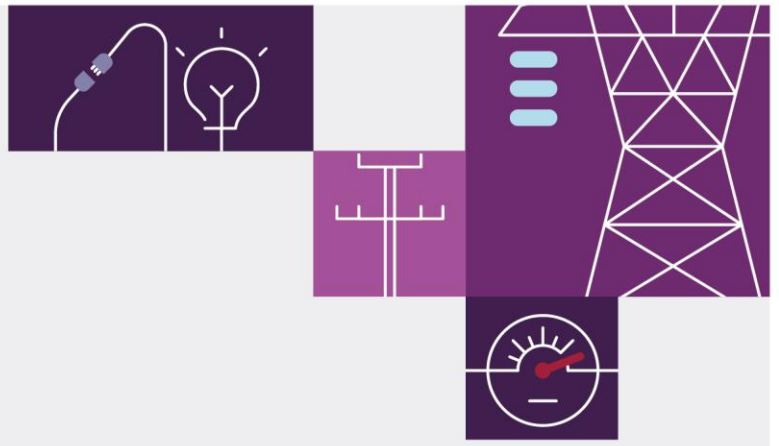


Draft 2022 Integrated System Plan

December 2021

For the National Electricity Market





Important notice

Purpose

AEMO publishes the Draft 2022 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.

Disclaimer

This Draft 2022 ISP contains data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data.

AEMO has made every reasonable effort to ensure the quality of the information in this Draft 2022 ISP but cannot guarantee that the information, forecasts and assumptions in it are accurate, complete or appropriate for your circumstances. This Draft 2022 ISP does not include all of the information that an investor, participant or potential participant in the national electricity market might require and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this Draft 2022 ISP should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

The Draft 2022 ISP does not constitute legal or business advice and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies.

AEMO has made every effort to ensure the quality of the information in this Draft 2022 ISP but cannot guarantee its accuracy or completeness. Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this Draft 2022 ISP; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this ISP, or any omissions from it, or for any use or reliance on the information in it.

Version control

Version	Release date	Changes
1.0	10/12/2021	Initial release.



Invitation to engage

Since 2018, the *Integrated System Plan* (ISP) has guided industry and government on the best investments to supply affordable and reliable electricity to Australian homes and businesses.

On behalf of AEMO, I am incredibly proud of this Draft 2022 ISP.

It is a 'whole of system plan' that offers a roadmap for development in eastern Australia's electricity system. A roadmap that responds to the latest technology, economic shifts and policy developments.

Read as a whole, it offers a clear view of how we can best respond to challenges that will emerge over the next 30 years.

The draft document calls for significant investment across generation, storage, transmission and system services. A transformation of the National Electricity Market, to provide high reliability at low cost, while meeting the nation's objective to reduce emissions.

Of course, the final version of the ISP can only do this with constructive and critical input from a wide range of stakeholders.

This draft document is itself the result of consultation over the past year. I would like to thank the ISP Consumer Panel and the many organisations and individuals who have contributed to the consultations that have made this draft what it is today.

As we publish this draft and work in the coming months to finalise the 2022 ISP, we will again rely on your contribution. We have planned public forums during February, and I encourage you to make a written submission. All views will be considered as we prepare the final report.

The consultation process is set out in Part D of this document.

We look forward to your feedback and contributions.

Daniel Westerman
Chief Executive Officer



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Abbreviations

AC	alternating current	NER	National Electricity Rules
AEMC	Australian Energy Market Commission	NSCAS	network support and control ancillary services
AER	Australian Energy Regulator	NSG	non-scheduled generation
ARENA	Australian Renewable Energy Agency	NSP	network service provider
CCS	carbon capture and storage	ODP	optimal development path
CDP	candidate development path	OWZ	offshore wind zone
DER	distributed energy resources	PACR	Project Assessment Conclusions Report
DNSP	distribution network service provider	PADR	Project Assessment Draft Report
DSP	demand-side participation	PEC	Project EnergyConnect
ESB	Energy Security Board	PFR	primary frequency response
EV	electric vehicle	PV	photovoltaic
FCAS	frequency control ancillary services	QNI	Queensland – New South Wales Interconnector
FFR	fast frequency response	RET	Renewable Energy Target
FOM	fixed operating and maintenance	REZ	renewable energy zone
GW	gigawatt/s	RIT-T	Regulatory Investment Test for Transmission
HVDC	high voltage direct current	SIPS	System Integrity Protection Scheme
IASR	<i>Inputs, Assumptions and Scenarios Report</i>	TNSP	transmission network service provider
IBR	Inverter-based resources	TRET	Tasmanian Renewable Energy Target
IIO	Infrastructure Investment Opportunities	TWh	terawatt hour/s
ISP	<i>Integrated System Plan</i>	V2G	Vehicle-to-grid
kW	kilowatt/s	VNI	Victoria – New South Wales Interconnector
MW	megawatt/s	VPP	virtual power plant
NEM	National Electricity Market	VRE	variable renewable energy



Acknowledgements

Producing a robust Draft ISP is only possible with the extensive involvement of a wide variety of critical energy market stakeholders.

AEMO acknowledges and sincerely thanks the more than 200 individual stakeholders who have actively participated in the process leading up to this publication. Since September 2020, AEMO has received 120 written submissions and held 25 webinars and forums. This formal engagement has been supplemented and enhanced through extensive informal discussions.

The contributions of consumer groups, generators, developers, electricity and gas networks, retailers, advisory firms, academics and environmental groups have each been invaluable throughout this process.

The Australian and State Governments have been generous and rigorous in the input they have provided.

Transmission networks have played an invaluable role, in particular through their participation in the Electricity Joint Planning Committee.

AEMO thanks the many Australian Energy Regulator (AER) Board and staff who have offered AEMO their input and advice on key issues whenever requested.

The ISP Consumer Panel has guided AEMO in a range of areas, not just on issues of content but also on communication and stakeholder engagement. AEMO thanks the Panel Chair, Andrew Nance, and Members for their contribution.

Finally, AEMO acknowledges the immense efforts of our own people to produce the Draft ISP. Staff from across AEMO's Forecasting Group and System Planning Group, as well as AEMO's legal, engagement and communications teams, have worked with precision, expertise and dedication to produce the Draft ISP.

AEMO looks forward to further meaningful engagement on the Draft ISP, as we work towards finalising the 2022 ISP.



Executive summary

Australia's National Electricity Market (NEM) is supporting a once-in-a-century transformation in the way society considers and consumes energy: drawing on electricity in place of much of the oil and gas for industry and homes, replacing legacy assets with low-cost renewables, adding batteries and other new forms of firming capacity, and reconfiguring the grid to support two-way energy flow to new power sources in new locations. It is doing so at world-leading pace, while continuing to provide reliable, secure and affordable electricity to consumers.

Since November 2020, AEMO has engaged comprehensively with energy consumers, policy makers, regulators, industry representatives and other stakeholders to prepare this Draft ISP. Towards the end of that consultation, Australia's Long Term Emissions Reduction Plan (Australia's Emissions Reduction Plan) was launched, adding to existing NEM jurisdiction policies to deliver net zero emissions by 2050.

The Draft ISP proposes to support this highly complex, once-in-a-century transformation with a development path that optimises the consumer benefits of affordable, reliable and secure power.

Significant investment in the NEM is needed to:

- Double the electricity it now delivers, without coal generation, requiring a nine-fold increase in utility-scale variable renewable energy (VRE) capacity, and a five-fold increase in distributed photovoltaics (PV),
- Treble the firming capacity that can respond to a dispatch signal, including utility-scale batteries, hydro storage, gas generation, and smart behind-the-meter batteries or "virtual power plants" (VPPs),
- Adapt networks and markets for two-way electricity flow and to provide essential power system services,
- Efficiently install more than 10,000 km of new transmission as part of the transformation, to connect geographically and technologically diverse, low-cost generation and firming with the consumers who rely on it,
- Pursue these actionable ISP transmission projects on a pathway that is low cost and low regrets for consumers, with work commencing on their earliest planned schedule, and
- Manage the supply chain and social licence risks for investments of this scale.

Stakeholder consultation on the Draft ISP including public forums and written submissions will be open until 11 February 2022, following which AEMO will finalise the 2022 ISP by 30 June 2022.

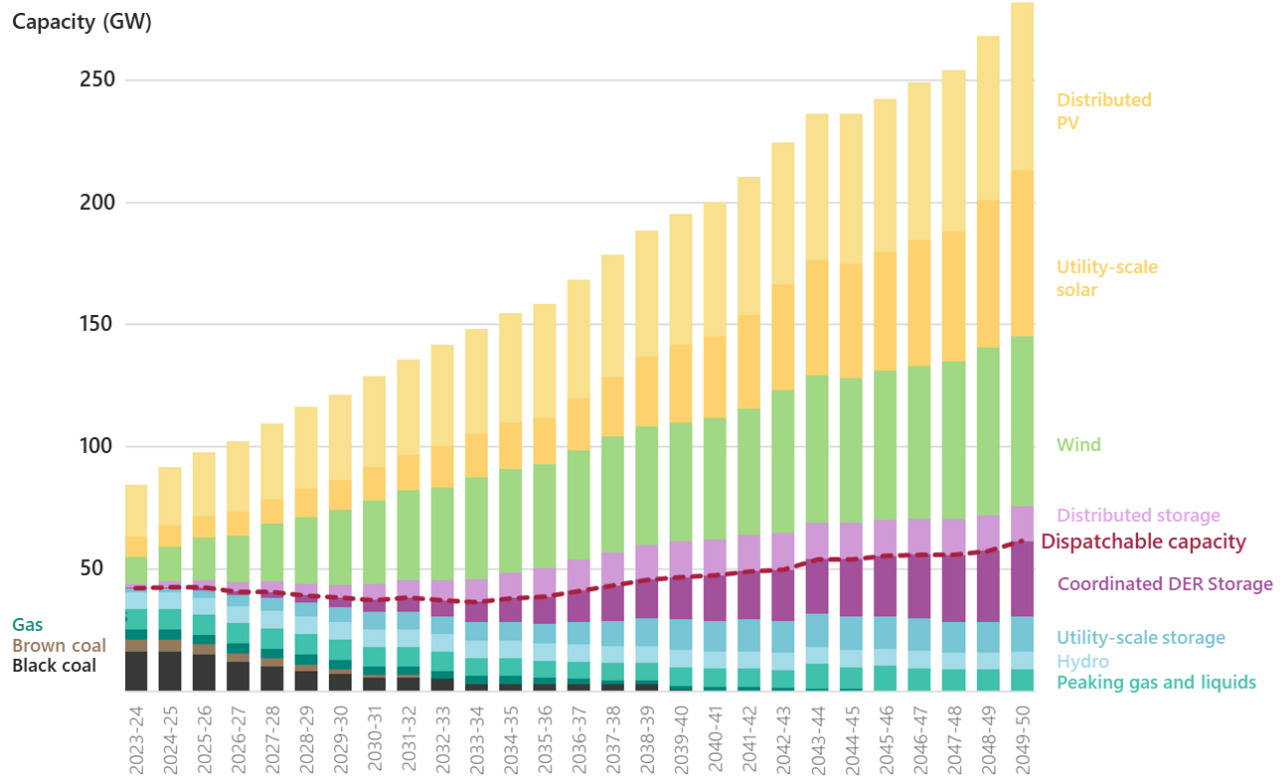
The power system's transformation is profound

The Draft ISP considers four scenarios that cover a broad range of plausible trends and events in its operating environment through the power system's transformation. A strong consensus of stakeholder representatives sees the *Step Change* scenario as being the most likely.

Figure 1 below shows the modelled transformation of the NEM through the *Step Change* scenario through to 2050.



Figure 1 Forecast NEM capacity to 2050, Step Change scenario, with transmission



The ISP development opportunities that form part of the Draft Optimal Development Path (ODP) will assist the NEM catering for:

- Double the delivered electricity to approximately 330 terawatt hours (TWh) per year.** Today the NEM delivers just under 180 TWh of electricity to industry and homes per year. The NEM would need to nearly double that by 2050 to replace much of the gas and petrol currently consumed in transport, industry, office and domestic use. That growth is needed in addition to the significant ongoing investment by consumers in distributed energy and energy efficiency. The needs of proposed hydrogen production, if supplied from the grid, would be additional to this growth and are explored further in AEMO’s *Hydrogen Superpower* scenario.
- Coal retiring two to three times faster than anticipated.** Current announcements by thermal plant owners suggest that about 5 gigawatts (GW) of the current 23 GW of coal capacity will withdraw by 2030. However, modelling suggests that 14 GW may do so. Over the past decade, coal-fired generators have withdrawn from the market before their announced dates, and competitive and operational pressures will intensify with the ever-increasing penetration of cheap renewable generation. All brown coal generation and over two-thirds of black coal generation could withdraw by 2032.
- Nine times the utility-scale VRE capacity.** On a per capita basis, Australia added four to five times more VRE than the European Union, the USA or China in 2018-19. The NEM now needs to maintain that record rate every year for the decade to triple VRE capacity by 2030 – then almost double it again by 2040, and again by 2050. Much of this resource will be built in renewable energy zones (REZs) that coordinate network and renewable investment, and foster a more holistic approach to regional employment, economic opportunity and community participation.



- **Nearly five times the distributed PV capacity, and substantial growth in distributed storage.** The NEM's transformation includes the generation and feed-in capability of millions of individual consumer-owned solar power plants. Today, ~30% of detached homes in the NEM have rooftop PV, their ~15 GW capacity meeting their owners' energy needs and exporting surplus back into the grid. By 2032, over half of the homes in the NEM will do so, rising to 65% with 69 GW capacity by 2050, with most systems complemented by battery energy storage. Their 90 TWh of electricity will then meet nearly one fifth of the NEM's total underlying demand.

When successful, the transformation will deliver low-cost renewable electricity with reliability and security, help meet regional and national climate targets, and contribute significantly to regional jobs and economic growth.

Treble the firming capacity as coal retires

As coal withdraws and sun- and wind-dependent generation starts to dominate the NEM, the system must match when and where electricity is generated, with when and where it is needed. To do so, significant investment in the NEM is needed to treble the firming capacity that can respond to a dispatch signal, together with efficient network investment to access this firm capacity.

Currently, the NEM relies on 23 GW of firm capacity from coal, and another 20 GW of dispatchable firming capacity from storage and gas generation. By 2050, without coal, the NEM will require:

- **45 GW / 620 GWh (gigawatt hours) of storage, in all its forms.** The most pressing need in the next decade (beyond what is already committed) is for batteries, hydro or viable alternative storage of up to eight hours' depth to manage daily variations in the fast-growing solar and wind output. By 2050, the ISP modelling forecasts that VPPs, vehicle-to-grid (V2G) services and other emerging technologies will provide approximately 30 GW of dispatchable storage capacity, and utility-scale battery and pumped hydro storage 15 GW (see Figure 1). This balance reinforces the need for close collaboration between AEMO, network service providers (NSPs) and investors to ensure investments work to optimise benefits for consumers. Deeper pumped hydro storages will be vital for seasonal and long duration needs as coal exits the market at scale.
- **7 GW of existing dispatchable hydro**, which relies on natural water inflows rather than other forms of energy to pump water and recharge (and so is not considered 'storage').
- **9 GW of gas-fired generation in total for peak loads and firming.** At forecast gas prices, gas-fired generation will play a crucial role as significant coal generation retires. It will complement battery and pumped hydro generation to support periods of peak demand, particularly during long 'dark and still' weather periods, as well as provide power system services to provide grid security and stability. The development opportunities are forecast to primarily be for peaking gas generators, with limited opportunities for mid-merit gas plant unless VRE is limited by transmission access. Over time, its emissions will need to be offset, or natural gas will need to be replaced by net-zero carbon fuels such as green hydrogen or biogas.
- **Wholesale demand response and other flexible loads** to also help manage peak loads and troughs, reducing reliance on more capital-intensive responses.

All major projects will need careful design to meet environmental, economic and social licence expectations.



Market and technical reforms for system services and two-way electricity flow

Significant market and technical reforms are underway to securely manage the transformation to a low emissions grid:

- **Significant market reforms have already been implemented.** AEMO and its industry partners have recently implemented Five Minute Settlement and Wholesale Demand Response in the NEM. These major reforms provide better price signals for fast response and flexible technologies, and enable businesses to provide peak shaving services in the spot energy market.
- **Further significant market reforms are underway.** Following Ministerial approval of the Energy Security Board's (ESB's) post-2025 reform recommendations, AEMO is working with the Australian Energy Market Commission (AEMC) through rule changes to implement mechanisms for essential system services for the physical power system, and better integration of distributed energy resources (DER). The ESB has also been tasked by Ministers to undertake further policy work on capacity and network congestion for consideration in late 2022. Given the amount of reform underway, AEMO is also working with industry to develop a NEM Regulatory and IT Implementation Roadmap, aiming to reduce reform implementation costs and risks.
- **Collaborative framework for power system requirements.** AEMO's Engineering Framework¹ enables industry participants to collaboratively define the operational, technical and engineering requirements for the NEM's future, and informs the market reforms being undertaken by the ESB. It describes the initial roadmap to inform preparation of the NEM for operation under six identified operational conditions², including 100% instantaneous penetration of renewable energy by 2025. These actions will be prioritised with industry and integrated into implementation workplans.

Transmission projects add \$29 billion in value while enabling the transformation

The new generation and storage opportunities listed above constitute the ISP development opportunities of the draft optimal development path (ODP) to 2050. The Draft ODP then identifies 10,000 km of new transmission to connect these developments and deliver renewable energy to consumers through the NEM. It identifies projects that are actionable now as well as in the future, and is selected from candidates in accordance with the Cost Benefit Analysis Guidelines made by the Australian Energy Regulator (AER), as detailed in AEMO's *ISP Methodology*.

The transmission projects within the Draft ODP are forecast to deliver scenario-weighted net market benefits of \$29 billion, returning 2.5 times its investment.³ It optimises benefits for all who produce, consume and transport electricity in the market, as well as providing investment certainty and flexibility to reduce NEM emissions faster in the next decade if needed, and time for greater community engagement and supply chain risk management.

The Draft ODP retains that balance and flexibility, while foregoing only \$20 million (less than 0.1% of benefits) against the candidate development path (CDP) with the absolute highest net market benefits. This is a

¹ See <https://aemo.com.au/initiatives/major-programs/engineering-framework>.

² See <https://aemo.com.au/newsroom/news-updates/engineering-framework-takes-shape>.

³ The network investment identified as actionable in this ISP is ~\$12.5 billion in today's value, and constitutes about 3% of the total spend needed to develop, operate and maintain the generation, storage and future network investments of the NEM to 2050 (in net present value [NPV] terms). Considering all transmission investments (actionable and future), the total transmission capital investment represents about 7% of the total spend (in NPV terms), delivering \$29 billion of benefits to consumers.

negligible regret or insurance cost, given that all of the ODP projects are needed – the only question being when. They will all cost-effectively serve the needs of consumers, support Australia’s transition to net zero emissions, and support regional employment and economic growth.

This insurance is provided by staging two transmission projects – the Victoria – New South Wales Interconnector (VNI) West and HumeLink. Both are supported in Australia’s Long Term Emissions Reduction Plan as major projects to transport energy to consumers, including from Snowy 2.0. Staging the projects ensures they can be delivered when needed under all scenarios, with an additional checkpoint before construction to reconfirm that need. In particular, delivery of these projects as early as possible, with early works as the first stage, protects consumers against:

- **the risk of faster than anticipated coal retirements**, while giving greater market and price certainty and enhanced power system resilience when they do retire,
- **the risk of project delivery delays**. Currently stated lead-times suggest that HumeLink could be paused until after the 2024 ISP and still be delivered just-in-time, in the most likely *Step Change* scenario. However, any schedule slippage would mean the project is not available when it is most likely to be needed, leading to \$200 million regret cost. There only needs to be a 10% possibility of that occurring for HumeLink as an actionable staged project to optimise net market benefits. Since the 2020 ISP, project delays have pushed back the earliest commissioning timing for both VNI West and Marinus Link, and it is foreseeable that HumeLink could face similar delivery risks. Progressing the project now with staging is therefore considered an appropriate low regret action for consumers,
- **the risk that storage of more than 8 hours duration takes longer than expected to materialise**. There is a high degree of uncertainty in terms of technology readiness and cost for this type of storage, and more pumped hydro energy storage (additional to Snowy 2.0) may not be able to be delivered in time to cover coal closures if not already well progressed, and
- **the possibility that cost allocation and regulatory arrangements needed to enable Marinus Link are not resolved in a timely manner**. Without Marinus Link, the value of having VNI West built by 2031 increases further.

While not valued in the cost benefit analysis under the current regulatory framework, these projects also provide broader benefits including regional economic stimulus, jobs growth and lower emissions.

The early works stage for HumeLink and VNI West may also identify cost savings, reduce cost uncertainties, and provide greater consumer confidence that they will not be over- or under-investing. To ensure benefits are optimised for consumers, further work to drive down costs of these projects should be urgently undertaken as part of these early works.

The draft optimal development path

The Draft ISP identifies the new transmission projects needed to support the transformation, categorised as:

- committed and anticipated projects already underway,
- actionable ISP projects, for which work should commence at the earliest planned time, and
- future ISP projects, for which AEMO may require (in the final 2022 ISP) the transmission network service provider (TNSP) to undertake preparatory works or REZ Design Reports.

These projects are listed in Table 1, and set out visually in Figure 2 below.

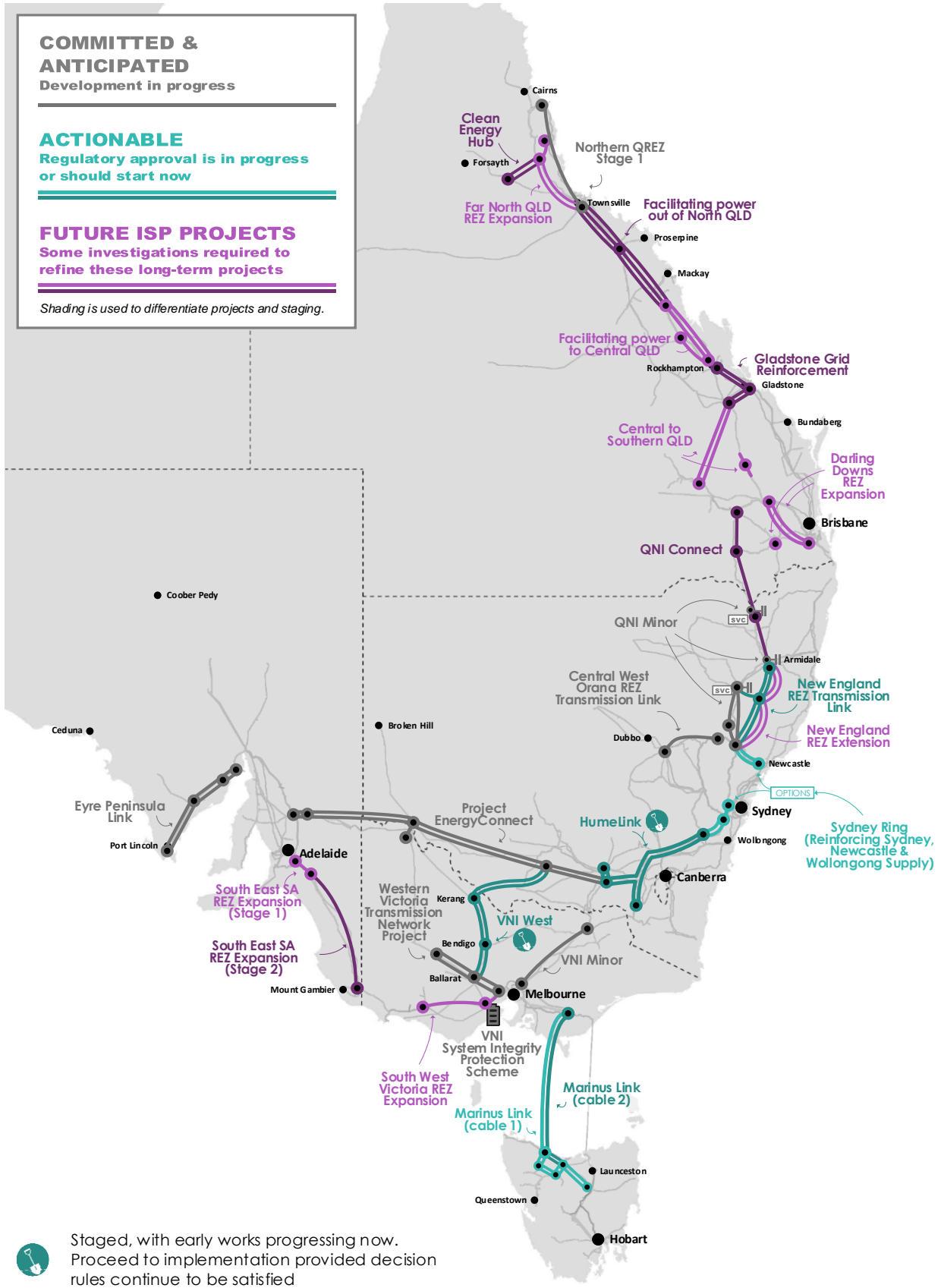
**Table 1 Network projects in the Draft ODP**

Committed and anticipated ISP Projects	To be delivered by
VNI SIPS: Victoria – New South Wales Interconnector System Integrity Protection Scheme	Summer 2021-22 ⁴
QNI Minor: Queensland – New South Wales Interconnector Minor upgrade	July 2022
Eyre Peninsula Link	December 2022
VNI Minor: Victoria – New South Wales Interconnector Minor upgrade	September 2023
Northern QREZ Stage 1	November 2023
Project EnergyConnect	July 2025
Central West Orana REZ Transmission Link	July 2025
Western Victoria Transmission Network Project	July 2026
Actionable ISP Projects	To be delivered by
New England REZ Transmission Link	July 2027
Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply)	July 2027
HumeLink, commencing with early works, and then proceeding with implementation so long as the project passes decision rules that demonstrate consumers will continue to benefit from the project.	Early works: 2024 Implementation: Target July 2026
Marinus Link	Cable 1: July 2027 ⁵ Cable 2: July 2029
VNI West (via Kerang), commencing with early works, and then proceeding with implementation so long as the project passes decision rules that demonstrate consumers will continue to benefit from the project.	Early works: 2026 Implementation: Target July 2031
Future ISP Projects	
Interconnector projects: QNI Connect	
New South Wales Projects: New England REZ Extension	
Queensland Projects: Central to Southern Queensland, Darling Downs REZ Expansion, Gladstone Grid Reinforcement, Far North Queensland REZ Expansion, Facilitating Power to Central Queensland, Facilitating Power out of North Queensland, North Queensland Energy Hub, Far North Queensland REZ Expansion	
South Australia Projects: South East South Australia REZ Expansion.	
Victoria Projects: South West Victoria REZ Expansion	
Additional projects to expand REZs and upgrade flow paths beyond 2040, which are highly uncertain and vary significantly between scenarios.	

⁴ The VNI SIPS project is expected to be in service at or just after release of this Draft ISP.

⁵ TasNetworks has now advised that the earliest full commissioning date for the first cable is July 2029 (750 MW, with 250 MW available in 2028) and the second cable in July 2031 (a further 750 MW, with 250 MW available in 2030). These revised dates will be reflected in the final 2022 ISP, but preliminary modelling indicates that it does not materially change the outcomes of the ODP.

Figure 2 Network projects in the optimal development path



†Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown in this map. See Appendix 5 for more information.



Significant risks and limitations are being monitored and need to be addressed

The scenario and cost-benefit analysis methodologies of this Draft ISP take a comprehensive set of transformation risks into account. These risks are incorporated into policy, technology and cost assumptions, and include the risks of coal generation retiring earlier than announced or anticipated.

However, some important considerations may still risk the Draft ODP's timely implementation:

- **Securing social licence for VRE, storage and transmission.** This Draft ISP shows how the NEM can optimise consumer benefits while supporting government policies for emissions reduction and Australia's new net zero target. However, the land needed for major VRE, storage and transmission projects to realise these goals is unprecedented. Early community engagement will be needed to ensure investments have an appropriate social licence. The new REZ Design Report framework is a start, but proactive engagement and integrated land-use planning is also needed at a jurisdictional level. In some cases, this may lead to alternative developments that reduce the need for new transmission, including batteries, gas-fired generation and offshore wind developments that connect to the existing network easements.
- **Project sequencing to manage supply chain risks.** There is strong industry consensus on the acceleration in global infrastructure and renewable energy investment over the next two decades. This will significantly increase demand for expertise, materials, and equipment, putting pressure on costs and schedules for new NEM generation and transmission projects. Development optimisation through the ISP process alone cannot fully secure the strategic sequencing of projects to manage supply chain risks.

Additional factors that may be considered in future ISPs include:

- **Consideration of broader public benefits when selecting the Draft ODP.** The AER's Cost Benefit Analysis Guidelines consider only benefits for those who consume, produce and transport electricity in the NEM. They make it clear that consumers should not have to pay for broader public benefits, even if these benefits may be valued by governments on behalf of the wider community. These benefits include regional economic and jobs growth, the full societal value of emission reductions, and resilience and adaptation for more extreme climate events.
- **Potential need for additional transmission investment in the NEM's main flow paths.** While the Draft ODP identifies the need for significant new transmission, the NEM may require further augmentation of its main transmission flow paths, or potentially new transmission flow paths, to cater for more significant VRE developments by the 2050s. This Draft ISP has started to study these needs – including alternatives to transmission and the use of alternative technologies such as dedicated high voltage direct current (HVDC) ties – but further work would map out the detailed implications beyond the planning horizon.
- **Securing social licence for greater DER integration.** The Draft ISP recognises the significant market reforms achieved since the 2020 ISP to support the technical integration of DER and other modern energy resources. While the Draft ISP assumes all DER generation can be exported into the network, there comes a point beyond which some active management is needed to maintain the reliability and security of the whole system. The emergence of VPPs across the NEM is expected to assist in meeting this challenge and provide further benefits for consumers. AEMO is actively collaborating with distribution network service providers (DNSPs) to better understand how developments in the distribution network interact with the transmission network and ultimately support optimisation of benefits for consumers. Full DER integration requires a step change in engagement across the industry to ensure all consumers, retailers, networks and other market participants orchestrate these resources to optimise net benefits and maintain security and reliability.



Invitation for written submissions

Drawing on extensive consultation over the past 18 months, this Draft ISP outlines a whole-of-system plan that provides an integrated roadmap for the efficient development of the NEM to 2050, and in AEMO's view, balances consumer risks and benefits.

All stakeholders are invited to provide a written submission on any aspect of the Draft ISP, including development path outcomes, and in particular answering the following questions:

- Do you consider that the Draft ODP appropriately reflects the consumer risk preferences? Is the reasoning for the ODP clear? Are there any other risks that should be quantified?
- Is the proposed staging for HumeLink and VNI West, with early works as the first stage and then proceeding to implementation subject to conditions, appropriate?
- Is the proposed treatment of Marinus Link as a single actionable ISP project appropriate?
- Do you consider that REZ Design Reports are warranted for the indicated REZs?
- Do you have any feedback on the Addendum to the 2021 *Inputs, Assumptions and Scenarios Report* (IASR)?

Submissions need not address every question posed and are not limited to them, but should not relate to inputs and assumptions or methodology which have been consulted on separately.

The full extent of stakeholder consultation on the Draft ISP is set out in Table 2.

Table 2 Stakeholder consultation forums and milestones for the Draft ISP

Date	Event	Purpose
10 Dec 2021	Draft ISP published	Provide a basis for consultation on draft outcomes of the ISP modelling and analysis process.
10 Dec 2021	Public Forum 1	Public briefing on and explanation of the Draft ISP, as well as an opportunity for stakeholders to ask initial questions and clarifications.
15 Dec 2021	AEMO Consumer Forum	Provide a tailored briefing and opportunity for questions from Consumer Forum attendees.
1 Feb 2022	Public Forum 2	Provide all stakeholders with the opportunity to ask more in-depth and specific questions arising from their consideration of the Draft ISP materials.
4 Feb 2022	Consumer Advocate verbal comment	Allow energy consumer advocates to make verbal comments on the Draft ISP, which AEMO will record and consider.
11 Feb 2022	Submissions close	Seek written comments on the Draft ISP from all stakeholders.



Part A

Meeting the ISP's challenge

Australia's energy sector has now commenced a complex and accelerating transformation, aimed at reducing both the sector's emissions and its long-term cost. Traditional generators are being replaced by consumer-led DER, utility-scale VRE and new forms of dispatchable resources. The NEM must provide the power system assets and services to ensure these resources are efficient, safe, reliable and secure.

To meet its prescribed purpose, the 2022 ISP⁶ sets out an optimal development path (ODP) which includes transmission projects and non-network options. It may also include “distribution assets, generation, storage projects or demand-side developments that are consistent with the efficient development of the power system”.⁷ It guides investors and other decision-makers on the optimal timing and placement of those resources.

The ISP is published every two years as the NEM's operating environment changes. Over the last four years, the NEM's transformation has outpaced this cycle. VRE and rooftop PV development is accelerating faster than assumed likely in the previous ISP, and new technology and business models are driving consumer adoption faster than anticipated. This rate of transformation will continue to accelerate, with state and Commonwealth governments announcing significant new policies to support a lower emissions power system.

The accelerating shifts in technologies, behaviours and business models, not to mention the complexity of the system itself, mean a single pre-determined path is not sufficient. This Draft ISP therefore takes a balanced risk-based approach to the NEM's future development, considering a range of scenarios and risks, and carefully examining the upsides and downsides of key decision points.

AEMO has consulted extensively with stakeholders for this Draft 2022 ISP. In particular, AEMO has worked with all NEM participants to draft and publish the *2021 Inputs, Assumptions and Scenarios Report* (IASR)⁸, the *ISP Methodology*⁹ and the *2021 Transmission Cost Report*¹⁰. These reports have done much of the preparatory heavy-lifting for the Draft ISP, which incorporates their content unless otherwise stated.

This Part A completes that groundwork for the Draft ISP, by setting out:

- **Section 1** – the objective of the 2022 ISP and the challenges it faces, and
- **Section 2** – the extensive consultation undertaken to agree on the scenarios, inputs and assumptions relied on by the ISP.

Given the material investment and policy changes since the 2020 ISP, this Draft ISP also serves as an ISP update of the 2020 ISP. Any feedback loop assessments that may be requested between now and publication of the final ISP in June 2022 then benefit from using the latest inputs, assumptions and ODP. An ISP update accompanies this Draft 2022 ISP, and provides reasons for the update and the specific elements of the 2020 ISP that have been updated.¹¹

⁶ The term “2022 ISP” refers to both this Draft ISP and the final 2022 ISP due to be published before 30 June 2022.

⁷ NER 5.10.2

⁸ See <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en>.

⁹ See <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology>.

¹⁰ See <https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-report.pdf?la=en>.

¹¹ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>.



1. The ISP's purpose and challenge

The ISP's prescribed 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 for the long-term interests of the consumers of electricity."¹²

This section first clarifies each of the underlined phrases in this purpose. It then considers the extent of the challenge this purpose represents, given the inherent and emerging complexities the NEM faces. In particular, AEMO has considered policies for the rapid decarbonisation of the NEM. This transformation must negotiate the complexities of the NEM's physical operating system, the rising need to secure community support, and the uncertainties of global policies and supply chains.

1.1 Interpreting the ISP's prescribed purpose

The whole NEM power system, through to 2050

The NEM is an intricate system of systems, which includes regulatory, market, policy and commercial components. At its centre is the power system, an inherently complex machine of transcontinental scale. This system is now experiencing the biggest and fastest transformation since its inception over 100 years ago.

The ISP is a whole-of-system plan to efficiently achieve power system needs through that transformational change, in the long-term interests of electricity consumers. AEMO has extended the ISP's planning horizon through to 2050, to reflect Australia's 2050 net zero emissions target.

The ISP takes into account:

- consumer-led DER investments, storage and generation investments, and demand side responses,
- the capital and fuel costs of generation, storage, transmission, distribution and DER,
- State and Commonwealth energy and environmental policies,
- power system requirements¹³ that must continue to be satisfied as new technologies are integrated, and
- the impacts of coupled sectors such as transport, gas and hydrogen.

As a rigorous whole-of-system plan, prepared in collaboration with NEM jurisdictional planners and policy-makers, energy consumers, asset owners and operators, and market bodies, the ISP is the most comprehensive analysis of Australia's energy future.

Power system requirements

NEM power system requirements are the reliability and security needs for operating a power system within operating limits and in accordance with operating standards. Table 3 summarises the fundamental power system requirements that are considered in the ISP. Primary among these is that the system remains in a

¹² NER 5.22.2

¹³ See <https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper>.

satisfactory operating state through a contingency¹⁴ and can be returned to a secure operating state within 30 minutes. Appendix 7 provides detail on the power system security needs as the NEM transforms from a power system dominated by large thermal power stations, to a system that is more decentralised.

Table 3 Power system requirements considered in the ISP

Need	Operational requirements considered when developing the ISP	
Reliability	Resource adequacy and capability <ul style="list-style-type: none"> There is a sufficient overall portfolio of energy resources to continuously achieve the real-time balancing of supply and demand. 	Energy resources provide sufficient supply to match demand from consumers at least 99.998% of the time.
		Operating reserves exist to provide the capability to respond to large continuing changes in energy requirements.
		Network capability is sufficient to transport energy to consumers.
Security	Frequency management and inertia response <ul style="list-style-type: none"> Ability to maintain system frequency within operating standards. 	Frequency remains within operating standards – considering primary frequency response and frequency controls, minimum inertia requirements, and the availability of alternatives; the system is maintained within transient and oscillatory stability limits.
		Voltage management and system strength <ul style="list-style-type: none"> Ability to maintain voltages on the network within acceptable limits. System strength is above minimum levels.

Public policies considered

In determining these power system needs, AEMO may consider the current environmental or energy policies of the NEM jurisdictions.¹⁵ In this ISP, the following policies are included in its assumptions:

- Emissions reduction targets.** Australia's 2030 target (to reduce greenhouse gas emissions economy-wide to 26-28% below 2005 levels) is included in forecast assumptions, as well as the Australia-wide net zero emissions target by 2050.
- Renewable Energy Targets (RETs)** for Victoria, Queensland and Tasmania. AEMO applies a linear development trajectory to meet the RET targets, starting from the latest forecasts of existing, committed and anticipated renewable energy. For Victoria, this also includes the development requirements anticipated by the second Victorian Renewable Energy Target (VRET2)¹⁶ auction process.
- Policies affecting REZs and associated transmission.** For New South Wales, AEMO applies a generation development trajectory at least as fast as that specified in the Consumer Trustee's 2021 Infrastructure Investment Opportunities (IIO) Report.¹⁷

¹⁴ An event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements.

¹⁵ NER 5.22.3(b)

¹⁶ Further details available at <https://www.energy.vic.gov.au/renewable-energy/vret2>.

¹⁷ See https://aemo.com.au/-/media/files/about_aemo/aemo-services/iio-report-2021.pdf?la=en.

- **Various DER and energy efficiency policies.** AEMO incorporates each of these schemes in its DER uptake and behavioural analysis.¹⁸
- **Electric vehicle (EV) policies.** The EV policies within NEM jurisdictions are included in electricity demand forecasts and apply them to all scenarios. *Slow Change* follows the targets, but ultimately falls short in a slower economy.¹⁹ Some V2G services are also assumed in all scenarios.
- **Energy efficiency policies.** Both Commonwealth and NEM jurisdiction policies are incorporated into electricity demand forecasts for all scenarios. These include building and equipment energy performance standards and ratings, and energy savings or efficiency schemes.

Long-term interests and net market benefits

The ISP must pursue its purpose in the long-term interests of electricity consumers. This is measured primarily by the net market benefits that a development path will bring to those consumers, although AEMO may justify the inclusion of other factors (see Section 7). The extensive classes of market benefits and costs that are included in this calculation are set out in the National Electricity Rules (NER) (rule 5.22.10). As detailed in the *ISP Methodology*, these market benefits align with the categories in the Regulatory Investment Tests for Transmission (RIT-Ts).

In most cases, assuming an efficient market, the greatest net market benefits will arise from the lowest long-term system costs. Table 4 sets out the classes of market benefits and costs the ISP must consider in terms of operation and capital costs. As perfect foresight of future events is unlikely, these market benefits include the option value of an asset whose future need or timing may not be certain, but which would be highly desirable in some future scenarios. This option value may be realised by staging a project: starting it now on the information available, with the option to pause development based on the best information available at a later time.

All values presented in this report are 30 June 2021 real dollars unless stated otherwise.

Table 4 Optimal net market benefits seen as minimal long-term system costs

Benefit	Realised by	Identified by	Costs avoided
Low operation cost	Low marginal cost	Cost of fuel, other operating costs, plant maintenance and plant start-up	Higher cost
	Efficient generation	Co-optimising future generation and transmission build (and retirement) timings and calculating the fuel costs associated with this generation mix	Greater fuel consumption
	Efficient storage and transmission	Assessing additional generation costs effectively wasted due to network losses under each alternate development path	Network losses
Low capital cost	Deferred capital	Time value of money	Capital expenditure
	Optimal investment size	Total generation and transmission costs, compared to counterfactual	Capital expenditure
Option value	Least-regrets modelling	Assessing risks and regret of an investment (or lack of) based on an assumed future that does not play out, and the value of staging	Lost options/flexibility

¹⁸ See Appendix A3 of the *Electricity Demand Forecasting Methodology* for details of the approach to incorporate DER. Available at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach>.

¹⁹ See IASR Section 3.3.5 and CSIRO's *Electric Vehicle Projections 2021* report, at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.



1.2 The complex race to net zero emissions

The Commonwealth and all state NEM jurisdictions have now confirmed the objective of a net zero emission economy by 2050. Not only is the NEM going through its own decarbonisation, but it is a critical enabler for other sectors to reach their net zero emissions objectives through electrification. As a result, the ISP must help guide the NEM through both the inherent complexities in its physical system, and a rapid doubling of demand to meet the needs of electrification.

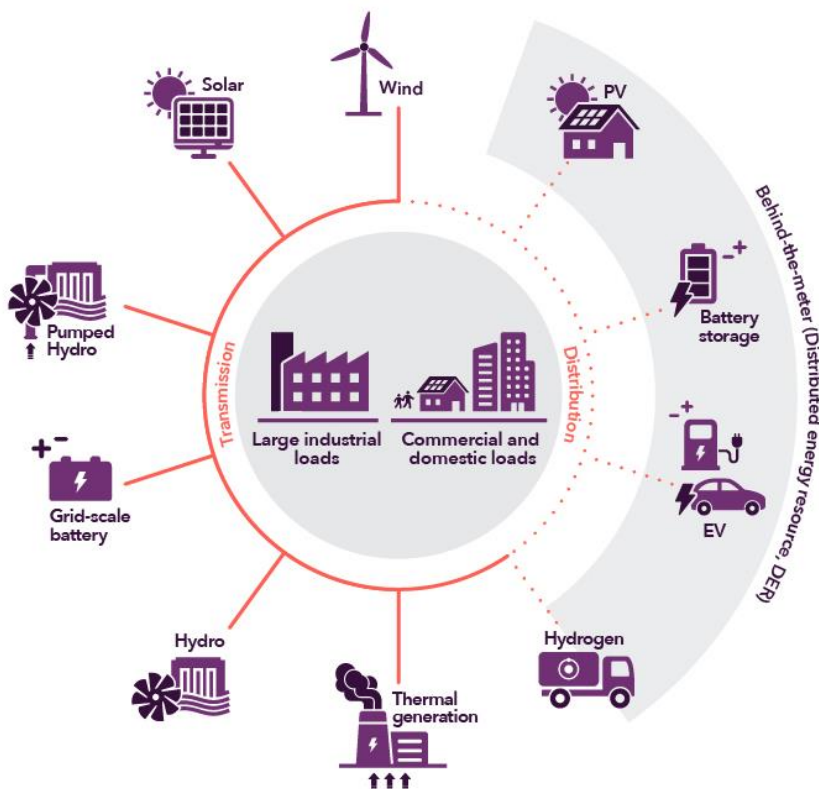
The physical system is complex enough

The inherent complexities in operating the NEM's physical system include:

- the rapid introduction of increasing levels of consumer-driven DER,
- uncertainties in the timing of and market response to the retirement of coal generators,
- satisfying the critical operational needs for the power system with increasingly scarce system services, and
- uncertain yet intensifying climate change impacts.

The first major complexity is the interaction between DER and utility-scale supply (see Figure 3). As more behind-the-meter PV is installed, and more batteries and EVs charge and discharge, the demand profiles for grid-supplied energy shifts. This in turn influences how generators operate, and increases the value of flexible generation, storage and loads in the power system.

Figure 3 Power system interactions between grid and behind-the-meter energy supply





The second major complexity for the ISP is forecasting when existing black and brown coal plants will reduce generation, temporarily withdraw units from the NEM, or shut down. Owners of coal generators have already either brought forward their announced retirements, or indicated that they would, citing market, financial and operating pressures from the rise in renewable generation. The financial viability of existing thermal generation will become increasingly uncertain, particularly coal-fired generation that is less able to adjust generation levels rapidly in response to changes in market prices. Significant financial decisions to repair and maintain plant may be harder to justify under this uncertainty, potentially resulting in declining plant reliability.

Asset owners make these decisions based on a range of commercial factors, in the context of energy and climate change policies, market arrangements, competing technologies, and social and investor licences. These traditional assets have guided the NEM's design, construction and operation to date. Their replacement with DER, VRE and alternate dispatchable resources also means a transformational modernisation of the NEM's operations, including the system services which synchronous generators have traditionally delivered.

As sun, wind and water become the NEM's primary energy resources, supported by gas, it will become increasingly complex to preserve the resilience of the system against a broad array of extreme weather and climate impacts. System resilience is enhanced through fuel diversity, geographic diversity and strategic redundancy, and with design standards that meet Australia's expected climate and often high temperatures. Gas-fired generation, potentially fuelled by hydrogen, will play a crucial role as coal generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability (see Section 4.3).

The race to reduce emissions adds to the complexity

The NEM's operating environment is always subject to an array of economic, trade, security, policy (including on-land gas extraction) and technology environments, as set out in the 2020 ISP. However, the speed and scale of the transformation to a decarbonised NEM poses a unique set of challenges.

So far, the NEM's transformation has outpaced all expectations. On a per capita basis, Australia added over four times the VRE the European Union did in 2018, and five times in 2019.²⁰ In the last two years, through the pandemic, VRE development accelerated, with 40% more VRE now committed or anticipated to be connected to the grid by 2023-24 than was forecast in the 2020 ISP. By May 2021, a surge of renewable generation set a record, delivering 57% of the total generation in the NEM for one trading interval. That record rose twice in September 2021, first to 59% and then again to 61%. AEMO now forecasts periods of 100% renewable generation in some periods as early as 2025, across the NEM rather than in significant parts of it.²¹

Modelling for the Draft ISP confirms that this rate of transformation will continue to accelerate (see Part C). The decarbonisation challenge has now been confirmed by the Commonwealth Government's *Australia's Long-term Emissions Reduction Plan*²² (Australia's Emissions Reduction Plan). Five of this plan's seven priority technologies depend on a low emission NEM, and three depend on clean hydrogen (see Figure 4).

Two new NEM challenges arising from the pace and scale of transformation require urgent and continuing focus. The first is the need to secure community and land owner support for the large amount of VRE, storage and network development signalled in this plan. While generation, transmission and distribution assets have

²⁰ Blakers et al. 'Pathway to 100% renewable electricity', *IEEE Journal of Photovoltaics*, vol. 9, no. 6, November 2019.

²¹ Base case for the 2021 *Electricity Statement of Opportunities*.

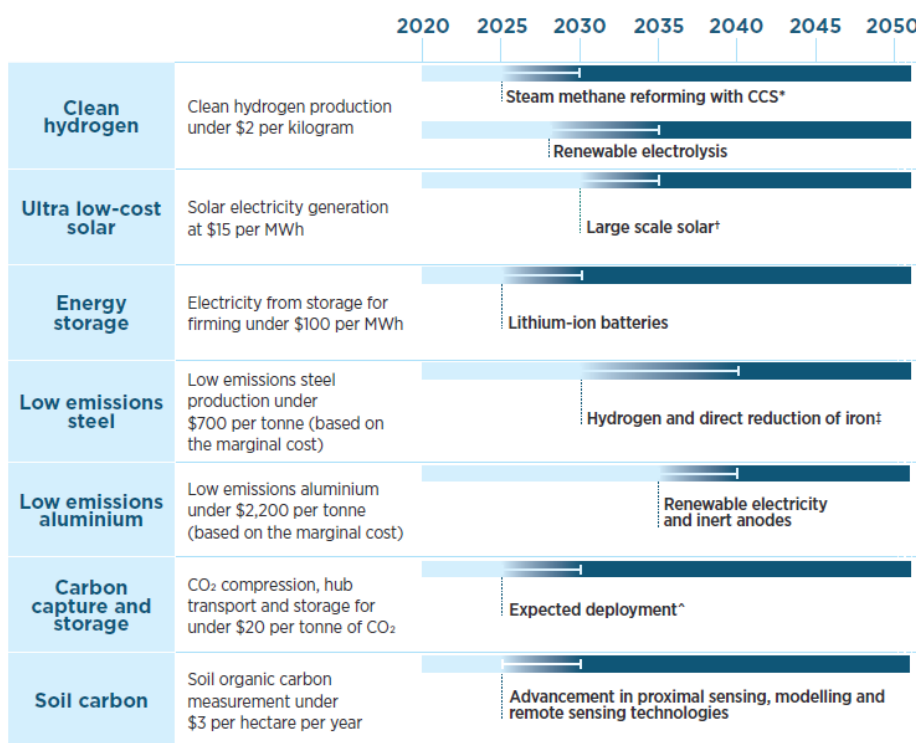
²² See <https://www.industry.gov.au/sites/default/files/October%202021/document/australias-long-term-emissions-reduction-plan.pdf>.



always been a difficult local planning issue, the transformation will require greater local community support for the proposed use of larger amounts of land, potentially including dual-use considerations.

The second is that Australia is not alone in this race to decarbonise. The already heavy investment in global power systems is expected to surge in the wake of COP26.²³ This is on top of a long-running and accelerating global boom in infrastructure investment – from a public perspective to catch-up on infrastructure needs, and from an investor perspective as a newly favoured asset class in a low-interest-rate environment. These trends will require continued focus on supply chain reliability, availability of skilled labour, and cost management for power system development in Australia. Some actionable ISP projects have already experienced schedule delays, and such slippages are likely to continue.

Figure 4 Priority technologies in Australia's Emission Reduction Plan



Source: Australia's Long-term Emissions Reduction Plan, 2021 (Figure 2.4).

The ISP aims to consider and model these variables and complexities in the most rigorous way possible. The following section sets out how AEMO has consulted with industry to settle on the scenarios upon which that analysis relies.

²³ The 26th Conference of the Parties to the UN Framework Convention on Climate Change, Glasgow, November 2021.



2. Consultative modelling for the ISP

As discussed in Section 1, the challenge for the ISP is to meet power system needs in the long-term interests of the consumers of electricity, responding to government policies for decarbonisation.

This is a complex challenge, to which all NEM participants have risen through the ISP consultation process to date.

This section briefly summarises the modelling process of the ISP to achieve that purpose. It sets out:

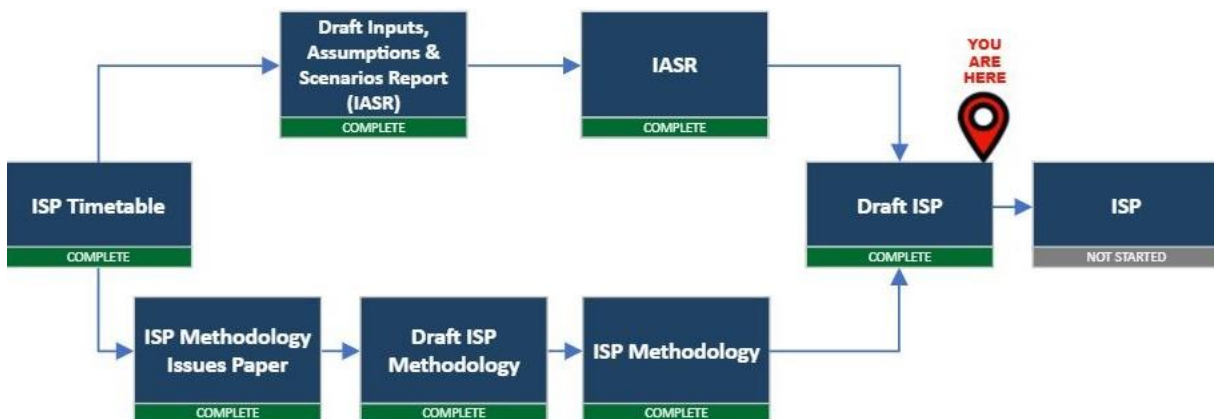
- the extensive industry consultation to date on the *ISP methodology*, inputs and scenarios,
- the scenarios developed through that consultation to consider the future possibilities,
- the selection of *Step Change* as the scenario that industry stakeholders believe is most likely to play out, and
- the modelling used to determine how the NEM could optimally meet its electricity demand and emission reduction objectives for consumers.

The results of this modelling are set out in Parts B and C of this Draft ISP.

2.1 Consultations to date

Consultations for the Draft ISP commenced in September 2020. The first phase culminated in the 2021 IASR²⁴ and the *ISP Methodology*²⁵, published on 30 July 2021. Those reports benefited from the insights of industry and consumer stakeholders, through 88 detailed written submissions, four workshops and numerous stakeholder meetings (see Figure 5²⁶). Consultation for potential minor amendments to the *ISP Methodology* and 2021 IASR relating to competition benefits was held in October.

Figure 5 Parallel ISP consultations



²⁴ See <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en>.

²⁵ See <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology>.

²⁶ A consultation on minor amendments to the *ISP Methodology* and *IASR* regarding the inclusion of competition benefits in ISP analysis was launched on 15 October 2021. All material related to that consultation, including the final report, is available at <https://aemo.com.au/consultations/current-and-closed-consultations/competition-benefits-in-the-isp>



A second phase of engagement was to determine the relative likelihood of the five scenarios identified in the IASR. This process is detailed in Section 2.2 below, and resulted in one scenario being dropped from this ISP analysis and a name change for another, as well as determining the most likely scenario.

ISP Consumer Panel

The five-member ISP Consumer Panel (the Panel) remains highly engaged in all aspects of the ISP process. The Panel delivered its statutory report on the IASR on 30 September 2021, which stated that, in the Panel's assessment, the evidence and reasons supporting the IASR were sound and the selected scenarios are appropriate.

The Panel also made 23 recommendations related to many aspects of the IASR process and AEMO as an organisation. AEMO is considering, consulting on, and actioning these recommendations through a range of processes, including consultation on the Draft ISP. Full discussion of the Panel's report and subsequent actions is provided in Appendix 1.

AER transparency reviews

The NER require the AER to review and report on whether AEMO has adequately explained how it has derived key inputs and assumptions at both the IASR development stage and for the Draft ISP.²⁷

On 30 August 2021, the AER published its transparency review of the 2021 IASR (the IASR review report).²⁸ This review report focused on the adequacy of AEMO's explanation of the inputs and assumptions to be used in the cost benefit analysis to identify the ODP in the Draft 2022 ISP.

The IASR review report concluded that the majority of AEMO's inputs and assumptions were adequately explained and that AEMO has demonstrated that it has taken into account stakeholder feedback.

In addition to the overall finding, and to promote the transparency of the 2021 IASR, the IASR review report required AEMO to provide further explanation to address specific inputs and assumptions, and to consult on these matters in the Draft 2022 ISP.²⁹

AEMO has published an addendum to the 2021 IASR that provides further explanation on these matters, and welcomes submissions on the content of the addendum and this Draft 2022 ISP by 11 February 2022.³⁰

The AER will undertake the second transparency review of the Draft ISP (an ISP review report) as to whether AEMO has adequately explained how it has derived key inputs and assumptions and how these inputs and assumptions have contributed to the outcomes in the Draft 2022 ISP.³¹

2.2 Four scenarios to span a range of plausible futures

Five scenarios were developed through industry consultations and published in the IASR. Further consultations determined the *Steady Progress* scenario to be no longer relevant for this ISP, given Australia's

²⁷ NER 5.22.9 (IASR review report) and NER 5.22.13 (ISP review report)

²⁸ AER, *Transparency Review Integrated System Plan 2022: Final Inputs, Assumptions and Scenarios Report*, at <https://www.aer.gov.au/networks-pipelines/performance-reporting/transparency-review-of-aemo-2021-inputs-assumptions-and-scenarios-report>.

²⁹ Publication of an IASR addendum and consultation in the Draft ISP is required by NER clause 5.22.9(c).

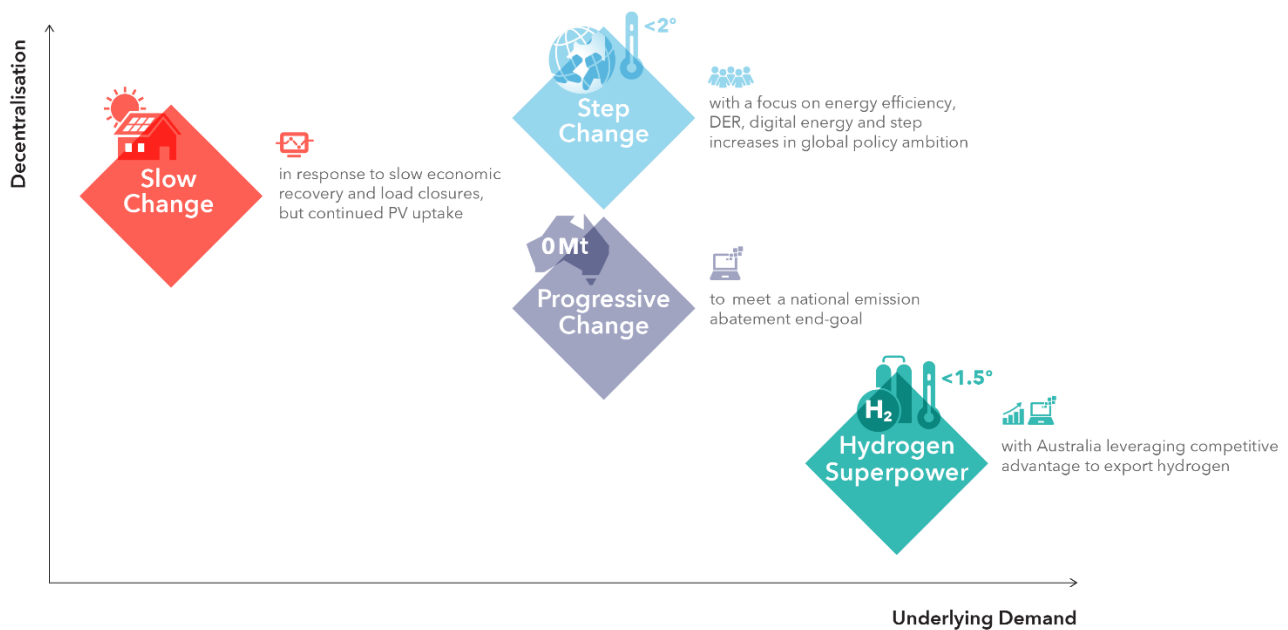
³⁰ AEMO, *2021 Inputs, Assumptions and Scenarios Report: Addendum*, at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

³¹ NER clause 5.22.13(a) requires the AER to publish this ISP review report within one month of the publication of the Draft ISP.

commitment to net zero emissions by 2050, and that the *Slow Change* scenario already tested the impact of slower than anticipated decarbonisation.

The four remaining scenarios span a range of plausible futures with varying rates of decarbonisation, electricity demand, and decentralisation (see Figure 6). The scale of electricity demand is influenced by the extent to which other sectors electrify (for example, the transportation sector via EVs). 'Decentralisation' is the extent to which business and household consumers manage their own electricity generation, storage or services, rather than just draw power from the grid. In the case of *Hydrogen Superpower*, this decentralisation is swamped by the scale of electricity demand needed for a hydrogen export industry.

Figure 6 Scenarios used for the Draft 2022 ISP



The set of scenarios aligns to some degree with those in the 2020 ISP, but has been refined in response to stakeholder feedback and extended to consider greater electrification of other sectors. Since 2019-20, consumer-driven DER has continued to outpace historical forecasts, government policies have supported stronger large-scale renewable energy investments, and some coal retirements have been brought forward.³² From that shared starting point, the scenario trajectories were driven by a range of assumptions, laid out in Figure 7 and discussed in detail in the 2021 IASR.

Diverse future demand scenarios

The scenario broad descriptions are:

- **Slow Change – Challenging economic environment** following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. Consumers continue to manage

³² See 2021 IASR, at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.



their energy needs through DER, particularly distributed PV. However, *Slow Change* would not reach the decarbonisation objectives of Australia's Emissions Reduction Plan.

- **Progressive Change – Pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.** *Progressive Change* (previously *Net Zero 2050*³³) delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build up of momentum ending with deep cuts in emissions across the economy from the 2040s. The 2020s would continue the current impressive trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions. The 2030s would see commercially viable alternatives to emissions-intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification in the 2040s, and nearly doubling the total capacity of the NEM. EVs become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses. Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2045.
- **Step Change – Rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.** *Step Change* moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2° compared to pre-industrial levels. Rather than building momentum as *Progressive Change* does, *Step Change* sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. On top of the *Progressive Change* assumptions, there is also a step change in global policy commitments, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification. By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased. Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2040.
- **Hydrogen Superpower – strong global action and significant technological breakthroughs.** While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, *Hydrogen Superpower* nearly quadruples NEM energy consumption to support a hydrogen export industry. The technology transforms transport and domestic manufacturing, and renewable energy exports become a significant Australian export, retaining Australia's place as a global energy resource. As well, households with gas connections progressively switch to a hydrogen-gas blend, before appliance upgrades achieve 100% hydrogen use.

³³ Renamed from 'Net Zero 2050' to avoid confusion with any NEM jurisdiction or national plan.

Figure 7 Scenario input assumptions

DEMAND	Slow Change		Progressive Change		Step Change		Hydrogen Superpower	
	2030	2050	2030	2050	2030	2050	2030	2050
Electrification								
- Road transport that is EV (%)	2	36	5	84	12	99	18	94
- Residential EVs still relying on convenience charging (%)	82	58	75	44	70	31	66	22
- Industrial Electrification (TWh)	-24	-21	4	92	27	54	37	64
- Residential Electrification (TWh)	0	0	0.2	15	4	13	2	4
- Energy efficiency savings (TWh)	8	19	14	40	22	55	22	56
Underlying Consumption								
- NEM Underlying Consumption (TWh)	163	213	201	394	222	336	243	330
- Hydrogen consumption - domestic (TWh)	0	0	0	32	0.1	58	2	132
- Hydrogen consumption - export, incl. green steel (TWh)	0	0	0	0	0	0	49	816
- Total underlying consumption (TWh)	163	213	201	425	223	394	294	1,278
SUPPLY								
Distributed PV Generation (TWh)	39	58	39	80	45	93	51	112
Household daily consumption potential stored in batteries (%)	3	5	5	22	12	38	13	39
Underlying consumption met by DER (%)	24	27	20	19	20	24	17	9
Coal generation (% of total electricity production)	34	5	38	2	21	0	6	0
NEM emissions (MT CO ₂ -e)	57.4	12.1	77.8	23.6	48.3	7.2	19.0	5.6
2020 NEM emissions (% of)	40	9	55	17	34	5	13	4

Emissions reduction targets and trajectories for the scenarios

Included in these assumptions are carbon budgets for the electricity sector itself – that is, the NEM's contribution to reducing Australia's emissions to net zero by 2050. Figure 8 below sets out the emission reduction trajectory for the electricity sector in each scenario. While each gets to net zero by 2050, each takes a very different path. *Progressive Change* gets there 'just in time', while *Step Change* and *Hydrogen Superpower* move faster to approach or reach net zero by 2035. *Slow Change* sees reductions in emissions early due to assumed load closures, but abatement then slows considerably in the second and third decade.

To determine these carbon budgets, AEMO and its consultants (CSIRO and ClimateWorks) considered four means (or "pillars") by which to decarbonise the economy. The decarbonisation of the NEM is a key pillar, which influences, and is influenced by, shifts in the other three pillars:

- **Electricity sector decarbonisation**, being the speed at which the carbon intensity of electricity generation approaches zero.
- **Fuel switching** from fossil fuels to zero or near-zero emissions alternatives, including electrification. By 2050, at least 150 TWh of new consumption is forecast from the switching of other energy sources to electricity, almost doubling today's delivered consumption of just under 180 TWh per year. Transport, heating, cooking, hot water and almost all transport and industrial processes are able to be electrified. As some electrification is more expensive than others, the level increases over time in all scenarios as emission targets tighten and/or technology breakthroughs reduce the cost of fuel-switching.

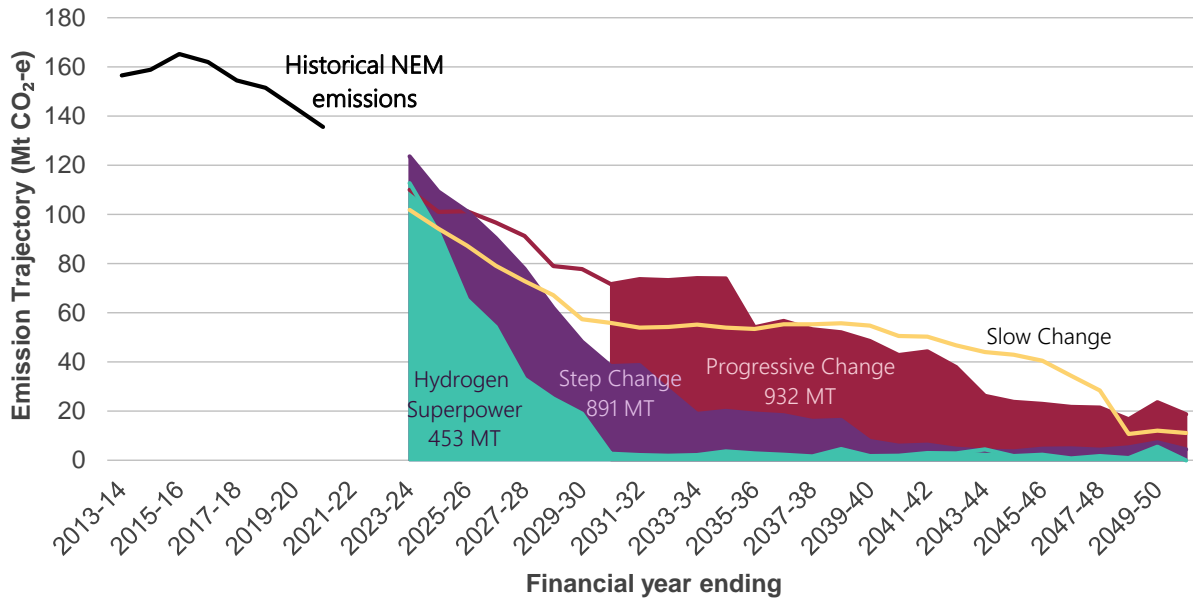
As the price of EVs falls, for example, their share of the total vehicle fleet is expected to increase, rising in *Step Change* to 58% by 2040. This would account for approximately 37 TWh of electricity demand, with a demand profile that would ideally provide a sponge for solar supply, but may exacerbate peak demands without proper infrastructure and consumer incentives to charge outside those periods.

- **Energy efficiency** through improved energy productivity and waste reduction.



- **Carbon offsets** through non-energy emission reductions and sequestration, with technology-based carbon sequestration likely accounting for 3 to 10% of all sequestered carbon (depending on the scenario).

Figure 8 NEM carbon budgets and the resulting emission trajectories



2.3 Step Change scenario most likely

Step Change is considered by energy industry stakeholders to be the most likely scenario to play out, ahead of the *Progressive Change* scenario. This was the conclusion of a careful process through which AEMO twice convened a panel of Australian energy market experts representing all stakeholder groups, with an intervening round of public consultation:

- **First panel considers two scenarios equally likely.** The panel of experts representing government, market bodies, generators, consumer and network service providers first met on 5 October 2021. They deliberated using a Delphi Technique, which allowed them to maintain their anonymity, rate the scenarios using web-based software, offer written reasons for those ratings, and consider the responses of others to revise their ratings if appropriate.

In this first forum, *Step Change* and *Progressive Change* each earned over one-third of participant votes. Another 30% of votes was split between *Hydrogen Superpower* and *Steady Progress*, with very few votes expecting *Slow Change* to play out.

- **Public forum tests the panel findings.** AEMO then held a public forum on 22 October 2021, in which the first Panel views were published, in aggregate and by stakeholder sub-groups. Those attending were asked whether they had any concerns about the use of the Panel's weightings, and importantly, about the approach AEMO should follow to update the scenario weightings if the Commonwealth Government committed to net-zero emissions economy-wide by 2050 (which it subsequently did). Written comments on all three issues were also invited. Stakeholders considered that if commitments were made that invalidated the *Steady Progress* scenario, reconvening the Delphi Panel to reconsider their weightings was most appropriate (see Appendix 1).

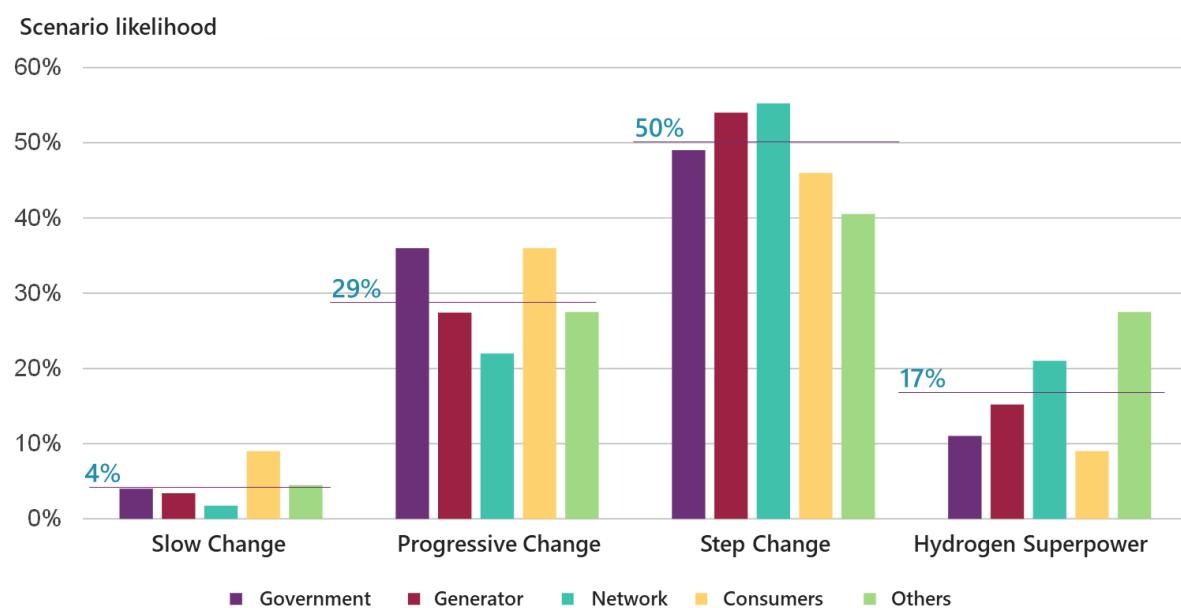


- Second panel prefers Step Change.** The same experts from the first panel were invited back to repeat the Delphi process on 16 November 2021. In this second sitting, the same Delphi Technique was deployed, with the same question being asked of the Panel. In addition, Panel members were asked whether it was appropriate to discard the *Steady Progress* scenario and focus ISP modelling efforts on the remaining four scenarios; approximately 80% of panellists agreed that this was an appropriate action considering Australia's Emissions Reduction Plan. In considering the remaining four scenarios, the panellists concluded that the *Step Change* scenario was the clear 'most likely' scenario, securing approximately half of all votes, followed by *Progressive Change* and then *Hydrogen Superpower*. Again *Slow Change* received very few votes. The increased weighting for *Step Change* reflected the Panel's view that the economy may exceed the ambition of Australia's Emissions Reduction Plan, and do so faster than currently envisaged.

The following comments, made by participants during the second Delphi Panel, illustrate this point:

- *Step change is most likely as the will to change is clear. International pressure to decarbonise will continue to increase, the step change scenario could roll out faster than the ISP scenario timing* (Network participant).
- *I think domestic politics will aim for net zero scenario but global politics and global technology change will drag us towards Step change with slightly higher probability* (Government participant).
- *I expect a significant increase in policy ambition within the next 5 years* (other).
- *I think there will be significant international pressure to achieve the Paris goal of <2 degrees. The only two scenarios that achieve this are Step change and Hydrogen superpower* (network).
- *Globally the financial, policy and political momentum to reduce emissions is now unstoppable* (generator).
- *Most industries are looking to achieve significant decarbonisation and looking to electricity for this, biasing [the likelihood of] the step change* (consumer).

Figure 9 Voting in second Delphi panel

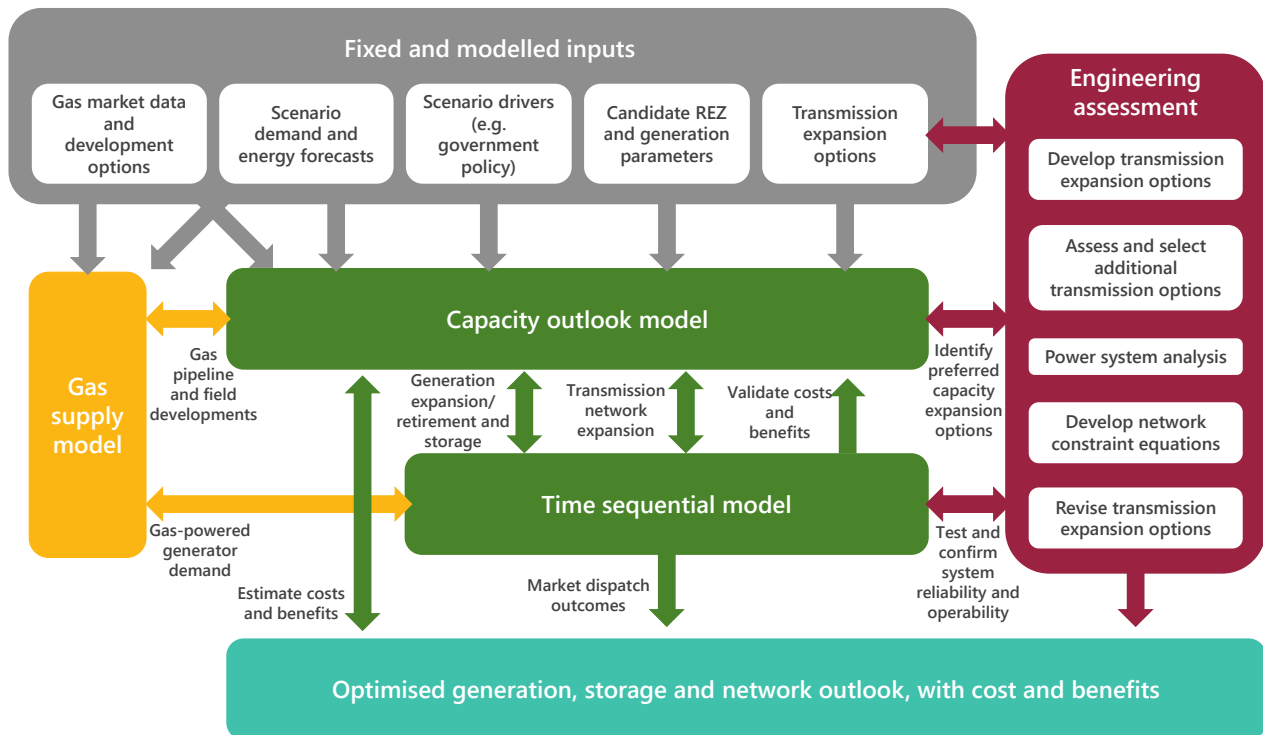




2.4 Modelling of the power system to meet targets

All scenarios and potential power system investments have been analysed through an integrated suite of forecasting and planning models and assessments, to determine which investments would form the optimal development path. It is an iterative approach, where the outputs of each process determine or refine inputs into others. An overview of the integrated suite is shown in Figure 10.

Figure 10 Overview of ISP modelling methodology



- The fixed and modelled inputs are the inputs, assumptions and scenarios published in the IASR. Significant changes to the 2020 ISP are noted in the IASR, and include:
 - The updated GenCost 2020-21 report³⁴ confirms that the costs of inverter-based resources (IBR) like wind, solar (utility-scale and rooftop) and batteries are expected to keep falling, while costs for mature technologies such as coal, gas and hydro generation (pumped storage and conventional) remain flat. That said, larger gas peaking plant recently preferred by the market have a 35% lower capital cost than the smaller sized options considered in the 2020 ISP, and have been included as options this time round.
 - Multisectoral modelling identified a strong opportunity for the NEM to support emissions reduction across Australia’s economy through electrification, and produced carbon budgets where applicable to achieve each scenarios’ decarbonisation intent (see Section 2.2).
 - AEMO has also invested heavily in improving the accuracy and transparency of transmission costs used for the 2022 ISP, following feedback from stakeholders on the 2020 ISP. The resulting 2021

³⁴ CSIRO. GenCost 2020-21, at https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

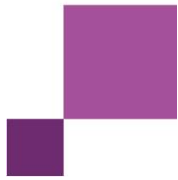


*Transmission Cost Report*³⁵ and associated public database are world-leading initiatives in transparency for regulated transmission builds.

- DER, particularly distributed PV systems, have continued to grow strongly since the 2020 ISP's release, despite the economic and social challenges associated with COVID-19. AEMO's updated DER forecasts for the 2022 ISP forecasts continued strong growth for distributed PV, noticeably higher than previously applied.
- The **capacity outlook model** projects the generation, transmission and dispatch outcomes in each scenario, seeking to optimise capital and operational costs.
- The **time-sequential model** then optimises electricity dispatch for every hourly or half-hourly interval.
- The **engineering assessment** tests and validates the capacity outlook and time-sequential outcomes using power system security assessments to ensure that investments are aligned and robust.
- The **gas supply model** may then validate any assumptions on gas pipeline and field developments.
- Finally, the **cost-benefit analyses** test each individual scenario and development plan, to determine the ODP and test its robustness (see Part C).

The results of this modelling process are given in Part B (ISP Development Opportunities) and Part C (the Optimal Development Path) below.

³⁵ AEMO. 2021 *Transmission Cost Report*, at <https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.



Part B

ISP Development Opportunities

AEMO has comprehensively modelled each of the scenarios introduced in Part A, in line with the *ISP Methodology* and in consultation with NEM stakeholders.

The ISP has found that the NEM must triple its overall generation and storage capacity if it is to meet the economy's electricity needs in the most likely scenario. Today, NEM installed capacity of nearly 60 GW delivers just under 180 TWh of electricity to industry and homes per year. In *Step Change*, utility-scale generation and storage capacity would need to grow to 170 GW and deliver almost 400 TWh per year by 2050 to cater for existing loads and replace the gas and petrol currently consumed by much of our transport, industry, office and domestic use. That growth is needed despite significant investment by consumers in distributed energy and energy efficiency. The needs of any hydrogen production would be *additional* to this growth and result in an eight-fold increase in capacity being required to meet the assumed scale of opportunity in *Hydrogen Superpower*.

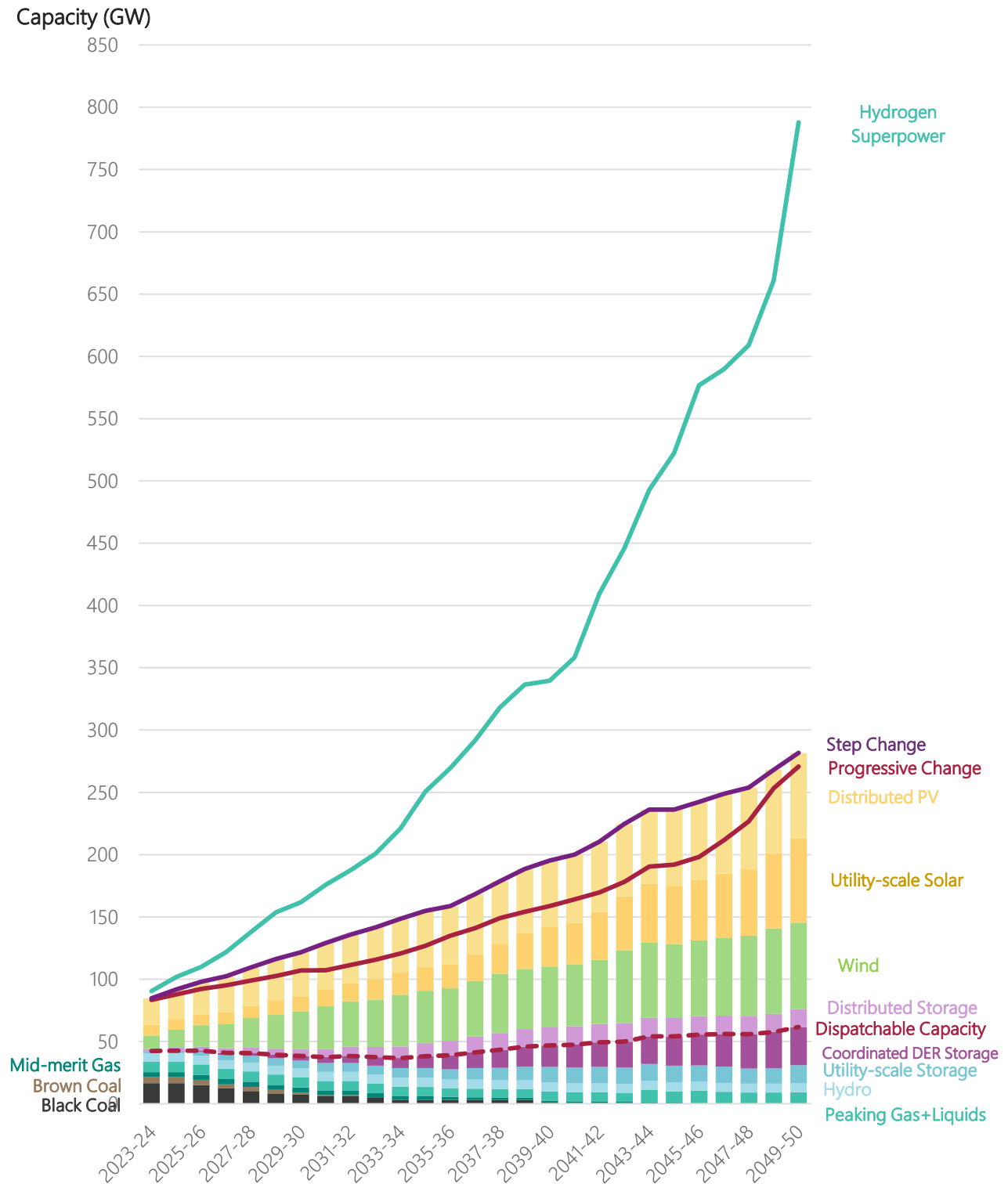
This Part B details how the NEM is forecast to deliver those needs.

- **Section 3 – Conversion to renewable generation.** The ISP forecasts that VRE capacity will increase nine-fold by 2050, from 15 GW currently to nearly 140 GW in *Step Change*. That is over a doubling of capacity every decade. Additionally, distributed PV is forecast to increase from 15 GW to nearly 70 GW over the same period.
- **Section 4 – Storage and services to support renewable generation.** To firm that VRE and DER, 60 GW firm dispatchable generation (30 GW utility-scale) and additional power system security services will be needed.

These resources are the ISP development opportunities that form part of the ISP's ODP (see Figure 11). The other part of the ODP, the actionable and future ISP projects, are set out in Part C.



Figure 11 Development opportunities to 2050 in Step Change, and compared to total capacity required in Progressive Change and Hydrogen Superpower



3. Renewable energy capacity needed to achieve net zero NEM emissions

The shift to renewables is already accelerating. On a per capita basis, Australia added over four to five times the solar and wind generation of any of the European Union, the USA, Japan or China in 2018-19³⁶, building to today's 15 GW of VRE. Records for instantaneous renewable generation penetration (including hydro generation and distributed PV) were broken time and again in 2021.

However, the pace is forecast to accelerate further. Since the 2020 ISP, NEM jurisdictions and the Commonwealth Government have strengthened their emission reduction targets and industry has committed to the electrification of Australia's economy. Their confidence is rising in the viability of electric alternatives in transportation, manufacturing and mining. At the same time, coal-fired generation is withdrawing faster than anticipated, so that investment in utility-scale generation and storage must accelerate to replace it.

This Section 3 details the renewable energy development opportunities needed to help double the NEM's operational consumption by 2050 to meet decarbonisation objectives of other sectors, while simultaneously replacing coal-fired generation. In *Step Change*:

- DER will deliver about 30% of renewable capacity, with 54 GW of new capacity needed to increase the current 15 GW capacity nearly five-fold to 69 GW.
- VRE will deliver about 70% of renewable capacity, with over 120 GW of new capacity needed to increase the current 15 GW capacity over nine-fold to nearly 140 GW, to meet renewable energy policies and provide electricity consumers with the lowest-cost generation supply.
- This VRE capacity is best developed in REZs that coordinate network and renewable investment and foster a more holistic approach to regional employment, economic opportunity and community participation.
- The renewable share of total annual generation will rise from approximately 28% in 2020-21 to 79% by 2030, to 96% by 2040, and to 97% by 2050.
- Some curtailment of installed VRE generation may be expected, as it is not economically efficient to further expand the transmission system or build even more storage to enable delivery of all available electrons at all locations at all times (see Section 3.5 for more about curtailment).

This rate of conversion to renewable capacity is fast in both historical and global terms. However, it is far from a stretch target when Australia's uniquely rich renewable resource is considered. If Australia chose to become a renewable energy powerhouse and capture, store and export that renewable energy in the form of hydrogen, the NEM could require eight times its current capacity.

3.1 Nearly five times today's distributed energy resources

DER describes consumer-owned devices that, as individual units, can generate or store electricity or have the 'smarts' to actively manage energy demand. This includes small-scale embedded generation such as

³⁶ Blakers A et al, "Pathway to 100% Renewable Energy", *IEEE Journal of Photovoltaics*, Volume: 9, Issue 6, November. 2019.



residential and commercial rooftop PV systems (less than 100 kilowatts [kW]), PV non-scheduled generation (NSG, up to 30 MW), distributed battery storage, VPPs and EVs.

By 2050, over 65% of detached homes are projected to have rooftop PV in *Step Change*, with most systems coupled with a battery, meeting these households' own energy needs and exporting surplus back into the grid. In the most likely scenario, total distributed PV capacity (including rooftop PV and PV NSG) would reach 69 GW, up from 15 GW today. These distributed systems would produce approximately 90 GWh of electricity, enough to meet about a fifth of the NEM's total underlying demand.

Behind-the-meter domestic and commercial batteries are expected to grow strongly in the late 2020s and early 2030s, as costs decline. EVs are also expected to surge in the 2030s, driven by falling costs, greater model choice and more charging infrastructure. By 2050, between 50% (*Progressive Change*) and 60% (*Step Change*) of all vehicles are expected to be battery EVs.

The growth in distributed PV is radically influencing the NEM operational demand profile, with maximum demand now occurring near sunset in most regions, and minimum demand rapidly declining. New sources of dispatchable capacity and critical system services will be required to complement these new resources (see Section 4). The impact of other emerging forms of DER such as EVs will depend on how well the interface with the energy system is planned.

Full DER integration requires a step change in engagement across the industry to ensure all consumers, retailers, networks and other market participants orchestrate these resources to optimise net benefits and maintain security and reliability (see Section 7.2).

3.2 Nine times today's utility-scale variable renewables

The ISP forecasts the need for ~122 GW of additional VRE by 2050 in *Step Change*, to meet demand as coal-fired generation withdraws (see Section 5.1). This means maintaining the current record rate of VRE development every year for the decade to treble the existing 15 GW of VRE by 2030 – and then double that capacity by 2040, and again by 2050.

In *Hydrogen Superpower*, the scale of development can only be described as monumental. To enable Australia to become a renewable energy superpower as assumed in this scenario, the NEM would need approximately 256 GW of wind and approximately 300 GW of solar – 37 times its current capacity of VRE. This would expand the total generation capacity of the NEM 10-fold (rather than over three-fold for the more likely *Step Change* and *Progressive Change* scenarios).

Australia has long been in the top five of energy exporting nations. It is now in the very fortunate position of being able to remain an energy superpower, if it chooses, but in entirely new forms of energy.

A mix of solar and wind is required

Both wind and solar VRE is needed for the efficient transformation of the NEM, as they offer complementary daily and seasonal profiles. Taking distributed PV into account, wind and solar will have almost equal shares of NEM generation by 2050.

However, investments in utility-scale wind and solar are forecast to take different paths (see Figure 12 and Figure 13). In the next decade, more wind capacity than solar is efficient to develop to complement the strong uptake of distributed PV. By 2030, wind would represent approximately 80% of all utility-scale VRE installed beyond existing, committed and anticipated projects in *Step Change*. Utility-scale solar will accelerate again



once there is enough storage and network investment (see Section 5). Although utility-scale solar is relatively low-cost, it needs more storage to time-shift its midday generation peaks to the morning and evening demand peaks, particularly given the abundance of distributed PV generation. By 2050, it is projected to make up 50% of newly installed VRE capacity in *Step Change*.

Geographical as well as technical diversity across the NEM will help reduce the need for firming and dispatchable resources. The geographic spread of REZs provides that diversity (see Section 3.3).

Offshore wind has great potential due to resource quality, possible lower social licence hurdles, and proximity to strong transmission, but the economics are not yet proven. It is therefore not currently projected to play a large role in the future energy mix at current forecasts of future costs, unless land use considerations limit onshore development. Further cost reductions could see offshore wind feature more prominently in future ISPs.

Figure 12 Growth and share of utility-scale solar and wind capacity, all scenarios

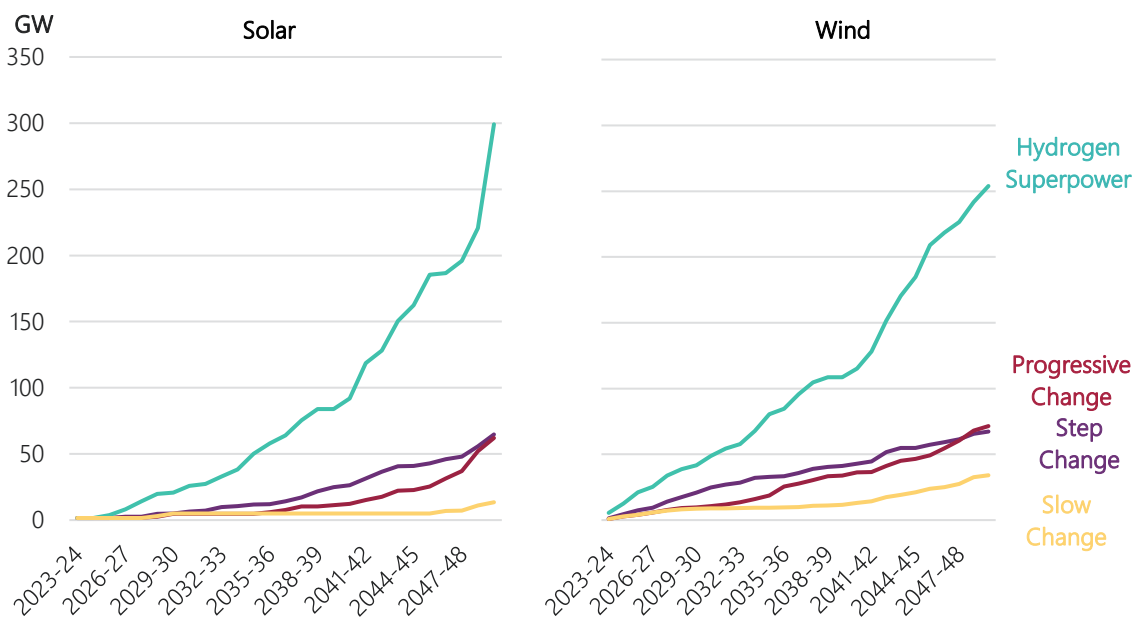
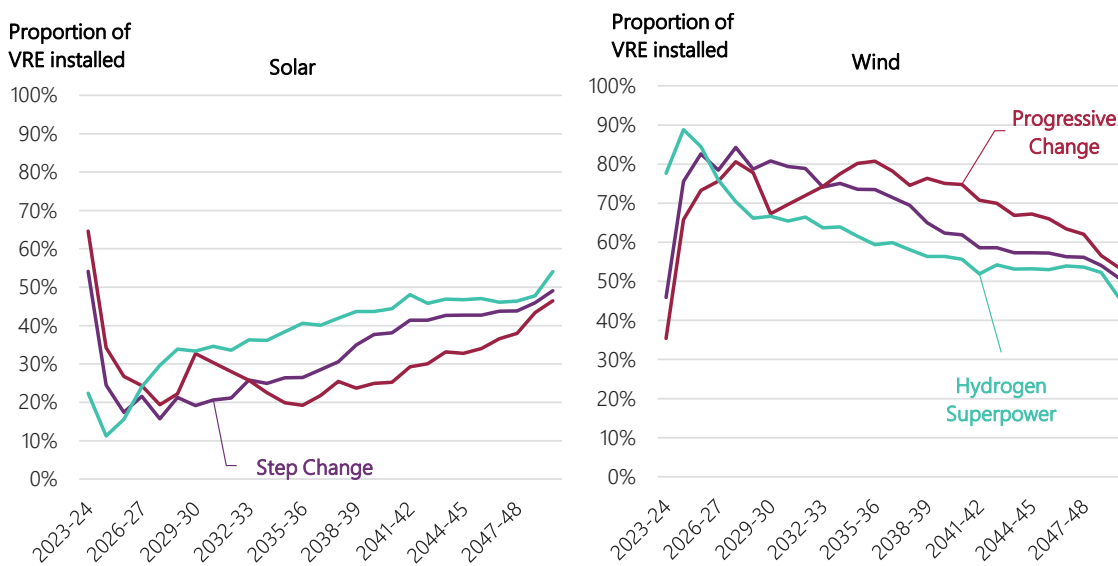


Figure 13 Proportional cumulative development of new utility-scale renewable capacity





3.3 Renewable energy zones for new VRE

Much of the VRE will be built in REZs that coordinate network and renewable investment and foster a more holistic approach to regional employment, economic opportunity and community participation.

Located in areas with strong community support, quality renewable resources and network with existing or committed spare capacity and system strength, REZs can materially reduce costs and risks for VRE investors, ultimately for the benefit of consumers, by:

- reducing transmission and connection costs and risks,
- sharing costs and risks across multiple connecting parties,
- co-locating and optimising system support infrastructure and weather observation stations, and
- promoting regional expertise and employment at scale.

The ISP seeks to co-optimize these REZs with potential network investments. The modelling considers how new and existing transmission and the emerging REZs can be a critical enabler for economy-wide emissions reductions. If well planned and supported by appropriate social licence, REZs can improve grid reliability and security, minimise community, environmental and aesthetic impacts, adhere to relevant design standards and regulatory requirements, and offer flexibility and expandability to address the future needs of the power system.

There is already approximately 15 GW of utility-scale VRE installed in the NEM, and approximately another 5 GW is expected to be operational over the next few years, as either committed or anticipated projects.³⁷

While some developments may connect efficiently to existing transmission capacity, many will need strong technical coordination for their connection, and also to engage effectively with local communities, build social licence, and strengthen resource and employment supply chains. The new REZ Design Report process³⁸ has been introduced for that purpose, and is detailed in Section 9.2.

Appendix 3 details each of the 39 REZs, including four offshore wind zones (OWZs), considered in the ISP. In *Step Change*, the following development is projected above what is already existing, committed or anticipated in each region over the next 10 to 20 years:

- **38 GW new VRE in New South Wales by 2050.** The Central-West Orana REZ would install 3 GW by 2026-27, increasing to 5 GW by 2030 and 10 GW by 2040. The New England REZ would start behind Central-West Orana, but would also install 5 GW by 2030 and 10 GW by 2040. This development is consistent with the minimum development requirements of the New South Wales Roadmap to deliver at least 33,600 GWh p.a. by the end of 2029, as outlined in the 2021 IIO Report³⁹.
- **47 GW new VRE in Queensland by 2050.** Darling Downs, Far North Queensland, North Queensland Clean Energy Hub, Isaac and Fitzroy REZs would all take advantage of spare network capacity to together install approximately 7.2 GW by 2030. Following that, Darling Downs and Fitzroy would see greater development to add more than 4–6 GW each between 2030 and 2040.

³⁷ Data is as of July 2021, AEMO Generation Information Page, at <https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>. Definitions of committed and anticipated are included in each Generation Information update.

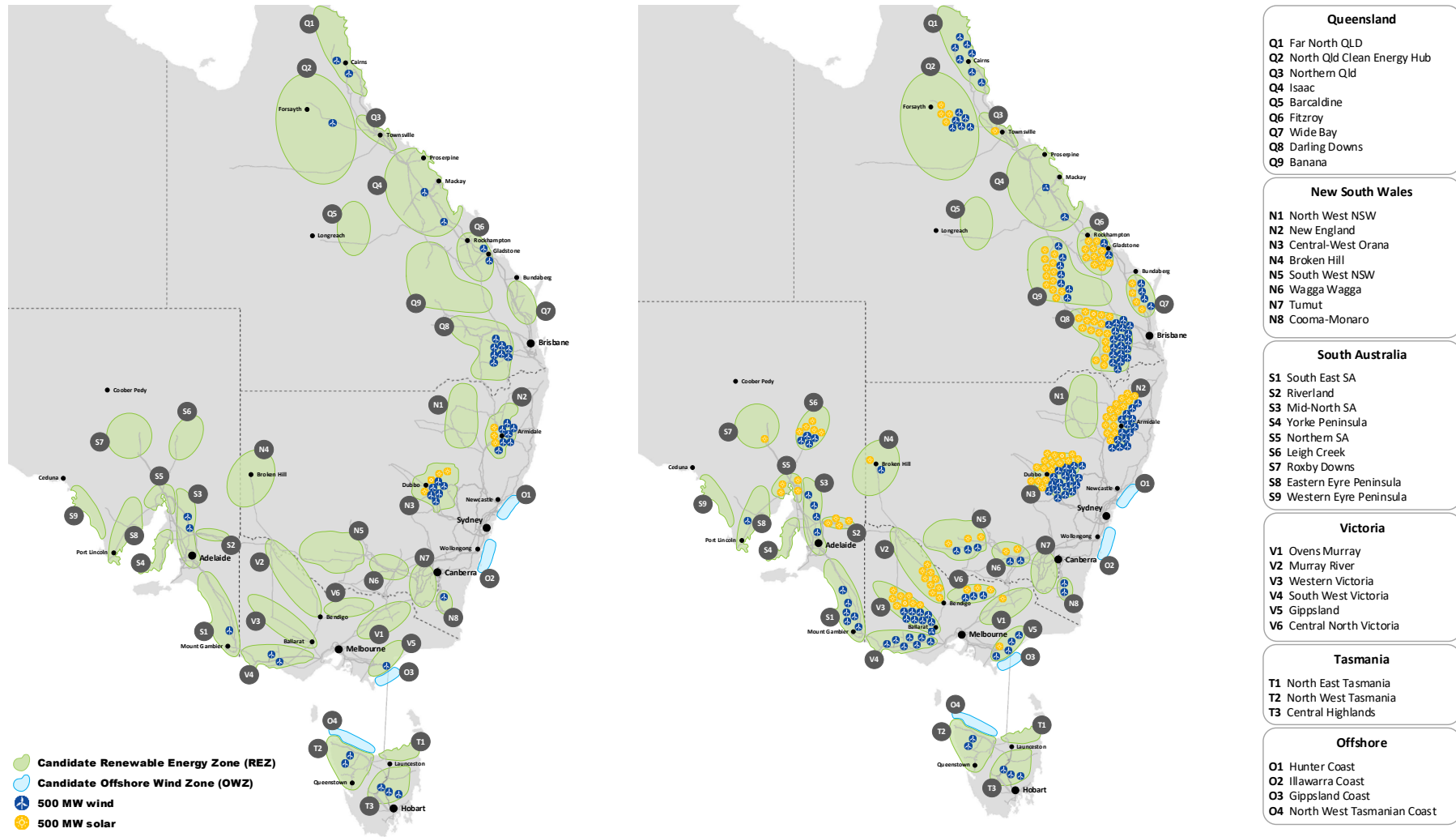
³⁸ See NER 5.24

³⁹ At <https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee>.



- **15 GW new VRE in South Australia by 2050**, taking advantage of the Project EnergyConnect inter-connector. REZs with high wind quality would see the earliest development: South East South Australia with an additional 1 GW by 2030 and 2 GW by 2040, and Mid-North South Australia installing 1.5 GW between 2027 and 2035, reaching 2.5 GW by 2040.
- **2.5 GW new wind in Tasmania by 2050**, provided Marinus Link is built. Of that, approximately 1.5 GW is projected to be installed in the Central Highlands REZ, and 1 GW in the North West Tasmania REZ. No further VRE capacity is forecast and, without significant cost reductions, there is no offshore wind projected in any scenario.
- **23 GW new VRE in Victoria by 2050**, with only 3 GW above what is already existing, committed or anticipated forecast to be required by 2030, in the South West Victoria and Gippsland REZs utilising the existing spare network. Without significant cost reductions, no offshore wind development is projected in Victoria in any scenario.

Figure 14 REZ development in the Step Change scenario – 2029-30 (left) and 2049-50 (right)

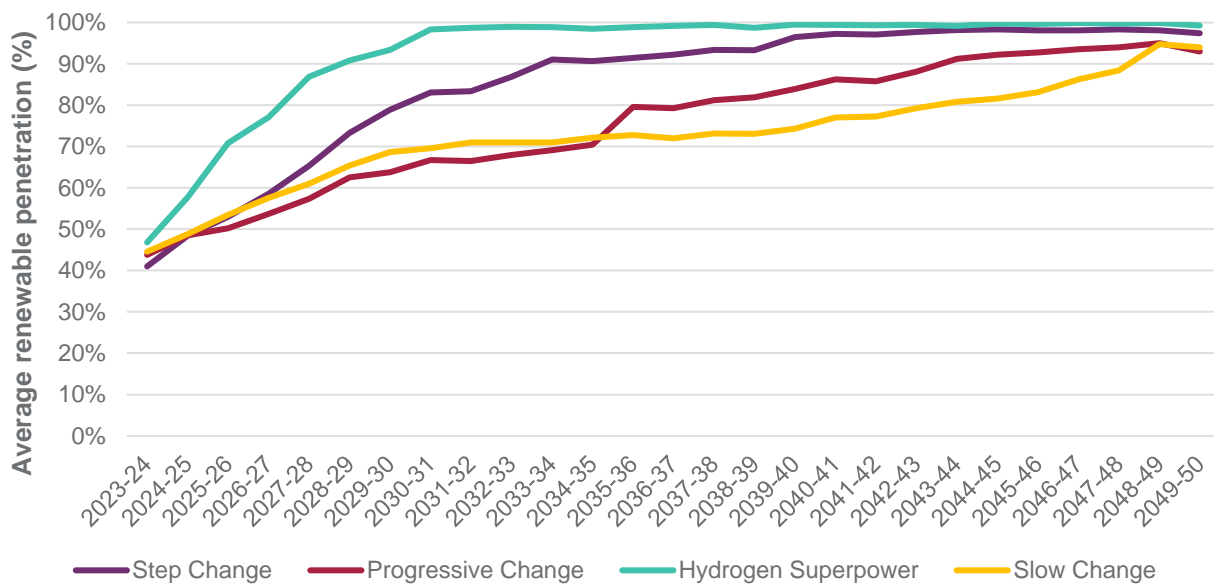




3.4 Renewable penetration

The NEM is continuing its transformation to world-leading levels of renewable energy output, measured as a percentage of annual generation as well as instantaneously, period by period. Figure 15 presents the level of renewable energy as a proportion of annual generation by scenario to 2049-50. In *Step Change*, the renewable share of total annual generation will rise from approximately 28% in 2020-21 to 79% by 2030, to 96% by 2040, and to 97% by 2050. In the 2020s alone, half of all NEM generation will switch to renewables.

Figure 15 Evolution of the annual share of total generation from renewable sources for each least-cost development path

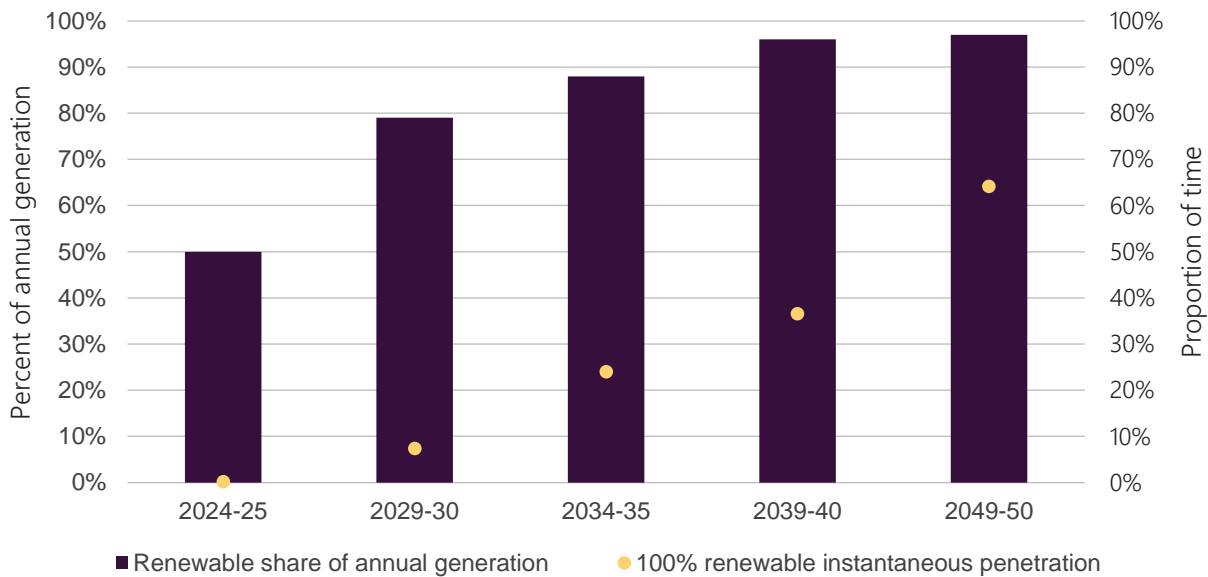


Increasingly, AEMO must engineer the power system to operate securely through periods of 100% instantaneous penetration of renewable generation. Based on resource potential in the most likely *Step Change* scenario, the ISP projects that those periods may commence by 2025, in periods of low demand, and then become more frequent. At times the renewable penetration will exceed the instantaneous demand for electricity from consumers, with storage helping absorb the excess.

By the mid-2040s, electricity supply is expected to be generated almost exclusively from renewable resources, with energy storages helping manage their seasonality and intermittency, and peaking gas generation providing firming support. By 2040, 100% instantaneous renewable penetration is projected to be achieved 36% of the time and 65% by 2050 (see Figure 16), unless constrained due to system security or other operability constraints in the network.



Figure 16 NEM annual share of renewable generation and instantaneous penetration, 2025-2050, Step Change scenario



3.5 Curtailment of VRE will sometimes be efficient

The ISP modelling confirms that, rather than build network and storage to capture every last watt of energy, it is sometimes more efficient to curtail or ‘waste’ some generation. This may occur when there are system security or other operability constraints in the network, or there is simply over-abundant renewable energy available.

Assuming new transmission infrastructure is developed in accordance with this ISP’s ODP, most of the curtailment identified in the ISP modelling will be at times when utility-scale wind and solar become direct competitors for dispatch, rather than pricing out fossil fuel generation. At these times there is simply not enough operational demand to utilise all available renewable resources. Adding more storage to soak up the surplus supply is unlikely to be economically efficient because, with so much annual renewable generation, there is little marginal value in shifting VRE to other times in the day, month or year.

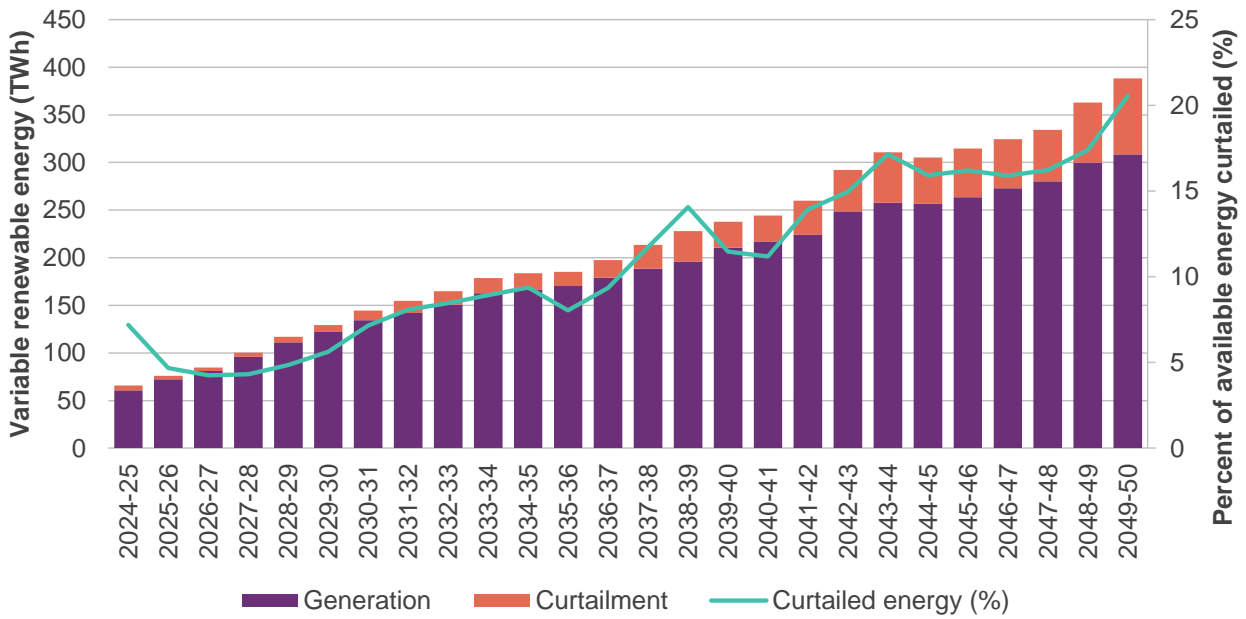
Curtailment is strongly correlated with daylight hours and therefore solar output, with only a small proportion of curtailment projected to occur at night. Curtailment also occurs most frequently during spring and summer months as solar irradiation improves. This indicates that, based on future technology cost estimates, installing sufficient VRE to meet the energy needs of winter and accepting some curtailment in summer is likely to be a more efficient outcome than the alternative of building less utility-scale solar but more seasonal storage.

By 2050, the proportion of curtailed generation in *Step Change* increases to approximately 20% of total available VRE output in aggregate (assuming some new transmission): see Figure 17. At these levels, market reform will be needed to maintain incentives for investors to develop the optimal VRE capacity. The market reforms presently being developed by the ESB⁴⁰, including capacity mechanisms and increased market transparency, will be important enablers to support the continued transition to deliver the outcomes forecast by this Draft ISP.

⁴⁰ ESB post-2025 market reform recommendations, available at <https://esb-post2025-market-design.aemc.gov.au/delivering-post-2025-reforms>.



Figure 17 NEM variable renewable generation and curtailment, Step Change





4. Dispatchable capacity needed to firm the renewable supply

Section 3 detailed the renewable resources that will be needed to meet consumer demand efficiently as coal generation retires, at the same time as industry and households switch to electricity from petrol and gas-fired power.

This transformation poses significant operability challenges to retain the levels of reliability and security that consumers rightly expect from their power system. Significant investment in the NEM is needed to treble the firming capacity that can respond to a dispatch signals, along with efficient network investment. Wholesale demand response and other flexible loads will also help manage peak loads and troughs, and reduce reliance on more capital-intensive responses.

The ISP seeks to find the most cost-efficient balance between investment in network transmission (see Part C) and in dispatchable capacity to complement renewable generation development. The less transmission capacity there is, the more dispatchable capacity is needed, and vice versa.

This Section 4 details the development opportunities in the NEM to meet those challenges, as part of the ODP. It discusses the following projected shifts:

- the withdrawal of 23 GW of coal capacity, 14 GW of it by 2030 in the *Step Change* scenario,
- 45 GW of new battery and hydro storage (distributed and utility-scale), able to respond to a dispatch signal to help firm the renewables,
- a total of 9 GW of gas-fired generation for peak loads and firming, particularly during long ‘dark and still’ weather periods, with the need to offset emissions,
- the increased value of wholesale demand response and other flexible loads to take advantage of renewable energy oversupply, and minimise disruption during undersupply,
- the increased need for network to shift electricity from where it is produced to where it is needed, maximise the value of geographic diversity and efficiently share resources across the NEM, and
- the increased need to strengthen power system services as the system rapidly approaches 100% instantaneous penetration of renewables.

The detailed analysis underpinning this section is set out in Appendix 4 (System Operability).

4.1 Coal retiring two to three times faster than anticipated

Current announcements by thermal plant owners suggest 5.4 GW of the current 23 GW of coal capacity will withdraw by 2030, but the modelling suggests 14 GW is likely to withdraw by then in *Step Change*.

The sector is undergoing a more rapid change than has been previously expected. Owners of coal generators have already either brought forward their announced retirements, or indicated they would.⁴¹ Their decisions

⁴¹ Yallourn Power Station (by four years, to 2028), Eraring Power Station (one unit by two years, to 2030, another by one year, to 2031), Mt Piper power station (by two years, to 2040). Mothballing of one unit of Torrens Island B Power Station for three years from October 2021. Early closure of both the Loy Yang A and B power stations increasingly likely. See AGL’s media release <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/july/agl-to-mothball-one-unit-at-torrens-b-in-south-australia?zcf97o=vlx3ap>, <https://www.afr.com/policy/energy-and-climate/alinta-concedes-coal-plant-may-shut-15-years-early-20211012-p58z8x>.

remain necessarily uncertain, as they grapple with operating dynamics in the face of cheap renewable generation, their own competitive strategies, plant conditions, regulatory and remediation costs, and the wishes of local communities (to either close or remain open). Given these uncertainties, the effective coordination of closures will be extremely challenging, and prudent planning takes into consideration the potential impacts of less coordinated closures on consumers.

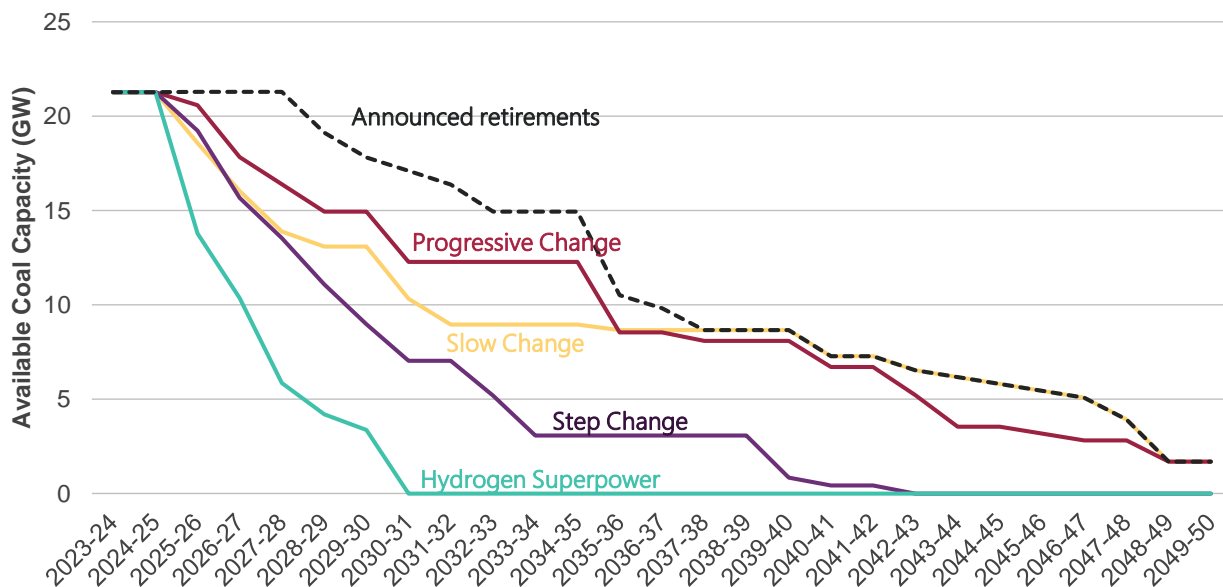
14 GW of coal forecast to withdraw by 2030, but uncertainty expected

The currently announced closure timings suggest that only 5 GW of the current 23 GW of coal capacity will withdraw by 2030. The Draft ISP forecasts faster withdrawals across all scenarios:

- In *Step Change*, modelling indicates 14 GW of coal generation is likely to withdraw by 2030 to meet tighter carbon budgets for the sector. All coal capacity could close as early as 2040.
- In *Progressive Change*, modelling indicates 8 GW of coal generation is likely to withdraw by 2030. From then, competitive operating conditions drive regular withdrawals slightly earlier than currently reported by participants, until 2 GW capacity remains, then representing only 2% of the total generation capacity.
- In *Hydrogen Superpower*, modelling indicates 20 GW of the current 23 GW of installed capacity is likely to withdraw by 2030, in response to the ambitious decarbonisation objectives, and all coal (as well as mid-merit gas) would retire by 2050. This is in spite of the increase in demand for electricity for hydrogen production.
- In *Slow Change*, modelling indicates that 10 GW of coal generation is likely to withdraw by 2030, even more than in *Progressive Change*. This is because lower loads and the same investment in VRE to meet renewable energy policies result in lower daytime residual demand (operational demand met by generators other than VRE), and so less need for dispatchable coal. By 2050, only 2 GW of coal capacity is expected to remain operational (as forecast in *Progressive Change*).

These retirements are shown in Figure 18 below. The retiring coal will require significant scale and diversity of storages and other dispatchable generation to firm VRE (see Section 5.2 below).

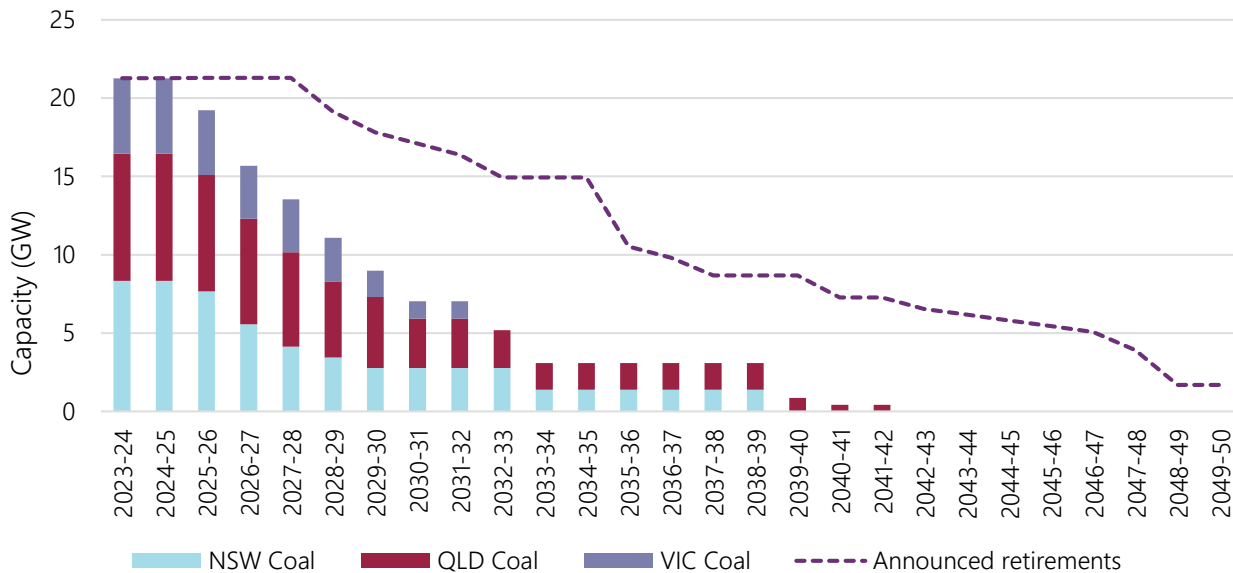
Figure 18 Forecast coal retirements, all scenarios versus announced retirements





Of the coal types, higher emission brown coal generation may be retired ahead of black coal generation to help meet the faster emission reduction ambitions of *Step Change* and *Hydrogen Superpower*. However, the pathway to a zero-coal grid would likely progressively retire power stations across more than one region at a time so closures can be managed reliably and securely. Figure 19 sets out that modelled pathway for *Step Change*, highlighting an earlier and diverse retirement schedule than present announcements would suggest.

Figure 19 Forecast coal retirements, *Step Change* technology and regional outlook



4.2 Treble the capacity of dispatchable storage, hydro and gas-fired generation to firm renewables

Approximately 45 GW / 620 GWh of dispatchable storage capacity, 7 GW of existing dispatchable hydro and 9 GW of gas-fired generation is required by 2050, to efficiently operate and firm VRE.

By 2050, the most likely *Step Change* scenario would call for over 60 GW of firming capacity that can respond to a dispatch signal, including utility-scale batteries, hydro storage, gas-fired generation, smart behind-the-meter batteries or VPPs and (potentially) V2G services from EVs. The willingness of consumers to lower their consumption during high price periods (referred to as demand-side participation, or DSP) will also have an important role to maintain reliability and avoid involuntary load shedding. While the system today has approximately 43 GW of firming capacity, 23 GW of this is coal capacity. As this coal retires, it needs to be replaced with new low-emission firming alternatives. New utility-scale battery and pumped hydro storage, located at appropriate parts of the network, will both enable more effective dispatch of clean electricity on demand, and provide critical system security services.

This Section 4.2 considers how:

- the NEM’s daily operational demand pattern is forecast to change as distributed storage helps soak up excess distributed PV during the day, and reduce peak demands in the evening,
- different storage depths are needed to manage this intra-day pattern, as well as match supply and demand between days and between season, with high levels of consumer engagement needed to coordinate DER storages, and



- gas-fired generation will help manage extended periods of low VRE output and peak demands, and also deliver power system services to provide grid security and stability as coal retires.

The average daily operational demand pattern will flatten over time

Energy consumption behaviours will continue to change, driven by continued DER uptake, improving energy efficiency and increasing electrification. As it does, the time-of-day operational demand will change shape, with a gradual flattening of the peaks and troughs. Figure 20 shows the outcomes in *Step Change*, normalised to remove the effects of rising energy consumption.

Figure 20 NEM normalised average time of day operational demand, *Step Change*



Figure 20 demonstrates a number of underlying trends in consumer demand occurring over the next 30 years:

- Daytime minimum demand will initially be driven lower with continued uptake of distributed PV, but then be driven up by the electrification of other sectors and the opportunities for customer battery systems to charge during periods of excess solar generation.
- Evening peak demand will flatten as distributed storages use the energy absorbed from distributed PV during the day and discharge this during the evenings.
- EV charging during the day will further improve the operability of the power system. EV charging in the evening will add to system peaks and so to system costs, so charging infrastructure and tariff design to encourage daytime charging would benefit consumers.

Additional insights on consumer demand (not captured in Figure 20) include:

- Flexible demand response will be used to flatten the shape of operational demand, helping to reduce the need for new firming capacity⁴².

⁴² To enable the scale of demand response potential assumed in later years in some scenarios, market reforms such as those reported on in Section 4.3, may be necessary, as well as acceptance from consumers.

- Operational electricity consumption will increase during winter more than summer, as electrification of heating loads in particular introduces new load, and shorter winter days reduce the output from distributed PV systems.
- Maximum demand in winter is still forecast to be lower than in summer in most regions, however the NEM-wide maximum daily operational consumption is projected to occur in winter, representing a shift from historical trends.
- In the later years, hydrogen production may provide new, flexible load. Electrolyser facilities will operate strongly during periods of excess supply such as during the day when solar production is strongest.

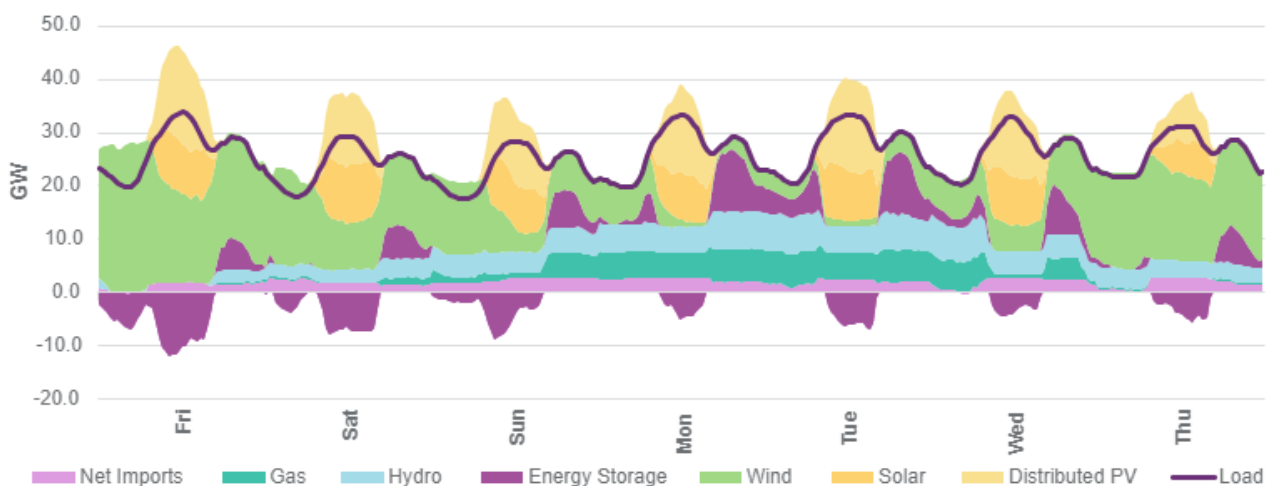
A range of firm, dispatchable resources needed to firm VRE

Figure 21 shows how the different forms of dispatchable capacity interact to deliver electricity to consumers across New South Wales, Victoria, South Australia and Tasmania through a forecast winter week in 2039, using a historically observed set of weather conditions. Queensland consumers are excluded to showcase the dynamics in the other regions more easily, but Queensland generation is available to be imported.

In this sample winter week, weather conditions are calm, cloudy and cool, leading to higher heating loads in the southern regions and limited renewable energy availability. Above 0 on the Y-axis is generation consumed, and below 0 is excess generation stored.

Figure 21 demonstrates why the ISP calls for technological and geographic diversity in the ISP development opportunities, supported by transmission capacity to share resources. In the illustrated week, Queensland and northern New South Wales wind offered reasonable generation, unlike the becalmed sites across the southern mainland and Tasmania. Inland locations for utility-scale PV are less likely to be shaded by cloud than the distributed PV in coastal cities.

Figure 21 A week's dispatch outcomes across the NEM (excluding Queensland), Step Change, 2039



The most severe renewable energy shortfall runs from Sunday to Tuesday, when there is very little wind generation and greater reliance is placed on gas and hydro generation. In support, transmission enables sharing of available firm resources, including surplus renewable energy from Queensland. Storages play a pivotal role. On Friday to Sunday, they absorb abundant renewable energy, particularly during the day when



excess solar generation is available. They then play a strong firming role during the three days of low renewable energy – even discharging throughout Monday night.

Through this modelled week and from season to season, the NEM will draw on a range of different storage types and depths: see the box below. These uses are described through the rest of this section.

Different types and depths of storage

- **Distributed storage** – includes non-aggregated behind-the-meter battery installations designed to support the customer’s own load
- **Coordinated DER storage** – includes behind-the-meter battery installations that are enabled and coordinated via VPP arrangements. This category also includes EVs with V2G capabilities.
- **Shallow storage** – includes grid-connected energy storage with durations less than four hours. The value of this category of storage is more for capacity, fast ramping and frequency control ancillary services (FCAS, not included in AEMO’s modelling) than for its energy value.
- **Medium storage** – includes energy storage with durations between four and 12 hours (inclusive). The value of this category of storage is in its intra-day energy shifting capabilities, driven by the daily shape of energy consumption by consumers, and the diurnal solar generation pattern.
- **Deep storage** – includes energy storage with durations greater than 12 hours. The value of this category of storage is in covering VRE “droughts” (long periods of lower-than-expected VRE availability) and seasonal smoothing of energy over weeks or months.

Medium utility-scale storage needed over the next decade

Figure 22 shows the forecast need for each of the storage types through the *Step Change* scenario. The most obvious feature on the left-hand chart is the projected growth of coordinated DER (see next section) and other distributed storage. However, the most pressing utility-scale need in the next decade (beyond what is already committed) is for storage of 4 to 12 hours duration to manage daily variations in solar and wind output and meet consumer demand as coal capacity declines. This is visible in the left-hand figure, with most utility-scale storage (aqua-coloured bands) shown at medium depth.

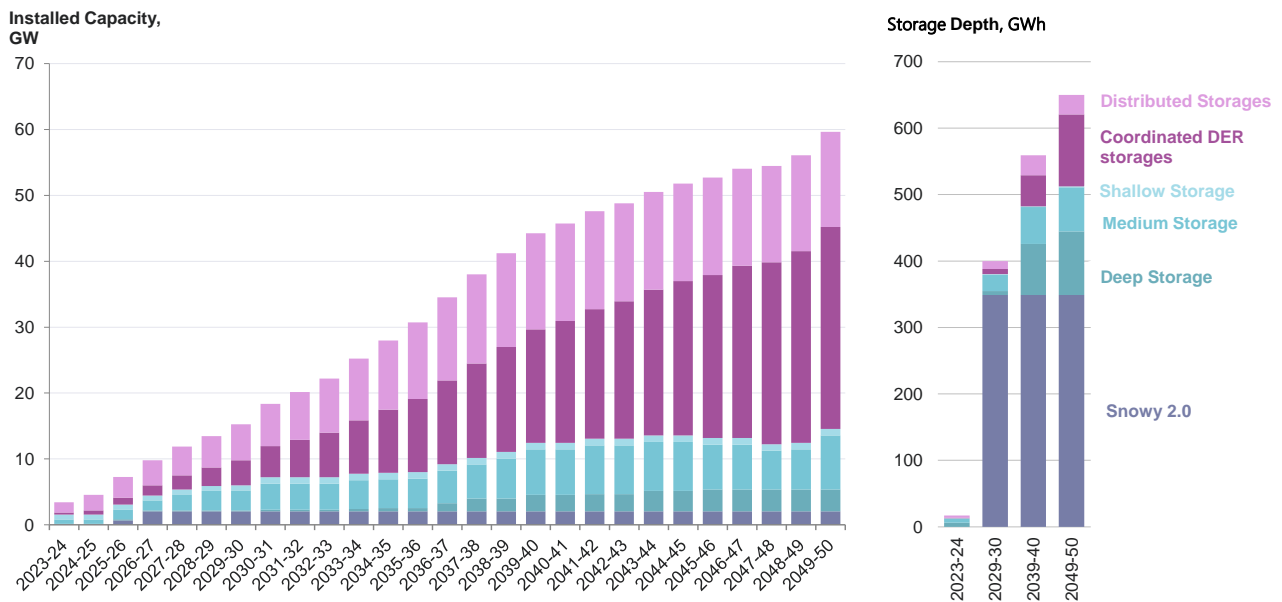
This need for medium-depth storage includes the 2 GW of storage that can be dispatched for at least eight hours, needed by the end of 2029 to help meet the objectives of the New South Wales Roadmap. The 2021 IIO Report⁴³ recognises the supply chain and other issues that may delay delivery of these projects, and allows for contingencies. This delivery risk is not inherently captured in the modelling of the Draft ISP, but is qualitatively considered when selecting the Draft ODP (see Section 6.3.3).

As demonstrated in the right-hand figure, Snowy 2.0 provides much of the necessary additional storage depth to 2030, although additional storage depth is needed in the 2030s and 2040s.

⁴³ At <https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee>.



Figure 22 Forecast of MW storage capacity (left) and energy storage capacity (right), Step Change



Distributed storage to be coordinated with daily PV generation

As shown in Figure 22, distributed storages including coordinated VPPs are forecast to represent almost three-quarters of dispatchable capacity in *Step Change* by 2050. The forecast strong uptake of distributed battery storage over the next decade reduces the need for shallow storage at utility scale⁴⁴. This distributed storage will work in tandem with the daily solar PV generation cycle to smooth out much of the daily curve for NEM operational demand, and reduce the need for traditional generation and firming sources such as coal and gas.

Daily demand and PV supply cycles

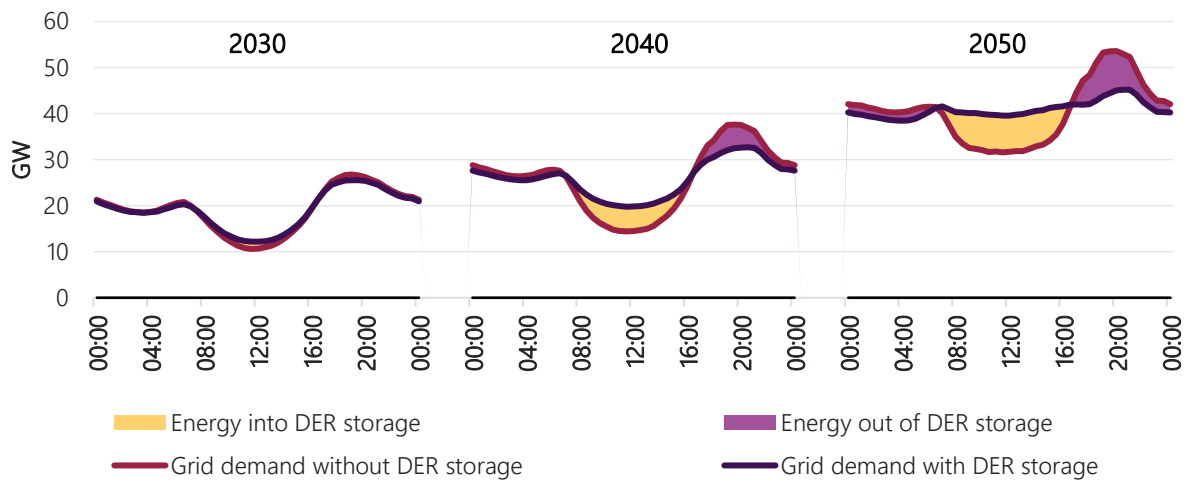
The complementary daily profiles for electricity demand and solar PV generation create a great opportunity for coordinated DER storages to shift energy from day to evening and night.

In Figure 23 below, the red line represents grid demand without the impact of coordinated DER storage. The yellow shape represents excess PV generation through the daylight hours, which is sent into this distributed storage. After 4:00 pm, the evening peak can then draw on that stored energy. The black line represents the resultant grid demand after taking into account the charging and discharging of coordinated DER storage. Without that storage, there would be greater need for traditional hydro and gas-fired generators, as well as utility-scale shallow storage, to meet higher peaks of demand.

⁴⁴ If distributed storage uptake is slower than assumed, more utility-scale shallow storage would be needed instead.



Figure 23 Average time of day profile – impact of co-ordinated distributed storage, Step Change



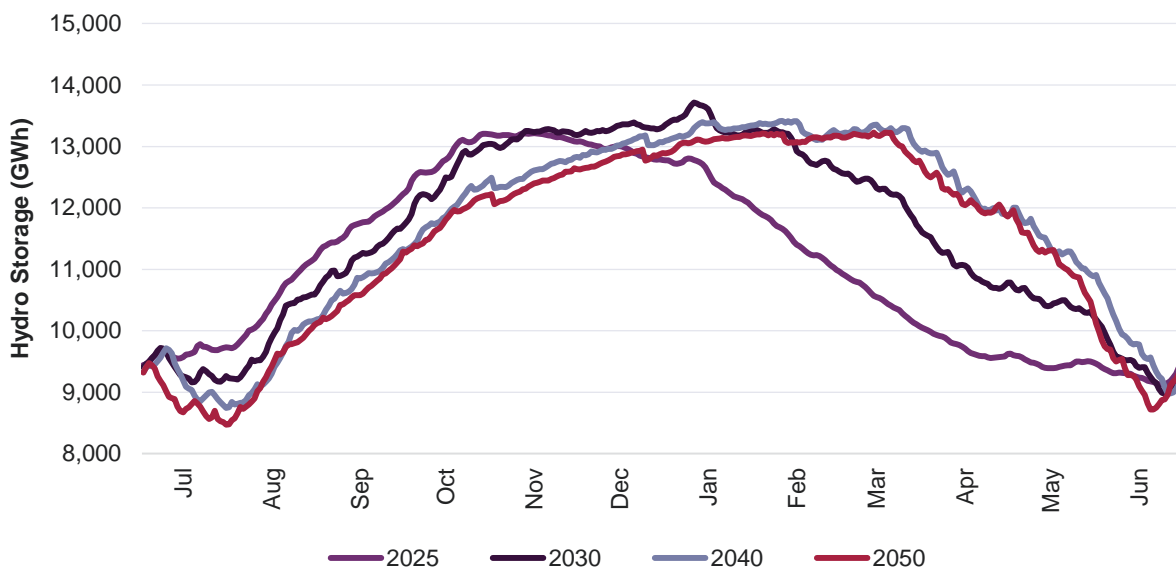
Need for high levels of engagement to coordinate DER storages

The effectiveness of this DER storage depends on it being well coordinated, for example through VPPs. Increasingly active management of consumer devices (through smart, cloud-connected and rule-based devices) will reduce the scale of utility-scale investment needed to maintain the reliability and security of the system. This in turn depends on greater consumer adoption of those smart technologies, with support of retailers, networks and other market participants. This need is further discussed in Section 7.3.

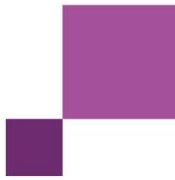
Deep storage to manage seasonal variability

Deeper storage (and traditional hydro generation) will be vital to manage seasonal, and long duration variations in renewable resource availability. Figure 24 shows two aspects of this seasonal cycle that will heavily influence NEM planning and operation.

Figure 24 Daily energy stored in deeper storages and traditional hydro reservoirs over a year



First, the relatively strong spring water inflows (from snow melt) enables traditional deep storages to discharge over the summer. Then, as early as 2030, additional VRE means that less discharge is required over



summer⁴⁵, allowing the stored energy to be held over to autumn where solar generation is lower, and then into winter to meet heating needs as gas appliances are increasingly converted to electricity.

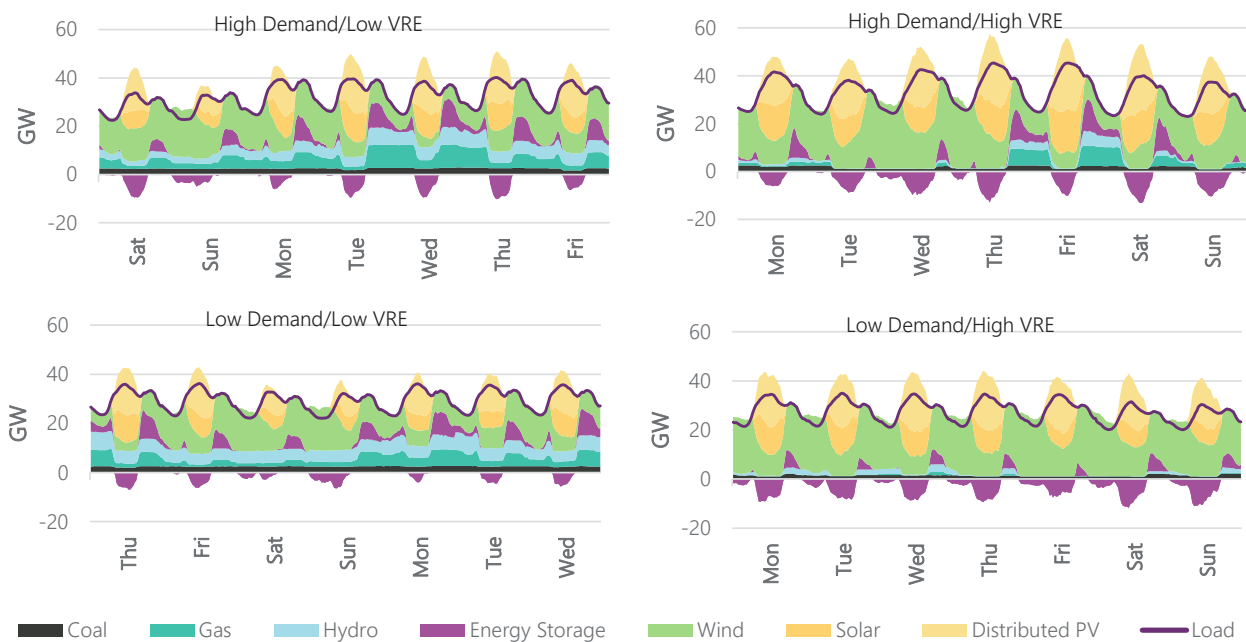
Peaking gas generation needed to balance VRE variability

Gas-fired generation will play a crucial role as significant coal generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability (see Section 4.3).

The development opportunities for gas-fired generation are forecast to primarily be for peaking gas generators, to provide firming. With the cost of VRE declining rapidly in the ISP assumptions, limited opportunities exist for expansion of mid-merit gas plant, unless VRE is limited by transmission access.

In a high renewable penetration grid, the exposure to low VRE availability conditions, and other conditions that provide operability challenges, will likely increase. Gas-fired generation and storage will play an important role in these conditions. Figure 25 shows four additional examples of a week’s variable conditions in 2035. It demonstrates the complementary role that storage, hydro and gas generation will need to play to efficiently operate beside renewable generation.

Figure 25 Indicative generation mix in the NEM, Step Change, 2035



The figure demonstrates four conditions:

- **Low renewable output and high demand (top left):** the system relies more on hydro, and gas, complemented in the evening peak by shallow storage (including VPP) charged from distributed PV and utility-scale solar during the day. Existing mid-merit gas generators assist through the night, with peaking gas generators needed in the evening and occasionally the morning peaks.

⁴⁵ Although minimum releases for environmental or irrigation purposes are still observed.



- **High renewable output and high demand (top right):** gas is needed to meet the demand peaks just after sunset, and to keep going through the night to cover wind variability.
- **Low renewable output and low demand (bottom left):** gas is needed through the night, particularly during winter, when solar output is lower.
- **High renewable output and low demand (bottom right):** With VRE output well in excess of total demand, gas generation is barely needed. Deeper storages fill their reservoirs from the excess energy.

The role of gas as an on-demand fuel source for extended operating periods could also be met by alternative technologies such as hydrogen turbines, or potentially greater investment in long-duration storages. However, under current assumptions, gas remains the most cost effective solution, complementing storages, to firm renewables.

4.3 Stronger services for power system requirements

Just as the NEM's generation and dispatchable resources are transforming, so too will the manner in which the power system services needed to keep the NEM secure and reliable are provided. For example, with fewer synchronous generating units, there are fewer sources of system strength, dynamic reactive support, inertia, primary frequency response and frequency control ancillary services that these units have traditionally provided. Likewise, there are fewer options for black restart services and sources.

There are several actions being taken to ensure these system services support the NEM as it decarbonises and decentralises as projected in this ISP.

- **AEMO's annual System Security Reports⁴⁶** assess the current and five years' projected needs for system strength, inertia and network support and control ancillary services (NSCAS) in the NEM, and declares any shortfalls. The assessments are based on the modelling in this Draft ISP, and demonstrate the growing and accelerating need for system services as the system transforms.
- **AEMO's Engineering Framework⁴⁷** enables industry participants to collaboratively define the operational, technical and engineering requirements for the NEM's future, and informs the market reforms being undertaken by the ESB. It describes the initial roadmap to inform preparation of the NEM for operation under six identified operational conditions⁴⁸, including 100% instantaneous penetration of renewable energy by 2025. These actions will be prioritised with industry and integrated into implementation workplans.
- **Advanced inverters with grid-forming capabilities** and suitable design, placed at strategic sites in the NEM, have the potential to provide a range of future power system requirements. Advanced inverters are not yet demonstrated at the necessary scale to completely replace the services currently provided by synchronous generation in the NEM, and focused engineering is urgently needed to address the remaining issues and realise their promise. To this end, the Australian Renewable Energy Agency (ARENA) is currently exploring the viability of further funding to rapidly prove up the capability of advanced inverters at scale, and hosted a webinar on Monday, 8 November 2021 to gain insight on the

⁴⁶ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability>.

⁴⁷ At <https://aemo.com.au/initiatives/major-programs/engineering-framework>.

⁴⁸ See <https://aemo.com.au/newsroom/news-updates/engineering-framework-takes-shape>.



ability to accelerate advanced inverter capabilities on battery projects and address the associated barriers.

These technical requirements are complemented by numerous regulatory and market reforms underway for essential system services, which are vital to enable participants to invest in and operate infrastructure that will provide system services in addition to energy. The market reforms already implemented or in advanced stages include:

- **Five Minute Settlement and Wholesale Demand Response** to provide better price signals for fast response and flexible technologies, and enable businesses to provide peak shaving services in the spot energy market.
- **The ESB's post-2025 reform recommendations.** Following Ministerial approval of these recommendations, AEMO is working with the AEMC through the rule change process to implement mechanisms for essential system services for the physical power system, and better integration of DER. The ESB has also been tasked by Ministers to undertake further policy work on capacity and network congestion mechanisms for consideration in late 2022. Given the amount of reform underway, AEMO is also working with industry to develop a NEM Regulatory and IT Implementation Roadmap, aiming to reduce reform implementation costs and risks.
- **Fast frequency response (FFR) market for ancillary services**, designed to provide faster frequency control services. AEMO is required to design and put in place these market arrangements by October 2023.⁴⁹
- **Efficient management of system strength**, to address the urgent need to make it simpler, faster and more predictable for new generation, renewables in particular, to connect to the grid while keeping supply as secure as possible.
- **Primary frequency response (PFR) incentives.** A Rule change consultation by the AEMC is currently underway⁵⁰, to examine arrangements supporting the control of power system frequency and to incentivise plant behaviour with the aim of reducing overall consumer costs.

⁴⁹ AEMC Fast Frequency Response market ancillary service, at <https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service>.

⁵⁰ See <https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements>.



Part C

The Draft Optimal Development Path

Part B presented a re-imagined future power system that will require community support for large amounts of renewable resource and dispatchable generation to achieve the decarbonisation goals for the NEM.

AEMO has now conducted a rigorous analysis of the network investments needed to serve that power system, and the optimal path for their development.

This Part C presents:

- **Section 5: The Draft ODP and its network investments.** The Draft ODP defines the project and timing of 22 network investments, together with the ISP development opportunities set out in Part B. If these network investments are completed, they would deliver over \$29 billion in net market benefits to consumers, while fulfilling public policy needs, security, reliability and sustainability expectations, and managing risk through a complex transformation, and
- **Section 6: The rationale that supports the Draft ODP**, in particular, the timing and early works of the actionable ISP projects, following the steps set out in the *ISP Methodology*.

AEMO stresses that the draft ODP integrates both network projects and ISP development opportunities. The network projects are key to enabling the development of the VRE, storage and gas-fired generation discussed. Changing one set is likely to render both the other set, and the whole, sub-optimal.



5. The optimal development path

The ODP identified in this Draft 2022 ISP is a Draft ODP, and is based on information published in the 2021 IASR⁵¹, with minor updates to key generation information made available in October 2021. AEMO welcomes comment and feedback through the extensive consultation process detailed in Section 9, before the ODP is settled in the final 2022 ISP.

The Draft ODP comprises both the ISP development opportunities described in Part C, and the network investments described in this Section 5. This section lays out:

- an overview of the committed, anticipated, actionable and future ISP projects that are included in the Draft ODP, and the \$29 billion in net market benefits that these network investments deliver for the NEM's consumers, and
- key information for actionable ISP projects including the identified need, estimated cost, and any applicable decision rules.

The detailed analysis leading to the selection and timing of these network investments is set out in Section 6.

5.1 The Draft ODP and its benefits

The Draft ODP would:

- provide a reliable and secure power supply
- deliver \$29 billion in net market benefits⁵² by saving costs elsewhere
- be resilient to events that can adversely impact future costs to consumers
- retain flexibility to decarbonise the NEM faster than currently planned, particularly in *Step Change*, considered by stakeholders to be the most likely scenario, and
- be relatively insensitive to changes in input assumptions.

Network investments in the Draft ODP

The following network investments are identified as part of the Draft ODP in Figure 26 and through Sections 5.2 to 5.4. Further details on each project are set out in Appendix 5. Together, these projects comprise over 10,000 km of new network investment that is a critical enabler for the resources that comprise the Draft ODP.

- **Committed and anticipated projects** – Eyre Peninsula Link, Queensland – New South Wales Interconnector (QNI) Minor, VNI Minor, VNI System Integrity Protection Scheme (SIPS), Central West Orana REZ Transmission Link, Northern QREZ Stage 1, Project EnergyConnect (PEC), and Western Victoria Transmission Network Project.
- **Actionable ISP projects** – Marinus Link (cable 1 and 2), VNI West (via Kerang) staged with decision rules, HumeLink staged with decision rules, New England REZ Transmission Link, and Sydney Ring (the project to reinforce Sydney, Newcastle, and Wollongong supply).

⁵¹ Minor updates to inputs and assumptions are outlined in the 2021 Inputs and Assumptions workbook, available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

⁵² Net present value (NPV) of annual net market benefits from 2021-22 to 2050-51, weighted across the scenarios by their relative likelihood – see Section 2.3 for scenario weightings.

- **Future ISP projects** – Darling Downs REZ Expansion, South East South Australia A REZ Expansions, Far North Queensland REZ Expansion, Facilitating Power out of North Queensland, Facilitating Power to Central Queensland, Gladstone Grid Reinforcement, Central to Southern Queensland, QNI Connect, New England REZ Extension, and South West Victoria REZ Expansion.

Benefits of the network investments

The Draft ODP is calculated through the *ISP methodology* to offer \$29 billion in net market benefits for consumers. This is the probability-weighted average of the net present value (NPV) of net annual benefits offered to 2050-51 in the four modelled scenarios.

The benefits of the new network infrastructure rise as the speed of the NEM's emission reductions accelerate, with higher benefits in scenarios with faster reductions in emission intensity. The network investments in the ODP deliver up to \$4 billion in net market benefits in the *Slow Change* scenario, \$16 billion in *Progressive Change*, \$26 billion in *Step Change*, and \$70 billion in *Hydrogen Superpower* (see Table 5 below).

These benefits highlight the value of network investments in an efficient power system transformation. They allow NEM consumers to secure the full benefit of zero-emission VRE generation, which will become even more cost-efficient over the ISP horizon. Without that transmission, the NEM would require more expensive generation capacity nearer to load centres – either offshore wind, or gas-fired generation with carbon capture and storage (CCS) projects to manage its cumulative emissions. These technologies have higher capital costs than VRE⁵³, in addition to the fuel costs associated with gas generation.

Table 5 Market benefits of the Draft ODP (\$M, NPV)

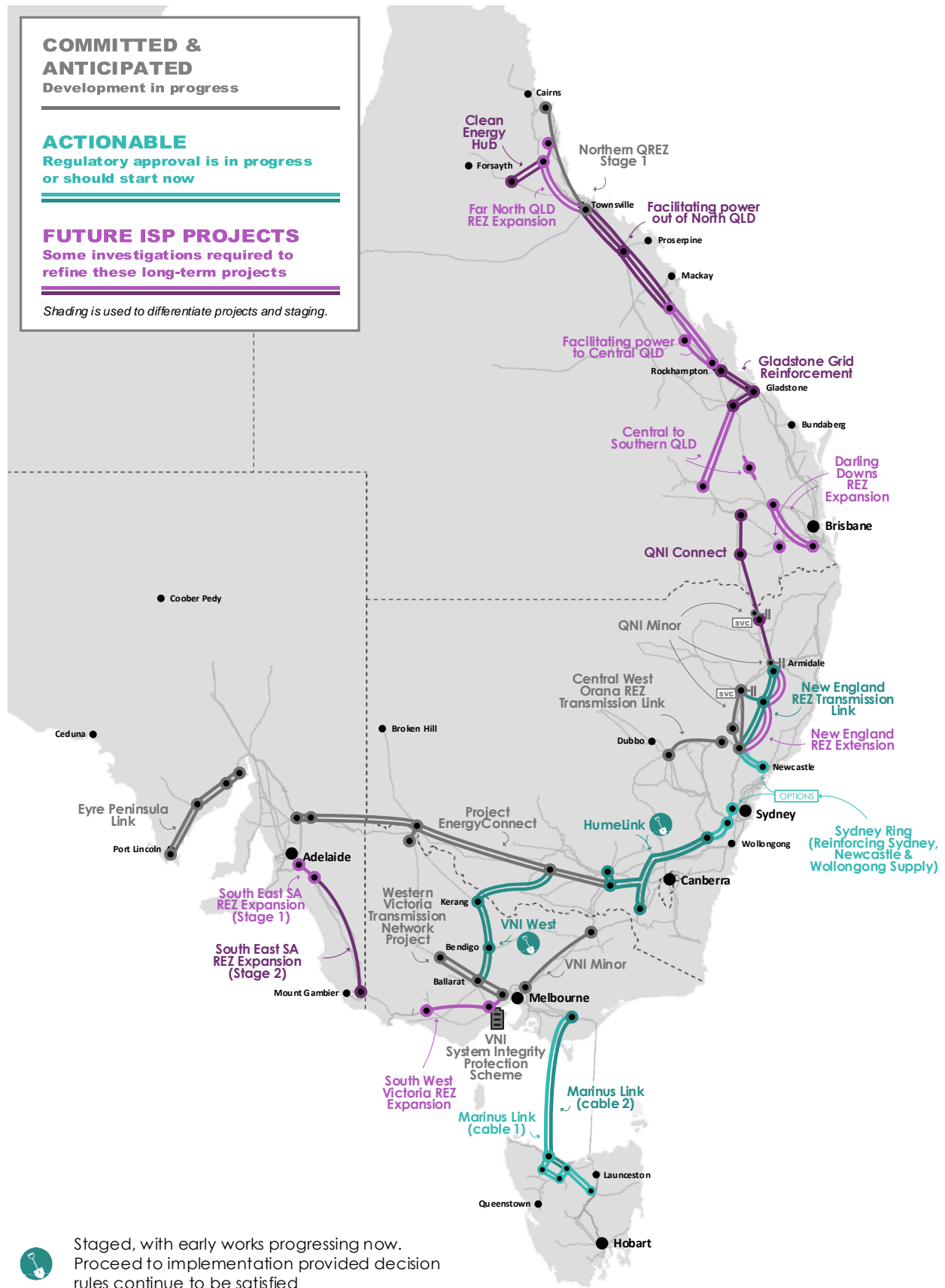
Class of market benefit	Slow Change	Progressive Change	Step Change	Hydrogen Superpower	Scenario weighted
Scenario weighting	4%	29%	50%	17%	
Generator and storage capital deferral	5,239	10,091	19,533	60,970	23,267
FOM cost savings	810	1,190	2,778	16,268	4,500
Fuel cost savings	3,853	13,388	15,205	7,897	12,827
VOM cost savings	-106	278	361	21	265
USE+DSP reductions	9	20	-120	3,649	566
Gross market benefits	9,806	24,966	37,757	88,805	41,215
Network projects (Flow paths⁵⁴)	-6,281	-7,018	-8,686	-10,650	-8,189
Network projects (REZ expansion)	-170	-1,748	-3,477	-7,957	-3,598
Total network cost⁵⁵	-6,451	-8,766	-12,163	-18,607	-11,787
Total net market benefits	3,355	16,199	25,594	70,198	29,428
Return on investment (ratio)	0.5	1.8	2.1	3.8	2.5

⁵³ CSIRO. *GenCost 2020-21*, at https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

⁵⁴ Flow paths are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected network to load centres.

⁵⁵ This does not reflect the full capital investment in network in today's dollars, but rather the NPV of the equivalent annuity calculated from time of commissioning to 2050-51.

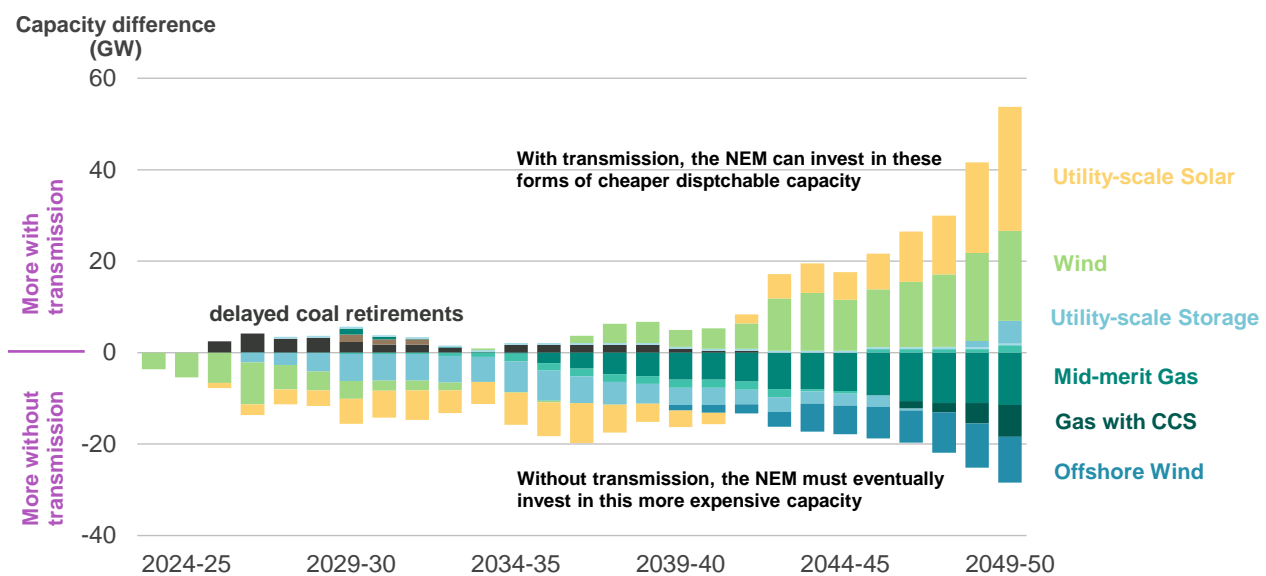
Figure 26 Map of the network investments in the optimal development path



†Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown in this map. See Appendix 5 for more information.

Figure 27 below sets out these advantages in terms of the generation capacity that is needed over the ISP horizon in *Step Change*, with and without the network investments of the Draft ODP. For the first 15 years or so, the NEM can continue to invest in solar, wind and storage without additional transmission. From then, the need for gas generation and offshore wind grows, rather than the cheaper wind and solar generation available with transmission. As well, two sets of costs are incurred to keep the NEM within its assumed carbon budget. First, coal is withdrawn earlier than otherwise needed to leave more of the carbon budget for the end of the ISP horizon. Then, additional CCS is needed to capture and store emissions from the additional gas generation needed in the late 2040s.

Figure 27 Differences in capacity needed in *Step Change*, with and without new network



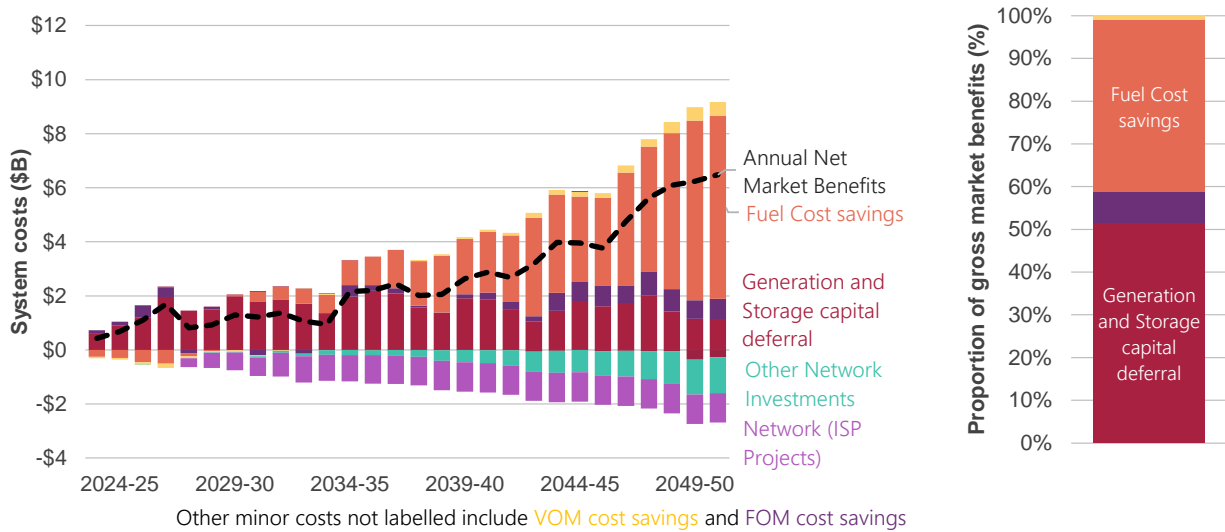
Through network investment, cost savings can therefore be delivered for consumers:

- **in the next 15 years**, by keeping slightly more coal in the system and therefore delaying the need for some VRE and storage while still achieving the same decarbonisation outcomes over the ISP horizon,
- **in the longer term**, by avoiding the need to rely on greater volumes of gas-fired generation and more costly generation technologies such as off-shore wind (and associated fixed operating and maintenance [FOM] costs). This benefit increases over time and will continue to be realised beyond the ISP's 2050 planning horizon.

Of the total benefits, 50% are from generation capital cost reductions, and 40% from fuel cost savings (see Figure 28). Fuel cost savings are a larger part of the annual savings from 2041 onwards. However, the earlier savings in generation capital costs contribute the most overall, due to the time value of money. (For this reason, the Draft ODP is tested against material changes to discount rates and gas prices: see Section 6.4.)

The contributions of each network investment to the overall ODP benefits are discussed in Section 5.3 below.

Figure 28 Net market benefits by benefit category, Step Change least-cost development path



5.2 Committed and anticipated network projects

The earliest projects in the Draft ODP already have regulatory approval and are highly likely to proceed. They are therefore included in the modelling for all development paths, scenarios and sensitivities. Table 6 below gives an overview of:

- **committed network projects**, which meet all five commitment criteria in the *ISP methodology*⁵⁶ (relating to site acquisition, components ordered, planning approvals, finance completion and set construction timing), and
- **anticipated network projects**, which are in the process of meeting at least three out of the five criteria, and have been consulted on through the IASR.

Table 6 Committed and anticipated network investments in the optimal development path

Project	Estimated timing	Description	Regulatory status
VNI SIPS	Summer 2021-22	A system integrity protection scheme (SIPS) that will increase VNI import capabilities by up to 250 MW from November to March each year.	Committed
QNI Minor	July 2022	An incremental upgrade to the transfer capacity of the existing QNI.	Committed
Eyre Peninsula Link	Dec 2022	A network upgrade that will improve reliability and network capacity on the Eyre Peninsula in South Australia.	Committed
VNI Minor	Sept 2023	An incremental upgrade to the transfer capacity of the existing VNI.	Committed
Northern QREZ Stage 1	Nov 2023	A network upgrade to provide additional capacity to the Far North Queensland REZ.	Anticipated
Project EnergyConnect	Jul 2025	A new 330 kilovolt (kV) double-circuit interconnector between South Australia and New South Wales.	Anticipated
Central West Orana REZ Transmission Link	Mid-2025	A network upgrade to provide additional capacity to the Central West Orana REZ.	Anticipated
Western Victoria Transmission Network Project	July 2026	A network upgrade to provide additional capacity to the Western Victoria REZ.	Anticipated

⁵⁶ At <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology>.



5.3 Actionable ISP projects

Actionable ISP projects deliver positive net market benefits to consumers in the most likely scenario if progressed before the next ISP. They are identified in Table 7 below, with further information below the table and the complete technical information for each project in Appendix 5.

The optimal timing for completion in *Step Change* shown in Table 7 is generally within two years of the estimated earliest completion year, which includes any subsequent testing and release of network capacity, but does not allow significant contingency for schedule slippage. Note also that the optimal timings depend in part on other network projects, as identified through the ISP, rather than through an assessment that focuses on a project in isolation.

For actionable ISP projects identified in the final 2022 ISP, the relevant TNSP must assess the project under the RIT-T (as relevant), including selecting any relevant project option in accordance with the requirements of this ISP.

Table 7 Actionable network investments in the optimal development path

Project	Timing	Description	RIT-T Status
New England REZ Transmission Link	July 2027	Transmission network augmentations as defined in the New South Wales Electricity Strategy, costing \$1.9 billion \pm 50%.	Not started†
Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply)	July 2027	High capacity 500 kV transmission network to reinforce supply to Sydney, Newcastle and Wollongong load centres. Cost estimates of \$0.9 billion \pm 50% for northern option, and \$2.25 billion \pm 50% for southern alternative option.	Not started†
HumeLink staged with decision rules	Stage 1 (early works): now Stage 2 (implementation): targeting July 2026 subject to decision rules and feedback loop	A 500 kV transmission upgrade connecting the Snowy Mountains Hydroelectric Scheme to Bannaby. Cost estimates of \$330 million (stage 1)‡ and \$2,985 million (stage 2).	Nearing completion†
Marinus Link	July 2027* (cable 1) July 2029 (cable 2)	Two new HVDC cables connecting Victoria and Tasmania, each with 750 MW of transfer capacity and associated alternating current (AC) transmission, costing \$2.3 billion \pm 15% (cable 1) and \$1.2 billion \pm 15% (cable 2).	Completed
VNI West staged with decision rules	Stage 1 (early works): now Stage 2 (implementation): targeting July 2031, subject to decision rules and feedback loop	A new high capacity 500 kV double-circuit transmission line to connect the Western Victoria Transmission Network Project (north of Ballarat) with Project EnergyConnect (at Dinawan) via Kerang, costing \$491 million (stage 1) and \$2.5 billion** (stage 2).	In progress

† This project could proceed under the alternate planning arrangements under the New South Wales Government's Electricity Infrastructure Roadmap, at <https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap>.

‡ The preliminary high-level estimate for early works of \$330 million has been provided by Transgrid and is based on a top-down estimate which is currently being reviewed, developed and refined for a planned contingent project application in 2022.

* TasNetworks had now advised that the earliest full commissioning date for the first cable is July 2029 (750 MW, with 250 MW available in 2028) and the second cable in July 2031 (a further 750 MW, with 250 MW available in 2030), later than what has been assumed for this modelling. The cost of the first cable is now reported as \$2.3 billion, which includes early works and escalation from 2020 to 2021 dollars. While the timing information was received too late to incorporate in this Draft ISP, AEMO will investigate the impact of this delayed schedule for the final 2022 ISP. Progressing the project to enable commissioning as early as possible is still the correct course of action for this project to optimise benefits for consumers.

** Estimates for costs for the New South Wales works on VNI West include estimates provided by Transgrid. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.



New England REZ Transmission Link

The New England REZ Transmission Link was a future ISP project in the 2020 ISP, and is now an actionable ISP project to commence immediately, given the lead time required, for delivery in 2027-28. It is also identified as a REZ-critical project in AEMO Services' 2021 IIO report.

Optimal benefits and timing

The rationale for the New England REZ Transmission Link being included as part of the Draft ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

New England REZ Transmission Link contributes roughly \$5.5 billion of the \$26 billion in net market benefits delivered by the draft ODP in the most likely scenario, and is also part of all other high-ranking candidate development paths. It will unlock approximately 5,820 MW of VRE and storage capacity in the New England REZ, helping meet the objectives of both the New South Wales Electricity Infrastructure Roadmap and the 2021 IIO report.⁵⁷ ISP modelling suggests that New England has the potential to become one of the largest REZs in the NEM (see Figure 14), so without the New England REZ Transmission Link there would be costly investment in more expensive, larger-scale and/or poorer quality alternative resources likely.

The optimal delivery time is 2027-28 for all scenarios. If it were delayed by two years, its net market benefits would reduce by \$110 million (scenario weighted) and it would contribute an additional \$500 million to the regret cost of the transmission investments, due to under-investment in *Hydrogen Superpower*. Considering the likelihood of the scenarios, the weighted regret of under-investment reduces to approximately \$80 million.

The project is estimated to cost \$1.9 billion \pm 50%. At the higher end of this cost range, the project is still optimally timed for delivery in 2027-28, but only just. Its status as an actionable ISP project is not affected by materially higher discount rates, materially lower gas prices, or any other variations in inputs tested through sensitivity analysis (see Section 6.4).

Identified need

The identified need for this project is:

To increase the capability of the transmission network to enable the connection of expected generation in the New England REZ:

- *increasing the transfer capacity between expected generation in the New England REZ and the existing transmission network in the Hunter region, and*
- *ensuring sufficient resilience to avoid material reductions in transfer capacity during an outage of a transmission element*

or as otherwise consistent with the New South Wales Government's Electricity Infrastructure Roadmap.

Next steps

To inform the RIT-T process⁵⁸, AEMO has specified the following parameters for this project:

- **Project Assessment Draft Report (PADR) deadline:** 8 December 2023.

⁵⁷ At <https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee>.

⁵⁸ The New England REZ Transmission Link project may be progressed under the *Electricity Infrastructure Investment Act 2020* (NSW).



- **The RIT-T proponent:** Transgrid.
- **Scenarios to be assessed:** Step Change (100%) – AEMO has selected one scenario because the optimal timing for this project does not vary across scenarios (see Table 9).
- **ISP candidate options** that must be assessed in the RIT-T: The project is a sequence of 330 kilovolt (kV) and 500 kV network upgrades between New England and the Hunter region, with options and potential staging (see Appendix 5).
- **Non-network options** have not been assessed yet but are subject to consultation (see Section 8.3).

Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply)

The Reinforcing Sydney, Newcastle, and Wollongong Supply project was a future ISP Project in the 2020 ISP, and is now an actionable ISP project. It is also identified as a REZ-critical project in AEMO Services' 2021 IIO report.

The project increases transfer capacity into the Sydney, Newcastle and Wollongong area by approximately 5,000 megawatts (MW). It should commence immediately, to support REZ development in the New South Wales Government's Electricity Infrastructure Roadmap and maintain reliability of supply for New South Wales consumers.

Optimal benefits and timing

The rationale for Sydney Ring being included as part of the draft ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

Sydney Ring contributes roughly \$3.4 billion of the \$26 billion in net market benefits delivered by the Draft ODP in the most likely scenario, and is also part of all other high-ranking candidate development paths. The project would maintain reliability of supply for New South Wales consumers following the closure of coal in the Newcastle area. Alternatives may be available but in AEMO's analysis would come at a much higher cost for consumers than the reinforcement project. The alternatives include peaking support and annual energy production in close proximity to Sydney's major loads, local battery storages to manage intra-day peak variations, nearby deeper storages to support energy transfers into the Sydney Ring at other times, offshore wind projects that connect to existing transmission corridors, and greater voluntary load reductions (to be compensated appropriately).

The optimal timing in all scenarios other than the unlikely *Slow Change* is as soon as possible (assumed to be by 2027–28). If it were not actionable until the 2024 ISP, its net market benefits would reduce by \$140 million (scenario-weighted) and its worst regret cost would increase by approximately \$200 million due to under-investment in *Hydrogen Superpower*. Considering the likelihood of the scenarios, the weighted regret of under-investment reduces to approximately \$40 million.

Depending on route, the project is estimated to cost between \$0.9 billion (northern option) and \$2.25 billion (southern option) $\pm 50\%$. At the higher end of the northern options' cost range, and the middle of the range for the southern option, the project is still clearly optimally timed for delivery in 2027-28. Significant cost increases above \$2.25 billion have not been tested but could lead to delays in the project's optimal timing. Its status as an actionable ISP project is not affected by materially higher discount rates, materially lower gas prices, or any other variations in inputs tested through sensitivity analysis (see Section 6.4).



Identified need

The identified need for the Sydney Ring project is:

Deliver net market benefits for consumers by increasing the power system's capability to supply the Sydney, Newcastle and Wollongong load centres, replacing supply capacity that will be removed on the closure of coal-fired power stations in the Newcastle area.

Next steps

To inform the RIT-T process⁵⁹, AEMO has specified the following parameters for the Sydney Ring project:

- **PADR deadline:** 8 December 2023.
- **The RIT-T proponent:** Transgrid.
- **Scenarios to be assessed:** *Step Change* (100%) – AEMO has selected one scenario because the optimal timing only varies in the *Slow Change* scenario (which has a 4% relative likelihood and therefore does not materially impact the weighted net market benefits or weighted worst regret). See Table 9 for information on optimal timing.
- **ISP candidate options** that must be assessed in the RIT-T: Two options are specified in Appendix 5 – a northern 500 kV option and a southern 500 kV option. These options do not include staging.
- **Non-network options** have not been assessed yet but are subject to consultation (see Section 8.3).

HumeLink

HumeLink was an actionable ISP project in the 2020 ISP. It is now a staged actionable ISP project with a decision rule.

- **Stage 1** of the HumeLink project is to complete the early works by 2024.
- **Stage 2** is to complete implementation of the project – a proposed 500 kV transmission project that links the greater Sydney load centre with the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect in South West NSW.

Optimal benefits and timing

The rationale for HumeLink being included as part of the Draft ODP is set out extensively step-by-step in Section 6 below, and in Appendix 6, and is summarised here. This analysis suggests that staging HumeLink, with early works as the first stage, would best align with consumer risk preferences.

HumeLink contributes roughly \$1.3 billion of the \$26 billion in net market benefits delivered by the Draft ODP in the most likely scenario and delivers value in all scenarios, it is just a matter of when. The net market benefits of HumeLink accrue once a fourth New South Wales coal-fired power station (including Liddell) retires. The optimal timing of HumeLink therefore depends heavily on the timing of projected coal retirement. Without HumeLink, investment in more long-duration storage would be required to maintain power system reliability in New South Wales.

⁵⁹ The Sydney Ring project may be progressed under the *Electricity Infrastructure Investment Act 2020* (NSW).



The Actionable ISP Rules, made by the AER, have governed the market benefits assessment for all projects in this ISP. Under this framework, the strictly rules-based optimal timing is for HumeLink to be completed by 2028-29 in *Step Change* and 2035-36 in *Progressive Change*. This is as a result of significant cost increases as provided by TransGrid, the additional investments in dispatchable capacity made since the 2020 ISP, and the dependency on completion of the Sydney Ring reinforcement to realise the full benefits of HumeLink.

However, it is AEMO's assessment that the project would optimise benefits to consumers if it were staged, targeting delivery by 2026-27. This would protect consumers against schedule slippage or further coal closures, while retaining the option to pause the project if circumstances change. It is the only identified actionable ISP transmission project that could be delivered in that timeframe to help mitigate these risks.

Proceeding now in this way would avoid \$200 million of regret associated with having the project delivered too late in *Step Change*, either due to schedule slippage or earlier than expected closures. On the other hand, making HumeLink actionable now without staging, to be ready by its earliest delivery date (2026-27), would reduce the scenario-weighted net market benefits of the ODP by \$280 million on current costs.

Introducing a first, early works stage would reduce that deficit to just ~\$20 million or 0.1%, while mitigating against the risk the project is not delivered in time. There would only need to be a 10% possibility of a two-year project delay to make staging of HumeLink part of the development path that would deliver the highest net market benefits for consumers. Similarly, there would only need to be a 10% chance of Vales Point, Eraring and either Mount Piper or Bayswater closing by 2027-28 for staging to optimise benefits for consumers. This impact would be similar if storage of at least eight hours duration, assumed to be developed to help firm renewables as coal closes, did not materialise in time. As well, targeting 2026-27 would be \$180 million less regretful in *Hydrogen Superpower* as the project can proceed in the timeline needed.

Nonetheless, protection is needed against rising project costs. To ensure the benefits are robust, the project costs cannot materially increase from the current estimate of \$3.3 billion. Further work to drive down costs should be undertaken urgently and, if necessary, a government co-contribution could be considered in recognition of the broader economic and societal value this project delivers (see Section 7.3). The early works would also help reduce cost uncertainties, and so build greater consumer confidence that they will not be over- or under-investing. As part of any feedback loop between stage 1 and stage 2, net market benefits will be reassessed to confirm the project still remains part of the ODP in the latest ISP.

For HumeLink, as in other staged projects, the early works costs are incurred early and the benefits potentially accrued later in scenarios where the project is paused. This makes staging particularly sensitive to higher discount rates (see Section 6.4).

Identified need

The identified need for this HumeLink project has not changed since the 2020 ISP:

To deliver a net market benefit by:

- *increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong*
- *enabling greater access to lower cost generation to meet demand in these major load centres; and*
- *facilitating the development of renewable generation in high quality renewable resource areas in southern New South Wales, which will further lower the overall investment and dispatch costs in meeting New South Wales demand while also ensuring emissions targets are met at the lowest overall cost to consumers.*



Draft decision rules and next steps

Transgrid is nearing completion of a RIT-T⁶⁰ to determine the preferred option for the HumeLink project⁶¹.

The next milestone for the project is the ISP feedback loop, which will assess whether the preferred option identified in the RIT-T remains aligned with the ODP in the most recent ISP. Because the HumeLink project is staged, the feedback loop will consider the alignment and cost of the first stage, while also having regard to the total project cost. If the feedback loop is successfully completed, Transgrid may then request funding for early works via a contingent project application with the AER.

- **Decision rules** are as follows:

After completion of Stage 1 (early works), the HumeLink project is to progress to Stage 2 (implementation) unless any of the following occur:

(a) there are new commitments that increase the likelihood that either:

- (i) material volumes of existing dispatchable capacity are retained in New South Wales; or
- (ii) material volumes of new dispatchable capacity are developed in New South Wales beyond what is currently assumed in the Step Change scenario, or

(b) the total project cost (including the cost of completed early works) has materially increased from the current cost estimate of \$3.3 billion.

- **Early works** for HumeLink may include:

- **Project initiation** – planning and design activities needed to accurately define the project, including pre-contracting activities for engineering, procurement and construction contracts such as obtaining binding bids.
- **Stakeholder engagement** – with local communities, landowners and other stakeholders.
- **Land-use planning** – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection, easement acquisition and preparation of option agreements with landowners.
- **Detailed engineering design** – transmission line, structure and substation design, detailed engineering design and planning.
- **Cost estimation** – finalisation, including quotes for primary and secondary plant.

Marinus Link

Marinus Link was a staged actionable ISP project with decision rules in the 2020 ISP and is now a single actionable ISP project without decision rules. Decision rules in the 2020 ISP relating to the Tasmanian Renewable Energy Target (TRET) and cost allocation are no longer required because TRET was legislated in November 2020 and cost allocation risks are instead recognised as a key project risk (see Section 7.2).

⁶⁰ Transgrid. *HumeLink RIT-T*, at <https://www.transgrid.com.au/projects-innovation/humelink>.

⁶¹ The HumeLink project may be progressed under the *Electricity Infrastructure Investment Act 2020* (NSW).



Optimal benefits and timing

The rationale for Marinus Link being included as part of the draft ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

Marinus Link contributes roughly \$4.6 billion of the \$26 billion in net market benefits delivered by the Draft ODP in the most likely scenario, and is also part of all other high-ranking candidate development paths. Marinus Link provides improved access to Tasmania's dispatchable capacity (including deep storages) and high quality VRE opportunities, helping reduce the scale of investment needed on the mainland. Wind farms located in Tasmania (particularly Tasmania's Central Highlands and North-West REZs) produce more energy than almost all REZs on the mainland, and also provide greater resource diversity to mainland wind farms. Without improved access to these resources, more mainland capacity would be required for the equivalent volume of energy, which would increase system costs all else being equal.

The optimal delivery of Marinus Link in the most likely *Step Change* scenario is 2027-28 for Cable 1, and 2029-30 for Cable 2, so that it is actionable now with no regulatory staging requirements. It would be two years later in *Progressive Change*, however this delay would reduce scenario-weighted net market benefits by \$40 million (scenario weighted) and increase the regret of under-investing in *Hydrogen Superpower* by \$650 million. Considering the likelihood of the scenarios, the weighted regret of under-investment reduces to approximately \$110 million.

The project is estimated to cost \$2.3 billion $\pm 15\%$ (cable 1) and \$1.2 billion $\pm 15\%$ (cable 2). At the higher end of this cost range, the project is no longer optimally timed for delivery as soon as possible, but the regret of having invested too early is small (less than \$20 million). Its status as an actionable ISP project is not affected by materially higher discount rates, materially lower gas prices, or any other variations in inputs tested through sensitivity analysis (see Section 6.4).

Identified need

The identified need for the Marinus Link project has not changed since the 2020 ISP:

The characteristics of customer demand, generation and storage resources vary significantly between Tasmania and the rest of the NEM. Increased interconnection capacity between Tasmania the other NEM regions has the potential to realise a net economic benefit by capitalising on this diversity.

Next steps

TasNetworks has completed a RIT-T to determine the preferred option for Marinus Link. The next step in the regulatory approval process for this project is the feedback loop.

VNI West

VNI West (via Kerang) remains a staged actionable ISP project as it was in the 2020 ISP, but with an updated decision rule.

- **Stage 1** is to carry out early works that are needed to ensure the project can be delivered by July 2031.
- **Stage 2** is to complete implementation of the project – a proposed 500 kV interconnector from a substation near Ballarat in Victoria to a new substation named Dinawan in South West New South Wales.



Optimal benefits and timing

The rationale for VNI West being included as part of the draft ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

VNI West contributes roughly \$1.9 billion of the \$26 billion in net market benefits delivered by the Draft ODP in the most likely scenario, and delivers value in all scenarios. It will increase access to Snowy 2.0's deep storages and other firming capacity, support new VRE needed to replace coal generation (particularly in the Murray River and Western Victoria REZs), provide greater system resilience to earlier than projected coal closures, secure the fuel cost savings of needing less gas for generation, and reduce VRE curtailment by sharing geographically diverse VRE.

The optimal timing for delivery of VNI West was explored through multiple CDPs. In *Step Change*, it would be needed by July 2031. That need would be delayed if there was greater certainty that coal retirements were unlikely to be accelerated (in the *Progressive Change* scenario or otherwise). By staging the project, with early works as the first stage, the option to pause delivery is retained. This option increases net market benefits by \$40 million (scenario weighted) and reduces the regret of over-investing in *Progressive Change* and *Slow Change* by up to \$270 million. Considering the likelihood of the scenarios, the weighted regret of over-investment reduces by approximately \$30 million, compared to not staging the project and instead proceeding in full.

Staging also allows the project to be delivered as quickly as possible under *Step Change* and *Hydrogen Superpower*, or if there are earlier than expected coal closures (other than Yallourn), which would increase the project's value by \$530 million in *Progressive Change* if this occurred.

Nonetheless, protection is needed against rising project costs. To ensure the benefits are robust, the project costs cannot materially increase from their current estimate of \$2.9 billion. As part of any feedback loop between stage 1 and stage 2, net market benefits will be reassessed to confirm the project still remains part of the ODP in the latest ISP.

For VNI West as in other staged projects, the early works costs are incurred early and the benefits potentially accrued later in scenarios where the project is paused. This makes staging particularly sensitive to higher discount rates (see Section 6.4).

Identified need

The identified need for the VNI West project has not changed since the 2020 ISP:

To increase transfer capacity between New South Wales and Victoria to realise net market benefits by:

- *efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in aging generator reliability – including mitigation of the risk that existing plant closes earlier than expected*
- *facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres, and*
- *enabling more efficient sharing of resources between NEM regions.*



Draft decision rules and next steps

VNI West was determined to be an actionable ISP project in the 2020 ISP, and the RIT-T for this project has already been initiated. AEMO specifies the following parameters for the VNI West project:

- **PADR deadline:** 31 August 2022.
- **The RIT-T proponent:** AEMO (Victorian Planner) and Transgrid.
- **Scenarios to be assessed:** *Step Change* (52%), *Progressive Change* (30%) and *Hydrogen Superpower* (18%) – AEMO has not included the *Slow Change* scenario because it carries a low likelihood (4%) and the optimal timing is similar to the *Progressive Change* scenario.
- **ISP candidate options** that must be assessed in the RIT-T: AEMO identifies one option (VNI West via Kerang) to be delivered in two stages – early works, then implementation if decision rules are satisfied. The technical specifications of this option are provided in Appendix 5.
- **Non-network options** were not assessed in this Draft ISP but are currently being assessed as part of the RIT-T.
- **Decision rules** are as follows:
 - After completion of Stage 1 (early works), the VNI West project is to progress to Stage 2 (implementation) unless any of the following occur:
 - (a) there are new commitments that increase the likelihood that either:
 - (i) material volumes of existing dispatchable capacity are retained in New South Wales or Victoria, or
 - (ii) material volumes of new dispatchable capacity are developed in those regions beyond what is currently assumed in the Step Change, or
 - (b) the total project cost (including the cost of completed early works) has materially increased from the current cost estimate of \$2.9 billion.
- **Early works** for VNI West may include:
 - **Project initiation** – scope, team mobilisation, service procurement.
 - **Stakeholder engagement** – with local communities, landowners and other stakeholders.
 - **Land-use planning** – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
 - **Detailed engineering design** – transmission line, structure and substation design, detailed engineering design and planning.
 - **Cost estimation** – finalisation, including quotes for primary and secondary plant.
 - **Strategic network investment** – an uplift to the delivered capacity of PEC between Dinawan and Wagga Wagga⁶².

⁶² The Commonwealth Government has underwritten funds to build a component of PEC at a larger capacity such that it removes the need to duplicate lines for VNI West when it is constructed. See <https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw>.



5.4 Future ISP projects

The future ISP projects are identified in Table 8 below, and further detailed in Appendix 5. The dates shown are the earliest feasible timing as well as the optimal timing in the most likely scenario. The timings are indicative, as the actual timing will depend on which scenario unfolds in future.

These projects will deliver net market benefits to consumers but, as they are not needed until later in the horizon, the RIT-T has not yet been initiated for them. This gives time to start planning and engaging with communities now, to ensure the projects optimise long-term benefits for consumers.

QNI Connect

The future ISP project referred to as “QNI Connect” in Table 8 is a smaller revised version of the QNI Medium and QNI Large projects listed as future ISP projects in the 2020 ISP. Much of the infrastructure intended in those projects is now included in the actionable New England REZ Transmission Link. Modelling indicates this smaller link would be optimal in 2032-33 in *Step Change*.

Central to Southern Queensland

The 2020 ISP triggered preparatory activities to explore options to expand the Central Queensland to Southern Queensland flow path (CQ-SQ). ISP modelling identified two stages to incrementally expand transmission capacity across this CQ-SQ. The first stage involves establishing a mid-point switching station along the existing Calvale – Halys 275 kV double-circuit line. This project is estimated to deliver 300 MW of additional capacity at a cost of cost \$55 million $\pm 30\%$.

Gladstone Grid Reinforcement

The 2020 ISP triggered preparatory activities to explore options to supply the Gladstone area following the closure of Gladstone Power Station. At a cost of \$408 million $\pm 75\%$, ISP modelling has indicated that a 275 kV double-circuit network solution is likely to be the most economic solution to meet this ongoing need. The timing of this project is linked to the continued commercial operation of the Gladstone Power Station.

New England REZ Extension

Following the establishment of the New England REZ Transmission Link (see Section 5.3), a subsequent expansion of network capacity is required in all scenarios – ranging from 2031-32 to 2045-46. This network project increases network capacity by 5,820 MW at a cost of approximately \$3,142 million $\pm 50\%$.

Other future ISP projects

AEMO welcomes feedback on the future ISP projects listed in Table 8 below, and detailed in Appendix 5.

These projects are expected to evolve from one ISP to the next. Due to the scale of infrastructure required in some REZs, AEMO welcomes specific feedback on activities to design and deliver REZs (see Section 8.2).



Table 8 Future ISP projects in the optimal development path†

Project	Timing in most likely scenario	Earliest feasible timing	Description
Central to Southern QLD	Stage 1: 2028-29	2025-26	A new mid-point switching substation on the Calvale –Halys 275 kV double-circuit line, to increase transfer capacity in both directions by approximately 300 MW. Cost: \$55 million
	Stage 2: 2038-39	2027-28	A new double-circuit line from Calvale to Wandoan South, to increase transfer capacity to Southern QLD by approximately 900 MW. Cost: \$476 million
Darling Downs REZ Expansion	Stage 1: 2028-29	2025-26	A transformer upgrade at Middle Ridge in combination with non-network solutions to lift the capacity of the Darling Downs REZ by approximately 800 MW. Cost: \$43 million + BESS contract cost
	Stage 2: 2039-40	2029-30	Targeted 500 kV network expansion across Darling Downs to increase the network capacity of this REZ by 2,500 MW. Cost: \$1,160 million
South East SA REZ Expansion	Stage 1: 2029-30	2025-26	Incremental network augmentations to expand the capacity of the South East SA REZ by approximately 600 MW. Cost: \$57 million
	Stage 2: 2035-36	2029-30	Additional 275 kV lines between South East – Tailern Bend – Tungkillio, dependent on new generation location, could increase the network capacity of this REZ by 950 MW. Cost: \$949 million.
Gladstone Grid Reinforcement	2030-31	2027-28	To enable ongoing supply to the Gladstone area following the closure of Gladstone Power Station and increased generation in North Queensland. Cost: \$408 million
Far North QLD REZ Expansion	Stage 1: 2031-32	2029-30	Targeted 275 kV network upgrades between Cairns and Townsville to increase the network capacity of Far North Queensland REZ by approximately 945 MW. Cost: \$1,264 million
	Stage 2: 2039-40	2029-30	String and energise the second Chalumbin – Ross 275 kV circuit can increase the capacity of the REZ by approximately 345 MW. Cost: \$155 million
Facilitating Power to Central QLD	Stage 1: 2031-32	2029-30	Two new 275 kV circuits between Bouldercombe and Stanwell to increase the transfer capacity from North to Central Queensland by approximately 400 MW. Cost: \$137 million
	Stage 2: 2038-39	2029-30	Additional 275 kV double circuit lines between Central and North Queensland which will increase transfer capacity to Central Queensland by approximately 1,400 MW. Cost: \$816 million
QNI Connect	2032-33	2028-29	To enable approximately 1,000 MW transfer capacity between southern Queensland and New England, following development of the New England REZ Transmission Link. Cost: \$1,253 million
South West Victoria REZ Expansion	2033-34	2029-30	New 500 kV network into South West Victoria can increase the capacity of the REZ by approximately 1,500 MW. Cost: \$930 million
New England REZ Extension	2035-36	2031-32	To enable approximately 5,820 MW of additional export from New England to major load centres around Sydney, following development of the New England REZ Transmission Link. Cost: \$3,142 million
Facilitating Power out of North QLD	Stage 1: 2038-39	2029-30	A new 275 kV circuit from Ross to Strathmore to Nebo to increase transfer capacity from REZs in North Queensland by approximately 740 MW. Cost: \$801 million
	Stage 2: 2039-40	2029-30	Additional 275 kV double circuit between Ross and Nebo regions can increase transfer capacity from REZs in North Queensland by approximately 1,400 MW. Cost: \$862 million
North Queensland Energy Hub	2038-39	2029-30	Additional 275 kV double circuit to Kidston area can increase the capacity of the REZ by approximately 1,000 MW. Cost: \$529 million

†Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown in this table. See Appendix 5 for more information.



6. Determining the Draft Optimal Development Path

This section sets out how and why AEMO has determined the Draft ODP in accordance with the NER, the AER's Cost Benefit Analysis Guidelines and the *ISP Methodology*.

It follows the six-step cost-benefit analysis set out in the *ISP Methodology*, through which AEMO has compared over 800 development paths, including the counterfactual path that has no network developments, and identified a shortlist of 12 candidate development paths (CDPs).

The steps through this section are:

- **Step 1: Determine the least-cost development paths for each scenario** – which establishes that all of the major network investments have positive net market benefits, so that the only question is ‘when’ they are needed, not ‘if’.
- **Step 2: Build additional CDPs** – to assess the risk of under- or over-investment by delivering network projects either too early or too late, to assess the value of staging projects with early works to mitigate against those risks, and to test potential project-related decisions that may affect the outcomes.
- **Steps 3-5: Assess, evaluate and rank CDPs** using the scenario-weighted net market benefits and least-worst regrets approaches.
- **Step 6: Test shortlisted CDPs** through sensitivity analyses against variations in input assumptions that may affect the outcomes.
- **Selection of the draft optimal development path** for consultation, considering the previous steps.

Appendix 6 provides detail on how the least-cost development paths were developed, including assessment of alternate credible options that were assessed and rejected as being sub-optimal. This section provides insights from the analysis to help understand the rationale for the selection of the Draft ODP.

6.1 Step 1: the least-cost path for each scenario – a case of not ‘if’ but ‘when’

In all scenarios, the least-cost development paths feature major network development, leveraging geographic diversity of renewable resources and demand to ensure that the generation and storage that is built is utilised efficiently, and that more expensive carbon-emitting fuel sources such as gas are used sparingly.

The difference between scenarios is that the optimal timing for network development varies considerably, dependent on when substantial coal-fired generation withdraws. The optimal timings of each scenario's transmission developments are shown in Table 9. Each represents the least-cost development path if there was certainty that the future world would unfold as projected in that scenario.

Working down Table 9, there are three levels of certainty:

- **Needed as soon as possible.** The Sydney Ring reinforcement and New England REZ Transmission Link projects are needed as early as possible (by 2027-28) in all, or nearly all, scenarios and so are effectively “low regret” investments. They are actionable ISP projects in all CDPs.

- **Future projects.** The Central to Southern Queensland Reinforcement, QNI Connect and New England REZ Extension projects do not need to commence before the next ISP in most scenarios, given their lead-times. They are all future ISP projects in all CDPs.
- **Uncertain timing.** The optimal timing for three of the strategic projects identified in Australia's Emission Reduction Plan – VNI West, HumeLink and Marinus Link – as well as the Gladstone Grid Reinforcement project, depends on the scenario that plays out.

In the faster emission reduction scenarios – *Hydrogen Superpower* or *Step Change* – progress on all three strategic projects would need to continue now, given their implementation lead times, and risk of schedule slippage. The projects are needed in *Step Change* at the same time or within a year of *Hydrogen Superpower*.

In *Progressive Change* and *Slow Change*, progress on these projects could afford to slow down or pause, as they would not be needed until three to nine years later than in the other scenarios.

If it were certain which scenario would play out, or if the mix of projects and their timings were the same in all scenarios, then no further work would be needed beyond this Step 1. However, that is not the case, and many potential combinations of transmission projects, or candidate development paths, must be designed in Step 2, and assessed in Steps 3 through 5 to determine which projects should be progressed now and which projects are best delayed.

Table 9 Optimal timing of major network projects in each scenario, assuming perfect foresight

	Earliest Commissioning Date	Slow Change	Progressive Change	Step Change	Hydrogen Superpower
Sydney Ring	2027-28	2039-40	2027-28	2027-28	2027-28
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28	2027-28
CQ – SQ Stage 1	2025-26	2040-41	2030-31	2028-29	2028-29
QNI Connect	2028-29	2035-36	2036-37	2032-33	2029-30
New England REZ Extension	2031-32	2045-46	2038-39	2035-36	2031-32
HumeLink	2026-27	2037-38	2035-36	2028-29	2027-28
Marinus Link (Cable 1)	2027-28*	2034-35	2030-31	2027-28	2027-28
Marinus Link (Cable 2)	2029-30*	2037-38	2032-33	2029-30	2029-30
VNI West	2030-31	2040-41	2038-39	2031-32	2030-31
Gladstone Grid Reinforcement	2027-28		2035-36	2030-31	2028-29

* The earliest commissioning date for Marinus Link has been revised to June 2029 (cable 1) and June 2031 (cable 2). This revision will be updated in modelling for the final ISP but is not expected to materially impact the assessment.

Note: Teal shading shows those projects that would be optimally delivered in line with the earliest commissioning date, or one year delayed. Pink shading shows those projects that would likely be re-assessed as actionable at the 2024 ISP, being within 2-3 years of the earliest commissioning date and assuming no risk of schedule slippage.



6.2 Designing candidate development paths – to assess risks of investing too early or too late (Step 2)

While all major network projects identified in Table 4 are part of the least-cost development path in each scenario and are therefore needed within the ISP horizon, the timing of network investments is an important variable in quantifying the magnitude of net market benefits for consumers. Progressing all projects now to meet *Hydrogen Superpower* or *Step Change* could lead to the regret of over-investment if *Progressive Change* or *Slow Change* eventuated. However, delaying progress would lead to more expensive alternative investments to meet the carbon budgets of *Hydrogen Superpower* or *Step Change*.

To explore these and similar risks, AEMO created a number of CDPs, each with a different combination of timings for the network projects. These CDPs were defined by the projects taken to be potentially actionable (that is, they could be on the critical path to progress before the next ISP) and these projects were treated as if committed in the CDP under all scenarios. The timing of other projects deemed potential future projects are optimised for each scenario independently, although earliest timing is delayed two years as the earliest these future projects could be declared actionable is after the next ISP.

In all, over 800 unique development paths were tested across the scenario collection, designed to assess:

- **Which least-cost development path performed best across scenarios** applying timings as suggested in Section 6.1 above and assessing regret cost if projects are built too early, or too late.
- **The impact of event-driven scenarios, where appropriate** – specifically to test how robust the CDPs are in the event that Marinus Link cost allocation arrangements (or alternative funding arrangements) are not resolved, or that third party funding commitments (or other interventions) led to either or both VNI West and HumeLink progressing at earliest timing without staging.
- **How less network investment impacts net market benefits** – at least one CDP excludes one or more projects in the combination of transmission investment, ensuring a robust assessment of not only project timings, but also variations in the overall scale of investment.
- **The option value of staged projects** – projects may commence and complete early works, as the first of multiple project stages, enabling on-time delivery to a project's development schedule, and establishing option value for a project to pause if future circumstances do not warrant early completion (see Section 6.5).

Table 10 below shows 13 of the CDPs that were assessed in the most detail. As shown in the table, CDPs 1 to 4 are the least-cost development path in each scenario. The CDPs are then built up to test the addition or removal of potentially actionable projects (for example, CDP5 adds Marinus Link to the potentially actionable projects of CDP 1), and then the staging of some projects. With these variations in place, all other network investment options (including potential actionable projects not listed) may then be optimised as future projects.

Table 10 The candidate development paths for the Draft 2022 ISP

		Potentially actionable projects (all other candidates available for future development with at least a two-year delay in earliest possible timing)					
		New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
Least-cost CDPs in each scenario							
1	Progressive Change least-cost	Potential actionable	Potential actionable				
2	Step Change least-cost	Potential actionable	Potential actionable	Potential actionable	Potential actionable		
3	Hydrogen Superpower least-cost	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable
4	Slow Change least-cost	Potential actionable					
Testing variations to test timing of project delivery and/or event-driven scenarios							
5	CDP1, adding Marinus Link	Potential actionable	Potential actionable	Potential actionable			
6	CDP1, adding VNI West	Potential actionable	Potential actionable		Potential actionable		
8	CDP2, adding HumeLink	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	
13	CDP12, removing Marinus Link	Potential actionable	Potential actionable	Never available	Stage 1 (early works)	Stage 1 (early works)	
Testing slower investments							
7	CDP1, without New England		Potential actionable				
9	No actionable projects						
Testing staged projects with early works							
10	CDP5, with VNI West staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (early works)		
11	CDP8, with VNI West staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (early works)	Potential actionable	
12	CDP10, with HumeLink staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (early works)	Stage 1 (early works)	

6.3 Assess, evaluate and rank candidate development paths (Steps 3-5)

For each scenario, AEMO assessed the net market benefits of the CDPs by comparing total system costs against the counterfactual with no new network investment, then ranked the CDPs according to the two analysis approaches detailed in the *ISP Methodology*:

- A. the (mandatory) ‘scenario-weighted’ average approach, and
- B. AEMO’s additional ‘least-worst weighted regrets’ approach.

Both approaches help inform the decision-making process by highlighting what may be an asymmetry between benefits and risks. For example, some CDPs may have slightly higher net market benefits but expose consumers to greater regret costs, while other CDPs may have the opposite profile.

6.3.1 Approach A – scenario-weighted net market benefits

All CDPs offer very similar net market benefits

The scenario-weighted net market benefits approach assigns weightings to each scenario based on the relative likelihood determined through the Delphi process (see section 2.3), multiplies the net market benefits in each scenario by each weighting, and aggregates the results.

The results of this analysis for the 13 featured CDPs are set out in Table 11 below. Note that the net market benefits of all but one are extremely close, delivering benefits of ~\$29 billion (NPV of annual benefits to 2050) on a scenario-weighted basis, with only a \$420 million difference between the top and 12th ranked CDPs. All CDPs also show positive net benefits in all scenarios.

Table 11 Performance of candidate development paths across scenarios (in \$b) – ranked in order of weighted net market benefits

CDP	Description	Slow Change	Progressive Change	Step Change	Hydrogen Superpower	Weighted Net Market Benefits	Rank
	Scenario weighting	4%	29%	50%	17%		
10	CDP5, with VNI West staged	3.52	16.35	25.59	70.01	29.58	1
12	CDP10, with HumeLink staged	3.35	16.20	25.59	70.20	29.56	2
2	Step Change least-cost	3.25	16.26	25.59	70.01	29.54	3
5	CDP1, adding Marinus Link	3.71	16.51	25.51	69.60	29.52	4
6	CDP1, adding VNI West	3.62	16.47	25.59	69.37	29.51	5
1	Progressive Change least-cost	4.17	16.72	25.50	68.95	29.49	6
7	CDP1, without New England	3.94	16.67	25.49	68.45	29.37	7
4	Slow Change least-cost	4.34	16.50	25.41	68.73	29.35	8
11	CDP8, with VNI West staged	3.13	15.66	25.39	70.20	29.30	9
8	CDP2, adding HumeLink	2.87	15.56	25.39	70.20	29.26	10
3	Hydrogen Superpower least-cost	2.51	15.47	25.34	70.53	29.25	11
9	No actionable projects	4.05	16.36	25.28	68.33	29.16	12
13	CDP12, removing Marinus Link	2.19	13.54	20.96	64.50	25.46	13

Insights on the preferred timing of major network projects

The rankings of CDPs offer interesting insights towards determining which projects should be actionable rather than future projects and whether staging delivers option value.

- **Comparing CDPs 10, 2 and 5 (delaying, staging or delivering the VNI West project in actionable timeframe)** suggests commencing VNI West now (CDP2) delivers \$20 million more in market benefits than delaying for at least two years (CDP5), and that staging the project with early works as the first stage delivers a further \$40 million of option value under all scenarios (CDP10).
 - This analysis suggests that making VNI West a staged actionable ISP project with early works would help optimise benefits for consumers, depending on the outcome of Approach B. The staged

actionability would also offer an insurance benefit in being ready for faster decarbonisation or unexpectedly early coal closures if needed, and an option to pause the project if the operating environment is closer to the *Progressive Change* or *Slow Change* scenarios.

- **Comparing CDPs 6, 2, 1 and 5 (delaying or delivering both cables of Marinus Link in actionable timeframe)** shows that the scheduled earliest development of Marinus Link (both cables) offers consumers \$40 million more in net market benefits than delaying two years (both CDP6 vs CDP2 and CDP1 v CDP5).
 - These benefits are largely unaffected by the delivery schedule of VNI West.
 - Further, if Marinus Link is not developed at all (CDP13), net market benefits reduce by over \$4 billion. The unavailability of Marinus Link does not materially change the ranking of the remaining CDPs, although it does further increase the benefits provided by VNI West.
 - This analysis suggests that making Marinus Link (both cables) an actionable ISP project would help optimise benefits for consumers, depending on the outcome of Approach B. There is no benefit in pausing the project on the assumptions in these CDPs. In addition, delays may risk losing development momentum and risk cost increases, given expected global competition for submarine cable-laying services.
- **Comparing CDPs 8, 2, 10, 11 and 12 (delaying, staging or delivering the HumeLink project in actionable timeframe)** shows that CDP 10, which progresses all projects except HumeLink as actionable, ranks highest on this assessment. CDP 12 (with HumeLink as a staged project with early works as first stage) delivers just ~\$20 million or 0.1% less in scenario-weighted benefits, so should be considered further in case staging offers other benefits. In addition, pausing the project now may risk losing development momentum and risk cost increases. CDP11 (full actionable project, no staging) would deliver ~\$280 million less net market benefit to consumers than CDP10, (as would CDP8 vs CDP2), and therefore neither CDP11 or CDP8 are likely to be the Draft ODP.
- **Comparing CDPs 7 and 1 (delivering New England Stage 1 in actionable timeframe)** shows that the project delivers net market benefits if developed now, with \$110 million greater benefits than if the project was delayed. AEMO's analysis of development paths identified that if New England was delayed, it would still be preferred to be delivered at the next earliest opportunity two years later.
- **Comparing CDPs 4, 1, 7 and 9 (delivering Sydney Ring Reinforcement in actionable timeframe)** shows that the project delivers net market benefits if developed now, with between \$140 million and \$210 million greater benefits than if the project was delayed, depending on the availability of other New South Wales infrastructure, such as New England REZ Transmission Link. Actionable delivery of New England REZ Transmission Link marginally reduces the net benefits of the project, but they are still significant. Sensitivity analysis was conducted to see if increased storage development in the Hunter region increased the value of delaying this project (see Section 6.6).
- **Comparing CDPs 3 and 8 (actioning Gladstone Grid Reinforcement)** shows the marginal value of progressing with the project as soon as possible. The project's inherent value will be to support the Gladstone load once Gladstone Power Station retires.

Insights on event-driven scenario analysis

Impact of Marinus Link cost allocation decision on CDPs: While CDPs in most scenarios include Marinus Link, the project relies on cost allocation arrangements being resolved (or alternative funding arrangements).



AEMO has compared CDPs with CDP13 to quantify the impact that a withdrawal of Marinus Link would have on the overall net market benefits. This analysis has identified that the most significant influence is on VNI West, with minimal impact on any other project. Without Marinus Link developed, progressing VNI West as soon as possible (CDP2) is \$175 million more beneficial to consumers than waiting and reassessing in the 2024 ISP (CDP5). This supports the decision to progress with an actionable staged VNI West so that the project can still be commissioned as early as possible in the event that Marinus Link is unable to progress.

Third party funding or other intervention to progress VNI West in full for earliest commissioning:

The above analysis comparing CDPs 10 and 2 has highlighted that a staged actionable VNI West delivers \$40 million option value and, as such, is preferable to proceeding with full delivery in 2030-31 under all scenarios, provided there is no material cost incurred due to staging that would not have been incurred without staging.

Nonetheless, there may be good reasons why third parties would like to see this project progressed unconditionally for delivery by or before 2030-31. A third party funding commitment of approximately \$500 million (just under 20% of the project cost) would result in CDP2 with VNI West actionable without staging being the equal-highest ranked CDP under Approach A.

Inclusion of VNI West from 2030-31 in all scenarios does not diminish the value of any of the other potentially actionable ISP projects proceeding.

Third party funding or other intervention to progress HumeLink in full for earliest commissioning: The above analysis comparing CDPs 11 and 12 has highlighted that a staged actionable HumeLink delivers option value and, as such, is preferable to proceeding with full delivery now, provided there is no material cost incurred due to staging that would not have been incurred without staging. Further, proceeding with the project to its current 2026-27 schedule would reduce net market benefits to consumers by approximately \$260 million to \$280 million compared to CDP10 that delivers the highest net market benefits, assuming that losing current momentum does not result in significant cost increases.

Nonetheless, there may be good reasons why third parties would like to see this project progressed unconditionally for delivery in 2026-27. A third party funding commitment of \$330 million to \$370 million (just over 10% of the project cost) that is conditional on the project progressing to schedule would result in CDP11 with HumeLink actionable without staging being the equal-highest ranked CDP under Approach A.

Inclusion of HumeLink from 2026-27 in all scenarios does not diminish the value of any of the other potentially actionable ISP projects proceeding.

6.3.2 Approach B – least-worst regrets approach

AEMO's least-worst regrets approach identifies the CDP that would cause the least under- or over-investment regret, if any particular scenario played out. In this approach AEMO has applied a least-worst weighted regret (LWWR) method, as defined in the *ISP Methodology*, given the wide range of scenario likelihoods. This avoids the possibility that a highly unlikely scenario may have undue influence on the overall assessment of regret.

The regrets being calculated are associated with decisions that are later shown to have over- or under-invested in infrastructure, given the market conditions that later unfold. Consumers may regret over-investing if conditions no longer require these assets, and consumers may regret under-investment if disruption occurs faster than anticipated and the asset is needed sooner than planned.

The LWWR results of this analysis for the 13 featured CDPs are set out in Table 12 below. CDP10, with New England REZ Transmission Link, Sydney Ring, Marinus Link (both cables) and a staged VNI West, is ranked

highest using both this LWWR approach and the scenario-weighted net market benefits approach. The CDP without Marinus Link ever (CDP13) is included for completeness but ignored for the purpose of discussion as it yields the greatest regret in all scenarios and is therefore the exception for all remaining insights.

Table 12 Regret cost of candidate development paths across scenarios (in \$b) – ranked in order of weighted worst regret

CDP	Description	Slow Change	Progressive Change	Step Change	Hydrogen Superpower	Weighted worst regret	Rank
	Scenario weighting	4%	29%	50%	17%		
10	CDP5, with VNI West staged	0.82	0.37	0.00	0.52	0.11	1
2	Step Change least-cost	1.09	0.46	0.00	0.52	0.13	2
12	CDP10, with HumeLink staged	0.99	0.52	0.00	0.34	0.15	3
5	CDP1, adding Marinus Link	0.63	0.21	0.08	0.94	0.16	4
6	CDP1, adding VNI West	0.72	0.25	0.01	1.16	0.20	5
1	Progressive Change least-cost	0.17	0.00	0.09	1.59	0.27	6
11	CDP8, with VNI West staged	1.22	1.05	0.20	0.34	0.31	7
4	Slow Change least-cost	0.00	0.22	0.18	1.80	0.31	8
8	CDP2, adding HumeLink	1.47	1.16	0.20	0.34	0.34	9
7	CDP1, without New England	0.40	0.04	0.11	2.08	0.35	10
3	Hydrogen Superpower least-cost	1.83	1.24	0.25	0.00	0.36	11
9	No actionable projects	0.29	0.35	0.32	2.21	0.38	12
13	CDP12, removing Marinus Link	2.15	3.18	4.63	6.04	2.32	13

The weighted worst regret shown in this table represents the maximum regret observed across the scenarios, after the individual scenario regrets are weighted using the scenario weightings at the top of the table. The scenario regrets are provided unweighted.

At the scenario level:

- All the regrets in the *Step Change* scenario are relatively low, with the maximum regret only being \$320 million (in NPV terms to 2050) given the ability to act following a two-year delay if the project is not initially progressed but we subsequently find ourselves in a scenario where it would have been beneficial. The regret of not making any projects actionable (CDP9) is greater than the regret of making all the projects actionable (CDP3).
- If *Slow Change* eventuates, the risk of over-investment is as high as \$1.8 billion in lower benefits. However, if *Hydrogen Superpower* eventuates (or if coal closures are in line with that scenario), the risk of under-investment is higher still, at \$2.2 billion. This supports the previous insight, that there is a relatively small potential skew towards under-investment risk being greater than over-investment risk.

Insights for timing of actionable projects

The CDP rankings also reveal the regret costs of different timings for the major potentially actionable projects, and so offer insights towards their selection in the Draft ODP.

- **Comparing CDPs 5 and 1 (delaying or delivering both cables of Marinus Link in actionable timeframe)** shows that regret costs could be \$650 million higher in *Hydrogen Superpower* and \$10 million higher in *Step Change* if Marinus Link is delayed two years. Progressing Marinus Link now (CDP5) would lower worst weighted regrets by \$110 million. This aligns with the insights from Approach A, and confirms that the timings for both Marinus Link cables in the ODP most likely would help to optimise benefits for consumers.



- **Comparing CDPs 10, 2 and 5 (delaying, staging or delivering the VNI West project in actionable timeframe)** shows that staging the project (CDP10) helps to minimise weighted worst regret by ensuring the project is not built earlier than it needs to in *Progressive Change* and *Slow Change* while also making sure it can be built in time in the other two scenarios (avoiding \$80 million regret due to delivery delay in *Step Change* – see CDP5). This aligns with the insights from Approach A, and confirms that staging the VNI West project with early works in the ODP is most likely to optimise benefits for consumers.
- **Comparing CDPs 12, 10, and 11 (delaying, staging or delivering the HumeLink project in actionable timeframe)** suggests that delaying investment in HumeLink would lead to ~\$40 million less weighted regrets than staged actionable development, all else being equal (CDP10 vs CDP12). There would be \$180 million regret in *Hydrogen Superpower* due to delivery delay, but \$150 million to \$170 million less regret for consumers in *Progressive Change* and *Slow Change* as early works are not spent earlier than necessary. On the other hand, staged actionable development provides significant value compared to delivering as a single stage actionable project by 2026-27 (CDP12 vs CDP11) which would increase weighted regrets by \$160 million.

This analysis aligns with the insights from Approach A, with both suggesting that delaying investment in HumeLink would offer greater net market benefits than making it actionable as a staged project or investing immediately. However in both approaches the difference is so marginal that further analysis was warranted (see below).

6.3.3 Insurance value associated with staging HumeLink as an actionable project

Both approaches of the cost-benefit analysis confirm the timing and benefits of all the actionable ISP projects in the ODP, except HumeLink. However, there are only marginal differences in the potential benefits and regrets between delaying HumeLink (CDP10) and including it as an actionable staged ISP project with early works as the first stage (CDP12). This section therefore considers additional risks that CDP12 may protect consumers from.

It concludes that there is sufficient insurance value to lift the value of CDP12 above CDP10 and make HumeLink an actionable ISP project with an early works first stage. There would only need to be a 10% or greater chance for schedule slippage resulting in a two-year delay, or a 10% or greater chance of earlier than projected coal closures in *Progressive Change*, for consumers to be better off progressing with HumeLink as a staged actionable ISP project now.

Value of staging HumeLink

Staged projects increase protections for consumers: an on-time start date as insurance against the need for on-time deployment, and the option to pause the project if a slower decarbonisation scenario plays out.

The potential value of project staging for HumeLink is in:

- Preserving the ability to deliver it as soon as possible if required in *Step Change* or *Hydrogen Superpower*, or allowing it to be deferred in the event of *Slow Change* or *Progressive Change*, if that would bring greater benefits to consumers (its option value).
- Mitigating the risk of schedule slippage in *Step Change* or *Hydrogen Superpower* and the risk of coal exiting faster than projected in *Progressive Change* (its insurance value).
- Maintaining momentum that may further improve the design of the project, potentially reducing uncertainty around cost estimates, and ideally bring the project costs down.



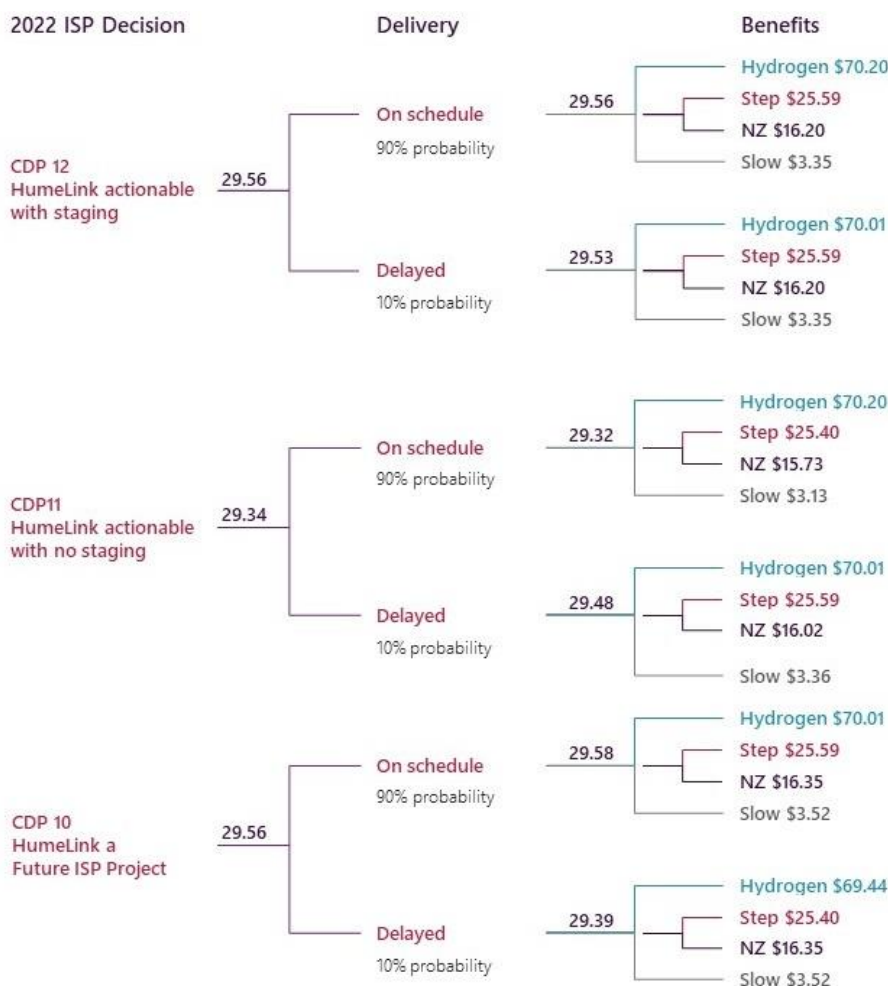
Project staging secures this additional value by either spending money earlier than otherwise needed, and having to re-incur expenses (in a paused project), or in writing off incurred costs (in an abandoned project). Therefore, for project staging to be actionable, the option and insurance values need to exceed this cost, and/or reflect consumer risk preferences.

Risk of schedule slippage

Figure 29 shows how this option and insurance value has been calculated using a decision tree approach and incorporating risk of schedule slippage. It focuses on the potential consequences of selecting CDP10, CDP11 or CDP12 as the Draft ODP, and on the balance of probability highlights which option optimises benefits to consumers if there is a 10% likelihood that schedule slippage delays the project two years.

The net market benefits at the end of each branch reflect the net market benefits of each scenario as already summarised in Table 11. To simplify the calculation, it is assumed that a decision made now cannot predict the scenario that is playing out, whereas in two years' time it can. In reality, there may still be uncertainty.

Figure 29 Option value with HumeLink as a staged project and risk of schedule slippage, \$ billion



In Figure 29, the third branch represents HumeLink not being actionable in the 2022 ISP, becoming actionable in the 2024 ISP if in *Step Change* or *Hydrogen Superpower* (but not, if in either of the other two scenarios), and then being delivered on time – as the cost benefit analysis assumes for all projects. That would enable



the development path to deliver a \$29.58 billion net benefit to consumers (on a scenario-weighted basis, relative to the Draft ISP's counterfactual scenario).

However, the bottom limb of the third branch assumes instead that there is a two-year schedule slippage in the delivery of HumeLink so it is actually commissioned later than needed in *Step Change* or *Hydrogen Superpower*. Here the net benefit falls by \$190 million to \$29.39 billion. Yet CD10 only has a \$20 million advantage in the cost-benefit analysis (see Section 6.3.1). Therefore, if there is a 10% likelihood of the project being delayed by two years after becoming actionable in the 2024 ISP, then the rankings would turn. Given the recent history of progressing major NEM projects, that 10% likelihood of delay is very plausible.⁶³

Risk of early coal exits

The analysis represented by Figure 29 could be extended to include the chance of earlier than expected coal closures in *Progressive Change*, which would further increase the value of staging. Even ignoring the chance of schedule slippage, if there was a 10% or greater chance of Vales Point, Eraring and either Mt Piper or Bayswater closing by 2027-28 in *Progressive Change* and *Step Change* scenarios, HumeLink staged as an actionable project would deliver further benefits for consumers.

In *Progressive Change*, if coal withdrew before HumeLink was available, an additional ~2 GW of firming capacity would be needed. In these circumstances in *Progressive Change*, HumeLink would have delivered consumers \$450 million additional market benefit in NPV terms. This risk is less relevant for the *Step Change* and *Hydrogen Superpower* only because more coal is already projected to retire early in these scenarios.

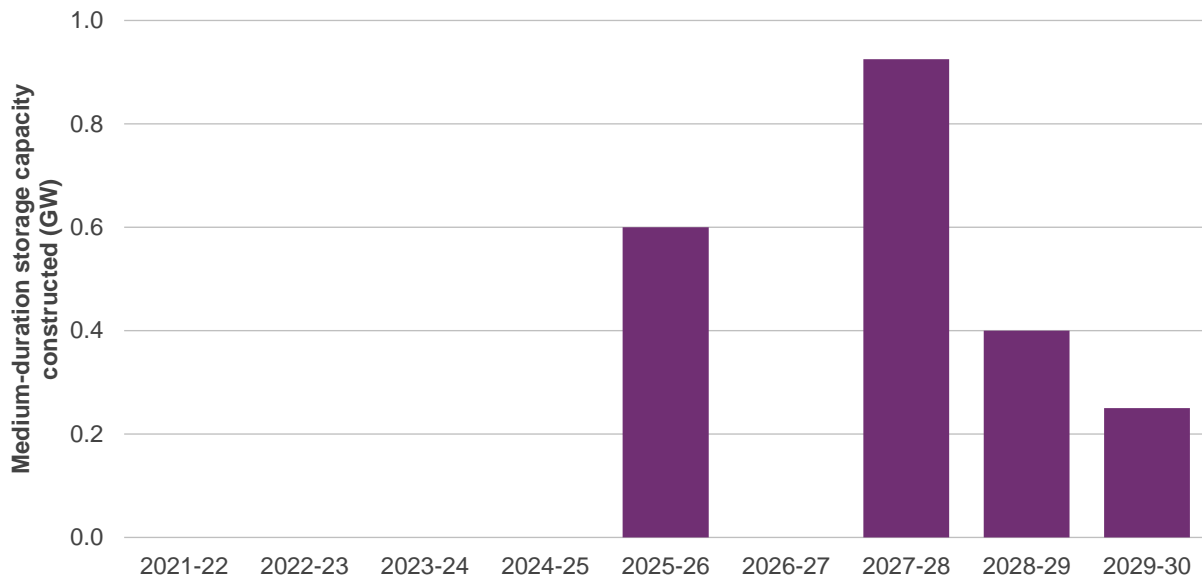
Risk of delays in storage development

HumeLink would also help insure against the unavailability of storage that is planned to be ready before black coal withdraws from New South Wales. As black coal withdraws over the next decade, system reliability will rely in part on storage that is capable of continuously generating for at least eight hours. This storage is assumed to be developed in the Development Pathway of the 2021 IIO Report, to meet the minimum objectives of the New South Wales Roadmap (see Figure 30).

However, the 2021 IIO report recognises that the timing, technology readiness and cost of this deeper storage is subject to a high degree of uncertainty. If it were to be pumped hydro, it is unclear if it could be constructed quickly enough to meet the IIO objectives.

If this storage is delayed, HumeLink would reduce the risk of supply scarcity for New South Wales consumers. While not explicitly quantified, this risk further supports the option and insurance value of progressing HumeLink as a staged actionable project targeting implementation as soon as possible, and no later than 2028-29.

⁶³ Supported by analysis conducted by Independent Project Analysis, Inc on industrial mega projects and large infrastructure projects, available at <https://www.ipaglobal.com/news/article/edward-merrow-reveals-why-megaprojects-fail-in-project-manager-magazine-cover-story/>.

Figure 30 Medium-duration* storage development to meet the New South Wales Roadmap

* AEMO's medium duration storage definition includes storages of between four and 12 hours inclusive in depth. The New South Wales Roadmap requires storage of a minimum eight hours duration, referred to as long-duration storages in the Roadmap.

Conclusion

The decision tree and risk analysis suggest that an actionable staged HumeLink project (with early works as first stage) would be a prudent approach that optimises benefits from consumers. For \$20 million in net market benefits foregone (that is, compared to the CDP that delivers highest net market benefits under Approach A), it provides insurance against delivery delays, earlier than projected coal closures, or the risk that long duration storage takes longer than expected to materialise. HumeLink is needed eventually in all scenarios, so early works is a low regret investment. Further, the early works stage provides opportunity for the project proponent to identify cost savings, reduce cost uncertainties, and provide greater consumer confidence that they will not be over- or under-investing.

For these reasons, AEMO considers that staging HumeLink with early works as the first stage would align with consumer risk preferences.

6.3.4 Competition benefits have not influenced the CDP assessments

AEMO has not included competition benefits in the assessment of the Draft ODP due to the significant uncertainty surrounding key assumptions that would need to be made in the calculation of these benefits. In Appendix 6, an indicative calculation of this class of benefits is provided for a few select CDPs (CDP2, 5, 8, 10, 11 and 12).

The indicative assessment suggests that CDPs with HumeLink built early deliver greater competition benefits than other CDPs, and if the calculation of this class of market benefits was sufficiently robust and supported by stakeholders, it could potentially narrow the gap in net market benefits between CDP11 (with HumeLink actionable in a single stage) and CDP10 (the CDP with the highest net market benefits, without HumeLink actionable).

However, even if these competition benefits were to be included, a Draft ODP with HumeLink actionable as a staged project delivers greater net market benefits for consumers due to the option value associated with



being able to pause the project if circumstances change materially. Therefore, inclusion of competition benefits is unlikely to materially change the outcome of the development path.

6.4 Testing the robustness of the candidate development paths through sensitivity analysis (Step 6)

Step 6 of the cost benefit analysis methodology is to explore the robustness of high ranking CDPs to material changes in key assumptions. This analysis tests a range of sensitivities to reveal if they would have any material impact on the selection of the timing of network projects in the Draft ODP, and confirm that they pose no barrier to the leading candidate becoming the ODP.

The following changes to key assumptions would have no material impact on the selection or the timing of network projects in the Draft ODP:

- **Higher discount rates** (see discussion below)
- **Lower gas prices** (see discussion below).
- **Stronger electrification** (see discussion below).
- **Higher installed capacity of distributed PV systems** (although it would tend to preference utility-scale wind development to keep the wind-solar mix in balance: see Section 3.2).
- **Additional deep storage in Queensland** (although it would lead to more development opportunities for Queensland solar generation).
- **Initial storage developments in New South Wales** located within the Sydney, Newcastle and Wollongong area (although it would slightly reduce the net market benefits of the Sydney Ring project).

One change did have a material impact on the timing of a network project:

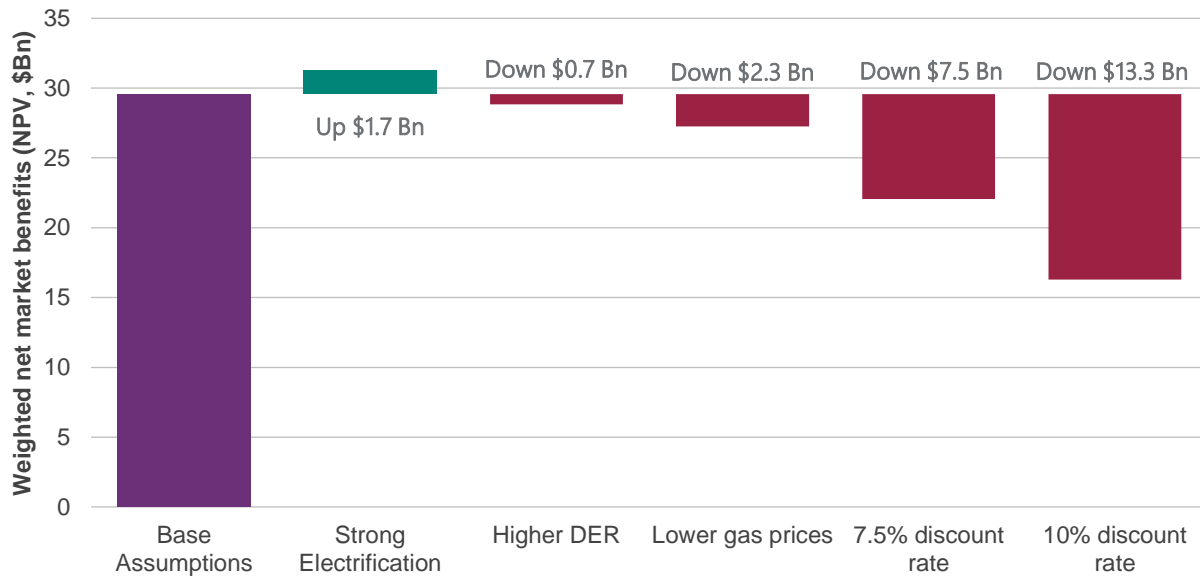
- **Removing the influence of TRET** would slow the accumulation of benefits provided by the Marinus Link project. Under these circumstances, the optimal timing of the first Marinus Link cable could be pushed back up to four years in the *Progressive Change* scenario.

Figure 31 shows the impact of varying these assumptions on the scenario-weighted net market benefits of the ODP.

While they are significant in absolute terms, there are similar impacts on all of the short-listed CDPs, so the rankings do not change. The exception is the higher discount rate which not only impacts the net market benefits the most, but also changes the rankings slightly.



Figure 31 Impact of materially varied assumptions on the optimal development path's scenario-weighted net market benefits



Higher discount rates

The choice of discount rate materially influences net market benefits, particularly for early investments in large capital projects with longer-term benefits. The assumed discount rate for the CBA methodology is 5.5%. AEMO has conducted sensitivity analyses for two higher discount rates identified in the IASR: the upper bound (7.5%) and highest value (10%) rates. The results of this analysis are detailed in Appendix 6, and summarised here.

Overall, the higher discount rates make little difference to either the spread of net market benefits and worst weighted regrets of the CDPs, or their resulting rankings. Even with the 10% discount rate, nine of 12 CDPs are separated by only \$260 million in NPV terms, although minor changes in rankings are observed.

The analysis also assessed the impact of high discount rates on individual projects by comparing the relevant pairs of CDPs. It reinforces that the New England and Sydney Ring projects are low-regret actionable projects, as CDPs with them continue to be ranked higher than those which delay them (CDP9). Mariner Link is also less sensitive to discount rate selection, and CDP5 (with Mariner Link actionable) becomes the highest ranked CDP in the LWWR approach with high discount rates (due mainly to the high regret of not having Mariner Link available in the *Hydrogen Superpower* scenarios).

Applying the highest discount rate (10%), CDPs that stage the HumeLink and VNI West projects fall in the overall ranking; however the best of the options under the base assumptions (CDP12) is only approximately \$150 million worse off than the highest ranking CDP (CDP1), with an approximately \$220 million potential worst weighted-regret, associated with over-investment in *Progressive Change*.

With the higher discount rate, CDP12 still delivers positive net market benefits overall, and positive benefits in all scenarios. Given that this CDP is robust to all other sensitivities and continues to deliver positive benefits in all scenarios, AEMO does not consider that any change to the Draft ODP is warranted as a result of the sensitivity analysis.



Lower gas prices

Gas-fired generation plays a critical role in firming VRE and meeting extreme demand conditions. However, the annual volume of gas required is projected to decline relative to recent history. By the end of the forecast period, approximately half of the net market benefits of the ODP derive from the fuel cost savings of avoided gas generation: see Figure 27 in Section 5.1 above. As gas prices fall, so too would these benefits. AEMO has tested the impact of lower gas prices on the CDPs with three of the strategic projects identified in Australia's Emissions Reduction Plan (Marinus Link, VNI West and HumeLink), to compare their net market benefits against CDPs with fewer actionable projects. The detailed results are given in Appendix 6, and show that the lower gas prices reduce the net market benefits of all of the CDPs by approximately \$2.3 billion, but do not change the ranking of these higher ranked CDPs.

The reduction in net market benefits is largely attributable to a lowering of overall costs in the counterfactual which has greater reliance on gas generation without transmission to share VRE. Gas prices have a lesser impact on the relativity between CDPs (and hence the rankings), as all result in similar reductions in gas consumption relative to the counterfactual.

Stronger electrification

The *Hydrogen Superpower* scenario incorporates a strong decarbonisation objective, and this may be pursued even without the ubiquitous availability of hydrogen – for technical or economic reasons. AEMO has therefore modelled a *Strong Electrification* sensitivity, as a potential alternative that assumes the same emission reduction objectives, but with limited hydrogen uptake. Stronger and faster electrification of transport and heavy industry is therefore needed to achieve the economy-wide emission reductions.

The results of this analysis are set out in Appendix 6, and suggest that the CDP rankings are relatively robust to this sensitivity. This would confirm that the potential need for early transmission investments is set by the emission reduction objectives and the speed of coal closures, rather than by the electrolyser demand for electricity from hydrogen developments in the 2030s and 2040s in *Hydrogen Superpower*. In this *Strong Electrification* sensitivity, without the benefit of hydrogen, the transmission investments would be needed to support faster and larger scale VRE development and greater storage as coal retires earlier. Additional high quality renewables such as offshore wind may also be needed in the 2040s to support the larger energy consumption associated with the greater and faster electrification.



Part D

Advancing the Draft Optimal Development Path

Parts B and C of the Draft ISP set out the ODP of ISP development opportunities and complementary network projects. It has been an extensive, collaborative effort by all NEM stakeholders over 15 months that have been marked by the pandemic. However, there is still a considerable amount of work to complete before the 2022 ISP is finalised.

This Part D sets out that work by confirming:

- **Section 7** – the range of reasonably foreseeable events that may risk either the identification or the implementation of the Draft ODP,
- **Section 8** – the three major streams of consultation that will start with or continue through publication of the Draft ISP, and
- **Section 9** – the additional analysis AEMO will undertake before the final 2022 ISP to support its conclusions.



7. Significant risks and limitations are being monitored

The *ISP methodology* is a comprehensive and collaborative analysis to reveal an ODP that will optimise net market benefits for consumers. Nonetheless, there are a range of reasonably foreseeable events that may risk either the identification or the implementation of the Draft ODP.

This section considers those risks, either as:

- risks that are quantified within the ISP methodology to identify the Draft ODP,
- risks to the timely implementation of projects identified as part of the Draft ODP, or
- additional factors that may be considered in future ISPs.

7.1 Risks quantified within the ISP methodology

The ISP methodology accounts, as far as is possible, for a range of quantifiable risks. Accordingly, the Draft ODP is robust against:

- **The range of policy and input assumptions** contemplated by the ISP scenarios (see Section 4),
- **Risks that coal generation retires even earlier** than announced or anticipated, tested through option values,
- **Changes in gas price assumptions** tested through sensitivity analysis,
- **Changes in discount rate**, tested through sensitivity analysis, and
- **Risks of schedule slippage**, tested through option value.

7.2 Risks to timely implementation of the Draft ODP network projects

While the Draft ODP sets out a clear timing and process for the actionable ISP projects, there are material risks that delivery may not be as complete or as timely as called for. These risks include:

- **the timely resolution of Marinus Link cost allocation** and other factors,
- **securing social licence for VRE, storage and transmission**,
- **project sequencing to manage supply chain risks**, and
- **completing actions in AEMO's Engineering Framework**.

Timely resolution of cost allocation and other factors for Marinus Link

There are a number of technical, commercial, regulatory and stakeholder risks in relation to Marinus Link proceeding to the timings identified in the Draft ODP. These include:

- appropriate resolution and implementation of the regulatory arrangements for the project, including allocation of interconnector costs,
- the timely completion of community engagement and environmental approvals by the Commonwealth, Tasmanian, and Victorian governments,



- the risk of increased costs and delays should the need for the first and second cable be spaced more than 2-3 years apart at the time of the Final Investment Decision. For the project to receive economies of scale benefits from the suppliers, procurement for both cables would need to be undertaken simultaneously, but the second cable could be commissioned up to three years after the first cable is installed, and
- a range of project, implementation and other risks associated with infrastructure build of this type.

Securing social licence for VRE, storage and transmission

This Draft ISP shows how the NEM can optimise consumer benefits while supporting government policies for emissions reduction and Australia's new net zero target. However, the land needed for major VRE, storage and transmission projects to realise these goals is unprecedented. Early community engagement will be needed to ensure investments have an appropriate social licence. In some cases, this may lead to alternative developments that reduce the need for new transmission, including batteries, gas-fired generation and offshore wind developments that connect to the existing network easements.

The new REZ Design Report framework is a start, but proactive engagement and integrated land-use planning is also needed at a jurisdictional level. The sector continues to underestimate the time and money that community consultation requires, with the rules placing it 'at the back end' rather than the front of the process. Where consultation does occur, it tends to focus on individual transmission projects, rather than on integrated land use planning, and even on the benefits of decarbonisation itself.

Currently, land owners and communities are focused on specific major transmission projects underway, with a range of bodies actively involved in advocating for alternatives (to transmission). However, social licence will be even more relevant to address the full land use implications of a decarbonised NEM. Even with multi-purpose land use, there will be a significant increase in the land needed for generation, storage and transmission assets. While land needed for network easements will be much smaller than that required for VRE, more landholders are likely to be affected by their longer routes.

The Draft ISP seeks to limit the impact by concentrating VRE development in the REZs, and limiting the proportion of land within a REZ that may be applied to VRE. Even so, VRE developments will tend to be concentrated or clustered in particular areas within the REZ where the network access and/or land use is most suitable. As well, NEM jurisdictions and the REZ Design Reports are doing much to identify alternative REZ locations and innovative dual-land-use initiatives that may offer additional revenue opportunity for communities, without being in competition with existing businesses.

Regional planning bodies have the primary responsibility to manage the development of network infrastructure to support the projected VRE in REZs. Networks, developers, and governments will need to engage with local communities to ensure the coordinated development of VRE and enabling network, both connection assets and shared transmission network augmentations. Collaboration between NEM participants and jurisdictions may be needed to:

- harmonise the infrastructure, policies and objectives across jurisdictions,
- leverage the REZ Design Report process in the NER to accelerate engagement with communities and land owners on developments planned for at least the next 12 years,
- consolidate an integrated approach to land use planning that optimises multi-purpose land use and aligns with local interests,



- broaden engagement to incorporate broader community and environmental benefits (including regional economic and jobs growth, emission reductions, and biodiversity habitat and corridors),
- systematically document local concerns and incorporate them in the ISP, REZ Design Report, and local planning processes,
- consolidate and align appropriate compensation mechanisms for affected land owners and communities, and
- ensure the design of transmission and VRE assets take advantage of available design and technology choices to minimise their impact on land use.

Project sequencing to manage supply chain risks

There is strong industry consensus on the acceleration in global and national infrastructure and renewable energy investment over the next two decades. This will significantly increase demand for expertise, materials, and equipment, putting pressure on costs and schedules for new NEM generation and transmission projects. Development optimisation through the ISP process alone cannot fully secure the strategic sequencing of projects to manage these supply chain risks, and NEM participants will need to continue working to ensure a smooth and sequenced construction schedule.

The worldwide growth in renewable energy over the next three decades, spurred by 2030 and 2050 emissions targets, will significantly increase demand for labour, expertise, materials and specialised electrical equipment. A bottleneck in any one supply sector will risk delivery of the many significant projects in the Draft ODP forecast for the late 2020s and, if those projects slide, they risk competing for skills and materials with further projects slated for the 2030s.

These supply-side constraints are expected to be felt within the next three years. Infrastructure Australia's recent Market Capacity Report⁶⁴ found that the infrastructure skills shortage for 2022-24 is expected to be five times worse than for 2017-19, with a shortfall of over 105,000 roles in mid-2023, and that up to 40% of the infrastructure workforce is expected to retire over the next 15 years, without the population growth needed to replenish it.

The projected constraints may be intensified in the energy sector. A further Infrastructure Australia initiative⁶⁵ studied labour and material requirements to fulfil the NEM-wide generation and transmission projects included in the 2020 ISP, with revised assumptions on scenarios. It found that the total number of roles in the energy sector varied between 80,000 and 95,000 over the next 15 years, primarily for large-scale renewable energy, but that there would be significant volatility in demand through the peaks and troughs in construction, and between states and regions, and a lack of diversity in projects – three factors that tend towards skill shortages. It also forecast that demand for steel from the electricity sector (NEM-wide) would increase by ~50% from 2021 to 2027, and that demand for concrete would double.

To help reduce these risks, NEM participants and jurisdictions may collaborate to:

- coordinate the timing of ISP transmission projects and development opportunities to smooth out the construction schedule and avoid peaks and troughs in labour and skills demands,

⁶⁴ See <https://www.infrastructureaustralia.gov.au/publications/2021-infrastructure-market-capacity-report>.

⁶⁵ Infrastructure Australia, Market capacity for electricity generation and transmission projects, October 2021, at <https://www.infrastructureaustralia.gov.au/sites/default/files/2021-10/Market%20Capacity%20for%20Electricity%20Infrastructure%2020211013.pdf>.



- provide more certainty to network companies on the timing of the large-scale transmission builds, which will allow them to negotiate better contract outcomes, order long-lead equipment at lower cost, and book specialised construction equipment well in advance,
- develop more detailed projections of skills needed over the next 10-20 years for the build out of the electricity system, and
- develop programs to meet these skills requirements, potentially by coordinating training programs domestically, combined with targeted skilled migration.

The need to initiate action on the priorities identified in AEMO's Engineering Framework

AEMO's Engineering Framework⁶⁶ describes the initial roadmap to inform preparation of the NEM for operation under six identified operational conditions⁶⁷, including 100% instantaneous penetration of renewable energy by 2025. Today's power system and the incremental trajectory of reform were not designed for the scale and pace of disruptive transformation now underway. The approaches to design, investment decisions, and construction of new assets will need further adaptation to keep pace with the transformation. Decision-makers must urgently align on the priorities, timing and approach for the key efforts identified in the Engineering Framework Initial Roadmap.

7.3 Additional factors that may be considered in future ISPs

Additional factors that may be considered in future ISPs include:

- broader public benefits and risks when selecting the Draft ODP,
- potential for additional investment in NEM's main flow path, and
- securing social licence for DER.

Broader public benefits and risks when selecting the Draft ODP

The AER's Cost Benefit Analysis Guidelines consider only benefits for those who consume, produce and transport electricity in the NEM. They make it clear that consumers should not have to pay for broader public benefits, even if these benefits may be valued by governments on behalf of the wider community (including electricity consumers). These benefits may be significant, and include regional economic growth, jobs growth, the full societal value of emission reductions, and resilience and adaptation to more extreme climate events. In future, the tests applied to determine the ODP might take account of these broader considerations, given the profound nature of the power system's transformation, and the critical importance of electricity to Australia's decarbonised future. Such a review would need to carefully consider to whom these costs and risks are best allocated.

Potential for additional investment in NEM's main flow paths

The Draft ODP includes significant development of VRE in major REZs. These are supported by the large ISP transmission projects identified in this ISP, together with a significant infrastructure within REZs to connect VRE to the network. However, the NEM may require further augmentation of its main transmission flow paths

⁶⁶ See <https://aemo.com.au/initiatives/major-programs/engineering-framework>.

⁶⁷ See <https://aemo.com.au/newsroom/news-updates/engineering-framework-takes-shape>.



or potentially new flow paths to cater for more significant resource developments by the 2050s. This scale of infrastructure development will require coordinated approaches to technical, policy, and community issues, at a level that is unprecedented in the NEM. This Draft ISP has started to study these needs – including alternatives to transmission and the use of alternative technologies such as dedicated HVDC ties – but further work would map out the detailed implications beyond the planning horizon.

Securing social licence for DER

The Draft ISP recognises the significant market reforms achieved since the 2020 ISP to support the technical integration of DER and other modern energy resources. While the Draft ISP assumes all DER generation can be exported into the network, there comes a point beyond which some active management is needed to maintain the reliability and security of the whole system. The emergence of VPPs across the NEM is expected to assist in meeting this challenge and provide further benefits for consumers. Full DER integration requires a step change in engagement across the industry to ensure all consumers, retailers, networks and other market participants orchestrate these resources to optimise net benefits and maintain security and reliability.

A working group consisting of representatives from DNSPs, Energy Networks Australia (ENA), and AEMO has been established. The vision of the group is to collaborate to better understand how developments in the distribution network interact with the transmission network and ultimately support incorporating DNSP planning inputs into the ISP in a way that optimises benefits for consumers. This collaborative working group is planning to produce qualitative outputs for the 2022 ISP with the view to lay the foundation for sharing scenarios and developing joint modelling approaches for the 2024 ISP. Insights gained through this process will also be considered for the 2022 ISP where possible.

8. Consultations relating to the Draft ISP

Consultation with all NEM stakeholders is critical to the ISP and more generally to AEMO's role as the NEM operator and transmission planner. It will continue through and beyond publication of the final 2022 ISP.

This section sets out three major streams of consultation that will start with or continue through publication of the Draft ISP:

- **industry consultation on the Draft ISP itself**, including written submissions on particular questions that AEMO has posed,
- **community and jurisdictional consultation on potential REZs**, and
- **industry consultation on non-network options for the two actionable ISP projects** within New South Wales.

8.1 Consultation on the Draft ISP

AEMO welcomes and encourages written submissions from all stakeholders on the Draft ISP, as well as participation in our specialised and public forums. AEMO acknowledges that the Draft ISP has been published shortly before the summer holiday period, and has extended the consultation timelines accordingly.

Four events are planned for the consultation process, as listed in Table 13 below. Please register for events through the ISP Opportunities for Engagement page on the AEMO website⁶⁸.

Written submissions should be sent in PDF format to ISP@aemo.com.au, and will be responded to if received by 11 February 2022. Guidance on the content of those submissions is given below.

Table 13 Consultation and submission dates for the Draft ISP

Date	Event	Purpose
10 Dec 2021	Draft ISP published	
10 Dec 2021	Public Forum 1	A public briefing on the Draft ISP, with questions encouraged
15 Dec 2021	AEMO Consumer Forum	A tailored briefing for Consumer Forum attendees.
1 Feb 2022	Public Forum 2	More in-depth discussion arising from participant's consideration of the Draft ISP materials.
4 Feb 2022	Consumer Advocate verbal comment	Verbal comments from energy consumer advocates for AEMO to record and consider
11 Feb 2022	Submissions close	Written comments from all stakeholders

Guidance on written submissions

AEMO welcomes and encourages written submissions from all stakeholders on any aspect of the development path outcomes, and in particular answering the following questions:

- Do you consider that the Draft ODP appropriately reflects the consumer risk preferences? Is the reasoning for the Draft ODP clear? Are there any other risks that should be quantified?

⁶⁸ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement>.



- Is the proposed staging for HumeLink and VNI West, with early works as the first stage and then proceeding to implementation subject to conditions, appropriate?
- Is the proposed treatment of Marinus Link as a single actionable ISP project appropriate?
- Do you consider that REZ Design Reports are warranted for the indicated REZs?
- Do you have any feedback on the Addendum to the 2021 *Inputs, Assumptions and Scenarios Report*?

Submissions need not address every question posed and are not limited to them, but should not be related to inputs and assumptions or methodology which have been consulted on separately.

Please identify any parts of your submission that you wish to remain confidential and explain why.

8.2 Preparatory activities and REZ design reports

Substantially expanded community engagement programs are needed to explore the social licence for both generation and transmission investments. Subject to findings in the final 2022 ISP and feedback from stakeholders, AEMO may trigger the following investigations to initiate community consultation and refine the design of future projects in future ISPs:

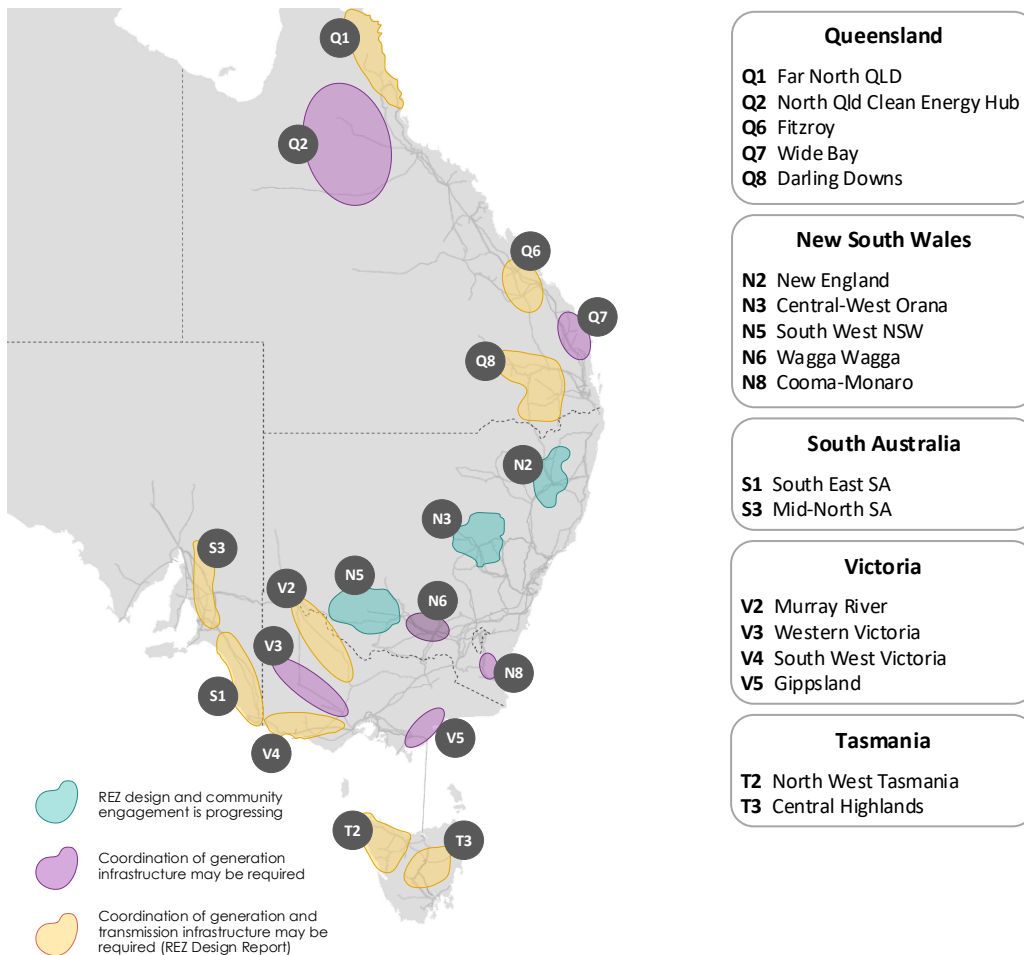
- **Preparatory Activities** can be triggered in the final 2022 ISP for future ISP projects. In 2020, AEMO triggered this work for projects that it considered might become actionable in the 2022 ISP – this included the two new actionable projects and four projects that are not actionable.
- **REZ Design Reports** are part of a new framework that goes beyond the scope of preparatory activities. They explore the technical, economic and social barriers to unlocking REZs. With state government support, these reports can be triggered in the final 2022 ISP for REZs that require coordination of both generation and transmission infrastructure within 12 years, and are reasonably considered by AEMO to have the support of the Minister for the relevant jurisdiction.⁶⁹ This is a significant investigation, led by the local jurisdictional planning body, involving:
 - engineering designs, cost estimates and easement investigations that considers developer and community interest,
 - stages that can be delivered to meet capacity targets in the ISP,
 - identification of barriers to community acceptance and estimates of costs associated with overcoming them, and
 - a draft report and a six-week consultation.
- **Other recommendations** may be helpful to continue to advance REZ development across the NEM. Based on feedback to ISP consultations, AEMO is particularly interested in actions that can be taken to improve the coordination and design of generator connection assets within REZs (that is, the private network that connects generators into the shared network). This might involve collaboration between governments, councils, communities and developers so connection assets are designed in a way that establishes and maintains social licence in the area – for example, requiring connection assets to be undergrounded or shared.

⁶⁹ NER 5.24.1(a)



The following map shows three groupings of REZs where ISP modelling suggests that significant infrastructure may optimally be required by 2034-35. Three REZs in New South Wales are identified as requiring coordination of generation and transmission in the medium term (shaded turquoise), but are not flagged for potential REZ Design Reports because similar activities are already progressing under the New South Wales Government’s Electricity Infrastructure Roadmap.

Figure 32 REZ developments requiring coordination in the medium term



AEMO welcomes feedback on actions that can be taken to support the targeted and successful delivery of these REZs. This might include topics such as:

- 1. How to build community support** – early activities might include environmental and community impact assessments, a review of benefit sharing schemes, uplifted engagement approaches and a review of land-use planning.
- 2. How to coordinate investment decisions** – approaches that can deliver “hub-and-spoke” infrastructure rather than “spaghetti infrastructure” (which can be the result of individual investors acting incrementally).
- 3. How to grow local expertise** – regional jobs, establishing skilled work forces and supporting local industries will be important.



4. **How to expand existing industries and attract new ones** – supporting both local and national economies by providing access to low-cost electricity. This might include energy intensive industries such as manufacturing, aluminium smelting, hydrogen production or datacentres.

8.3 Call for submissions on non-network options

AEMO has issued a **call for submissions on non-network options** for the two new actionable ISP projects:

- New England REZ Transmission Link⁷⁰, and
- Reinforcing Sydney, Newcastle and Wollongong Supply⁷¹.

Submissions to both consultations are requested **by 4 March 2022**. Following the close of consultation, AEMO will review submissions in consultation with EnergyCo and Transgrid. This review will consider whether any proposals meet, or are reasonably likely to meet, the relevant identified need specified in Section 5.3.

The next step in determining a solution to these projects is the RIT-T, which is conducted by Transgrid. Through this process, a cost-benefit assessment is performed and the non-network options that were assessed as likely to meet the identified need must be included. The results of this analysis will be published by Transgrid in a PADR, specifying the draft preferred option. Following that publication, there is a written consultation prior to publication of a Project Assessment Conclusions Report (PACR).

If an alternative regulatory approval path is adopted for these projects, such as the New South Wales Government's *Electricity Infrastructure Investment Act*⁷², AEMO recommends that non-network options be included as credible solutions to meet (or partly meet) the identified need.

⁷⁰ See <https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-new-england-rez-link>.

⁷¹ See <https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-supply-sydney-newcastle-wollongong>.

⁷² At <https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044>.



9. Further analysis in preparation for final 2022 ISP

AEMO will be conducting additional analysis between draft and final 2022 ISP to further validate the analysis and help decision makers and industry better understand:

- the distributional effects of the ODP,
- the impact of changes in marginal loss factors on REZs, and
- climate scenarios and extreme weather case studies.

Distributional effects of the ODP

The distribution of benefits of the ODP is unlikely to be uniform to all consumers in all regions. AEMO identified in the *ISP Methodology* that detailed short-term modelling would be deployed to evaluate these effects, including consumer bill impacts and transmission network charges. This analysis will be conducted for the final ISP, in accordance with the AER's CBA Guidelines⁷³.

Impacts of changes in marginal loss factors on REZ

Network losses occur as power flows through transmission lines and transformers. In the NEM, losses are financially represented through marginal loss factors (MLFs). A renewable generator's revenue is directly scaled by its MLF. Increasing the amount of VRE connected in remote REZs will typically increase losses and decrease local MLFs.

AEMO is aware of the potential impact of REZ design on MLFs and so on the financeability of individual investments. Renewable energy investors may tolerate a relatively low MLF if the project is likely to have low network congestion or high resource quality. In the final ISP, AEMO will aim to provide information on risks relating to MLFs alongside other key REZ investment metrics such as network congestion and resource quality and consider whether future changes in MLFs are likely to materially influence the choice of REZ developments in the ODP.

Climate scenarios and extreme weather case studies

Australian energy consumers have historically enjoyed the benefits of resilient energy systems, but a renewed focus on resilience is needed to maintain these benefits as the climate changes and the energy system transforms. These two shifts, in combination, have the potential to significantly decrease energy system resilience and increase the likelihood of undesirable outcomes. The vulnerabilities, in particular extreme weather events, are recognised as material risks to individual assets and the integrated energy system.

Where possible, AEMO has considered these vulnerabilities in the Draft ODP, aiming to maximise energy system resilience through good system planning and design. Despite these efforts, limitations in climate, energy system and cost benefit modelling mean that many of these risks are excluded from primary ODP decision-making.

⁷³ At <https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%202025%20August%202020.pdf>.



To ensure these risks are fully understood, AEMO will develop a small selection of compound extreme event case studies for the final 2022 ISP. Building on AEMO's work with the Bureau of Meteorology and CSIRO⁷⁴, these case studies will demonstrate energy system and societal outcomes that could plausibly occur in response to events such as:

- **coincident heatwaves and bushfires**, impacting consumer demand and power system capability,
- **extreme wind or solar droughts**, possibly resulting in extremely low energy availability,
- **extreme storm or cyclone risks**, that have the potential to damage generation and transmission infrastructure, and
- **other multiple or non-credible contingencies**, impacting key inter- or intra-regional transmission availability.

These case studies will demonstrate whether some CDPs are more resilient to extreme weather events than others, and identify risk mitigation strategies aligned with AEMO's Engineering Framework⁷⁵. Where opportunities are identified through these case studies that enhance energy system resilience in the long-term interests of consumers, AEMO may consider these opportunities within, or in addition to the Draft ODP.

⁷⁴ See <https://www.climatechangeinaustralia.gov.au/en/projects/esci/esci-case-studies/case-study-extremes/>.

⁷⁵ See <https://aemo.com.au/en/initiatives/major-programs/engineering-framework>.

Supporting documents

Draft ISP Appendices and web assets are available on AEMO's website at <https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation>.

Draft ISP Appendices

- Appendix 1 Stakeholder engagement see Section 2
- Appendix 2 ISP development opportunities see Section 3 and Section 4
- Appendix 3 Renewable energy zones see Section 3.3
- Appendix 4 System operability see Section 4
- Appendix 5 Network investments see Section 5
- Appendix 6 Cost benefit analysis see Section 6
- Appendix 7 Power system security see Section 4.3

Draft ISP web assets

- Chart data
- Generation outlook

IASR

Information relating to inputs, assumptions and scenarios is available at: <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

- 2021 Inputs, Assumptions and Scenarios Report (IASR)
- IASR Addendum
- IASR Workbook

Non-network consultations

AEMO has issued a call for submissions on non-network options for the two new actionable ISP projects:

- New England REZ Transmission Link⁷⁶, and
- Reinforcing Sydney, Newcastle and Wollongong Supply⁷⁷.

⁷⁶ See <https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-new-england-rez-link>.

⁷⁷ See <https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-supply-sydney-newcastle-wollongong>.