AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

Draft 2026
Integrated System Plan

For the National Electricity Market

A roadmap for the energy transition

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

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

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

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

Important notice

Purpose

AEMO publishes the *Draft* 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 1 December 2025 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	10/12/2025	Initial release

CEO preface

Following 18 months of extensive consultation, analysis and review, I am pleased to present the Draft 2026 *Integrated System Plan* (ISP) for stakeholder feedback, ahead of finalising the 2026 ISP by June 2026.

This Draft ISP has had more consultation than any before it. It has benefitted from the review and input of more than 1,400 stakeholders representing consumers, communities, industry, and governments. In total, 37 separate reports and reference materials have been shared and 241 written submissions have shaped its conclusions.

Australia's energy system is changing rapidly. Coal-fired power stations are retiring and being replaced with a combination of renewable energy, storage and gas-powered generators. Australian consumers continue to invest in rooftop solar at world leading pace and are now adding home batteries and electric vehicles.

The ISP sets out the least-cost investment pathway for the National Electricity Market (NEM) to meet consumer energy needs and government policies through to 2050. It is underpinned by detailed analysis of around 2,000 potential development paths assessed for cost, benefits, and future power system needs across three electricity market scenarios.

The Draft 2026 ISP reaffirms that renewable energy, firmed with storage, backed up by gas and connected by upgraded networks, presents the least-cost way to supply secure and reliable electricity to consumers, while meeting government policies.

Significant momentum is already underway in delivering investments in generation, storage and transmission, but challenges remain in delivering this essential infrastructure at the pace required. Slower progress will erode benefits to consumers, and present risks to reliability.

I would like to acknowledge and thank everyone who has been involved in the development of this ISP, at AEMO and so many of our stakeholders, whose work has shaped this roadmap and will help guide Australia through the energy transition.

Daniel Westerman
Chief Executive Officer

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Executive summary

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

This complex transition is well underway. Nearly 40% of the coal fleet has retired and renewables are fast approaching the milestone of delivering half the NEM's electricity. Households are investing in rooftop solar, batteries and electric vehicles, and industry is set to near double its use of electricity by 2050.

AEMO's *Integrated System Plan* (ISP) outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet both consumer needs and government policies, at least cost, for at least the next 20 years.

The ISP is a two-year effort, with its inputs and methodology informed by extensive consultation with consumers and advocates, industry, market bodies, governments, academics, environmental groups and consultants. It uses comprehensive, integrated models to find the optimal mix of NEM developments, tested for a range of future outcomes.

The Draft 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 summary, the Draft 2026 ISP sets out how:

- **The ISP is a roadmap for the NEM's transition, with a specific and expanded role**. The ISP provides a least-cost pathway for investment in grid-scale generation, storage and networks, to meet household and industry needs given what consumers are doing themselves. In response to the Energy and Climate Change Ministerial Council's (ECMC's) review of the ISP, its scope was increased in 2025 to consider more explicitly how grid-scale electricity investment, consumer energy resources (CER), distribution networks, gas markets and infrastructure all interact.
- By 2050, the proposed ODP would see the NEM with a total of 120 gigawatts (GW) of grid-scale wind and solar, 40 GW of grid-scale storage and hydro, 14 GW of flexible gas-powered generation and an additional 6,000 km of transmission. New gas supply chain investments would be needed to support gas generation. CER would continue to form an important part of the mix, with support from distribution networks. AEMO estimates that consumers would by 2050 have invested in 87 GW of rooftop and other small-scale solar, and 27 GW of household and commercial batteries. All of the actionable and future transmission projects in the ODP would repay their upfront costs and deliver net market benefits to consumers of $24 billion, compared to a future with no additional transmission.
- If near-term delivery constraints delay the ODP, benefits for consumers would remain positive, but they would be reduced and some 2030 policy targets would be delayed. By 2030, grid-scale wind and solar capacity would reach 58 GW, accelerating the current rate of connections, and a further 35% of the remaining coal capacity would retire. However, generation and transmission projects face delivery constraints in planning approvals, in the supply chain, in gaining social licence, and in construction. AEMO

has modelled a future in which project delivery takes longer than planned, and consequently costs more. The results underscore the need to progress the actionable transmission projects in the ODP without delay. Apart from securing consumer benefits, the projects offer critical mitigation for the risks that generation projects are delayed or that coal plants retire earlier than announced. In this case, developments would meet 2030 targets two years late, and would catch up to emission targets by around 2035.

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. 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.

AEMO welcomes stakeholders' feedback on this Draft 2026 ISP, with written submissions requested by Friday, 13 February 2026. AEMO looks forward to working with industry, governments, consumers and advocates, and other stakeholders, to prepare the final 2026 ISP by the end of June 2026.

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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 renewables. Renewables from home-scale to grid-scale met over 40% of all demand for electricity in the NEM during the 2024-25 year, 51% for the month of October 2025, and reached 79% for a half-hour on 11 October 2025. These record levels vary seasonally, but are consistently rising.

The shift to renewables is happening globally. Decisions on how best to replace the NEM's coal-fired plants are primarily made by private investors. That investment favours renewable energy and supporting technologies over fossil fuels. Globally in 2024, 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].

Government targets are de-risking Australia's transition. As consumers continue to set the pace in adopting rooftop solar, federal, state and territory policies are in place to support industry in ensuring there is enough grid-scale infrastructure in place for coal's retirement. These policies recognise that de-carbonising the energy sector is essential if other sectors are to reduce emissions in line with global agreements. As a whole, they are no longer kickstarting a transition that is well underway, but focus on de-risking its delivery.

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:

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

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

- **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** 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 they get cheaper** to allow households, businesses and the grid to store surplus energy from daytime solar to use in the evening and morning peaks, and to support grid reliability and security as coal plants withdraw.
- **New flexible gas-powered generation plants** provide critical back-up power supply when renewables are not generating power (and to help pre-charge batteries for those times), as well as providing supply for peak demand events and supporting grid security as coal plants withdraw.
- **Existing hydro generators and other long-duration 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.
- **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 increasing their flexibility.** Owners are investing to keep their coal plants economic through increased volatility in 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 or take units offline for hours, days or even months at a time.

Consumers are both producing and using more electricity

Households and businesses are investing in their own energy resources. Already, over 40% of detached homes in the NEM have rooftop solar. Together, households and businesses met a record 61% of energy demand across the NEM on 4 October 2025, and have met over 100% of demand at certain times in South Australia. Distribution networks are continuing to optimise and innovate to cater for the sharply rising increase in daily flows to and from these resources.

Business use of grid-scale electricity may rise by 90%, while household falls 40%. Total electricity use is expected to rise due to population growth, economic growth, electrification (the switch from petrol and gas to electricity for industrial processes, transport, heating, cooling and cooking), and large new users of electricity such as data centres. Total consumption across the NEM is forecast to nearly double from the current 205 terawatt hours (TWh) to 389 TWh in 2049-50.

Nearly 116 TWh of this electricity is projected to come from CER and other on-site generation in 2049-50. As a result, the amount that business and industry needs from grid-scale resources is forecast to rise 90% to 253 TWh, while that for households would fall 40% to just 20 TWh – despite having more electric vehicles (EVs) and appliances. However, this is a net amount over the year, and depends on the future grid being able to cater for much larger energy flows both to and from home-scale systems.

Grid-scale work is building momentum

Coal is being replaced by renewables and batteries. Of the 26 major power stations operating in the NEM in 2010, 15 remain operational, reducing coal's capacity from about 30 GW to about 21 GW. Meanwhile, about 6.6 GW of renewable generation and battery storage projects achieved full output in the two years to June 2025 (a doubling of outcomes year on year), and 27 GW of new project connection applications were approved. Year-on-year growth in grid connections is accelerating. In total, 56 GW of projects are currently progressing through various stages in the connections process, half of them being battery storage projects.

Transmission work is building momentum. In the past three years, transmission capacity between Queensland, New South Wales, South Australia and Victoria has increased, and new projects have increased the ability for networks to meet electricity demand on the Eyre Peninsula and to support reliability of supply and new generation in Far North Queensland. Another five transmission projects (Project EnergyConnect, HumeLink, Hunter Central-Coast Renewable Energy Zone [REZ] Network Infrastructure Project, Central-West Orana REZ Network Infrastructure Project and Western Renewables Link) are on track for completion by 2029 across the NEM.

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

The National Electricity Rules (NER) require AEMO, every two years, "to establish 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" [3].

The core element of the ISP is the 'optimal development path' (ODP) – the mix of grid-scale generation, storage and network investments to replace coal as it retires and meet consumer needs and government targets, at least cost, between now and 2050. Other ISP elements included for the first time are:

- demand-side factors[4] that may affect the power system (moves by consumers to invest in their own energy systems and to be more energy efficient),
- opportunities to upgrade the distribution network[5], and
- projections of gas demand, supply and capacity (including infrastructure to support that capacity)[6].

The ODP optimises only grid-scale (or 'supply-side') investments, that is, the grid-scale generation, firming and storage and the large transmission and distribution networks to which they connect. That is where system-wide planning is essential, so that large investments can benefit energy consumers. Although AEMO has included gas development projections to inform electricity investment, that development is not optimised in the ODP, and gas investment remains the responsibility of the gas industry. Smaller investments are also left to individual participants in the energy market, from single households through to distribution network operators.

The ISP must contribute 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

[3] NER 5.22.2.

[4] Demand-side factors may affect the use of distribution networks, and include the assets, technologies and services available to end users, policies that promote electrification, and demand management or energy efficiency schemes.

[5] NER 5.22.6A.

[6] NER 5.22.6A(c)(2).

long-term interests include the price, quality, safety and reliability of electricity supply, and the achievement of emissions reduction targets.

The ISP seeks the least-cost path to balance those factors. There are many factors that affect the final bills that electricity consumers receive. For its part, the ISP contributes the least-cost plan to meet both consumer and policy needs. Investment is essential to maintain reliable and secure power supply as coal plants retire. 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. However, this is not necessarily an indication of future retail electricity prices, as there are many other factors that ultimately determine those prices.

The ISP incorporates all relevant government policies and targets. Targets that must be included are published in the Australian Energy Market Commission's (AEMC's) *Targets Statement.* They and other policies relate to emissions, renewable energy, storage, offshore wind, hydrogen, CER, EVs, energy efficiency, 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

Starting just after the 2024 ISP, AEMO has listened to valuable insights and feedback from all stakeholders and incorporated them into this Draft 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. AEMO has formally engaged with over 1,400 stakeholders, including 1,160 webinar attendees and 241 written submissions. For these consultations, AEMO has published 37 reports and reference materials, and hosted 17 webinars and workshops. Those consultations span all aspects of the ISP's inputs and modelling approach, and continue with this Draft 2026 ISP.

AEMO published 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[7], and the interaction of the power system with other 'coupled' sectors such as transport, gas and hydrogen.

AEMO also considered and published three scenarios of the future that meet government policies and for which the power system needs to be prepared to operate, reliably and securely – *Step Change, Slower Growth* and *Accelerated Transition*. Each of these scenarios are integrated into the ODP, weighted by a relative likelihood that is 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 23 candidate development paths, shortlisted from around 2,000 potential paths. These incorporate both the transmission and relevant distribution projects and all the generation, storage, CER and gas supply chain investments[8] needed for each of the three NEM futures considered. They were compared with a 'counterfactual' that has no new transmission projects beyond those

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

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

already committed or anticipated. Net market benefits were assessed across the three scenarios to help protect consumers from risks of over- or under-investment in network assets in an uncertain future environment.

AEMO tested the leading candidates against changes in key assumptions, to test their resilience against uncertainty or understand the impacts of important possible changes. The tested sensitivities were on constrained delivery of the proposed ODP, faster or slower coal retirements, and alternative gas development projections. The effects of demand-side factors on the power system were also tested by assessing impacts of reduced energy efficiency measures and no further CER coordination.

Generation, storage and network investments in the proposed ODP

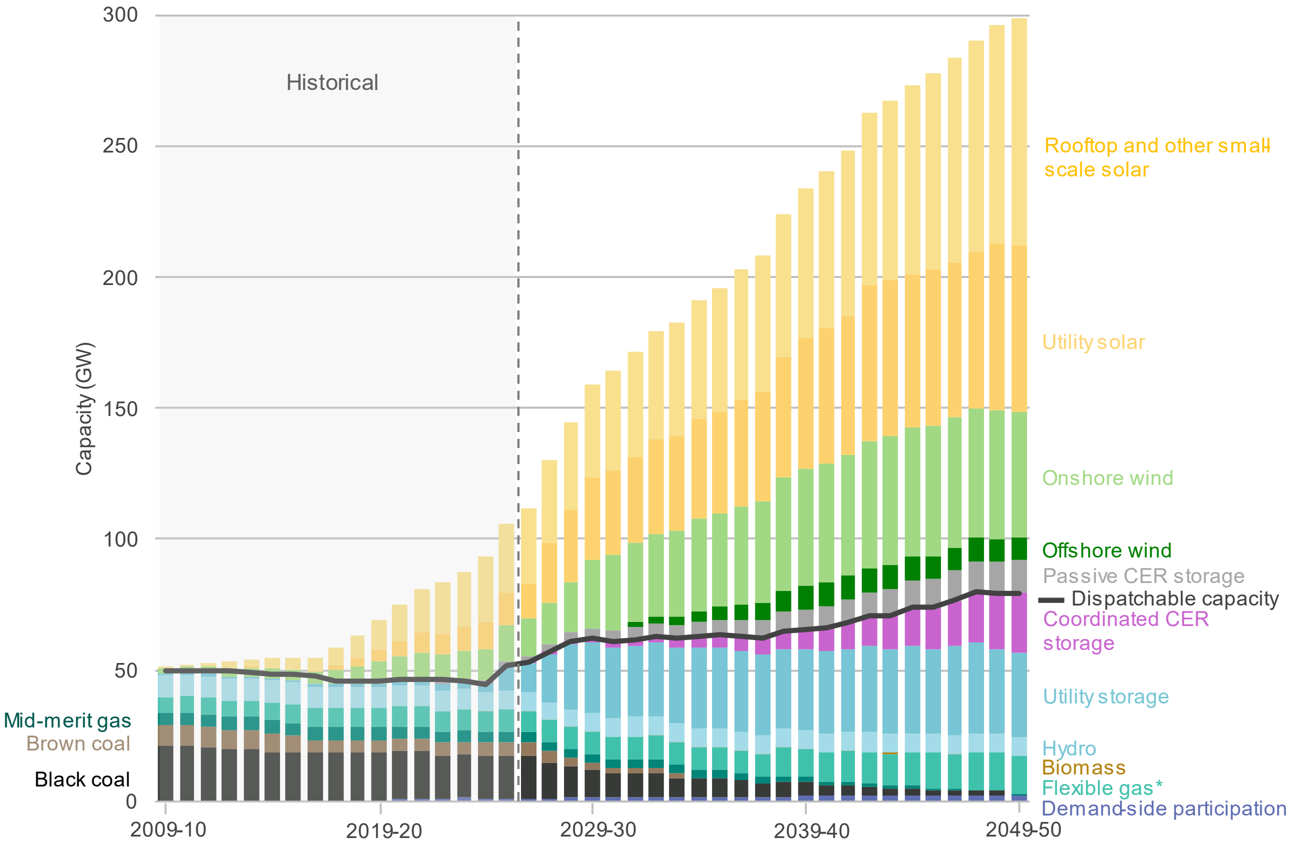
The proposed ODP is put forward as the optimal mix of grid-scale generation, storage and network investments to replace coal as it retires, and meet consumer needs and government policies, at least cost, through to 2050.

The resulting capacity in the *Step Change* scenario is shown in **Figure 1**. Its various elements are discussed below, followed by more detailed information on the transmission projects that enable this capacity to be used most effectively for the benefit of consumers.

Coal power stations are steadily retiring

In the near term, coal-fired generators would be needed to help meet both generation and system security requirements until replacement services are installed. Under the ODP, two-thirds of the remaining fleet would close by 2035, in many cases earlier than publicly announced closure dates, with all due to retire by 2049: see **Figure 2**.

Figure 1 **NEM capacity** (GW, 2009-10 to 2049-50, *Step Change*)



Notes: Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 IASR. "Rooftop and other small solar" includes forecast residential and commercial rooftop photovoltaic (PV) systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems. "Utility 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 hydrogen capacity.

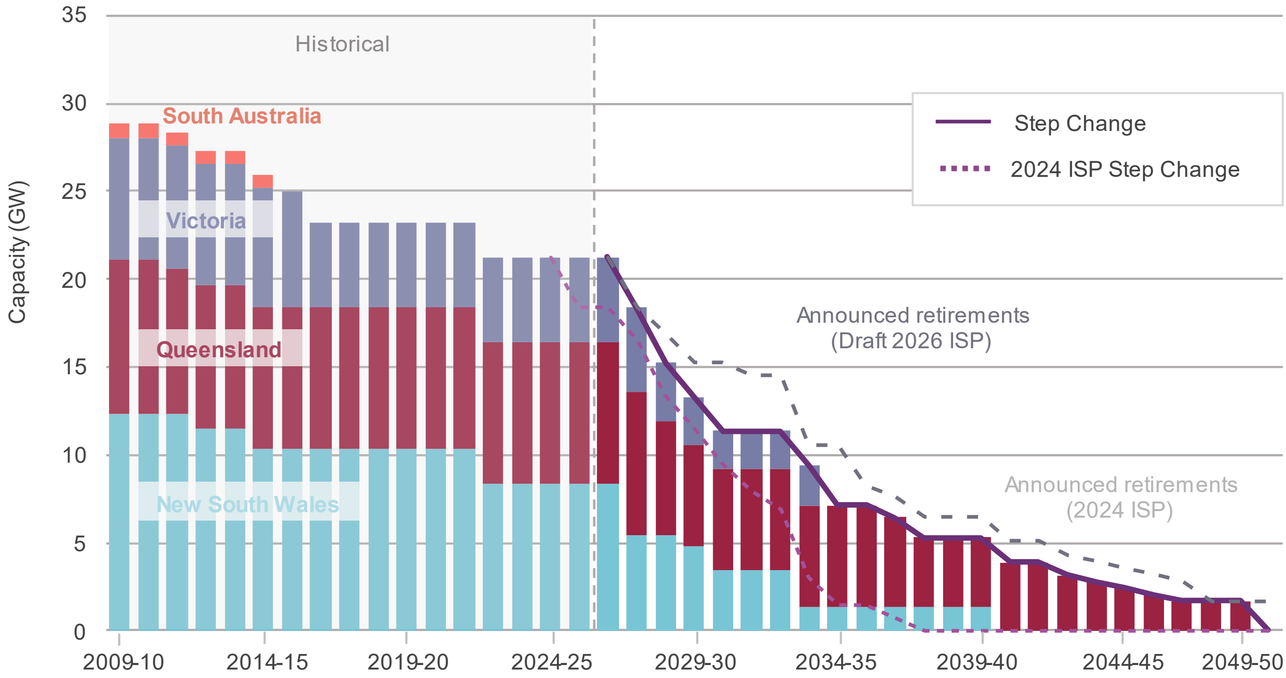
Queensland's fleet of coal plants have served for an average 30 years, and the Queensland Energy Roadmap sees their key role continuing. Elsewhere, the average age of the remaining fleet is 40 years, with their owners declaring planned retirements that are on average only 10 years away.

Coal plants may become increasingly unreliable as they approach end of life. Based on recent history and their future age, full unplanned coal plant outages are projected to occur around 7% of the time between 2027 and 2035, and partial loss of capacity a further 17% of the time. In other words, coal plants are likely to be fully available only three quarters of the time over that period.

Coal retirements may occur even faster than these forecasts. Higher operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market are challenging the financial viability of some power stations.

To extend their availability, many coal plant operators are investigating plant modifications to enable 'two-shifting'[9] and other more flexible operations. In some cases, coal generators may operate only during peak seasons – remaining active in summer and winter while shutting down during the shoulder periods.

Figure 2 Coal capacity, NEM (GW, 2009-10 to 2049-50)



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

Renewables are needed to replace coal, and to meet rising demand and government targets. Under the proposed ODP, grid-scale wind and solar capacity would rise from its current 23 GW to 58 GW by 2030, then double to 120 GW by 2050. Grid-scale solar capacity would reach 32 GW by 2030, 38 GW by 2035, and 63 GW by 2050. Wind would reach 26 GW by 2030, 40 GW by 2035, and 57 GW by 2050. In addition, the NEM's existing 7 GW of hydro-electric generation capacity remains in place. Additional gas- and hydro-powered generation is also needed, as noted below.

Grid-scale generation would ideally be situated in renewable energy zones[10] (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.

While the connections pipeline is building for new grid-scale solar and wind, more projects are needed to reach 2030 target levels. By then, about 35 GW of new grid-scale solar and wind would be needed under the proposed

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

[10] 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.

ODP. Currently, wind and solar projects to deliver the equivalent of 24 GW[11] are progressing through the connections process. On average, solar and wind projects take four years from connection application to full output.

40 GW of dispatchable grid-scale storage and hydro

The ODP projects 33 GW of dispatchable, grid-scale battery and pumped-hydro storage would be needed by 2050, with 27 GW by 2030, in addition to the 7 GW provided by the NEM's existing hydro-electric power stations. These projects are spread across the NEM, and within and outside REZs.

The decline in battery costs is now making its mark, with new capacity in the connections pipeline increasing from approximately 3 GW in September 2022, to 15 GW in 2024 and to 26 GW in 2025. These are battery or hybrid projects (solar or wind with batteries) that provide either shallow storage (up to 4 hours discharge for daily peaks) or medium storage (4 to 12 hours discharge to cover renewable lulls of low sunlight and wind). After this wave of development, most future investments would be medium storage, as shallow storage would increasingly be provided by household and business-owned batteries.

The mix also includes deep storage, whose role should not be underestimated in being able to shift energy over weeks or months (seasonal shifting) and cover extended renewable lulls. Long-duration storage is already offered by the NEM's existing hydro-electric power stations, whose reservoirs store rainfall as potential energy. New pumped-hydro projects, including Snowy 2.0, Borumba and Kidston, would add 5 GW to that capacity by using surplus energy to pump water upstream to be stored as potential energy. For example, Snowy 2.0 would provide up to 350 gigawatt hours (GWh) over a week, enough to meet the average needs of around 2.7 million households (almost as many as in Sydney and Melbourne combined).

14 GW of flexible gas-powered generation

Gas-powered generation is changing from regular 'mid-merit' and 'peaking' operations, to a more strategic, back-up role by flexible generators that can also operate with a clutch to provide critical system security services without burning fuel. Currently, the NEM has 4 GW of mid-merit and 8 GW peaking gas-powered generation capacity, of which 9 GW is forecast or announced to retire between now and 2050 as the plants reach end-of-life. As the mid-merit and some peaking plants retire, they would be replaced, and the fleet expanded to a 14 GW fleet of flexible capacity able to deliver both generation and system security services.

New gas supply, transport and storage infrastructure would also be needed to ensure sufficient gas is available, to meet demands of direct-use gas consumers and ensure adequate fuel is available to support the operation of gas-powered generation. There may not be enough gas supply accessible from existing pipelines, production facilities and storages when gas and electricity demands peak simultaneously, as they sometimes do in the southern states in winter, restricting the gas available for electricity generation. Several solutions exist that would provide sufficient fuel for both gas and electricity consumers, and a combination of market-led investments would need to be developed. 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.

[11] Projects totalling 27 GW have actually applied, but historically 10% of connection applications do not progress through to actual output.

Distribution networks and consumers reducing grid-scale investments

Distribution networks are innovating to be able to cater for much larger energy flows to and from households and business systems every day. By 2050, consumers are forecast to have invested in 87 GW of rooftop and other small-scale solar and 27 GW supporting batteries, and 80% of all vehicles are expected to be battery EVs.

This growth in consumer resources presents an opportunity for the system to be planned and operated in a more flexible and two-sided manner, and reduce the scale of grid-scale investments. When CER is bundled and coordinated either through as virtual power plants (VPPs) or vehicle-to-grid (V2G) charging of electric vehicles, it can respond to market signals, and contribute to system reliability and system security. It would also avoid up to $7.2 billion being spent on additional grid-scale storage in the NEM through to 2050.

Distribution networks can also unlock 4 GW of latent CER capacity by optimising their voltage management and other relatively lower cost innovations. They may also be able to accommodate 2 GW of grid-scale generation and storage within the network itself.

Transmission being extended by a further one-seventh

Around 6,000 km of new transmission would be needed by 2050 under the *Step Change* scenario, a 13% extension of the current 44,000 km network. This includes 2,800 km from already committed or anticipated projects that are well underway for delivery. Almost half of the new transmission projects are needed to strengthen the connection between states, adding reliability and stability to electricity supply across the NEM, and the remainder is to connect new capacity in REZs.

The overall extent of new transmission has reduced compared to the previous ISP, with some projects being downsized or no longer needed in response to policy or other changes (1,350 km)[12], and others being removed from the total as they have progressed to operation (365 km). As well, the 2026 ISP's *Accelerated Transition* scenario is less ambitious than its predecessor, reducing the potential need for transmission.

Actionable and future ISP projects in the 2026 ODP

The proposed ODP in this Draft ISP includes the following transmission projects, detailed in **Table 1** and **Figure 3** on the following pages:

- **seven committed and anticipated transmission** projects which are underway to be delivered over the next six years,
- **eleven actionable projects** to be delivered over the next decade, and
- **seven future ISP projects** which may be needed in the future.

Of the actionable transmission projects from the 2024 ODP, three are now committed or anticipated projects, seven are proposed to remain actionable, and one would be deferred to become a future project (Central Queensland to Southern Queensland Expansion[13]).

[12] The total difference in new major transmission in the 2024 ISP and Draft 2026 ISP (*Step Change*) is 1,871 km, of which 1,506 km is no longer needed in response to policy or other changes, and 365 km has been removed as a project has progressed to operation. In addition, the Dubbo Distribution project adds a further 156 km in this proposed ODP, noting that some scope of this project is not defined as transmission.

[13] Previously known as Queensland SuperGrid South.

Two further actionable transmission projects from the 2024 ODP are subject to ongoing analysis and stakeholder engagement to confirm their status, due to uncertainty on input assumptions that could materially impact consumer benefits. The first is the Northern Transmission Project[14] (previously known as the Mid-North South Australia REZ project). While the identified need for this project remains, further analysis is required to ascertain whether it would provide optimal benefit to consumers as previously identified in the 2024 ISP. The other is QNI Connect, which still forms part of the proposed ODP, but whose benefits could be heavily influenced by jurisdictional energy policies such as the recently announced Queensland Energy Roadmap. Both projects are being assessed further, prior to confirming their status in the final 2026 ISP.

Two future projects from 2024 (Western Victoria Reinforcement and the Gippsland Offshore Wind Transmission) would become actionable, and an additional smaller project (Switching Station Near Wondalga) has been identified as likely to become actionable. The need for the two Victorian projects remains unchanged but work to progress these projects will soon need to commence, such that they now fall within the actionable window.

Some additional new future projects feature in the proposed ODP – they are the Sydney Ring South (500 kilovolts [kV] option) and the South West Victoria Expansion.

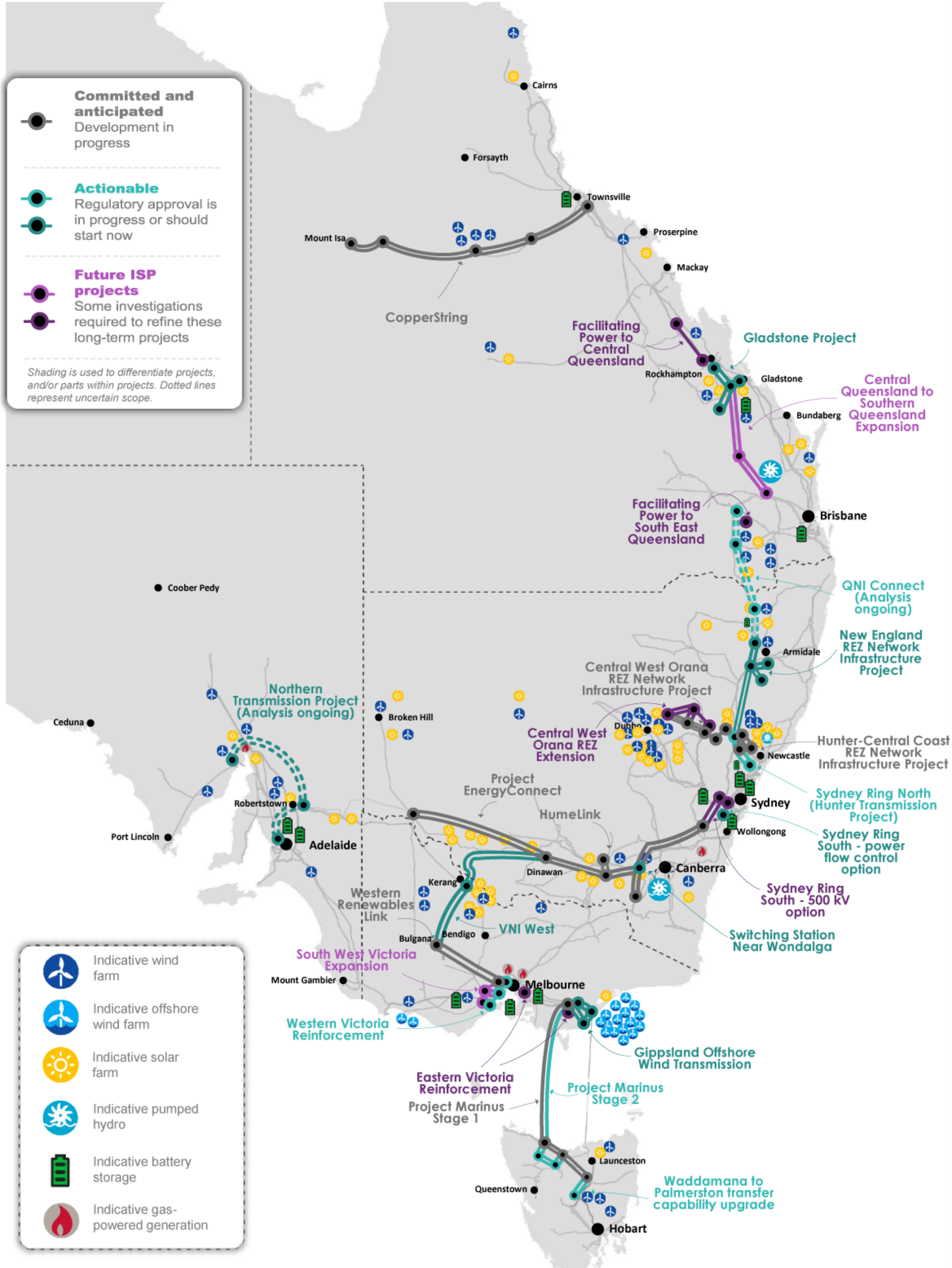
[14] The Northern Transmission Project is not included in the actionable project counts, cost benefit assessment totals and other metrics reported for the ODP in this Draft 2026 ISP.

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

Committed and anticipated transmission projects		In service timing advised by proponent[A]	Full capacity timing advised by proponent[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		June 2031	June 2031
Projects likely to remain actionable	**Actionable framework**	**In service timing advised by proponent[A]**	**Full capacity timing advised by proponent[A]**
Gladstone Project	QLD[C]	March 2029	March 2029
Sydney Ring North (Hunter Transmission Project)	NSW[D]	November 2029	November 2029
Sydney Ring South – power flow control option	ISP	July 2030	July 2030
Waddamana to Palmerston transfer capability upgrade	ISP	July 2030	July 2030
Victoria – New South Wales Interconnector West (VNI West)	ISP	November 2030	November 2031
New England REZ Network Infrastructure Project	NSW[D]	July 2032	July 2032
Project Marinus Stage 2	ISP	June 2034	December 2034
Projects actionable in 2024 ISP, requiring ongoing analysis	**Actionable framework**	**In service timing advised by proponent[A]**	**Full capacity timing advised by proponent[B]**
Northern Transmission Project[E]	ISP	July 2029	July 2029
Queensland – New South Wales Interconnector (QNI Connect)[F]	ISP	March 2032	March 2034
Projects likely to be identified as newly actionable	**Actionable framework**	**Earliest feasible in service timing[A]**	**Earliest feasible full capacity timing[B]**
Switching Station Near Wondalga (new)	ISP	July 2029	July 2029
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[G]	June 2029	June 2029
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC[G]	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
Future ISP projects			
New South Wales	Central West Orana REZ Expansion, Sydney Ring South – 500 kV option		
Queensland	Central Queensland to Southern Queensland Expansion[H], Facilitating Power to South East Queensland, Facilitating Power to Central Queensland		
Victoria	Eastern Victoria Reinforcement, South West Victoria Expansion		

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
C. This project would progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.
D. These projects would progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
E. Northern Transmission Project (previously known as the Mid North South Australia REZ Expansion) is undergoing further analysis and is not identified in the proposed ODP, ODP project counts, cost benefit assessment totals and other metrics in this Draft 2026 ISP.
F. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including alignment with the Queensland Energy Roadmap.
G. This project would progress under the *National Electricity (Victoria) Act 2005* (Vic) rather than the ISP framework.
H. Previously known as Queensland SuperGrid South. This project has changed from being an 'actionable' project in the 2024 ISP to being a 'future' ISP project in the Draft 2026 ISP.

Figure 3 Transmission projects in the proposed Draft 2026 ISP optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that increase capacity by 400 MW or more and are part of the proposed Draft 2026 ISP optimal development path.

Delivering the optimal development path

Supplying secure and reliable electricity at least cost

The ISP methodology assesses both the initial capital costs and the annual operating costs of potential infrastructure, including the values of fuel and emissions, to determine the ODP. It looks only forward in time: existing assets and committed investment decisions are not costed or re-evaluated, as they do not affect future planning. In this section only the initial capital costs are reported.

The weighted net market benefits of the proposed ODP to consumers, across all scenarios, compared to there being no major new transmission at all, would be $24 billion. In other words, the actionable and future ISP transmission projects would repay their investment costs, and collectively save consumers a further $22 billion in additional costs (weighted across all scenarios), and deliver emissions reductions valued at a further $2 billion (also weighted across all scenarios).

To 2050, the annualised capital cost in present value (PV) terms of the future capital costs of all utility-scale generation, storage, firming and transmission and distribution network in the ODP would be $128 billion in the *Step Change* scenario. As the assets have a technical life beyond 2050, the total present value of these investments is $156 billion. The transmission element of this capital cost would be $9 billion in PV terms, or 7% of the total. All other combinations of generation, storage, firming and network technologies, seeking to meet consumer needs and government policies, would cost more than the ODP.

In a period of rising infrastructure costs, AEMO notes that the overall capital cost of the ODP in the Draft 2026 ISP *Step Change* scenario is 2.8% higher than in the 2024 ISP (after accounting for inflation, the time value of money, and costs incurred in the past two years). Factors adding to the capital cost of the ODP include a lower CER forecast (requiring more grid-scale investment), new emissions reduction policies (requiring changes in the type and/or timing of investments), the inclusion of distribution network development opportunities, and higher capital costs for transmission. Factors reducing the overall cost of the ODP include lower capital costs of solar and batteries, fewer transmission projects, and recent progression of projects towards construction.

There has also been a material change to the weighted average cost of capital (WACC) for all infrastructure investments since 2024. In response to stakeholder feedback, the assumed real pre-tax WACC for transmission projects has been reduced from 7% to 3% in recognition that, as assets with regulated revenues, they have lower risk than other investments. The assumed WACC for generation and storage projects increased by different amounts in recognition of 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, including that 82% of the NEM's supply be from renewable sources by 2030. However, as noted below, there is risk that generation, storage and transmission delivery is delayed due to current supply chain pressures and other constraints, inhibiting achievement of some 2030 policy targets.

Providing value if infrastructure delivery is constrained

Development of all grid-scale infrastructure is gaining momentum, with the pipeline for battery storage projects ahead of expectation in the 2024 ISP. However, AEMO is aware that the rate of infrastructure build in the ODP is faster through to 2030 than has been achieved to date.

AEMO has explored a *Constrained Delivery* sensitivity analysis to see whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission as well as generation and storage projects were unable to be delivered at the pace required. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction – but the sensitivity only limited the rate of build, not what determined the delays. The costs of the projects were also assumed to rise, on average by 30%, due to these constraints. Again, there may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the rise in cost only.

The results of the *Constrained Delivery* sensitivity underscore the need to commence and progress actionable projects in the ODP as quickly as possible, so that the energy transition can be delivered at lowest cost to consumers, and risks of delivery delays are mitigated to the extent possible:

- **Transmission projects in the ODP still deliver benefits, even if the pace of delivery is constrained**. Under this sensitivity, the transmission projects in the proposed ODP would continue to deliver positive net market benefits to consumers, compared to there being no major new transmission at all. However, both the consumer benefits and emission reductions would be reduced and delayed, and some of the 2030 policy targets would not be achieved.
- **Renewable energy would contribute 75% of NEM supply by 2030**, based on the modelling, missing both the 2030 renewable energy target and the electricity sector's contribution to the national emissions target. Development would then catch up to help meet the 2035 emission targets. Grid-scale solar capacity would reach 25 GW by 2030 (down from 32 GW in the *Step Change* scenario) and 38 GW by 2035. Wind would reach 25 GW by 2030, and 43 GW by 2035.
- **Some coal would remain in the system longer.** With less renewable generation in the near term, some coal would 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 end of their planned operational life. An unforeseen critical failure of any one of these ageing power stations could jeopardise power system reliability, especially if renewable development is delayed – as in this sensitivity.
- **Strong interconnection between states helps mitigate risks of unforeseen coal closures**. Strong interconnection between states, through the timely development of committed, anticipated and actionable transmission projects proposed in this Draft 2026 ISP, would help mitigate this risk by allowing greater sharing of resources across the NEM.

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.

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. Many factors will determine the actual rate at which future infrastructure is delivered, including market conditions, consultation processes and NER frameworks.

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. Delays to its delivery reduces consumer benefits. As well, 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 delaying their closure is not an option, and periods of decommitment are anticipated well in advance of when they do.

To deliver the ODP, continued coordinated action is needed from industry, governments and market bodies, including in their engagement with communities.

Significant progress on preparing for coal's retirement

Significant progress is being made towards the ODP, although not without challenges. There is a growing wave of new generation and storage projects across the NEM. The development pipeline of new capacity has now reached 56 GW, a 24% increase over the past year. Over 650 km of new transmission has been completed, with another 2,800 km underway and on track to be delivered by 2031. 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 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. 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 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 needed in next 10 years to ensure a smooth transition and a secure and reliable future energy system. To that end, AEMO has also requested the AEMC to amend the NER's 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. By July 2025, the CER

Taskforce had commenced work on 14 of the 16 priorities in the roadmap, and will start work on the remaining two within the next year.

In parallel, the ECMC also recommended changes to the ISP framework which led to further consideration of distribution networks and CER in the ISP. The AEMC recently published a directions paper for Integrated Distribution System Planning, setting out three different approaches for improvements. Distribution networks will play a critical role in achieving a least-cost transition of the energy sector, particularly in delivering effective and timely integration of CER and other distributed energy resources. AEMO will continue working with distribution network planners, governments, market bodies and consumer groups on reforms that drive benefits for both consumers and the power system.

Similar collaboration needed on infrastructure development delivery

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, and also with global supply chain partners to secure equipment and materials.

- **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 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. Even with guideline documents in place, greater clarity is needed on the roles and responsibilities for social licence. The primary responsibility rests with project proponents, yet approvals are granted by government bodies, to which communities often look when concerns arise.
- **Continue to streamline and enhance planning and environmental approval processes for infrastructure.** The delivery of renewable generation projects in the proposed ODP would be 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 working to continue streamlining connections approval processes, in partnership with the Clean Energy Council and industry.
- **Ensure the supply chain for critical energy assets and workforces is secured.** Australia's energy transition depends on deep investment in CER, grid-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers – over the next 10 years in particular, and in competition with countries around the world as they transform their own power systems. Similarly, a large and skilled workforce, spanning many disciplines, is needed for the tasks ahead.

* * *

The Draft 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 meet a doubling of demand for secure and reliable electricity, as coal plants retire through to 2050, while meeting government policies.

Its message remains consistent with previous ISPs on the least-cost mix of investments needed: renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas. It delivers consumers material benefits while balancing risks in their long-term interests. It also demonstrates that the proposed ODP and its transmission projects would benefit consumers even if project delivery is delayed due to current supply chain pressures or other constraints.

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

* * *

Invitation for submissions on the Draft 2026 ISP and actionable project

AEMO thanks all industry, government, consumer representative and other stakeholders for their advice and input during the extensive consultation over the last 18 months, and will continue through to the final 2026 ISP.

All stakeholders are invited to provide a written submission on the Draft 2026 ISP, which should be sent in PDF format to ISP@aemo.com.au by 6.00 pm (AEST) on Friday, 13 February 2026[15].

While all comments are welcome, AEMO is particularly interested in views on the consultation questions listed over the page.

In addition, AEMO calls for any written submissions on non-network options proposals for the proposed new actionable ISP project, Switching Station Near Wondalga (see Appendix A5 and the 'consultation on non-network options' section of the Draft 2026 ISP website for more detail). **Proposals should be sent in PDF format to ISP@aemo.com.au by 6.00 pm (AEDT) on Friday, 20 March 2026.**

[15] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines.pdf.

Consultation questions

1. AEMO has proposed an ODP that represents a mix of investments that help deliver a reliable, secure, and least-cost power system while also meeting government policy targets.

   Do stakeholders agree with AEMO's optimal development path selection in the Draft 2026 ISP? If yes, what gives you that confidence? If not, what should be further considered, and why?

2. In the Draft 2026 ISP, AEMO has proposed some changes to actionable transmission projects including:

   – 11 actionable projects to remain for delivery over the next decade,

   – three projects to move to 'committed or anticipated' status,

   – one project to move to 'future' status to align with the timing of other projects that influence its benefits (Central Queensland to Southern Queensland Expansion aligned with Borumba Pumped Hydro), and

   – two projects under review due to uncertainty in input assumptions and the influence of recent policies (Northern Transmission Project and QNI Connect).

   Do you agree with the proposed timing and treatment of actionable projects in this draft?

3. For the Draft 2026 ISP, the tested sensitivities were on constrained delivery of the ODP, variations on the gas development projection, and the pace of coal closures. The effect of demand-side factors was also tested by assessing the impact of reduced energy efficiency measures, and no further CER coordination.

   What other sensitivities should be considered to further test the robustness of the candidate development paths, and why? What other sensitivities are relevant to testing robustness of investment decisions, why?

4. For the first time, AEMO has assessed opportunities for investment in distribution networks across the NEM, that are consistent with the efficient development of the power system, to support operation of consumer energy resources. This recognises the key role of distribution networks in supporting the integration of consumer energy resources. See Appendix A9 for more information.

   Does the ODP appropriately identify and leverage distribution investment opportunities?

5. For the first time in the Draft 2026 ISP, AEMO has incorporated combinations of gas investments that may be developed by the gas industry. These gas development projections influence the availability of gas to support the power system in the future, and (potentially) the mix of investments required in the ODP.

   Do the gas development projections reflect an appropriate level of investment to support the gas sector, including gas-powered generation in the NEM?

6. The Addendum to the 2025 *Inputs Assumptions and Scenarios Report* (IASR) provides further explanation in response to the AER's Transparency Review. This includes further explanation of forecast components including policies affecting consumer demand, data centres, hydrogen production, biomethane and community batteries.

   Do stakeholders have feedback on the Addendum to the 2025 IASR?

Key changes from the 2024 ISP

The Draft 2026 ISP sets out how AEMO has identified the optimal development path (ODP) for the NEM. The ISP is adjusted with changes in the economic, physical and policy environments. AEMO notes the following key differences between the 2024 ISP and this Draft 2026 ISP.

Changes in inputs

Enhanced consideration of gas, demand side factors and distribution networks

- In response to the ECMC ISP Review, changes to the NER see the Draft ISP include gas development projections, distribution network development opportunities, and an inaugural demand side factors statement.

Updates in inputs and assumptions used to analyse the ODP, following extensive consultation

- **For transmission network**, cost estimates increased up to 100% in real terms; pre-tax real weighted average cost of capital for regulated assets reduced from 7% to 3% consistent with Australian Energy Regulator (AER) assessments; project options and delivery lead times were updated for all projects; HumeLink, Hunter Central Coast and Project Marinus Stage 1 progressed to committed or anticipated status and are therefore no longer evaluated through the ISP.
- **For wind resources,** updated traces are based on evidence from developers and jurisdictional bodies.
- **Future scenarios** were updated to reflect market, policy and economic shifts; *Slower Growth* replaced *Progressive Change*, and *Accelerated Transition* replaced *Green Energy Exports* to reflect a focus on domestic economy.
- **Rooftop and other distributed solar** forecast by 2050 is 87 GW, up from 72 GW in the 2024 ISP.

Updates in approach to social licence

- **New land use complexity analysis** – in response to the ECMC ISP Review recommendation for deeper consideration of community sentiment in network planning, incorporating local advice from jurisdictional planners and TNSPs on social licence in early-stage options planning.
- **Refreshed Transmission Cost Database** – to better reflect the resources required to undertake meaningful community engagement and communications, and to costs associated with likely changes to proposed transmission line routes to avoid complex areas and unsuitable landscapes.

Changes in outcomes

No change to the key finding of the ODP

- 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.

ODP projects a similar scale of investment through to 2050

- **Coal** is retained in the NEM until 2049, compared to 2038 under *Step Change* in the 2024 ISP, reflecting the intent of the Queensland Energy Roadmap. To retain these plant, more flexible operation is required, with increasingly frequent periods where coal plant are offline for hours, days, or even months at a time, to complement high solar generation periods.

- **Grid-scale renewables, dispatchable storage and flexible gas** needed by 2050 are 120 GW, 55GW/618 gigawatt hours (GWh) and 14 GW respectively, all at similar scales in the 2024 ISP, reflecting the pairing of variable renewable energy (VRE) with batteries, and higher wind output (that is, more energy for every megawatt [MW] of capacity compared to the 2024 ISP.
- **Transmission projects** are forecast to add about 6,000 km to the existing grid (with 365 km recently built and 2,800 km already committed or anticipated), down from 7,600 km in *Step Change* and close to 10,000 km overall in the 2024 ISP.

Broadly consistent net market benefits to consumers

- Net market benefits of transmission investment are broadly consistent, having increased slightly to $24 billion, from $22 billion in the 2024 ISP.

Proposed changes in actionable and future ISP projects

- Of the actionable projects from the 2024 ODP, three are now committed or anticipated projects, seven are likely to remain actionable, and one is likely to become a future project (Central Queensland to Southern Queensland Expansion).
- Two actionable projects from the 2024 ODP are subject to ongoing analysis and stakeholder engagement: Northern Transmission Project, and QNI Connect. The status of both will be confirmed in the final 2026 ISP.
- Two future projects from 2024 (Western Victoria Reinforcement and the Gippsland Offshore Wind Transmission) would become actionable, along with an additional smaller project (Switching Station Near Wondalga).
- Two new future projects are the Sydney Ring South (500 kilovolts [kV] option) and the South West Victoria Expansion, while a number are no longer considered.

PART A

The ISP is a roadmap for the NEM's transition

Part A
The ISP is a roadmap for the NEM's transition

The energy transition 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:

- **Section 1 – the energy transition is well underway.** 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 from home-scale to grid-scale met 43% of all demand for electricity in the NEM in the September 2025 quarter[16], and reached 79% for a half-hour on 11 October 2025. But renewables need support from multiple technologies, and nearing 100% renewables will be challenging. Those challenges are being managed, and the direction is clear.
- **Section 2 – consumers are forecast to use twice as much electricity in future.** They are 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, more than a third of it would be met by consumer resources.
- **Section 3 – the ISP is a roadmap for the NEM's transition.** Its legislated purpose is "to establish 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 to contribute to achieving the national electricity objective"[17].

  The centrepiece of that plan is an 'optimal development path' (ODP), the mix of generation, storage and network investments to meet consumer needs at least cost through to 2050, while meeting government policies. The ODP also triggers initial steps for the regulatory approval of specific transmission projects.
- **Section 4 – AEMO identifies the ODP through an extensive two-year, consultative process.** To date on the 2026 ISP, this has included consultation on 37 preliminary reports that provided the inputs, assumptions and defined the scenarios of the ISP. AEMO then considered around 2,000 potential development paths and modelled a shortlist of 23 candidates to identify the ODP.

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

[16] AEMO (2025) *Quarterly Energy Dynamics Q1 2025 p 4.*

[17] See https://www.aemc.gov.au/regulation/neo.

1 The transition to renewables is well underway

Electricity is indispensable to households and businesses, and to the transport and communication networks they rely on. The NEM has delivered that electricity for 25 years. It must now do so while coal generators retire, while consumers add their own solar and batteries, and while other sectors switch to electricity. This transition is the biggest overhaul of the NEM power system for 100 years.

This 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[18]. Policies have promoted renewables to replace them. Renewables are fast approaching the milestone of delivering half the NEM's electricity, and continue to attract private investment. To support them, investments in networks, storage and system security services are 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 challenge and opportunity 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 and that connect them all.

Electricity and gas markets are interconnected

AEMO operates two energy markets that are referred to in this ISP: the NEM and the East Coast Gas Market.

The NEM is the wholesale electricity market and the 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.

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

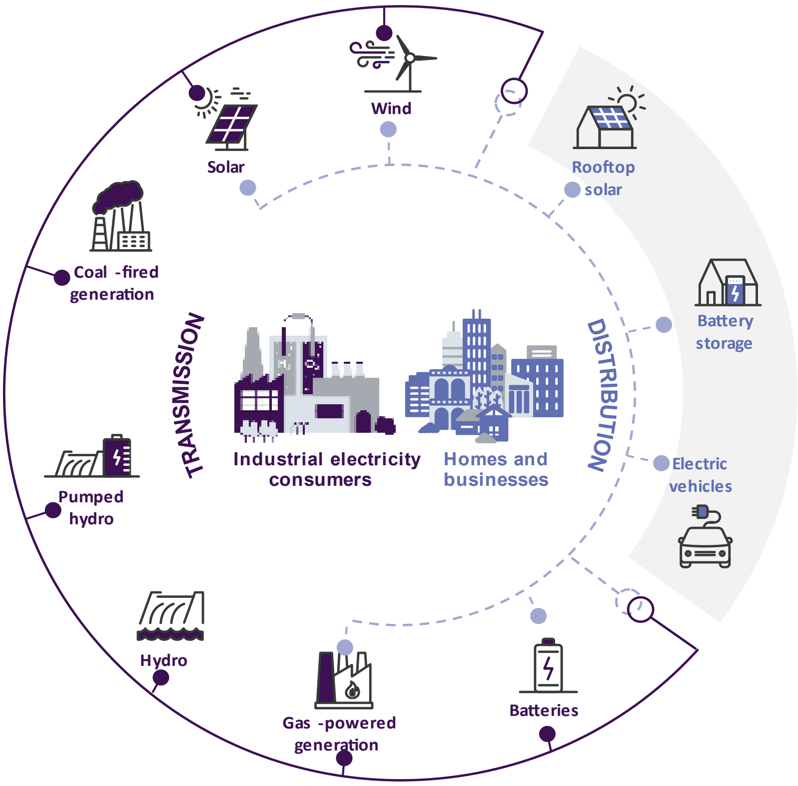
The East Coast Gas Market is the wholesale gas market for the physical East Coast Gas System, an interconnected grid of gas pipelines connecting all of Australia's eastern and southern states and territories. It is particularly important to the ISP as it supplies gas to the gas-powered generators which are an integral part of our electricity system. 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 4** 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 (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.

Figure 4 A power system with both grid-scale and consumer energy resources



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 companies (transmission network service providers or TNSPs) in each state are responsible for planning, building and safely and securely operating the transmission lines in their regions. 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, and in 2010 the 26 major power stations operating in the NEM delivered over 80% of its energy. Of these, 15 remain operational, reducing coal's capacity from about 30 GW to about 21 GW.

Queensland's fleet of coal plants have served for an average 30 years, and the Queensland Energy Roadmap sees their key role continuing. Elsewhere, the average age of the remaining fleet is 40 years, approaching the average of 44 years for the retired coal generators[19], with their owners declaring planned retirements that are on average only 10 years away.

Many were built in the 1970s and 1980s, 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 3.5 GW of coal-fired generation was out of service for sustained periods – 15% of the NEM's coal capacity. These rates have been increasing. For example, New South Wales black coal-fired generators were in full forced outage 7% of the time in 2011, rising to 17% in 2020[20].

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. In the meantime, owners are investing to keep their coal plants economic as renewables put downward pressure on wholesale prices. More flexible operations allow them to 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. These innovations are expected to continue, especially in the younger Queensland fleet.

Consumers and governments have led the push to renewables

In Australia, renewables from home-scale to grid-scale met over 40% of all demand for electricity in the NEM during the 2024-25 year and 51% in the month of October 2025, and reached 78.6% for a half-hour on 11 October 2025. These record levels vary seasonally, but are consistently rising. The renewable potential from wind, solar and hydro generation reached 113.9% of the grid's needs on 5 October 2025, but not all of that capacity could be used.

Already, in aggregate, rooftop solar installed by homes and businesses is currently capable of meeting 61% of underlying energy demand across the NEM in the middle of a sunny day. Over the summer (Q1) of 2025, they contributed 14.7% of the NEM's total electricity production, more than grid-scale solar (9.3%), wind power (13.7%), hydro (4.9%) or gas (3.7%)[21]. Even in the winter of 2025 (Q2), rooftop solar supplied 9.5% of the

[19] Note Redbank is excluded from the average age calculation as this plant is planned to be converted to biomass generation.

[20] AEMO, 2020 *Electricity Statement of Opportunities* p 47, 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.

[21] AEMO. *Quarterly Energy Dynamics* Q1, April 2024, https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

NEM's mix, outstripping hydro (6.8%), grid-scale solar (6.7%) and gas (6.1%) – with wind showing its winter value (14.1% of supply).

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 and batteries. 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) between 2010 and the present.

Government targets are de-risking Australia's transition. As consumers continue to set the pace in adopting rooftop solar, NEM government policies are in place to support industry in ensuring there is enough grid-scale infrastructure in place for coal's retirement. 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
- are no longer kickstarting a transition that is already well underway, but focus on de-risking its delivery.

They include support for grid-scale assets (such as the Capacity Investment Scheme), the decarbonisation of businesses (such as the Safeguard Mechanism), and for consumers to embrace CER (such as the Cheaper Home Battery Scheme and the Solar Sharer retail tariff).

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. These 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 respond to market signals. This is done by 'bundling' CER through a retailer or an independent service, to form a 'virtual power plant' or VPP.

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 roles, including the ISP. However, many renting and low-income households do not have the option to invest in or even access CER. Policies are being advanced to overcome this equity challenge, for example the Solar Sharer scheme to offer free electricity in the middle of the day, drawing on the abundant output of rooftop solar.

Global economics are driving down the cost of renewables

The decisions on how best to replace old coal-fired plants are made by private investors. That investment favours renewable energy and supporting technologies over fossil fuels. Globally in 2024, wind and solar received over three times as much investment as did coal[22]. In the first half of 2025 and for the first time, more of the world's energy was delivered by renewables than by coal[23].

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

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

While meeting commitments to reduce emissions kickstarted that trend, 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 kilowatt (kW) to $1,500/kW in the four years to 2025, and is anticipated to drop again to $1,100/kW by 2030. The capital cost of two-hour battery storage similarly fell from $1,300/kW to $1,250/kW and is forecast to drop again to $800/kW by 2030[24]. Meanwhile, the capital cost of new coal-fired power stations with carbon capture and storage has risen from $7,650 to $11,700 per kW over the last eight years[25]. Even with the additional support discussed in Section 1.3 below, 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 examples, there can be 'still and dark' periods (a 'renewable lull') when other resources are needed, and solutions are needed to cater for the flood of solar energy in the middle of the day. Further, system security services that have been a by-product of coal fired power generation for decades will need to be provided from alternate sources.

A range of solutions are supporting the transition from coal to renewables, in the NEM and globally, with often the same investment (batteries and gas plants in particular) 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 two-way flows of electricity and support population growth.
- **Batteries are becoming more common as they get rapidly cheaper** to allow households, businesses and the grid to store surplus energy from cheap daytime solar to use in the evening and morning peaks, and to support grid security and reliability as coal plants withdraw.
- **New flexible gas-powered generation plants** provide critical back-up power supply in 'dark and still' conditions (and to help pre-charge batteries for those times), as well as providing supply for peak demand events and supporting grid security as coal plants withdraw.
- **Existing hydro generators and other long-duration 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 infrastructure is connected.
- **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

[24] AEMO 2021 IASR and 2025 IASR. Converted to $2025.

[25] CSIRO (2025), GenCost 2024-25 Section 5.3.2, https://www.csiro.au/-/media/Energy/GenCost/GenCost-2024-25-Final_20250728.pdf.

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 increasing their 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. The 2025 *Transition Plan for System Security* sets out AEMO's plan to maintain power system security in the NEM through the transition.

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

The NEM is transforming as coal plants approach their end-of-life, consumers add their own solar and batteries, and other sectors switch to electricity. Australia is in a globally enviable position to deliver a successful energy transition if appropriately coordinated with good system planning, having a strong regulatory and market environment, and wide availability of renewable energy options and complementary services.

The ISP contributes to that planning to help ensure the transition meets consumer needs. It does this by ensuring investment in Australia's transmission networks is efficient, 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 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. There are also broader concerns that the upfront investment in new energy infrastructure is adding to today's cost of living. 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 around 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 C.

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 international commitments to reduce emissions, energy independence, new sectors for skilled jobs, global 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.

2 Electricity consumption is rising

Household and business consumers are in many ways leading the energy transition. Before the transition started, few thought of what lay behind the three-point plugs, or even how much electricity they used. Now, there is everyday engagement on how homes and businesses source electricity and significant changes to how, and how much, they use it.

This section sets out how:

2.1 **Total (or 'underlying') electricity consumption is forecast to nearly double** from the current 205 TWh to 389 TWh in 2049-50. This includes electricity delivered from the NEM's utility-scale resources (273 TWh) and from the other smaller resources on-site and through the distribution network. The 'electrification' of the economy is driving most of this rise, as consumers switch from petrol and gas to electricity for industrial processes, transport, heating, cooling and cooking.

2.2 **Business and industry are driving most of the increase in consumption**, due to economic growth, new industries like data centres and hydrogen production, and electrification. Their forecast operational consumption would rise 90% to 253 TWh in 2050.

2.3 **Households are forecast to rely more and more heavily on consumer energy resources**. Household investment in rooftop solar, home batteries and energy efficiency is projected to more than offset the rising electricity use by electrical appliances, vehicles and a growing population. As a result, households would depend on just 20 TWh to be delivered from the grid, down 40% from today. While this a relatively small amount, the future grid will need to be able to cater for much larger energy flows to and from home-scale systems every day.

Section 3 introduces the ISP's role in setting a plan for how the NEM will manage the transition to renewables and the near doubling of electricity consumption, at the same time.

Section 10 below explores how consumers are investing in their own energy resources, and what that means for grid-scale investment.

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). Consumers may draw up to 21 GW of electricity from the grid at one time, and up to another 2 GW from their own 'behind-the-meter' resources.
- '**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).

There are three types of 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.

2.1 Total or underlying consumption is forecast to near double

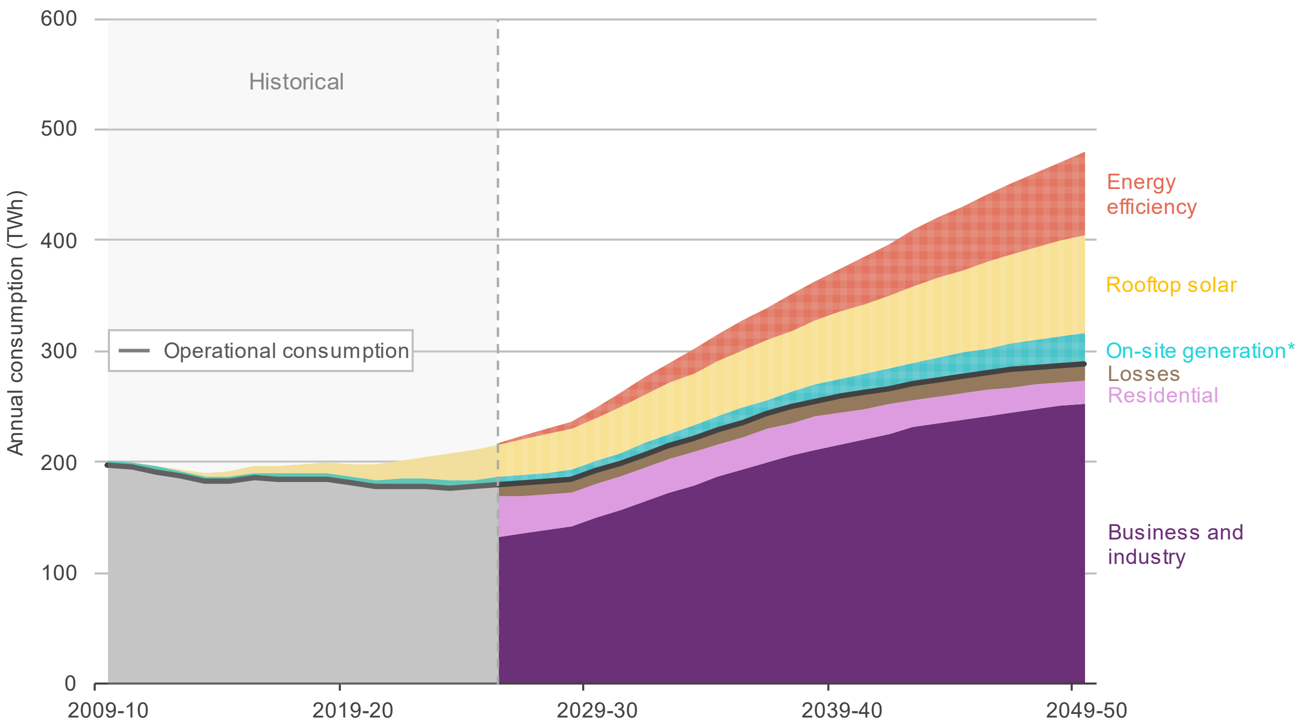
Electricity use is expected to rise due to population growth, economic growth, electrification (the switch from petrol and gas to electricity for industrial processes, transport, heating, cooling and cooking), and large new users of electricity such as data centres and hydrogen. As a result, underlying consumption across the NEM is forecast to near double from the current 205 TWh to 389 TWh in 2049-50: see **Figure 5**. Of this amount, consumers are projected to supply 116 TWh with CER and other on-site generation, which may be either used on site, or fed into the grid.

The remaining 273 TWh would be delivered consumption supplied by utility-scale resources. Business and industry would account for 253 TWh (a 90% rise from today), and households would consume an aggregate of just 20 TWh (down from 33 TWh today). The future power system must be able to cater for large energy flows to and from the grid at different times of the day and year, and also supply the growth in business and industrial consumption.

Electrification is the main driver of rise in electricity consumption, adding 114 TWh by 2050 – about three quarters of the NEM's current total. Road transport is the dominant single element of that shift, rising from today's 1 TWh up to 61 TWh by 2050[26]. Of that amount, about half would power household EVs the other half would power commercial and freight EVs; both vehicle categories would charge from consumer-generated and grid-supplied electricity at various times, depending on driving and charging behaviours.

[26] AEMO 2025 IASR*,* p 65.

Figure 5 Electricity consumption, NEM (TWh, 2009-10 to 2049-50, *Step Change)*



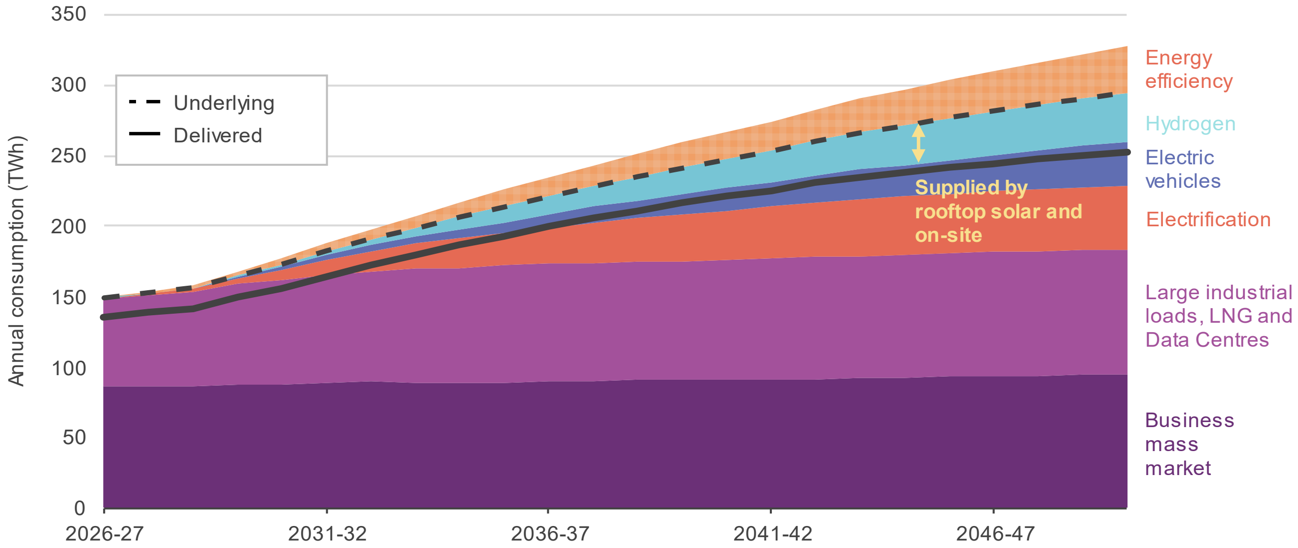
Note: On-site generation (including "non-scheduled generation") is non-utility generation that includes on-the-ground PV and small wind and biomass, typically for industrial use.

2.2 Grid consumption by industry to rise 90% by 2050

The operational or grid consumption from business and industry is forecast to rise by 90% from today's 133 TWh to 253 TWh in 2050: see **Figure 6**. The switch of transport and industrial processes to electricity accounts for over half of this expected rise (76 TWh). Most of the rest is from new sources of demand: data centres to support AI and cloud-based services add 29 TWh, while hydrogen production is forecast to add 34 TWh.

Businesses are investing in their own on-site generation and batteries as larger distributed resources, reducing operational consumption by up to 42 TWh. These investments may also give businesses more flexibility to take advantage of lower electricity costs when the grid supply is in surplus (potentially in the middle of the day) and reduce grid reliance when supply is more scarce (potentially in the evenings).

Figure 6 Business and industry electricity consumption, NEM (2026-27 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.

2.3 Grid consumption by households to reduce by 40% by 2050

As a net figure over the year, households across the NEM are forecast to consume 40% less from the NEM in 2050 than they do now – even with EV charging and a growing population.

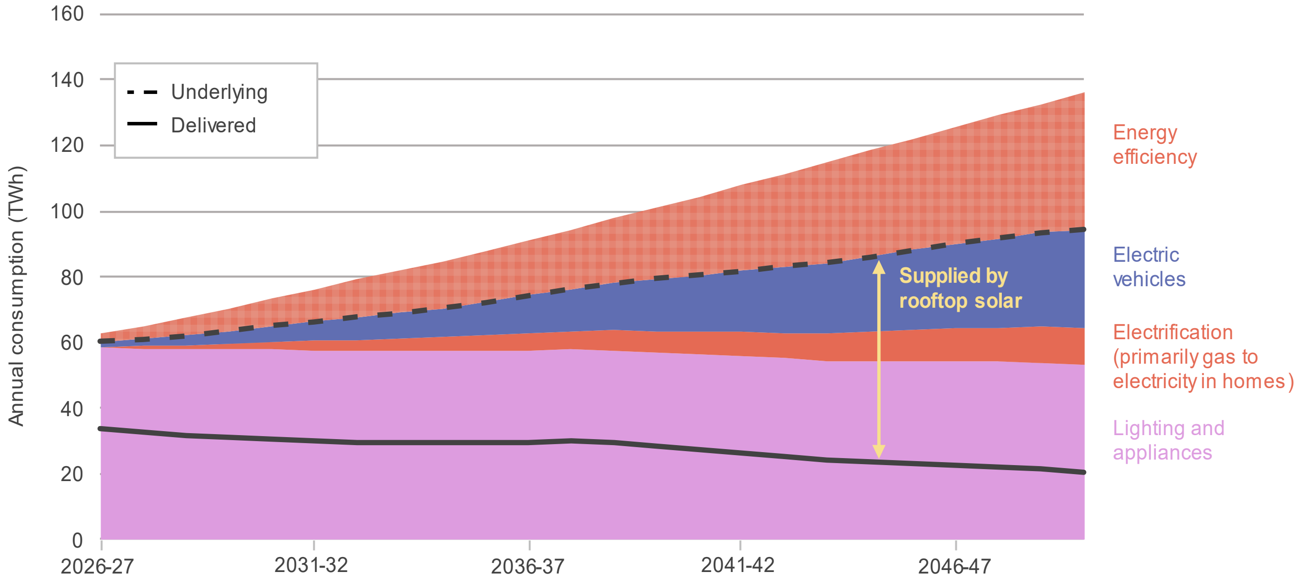
Individual households will continue to differ in how they rely on the grid. Those without rooftop solar and/or battery systems would rely wholly on the grid; those with solar may export excess energy during the day and import from the grid overnight; while those with solar and batteries may store any excess daytime solar for use later, or feed it back into the grid (and consume from the grid at other times). Some might opt to 'coordinate' their CER by connecting them with others through a retailer or independent aggregator, so that they interact with the grid in a way that maximises both their benefit and that of the power system.

Figure 7 shows how electricity use for existing home lighting and appliances currently makes up almost all residential consumption, and how projected energy efficiency improvements would more than offset population growth. As a growing number of households charge EVs and use more electricity for heating, cooling and cooking (shifting from gas appliances in particular), their underlying consumption would increase to 136 TWh by 2050.

At the same time, households are investing in more efficient buildings and appliances, and changing behaviours to minimise energy use. That is forecast to reduce their underlying consumption to 94 TWh.

Their continued investment in rooftop solar, supported by batteries, then reduces the consumption delivered by the NEM from 33 TWh to just 20 TWh in 2050. This small amount represents all that consumers take from the grid *less* all that they have fed into it. The future grid will need to make that possible, by being able to cater for much larger daily energy flows both to and from home-scale systems.

Figure 7 Residential electricity consumption, NEM (TWh, 2026-27 to 2049-50, *Step Change)*



3 The ISP has a specific and expanded role

The NER require AEMO to produce a plan every two years for essential electricity infrastructure. This is known as the *Integrated System Plan* (ISP). The ISP is a roadmap for the NEM's transition over at least the next 20 years.

This section sets out how:

3.1 **The ISP is a plan for grid-scale power system infrastructure.** It informs investment by private companies and governments, flows through to planning by individual transmission and distribution networks, and triggers action on specific transmission projects.

3.2 **The ISP delivers an 'optimal development path' (ODP), and more.** The ODP is the mix of grid-scale generation, storage and network investments that meets consumer needs at least cost through to 2050, while meeting government policies. This ODP also takes into account how consumer demand is rising, how households and businesses are investing in their own energy systems, how the distribution network is accommodating that, and how gas infrastructure must support gas-powered generation.

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

The Draft 2026 ISP meets this regulated scope, and builds on previous ISPs to offer a comprehensive plan for the NEM's future. This draft and its proposed ODP is released for consultation, and will be finalised with ongoing analysis and after close consideration of stakeholder feedback.

3.1 The ISP is a plan for grid-scale infrastructure

The Australian and NEM state governments have agreed through the 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

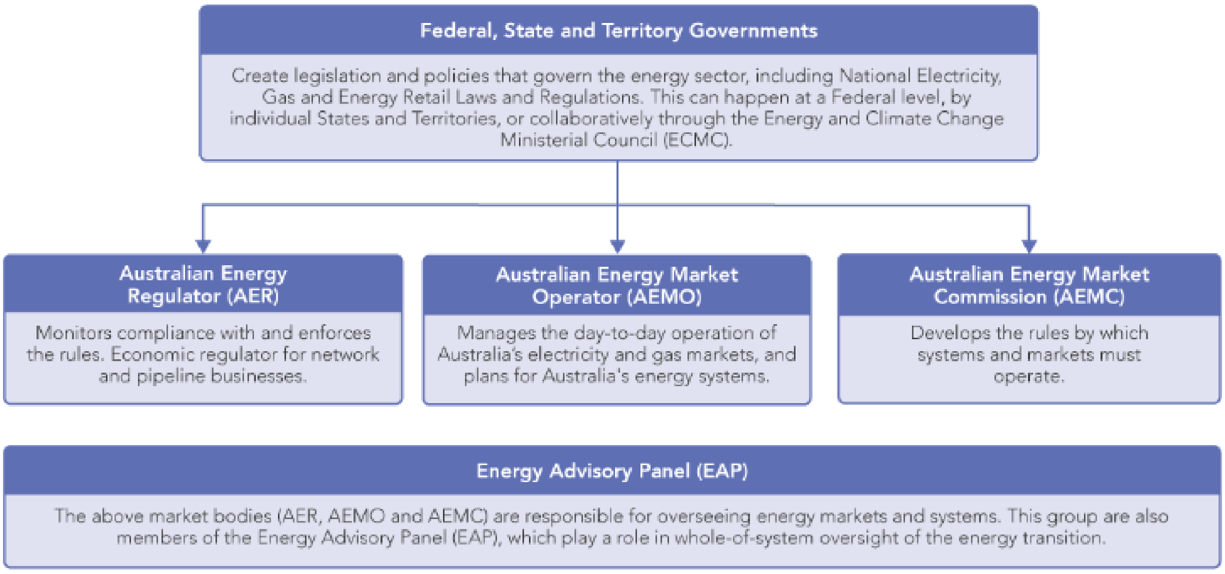
The Australian and NEM state governments have agreed on a governance framework for the power system, as set out in the National Electricity Law, Regulations and Rules (the NER). The three energy market bodies work closely together, each as an independent decision-maker with clear statutory functions, accountabilities and powers: see **Figure 8**.

- The AEMC sets the electricity and gas rules and publishes the statement of governments' emission 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 AER ensures that AEMO and industry participants comply with the rules, 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.

Figure 8 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 grid planning document that guides other grid-scale investment

The NER set out how AEMO is responsible for overall NEM transmission planning, which then cascades into planning by the NEM's transmission and distribution networks: see **Figure 9.**

- AEMO primarily undertakes and delivers these responsibilities through the ISP, and related documents such as the *Transition Plan for System Security*.
- Together, these inform (and are informed by) planning of regional and inter-regional transmission lines and REZs by TNSPs and jurisdictional bodies – Powerlink, Transgrid, EnergyCo, VicGrid, AusNet Services, ElectraNet, Marinus Link Pty Ltd, and TasNetworks.
- Finally, that regional planning informs the distribution network planning by the distribution operators across the NEM – Energex, Ergon Energy, Ausgrid, Endeavour Energy, Essential Energy, Evoenergy, CitiPower & Powercor, United Energy, SA Power Networks and TasNetworks.

The ISP does not bind governments or private network operators in their investment decisions. In fact, 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.

For all other grid-scale investment, such as in generation or storage, the ISP offers guidance only. Decisions to propose and build any of that infrastructure rest with developers.

The ISP does not plan for 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 9 The national network planning process

The ISP triggers key regulatory steps for 'actionable' transmission projects

In addition to its planning purpose, the ISP is a key trigger point for potential transmission projects in the NEM. A large transmission project cannot continue down a regulatory approval pathway until it is actionable under the ISP or an equivalent state-based scheme[27].

If it is an actionable ISP project, the transmission proponent must examine options to meet the identified need, and set out the project's full details in a regulatory investment test for transmission (RIT-T). AEMO then re-considers the project in a feedback loop to ensure that the project is still aligned with the ODP in the most recent draft or final ISP. This process may take several years to complete, but ensures the resulting transmission projects are efficient and remain in consumers' long-term interests.

[27] 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'. This occurs where it is known that the project will progress through an approval process which is an equivalent state-based process rather than through the RIT-T assessment. These alternate pathways currently exist in New South Wales, Queensland and Victoria, each with a specified approval process including an economic assessment and public consultation process.

3.2 The ISP delivers an 'optimal development path', and more

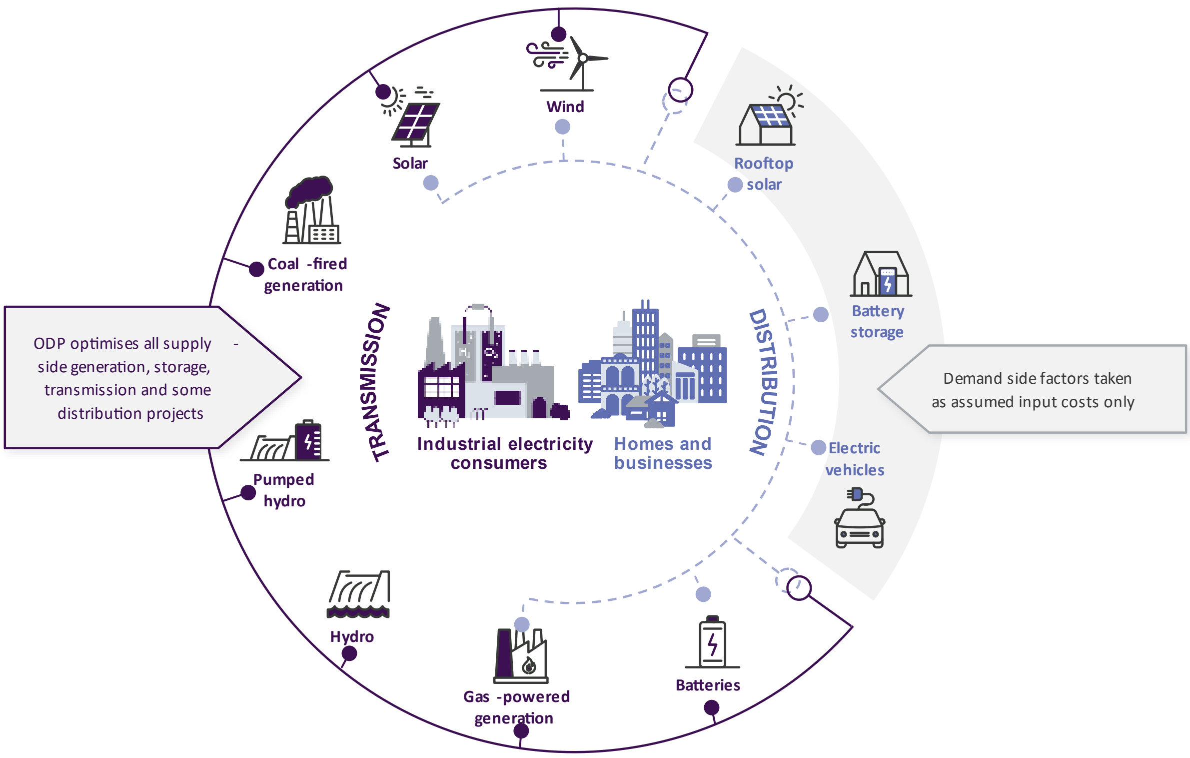
Each ISP has been required to lay out[28] a proposed ODP for at least the next 20 years (which AEMO has extended through to 2050). This includes actionable ISP and future ISP transmission projects, and development opportunities such as generation, storage, distribution network assets or demand side developments.

Following the 2024 ISP Review, the Draft 2026 ISP considers more explicitly the interactions between grid-scale electricity investment, CER, distribution networks, and gas market development. This existing and new mandated content is discussed below.

The ODP optimises 'grid-scale' or 'supply-side' investments

The ODP optimises the grid-scale 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 10** below. That is where system-wide planning is essential, so that large investments are made efficiently and effectively to benefit energy consumers. In addition, some of the distribution network development opportunities to support CER and other distributed resources are considered.

Figure 10 Grid-scale planning based on demand-side assumptions



[28] NER 5.22.6.

The 2026 ISP deepens its analysis of demand side and gas supply factors

In April 2024 the Energy and Climate Change Ministerial Council (ECMC) published its ISP Review, with 12 actions to be taken. The 'Implementation of the ISP Review' section at the end of this report outlines how those actions have been pursued through the ISP development process.

The three main responses are that the ISP now has deeper consideration of demand side factors such as CER, of distribution networks, and of gas market development. These considerations are an important addition to the ISP's scope and modelling, increasing the information available to industry, government and consumers for potential future investments.

Demand side factors and the distribution network

The ISP must make a statement of demand-side factors[29] that may affect the power system. These factors include the development of assets, technologies and services available to end users, the rise of electrification, and demand management or energy efficiency schemes.

This statement is set out in Appendix A9, with its main insights in Section 9 below. The analysis also identifies distribution network development opportunities to support CER and other distributed resources. AEMO has also conducted sensitivity analysis to assess how changes in energy efficiency, CER and co-ordination levels may affect the ODP's benefits.

These demand-side elements (the right-hand side of **Figure 10**) are input assumptions for the ODP modelling, and are not optimised as the grid-scale elements are. These smaller investments are left to individual participants in the energy market, from single households through to distribution network operators. AEMO engages continually with consumer and industry representatives to forecast how much those participants would invest in future years, and the final assumptions relevant to the 2026 ISP are published in the 2025 IASR.

Gas development projections

The ISP must include gas development projections for at least 20 years[30]. These projections are combinations of developments in the 'covered gas' industry, to explore how they would affect the efficient development of the power system. Covered gases includes natural gas, hydrogen, biomethane, synthetic methane, or a blend of these gases. AEMO has included analysis of potential natural gas and biomethane developments in the gas development projections for the Draft 2026 ISP.

The gas development projections and expanded gas analysis is in Appendix A10, with key outcomes summarised below in Section 7. The projections identify combinations of gas investments that would support the needs of all gas consumers, including the gas fuel requirements of the ODP. The assumptions relevant to the Draft 2026 ISP are published in the 2025 *Gas Infrastructure Options Report*.

Although AEMO has included gas development projections to inform electricity investment, gas and electricity infrastructure has not been co-optimised. The projections do not provide an 'optimal development path' for gas, and the investments modelled are not actionable in the same way as electricity transmission

[29] NER 5.22.6A(c)(2).

[30] NER 5.22.6(a)(8).

projects identified as actionable projects in the ODP. Gas investment remains the responsibility of the gas industry.

3.3 The ISP is developed over two years of extensive consultation

AEMO publishes the ISP every two years, the result of a two-year industry-wide journey with consumers, 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. Consultation on the Draft 2026 ISP is one of the last stages of industry engagement towards the 2026 ISP: see **Figure 11**.

Throughout these consultations, AEMO has engaged with over 1,400 stakeholders, and considered 241 written 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. 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.

The consultations are detailed in Appendix A1, and focus on:

- inputs, assumptions and scenarios used by AEMO for electricity and gas system forecasting and planning, as finalised in the 2025 IASR[31],
- the methods for forecasting electricity use across the energy scenarios AEMO plans for, as well as engagement on the electricity and gas demand and consumption forecasts provided in the 2025 *Electricity Statement of Opportunities* (ESOO) and the 2025 *Gas Statement of Opportunities* (GSOO)[32],
- the potential additions and upgrades to the transmission and distribution electricity networks in the 2025 *Electricity Network Options Report*[33]*,*
- potential gas pipeline, storage and supply developments in the 2025 *Gas Infrastructure Options Report*[34],
- the cost benefit analysis and market modelling approaches set out in the 2025 *ISP Methodology*[35], including the impacts of updating the ISP in response to the Federal Government's 2024 review of the ISP and subsequent changes to the NER to support better integration of gas and demand side factors[36].

All of these consultations feed into AEMO's work to determine the optimal development path.

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[31] AEMO must consult on the inputs, assumptions and scenarios to be used for the ISP: NER 5.22.8.

[32] The ISP must have regard to these reports: NER 5.22.10(b).

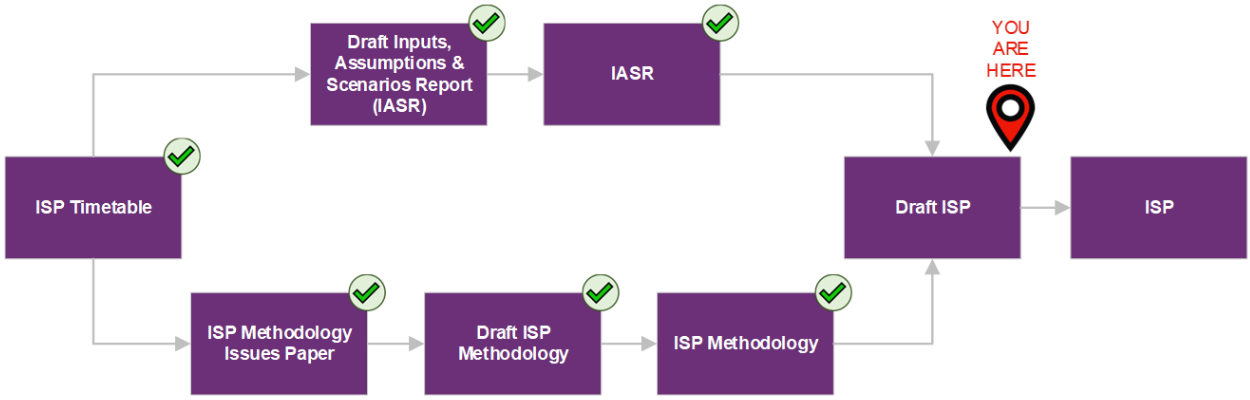
[33] AEMO must consult on the inputs, assumptions and scenarios to be used for the ISP: NER 5.22.8.

[34] AEMO must consult on the inputs, assumptions and scenarios to be used for the ISP: NER 5.22.8.

[35] The ISP must be prepared consistent with this methodology: NER 5.22.8(d).

[36] Energy ministers' responses to the Federal Government's review of the ISP is at https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan.

Figure 11 ISP consultations

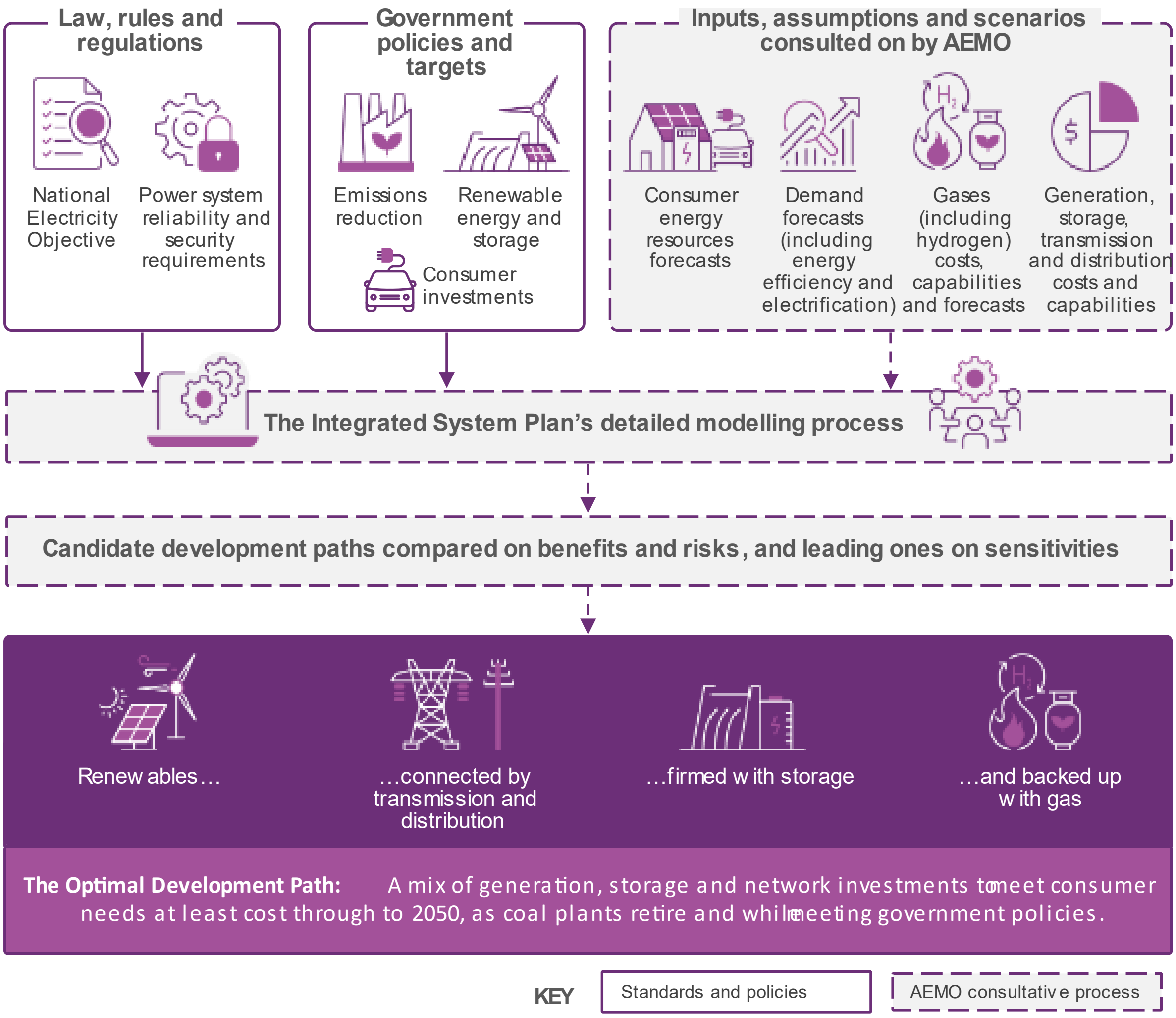


4 AEMO identifies the optimal development path

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. The proposed 2026 ODP is set out in Part B.

Section 4 offers an understanding of how AEMO identifies the ODP: a methodology that models and analyses a range of market decisions, government policies and consumer initiatives. **Figure 12** sets out an overview of the process.

Figure 12 High level view of the *ISP Methodology*



This section sets out the elements of **Figure 12**:

4.1 The ODP must comply with the National Electricity Law and National Electricity Rules.

4.2 It must consider 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.

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 optimal development path after comparing the benefits and risks of the candidates, and testing the leading ones against various sensitivities.

These elements are detailed in Appendix A6 and in the 2025 *ISP Methodology.*

4.1 The ISP complies with laws, rules and regulations

The ISP must comply with the National Electricity Law and NER, which include achieving power system needs to contribute to achieving the National Electricity Objective, and preparing the ISP in accordance with rule requirements and guidelines, including considering government policies.

The National Electricity Law sets out the National Electricity Objective, which 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*."

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 power system's reliability and security, and government emissions targets.

ODP and the 'least-cost' path

AEMO seeks an optimal development path (ODP) from a short-list of candidates that has 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.

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 without any new transmission build, taking into account all of their capital, fuel and operating costs. 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.

The costs and benefits considered in the ISP, including changes in greenhouse gas emissions, are set out in **Table 2**, 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.

Table 2 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 of new generation, storage and electrolyser capital expenditure.
	Retirement costs	The cost of retiring and decommissioning generation and storage assets is separated from the cost of building new generation and storage.
	REZ investment	Differences in the timing of REZ network infrastructure that is not considered as a potential actionable or future project.
	System security costs	Differences in the timing of network 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 depreciating 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 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 using the value of consumer reliability (VCR).
Emissions	Emissions reduction benefits	Reductions in Australia's greenhouse gas emissions using the value of emissions reduction (VER).

Note: AEMO does not consider changes in network losses, ancillary service costs or competition benefits are material to the selection of the optimal development path for the ISP, as explained in the *ISP Methodology*. Where material, changes in these market benefit classes 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[37] 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.

[37] NER 5.22.3(a), with the details set out in the NER for the reliability standard (3.9.3C(a)); system security principles (4.2.6), system standards (Schedules 5.1 and 5.1a), and applicable regulatory instruments (defined in NER Chapter 10).

System reliability

A *reliable* power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence[38]. The NEM's reliability standard[39] requires at least 99.998% of forecast customer demand to be met 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 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 3** below and further in Section 5.1, Appendix A7 and the 2025 *Transition Plan for System Security*.

Table 3 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.

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

[39] The reliability standard is set in the NER and is reviewed by the independent Reliability Panel. It was last reviewed in 2018; see https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018.

4.2 The ISP meets government policies and targets

As the ISP informs investment decisions, it must reflect current government policy settings to ensure these decisions can be made efficiently. Two sets of policies are included:

- the ISP *must* consider the emission reduction and energy targets stated in the AEMC's *Emissions Targets Statement,* and
- the ISP *may* 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 (by meeting at least one of five criteria defining that commitment)[40].

In considering the second policy set, 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.

AEMO incorporates these targets and policies into the ISP as detailed in the 2025 IASR. It incorporates them into each of the three ISP scenarios, so that each of the 24 candidate development paths would meet them. AEMO does not assess the merits or feasibility of these targets and policies.

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[41].

Policies and targets included in ISP modelling

The policies and targets included in the Draft 2026 ISP modelling include:

- **emission reduction targets**, including the national target of 43% below 2005 levels by 2030, by 62-70% by 2035, and net zero by 2050, as well as state targets and the federal Safeguard Mechanism affecting major business and industrial loads,
- **renewable energy support**, including the national target of 82% of national supply by 2030, and state targets that may be either in absolute terms (for example, New South Wales' 12 GW new renewable energy generation target, the Tasmanian Renewable Energy Target that sets targets for 2030 and 2040 respectively, and the South Australian Firm Energy Reliability Mechanism) or proportional (for example, the Victorian target of 65% renewables by 2030[42],
- **CER policies**, including the 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 and the Victorian Solar Homes Program and Solar for Business Program, and the gas substitution programs in the Australian Capital Territory and Victoria,

[40] For more information, see Addendum to the 2023 IASR, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/supporting-materials/addendum-to-2023-inputs-assumptions-and-scenarios-report.pdf?la=en.

[41] 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.

[42] *Electricity Infrastructure Investment Act (NSW) 2020, Energy Co-ordination and Planning Amendment (Tasmanian Renewable Energy Target) Act 2020*), and *Renewable Energy (Jobs and Investment) Act (VIC) 2017*.

- **EV policies,** including the federal New Vehicle Efficiency Standard and EV fringe benefits tax exemption, and 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),
- **energy efficiency policies**, including building and construction codes, and specific rating, disclosure, efficiency, upgrade and peak demand reduction schemes,
- **transmission, REZ and regional energy hub policies (including 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,
- **storage targets**, including 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, Queensland's Borumba Pumped Hydro Energy Storage project, South Australia's firm energy reliability mechanism, and the Federal Government's expanded Capacity Investment Scheme target of 14 GW of dispatchable capacity by 2027,
- **offshore wind targets,** being the progressive targets building to 9 GW by 2040 under the Victorian Offshore Wind Policy, and
- **hydrogen policies**, being the federal Hydrogen Production Tax Incentive and the New South Wales Hydrogen Strategy.

4.3 AEMO consults on inputs, assumptions and scenarios

The ISP takes in a number of market and technology inputs and assumptions. These inputs are set out in a number of AEMO publications, including the 2025 *Inputs, Assumptions and Scenarios Report,* the 2025 *Electricity Network Options Report*, the 2025 *Gas Infrastructure Options Report,* the 2025 *Electricity Statement of Opportunities,* the 2025 *Gas Statement of Opportunities* and Appendix 2 of the 2025 *Transition Plan for System Security*[43].

- **Demand-side forecasts** are the future trends in electricity consumption, taking into account 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 above, and Section 9.
- **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 required to meet domestic hydrogen consumption forecasts, and any gas development projections that might be needed to supply gas consumers, including the supply of gas for gas generation: see Section 7.

[43] The ISP must have regard to these publications, and others listed in NER 5.22.10(b).

- **Generation, storage and transmission costs and capabilities** are future trends for existing and any new technologies, including the design and implementation of new REZs. 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 on 4 August 2025[44]. To support this forecast, Aurecon provides estimates of the current capital cost of each generation technology. These estimates 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 reflect the local deployment of global technologies.

Three potential scenarios for the future

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 potential 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.

The scenarios represent a broad range of global and domestic influences on Australia's energy transition.

- ***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, with some larger energy-intensive industrial users assumed to close.
- ***Accelerated Transition***[45] 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[46] (decarbonisation targets, demand drivers and technological trends) which are inherently uncertain, but can materially influence the development of the future power system: see **Figure 13**. 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 conducted a transparent process with in-person participation of 25 expert stakeholders[47]. *Step Change* was identified as the most likely of the three scenarios to eventuate (46%), with equal weighting of a 27% likelihood for *Slower Growth* and *Accelerated Transition*. The balanced outcome is helpful to ensure that risks are being explored more evenly – an

[44] See https://data.csiro.au/collection/csiro:44228.

[45] 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.

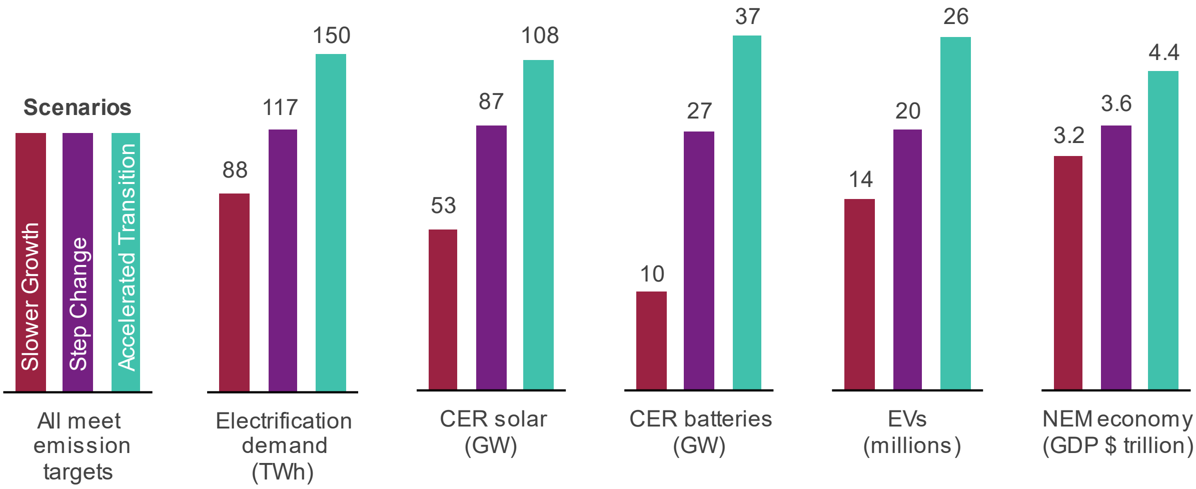
[46] The IASR suggested 15 parameters, and another three were added in the later workshop to determine scenario likelihoods.

[47] 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.

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.

Figure 13 Three scenarios of the future for ISP modelling, including five of the major parameters driving scenario differences

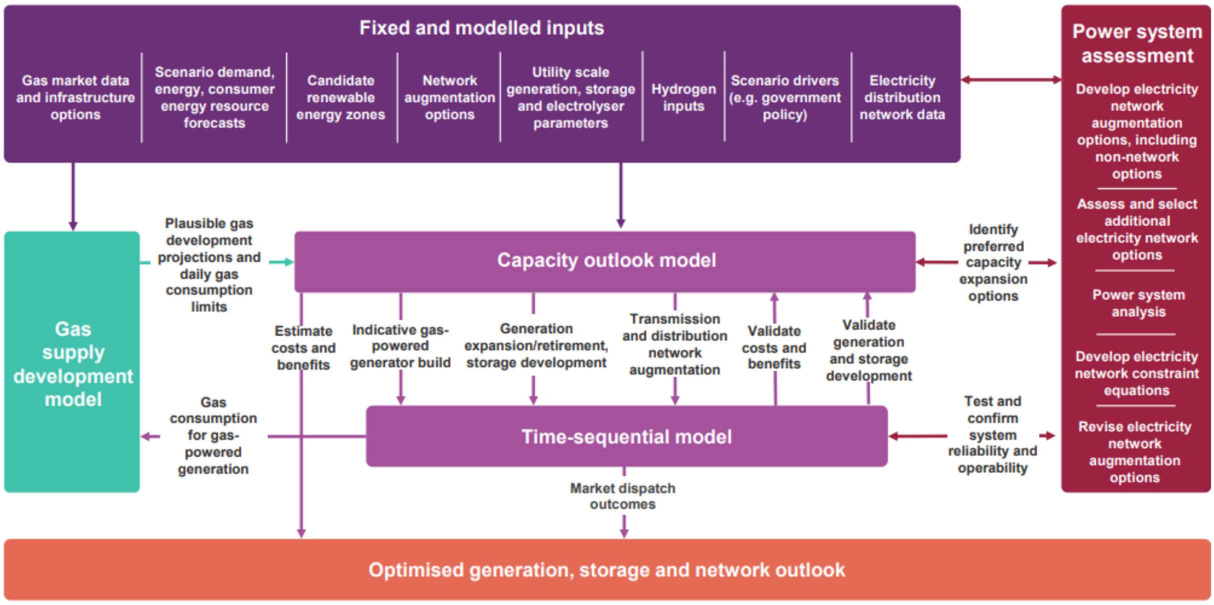


4.4 The ISP's modelling integrates six different analyses

AEMO relies on a suite of models and analyses that covers generation, storage and network investments. The components of this suite are shown in **Figure 14** below:

- The **fixed and modelled inputs** are published in the IASR, and are influenced by **engineering assessments** of the NEM's capabilities.
- The **gas supply development model** identifies gas infrastructure limitations and gas development projections 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 **engineering 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.
- Finally, the **cost-benefit analyses** identify the net market benefits and potential 'regret' costs of each development path, in each scenario, including consideration of relevant sensitivity analysis.

Figure 14 **Detailed ISP modelling methodology**



4.5 The ODP is selected from 23 candidate development paths

To determine the ODP, AEMO identifies and ranks the leading candidates. It then tests that ODP to ensure it is robust against changing assumptions or 'sensitivities'.

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.

Identify and 'rank' the strongest candidate development paths

AEMO considered around 2,000 potential development paths of new transmission investments to support the generation, storage and CER developments needed, and whittled them down to a shortlist of 23 candidate development paths.

These candidates incorporate all the transmission and other investments needed. They are compared to a 'counterfactual' that still includes investment in generation, storage and distribution, but has no new transmission projects beyond those already committed or anticipated.

AEMO uses the AER's *Cost Benefit Analysis Guidelines* to select the ODP from these candidate development paths. The steps are:

- **Determine the least-cost development path for each of the three scenarios.** These three candidate development paths would maximise net market benefits under their respective scenarios.
- **Determine a shortlist of candidate development paths.** The three least-cost development paths provide the basis for other candidates. Variations are made to form other candidate paths, with one or two projects pushed back to be delivered later, or brought forward to be delivered earlier, added, or removed entirely. That way, the impact and market benefit of those projects can be assessed and accounted for appropriately.
- **Calculate the net market benefits of each candidate.** The net market benefits of each candidate development path are calculated for each scenario, by comparing their total costs (all grid-scale generation, storage and network costs) against the total costs of a counterfactual development path in which no major transmission projects are developed.
- **Rank the candidates by their net market benefits.** The first 'risk neutral' assessment is the candidate's net market benefits, weighted across the three scenarios to reflect the relative likelihood of the scenarios occurring: see Section 4.3.
- **Consider risks arising to consumers from uncertainty**[48]. These risks may relate to over-investment, under-investment, and the timing of investments. AEMO conducts a second 'risk averse' assessment to consider 'regret costs': the benefits that are lost if projects are planned and delivered for one scenario, but another scenario plays out. AEMO may use its understanding of consumer risk preferences (informed through targeted engagements including with the ISP Consumer Panel) to inform this analysis.

Test candidate development paths against sensitivities

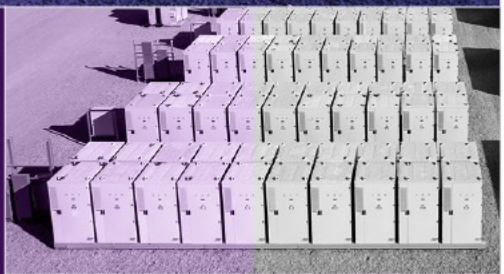
AEMO then uses sensitivity analysis to test the resilience of candidate development paths under the most likely of the three scenarios (the *Step Change* scenario), when key assumptions are changed. AEMO can use these additional tests to select the ODP, particularly if they reveal additional, or fewer, investments that would align with consumer attitudes to risk, consistent with the AER's *ISP Cost Benefit Analysis Guidelines*. This may happen if the ODP is not the least-cost option under the weighted-scenario method, but still has a positive net benefit in the most likely scenario. This approach has not been applied for the proposed ODP in this Draft 2026 ISP.

For the Draft 2026 ISP, the tested sensitivities were constrained delivery of the proposed ODP (see Section 11), faster or slower coal retirements (see Section 5.1), variations on the gas development projection (see Section 7.2). The effects of demand-side factors on the power system were also tested by assessing the impact of reduced energy efficiency measures, and no further CER coordination (see Section 9.2).

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








PART B

Generation, storage and network investments in the proposed ODP

Part B
Generation, storage and network investments in the proposed ODP

In consultation with stakeholders, AEMO has comprehensively considered each of the power system, consumer and policy needs introduced in Part A. Part B sets out the proposed 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.

The forecast capacities in Part B are those under the *Step Change* scenario. Given the risks of delay to infrastructure builds, Section 12 discusses how constrained delivery might affect that development. Other scenario forecasts are in the appendices.

- **Section 5 – 120 GW of grid-scale renewables by 2050, to replace coal and meet rising demand.** Ageing coal is steadily retiring and may retire faster than announced. The ODP projects that grid-scale wind and solar capacity would rise from its current 23 GW to 58 GW by 2030, then near double to 120 GW by 2050, ideally focused in renewable energy zones. Two-thirds of the generation required by 2030 is already going through the connections process. In addition, the NEM's existing hydro-electric generation capacity remains in place.
- **Section 6 – 40 GW of grid-scale storage and hydro by 2050, with battery costs falling.** The ODP projects 33 GW of dispatchable, grid-scale storage would be needed by 2050. This includes 5 GW in 'pumped hydro' capacity to cater for renewable lulls and seasonal shifts, in addition to the 7 GW provided by the NEM's existing hydro-electric power stations. The connections pipeline for storage has 26 GW in battery projects and around 2.5 GW in pumped hydro projects, well on the way to the 27 GW of total grid-scale storage expected to be needed by 2030.
- **Section 7 – 14 GW of flexible gas-powered generation to back up renewables**, progressively replacing the current fleet of mid-merit and peaking plants, with investment in gas infrastructure to ensure gas is available.
- **Section 8 – a 13% extension of the transmission network**. Around 6,000 km of new transmission would be needed by 2050, extending the current 44,000 km network, with most needed in the next decade. Almost half the new transmission projects would strengthen the connection between states, adding reliability and stability to supply across the NEM, with the others connecting new capacity in renewable energy zones.
- **Section 9 – Consumer and distribution actions may reduce grid-scale investment.** Voltage management in distribution networks and consumer investments offer significant additional benefits to all consumers if appropriately integrated.

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.

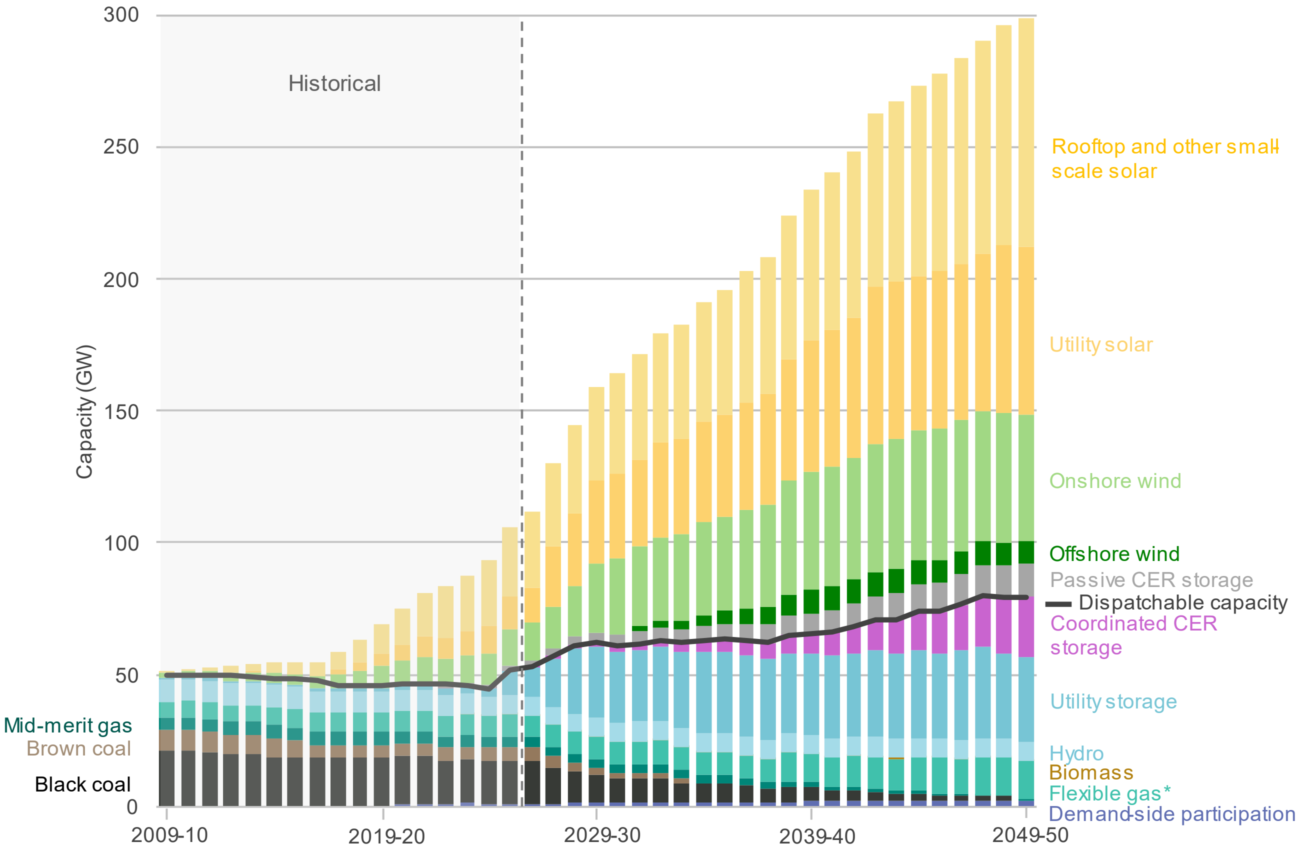
5 Renewables to replace coal as bulk generation

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 on the grid by 2050.

This section sets out the grid-scale renewable generation capacity that is forecast by the proposed ODP, as shown in **Figure 15**.

Figure 15 NEM capacity (GW, 2009-10 to 2049-50, *Step Change*)



Notes: Projections for "Rooftop and other small-scale solar" and "CER storage" are forecast as outlined in the 2025 IASR. "Rooftop and other small solar" includes forecast residential and commercial rooftop photovoltaic (PV) systems as well as larger distributed PV systems referred to as PV non-scheduled generation (PVNSG) systems. "Utility 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 hydrogen capacity.

5.1 **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 expected closure dates.

5.2 **120 GW of renewables 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 58 GW by 2030, then double by 2050. In addition, the NEM's existing 7 GW of hydro-electric generation capacity remains in place.

5.3 **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 dispatchable storage capacity (batteries, new and existing hydro facilities and other potential storages) that would be needed under the proposed ODP to firm up this variable grid-scale solar and wind.

As well, consumers are forecast to invest in 27 GW of storage and 87 GW of rooftop and other distributed solar by 2050, up from 25 GW today. 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 Two-thirds of the remaining coal fleet could retire by 2035

The NEM's installed coal capacity peak was in 2012 when 26 coal-fired plants operated to generate electricity. 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 about half announcing retirements by 2035.

In the near term, until replacement services are installed, coal-fired plants will be needed to help meet both reliability and system security requirements, and some owners are modifying their plants to provide these services more flexibly. The proposed ODP in the *Step Change* scenario projects that about 66% of the NEM's coal fleet would retire by 2035 (more than that announced), with all to retire by 2049: see **Figure 16**. From 2040 only Queensland coal plants would operate, to align with the Queensland Energy Roadmap intention to keep coal in the system for as long as needed or as technically viable[49].

Coal retirements may occur even faster than these forecasts, including in Queensland. Higher operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market is challenging the financial viability of some power stations.

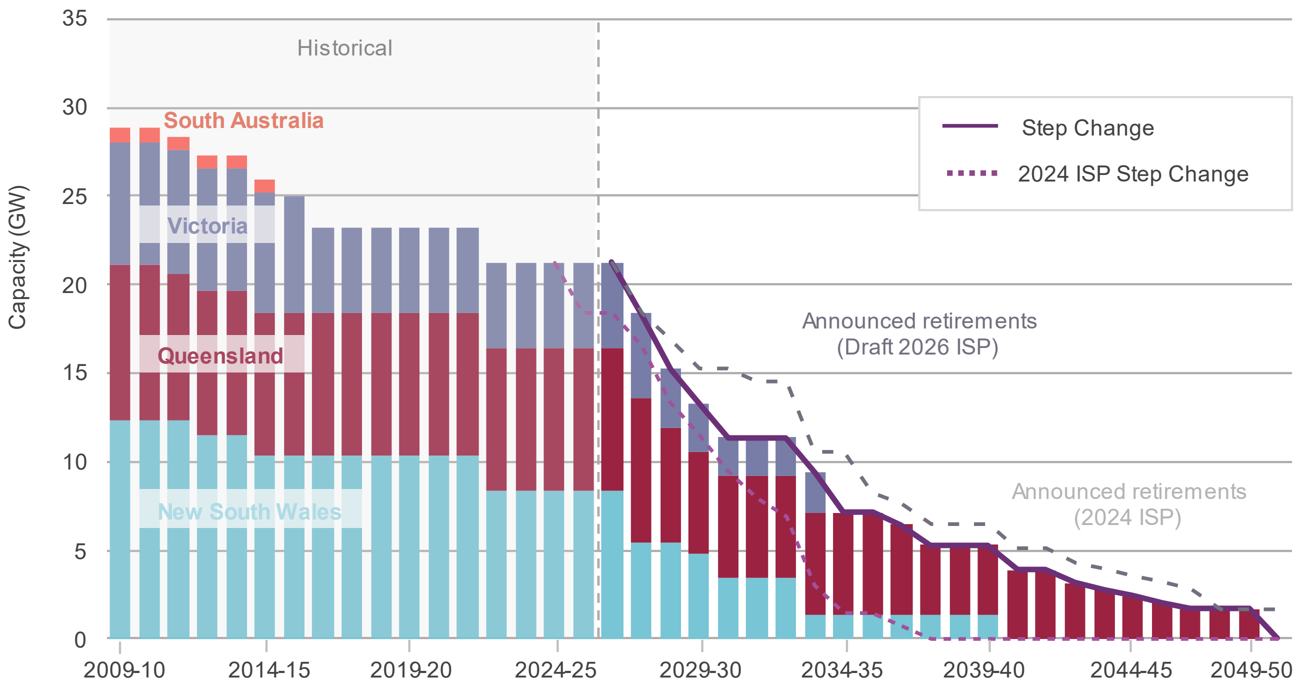
[49] Some Queensland coal plants are projected in this Draft 2026 ISP to still close earlier than the announced closure date, if and when no longer needed for reliability or security and where projected to operate at economically unsustainable levels. The Queensland Energy Roadmap acknowledges that,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

To extend their availability, many coal plant operators are investigating plant modifications that would enable two-shifting and other more flexible operations. Two-shifting means switching off during the daytime peaks of solar generation, and returning for the evening peak and through the night and morning. In some cases, coal generators may operate only during peak seasons – remaining active in summer and winter while shutting down during the shoulder periods. This flexible operation means that there would be many periods in which all coal is offline, and this possibility has been incorporated into the proposed ODP, in particular to allow Queensland coal plants to continue operating into the 2040s.

The proposed ODP is projected to remain the least-cost path whether or not coal plants are able to operate flexibly. AEMO conducted two sensitivity analyses to test the ODP's resilience: see Appendix A6. 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 ODP would remain the least-cost path to deliver secure and reliable power to consumers as coal plants retire.

At the moment, coal owners are only required to give three-and-a-half years' notice of a closure, which gives very little time for the NEM to react. AEMO's 2025 *Transition Plan for System Security* outlines the work being done by industry and governments, supported by AEMO where necessary, to ensure replacement system security services are in place before each coal plant switches off or retires.

Figure 16 Coal capacity, NEM (GW, 2009-10 to 2049-50)



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, and
- if a fault occurs somewhere in the system, the generators can add needed current to the system so that protections can operate until the fault can be isolated.

As coal generators retire the NEM will lose these services, so new assets will be needed before they retire. 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 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.

Many such assets are being delivered across the NEM, but they have long lead times (five or more years) for approvals, procurement and installation.

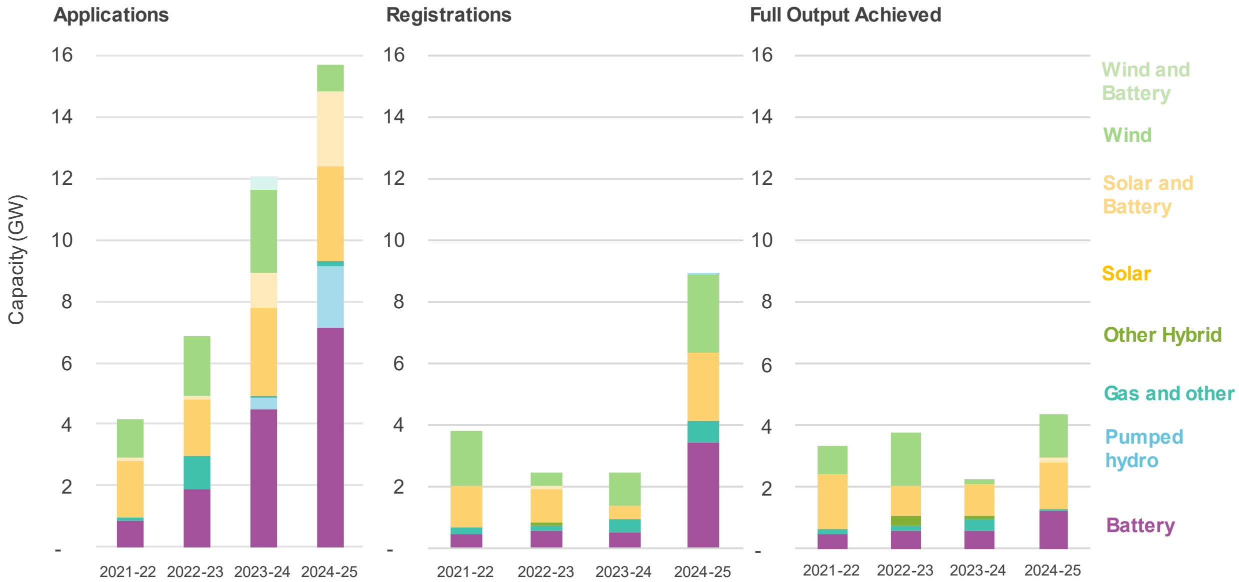
5.2 120 GW of grid-scale wind and solar

Renewables are needed to replace coal, and to meet rising demand and government targets. Under the proposed ODP, the NEM would need approximately 120 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 58 GW by 2030 and 77 GW by 2035, ideally situated in REZs. Including hydro capacity (Section 6.2), grid-scale renewables would reach an 80% share of generation across the 2029-30 year, and a 90% share across 2034-35.

Additional projects are needed to meet 2030 targets

While the connections pipeline is encouraging for grid-scale solar and wind, more projects are needed to reach 2030 target levels. By then, about 35 GW of grid-scale solar and wind would need to be added under the proposed ODP. Currently, wind and solar projects to deliver the equivalent of 24 GW[50] are progressing through the connections process – that is about two-thirds of the total additional capacity required by 2030 to meet government policies: see **Figure 17**. On average, solar and wind projects take four years from connection application to full output. Aware of a potential shortfall, AEMO has analysed the effects of continuing the current rate of wind and solar build: see Section 11.

Figure 17 Connection milestones, NEM (GW, 2021-22, 2022-23, 2023-24, 2024-25)



Mix and spread of renewable generation

Renewable energy technologies complement each other, and transmission allows the NEM to take advantage of different weather conditions across eastern Australia. While conditions may be 'dark and still' in some places, it is highly unlikely to be so everywhere, so fewer grid-scale generation and storage assets are needed for secure and reliable supply across the NEM with strong network capabilities: see Section 5.2.

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 proposed ODP forecasts 32 GW of grid-scale solar by 2030, and 63 GW by 2050. It forecasts 26 GW of onshore wind by 2030, and 57 GW by 2050. This is down from 69 GW in the 2024 ISP, as the wind resources in some generation areas are forecast to generate more energy per GW installed.

Offshore wind farms may also contribute to Australia's energy mix. They can provide good wind resource quality and diversity when connected to onshore transmission. However, the opportunities for offshore wind are limited due to it being approximately 40% more expensive than onshore wind to build and connect. Only 9 GW of offshore wind is forecast to be online by 2040, supported by government policies, with no more built through to 2050.

[50] Projects totalling 27 GW have actually applied, but historically some projects do not progress through to actual output.

Strategies to manage surplus renewable generation

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

The first strategy to absorb this daytime surplus is through flexible demand. Large industrial loads (in scheduled industrial processes and, in future, the electrolysers that support hydrogen production) may be set to take advantage of surplus renewable generation, particularly during daylight hours. The ISP suggests that co-locating up to 3.7 GW electrolysers near grid-scale solar generation would materially reduce the network investment in the ODP. As well, consumer incentives (including free power) are being offered to use the daytime surplus, and EV owners can charge during that time.

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 could be 'curtailed' when there are security constraints in the network, or some could be 'spilled' when the supply is over-abundant. The proposed 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.

Approximately 10% of grid-scale renewable generation is forecast to be spilled or curtailed by 2050. At the same time, about 5% of CER are forecast to be curtailed, despite investment in the distribution network to harness latent rooftop solar capacity: see Section 9.

5.3 Renewable energy zones to efficiently connect renewables

Much of the new grid-scale generation would be built in renewable energy zones (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.

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. State 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.

[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.

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, forecast generation capacity, transmission implications, climate and event risks, and forecast curtailment and spill levels. By NEM region, the forecasts of new grid-scale solar and wind (beyond existing, committed and anticipated projects) are:

- **New South Wales (including Australian Capital Territory): 35 GW new grid-scale wind and solar by 2049-50.** Resource diversity would be opened by new networks, with an even mix of wind and solar across the state. Over 13 GW new generation capacity in Central-West Orana, 6.5 GW in New England, 2.1 GW in South West New South Wales, and 5.1 GW in Hunter-Central Coast by 2050. No offshore wind is yet forecast for New South Wales.
- **Queensland: 27 GW new grid-scale wind and solar by 2049-50**. Targeted network investments would allow new renewables in the regional energy hubs of North Queensland (4 GW), Isaac (2.4 GW, mainly solar), Fitzroy (7.5 GW, mainly solar), Darling Downs (10 GW of solar and wind). Regional energy hubs in the south of the state are projected to make use of existing network capacity as coal retires.
- **South Australia: over 8 GW new grid-scale wind and solar by 2049-50**. New generation in Mid North South Australia REZ (3 GW) and Northern South Australia REZ (3 GW) is forecast for the region by 2050.
- **Tasmania: over 2 GW of new grid-scale wind and solar by 2049-50**. The Central Highlands REZ is established from 2030-31 onward.
- **Victoria: 19 GW new grid-scale wind and solar by 2049-50 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 in the Central Highlands and the Western Victorian REZ. Transmission network connections are modelled to support connection of offshore wind, and transmission augmentations provide access for offshore wind to supply both Victoria and the NEM.

[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.

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

This variable renewable energy would need to be firmed by grid-scale storage. Batteries can store surplus energy from cheap daytime solar to use in the evening and morning 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 can firm renewables through longer dark and still conditions, especially during winter, and also help manage planned network outages as infrastructure is connected.

This section sets out how 40 GW of dispatchable grid-scale storage and hydro contributes to the optimal development path by 2050:

6.1 **33 GW of grid-scale dispatchable storage capacity in total by 2050**. About 27 GW is needed by 2030, a target which the growing current connections pipeline suggests would be met or even exceeded. However, most of this near-term storage is relatively shallow, storing only enough energy to discharge at full capacity for four hours or less. As these batteries it reach end of life, they would be replaced by medium duration storage able to dispatch electricity for four to 12 hours.

6.2 **The 2050 storage capacity includes 6 GW of pumped hydro, complementing the existing 7 GW of deep hydro storage** to ensure reliable supply through seasonal demands and renewable lulls**.**

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

ISP Explainer: firming and shaping by storages

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.

On a daily cycle, this shaping can be achieved by households and businesses energy systems, by community-scale batteries embedded within distribution networks, and by grid-scale batteries and new hybrid grid-scale systems that combine solar and battery assets.

For seasonal cycles, long periods of 'dark and still' renewable lulls and times of extreme peak demand, different solutions are needed. Traditional hydro generators, new pumped hydro schemes and deep storages such as Snowy 2.0 can shape energy for use through monthly and seasonal weather cycles. Along with gas-powered generators, they can provide back-up supply in times of peak demand. With accurate weather forecasting, hydro and gas generators can pre-charge shallow storages to improve the reliability of supply through renewable lulls or peak demand.

Since they are not weather reliant, these firming technologies allow the NEM to accommodate the peaks and troughs in renewable generation, match energy supply to consumers' use of electricity, and also support the grid with power system services. They can help maintain grid stability and inertia, smooth out volatile frequencies, and can balance out fast changes in supply and demand if designed to.

These technologies play different yet overlapping roles. The ISP seeks the most efficient balance between them to meet its reliability, affordability and emission priorities. Project design may deliver further efficiency gains by co-optimising both reliability and system security services.

ISP Explainer: categories of energy storage

Different forms of energy storage are needed to firm both consumer-owned and grid-scale renewables at different times of the day and year. These vary according to their 'depth': the length of time that electricity can be dispatched at maximum output before the stored energy is exhausted.

The broad categories used by AEMO are:

- **Consumer-owned storage** (or CER storage): behind-the-meter household and business storage, including EVs that may be able to send electricity back into the grid. **Coordinated CER storage** is managed as part of a VPP; **passive CER storage** is not, operating to service the household's needs in isolation.

  While the combined installed capacity of these batteries is large, they can only dispatch electricity for short time periods at full discharge (typically only two hours, although consumers are progressively installing larger devices), so their energy storage capacity is relatively small.

- **Shallow storage**: utility-scale storage, connected to either the transmission or distribution network, to dispatch electricity for less than four hours and provide system security services.
- **Medium storage**: to 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. These solutions are increasingly needed to support renewable energy growth.
- **Deep storage:** strategic reserves that 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 may be the NEM's existing hydro-electric power stations, whose reservoirs store rainfall as potential energy for use when needed, or newer 'pumped-hydro' schemes that use surplus renewable energy to pump water upstream to be stored as potential energy. For example, Snowy 2.0 would provide 350 GWh continuously over a week, enough to meet the average needs of around 2.7 million households (almost as many as in Sydney and Melbourne combined): see its capacity in **Figure 18** below.

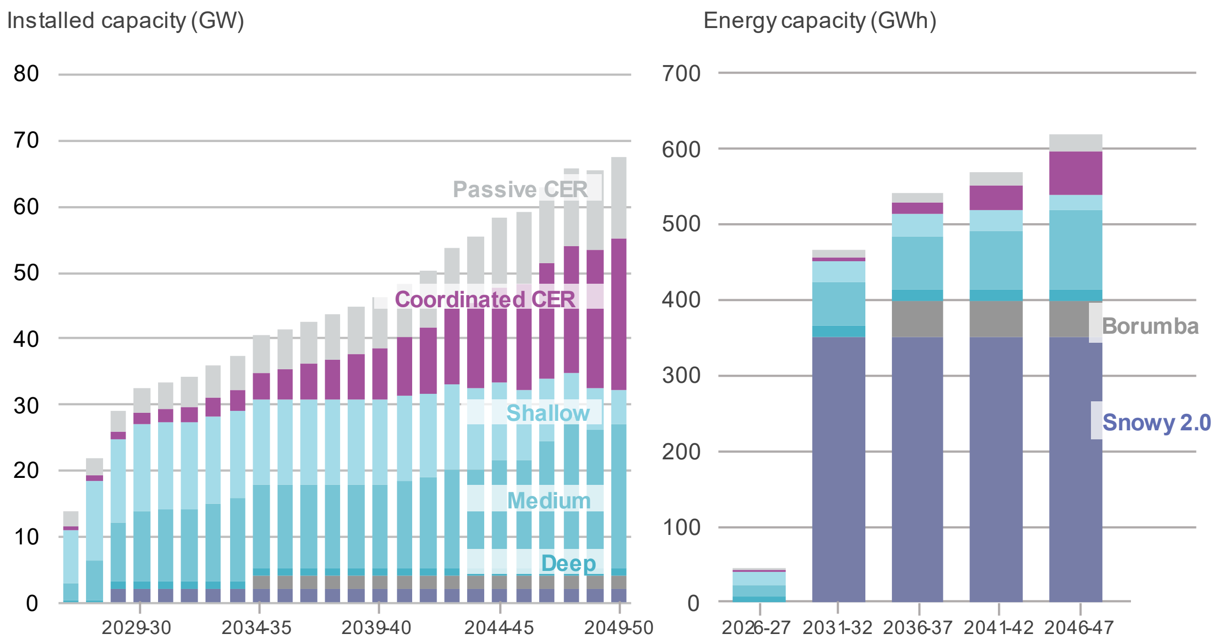
6.1 33 GW storage for intra-day firming

Intra-day firming is typically achieved with both consumer-owned and utility-scale batteries, the latter also offering power system services. Longer duration storage – batteries, pumped hydro and hydro generation – can also provide intra-day firming, but its greatest value is in providing seasonal storage and firming longer duration events: see Section 6.2.

In total, approximately 33 GW of utility-scale storage is forecast to be needed by 2050. This includes 27 GW of grid-scale batteries and 6 GW of pumped hydro storage. By 2030, the projected need of total storage is 27 GW, with an optimal mix of 3.3 GW deep storage, 10.7 GW medium and 13.2 GW shallow. Deep storage will be a critical contributor to system reliability, accounting for about 80% of energy storage capacity by 2030: see **Figure 18.**

In addition, household and other distributed batteries are forecast to rise from today's 1.5 GW to 5.2 GW in 2030, benefiting from strong recent incentives and take up for household batteries. They would continue to build to reach 35 GW in 2050 – by then making up 52% of the NEM's installed storage capacity: see Section 9.1.

Figure 18 Forecast storage capacities, NEM (2026-27 to 2049-50, *Step Change*)



Many utility-scale batteries are already installed across the NEM, with a large pipeline being developed or seeking connection to the grid. More than half 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 below and 2025 *Transition Plan for System Security*.

Although battery installations have only recently begun, the decline in battery costs is making its mark. New capacity in the connections pipeline is increasing markedly, from approximately 3 GW in September 2022, to

15 GW in 2024 and to 26 GW in 2025. These projects are evenly spread across the NEM, within and outside REZs, and connect to both transmission and distribution.

The role of shallow grid-scale batteries would be replaced by household and other distributed batteries over time, complemented by more flexible gas-powered generation, hydro and deep storages for periods of low renewable energy availability. 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.

ISP Explainer: Reliability through renewable lulls

Renewable lulls are common, 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. Assuming new transmission is delivered as planned, renewable resources can be shared across the NEM, so only lulls that affect considerable portions of the NEM are a key concern. Extended renewable lulls covering wide areas are hard to predict in duration and intensity, and will become harder to predict as the climate changes.

6.2 Pumped hydro and hydro generation for seasonal firming and renewable energy lulls

Currently, hydroelectric power stations driven by water released from dams offer the NEM about 7 GW of capacity when needed. The largest five existing stations together offer 4 GW (Tumut 3, Murray 1 and Murray 2 in the Snowy Mountains Scheme, Wivenhoe in Queensland and Gordon in Tasmania). The remaining 3 GW comes from smaller hydro schemes across the NEM.

The 6 GW of pumped hydro energy storage noted in Section 6.1 would include existing schemes and a further 5 GW expected by 2035: including Snowy 2.0, Borumba and Kidston (both in Queensland), and Phoenix in NSW. This would help improve reliability outcomes across the NEM by firming supply throughout peak demand and renewable lull periods.

A buffer of deep storage adds resilience against known yet unpredictable climate risks in the future, as well as 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.

A number of governments are supporting the development of new deep (or medium) storages. Hydro Tasmania is investigating a new pumped-hydro Battery of the Nation initiative at Cethana and Queensland is developing the Borumba and Kidston pumped hydro projects (noted above). The Federal Government's Capacity Investment Scheme offers incentives for large dispatchable 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. In the longer term, flexible loads such as electrolysers will also act to firm renewable generation, with 15 candidate REZs in the NEM now including forecast flexible loads which move electricity demand to the time of day when generation is most available.

ISP Explainer: How hydro schemes support reliability of energy supply

Major hydroelectric schemes store potential energy in deep reservoirs, and can support reliability by accessing this energy when most needed, while balancing electricity generation with other roles in irrigation and flood mitigation. They therefore play an important role in helping mitigate renewable lulls and balancing energy availability across weeks and seasons.

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'. 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. Some of the existing hydroelectric schemes form river chains, allowing water to be used a number of times to produce electricity as it flows downstream.

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. 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 the water reservoirs.

Forecasting both energy demand and weather can never be perfect. A buffer of deeper solutions adds resilience against known yet unpredictable risks. Market and policy settings may need to evolve to incentivise further investment in deep storage solutions such as PHES, with cost recovery mechanisms that are not limited to actual usage.

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 would need 14 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. New more flexible gas-powered generation is offering even more capability to deliver power system security services.

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 demands peak simultaneously. Without action to develop more infrastructure, gaps may be large enough to risk delivery of the proposed ODP.

7.1 14 GW flexible gas for renewable lulls and peaking

In total, under the proposed ODP, the NEM is projected to need 14 GW of flexible gas-powered generation by 2050 to ensure resilience under a range of power system conditions and weather events[54].

Gas-powered generation is changing from its current 'mid-merit' and 'peaking' operations. It will be needed most 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 can also operate with a clutch to provide critical system security services without burning fossil fuel.

Currently, the NEM has 4 GW of mid-merit and 8 GW of peaking gas-powered generation capacity, of which 9 GW is forecast or announced to retire between now and 2050 as the plants reach end-of-life. As they do, the fleet would be developed to a 14 GW fleet of flexible capacity. This may be either as greenfield or brownfield development, but the gas generation must be flexible.

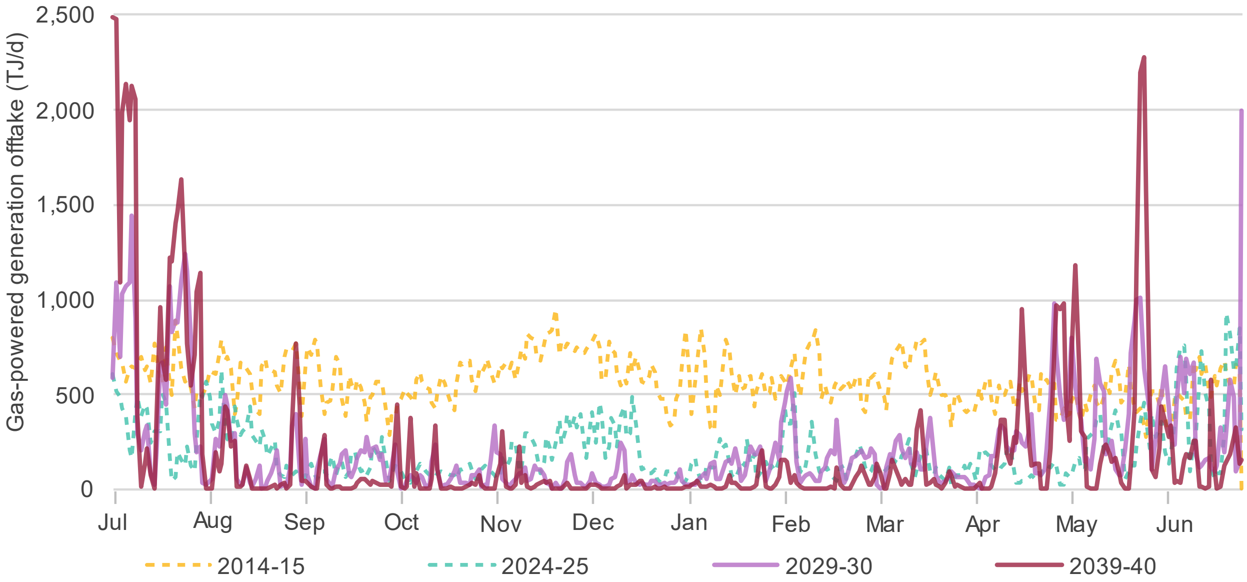
Flexible gas generation used for power system reliability and security is not forecast to run frequently. A typical gas plant may generate just 7% of its annual potential, but will be critical when it runs. It may be needed as back-up capacity in peak demand periods, but will mostly be needed on days with low renewable

[54] A single 400 MW mid-merit plant would also still be operating in 2050.

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, particularly as households shift to electric forms of heating.

Figure 19 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.

Figure 19 Gas-powered generation offtake, NEM (TJ/day 2014-15 and 2039-40, *Step Change*)



7.2 Gas infrastructure is needed to support gas-powered generation

Under the proposed ODP, the flexible, back-up role of gas-powered generation may require relatively large amounts of gas to be consumed in a short period. This is more likely to be in winter, when renewable resources are lower, and households demand for both electricity and gas heating can peak simultaneously.

The 2025 *Gas Statement of Opportunities* forecast that by 2028 and 2029 there may be gaps in the available gas supply to meet southern Australia demand for both gas-powered generation and for other gas uses. 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.

A number of potential gas development projections would support the needs of the proposed ODP as well as other gas consumers, and three of these have been assessed in Appendix A10. Each has a different set of developments currently being proposed, with many developments common to all three projections. It remains up to the gas industry to identify and progress projects that would resolve the risk of structural supply gaps from 2029.

One potential projection modelled for the *Step Change* scenario includes:

- two 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.

If investment in accordance with any of the three gas development projections occurs, developers of gas-powered generation can expect a sufficient gas supply, especially if they locate at the strongest parts of the gas network. If not, they would likely access gas at most times, but would need to rely on diesel backup fuels and on-site fuel storages to a greater degree.

These gas development projections are not designed to offer an ‘optimal development path’ for gas, and the investments modelled are not actionable in the same way as electricity network projects in the ODP. However, they do improve the ISP’s consideration of the appropriate electricity investments to ensure a robust and resilient NEM.

While most of the investments in these projections are needed to support direct-use gas demand, some are needed solely to support electricity generation. However, the commercial viability of investments that primarily support generation is largely untested. AEMO has used a sensitivity analysis in this Draft 2026 ISP to explore a future in which this additional investment is not made. In that case, similar levels of gas-fired generation capacity would still form part of the ODP. However, individual power plants may need on-site storage or the capability to use secondary fuels (such as diesel) to support their operation if gas supply were constrained.

8 Transmission 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.

So far, Part B has detailed the generation, storage and firming resources needed to meet rising consumer demand, as coal generation retires.

The grid is needed to connect these diverse resources to electricity consumers, with 90% of the energy supplied by the NEM being consumed by business and industry. The transmission network brings electricity where it is needed, when it is needed, and improves the power system's renewable energy diversity and weather resilience. Modernised 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, for example by working with distribution planners to use capacity in the lower-voltage network, and by using real-time weather monitoring to maximise line use. Nonetheless, new transmission augmentations will be necessary to navigate the energy transition at lowest cost for consumers.

This section describes the transmission projects in the proposed ODP, covering:

8.1 **Network being extended by about one-seventh.** The proposed ODP would extend the network by about **13**%, with **18** projects are either underway or actionable. Market and regulatory changes are affecting the timing of projects, and AEMO has modelled a *Constrained Delivery* sensitivity to test the ODP's resilience to supply chain and other constraints.

8.2 **Seven projects already committed or anticipated.**

8.3 **Seven projects that are likely to remain actionable.**

8.4 **Two projects that were actionable in 2024 ISP and are requiring ongoing analysis**

8.5 **Three projects likely to be identified as newly actionable.**

8.6 **Seven potential future projects.**

Appendix A5 sets out full details of the transmission projects, including their identified need as required by the NER.

8.1 Transmission network being extended by about one-seventh

The NEM's transmission network was already one of the world's longest interconnected power systems in 2022, stretching for about 43,350 km and connecting a distribution network of over 764,000 km. Since then, the transmission network has been extended by another 365 km by the completion of Project EnergyConnect Stage 1 between South Australia and its eastern neighbours, and network capacity has been increased between Queensland, New South Wales and Victoria. As well, two intrastate transmission projects have been completed: the Eyre Peninsula Link in South Australia which added 270 km of new line, and the Far North Queensland connection into Woree.

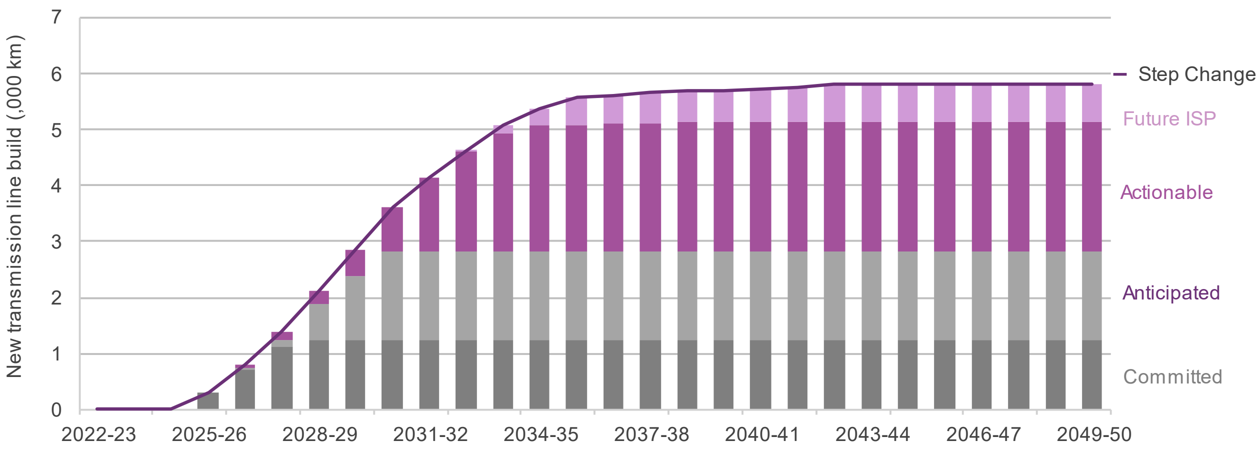
This section gives an overview of the transmission projects that would follow in the proposed ODP.

Transmission projects in the proposed ODP

The transmission projects identified in the proposed ODP are part of the least-cost way to meet rising consumer needs through to 2050, as coal plants retire and while meeting government policies. They would add about 6,000 km of new transmission to the network by 2050 under the *Step Change* scenario – including all committed, anticipated, actionable and future ISP transmission projects. About half that length is needed to strengthen the connection between states, adding reliability and stability to electricity supply across the NEM. The remainder connects new capacity in REZs within each state.

The total build of transmission needed by 2050 has reduced by about 1,350 km compared to the 2024 ODP[55]. Some projects have been downsized or are no longer needed in response to policy or other changes. These changes are noted in the lists of anticipated, committed, actionable and future projects below. As well, the previous ISP accommodated the possibility of an ambitious *Green Energy Export* scenario, which needed significantly more transmission. As the ISP now adopts the less ambitious *Accelerated Transition* scenario, the potential need for more transmission is reduced.

Figure 20 New transmission in *Step Change* (,000 km, 2022-23 to 2049-50)



[55] The total difference in new major transmission in the 2024 ISP and Draft 2026 ISP (Step Change) is 1,871 km, of which 1,506 km is no longer needed in response to policy or other changes, and 365 km has been removed as a project has progressed to operation. In addition, the Dubbo Distribution project adds a further 156 km in this proposed ODP, noting that some scope of this project is not defined as transmission.

The ODP includes the following transmission projects, detailed in **Table 4** and **Figure 21** below:

- **Seven committed and anticipated** projects already underway, including three that were actionable in 2024. These would add 2,800 km to the NEM's transmission network, and proponents advise that projects will reach full capacity from 2027 to 2031.
- **Eleven actionable projects,** being eight that were actionable in the 2024 ISP, two future projects from 2024 which now fall within the actionable window as planned (Western Victoria Reinforcement and the Gippsland Offshore Wind Transmission), and an additional smaller project (Switching Station Near Wondalga). These would add 2,300 km to the NEM's transmission network. Work on all actionable projects should continue or commence as soon as possible under the ISP framework (actionable ISP projects) or the relevant state approvals framework. Proponents advise that projects will reach full capacity from 2029 to 2034.
- **Seven future ISP projects** that would deliver net market benefits later in the horizon, and would be actionable when needed. These are mainly network upgrades and would add only 700 km to the NEM's transmission network. Additional new future projects are the Sydney Ring South (500 kV option) and the South West Victoria Expansion.

One actionable project identified in the 2024 ISP is deferred to become a future project (Central Queensland to Southern Queensland Expansion), to align with the deferred delivery of the Borumba pumped hydro project. The status of two others is under review and will be confirmed in the final 2026 ISP following further analysis and stakeholder engagement: see Section 8.4 below.

Cost changes influencing actionability and timing

The changes to actionable and future ISP projects since 2024 have been driven by a range of factors, in some cases directly related with the projects themselves, in other cases due to alternative options becoming available. The main driver has been the increase in estimated delivery costs of almost all transmission projects, though some of this has been offset by changes to the assumed weighted average cost of capital (WACC) for network projects.

During consultation on the 2025 IASR, the ISP Consumer Panel and other stakeholders made recommendations on the WACC used in previous ISPs. As a result, AEMO adjusted its approach from a technology-agnostic to a technology-specific WACC, so each project's financing costs could appropriately reflect the level of risk and therefore the level of return that investors expect. Network projects have the lowest WACC as their regulation provides revenue certainty to network owners, which translates to lower investment risk.

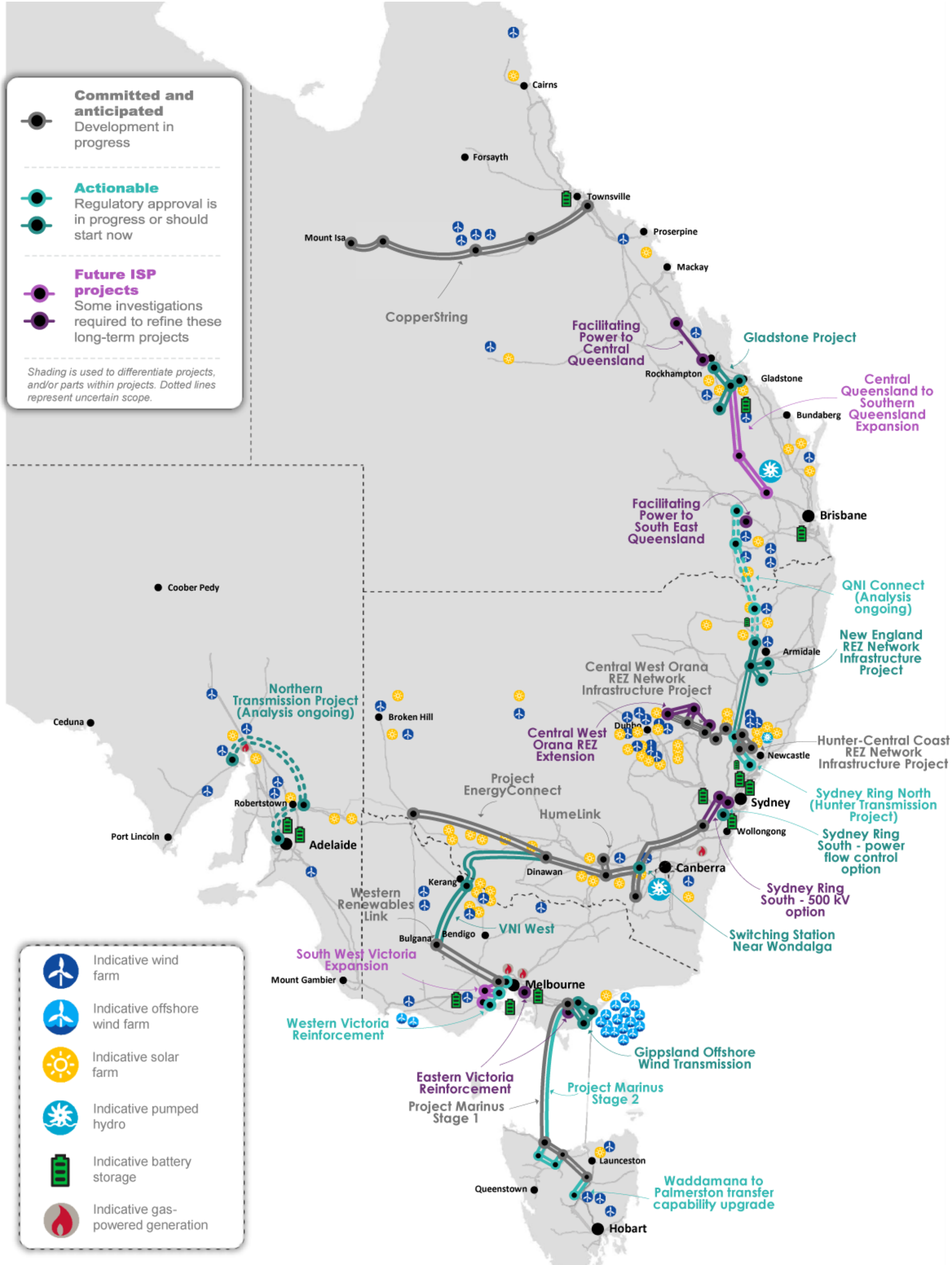
The combination of cost increases and WACC reductions has had a mixed impact on proposed transmission projects. While some have had options to mitigate the rises, others have not, and project costs have risen sharply. As well, the net market benefit of a transmission project may fall if well-located battery capacity is available, as both transmission and storage act to mitigate reliability risks in the power supply. The forecast of aggregate battery capacity has risen due to policy incentives and reducing costs, so this has affected the market benefits of some projects.

Table 4 Network projects in the proposed optimal development path in the Draft 2026 ISP

Committed and anticipated transmission projects		In service timing advised by proponent[A]	Full capacity timing advised by proponent[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		June 2031	June 2031
Projects likely to remain actionable	**Actionable framework**	**In service timing advised by proponent[A]**	**Full capacity timing advised by proponent[A]**
Gladstone Project	QLD[C]	March 2029	March 2029
Sydney Ring North (Hunter Transmission Project)	NSW[D]	November 2029	November 2029
Sydney Ring South – power flow control option	ISP	July 2030	July 2030
Waddamana to Palmerston transfer capability upgrade	ISP	July 2030	July 2030
Victoria – New South Wales Interconnector West (VNI West)	ISP	November 2030	November 2031
New England REZ Network Infrastructure Project	NSW[D]	July 2032	July 2032
Project Marinus Stage 2	ISP	June 2034	December 2034
Projects actionable in 2024 ISP, requiring ongoing analysis	**Actionable framework**	**In service timing advised by proponent[A]**	**Full capacity timing advised by proponent[B]**
Northern Transmission Project[E]	ISP	July 2029	July 2029
Queensland – New South Wales Interconnector (QNI Connect)[F]	ISP	March 2032	March 2034
Projects likely to be identified as newly actionable	**Actionable framework**	**Earliest feasible in service timing[A]**	**Earliest feasible full capacity timing[B]**
Switching Station Near Wondalga (new)	ISP	July 2029	July 2029
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[G]	June 2029	June 2029
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC[G]	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
Future ISP projects			
New South Wales	Central West Orana REZ Expansion, Sydney Ring South – 500 kV option		
Queensland	Central Queensland to Southern Queensland Expansion[H], Facilitating Power to South East Queensland, Facilitating Power to Central Queensland		
Victoria	Eastern Victoria Reinforcement, South West Victoria Expansion		

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
C. This project would progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.
D. These projects would progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
E. Northern Transmission Project (previously known as the Mid North South Australia REZ Expansion) is undergoing further analysis and is not identified in the proposed ODP, ODP project counts, cost benefit assessment totals and other metrics in this Draft 2026 ISP.
F. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including alignment with the Queensland Energy Roadmap.
G. This project would progress under the *National Electricity (Victoria) Act 2005* (Vic) rather than the ISP framework.
H. Previously known as Queensland SuperGrid South. This project has changed from being an ‘actionable’ project in the 2024 ISP to being a ‘future’ ISP project in the Draft 2026 ISP.

Figure 21 Transmission projects in the proposed Draft 2026 ISP optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that increase capacity by 400 MW or more and are part of the proposed Draft 2026 ISP optimal development path.

8.2 Seven committed and anticipated transmission projects

These projects already have regulatory approval and are highly likely to proceed. They are included in the modelling for all development paths, scenarios and sensitivities:

- **committed network projects** meet all five commitment criteria[56] (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 5 Committed and anticipated transmission projects in the proposed 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
Anticipated	**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.	June 2031, Powerlink	840

A. The capacity release and timing is 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.

[56] 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.

8.3 Seven projects likely to remain actionable

The projects that are likely to remain actionable are listed in Table 6, including target delivery dates provided by project proponents. Appendix A5 provides detailed technical information on each project, including the identified need[57], progress and next steps.

Subject to consultation, and continued inclusion in the final 2026 ISP, all actionable projects should progress quickly to meet the project proponents' delivery dates in **Table 6**. Any earlier delivery would provide valuable insurance against early coal closures, project delivery risk, or if the development of generation and storage slows.

Table 6 Projects likely to remain 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	March 2029	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[C]	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 option[58]	July 2030	July 2030	Power flow control devices on the 330 kV network to reinforce supply to Sydney, Newcastle and Wollongong load centres. $261 million (±50%)	ISP	0
Waddamana to Palmerston transfer capability upgrade	July 2030	July 2030	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%)	ISP	0
VNI West	November 2030	November 2031	A new high capacity 500 kV double-circuit line to connect Western Renewables Link (from Bulgana) with Project EnergyConnect and HumeLink (at Dinawan) via a new substation near Kerang. $7,600 million (-30% to +50%)	ISP	491
New England REZ Network Infrastructure Project	July 2032	July 2032	Increase the transfer capability between central and northern New South Wales, enable more transfer capacity out of the Queensland New South Wales	New South Wales[D]	447

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

58 The Sydney Ring South Project Assessment Draft Report (PADR) will assess the near-term actionable ISP project (i.e. the power flow control option) and also further test the scope and timing of the 500 kV transmission future ISP project, to identify which option best positions New South Wales for a range of credible futures, delivering the best long-term outcome for consumers. As part of the RIT-T process, Transgrid may consider engaging communities in relation to both the actionable Sydney Ring South project (power flow control option) and the future ISP project (Sydney Ring South 500 kV option) to provide greater certainty to communities on the overall project scope and timing, and to minimise the impacts of duplicated consultation processes.

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)
			Interconnector, and expand the New England REZ. $3,673 million (±50%) Further stages of this project may progress through the New South Wales framework.		
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 2 total (**$2023**): $2,535 million (±30%) • HVDC: $2,010 million (±30%) • HVAC: $525 million (-20% to +30%)	ISP	454

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
C. This projects would progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.
D. These projects would progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

8.4 Two projects actionable in the 2024 ISP, requiring ongoing analysis

This Draft ISP does not change the current status of any of previously actionable ISP projects. However, two projects identified as actionable in the 2024 ISP may have their status changed in the final 2026 ISP. AEMO is continuing stakeholder engagement and sensitivity analyses to understand how any changes in assumptions between the 2024 and 2026 ISP may lead to a different outcome.

AEMO recognises the significance of changing the status of an actionable project and its potential impacts on proponents, consumers and communities. AEMO is also mindful of the impacts of even flagging that the benefits of an actionable project must be confirmed. There must be a high degree of confidence in the outcomes before pausing or stopping a project in which communities and proponents have invested significant time, energy and emotion. Equally, there must be a high degree of confidence in a decision to make a large investment that may impact local communities. The need for that confidence one way or the other is why further analysis and stakeholder engagement is needed.

- **Northern Transmission Project**[59] (previously known as the Mid North South Australia REZ project). While the identified need for this project remains, as in the 2024 ISP, further analysis is needed to consider the extent of project benefits. Material influences on net market benefits include assumptions around project cost, industrial load growth, and the technology type and location of development opportunities, including outcomes of the South Australian Firm Energy Reliability Mechanism (FERM) Tender Round 1.

[59] The Northern Transmission Project is not included in the actionable project counts, cost benefit assessment totals and other metrics reported for the proposed ODP in this Draft 2026 ISP.

AEMO continues to work with ElectraNet and the South Australian Government to reduce uncertainty on these assumptions, before determining the status of this project in the final 2026 ISP.

- **QNI Connect.** While actionable in the proposed ODP, the Queensland Energy Roadmap and strong policy-driven development of generation and storage in both Queensland and New South Wales may impact the benefits of greater resource sharing between the two states. Before the final 2026 ISP, AEMO will engage with stakeholders and conduct sensitivity analyses to reduce the uncertainty around material assumptions for this investment. New England REZ Network Infrastructure project is a pre-requisite for QNI Connect and their inter-dependencies will be further considered as part of this analysis. Ultimately, the New England REZ Network Infrastructure project would progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

Table 7 Projects actionable in the 2024 ISP, requiring ongoing analysis

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 date*	Proposed new line build (km)
Northern Transmission Project (Mid North South Australia REZ Expansion)	July 2029	July 2029	New 275 kV and 132kV transmission lines to connect renewable generation to Adelaide and to supply increasing industrial load. $620 million (±50%)	ISP	115
QNI Connect	March 2032	March 2034	Add capacity between southern Queensland and New England, following development of the New England REZ Network Infrastructure project. $2,989 million (±50%)	ISP	460

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.

8.5 Three projects likely to be identified as newly actionable

Two future ISP projects from the 2024 ISP (Western Victoria Reinforcement and Gippsland Offshore Wind Transmission) have progressed to being recognised as actionable in the proposed ODP. A newly identified Switching Station Near Wondalga project is also likely to become actionable: see **Table 8**.

AEMO is also consulting on non-network options as alternatives for these newly identified actionable projects. For those intended to be actioned under state frameworks, the processes in the relevant legislation would apply.

Table 8 Projects likely to be identified as newly 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]	New line build length (km)
Western Victoria Reinforcement	June 2029	June 2029	Minor network augmentations and equipment upgrades to reinforce supply to metropolitan Melbourne. $128 million (±50%)	Victoria	0
Switching Station Near Wondalga	July 2029	July 2029	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 20 March 2026	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]

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
B. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
C. See 'Continued consultation on the Draft 2026 ISP' below for details on providing submissions regarding non-network options.

8.6 Seven future ISP transmission and distribution projects

Future ISP transmission projects would deliver net market benefits to consumers, and are projected to be actionable in the future. The projects and their timings are identified in **Table 9** below 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.

The Dubbo Distribution Project is identified as a future distribution project: see **Table 10**. 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 9 Future ISP projects in the proposed optimal development path

Project	Optimal timing *Step Change*	Earliest feasible full capacity timing	Brief description Cost estimate in $2025
New South Wales			
Central-West Orana REZ Expansion	Option 1: 2034-35 Option 3: 2041-42	Option 1: 2030-31 Option 3: 2032-33	Enable additional Central-West Orana REZ capacity following initial Network Infrastructure Project (Committed project). Option 1: $855 million (±50%) Option 3: $657 million (±50%)
Sydney Ring South – 500kV option[60]	2037-38	2033-34	A new double-circuit 500 kV line to supply the Sydney, Newcastle and Wollongong load centres. $2,360 million (±50%)
Queensland			
Central Queensland to Southern Queensland Expansion	2035-36	2031-32	To increase the transfer limit between Central and Southern Queensland and connect to the Borumba Pumped Hydro project. In addition, a switching station on the existing double-circuit 275 kV network at Auburn River to increase the transfer limit between Central and Southern Queensland. $3,810 million (±50%)
Facilitating Power to South East Queensland	2035-36	2028-29	Improving transfer from South West Queensland to the Brisbane load centre. $33 million (±50%)
Facilitating Power to Central Queensland	2039-40	2030-31	Enable Northern Queensland and Isaac and Barcaldine REZ capacity, and transmission to Central Queensland. $209 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. $350 million (-50% to +100%)
South West Victoria Expansion	2035-36	2033-34	Add transfer capacity between Western Victoria and Melbourne to accommodate increased onshore wind power generation. $1,330 million (-50% to +100%)

Table 10 Future distribution projects in the proposed optimal development path

Project	Optimal timing *Step Change*	Earliest feasible full capacity timing	Brief description Cost estimate in $2025
New South Wales			
Dubbo Distribution Project	2032-33	2030-31	Both transmission and distribution works 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. ($2024) $601 million (±50%)

[60] The Sydney Ring South Project Assessment Draft Report (PADR) will assess the near-term actionable ISP project (i.e. the power flow control option) and also further test the scope and timing of the 500 kV transmission future ISP project, to identify which option best positions New South Wales for a range of credible futures, delivering the best long-term outcome for consumers. As part of the RIT-T process, Transgrid may consider engaging communities in relation to both the actionable Sydney Ring South project (power flow control option) and the future ISP project (Sydney Ring South 500 kV option) to provide greater certainty to communities on the overall project scope and timing, and to minimise the impacts of duplicated consultation processes.

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.

Demand-side factors include consumers' investments in CER, energy efficiency, electrification and demand management devices, and their decisions to allow their CER to be coordinated by an aggregator or retailer. These factors are household and business decisions, often supported by government policies.

Distribution networks have always been critical in connecting those who produce and consume electricity across the NEM. That is more so the case as consumers invest in CER, and can export surplus electricity to the grid, and as other 'demand-side factors' shape network efficiency.

AEMO has modelled how these demand-side factors affect the grid's efficiency, and what both consumers and distribution networks might do to improve both that efficiency and customer value.

The take-up and use of CER by consumers, combined with efficient distribution network support, makes grid-scale investment more efficient.

9.1 **Consumers are investing in their own energy resources.** Those who can are investing in rooftop solar, batteries and other resources, with government policies making the economics more attractive. These consumer energy resources or CER (see definition box in Section 1.2) are forecast to reach over a third of the NEM's installed generation capacity by 2050.

9.2 **Relatively small investments in the distribution networks would support that CER.** Modelling confirms that optimising voltage management would overcome current network constraints and unlock latent capacity so CER can export an additional 3.5 GW to the grid. This would avoid larger investments, and the needed investment may even reduce as more home batteries are installed.

9.3 **CER contribution reduces grid-scale investment.** In total, the assumed levels of CER coordination, particularly from coordination of EVs, would reduce total system costs by $7.2 billion. Extending current policies that support energy efficiency, as assumed, is estimated to provide $12 billion in cost savings.

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

9.1 CER are forecast to reach over a third of the NEM's capacity by 2050

The 2025 IASR details how these valuable consumer resources are forecast to grow through to 2050, when they are expected to reach over a third of the NEM's capacity.

- **Rooftop solar continues to grow.** Currently, consumer-owned rooftop solar systems in NEM regions provide a total capacity of 25 GW[61]. By 2035 in the *Step Change* scenario, 47% of the households[62] in NEM regions would have rooftop solar, rising to 56% in 2050, driven by ever-falling costs. At that time, forecast total rooftop solar capacity would be 87 GW. As rooftop solar can generate mid-day surpluses, investments in home-scale storage, the distribution network and flexible loads are needed to optimise its potential benefits.
- **By 2050, around half the households with solar are projected to have supporting batteries.** Household and commercial battery installations are growing rapidly on the back of lower costs, easier-to-use technology, and government policies such as the Cheaper Home Batteries Program. Take-up is forecast to grow strongly in the next decade. The *Step Change* scenario forecasts growth in capacity from today's 2 GW to an estimated 5 GW in 2029-30, then 27 GW in 2049-50. In this scenario, 53% of batteries are forecast to be coordinated as part of a VPP by 2049-50, as consumer confidence in their benefits rises. Increased coordination will benefit all consumers, not only the battery owners, as it reduces the extent of grid-scale investment needed.
- **EV ownership is forecast to surge from the late 2020s**, driven by falling costs, greater model choice and availability (assisted by new vehicle efficiency standards), and more charging infrastructure. By 2050, assuming federal and state targets would be met, up to 80% of all vehicles are expected to be battery or plug-in EVs.

Consumers are using their CER to shape their daily demand, reducing their own energy costs and also their operational demand on the grid: see *Consumers are shaping their daily demand* below.

This growth in CER would continue to materially reduce the consumption of electricity generated by grid-scale resources, even as the consumer need for electricity rises: see Section 9.3.

ISP explainer: Consumers are shaping their daily demand

Electricity demand is not constant 24 hours a day, but rises for the morning and especially the evening peak.

Consumers are helping to smooth out the demand profile by drawing on their own assets and by choosing what time of day they use electricity. The more they do so, with the appropriate third party specialists and consumer protection, the easier it is for the NEM to manage load variations through the day, and the lower the ultimate cost of electricity for consumers.

- **Residential and commercial batteries** can be installed to soak up surplus daytime solar for discharge later in the evening, and aggregated as VPPs.
- **EVs** can contribute by being charged outside the morning and evening peaks, preferably through the peak solar daylight. For this to occur, further investment is needed in workplace or on-road charging infrastructure through the distribution network. Owners may also discharge their EV's stored energy back to the home, or to the broader grid when needed.

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

[62] 'Households' refers to PV-suitable dwellings, which include houses and semi-detached dwellings.

- **Smart home management systems** may similarly control hot water systems and other appliances to take advantage of cheaper daylight electricity and avoid the more expensive peaks.

Batteries, VPPs and EVs can reduce even more grid demand if their charging and especially discharging can be coordinated with the grid, reducing the need for more utility-scale investment.

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. Distribution networks across the NEM have limited capability to support this surplus CER generation, as they must manage voltage levels and cannot exceed equipment limits.

As more consumers are expected to invest in energy resources, AEMO has identified efficient opportunities for distribution networks to support greater surplus CER generation. They may improve voltage management through software upgrades, control schemes or operational changes, with relatively low capital investment.

Innovations to distribution networks are already being made to cater for more CER and even larger assets. SA Power Networks has enhanced its voltage management across zone substations, several networks are trialling community batteries, and in New South Wales "urban renewable energy zones" are being tested to accommodate more utility-scale resources within the distribution grid.

Across the NEM, AEMO's modelling reveals opportunities to deliver benefits in the long-term interest of consumers by investing $160 million to optimise voltage management at the distribution level so more CER generation can be exported. The scale of these opportunities are relatively modest, and are identified at a sub-regional level in **Table 11.** AEMO recognises that DNSPs may identify and plan for additional investments through to 2050 as consumer demand for electricity grows.

Table 11 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	118		Central South Australia	766
	Sydney, Newcastle & Wollongong	214		South East South Australia	38
	Southern New South Wales	305	**Tasmania**	Tasmania	0
Queensland	Northern Queensland	0	**Victoria**	West and North Victoria	466
	Central Queensland	0		Greater Melbourne and Geelong	1,334
	Gladstone Grid	2		South East Victoria	22
	Southern Queensland	114			

9.3 CER and its coordination brings system-wide benefits

Consumers take up CER for the household or business benefits they bring. They also contribute to an efficient power system by helping operators to manage minimum demand and reduce peak demand, and by avoiding investment in grid-scale infrastructure.

In this section, AEMO has quantified the potential gains from CER coordination, as well as the value of energy efficiency improvements, in the *Step Change* scenario through to 2050:

- **Coordination adds to CER benefits.** The *Step Change* scenario assumes that rooftop solar capacity would reach 87 GW in 2050 supported by 27 GW of CER battery capacity, of which 53% would participate in a VPP. The scenario also forecasts 80% of all vehicles to be EVs, with 11% participating in V2G programs to provide an additional 9 GW of coordinated storage. These two forms of coordination enable CER to respond to market signals, in particular helping to reduce operational demand from the grid during the evening peaks. In the ODP, this reduction would avoid up to $7.2 billion being spent on additional utility-scale storage in the NEM.

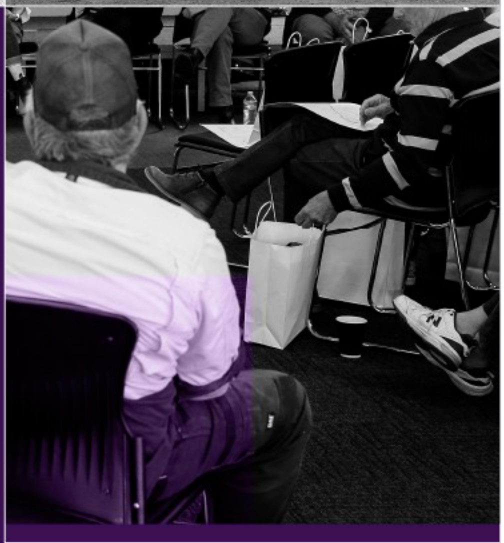
  Efforts are also underway through the National CER Roadmap[63] to plan and prepare the grid to safely and effectively integrate these technologies and maximise their benefits to consumers and the power system. However, a number of supporting factors need to be in place for higher levels of coordination to be reached. VPP specialists might offer clear and explicit benefits to CER owners. Consumer protections must be in place so that homeowners and small businesses can trust those specialists 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[64] will help remove financial barriers.

- **Energy efficiency investment remains invaluable.** The ODP modelling incorporates all government energy and environmental policies, including those supporting energy efficiency. The current policies are not indefinite, and the modelling takes into account when they are due to end. However, the *Step Change* scenario assumed that similar policies would continue through to 2050. If instead government support ends as anticipated, energy efficiency improvements would be 34% lower than forecast in *Step Change.* As a result, the capital investment in grid-scale infrastructure would increase by $9.4 billion through to 2050, and total system costs would increase by $12.2 billion.

For further details see Appendix A9 for the Demand Side Factors statement.

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

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



PART C

Delivering the optimal development path

Part C
Delivering the optimal development path

New power system infrastructure is essential to replace ageing coal assets. Part B has identified the proposed ODP as the least-cost way to rising meet consumer needs through to 2050, as coal plants retire and while meeting government policies.

Delivering the proposed ODP would provide consumers with reliable and secure electricity, support consumer investments in their own energy resources, contribute to keeping energy costs as low as possible, meet government policy settings, and manage risk through a complex transformation.

Part C sets out how:

- **Section 11 – The ODP would achieve its objectives in meeting power system needs, consumer interests and policy commitments.** The ODP provides net market benefits of $24 billion (weighted across all scenarios) but would require a concerted effort across industry to continue accelerating the rate of infrastructure build.
- **Section 12 – Benefits to consumers would remain positive, even if development is constrained**. Additional analysis shows that if development is impeded by various constraints, the slower build of infrastructure would still deliver benefits, although they would be reduced, and 2030 emission targets would not be met.
- **Section 13 – Significant progress is being made in delivering the transition**, with coordinated action needed to meet the challenges ahead. Investment in infrastructure remains urgent. Market and policy settings are progressing to support the transition, and ensure the NEM is ready for each coal plant retirement. Similar collaborative action is still needed on planning approvals, social licence and supply chain issues.

The Draft 2026 ISP finishes with a request for written submissions by 13 February 2026.

AEMO will continue to consult on the way to the final 2026 ISP being published in June 2026.

10 The ODP contributes to the National Electricity Objective

Part B has laid out that by 2050, the proposed ODP would see the NEM with a total of 120 GW of grid-scale wind and solar, 40 GW of grid-scale storage and hydro, 14 GW of flexible gas powered generation, an additional 6,000 km of transmission, and optimised distribution networks to connect these assets to consumers.

The next five to 10 years are critical to the transition. The rate of build for new generation and storage would need to be faster than at any time achieved to date or needed after, and most of the new transmission projects would need to be in service within the next decade.

This section sets out how the ODP would fulfil the ISP's legislated purpose to supply secure and reliable power to consumers through to 2050, while meeting rising demand and government policies. If delivered as planned:

10.1 **The power system needs for safe, secure and reliable delivery** would be met as coal plants retire.

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

10.3 **Consumer needs would be met at least cost through to 2050.** The net benefit to consumers of the proposed ODP's transmission, distribution and system security projects would be $24 billion (weighted across all scenarios).

However, supply chain and other constraints may mean that ODP project delivery 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

Security and reliability becomes more challenging as the system approaches 100% renewable generation. AEMO's 2025 *Transition Plan for System Services* sets out the requirements to maintain a secure and reliable power system through the next phase of the energy transition.

System security supported by multiple technologies

The *Transition Plan for System Security* continues to 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. The estimated cost of these investments is $3.6 billion.

The technical requirements needed for system security during periods of 100% renewable generation are laid out in AEMO's Engineering Roadmap. These requirements remain the same, even though the generation technologies change.

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. The *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.

AEMO has also published several 'Statements of Security Need' for new transitional services, with more in development. These services were introduced under the 2024 'Improving Security Frameworks' rule change, and will support operability and help trial new technologies such as grid-forming inverters.

Details of system security through the ODP are set out in Appendix A7.

System reliability to be confirmed for the final 2026 ISP

AEMO has undertaken preliminary analyses to determine if there is enough electricity supply to meet demand through all daily and seasonal periods, and in all regions, over the ISP's 24-year horizon.

AEMO is continuing to assess any potential risk factors to determine whether minor refinements to the proposed ODP development opportunities (generation and/or firming) may be needed before finalising the 2026 ISP. These refinements are not expected to have a material impact on the selection of the proposed ODP or total system costs.

The details of system operability through the ODP under a range of conditions are set out in Appendix A4.

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 any other committed environmental or energy policy that may impact the power system: see Section 4 and the 2025 *ISP Inputs, Assumptions and Scenarios Report*.

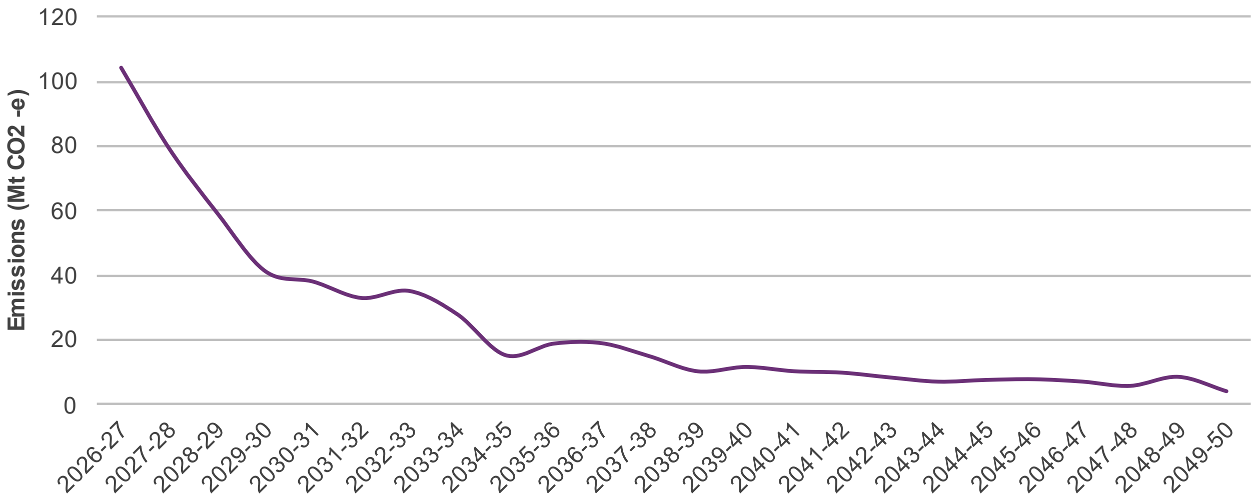
If delivered, the proposed ODP would meet the federal 2030 and 2035 targets for the NEM's supply to be from renewable sources, and would contribute to all 2030 and later state and federal emission reduction targets across the economy.

NEM emissions would decline rapidly from just over 100 Mt CO_2-e today to about 40 Mt CO_2-e in 2029-30, as renewable generation plays an increasing role. They would then fall more gradually to about 10 Mt CO_2-e in 2038-39, and finally to 3 Mt CO_2-e in 2049-50: see **Figure 22**. 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 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 2038-39, the achievement of longer-term national targets will depend on other sectors.

By supporting the achievement of state and government energy policies, the ODP would also contribute to achieving their intended economic, social and environmental benefits. These include: reducing emissions; delivering secure and reliable electricity to homes and businesses at least cost; creating demand for investment and skilled careers; and opening new economic opportunities in the growing global markets for low-emission, energy-intensive products and services.

Figure 22 Forecast NEM emissions trajectory, *Step Change*, 2026-27 to 2049-50 (Mt CO2-e)



10.3 Consumer needs would be met at least cost

As discussed in Section 4, AEMO seeks an optimal development path (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. Consumer needs (and the National Electricity Objective) are met by providing reliable and secure supply at lowest cost while reducing emissions and enabling consumers to maximise the value of any investments in CER.

ODP selected on basis of capital and operating costs

The ISP methodology assesses both the initial capital costs and the annual operating costs of potential infrastructure, including the costs of fuel and emissions, to determine the ODP. It looks only forward in time: existing assets and committed investment decisions are not costed or re-evaluated, as they do not affect future planning. The full cost benefit analysis is discussed in Appendix A6.

As discussed in Section 4.5, the preferred ODP is the one that has lowest capital and operating cost, weighted across the three scenarios to reflect the relative likelihood of their occurring (*Slower Growth, Step Change, and Accelerated Transition*). The ODP is the combination of generation, storage, firming and network technologies that meets this test. All other combinations, seeking to supply secure and reliable electricity to consumers and meet government policies through to 2050 (weighted across all three scenarios), would cost more than the ODP.

Net benefits of the ODP

The net market benefits to consumers of a development path are its total long-term system costs (for all grid-scale generation, storage and network development) less those of the counterfactual with no new major transmission projects. These are then weighted to reflect the relative likelihood of the three scenarios.

The weighted net market benefits of the proposed ODP would be $24 billion in reduced costs to consumers. In other words, compared to the counterfactual with no new transmission, it would repay the investment in new transmission projects, save consumers a further $22.3 billion in additional costs, and deliver emissions reductions valued at a further $1.9 billion. This cost-benefit analysis, including how it compares with the 2024 ISP is set out below, and in more detail in Appendix A6.

Given rising costs, and incorporating all the investments required to maintain secure and reliable power while coal plants retire, the proposed ODP would deliver a significant benefit to consumers.

Capital costs for the ODP investments, and changes since 2024

To 2050 in the *Step Change* scenario, the annualised capital cost in present value (PV) terms of all utility-scale generation, storage, firming and transmission and distribution network in the ODP would be $128 billion[65, 66]. The transmission element of this capital cost would be $9 billion[67] in PV terms, or 7% of the total.

Figure 23 over the page shows how the overall costs have changed since 2024.

- **Starting point.** In 2024, the ODP's present value was $122 billion in real 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 cost is incurred or a benefit received, the more it is worth today. While many of the 2026 ODP investments are needed in the same years as they were in 2024, we are now two years closer to them, and so their present value increases. These two time effects take the 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 actionable ISP projects have progressed to become 'committed' or 'anticipated' projects, so $23 billion is excluded in the costs of the proposed ODP. The assumed cost of these projects in the 2024 ISP is therefore also removed.

Now comparing like-for-like, the equivalent cost of the ODP in the 2024 ISP would be $125 billion in June 2025 dollars.

- **Changes in capital costs.** The proposed 2026 ODP has updated assumptions on the capital costs of all energy infrastructure. There are lower CER forecasts (requiring more grid-scale investment), new emissions reduction policies (requiring changes in the type and/or timing of investments), the inclusion of distribution network development opportunities, and higher capital costs for transmission. Factors reducing the overall capital cost of the ODP include lower capital costs of solar and batteries, fewer transmission projects, and recent progression of projects towards construction.
- **The weighted average cost of capital** (WACC) has changed for all infrastructure investments since 2024, in response to stakeholder feedback. The assumed pre-tax real WACC for transmission projects has been reduced from 7% to 3% in recognition that, as assets with regulated revenues, they have lower risk than

[65] This value includes transmission and distribution augmentation, and utility-scale generation and storage capex converted into an equivalent annuity, and does not include the cost of commissioned, committed or anticipated transmission projects.

[66] As the assets have a technical life beyond 2050, the total present value of these investments as 'upfront capital investment' is $156 billion.

[67] This value is the present value of capital costs for transmission augmentation up to 2049-50 only.

other investments. The assumed WACC for generation and storage projects increased by different amounts in recognition of their slightly higher investment risk in a competitive market.

- **Addition of system security costs**. For the first time, the ISP is including the cost of additional system security investments as coal plants retire: see Section 10.1. The estimated cost of these investments is $3.6 billion.

With the updated assumptions and new scope item, the capital cost of the 2026 ODP rises to $128 billion. This is 2.8% higher than in the 2024 ISP on a like-for-like basis, in a period of rising infrastructure costs.

Figure 23 Changes between 2024 ISP and Draft 2026 ISP costs
(amortised capital costs to 2049-50, PV, $ billion)

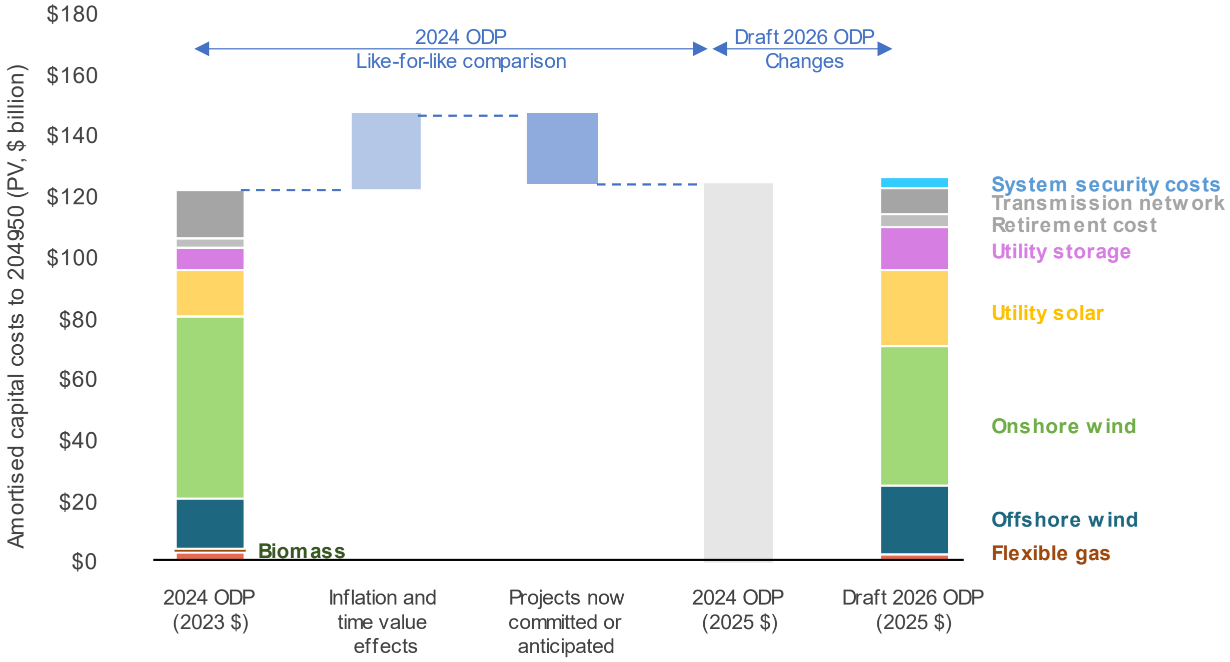


Figure 23 shows the capital costs of the ODP's grid-scale investments in the NEM. In addition, the Draft ISP has discussed how consumers, distribution networks and the gas industry could be investing in the energy transition.

- **Consumer investments.** Consumers are forecast to invest around $50 billion (present value of amortised costs) in rooftop solar, batteries and EV chargers[68], through to 2050 in the *Step Change* scenario. They would also invest a non-estimated amount in CER operating costs, energy efficiency upgrades and electric appliances and conversions. They do so to meet their energy needs, mitigate the risk of rising energy costs and/or contribute to emission reductions. The decisions are made by individual households and businesses and the ISP, that focuses on economic efficiency, cannot attempt to optimise them. Instead, its modelling takes into account the likely level of these investments.

[68] While considered CER for planning purposes, the cost of EVs is not included as an energy investment, along with other household and business appliances that consume electricity.

- **Addition of distribution investment.** For the first time, the proposed ODP includes two sets of distribution network investments, adding $420 million to the ODP's capital costs – $260 million is to connect grid-scale generation and storage within the distribution networks, such as the Dubbo distribution project, and another $160 million would support network refinements to help utilise what would otherwise be latent CER capacity.
- **Gas sector investments**. AEMO has identified three gas development projections in this ISP, for midstream[69] gas investments such as transmission pipelines and expansions, regasification terminals, storage facilities and production plants. It has used one of these projections to help calculate gas fuel limits in the ODP, although ultimately the gas investment will be market-led and any one of the gas development projections (or new alternatives) could be developed. Its capital costs are estimated at $0.95 billion and its operating costs $1.3 billion through to 2050. These cost estimates do not include any upstream costs for the exploration, drilling and extraction of raw gas.

[69] 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.

11 Benefits to consumers under constrained development

AEMO is aware that the rate of build of all types of infrastructure in the ODP is faster through to 2030 than has been achieved to date.

AEMO has explored whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission, generation and storage projects were unable to be delivered at the pace required. This *Constrained Delivery* sensitivity analysis was based on the *Step Change* scenario, but applied a slower rate of delivery and assumes higher delivery costs.

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.

Project costs were assumed to rise on average by 30%, due to these constraints. Again, there may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the rise in cost only.

Its results underscore the need to commence planned and actionable projects in the ODP now. The actionable and future transmission projects would still benefit consumers if delayed, however those benefits would reduce and 2030 policy targets would also be delayed as coal would remain in the system longer.

This section considers how under *Constrained Delivery*:

11.1 **Delivery of generation and storage projects** would be delayed and more costly in the near term.

11.2 **Delivery of transmission projects** would be delayed and more costly in the near term.

11.3 **Benefits for consumers would remain positive**, but they would be reduced and some 2030 policy targets would be delayed.

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.

11.1 Constrained delivery of generation and storage projects

The pace of new wind, solar and storage development depends on supply chain and construction timeframes, market capacity, social licence and planning approvals, as well as financing and connection processes.

As shown in Section 5.2, the current build of solar and wind in the connections pipeline would fall short of what is needed by 2030 in the *Step Change* scenario. By 2030, about 35 GW of grid-scale solar and wind would need to be added. Projects to deliver the equivalent of 24 GW[70] are progressing through the connections process, and on average they take four years from connection application to full output.

[70] Projects totalling 27 GW have applied, but historically 10% of connection applications do not progress through to output.

Under *Constrained Development*, AEMO assumed that the build of generation capacity would rise faster than its current rate, although not as fast as required in *Step Change.* The imposed annual delivery cap for solar rises from the recent average of 1.1 GW up to 5 GW in 2029-30, and regains the ODP delivery trajectory by 2031-32: see **Figure 24**. Similarly, the annual delivery cap for wind rises from 0.9 GW up to 4.2 GW[71], also regaining the ODP delivery trajectory by 2031-32: see **Figure 25**. (Victorian offshore wind would be delayed by three years, regaining its delivery trajectory by 2038.)

In this analysis, project costs would also rise. AEMO assumed an average rise of 30% – the upper range of the cost uncertainty for new developments in the 2025 GenCost analysis.

The *Constrained Delivery* analysis suggests that the NEM would reach only 75% renewables by 2030 (short of the national 82% target and corresponding state targets), however comparable 2035 targets would be met.

Figure 24 Capacity build of grid-scale solar under *Constrained Delivery* (GW, 2025-26 to 2034-35, compared to *Step Change*)

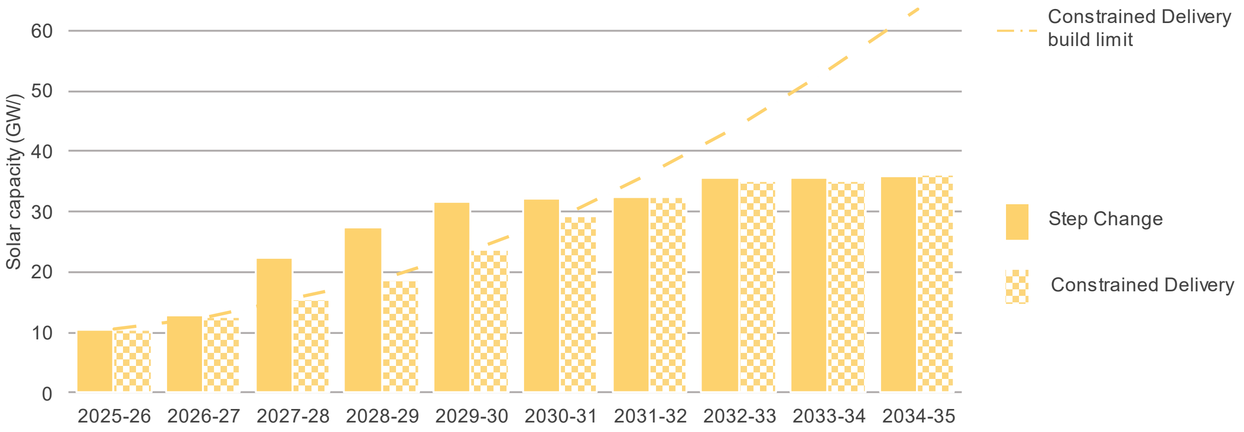
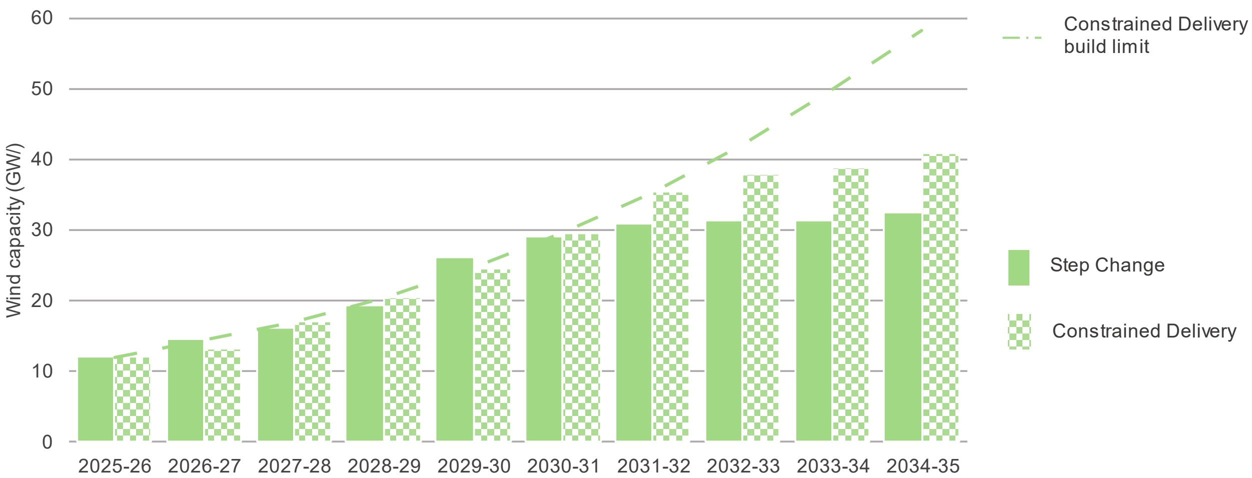


Figure 25 Capacity build of grid-scale wind under *Constrained Delivery* (GW, 2025-26 to 2034-35, compared to *Step Change*)



[71] 0.9 GW is the average wind build per year over the period 2019-20 to 2024-25, and 1.1 GW is the average solar build per year over the period 2019-20 to 2024-25.

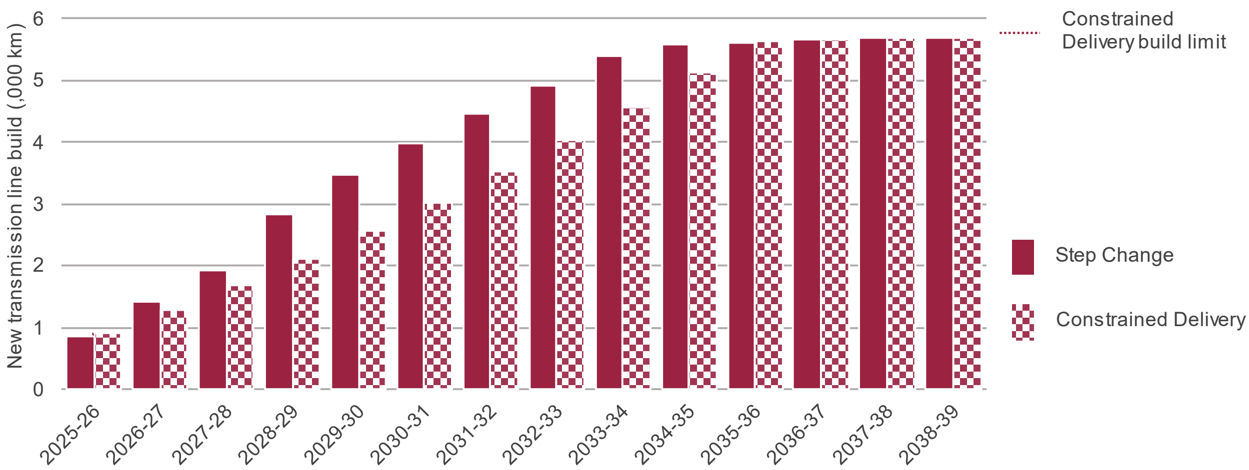
11.2 Constrained delivery of transmission

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

The assumed build rates for transmission projects under *Constrained Development* are shown in **Figure 26**. It was assumed that committed projects would be delayed six months, anticipated projects 12 months, and actionable projects an average of two years. These assumptions were set to allow a 5% year-on-year increase from recent transmission line build history (approximately 365km/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. As delivery constraints slow transmission delivery, AEMO has assumed that their costs would rise, also by an average of 30%.

Ultimately, transmission build would regain the ODP trajectory in 2035-36.

Figure 26 Transmission new build under ODP and under *Constrained Delivery* (,000 km)



11.3 Results confirm need to action transmission projects

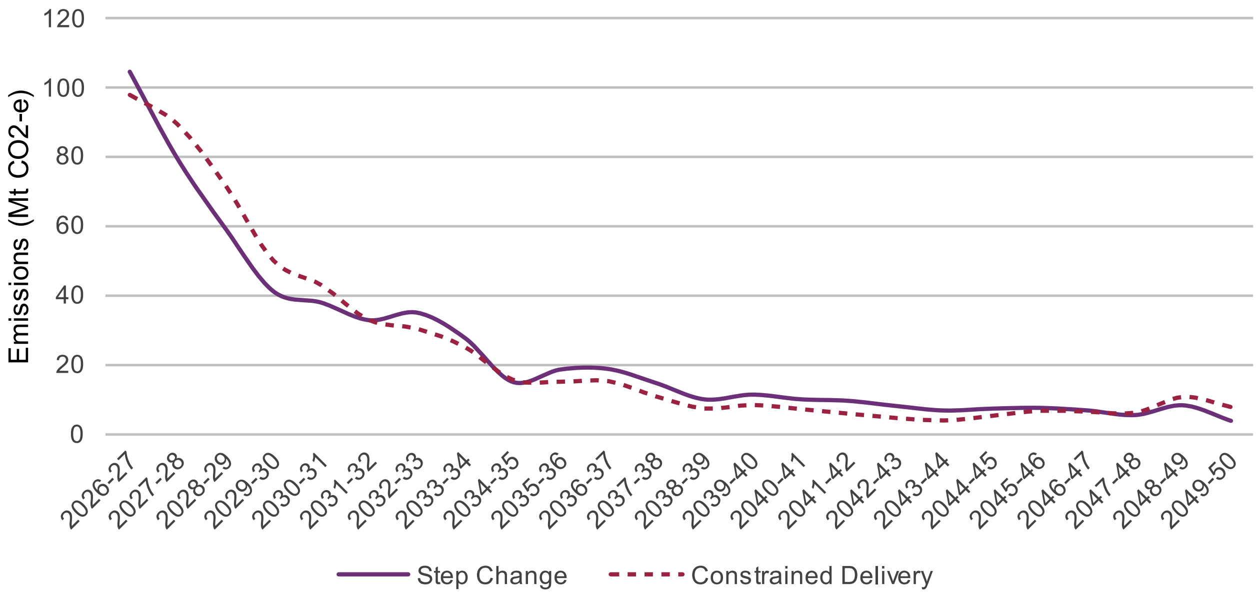
The *Constrained Delivery* sensitivity underscores the need to commence and progress actionable projects in the ODP now, so the energy transition can be delivered at lowest cost to consumers, and risks of delivery delays are mitigated to the extent possible:

- **Transmission projects in the ODP still deliver benefits, even if the pace of delivery is constrained**. Under this sensitivity, the transmission projects in the proposed ODP would continue to deliver positive net market benefits to consumers ($17 billion under *Step Change)*, compared to there being no major new transmission at all. However, both the consumer benefits and emission reductions would be reduced and delayed (see **Figure 27**) and some of the 2030 policy targets would not be achieved. Under this sensitivity, candidate development paths featuring accelerated delivery of transmission augmentations are slightly more beneficial, highlighting the advantages of stronger network connections across the NEM.

- **Renewable energy would contribute 75% of NEM supply by 2030**, missing both the 2030 renewable energy target and the electricity sector's contribution to the national emissions target. Development would then catch up to help meet the 2035 emission targets. Grid-scale solar capacity would reach 25 GW by 2030 (down from 32 GW in the *Step Change* scenario) and 38 GW by 2035. Wind would reach 25 GW by 2030 (down only slightly from 26 GW in the *Step Change* scenario), and 43 GW by 2035.
- **Some coal would remain in the system longer.** With less renewable generation in the near term, 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 end of their planned operational life. An unforeseen critical failure of any one of these ageing power stations could create price scarcity risks, and potentially threaten power system reliability and security (especially if renewable development is delayed, as in this sensitivity).
- **Strong interconnection between states helps mitigate risks of unforeseen coal closures**. Strong interconnection between states, through the transmission projects proposed in this Draft 2026 ISP, allows resource sharing across the NEM which mitigates against the risks of unanticipated coal closures. If those projects are delayed, they are less effective as a risk mitigant. Starting without delay, with contingencies incorporated into schedules, is therefore essential.

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 27 Forecast NEM emissions trajectory, *Step Change* versus *Constrained Delivery*, 2026-27 to 2049-50 (Mt Co2-e)



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. As well, replacement generation and system security services must be available in advance of coal power station closures, and 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, 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 proposed 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 to ensure that it continues to advance quickly through to 2030. For the proposed ODP in this Draft 2026 ISP, the potential benefits are significant, but coordinated action is needed to achieve it.

12.1 Significant progress on 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. This will mitigate against delivery risks that may later be encountered.

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 100% renewables and key transition points, and
- integrating CER into grid operations.

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 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 ongoing NEM Wholesale Market Settings Review will help ensure there are long-term mechanisms in place that provide the market with the required certainty and confidence to invest, 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 proposed 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 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 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.

Additionally, in November 2025, AEMO requested that the AEMC amend the NER's planning and procurement frameworks for system strength and inertia, building on recent updates to support the efficient and timely actions required to meet system security needs over the energy transition. The rule change request focuses on options to address issues including the timing mismatch between transition points where security resources exit and the longer lead times within which approval, procurement and commissioning activities can respond.

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.

AEMO will continue working with distribution network planners, industry, governments, market bodies and consumer groups on reforms that drive benefits for both consumers and the power system. Opportunities include:

- pricing and incentives for solar soaking and peak reduction (such as the Cheaper Home Batteries program and the proposed Solar Sharer Offer scheme) and addressing counter-acting incentives where they exist,
- a broader view of demand side flexibility that recognises its value in a high-renewable power system throughout the day and year, and
- demand flexibility programs that are visible to network and system operations and, where feasible, available to participate in the wholesale market.

In July 2024, the 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. By July 2025, the CER Taskforce had commenced work on 14 of the 16 priorities in the Roadmap, and will start work on the remaining two within the next year. Further recommendations to Ministers are expected in December 2025.

In parallel, the ECMC also recommended changes to the ISP framework which led to further consideration of distribution networks and CER in the ISP, and the AEMC recently published a directions paper for Integrated Distribution System Planning, setting out three different approaches to improve distribution planning.

12.2 Similar collaborations 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, and also with global supply chain partners to secure equipment and materials.

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 the development of new infrastructure, the integration of CER with grid operations, and broader public support for national investment in the transition. Communities engage with this transition through a lens of local social, cultural, environmental, and economic values. Ensuring affordability and reliability across these dimensions is critical to maintaining trust and acceptance. Developers, network planners, governments, and energy market bodies are working harder to build the trusting relationships with communities that underpin social licence. Details of AEMO's approach to social licence issues and how they are incorporated into the ISP are in Appendix A8.

AEMO recognises the importance of early, inclusive, and genuine engagement with communities, particularly those hosting new infrastructure. Building and maintaining social licence requires coordinated effort across energy institutions, governments, and industry. 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.

Social licence is equally critical for the successful coordination of CER. As households and communities take on a more active role in the energy system, it is essential that CER integration reflects their values – including fairness in access and participation, environmental sustainability, and community agency. Affordability is also a key concern, particularly for vulnerable households and renters, and must be addressed to ensure CER benefits are equitably distributed.

The above principles provide a strong foundation and are being pursued by the responsible parties with appropriate intent. There also remains a need for greater clarity around roles and responsibilities 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.

In parallel, there is also an 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.

Ensuring 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.

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[72] 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

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

was forecast in the 2024 ISP to increase from approximately 36,000 in 2025, to over 57,000 by 2050[73]. 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.

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

Continued consultation on the Draft 2026 ISP

The transition of the NEM is well underway: a once-in-a-century change in the way electricity is generated, stored, moved and used.

The Draft 2026 ISP offers planning insights and guidance to help keep that transition on track.

AEMO welcomes and encourages written submissions from all stakeholders on the Draft 2026 ISP. AEMO has extended the required consultation period in acknowledgement of the summer holiday period and is seeking written submissions by Friday, 13 February 2026.

AEMO is also calling for written submissions on non-network options proposals for the proposed new actionable ISP project, Switching Station Near Wondalga: see below and in Appendix A5.

Table 12 lists the consultation and submission dates for the Draft ISP. Stakeholders can register for public and specialised forums (in the form of webinars) through the AEMO website[74].

On the following page, AEMO provides guidance on the content of written submissions, including a list of specific consultation questions, and calls for written submissions on the Draft 2026 ISP as well as non-network options on newly actionable ISP projects.

AEMO sincerely thanks all those who have contributed to this Draft ISP. Consultation will continue with all industry, governments, networks, consumer representatives and other stakeholders, on the way to the final 2026 ISP being published in June.

Table 12 Draft 2026 ISP consultation and submission dates

Date	Event	
10 December 2025	Draft 2026 ISP published	Consultation on the Draft 2026 ISP (including a preliminary optimal development path) commences, with written submissions invited.
16 December 2025	Draft 2026 ISP publication webinar	A public forum on the Draft ISP, with questions encouraged
13 February 2026	Consumer advocates verbal submission	A specialised forum for consumer advocates to provide verbal comments
13 February 2026	Written submissions close	
20 March 2026	Non-network submissions close	Non-network options proposals for the proposed new actionable ISP project, Switching Station Near Wondalga
25 June 2026	Final 2026 ISP published	AEMO finalises the 2026 ISP (confirming the optimal development path) after considering stakeholder feedback.

[74] At https://events.teams.microsoft.com/event/6a058bb7-6773-40e1-9f84-0fc78009853a@320c999e-3876-4ad0-b401-d241068e9e60.

Submissions on the Draft ISP

All stakeholders are invited to provide a written submission on the Draft 2026 ISP. These should be sent in PDF format to ISP@aemo.com.au by 6.00 pm (AEST) on Friday, 13 February 2026[75].

While any comment on the Draft are welcome, the specific consultation questions are:

1. AEMO has proposed an ODP that represents a mix of investments that help deliver a reliable, secure, and least-cost power system while also meeting government policy targets.

   Do stakeholders agree with AEMO's optimal development path selection in the Draft 2026 ISP? If yes, what gives you that confidence? If not, what should be further considered, and why?

2. In the Draft 2026 ISP, AEMO has proposed some changes to actionable transmission projects including:

   – 11 actionable projects to remain for delivery over the next decade,

   – three projects to move to 'committed or anticipated' status,

   – one project to move to 'future' status to align with the timing of other projects that influence its benefits (Central Queensland to Southern Queensland Expansion aligned with Borumba Pumped Hydro), and

   – two projects under review due to uncertainty in input assumptions and the influence of recent policies (Northern Transmission Project and QNI Connect).

   Do you agree with the proposed timing and treatment of actionable projects in this draft?

3. For the Draft 2026 ISP, the tested sensitivities were on constrained delivery of the ODP, variations on the gas development projection, and the pace of coal closures. The effect of demand-side factors was also tested by assessing the impact of reduced energy efficiency measures, and no further CER coordination.

   What other sensitivities should be considered to further test the robustness of the candidate development paths, and why? What other sensitivities are relevant to testing robustness of investment decisions, why?

4. For the first time, AEMO has assessed opportunities for investment in distribution networks across the NEM, that are consistent with the efficient development of the power system, to support operation of consumer energy resources. This recognises the key role of distribution networks in supporting the integration of consumer energy resources. See Appendix A9 for more information.

   Does the ODP appropriately identify and leverage distribution investment opportunities?

5. For the first time in the Draft 2026 ISP, AEMO has incorporated combinations of gas investments that may be developed by the gas industry. These gas development projections influence the availability of gas to support the power system in the future, and (potentially) the mix of investments required in the ODP.

   Do the gas development projections reflect an appropriate level of investment to support the gas sector, including gas-powered generation in the NEM?

6. The Addendum to the 2025 *Inputs Assumptions and Scenarios Report* (IASR) provides further explanation in response to the AER's Transparency Review. This includes further explanation of forecast components

[75] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines.pdf.

including policies affecting consumer demand, data centres, hydrogen production, biomethane and community batteries.

Do stakeholders have feedback on the Addendum to the 2025 IASR?

Submissions on non-network options

AEMO has published a notice calling for written submissions on non-network options proposals for the proposed new actionable ISP project, Switching Station Near Wondalga. More details are in Appendix A5.

Submissions should be sent in PDF format to **ISP@aemo.com.au** by 6.00 pm (AEST) on Friday, 20 March 2026.

Implementation of the ISP Review

In early 2024, the Energy and Climate Change Ministerial Council (ECMC) finalised a review of the ISP[76] and on 5 April 2024 published the Energy Ministers' *Response to the ISP Review*[77]. 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 13 shows the publications that AEMO has amended or proposes to amend to address each ISP Review action or rule change, to help inform engagement by stakeholders on appropriate publications.

Table 13 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]	Draft 2026 ISP and final 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					✔
Improving locational information				✔	✔
Enhanced analysis of system security	✔	✔			✔
Jurisdictional policy transparency	✔ [E]				✔
Clarifying policy inclusions	✔ [E]				✔
Improving the accessibility of the ISP[D]	✔				✔

[76] 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.

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

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]	Draft 2026 ISP and final 2026 ISP
Incorporating community sentiment	✔		✔		✔
Additional planning inputs	✔				✔

A. The *Electricity Network Options Report* forms part of the IASR. It was previously known as the *Transmission Expansion Options Report*, but has been renamed to reflect the inclusion of both transmission and distribution in future ISPs.
B. The *Gas Infrastructure Options Report* was released as draft in May 2025 and final in July 2025 to support better integration of gas into the ISP.
C. The *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.
D. AEMO as 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.
E. These actions were implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions. The guideline is available at consultation-with-jurisdictions-for-the-integrated-system-plan.pdf.

List of tables and figures

Tables

Figures

Glossary

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

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

Term	Acronym	Explanation
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Economic offloading	-	Refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price. This may also be referred to as economic ‘spill’ or ‘spilled energy’ as generators reduce output due to low market prices or lack of available demand.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
National Electricity Rules	NER	The 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.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: “solar, wind, biomass, hydro, and hydrogen turbines”. Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large renewable energy projects can be developed using economies of scale.

Term	Acronym	Explanation
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 the Draft 2026 ISP, AEMO has considered three scenarios: *Slower Growth*, *Step Change* and *Accelerated Transition*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price. This can also be referred to as 'economic offloading'.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Utility-scale or utility	-	For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.

Supporting documents

All documents comprising or supporting the Draft 2026 ISP are available on AEMO's website[78].

Appendices to the Draft 2026 *Integrated System Plan*

- Appendix A1 – Stakeholder Engagement
- Appendix A2 – Generation and Storage 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

- Draft 2026 Integrated System Plan – overview
- Draft 2026 ISP chart data
- Draft 2026 ISP generation and storage outlook
- Draft 2026 ISP Inputs and Assumptions workbook, including the latest input data used for the Draft 2026 ISP modelling
- ISP model [will be published in January 2026]
- Addendum to the 2025 Inputs, Assumptions and Scenarios Report
- Draft 2026 ISP demand and VRE trace data
- Jacobs 2025 Strategic land use distributed resources limit update

Regulatory publications

- Non-network options notice – Switching Station Near Wondalga

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