and medium storage – typically batteries. These may be household and business CER, network and community-scale batteries embedded within distribution networks, grid-scale batteries, and new hybrid systems that combine solar and battery assets at scale. Deep storage can also provide intra-day firming if called on, but its greatest value is to store energy across seasons and in reserve for 'renewable lulls': see Section 6.2.

Batteries are projected to be the primary source of medium storage. The decline in utility-scale battery costs is making its mark. Although there is only 4 GW of existing capacity, new storage in the connections pipeline[55] has increased substantially – from 3 GW in September 2022, to 17 GW in 2024 and to 45 GW in 2026. This is now well ahead of the 33 GW of battery storage that the ODP projects would be needed in 2030. To date, battery projects have taken just over two years to go through the connections process.

About 70% of the batteries in the connections pipeline are coupled with grid-forming inverters to add valuable system services. They can dispatch electricity instantaneously and support grid security with frequency control ancillary services (FCAS), and provide a stable voltage waveform to support system strength: see Section 10.1 and the 2025 *Transition Plan for System Security*.

As mentioned, the role of shallow grid-scale batteries would be supplemented by consumer and mid-scale batteries over time. Other emerging technologies like advanced compressed air energy storage, gravitational storage, flow batteries and concentrated solar thermal systems may also be added to the mix.

6.3 5 GW deep storage for seasonal firming and renewable energy lulls

Deep storages can dispatch electricity for more than 12 hours, and are therefore able to supply consumers during prolonged dark or still periods. The ODP projects that by 2050 there would be about 5 GW of deep storage, delivered by new pumped hydro projects. Continued improvements in battery technology may mean that they also provide deep storage in future. Much of the NEM's existing 7 GW of hydro-electric power stations also offer significant deep storage, as many have reservoirs to store rainfall and snowmelt as potential energy, and add to system security and resilience when released (or when the station is operated in 'spinning mode').

Deep storage is needed for seasonal firming and renewable lulls

The primary purpose of deep storage is to firm renewable energy over weeks or months (seasonal firming, see ISP Explainer below) or help cover long periods of low sunlight and wind (renewable lulls). It can also be called on in times of extreme peak demand.

A buffer of deep storage in the NEM also adds to system security and inertia. It offers resilience against known yet unpredictable climate risks in the future, and the challenges of reduced renewable energy availability during the winter season as heating demand increases. Deep storage would also cover planned network outages that will inevitably be required to connect future infrastructure.

Deep storage is especially valuable during extended renewable lulls. Low renewable output is often driven by local weather events that typically last a few hours, a day or two, or on rare occasions a week. They are more likely in winter when there is less solar irradiation (energy) and shorter daylight hours. If new transmission is delivered as planned, then renewable resources can be shared across the NEM to overcome localised lulls.

[55] Committed and anticipated projects meet criteria set in the AER regulatory investment test for transmission (RIT-T) Guidelines and *Cost Benefit Analysis Guidelines*, are listed in the AEMO Generation Information page, and are assumed to be underway for delivery for ISP purposes. The connections pipeline refers to projects going through the AEMO and networks' connections process. Many projects are common to both lists.

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However, extended lulls may cover wide areas and are hard to predict in duration and intensity, and may become harder to predict as the climate changes: see ISP Explainer below, and Appendix A4.

Adding pumped hydro to existing hydroelectric schemes

Deep storage, in the form of hydro reservoirs, is currently provided by many of the NEM's existing hydro-electric power stations. These traditional hydro generators collect rainfall and water inflows in dams, cascading river systems, and other reservoirs to store as potential energy for use when needed. 'Pumped hydro' schemes first use surplus renewable energy to pump the water upstream.

Hydro-electric power stations currently offer about 7 GW of capacity when needed. The largest four existing stations together offer 4 GW (Tumut 3, Murray 1 and Murray 2 in the Snowy Mountains Scheme, and Gordon in Tasmania)[56]. The remainder comes from smaller hydro schemes across the NEM, some of which are run-of-river.

Pumped hydro projects would make up 6 GW of capacity in the NEM by 2050, using surplus energy to first pump water upstream. Existing schemes offer about 1 GW capacity, and a further 5 GW is expected to be delivered by 2035. Snowy 2.0 and Kidston (Queensland) are committed projects that would add 2.5 GW by the end of 2028, with Borumba (Queensland) anticipated to add another 2 GW, and smaller existing and planned[57] projects making up the balance. Snowy 2.0 stores up to 350 GWh of water that would enable full output for a week if discharging at its maximum rate. This would be over half the NEM's energy storage capacity in 2050 and enough to meet the average needs of around 3 million households (about as many as in Sydney and Melbourne combined): see **Figure 20**.

ISP Explainer: How hydro schemes support reliability of energy supply

Major hydro-electric schemes store potential energy in deep reservoirs, filled by rainfall and snowmelt, and can support reliability by accessing this energy when most needed, while balancing electricity generation with other roles in irrigation and flood mitigation, and providing environmental releases, as required, to maintain river health. They therefore play an increasingly important and strategic role in helping to mitigate renewable lulls, and to balance energy availability across weeks as well as seasons.

Some of the existing hydro-electric schemes form river chains, allowing water to be used a number of times to produce electricity as it flows downstream. There are also run-of-river hydro schemes in the NEM, though their storage and generation capacity is limited by their smaller dams and the need to deliver water for other uses.

Other hydro schemes have an upper and lower reservoir, and pump water back up after it has passed through the generation turbine, creating a 'closed loop'. Snowy 2.0 is an example of a deep pumped hydro energy storage (PHES) system, with potential to discharge at full capacity for nearly a week. In summer, when solar generation is highest, PHES systems can utilise surplus renewable energy to return water to higher elevations and replenish storages.

[56] Importantly, some hydro-electric power stations do have pumping capability.

[57] Specifically, the 800 MW Phoenix Pumped Hydro Project selected for a Long-Term Energy Service Agreement under the New South Wales Electricity Infrastructure Roadmap.

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Into autumn, with typically more variable winds and decreasing sunlight, more energy starts to be drawn from hydro reservoirs. These play their biggest role in winter, supported by gas, when heating demands are high, solar is reduced, and wind can be strong but relatively more intermittent. In spring, solar again starts to generate more than is consumed, and snowmelt and higher rainfall replenish water reservoirs.

Forecasting both energy demand and weather can never be perfect. A buffer of deeper solutions adds resilience against known yet unpredictable risks.

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7 Gas to back up renewables

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.

Electricity from gas-powered generation will continue to have an important role in the NEM. After coal-fired generators retire, gas will increasingly be needed to back up renewable supply (during periods of renewable lulls and peak demand), as well as for power system security services.

This section sets out how:

7.1 **The NEM is projected to need 17 GW of flexible gas-powered generation by 2050**, adding to and progressively replacing all of today's 4 GW mid-merit and much of today's 8 GW peaking gas-powered generation capacity as they reach end-of-life. If installed with a clutch, new more flexible gas-powered generation can also deliver system security services without burning fuel.

7.2 **New gas supply, transport and storage infrastructure would also be needed** to bring sufficient gas from production in northern states, and so support the reliability and operability of gas-powered generation**.** Pipeline constraints may restrict the gas available for electricity generation when gas and electricity demand peak simultaneously. Without action to develop more infrastructure, gas supply gaps may be large enough to risk delivery of the ODP.

7.1 17 GW flexible gas by 2050

In total, under the ODP, the NEM is projected to need 17 GW of flexible gas-powered generation by 2050 to ensure resilience under a range of power system conditions and weather events.

Gas-powered generation is changing to a more strategic, back-up role, with flexible generators that can also provide system security services. They will act mostly as a backup for renewable generation and storage, as the cost of gas makes it a more expensive option for everyday use. Newer flexible generators can be regularly switched on to serve that back-up role, and could also be designed to operate with a clutch to provide critical system security services without burning fossil fuel.

Currently, the NEM has 4 GW of 'mid-merit' continuous generating plants, and 8 GW of 'peaking' plants. Almost all of the mid-merit and half the peaking plants are forecast or announced to retire between now and 2050 as the plants reach end-of-life[58]. As they do, the fleet would be developed in *Step Change* to a 17 GW fleet of flexible capacity. This may be either as greenfield or brownfield development, but the gas generation must be flexible. **Figure 21** shows the change in the role of gas, from relatively stable supply in 2015 to the forecast winter peaks in 2040 and more intermittent use throughout the year.

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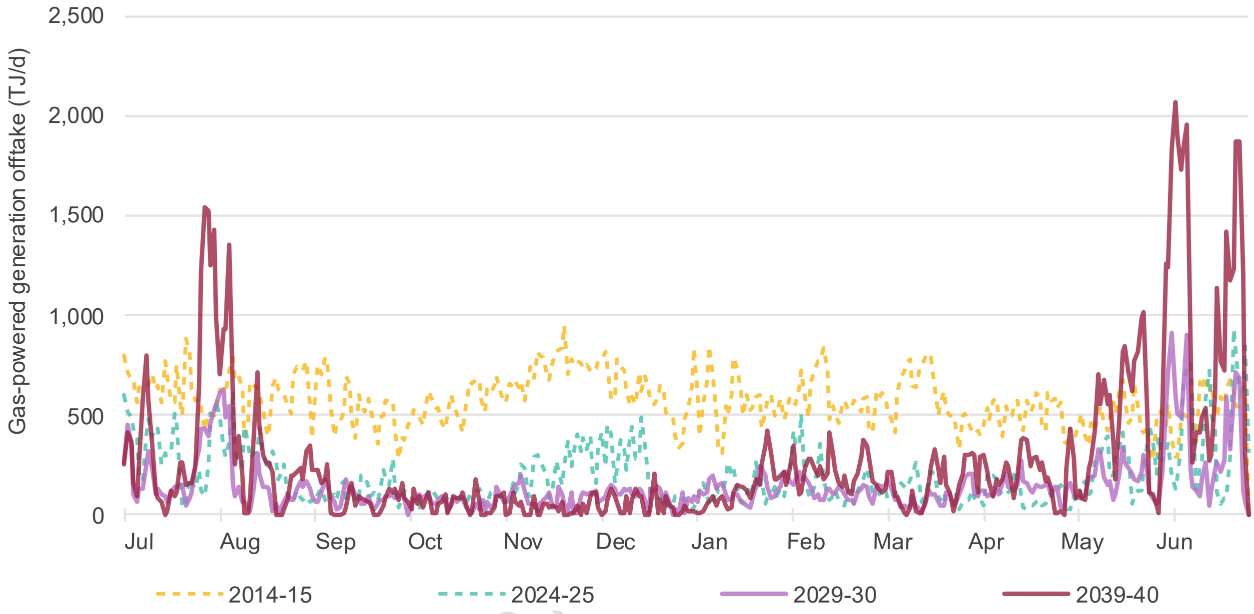
[58] The exception is Yarwun, a dedicated mid-merit gas plant to support Rio Tinto's aluminium refinery at Gladstone.

Flexible gas generation is used to support power system reliability and security, but is used sparingly. Through to 2050, the gas fleet is projected to supply a similar share of the NEM's annual generation, which is about 4%[59]. Individual plants would generate up to 10% of their annual potential, but will be critical when they run. They may be needed as back-up capacity in peak demand periods, and will be needed most on days with low renewable availability. This is more likely to be in winter, especially in the southern states, when shorter days reduce solar output, and when more electricity is needed for longer and colder nights.

Figure 21 Gas-powered generation offtake, NEM (TJ/day 2015 and 2040, *Step Change*)



7.2 Gas infrastructure needed to support gas-powered generation

Under the ODP, the flexible, back-up role of gas-powered generation may require relatively large amounts of gas to be consumed in a short period, particularly in winter.

AEMO's 2026 *Gas Statement of Opportunities* forecast that from 2029 there may be the risk of gas shortfalls during periods of extreme peak demand in southern Australia, with a need for additional supply in most scenarios from 2030. Timely and efficient investment in new gas resources and/or infrastructure is critical to ensure the operability, reliability and security of the power system through the energy transition, as well as maintaining gas supply to residential, commercial and industrial gas consumers.

AEMO has modelled potential combinations of gas investments – 'gas development projections' – for the gas industry to address this opportunity and ensure gas is available for both electricity generation and other gas uses. Lack of fuel availability may influence the type of dispatchable capacity that is least cost to the power system, the renewable generation resources that are needed, and the network investments that deliver electricity to consumers.

[59] Gas use projections are highly uncertain, as they vary from year to year depending on weather and operational conditions. Figure 17 shows a share of 2% due to the assumptions of that single year.

A number of potential gas development projections would support the needs of the ODP as well as other gas consumers, and four of these have been assessed in Appendix A10. Each has a different set of developments currently being proposed, with some developments common to all four projections. All are subject to current policies and technologies: see Section 4.2[60]. It remains up to the gas industry to identify and progress projects that would resolve the risk of structural supply gaps from 2030 under most weather conditions.

Potential solutions could include:

- regasification terminals in south-east Australia and the necessary pipeline infrastructure to bring this supply to demand locations,
- expansions to the existing east-coast gas pipeline network to transport gas to where it is required in both southern and northern Australia, including to specific locations in the NEM where new gas-powered generation is required for power system security and reliability as coal-fired generators retire,
- new seasonal gas storages and expansions to existing gas storages in southern Australia, and
- new supplies for existing and additional processing plants, for both natural gas and biomethane.

The ISP's gas development projections are not an 'optimal development path' for gas, and the investments modelled are not actionable in the same way as electricity network projects in the ODP. In particular, the impact of each projection on gas prices has not been assessed, and the ISP does not test the commercial viability of investments in the projections.

However, modelling these projections has helped explore how both electricity and gas infrastructure together underpin a robust and resilient NEM. For example, where gas investments are needed to support direct-use gas demand, electricity generation may improve the case for investment. Where the additional investment is not made, ISP sensitivity analysis suggests that the ODP's projected level of gas-fired generation capacity would still be needed.

If gas infrastructure investment occurs as needed, developers of gas-powered generation can expect a sufficient gas supply, especially if they locate at the strongest parts of the gas network. If gas supply is constrained, individual power plants may need on-site storage or the capability to use secondary fuels to support their operation. On-site storages could include natural gas, biomethane, hydrogen, liquid biofuels or diesel.

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[60] The 2026 ISP does not incorporate future gas market policies identified through the Federal Government's Gas Market Review, including the domestic gas reservation scheme. At the time of modelling, the detailed design and legislative framework for these measures was under consultation and had not been finalised.

8 Network to connect the NEM

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.

Transmission brings electricity where it is needed, when it is needed, and makes the most of the diverse renewables and weather across the NEM. While solar farms are well spread across the NEM, transmission is particularly important for the more scattered wind farms that generate power at night and through cloudy days. Distribution networks then deliver that electricity to homes and businesses, and take back any surplus from consumers' own assets.

Transmission planners make the most of the existing network before considering new projects. They work with distribution planners to use capacity in the lower-voltage network, and use real-time weather monitoring to maximise line use. Nonetheless, new transmission projects are needed to deliver electricity at least cost for consumers. By sharing electricity within and between states, they reduce the amount and cost of local generation or storage infrastructure. Community confidence is critical for these projects, and depends on rigorous planning and consultation that provides certainty for the communities involved.

This section describes the transmission and distribution projects in the ODP in the 2026 ISP:

8.1 **A network extended by about one-seventh.** The ODP would extend the current 44,000 km network by about 6,000 km or 14%, with 20 transmission projects either underway or actionable.

8.2 **Changes to ODP transmission projects since the 2024 ISP.** The identified need for an ISP transmission project may change for many reasons, leading to a change in timing, a smaller or larger project, an alternative solution, or no transmission at all in the relevant area.

8.3 **Eight transmission projects already committed or anticipated** and underway to be delivered over the next eight years that will add 3,500 km to the NEM's transmission network.

8.4 **Twelve actionable ISP projects** to be delivered over the next 12 years that would add 1,660 km to the network.

8.5 **A number of future ISP projects** which may add up to 876 km to the transmission networks and are forecast to be actionable in one or more future scenarios, including three previously actionable projects.

8.6 **Two distribution projects** identified as a cost-effective development opportunities to connect utility-scale generation and storage to load centres, but not actionable under the ISP framework.

Appendix A5 sets out full details of the transmission projects, including their identified need as required by the NER. Section 9.1 explores how distribution networks can help fulfil CER potential. AEMO has also modelled a sensitivity to test the ODP's resilience to constraints on the timely delivery of transmission projects: see Section 11. Section 9.1 explores how distribution networks can help fulfil CER potential.

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8.1 Transmission network being extended by about one-seventh

The NEM's transmission network is one of the world's longest interconnected power systems. In 2022, it stretched for about 43,350 km and connected a distribution network of over 764,000 km. Since then, another 635 km of transmission has been added. The 365 km Project EnergyConnect Stage 1 now connects South Australia and its eastern neighbours, and network capacity has been increased between Queensland, New South Wales and Victoria. As well, two intrastate projects have been completed: the Eyre Peninsula Link in South Australia (270 km of new line), and the Far North Queensland connection into Woree. The transmission network now spans about 44,000 km.

Figure 22 shows how the ODP's transmission projects would extend the network by about 6,000 km[61] or one-seventh by 2050 (including all committed, anticipated, actionable and future projects in the *Step Change* scenario). About 40% of the additional length is needed to strengthen the connection between states, adding reliability and stability to electricity supply across the NEM. The other 60% connects new capacity in REZs within each state, including to energy-intensive industries in regional hubs, or provides additional capacity within states to allow cost-effective generation to be transported to demand centres. This is essential infrastructure, with over 90% of the energy supplied by the NEM to serve business and industry by 2050: see Section 2.3.

The total build of new transmission is about 1,435 km less than projected in the 2024 ISP. The changes are detailed in Section 8.2 and in the lists of projects below. Compared to 2024, projects of about 165 km have progressed to operation and are no longer included, while 410 km has been added by scope increases. About 1,680 km of potential transmission is no longer needed as there is more generation and storage in particular locations, or due to policy changes.

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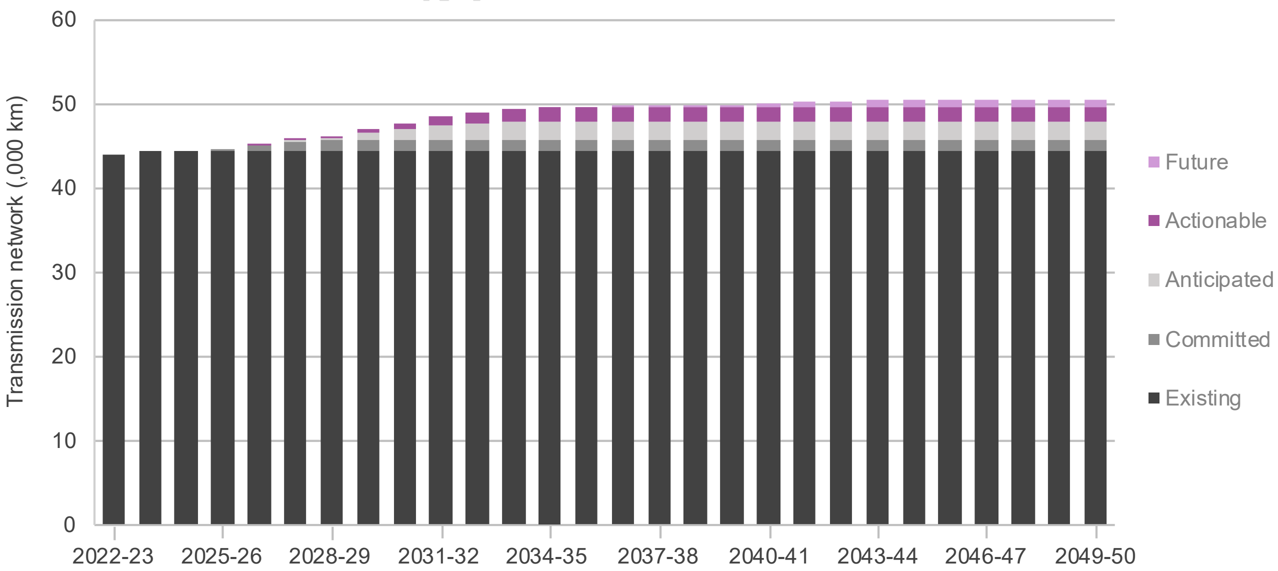
Figure 22 Total NEM transmission (,000 km, *Step Change,* 2022-23 to 2049-50)



[61] In this report, transmission lengths in kilometres are reported for the *Step Change* scenario only. The ISP cost benefit analysis assessment considers costs of all future ISP projects, weighted by scenario: see Section 10.3.

8.2 Transmission projects now in the ODP

The ODP's transmission projects form part of the least-cost way to meet rising consumer needs through to 2050, as coal plants retire and while meeting government policies.

The ODP includes the following transmission projects, detailed in **Table 7** and **Figure 23** below:

- **Eight committed and anticipated** projects are already underway and will add 3,500 km to the network over the next eight years.
- **Twelve actionable projects** to add 1,660 km over the next 12 years. Five of these were already actionable, five were future projects in the 2024 ISP and now fall within the actionable window, and two are new projects in this ISP. Work on all actionable projects should continue or commence as soon as possible under the ISP or relevant framework.
- **A number of future ISP projects** are forecast to be actionable under at least one future scenario, including three projects that were previously actionable.

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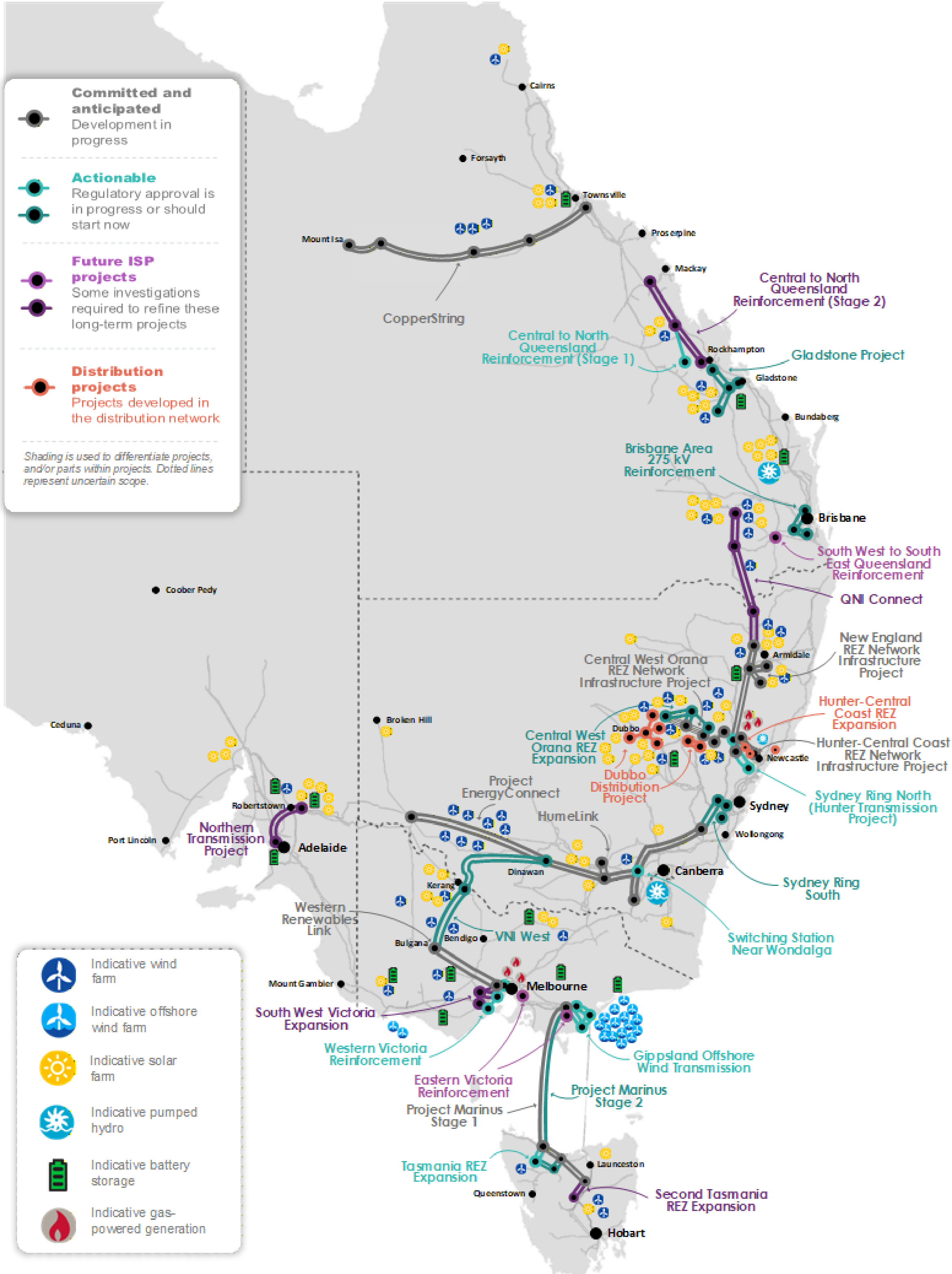
Table 7 Network projects in the optimal development path in the 2026 ISP

Committed and anticipated transmission projects		In service timing[A]	Full capacity timing[B]
Project EnergyConnect Stage 2		October 2026	November 2027
HumeLink		December 2027	December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central-West Orana REZ Network Infrastructure Project		December 2028	December 2028
Western Renewables Link		November 2029	November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		2032	2032[C]
New England REZ Network Infrastructure Project[D]		January 2034	January 2034
Already actionable projects (confirmed in this ISP)	**Framework**	**In service timing[A]**	**Full capacity timing[B]**
Gladstone Project	QLD[E]	March 2029	Mid-2030[C]
Sydney Ring North (Hunter Transmission Project)	NSW[E]	November 2029	November 2029
Sydney Ring South	ISP	Power flow control: July 2030 500 kV assets: July 2033	Power flow control: July 2030 500 kV assets: July 2033
Victoria – New South Wales Interconnector West (VNI West)	NSW[E] ISP	South West REZ: August 2029 NSW-VIC: November 2030	South West REZ: August 2029[C] NSW-VIC: November 2031
Project Marinus Stage 2	ISP	June 2034	December 2034
Newly actionable projects (identified in this ISP)	**Framework**	**Earliest feasible full capacity timing[B]**	
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[E]	June 2029	
Tasmania REZ Expansion (future project in 2024 ISP)	ISP	July 2030	
Switching Station Near Wondalga	ISP	April 2031[C]	
Central to North Queensland Reinforcement (Stage 1) (smaller option of Queensland SuperGrid North project in 2024 ISP)	ISP	July 2031[C]	
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC[E]	Stage 1: July 2031; Stage 2: (Phase 1) July 2033; (Phase 2): July 2038	
Brisbane Area 275 kV Reinforcement	ISP	June 2032	
Central-West Orana REZ Expansion (future project in 2024 ISP)	NSW[E]	March 2033	
Future ISP projects[F]			
Interconnector projects	**Queensland – New South Wales Interconnector (QNI Connect)**		
Queensland	**Central to North Queensland Reinforcement (Stage 2), South West to South East Queensland Reinforcement**		
South Australia	**Northern Transmission Project[G]**		
Victoria	**Eastern Victoria Reinforcement, South West Victoria Expansion**		
Tasmania	**Second Tasmania REZ Expansion**		
Distribution projects			
New South Wales	**Hunter-Central Coast REZ Expansion, Dubbo Distribution Project**		

A. The in-service date, advised by the project proponent, gives an indication of when construction and commissioning will be complete and equipment in-service.
B. The capacity release and timing, advised by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.
D. This project is newly categorised as anticipated. It is progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).
E. These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), *Electricity Infrastructure Investment Act 2020* (NSW), or the *National Electricity (Victoria) Act 2005* (Vic), rather than the ISP framework. Elements of the Victoria Reinforcement program are expected to be delivered under a mix of the Victorian Transmission Investment Framework (VTIF) and the ongoing AusNet and Powercor RIT-Ts.
F. This list shows future ISP projects which are identified as part of the ODP in *Step Change* or are subject to an ongoing RIT-T. Appendix A5 provides information about additional future ISP projects identified in only one scenario.
G. AEMO considers ElectraNet should continue the Northern Transmission Project RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options.

Figure 23 Transmission projects in the 2026 ISP optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that include new transmission lines, increase capacity by 400MW or more, are required in *Step Change*, or have a regulatory test for transmission (RIT-T) underway. Transmission projects recently commissioned (for example, sections of Project EnergyConnect) are represented as thin light grey lines, consistent with the depiction of the existing network.

Drivers of the re-classification of transmission projects

The identified need for an ISP transmission project may occasionally change between ISPs, or between the Draft and final ISP. Different drivers may result in a smaller or larger project, an alternative solution, or no transmission in a given area. While these factors affect individual projects, the overall set of transmission investments in the ODP has remained broadly consistent over recent ISPs.

Consistency is important, as community engagement often starts once a project becomes part of the ODP, and stopping and restarting engagement can be disruptive, may erode trust, and could make it more difficult to build and maintain social licence for all projects over time.

The main drivers of changes in ISP projects since 2024 are:

- **Inclusion of opportunities in the distribution network**. Some transmission projects to connect generation and storage have been replaced by more cost-effective options within the distribution network, supported by transmission capacity as necessary.
- **Acceleration of battery investment**. The benefit of a transmission project may fall if well-located battery capacity is available, as both transmission and storage add reliability to the power supply and make the most of available renewable generation. The project's benefit would reduce further if its costs rise and battery costs fall.
- **Changes in generation capacity expected in an area.** Transmission benefits typically increase with the distance between generation capacity and demand centres. Where capacity is added close to demand (typically solar), the need for transmission falls. Where capacity is added in more remote areas such as South West NSW (typically wind) the need for transmission increases.
- **Increase in estimated transmission costs.** While some projects have had options to mitigate cost rises, others have not and have become too expensive to deliver a net benefit to consumers.
- **Change to treatment of financing costs.** After consultation on the 2025 IASR, AEMO has changed the assumed weighted average cost of capital for different types of infrastructure: see "Changes in costs since 2024" in Section 10.3.
- **Change in government policies.** A government may change policy and increase or reduce its support for a particular project.

A mix of these factors has driven changes in the classification of particular projects since both the 2024 ISP and the Draft 2026 ISP, as described below.

Changes to actionability since the 2024 ISP

There were 12 actionable ISP transmission projects in the 2024 ISP (although one, Project Marinus, has now been split into two separate projects). Of these, four projects have advanced to committed or anticipated status, five remain actionable, and four are no longer actionable in the 2026 ISP – noting that one 2024 ISP project has since been separated into stages. As well, five future projects in the 2024 ISP now fall within the actionable window, and there are two new projects identified as actionable in this ISP. **Table 8** summarises the project status changes since the 2024 ISP.

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Table 8 Classification status of transmission projects between 2024 ISP and 2026 ISP

Status between ISPs	Projects
Advanced to in service, committed or anticipated	• **Far North Queensland REZ** and **Project EnergyConnect Stage 1** are now in service. • **HumeLink** and **Hunter-Central Coast REZ Network Infrastructure Project** have advanced from actionable to committed. • **Project Marinus Stage 1** and **New England REZ Network Infrastructure Project** have advanced from actionable to anticipated.
Continue to be actionable	• **Gladstone Project** (previously Gladstone Grid Reinforcement) remains actionable, with Powerlink progressing through the Queensland Government's priority transmission investment assessment. • **Sydney Ring South** project continues to be actionable, but the ISP candidate option has now been updated from a power flow control option only to also include larger 500 kV upgrades to support the major load centre in New South Wales, consistent with Transgrid's PADR in May 2026. • **Sydney Ring North (Hunter Transmission Project)** remains actionable, with EnergyCo having lodged reports required for the New South Wales planning approval pathway. • **VNI West** remains actionable. Delivery pathways for the New South Wales component, providing access to South West REZ, are now aligned to the New South Wales framework, and include three transformers at Dinawan Substation, as advised by Transgrid and EnergyCo. • **Project Marinus Stage 2** remains actionable, with Marinus Link and TasNetworks' RIT-T completed and the 2026 ISP re-affirming actionable status for Stage 2.
Newly identified as actionable	• **Western Victoria Reinforcement, Gippsland Offshore Wind Transmission Project, Central to North Queensland Reinforcement (Stage 1), Central-West Orana REZ Expansion** and **Tasmania REZ Expansion** (previously North West Tasmania REZ Expansion) have all moved into actionable timeframes due to the two-year progression between ISPs, as well as updated scopes and cost estimates, increased certainty in committed and anticipated generation and storage at defined locations, and improved alignment with the connections pipeline. • **Switching Station Near Wondalga** and **Brisbane Area 275 kV Reinforcement** are new transmission network options which have now been identified as actionable.
Reclassified from actionable to future ISP projects	• **QNI Connect** is identified as a future ISP project, with the change driven by updates to reduce assumed flexibility of Queensland coal generators and incorporate newly-committed and anticipated batteries in the modelling. • **Northern Transmission Project** (previously Mid North South Australia REZ Expansion) delivers the greatest benefits in the *Accelerated Transition* scenario, particularly once significant industrial demand growth eventuates. ElectraNet's PADR identifies potential consumer benefits under a broader range of conditions. Given the project remains on the ODP and there is an active RIT-T underway, AEMO considers ElectraNet should conclude the RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options. Continuing community engagement may also help to narrow the corridor and reduce uncertainty for affected communities, while ensuring community considerations are reflected in future planning and decision-making. Stopping and restarting engagement can be disruptive, may erode trust, and could make it more difficult to build and maintain social licence for the project over time. • **Second Tasmania REZ Expansion** (previously **Waddamana to Palmerston transfer capability upgrade**) has moved to the future timeframe, delivering benefits in the *Accelerated Transition* scenario. TasNetworks will consider this augmentation as an option in the actionable Tasmania REZ Expansion project.
Continue to be future ISP projects	• **Eastern Victoria Reinforcement** and **South West to South East Queensland Reinforcement** (previously Darling Downs REZ Expansion).
Newly-identified as future ISP	• **South West Victoria Expansion** has now been identified as a future ISP project**.**
No longer identified on the ODP	• **Central Queensland to Southern Queensland Expansion** (formerly Queensland SuperGrid South) was actionable, but is no longer identified on the ODP. Alternative connection arrangements for Borumba Pumped Hydro have been identified to meet consumer needs and deliver efficient dispatch outcomes. • **Cooma-Monaro REZ Expansion, Facilitating Power to Central Queensland, North Queensland Energy Hub Expansion** and **Central Highlands REZ Extension** were previously identified as future ISP projects but are no longer identified on the ODP. Changes to the Cooma-Monaro outcomes are as a result of taking into account other changes in New South Wales, including access rights arrangements, adjusting near-term ISP outcomes to prioritise the existing project pipeline, updated generation cost inputs, distribution network option changes, and more. Changes to the Queensland regional energy hub outcomes reflect changes to jurisdictional targets for renewable energy, and changed consideration of the Pioneer-Burdekin pumped hydro project. On the Central Highlands REZ Extension, while there continues to be a need to augment the Tasmanian transmission network, the need for this project is

Status between ISPs	Projects
	now captured by the actionable Tasmania REZ Expansion project and the future Second Tasmania REZ Expansion project.

Note: Some future ISP projects identified in single scenarios or identified towards the end of the modelling horizon which are expected to evolve from one ISP to the next are tabulated in Appendix A5 Network Investments but are not listed in this table.

8.3 Eight committed and anticipated transmission projects

Eight transmission projects are highly likely to proceed and are included in the modelling for all development paths, scenarios and sensitivities:

- **committed network projects** meet all five commitment criteria[62] (site acquisition, components ordered, planning approvals, finance completion and set construction timing), and
- **anticipated network projects** are in the process of meeting at least three of those criteria.

Table 9 Committed and anticipated network projects in the ODP

Status	Project	Description	Full capacity timing[A] (advised by proponent)	Proposed new line build (km)
Committed	**Project EnergyConnect Stage 2**	A new 330 kilovolts (kV) double-circuit interconnector between South Australia and New South Wales, with a new 220 kV double-circuit line to Victoria.	November 2027 Transgrid, ElectraNet and AusNet Services	535
Committed	**HumeLink**	A 500 kV transmission upgrade connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby.	December 2027, Transgrid	365
Committed	**Hunter-Central Coast REZ Network Infrastructure Project**	Distribution network upgrades to supply generation from the Hunter and Central Coast to Sydney, Newcastle and Wollongong load centres.	July 2028, EnergyCo	82
Committed	**Central-West Orana REZ Network Infrastructure Project**	A network upgrade consisting of 500 kV and 330 kV circuits to provide additional capacity to the Central-West Orana REZ.	December 2028, EnergyCo	330
Anticipated	**Western Renewables Link**	A 500 kV double-circuit network upgrade to provide additional REZ capacity, including updated project scope to relocate a terminal station and increase the line capacity.	November 2029, VicGrid	190
Anticipated	**Project Marinus Stage 1**	One new high voltage direct current (HVDC) cable connecting Victoria and Tasmania, with 750 MW of transfer capacity and associated alternating current (AC) transmission, to enable more efficient power sharing between these regions. HVAC network assets in Tasmania for REZs under Stage 1 of the North West Transmission Developments project.	December 2030, Marinus Link Pty Ltd and TasNetworks	474
Anticipated	**CopperString[B]**	An 840 km new double-circuit line to connect Queensland's North-West Minerals Province to the NEM near Townsville, as announced by the Queensland Government.	2032[63], Powerlink	840

[62] In accordance with the AER's *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[63] AEMO has modelled this project with an earliest in-service date of June 2031, as advised by Powerlink for the 2025 *Electricity Network Options Report*.

Status	Project	Description	Full capacity timing[A] (advised by proponent)	Proposed new line build (km)
Anticipated	**New England REZ Network Infrastructure Project[C]**	Two 500 kV double-circuit transmission lines and associated 330 kV circuits connecting Bayswater and the New England REZ	January 2034, EnergyCo	692

A. The capacity release and timing are conditional on availability of suitable market conditions and good test results.
B. CopperString will be built and owned by the Queensland Government, and is not being actioned under the ISP framework.
C. This project is now categorised by AEMO as anticipated, based on information provided by the New South Wales government, and is progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).

8.4 Twelve actionable projects to be delivered by 2038

As noted above, 12 actionable projects would reach full capacity from 2029 to 2038. Five were actionable in the 2024 ISP, five have advanced from being future to actionable projects as planned, and there are two entirely new actionable projects.

Five projects continue to be actionable

The projects that were previously actionable and continue to be actionable in the 2026 ISP are listed in **Table 10**, including target delivery dates provided by project proponents. Appendix A5 provides detailed technical information on each project, including the identified need[64], progress and next steps.

All actionable projects should progress as urgently as possible.

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Table 10 Projects continuing to be actionable

Project	In service timing advised by proponent[A]	Full capacity timing advised by proponent[B]	Brief description Cost estimates ($2025)	Actionable framework	Proposed new line build (km)
Gladstone Project	March 2029	Mid-2030[C]	Increase network capacity from Central Queensland into the Gladstone area to support the area's industry once Gladstone Power Station retires, and add capacity between Northern and Southern Queensland. $2,367 million (-20% to +30%)	Queensland[D]	180
Sydney Ring North *(Hunter Transmission Project)*	November 2029	November 2029	High capacity 500 kV transmission network to reinforce supply to Sydney, Newcastle and Wollongong load centres. $1,364 million (±50%)	New South Wales[D]	110
Sydney Ring South	Power flow control: July 2030 500 kV assets: July 2033	Power flow control: July 2030 500 kV assets: July 2033	Power flow control: Power flow control devices on the 330 kV network to reinforce supply to Sydney, Newcastle and Wollongong load centres. $261 million (±50%) 500 kV assets: A new double-circuit 500 kV and 330 kV transmission lines connecting HumeLink lines from Bannaby to Sydney, Newcastle, Wollongong at a new substation at South Creek. $2,360 million (±50%)[E]	ISP	114

[64] The ISP must specify the identified need for each project (NER 5.22.6(a)(6)(v)), with credible options to address the identified need able to be implemented in sufficient time to meet the need (NER 5.15.2(a)).

Project	In service timing advised by proponent[A]	Full capacity timing advised by proponent[B]	Brief description Cost estimates ($2025)	Actionable framework	Proposed new line build (km)
VNI West	South West REZ: August 2029 NSW-VIC: November 2030	South West REZ: August 2029[C] NSW-VIC: November 2031	South West REZ: Upgrade Dinawan-Gugga double-circuit line from 330 kV to 500 kV. NSW-VIC: A new high capacity 500 kV double-circuit line to connect WRL (from Bulgana) with Project EnergyConnect and South West REZ (at Dinawan) via a new substation near Kerang. $7,600 million (-30% to +50%)	South West REZ: NSW[D] NSW-VIC: ISP	491
Project Marinus Stage 2	June 2034	December 2034	A second new HVDC cable connecting Victoria and Tasmania, with another 750 MW of transfer capacity and associated AC transmission, to enable more efficient power sharing between these regions. HVAC network assets in Tasmania for REZs under Stage 2 of the North West Transmission Developments project. Stage 2A total $2,485 million (±30%) • HVDC: $2,125 million (±30%) • HVAC: $360 million (-20% to +30%)	ISP	424

A. The in-service date, provided by the project proponent, provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing, provided by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.
D. These projects will progress under the Energy (Renewable Transformation and Jobs) Act 2024 (Qld*)*, Electricity Infrastructure Investment Act 2020 (NSW), or the National Electricity (Victoria) Act 2005 (Vic), rather than the ISP framework.
E. Transgrid's May 2026 Sydney Ring South Project Assessment Draft Report (PADR) included an updated cost estimate, different to this estimate included in the modelling for the final ISP.

Seven projects are newly actionable

Five future projects from 2024 now fall within the actionable window as planned, as noted in **Table 11**: the Western Victoria Reinforcement, the Tasmania REZ Expansion (previously known as the North West Tasmania REZ Expansion), a smaller option of the Central to North Queensland Reinforcement (previously known as Queensland SuperGrid North), the Gippsland Offshore Wind Transmission, and Central West Orana REZ Expansion.

In addition, two new projects have been identified as actionable: the Switching Station Near Wondalga[65] and the Brisbane Area 275 kV Reinforcement.

AEMO is consulting on non-network options for projects which are newly actionable since the Draft 2026 ISP that are proceeding through the ISP framework: Brisbane Area 275 kV Reinforcement, Central to North Queensland Reinforcement (Stage 1), and Tasmania REZ Expansion. AEMO will provide all submissions to the proponent for consideration in the Project Assessment Draft Report (PADR).

For the newly actionable ISP projects, AEMO calls for nomination of non-network options[66] and publication of PADRs by the dates set out in **Table 11**. For projects being actioned under jurisdictional frameworks, the relevant jurisdictional legislation applies.

[65] AEMO called for non-network options for Switching Station Near Wondalga in response to the Draft 2026 ISP at, https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-non-network-options-consultation-switching-station-near-wondalga

[66] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/non-network-options-consultations.

Table 11 Projects newly identified as actionable

Project	In service timing advised by proponent[A]	Full capacity timing advised by proponent[B]	Brief description Cost estimates in $2025	Actionable framework *Non-network options submissions due date[C]* *PADR date[D]*	New line build length (km)
Progressed from future to actionable ISP project					
Western Victoria Reinforcement	June 2029	June 2029	Minor network augmentations and equipment upgrades to reinforce supply to metropolitan Melbourne. $128 million (±50%)	Victoria	0
Tasmania REZ Expansion (previously known as North West Tasmania REZ Expansion)	July 2030	July 2030	A new double-circuit 220 kV transmission line from Burnie to Hampshire Hills. $245 million (±50%)	ISP *17 September 2026* *25 June 2028*	30
Central to North Queensland Reinforcement (Stage 1)	July 2031	July 2031[E]	String the 2nd circuit between Stanwell and Broadsound 275 kV. $209 million (±50%)	ISP *17 September 2026* *25 June 2028*	0
Gippsland Offshore Wind Transmission	Stage 1: July 2031 Stage 2 (Phase 1): July 2033 Stage 2 (Phase 2): July 2038	Stage 1: July 2031 Stage 2 (Phase 1): July 2033 Stage 2 (Phase 2): July 2038	Gippsland Offshore Wind Transmission is required to integrate offshore wind into the existing Latrobe Valley infrastructure. Stage 1 is a 500 kV double-circuit radial line from Loy Yang to Giffard. Stage 2 (Phase 1) is a 500 kV double-circuit radial line from near Woodside to near Hazelwood. Stage 2 (Phase 2) is a 500 kV double-circuit line linking the two Gippsland radial lines Stage 1: $1,500 million (-50% to +100%) Stage 2 (Phase 1): $790 million (-50% to +100%) Stage 2 (Phase 2): $400 million (-50% to +100%)	Victoria	175 all Stages
Central-West Orana REZ Expansion	March 2033	March 2033	Operate the existing Central-West Orana lines between Elong Elong and Merotherie substations to 500 kV, including expanding Elong Elong substation and adding a second Merotherie Substation. $855 million (±50%)	New South Wales	134
Other projects identified as newly actionable					
Switching Station Near Wondalga	April 2031	April 2031[F]	A new switching station at the 'Y-point' connecting the three 500 kV HumeLink lines to improve transfer from Southern NSW to Bannaby. $220 million (±50%)	ISP *Non-network options already requested for Draft 2026 ISP* *30 April 2028*	0
Brisbane Area 275 kV Reinforcement	June 2032	June 2032	A new double-circuit 275 kV transmission line between Blackwall and Karana Downs, including reconfiguring existing circuits between Blackwall, South Pine, and Rocklea. $63 million (-20% to + 30%)	ISP *17 September 2026* June 2028	4

A. The in-service date, provided by the project proponent, provides an indication for construction and commissioning to be complete and equipment is in service.
B. The capacity release and timing, provided by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/non-network-options-consultations for details on how to participate in non-network options consultation for the 2026 ISP.
D. For actionable ISP projects, the ISP may specify a date by which the project proponent must publish a PADR: NER 5.16A.4(c).
E. AEMO modelled this project with an earliest in-service date of December 2029, as advised by Powerlink for the 2025 *Electricity Network Options Report*, but Powerlink has subsequently advised a later timing.
F. AEMO modelled this project with an earliest in-service date of December 2030, as advised by Transgrid following the Draft 2026 ISP.

8.5 Future ISP transmission projects

Future ISP transmission projects would deliver net market benefits to consumers in at least one scenario, and are projected to be actionable in the future if that scenario eventuates. The projects and their timings are listed in **Table 12** and detailed in Appendix A5. The timings are indicative, as they depend on which scenario unfolds in future.

Future projects intending to proceed under the ISP framework do not yet need a RIT-T. Proponents may start planning and engaging with communities, if appropriate, to ensure the projects optimise long-term benefits for consumers.

Table 12 Future ISP projects in the optimal development path

Project[A]	Optimal timing *Step Change*	Earliest feasible full capacity timing	Brief description Cost estimate in $2025
Interconnector projects			
Queensland – New South Wales Interconnector (QNI Connect)	2041-42	2033-34	Add capacity between southern Queensland and New England, following development of the New England REZ Network Infrastructure project. $2,989 million (±50%)
Queensland			
Central to North Queensland Reinforcement (Stage 2)	2042-43	2033-34	Add transfer capacity between Central Queensland and Northern Queensland and allow the decommissioning of existing circuits between Bouldercombe and Nebo. $1,850 million (±50%)
South West to South East Queensland Reinforcement	2041-42	2028-29	Replace existing transformer at Middle Ridge and implement a limit extension special protection scheme (similar to a virtual transmission line). $33 million (±50%)
Victoria			
Eastern Victoria Reinforcement	2033-34	2031-32	Add transfer capacity between Latrobe Valley and Melbourne to accommodate increased onshore and new offshore wind power generation. $70 million (-50% to +100%)
South West Victoria Expansion	2045-46	2033-34	Add transfer capacity between Western Victoria and Melbourne. $1,330 million (-50% to +100%)
South Australia			
Northern Transmission Project	2041-42 (*Accelerated Transition,* see Note)	2031-32[B]	A new 275 kV line between Bundey and Adelaide (Bolivar/Dry Creek) to transfer renewable generation north of Adelaide to the Adelaide demand centre. $1,429 million (±50%)
Tasmania			
Second Tasmania REZ Expansion	2034-35 (*Accelerated Transition,* see Note)	2030-31	Convert a 110 kV line to 220 kV operation, to connect renewable generation to Hobart, as well as mainland Australia. $224 million (-30% to +50%)

A. This table provides detail for the seven future ISP projects that are developed in *Step Change* by 2050 or are currently undergoing a RIT-T. Other future ISP projects that are developed in only one scenario are listed in Appendix A5 Network Investments.
B. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.

8.6 Distribution projects as ISP development opportunities

Two projects have been identified in this 2026 ISP to facilitate connection of utility-scale generation and storage to the distribution network. These projects are identified as development opportunities, and cannot be actioned under the ISP framework: see **Table 13**.

The **Hunter-Central Coast REZ Expansion** is an extension of the **Hunter-Central Coast REZ Network Infrastructure Project**, needed to bring renewable generation in the Hunter to the demand centres of Newcastle and the Tomago aluminium smelter.

The **Dubbo Distribution Project** is also identified as an ISP development opportunity. EnergyCo, Transgrid and Essential Energy will continue to jointly plan this project, which may progress under the New South Wales *Electricity Infrastructure Investment Act* or alternative frameworks.

Table 13 Distribution development opportunities in the optimal development path

Project	Optimal timing *Step Change*	Earliest feasible full capacity timing	Brief description Cost estimate in $2025
New South Wales			
Hunter-Central Coast REZ Expansion	2030-31 (Option 2a) 2038-39 (Option 2b)	2030-31 (Option 2a) 2030-31 (Option 2b)	Distribution network augmentations between Singleton, Kurri, Newcastle and Tomago to supply generation from the Hunter and Central Coast REZ. $636 million (Option 2a, ±50%) $327 million (Option 2b, ±50%)
Dubbo Distribution Project	2032-33 (Option 1) 2033-34 (Option 2a)	2030-31 (Option 1) 2031-32 (Option 2a)	Both transmission and distribution works near Dubbo comprising new and upgraded substations and rebuild of 132 kV lines, to export generation and storage to supply the Sydney, Newcastle and Wollongong load centres. $607 million (Option 1, ±50%) $126 million (Option 2a, ±50%)

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9 Consumer and distribution actions to reduce grid-scale investments

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.

Consumer actions influence the nature and scale of grid-scale infrastructure in many ways. These actions include investments in CER, energy efficiency, electrification and demand management devices, decisions to allow their CER to be coordinated by an aggregator or retailer, and decisions to reduce loads when doing so would help system reliability: see Section 2.

These consumer actions rely on distribution networks to be effective. Those networks have always been critical in connecting those who produce and consume electricity, and their role is expanding to support the consumer actions and as surplus electricity is exported to the grid.

The ISP treats these demand-side factors as inputs to the modelling that identifies the optimal development path. While the modelling co-optimises the grid-scale investments in generation, storage and networks, it does not co-optimise these with the demand-side factors. These consumer decisions are made for a range of reasons that are largely independent of total energy system costs.

The ISP's three scenarios incorporate different levels of consumer action. As well, AEMO has tested how changes in the distribution network, CER coordination, and energy efficiency would affect both grid efficiency and consumer benefits. This section sets out how:

- **9.1 CER coordination and energy efficiency reduce grid-scale investment.** In *Step Change,* the coordination of consumer batteries and EVs have reduced the ODP's projected costs by $5.2 billion. Maintaining current or like policies to support energy efficiency has reduced costs by a further $9.5 billion, and greater investment may reduce them a further $7.2 billion. These benefits would flow through to consumers who do not own CER, as well as those who do.
- **9.2 Relatively small distribution investments would unlock more CER.** Optimising voltage management would overcome current network constraints so that CER would export an additional 3.8 GW to the grid. In the ODP, this avoids more expensive grid-scale investments, benefiting all consumers, and the distribution work may even reduce as more home batteries are installed.

These opportunities are detailed in the Demand Side Factors statement in Appendix A9.

9.1 Consumer actions bring system-wide benefits

Consumers take up CER, invest in energy efficiency or reduce demand for the household or business benefits they bring. Doing so helps make the power system more efficient, by helping operators manage minimum demand and reduce peak demand, and by avoiding investment in grid-scale infrastructure. As well, the

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benefits experienced by consumers with their own CER helps build support for larger-scale renewables and for the energy transition itself.

This section quantifies the potential benefits of CER coordination, energy efficiency and demand-side participation in the *Step Change* scenario through to 2050. For further details see the Demand Side Factors statement in Appendix A9.

Benefits larger if CER is coordinated

As well as operating on their own, CER can be ‘coordinated’ with other CER in many beneficial ways. Third party providers offer CER owners financial incentives to participate in a ‘virtual power plant’ or VPP, and coordinate energy flows to and from batteries and rooftop solar.

The *Step Change* scenario assumes that the capacity of rooftop and other small-scale solar would reach 87 GW in 2050 supported by 35 GW/78 GWh of CER battery capacity, of which just over half would participate in a VPP. The scenario also forecasts 80% of all vehicles to be EVs by 2050, with over 10% of private EVs participating in V2G programs, providing an additional 4 GW/49 GWh of coordinated storage.

This coordination benefits all consumers, not just those who own CER. It helps balance supply and demand across the grid, lowering the need for grid-scale investment. In particular, coordination enables CER to respond to market signals, helping to reduce operational demand from the grid and moderate prices during the evening peaks. In the ODP, this reduction would avoid up to $5 billion being spent on additional utility-scale storage in the NEM. A number of coordination trials are either underway or have been completed recently to help facilitate greater coordination uptake, including V2G trials supported by the Australian Renewable Energy Agency (ARENA) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO), and VPP trials including Project EDGE and Project Symphony.

Efforts are also underway through the National CER Roadmap[67] to plan and prepare the grid to safely and effectively integrate these technologies and maximise their system-wide benefits. However, more is needed to build consumer awareness and social licence, so that higher levels of coordination can be reached. VPP products might offer explicit benefits to CER owners, alongside broader campaigns that stress the benefits to all consumers. Consumer protections must be in place so that homeowners and small businesses can trust those providers to run their CER safely, in their interest, and without them having to be energy experts. Policy support such as the Cheaper Home Batteries Program[68] will help remove financial barriers.

Energy efficiency reduces grid-scale investment

More benefits are secured by the more efficient use of energy, where households and businesses are able to reduce or avoid its use, or shift it away from peak demand periods. When they do, there are benefits for the individual consumer, the grid as a whole, and the environment. Energy efficiency reduces the total cost of the energy system by lowering energy use through the year and avoiding unnecessary investment. It also accelerates decarbonisation by making each renewable investment go further to meet the needs of consumers – after all, reducing energy use is the most effective means of reducing emissions.

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[67] See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

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

These options are supported by current government policies, and like policies are assumed to continue to 2050. If they did not continue, energy efficiency improvements would be about 35% lower than forecast, investment in grid-scale infrastructure would rise by $8 billion through to 2050, and total system costs would rise by $10 billion. Conversely, if energy efficiency was 27% stronger than forecast in *Step Change*, it would avoid an additional $6 billion of investments in grid-scale infrastructure by 2050, and over $7 billion in total system cost.

Demand flexibility reduces grid-scale investment

Large consumers may agree to reduce their electricity consumption during extreme conditions of system stress. This 'demand-side participation' is a valuable way to reduce system reliability risks. VPPs are also able to offer this flexibility on behalf of smaller businesses and households. In total, AEMO projects that demand-side participation would make over 2 GW available for use by 2050 under *Step Change.* This would correlate to 1% of NEM capacity in the ODP, though it would not be called on often. Individual consumers would also be able to shift the patterns of their energy use to take advantages of cheaper tariffs and other demand management systems: see Section 2.1.

9.2 Distribution networks can help fulfil CER potential

Consumers may supply electricity to the grid when their CER generation exceeds what they need themselves. This surplus electricity may then be available to benefit all consumers, and reduce the need for grid-scale investment. Retail competition and government policies are supporting this equitable sharing of benefits, but they depend on distribution networks across the NEM being able to cater for the energy flows. To date, distribution networks have limited capability to do so, as they must manage voltage levels and cannot exceed equipment limits.

Distribution networks are now being rapidly upgraded to cater for the forecast doubling of electricity demand through the NEM by 2050: see Section 2. In addition, the ISP estimates that distribution network expansions would accommodate 8 GW of grid-scale generation and storage and 3 GW of mid-scale generation, as well as innovations to cater specifically for the forecast expansion of CER.

Distribution network opportunities to facilitate operation of CER may include voltage management through software upgrades, control schemes or operational changes, with relatively low capital investment. SA Power Networks has enhanced its voltage management across zone substations, several networks are trialling network and community mid-scale batteries, and in New South Wales "urban renewable energy zones" are being considered in the Illawarra and the metropolitan Sydney area, to accommodate more utility-scale resources within the distribution grid.

AEMO's modelling suggests that optimising voltage management at the distribution level would unlock almost 4 GW of latent CER capacity, for an investment of $214 million in present value terms: see **Table 14.** This is a relatively modest investment and return, but is on top of the broader investments noted above, as DNSPs upgrade their networks through to 2050.

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Table 14 Additional CER export capacity unlocked through distribution network investment in voltage management schemes (MW)

Region	Sub-region	Additional CER export capacity (MW)	Region	Sub-region	Additional CER export capacity (MW)
New South Wales	Northern New South Wales	0	**South Australia**	Northern South Australia	79
	Central New South Wales	526		Central South Australia	851
	Sydney, Newcastle & Wollongong	101		South East South Australia	41
	Southern New South Wales	291	**Tasmania**	Tasmania	0
Queensland	Northern Queensland	46	**Victoria**	West and North Victoria	500
	Central Queensland	0		Greater Melbourne and Geelong	1,168
	Gladstone Grid	4		South East Victoria	22
	Southern Queensland	146			

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PART D

Delivering the optimal development path

Part A
The energy transition is well underway

Part B
Preparing a least-cost path for the NEM

Part C
Generation, storage and network investments in the ODP

Part D

Part D
Delivering the optimal development path

Part C has identified the ODP as the least-cost way to meet rising consumer needs through to 2050, as coal plants retire and while meeting government policies.

Delivering the ODP would provide secure and reliable electricity, keep energy costs as low as possible while meeting government policies, support investment in CER and broaden access to its benefits, help reduce emissions across the economy, add to energy self-reliance and insulation from global shocks to the price or supply of fuel for generation and especially transport, and manage risks through a complex transformation.

The next five to 10 years are critical to the transition, with the withdrawal of most remaining coal plants. The pipeline of project development is encouraging, but achieving the ODP will require a faster rate of generation and storage delivery than has been achieved to date, alongside the timely delivery of most transmission projects within the next decade.

Part D sets out how:

- **Section 10 – The ODP would achieve its objectives.** It would maintain system reliability and security and reduce emissions at least cost. Its transmission elements would reduce total system costs by $28 billion (weighted across all scenarios).
- **Section 11** – **The value of transmission increases if generation is delayed.** Investment in transmission would mitigate the impacts of delayed generation, even if the transmission itself experiences costly delays. Transmission would also become more valuable to consumers if there is significantly higher demand for electricity.
- **Section 12 – Coordinated action is meeting the challenges ahead,** to ensure the NEM is ready for each coal plant retirement. While significant investment is being made, and market and policy settings are being tightened, more action is needed on planning approvals, social licence and supply chain issues.

Part D concludes with Section 13, the next steps for advancing the ODP and its projects.

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10 The ODP would achieve its objectives

AEMO has applied the ISP methodology (Section 4) to identify an ODP that offers the greatest net market benefits for consumers. It has balanced the risks of over- and under-investment, and used sensitivity analysis to test it against differing assumptions, given various uncertainties facing the energy future.

Delivering the ODP would provide secure and reliable electricity, keep energy costs as low as possible while meeting government policies, support investment in CER and broaden access to its benefits, help reduce emissions across the economy, add to energy self-reliance and insulation from global shocks to the price or supply of generation and especially transport fuels, and manage risks through a complex transformation.

This section sets out how the ODP would fulfil the ISP's legislated purpose and contribute to meeting the National Electricity Objective if it is delivered as planned through to 2050:

10.1 **The power system would remain safe, secure and reliable** as coal plants retire.

10.2 **Government energy and emissions policies** would be met.

10.3 **Consumer needs would be met at least cost.** Total system costs would be reduced by $28 billion (weighted across all scenarios), compared to there being no new transmission.

However, supply chain and other constraints may mean that ODP project delivery for both generation and transmission is delayed, which would in turn delay achievement of renewables and emissions targets. This possibility is canvassed in Section 11.

10.1 Power system needs would be met as coal retires

Power system security and reliability require different technical solutions and operational approaches as the system approaches 100% renewable generation. AEMO's 2025 *Transition Plan for System Security* sets out the requirements to maintain a secure and reliable power system through the next phase of the energy transition. Grid security and reliability are defined in Section 4.1.

System security supported by multiple technologies

New generation and firming technologies provide both opportunities and challenges for system security through the energy transition – in particular as coal plants progressively decommit and close through the transition. AEMO's 2025 *Transition Plan for System Security* navigates these and other key "transition points" that require material changes in the operational approach to managing power system security.

For the ISP, AEMO has tested how system security would be maintained by the ODP through to 2050: see Appendix A7. The projected total inertia online in the mainland NEM remains above the system-wide minimum requirement to at least 2042.

In the near term, emerging system strength deficits are being addressed by TNSPs in Queensland, Victoria, New South Wales and Tasmania. While most of the identified risks have solutions underway, interim measures such as contracting synchronous plant may be required until the permanent solutions are installed.

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Solutions are being explored to manage risks when multiple coal units are offline at the same time due to maintenance, two-shifting and other market conditions, or contingency events.

In the longer term, an increase in system security services will be needed as coal-fired generation is replaced by variable wind and solar. AEMO estimates that the cost to provide system strength services across the NEM would be just under $3 billion through to 2050. These costs are included in the ODP's capital cost (see Section 10.3 below) and include:

- synchronous condensers fitted with flywheels to provide both system strength and inertia, and
- grid-forming BESS that are able to provide frequency control, voltage stability and some system strength services.

In addition, the following costs are captured in the ODP's generation and transmission estimates:

- gas turbines fitted with clutches to act as synchronous condensers, providing security services even when not generating power, and supporting system restart if fitted with self-start capabilities, and
- new transmission interconnectors that help system strength and voltage control by lowering system impedance, with additional system strength solutions included by TNSPs in the RIT-Ts of these projects.

The appendix also explains AEMO's approach to power system security planning across multiple timeframes; reviews how recent and ongoing regulatory reforms are aiming for increasingly efficient and proactive investments for system security; and describes the technical, economic and locational drivers of the services needed.

This work confirms the *Transition Plan for System Security*'s call for timely investment in system security services over the next 10 years to make sure the grid remains stable and secure when coal-fired power stations switch off.

AEMO has also published several 'Statements of Security Need' for new transitional services, with more in development. The ability for AEMO to procure these services was introduced under the 2024 'Improving Security Frameworks' rule change. It will support operability and help trial new technologies to maintain system security as the grid transitions to a low-emissions environment.

System reliability secured by storage and gas

To be reliable, the NEM must match supply with demand from consumers while keeping power system equipment within its operating requirements: see Section 4.1. The details of system reliability and operability through the ODP under a range of conditions are set out in Appendix A4.

Peak demand is projected to be met within the reliability standard throughout the entire planning horizon, through combinations of renewable generation and storage, backed up by gas-powered generation.

A primary risk to the NEM's reliability is through an extended renewable lull: see Section 6. The ODP was tested to ensure supply could meet sustained periods of high demand during a 15-day winter period with intermittent renewable lulls across the southern mainland: see **Figure 24**. Demand was met by storages shifting what energy is available during the middle of the day to support the evening peaks, as well as sustained gas generation and imports from other regions.

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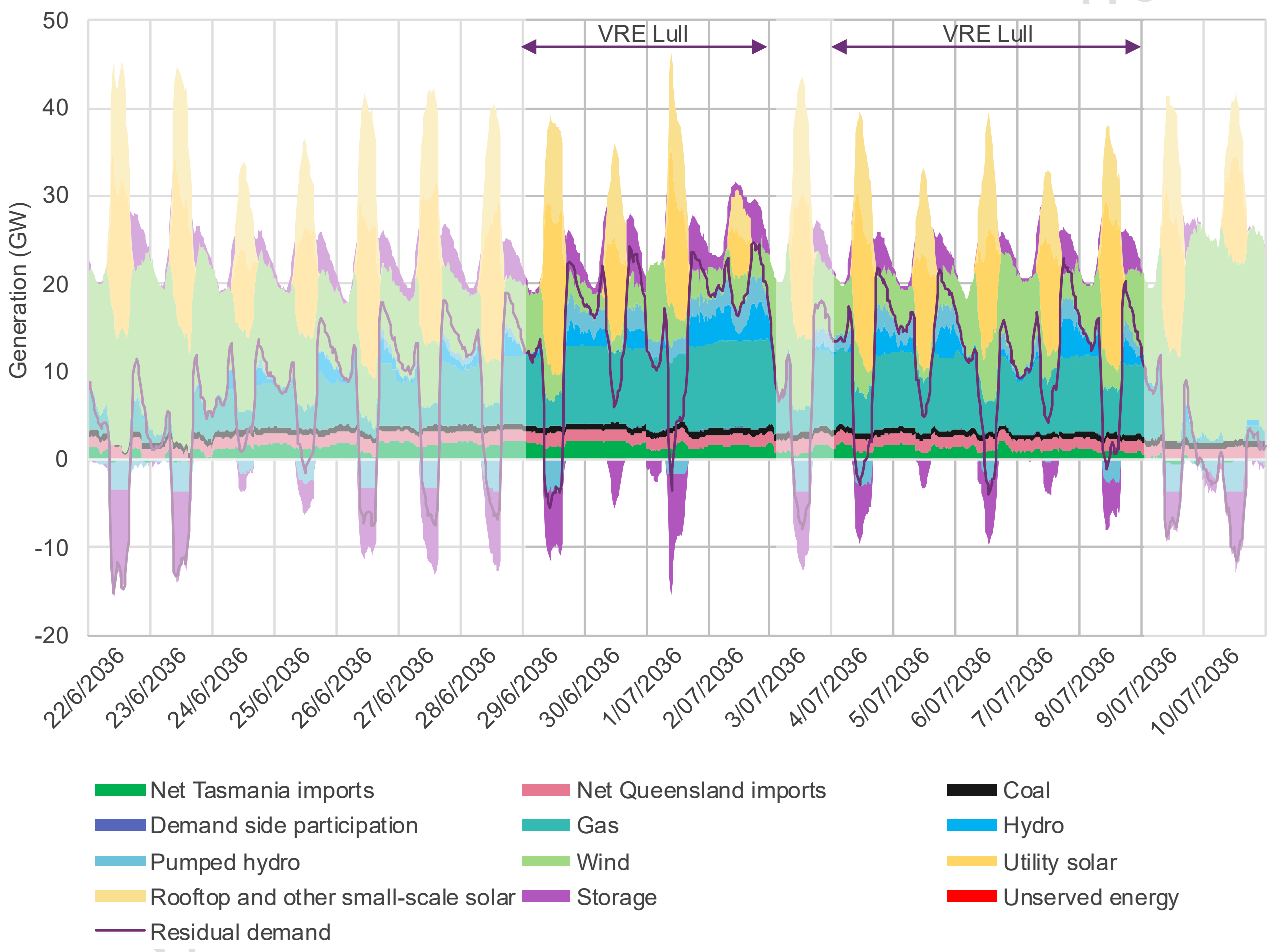
After a lull, storages may be charged up in preparation for the next lull, from gas generation if there is not enough surplus wind and solar. If there is no time for shallow and medium storage to recover between lulls, their role is severely limited. On the other hand, deep storages would still be available for the next lull, as long as their reservoirs are managed to have that capacity when needed most.

The strategic back-up role of gas generation is evident through this period, although events needing its heavy utilisation would be rare: see Section 7.1. The reliance on expensive gas generation may be reduced by demand flexibility, energy efficiency, or other demand side factors that lower electricity use: see Section 9.2.

Figure 24 Southern mainland NEM generation profile during a prolonged low renewable event (GW, 2035-36 and 2036-37, *Step Change*)



10.2 Government policies and targets would be met

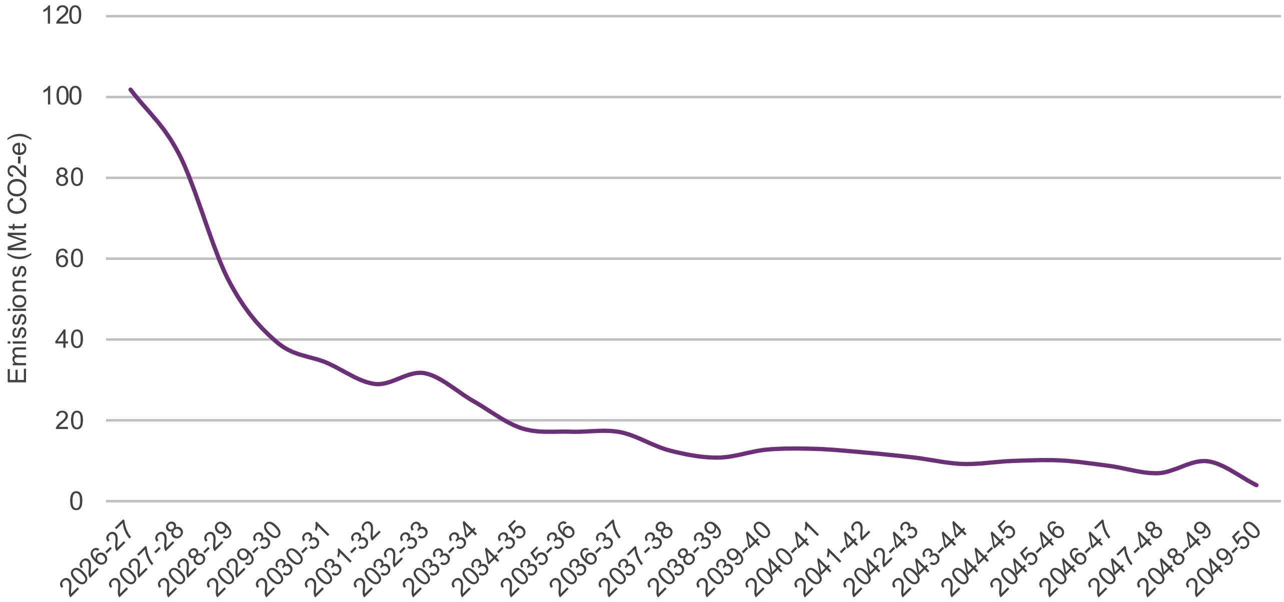
The ISP considers the emission reduction and energy targets stated in the AEMC's *Emissions Targets Statement,* and the other committed environmental or energy policies listed in Section 4.2 and likely to impact the power system.

If delivered, the ODP would meet the federal 2030 targets for the NEM's supply to be from renewable sources, and would contribute to all 2030 and later state and federal emissions reduction targets across the economy.

Under the ODP, NEM emissions would decline rapidly from just over 100 million carbon dioxide-equivalent tonnes (tCO_2-e) today to about 39 Mt CO_2-e in 2030. Emissions would then fall more gradually to about 10 Mt CO_2-e in 2039, and finally to 3.8 Mt CO_2-e in 2050: see **Figure 25**. Amid the downward trend, year-on-year variations would occur to reflect the availability of renewable resources, water in hydro reservoirs, and the need for gas generation to operate as backup supply to meet demand.

The NEM's transition would also support emission reductions across other sectors of the economy such as transport and services, and complement reductions in sectors such as agriculture and land use. As electricity sector emissions all but flatline after 2039, the achievement of longer-term national targets will depend on other sectors.

Figure 25 Projected NEM emissions trajectory, *Step Change*, 2026-27 to 2049-50 (Mt CO_2-e)



10.3 Consumer needs would be met at least cost

As discussed in Section 4, AEMO seeks an ODP with the lowest long-term system costs – or 'least cost' – that meets power system and rising consumer needs, while coal plants retire and while meeting government policies. The full cost benefit analysis of the ODP is set out in Appendix A6.

The identified ODP would cost less than all other tested combinations of generation, storage, firming and network technologies, seeking to meet government policies, and to meet consumer needs while taking into account their own energy investments.

The ODP's direct value to all energy consumers is threefold. It would meet their need for reliable and secure supply at least cost, lower CO2-e emissions, and broaden access to the benefits of CER investment and use.

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ISP Explainer: Calculating the ODP's benefits and costs

The ISP applies a standard approach with several elements to assess and compare long-term infrastructure investments, following the AER's guidelines for cost-benefit analysis.

First, the ISP looks only at decisions that are yet to be made. Existing, committed and anticipated investment decisions are not costed or re-evaluated, as they do not affect future planning. The electricity network in eastern and southern Australia has been progressively built since 1924, with major grid-wide investments in the 1950s and the 1980s, continuing up to the present day. The costs of these existing assets have already been incurred, and do not affect the cost-benefit analysis to determine the optimal path for future development. Similarly, capital costs of committed and anticipated projects are common to all potential development paths and therefore do not affect the cost-benefit analysis.

Second, while the ISP co-optimises all grid-scale generation, storage and network investments to find the optimal mix, the comparative measure is based on the choice of transmission projects. This reflects the specific role the ISP has in 'actioning' transmission projects. To compare candidates, AEMO looks at the market benefits of the transmission projects only. One of the candidates is the 'counterfactual', the path with generation, storage and distribution projects, but no new transmission projects beyond those already committed or anticipated. A candidate path has a *gross* market benefit if it reduces the other system costs more than the counterfactual. They may avoid or defer new generation and storage, or lower fuel and emissions costs from both existing and new plant: see Section 4.1. A candidate has a *net* market benefit if the gross benefits are more than its own transmission project costs. The candidate with the highest net market benefit is further examined for its suitability as the ODP (subject to its selection being robust to uncertainty, as tested in the sensitivity analysis). This is the net market benefit reported in the ISP.

Finally, AEMO reports on ODP costs and benefits over the ISP time horizon (that is, to 2050), in 'present value' terms. All the future costs and benefits of investments are discounted to today's dollar value, to be compared on a like-for-like basis. This is needed because most of the asset costs are incurred upfront, while the benefits continue to flow for decades[69].

There are four steps in calculating the present value of ODP transmission projects and development opportunities:

1. Annualise capital costs. Upfront capital costs are spread evenly over each year of the asset's expected economic life. This starts from when the investment is made, and may extend well past the ISP's outlook period, up to 2050.
2. Add the financing costs. A compounding weighted average cost of capital (between 3% and 12%, depending on the asset) is applied to these annual costs to reflect the cost of raising equity and servicing debt.
3. Discount to present value. The future annualised costs to 2050 are then discounted to today's dollars using a uniform rate of 7%, reflecting that costs and benefits are worth less in the future.
4. Sum over time. The discounted annual costs are added together through to 2050.

These concepts are applied to the 2026 ISP below, as they have been for past ISPs.

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The ODP is the least-cost option, and its transmission offers $28 billion in consumer benefits

The ODP's net market benefits to consumers are calculated across the three scenarios. Across the three scenarios, the net market benefit to consumers to 2050 from the actionable and future ISP transmission projects is $28 billion. By avoiding more costly investment across the NEM, they would repay their investment costs, save consumers $26 billion in additional capital and operating costs, and deliver emissions reductions valued at a further $2 billion.

In the most likely *Step Change* scenario, the ODP's annualised capital cost of all new generation, storage and network projects to 2050 would be $106 billion, and its operating and fuel costs would be $77 billion, all in present value terms. Of the capital costs, the ODP's actionable and future ISP transmission projects account for $6 billion to 2050 in present value terms. Together with $3 billion in system security capital costs, these transmission projects support $97 billion of generation, storage, firming and distribution. In the counterfactual path without this transmission, far more solar, wind, storage and especially gas-powered generation would be needed, with much of the emissions from gas generation to be captured and stored underground[70]. In this case, the capital cost of the other investments would be $123 billion ($17 billion more than the ODP), and operating and fuel costs would be $89 billion ($12 billion more), meaning that under the *Step Change* scenario the ODP would save consumers nearly $30 billion in avoided capital, operating and fuel costs[71].

AEMO recognises that the actionable and future ISP transmission projects will continue to deliver value after 2050 (the time horizon for the ISP's cost-benefit analysis). In the ISP, transmission lines are conservatively assumed to have an economic life of 50 years, and most will be built in the early 2030s. The total upfront capital cost of the ODP's transmission projects is $16 billion in present value terms. In this cost-benefit analysis, $6 billion of the value is recognised up to 2050. These assets would become part of a transmission grid to benefit consumers for many decades to come.

Changes in ODP costs since 2024

Figure 26 below shows how the overall costs have changed since 2024:

- **Starting point** – in 2024, the ODP's annualised capital cost to 2050 including transmission was $122 billion, in present value terms based on June 2023 dollars.
- **Time effects** – there are two time effects on the value of money that increase the 2026 ODP costs, using standard accounting practices. The first is inflation: a $100 cost in June 2023 has become a $106 cost in June 2025. The second is less obvious: the time value of money, or the present value of future costs or benefits. The sooner a future cost is incurred or a benefit received, the more it is worth today. For example, if given a choice between receiving $100 next year or in ten years time, most would value the

[69] The Australian Centre for Evaluation, *Cost-Benefit Analysis*, The Australian Treasury, 2025, https://evaluation.treasury.gov.au/sites/evaluation.treasury.gov.au/files/2025-07/guide-cost-benefit-analysis.pdf.

[70] While this assessment includes the cost for gas-powered generation with carbon capture and storage (CCS) technology included, it does not include the costs of establishing CCS transport and storage infrastructure.

[71] The 'scenario weighted' benefits are less than in *Step Change,* as they are increased in *Accelerated Transition* less than they are reduced in the equally weighted *Slower Growth.*

nearer term payment more highly. While many of the 2026 ODP investments are needed in the same years as they were in 2024, two years have now passed. As a result future value is not discounted as much, so present value rises. These two time effects take the 2024 ODP's present value of capital costs to $147 billion, however they have a similar effect in raising the present value of the ODP's benefits.

- **Projects progressed** – in that time, some generation, storage and transmission projects have progressed to become 'committed', 'anticipated' or 'policy-supported' projects, so $48 billion is excluded in the costs of the 2026 ODP. The assumed cost of these projects in the 2024 ISP is therefore also removed so that the two capital costs are comparable.

Now comparing like-for-like, the equivalent cost of the ODP in the 2024 ISP would be $99 billion in June 2025 dollars.

However, several external factors have also driven changes in total system costs since the 2024 ISP, as reflected in updated inputs and assumptions.

- **For the overall cost of the ODP**, reducing factors include a higher CER forecast (leading to less grid-scale investment), and lower capital costs of solar and batteries. Those adding to the overall capital cost are the inclusion of distribution network development opportunities (which in previous ISPs had not been costed), and higher capital costs for wind projects.
- **The overall cost of transmission** in the ODP is reduced as the overall length of transmission is about 1,435 km less and some projects use less equipment. This, combined with the progression of some transmission projects to 'anticipated', reduces the required actionable and future transmission build by around 50%. These factors have outweighed the higher capital costs for transmission per km, and the increased number of (smaller) transmission projects.
- **Addition of system security costs**. For the first time, the ISP is including the cost of additional system security investments as coal plants retire (system security services to accommodate new renewable energy projects were already included): see Section 10.1. These additional investments are projected to be $3 billion.
- **Addition of distribution development.** For the first time, the ODP includes two sets of distribution network investments, adding $600 million to the ODP's annualised capital costs – $383 million is to connect grid-scale generation and storage within the distribution networks, such as the Dubbo distribution project, and another $214 million would support network refinements to help broaden access to what would otherwise be latent CER capacity.
- **Weighted average cost of capital** (WACC). There has also been a material change to the WACC for all infrastructure investments, in response to stakeholder feedback. In previous ISPs, an assumed pre-tax WACC of 7% was applied to all infrastructure. This has been reduced to 3% for transmission projects, recognising that the assets have regulated revenues, and so carry lower risk. The assumed WACC has increased to between 7% and 12% for generation and storage projects, depending on the technology, recognising their slightly higher investment risk in a competitive market.

The updated assumptions lift the capital cost of the ODP to $102 billion - 3% higher than the adjusted ODP capital cost equivalent of $99 billion in the 2024 ISP. The new scope items then further lift the capital cost of the 2026 ODP to $106 billion (7% higher).

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Figure 26 shows the capital costs of the ODP's grid-scale investments in the NEM. Selection of the ODP is based on a range of costs, which also includes operating and fuel costs amounting to $77 billion.

Separate to this, the ISP has discussed how consumers and the gas industry would be investing in the energy transition. These costs do not directly drive the selection of the ODP, but they may influence it indirectly by shaping key assumptions, including gas availability, CER uptake and underlying demand forecasts.

- **Consumer investments.** Uptake of rooftop solar, batteries and EV chargers is forecast to increase through to 2050 in the *Step Change* scenario. Consumers also make additional investments in CER, including energy efficiency upgrades, electric appliances and conversions, vehicle purchases, and associated operating costs. Individual households and businesses invest to meet their energy needs, managing the risk of rising energy costs, and contribute to emission reductions. The ISP does not optimise these investments, but takes into account expected uptake when determining the required utility-scale investment.
- **Gas sector investments**. AEMO has identified four gas development projections in this ISP, for midstream[72] gas investments such as transmission pipelines and expansions, regasification terminals, storage facilities and production plants. One of these projections has been used to help calculate gas fuel limits in the ODP, although ultimately the gas investment would be market-led and any one of the gas development projections (or new alternatives) could be developed. Its capital costs are estimated at $1 billion and its operating costs $1.4 billion through to 2050. These cost estimates do not include any upstream costs for the exploration, drilling and extraction of raw gas.

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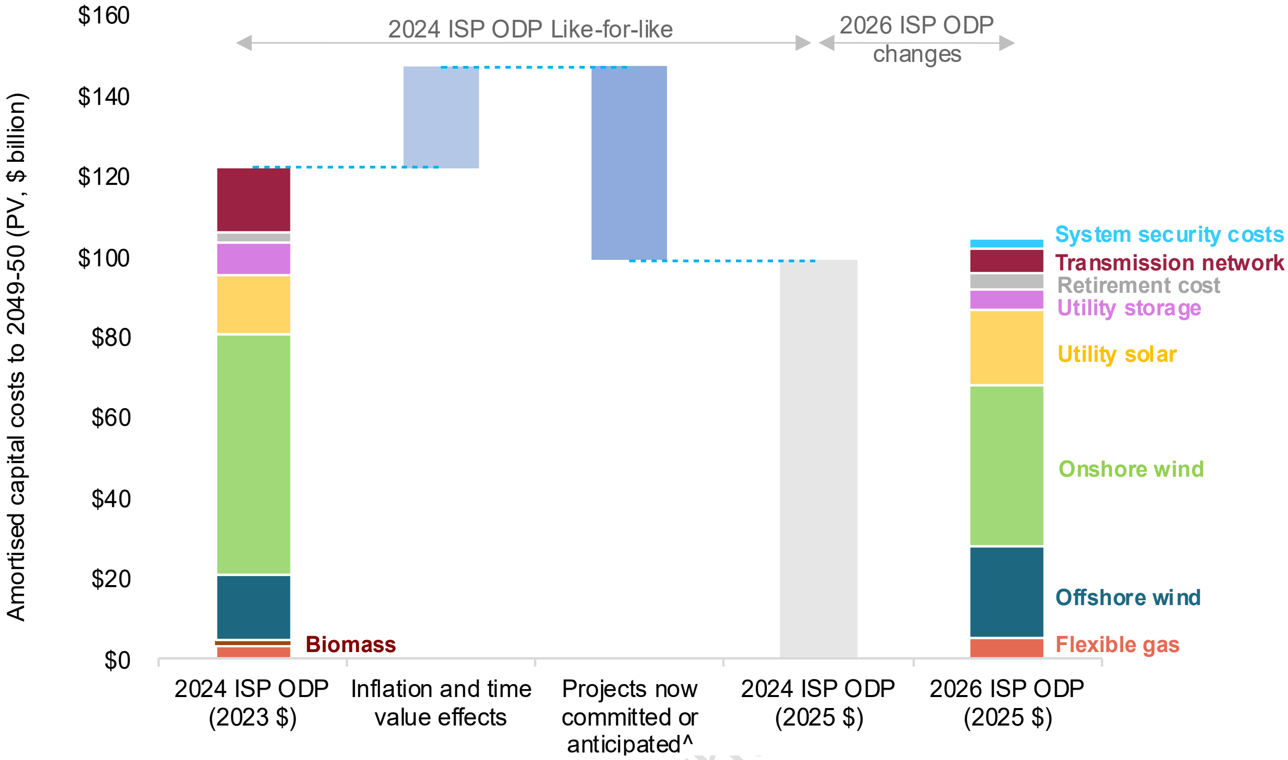
[72] Production of gas can be divided into upstream, midstream and downstream components. Midstream infrastructure costs are those associated with the processing of gas, and the transport and storage of that processed gas. Upstream costs are those associated with the exploration, drilling, and extraction of raw gas.

Figure 26 Changes between 2024 ISP and 2026 ISP costs annualised capital costs to 2049-50 (present value, $ billion)



^ This includes generation, storage and network projects.

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11 ODP selection is robust to delays in delivery and to higher demand

The next five to 10 years are critical to the transition. Most coal-fired plants are projected to retire by 2038, and the ODP projects a rate of infrastructure build to 2030 that is faster than has been achieved to date. As well, there is a possibility that high growth in data centres and other electricity-reliant industries may increase demand on the NEM beyond the scenario assumptions.

The current connections pipeline is encouraging, but on its own would not reach the ODP's projected level of generation capacity for 2030. Even if all of the pipeline's solar and wind projects are delivered as planned, they would only deliver three-quarters of the new capacity needed. Reaching that level therefore requires both the delivery of the existing pipeline and the delivery of additional projects, particularly in areas where the pipeline remains thin. This represents a material delivery challenge, with timely development, financing, approvals, connection and construction. While battery projects are progressing ahead of expectations, storage alone cannot close the supply gap.

AEMO has conducted a *Constrained Delivery* sensitivity analysis to explore what may happen if new generation, storage and transmission were delivered faster than has been achieved to date, but still not as fast as in the ODP. This sensitivity applies slower build rates (closer to the rates recently observed) and higher capital costs (reflecting potential constraints such as planning approvals and the need for social licence, the supply chain, or construction). This section considers how under *Constrained Delivery*:

11.1 Delivery of generation projects would be delayed and more costly in the near term, before rejoining the *Step Change* trajectory by 2035.

11.2 Delivery of transmission projects would be delayed and more costly in the near term, before rejoining the *Step Change* trajectory by 2035.

11.3 Results confirm the need to progress transmission projects without delay. If near-term infrastructure delivery is slower and more costly than in *Step Change*, transmission becomes even more valuable. It also confirms that the ODP is robust to these delays in infrastructure delivery.

AEMO has also conducted a *Higher Demand* sensitivity analysis to explore the impact of significantly higher demand from data centres and other large industrial loads. It has found that:

11.4 The ODP is robust to higher industrial demand. Though the growth in new data centres and other industrial loads is highly uncertain, the *Higher Demand* sensitivity confirmed that the ODP is sufficiently robust to accommodate a sharper increase in demand from these sources, and indeed deliver even greater overall benefits to consumers in those circumstances.

Section 12 continues to discuss the coordinated action needed by market bodies, governments and industry to deliver the ODP as close to its timing as possible.

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11.1 Constrained delivery of generation projects

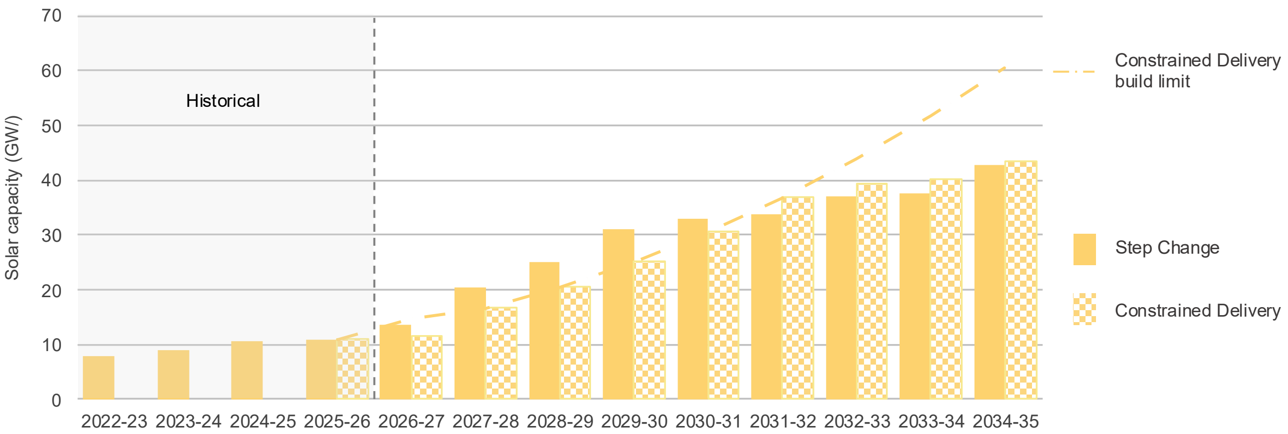
As shown in Section 5.2, the current build of solar and particularly wind in the connections pipeline would fall short of what is needed by 2030 in the *Step Change* scenario. Under *Constrained Delivery*, AEMO assumed that the build of generation capacity to 2030 would rise faster than its current rate, although not as fast as required in *Step Change.*[73]

The pace of new wind and solar development depends on supply chain and construction timeframes, market capacity, social licence and planning approvals, as well as financing and connection processes. Though there may be many reasons for delivery delays, the sensitivity only limited the rate of build, not what determined the delays. Appendix A2 explains how the assumed annual build limits were derived for this sensitivity.

The imposed annual delivery cap for solar is assumed to rise from the recent average of 1.3 GW up to 4.6 GW in 2030, and regains the ODP delivery trajectory by 2032: see **Figure 27**. Similarly, the annual delivery cap for wind is assumed to rise from 0.3 GW up to 2.3 GW, regaining the ODP delivery trajectory by 2035: see **Figure 28**. Victorian offshore wind would be delayed by three years, regaining its delivery trajectory by 2038.

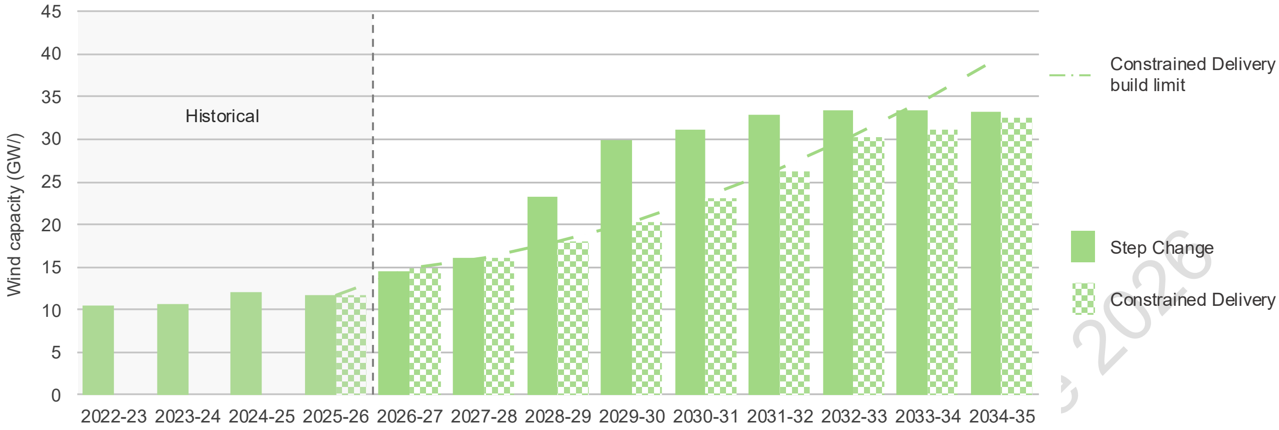
In this analysis, AEMO assumed that project costs would rise an average 30% – the upper range of the cost uncertainty for new developments in the 2025 GenCost analysis. Again, there may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the rise in cost only.

Figure 27 Capacity build of grid-scale solar under *Constrained Delivery* (cumulative GW, 2025-26 to 2034-35, compared to *Step Change*)



[73] The sensitivity also assumed a constrained delivery of battery storage projects, however, there is expected to be a relatively small impact, or less than 1 GW, on the overall battery build due to the strong pipeline of battery projects: see Appendix A6.

Figure 28 Capacity build of grid-scale wind under *Constrained Delivery* (cumulative GW, 2025-26 to 2034-35, compared to *Step Change*)



11.2 Constrained delivery of transmission

The constraints on the delivery of generation and storage development are equally likely to slow the delivery of network developments. Again, 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.

The assumed build rates for transmission projects under *Constrained Delivery* are shown in **Figure 29**. It was assumed that committed projects would be delayed six months, anticipated projects 12 months, and actionable and future 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). The Gippsland offshore wind transmission connection in particular would be delayed three years to align with delays in the proposed offshore wind projects in the *Constrained Delivery* sensitivity. Transmission build would then regain the ODP trajectory by 2036.

As delivery constraints slow transmission delivery, AEMO has assumed that their costs would rise, also by an average of 30%. 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.

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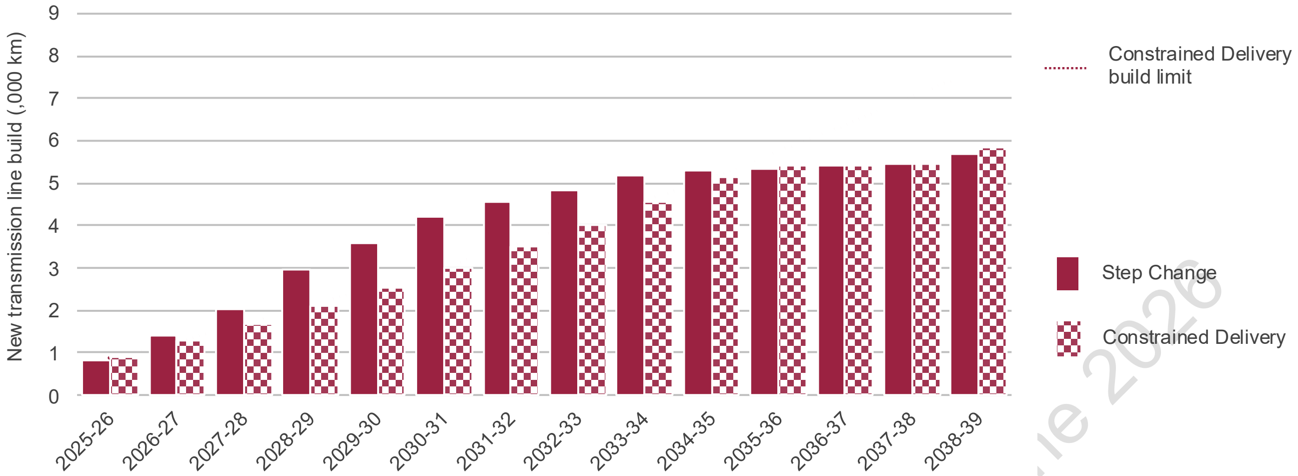
Figure 29 Transmission new build under ODP and under *Constrained Delivery* (,000 km)



11.3 Results confirm need to action ODP transmission projects

The *Constrained Delivery* analysis shows that if the delivery of generation and storage is slower and more costly, then the value of the ODP transmission would increase, even though its own delivery is slower and more costly. The analysis also confirms that the choice of ODP is robust to these delays, and underscores the need to progress the planned and actionable transmission projects in the ODP, without delay.

If infrastructure delivery is slower due to constraints, as in *Constrained Delivery*, the 2030 renewable energy targets would not be met to schedule and overall costs would increase by even more than the assumed 30% increase in capital costs. To ensure supply remains reliable, coal would remain in the system longer and far more gas generation would be used, slowing the rate of emission reductions and heightening gas supply risks.

However, transmission projects would mitigate some of these impacts, even if it also experiences costly delivery delays. Although there would be less new generation in the system in 2030, there would still be a very considerable 45 GW of renewables and 31 GW of storage capacity needing to connect. Transmission, delivered as soon as possible, supports access to this capacity, shares it efficiently across the NEM, and connects it to deep storages. These capabilities become increasingly important as coal plants age and the risk of unplanned outages or early closures rises.

- **Renewable energy would still contribute 75% of NEM supply by 2030**, though falling short of both the 82% renewable energy target for 2030 and the electricity sector's contribution to the national emissions target: see **Figure 30**. Development would then catch up to help meet the 2035 emission targets. Grid-scale solar capacity would reach 25 GW by 2030 (or 20% less than in the *Step Change* scenario) and then reach the *Step Change* level of 44 GW by 2035. Wind would reach 20 GW by 2030 (32% less) and then reach the *Step Change* level of 35 GW by 2035.
- **More gas and coal are needed for reliable supply, at higher cost.** With less renewable generation in the near term, more gas generation would be needed, increasing the capital cost of new plants by 44% over *Step* Change. As well, some coal would need to remain in the system longer to help maintain reliability, then close on or before announced closure dates. Statistically, failure rates increase as plants near the

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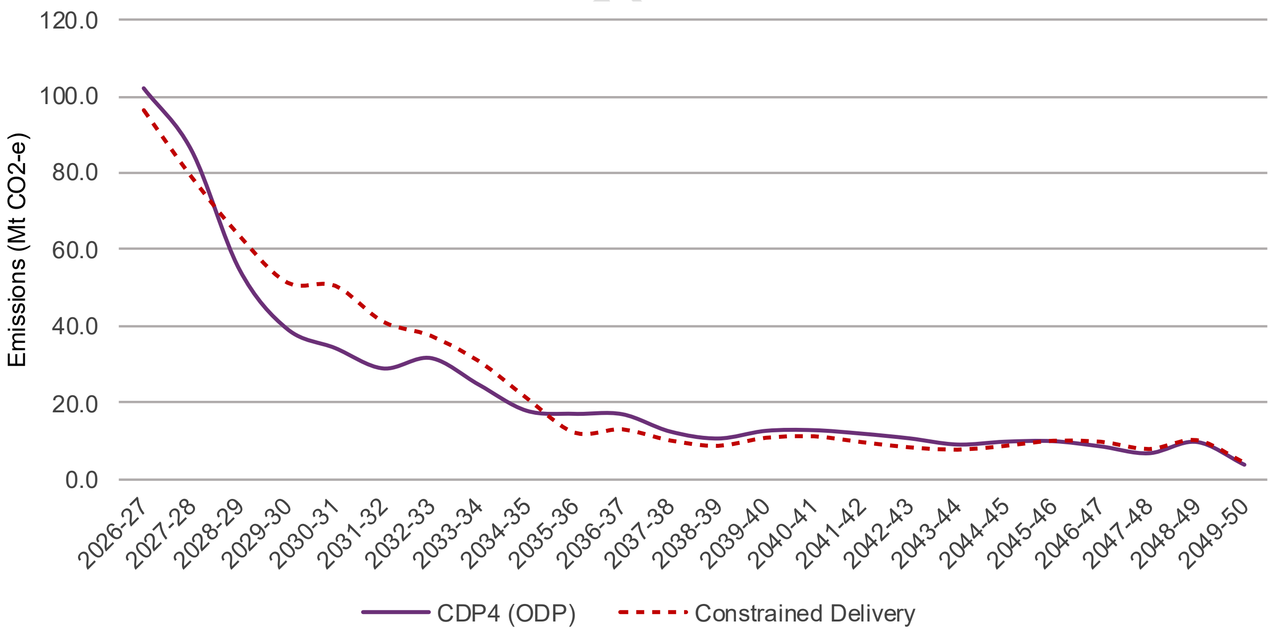
end of their planned operational life. An unforeseen critical failure of any one of these ageing power stations could potentially threaten power system reliability and security (especially if renewable development is delayed, as in this sensitivity).

- **Transmission connects renewables efficiently and helps mitigate the rising risks of unforeseen coal closures.** The transmission projects in ODP allow resource sharing across the NEM, which mitigates against the risks of unanticipated coal closures. These benefits are also evident for all candidate development paths considered for the 2026 ISP, although candidate development paths with more transmission built in near term perform marginally better in this sensitivity. This highlights the advantages of stronger network connections across the NEM, even if these network projects also experience costly delays.
- **Transmission is even more beneficial if renewables are delayed.** As set out in Section 10.3, the actionable and future ISP transmission projects in the ODP would bring consumers a benefit of $28 billion, weighted across the three scenarios, by reducing other costs and emissions. If infrastructure delivery was delayed and more costly, this benefit would increase. Although overall development costs are higher under *Constrained Delivery*, transmission would reduce those costs by $30 billion, compared to the counterfactual path with no transmission.

Delivering infrastructure at the pace required to meet both consumer and policy needs, while respecting community and stakeholder needs, remains the priority for the energy transition.

Figure 30 Forecast NEM emissions trajectory, *Step Change* versus *Constrained Delivery*, 2026-27 to 2049-50 (Mt CO_2-e)



11.4 Testing higher demand from data centres and other industries

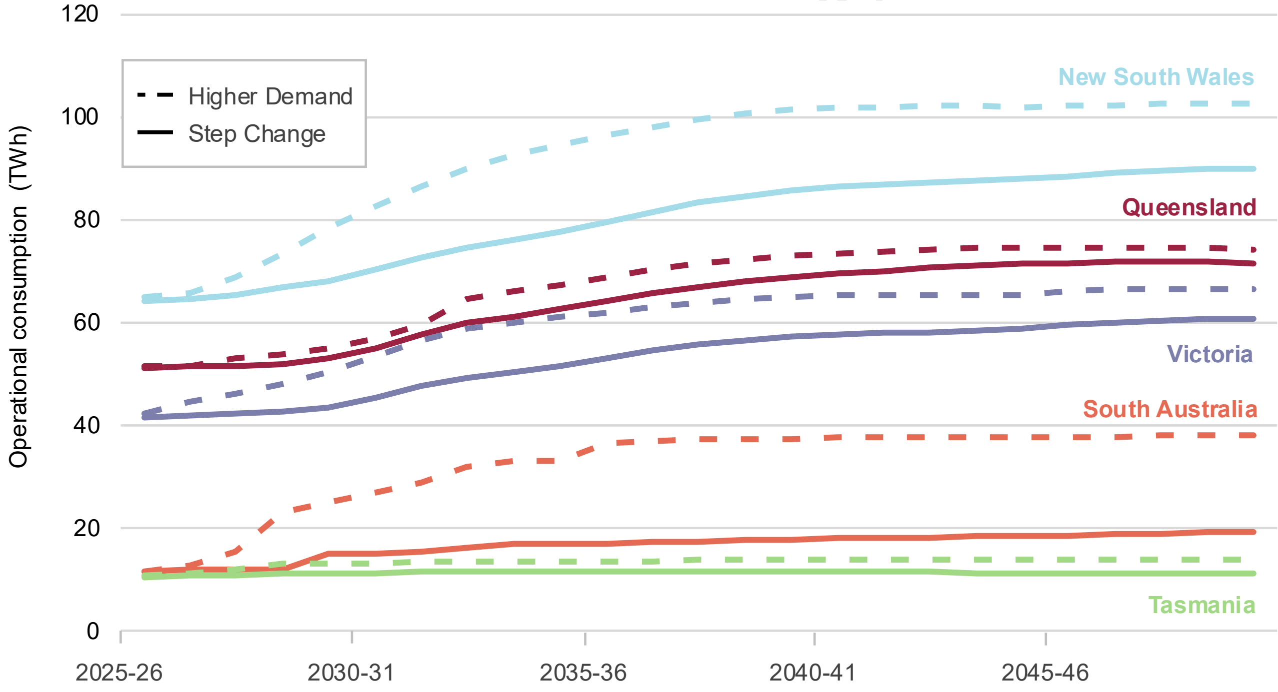
AEMO considered and modelled different levels of industrial demand in its three core scenarios, varying in their degrees of economic activity, decarbonisation, electrification and new green industries. A *Higher*

Demand sensitivity analysis then tested the ODP's resilience to a sharper increase in demand from data centres and other large industrial loads.

The *Higher Demand* sensitivity assumed about 39 TWh more electricity than *Step Change* would be needed in 2050, largely in the industrial centres of South Australia (an additional 18 TWh), Melbourne-Geelong (4 TWh), Sydney-Newcastle-Wollongong (11 TWh), and Gladstone (3 TWh). South Australia had the largest load increase in both absolute and proportional terms: see **Figure 31**.

Overall, the sensitivity projected the need for a large increase in generation and storage capacity across the NEM, largely proportional to the ODP's mix of solar, wind, gas and storage. Given the higher levels of demand and generation, the net market benefits of the ODP's transmission projects also increased significantly, from nearly $30 billion[74] in *Step Change* to $61 billion. The results did not affect the choice of ODP. The ODP remained very close to being the least-cost candidate in this sensitivity (only $60 million behind the candidate that was) which, along with other favourable sensitivity results, confirmed the ODP's robustness to uncertainties in key assumptions.

Figure 31 Impact of *Higher Demand* on operational consumption (TWh)



[74] This may be different to the figure in Section 10.3 due to the rounding of the component $17 billion and $12 billion parts.

12 Coordinated action to deliver the ODP

The ODP is the most efficient path to maintain reliable and secure electricity supply and meet government emission targets as coal retires. Ultimately, the market, consultation processes and NER frameworks determine the rate at which infrastructure is delivered.

The delivery of planned investment in generation, storage, network and system security, on time and in full, is critical to mitigate power system reliability and security risks while meeting government policies. As well, replacement generation and system security services must be available in advance of coal power station closures. The age and condition of some of these power stations may mean that delaying closure is not an option. The sooner firmed renewables are developed with deep access to the network, and alternate providers of system security services are available, the less risk there will be for the energy transition.

Significant progress is being made towards the ODP, although more work is needed. To deliver on that path, continued coordinated action is needed from industry, governments and market bodies, including in their engagement with communities.

This section sets out how:

12.1 **Significant progress is being made to ensure the NEM can be ready for each coal retirement.** There will remain challenges and risks to the ODP (or any potential delivery pathway), given the time needed for development, approval and connection processes, cost pressures and investment decision uncertainty. Energy market bodies and industry are cooperating to overcome these challenges one by one.

12.2 **Similar cooperative action is still needed on social licence and supply chain issues.** Planning for such a peak in infrastructure investment over the next decade requires early and genuine engagement with communities, and careful management of financial, supply chain and workforce resources.

The energy transition is well underway, and many projects are already committed or anticipated to ensure that it continues to advance quickly through to 2030. For the ODP in this 2026 ISP, the potential benefits are significant, but coordinated action is needed to achieve it.

12.1 Significant progress being made in the energy transition

The *Constrained Delivery* sensitivity in particular demonstrates that the best way to ensure the ODP delivers its benefits to consumers and the economy is to continue existing projects to plan, and start planned ones as soon as practicable.

Collaborative action is being taken on at least three fronts to ensure readiness for a low- or zero-emission power system:

- securing sufficient infrastructure investment,
- preparing market and power system operations for periods of 100% renewables and key transition points, and

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- integrating CER into grid operations to broaden access to benefits for all consumers.

Market and policy settings must be in place to support industry progress and keep the energy transition on track.

Ensuring timely and sufficient infrastructure development

The energy transition depends on timely investment decisions, which are hampered by uncertainty. Delays and uncertainties in energy regulation and environmental and planning approvals increase the complexity faced by electricity infrastructure investors and add to the cost and risk of project delay.

To help reduce that uncertainty, governments have a range of targets, policies, mechanisms and initiatives to support energy infrastructure and investment. Examples include the Federal Capacity Investment Scheme, the Electricity Infrastructure Roadmap in New South Wales, the Firm Energy Reliability Mechanism in South Australia, the Queensland Energy Roadmap, the State Electricity Commission of Victoria, the Tasmanian Renewable Energy Target and battery programs in the Australian Capital Territory. To complement these, the Electricity Services Entry Mechanism is proposed to follow the Capital Investment Scheme, a recommendation of the NEM Wholesale Market Settings Review. This would provide a long-term mechanism to support market certainty and confidence, which is essential given the scale and pace of investment required to achieve the energy transition.

The Climate Change Authority's *2025 Annual Progress Report* underscores what is needed to deliver these investments. The recent changes to the *Environmental Protection and Biodiversity Conservation Act* promise to streamline and enhance the planning and environmental approval processes for infrastructure. The delivery of renewable generation projects in the ODP would require a significant scaling-up, and while the current connections pipeline is encouraging, planning and environmental approvals will need to keep pace. For its part, AEMO is continuing to support streamlining connections approval processes, in partnership with the Clean Energy Council and industry.

As well, the need for higher levels of flexible gas capacity and utilisation depends on Australia's gas supply infrastructure. While investment in that infrastructure is determined primarily by other gas needs, investment is required to support the availability and operation of flexible gas: see Section 7.2.

Ensuring system security is ready for periods of 100% renewables generation

The NEM's energy markets, networks and operations are preparing for very high penetrations of renewable energy, including periods of 100% renewable generation, and the eventual departure of coal from the system. Continued action is needed to make sure that system services, resource adequacy and operational capability are in place in time for coal retirements.

AEMO published a *Transition Plan for System Security* in December 2025, setting out the actions and investments needed to ensure a smooth transition and a secure and reliable future energy system. As well, the AEMC published a consultation paper in March 2026 to consider changes to the NER's planning and procurement frameworks for system strength and inertia. This would address the emerging issue that security resources may exit the market before replacements can complete their approval, procurement and commissioning. The changes would build on other updates that support timely actions to meet system security needs over the energy transition.

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Integrating consumer and distributed energy resources

A least-cost transition for the NEM depends in part on the effective integration of consumer and distributed energy resources. Distribution networks will play a critical role in achieving this objective.

Distribution network planners, industry, governments, market bodies and consumer groups continue to work on reforms to drive benefits for both consumers and the power system. Opportunities include:

- Governments and retailers are introducing pricing and incentives for solar soaking and peak reduction (such as the Cheaper Home Batteries program and the Solar Sharer Offer scheme) and addressing counter-acting incentives where they exist,
- AEMO is collaborating with all NEM governments to develop a Demand Side Statement of Opportunities, similar to its existing gas and electricity statements. This would help identify and quantify demand-side opportunities to enable decarbonisation, support energy system reliability and security, and lower the cost of the energy transition. These opportunities would include demand flexibility initiatives beyond demand-side participation.
- The 2024 National CER Roadmap sets out an overarching vision and plan to unlock the benefits of CER for all Australians and the electricity system. Work on the Roadmap's 16 priorities has commenced, with the first completed priority being a list of 18 minimum requirements for CER devices to support their integration into the grid, endorsed by the ECMC in December 2025.
- The ECMC's recommended changes to the ISP framework has led to further consideration of distribution networks and CER in the ISP. This includes an AEMC directions paper for integrated distribution system planning, on which the AEMC is currently receiving feedback.

These and other initiatives are helping to ensure that all consumers benefit from the efficient integration of CER opportunities in the NEM.

Responding to the growth in data centres

AEMO is actively preparing for the rapid growth of data centres through the NEM, working with industry and market bodies to support their secure, efficient integration into the grid and energy system planning.

AEMO's *Quarterly Energy Dynamics* report now includes insights into data centre connections across the NEM, which in turn help guide AEMO's power system planning. Currently there are over 160 operational data centres in Australia, with almost half in Sydney and most others in Melbourne, Brisbane and Perth. They account for around 2% of today's grid-supplied electricity use. However, that use is projected to grow in the ISP by around 25% annually to reach almost 10% of the NEM's underlying demand by 2050 – five times the share it has today and the equivalent of 20% of today's total demand. At the end of the March 2026 quarter, 11 large data centres representing a total of over 5 GW of maximum demand were in the connections pipeline. To date, connections have taken about two years from application to energisation, similar to battery projects, and ramp up to full demand over 5-10 years.

AEMO has been working formally with the ECMC and other energy market bodies on the energy implications of data centres since March 2025. This includes investigating options to minimise system impacts, maximise potential system benefits, and ensure regulatory frameworks for data centres remain appropriate. AEMO also

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works closely with system operators across the United States and Europe to better understand the behaviour of large loads, improve operational visibility, and develop best-practice approaches to integration. AEMO's current focus is on efficient connections, demand forecasting, and system security.

To those ends, the AEMC is currently considering feedback on a draft rule change, initiated by AEMO, for new technical standards for large data centres. AEMO has developed interim guidelines to support proponents, and is also preparing a rule change for operational integration and visibility of large inverter-based loads (including data centres). These reforms respond to the current reliance on bespoke, case-by-case arrangements, which limit efficient investment signals and system operation. The proposed changes will introduce consistent operational requirements and streamline connection processes.

12.2 Similar collaboration needed on social licence and supply chain

The policy, market and operational settings noted above are largely in the hands of the energy industry. Even if they are in place, delivery of the ODP and the energy transition would not be guaranteed.

To deliver the transition on time, industry and governments are continuing to collaborate and coordinate their actions with communities throughout the NEM to secure the social acceptance and planning approvals needed. Similar collaboration is needed with global supply chain partners and governments to ensure the NEM has equipment, materials and workforce it needs to complete the transition.

Continue to build social licence through engagement, benefits and clear roles

Social licence – the ongoing acceptance and trust of communities – is essential to the success of the energy transition. It underpins three distinct needs: the development of new infrastructure, the integration of CER with grid operations, and broader support for national investment in the transition. Communities engage with this transition through a lens of local social, cultural, environmental, and economic values. Developers, network planners, governments and energy market bodies are working harder to appreciate those values and build trusting relationships with communities.

AEMO's approach to social licence issues and how they are incorporated into the ISP are detailed in Appendix A8. Building and maintaining social licence requires the coordinated effort of energy institutions, governments, industry and consumer and community advocates. The appendix lists the extensive work being undertaken on guidelines, market reforms and research. AEMO continues to participate where appropriate and recognises the importance of early, inclusive, and genuine engagement with communities, particularly those hosting new infrastructure.

- For **grid-scale infrastructure**, best practice approaches are reflected in the Federal Government's *National Guidelines for Social Licence for Transmission*, alongside state-based frameworks. These guidelines emphasise the importance of engaging early and inclusively, managing impacts fairly, delivering lasting community benefits, and continuously evaluating community sentiment. AEMO also recognises how uncertainty over projects can undermine community confidence in development, especially if they have already invested significant time, energy and emotion: see Section 8.4 and Section 8.5.

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- Meaningful partnerships with Aboriginal and Torres Strait Islander communities are being established and maintained to support First Nations economic empowerment and self-determination. For example, the First Nations Social Licence Merit Criteria in the federal Capacity Investment Scheme sets aside part of its capacity target for projects that show strong equity or revenue sharing agreements with First Nations communities.
- New infrastructure impacts the communities that host it, which in turn influences how projects are designed, approved and delivered. Projects for which community considerations are more complex would typically have longer design and approval processes. This effort is well spent, typically leading to better outcomes for the local community and for energy consumers. AEMO receives information on these issues from project proponents throughout their planning processes, and incorporates it into its modelling: see Section 4.1.
- For **the successful coordination of CER**, social licence is equally critical. Those who do wish to coordinate their CER must be able to trust VPP providers to run their CER safely, in their interest, and without them having to be energy experts. Consumer confidence in their experience of CER and VPPs is valuable in helping to build social licence for the energy transition itself. However, with vulnerable households and renters having limited access to CER, continued efforts are needed to ensure CER benefits are equitably distributed. Pricing reviews and reforms, and policies such as Solar Sharer, are aimed at equity and cost-of-living concerns, helping ensure that CER and its coordination benefit all consumers.
- For **the transition itself**, there is also the opportunity to develop and promote a shared national narrative that articulates the purpose and benefits of the energy transition – both broadly and in specific local contexts. This narrative should reflect the lived experiences of communities, acknowledge the challenges, and highlight the opportunities for shared value creation.

These principles provide a strong foundation and are being pursued by the responsible parties with appropriate intent. Communities may need greater clarity on who is responsible for building and maintaining social licence – not only in policy documents, but in practice. Under the NER and relevant state legislation, the primary responsibility for infrastructure-related community engagement and impact management typically rests with project proponents, whether public or private entities. However, approvals are granted by government bodies, and communities often look to these bodies when concerns arise. In the case of CER, governments also have a key role to play through the implementation of the National CER Roadmap, which outlines actions to support consumer participation, equity, and trust in the evolving energy system.

Consideration of social licence issues continues to strengthen through each ISP cycle, with support from the ISP Consumer Panel and AEMO's Consumer and Community Reference Group, and AEMO thanks them for their continued support and invaluable insights.

Ensure access to critical energy assets and workforce

The deep investments required in the ISP imply the need for hundreds of critical energy assets – utility-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers – and the people needed to install and operate them.

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In a global energy transformation, countries are competing for the same materials and technologies, which is exacerbating delivery risks. Australia may not be able to access reliable and cost-effective supply of these assets as global demand remains high, especially if the global supply chain is vulnerable. The competition is also increasing costs, for transmission in particular.

Governments are also aware of the need to build and shape Australia's skilled workforce[75] to support the continued investment in mining, infrastructure and construction and, increasingly, in defence industries and critical minerals. The demand for skilled people directly employed to build and maintain energy infrastructure was forecast in the 2024 ISP to increase from approximately 36,000 in 2025, to over 57,000 by 2050[76]. This growth will challenge engineering, procurement and construction (EPC) firms and regional communities, particularly if there are boom-and-bust cycles or if workers and contractors are engaged project-to-project.

Along with its other benefits, early investment in essential infrastructure may mitigate against supply chain risks in future, retain Australia's spot in global queues for essential equipment and materials, and ensure our ability to respond to future market and climate events.

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[75] See https://ministers.dewr.gov.au/oconnor/launch-towards-renewable-energy-superpower-report.

[76] The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050, https://www.aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.

13 Next steps to advance the ODP

The NEM is delivering the energy transition: a once-in-a-century change in the way electricity is generated and consumed in Australia, the largest since electricity generated from Latrobe Valley coal was carried to Melbourne by transmission in 1924. That transition is essential for the Australian economy to enjoy low cost and reliable energy, while achieving net zero emissions by 2050.

While the precise mix and location of future generation, storage and transmission will be determined by investors, network providers and, in some cases, governments, the ODP identifies a near term development pathway that can be progressed with confidence to support a secure, reliable, least cost and lower emissions power system.

The energy transition and the ODP's delivery will require a concerted effort from industry, governments and communities – over the next decade in particular. That effort is being made in every necessary quarter, as the energy transition's momentum continues to build. The 2028 ISP will again report on that progress, and update priorities as the NEM continues to adjust to market and policy signals.

13.1 Advancing the ISP

The 2026 ISP has offered an even more comprehensive plan for Australia's energy future, at the request of the ECMC. It has more detail on gas integration, demand side factors and distribution networks, system security and alignment with state planning and policies: see 'Implementation of the ISP Review' section below.

The AEMC is now reviewing the long-term planning frameworks for the electricity sector, including a statutory review of the ISP, to ensure they remain fit for purpose. This will be an important opportunity for stakeholder perspectives on the ISP to be voiced and considered. AEMO will work closely with the AEMC and stakeholders to ensure the future frameworks best meet the evolving role and purpose of the ISP.

The 2026 ISP has also benefited significantly from stakeholder feedback on the Draft 2026 ISP. This feedback also informs AEMO's preparation of the 2028 ISP, and AEMO remains open to any further reviews on the ISP's purpose and approach.

13.2 Advancing projects along the ODP

The next five to 10 years are critical to the transition. Federal and state governments continue to put policies in place to secure the finance, assets and workforce required. These policies support both grid-scale and consumer investment in energy resources, including support for battery storage and VPPs which can help take full advantage of Australia's rapid adoption of rooftop solar.

Substantial generation, storage and transmission projects are underway across the NEM, in keeping with previous ISPs. Additional projects will progress as the ODP and energy transition gain momentum, and as communities are engaged respectfully and effectively in the transition.

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- **A further 23 GW in household and business energy systems** – individual distributed battery and solar systems – is forecast to be installed by 2030, at a rate of 6 GW per year.
- **Utility-scale development of generation and storage** continues at pace, with more than 74 GW of solar, wind, batteries and other generation and storage in the pipeline. However, this pipeline would only deliver about 75% of the renewable generation needed by 2030. More is needed – particularly wind capacity.
- **About 3,500 km of new and upgraded transmission lines** are currently being delivered in eight projects across the NEM. The projects that would be at full capacity before the end of 2030 include the Western Renewables Link in Victoria, HumeLink, Hunter-Central Coast REZ and Central-West Orana REZ Network Infrastructure projects in New South Wales, Project EnergyConnect linking New South Wales and South Australia, and Project Marinus Stage 1 linking Tasmania and Victoria. In addition, CopperString in Queensland and New England REZ Network Infrastructure Project would be in place by 2034.
- **Eleven of the proposed 44 REZs across the NEM are underway**, with their respective jurisdictional bodies leading planning, community consultation, and community benefit and employment efforts. The most advanced REZs to date are Western Victoria, Far North Queensland and the Central-West Orana REZ in New South Wales.

Although the ISP cannot forecast exactly where and how the generation, storage and transmission of the future will emerge, the ODP is clear that urgent investment and delivery across the sector continue to be needed to ensure secure, reliable, affordable, low-emission electricity through the NEM.

* * *

The ISP's proposed investment in the NEM will provide opportunities for Australia's industries and regions, while reducing local emissions in line with government policies. The transmission elements would repay their investment costs, save consumers a further $26 billion in avoided costs, and deliver emission reductions valued at $2 billion.

AEMO will continue to work collaboratively with all industry, governments, networks, consumer representatives and other stakeholders to address risks and deliver the energy transition.

AEMO again sincerely thanks all those who have contributed to this ISP, and looks forward to engaging with all NEM participants in developing the 2028 ISP.

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Implementation of the ECMC ISP Review

In early 2024, the Energy and Climate Change Ministerial Council (ECMC) finalised a review of the ISP[77] and on 5 April 2024 published the Energy Ministers' *Response to the ISP Review*[78]. The response outlined a series of actions to enable the ISP to set a direction for the energy system as a whole, while maintaining the critical function of the ISP in transmission planning. The ISP Review focused on enhancing the ISP's ability to support emissions reduction, integrate gas and electricity planning, enhance demand side considerations, and clarify how AEMO engages with jurisdictions to decide which government policies the ISP must meet.

In December 2024, the AEMC amended the NER and National Gas Rules (NGR) to implement aspects of the ISP Review, namely to improve consideration of demand side factors in the ISP and to better integrate gas and community sentiment into the ISP.

Table 15 shows the publications that AEMO has amended to address each ISP Review action or rule change, to help inform engagement by stakeholders on appropriate publications.

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[77] Energy and Climate Change Ministerial Council. *Review of the Integrated System Plan – Final Report*, January 2024. At https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Energy_Planning_and_Regulation_in_Australia/EnergyPlanning/Additional_Documents.

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

Table 15 Implementation of the ECMC ISP Review

Implementing ISP Review actions	Process for implementation				
	2025 IASR	*ISP Methodology*	2025 *Electricity Network Options Report*[A] and 2025 *Gas Infrastructure Options Report*[B]	*Enhanced Locational Information* report[C]	2026 ISP
Integrating gas into the ISP	✔	✔	✔		✔
Enhancing demand forecasting	✔	✔	✔		✔
Better data on industrial and consumer electrification					✔
Optimising for the demand side	✔	✔	✔		✔
Coal-fired generation shutdown scenarios					✔ [D]
Improving locational information				✔	✔
Enhanced analysis of system security	✔	✔			✔
Jurisdictional policy transparency	✔ [F]				✔
Clarifying policy inclusions	✔ [F]				✔
Improving the accessibility of the ISP[E]	✔				✔
Incorporating community sentiment	✔		✔		✔
Additional planning inputs	✔				✔

A. The *Electricity Network Options Report* forms part of the IASR. It was previously known as the *Transmission Expansion Options Report*, but has been renamed to reflect the inclusion of both transmission and distribution in future ISPs.
B. The *Gas Infrastructure Options Report* was released as draft in May 2025 and final in July 2025 to support better integration of gas into the ISP.
C. The *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.
D. This action was addressed in the Draft 2026 ISP rather than the final 2026 ISP.
E. AEMO has considered opportunities throughout the ISP development process to enhance consumer understanding of key elements, including through the release of an ISP toolkit to help energy consumers and community advocates understand the ISP more and learn how they can contribute to its development. The toolkit is available at https://www.aemo.com.au/-/media/files/major-publications/isp/2025/isp-toolkit.pdf.
F. These actions were implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions. The guideline is available at consultation-with-jurisdictions-for-the-integrated-system-plan.pdf.

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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 apply, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.

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Term	Acronym	Explanation
Demand-side participation	-	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.
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'.
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.
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.

Term	Acronym	Explanation
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.
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).
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'.
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.

Supporting documents

All documents comprising or supporting the 2026 ISP are available on AEMO's website[79].

Appendices to the 2026 *Integrated System Plan*

- Appendix A1 – Stakeholder Engagement
- Appendix A2 – ISP Development Opportunities
- Appendix A3 – Renewable Energy Zones
- Appendix A4 – System Operability
- Appendix A5 – Network Investments
- Appendix A6 – Cost Benefit Analysis
- Appendix A7 – System Security
- Appendix A8 – Social Licence
- Appendix A9 – Demand Side Factors Statement
- Appendix A10 – Gas Development Projections

Supporting documents

- 2026 Integrated System Plan – Infographic
- 2026 Integrated System Plan – Explainer
- 2026 ISP Consultation Summary Report
- 2026 ISP chart data
- 2026 ISP generation and storage outlook
- 2026 ISP Inputs and Assumptions workbook
- 2026 ISP Model
- 2026 ISP demand and VRE trace data
- Indicative REZ boundaries 2026 – GIS data
- Indicative sub-regional boundaries 2026 – GIS data

Ministerial letter regarding New England REZ network infrastructure project

Regulatory publications

- Non-network options notice – Brisbane Area 275 kV Reinforcement
- Non-network options notice – Central to North Queensland Reinforcement (Stage 1)
- Non-network options notice – Tasmania REZ Expansion

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